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DISTANCE PROTECTION OF POWER SYSTEM IN PRESENCE OF FACTS ELEMENTS

BY

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ABSTRACT

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Title: Distance Protection of Power System in presence of FACTS elements

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With the development and implementation of various compensation devices, i.e. Flexible AC Transmission Systems (FACTS), protection relays are inevitably impacted in negative ways causing loss of protection accuracy. In this Thesis, firstly, detailed study of power system in presence of different faults is performed. Secondly, the compensation elements are added to the power system and impact of these elements on the faults and distance protection are completely studied. The faults are considered as symmetrical and unsymmetrical.

The objective of this Thesis is to verify the effect of different compensation elements to the fault currents and on the zone settings to adjust protection devices.

The compensation elements in this study are chosen to simulate the purpose of FACTS devices. Capacitors are connected in parallel and in series. In addition, inductors are connected in parallel to the transmission line. Shunt capacitors are required to adjust the power system voltage, while the purpose of series capacitance, is to increase power transfer capacity. Shunt reactors are used for voltage control in cases of light loads or capacitive loads.

The results of this Thesis show impact of compensation techniques in different fault currents and consequently on the protection devices. Furthermore, the settings of the protection devices should be readjusted to correctly cover intended zone.

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CHAPTER 1: INTRODUCTION

The power system is composed of several parts: generation units, transmission network and distribution network, all these systems interconnect for the whole power system to work. The generation units are part of the network where the electricity is produced, and it includes the power plants which generate electricity. The transmission network is responsible for transmission of electricity at high voltages over long distances. It consists of high voltage lines and transformers, which raise the voltage so it can be transmitted efficiently, while the distribution network is the part of the network which is closest to the end consumers and delivers the energy [1].

This complex network of generators, transformers, transmission and distribution lines is designed, planned and operated to give continuous, uninterrupted and reliable energy supply to its customers. The power system usually is subjected to various disturbances, that may be the result of load changes or faults due to natural causes or equipment damage. Any malfunction in the grid is identified as fault. The faults can cause damage to load, revenue losses, power loss and may be severe to cause life losses. Therefore, it is vital to do fault diagnostic and prevention.

The most important thing is to isolate the fault from the other parts of the grid as soon as possible. For this reason, the protective device is used. The definition of IEEE describes protective relaying system as devices that respond to input conditions in a prescribed manner and cause contact operation or other similar change when some specified conditions are met. The specified condition denote fault. These devices are called relays and are installed at the ends of the transmission line. When it detects fault, it trips (open) to isolate the other part of the line from the fault.

Natural events like lightning can cause short circuit, which occurs when the current of the system is several times higher than the normal operating current. Since faults due to natural events are usually temporary, reclosers are installed in some transmission networks. Reclosers function is to clear the fault and resume normal operation, or else if fault not cleared it will re-open.

Analysis of faults is the continuous monitoring of grid status. Faults detecting is done by relays based on some of the system measures compared to reference points, stored usually in database. These parameters are impedance, current, voltage or phase angle.

Coombe and Lewis proposed and described the first short circuit analysis program in their paper [1] in 1956. They defined two types of faults which can occur on any transmission lines: balanced faults and unbalanced faults. The most accurate way to present, design and analyze the power system is using the three-phase balanced system characterized with three conductors (e.g. wires), each carrying alternating current (AC) shifted by 1/3 cycle from the other two. System denoted as balanced is the system in which the power carried by each phase is equal. Unbalanced system on the other hand is system in which each phase carries different power.

New technologies and integration with information technology (IT) enabled power systems evolving into smart grids. Smart grids have many benefits, in the sense of protection and fault analyses. New technologies enable more efficient transmission of electricity, quicker restoration of electricity after power disturbances and makes the system better prepared to address emergencies.

In [2] simulation of the transmission lines in combination with the increased demand was performed to clarify reduction of the network stability concept, which may lead to voltage collapse eventually.

Besides short circuits, voltage collapse is the most common fault in the power grid, mainly caused by the growing consumer demand and the transition to distributed and deregulated small-scale generation, when the network and its physical characteristics cannot handle the voltage load, the network is stressed and become instable [3].

In [4] analysis of voltage instability explained and description of the most important factors to instability introduced, such as reactive power imbalance in the system. Understanding and controlling reactive power is therefore essential for the efficient and safe operation of the grid. In this direction Flexible AC Transmission Systems (FACTS) devices are introduced. FACTS enable reactive power compensation, make the system stable and prevent voltage collapses. The compensation is made either by injecting or absorbing reactive power from the grid.

It is the objective of this Thesis to study all types of shunt faults in power systems before and after adding FACTS compensation devices in addition, to the study of effects of these elements on distance protection. Various scenarios to be studied like, faults and FACTS in the same line also fault in one line and FACTS connected to different line. The results of this work to be used in further over current and distance protection studies for larger systems.

CHAPTER 2: LITERATURE SURVEY

2.1 Faults Overview

The term fault in power system denotes connection between phases of a transmission lines or the phase conductors to ground and can be caused by insulation deterioration, wind damage or human vandalism etc. [5, 6].

The results of faults include equipment damage, blackouts, injuries and even death, which explains protection importance.

During short circuit, the current is referred to, as fault current and its value depends on the voltage of the system and the total impedance of the path of the current. If the short circuit is not located and eliminated as fast as possible, it can result in long-term power loss, blackouts and equipment damage.

The protective relaying system is used to prevent short-circuit problems. This system prevents the fault from affecting the whole system, by isolating the fault from the whole system. The specific protective relaying system needed for a specific scenario is determined by the process of fault analysis. The main goal of this process is public safety, maintaining a continuous and uninterrupted power supply to all customers and defining the required protection system and safety measures in order to achieve that [6].

The process of fault analysis evaluates the voltages and currents mainly, but it should include also parameters like suitable fuse, circuit breaker size, location of the fault, type of relay, the path of the current and the impedance of the system, in order to determine the protection system and its settings [5]. One way to do fault analysis is using a signal which in case of fault will trip or open the circuit breaker by assuming several fault scenarios (several conditions that caused the fault). However, this is not always an easy task as practical systems may consist of thousands of buses.

Software programs like MATLAB/ETAP are used for these calculations. The first analysis program was proposed by L.W. Coombe and D.G. Lewis in 1956 [6].

Paul Anderson in [5] describes methods of finding solutions for faulted power systems and maintaining protective system applications. Turan Gonen in [7] explains the theory as well as the practice of power systems protection.

2.2 Faults Types

There are two main types of faults in power systems: balanced faults and unbalanced faults. In some books the terminology symmetrical and unsymmetrical is used. It is more likely to have unbalanced faults in the system than the possibility of balanced faults. Both types however are considered as shunt faults which are different from series faults, and both to be explained below [7].

2.2.1 Series Faults

Series faults, or also known as open circuit faults. They are referred to as open, because one or two phases are open while the third phase remain connected [7]. This introduce unbalance in the system because of the unbalanced impedance conditions caused by the transmission lines.

The system is unbalanced because the current differs in magnitude and phases in the three phases of the power system. There is lower current and higher voltage and frequency.

2.2.2 Shunt Faults

Shunt faults involve short circuit between power conductors or power conductors to ground. Shunt faults are the reason for most short circuit cases. Hence, it will be studied in this Thesis in details.

The classification of the shunt faults is line-to-ground fault (L-G fault), line-to-line fault (L-L fault), double line-to-ground (D-L-G fault) and three-phase fault (L-L-L fault).

1. L-G faults occur when one conductor drop to ground or contact the neutral conductor. High-speed wind, falling tree or lightning are the most common reasons for L-G faults.
2. L-L faults on the other hand occur when two conductors are short circuited.
3. D-L-G fault in comparison to L-L faults occur when two conductors instead of one, are shorted to ground or contact the neutral conductor.

These three types of shunt faults are unsymmetrical faults.

4. L-L-L faults are symmetrical faults which rarely occur in power systems. This type of fault is characterized with breakdown of insulation between all the phases or three phases shorted to ground.

In [9] overview of the fundamental concepts of power system analysis and their applications to real-world problems is given, but besides that it also gives numerical insights about the occurrence of different types of faults. 70% of all faults in power systems are L-G faults, 15% are classified as L-L faults, 10% are D-L-G faults and only 5% are L-L-L faults. [7]

2.3 Symmetrical Components

2.3.1 Definition of Symmetrical Component

Fortescue gives his definition of the symmetrical component in [13]. He defined a linear transformation from three-phase components to a new set of components called symmetrical components. According to the theorem N unbalanced phasors can be represented by a systems of N balanced phasors.

In [10], special transformation matrices for handling different distribution network configurations, according to the dependence of the system dimension are defined and described.

This method is also known as the three-component method, because the unbalanced 3-phase voltages denotes as V_a, V_b and V_c could be transformed into 3 sets of balanced 3-phase components, also known as positive, negative and zero sequence components.

1) Positive-sequence components, or voltages are phasors characterized with equal magnitude, but are 120 degrees apart. They are referred to as positive because they are having the same phase sequence as the original unbalanced phasors.
2) Negative-sequence components are characterized with equal magnitude and are 120 degrees apart, having the phase sequence opposite to that of the original phasors
3) Zero-sequence components are voltages which are equal in magnitude and in phase, but there is no rotation sequence between them.

The fact that a set of unbalanced voltages or currents, may be resolved into balanced systems of equal number of phases involved, makes the analysis for electrical quantities during power system disturbances much less complex. The three-phase network is represented and solved as a set of three separate sequence networks [11].

Uncoupling the network into three separate sequence networks can be used in fault location identification too as in [12]. Based on positive, negative and zero sequence method, power systems during normal operation are symmetrical systems, meaning that no negative or zero sequence components exists. When fault happen all sequence components will exist in the power system and it will be necessary to find currents and voltages of all the components in the system.

An introduction and explanation of different methods of analysis for different types of faults are presented in [5]. During faults, systems are unbalanced, the symmetrical method visualizes and analyses these conditions with separate matrices.

In some cases, the fault type makes implementation of symmetrical component-based analysis difficult to implement. Example is the case when the sequence elements cannot be separated and are coupled, like the fault in which the transmission line is not completely transposed.

Specific case is when there is fault on mutual couplings in the power system. In that case, the produced current can cause the relay of the line to operate. This scenario must be prevented.

The mutually coupled lines are called simultaneous faults. Modelling mutually coupled lines for short-circuit analysis requires considering multiple factors, including line geometry. Solution of this problem and alternative method was introduced by Rao and Roy in [14].

The second method involves phase frame representation of network elements and the use of the distributed source solution technique in conjunction with the principle of superposition. It is also referred to as the phase domain method. The main drawback in comparison to the symmetrical component method is the complexity (the number of calculations) [3N] x [3N] matrices, in comparison to [N] x [N] matrices.

2.4 FACTS devices

FACTS are power electronics-based systems used in power transmission systems, to enhance power system stability by injecting/absorbing reactive power from the system. FACTS provide control of one or more AC transmission parameters (such as voltage, impedance, phase angle and power). It increases the reliability of AC grids by achieving better utilization of the network, increased availability, and improved network stability [15].

It can be divided into four categories 1) Shunt 2) Series 3) Series - Series 4) Shunt – Series.

Shunt compensation is used to supply reactive power and improve voltage profile. Series compensation is used to increase transmission line capacity and system stability. The value of the used capacitors in different types of compensators, to reach the same voltage reference, will differ as shown and discussed in [16].

In [17] different types of faults in transmission lines are simulated, in [18] different FACTS controllers are used, to ensure stable operation of power systems in the event of large disturbances and faults, referred to as transient stability control.

2.5 Effect of FACTS devices on distance protection

FACTS devices used to control voltage stability by supplying or absorbing reactive power. Some FACTS (ex. STATCOM) are positioned mainly in the mid-point of a transmission line or heavy load area, to maintain the connecting point voltage [15].

Many researches are written in the area of FACTS compensation, installation and its effects on fault currents [19], [20],[21],[22],[23]. The main conclusion is that in a case of fault loop, FACTS will affect components both in the steady and the transient state and will change the impedance of the system, compared with that of a system without FACTS.

In [19] description of FACTS installation and special features presented in addition to its operation principle. Fault location identification when compensation devices are connected (ex. SVC) is studied in [24].

Procedure for the distance relaying of power transmission lines involving FACTS devices, particularly the UPFC (unified power flow controller) and study of the impact of FACTS on the tripping boundaries are proposed in [23] and [25]. The impact of the thyristor-controlled series capacitor (TCSC) on the distance protection relay, its influence on the mho characteristic, reactance characteristic and directional characteristic is presented in [22]. The results in [23] show that FACTS devices affect the trip boundary of distance relay.

2.6 Relay types

There are several types of switching devices used to isolate or change the state of an electric circuit from one state to another, referred to as relays.

2.6.1 Directional relays

Directional relays are relays used to isolate and protect the system against fault currents that circulate in one direction. In order to calculate the angle of the current $\emptyset$ and to determine whether the relay should operate or not, the directional relays use the reference voltage $\mathrm{V} = \mathrm{V}\angle 0°$ and the current $\mathrm{I} = \mathrm{I}\angle\emptyset°$.

If the following condition is satisfied, $-180° < (\emptyset - \emptyset_1) < 0°$ then the relay will trip. Otherwise will block.

2.6.2 Distance relays

In a complex power system with many radial lines and buses, in which the fault current varies according to the changes in the system, the directional relays are not very helpful. The relays should be able to coordinate in transmission loops with multiple sources and to be in accordance with the voltage-to-current ratio. These relays are called distance relays, or impedance relays [11]. The distance relay had its name because it depends on the distance between the impedance of the faulty section and the position on which relay installed.

When fault occurs, if the current increases by a factor of 6 while voltage decreases by a factor of 3, then the voltage-to-current ratio decreases by a factor of 12. In some cases, like high impedance faults, the traditional voltage to current ratio method may not be enough and modified algorithms to be used as discussed in [26].

The most common scenario in real transmission systems is the following: distance relays as primary protection and directional relays as secondary protection. Distance relays are used in the first zone, which is set between 85 and 90% of the line length and in the second zone which covers the complete section of the transmission line to be protected. Analysis of power system in which both directional and distance relays are implemented is presented in [27], [28] and [29] in addition to optimum timing for the second zone of distance relay.

Having in mind the influence of the FACTS in general on the protection relays, the aim of this Thesis is to analyze the influence of compensation capacitors and inductors on the performance of distance and over current relay. In order to do that, first step is to calculate the symmetrical component of the system. Then analysis of different types of faults and symmetrical component transformation with and without addition of compensation devices to be done. At the end comparison of the obtained analytical results will be used to highlight the effect on faults currents and distance protection relays.

CHAPTER 3: SYMMETRICAL COMPONENTS

The symmetrical component or impedances of power system elements is important part that enable us to do fault analysis using sequence method. It can be calculated or in some cases provided by manufacturers. The concept of sequence impedance is introduced and explained in further details in [30].

3.1 Synchronous Machines:

Synchronous machines have different values of positive, negative and zero sequence components. The positive sequence of a synchronous machine can be selected depending on the time the fault starts to the time of the desired relay response, breaker opening, and sustained fault conditions are achieved. Therefore, the positive sequence impedance can be its sub transient ($X_d^{"}$), transient (X_d'), or synchronous (X_d) reactance, but sub transient is the usually taken during fault analysis [7].

When the synchronous machine has a cylindrical rotor the sub transient and negative sequence are same and are given by

$$Z_2 = jX_2 = j\left(\frac{X"_d + X"_q}{2}\right) \qquad (3.1.1)$$

Cylindrical rotor based synchronous generators to be used in this study, due to the prime movers used (steam turbines) and high-speed alternators which requires this type of rotors.

The zero-sequence impedance is much smaller than the positive and negative sequences, but it is very complicated since it varies widely due to its dependence on the pitch of armature coils. In order to determine it, it is essential to add all three-armature windings in series and apply single-phase voltage [11].

3.2 Transmission lines:

A passive and bilateral device due to the absence of voltage and current and it performs the same no matter the direction of current. This, however, is only true for a single transmission line, an interconnected network of lines is not bilateral since it has active components along the way.

Due to these characteristics the positive and negative sequences both have same impact on the lines, only if the line is transposed (the phase conductors of the line physically exchange positions alone the way) [31].

Figure 1 below shows a representation of transmission line with unequal self-impedances and unequal mutual impedance [11]. The representation below is general and can be used for short, medium or long lines. However, the length of the lines in this study is selected to be medium.

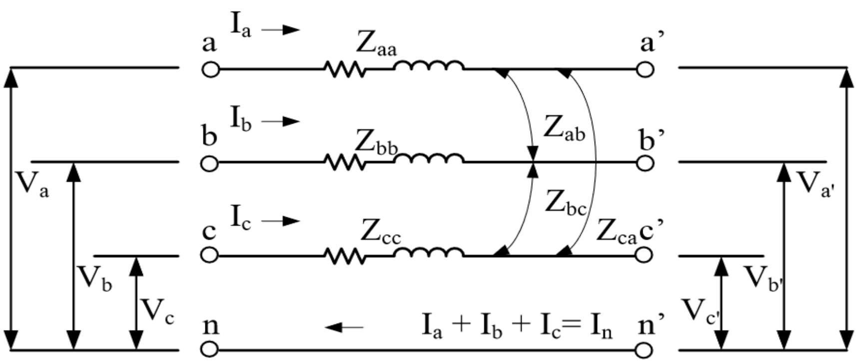

Figure 1. Transmission line diagram with unequal impedance [11].

So, for these transmission lines.

