Considerations and Experiences in Implementing Ground Differential Protection for Transformer Protection at TVA

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ABSTRACT

This paper discusses the installation of and operational experience with ground differential protection (sometimes referred to as restricted earth fault or restricted ground fault) on power transformers at TVA. In the early 2000s, to improve transformer protection, TVA decided to include the ground differential protection function on grounded wye-connected winding (impedance grounded as well as solidly grounded) for all power transformers on new installations as well as relay retrofit installations. For ground faults near the neutral of a grounded wye winding of a transformer, the percentage phase differential protection function may not have the sensitivity to detect and clear this fault. The ground differential protection function is used to sensitivity detect ground faults near this location.

However, since the implementation of this protective function, TVA has experienced 11 erroneous trips. This paper will discuss misoperations that resulted from incorrect designs as well as due to incorrect installations with inadequate verification testing.

INTRODUCTION

In most cases, power transformers are the most expensive asset in a switchyard or substation. To protect this valuable equipment, various schemes are employed to prevent catastrophic transformer failure due to abnormal electrical and mechanical operating conditions. Transformer failures due to abnormal electrical operation conditions include overload, internal or external short circuit, overvoltage, and overexcitation.

The differential protection scheme provides the fastest clearing time to minimize the damage to the power transformer during an internal short circuit condition. The differential scheme compares the currents entering and leaving the protected zone of the windings of the transformer. The sum of those currents should almost be zero, excluding losses. If the sum of the currents exceeds a pre-determined value, this indicates a fault condition within the protection zone of the transformer.

Phase differential relays compare the sum of the phase currents entering and leaving the windings of the transformer. It is used to detect phase and ground faults within the protected zone of the transformer. Due to the turns ratio and the phase angle transformation of the transformer windings, the secondary currents from either of the windings will need to be compensated so that the sum of the compensated currents will be as close to zero as possible.

Ground differential relays are used to detect ground faults within the grounded wye winding of a transformer. For ground faults near the neutral end of the grounded wye winding of a transformer, the phase differential relay may not have the sensitivity to detect this condition. This is especially true when the winding is grounded through a resistor or reactor. Ground differential relays compare the winding residual ground current, 3I0, and the neutral current, IN, of the grounded wye winding of the transformer.

The concept of the differential protection for a power transformer is fairly simple and straightforward. It is very important to perform all the necessary field commissioning tests to verify that the installation of the protective relaying circuit agrees with the intent of the design. When the power transformer is initially placed in service, online readings can confirm the correctness of the installation. The online readings will show if the compensating settings and phase connections on the relay are correct. However, most of the time the online readings cannot verify the validity of the ground differential relaying circuit, because under normal conditions there will not be enough unbalanced current present.

This paper summarizes the misoperations TVA has experienced with ground differential protection of the power transformer. The majority of misoperations resulted from mistakes in the design phase. Field commissioning tests would have caught the design mistakes, but there were challenges on performing the field verification test. Also, the online readings were not or could not be obtained to verify the ground differential protection scheme.

DIFFERENTIAL PROTECTION FOR POWER TRANSFORMER

Phase Percent Differential Protection

The fundamental concept of current differential protection is straightforward. Under normal loading conditions, as well as during external fault conditions, the sum of the currents entering and leaving the differential protective relaying circuit should be zero. This percentage differential concept is illustrated in Figure 1.

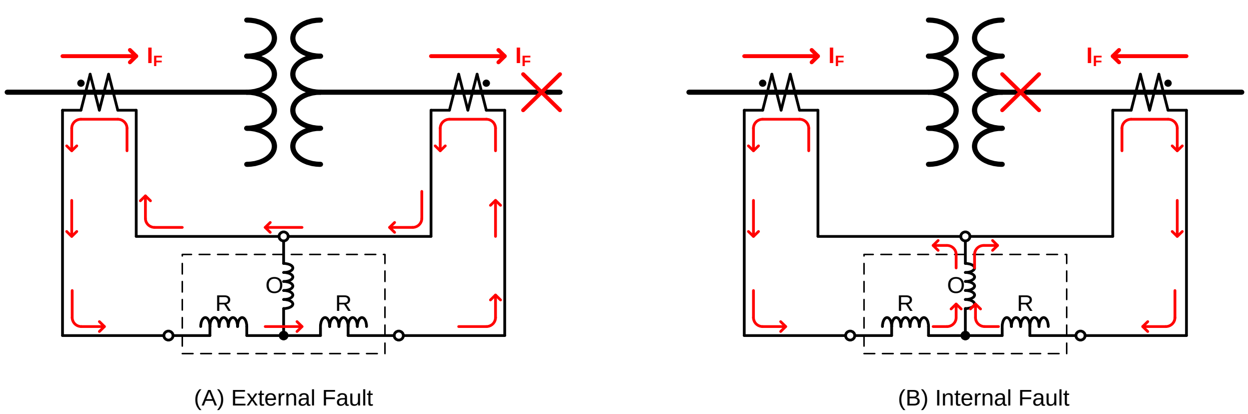


Figure 1: Simplified Current Differential Protection for Power Transformer

In Figure 1 (A), the fault is external to the protective zone, so fault current enters and leaves the zone of protection. The secondary current only flows through the restraining coils, and not through the operating coil. For faults within the protected zone, as shown in Figure 1 (B), the secondary current flows through the operating coil, as well as the restraining coils. For power transformer differential protection, due to the transformer turns ratio tap range, auto tap changer, losses, variation of transformer connections, and CT error, it is impossible to choose a readily available CT ratio where the secondary current would be perfectly balanced during normal loaded condition and for external fault condition. Compensating circuit or relay settings are used to minimize this mismatch. There will always be some current flowing through the operating coil. Restraining coils are used to provide a percentage differential characteristic with an opening "torque" on the trip contacts. The current flowing through the operating coil has to exceed a certain percentage of the current flowing through either of the restraining coils to overcome this opening "torque" and produce a trip. This characteristic is frequently referred to as the "slope".

Ground Differential Protection

This phase percentage differential protection scheme provides effective detection of most faults within the transformer zone of protection. However, it may not have the sensitivity to detect some ground faults near the neutral of the grounded wye-connected winding. This is especially true for wye-connected windings that are grounded through an impedance. Figure 2 illustrates a ground fault near the neutral of a solidly grounded wye-connected winding transformer.

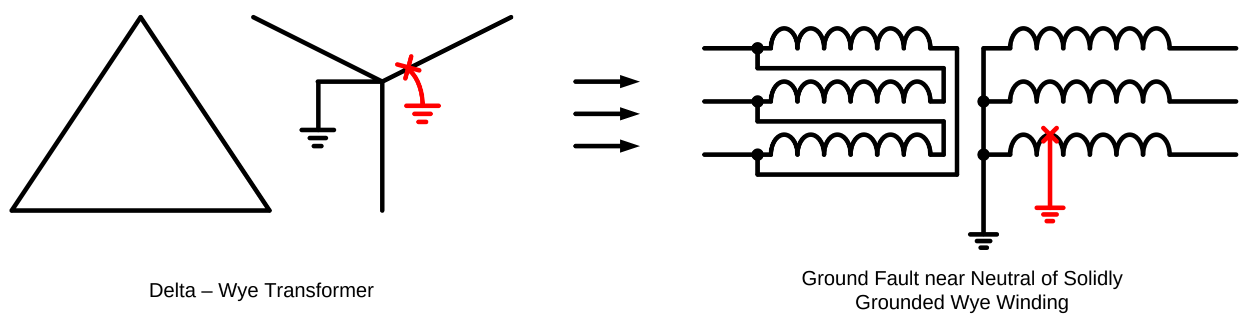


Figure 2: Ground Fault on a Solidly Grounded Wye Winding Transformer

For a ground fault near the neutral of a solidly grounded transformer, the fault current circulating between the fault point and the neutral can be significant. This is due to the small impedance between the fault point and the neutral conductor. However the terminal phase current for this fault is relatively small and the percentage phase differential relay may not detect this ground fault until the fault has evolved into a more substantial fault causing further damage to the transformer. For a fault near a solidly grounded wye-connected winding, the relationship between the neutral current and primary phase current is illustrated in Figure 3 [1].

