

USING I_{OP} CHARACTERISTICS TO TROUBLESHOOT TRANSFORMER DIFFERENTIAL RELAY MISOPERATION

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Abstract – When a transformer differential relay operates with no obvious transformer fault, system operators have a serious decision to make. Is there a transformer fault, or did the relay operate incorrectly? Testing the transformer requires significant time, with the associated direct and indirect costs to do so. On the other hand, reenergizing a faulted transformer can lead to catastrophic equipment failure. This scenario of a questionable transformer operate occurs more often than we would like to think, particularly during the equipment commissioning process.

Several conditions can cause differential relay false tripping. These conditions can cause false trips from external faults, or simply increased transformer loading. Some indication is needed that the relay is not operating as desired before an incorrect operate happens. A potential problem can be identified by monitoring the operating condition of the differential relay. Indications provided by this monitoring can serve as a warning if the settings or connections are not correct.

This paper will explore the issues contributing to transformer differential false trips, and suggest methods to alleviate this issue.

REVIEWING DIFFERENTIAL RELAYING PRINCIPLES

When assessing relay system operation, a basic understanding of differential relay operation is necessary. A summary of the concepts follows:

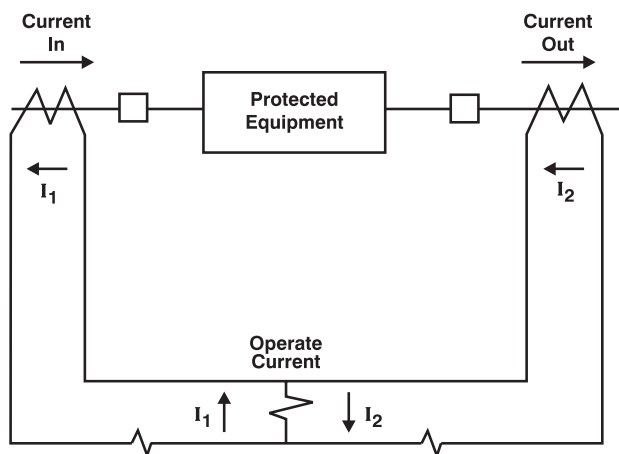


Fig. 1 General Differential Principle

Differential relaying offers the highest selectivity and, therefore, the highest speed and most secure type of system protection. In theory, a differential relay compares the currents into and out of the protected zone. If the sum of the currents is not zero, the relay will operate. This is shown in the phasor diagram, Figure 2.

The sum of the currents is identified as the operate (I_{op}) or unbalance current. The relay does not acknowledge conditions external to the protected zone. Accordingly, coordination delay times are not necessary, and sensitivity can be optimized.

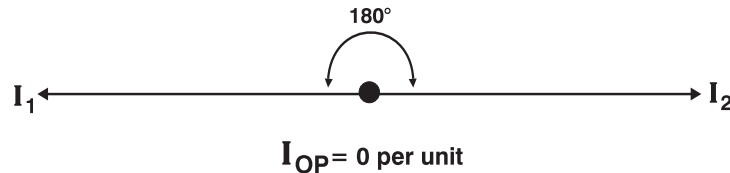


Fig. 2 Phasors of Ideal Non-Fault Condition

Differential relaying relies on the quality of the incoming currents from current transformer secondaries. Therefore, CT performance is of particular concern in this application. Although the relay must be desensitized to ensure security for all non-fault conditions, it must remain highly sensitive to faults within the zone of protection. To accomplish this, a fixed minimum pickup setting is commonly used, as well as percentage restraint. Percentage restraint increases the amount of unbalance, or operate current, needed to actuate the relay based on the current flowing through the protected equipment. The restraint setting, or slope, defines the relationship between restraint and operate currents (See Figure 3). Relays vary in the way they define the restraint value in the calculation of $I_{op}/I_{restraint}$ percentage ratio. Two common methods are to take the average of the two currents (current entering the zone and current exiting the zone) or to take the maximum of the two currents to use in the percentage ratio.

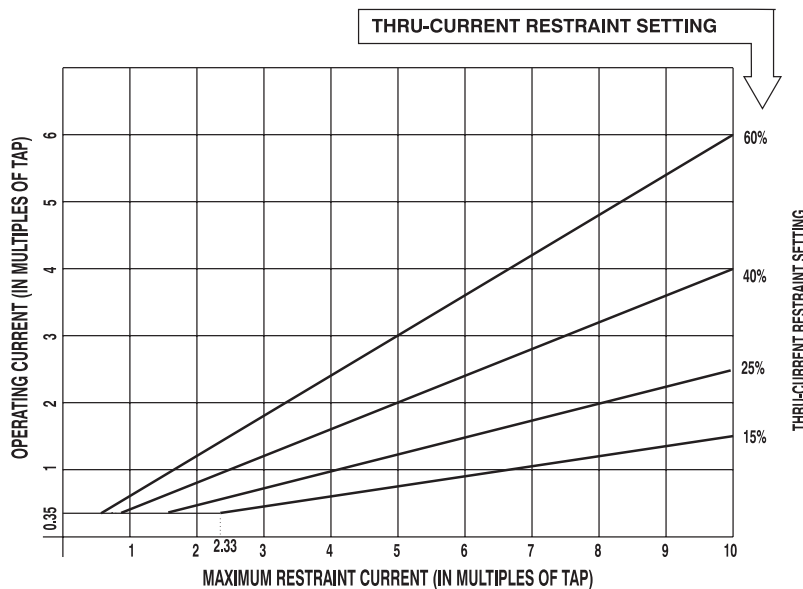


Fig. 3 Percent Restraint Characteristic

TRANSFORMER DIFFERENTIAL SPECIFICS

Transformer differential relaying does have some complications, which can be the source of errors in connections and set-up. As noted, differential relaying is based on virtually balanced current into and out of the protected zone. However, a transformer is not a balanced current device. The currents into and out of a transformer will differ by the inverse of the transformer's voltage ratio. Thus, the associated currents need to be adjusted to represent a balance during non-fault conditions. To a great extent, this adjustment can be accomplished with the selection of the system current transformers. The final balancing is accomplished in the relay's TAP settings. The TAP settings scale the input currents, effectively defining per unit values. The success of this balancing is measured by the mismatch, which is the percentage difference between the ratio of the currents seen by the relay and ratio of the relay taps.

