Proper Testing of Protection Systems Ensures Against False Tripping and Unnecessary Outages

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Abstract—**This paper discusses the role of three-phase primary injection testing as an important part of the substation commissioning process. Individually testing the components of a protective relay scheme is common practice. Many times, this testing is performed without looking at how the equipment under test interacts with all the other components of the protective relay scheme. Several relay misoperations can be avoided by executing an overall testing plan with all the interconnected components. Three-phase primary current injection tests can be easily performed during equipment commissioning and can detect mistakes that would otherwise only be detected when load is available. This paper describes the planning, execution, and analysis of results of three-phase primary injection tests.**

Index Terms—**through-fault, testing and commissioning, transformer testing, management of protection, avoid misoperations, bus protection, transformer protection, current transformers, testing procedures.**

I. Introduction

Protective relays respond to current and/or voltage inputs. As an example, a directional overcurrent relay requires both polarization and operating quantities to operate. If the instrument transformers providing these quantities are not properly installed (incorrect ratio, primary polarity orientation, secondary wiring connections, etc.), the relay may incorrectly operate and cause unnecessary loss of service to customers, loss of revenue, environmental disasters, etc.

It is common practice to individually test the components of a protective relay scheme (e.g., instrument transformer tests, relay tests, wiring checks, trip checks, and end-to-end tests). Complexity is added when companies opt to hire different contractors to perform these tests. Each contractor will focus on its scope of work and most likely not spend time considering the big picture of how the equipment being tested interacts with all the other components of the protective relay scheme.

An effective way to prove the proper installation of the components of a protective relay scheme and eventually the correct value of a few relay settings is to carry some type of load and perform in-service relay checks. In some cases, load will only be available after the commissioning is complete, and the equipment owner will not perform the in-service checks, resulting in possible future relay misoperations.

Three-phase primary current injection tests can be easily performed during equipment commissioning and can detect mistakes that would otherwise only be detected when load is available.

The term "primary injection" suggests that relatively high current is applied to the primary conductors. This is done to prove that the current transformers (CTs), current circuits, and protective devices are all properly connected. Depending on the equipment, primary injection has different implications and can have vastly different setup requirements and measurement expectations. This type of test can be carried out on buswork, switchgear, high-voltage breakers, low-voltage breakers, and power transformers.

Primary injection in power transformers is sometimes called a "through-fault" or "thru-fault" test. Essentially, a three-phase source of sufficient voltage, current, and volt-ampere rating is connected to a short-circuited transformer to supply current through the windings. The CT circuits are then checked for current magnitude and phase angle to verify that all test switches and protective relays receive the proper current at the proper angle, as expected. The test is usually set up to include the high-side and low-side breakers and often is expanded to simultaneously test the CT circuits from other breakers connected to the same, or adjacent, bus.

Protective relays have the function of detecting abnormal power system conditions and initiating appropriate actions, such as the tripping of a circuit breaker, keying of a communications channel, or picking up of an alarm contact for local or remote annunciation. These relays are connected throughout the power system with the main goal of protecting personnel, limiting equipment damage, and maintaining service continuity [1].

Typically, protective relays are connected to the secondary windings of CTs, voltage transformers (VTs), or coupling capacitor voltage transformers (CCVTs). These transformers, also known as instrument transformers (ITs), provide insulation from high voltages and reduce primary currents and voltages to standardized values for application with protective relays.

Fig. 1 illustrates the polarity marks found on ITs. These marks define the relative instantaneous directions of the currents entering the primary winding terminals and leaving the secondary winding terminals. I_P and V_P are the primary values of current and voltage, respectively. I_S and V_S are the secondary values of current and voltage, respectively. Current I_S is in phase with Current I_P, and Voltage V_S is in phase with Voltage V_P.

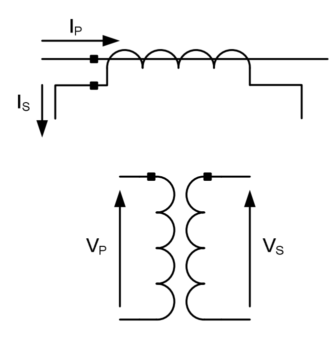

Fig. 1. Instrument transformer polarity marks

Relays that operate from the combination of two or more input quantities will also display polarity marks for their proper operation. Fig. 2 shows the polarity marks on all six current inputs on the rear of a digital differential relay: IAW1, IBW1, ICW1, IAW2, IBW2, and ICW2.

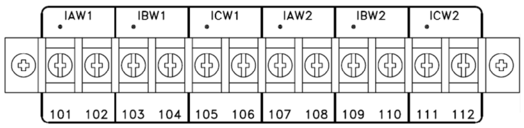

Fig. 2. Polarity marks on protective relay current inputs

Fig. 3 illustrates the ac connections of a transformer differential relay. In this case, the schematic diagram defines the following:

- The primary polarity of the CTs should face away from the transformer.
- The secondary polarity of the CTs should connect to the polarity of the relay current input coils.
- Both sets of CTs should connect in wye and share a common ground point.
- CTs located on Phases A, B, and C should connect to relay current input coils IAW1, IBW1, and ICW1, respectively.
- CTs located on Phases a, b, and c should connect to relay current input coils IAW2, IBW2, and ICW2, respectively.