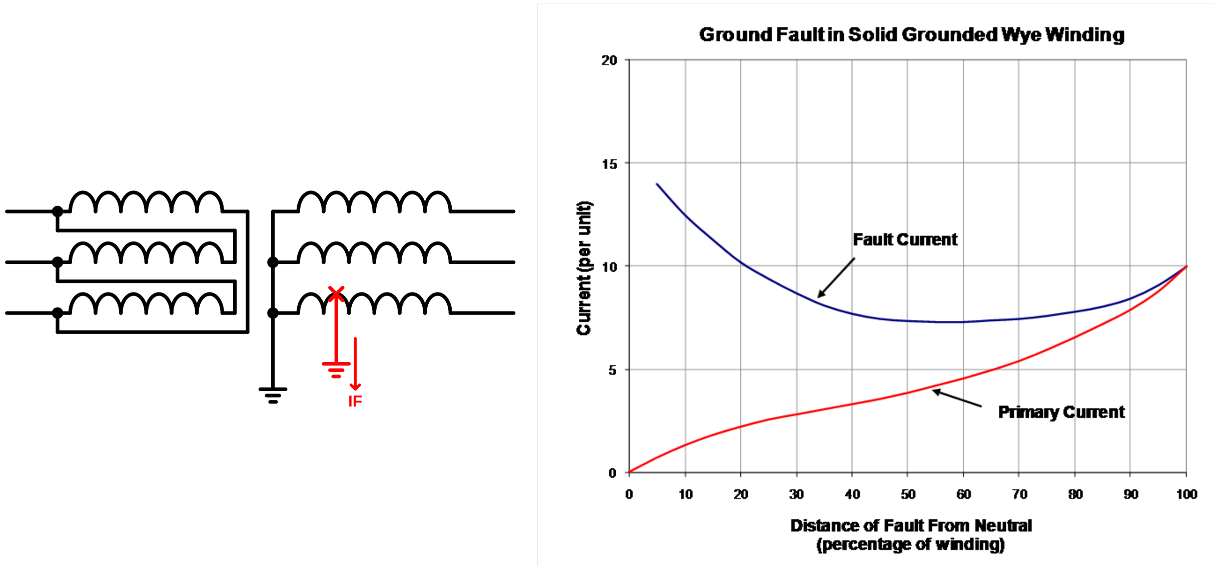


Figure 3: Fault Currents for Solidly Grounded Wye-Connected Transformer

For a wye-connected winding with impedance grounding, the fault current circulating through the neutral is linear with respect to the location of the fault. This is because the impedance of the neutral resistor or reactor dominates the winding impedance. For ground faults in the lower 30% of the winding, the primary phase fault is negligible [2]. The phase differential relay will not be able to detect this fault condition. Figure 4 shows the relationship of the currents vs. the fault location for an impedance grounded wye-connected transformer [1].

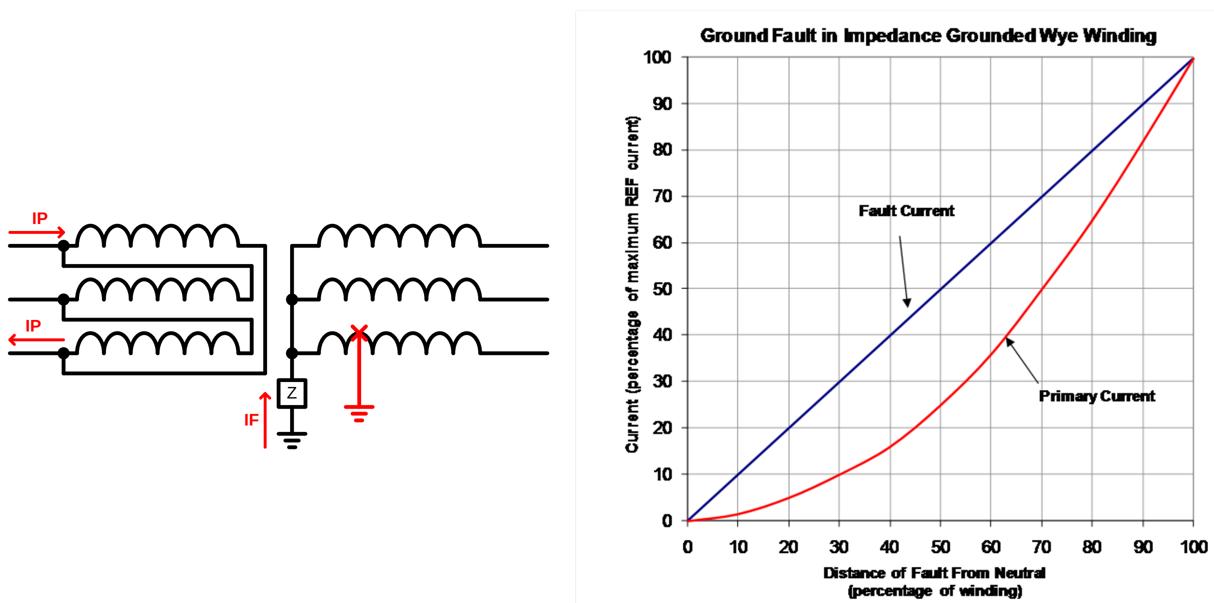


Figure 4: Fault Currents for Impedance Grounded Wye-Connected Transformer

The traditional design for ground differential protection scheme is simple and straightforward compared to the phase differential protection scheme. The scheme (device 87G) compares the phase residual ground current ($3I0 = I_A + I_B + I_C$) against the neutral current. Since the zone of protection covers a single winding, no compensation is needed. The only requirement is that the ratios of the terminal CT and the neutral CT have to be the identical. Often an auxiliary CT is needed when the neutral CT circuit is also used to polarize directional ground relays, and its CT ratio is usually smaller than the terminal CT ratio. Figure 5 shows two differential schemes for ground differential protection.

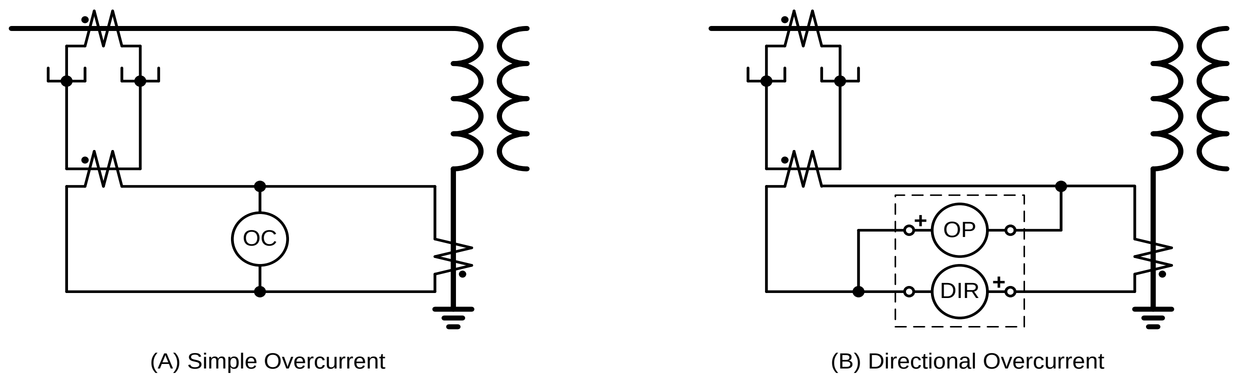


Figure 5: Simplified Ground Differential Protection for Power Transformer

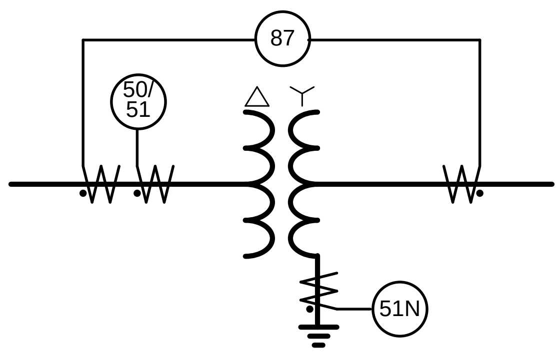
Figure 5(A) uses a non-directional overcurrent. In this scheme, care must be taken when selecting the phase CT and the neutral CT. The excitation characteristics of each CT must match for the most severe external ground fault condition. When CT saturation is problematic for the neutral CT for heavy external ground fault conditions, a directional overcurrent relay can be used to provide security against misoperation. This is the case when the neutral CT is of a lower relaying accuracy class than the phase CT. The use of a directional overcurrent element is illustrated in Figure 5(B).

TVA'S APPLICATION OF GROUND DIFFERENTIAL PROTECTION FOR POWER TRANSFORMER

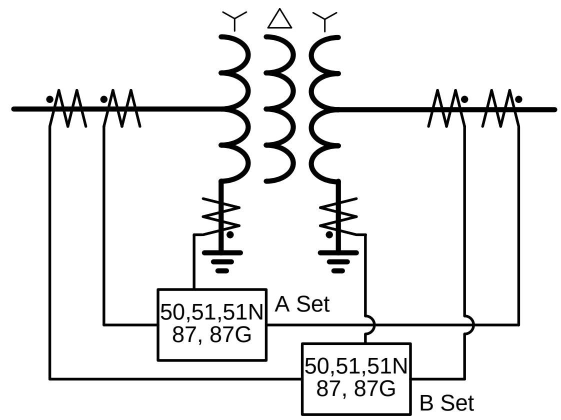
Update TVA Transformer Differential Standard Protection Design

In early 2000, TVA decided to include the ground differential protection for all new and retrofit installations on power transformers to its existing transformer protection standard design, and bring TVA in line with IEEE Standards [3][4]. At the time the decision was made, TVA was using a solid state transformer differential relay and the ground differential function was not incorporated in this particular relay. TVA then decided to use microprocessor numerical transformer differential relays that have ground differential function built in.

In the earlier days, electromechanical relays were used to protect the power transformer against electrical faults. The protection package consisted of a percentage differential relay (e.g., Westinghouse HU or GE BDD), high side three-phase time overcurrent relays with inverse or moderately inverse characteristic, and a neutral overcurrent relay fed from the neutral CT in the grounded wye-connected winding. Although the neutral overcurrent relay can detect ground faults on the lower winding of the transformer, its main intent is to provide backup protection for system ground faults. Because the neutral overcurrent is used as a backup, it is typically set to have a long delay trip for coordination, so its effectiveness as transformer ground fault protection is very limited. In the 1990's, with the advent of solid state relays and microprocessor relays, TVA replaced the older electromechanical relays. But, the transformer protection standard design scheme stayed the same. Figure 6 (A) shows this basic protection package consisted of a percentage differential relay, 87, a phase overcurrent relay, and a transformer neutral overcurrent relay.



