AC Transmission Line Model Parameter Validation

A report to the
Line Protection Subcommittee of the
Power System Relay Committee of
the IEEE Power & Energy Society

Prepared by working group D6
Sept 2014

Abstract

This report discusses the uses of AC transmission line modeling used for relaying. The report also covers the important issues and problems that affect the model parameters and discusses the various methodologies for validating the accuracy of the model.

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1 Introduction

In the virtual tool box of any relay engineering works, the most fundamental and popular tool would be the fault analysis program. This tool is used to determine the proper settings for relay coordination; it is used to help locate faults out in the electrical transmission system; and it is used to evaluate the adequacy of the settings and the review of relay applications/coordination following a fault event. The same data is also generally applied for power flow models, stability models, SCADA models, etc. Because of the widespread use of this data, it is important that the system parameters be modeled accurately. Many of the data parameters such as those used for transformers and generators are based on testing and are accepted as long as errors are not introduced during programming of the model. Transmission line parameters, however, are normally based on calculated values. Therefore, these parameters require the closest scrutiny for program accuracy. Especially, the zero sequence parameters are usually found to be inaccurate. The inaccuracy of these parameters can be traced to common assumptions used for modeling. These include the selection of earth resistivity, temperature, assumed line transposition, line homogeneity, and simplified mutual effects. Most of these are difficult to apply in a precise manner and are applied to the calculations empirically.

Due to too many variables in parameters as listed above, the accuracy is difficult to quantify. In practice, the model is validated to performance. The result of short-circuit program accuracy is generally acceptable and adequate for relay engineering works. This report will discuss the various parameters that affect the accuracy of the model. In addition, the various methods comparing the models to the actual electrical system will be presented that show the model accuracy is adequate for relay engineering work. Newer methods which allow for direct measurement of the parameters are also discussed. Throughout it is important to understand that the model should be constantly under review and refinement. Significant adjustments to parameters must also be widely distributed to other groups who use the same data.

2 Uses of Line Modeling

Line modeling is used for a variety of power system analysis and protective relay setting applications. The model type and detail used to represent the transmission line impedances depends on the type of analysis performed and the type of relay settings required. In general, for the purpose of setting protective relays and analyzing protective relay performance, relatively simple fundamental frequency sequence component impedance models are used. These impedance parameters can be calculated by hand, or through the use of readily available computer programs using physical conductor size, material, and spacing information. Information about shield conductors and ground resistivity are also required for complete modeling.

2.1 Short Circuit Analysis

Short circuit analysis is used to calculate the phase and sequence currents and voltages measured by protective relays for simulated faults at various locations internal and external to the relay's desired zone of protection. These voltage and current quantities are used to determine the relay's sensitivity and expected operating times for faults at various locations and with various power system configuration contingencies. Short circuit analysis is also used to establish the minimum fault current interrupting capacity of circuit breakers and the fault closing ratings of breakers and switches required for an application.

Lumped series impedance parameters are used for short circuit analysis. Shunt admittances are generally ignored, first of all to simplify the short circuit calculations, and secondly because the effect of shunt impedance parameters is generally negligible under the reduced voltage and high current conditions during a fault.

Short circuit calculations are generally made using sequence component analysis to simplify the calculation of unbalanced three-phase systems into balanced single phase sequence networks. Positive-, negative-, and zero-sequence impedances are required to perform the complete array of three-phase, phase-to-phase, phase-to-phase-to-ground, and phase-to-ground fault analysis. Sequence quantities are computed, then used directly, or converted to phase quantities for protective relay analysis and settings, and for circuit breaker and switch rating analysis.

2.2 Load Flow and Stability

Load flow and power system transient and dynamic stability analysis are sometimes required to determine protective relay settings and analyze performance under stressed system conditions following a cleared fault or during a significant power system contingency that causes maximum power or current flow on the line associated with the protective relay. Only positive-sequence line impedance is required for load flow analysis because the power system phases remain balanced during these simulated conditions. Lumped series and shunt admittances are typically included for this analysis because these conditions occur at or near full system voltage. Stability analysis is also performed during unbalanced conditions, which may require knowledge of sequence components. For example, according to Northeast Power Coordinating Council (NPCC) "Transmission Design/Operating Criteria", stability of the bulk power system shall be maintained when subjected to "A permanent phase to ground fault on any transmission circuit, transformer, or bus section with delayed fault clearing" which is definitely an unbalanced condition that may require knowledge of the line negative and zero sequence impedances in addition to the positive sequence impedance.

2.3 Relay Settings and Data

Transmission line impedances are commonly used to set phase and ground distance relay reach settings and maximum torque angles. Positive- and zero-sequence lumped series impedances are used to determine settings for under-reaching and overreaching distance elements associated with step-distance protection schemes or directional comparison schemes.

Phase and ground distance element reach settings are generally set in terms of positive-sequence line impedance. The operation of the ground distance elements are compensated for the different "loop" impedance for ground fault conditions by a residual or zero-sequence compensation factor that is computed using positive- and zero-sequence line impedance information. Shunt line data is used to compensate for line capacitance in line current differential relay settings.

Lumped series line impedances are also used to set fault location parameters in modern microprocessor based relays, although distributed line impedance data may be used where different line construction, conductor size, and/or shielding are used. Lumped series line impedances are also used to set directional element limits for relays using impedance based directional elements.

Current values from short circuit calculations are used to set overcurrent element pickup settings for distance and directional element current supervision elements and to set overcurrent element pickup and time delay settings for overcurrent relay elements.

2.4 Relay Testing

Transmission line impedance data is commonly used to develop test data to verify relay element performance and to verify proper relay distance element reach settings. Test currents and voltages can be developed for various fault types using simplified calculation techniques. Test set vendors typically include software or calculation techniques with their test set software or documentation to calculate relay test quantities based on line impedance data.

Testing more sophisticated microprocessor based distance relays may require source impedance data to create proper test quantities. Strong, moderate, and weak source impedances can be estimated by applying a source-to-line impedance ratio, otherwise referred to as SIR. The higher the SIR, the weaker the source (larger the source impedance) when compared with the transmission line impedance.

2.5 Fault Location

A common technique for calculating transmission line fault location uses fault current and voltage measured at the transmission line terminal to calculate apparent fault impedance. This calculated fault impedance is scaled against known line impedance and line length parameters to determine the distance to the fault from the line terminal. This technique relies on accurate line data, typically positive- and zero- sequence line impedance and an associated line length, to provide a distance-to-fault location following a fault.

Quickly finding a fault can significantly reduce the overall time to restore the line to service following a permanent transmission line fault. It is also useful in locating damaged and degraded insulation or trees that have grown too close to transmission lines, causing temporary or intermittent faults.

Many modern microprocessor based relays are able to provide transmission line fault location as part of their post fault event reporting function. This information is typically available from the relay within seconds after the fault, making it a valuable tool for operating and maintenance personnel.

Impedance based fault location has also proven helpful in corroborating line impedance data when the fault location is known. If the calculated fault location differs from the actual fault location, the line impedance or line length data used to calculate the fault location may be in error. Voltage and current fault data from both terminals of a two terminal line can often be used to develop a more accurate calculated fault location Several transmission line fault locating techniques are available. The IEEE Standard C37.114, "IEEE Guide for Determining Fault Location on AC Transmission and Distribution Lines" provides an excellent reference for more information about fault locating techniques.

3 System Modeling Issues

Many of the parameters needed to calculate the impedance parameters are variable. It would be impossible to create a short circuit model that accurately encompassed every detail and if it were possible the model would be constantly changing. The solution is to assume average values for many of these variables to simplify the effort. It is important to understand how these assumptions can affect the model.

3.1 Effect of Modeling Assumptions

It is important for the engineer to understand the use of transmission line models and how modeling assumptions affect the accuracy of the model for the particular study. The transmission lines are mainly classified as short, medium or long lines. The classification is based upon the accuracy of the model and simplicity. This ranges between short line model being quite simple to the long line model being somewhat complex. The Pi model is often used as a model of a transmission line. However various forms which results from assumptions of the Pi model can add complexity to the model. A lumped sum nominal Pi circuit is shown below and is often used for medium length transmission lines. The model shows the series impedance with the shunt admittances shown equally split on each side of the line series impedance. For short lines and for many fault studies, the shunt admittances are ignored. For long lines, the exact-Pi model could be used. The exact-Pi model is the most accurate model for a single frequency because it includes the hyperbolic corrections with no approximations involved.

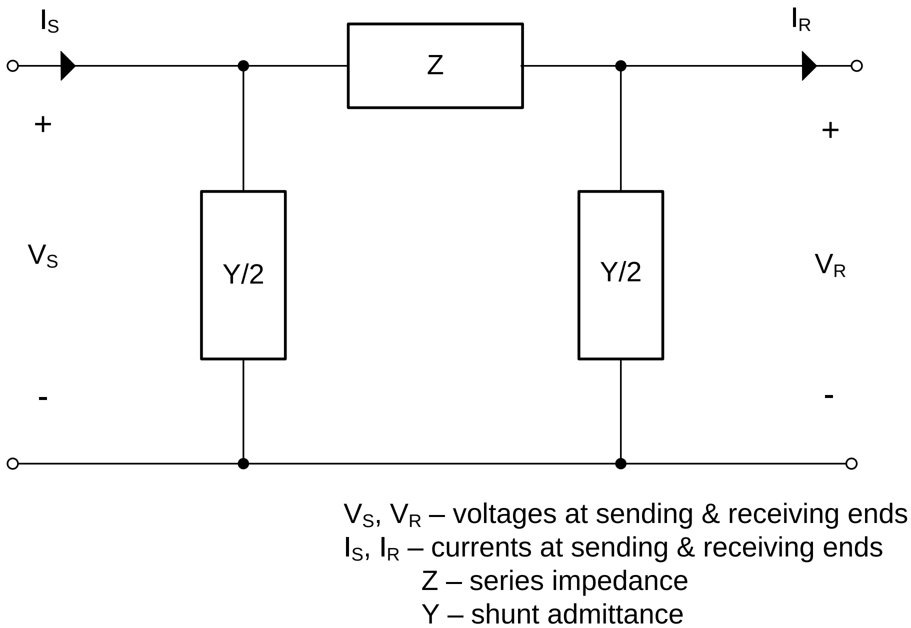

Fig 3.1 Lumped Sum Nominal Pi circuit

For instance, the error for the impedance parameter calculations for a 200km line using a lumped sum nominal-Pi model is about 1%. However if a similar model is used for a 400km line, the error is over 4%. Longer lines and lines of higher voltage would have even larger errors.

Pi models make assumptions regarding transpositions which prove to be acceptable for short and medium lines. However, long lines can be modeled using a number of short nominal-Pi circuits in which the line transpositions are taken into account. **[1]**

3.2 Overhead Line Parameters

There are four parameters that affect the ability of a transmission line to function as part of a power system, these are: resistance (R), inductance (L), capacitance (C) and the conductance (G). Only the resistance, inductance and capacitance will be considered here. For the uses described in Section 2, the conductance can be ignored. It represents the component of current that is in phase with the applied voltage when the line is energized but open-ended. This leakage current creates resistive losses through the insulating medium which are nearly always negligible. These parameters will be discussed briefly in this section. The inductance and capacitance parameters are discussed in more detail in Appendix A1.

Resistance:

The resistance of a uniform conductor is directly proportional to its length and inversely proportional to its cross-sectional area. Resistance is dependent upon the resistivity of the conductor material. Thus,

$$R = \rho \frac{l}{A} \qquad [3.2.1]$$

where R = conductor resistance in ohms
ρ = resistivity of conductor material in ohm-meters
l = conductor length in meters
A = conductor cross-sectional area in square meters

Because of skin effect, an alternating current will have a higher current density near the surface of the conductor and the resistance to alternating current, even at fundamental power frequency, will be greater than that measured using a direct current. Because this effect is more pronounced at higher frequencies, the effective resistance of a conductor to higher harmonic currents will be greater than its resistance at fundamental frequency.

Conductor resistance is also greatly affected by temperature. If verification of conductor resistance is performed at a conductor temperature different from that at which the standard conductor characteristics are given (usually 20°C) the resistance can be corrected by use of the formula,

$$\frac{R_{t2}}{R_{t1}} = \frac{T_0+t_2}{T_0+t_1} \qquad [3.2.2]$$

where R_{t2} = resistance at desired temperature
R_{t1} = resistance at known temperature
t_1, t_2 = temperatures in degrees C
T_0 = temperature constant for conductor material (241.0 °C for copper with 97.5% conductivity and 224.1 °C for aluminum with 62% conductivity).

Conductor resistance variation with temperature can be significant. For example an ACSR conductor operated in winter conditions at 10°C will experience an increase in resistance of approximately 40% when going from an unloaded condition to a heavy load condition where conductor temperature is 100°C. **[2]**

Inductance:

The self-inductance for a conductor is dependent on its own geometry, generally defined by its GMR (Geometric Mean Radius), its distance to earth, and earth's soil resistivity ρ_e. The configuration of a transmission line does not affect the self- inductance of a conductor.

The positive-sequence inductance, (composed of self and mutual inductance) for a transposed transmission line can be expressed generally as follows:

$L= \mu_o/2\pi \ln (D/r)$ **[18]** [3.2.3]

where μ_o = permeability of free space
D = distance between conductors
r = radius of conductor

The zero-sequence inductance is typically between 2 and 3.5 times the positive-sequence inductance for overhead lines.

Mutual inductance is largely dependent on the influence of other nearby conductors. The mutual impedance between two conductors is directly related to the distance between the two conductors. Therefore the configuration of the transmission line directly impacts the inductance of a transmission line.

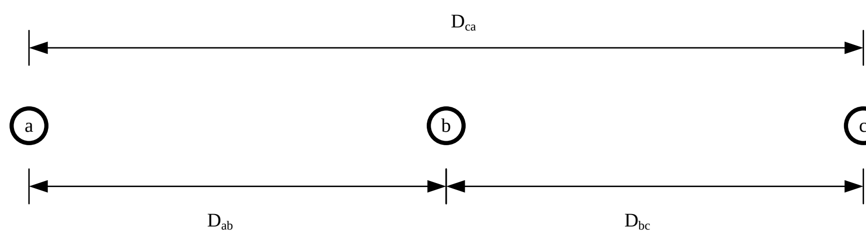

Fig 3.2.1 Sketch of a single conductor 3 phase transmission line without ground wire

For non-segmented overhead ground wires, each ground wire can be treated as an additional conductor. The mutual impedance between each phase conductor and the ground conductor is then calculated as shown in figure 3.2.2.

