POWER SYSTEM PRINCIPLES APPLIED IN PROTECTION PRACTICE

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The Problem …

- Calculate & sketch the ZPS, NPS & PPS impedance networks.
- Calculate feeder faults.
- Calculate transmission line fault current.
- Specify suitable CTs for protection scheme.
- Design Over-current protection for the 22kV feeders, busbar and 66/22 kV transformer
- Specify and design Distance Protection that will coordinate with Over-current protection scheme above.

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POWER SYSTEM

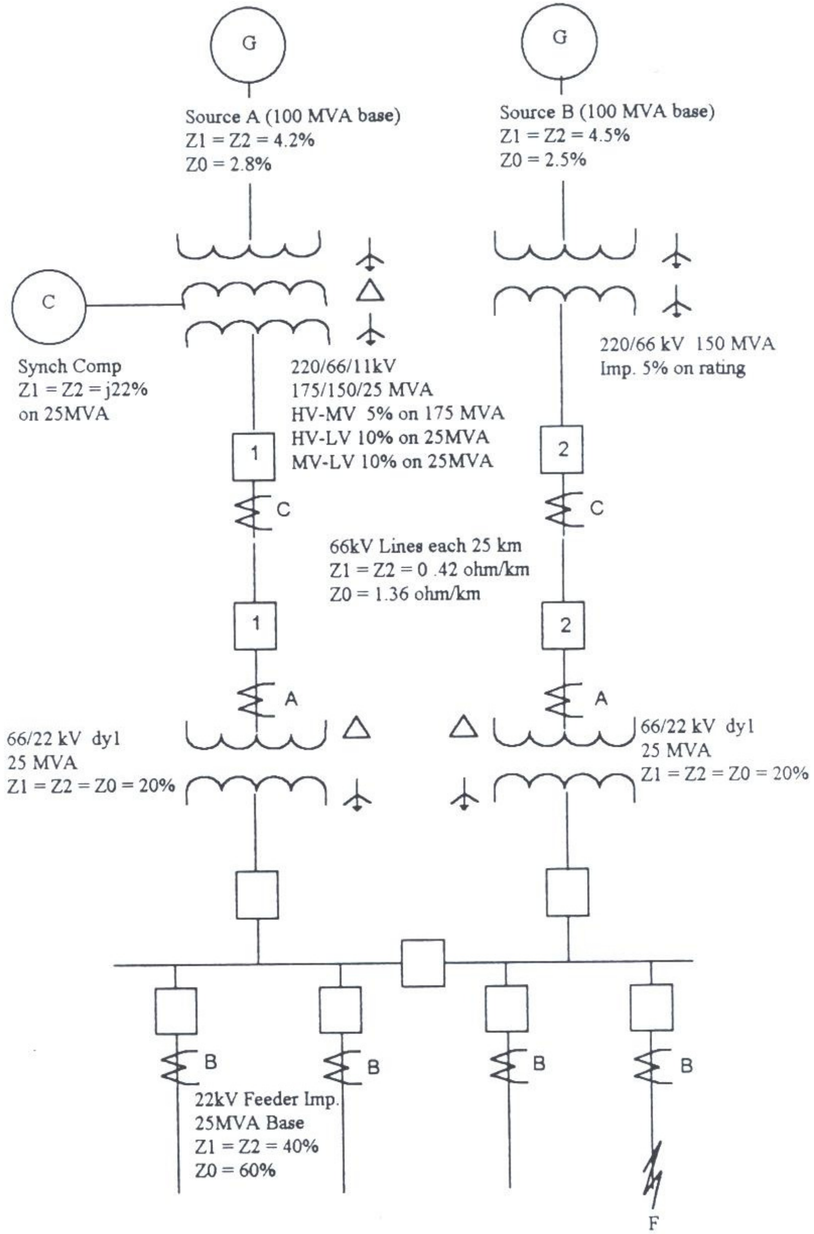


FIGURE 1

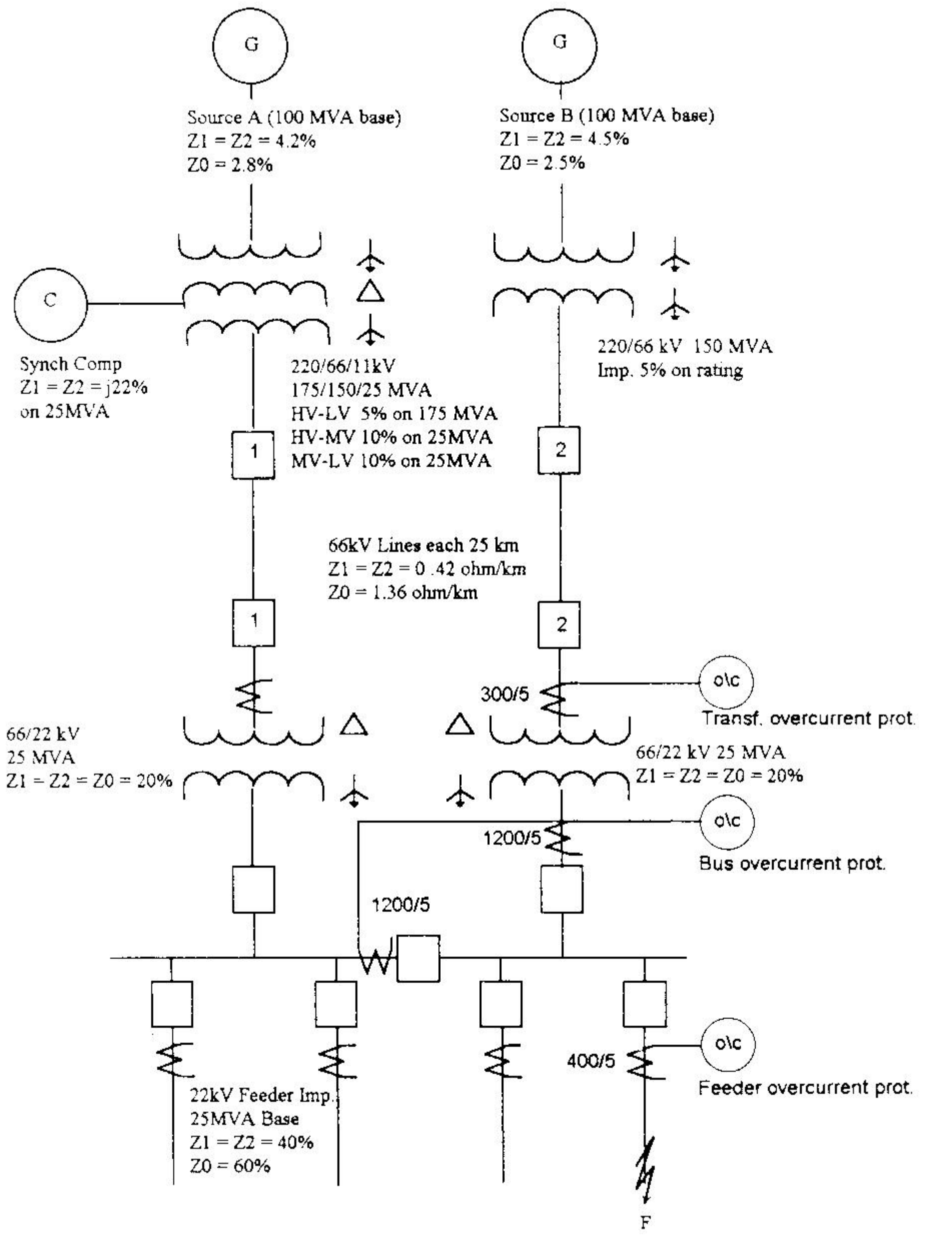
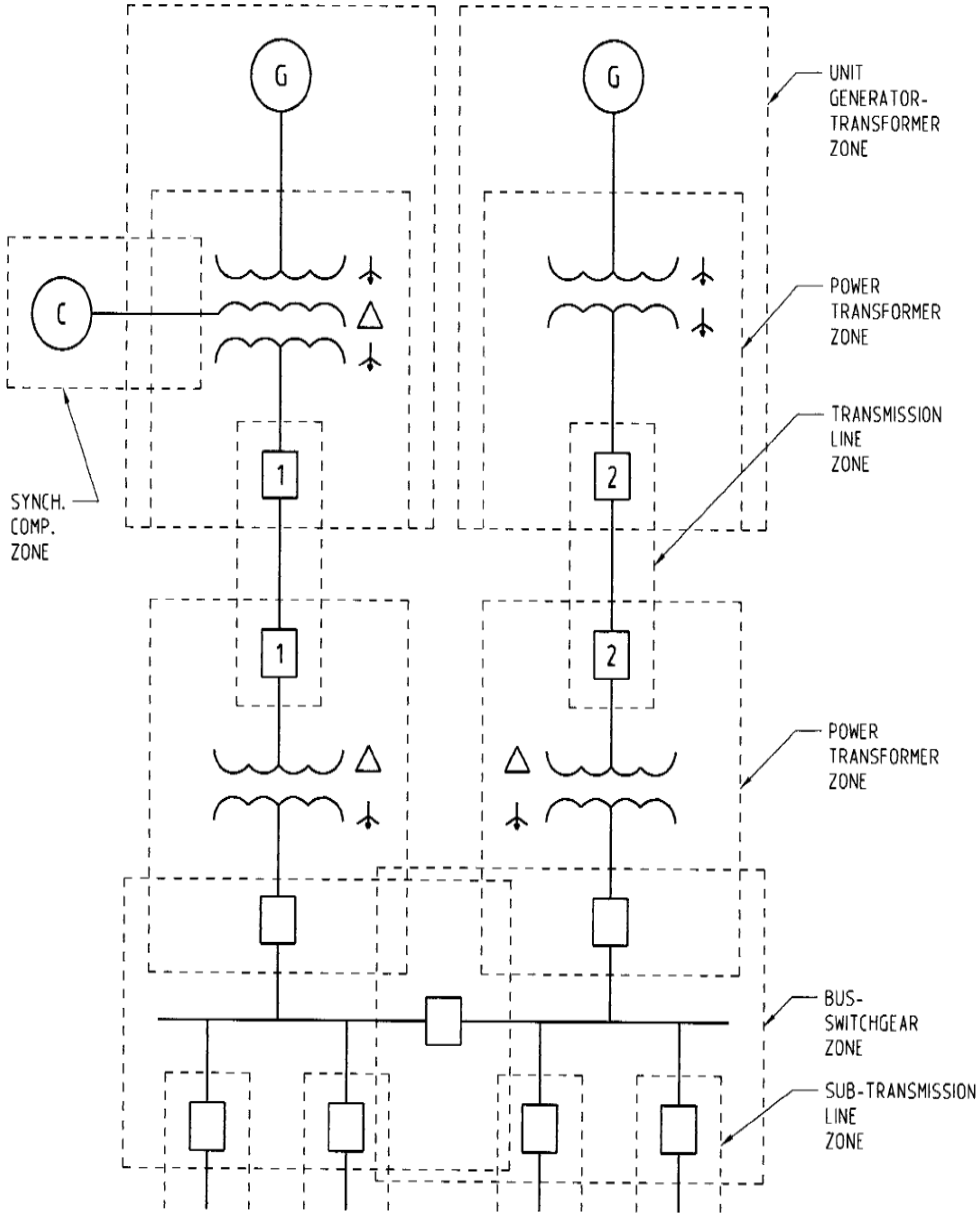

G
G
Source A (100 MVA base)
Z1 = Z2 = 4.2%
Z0 = 2.8%
Source B (100 MVA base)
Z1 = Z2 = 4.5%
Z0 = 2.5%
C
Synch Comp
Z1 = Z2 = j22%
on 25MVA
220/66/11kV
175/150/25 MVA
HV-LV 5% on 175 MVA
HV-MV 10% on 25MVA
MV-LV 10% on 25MVA
220/66 kV 150 MVA
Imp. 5% on rating
1
2
66kV Lines each 25 km
Z1 = Z2 = 0 .42 ohm/km
Z0 = 1.36 ohm/km
1
2
300/5
o\c
Transf. overcurrent prot.
66/22 kV
25 MVA
Z1 = Z2 = Z0 = 20%
66/22 kV 25 MVA
Z1 = Z2 = Z0 = 20%
1200/5
o\c
Bus overcurrent prot.
1200/5
400/5
o\c
Feeder overcurrent prot.
22kV Feeder Imp.
25MVA Base
Z1 = Z2 = 40%
Z0 = 60%
F

FIGURE 2



UNIT GENERATOR-TRANSFORMER ZONE
POWER TRANSFORMER ZONE
TRANSMISSION LINE ZONE
SYNCH. COMP. ZONE
POWER TRANSFORMER ZONE
BUS-SWITCHGEAR ZONE
SUB-TRANSMISSION LINE ZONE
G
G
C
1
1
2
2

PPS, NPS and ZPS Calculations

For a fault 'F', at the end of the 22 kV feeder, sketch the positive phase sequence (PPS), negative phase sequence (NPS) and zero phase sequence (ZPS) impedance networks. Show the value of all impedances as % on a 25 MVA base.