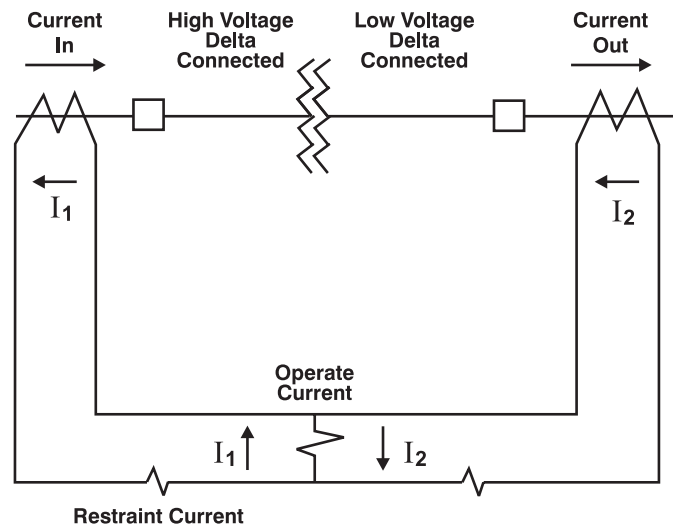


Fig. 4 Transformer Differential Relaying

There are also conditions on the power system that create unbalance currents in a transformer, but do not represent transformer faults. When system voltage is applied to a transformer at a time when normal steady-state flux should be at a different value from that existing in the transformer, a current transient occurs, known as magnetizing inrush current. The differential relay must detect energization inrush current and inhibit operation. Otherwise, the relay must be temporarily taken out of service to permit placing the transformer in service. In most instances this is not an option. The harmonics in faults are generally small. In contrast, the second harmonic is a major component of the inrush current. Thus, the second harmonic provides an effective means to distinguish between faults and inrush.

Almost every transformer differential relay available inhibits operation based on the 2nd harmonic content of the energization current. A parallel 'high set' operate level is included to ensure that larger faults will still be detected during energization. The high set, unrestrained element is also provided to ensure operation for a heavy internal fault such as a high side bushing flashover. This high grade fault may result in CT saturation, which can generate significant harmonics that may restrain the sensitive harmonic restrained element. This is shown in Figure 5.

External faults can also cause unbalanced currents in a power transformer, depending on the transformer's connections. A Wye connected transformer winding can act as a power system ground source, providing ground current to external faults. This unbalanced current must be blocked from the differential circuit to ensure relay security. This blocking is usually achieved by a Delta connection in the associated relay input transformer circuit, which traps the zero sequence (ground) current component. This delta connection can be achieved either with the current transformers, or, if an option, within the transformer differential relay itself.

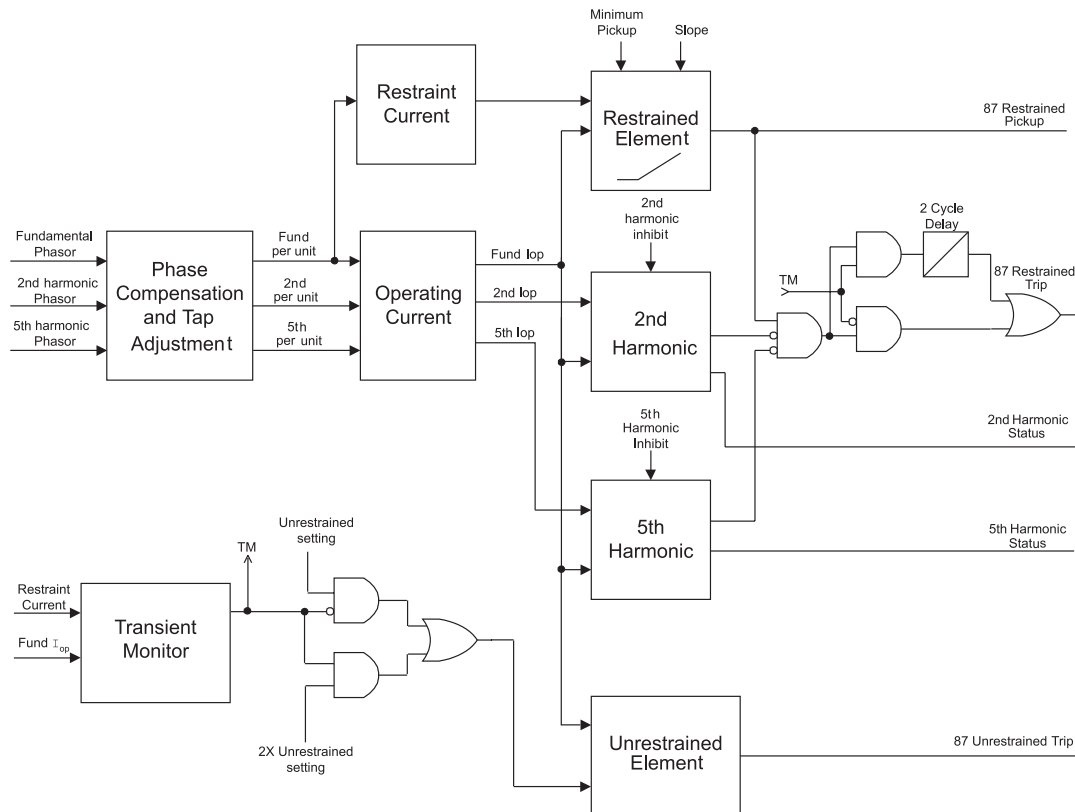


Fig. 5 Simplified Block Diagram

An important issue with transformer differential relaying is the phase shifts inherent in most transformer connections. A delta connection in a power transformer affects a 30° phase shift in the associated currents. Since the differential relay compares the currents on an instantaneous basis, this phase shift will create an unbalance, which must be compensated. This compensation is usually achieved with a corresponding delta connection in the CT secondary circuits and must be coordinated with any zero sequence blocking connections required.

Many transformers are connected with delta windings on the high side and wye windings on the low side. This provides isolation between the power system voltages and a ground source for detecting faults on the low voltage side. The three-line drawing, Figure 6, shows a delta/wye

transformer with the associated phase shifts. In this example, the phase shift is accomplished by connecting the CT's on the wye side in a delta configuration. The required phase shift compensation can also be accomplished within the differential relay. This is desirable for several reasons. Probably the most important of these is that it allows the CT's to be connected in wye, making them easier to connect and verify during installation.