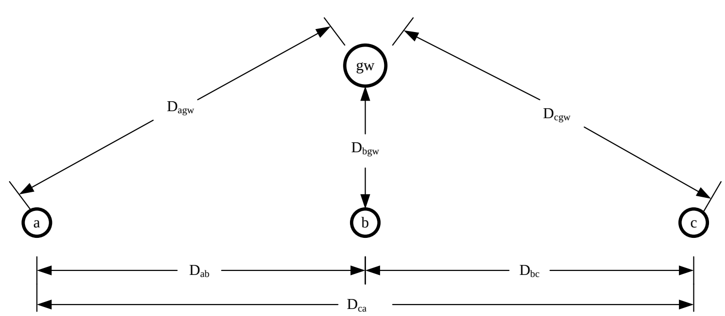

Fig 3.2.2 Sketch of a single wire 3 phase transmission line with a ground wire

Capacitance:

The calculation of the capacitance of a line is based upon the relative position of the conductors, the height, and the presence of a ground wire. Overhead transmission line models are usually divided into three categories, with the length of the transmission line determining which model to be used. When trying to determine the line parameters of a short transmission line (50 miles or less), the shunt admittances can be neglected without much loss of accuracy (< 5%). For transmission lines longer than 50 miles, the shunt admittance can no longer be ignored when trying to determine the line parameters. However, depending on the purpose for which the parameters are required, these may be ignored. For example, if the sole purpose of the study is to determine the fault currents associated with faults on a particular line, then the shunt parameters can be ignored. The same cannot be said if the goal is to determine the sensitivity of a line current differential relay etc.

For cable models the shunt admittance is an order of magnitude greater than that of the equivalent overhead line and therefore has to be taken into consideration whenever line parameters are determined. (see section 3.9)

3.3 Transpositions

A transposition is a common technique to minimize overhead line unbalance caused by unsymmetrical placement of transmission line conductors above the ground and to each other. In practice, lines are often not transposed due to several factors including the cost. At times, the transposition is interrupted by the insertion of a new substation on the line. Unbalance leads to generation of negative- and zero-sequence voltages and currents, which affect performance of many components of the power system including protective relays. To reduce the effect of unsymmetrical spacing of conductors, the conductors are transposed so that each conductor occupies successively same positions as the other two conductors in two successive line sections. For three such transposed sections, the total voltage drop for each conductor is the same thus eliminating negative- and zero-sequence voltages and currents. Double circuit lines create more challenges because the effect of mutual inductance is not entirely eliminated by the transposition.

The value of unbalance depends on several factors, such as geometry of the conductors and ground wires on the tower, spacing, capacitance to ground of conductors etc. The unbalance is characterized by the unbalance factor, which can vary significantly. This may affect the results of a protective relay study if not accounted for.

3.4 Effects of Non-Homogeneous Lines

For typical transmission lines, the impedance is not a linear function of distance. All transmission lines have, to varying degrees, some non-homogeneity; that is, the impedance per unit length is not constant over the length of the line. This can be a source of error in distance relay and fault location applications.

Sources of non-homogeneity in overhead lines include:

- Substation entrance/exit structures may differ from line structures
- Angle structures may be of a different design than tangent structures
- River/highway crossings may have longer spans, wider spacing, and larger conductors
- Regulatory agencies may require compact or low profile tower designs in sensitive areas
- On upgrade or reconductoring projects, it may not be necessary or feasible to rebuild the entire line
- Interim or temporary line designs may be used during construction

- Tower spacing and effective conductor sag will differ in hilly or uneven terrain
- Soil characteristics and thus ground resistivity may vary along line length
- Mutual impedances may be present over portions of the line

Transmission line constants programs generally allow the line impedance to be calculated in segments, with the ability to sum the characteristics of individual segments into a terminal-to-terminal total. The individual using these programs must exercise judgment regarding which identifiable line characteristic changes are significant enough to warrant calculation as a separate line segment. Typically, single span line sections, such as river and highway crossings are ignored if they are not a significant fraction of the entire line length. In addition, the line sections that transition from one line construction type to another are frequently ignored, since they must be modeled with conventional transmission line constants programs as separate segments because of the variable geometry.

Distance relays and fault locating algorithms generally assume that the line is homogeneous from terminal to terminal. The total line impedance and line length are entered as setting parameters. This assumption can introduce error in the distance-to-fault calculation if the line has significant non-homogeneity. Figure 3.4 gives an example of a transmission line having three construction types over its length from Terminal A to Terminal B. The error in distance is most significant near the transition points between line construction types. An impedance table or graph can be used to correct the distance calculation for this error.

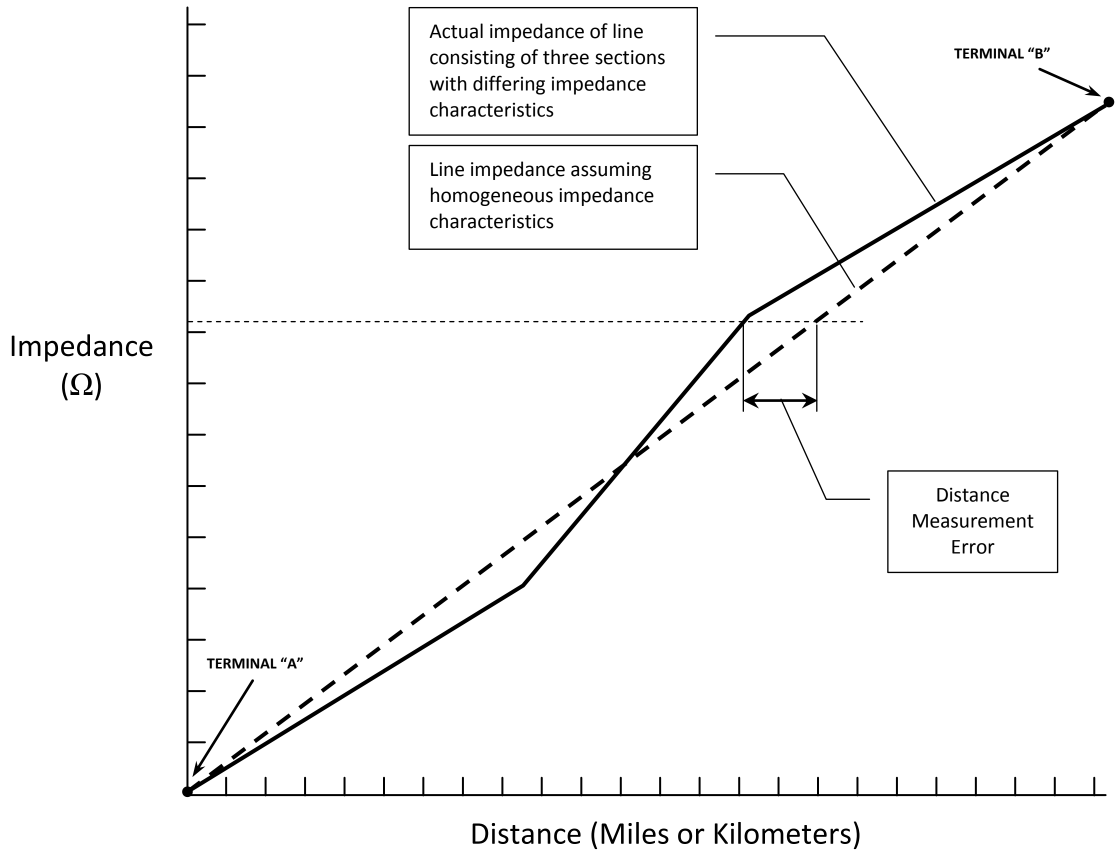

Fig 3.4 Sample Non-homogeneous line

3.5 Segmented and Insulated Shield Wires

Segmented or insulated shield wires provide a discontinuity in the ground paths, thus impacting the zero sequence networks. The first question is how this type of shield wire is treated in the zero-sequence line impedance calculation.

In the EMTP theory book by Hermann Dommel, the ground wires are ignored when calculating the series impedance matrix but are taken into account for the shunt impedance matrix. Thus, for lines that have segmented ground wires, the ground wires do not affect the inductance of the line. The basis Dommel gives for this reasoning is that the ground wires do not carry any significant fundamental current because the wave length of the fundamental frequency is much larger than the segmented span. However, this is not true for transients such as lightning strikes. Some utilities follow the practice of not including segmented/insulated shield wires in the series inductance calculations for the line constants. Also, line constants programs typically contain the option to select segmented versus continuous shield wires. **[14]**

In the paper by Gerez and Balakrishnan entitled "Zero-sequence Impedance of Overhead Transmission Lines with Discontinuous Ground Wire", the authors give a method to calculate the zero-sequence impedance of a transmission line having ground wires that are not continuous or are not connected to the station grounds at the end of the line. The calculated values are compared with the measured zero-sequence impedance of a line. The authors observe that for transmission lines having discontinuous ground wires, the actual zero-sequence impedance is different from the zero-sequence impedance of the line calculated with the classical methods and considering either no ground wire or continuous ground wire. This difference is significant if the ground wire is of ACSR conductor. The method given for calculating the zero-sequence impedance of a transmission line with discontinuous ground wire gives more accurate results, which are close to the measured values. While the paper does not directly address segmented/insulated ground wires, it does discuss the implications of missing shield spans and the effect of not connecting shields to the substation ground grid. **[3]**

3.6 Earth Resistivity

A basic understanding of the factors that influence earth resistivity is required for the protection engineer to accurately model a given system or line.

Variation in Soils

The first and foremost factor affecting resistivity is the soil material and its physical conditions, like moisture content and temperature. For example, soil with quartz grains have a thermal resistivity of 11ºC-cm/W, water is 165, organic material can be from 400 wet to 700 dry, and air is 4000. Thus, it is generally concluded that soil with the lowest thermal resistivity has a maximum amount of soil grains and water, while having a minimum amount of air. Simply stated, the resistivity of sandy dry soil, such as in Nevada, will be very different from Illinois' silty-clay-organic soil. Also, river-bottom soil will be vastly different than the soil on top of a ridge, or bluff within the same general area.

Soil resistivity is measured in ohm-m. Variations in soil compositions are as vast as the ranges of published soil resistivity. Generally, clay-silty-loam soils have much lower values (e.g., 40 ohm-m average per US bureau of standards report 108) than sandy soils (e.g., 940 ohm-m average per the same data source). The very nature of the soil and the factors that determine resistivity equate to a dynamically changing value of resistivity. The transmission line in Nevada will have a different local resistivity during a major precipitation event, than during a drought.

To emphasize the affect that resistivity can have on a given line, a 138 kV line was arbitrarily chosen within a line constant program. The line was modeled at 100 miles long with 10 ohm-m and 100 ohm-m resistivity value. All other line parameters were held constant. The difference in zero-sequence impedance was over 10%. Note that this was utilized for demonstration purposes and additional cases may have different results.

The important point to the system protection engineer is that the physical characteristics of a transmission line must be known to accurately model it, resistivity notwithstanding. If certain factors are not addressed the model will be inaccurate, perhaps at the most inopportune time. For example, the season of the year, like when the soil is saturated, or if a company that encompasses different geological areas uses a "standard" resistivity value, the model accuracy can be compromised.

A couple of good ways to check against the system model including resistivity are right-of-way measurements and fault data review. Both topics are also covered in this report. **[4-7]**

3.7 Other Conducting Ground Paths

Line constant programs typically contain configurations that share multiple conductors on the same pole structure and the same right-of-way. What may not be addressed are other conductors that follow the same path. Examples include railroad track, railroad communication and control lines, pipelines, etc. These other conductors can be buried or be on pole structures that run parallel to the power lines. The difficulty is in modeling these other conductors.

While railroad control lines look like an adjacent line, grounding information or pole structure characteristics are not readily available. For the other structures the question becomes how to approximate their properties within the confines of the line constant programs.

Regardless of the methods used for approximating the zero sequence networks for situations that have these other conductors, the fault analysis studies of such areas would benefit from revising the model.

3.8 Mutual Coupling Effects

It is important to consider the effects of mutual coupling between transmission lines. As the different phases of a transmission line influence each other's voltage drop, the phases of a line sharing the same right of way or the same tower will also influence the voltage drop of the other line.

Assume a transmission system as shown in Fig 3.8.1 where two transmission lines are a distance Dd from each other.

Fig 3.8.1 Simple sketch showing conductors of a two transmission line system

The mutual coupling between all the conductors and the A-phase of circuit 1 are shown in Fig 3.8.2

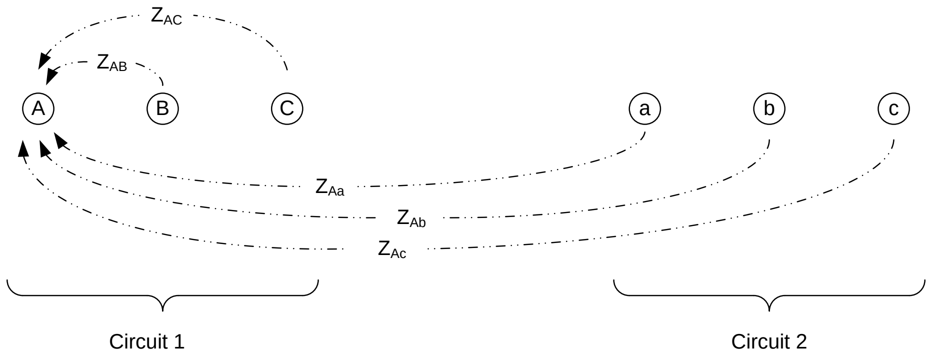

Fig 3.8.2 Mutual Coupling Between Circuit 1 Phase A and Circuit 2 Phases

Section 3.2, capacitance, discusses the capacitance between two conductors from a common circuit. To calculate the mutual impedance between two conductors from two different circuits is done in exactly the same manner.