THE DESIGN

FAULT CALCULATION

Equation used for reactances already expressed as a percentage

$$X\%_{NEW\ BASE} = Z\% \frac{MVA_{NEW\ BASE}}{MVA_{RATING}}$$

Equation used for reactances expressed as ohmic values:

$$X\%_{NEW\ BASE} = Z\Omega \frac{MVA_{NEW\ BASE}}{kV^2} 100$$

1. Source A

$$Z1 = Z2 = 4.2\% \times \frac{25}{100} = \underline{1.050\%}$$

$$Z0 = 2.8\% \times \frac{25}{100} = \underline{0.700\%}$$

2. Source B

$$Z1 = Z2 = 4.5\% \times \frac{25}{100} = \underline{1.125\%}$$

$$Z0 = 2.5\% \times \frac{25}{100} = \underline{0.625\%}$$

3. Synchronous Compensator (already on 25MVA base)

$$Z1 = Z2 = \underline{22.000\%}$$

4. 220/66/11kV Three Winding Transformer in Line 1

$$HV - MV = 5\% \times \frac{25}{175} = \underline{0.714\%}$$

Therefore Leakage impedances expressed on 25MVA base are:

$$HV - MV = 0.714\%$$

$$HV - LV = 10.000\%$$

$$MV - LV = 10.000\%$$

Using:

$$Z_H = \frac{1}{2}(Z_{HM} + Z_{HL} - Z_{ML}) = \frac{1}{2}(0.714 + 10.000 - 10.000) = \underline{0.357\%}$$

$$Z_M = \frac{1}{2}(Z_{HM} + Z_{ML} - Z_{HL}) = \frac{1}{2}(0.714 + 10.000 - 10.000) = \underline{0.357\%}$$

$$Z_L = \frac{1}{2}(Z_{HL} + Z_{ML} - Z_{HM}) = \frac{1}{2}(10.000 + 10.000 - 0.714) = \underline{9.643\%}$$

The same result could have been obtained by solving three simultaneous equations of the form:

$$HV + MV = 0.714$$

$$HV + LV = 10.000$$

$$MV + LV = 10.000$$

Equivalent diagram of impedances to be incorporated in to *Positive Phase Sequence* (PPS) and *Negative Phase Sequence* (NPS) networks is given in Figure 3 below:

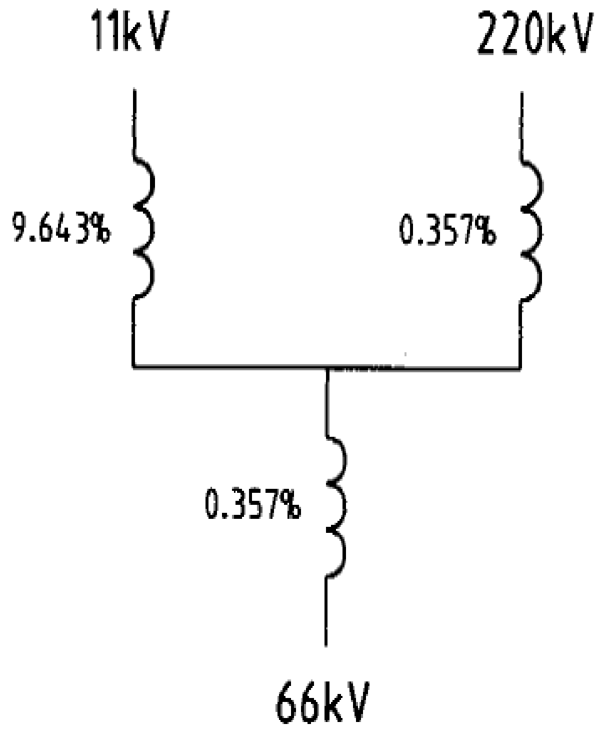


Figure 3
Equivalent Diagram of Three Winding Transformer Impedances

5. 220/66kV Transformer in Line 2

$$Z1 = Z2 = Z0 = 5\% \times \frac{25}{150} = \underline{0.834\%}$$

6. 66kV Transmission Line 1 and 66kV Transmission Line 2

$$Z1 = Z2 = 25km \times 0.42\Omega \times \frac{25}{66^2} \times 100 = \underline{6.026\%}$$

7. 66/22kV Transformer in Line 1 (already on 25MVA base)

$$Z1 = Z2 = Z0 = \underline{20.000\%}$$

8. 66/22kV Transformer in Line 2 (already on 25MVA base)

$$Z1 = Z2 = Z0 = \underline{20.000\%}$$

9. 22kV Feeder with Fault (already on 25MVA base)

Z1 = Z2 = 40.000%

Z0 = 60.000%

Positive Phase Sequence (PPS), *Negative Phase Sequence* (NPS), and *Zero Phase Sequence* Networks (ZPS) are presented in Figures 4, 5, and 6, on pages 6, 7 and 9 respectively.

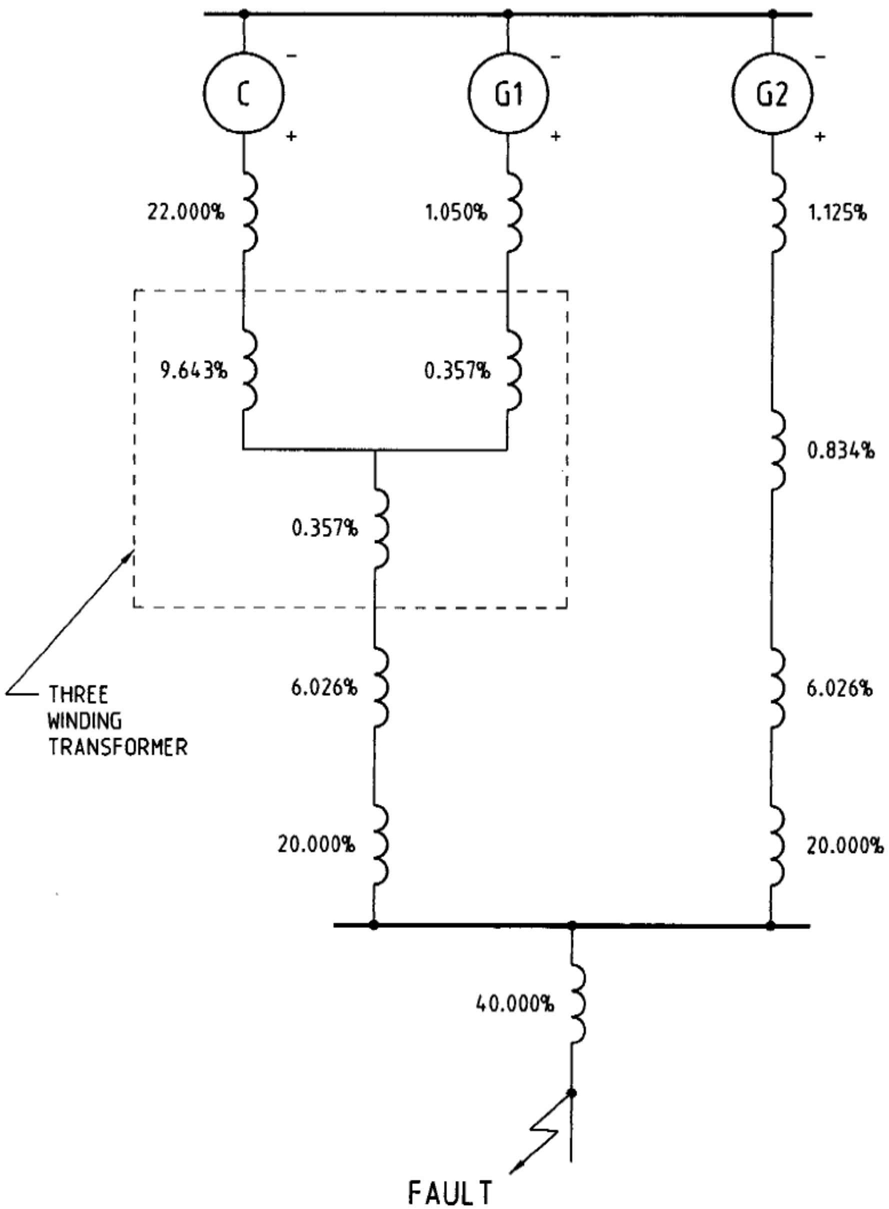


Figure 4
Positive Phase Sequence (PPS) Impedance Network

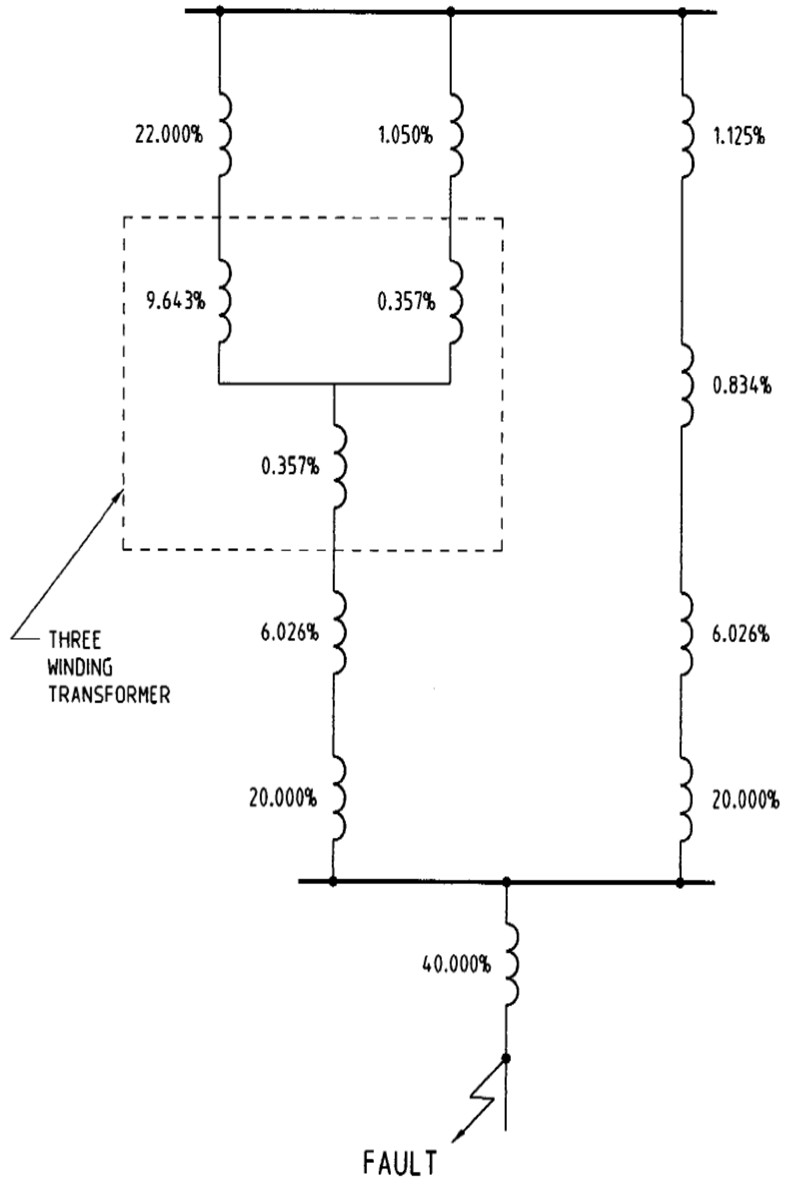


Figure 5

Negative Phase Sequence (NPS) Impedance Network

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Zero Phase Sequence (ZPS) impedance diagram is represented by Z0 of the 22kV feeder combined with Z0's of both 66/22kV transformers, as this is the only area in the network where zero sequence currents can appear relative to the fault.

