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Ground Fault Protection of Transmission Lines

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Problem Description

Ground faults are the most common type of fault in the power system. Protection of transmission lines is performed using distance relays. These relays are dependent on knowing the zero sequence impedance of the transmission line it shall protect in order to be set correctly. For transmission lines totally without or with discontinuous ground wires, the zero sequence impedance of the line is dependent on and varying with the conductivity in the actual ground that the line travels across. The fault current rising as a result of a ground fault is dependent on the neutral grounding of the system, and this fault current has impact on the ability of the distance relay to detect the fault.

This masters thesis is written in cooperation with Statnett. The power system owned by Statnett mostly has solid earthed neutral, but some parts of the grid has compensated neutral earthing through Petersen coils. The compensated parts of the grid has to have a lower system voltage than the solid earthed parts. In order to increase the capacity of the transmission network, some of these low voltage parts of the grid are subject to a voltage upgrade. As a result of the upgrade, the system earthing method must be changed from compensated to solid earthed.

The objective of this thesis is twofold. First to identify the impact that line design with discontinuous ground wire has on the ability of the distance relay to detect a ground fault occurring at a line in a solid earthed system. Second, to consider a network that has compensated neutral earthing and no ground wires. It is an open question whether or not two ground faults occurring at the same time but at different locations will be detected. The thesis also aims to answer whether or not the distance relays are able to detect ground faults at transmission lines if the system earthing was changed from compensated to solid earthed without installing ground wires.

Preface

This thesis is the result of my work on ground fault protection of transmission lines carried out during the spring semester of 2017 at the Department of Electric Power Engineering, Norwegian University of Science and Technology (NTNU). Along with simulations in ATPDraw this thesis makes up my master thesis of the 5 year Msc programme Energy and Environmental Engineering.

The thesis is written in cooperation with Statnett, and the objective is to analyse the impact that presence of ground wires and method of system neutral earthing has on the ability of the distance relay to detect ground faults. The readers of this report are assumed to possess basic knowledge within power system analysis and protection theory.

I wish to express my gratitude towards my supervisor Professor Hans Kristian Høidalen, for his guidance and help throughout the year that has passed. I am also grateful for all help I have received from fellow students, professors, researchers at SINTEF and all others answering my many questions this semester.

The content of this thesis was partly developed during my specialisation project with the same title, carried out in the fall semester of 2016. The specialisation project was a pre-project to the master thesis, and therefore covers a lot of the same ground. Due to rules concerning business confidentiality, parts of this thesis will be unavailable to the public.

Trondheim, June 2017

Mari Lauglo

Summary

The ever more electrified and energy-intensive society increases the need for a secure power grid and energy service. The transmission system is the backbone of the electrical power infrastructure, to have a well-functioning protection system of this is therefore crucial. The most common type of faults in the power grid are ground faults on overhead lines, which makes it important to be sure about how the relays will measure such a fault. Distance protection is the preferred protection scheme for the transmission grid, thus it is of importance to determine how the performance of these depends on parameters like presence of ground wires, ground conductivity, system neutral earthing, different types of faults and size of fault resistance.

This masters thesis investigates the impact that presence of ground wires has on the ability of the distance relay to detect single phase-to-ground faults in a grid with solid earthed neutral. In compensated earthed networks it is investigated whether the distance relays are able to distinguish two single phase-to-ground faults at two different phases occurring at the same time but at distant locations from a single ground fault. To investigate these scenarios, models of a transmission line and a section of a transmission grid were implemented in the simulation programme ATPDraw. The models were used for testing of various fault scenarios in combination with different system neutral earthing methods, line design and ground conductivity.

It was found that presence of overhead ground wires does not have decisive impact on whether the distance relays are able to detect a single ground fault in a solid earthed grid. However, estimated fault location was severely improved for lines with ground wires compared to those without. Fault resistance was found to be the factor deciding whether a ground fault was detected. For a solid earthed grid lacking ground wires, high earth potential rise at fault location during a ground fault is a concern. The distance relays are displaying a clear difference in measured impedance for one ground fault versus two ground faults. Thus, in theory, it should be possible to implement more advanced protection zones that will only trip the relay for double faults and persistent single faults. However, this subject needs further analysis before a general conclusion applicable to all possible fault scenarios can be stated.

Sammendrag

Med et stadig mer elektrifisert og energikrevende samfunn kommer et økt behov for å sikre at strømnettet holder seg operativt. Transmisjonssystemet er ryggraden i elektrisk infrastruktur, og det er derfor avgjørende at dette har et velfungerende beskyttelsessystem. De fleste feil i strømnettet er jordfeil som skjer på luftlinjener, noe som gjør det viktig å være sikker på hvordan feilhåndtering av disse utføres av vernene. I transmisjonsnettet er det brukt distansevern, så hvordan dets måleforhold for å detektere jordfeil avhenger av systemjording, tilstedeværelse av jordline, jordkonduktivitet, forskjellige feiltyper og feilmotstander er viktig å fastsette.

Denne masteroppgaven undersøker hvilken påvirkning design av transmisjonslinjer med eller uten jordline har på distansevernets evne til å detektere enfase jordfeil i et direktejorda nett. I spolejorda nett blir det undersøkt om distansevernet klarer å skille mellom to enfase jordfeil som skjer på samme tid men på forskjellige lokasjoner og to forskjellige faser fra en singel jordfeil.

For å kunne simulere disse problemstillingene ble flere modeller av en virkelig transmisjonslinje samt en del av transmisjonsnettet implementert i simuleringsprogrammet ATPDraw. Modellene ble brukt til å teste ulike feilscenario i kombinasjon med forskjellig systemjording, linjedesign og jordkonduktivitet.

Det ble funnet ut at installasjon av overliggende jordliner ikke har avgjørende påvirkning på om vernet detekterer en jordfeil i direktejorda nett. Men, antydning av feillokasjon ble forbedret når et direktejorda har jordline i forhold til uten. Feilmotstand ble funnet å være avgjørende faktor for om en feil blir oppdaget av distansevernet. I direktejorda nett uten jordline vil man få problemer med økt jordpotensial på feillokasjon under en jordfeil, noe som kan være skadelig for folk og dyr.

Vernet viser for de gjennomførte simuleringene en klar forskjell i målt impedans for single feil versus to samtidige enfase jordfeil. Dermed skal det i teorien være mulig å implementere mer avanserte beskyttelsesoner som kun vil koble ut for doble feil og vedvarende single feil. Dette må imidleritd undersøkes nærmere før man kan dra en generell konklusjon for alle ulike feilscenario.

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Chapter 1

Introduction

The power system is continuously increasing in size all over the globe, and people are more than ever dependent on the availability of electrical power. Thus the need of a well functioning power system is obvious, which in turn makes power system protection crucial. This report will focus on distance protection of transmission lines against the most common type of fault; ground faults.

1.1 Problem Background

The electrical power transmission system in Norway has been built in various designs throughout the years, and as a result of this we are experiencing issues today. An issue of concern is whether distance relays are able to detect ground faults on overhead transmission lines that has discontinuous or no ground wire. This kind of network configuration results in a non-linear short circuit impedance of the transmission line, which causes problems for the distance relay as its trip settings are impedance based. In the best case scenario, the relay will detect the fault but give erroneous estimates of the distance to the fault location. In the worst case scenario the relay will not be able to detect a persistent fault which will remain, possibly damaging system components or causing cascading faults.

The relay protecting the line with discontinuous ground wire investigated in this thesis has not yet detected a fault located in the line section lacking ground wire. The owner of the line, the Norwegian transmission system operator Statnett, questions whether this is because there has been no faults to detect or because the relay was unable to see faults that actually have occurred.

Statnett is also performing a study on the performance of one of their networks that was built with Petersen coil grounded neutral, and no ground wire in the whole grid. If the study results in a decision to perform a voltage upgrade in order to increase the power transfer capacity of the grid, there will be a need to change the grounding conditions from compensated to solid earthed. In this case Statnett will have to decide whether or not they should install ground wires, a decision that is partially dependent on the performance of the distance protection in a solid earthed grid without ground wires. There is also a question concerning the ability of the distance relays to detect two ground faults occurring at the same time at distant locations, if the network is to remain compensated grounded.

1.2 Objective

The objectives of this masters thesis are to identify:

- The impact of line design with discontinuous ground wire on the ability of the distance relay to detect ground faults when the line is part of a solid grounded network
- If two ground faults occurring at the same time in a network with compensated earthed neutral and no ground wires will be detected
- If the distance relay has adequate measuring conditions to be able to detect a ground fault if the grounding system of the compensated grid without ground wires simply was changed into solid neutral earthing, without installing ground wire

1.3 Approach

The approach used to meet the stated objectives was to first perform an in-depth literature survey on distance protection and over-head transmission lines. Then simulation of the problem scenarios was performed using the computer programme ATPDraw made by professor

Hans Kristian Høidalen. ATPDraw is a graphical pre-prosessor, generating input to the ATP version of the Electro-Magnetic Transients Programme [8]. The models in ATPDraw were built based on given data and information provided by Statnett. Simulations with parameter variations chosen to investigate the objectives were run and analysed.

Literature Survey

The performed literature survey serves as a basis for this masters thesis and has been on distance protection of transmission systems, and on mapping out which parameters has an influence on the ability of the relays to detect a fault. The purpose of the literature survey has been two-sided. One part for theoretical foundation on the distance relay and ground faults, as well as for what results to expect from the performed simulations. The other part for knowledge on rules and regulations in order to analyse if the simulated results are in accordance to the requirements of the power system.

Books, articles, slides from previously attended courses, talks with my supervisor and a number of NTNU professors and SINTEF researchers have been sources of information. For articles especially the internet database IEEE Xplore has been visited frequently. Internet searches in the search-engine Google Scholar have also been a valuable source of literature.Main sources for the theory part are:

- Protective Relaying - Principles and Applications, by J. L. Blackburn and T. J. Domin [9]
- Power System Relaying, by s. Horowitz, A. G Phadke and J. K. Niemira [10]
- Fault Location on Power Networks, by M. M. Saha, J. Izykowski and E. Rosolowski [11]
- Numerical Distance Protection Principles and Applications, by Gerhard Ziegler [12]
- Power System Analysis & Design, by J. D. Glover, M. S. Sarama and T. J. Overbye [2]

1.4 Limitations

The method used to give an answer to the objectives will only be as good as its limitations, therefore it is important to acknowledge its possible errors and limitations.

The input data to the simulations is an important limitation. The input data were provided by Statnett and consists of both calculated and measured values. The calculated data could be a source of errors and/or deviations as they do not represent the reality with the same certainty as measured data. Measured data could on the other hand be subject to measurement errors.

A few simplifications had to be made when making the simulated models in ATPDraw due to some limitations in the computer programme. These are presented in the discussion part of each simulation.

1.5 Structure of the Report

In this report, the reader is first provided with a theoretical foundation before approach to the simulations, results and conclusions are provided. The rest of the report is structured as follows:

Chapter 2 provides a theoretical foundation on unsymmetrical faults, transmission line parameters and system earthing methods

Chapter 3 is elaborating on distance relays, their principle of measurement, settings and detection problems

Chapter 4 presents the simulation model used to investigate the first objective, the results from the simulation as well as a discussion of the model and the results given by it. The discussion tries to bring the theory and the results together by comparing the actual results to what was expected based on the theory

Chapter 5 presents the simulation model used for investigating the second and the third objective, the results from the simulations as well as a discussion of the model and the results given by it

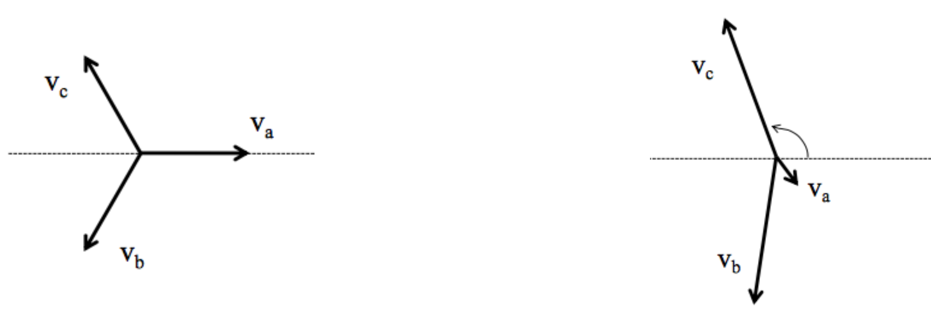
Chapter 6 Gives a short conclusion to the three stated objectives, and suggests some further work on the analysed subjects

Chapter 2

Theory

2.1 Unsymmetrical Conditions

Unsymmetrical conditions occur in the power system when it is subjected to power unbalance on its three phases [9]. This can happen in numerous ways, but is most often caused by a connection between one of the phases and ground. All faults involving ground in one way or the other are called ground faults.



(a) Balanced voltages [1]

(b) Unbalanced voltages [1]

Figure 2.1: Symmetrical and unsymmetrical conditions

This report will treat the single phase-to-ground fault involving only one phase and ground, along with the broken conductor to ground fault. The single phase-to-ground fault is the simplest and most common type of ground fault [13]. This type of fault can be caused by for example a tree falling over the phase, a bird stretching its wings causing contact between neutral and phase conductor, or by lightning causing a flash-over from phase to tower. The broken conductor to ground fault can be caused by for example a three falling over the line, causing one of the phases to break and fall to ground. These two types of ground faults are graphically presented in figure 2.2. The fault resistance Z_F is dependent on the nature of the connection from the faulted phase to ground, and is assumed to be purely resistive [11]. More advanced types of ground faults exist, but these will not be elaborated on in this report.

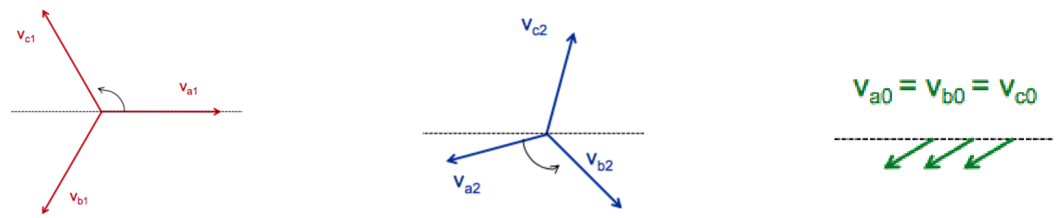
(a) Single phase-to-ground fault (b) Broken conductor to ground fault

Figure 2.2: Single phase-to-ground faults

2.1.1 Symmetrical Components

When unsymmetrical conditions occur, the result is that the three phase system no longer can be analysed on a per-phase basis in the way that calculations are done for symmetrical conditions. To be able to perform calculations on a system in unsymmetrical state, Fortescue‘s theorem on symmetrical components is applied. The theorem states that the unbalanced set of phasors can be resolved into three distinct sets of balanced phasors, i.e. the symmetrical components of the originally unbalanced set [14]. These symmetrical sets are called the positive-, negative- and zero-sequence, and are related as shown in figure 2.3. The symmetry of each of these components makes it possible to obtain network quantities on a per-phase basis, easing fault calculations. It is important to acknowledge that the sequence sets are defined as a set of three, they do not exist alone or in pairs.

The positive sequence set is rotating with system frequency in counter-clockwise direction, its vectors having the same amplitude and being equally distributed in the phasor diagram. Values of positive sequence current and voltage are labelled respectively I_1 and V_1. The negative sequence has a different order of its phases compared to positive sequence, with



(a) Positive sequence (b) Negative sequence (c) Zero sequence

Figure 2.3: Symmetrical components of figure 2.1b [1]

negative sequence current and voltage labelled I_2 and V_2. The zero sequence stands out from the foregoing as its vectors all have the same phase angle. Zero sequence current can only flow where there is a physical path to earth, and is therefore dependent on conditions like the neutral grounding of the system and the coupling group of transformers and loads [14]. Values of zero sequence current and voltage are labelled I_0 and V_0.

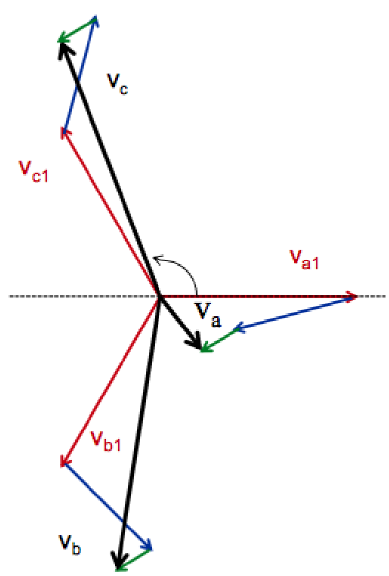


Figure 2.4: Combined sequence voltage phasors [1]

Figure 2.4 is showing graphically how the combination of figures 2.3a, 2.3b and 2.3c together makes up the original unbalanced phasors of figure 2.1b. An important fact to acknowledge is that the zero sequence is the only sequence which involves currents to earth, and it is therefore the only sequence that is influenced by a change to grounding conditions in the network or ground conductivity.

The Phasor Operator a

The phasor operator a is being used to describe the angle displacement of the phasors in a sequence set. A multiplication of a phasor with the a operator is equal to the phasor being rotated by 120° counter-clockwise [9].

$$1 + a + a^2 = 0 \tag{2.1}$$

Per phase, the positive-, negative- and zero-sequence components of voltage and current are related to the phase quantities of voltage and current as shown in equation (2.2) [2].

$$\begin{bmatrix} V_0 \\ V_1 \\ V_2 \end{bmatrix} = \frac{1}{3} \begin{bmatrix} 1 & 1 & 1 \\ 1 & a & a^2 \\ 1 & a^2 & a \end{bmatrix} \begin{bmatrix} V_a \\ V_b \\ V_c \end{bmatrix} \qquad \begin{bmatrix} I_0 \\ I_1 \\ i_2 \end{bmatrix} = \frac{1}{3} \begin{bmatrix} 1 & 1 & 1 \\ 1 & a & a^2 \\ 1 & a^2 & a \end{bmatrix} \begin{bmatrix} I_a \\ I_b \\ I_c \end{bmatrix} \tag{2.2}$$

For the positive sequence the three sequence phasors V_{a1}, V_{b1}, V_{c1} or I_{a1}, I_{b1}, I_{c1} are related as shown in equations (2.3) to (2.5).

$$V_{a1} = V_1 \qquad I_{a1} = I_1 \tag{2.3}$$

$$V_{b1} = a^2 V_{a1} = a^2 V_1 = V_1\underline{/240°} \qquad I_{b1} = a^2 I_{a1} = a^2 I_1 = I_1\underline{/240°} \tag{2.4}$$

$$V_{c1} = aV_{a1} = aV_1 = V_1\underline{/120°} \qquad I_{c1} = aV_{a1} = aI_1 = I_1\underline{/120°} \tag{2.5}$$

For the zero sequence, the three sequence phasors V_{a0}, V_{b0}, V_{c0} or I_{a0}, I_{b0}, I_{c0} are related as shown in equation (2.6).

$$V_{a0} = V_{b0} = V_{c0} = V_0 \qquad I_{a0} = I_{b0} = I_{c0} = I_0 \tag{2.6}$$

2.1.2 Sequence Networks

A sequence network shows how the sequence currents will flow if they do exist. If unbalanced conditions should arise, the three sequence networks will be interconnected at the point of the unbalance, i.e. the fault location [2]. This makes calculation of fault currents and network quantities easy compared to analysis not using symmetrical components theory. The way the sequence networks are coupled depends on the type of fault.

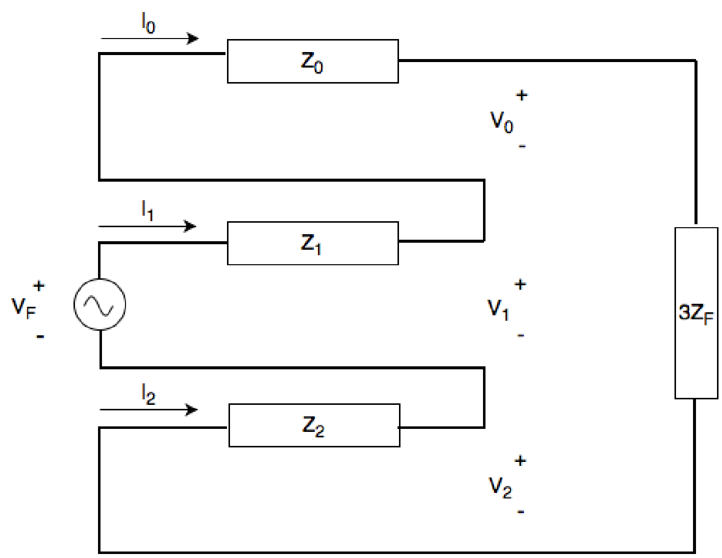


Figure 2.5: Interconnected sequence networks for a phase-to-ground fault [2]

Figure 2.5 shows interconnection of the three sequence networks for a single phase-to-ground fault with fault resistance Z_F. If $Z_F \approx 0$, the fault is called bolted. Fault resistances varies with the nature of the fault [11]. Z_1, Z_2 and Z_0 represent the sequence impedance of the positive-, negative- and zero-sequence network respectively.

2.2 Transmission Lines

Overhead transmission lines are the highways of the electrical power infrastructure, and important to maintain stability in the system as they transport huge amounts of power from production site to consumers and even interconnecting countries. As a fault on a transmission line will have consequences in all levels of the power system, in worst case causing blackout in multiple countries, they are crucial to monitor and protect from faults [15].

2.2.1 Transmission Line Design

The design of a transmission line is subject to a number of considerations, from dimensioning of electrical components to social-economic optimisation. Important for the choice of design is voltage level of the grid and type of system neutral grounding, along with required power transfer capacity [2].

Symmetric Transmission Lines

An overhead transmission line does not generally have electrical symmetry. In a planar configuration which is standard in the high voltage network [16], capacitance between phase and ground will be almost equal for all three phases whilst the capacitance between the phases will differ [17]. In order to make the overhead line symmetrical, the method of transposition has been adapted. As shown in figure 2.6, transposition of a transmission line is done by revolving the phases such that each phase occupy one physical position as viewed from above for one third of the total line length.

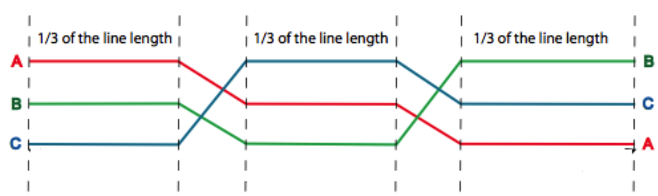


Figure 2.6: Transposed transmission line [1]

Transposition makes both inductive and capacitive quantities of the line electrical symmetrical [17]. The phases being symmetric means that per-phase calculations can be made, and the three sequence networks are completely decoupled. With completely decoupled sequence networks the assumption of positive sequence line parameters being dependent solely on positive sequence voltages and currents holds true [18]. For the sake om simplicity, it is usual to assume full transposition when performing calculations on transmission lines. Although not all transmission lines are symmetrical, the assumption that they are transposed is the basis for further calculations in this report.

Ground Wire

One or multiple neutral wires positioned over the phase conductors have many names applied to them, such as ground wire, earth wire, neutral conductor or shield wire. Under normal, symmetrical conditions there will be no current flowing through the ground wire [2]. In the event that an unsymmetrical fault takes place causing unbalanced conditions, a current may flow in the ground wire.

The purpose of installing a ground wire is to shield the phase conductors from lightening strokes, and to obtain control of the fault loop in case of a ground fault [19]. Also a ground wire will interconnect all the tower impedances as parallel connections to ground, drastically reducing the total resistance to ground of the grounding system. This results in a reduced earth potential rise at fault location in case of a ground fault, as this is determined by the ground fault current multiplied with the resistance from neutral to ground at fault location [20]. In turns this reduces the touch- and step voltage [21]. To be able to offer protection against lightening, the number and location of ground wires are chosen so that most lightening strikes will hit the ground wire before it can reach a phase conductor.

Ground wires are usually made of high-strength steel, and have a much smaller dimension than the phase conductors [2]. The ground wire is grounded at each tower through the tower impedance, so that when a lightening strikes the current ideally flows to ground without flashing over to the phase conductors. A prerequisite for this method to successfully work is that the tower impedance and its footing resistance are small enough to allow the current to flow easily to ground [2]. Transmission lines in Norway are most often built with continuous ground wires [22], but there exist transmission lines totally or partially without ground wires. Reasons for the ground wires to be discontinuous or totally absent for a transmission line can be:

- Reduced risk of strike of lightening due to the sagging of the line over a fjord
- Problems with icing making the ground wire sag into the phase conductors, as it will have a lower temperature than the energised phases
- Cost of installing the extra wire

- The grid has compensated grounded neutral, resulting in a low ground fault current

2.2.2 Transmission Line Parameters

Transmission lines are considered to be static components in the power system, hence the phase sequences of voltages and currents has no effect on the sequence impedance given by the transmission line [2]. As the distance relay is impedance based, knowing the sequence impedances of the transmission line to be protected is crucial to make the correct relay settings [12]. The derivation of some of the following equations on transmission line parameters are not explained, as this is quite laborious work. The need for the reader of this report is simply to acknowledge which parameters the sequence impedances are dependent on, in order to understand what parameters that affects distance relay settings and operation. For the curious reader, a thorough explanation is found in references [3], [17] and [19].

Inductive and Capacitive Quantities

For a three phase transmission line with a possible return path trough earth for fault current (2.7) describes the phase-to-ground voltages. From this the per-phase impedance of the transmission line can be obtained assuming full transposition [3].

$$\begin{bmatrix} V_{a-g} \\ V_{b-g} \\ V_{b-c} \end{bmatrix} = \begin{bmatrix} r_a + r_e & r_e & r_e \\ r_e & r_a + r_e & r_e \\ r_e & r_e & r_a + r_e \end{bmatrix} \begin{bmatrix} I_a \\ I_b \\ I_c \end{bmatrix} + j \begin{bmatrix} x_{aa-g} & x_{ab-g} & x_{ac-g} \\ x_{ab-g} & x_{bb-g} & x_{bc-g} \\ x_{ac-g} & x_{bc-g} & x_{cc-g} \end{bmatrix} \begin{bmatrix} I_a \\ I_b \\ I_c \end{bmatrix} \tag{2.7}$$

Here the notation a, b and c declares the three phases while g represents ground, so that x_{aa-g} is the self-inductance of phase a with a return path to ground. Further x_{ab-g} is the mutual impedance between phases a and b.

It is shown in electromagnetic basics that the inductance of a conductor can be found using the *mirror charge* method which involves the magnetic field set up by the conductor and its equivalent mirror conductor in the ground [17]. The principle is shown in figure 2.7. The method is based on assumptions of homogeneous ground conductivity and that the ground

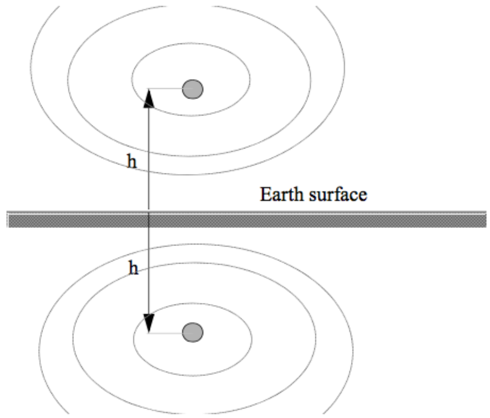


Figure 2.7: The mirror charge method [3]

extends into infinity. Further, it requires that the induced electric field does not create a potential difference in the ground. Because of the low conductivity in ground compared to the phase conductors, the current in the ground will have its highest density in a plane in the ground just below the phase conductor [17].

As the distance from the conductor to its mirror charge is much bigger than the distance from the conductor to ground, the equivalent mirror charge dominates and the line inductance will not be affected by the distance from the phases to ground. Line inductance is therefore solely dependent on the physical distance from phase conductor to its mirror charge and the distance between the phase conductors [3]. For the sake of simplicity in calculations an assumption of the phase conductors being non-magnetic is made, yielding $\mu_r = 1$. Using this assumption along with the mirror charge method and (2.7) it can be shown that for low frequencies (50 Hz) the line self-inductance and mutual impedance can be expressed by (2.8) and (2.9) [3].

$$x_{aa-g} = x_{bb-g} = x_{cc-g} = \mu_0 f ln\frac{D_g}{g_{aa}} = 0.063\left(\frac{f}{50}\right) ln\frac{D_g}{g_{aa}} \quad \left[\frac{\Omega}{km}\right] \tag{2.8}$$

$$x_{ab-g} = x_{bc-g} = x_{ac-g} = \mu_0 f ln\frac{D_g}{D} = 0.063\left(\frac{f}{50}\right) ln\frac{D_g}{D} \quad \left[\frac{\Omega}{km}\right] \tag{2.9}$$

$$D_g = 1.31 \cdot \delta = 1.31\sqrt{\frac{2\rho'}{\mu_0 \omega}} \quad [m] \tag{2.10}$$

Where: μ_0 Permeability in free space $= 4\pi \cdot 10^{-7}$ $\left[\frac{H}{m}\right]$
f Frequency [Hz]
D_g Equivalent distance virtual mirror conductor - phase conductor [m]
ρ' Resistance of the fault current return path [$\Omega\cdot$ m]
D Distance between the phases a and b [m]
δ Skin depth of the ground [m]

The mirror charge method shown previously in figure 2.7 is being used for calculation of capacitive line quantities as well as inductive. When the same assumptions are made for calculation of capacitance as for the previously deducted inductive parameters, the charge per meter of the phase conductors is as described in (2.11) [3].

$$\begin{bmatrix} q_a \\ q_b \\ q_c \end{bmatrix} = \begin{bmatrix} c_g + 2c_{ab} & -c_{ab} & -c_{ab} \\ -c_{ab} & c_g + 2c_{ab} & -c_{ab} \\ -c_{ab} & -c_{ab} & c_g + 2c_{ab} \end{bmatrix} \begin{bmatrix} V_a \\ V_b \\ V_c \end{bmatrix} \tag{2.11}$$

Here q_a, q_b and q_c are the charges per meter of the phase conductors a, b and c respectively. Further, c_g is the capacitance from phase to ground and c_{ab} the capacitance between phase a and phase b. As the transmission line is assumed to be fully transposed and therefore symmetric, the capacitances between the phases are the same, and the capacitance from either phase to ground is likewise equal.

