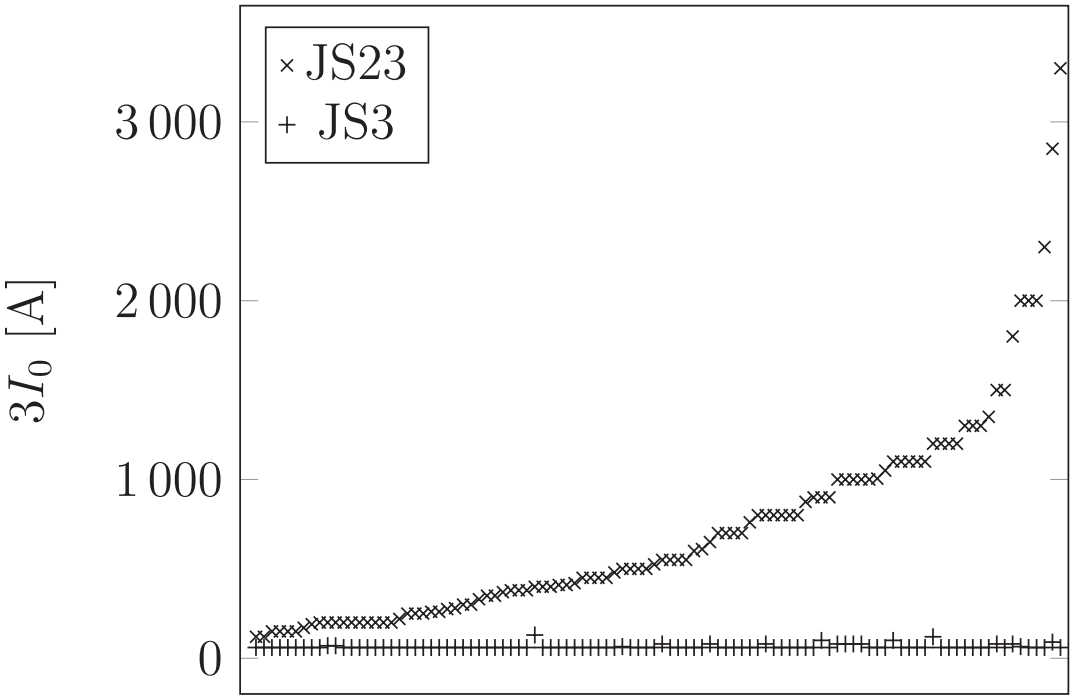

Benefits with inverse time relay protection in regional transmission grids

Master's thesis in Electrical Engineering

MAX BÖRJESSON

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CHALMERS UNIVERSITY OF TECHNOLOGY
Gothenburg, Sweden 2020
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VATTENFALL

Master's thesis 2020

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Cover: Current magnitude of JS3 and JS4 for various bays in Vattenfalls 130 kV network.

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Abstract

In regional transmission grids the residual current protection traditionally consists of four steps with different current threshold and time settings. The last step has a constant current threshold generally set to 60 A, a requirement set to avoid induced currents onto telecommunication wires. It also lacks a directional element and is therefore unselective. In later years the gap between the current thresholds of the last two steps has increased in many line bays due to expansion of the grid. Unselective clearing of faults has as a result of this also increased.
Simulations of the residual current protection are done on a grid model to demonstrate the problems due to the non-directional residual current step. The non-directional step is then replaced by a step with an inverse time characteristic with the necessary requirements, which shows substantial improvement of the selectivity.

Acknowledgements

I want to thank Stig Holst and Sture Lindahl for help with finding material that was crucial for the thesis. Also, i also want to thank Niklas Svensson, Svenska kraftnät, for the briefing about Svenska kraftnäts relay protection. Finally i want to thank my supervisor Professor Per Norberg, Chalmers University of Technology/Vattenfall Eldistribution AB, without whose help this had not been possible.

Max Börjesson, Järnskogsboda, July 2020

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1
Introduction

1.1 Background

For a secure operation of power systems, it is fundamental to protect the system from fault conditions. To achieve a high reliability faults needs to be disconnected selectively which places strict requirements on the protection equipment.

1.1.1 History

A brief history of, for the report, important technical considerations in Vattenfalls regional transmission grid that have impact on the work. Since the regional transmission grids largely have followed the development of national transmission grid its history is also presented.

1.1.1.1 Residual current protection

Relay protection for transmission networks has for decades been built up by distance protection. Two major factors that have contributed to the need of the non-directional earth current protection has been the requirement to detect small residual currents caused by line breaks and high earth impedance faults. The latter arise from the use of wooden poles with isolated cross bars previously installed by Vattenfall and still a overall majority of the overhead lines.

During the 1950's the Swedish national and regional transmission grids was directly earthed. Due to this reliable fault protection became a necessity since direct earthing can cause high zero sequence currents compared to other earthing techniques. Due to demands from the telecommunication agency even small zero sequence currents needs to be disconnected since they can cause disturbances in the telecommunication network, for 130 kV networks the requirement was set to 60 A and for 220 and 380 kV[1] networks 100 A was decided as the requirement [1]. For consultation between the telecommunication agency and the electricity network operators the Telecommunication Interference Board, Telestörningsnämnden (TSN), was established.

For better reliability earth fault current protection was introduced with three steps called JS1, JS2 and JS3. The idea behind the three steps is that they have different time settings and current thresholds. The first two steps also had directional elements and can therefore clear faults with selectivity if set correctly. However,

[1] Later increased to 400 kV.

because of the residual current requirement of JS3 the current threshold was needed to be set to the one demanded by the telecommunication agency and because of the lack of directional element (due to technical reasons). JS3 came to lack the possibility of clearing faults with selectivity. However, this was no practical problem when this solution was chosen.

Because of further expansion of the national transmission grid the distance between stations decreased which increased the current settings of the first two steps. However, as mentioned above JS3 had a mandatory setting which was not increased. As a result many faults were cleared unselective by JS3 with large power outages. To counter this problem a fourth step was introduced with its current threshold set between JS2 and JS3, this new step was called JS23. The purpose was to shrink the gap above JS3 to minimise unselective clearing.

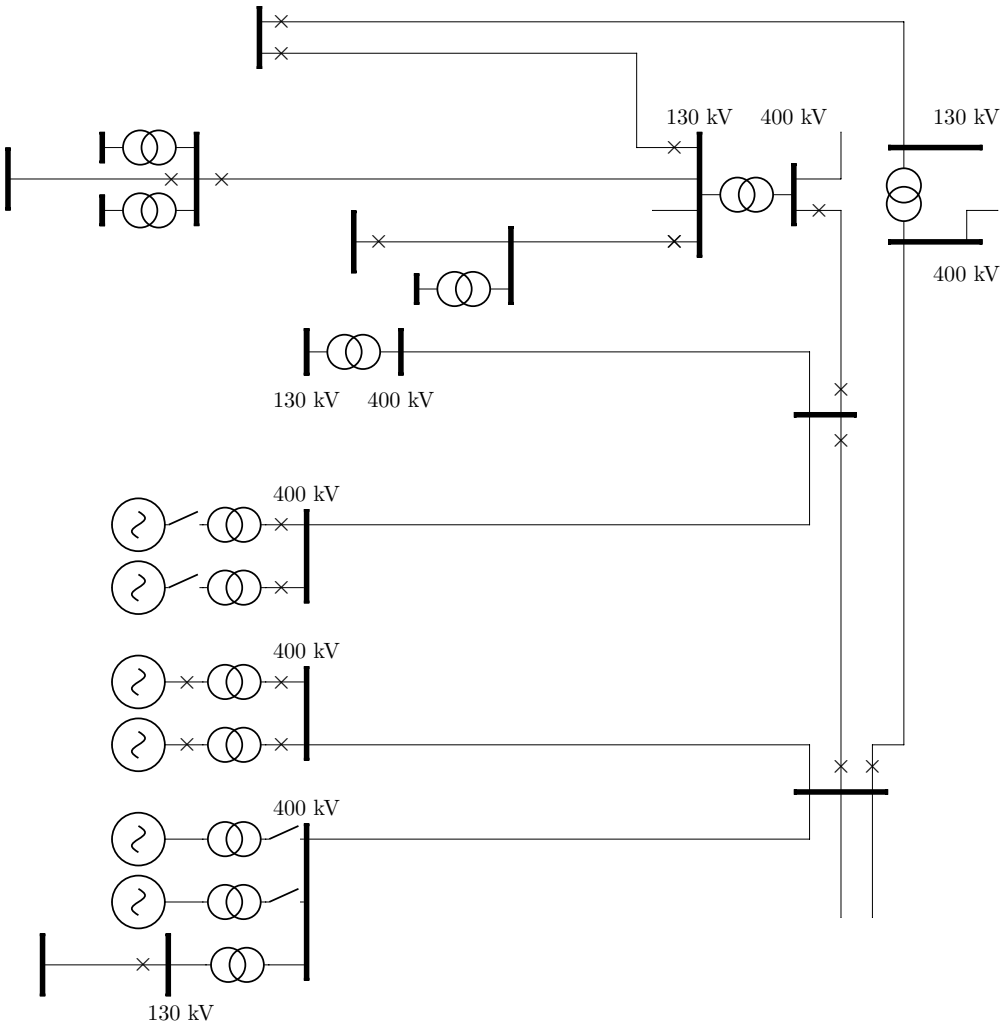


Figure 1.1: One-line diagram of a disturbance on June 23 1979 in the area around Ringhals [1]. × marks a breaker that was tripped by JS3. The fault location is unknown.

However, in the end of the 1970's when the national transmission grid had been expanded even further and similar problems occured but this time between JS23 and JS3. Two of the most severe disturbances occurred in 1979. The first one on June 23 close to the nuclear power plant Ringhals. As can be seen in Figure 1.1

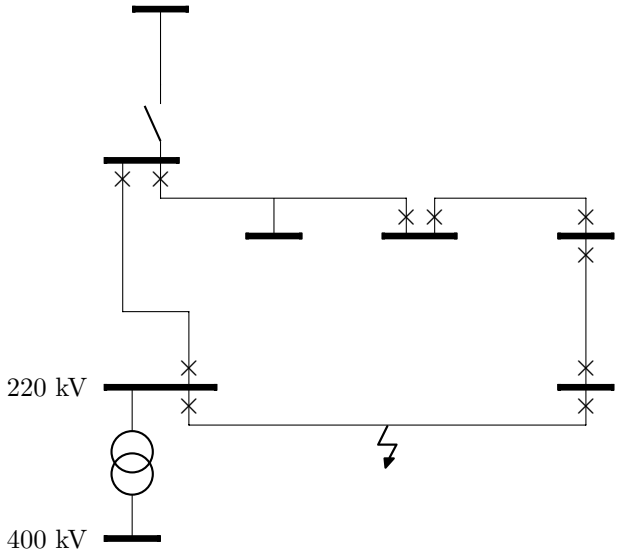


Figure 1.2: One-line diagram of a disturbance on June 25 1979 in the Stockholm area [1]. × marks a breaker that was tripped by JS3. The open line was out of service at the time of the disturbance.

several 400 kV and 130 kV lines were disconnected in either one or both ends due to an unknown fault. Worse though were that reactor 1 was disconnected, if the other two[2] had been in operation vast consequences would have followed [1].

The second disturbance occurred two days later on June 25 in the Stockholm area after an automatic re-connection of a line due to a lightning strike (probably due to unsymmetrical operation of one of the breakers) [1]. A one-line diagram showing the disturbance can be seen in Figure 1.2, as can be seen every line in the area has tripped. To avoid similar problems in the future, inverse time relays were proposed and introduced as a replacement of the constant time of the JS3 relay and the clearing time became dependent upon the residual current which made also the JS3 selective. The regional transmission grids did not have these problems at the time and the regional system operators were instead advised to introduce JS23 in the 130 kV network, as had been done before in the national transmission grid [1]. The question of inverse time in the 130 kV regional transmission grids was postponed to be taken up for consideration in the future. When it has been evaluated for the 220 kV and 400 kV networks.

1.1.2 The situation today

Faults in directly earthed power systems is often low ohmic which results in large fault currents with magnitudes of several kilo amperes which are easy to detect, however, faults can also be high ohmic.

Since 1980's the situation in Vattenfalls 130 kV network has become more problematic with an increased selective gap mainly in tightly meshed parts of the network which has led to unselective clearing of faults. Relay protection mainly consists of the previously mentioned residual current protection but also distance protection.

[2]Ringhals 4 was not completed at the time.

During recent year Line Differential Protection (LDP) and Busbar Differential Protection (BDP) has been installed and in comparison with residual current protection these are absolute selective (i.e. it only detects faults on the line or equipment that it is protecting).

When new transmission lines are built the cross bars are earthed which lowers the possibility of high ohmic faults. Also, with the introduction of LDP and BDP in the network, earth faults can now be detected with absolute selectivity. However, faults can also occur between towers which result in higher fault impedance's due to the resistance of the soil. Also, loss of a phase also causes small zero sequence currents and problems similar to a high ohmic fault. This can cause undesirable disconnections with loss of many lines and a breakdown of the network, with consequences for society, due to the constant time characteristic of non-directional earth fault protection. Due to this, alternatives to the standard non-directional earth fault protection has been discussed. Today, as mentioned above, Svenska kraftnät uses an inverse time relay in the 220 and 400 kV transmission system where the operating time of the last stage depends on the magnitude of the fault current. Earth fault currents can cause interference and damages to telecommunication equipment. However, due to the replacement of copper wires with fiber optics this may decrease the demand on the earth fault protection. With an increasing need of operational reliability of the regional transmission grid there is a need to investigate how to decrease undesirable disconnections.

1.2 Aim

This project will investigate the impact of implementing the inverse time relays in 130 kV systems for improving the selectivity for residual current protection by investigating existing protection methods deployed in the transimssion grid.

1.3 Limitations

The project will only look into directly earthed 130 kV systems with the protective relay structure used in Vattenfalls regional transmission grids.

1.4 Specification of issue under investigation

To carry out the project several issues have to be dealt with. Inverse time characteristic of the non-directional relays in the investigated system needs to be calculated.

The other relays in the protective relay structure shall be investigated as well. Earth fault current protection as well as line differential protection and distance protection should be investigated.

Consequences to the surroundings of the system due to earth fault currents such as earth potentials and interference to telecommunications needs to be investigated.

Any proposed changes in relay structure need to be done cautiously to ensure that selectivity is preserved. Regulations and standards needs to be fulfilled to

ensure safety of people and property in the surroundings of the system.

1.5 Method

The project will primarly be conducted in two steps: literature review and simulations.

1.5.1 Literature review

A literature review will be conducted on the subjects of symmetrical components, fault impedance, line differential protection, non-directional earth fault protection and other types of protection in use.

1.5.2 Simulations

To ensure desired behaviour of the relay protection during operation, i.e. loaded system, simulations will be conducted in PSS®E. The simulations will be used to verify that the relay protection is sufficient to fullfill regulations, standards and ensure high operational reliability.

More specifically different cases of small zero sequence currents that trigger the non-directional residual current protection, slightly above 60 A, will be investigated. These low zero sequence currents can originate from both shunt and series faults so both of these will be tested for and how the protective relays will function during such conditions.

2

Fault analysis in three-phase systems

This chapter describes the theoretical background for analysis of unsymmetrical faults in a three-phase power system and the different types of faults used in for fault analysis. The chapter is largely based on [2] if not otherwise stated.

2.1 Symmetrical components

A general unsymmetrical three-phase system can be represented as three symmetrical components called positive, negative and zero sequence component [3]. The phasor diagrams for a general unsymmetrical three-phase system is show in Figure 2.1.

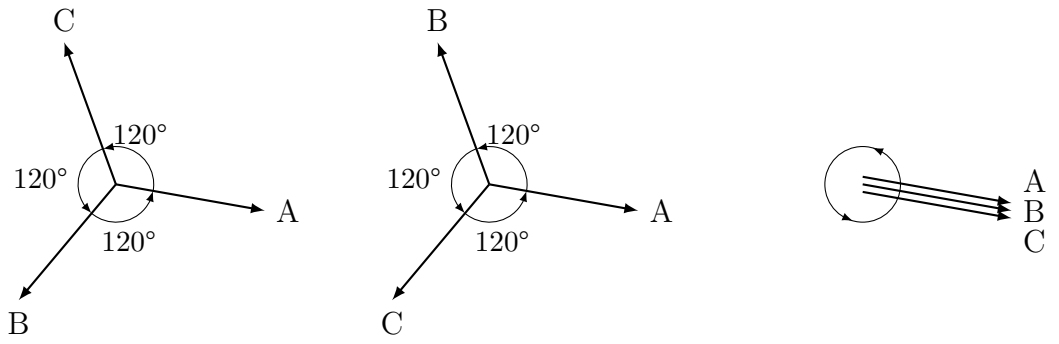


Figure 2.1: Phasor diagram for the positive (a), negative (b) and zero sequence (c) components.

The transformation between the phase components and the symmetrical components is called Fortescue transformation, which is written as

$$\begin{bmatrix} U_0 \\ U_+ \\ U_- \end{bmatrix} = \frac{1}{3} \begin{bmatrix} 1 & 1 & 1 \\ 1 & \alpha & \alpha^2 \\ 1 & \alpha^2 & \alpha \end{bmatrix} \begin{bmatrix} U_A \\ U_B \\ U_C \end{bmatrix} \tag{2.1}$$

for voltage and

$$\begin{bmatrix} I_0 \\ I_+ \\ I_- \end{bmatrix} = \frac{1}{3} \begin{bmatrix} 1 & 1 & 1 \\ 1 & \alpha & \alpha^2 \\ 1 & \alpha^2 & \alpha \end{bmatrix} \begin{bmatrix} I_A \\ I_B \\ I_C \end{bmatrix} \tag{2.2}$$

for current. U_A, U_B, U_C, I_A, I_B and I_C are the phase components and U_+, U_-, U_0, I_+, I_- and I_0 are the symmetrical components per phase [3]. The inverse of the Fortescue transformation can be written as

$$\begin{bmatrix} U_A \\ U_B \\ U_C \end{bmatrix} = \begin{bmatrix} 1 & 1 & 1 \\ 1 & \alpha^2 & \alpha \\ 1 & \alpha & \alpha^2 \end{bmatrix} \begin{bmatrix} U_0 \\ U_+ \\ U_- \end{bmatrix} \tag{2.3}$$

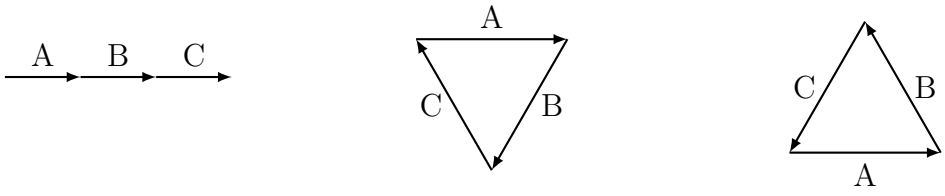
for voltage and

$$\begin{bmatrix} I_A \\ I_B \\ I_C \end{bmatrix} = \begin{bmatrix} 1 & 1 & 1 \\ 1 & \alpha^2 & \alpha \\ 1 & \alpha & \alpha^2 \end{bmatrix} \begin{bmatrix} I_0 \\ I_+ \\ I_- \end{bmatrix} \tag{2.4}$$

for current. α is the phasor operator and is equal to

$$\alpha = e^{\frac{2\pi i}{3}} = 1\underline{/120°} \tag{2.5}$$

and is used to rotate a phasor with 120° in anticlockwise direction. As shown in Figure 2.2 during symmetrical conditions the negative and zero sequence component will be 0, independent of the phase magnitudes.



(a) **(b)** **(c)**

Figure 2.2: Vector addition of the postive (a), negative (b) and zero sequence (c) components. During symmetrical conditions the negative and zero sequence will cancel out.

2.2 Thévenins theorem

According to Thévenins theorem a network can always be represented as a single voltage source and impedance, this is also true for each of the symmetrical components. However, different voltages and impedance values are used for shunt and series faults [2].