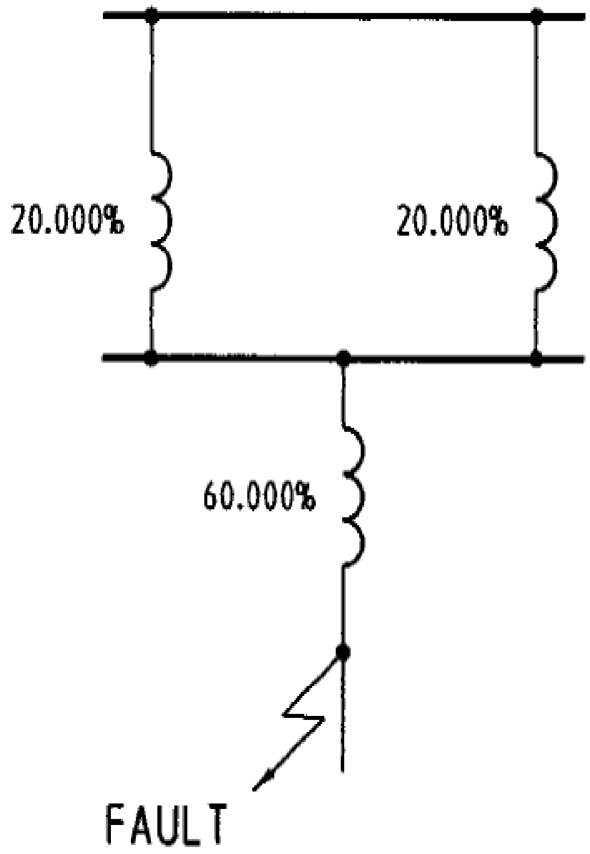


Figure 6
Zero Phase Sequence (PPS) Impedance Network

Calculate the currents at the fault ‘F’, for a three-phase short-circuit and an ‘a’-phase-to-ground short-circuit.

Network Reduction

Individual networks need to be reduced in order that a single reactance to the fault may be ascertained for each of the phase sequence networks.

1. Positive Phase Sequence Impedance Network Reduction (Refer Figure 4)

$$22.000\% \textit{ in series with } 9.643\% = \underline{31.643\%}$$

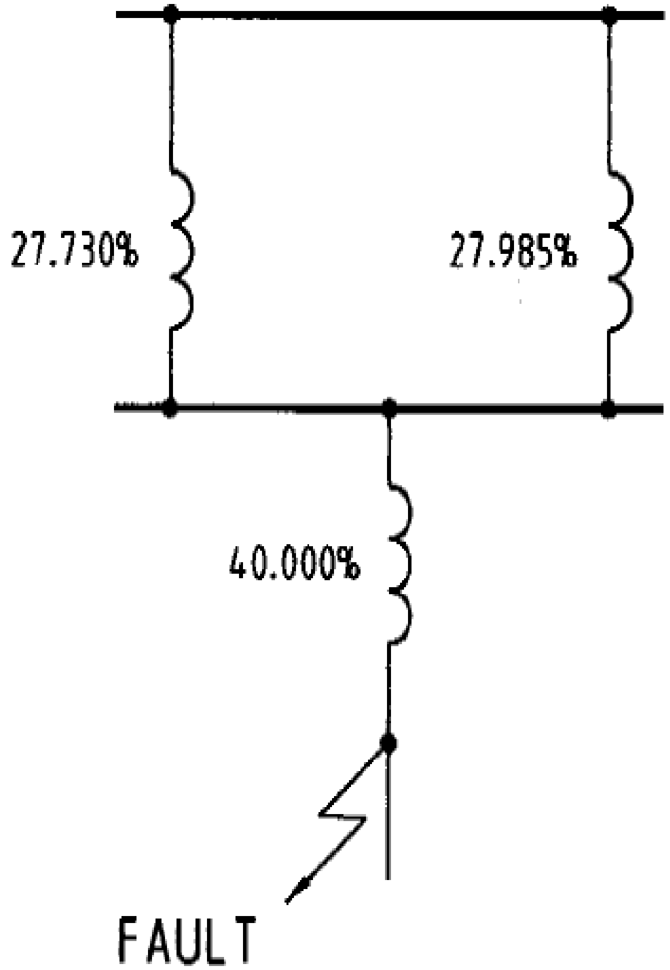
$$1.050\% \textit{ in series with } 0.357\% = \underline{1.407\%}$$

$$31.643\% \textit{ in parallel with } 1.407\% = \frac{31.643\% \times 1.407\%}{31.643\% + 1.407\%} = \underline{1.347\%}$$

$$1.347\% \textit{ in series with } 0.357\% \textit{ and } 6.026\% \textit{ and } 20.000\% = \underline{27.730\%}$$

$$1.125\% \textit{ in series with } 0.834\% \textit{ and } 6.026\% \textit{ and } 20.000\% = \underline{27.985\%}$$

Network is now reduced to:



Total positive phase sequence impedance will be:

$$Z1_{TOTAL} = \frac{27.730\% \times 27.985\%}{27.730\% + 27.985\%} + 40.000\% = \underline{\underline{53.928\%}}$$

2. Negative Phase Sequence Impedance Network Reduction (Refer Figure 5)

The value is exactly the same as for positive phase sequence impedance i.e.:

$$Z2_{TOTAL} = \underline{\underline{53.928\%}}$$

3. Zero Phase Sequence Impedance Network Reduction (Refer Figure 6)

$$Z0_{TOTAL} = \frac{20.000\% \times 20.000\%}{20.000\% + 20.000\%} + 60.000\% = \underline{\underline{70.000\%}}$$

<u>In summary:</u>

$$Z1_{TOTAL} = \underline{\underline{53.928\%}}$$

$$Z2_{TOTAL} = \underline{\underline{53.928\%}}$$

$$Z0_{TOTAL} = \underline{\underline{70.000\%}}$$

Fault Current Calculation

It is now possible to calculate fault currents for symmetrical and asymmetrical faults.

1. Fault Current for Three Phase Short Circuit (Symmetrical Fault)

Equation for a three phase short circuit only involves positive phase sequence impedance and is given by:

$$I_f = \frac{I \times 100}{Z1_{TOTAL}}$$

where I is the current due to 25MVA at 22kV, i.e.:

$$I = \frac{25 \times 10^6}{\sqrt{3} \times 22 \times 10^3} = \underline{656.080A}$$

and fault current will be:

$$I_f = \frac{656.080 \times 100}{53.928} = \underline{\underline{1216.585A}}$$

2. *Fault Current for Phase to Ground Short Circuit (Asymmetrical Fault)*

Equation for a phase to ground short circuit involves all three sequence impedance components and is given by:

$$I_f = \frac{3I \times 100}{Z1_{TOTAL} + Z2_{TOTAL} + Z0_{TOTAL}}$$

therefore fault current will be:

$$I_f = \frac{3 \times 656.080 \times 100}{53.928 + 53.928 + 70.000} = \underline{\underline{1106.648A}}$$

Calculate the current in each phase of the two 66 kV lines for the a--phase-to-ground fault at ‘F’. Remember that a delta/star transformation shifts the PPS and NPS currents each 30° in opposite directions.

Currents in Each Phase of the Two 66kV Lines for a Phase to Ground Fault at "F"

Assume that the phase to ground fault is in phase "A".

The positive, negative and zero phase sequence currents in the fault are equal, and each are one third of I_f, i.e.:

$$I_{f1} = I_{f2} = I_{f0} = \frac{I_f}{3}$$

Where:

I_{f1} = Positive phase sequence current;

I_{f2} = Negative phase sequence current;

I_{f0} = Zero phase sequence current.

In the faulty phase “A”, the total fault current I_{fA} is the sum of the three sequence currents I_1, I_2 and I_0, i.e.:

$$I_{f1} = I_{f2} = I_{f0} = I_f = I_{fA}$$

The total fault current in the phases “B” and “C” is given by:

$$I_{fB} = I_0 + a^2 I_1 + a I_2$$

$$I_{fC} = I_0 + a I_1 + a^2 I_2$$

Where the complex operators “a”, and “a^2” denote a phase shift operation of 120°, and a multiplication of unit magnitude, i.e.:

$$a = 1\angle 120^0 = \cos 120^0 + j \sin 120^0 = -0.5 + j\frac{\sqrt{3}}{2} = -0.5 + j0.866$$

$$a^2 = 1\angle 120^0 \times 1\angle 120^0 = \cos 240^0 + j \sin 240^0 = -0.5 - j\frac{\sqrt{3}}{2} = -0.5 - j0.866$$

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So that:

$$I_{fB} = I_0 - 0.5(I_1 + I_2) - j0.866(I_1 - I_2)$$

$$I_{fC} = I_0 - 0.5(I_1 + I_2) + j0.866(I_1 - I_2)$$

In our problem we have been using 22kV star base to calculate fault currents. To obtain the true currents in 66kV transmission lines i.e. in the secondary of 220/66kV transformers and in the primary of 66/22kV transformers, account must be taken of the phase displacement which occurs with respect to 22kV base.

The equations for these conversions are:

$$I_a' = n\left(I_b'' - I_c''\right) = I_B' - I_C'$$

$$I_b' = n\left(I_c'' - I_a''\right) = I_C' - I_A'$$

$$I_c' = n\left(I_a'' - I_b''\right) = I_A' - I_B'$$

Where:

n = Turns per phase ratio of transformation in the direction of transformation being considered;

I_a' I_b' I_c' = Converted line currents being sought;

I_a'' I_b'' I_c'' = Line currents on star base.

Calculations

Working backwards from the fault (refer Figure 7), to determine the distribution of the current in the two 66kV lines, the total fault current (by current dividers rule) will divide in inverse proportion to the reactances.

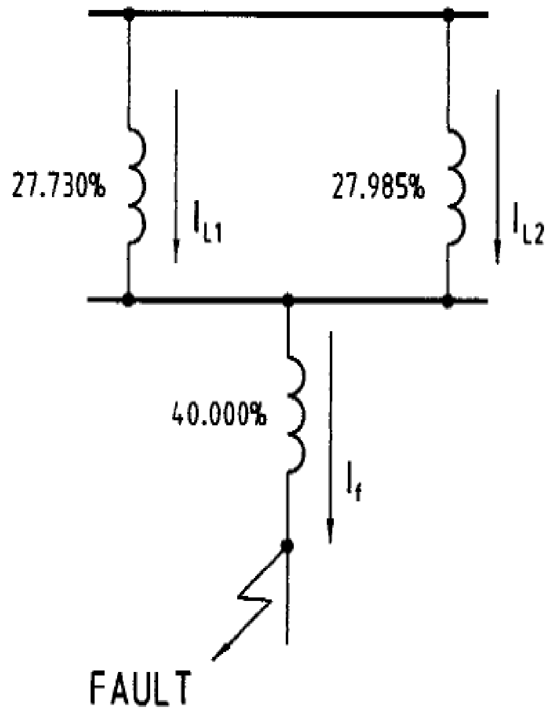

Figure 8
Fault (I_f) Current Division in the Two Transmission Lines

$$I_{L1} = I_f\left(\frac{Z_{L2}}{Z_{L1}+Z_{L2}}\right) = 1106.648\left(\frac{27.985}{27.730+27985}\right) = \underline{555.856A}$$

$$I_{L2} = I_f\left(\frac{Z_{L1}}{Z_{L1}+Z_{L2}}\right) = 1106.648\left(\frac{27.730}{27.730+27985}\right) = \underline{550.792A}$$

1. Currents in 66kV Distribution Line 1

Label 66/22kV transformer in line 1 a $\mathbf{T_1}$, and 66/22kV transformer in line 2 as $\mathbf{T_2}$.

Line 1 contributes 555.856A to the total fault current of 1106 648A.

I_{f1} = Positive sequence network current = 555.856/3 = 185.285A

I_{f2} = Negative sequence network current = 555.856/3 = 185.285A

I_{f0} = Zero sequence network current = 555.856/3 = 185.285A

$$I_{fA} \textit{ in secondary line } T_1 \quad = I_{f1} + I_{f2} + I_{f0} = \underline{555.856A}$$

$$I_{fB} \text{ in secondary line } T_1 = I_0 + a^2 I_1 + aI_2$$
$$= I_0 - 0.5(I_1 + I_2) - j0.866(I_1 - I_2)$$
$$= 185.285 - 0.5(185.285 + 185.285) - j0.866(185.285 - 185.285)$$
$$= 185.285 - 185.285 - j0.866(0)$$
$$= \underline{0A}$$

$$I_{fC} \text{ in secondary line } T_1 = I_0 + aI_1 + a^2 I_2$$
$$= I_0 - 0.5(I_1 + I_2) + j0.866(I_1 - I_2)$$
$$= 185.285 - 0.5(185.285 + 185.285) + j0.866(185.285 - 185.285)$$
$$= 185.285 - 185.285 + j0.866(0)$$
$$= \underline{0A}$$

$$\text{Transformation Ratio} = \frac{22000}{66000 \times \sqrt{3}} = -0.192$$

The minus sign before the turns ratio signifies reversal of line currents due to the delta/star transformation.