Using (2.11) and geometry from figure 2.8 it can be shown that the capacitance from phase to ground and phase-to-phase are as stated in (2.12) and (2.13) [3].

$$c_g = \frac{2\pi\varepsilon}{ln\left[\frac{4h}{d}\left(\frac{D'_{mean}}{D_{mean}}\right)^2\right]} \quad \left[\frac{nF}{km}\right] \tag{2.12}$$

$$c_{ab} = \frac{2\pi\varepsilon ln\left[\frac{4h}{d}\right]}{ln\left[\frac{4h}{d}\left(\frac{D'_{mean}}{D_{mean}}\right)^2\right] \cdot ln\left[\frac{4hD_{mean}}{dD'_{mean}}\right]} \quad \left[\frac{nF}{km}\right] \tag{2.13}$$

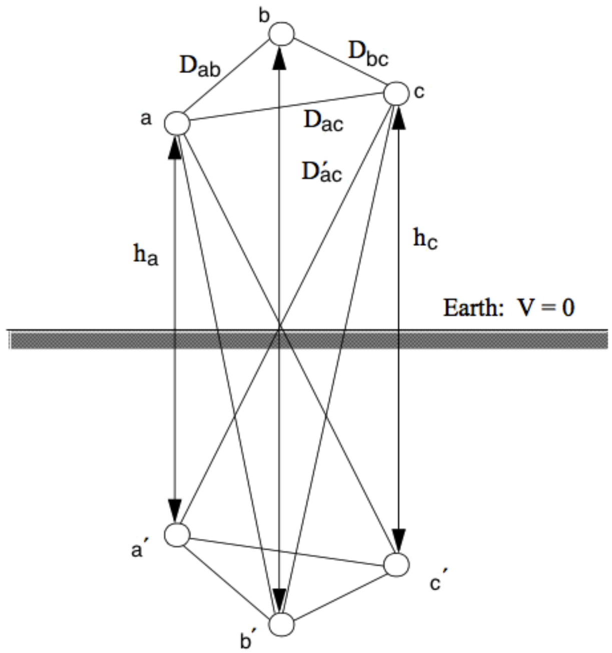


Figure 2.8: Phase conductors and their mirror charges [3]

Where:

	ε	Permittivity, $= \epsilon_0\epsilon_r$
	ε_0	Permittivity in free space, $= 8.85 \cdot 10^{-12}$ $\left[\frac{F}{m}\right]$
	ε_r	Relative permittivity, $= 1.0$ $\left[\frac{F}{m}\right]$
	d	Diameter of the phase conductor [m]
	h	Geometric mean conductor height above ground
		$= \sqrt[3]{h_a h_b h_c}$ [m]
	D_{mean}	Geometric mean distance between the phases
		$= \sqrt[3]{D_{ab} D_{bc} D_{ca}}$ [m]
	$D`_{mean}$	Geometric mean distance between mirror charge and phase
		$= \sqrt[3]{D`_{ab} D`_{bc} D`_{ca}}$ [m]
	D_{ab}, D_{bc}, D_{ca}	Distance between the phases a-b, b-c and c-a [m]

Positive Sequence

By combining the equations (2.7) and (2.1) - (2.5) it is possible to obtain equation (2.14) which gives the positive sequence voltage [3].

$$\begin{aligned} V_{a-g,1} &= (r_a + r_e)I_a + r_e a^2 I_a + r_e a I_a + j(x_{aa-g} I_a + x_{ab-g}(I_b + I_c)) \\ &= r_a I_a + r_e I_a(1 + a^2 + a) + jI_a(x_{aa-g} + x_{ab-g}(a^2 + a)) \\ &= r_a I_a + jI_a(x_{aa-g} - x_{ab-g}) \quad [V] \end{aligned} \tag{2.14}$$

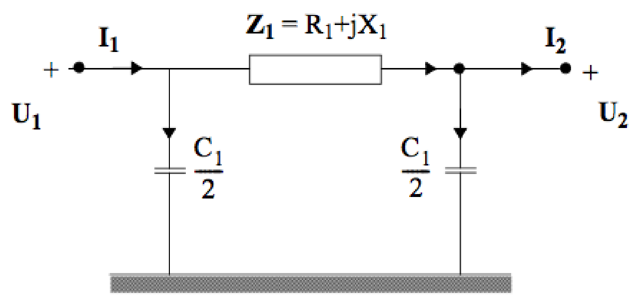


Figure 2.9: Positive sequence π equivalent of a transmission line [3]

Where: R_1 Resistance, $r_a \cdot l$ $[\Omega]$

X_1 Reactance, $x_{aa-g} - x_{ab-g} \cdot l$ $[\Omega]$

C_1 Capacitance, $c_1 \cdot l$ [nF]

By inserting for x_{aa-g} and x_{ab-g} with equations (2.8) and (2.9) in equation (2.14) and rearranging the equation, the positive sequence impedance of a overhead transmission line Z_{1Line} can be derived as shown in equation (2.15) [3].

$$Z_{1Line} = r_a + j0.063\left(\frac{f}{50}\right) ln\frac{D}{g_{aa}} \quad \left[\frac{\Omega}{km}\right] \tag{2.15}$$

Where: r_a Ac resistance of the conductor $[\frac{\Omega}{m}]$

f Frequency [Hz]

D Distance between the phases [m]

g_{aa} 0.5d for hollow tube conductor, d = diameter of conductor [m]

There are no parameters in equation (2.15) that includes the effect of earth resistance, and the positive sequence line impedance Z_{1Line} is therefore independent on earth. This is as expected, as there is no current flowing to earth in the positive sequence network. As the negative sequence line impedance Z_{2Line} will be the exact same as the positive sequence line impedance Z_{1Line} , Z_{2Line} will not be derived individually [3].

The per phase positive sequence capacitance c_1 will not be derived here, but [3] shows that it can be approximated by equation (2.16).

$$c_1 \approx \frac{2\pi\varepsilon}{ln\frac{2D_{mean}}{d}} \quad \left[\frac{nF}{km}\right] \tag{2.16}$$

Where:	ε	Permittivity, $= \epsilon_0\epsilon_r$
	ε_0	Permittivity in free space, $= 8.85 \cdot 10^{-12} \quad \left[\frac{F}{m}\right]$
	ε_r	Relative permittivity, $= 1.0 \quad \left[\frac{F}{m}\right]$
	d	Diameter of the phase conductor [m]
	D_{mean}	Geometric mean distance between the phases $= \sqrt[3]{D_{ab}D_{bc}D_{ca}}$ [m]
	D_{ab}, D_{bc}, D_{ca}	Distance between the phases a-b, b-c and c-a [m]

From equation (2.16) it can be seen that the positive sequence capacitance c_1 is solely dependent on the arrangement of the transmission line conductors, the distance between them and their diameter. This is as expected, as there is no current flowing to ground in the positive sequence system, and therefore no influence of earth.

Zero Sequence

By combining the equations (2.7) and (2.6), it is possible to obtain (2.17) which describes the zero sequence voltage between phase a and ground [3].

$$\begin{aligned} V_{a-g,0} &= (r_a + r_e)I_0 + r_eI_0 + r_eI_0 + jI_0(x_{aa-g} + 2x_{ab-g}) \\ &= (r_a + 3r_e)I_0 + jI_0(x_{aa-g} + 2x_{ab-g}) \quad [V] \end{aligned} \tag{2.17}$$

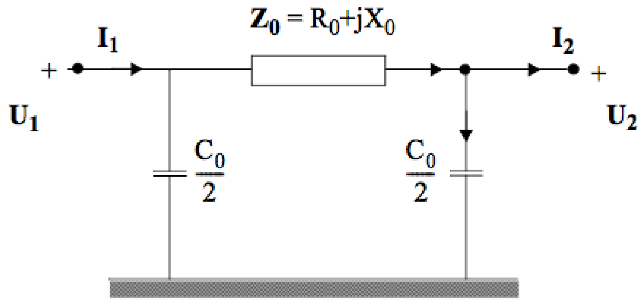


Figure 2.10: Zero sequence π equivalent of a transmission line [3]

Where: R_0 Resistance, $(r_a + 3r_e) \cdot l$ [Ω]

X_0 Reactance, $x_{aa-g} + 2x_{ab-g} \cdot l$ [Ω]

C_0 Capacitance, $c_0 \cdot l$ [nF]

By inserting for x_{aa-g} and x_{ab-g} with equations (2.8) and (2.9) in (2.17) and rearranging the equation, the zero sequence line impedance Z_{0Line} can be derived as shown in (2.18) [3].

$$Z_{0Line} = (r_a + 3r_e) + j0.063\left(\frac{f}{50}\right) ln \frac{D_g^3}{g_{aa} D^2} \quad \left[\frac{\Omega}{km}\right] \tag{2.18}$$

$$r_e = \frac{1}{4}\mu_0 f \pi \quad \left[\frac{\Omega}{m}\right] \tag{2.19}$$

Where: r_a AC resistance of the conductor $\left[\frac{\Omega}{m}\right]$

r_e Equivalent resistance in earth $\left[\frac{\Omega}{m}\right]$

f Frequency [Hz]

μ_0 Permeability in free space $= 4\pi \cdot 10^{-7}$ $\left[\frac{H}{m}\right]$

D_g Equivalent distance virtual mirror conductor - phase conductor [m], given by equation (2.10)

D Distance between the phases [m]

g_{aa} 0.5d for hollow tube conductor, d = diameter of conductor [m]

By studying equation (2.18), it can be seen that the zero sequence line impedance Z_{0Line} *is dependent* on the ground conditions, which is taken into account by the terms $3r_e$ and D_g. The parameter D_g is as stated in equation (2.10), where ρ' is the resistance offered to the returning fault current. This is given either by the resistance in the ground wire, or in the case of a line without ground wire, by the specific resistance of the actual ground, ρ. Hence the zero sequence impedance is a *loop impedance*, describing the impedance offered to an unsymmetrical fault current [12]. The contribution r_e is describing the resistance offered to the induced current in the mirror charges of the conductor.

For the zero sequence, the per phase zero sequence capacitance is equal to the capacitance between phase and ground [3]. This yields equation (2.20).

$$C_0 = C_g = \frac{2\pi\varepsilon}{ln\left[\frac{4h}{d}\left(\frac{D`_{mean}}{D_{mean}}\right)^2\right]} \quad \left[\frac{nF}{km}\right] \tag{2.20}$$

Where:

ε	Permittivity, $= \epsilon_0\epsilon_r$
ε_0	Permittivity in free space, $= 8.85 \cdot 10^{-12} \quad \left[\frac{F}{m}\right]$
ε_r	Relative permittivity, $= 1.0 \quad \left[\frac{F}{m}\right]$
h	Geometric mean conductor height above ground $= \sqrt[3]{h_a h_b h_c}$ [m]
d	Diameter of the phase conductor [m]
D_{mean}	Geometric mean distance between the phases $= \sqrt[3]{D_{ab}D_{bc}D_{ca}}$ [m]
$D`_{mean}$	Geometric mean distance between mirror charge and phase $= \sqrt[3]{D`_{ab}D`_{bc}D`_{ca}}$ [m]
D_{ab}, D_{bc}, D_{ca}	Distance between the phases a-b, b-c and c-a [m]

It can be seen by studying equation (2.20) that the zero sequence capacitance is dependent on earth. The parameter h is describing the height of the conductors above the earth, and it is obvious that there are not many (if any) transmission lines which hold a constant height of its conductors. The varying height could be due to variations in temperature expanding and shrinking the material in the line, or because of varying terrain between two towers. This means that if the zero sequence capacitance is to be calculated properly, and not just be an estimate, it demands a tremendous amount of measurements and time.

2.3 System Earthing

In the case of a star-connected transformer, there is an existing neutral point. This neutral point is assumed to have earth potential in order to obtain symmetrical conditions for the system. The available neutral point can be handled in several ways, which is chosen based on multiple conditions such as the system voltage, fault detection, requirements to service continuity, inherited practise as well as touch and step voltages [21]. The way the neutral is handled, i.e. how neutral is connected to ground, is called the system earthing. With respect to the behaviour of the system during an unsymmetrical fault, the system earthing is the most influential parameter [23]. In the forthcoming sections the solid, isolated and compensated neutral is elaborated. There are other possible ways to treat the system neutral, like resistance and low-resistance earthing, but these methods will not be discussed in this report.

2.3.1 Solid Earthing

The system is solid earthed when the transformer neutral has a direct connection with the ground as shown in figure 2.11.

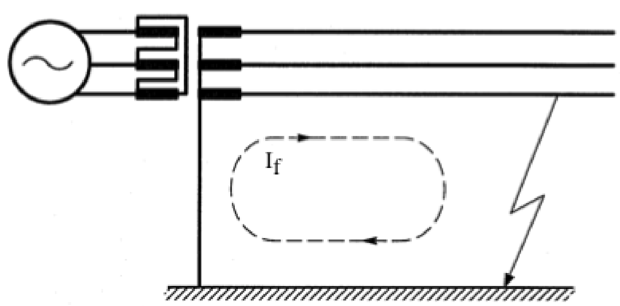


Figure 2.11: Solid grounded neutral [4]

With such a grounding configuration, the fault current I_f in case of a ground fault will flow through the very low resistance of the neutral grounding, the resulting low fault loop impedance causing a high fault current [21]. As the neutral is assumed to hold earth potential, the neutral point does not move during a ground fault, resulting in almost no over-voltages on healthy phases [24]. Whether there is any over-voltage at all on healthy phases is dependent on the earth plant resistance and the fault current. These properties makes the solid grounded neutral the preferred choice for high voltage systems such as the transmission network. Not all transformers in a solid earthed network are required to have their neutral solid earthed, it is custom to limit the number of grounding points in order to reduce the fault current [23].

2.3.2 Isolated Neutral

A system has isolated neutral if there is no connection made between the transformer neutral and ground potential, as illustrated in figure 2.12. All transformers in the system have to be isolated for this type of neutral earthing [21]. Neutral isolation from ground could be the chosen because of delta connection of the transformer, yielding no available neutral point to make the connection, or because it is the neutral earthing of choice for the network.

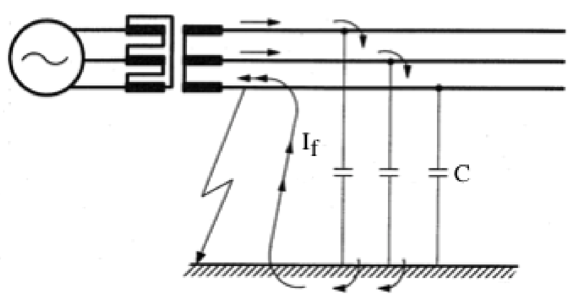


Figure 2.12: Isolated neutral [4]

In the event of a ground fault occurring in an isolated system, the fault loop impedance will be high [4]. This is because although the system is technically isolated from ground, the capacitive connection between the phases and ground will provide a path where the fault current can flow in the shape of an arc. The fault current being small, limited by the capacitances, results in over-voltages on the healthy phases, the largest occurring for a bolted fault [21]. This yields that a neutral point displacement has taken place, as the voltage between healthy phases and ground has risen to meet the line voltage [24]. For big networks and networks with high capacitance to ground, the fault current can be so big that an arc does not self-extinguish. Isolated neutral is used in lower voltage grids such as the distribution network.

2.3.3 Compensated Earthing

A network with its neutral point connected to ground through an inductance is compensated earthed. The inductor is often called a Petersen coil or an arc suppression coil, the principle is illustrated in figure 2.13. The name Petersen coil is inherited from its inventor, Waldemar Petersen.

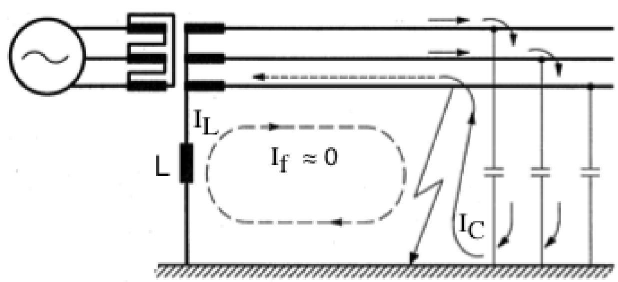


Figure 2.13: Coil compensated neutral [4]

The term compensated earthing is derived from the operating principle of the Petersen coil, which is to make an inductive compensation to the capacitive connection between phase and ground in order to limit the fault current [25]. In case of a ground fault the fault current will flow both through the capacitances and the inductive coil, making the resulting ground fault current very small as the inductive contribution to the fault current is almost cancelled by the capacitive contribution [21]. By limiting the total fault current the hope is that arcing faults will self distinguish. The losses in the system due to a ground fault will also be limited.

The Petersen coil can be tuned so that it adapts to changes in the system capacitance. It is common practise to combine the neutral point inductor with a parallel resistance, because the remaining earth fault current after compensation could be too small for the relay to measure [15]. The additional resistor will create a resistive component to the fault current, making it easier to detect for the relays [23].

Compensated earthing is mostly used in medium voltage networks, but is also to some degree present in high voltage networks. According to the literature on the subject, successful arc extinction is only possible for system voltages below 220 kV [1]. For higher system voltage levels the over-voltages on healthy phases due to the neutral point displacement caused by the compensated earthed neutral will be a problem as well [21].

Resonant Earthing

If the coil is tuned so that its inductance is exactly equal to the system capacitance, the system is resonant grounded. This will totally cancel all fault current, but gives rise to large voltage differences in case of non-symmetrical capacitances. The voltage over the Petersen coil will also peak at resonance [21].

Overcompensated Earthing

In order to avoid resonance in the system, the Petersen coil has to be tuned in such a way that its inductance is not equal to the system capacitance to ground. The preferred method is to slightly overcompensate, i.e. making the inductive contribution to the fault current a little bit bigger than the capacitive fault current contribution [15]. This is an act of security, as in the event of a line in the system falling out, resonance due to the decrease in system capacitance to ground will not be an issue. It is common practice to overcompensate by about 5%, set by the relation (2.21) [24]. If $X_c = X_l$ then the system is resonant.

$$X_c = \frac{1}{3 \cdot \omega C_0} \quad [\Omega] \qquad X_l = \omega \cdot L \quad [\Omega] \qquad X_{coil} = 0.95 \cdot X_c \quad [\Omega] \tag{2.21}$$

2.4 Ground Fault Regulations

Dependent on the specifications of a network, there are different requirements to how the protection system should act in case of a ground fault. These requirements are not the same all over the world as not all countries have equally developed power grids or expectations to its quality of service. This section will treat the Norwegian laws and regulations. The regulations specify that the earthing system of an overhead transmission line should be constructed in such a way that [5]:

- It protects humans and animals from dangerous touch voltages, also at the highest possible ground fault current
- Damage to property and equipment is avoided

- It is dimensioned to withstand thermal stress due to fault currents
- It is dimensioned to withstand corrosion and mechanical stress for the entire life of the grid section
- It provides sufficient operational reliability of the line

Disconnection Time for Single Phase-to-Ground Faults

For a single phase-to-ground fault like the one illustrated in figure 2.2a, the maximum time for disconnection of the fault is listed in table 2.1. The fault should of course be disconnected as soon as possible, the regulation is simply stating the minimum requirements to the protection system. The disconnection times does not include eventual re-connections of the faulted area.

System Earthing	**Power System**	**Disconnection Time**
Solid Earthed Neutral	All configurations	8 seconds
Isolated and Compensated	Overhead lines and mixed cable/overhead lines connected to a distribution transformer	10 seconds
	Overhead lines and mixed cable/overhead lines not connected to a distribution transformer	120 minutes
	Industrial grid with overhead lines and mixed cable/ overhead lines	120 minutes
	All cable grid without any overhead lines, with global earthing	240 minutes

Table 2.1: Demands for a single phase-to-ground fault disconnection [5]

Regulations for Other Types of Faults

Any short-circuit faults and cross-country faults, that is phase-to-phase and phase-to-phase-to-ground faults, should be cleared both fast and automatic in the transmission network. In the event of two single phase-to-ground faults occurring at different locations in a compensated grid, the protection system should in the fastest possible way, and within 1.0 seconds, split the network into two galvanically separated parts [15]. In this way the electrical perception is that there now exist two individual networks, each suffering one single line-to-ground fault to be cleared with respect to table 2.1.

Touch- and Step Voltage

Touch voltage is defined as a part of the earth potential rise during a ground fault that can affect a person or an animal by causing current to flow through its body, from the touching point of conductive parts to ground [5]. The damage to a human or an animal due to electric current is dependent on the amplitude of the current and the duration of the contact. As the human body is assumed to have a resistance of about 1000Ω [26], this limit is given in the resulting voltage over the connection points as shown graphically in figure 2.14.

The voltage across the connection points is dependent on the earth potential rise and the conductivity in the ground. The earth potential rise is equal to the resistance to ground of the grounding system multiplied by the fault current flowing in the grounding system. The resistance to ground of the grounding system is determined, in the case of steel tower, by the tower impedance, or the grounding wire going down a wooden non-conductive power pole [2]. As given by basic electric circuit laws, multiple parallel resistances to ground results in a small equivalent of total resistance to ground. The interconnection of tower grounding impedances through ground wires is therefore reducing the total resistance to ground of the grounding system by creating parallel paths to ground for the fault current to be distributed amongst. Although the reduced resistance to ground of the grounding system allows a higher total fault current to flow to ground, reducing the resistance to ground in the fault current path will result in a reduced earth potential rise at fault location [21]. In turn this will reduce the touch- and step-voltage.

If the human or animal is exposed to such a voltage caused by earth potential rise for an unlimited amount of time, the touch voltage should be less than 75 V according to the Norwegian regulations [26]. The regulation also demands that the step voltage, that is the voltage over two points in the ground that are 1 meter apart during a ground fault, should be so low that a person walking does not suffer from electric current of a quantity dangerous to the body. The step voltage does not have a set limit, as this always will be lover than the touch voltage and therefore will be within limits if the touch voltage already is. If it is known that the current will last shorter than for 1 second, a higher touch voltage is allowed as shown in figure 2.14.

The touch- and step-voltage is dependent on the power systems neutral connection to ground as well as the local ground conductivity. The touch- and step-voltages can therefore also be reduced by adding highly resistive surface layers like bedrock on the ground around towers, or by proper use of ground electrodes connecting the tower footing to highly conductive soil layers so that the total neutral to ground impedance is reduced [20].

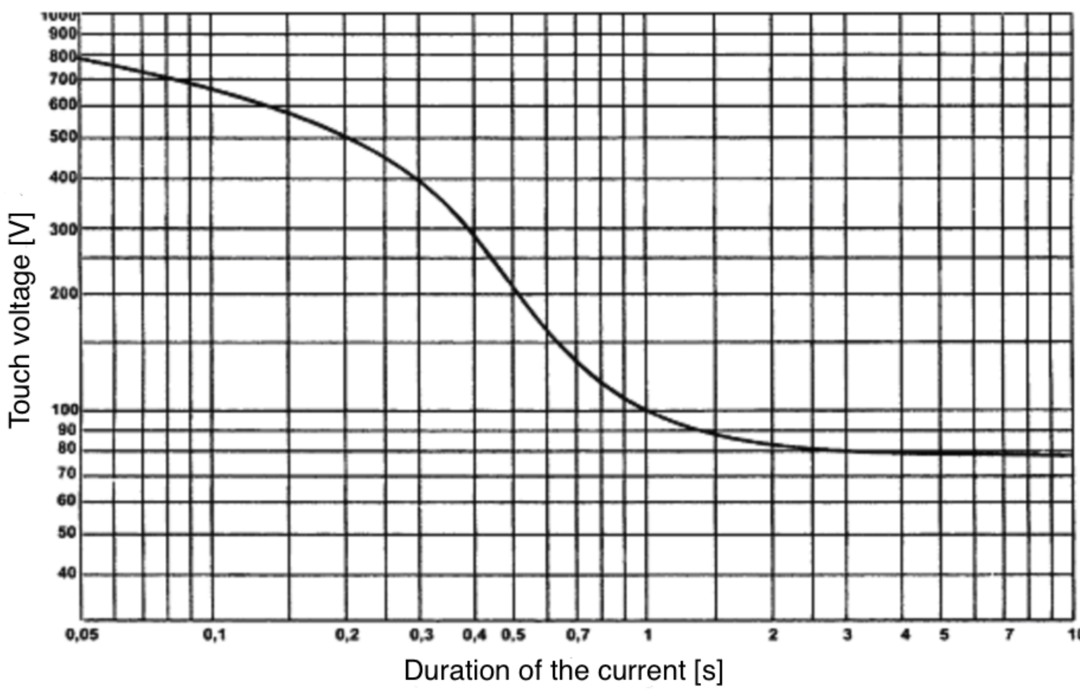


Figure 2.14: Allowed touch voltage as a function of current duration [5]

2.5 Comparison of Neutral Earthing Methods for the Transmission Network

This section will provide an overview of the advantages and disadvantages of the previously presented neutral earthing methods, in addition to a comparison given with respect to the high voltage system. In Norway the majority of the transmission network has solid grounded neutral, whilst there are some sections that are compensated earthed. The compensated parts normally hold a lower voltage level (132kV) than the solid grounded grid (300-420kV) sections although both are considered to be high voltage networks and part of the transmission network [22].

In table 2.2 the advantages and disadvantages of the different neutral earthing methods are stated. An important feature of the different neutral earthing methods is the difference in caused over-voltage to healthy phases. As this over-voltage is a function of the system voltage, over-voltage to healthy phases are causing more damages for a high system voltage level than in lower voltage levels [21]. This is because the bigger the system voltage is, the greater the voltage rise in the healthy phases will be. This high over-voltage can cause further damage to the grid. The losses due to the high ground fault current is a better alternative than damaged equipment as a result of over-voltages, and therefore the solid earthed neutral point is the preferred solution for the transmission grid, whilst compensated neutral can be accepted in the lower voltage level transmission grid [15].

A reason for choosing the compensated neutral earthing could be if there is a need to keep the power grid in service at all time, as this can be kept in operation even though it suffers from a ground fault. The Petersen coil will in most cases manage to extinguish an arcing fault caused by lightening, and many faults clear themselves after a short time if they are caused by for example birds [13]. In such cases the network operator will not have to take any actions to mend the fault, as it cleared itself and the grid remained in operation. If the network was solid earthed, the relay would have to disconnect the faulted area for a short time, then try to reconnect and see if the fault has cleared. The process of disconnection and re-connection could have an impact for consumers, dependent on the topology and level of redundancy in the grid.

System Earthing	**Application**	**Advantages**	**Disadvantages**
Solid Earthed Neutral	Transmission network and some small industrial grids [27].	Simple detection of ground faults. Small (less than 0.8 phase-to-phase voltage) to none over-voltages on healthy phases.	Huge ground fault currents. Can not continue service during a ground fault. Can cause a rise to voltage in underlying grids. Could have trouble with too high step- and touch-voltage [4].
Isolated Neutral	Small distribution grids / grids with a low capacitive connection to ground.	Cost effective and easy. The grid can continue to provide service during a ground fault. Small, capacitive ground fault current.	Troubles to extinguish arc under high currents. Trouble to detect ground faults with high fault resistance. Over-voltages ($\geq$ phase-to-phase voltage) on healthy phases [21].
Compensated Neutral	Big distribution networks/distribution networks with a lot of cables causing a big capacitive connection to ground. Some lover voltage transmission networks.	Limits the ground fault current and step-/touch-voltages. Easier to detect ground faults with high fault resistance. The grid can continue to provide service during a ground fault.	High costs. Can be difficult to decide the direction of a ground fault. Between 0.8 and full phase-to-phase over voltage on healthy phases [24].

Table 2.2: Neutral earthing methods

Chapter 3

Distance Protection

The laws and regulations are providing some minimum requirements that the power system protection have to satisfy. It is technically and economically not possible to completely shield a power system from all possible faults it could be exposed to during its lifetime, but the use of a correct protection system will make the impact of any occurring faults as small as possible. The main purpose of the power system protection is therefore to minimise [28]:

- Damages to life and property
- Damages to production units, transmission and distribution networks
- Interruption of the power supply to customers

To be able to fulfil its purpose, the requirements for the power system protection are that it should be [10]:

- Dependable: Always trip when supposed to
- Secure: Never trip when not supposed to
- Reliable: Leave all healthy parts intact
- Selective: Detect and isolate only the faulty item
- Sensitive: Detect even the smallest fault

- Speedy: Disconnect a fault as quickly as possible to minimise damage
- Simple: Minimise risk of wrong operation due to complications
- Economical: Maximum protection at minimal total cost

A protective relay is defined as *"an electric device that is designed to respond to input conditions in a prescribed manner and, after specified conditions are met, to cause contact operation or similar abrupt change in associated electric control circuits"* [9]. In other words, the protective relay is the hearth of the electrical protection system, analysing measured values and making decisions based upon these.

There are many types of protection schemes existing, as the topology of networks and the resulting need for protection varies a lot worldwide. In this chapter, only the distance protection scheme will be elaborated. Distance protection is the most common protection scheme applied in transmission networks, as it handles meshed network topology [12]. In some areas, the standard distance protection is supplemented by teleprotection signalling, i.e. a communication channel between the relays. Communication makes it possible to provide full line coverage with immediate tripping, and provides a backup if either some protection device or a breaker experience a failure [10]. Communication between relays will not be discussed further in this report.

3.1 Fundamentals of Distance Protection

Distance protection is defined as a short-circuit protection [12]. The distance relay is based upon evaluation of a measured impedance which is calculated from local measurements of voltage and current. The principle of fault location is that the measured short-circuit impedance as seen from the distance relay is proportional to the distance to the fault location [4].

The relay operates by comparing the measured impedance Z_1 to the known total line impedance Z_{Line}, and uses the result of this comparison to decide if a fault has occurred. If the relation is low, the relay will start. This gives that for the simplest form of distance protection, the only requirements of the relay is voltage and current measurements. It does not depend on complicated services like communication channels or additional technology to work, and is therefore a cheap and simple protection scheme [10].

3.1.1 Relay Input Sources

The input information on voltage and current from the transmission line are delivered to the relay by voltage transformers (VT) and current transformers (CT). This makes the distance relay a secondary relay, in the sense that the overhead lines are the primary system. As a result, the impedance calculated from the voltage and current input to the relay is dependent on the transformation ratios of the CT and VT, as shown in equation 3.1 [12].

$$Z_{sec} = \frac{I_{prim}/I_{sec}}{U_{prim}/U_{sec}} \cdot Z_{prim} \quad [\Omega] \tag{3.1}$$

The current transformer acts like a current source to the distance relay, and has a small error as long as the burden Z_b is small. Voltage transformers are close to error free, simple and reliable. There are several types of VT and CT available at the market, with different measurement methods. For the reader of this report the important part is to understand how the distance relay gets its input values, not to immerse themselves in the different types of voltage- and current-transformers. Therefore the simple working principle of VT and CT are shown in figure 3.1, and the curious reader is suggested to look to references [9] and [29] for extensive theory on the subject.

(a) Current transformer

(b) Voltage transfomer

Figure 3.1: Working principles for CT and VT

3.1.2 Principle of Measurement

The distance relay obtains the positive sequence impedance Z_1 as seen by the relay, given in equation (3.2) for a single phase to ground fault on phase a by measuring U_a, I_a and I_0 [28]. Here U_a is the voltage of phase a, I_a the current flowing in phase a and I_0 is the zero sequence current.

$$Z_1 = \frac{U_a}{I_a + kI_0} \quad [\Omega] \tag{3.2}$$

The grounding factor k in (3.2) represents a constant factor for a given configuration of a line, and is defined as a correction factor for ground fault impedance. It is dependent on the relationship between the zero sequence impedance and the positive sequence impedance of the line that the relay is set to protect, as shown in equation (3.3) [4].

$$k = \frac{Z_{0Line}}{Z_{1Line}} - 1 \tag{3.3}$$

In the expression for k, Z_{0Line} and Z_{1Line} are given by equation (2.18) and (2.15) respectively. The ground fault correction factor k is assumed to be known in the setting of the distance relay protection zones. As k is dependent on Z_0, it is also dependent on the available ground fault current return path as proved by equation (2.18). This relationship can make it difficult to set k correctly for lines without ground wires, as the ground resistance ρ may be unknown.

To be able to detect faults not involving ground, the distance relay also measures phase to phase values. These are described in equation (3.4). For a ground fault however, none of these impedances will go low, therefore not tripping the relay [12].

$$Z_1 = \frac{U_a - U_b}{I_a - I_0} \quad [\Omega] \qquad Z_1 = \frac{U_a - U_c}{I_a - I_c} \quad [\Omega] \qquad Z_1 = \frac{U_b - U_c}{I_b - I_c} \quad [\Omega] \tag{3.4}$$

3.1.3 Setting the Distance Relay

The settings of the distance relay have great impact on the performance of the transmission line protection [29]. To satisfy the demands to a protection system given previously, the distance relay has to be set in such a way that it protects the transmission lines in front of it in the best possible way, detecting even the smallest fault without tripping during normal load conditions.

