Relay-Assisted Commissioning

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Abstract—**Power transformer differential relays were among the first protection relays with digital technology. These new power transformer relays offered such improvements over electromechanical relays as automatic calculation of TAP values, and the use of calculations instead of current transformer (CT) connections to eliminate zero-sequence currents. While these improvements reduced setting complexity, Elmore [1] identifies 19 different ways in which errors can occur during the commissioning of a power transformer. There is a clear need for relays to offer commissioning personnel assistance during commissioning of a power transformer.**

This paper describes an algorithm that checks for correct CT polarities, consistent CT ratios, and the existence of any crossed-phase wiring errors, provided minimum, balanced load current flows. Other algorithms [2] [3] describe systems that test for similar wiring errors, but these systems fail to calculate an alternate vector-group compensation setting if the present relay vector-group compensation setting is incorrect. The algorithm this paper describes includes a vector-group compensation calculation. After verifying CT connections, the algorithm calculates the correct CT compensation connections for the particular vector group within the transformer. The algorithm also produces a commissioning report that includes information such as phase rotation, measured load current during the test, and the recommended vector-group setting resulting from these load current and operating current measurements. Commissioning personnel can use the commissioning report to confirm immediately and conclusively the correctness of wiring and the integrity of differential element configuration settings.

I. Introduction

In general, commissioning protection equipment involves verification of physical connections (cabling, wiring, etc.), relay settings, and proper operation of the complete system. Usually, a commissioning engineer first verifies physical connections, and then tests the appropriate analog signals and applies appropriate digital signals. To verify the complete system, the commissioning engineer takes a number of measurements during injection testing and compares these measured values against expected values. When differences between measured values and expected values exceed pre-determined margins, the commissioning engineer suspects the existence of system errors and performs further tests to determine the cause of these errors.

Commissioning engineers most often use the operating (differential) current of the current differential element to determine whether commissioning errors exist. However, use of the operating current as a catchall method for detecting all commissioning errors can result in ambiguous conclusions. For example, both incorrect CT polarity and a CT connected to the incorrect CT tap result in the presence of operating current.

In fact, operating current can exist in an error-free installation [3]. Although numerical relays compensate for most unbalances, the so-called TAP compensation can result in operating current. Because standard CT ratios seldom match the full load current of the transformer, transformer relays adjust each phase current to compensate for the ratio mismatch between installed CTs and the transformer full load current. To determine the adjustment for each phase current, the relay uses either Equation 1 or Equation 2 to calculate a scaling factor called TAP.

$$\text{TAP} = \frac{\text{MVA} \bullet 1000}{\sqrt{3} \bullet \text{kV} \bullet \text{CTR}} \quad (\text{wye-connected CTs}) \qquad (1)$$

$$\text{TAP} = \frac{\text{MVA} \bullet 1000}{\sqrt{3} \bullet \text{kV} \bullet \text{CTR}} \bullet \sqrt{3} \quad (\text{delta-connected CTs}) \qquad (2)$$

where:
MVA = transformer rating in MVA
kV = nominal system line-to-line rated voltage in kV
CTR = CT ratio (normalized)

If the commissioning engineer measures operating current while the transformer tap position does not correspond with the rated voltage of the network (nominal tap position), operating current can be present. In this case, there is operating current present although there may be no setting or commissioning errors at the installation.

Therefore, although the presence of excessive operating current indicates commissioning error(s), the commissioning engineer cannot identify the specific cause of the unbalance by the mere presence of operating current. Clearly, we need to take measurements other than just the differential current to identify the specific cause of the operating current. Table 1 shows the measurement methods we use in the algorithm this paper describes.

TABLE I
MEASUREMENT METHODS TO IDENTIFY VARIOUS CAUSES OF OPERATING CURRENT

Error	Measuring Method
Insufficient load current	Current magnitude measurement
Two crossed phases	Negative-sequence current measurement
CT connected to the incorrect tap	Expected current to measured current magnitude comparison; negative-sequence current measurement
Incorrect CT polarity	Angular comparison between a reference phase and all other phases
Vector-group compensation selection	Operating current and phase angle measurement

II. Measurement Quantities

As we see from Table I, the relay uses operating current to select the correct vector-group compensation. Because we can apply the vector-group selection resulting from this algorithm as a relay setting (overwrite officially approved settings), we must eliminate all possible ambiguities and error sources. To avoid errors resulting from primary or secondary current injection, we require at least 250 mA (for a 5A secondary relay) of balanced-load current (approximately five percent of full load) instead of injected current.

We specify 250 mA load current because CT characteristics can vary significantly among phases at low current values (ankle point). For greater current magnitudes, CTs operate on the linear portions of their respective magnetization (B/H) curves. On the linear portion of the B/H curve, the CT characteristics are substantially similar to each other, and the secondary currents from the CTs are balanced. It is important to have balanced load current, because we use symmetrical components in some of the tests (see Table 1), and unbalanced load current can distort test results.

The value of 250 mA also ensures that relay errors do not obscure proper compensation selection. Table 2 shows the various differential current values for each 30° phase shift. From Table 2 we see that, with the correct compensation selection on both windings, the differential current is (ideally) zero. With 250 mA secondary current flowing, differential current resulting from a 30° phase error (150° instead of 180°, for example) is ± 130 mA. Because a current of 130 mA is substantially larger than any relay error, the relay can conclusively make correct compensation selections.

Table II
Differential Current For 30° Phase Shifts

Angular Error	A-Phase HV	A-Phase LV	Differential Current
No error	250∠0° mA	250∠180° mA	0.0 ∠0° mA
30° error	250∠0° mA	250∠150° mA	129.4∠75° mA
60° error	250∠0° mA	250∠120° mA	250.0∠60° mA
90° error	250∠0° mA	250∠90° mA	353.6∠45° mA
120° error	250∠0° mA	250∠60° mA	433.0∠30° mA
150° error	250∠0° mA	250∠30° mA	482.9∠15° mA
180° error	250∠0° mA	250∠0° mA	500∠0° mA

III. Current Compensation

We define current compensation in three parts: vector-group compensation (phase-angle correction), zero-sequence removal, and scaling (TAP). We can achieve vector-group compensation and zero-sequence removal either by appropriate CT connections or by mathematical calculations. In numerical relays, actual compensation transformer taps (used for TAP compensation in electromechanical relays) do not exist, and all determinations of TAP are by way of mathematical calculations (Equation 1 or Equation 2).