$V_{abc} = (Z_{abc})(I_{abc})$ (3.2.1)

Where

$$[Z_{abc}] = \begin{bmatrix} Z_{aa} & Z_{ab} & Z_{ac} \\ Z_{ba} & Z_{bb} & Z_{bc} \\ Z_{ca} & Z_{cb} & Z_{cc} \end{bmatrix} \tag{3.2.2}$$

In general, the sequence-impedances are

$$[Z_{012}] = [A^{-1}][Z_{abc}][A] \tag{3.2.3}$$

The sequence impedance of an un-transposed line can be obtained from equation 3.2.3 and is expressed as.

$$[Z_{012}] = \begin{bmatrix} Z_{00} & Z_{01} & Z_{02} \\ Z_{10} & Z_{11} & Z_{12} \\ Z_{20} & Z_{21} & Z_{22} \end{bmatrix} \tag{3.2.4}$$

It can also be expressed as

$$[Z_{012}] = \begin{bmatrix} Z_{10} + 2Z_{m0} & Z_{12} - Z_{m2} & Z_{s1} - Z_{m1} \\ Z_{s1} - Z_{m1} & Z_{s0} - Z_{m0} & Z_{s2} - 2Z_{m2} \\ Z_{s2} - Z_{m2} & Z_{s1} - 2Z_{m1} & Z_{s0} - Z_{m0} \end{bmatrix} \tag{3.2.5}$$

It is known that Z_{s0} = zero sequence self-impedance

$$Z_{s0} = \frac{1}{3}(Z_{aa} + Z_{bb} + Z_{cc}) \tag{3.2.6}$$

Z_{s1} = positive sequence self-impedance

$$Z_{s1} = \frac{1}{3}(Z_{aa} + a\,Z_{bb} + a^2\,Z_{cc}) \tag{3.2.7}$$

Z_{s2} = negative sequence self-impedance

$$Z_{s2} = \frac{1}{3}(Z_{aa} + a^2 Z_{bb} + a\,Z_{cc}) \tag{3.2.8}$$

Z_{m0} = zero sequence mutual impedance

$$Z_{m0} = \frac{1}{3}(Z_{bc} + Z_{ca} + Z_{ab}) \tag{3.2.9}$$

Z_{m1} = positive sequence mutual impedance

$$Z_{m1} = \frac{1}{3}(Z_{bc} + a\,Z_{ca} + a^2\,Z_{ab}) \tag{3.2.10}$$

Z_{m2} = negative sequence mutual impedance

$$Z_{m2} = \frac{1}{3}(Z_{bc} + a^2 Z_{ca} + a\, Z_{ab}) \qquad (3.2.11)$$

Therefore

$$[V_{012}] = [Z_{012}][I_{012}] \qquad (3.2.12)$$

The resultant matrix $[Z_{012}]$ was not symmetric so this means that the Equation 3.2.12 will not show desirable results.

To solve this problem there are two methods. One is to completely transpose the line and the other one is to obtain equal mutual impedance by placing the conductors with equal spacing between them [11].

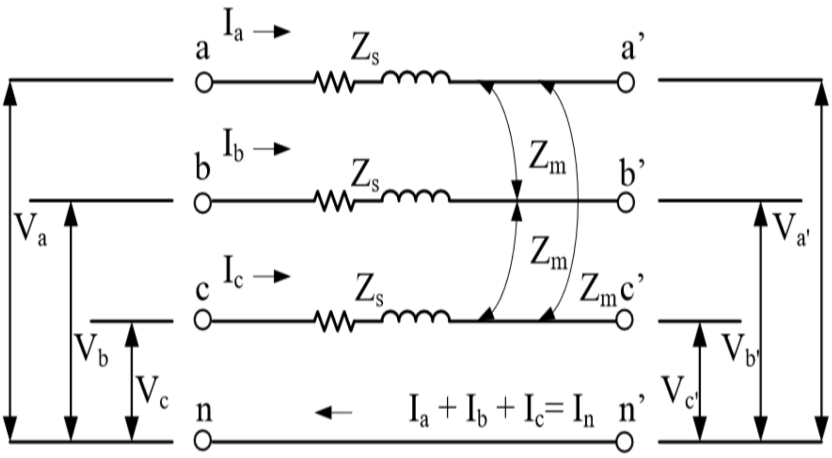

Figure 2. Transmission line diagram with equal series and mutual impedance [11].

For a transposed line, mutual impedance is:

$$Z_{bc} = Z_{ca} = Z_{ab} = Z_m \qquad (3.2.13)$$

And the self-impedance is:

$$Z_{aa} = Z_{bb} = Z_{cc} = Z_s \qquad (3.2.14)$$

So, by calculation:

$$Z_{abc} = \begin{bmatrix} Z_s & Z_m & Z_m \\ Z_m & Z_s & Z_m \\ Z_s & Z_m & Z_s \end{bmatrix} \quad (3.2.15)$$

Where the self and mutual impedance are given by

$$Z_s = R_k + R_k' + j\omega 2 \times 10^{-7} ln \frac{D_{kk'}}{D_{kk}} \ \Omega/m \quad (3.2.16)$$

$$Z_m = R_k' + j\omega 2 \times 10^{-7} ln \frac{D_{km'}}{D_{km}} \ \Omega/m \quad (3.2.17)$$

Where D_{kk} is the Geometric Mean Radius (GMR) and D_{kk}' is a function of both the earth resistivity and the frequency.

R_k: Cable resistance

R_k': Mutual resistance between cables

ρ: Resistivity

D_{km}: Distance between conductors

$D_{km'}$: Geometric Mean Distance (GMD) between the three phases

When Equation 3.2.5 is applied

$$[Z_{012}] = \begin{bmatrix} Z_s + 2Z_m & 0 & 0 \\ 0 & Z_s - Z_m & 0 \\ 0 & 0 & Z_s - Z_m \end{bmatrix} \quad (3.2.18)$$

The above equation can also be written as:

$$[Z_{012}] = \begin{bmatrix} Z_1 & 0 & 0 \\ 0 & Z_2 & 0 \\ 0 & 0 & Z_3 \end{bmatrix} \quad (3.2.19)$$

Now this result is desirable because each sequence is causing a drop in its respective sequence network and no mutual coupling is happening.

3.3 Transformers:

A three-phase transformer can be made by connecting three single-phase transformers. This is called transformer bank. In a transformer usually positive and negative sequence impedance are same and zero sequence impedance is different but still they are all considered same [11].

$$Z_0 = Z_1 = Z_2 = Z_{trf} \tag{3.3.1}$$

Z_0 is infinite when the flow of sequence current is prevented by transformer connection. Zero sequence current flows inside the delta-delta bank for delta windings but it is prevented to flow outside the windings because there is no path provided. In a wye-grounded-wye-connected three phase transformer bank there is path for the zero-sequence current to flow through the neutral impedance. [11]

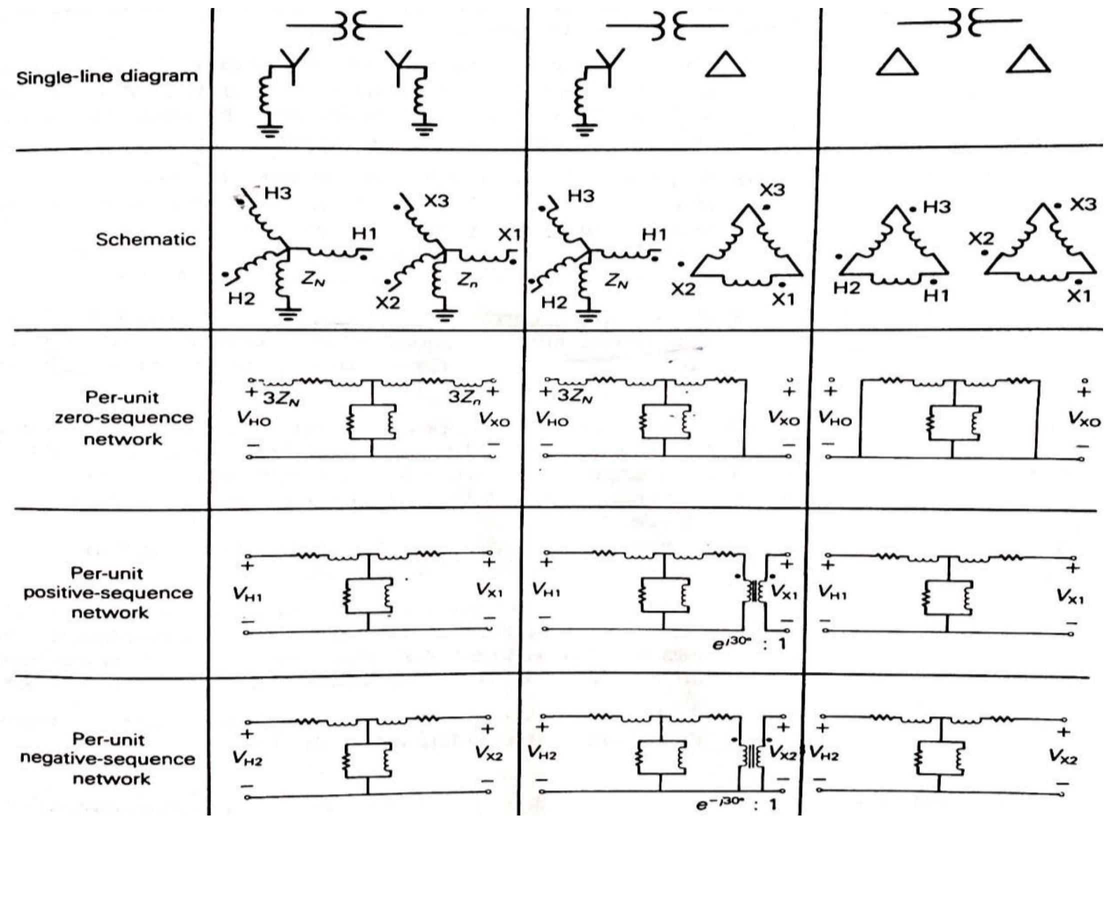

Figure 3. Per unit zero, positive and negative sequence transformer network [11].

The per unit sequence networks of the Y-Δ transformer have the following features.

1. Per unit impedances are the same for all winding configurations of a transformer since, it does not depend on the winding connections. The base voltages depend on the winding connections.
2. There is a phase shift included in the per unit impedance network. In the American system, the positive sequence voltages and currents on the high voltage side leads the current and voltages on the other side by 30 degree. For negative sequence it is the opposite.
3. Zero sequence currents do not flow in Y windings unless there is a neutral connection. In the case of Δ windings, it always flows but never enters or leaves the Δ windings.

The per unit sequence networks for the Δ-Δ transformer have the following features:

1. The positive and negative sequence impedances are same as those for Y-Y transformers because they do not depend on winding connections.
2. Zero sequence currents cannot enter or leave the Δ windings although the keep circulating within the Δ windings.

3.4 Loads:

Figure 4 below shows a balanced Y impedance load. Each phase has an impedance labeled as Z_Y and the impedance between load neutral and ground is Z_n.

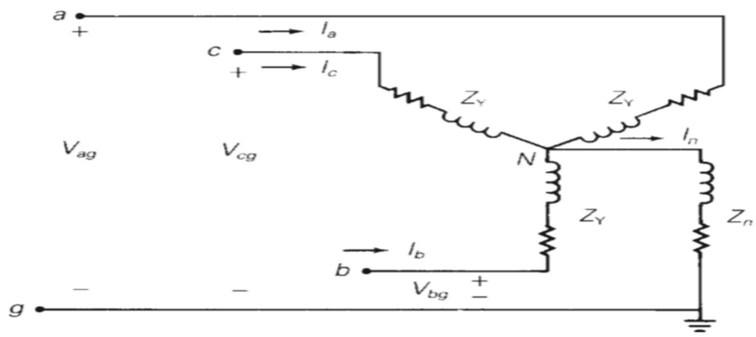

Figure 4. Balanced Y impedance load [11].

Now from this figure line to ground Voltage V_{ag} is

$$V_{ag} = Z_Y I_a + Z_n I_n \quad (3.4.1)$$

$$V_{ag} = Z_Y I_a + Z_n (I_a + I_b + I_c) \quad (3.4.2)$$

$$V_{ag} = (Z_Y + Z_n) I_a + Z_n I_b + Z_n I_c \quad (3.4.3)$$

Similar equations can be written for $V_{bg}$and V_{cg}

$$V_{bg} = (Z_Y + Z_n) I_b + Z_n I_a + Z_n I_c \quad (3.4.4)$$

$$V_{cg} = (Z_Y + Z_n) I_c + Z_n I_b + Z_n I_a \quad (3.4.5)$$

$$V_P = Z_P I_P \quad (3.4.6)$$

Where V_P the vector of line to line ground voltages, I_P the vector of line current voltages and Z_P the 3x3 matrix of the impedance.

$$V_S = Z_S I_S \tag{3.4.7}$$

$$Z_S = A^{-1} Z_P A \tag{3.4.8}$$

So, the impedance Matrix Z_S can be found by using Matrix A and Z_P and Inverse of A

$$A = \begin{bmatrix} 1 & 0 & 0 \\ 0 & a & 0 \\ 0 & 0 & a^2 \end{bmatrix} \tag{3.4.9}$$

$$Z_S = \frac{1}{3}\begin{bmatrix} 1 & 0 & 0 \\ 0 & a & 0 \\ 0 & 0 & a^2 \end{bmatrix} \times \begin{bmatrix} Z_Y + 3Z_N & Z_Y & Z_Y \\ Z_Y + 3Z_N & a^2 Z_Y & aZ_Y \\ Z_Y + 3Z_N & aZ_Y & a^2 Z_Y \end{bmatrix} = \begin{bmatrix} Z_Y + 3Z_N & 0 & 0 \\ 0 & Z_Y & 0 \\ 0 & 0 & Z_Y \end{bmatrix}$$

(3.4.10)

This matrix can be used to find the values of all three voltages

$$V_0 = Z_Y + 3Z_N I_0 \tag{3.4.11}$$

$$V_1 = Z_Y I_1 \tag{3.4.12}$$

$$V_2 = Z_Y I_2 \tag{3.4.13}$$

So, these equations show that the zero-sequence component only depends on the zero-sequence current and the impedance $Z_Y + 3Z_N$, this impedance is called zero sequence impedance and can be represented by Z_0. Similarly, positive and negative sequence impedances can be represented as $Z_1 = Z_2 = Z_y$.

The three equations given above can be represented by three networks, each sequence network is separate, uncoupled from the other two. The separation of these sequence networks is a consequence of the fact that Z_S is a diagonal matrix for a balanced-Y load.

CHAPTER 4: FAULTS ANALYSIS

This aim of this chapter is to study different type of fault currents, based on the symmetrical component definition presented in chapter 3. In the beginning differences between faults' types to be explained.

For an accurate fault analysis series and shunt faults need to be differentiated. There is one main difference between series and shunt faults, when the fault is caused by an unbalance in the line impedance, but no two lines are in contact or line to ground, this fault is called series fault. On the other hand, if due to some reason, two lines or a line and ground come in contact this is called shunt fault, as introduced in chapter 2.

Series fault are less likely to happen as compared to shunt faults. That is why shunt faults are discussed in detail here.

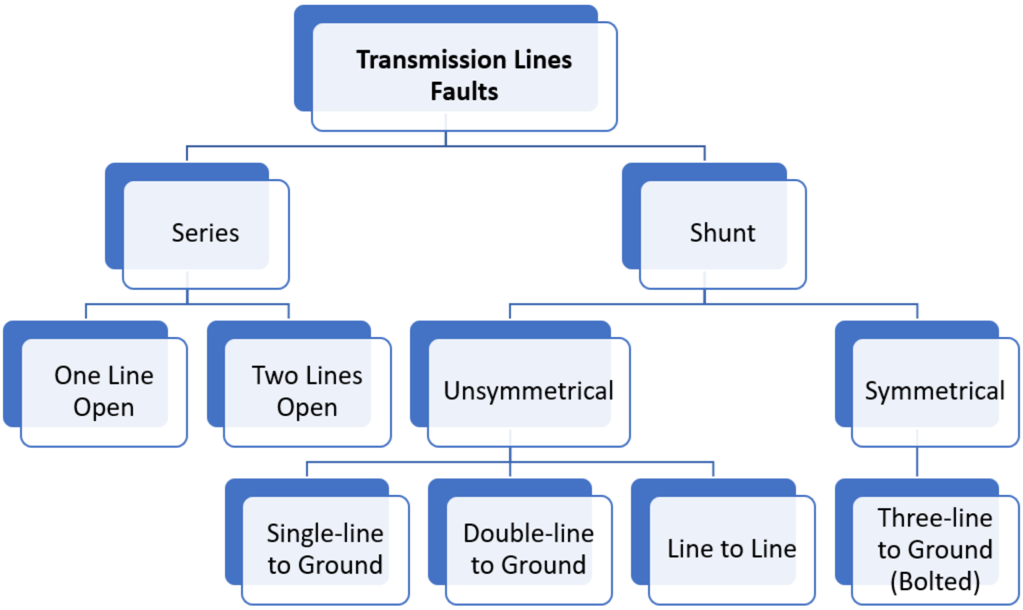

Figure 5. Types of transmission lines faults.

4.1 Series Faults:

These types of faults occur when there is an impedance unbalance on one of the three lines. One reason for these faults could be that a fuse or a circuit breaker controls the system and it does not open all three phases or one or two phases. It can also happen when one or two lines are broken so there is an unbalance of impedance, or when impedance is inserted in one or two phases creating an imbalance. [30]

4.2 Shunt Faults

There are two types of shunt faults, Symmetrical faults and Unsymmetrical faults:

4.2.1 Symmetrical Faults

When fault occurs between three phases, i.e. three phases are short-circuited then this it is called symmetrical faults.