Impedance Diagram

As shown in figure 3.2 the zones of protection is chosen with respect to the line impedance seen by the relay. The relay will activate when the measured Z_1 is lower than a preset value for the impedance seen by the relay, which is determined by the protection zones [29].

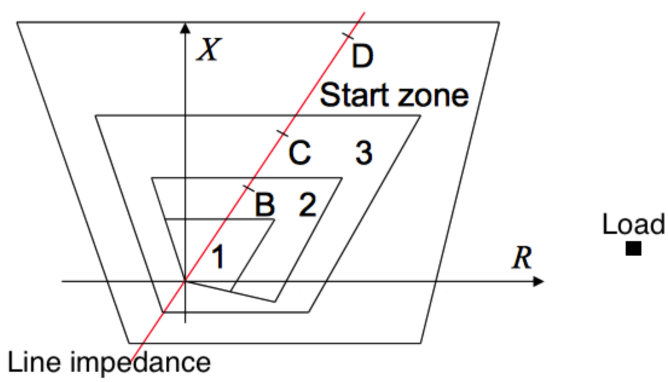


Figure 3.2: Polygonal impedance diagram for setting of protection zones [6]

The polygonal shape of the impedance diagram shown here is the modern standard for the shape of the protection zones, but there are many other designs of zone shapes existing [12]. It is important to keep the starting zone of the relay in good distance to the point of heavy load in order to avoid tripping in such situations. At maximum load the current flowing in the line will be respectively high causing the real part of the impedance measured by the distance relay to go low and thus approaching the starting zone. The load as it is represented in the impedance diagram of the protection zones can be calculated as shown in equation (4.3) [4].

$$Z_{max\ load} = \frac{U_{min}^2}{P_{max}} = \frac{U_{min}}{\sqrt{3} \cdot I_{max}} \quad [\Omega] \tag{3.5}$$

Protection Zones

The settings of protection zones 1, 2 and 3 in figure 3.2 are based on the characteristic of the transmission line to be protected which in this case in the line section A to B in figure 3.3. To obtain selectivity, i.e. only isolate the faulted line, time delay of the protection zones are introduced. In this way the tripping time increases with the distance to the fault from the relay, giving the relay located closest to the fault a chance to trip first and in that way keep the number of interrupted customers as low as possible [4]. This practise also leaves the network operators with the smallest line section possible in which they have to locate the fault before they can repair it in a case where the fault does not self-extinguish.

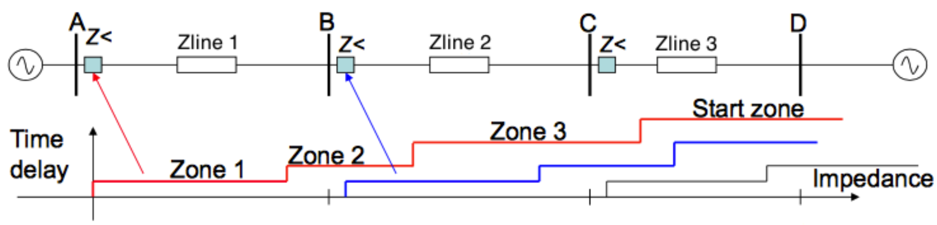


Figure 3.3: Time graded distance protection zones [6]

Zone 1 is typically set to cover about 80-90% of the line section with no time delay [6]. For relay A in 3.3 most of line 1 will be covered. If a fault is detected in zone 1, the relay detecting the fault is the relay closest to the fault and it should trip immediately in a transmission system with solid neutral grounding.

Zone 2 for relay A should reach a bit over the next bus B, about 120% of line 1 [6]. It should have a small time delay of about 15-30 cycles, resulting in 0.3-0.6s for a 50Hz system, to allow relay B to trip first for a fault on line 2.

Zone 3 should have a reach of just above two buses in front of the relay, so 120% of line 1 + line 2 and a bit in front of bus C, and have a bigger time delay [6]. To be able to set these protection zones the line parameters, i.e the line impedance must be known.

The purpose of the starting zone is to start or release the zone measurements [4]. Not all relays have a functioning starting zone, in which case the start zone is just a back up protection zone and does not have a signal release function. The start zone can be triggered by either an over-current or an under-impedance detection. The over-current is defined as

$1.5 \cdot I_{max}$, where I_{max} is the maximum load current or the maximum rated current for the current transformer. For the under-impedance detection an impedance measured by the relay which is under $0.8 \cdot Z_{max\ load}$ where $Z_{max\ load}$ is given by equation (3.5) will trigger the start of the relay. For solid grounded networks the under-impedance starting must be used in order to achieve tripping of only the faulted phase, as it is possible for short-circuit currents to flow in the healthy phases during a ground fault [12].

3.1.4 The Fault Loop

The equivalent circuit shown in figure 3.4 is defining the fault loop for a single phase-to-ground fault. Z_{Line} is given per kilometre of the line by equation (2.15), and is therefore dependent on the distance to the fault from the relay. Z_F is the fault resistance, dependent on the characteristic of the fault. Z_F can vary from 0 to thousands of ohms, but is considered to be purely resistive [11]. Z_E is the impedance offered to the return path of the fault current, which is determined by the impedance of the ground wire in addition to the tower impedance and the tower footing resistance as the fault current will have to flow through these to reach the ground wires. If the line does not have ground wires Z_E is given by the resistance in the actual soil, ρ [12].

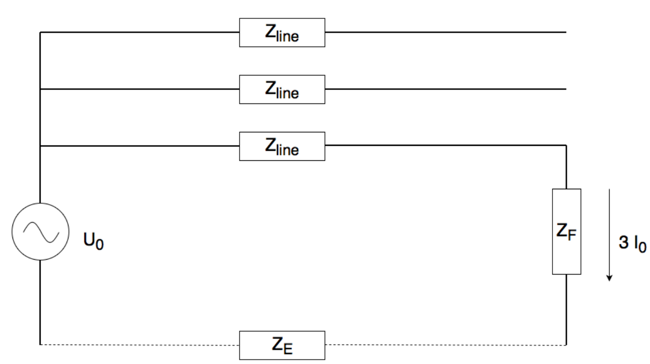


Figure 3.4: Fault loop for a single phase-to-ground fault

The total impedance of the fault loop, the short-circuit impedance Z_{sc} which is measured by the distance relay in case of a ground fault is given by equation (3.6) [4].

$$Z_{sc} = Z_{line} + Z_F + Z_E \quad [\Omega] \tag{3.6}$$

3.2 Detection Problems

If the distance relay does not see an ongoing fault the relay has a detection problem [4]. The reasons as to why it under certain conditions can be difficult for the distance relay to detect an ongoing ground fault will be presented in this section.

3.2.1 Lack of Ground Wire

The first problem caused by the lack of ground wires is the fact that the zero sequence impedance Z_{0Line} of the line that the relay should protect would be dependent on the varying ground resistance ρ as given by equation (2.18), because this is the only path available for the ground fault return current to flow in. As the ground fault correction factor is based on the zero sequence line impedance, k will be dependent on the varying ground resistance ρ instead of the constant resistance of the ground wire. This relation causes problems with the setting of the relay when the ground resistance is unknown or varying. Incorrect settings causes incorrect measurements, which could result in the relay not being able to detect a fault [4].

Another problem is the difference in resistance of ground wires and the actual ground. This is a cause to detection problems because the impedance offered to the ground fault return current Z_E will be much higher when the current is flowing in the actual soil of the ground than if the return current was flowing through a highly conductive ground wire. As given by the basic electric laws, a high impedance results in a low current, i.e. for a high impedance Z_E the fault current $I_f = 3 \cdot I_0$ will become small. This has an impact on the impedance measured by the relay Z_{sc} according to the relation given by equations (3.6) and (3.2). When the measured fault current is small, the impedance measured by the relay will be high.

When the line has ground wires, the resistance in the fault return path is low as the returning fault current will flow in the ground wires. This means that the fault current I_f will be higher for a fault occurring at the same place and with the same fault resistance Z_F on a line with ground wires than on a line without ground wires. As a result, the impedance Z_{sc} seen by the relay will be lower for a line with ground wires than for a line without ground wires. The distance relay tripping is based on a comparison of the known total positive sequence line impedance to the measured impedance. This comparison can be compromised, causing the relation to be high even though there is a fault, as the measured impedance Z_{sc} of a line without ground wires can be too high to be seen within the protection zones of the relay.

3.2.2 Unknown and Varying Ground Resistance

As discussed in the previous section, the varying and often unknown ground resistance ρ can be a cause to detection problems for the distance relay both due to difficulties in settings of the relay as well as a reduction in the fault current.

The biggest cause to variation in the ground resistance ρ is due to different types of soil in the terrain that the transmission line is passing through. Some typical resistances are given by table 3.1. The ground resistance will also vary with moisture and salt content in the soil as well as temperature changes, as electrical conduction in soil is considered to be electrolytic [2]. For a line without ground wire this means that both seasons and the daily weather will have impact on the zero sequence line impedance due to the relation given in equation (2.18). If the ground resistance ρ and therefore also k varies a lot, it may not be possible to set the distance relay in a way that allows it to detect ground faults for all possible conditions, i.e. all possible ρ.

To be able to set the ground fault correction factor of the distance relay correctly for a transmission line, the ground resistance will have to be approximated or measured. There are several existing methods for measurement of ground resistance ρ, which will not be further elaborated in this report. The curious reader is suggested to look to reference [30] for a thorough elaboration on the subject.

3.2.3 Variations in Fault Resistance

For transmission networks with solid earthed neutral, ground faults that have a high fault resistance Z_F can be hard to detect [4]. This is because the high fault resistance will result in a very low fault current, and if this fault current is below 10% of the nominal line current,

Type of earth	**Resistance** ρ $[\Omega \cdot m]$
Sea water	1 - 10
Marine clay	10 - 100
Swampy ground	100 - 600
Fresh water	100 - 1000
Moist uncultivated soil	500 - 1000
Moist mountain	3000 - 10000
Dry bedrock and sand moraine	10000 - 100000

Table 3.1: Earth resistances [7]

then the relay will not detect the fault. The combination of a high fault resistance together with highly resistive ground conditions results in a small ground fault current. Due to the high voltage in the transmission system, even a small fault current going to ground equals a huge loss of power [2].

The fault resistance is dependent on what is causing the fault. For ground faults in the Norwegian transmission grid the main triggering reasons for a fault occurring on a transmission line are vegetation, thunderstorms and snow/ice [13]. Out of these reasons, vegetation can be a source to high fault impedance, for example if a tree falls over the line, as wood dis almost non-conductive.

Snow and ice may cause the suspension insulator to be faulted, whilst during a thunderstorm the line can be struck by lightning and the resulting over-current causing an arc to the transmission tower. As all towers in the transmission system are made out of steel, an arc from one phase to the grounded steel transmission tower is considered a ground fault with the arc resistance as the fault impedance [12]. The same goes for a fault due to snow and ice on an insulator allowing some current to flow from the phase to the transmission tower. The fault impedance due to an arc is given by equation (3.7) [4]. Here D is the distance of the arc, i.e. the distance from the faulted phase to the tower, while I_{sc} is the short circuit current.

$$Z_{arc} = \frac{2500 \cdot D}{I_{sc}} \quad [\Omega] \tag{3.7}$$

Chapter 4

Analysis of a Transmission Line

In this chapter the simulation and analysis of a transmission line with discontinuous ground wire is presented. Due to business confidentiality concerns, geographical locations will not be available to the public.

4.1 Design and Conditions

The analysed transmission line is a part of a system that has solid neutral earthing. When the line starts from the station in point A it has two ground wires located above its phase conductors. Then, after about one third of the line length the line leaves the lowland and goes up to and over a mountain area, before it reaches the station at point B. The point where the terrain goes from lowland to mountain area is refered to as point C. At point C the ground wires are terminated. From point C to point B, the line carries on without its ground wires.

Like many other parts of the Norwegian electrical power system, the transmission line in question is quite old. The reasons as to why the line was designed and built the way it is with discontinuous ground wires are not clearly known today. Because of the tough climate in the mountain areas during winter time it is possible that the weight of ice and snow accumulating to the ground wires is the reason why they were omitted. If the ground wires comes too close to the phase conductors due to the sagging explained in section 2.2.1, the risk of an arc is increasing. In the worst case scenario, the ground wire will make contact with the phase conductor. This would in either case be classified as a ground fault.

As the line is part of a solid earthed system, the requirements to the distance protection for ground fault detection and isolation are strict. According to table 2.1 the maximum disconnection time is 8 seconds. Section 3.2 explains why the short disconnection time limit could be hard to meet, as the measurements made by the distance relay of this line will depend on the varying ground conductivity for a fault occurring at the part of the line without ground wires.

A simple figure of the transmission line for illustration purposes is shown in 4.1. Simulation models, line design and line parameters are all found in appendix A.

Figure 4.1: Transmission line A to B with discontinuous ground wire

4.2 ATPDraw Simulation

To investigate the measuring conditions of the distance relay for this transmission line, two models have been built in ATPDraw. The first model is built to be as equal to the actual transmission line A-B as possible, and is used to simulate what the real life situation will be. The second model is built exactly like the first, with the exception that model two has a continuous ground wire for the entire length of the line. Model two represents the ideal solution, and is used for reference and comparison of relay fault detection performance.

The tests performed on both models are simulating different types of faults occurring at multiple locations of the line. The fault types simulated are single phase-to-ground, broken conductor to ground and arcing fault to ground. These types of faults have been placed at four different locations of the line. At the same time, the fault resistance R_f has been varied. The last parameter that has been varied is the ground resistance. Variation of one parameter at the time whilst the other are held constant will show which parameter that has the greatest effect on the ability of the distance relay to detect a fault.

4.2.1 Simulation Models

The ATPDraw models for transmission lines are based on the known positive sequence line impedance Z_{1Line}, the ground resistance ρ and the geometry of the line. When ATPDraw gets these input data, it can simulate the zero sequence impedance Z_{0Line} of the line as well as line capacitances. The input parameters to the simulation of the transmission line sections, i.e. the line between two towers are:

- x-coordinates: distance from the centre of the tower to the centre of the phase conductors and eventual ground wires $[m]$
- y-coordinates: distance from the ground to the centre of the phase conductors and eventual ground wires $[m]$
- core diameter of the phase conductors and the ground wires $[cm]$
- total diameter of the phase conductors and the ground wires $[cm]$
- DC resistance of phase conductors and ground wires $[\Omega/km]$
- height of the tower, i.e. distance from ground to the attachment point of phase conductors and ground wires to the tower $[m]$
- ground resistance ρ $[\Omega m]$
- length of the line $[km]$

The line models have been built using the approximation of merging ten towers and their impedances into one. The towers are modelled as resistors the size of the combined tower impedance and tower footing impedance. The ground wire starting at point A is connected to ground with a very low resistance as the earthing of this is assumed to be done using a sufficient ground electrode. Where the ground wire is terminated at point C the resistance to ground is assumed to be equal to the tower impedance. For model two with continuous ground wire the ground wire is assumed to be connected to ground in both point A and B through a very low resistance. The line sections are also modelled merging ten into one resulting in a length ten times their actual length. The line is assumed to have power flowing in the direction from A to B, with the grid connected to point A modelled as an ideal voltage source. The load at point B is modelled as purely resistive and is symmetrically distributed on all three phases. All these input data are presented in table A.3, A.1 and A.2.

When both the positive- and the zero sequence impedance of the line are known, the relay protection zones and the grounding factor k can be set according to section 3.1.3. As the relay in ATPDraw has one single input for k and is not split in real and imaginary values, the absolute value of k needs to be computed using equation (4.1). The resulting protection zones and ground fault correction factor are shown in tables A.6 and A.8. In order to emphasise the influence of the ground fault correction factor $|k|$ on the impedance measured by the distance relay, each fault scenario was simulated using a common $|k|$ calculated by the given sequence impedances as well as a k fitted to match the ground resistance.

$$|k| = \frac{|Z_0|}{|Z_1|} - 1 \tag{4.1}$$

When the protection zones and k was set, the fault was placed one at the time at the four locations shown in figures A.1 and A.2, while the fault resistance and the ground conductivity were varied. The fault resistances used for simulation are presented in table A.4. As the transmission line goes through both lowland an mountain area, the chosen ground resistances for simulation are $\rho = 500\ \Omega m$ and $\rho = 100000\ \Omega m$ from table 3.1. Choosing such different ground resistances for simulation will also make the impact of this parameter on the performance of the distance protection more clear.

The arc impedance for an arcing fault from phase conductor to the tower is calculated using equation (3.7) and input data from A.1 and A.2. The calculation of the arc impedance is shown in equation (4.2). As this is close to 10, $R_f = 10\Omega$ is chosen to represent an arcing fault for the sake of simplicity in the simulations.

$$Z_{arc} = \frac{2500\ \cdot 3.5}{920} = 9.2 \quad [\Omega] \tag{4.2}$$

In order to determine the distance relay starting zone, the maximum possible load as seen in the impedance diagram is calculated using equation (3.5) and parameters from table A.2. The maximum current leading capacity of the transmission line is $I_{max} \approx 1400A$ according to tables for the conductor type in [16]. The resulting maximum load in the impedance diagram is given by equation (4.3). The absolute maximum limit of the relay starting zone is given by equation (4.4).

$$Z_{max\ load} = \frac{220\ kV}{\sqrt{3} \cdot 1400A} = 90.73 \quad [\Omega] \tag{4.3}$$

$$Z_{start\ zone} = Z_{max\ load} \cdot 0.8 = 90.73 \cdot 0.8 = 72.6 \quad [\Omega] \tag{4.4}$$

Single Phase-to-Ground Fault

The single phase-to-ground fault is simulated in ATPDraw by a time controlled single-phase switch connecting phase a to ground through a resistor. At the beginning of the simulation the switch is open. At $t = 0.02s$ the switch closes so that phase a is connected to ground through the varying fault resistance R_f.

Broken Conductor to Ground Fault

The broken conductor to ground fault is also simulated in ATPDraw by a time controlled single phase switch connecting phase a to ground through a resistor. In addition there is a three-phase switch located immediately after the node where the single-phase switch is connected. The three-phase switch is closed for all three phases when the simulation begins, before it opens at phase a at the same time as the single-phase switch closes at phase a. In this way, at $t = 0.02s$ phase a is connected to ground through the varying resistor, and phase a is broken at the fault location. The size of the resistor connecting the broken phase to ground is following the same variations as the resistor used in the single phase-to-ground fault simulation, presented in table A.4. This is valid because the fault resistance for a broken conductor to ground fault is given by how the conductor is connected to ground. R_f can be given by the ground resistance ρ in the ground where the conductor lies on the ground, or by a combination of for example the resistance of a tree in addition to the ground resistance in a scenario where the conductor breaks and fall to land in top of a tree.

4.3 Results

The total line impedance as a result of the simulation is presented in table 4.1. The simulated line impedances for the different parts of the line that has discontinuous ground wire are presented in table A.5.

Ground resistance ρ	**Discontinuous ground wire**		**Continuous ground wire**	
	$Z_1[\Omega]$	$Z_0[\Omega]$	$Z_1[\Omega]$	$Z_0[\Omega]$
Moist soil $\rho = 500\Omega m$	6.8 + j45.6	26.1 + j147.2	6.9 + j45.5	29.3 + j95.0
Dry mountain $\rho = 100000\Omega m$	6.8 + j45.6	28.4 + j192.0	6.9 + j45.5	35.0 + j103.8

Table 4.1: Total line impedance

Figure 4.2 graphically shows the calculated protection zones from table A.6 and A.8 along with the positive sequence impedance for the total length of the line Z_{1Line} and the limit of the starting zone calculated in equation (4.4). The positive sequence line impedance is set to be as given by (4.5) for both model 1 with discontinuous ground wire and model 2 that has continuous ground wire, as table 4.1 shows that the impedances are approximately of the same value.

$$Z_{1Line} \approx 6.85 + j45.5 \quad [\Omega] \tag{4.5}$$

The maximum total ground fault current $I_{f\ max}$ for the line section with ground wire is measured to be as given by equation (4.6). The maximum total ground fault current of the line section without ground wire is measured to be as given by equation (4.7). Both of these fault currents are measured for a bolted fault when the soil resistance is $\rho = 500\Omega m$.

$$I_{f\ fault\ location\ 1} = 8131.7 \quad [A] \tag{4.6}$$

$$I_{f\ fault\ location\ 2} = 2651.7 \quad [A] \tag{4.7}$$

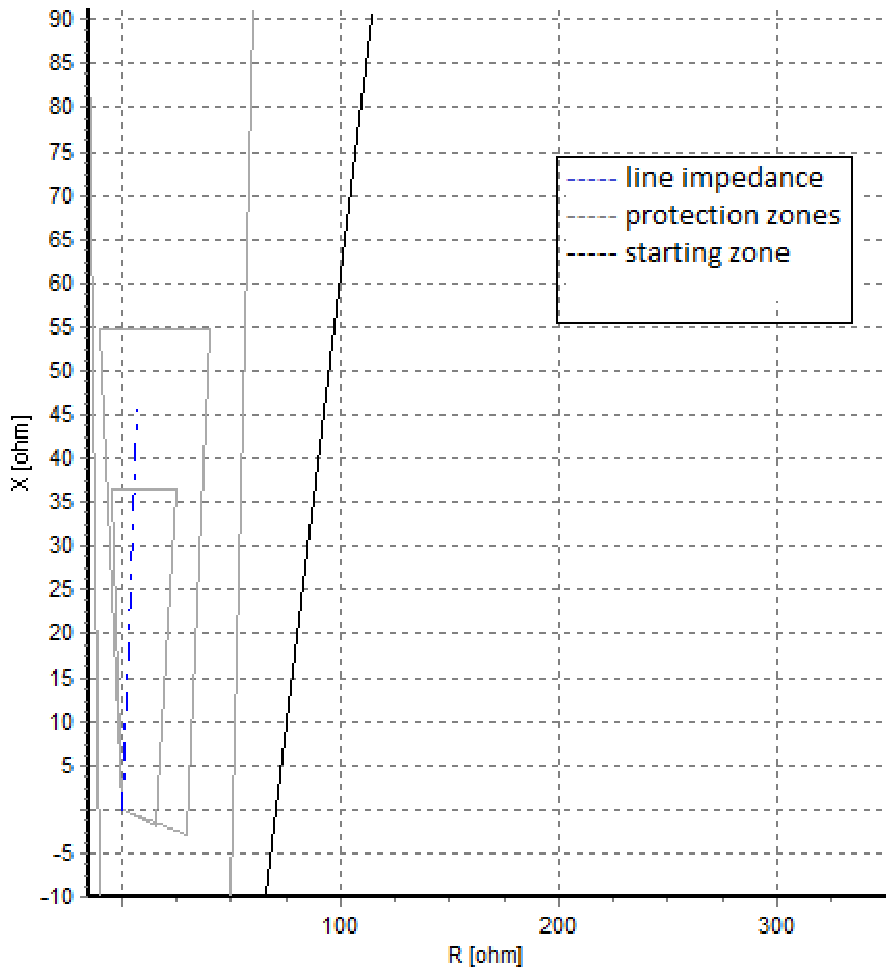


Figure 4.2: Protection zones and starting zone

4.3.1 Single Phase-to-Ground Fault

Table 4.2 gives an overview of the biggest fault resistances that are detected by the relay as well as the biggest fault resistance detected within each protection zone when $|k|$ is set to be the same for all single phase-to-ground fault scenarios. The table is based on figures A.11 - A.14. The figures shows that jX seen by the relay is biggest for the case with discontinuous ground wire and soil of bedrock, followed by discontinuous ground wire and moist soil. Then continuous ground wire with bedrock gives the second smallest jX measured, and continuous ground wire with moist soil in the ground results in the lowest measured jX.

Despite the relationship between measured jX by the relay and the combination of ground wire design and soil conditions, table 4.2 shows that the variations in jX measured keeps within the same protection zone for most fault resistances. The exception is for fault location

3 and 4, where the relay does not see faults in its first protection zone for the line having discontinuous ground wire. The relay is not able to detect any faults with a fault resistance above 100Ω, as the impedance measured by the relay end up outside the starting zone for all such fault scenarios.

Fault location	**Ground resistance**	**Line design**	**Highest Rf [Ω] detected within**			
			Zone 1	Zone 2	Zone 3	Starting zone
1	Wet soil	Cont. ground wire	25	50	100	100
		Disc. ground wire	25	50	100	100
	Mountain	Cont. ground wire	25	50	100	100
		Disc. ground wire	25	50	100	100
2	Wet soil	Cont. ground wire	25	50	100	100
		Disc. ground wire	25	50	100	100
	Mountain	Cont. ground wire	25	50	100	100
		Disc. ground wire	25	50	100	100
3	Wet soil	Cont. ground wire	25	50	100	100
		Disc. ground wire	25	50	100	100
	Mountain	Cont. ground wire	25	50	100	100
		Disc. ground wire	-	50	100	100
4	Wet soil	Cont. ground wire	25	50	100	100
		Disc. ground wire	-	50	100	100
	Mountain	Cont. ground wire	25	50	100	100
		Disc. ground wire	-	50	100	100

Table 4.2: Detectable single phase-to-ground faults when k is common, $|k| = 2.67$

Table 4.3 gives an overview of the biggest fault resistances that are detected by the relay as well as the biggest fault resistance detected within each protection zone when $|k|$ is set to be the individually fitted to each fault scenario as given by tables A.6 and A.8. The table is based on figures A.15 - A.18. It can be seen that the individual set ground correction factors $|k|$ has impact on the impedance measured by the relay, as table 4.3 differs slightly from table 4.2. Important differences are that the highest measured fault resistance that results in a measured impedance within the protection zones goes slightly down for all scenarios that has continuous ground wire for faults occurring at fault location one and two. Further is the relay now unable to see any fault scenario in protection zone 1 for faults occurring at fault location three and four.

Fault location	**Ground resistance**	**Line design**	**Highest Rf [Ω] detected within**			
			Zone 1	Zone 2	Zone 3	Starting zone
1	Wet soil	Cont. ground wire	10	25	75	100
		Disc. ground wire	25	50	100	100
	Mountain	Cont. ground wire	10	25	75	100
		Disc. ground wire	25	50	100	100
2	Wet soil	Cont. ground wire	10	25	75	100
		Disc. ground wire	25	50	100	100
	Mountain	Cont. ground wire	10	25	75	100
		Disc. ground wire	25	50	100	100
3	Wet soil	Cont. ground wire	-	25	50	100
		Disc. ground wire	-	25	50	100
	Mountain	Cont. ground wire	-	25	75	100
		Disc. ground wire	-	50	100	100
4	Wet soil	Cont. ground wire	-	25	50	100
		Disc. ground wire	-	50	75	100
	Mountain	Cont. ground wire	-	25	75	100
		Disc. ground wire	-	50	100	100

Table 4.3: Detectable single phase-to-ground faults when k is individual, $|k|$ set according to tables A.6 and A.8

4.3.2 Broken Conductor to Ground Fault

Table 4.4 gives an overview of the biggest fault resistances that are detected by the relay as well as the biggest fault resistance detected within each zone when $|k|$ is set to be the same for all broken conductor to ground fault scenarios. The table is based on figures A.27 - A.30. In the same way as for the single phase-to-ground fault, the figures shows that jX seen by the relay is biggest for the scenario of discontinuous ground wire in combination with bedrock soil. Then in decreasing order the measured jX is smaller for discontinuous ground wire combined with moist soil, continuous ground wire with bedrock and continuous ground wire with moist soil.

Also for the broken conductor to ground fault, the variations in measured jX are not big enough to have any impact on which protection zone the fault is seen in for all fault scenarios at fault location one and two. In fault location three the relay will not see a fault in its first protection zone for the combination of discontinuous ground wire and mountain ground. For a fault at fault location four none of the discontinuous ground wire scenarios are seen within protection zone one.

Fault location	Ground resistance	Line design	Highest Rf [Ω] detected within Zone 1	Zone 2	Zone 3	Starting zone
1	Wet soil	Cont. ground wire	25	50	75	100
		Disc. ground wire	25	50	75	100
	Mountain	Cont. ground wire	25	50	75	100
		Disc. ground wire	25	50	75	100
2	Wet soil	Cont. ground wire	25	50	75	100
		Disc. ground wire	25	50	75	100
	Mountain	Cont. ground wire	25	50	75	100
		Disc. ground wire	25	50	75	100
3	Wet soil	Cont. ground wire	25	50	75	100
		Disc. ground wire	25	50	75	100
	Mountain	Cont. ground wire	25	50	75	100
		Disc. ground wire	-	50	75	100
4	Wet soil	Cont. ground wire	25	50	75	100
		Disc. ground wire	-	50	75	100
	Mountain	Cont. ground wire	25	50	75	100
		Disc. ground wire	-	50	75	100

Table 4.4: Detectable broken conductor to ground faults when k is common, $|k| = 2.67$

Fault location	Ground resistance	Line design	Highest Rf [Ω] detected within Zone 1	Zone 2	Zone 3	Starting zone
1	Wet soil	Cont. ground wire	10	25	50	75
		Disc. ground wire	25	50	75	100
	Mountain	Cont. ground wire	10	25	50	100
		Disc. ground wire	25	50	100	100
2	Wet soil	Cont. ground wire	10	25	50	75
		Disc. ground wire	25	50	75	100
	Mountain	Cont. ground wire	10	25	50	75
		Disc. ground wire	25	50	100	100
3	Wet soil	Cont. ground wire	-	25	50	75
		Disc. ground wire	-	50	75	100
	Mountain	Cont. ground wire	-	25	50	75
		Disc. ground wire	-	50	75	100
4	Wet soil	Cont. ground wire	-	25	50	75
		Disc. ground wire	-	50	75	100
	Mountain	Cont. ground wire	-	25	50	75
		Disc. ground wire	-	50	75	100

Table 4.5: Detectable broken conductor to ground faults when k is individual, $|k|$ set according to tables A.6 and A.8

Table 4.5 gives an overview of the biggest fault resistances that are detected by the relay as well as the biggest fault resistance detected within each protection zone when $|k|$ is set to be the individually fitted to each fault scenario as given by tables A.6 and A.8. The table is based on figures A.31 - A.34. It can be seen that the individual set ground correction factors $|k|$ has impact on the impedance measured by the relay, as table 4.5 differs slightly from table 4.4. For individually set ground fault correction factor $|k|$ no faults at fault location three and four are seen within protection zone one. Also the biggest fault resistance the relay is able to detect goes down for fault scenarios where the line has continuous ground wire compared to the line with discontinuous ground wire.

An important result that is not seen from the tables 4.2 - 4.5 but is found by comparing figures A.3 - A.10 to figures A.19 - A.26 is that the real part R of the impedance measured by the distance relay reaches its maximum of about 200Ω for the single phase-to-ground fault and $R_f = 1000\Omega$. The maximum R measured for a broken conductor to ground fault is significant bigger, about $550 - 750\Omega$ when $R_f = 1000\Omega$.

4.4 Discussion

4.4.1 The Simulation Model

A simulation model is a simplified replica of the real power system. The results obtained from such a model could suffer from these simplifications. In model 1 and 2, the line sections are modelled carefully whilst the rest of the grid stretching out from point A and B is heavily simplified, only modelled as an ideal voltage source and a load respectively. These choices were made because the working function of the model is to determine how the ground resistance influences the line parameters, which in turn has an effect on the ground fault detection capability of the distance relay. The voltage source and the load are not important to this study. The load was first randomly chosen, then checked in ATPDraw to find it pulling a current about half the amplitude of the rated maximum current of the line under no-fault conditions given by [16], and therefore the load is deemed to be of adequate size.

