1. Distance Protection

1.1 Procedure for Relay setting Calculation for MiCOM P442 Distance Relay

Data required

1. Positive sequence Line impedance = R_1+jX_1
2. Zero sequence Line impedance = R_0+JX_0
3. CT Ratio
4. PT Ratio
5. Protected Line Length in kms
6. Adjacent Shortest Line Length in kms
7. Adjacent Longest Line Length in kms
8. Voltage ratio of the transformer at the remote end if any
9. MVA of the transformer at the Remote end
10. % Impedance of the transformer at remote end
11. Maximum load on the feeder in Amperes

Calculation Procedure

The relay settings are in terms of impedance that is Z

Total Positive sequence impedance of protected line with reference to primary

ZPL = [ZPL (Ohms /km)*Protected Line Length (km)]

ZPL W.R.T Secondary = Z**PL** W.R.T Primary *(CT ratio/PT ratio)

Positive sequence impedance Angle = $Tan^{-1}(X_1/R_1)$

Similarly the Impedance for Adjacent Shortest Line **ZSL**, Adjacent Remote Long

Line **ZLL** and second Adjacent Long Line **Z2LL** can be calculated.

Total Transformer Impedance **ZT (**At remote end**)**

If there is more than one Transformer, the resultant Impedance considering the Transformers are in parallel is taken.

ZT = (%Transformer Impedance)*((KV) ^{2}/ MVA)]

Zero sequence impedance $\mathbf{Z_0}$ = $\sqrt{R_0^2+X_0^2}$

Zero sequence impedance Angle $\mathbf{Z_0}$ = $Tan^{-1}(X_0/R_0)$

Loadability:

The Limiting conditions for setting the distance relay reach to avoid encroachment into loads. As per "Reliability Standard PRC-023", The maximum impedance for the distance relay characteristics along 30º on the impedance plane for 0.85 per unit rated voltage and the maximum specified current for each condition.

The maximums Load w.r.t Secondary $\mathbf{Z_{max}} = 0.85*\mathbf{V_{L\text{-}L}}/ (\sqrt{3}*1.5*.\mathbf{I_L})$

Where I_L corresponds to thermal limit of the conductor.

The Resistance reach corresponding to $\mathbf{Z_{max}}$ w.r.t Secondary

$$\mathbf{R} = Z_{max} * \mathrm{COS}\ (30)$$

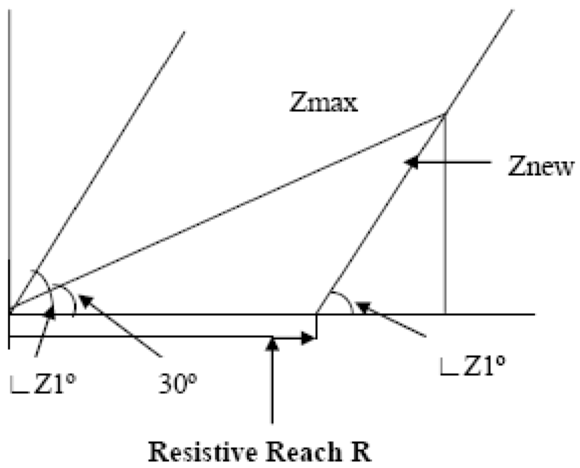
The Reactance reach corresponding to **Zmax** w.r.t Secondary

$$\mathbf{X} = Z_{max} * \mathrm{SIN}\ (30)$$

The New impedance for Parallel line drawn parallel to the Line impedance passing through Zmax to the point at which the parallel line cuts

The Resistance axis is $\mathbf{Z_{new}} = X\ \mathbf{(at\ Z_{max})}$ /SIN (Line angle)

The New Resistance from Known Reactance **Rnew** = Znew* COS (Line angle)



Resistance reach of Relay Characteristics obtained from maximum Loadability condition

Resistive Reach R = (R correspond to $Z_{max} - R_{new}$)

Zone Settings

<u>Zone 1</u>

Zone 1 = 80 % of Protection Line

Kz 1 Zero sequence compensation

Kz1 = $(Z_0\text{-}Z_1/3*Z_1)$

Kz1 angle = angle of Kz1

As per manufacturer's specification the maximum X/R ratio allowed is 10, hence considering this limitation and the maximum loadability limit the minimum of the two is considered

Resistive reach

R1G= MIN of **[**(10 times of Zone1 Impedance) and 0.8*Resistive Reach at Max load)**]**

R1PH= MIN of **[**(10 times of Zone1 Impedance) and 0.6*Resistive Reach at Max load)**]**

<u>Zone 2</u>

Zone 2 = [MAX OF ((Protection line+ (0.5*Adjacent shortest line)) AND (1.2*Protection line)]

tz2 = if [ZONE 2 > 80 % of Next shortest line then t=0.5sec else t=0.3 sec

Kz2 = (Z0-Z1/3*Z1)

Kz2 angle = angle of Kz2

R2G = Minimum [10 times of Zone 2 Impedance and 0.8*Resistive Reach at Max load]

R2PH = Minimum [10 times of Zone 2 Impedance and 0.6*Resistive Reach at Max load]

<u>Zone 3</u>

Zone3 = [MIN OF (1.2*Protection line + Adjacent Long line) & (Protection line + Adjacent Long line +0.25* Adjacent Second Long Line) & (Protection line +Transformer impedance))]

R3G-R4G = Minimum [(10 times of Zone 3 Reactance) and 0.8* Resistance at Maximum load]

R3PH-R4PH = Minimum [(10 times of Zone 3 Reactance) and 0.6* Resistance at Maximum load]

tz3 = 1 sec

<u>Zone 4</u>

Zone4 = 0.25 *Zone 1

tz4 = 1 sec

<u>Power Swing:</u>

Criteria 1:

Δf = 5Hz (As Per Manufacturer Specification)

ΔR = 0.032*Δf*Maximum Loadability

= 0.032*5*Resistance at Maximum Load

ΔX = 0.032*Δf*Maximum Loadability

= 0.032*5*Resistance at Maximum Load

Criteria 2:

$\Delta R = \Delta X = 20\%$ of Resistive reach of R3Ph

So a setting below the value can be retained of it.

<u>Sample setting calculation for MiCOM P44X</u>

Substation : 220kV GSS Ballabgargh

Line : Ballabgargh to Charki dadri

Relay Name : MiCOM P442

<u>Data</u>

Positive sequence Line impedance = 0.09705+j0.39314

Zero sequence Line impedance = 0.57146+j1.83241

CT Ratio = 1200A/1A

PT Ratio = 220kV/110V

Protected Line Length (Charki dadri) = 119.9 Km

Adjacent Shortest Line Length **(**two different conductor connected) (Bhiwani) = 26 (0.3) + 8.7 (0.4) Km

Adjacent Longest Line Length (Samayapur) = 116.10 (0.3) Km

Second Longest Line Length (Bhadshapur 1) = 24.10 (0.4) Km

Voltage ratio of the transformer = 220kV/132 kV

MVA of the transformer at the Remote end = 2*100 MVA

Impedance of the transformer = %12.344, 12.00

CT/PT ratio = 0.6

<u>Calculation</u>

Positive sequence impedance of Protected line ZPL = $\sqrt{R^2+X^2}$

$= \sqrt{0.09705^2+0.39341^2}$

ZPL = 0.4052 Ohms/Km

Total Positive sequence impedance of Protected line **ZPL**=

= [ZPL (Ohms /Km)*Protected Line Length (km)]

= [0.4049 * 119.9]

ZPL W.R.T Primary = **48.548 Ω**

ZPL W.R.T Secondary = ZPL W.R.T Primary *(CT/PT ratio)

= 48.548*(1200/1) / (220kV/110V)

ZPL = 29.129 Ω

Total Positive sequence impedance of the Adjacent Shortest line = (ZS1 + ZS2) * (CT/PT ratio)

Positive sequence impedance of Adjacent Shortest line 1 ZS1 = $\sqrt{R^2+X^2}$

= $\sqrt{0.09705^2+0.39341^2}$

= 0.4052* Line length

= 0.4052* 26

ZS1= 10.5352

Positive sequence impedance of Adjacent Shortest line 2 ZS2 = $\sqrt{R^2+X^2}$

= $\sqrt{0.0741^2+0.383^2}$

= 0.390* Line length

= 0.390* 8.7

ZS2 = 3.393

Total Positive sequence impedance of the Adjacent Shortest line = (ZS1 + ZS2) * (CT/PT ratio)

= (10.5352 + 3.393)* 0.6

ZSL W.R.T Secondary = 8.356 Ω

Total Positive sequence impedance of Adjacent Longest line **ZLL**=

= [ZLL (Ohms /Km)*Longest Line Length (km)]

= [0.4052 * 116]

ZLL W.R.T Primary = 47.00 Ω

ZLL W.R.T Secondary = ZLL W.R.T Primary * (CT/PT ratio)

= 47.00 * (1200/1) / (220kV/110V)

ZLL W.R.T Secondary = 28.201 Ω

Total Positive sequence impedance of Adjacent Second Longest line **Z2LL**=

= [ZLL (Ohms /Km)*Longest Line Length (km)]

= [0.4052 * 24.1]

Z2LL W.R.T Primary = 9.765Ω

Z2LL W.R.T Secondary = Z2LL W.R.T Primary * (CT/PT ratio)

= 9.765 * (1200/1) / (220kV/110V)

Z2LL W.R.T Secondary = 5.726 Ω

Total Transformer Impedance ZT (Remote):

If there is more than one Transformer, the resultant Impedance considering the Transformers are in parallel is taken.

Considering Transformers are connected in parallel

Total Transformer Impedance ZT (Remote) **=** (% Transformer Impedance) *((kV) 2/MVA)]

Transformer Impedance Z1 = $0.12*(220^2/100)$

= 58.08 Ω

Transformer Impedance Z2 = $0.12344*(220^2/100)$

= 59.74496 Ω

Transformer Impedance W.R.T primary ZT = (1/((1/Z1)+(1/Z2)))

= 1/((1/58.08)+(1/59.74496))

ZT= 29.450 Ω

Transformer Impedance W.R.T Secondary ZT = 29.450 * 0.6

= 17.670 Ω

Load impedance for (as Per the NERC loadability)

Positive sequence impedance Angle $=\text{Tan}^{-1}(X/R)$

Z1= $\text{Tan}^{-1}(0.39341/0.09705)$

Line Angle = 76.14 Degree

The maximums Load w.r.t Secondary ZMAX primary $= 0.85*V_{L-L}/(\sqrt{3}*1.5*.I_L)$

ZMAX = 0.85* 220 /(√3*1.5*525)

[525 A is the maximum capacity of ACSR Goat conductor]

ZMAX = 137.1 Ω

The Resistance reach corresponding to Zmax w.r.t. Secondary

R = ZMAX *COS (30)

= 137.1*0.8660

R = 118.733Ω

The Reactance reach corresponding to Zmax w.r.t Secondary

X = ZMAX *SIN (30)

= 137.1*0.5

X = 68.55 Ω

The New impedance for Parallel line Drawn Parallel to the Line impedance passing through Zmax to the point at which the parallel line cuts the Resistance axis is

Znew = X (at Zmax) /SIN(76.14)

= 68.55/0.9708

Znew = 70.608 Ω

The New Resistance from Known Reactance Rnew = Znew* COS (76.14)

= 70.608 *0.239

R new = 16.922

Resistances reach of Relay Characteristics With respect to primary

= (R corresponds to Zmax – R new)

R = 118.733 – 16.922 ; **R =101.811 Ω**

With respect to secondary = 101.811*0.6

= 61.086 Ω

Zone Settings

<u>Zone 1</u>

Zone 1= 80 % of Protection Line

=0.8* 29.129

Zone 1 = 23.30 Ω

Kz1 = (Z0-Z1/3*Z1)

= (0.57146+j1.83241)-(0.09705+j0.39314) -/3(0.09705+j0.39314)

Zero sequence Line impedance = 1.247 ∟-4.378

Kz1 Magnitude = 1.247

Kz1 angle = - 4.378 degree

R1G = Minimum of [(10 times of Zone1 Impedance) and 0.8 *(Resistance at Max load)]

R1G = Min [(23.30) and (0.8*61.086)]

R1G =Min [233 and 48.869]

R1G = 48.869 Ω

R1PH = Minimum of [(10 times of Zone1 Impedance) and 0.6 *(Resistance at Max load)]

R1PH = Min [(10*23.30) and (0.6*61.086)]

R1PH =Min [233 and 36.65]

R1PH = 36.65 Ω

<u>Zone 2</u>

Zone 2 = Minimum of [[Maximum of ((Protection line+ (0.5*Adjacent shortest line))

AND (1.2*Protection line)] (Protection line+ (0.5*Transformer impedance)]

= Min of [[Max of **[(29.129**+ (0.5***8.356**)) and (1.2***29.129**] & (**29.129**+0.5***17.67**)]

= Min of [[Max of **33.307** and **34.95**] and **37.96**]

Zone 2 = 34.95 Ω

tz2 = 0.35 sec

Kz1 = (Z0-Z1/3*Z1)

= (0.57146+j1.83241)-(0.09705+j0.39314) -/3(0.09705+j0.39314)

Zero sequence Line impedance = 1.247 ∟-4.378

Kz1 Magnitude = 1.247

Kz1 angle = - 4.378 degree

R2G = Min [10 times of Zone 2 Impedance and 0.8*Resistance at Max load]

= Min [10*34.95) and 0.8*61.086]

R2G = Min [349.5 and 48.869]

R2PH = Min [10 times of Zone 2 Impedance and 0.8*Resistance at Max load]

= Min [10*34.95) and 0.6*61.086]

R2PH = Min [349.5 and 36.65]

R2PH = 36.65 Ω

<u>Zone 3</u>

Zone3= [MIN OF (1.2(Protection line) +Adjacent Long line) & (Protection line Adjacent Long line+25% Second Adjacent Long Line) & (Protection line+ Transformer impedance)]

= Min of (1.2*29.129+ **28.208**) & **(2**9.129+**28.208**+0.25*5.726) and (29.129+17.670)

= Min of (63.163 and 58.768 & **46.799**)

Zone3 = 46.799 Ω

tz3 = 1 sec

Kz1 = (Z0-Z1/3*Z1)

= (0.57146+j1.83241)-(0.09705+j0.39314) -/3(0.09705+j0.39314)

Zero sequence Line impedance = 1.247 ∟-4.378

Kz1 Magnitude = 1.247

Kz1 angle = - 4.378 degree

R3G= Min [10 times of Zone 3 Impedance and 0.8*Resistance at Max load]

= Min [10*46.799 and 0.8*61.086]

= Min of [467.99 and 48.8688]

R3G = 48.869 Ω

R3PH= Min [10 times of Zone 3 Impedance and 0.6*Resistance at Max load]

= Min [10*46.799 and 0.6*61.086]

= Min of [467.99 and 36.65]

R3PH= 36.65 Ω

<u>Zone 4</u>

Zone4 = 0.25 *Zone1 ; Zone4 = 0.25* 23.30 Ω

Zone4 = 5.82 Ω

tz4 = 1 sec

<u>Power Swing:</u>

Criteria 1:

Δf = 5Hz (As Per Manufacturer Specification)

ΔR = 0.032*Δf*Maximum Loadability

= 0.032*5*40.35

= **6.456 Ω**

ΔX = 0.032*Δf*Maximum Loadability

= 0.032*5*40.35

= **6.456 Ω**

Criteria 2:

ΔR =ΔX = 20% of R3 Ph

= 0.2 * 36.69

= 7.33 Ω

So a setting below the value can be retained of it.

1.2 Procedure for Relay setting Calculation for MiCOM P433 Distance relay

Data required

1. Positive sequence Line impedance = R_1+jX_1
2. Zero sequence Line impedance = R_0+JX_0
3. CT Ratio
4. PT Ratio
5. Protected Line Length in kms
6. Adjacent Shortest Line Length in kms
7. Adjacent Longest Line Length in kms
8. Adjacent Second Longest Line Length in kms
9. Voltage ratio of the transformer at the remote end if any.
10. MVA of the transformer at the Remote end
11. % Impedance of the transformer at remote end
12. Maximum load on the feeder in Amperes

Calculation Procedure

The relay settings are in terms of impedance that is R and X
Total Positive sequence impedance of protected line with reference to primary
ZPL = [ZPL (Ohms /km)*Protected Line Length (km)]
ZPL W.R.T Secondary = Z**PL** W.R.T Primary *(CT ratio/PT ratio)
Reactance of protected line = ZPL W.R.T Secondary *SIN(Line angle)
Resistance of protected line= ZPL W.R.T Secondary *COS (Line angle)
Positive sequence impedance Angle = $Tan^{-1}(X_1/R_1)$
Similarly the Impedance for Adjacent Shortest Line **ZSL**, Adjacent Remote Long Line **ZLL** and second Adjacent Long Line **Z2LL** can be calculated.
Total Transformer Impedance **ZT**(At Remote end) =
(% Transformer Impedance) *((KV) ^{2}/MVA)]
Zero sequence impedance $\mathbf{Z_0}$ = $\sqrt{R_0^2+X_0^2}$
Zero sequence impedance Angle $\mathbf{Z_0}$ = $Tan^{-1}(X_0/R_0)$

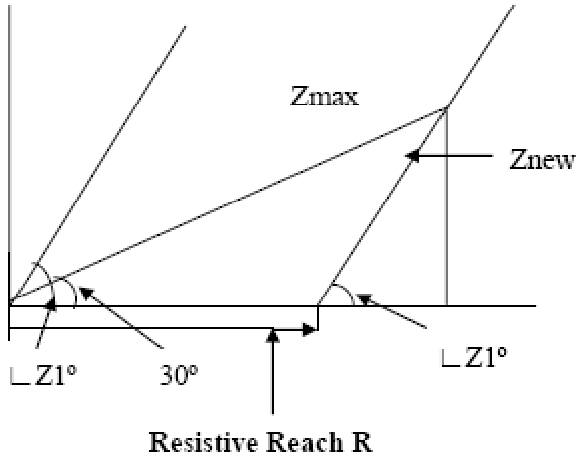
Loadability:
The Limiting conditions for setting the distance relay reach to avoid encroachment into loads. As per "Reliability Standard PRC-023", the maximum impedance for the distance relay characteristics along 30º on the impedance plane for 0.85 per unit rated voltage and the maximum specified current for each condition.
The maximums Load w.r.t Secondary $\mathbf{Z_{max}} = 0.85*\mathbf{V_{L-L}}/ (\sqrt{3}*1.5*.\mathbf{I_L})$

Where I_L corresponds to thermal limit of the conductor.

The Resistance reach corresponding to $\mathbf{Z_{max}}$ w.r.t Secondary
$\mathbf{R} = Z_{max}$ *COS (30)
The Reactance reach corresponding to **Zmax** w.r.t Secondary
$\mathbf{X} = Z_{max}$ *SIN (30)

The New impedance for Parallel line drawn parallel to the Line impedance passing through Zmax to the point at which the parallel line cuts
the Resistance axis is **Z** $_{new}$= X **(at Z$_{max}$)** /SIN (Line angle)

The New Resistance from Known Reactance **Rnew** = Znew* COS (Line angle)



Resistance reach of Relay Characteristics obtained from maximum loadability condition

Resistive Reach R = (R correspond to Z_{max} – R_{new})

Zone Settings

<u>Zone 1</u>
Zone 1 = 80 % of Protection Line
X1 = Z1 * SIN (Line Angle)
Kz 1 Zero sequence compensation
Kz1 = (Z_0-Z_1/3*Z_1)
Kz1 angle = angle of Kz1
As per manufacturer's specification the maximum X/R ratio allowed is 10, hence considering this limitation and the maximum loadability limit the minimum of the two is considered Resistive reach
R2= Zone2 impedance W.R.T Secondary *COS (Line angle)

R1 PH = Minimum of (8* Zone 1 Reactance and Resistance at maximum Load)
R1G = Minimum of (8* Zone 1 Reactance and Resistance at maximum Load)

<u>Zone 2</u>
Zone 2 = Min of [MAX OF ((Protection line+ (0.5*Adjacent shortest line)) and (1.2*Protection line)] and (Protected line + 05* Transformer impedance)
X2 = Z2 * SIN (Line Angle)
tz2 = if [ZONE 2 > 80 % of Next shortest line then t=0.6sec else t=0.3 sec
Kz2 = (Z0-Z1/3*Z1)
Kz2 angle = angle of Kz2

R2= Zone2 impedance W.R.T Secondary *COS (Line angle)
R2 PH = Minimum of (8* Zone 2 Reactance and Resistance at maximum Load)
R2 G = Minimum of (8* Zone 2 Reactance and Resistance at maximum Load)

Zone 3

Zone3 = [MIN OF (1.2*Protection line + Adjacent Long line) & (Protection line + Adjacent Long line +0.25* Adjacent Second Long Line) & (Protection line +Transformer impedance)]
R3= Zone3 impedance W.R.T Secondary *COS (Line angle)
R3 PH-R4PH = Minimum of (8* Zone 3 Reactance and Resistance at maximum Load)
R3 G-R4G =Minimum of (8* Zone 3 Reactance and Resistance at maximum Load)

tz3 = 1 sec

Zone 4

Zone4 = 0.25 *Zone 1
R4= Zone4 impedance W.R.T Secondary *COS (Line angle)
tz4 = 1 sec

Sample setting calculation for MiCOM P433

Substation : 220 kV Bhakra Power House

Line : 220 kV GSS Bhakra right to 220 kV GSS Mahilpur

Relay Name : Areva MiCOM P433

Data

Positive sequence Line impedance = 0.0797+j0.40651

Zero sequence Line impedance	= 0.233+j1.329
CT Ratio	= 1200A/1A
PT Ratio	= 220kV/110V
Protected Line Length(Mahilpur)	= 51.1 Km
Adjacent Shortest Line Length (Rehan)	= 26.7 Km
Adjacent Longest Line Length (Bhakra Right)	= 51.1 Km
Second Longest Line Length	= 0 Km
Voltage ratio of the transformer	= 220 kV/132 kV
Maximum load on the feeder	= 795 A (for Zeebra)
CT/PT ratio	= 0.6

Calculation

Positive sequence impedance of Protected line ZPL = $\sqrt{R^2+X^2}$

$= \sqrt{(0.0797^2+0.4065^2)}$

ZPL = 0.4142 Ohms/Km

Total Positive sequence impedance of Protected line **ZPL**=

= [ZPL (Ohms /Km)*Protected Line Length (km)]

= [0.4142 * 51.1]