Symmetrical fault can be bolted, meaning zero impedance fault or it can be of impedance Z. During a bolted three-phase fault, the sequence fault currents are $I_0 = I_2 = 0$ and $I_1 = V_f/Z_1$. The sequence fault voltages are $V_0 = V_1 = V_2 = 0$, which must be true since $V_{ag} = V_{bg} = V_{cg} = 0$

$$\begin{bmatrix} Vo \\ V1 \\ V2 \end{bmatrix} = \begin{bmatrix} 0 \\ Vf \\ 0 \end{bmatrix} - \begin{bmatrix} Z_1 & 0 & 0 \\ 0 & Z_2 & 0 \\ 0 & 0 & Z_3 \end{bmatrix} \begin{bmatrix} Io \\ I1 \\ I2 \end{bmatrix} \qquad (4.2.1)$$

4.2.2 Unsymmetrical Faults

1- Single line to ground faults (SL-G):

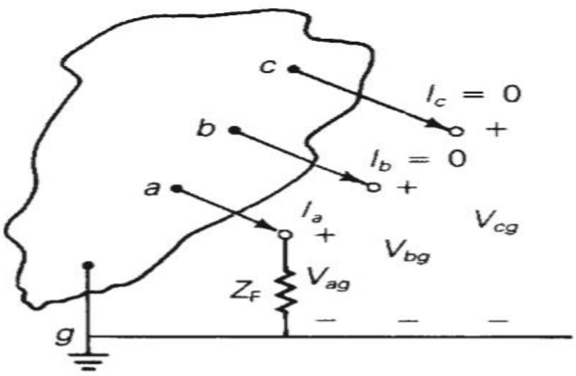

Figure 6. Single line to ground fault [11].

From figure 6 above

$$\begin{bmatrix} I_0 \\ I_1 \\ I_2 \end{bmatrix} = \frac{1}{3}\begin{bmatrix} 1 & 0 & 0 \\ 0 & a & a \\ 0 & a & a^2 \end{bmatrix}\begin{bmatrix} I_a \\ 0 \\ 0 \end{bmatrix} = \begin{bmatrix} I_a \\ I_a \\ I_a \end{bmatrix} \qquad (4.2.2)$$

Transforming 4.2.2 to sequence domain.

$$V_0 + V_1 + V_2 = Z_F(I_0 + I_1 + I_2) \qquad (4.2.3)$$

Fault conditions in sequence domain single line to ground fault.

$$I_0 = I_1 = I_2 \qquad (4.2.4)$$

$$V_0 + V_1 + V_2 = 3Z_F I_1 \qquad (4.2.5)$$

The above equations can be satisfied by interconnecting the sequence networks in series at the fault terminals through the impedance, the sequence of the fault currents is:

$$I_0 = I_1 = I_2 = \frac{V_F}{Z_0 + Z_1 + Z_2 + 3Z_F} \qquad (4.2.6)$$

$$I_a = I_0 + I_1 + I_2 = \frac{3V_F}{Z_0 + Z_1 + Z_2 + 3Z_F} \quad (4.2.7)$$

2- Double line fault (DL-G):

In figure 7 below a double line fault is shown from phase b to phase c through fault impedance to ground.

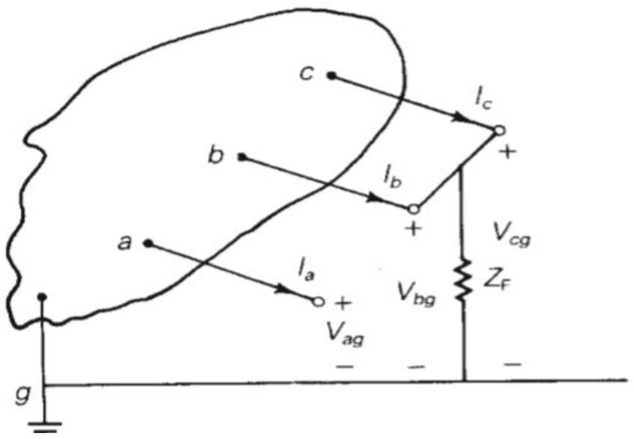

Figure 7. Double line to ground fault [11].

Fault conditions in the case of double line fault

$$I_a = 0 \quad (4.2.8)$$

$$V_{cg} = V_{bg} \quad (4.2.9)$$

$$V_{bg} = Z_F I_b + I_C \quad (4.2.10)$$

Transforming the above equations into sequence domain

$$V_0 + a^2V_1 + aV_2 = Z_F(I_0 + a^2I_1 + aI_2 + aI_1 + a^2I_2) \quad (4.2.11)$$

Using the identity $a^2 + a = -1$

$$V_0 - V_1 = Z_F(2I_0 - I_1 - I_2) \quad (4.2.12)$$

Using $I_0 = -I_1 - I_2$

$$V_0 - V_1 = 3Z_F I_0 \tag{4.2.13}$$

Fault conditions in sequence domain double line to ground fault.

$$I_0 + I_1 + I_2 = 0 \tag{4.2.14}$$

$$V_0 - V_1 = 3Z_F I_0 \tag{4.2.15}$$

$$V_1 = V_2 \tag{4.2.16}$$

Using current division, the negative and zero sequence fault currents are

$$I_2 = -I_1 \left(\frac{Z_0 + 3Z_F}{Z_0 + 3Z_F + Z_2}\right) \tag{4.2.17}$$

$$I_0 = -I_1 \left(\frac{Z_2}{Z_0 + 3Z_F + Z_2}\right) \quad (4.2.18$$

And the positive sequence current is given by

$$I_1 = \frac{V_F}{Z1 + \left(\frac{Z_2\,(Z_0 + Z_F)}{Z_0 + 3Z_F + Z_2}\right)} \tag{4.2.19}$$

3- Line to line faults (L-L):

Consider a line to line fault from phase b to c as shown in figure 8 below.

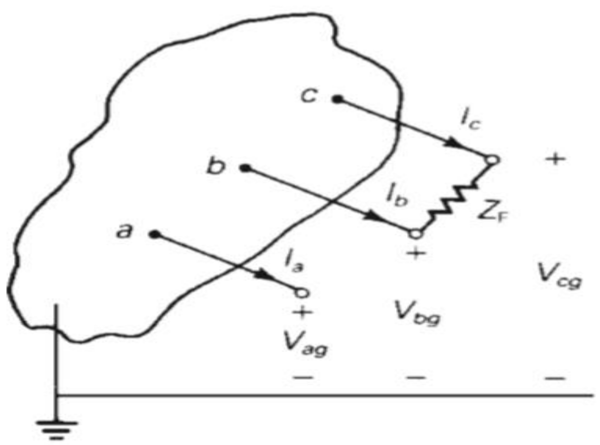

Figure 8. Line to line fault [11].

Fault conditions in the case of double line fault

$$I_a = 0 \tag{4.2.20}$$

$$I_c = -I_b \tag{4.2.21}$$

$$V_{bg} - V_{cg} = Z_F I_b \tag{4.2.22}$$

Transform the above equations to the sequence domain

$$\begin{bmatrix} I_0 \\ I_1 \\ I_2 \end{bmatrix} = \frac{1}{3}\begin{bmatrix} 1 & 1 & 1 \\ 1 & a & a^2 \\ 1 & a^2 & a \end{bmatrix}\begin{bmatrix} 0 \\ I_b \\ I_b \end{bmatrix} = \begin{bmatrix} 0 \\ \frac{1}{3}(a - a^2) I_b \\ \frac{1}{3}(a - a^2) I_b \end{bmatrix} \tag{4.2.23}$$

$$I_1 = -I_2 = \left(\frac{V_F}{Z_1 + Z_F + Z_2}\right) \tag{4.2.24}$$

Transforming the above equation to phase domain and the identity $(a - a^2) = -j\sqrt{3}$

$$I_b = -j\sqrt{3} I_1 = \left(\frac{-j\sqrt{3}\, V_F}{Z_1 + Z_F + Z_2}\right) \tag{4.2.25}$$

$$I_a = 0\ ,\ -I_b = I_c$$

CHAPTER 5: MATHEMATICAL CALCULATIONS OF FAULT CURRENT IN ABSENCE OF FACTS VERSUS PRESENCE OF FACTS

In this chapter fault current to be calculated in two cases; Fault in the same line as the FACTS installation and fault in different line other than the one in which FACTS is connected. In case 1 a study of different types of faults occur in line 7-8 in which FACTS installed it shall include different sizes of compensation devices and their impact on the fault current. In case 2 the same to be recalculated however, fault to be assumed in different line 8-9 and compensation will be connected to the same previous line 7-8.

The aim of the study in this chapter is to use its results, in voltage to fault current ratio calculations, which is used in distance protection in chapter 6 for relay settings. The main steps followed to obtain the targeted results are:

1. Power System Case Selection:

IEEE 9-bus case studied in this chapter and the needed power flow data was obtained using MatPower.

2. Cable and dimension selection

In order to get cable characteristics an exact cable type is chosen, and its size is selected based on the voltage ratings. An important factor to be chosen carefully is the distance between conductors and the height from conductors to ground. These values are vital to determine cables self and mutual impedance.

3. System sequence calculations

MATLAB software is used to develop mathematical model of the system, making it easier to calculate different fault types currents with manipulation of the value of compensation (FACTS) injected/absorbed power.

5.1 Power system case selection:

To investigate the validity of the sequence method, it has been applied to IEEE 9-bus system (Figure 9). The system consists of nine buses, three synchronous generators, three loads and six transmission lines. After load flow, the initial parameters of the system are studied (bus voltages, power generated, power absorbed etc.)

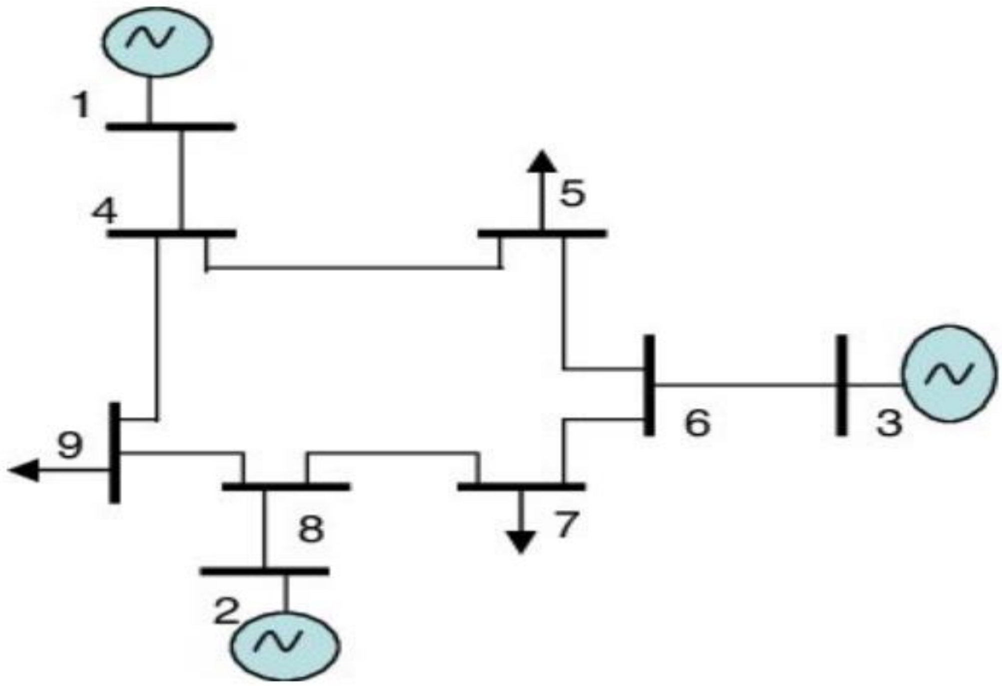

Figure 9. IEEE 9-bus case.

The power flow of the case above was done by MatPower using Newton's method, with system MVA base = 100 and system KV base = 345. The result of the power flow is provided in Appendix A.

The system consists of 3 Generators, 3 Transformers, 3 Loads, 9 Buses and 6 Transmission lines.

5.2. Cable and dimension selection:

The size of the cable selected depends on the length of the transmission line, load on the line and the voltage of the line. For high voltage lines over long distances, there are two important factors that contribute to the selection of the conductor; span length, and the weight of the conductors to be supported. That is why most of countries these days are using ACSR. One reason for using ACSR is also the problem with some countries that they do not have enough copper reserves.

For a given percentage of energy that is to be transmitted, the area and weight of the conductor is inversely proportional to the voltage of the line. The losses in the lines are given by $3I^2R$ where R is the resistance of line per unit length. That means the losses are directly proportional to the square of current flowing through the lines. So, keeping the current low and increasing the voltage, can decrease the losses as well as the cross-sectional area required to transmit that amount of current.

Current depends upon the nature of load and power factor. However, for very high voltage lines i.e. above 166 KV there are other losses that should be considered, losses due to leakage over insulators and corona losses.

Assuming transposed lines with solid conductor. Reference to the data given in [5] table 1 below will be used to determine cable Cross-Section area per conductor.

Table 1. Optimal Conductor Cross-Section Area for Different Voltage Ratings [11]

Nominal Voltage (kV)	Phase Conductors				
	Number of Conductors per Bundle	Aluminium Cross-Section Area per Conductor (ACSR) (Kcmil)	Bundle Spacing (cm)	Minimum Clearances Phase-to-Phase (m)	Phase-to-Ground (m)
69	1	-	-	-	-
138	1	300 – 700	-	4 to 5	-
230	1	400 – 1000	-	6 to 9	-
345	1	2000 – 2500	-	6 to 9	7.6 to 11
345	2	800 – 2200	45.7	6 to 9	7.6 to 11
500	2	2000 – 2500	45.7	9 to 11	9 to 14
500	3	900 – 1500	45.7	9 to 11	9 to 14
765	4	900 - 1300	45.7	13.7	12.2

As per the table above, for 345 KV 1 conductor of 2000 – 2500 kcmil area to be selected with space of 6-9 meters between phases and 7.6 to 11 meters from phases to ground.

Between phases space is assumed to be 6 meters. Phase to ground height is 11 meters as shown in figure 10 below.

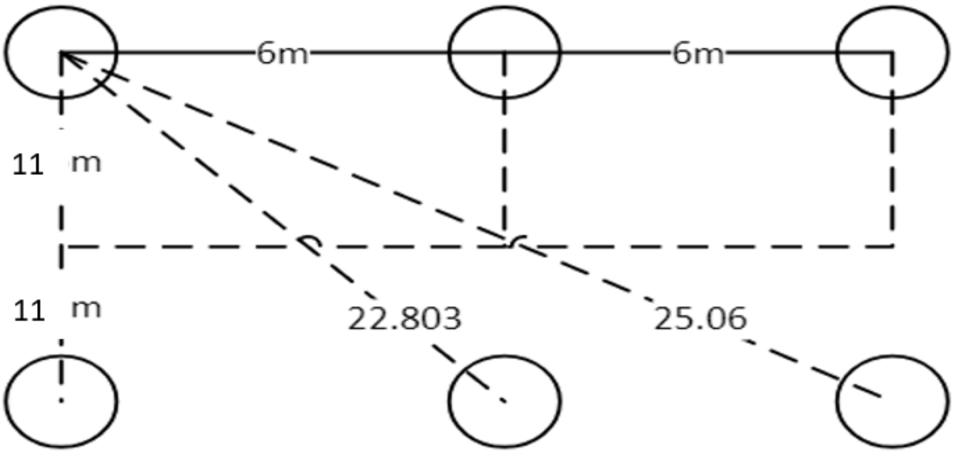

Figure 10. Transmission lines layout.

From table 2 below Bluebird conductor satisfies the above-mentioned characteristics and hence, it was selected.

Table 2.Characteristics of aluminum cable, steel, reinforced – ACSR [11]

	Aluminum						50 ◦C (122 ◦F) Small Current Approx. 75% Capacity
Code Word	Circular Mils Aluminum			Strand Diameter (inches)	Outside Diameter (inches)	Geometric Mean Radius (feet)	60 Hz
Joree	2 515 000	76	-	0.1819	1.880	0.0621	0.045
Thrasher	2 312 000	76	-	0.1744	1.802	0.0595	0.0482
Krwl	2 167 000	72	4	0.1735	1.735	0.057	0.0511
Bluebird	2 156 000	84	4	0.1602	1.762	0.0588	0.0505
Chukar	1 781 000	84	4	0.1456	1.602	0.0534	0.0598

5.3 System sequence calculations

After exact cable selection, the next step is calculation of lines' self and mutual impedance that will be used to find sequence values of the transmission lines in section 5.3.1. To find the line self-impedance (Z_{kk}) and mutual impedance (Z_{km}), equations (3.2.16) and (3.2.17) are used where:

R_k: Cable resistance, obtained from table 2

$$R'_k = 9.869 \times 10^{-7} \times f \ \ \Omega/m \quad (5.3.1)$$

$$D'_{kk} = 658.5 \times \sqrt{\rho/f} \quad (5.3.2)$$

ρ: Resistivity (Ωm) $= 100\Omega$m for average damp earth [11]

D_{kk} = GMR (from table 2)

$$D_{km} = \sqrt[3]{D_{12} \times D_{23} \times D_{13}} \quad (5.3.3)$$

$$D_{km'} = \sqrt[3]{D'_{12} \times D'_{23} \times D'_{13}} \quad (5.3.4)$$

Table 3 below shows cable characteristics, calculated based on cable type and conductors' installation.