Now considering the voltage drop for a section of circuit 1, A-phase yields the following relationship:

$$V_A = Z_{AA}I_A + Z_{AB}I_B + Z_{AC}I_C + Z_{Aa}I_a + Z_{Ab}I_b + Z_{Ac}I_c \qquad [3.8.1]$$

Where:

Z_{AA} = Self impedance of conductor A (circuit 1)
Z_{AB} = Mutual impedance between conductor A and B (circuit 1)
Z_{AC} = Mutual impedance between conductor A and C (circuit 1)
Z_{Aa} = Mutual impedance between conductor A (circuit 1) and conductor a (circuit 2)
Z_{Ab} = Mutual impedance between conductor A (circuit 1) and conductor b (circuit 2)
Z_{Ac} = Mutual impedance between conductor A (circuit 1) and conductor c (circuit 2)

For simplicity assume that mutual impedance between the phases of circuit 1 are equal ($Z_{AB} = Z_{AC} = Z_M$) and lets also assume that the distance "Dd" is large enough that the mutual impedance between the conductors of circuit two are also approximately equal ($Z_{Aa} \cong Z_{Ab} \cong Z_{Ac} \rightarrow Z_{mp}$). Using these assumptions equation 3.8.1 can now be rewritten as follows:

$$V_A = Z_{AA}I_A + Z_M(I_B + I_C) + Z_{mp}(I_a + I_b + I_c) \qquad [3.8.2]$$

The second half of equation [3.7.2] shows that for all positive and negative sequence currents that flow in circuit 2 the effective mutual coupling is zero since (Ia + Ib + Ic) = 0 However this is not true if the circuit 2 contains zero sequence current, (Ia + Ib + Ic) ≠ 0 therefore the mutual coupling between circuit 1 and circuit 2 is mainly due to zero sequence current. "Z_{mp}" is the zero sequence mutual coupling between circuit 1 and 2, and can be computed by taking the average mutual impedance between circuit 1 and 2 [3.6.3].

$$Z_{mp} = (Z_{Aa} + Z_{Ab} + Z_{Ac} + Z_{Ba} + Z_{Bb} + Z_{Bc} + Z_{Ca} + Z_{Cb} + Z_{Cc}) \div 9 \qquad [3.8.3]$$

In reality there is some mutual coupling between the circuits due to positive and negative sequence current but in general these are less than 5% and for all practical purposes can be ignored. This small coupling is due to the mutual impedances between the conductors of circuit 1 and circuit 2 not being exactly equal to one another.

3.9 Special Concerns with Modeling Cable

Underground cable electrical characteristics differ significantly from overhead transmission lines. Underground cables exhibit a much lower series inductance and a much higher shunt capacitance. The series inductance of cable circuits is typically 30–50% lower than overhead lines because of close spacing of cable conductors. The difference in the cable shunt capacitance is even more pronounced. Cable capacitance can be 30-40 times higher than the capacitance of overhead lines. The closer proximity of the cable conductor to ground potential, surrounded by the cable grounded sheath, and the dielectric constant of the insulation, which is several times that of air, cause this difference.

Electrical Characteristics of Underground Cables

Calculating the series sequence impedances of underground cables is not as simple as calculating the series sequence impedance of overhead lines. In underground cables there is magnetic coupling among the phase currents and in some cases among currents in the cable sheaths, depending on the type of sheath bonding. Calculating the series sequence impedances, in general, requires that a set of simultaneous equations be solved for the voltage drop in each of the current carrying conductors, including the sheaths. Fortunately, calculating the series sequence impedances of single-conductor cables, excluding pipe-type cables, is much easier, using approximate formulas. **[13]**

Table 3.9 lists the series sequence impedances in Ω/km and the charging current in A/km for two 230 kV cables and an overhead transmission line. **[9]**

Circuit Type	Z1 and Z2 in Ω/km	Z0 in Ω/km	Charging Current in A/km
230-kV SC Cable	0.039 + j 0.127	0.172 + j 0.084	9.37
230-kV HPOF Pipe-Type Cable	0.034 + j 0.152	0.449 + j 0. 398 at 5000 A	18.00
230-kV OH line	0.060 + j 0.472	0.230 + j 1.590	0.47

Table 3.9 Typical Series Impedance and Charging Current Data

The zero-sequence series impedance of single-conductor cables varies significantly with the resistance of the sheath, the soil electrical resistivity “ρ“ and the presence of other conductors in the ground, such as ground continuity conductors, water pipes, and adjacent cables. Underground cables have sheaths that are grounded in one or in several locations along the cable length. During unbalanced faults, the ground fault current can return through the sheath only, through the ground only, through the sheath and the ground in parallel, or through the ground and the sheath of adjacent cables.

The presence of water pipes, gas pipes, railways, and other parallel cables makes the zero-sequence current return path rather complex. All of the above factors often make the zero-sequence impedance calculations difficult to determine precisely, and in many cases questionable, even with the use of computer modeling simulations. Therefore, many utilities perform field tests during cable commissioning to measure the zero-sequence impedance value of single-conductor cables.

Pipe-type cables are a common type of transmission cable found in electric utility systems in the United States. The impedance calculation methods for pipe-type cables is the least refined. The nonlinear permeability and losses in the steel pipe make it very difficult to calculate the flux linkage within the wall of the pipe and external to the pipe. Electromagnetic effects in the steel pipe make determining zero-sequence impedance for pipe-type cables more complex than for single-conductor cables. This compounds the normal issues of ground-current return paths mentioned previously. Another problem with calculating the zero-sequence impedance of pipe-type cables is that the zero-sequence impedance varies with the effective permeability of the steel pipe, and the permeability of the steel pipe varies with the magnitude of the zero-sequence current. Under unbalanced fault conditions, a pipe made of magnetic material such as steel can be driven into saturation. Since the pipe forms part of the return path for ground currents, changes in its effective resistance and reactance alter the cable zero-sequence impedance. The nonlinear magnetic characteristics of the steel pipe cause the equations that relate the series voltage drop along the pipe-type cable to the current flowing in each of the conductors to become nonlinear simultaneous equations.

The most common method for calculating the sequence impedances of a pipe-type cable is based on an analysis of pipe-type cable impedances performed by Neher in 1964 **[10]**. Neher derived empirical formulas based on laboratory test measurements on short-sections of pipe-type cables. Neher's formulas are of questionable accuracy, especially for the zero-sequence impedance, but there are no other methods currently available that provide more accurate results. Reference **[11]** presents an improved method for calculating the zero-sequence impedance of pipe-type cables using a finite element solution technique, but this method has not been used extensively yet by the industry.

Most utilities obtain the sequence impedances for pipe-type cables from cable manufacturers, including the variation of the zero-sequence impedance as a function of ground current magnitude. Fig. 3.9.1 illustrates the variation of the zero-sequence impedance with ground fault current for a 230 kV, 3,500 kcmil HPOF pipe-type cable in a 10.75-inch pipe.

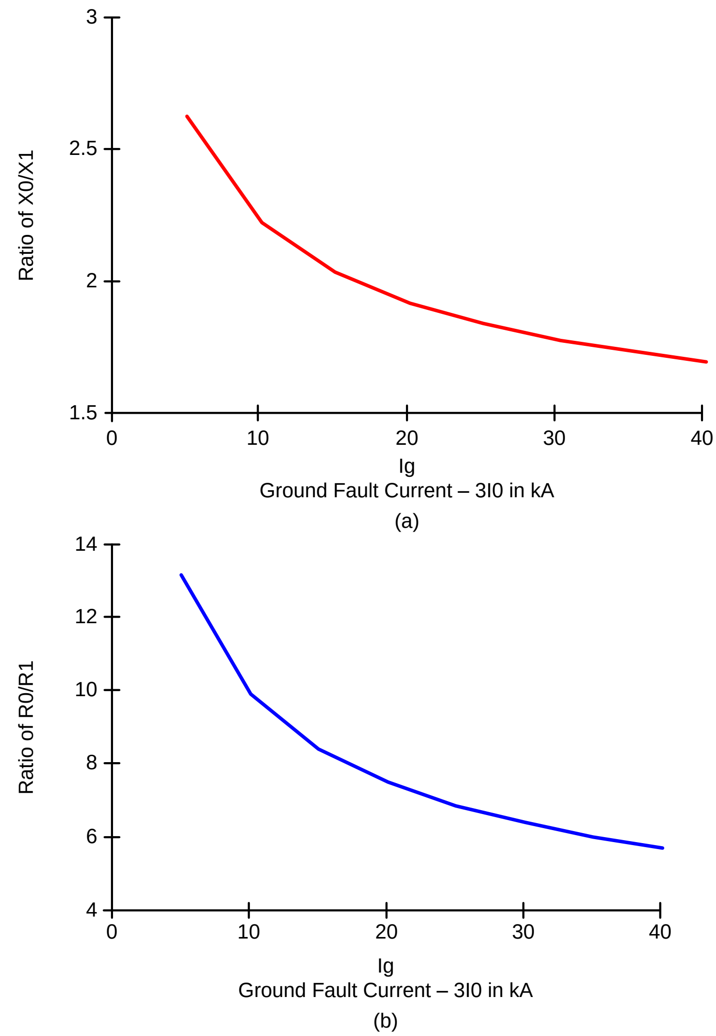

Fig 3.9.1 Variation of zero-sequence resistance and reactance in a 230 kV pipe-type cable as a function of ground fault current

The variation of the zero-sequence impedance shown in Fig. 3.9.1 is for currents greater than 5 kA and is applicable for fault current calculations. The nonlinearity of the zero-sequence impedance for currents below 5 kA is more pronounced. Reference 11 provides more detailed data about the variation of zero-sequence impedance of pipe-type cables for ground currents below 5 kA. A sample calculation of the zero sequence impedance matrix for an underground cable can be found in Appendix A2.

Short-circuit programs cannot handle nonlinearities, such as the variation that steel pipe saturation causes in zero-sequence impedance of pipe-type cables. For that reason, short-circuit studies near pipe-type cables will probably require an iterative process for better accuracy **[12]**. Using a linear short-circuit model and a few discrete zero-sequence impedance data for different levels of pipe saturation (i.e., low [unsaturated], medium, and high currents [saturated]) with a couple of iterations will be adequate.
[9-13]

3.10 Six Wire Lines

Six wire lines as defined in this report are single circuit three phase lines with two non-bundled conductors per phase. The separation of the two wires making up each phase is typically greater than distance between the phases. These single circuit lines look like double circuit lines.

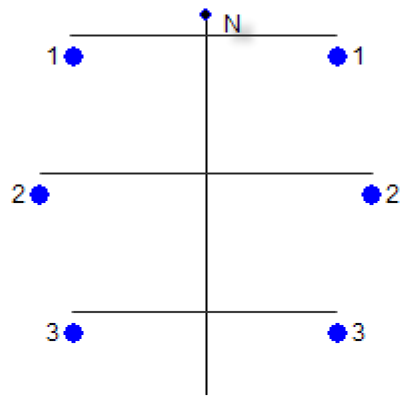

Fig 3.10 Typical six wire circuit

Where bundled conductors can be considered continuously connected, the two wires per phase on six wire lines may only be connected at the beginning and ending points, and possibly, but not necessarily at tap points. If the two wires per phase are not connected at tap points, then the only way to model six wire lines is as two separate circuits. If, however, the two wires per phase are connected at every tap point, then the six wires can be reasonably represented with one set of impedances.

Operating double-circuit lines as a single circuit (six wire lines) may cause severe underreaching of protective relays and consequently inability to clear internal line faults **[19]**. The reference provides guidelines on the minimum amount of jumpers that should be installed between the same phase conductors (taps) along the line to minimize phase distance element under reaching.

4 Model Verification Methods

System computer modeling is normally based on static information. For fault activity and locating, modeling is based on minimum available impedance and maximum generation mix in order to calculate the maximum fault current anticipated. Engineers performing relay coordination will use operating experience to determine practical relay settings that will protect the system for the majority of time. Unlike the static model, the power system grid configuration is a function of numerous external variables that will create ever changing values of transmission line impedance.

In previous sections, it can be observed that conductor resistance changes with ambient temperature, wind velocity, and current density and can vary over the length of the line. The conductor resistance increases with skin effect but can be held constant for fault studies because the power system operating frequency is normally constant at 50Hz or 60Hz. The rated load currents flowing in the conductor results in losses that manifest as conductor heating which causes thermal expansion in the length of the line.

Technology has strived to develop instrumentation to measure line impedance in a quiescent state in order to compare measured values to the model. Voltage, current, and oscillographic information can be collected on an energized line to compare fault data with the computer model. Technology is available to monitor lightning strike locations and compare with transmission maps to offer relative fault locations. Digital relays and digital fault recorders can offer relative fault locating. When the technology to monitor the system is unavailable, the only available method is to determine from relay targets if the fault was internal or external to the zone of protection.

Once the possible location is determined, a visual inspection can be performed to determine the exact location and probable cause for the fault. From the determination, a similar fault condition may be applied to the computer model to determine if the actual fault information agrees with the computer results.

4.1 Required Accuracy

From a line protection perspective, it is desirable to cover 100% of the protected transmission line without overreaching the remote line terminal. Even with perfectly accurate line impedance data, the accuracy available from instrument transformers and relays does not support such a perfect degree of protection coverage. Instrument transformers are electro-magnetic devices that are designed to provide a stated accuracy within a primary range of voltage and current. These transformers are designed to provide a degree of accuracy based on the secondary circuit burden (impedance and power factor) presented to them.

Current transformers for relaying applications are required to provide current at magnitudes up to 20 times nominal rating to burdens from 1 to 8 ohms at a power factor no less than 0.5. The standard accuracy for supplying such magnitudes ranges from ±5% to ±10%. Fortunately, installations designed properly within maximum current and burden will provide much more reasonable accuracy, typically within a few percent or less. The maximum accuracy ranges are reached only when the primary current approaches and exceeds the operating range with a burden that equals or exceeds the standard burden.

Voltage transformer accuracy is available in ±0.3%, ±0.6%, and ±1.2% when applied voltage is within ±10% of nominal. Secondary burdens range from 12.5VA to 400VA with power factors between 0.1 and 0.85. Relaying applications normally are applied to windings capable of 75VA, 200VA, and 400VA at a power factor of 0.85. Like current transformers, the accuracy will be different for burdens and power factors outside the stated range.

4.1.1 Performance of Impedance Relays (Electro-mechanical)

Electro-mechanical relays utilize passive elements to filter secondary voltages and currents from the voltage and current transformers. Settings are made by discrete taps on auxiliary transformers in the relay that are limited in selection. The relay capability is determined prior to application based on initial system model fault studies and selected source transformer ratios. The burdens presented by electro-mechanical relays vary based on the taps selected in the relay. Current burdens may range from 0.7 to 8.5VA. Voltage burdens may range from 1 to 40VA. These variations make it difficult to determine the resulting accuracy of the source transformers.

The tap settings of electro-mechanical relays make it difficult to select a fine adjustment to the relay pickup. The limited adjustment makes it necessary to allow for initial differences in the desired pickup and what the relay is capable of supplying. Electro-mechanical relays have limitations on sensitivity to determine fault location. As the fault nears the pickup point of the relay, determination of the fault location is difficult to measure and is usually exhibited by an increase in the amount of time it takes for the relay to initiate a trip. At the other extreme, close-in faults present a very low impedance to the measuring elements which can be reflected in slow trip initiation or undetermined operation from that element. For close-in faults, tripping may be initiated by overcurrent elements that do not require voltage to operate.

