Tutorial on Distance and Over Current Protection

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Contents

• Protection Philosophy of ERPC

• Computation of Distance Relay Setting

• System Study to Understand Distance Relay Behavior

• DOC and DEF for EHV system
Protection Philosophy of ERPC
Introduction

- Based on the CEA Report of “The task Force on Power System Analysis Under Contingency”
- Discusses the Coordination practice to be followed for
  - Coordination of Distance protection
  - Coordination of Backup DOC and DEF
# Philosophy

<table>
<thead>
<tr>
<th>Zone</th>
<th>Direction</th>
<th>Protected Reach</th>
<th>Time Setting (s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Zone 1</td>
<td>Forward</td>
<td>80% of the PL</td>
<td>Instantaneous</td>
</tr>
<tr>
<td>Zone 2 (for 400kV and above)</td>
<td>Forward</td>
<td>For Single Circuit – 120% of the PL</td>
<td>0.35</td>
</tr>
<tr>
<td>Zone 2 (for 220kV and below)</td>
<td>Forward</td>
<td>For Double Circuit – 150% of PL</td>
<td>0.5 to 0.6 – If Z2 reach overreaches 50% of the shortest line; 0.35 – otherwise</td>
</tr>
<tr>
<td>Zone 2 (for 220kV and below)</td>
<td>Forward</td>
<td>120% of PL or 100% of PL + 50% of ASL</td>
<td>0.35</td>
</tr>
</tbody>
</table>

PL: Protected Line, ASL: Adjacent Shortest Line, ALL: Adjacent Longest Line
# Philosophy

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<tr>
<th>Zone</th>
<th>Direction</th>
<th>Protected Reach</th>
<th>Time Setting (s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Zone 3</td>
<td>Forward</td>
<td>120% of (PL + ALL)</td>
<td>0.8 to 1.0</td>
</tr>
<tr>
<td>Zone 4</td>
<td>Reverse</td>
<td>10% for the Long line (&gt;100 km)</td>
<td>0.5 if Z4 overreaches 50% of reverse shortest line</td>
</tr>
<tr>
<td></td>
<td></td>
<td>20% for short line (&lt;100 km)</td>
<td>0.35: otherwise</td>
</tr>
</tbody>
</table>

Note:
- Z2 reach should not encroach the next lower voltage level.
- If Z3 reach encroaches next voltage level (after considering in feed), Z3 time must be coordinated.
- If utility uses carrier blocking scheme, then the Z4 reach may be increased as the requirement. It should cover the LBB of local bus bar and should be coordinated with Z2 time of the all other lines.

PL: Protected Line, ASL: Adjacent Shortest Line, ALL: Adjacent Longest Line
Zone 1

- Instrument Transformer errors
- Transmission line is not completely balanced
- Hence apparent impedance is susceptible to an error of 20%.
- Zone 1 is under reached to prevent incorrect operation for fault on next line (Eg. Close to adjacent bus)
Zone 2 for single circuit line

- To provide coverage to remaining portion of protected line
- Over reach margin should be min 20% (for reason discussed in Zone 1)

What about backup protection for fault here?
Zone 2 for double circuit line

- Under reach due to mutual coupling between parallel line
  \[ \Delta Z = \frac{k_{0m}}{1+k_0}, \quad k_{0m} = \frac{Z_{0m}}{3Z_1}, \quad k_0 = \frac{Z_0-Z_1}{3Z_1} \]
- For twin moose, \( \Delta Z = 27\% \) considering additional 20\% margin, total 150\% of PL

What about backup protection for fault here?
Zone 3

• Zone 3 protection is backup protection for fault on adjacent line.
• Need to reach the PL + ALL
Resistive Reach (Zone 1)

- **Earth**
  - Should provide maximum coverage considering fault resistance, arc resistance and tower footing resistance.
  - Should be $< 4.5 \times X_1$ ($X_1=$ Zone 1 reach)

- **Phase**
  - Reach should be set to provide coverage against all types of anticipated phase to phase faults subject to check of possibility against load point encroachment
  - Should be $< 3 \times X_1$
Resistive Reach (Zone 2 and Zone 3)

• The philosophy used for Zone 1 is applicable here also.
• Additionally
  ▫ Due to in-feeds, the apparent fault resistance seen by relay is several times the actual value, this should be considered before arriving at the setting.
Load Encroachment Consideration

- Reach setting is given considering the various “under reach” effect that can occur. This makes the resistive setting “high”
- Phase loop measures the phase impedance and hence has to be set such that it does not trip for abnormal or emergency system loading condition
- Emergency loading condition is to be used to decide the load encroachment point.
Load Encroachment Consideration

- Following criteria may be considered
  - 1.5 times the thermal rating of line
  - OR
  - 1.5 times associated bay equipment rating (minimum of all equipment)
  - Minimum voltage of 0.85 pu to be considered
  - Load encroachment angle can be considered as 30° (approx. 0.85 pf)
Load Encroachment Consideration

- **Basic Check**
  - Rated $V = 63.5 \text{ V}$ and Rated $I = 1 \text{ A}$. (Secondary Referred)
  - $R_{reach}$ should always be less than $63.5 \Omega$
  - Phase Impedance $= (0.85 \times V)/(1.5 \times I) = 36 \Omega$
Operating Time coordination

- Zone 1 is primary protection, hence instantaneous operation
- Zone 2 is a overreach zone and hence needs to be delayed.
  - If errors involved is less, then Zone 2 can trigger for Zone 1 fault of adjacent line. Hence Zone 2 is to be coordinated with Zone 1.
Operating Time Coordination