Electromechanical relays require delta-connected CTs to compensate for wye-connected power transformer windings; wye-connected CTs generally provide more information. Because numerical relays compensate for input currents mathematically, delta-connected CTs are no longer necessary. The algorithm this paper describes assumes that all CTs are wye-connected, regardless of the transformer vector group.

IV. Phase-Angle Compensation

Phase angle differences come about when the vector group of one set of power transformer windings differs from the group for another set of power transformer windings (such as wye-connected and delta-connected windings). For example, consider the YDAB (YNd11) connection shown in Fig. 1. Taking the A-phase of the HV winding as reference, the a-b delta connection causes the A-phase of the LV winding to differ by 30° with respect to the A-phase HV winding.

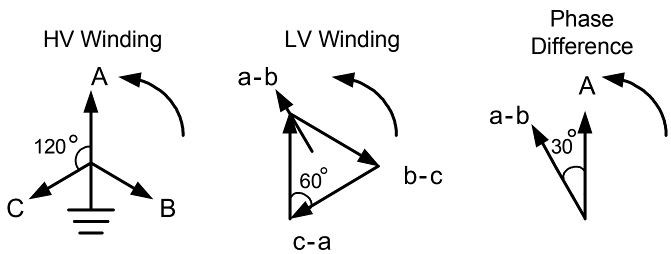

Fig. 1 Phase Shift Between HV and LV Sides of a YDAB (YNd11) Transformer

When electromechanical relays are in use, CTs from wye-connected power transformer windings are connected in delta, and CTs from delta-connected power transformer windings are connected in wye to compensate for the 30° phase shift. When both HV and LV CTs are wye-connected, CT connections cannot compensate for this 30° phase difference, and the secondary current from the HV winding and the secondary current from the LV winding are phase-shifted by 30°. For correct differential operation, we need to correct for the phase shift of wye-delta transformers in the relay software. To achieve this phase-shift correction, the relay software calculates the appropriate delta connection. Equations 3 through 5 show the three line current equations for the YDAB transformer connection.

$$I_{ab} = I_a - I_b \quad (I_c = 0) \tag{3}$$

$$I_{bc} = I_b - I_c \quad (I_a = 0) \tag{4}$$

$$I_{ca} = I_c - I_a \quad (I_b = 0) \tag{5}$$

If we were to write Equations 3 through 5 in matrix format, the placeholders for the current vectors would be as follows:

$$\begin{bmatrix} Ia & Ib & Ic \\ Ia & Ib & Ic \\ Ia & Ib & Ic \end{bmatrix} \text{ so that } I_{ab} = I_a - I_b \text{ becomes}$$

$$\begin{bmatrix} 1 & -1 & 0 \end{bmatrix} \bullet \begin{bmatrix} Ia \\ Ib \\ Ic \end{bmatrix} \quad (I_c = 0)$$

We can then rename I_{ab} to I_{ACOMP} and complete the current relationships of the YDAB transformer in matrix form as follows (divide by $\sqrt{3}$ to scale the magnitude, see Appendix 1):

$$\begin{bmatrix} I_{A_{COMP}} \\ I_{B_{COMP}} \\ I_{C_{COMP}} \end{bmatrix} = \frac{1}{\sqrt{3}} \begin{bmatrix} 1 & -1 & 0 \\ 0 & 1 & -1 \\ -1 & 0 & 1 \end{bmatrix} \bullet \begin{bmatrix} I_A \\ I_B \\ I_C \end{bmatrix}$$

In the same manner, we can form other "delta" matrices for transformer vector groups that require integer multiples of 30° phase-shift correction (see Appendix 2).

V. Zero-Sequence Elimination

Why eliminate zero-sequence current? Fig. 2 shows a wye-delta transformer with the wye winding grounded. Ground faults on the HV side of the transformer result in current flowing in the lines of the wye-connected windings and therefore the HV CTs. This current distribution is different in the LV windings of the transformer. Fault current for ground faults on the HV side of the transformer circulate in the delta-connected windings, but no zero-sequence current flows in the LV lines or in the LV CTs. Because fault current flows in the HV CTs only, the differential protection is unbalanced and can misoperate.

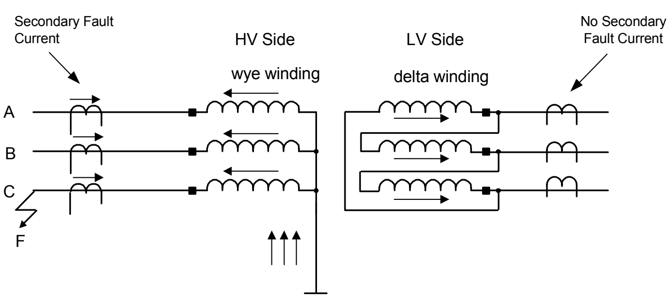

Fig. 2 System Fault on the Wye-Connected Winding of a YDAB transformer

Clearly, we need to eliminate zero-sequence currents from CTs connected to all grounded, wye-connected transformer windings or where a grounding transformer is installed on the delta winding within the differential zone. Because all CTs are wye-connected, we must remove the zero-sequence currents mathematically in the relay. One way to remove the zero-sequence currents is by means of the delta matrices we use for phase-angle correction. For a DAB delta, connecting a–b, b–c, and c–a phases forms the delta connection. Of these three groups, consider the $I_a - I_b$ connection. Equation 6 and Equation 7 express I_a and I_b in terms of symmetrical components, A-phase being the customary reference.

$$I_a = I_1 + I_2 + I_0 \qquad (6)$$

$$I_b = \alpha^2 I_1 + \alpha I_2 + I_0 \qquad (7)$$

$$I_a - I_b = I_1 + I_2 + I_0 - \alpha^2 I_1 - \alpha I_2 - I_0 \qquad (8)$$

$$I_a - I_b = I_1\left(1 - \alpha^2\right) + I_2\left(1 - \alpha\right) \qquad (9)$$

where: α is the alpha operator, i.e., $1\angle 120°$

Equation 8 shows the $I_a - I_b$ connection in terms of symmetrical components. From Equation 9, we see that the zero–sequence currents cancel, and only positive-sequence and negative-sequence currents flow. Although delta connections effectively eliminate zero–sequence currents, delta connections also create phase shifts.