ZPL W.R.T Primary = 21.167 Ω

ZPL W.R.T Secondary = ZPL W.R.T Primary *(CT/PT ratio)

= 21.167 * 0.6

ZPL = 12.70 Ω

Positive sequence impedance of Adjasent Shortest line ZSL = $\sqrt{R^2+X^2}$

$= \sqrt{(0.0797^2+0.4065^2)}$

ZSL = 0.4142 Ohms/Km

Total Positive sequence impedance Adjacent Shortest **ZSL**=

= [Z (Ohms /Km)*Protected Line Length (km)]

= [0.4142 * 26.7]

ZSL W.R.T Primary = 11.06 Ω

ZSL W.R.T Secondary = ZSL W.R.T Primary * (CT/PT ratio)

= 11.06 *0.6

ZSL = 6.635 Ω

ZSL W.R.T Secondary = 6.635 Ω

Positive sequence impedance of Adjasent Longest line ZLL = $\sqrt{R^2+X^2}$

= $\sqrt{(0.0797^2+0.4065^2)}$

ZLL = 0.4142 Ohms/Km

Total Positive sequence impedance Adjacent Shortest **ZLL**=

= [Z (Ohms /Km)*Protected Line Length (km)]

= [0.4142 * 51.1]

ZLL W.R.T Primary = 21.167 Ω

ZLL W.R.T Secondary = ZLL W.R.T Primary * (CT/PT ratio)

= 21.167 * 0.6

ZLL W.R.T Secondary = 12.70 Ω

Total Positive sequence impedance of Adjacent Second Longest line **Z2LL**=

= [Z2LL (Ohms /Km)*Longest Line Length (km)]

= [0.4142 * 0]

Z2LL W.R.T Primary = 0 Ω

Z2LL W.R.T Secondary = Z2LL W.R.T Primary * (CT/PT ratio)

= 0 * 0.6

Z2LL W.R.T Secondary = 0 Ω

Positive sequence impedance Angle = $\tan^{-1}(X/R)$

Line Angle = $\tan^{-1}(0.4065/0.0797)$

Line Angle = 78.91 Degree

The maximums Load w.r.t Secondary ZMAX primary $= 0.85*V_{L-L}/(\sqrt{3}*1.5*.I_L)$

ZMAX $= 0.85* 220 /(\sqrt{3}*1.5*795)$

[795 A is the maximum capacity of ACSR Zebra conductor]

ZMAX = 90.53 Ω

Corresponding Zmax secondary = Zmax * CT/PT Ratio = 90.53 * 0.6

= 54.32 Ω

The Resistance reach corresponding to Zmax w.r.t Secondary

R = ZMAX *COS (30)

= 54.32*0.8660

R = 47.044 Ω

The Reactance reach corresponding to Zmax w.r.t Secondary

X = ZMAX *SIN (30)

= 54.32*0.5

X = 27.16 Ω

The New impedance for Parallel line Drawn Parallel to the Line impedance passing through Zmax to the point at which the parallel line cuts the Resistance axis is

Znew = X (at Zmax) /SIN(78.91)

= 27.16/ SIN (78.91)

Znew = 27.67 Ω

The New Resistance from Known Reactance Rnew = Znew* COS (78.91)

= 27.67*cos 78.91

R new = 5.322

Resistances reach of Relay Characteristics with respect to secondary

= (R corresponds to Zmax – R new)

R = 47.044 -5.322

R = 41.722 Ω

Zone Settings

<u>Zone 1</u>

Zone 1= 80 % of Protection Line

= 0.8 * 12.70

Zone 1 = 10.16 Ω

R1= Zone1 impedance W.R.T Secondary *COS (Line angle)
R1 (PH-PH) = Minimum of (8* Zone 1 Reactance and Resistance at maximum Load)
R1 (PH-E) =Minimum of (8* Zone 1 Reactance and Resistance at maximum Load)

X1PP, X1PG = 10.16* SIN (78.91)

X1PP, X1PG = 9.97 Ω

R1PP = Minimum of (8 *10.16 and 41.722)

R1PP = 41.722 Ω

R1PG = Minimum of (8*10.16 and 41.722)

R1PG= 41.722 Ω

<u>**Zone 2**</u>

Zone 2 = MIN OF [(Protected Line + 0.5*Transformer impedance at remote end) AND (MAX OF (Protected line + (0.5*Adjacent shortest line) AND (1.2*Protected line))]

Since Transformer not available in Remote end.

= Max of **[(16.02**) and (**15.24**)]

= 16.02 Ω

Zone 2 = 16.02 Ω

tz4 = **0.35 sec**

R2= Zone1 impedance W.R.T Secondary *COS (Line angle)

R2 (PH-PH) = Minimum of (8* Zone 2 Reactance and Resistance at maximum Load)

R2 (PH-E) =Minimum of (8* Zone 2 Reactance and Resistance at maximum Load)

X2PP, X2PG =16.02 * SIN (78.91)

X2PP, X2PG = 15.72 Ω

R2PP = Minimum of (8* 16.02 and 41.722)

R2PP = 41.722 Ω

R2PG = Minimum of (8* 16.02 and 41.722)

R2PG= 41.722 Ω

<u>Zone 3</u>

Zone3= [MIN OF (1.2(Protected line) +Adjacent Long line) & (Protected line + Adjacent Long line+25% Second Adjacent Long Line) & (Protected line +Transformer impedance at remote end)]

Since Transformer not available in Remote end.

= Min of (15.24+ 12.7) & (12.70+12.70+0.25*0)

= Minimum of (27.94 and 25.40)

Zone3 = 25.40

tz3 = 1 sec

R3= Zone1 impedance W.R.T Secondary *COS (Line angle)

R3 (PH-PH) = Minimum of (8* Zone 3 Reactance and Resistance at maximum Load)

R3 (PH-E) =Minimum of (8* Zone 3 Reactance and Resistance at maximum Load)

X3PP, X3PG = 25.4 * SIN (78.91)

X3PP, X3PG = 24.925 Ω

R3PP = Minimum of (8*25.4 and 41.722)

R3PP = 41.722 Ω

R3PG = Minimum of (8*25.4 and 41.722)

R3PG= 41.722 Ω

<u>Zone 4</u>

Zone4 = 0.25 *Zone1 Impedance

Zone4 = 0.25*10.16 =2.54

X4 = 5.73 *SIN (78.91)

X4 = 2.49 Ω

tz4 = 1 sec

1.3<u>**Procedure for Relay Setting Calculation For REL670**</u>

<u>**Calculation**</u>

<u>**Protected line**</u>

Total Positive sequence Resistance of Protected line

R1 W.R.T Primary = [R1 (Ohms /Km)*Protected Line Length (km)]

Total Positive sequence Reactance of Protected line X1 =

X1 W.R.T Primary = [**X1** (Ohms /Km)*Protected Line Length (km)]

<u>**Adjacent Shortest line**</u>

Total Positive sequence Resistance of Adjacent Short Line R =

R1 W.R.T Primary = [R1 (Ohms /Km)*Protected Line Length (km)]

Total Positive sequence Reactance of Adjacent Short Line**X1** =

X1 W.R.T Primary= [**X1** (Ohms /Km)*Protected Line Length (km)]

<u>**Adjacent Long Line**</u>

Positive sequence Resistance of Adjacent Longest Line Primary

R1 = [**R1** (Ohms /Km)*Longest Line Length (km)]

Total Positive sequence Reactance of Adjacent Long Line**X1** =

X1 W.R.T Primary = [**X1** (Ohms /Km)* Adjacent Long Line Length (km)]

<u>**Transformer Impedance**</u>

Total Transformer Impedance **ZT (**At remote end**)**

If there is more than one Transformer, the resultant Impedance considering the Transformers are in parallel is taken.

ZT = (%Transformer Impedance)*((KV) ^{2}/ MVA)]

Loadability

Load impedance for (as Per the NERC Loadability)

The maximums Load w.r.t Secondary **ZMAX** = 0.85*$\mathbf{V_{L-L}}$ / (√3*1.5*.$\mathbf{I_L}$)

Where $I_L$corresponds to thermal limit of the conductor.

The Resistance reach corresponding to **Zmax** w.r.t Secondary

R = ZMAX *COS (30)

The Reactance reach corresponding to **Zmax** w.r.t Secondary

X=ZMAX *SIN (30)

The New impedance for Parallel line Drawn Parallel to the Line impedance passing through Zmax to the point at which the parallel line cuts the Resistance axis is **Znew**=X **(at Zmax)** /SIN(Line Angle)

The New Resistance from Known Reactance **Rnew**= Znew* COS (Line Angle)

Resistance reach of Relay Characteristics

= (R corresponds to Zmax – Rnew)

Zero sequence impedance Z0 = $\sqrt{R^2+X^2}$

Zero sequence impedance Angle Z0

= Tan-1(X/R)

Protected line

Total Zero sequence Resistance of Protected line R =

Primary = [**R0** (Ohms /Km)*Protected Line Length (km)]

Total Zero sequence Reactance of Protected line X0

W.R.T Primary = [ZPL (Ohms /Km)*Protected Line Length (km)]

Adjacent Short line

Total Zero sequence Resistance of Adjacent Short line R =

W.R.T Primary = [**R0** (Ohms /Km)*Protected Line Length (km)]

Total Zero sequence Reactance of Adjacent Short line X0 =

X0 W.R.T Primary = [ZPL (Ohms /Km)* Adjacent Short line Length (km)]

Adjacent Long Line

Total Zero sequence Resistance of Adjacent Long line R

(Primary) = [**R0** (Ohms /Km)* Adjacent Long Line Length (km)]

Zero sequence Reactance of Adjacent Long line **X0** =

Total Zero sequence Reactance of Adjacent Long line X0 =

(Primary) = [ZPL (Ohms /Km)* Adjacent Long line Length (km)]

Positive sequence impedance Angle =Tan-1(X/R)

Zone Settings

Zone 1

Phase –Phase

X 1 = 80 % of (Protected Line)

R1 =80 % of (Protected Line)

RFPP = min [(3 times of Zone1 Reach) and 1.6*Zload min*(CosΘ-R1/X1*SinΘ)]

RFPE= min [4.5time Zone1 and [0.8*Zmin*[cos30 – ((2*R1PP+ROPE)/(2*X1PP+XOPE)*sin30)]

Ref catalogue ABB REL 670 application manual page no 197,198 for the above condition and the load encroachment function to be enabled for the second condition to prevail.

XO =80 % of (Protected Line Zero Sequence Reactance)

RO=80 % of (Protected Line Zero Sequence Resistance)

<u>Zone 2</u>

<u>Phase –Phase</u>

X 1 =Min of ([MAX OF ((Protected Line+ (0.5*Adjacent shortest line)) AND (1.2*Protected Line)]), Protected Line + 0.5*Transformer Impedance at remote end)

R1 = MAX of ((Protected Line+ (0.5*Adjacent shortest line)) AND (1.2*Protected Line)))

RFPP = min [(3 times of Zone1 Reach) and 1.6*Zload min*(CosΘ-R1/X1*SinΘ)]

RFPE= min [4.5time Zone1 and [0.8*Zmin* [cos30 – ((2*R1PP+ROPE)/(2*X1PP+XOPE) *sin30)]

X0 = Min of ([MAX OF ((Protected Line+ (0.5*Adjacent shortest line)) AND (1.2*Protected Line)]),Protected Line+ 0.5*Transformer Impedance at remote end)

RO = MAX of ((Protected Line+ (0.5*Adjacent shortest line)) AND (1.2*Protected Line))

T2pp = if Zone2 > 80 % of the Next Shortest Line then t =0.6 sec else t=0.3 sec

t2pp= 0.35 sec

<u>Zone 3</u>

<u>Phase –Phase</u>

X1= MIN OF [(1.2*Protected Line Adjacent Long line)) & Protected Line Adjacent Long line+0.25*second Long line & Protected Line+Transformer impedance at remote end]

R1= MIN of [(1.2*Protected Line+Adjacent Long line)) & Protected Line+Adjacent Long line+0.25*second Long line]

RFPP = min [(3 times of Zone1 Reach) and 1.6*Zload min*(CosΘ-R1/X1*SinΘ)]

RFPE=min [4.5time Zone1 and [0.8*Zmin*[cos30 – ((2*R1PP+ROPE)/ (2*X1PP+XOPE)*sin30)]

X0 = [MIN OF (1.2*Protected Line+Adjacent Long line)) & Protected Line+Adjacent Long line+0.25*second Long line & Protected Line+ Transformer impedance at remote end]

R0 = [MIN OF (1.2*Protected Line+Adjacent Long line)) & Protected Line+Adjacent Long line+0.25*second Long line]

tz3 = 1 sec

Zone 4

Phase –Phase

X1 =0.25 ***Zone 1 reach**

RFPP = min [(3 times of Zone1 Reach) and 1.6*Zload min*(CosΘ-R1/X1*SinΘ)]

RFPE= min [4.5time Zone1 and [0.8*Zmin*[cos30 – ((2*R1PP+ROPE)/(2*X1PP+XOPE)*sin30)]

XO= 0.25* **Zone 1 reach**

t4=1 sec

Sample setting Calculation for ABB REL 670 Distance Relay

Substation : 220kV Ganguwal

Line : 220kV Ganguwal to Bhakra

Relay Name : REL670

Protected Line

Positive sequence Line impedance = 0.0797+j0.4065
Zero sequence Line impedance = 0.233+j1.329
Adjacent Short Long line
Positive sequence Line impedance = 0.0797+j0.4065
Zero sequence Line impedance = 0.233+j1.329
Adjacent Longest Long line
Positive sequence Line impedance = 0.0797+j0.4065
Zero sequence Line impedance = 0.233+j1.329
Second Adjacent Longest Long line
Positive sequence Line impedance = 0.0797+j0.4065
Zero sequence Line impedance = 0.233+j1.329

CT Ratio = 1200A/1A

PT Ratio = 220kV/110V

ProtectedLineLength = 22.3 Km

Adjacent Shortest LineLength = 22.3 Km

AdjacentLongestLineLength = 86.4 Km

Second AdjacentLongestLine = 86.4 Km

Voltage ratio of the transformer = nil

MVA of the transformer at the Remote end = NA

Maximum load on the feeder = 795 A

CT/PT ratio = 0.6

Calculation

Protected line

Positive sequence Impedance of Protected line ZPL = (0.0797+j0.4065)**Ohms/Km**

Total Positive sequence Impedance of Protected line R =

= [Z1 (Ohms /Km)*Protected Line Length (km)]

= [22.3* (0.0797+j0.4065)]

ZPL W.R.T Primary = 1.77731+j9.06495

R1p-p = 1.77731 Ω =**R1p-e**

X1p-p = 9.06495 Ω =**X1p-e**

Zero sequence Impedance of Protected line ZPL = 0.233+j1.329**Ohms/Km**

Total Zero sequence Impedance of Protected line R =

= [Z1 (Ohms /Km)*Protected Line Length (km)]

= [22.3*(0.233+j1.329)]

ZPL W.R.T Primary = 5.1959+j29.63

ROp-e =5.1959Ω

XOp-e =29.63Ω

Adjacent Shortest line

Positive sequence Impedance of Adjacent Short line ZSL

Total Positive sequence impedance of Adjacent Short Line =

Total Positive sequence Impedance of Protected line R =

= [Z1 (Ohms /Km)*Protected Line Length (km)]

= [22.3* (0.0797+j0.4065)]

ZPL W.R.T Primary = 1.77731+j9.06495

ZSLW.R.T Primary = [22.3* (0.0797+j0.4065)]

= 1.77731+j9.06495

R1 W.R.T Primary **=** 1.77731 Ω

X1 W.R.T Primary = 9.06495 Ω

50% of Positive sequence Impedance of Adjacent Short line

50% ZSL = 0.8886+j4.5324 Ohms/Km

Zero sequence Impedance of Adjacent Short line ZSL

= [22.3*(0.233+j1.329)]**Ohms/Km**

=5.1959+j29.63

50% of Zero sequence Impedance of Adjacent Short line

ZSL W.R.T Primary = 50% (5.1959+j29.63)

R1 W.R.T Primary **=** 2.59795Ω

X1 W.R.T Primary = 14.815Ω

<u>**Adjacent Long Line**</u>

Positive sequence Impedance of Adjacent Longest Line =0.0797+j0.4065**Ohms /Km**

Total Positive sequence Impedance of Adjacent Longest Line

Z1 = [Z1 (Ohms /Km)*Longest Line Length (km)]

= [0.0797+j0.4065] *86.4]

Z1 W.R.T Primary = 6.88+j35.12

R1 W.R.T Primary = 6.88 Ω

X1 W.R.T Primary = 35.12 Ω

Zero sequence Impedance of Adjacent Longest Line=0.233+j1.329**Ohms /Km**

Z0 = [Z0 (Ohms /Km)*Longest Line Length (km)]

= [0.233+j1.329] * 86.4]

Z0 W.R.T Primary = 20.1312+j114.8256

R0 W.R.T Primary = 20.1312 Ω

X0 W.R.T Primary = 114.8256 Ω

<u>Adjacent Second Long Line</u>

Positive sequence Impedance of Adjacent Longest Line = 0.0797+j0.4065**Ohms /Km**

25 % of Z2LL = 0.25* [Z1 (Ohms /Km)*Longest Line Length (km)]

=0.25*[0.0797+j0.4065]*86.4)]
=0.25*[6.88+j35.12]

25% of Z2LL Positive sequence W.R.T Primary = (01.72+j8.78)

R1 W.R.T Primary **=**1.72Ω

X1 W.R.T Primary = 8.78 Ω

Zero sequence Impedance of Adjacent Longest Line= 0.48787+j1.92051**Ohms /Km**

25 % of Z2LL = [Z0 (Ohms /Km)*Longest Line Length (km)]

Total length = 0.25*(0.233+j1.329)*86.4

25% Z2LL Zero sequence W.R.T Primary = (5.0328+j28.7064)

R1 W.R.T Primary **=** 5.0328 Ω

X1 W.R.T Primary = 28.7064 Ω

<u>Loadability</u>

Load impedance for (as Per the NERC Loadability)

The maximums Load w.r.t Primary **ZMAX** $= 0.85*\mathbf{V_{L\text{-}L}}/(\sqrt{3}*1.5*.\mathbf{I_L})$

ZMAX $= 0.85*220000/\sqrt{3}*1.5*795)$

ZMAX= 90.536 Ω

The Resistance reach corresponding to **Zmax** w.r.t Primary

R = ZMAX *COS (30)

=**90.536*0.8660**

R = 78.41 Ω

The Reactance reach corresponding to **Zmax** w.r.t Primary

X=ZMAX *SIN (30)

X = 45. 25 Ω

The New impedance for Parallel line Drawn Parallel to the Line impedance passing through Zmax to the point at which the parallel line cuts the Resistance axis is **Znew**=X **(at Zmax)** /SIN(78.85)

= **45.25 /0.9811**

Znew = 46.12 Ω

The New Resistance from Known Reactance **Rnew**= Znew* COS (78.9)

= 46.12*0.1925

Rnew = 8.879 Ω

Resistance reach of Relay Characteristics

= (R corresponds to Zmax – Rnew)

R = 78.41 – 8.879

R = 69.531 Ω

Resistance reach of Relay Characteristics w r t Primary = 69.531 Ω

Positive sequence impedance Angle =Tan-1(X/R)

= Tan-1(X/R)

= Tan-1(0.4065/ 0.0797)

Z1 angle = 78.9 Degree

Zero sequence impedance Angle Z0

= Tan-1(1.329/0.233)

Z0 angle = 80.05 Degree

Zone Settings

<u>Zone 1</u>

Total length =22.3km

Zone 1 Length = 0.8 * Total length

= 0.8*22.3

= 17.84km

<u>Phase –Phase</u>

Zone 1= 80 % of (Protected Line)

= [0.8*(1.77731+9.06495j)]

= 1.421+ j7.2519

X 1PP = 7.2519 Ω

R1PP= 1.421 Ω

RFPP = min [(3 times of Zone1 Reach) and 1.6*Zloadmin*{cosΘ-R1/X1*SinΘ)]

= min of (3*7.25) and 1.6*90.536*{cos30 -1.421/7.2519*sin 30}

RFPP =21.76Ω

<u>Phase –Earth</u>

X 1PP= **X1PE= 7.2519 Ω**

R1PP = **R1PE= 1.421 Ω**

Zone1 Zero sequence Impedance = 80 % of Protected line Zero sequence impedance

= [0.8*(5.1959+j29.63)]

= 4.15672+j23.704

ROPE = 4.15672 Ω

XOPE = 23.704 Ω

RFPE = min [(4.5 times of Zone1 Reach) and 0.8* $Zload_{max}$ (cos ¢-((2*R1PE + ROPE / 2* X1PE + XOPE) * sin¢)])]

= min (4.5*7.25) and [0.8*Zload-cos¢-(2*R1PP+ROPE) / (2*X1PP+XOPE)*sin¢

= min (4.5*7.25) and [0.8*90.536*[cos30–2*1.421 +4.156)/(2*7.2519+23.704)*sin30)]

= 32.625

RFPE = 32.625 Ω

<u>Zone 2</u>

<u>Phase –Phase</u>

ZONE2 = [MAX OF ((Protected Line+ (0.5*Adjacent shortest line)), AND (1.2*Protected Line)] and MIN OF [Protected Line +0.5*Transformer impedance at remote end]

1.2*Protected Line = 1.2*(1.77731+j9.06495)

= **(2.132+j10.877)**

Protected Line + (0.5*Adjacent shortest line) = (1.77731+j9.06495) + 0.5*(1.77731+j9.06495)

= (2.665965+ j13.597)

X 1PP = 13.597Ω

R1PP = 2.665965Ω

RFPP = min [3 times of X1PP and 1.6*Zloadmin*{cosΘ-R1/X1*SinΘ)]

= (3*13.597) and 1.6* 90.536*{cos30-2.66/13.597*sin30}

RFPP = 40.791 Ω

T2pp= if Zone2 > 80 % of the Next Shortest Line then t =0.6 sec else t=0.3 sec

t2pp= 0.350 sec

<u>Phase –Earth</u>

X 1PE = 13.597**Ω**

R1PE = 2.665965**Ω**

<u>Zone 2</u>

Zero Sequence = Min of [MAX OF ((Protected Line+ (0.5*Adjacent shortest line)) AND1.2 *Protected Line])

1.2*Protected Line = 1.2 * (5.1959+j29.63)