(A) Previous Standard Design



(B) Present Standard Design

Figure 6: Previous and Present TVA Transformer Protection Standard Design Package

TVA had employed a couple of ground differential schemes before this new standard was adopted. The relay used was a non-directional overcurrent relay as shown in Figure 5(A). One application was at Arab, AL 161 kV substation. The relay used was a Westinghouse SC instantaneous overcurrent with pickup of 240 amps. This relay was taken out of service in June 1995 due to numerous misoperations. The other ground differential application was at South Calvert, KY 161 kV Substation, and the relay used was a GE IAC55 with 800 amps pickup and #2 TL. This relay was taken out of service in October 2003 due to false trips. It is clear the excitation characteristics of the neutral CT and terminal CT were incompatible and the cause of the false trips.

Ground Differential Protection

Today the present transformer protection standard design package uses redundant microprocessor numerical relays, as shown in Figure 6 (B). Most of the differential relays protection logic is similar with only minor variations among different relay manufactures. The logic of the ground differential for the particular relay that TVA uses is similar to the concept shown on Figure 5 (B). Simply put, it is just the neutral overcurrent element and the phase residual ground overcurrent element with similar pickup settings, supervised by a directional unit. The pickup settings can be set to provide very sensitive protection, with the typical constraint being that the pickup will be above normal unbalance. The directional unit compares the phase terminal residual ground current (3I0) against the neutral current of the grounded wye winding. The phase residual ground current, 3I0, is the reference. Ground faults that are external to the zone of protection will have the neutral current 180° out of phase with the phase residual ground current. If the ground faults are within the zone of protection, the neutral current will be in phase with the phase residual ground current. The directional relationship of the phase residual ground current and the neutral current for internal or external faults for this particular relay is shown in Figure 7. An internal ground fault is declared when the phase residual ground current and the neutral current are within ±90°, the neutral current magnitude exceeds the pickup setpoint, and the phase residual ground current magnitude exceeds 80% of the pickup setpoint. Otherwise, the relay declares an external fault.

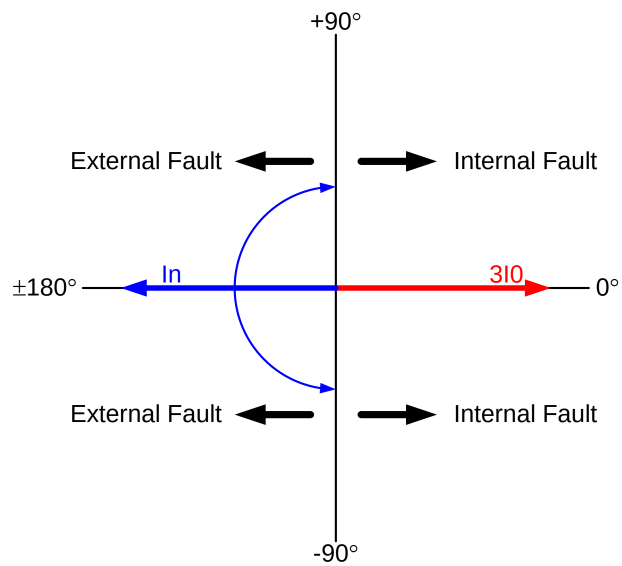


Figure 7: Directional Supervision for Phase Residual Ground Current and Neutral Current

With careful selection of the CT, this method of detecting lower winding ground faults provides both secure and sensitive protection. The CT chosen for differential protection should have an adequate relaying class accuracy rating. Sometimes CT saturation cannot be avoided. This is particularly true for the neutral CT of a grounded wye winding. The neutral CT typically has a lower relaying class accuracy rating than the terminal CT. In addition, the neutral CT is often used in polarizing circuit for line relaying and the ratio chosen is smaller to provide adequate sensitivity. With smaller CT ratio, lower relay class accuracy rating, and increased secondary burden in the polarizing circuit, there is an increased likelihood of CT saturation. However, with careful selection of the neutral CT, extreme saturation can be avoided. The output of the saturated current vector after going through the numerical relay cosine filtering process results in reduced magnitude and phase angle advancement as compared to the true current [5]. After the filtering process, light to moderate saturation would yield a current vector having magnitude of no lower than 50% and angle advancement not exceeding 45° of the true current. Assuming no saturation to the terminal phase CT, the saturated neutral current vector should not advance past 90°. Even if the neutral CT experienced heavy saturation, the filtered current vector should have a magnitude of 20%-50% and a degree advancement of 45°-85° as compared to the true original current [5]. This would provide secure directional operation.

INCORRECT GROUND DIFFERENTIAL APPLICATION DESIGN

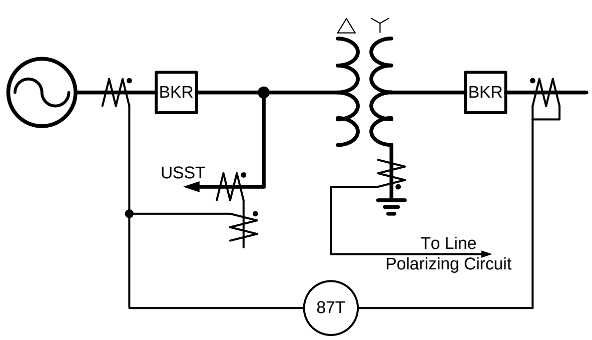
With the relay and the scheme proven to provide secure operation, what was the root cause of the 11 false trips TVA had experienced for the past 7 years? As with most false trips involving differential relays, the main cause was incorrect CT polarity connection. In addition, there was a general lack of understanding the ground differential protection principle. In most cases, inadequate or no verification test was performed to check the correctness of the secondary current circuit.

Historic P&C Design Background

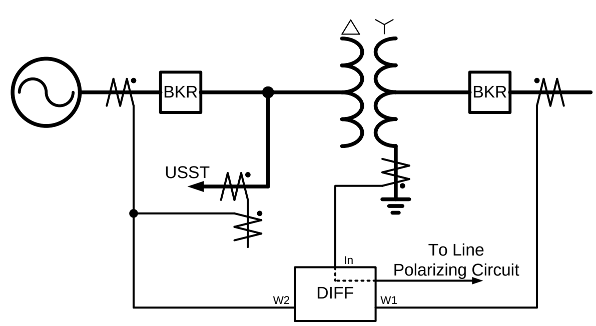
Previous to the present day department structure, TVA's P&C design departments were separated into two groups. One group was located in Chattanooga, TN, and they were responsible for projects involving substations. The other group was based in Knoxville, TN, and they were responsible for projects involving switchyards of generating plants. The two groups were independent of each other and the protection and control circuits for substations and generating plant switchyards were noticeably different. One unique difference between the two groups was differential protection.

Plant vs. Substation Design

Substation differential protection design had a more conventional configuration where the polarity of the CT of the current circuit points away from the protected equipment, as shown in Figure 6. This configuration is illustrated in most relay manufacturer instruction manuals. But, at TVA generating plants, the polarity of the phase differential CT points **toward** the protected equipment. An example of this is shown in Figure 8. In Figure 8 (A), the electromechanical percentage differential relay is either a Westinghouse HU or a GE BDD. The low side CT is wye connected, while the high side CT is delta connected to compensate for the transformer delta-wye phase shift. When an old electromechanical differential relay is replaced with a new numerical microprocessor relay, the wye connected CT circuit on the low side is more often left untouched. The high side phase CT is reconnected in a wye configuration and the polarity of the CT points toward the protected equipment to match that of the low side.



(A) Electromechanical Differential Relaying Current Circuit



(B) Numerical Differential Relaying Current Circuit with Ground Differential

Figure 8: Typical TVA Generating Plant Differential Current Circuit (Polarity of the Phase CT Points toward the Protected Equipment)

Most microprocessor numerical differential relays can internally compensate different CT connection configurations (wye or delta) to filter out zero sequence current and account for delta-wye phase shift for traditional phase differential protection. Most can even compensate for "mismatch" of phase CT polarity on different windings. It is not necessary to connect all phase CTs on all windings with polarity points either away or toward the protected equipment. Due to internal compensation capability, it is recommended that all CTs be wye connected for simplicity.

Ground Differential CT Configuration Connection

When implementing ground differential function, it is necessary for the differential phase CT of the grounded wye winding to be connected in wye configuration. The reason for this is delta connected CT cannot source zero sequence current that is needed to compare with the neutral current of the winding. The present transformer differential relay that TVA uses can internally compensate for phase shift and mismatch of polarity for phase differential protection. However, when enabling the ground differential protection function for this particular relay, it only compensates for CT ratio mismatch, and the CTs involved must observe correct polarity in respect to fundamental differential concept. If the polarity of the phase CT on the grounded wye winding is pointing away from the protected equipment, the neutral CT polarity must also points away from the equipment toward the ground. This concept is shown in Figure 5.