We may need this phase shift in wye-delta transformers, but we do not need a phase shift in autotransformers or wye-wye connected transformers. With autotransformers or wye-wye connected transformers, the HV and LV currents are in phase with each other (or 180° out of phase). Use of a delta connection to remove zero-sequence current introduces an unnecessary 30° phase shift between the HV and LV currents.

Fortunately, numerical relays make it possible to remove zero-sequence current mathematically without creating a phase shift. Perform the following calculation to remove zero–sequence current from the A-phase current:

$$I_{A_{COMP}} = \left(I_A - I_0\right), \text{ where } I_0 = \frac{1}{3}\left(I_A + I_B + I_C\right)$$

$$I_{A_{COMP}} = \left[I_A - \frac{1}{3}\left(I_A + I_B + I_C\right)\right]$$

$$I_{A_{COMP}} = \frac{1}{3}\left(3I_A - I_A - I_B - I_C\right)$$

$$I_{A_{COMP}} = \frac{1}{3}\left(2I_A - I_B - I_C\right)$$

Similarly for the B and C phases:

$$I_{B_{COMP}} = \frac{1}{3}\left(2I_B - I_A - I_C\right)$$

$$I_{C_{COMP}} = \frac{1}{3}\left(2I_C - I_B - I_A\right)$$

Arranging the results in matrix form yields the following:

$$\begin{bmatrix} I_{A_{COMP}} \\ I_{B_{COMP}} \\ I_{C_{COMP}} \end{bmatrix} = \frac{1}{3} \begin{bmatrix} 2 & -1 & -1 \\ -1 & 2 & -1 \\ -1 & -1 & 2 \end{bmatrix} \bullet \begin{bmatrix} I_A \\ I_B \\ I_C \end{bmatrix}$$

Matrix 0 is the identity matrix; it does not alter the currents:

$$\begin{bmatrix} I_{A_{COMP}} \\ I_{B_{COMP}} \\ I_{C_{COMP}} \end{bmatrix} = \begin{bmatrix} 1 & 0 & 0 \\ 0 & 1 & 0 \\ 0 & 0 & 1 \end{bmatrix} \bullet \begin{bmatrix} I_A \\ I_B \\ I_C \end{bmatrix}$$

Adding the "even" matrices (M2, M4, .. M12, see Appendix 2) brings the total number of available matrices to 13 (including the identity matrix). Even with all CTs connected in wye configuration, there are $13^4 \approx 30{,}000$ possible matrix combinations for a four-winding installation. Clearly, with so many combinations, it is easy to make an error in selecting the correct matrix combination when setting the differential element. The following discussion describes an algorithm that automatically selects the correct matrices.

VI. Automatic Vector-Group Selection

A. Overview

Fig. 3 shows a typical two-winding transformer installation. Both HV CTs (CT2) and LV CTs (CT3) are wye connected. In the figure, the differential protection obtains three-phase current inputs (only one phase shown) from current transformers CT2 and CT3. There are three restraint-differential elements inside the differential relay, one element per phase. Each of the three differential elements calculates operate current (IOP1 through IOP3) and restraint current (IRT1 through IRT3).

The vector-group selection algorithm reverses the process that engineers usually follow when setting and commissioning protection relays. Usually, the setting engineer selects relay settings and the commissioning engineer takes suitable measurements to verify the correctness of these relay settings. For example, if the commissioning engineer measures high restraint current (1 per unit, for example) and low operating current (0.05 per unit), then the commissioning engineer concludes that the differential settings are correct. With the vector-group selection algorithm, the inverse applies: we first do the measurement, then we select the relay settings.

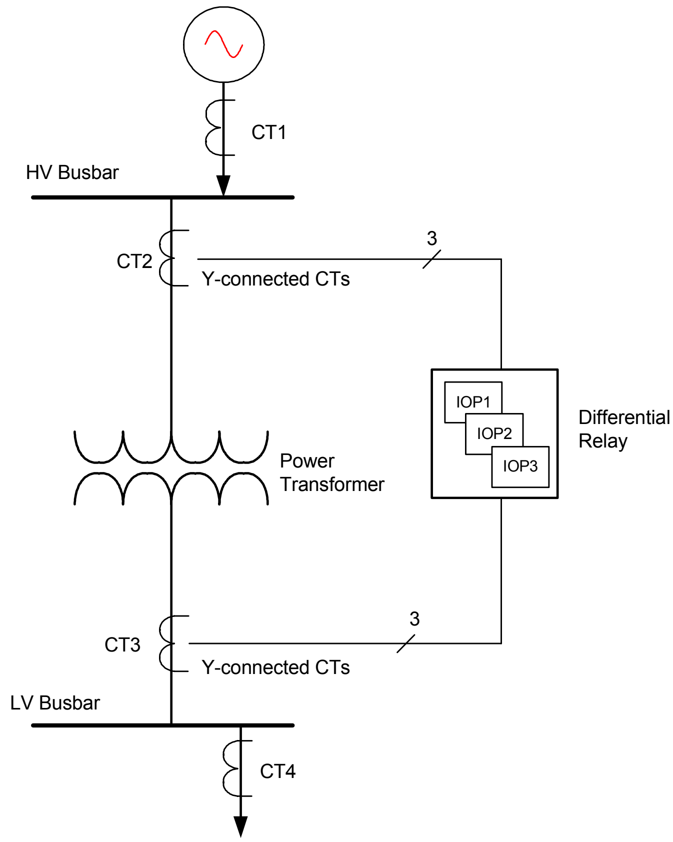

Fig. 3 Typical Two-Winding Transformer Installation

The vector-group selection algorithm is essentially in two parts: a part that checks for correct CT wiring (single contingency, balanced conditions) and a part that calculates vector-group compensation, two windings at a time (i.e., a reference and a test winding), for a power transformer. Both parts require that 250 mA balanced, load current flows through the transformer.

