Applying SEL Differential Relays

Introduction to Transformer Differential Protection
Transformer Differential Protection Presentation Objectives

• Explain challenges of transformer differential protection

• Understand need for tap, phase, and zero-sequence compensation and how they work

• Understand how transformer differential relays are made secure for inrush and overexcitation
Differential Protection is Easy in Theory

Kirchhoff’s Current Law (KCL): \[ \sum_{k=1}^{n} I_k = 0 \]
Challenges to Transformer Differential Protection

- Current magnitude mismatch
- Phase shift across transformer
- Zero-sequence sources
- Energization inrush
- Overexcitation
- Unequal CT performance
Differential Protection Principle
Differential Protection Principle

Balanced CT Ratio

Protected Equipment

CT

CT

Internal Fault

50

IOP ≠ 0
Current Magnitude and Phase Angle Difference Compensation
ANSI Transformer Connections
DABY or Dy1

\[ (I_a - I_b)(N_2 / N_1) \]
\[ (I_b - I_c)(N_2 / N_1) \]
\[ (I_c - I_a)(N_2 / N_1) \]

For 1 pu current flow
1.73 pu

1 pu
ANSI Transformer Connections

YDAC or Yd1

For 1 pu current flow

1 pu

1.73 pu

\[
\begin{align*}
\text{A} & \quad I_A \\
\text{B} & \quad I_B \\
\text{C} & \quad I_C \\
\text{N} & \quad \frac{I_A - I_C}{N_1 / N_2} \\
\text{a} & \quad \frac{I_A - I_C}{N_1 / N_2} \\
\text{b} & \quad \frac{I_B - I_A}{N_1 / N_2} \\
\text{c} & \quad \frac{I_C - I_B}{N_1 / N_2}
\end{align*}
\]
Secondary Currents

$IW_1$  $CT_1$  $Power$  $Transformer$  $CT_2$  $IW_2$

$IW_{1_{SEC}}$  $IOP = |IW_1 + IW_2|$  $IW_{2_{SEC}}$

Low-side secondary current **leads** by 150 degrees!
Result of Uncompensated Phase Shift

IW2

30°

IOP

IW1
Traditional Compensation

\[
\begin{align*}
\frac{N_2}{N_1} \frac{1}{CTR_1} &= \frac{1}{CTR_2} \\
(I_a - I_b)(N_2 / N_1) / CTR_1 &= (I_b - I_c)(N_2 / N_1) / CTR_1 \\
(I_c - I_a)(N_2 / N_1) / CTR_1 &= (I_b - I_c)(N_2 / N_1) / CTR_1 \\
(I_c - I_a) / CTR_2 &= (I_b - I_c) / CTR_2 \\
(I_a - I_b) / CTR_2 &= (I_a - I_b)(N_2 / N_1) / CTR_1
\end{align*}
\]
CTR₁ and CTR₂ Ideal Relationship

\[
\frac{N_2}{N_1} \cdot \frac{1}{CTR_1} = \frac{1}{CTR_2} \implies \\
\frac{N_1}{N_2} CTR_1 = CTR_2 \implies \\
CTR_2 = \sqrt{3} \frac{kV_1}{kV_2} CTR_1
\]

Not always possible with standard CT ratios
Compensation With Relays

- EM relays provide limited magnitude compensation
- SEL relays provide magnitude and phase-shift compensation (SEL-387 considers not only ANSI / IEEE standard connections, but all possible connections)
Current Magnitude Mismatch

• Current magnitude is transformed (transformer is constant KVA device)
  • $kV_H \cdot I_{\text{high-side}} = kV_L \cdot I_{\text{low-side}}$
  • $I_{\text{high-side}} \neq I_{\text{low-side}}$

• Load tap changer dynamically changes transformation ratio
Tap Compensation

\[ TAP = \frac{MVA \cdot 1000 \cdot C}{\sqrt{3} \cdot kV_{WDG} \cdot CTR} \]

where:
- \( C = 1 \) for wye-connected CTs
- \( C = \sqrt{3} \) for delta-connected CTs
Wye Connection Compensation

\[ I_{W1C} = \frac{I_{AW1}}{TAP1} \]

\[ I_{2W1C} = \frac{I_{BW1}}{TAP1} \]

\[ I_{3W1C} = \frac{I_{CW1}}{TAP1} \]
DAB Connection Compensation

\[ I_{1W2C} = \frac{1}{TAP2} \cdot \frac{(IAW2 - IBW2)}{\sqrt{3}} \]

\[ I_{2W2C} = \frac{1}{TAP2} \cdot \frac{(IBW2 - ICW2)}{\sqrt{3}} \]

\[ I_{3W2C} = \frac{1}{TAP2} \cdot \frac{(ICW2 - IAW2)}{\sqrt{3}} \]
\[ I_{W2C} = \frac{1}{\text{TAP2}} \cdot \frac{(I_{AW2} - I_{CW2})}{\sqrt{3}} \]

\[ I_{W2C} = \frac{1}{\text{TAP2}} \cdot \frac{(I_{BW2} - I_{AW2})}{\sqrt{3}} \]

\[ I_{W2C} = \frac{1}{\text{TAP2}} \cdot \frac{(I_{CW2} - I_{BW2})}{\sqrt{3}} \]
Compensation for Zero-Sequence Currents
Why Eliminate Zero-Sequence Current?