The accuracy of electro-mechanical relays is best between 20 to 80% of tap setting. The accuracy will typically be within ±5% of the available tap applied.

4.1.2 Performance of Impedance Relays (Analog Solid State)

Analog solid state relays utilize passive elements and analog comparators to compare the relay circuit model to source currents and voltages. Settings are made by discrete taps or continuously variable potentiometers on auxiliary circuits in the relay. Unlike electro-mechanical relays that must be specified for a specific range of settings, the analog solid state relay is capable of multiple ranges in one unit. The burdens presented by solid state relays remain relatively constant over the full tap range of the relay. Current burdens are much lower than electro-mechanical relays and may range from 0.05 to 1 or 2VA. Voltage burdens are equally lower and may range from 0.1VA to 1 or 2VA. The low burdens also present a constant power factor which supports the accuracy of the source transformers.

The tap settings of an analog solid state relay simplify the fine adjustment of the relay pickup. The relays offer improved precision on settings to determine reach. The accuracy of solid state relays is usually quoted over a given Source Impedance Ratio (SIR) or Z source/Z line range. For low SIR values, the quoted accuracy increases as the system impedance greatly exceeds the line impedance. As with electro-mechanical relays, as the fault approaches the relay tap setting the time to trip will increase as determination becomes more difficult.

4.1.3 Performance of Impedance Relays (Digital Microprocessor based)

Digital relays utilize analog to digital converters to convert the analog signal into a binary domain. The relay settings are made by a human machine interface (HMI) on the relay faceplate or by a communications port connected to a computer. As with analog solid state relays, the burdens presented to the source transformers are constant over the full range of the relay. Current burdens are around 0.25VA and voltage burden is around 0.1VA at a constant power factor.

The relays settings are precise and do not drift due to component aging as in passive analog and electro-mechanical relays. The accuracy of a digital relay is stable over most of the source input levels. This accuracy will degrade for source values falling below 5V and 2A. Digital relays are capable of more precise measurements at the reach setting, however as SIR values increase the time to initiate trip will increase.

4.1.4 Performance of Fault Locating Algorithms

The primary purpose for validating line impedance models is to provide accurate protective relay settings. With the advent of impedance-based real-time/post-event fault locating algorithms built into modern microprocessor-based Intelligent Electronic Devices [IEDs], line impedance accuracy has taken on an added significance. Utility operating personnel now rely heavily on accurate fault location from these IEDs to quickly dispatch crews to repair damage following a permanent fault. Knowing the location of temporary faults also permits inspection crews to more easily find sources of incipient faults, such as damaged insulation or trees growing near the line. Fault locating algorithms are relied on to accurately pinpoint the location of line faults. This adds incentive to provide improved line impedance accuracy because it can have a very significant impact on utility costs and system reliability. Although there is little that can be done about instrument transformer accuracies, fault locating requires a higher degree of line impedance modeling accuracy to achieve the optimum fault locating accuracy. Based on published values, the accuracy of zone distance relays is limited by the source transformers and the relay capabilities.

Given a standard relay class current transformer, standard voltage transformer at minimum and maximum percentage error margins applied to electromechanical, analog solid state, and digital relays. The effect is illustrated in the table.

Relay type	ct	vt	(R) relay	ct * vt* R	effect	notes
relay class ct and vt at minimum margin (in p.u.)						
electromechanical	0.9	0.988	0.95	84.50%	under reach	over 20 to 80% of tap reach
analog solid state	0.9	0.988	0.95	80.00%	under reach	low SIR over 99% of tap reach
analog solid state	0.9	0.988	0.9	84.50%	under reach	high SIR over 99% of tap reach
digital	0.9	0.988	0.95	80.00%	under reach	99% of tap reach
digital	0.9	0.988	0.9	84.50%	under reach	low VA levels 99% of tap reach
relay class ct and vt at maximum margin (in p.u.)						
electromechanical	1.1	1.012	1.05	117%	over reach	over 20 to 80% of tap reach
analog solid state	1.1	1.012	1.05	117%	over reach	low SIR over 99% of tap reach
analog solid state	1.1	1.012	1.1	122%	over reach	high SIR over 99% of tap reach
digital	1.1	1.012	1.05	117%	over reach	99% of tap reach
digital	1.1	1.012	1.1	122%	over reach	low VA levels 99% of tap reach

Table 4.2 Effects of Error Margins on Relay Setting Reach

This table illustrates the worst case accuracy error. In practice, source transformer error will not be linear over the operating range and both voltage and current transformer errors will not be the same. As seen in the comparisons, the relay accuracy will vary based on SIR, input voltage and current magnitudes, and whether the relay burden impacts the source transformers.

4.2 Comparison with Measured Results

The use of oscillographic data to verify model parameters has been in practice for many years. Originally, data was obtained primarily from light-beam transient recording equipment (oscillographs). Today, the data is obtained from a variety of digital devices including fault recorders and microprocessor relays. Initially the data is used to analyze the fault event and attempt to determine the location of the fault. Whether the actual location was determined or not, comparison of the fault study to the data obtained provides insights to the accuracy of the model parameters. Determining an approximate location using the short circuit model and comparing the current flows and voltages to measured quantities can reveal potential problems with the model parameters. If the actual location of the fault is known, the comparison is better.

The procedure for locating the fault using a short circuit program is straightforward. The data from a fault is obtained from the sources mentioned above. The short circuit model is adjusted to match the system configuration at the time of the fault. (i.e. out-of-service lines, transformers, and generators are removed from the model) A fault of the type identified is applied at a point in the model coincident with the suspected location. This point is moved and the fault is reapplied until the results of the study match the data as close as possible. This point is considered the best estimate of the fault location. If the precise location is known, the fault is placed at that point in the model and the result is compared.

This method of using comparison is not only useful in identifying potential problems with the model parameters it also helps establish confidence in the validity of the overall model.

4.3 Direct Measurement [21]

Direct measurement of line impedance using the proper techniques, equipment, and safety precautions provides the opportunity to eliminate many uncertainties related to estimation of transmission line parameters. Historically, direct line parameter measurement was considered prohibitive and costly, since it required primary signal injection using large high-power equipment to overcome nominal frequency interferences. However, modern digital technology and ingenious design in commercially available microprocessor-based multifunctional primary test set systems allow the opportunity to perform direct measurements on transmission lines in a much safer, more cost effective, and accurate manner.

Transmission circuit parameters can be validated from direct measurements from load unbalances and short circuit tests. The load unbalance technique requires synchronized measurements from each line terminal. Even with synchronized measurements, the zero sequence impedance validation can be challenging because transmission circuits experience low load unbalance. Staged short circuit tests are expensive and cause undesirable stress on the equipment, not to mention the adverse effect they may have on customer service. Under certain configurations, relay records from actual short circuits on a transmission line can be helpful in validating its parameters.

A signal injection method provides an alternative to staged short circuit faults on live circuits. However, this method requires that the circuit be taken out-of-service for the test and isolated from sources at both ends. Figure 4.3.1 shows a test set-up. It consists of signal generator, an amplifier and a dynamic signal analyzer. Typically, the signal generator and analyzer functions are available in a single piece of equipment. To measure series parameters of a line, all three phases of the receiving terminal are shorted to the ground as in shown in Figure 4.3.1. Measurements of shunt parameters, mainly for the cable circuits, require the terminals to be left open circuited.

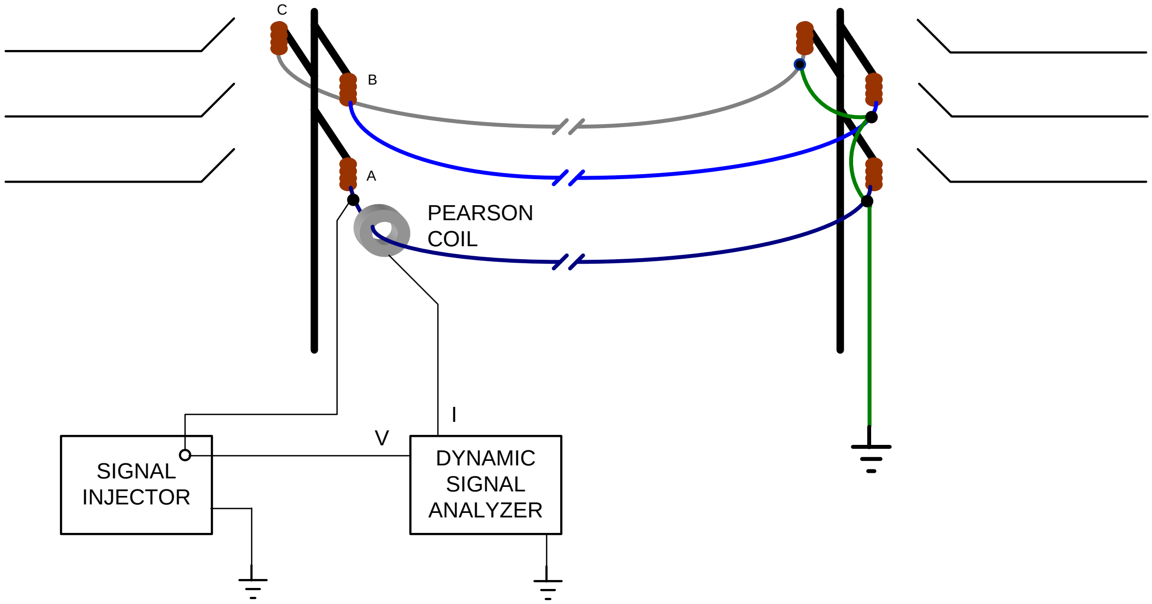

Fig 4.3.1 Test set-up for measuring series self-impedance of Phase A

The signal generator injects a low voltage signal via the amplifier into the isolated circuit. The signal can be white noise or sweep from low frequency of about 10 Hz to 200 Hz in small steps. The applied voltage and the current measured using a Pearson coil CT are applied to the dynamic signal analyzer. The dynamic signal analyzer performs spectrum analysis on the measured signals. It then uses auto (voltage) and cross (voltage and current) correlations to determine the impedance of the transmission circuit over the frequency range using the following relationship:

$$Z_{aa}(f) = V_a(f)*ConjV_a(f)/I_a(f)*ConjV_a(f) \qquad [4.3.1]$$

Where:

$V_a(f)$ = voltage phasor of frequency f extracted from applied voltage on Phase A
Ia(f) = current phasor of frequency f extracted from measured current into Phase A
$Z_{aa}(f)$ = series self-impedance of Phase A of transmission circuit
Conj = conjugate

Several measurements are averaged to improve the accuracy of results.

The impedance measurement obtained using the set-up in Figure 4.3.1 provides self-impedance of Phase A. The mutual impedance between Phase A and B can be measured repeating the experiment – except Phase B voltage from the transmission circuit is applied to the signal analyzer while the signal generator injects voltage into Phase A as follows:

$$Z_{ab}(f) = V_b(f)*ConjV_b(f)/I_a(f)*ConjV_b(f) \qquad [4.3.2]$$

Where:

$V_b(f)$ = voltage phasor of frequency f extracted from voltage measured on Phase B while signal injected on Phase A
$Ia(f)$ = current phasor of frequency f extracted from measured current into Phase A
$Z_{ab}(f)$ = series mutual impedance between Phases A and B
Conj = conjugate
These two measurements are sufficient to calculate positive and zero sequence impedances. Similar measurements on each phase can be averaged to obtain better estimates of self and mutual impedances.

$$Z_s(f) = (Z_{aa}(f) + Z_{bb}(f) + Z_{cc}(f))/3$$
$$Z_m(f) = (Z_{ab}(f) + Z_{ac}(f) + Z_{ba}(f) + Z_{bc}(f) + Z_{ca}(f) + Z_{cb}(f))/6$$

Average values of self and mutual impedance values result in positive and zero sequence impedances of a symmetrical or transposed line as follows:

$$Z_1(f) = Z_s(f) - Z_m(f)$$
$$Z_0(f) = Z_s(f) + 2\ Z_m(f)$$

In the case of untransposed or non-symmetrical lines, the measurements provide a full 3x3 matrix of line impedances, which can be converted into a sequence component matrix using symmetrical component transformations. **[21]** In the case of long lines and cable, shunt impedances can also be obtained with similar tests by keeping the receiving terminal open circuited instead of short circuited.

Figures 4.3.2 and 4.3.3 show the magnitude and phase angle of series self and mutual impedances measured for a short cable circuit. Since a low-voltage signal is applied, measurements near 60 Hz are corrupted due to stray signals from adjacent equipment. These corrupted estimates are rejected. Curve fitting or interpolation techniques from estimates at non-60 Hz frequencies are then used to determine impedance parameters at 60 Hz.