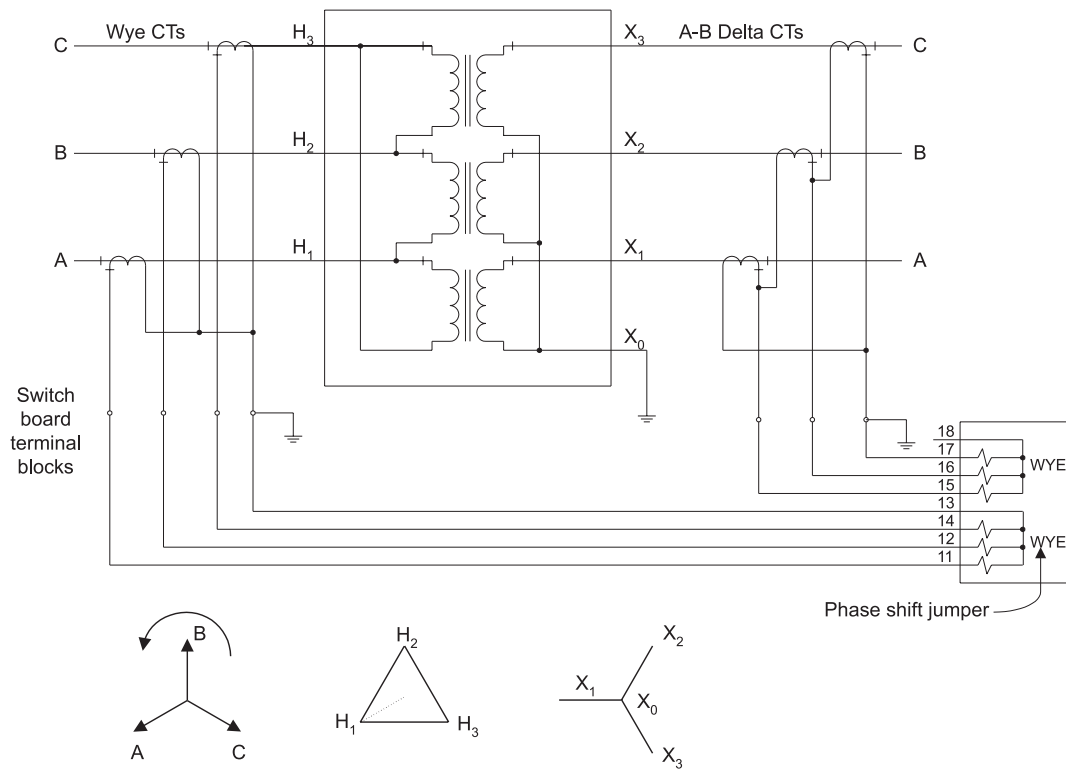


Fig. 6 Phase Shifts in Transformers

The presence of a Load Tap Changer (LTC) in transformers will also affect differential relay operation. Usually, these taps provide the possibility of modifying the voltage ratio 10% for voltage or Var control. This ratio variance, in turn, varies the current ratios. This variation is usually within the security margin provided by the relay's restraint characteristic. For a given LTC position, the ratio of operate current to restraint current will remain constant, as shown in Figure 7.

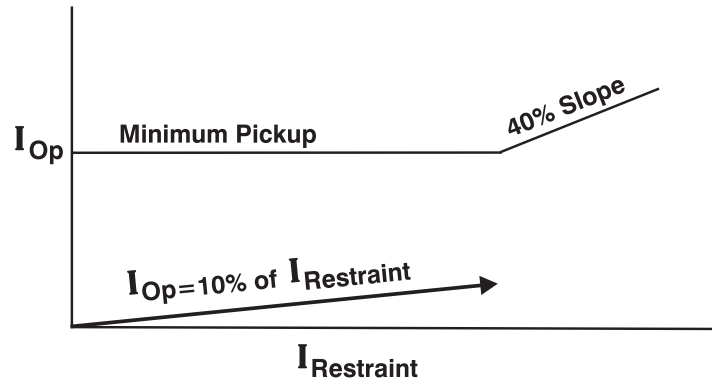


Fig. 7 Operate Characteristics with Proper Configuration (10% Mismatch)

CONNECTION CONCERNS

Almost all nuisance trips associated with transformer differential relay applications can be attributed to incorrect relay settings or CT connections or mismatch. During a through-fault condition, the differential operating current due to mismatch can approach the current rating of the transformer. These typical mistakes will be discussed, along with their effects on relay performance.

For each case discussed, the TAP settings are presumed to be set to the transformer's full load current. This defines the 1 per unit value to be equal to full load. This is the easiest setting to calculate, and simplifies analysis. The minimum pickup of the transformer differential relay is taken as 0.35 times TAP for this discussion, or when $I_{op} = 35\%$ of transformer full load, given the defined setting. A restraint slope of 40% of maximum restraint current is assumed. The % of Maximum characteristic is preferred because it uses information from the *best* performing CT to restrain the relay. A relay using % of Average restraint current would provide different results but the concepts are the same. In modern numerical differential relays, the restraint characteristic may be user-selectable.

SINGLE RESTRAINT INPUT

If one set of current transformers is not connected to the differential relay or the current transformers are shorted out, the differential relay acts as an overcurrent relay. Given this scenario, $I_{op} = I_{restraint}$.

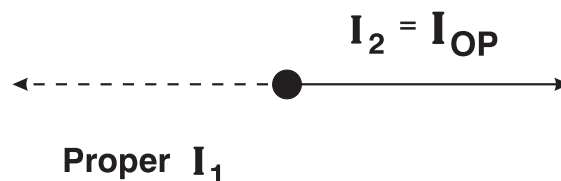


Fig. 8 Transformer Differential Phasors with Missing Input Current

When the single input current exceeds the minimum pick-up the relay will operate. So for this scenario, the transformer will trip at 35% of full load under this condition.