Table 3. Calculations Results of Cable Characteristics

Self-Characteristics	$R'_k = 9.869 \times 10^{-7} \times 50 \ \Omega/m = 4.9345 \times 10^{-5} \ \Omega/m$	$D'_{kk} = 658.5 \times \sqrt{100/50} =$ 931.259m	$R_k = 3.138 \times 10^{-5} \ \Omega/m$
Mutual Characteristics	$D_{km'} = \sqrt[3]{22.00 \times 22.80 \times 25.06} = 23.25m$	$D_{km} = \sqrt[3]{6 \times 6 \times 12} = 7.56m$	$D_{kk} = 0.01786 \ m$

$$Z_s = (3.138 \times 10^{-5}) + (4.94 \times 10^{-5}) + j\omega 2 \times 10^{-7} ln \frac{931.26}{0.01786}$$

$$= (8.07 \times 10^{-5}) + j6.83 \times 10^{-4}\ \Omega/_m$$

$$Z_m = 4.94 \times 10^{-5} + j\omega 2 \times 10^{-7} ln \frac{23.25}{7.56} = (4.94 \times 10^{-5}) + j7.06 \times 10^{-5}\ \Omega/_m$$

5.3.1 Lines sequence impedance

- **Line 4-5**

Assumed line length is 250 Km

For the self and mutual line impedance per meter calculated below.

$$Z_s = (3.138 \times 10^{-5}) + (4.94 \times 10^{-5}) + j\omega 2 \times 10^{-7} ln \frac{931.26}{0.01786}$$

$$= (8.07 \times 10^{-5}) + j6.83 \times 10^{-4}\ \Omega/_m$$

$$Z_m = 4.94 \times 10^{-5} + j\omega 2 \times 10^{-7} ln \frac{23.25}{7.56} = (4.94 \times 10^{-5}) + j7.06 \times 10^{-5}\ \Omega/_m$$

Line 4-5 impedance in ohm and per unit (p.u.) is shown in table 4 below.

Table 4. Line 4-5 (250km) self and mutual impedance in ohm and per unit

Impedance in ohm	Impedance in per unit
$Z_s = 20.18 + j\ 170.62\ \Omega$	$Z_s = 0.017 + j\ 0.14\ p.u$
$Z_m = 12.34 + j17.65\Omega$	$Z_m = 0.01 + j0.015\ \ p.u$

The base impedance used above is calculated as follow:

$$Z_{base} = \frac{(345 \times 10^3)^2}{100 \times 10^6} = 1190.25\ \Omega$$

$$Z_0 = Z_s + 2Z_m \tag{5.3.5}$$

$$Z_1 = Z_2 = Z_s - Z_m \tag{5.3.6}$$

$Z_0 = 0.038 + j\ 0.17\ p.u;$ $\qquad Z_1 = Z_2 = 6.59 \times 10^{-3} + j1.29 \times 10^{-1}\ \ p.u$

From equation 5.3.6 Positive and Negative sequence impedances will be equal for the same transmission line. Equations 5.3.5 and 5.3.6 will be used to calculate Zero, Positive and Negative impedances for the transmission lines based on their lengths as shown in table 5 below.

Table 5. Zero, Positive and Negative Sequence Impedance for the Transmission Lines

Line	Length (km)	Zero-Sequence Impedance (p.u.)	Positive and Negative Sequence Impedance (p.u.)
Line 4-5	250	$0.038 + j\,0.17$	$6.59 \times 10^{-3} + j1.29 \times 10^{-1}$
Line 5-6	220	$0.033 + j\,0.15$	$5.80 \times 10^{-3} + j1.13 \times 10^{-1}$
Line 4-9 and 6-7	180	$0.027 + j\,0.12$	$4.75 \times 10^{-3} + j9.25 \times 10^{-2}$
Line 7-8 and 9-8	100	$0.015 + j\,0.07$	$2.64 \times 10^{-3} + j5.14 \times 10^{-2}$

5.3.2 Loads Calculations

Table 6 below illustrate the three different loads data.

Table 6. Load Power Absorption and Load Bus Voltage from MatPower

Bus	Voltage		Load	
	Mag (p.u.)	Ang(deg)	P (MW)	Q (MVAR)
5	0.975	-4.017	90.00	30.00
7	0.986	0.622	100.00	35.00
9	0.958	-4.350	125.00	50.00

Voltage, power and reactive power data in table 6 above, is used to calculate loads impedance, shown in table 7 below.

Table 7. Per Unit Impedance for Load 5, Load 7 and Load 9

Load	Per unit Impedance
Load 5	$1.06 + j3.17p.u$
Load 7	$0.97 + j2.78p.u$
Load 9	$0.73 + j1.84p.u$

5.3.3. Rotating Machines:

A three-phase synchronous generator produces balanced internal phase voltages E_a, E_b, E_c. These phase voltages only have one sequence component and that is positive, same is the case for the source voltage.

Synchronous machines usually have different values for all three-sequence impedances. When a three-phase synchronous generator has all three positive sequence currents balanced, then under steady state conditions these balanced positive sequence currents generate magnetomotive force (m.m.f.) which rotates at the synchronous speed in the same direction as rotor [31].

As a result, a very strong magnetic flux penetrates the rotor and the value of the positive sequence impedance comes out to be very high. This positive sequence impedance is called synchronous impedance. On the other hand, when a generator has balanced negative sequence currents, these currents generate m.m.f. which rotates at synchronous speed in a direction opposite to the rotor. Hence, allowing very less amount of magnetic flux to penetrate the rotor and so the value of the negative sequence impedance is usually very low. The case of zero sequence currents is totally different.

When a generator has only zero sequence currents, the net m.m.f. generated by these currents is theoretically zero. Most of these currents are generated due to leakage flux, end turns and harmonic flux from winding that do not produce a sinusoidal m.m.f.

Table 8 below gives us the typical values of machine sequence impedances. The positive-sequence machine impedance is synchronous, transient, or sub-transient. Synchronous impedances are used for steady-state conditions, such as in power-flow studies. Transient impedances are used for stability studies. Sub-transient impedances are used for short circuit studies.

Unlike the positive-sequence impedances, a machine has only one negative-sequence impedance and only one zero-sequence impedance [11].

Table 8. Typical average values of synchronous-machine constants [11]

Constant (units)	Type	Symbol	Turbo-Generator (solid rotor)	Synchronous Condenser	Synchronous Motor
Reactance (Per unit)	Synchronous	X_d	1.1	1.80	1.20
		X_q	1.08	1.15	0.90
	Transient	X_d'	0.23	0.40	0.35
		X_q'	0.23	1.15	0.90
	Sub transient	X_d''	0.12	0.25	0.30
		X_q''	0.15	0.30	0.40
	Negative sequence	X_2	0.13	0.27	0.35
	Zero sequence	X_0	0.05	0.09	0.16
Resistance (Per unit)	Positive sequence	R (dc)	0.003	0.008	0.001
		R (ac)	0.005	0.008	0.001
	Negative sequence	R_2	0.035	0.05	0.06

5.4 Case I: Transmission fault in line 7-8

5.4.1 No Compensation

In section 5.3 the sequence values of all transmission system component, were presented. The next step is to use these values in short circuit fault current analysis. Assuming fault between bus 8 and bus 7. The fault point is exactly 75 km away from bus 8 (total length 100km) as shown below in figure 11.

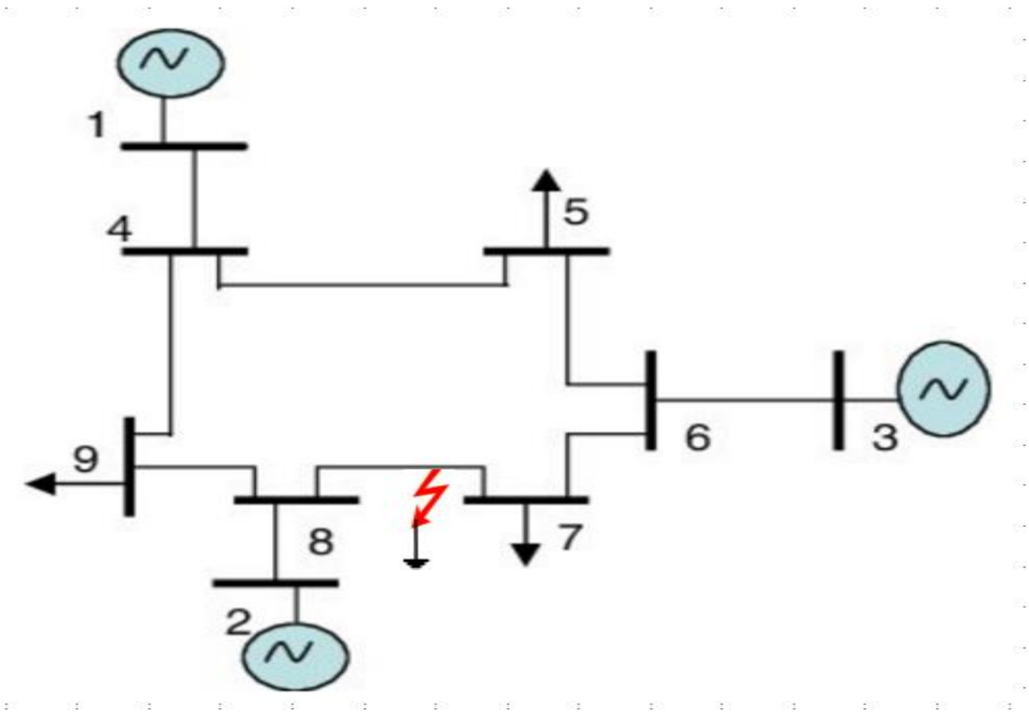

Figure 11. Fault located 75 km away from bus 8 (Fault in Line 7-8, 100km long).

Figures 12, 13 and 14 below shows Zero, Positive and Negative sequence models, respectively. For short circuit fault current calculations in one of the transmission lines, Thevenin impedance to be calculated for the system with reference to the fault point, and pre-fault voltage is the voltage at the fault point too.

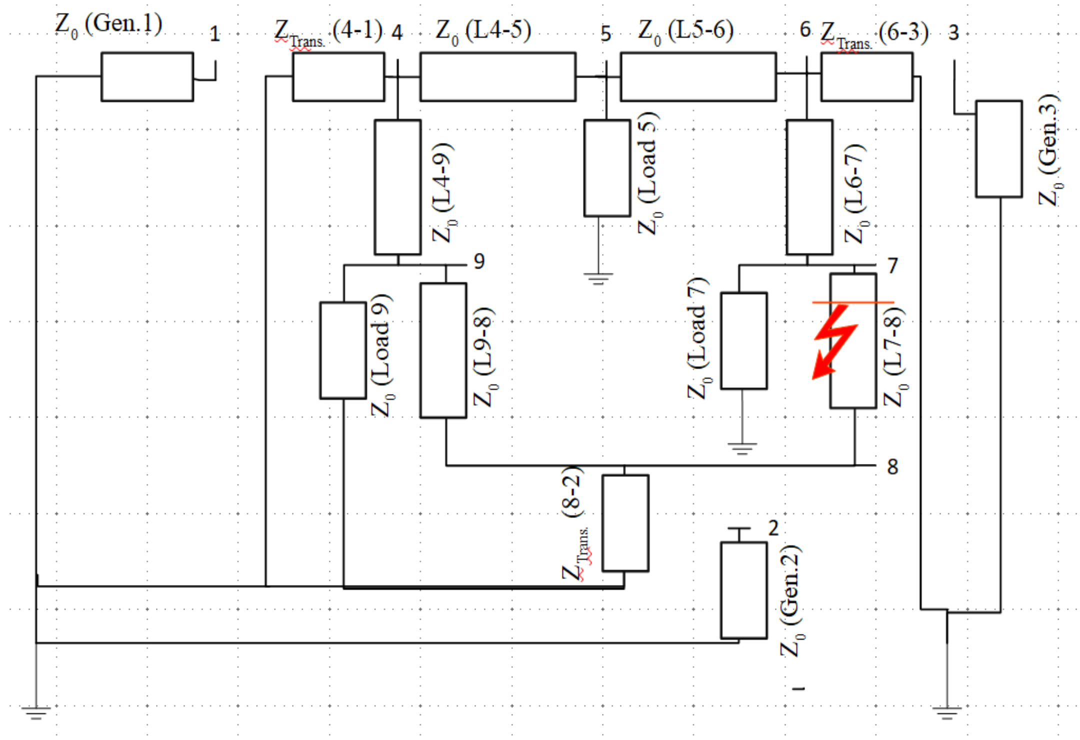

Figure 12. Zero sequence network (fault in line 7-8).

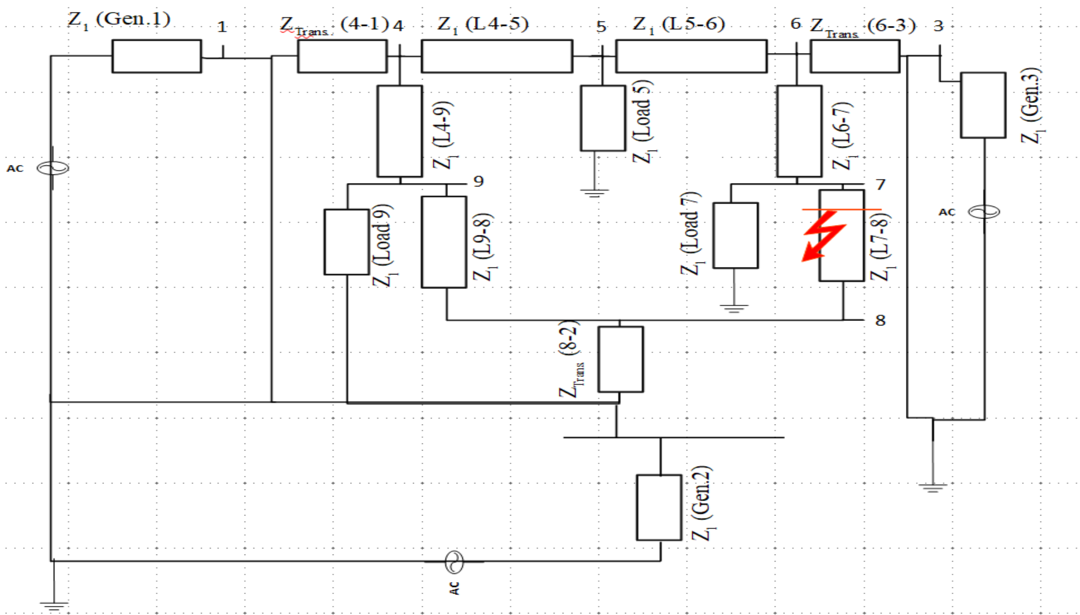

Figure 13. Positive sequence network (fault in line 7-8).

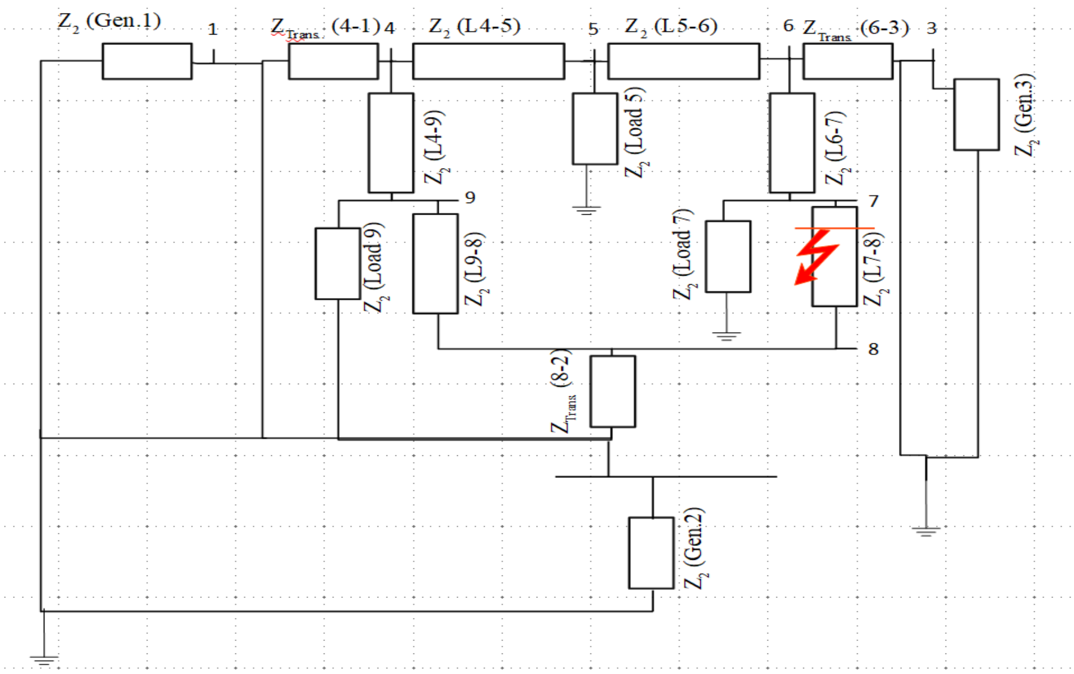

Figure 14. Negative sequence network (fault in line 7-8).

Line 7-8 Impedance will be separated into $Z_{78}(F1)$ for 25% of the line and $Z_{78}(F2)$for 75% of the line.