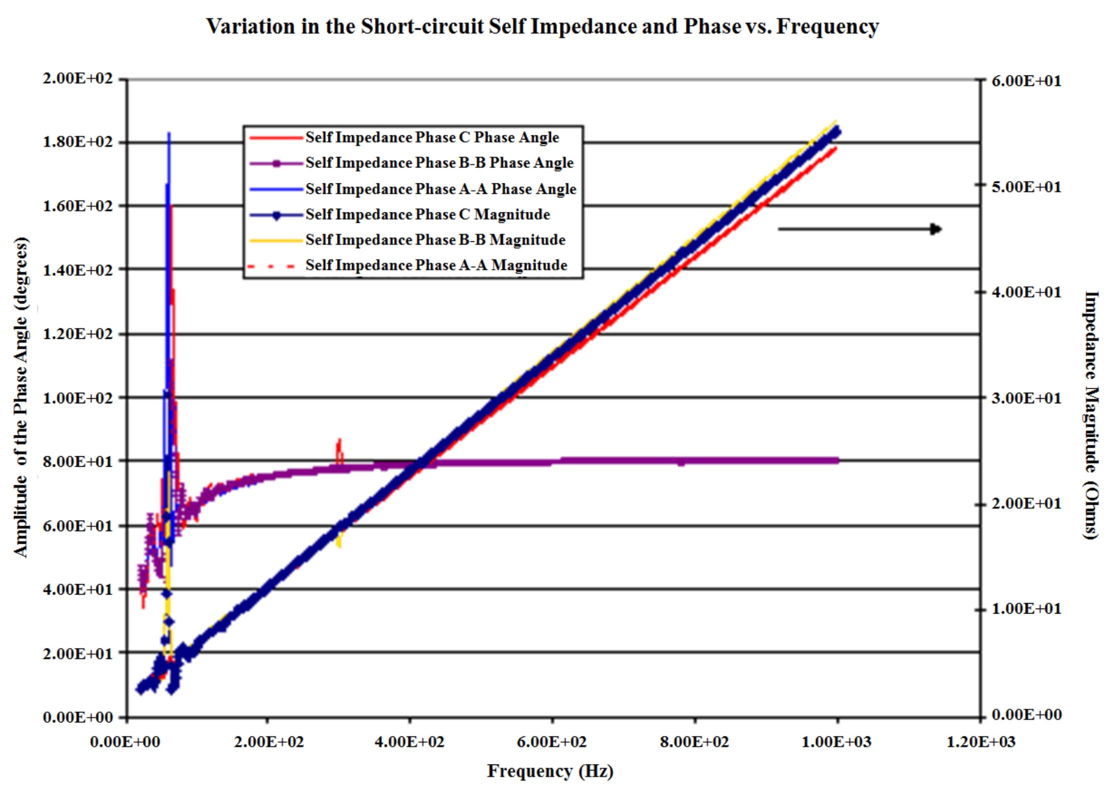

Fig 4.3.2 Magnitude and phase angle of the cable's self-impedance during the short-circuit tests

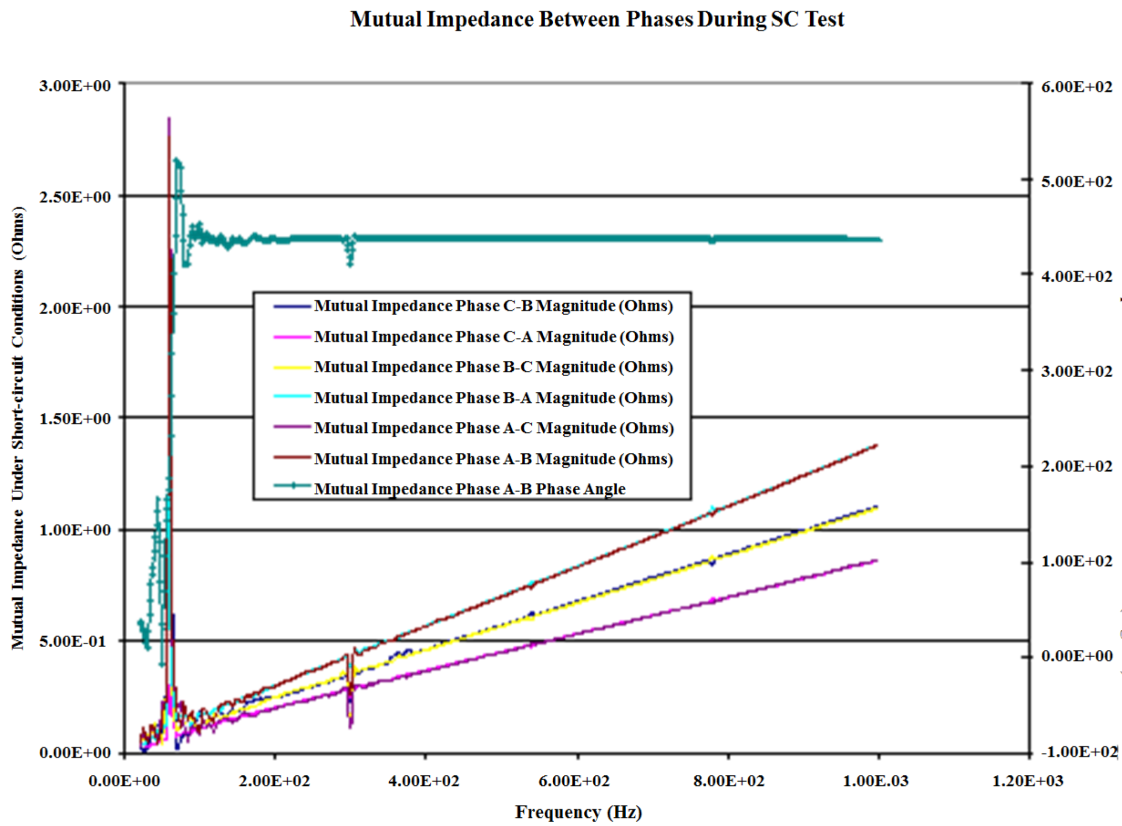

Fig 4.3.3 Mutual impedances between phases during the short circuit test

K-factor

The k factor is a critical parameter for ground distance relay settings. Ground impedance cannot be calculated as accurately as line impedance, and Z_0 estimates are not as accurate as Z_1. Positive-sequence impedance calculations are generally accurate, but ground impedance estimation is prone to errors. The k factor can be accurately calculated from the direct measurements described above. By performing the measurements on each of the 7 fault loops (i.e., phase-a-to-ground; phase-b-to-ground; phase-c-to-ground; phase-a-to-b; phase-b-to-c; phase-c-to-a; and phase-a-b-c-ground), a high degree of accuracy can also be achieved. Figure 4.3.4 illustrates an example of a test setup for direct measurement of phase to ground parameters. The setup includes a signal generator, booster and ground protective device where actual fault loop connections are also made. **[22]**

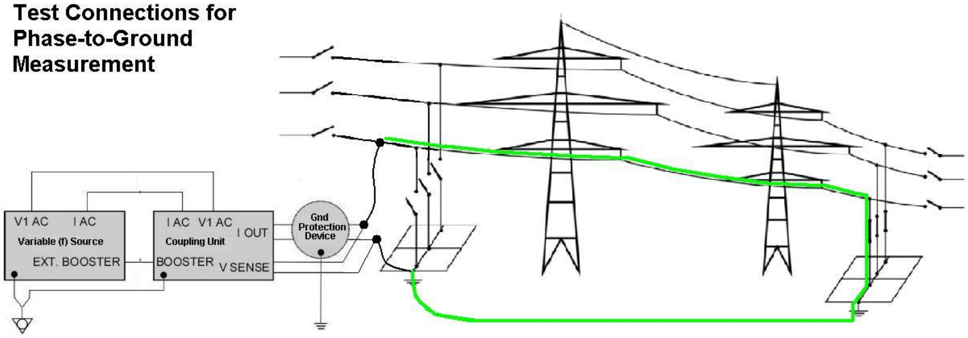

Fig 4.3.4 Test connections for phase-to-ground parameter measurement

It is also possible to perform measurements of mutual impedances between transmission lines with the same techniques and with commercially available multifunctional test sets, although taking out multiple transmission circuits at a time to perform the measurements is often prohibitive.

A technical limitation of direct measurements of transmission line parameters can be the actual length of the line, although transmission lines with up to 250 miles have been successfully submitted to such tests and measurements using present day technology.

4.4 Use of Synchrophasors

4.4.1 Fine tuning of line parameters

In **[8]**, an online optimal estimator for line parameters is proposed based on synchronized phasors measured from both ends of a transmission line. The line is shown in Figure 4.4.1. The state estimation technique is used to identify possible measurement errors contained in both the voltage and current phasors and the potential synchronization error. Only the reliable measurements are employed to estimate line parameters to improve accuracy.

Fig 4.4.1 Transmission Line

In **[15]**, an online approach is described to estimate the parameters for series compensated lines. The proposed method makes use of synchronized voltage and current phasors from both ends of a line. The compensation device can be a simple capacitor bank, or more complicated thyristor-controlled power flow controller. The voltage across the compensation device can also be estimated in real time, and may be utilized for monitoring and control purposes. The transmission line considered is shown in Figure 4.4.2 with the compensation device located at point R.

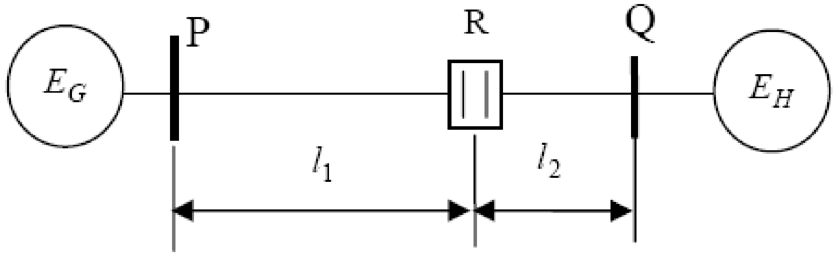

Fig 4.4.2 Transmission line with compensation device

4.4.2 Verification of Overheard Transmission Line Zero-Sequence Impedance

This technique uses synchronized phasor measurements from both ends of a faulted overhead transmission line. The fault type must be either single phase-to-ground or phase-to-phase-to-ground since these involve the zero-sequence network. First the fault location should be calculated using a double ended calculation. Next the zero-sequence impedance of the transmission line should be calculated and the result compared to the model at nominal load. It is best if the negative sequence is accurately known. Note that this method does not apply if the lines are mutually coupled. The calculations are shown in appendix **A3**.

This double-ended fault location calculation is not impacted by fault resistance or zero-sequence mutual coupling due to the following two reasons:

- Uses time-synchronized voltage and current measurements from both ends of the overhead transmission line,
- Only the negative-sequence voltage and current is used to calculate the fault location.

Time synchronization is available and commonly applied via GPS satellite clock receivers. Both modern protective relays and digital fault recorders record the fault voltage and current from each end of the overhead transmission line.

The voltage and current measurements must be filtered such that only the fundamental frequency quantities are applied for the calculations. Modern protective relays filter the voltage and current prior to executing any protection related functions. These signals are usually available via an event report or fault record.

4.4.3 Impact of Time-Alignment Error on the Fault Location Estimation Accuracy

The calculations shown in the appendix yield the following equation for per unit fault location:

$$m = \frac{V_{2S} - V_{2R} + I_{2R} \bullet Z_L}{I_{2S} \bullet Z_L} \quad \text{[A3.7]}$$

In order to use Equation [4.2] to calcuate an accurate fault location, the voltage and current phasors from both terminals have to be closely time-aligned. Any mis-alignement will introduce error in the estimated fault location unless the method used allows for time mis-aligned data captured from numerical relays **[20]**. Considering the time alignment error between the measurements from both terminals, Equation [4.2] should be reformalized as the following equation.

$$m = Re\left[\frac{V_{2S} \cdot e^{j2\pi f t_\Delta} - V_{2R} + I_{2R} \cdot Z_L}{(I_{2S} \cdot e^{j2\pi f t_\Delta} + I_{2R}) \cdot Z_L}\right] \quad \text{[4.2.1]}$$

Where t_Δ is the time-alignment error between two terminals in msec.

Using the power system short-circuit analysis case presented in **[17]**, a plot showing the percentage of the fault location error versus the time-alignment error can be made as shown in figure 4.2.2. When the time-alignment error is zero, the fault location estimation is perfect. But the error will be 100% of the line length if the phasor measurements between to terminals are 5 milliseconds apart.

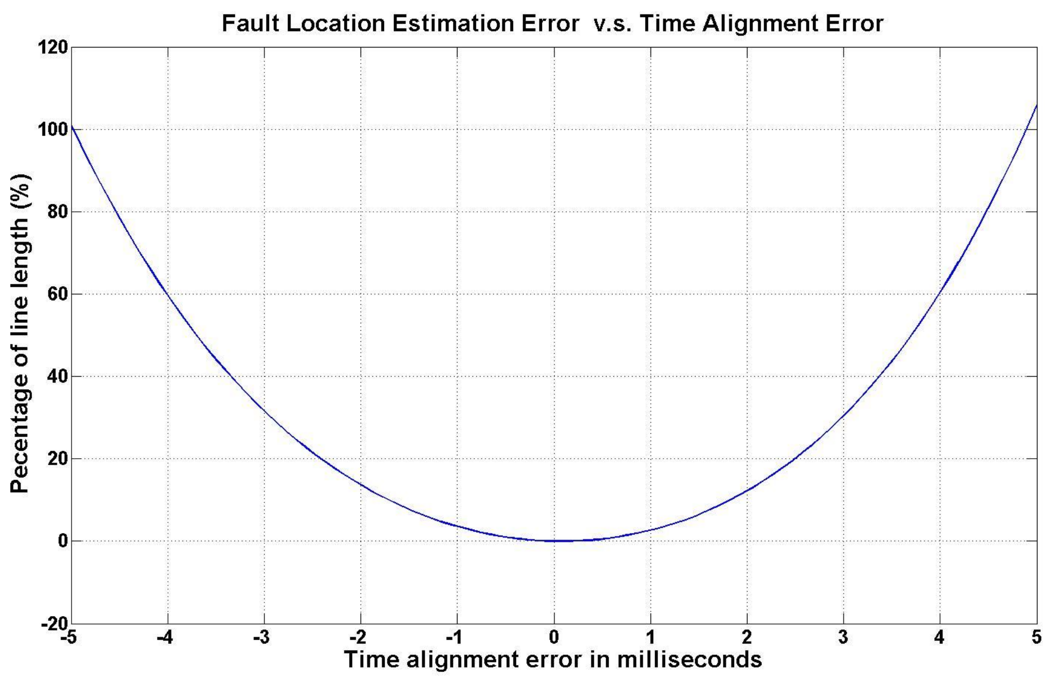

Fig 4.2.2 Fault Location Estimation Error vs Time Alignment Error

4.5 Use of Staged Faults

Staged fault testing is a set of short circuit tests performed on high voltage equipment while it is in service. Some of the equipment used to apply short circuit tests includes portable High Speed Ground Switches (HSGS) and Gas Operated Fault Initiators (GOFI). The HSGS is a single phase Gas Insulated Switch (GIS) typically used in EHV single phase tripping schemes. The GOFI is a remote controlled rocket driven by a carbon-dioxide bottle to shoot a section of fuse wire between two hoops mounted across bus support insulators. One object of staged fault testing is to use the resulting measurements to improve transient software and short circuit and relay coordination modeling of high voltage equipment being tested and the surrounding system. **[16]** Other primary objectives for staged fault testing include the following:

- To establish that the insulation levels of the platform mounted high voltage equipment on series capacitors have been properly coordinated.
- To verify that the control and protection systems operate properly and provide the appropriate alarms, annunciation, and quantities at ground level.
- To verify that all the high voltage equipment within the current carrying path can, under fault conditions, withstand a nominal duty (which in some cases can approach their specified capability).
- To investigate and ensure that high voltage equipment operates properly (i.e. triggered air gaps protecting series capacitors fire only for high fault currents)
- To check for proper relay operation of the adjacent power system during faults on the series capacitor bank.
- To provide valuable data to document the actual contribution to transmission system faults from different types of generation such as wind farms.
- To investigate the magnitude of live-line overvoltage levels during transmission line faults, shunt capacitor switching and parallel line switching.
- To verify the system model and sizing of components for the timing of secondary arc extension during single phase tripping.

