Testing Numerical Transformer Differential Relays

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Introduction

Numerical transformer differential relays require careful consideration as to how to test properly. These relays provide different types of protection such as restrained phase differential, high set phase differential, restrained ground differential and overcurrent protection. All protection elements that are enabled should be adequately tested.

A common commissioning practice is to test all the numerical relay settings to verify they were properly entered. Automated testing using computer software to run the test set has made this possible since the overall commissioning for a numerical relay could consist of several hundred tests. While this is a good check, it is still important to ensure that the transformer is thoroughly protected for the particular application.

Transformer Differential Characteristic Boundary Test

A common practice for commissioning distance protection is to test along the boundary of the operating characteristic; for example, circles, lenses, or quadrilaterals. This practice can also be applied to transformer differential protection. Consider the simple example of a two winding transformer with both sets of windings wye connected. To keep the example simple also assume both sets of CTs are wye connected and have the same CT ratios, that is both windings are at the same potential. If you connect the current leads from the test set such that the test currents \( I_1 \) and \( I_2 \) are flowing through the transformer winding then the per phase differential and restraint currents can be expressed as follows:

\[
I_d = |I_1 - I_2| \quad [1]
\]

\[
I_r = \frac{|I_1| + |I_2|}{2} \quad [2]
\]

Where

\( I_1 = \) Winding 1 per unit current (A, B, or C-phase)

\( I_2 = \) Winding 2 per unit current (A, B, or C-phase)

Express equations [1] and [2] using matrices as follows:

\[
\begin{bmatrix}
I_d \\
I_r
\end{bmatrix} =
\begin{bmatrix}
1 & -1 \\
0.5 & -0.5
\end{bmatrix}
\begin{bmatrix}
I_1 \\
I_2
\end{bmatrix} \quad [3]
\]

Invert the matrix \( M \) in equation [3] to determine the two equations for the test currents:

\[
\begin{bmatrix}
I_1 \\
I_2
\end{bmatrix} =
\begin{bmatrix}
0.5 & 1 \\
-0.5 & 1
\end{bmatrix}
\begin{bmatrix}
I_d \\
I_r
\end{bmatrix} \quad [6]
\]

Calculate the test currents based upon an operating point on the differential characteristic as follows:

\[
I_1 = \frac{I_d}{2} + I_r \quad [7]
\]

\[
I_2 = \frac{-I_d}{2} + I_r \quad [8]
\]

1st Example

Consider a transformer differential characteristic for the two-winding transformer described earlier with the following settings:
Pickup = 0.2 per unit
Slope = 28.6%

To test the A-phase differential element at point \( \Box \) of the characteristic shown in Figure 1, use the following equations:

\[
I_{A1} = I_1 \cdot \text{TAP1} \quad [15] \\
I_{A2} = I_2 \cdot \text{TAP2} \cdot \sqrt{3} \quad [16]
\]

From Table 1:

\[
I_1 = 0.8 \text{ per unit} \quad [17] \\
I_2 = 0.6 \text{ per unit} \quad [18] \\
I_{A1} = 0.8 \cdot \text{TAP1} \quad [19] \\
I_{A2} = 0.6 \cdot \text{TAP2} \cdot \sqrt{3} \quad [20]
\]

Where \( I_{A1} \) and \( I_{A2} \) are the two test currents.

Testing at Breakpoints for Dual Slope Characteristics

Figure 2B below is the operating characteristic that corresponds to the following settings:

<table>
<thead>
<tr>
<th>Id</th>
<th>Ir</th>
<th>I1</th>
<th>I2</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.2</td>
<td>0.3</td>
<td>0.4</td>
<td>0.2</td>
</tr>
<tr>
<td>0.2</td>
<td>0.7</td>
<td>0.8</td>
<td>0.6</td>
</tr>
<tr>
<td>0.4</td>
<td>1.4</td>
<td>1.6</td>
<td>1.2</td>
</tr>
<tr>
<td>0.6</td>
<td>2.0</td>
<td>2.3</td>
<td>1.7</td>
</tr>
</tbody>
</table>

Table 1 — Test Currents for Transformer Differential Characteristic Boundary

Remember that the test currents are connected such that they are 180 degrees out of phase.

2nd Example

Now consider a transformer differential characteristic for a two-winding transformer connected delta (DAB) – wye, with wye connected CTs on both sides. A numerical transformer differential relay internally compensates the CT currents as follows:

\[
\text{Winding 1 (DAB)} \quad \text{Winding 2 (Wye)}
\]

\[
I_{A1\text{relay}} = \frac{I_{A1}}{\text{TAP1}} \quad [09] \quad I_{A2\text{relay}} = \frac{I_{A2} - I_{B2}}{\text{TAP2} \cdot \sqrt{3}} \quad [12]
\]

\[
I_{B1\text{relay}} = \frac{I_{B1}}{\text{TAP1}} \quad [10] \quad I_{B2\text{relay}} = \frac{I_{B2} - I_{C2}}{\text{TAP2} \cdot \sqrt{3}} \quad [13]
\]

\[
I_{C1\text{relay}} = \frac{I_{C1}}{\text{TAP1}} \quad [11] \quad I_{C2\text{relay}} = \frac{I_{C2} - I_{A2}}{\text{TAP2} \cdot \sqrt{3}} \quad [14]
\]

Where \( I_{A1}, I_{B1}, I_{C1}, I_{A2}, I_{B2} \) and \( I_{C2} \) are the CT currents.
There are two breakpoints. The first breakpoint occurs when the minimum pickup intersects with slope 1. The second breakpoint is the relay setting Slope Breakpoint (SBP).