No Current Through HV CTs

Zero-Sequence Current Through LV CTs
Removal Via Delta Connection

\[ l_a = l_1 + l_2 + l_0 \]
\[ l_b = a^2l_1 + al_2 + l_0 \]
\[ l_a - l_b = l_1 + l_2 + l_0 - (a^2l_1 + al_2 + l_0) \]
\[ = l_1(1 - a^2) + l_2(1 - a) + (l_0 - l_0) \]

Zero-Sequence Current Eliminated
Restrained Differential Element
Differential Protection Principle
Unequal CT Performance

CT saturation and CT ratio error
Percentage Differential Protection Principle

IOP = |I_1 + I_2|
IRT = 0.5 \cdot (|I_1| + |I_2|)
Differential Element Operate and Restraint Quantities

\[ \frac{1}{\text{TAP}_1} \quad \frac{1}{\text{TAP}_2} \]

Transformer / CT Connection Compensation

\[ |I_1 + I_2| \]

IOP (multiples of tap)

IRT (multiples of tap)
Percentage Restraint Differential Characteristic

- Unrestrained Pickup
- Operate Region
- Slope 1
- Slope 2
- Restraint Region
- Multiples of Tap
- Multiples of IRT
- Slope 1–2 Transition
Percentage Restraint Differential Characteristic

- Operate Region
- Slope 1
- Slope 2
- Restraint Region
- IRS1

Multiples of Tap vs. Multiples of Tap

IOP

IRT
Transformer Energization
C-Phase Inrush Current
Discriminating Internal Faults Versus Inrush Conditions

- Harmonic blocking
- Harmonic restraint
- DC blocking
DC Blocking

Inrush Current

\[ S^+ = 1 \]
\[ S^- = 0 \]
\[ 0/1 = 0 \]
\[ 0 < 0.1 \]
DCBL1 is asserted
DC Blocking

Internal Fault Current

IOP

$S^+ = 1$
$S^- = 1$
$1/1 = 1$
$1 > 0.1$
DCBL1 is not asserted
Inrush Conditions (Blocking)
Inrush Conditions (Restraint)
Unrestrained Differential Element
Unrestrained Element

- Element instantaneously trips on magnitude of differential current
  - No percentage restraint
  - No harmonic block
- CT saturation includes harmonics
Transformer Overexcitation
Excitation Current From Testing
150 Percent Overvoltage

![Graph showing excitation current over cycles with primary current (A) and cycles on the axes. The graph peaks at 60 and troughs at -60.]
# Fifth-Harmonic Content in Excitation Current

<table>
<thead>
<tr>
<th>Frequency Component</th>
<th>Magnitude (primary A)</th>
<th>Percent of Nominal</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fundamental</td>
<td>22.5</td>
<td>52.0</td>
</tr>
<tr>
<td>3rd</td>
<td>11.1</td>
<td>26.0</td>
</tr>
<tr>
<td>5th</td>
<td>4.9</td>
<td>11.0</td>
</tr>
<tr>
<td>7th</td>
<td>1.8</td>
<td>4.0</td>
</tr>
</tbody>
</table>
Excitation Current Harmonics

Graph showing the relationship between Voltage (%) and Transformer Nominal Current (%). The graph highlights the fundamental, 3rd, and 5th harmonics.
Application Considerations
Paralleling CTs on Restraint Input

Through Current

No Restraint

R1

R2

OP
Paralleling CTs on Restraint Input
Paralleling Transformers
Sympathetic Inrush

R1

R2

OP
Setting Taps for Three-Winding Transformers

- Know that third winding may not be rated at same MVA as main windings
- Set taps on multirestraint relay
  - Work through matching taps in pairs
  - Be sure to use same MVA base for each tap calculation
Restricted Earth Fault (REF) Protection
Protect Windings Close to Neutral
Protection Basics – Why Use REF Protection?

The diagram illustrates the relationship between fault current and primary current as a function of the distance of a fault from the neutral. The x-axis represents the distance of the fault from the neutral (percentage of winding), while the y-axis represents current (pu). Two curves are shown:

- **Fault Current**: This curve represents the current that flows through the winding due to a fault. As the distance from the neutral increases, the fault current decreases.
- **Primary Current**: This curve represents the current flowing in the primary winding. As the distance from the neutral increases, the primary current increases.

The diagram helps to understand how REF protection systems operate by comparing the fault current to the primary current, ensuring that the protective system operates within the intended parameters.
Prevention Before Protection

• Thermal model
• Through-fault monitoring
What Causes Transformer Overheating?
What Does Overheating Do?
Prevention Basics – Control Fan Banks

- Ambient Temperature
- Top-Oil Temperature
- Cooling Stage
- Control
- Thermal Model
- Temperature Data
Why Enable Through-Fault Monitoring?
Track Through Faults  
Transformer Has Experienced
Prevention Basics – Enable Through-Fault Monitoring
Questions?