= 6.236+ j35.55

Protected Line+ (0.5*Adjacent shortest line) = (5.1959+j29.63)+ 0.5*(5.1959+j29.63)

= 7.795 + j44.445

XOPE = 44.445 Ω

ROPE = 7.795 Ω

RFPE = min (4.5*44.445) and [0.8*Zload-cos¢-(2*R1PP+ROPE)/ (2*X1PP+XOPE)*sin¢

= min (200) and 0.8* 90.536- cos(30)-(2*2.66+7.795)/ (2*13.597+44.445)*sin(30)

= 200 and 56.095

RFPE = 56.095 Ω

<u>Zone 3</u>

<u>Phase –Phase</u>

Zone 3= [MIN OF (1.2*Protected Line + Adjacent Long line)), Protected Line +Adjacent Long line+0.25 second long line)]

1.2*Protected Line+ Adjacent Long line =1.2 *(1.77731+j9.06495) + (6.88+j35.12)

= 9.012772+ j45.99

Protected Line +Adjacent Long line+0.25 second long line

= (1.77731+j9.06495) + (6.88+j35.12) + 0.25* (6.88+j35.12)

= 10.377 +j52.964

Zone 3 impedance =9.012772+ j45.99

X1PP = 45.99Ω

R1PP= 9.012772Ω

RFPP= min [3 times of Zone Reach and 1.6*Zloadmin*{cosΘ-R1/X1*SinΘ}]

=min [3 * 45.90 and (1.6*90.536*0.753)]

= 109.077Ω

X1PE = 45.99Ω

R1PE= 9.012Ω

<u>Phase –Earth</u>

Zone 3= [MIN OF (1.2*Protected Line +Adjacent Long line)), Protected Line +Adjacent Long line+0.25 second long line)]

1.2*Protected Line +Adjacent Long line = 1.2*(5.1959+j29.63)+ (20.1312+j114.8256)

= 26.366+j150.38

Protected Line +Adjacent Long line+0.25 second long line

= (5.1959+j29.63)+(20.1312+j114.8256)+0.25*(20.1312+j114.8256)

= 30.3599+j173.162

XOPE = 150.38Ω

ROPE = 26.366Ω

RFPE = min (4.5*150.38) and [0.8*Zload-cos¢-(2*R1PP+ROPE)/ (2*X1PP+XOPE)*sin¢

= min 676.71& (0.8*90.536 [cos(30)-(2*9.012+26.366)/(2*45.99+150.38)*sin(30)]

RFPE = 56.09Ω

tz3 =1 sec

<u>Zone 4</u>

<u>Phase –Phase</u>

Zone4 = 0.25 *Zone 1 impedance = 0.25*(1.421+ j7.2519)

X1PP= 1.812Ω

R1PP= 0.355 Ω

RFPP = min [3 times of Zone Reach and 1.6*Zloadmin*{cosΘ-R1/X1*SinΘ}]

= 3 *1.812and 1.6 *90.536*{cos30-0.355/1.812sin30}

RFPP = 5.436 Ω

<u>Phase –Earth</u>

X1PE= 1.812Ω

R1PE= 0.355Ω

RFPE = min [4.5 times of Zone Reach and [0.8*Zload-cos¢-(2*R1PP+ROPE)/(2*X1PP+XOPE)*sin¢]

= 4.5*1.812 and 0.8*90.536*0.7744

RFPE = 8.154Ω

Zone4 Zero sequence = 0.25*zone 1 zero sequence= (5.1959+j29.63)*0.25

XOPE =7.4075Ω

ROPE = 1.298Ω

tz4=1 sec

Note: If Arc and Tower footing resistance are known then it is possible to set the correct value of RFPP and RFPE by taking the consideration as;

Criteria 1= Arc resistance

Criteria 2=Arc resistance+Tower footing resistance

Then the equation can be modified as given below;

RFPP= Min(3 times of Zone Reach and 1.6*Zloadmin*{cosΘ-R1/X1*SinΘ}],2*criteria1)

RFPE=min [4.5 times of Zone Reach and [0.8*Zload-cos¢-(2*R1PP+ROPE)/(2*X1PP+XOPE)*sin¢, 2*criteria 2]

1.4 Procedure for Relay setting Calculation for SIEMENS SIPROTECH 7SA52X/7SA61X

Data required

1. Positive sequence Line impedance = R_1+jX_1
2. Zero sequence Line impedance = R_0+JX_0
3. CT Ratio
4. PT Ratio

5. Protected Line Length in kms
6. Adjacent Shortest Line Length in kms
7. Adjacent Longest Line Length in kms
8. Adjacent Second Longest Line Length in kms
9. Voltage ratio of the transformer at the remote end if any.
10. MVA of the transformer at the Remote end
11. % Impedance of the transformer at remote end
12. Maximum load on the feeder in Amperes

Calculation Procedure

The relay settings are in terms of impedance that is R and X

Total Positive sequence impedance of protected line with reference to primary

ZPL = [ZPL (Ohms /km)*Protected Line Length (km)]

ZPL W.R.T Secondary = Z**PL** W.R.T Primary *(CT ratio/PT ratio)

Reactance of protected line = ZPL W.R.T Secondary *SIN(Line angle)

Resistance of protected line= ZPL W.R.T Secondary *COS (Line angle)

Positive sequence impedance Angle = $\tan^{-1}(X_1/R_1)$

Similarly the Impedance for Adjacent Shortest Line **ZSL**, Adjacent Remote Long Line **ZLL** and second Adjacent Long Line **Z2LL** can be calculated.

Total Transformer Impedance **ZT (**At remote end**)**

If there is more than one Transformer, the resultant Impedance considering the Transformers are in parallel is taken.

ZT = (%Transformer Impedance)*((KV) ^{2}/ MVA)]

Zero sequence impedance $\mathbf{Z_0}$ = $\sqrt{R_0^2+X_0^2}$

Zero sequence impedance Angle $\mathbf{Z_0}$ = $\tan^{-1}(X_0/R_0)$

Loadability:

The Limiting conditions for setting the distance relay reach to avoid encroachment into loads. As per "Reliability Standard PRC-023", The maximum impedance for the distance relay characteristics along 30º on the impedance plane for 0.85 per unit rated voltage and the maximum specified current for each condition.

The maximums Load w.r.t Secondary $\mathbf{Z_{max}} = 0.85*\mathbf{V_{L\text{-}L}}/(\sqrt{3}*1.5*.\mathbf{I_L})$

Where I_L corresponds to thermal limit of the conductor.

The Resistance reach corresponding to $\mathbf{Z_{max}}$ w.r.t Secondary

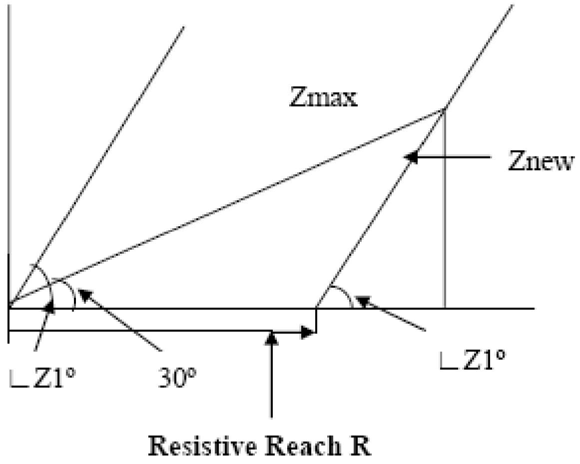
$\mathbf{R} = Z_{max}$ *COS (30)

The Reactance reach corresponding to **Zmax** w.r.t Secondary

$\mathbf{X} = Z_{max}$ *SIN (30)

The New impedance for Parallel line drawn parallel to the Line impedance passing through Zmax to the point at which the parallel line cuts the Resistance axis is $\mathbf{Z_{new}}$= X **(at $\mathbf{Z_{max}}$)** /SIN (Line angle)

The New Resistance from Known Reactance **Rnew** = Znew* COS (Line angle)



Resistance reach of Relay Characteristics obtained from maximum loadability condition

Resistive Reach R = (R correspond to $Z_{max} - R_{new}$)

Zone Settings

<u>Zone 1</u>

Zone 1 = 80 % of Protection Line

R1= Zone1 impedance W.R.T Secondary *COS (Line angle)

<u>Zone 2</u>

Zone 2 = Min of [MAX OF ((Protection line+ (0.5*Adjacent shortest line)) AND (1.2*Protection line)] & (Protection line+ 0.5*Transformer Impedance at remote end)

tz2 = if [ZONE 2 > 80 % of Next shortest line then t=0.6sec else t=0.35 sec

R2= Zone2 impedance W.R.T Secondary *COS (Line angle)

R2 (PH-PH) = R2 + (Arc Resistance / 2)

R2 (PH-E) = R2 + Arc Resistance + Tower Footing Resistance

<u>Zone 3</u>

Zone3 = [MIN OF (1.2*Protection line + Adjacent Long line) & (Protection line + Adjacent Long line +0.25* Adjacent Second Long Line) & (Protection line +Transformer impedance))]

R3= Zone3 impedance W.R.T Secondary *COS (Line angle)

R3 (PH-PH) = R3 + (Arc Resistance / 2)

R3 (PH-E) = R3 + Arc Resistance + Tower Footing Resistance

tz3 = 1 sec

<u>Zone 4</u>

Zone4 = 0.25 *Zone 1

R4= Zone4 impedance W.R.T Secondary *COS (Line angle)

R4 (PH-PH) = R4 + (Arc Resistance / 2)
R4 (PH-E) = R4 + Arc Resistance + Tower Footing Resistance
tz4 = 1sec

Power Swing Blocking:

As per manufactures specification power swing zone has a minimum distance

Z_{diff} of 5 Ω (at i_{nom} = 1 A) or 1 Ω (at i_{nom} = 5 A)

Sample setting calculation for SIPROTECH 7SA522

Substation : Charkhi Dadri

Line : Charkhi dadri to Khethri I

Relay Name : SIEMENS SIPROTECH 7SA522

Data

Protected Line

Positive sequence Line impedance = 0.0797+j0.4065
Zero sequence Line impedance = 0.233+j1.329
Adjacent Short Long line
Positive sequence Line impedance = 0.0797+j0.4065
Zero sequence Line impedance = 0.233+j1.329
Adjacent Longest Long line
Positive sequence Line impedance = 0.0797+j0.4065
Zero sequence Line impedance = 0.233+j1.329
Second Adjacent Longest Long line
Positive sequence Line impedance = 0.0797+j0.4065
Zero sequence Line impedance = 0.233+j1.329
CT Ratio = 600A/1A
PT Ratio = 220kV/110V
Protected Line Length = 71.61 Km
Adjacent Shortest Line Length (Khethri) = 34.5 Km
Adjacent Longest Line Length (Heerapura) = 144 Km
Second Longest Line Length (Heerapura -Khethri) = 139 Km
Voltage ratio of the transformer = 220kV/132kV
MVA of the transformer at the Remote end = 3*100 MVA and 1*150 MVA
Impedance of the transformer = %12,08, % 10.35, %9.65, %10.98
Maximum load on the feeder = 795 A
CT/PT ratio = 0.3

Calculation

Positive sequence impedance of Protected line ZPL = $\sqrt{R^2+X^2}$

$= \sqrt{(0.0797^2+0.4065^2)}$

ZPL = 0.414 Ohms/Km

Total Positive sequence impedance of Protected line **ZPL**=

= [ZPL (Ohms /Km)*Protected Line Length (km)]

= [0.414 * 71.61]

ZPL W.R.T Primary = 29.66 Ω

ZPL W.R.T Secondary = ZPL W.R.T Primary *(CT/PT ratio)

= 29.66 *0.3

ZPL = 8.90 Ω

Positive sequence impedance of Adjacent Shortest line ZSL= $\sqrt{R^2+X^2}$

= $\sqrt{(0.0797^2+0.4065^2)}$

ZSL = 0.414 Ohms/Km

Total Positive sequence impedance Adjacent Shortest **ZSL**=

= [Z (Ohms /Km)*Adjacent short Line Length (km)]

= [0.414 * 34.5]

ZSL W.R.T Primary = 14.29 Ω

ZSL W.R.T Secondary = ZSL W.R.T Primary * (CT/PT ratio)

= 14.29 * 0.3

ZSL W.R.T Secondary = 4.29 Ω

Positive sequence impedance of Adjacent Longest line ZLL = $\sqrt{R^2+X^2}$

= $\sqrt{(0.0797^2+0.4065^2)}$

ZLL = 0.414 Ohms/Km

Total Positive sequence impedance of Adjacent Longest line **ZLL**=

= [ZLL (Ohms /Km)*Longest Line Length (km)]

= [0.414 * 144]

ZLL W.R.T Primary = 59.65 Ω

ZLL W.R.T Secondary = ZLL W.R.T Primary * (CT/PT ratio)

= 59.65 * 0.3

ZLL W.R.T Secondary = 17.90 Ω

Positive sequence impedance of Adjacent Second Longest line ZS = $\sqrt{R^2+X^2}$

= $\sqrt{(0.0797^2+0.4065^2)}$

Z2LL = 0.414 Ohms/Km

Total Positive sequence impedance of Adjacent Second Longest line **Z2LL**=

= [Z2LL (Ohms /Km)*Longest Line Length (km)]

= [0.414 * 144]

Z2LL W.R.T Primary = 57.58 Ω

Z2LL W.R.T Secondary = Z2LL W.R.T Primary * (CT/PT ratio)

= 57.58 * 0.3

Z2LL W.R.T Secondary = 17.27 Ω

Total Transformer Impedance ZT (Remote):

If there are more than one Transformer, the resultant Impedance considering the Transformers are in parallel is taken.

Considering Transformers are connected in parallel

Total Transformer Impedance ZT (Remote) = (% Transformer Impedance) *((kV) 2/MVA)]

Transformer 1 Impedance Z1 = $0.0965*(220^2/100)$

= 46.706 Ω

Transformer 1 Impedance Z2 = $0.1208*(220^2/100)$

= 58.4672 Ω

Transformer 1 Impedance Z3 = $0.1035*(220^2/100)$

= 50.094 Ω

Transformer 1 Impedance Z4 = $0.1098*(220^2/150)$

$= 35.4288\ \Omega$

Total Transformer Impedance W.R.T primary **ZT** = 1/ ((1/Z1) + (1/Z2) + (1/Z3) + (1/Z4))

ZT = 1/ ((1/46.706)+(1/58.467)+(1/50.094)+(1/35.4288))

ZT = 11.5337 Ω

Load impedance for (as Per the NERC loadability)

Positive sequence impedance Angle $= \mathrm{Tan}^{-1}(X/R)$

$Z1 = \mathrm{Tan}^{-1}(0.415/.0741)$

Line Angle = 78.91 Degree

The maximums Load w.r.t Secondary ZMAX primary $= 0.85 * V_{L-L}/(\sqrt{3}*1.5*.I_L)$

ZMAX = 0.85* 220 / (√3*1.5*795)

[795 A is the maximum capacity of ACSR Zebra conductor]

ZMAX = 90.53 Ω

Corresponding Zmax secondary = Zmax * CT/PT Ratio = 90.53 * 0.3 = 27.159 Ω

The Resistance reach corresponding to Zmax w.r.t Secondary

R = ZMAX *COS (30)

= 27.159 *0.8660

R = 23.519 Ω

The Reactance reach corresponding to Zmax w.r.t Secondary

X = ZMAX *SIN (30)

= 27.159 *0.5

X = 13.579 Ω

The New impedance for Parallel line Drawn Parallel to the Line impedance passing through Zmax to the point at which the parallel line cuts the Resistance axis is

Znew = X (at Zmax) /SIN(78.91)

= 13.579/ SIN(78.91)

Znew = 13.83 Ω

The New Resistance from Known Reactance Rnew = Znew* COS (78.91)

= 13.83*cos 78.91

R new = 2.66

Resistances reach of Relay Characteristics

= (R corresponds to Zmax – R new)

R = 23.519 -2.66

R = 20.86 Ω

Tower Footing Resistance assuming = 10 Ω in secondary

Arc Resistance(Ph-Ph) assuming = 10 Ω in secondary

Zone Settings

<u>Zone 1</u>

Zone 1= 80 % of Protection Line

= 0.8* 8.90

Zone 1 = 7.12 Ω

R1= Zone1 impedance W.R.T Secondary *COS (Line angle)
R1 (PH-PH) = R1 + (Arc Resistance / 2)
R1 (PH-E) = R1 + Arc Resistance + Tower Footing Resistance

R1 = 7.12* COS (78.91)

R1 = 1.37 Ω

R1(PH-PH) = 1.37 +(10/2)

R1(PH-PH) = 6.37Ω

R1(PH-PE) = 1.37+10+10

R1(PH-PE)= 21.37 Ω

<u>Zone 2</u>

Zone 2 = MIN OF [MAX OF (Protected line + (0.5*Adjacent shortest line) and (1.2*Protected line)] and (Protected Line + 0.5*Transformer impedance at remote end)

= Min Of [Max of **[(**8.90+ (0.5*4.29) and (1.2*8.90)] and (8.90+0.5*3.46)

= Min Of [Max of **[**11.045 and 10.68] and 10.63

= 11.045 and 10.68

Zone 2 = 10.63 Ω

tz2 = 0.35 sec

R2= Zone 2 impedance W.R.T Secondary *COS(Line angle)
R2 (PH-PH) = R2 + (Arc Resistance / 2)
R2 (PH-E) = R2 + Arc Resistance + Tower Footing Resistance

R2 = 10.63 * COS (78.91)

R2 = 2.044 Ω

R2(PH-PH) = 2.044 +(10/2)

R2(PH-PH) = 7.05 Ω

R2(PH-PE) = +10+10

R2(PH-PE)= 22.05 Ω

<u>Zone 3</u>

Zone3= MIN OF [(1.2(Protected line) +Adjacent Long line) & (Protected line + Adjacent Long line+25% Second Adjacent Long Line) & (Protected line +Transformer impedance)]

= Min of (1.2*8.90+ 17.90) & (8.90+17.90+0.25*17.27) and (8.90+3.46)

=Min of (28.58 and 31.117 & **12.36**)

Zone3 = 12.36 Ω

tz3 = 1 sec

R3= Zone 3 impedance W.R.T Secondary *COS(Line angle)

R3 (PH-PH) = R3 + (Arc Resistance / 2)
R3 (PH-E) = R3 + Arc Resistance + Tower Footing Resistance

R3 = 12.36 * COS (78.91)

R3 = 2.377 Ω

R3(PH-PH) = 2.377 +(10/2)

R3(PH-PH) = 7.377 Ω

R3(PH-PE) = 2.377+10+10

R3(PH-PE)= 22.377 Ω

<u>Zone 4</u>

Zone4 = 0.25 *Zone1

Zone4 = 0.25*7.12

Zone4 = 1.78 Ω

tz4 = 1sec

R4= Zone 3 impedance W.R.T Secondary *COS(Line angle)
R4 (PH-PH) = R3 + (Arc Resistance / 2)
R4 (PH-E) = R3 + Arc Resistance + Tower Footing Resistance

R4 = 1.78 * COS (78.91)

R4 = 0.342 Ω

R4(PH-PH) = 0.342 +(10/2)

R4(PH-PH) = 5.342 Ω

R4(PH-PE) = 0.342+10+10

R4(PH-PE)= 20.342 Ω

1.5 <u>Procedure for Relay setting Calculation for GE D60</u>

Data required

1. Positive sequence Line impedance = R_1+jX_1
2. Zero sequence Line impedance = R_0+JX_0
3. CT Ratio
4. PT Ratio
5. Protected Line Length in kms

6. Adjacent Shortest Line Length in kms
7. Adjacent Longest Line Length in kms
8. Voltage ratio of the transformer at the remote end if any
9. MVA of the transformer at the Remote end
10. % Impedance of the transformer at remote end
11. Maximum load on the feeder in Amperes

Calculation Procedure

The relay settings are in terms of impedance that is Z

Total Positive sequence impedance of protected line with reference to primary

ZPL = [ZPL (Ohms /km)*Protected Line Length (km)]

ZPL W.R.T Secondary = Z**PL** W.R.T Primary *(CT ratio/PT ratio)

Positive sequence impedance Angle = $Tan^{-1}(X_1/R_1)$

Similarly the Impedance for Adjacent Shortest Line **ZSL**, Adjacent Remote Long

Line **ZLL** and second Adjacent Long Line **Z2LL** can be calculated.

Total Transformer Impedance **ZT (**At remote end**)**

If there is more than one Transformer, the resultant Impedance considering the Transformers are in parallel is taken.

ZT = (%Transformer Impedance)*((KV) ^{2}/ MVA)]

Zero sequence impedance $\mathbf{Z_0}$ = $\sqrt{R_0^2+X_0^2}$

Zero sequence impedance Angle $\mathbf{Z_0}$ = $Tan^{-1}(X_0/R_0)$

Loadability:

The Limiting conditions for setting the distance relay reach to avoid encroachment into loads. As per "Reliability Standard PRC-023", The maximum impedance for the distance relay characteristics along 30º on the impedance plane for 0.85 per unit rated voltage and the maximum specified current for each condition.

The maximums Load w.r.t Secondary $\mathbf{Z_{max}} = 0.85*\mathbf{V_{L\text{-}L}}/(\sqrt{3}*1.5*.\mathbf{I_L})$

Where I_L corresponds to thermal limit of the conductor.