From figures 12, 13 and 14 above it is shown that generation source impedance will not be included in zero sequence Thevenin impedance, due to Δ-Y connection of the transformer.

The circuit representation below will be used to find the Thevenin equivalent impedance for the different sequences.

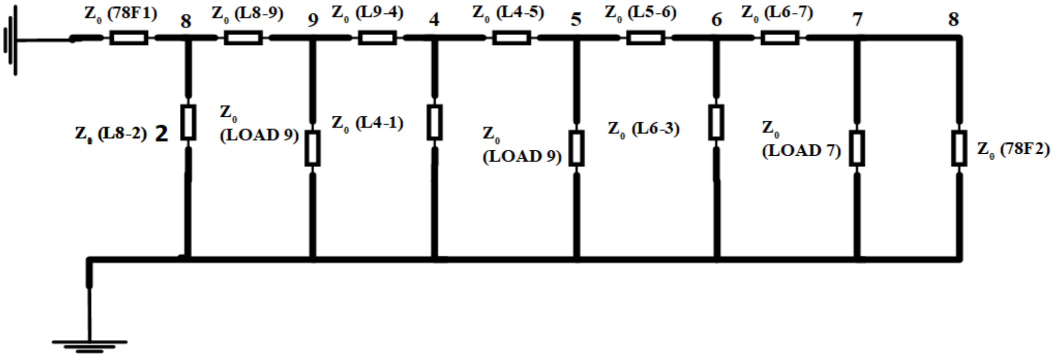

Figure 15. Circuit representation of zero sequence network (fault in 7-8).

The zero sequence impedance values of the system components are used in figure 15 above, to calculate zero Thevenin impedance of the system.

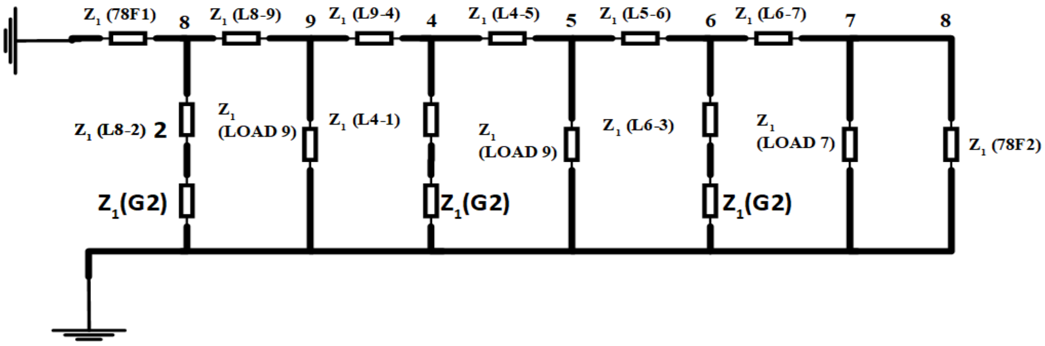

Figure 16. Circuit representation of positive sequence network (fault in 7-8).

The positive sequence impedance values of the system components are used in figure 16 above, to calculate positive Thevenin impedance of the system.

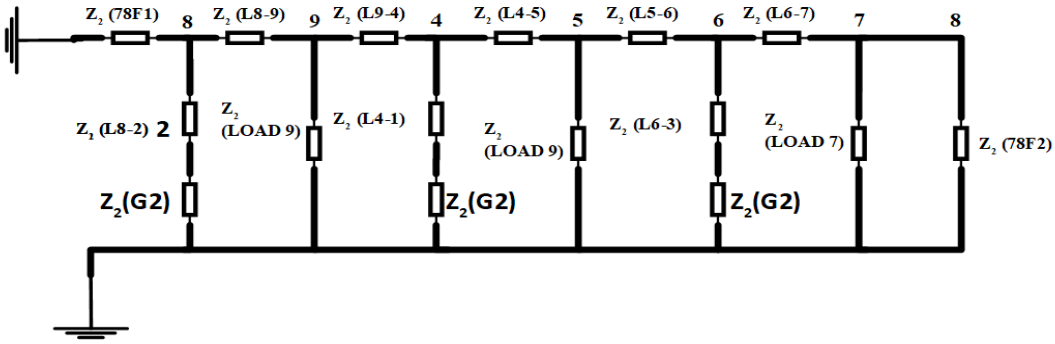

Figure 17. Circuit Representation of Negative Sequence Network (Fault in 7-8)

The negative sequence impedance values of the system components are used in figure 17 above, to calculate negative Thevenin impedance of the system.

Thevenin equivalent impedance, in case of fault point 75km away from bus 8 is shown in table 9 below.

Table 9.Thevenin Zero, Positive and Negative Impedance (reference to the fault point)

Network Sequence	Impedance value (p.u.)
Zero	$11.50 \times 10^{-3} + j37.81 \times 10^{-3}$
Positive	$2.23 \times 10^{-3} + j31.89 \times 10^{-3}$
Negative	$2.40 \times 10^{-3} + j31.52 \times 10^{-3}$

After finding equivalent impedance, the pre fault voltage value in fault point is needed.

To find the voltage at any point (x), transmission line to be represented by a two-port network system as shown in figure 18. The quantities on the sending end are I_s and V_S which are sending end voltage and current.

Similarly, on the receiving end V_R and I_R used, which are receiving end voltage and current. The relation between these two is given below.

$$V_S = AV_R + BI_R \tag{5.4.1}$$

$$I_S = CV_R + DI_R \tag{5.4.2}$$

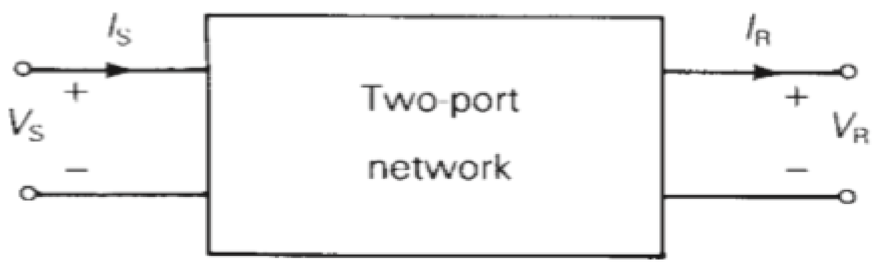

Figure 18. Schematic diagram of two-port network.

For medium-length lines, typically ranging from 25 to 250 km at 50 Hz, it is common to lump the total shunt capacitance and locate half at each end of the line. Such circuit is called a nominal ∏ circuit, to obtain the ABCD parameters of the nominal ∏ circuit, the equations below are used.

$$V_S = V_R + Z\left(I_R + \frac{V_R Y}{2}\right) \tag{5.4.3}$$

$$V_S = ZI_R + V_R\left(1 + \frac{ZY}{2}\right) \tag{5.4.4}$$

$$I_S = I_R + \frac{V_R Y}{2} + \left[\left(1 + \frac{ZY}{2}\right)V_R + ZI_R\right]\left(\frac{Y}{2}\right) \tag{5.4.5}$$

$$\left[Y\left(1 + \frac{ZY}{4}\right)V_R + \left(1 + \frac{YZ}{2}\right) I_R\right] \tag{5.4.6}$$

$$\begin{bmatrix} V_S \\ I_S \end{bmatrix} = \begin{bmatrix} \left(1 + \frac{YZ}{2}\right) & Z \\ Y\left(1 + \frac{YZ}{4}\right) & \left(1 + \frac{YZ}{2}\right) \end{bmatrix} \begin{bmatrix} V_R \\ I_R \end{bmatrix} \tag{5.4.7}$$

Z: 75% of the positive sequence impedance between bus 8 and bus 7

$Z = \ 1.98 \times 10^{-3} \ + \ 38.56 \times 10^{-3}\, i$

$$C_{an} = \frac{2\pi\epsilon}{\ln\frac{D_{eq}}{r}} \, {}^{F}\!/_{m} \tag{5.4.8}$$

$C_{an} = 9.55 \times 10^{-12}\, {}^{F}\!/_{m}$

$Y = j(2 \times \pi \times 50)(\,9.55 \times 10^{-12})(75000) = j2.25 \times 10^{-4}$

$Y_{base} = \frac{1}{Z_{base}} = 8.40 \times 10^{-4} pu;$ $\qquad Y = j\ 0.27pu$

Using 5.4.7

Where:

$V_S = V_8;$ $\qquad I_S = I_{8-7};$ $\qquad V_R = 0.989\angle 2.10\ pu;$ $\qquad V_R = 341.43\ \angle 2.10\ KV$

The next step is fault current calculations. A MATLAB code (Appendix B) was created using the equations presented earlier in chapter 4 to calculate symmetrical and unsymmetrical faults in line 7-8. Corresponding results are presented below in table 10.

Table 10. Symmetrical and Unsymmetrical Fault currents

Phase	SL-G Fault current (kA)	DL-G Fault current (kA)	L-L Fault current (kA)	Three L-G (Bolted) Fault current (kA)
a	$4.8\angle -78.44$	0	0	$5.2\angle -83.86$
b	0	$5.3\angle -161.8$	$3.7\angle -167.48$	$5.2\angle 156.13$
c	0	$4.6\angle 34.3$	$3.7\angle 12.52$	$5.2\angle 36.14$

It is important to note that sequence current of three line to ground fault is always greater than sequence current of double line to ground fault. However, the phase current for double line to ground faults sometimes is greater than that of symmetrical faults. The reason behind this is the fact that the unsymmetrical double line to ground fault will have zero, positive and negative components that will add up to phase current.

In many researches and books only single line to ground and three line to ground faults are considered for analysis, although both will have minimum and maximum sequence currents, but when it comes to phase currents unsymmetrical faults may have higher fault current than symmetrical fault, as also shown in [31].

After obtaining symmetrical and unsymmetrical current values, for fault in line 7-8, next is to add compensation elements of different values in parallel and series, to examine the effect of these devices.

5.4.2 Parallel and series FACTS compensation

In 5.4.2 addition of parallel and series FACTS compensation of different values in mid of line 7-8 was performed as shown in figure 19 below. The effect of such addition will directly be on Thevenin equivalent impedance and pre fault voltage hence, compensation elements will affect the fault current.

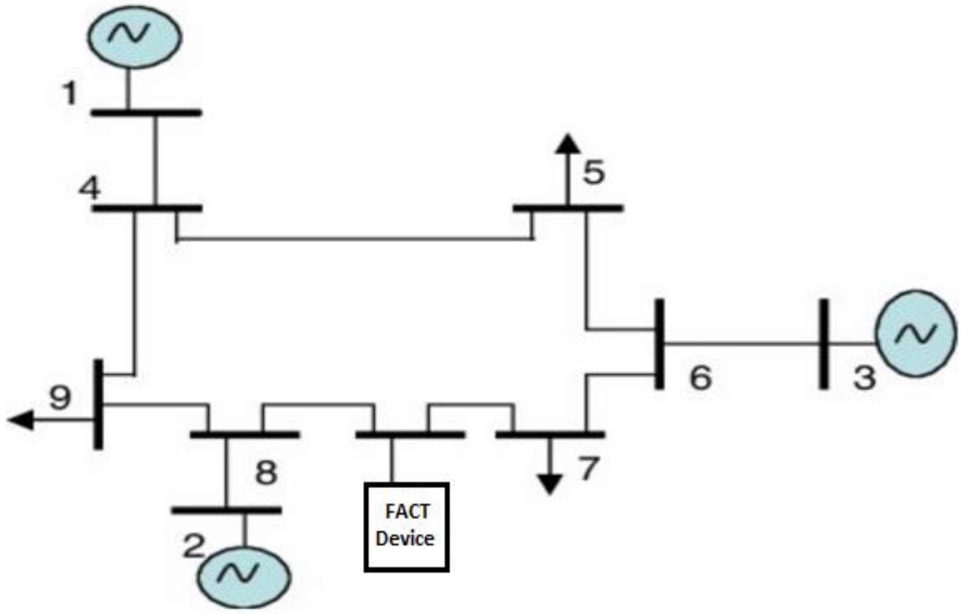

Figure 19. Transmission system after addition of FACTS in mid of line 7-8.

Recalculation of system's Thevenin impedance was done after connecting FACTS elements to the system. FACTS value was chosen based on injected/rejected reactive MVAR needed to maintain Bus 8 voltage at 1 p.u (345KV). The MVAR value is used to calculate $X_c \; and \; X_L$, from both rated capacitance and inductive is calculated [31]. Estimation of highest and lowest values is used in this Thesis.

The steps followed to calculate the Thevenin impedances are the same as in 5.4.1with inductive/capacitive load connected in mid of line 7-8.

and the results are listed in table 11 below, these results will be used to find new fault currents values.

Table 11. Thevenin Zero, Positive and Negative Impedance (reference to the fault point in line 7-8) after adding FACTS in parallel

FACTS Equivalent impedance	Thevenin Impedance (Zero-Sequence)	Thevenin Impedance (Positive-Sequence)	Thevenin Impedance (Negative-Sequence)
1mF	$7.63 \times 10^{-3} + 0.026i$	$1.43 \times 10^{-3} + 0.020i$	$1.49 \times 10^{-3} + 0.020i$
0.1mF	$23.38 \times 10^{-3} + 0.047i$	$3.67 \times 10^{-3} + 0.040i$	$3.90 \times 10^{-3} + 0.039i$
1mH	$7.80 \times 10^{-3} + 0.028i$	$1.46 \times 10^{-3} + 0.023i$	$1.55 \times 10^{-3} + 0.023i$
0.1mH	$7.79 \times 10^{-3} + 0.028i$	$1.46 \times 10^{-3} + 0.023i$	$1.54 \times 10^{-3} + 0.022i$

New symmetrical and unsymmetrical fault currents in line 7-8 are calculated after parallel and series compensation in line 7-8, and new values are presented in table 12 and 14 below.

Table 12. Symmetrical and Unsymmetrical Fault Currents in Line 7-8 after Adding FACTS in Parallel

FACTS Equivalent Reactance	Phase	SL-G Fault current (kA)	DL-G Fault current (kA)	L-L Fault current (kA)	Three L-G (Bolted) Fault current (kA)
	a	$7.54\angle 281.80$	0	0	$8.33\angle 276.72$
1mF	b	0	$8.46\angle 163.38$	$7.24\angle 6.83$	$8.33\angle 156.72$
	c	0	$7.50\angle 33.42$	$7.24\angle 6.83$	$8.33\angle 36.72$
	a	$3.84\angle 281.46$	0	0	$4.16\angle 276.89$
0.1mF	b	0	$4.41\angle 164.74$	$3.63\angle 187.09$	$4.16\angle 156.89$
	c	0	$3.58\angle 34.79$	$3.63\angle 187.09$	$4.16\angle 36.89$
	a	$6.73\angle 281.06$	0	0	$7.27\angle 276.66$
1mH	b	0	$7.43\angle 162.16$	$6.32\angle 6.46$	$7.27\angle 156.34$
	c	0	$6.62\angle 33.90$	$6.32\angle 6.46$	$7.27\angle 36.34$
	a	$6.77\angle 281.10$	0	0	$7.34\angle 276.36$
0.1mH	b	0	$7.49\angle 162.22$	$6.38\angle 6.48$	$7.34\angle 156.36$
	c	0	$6.67\angle 33.88$	$6.38\angle 6.48$	$7.34\angle 36.36$

In table 13 summery of system Thevenin impedances after adding compensation in series is shown. The fault currents calculated and presented in table14 below are based on the values from the table below.

Table 13. Thevenin Zero, Positive and Negative Impedance (Reference to the Fault Point in Line 7-8) after Adding FACTS in Series

FACTS Impedance	Thevenin Impedance (Zero-Sequence)	Thevenin Impedance (Positive-Sequence)	Thevenin Impedance (Negative-Sequence)
1mF	11.27×10^{-3} + 0.036i	$2.17 \times 10^{-3} + 0.030i$	$2.31 \times 10^{-3} + 0.030i$
0.1mF	9.88×10^{-3} + 0.021i	$1.85 \times 10^{-3} + 0.011i$	$1.86 \times 10^{-3} + 0.011i$

From both new pre fault voltage and new overall system Thevenin impedance fault currents are calculated as in table 14 below.

Table 14. Symmetrical and Unsymmetrical Fault currents in line 7-8 after adding FACTS in series

FACTS Equivalent Reactance	Phase	SL-G Fault current (kA)	DL-G Fault current (kA)	L-L Fault current (kA)	Three L-G (Bolted) Fault current (kA)
	a	$5.11\angle281.39$	0	0	$5.51\angle276.20$
1mF	b	0	$5.66\angle162.15$	$4.80\angle6.36$	$5.51\angle156.20$
	c	0	$4.99\angle34.00$	$4.80\angle6.36$	$5.51\angle36.20$
	a	$10.99\angle290.7$	0	0	$14.77\angle282.77$
0.1mF	b	0	$14.38\angle175.73$	$12.81\angle12.82$	$14.77\angle162.77$
	c	0	$12.60\angle32.39$	$12.81\angle12.82$	$14.77\angle42.77$

Tables 12 and 14 above shows the direct effect of FACTS on fault currents when installation and fault are in the same line. In most cases fault current will be much higher than fault with no FACTS compensation as in table 10, except when small effective capacitance is connected in parallel or high effective capacitance is connected in series. Only in these two scenarios fault current will be reduced slightly.

5.5 Case II: Transmission fault in line 9-8

5.5.1 No Compensation

In 5.4 transmission fault in line 7-8 occurs, resulting in different types of fault currents, analysis was done as well considering MVAR compensation in line 7-8. In 5.5 assumption of fault in line 9-8 will be considered as shown in figure 20 below and based on it, analysis of different fault scenarios to be done. In addition to, analysis considering parallel and series compensation in line7-8. The difference between this section and the previous is installation of FACTS in the same faulted line in 5.4 while in 5.5 FACTS are installed in line 7-8 and fault is in different line 9-8.