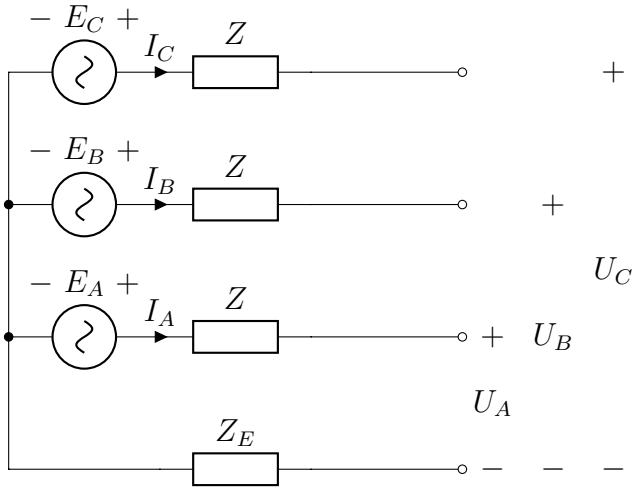


Figure 2.3: The three-phase Thévenin equivalent circuit.

2.2.1 Shunt fault

The Thévenin equivalent circuit for a three-phase power system is shown in Figure 2.3. During no-load condition using (2.1) and (2.2) it can be shown that

$$I_+ = I_- = I_0 = 0 \tag{2.6a}$$

$$U_- = U_0 = 0 \tag{2.6b}$$

$$U_+ = E_+ \tag{2.6c}$$

where E_+ is the Thévenin voltage of the positive sequence network which is equal to the Thévenin voltage of the reference phase. The relationship between the symmetrical components can for the general case therefore be written as

$$U_+ + Z_+ I_+ = E_+ \tag{2.7a}$$

$$U_- + Z_- I_- = 0 \tag{2.7b}$$

$$U_0 + Z_0 I_0 = 0 \tag{2.7c}$$

which also can be represented as sequence networks (see Figure 2.4).

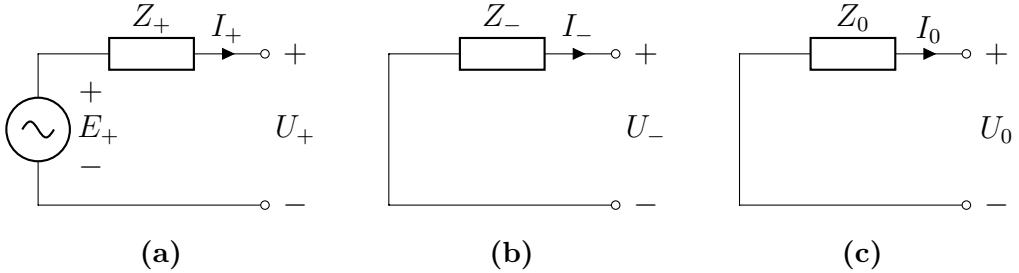


Figure 2.4: Thévenin equivalent sequence networks. (a) shows the positive, (b) the negative and (c) the zero sequence network.

For shunt faults (i.e. phase to phase and phase to earth faults) the positive sequence impedance is equal to the Thévenin impedance during steady state [2].

The negative sequence impedance can for line and transformers be set to that of the positive sequence which can be set to the Thévenin impedance

$$Z_+ = Z_- = Z \tag{2.8}$$

[2], [3]. The zero sequence impedance, Z_0, is largely dependent on the impedance of the neutral path, Z_E, including earthing conductors for the lines and transformer shunt impedances [2], [3].

2.2.2 Series fault

For a series fault a two-port is used to represent the difference between the two buses as shown in Figure 2.5. Similar to shunt faults the relationship between voltage and current for sequence component can be written as

$$\Delta U_+ + Z_{+(aa')} I_+ = \Delta E_+ \tag{2.9a}$$
$$\Delta U_- + Z_{-(aa')} I_- = 0 \tag{2.9b}$$
$$\Delta U_0 + Z_{0(aa')} I_0 = 0. \tag{2.9c}$$

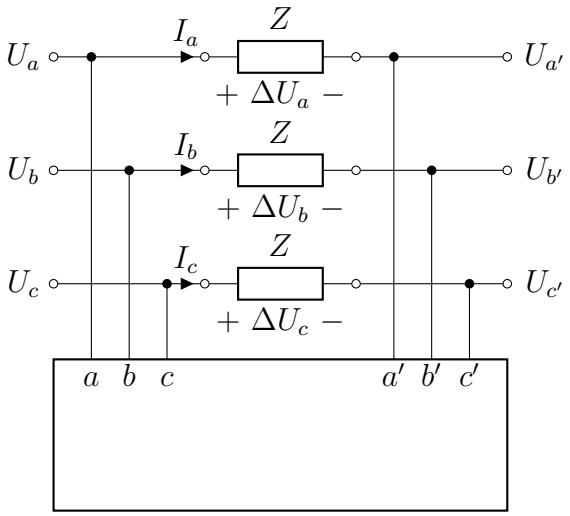


Figure 2.5: The three-phase Thévenin equivalent circuit for series fault calculations between two buses. The two-port represents the rest of the network.

These equations represent the two port which can be represented as sequence networks as shown in Figure 2.6.

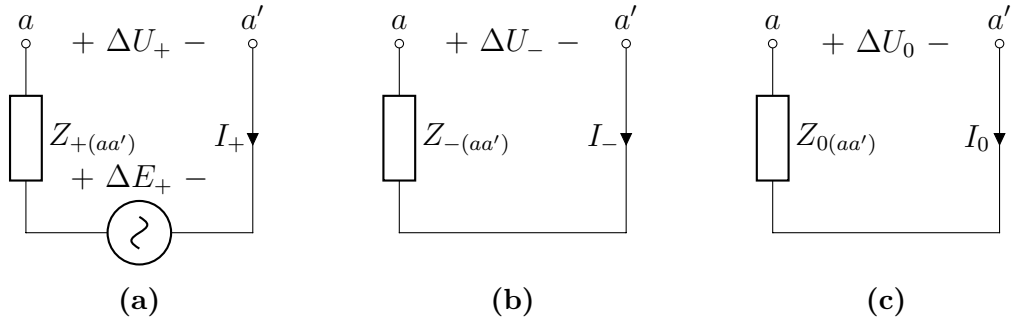


Figure 2.6: (a) shows the positive, (b) the negative and (c) the zero sequence network.

2.3 Fault calculation

Faults in a three phase system can mostly be divided into two different categories: series and shunt faults.In addition to this, combinations between the two types can also occur.

2.3.1 Shunt faults

A shunt fault occurs when there is an electrical connection between either multiple phases or at least one phase and earth. In regional and national transmission grids with tree safe lines shunt faults are generally caused by lightning strikes.

2.3.1.1 Three phase fault

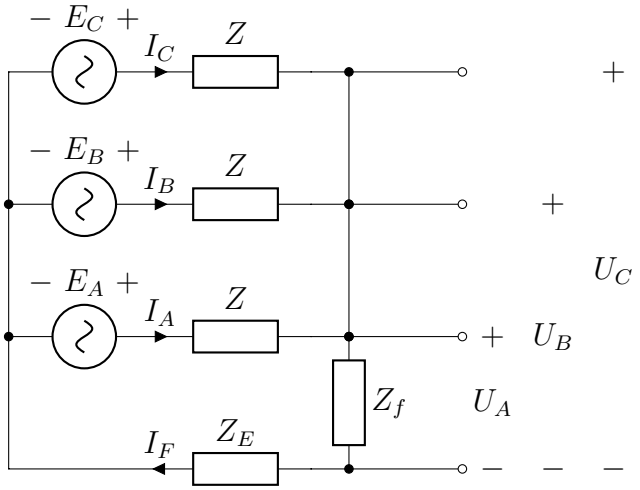


Figure 2.7: Three phases to earth fault.

During a symmetrical three-phase fault the magnitude of the phase currents will be equal

$$|I_A| = |I_B| = |I_C| \tag{2.10}$$

with a phase difference of 120°. From (2.2) it can be concluded that this does not result in either a negative nor zero sequence current. As a result no current will flow

through the fault impedance between the phases and earth. Instead the currents will return through the other phases.

2.3.1.2 Phase to phase fault

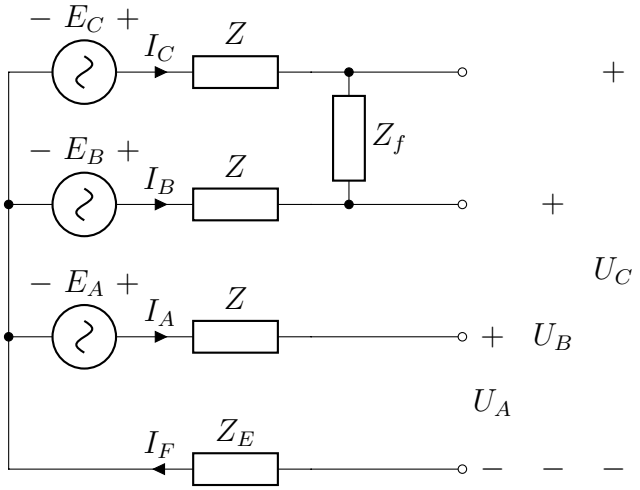


Figure 2.8: Phase to phase fault.

For a phase to phase fault it can be seen in Figure 2.8 the currents will be

$$I_A = 0 \tag{2.11a}$$
$$I_B + I_C = 0 \tag{2.11b}$$
$$U_B - U_C = Z_f I_B. \tag{2.11c}$$

By using (2.2) it can be represented as the symmetrical components

$$I_0 = 0 \tag{2.12a}$$
$$I_+ + I_- = 0 \tag{2.12b}$$
$$U_+ - U_- = Z_f I_+. \tag{2.12c}$$

From (2.7) it can be seen that

$$U_+ - U_- = E_+ - Z_+ I_+ - (-Z_- I_-) = Z_f I_+ \tag{2.13}$$

and since (2.12b) it can be concluded that

$$I_+ = -I_- = \frac{E_+}{Z_+ + Z_- + Z_f}. \tag{2.14}$$

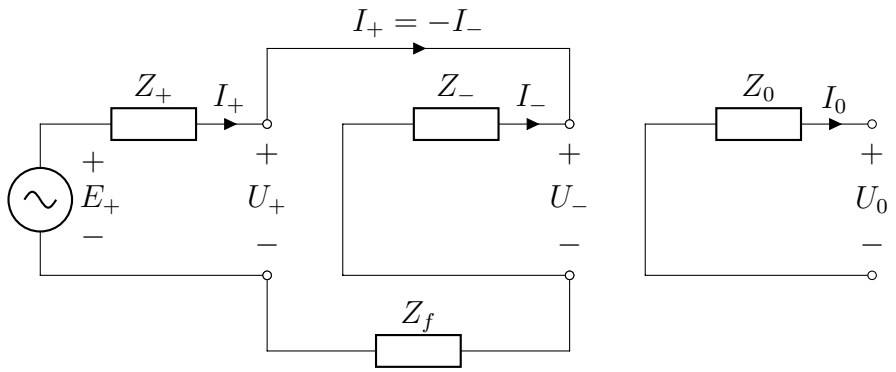


Figure 2.9: The sequence networks connected together for a phase to phase fault.

2.3.1.3 Dual phase to earth fault

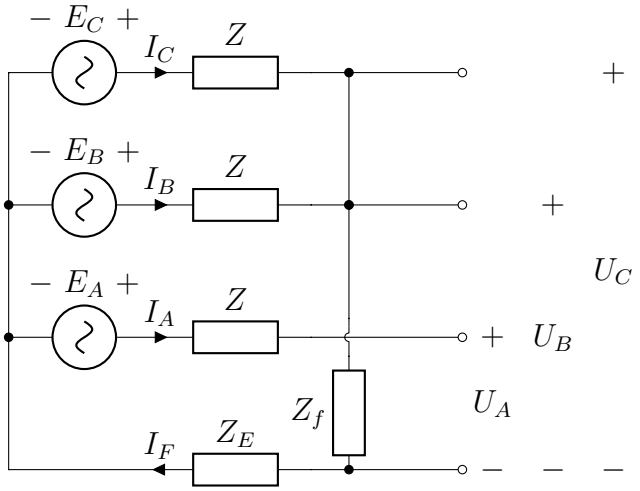


Figure 2.10: A dual phase to phase fault.

Dual phase to phase fault is when two phases are short circuited and with a common impedance to earth as shown in Figure 2.10. It can be seen that the earth fault current can be expressed as

$$I_A = 0 \tag{2.15a}$$
$$I_F = I_B + I_C. \tag{2.15b}$$

$$U_B = U_C = Z_f(I_B + I_C) \tag{2.16}$$

From (2.4)

$$I_A = I_0 + I_+ + I_- = 0. \tag{2.17}$$

Using (2.3) and (2.16) it can be concluded that

$$U_0 + \alpha^2 U_+ + \alpha U_- = U_0 + \alpha U_+ + \alpha^2 U_- \tag{2.18}$$

thus

$$U_+ = U_- \tag{2.19}$$

From this it can be concluded that

$$U_B = V_0 + \alpha^2 U_+ + \alpha U_- = V_0 + (\alpha^2 + \alpha)U_+. \tag{2.20}$$

$$\begin{aligned} I_B + I_C &= (I_0 + \alpha^2 I_+ + \alpha I_-) + (I_0 + \alpha I_+ + \alpha^2 I_-) \\ &= 2I_0 + (\alpha^2 + \alpha)(I_+ + I_-) = 3I_0. \end{aligned} \tag{2.21}$$

By combining (2.16), (2.20) and (2.21) it can be concluded that

$$U_0 = U_+ + 3Z_f I_0. \tag{2.22}$$

Equation (2.19) and (2.22) results in the sequence network shown in Figure 2.9. The

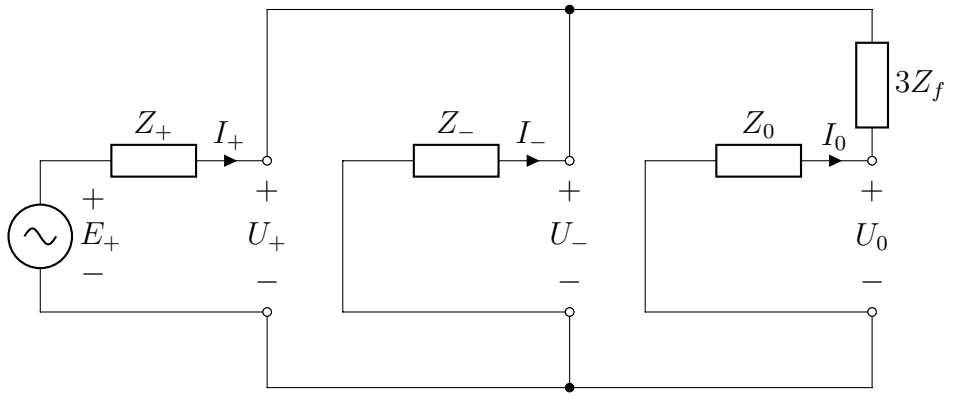


Figure 2.11: The sequence networks connected together for a dual phase to earth fault.

sequence current can then be derived

$$I_+ = \frac{E_+}{Z_+ + \frac{Z_-(Z_0+3Z_f)}{Z_-+Z_0+3Z_f}} \tag{2.23a}$$

$$I_- = -I_+ \frac{Z_-}{Z_- + Z_0 + 3Z_f} \tag{2.23b}$$

$$I_0 = -I_+ \frac{Z_0 + 3Z_f}{Z_- + Z_0 + 3Z_f}. \tag{2.23c}$$

2.3.1.4 Single phase to earth fault

If a phase to earth fault occurs on phase A, the equivalent circuit will be as in Figure 2.12. This is by far the most common type of fault.

This results in that the same fault current will flow through the phase, fault impedance and earth. By setting I_B and $I_C = 0$ in (2.2) it can be seen that

$$\frac{I_A}{3} = I_+ = I_- = I_0. \tag{2.24}$$

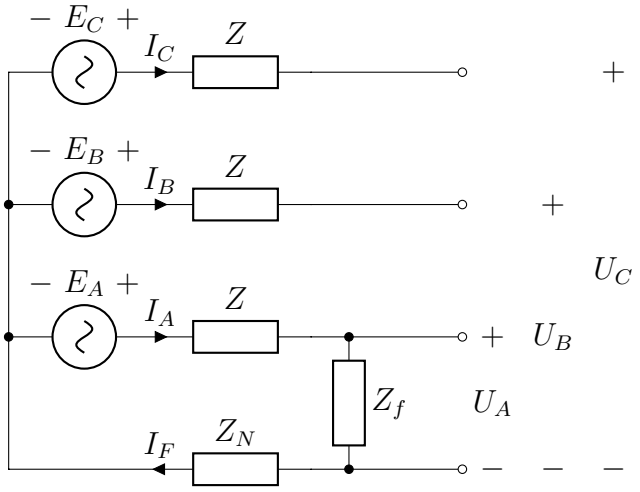


Figure 2.12: Single phase to earth fault.

This means that the same current will flow through each of the sequence networks and the fault. Due to this by summing the voltages together, the current through the fault impedance can be written as

$$3Z_f = \frac{U_+ + U_- + U_0}{I_A}, \tag{2.25}$$

the complete sequence netwok can be seen in Figure 2.7.

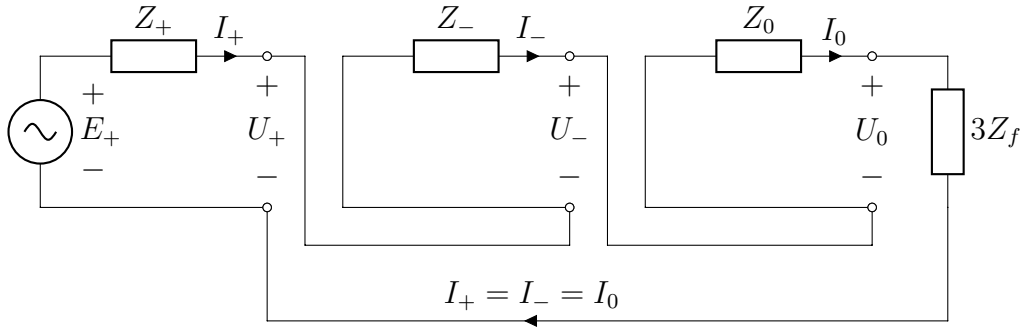


Figure 2.13: The sequence networks connected together for a single phase to earth fault.

The earth fault current can be written as

$$I_F = 3I_0 = \frac{E_+}{\frac{1}{3}(Z_+ + Z_- + Z_0) + Z_f}. \tag{2.26}$$

2.3.2 Series faults

A series fault occurs when there is a discontinuity in at least one of the phases. This is often caused by either line breaks or a breaker/disconnector failure for either one or two phases.

2.3.2.1 Single phase interruption

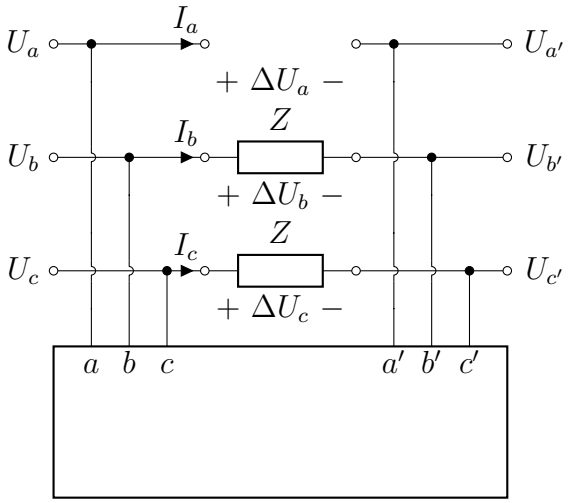


Figure 2.14: Equivalent diagram of a single phase interruption between two buses.