The Resistance reach corresponding to $\mathbf{Z_{max}}$ w.r.t Secondary

$$\mathbf{R} = Z_{max} * \mathrm{COS}\ (30)$$

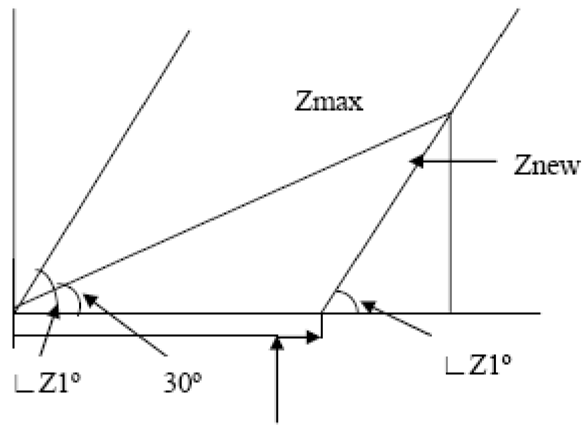
The Reactance reach corresponding to **Zmax** w.r.t Secondary

$$\mathbf{X} = Z_{max} * \mathrm{SIN}\ (30)$$

The New impedance for Parallel line drawn parallel to the Line impedance passing through Zmax to the point at which the parallel line cuts

the Resistance axis is $\mathbf{Z_{new}} = X\ \mathbf{(at\ Z_{max})}\ /\mathrm{SIN\ (Line\ angle)}$

The New Resistance from Known Reactance **Rnew** = Znew* COS (Line angle)



Resistance reach of Relay Characteristics obtained from maximum Loadability condition

Resistive Reach R = (R correspond to $Z_{max} - R_{new}$)

Zone Settings

<u>Zone 1</u>

Zone 1 = 80 % of Protection Line

<u>Zone 2</u>

Zone 2 = Min of [MAX of ((Protection line+ (0.5*Adjacent shortest line)) and (1.2*Protection line)] and (Protected line + 0.5* Transformer impedance at remote end)

tz2 = if [ZONE 2 > 80 % of Next shortest line then t=0.6sec else t=0.3 sec

Zone 3

Zone3 = [MIN OF (1.2*Protection line + Adjacent Long line) & (Protection line + Adjacent Long line +0.25* Adjacent Second Long Line) & (Protection line + (Transformer impedance))]

tz3 = 1 sec

Zone 4

Zone4 = 0.25 *Zone 1

tz4 = 1 sec

Power Swing:

Inner Forward Reach = Zone 3 Reach

Outer Forward Reach = 1.2* Inner Forward Reach

Sample setting calculation for GE D60 Distance Relay

Substation : 400kV GSS Bhiwani

Line : 400kV Bhiwani to 400kV Hissar

Relay Name : GE D60

DATA:

Protected Line

Positive sequence Line impedance = 0.026626+j0.330931

Zero sequence Line impedance = 0.261887+j1.03144

Adjacent Short Long line

Positive sequence Line impedance = 0.026626+j0.330931

Zero sequence Line impedance = 0.261887+j1.03144

Adjacent Longest Long line

Positive sequence Line impedance = 0.026626+j0.330931

Zero sequence Line impedance = 0.261887+j1.03144

CT Ratio = 1000A/1A

PT Ratio = 400kV/110V

Protected Line Length = 32.74 km

Adjacent Shortest Line Length = 65.4 km

Adjacent Longest Line Length = 212 km

Voltage ratio of the transformer = 400kV/220kV

MVA of the transformer at the Remote end = 3*315 MVA

Impedance of the transformer = 12.52%, 12.52% & 12.52%

Maximum load on the feeder = 900 A

CT/PT ratio = 0.275

Calculation

Protected line

Positive sequence impedance of Protected line ZPL = $\sqrt{R^2+X^2}$

$= \sqrt{0.026626^2 + 0.330931^2}$

ZPL = 0.332 Ohms/Km

Total Positive sequence impedance of Protected line **ZPL**=

= [ZPL (Ohms /Km)*Protected Line Length (km)]

= [0.332 * 32.74]

ZPL W.R.T Primary = **10.869 Ω**

ZPL W.R.T Secondary = ZPL W.R.T Primary *(CT/PT ratio)

= 10.84 * 0.275

ZPL = 2.989 Ω

Positive sequence impedance of Adjacent Shortest line ZPL = $\sqrt{R^2+X^2}$

$= \sqrt{0.026626^2 + 0.330931^2}$

ZSL = 0.332 Ohms/Km

Total Positive sequence impedance Adjacent Shortest **ZSL**=

= [Z (Ohms /Km)*Protected Line Length (km)]

= [0.332 * 65.4]

ZSL W.R.T Primary = 21.71 Ω

ZSL W.R.T Secondary = ZSL W.R.T Primary * (CT/PT ratio)

= 21.71*0.275

ZSL W.R.T Secondary = 5.97 Ω

Total Positive sequence impedance of Adjacent Longest line **ZLL**=

= [ZLL (Ohms /Km)*Longest Line Length (km)]

= [0.332* 212]

ZLL W.R.T Primary = 70.384 Ω

ZLL W.R.T Secondary = ZLL W.R.T Primary * (CT/PT ratio)

= 70.384 * 0.275

ZLL W.R.T Secondary = 19.355 Ω

Total Transformer Impedance ZT (Remote):

If there are more than one Transformer, the resultant Impedance considering the Transformers are in parallel is taken.

Considering Transformers are connected in parallel

Total Transformer Impedance ZT (Remote) = (% Transformer Impedance) *((kV) 2/MVA)]

Transformer Impedance of Z1 = [0.1252*(400^2/315)]

= 63.59 Ω

Transformer Impedance of Z2 = [0.1252*(400^2/315)]

= 63.59 Ω

Transformer Impedance of Z3 = [0.1252*(400^2/315)]

= 63.59 Ω

Total Transformer Impedance ZT (Remote) = 1/((1/Z1)+ (1/Z2) + (1/Z3))

ZT (Remote) = 1/((1/63.59)+(1/3.59)+(1/63.59))

Transformer Impedance W.R.T primary **ZT** = 21.197 Ω

Total Transformer Impedance ZT (Remote) Secondary = ZT (Remote) *(CT/PT ratio)

= 21.197 * 0.275

Transformer Impedance W.R.T Secondary ZT = 5.829 Ω

Loadability

Positive sequence impedance Angle =$Tan^{-1}(X/R)$

Z1= $Tan^{-1}(0.33/0.0266)$

Line Angle = 85.40 Degree

The maximums Load w.r.t Secondary ZMAX primary = $0.85*V_{L-L}/(\sqrt{3}*1.5*.I_L)$

ZMAX = 0.85* 400 / (√3*1.5*900)

[900 A is the maximum capacity of ACSR Markulla and Moose conductor]

ZMAX = 145.41 Ω

Corresponding Zmax secondary = Zmax * CT/PT Ratio = 145.41 * 0.275 = 40.01 Ω

The Resistance reach corresponding to Zmax w.r.t Secondary

R = ZMAX *COS (30)

= 40.01*0.8660

R = 34.648 Ω

The Reactance reach corresponding to Zmax w.r.t Secondary

X = ZMAX *SIN (30)

= 40.01 * 0.5

X = 20.00 Ω

The New impedance for Parallel line Drawn Parallel to the Line impedance passing through Zmax to the point at which the parallel line cuts the Resistance axis is

Znew = X (at Zmax) /SIN(85.4)

= 20.00 / 0.9967

Znew = 20.066 Ω

The New Resistance from Known Reactance Rnew = Znew* COS (85.4)

= 20.066 *0.080

R new = 1.609

Resistances reach of Relay Characteristics

= (R corresponds to Zmax – R new)

$R = 34.648 - 1.609$

$R = 33.0219\ \Omega$

Zero sequence impedance $Z0 = \sqrt{R0^2 + X0^2}$

$= \sqrt{0.261887^2 + 1.03144^2}$

$Z0 = 1.064\ \Omega$

Zero sequence impedance Angle Z0 = Tan-1(X0/R0)

= Tan-1(1.03144 / 0.26188)

Z0 = 75.75 Degree

Positive sequence impedance Angle = Tan-1(X/R)

Z1= Tan-1(0.330931/0.026626)

Z1= 85.40 Degree

Zone Settings

<u>Zone 1</u>

Zone 1= 80 % of Protection Line

=0.8* 2.989

Zone 1 = 2.391 Ω

<u>Zone 2</u>

Zone 2 = MIN of [[MAX OF ((Protection line+ (0.5*Adjacent shortest line)) AND (1.2*Protection line)](Protection line+ (0.5*Transformer impedance at remote end)]

= Min of [[Max of **[(**2.989+ (0.5*5.97)) and (1.2*2.989) and (2.989 + 0.5*5.829)]

= Min of [[Max of 5.974 and 3.586] 5.90]

Zone 2 = 5.90 Ω

tz2 = if [ZONE 2 > 80 % of Next shortest line then t=0.6sec else t=0.35 sec

tz2 = 0.35 sec

<u>Zone 3</u>

Zone3= [MIN OF (1.2(Protection line) +Adjacent Long line) & (Protection line+Adjacent Long line+25% Second Adjacent Long Line) & (Protection line +Transformer impedance)]

= Min of (1.2*2.989+ 19.355) & (2.989+19.355+0.25*0) and (2.989+5.829)

=Min of (22.941 & 22.344 and 8.818)

Zone3 = 8.818 Ω

tz3 = 1.0 sec

<u>Zone 4</u>

Zone4 = 0.25 *Zone1

= 0.25* 2.3912

Zone4 = 0.5978 Ω

tz4 = 1 sec

Power Swing:

Inner Forward Reach = Zone 3 Reach

= 8.818 Ω

Outer Forward Reach = 1.2* Inner Forward Reach

= 1.2* 8.818

= 10.58 Ω

1.6 Procedure for Relay setting Calculation for EPAC 3000

Data required

1. Positive sequence Line impedance = R_1+jX_1
2. Zero sequence Line impedance = R_0+JX_0
3. CT Ratio
4. PT Ratio
5. Protected Line Length in kms
6. Adjacent Shortest Line Length in kms
7. Adjacent Longest Line Length in kms
8. Voltage ratio of the transformer at the remote end if any
9. MVA of the transformer at the Remote end
10. % Impedance of the transformer at remote end
11. Maximum load on the feeder in Amperes

Calculation Procedure

The relay settings are in terms of impedance that is Z

Total Positive sequence impedance of protected line with reference to primary

ZPL = [ZPL (Ohms /km)*Protected Line Length (km)]

ZPL W.R.T Secondary = Z**PL** W.R.T Primary *(CT ratio/PT ratio)

Positive sequence impedance Angle = $Tan^{-1}(X_1/R_1)$

Similarly the Impedance for Adjacent Shortest Line **ZSL**, Adjacent Remote Long

Line **ZLL** and second Adjacent Long Line **Z2LL** can be calculated.

Total Transformer Impedance **ZT (**At remote end**)**

If there is more than one Transformer, the resultant Impedance considering the Transformers are in parallel is taken.

ZT = (%Transformer Impedance)*((KV) ^{2}/ MVA)]

Zero sequence impedance $\mathbf{Z_0}$ = $\sqrt{R_0^2+X_0^2}$

Zero sequence impedance Angle $\mathbf{Z_0}$ = $Tan^{-1}(X_0/R_0)$

Zone Settings

<u>Zone 1</u>

Zone 1 = 80 % of Protection Line

Kz 1 Zero sequence compensation

Kz1 = $(Z_0-Z_1/3*Z_1)$

Kz1 angle = angle of Kz1

As per manufacturer's specification the maximum X/R ratio allowed is 10, hence considering this limitation and the maximum loadability limit the minimum of the two is considered

Resistive reach

R1G= Minimum of **[**(10 times of Zone1 Reactance) and 0.8 *Resistive Reach (loadability)**]**

R1PH= Minimum of **[**(10 times of Zone1 Reactance) and 0.6 *Resistive Reach (loadability)**]**

Zone 2

Zone 2 = Min of [MAX OF ((Protection line+ (0.5*Adjacent shortest line)) AND (1.2*Protection line)] and (Protected line + Transformer impedance at remote end)

tz2 = if [ZONE 2 > 80 % of Next shortest line then t=0.6sec else t=0.3 t0 0.35 sec

Kz2 = (Z0-Z1/3*Z1)

Kz2 angle = angle of Kz2

R2G= Minimum of **[**(10 times of Zone1 Reactance) and 0.8 *Resistive Reach (loadability)**]**

R2PH= Minimum of **[**(10 times of Zone1 Reactance) and 0.6 *Resistive Reach (loadability)**]**

Zone 3

Zone3 = [MIN OF (1.2*Protection line + Adjacent Long line) & (Protection line + Adjacent Long line +0.25* Adjacent Second Long Line) & (Protection line + (Transformer impedance at remote end))]

R3G= Minimum of **[**(10 times of Zone1 Reactance) and 0.8 *Resistive Reach (loadability)**]**

R3PH= Minimum of **[**(10 times of Zone1 Reactance) and 0.6 *Resistive Reach (loadability)**]**

tz3 = 1 sec

Zone 4

Zone4 = 0.25 *Zone 1

tz4 = 1 sec

<u>Sample setting calculation for EPAC 3000 Distance Relay</u>

DATA:

Substation name: 220kV GSS Kurukshethra

Protected feeder: 220kV Kurukshetra to 220kV Jagadhri

Protected Line Length : 48.29 km

Adjacent Shortest Line Length : 158 km (220 kV Gangual)

Adjacent Longest Line Length : 158 km (220 kV Gangual)

Second Adjacent Longest Line : 110 km (Dhulkote)

<u>Protected Line</u>

Positive sequence Line impedance = 0.07411+j0.40988

Zero sequence Line impedance = 0.29524+j1.260416

<u>Adjacent Short Long line</u>

Positive sequence Line impedance = 0.07505+j0.415

Zero sequence Line impedance = 0.2989+j1.2804

<u>Adjacent Longest Long line</u>

Positive sequence Line impedance = 0.07505+j0.415

Zero sequence Line impedance = 0.2989+j1.2804

<u>Adjacent Second Longest Long line</u>

Positive sequence Line impedance = 0.09944+j0.4004

Zero sequence Line impedance = 0.5746+j1.9712

Nomber of Remote end Transformers : 3

Voltage Ratio of Transformer on Remote Bus: 220/132 kV

Remote end Transformer MVA: 60 MVA

% Impedance of the Remote end Transformer: 9.76 %, 10.1%, 11.1%

CT Ratio : 1200/1

PT Ratio : 220 kV/110 V

CT/PT Ratio: 1200/2000 = 0.6

Positive Sequence Impedance of Protected Line = $\sqrt{(R1^2 + X1^2)}$

$= \sqrt{(0.07411^2 + 0.40988^2)}$

ZPL = 0.416 Ω/km

Total Positive Sequence of Protected Line w.r.t. Primary = ZPL * Line Length

= 0.416*48.29

=20.11Ω

Total Positive Sequence Impedance w.r.t. Secondary = 18.99 * CT/PT Ratio

= 20.11*0.6

ZPL Secondary =12.068 Ω

Positive Sequence Impedance of Shortest Line ZSL = $\sqrt{(R1^2 + X1^2)}$

$= \sqrt{(0.07505^2 + 0.415^2)}$

ZSL = 0.421 Ω/km

Total Positive Sequence of Protected Line w.r.t. Primary = ZSL * Line Length

= 0.421*158

= 66.633 Ω

Total Positive Sequence Impedance w.r.t. Secondary = ZSL * CT/PT Ratio

= 66.633 * 0.6

ZSL Secondary = 39.98 Ω

Positive Sequence Impedance of Longest Line ZLL = $\sqrt{(R1^2 + X1^2)}$

$= \sqrt{(0.07505^2 + 0.415^2)}$

ZLL = 0.421 Ω/km

Total Positive Sequence of Protected Line w.r.t. Primary = ZLL * Line Length

= 0.421*158

= 66.633 Ω

Total Positive Sequence Impedance w.r.t. Secondary = ZLL * CT/PT Ratio

= 66.633 * 0.6

ZLL Secondary = 39.98 Ω

Positive Sequence Impedance of Second Longest Line Z2LL = $\sqrt{(R1^2 + X1^2)}$

$= \sqrt{(0.09944^2 + 0.4004^2)}$

Z2LL = 0.412 Ω/km

Total Positive Sequence of Protected Line w.r.t. Primary = Z2LL * Line Length

= 0.412*110

= 45.38 Ω

Total Positive Sequence Impedance w.r.t. Secondary = Z2LL * CT/PT Ratio

= 66.633 * 0.6

Z2LL Secondary = 27.229 Ω

Total Transformer Impedance ZT (Remote):

If there are more than one Transformer, the resultant Impedance considering the Transformers are in parallel is taken.

Considering Transformers are connected in parallel

Total Transformer Impedance ZT (Remote) **=** (% Transformer Impedance) *((kV) 2/MVA)]

Transformer Impedance of Z1 $= [0.0976*(220^2/60)]$

= 78.7307 Ω

Transformer Impedance of Z2 $= [0.101*(220^2/60)]$

= 81.4733 Ω

Transformer Impedance of Z3 $= [0.111*(220^2/60)]$

= 89.54 Ω

Total Transformer Impedance ZT (Remote) = 1/((1/Z1)+ (1/Z2) + (1/Z3))

ZT (Remote) = 1/((1/78.7307)+(1/81.4733)+(1/89.54))

Transformer Impedance W.R.T primary ZT = 27.6674 Ω

Total Transformer Impedance ZT (Remote) Secondary = ZT (Remote) *(CT/PT ratio)

= 27.6674 * 0.6

Transformer Impedance W.R.T Secondary ZT = 16.60 Ω

Loadability

Positive sequence impedance Angle $=\tan^{-1}(X/R)$

Line Angle $= \tan^{-1}(0.40988/0.07411)$

Line Angle =79.75 Degree

The maximums Load w.r.t Secondary ZMAX primary $= 0.85*V_{L-L}/(\sqrt{3}*1.5*.I_L)$

ZMAX $= 0.85*220 / (\sqrt{3}*1.5*795)$

[900 A is the maximum capacity of ACSR Markulla and Moose conductor]

ZMAX = 90.54 Ω

Corresponding Zmax secondary = Zmax * CT/PT Ratio = 90.54 * 00.6 = 54.32 **Ω**

The Resistance reach corresponding to Zmax w.r.t Secondary

R = ZMAX *COS (30)

= 54.32*0.8660

R = 47.05 **Ω**

The Reactance reach corresponding to Zmax w.r.t Secondary

X = ZMAX *SIN (30)

= 54.32 * 0.5

X = 27.16 Ω

The New impedance for Parallel line Drawn Parallel to the Line impedance passing through Zmax to the point at which the parallel line cuts the Resistance axis is

Znew = X (at Zmax) /SIN(79.75)

= 27.16 / 0.9967

Znew = 27.60 Ω

The New Resistance from Known Reactance Rnew = Znew* COS (79.75)

= 27.60*0.01779

R new = 4.911

Resistances reach of Relay Characteristics

= (R corresponds to Zmax – R new)

R = 47.05 - 4.911

R = 42.13 Ω

Zone Settings

Zone 1

Zone 1= 80 % of Protection Line

= 0.8* 12.068

Zone 1 = 9.654 Ω

Kz 1 Zero sequence compensation

Kz1 = $(Z_0\text{-}Z_1/3{*}Z_1)$

= (0.29524+j1.260416)-(0.07411+j0.40988) / 3(0.07411+j0.40988)

Zero sequence Line impedance = 0.703 ∟-4.33

Kz1 angle = angle of Kz1

Resistive reach

R1G= MIN of [(10 times of Zone1 Impedance) and 0.8*Resistive Reach at Max load)]

R1G = Min of (10* 9.654 and 0.8* 42.13)

R1G = 33.71 Ω

R1PH= MIN of [(10 times of Zone1 Impedance) and 0.6*Resistive Reach at Max load)]

R1PH = Min of (10* 9.654 and 0.8* 42.13)

R1PH= 25.28 Ω

Zone 2

Zone 2 = Min of [[MAX OF ((Protection line+ (0.5*Adjacent shortest line)) AND (1.2*Protection line)](Protection line+ (0.5*Transformer impedance at remote end)]

= Min of[[Max of [(12.068+ (0.5*39.98)) and (1.2*12.068)](12.068 +0.5*16.60)]

= Min of [Max of 32.058 and 14.48] and 20.368

Zone 2 = 20.368 Ω

tz2 = 0.35 sec

Kz 1 Zero sequence compensation

Kz1 = $(Z_0 - Z_1/3*Z_1)$

= (0.29524+j1.260416)-(0.07411+j0.40988) / 3(0.07411+j0.40988)

Zero sequence Line impedance = 0.703 ∟-4.33

Kz1 angle = angle of Kz1

Resistive reach

R2G= MIN of **[**(10 times of Zone1 Impedance) and 0.8*Resistive Reach at Max load)**]**

R2G = Min of (10* 20.368 and 0.8* 42.13)

R2G = 33.71 Ω

R2PH= MIN of **[**(10 times of Zone1 Impedance) and 0.6*Resistive Reach at Max load)**]**

R2PH = Min of (10* 20.368 and 0.8* 42.13)

R2PH= 25.28 Ω

<u>**Zone 3**</u>

Zone3= [MIN OF (1.2(Protection line) +Adjacent Long line) & (Protection line+Adjacent Long line+25% Second Adjacent Long Line) & (Protection line +0.8Transformer impedance)]

= Min of (1.2*12.068 + 39.98) & (12.068 +39.98 +0.25*27.229) and (12.068+ 16.60)

=Min of (54.46 and 58.855 & 28.668)

Zone3 = 28.668 Ω

tz3 = 1 sec

Resistive reach

R3G= MIN of **[**(10 times of Zone1 Impedance) and 0.8*Resistive Reach at Max load)**]**

R3G = Min of (10* 28.668 and 0.8* 42.13)

R3G = 33.71 Ω

R3PH= MIN of **[**(10 times of Zone1 Impedance) and 0.6*Resistive Reach at Max load)**]**

R3PH = Min of (10* 28.668 and 0.8* 42.13)

R3PH= 25.28 Ω

<u>Zone 4</u>

Zone4 = 0.25 *Zone1

Zone4 = 0.25*9.654 Ω

Zone4 = 2.413 Ω

tz4 = 1 sec

1.7 **Procedure for Relay setting Calculation for Quadramho Relay**

Total Positive sequence impedance of Protected line **ZPL**=

= [ZPL (Ohms /Km)*Protected Line Length (km)]

ZPL W.R.T Secondary = Z**PL** W.R.T Primary *(CT/PT ratio)

Similarly the Impedance for Adjacent Shortest Line Z**SL** and Adjacent Remote Long Line **ZPL** can be calculated like above.

Total Transformer Impedance **ZT (**At remote end**)**

If there is more than one Transformer, the resultant Impedance considering the Transformers are in parallel is taken.

ZT = (%Transformer Impedance)*((KV) ^{2}/ MVA)]

Zero sequence impedance Z0 = $\sqrt{R_0^2+X_0^2}$

Zero sequence impedance Angle Z0 = $Tan^{-1}(X_0/R_0)$

Positive sequence impedance Angle = $Tan^{-1}(X_1/R_1)$

The setting below are calculated on the basis of 1A Relay ie.In = 1.