A simplification made that has impact on the results is the assumption that the ground under the line has a constant resistivity for the entire length of the line, being either $\rho = 500\Omega$

or $\rho = 100000\Omega$. This is not the case in reality. The simplification was made for two reasons. One is that the ground resistance is not known, both because it has not been measured but also because it will be changing rapidly along with the weather and the seasons. The other reason that ρ is chosen to be at these two levels is because two extremely different scenarios clarifies the impact of the ground resistance on the transmission line parameters better than scenarios that does not differ that much. The ground resistance has impact on the impedance offered to the ground fault return current as shown in figure 3.4. The impact is bigger for the part of the line without ground wires, where the current flows in the ground for some distance. In the part of the line with ground wires it does not have that much impact, as the current is only flowing in the ground for a short distance until it reaches the closest tower and from there goes through the tower impedance into the ground wires.

The ground resistance also has impact on the zero sequence impedance of line sections without ground wire through D_g as stated in equation (2.18). This is why all simulations have been performed for both a common $|k|$ set from the given line impedances, as well as for an individual fitted $|k|$ set based on the real zero sequence impedance of the line given by the ground resistance for the system.

Another simplification is the assumption of the phase conductors being located at the same height above the ground for the whole length of the line. The conductor height above ground has an impact on the sequence capacitance of the transmission line as stated in equations (2.16) and (2.20). Due to fluctuations in the terrain that the line is moving across, this assumption can not be said to represent the true height of the conductors. However, this simplification is not of importance to the relay performance or the simulated sequence impedances as the expressions for these does not include the distance from the conductors to ground.

A source to small errors in the result from the simulation is the fact that ATPDraw does not allow revolving of phases when pi-equivalent models are used for the transmission lines. This means that there will not be perfect symmetrical conditions in the system, even prior to a fault. As all theory has symmetry as a prerequisite, this could cause deviations in the results compared to what is expected from the theory.

4.4.2 Simulated Sequence Impedances

The simulated positive sequence line impedances are almost as expected with regards to the theory. Equation (2.15) for the positive sequence impedance states that the positive sequence impedance of the line Z_{1Line} should be constant for variations in the ground conditions of the line. Table 4.1 shows that for the line design with discontinuous ground wire $Z_{1Line,\rho=500\Omega}$ is equal to $Z_{1Line,\rho=100000\Omega}$ which is as expected. This also holds true for variations in ground resistance for the line with continuous ground wire. The small deviation from the theory is that the positive sequence impedance of the line with continuous ground wire in model 2 is not exactly equal to the positive sequence impedance of the line with discontinuous ground wire in model 1. However, the deviation is very small and could be due to unsymmetrical line conditions.

The simulated zero sequence impedances for the line in model 1 that has discontinuous ground wire are as expected from the theory. Equation (2.18) states that the zero sequence impedance for a line is dependent on the available path for the ground fault return current. For the line with discontinuous ground wire in model 1, the available path for the return current is the actual ground, i.e. $Z_{0Line,\rho=500\Omega}$ should differ from $Z_{0Line,\rho=100000\Omega}$. Table 4.1 confirms this. On the other hand the zero sequence line impedance of the line in model 2 that has continuous ground wire should be equal for both ground resistances, as the ground fault return current will flow in the ground wires and not in the actual soil. There is a small deviation in Z_{0Line} for different ground resistances of the line with continuous ground wire as shown in table 4.1. This could be explained by the fact that the ground fault current will have to flow in the actual ground from the fault location to the nearest tower, from where it will flow in the ground wires. The short travel distance in the actual ground makes up the contribution that results in a deviation in the zero sequence impedance of the line for the two ground resistances even though the line has continuous ground wire. Asymmetry in the simulation model because the phase conductors not are revolved could also be the reason to the deviation, as equations (2.15) and (2.18) only holds true for perfect symmetrical transmission lines.

The fact that the simulated positive sequence line impedance is very close to the given positive sequence line impedance verifies the results from the simulation, as this implies that the model is close to the real situation. This can be said because the given Z_{1Line} is measured and not calculated, and therefore truly represents the real situation. For the zero sequence system there is no point in comparing the simulated line impedance to the given Z_{0Line} as this is calculated, not measured, based on an assumption of continuous ground wire and for an unknown ground resistance.

4.4.3 Detectable Fault Resistance

For the single phase-to-ground fault the distance relay will not be able to detect any faults that have a fault resistances above 100Ω as these are outside the starting zone of the relay. This does not mean that the maximum detectable fault resistance is 100Ω, as the next step in the simulated R_f is 200Ω. The limit for detectable R_f lies somewhere between the two and should be subject to further and more accurate tests in order for it to be exactly determined.

For the broken conductor to ground fault the highest detectable fault resistance is dependent on whether the ground fault correction factor is set individual or not. When $|k|$ is common, the relay can see faults up to $R_f = 100\Omega$ equal to the single phase-to-ground faults. When $|k|$ is set individually, the maximum fault resistance that falls within the starting zone of the relay is alternating between 75Ω and 100Ω depending on if the line has continuous ground wire or not. Concerning the exact detection limit the same goes here as for the single phase-to-ground fault. The maximum fault resistance that the relay is able to detect lies somewhere in the range of $75 - 100\Omega$ and $100 - 200\Omega$ for continuous ground wire and discontinuous ground wire respectively.

The setting of the protection zones in R direction is set as an example deemed adequate to fit the line and its load, and to give a reference of how the measured fault impedance is closing in on the load impedance for big fault resistances. These zone limits in R direction can be chosen more carefully if the whole system downstream of the relay is known. Also the zones should be set depending on which fault scenarios the system operator wants the relay to detect in the different zones, i.e. how fast the relay should trip for different fault scenarios.

In order to increase the ability of the distance relay with respect to detecting ground faults that have a high fault resistance, the starting zone of the relay could be set farther out in the R direction. This solution is only applicable if it is known with certainty that the maximum load impedance seen by the relay will be bigger than calculated in this simulation. This could be the case if there are other ruling restrictions to the maximum power transfer capacity of the line than its maximum current carrying capability.

According to Statnetts internal regulations, they do not set their starting zones above $150 - 180\Omega$. If this starting zone expansion is performed, it can be seen from figures A.3 to A.10 that the relay will be able to detect single phase-to-ground faults with a fault resistance up to the range of $400 - 500\Omega$. For the broken conductor to ground fault, the effect will not be that great. It can be seen from figures A.19 to A.26 that these faults will be detected if they have a fault resistance up to the range of $200 - 300\Omega$.

4.4.4 Ground Fault Correction Factor

When the ground fault correction factor is individual set for each fault scenario with respect to the combination of the line design (continuous ground wire/discontinuous ground wire) and the ground resistance, the imaginary part jX of the impedance measured by the relay is much more correct with respect to location of the fault. This means that the fault location can be calculated from the measured impedance, as the relation between distance to the fault from the relay and measured impedance is approximately correct. For a long transmission line this eases the fault correction work when the fault location is known and therefore possibly also the time the line is disconnected.

When the line has continuous ground wire, there is a much smaller change to the measured zero sequence impedance for the two simulated ground resistances as discussed in the previous section. This means that the ground fault correction factor can be set more correct for a line with continuous ground wire than for a line that has discontinuous or no ground wire. It is worth to mention that although if there were measurements made of the ground resistance in the ground below a transmission line in order to set $|k|$ properly for a line without ground wires, the ground will change with the seasons as discussed in section 3.2.3 causing the settings of the relay to be incorrect. It would require a tremendous amount of work to keep $|k|$ updated all the time.

When $|k|$ is set to be common for all line design/ground resistance combinations the imaginary part jX of the impedance measured by the relay is too high for the line with discontinuous ground wire compared to the location of the fault. For the line with continuous ground wire the measured jX is too low compared to the fault location. This holds true for all fault locations and ground resistances. When $|k|$ is individually set, measured jX for the lines with discontinuous ground wire are lower whilst jX is higher for the lines with continuous ground wire. The result of this is that all fault scenarios at fault location 3 and 4 are no longer detected in protection zone 1. This is the same for both the single phase-to-ground fault and the broken conductor to ground fault. As protection zone 1 is set to cover 80% of the line, and both fault location 3 and 4 are located at or above 80% of the line, this is correct zone selectivity. If there is a relay in point B of the line looking in direction of point A, this relay will detect the fault in its zone 1 and therefore trip before the relay in point A which sees the fault in its protection zone 2.

This effect of individually set $|k|$ is beneficial if there is a relay in point B looking in direction of point A. However, if the relay in point A is the only relay protecting the line, then the benefit of a good estimate of the fault location must be weighted against the disadvantage of a slightly delayed trip for a fault at fault location 2 and 3 due to the small time delay for tripping of protection zone 2 compared to protection zone 1. Regarding the time limit for disconnection of ground faults for a solid grounded grid, tripping in protection zone 2 is within the regulations.

4.4.5 Touch and Step Voltage

The touch voltage a person would be exposed to if he/she should be unfortunate enough to touch a tower that is leading a fault current to ground will be much higher for the part of the line that does not have ground wires, as explained in section 2.2.1. The maximum fault currents measured in the simulations are given by (4.6) and (4.7). The earth potential rise and therefore also the step- and touch-voltages will be different depending on if the total fault current is flowing through one tower or if it is distributed amongst many. The total resistance to ground of the grounding system in the line section with ground wire is as calculated in equation (4.8).

$$R_{total\ towers} = \frac{1}{\frac{1}{2.5} \frac{1}{2.5} \frac{1}{2.5} \frac{1}{2.5} \frac{1}{2.5} \frac{1}{2.5} \frac{1}{2.5} \frac{1}{2.5} \frac{1}{0.1}} = 0.076 \quad [\Omega] \tag{4.8}$$

From the total resistance of the parallel connected towers and the measured maximum fault current, the maximum earth potential rise a human touching a faulted tower in the line section with ground wires will be exposed to is calculated in equation (4.9). The total fault current is distributed amongst the towers by the ground wire.

$$V_{earth\ potential\ rise} = I_{f\ max} \cdot R_{total\ towers} = \frac{8131.7A}{9towers} \cdot 0.076\Omega = 68.7 \quad [V] \tag{4.9}$$

For the line section without ground wire, the total fault current is lower than for the line section with ground wire. This is both due to the increased distance from the relay to the fault location, and because of a higher resistance to ground for the fault current. As the towers are not interconnected, the total fault current will flow to ground through the faulted tower. The resulting earth potential rise at fault location is given by equation (4.10).

$$V_{earth\ potential\ rise} = I_{f\ max} \cdot R_{tower} = 2651.7A \cdot 25\Omega = 66292.5 \quad [V] \tag{4.10}$$

It can be seen that the earth potential rise is significantly bigger when the towers are not interconnected by ground wires. This means that other measures will have to be taken for these towers to be safe and within regulations in case of a ground fault. This analysis is only considering the impact that ground wires has on the earth potential rise. This means that the whole picture considering grounding of the towers and measures taken to secure the tower footing area from dangerous currents are not known, and the real earth potential rise could be much lower than calculated in this report. The calculated case is the worst case scenario, as the fault current will be smaller for a bigger fault resistance, which in turn will reduce the earth potential rise. The two earth potential rises are calculated in order to make the impact of ground wires on the earth potential rise during a ground fault clear, and does not necessary correctly represent the real earth potential rises.

Chapter 5

Analysis of a Transmission Network

In this chapter the simulation and analysis of a part of the transmission grid that does not have ground wire installed will be presented. In one simulation model the grid is compensated earthed by three Petersen coils, whilst in model two the grid is modelled as solid earthed. Due to business confidentiality concerns all geographical locations are withheld from the public, and therefore given fictional names.

5.1 Network Design and Conditions

In reality the simulated section of the transmission network has compensated earthed neutral. From table 2.1 this means that a single ground fault does not have to be disconnected until two hours after the fault occurred, making the grid a highly reliable power source as it can continue to provide its service during a fault. The requirements to disconnection in case of more than one ground fault are strict, according to section 2.4 demanding that the faults are galvanically separated within 1 second.

If the grid section is to be subject for a voltage upgrade, a change in system neutral earthing from compensated to solid is required. As stated in table 2.2 and discussed in section 2.3.3, the solid earthed neutral is the preferred neutral grounding method for system voltages above 220 kV. If this change in system neutral earthing is performed, the requirements to the performance of the protection system gets much stricter. According to table 2.1 now all types of ground faults must be detected and disconnected within maximum 8 seconds, preferably faster.

The grid is a part of the transmission network, but on a lower voltage level as it has a system voltage of $132kV$. There are connection points in the grid both to the higher voltage level transmission network and multiple distribution networks of varying voltage levels. The grid mainly consist of overhead lines, but there are some sections of cables present in the system. A single line diagram displaying the structure of the transmission system is given by figure 5.1. It can be seen that there are three voltage sources in the grid. The sources in A and B are representing connection to a transmission network of higher system voltage. The source in C is a generator connected to the system. The arrows are loads, representing connections to power systems of lower system voltage. Simulation models, line design, cable and line parameters are all found in appendix B.

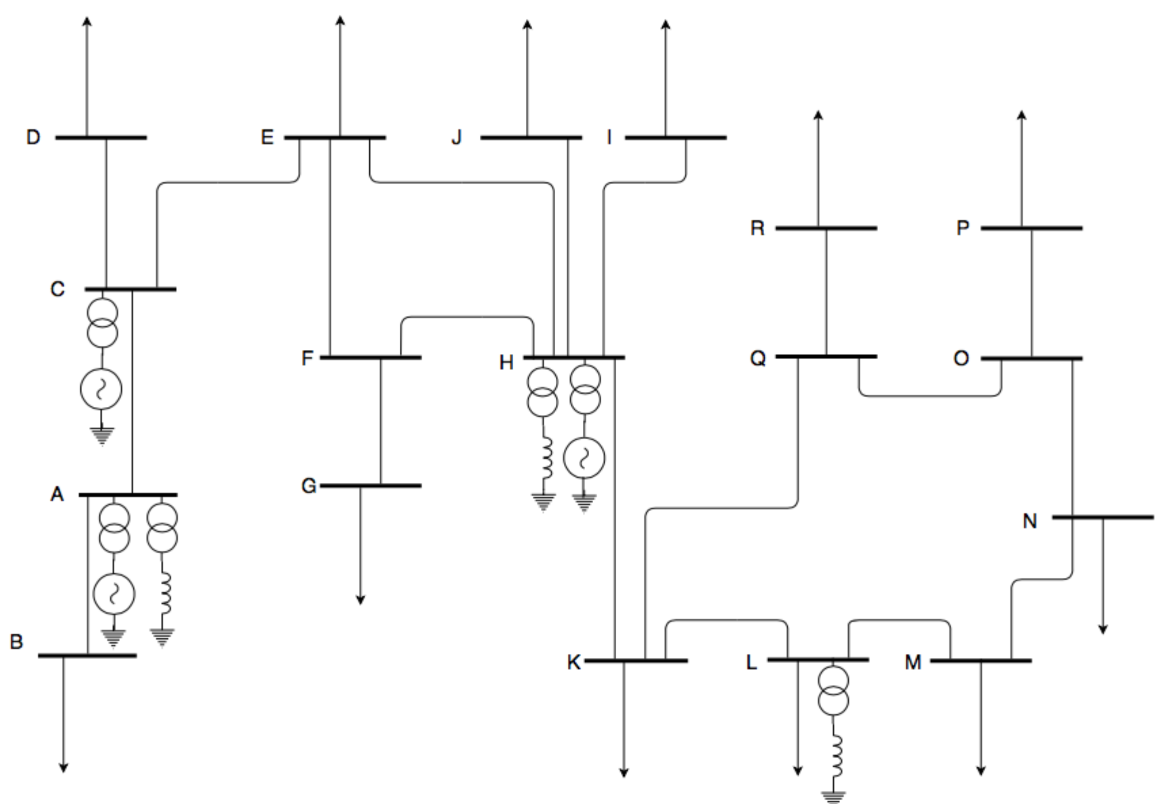


Figure 5.1: Single line diagram of the transmission grid

5.2 ATPDraw Simulation Models

As input for the simulation of line impedances in ATPDraw, the same line parameters as listed in section 4.2.1 are required. In addition the impedance, capacitance and length of cables in the system are needed. These are all given by tables B.1 and B.2.

The two models are equal in all other ways than their connection from neutral to earth. For both models the following simplifications and assumptions have been made in the transfer from real system to model for simulations.

Connections in A and H to a system that has a higher system voltage are modelled as voltage sources along with an inductance representing their short circuit effects. The same goes for the generator in C. The size of the short circuit inductances are shown in equations (5.2), (5.3) and (5.4) and are calculated using the short circuit effects from table B.1 along with equation (5.1).

$$L_{sc} = \frac{X_L}{2\pi f} = \frac{U^2}{S_{sc} \cdot 2\pi f} \quad [H] \tag{5.1}$$

$$L_{sc\ A} = \frac{132kV^2}{2446MVA \cdot 2\pi 50Hz} = 22.7 \quad [mH] \tag{5.2}$$

$$L_{sc\ H} = \frac{132kV^2}{2378MVA \cdot 2\pi 50Hz} = 23.3 \quad [mH] \tag{5.3}$$

$$L_{sc\ gen} = \frac{132kV^2}{360MVA \cdot 2\pi 50Hz} = 154.1 \quad [mH] \tag{5.4}$$

Connections to systems of lower voltage levels are modelled as loads. The size of these loads are set to be equal, as the actual load on the system is unknown. The loads were chosen so that the system was within limits with respect to node voltages and line currents prior to fault, i.e. all node voltages within ±10% of the system voltage and no line currents violating rated values given by [16]. The loads are modelled as delta connected resistors, assuming a purely resistive load. Each load was set to be $10MW$, summing up to a total load of $120MW$ on the system. The equivalent resistance of the load on each phase is given by equation (5.5).

$$R_{load} = 3 \cdot \frac{U^2}{P} = 3 \cdot \frac{132kV^2}{10MW} = 5227.2 \quad [\Omega] \tag{5.5}$$

The transformers in A, E, H and L are all three winding transformers. Because ATPDraw ran into some trouble concerning the sequence of the windings and the reactance between the windings, these transformers had to be modelled as regular two winding transformers with Y-Y coupling. In ATPDraw a setting of typical values for the transformer with respect to the system voltage level was chosen. In that way the computer programme decides the core, inductive and resistive parameters of the transformer. Transformer capacities are stated in table B.1. Transformers were only used for connection of voltage sources and Petersen coils, whilst all loads are connected directly to the network. This is because information provided by Statnett shows that the transformers were mostly delta connected at the distribution network side, thereby providing no possible path for a zero sequence current to flow in. This means that there will be no contribution to an unsymmetrical fault in the transmission system from the distribution systems, therefore there is no need in modelling them more thoroughly than as loads.

The type of fault simulated for this transmission network is the single phase-to-ground fault caused by an arc from phase conductor to tower. Using equation (3.7) and the smallest short circuit current from the sources found in table B.1, the maximum arc resistance is found to be as presented in (5.6).

$$Z_{arc} = \frac{2500 \cdot D}{I_{sc}} = \frac{2500 \cdot \frac{6m}{2}}{10.4kA} = 0.72 \quad [\Omega] \tag{5.6}$$

This arc resistance can of course be bigger if the arc is not offered such a big short circuit current due to a fault location far from any voltage source. Anyway, as the tower impedance is not present in the model because there are no ground wires to connect them to, the tower impedance has to be added to the fault resistance representing an arcing fault to ground via a tower. The tower impedance found in table B.1 results in a fault resistance given by (5.7) used for simulation of an arcing fault. Some ohms are added to represent the fault locations provided by a lower short circuit current.

$$R_f = Z_{arc} + Z_{tower} = 0.72 + 25 \approx 30 \quad [\Omega] \tag{5.7}$$

The distance relays are strategically placed in the model of the transmission network. DR1 is protecting lines A-C, with its third protection zone also covering line C-E and A-B to some extent. DR2 is looking in the opposite direction of relay DR1, and is protecting line H-F. DR2 is also covering some of lines F-E and F-G. DR3 is the only relay that has all the voltage sources behind it. DR3 is protecting line H-K in addition to some of line K-L. The protection zones of the three distance relays are given by table B.4.

The values in the table are calculated based on the simulated line impedances from table B.3 and section 3.1.3. The setting of the protection zones in R direction in the impedance diagram is left as their default value is given by ATPDraw. This is because there is not enough information on the system to set these correctly, and they are not important to the simulation results. What is of interest is the starting zone of the relay, to tell if the relay will see a fault, and how a combination of two faults is seen by the relay compared to a single fault. The starting zone is assumed to be 150Ω, the maximum value given by Statnett. As discussed in section 4.2.1 the ground fault correction factor that ATPDraw takes as an input has to be an absolute value, not a real and an imaginary part. The ground fault correction factor for each relay was found using equation (4.1).

5.2.1 Compensated Earthed Neutral Model

The model and simulation performed in this section aims to determine if two single phase-to-ground faults occurring at the same time, but at distant locations and to different phases, will be detected by the distance relays when the grid has compensated neutral earthing. To do this, the model shown in figure B.1 was built in ATPDraw.

The two faults are each modelled by a resistance to ground that is connected to a phase conductor through a time controlled switch. The resistance equals the fault resistance R_f given by equation (5.7), and are equal for both faults. First at t=0.02s the switch at phase a closes, then at t=0.03s the switch at phase b closes. The fault locations are varied between the four spots shown in the figure of the simulation model in B.1.

Performing the simulations, first a single ground fault was placed on the other end of the line that each relay is protecting. Then fault number two was added at the three other fault locations one at the time to see how the impedance measured by the relay changes for the different scenarios.

The Petersen coils are modelled as inductors P_A, P_H and P_L connected from the neutral point of transformers T_A, T_H and T_L to ground. The normal settings of the current flowing through the coils in case of a ground fault were provided by Statnett to be as given in table 5.1, from which the inductance of the coils were calculated as shown in equations (5.9), (5.10) and (5.11).

Coil	**Normal current [A]**
P_A	60
P_H	53
P_L	164

Table 5.1: Normal settings for current flowing through the Petersen coils during a ground fault

$$P_{coil} = \frac{\frac{U}{\sqrt{3}}}{I_{coil} \cdot 2\pi f} \quad [H] \tag{5.8}$$

$$P_A = \frac{\frac{132kV}{\sqrt{3}}}{60A \cdot 2\pi 50Hz} = 4043.1 \quad [mH] \tag{5.9}$$

$$P_H = \frac{\frac{132kV}{\sqrt{3}}}{53A \cdot 2\pi 50Hz} = 4577.1 \quad [mH] \tag{5.10}$$

$$P_L = \frac{\frac{132kV}{\sqrt{3}}}{164A \cdot 2\pi 50Hz} = 1479.2 \quad [mH] \tag{5.11}$$

The three Petersen coils are parallel coupled to ground. This gives a total inductive connection to ground as calculated in equation (5.12).

$$P_{total} = \frac{1}{\frac{1}{4043.1mH} + \frac{1}{4577.1mH} + \frac{1}{1479.2mH}} = 875.8 \quad [mH] \tag{5.12}$$

According to equation (2.21) this means that the total capacitance to ground in the system is expected to be smaller than or equal to equation (5.13), assuming that the system is overcompensated by 5%.

$$C_{0\ expected} = \frac{0.95}{\omega^2 \cdot 3P_{total}} = \frac{0.95}{(2\pi 50Hz)^2 \cdot 3 \cdot 875.8mH} = 3.67 \quad [\mu F] \tag{5.13}$$

Adding all the capacitances found from the simulation of the system in table B.3 yields a simulated total capacitance to ground as stated in equation (5.14). Because $C_{0\ simulated}$ is barely smaller than $C_{0\ expected}$, the coil sizes calculated based on the given values are appropriate and therefore used in the simulation model. This means that the system is a little bit more than 5% overcompensated.

$$C_{0\ simulated} = 3.587 \quad [\mu F] \tag{5.14}$$

5.2.2 Solid Earthed Neutral Model

The model and simulation performed under this section aims to determine if the distance relay is able to detect single phase-to-ground faults when the system has solid earthed neutral, without further changes being made to the system design. To do this, the model shown in figure B.2 was built in ATPDraw.

This model is exactly the same as the compensated one, but the coils are replaced by solid grounding of the same three nodes. Also here the single phase to ground fault is modelled by a time-controlled switch connected to phase a. The switch is connecting phase a to ground through a resistor representing the fault resistance R_f given by equation (5.7). At t=0.02 s the switch closes, so that the system suffers from a ground fault. The location of the fault is moved between the fault locations marked in the simulation model given by figure B.2.

5.3 Results

5.3.1 Compensated Earthed Neutral and Double Ground Faults

Figures 5.2 to 5.4 are displaying comparisons of the impedance measured by the distance relays for the different fault location combinations.

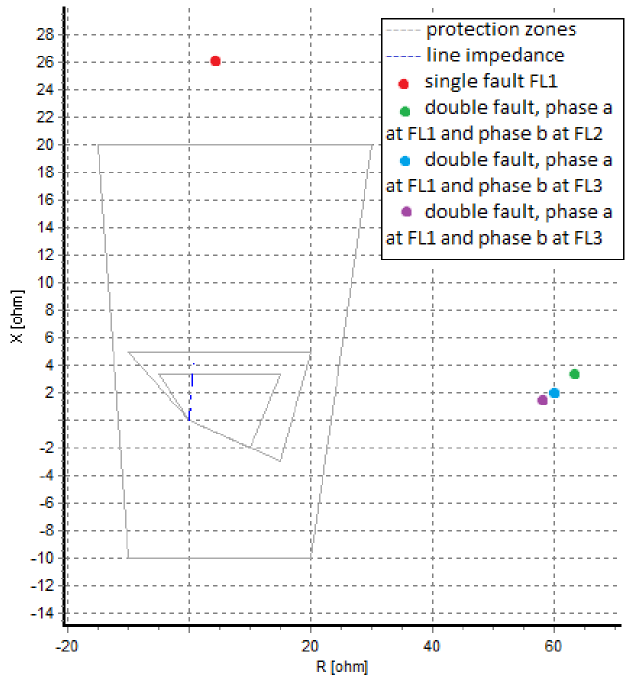


Figure 5.2: Impedance measured by DR1 for various fault combinations, made from figures B.3 to B.6

For relay 1 all possible faults are downstream in the system, and therefore in front of the relay. The relay see all double faults in approximately the same area of the impedance diagram with an R value of about $2 \cdot R_f$. The single fault in FL1 is measured very high on the jX-axis, whilst the double faults are situated at about the reactance of the total line A-C.

For relay 2, FL1 and Fl2 are in front of the relay whilst FL3 and FL4 are in the backwards direction of the relay. All double faults are measured at about the same jX value representing the total reactance of line H-F, but the faults in backwards direction are measured about 10Ω smaller in R-direction than the forward double fault. Also here the single fault in front of the relay is measured high on the jX axis.

For relay 3, FL3 and FL4 are in front of the relay whilst FL1 and FL2 are in its backward direction. Figure 5.4 shows the same trend for the impedance measured by this relay as for the two previously presented. All double faults are at about the same value on the jX-axis, approximately equal to the total reactance of the line the relay is protecting here meaning line H-K. Faults in backward direction are also here measured about 10Ω smaller in R-direction

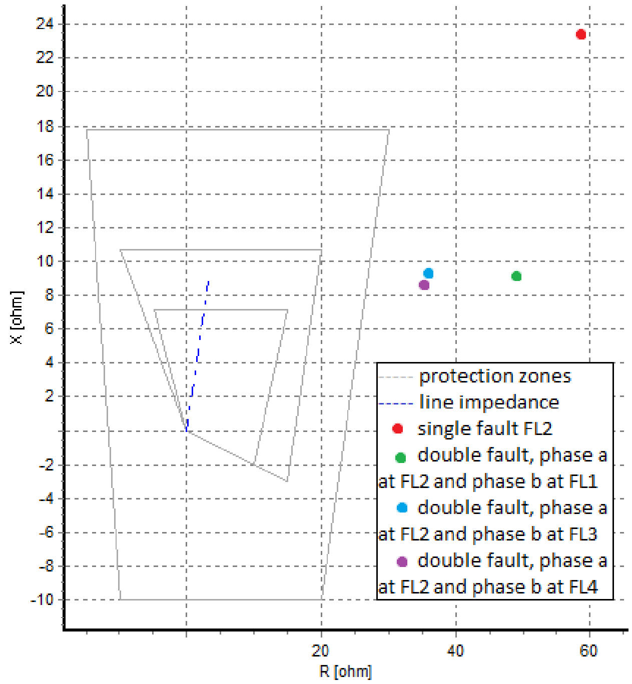


Figure 5.3: Impedance measured by DR2 for various fault combinations, made from figures B.7 to B.10

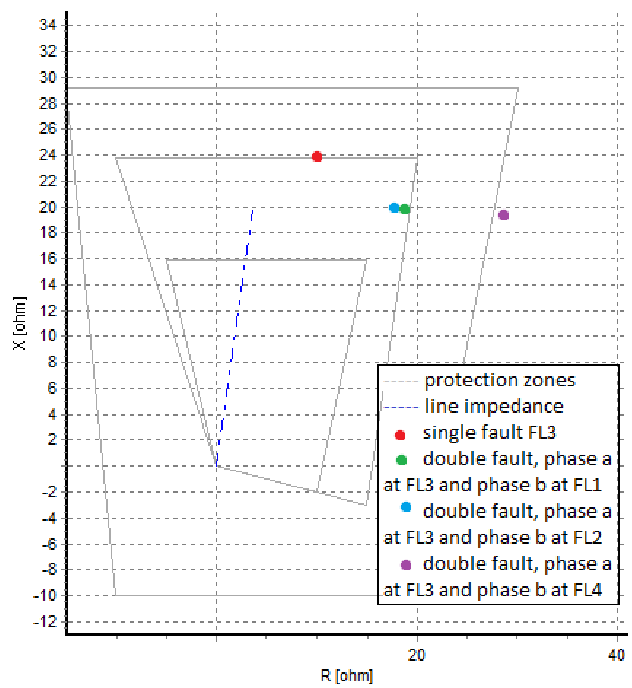


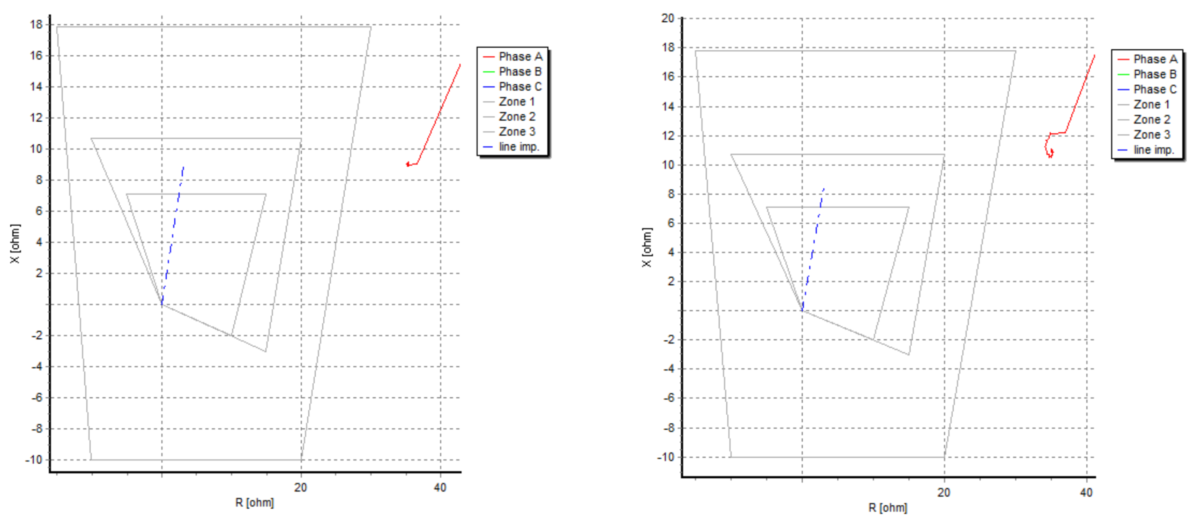
Figure 5.4: Impedance measured by DR3 for various fault combinations, made from figures B.11 to B.14

than the forward double fault. The single fault in front of the relay is also here measured high on the jX-axis.