- For fault at 80% of segment B, Segment B zone 1 can also under reach by 20%
- Hence only Zone 2 of Segment B pick up
- Segment A Zone 2 can also pickup.
- Hence segment A Z2 to be coordinated with segment B Z2
Operating Time coordination

- For 220 kV and below, if Zone 2 of PL can encroach the Zone 2 of ASL, then coordination is achieved by reducing the Zone 2 reach of PL to coordinate with Zone 2 reach of ASL.
Operating Time coordination

- Zone 3 is the backup protection and hence needs to be operate after Zone 1 or Zone 2 has failed to clear the fault.
- Zone 3 is coordinated with Zone 2 time of adjacent line relay.
Computation of Distance Relay Settings
Points to be Considered

• Obtain the actual line parameters from line impedance test results. If not available, consider the standard values.

• Check Relay Setting type
  ▫ Primary or secondary referred values
  ▫ RX or Zθ
  ▫ Computation of Zero sequence compensation factor. (K₀, Kₙ or Kᵣ-Kₓ)

\[ k₀ = \frac{Z₀ - Z₁}{3Z₁} \quad kₙ = \frac{Z₀ - Z₁}{Z₁} \quad kᵣ = \frac{R₀ - R₁}{3R₁} \quad kₓ = \frac{X₀ - X₁}{3X₁} \]
Points to be Considered

- Note the shortest and longest line emanating from the adjacent substation, along with impedance values
- For double circuit lines, check if it is two single circuit tower or one double circuit tower
- If necessary, carry out system study to study the effect of in feed, mutual coupling, power swing to achieve coordinated setting.
Sample System

- **400 kV Kolaghat**
- **400 kV Jeerat**
- **220 kV Jeerat**
- **Subhashgram**: 80 km Twin Moose, 130 km Twin Moose, 162 km Twin Moose, 200 km Twin Moose
- **Berhampore**: 89 km Twin Moose
- **Bakreshwar**: 200 km Twin Moose

- **CT input**
- **CCVT input**

- **Z = 0.12 pu**

- **R1 = 0.0297 Ω/km**
- **X1 = 0.332 Ω/km**
- **R0 = 0.161 Ω/km**
- **X0 = 1.24 Ω/km**
- **Zm = 0.528 Ω/km**
Zone 1

- **Primary referred**
  - $X_{1\_prim} = 0.332 \times 130 \times 0.8 = 34.5 \ \Omega$

- **Secondary referred**
  - $X_{1\_sec} = 34.5 \times CTR/PTR$, CTR: CT Ratio, PTR: PT Ratio

- **Operating Time**: Instantaneous
Zone 2

- Protected line is single circuit
- ASL: 80 km to subhashgram
- \( X_2_{\text{Prim}} = 0.332 \times 130 \times 1.2 = 51.79 \, \Omega \) (130+26 km)
- \( X_2 \) covers only 32% of ASL.
- Operating Time: 0.35s
Zone 3

- **ALL is 200 km to Berhampore**
- **$X_{3\text{-Prim}} = 0.332 \times (130 + 200) \times 1.2 = 131.47 \, \Omega$**
  - That is 130 km PL + additional 266 km
- **Time Setting**
  - Check if Zone 3 of PL encroach Zone 3 of adjacent line protection
  - Zone 3 of Jeerat - Subhashgram line is 202.8 km.
  - The Two Zone 3 are overlapping and hence must be time coordinated.
  - Time = $0.8 + 0.06 \, t_{cb} + 0.03 \, t_{\text{reset}} + 0.06 \, t_{sf} = 0.95$ (set 1s)

* $t_{cb}$, $t_{\text{reset}}$ and $t_{sf}$ values are as per CEA report
System Study to Understand Distance Relay Behavior
Case 1 (general concept)

- Neglecting Resistance of the line
- Considering 3ϕ fault
- Compute impedance seen by relay R1

**Assuming 100 MVA base**

- \( Z_{\text{base}} = 1600 \, \Omega \)
- \( I_{\text{base}} = 144 \, A \)

**Network Diagram**

- 400 kV Kolaghat
  - 15000 MVA
  - \( X_{\text{ga}} = 0.00666 \, \text{pu} \)
- Jeerat
  - 130 km, 43 Ω
  - \( X_{\text{la}} = 0.0269 \, \text{pu} \)
- Subhashgram
  - 80 km, 27 Ω
  - \( X_{\text{lb}} = 0.01688 \, \text{pu} \)
- Berhampore
  - 200 km, 66 Ω
  - \( X_{\text{lc}} = 0.04125 \, \text{pu} \)

**Base Conditions**

- 400 kV
- 5000 MVA
- \( X_{\text{gb}} = 0.02 \, \text{pu} \)
• \(X_a\) (section a) = \(X_{ga} + X_{la}\) = 0.03346 pu
• \(X_b\) (section b) = \(X_{gb} + X_{lb}\) = 0.03687 pu

• \(X_{eq} = X_a \| X_b\) = 0.01754 pu
• \(I_f = 1/X_{eq} = 57\) pu = 57\*144 = 8209 A

• \(I_a = I_f \times X_b / (X_a + X_b)\) = 4303.5 A
• \(I_b = I_f \times X_a / (X_a + X_b)\) = 3905.5 A

• \(V_a = (I_a \times X_{la})\) = 4303.5\*43 = 185.05 kV
• \(Z_1 = V_a / I_a = 43\) \(\Omega\)