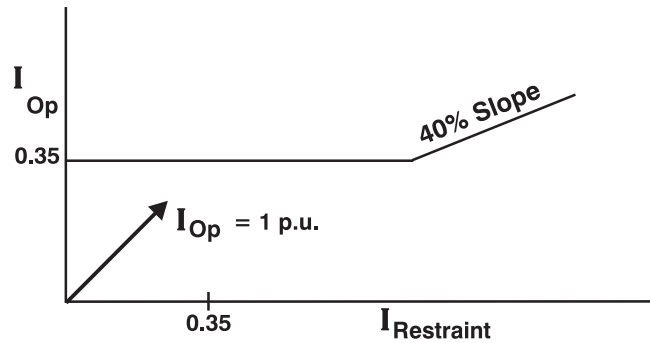


Fig. 9 Operate Characteristic with Missing Input Current

CURRENT TRANSFORMER LEAD REVERSAL

Reversing a current transformer lead, or group of leads, is the simplest mistake made when wiring a new panel or upgrading a protection system. Since the differential relay compares the transformer currents, CT polarity is extremely important. When a CT lead is reversed, the resulting unbalance current is double the normalized load current. That is $I_{op} = 2 * I_{load}$. Assuming balanced currents (proper TAP settings), $I_{op} = 2 * I_{restraint}$. This is shown in the phasor diagram, Figure 10.

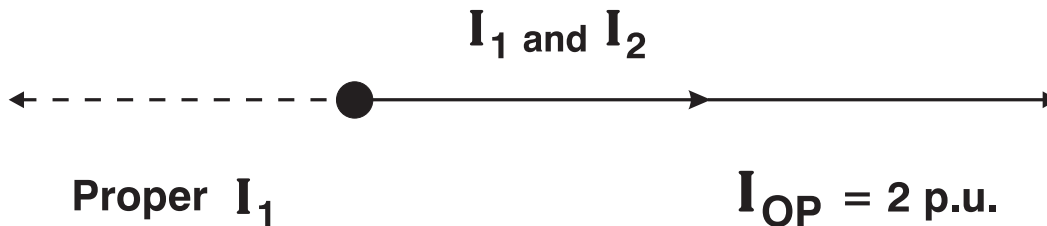


Fig. 10 Transformer Differential Phasors with Reversed Input Current

Under this condition, increased loading will cause the relay to operate. This operation will occur when I_{op} exceeds 35% of transformer full load (based on the setting presumptions). This will be when the load (restraint) current reaches 17.5% of full load (or 17.5% of TAP setting). This condition is plotted on the characteristic graph in Figure 11.

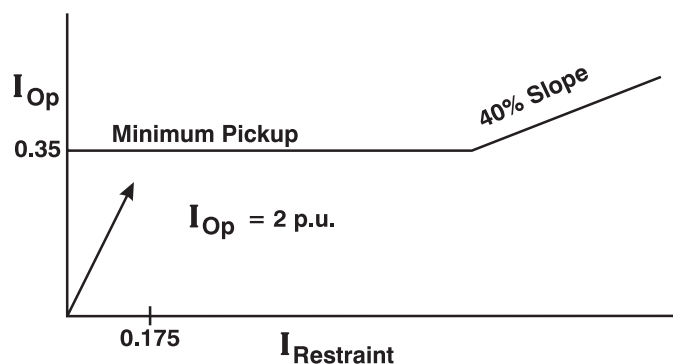


Fig. 11 Operate Characteristic with Reversed Input Current

PHASE SHIFT COMPENSATION

There are two problems that can occur with phase shift compensation. The engineer performing the work can forget to apply compensation, or compensation can be incorrectly applied.

When a transformer includes a phase shift, a corresponding adjustment **must** be made in the relay scheme. This is generally accomplished by connecting the relay input currents in delta, and can be done either at the CT inputs or within the relay's circuitry. The proper correction is shown in phasor diagram in Figure 12.

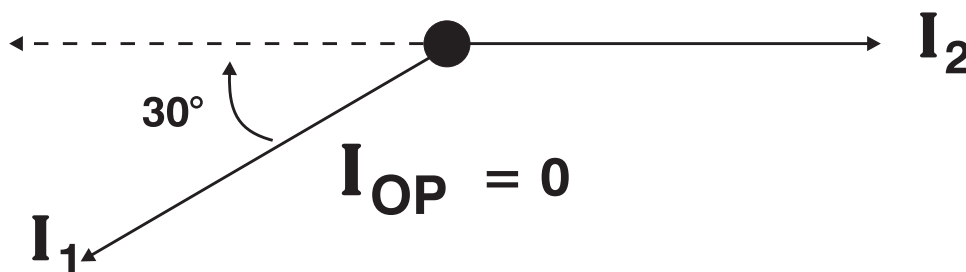


Fig. 12 Transformer Differential Phasors with Proper Phase Shift Adjustment

If phase shift compensation is not performed when the application requires it, there will be a resulting I_{op} in the relay. As load increases, the relay will begin to see an unbalance. The differential relay will interpret this unbalance as a fault and operate. Phasor analysis, Figure 13, shows that an uncompensated 30° phase shift will cause an unbalance current which is approximately half the normalized load current. That is $I_{op} = 0.5 * I_{load}$.

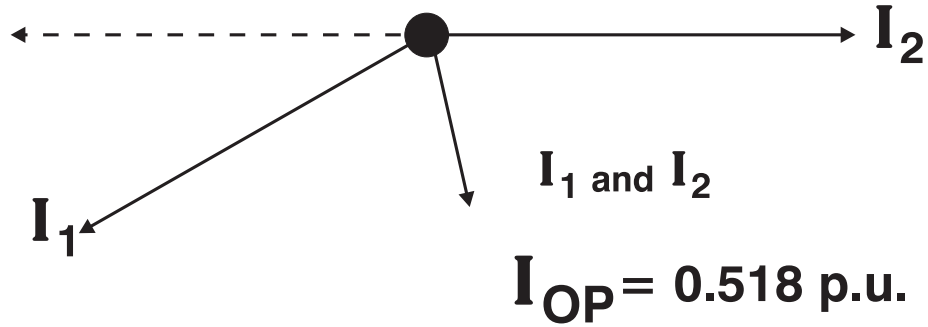


Fig. 13 Phasor Diagram with Missing Phase Shift

If this condition exists, the relay will operate with increases in load, unless the restraint slope setting is larger than 50%. The relay will operate when I_{op} exceeds 35% of transformer full load (based on the previous setting presumptions). This will occur when the load (restraint) current reaches 68% of full load (or 68% of TAP setting). Figure 14 shows this situation.