By studying Figure 2.14 it can be concluded that

$$I_a = 0 \tag{2.27a}$$
$$ZI_b = \Delta U_b \tag{2.27b}$$
$$ZI_c = \Delta U_c \tag{2.27c}$$

which when inserted into (2.2) gives that

$$I_0 = I_b + I_c \tag{2.28a}$$
$$I_+ = \alpha I_b + \alpha^2 I_c \tag{2.28b}$$
$$I_- = \alpha^2 I_b + \alpha I_c \tag{2.28c}$$

if summed togheter

$$I_+ + I_- + I_0 = 0. \tag{2.29}$$

By using (2.3) and (2.4) the inverse

$$\alpha^2 \Delta U_+ + \alpha \Delta U_- + \Delta U_0 = Z(\alpha^2 I_+ + \alpha I_- + I_0) \tag{2.30a}$$
$$\alpha \Delta U_+ + \alpha^2 \Delta U_- + \Delta U_0 = Z(\alpha I_+ + \alpha^2 I_- + I_0) \tag{2.30b}$$

by subtracting

$$\Delta U_- - ZI_- = \Delta U_+ - ZI_+ \tag{2.31a}$$
$$\Delta U_0 - ZI_0 = \Delta U_+ - ZI_+ \tag{2.31b}$$

$$I_+ = \frac{\Delta E_+}{Z_{+(aa')} + Z + \frac{(Z_{-(aa')}+Z)(Z_{0(aa')}+Z)}{Z_{-(aa')}+Z_{0(aa')}+2Z}} \tag{2.32a}$$

$$I_- = -\frac{Z_{0(aa')} + Z}{Z_{-(aa')} + Z_{0(aa')} + 2Z} I_+ \tag{2.32b}$$

$$I_0 = -\frac{Z_{-(aa')} + Z}{Z_{-(aa')} + Z_{0(aa')} + 2Z} I_+ \tag{2.32c}$$

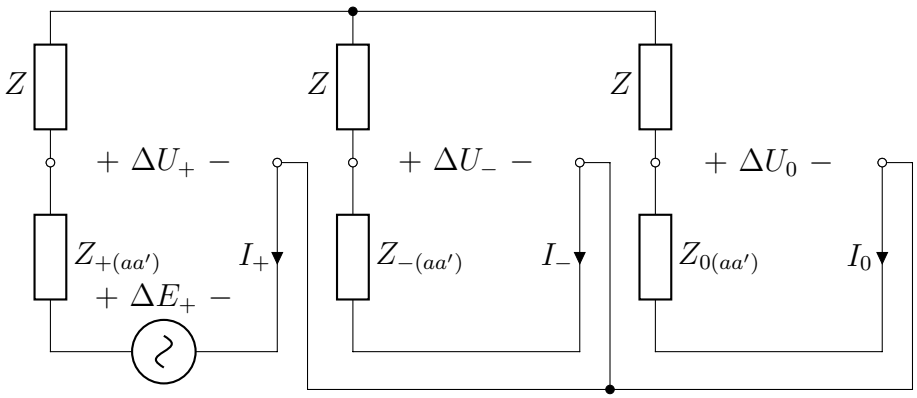


Figure 2.15: The sequence networks connected together for a single phase interruption.

2.3.2.2 Dual phase interruption

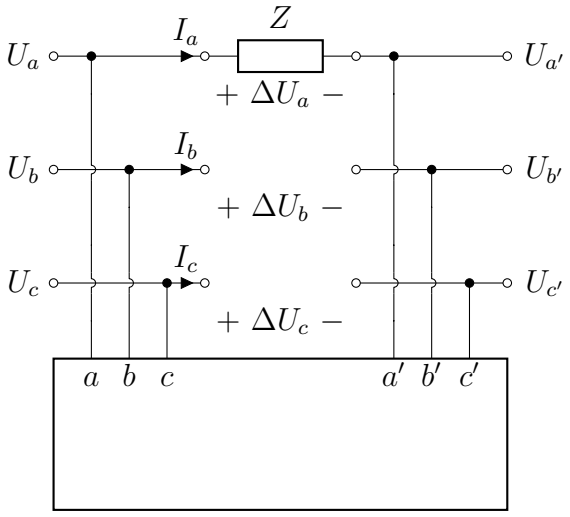


Figure 2.16: Dual phase interruption.

In Figure 2.16 it can be seen that the phase currents will be

$$\Delta U_a = Z I_a \tag{2.33a}$$

$$I_b = 0 \tag{2.33b}$$

$$I_c = 0. \tag{2.33c}$$

Similar to the single phase to earth fault by using (2.1) and (2.2) this results in

$$I_+ = I_- = I_0 \tag{2.34}$$

and

$$\Delta U_+ + \Delta U_- + \Delta U_0 = 3ZI_+ \tag{2.35}$$

which means that

$$I_+ = I_- = I_0 = \frac{\Delta E_+}{Z_{+(aa')} + Z_{-(aa')} + Z_{0(aa')} + 3Z}. \tag{2.36}$$

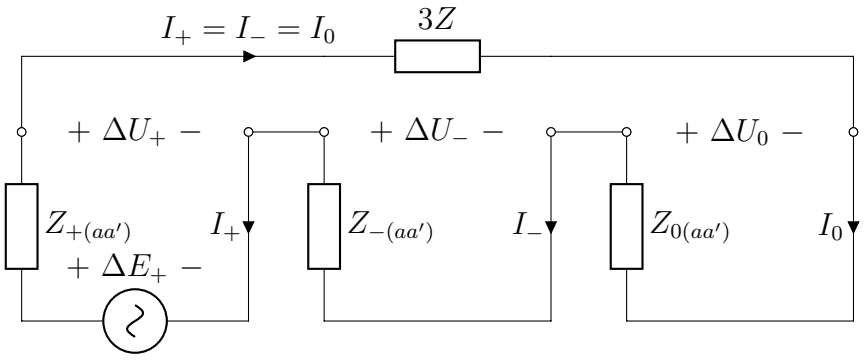


Figure 2.17: The sequence networks connected together for a dual phase interruption.

3

Modelling of sequence networks

This chapter describes the how the zero sequence network is modelled from individual components. It is largely based on [2] if not stated otherwise.

3.1 Zero sequence impedance of transformers

The common transformer model shown in Figure 3.1 has a magnetising impedance, Z_M, which is dependent upon the transformer core. Examples of different types

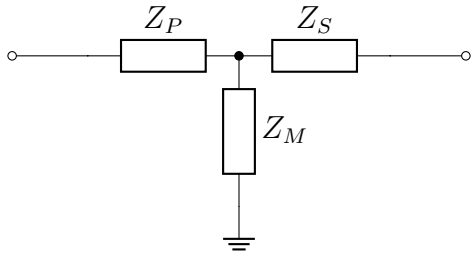


Figure 3.1: Model of a transformer for positive sequence.

of transformer cores can be seen in Figure 3.2. During symmetrical conditions the flux in the three-phase transformer, which is proportional to the respective phase current, will close inside the core

$$\Phi_M = \Phi_A + \Phi_B + \Phi_C = 0 \tag{3.1}$$

for the mutual cores types (i.e. 3 and 5 leg transformer cores) similar to the phase currents. In the single phase transformer however, the flux for each phase will close within each core independently. Ideally the magnetising flux be very small thus the equivalent impedance can be seen as infinite

$$Z_M = \infty. \tag{3.2}$$

As mentioned earlier the positive sequence is equivalent with the symmetrical three-phase case, this can also be assumed for the negative sequence, thus

$$Z_{M+} = Z_{M-} = Z_M. \tag{3.3}$$

For the zero sequence the phase current components will have the same phase thus

$$\Phi_{M0} = \Phi_{A0} + \Phi_{B0} + \Phi_{C0} \neq 0. \tag{3.4}$$

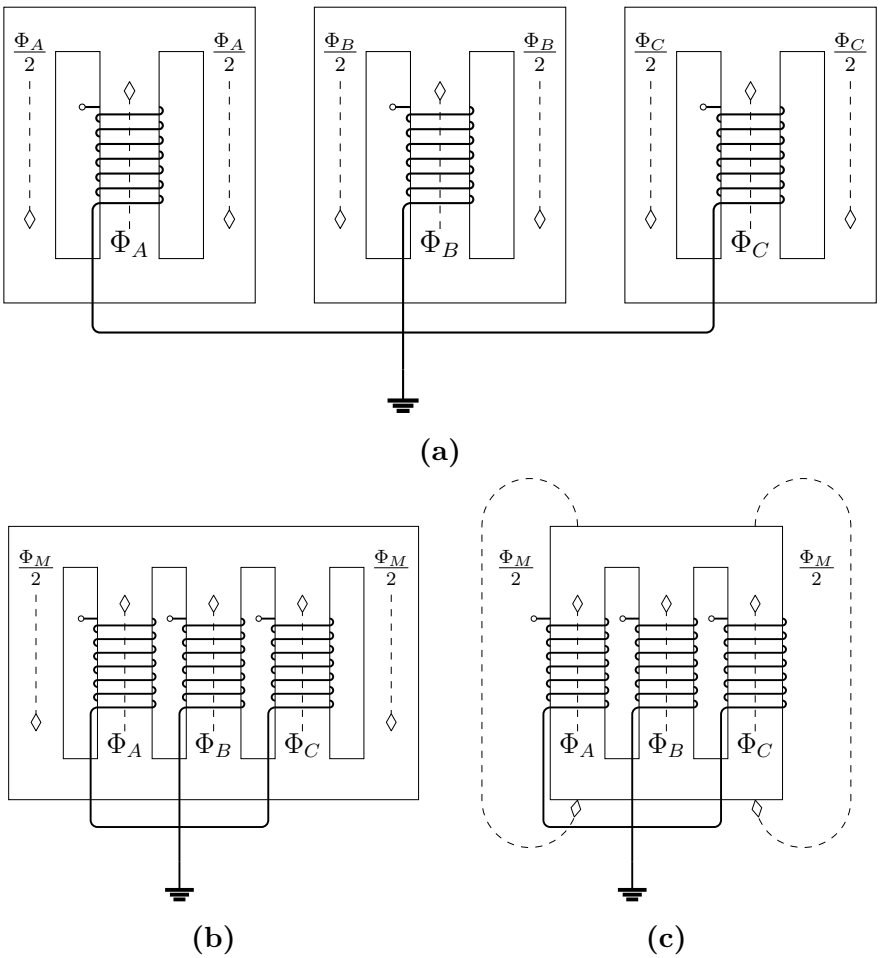


Figure 3.2: Three common transformer cores the three single phase transformers (a) show 3 single phase cores, (b) a 5 leg transformer core and (c) a 3 leg transformer core.

This will results in different magnetising impedances for the zero sequence depending on the core type. For the single phase transformer cores shown in Figure 3.2a the flux will still close independently in each core. For the 5 leg mutual core shown in Figure 3.2b the flux will close through the outer legs. However, this does not result in a perfectly closed circuit and some of the flux leakage through the air can be expected. For the 3 leg mutual core shown in Figure 3.2c the flux cannot close within the core thus the flux will entirely go through the air, which results in high leakage.

From this the following conclusions can be drawn from the leakage of the magnetic field

$$Z_{M0} = Z_{M+} \tag{3.5a}$$
$$Z_{M0} \lesssim Z_{M+} \tag{3.5b}$$
$$Z_{M0} << Z_{M+}. \tag{3.5c}$$

Equation (3.5a) is valid for three single phase cores, (3.5b) for five-leg cores and (3.5c) for three legged cores. The positive sequence magnetising impedance, Z_{M+}, is as mentioned above very large and can be seen a infinite.

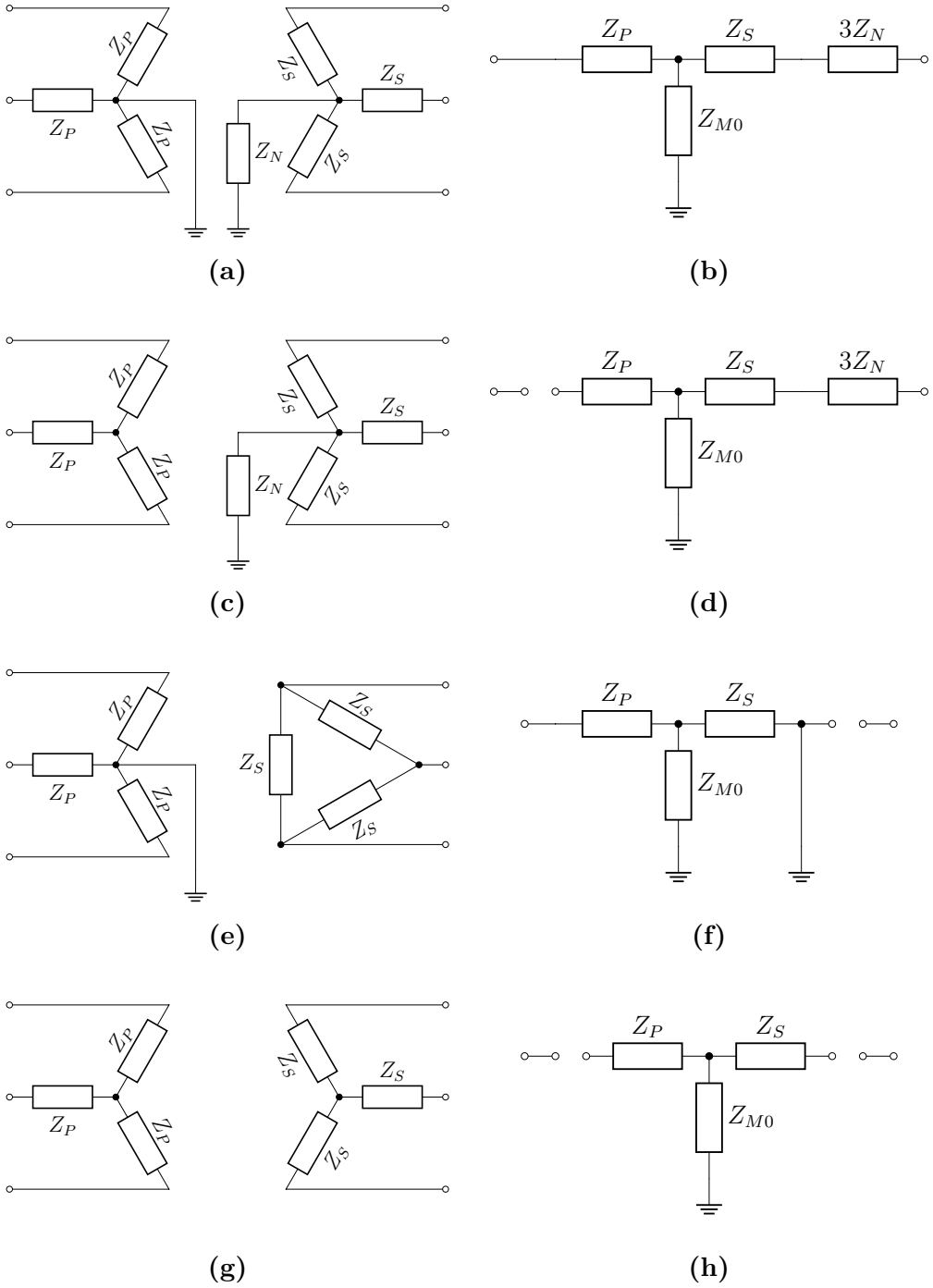


Figure 3.3: Different variations of transformer topologies and the respective zero sequence circuit [2], [4].

3.1.1 Common transformer topologies

Between the regional transmission grid and the medium voltage distribution grid there are generally three different topologies of two winding transformers used the Yn-Yn and Y-Yn with a Petersen coil connected to the neutral point of the secondary side, represented as Z_N. Also, Yn-Δ is used in some networks. These are shown in Figure 3.3.

3.1.2 Three winding transformers

Some transformers have a tertiary winding which is used as equalising winding. Which is used to reduce the zero sequence impedance to earth. This is shown with its equivalent zero sequence circuit in Figure 3.4. This is an alternative to using Y-Δ transformers, with the advantage of having a neutral point available on the secondary side. As can be seen in Figure 3.3 the primary side of the transformer needs to be earthed for this winding to have any effect.

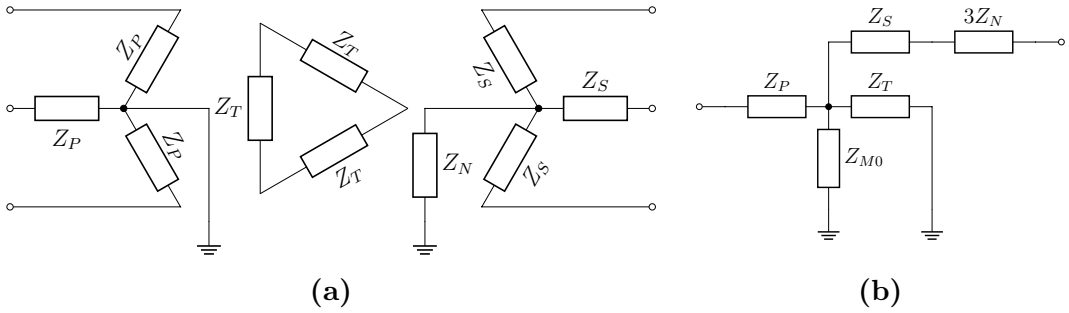


Figure 3.4: A three winding transformer with a directly earthed neutral point on the primary side and a reactance earthed neutral point on the secondary side (a). The equivalent zero sequence circuit is shown in (b).

3.2 Sequence networks

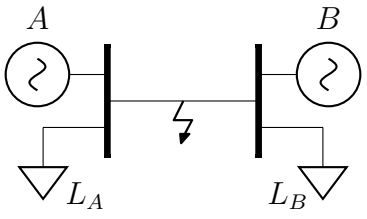
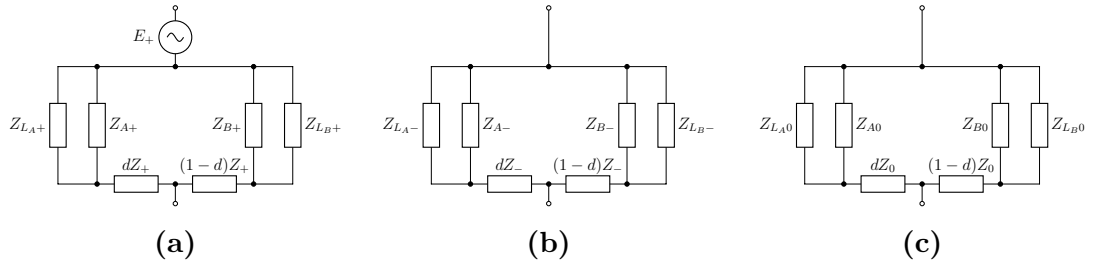


Figure 3.5: Thévenin equivalent circuit of a system with a transmission line and two buses

By representing the network as three different sequence networks, the current flow for each sequence can be studied independently. In Figure 3.5 an example network is shown. The generators represent the Thévenin equivalent circuit of the network beyond the bus.

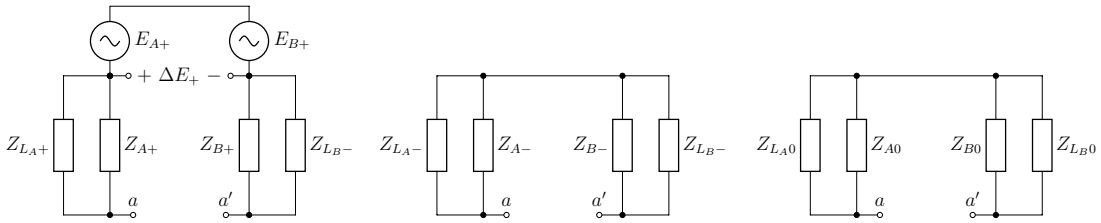
If the fault is a shunt fault type the sequence networks will be as shown in Figure 3.6.



(a) **(b)** **(c)**

Figure 3.6: Thévenin equivalent sequence networks for a shunt fault of a bus with a load and a transmission line.

If the fault is a series fault type the sequence networks will be as shown in Figure 3.7.



(a) **(b)** **(c)**

Figure 3.7: Thévenin equivalent sequence networks for a series fault of a bus with a load and a transmission line.

4

Relay protection techniques

This chapter describes the different types of relay protection commonly used in the Swedish power system today.

To protect the surroundings and the power system itself from short circuits and the potential hazards of fault currents they need to have some kind of detection equipment. This equipment is usually called protective relays and various techniques are used to detect such faults as mentioned above.

4.1 Residual current protection

The residual current protection usually consists of 4 steps called JS1, JS2, JS23 and JS3 [5]. It measures the zero sequence current, $3I_0$, at the line end and each step have different current threshold and time settings. The name of step 23 comes from that it was introduced later than the other steps, when the "selective gap" (the difference between step 2 and 3) increased, to lower the problems in tightly meshed parts of the grid [1].

4.1.1 Directional earth fault current relay

The first three steps (JS1, JS2 and JS23) have a directional element which block the relay from operating for faults in reverse direction. However, it may trip for faults further away in forward direction depending on the settings.