\textit{Note:} \(Z_a = V_a / I_a\) is valid because we are only considering three phase fault.
• The distance relay measures an apparent impedance of 43 which is the actual line impedance. As per setting pick up in Zone 2.
• Consider 5P20 CT class and 1.2R class CVT. For worst case considering -5% CT error and +3% CVT error
• With this the theoretical impedance will change by factor of 1.03/0.95 = 1.085
• Measured impedance with error = 46.655 Ω.
• With Zone2 setting of 51.79 Ω, R1 will pick up in Zone 2.
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Case 2 (in feed effect)

- **400 kV Kolaghat** (15000 MVA) with:
  - $X_{ga} = 0.00666$ pu

- **Subhashgram** (5000 MVA) with:
  - $X_{gb} = 0.02$ pu

- **Jeerat** (80 km, 27 Ω) with:
  - $X_{lb} = 0.01688$ pu

- **Berhampore** (200 km, 66 Ω) with:
  - $X_{lc} = 0.04125$ pu

Assuming 100 MVA base:
- $Z_{base} = 1600$ Ω
- $I_{base} = 144$ A

@ 26km (13% of line)
- \( X_{eq} = (X_a \parallel X_b) + X_{cf} = 0.01754 + 0.00536 \)

- \( I_f = \frac{1}{X_{eq}} = \frac{1}{0.022935} = 43.601 \text{ pu} = 6278 \text{ A} \)
- \( I_a = 3286 \text{ A} \)

- \( V_c = I_f \times X_{cf} = 6278 \times 8.58 = 53.87 \text{ kV} \)
- \( V_a = (I_a \times X_{la}) + V_c = 195.3394 \text{ kV} \)

- \( Z_1 = \frac{V_a}{I_a} = 59.42 \Omega \).
- Actual Fault location \( X_{la} + (0.13 \times X_{lc}) = 51.62 \)
- It can be inferred that Relay R1 will under reach for the fault by 15%, due to in-feed from section B
Case 3 (Weak in feed effect)

Assuming 100 MVA base
Zbase = 1600 Ω
Ibase = 144 A

15000 MVA
Xga = 0.00666 pu

1000 MVA
Xgb = 0.1 pu

400 kV Kolaghat → Jeerat
130 km, 43 Ω
Xla = 0.0269 pu

80 km, 27 Ω
Xlb = 0.01688 pu

200 km, 66 Ω
Xlc = 0.04125 pu

@ 26 km (13% of line)

R1

Xa (section a) = Xga + Xla = 0.03346 pu
Xb (section b) = Xgb + Xlb = 0.11687 pu
• $X_{eq} = (X_a \parallel X_b) + X_{cf} = 0.026017 + 0.00536$

• $I_f = 1/X_{eq} = 1/0.03144 = 31.806 \text{ pu} = 4580 \text{ A}$
• $I_a = 3558 \text{ A}$

• $V_c = I_f \times X_{cf} = 4580 \times 8.58 = 39.297 \text{ kV}$
• $V_a = (I_a \times X_{la}) + V_c = 192.445 \text{ kV}$

• $Z_1 = V_a/I_a = 54.08 \Omega$.

• Actual Fault location $X_{la} + (0.13 \times X_{lc}) = 51.62$

• It can be inferred that Relay R1 will under reach for the fault by 4.7 %, due to in-feed from section B
### Case 4 (Strong in feed effect)

**Assuming 100 MVA base**
- $Z_{base} = 1600 \, \Omega$
- $I_{base} = 144 \, A$

#### Line Parameters

- **400 kV Kolaghat to Jeerat**
  - $130 \, km, 43 \, \Omega$
  - $X_{la} = 0.0269 \, pu$

- **Subhashgram to Berhampore**
  - $200 \, km, 66 \, \Omega$
  - $X_{lc} = 0.04125 \, pu$

- **25000 MVA** at Kolaghat
  - $X_{gb} = 0.004 \, pu$

- **15000 MVA** at Subhashgram
  - $X_{ga} = 0.00666 \, pu$

#### Fault Impedance

- $X_{a} (section \, a) = X_{ga} + X_{la} = 0.03346 \, pu$
- $X_{b} (section \, b) = X_{gb} + X_{lb} = 0.02087 \, pu$

[@ 26km (13% of line)]
• $X_{eq} = (X_a || X_b) + X_{cf} = 0.01285 + 0.00536$

• $I_f = \frac{1}{X_{eq}} = \frac{1}{0.018235} = 54.839 \text{ pu} = 7896 \text{ A}$
• $I_a = 3028 \text{ A}$

• $V_c = I_f \times X_{cf} = 7896 \times 8.58 = 67.75 \text{ kV}$
• $V_a = (I_a \times X_{la}) + V_c = 198.0971 \text{ kV}$

• $Z_1 = \frac{V_a}{I_a} = 65.41 \Omega$
• Actual Fault location $X_{la} + (0.13 \times X_{lc}) = 51.62$
• It can be inferred that Relay R1 will under reach for the fault by 26.7 %, due to in-feed from section B
Case 5 (without in feed effect)

Assuming 100 MVA base
Z_{base} = 1600 \, \Omega
I_{base} = 144 \, A

400 \, kV \, Kolaghat \quad Jeerat \quad Berhampore

130 \, km, 43 \, \Omega

X_{la} = 0.0269 \, \text{pu}

200 \, km, 66 \, \Omega

X_{lc} = 0.04125 \, \text{pu}

X_{a} \, (section \, a) = X_{ga} + X_{la} = 0.03346 \, \text{pu}

R_{1}

V_{a}, I_{a}

X_{ga} = 0.00666 \, \text{pu}

@ 26km (13\% \, of \, line)
• \( X_{eq} = X_a + X_{cf} = 0.03346 + 0.005363 \)