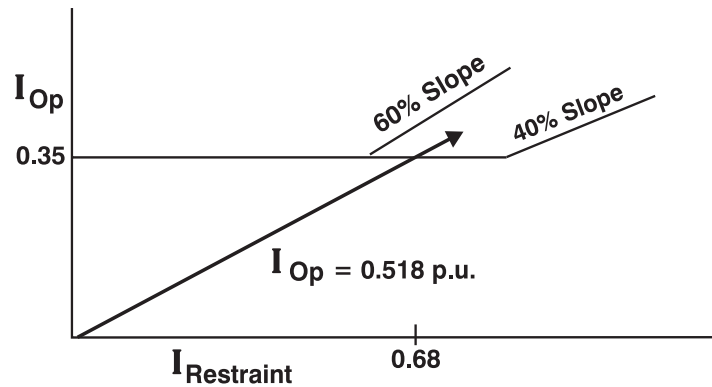
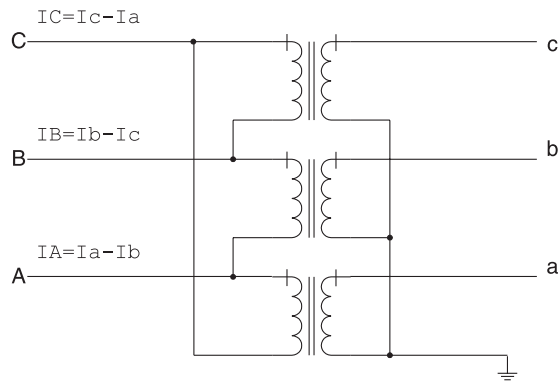
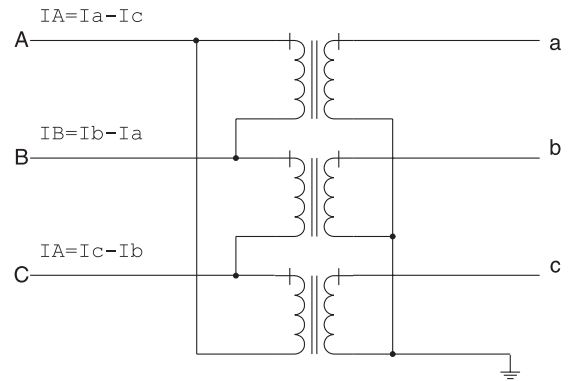


Fig. 14 Relay Operate Characteristic with Missing Phase Shift

Another error can occur by incorrectly applying a phase shift. For example, shifting the relay input on the delta side of a delta/ye transformer. While the required phase angle adjustment is achieved, the necessary zero sequence blocking is not provided. In this case, the differential relay will operate for external ground faults on the wye side of the transformer. This condition is not detectable by taking readings under balanced loading conditions. The other incorrect shift is a phase shift in the wrong direction.



Ia-Ib Delta



Ia-Ic Delta

Fig. 15 Two Delta Applications

As shown in Figure 15, there are two ways to apply a delta connection. Each affects a 30° phase shift, but in different directions. If the wrong connection is applied, it will result in a 60° difference rather than proper phase compensation. Again, this will cause a non-fault, or false, I_{op} , and the relay will operate with increasing load. Phasor analysis, Figure 16, shows that a 60° difference in the relay currents will cause an unbalance current equal to the normalized load current. That is $I_{op} = 1 * I_{load}$.

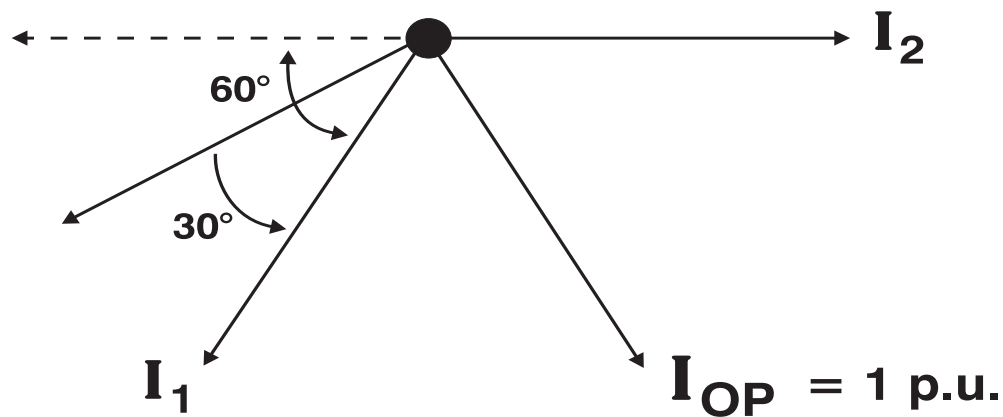


Fig. 16 Phasor Diagram with Wrong Phase Shift

The relay will operate when the load (restraint) current reaches 35% of full load (or 35% of TAP setting) as shown in Figure 17. This is a similar level of load to the scenario where one side of the differential zone is completely missing as shown in Figure 9.

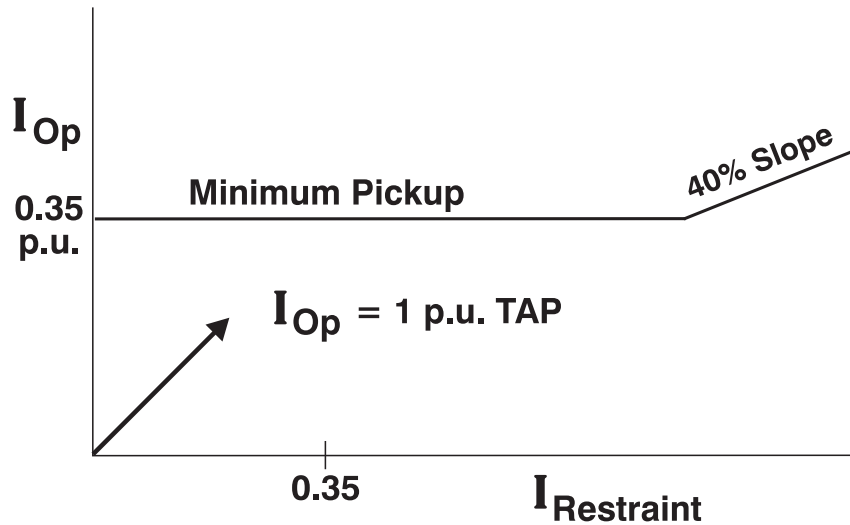


Fig. 17 Operate Characteristic with Wrong Phase Shift

TRANSPPOSED TAP SETTINGS

Incorrect TAP settings can occur when the TAP settings for the relay are transposed. That is, the high side TAP setting is applied to the low side input, and vice versa. The resulting relay performance will depend on how closely matched the current signals into the relay are. If the currents into the relay are very close, the TAP settings will also be similar, and relay security may not be affected. However, if the inputs are substantially different, the resulting unbalance will likely cause the relay to operate and cause a nuisance trip.