5.3.2 Solid Earthed Neutral and Detection of Single Ground Faults

Figure 5.5 is representative for the impedance measured by the distance relays as the result of a single phase-to-ground fault when the network has solid earthed neutral. Results for all three relays are found in appendix B, figures B.15 - B.20. As previously stated, the setting of the protection zones in R-direction is left as proposed by ATPDraw, and should be fitted according to the unknown load on the system. By doing this, it can be determined which protection zone this type of fault would be detected in. Anyway, all faults of the simulated fault impedance will be detected, as they are well within the suggested maximum starting zone of 150Ω.

The faults are all measured to have a reactance according to their fault location, i.e. equal to the total reactance of the line, when the ground fault correction factor is correctly set. If the ground resistance is considerably increased, but $|k|$ kept constant fitted to $\rho = 500\Omega m$, the measured reactance goes up by a few ohms. The measured resistance is somewhat deviant from the expected resistance which consist of the resistance of the line in addition to the fault resistance.



(a) $\rho = 500\Omega m$ (b) $\rho = 100000\Omega m$

Figure 5.5: Impedance measured by DR2 for a fault at FL2 with the same $|k| = 2.478$

5.4 Discussion

5.4.1 The Simulation Model

A lot of simplifications has been made in order to be able to simulate the network. As the model is not an exact replica of the real network, the results given by the simulations could suffer from these simplifications.

All lines are modelled by their pi-equivalent in ATPDraw. As all lines in this network are shorter than 100km long, the pi-equivalent should be valid and not causing errors. A source to small errors is however the fact that ATPDraw does not allow revolving of the phases for pi-equivalent line models. Therefore the simulated system will not have perfect symmetry even before a fault occur. This has greatest impact on the zero sequence system, especially on the longer lines.

The performance of the simulation model is dependent on its input data. All input data were provided by Statnett, in form of an e-mail simply stating some parameters, data sheets or a single line diagram. There has been a few occasions where different sources on the same parameter has provided deviant information. In these cases the value of newest origin has been used. Errors in the input data could result in errors to the output data.

The load assigned to the network does not have root in the reality, and may not be representative. However, this should not affect the behaviour of the network during a ground fault, and therefore not give cause to errors.

A simplification made also in this simulation model is the assumption of constant ground resistance ρ. This will not be the case in reality. As shown in chapter 4 the ground resistance has impact on the zero sequence impedance of the transmission lines, thereby also affecting the ground fault correction factor $|k|$.

The single line diagram of the network suggested some delta coupled coils representing an inductive load located at bus H. As these coils were present in order to compensate for some capacitive load on the system which is unknown, the inductive loads are not a part of the model. This should not cause errors to the simulation model because the load on the system is modelled as purely resistive, making inductive load compensation excessive. The capacitive load in the real network could be due to cables in the distribution networks that are fed from the simulated transmission network.

A simplification that has impact on both the zero sequence line impedances and the zero sequence capacitance is that all lines are assumed to have the same geometrical parameters. It can be seen by equations (2.18) and (2.20) that the distance between the phases has impact on both C_0 and Z_{0Line}. The exact distance between the phase conductors is not known for all lines, therefore assumed to be equal. The distance used is suggested to be the standard for the system voltage level, given by [16].

Another simplification on the line parameters is the assumption that the phase conductors all have the same diameter and hold the same height above the ground for the whole network. The deviation in the diameter of the phase conductors is expected to be small, as the lines should be of about the same types. The height from phase to ground however, could suffer from huge deviations. The zero sequence capacitance, i.e. the capacitance between phases and ground, is dependent on both the diameter and the height of the phase conductors as stated in equation (2.20). Due to variations in the terrain and possibly different height of the towers, the assumed height could be a reason to fairly big errors in the simulated capacitance to ground of the lines. The height used in the model is suggested to be the standard for the system voltage level, given by [16].

5.4.2 Double Ground Faults in a Compensated Network

For the single fault, the two relays DR1 and DR2 that has voltage sources in both forward and backward direction both measure a high reactance. This could be explained by the inductive current drawn by the Petersen coils during a ground fault. The relay will see an impedance that is determined as stated in equation (3.6), but the inductive current flowing to the compensation coils affects the fault behaviour of the system, i.e. the flow and direction of currents during a fault. The impedance measured by the relays for a single ground fault depend on the location of voltage sources and compensation coils relative to the fault location.

For DR1, a single fault at FL1 right in front of the relay is measured high in the jX-axis and low on the R-axis considering the fault impedance. This is because there are sources both in front and back of the relay, and a compensation coil is located behind the relay. When the single fault occur in FL1, fault current will flow from source in A to FL1 and P_A.

Also the generator will supply the fault from the other direction, causing the relay to measure a small fault current in total. Due to the inductive properties of the current drawn by P_A, the small fault current measured by DR1 will be highly inductive, resulting in a measured impedance represented by the point marked in red on figure 5.2.

The same explanation applies to the high reactance measured by DR2 for a fault at FL2. For this fault however, the resistance is measured to be about twice the fault resistance. There are not any obvious reasons to this measurement.

For DR3 that has all voltage sources behind it, a single fault in FL3 is measured more correct. The fault current measured by the relay will be higher because all the contributions to the fault current flows through the position of the relay, therefore the measured impedance is lower. The inductive current drawn by the coil P_L is moving the point of measured impedance a bit lower on the R-axis and higher on the jX-axis than expected from the combination of the line- and fault impedance.

A clear trend shown by figures 5.2, 5.3 and 5.4 is that the relays sees the double faults at about the reactance of the total line, but at different resistance depending on if the second fault is located in forward or backward direction of the relay. For DR1 all fault combinations are seen at about twice the fault resistance, as all are in front of the relay. For DR2, double faults combining FL2 with FL3 or FL4 that are in backward direction of DR2 are measured at a resistance a few ohms higher than the fault resistance. The double fault involving FL1 and FL2 is measured at about 10Ω lower than two times the fault resistance, maybe as a result of FL1 being supplied both by source A and the generator. For DR3 the double faults combining FL3 with fault locations FL2 and FL1 that are in backward direction of DR3, gives a measured resistance about 10Ω lower than the fault resistance. The double fault combining FL3 and FL4 is measured at about the same resistance as the fault resistance. The reason why this is not equal to twice the fault resistance is not obvious, but could maybe have something to do with the coil P_L being located between FL3 and FL4.

It is not a big problem that the impedance measured by the relays for a single fault has such a high reactance, as these faults are allowed to stay for 120 minutes according to table 2.1 before they must be disconnected. Most faults are transient and self-extinguish after some seconds. For the persistent faults however, it could be a problem associated with the unknown location of the fault due to the corrupted ratio of measured impedance versus line impedance. This means that a repair team will have to spend time searching the line in order to find the fault, extending the down-time of the line. As the single faults all are within the suggested maximum starting zone of 150Ω used by Statnett, they will be detected even though they are outside the protection zones of the relay in jX-direction.

Because the impedance of phase a measured by all three relays for double faults are distinctively deviant from the impedance measured for a single fault, it should in the theory be possible for the relay to separate a single fault from a double fault. Sophisticated setting of the relay would however be required. A suggested method to make the relay trip only for double faults could be to introduce a limit on the jX-axis for the starting zone of the relay as well as the regular limit in R-direction. In this way the relay would not start for the single faults. This starting zone could be altered to have a trip delay of 120min, so that the single fault would be disconnected if it is still present after the allowed time of operation of the system with such a fault present has passed.

It is important to remember that the double faults simulated in this analysis are of equal fault resistance, which is low compared to all possible fault resistances. In order to properly set such a horizontal starting zone as mentioned, further test with variations in fault impedances would be required. The ground resistance used in this simulation is also known and used to set the relays. Because this will be varying in the reality, further tests on how the impedance measured by the relays will be affected by variations in ρ for a compensated earthed grid is required. Dependent on the ground conditions of this network, an opinion on how much the ground resistance is expected to vary would be helpful in order to determine the best fitting $|k|$ for all reasonable ground resistances.

As the Petersen coils are limiting the total ground fault current, exceeding the limit for allowed touch- and step-voltage is not a problem in a well-compensated grid. If the compensation is badly performed in terms of either too big or too small coils installed allowing a high ground fault current, earth potential rise could be an issue.

5.4.3 Detection of Single Faults in Solid Earthed Network

When the grid is solid earthed the fault current is only flowing to ground in the fault location, which provides much better conditions for the distance relay to measure the short circuit impedance correctly compared to the compensated earthed grid. It can be seen that for all three distance relays, the total resistance measured is about the fault resistance plus the line resistance from the relay to the fault location. The reactive part of the measured impedance is pretty close to the total reactance of the line, which is correct according to the theory with respect to the fault location.

All relays measure R with some error compared to the expected value of measured resistance that is the line resistance plus the fault resistance. The deviation in measured R to the expected, too low or too high, is probably caused by unsymmetrical conditions in the network prior to the fault. As mentioned before, not being allowed by ATPDraw to revolve the phases makes the lines unsymmetrical even before a fault, which has the most impact on the zero sequence system. Also some contribution to the fault loop impedance seen by the relay comes from the ground resistance, moving the measured resistance to the right in the impedance diagram for increasing ground resistance.

It is important to be aware of the fact that the results from the simulation of the transmission grid as solid grounded is based on a known and constant ground resistance ρ used in the model, which means that the zero sequence line impedance and therefore also the ground fault correction factor $|k|$ is set properly. This means that even though the measurements by the distance relays are looking good with respect to fault detection, the effect of variations in ρ and its influence on the zero sequence impedance and $|k|$ must be considered for real world application of distance protection of lines without ground wire.

When the grid has solid earthed neutral point but is lacking ground wires, all of the discussion from chapter 4 is applicable. This includes the trouble experienced concerning corruption of the measured impedance versus line impedance ratio yielding a wrong distance to fault when the ground fault correction factor is not properly set, i.e. when ground wires not are installed. Also here, the crucial parameter deciding if a fault will be detected by the relay will be the fault impedance. The simulations show that even when the ground resistance is severely increased, but the ground fault correction factor held constant as it was set for $\rho = 500\Omega m$, the error in the measurements is not big enough to impact whether the relay will trip or not. Last but not least, the stand alone tower impedances not being interconnected gives cause to a possibly very high earth potential rise at the faulted tower. This could lead to trouble keeping the touch- and step-voltage during a ground fault within the limits given by the regulations.

Chapter 6

Conclusions and Future Work

6.1 Conclusion

The ambition of this masters thesis was to identify:

- The impact that line design with discontinuous ground wire has on the ability of the distance relay to detect ground faults when the line is part of a solid grounded network

- If two ground faults occurring at the same time but at different locations in a network with compensated earthed neutral and no ground wires will be detected by distance relays

- If the distance relay has adequate measurement conditions for them to be able to detect a ground fault if the grounding of the compensated grid without ground wires simply were changed into solid neutral earthing without installing ground wire

The following conclusions are based on the results from the simulated models in ATPDraw, and does not represent the real power system to a full extent due to simplifications and assumptions made in the models. The conclusions however gives a good indication of what to expect if the same tests were performed in the reality.

6.1.1 Transmission Line

The presence of ground wires does not have a great impact on the ability of the distance relay to detect a ground fault. The fault impedance is the parameter found to be the most influencing as to whether a fault is seen by the relay or not.

However, the presence of continuous ground wires means that the ground fault correction factor $|k|$ can be set correctly as the impedance of the ground wire is known and constant. With a correct set $|k|$ the ability of the relay to indicate the location of a fault is severely improved.

Ground wires installed will make all towers a part of a parallel connection from neutral to ground, which limits the ground fault current flowing to ground at the fault location. This reduces the earth potential rise, and thereby reduce the touch- and step-voltage.

If no ground wires are installed it is crucial for all towers to have sufficient earth electrodes or other measures made in order to prevent and/or protect humans and livestock from high touch- and step-voltages near towers.

6.1.2 Transmission Network

The results are stating that the distance relay will see a different impedance based on if there is one or two single phase-to-ground faults occurring in the system. The impedance measured for double faults are very similar to each other independent on the location of the second fault. This means that it could be possible for the distance relay to separate single faults from multiple faults, if the relay protection zones are set in a sophisticated way. However, this conclusion is only valid for the analysed fault- and ground resistance.

Distance relays will based on the performed simulation have adequate measurement conditions in order to detect single ground faults when the network has solid neutral earthing. However, the change of earthing method will result in a higher ground fault current. The combination of high ground fault current with lack of ground wires will lead to challenges when it comes to keeping the touch- and step-voltage within allowed limits. In addition, the ability of the relay to indicate a correct fault location will be pour because the ground fault correction factor $|k|$ will be varying with the ever changing ground conductivity.

6.2 Future Work

For further work on the subjects of this masters thesis some of the concepts one could look deeper into are:

- Further simulations where the ground fault correction factor is split into a real and an imaginary part to investigate the consequence of using an absolute value of $|k|$
- Other geometrical shapes of the protection zones, that gives room for the maximum load impedance but reaches further in the R direction of the impedance diagram for areas on the imaginary axis jX where the load is not expected (bone-shaped protection zones). Can this make the relay able to detect faults that have a higher fault impedance than the presented solution managed?
- How the soil resistance varies with meteorological conditions, and how this can be measured/monitored
- The use of PMUs to measure sequence impedances in combination with adaptive relaying
- Further simulations on multiple ground faults in a grid with compensated neutral earthing, to see if the results from the analysis performed in this thesis holds true for variations in fault resistance and ground conductivity
- Implementation and testing of a logical trip scheme setting the rules for tripping of a relay so that it detects all ground faults, but only disconnect for multiple faults and/or for violating the allowed duration of a single ground fault
- The possibility and cost versus benefit analysis of interconnecting towers by their footing, possibly below ground, compared to installing overhead ground wires

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Appendix A

Simulation of a Transmission Line: Parameters and Results

A.1 Input Parameters and Design

Simulation parameters and design of the transmission line.

Total length A-B	117 [km]
Length with ground wires A-C	33 [km]
Length without ground wires C-B	84 [km]
Number of towers	325
Distance between towers	360 [m]
Distance between phase conductors	7 [m]
Diameter steel core phase conductors	1 [cm]
Diameter phase conductors	4 [cm]
Distance phase to ground	15 [m]
Distance ground wires to ground	20 [m]
Diameter ground wire	2 [cm]
Number of ground wires	2
Type of suspension	horizontal

Table A.1: Design of the line

Conductor type	FeAl326
Positive sequence impedance Z_1	6.81 + j48.89 Ω
Given zero sequence impedance Z_0	22.69 + j179.74 Ω
k calculated using (4.1) and given Z_1 and Z_0	2.670
Resistance ground wires	0.3 Ω/km
Tower impedance, included tower footing impedance	25 Ω
Grounding resistance start/end of ground wire	0.01 Ω
Chosen load in B at each phase	1000 Ω
Voltage level	220 kV
$I_{k\ min}$ A	920 A
$S_{sc\ min}$ A	350 MVA
$S_{sc\ max}$ B	2028 MVA

Table A.2: Given line parameters

Merge	Original data	In simulation model
10 towers merged to 1	$10 \cdot 25\Omega$ in parallel	2.5Ω per tower
Distance between towers	360 m	3600 m
Nr. of towers with ground wire model 1	92	9
Nr. of towers without ground wire model 1	233	23
Nr. of towers with ground wire model 2	325	32

Table A.3: Merging of line sections and towers

Fault equivalent	Fault resistance [Ω]
Bolted	0.1
Low resistance arc	5
High resistance arc	10
Vegetation	25
	50
	75
	100
	200
	300
	400
	500
	600
	700
	800
	900
	1000

Table A.4: Simulated fault resistances

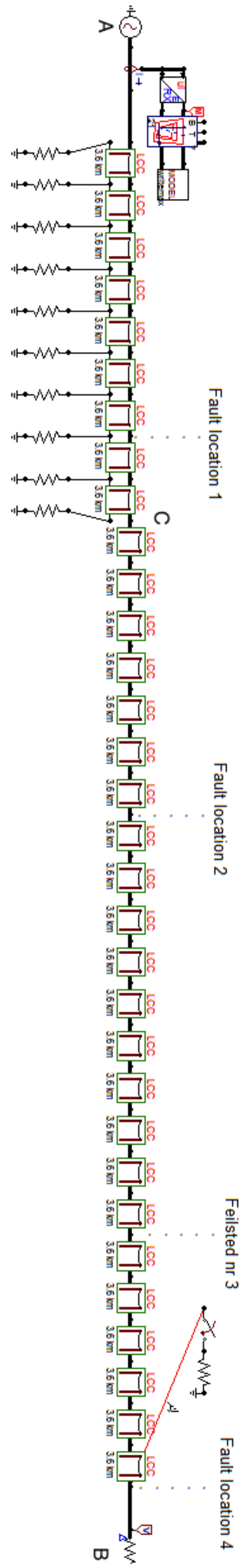

Figure A.1: ATPdraw model 1: Discontinuous ground wire

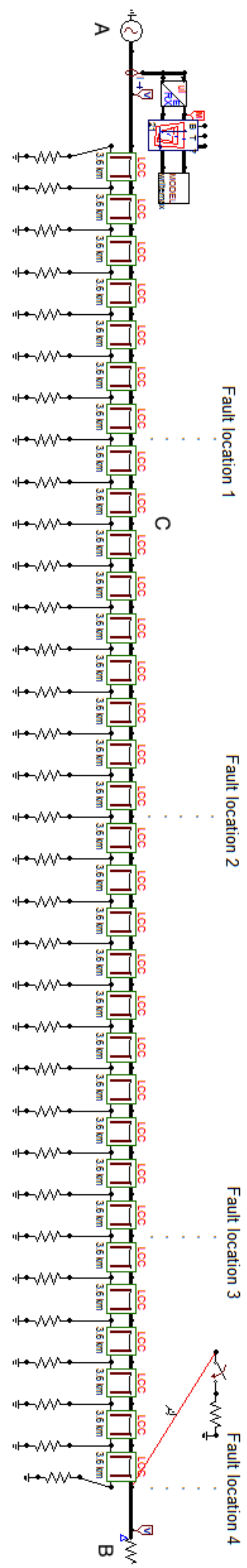

Figure A.2: ATPdraw model 2: Continuous ground wire

A.2 Simulated Parameters and Relay Settings

Output from the simulation models and the belonging distance relay settings.

A.2.1 Discontinuous Ground Wire: Model 1

Ground resistance	**With ground wire A-C**		**Without ground wire C-B**		**Total line A-B**	
	Z_1	Z_0	Z_1	Z_0	Z_1	Z_0
Moist soil $\rho = 500\Omega m$	1.944 + j12.798	9.171 + j28.887	4.887 + j32.828	16.956 + j118.32	6.831 + j45.626	26.127 + j147.207
Dry mountain $\rho = 100000\Omega m$	1.943 + j12.799	11.284 + j32.566	4.887 + j32.828	17.131 + j159.48	6.830 + j45.627	28.415 + j192.046

Table A.5: Simulated line impedance model 1

Ground resistance	**Zone 1** $= 0,8 \cdot jX_1$	**Zone 2** $= 1,2 \cdot jX_1$	**Zone 3** $= 2 \cdot jX_1$	$\|k\|$
Moist soil $\rho = 500\Omega m$	36.5	54.8	91.3	2.241
Dry mountain $\rho = 100000\Omega m$	36.5	54.7	91.3	3.208

Table A.6: Line protection zones model 1

A.2.2 Continuous Ground Wire: Model 2

Ground resistance	**Total line A-B**	
	Z_1	Z_0
Moist soil $\rho = 500\Omega m$	6.912 + j45.502	29.342 + j94.999
Dry mountain $\rho = 100000\Omega m$	6.909 + j45.507	35.022 + j103.82

Table A.7: Simulated line impedance model 2

Ground resistance	**Zone 1** $= 0,8 \cdot jX_1$	**Zone 2** $= 1,2 \cdot jX_1$	**Zone 3** $= 2 \cdot jX_1$	$\lvert k \rvert$
Moist soil $\rho = 500\Omega m$	36.4	54.6	91.0	1.160
Dry mountain $\rho = 100000\Omega m$	36.4	54.6	91.0	1.380

Table A.8: Line protection zones model 2

A.3 Relay Measurements

Measured impedance by the distance relay for the four fault locations. The scattered points are showing the impact of the fault resistances from table A.4, from $Rf = 0.1\Omega$ in the leftmost point to $Rf = 1000\Omega$ in the rightmost point of every plot.

A.3.1 Single Phase-to-Ground Fault

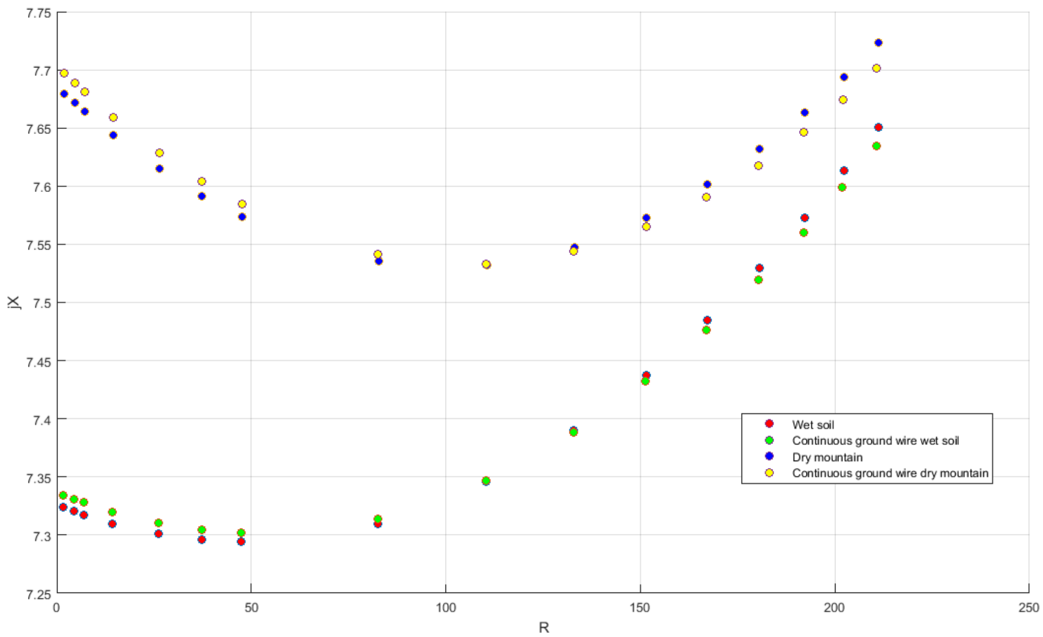

Figure A.3: Fault location 1, single phase-to-ground fault, common $|k|$=2.67

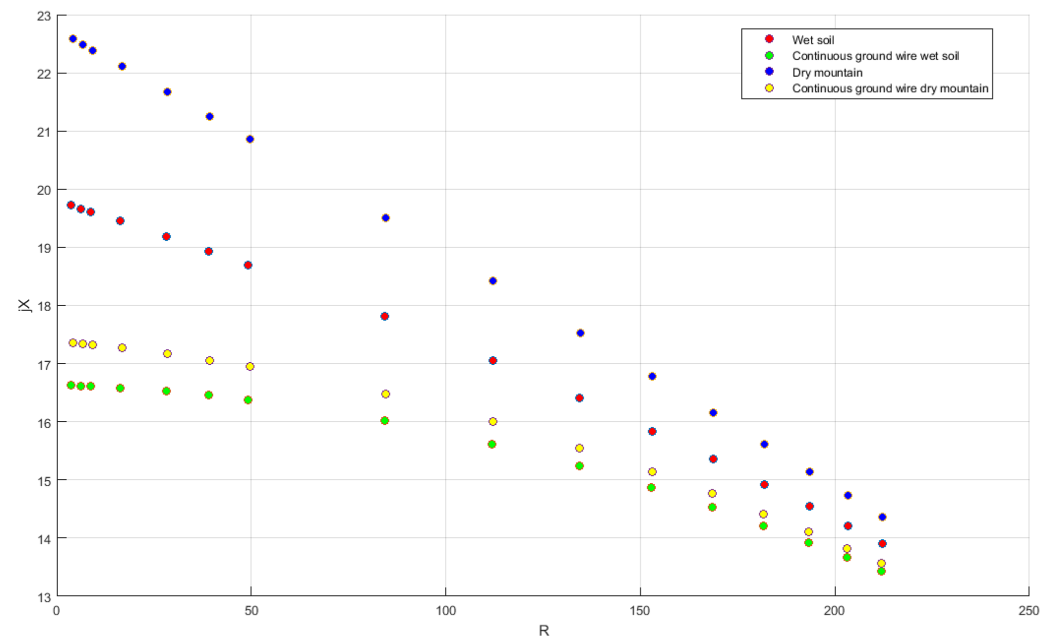

Figure A.4: Fault location 2, single phase-to-ground fault, common $|k|$=2.67

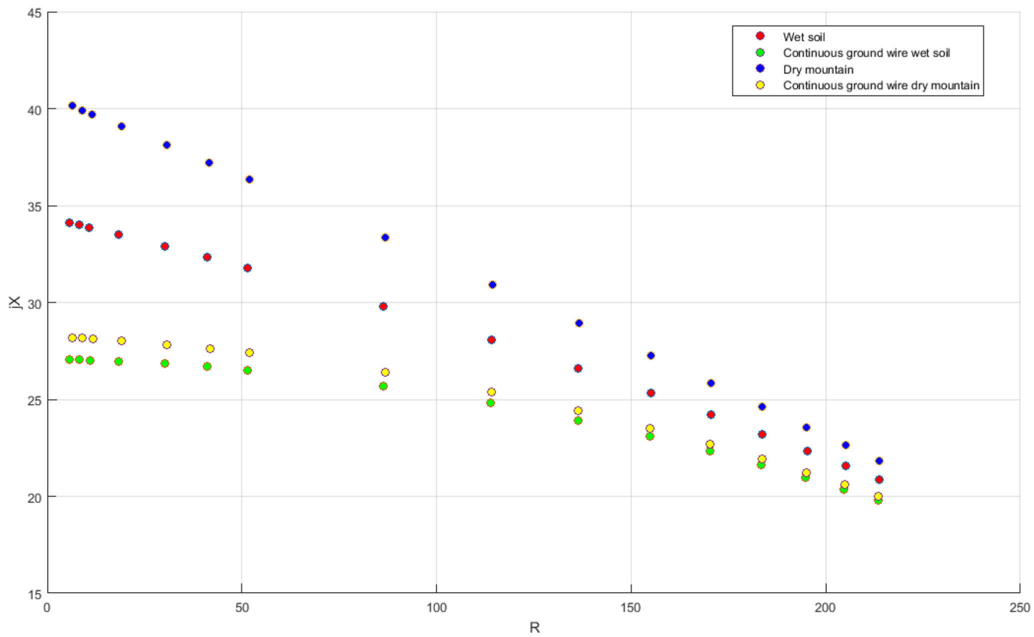

Figure A.5: Fault location 3, single phase-to-ground fault, common $|k|$=2.67

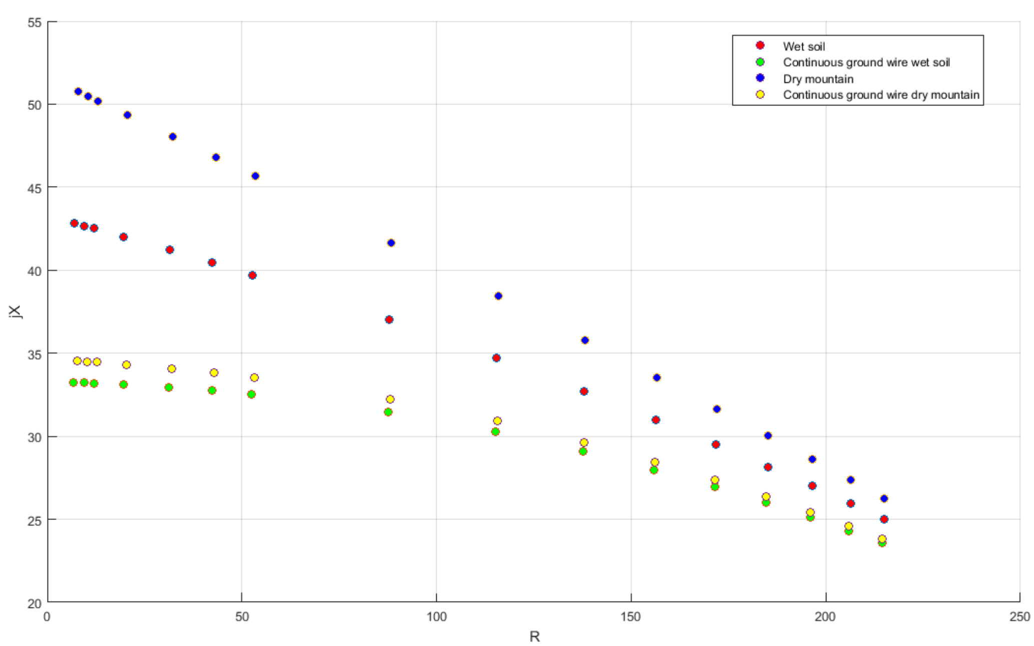

Figure A.6: Fault location 4, single phase-to-ground fault, common $|k|$=2.67

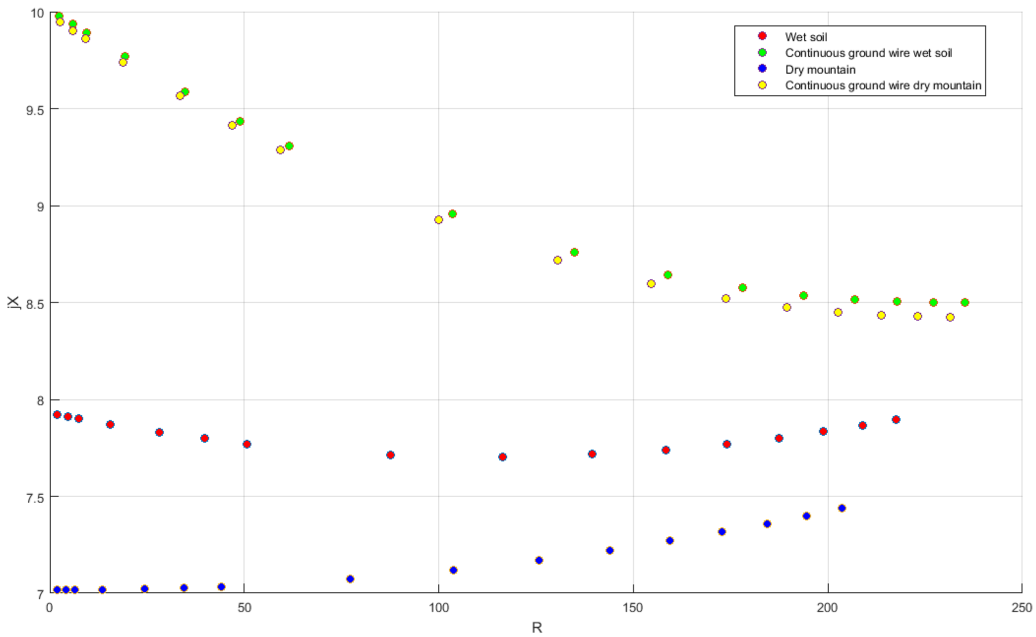

Figure A.7: Fault location 1, single phase-to-ground fault, $|k|$ set according to tables A.6 and A.8