• \( \text{If} = \frac{1}{X_{eq}} = \frac{1}{0.038929} = 25.6877 \text{ pu} = 3699 \text{ A} \)
• \( I_a = 3699 \text{ A} \)

• \( V_c = I_a \cdot X_{cf} = 3699 \cdot 8.58 = 31.738 \text{ kV} \)
• \( V_a = (I_a \cdot X_{la}) + V_c = 190.943 \text{ kV} \)

• \( Z_1 = \frac{V_a}{I_a} = 51.62 \Omega. \)
• Actual Fault location \( X_{la} + (0.13 \cdot X_{lc}) = 51.62 \)
• It can be inferred that the Relay R1 measures the exact impedance to fault point.
### Comparison of in-feed effect

<table>
<thead>
<tr>
<th>In-feed type</th>
<th>Measured Impedance (Ω)</th>
<th>Voltage Vc (kV)</th>
<th>Voltage Va (kV)</th>
<th>Under Reach margin (%)</th>
<th>Effective Z2 Coverage (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>No-infeed</td>
<td>51.62</td>
<td>31.738</td>
<td>190.95</td>
<td>0</td>
<td>20</td>
</tr>
<tr>
<td>Weak (Xgb/Xga = 0.066)</td>
<td>54.08</td>
<td>39.29</td>
<td>192.44</td>
<td>4.77</td>
<td>16</td>
</tr>
<tr>
<td>Moderate (Xgb/Xga = 0.33)</td>
<td>59.429</td>
<td>53.87</td>
<td>195.33</td>
<td>15.13</td>
<td>10</td>
</tr>
<tr>
<td>Strong (Xgb/Xga = 1.66)</td>
<td>65.41</td>
<td>67.75</td>
<td>198.09</td>
<td>26.72</td>
<td>7.7</td>
</tr>
</tbody>
</table>

- With increase in in-feed, increases the voltage at the relay location, which is the primary reason for the relay to under reach the fault.
- Therefore, Zone 2 is primarily used to provide complete line coverage only.
Tutorial on Distance and Over Current Protection

- **Under Reach due to strong in-feed**
- **Under Reach due to moderate in-feed**
- **Under Reach due to Weak in-feed**
- **Zone 2 Set Reach**
- **Distance coverage due to Weak in-feed**
- **Distance coverage due to moderate in-feed**
- **Distance coverage due to strong in-feed**

**Protected Line Reach / Distance**
Case 6 (Zone 3 Over reach)

- **Z_1 = V_a/I_a = 109 \Omega** (Zone 3 setting is 130 \Omega)
- Relay R1 is encroaching the next voltage level.
- Hence Zone 3 time to be coordinated with transformer DOC operating time.

Assuming 100 MVA base
Z_base = 1600 \Omega
I_base = 144 A
Case 7 (Zone 3 Over reach)

- \( Z_1 = \frac{V_a}{I_a} = 186 \ \Omega \) (Zone 3 setting is 130 \( \Omega \))
- Relay R1 is not encroaching the next voltage level.

Assuming 100 MVA base
- \( Z_{base} = 1600 \ \Omega \)
- \( I_{base} = 144 \ \text{A} \)

\[ 
\begin{align*}
X_{ga} &= 0.00666 \ \text{pu} \\
X_{gb} &= 0.004 \ \text{pu} \\
X_{la} &= 0.0269 \ \text{pu} \\
\end{align*}
\]
Case 8 (Mutually coupled lines)

Assuming 100 MVA base
Z_{base} = 1600 \ \Omega
I_{base} = 144 \ \text{A}

15000 MVA
X_{ga} = 0.00666 \ \text{pu}
10000 MVA
X_{gb} = 0.01 \ \text{pu}

- Use Earth loop for computation of apparent impedance

\[ Z_1 = \frac{V_a}{I_a \times (1 + k_0)} \]

\[ k_0 = \frac{Z_0 - Z_1}{3Z_1} \]
• $Z_1 = 32.4 + j \ 87.84 \ \Omega$
• Theoretical $X$ is $56.2 \ \Omega$

• It can be observed that with mutually coupled parallel line, the apparent impedance measured in 57% more than the theoretical value
DOC and DEF for EHV System
Introduction

- DOC and DEF are used in majority of the utility as Main 2 protection for 220 kV line.
- DOC and DEF are used at both HV and LV side of ICT as backup protection (87 being the main protection)
- DEF is used in 400 kV line as protection for high impedance earth faults.
- Non directional OC is also used in 400kV line under fuse fail condition
DOC Setting Philosophy

• For 220 kV and 132 kV line with only one main distance protection, DOC must be set in such a way that for fault at remote bus the DOC (IDMT) is coordinated with Zone 2 time (not finalized in ERPC philosophy), typically 1.1 s.