Part I: the algorithm checks for correct CT polarities, consistent CT ratios, and whether any crossed-phase wiring errors exist.

Part II: after verifying the CT connections in Part I, the algorithm calculates the correct CT compensation for the particular vector group within the transformer. After calculating the correct compensation settings, the relay accepts the new setting only if the tester confirms the setting change.

B. Part I. CT Checks

Through the use of balanced load current, we can identify the occurrence of one of the following CT errors (wye-connected CTs):

- CT secondary wire connected to the incorrect tap on the CT
- Crossed phases
- Incorrect CT polarity

Fig. 4 shows a CT secondary wire connected to the incorrect tap on the CT, as well as a connection that results in an incorrect CT polarity. Fig. 5 shows the crossing of two phases.

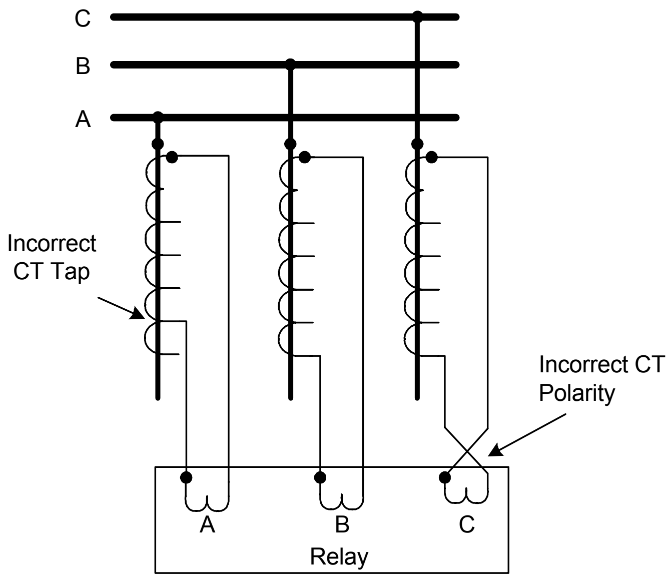

Fig. 4 Incorrect CT Ratio or CT Polarity

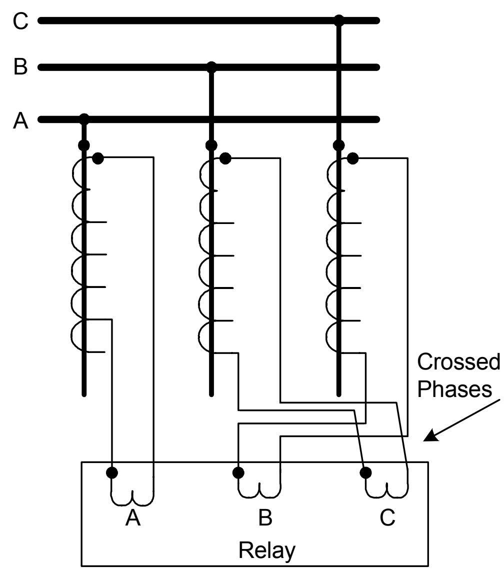

Fig. 5 Crossed Phases

1) Incorrect CT polarity

To check for correct CT polarities, the relay uses the A-phase current as a reference for all tests. Table 3 shows the angular relationship between phases when the polarities of all three CTs are correct in an ABC phase-sequence power system.

TABLE III ANGULAR RELATIONSHIP FOR CORRECT CT POLARITIES

A-Phase	B-Phase	C-Phase
IA∠0°	IB∠–120°	IC∠120°

Table 4 shows the three-phase angular relationships for incorrect polarity of each of the three phases. Because A-phase is the reference, the A-phase angle remains at 0°.

TABLE IV ANGULAR RELATIONSHIP FOR INCORRECT CT POLARITIES

A-Phase	B-Phase	C-Phase
*IA∠0°	IB∠60°	IC∠–60°
IA∠0°	*IB∠60°	IC∠120°
IA∠0°	IB∠–120°	*IC∠–60°

*Incorrect polarity

2) Crossed Phases

The relay considers the relay phase rotation setting (ABC or ACB) and uses Equation 10 to calculate the positive-sequence current of the reference winding. The relay uses Equation 11 to calculate the negative-sequence current of the reference winding for an ABC phase rotation.

$$I1_{REF} = \frac{1}{3}(IA_{REF} + \alpha IB_{REF} + \alpha^2 IC_{REF}) \quad (10)$$

$$I2_{REF} = \frac{1}{3}(IA_{REF} + \alpha^2 IB_{REF} + \alpha IC_{REF}) \quad (11)$$

where:

$I1_{REF}$ = Positive-sequence current of the reference winding
$I2_{REF}$ = Negative-sequence current of the reference winding
IA = A-phase current of the reference winding
IB = B-phase current of the reference winding
IC = C-phase current of the reference winding
α = alpha-operator (1∠120°)

In a separate calculation, the relay calculates the positive-sequence current and the negative-sequence current of a test winding. The relay declares a crossed-phase condition when the positive-sequence current is less than 10 percent of the negative-sequence current.