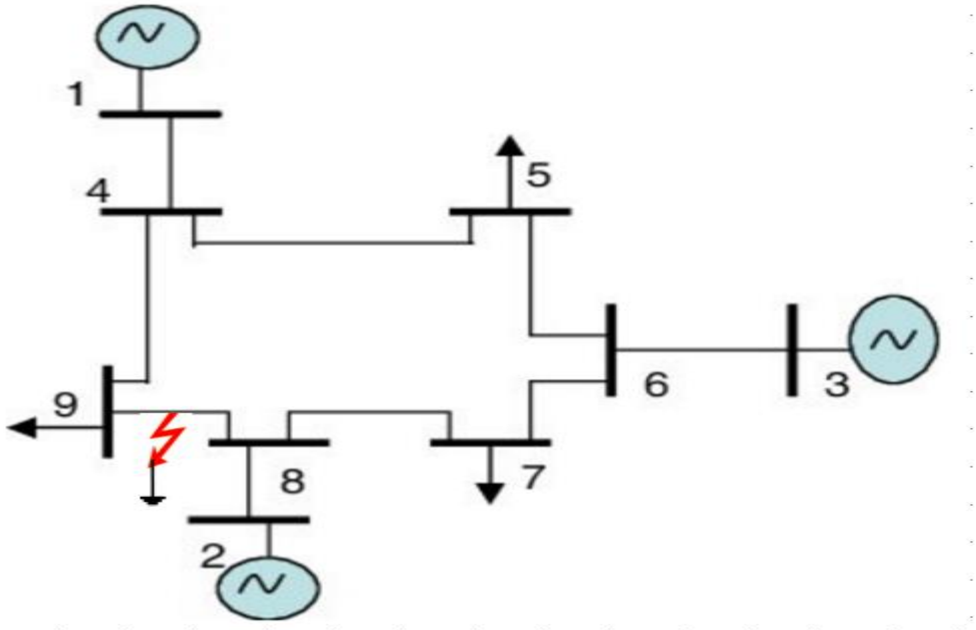

Figure 20. Fault located 50 km away from bus 8 in line 8-9.

Figures 21, 22 and 23 below shows Zero, Positive and Negative sequence models respectively. For short circuit fault current calculations in one of the transmission lines, Thevenin impedance to be calculated for the system with reference to the fault point, and pre-fault voltage is the voltage at the fault point too.

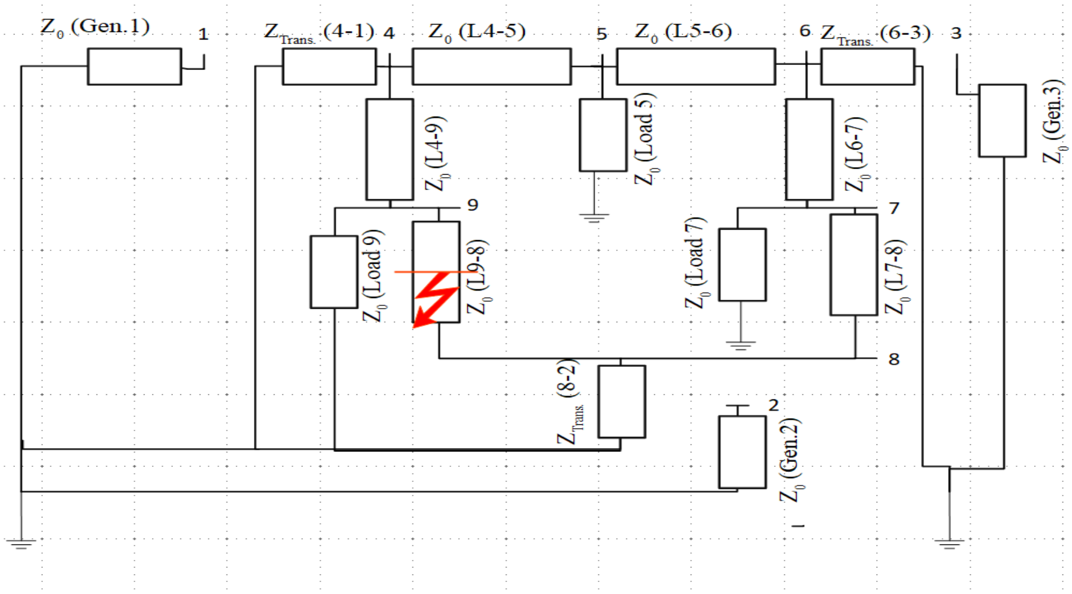

Figure 21. Zero sequence network for fault in line 8-9.

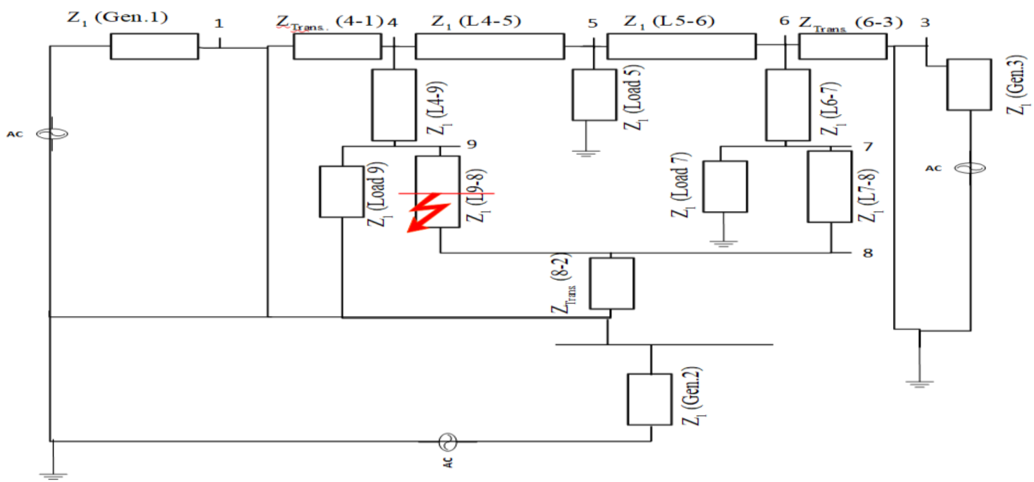

Figure 22. Positive sequence network for fault in line 8-9.

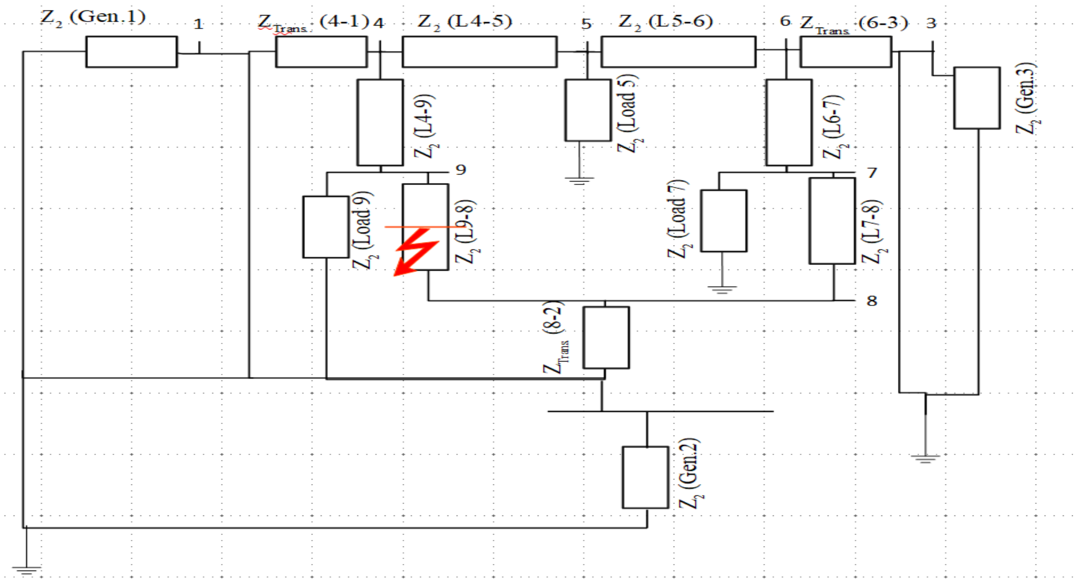

Figure 23. Negative sequence network for fault in line 8-9.

Line 8-9 Impedance will be separated into Z89_1 for 50% of the line and Z89_2 for 50% of the line. The circuit representation in figures 24, 25 and 26 below will be used to find the Thevenin equivalent impedance for positive, negative and zero sequence networks.

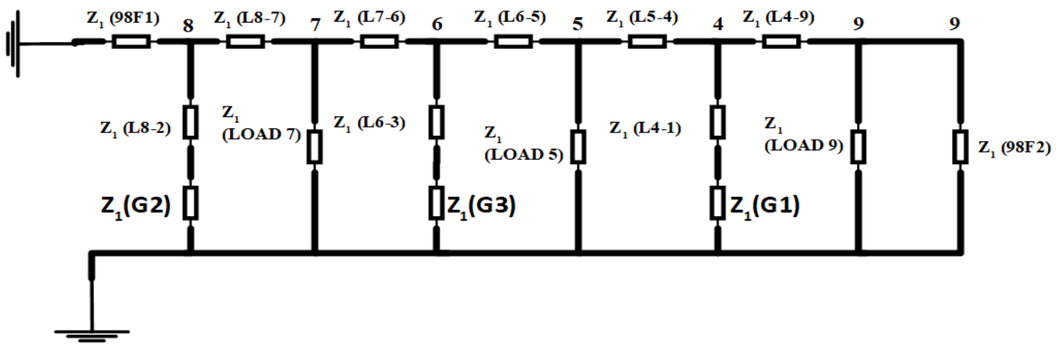

Figure 24. Circuit representation of positive sequence network (fault in 8-9).

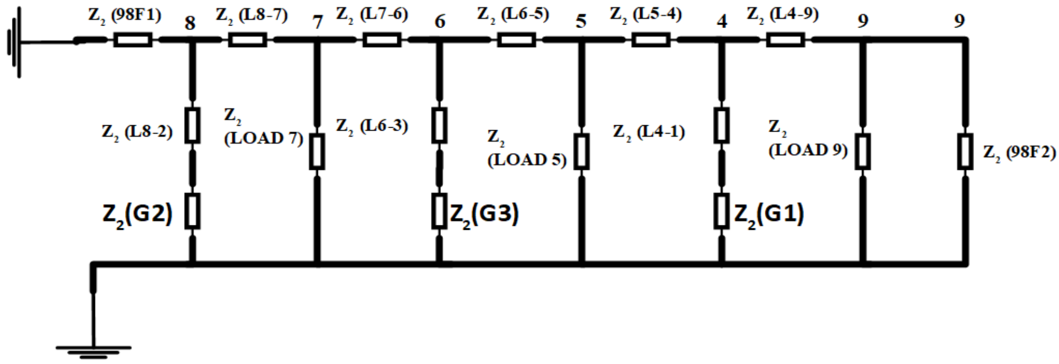

Figure 25. Circuit representation of negative sequence network (Fault in 8-9).

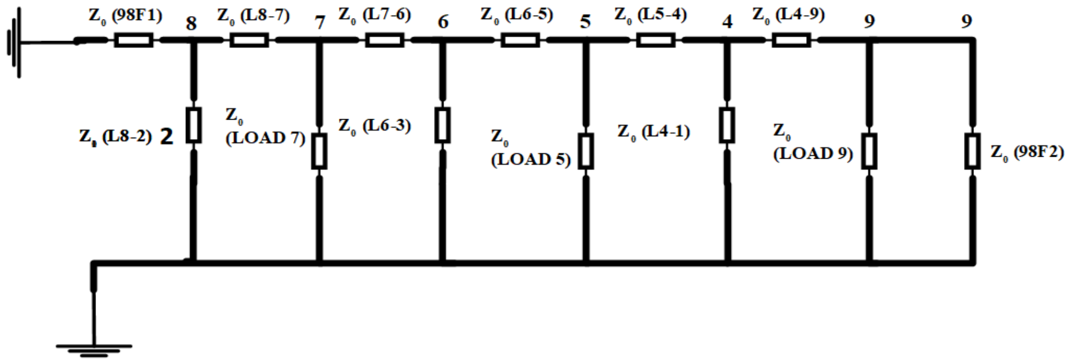

Figure 26. Circuit representation of zero sequence network (Fault in 8-9)

Figure 24 and 25 above represent the circuit used to find equivalent impedance, for positive and negative sequence analysis. For negative sequence corresponding value of generator impedance to be used, and for zero sequence as shown in figure 26 above primary side of the transformer is open.

Thevenin equivalent impedance, in case of fault point 50km away from bus 9 is shown in table 15 below.

Table 15. Thevenin Zero, Positive and Negative Impedance (Reference to the Fault Point)

Network Sequence	Impedance value (p.u.)
Zero	$7.70 \times 10^{-3} + j27.61 \times 10^{-3}$
Positive	$1.44 \times 10^{-3} + j22.47 \times 10^{-3}$
Negative	$1.43 \times 10^{-3} + j22.17 \times 10^{-3}$

After finding equivalent impedance, the pre fault voltage value in fault point is needed. To find the voltage at any point (x), the same steps in *5.4.1* to be repeated using fault line (L9_8) impedance.

$Z = 1.32 \times 10^{-3} + 25.70 \times 10^{-3}\, i$ **(50% of the impedance between bus 9 and 8)**

Fault point in line 9-8 is 50 km from bus 8 and hence

$Y = j(2 \times \pi \times f)(C_{an})(50000) = j1.50 \times 10^{-4}$; $\quad Y = j\ 0.18pu$

Using 5.4.7

Where:

$V_S = V_8$ and $I_S = I_{8-7}$;

Voltage at receiving point 50 km from bus 8 will be:

$V_R = 0.994\angle 2.67\, pu$; $\quad V_R = 342.81\ \angle 2.67\ KV$

The equations presented in chapter 4 for symmetrical and unsymmetrical fault currents will be used to find faults in line 9-8. Corresponding results are presented below in table 16 below.

Table 16. Symmetrical and Unsymmetrical Fault Currents

Phase	SL-G Fault current (kA)	DL-G Fault current (kA)	L-L Fault current (kA)	Three L-G (Bolted) Fault current (kA)
a	$6.93\angle-79.17$	0	0	$7.38\angle-83.67$
b	0	$7.55\angle162.17$	$6.43\angle186.34$	$7.38\angle156.33$
c	0	$6.71\angle33.74$	$6.43\angle6.34$	$7.38\angle36.33$

5.5.2: Parallel and series compensation

In 5.5.2 addition of parallel and series compensation of different values in mid of line 7-8 was done. The aim in this section is to highlight the effect of compensation installed in line 7-8 on faults in line 8-9. Recalculation of system's Thevenin impedance is done and the results are listed in table 17 below.

Table 17. Thevenin Zero, Positive and Negative Impedance (reference to the fault point in line 8-9) after adding FACTS in line 7-8

FACTS impedance	Thevenin Impedance (Zero-Sequence)	Thevenin Impedance (Positive-Sequence)	Thevenin Impedance (Negative-Sequence)
1mF	$7.69 \times 10^{-3} + j0.028$	$1.45 \times 10^{-3} + j0.023$	$1.44 \times 10^{-3} + j0.022$
0.1mF	$7.72 \times 10^{-3} + j0.027$	$1.41 \times 10^{-3} + j0.022$	$1.40 \times 10^{-3} + j0.022$
1mH	$7.69 \times 10^{-3} + j0.028$	$1.45 \times 10^{-3} + j0.022$	$1.44 \times 10^{-3} + j0.022$
0.1mH	$7.69 \times 10^{-3} + j0.027$	$1.45 \times 10^{-3} + j0.022$	$1.44 \times 10^{-3} + 0.022$

New symmetrical and unsymmetrical fault currents in line 8-9 are calculated after adding compensation in line 7-8 (based on the system impedances in table 17) and new values are presented in table 18 and 20 below.

Table 18. Symmetrical and Unsymmetrical Fault Currents in Line 8-9 after Adding FACTS in Parallel (mid of line 7-8)

FACTS Equivalent Reactance	Phase	SL-G Fault current (kA)	DL-G Fault current (kA)	L-L Fault current (kA)	Three L-G (Bolted) Fault current (kA)
	a	$6.82\angle 281.00$	0	0	$7.37\angle 276.35$
1mF	b	0	$7.53\angle 162.20$	$6.42\angle 6.37$	$7.37\angle 156.35$
	c	0	$6.70\angle 33.74$	$6.42\angle 6.37$	$7.37\angle 36.35$
	a	$6.83\angle 280.79$	0	0	$7.39\angle 276.28$
0.1mF	b	0	$7.57\angle 162.17$	$6.41\angle 6.28$	$7.39\angle 156.27$
	c	0	$6.71\angle 33.64$	$6.41\angle 6.28$	$7.39\angle 36.28$
	a	$6.82\angle 280.99$	0	0	$7.37\angle 276.35$
1mH	b	0	$7.54\angle 162.20$	$6.42\angle 6.36$	$7.37\angle 156.35$
	c	0	$6.70\angle 33.73$	$6.42\angle 6.36$	$7.37\angle 36.35$
	a	$6.82\angle 281.00$	0	0	$7.37\angle 276.35$
0.1mH	b	0	$7.53\angle 162.20$	$6.42\angle 6.36$	$7.37\angle 156.35$
	c	0	$6.70\angle 33.73$	$6.42\angle 6.36$	$7.37\angle 36.35$

In table 19 summery of system Thevenin impedances after adding compensation in series is shown. The fault currents calculated and presented in table 20 are based on the values from table 19 below.