• For DOC at 400 kV side of ICT, it is to be set such that for fault at remote end bus (longest line), DOC (IDMT) is coordinated with Zone 3 time (as per ERPC finalized philosophy).
DOC Setting Philosophy

- Instantaneous DOC can be used at 400 kV side of ICT, set such that
  - It does not pickup for fault on 220 kV bus
  - It does not pickup for transformer charging current
  - Time setting of **0.05 s** to **0.1 s** can be considered.
DEF Setting Philosophy

- For 220 kV and 132 kV line with only one main distance protection, DEF (IDMT) must be set in such a way that it is coordinated with Zone 2 time.
- For 400 kV line or where two main distance protection is used, DEF is used only for protection against high impedance faults and is coordinated with Zone 3 time.
- For DEF at 400 kV side of ICT, it is to be set such that for fault at remote end bus (longest line), DEF (IDMT) is coordinated with Zone 3 time (as per ERPC finalized philosophy).
DEF Setting Philosophy

- Instantaneous DEF can be used at 400 kV side of ICT, set such that
  - It does not pickup for fault on 220 kV bus
  - It does not pickup for transformer charging current
  - Time setting of **0.05 s** to **0.1 s** can be considered.
Sample Setting Calculation

15000 MVA

315 MVA

Zps=0.12 pu

3000 MVA

_phi_Fault

Ia = 1465 A

In = 1026 A

Ia = 3121 A

In = 4370 A

55 km

3φ Fault

SLG fault
DOC Setting

- **Line**
  - $I_p = 1.5 \times I_{rated} = 1.5 \times 580 = 870$ A.
  - $I_{relay} = 3121$ A
  - $Top = Zone 2 + \Delta t = 0.6s. \ (\Delta t = 0.2s)$
  - $TMS = 0.11$ s (Considering NI curve)

- **Transformer**
  - $I_p = 1.5 \times 450 = 675$ A
  - $I_{relay} = 1465$ A
  - $Top = t_{zone3} + \Delta t = 1.0$ s
  - $TMS = 0.12$ s (Considering NI curve)
DEF Setting

- **Line**
  - \( I_e = 0.2 \times \text{Irated} = 0.2 \times 580 = 116 \, \text{A} \).
  - \( I_{\text{relay}} = 4370 \, \text{A} \)
  - \( \text{Top} = \text{Zone 2} + \Delta t = 0.6 \, \text{s} \).
  - \( \text{TMS} = 0.26 \, \text{s} \) (Considering NI curve)

- **Transformer**
  - \( I_p = 0.2 \times 450 = 90 \, \text{A} \)
  - \( I_{\text{relay}} = 1026 \, \text{A} \)
  - \( \text{Top} = t_{\text{zone3}} + \Delta t = 1.0 \, \text{s} \)
  - \( \text{TMS} = 0.35 \, \text{s} \) (Considering NI curve)

*Consideration of relay saturation is crucial*
*Here 20 time is assumed*
Instantaneous Setting calculation

- Reflected Current = $1.3 \times 3225 = 4195$ A
- Inrush Current = $8 \times 450 = 3600$ A
- $I_p >> = \text{Highest of the above two} = 4200$ A (Set value).
Concluding Remarks

- Recommended philosophy for setting distance relay are well established and can provide fairly effective setting.
- Based on the network condition, protection engineer should be able to decide if system study is required for obtaining effective setting.
Thank You
## Duration spectra of Main effects

<table>
<thead>
<tr>
<th>Duration Spectra</th>
<th>Electric Switching Transients</th>
<th>Electrical machine &amp; System Dynamics</th>
<th>System Governin g &amp; load Controls</th>
<th>Prime mover energy supply system dynamics</th>
<th>Energy resource dynamics</th>
</tr>
</thead>
<tbody>
<tr>
<td>µs/ms</td>
<td>Few seconds</td>
<td>Seconds to minutes</td>
<td>Several minutes</td>
<td>Days to weeks</td>
<td></td>
</tr>
</tbody>
</table>

**Notes:**
- Electrical Switching Transients: Over Voltages
- Fault Transients: µs/ms Few seconds
- System Dynamics: Seconds to minutes
- Prime Mover: Several minutes
- Energy Resource Dynamics: Days to weeks
Transient Phenomena

- Initial transient, Recovery Voltage
  - µs

- Switching surges, Fault transients
  - ms

- Ferro - resonance
  - Several cycles

- Surge period
- Dynamic period
- Steady State period
Simulation Cases
Why Load flow study for protection engineer?
Power flow to know
1. Normal load current
2. Worst contingency load current

Plug setting based on this information
1. Steady state maximum voltage
2. Steady state minimum voltage

Voltage relay setting based on this info.
Fault simulation to aid protection engineer
Fault calculation to determine
1. Fault current from various sources
2. Post fault voltage
3. Earth fault current
4. Primary and back up relay current
5. Temporary over voltage (during single line to ground fault)
No source in this part of the network

Earth fault relay picks up, because of transformer Vector group
Short Circuit Study

Fault study

1. Symmetrical AC current
2. DC off set current
3. Asymmetrical AC current

Time in Seconds
Short Circuit Study

DC offset current
1. Maximum at voltage zero
2. Minimum at voltage maximum
What machine impedance to consider for fault study and relay-coordination?
Transient Stability Study

Sustained fault at the machine terminal
1. Initial Sub-transient current.
2. Intermediate transient current.
3. Final steady state current.
Stability study simulation and its importance
Stability study
1. To determine the critical clearing time
2. To find the voltage and frequency variation in the grid.
3. Helps in relay setting calculations
Transient Stability Study

Frequency plot

1. Under frequency and over frequency relay setting
2. Operate the system around designed values.
Parallel line, one line trips

1. Directional over current relay should not operate for the healthy line.
2. There should not be load encroachment
Terminologies