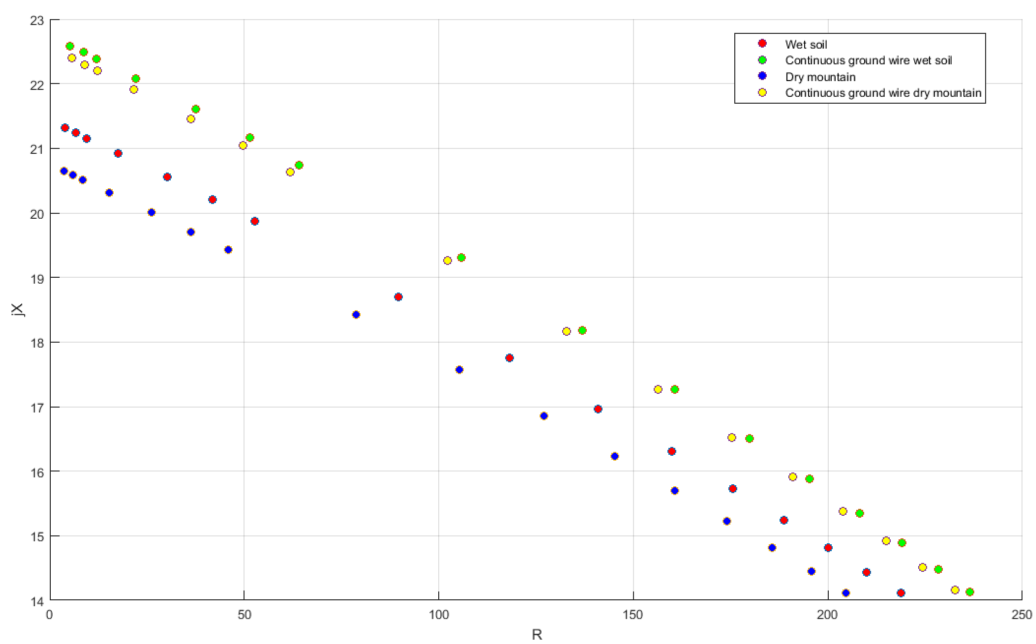

Figure A.8: Fault location 2, single phase-to-ground fault, $|k|$ set according to tables A.6 and A.8

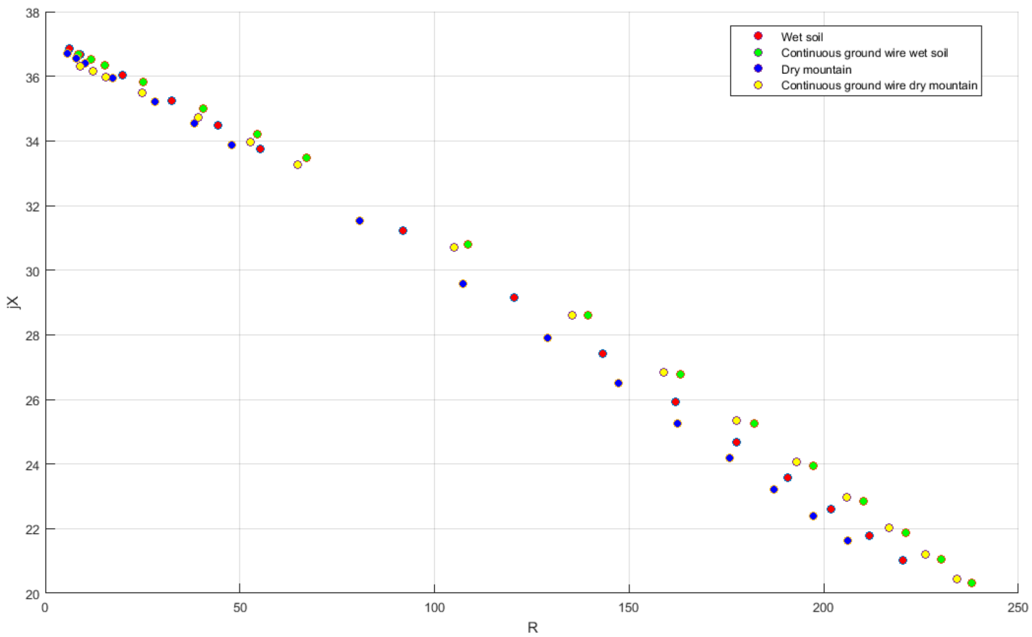

Figure A.9: Fault location 3, single phase-to-ground fault, $|k|$ set according to tables A.6 and A.8

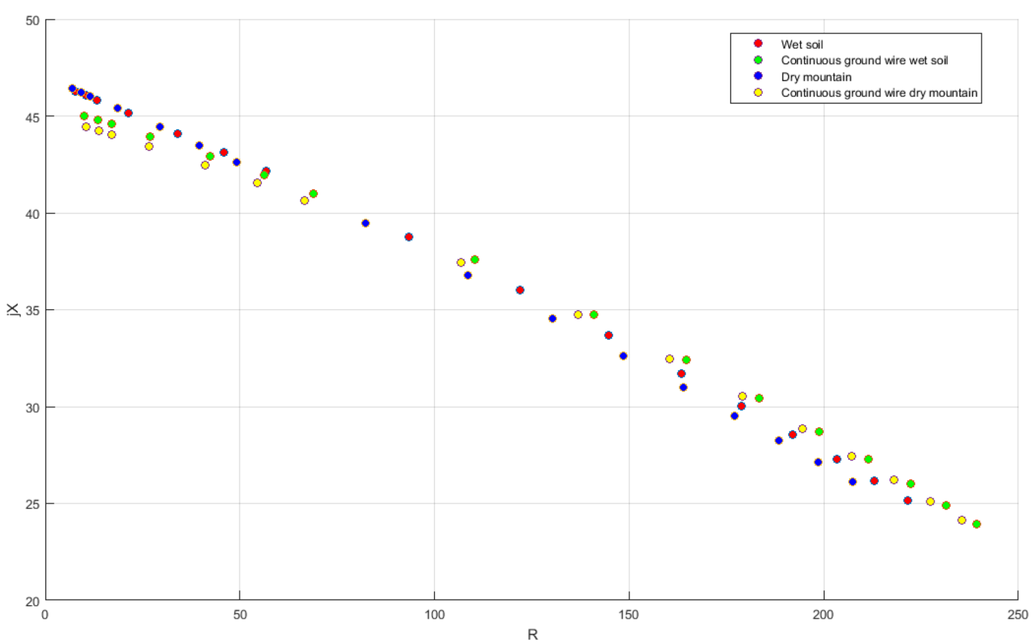

Figure A.10: Fault location 4, single phase-to-ground fault, $|k|$ set according to tables A.6 and A.8

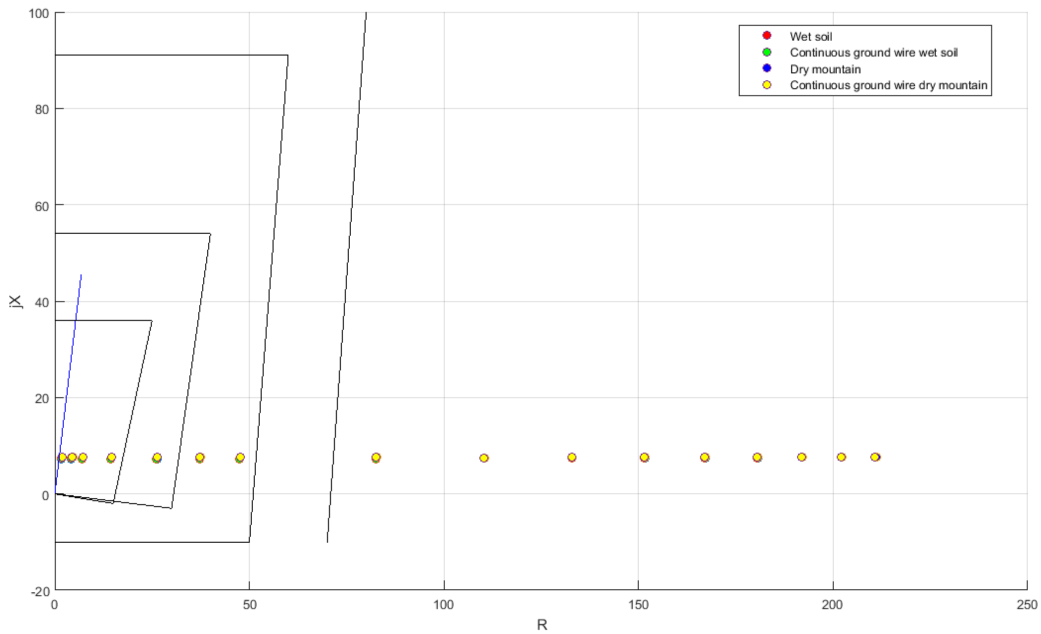

Figure A.11: Fault location 1, single phase-to-ground fault, common $|k|$=2.67 with protection zones and line impedance

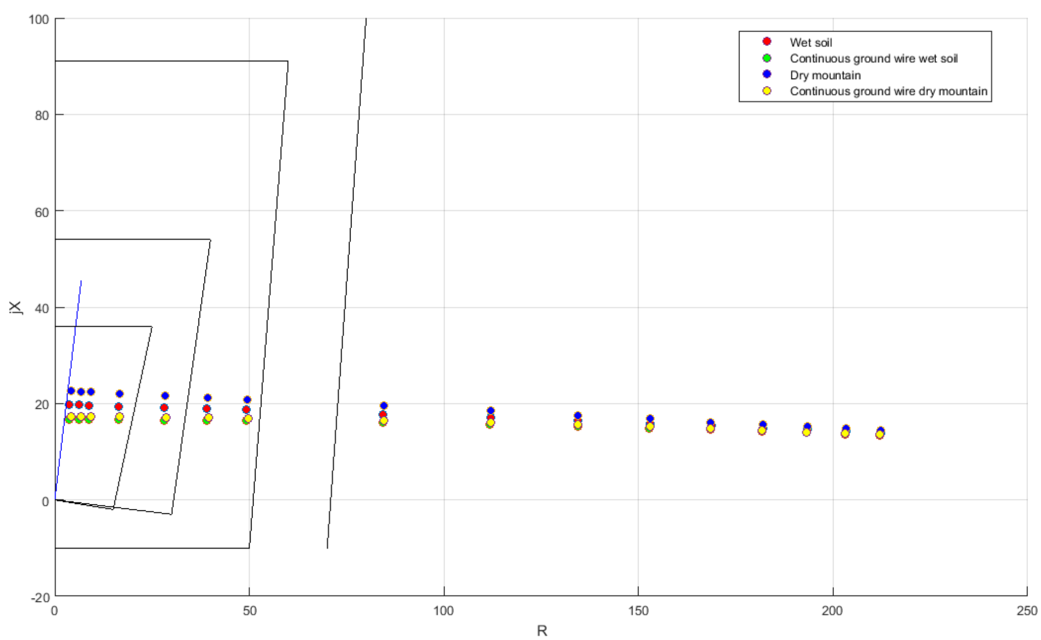

Figure A.12: Fault location 2, single phase-to-ground fault, common $|k|$=2.67 with protection zones and line impedance

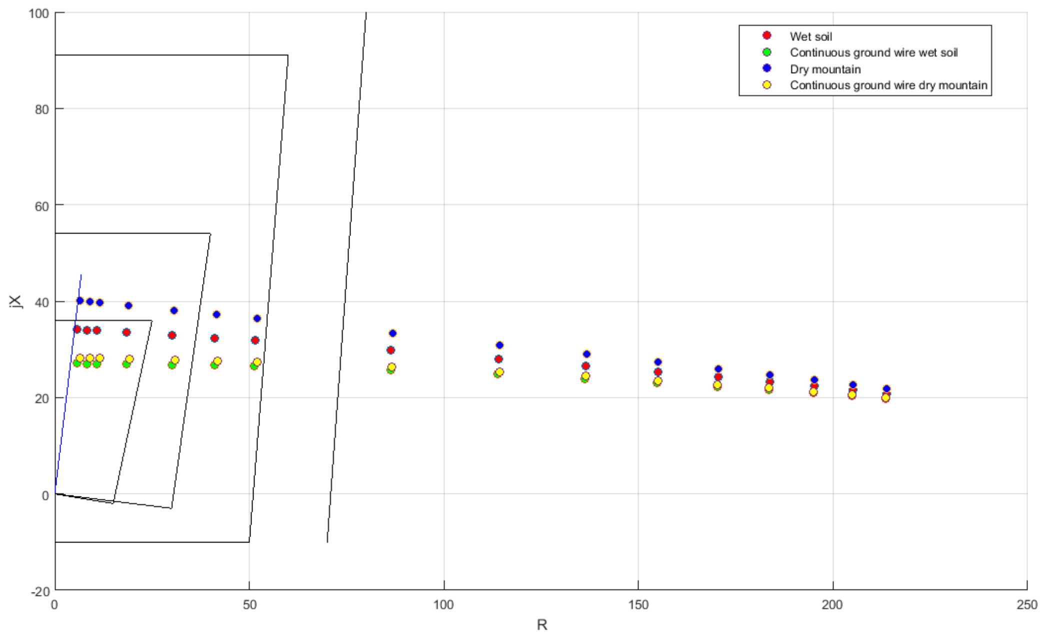

Figure A.13: Fault location 3, single phase-to-ground fault, common $|k|$=2.67 with protection zones and line impedance

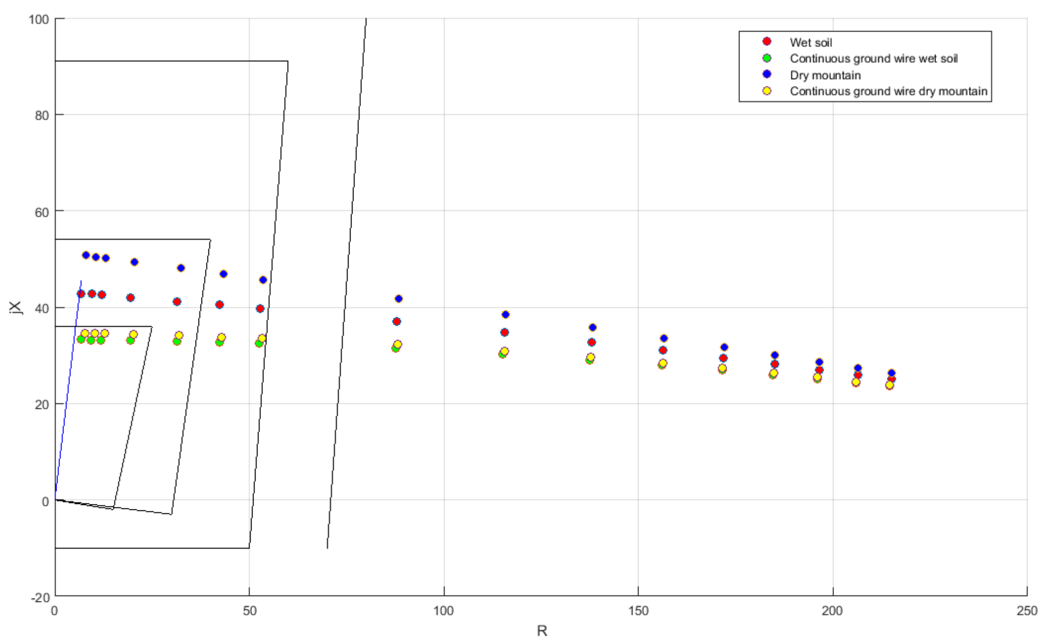

Figure A.14: Fault location 4, single phase-to-ground fault, common $|k|$=2.67 with protection zones and line impedance

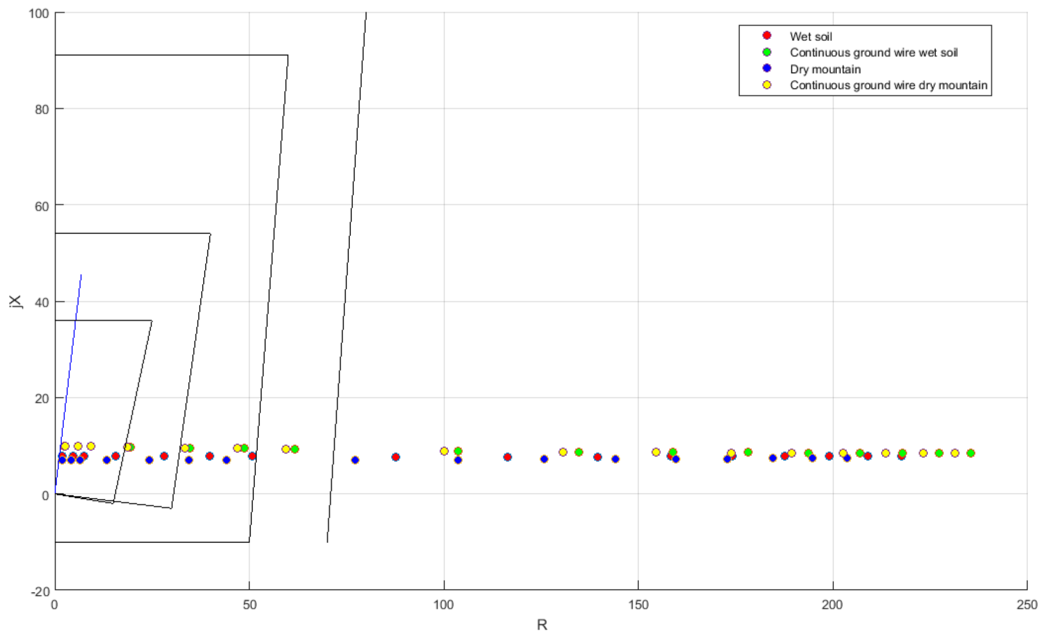

Figure A.15: Fault location 1, single phase-to-ground fault, $|k|$ set according to tables A.6 and A.8 with protection zones and line impedance

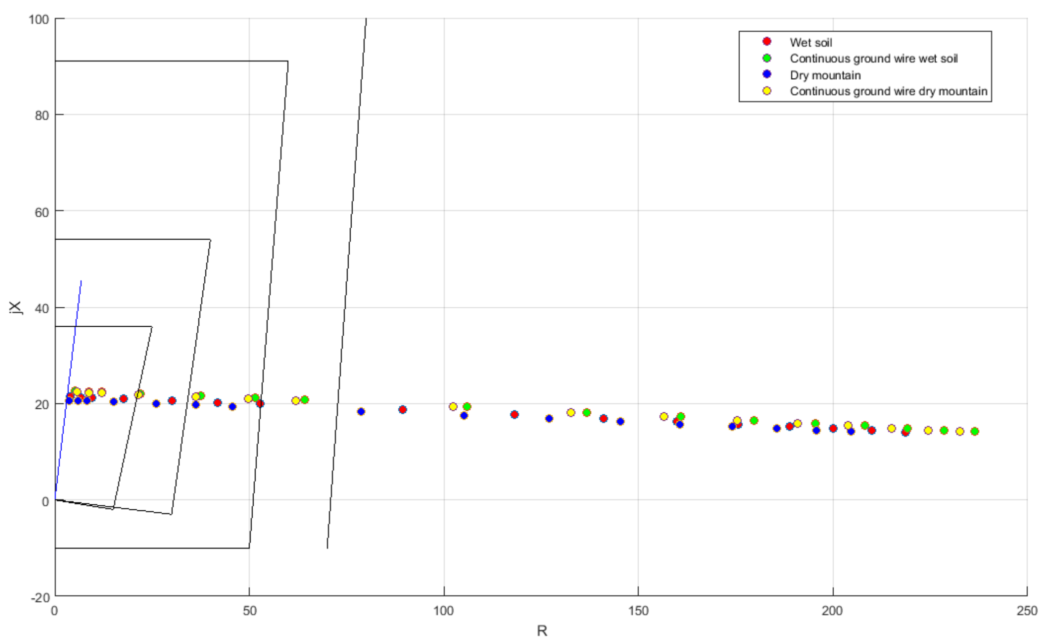

Figure A.16: Fault location 2, single phase-to-ground fault, $|k|$ set according to tables A.6 and A.8 with protection zones and line impedance

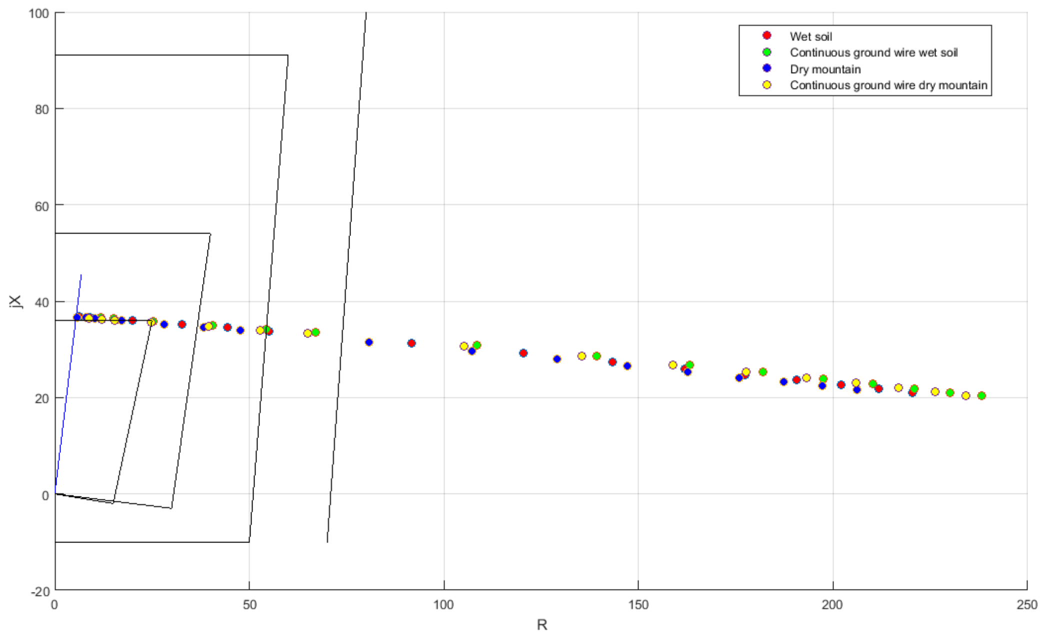

Figure A.17: Fault location 3, single phase-to-ground fault, $|k|$ set according to tables A.6 and A.8 with protection zones and line impedance

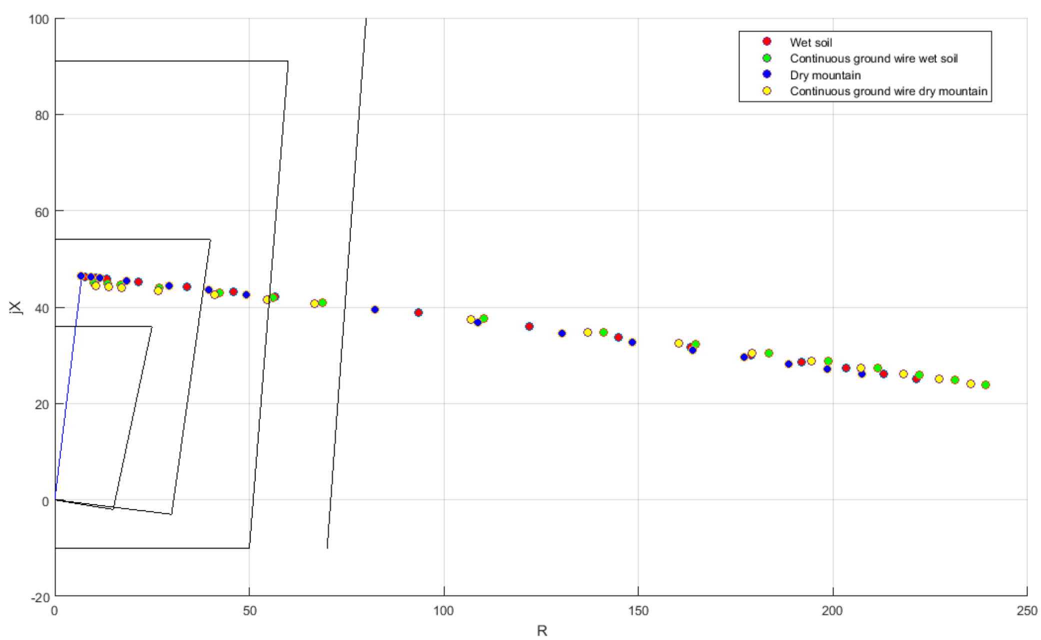

Figure A.18: Fault location 4, single phase-to-ground fault, $|k|$ set according to tables A.6 and A.8 with protection zones and line impedance

A.3.2 Broken Conductor to Ground Fault

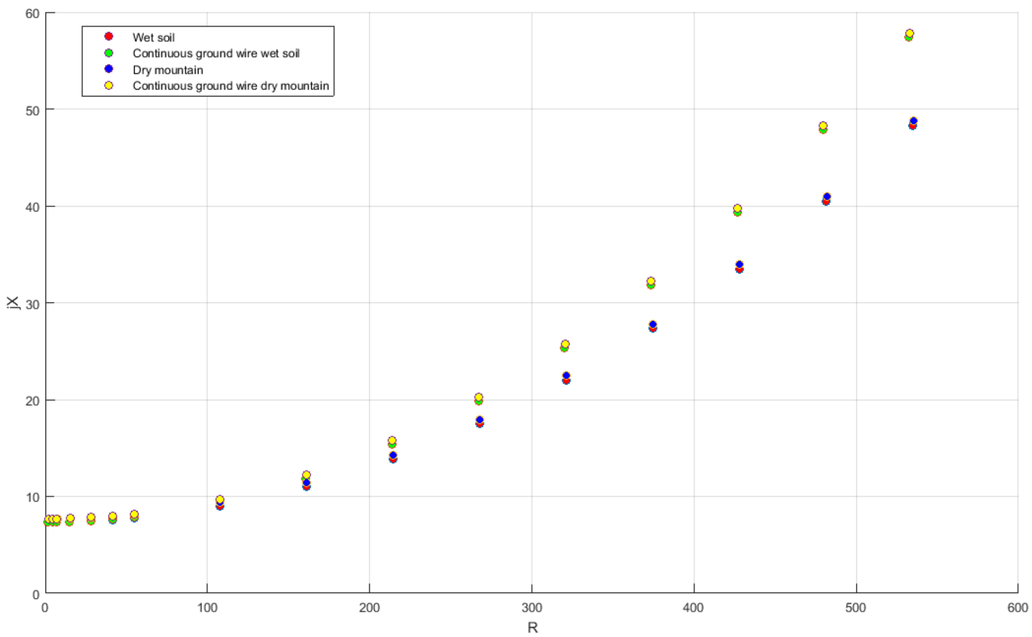

Figure A.19: Fault location 1, broken conductor to ground fault, common $|k|$=2.67

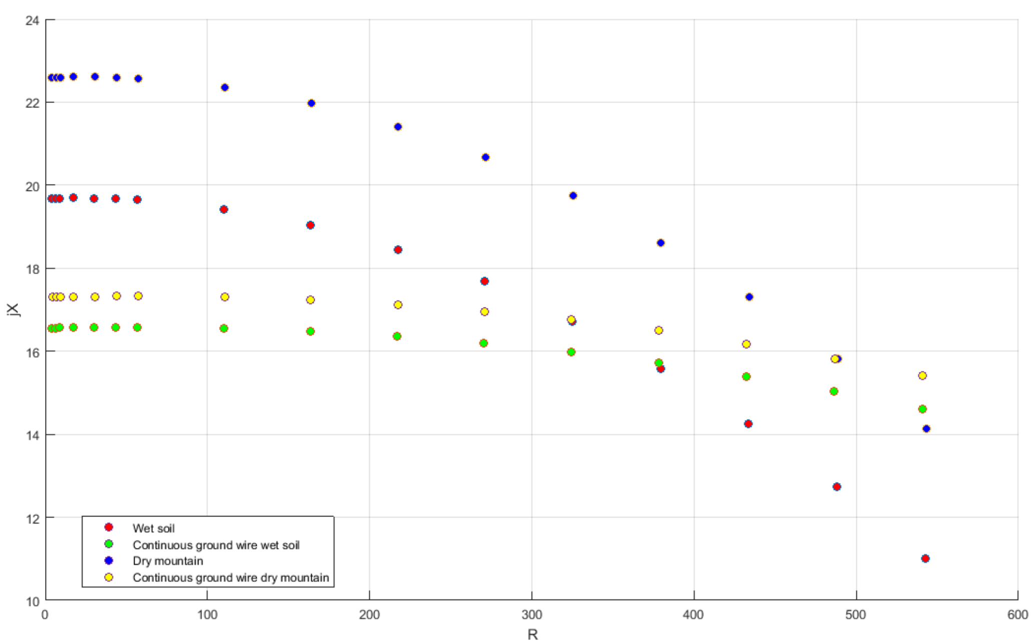

Figure A.20: Fault location 2, broken conductor to ground fault, common $|k|$=2.67

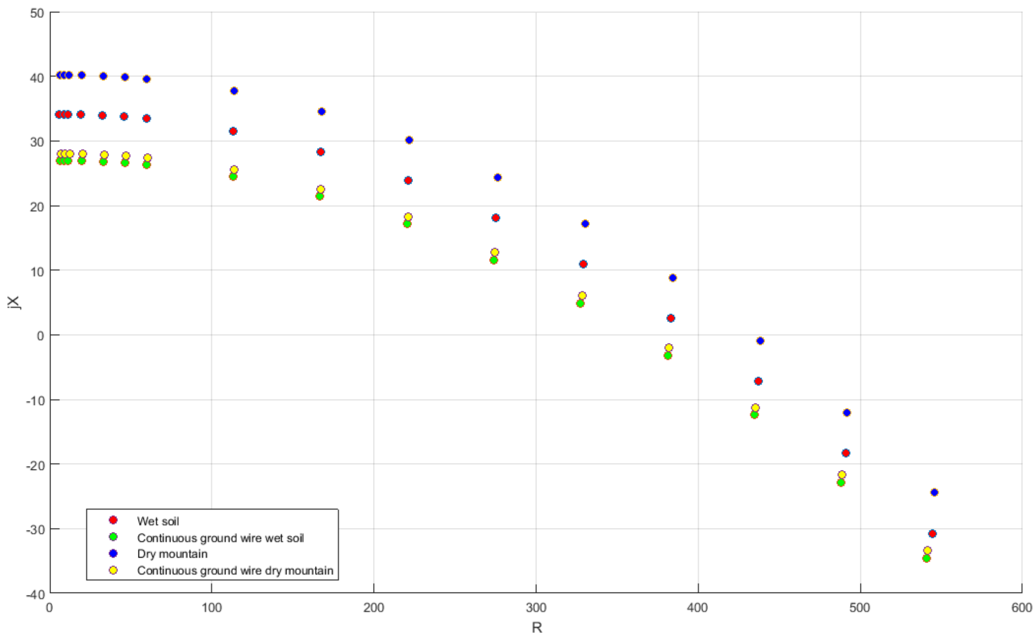

Figure A.21: Fault location 3, broken conductor to ground fault, common $|k|$=2.67