5 Summary

It is important to maintain a short circuit model as accurately as possible in order to perform useful and effective fault location studies, relay setting calculations, relay performance studies, and any other similar tasks. The real-world power system is itself variable and influenced by temperature, moisture, spacing and structure design, variation in earth resistivity, and variation in conductors used to construct lines just to name a few of the important items. It is also equally important to understand how modeling assumptions and practices affect the accuracy. Any time spent working with a model will reveal that the zero sequence part is the most difficult to get accurate. Earth resistivity is variable not only due to geographical conditions but also to moisture levels, the proximity to rail lines or pipelines or similar structures which all serve to affect a line’s ability to couple with remote earth.

There are various methods of reviewing accuracy. Perhaps the most common method is the comparison of the short circuit model to measured quantities taken from an actual system fault event. This is particularly valuable if the location of the fault is accurately known. A variation of this method is to perform a staged fault. This long standing method of comparing the short circuit or load flow models to measured quantities has improved with the increase in the number of relays and other devices that provide measured quantities for comparison.

The increased use of synchrophasor measurements has served to refine the process of comparing the model to measured system parameters. The synchrophasor measurements can be used to compare values from a state estimator to perform comparisons even in a steady state condition.

One very new technique involves the injection of currents on an isolated line and using the resulting measurement to calculate the impedance parameters directly. The results of these calculations have produced some surprising results especially with the zero sequence part of the impedances.

Regardless of the methods used, maintaining ongoing review and adjustment of the power system model will continue to be an important part of the daily work of a protection engineer.

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Appendix

A1. Detail discussion of Inductance and Capacitance Parameters

There are four parameters that affect the ability of a transmission line to function as part of a power system, these are: Resistance (R), Inductance (L), Capacitance (C) and the Conductance (G). Of these only two, the inductance and the capacitance are affected by the configuration of the conductors that compose the transmission line.

Inductance:
From the theory it is shown that the *self-inductance* for a conductor that is suspended above the earth is given by:

$$L_{xx} = 2 \cdot 10^{-7} \cdot \ln\left(\frac{De}{r_x^*}\right) \quad [A1.1]$$

$$De = 2160 \cdot \sqrt{\frac{\rho}{Fre\,q}} \cdot ft \quad [A1.2]$$

$$r_x^* = e^{-\frac{1}{4} \cdot radius\_of\_conductor} \quad [A1.3]$$

(*De* is referred to in literature as an image conductor beneath the surface of the earth. This parameter is dependent on the resistivity of the earth and is adjusted so that the inductance calculated with its configuration is equal to that measured by testing.
r_x^* is defined as the GMR (Geometric Mean Radius) and for a single round conductor is equal to the radius of the conductor. A calculated equivalent GMR is commonly used in the case of bundled conductors)

The *mutual inductance* between two conductors suspended above the earth, is determined as follows:

$$L_{xy} = 2 \cdot 10^{-7} \cdot \ln\left(\frac{De}{D_{xy}}\right) \quad [A1.4]$$

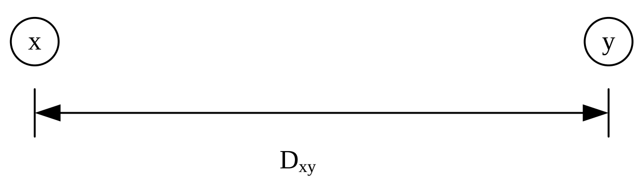

Fig A1.1 Two conductors to illustrate basic mutual inductance

From equation [A1.1] it can be seen that the configuration of a transmission line does not affect the self- inductance of a conductor, but from equation [A1.4] the mutual impedance between two conductors is directly related to the distance between the two conductors. The mutual inductance between the conductors increases as the distance between them decreases. Therefore the configuration of the transmission line directly impacts its inductance.
For a three phase transmission system, the self and mutual inductance for the line is shown in Fig A1.2:

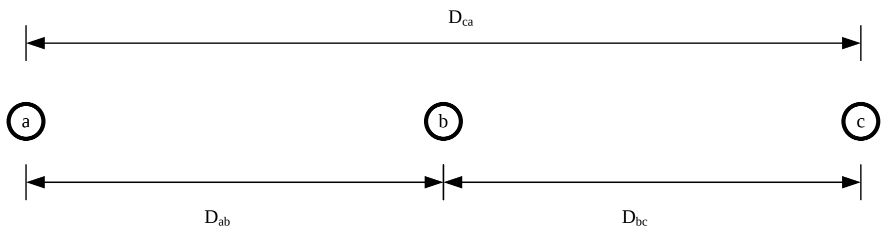

Fig A1.2 Sketch of a single conductor 3 phase transmission line without ground wire

$$L_{abc} = 2 \cdot 10^{-7} \begin{bmatrix} ln\left(\frac{De}{r_a{}^*}\right) & ln\left(\frac{De}{D_{ab}}\right) & ln\left(\frac{De}{D_{ac}}\right) \\ ln\left(\frac{De}{D_{ba}}\right) & ln\left(\frac{De}{r_b{}^*}\right) & ln\left(\frac{De}{D_{bc}}\right) \\ ln\left(\frac{De}{D_{ca}}\right) & ln\left(\frac{De}{D_{bc}}\right) & ln\left(\frac{De}{rc^*}\right) \end{bmatrix} \cdot H/unit\_length \qquad [A1.5]$$

There are two methods that can be used to deal with bundled conductors (more than one conductor per phase). The first computes the GMR of the bundle and uses the value for GMR in Equation [A1.5] to replace $r_a{}^*$, $r_b{}^*$ and $r_c{}^*$.

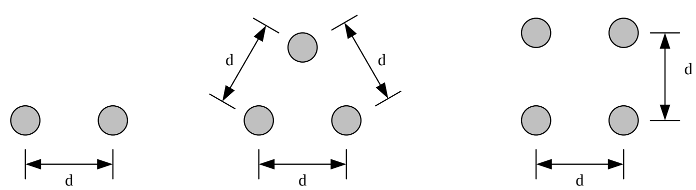

Fig A1.3 Typical configuration for bundle conductors

For a double bundled conductor:

$$GMR_2 = \sqrt{(r_a \cdot d)} \qquad [A1.6]$$

For a triple bundled conductor

$$GMR_3 = \sqrt[3]{r_a \cdot d \cdot d} \qquad [A1.7]$$

For a Quad bundled conductor

$$GMR_4 = \sqrt[4]{r_a \cdot d \cdot d \cdot \sqrt{2} \cdot d}$$

$$GMR_4 = 1.09 \sqrt[4]{r_a \cdot d \cdot d \cdot d} \qquad [A1.8]$$

If the bundle contains more than 4 conductors the GMR for this configuration may be obtained by following the method shown in equations [A1.6] to [A1.8].
The second method that can be used when bundled conductors are present, is to treat each conductor as an individual conductor and compute the mutual impedance between each conductor. For example if you had a double stranded bundled conductor the inductance matrix would be as given by equation A1.9.

$$L_{abca'b'c'} = 2 \cdot 10^{-7} \begin{bmatrix} ln\left(\frac{De}{r_{a1}{}^*}\right) & ln\left(\frac{De}{D_{a1b1}}\right) & ln\left(\frac{De}{D_{a1c1}}\right) & ln\left(\frac{De}{D_{a1a2}}\right) & ln\left(\frac{De}{D_{a1b2}}\right) & ln\left(\frac{De}{D_{a1c2}}\right) \\ ln\left(\frac{De}{D_{b1a1}}\right) & ln\left(\frac{De}{rb1^*}\right) & ln\left(\frac{De}{D_{b1c1}}\right) & ln\left(\frac{De}{D_{b1a2}}\right) & ln\left(\frac{De}{D_{b1b2}}\right) & ln\left(\frac{De}{D_{b1c2}}\right) \\ ln\left(\frac{De}{D_{c1a1}}\right) & ln\left(\frac{De}{D_{c1b1}}\right) & ln\left(\frac{De}{r_{c1}{}^*}\right) & ln\left(\frac{De}{D_{c1a2}}\right) & ln\left(\frac{De}{D_{c1b2}}\right) & ln\left(\frac{De}{D_{c1c2}}\right) \\ ln\left(\frac{De}{D_{a2a1}}\right) & ln\left(\frac{De}{D_{a2b1}}\right) & ln\left(\frac{De}{D_{a2c1}}\right) & ln\left(\frac{De}{r_{a2}{}^*}\right) & ln\left(\frac{De}{D_{a2b2}}\right) & ln\left(\frac{De}{D_{a2c2}}\right) \\ ln\left(\frac{De}{D_{b2a1}}\right) & ln\left(\frac{De}{D_{b2b1}}\right) & ln\left(\frac{De}{D_{b2c1}}\right) & ln\left(\frac{De}{D_{b2a2}}\right) & ln\left(\frac{De}{r_{b2}{}^*}\right) & ln\left(\frac{De}{D_{b2c2}}\right) \\ ln\left(\frac{De}{D_{c2a1}}\right) & ln\left(\frac{De}{D_{c2b1}}\right) & ln\left(\frac{De}{D_{c2c1}}\right) & ln\left(\frac{De}{D_{c2a2}}\right) & ln\left(\frac{De}{D_{c2b2}}\right) & ln\left(\frac{De}{r_{c2}{}^*}\right) \end{bmatrix}$$

H/unit_length [A1.9]

The 6 x 6 matrix of equation [A1.9] can be reduced to a 3 x 3 matrix by making use of the fact that $V_A - V_A' = 0$, $V_B - V_B' = 0$ and $V_C - V_C' = 0$ and $I_{ATotal} = I_{A1} + I_{A2}$.
For a non-segmented overhead ground wire, regard the ground wire or wires as extra conductors. Then calculate the mutual impedance between each phase conductor and the ground conductor.

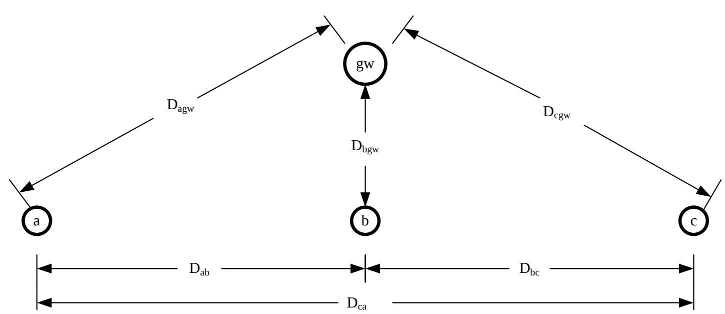

Fig.A1.4. Sketch of a single wire 3 phase transmission line with a ground wire.

The inductance matrix is as follows:

$$L_{abcg} = 2 \cdot 10^{-7} \begin{bmatrix} ln\left(\frac{De}{r_a{}^*}\right) & ln\left(\frac{De}{D_{ab}}\right) & ln\left(\frac{De}{D_{ac}}\right) & ln\left(\frac{De}{D_{agw}}\right) \\ ln\left(\frac{De}{D_{ba}}\right) & ln\left(\frac{De}{r_b{}^*}\right) & ln\left(\frac{De}{D_{bc}}\right) & ln\left(\frac{De}{D_{bgw}}\right) \\ ln\left(\frac{De}{D_{ca}}\right) & ln\left(\frac{De}{D_{cb}}\right) & ln\left(\frac{De}{r_c{}^*}\right) & ln\left(\frac{De}{D_{cgw}}\right) \\ ln\left(\frac{De}{D_{gwa}}\right) & ln\left(\frac{De}{D_{gwb}}\right) & ln\left(\frac{De}{D_{gwc}}\right) & ln\left(\frac{De}{D_{gw}{}^*}\right) \end{bmatrix} H/unit\_length \qquad [A1.10]$$

Reduce this 4 x 4 matrix to a 3 x 3 matrix by eliminating the 4th row and column, using a Kron reduction method.

$$L_{abc} = 2 \cdot 10^{-7} \begin{bmatrix} ln\left(\frac{De}{r_a{}^*}\right) - \frac{ln\left(\frac{De}{D_{gwa}}\right) \cdot ln\left(\frac{De}{D_{gwa}}\right)}{ln\left(\frac{De}{D_{gw}{}^*}\right)} & ln\left(\frac{De}{D_{ab}}\right) - \frac{ln\left(\frac{De}{D_{gwa}}\right) \cdot ln\left(\frac{De}{D_{gwb}}\right)}{ln\left(\frac{De}{D_{gw}{}^*}\right)} & ln\left(\frac{De}{D_{ac}}\right) - \frac{ln\left(\frac{De}{D_{gwa}}\right) \cdot ln\left(\frac{De}{D_{gwb}}\right)}{ln\left(\frac{De}{D_{gw}{}^*}\right)} \\ ln\left(\frac{De}{D_{ba}}\right) - \frac{ln\left(\frac{De}{D_{gwb}}\right) \cdot ln\left(\frac{De}{D_{gwa}}\right)}{ln\left(\frac{De}{D_{gw}{}^*}\right)} & ln\left(\frac{De}{r_b{}^*}\right) - \frac{ln\left(\frac{De}{D_{gwb}}\right) \cdot ln\left(\frac{De}{D_{gwb}}\right)}{ln\left(\frac{De}{D_{gw}{}^*}\right)} & ln\left(\frac{De}{D_{bc}}\right) - \frac{ln\left(\frac{De}{D_{gwb}}\right) \cdot ln\left(\frac{De}{D_{gwc}}\right)}{ln\left(\frac{De}{D_{gw}{}^*}\right)} \\ ln\left(\frac{De}{D_{ca}}\right) - \frac{ln\left(\frac{De}{D_{gwc}}\right) \cdot ln\left(\frac{De}{D_{gwa}}\right)}{ln\left(\frac{De}{D_{gw}{}^*}\right)} & ln\left(\frac{De}{D_{bc}}\right) - \frac{ln\left(\frac{De}{D_{gwc}}\right) \cdot ln\left(\frac{De}{D_{gwb}}\right)}{ln\left(\frac{De}{D_{gw}{}^*}\right)} & ln\left(\frac{De}{r_{ac}{}^*}\right) - \frac{ln\left(\frac{De}{D_{gwc}}\right) \cdot ln\left(\frac{De}{D_{gwc}}\right)}{ln\left(\frac{De}{D_{gw}{}^*}\right)} \end{bmatrix} \cdot H/unit\_length$$

[A1.11]

Once the matrix has been reduced to a 3 x 3 matrix, the series phase impedance for the line can be calculated and from this the sequence series impedances can be calculated.

Capacitance:

Consider the group of charged lines and their images as shown in Fig.A1.5.