3) Incorrect CT Tap Position

We use the fact that the HV/LV turns ratio describes the relationship between the HV current and the LV current of a power transformer, i.e., the LV current is a scaled version of the HV current. Furthermore, when the transformer is on the nominal tap, we can use the line-to-line voltage ratio instead of the transformer turns ratio. Use Equation 12 to calculate the scaling factor N.

$$N = \frac{VHV}{VLV} \quad (12)$$

Fig. 6 shows the logic to detect an incorrect CT tap connection. The relay uses the voltage ratio (Equation 12), to scale the measured HV current (IAW1 • N) for each HV phase and compares this result (expected LV current) to the measured LV current (IAW2) of the corresponding LV phase. If the difference between the expected LV current and measured LV current exceeds 0.04 per unit, the relay declares an incorrect CT tap connection. To determine the location (HV side or the LV side) of the offending CT, the relay calculates the negative-sequence currents from the HV side and the negative-sequence currents from the LV side and identifies the side with the greater negative-sequence current as the side with the CT on the incorrect tap.

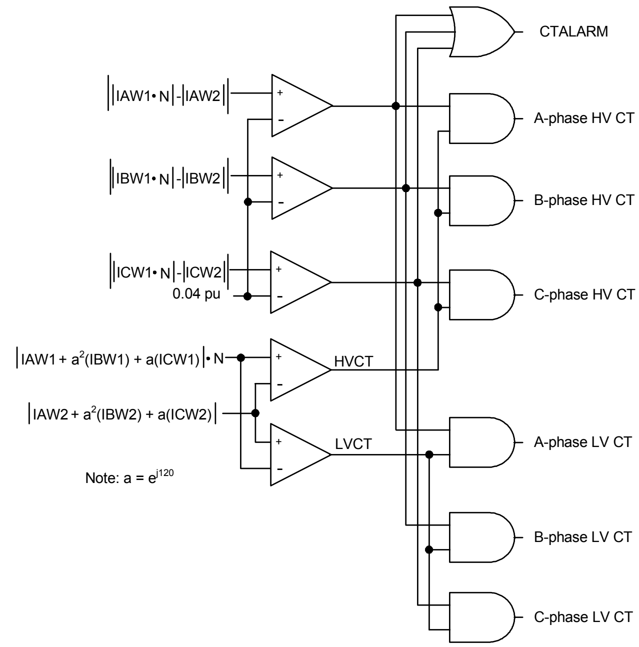

Fig. 6 Logic to Detect the Phase With Incorrect CT Tap Connection

To avoid possible misleading results from unbalanced loading, the relay provides a separate alarm that is independent of the negative-sequence calculation. Because the previously discussed three cases are wiring errors and not setting errors, the algorithm does not attempt to rectify such errors. When detecting one of the wiring errors, the algorithm reports that such an error exists and suspends the selection process. This suspension gives the commissioning engineer the opportunity to correct the wiring error before continuing with the selection process.

C. Part II. Calculation of Vector-Group Compensation

Calculating the correct vector group consists of two separate calculations: vector-group selection through use of operate current, and vector-group selection through use of relative phase angles. Fig. 7 shows vector-group selection through use of operate current for a two-winding transformer.

1) Selection Using The Operate Current

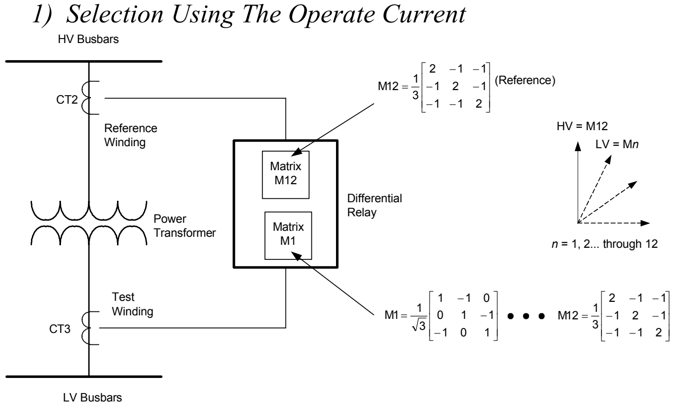

Fig. 7 Vector-Group Selection for a Two-Winding Transformer

In general, to correct an angular difference of 30° between two windings, we need to rotate the CT secondary current phasors of one winding by 30° with respect to the CT secondary current phasors of the other winding (assuming wye-wye connected CTs). The direction of the rotation (30° clockwise or 30° counter clockwise) is a function of the transformer vector group and the choice of reference winding.

For example, consider the YDAB vector group shown in Fig. 8. When we take the HV winding as reference, the LV current resulting from the a-b connection leads the A-phase HV current by 30°. To correct for this 30° angular difference, we rotate the LV current clockwise by 30°. After rotating the a-b current clockwise by 30°, the LV current is in phase with the HV current.

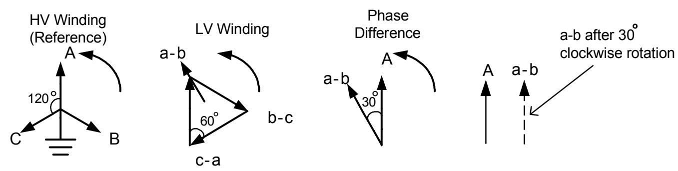

Fig. 8 YDAB Transformer With the HV Winding as Reference

Taking the HV winding as reference is arbitrary; we could just as easily take the LV winding as reference. Fig. 8 shows the same YDAB vector group, but with the LV winding as reference.

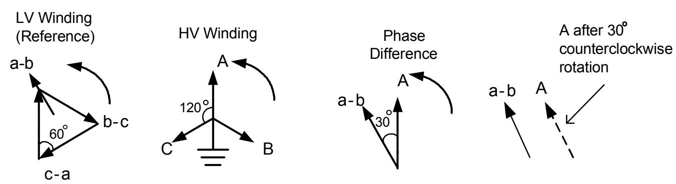

Fig. 9 YDAB Transformer With the LV Winding as Reference

With the LV winding as reference, we must rotate the HV currents counterclockwise to correct for angular difference. After we rotate the A-phase-current counterclockwise by 30°, the HV current is in phase with the LV current.