Zone Settings

Zone 1

Zone 1= 80% of Protection Line

Phase Fault Reach

Phase reach should not exceed the Zone 1 Reach

Zph = (K1+K2)/In

Existing Setting of Zone 1 = (K11+k12+K13)*K14*Zph

K1 = 1 (0 to 4 in steps of 1)

K2 = 0.8 (0 to 0.8 in steps of 0.2

K11 = 1 (1 to 9 in steps of 1)

k12 = 0 (0 to 0.9 in steps of 0.1)

k13 = 0.04 (0 to 0.08 in steps of 0.02)

K14 = 1 (1,5)

Zone 2

Zone 2 =Minimum of [[MAX OF ((Protection line+ (0.5*Adjacent shortest line)) AND (1.2*Protection line)] and (Protected Line + 0.5 *Transformer Impedance)]

Existing setting of Zone 2 =K24*(K21+K22)*Zph

K21=1 (1 to 9 in steps of 1)

K22=0.6 (0 to 0.9 in steps of 0.1)

K24=1

tz2= if [ZONE 2 > 80 % of Next shortest line then t=0.6sec else t=0.3 sec]

Zone 3(forward)

Zone3= [MIN OF (1.2*Protection line +Adjacent Long line)), Protection line +Adjacent Long line+0.25*Second Long Line & Protection line + (Transformer impedance)]

Existing Setting of Zone 3 = (K31+K32)*K33*Zph

K31= (1 to 9 in steps of 1)

K32= (0 to 0.9 in steps of 0.1)

K33= (1,5)

tz3 = 0.8 sec

Zone 3 (Offset)

Zone 4 = 0.25 *Zone 1 reach

The Existing setting of Zone 4 = (K35*K36)K33*K37*Zph

K33 = (1, 5)

K35 = (1 to 9 in steps of 1)

K36 = (0 to 0.9 in steps of 0.1)

K37 = (0, 0.25, 0.5, 1.0)

tz3 = **0.8 sec**

Earth Fault Compensation Zn=Z0-Z1/3Z1

Zn = (K4+K5+K6) =Zph

K4 = (0 to 5 in steps of 1)

K5 = (0 to 0.9 in steps of 0.1

K6 = (0 to 0.08 in steps of 0.02)

<u>Relay Characteristics angle</u>

Relay Characteristics angle Θ_{Phase}= Tan-1 X/R

Θ_{Earth} = Angle Zn

<u>Sample setting Calculation for Quadra mho relay</u>

Substation : 400 kV GSS Bhiwani

Line : Bhiwani to Bapora 1

Relay Name : Quadramho Relay

DATA:

Protected Line Length : 6.8 km

Adjacent Shortest Line Length : 6.8 km (220 kV Bapora 2)

Adjacent Longest Line Length : 6.8 km (220 kV Bapora 2)

<u>Protected Line</u>

Positive sequence Line impedance = 0.0797 + j0.4065

Zero sequence Line impedance = 0.233 +j1.329

<u>Adjacent Short Long line</u>

Positive sequence Line impedance = 0.0797 + j0.4065

Zero sequence Line impedance = 0.233 +j1.329

<u>Adjacent Longest Long line</u>

Positive sequence Line impedance = 0.0797 + j0.4065

Zero sequence Line impedance = 0.233 +j1.329

Nomber of Remote end Transformers: 3

CT Ratio = 1200A/1A

PT Ratio = 220kV/110V

Protected Line Length = 6.8 Km

Adjacent Shortest Line Length = 6.8 Km

Adjacent Longest Line Length = 6.8 Km

Voltage ratio of the transformer = 220kV/132V

MVA of the transformer at the Remote end = 3*100 MVA,

Impedance of the transformer = 10.302 %, 11.87 %, 12.34%

CT/PT ratio = 0.6

<u>Calculation</u>

Positive sequence impedance of Protected line ZPL = $\sqrt{R^2+X^2}$

$= \sqrt{0.0797^2+0.4065^2}$

ZPL = 0.414 Ohms/Km

Total Positive sequence impedance of Protected line ZPL=

= [ZPL (Ohms /Km)*Protected Line Length (km)]

= [0.414 * 6.8]

ZPL W.R.T Primary = 2.8168 Ω

Total Positive Sequence Impedance of Protected Line w.r.t. Secondary

= 2.8168 *0.6

ZPL W.R.T. Secondary = 1.69 Ω

Positive sequence impedance of Shortest line ZSL = $\sqrt{R^2+X^2}$

$= \sqrt{0.0797^2+0.4065^2}$

ZSL = 0.414 Ohms/Km

Total Positive sequence impedance Adjacent Shortest ZSL=

= [ZSL (Ohms /Km)*Protected Line Length (km)]

= 0.414* 6.8

ZSL W.R.T. primary = 2.8168 Ω

Total Positive Sequence Impedance of the Adjacent Shortest Line w.r.t. Secondary

= 2.8168 * 0.6

ZSL W.R.T. Secondary = 1.69 Ω

Positive sequence impedance of Longest line ZLL = $\sqrt{R^2+X^2}$

= $\sqrt{0.0797^2+0.4065^2}$

ZLL = 0.414 Ohms/Km

Total Positive sequence impedance Adjacent Longest ZLL=

= [ZLL (Ohms /Km)*Protected Line Length (km)]

= 0.414* 6.8

ZLL W.R.T. primary = 2.8168 Ω

Total Positive Sequence Impedance of the Adjacent Shortest Line w.r.t. Secondary

= 2.8168 * 0.6

ZLL W.R.T. Secondary = 1.69 Ω

Total Transformer Impedance ZT (Remote):

If there is more than one Transformer, the resultant Impedance considering the Transformers are in parallel is taken.

Considering Transformers are connected in parallel

Total Transformer Impedance ZT (Remote) = (% Transformer Impedance) *((kV) 2/MVA)]

Transformer Impedance of Z1 = [0.1032*(220^2/100)]

= 49.9488 Ω

Transformer Impedance of Z2 = [0.1187*(220^2/100)]

= 57.45Ω

Transformer Impedance of Z3 = [0.1234*(220^2/100)]

= 59.74496 Ω

Total Transformer Impedance ZT (Remote) = 1/((1/Z1)+ (1/Z2) + (1/Z3))

ZT (Remote) = 1/((1/49.9488)+(1/57.45)+(1/59.74496))

Transformer Impedance W.R.T primary ZT = 18.4503 Ω

Total Transformer Impedance ZT (Remote) Secondary = ZT (Remote) *(CT/PT ratio)

= 18.4503 * 0.6

Transformer Impedance W.R.T Secondary ZT = 11.0702 Ω

Zone Settings

<u>Zone 1</u>

Zone 1 = 80% of Protection Line

= 0.8*1.69

Zone 1 = 1.352 Ω

Phase Fault Reach

Phase reach should not exceed the Zone 1 Reach

Zph = (K1+K2)/In

K1+K2 = 1+0.2

Zph = 1.2

Existing Setting of Zone 1 = (K11+k12+K13)*K14*Zph

= (K11+k12+K13)*K14*1.2

= (1+0+0.08) * 1.0 *1.2 =1.296 Ω

<u>Zone 2</u>

Zone 2 = Min of [MAX of ((Protected line+ (0.5*Adjacent shortest line)) AND (1.2*Protected line)] and (Protected Line + 0.5 * Transformer Impedance at remote end)

= Min of (Max Of **((**1.69 + (0.5*1.69)) and (1.2*1.69)) and (1.69 + 0.5 *11.0702)

= Min of (Max of 2.535 and 2.028) and 7.2251

Zone 2 = 2.535 Ω

Existing Zone 2 setting = K24*(K21+K22)*Zph

= 1*(2+0)*1.2

= 2.4 Ω

K21=5 (1 to 9 in steps of 1)

K22=0.2 (0 to 0.9 in steps of 0.1)

K24=1

tz2= if [ZONE 2 > 80 % of Next shortest line then t=0.6sec else t=0.3 sec]

tz2= 0.350 sec

Zone 3(forward)

Zone3= MIN OF [(1.2*Protected line + Adjacent Long line)), (Protected line + Adjacent Long line+0.25* Second Adjacent Long line) & (Protected line + Transformer impedance at remote end)]

= Min of [(1.2*1.69+1.69) and (1.69+1.69+0) and (1.69+11.0702)]

= Min of [3.718 and 3.38 and 12.7602]

= 3.38 Ω

Zone 3 = 3.38 Ω

Existing Zone 3 setting = (K31+K32)*K33*Zph

=(K31+K32)*K33*1.2

= (8+0.7)*1*1.2

= 10.44 Ω

K31 = 2 (1 to 9 in steps of 1)

K32 = 0.5 (0 to 0.9 in steps of 0.1)

K33 = 5 (1, 5)

tz3 = 1 sec

Zone 4(Reverse)

Zone 4 = 0.25 *Zone 1

Zone 4 = 0.25*1.352

Zone 4 =0.338 Ω

Existing Zone 4 (Reverse) = (K35+K36)K33*K37*Zph

= (1+0.1)*1*0.25*1.2 =0.33 Ω

K33=5 (1, 5)

K35=1 (1 to 9 in steps of 1)

K36=0 (0 to 0.9 in steps of 0.1)

K37=0.25 (0, 0.25, 0.5, 1.0)

$tz3 = 1$ sec

Relay Characteristics angle

Relay Characteristics angle Θ_{Phase}= Tan-1 X/R

= Tan-1 (0.4065/0.0797)

Θ_{Phase} = 78.90 degree

Θ_{Earth} = Angle Positive Sequence impedance +Angle Of Kn

=78.9 + (-5)

= 74.9 Degree

1.8 <u>Procedure for Relay setting Calculation for Micro Mho Relay</u>

Total Positive sequence impedance of Protected line **ZPL**=

= [ZPL (Ohms /Km)*Protected Line Length (km)]

ZPL W.R.T Secondary = Z**PL** W.R.T Primary *(CT/PT ratio)

Similarly the Impedance for Adjacent Shortest Line Z**SL** and Adjacent Remote Long Line **ZPL** can be calculated like above.

Total Transformer Impedance **ZT (**At remote end**)**

If there is more than one Transformer, the resultant Impedance considering the Transformers are in parallel is taken.

ZT = (%Transformer Impedance)*((KV) ^{2}/ MVA)]

Zero sequence impedance Z0 = $\sqrt{R_0{}^2+X_0{}^2}$

Zero sequence impedance Angle Z0 = $\mathrm{Tan}^{-1}(X_0/R_0)$

Positive sequence impedance Angle = $\mathrm{Tan}^{-1}(X_1/R_1)$

The setting below are calculated on the basis of 1A Relay ie.In = 1.

Zone Settings

<u>Zone 1</u>

Zone 1= 80% of Protection Line

Phase Fault Reach

Phase reach should not exceed the Zone 1 Reach

Zph = (K1+K2)/In

Existing Setting of Zone 1 = (K11+k12+K13)*K14*Zph

K1 = 1 (0 to 4 in steps of 1)

K2 = 0.8 (0 to 0.8 in steps of 0.2

K11 = 1 (1 to 9 in steps of 1)

k12 = 0 (0 to 0.9 in steps of 0.1)

k13 = 0.04 (0 to 0.08 in steps of 0.02)

K14 = 1 (1,5)

Zone 2

Zone 2 =Min of [[MAX OF ((Protection line+ (0.5*Adjacent shortest line)) AND (1.2*Protection line)] and (Protected Line + 0.5 *Transformer Impedance at remote end)]

Existing setting of Zone 2 =K24*(K21+K22)*Zph

K21=1 (1 to 9 in steps of 1)

K22=0.6 (0 to 0.9 in steps of 0.1)

K24=1

tz2= if [ZONE 2 > 80 % of Next shortest line then t=0.6sec else t=0.3 sec]

Zone 3(forward)

Zone3= [MIN OF (1.2*Protection line +Adjacent Long line)), Protection line +Adjacent Long line+0.25*Second Long Line & (Protection line + Transformer impedance at remote end)]

Existing Setting of Zone 3 = (K31+K32)*K33*Zph

K31= (1 to 9 in steps of 1)

K32= (0 to 0.9 in steps of 0.1)

K33= (1,5)

tz3 = 0.8 sec

Zone 3 (Offset)

Zone 4 = 0.25 *Zone 1 reach

The Existing setting of Zone 4 = (K35*K36)K33*K37*Zph

K33 = (1, 5)

K35 = (1 to 9 in steps of 1)

K36 = (0 to 0.9 in steps of 0.1)

K37 = (0, 0.25, 0.5, 1.0)

tz3 = 0.8 sec

Earth Fault Compensation Zn=Z0-Z1/3Z1

Zn = (K4+K5+K6) =Zph

K4 = (0 to 5 in steps of 1)

K5 = (0 to 0.9 in steps of 0.1

K6 = (0 to 0.08 in steps of 0.02)

<u>Relay Characteristics angle</u>

Relay Characteristics angle Θ_{Phase}= Tan-1 X/R

Θ_{Earth} = Angle Zn

<u>Sample setting Calculation for Micro mho relay</u>

Substation : 400 kV GSS Bhiwani

Line : Bhiwani to Charkhi Dhadri

Relay Name : Micro Mho Relay

<u>Protected line 1</u>

Positive sequence Line impedance = 0.0797+j0.405

Zero sequence Line impedance = 0.233+j1.329

<u>Protected line 2</u>

Positive sequence Line impedance = 0.097105+j0.39314

Zero sequence Line impedance = 0.57146+j1.83241

<u>Adjacent Shortest line 1</u>

Positive sequence Line impedance = 0.0797+j0.405

Zero sequence Line impedance = 0.233+j1.329

<u>Adjacent Shortest line 2</u>

Positive sequence Line impedance = 0.097105+j0.39314

Zero sequence Line impedance = 0.57146+j1.83241

<u>Adjacent Longest line</u>

Positive sequence Line impedance = 0.097105+j0.39314

Zero sequence Line impedance = 0.57146+j1.83241

<u>Second Adjacent longest line</u>

Positive sequence Line impedance = 0.0741+j0.389

Zero sequence Line impedance = 0.48787+j1.92051

CT Ratio = 1200A/1A

PT Ratio = 220kV/110V

Protected Line Length = 8.7 Km (0.0797+j0.405)

Protected Line Length = 26 Km (0.097105+j0.39314)

Adjacent Shortest Line Length = 8.7 Km (0.0797+j0.405)

Adjacent Shortest Line Length = 26 Km (0.097105+j0.39314)

Adjacent Longest Line Length = 119.89 Km (0.097105+j0.39314)

Adjacent Second Longest Line Length = 24.73 Km (0.0741+j0.389)

Voltage ratio of the transformer at remote end = 220kV/132V

MVA of the transformer at the Remote end = 2*100 MVA

Impedance of the transformer = 12.344 %, 12.00%

CT/PT ratio = 0.6

<u>Calculation</u>

Total Positive sequence impedance of Protected line ZPL = $\sqrt{R^2+X^2}$

$= (\sqrt{0.0797^2+0.405^2})*8.7+ (\sqrt{0.097105^2+0.39314^2})*26$

ZPL = 14.129 Ohms/Km

Total Positive Sequence Impedance of the Protected Line w.r.t. secondary

ZPL W.R.T. Secondary = 14.129 * 0.6

= 8.4774 Ω

Total Positive sequence impedance of Shortest line ZSL = $\sqrt{R^2+X^2}$

$= (\sqrt{0.0797^2+0.405^2})*8.7+ (\sqrt{0.097105^2+0.39314^2})*26$

ZSL = 14.129 Ohms/Km

Total Positive Sequence Impedance of the Protected Line w.r.t. secondary

ZSL W.R.T. Secondary = 14.129 * 0.6

= 8.4774 Ω

Total Positive sequence impedance of Adjacent Longest line **ZLL**=

= [ZLL (Ohms /Km)*Longest Line Length (km)]

$= \sqrt{(0.097105^2+0.39314^2)}*119.89$

ZLL W.R.T Primary = 48.55 Ω

Total Positive Sequence Impedance of the Adjacent Longest Line w.r.t. Secondary

ZLL W.R.T. Secondary = 48.55 * 0.6

= 29.13 Ω

Total Positive sequence impedance of Second Adjasent Longest line **Z2LL**=

= [Z2LL (Ohms /Km)*Longest Line Length (km)]

$= \sqrt{(0.0741^2+0.389^2)}*24.73$

Z2LL W.R.T Primary = 9.7929 Ω

Total Positive Sequence Impedance of the Adjacent Longest Line w.r.t. Secondary

Z2LL W.R.T. Secondary = 9.7929 * 0.6

= 5.8757 Ω

Total Transformer Impedance ZT (Remote):

If there is more than one Transformer, the resultant Impedance considering the Transformers are in parallel is taken.

Considering Transformers are connected in parallel

Total Transformer Impedance ZT (Remote) = (% Transformer Impedance) *((kV) 2/MVA)

Transformer Impedance $Z_1 = 0.12 * 220^2/ 100$

= 58.08 Ω

Transformer Impedance $Z_2 = 0.1234 * 220^2/100$

= 59.744 Ω

Total Transformer impedance: $Zt = Z_1*Z_2/ (Z_1 + Z_2)$

Zt = 58.08 * 59.744/ (58.08+ 59.744)

Zt w.r.t. primary = 29.45 Ω

Transformer Impedance w.r.t. Secondary = 29.45 * (CT/PT Ratio)

= 29.45 * 0.6

= 17.67 Ω

Zone Settings

<u>Zone 1</u>

Zone 1 = 80% of Protection Line

= 0.8*8.477

Zone 1 = 6.782 Ω

Phase Fault Reach

Phase reach should not exceed the Zone 1 Reach

Zph = (K1+K2)/In

K1+K2 = 4+0.8

Zph = 4.8

Existing Setting of Zone 1 = (K11+k12+K13)*K14*Zph

= **(K11+k12+K13)*K14*4.8**

= (1+0.5+0.02) * 1.0 *1.2 =7.296 Ω

<u>Zone 2</u>

Zone 2 = Min of [MAX of ((Protected line+ (0.5*Adjacent shortest line)) and (1.2*Protected line)] and (Protected Line + 0.5 * Transformer Impedance)

= Min of (Max Of **((**8.477 + (0.5*8.477)) and (1.2*8.477) and (8.477 + 0.5 *17.67)

= Min of (Max of 12.71 and 10.172) and 17.312

Zone 2 = 12.71 Ω

Existing Zone 2 setting =K24*(K21+K22)*Zph

K24*(K21+K22)*4.8= 12.96 Ω

K21=5 (1 to 9 in steps of 1)

K22=0.2 (0 to 0.9 in steps of 0.1)

K24=1

tz2= if [ZONE 2 > 80 % of Next shortest line then t=0.6sec else t=0.3 sec]

tz2= 0.350 sec

<u>Zone 3(forward)</u>

Zone3= Min of (1.2*Protected line + Adjacent Long line)), Protected line + Adjacent Long line+0.25* Second Adjacent Long line) & (Protected line + Transformer impedance at remote end)]

= Min of [(1.2*8.477+29.13)] and [8.477+29.13+0.25*5.8757] and [8.477+17.67]

= Min of [39.30 and 39.076 and 26.1477]

= 26.1477 Ω

Zone 3 = 26.1477 Ω

Existing Zone 3 setting = (K31+K32)*K33*Zph

=(K31+K32)*K33*4.8

=(9+0.4)*1*4.8= 45.12 Ω

K31 = 9 (1 to 9 in steps of 1)

K32 = 0.4 (0 to 0.9 in steps of 0.1)

K33 = 1 (1,5)

tz3 = 1 sec

<u>Zone 4(Reverse)</u>

Zone 4 = 0.25 *Zone 1

Zone 4 = 0.25*6.782

Zone 4 =1.695 Ω

Existing Zone 4 (Reverse) = (K33+K34)*Zph

(K33+K34)*4.8 = (1+0.5)*4.8 = 2.4 Ω

K33=1 (1, 5)

K34=1 (0 to 0.9 in steps of 0.1)

tz3 (Reverse) = 1 sec

<u>Power Swing Blocking:</u>

Existing setting =K50= (K51+K52)*K53*ZPH

= (6+0)*1*4.8

=28.8 Ω

Setting should be equal to the reach value of zone3 according to manufacturer's recommendation for detecting the Power Swing.

Earth fault compensation = (Z0-Z1)/3*Z0 *Zph

= (Total Zero Sequence Impedance - Total Positive Sequence Impedance)/

(3*Total Zero Sequence Impedance) *Zph

= (((0.57146+j1.83241)-(0.097105+j0.39314))/(3*(0.097105+j0.39314)))*4.8

= 2.312 Ω

2. Differential Protection

2.1 <u>Differential Relay Settings Calculations MiCOM P63X</u>

Relay Type: MICOM P63X

Required Data

Ratings of the Power and Current Transformers

MVA

Voltage Ratio

Rated Voltage in kV (HV Side)

Rated Voltage in kV (LV Side)

Vector Group

CT Ratio (HV Side)

CT HV Side Vector Group

CT Ratio (LV Side)

CT LV Side Vector Group

Minimum Tap = - %

Maximum Tap = +%

Rated Current (HV Side) = MVA / (√3*kV)

Current on CT Secondary (HV) = Rated Current (HV Side)/CT Ratio

Required Ratio Compensation = 1/ Current on CT secondary (HV)

Rated Current (LV Side) = MVA / (√3*kV)

Current on CT Secondary (LV) = Rated Current (LV Side)/CT Ratio

Required Ratio Compensation = 1/ Current on CT Secondary (LV)

Relay current on LV side I_2 = Current on CT secondary LV side / Ratio compensation for LV side

Calculations for OLTC tap setting -% and +%

Full load Current (- % or +% HV Side) = MVA / (√3*kV)

Current on CT Secondary (HV) = Rated Current (HV Side)/CT Ratio

Relay Current for HV side I_1= Current on Ct secondary (HV)/ Ratio compensation for HV side

I_1 is calculated for extreme transformer taps

The differential current is = I_1-I_2

Bias current $I_{bias} = (I_1+I_2)/2$

Differential current I_{dif} and I_{bias} is calculated foe extreme Transformer taps

Therefore the operating current of the relay

If Ibias < 2

$= I_s + m1 * I_{bias}$

If Ibias > 2

$= m2*(I_{bias} – 2)+ m1 * 2$

Where m1 and m2 are the slope of relay characteristics, Pick up setting is chosen such that the Differential current at worst tap condition should not be more than 90% of operating current for better stability

Sample setting calculations for MiCOM P63X Transformer Differential Relay

Substation Name: 400 kV GSS Bhiwani

Relay Type: MICOM P632

Ratings of the Power and Current Transformers

Transformer Name: BHEL

MVA = 500

Voltage Ratio = 400/220

Rated Voltage in kV (HV Side) = 400

Rated Voltage in kV (LV Side) = 220

Vector Group = Yy0d11

CT Ratio (HV Side) = 1000/1

CT HV Side Vector Group = Star/Star

CT Ratio (LV Side) = 1500/1

CT LV Side Vector Group = Star/Star

Minimum Tap = -5

Maximum Tap = +15

Rated Current (HV Side) = MVA / (√3*kV)

=500*10^6/ (√3*400*10^3)

=721.68 A

Current on CT Secondary (HV) = Rated Current (HV Side)/CT Ratio

= 721.68/1000

=0.722 A

Required Ratio Compensation = 1/ 0.722

= 1.386 A

Rated Current (LV Side) = MVA / (√3*kV)

=500*10^6/ (√3*220*10^3)

=1312.60 A

Current on CT Secondary (LV) = Rated Current (LV Side)/CT Ratio

=1312.60 /1500

= 0.875 A

Required Ratio Compensation = 1/ 0.875

=1.143 A

Calculations for OLTC tap setting -5%

Full load Current for 400 kV %(HV Side) Winding at -5% = MVA / (√3*0.95*kV)

=500*10^6/ (√3*400*0.95*10^3)

=759.671 A

Current on CT Secondary (HV) = Rated Current (HV Side)/CT Ratio

= 759.671 /1000

=0.76 A

As the adopted ratio correction is 1.386 A the current to relay bias terminal

= 0.76 * 1.386

=1.053 A

Hence the differential current is = 1.053 – 1

= 0. 053 A

Bias current = $(I_1+I_2)/2$

= (1.053+1)/2

= 1.026 A

[Since the bias current is less than 1.5 A the slope will be within 20%]

Therefore the operating current of the relay will be = I_s + (0.2* I_{bias})

= 0.2 + (0.2 * 1.026)

= 0.4052 A

Differential current should be less than operating current for stability,

Here for worst tap condition, Differential current is less than operating current, hence stable.