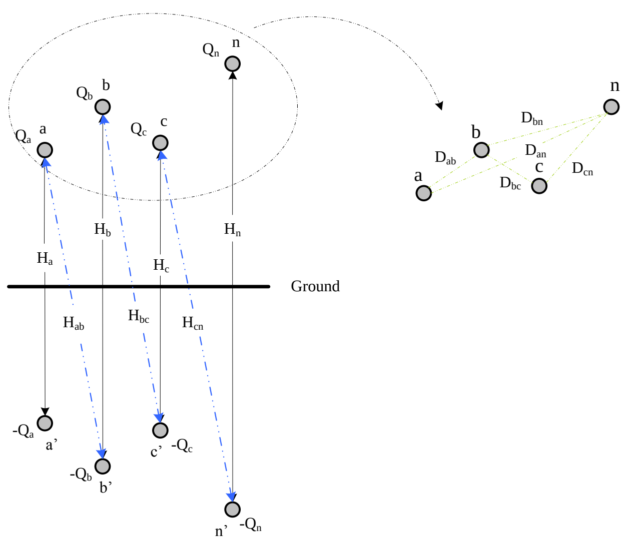

Fig A1.5 Group of charged lines and images

From theory:

$$V_{abcn} = P_{abcn} \cdot Q_{abcn} \qquad [A1.12]$$

Where: V_{abcn} = Voltage vector matrix
P_{abcn} = Potential coefficient matrix
Q_{abcn} = Charge vector matrix

The potential coefficient matrix (P) is computed as follows:

$$P_{xy} = k \cdot \ln\left(\frac{H_x}{r_x}\right) \text{ , x = y} \qquad [A1.13]$$

$$P_{xy} = k \cdot \ln\left(\frac{H_{xy}}{D_{xy}}\right) \text{ , x} \neq \text{y} \qquad [A1.14]$$

Where: $k = \frac{1}{2 \cdot \pi \cdot \varepsilon o}$

$$\varepsilon o = 8.85 \cdot 10^{-12} \quad F/m$$

But

$$\boldsymbol{Q = CV}$$

Therefore

$$\boldsymbol{C = P^{-1}}$$

The potential coefficient matrix for a transmission line with a configuration as shown in Fig.A1.5, but ignoring the ground wire (conductor "n") is as follows:

$$P_{abc} = \frac{1}{2 \cdot \pi \cdot \varepsilon o} \cdot \begin{bmatrix} ln\left(\frac{H_a}{r_a}\right) & ln\left(\frac{H_{ab}}{D_{ab}}\right) & ln\left(\frac{H_{ac}}{D_{ac}}\right) \\ ln\left(\frac{H_{ba}}{D_{ba}}\right) & ln\left(\frac{H_b}{r_b}\right) & ln\left(\frac{H_{bc}}{D_{bc}}\right) \\ ln\left(\frac{H_{ca}}{D_{ca}}\right) & ln\left(\frac{H_{cb}}{D_{cb}}\right) & ln\left(\frac{H_c}{r_c}\right) \end{bmatrix} \; F^{-1}/m \qquad [A1.15]$$

$$\boldsymbol{C}_{abc} = [\boldsymbol{P}_{abc}]^{-1} \quad F/m$$

The diagonal elements of $\mathbf{C}_{abc}$ are called the "Maxwell's coefficients" or the "capacitance coefficients". The off-diagonal elements are known as the "electrostatic induction coefficients". The off-diagonal elements are negative due to the fact that all the elements (coefficients) in the potential coefficient matrix are positive. The $\mathbf{C}_{abc}$ matrix is obtained by inverting the $\mathbf{P}_{abc}$ matrix.

$$\boldsymbol{C}_{abc} = \frac{[P_{ij}]^t}{\det \boldsymbol{P}}$$

$$Cabc = \begin{bmatrix} c_{aa} & -c_{ab} & -c_{ac} \\ -c_{ba} & c_{bb} & -c_{bc} \\ -c_{ca} & -c_{cb} & c_{cc} \end{bmatrix} \quad F/m$$

Note that irrespective if the ground wire is *segmented* or *non- segmented* the ground wire if present is considered in the potential coefficient (capacitance) matrix. The potential coefficient matrix when ground wires are present is similar to the inductance matrix and is reduced to a 3 x 3 matrix using Kron reduction similar to the inductance matrix.

A2. Calculation of UG Cable Series Impedance Matrix Example

The following underground cable parameters are taken from [9].

Cable type:	Single-conductor 230 kV 1,200 mm2 copper
Cable length:	1,000 m
Conductor radius:	2.15 E-02 m
Insulation radius:	4.52 E-02 m
Sheath radius:	4.98 E-02 m
Polyvinyl chloride (PVC) radius:	5.38 E-02 m
Conductor resistivity:	1.72 E-08 Ωm at 20°C
Sheath resistivity:	2.14 E-07 Ωm at 20°C
Permittivity of insulation:	1.0
Permittivity of PVC:	8.0
Earth resistivity:	100.0 Ωm
Frequency:	60 Hz

Figure A2.1 shows the cable conductors are laid in trefoil configuration. The cable sheaths are grounded at both cable ends and there is no ground continuity conductor.

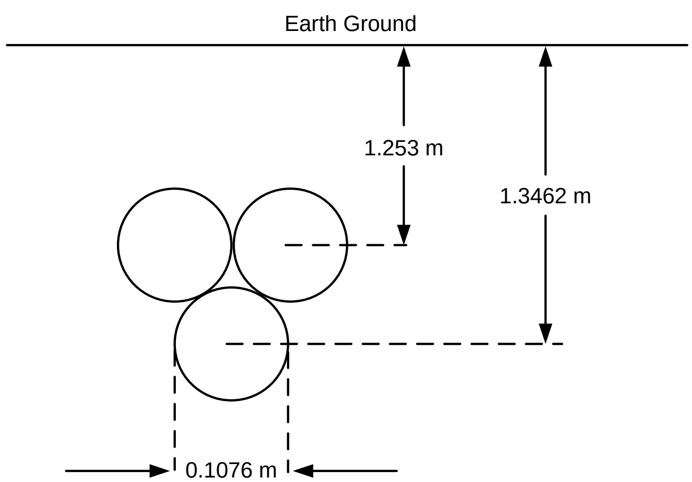

Fig A2.1 UG Cable placed in trefoil configuration

The series impedance matrix of the underground example cable using handbook formulas [13] is given by

$$Zc = \begin{pmatrix} 0.079+0.8169j & 0.0592+0.6766j & 0.0592+0.6766j & 0.0592+0.7383j & 0.0592+0.6766j & 0.0592+0.6766j \\ 0.0592+0.6766j & 0.079+0.8169j & 0.0592+0.6766j & 0.0592+0.6766j & 0.0592+0.7383j & 0.0592+0.6766j \\ 0.0592+0.6766j & 0.0592+0.6766j & 0.079+0.8169j & 0.0592+0.6766j & 0.0592+0.6766j & 0.0592+0.7383j \\ 0.0592+0.7383j & 0.0592+0.6766j & 0.0592+0.6766j & 0.2151+0.7383j & 0.0592+0.6766j & 0.0592+0.6766j \\ 0.0592+0.6766j & 0.0592+0.7383j & 0.0592+0.6766j & 0.0592+0.6766j & 0.2151+0.7383j & 0.0592+0.6766j \\ 0.0592+0.6766j & 0.0592+0.6766j & 0.0592+0.7383j & 0.0592+0.6766j & 0.0592+0.6766j & 0.2151+0.7383j \end{pmatrix}$$

The series impedance matrix of the example underground cable using EMTP/ATP [14] is given by

$$Zc = \begin{pmatrix} 0.077+0.8126j & 0.059+0.6769j & 0.059+0.6769j & 0.0591+0.7385j & 0.059+0.6769j & 0.059+0.6769j \\ 0.059+0.6769j & 0.077+0.8126j & 0.059+0.6769j & 0.059+0.6769j & 0.059+0.7386j & 0.059+0.6769j \\ 0.059+0.6769j & 0.059+0.6769j & 0.077+0.8126j & 0.059+0.6769j & 0.059+0.6769j & 0.0591+0.7385j \\ 0.0591+0.7385j & 0.059+0.6769j & 0.059+0.6769j & 0.2149+0.7373j & 0.059+0.6769j & 0.059+0.6769j \\ 0.059+0.6769j & 0.059+0.7386j & 0.059+0.6769j & 0.059+0.6769j & 0.2149+0.7373j & 0.059+0.6769j \\ 0.059+0.6769j & 0.059+0.6769j & 0.0591+0.7385j & 0.059+0.6769j & 0.059+0.6769j & 0.2149+0.7373j \end{pmatrix}$$

The cable sequence impedance matrix is given below using the EMTP/ATP calculated series impedance matrix.

$$Zseq = \begin{pmatrix} 0.1951+2.1664j & 0+0j & -0-0j & 0.1771+2.0924j & 0+0j & 0-0j \\ -0-0j & 0.018+0.1356j & 0-0j & 0-0j & 0+0.0616j & 0-0j \\ 0+0j & -0-0j & 0.018+0.1356j & 0+0j & -0-0j & 0+0.0616j \\ 0.1771+2.0924j & 0+0j & 0-0j & 0.3329+2.0911j & 0+0j & 0-0j \\ 0-0j & 0+0.0616j & 0-0j & 0-0j & 0.1559+0.0604j & 0-0j \\ 0+0j & -0-0j & 0+0.0616j & 0+0j & -0+0j & 0.1559+0.0604j \end{pmatrix}$$

The zero-sequence impedances of the core conductor, the sheath, and the mutual zero-sequence impedance of the core-to-sheath are:

Zero-sequence of core conductor Z_{0C} (Ω): $Z_{0C} = 0.1951 + j\ 2.1664$

Zero-sequence of cable sheath Z_{0S} (Ω): $Z_{0S} = 0.3329 + j\ 2.0911$

Zero-sequence mutual (core-sheath) Z_{0M} (Ω): $Z_{0M} = 0.1771 + j\ 2.0924$

To calculate the zero-sequence impedance of the cable, Z_0, for the three different return paths, we can use the equivalent circuit shown in Fig. A2.2 [9].

The cable zero-sequence impedances for the three possible current return paths are:

1. Current return in the sheath only:

   $$Z_0 = Z_{0c} + Z_{0s} - 2 \bullet Z_{0m}$$

   $$Z_0 = 0.174 + j\ 0.073\Omega$$

2. Current return in the ground only:

$$Z_0 = Z_{0c} - Z_{0m} + Z_{0m} = Z_{0c}$$

$$Z_0 = 0.195 + j\ 2.166\Omega$$

3. Current in the sheath and ground in parallel:

$$Z_0 = Z_{0c} - Z_{0m} + \frac{(Z_{0s} - Z_{0m}) \bullet Z_{0m}}{Z_{0s}} = Z_{0c} - \frac{Z_{0m}^2}{Z_{0s}}$$

$$Z_0 = 0.172 + j\ 0.084\Omega$$

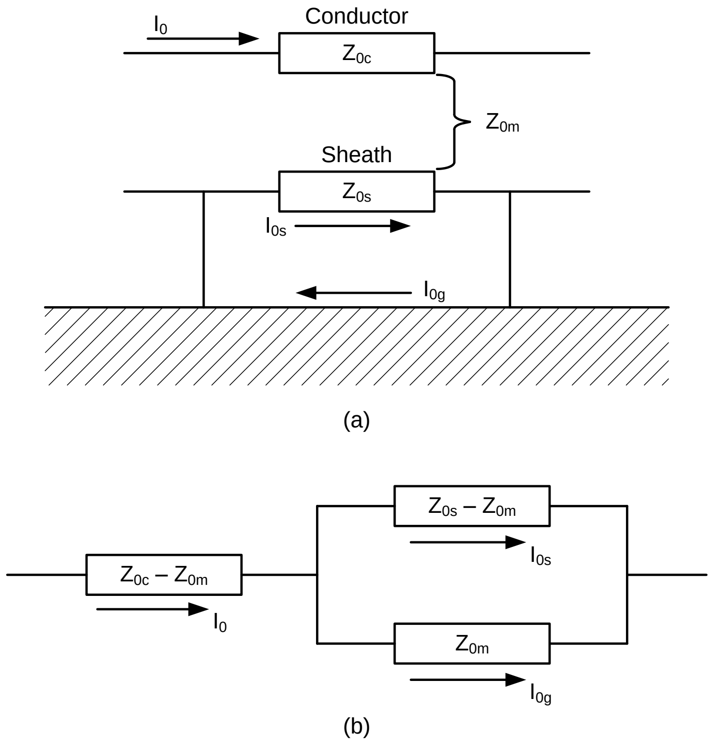

Fig A2.2 Zero-sequence return currents and equivalent circuit

Assuming that the cable sheaths are grounded at both cable ends we can get a 3x3 reduced series impedance matrix by applying Kron's reduction. The reduced series impedance matrix is:

$$\text{Zred} = \begin{pmatrix} 0.08351+0.11299j & 0.04434-0.01442j & 0.04434-0.01442j \\ 0.04434-0.01442j & 0.08353+0.11301j & 0.04434-0.01442j \\ 0.04434-0.01442j & 0.04434-0.01442j & 0.08351+0.11299j \end{pmatrix}$$

The sequence impedance matrix of the underground cable (1000 meters) with sheaths grounded at both ends is:

$$\text{Zseq} = \begin{pmatrix} 0.1722+0.0841j & 0-0j & -0+0j \\ -0+0j & 0.0392+0.1274j & 0-0j \\ 0-0j & -0+0j & 0.0392+0.1274j \end{pmatrix}$$

From the above matrix we have:

Positive-sequence impedance of the cable Z_{1C} (Ω): $Z_{1C} = 0.0392 + j\ 0.1274$

Negative-sequence impedance of the cable Z_{2C} (Ω): $Z_{2C} = 0.0392 + j\ 0.1274$

Zero-sequence impedance of the cable Z_{0C} (Ω): $Z_{0C} = 0.1722 + j\ 0.0841$

A3. Double ended Fault Location

The following calculations are associated with section 4.2.1

Step 1- Double Ended Fault Location Calculation

Sequence Components

Transform the voltage and current measured during fault conditions to their respective positive-, negative-, and zero-sequence quantities. Negative-sequence quantities are present for single phase-to-ground, phase-to-phase, and phase-to-phase-to-ground faults. Therefore, negative-sequence quantities are very reliable.