**First Breakpoint**

Here is how to determine the first breakpoint where the operating characteristic switches from the minimum pickup to the first slope. The equation for a straight horizontal line (minimum pickup) is as follows:

\[ y = a \quad [\text{Equation 1}] \]

Where \( a \) is the minimum pickup setting

The equation for the first slope is as follows:

\[ y = m_1 \cdot x \quad [\text{Equation 2}] \]

Where \( m_1 \) is the first slope setting

To find the breakpoint set the two equations [1] and [2] equal then solve for \( x \):

\[ a = m_1 \cdot x \]

\[ x = \frac{a}{m_1} \]

So the first breakpoint is calculated as follows:

\( (x_1 = a/m_1, \; y_1 = a) \)

From Figure 2B:

\[ y = 0.5 \quad [\text{Equation 1, minimum pickup}] \]

\[ y = 0.2 \cdot x \quad [\text{Equation 2, first slope}] \]

\[ 0.5 = 0.2 \cdot x \]

\[ x = 0.5/0.2 = 2.5 \]

The first breakpoint is as follows:

\( (x_1 = 2.5, \; y_1 = 0.5) \)

**Second Breakpoint**

Here is how to determine the second breakpoint where the operating characteristic switches from the first slope to the second slope.

\[ x_2 = SBP \]

\[ y_2 = m_1 \cdot SBP \]

Where \( SBP = \text{Slope Breakpoint} \)

The second breakpoint for Figure 2B is as follows:

\( (x_2 = 4.0, \; y_2 = 0.8) \)

The equation of the line that corresponds to the second slope passing through the second breakpoint is determined as follows:

\[ y_2 = m_2 \cdot x_2 + b \]

Where \( b \) is the \( y \)-intercept

\[ b = y_2 - m_2 \cdot x_2 \]

The \( y \)-intercept for the equation of the line that corresponds to the second slope passing through the second breakpoint is as follows:

\[ b = 0.8 - 0.75 \cdot 4.0 \]

\[ b = -2.2 \]

The equation is as follows:

\[ y = 0.75 \cdot x - 2.2 \]

**Ground Differential Element Sensitivity Test**

Ground differential protection can provide good sensitivity for ground faults on wye-connected transformer windings. Figure 3 shows a simple three-line diagram for a typical application. The CTs are connected such that:

If \( I_G \) and \( 3I_0 \) are in phase, the ground fault is external.

If \( I_G \) and \( 3I_0 \) have opposite polarity, the ground fault is internal.
Stability is improved for CT saturation during external faults if the ground differential protection is disabled when \( I_G \) is less than a preset value, 200 milliamperes for example. The ground differential element operates when the difference between \( 3I_0 \) and \( I_G \) is greater than the pickup setting:

\[
|3I_0 - I_G| > 50GD \quad [21]
\]

\( 3I_0 \) and \( I_G \) add together in equation [21] above when the ground fault is internal since they have opposite polarity for this condition.

A good test is to check how much sensitivity 87GD provides for ground faults located close to the neutral of wye-connected windings coupled with fault resistance \( R_F \). Consider the case of a two-winding delta-wye 25 MVA distribution transformer connected to a 230 kV grid and serving load at 23 kV. Here is the power system data:

- Source impedance \( (X_S) \) varies
- \( X_T = 10\% \)
- \( R_F \) varies
- Ground fault located 5% from neutral
- CTR \( 23\text{kV} = 600:5 \)
- CTR \( \text{GND} = 600:5 \)

Figure 4 illustrates the sensitivity of 87GD as a function of the source impedance and ground fault resistance. The top curve corresponds to each point where \( I_G \) is equal to 200 milliamperes (that is, the minimum amount required for operation or the maximum sensitivity possible). The middle curve corresponds to each point where \( I_G \) is equal to 500 milliamperes. The bottom curve corresponds to each point where \( I_G \) is equal to 1 ampere. The source impedance and ground fault resistance are in ohms primary.

Even Harmonic Restraint during Transformer Inrush

Events such as transformer energization can be captured by utilities using digital fault recorders or numerical relays and then later played back via COMTRADE to observe relay performance. Some customers have access to software such as the Alternative Transients Program (ATP) and can build their own transformer models to simulate inrush. This is a very practical method to check that the relay is properly set. One example of playback is to evaluate the performance of the restrained differential protection for transformer inrush with varying levels of harmonic content in the current waveforms.