Therefore, to compensate for the angular difference of the YDAB transformer, an HV/LV matrix combination of M12/M11 is equally correct as an M1/M12 combination or as an M2/M1 combination. Clearly, it is not necessary that we know the actual transformer vector group; to correct for an angular difference, we simply declare one set of secondary current phasors as reference and rotate the other set of secondary current phasors either clockwise or counterclockwise by the appropriate amount.

After we select the reference winding (WDG1 in Fig. 11), the vector-group compensation algorithm assigns Matrix 12 to the reference winding. Assume for this example that we select WDG2 as the test winding. With Matrix M12 assigned to the reference winding, we now sequentially assign, starting from Matrix M1, all 12 matrices to the test winding. The objective is to find the combination of matrices that produces an operate current that is (ideally) zero (see Table 2).

Because the existing relay settings can be the correct matrix combination, the relay calculates the operate current and restraint current with the existing settings before assigning matrices to any of the windings. If the operate current is less than 0.05 per unit, the existing settings are correct and the relay records the numbers of the two matrices. Although the relay found the correct combination with the first calculation, the relay still assigns all 12 matrices to the test winding, and records all calculated values.

If the operate current is greater than 0.05 per unit with the present settings, the relay does not record the matrix combination, but it assigns Matrix M1 to the test winding. By keeping the reference winding at Matrix M12 and assigning all 12 matrices in succession to the test winding, the algorithm finds, by process of elimination, the correct matrix combination. Fig. 11 shows a flow diagram of the selection process.

At the conclusion of the test, the relay displays the recorded, calculated values from the 12 calculations in a commissioning report. Table 5 summarizes the operate-current vector-group selection process.

TABLE V. VECTOR-GROUP SELECTION PROCESS

Steps	Activity	Comment
Step 1	Calculate IOP, the operating current, and IRT, the restraint current.	Evaluate the existing relay settings
Step 2	Assign Matrix 12 to the reference winding.	Declare Matrix 12 as the reference.
Step 3	Assign Matrix 1 as the initial matrix for the test winding.	Assign the M12–M1 matrix combination.
Step 4	Calculate IOP, the operating current, and IRT, the restraint current.	Get the data to evaluate in Step 5 and data for the commissioning report.
Step 5	If IOP is less than 0.05 per unit, record the matrix number, and assign the next matrix to the test winding. If IOP is greater than 0.05 per unit of IRT, do not record the matrix number and assign the next matrix to the test winding.	If IOP is less than 0.05 per unit, the present matrix combination is the correct combination. However, we continue to evaluate the remaining combinations.

2) Selection Using Relative Phase Angles

Because we can permanently assign the selected matrix as the relay setting, a further test is necessary. Relative angle selection provides a second, independent method for determining the correct matrix combination. We can confirm that the calculation using the operate current determined the correct matrix combination by checking (after reversing the polarity of the test winding CTs) that the reference winding and test winding current phasors are in phase (± 5°) with each other. Fig. 10 shows the logic to compare the HV winding A-phase phasor with the LV winding A-phase phasor. Because of the CT polarity connections, the HV and LV phasors are 180° out of phase. Arbitrarily selecting the HV phasors as reference, we add 180° to the LV phasors and test whether the HV phasors and LV phasors are in phase with each other (± 5°).

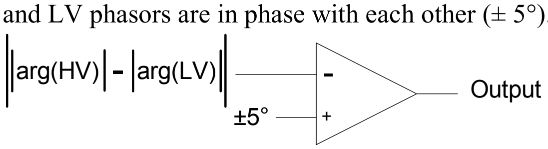

Fig. 10 A-Phase Vector-Group Selection Angular Verification

When both selection processes agree, the relay considers the present calculated matrix combination to be the correct combination to compensate for the angular difference between HV and LV windings.

To provide visual confirmation to the commissioning engineer, the relay displays a commissioning report of the operate currents and the restraint currents for each of the 12 matrix combinations. Fig. 12 shows an example commissioning report that includes information such as the phase rotation setting and the operate currents and the restraint currents with original matrix settings.