Often transformer neutral current is used in the line ground relay current polarizing circuit. With conventional line CT polarity points toward the bus and away from the line, the polarity of the neutral CT used to feed the line ground relay polarizing circuit must point toward the ground and away from the winding. When implementing ground differential protection, the neutral current connection to the differential relay must accommodate this line ground relay neutral polarizing CT circuit requirement. This is illustrated in Figure 9.

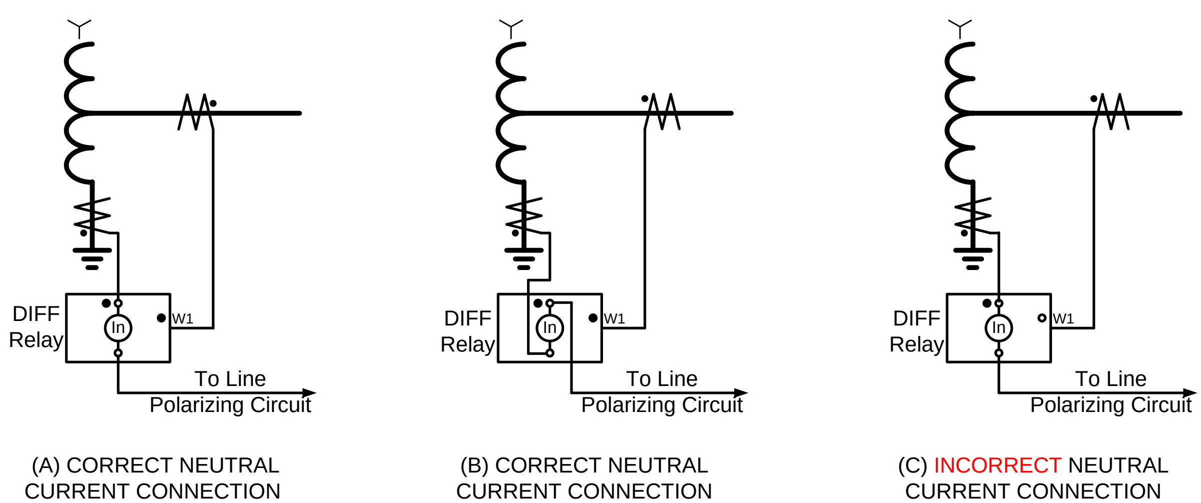


Figure 9: CT Polarity Connection for Ground Differential Function

Figure 9(A) shows the differential phase CT polarity points away from the transformer and its corresponding neutral CT connection to the relay. The current output from the polarity of the neutral CT must be connected to the polarity of neutral current input to the relay. This is the configuration shown in most relay manuals. If the differential phase CT polarity is pointing toward the transformer, as with the practice followed by the previous TVA plant P&C Design department, the current output from polarity of the neutral CT must be connected to the non-polarity neutral current input of the relay, as shown in Figure 9 (B).

Incorrect Design for Ground Differential Protection

The CT connections for a transformer protection relay are straightforward as illustrated in the relay instruction manual shown in Figure 10. At plants, it was well understood that even though the polarity of the differential phase CT points toward the transformer, as long as the polarity of all CTs for all windings are consistent in their orientation, the relay would function correctly. In the example application of Figure 10, it appears that to implement ground differential protection, the only requirement is the inclusion of the neutral current as shown below. However, because the ground differential protective function was not part of the traditional transformer protection design and rarely applied prior to the new standard, there was not a good understanding of its purpose, concept, and connection requirement. After the ground differential standard have be adopted, in earlier plant applications, where differential phase CT polarity points toward the equipment, polarity connection requirement to the neutral current input of the relay as shown in Figure 9 (B) was not followed and incorrectly designed as shown in Figure 9(C).

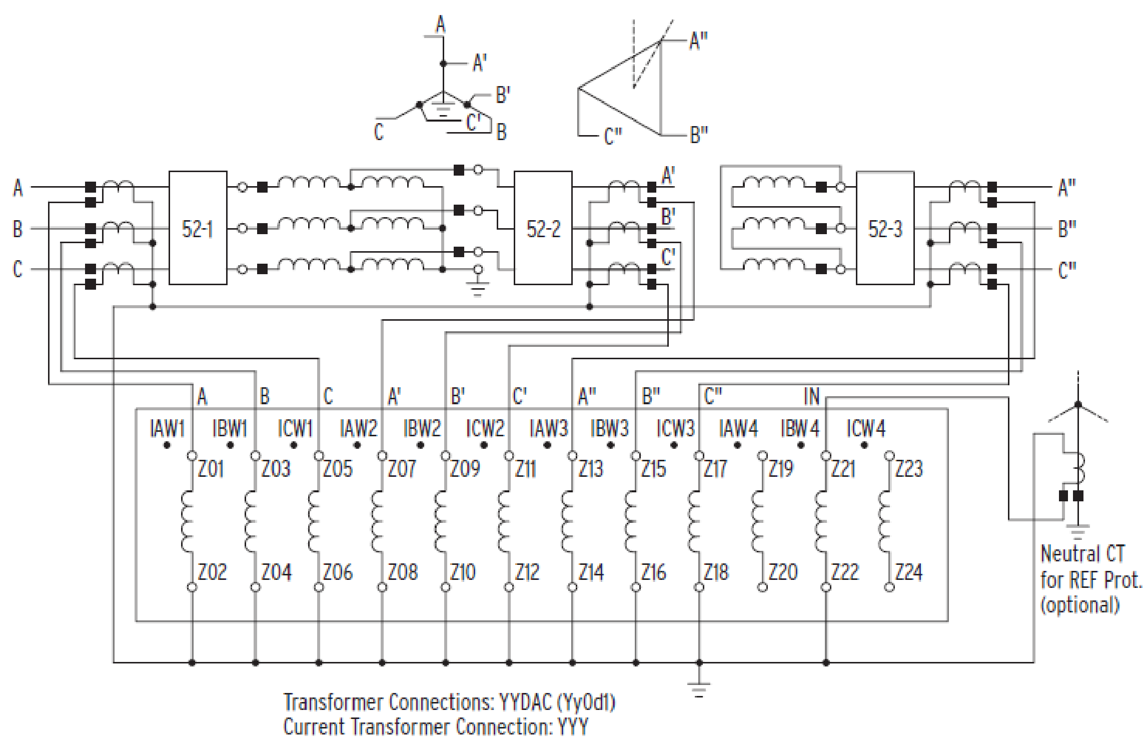


Figure 10: Relay Instruction Manual Typical AC Connections for 3 Windings Transformer

DIFFERENTIAL PROTECTION VERIFICATION TESTS

After several false trips with design deficiency identified, the initial root cause of those misoperations was determined. However, TVA continued to experience ground differential false trips. The root cause of those misoperations was and continues to be human performance error. This can be anything from wiring connection diagrams that do not agree with the single or three-line diagram, or simple field wiring termination error. It is impossible to avoid those types of mistakes. However, they can be greatly reduced or even eliminated by implementing a well defined verification process to make sure everything works as intended. IEEE Standard C37.103, "IEEE Guide for Differential and Polarizing Relay Circuit Testing" provides guidelines for differential secondary current circuit testing and verification.

Online Phasing Verification Reading?

Online verification of the phase secondary current is fairly simple to obtain and it is the ultimate check for the correct input signals to the relay. Wiring checks to confirm correct termination of CT secondary leads can be challenging, due to the continuity of secondary current circuit. As a result, the CT leads that are erroneously "rolled" with respect to their polarity markings may not be detected with wiring checks. For any relay, online "phasing" is the final step of the verification process when initially placed in service. For a numerical relay, this is just simply taking an online reading. For electromechanical relays, obtaining current phasor readings requires a phase angle meter and a current meter. For microprocessor numerical relays, online readings for correct balanced three-phase secondary current should have very little if any negative sequence and zero sequence current to indicate correct ABC rotation. The magnitude and the phase angle of the secondary phase current should correspond to the correct CT ratio and the transformer voltage vector shift of a delta-wye or wye-delta transformer. Also there should be little or no differential operating current, which would indicate correct compensating setting and polarity termination.

When initially placing a transformer in service, incorrect CT wiring may cause the differential relay to operate. This is largely dependent on the loading of the transformer. If the initial loading is sufficiently small and the CT input to the relay for one winding is mistakenly wired in incorrect polarity with respect to the other winding CT, the differential relay would only operate if the operating quantity exceeds the minimum pickup setting. Online verification check would catch this error, allowing the operator and engineer to correct the problem. This online verification check works fine with phase differential protection, because most of the time there is sufficient load to check the magnitude and phase angle of the phase currents. Unfortunately, the ground differential online verification check for CTs cannot be performed. This is because there is little to no primary unbalance current for the relay to obtain a good secondary winding terminal 3I0 current and a neutral current reading for comparison. The only way to confidently verify the relaying current circuit is to perform an offline verification test.

DC Primary and Secondary Injection Test

One of the CT polarity verification tests is the DC primary and secondary injection test, or more commonly referred as the DC kick test. This concept is explained in C37.103, Section 6.3 [6] and the test setup is shown in Figure 11 below. The negative terminal of the DC battery is connected to the ground of the transformer, while the positive terminal of the battery is left hanging for the time being. The polarity of the secondary CT lead wired to the polarity of the relay input termination point is lifted. A DC volt meter is inserted. The positive terminal of the volt meter is connected to the polarity of the CT lead, and the negative of the volt meter is connected to the polarity of the relay input termination point. To initiate the test, the positive terminal of the battery is temporary connected to the phase terminal of the transformer. Initially when the circuit is made, the DC volt meter should kick upscale briefly and then settle back to zero. To continue the test, the positive terminal of the battery is then disconnected from the phase terminal of the transformer. When this circuit is disconnected, the DC volt meter should kick down scale briefly and then settle back to zero. This test verifies the connection of the polarity lead of the CT to the relay.