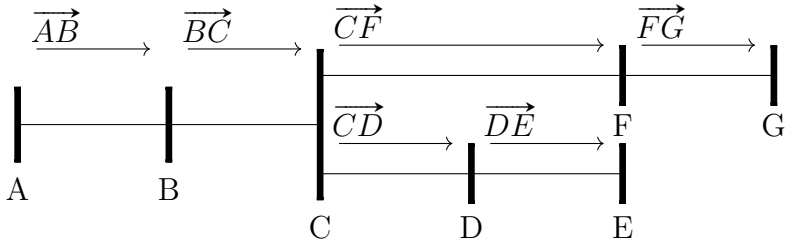


Figure 4.1: Example network with directional relays. Note that in a transmission system there will also be relays in the opposite direction.

For example, in Figure 4.1 if a fault occurs on the line between bus B and C it is in the detection zone of relay $\overrightarrow{BC}$ but also $\overrightarrow{AB}$. However, for relay $\overrightarrow{CD}$ and $\overrightarrow{CF}$ the fault is in reverse direction and therefore outside its detection zone. Due to the directional element and the different current thresholds of JS1, JS2 and JS23. The higher operating time relays are also used as remote backup in which a relay with

longer operating time on a preceding bus clears a fault if a relay on a preceding fails to operate (e.g. $\overrightarrow{BC}$ trips if $\overrightarrow{CF}$ or $\overrightarrow{CD}$ fails to clear the fault).

The different current thresholds of the steps results in different reach of the fault current relay, with a high threshold. In Figure 4.2 the example reach of the relays are shown. JS1 should only protect the line itself since outreach would cause unselective clearing of the fault. JS2 should overreach to protect the line itself and also the opposite busbar (especially if busbar protection is not installed).

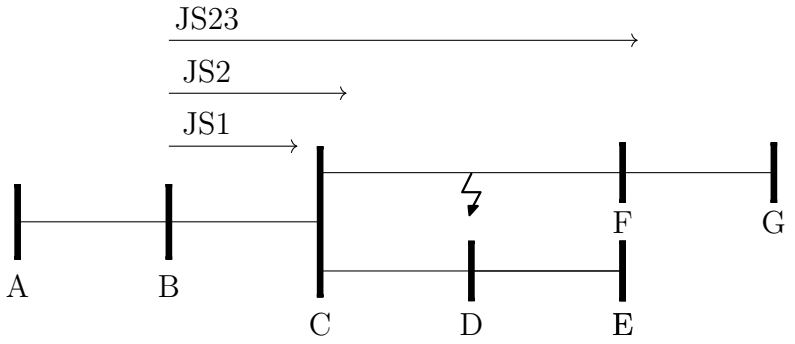


Figure 4.2: Example of remote backup operation at bus B, the length of the arrows represent the reach of the relays. If the relays at bus C fail to operate, JS23 at bus B will instead clear the fault.

The current threshold for each relay is dependent on the line and is determined by a elaborate procedure to ensure selectivity which result in different thresholds for each relay [1].

4.1.2 Independent time earth fault current relay

As described in the background, at least earlier, there was a need to clear rather small zero sequence currents to avoid damages to telecommunication equipment. Since the zero sequence voltage will be small during small zero sequence currents it will be hard to detect the phase therefore the directional element will be less precise. Thus, the JS3 relays lacks the directional element [6].

The independent time relay will trip at the set time and above the current threshold. This type of relay is currently used in Vattenfalls regional grid where it is usually set to 1,2 s and 60 A. However, due to that its non-directional design it can cause unselective clearing with vast consequences since multiple relays may operate at the same time.

4.1.3 Inverse time earth fault current relay

The inverse time relay is non-directional with an operating time inversely depending on the zero sequence current magnitude. Since the 1980s Statens vattenfallsverk and nowadays Svenska kraftnät have used this type of relay instead of the standard JS3 independent time relay due to similar problems described in [6].

In [1]

$$t = t_a + \frac{\Delta t}{\ln(k)} \cdot \ln\left(\frac{I_F}{I_a}\right) \tag{4.1}$$

is derived. I_F represents the fault current, I_a the minimum current, t_a the highest operating time, Δt the selective time difference and k the highest fault current contribution from a branch and t the operation time of the relay. The lowest operating time, t_0, will be achieved at the current I_0 and above.

The maximum fault current contribution constant at a bus is decided by studying a fault on a connected branch. In Figure 4.3 fault current contribution from connected branches is shown.

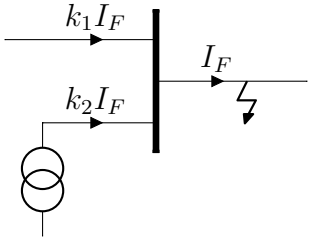


Figure 4.3: The fault current contribution at a bus with two branches and a transformer.

The fault current contribution from of the adjoining branches are added together. If the loss-angle of the two adjoining branches are the same, the following statement can be made

$$I_F = k_1 I_F + k_2 I_F \tag{4.2}$$

which can be written as

$$I_F = I_F(k_1 + k_2) \tag{4.3}$$

which means that

$$k_1 + k_2 = 1 \tag{4.4}$$

since the fault current will flow towards the fault the following conclusion can be drawn

$$0 \leq k_1 \leq 1 \tag{4.5a}$$
$$0 \leq k_2 \leq 1. \tag{4.5b}$$

The current contribution factor from an adjoining branch can also be defined as

$$k_i = \frac{I_i}{I_F} \tag{4.6}$$

where I_i is the current in the adjoining branch.

The limits ($k = 0$ or 1) are obtained if:

$k = 0$ this occur on a branch connected to an unearthed radial branch.

$k = 1$ only one of the adjoining branches contribute to the fault. Generally this occurs at a bus with two branches and an unearthed transformer.

Of the cases described above $k = 0$ is not generally a problem, it is only a problem if also $k = 1$ in an adjoining branch which would mean that the inverse time relay can not operate with selectivity, since the zero sequence current will be the same in one of the non-faulty and the faulty branch. This can be solved by earthing the transformer (if applicable) so that it contributes with zero sequence current [1].

Except from $k = 1$ the highest possible fault current contribution constant found from studying the entire network is chosen. An example of the characteristics of an inverse time relay is shown in Figure 4.4.

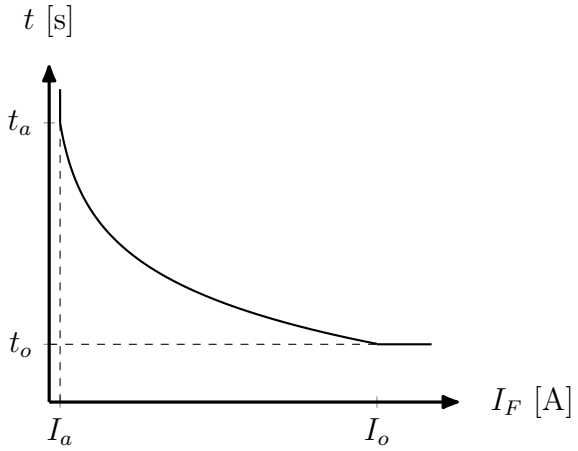


Figure 4.4: Example of an inverse time charateristic.

4.1.3.1 Inverse time settings limits

To choose the correct parameter k is important since it sets the difference in operating time between the maximum contributing adjoining branch and the branch at which the fault occurs to the selective time difference Δt. By solving (4.1) for Δt the required execution time of disconnection can be calculated when the required operation current I_o is known

$$\Delta t = (t_o - t_a)\frac{\ln(k)}{\ln(\frac{I_o}{I_a})}. \tag{4.7}$$

The execution time is the time from the trip signal from the relay until the disconnection of the line by the breakers, the relays also have a reset time. This is simplified to

$$t_s = t_{operate} + t_{breakers} + t_{reset}. \tag{4.8}$$

and the requirement for selectivity is

$$\Delta t > t_s \tag{4.9}$$

where $t_{breakers}$ is the operating time of the breakers, $t_{operate}$ is the time delay of the relay and t_{reset} the reset time for the next relay. As long as (4.9) is valid, the inverse time relay will operate with selectivity.

Similarly if (4.1) is solved for I_o:

$$I_o = I_a e^{(t_o - t_a)\frac{\ln(k)}{\Delta t}}, \tag{4.10}$$

the operation current can be calculated if the selectivity time difference is known.

4.2 Distance protection

Distance protection uses the electrical distances (i.e. the impedance) from the bus out towards the line to detect a fault. By measuring the positive sequence voltage and current the equivalent impedance can be calculated

$$Z = \frac{U_+}{I_+}. \tag{4.11}$$

The calculated impedance can then be compared to the line impedance and the occurrence of a fault can be determined. As shown in Figure 4.5 the distance relay have different protection zones which is set by the line length. Each protection zone have a set time and a maximum resistance and reactance depending on the line (the diagonal lines). The maximum fault resistance which the relay is set to detect is represented as the width of the protection zone.

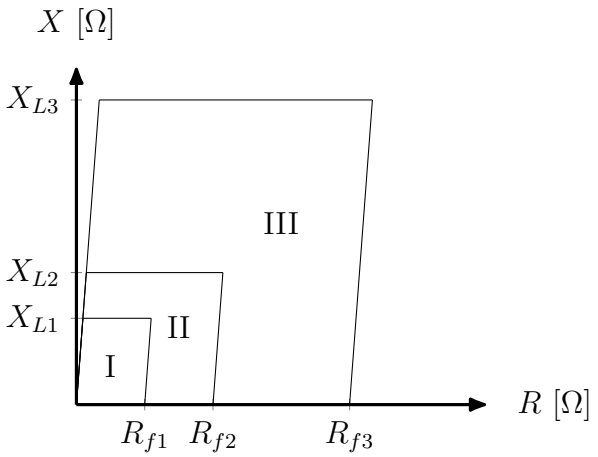


Figure 4.5: A simplified quadrilateral characteristic that show the different zones (I, II and III) of a distance protection relay.

Usually the first zone protect only a single line. To prevent overreach, and as a result unselective operation, the first protection zone have a safety margin and they are set to only reach around 85 % of the line. The second protection zone should reach at least 120 % of the line and the third the length of the longest line in the next substation. Common fault resistances used by Vattenfall for the three zones are 0, 10 and 20 Ω.

Distance protection detects faults that result in low ohmic shunt faults effectively such as: 3 phase, 3 phase to earth, phase to phase fault and dual phase to earth faults. Distance protection is especially needed for the phase to phase fault and symmetrical three-phase faults since these result in either low or no zero sequence current. However, distance protection cannot detect series faults nor high ohmic shunt faults, thus earth fault current protection is necessary.

4.3 Line differential protection

A more advance and modern approach to detect shunt faults are the line differential protection, LDP. It measures and sums the currents at the line ends and trips if it differs to much from each other (i.e. if the sum of the currents at the line ends is larger than a set threshold). This means that it detect faults with absolute selectivity (i.e. only faults on the line which it is protecting). However, disadvantage with LDP includes that communication between two the buses are needed. Furthermore it can only detect shunt type faults since series faults does not influence the net current between the line ends. The principle is shown in Figure 4.6.

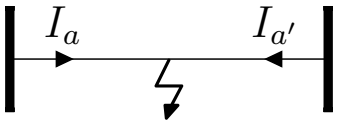


Figure 4.6: The currents measured by the line differential protection.

The LDP can be described as the following set of equations

$$I_{differential} = |I_a + I_{a'}| \tag{4.12a}$$

$$k(|I_a| + |I_{a'}|) = I_{restraint} \tag{4.12b}$$

$$I_{differential} > I_{block} + I_{min} \tag{4.12c}$$

where I_a and $I_{a'}$ are the phase current for a single phase at each line end, k is the setting for the slope, I_{ES} is the breaking point, I_{block} the variable restraint current above the breaking point, and I_{min} the minimum working current [7].

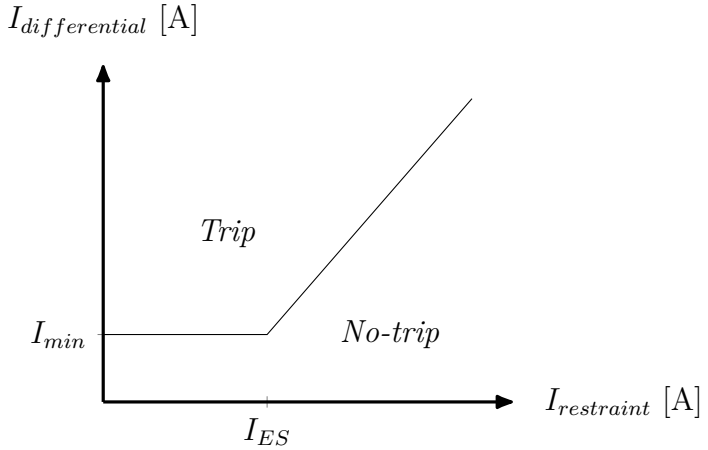


Figure 4.7: The characterstic of the LDP.

4.4 Busbar differential protection

To ensure protection of the busbars, busbar differential protection can be installed at the bus. Often the busbar is protected by the step 2 of the earth current protection in neighbouring stations but if it is not possible to reach the requirements, Busbar Differential Protection (BDP) needs to be installed. BDP are based on the

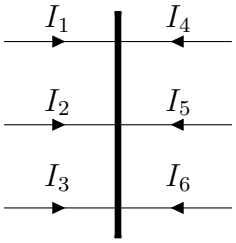


Figure 4.8: A busbar with 6 connected branches.

principle of current summation similar to the LDP where the sum of the incoming and outgoing currents of the connected branches. In Figure 4.8 a busbar with 6 connected branches is shown. The branch currents are added together

$$I_1 + I_2 + I_3 + I_4 + I_5 + I_6 = I_{differential}. \tag{4.13}$$

If sum of the currents are larger than the set threshold this means that there is a fault on the busbar and the incoming branches are disconnected. Advantages with busbar protection include fast disconnection of shunt faults in buses, instantaneous disconnection compared to the time delay of step 2. Also, it allows for continued operation of branch connections as compared to using step 2 for busbar protection. If step 2 is used it would disconnect the opposite line ends as shown in Figure 4.9.

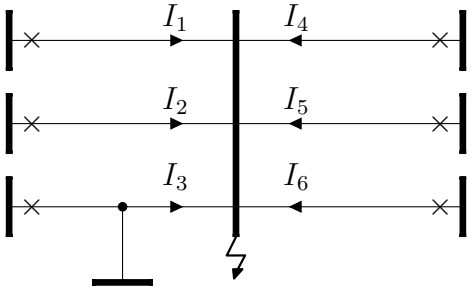


Figure 4.9: A busbar with 6 branches and a branch connection with step 2 as main protection.

If BDP is used the branch connection would still be in use during a fault on the protected busbar as shown in Figure 4.10.

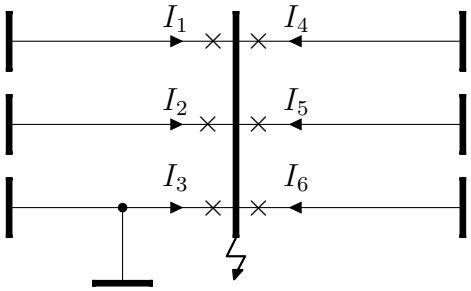


Figure 4.10: A busbar with 6 branches disconnected and a branch connection with busbar protection.

5

Description of the problems due to the non-directional relays

This chapter presents and describes the problems that are related to the non-directional independent time relays. Simulations are done to get a representation of the problems in an actual power system. This includes fault current magnitudes and operating times of the relays for the situation today (i.e. independent time is used for JS3). From Chapters 2 through 4 it can be concluded that there is a need to validate the relay protection for both shunt and series fault. Since the sequence networks are independent of each other only a fault of each type (one series and one shunt fault) needs to be used for the simulations. In this study, single phase to earth and single line interruption is chosen.

The grid that is used for the simulations is a part of a real network with real sequence data provided by Vattenfall Eldistribution. However, fictitious load is added to make it possible to simulate series faults. A one-line diagram of the network can be seen in Figure 5.2. The relay settings used in this chapter are real settings used in the corresponding station in Vattenfalls network.

5.1 Selective gap in earth fault protection

Since the relay settings depend on the branches, the settings will vary depending on where in the grid the branch is located. A known problem in the grid is the so-called selective gap which is the difference of the current setting between JS23 and JS3. This gap grows when the grid is extended with more stations which lowers the protection distance leading to higher current settings for the relays.

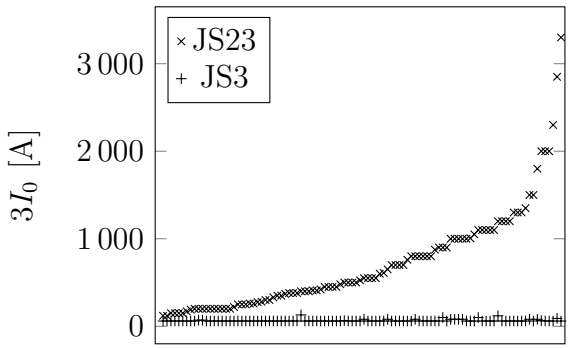


Figure 5.1: Example of settings for JS23 and JS3 in same bay from Vattenfalls 130 kV network. The vertical distance between each point of JS23 and JS3 are the selective gap.

A large selective gap causes problem since JS3 is generally set to 60 A and will therefore trip for currents above 60 A but JS23 may have a to large current setting to trip the faulty line which can cause breakdown of large part of the network. The selective gap is illustrated in Figure 5.1. As can be seen the gap between JS23 and JS3 varies from around 100 A to above 3000 A. A fault causing currents inside this gap at multiple branches (i.e. above the JS3-threshold but not exceeding the JS23-threshold at any branch) leads to unselective operation of the relay when JS3 trips every branch above the JS3-threshold. Examples of the other settings for the lines 32204-32224 and 32206-32224 can be seen in Table 5.1 and 5.2 respectively.

Table 5.1: Example of relay settings from each line end from the line 32204-32224 from the real network. JS1 has been turned off and LDP is used instead.

	32204		**32224**	
Step	**I [A]**	**t [s]**	**I [A]**	**t [s]**
1	—	0,0	—	0,0
2	1 500	0,4	1 600	0,4
23	1 200	0,8	1 350	0,8
3	60	1,2	60	1,2

Table 5.2: Example of relay settings from each line end from the line 32206-32224 from the real network.

	32206		**32224**	
Step	**I [A]**	**t [s]**	**I [A]**	**t [s]**
1	15 000	0,0	5 000	0,0
2	2 000	0,4	1 000	0,4
23	1 300	0,8	800	0,8
3	60	1,2	60	1,2

5.2 Selectivity of fault clearing

By comparing the zero sequence current from the simulation towards the relay settings the selectivity of the fault clearing can be evaluated. JS3 will during this evaluation be set to non-directional independent time to represent the current residual current protection setup.

5.2.1 Series fault

For a single phase interruption on the line between bus 32204 and 32224 this results in the tripping times shown in Table 5.3 are obtained. It can be seen that since it is a series fault, no differential current will be obtained between the ends of the faulty branch.