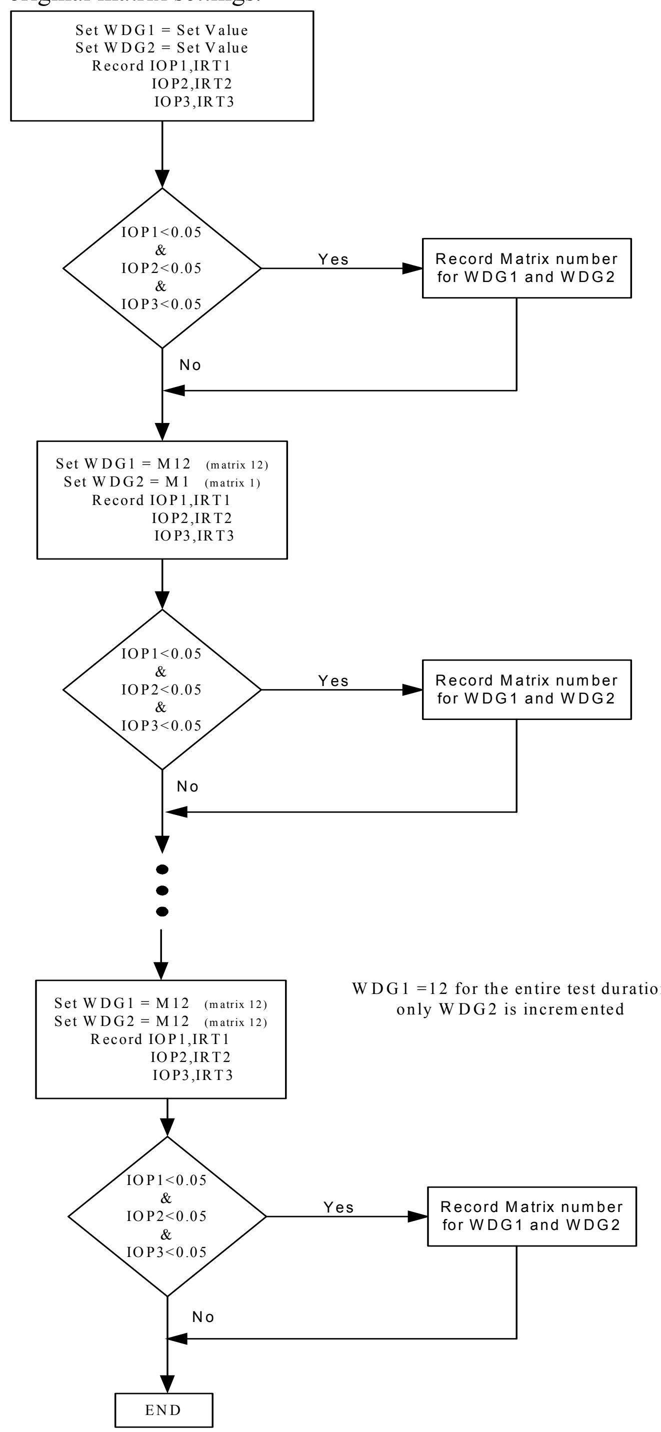

Fig. 11 Algorithm for IOP-Matrix Selection

VII. Commissioning Report

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Automatic Matrix Selection Successful.

Phase Rotation: ABC
Reference Winding: Winding Z
Matrix assigned to Winding Z: Matrix 12

Test Winding: Winding X
Matrix auto-selected for Winding X: Matrix Y

With the present matrices, the differential measurements are:
IOP1(pu)   IOP2(pu)   IOP3(pu)
0.00       0.00       0.00

IRT1(pu)   IRT2(pu)   IRT3(pu)
00.00      0.00       0.00

With the auto-selected matrices, the differential measurements are:
IOP1(pu)   IOP2(pu)   IOP3(pu)
0.00       0.00       0.00

IRT1(pu)   IRT2(pu)   IRT3(pu)
00.00      0.00       0.00

A-phase Values From All Matrices (Winding Z Matrix: Matrix 12)
      Matrix 1        Matrix 2
IOP1(pu)  IRT1(pu)    IOP1(pu)  IRT1(pu)
0.00      0.00        0.00    0.00

      Matrix 3        Matrix 4
IOP1(pu)  IRT1(pu)    IOP1(pu)  IRT1(pu)
0.00      0.00        0.00    0.00

      Matrix 5        Matrix 6
IOP1(pu)  IRT1(pu)    IOP1(pu)  IRT1(pu)
0.00      0.00        0.00    0.00

      Matrix 7        Matrix 8
IOP1(pu)  IRT1(pu)    IOP1(pu)  IRT1(pu)
0.00      0.00        0.00    0.00

      Matrix 9        Matrix 10
IOP1(pu)  IRT1(pu)    IOP1(pu)  IRT1(pu)
0.00      0.00        0.00    0.00