Table 19. Thevenin Zero, Positive and Negative Impedance (reference to the fault point in line 8-9) after Adding FACTS in Series in line 7-8

FACTS Equivalent impedance	Thevenin Impedance (Zero-Sequence)	Thevenin Impedance (Positive-Sequence)	Thevenin Impedance (Negative-Sequence)
1mF	$7.70 \times 10^{-3} + j0.028$	$1.44 \times 10^{-3} + j0.022$	$1.43 \times 10^{-3} + j0.022$
0.1mF	$7.70 \times 10^{-3} + j0.027$	$1.44 \times 10^{-3} + j0.022$	$1.42 \times 10^{-3} + j0.022$

Based on the results presented in table 19 above, which shows small effect of series compensation impedance on overall system impedance, fault currents in line 8-9 are calculated and presented in table 20 below.

Table 20. Symmetrical and Unsymmetrical Fault Currents in Line 8-9 After Adding FACTS in Series in Line 7-8

FACTS Equivalent Reactance	Phase	SL-G Fault current (kA)	DL-G Fault current (kA)	L-L Fault current (kA)	Three L-G (Bolted) Fault current (kA)
	a	$6.82\angle 280.99$	0	0	$7.37\angle 276.34$
1mF	b	0	$7.54\angle 161.07$	$6.43\angle 6.35$	$7.37\angle 156.34$
	c	0	$6.70\angle 33.71$	$6.43\angle 6.35$	$7.37\angle 36.34$
	a	$6.82\angle 280.98$	0	0	$7.38\angle 276.33$
0.1mF	b	0	$7.54\angle 162.19$	$6.43\angle 6.34$	$7.38\angle 156.33$
	c	0	$6.70\angle 33.70$	$6.43\angle 6.34$	$7.38\angle 36.33$

The main conclusion from this section, is that when FACTS are installed in different line other than fault line, the effect on fault current will be small, due to the fact that pre fault voltage will be negligibly affected by FACTS installed in different line and overall Thevenin impedance will be slightly changed as well. It is worth mentioning that the larger the power system, the smaller will be the effect.

In summary, the study performed in this chapter is for two cases. The first one includes shunt faults calculation in one line (7-8) compared to the fault currents of the same line when FACTS installed in mid of the line. In the second case shunt faults were calculated in line 8-9, then FACTS were installed back in different line (7-8) to study its effect on fault currents. Used method of analysis is symmetrical components.

CHAPTER 6: ZONE DISTANCE PROTECTION

6.1 Zones Definition

In previous chapters discussion of power system protection was done in addition to fault current calculations in presence and absence of FACTS. One of the main parts of power system protection is division of a system into zones, in which the protection relays will be set to isolate a zone if fault occurred within it.

Protective zones have the following characteristics:

1- Zones are overlapped.
2- Circuit breakers located in the overlap regions.
3- When fault occurs in a zone, all circuit breakers in that zone open to isolate the fault. [11]

6.2 Distance Protection for transmission lines

The huge number of lines and busses in radial systems, makes it difficult to coordinate systems' overcurrent relays. Coordination is mainly about operating the closest relay to fault point, but when many generation sources are used, it is difficult to coordinate directional relays.

To overcome these problems in transmission systems, the concept of impedance relay or distance protection is introduced. The operational principle of impedance relay is based on voltage to current ratio, which is more sensitive than over current protection, since at fault instance voltage drops and current increases [11].

The idea of distance protection is simply obtained by including directional relay in series with impedance relay. The relay reach will be based on impedance setting and for the relay to protect a line it will be set based on the line impedance, with trip condition of $Z_{line} < Z_r$ (Z_r: setting of relay impedance).

It is common practice in distance protection to have primary protection set to 80%-line protection, other relays with different time delay and protection percentage are added as well. Zones protection are very useful in coordination and better trip decisions.

Malfunction of distance relays is expected when transmission line impedance change, and from the study conducted in chapter 5, the addition of FACTS has direct effect on measured line impedance. To overcome this problem, protection device reach before and after adding FACTS of different sizes to be studied in addition, to new needed setting.

In chapter 5 fault was introduced in line 7-8 and line 8-9 then compensation elements were added to line 7-8, therefore the consequence of these changes to previous setup values of impedance relay shall be studied.

In table 21 and 22 below, comparison between line 7-8 impedance in the case of no MVAR injection/absorption to different injection/absorption values. The aim of such comparison is to give us clear vision of distance protection device performance (overreach/under reach) when FACTS are installed in the power system for power compensation.

The zones presented in figure 27 below represent protection of 80% of line 7-8 (zone I) and protection of 120% of line 7-8 (zone II). In addition to zone III which is 100% line 7-8 plus 120% of line 5-6. It is important to highlight that for zone III it will cover in addition to line 7-8 120% of the line of larger impedance between lines 6-7 and 5-6. 120% protection means that line impedance to be multiplied by 1.2.

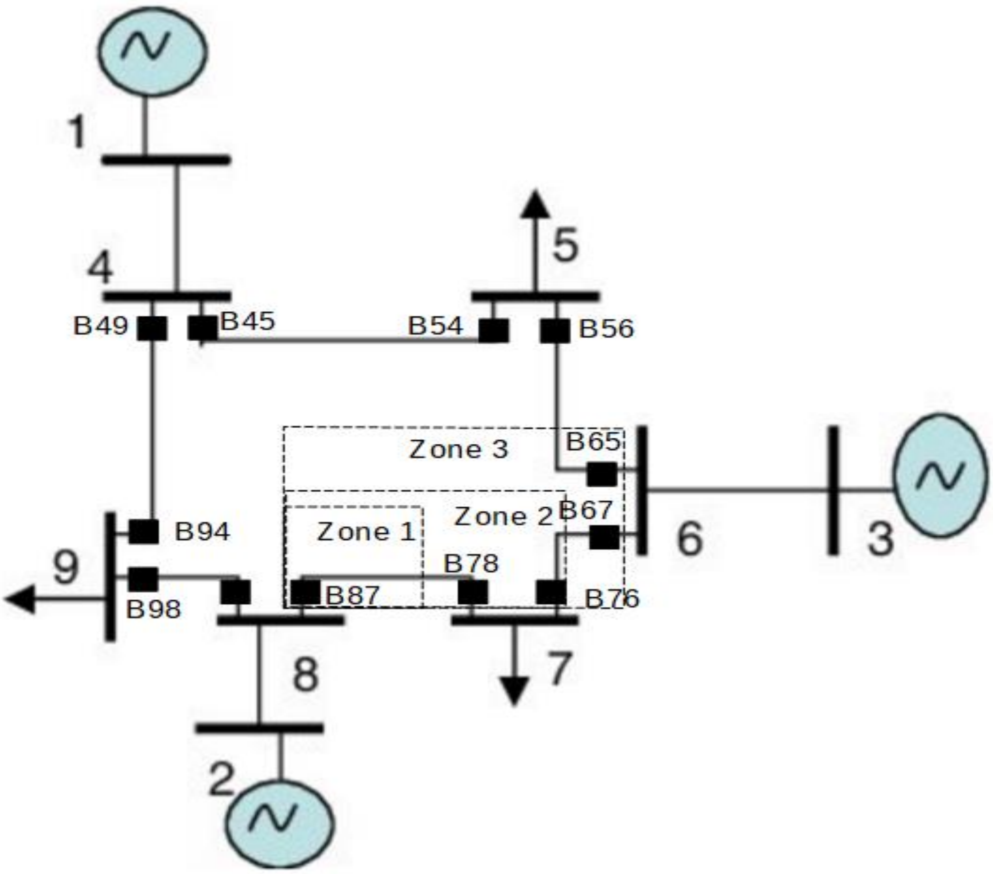

Figure 27. Zone I, II and III representation in IEEE 9-bus system for circuit breaker B87.

Line 7-8 then was compensated with different parallel and series compensation elements. In tables 21 and 22 the effect of such installation on distance relay settings to be highlighted.

In table 21 below the effect of different parallel connected elements is shown.

Table 21. Line 7-8 Relay Settings in Case of No MVAR Injection/Absorption Compared to Different Injection/Absorption Values Connected in Parallel Using Per Unit Values.

FACTS value	Zone I (80%)	Zone II (120%)	Zone III (220%)
NO FACTS	$41.18 \times 10^{-3} \angle 87.05$	$61.77 \times 10^{-3} \angle 87.03$	$187.36 \times 10^{-3} \angle 87.06$
0.1mF	$36.73 \times 10^{-3} \angle 258.25$	$55.09 \times 10^{-3}\ 258.28$	$90.79 \times 10^{-3} \angle 91.50$
1mF	$98.51 \times 10^{-3} \angle 87.67$	$147.76 \times 10^{-3} \angle 87.67$	$259.02 \times 10^{-3} \angle 87.35$
0.1mH	$82.11 \times 10^{-3} \angle 87.05$	$124.16 \times 10^{-3} \angle 87.08$	$238.53 \times 10^{-3} \angle 87.06$
1mH	$81.12 \times 10^{-3} \angle 87.02$	$121.68 \times 10^{-3} \angle 87.02$	$237.29 \times 10^{-3} \angle 87.04$

The zones values in table 21 above were obtained from line 7-8 and line 5-6 positive sequence impedances (calculated in chapter 5) for no FACTS case. Then for each FACTS value line 7-8 impedance recalculated based on FACTS effective capacitance/inductance value and connection type (parallel/series).

In table 22 below the effect of different series connected elements on distance protection relay setting is shown.

Table 22. Line 7-8 Relay Settings in Case of No MVAR Injection/Absorption Compared to Different Injection/Absorption Values Connected in Series Using Per Unit Values.

FACTS value	Zone I (80%)	Zone II (120%)	Zone III
NO FACTS	$41.18 \times 10^{-3} \angle 87.05$	$61.77 \times 10^{-3} \angle 87.03$	$187.36 \times 10^{-3} \angle 87.05$
0.1mF	$20.11 \times 10^{-3} \angle 83.98$	$30.17 \times 10^{-3} \angle 83.97$	$160.99 \times 10^{-3} \angle 86.58$
1mF	$39.04 \times 10^{-3} \angle 86.90$	$58.56 \times 10^{-3} \angle 86.90$	$184.69 \times 10^{-3} \angle 87.02$

From the table above, connecting series capacitive compensation is clearly causing distance relay overreach malfunction. The main difference between series and parallel compensation when using series capacitance element, is that relay will always overreach. Unlike parallel compensation where element value directly affects malfunction type. From tables 21 and 22 above, during normal operation after FACTS installation in series, impedance relay will trip due to $Z_{new} < Z_{old}$ when capacitance of 0.1mF is connected in parallel the same condition will apply $Z_{new} < Z_{old}$ hence impedance relay will trip.

In other cases of inductive element connected in parallel or 1mF capacitive element in parallel the condition $Z_{new} < Z_{old}$ will not hold hence, no trip for impedance relay (similar to light loads condition).

The last part of analysis to be carried out is calculations of line 7-8 impedance after fault occurs 75 km away from bus 8. The purpose is to see if impedance after fault will remain out of trip boundary. Compensation cases in which $Z_{new} > Z_{old}$ will be studied and results to be shown in table 23 below.

Table 23. Fault Impedance 75km Away from Bus 8 Compared to Zone I Settings

FACTS value	Zone I (80%)	Fault Impedance
NO FACTS connected	$41.18 \times 10^{-3} \angle 87.05$	$38.61 \times 10^{-3} \angle 87.06$
1mF	$98.51 \times 10^{-3} \angle 87.67$	$22.37 \times 10^{-3} \angle 87.51$
0.1mH	$82.11 \times 10^{-3} \angle 87.05$	$25.76 \times 10^{-3} \angle 87.07$
1mH	$81.12 \times 10^{-3} \angle 87.02$	$26.00 \times 10^{-3} \angle 87.09$

From table 23 above it can be concluded that when fault occurs, and FACTS of effective capacitance or inductive of 0.1 mH, 1mH or 1mF installed in parallel, the following condition will occur $Z_{new} < Z_{old}$ resulting in relay trip. It is important to highlight that the main concern is normal operation conditions that will result in relay tripping during normal operation.

CONCLUSION

In this Thesis, IEEE 9-Bus power system was studied in normal and different faults conditions. Afterward, compensation devices were added to highlight the influence on fault currents and distance protection settings. The analysis method was based on zero, positive and negative sequences.

Two scenarios were studied in this Thesis, the first scenario was fault in the same line as compensation installation. And the main conclusion for short circuit current, is that for small capacitance (0.1mF) connected in parallel in regardless of fault type, current is expected to be less than fault current with no compensation. On the other hand, for inductance compensation and larger capacitance (1mF) connected in parallel to the line, fault current in regardless of fault type was almost doubled. The reason behind it, is the direct impact of compensation on the line impedance and pre fault voltage.

In second scenario, faults are considered in other lines than compensation installation. The impact on fault current is negligible, which is expected since pre fault voltage is not affected by compensation in other lines and change of overall system impedance (Thevenin) is insignificant. From the second scenario it can be concluded that the larger the system, the smaller will be the effect of compensation devices on fault currents, if installed in different line other than fault occurrence line.

Connecting series capacitance compensation in the same line as fault occurred, will result in increasing fault current in a relative relation to compensation values.

For distance protection settings, connecting capacitance compensation or in other words injecting reactive power will result in relay overreach, except for connecting 1mF in parallel which will result in under reach, the reason is that distance relay settings is based on line impedance and connecting $X_c < 1\Omega$ will increase the equivalent impedance.

The effect of connecting inductive compensation in parallel or absorbing reactive power, will cause distance relay under reach since, it will increase the line equivalent impedance.

Finally, it should be highlighted that when FACTS installed in series, distance protection devices should be adjusted to avoid interruptions and faulted trip.

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APPENDIX A: POWER FLOW DATA FROM MATPOWER

function mpc = case9

CASE9 Power flow data for 9 bus, 3 generator case.

Based on data from Joe H. Chow's book, p. 70.

MATPOWER

mpc.version = '2';

----- Power Flow Data -----

system MVA base mpc.base MVA = 100;

bus data

bus_i	type	Pd	Qd	Gs	Bs	area	Vm	Va	baseKV	
zone	Vmax	Vmin								

mpc.bus = [

1	3	0	0	0	0	1	1	0	345	1
1.1	0.9;									
2	2	0	0	0	0	1	1	0	345	1
1.1	0.9;									
3	2	0	0	0	0	1	1	0	345	1
1.1	0.9;									
4	1	0	0	0	0	1	1	0	345	1
1.1	0.9;									
5	1	90	30	0	0	1	1	0	345	1
1.1	0.9;									
6	1	0	0	0	0	1	1	0	345	1
1.1	0.9;									

```
	7	1	100	35	0	0	1	1	0	345	1
	1.1	0.9;
	8	1	0	0	0	0	1	1	0	345	1
	1.1	0.9;
	9	1	125	50	0	0	1	1	0	345	1
	1.1	0.9;
];
generator data
%	bus	Pg	Qg	Qmax	Qmin	Vg	mBase	status	Pmax	Pmin	Pc1
	Pc2	Qc1min		Qc1max		Qc2min		Qc2max		ramp_agc
	ramp_10		ramp_30		ramp_q		apf
mpc.gen = [
	1	0	0	300	-300	1	100	1	250	10	0
	0	0	0	0	0	0	0	0	0	0;
	2	163	0	300	-300	1	100	1	300	10	0
	0	0	0	0	0	0	0	0	0	0;
	3	85	0	300	-300	1	100	1	270	10	0
	0	0	0	0	0	0	0	0	0	0;
];
 branch data
%	fbus	tbus	r	x	b	rateA	rateB	rateC	ratio	angle
	status	angminangmax
mpc.branch = [
	1	4	0	0.0576	0	250	250	250	0	0	1
```

```
	-360	360;
	4	5	0.017	0.092	0.158	250	250	250	0	0	1
	-360	360;
	5	6	0.039	0.17	0.358	150	150	150	0	0	1
	-360	360;
	3	6	0	0.0586	0	300	300	300	0	0	1
	-360	360;
	6	7	0.0119	0.1008	0.209	150	150	150	0	0	1
	-360	360;
	7	8	0.0085	0.072	0.149	250	250	250	0	0	1
	-360	360;
	8	2	0	0.0625	0	250	250	250	0	0	1
	-360	360;
	8	9	0.032	0.161	0.306	250	250	250	0	0	1
	-360	360;
	9	4	0.01	0.085	0.176	250	250	250	0	0	1
	-360	360;
];
----- OPF Data -----
 generator cost data
	1	startup	shutdown	n	x1	y1	...	xn	yn
	2	startup	shutdown	n	c(n-1)	...	c0
mpc.gencost = [
	2	1500	0	3	0.11	5	150;
```

```
        2       2000    0       3       0.085   1.2     600;
        2       3000    0       3       0.1225 1        335;

MATPOWER Version 6.0, 16-Dec-2016 -- AC Power Flow (Newton)


Newton's method power flow converged in 4 iterations.


Converged in 1.06 seconds
================================================================================
|     System Summary                                                           |
================================================================================

How many?                How much?              P (MW)            Q (MVAr)
---------------------    -------------------  -------------  -----------------
Buses              9     Total Gen Capacity     820.0       -900.0 to 900.0
Generators         3     On-line Capacity       820.0       -900.0 to 900.0
Committed Gens     3     Generation (actual)    320.0              34.9
Loads              3     Load                   315.0             115.0
  Fixed            3       Fixed                315.0             115.0
  Dispatchable     0       Dispatchable          -0.0 of -0.0      -0.0
Shunts             0     Shunt (inj)             -0.0               0.0
Branches           9     Losses (I^2 * Z)         4.95             51.31
```