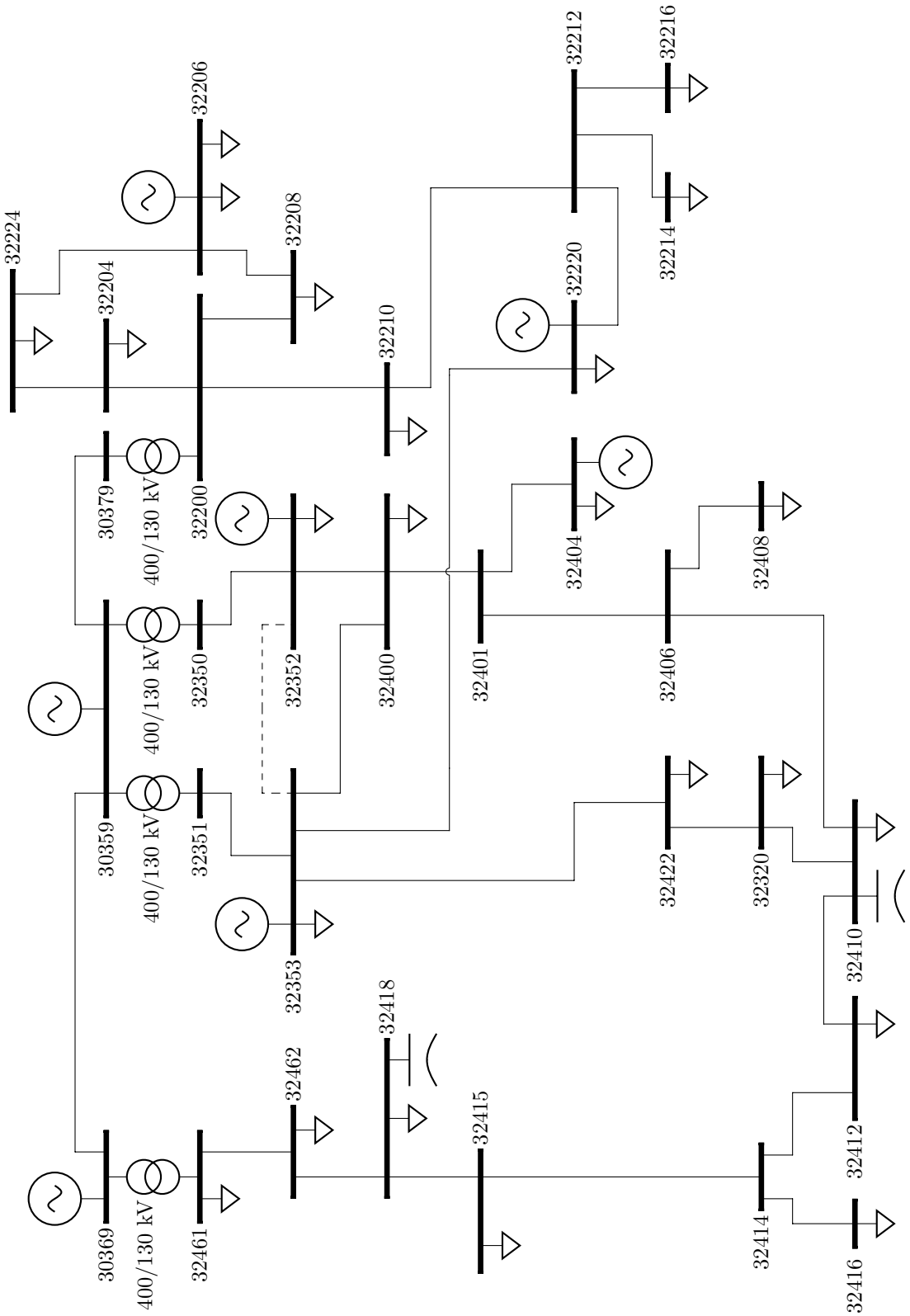


Figure 5.2: One-line diagram of the network used for the simulations.

Table 5.3: Tripping times of the independent time earth fault current relays for a single phase interruption between bus 32204 and 32224.

Bus A	Bus B	t [s]	$3I_0$ [A]	I_A [A]	I_B [A]	I_C [A]	I_{diff} [A]
32204	32224	1,2	150,4	0,0	169,6	172,9	0,0
32224	32204	1,2	150,4	0,0	169,6	172,9	0,0
32206	32227	1,2	141,8	211,3	89,0	63,1	0,0
32224	32225	1,2	141,8	211,3	89,0	63,1	0,0
32200	32202	1,2	139,9	212,8	373,6	378,8	0,0
32204	32203	1,2	139,9	212,8	373,6	378,8	0,0
32206	32208	1,2	114,2	594,6	448,0	450,8	0,0
32208	32206	1,2	114,2	594,6	448,0	450,8	0,0
32200	32201	1,2	113,6	716,1	571,3	571,1	—
32208	32201	1,2	113,6	716,1	571,3	571,1	—

This is visualised in Figure 5.3 and as can be seen all lines in the loop will trip at both ends due to the unselectivity of JS3 since the zero sequence currents are to small for JS23 to react.

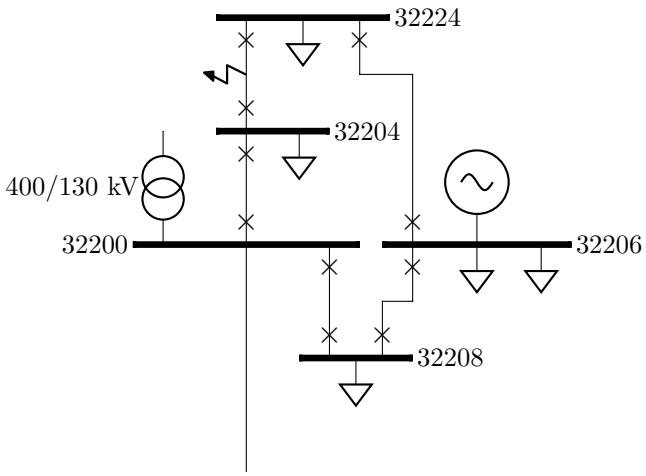


Figure 5.3: Circuit diagram of the part of the network during a single phase interruption between bus 32204 and 32224. The tripped breakers are marked with ×.

5.2.2 Shunt fault

For shunt faults the selectivity will be dependent upon whether or not LDP is installed on the faulty branch. If installed the fault will be cleared instantaneously and with absolute selectivity. If not installed the tripping time will be as shown in Table 5.4. This is visualised in Figure 5.4.

As can be seen in Table 5.4 the differential current is very high on the faulty branch and as mentioned before the LDP can detect differential currents down to 200 A. Thus, theoretically the maximum fault resistance can be approximated to

$$R_f = \frac{U_s}{\sqrt{3} I_{diff}} = \frac{140\,\mathrm{kV}}{\sqrt{3} \cdot 200\,\mathrm{A}} = 404\,\Omega \tag{5.1}$$

Table 5.4: Tripping times of the earth fault current relays for a single phase to ground fault between bus 32204 and 32224 at 50 % of the line length with 100 Ω fault resistance.

Bus A	**Bus B**	**t [s]**	**3I$_0$ [A]**	**I$_A$ [A]**	**I$_B$ [A]**	**I$_C$ [A]**	**I$_{diff}$ [A]**
32224	32204	1,2	450,3	234,3	184,0	192,1	803,5
32204	32224	1,2	353,2	569,5	184,0	192,1	803,5
32206	32227	1,2	397,6	426,1	69,2	77,4	0,0
32224	32225	1,2	397,6	426,1	69,2	77,4	0,0
32200	32202	1,2	300,3	756,4	397,1	410,2	0,0
32204	32203	1,2	300,3	756,4	397,1	410,2	0,0
32200	32210	1,2	63,6	586,5	695,2	705,6	0,0
32210	32200	1,2	63,6	586,5	695,2	705,6	0,0

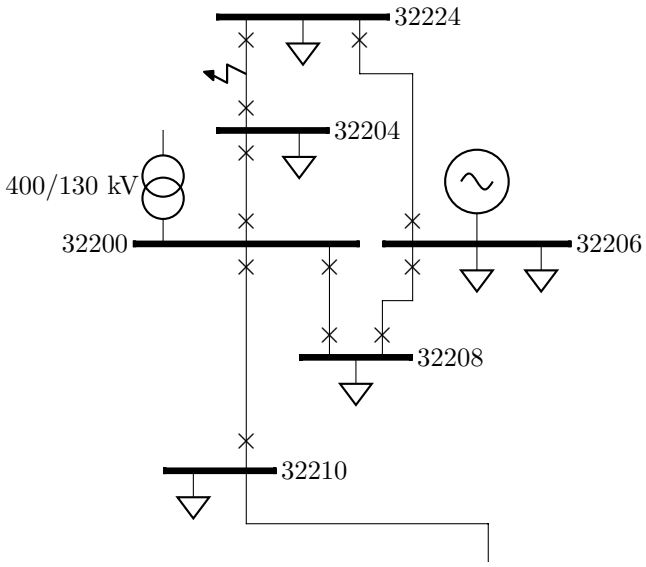


Figure 5.4: One-line diagram of the part of the network during a single phase to earth fault between bus 32204 and 32224 with a 50 Ω fault resistance at 50 % of the line length. The tripped breakers are marked with ×.

where 140 kV is the normal operational voltage. For fault resistances below this, the fault will be cleared with selectivity by the LDP.

For high ohmic earth faults that cannot be cleared by the LDP the situation will in the worst case scenario (i.e. when the the differential current is slightly below threshold and therefore larger than the resistance mentioned above) for the same branch be as shown in Table 5.5. This is visualised in Figure 5.5.

5.3 Selectivity dependence on power system load

In a loaded power system the voltages and current will deviate from the ones in the simplified unloaded case. However, since the power system is never completely unloaded in reality and that the bus load affect the zero sequence current during series faults. All loads will be scaled proportionally between 0 to 200 % to visualise impact during different load conditions. Bear in mind that this does not take any

Table 5.5: Tripping times of the earth fault current relays for a single phase to ground fault between bus 32204 and 32224 at 50 % of the line length with 410 Ω fault resistance.

Bus A	**Bus B**	**t [s]**	**$3I_0$ [A]**	**I_A [A]**	**I_B [A]**	**I_C [A]**	**I_{diff} [A]**
32224	32204	1,2	110,8	76,7	179,3	181,0	197,7
32204	32224	1,2	86,9	274,1	179,3	181,0	197,7
32206	32224	1,2	97,8	141,3	72,1	74,1	0,0
32224	32206	1,2	97,8	141,3	72,1	74,1	0,0
32200	32208	1,2	73,9	475,8	387,6	390,2	0,0

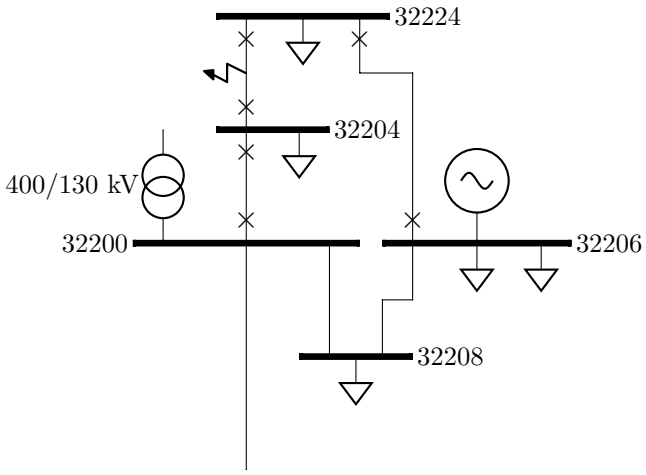


Figure 5.5: One-line diagram of the part of the network during a single phase to earth fault between bus 32204 and 32224 with a 410 Ω fault resistance at 50 % of the line length. The tripped breakers are marked with ×.

real load conditions into account but only serves the purpose to show how zero sequence current changes with load.

5.3.1 Series fault

As can be seen in (2.32) the zero sequence current during a series fault depends on the complex voltage difference between the two buses at each end of the branch. This implies that higher load results in high earth fault currents since higher load result in a higher transfer angle between the buses. Two different cases with one with one low and one high JS23-setting in one end and one with two high JS23-settings in both ends will be studied. The load will be scaled between 0 and 200 % to show the impact of the load to the zero sequenc current. For simulations regarding independent time at JS3 single line interruption will be used since the zero sequence current is slightly smaller and therefore have a higher probability to be in the selective gap.

5.3.1.1 Branch with low JS23-thresholds

If all the loads in the system are scaled equally the result will be as shown in Figure 5.6. A series fault on this branch only causes the relays to clear the fault unselective if the load is very low. Also, this happens only in a small window between

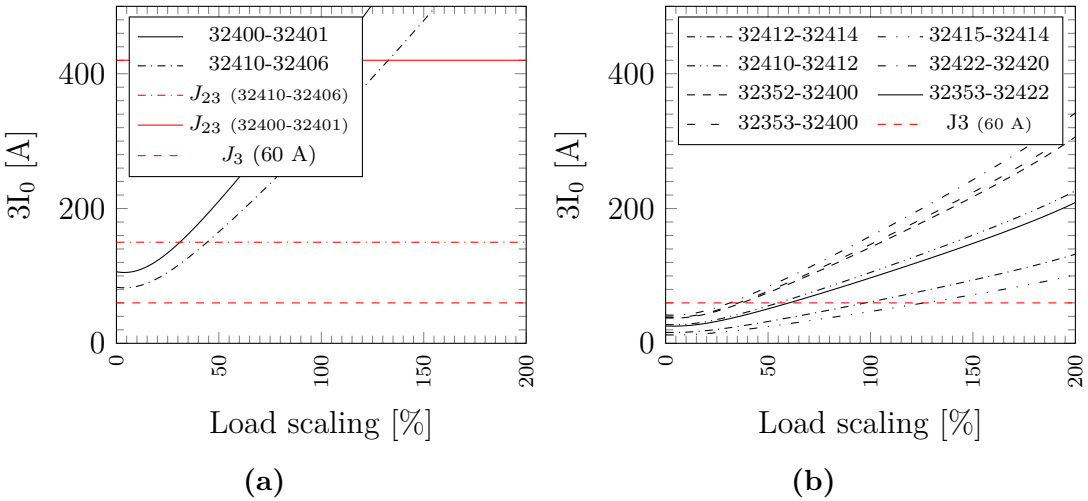


Figure 5.6: Zero sequence current in some of the transmission lines during a single phase interruption between bus 32400 and 32401. Fault currents above the line representing a relay would cause it to clear the fault under the prerequisites of that relay. (a) shows the currents measured by the relays protecting the line and (b) other currents measured by relays in the grid exceeding 60 A.

approximately 35-45 % of the load. From this it can be concluded that with one JS23-relay set at very low, for high loading of the system it would be no problem to achieve selectivity.

5.3.1.2 Branch with high JS23-thresholds

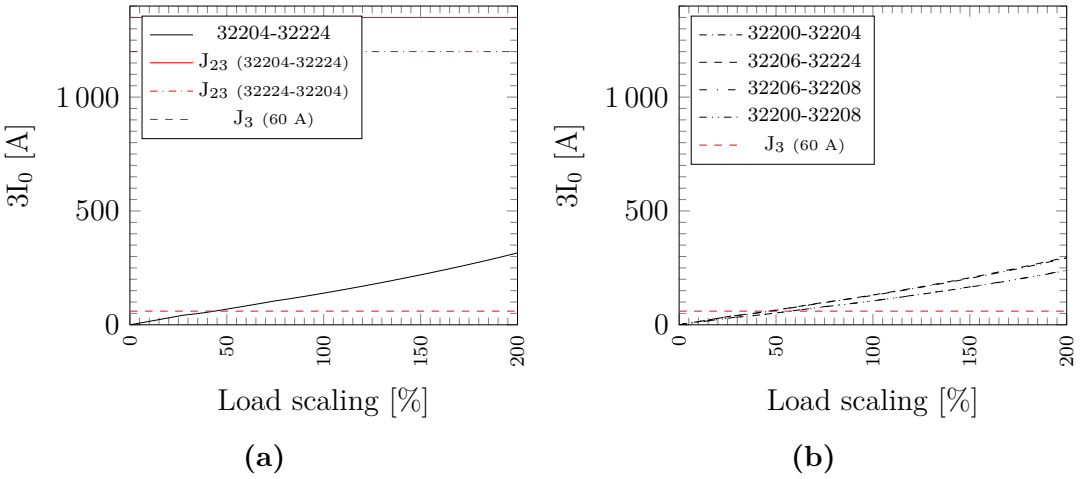


Figure 5.7: Zero sequence current in some of the transmission lines during a single phase interruption between bus 32204 and 32224.

Using the same procedure as above, but for a branch with higher JS23-thresholds the results shown in Figure 5.7 are obtained. It can be seen that the fault current stays in the gap between JS23 and JS3 when the load increases. Due to this, clearing of faults will be unselective during high loading of this branch. Also, during low loading of the line the fault may not be detected until loading increases.

5.3.2 Shunt faults

As can be seen in (2.32) and Figure 2.7 the fault current depends on the Thévenin voltage, which is independent of the load.

5.4 Selectivity dependence on fault resistance

For single line to earth faults the earth fault currents are inversely proportional to fault impedance which can be seen in (2.32). Similar to the series fault the zero sequence current will also flow through neighbouring transmission lines which can cause undesirable disconnections caused by high fault impedance's as shown in Figure 5.8.

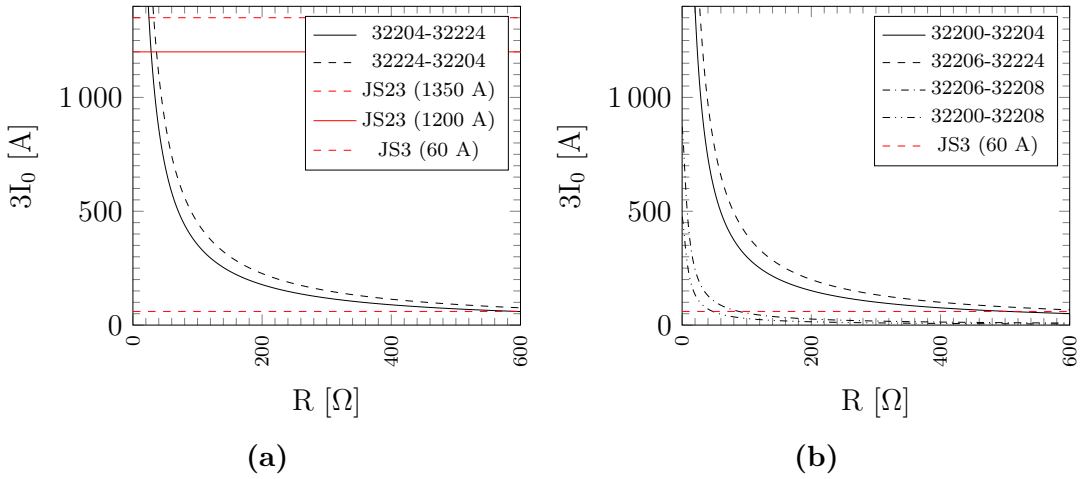


Figure 5.8: Zero sequence current in some of the transmission lines during a single phase to ground fault between bus 32204 and 32224 at 50 % of the line length during different fault resistances. (a) shows the currents measured by the relays protecting the line and (b) other currents measured by fault relays in the grid exceeding 60 A.

6

Considerations regarding implementation of inverse time relays

In this chapter a inverse time relay is implemented instead of the constant time JS3. The required specifications of the characteristic together with other aspects regarding implementation of the inverse time relay are discussed.

6.1 Determining the optimal inverse current characteristic

Theoretically all JS23 thresholds needs to be equal or lower than the maximum current of the inverse time characteristic to achieve full selectivity. However, this is not necessary since series faults does not cause large earth fault currents and high ohmic earth faults (to a certain degree) will be cleared by the LDP.

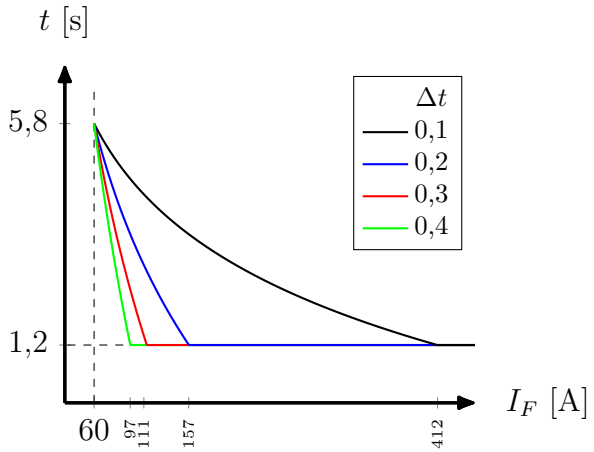


Figure 6.1: Alternatives of the inverse time characteristics by setting the selectivity time when $k = 0{,}959$. In this graph the selective gap can be represented as the horizontal distance between the threshold of the JS23-relay and where the inverse time curve is equal to 1,2 s.

More important for selective clearing are the selective time difference and the current contribution factor which both sets the slope. To ensure full selectivity the difference of the clearing time between two relays should under no circumstances

be smaller than the total delay time of the protection equipment. Also, the current contribution factor needs to be set so that the time difference becomes sufficient.

For the implementation of inverse time relays in this study 60 A will be used for the minimum fault current to full fill the requirements from Telestörningsnämnden. As the maximum time 5,8 s is chosen since that is already used by Svenska kraftnät.