The following two equations demonstrate how to calculate the negative-sequence voltage and current from the three-phase voltage and current measurements.

$$V_2 = 0.333 \bullet (V_a + a^2 \bullet V_b + a \bullet V_c) \qquad [A3.1]$$

$$I_2 = 0.333 \bullet (I_a + a^2 \bullet I_b + a \bullet I_c) \qquad [A3.2]$$

Where:

$a = 1 \angle 120°$

$a^2 = 1 \angle -120°$

Figure 4.2.1.1 illustrates the negative-sequence network for a faulted overhead transmission line where I_2 is the fault current. S and R indicate the location of two stations at the ends of a line with impedance Z_L.

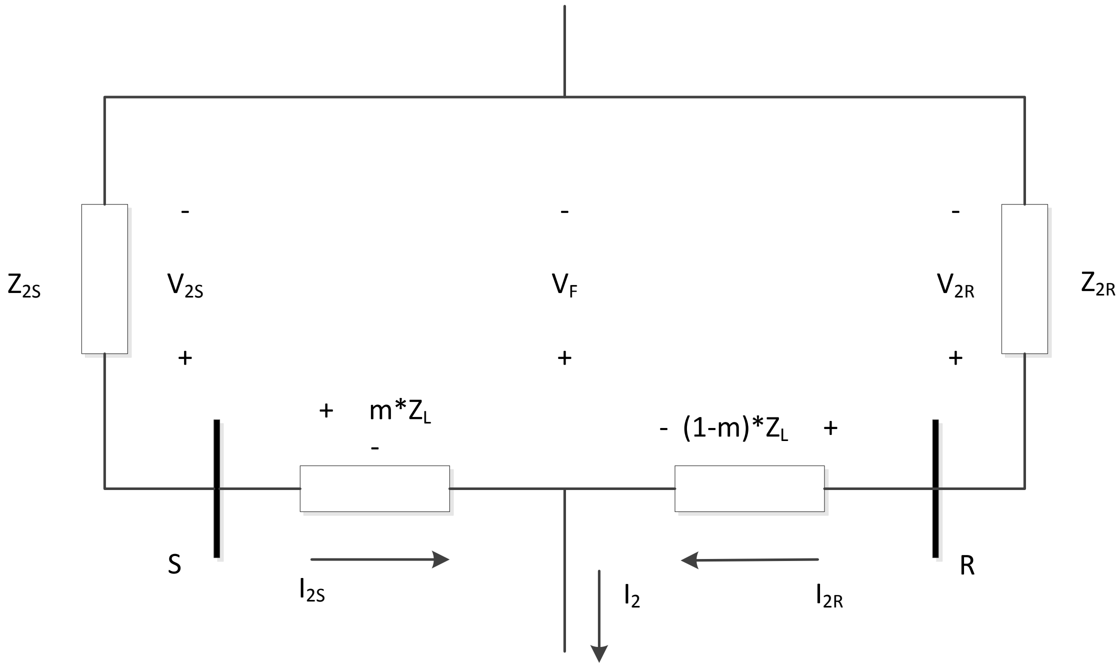

Fig A3.1 Negative-Sequence Network for Faulted Overhead Transmission Line

V_{2S} and I_{2S} are the negative-sequence quantities measured at Station S. V_{2R} and I_{2R} are the negative-sequence quantities measured at Station R. "m" is the per-unit distance to the fault with respect to Station S. Therefore,

$m \bullet Z_L$ =	Total impedance of the conductor to the point of the fault from Station S
$(1-m) \bullet Z_L$ =	Total impedance of the conductor to the point of the fault from Station R
V_F =	Fault voltage at the point of the fault
V_{2S} =	Negative-sequence voltage measured at Station S
I_{2S} =	Negative-sequence current measured at Station S
V_{2R} =	Negative-sequence voltage measured at Station R
I_{2R} =	Negative-sequence current measured at Station R
I_2 =	Total negative-sequence fault current ($I_{2S} + I_{2R}$)

Determine the apparent negative-sequence source impedances at Stations S and R as follows:

$$Z_{2S} = -V_{2S}/I_{2S} \qquad [A3.3]$$

$$Z_{2R} = -V_{2R}/I_{2R} \qquad [A3.4]$$

Derive two loop voltage equations in terms of the fault voltage:

<u>@ Station S</u>

$$-V_{2S} + I_{2S} \bullet m \bullet Z_L + V_F = 0$$

$$V_F = V_{2S} - m \bullet I_{2S} \bullet Z_L \qquad [A3.5]$$

@ Station R

$$-V_{2R} + I_{2R} \bullet (1 - m) \bullet Z_L + V_F = 0$$

$$V_F = V_{2R} + m \bullet I_{2R} \bullet Z_L - I_{2R} \bullet Z_L \qquad [A3.6]$$

Set equations A3.5 and A3.6 equal to each other and solve for "m" with respect to Station S.

$$V_{2S} - m \bullet I_{2S} \bullet Z_L = V_{2R} + m \bullet I_{2R} \bullet Z_L - I_{2R} \bullet Z_L$$

$$V_{2S} - V_{2R} + I_{2R} \bullet Z_L = m \bullet I_{2s} \bullet Z_L$$

$$m = \frac{V_{2S} - V_{2R} + I_{2R} \bullet Z_L}{I_{2S} \bullet Z_L} \qquad [A3.7]$$

Step 2-Zero-Sequence Impedance Calculation

Figure 4.2.1.2 is the corresponding zero-sequence network for faults involving ground.

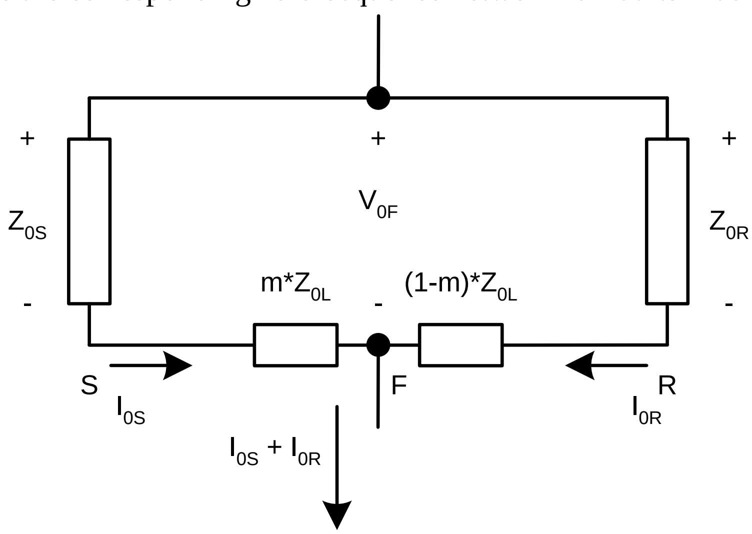

Fig A3.2. Zero-Sequence Network

The zero-sequence impedance of the transmission line can be calculated using the synchronized zero-sequence voltage and current measured at each end of the line using the following equation:

$$Z_{0L} = \frac{I_{0S} \cdot Z_{0S} - I_{0R} \cdot Z_{0R}}{m \cdot I_{0S} - (m-1) \cdot I_{0R}} \quad [A3.8]$$

Derive two loop voltage equations in terms of the fault voltage:

@ Station S

$-V_{0S} + I_{0S} \bullet m \bullet Z_0 + V_F = 0$

$$V_F = V_{0S} - m \bullet I_{2S} \bullet Z_0 \quad [A3.9]$$

@ Station R

$-V_{0R} + I_{0R} \bullet (1 - m) \bullet Z_0 + V_F = 0$

$$V_F = V_{0R} + (m - 1) \bullet I_{0R} \bullet Z_0 \quad [A3.10]$$

Set the two equations above equal to each other and solve for Z_0.

$V_{0S} - m \bullet I_{0S} \bullet Z_0 = V_{0R} + (m - 1) \bullet I_{0R} \bullet Z_0$

$m \bullet I_{0S} \bullet Z_0 + (m - 1) \bullet I_{0R} \bullet Z_0 = V_{0S} - V_{0R}$

$Z_0 \bullet \{m \bullet I_{0S} + (m - 1) \bullet I_{0R}\} = V_{0S} - V_{0R}$

$$Z_0 = \frac{V_{0S} - V_{0R}}{mI_{0S} + (m-1) \bullet I_{0R}} \quad [A3.11]$$

A4. Use of Time Synchronized Measurements Examples

The following examples demonstrate the use of time synchronized measurements recorded during an unbalanced fault from two ends of an overhead transmission line to verify the positive-sequence impedance and calculate the actual zero-sequence impedance.

Figure A4.1 is a simple model of a faulted transmission line. Substation S is the reference bus with respect to the distance-to-fault (m).

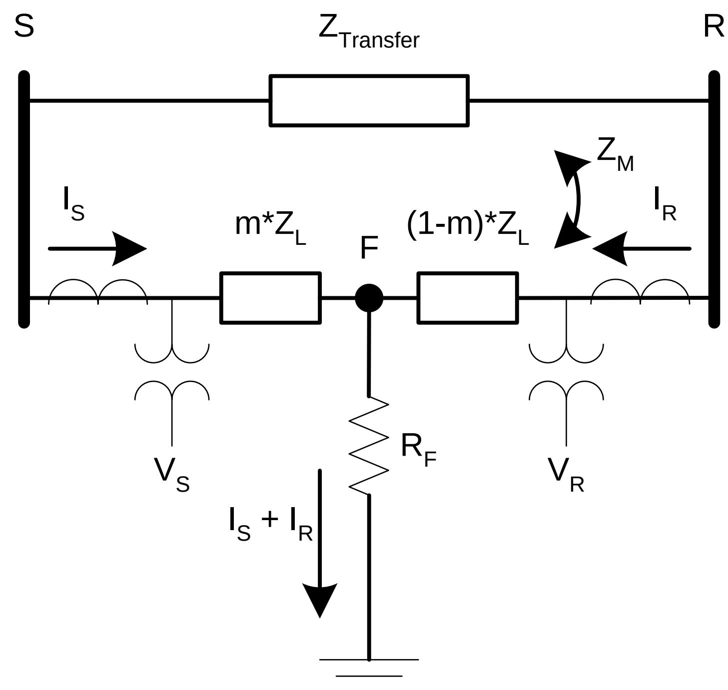

Fig A4.1 Transmission Line Model

Z_L =	Line Impedance
$Z_{Transfer}$ =	Transfer Impedance
Z_M =	Mutual Coupling
F =	Fault Location
V_S =	Fault Voltage at Substation S
V_R =	Fault Voltage at Substation R
I_S =	Fault Current from Substation S

I_R = Fault Current from Substation R

Equation A4.1 calculates the per unit distance to fault with respect to Substation S:

$$m = \frac{V_S - V_R + I_R \bullet Z_L}{I_S \bullet Z_L} \qquad [A4.1]$$

EXAMPLE I

The first example is the case of a resistive "A" phase-to-ground fault located 75 percent of the line (15 miles) from substation S that was simulated using Mathcad. There was moderate load prior to the fault and the line is mutually coupled to another transmission line. The fault voltage and current at each end of the line were as follows:

V_{AS} = 53.4 ∠-32.1° volts V_{AR} = 55.6 ∠-18.1° volts
V_{BS} = 68.6 ∠-128.5° volts V_{BR} = 63.2 ∠-123.0° volts
V_{CS} = 63.9 ∠115.2° volts V_{CR} = 66.3 ∠114.6° volts

The negative-sequence voltage and negative-sequence current are calculated as follows:

$V_2 = \frac{1}{3} \bullet (V_A + a^2 V_B + a V_C)$ $I_2 = \frac{1}{3} \bullet (I_A + a^2 I_B + a I_C)$

V_{2S} = 7.86 ∠-133.8° volts V_{2R} = 6.90 ∠-133.6° volts
I_{2S} = 0.58 ∠-13.9° amps I_{2R} = 2.82 ∠-36.4° amps

Equation (1) yields a location of 75 percent of the line which matches the actual fault location. Verify the positive-sequence impedance of the transmission line by checking to see if the calculated distance-to-fault matches with the actual fault location. Equation A3.1 is immune to problems associated with fault resistance and zero-sequence mutual coupling since it only uses negative-sequence quantities.

EXAMPLE II

This example is an actual case where an "A" Phase-to-ground fault occurred on a 230 kV overhead transmission line running from Wilson substation to Greenville substation within the Carolina Power and Light transmission system. Conventional methods proved futile when utility personnel tried to locate the fault. The fault turned out to be an old oak tree growing under the line. This vegetation represented an extremely high level of fault resistance (that is, many times greater than the impedance of the transmission line). The double-ended distance-to-fault equation correctly calculated the distance-to-fault with an error less than 5 percent. Below are the actual calculations for this case. Substation S represents Greenville and Substation R represents Wilson.

Below are the time synchronized negative-sequence quantities measured at each end of the line:

V_{2S} = 8.454 $\angle$238.6° kV V_{2R} = 6.697 $\angle$239.4° kV
I_{2S} = 456.69 $\angle$368.4° A I_{2R} = 345.82 $\angle$350.4° A

I_2 = $I_{2S} + I_{2R}$ = 792.82 $\angle$0.7° A

Z_L = 24.899 $\angle$82.7° Ω primary

$$m = \frac{V_{2S} - V_{2R} + I_{2R} \bullet Z_L}{I_2 \bullet Z_L}$$

$V_{2S} - V_{2R} + I_{2R} \bullet Z_L$ = 6.952 $\angle$77.5° kV

$I_2 \bullet Z_L$ = 19.7 $\angle$83.4° kV

$|m|$ = 0.352 per-unit

The actual line length is 35.43 miles. Therefore, the distance-to-fault with respect to Greenville was 12.5 miles. The actual distance-to-fault was 13 miles.

EXAMPLE III

A “B” Phase-to-“C” Phase fault occurred on the 230 kV overhead transmission line running from Wake substation to Selma substation within the Carolina Power and Light transmission system. The fault was due to a truck that caught fire under the line. The resulting smoke created a path for electrical current to flow between “B” and “C” Phase conductors. The double-ended distance-to-fault equation was applied using the negative-sequence voltage and current recorded by instrumentation at the two ends of the line. The error was less than 2 percent. Below are the actual calculations for this case. The subscript ‘S’ represents Wake and subscript ‘R’ represents Selma.

V_{2S} = 51.7 $\angle$1.9° kV V_{2R} = 37.9 $\angle$1.3° kV
I_{2S} = 11,900 $\angle$96.5° A I_{2R} = 2,470 $\angle$94° A

$I_2 = I_{2S} + I_{2R}$ = 14,370 $\angle$96° A

Z_L = 11.96 $\angle$85.8° Ω primary

$|m|$ = 0.092 per-unit

The actual line length is 21 miles. Therefore, the distance-to-fault with respect to Wake was 1.93 miles.