1. Load encroachment
2. Power swing
Impedance seen by the distance relay

1. Helps in distance relay setting calculations
2. Re-shaping the relay characteristic to avoid third zone load encroachment

Transient Stability Study


Fault cleared in 0.1 seconds
Transient Stability Study

- Distance Relay Characters:-

Zone Entering Leaving Elapsed Trip
Des Time Time Time Signal

Zone1 NE NL NV --
Zone2 1.020 1.320 0.300 --
Zone3 1.020 1.320 0.300 --
PS1 1.020 1.320 0.300
PS2 1.020 1.320 0.300
Starter 1.020 1.320 0.300

NE - NotEntered, NL - NotLeft
NV - NotValid

Fault cleared in 0.3 seconds
Fault cleared in 0.5 seconds
Out of step detected and generator tripped
Power reversal in the line
And the system is saved.
Both the lines carry same current

Healthy line carries full load

Healthy line current

Unsuccessful re-closure, once again fault

Faulted line current

Faulty line trips

Understanding single pole auto re-closing facility

Transient Stability Study

Both the lines carry same current

Healthy line carries full load

Healthy line current

Unsuccessful re-closure, once again fault

Faulted line current

Faulty line trips
Transient Stability Study

Out of step operation
1. Out of step protection for the machine
2. Pole slipping relay
Protection Engineer designs the relay, based on system behaviour
Power Research & Development Consultants Pvt Ltd.

Loss of excitation
1. Machine draws very large reactive power
2. Over heating of stator
3. If not protected, burning out of stator
Loss of excitation
1. Impedance moves from the first quadrant
2. Settles in a circle with dia xd and off set xd'/2
3. Off set mho relay detects the fault
Transient Stability Study

Loss of excitation relay
1. Off set mho relay
2. Off set of $\frac{x_d'}{2}$
3. Diameter of $x_d$

[ Genbus - 1 ] to [ Bus2 - 2 ] X in PU

Forward X in PU

Why current limiting reactor for capacitor banks?
Overvoltage Study Results

Capacitor charging

Time in seconds

[ YABus6 : 6 ] Voltage in PU
[ VBBus6 : 6 ] Voltage in PU
[ VCBus6 : 6 ] Voltage in PU
Inrush current capacitor charging

Overvoltage Study Results

IC in Amp

Time in seconds
2nd Harmonic and 5th Harmonic restraint for transformer differential protection
Overvoltage Study Results

Magnetizing inrush current

Time in seconds

IA in Amp

-2.00
-1.00
0.00
1.00
2.00
3.00
4.00
5.00
6.00
7.00
8.00
9.00
10.00
11.00
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69.00
70.00
71.00
72.00
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78.00
Why to provide surge arrestor and RC circuit for VCB switching
VCB current chopping and voltage raise problem

Energy stored in the Inductor = \( \frac{1}{2} \times L \times I^2 \)

Energy stored in the Capacitor = \( \frac{1}{2} \times C \times V^2 \)

Voltage = \( I \times \sqrt{\frac{L}{C}} \)

Solution: Provide surge suppressor/RC circuit or both after the VCB, close to equipment.
Simphatic Tipping, what it means?
1. Voltage dip during the fault
2. Healthy feeder motors stall or speed reduces
3. Once the voltage recovers, large current drawn by motors
4. Healthy feeder may trip
Ferroresonance when and how?
Ferroresonance (FR) TOV

- An oscillating phenomena occurring in an electric circuit which must contain at least:
  1. a non-linear inductance
  2. a capacitor,
  3. a voltage source (generally sinusoidal),
  4. low losses.

- Transients, lightning over voltages, energizing or de-energizing transformers or loads, occurrence or removal of faults, etc...may initiate ferroresonance.

- The main feature of this phenomenon is that more than one stable steady state response is possible for the same set of the network parameters.
Examples of systems at risk from ferroresonance.
Case study for predicting and understanding of TOV and FR
HT side LR by opening CB2

1-pole

3-pole
Voltage
FR existence when 2-poles opening of CB1

Current
Conclusions

1. The various issues in the protection are discussed
2. It is concluded that close co-ordination for protection department with other departments are required.
3. The simulation tools help in learning the protection aspects
4. Automated fault analysis system will help in understanding the relay tripping incidences better.
Discussions
Thank You
Tripping Analysis - Methodology

Dr. Nagaraja R,
Managing Director,
Power Research and Development Consultant Pvt. Ltd
Contents

- Importance
- Source of Data for Analysis
- Analysis Approach
- Simulation Model
- Conclusion and Recommendations
Importance

- Helps in identifying issues related to
  - Commissioning errors (Eg. CT polarity reversal)
  - Setting errors
  - Adequacy of present relaying philosophy
- Helps in preventing incorrect operations in future
- Improves effectiveness of the protection system
Sources of Data for Analysis

- COMTRADE files from
  - Relay
  - DR
- SCADA Data (understanding the operating scenario)
- PMU
  - Time Synchronized data for sequence of operation
- Observation
Analysis Approach

- Analyze every data to classify it as use full “information” for fault analysis
- The use full information is studied in greater detail to derive meaning full results
- Aid for analysis
  - Instantaneous / RMS plots
  - Phasor Angle Comparison
  - Harmonic Plot
  - Relay trajectories (Eg. Impedance and differential)
  - Reasoning of obtained Waveforms and observations
Simulation Model

- The scenario can be reconstructed in simulation platform
  - Electro-Magnetic Transient Study
  - Transient Stability Study
- Validate the analysis results derived using disturbance data
- Can also help to find solution for identified issues.
Case Study