6.1.1 Current contribution

By studying the currents in Table 5.3 and 5.4 it can be seen that the current contribution differ between series and shunt fault. By dividing the current of the adjoining branch as

$$\frac{141{,}8\,\text{A}}{150{,}4\,\text{A}} = 0{,}943 \tag{6.1a}$$

$$\frac{139{,}9\,\text{A}}{150{,}4\,\text{A}} = 0{,}930 \tag{6.1b}$$

from the adjoining branch at each side for a series fault and

$$\frac{783{,}8\,\text{A}}{887{,}7\,\text{A}} = 0{,}883 \tag{6.2a}$$

$$\frac{129{,}3\,\text{A}}{139\,\text{A}} = 0{,}850 \tag{6.2b}$$

and for a shunt fault. As can be seen, the current contribution from an adjoining branch is higher for a series fault than a shunt fault. This can be seen by studying a network with a fault as shown in Figure 6.2. The zero sequence network for a

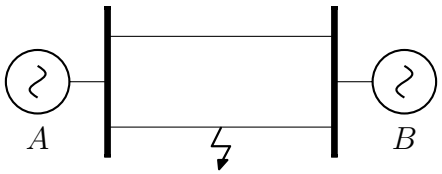


Figure 6.2: One-line diagram of a two bus parallel line network.

series fault will be as shown in Figure 6.3. The current will take the low impedance path as drawn, since the impedance of the shunts is generally much larger than the transmission lines. This means that the current contribution from the transmission line will be very high.

The zero sequence network for a shunt fault will be as shown in Figure 6.4. In this case the current needs to take the paths through the shunts as drawn, thus the current contribution from the transmission line will be low in this case.

From the different faults described above, it can be concluded that a series fault will result in a higher current contribution from the adjoining transmission lines than a shunt fault. Thus, the current contribution factors should be determined by applying series faults.

By repeating this for each branch the results in Table 6.1 is achieved with the highest current contribution factor determined to $k = 0{,}959$. The selective time difference as described above needs to be larger than the delay of the protection

Table 6.1: Current contribution factor for series faults of a fault between bus A and B. k is the maximum current contribution factor of an adjoining branch at bus A and X_A is the zero sequence shunt reactance of the bus A typically from the transformer earthing

Bus A	**Bus B**	$\boldsymbol{k}$	$\boldsymbol{X_A}$ [Ω]
32200	32208	0,565	—
32200	32204	0,765	—
32200	32210	0,510	—
32204	32224	0,930	81
32204	32200	0,940	81
32206	32224	0,756	12
32206	32208	0,569	12
32208	32200	0,959	82
32208	32206	0,944	82
32210	32200	0,575	51
32210	32212	0,933	51
32220	32212	0,056	8
32220	32353	0,079	8
32224	32204	0,943	76
32224	32206	0,920	76
32400	32401	0,367	33
32410	32406	0,493	51
32410	32412	0,437	51
32410	32420	0,448	51
32412	32410	0,584	74
32412	32414	0,581	74
32415	32414	0,485	60
32415	32418	0,569	60
32418	32415	0,903	66
32418	32462	0,814	66
32422	32453	0,571	32
32422	32420	0,380	32
32461	32462	1	9

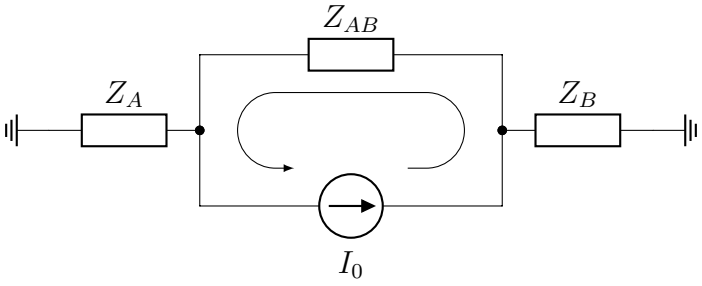


Figure 6.3: Zero sequence network of a two bus parallel line network.

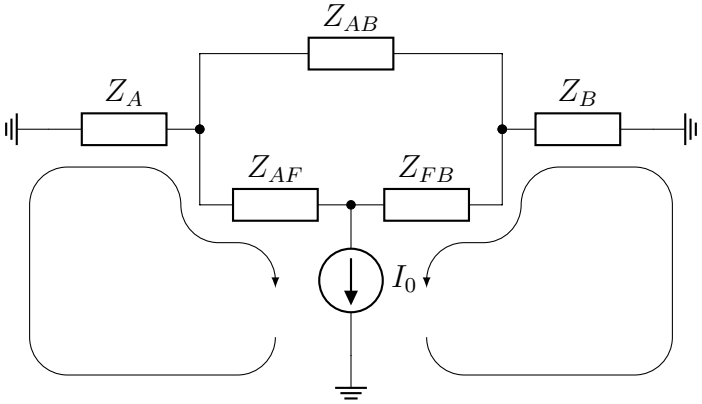


Figure 6.4: Zero sequence network of a two bus parallel line network.

system, the impact of the different values can be seen in Figure 6.1. However, this results in rather low maximum operating currents due to the high current contribution factor as shown in Figure 6.9. Also, the selectivity when $\Delta t = 0{,}1$ s are questionable since it is upper part the tripping interval.

If instead $k = 0{,}8$ is chosen which is the same as Svenska kraftnät uses [1]. The characteristics for different time settings will be as shown in Figure 6.5. Δt should not be set to low since that would lead to small clearing time difference between two adjoining branches. Also, this leads to an unnecessary high maximum current, which could not be fully utilised. It should neither be set to high since that leads to low maximum currents.

6.1.1.1 Impact of a large current contribution factor

If a current contribution factor is chosen that is lower than the maximum one in the system (i.e. choosing the one used by Svenska kraftnät rather than the largest one in the system). The selective time difference will become smaller for lines with high current contribution at the end buses. This can be calculated by subtracting (4.1) from itself with a scaling on the current

$$\begin{aligned}\Delta t_\Delta &= \left(t_o + \frac{\Delta t}{\ln k}\ln\left(\frac{k_\Delta I}{I_o}\right)\right) - \left(t_o + \frac{\Delta t}{\ln k}\ln\left(\frac{I}{I_o}\right)\right) \\ &= \frac{\Delta t}{\ln(k)}((\ln(k_\Delta) + \ln(I) - \ln(I_o)) - (\ln(I) - \ln(I_o)))\end{aligned} \tag{6.3}$$

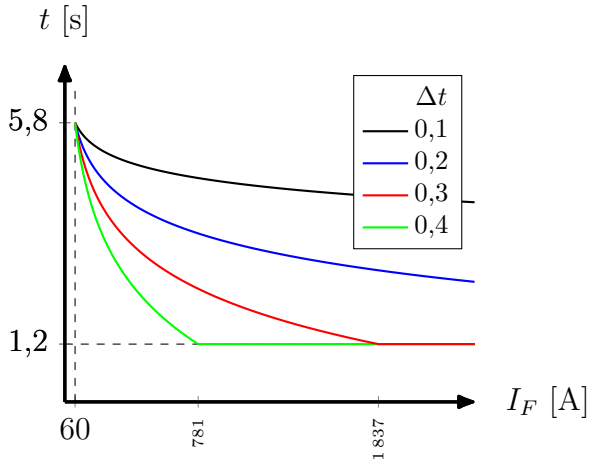


Figure 6.5: Alternatives of the inverse time characteristics by setting the selectivity time when $k = 0{,}8$. In this graph the selective gap can be represented as the horizontal distance between the threshold of the JS23-relay and where the inverse time curve is equal to 1,2 s.

which result in

$$\Delta t_\Delta = \Delta t \frac{\ln(k_\Delta)}{\ln(k)}. \tag{6.4}$$

By drawing (6.4) with $k = 0{,}8$ for various values of Δt the result in Figure 6.6 is obtained. As can be seen the selective time difference will be low for branches with the highest current contribution factors.

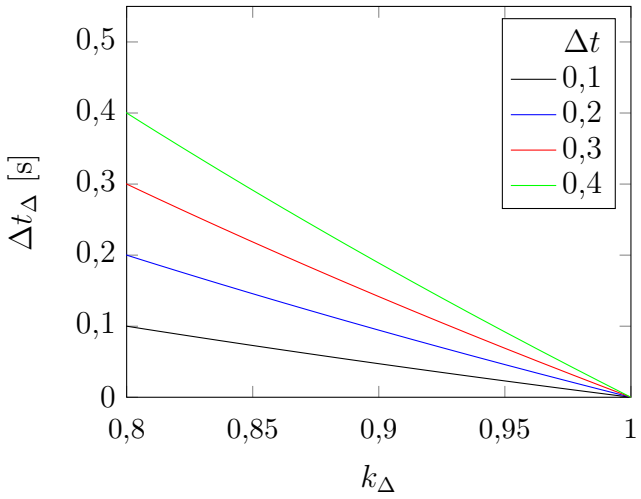


Figure 6.6: Selective time difference depending on the current contribution factor k_Δ when $k = 0{,}8$ for different values of Δt.

6.1.1.2 Impact of impedance preceding branches

By representing a small part of a network as in Figure 6.7 the impact of the zero sequence impedance can be studied.

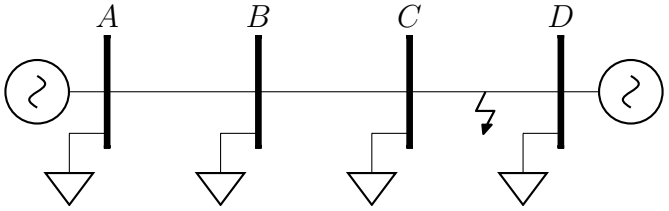


Figure 6.7: A representation of a network with multiple buses.

The zero sequence network is shown in Figure 6.8. Since only the current path is studied, the positive and negative sequence network can be represented as a current source. The longitudinal impedances represent transmission lines and the shunt impedances represent can be seen as transformers between the 130 kV network and medium voltage grids.

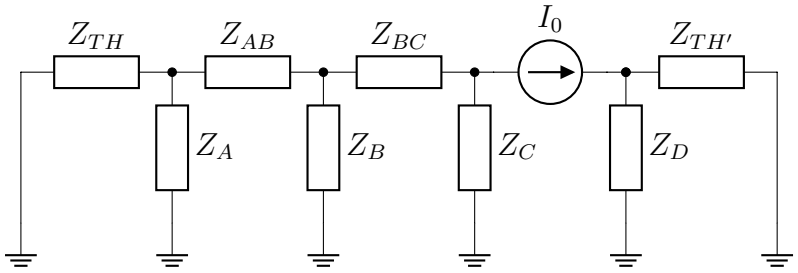


Figure 6.8: A representation of a zero sequence network with multiple buses.

The current contribution from the two preceding branches AB and BC can then be studied and is determined to

$$k_{AB} = \frac{I_{AB}}{I_{BC}} = \frac{Z_B}{\frac{Z_T Z_A}{Z_T + Z_A} + Z_{AB} + Z_B} \tag{6.5}$$

from line AB to line BC and

$$k_{BC} = \frac{I_{BC}}{I_0} = \frac{Z_C}{\frac{\left(\frac{Z_T Z_A}{Z_T + Z_A} + Z_{AB}\right) Z_B}{\frac{Z_T Z_A}{Z_T + Z_A} + Z_{AB} + Z_B} + Z_{BC} + Z_C} \tag{6.6}$$

from line BC to line CD. By inserting different impedances in the same range as occurring impedance values in the real network the impact of the lines and shunt on the current contribution factors. The result can be seen in Table 6.2. As expected when all shunt impedances are large this result in a high current contribution factor. However, if a single shunt impedance is large this result in an increase of the current contribution factor. In the real network this can especially be seen for bus 32208 which have a large shunt impedance while the neighbouring buses have rather small shunt impedances. The current contribution factor for a fault on one of the adjoining branches are therefore very high. A "worst case scenario" occurs when the local shunt impedances are high, short transmission lines and small Thévenin impedance.

As can be seen in Figure 6.9 the relays cannot solve for the largest currents in the selective gap meaning that residual currents above the threshold will be unselective.

Table 6.2: Example of different impedance values and their impact on the current contribution factor for the system shown in Figure 6.7.

Z_T [Ω]	Z_{AB} [Ω]	Z_{BC} [Ω]	Z_A [Ω]	Z_B [Ω]	Z_C [Ω]	k_{AB} [Ω]	k_{BC} [Ω]
5	2	2	10	10	10	0,652	0,690
5	2	2	10	10	100	0,652	0,957
5	2	2	10	100	10	0,949	0,657
5	2	2	10	100	100	0,949	0,950
5	2	2	100	10	10	0,597	0,657
5	2	2	100	10	100	0,597	0,950
5	2	2	100	100	10	0,937	0,604
5	2	2	100	100	100	0,937	0,939
5	2	10	10	10	10	0,652	0,444
5	2	10	10	10	100	0,652	0,889
5	2	10	10	100	10	0,949	0,431
5	2	10	10	100	100	0,949	0,883
5	2	10	100	10	10	0,597	0,431
5	2	10	100	10	100	0,597	0,883
5	2	10	100	100	10	0,937	0,407
5	2	10	100	100	100	0,937	0,873
5	10	2	10	10	10	0,429	0,690
5	10	2	10	10	100	0,429	0,957
5	10	2	10	100	10	0,882	0,657
5	10	2	10	100	100	0,882	0,950
5	10	2	100	10	10	0,404	0,657
5	10	2	100	10	100	0,404	0,950
5	10	2	100	100	10	0,871	0,604
5	10	2	100	100	100	0,871	0,939
5	10	10	10	10	10	0,429	0,444
5	10	10	10	10	100	0,429	0,889
5	10	10	10	100	10	0,882	0,431
5	10	10	10	100	100	0,882	0,883
5	10	10	100	10	10	0,404	0,431
5	10	10	100	10	100	0,404	0,883
5	10	10	100	100	10	0,871	0,407
5	10	10	100	100	100	0,871	0,873
20	2	2	10	10	10	0,536	0,625
20	2	2	10	10	100	0,536	0,943
20	2	2	10	100	10	0,920	0,548
20	2	2	10	100	100	0,920	0,924
20	2	2	100	10	10	0,349	0,548
20	2	2	100	10	100	0,349	0,924
20	2	2	100	100	10	0,843	0,380
20	2	2	100	100	100	0,843	0,860
20	2	10	10	10	10	0,536	0,417
20	2	10	10	10	100	0,536	0,877
20	2	10	10	100	10	0,920	0,381
20	2	10	10	100	100	0,920	0,860
20	2	10	100	10	10	0,349	0,381
20	2	10	100	10	100	0,349	0,860
20	2	10	100	100	10	0,843	0,292
20	2	10	100	100	100	0,843	0,805
20	10	2	10	10	10	0,375	0,625
20	10	2	10	10	100	0,375	0,943
20	10	2	10	100	10	0,857	0,548
20	10	2	10	100	100	0,857	0,924
20	10	2	100	10	10	0,273	0,548
20	10	2	100	10	100	0,273	0,924
20	10	2	100	100	10	0,789	0,380
20	10	2	100	100	100	0,789	0,860
20	10	10	10	10	10	0,375	0,417
20	10	10	10	10	100	0,375	0,877
20	10	10	10	100	10	0,857	0,381
20	10	10	10	100	100	0,857	0,860
20	10	10	100	10	10	0,273	0,381
20	10	10	100	10	100	0,273	0,860
20	10	10	100	100	10	0,789	0,292
20	10	10	100	100	100	0,789	0,805

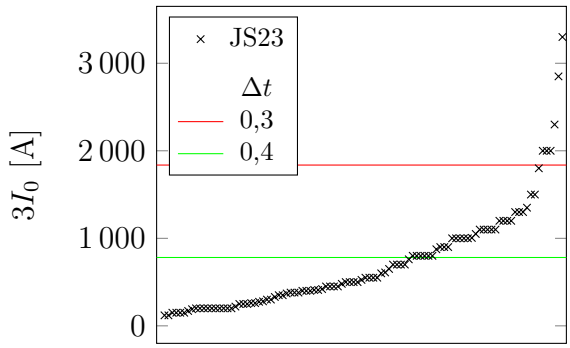


Figure 6.9: JS3 has been replaces by two lines representing the maximum operating currents of two different inverse time characteristics. The vertical distance between each point of JS23 and the respective line are the selective gap.

6.2 Zero sequence currents in the selective gap

To ensure selectivity it should either be guaranteed that no currents will occur in the selective gap or that the selective gap is fully bridged. However, series and shunt faults has to be handled separately since, if installed, differential protection is only applicable to shunt faults.

6.2.1 Shunt fault

For shunt fault the selective gap between is dependent on the restrain current of the LDP in each bay. The characteristic of the LDP shown in Figure 4.7 has two important settings, the recommended minimum settings for ABB's RED670 relay are

$$I_{min} = 0{,}2I_N \tag{6.7a}$$

$$I_{ES} = 1{,}35I_N \tag{6.7b}$$

where I_N is the rating of the primary side of the current transformer, typically 1000 A [8]. This means that (with these settings) during earth faults $3I_0 < I_{ES}$ the threshold will be the minimum operating current, I_{min}, which can be set as low as 200 A. Similarly for BDP the recommended settings for ABB's REB670 are

$$I_{min} = 0{,}5I_N \tag{6.8a}$$

$$I_{ES} = 1{,}35I_N \tag{6.8b}$$

which means that the minimum differential current for BDP is then 500 A. Due to this, the selective gap for earth faults will be bridged by the LDP and also the BDP.

6.2.2 Series fault

Since LDP is unable to detect series fault it must be ensured that the zero sequence currents are below the selective gap (i.e. in the region of the inverse time relay). The zero sequence current in a transmission line can be estimated using the pre-fault conditions. From (2.36) it is known that

$$I_+ = I_- = I_0 \tag{6.9}$$

for a dual phase interruption. $3I_0$, which is also equal to the phase current, can therefore be estimated with

$$3I_0 \approx \frac{P}{\sqrt{3}U_s}. \tag{6.10}$$

By plotting it for different power flows through the line the result in Figure 6.10 is obtained. Power flows in a branch above 300 MW are rare thus $\Delta t = 0{,}3$ would be sufficient.

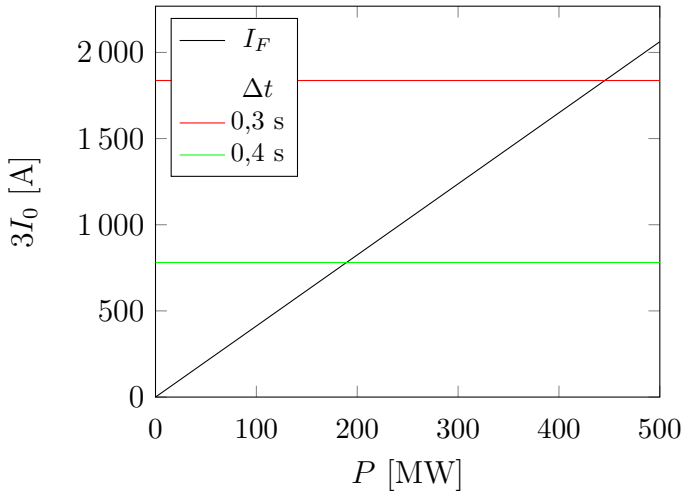


Figure 6.10: The zero sequence current for different power-flow for a system voltage of 130 kV. The horizontal lines are for different selective time differences.

6.3 Selectivity with inverse time relays

With inverse time relays installed the branches with zero sequence currents below JS23 and in the range of the inverse time characteristics will now be selective if the time difference between the current of the faulty branch and other branches are large enough. However, even if the time difference is to small (which may result in that a preceding and/or succeeding trips as well) the selectivity will increase. By implementing the determined settings,

$$t = 5{,}8 + \frac{0{,}3}{\ln(0{,}8)} \ln\left(\frac{I_F}{60}\right) = 5{,}8 + 1{,}35 \ln\left(\frac{I_F}{60}\right) \tag{6.11}$$

is achieved. By implementing this on the previous series fault example, the tripping times shown in Table 6.3 is achieved.

6.4 Simultaneous operation of inverse time and constant time relay

During the implementation phase of the inverse time relay it may be necessary to continue to operate the protection with constant time relays. Since the implementation will be done gradually due to the fact that not every bay will be prepared with

Table 6.3: Tripping times of the earth fault current relays for a single phase interuption between bus 32204 and 32224 when the transmission lines are equipped with inverse time relays.