The fault currents now, in primary of T1 i.e. ***in 66kV distribution line 1*** are:

$$I_{fA} \text{ in primary line } T_1 = -0.192(0-0) = \underline{\underline{0A}}$$

$$I_{fB} \text{ in primary line } T_1 = -0.192(0-555.856) = \underline{\underline{106.724A}}$$

$$I_{fC} \text{ in primary line } T_1 = -0.192(555.856-0) = \underline{\underline{-106.724A}}$$

2. *Currents in 66kV Distribution Line 2*

Line 2 contributes 550.792A to the total fault current of 1106 648A.

I_{f1} = Positive sequence network current = 550.792/3 = <u>183.597A</u>

I_{f2} = Negative sequence network current = 550.792/3 = <u>183.597A</u>

I_{f0} = Zero sequence network current = 550.792/3 = <u>183.597A</u>

$$I_{fA} \text{ in secondary line } T_2 = I_{f1} + I_{f2} + I_{f0} = \underline{550.792A}$$

$$I_{fB} \text{ in secondary line } T_2 = I_0 + a^2 I_1 + aI_2$$
$$= I_0 - 0.5(I_1 + I_2) - j0.866(I_1 - I_2)$$
$$= 183.597 - 0.5(183.597 + 183.597) - j0.866(183.597 - 183.597)$$
$$= 183.597 - 183.597 - j0.866(0)$$
$$= \underline{0A}$$

$$I_{fC} \text{ in secondary line } T_2 = I_0 + aI_1 + a^2 I_2$$
$$= I_0 - 0.5(I_1 + I_2) + j0.866(I_1 - I_2)$$
$$= 183.597 - 0.5(183.597 + 183.597) + j0.866(183.597 - 183.597)$$
$$= 183.597 - 183.597 + j0.866(0)$$
$$= \underline{0A}$$

$$\boxed{\textit{Transformation Ratio} = \frac{22000}{66000 \times \sqrt{3}} = -0.192}$$

The minus sign before the turns ratio signifies reversal of line currents due to the delta/star transformation.

The fault currents now, in primary of T2 i.e. ***in 66kV distribution line 2*** are:

$$I_{fA} \text{ in primary line } T_2 = -0.192(0-0) = \underline{\underline{0A}}$$

$$I_{fB} \text{ in primary line } T_2 = -0.192(0-550.792) = \underline{\underline{105.752A}}$$

$$I_{fC} \text{ in primary line } T_2 = -0.192(550.792-0) = \underline{\underline{-105.752A}}$$

Specify a suitable CT'B' for the 22 kV feeders, giving a ratio and a performance specification suitable for protections applicable to distribution systems, i.e. protections which operate in greater than 0.2 second.

You can assume that the rated load current of the 22 kV switchgear is 400 amps, that the rated fault capacity is 250 MVA, that the secondary equipment has a 5-amp rating and that the total burden represented by the leads and the relays is 0.7 ohms.

CT "B" Suitable for 22kV Feeder Protection

Given parameters:

1. CT suitable for protections applicable to distribution systems (operate at >0.2 second);
2. Rated load current of 22kV switchgear is 400A;
3. Secondary equipment has a 5A rating;
4. Total burden represented by the leads and relays is 0.7Ω.

Solution:

Select Class P current transformer with rated composite error at accuracy limit current of 10, i.e. **10P**, which is typically satisfactory for this application.

CT ratio will be **400/5**.

For 250MVA at 22kV short circuit current will be:

$$I_{sc} = \frac{250 \times 10^6}{\sqrt{3} \times 22 \times 10^3} = \underline{6561A}$$

$$Acuracy\ Limit\ Factor = \frac{6561A}{400A} = \underline{16.4}$$

Secondary CT current will be:

$$I_{Sec} = \frac{I_{sc}}{CT\ ratio} = \frac{I_{sc}}{\frac{400}{5}} = I_{sc}\frac{5}{400} = 5561 \times \frac{5}{400} = \underline{82A}$$

Rated secondary reference voltage will be:

$$Rated\ Secondary\ Reference\ Voltage = I_{Sec} \times Z = 82 \times 0.7 = 57.40V \cong \underline{60V}$$

Summarising CT Specification *(based on AS 1675 – 1986 – Appendix A):*

Nominal voltage of system, U_n	**22kV**
Highest voltage for equipment U_m	**24kV**
Rated frequency	**50Hz**
Rated insulation level	**LI 125, PF50**
Rated transformation ratio	**400/5**
Rated short-time current	**8kA**
Rated short time	**1s**
Class of insulation	**Class 120 (Class E)**

Specify suitable CT's 'C' for transformer protection and 'A' for 66 kV line protection. Both protections will be required to operate in less than 0.2 second. The power system X / R is to be taken as 4. Design CT 'A' for maximum 22 kV faults.

66 kV CB load current rating is 600 amps, and fault rating at the 220/66 kV station 66 kV bus is 2500 MVA. Burden of leads plus relay is 0.7 ohm. 66/22 kV transformer cyclic rating is 1.2 times nominal. Remember that the exciting current you specify is a measure of the composite error and size of the CT core.

CT "C" Suitable for 66kV Line Protection

Given parameters:

1. CT suitable for 66kV line protection (operate at <0.2 second);
2. Power system X/R is 4;
3. 66kV CB load current is 600A;
4. Fault rating at the 220/66kV station 66kV bus is 2500MVA;
5. Total burden represented by the leads and relays is 0.7Ω.

Solution:

Select Class **PL** current transformer for this application.

Select **5A** secondary current.

Select CT ratio of **600/5**.

For 2500MVA at 66kV short circuit current will be:

$$I_{sc} = \frac{2500 \times 10^6}{\sqrt{3} \times 66 \times 10^3} = \underline{21869A}$$

With transformation ratio of 600/5, secondary CT current corresponding to the maximum primary fault current at which the protection must operate satisfactorily is:

$$I_{Sec} = \frac{21869 \times 5}{600} = \underline{182.24A}$$

This is too high so CT ratio of **1200/5** is selected, giving the secondary CT current of **91.12A,** which is acceptable.

Select maximum secondary winding resistance of **0.6Ω.**

$$TF = 1 + \frac{X}{R} = 1 + 4 = \underline{5}$$

Knee point voltage can now be calculated

$$U_k = TF \times I_{sm}(R_b + R_s)$$
$$= 5 \times 91.12(0.7 + 0.6)$$
$$= \underline{592.28V}$$

Therefore chose knee point voltage of **600V**.

Chose exciting current of **0.2 A**.

CT specification is therefore:

AS 1675 – 1986: 0.2PL 600 R0.6

on 1200/5 ratio

CT "A" Suitable for 66/22kV Transformer Protection

Given parameters:

1. CT suitable for 66/22kV transformer protection (operate at <0.2 second);
2. Power system X/R is 4;
3. 66kV CB load current rating is 600A.
4. CT is to be designed for maximum fault capacity of 250MVA on 22kV;
5. 66/22kV transformer cyclic rating is 1.2 times nominal;
6. Total burden represented by the leads and relays is 0.7Ω.

Solution:

Select Class **PL** current transformer for this application.

Select **5A** secondary current.

For 250MVA at 66kV short circuit current will be:

$$I_{sc} = \frac{250 \times 10^6}{\sqrt{3} \times 66 \times 10^3} = \underline{2186.9A}$$

Primary current of 25MVA, 66/22kV transformer will be:

$$I_{Prim} = \frac{25 \times 10^6}{\sqrt{3} \times 66 \times 10^3} = \underline{218.7A}$$

With transformer cyclic rating of 1.2 primary current is 218.7 x 1.2 = **262.44A.** Therefore the preferred value of 300 is selected and CT ratio is will be **300/5.**

With transformation ratio of 300/5, CT secondary current corresponding to the maximum primary fault current at which the protection must operate satisfactorily is:

$$I_{Sec} = \frac{2186.9 \times 5}{300} = \underline{36.45A}$$

Select maximum secondary winding resistance of **0.2Ω.**

From AS 1675 – 1986 (Appendix B):

$$TF = 1 + \frac{X}{R} = 1 + 4 = \underline{5}$$

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Knee point voltage can now be calculated

$$U_k = TF \times I_{sm}(R_b + R_s)$$
$$= 5 \times 36.45(0.7 + 0.2)$$
$$= 164.025V \cong \underline{170V}$$

Therefore chose knee point voltage of **170V**.

Chose exciting current of **0.1 A**.

CT specification is therefore:

AS 1675 – 1986: 0.1PL 170 R0.2

on 300/5 ratio

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It is planned to apply overcurrent protections to the 22 kV feeders, 22 kV busbars and 66 kV transformer connections of the system shown on Figure 1. CT connections and ratios are shown in Figure 2. Determine minimum operating currents and plot the time/current curves for the three overcurrent protections, showing discriminating margins. Use CDG11 inverse definite minimum-time overcurrent 3-second relays [Reference A.Kalam et. al., 'Power system Protection', Figure 2b, page 5-23]. The bus overcurrent protection is to be set to provide backup for failure of the 22 kV feeder protection and the transformer overcurrent to backup for failure of the bus protection.

The time current curves should be plotted on the log-log graph paper provided.

Base the settings on the three-phase fault currents that you calculated in earlier parts.

Assume the CDG 11 relay has plug settings of 1, 2, 2.5, 3.75 and 5 amps.