CT Saturation Case

Zero Sequence Case
Conclusion and Recommendations

• Modification in relay settings
• Correction of any commissioning related issues
• Enhancement in operating philosophy that can prevent future occurrence
• Recommendations that can help reduce occurrence of disturbance
• If no incorrect operation – protection scheme healthiness can be studied.
Thank You
POWER SWING AND OUT-OF-STEP CONSIDERATIONS ON TRANSMISSION LINES

Tutorial on Protection
Contents

- Introduction
- Definitions
- Power-swing phenomena and their effect on transmission line relaying
- Power-swing detection methods
- PSB and OST protection philosophy
- Summary and conclusions

Acknowledgements: All contents are based on references [1] and [2]
INTRODUCTION

- Changes in regulations and the opening of the power markets are causing rapid changes in the way the power grid is operated.
- Large amounts of power are commonly shipped across a transmission system that was not designed for such transactions.
- Independently owned and operated generating units are being built in locations that may not be optimum for system stability and system needs.
- Power plant systems are being upgraded to get every possible megawatt out.
- The results of these upgrades often make the generating units more susceptible to instability.
Impact

The August 14, 2003 blackout in the northeastern United States and southeastern Canada has led to substantial scrutiny of many aspects of transmission line protection. One of the more difficult and commonly misunderstood issues being addressed is that of power swing and out-of-step protection applied to transmission lines.
DEFINITIONS

Power Swing: a variation in three phase power flow which occurs when the generator rotor angles are advancing or retarding relative to each other in response to changes in load magnitude and direction, line switching, loss of generation, faults, and other system disturbances.
**DEFINITIONS**

**Pole Slip:** a condition whereby a generator, or group of generators, terminal voltage angles (or phases) go past 180 degrees with respect to the rest of the connected power system.
**DEFINITIONS**

**Stable Power Swing:** A power swing is considered stable if the generators do not slip poles and the system reaches a new state of equilibrium, i.e. an acceptable operating condition.

**Unstable Power Swing:** A power swing that will result in a generator or group of generators experiencing pole slipping for which some corrective action must be taken.

**Out-of-Step Condition:** Same as an unstable power swing.

**Electrical System Center or Voltage Zero:** It is the point or points in the system where the voltage becomes zero during an unstable power swing.
1. Fundamental power-swing detection problem: The power grid is a very dynamic network connecting generation to load via transmission lines. Power systems under steady-state conditions operate very close to their nominal frequency and typically maintain absolute voltage differences between busses of 5%. The system frequency on a 60 Hz system normally varies by less than +/- 0.02 Hz.
2. Effect of power swings on transmission line relays and relay Systems

Zone 1 and Directional Comparison Blocking Scheme Characteristics
3. Impedance measured by distance relays during power swings

Two Machine System

\[ I_L = \frac{E_S - E_R}{Z_S + Z_L + Z_R} \]
\[ Z = \frac{VA}{IL} = \frac{ES - IL \cdot ZS}{IL} = \frac{ES}{IL} - ZS = \frac{ES \cdot (ZS + ZL + ZR)}{ES - ER} - ZS \]

\[ \frac{ES}{ES - ER} = \frac{k(\cos \delta + j \sin \delta)}{k(\cos \delta + j \sin \delta) - 1} = \frac{k[(k - \cos \delta) - j \sin \delta]}{(k - \cos \delta)^2 + \sin^2 \delta} \]

\[ \frac{ES}{ES - ER} = \frac{1}{2} \left( 1 - j \cot \frac{\delta}{2} \right) \]

\[ Z = \frac{VA}{IL} = \frac{(ZS + ZL + ZR)}{2} \left( 1 - j \cot \frac{\delta}{2} \right) - ZS \]
Impedance trajectories at the Relay During a Power Swing for Different k values
POWER-SWING DETECTION METHODS

1. Conventional rate of change of impedance PSB and OST methods
   a. Concentric Characteristic Schemes

PSB and OST
Concentric Distance Relay Characteristics
b. Blinder Schemes.

Two-Blinder Scheme
C. Rdot Scheme

Conventional OST Relay
Y₁ = (R - R₁) ≤ 0

R-dot relay:
Y₂ = (R - R₁) + T₁ dR/dt ≤ 0

Wherein
Y₁ and Y₂ are control outputs
R: Apparent resistance
R₁ and T₁: Relay settings

Phase-plane Diagram Illustrating the Concept of R-dot Principle
2. Additional power swing detection methods

a. Continuous Impedance Calculation

Power swing detection with continuous impedance calculation
b. Swing-Center Voltage and its Rate of Change

\[ V_S \cos \phi \] is a Projection of Local Voltage, VS, Onto Local Current, I. Measure of Swing Center Voltage is going to detect the out of step.
C. Synchrophasor-Based Out-Of-Step Relaying

1. To the extent that a two-machine system equivalent can represent a network, one approach consists of synchronous measurement of the phase angle between the voltages behind the transient reactances of the two machines. When a disturbance occurs, the new phase angle between the two machines is computed and the equal area algorithm is implemented in real time to determine whether the new point of operation is stable.