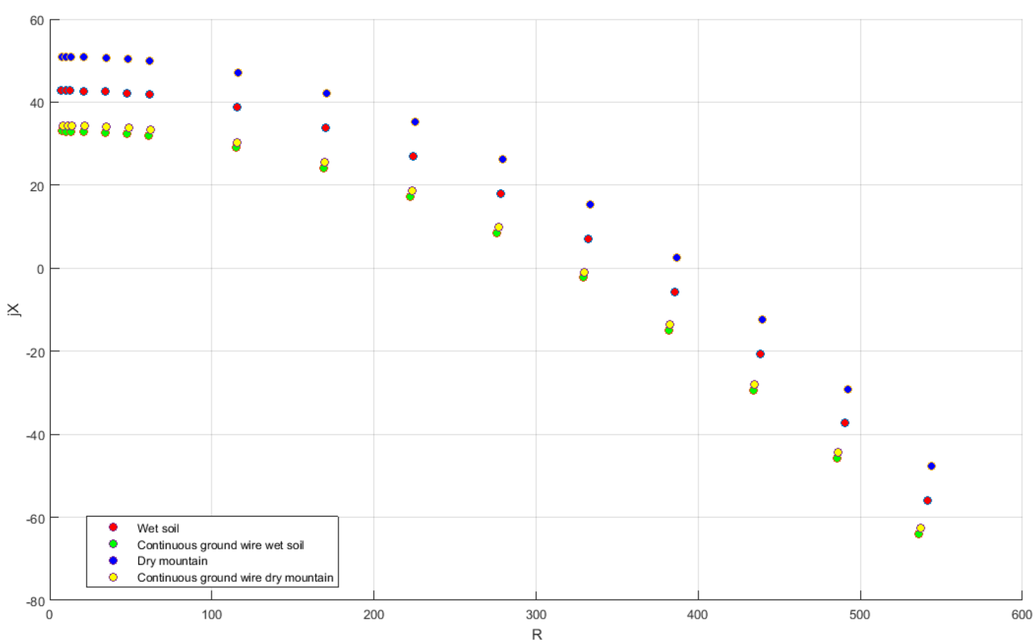

Figure A.22: Fault location 4, broken conductor to ground fault, common $|k|$=2.67

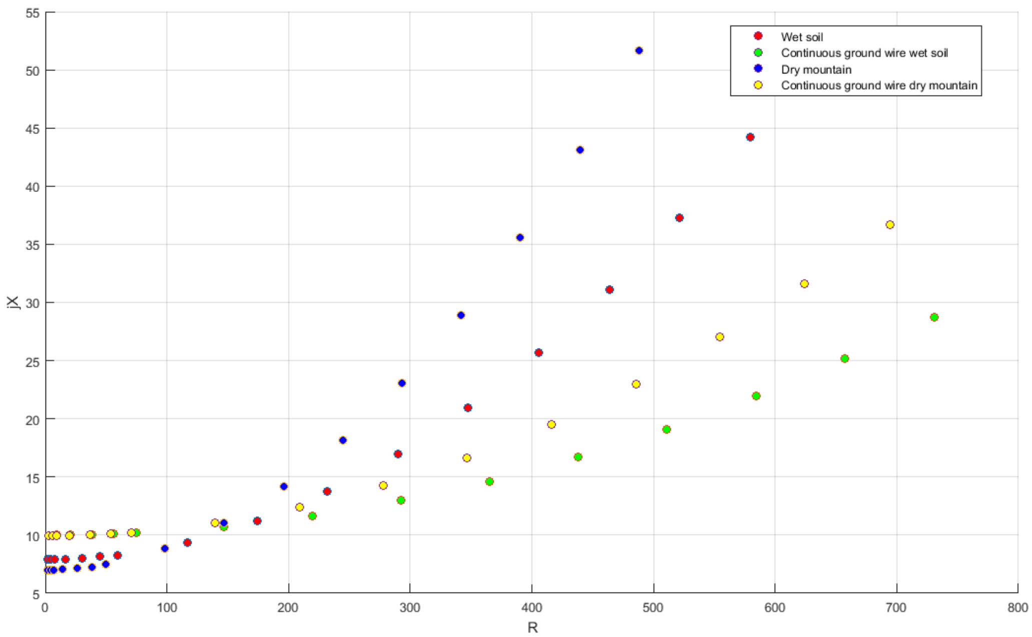

Figure A.23: Fault location 1, broken conductor to ground fault, $|k|$ set according to tables A.6 and A.8

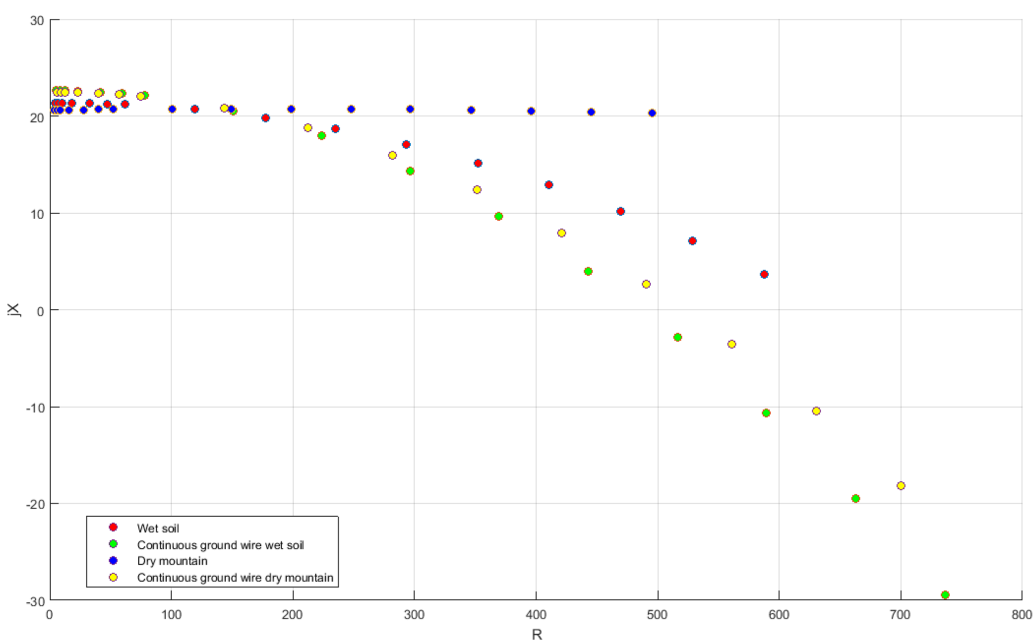

Figure A.24: Fault location 2, broken conductor to ground fault, $|k|$ set according to tables A.6 and A.8

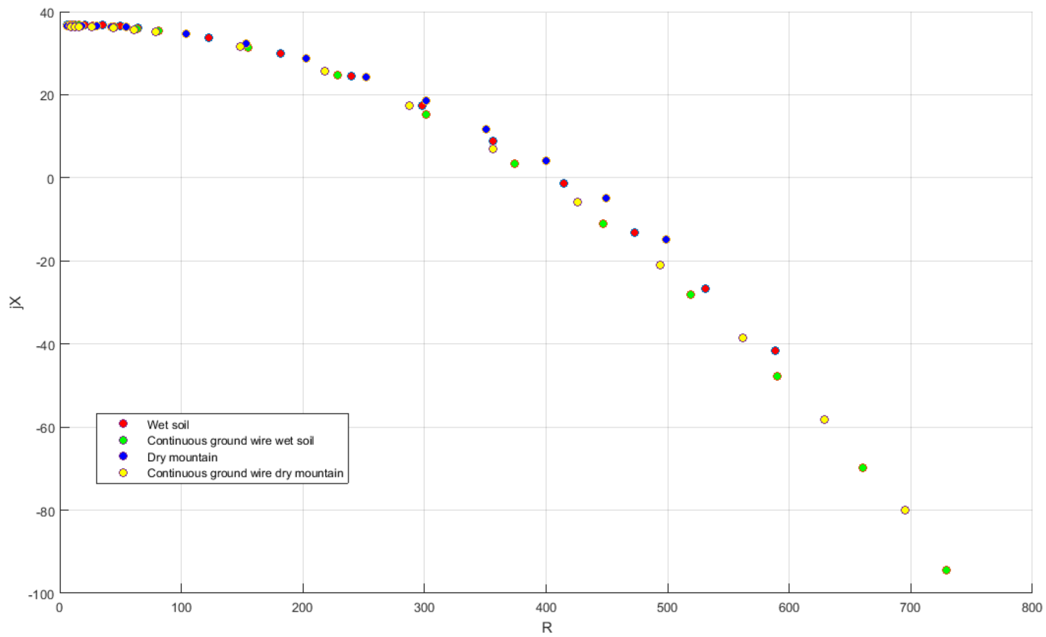

Figure A.25: Fault location 3, broken conductor to ground fault, $|k|$ set according to tables A.6 and A.8

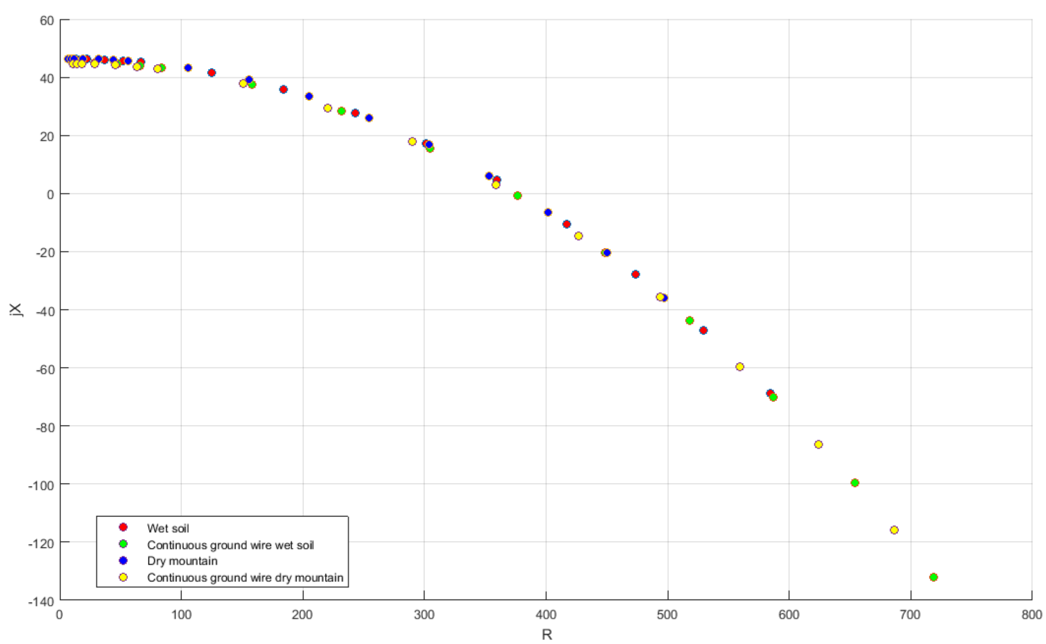

Figure A.26: Fault location 4, broken conductor to ground fault, $|k|$ set according to tables A.6 and A.8

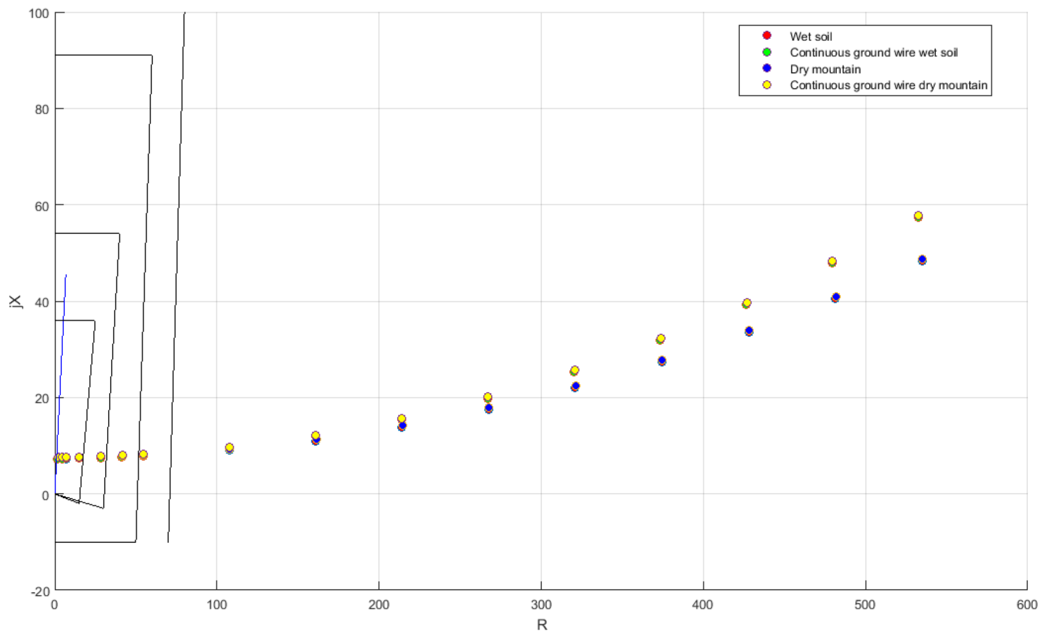

Figure A.27: Fault location 1, broken conductor to ground fault, common $|k|$=2.67 with protection zones and line impedance

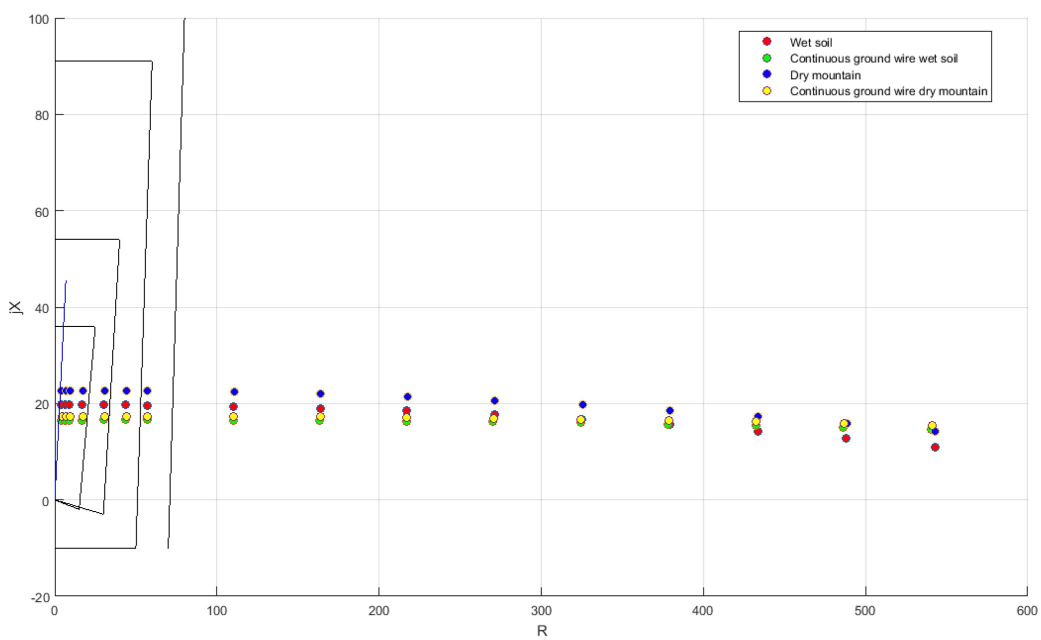

Figure A.28: Fault location 2, broken conductor to ground fault, common $|k|$=2.67 with protection zones and line impedance

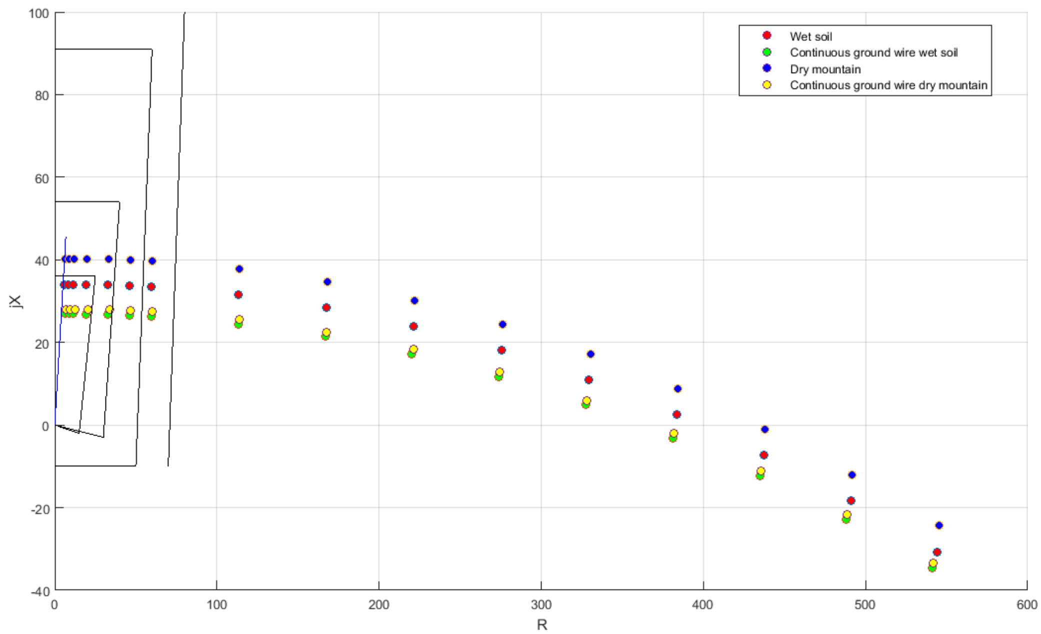

Figure A.29: Fault location 3, broken conductor to ground fault, common $|k|$=2.67 with protection zones and line impedance

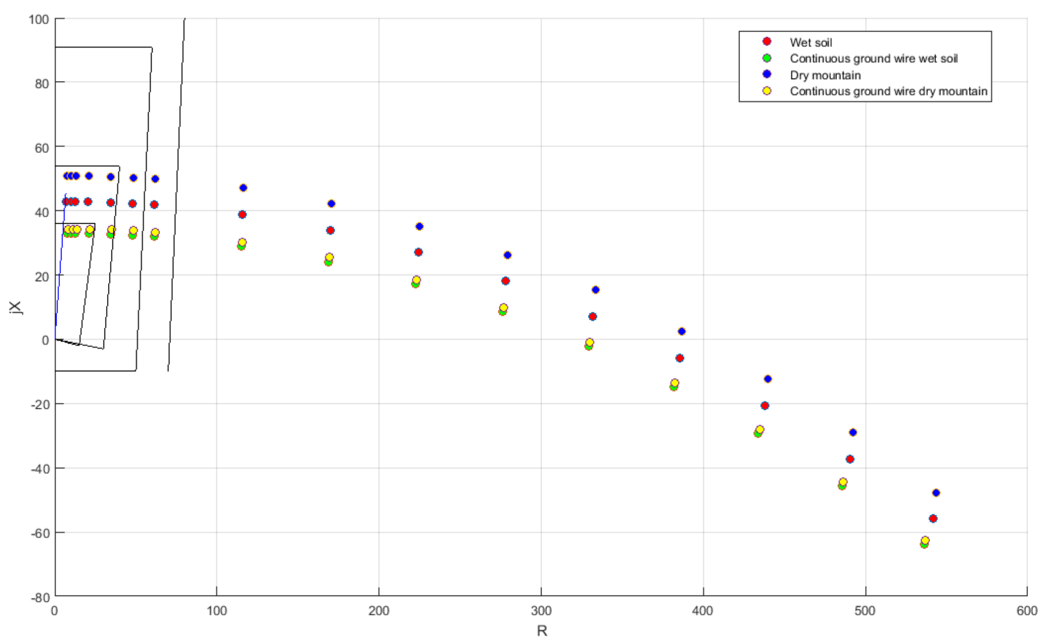

Figure A.30: Fault location 4, broken conductor to ground fault, common $|k|$=2.67 with protection zones and line impedance

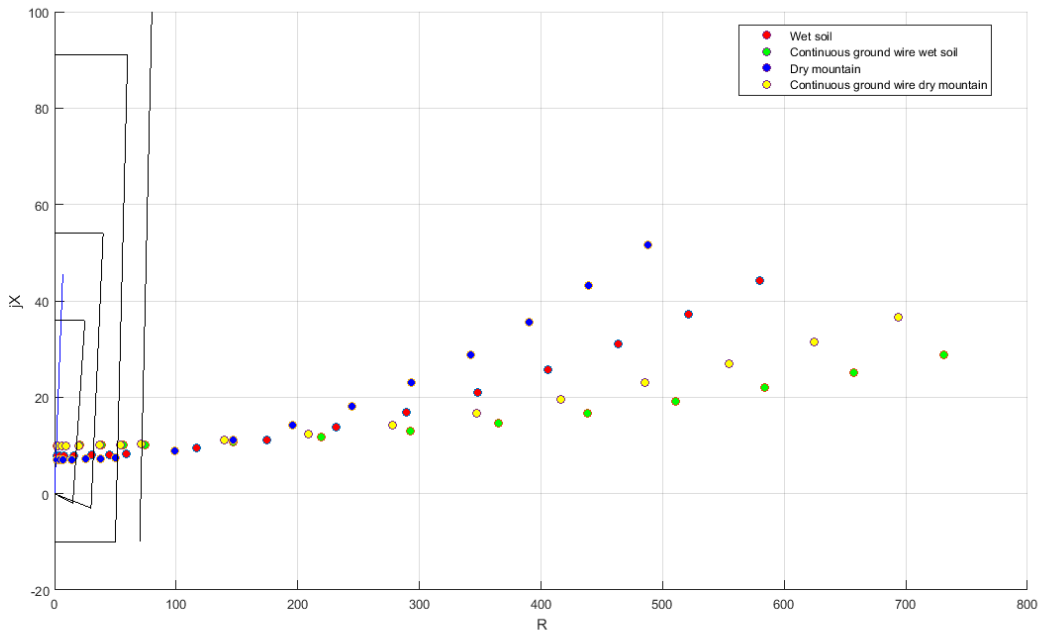

Figure A.31: Fault location 1, broken conductor to ground fault, $|k|$ set according to tables A.6 and A.8 with protection zones and line impedance

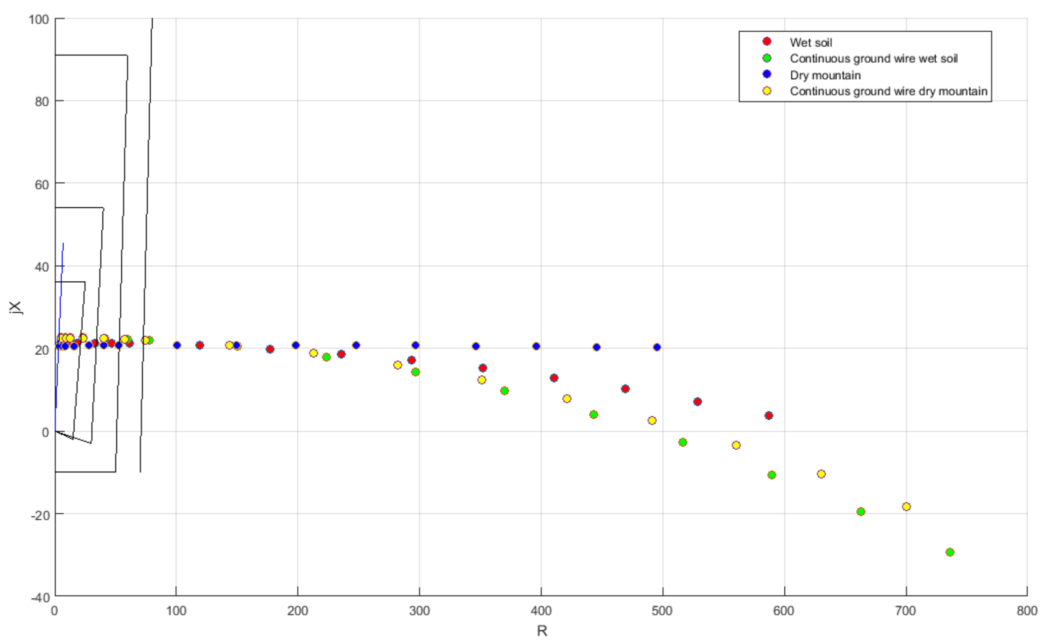

Figure A.32: Fault location 2, broken conductor to ground fault, $|k|$ set according to tables A.6 and A.8 with protection zones and line impedance

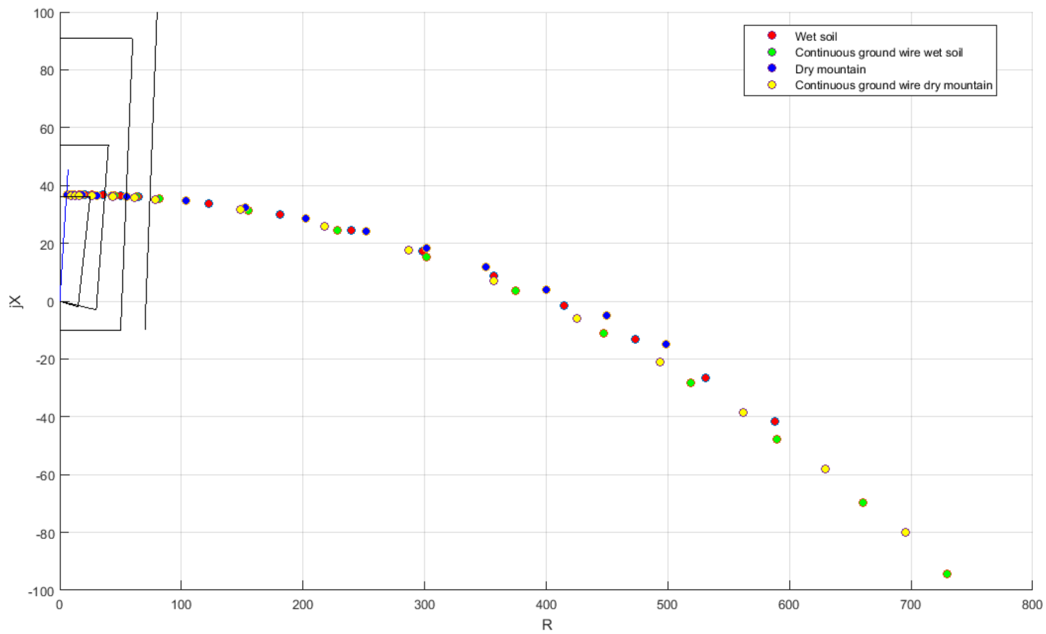

Figure A.33: Fault location 3, single phase-to-ground fault, $|k|$ set according to tables A.6 and A.8 with protection zones and line impedance

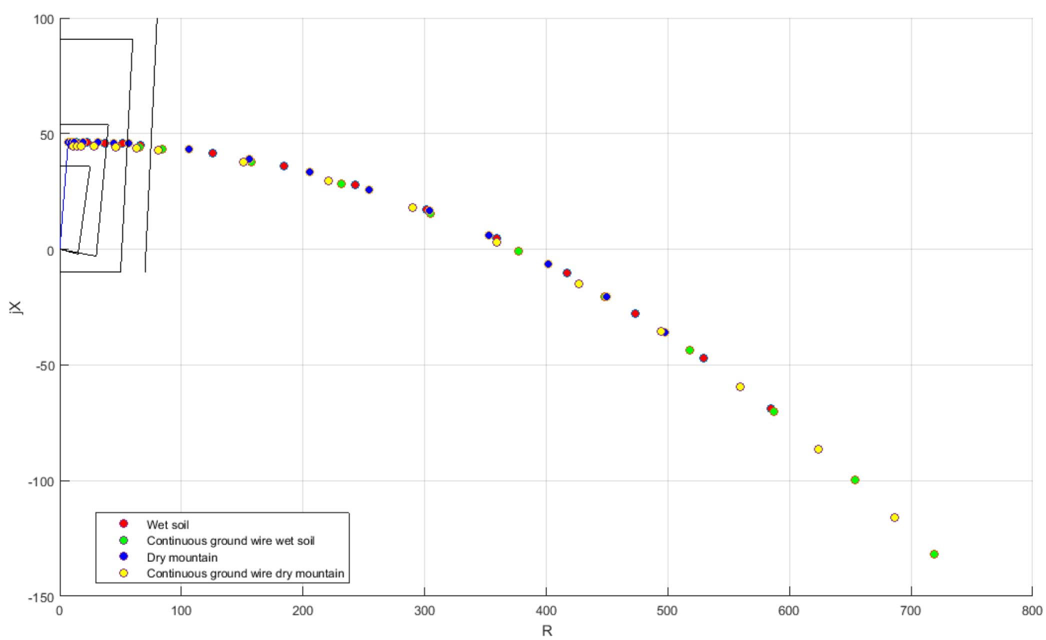

Figure A.34: Fault location 4, single phase-to-ground fault, $|k|$ set according to tables A.6 and A.8 with protection zones and line impedance

Appendix B

Simulation of a Transmission Grid: Parameters and Results

B.1 Input Parameters and Design

Simulation parameters and design of the transmission network.

Voltage level	132 kV
S_{sc} source A	2446 MVA
Transformer capacity T_A	250 MVA
I_{sc} source A	10.7 kA
S_{sc} source H	2378 MVA
Transformer capacity T_H	250 MVA
I_{sc} source H	10.4 kA
S_{sc} generator	360 MVA
Transformer capacity T_{gen}	360 MVA
Transformer capacity T_L	25 MVA
Distance between phase conductors	6 m
Distance phase to ground	11 m
Diameter steel core phase conductors	0.8 cm
Diameter phase conductors	3 cm
Type of suspension	horizontal
Assumed ground resistance	$500\ \Omega \cdot m$

Table B.1: Network parameters and design

Line section	**Overhead line**		**Cable**		
	Z_1 [Ω]	Distance [km]	Z_1 [Ω]	C [μF]	Distance [km]
A - C	0.76 + j4.19	10.2	-	-	-
A - B	1.81 + j4.82	11.5	-	-	-
C - D	2.24 + j12.32	30.0	0.028 +j0.001	0.132	0.3
C - E	2.20 + j12.60	30.5	-	-	-
E - F	2.07 + j6.34	14.7	-	-	-
F - G	0.09 + j0.34	0.9	-	-	-
F - H	3.17 + j9.47	22.0	-	-	-
E - H	1.14 + j6.17	15.1	0.147 +j0.149	0.714	2.1
H - J	11.76 + j31.61	74.4	0.074 +j0.017	0.576	2.4
H - I	2.22 + j13.31	51.3	-	-	-
H - K	3.60 + j20.30	49.0	-	-	-
K - L	0.77 + j4.42	11.0	-	-	-
L - M	0.74 + j3.73	9.4	0.039 +j0.039	0.187	0.55
M - N	0.57 + j2.91	7.2	0.0204 +j0.094	0.094	0.55
N - O	0.53 + j2.75	6.9	-	-	-
O - P	0.21 + j1.08	2.7	-	-	-
O - Q	0.47 + j2.39	6.0	-	-	-
Q - R	2.72 + j14.66	40.9	-	-	-
Q - L	0.43 + j2.33	6.0	-	-	-

Table B.2: Given line and cable parameters

Remark: the cable in line section E - H consists of two groups of cables, each with the parameters given in table B.2. All cable parameters is given per cable, a cable group normally consisting of three cables.