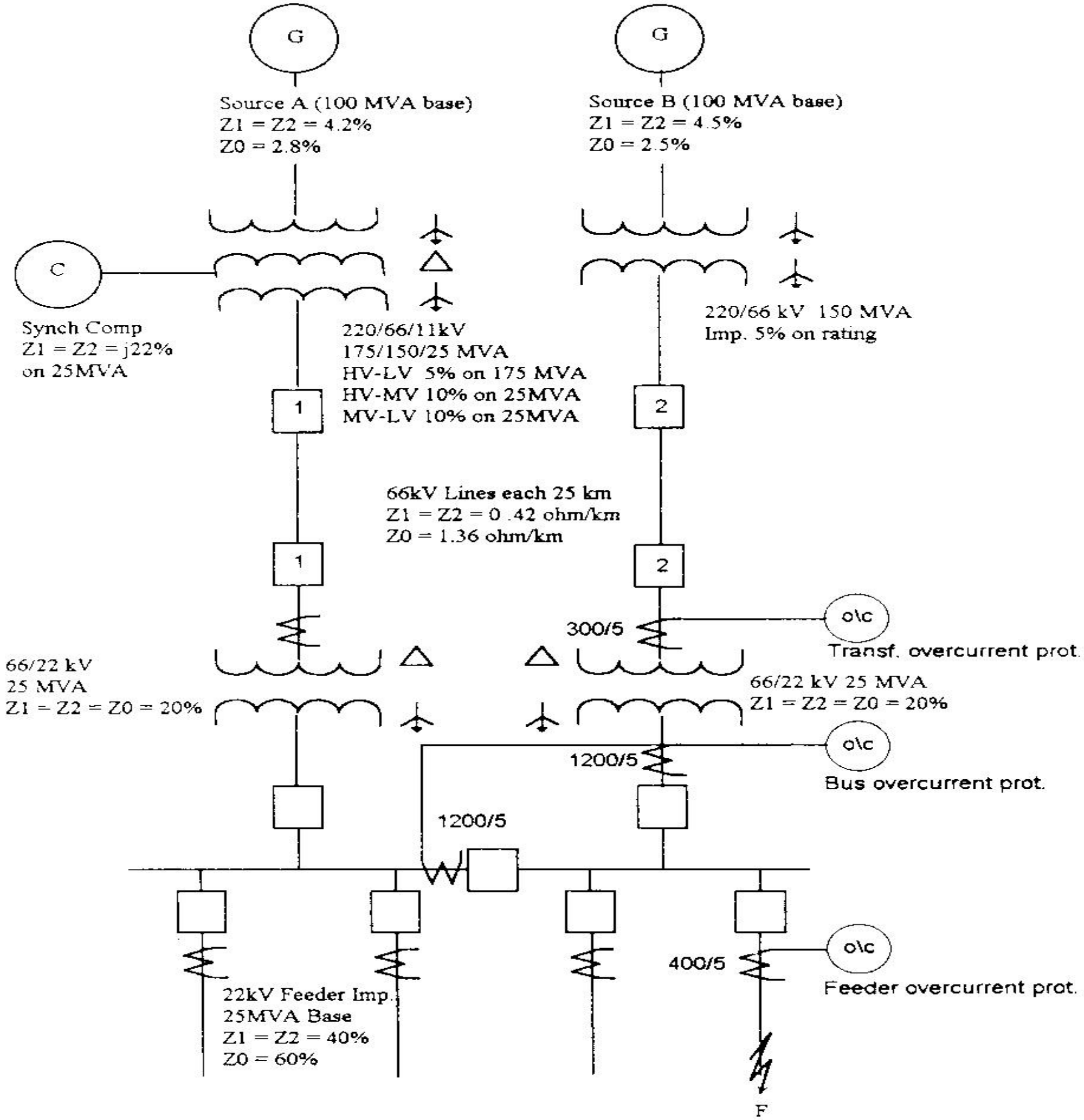
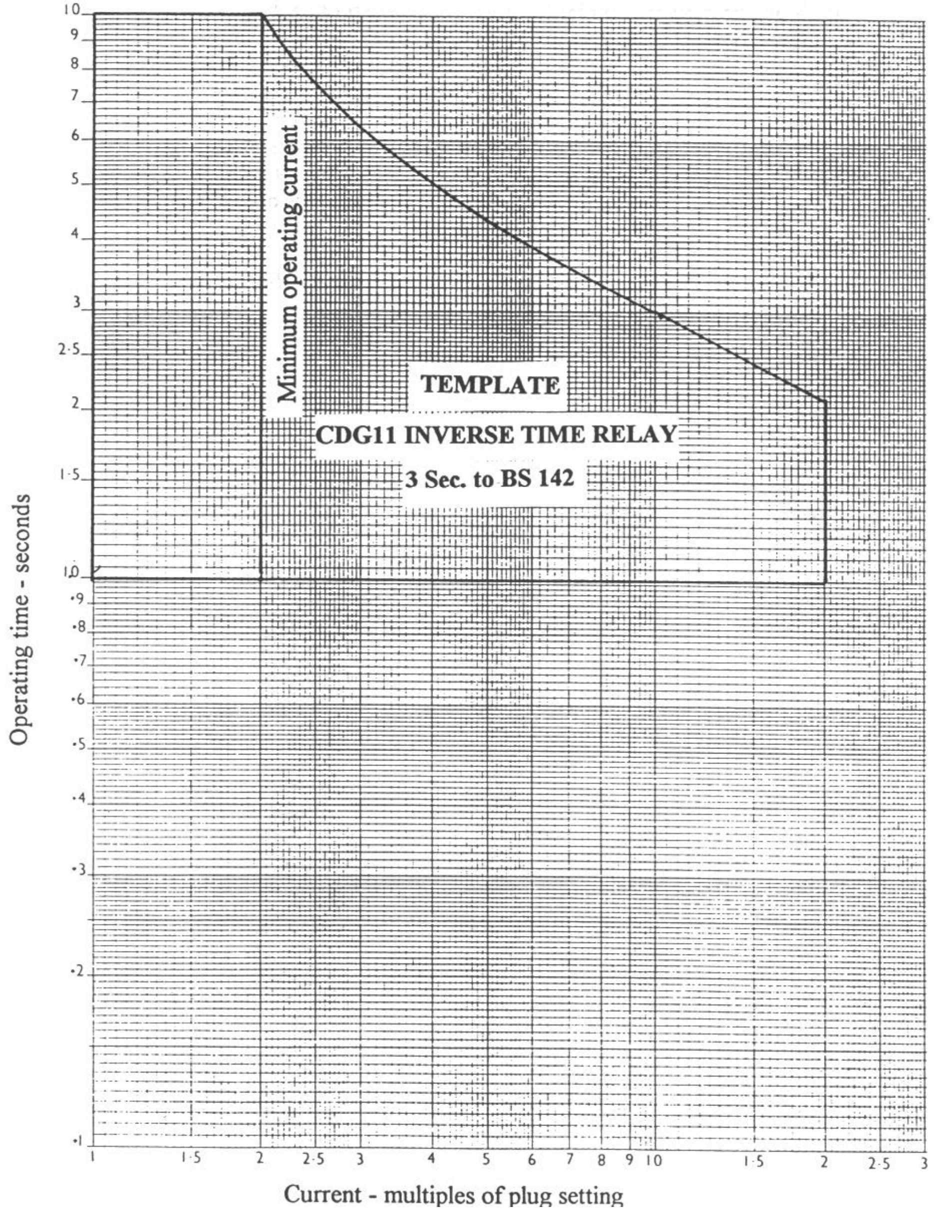

G
G
Source A (100 MVA base)
Z1 = Z2 = 4.2%
Z0 = 2.8%
Source B (100 MVA base)
Z1 = Z2 = 4.5%
Z0 = 2.5%
C
Synch Comp
Z1 = Z2 = j22%
on 25MVA
220/66/11kV
175/150/25 MVA
HV-LV 5% on 175 MVA
HV-MV 10% on 25MVA
MV-LV 10% on 25MVA
220/66 kV 150 MVA
Imp. 5% on rating
1
2
66kV Lines each 25 km
Z1 = Z2 = 0 .42 ohm/km
Z0 = 1.36 ohm/km
1
2
300/5
o\c
Transf. overcurrent prot.
66/22 kV
25 MVA
Z1 = Z2 = Z0 = 20%
66/22 kV 25 MVA
Z1 = Z2 = Z0 = 20%
1200/5
o\c
Bus overcurrent prot.
1200/5
400/5
o\c
Feeder overcurrent prot.
22kV Feeder Imp.
25MVA Base
Z1 = Z2 = 40%
Z0 = 60%
F

FIGURE 2

You can make your own template by plotting the time/current curve on the same scale as the graph paper and cutting along the curve—refer to the example below.

The template can be positioned so that the curve passes through the point at which the relay is required to discriminate and gives a suitable minimum operating level.



Calculations

1. 22kV Feeder Protection

fault current for a three phase symmetrical short circuit was calculated

$$I_{sy} = \frac{MVA_{RATING}}{\sqrt{3} \times V_{SY}} = \frac{25 \times 10^6}{\sqrt{3} \times 22 \times 10^3} = \underline{656.08\ A}$$

Fault current will be:

$$I_f = \frac{I_{sy} \times 100}{Z1_{TOTAL}} = \frac{656.08 \times 100}{53.928} = \underline{\underline{1216.58\ A}}$$

Starting at 22kV feeder furthest from the power source the following parameters are known:

a. CT Ratio = **400/5A**

b. Relay CDG11 (Standard I.D.M.T.) – Current setting = **100%**

c. Maximum fault level = **1216.58A**

Calculate the plug setting multiplier:

$$PSM = \frac{Fault\ Current}{(CT\ Secondary\ Current \times Relay\ Setting)(CT\ Ratio)} = \frac{1216.58}{(5 \times 1.00)(400/5)} = \underline{3.04}$$

Calculate the operating time of the standard I.D.M.T. relay at 3.04 times the relay plug setting and 1.0 TMS:

$$T_m = \frac{0.14}{\left((PSM)^{0.02} - 1.0\right)} = \frac{0.14}{\left((3.04)^{0.02} - 1.0\right)} = \underline{6.23\,\text{sec.}}$$

To permit discrimination with the lower voltage system, and to ensure that the contact travel of this relay is not made unduly small, a time multiplier of ***0.10 = TMS*** is adopted.

An actual tripping time for 22kV protection relay can be calculated as:

$$T = TMS \times T_m = 0.10 \times 6.23 = \underline{0.62\,\text{sec.}}$$

Select a relay with a ***5.0A trip*** and ***0.10 TMS*** for 22kV feeder protection.

2. ***22kV Bus Overcurrent Protection***

For 22kV bus overcurrent protection the following parameters are known:

a. CT Ratio = **1200/5A**

b. Relay CDG11 (Standard I.D.M.T.) – Current setting = **50%**

c. Maximum fault level for grading with 22kV feeder protection = **1216.58A**

Calculate the plug setting multiplier:

$$PSM = \frac{Fault\ Current}{(CT\ Secondary\ Current \times Relay\ Setting)(CT\ Ratio)} = \frac{1216.58}{(5 \times 0.50)(1200/5)} = \underline{2.03}$$

Time Relay at TMS = 0.1, PSM of 2.03 correspond to **Tm = 0.82 sec.**

Using 0.4 sec. grading margin relay discrimination time is = 0.40 + 0.82 = **1.22 sec.**

$$PSM = \frac{Fault\ Current}{(CT\ Secondary\ Current \times Relay\ Setting)(CT\ Ratio)} = \frac{4711}{(5 \times 0.50)(1200/5)} = \underline{7.85}$$

Calculate the operating time of the standard I.D.M.T. relay at 7.85 times the relay plug setting and 1.0 TMS:

$$T_m = \frac{0.14}{\left((PSM)^{0.02} - 1.0\right)} = \frac{0.14}{\left((7.85)^{0.02} - 1.0\right)} = \underline{3.33\,\text{sec.}}$$

Calculate the time multiplier setting:

$$TMS = \frac{T}{T_m} = \frac{1.22}{3.33} = \underline{\underline{0.37}}$$

Select a relay with a ***2.5A trip*** and ***0.37 TMS*** for 22kV bus protection.

3. 66/22kV Transformer Protection

fault current for a three phase symmetrical short circuit was calculated

$$I_{sy} = \frac{MVA_{RATING}}{\sqrt{3} \times V_{SY}} = \frac{25 \times 10^6}{\sqrt{3} \times 66 \times 10^3} = \underline{218.69A}$$

Fault current for a three phase short circuit at transformer secondary will be:

$$I_f = \frac{I_{sy} \times 100}{Z1_{TOTAL}} = \frac{218.69 \times 100}{13.93} = \underline{\underline{1570.17A}}$$

For 66/22kV transformer overcurrent protection the following parameters are known:

a. CT Ratio = **300/5A**

b. Relay CDG11 (Standard I.D.M.T.) – Current setting = **100%**

c. Maximum fault level for grading with 22kV bus protection = **1570.17A**

Calculate the plug setting multiplier:

$$PSM = \frac{Fault\ Current}{(CT\ Secondary\ Current \times Relay\ Setting)(CT\ Ratio)} = \frac{1570.17}{(5 \times 1.00)(300/5)} = \underline{5.23}$$

Calculate the operating time of the standard I.D.M.T. relay at 5.23 times the relay plug setting and 1.0 TMS:

$$T_m = \frac{0.14}{\left((PSM)^{0.02} - 1.0\right)} = \frac{0.14}{\left((5.23)^{0.02} - 1.0\right)} = \underline{4.16\,\text{sec.}}$$

Using 0.4 sec. grading margin, relay discrimination time is = 1.22 + 0.4 = **1.62 sec.**

Calculate the time multiplier setting:

$$TMS = \frac{T}{T_m} = \frac{1.62}{4.16} = \underline{\underline{0.39}}$$

Select a relay with a ***5.0A trip*** and ***0.39 TMS*** for 66/22kV transformer protection.

The time/current curves for three overcurrent protections

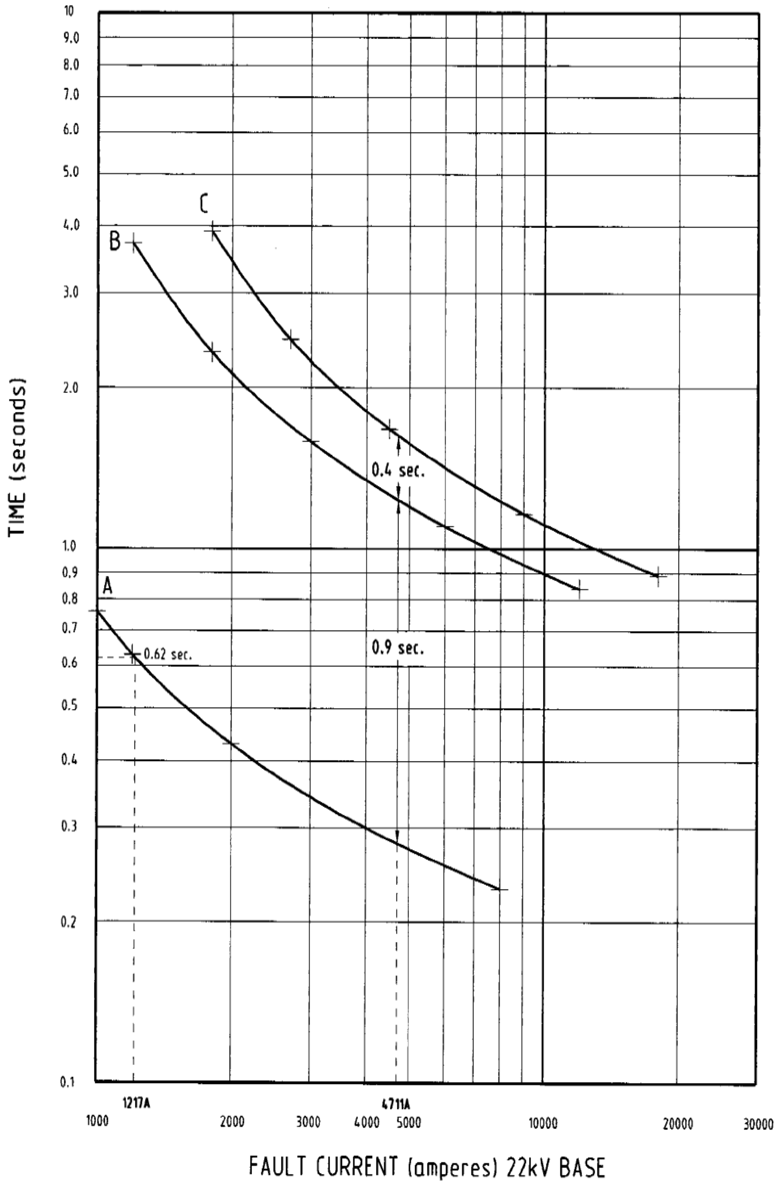


Figure 2.1

A = Time/Current Curve for 22kV Feeder Overcurrent Protection Relay;

B = Time/Current Curve for 22kV Bus Overcurrent Protection Relay;

C = Time/Current Curve for 66/22kV Transformer Overcurrent Protection Relay.