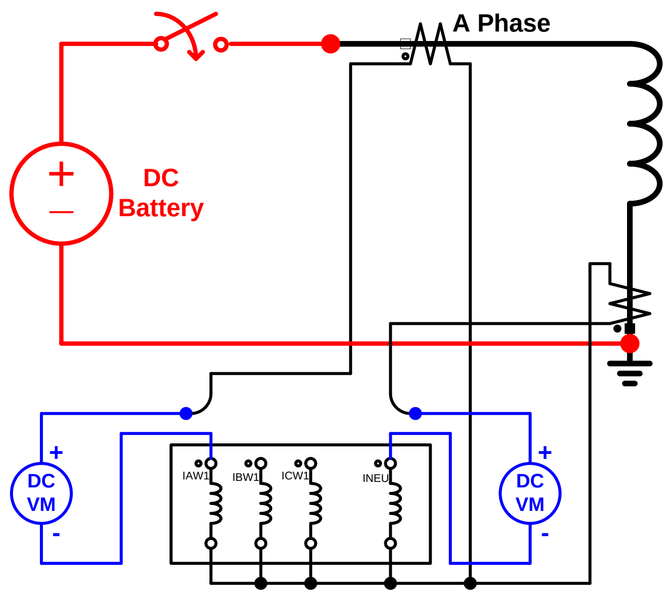
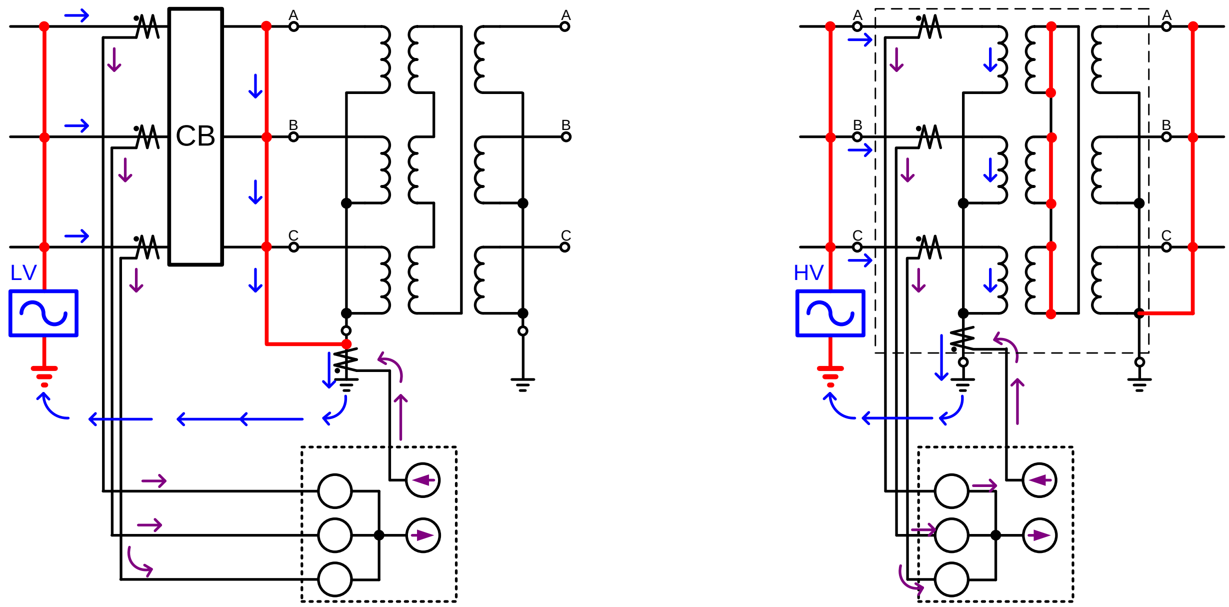


Figure 11: DC Kick Test for Verifying CT Polarity

AC Primary Current Injection Test

The AC primary current injection test is the preferred verification test at TVA. TVA refers to this test as the "Phantom Ground Test". This method is preferred because it actually simulates a primary fault condition, and the relay can obtain an "online" reading during the test. The test setup is described in IEEE Standard C37.103-2004, Section 12.1 and 12.2 [6]. Figure 12 (A) and (B) show two phantom ground test setups for a wye-wye-delta transformer. Both setups simulate an external fault to the ground differential protection zone. Figure 12 (A) shows the test setup for externally located phase and neutral CTs. In Figure 12 (B), the phase CT or the neutral CT is either on the base of the bushing of the phase or neutral terminal, respectively, or either CT is embedded inside the casing of the transformer. The TVA specification for new power transformers has the CTs embedded inside the casing of the transformer.



(A) Test Setup with Accessible External CTs

(B) Test Setup with Non-Accessible Internal CTs

Figure 12: "Phantom Ground Test" for Ground Differential Current Circuit Verification

CHALLENGES IN PERFORMING VERIFICATION TESTS

Test for transformer with external CTs

The test setup in Figure 12 (A) requires only a low voltage AC source to simulate an external fault to the ground differential protection zone. By tying all the winding phase terminals to the neutral terminal, the impedance to the transformer winding is shorted. The magnitude of the current forced through the short circuit is only dictated by the lead and the bus work impedance. For example, if the lead and the bus work impedance totaled 0.5 ohms, with a 20 VAC source, 40 primary amps will circulate through the circuit. Depending on the CT ratio, there should be adequate secondary current for the relay to obtain a good reading. The phase residual ground current phasor, 3I0, should be out of phase with the neutral current phasor, as illustrated in Figure 7, indicating an external ground fault outside the protected zone. For this test setup, it is much easier to obtain a test voltage source that can push this amount of the current.

Test for transformers with internal non-accessible CTs

The test on transformers with internal non-accessible CTs is much more challenging. It requires a much higher rated voltage source to force sufficient current through the circuit. The higher the voltage rating of the tested winding, the higher volt-ampere test source is required. Using Figure 12 (B) as our example, the sequence network of the wye-wye-delta transformer is shown is Figure 13.

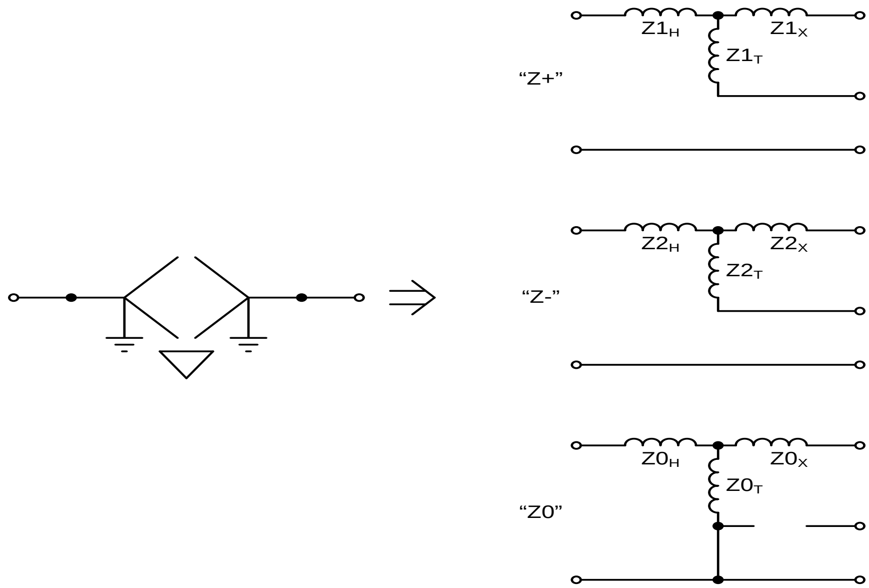


Figure 13: Sequence Network of Wye-Wye-Delta Transformer

For our example, the transformer has the following impedance:

500/161/26 kV Transformer, 100 MVA
Transformer Impedance:
500 to 161 kV: 1.55%
500 to 26 kV: 8.42%
161 to 26 kV: 2.61%

Converted to T model:
Z_H: 3.18%
Z_L: -1.63%
Z_T: 5.24%

At 500 kV, 100 MVA, base ohms is 2500 Ω/pu
Z_H: 3.18%*2500/100 = 79.5 Ω
Z_L: -1.63%*2500/100 = -40.75 Ω
Z_T: 5.24%*2500/100 = 131 Ω

At 161 kV, 100 MVA, base ohms is 259.21 Ω/pu
Z_H: 3.18%*259.21/100 = 8.24 Ω
Z_L: -1.63%*259.21/100 = -4.23 Ω
Z_T: 5.24%*259.21/100 = 13.58 Ω

As we can see above, the transformer impedance in ohms is much greater at 500 KV than at 161 kV. With the AC source providing common current to all three phases of the transformer, this is equivalent to only providing zero sequence current to the network, thus only the zero sequence network is involved in the test circuit. This is shown in Figure 14. With the simplified sequence network, the equivalent impedances looking from the 500 kV terminal and the 161 kV terminals are:

500 kV: $79.5\Omega+(-40.75\Omega \| 131\Omega) = 20.35\Omega$
161 kV: $-4.23\Omega+(8.24\Omega \| 13.58\Omega) = 0.90\Omega$

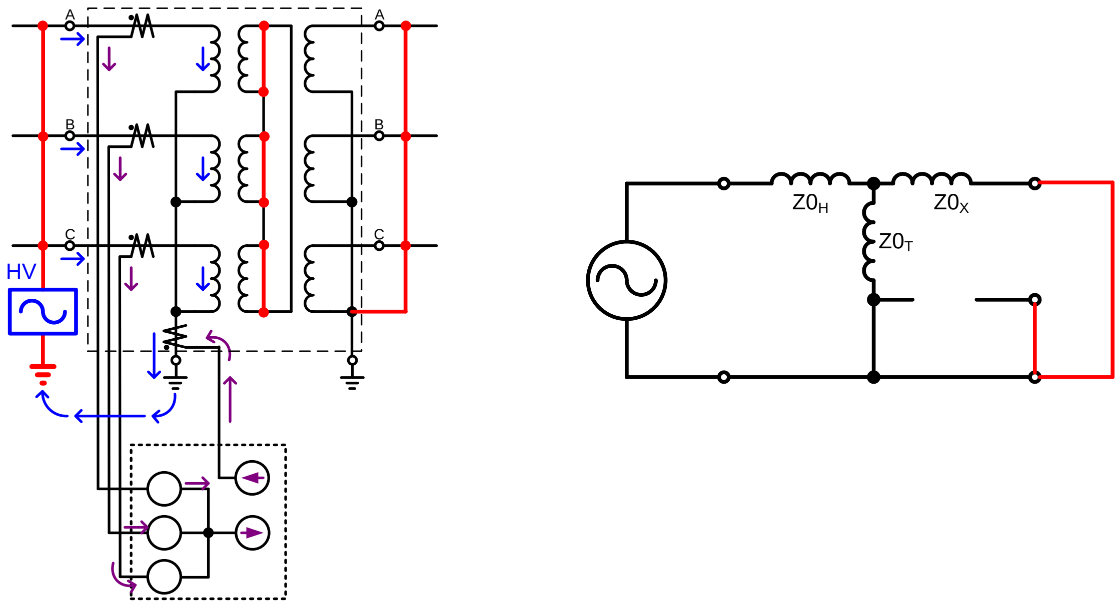


Figure 14: Sequence Network of the Phantom Ground Test

To test the 500 kV ground differential current circuits and to circulate 20 amps in the primary circuit, the test voltage needs to be around 400 volts. This requires a 400*20 = 8,000 volt-ampere test source. For 161 kV, the primary test current would need to be higher due to a higher CT ratio on the lower voltage winding side. If 60 amps are needed to obtain a sufficient reading in the ground differential secondary current circuit, the test voltage would need to be around 54 volts. Testing the low side voltage winding has a smaller volt-ampere requirement than the high side voltage winding, but a significant current requirement from test the circuit. TVA does not have many test sets to easily satisfy this test requirement.

Test involving Polarizing Circuit

Another obstacle found in testing the ground differential current circuit is taking precautionary measures with polarizing and neutral current circuits. Circulating current through the neutral ground differential element during testing also circulates current through all the elements in the neutral and polarizing circuits. Often, a neutral time-overcurrent relay is used to provide station backup ground protection. Most electromechanical line relays and relays that use a current polarizing method will have the overcurrent element in the polarizing circuit. Careful planning is essential before testing. One must disable the neutral backup ground time-overcurrent relays. Line relays with selectable polarizing methods must be set for a method not involving the transformer neutral current, i.e. negative sequence voltage or zero sequence voltage method. For line relays that use the dual zero-sequence polarizing method (neutral current and broken delta voltage polarized electromechanical relays), the polarizing current input to the relay must be shorted. At substations and generating plants with a significant number of lines, a great number of relays need to have their settings temporarily changed and current circuit temporarily altered. Due to the complexity of the task at hand, often plant and system operators do not allow the test to be performed.

Disable the function on initial installation?

There have been discussions within TVA about enabling the ground differential function, but blocking the trip initially and enabling the trip later once there have been a few ground faults around the area of the installation where fault records were used to verify the 87G scheme. Then the ground differential function trip would be enabled or correct the circuit where errors are detected. This proposal was rejected due to a couple of reasons. With the current work load of system, relay, and analysis engineers, there is not a systematic means to trigger a reminder to download the relay shot to be examined. In addition, in most of the relay installations, the protected power transformer was new. If a transformer was to fail, most likely the failure would occur at early in its life or at the expected end of life of the transformer (failures over the life of equipment-bathtub curve). Placing a transformer in service without full protection during its infancy would be considered unwise.

FALSE TRIP CASES

Since the decision to implement ground differential (87G) protection for power transformers as part of the transformer protection standard in the early 2000's, there have been 11 false trips involving this application. A brief description of each event is listed below:

2003-06-24 Watts Bar Hydro GSUs 1,2,4,5 misoperated by ground differential (SEL-387) for Watts Bar-Winchester 161kV line fault, due to neutral current input being rolled

2004-05-30 Chatuge GSU misoperated by ground differential (Basler CDS) during tests, due to neutral current input being rolled (Bank was energized and connected to system, generator was off-line)

2005-01-06 Browns Ferry GSU 1 misoperated by ground differential (SEL-387) for Trinity-Nance 161kV line fault, due to neutral current input being rolled

2007-03-24 Wilson Hydro GSUs 15 and 17 misoperate by ground differential (SEL-387) for Colbert-Wilson 161kV line fault, due to neutral current input being rolled

2007-05-03 Boone Hydro GSU misoperated by ground differential (SEL-387) for Boone-Holston 138kV line fault, due to neutral current input being rolled

2007-06-18 Apalachia Hydro GSU #1 misoperated by ground differential (Basler CDS) for Basin-Apalachia 161kV line fault, due to neutral current input being rolled

2007-06-29 Boone Hydro GSU misoperated by ground differential (SEL-387) for Boone-Sullivan 161kV line fault, due to neutral current input being rolled

2008-01-29 Johnsonville 500/161/13kV bank #14 misoperated by ground differential (SEL-387) for Montgomery-Davidson 500kV line fault, due to neutral current inputs being rolled

2008-04-10 Burnsville 161/46/13kV bank misoperated by ground differential (SEL-387) for a ground fault on a 46kV feeder out of Corinth, due to 161kV neutral current input being rolled

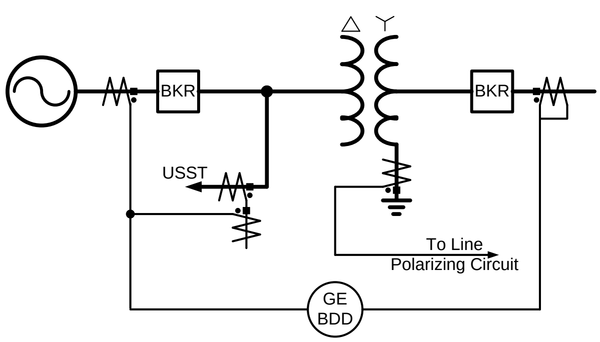
2008-07-09 Cumberland 161/13kV CSST G misoperated by ground differential (SEL-387) for an external system fault, due to phase current inputs being rolled

2008-07-31 Ocoee #3 161/69/13kV bank misoperated by ground differential (SEL-387) for ground fault on Apalachia-Benton-East Cleveland 161kV line, due to 69kV neutral current input being rolled

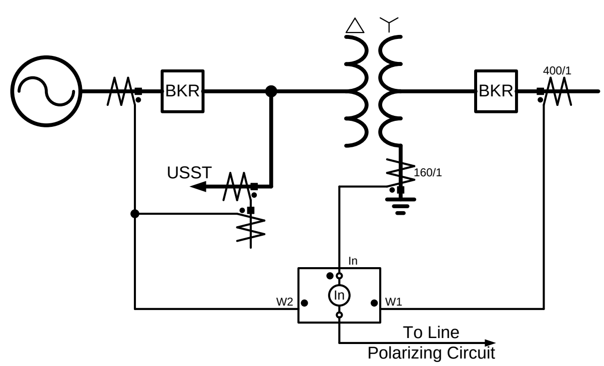
Details of a couple of false trips will be discussed below; one as result of deficiency in design at a generating plant, and the other as result of inadequate verification test being performed. Those two incidents also provide some insights as to how sensitive the ground differential protection can be, if the circuit is correctly designed and applied!

Relay Record for January 6th, 2005 Browns Ferry Unit 1- 500/22 kV Generator Step-Up Transformer

Browns Ferry Nuclear Plant Unit 1 generator step-up transformer differential CT circuit has the polarity of the differential phase CTs wired pointing toward the transformer. However the polarity of the neutral CT on the 500 kV neutral of the transformer points toward the ground and away from the transformer and it is used in the line ground relays polarizing circuit. This setup is shown in Figure 15. In anticipation of Unit 1 start up, the 3 old single phase transformers were replaced with three new ones, along with a new numerical differential relay replacing the old GE BDD differential relay. The neutral CT input to the new differential relay was erroneous designed with polarity of the neutral CT secondary output connected to the polarity of the relay neutral current element input.