Calculations for OLTC tap setting +15%

Full load Current for 220 kV %(HV Side) Winding at **+15**% = MVA / (√3*1.15*kV)

=500*10^6/ (√3*400*1.15*10^3)

=627.55A

Current on CT Secondary (HV) = Rated Current (HV Side)/CT Ratio

= 627.55 /1000

=0.628 A

As the adopted ratio correction is 1.386 A the current to relay bias terminal

= 0.628* 1.386

=0.870A

Hence the differential current is = 1 - 0.870

= 0.130 A

Bias current = $(I_1+I_2)/2$

= (0.870 +1)/2

= 0.935 A

[Since the bias current is less than 1.5 A the slope will be within 20%]

Therefore the operating current of the relay will be = $I_s + (0.3 * I_{bias})$

= 0.2 + (0.2 * 0.935)

= 0.387 A

Differential current should be less than operating current for stability,

Here for worst tap condition, Differential current is less than operating current, hence stable.

2.2 <u>Procedure for Relay Setting of Transformer Differential Relay MBCH</u>

<u>Data Required</u>

MVA Rating

Voltage ratio

Vector group

CT ratio on HV Side

Winding connection of CT on HV side

ICT ratio on HV Side

Winding connection of ICT on HV side

CT ratio on LV Side

Winding connection of CT on LV side

Transformer Tap

Min -% OLTC Tap and max % OLTC tap

<u>At Nominal tap</u>

Rated current (HV Side) = MVA / (√3*Rated voltage (HV side))

Rated current (LV Side) = MVA / (√3*Rated voltage (LV side))

If CT is Star/Star

Current on CT Secondary (HV) = Rated Current (HV Side) / CT Ratio (HV Side)

If CT is Star/Delta the current shall be multiplied by √3.

Current on the secondary of ICT for Star/Star = Current on CT Secondary (HV Side) / ICT Ratio (HV Side)

For Star/Delta the current shall be multiplied by √3.

The same procedure is followed for getting the relay current on LV side also.

I_{diff} = Relay Current = Difference between the HV and LV Current (Current at the secondary of ICT's)

To make sure that the relay does not operate when the Transformer taps are changed the currents are calculated at extreme taps.

At Tap on -%

Voltage corresponding to the above tap,

Full load current = MVA / √3 * Voltage corresponding to minimum tap.

At Tap on +%

Voltage corresponding to the above tap,

Full load current = MVA / √3 * Voltage corresponding to +ve tap.

Currents at the CT Secondary and ICT Secondary are calculated by using the above procedure. For extreme +ve and extreme –ve tap.

Relay current I_1= the difference between the HV and LV Currents for extreme +ive tap.

I_2= The difference between the HV and LV Currents for extreme +ve tap.

MBCH has an adjustable basic threshold setting of 10% to 50% current I selectable in 10% steps.

Dual Slope – 20% Slope upto In.

- 80% Slope for Current > In.

Relay operating current = Pickup setting + Bias Setting * Bias current

Bias Current = $(I_1+I_2)/2$

$I_{Operating}$ 1A = Pickup setting + 0.20 * Bias Current less than 1A +0.8*current above 1A

Bias current = $(I_1+I_2)/2$

$I_{Difference} = I_1 - I_2$

Operating current at extreme taps is calculated with the same procedure.

The pickup setting is acceptable if the I operating is less than the bias current at extreme taps.

Sample setting calculations for MBCH Transformer Differential relay

Differential Relay Settings Calculations

Substation Name: 220 kV GSS Jalandhar

Relay Type: MBCH

Ratings of the Power and Current Transformer

MVA = 90

Rated Voltage in kV (HV Side) = 220

Rated Voltage in kV (LV Side) = 132

Vector Group = Yy0d1

CT Ratio (HV Side) = 300

CT HV Side Vector Group = Star/Star

CT Ratio (LV Side) = 500

CT LV Side Vector Group = Star/Star

CT Ratio (HV Side) = 300

CT Ratio (LV Side) = 500

Rated Current (HV Side) = MVA / (√3*kV)

=90*10^6/ (√3*220*10^3)

= 236.19 A

Rated Current (LV Side) = MVA / (√3*kV)

=90*10^6/ (√3*132*10^3)

= 393.65 A

Current on CT Secondary (HV) = Rated Current (HV Side)/CT Ratio

= 296.19/300

= 0.7873 A

Current on CT Secondary (LV) = Rated Current (LV Side)/CT Ratio

=393.65/500

= 0.7873 A

Interposing CT (HV Side) = 0.7873/1/0.577

=0.45

Vector Group Interposing CT (HV Side) = Star/Delta

Interposing CT (LV Side) = 0.73/1/0.58

Ratio of compensation HV= 1/(Current on CT Secondary (HV)

=1/ (0.45)

=2.20

Ratio of compensation (LV) = 1/(Current on CT Secondary (LV)

(LV Side))

=1/ (0.45)

=2.20

Compensated current internally = 0.45*2.20

=0.99A

Difference between HV side and LV side currents = Current on ICT Secondary (HV) -

Current on ICT Secondary (LV)

= 0 A

Calculations for OLTC tap setting -3%

Full load Current for 220 kV %(HV Side) Winding at -3% = MVA / (√3*0.97*kV)

=90*10^6/ (√3*220*0.97*10^3)

= 243.49 A

Current on CT Secondary (HV) = Rated Current (HV Side)/CT Ratio

= 243.49 /300

=0.811 A

Current on ICT Secondary (HV) = 1/ (Current on CT Secondary (HV)

=1/ (0.811)

= 0.47 A

=2.13

Compensated current internally = 0.47*2.20

=1.03A

Difference between HV side and LV side currents = Current on ICT Secondary (HV) - Current on ICT Secondary (LV)

= 1.03 –0.99

= 0.04 A

$I_{bias} = (I_1+I_2)/2$

= (0.99 + 1.03)/2

=1.01 A

Consider the setting of $I_s = 0.2$

The I Operating Current = 0.2 + (0.2 * 1) + (0.8*(1.01-1)

= 0.1 + 0.2 + 0.8*0.01 =0. 308A

At tap of -12% with full load the relay require a current of 0.308 A at $I_s = 0.2$

Differential current should be less than operating current for stability,

Here for worst tap condition, Differential current is less than operating current, hence stable.

Calculations for OLTC tap setting +9%

Full load Current for 220 kV %(HV Side) Winding at +9% = MVA / (√3*1.09*kV)

=90*10^6/ (√3*220*1.09*10^3)

=216.69 A

Current on CT Secondary (HV) = Rated Current (HV Side)/CT Ratio

= 216.69 /300

Current on ICT Secondary (HV) = 1/(Current on CT Secondary (HV)

=1/(216.69 /(300/0.58))

=2.394A

Compensated current internally= 2.394*2.20

=0.92

Difference between HV side and LV side currents = Current on ICT Secondary (HV) -

Current on ICT Secondary

= 1.00-0.92

= 0.08 A

$I_{bias} = (I_1+I_2)/2$

= (0.92+1.00)/2

=0.96 A

Consider the setting of I_s = 0.2

The I Operating Current = 0.2 + (0.2 * 0.96)

= 0.1 + 0.196

= 0.39 A

At tap of +9% with full load the relay require a current of 0.39 A at I_s = 0.2

Differential current should be less than operating current for stability,

Here for worst tap condition, Differential current is less than operating current, hence stable.

2.3 Procedure for Relay Setting of Transformer Differential Relay Alstom KBCH

Data Required

MVA Rating

Voltage ratio

Vector group

HV voltage

LV voltage

Transformer percentage impedance:

Transformer vector group:

OLTC Tap: +%   OLTC Tap: -%

CT ratio and winding configuration

HV side

LV side

At Normal tap

HV Side full load current = MVA / √3*kV

Current on CT Secondary Ict (HV) = Rated Current (HV Side) / CT Ratio (HV Side)

N1=Required ratio compensation = 1/ Ict sec

Assuming Relay current = 1A

N1 is set on the relay

Current on HV side = Current on CT secondary (HV)/ N1

At Normal tap

LV Side full load current = MVA / (√3*kV)

Current on CT Secondary Ict (LV) = Rated Current (LV Side) / CT Ratio (LV Side)

N2=Required ratio compensation = 1/ Ict sec (LV)

At -% Tap

HV side current = MVA / (√3*kV

Where kV is the voltage corresponding to -% tap on HV side

Current on CT Secondary Ict (HV) = Rated Current (HV Side) / CT Ratio (HV Side)

With ratio compensation

Current on CT Secondary =Ict sec /N1

At Tap on +%

HV side current = MVA / (√3*kV)

Where kV is the voltage corresponding to +% tap on HV side

Current on CT Secondary Ict (HV) = Rated Current (HV Side) / CT Ratio (HV Side)

With ratio compensation

Current on CT Secondary =Ict sec /N1

Differential current at extreme taps

At -% tap =$I_{diff1} = I_{HV} - I_{LV}$

At +% tap =$I_{diff2} = I_{HV} - I_{LV}$

$I_{bias} = I_{HV} + I_{LV} /_2$

Operating current of Relay

$I_{Operating}$ = Pickup setting + 0.20 * Bias Current less than 1A +0.8*current above 1A

Relay Operating current is calculated using the above equation.

For extreme taps the I_{diff} and I_{bias} current are calculated., the pick up setting is chosen such that it will not operate for extreme taps

<u>Sample setting calculation for KBCH Transformer Differential relay</u>

<u>Differential Relay Settings Calculations</u>

Substation Name: 220 kV GSS Dhulkote

Relay Type: KBCH (Areva)

Ratings of the Power and Current Transformers

Transformer Name: Transformer 2(Mitsubishi)

MVA = 60

Voltage Ratio = 220/66 kV

Rated Voltage in kV (HV Side) = 220

Rated Voltage in kV (LV Side) = 66

Vector Group = Yd11

CT Ratio (HV Side) = 138.5/1

CT HV Side Vector Group = Star/Star

CT Ratio (LV Side) = 800/1

CT LV Side Vector Group = Star/Star

Minimum Tap = -3

Maximum Tap = +9

Rated Current (HV Side) = MVA / (√3*kV)

=60*10^6/ (√3*220*10^3)

=157.46 A

Current on CT Secondary (HV) = Rated Current (HV Side)/CT Ratio

= 157.46/138.5

=1.14 A

HV compensation ratio = 0.88

LV compensation ratio = 1.52

Compensated current internally= HV compensation ratio * HV Full load current secondary

= 1.14*0.88

=1.003

Rated Current (LV Side) = MVA / (√3*kV)

=60*10^6/ (√3*66*10^3)

=524.86 A

Current on CT Secondary (LV) = Rated Current (LV Side)/CT Ratio

=524.86/800

= 0.66 A

Compensated current internally= LV compensation ratio * LV Full load current secondary

= 0.66*1.52

=1.0032

Calculations for OLTC tap setting -3%

Full load Current for 220 kV %(HV Side) Winding at -3% = MVA / (√3*0.97*kV)

=60*10^6/ (√3*220*0.97*10^3)

=162.33 A

Current on CT Secondary (HV) = Rated Current (HV Side)/CT Ratio

= 162.4 /138.5

= 1.17 A

As the adopted ratio correction is 0.88 A the current to relay bias terminal

= 1.17 * 0.88

=1.03 A

Hence the differential current is = 1.03 – 1

= 0.03 A

Bias current = $(I_1+I_2)/2$

= (1.03+1)/2

= 1.01A

[Since the bias current is more than 1 A the slope will be more than 20%]

Therefore the operating current of the relay will be = $I_s + (0.2 * I_{bias}) + I_s + 0.8*(1.01-1)$

= 0.2 + (0.2 * 1.01) + 0.8*(1.01-1)

= 0.41 A

Differential current at worst tap condition should not be more than 90% of operating current for better stability. ***Here it is less than 90% so the setting is acceptable.***

Calculations for OLTC tap setting +9%

Full load Current for 66 kV %(HV Side) Winding at 9% = MVA / (√3*1.09*kV)

=60*10^6/ (√3*220*1.09*10^3)

= 144.46A

Current on CT Secondary (HV) = Rated Current (HV Side)/CT Ratio

= 144.46 /138.5

= 1.04 A

As the adopted ratio correction is 0.88 A the current to relay bias terminal

= 1.04 * 0.88

= 0.92 A

Hence the differential current is = 1 – 0.92

= 0.08 A

Bias current = $(I_1+I_2)/2$

= (0.92 +1)/2

= 0.96 A

[Since the bias current is less than 1 A the slope will be within 20%]

Therefore the operating current of the relay will be = I_s + (0.2* I_{bias})

= 0.2 + (0.2 * 0.96)

= 0.392 A

Differential current should be less than operating current for stability,

Here for worst tap condition, Differential current is less than operating current.

Hence stable.

2.4 <u>Procedure for Relay Setting of Transformer Differential Relay DTH 31/32</u>

Data Required

MVA Rating

Voltage ratio

Vector group

CT ratio on HV Side

Winding connection of CT on HV side

ICT ratio on HV Side

Winding connection of ICT on HV side

CT ratio on LV Side

Winding connection of CT on LV side

Transformer Tap

Min -% or OLTC Tap max +%

Rated current (HV Side) = MVA / (√3*Rated voltage (HV side))

Rated current (LV Side) = MVA / (√3*Rated voltage (LV side))

If CT is Star/Star

Current on CT Secondary (HV) = Rated Current (HV Side) / CT Ratio (HV Side)

If CT is Star/Delta the current shall be multiplied by √3.

Current on the secondary of ICT for Star/Star = Current on CT Secondary (HV Side) / ICT Ratio (HV Side)

For Star/Delta the current shall be multiplied by √3.

The same procedure is followed for getting the relay current on LV side also.

I_{diff} = Relay Current = Difference between the HV and LV Current (Current at the secondary of ICT's)

To make sure that the relay does not operate when the Transformer taps are changed the currents are calculated at extreme taps.

At Tap on -%

Voltage corresponding to the above tap,

Full load current = MVA / √3 * Voltage corresponding to –ve tap.

At Tap on +%

Voltage corresponding to the above tap,

Full load current = MVA / √3 * Voltage corresponding to +ve tap.

Currents at the CT Secondary and ICT Secondary are calculated by using the above procedure. For extreme +ive and extreme –ive tap.

Relay current I_1= The difference between the HV and LV Currents for extreme +ive tap.

I_2= The difference between the HV and LV Currents for extreme +ive tap.

DTH 31 relay has a fixed pick up setting and variable single slope bias setting.

For setting the Bias Setting

The operating current of DTH 31 is given by the equation

Relay operating current = Pickup setting + Bias Setting * Bias current

The pickup setting in DTH 31 = 0.15 (constant)

Bias Current = $(I_1+I_2)/2$

Operating Current at normal tap with Bias setting Is = 0.15(or) 0.3

$I_{Operating}$ 1A = 0.15 + 0.15 * Bias Current

Bias current = $(I_1+I_2)/2$

$I_{Difference}$ 1A = $I_1 - I_2$

Operating current at extreme taps is calculated with the same procedure.

Operating current at extreme taps is calculated with the same procedure.

Operating Current at extreme Minimum tap

$I_{Operating}$ 2A.

$I_{Difference}$ 2A = $I_1 – I_2$.

Operating Current at extreme Maximum tap

$I_{Operating}$ 3A.

I difference 3A = $I_1 – I_2$.

In each of the above cases $I_{Operating}$ current $>I_{Difference}$ + Tolerance

If the above is true a setting of 0.15 for bias is selected. In case the above is not true. Similar calculation is carried out for the next Bias Setting.

<u>Sample setting calculation for DTH31/32 Transformer Differential Relay</u>

<u>Bhinmal Differential Relay Settings Calculations</u>

Relay Type: DTH31

Station Name : 220 kV GSS DTL Narela

Ratings of the Power and Current Transformers

Transformer Name: CGL

MVA =50

Voltage Ratio = 220/132 kV

Rated Voltage in kV (HV Side) = 220 kV

Rated Voltage in kV (LV Side) = 132 KV

Vector Group = YNa0d1

CT Ratio (HV Side) = 150/1

CT HV Side Vector Group = Star/Star

CT Ratio (LV Side) = 250/1

CT LV Side Vector Group = Star/Star

ICT Ratio (HV Side) = 1/0.577

ICT Ratio (LV Side) = 1/0.577

Rated Current (HV Side) = MVA / (√3*kV)

=50*10^6/ (√3*220*10^3)

=131.216 A

Rated Current (LV Side) = MVA / (√3*kV)

=50*10^6/ (√3*132*10^3)

=218.69 A

Current on CT Secondary (HV) = Rated Current (HV Side)/CT Ratio

= 131.216/150

=0.874 A

Current on CT Secondary (LV) = Rated Current (LV Side)/CT Ratio

=218.69/250

= 0.874 A

ICT Ratio (HV Side) = 1/0.577

ICT Ratio (LV Side) = 1/0.577

Current on ICT Secondary (HV) = (Current on CT Secondary (HV)/ Interposing CT (HV Side))

=0.874*(1/0.577) * 1.732
=0.874 A

Current on ICT Secondary (LV) = (Current on CT Secondary (LV)/ Interposing CT (LV Side))

= (0.874/1/0.577)*1.732

= 0.874 A

Difference between HV side and LV side currents = Current on ICT Secondary (HV) – Current on ICT Secondary (LV)

= 0.874-0.874

=0

Calculations for OLTC tap setting -15%

Full load Current for 220 kV %(HV Side) Winding at **-15**% = MVA / (√3*0.85*kV)

=50*10^6/ (√3*220*0.85*10^3)

=138.12 A

Current on CT Secondary (HV) = Rated Current (HV Side)/CT Ratio

= 138.12 /150

=0.9208 A

Current on ICT Secondary (HV) = $\sqrt{3}$*(Current on CT Secondary (HV)/ Interposing CT (HVSide))

=0.92*1.732/1/0.577

=0.9205 A

Current on ICT Secondary (LV) = 0.874 A

Difference between HV side and LV side currents = Current on ICT Secondary (HV) -

Differential current = I1 –I2

= 0.92- 0.874

= 0.046 A

Ibias = (I1 + I2) /2

= (0.92+0.874) /2

= 0.897 A

Operating Current = Id + Slope 1 * I bias

= 0.15+0.3*0.897

= 0. 419A

As Id= 0.046, Operating current = 0.419, Hence stable

Calculations for OLTC tap setting +5%

Full load Current for 220 kV %(HV Side) Winding at +5% = MVA / ($\sqrt{3}$*1.05*kV)

=50*10^6/ ($\sqrt{3}$*220*1.05*10^3)

= 114.008A

Current on CT Secondary (HV) = Rated Current (HV Side)/CT Ratio

= 114.008 /150

= 0.7608 A

Current on ICT Secondary (HV) = $\sqrt{3}$*(Current on CT Secondary (HV)/ Interposing CT (HV Side))

=0.7602

Current on ICT Secondary (LV) = 0.874 A

Difference between HV side and LV side currents = Current on ICT Secondary (HV) -

Current on ICT Secondary (LV)

=0.874-0.760

= 0.114 A

At Tap of -10 % $I_{bias} = (I_1+I_2)/2$

= (0.760+0.874)/2 A

=0 .817 A

Consider a bias setting of I_s = 0.30

The I Operating Current = 0.15 + I_s * I_{bias}

= 0.15 + 0.3* 0.817

=0.395 A

At tap of +5% with full load the relay require a current 0.395 A at I_s = 0.30.

Since I_1-I_2 = 0.114 which is less than the operating value, relay will operate.

So a setting I_s = 0.30 is acceptable.