Plotting can be done by using master template, or by calculating the coordinates as outlined below:

22kV Feeder Overcurrent Protection Relay				
PSM	**Prim. Current (A) (22kV Base)**	**Tm**	**TMS**	**T = Tm x TMS**
2.5	**1000**	7.57	0.10	**0.76**
3	**1200**	6.30	0.10	**0.63**
5	**2000**	4.28	0.10	**0.43**
10	**4000**	2.97	0.10	**0.30**
20	**8000**	2.27	0.10	**0.23**

22kV Bus Overcurrent Protection Relay				
PSM	Prim. Current (A) (22kV Base)	Tm	TMS	T = Tm x TMS
2	**1200**	10.03	0.37	**3.71**
3	**1800**	6.30	0.37	**2.33**
5	**3000**	4.28	0.37	**1.58**
10	**6000**	2.97	0.37	**1.10**
20	**12000**	2.27	0.37	**0.84**

66/22kV Transformer Overcurrent Protection Relay				
PSM	Prim. Current (A) (22kV Base)	Tm	TMS	T = Tm x TMS
2	**1800**	10.03	0.39	**3.91**
3	**2700**	6.30	0.390	**2.46**
5	**4500**	4.28	0.39	**1.67**
10	**9000**	2.97	0.39	**1.16**
20	**18000**	2.27	0.39	**0.89**

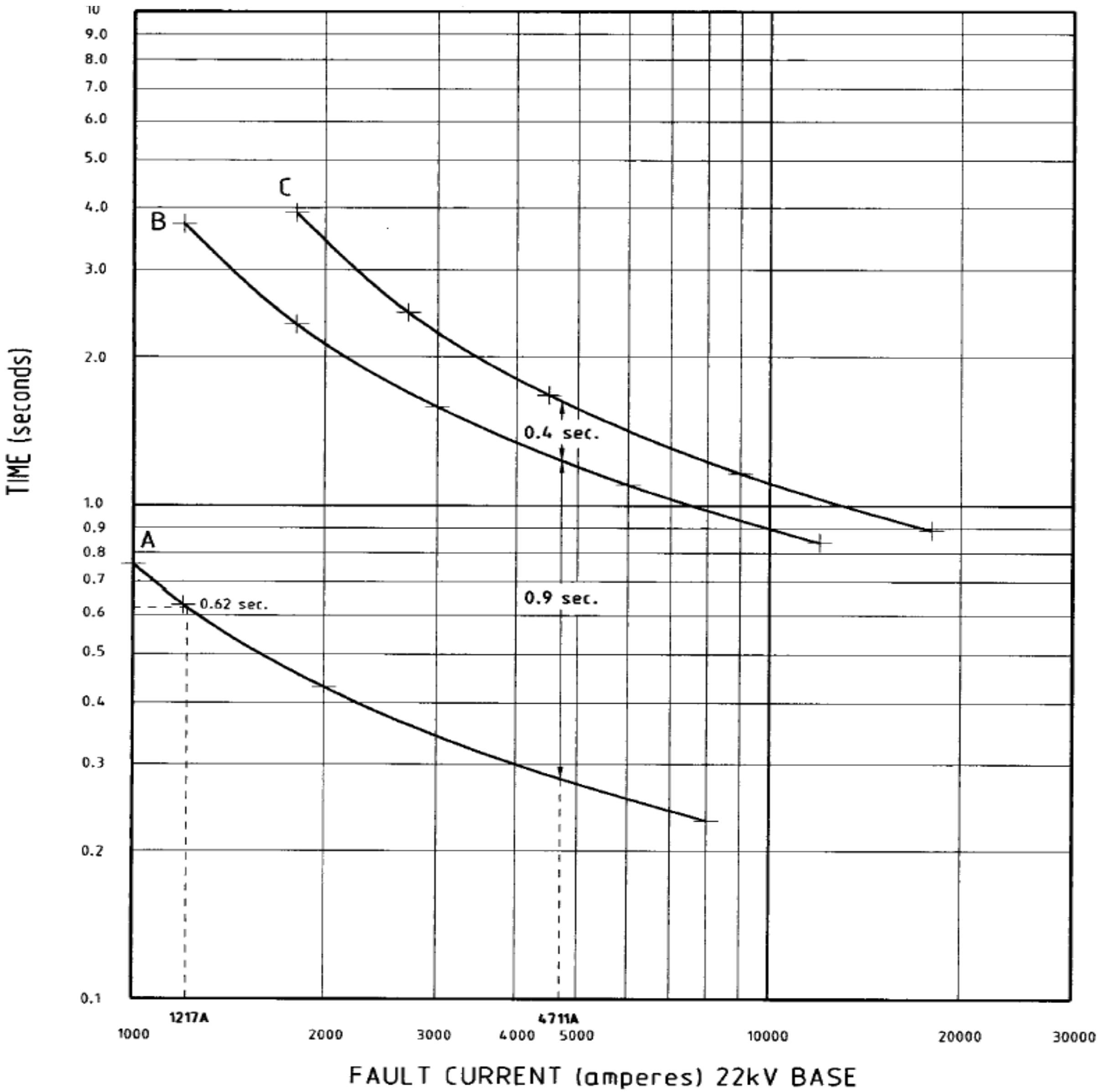


Figure 2.1

A = Time/Current Curve for 22kV Feeder Overcurrent Protection Relay;
B = Time/Current Curve for 22kV Bus Overcurrent Protection Relay;
C = Time/Current Curve for 66/22kV Transformer Overcurrent Protection Relay.

A three-zone distance protection is planned for the protection of the 66 kV line 2 in the system on figure 1 (connected to CT 'C' at the 220 kV station end). Assume that the zone 3 characteristic is an offset mho with 20% reverse reach and that zones 1 and 2 have an mho characteristic. Relay characteristic angle is 60°. Zone 3 reach is to be set to provide backup for failure of transformer protection.

(i) List the measuring elements that comprise a full distance scheme and the voltages and currents measured by each element.

(ii) Select suitable impedance settings, in primary ohms, for each zone and plot your results on an X-R polar diagram. Show the likely locus of the load under all possible operating conditions, given that the emergency rating of the 22 kV station is 120% of one transformer.

(iii) Select zone time settings that will coordinate with the overcurrent protection settings calculated in part (f).

(iv) Using current and voltage sequence components, calculate the current, voltage and impedance measured by the b-c phase element of the distance relay for a b-c phase fault at the end of the 66 kV line.

Remember that the PPS voltage at the fault is determined by the voltage drop from the source to the fault, through the PPS impedance network and the NPS voltage is maximum at the fault and zero at the source. Calculate the PPS and NPS at the relay location by proportion and add vectorially to obtain the actual voltage.

Part a) - Protection Scheme Components

Components of distance/impedance protection scheme for 66kV transmission line are:

1. **Current Transformer** (CT) **AS 1675 – 1986: 0.2PL 600 R0.6** on **1200/5** ratio. This is a PL class CT suitable for operation in less than 0.2 seconds, with 0.2A exciting current, 600V knee point voltage, and 0.6Ω secondary resistance. This CT will be required to measure maximum fault currents of 21869A (for 2500MVA fault capacity on 66kV, and load currents of 600A.
2. **Voltage Transformer** (VT) of conventional electromagnetic construction. This could be a cast resin insulated PT, which are available for voltages up to 66kV. For distance/impedance protection, where phase relationship between current and voltage is important, we will use accuracy Class 3 with **66000/110V** transformation ratio.
3. **Relay Unit** (with continuous setting adjustment 0f 0.25 – 8 ohms on 5A basis) typically comprising of:
   a. ***Two offset mho units*** (with three elements each). The first operates as earth-fault starting and third zone measuring relay, and the second operates as phase-fault starting and third zone measuring relay.
   b. ***Two polarised mho units*** (with three elements each). The first unit acts as first and second zone earth-fault measuring relay, and the second unit acts as first and second zone phase-fault measuring relay.
   c. ***Two time-delay relays*** for second and third zone time measurement.

Assuming full non-switched distance protection scheme, the relay would incorporate 18 measuring elements, 6 for each zone. Within each zone 3 elements are for phase faults and 3 are for earth faults. For each type of fault a particular pair of voltage and current values will be measured, requiring simultaneous monitoring of up to 6 voltage and current pairs and 18 comparisons of the measured values with the set values.

Six comparisons required per phase, with corresponding voltages and currents to be measured are listed in Table 3.1 below:

Table 3.1

For Earth Faults					
a - e	Va	→	Ia	+	KIg
b - e	Vb	→	Ib	+	KIg
c - e	Vc	→	Ic	+	KIg
For Phase Faults					
a - b	Vab	→	Ia	-	Ib
b - c	Vac	→	Ib	-	Ic
c - a	Vca	→	Ic	-	Ia

Part b) – Zone Impedance Settings and X-R Polar Diagram

For distance/impedance relay setting calculations, first convert all required percent impedance values to ohmic values at a common voltage base of 66kV.

Equations used are:

$$Z_{(\Omega)} = \frac{kV^2 \times Z\%}{MVA_{BASE} \times 100}$$

$$Z_{(\Omega)\,TO\,BASE\,V2} = Z_{(\Omega)\,TO\,BASE\,V1}\left(\frac{BASE\,V_2}{BASE\,V_1}\right)^2$$

Note: Transformer primary's are used to determine base voltage.

1. *Source B*

$$Z_{1(\Omega)} = Z_{2(\Omega)} = \frac{220^2 \times 4.5\%}{100 \times 100} = 21.780\,\Omega$$

$$Z_{1(\Omega)\,TO\,BASE\,66kV} = Z_{2(\Omega)\,TO\,BASE\,66kV} = Z_{1(\Omega)\,TO\,BASE\,220kV}\left(\frac{66}{220}\right)^2 = 21.780 \times \left(\frac{66}{220}\right)^2 = \underline{1.960\,\Omega}$$

$$Z_{0(\Omega)} = \frac{220^2 \times 2.5\%}{100 \times 100} = 12.100\,\Omega$$

$$Z_{0(\Omega)\,TO\,BASE\,66kV} = Z_{0(\Omega)\,TO\,BASE\,220kV}\left(\frac{66}{220}\right)^2 = 12.100 \times \left(\frac{66}{220}\right)^2 = \underline{1.089\,\Omega}$$

2. *220/66kV Transformer in Line 2*

$$Z_{1(\Omega)} = Z_{2(\Omega)} = Z_{0(\Omega)} = \frac{220^2 \times 5.0\%}{150 \times 100} = 16.134\,\Omega$$

$$Z_{1(\Omega)\,TO\ BASE\ 66kV} = Z_{2(\Omega)\,TO\ BASE\ 66kV} = Z_{0(\Omega)\,TO\ BASE\ 66kV} = 16.134 \times \left(\frac{66}{220}\right)^2 = \underline{1.452\,\Omega}$$

3. *66kV Transmission Line 2*

$$Z_{1(\Omega)} = Z_{2(\Omega)} = 25km \times 0.42\Omega = \underline{10.500\,\Omega}$$

$$Z_{0(\Omega)} = 25km \times 1.36\Omega = \underline{34.000\,\Omega}$$

4. *66/22kV Transformer in Line 2*

$$Z_{1(\Omega)} = Z_{2(\Omega)} = Z_{0(\Omega)} = \frac{66^2 \times 20\%}{25 \times 100} = \underline{34.848\,\Omega}$$

5. ***22kV Feeder***

$$Z_{1(\Omega)} = Z_{2(\Omega)} = \frac{22^2 \times 40\%}{25 \times 100} = 7.744\,\Omega$$

$$Z_{1(\Omega)\,TO\,BASE\,66kV} = Z_{2(\Omega)\,TO\,BASE\,66kV} = Z_{1(\Omega)\,TO\,BASE\,22kV}\left(\frac{66}{22}\right)^2 = 7.744 \times \left(\frac{66}{22}\right)^2 = \underline{69.696\,\Omega}$$

Relay Setting Calculations

(Assume 66kV transmission line angle impedance of 60^0).