(A) Browns Ferry Unit 1 Old EM Differential Relaying Circuit



(B) Browns Ferry Unit 1 Upgraded Differential Relaying Circuit with Ground Differential

Figure 15: Browns Ferry Unit 1 Transformer Old and Upgraded Differential Relaying Circuit

On January 6th, 2005, there was a phase to ground fault on the Trinity-Nance 161 kV line. This 161 kV line is one bus and a transformer away from the Browns Ferry Unit 1 generator step-up transformer. Figure 16 and 17 show the relay oscillography shot recorded by the Browns Ferry Unit 1 differential relay. In Figure 16, it shows the transformer was sourcing only zero sequence current to the system, for the generator was not in service. Each phase was sourcing about 50+ primary amps and the neutral current had about 160 primary amps. Figure 17 shows the sum of the phase currents, or 3I0. Note that the phase 3I0 current is in phase with the transformer neutral current. From Figure 7, using the phase 3I0 current as the reference, if the neutral current is within ±90° of the reference phase 3I0, this indicates an internal zone ground differential fault. The pickup setting for the neutral current element is set on 100 primary amps. With both the phase 3I0 current and the neutral current exceeding this setpoint, and both currents were within ±90° of each other, the relay tripped by the 87G function and disconnected Unit 1 GSU from service.

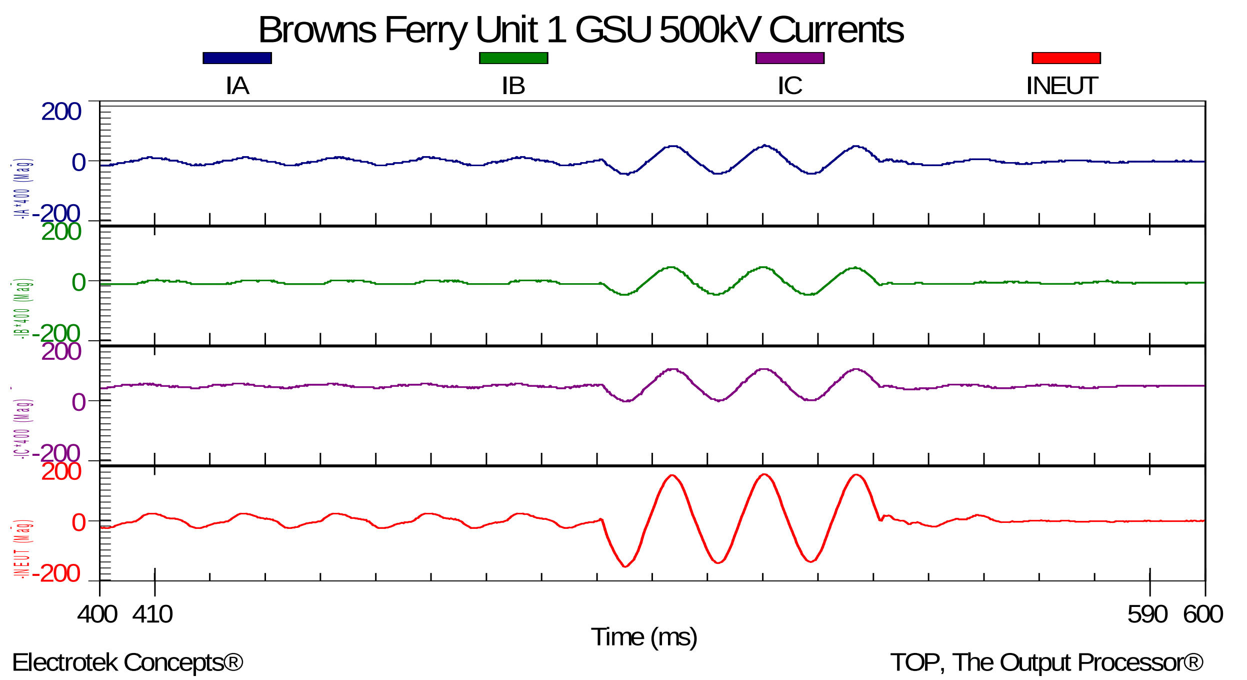


Figure 16: Browns Ferry Unit 1 Transformer 500 kV Phase and Neutral Currents

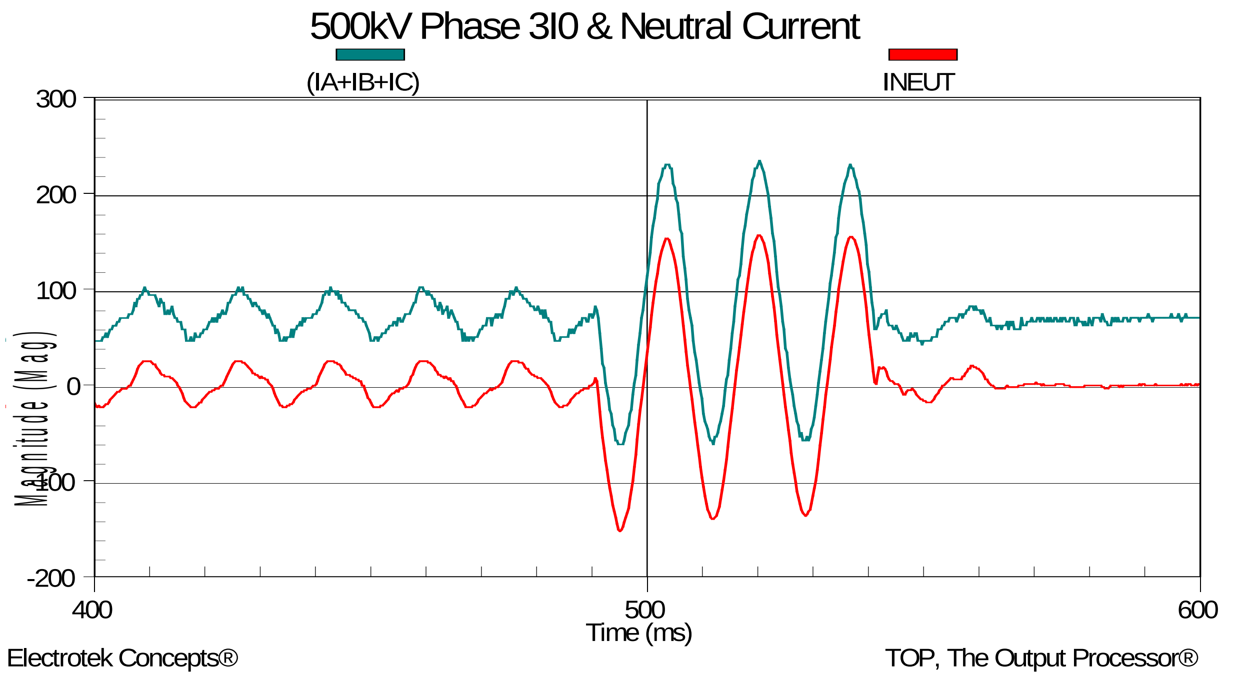


Figure 17: Browns Ferry Unit 1 Transformer 500 kV Phase 3I0 and Neutral Currents in Phase

One interesting note here is looking at Figure 17, there was some normal unbalance current flowing through the neutral of the 500 kV winding prior to the 161 kV line fault. Online verification reading would have indicated the erroneous polarity connection to the neutral current element of the relay. One can manually trigger an oscillography test shot and see this normal unbalance. Even though the unbalance was small, the oscillography shot would have gave an indication as to correctness of the neutral CT wiring connection. One can also see with the neutral current pickup setting being at 100 primary amps, and the phase 3I0 pickup being at 80% of the neutral current pickup, the ground differential protection provides sensitivity detection for lower winding faults.

Relay Record for April 10th, 2008 Burnsville, MS 161 kV Substation 161/46/13 kV Transformer

This is a brand new 50 MVA transformer installation with conventional CT polarity connections, as shown in most relay instruction manuals. It was reported that the DC kick test was performed to verify the polarity connections to all CTs, but the phantom ground test was not performed. It nevertheless false tripped on a 46 kV line fault that is a bus and a transformer away from the subject transformer. It was reported someone had later lifted the neutral CT wires to perform farther testing in the CT circuit and subsequently laid the wires back incorrectly. Figure 18 and 19 show the relay oscillography shot for the phase to ground fault on a 46 kV line a bus and a transformer away Burnsville 161 kV substation. Note that there was not any perceptible unbalance on this transformer winding that would have indicated any hint of the problem with the neutral CT polarity connection, thus an online verification reading cannot detect this erroneous wiring termination. Also observe that the fault current through the neutral of the winding was only about 35 amps. The pickup setting for this neutral current element is only 30 primary amps.