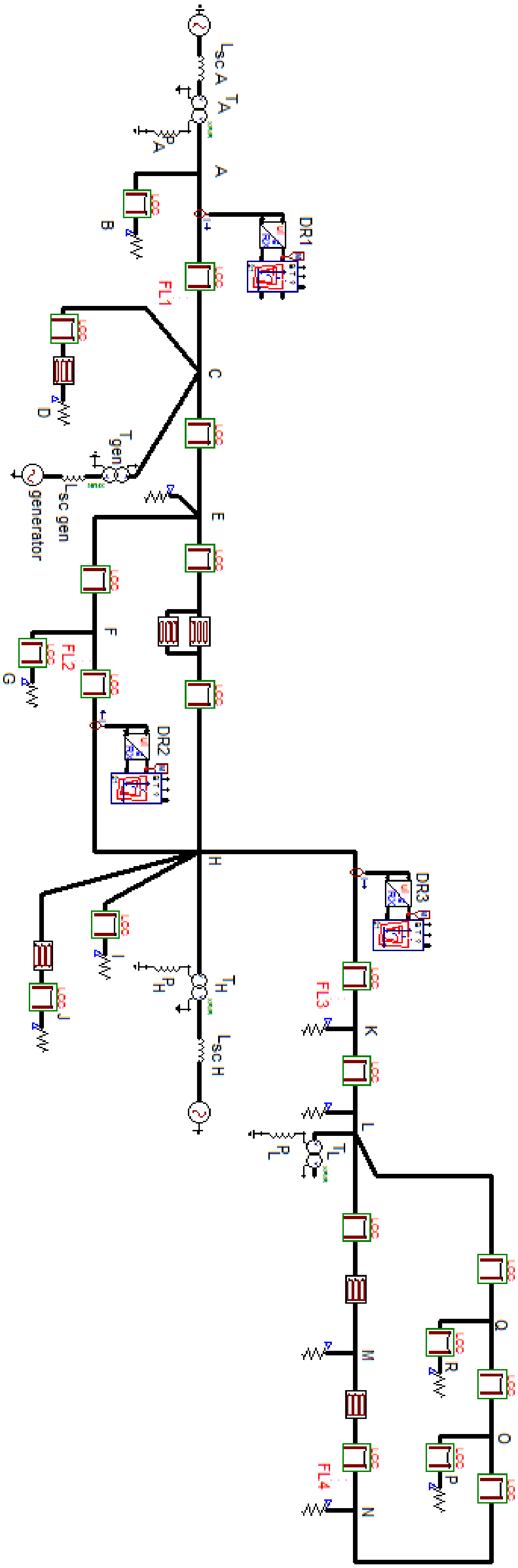

Figure B.1: ATPdraw model of transmission grid with compensated neutral earthing

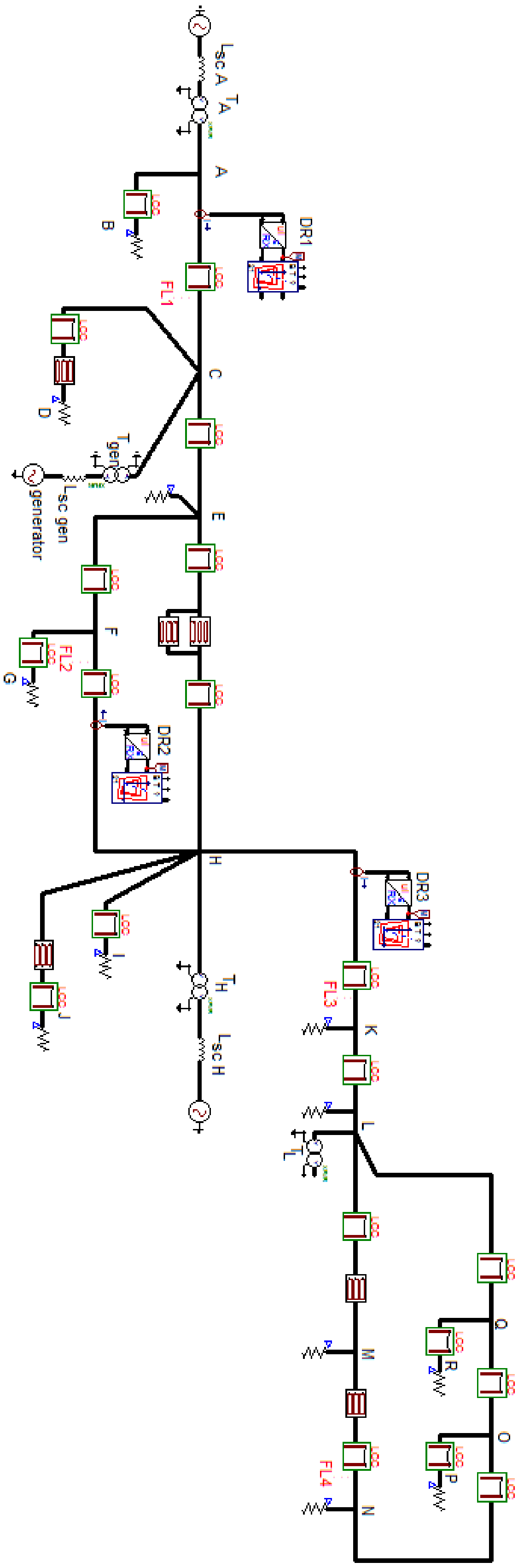

Figure B.2: ATPdraw model of transmission grid with solid neutral earthing

B.2 Simulated Parameters and Relay Settings

Output from the simulation models and the belonging distance relay settings.

Line section	**Total line** $\rho = 500\Omega m$		**Total line** $\rho = 100000\Omega m$		**Capacitance**
	Z_1 [Ω]	Z_0[Ω]	Z_1 [Ω]	Z_0[Ω]	C_0 [μF]
A - C	0.77 + j4.13	2.27 + j14.95	0.77 + j4.13	2.28 + j20.03	0.035
A - B	1.19 + j4.66	2.87 + j16.86	1.19 + j4.66	2.89 + j22.58	0.047
C - D	2.30 + j12.14	6.70 + j43.99	2.30 + j12.14	6.75 + j58.93	0.231
C - E	2.21 + j12.47	6.73 + j45.16	2.21 + j12.47	6.78 + j60.51	0.124
E - F	2.08 + j5.95	4.23 + j21.55	2.08 + j5.95	4.25 + j28.87	0.062
F - G	0.09 + j0.36	0.22 + j1.32	0.09 + j0.36	0.22 + j1.77	0.003
F - H	3.18 + j8.91	6.40 + j32.25	3.18 + j8.91	6.44 + j43.21	0.104
E - H	1.22 + j6.19	3.44 + j22.25	1.22 + j6.19	3.47 + j29.81	1.202
H - J	11.92 + j30.36	23.16 + j110.17	11.92 + j30.36	23.42 + j 148.00	0.723
H - I	2.28 + j20.77	9.80 + j72.27	2.28 + j20.77	9.89 + j100.87	0.217
H - K	3.62 + j19.84	10.81 + j71.89	3.62 + j19.84	10.90 + j96.34	0.205
K - L	0.78 + j4.45	2.39 + j16.12	0.78 + j4.45	2.41 + j21.60	0.044
L - M	0.79 + j3.84	2.16 + j13.82	0.79 + j3.84	2.18 + j18.50	0.202
M - N	0.61 + j3.09	1.70 + j10.94	0.61 + j3.09	1.71 + j14.63	0.117
N - O	0.54 + j2.79	1.55 + j10.11	0.54 + j2.79	1.56 + j13.55	0.020
O - P	0.22 + j1.09	0.61 + j3.96	0.22 + j1.09	0.62 + j5.30	0.013
O - Q	0.47 + j2.43	1.35 + j8.79	0.47 + j2.43	1.36 + j11.78	0.015
Q - R	3.02 + j16.56	9.02 + j59.99	3.02 + j16.56	9.09 + j80.38	0.208
Q - L	0.44 + j2.43	1.32 + j8.79	0.44 + j2.43	1.32 + j11.78	0.015

Table B.3: Simulated line and cable parameters

Relay	**Line**	**Zone 1** $= 0,8 \cdot jX_1$	**Zone 2** $= 1,2 \cdot jX_1$	**Zone 3** $= 1.2 \cdot jX_{1\ line} + jX_{1\ next\ line}$	$\lvert k \rvert$
DR1	A-C	3.302	4.954	19.914	2.600
DR2	H-F	7.124	10.686	17.826	2.478
DR3	H-K	15.871	23.807	29.149	2.605

Table B.4: Relay protection zones

B.3 Relay Measurements

The measurements made by the distance relays for different fault scenarios.

B.3.1 Compensated Network

Impedance Measured by DR1

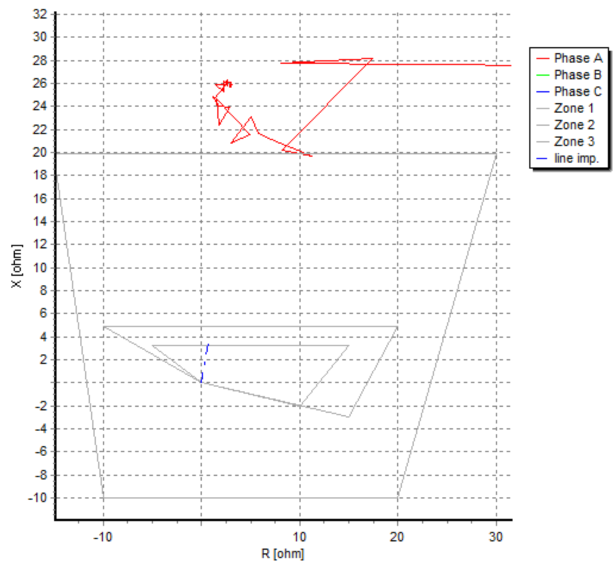

Figure B.3: Seen by DR1 for fault at phase a in fault location 1

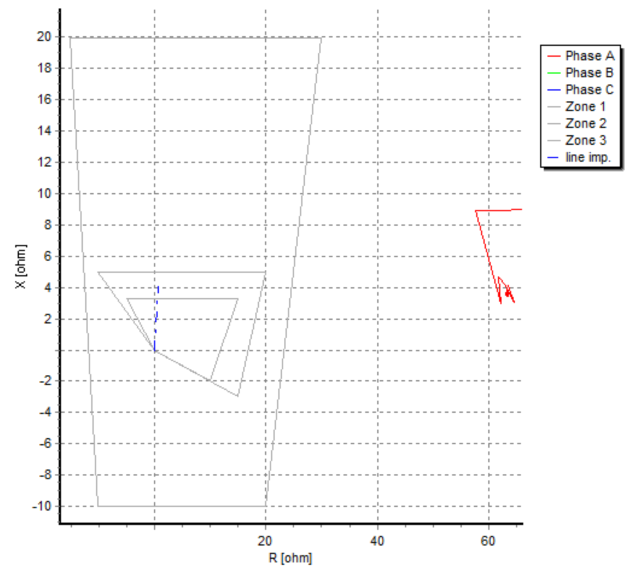

Figure B.4: Seen by DR1 for fault at phase a in FL1 and fault at phase b in FL2

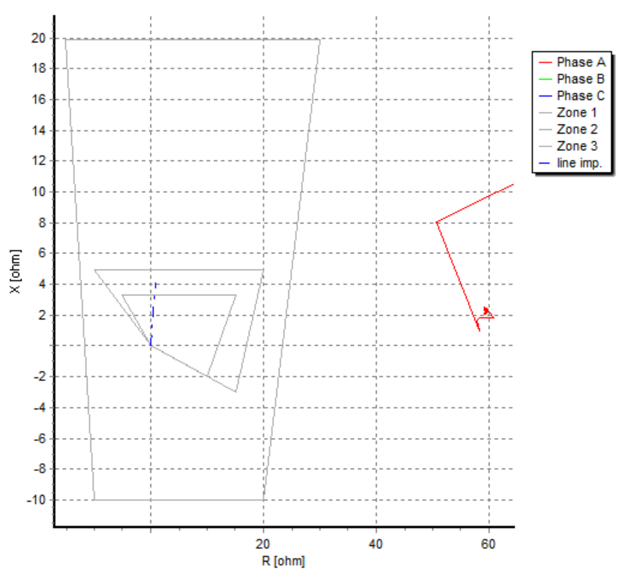

Figure B.5: Seen by DR1 for fault at phase a in FL1 and fault at phase b in FL3

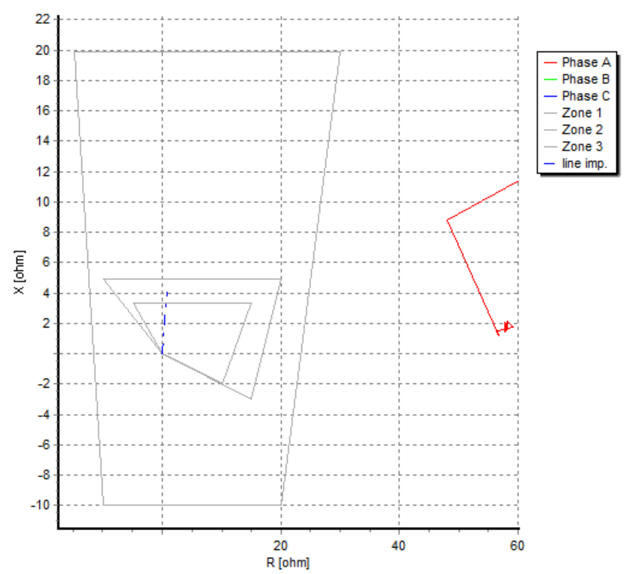

Figure B.6: Seen by DR1 for fault at phase a in FL1 and fault at phase b in FL4

Impedance Measured by DR2

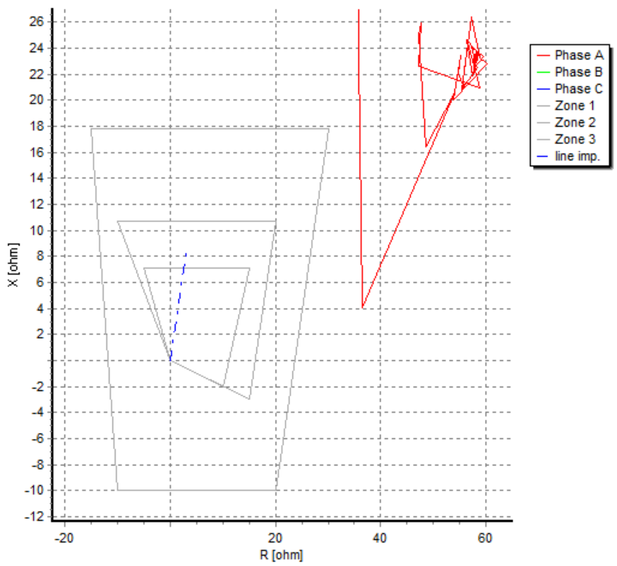

Figure B.7: Seen by DR2 for fault at phase a in fault location 2

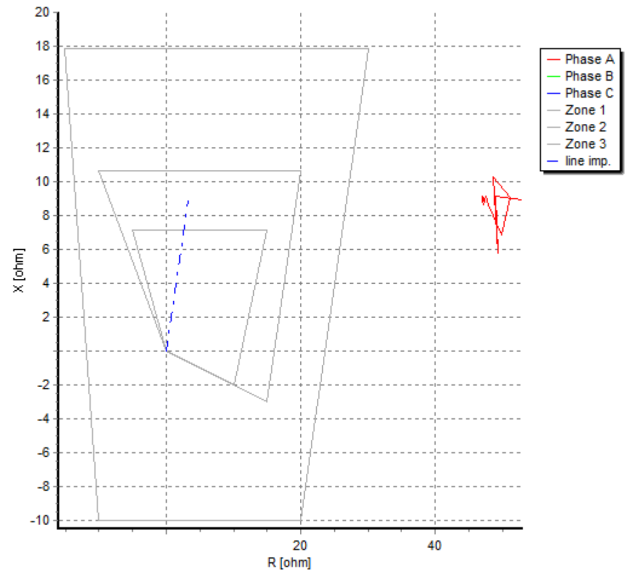

Figure B.8: Seen by DR2 for fault at phase a in FL2 and fault at phase b in FL1

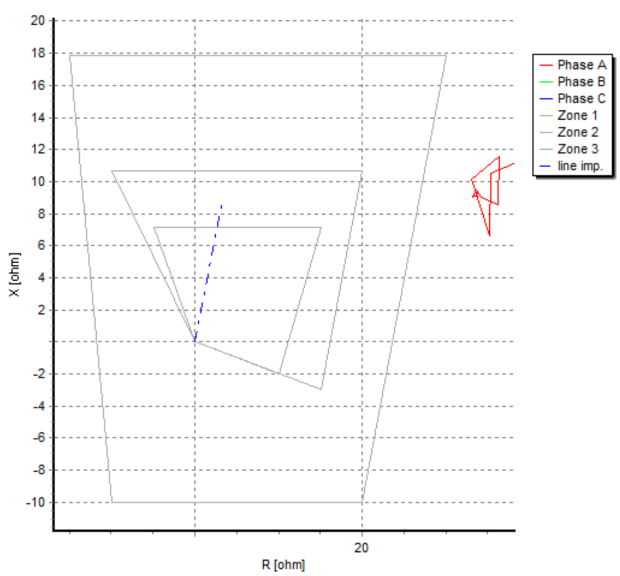

Figure B.9: Seen by DR2 for fault at phase a in FL2 and fault at phase b in FL3

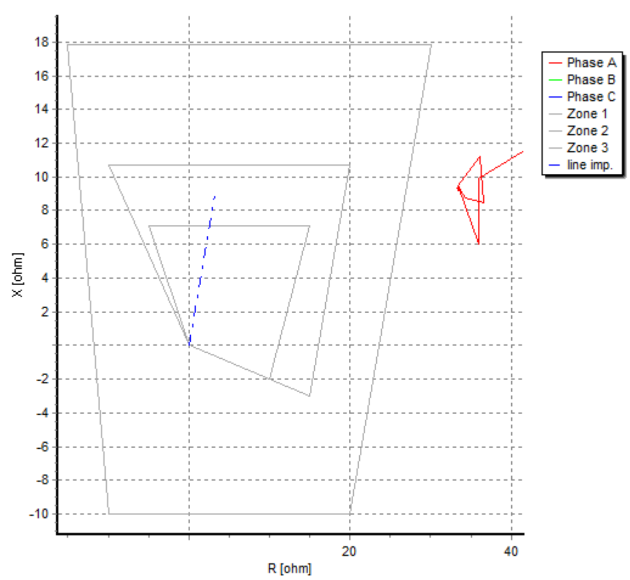

Figure B.10: Seen by DR2 for fault at phase a in FL2 and fault at phase b in FL4

Impedance measured by DR3

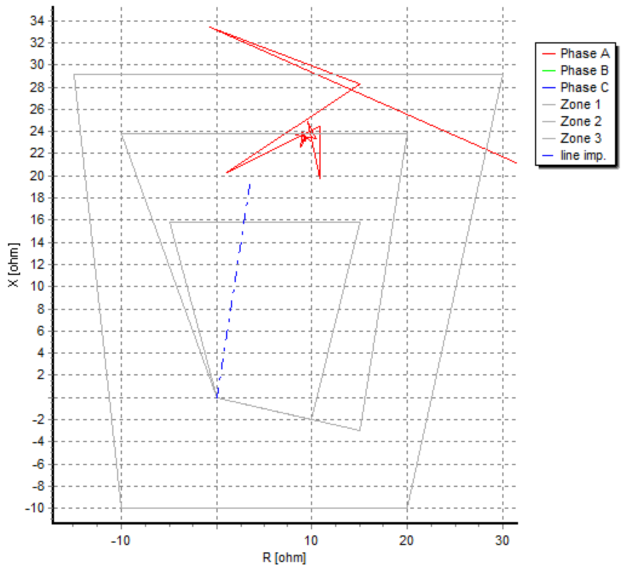

Figure B.11: Seen by DR3 for fault at phase in fault location 3

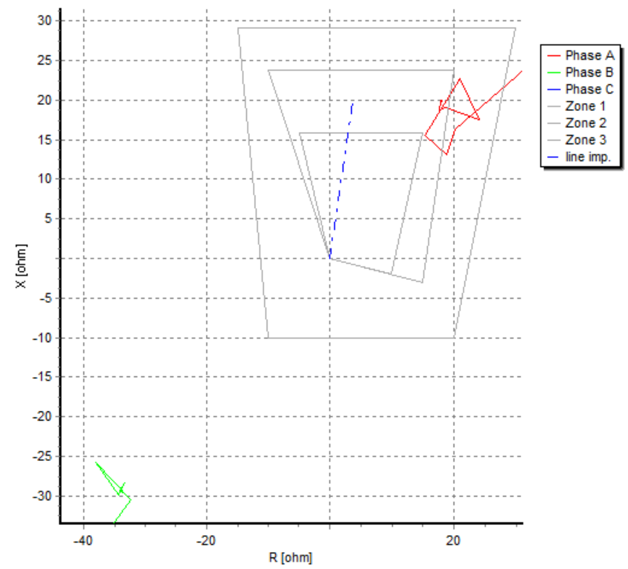

Figure B.12: Seen by DR3 for fault at phase a in FL3 and fault at phase b in FL1

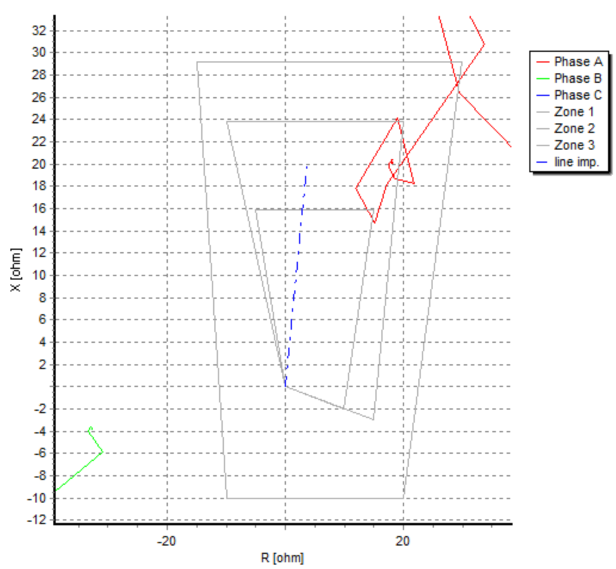

Figure B.13: Seen by DR3 for fault at phase a in FL3 and fault at phase b in FL2

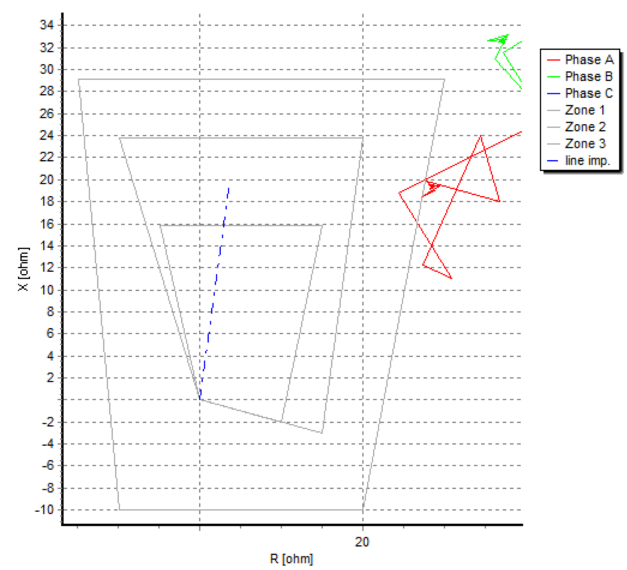

Figure B.14: Seen by DR3 for fault at phase a in FL3 and fault at phase b in FL4

B.3.2 Solid Grounded Network

Impedance Measured by DR1

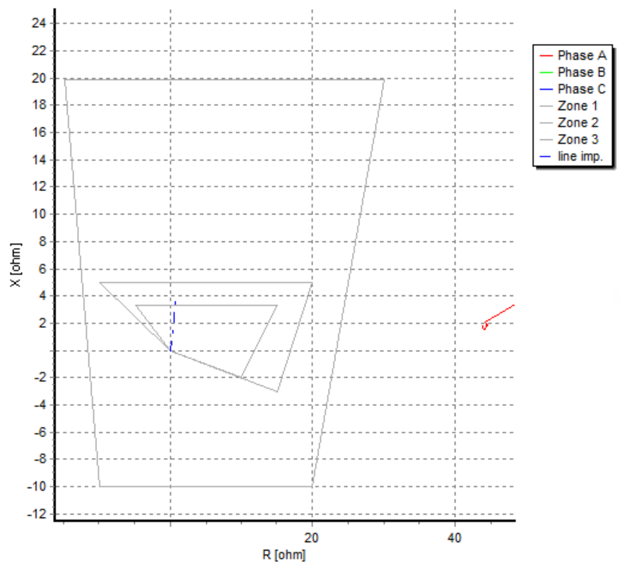

Figure B.15: Seen by DR1 for fault at phase a in fault location 1, $\rho = 500\Omega m$

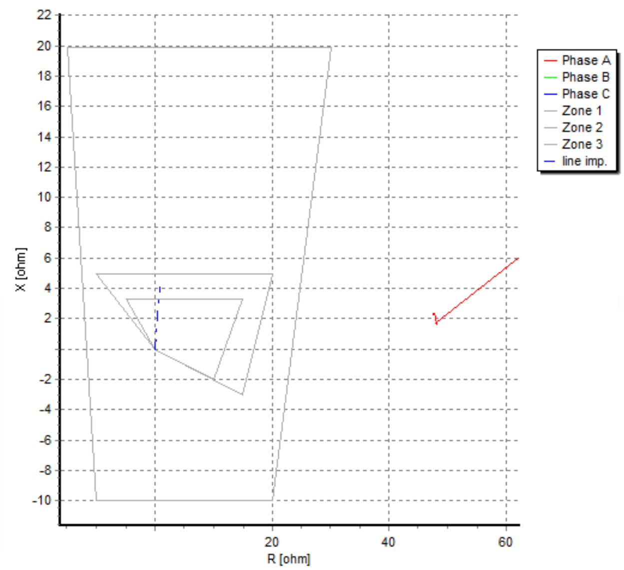

Figure B.16: Seen by DR1 for fault at phase a in fault location 1, $\rho = 100000\Omega m$

Impedance Measured by DR2

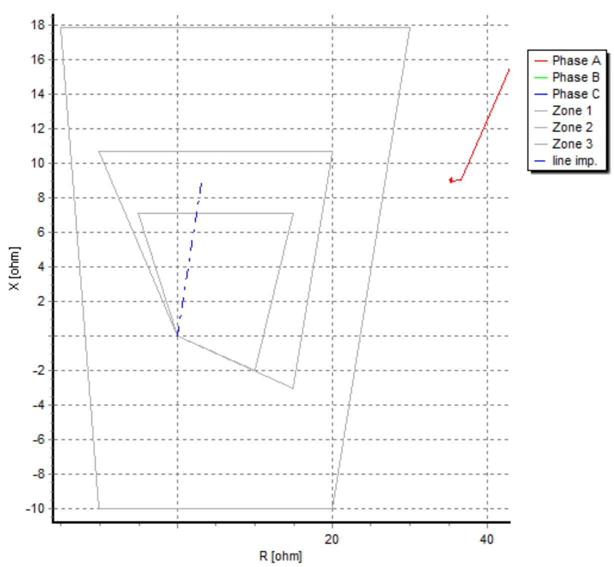

Figure B.17: Seen by DR2 for fault at phase a in fault location 2, $\rho = 500\Omega m$

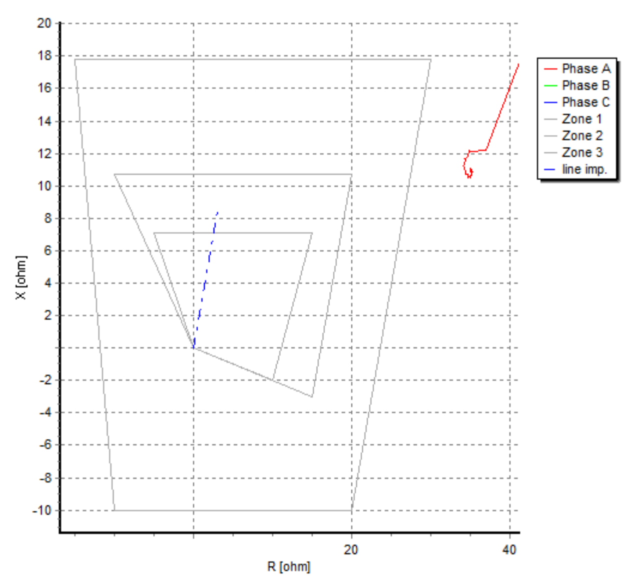

Figure B.18: Seen by DR2 for fault at phase a in fault location 2, $\rho = 100000\Omega m$

Impedance Measured by DR3

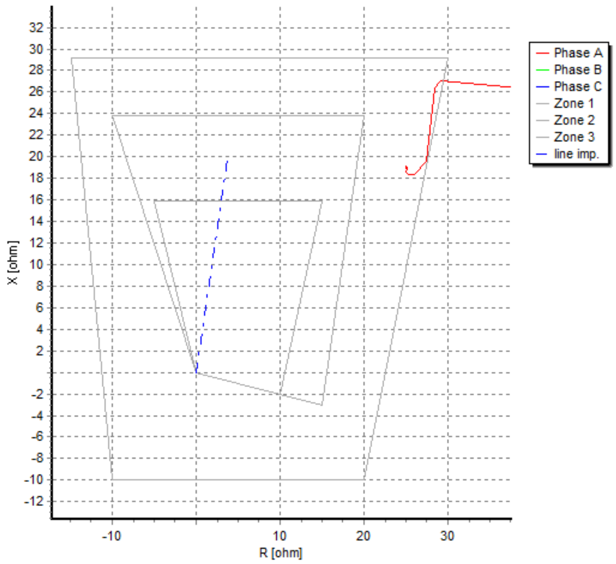

Figure B.19: Seen by DR3 for fault at phase a in fault location 3, $\rho = 500\Omega m$

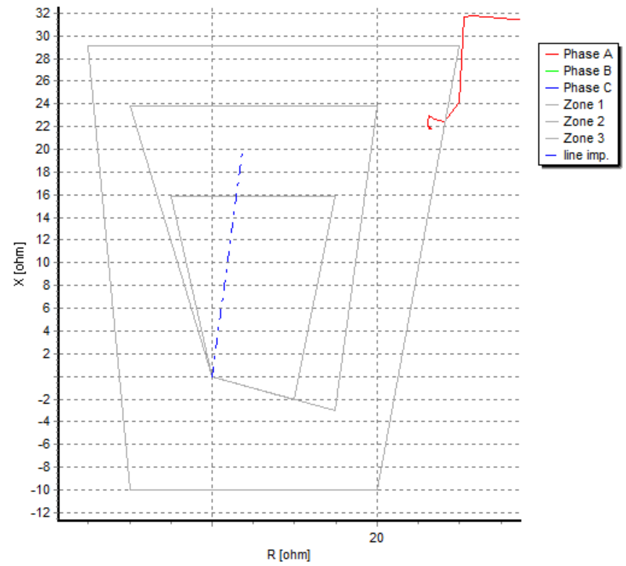

Figure B.20: Seen by DR3 for fault at phase a in fault location 3, $\rho = 100000\Omega m$