For example, presume a condition where the currents to the relay are 3.8 amps on the high side and 4.2 amps on the low side. The proper relay TAP settings would be 3.8 for the high side input and 4.2 for the low side input. If the settings are transposed, the current magnitudes will be incorrectly scaled. This results in a mismatch of 22%, as shown below.

$$\text{Mismatch} = \frac{(\text{current ratio}) - (\text{TAP ratio})}{\text{smaller of above}}$$

with proper settings:

$$\text{Mismatch} = \frac{(3.8/4.2) - (3.8/4.2)}{(3.8/4.2)} = 0\%$$

with transposed settings:

$$\text{Mismatch} = \frac{(3.8/4.2) - (4.2/3.8)}{(3.8/4.2)} = 22\%$$

In this example, the security of the relay will depend on the setting of the restraint slope. At a slope setting of 15%, the relay will operate on increasing load, when the I restraint exceeds about 1.6 multiples of TAP or at 160 % of transformer full loading. At a slope setting of 40%, it would not operate on load. However, the security margin would be reduced by this mismatch. Figure 18 shows this example.

√3 FACTOR NEGLECTED IN TAP SETTINGS

Another TAP setting problem that can occur is to overlook the magnitude increase associated with a delta connection in the current circuit. This is a by-product of the phase shift adjustment, and must be taken into account. The magnitude shift is the square root of 3, or 1.73. This magnitude compensation must be included if the delta compensation is achieved with CT connections. It may or may not be required if the delta compensation is achieved internal to the relay. Care must be taken to review the operating characteristics of the relay in question when calculating tap factors. This problem is mitigated in some numerical relays that are capable of automatically calculating their own tap adjust factors.

Using the previous example of 3.8 and 4.2 as the currents into the relay, assume that the 4.2 amps current requires a phase shift. The delta compensated 4.2 amps is now effectively $4.2 \times 1.73 = 7.3$ amps for the differential element. Thus, for the delta side of the transformer, 3.8 amps = 1PU and, for the wye side of the transformer 7.3 amps = 1PU. The proper current ratio is now (3.8/7.3) rather than (3.8/4.2). If the protection engineer overlooks this, the resulting mismatch will be:

$$\text{Mismatch} = \frac{(3.8/7.3) - (3.8/4.2)}{(3.8/7.3)} = 73\%$$

This will clearly cause a problem. The relay will operate at 48% of transformer full load current in this case. The effect of this setting error is shown in Figure 19.

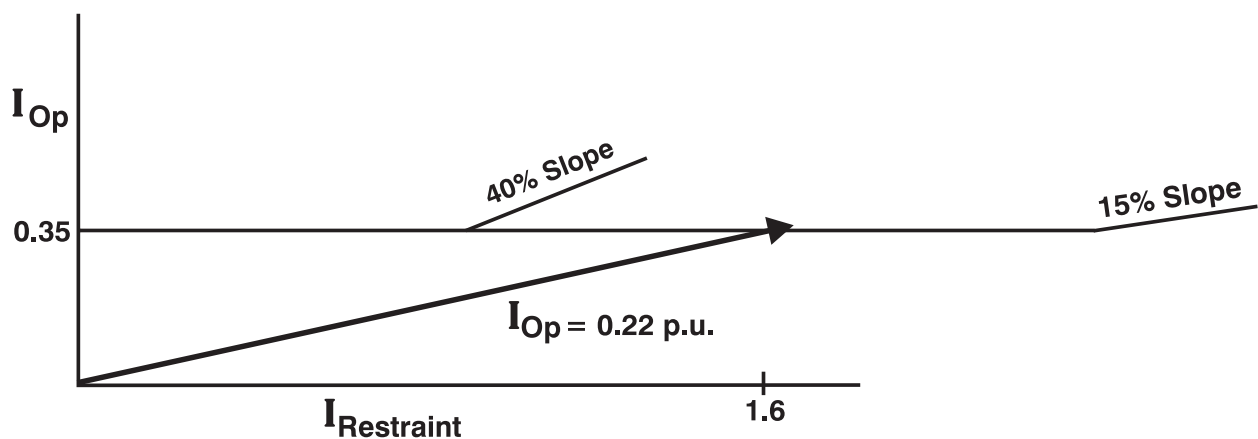


Fig. 18 Characteristic with Transposed Tap Settings

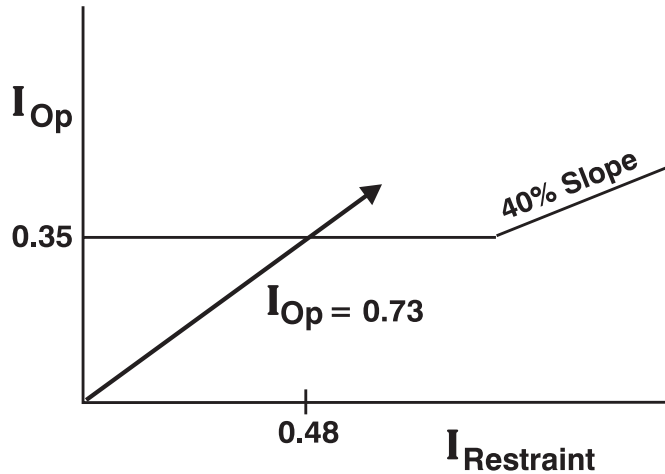


Fig. 19 Relay Operate Characteristic with Missing $\sqrt{3}$ Factor in Taps

CHECKING AND TROUBLESHOOTING DIFFERENTIAL CIRCUITS

Field personnel can apply the lessons noted in this paper in order to troubleshoot CT connections and rectify problems. For example, a quick simple check of measuring the current in the operate coil of the differential relay may be sufficient to detect the gross problems described such as reversed polarity or one CT completely missing. However, many of the problems identified result in relatively small mismatches.