      Matrix 11         Matrix 12
IOP1(pu)  IRT1(pu)    IOP1(pu)  IRT1(pu)
0.00      0.00        0.00    0.00
```

Fig. 12 Commissioning Report

VIII. CONCLUSION

The relay uses balanced, minimum load current to detect such single-contingency CT errors as crossed phase, incorrect CT polarity, and incorrect CT ratio. Although the algorithm can be used for delta-connected CTs, delta-connected CTs increase the risk for undetected double-contingency errors.

The vector-group compensation algorithm this paper describes uses two independent compensation selection methods to calculate the correct transformer differential protection matrix combination. With this assistance, commissioning transformer differential protection is much easier for both experienced and inexperienced protection personnel.

With the commissioning report the algorithm produces, commissioning personnel can immediately and conclusively confirm the correctness of relay wiring (balanced test) and the integrity of differential element configuration settings.

When relays assist commissioning personnel during commissioning, increased relay complexity need not mean increased complexity to protection personnel.

IX. APPENDIX 1. VECTOR-GROUP COMPENSATION USING MATRIX ALGEBRA

A vector (or phasor) is a quantity with both magnitude and direction, as opposed to a scalar quantity that has magnitude only. In the rectangular form, we represent a vector (Z) as follows:

$$Z = x + jy$$

where
Z = vector
x = real component
y = imaginary component
j = √-1

In the polar form, we represent a vector as follows:

$$Z = |Z| \angle \theta$$

where

$$|Z| = \sqrt{x^2 + y^2}$$

$$\theta = \tan^{-1}\left(\frac{y}{x}\right)$$

We require only basic vector algebra to manipulate the vector quantities. For example, calculate the difference between I_A and I_B in Fig. A1.

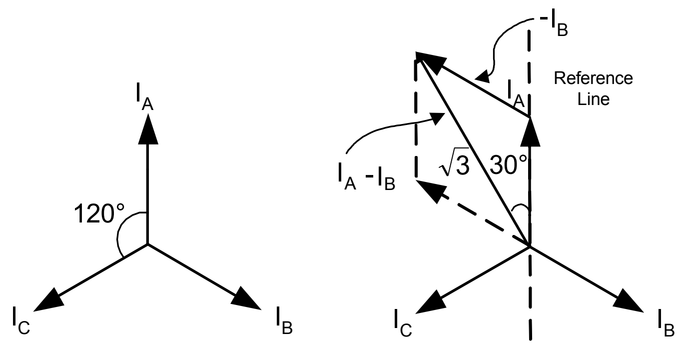

Fig. A1 Addition of Vector I_A and Vector $-I_B$

$$I_A - I_B = I_A \angle 0° - I_B \angle -120°$$
$$= \sqrt{3} \bullet I_A \ \angle 30° \text{ if } |I_A| = |I_B|$$

By dividing I_{AB} by $\sqrt{3}$, we have a vector with magnitude I_A, that is advanced by 30°. For example, to calculate the compensated values of three system currents (taking I_A as reference), multiply the three system currents (1∠0°, 1∠–120°, and 1∠120°) by matrix M1:

$$M1 = \begin{bmatrix} 1 & -1 & 0 \\ 0 & 1 & -1 \\ -1 & 0 & 1 \end{bmatrix}$$

$$\begin{bmatrix} I_{A\ COMP} \\ I_{B\ COMP} \\ I_{C\ COMP} \end{bmatrix} = \frac{1}{\sqrt{3}} \begin{bmatrix} 1 & -1 & 0 \\ 0 & 1 & -1 \\ -1 & 0 & 1 \end{bmatrix} \bullet \begin{bmatrix} 1\angle 0° \\ 1\angle -120° \\ 1\angle 120° \end{bmatrix}$$

$$\begin{bmatrix} I_{A\ COMP} \\ I_{B\ COMP} \\ I_{C\ COMP} \end{bmatrix} = \frac{1}{\sqrt{3}} \begin{bmatrix} 1\angle 0° & -1\angle 120° & 0 \\ 0 & 1\angle -120° & -1\angle 120° \\ -1\angle 0° & 0 & 1\angle 120° \end{bmatrix}$$

$$\begin{bmatrix} I_{A\ COMP} \\ I_{B\ COMP} \\ I_{C\ COMP} \end{bmatrix} = \frac{1}{\sqrt{3}} \begin{bmatrix} 1.73\angle 30° \\ 1.73\angle -90° \\ 1.73\angle -150° \end{bmatrix}$$

$$\begin{bmatrix} I_{A\ COMP} \\ I_{B\ COMP} \\ I_{C\ COMP} \end{bmatrix} = \begin{bmatrix} 1.0\angle 30° \\ 1.0\angle -90° \\ 1.0\angle -150° \end{bmatrix}$$

X. Appendix 2. Matrices

Fig. A.2 shows the 13 matrices (including M0, the unit matrix) available to the relay to determine test winding compensation.

$$M1 = \frac{1}{\sqrt{3}}\begin{bmatrix} 1 & -1 & 0 \\ 0 & 1 & -1 \\ -1 & 0 & 1 \end{bmatrix} \quad M2 = \frac{1}{3}\begin{bmatrix} 1 & -2 & 1 \\ 1 & 1 & -2 \\ -2 & 1 & 1 \end{bmatrix} \quad M3 = \frac{1}{\sqrt{3}}\begin{bmatrix} 0 & -1 & 1 \\ 1 & 0 & -1 \\ -1 & 1 & 0 \end{bmatrix}$$

$$M4 = \frac{1}{3}\begin{bmatrix} -1 & -1 & 2 \\ 2 & -1 & -1 \\ -1 & 2 & -1 \end{bmatrix} \quad M5 = \frac{1}{\sqrt{3}}\begin{bmatrix} -1 & 0 & 1 \\ -1 & 1 & 0 \\ 0 & 1 & -1 \end{bmatrix} \quad M6 = \frac{1}{3}\begin{bmatrix} -2 & 1 & 1 \\ 1 & -2 & 1 \\ 1 & 1 & -2 \end{bmatrix}$$

$$M7 = \frac{1}{\sqrt{3}}\begin{bmatrix} -1 & 1 & 0 \\ 0 & -1 & 1 \\ 1 & 0 & -1 \end{bmatrix} \quad M8 = \frac{1}{3}\begin{bmatrix} -1 & 2 & -1 \\ -1 & -1 & 2 \\ 2 & -1 & -1 \end{bmatrix} \quad M9 = \frac{1}{\sqrt{3}}\begin{bmatrix} 0 & 1 & -1 \\ -1 & 0 & 1 \\ 1 & -1 & 0 \end{bmatrix}$$

$$M10 = \frac{1}{3}\begin{bmatrix} 1 & 1 & -2 \\ -2 & 1 & 1 \\ 1 & -2 & 1 \end{bmatrix} \quad M11 = \frac{1}{\sqrt{3}}\begin{bmatrix} 1 & -1 & 0 \\ 0 & 1 & -1 \\ -1 & 0 & 1 \end{bmatrix} \quad M12 = \frac{1}{3}\begin{bmatrix} 2 & -1 & -1 \\ -1 & 2 & -1 \\ -1 & -1 & 2 \end{bmatrix}$$

$$M0 = \begin{bmatrix} 1 & 0 & 0 \\ 0 & 1 & 0 \\ 0 & 0 & 1 \end{bmatrix}$$

Fig. A2 Thirteen Available Matrices

XI. References

[1] W. A. Elmore, “Ways to Assure Improper Operation of Transformer Differential Relays,” in *1991 44th Annual Conference for Protective Relay Engineers Proceedings*.

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[3] M. Thompson, J. R. Closson, “Using IOP Characteristics to Troubleshoot Transformer Differential Relay Misoperation,” in *2001 International Electric Testing Association Technical Conference Proceedings*.

XII. Biographies

Casper Labuschagne has 20 years of experience with the South African utility Eskom, where he served as senior advisor in the protection design department. He began work at SEL in December 1999 as a product engineer in the Substation Equipment Engineering group. He earned his Diploma (1981) and Masters Diploma (1991) in Electrical Engineering from Vaal Triangle Technicon, South Africa. He is registered as a Professional Technologist with ECSA, the Engineering Council of South Africa.

Normann Fischer joined Eskom as a Protection Technician in 1984. He received a Higher Diploma in Technology, with honors, from the Witwatersrand Technikon, Johannesburg, in 1988, a B.Sc. in Electrical Engineering, with honors, from the University of Cape Town in 1993, and an M.S.E.E. from the University of Idaho in 2005. He was a Senior Design Engineer in Eskom’s Protection Design Department for three years, then joined IST Energy as a Senior Design Engineer in 1996. In 1999, he joined Schweitzer Engineering Laboratories as a Power Engineer in the Research and Development Division. He was a registered professional engineer in South Africa and a member of the South Africa Institute of Electrical Engineers.

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