2.5 <u>Differential Relay Settings Calculations RET 670</u>

Differential Relay Settings Calculation Procedure

Relay Type: RET 670

Required Data

Ratings of the Power and Current Transformers

MVA

Voltage Ratio

Rated Voltage in kV (HV Side)

Rated Voltage in kV (LV Side)

Vector Group

CT Ratio (HV Side)

CT HV Side Vector Group

CT Ratio (LV Side)

CT LV Side Vector Group

CT resistance value (Rct)

Lead resistance value (Rl)

Minimum Tap = - %

Maximum Tap = +%

Rated Current (HV Side) = MVA / (√3*kV)

Current on CT Secondary (HV) = Rated Current (HV Side)/CT Ratio

Required Ratio Compensation = 1/ Current on CT secondary (HV)

Rated Current (LV Side) = MVA / (√3*kV)

Current on CT Secondary (LV) = Rated Current (LV Side)/CT Ratio

Required Ratio Compensation = 1/ Current on CT Secondary (LV)

Relay current on LV side I_2 = Current on CT secondary LV side / Ratio compensation for LV side

Calculations for OLTC tap setting -% and +%

Full load Current (- % or +% HV Side) = MVA / (√3*kV)

Current on CT Secondary (HV) = Rated Current (HV Side)/CT Ratio

Relay Current for HV side I_1= Current on Ct secondary (HV)/ Ratio compensation for HV side

I_1 is calculated for extreme transformer taps

The differential current is = I_1-I_2

Bias current I_{bias} = (I_1+I_2)/2

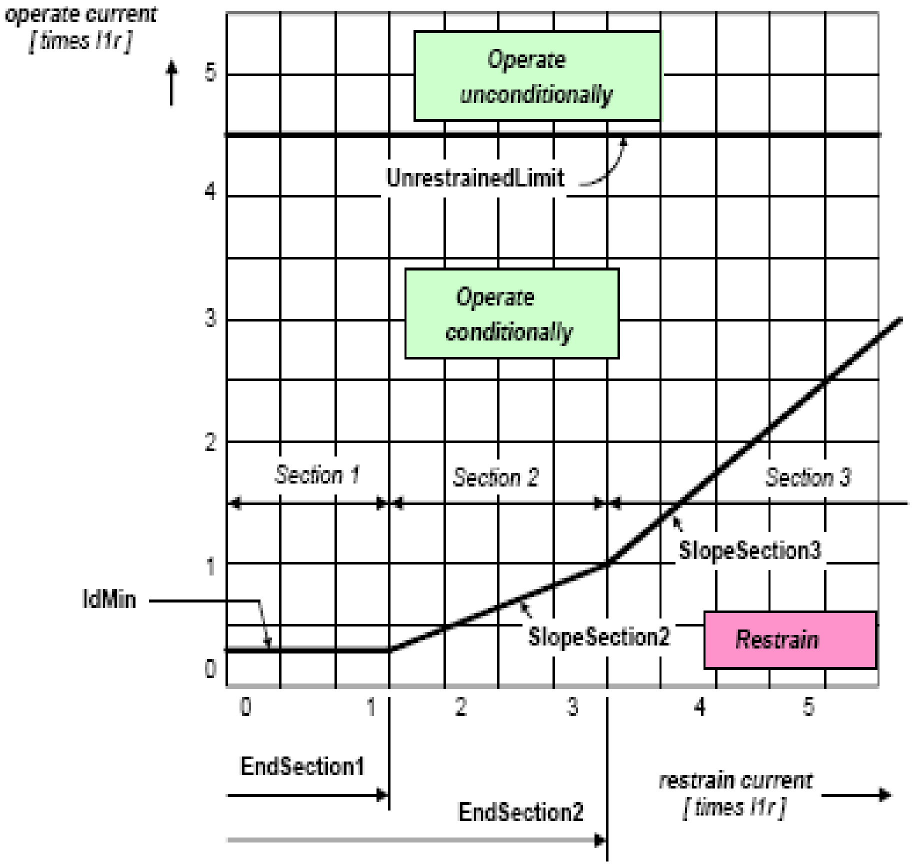
Differential current I_{dif} and I_{bias} is calculated foe extreme Transformer taps

Therefore the operating current of the relay

= I_s + m1* I_{bias} for current less than (4.Iref) + m2* I_{bias} for current greater than (4 Iref)

Where m1 and m2 are the slope of relay char

Pick up setting is chosen such that the Differential current at worst tap condition should not be more than 90% of operating current for better stability..



<u>Sample setting Calculation for ABB RET 670 (ALL Settings Are In Primary)</u>

A) <u>Biased Differential</u>

Substation Name : 220 kV GSS Jalandhar

Relay Type: ABB RET 670

Ratings of the Power and Current Transformers

Transformer Name: EMCO

MVA = 100

Voltage Ratio = 220/132

Rated Voltage in kV (HV Side) = 220

Rated Voltage in kV (LV Side) = 123

Vector Group = Yna0d1

CT Ratio (HV Side) = 300/1

CT HV Side Vector Group = Star/Star

CT Ratio (LV Side) = 500/1

CT LV Side Vector Group = Star/Star

Minimum Tap = -5

Maximum Tap = +15

Rated Current (HV Side) = MVA / (√3*kV)

=100*10^6/ (√3*220*10^3)

=262.47 A

Current on CT Primary (HV) = Rated Current (HV Side)*220/7

= 262.47*220/132

=437.45 A

Calculations for OLTC tap setting -5%

Full load Current for 220 kV %(HV Side) Winding at -5% = MVA / (√3*0.95kV)

=100*10^6/ (√3*220*0.95*10^3)

=276.244 A

Current on CT Primary (HV) = Rated Current (HV Side)* 220/7

= 276.244*220/132

=464.40 A

Bias current = $(I_1+I_2)/2$

= (464.40+437.45)/2

= 448.92 A

[Since the bias current is More than 437.45 A the slope will be within 70%]

Therefore the operating current of the relay will be = (I_s +M1*448.92) +(448.92-437.45)*M2

= 99.16 A

I Differential = Current on CT Primary (HV) at Min Tap- Current on CT Primary (HV) Rated

= 448.92-437.45

= 11.47

Differential current at worst tap condition should not be more than 90% of operating current for better stability. Here it s less than 90% so the setting is acceptable.

Calculations for OLTC tap setting +15%

Full load Current for 220 kV %(HV Side) Winding at **+15**% = MVA / (√3*1.15*kV)

=100*10^6/ (√3*220*1.15*10^3)

=228.01 A

Current on CT Primary (HV) = Rated Current (HV Side)* 220/132

= 228.01*220/132

=380 A

I bias = (Primary HV side current + Rated HV current in Primary)/2

= (380+437.45)/2

= 408.73 A

Hence the differential current is = 437.45-380

= 57.45 A

[Since the bias current is less than 437.45 A the slope will be within 30%]

Therefore the operating current of the relay will be = I_s + (m1)* I_{bias}

= 0.2+ (0.2) * 408.73

= 81.94 A

The operating Current value is larger than the differential value hence the system is Stable for the MAX tap condition.

3. BUS BAR PROTECTION CALCULATION

3.1 <u>Procedure for Relay setting Calculation for Bus Bar Protection EE/ CAD 34 Relay</u>

Enter the name of the substation:

Enter the name of the relay:

Enter the type of the Bus Bar Protection:

Enter the characteristics of Bus Bar protection:

Enter the Fault MVA of the Bus Bar of the Substation:

Enter the CT ratio:

Enter the Rct value of the CT:

Enter the lead resistance value:

Enter the Burden of the relay:

Calculation:

Fault Current (Il) =Fault MVA/(√3*Vl)

Voltage across the relay (Vr) = Il*(Rct+Rl)

Required Value of Rstab = Vr/Iset –(Relay Burden)/$Iset^2$

Where Iset is set current for the relay in case of High Impedance relay

Relay burden can be negligible for Numerical type relay

Sample Calculation For EE/ CAG34:

Enter the name of the substation: BBMB 400kV Bhiwani substation

Enter the name of the relay: EE, CAG34

Enter the type of the Bus Bar Protection: Electromechanical type

Enter the characteristics of Bus Bar protection: High impedance type

Enter the Fault MVA of the Bus Bar of the Substation: 13625 MVA (Based on short circuit report)

Enter the CT ratio: 1000/1

Enter the Rct value of the CT: 5Ω

Enter the lead resistance value: 1Ω

Enter the Burden of the relay: 1VA at the highest tap is taken for consideration

Calculation:

Fault Current (Il) =Fault MVA/ (√3*Vl)

=13625/(√3*400)

=19666.1A

On the secondary side of the CT =19666.1/1000

=19.6661A

Voltage across the relay (Vr) = Il*(Rct+Rl)

=19.6661*(5+2)

=137.6627V

Required Value of Rstab = Vr/Iset –(Relay Burden)/Iset^2

=137.6627/0.6 -1/0.6^2

Where Iset =0.6A Adopted value

Rstab = 221.72 Ω (The Adopted value is 194 Ω)

Setting is in order.

4. Generator Protection

4.1 Procedure for Relay setting Calculation for MICOM P343

GENARATOR PROTECTION:

Relay used: MICOM P343

TYPES OF PROTECTION:

1) Generator Differential
2) Reverse power
3) Field failure
4) Negative Phase Sequence Thermal
5) System Backup
6) Over current
7) Earth fault
8) Residual over voltage NVD
9) 100% Stator Earth fault
10) Dead machine
11) Volt protection
12) Freq protection
13) CB fail & I<

Generator Data:

Rated MVA = 120 MVA

Rated Voltage = 10.5kV

Rated Current = 6300A

Rated Power = 0.85 Lag

Synchronous D-Axis Reactance Xd=1.04

Transient D-Axis Reactance Xd' =0.33

Sub transient D-Axis Reactance Xd" =0.26

CT/PT Details:

CT Primary rating = 6000A

CT secondary rating =5A

PT Primary rating =11kV

PT secondary rating =110V

1) GENERATOR DIFFERENTAL:

Generator Rating = 120 MVA

Generator full load current Py = MVA/($\sqrt{3}$*V_L)

= 120 /($\sqrt{3}$*11)

Generator full load current Py= 6.3kA

CT Ratio =6000/5A

CT current Sy = $6.3*10^3/(6000/5)$

= 5.25A

Is1=0.25-0.5 A

This setting shall be more sensitive for internal faults and generally shall be more than the standalone differential (spill) current. The recommended setting is 10% of full load current.

K1=0-20%

Settings Adopted =0%

This setting is to achieve maximum sensitivity during internal fault; hence the value is set to 10% assuming a low or negligible stand alone differential current is flowing at rated load.

Is2=5-25A

This setting is for a current which the second slope is starting. Generally this shall be more than the full load current. The recommended setting is 120% of full load current.

By taking the 5.25A as the reference the setting of Is2 should not exceed the 120% which corresponds to the 6.3A

Settings Adopted-6A

K2 =20-150% of the value

This setting is to achieve clear discrimination for minor unbalances caused during external fault condition, and also better stability. .

Settings Adopted =150%

2) LOSS OF EXCITATION:

Transformation Ratio = CT Ratio/PT Ratio

= (6000/5)/(11000/110)

= 12

Diameter of the circle= Xd * 12=1.042*12=12.504Ω

Base Impedance = $(kV)^2$/MVA

= $(11)^2/120$

= 1.00833Ω

Xd' = 0.33*12=3.96Ω

Offset =0.5*Xd'=1.98Ω

SETTING ADOPTED:

Xa1=4Ω Xb1=12 Ω

3) SYSTEM BACKUP IMPEDANCE:

System backup impedance can be direct impedance type or the voltage restrained over current function or voltage controlled over current function .

For the voltage controlled over current function it is suitable for the application where the generators are connected directly to the bus bar .

Commonly the under voltage element can be set to 57% UB for detecting the phase to phase and phase to earth fault .if we set below 57%UB and current element can be set to 120% of Ib

Setting Adopted V = 40V

Setting Adopted I = 6.25A

4) LOW FORWARD POWER AND REVERSE POWER:

Low Forward Power and Reverse Power = 0.5% of Rated MVA (Pn)

Low Forward Power and Reverse Power = $(0.005*120*10^6)$ = 0.6MVA

Low Forward Power and Reverse Power in sec = (0.5% of Rated MVA (Pn))/(CTR*PTR)

Low Forward Power and Reverse Power in sec = $(0.005*120*10^6)$ / ((6000/5)*(11000/110))

Low Forward Power and Reverse Power in sec = 5 W

Setting Adopted = 20W {2%}

Time Delay = 5.0 sec.

5) NEGATIVE PHASE SEQUENCE THERMAL:

Assuming the i^2t curve is(since the curve is not been provided by authorities)

i^2t = 10 sec

Assuming the continuous withstand current of the generator is 8% then

Rated Current In = 5.25A

Typical Setting alarm = 5-6% of In

= 0.06*5.25 = 0.315A

Typical Setting = 300mA

Negative Withstand Current Capability = 8% of Rated Value

For the trip the value of the current to be higher than the above value usually 10 to 20% with shorter time delay, but it has to match with the generator permissible unbalance loading curve.

For the above problem the set value is 800mA which is 16% of the value.

SETTING ADOPTED:

Alarm = 6% Time Delay = 3.0 sec

Trip = 16% Time Delay (i2k) = 8.5 sec {below the withstand capability of current}.

6) VOLTAGE PROTECTION:

Under voltage protection (27G):

Typical setting = 70% of secondary voltage

= 0.7*110V

Typical setting = 77V

Setting Adopted = 88.00V {80% of Vn}

Time delay = 3 sec

Over voltage protection (89G):

Setting Adopted (1) = 120V Time Delay = 3.0 sec

SettingAdopted (2) = 148V Time Delay = 0 sec

For 120V → 110% of Machine Terminal Voltage

For 148V → 135% of Machine Terminal Voltage

7) OVER CURRENT PROTECTION:

Characteristic Curve = Definite time

Machine Rated Current = 5.25A

Setting Adopted (1) = 5.7A {110% of Rated Value}

8) RESIDUAL OVER VOLTAGE /NEUTRAL VOLTAGE DISPLACEMENT PROTECTION:

Characteristic Curve = Definite time

The OPEN delta PT or the from the NGT can be taken as the input for the protection

SETTING ADOPTED:

Voltage setting = 8V Time Delay = 1.0 sec

For a setting of 5V more than 95% of the Stator winding can be covered.

9) DEAD MACHINE:

Voltage setting:

Typical setting = 70=80% of the under voltage value

Typical setting = 0.8* 110

Typical setting = 84V

Setting Adopted = 80V

Current setting:

Typical setting = 10% of the full load current

Typical setting = 0.1* 5.25

Typical setting = 0.525

Setting Adopted = .5A.

12) OVERALL DIFFERENTIAL: KBCH 120

Generator Rated MVA = 120MVA

Generator Rated Voltage =11kV

Generator CT Ratio = 6000/5

GT Rated MVA = 120MVA

GT Voltage Ratio =11kV/220kV

GT CT Ratio = 300/1

UAT Rated MVA = 3 MVA

UAT Voltage Ratio =11kV/3.3kV

UAT CT Ratio = 600/1

Take 120MVA as a reference power

Rated current on Generator = MVA/($\sqrt{3}$*V_L)

Rated current on Generator = 120/($\sqrt{3}$*11)

Rated current on Generator = 6300A

Rated current on Generator in sec = 6300/ (6000/5)

Rated current on Generator in sec = 5.25 A

Rated current on Generator in sec = 5.25/5

Rated current on Generator in sec = 1.05A

Rated current on GT = 120/($\sqrt{3}$*220)

Rated current on GT = 314.91A

Rated current on GT in sec = 314.91/ (300/1)

Rated current on GT in sec = 1.0497 A

Rated current on UAT = 120/($\sqrt{3}$*11)

Rated current on UAT = 6298A

Rated current on UAT in sec = 6298/ (6000/5)

Rated current on UAT in sec = 5.25 A

Ratio of compensation Generator = 0.95

Ratio of compensation GT = 0.91

Compensated current on CT Sec Generator Side =√3*1.05*0.95

Compensated current on CT Sec Generator Side I_1 = 1.73A

Compensated current on CT Sec GT Side= √3*1.0497*0.91

Compensated current on CT Sec GT Side I_2= 1.65A

Bias setting:

Pickup Current Is = 0.2

Slope1 m1 = 20%

Slope2 m2 = 80%

Generator Vs Generator transformer:

Bias Current I_{bias} = $(I_1+I_2)/2$

Bias Current I_{bias} = (1.73+1.65)/2

Bias Current I_{bias} = 1.69A

Differential Current I_{Diff} = (I_1-I_2)

Differential Current I_{Diff} = 1.73-1.68

Differential Current I_{Diff} = 0.05A

If Bias Current I_{bias}greater than 1.5A = I_{bias} - 1.5 = 1.73 – 1.5 = 0.23A

Operating current I_{op} = Is+m1*1.5+m2*(I_{bias} - 1.5)

Operating current I_{op} = 0.3+0.2*1.5+0.8(0.23)

Operating current I_{op} = 0.784A

{If Bias Current I_{bias}lesser than 1.5A means

Operating current I_{op} = Is+m1* I_{bias} }

4.2 Procedure for Relay setting Calculation for REG 670

Generator details:
Enter the generator rating =165 MW(173.8 MVA)
Enter the generator terminal voltage =11kV
Enter the saturated direct axis reactance=1.1
Enter the saturated transient direct axis reactance=0.2
Enter the sub transient direct axis reactance =0.14
Enter the CT details =10000/1
Enter the pt details=11kV/110V
Enter the full load current ={MVA/(√3*kV)}=9122A
Enter the transformer rating =180MVA
Enter the transformer voltage level =11kV/220kV
Enter the transformer reactance value=11.98%

1. Procedure for calculating the generator differential and overall differential protection:

Idmin= 0.1 this setting can be done based on the basis of the CT inaccuracy and spill current and harmonics will flow through it.
Slope 1=10-50%
Slope 2=30-100%
To set the value of end section 2 based on the maximum contribution of the fault current by the generator.

=1/Xd"
=1/0.14 =7.14
End section 2 should not exceed this above value (settings adopted =6)

2. Procedure for calculating the generator distance protection:
This is backup type protection and usually having the time delay .the CT connection needs to be noted that whether it connected from the terminal end or neutral end.

The settings can be limited up to generating transformer or the long line depending upon the type of application and voltage level.For 220kV level it can be limited to far end or upto GT.

Zone 1 :70% of the generating transformer

Base value =kV^2/MVA
=11^2/173.8
=0.696Ω
70% of the transformer =0.7*reactance of the transformer * kV^2/MVA

=0.7*0.1198*121/180
=0.0563Ω
Since the CT is in the neutral direction the direct axis reactance also taken in to account
=1.1*121/173.8
=0.7658Ω
Total impedance is sum of the above= 0.0563+0.7658
=0.8221Ω
Setting adopted =0.833Ω

3. Procedure for calculating the generator pole slip protection:
This protection is used for protection against out of step condition of the generator
Settings
Za=sum of the transformer impedance and the system fault level impedance.
Zb=generator transient reactance
Zc=the value can be restricted up to 90% of the generating transformer impedance.
Assuming the fault level of 6500 MVA the corresponding system fault impedance to be 0.0186Ω
Za=Zt+Zs
=0.0805+0.0186
=0.0991Ω=14.23% of base impedance
Settings Adopted=23.49%
Zb=-Xd'
=-0.2*121/173.8
=0.1392Ω
=20% of Zbase
Settings Adopted=20%

Zc=90% of transformer impedance
= 0.9 *0.1198*121/180
=0.0725Ω =10.41% of Zbase
Settings Adopted =19.43% of Zbase

4. Procedure for calculating the generator under excitation protection:

The settings of the field failure can be set as follows
The offset reactance can be set as half of the transient direct axis reactance
Xoffset=-Xd'/2
Diameter of the circle can be set as direct axis reactance Xd

Xoffset =-0.2/2
=-0.1=10% of Zbase
Settings adopted =10%

Diameter of the circle =Xd =100% of Zbase

Settings adopted =100%

5. Procedure for calculating the generator reverse power and under power protection:
As per the BHEL guidelines the generators can allow 20% of the rated power in the motoring mode

It is recommended to set 0.5 % of the rated power for both reverse and under power as per the general guidelines.

6. Procedure for calculating the generator phase over current protection:

The setting of the relay is in such a way that value for definite time will be in the order of 110% to 120% of the I base value.

Generator full load current = {MVA/√3*kV}

= {173.8/√3*11}

= 9.122kA

Settings is 110% of I base with a time delay of 25 s

7. Procedure for calculating the generator negative sequence protection:

For reviewing this protection continuous unbalance withstand curve of the generator and the i2t value of the generator is needed.

Assuming the continuous unbalance current of the generator be in the order of 10% and used as inverse type, it is recommended to set the alarm setting to the lower value than trip.

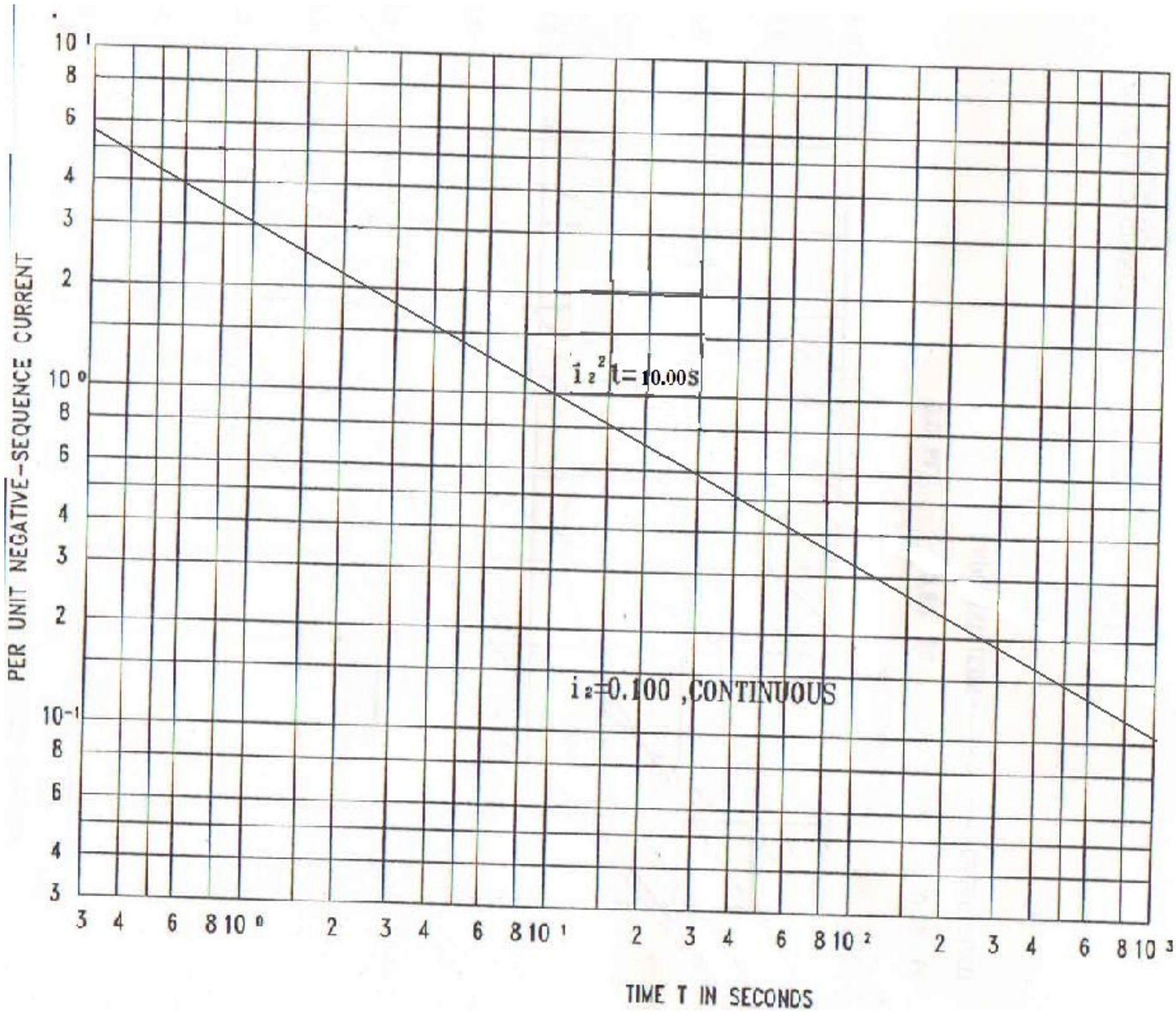
The value of trip can be chosen such that the relay curve should be below the generator curve value.