This check also does not acknowledge the fact that the relay can adjust for magnitude mismatch by its tap settings. For example, a properly designed differential relay circuit with one tap set at 5 amps and the other set at 10 amps would result in 5 amps of operate current under full load balanced conditions. On one side of the zone 5 amps = 1PU, while on the other side of the zone 10 amps = 1 PU. In electromechanical relays, $I_{operate}$ is the sum of the currents, which would be 10 - 5 = 5 amps for this example.

A better approach is to measure and record both the magnitude and angle of the restraint currents at each terminal of the relay. For example, the criteria should be:

- The ratio of the magnitudes of the restraint current on each phase should be equal to the ratio of the magnitudes of the tap settings.

$$\frac{High_Side_Current}{Low_Side_Current} = \frac{High_Side_Tap}{Low_Side_Tap}$$

- The currents on each phase relay should be nearly exactly 180° out of phase.

DIFFERENTIAL CURRENT MONITORING AS A DIAGNOSTIC TOOL

Modern relays with internal phase compensation do not allow the field engineer to do it the old way with phase angle and magnitude readings. It is necessary to see the values seen by the differential element after they have been manipulated inside of the relay, and this cannot be done by direct measurement. Other methods must be employed.

As this paper has noted, there are many connection or setting problems that can cause incorrect operations in transformer differential relays. The task is to detect these problems before an incorrect relay operation. Differential current monitoring is a diagnostic function designed to aid in the installation and commissioning of differential relays especially on transformer banks. This function attempts to identify and prevent false trips due to incorrect polarity, incorrect angle compensation, or mismatch.

During transformer commissioning, it would be particularly useful to analyze the system installation and create a record of the settings and measured currents. The differential current monitoring function can create a differential check record like the sample shown in Figure 20. These records are also useful when comparing the present system characteristics to the characteristics at commissioning during troubleshooting to determine if something has changed.

The differential check record shown in Figure 20 is an example of a differential current check record developed by a numerical differential relay. This particular example is from an actual installation. The names and dates on the record have been changed. Upon putting load on the transformer bank after installing the upgraded protection, the differential relay alarmed, triggering the diagnostic routine to generate this report, and tripped. The relay's trip outputs were not connected at the time.

The first grouping of information in the record is the date and time the record was captured and the basic relay identification. The second grouping is a record of the CT and transformer connection settings and the 87 (differential) settings that were entered by the user. The third grouping is a report of the tap and angle compensation factors that the relay is using for each of the three phase CT input circuits. It is important to note that the angle compensation cannot be entered manually. The angle compensation is calculated by the relay based on the CT and transformer connections. Additionally, the tap compensation setting may be entered manually or automatically calculated.

As mentioned earlier in the paper, a transformer delta winding can be configured in two ways: Delta IA-IB or Delta IA-IC. The type of delta and the normal phase sequence of the system determines whether the phase shift will be +30 degrees or -30 degrees. From the information in the report, it can be noted that the user has described the transformer winding connected to CT circuit 1 of the relay as a delta with DAB (Delta IA-IB) connections; and, the transformer winding connected to CT circuit 2 of the relay is described as a wye configuration. This would be a pretty safe assumption based on the fact that an ANSI standard delta high-side/wye low-side transformer uses this configuration so that the low side lags the high side by 30 degrees when system phase sequence is ABC.

The fourth grouping of information in the record attempts to identify polarity and angle compensation errors by looking at the phase angle differences of compared phases. The differential alarm is set whenever the minimum pickup or the slope ratio exceeds the differential alarm, percent of trip setting. If the differential alarm is set and neither the polarity alarm or angle compensation alarm is set, a mismatch error is identified indicating that the most likely cause of the alarm is incorrect tap settings. In this example, the record clearly identifies that the problem appears to be with the angle compensation.

The fifth grouping of information (MEASUREMENTS) displays the measured and calculated currents at the time of the differential record trigger. The relay measures secondary current and develops the tap and phase compensated currents for use by the differential element. Primary current (MEASURED I PRI) is calculated simply as the secondary current multiplied by the CT turns ratio. Secondary current (MEASURED I SEC) is the current actually measured by the relay. Angle compensated current (ANGLE COMPENSATED I) is the measured secondary current with phase compensation applied. Tap compensated current (TAP COMP I) is the tap and phase compensated current actually used by the differential function. From this information, it is easy to see how the relay goes about compensating for magnitude and angle differences between the two sides of the zone of protection.

The final two lines of the report give the most critical information. IOP is the operating current. SLOPE RATIO is the ratio of IOP to the restraint current (in this case it is the maximum of the two TAP COMP I currents). These values should be compared to the settings shown earlier in the report to determine if the relay is in a trip or alarm condition.

Figure 21 shows the A phase currents before and after compensation plotted on a polar graph. From the information in Figures 20 and 21, it is easy to see that the internal phase compensation is the opposite of what it should be and that the currents were shifted 30 degrees the wrong way. In this installation the transformer being protected was actually a delta IA-IC/wye configuration and that the low side leads the high side by 30 degrees. Changing the transformer connection parameters in the relay's settings, corrected the problem.

This facility of modern relays can also be used to simplify commissioning and documentation. To verify correct CT circuit connections, internal phase, zero sequence and tap compensation settings for the differential functions, load should be placed on the protected zone and a differential check record triggered, recorded, and examined. The check record can then become a permanent relay commissioning record.

SUMMARY

Differential protection is simple in concept. Measure the current that goes in versus what goes out. If there is a difference, there must be a short circuit within the protected zone and a trip should occur. When the protected zone includes a transformer, the situation is not so simple and special considerations must be made. One of the greatest challenges is compensation for phase

angle and magnitude differences. The paper describes the effects of many of the possible errors that can be made in installing and checking out a transformer differential circuit.

Proper installation checks and final in-service readings can detect these problems and ensure reliable and secure operation. The paper describes these traditional final in-service checks. However, with modern solid state and numerical differential relays, traditional checkout procedures may not be capable of detecting all possible errors. For this type of relay, diagnostic routines and reporting functions can make up for this. It is important for the relay technicians and engineers to make use of these advanced features to ensure proper operation of the protection system.