Transformers 0 Branch Charging (inj) - 131.4

Inter-ties 0 Total Inter-tie Flow 0.0 0.0

Areas 1

	Minimum	Maximum
Voltage Magnitude	0.958 p.u. @ bus 9	1.003 p.u. @ bus 6
Voltage Angle	-4.35 deg @ bus 9	9.67 deg @ bus 2
P Losses (I^2*R)	-	2.46 MW @ line 8-9
Q Losses (I^2*X)	-	16.74 MVAr @ line 8-2

==

| Bus Data |

==

Bus #	Voltage Mag(pu)	Voltage Ang(deg)	Generation P (MW)	Generation Q (MVAr)	Load P (MW)	Load Q (MVAr)
1	1.000	0.000*	71.95	24.07	-	-
2	1.000	9.669	163.00	14.46	-	-
3	1.000	4.771	85.00	-3.65	-	-
4	0.987	-2.407	-	-	-	-
5	0.975	-4.017	-	-	90.00	30.00

6	1.003	1.926	-	-	-	-
7	0.986	0.622	-	-	100.00	35.00
8	0.996	3.799	-	-	-	-
9	0.958	-4.350	-	-	125.00	50.00
			--------	--------	--------	--------
		Total:	319.95	34.88	315.00	115.00

==

| Branch Data |

==

Brnch	From	To	From Bus Injection		To Bus Injection		Loss (I^2 * Z)	
#	Bus	Bus	P (MW)	Q (MVAr)	P (MW)	Q (MVAr)	P (MW)	Q (MVAr)
-----	-----	-----	--------	--------	--------	--------	--------	--------
1	1	4	71.95	24.07	-71.95	-20.75	-0.000	3.32
2	4	5	30.73	-0.59	-30.55	-13.69	0.174	0.94
3	5	6	-59.45	-16.31	60.89	-12.43	1.449	6.31
4	3	6	85.00	-3.65	-85.00	7.89	0.000	4.24
5	6	7	24.11	4.54	-24.01	-24.40	0.095	0.81
6	7	8	-75.99	-10.60	76.50	0.26	0.506	4.29
7	8	2	-163.00	2.28	163.00	14.46	0.000	16.74
8	8	9	86.50	-2.53	-84.04	-14.28	2.465	12.40
9	9	4	-40.96	-35.72	41.23	21.34	0.266	2.26

-------- --------

Total: 4.955 51.31

APPENDIX B: MATLAB CODE

```
%Symmetrical components calculation
clear;
clc;
Rk = 3.138*(10^-5);     %%Rk value
Rkx = 4.935*(10^-5) ;       %%Rk’
w = 2*50*pi ;   %% w Value
Dkk = 0.01786;          %%Dkk Value
Dkkx = 931.259;         %%Dkk’ Value
Dkmx = 23.252;      %%Dkm’ Value
Dkm = 7.560;        %%Dkm Value
Zbase = 1190.25;
format long
Zkk = (Rk + Rkx) + (1i*w)*(2*10^-7)*log(Dkkx/Dkk);
Zkm = Rkx + (1i*w)*(2*10^-7)*log(Dkmx/Dkm);

%------------------------------------------------------------
%line 4-5 (length = 250km)
%format long
Zkk45 = Zkk*250000;
Zkm45 = Zkm*250000;
Zkkpu45 = (Zkk45/Zbase);
Zkmpu45 = (Zkm45/Zbase);
Z0_45 = Zkkpu45 + (2*Zkmpu45);
Z1_45 = Zkkpu45 - Zkmpu45;
Z2_45 = Zkkpu45 - Zkmpu45;
%------------------------------------------------------------
%line 5-6 (length = 220km)
%format long
Zkk56 = Zkk*220000;
Zkm56 = Zkm*220000;
Zkkpu56 = (Zkk56/Zbase);
Zkmpu56 = (Zkm56/Zbase);
Z0_56 = Zkkpu56 + (2*Zkmpu56);
Z1_56 = Zkkpu56 - Zkmpu56;
Z2_56 = Zkkpu56 - Zkmpu56;
%------------------------------------------------------------
%line 4-9 length is the same as line 6-7 (180km)
%format long
Zkk49 = Zkk*180000;
Zkm49 = Zkm*180000;
Zkkpu49 = (Zkk49/Zbase);
Zkmpu49 = (Zkm49/Zbase);
Z0_49 = Zkkpu49 + (2*Zkmpu49);
Z1_49 = Zkkpu49 - Zkmpu49;
Z2_49 = Zkkpu49 - Zkmpu49;
Z0_67 = Z0_49;
```

```
Z1_67 = Z1_49;
Z2_67 = Z2_49;
%--------------------------------------------------------------
%line 7-8 length is the same as line 9-8 (100km)

Zkk78 = Zkk*100000;
Zkm78 = Zkm*100000;
Zkkpu78 = (Zkk78/Zbase);
Zkmpu78 = (Zkm78/Zbase) ;
%-----------------------------------------
%this part to be removed when FACTS is connected
%Z0_78 = Zkkpu78 + (2*Zkmpu78);
%Z1_78 = Zkkpu78 - Zkmpu78;
%Z2_78 = Zkkpu78 - Zkmpu78;

%-------------------------------------------------
Z0_98 = Zkkpu78 + (2*Zkmpu78);
Z1_98 = Zkkpu78 - Zkmpu78;
Z2_98 = Zkkpu78 - Zkmpu78;
%-----------------------------------------------------------
%fault line impedance (when fault in line 7-8 use f1=25% f2 75%)
zf1_kk = Zkk*50000;
zf1_km = Zkm*50000;
zf1_kkpu = (zf1_kk/Zbase);
zf1_kmpu = (zf1_km/Zbase);
zf1_0 = zf1_kkpu + (2*zf1_kmpu);
zf1_1 = zf1_kkpu - zf1_kmpu;
zf1_2 = zf1_kkpu - zf1_kmpu;
%zf2_kk = Zkk*50000;  %no FACTS
%zf2_km = Zkm*50000;
%zf2_kkpu = (zf2_kk/Zbase);
%zf2_kmpu = (zf2_km/Zbase);
%zf2_0 = zf2_kkpu + (2*zf2_kmpu);
%zf2_1 = zf2_kkpu - zf2_kmpu ;
%zf2_2 = zf2_kkpu - zf2_kmpu;
%----------------------------------------------------------------
%this part is used when FACTS is added (fault in line 7-8), otherwise it is removed,
Zf3 is the
%part between fault point to FACTS 25km
zfact = 0.314i; %to be changed accordingly
zfact1 = (zfact/Zbase);
zf3_kk = Zkk*25000;
zf3_km = Zkm*25000;
zf3_kkpu = (zf3_kk/Zbase);
zf3_kmpu = (zf3_km/Zbase);
zf3_0_old = zf3_kkpu + (2*zf3_kmpu);
zf3_1_old = zf3_kkpu - zf3_kmpu;
zf3_2_old = zf3_kkpu - zf3_kmpu;
```

```
zf3_0 = ((zf3_0_old*zfact1) / (zf3_0_old+zfact1)); %Parallel connection
zf3_1 = ((zf3_1_old*zfact1) / (zf3_1_old+zfact1)); %Parallel connection
zf3_2 = ((zf3_2_old*zfact1) / (zf3_2_old+zfact1)); %Parallel connection
%zf3_0 = zf3_0_old+zfact1; %Series connection
%zf3_1 = zf3_1_old+zfact1; %Series connection
%zf3_2 = zf3_2_old+zfact1; %Series connection
zf2_kk = Zkk*50000;
zf2_km = Zkm*50000;
zf2_kkpu = (zf2_kk/Zbase);
zf2_kmpu = (zf2_km/Zbase);
zf2_0_old = zf2_kkpu + (2*zf2_kmpu);
zf2_1_old = zf2_kkpu - zf2_kmpu;
zf2_2_old = zf2_kkpu - zf2_kmpu;
zf2_0 = zf2_0_old + zf3_0;
zf2_1 = zf2_1_old + zf3_1
zf2_2 = zf2_2_old + zf3_2;
%this part is used when FACTS is added, otherwise it is removed
%------------------------------------------------------------
%load 5
PL5 = 90*(10^6);
QL5 = 30*(10^6) ;
VL5 = 0.975*345*(10^3);
RL5 = (VL5^2)/(PL5);
XL5 = (VL5^2)/(QL5);
RL5_pu = RL5/Zbase;
XL5_pu = 1i*XL5/Zbase;
ZL5_pu = RL5_pu + (XL5_pu);
Z0_L5 = (XL5_pu + (3*0.05*1i));
Z1_L5 = XL5_pu;
Z2_L5 = XL5_pu;
%------------------------------------------------------------
%load 7
PL7 = 100*(10^6);
QL7 = 35*(10^6) ;
VL7 = 0.986*345*(10^3);
RL7 = (VL7^2)/(PL7);
XL7 = (VL7^2)/(QL7);
RL7_pu = RL7/Zbase;
XL7_pu = 1i*XL7/Zbase;
ZL7_pu = RL7_pu + (XL7_pu);
Z0_L7 = (XL7_pu + (3*0.05*1i));
Z1_L7 = XL7_pu;
Z2_L7 = XL7_pu;
%------------------------------------------------------------
%load 9
%format short
PL9 = 125*(10^6);
QL9 = 50*(10^6) ;
```

```
VL9 = 0.958*345*(10^3);
RL9 = (VL9^2)/(PL9);
XL9 = (VL9^2)/(QL9);
RL9_pu = RL9/Zbase;
XL9_pu = 1i*XL9/Zbase;
ZL9_pu = RL9_pu + (XL9_pu);
Z0_L9 = (XL9_pu + (3*0.05*1i));
Z1_L9 = XL9_pu;
Z2_L9 = XL9_pu;
%-------------------------------------------------------------
% transformers
Z41 = 0.0576;
Z63 = 0.0586;
Z82 = 0.0626;
%-------------------------------------------------------------
%generators
Zg0 = 0.05i;
Zg1 = 0.15i;
Zg2 = 0.12i;
%---------------------------------------------------------------------------
%Theveinen Impedances
   clc
   % equivalent impedance for 9-bus system. fault in line 7-8 (zero sequence)
   zt0 = zf1_0*Z82 / (zf1_0+Z82);
   zt10 = zt0 + Z0_98;
   zt20 = zt10*Z0_L9 / (zt10+Z0_L9);
   zt30 = zt20 + Z0_49;
   zt40 = zt30*Z41 / (zt30+Z41);
   zt50 = zt40 + Z0_45;
   zt60 = zt50*Z0_L5 / (zt50+Z0_L5);
   zt70 = zt60 + Z0_56;
   zt80 = zt70*Z63 / (zt70+Z63);
   zt90 = zt80 + Z0_67;
   zt99 = zt90*zf2_0 / (zt90+zf2_0);
   zt100 = zt99*Z0_L7 / (zt99+Z0_L7)
   % equivalent impedance for 9-bus system. fault in line 7-8 (Positive sequence)
   zt1 = zf1_1*(Z82+Zg1) / (zf1_1+(Z82+Zg1));
   zt11 = zt1 + Z1_98;
   zt21 = zt11*Z1_L9 / (zt11+Z1_L9);
   zt31 = zt21 + Z1_49;
   zt41 = zt31*(Z41+Zg1) / (zt31+(Z41+Zg1));
   zt51 = zt41 + Z1_45;
   zt61 = zt51*Z1_L5 / (zt51+Z1_L5);
   zt71 = zt61 + Z1_56;
   zt81 = zt71*(Z63+Zg1)/ (zt71+(Z63+Zg1));
   zt91 = zt81 + Z1_67;
   zt98 = zt91*zf2_1 / (zt91+zf2_1);
   zt101 = zt98*Z1_L7 / (zt98+Z1_L7)
```

```
   % equivalent impedance for 9-bus system. fault in line 7-8 (Negative sequence)
   zt2 = zf1_2*(Z82+Zg2) / (zf1_2+(Z82+Zg2));
   zt12 = zt2 + Z2_98;
   zt22 = zt12*Z2_L9 / (zt12+Z2_L9);
   zt32 = zt22 + Z2_49;
   zt42 = zt32*(Z41+Zg2) / (zt32+(Z41+Zg2));
   zt52 = zt42 + Z1_45;
   zt62 = zt52*Z2_L5 / (zt52+Z2_L5);
   zt72 = zt62 + Z2_56;
   zt82 = zt72*(Z63+Zg2)/ (zt72+(Z63+Zg2));
   zt92 = zt82 + Z2_67;
   zt97 = zt92*zf2_2 / (zt92+zf2_2);
   zt102 = zt97*Z2_L7 / (zt97+Z2_L7)
%line 7-8 equevilant impedance when FACTS is added  and fault is in
%different line
%---------------------------------------------------
%first step transforming Y-Delta
zfact = -0.064i; %to be changed accordingly
zfact1 = (zfact/Zbase);
zf3_kk = Zkk*50000;
zf3_km = Zkm*50000;
zf3_kkpu = (zf3_kk/Zbase);
zf3_kmpu = (zf3_km/Zbase);
zf3_0_old = zf3_kkpu + (2*zf3_kmpu);
zf3_1_old = zf3_kkpu - zf3_kmpu;
zf3_2_old = zf3_kkpu - zf3_kmpu;
Za =
((zf3_0_old*zf3_0_old)+(zf3_0_old*zfact1)+(zf3_0_old*zf3_0_old))/(zf3_0_old);
Zb =
((zf3_0_old*zf3_0_old)+(zf3_0_old*zfact1)+(zf3_0_old*zf3_0_old))/(zf3_0_old);
Zc = ((zf3_0_old*zf3_0_old)+(zf3_0_old*zfact1)+(zf3_0_old*zf3_0_old))/(zfact1);
Zab = Za+Zb;
zf3_0 = (Zab*Zc)/(Zab+Zc);
%------------------------------------
Za =
((zf3_1_old*zf3_1_old)+(zf3_1_old*zfact1)+(zf3_1_old*zf3_1_old))/(zf3_1_old);
Zb =
((zf3_1_old*zf3_1_old)+(zf3_1_old*zfact1)+(zf3_1_old*zf3_1_old))/(zf3_1_old);
Zc = ((zf3_1_old*zf3_1_old)+(zf3_1_old*zfact1)+(zf3_1_old*zf3_1_old))/(zfact1);
Zab = Za+Zb;
zf3_1 = (Zab*Zc)/(Zab+Zc);
%--------------------------------------
Za =
((zf3_2_old*zf3_2_old)+(zf3_2_old*zfact1)+(zf3_2_old*zf3_2_old))/(zf3_2_old);
Zb =
((zf3_2_old*zf3_2_old)+(zf3_2_old*zfact1)+(zf3_2_old*zf3_2_old))/(zf3_2_old);
Zc = ((zf3_2_old*zf3_2_old)+(zf3_2_old*zfact1)+(zf3_2_old*zf3_2_old))/(zfact1);
Zab = Za+Zb;
```

```
zf3_2 = (Zab*Zc)/(Zab+Zc);
Z0_78 = zf3_0;
Z1_78 = zf3_1
Z2_78 = zf3_2;
%----------------------------------------------------
%zf3_0 = (zf3_0_old*2)+zfact1; %Series connection
%zf3_1 = (zf3_1_old*2)+zfact1; %Series connection
%zf3_2 = (zf3_2_old*2)+zfact1; %Series connection
%Z0_78 = zf3_0;
%Z1_78 = zf3_1
%Z2_78 = zf3_2;
%Shunt faults
Z_0 = zt100;
Z_1 = zt101; % positive sequence
Z_2 = zt102;
Z_F = 0;
V_F = 0.991 +0.0462i;  %fault in line 9-8
%V_F = 0.989 +0.0365i;             %FACTS connected
%single line to ground fault
I_0 = V_F/(Z_0+ Z_1+Z_2+3*Z_F);
I_a = (3*V_F)/(Z_0+ Z_1+Z_2+3*Z_F)
I_b = 0;
I_c = 0;
%double line to ground
I_1 = V_F/(Z_1+ ((Z_2*(Z_0+Z_F)))/(Z_0+(3*Z_F)+Z_2))
I_2 = -I_1* ((Z_0+3*Z_F)/(Z_0+3*Z_F+Z_2))
I_0 = -I_1* (Z_2/(Z_0+3*Z_F+Z_2))
%double line to ground phase faault currents
a = [(1) (1) (1); (1) (-0.5-0.866i) (-0.5+0.866i); (1) (-0.5+0.866i) (-0.5-0.866i) ];
b = [(I_0); (I_1); (I_2)];
c = a*b
%line-line
I_1 =(V_F)/(Z_1+Z_F+Z_2);
I_b =((-sqrt(3)*i)*V_F)/(Z_1+Z_F+Z_2)
I_a = 0
I_c = -I_b
%three line to ground phase fault currents
I_1 = V_F/Z_1
I_0 = 0;
I_2 = 0;
d = [(1) (1) (1); (1) (-0.5-0.866i) (-0.5+0.866i); (1) (-0.5+0.866i) (-0.5-0.866i) ];
e = [(0); (I_1); (0)];
f = d*e
```