Bus A	Bus B	t [s]	$3I_0$ [A]	I_A [A]	I_B [A]	I_C [A]	I_{diff} [A]
32204	32224	4,56	150,4	0,0	169,6	172,9	0,0
32224	32204	4,56	150,4	0,0	169,6	172,9	0,0
32206	32224	4,64	141,8	211,3	89,0	63,1	0,0
32224	32206	4,64	141,8	211,3	89,0	63,1	0,0
32200	32204	4,66	139,9	212,8	373,6	378,8	0,0
32204	32200	4,66	139,9	212,8	373,6	378,8	0,0
32206	32208	4,93	114,2	594,6	448,0	450,8	0,0
32208	32206	4,93	114,2	594,6	448,0	450,8	0,0
32200	32208	4,94	113,6	716,1	571,3	571,1	0,0
32208	32200	4,94	113,6	716,1	571,3	571,1	0,0

protective relays compatible with inverse time, and that reconfiguration may take some time. During such circumstances the protective relays will not be guaranteed to clear faults with selectivity, but it does not gets worse.

6.4.1 Fault in bay with independent time relay

If a fault occurs the non-faulty bay with installed inverse time relays will be in continued operation as shown in Table 6.4 and as a network diagram in Figure 6.11.

Table 6.4: Tripping times of the earth fault current relays for a single phase interuption between bus 32204 and 32224. Some of the transmission lines, not including the faulty one, are equipped with a constant time relay with 1,2 s clearing time.

Bus A	Bus B	t [s]	$3I_0$ [A]	I_A [A]	I_B [A]	I_C [A]	I_{diff} [A]
32204	32224	1,2	150,4	0,0	169,6	172,9	0,0
32224	32204	1,2	150,4	0,0	169,6	172,9	0,0
32206	32227	1,2	141,8	211,3	89,0	63,1	0,0
32224	32206	1,2	141,8	211,3	89,0	63,1	0,0
32200	32204	4,7	139,9	212,8	373,6	378,8	0,0
32204	32200	4,7	139,9	212,8	373,6	378,8	0,0
32206	32208	4,9	114,2	594,6	448,0	450,8	0,0
32208	32206	4,9	114,2	594,6	448,0	450,8	0,0
32200	32208	4,9	113,6	716,1	571,3	571,1	0,0
32208	32200	4,9	113,6	716,1	571,3	571,1	0,0

6.4.2 Fault in bay with inverse time relay

If the faulty bay instead is equipped with an inverse time relay the bays equipped with constant time relays will be cleared first followed by the faulty bay. The clearing times are shown in Table 6.5 and as a network diagram in Figure 6.11. The results is visualised in the network diagram in Figure 6.12.

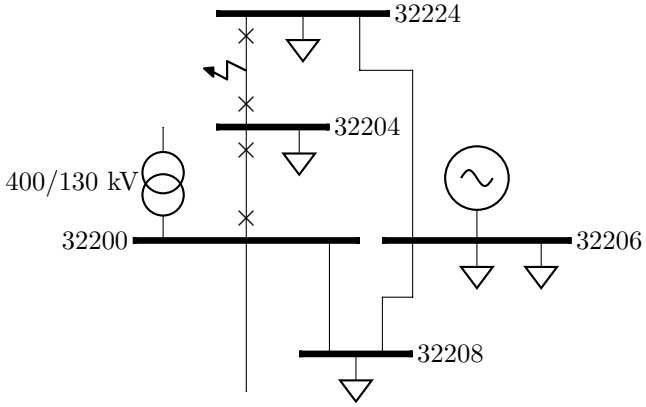


Figure 6.11: Circuit diagram of the part of the network which the relay have tripped during a single phase interruption on the line between bus 32204 and 32224. Some of the transmission lines, not including the faulty one, are equipped with a inverse time relay with 1,2 s clearing time.

Table 6.5: Solving times of the earth fault current relays for a single phase interruption between bus 32204 and 32224. Some of the transmission lines, including the the faulty one, are equipped with a inverse time relay.

Bus A	**Bus B**	**t [s]**	**$3I_0$ [A]**	**I_A [A]**	**I_B [A]**	**I_C [A]**	**I_{diff} [A]**
32206	32224	1,2	141,8	211,3	89,0	63,1	0,0
32224	32206	1,2	141,8	211,3	89,0	63,1	0,0
32200	32208	1,2	113,6	716,1	571,3	571,1	0,0
32208	32200	1,2	113,6	716,1	571,3	571,1	0,0
32204	32224	4,6	150,4	0,0	169,6	172,9	0,0
32224	32204	4,6	150,4	0,0	169,6	172,9	0,0
32200	32204	4,7	139,9	212,8	373,6	378,8	0,0
32204	32200	4,7	139,9	212,8	373,6	378,8	0,0
32206	32208	4,9	114,2	594,6	448,0	450,8	0,0
32208	32206	4,9	114,2	594,6	448,0	450,8	0,0

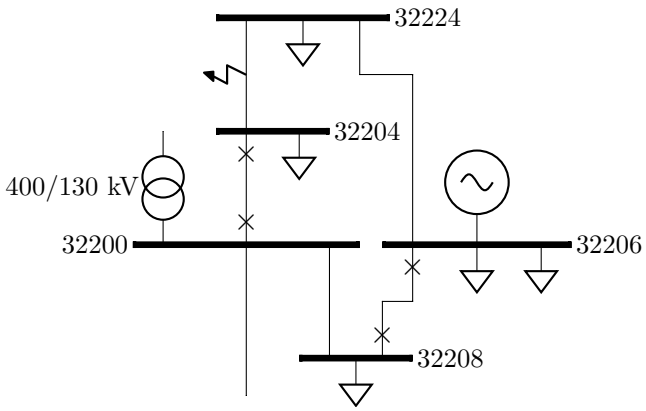


Figure 6.12: Circuit diagram of the part of the network which the relay have tripped during a single phase interruption between bus 32204 and 32224. Some of the transmission lines, including the the faulty one, are equipped with a inverse time relay.

6.4.3 Comparison

Compared to Figure 5.3 it can be seen that the selectivity in Figure 6.11 and 6.12 is if not better, at least not worse.

7
Conclusions and future work

Inverse time relays as the last step of the residual current protection will improve the selectivity. However, due to the highly meshed grid in some parts of the network that causes high contribution of the zero sequence current from the adjoining branches rather than from the shunts. The inverse time relay have problems with the small current difference between two adjoining branches in some parts of the example network.

7.1 Proposed protection scheme for the residual current protection

To clear faults with full selectivity a combination of several protection techniques are necessary.

7.1.1 Differential protection

Shunt faults is preferably cleared with absolute selectivity which can be achieved with differential protection.

7.1.1.1 Line differential protection

Line differential protection have the capability of clearing shunt faults down to differential currents ($3I_0$) of 200 A. This decreases the unselective gap for shunt faults. For bays with high step 23 settings this would decrease unselective clearing of adjoining branches but only for shunt faults.

7.1.1.2 Busbar differential protection

Since line differential protection only protects the line itself separate protection is needed for the busbar to achieve full selectivity. Even though the busbar sometimes is protected by the step 2, the shunt fault can be high ohmic which could cause unselective operation of the relays.

7.1.2 Inverse time characteristic

Inverse time relays will only be selective in the set current range between the pickup current and the maximum operating current. In [1] it was mentioned that it could be installed in 130 kV networks in the future when it becomes necessary, this has now

become necessary and needs to be considered. To clear series fault with selectivity in bays with a large selective gap the implementation of inverse time relays in the network is necessary.

7.1.2.1 Time difference

The selective time difference needs to be large enough to avoid that inverse time relays in adjoining branches does not solve due to internal delays in the protection equipment. Preferably the selective time difference is kept at a normal difference between two steps (e.g. 0,3 s).

7.1.2.2 Bridged selective gap

Inverse time relays will partly make the unselective gap selective. However, zero sequence currents above the maximum current faults will be cleared unselective. Thus, to achieve full selectivity other types of selective relays needs to cover currents below the maximum operating current.

For shunt faults the gap can be bridged by LDP and BDP which can be set lower than the maximum current. Also, this will clear faults with absolute selectivity. For branches without LDP, step 23 needs to be set lower than the maximum current.

However, for series fault LDP cannot be used and therefore it must be guaranteed that all series faults is below the maximum operating current to ensure selective clearing of series faults. Therefore a minimum level of the maximum operating current should be atleast

$$3I_0 = \frac{300\,\mathrm{MW}}{\sqrt{3}\cdot 130\,\mathrm{kV}} \approx 1\,330\,\mathrm{A} \tag{7.1}$$

since the power transfer of a 130 kV line rarely exceeds 300 MW.

7.1.2.3 Improvement of zero sequence shunt impedances

In tightly meshed parts where the current contribution factors are much higher the shunt impedances needs to be decreased for the inverse time relay to function properly. This could either be done by replacing the transformers or earthing unearthed parallel transformers. It is important to note that if the zero sequence shunt impedance is lowered at a single bus. This can worsen the situation at neighbouring buses. Due to this, the impact of lowered shunt impedance's needs to be studied.

7.2 Recommendations

Inverse time relays should be implemented in the entire network preferably with the characteristic

$$t = 5{,}8 - 1{,}35\ln\left(\frac{I_F}{60}\right) \tag{7.2}$$

which is appropriate for almost all possible faults in the network except some series faults in the tightly meshed parts. This curve will begin at 1,2 s for 1 837 A and end at 5,8 s for 60 A. The characteristic is already in used by Svenska kraftnät and

is refereed to as RD-type and is available as an option in common protective relay systems.

To ensure proper function in this part of the network the shunt impedances needs to be reduced by installing three winding transformers with a tertiary delta winding in new installations instead of two winding transformers. For present stations any unearthed parallel transformers can be earthed if applicable.

It is recommended that busbar differential protection and line differential protection is implemented in tightly meshed areas like the one around bus 32200 to decrease unselective operations of the step 3 relay.

7.3 Future work

A limiting factor during the work has been the 60 A current threshold for the step 3 of the residual current protection. This current threshold was once decided to limit the induced voltage induced on the telecommunication wires [1]. However, as can be seen in Figure 7.1 the damages has been reduced drastically since year 2000 despite the fact that the number of earth fault has remained almost the same. This is probably due to the large scale replacement of telecommunication wires with fiber optics. It should be investigated if the threshold due to this can be increased to at least the threshold of 80 A currently used by Svenska kraftnät. If the higher current threshold can be implemented the selectivity can be increased due to a flatter characteristic of the inverse time relay if implemented.

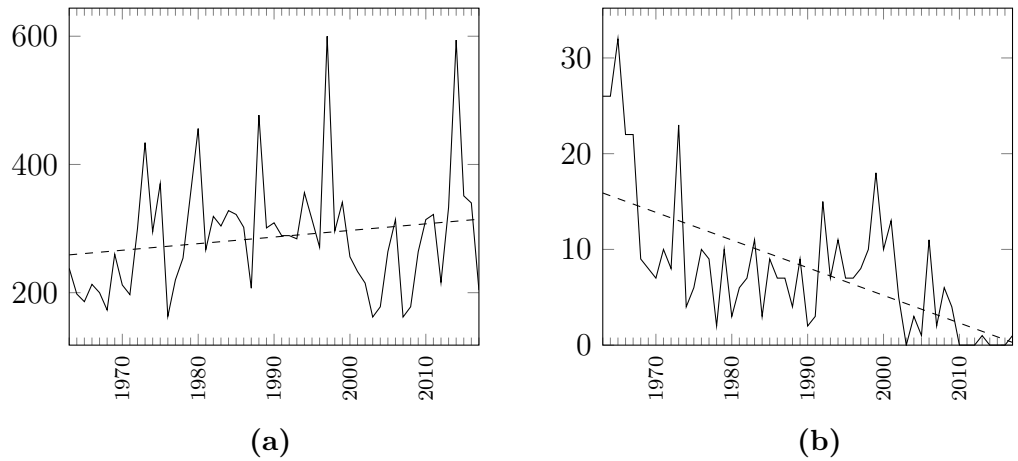


Figure 7.1: Number of earth faults (a) and caused damages (b) for each year between 1963-2017 [9].

7.4 Benefits for society

A reliable power system is a necessity in modern society. Power outages can cause problems for individuals, industries, and public functions and back-up power is also often expensive. Reliable and selective fault protection is necessary to avoid undesirable disconnections in the power system. Since the inverse time function is

included in modern protective relay solutions it is an economical way to improve the selectivity for both high ohmic shunt faults and series faults, since no investment in extra equipment is needed. Thus, minimising problems for individuals, industries and public functions. However, further studies to ensure minimal impact on telecommunication equipment needs to be done to ensure minimal impact on the remaining telecommunication equipment if a fault would occur.

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A

Series fault in meshed networks

If a series fault occur in the meshed parts of the networks the current in the faulty phases will take an alternative path. With two parallel branches, 1 and 2, as shown

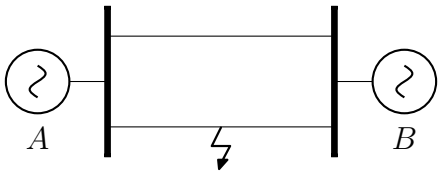

Figure A.1: One-line diagram of the network used for the simulations.

in Figure A.1 with equal impedance it can be realised that the phase currents would be

$$I_{A_1} = I_{A_2} = I_A \tag{A.1a}$$
$$I_{B_1} = I_{B_2} = I_B \tag{A.1b}$$
$$I_{C_1} = I_{C_2} = I_C. \tag{A.1c}$$

The magnitude of each phase current is considered equal

$$I = I_A = \alpha I_B = \alpha^2 I_C. \tag{A.2}$$

A.1 Single phase interruption

If a single phase interruption occurs in phase A in branch 1 the phase currents will then be

$$I_{A_1} = 0 \tag{A.3a}$$
$$I_{B_1} = I_B \tag{A.3b}$$
$$I_{C_1} = I_C \tag{A.3c}$$

for branch 1 and

$$I_{A_2} = 2I_A \tag{A.4a}$$
$$I_{B_2} = I_B \tag{A.4b}$$
$$I_{C_2} = I_C \tag{A.4c}$$

for branch 2. The sequence currents for each branch will then be

$$I_{+_1} = \frac{\alpha I_B + \alpha^2 I_C}{3} = \frac{2I}{3} \tag{A.5a}$$

$$I_{-_1} = \frac{\alpha^2 I_B + \alpha I_C}{3} = -\frac{I}{3} \tag{A.5b}$$

$$I_{0_1} = \frac{I_B + I_C}{3} = -\frac{I}{3} \tag{A.5c}$$

for branch 1 and

$$I_{+_2} = \frac{2I_A + \alpha I_B + \alpha^2 I_C}{3} = \frac{4I}{3} \tag{A.6a}$$

$$I_{-_2} = \frac{2I_A + \alpha^2 I_B + \alpha I_C}{3} = \frac{I}{3} \tag{A.6b}$$

$$I_{0_2} = \frac{2I_A + I_B + I_C}{3} = \frac{I}{3} \tag{A.6c}$$

for branch 2. Thus, the zero sequence amplitude will be the same in each branch.

A.2 Dual phase interruption

If a dual phase interruption occurs in phase A in branch 1 the phase currents will then be

$$I_{A_1} = I \tag{A.7a}$$

$$I_{B_1} = 0 \tag{A.7b}$$

$$I_{C_1} = 0 \tag{A.7c}$$

for branch 1

$$I_{A_2} = I \tag{A.8a}$$

$$I_{B_2} = 2I \tag{A.8b}$$

$$I_{C_2} = 2I \tag{A.8c}$$

and for branch 2. The sequence currents for each branch will then be

$$I_{+_1} = \frac{I}{3} \tag{A.9a}$$

$$I_{-_1} = \frac{I}{3} \tag{A.9b}$$

$$I_{0_1} = \frac{I}{3} \tag{A.9c}$$

for branch 1 and

$$I_{+_2} = \frac{I_A + \alpha 2 I_B + \alpha^2 2 I_C}{3} = \frac{5I}{3} \tag{A.10a}$$

$$I_{-_2} = \frac{I_A + \alpha^2 2 I_B + \alpha 2 I_C}{3} = \frac{-I}{3} \tag{A.10b}$$

$$I_{0_2} = \frac{I_A + 2I_B + 2I_C}{3} = \frac{-I}{3}. \tag{A.10c}$$

for branch 2. Thus, the zero sequence amplitude will be the same in each branch.

B

Series fault in radial branches

If the fault occurs in a radial branch such as in Figure B.1, the fault will instead be similar to a shunt fault.

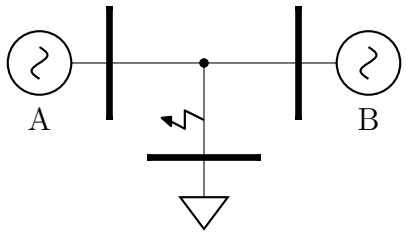

Figure B.1: One-line diagram of the network used for the simulations.

B.1 Earthed radial branches

In a earthed radial branch there is a earthed load ahead of the faulty line thus there is a alternate return path for the current.

B.1.1 Single phase interruption

For a single line interruption in the radial branch

$$I_A = 0 \tag{B.1}$$

by using (2.2)

$$I_+ = \frac{\alpha I_B + \alpha^2 I_C}{3} = \frac{2I_A}{3} \tag{B.2a}$$

$$I_- = \frac{I\alpha^2 I_B + \alpha I_C}{3} = -\frac{I_A}{3} \tag{B.2b}$$

$$I_0 = \frac{I_B + I_C}{3} = -\frac{I_A}{3}. \tag{B.2c}$$

It can be seen by adding sequence current together that they cancel each other

$$I_+ + I_- + I_0 = 0 \tag{B.3}$$

thus according to Kirchoff's current law the sequence network will be as show in Figure B.2.

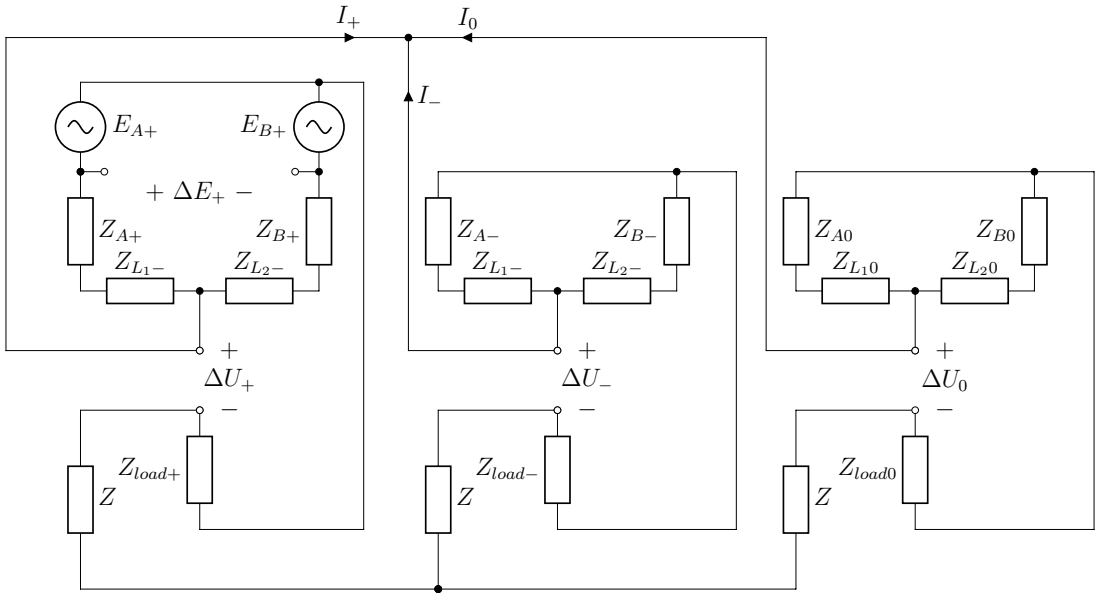

Figure B.2: The sequence network for a single line interruption in the unearthed radial branch.

B.1.2 Dual line interruption

For a dual line interruption

$$I_B = I_C = 0 \tag{B.4}$$

thus by using (2.2) the sequence currents can be determined to

$$I_+ = \frac{I_A}{3} \tag{B.5a}$$
$$I_- = \frac{I_A}{3} \tag{B.5b}$$
$$I_0 = \frac{I_A}{3} \tag{B.5c}$$

this can be represented as the sequence network shown in Figure B.2.