1. ***Zone 1 (reach to cover 80% of protected 66kV transmission line)***

Line Impedance **Z1 = 10.500Ω**

Required Zone 1 setting in primary ohms:

$$Z_{PRIM} = 0.8 \times 10.500\,\Omega = \underline{\underline{8.400\,\Omega}}$$

Required Zone 1 setting in secondary ohms:

$$Z_{SEC} = Z_{PRIM} \times \frac{CT\ Ratio}{VT\ Ratio} = 8.400 \times \frac{1200/5}{66000/110} = \underline{\underline{3.360\,\Omega}}$$

2. *Zone 2 (reach to cover 120% of protected 66kV transmission line – covering whole transmission line and reaching partially in to 66/22kV transformer)*

Line Impedance **Z1 = 10.500Ω**

Required Zone 2 setting in primary ohms:

$$Z_{PRIM} = 1.2 \times 10.500\ \Omega = \underline{\underline{12.600\ \Omega}}$$

Required Zone 2 setting in secondary ohms:

$$Z_{SEC} = Z_{PRIM} \times \frac{CT\ Ratio}{VT\ Ratio} = 12.600 \times \frac{1200/5}{66000/110} = \underline{\underline{5.040\ \Omega}}$$

3. *Zone 3 (reach to cover 120% of protected 66kV transmission line plus 66/22kV transformer*

Line Impedance **Z1 = 10.500Ω + 34.848Ω = 45.348Ω**

Required Zone 3 setting in primary ohms:

$$Z_{PRIM} = 1.2 \times 45.348\ \Omega = \underline{\underline{54.418\ \Omega}}$$

Required Zone 3 setting in secondary ohms:

$$Z_{SEC} = Z_{PRIM} \times \frac{CT\ Ratio}{VT\ Ratio} = 54.418 \times \frac{1200/5}{66000/110} = \underline{\underline{21.767\Omega}}$$

Zone 3 with 20% offset (as shown on the X – R polar diagram will provide backup protection for both 220/66kV and 66/22kV transformers.

X – R Polar Diagram

Per phase load impedance can be found from:

$$Z_{LOAD/PHASE} = \frac{V_{PHASE}}{I_{LOAD} \times 1.2} = \frac{66000/\sqrt{3}}{218.693 \times 1.2} = \underline{145.200\Omega}$$

For illustration purposes I have assumed that load **30^0 lag/lead** (i.e **cosφ = 0.866**) should cover the likely locus of the load under all possible operating conditions, although in practice, **cosφ** could be much closer to unity.

Above calculations can be represented on X – R polar diagram shown in Figure 3.1 below:

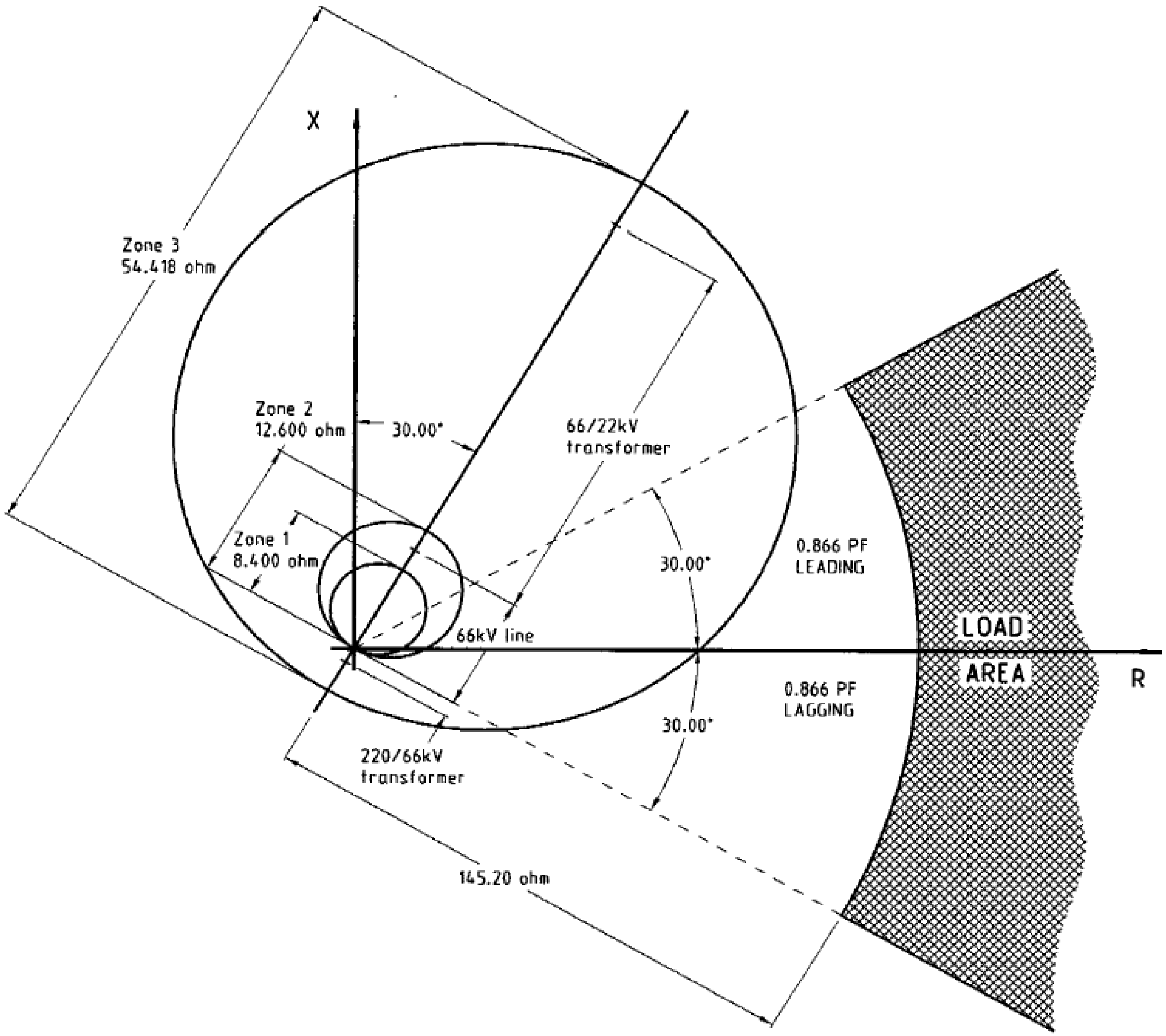

X
Zone 3
54.418 ohm
Zone 2
12.600 ohm
30.00°
66/22kV
transformer
Zone 1
8.400 ohm
30.00°
0.866 PF
LEADING
66kV line
LOAD
AREA
R
0.866 PF
LAGGING
30.00°
220/66kV
transformer
145.20 ohm

Figure 3.1

Part c) – Relay Time Settings

For proper coordination with the overcurrent protection settings calculated in question 2, following zone time settings should be selected:

1. **Zone 1** – Instantaneous operation;
2. **Zone 2** – **1.58** seconds time delay;
3. **Zone 3** – **3.50** seconds time delay.

Part d) – Current , Voltage and Impedance Measured by the b – c Phase Element of the Distance Relay for a b – c Phase Fault at the End of the 66kV Line

For double phase fault (b – c), positive and negative sequence networks are connected in parallel, and there is no zero sequence network connection in the equivalent circuit.

Figure 3.2 below illustrates the defining and equivalent circuits for double phase (b – c) fault:

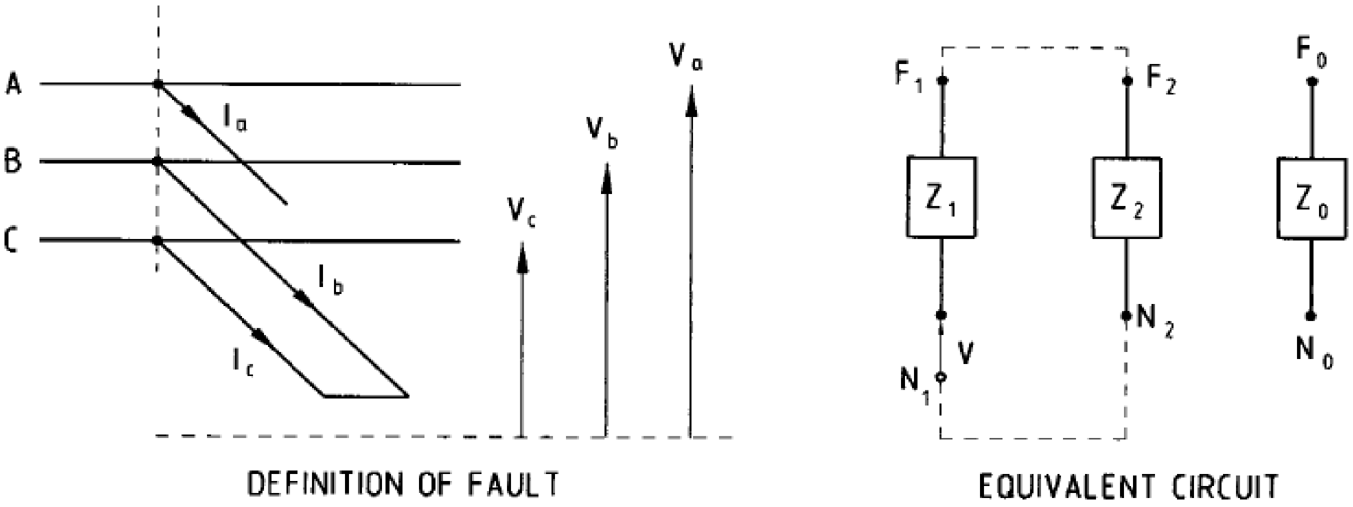


Figure 3.2

Assumptions and Symmetrical Component Circuit Theory Used

1. The calculations are on the basis that the various impedances are purely reactive i.e. that Z will be R + jX, where R is zero, therefore the resistance components of generators and transformers are neglected and *lumped reactance constants* are used.
2. All generated voltages are equal and in phase.
3. The faults occur with no load on the system, and transformer magnetising shunt admittance and transformer line capacitance are neglected.
4. The transmission circuits are separated by sufficient distance that the mutual impedance between lines for zero sequence currents can be neglected.
5. Effect of arc resistance has been neglected.