Eg

Alarm = can be set 5-8% value

With suitable time delay

Trip can be set to 10 -15% of the value with inverse or IDMT type of it.



8. Procedure for calculating the generator residual over voltage protection:

This protection is used to protect the 95% of the generator winding. The type of connection is shows whether it is covering from the generator terminal towards neutral or from the neutral to the generator terminal voltage. Here the principle of NGT concept is used.

Settings

To cover the 95% of the winding

Here Vph=6350V

This corresponds to 3.1754V in the NGT secondary side.

Settings adopted =5% of UB.

9. Procedure for calculating the generator 100% stator earth fault protection:

This protection is used to cover entire stator winding, based on the average value of 3rd harmonic voltage produced at the time of the commissioning. This relay will be a drop out type relay since this voltage may drop when stator fault occurred.

10. Procedure for calculating the generator over voltage protection:

The settings to be made in such a way that it should not harm to the generator .it can withstand upto 145% of the rated voltage as per BHEL guidelines for the generators .hence two stages can be used with definite time or inverse type

Stage 1 can be set from 110% to 120% with time delayed trip.
Stage 2 can be set from 125% to 145% with instantaneous of least time delayed trip.

11. Procedure for calculating the generator under voltage protection:

The under voltage usually coupled with the field failure relay for the instantaneous tripping and 85-95% of the rated voltage can be connected to alarm only with the time delay .

Under voltage trip normally set to 65 to 80 % for the least time delayed tripping or instantaneous tripping.

12. Procedure for calculating the generator over and under frequency protection:

The setting of this relay usually should not cross the 5% of the value.

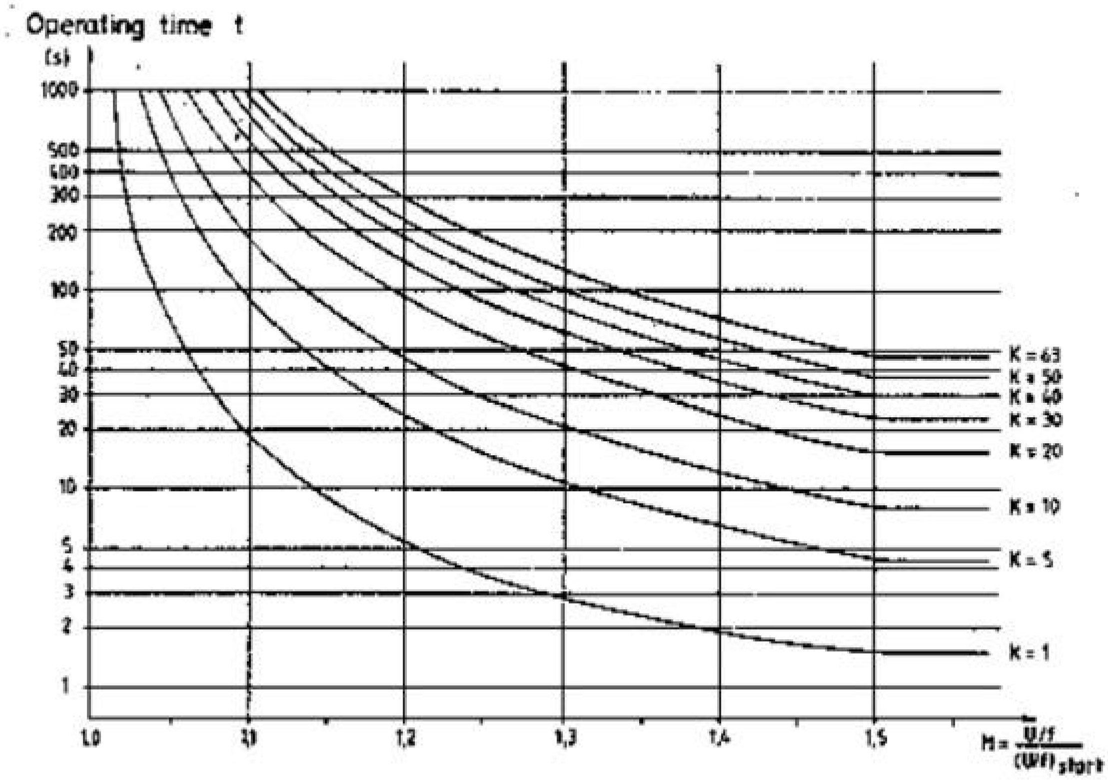
Stage 1 can be set to 2-3% of the Fbase with the long time delayed value.

Stage 2 can be set to 3-5% of the Fbase value with least time delayed value.

Note that the stage 1 can be set only for the alarm.

13. Procedure for calculating the generator over fluxing protection:

This setting is used to protect the generating transformer from saturation of the cores hence usually the setting would be inverse type in parallel with the over excitation withstand curve of the transformer. A sample over excitation curve is attached for the review



14. Procedure for calculating the generator dead machine protection:
This setting is usually set the voltage and current value to prevent the accidental energisation.

V setting =40 to 70% of the value
Setting adopted =50% of U base
I setting is set such that operating range to be adopted as below
I setting =50 to 150 % of I Base
Setting adopted =3% of I base.

5. Restricted Earth Fault Relays

5.1 Restricted Earth Fault Relay Settings Calculation Procedure for EE MCAG

Relay Type: EE/ MCAG

Required Data

MVA

Voltage Ratio

Rated Voltage in kV (HV Side)

Rated Voltage in kV (LV Side)

Vector Group

% Impedance of the transformer

Relay Operating Current

Magnetizing Current of the Ref (Ct)

Knew Point Voltage of the Ref (Ct)

Relay Burden

CT Ratio (HV Side)

CT HV Side Vector Group

CT Ratio (LV Side)

CT LV Side Vector Group

CT resistance value (Rct)

Lead resistance value (Rl)

Relay Stabilizing Value (K)

Other resistance that included in the circuit (rs) (if available):

Relay burden value (Rb):

Maximum fault current = (maximum fault MVA/ (1.732*voltage rating)

Maximum fault current secondary (if) =maximum fault current /ct ratio

Stabilizing voltage=setting current *stabilizing resistance value

Operating voltage =k*if*(rct+2*rl+Rb+rs)

Checking for the stability of the relay

Stability check condition: if stabilizing voltage is greater than operating voltage.

Sample Setting Calculation for MCAG relay

Substation : 220 kV GSS HISSAR

Transformer Name : BHEL

Relay Name : MCAG, EE

Calculation:

Transformer Name: BHEL

MVA = 100

Voltage Ratio = 220/132

Rated Voltage in kV (HV Side) = 220

Rated Voltage in kV (LV Side) = 132

Vector Group = YNA0d1

% Impedance of the transformer=0.1132

Relay Operating Current = 0.2A

Magnetizing Current of the Ref (Ct) = 60mA

Knee Point Voltage of the Ref (Ct) = 1000 V

Relay Burden = 1VA

CT Ratio (HV Side) = 500/1

CT Ratio (Neutral Side) = 500/1

CT HV Side Vector Group = Star/Star

CT Ratio (LV Side) = 500/1

CT LV Side Vector Group = Star/Star

CT resistance (Rct) =5Ω

Lead Resistance value=2.5 Ω

Rated Current (HV Side) = MVA / (√3*kV)

=100*10^6/ (√3*220*10^3)

=262.43 A

Maximum fault current contributed =Rated current /Percentage Impedance

=262.43/0.1132

=2318.286A

Maximum fault current contributed secondary=2318.286/500

= 4.636 A

I Operating Current =If *(Irelay Operating +n*Imag)

= 4.636 /1000 (0.2 /1000+4*60)

=1.112 mA

Operating Voltage Vs = If*(Rct+2*Rl)

=4.636*(5+2*2.5)

Vs =46.36V

R stable =Vs/I operating – R burden/Ioparating^2

=(46.36/0.2)-(1/0.2^2)

R stab =206.8 Ω

Stability Check : Stable If 2*Vs<Knee point Voltage

- ⇨ 2*46.36<1000
- ⇨ ***Relay setting is stable.***
- ⇨ ***Setting is in order.***

6. Back up Relay

6.1 Procedure for Setting Backup Earth Fault EE/CDD21 Relay:

I_f = the fault current through the feeder for fault at Remote end in kA

CT ratio of current transformer $=I_1A/I_2A$

The fault current through the feeder W.R.T Secondary is

I_f in A = I_f W.R.T Primary /CT ratio

Plug Setting Multiplier Setting

The Pickup current of the directional current relay has been set to 100% of the secondary rating. Since the actual load currents for the feeders much lower than this, are considering 100% of the CT rating so that relay does not pickup for transient over loading also.

Time Multiplier setting with plug setting Is =1A at I_f (Secondary) of C.T With IDMT characteristics.

Relay Operating time for above fault current

$t = 0.14/ ((I_f/I_s)^{0.02} - 1)$

The Backup relay delay setting is set reviewed such that for a full fault current contribution through the line, the Backup relay should not operate faster than the Zone 2 of the Distance relay.

$t = 0.14/ ((I_f/I_s)^{0.02} - 1) >$ Zone 2 time delay

Single Phase to Ground Fault for Split Bus at Remote end

I_f = the fault current through the feeder at Remote end in KA

The fault current through the feeder W.R.T Secondary is

I_f = I_f W.R.T Primary /CT ratio

Time Multiplier setting with plug setting Is =1A at I_f (Secondary) of C.T With IDMT characteristics.

Relay Operating time for above fault current

$t = 0.14/ ((I_f/I_s)^{0.02} - 1)$ * TMS Setting

t = Relay Operating time for above fault current

This is acceptable, if relay operates before the backup distance relay of adjacent line. But it operates only if distance relay of the protected Line fails to operate.

<u>Sample setting calculation for Backup Earth Fault relay EE/ CDD21:</u>

Line: 220 kV GSS BHIWANI I

Relay at 220 kV GSS CHARKHI DADRI

PSM = 0.2

TMS= 0.3

Fault at Bhiwani I

The fault current through the feeder is I_f= 1.7539 kA

CT ratio = 1200/1

The fault current through the feeder W.R.T Secondary is

I_f= I_f W.R.T Primary /CT ratio

= 1.7539 kA/1200/1 A

= 1.4615 A

Plug Setting Multiplier Setting

The Pickup current of the directional current relay has been set to 100% of the secondary rating. Since the actual load currents for the feeders much lower than this, are considering 100% of the CT rating so that relay does not pickup for transient over loading also.

Time Multiplier setting with plug setting Is = 5 at I_f (Secondary) of C.T = 11.72 A With IDMT characteristics.

Relay Operating time for above fault current

$t = 0.14/ ((I_f/I_s)^{0.02} - 1) * \text{TMS Setting}$

$t = 0.14/ ((1.4716/1)/0.2)^{0.02} -1)* 0.3$

t = 1.03 sec.

The zone 3 time delay of the Backup on the adjacent distance protection is set to 1000 ms., the setting of the backup over current relay is recommended such that for a full fault current contributed by that line, the Backup relay should NOT operate quicker than the Zone –III time delay of 1000 msec.

This is acceptable, as Back up relay operates only after the Zone 3 (Time Delay of 1000 msec) of the corresponding Distance relay.

Hence, setting is in order.

6.2 <u>Procedure for Setting HV and LV Backup Over Current Relay of EE/ CDG31 for Transformer:</u>

I_f = the fault current through the feeder for fault at Remote end in kA

CT ratio of current transformer $=I_1A/I_2A$

The fault current through the feeder W.R.T Secondary is

I_f in A = I_f W.R.T Primary /CT ratio

Plug Setting Multiplier Setting

The Pickup current of the directional current relay has been set to 100% of the secondary rating. Since the actual load currents for the feeders much lower than this, are considering 100% of the CT rating so that relay does not pickup for transient over loading also.

Time Multiplier setting with plug setting Is =1A at I_f (Secondary) of C.T With IDMT characteristics.

Relay Operating time for above fault current

$t = 0.14/\left((I_f/I_s)^{0.02} - 1\right)$

The Backup relay delay setting is set reviewed such that for a full fault current contribution through the line, the Backup relay should not operate faster than the Zone 2 of the Distance relay.

$t = 0.14/\left((I_f/I_s)^{0.02} - 1\right) >$ Zone 2 time delay

<u>Three Phase to Ground Fault for Split Bus at Remote end</u>

I_f = The fault current through the feeder at Remote end in KA

The fault current through the feeder W.R.T Secondary is

I_f = I_f W.R.T Primary /CT ratio

Time Multiplier setting with plug setting Is =1A at I_f (Secondary) of C.T With IDMT characteristics.

Relay Operating time for above fault current

$t = 0.14 / ((I_f/I_s)^{0.02} - 1) * TMS\ Setting$

t = Relay Operating time for above fault current

This is acceptable, if relay operates before the backup distance relay of adjacent line. But it operates only if distance relay of the protected Line fails to operate.

If the HV and LV over current relays are Non-Directional and fault on the Transformer LV side, HV side relay operating time is coordinated with the LV side relay, with suitable time discrimination, for through faults.

If Inter tripping present in the transformer HV to LV then no discrimination required.

<u>Sample setting calculation for HV Over Current Relay for Transformer</u>

Substation : 220 kV GSS DEHAR

Relay at 220/132 kV Transformer 7

Relay Make and Model: EE/ CDG31

PSM = 0.75

TMS= 0.3

Fault at 132kV Transformer End

The fault current through the feeder is I_f= 2.35878 kA

CT ratio = 150/1

The fault current through the feeder W.R.T Secondary is

I_f= I_f W.R.T Primary /CT ratio

= 2.35878 kA/ 150/1 A

= 15.7252 A

Plug Setting Multiplier Setting

The Pickup current of the directional current relay has been set to 100% of the secondary rating. Since the actual load currents for the feeders much lower than this, are considering 100% of the CT rating so that relay does not pickup for transient over loading also.

Time Multiplier setting with plug setting Is = 5 at I_f (Secondary) of C.T = 11.72 A With IDMT characteristics.

Relay Operating time for above fault current

t =0.14/ $((I_f/I_s)^{0.02} - 1)$ * TMS Setting

t = 0.14/ $((15.7252 /0.75))^{0.02} -1)$* 0.3

t = 0.6693 sec.

The zone 2 time delay of the Backup on the adjacent distance protection is set to 350 ms., the setting of the backup over current relay is recommended such that for a full fault current contributed by that line, the Backup relay should NOT operate quicker than the Zone –II time delay of 350 msec.

This is acceptable, as Back up relay operates only after the Zone 2 (Time Delay of 350 msec) of the corresponding Distance relay.

Hence, setting is in order.

Sample setting calculation for LV Over Current Relay for Transformer

Substation : 220 kV GSS DEHAR

Relay at 220/132kV Transformer 7

Relay Make and Model: EE/ CDG31

PSM = 0.75

TMS= 0.3

Fault at 132kV Transformer End

The fault current through the feeder is I_f= 3.9313 kA

CT ratio = 250/1

The fault current through the feeder W.R.T Secondary is

I_f = I_f W.R.T Primary /CT ratio

= 3.9313 kA / 300/1 A

= 13.104 A

Plug Setting Multiplier Setting

The Pickup current of the directional current relay has been set to 100% of the secondary rating. Since the actual load currents for the feeders much lower than this, are considering 100% of the CT rating so that relay does not pickup for transient over loading also.

Time Multiplier setting with plug setting Is = 1 at I_f (Secondary) of C.T = 13.104 A With IDMT characteristics.

Relay Operating time for above fault current

$t = 0.14 / ((I_f/I_s)^{0.02} - 1) * TMS\ Setting$

$t = 0.14 / ((13.104 / 0.75))^{0.02} - 1) * 0.3$

t = 0.6693 sec.

The zone 2 time delay of the Backup on the adjacent distance protection is set to 350 ms., the setting of the backup over current relay is recommended such that for a full fault current contributed by that line, the Backup relay should NOT operate quicker than the Zone –II time delay of 350 msec.

This is acceptable, as Back up relay operates only after the Zone 2 (Time Delay of 350 msec) of the corresponding Distance relay.

If the HV and LV over current relays are Non-Directional and fault on the Transformer LV side, HV side relay operating time is coordinated with the LV side relay, with suitable time discrimination, for through faults.

If Inter tripping present in the transformer HV to LV then no discrimination required and adoted setting can be retain.

Hence, setting is in order.

6.3 Procedure for Setting HV and LV Backup Earth Fault MiCOM P122 Relay for Transformer

I_f = the fault current through the feeder for fault at Remote end in kA

CT ratio of current transformer $= I_1 A / I_2 A$

The fault current through the feeder W.R.T Secondary is

I_f in A = I_f W.R.T Primary /CT ratio

Plug Setting Multiplier Setting

The Pickup current of the directional current relay has been set to 100% of the secondary rating. Since the actual load currents for the feeders much lower than this, are considering 100% of the CT rating so that relay does not pickup for transient over loading also.

Time Multiplier setting with plug setting Is =1A at I_f (Secondary) of C.T With IDMT characteristics.

Relay Operating time for above fault current

$t = 0.14/ ((I_f/I_s)^{0.02} - 1)$

The Backup relay delay setting is set reviewed such that for a full fault current contribution through the line, the Backup relay should not operate faster than the Zone 2 of the Distance relay.

$t = 0.14/ ((I_f/I_s)^{0.02} - 1) >$ Zone 2 time delay

If the HV and LV Earth fault relays are Non-Directional and fault on the Transformer LV side, HV side relay operating time is coordinated with the LV side relay, with suitable time discrimination, for through faults.

If Inter tripping present in the transformer HV to LV then no discrimination required.

Single Phase to Ground Fault for Split Bus at Remote end

I_f = The fault current through the feeder at Remote end in KA

The fault current through the feeder W.R.T Secondary is

I_f = I_f W.R.T Primary /CT ratio

Time Multiplier setting with plug setting Is =1A at I_f (Secondary) of C.T With IDMT characteristics.

Relay Operating time for above fault current

$t = 0.14/((I_f/I_s)^{0.02} - 1) * \text{TMS Setting}$

t = Relay Operating time for above fault current

This is acceptable, if relay operates before the backup distance relay of adjacent line. But it operates only if distance relay of the protected Line fails to operate.

Sample setting calculation for HV Earth Fault Relay for Transformer

Substation: 220kV GSS HISSAR

Relay at 220/132 kV NGEF – Transformer 2

Relay Make and Model: Alstom / MiCOM P122

PSM = 0.2

TMS= 0.3

Fault at 132kV Transformer End

The fault current through the feeder is I_f = 1.6086 kA

CT ratio = 300/1

The fault current through the feeder W.R.T Secondary is

I_f = I_f W.R.T Primary /CT ratio

= 1.6086 kA/ 300/1 A

= 5.362 A

Plug Setting Multiplier Setting

The Pickup current of the directional current relay has been set to 100% of the secondary rating. Since the actual load currents for the feeders much lower than this, are considering 100% of the CT rating so that relay does not pickup for transient over loading also.

Time Multiplier setting with plug setting Is = 1 at I_f (Secondary) of C.T =5.362 A With IDMT characteristics.

Relay Operating time for above fault current

$t = 0.14/((I_f/I_s)^{0.02} - 1) * \text{TMS Setting}$

$t = 0.14/((5.362/0.2))^{0.02} - 1) * 0.3$

t = 0.618 sec.

The zone 2 time delay of the Backup on the adjacent distance protection is set to 350 ms. the setting of the backup over current relay is recommended such that for a full fault current contributed by that line, the Backup relay should NOT operate quicker than the Zone –II time delay of 350 msec.

This is acceptable, as Back up relay operates only after the Zone 2 (Time Delay of 350 msec) of the corresponding Distance relay.

Hence, setting is in order.

Sample setting calculation for LV Earth Fault Relay for Transformer

Substation: 220kV GSS HISSAR

Relay at 220/132 kV NGEF – Transformer 2

Relay Make and Model: EE/ CDD31

PSM = 0.2

TMS= 0.25

Fault at 132kV Transformer End

The fault current through the feeder is I_f= 2.681 kA

CT ratio = 500/1

The fault current through the feeder W.R.T Secondary is

I_f = I_f W.R.T Primary /CT ratio

= 2.681 kA/ 500/1 A

= 5.362 A

Plug Setting Multiplier Setting

The Pickup current of the directional current relay has been set to 100% of the secondary rating. Since the actual load currents for the feeders much lower than this, are considering 100% of the CT rating so that relay does not pickup for transient over loading also.

Time Multiplier setting with plug setting Is = 1 at I_f (Secondary) of C.T =5.362 A With IDMT characteristics.

Relay Operating time for above fault current

$t = 0.14/ ((I_f/I_s)^{0.02} - 1) * \text{TMS Setting}$

$t = 0.14/ ((5.362 /0.2))^{0.02} -1)* 0.25$

t = 0.515 sec.

The zone 2 time delay of the Backup on the adjacent distance protection is set to 350 ms. the setting of the backup over current relay is recommended such that for a full fault current contributed by that line, the Backup relay should NOT operate quicker than the Zone –II time delay of 350 msec.

This is acceptable, as Back up relay operates only after the Zone 2 (Time Delay of 350 msec) of the corresponding Distance relay.

If the HV and LV Earth fault relays are Non-Directional and fault on the Transformer LV side, HV side relay operating time is coordinated with the LV side relay, with suitable time discrimination, for through faults.

If Inter tripping present in the transformer HV to LV then no discrimination required.

Hence, setting is in order.