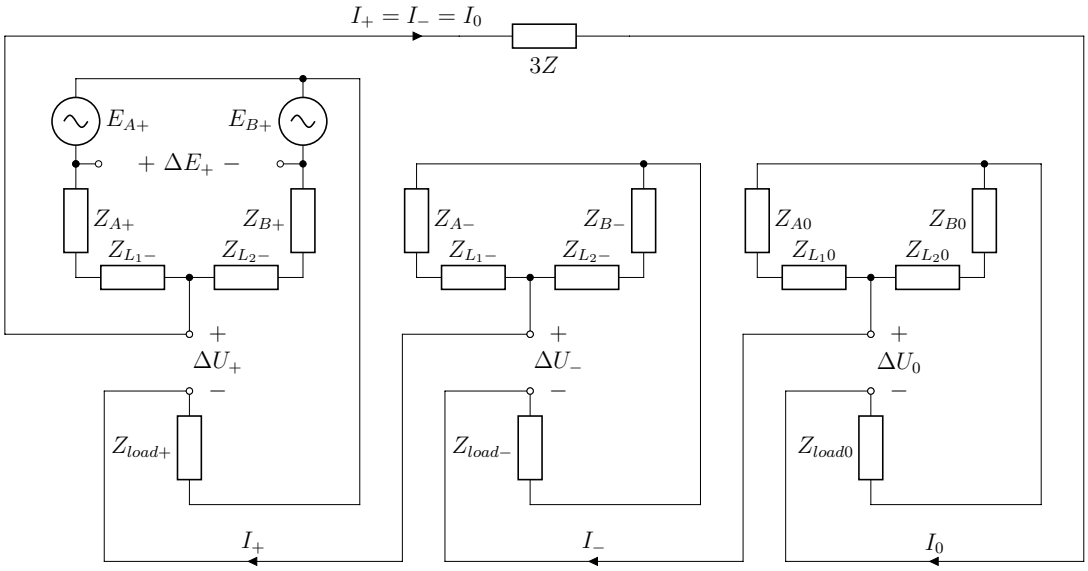

Figure B.3: The sequence network for a dual line interruption in the unearthed radial branch.

B.2 Unearthed radial branches

A radial branch with no connection to earth at the load means that

$$I_0 = 0. \tag{B.6a}$$

B.2.1 Single line interruption

If a discontinuity occur in the reference phase since (B.6) it means that

$$I_A = 0 \tag{B.7a}$$
$$I_B + I_C = 0 \tag{B.7b}$$

thus by using (2.2)

$$I_+ = \frac{I_B\alpha - \alpha^2 I_B}{3} = I_B\frac{(\alpha - \alpha^2)}{3} = I_B\frac{\sqrt{3}}{3}\underline{/90^\circ} = \frac{I_B}{\sqrt{3}}\underline{/90^\circ} \tag{B.8a}$$
$$I_- = \frac{\alpha^2 I_B - \alpha I_B}{3} = I_B\frac{(\alpha^2 - \alpha)}{3} = I_B\frac{\sqrt{3}}{3}\underline{/-90^\circ} = -\frac{I_B}{\sqrt{3}}\underline{/90^\circ} \tag{B.8b}$$
$$I_0 = I_B + I_C = 0 \tag{B.8c}$$

which can be written as

$$I_+ = -I_- \tag{B.9a}$$
$$I_0 = 0 \tag{B.9b}$$

this can be represented as the sequence network shown in Figure B.4.

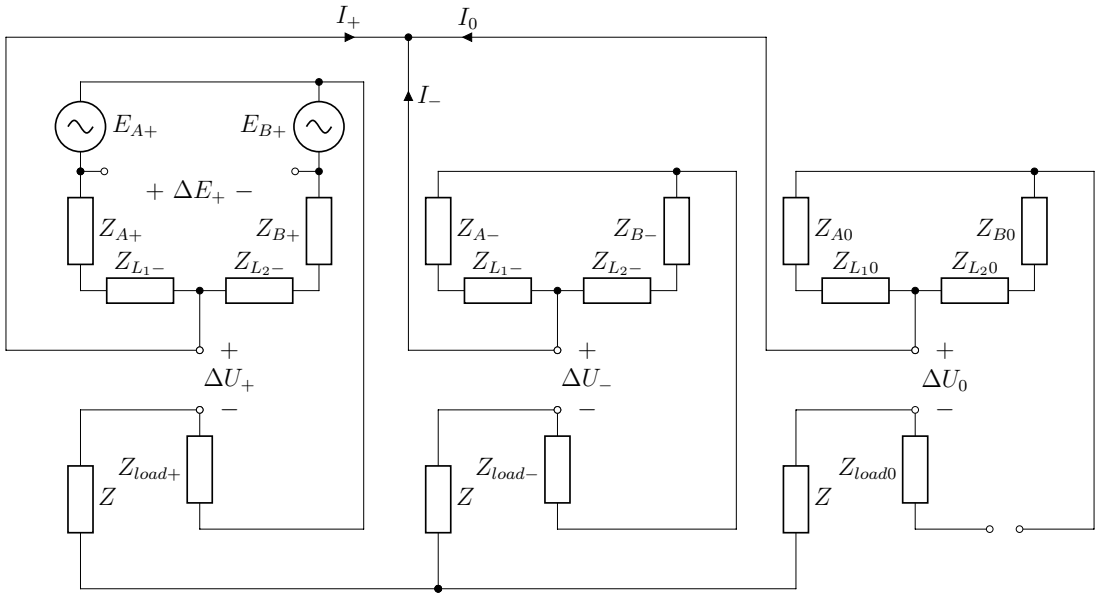

Figure B.4: The sequence network for the single line interruption in the unearthed radial branch.

this is similar to a phase to phase shunt fault.

B.2.2 Dual line interruption

For two open phases, B and C,

$$I_B = I_C = 0 \tag{B.10}$$

and since the load is unearthed this means that

$$I_A = 0 \tag{B.11}$$

thus no current will flow in the branch

$$I_+ = I_- = I_0 = 0. \tag{B.12}$$

this can be represented as the sequence network shown in Figure B.5.

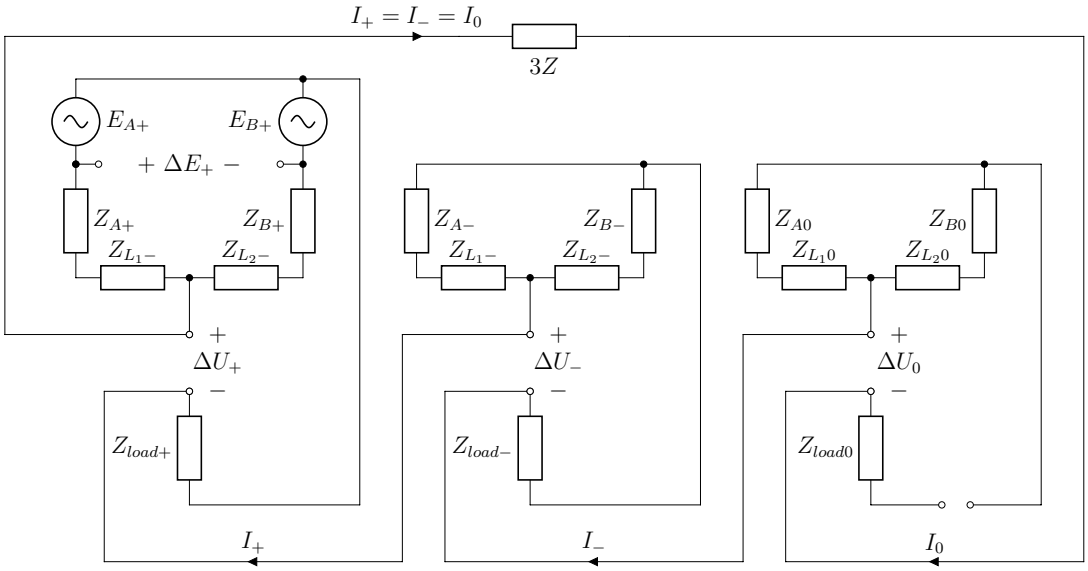

Figure B.5: The sequence network for the dual line interruption in the radial branch.

Due to the discontinuity in the zero sequence network no current will flow through the faulty branch.

C

Current distribution dependence of fault type

By studying a network with three buses as shown in Figure C.1 the dependence of the zero sequence current distribution dependence of the fault type, series or shunt, can be determined. The three buses are connected to each other and each one have generator with an earthed neutral point.

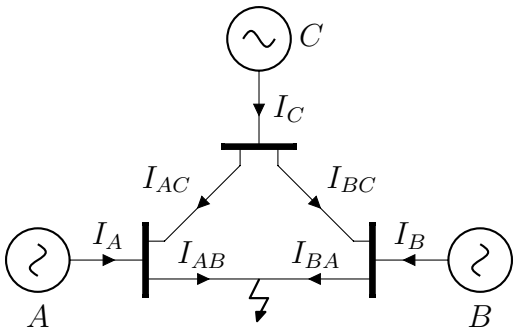

Figure C.1: A 3 bus system where all buses are interconnected with each other.

Since the positive, negative, and zero sequence impedance's are independent of each other, the positive and negative sequence network can be represented as a current source. Therefore only the zero sequence network needs to be studied.

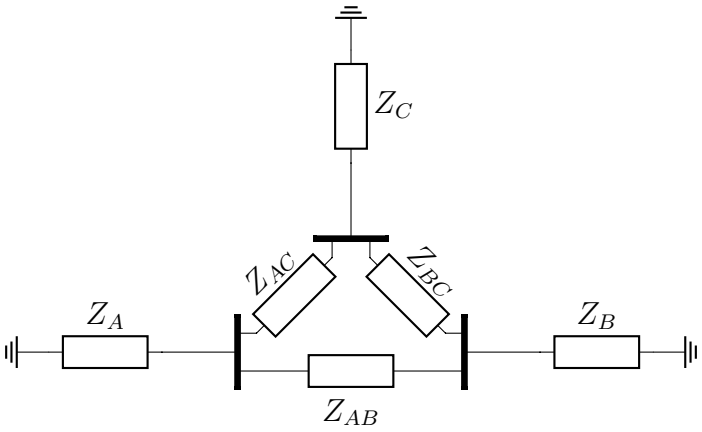

Figure C.2: The zero sequence Thévenin equivalent circuit of the 3 bus system.

C.1 Shunt fault

The equivalent circuit for a series fault can be seen in Figure C.3. To simplify the calculations, the impedances representing the faulty line is neglected.

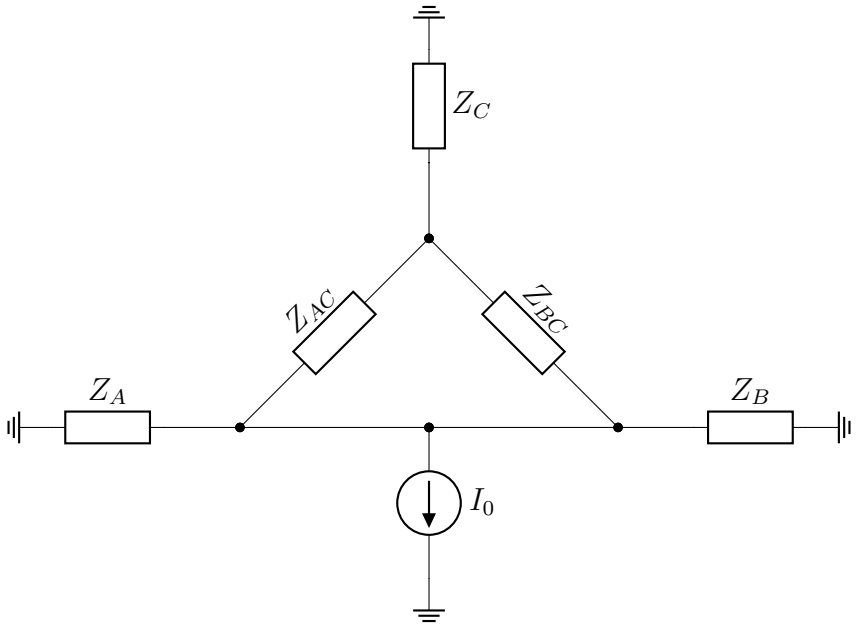

Figure C.3: The zero sequence Thévenin equivalent circuit of the 3 bus system.

The impedance's Z_C, Z_{AC} and Z_{BC} is equivalent to

$$Z'_C = Z_C + \frac{Z_{AC}Z_{BC}}{Z_{AC} + Z_{BC}}. \tag{C.1}$$

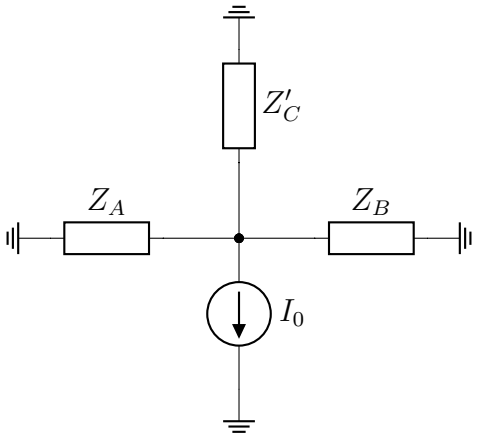

Figure C.4: The zero sequence Thévenin equivalent circuit of the 3 bus system.

Also, the equivalent impedance of the network is equal to

$$Z_T = \frac{1}{\frac{1}{Z_A} + \frac{1}{Z_B} + \frac{1}{Z'_C}} = \frac{1}{\frac{1}{Z_A} + \frac{1}{Z_B} + \frac{1}{Z_C + \frac{Z_{AC}Z_{BC}}{Z_{AC}+Z_{BC}}}} \tag{C.2}$$

By using current division it can be concluded that

$$I_A = \frac{Z_T}{Z_A} I_0 = \frac{\left(\frac{1}{\frac{1}{Z_A} + \frac{1}{Z_B} + \frac{1}{Z_C + \frac{Z_{AC} Z_{BC}}{Z_{AC} + Z_{BC}}}} \right)}{Z_A} I_0 \tag{C.3a}$$

$$I_C = \frac{Z_T}{Z'_C} I_0 = \frac{\left(\frac{1}{\frac{1}{Z_A} + \frac{1}{Z_B} + \frac{1}{Z_C + \frac{Z_{AC} Z_{BC}}{Z_{AC} + Z_{BC}}}} \right)}{Z_C + \frac{Z_{AC} Z_{BC}}{Z_{AC} + Z_{BC}}} I_0 \tag{C.3b}$$

$$\begin{aligned} I_{AC} &= \frac{Z_{BC}}{Z_{AC} + Z_{BC}} I_C = \frac{Z_{BC}}{Z_{AC} + Z_{BC}} \frac{Z_T}{Z'_C} I_0 \\ &= \frac{Z_{BC}}{Z_{AC} + Z_{BC}} \frac{\left(\frac{1}{\frac{1}{Z_A} + \frac{1}{Z_B} + \frac{1}{Z_C + \frac{Z_{AC} Z_{BC}}{Z_{AC} + Z_{BC}}}} \right)}{Z_C + \frac{Z_{AC} Z_{BC}}{Z_{AC} + Z_{BC}}} I_0 \end{aligned} \tag{C.4}$$

The current contribution factor is then the ratio between the current contribution from the adjoining branch and the sum of the current from the shunt and the adjoining brach

$$\begin{aligned} k_{AC} &= \frac{I_{AC}}{I_A + I_{AC}} = \frac{\frac{Z_{BC}}{Z_{AC} + Z_{BC}} I_C}{I_A + \frac{Z_{BC}}{Z_{AC} + Z_{BC}} I_C} = \frac{\frac{Z_{BC}}{Z_{AC} + Z_{BC}} \frac{Z_T}{Z'_C} I_0}{\frac{Z_T}{Z_A} I_0 + \frac{Z_{BC}}{Z_{AC} + Z_{BC}} \frac{Z_T}{Z'_C} I_0} \\ &= \frac{\frac{Z_{BC}}{Z_{AC} + Z_{BC}} \frac{1}{Z'_C}}{\frac{1}{Z_A} + \frac{Z_{BC}}{Z_{AC} + Z_{BC}} \frac{1}{Z'_C}} = \frac{Z_{BC}}{\frac{\left(Z_C + \frac{Z_{AC} Z_{BC}}{Z_{AC} + Z_{BC}} \right) (Z_{AC} + Z_{BC})}{Z_A} + Z_{BC}} \\ &= \frac{Z_A Z_{BC}}{Z_C (Z_{AC} + Z_{BC}) + Z_{AC} Z_{BC} + Z_A Z_{BC}} = \frac{Z_A}{\frac{Z_C Z_B}{Z_{BC}} + Z_{AC} + Z_A} \end{aligned} \tag{C.5}$$

C.2 Series fault

The equivalent circuit for a series fault can be seen in Figure C.5.

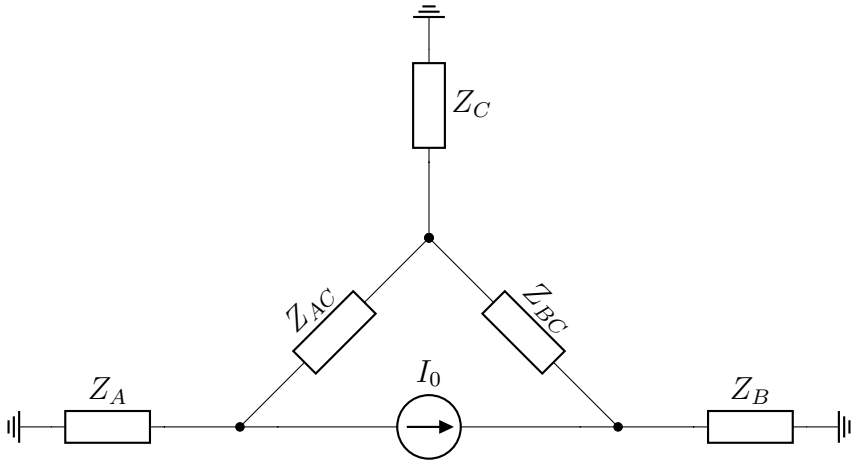

Figure C.5: The zero sequence Thévenin equivalent circuit of the 3 bus system.

$$Z_1 = \frac{Z_B Z_C}{Z_{BC} + Z_B + Z_C} \tag{C.6a}$$

$$Z_2 = \frac{Z_{BC} Z_C}{Z_{BC} + Z_B + Z_C} \tag{C.6b}$$

$$Z_3 = \frac{Z_{BC} Z_B}{Z_{BC} + Z_B + Z_C} \tag{C.6c}$$

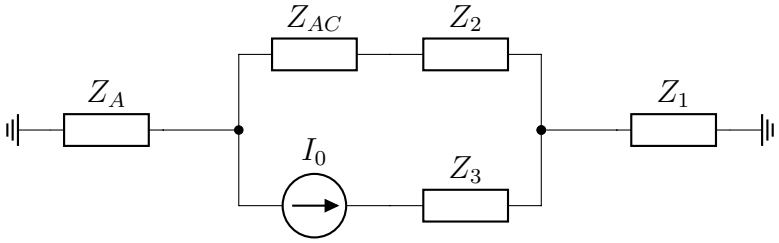

Figure C.6: The zero sequence Thévenin equivalent circuit of the 3 bus system.

Current division gives that

$$\begin{aligned} I_{AC} &= \frac{Z_A + Z_1}{Z_A + Z_{AC} + Z_1 + Z_2} I_0 = \frac{Z_A + \frac{Z_B Z_C}{Z_{BC}+Z_B+Z_C}}{Z_A + Z_{AC} + \frac{Z_B Z_C}{Z_{BC}+Z_B+Z_C} + \frac{Z_{BC} Z_C}{Z_{BC}+Z_B+Z_C}} I_0 \\ &= \frac{Z_A + \frac{Z_B Z_C}{Z_{BC}+Z_B+Z_C}}{Z_A + Z_{AC} + \frac{Z_B Z_C + Z_{BC} Z_C}{Z_{BC}+Z_B+Z_C}} I_0. \end{aligned} \tag{C.7}$$

The current contribution factor is then the ratio between the current contribution from the shunt respectively the adjoining branch and the zero sequence current in

the faulty branch

$$k_{AC} = \frac{I_{AC}}{I_0} = \frac{Z_A + \frac{Z_B Z_C}{Z_{BC}+Z_B+Z_C}}{Z_A + Z_{AC} + \frac{Z_B Z_C + Z_{BC} Z_C}{Z_{BC}+Z_B+Z_C}}. \tag{C.8}$$

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