Annotated Differential Check Record

DIFFERENTIAL CHECK RECORD

REPORT DATE : 11/10/2000
 REPORT TIME : 10:12:42.701
 STATION ID : BILLS_SUBSTATION
 RELAY ID : BANK-T1
 USER1 ID : WESTERN_DIVISION
 USER2 ID : WATTS_&_MORE_ELECTRIC_CO
 RELAY ADDRESS : 0
 ACTIVE GROUP : 0

87 SETTINGS	CTR	CT CON	TX CON	GROUNDED
CT CKT1	240	WYE	DAB	NO
CT CKT2	400	WYE	WYE	YES
MINPU	0.20	*TAP		
SLOPE	25	%		
ALARM	50	%		
URO	6	*TAP		

P0004-18.vsd
09-22-00

COMPENSATION	Angle	Tap
CT CKT1	WYE	3.12
CT CKT2	DAB	4.68

ALARMS	PHASE A	PHASE B	PHASE C
DIFFERENTIAL:	ALARM	ALARM	ALARM
POLARITY:	OK	OK	OK
ANGLE COMP:	ALARM	ALARM	ALARM
MISMATCH:	OK	OK	OK

MEASUREMENTS	PHASE A	PHASE B	PHASE C
MEASURED I PRI			
CT CKT1:	206 @ 0	202 @ 240	204 @ 121
CT CKT2:	516 @ 211	508 @ 91	516 @ 332
MEASURED I SEC			
CT CKT1:	0.86 @ 0	0.84 @ 240	0.85 @ 121
CT CKT2:	1.29 @ 211	1.27 @ 91	1.29 @ 332
ANGLE COMPENSATED I			
CT CKT1:	0.86 @ 0	0.84 @ 240	0.85 @ 121
CT CKT2:	1.29 @ 241	1.27 @ 122	1.29 @ 2
TAP COMP I			
CT CKT1:	0.27 @ 0	0.27 @ 240	0.27 @ 121
CT CKT2:	0.27 @ 241	0.27 @ 122	0.27 @ 2
IOP:	0.28 *TAP	0.28 *TAP	0.28 *TAP
SLOPE RATIO	104 %	104 %	104 %
>			

Examine

Plot these
currents

0.27 @ 0
0.27 @ 241

0.27 @ 240
0.27 @ 122

0.27 @ 121
0.27 @ 2

0.28 *TAP

0.28 *TAP

0.28 *TAP

Figure 20 Annotated Differential Check Record

In-Service Current Circuit Verification Form

Time and Date: 11/10/2000

Station ID: Bills Substation

Relay ID: Bank T1

User1 ID: Western Division

User2 ID: Watts & More Electric Co.

Trigger Differential Check Record

To trigger and retrieve a current check record, use the following commands:

A=

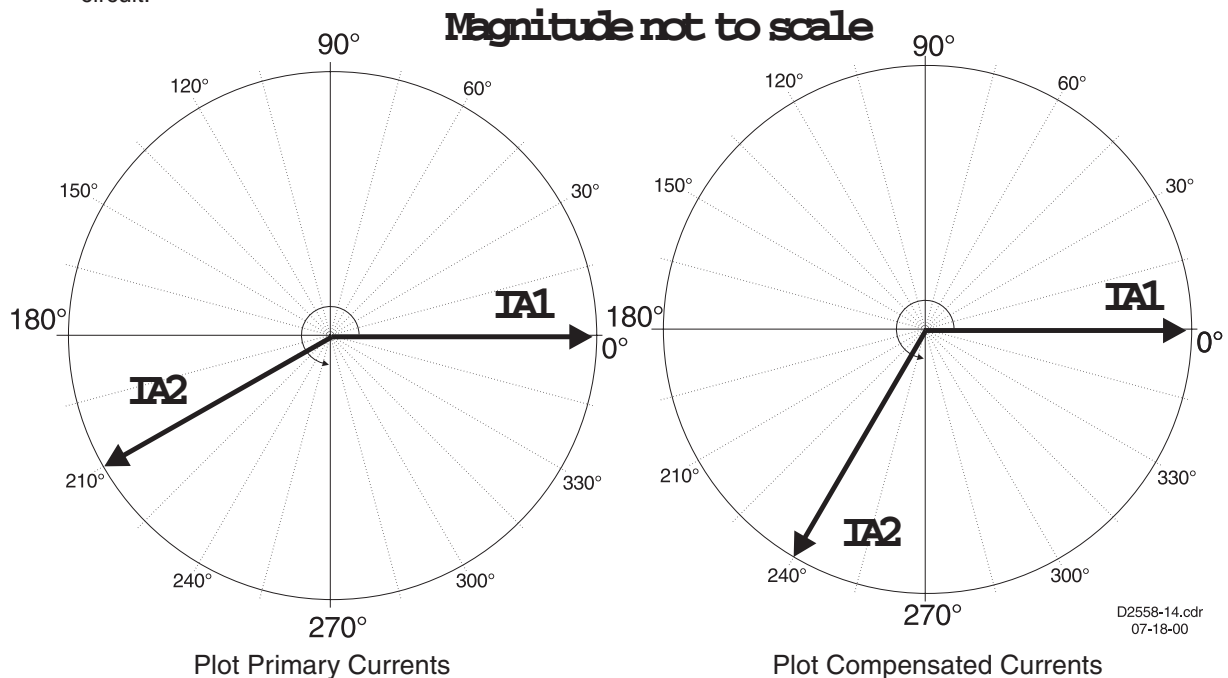
RA-DIFF=TRIG

RA-DIFF

A Phase only plotted

Examine Differential Check Record

1. Examine the *Measurements* portion of the report. Plot on the appropriate polar graph, the currents under the differential check record lines *Measured I Pri* and *Tap Comp I* for each phase and CT input circuit.



2. Examine the plotted currents.

X Is the phase sequence for both CT circuits the same as expected?

X Does the phase sequence match the phase sequence setting (SG-PHROT) or HMI screen 6.3.3?

NO Examine the angle and tap compensated currents on the polar graph from the line labeled *Tap Comp I*. For each phase, determine if the currents are approximately the same magnitude for each CT input circuit and approximately 180 degrees out of phase? Some small amount of mismatch is expected due to excitation and possible LTC or other tap adjust differences.

3. Examine the *Alarms* portion of the report.

Yes The line marked *Differential* will report *Alarm* for any phase where the differential current is above the alarm threshold on that phase.

Alarm The lines marked *Polarity*, *Angle Comp*, and *Mismatch* will report *Alarm* or *OK* as determined by the current circuit diagnostic function if the currents are above the minimum sensitivity. The diagnostic function for these lines operates even if the differential current is not above the alarm threshold.

Figure 21 In-Service Current Circuit Verification Form

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