To determine unbalanced currents and voltages from the sequence components, following fundamental equations will be applied:

$$I_a = I_{a1} + I_{a2} + I_{a0}$$

$$V_a = V_{a1} + V_{a2} + V_{a0}$$

$$I_b = a^2 I_{a1} + a I_{a2} + I_{a0}$$

$$V_b = a^2 V_{a1} + a V_{a2} + V_{a0}$$

$$I_c = a I_{a1} + a^2 I_{a2} + I_{a0}$$

$$V_c = a V_{a1} + a^2 V_{a2} + V_{a0}$$

From three phase unbalanced set the equations defining the sequence quantities are:

$$I_0 = \frac{1}{3}(I_a + I_b + I_c)$$

$$V_0 = \frac{1}{3}(V_a + V_b + V_c)$$

$$I_1 = \frac{1}{3}(I_a + aI_b + a^2 I_c)$$

$$V_1 = \frac{1}{3}(V_a + aV_b + a^2 V_c)$$

$$I_2 = \frac{1}{3}(I_a + a^2 I_b + aI_c)$$

$$V_2 = \frac{1}{3}(V_a + a^2 V_b + aV_c)$$

Also, from Figure 3.2 following applies:

$I_a = 0$

$I_b = - I_c$

$V_b = V_c$

$I_{a2} = - I_{a1}$

$I_{a0} = 0$

$V_{a1} = V_{a2}$

Calculations

Equivalent circuit and impedance network for Question 3d) is resented in the Figure 3.3 below:

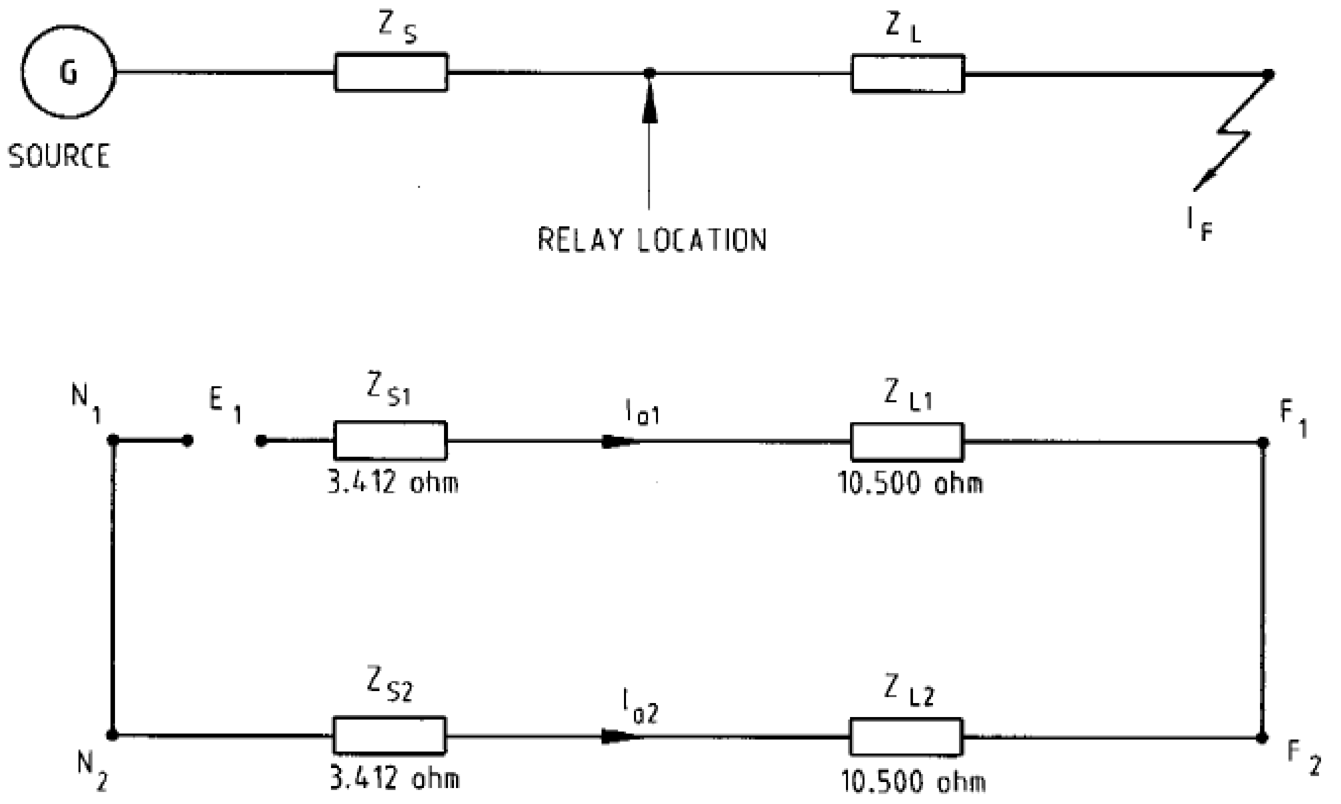


Figure 3.3

Referring to equations on page 15 and impedance network presented in figure 3.3 calculations are as follows (use % impedance values on 25MVA base developed in Assignment 1):

Total impedance to the end of 66kV transmission line:

$$Z\%_{TOTAL} = Z\%_{SOURCE} + Z\%_{LINE} = (1.125\% + 0.834\%) + (6.026\%) = \underline{0 + j7.985\%}$$

$$Z_{1TOTAL} = Z_{2TOTAL} = \underline{0 + j7.985\%}$$

Calculate Fault Currents

Primary current of 25MVA, 66/22kV transformer (and 66kV transmission line) will be:

$$I_{Prim} = \frac{25 \times 10^6}{\sqrt{3} \times 66 \times 10^3} = \underline{218.693A}$$

$$I_{a1} = \frac{I_{Prim} \times 100}{Z_{1TOTAL} + Z_{2TOTAL}} = \frac{218.693 \times 100}{2(0 + j7.985)} = \underline{0 + j1369.399\ A}$$

$$I_{a2} = -I_{a1} = \underline{0 - j1369.399\ A}$$

$$I_a = I_{a1} + I_{a2} + I_{a0} = \left[(0 + j2372.053) + (0 - j2372.053) + 0\right] = \underline{\underline{0\ A}}$$

$$I_b = a^2 I_{a1} + aI_{a2} = \left(a^2 - a\right)I_{a1} = \left[(-0.5 - j0.866) - (-0.5 + j0.866)\right] \times (0 + j1369.399)$$

$$= \underline{\underline{2372.053 + j0\ A}} = \underline{\underline{2372.053\angle 0^0\ A}}$$

$$I_c = aI_{a1} + a^2 I_{a2} = \left(a - a^2\right)I_{a1} = \left[(-0.5 + j0.866) - (-0.5 - j0.866)\right] \times (0 - j13699.399)$$

$$= \underline{\underline{-2372.053 + j0\ A}} = \underline{\underline{2372.053\angle 180^0\ A}}$$

Calculate Fault Voltages

$$V_{a1} = V_{a2} = V_L - I_{aPHASE} \times Z_{1(\Omega)TOTAL} = \left[66000 - (0 + j2372.053)(0 + j13.912)\right] = \underline{33000 + j0\ V}$$

$$V_a = V_{a1} + V_{a2} + V_{a0} = \left[2 \times (33000 + j0) + 0\right] = \underline{66000 + j0\ V}$$

V$_a$ expressed as phase voltage:

$$V_{aPHASE} = \frac{V_a}{\sqrt{3}} = \frac{66000 + j0}{\sqrt{3}} = \underline{\underline{38105.118 + j0\ V}} = \underline{\underline{38105.118\angle 0^0\ V}}$$

$$V_b = a^2 V_{a1} + a V_{a2} = \left[a^2(33000 + j0) + a(33000 + j0)\right] = \underline{-33000 + j0\ V}$$

V$_b$ expressed as phase voltage:

$$V_{bPHASE} = \frac{V_b}{\sqrt{3}} = \frac{-33000 + j0}{\sqrt{3}} = \underline{\underline{-19052.559 + j0\ V}} = \underline{\underline{19052.559\angle 180^0\ V}}$$

$$V_c = a V_{a1} + a^2 V_{a2} = \left[a(33000 + j0) + a^2(33000 + j0)\right] = \underline{-33000 + j0\ V}$$

V$_c$ expressed as phase voltage:

$$V_{cPHASE} = \frac{V_c}{\sqrt{3}} = \frac{-33000 + j0}{\sqrt{3}} = \underline{\underline{-19052.559 + j0\ V}} = \underline{\underline{19052.559\angle 180^0\ V}}$$

Calculate Positive Phase Sequence Voltage:

$$V_1 = \frac{1}{3}\left(V_a + aV_b + a^2V_c\right) = \frac{1}{3}\left[\left(38105.118 + j0\right) + a\left(-19052.559 + j0\right) + a^2\left(-19052.559 + j0\right)\right]$$
$$= \underline{\underline{19052.559 + j0\ V}} = \underline{\underline{19052.559\angle 0^0\ V}}$$

Calculate Negative Phase Sequence Voltage:

$$V_2 = \frac{1}{3}\left(V_a + a^2V_b + aV_c\right) = \frac{1}{3}\left[\left(38105.118 + j0\right) + a^2\left(-19052.559 + j0\right) + a\left(-19052.559 + j0\right)\right]$$
$$= \underline{\underline{19052.559 + j0\ V}} = \underline{\underline{19052.559\angle 0^0\ V}}$$

Considering above calculations and figure 3.3 we can state that:

$$\textit{PPS Voltage at Fault} = \underline{\underline{19052.559\ V}}$$

$$\textit{NPS Voltage at Fault} = -\underline{\underline{19052.559\ V}}$$

Adding vectorially PPS (V_1) and NPS (V_2) voltage components we get:

$$V_{1,2RESULTANT} = V_1 + V_2 = \left[\left(19052.559 + j0\right) + \left(19052.559 + j0\right)\right] = \underline{38105.118 + j0\ V}$$

Referring to Figure 3.3 and using proportions we get:

$$\textit{Total PPS Voltage Seen at Relay} = V_{b1} = \frac{38105.118 \times [2(13.912) - 3.412]}{2(13.912)} = \underline{\underline{33432.357\,V}}$$

$$\textit{Total NPS Voltage Seen at Relay} = V_{b2} = \frac{38105.118 \times 3.412}{2(13.912)} = \underline{\underline{4672.752\,V}}$$

Calculate Impedance as Seen by the Relay

Please refer to Figure 3.4 on the following page:

$$V_{b1} = \underline{33432.357\,V}$$

$$V_{b2} = \underline{4672.752\,V}$$

$$y = V_{b2} \times \sin 60^0 = 4672.752 \times 0.866 = \underline{4046.722}$$

$$z = V_{b2} \times \cos 60^0 = 4672.752 \times 0.500 = \underline{2336.376}$$

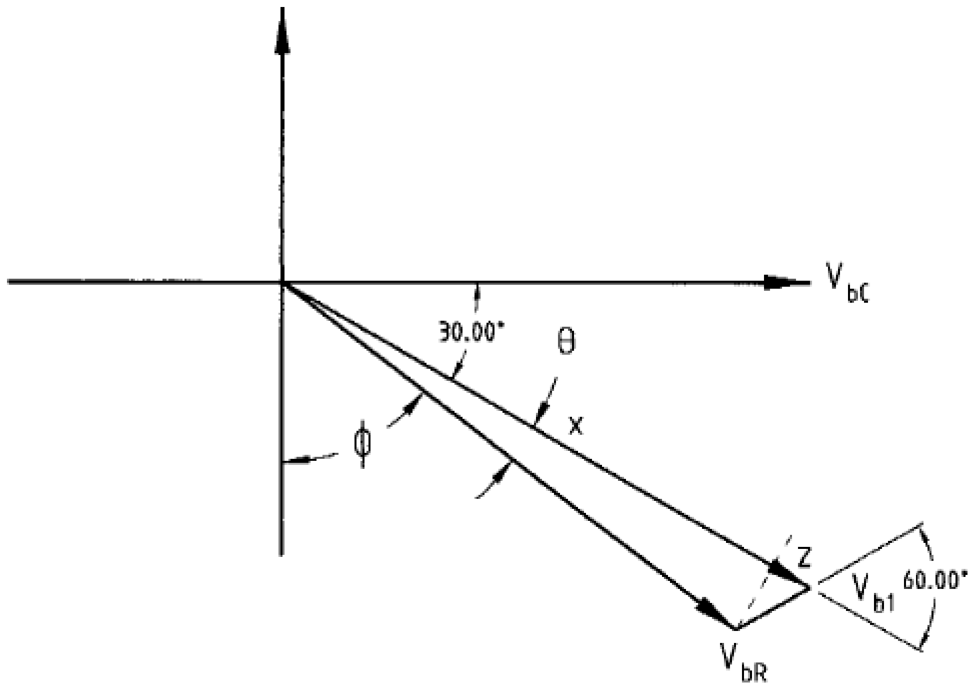


Figure 3.4

$$x = V_{b1} - z = 33432.357 - 2336.376 = \underline{31095.981}$$

$$\theta = \tan^{-1}\frac{y}{x} = \tan^{-1}\frac{4046.722}{31095.981} = \underline{7.415^0}$$

$$V_{bR} = \frac{x}{\cos\theta} = \frac{31095.981}{\cos 7.41^0} = \underline{31358.189\ V}$$

$$\phi = 60^0 - \theta = 60^0 - 7.415^0 = \underline{52.585^0}$$

$$\frac{V_{bC}}{Z} = V_{bR}\sin\phi$$

$$\therefore V_{bC} = \underline{49815\ V}$$

Impedance as seen by the relay is:

$$Z = \frac{V_{bC}}{I_b - I_c} = \frac{49815}{\left[2372.053 - (-2372.053)\right]} = \underline{\underline{10.500\ \Omega}}$$

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