2. Second approach consists of measuring the positive sequence phasors at two or more strategically located buses. During a disturbance, the phase angle between the signal pairs is computed in real time, and a predictive algorithm is used to establish whether the disturbance will be stable. One application uses a model of the phase angle time waveform in the form of an exponentially damped sine wave.

\[ \delta(t) = \delta_0 + A e^{\alpha t} \sin(\omega t + \beta) \]

\( \delta_0 \): Initial phase angle; \( \alpha \): damping constant; \( A \): Oscillation amplitude; \( \beta \) is the phase displacement.
3. Remarks on power-swing detection methods

Quantities Used for Power-Swing Detection
Wherein XT: Total system impedance
ES=ER=E1

Power: \[ P = E_1 \cdot I \cdot \cos \varphi = \frac{E_1^2}{XT} \cdot \sin \delta \]

Current: \[ I = 2 \cdot \frac{E_1}{XT} \cdot \sin \left( \frac{\delta}{2} \right) \]

Impedance: \[ Z = \frac{V}{I} = \frac{XT}{2} \cdot \cot \left( \frac{\delta}{2} \right) \]

Rate of change of Z: \[ \frac{dZ}{dt} = -\frac{XT}{2} \left( \frac{1}{1 - \cos \delta} \right) \frac{d\delta}{dt} \]

SCV: \[ V \cos \varphi = \frac{P}{I} = E_1 \cdot \cos \left( \frac{\delta}{2} \right) \]
b. Setting Issues for Concentric Impedance Elements and Blinder-Based schemes

Effects of Source and Line Impedance on the PSB Function
Equivalent Two-Source Machine Angles During OOS
T1: Power swing blocking timer value
Fslip: 4 to 7 Hz;

\[ T1 = \frac{(\text{Ang1R} - \text{Ang2R}) \cdot \text{Fnom(\text{Hz})}}{360 \cdot \text{Fslip(\text{Hz})}} \text{ (cycle)} \]
1. Power-swing protection functions

One of the traditional methods of minimizing the spread of a cascading outage caused by loss of synchronism is the application of power swing protection elements that detect OOS conditions and take appropriate actions to block relay elements that are prone to mis-operate during power swings and to separate affected system areas, minimize the loss of load, and maintain maximum service continuity.
2. Method for determining need for power swing and oos protection

1. Determine \( Z_{\text{oos}} = Z_S + Z_R + (Z_{TR} \parallel Z_L) \)
2. Determine \( (Z_{\text{oos}}/2) > Z_S \) or \( Z_R \), then electrical center falls within the line under consideration.

Where,
- \( E_S \) = Equivalent sending end voltage
- \( Z_S \) = Equivalent sending end source impedance
- \( Z_L \) = Line impedance
- \( E_R \) = Equivalent receiving end voltage
- \( Z_R \) = Equivalent receiving end source impedance
- \( Z_{TR} \) = Equivalent impedance of the system interconnecting sending and receiving busses
3. Application of PSB and OST protection functions

1. PSB and OST Options
   a. No Power Swing Detection
   b. Block All Elements Prone to Operate During Power Swings
   c. Block Zone 2 and Higher / Trip with Zone 1
   d. Block All Zones / Trip with OST Function

2. Placement of OST System

3. Additional Considerations
   a. Distance Protection Requirements During OOS Conditions
   b. Power Swing Protection During Single Pole Open Conditions
   c. Three-Phase Faults Following Power Swings
4. Effects of Small Generators

Figure: Transmission Line Connected IPP
5. System risks due to power swings and oos conditions

1. Transient Recovery Voltage (TRV) causing Breaker Failure
2. Isolating Load and Generation
3. Equipment Damage
4. Cascading Tripping of Lines
5. Unwanted Cascading Tripping of Generating Units
6. Methods to improve transient stability

Methods that can improve the transient stability are briefly discussed in this section and they try to achieve one or more of the following effects:

1. Minimize fault severity and duration.
2. Increase of the restoring synchronizing forces.
3. Reduction of the accelerating torque by:
   a. Control of prime-mover mechanical power.
   b. Application of artificial loads.
Methods to improve transient stability

1. High-Speed Fault Clearing
2. Local Breaker Failure Protection
3. Independent-Pole Operation of Circuit Breakers
4. Single-Pole Tripping
5. Dynamic Braking
6. Shunt Compensation
7. Steam Turbine Fast Valving
8. Generator Tripping
9. High-Speed Excitation Systems
10. Controlled Separation and Load shedding Using Special Protection Systems+
    a. Generator dropping.
    b. Turbine fast valving.
    c. Direct load shedding.
    d. Insertion of breaking resistors.
    e. Series capacitor insertion.
    f. Shunt capacitor insertion.
    g. Controlled islanding.
11. Reduction of Transmission System Reactance
12. Power System Stabilizers
13. High-Speed Reclosing
Case study

Pu on 100 MVA base

Zs = 0.00040+j 0.07247
Zt = 0.00280+j 0.05593
ZI = 0.06188+j 0.32996
Zr = 0.00000+j 0.02500
Fault Cleared in 0.1 s; Impedance seen by healthy line
Fault Cleared in 0.12 s; Impedance seen by healthy line
Line length 40 km; Fault Cleared in 0.12 s; Impedance seen by healthy line
Line length 400 km; Fault Cleared in 0.12 s; Out of step cleared the healthy line in 2 s;
SUMMARY AND CONCLUSIONS

Power swings both stable and unstable can precipitate wide spread outages to power systems with the result that cascade tripping of the power system elements occur. Protection of power systems against the effects of power swings both stable and unstable has been described in this paper. The paper has given an overview of power swings, their causes and detection. Methods of detecting and protecting the power system against power swings have been developed and elaborated.
References

[1] POWER SWING AND OUT-OF-STEP CONSIDERATIONS ON TRANSMISSION LINES, IEEE PSRC D6