Transformer differential protection has historically used the 2nd harmonic content of the differential current to prevent unwanted operation during transformer inrush. It is advantageous to use both the 2nd and 4th harmonic content of the differential current. The relay can internally calculate the total harmonic current per phase as follows:

\[
I_{2-4} = \sqrt{I_2^2 + I_4^2} \quad [22]
\]

The sum of the two even harmonics per phase helps to prevent the need to lower the value of restraint which could cause a delayed operation if an internal fault were to occur during transformer energization.

Cross phase averaging also helps prevent unwanted operation during transformer inrush. Cross phase averaging averages the even harmonics of all three phases to provide overall restraint. The cross phase averaged harmonic restraint can be internally calculated by the relay as follows:

\[
I_{r2-4} = \sqrt{I_{A2-4}^2 + I_{B2-4}^2 + I_{C2-4}^2} \quad [23]
\]

The transformer relay with even harmonic restraint and cross phase averaging tested for the following cases did not misoperate. The inrush currents presented here were created using ATP and have a slow rate of decay. The autotransformer data is as follows:

![Figure 4 — Ground Differential Sensitivity Diagram](image)

![Figure 5 — 600 MVA Autotransformer Single Line Diagram (Delta Winding DAC)](image)
**Auto-transformer Characteristics**

\[ Z_{HM} = 0.01073 \text{ per unit} \]
\[ Z_{HL} = 0.04777 \text{ per unit} \]
\[ Z_{ML} = 0.03123 \text{ per unit} \]

\[ ZH = \frac{Z_{HM} + Z_{HL} - Z_{ML}}{2} = 0.0140 \text{ per unit} \quad [24] \]

\[ ZM = \frac{Z_{HM} + Z_{ML} - Z_{HL}}{2} = -0.0029 \text{ per unit} \quad [25] \]

\[ ZL = \frac{Z_{HL} + Z_{ML} - Z_{HM}}{2} = 0.0340 \text{ per unit} \quad [26] \]

\[ \text{CTR}_{W1} = 1200:5 \text{ (wye connected)} \]
\[ \text{CTR}_{W2} = 2000:5 \text{ (wye connected)} \]

**87T Relay Settings**

\[ \text{TAP1} = \frac{600 \text{ MVA}}{345 \text{ kV} \times 240 \sqrt{3}} = 4.18 \quad [27] \]
\[ \text{TAP2} = \frac{600 \text{ MVA}}{230 \text{ kV} \times 400 \sqrt{3}} = 3.77 \quad [28] \]

87T Pickup = 0.5 per unit
Slope 1 = 25%
Slope 2 = 75%
Breakpoint = 2.0 per unit
Even Harmonic Restraint = 10% (cross phase averaging enabled)

**1st Case – Balanced Inrush**

*Energize Line with Bank from Single End*

*(No residual flux)*

![Figure 6A — Total Phase Currents for Balanced Inrush](image)

![Figure 6B — 2nd Harmonic Component Currents for Balanced Inrush](image)

![Figure 6C — 4th Harmonic Component Currents for Balanced Inrush](image)
2nd Case – Balanced Inrush
Energize Bank from Winding 2 with Winding 1 Open
(No residual flux)

3rd Case – Unbalanced Inrush
Energize Line with Bank from Single End
(Severe A-phase residual flux)

Figure 7A — Total Phase Currents for Balanced Inrush
Figure 7B — 2nd Harmonic Component Currents for Balanced Inrush
Figure 7C — 4th Harmonic Component Currents for Balanced Inrush

Figure 8A — Total Phase Currents for Unbalanced Inrush
Figure 8B — 2nd Harmonic Component Currents for Unbalanced Inrush
Figure 8C — 4th Harmonic Component Currents for Unbalanced Inrush
Conclusions

A common commissioning practice is to test all the numerical relay settings to verify they were properly entered. Automated testing using computer software to run the test set has made this possible since the overall commissioning for a numerical relay could consist of several hundred tests. While this is a good check it is still important to ensure that the transformer is thoroughly protected for the particular application.

This paper presented three types of test for transformer differential protection:

- Transformer Differential Characteristic Boundary Test
- Ground Differential Sensitivity Test
- Even Harmonic Restraint during Transformer Inrush

The first test determines if the transformer differential protection meets the stated accuracy for the operating characteristic slopes. The second test determines the fault resistance coverage of the ground differential protection as a function of the source impedance. The third test determines if the transformer differential protection harmonic restraint works during a variety of stringent conditions that could occur during actual energization.

Steve Turner is a Senior Applications Engineer at Beckwith Electric Company, Inc. His previous experience includes working as an application engineer with GEC Alstom for five years, primarily focusing on transmission line protection in the United States. He also was an application engineer in the international market for SEL, Inc. again focusing on transmission line protection applications. Steve wrote the protection-related sections of the instruction manual for SEL line protection relays as well as application guides on various topics such as transformer differential protection and out-of-step blocking during power swings. Steve also worked for Progress Energy in North Carolina, where he developed a patent for double-ended fault location on transmission lines and was in charge of all maintenance standards in the transmission department for protective relaying.

Steve has both a BSEE and MSEE from Virginia Tech University. He has presented at numerous conferences including: Georgia Tech Protective Relay Conference, Western Protective Relay Conference, ECNE and Doble User Groups, as well as various international conferences. Steve is also a senior member of the IEEE.