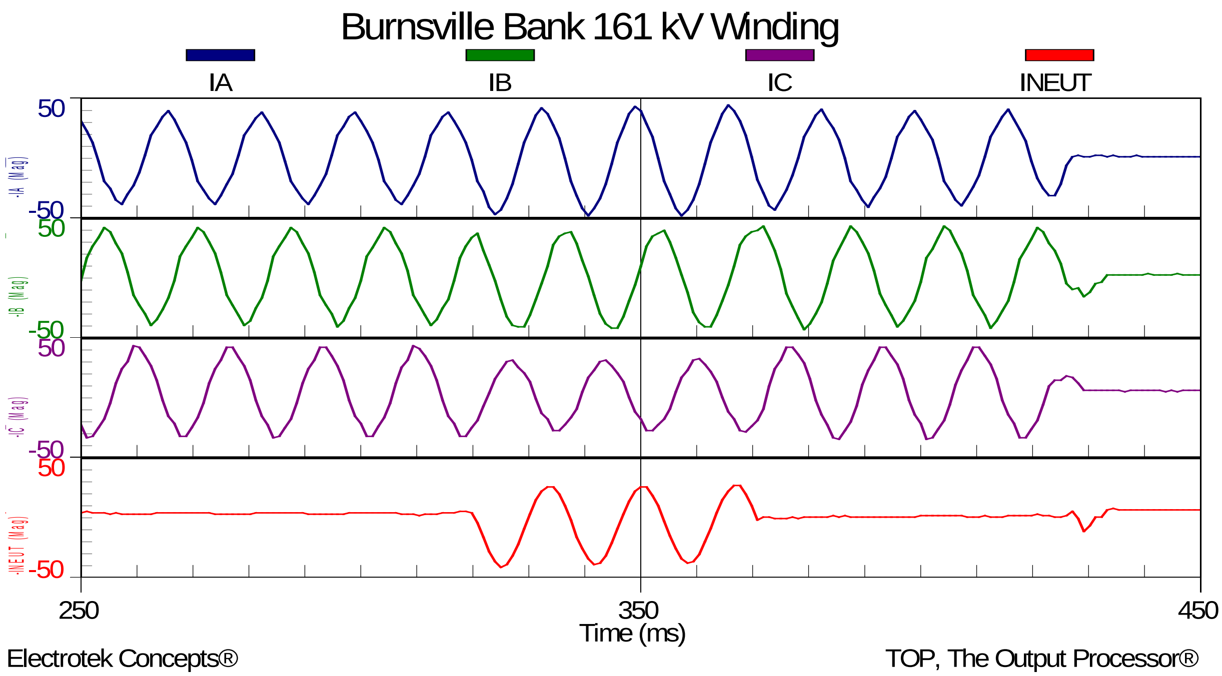


Figure 18: Burnsville MS 161/46/13 kV Transformer 161 kV Phase and Neutral Currents

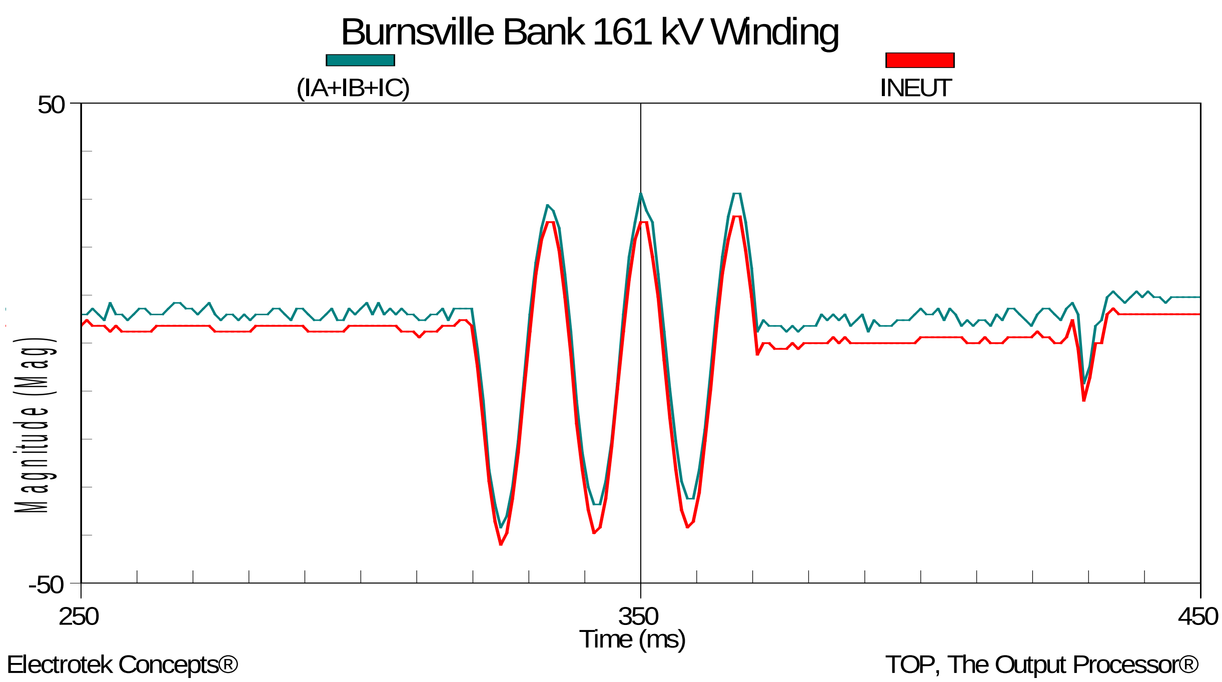


Figure 1: Burnsville MS 161/46/13 kV Transformer 161 kV Phase 3I0 and Neutral Currents

SUMMARY

This paper addresses the operating experience obtained commissioning ground differential protection for power transformers at TVA, specifically the false trips. It discusses the fundamental concept of the ground differential scheme and the reason for implementing the protection. The root cause of the initial design deficiency that led to the misoperations was identified. Even after the design problem had been resolved, false trips continued. Insufficient or lack of verification tests were the cause of all cases. A brief description of the each false trip was presented.

REFERENCE

[1] Protective Relays Application Guide, GEC Measurements

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[3] *"IEEE Recommended Practice for Protective and Coordination of industrial and Commercial Power Systems"*, IEEE Standard 242-2001 Buff_Book – Chapter 11.9.2.2.4.2

[4] *"IEEE Guide for Protective Relay Applications to Power Transformer"*, IEEE Standard C37.91-2000

[5] *"Securing Sequence-Current Differential Elements", Gabriel Benmouyal and Tony Lee of Schweitzer Engineering Laboratories, Inc.*

[6] *"IEEE Guide for Differential and Polarizing Relay Circuit Testing"*, IEEE Standard C37.103-2004

BIOGRAPHIES

Meyer M. Kao is current working as a protection engineer consultant. Prior to his present position, Meyer worked for Tennessee Valley Authority (TVA) for 17 plus years. The last position Meyer held was the acting manager of System Protection and Analysis group. Prior to that responsibility, Meyer was the Transmission System Specialist in the same group. As Transmission System specialist, Meyer was responsible for performing detailed technical analysis for unusual system events, including equipment failure and misoperations. He also had responsibility for protective relaying and control settings and field support. Prior to his position as Transmission System specialist, Meyer was a field test engineer for the TVA's Chattanooga Transmission Service Center. One of Meyer's main responsibility as a field test engineer was new installation and retrofit of substation control and protection circuits. Meyer earned the B.E.E. degree from the Georgia Institute of Technology in 1990. He is a registered professional engineer in the state of Tennessee, and member of IEEE. Meyer can be reach via email at meyerkao@gmail.com.

Gary Kobet is an Operations Engineer for the Tennessee Valley Authority (TVA) in Chattanooga, Tennessee. His responsibilities include performing voltage and generator stability studies for the operating horizon, as well as developing operational tools to monitor reactive reserve within the TVA service area. Previously he worked in TVA's System Protection department planning relaying schemes for transmission and generation projects, as well as calculating relay setpoints and performing post fault analysis. He has performed transient studies using EMTP for breaker TRV studies and switching surge overvoltages. Previously he worked as a field engineer and as power quality specialist. Mr. Kobet earned the B.S.E. (electrical) from the University in Alabama in Huntsville in 1989 and the M.S.E.E. from Mississippi State University in 1996. He is a member of the IEEE Power Engineering Society, CIGRE', Eta Kappa Nu, Tau Beta Pi, and is a registered professional engineer in the state of Alabama.

George T. Pitts is a Specialist in System Protection & Analysis group for the Tennessee Valley Authority (TVA, www.tva.gov) in Chattanooga, Tennessee. He is responsible for the setting of protective relays, supporting maintenance & testing, performing fault studies, and modeling of the Mississippi region of TVA's transmission system. He is a TVA representative to the Protection & Controls sub-committee for SERC Reliability Corporation and to the System Protection & Controls sub-committee for NERC. Prior to this he was a process control engineer for the Mead Corporation located at a pulp & paper mill in Stevenson, Alabama and responsible for control of power boilers, pulp mills and paper machines. Prior to this role he was the maintenance electrical & instrument engineer for Mead and was responsible for high voltage to control systems design, construction, and startup of a new pulp & paper plant along with Mead corporate engineers, BE&K construction, and Rust Engineering. Previously, he was with IDS Technical Services, Houston, Texas, where he served as a lead engineer/project manager of E & I aspects of pipeline engineering for customer Exxon. Before that, he was a project engineer in system-wide engineering at Texas Eastern Pipeline in Houston, Texas. Mr. Pitts earned the B.S.E.E. from the Mississippi State University in 1993. He is a member of the IEEE and a registered professional engineer in the state of Tennessee. He can be e-mailed at gtpitts@tva.gov.