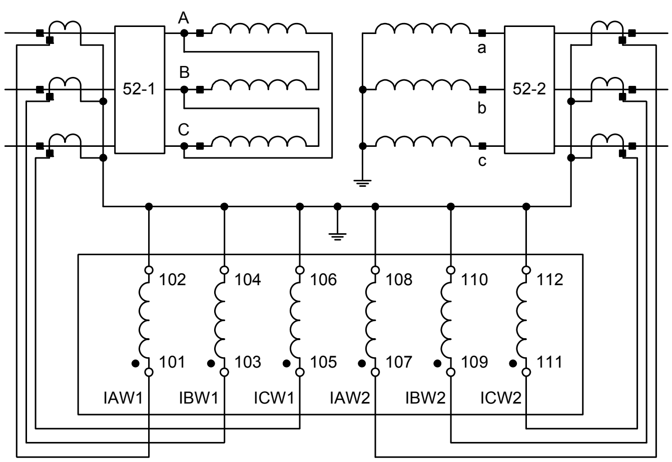

Fig. 3. AC connections of a transformer differential relay

During the commissioning of a protective relay scheme, such as the one presented in Fig. 3, the following activities take place:

- CT testing (ratio, polarity, saturation, and dielectric insulation)
- Wiring checks
- Relay testing with final relay settings
- Trip checks
- In-service tests

With the exception of in-service tests, each of the above activities proves the individual integrity of different components of the protective relay scheme. In-service tests are required to prove the ac portion, current and voltage circuits, of the protective relay scheme as a complete system.

In-service tests demonstrate that all CTs are correctly positioned, tapped, and connected to the relay. They indicate the stability of the differential protection under load conditions and validate a subset of the transformer differential relay settings.

In-service tests require a minimum amount of load current to circulate through the primary and secondary windings of the CTs, which may or may not be possible on first energization of the equipment.

The objective of three-phase primary current injection tests is to produce balanced current circulation through the primary windings of the CTs. With primary current circulation, it is possible to prove all CTs are correctly positioned, tapped, and connected to the relays. Transformer, bus, and line differential elements can be checked for stability. Current-polarized directional relays such as 87GD (ground differential relays) can also be checked.

Here are a few benefits of three-phase primary injection tests:

- The primary equipment does not have to be energized for the test.
- Load is not necessary.
- The test current can be interrupted at any time.
- Primary and secondary values of current can be calculated and later compared to measured values obtained during the test.
- After test completion, all protective relay elements that use only current as the operating quantity are ready to be put in service for equipment energization.

This paper describes the planning, execution, and analysis of results of three-phase primary injection tests.

II. Planning

A. *Safety*

Three-phase primary injection tests require the equipment under test to be dead and isolated from the power system.

All lockout and tagout procedures must be followed. If safety grounds are required to be removed during the test, a special permit or the expansion of the safety zone may be needed.

B. *Procedures*

Three-phase primary injection tests should be performed in accordance with a written procedure approved by all participating parties. The procedure should indicate the expected results for each test.

C. *Impact on Other Protection*

Test currents may flow through CTs other than those of interest at the time. Precautions are therefore needed to prevent the tripping of adjacent circuits.

D. *Test Equipment*

Secondary current magnitude and phase are measured with a phase angle meter connected to a voltage reference, while primary currents are measured with a clamp ammeter of appropriate range. All testing cables should be rated for the calculated primary current and be long enough to reach the equipment terminations. A test source, such as a station auxiliary power transformer or a portable source, should be considered, based on availability and the project budget. If using a station auxiliary transformer, install a safety switch capable of being locked and tagged at the secondary as an isolation point for the test.

E. *Calculation of Test Values*

The calculations of a primary fault current are based on equipment nameplate data. For transformers, the voltage ratings, power rating, and design impedance are used to convert into per-unit values and essentially into actual current values. For CTs, the ratio transforms the primary current value to its appropriate secondary value. In the case of multitapped CTs, the expected secondary results should match the actual CT ratio required by the designed three-line schematic.

Knowledge of symmetrical components is required to calculate fault currents. Phase CTs can be verified with a three-phase fault that only consists of positive-sequence values. If testing ground or neutral CTs, an unbalanced fault is required, and negative- and/or zero-sequence networks may be considered in the fault calculations. When the appropriate symmetrical component network is modeled for the test, Ohm's law is used to calculate the primary fault current based on a selected test voltage.

The fault current circulating through a power transformer lags the voltage source by approximately 90 degrees, because the characteristic of a power transformer impedance is almost purely inductive. Secondary current magnitude can be calculated by dividing the primary current by the CT ratio. The phase angle between the reference voltage and the measured primary and secondary currents is determined by examining the three-line diagram and takes into consideration the phase rotation of the voltage source, transformer winding connections, CT polarity, and measuring location. When a consistent measuring technique is carried out during the test, any phase angle deviation from the calculated values indicates that an error has been detected.

III. Execution

A. Personnel

At least two testers are necessary to conduct three-phase primary injection tests. One tester performs the measurements, while the other records the results and compares them with expected values. Additional personnel are required to execute power equipment switching (disconnect switches and circuit breakers) and relocate the testing source as needed.

B. Reduced-Voltage Power Supply

Three-phase primary injection tests require a reduced-voltage, three-phase power supply capable of supplying enough current for the duration of the test.

Auxiliary station power is the most economical solution, but it does not always have enough voltage or kVA rating for testing. The higher the voltage level of the transformer windings under test, the higher the voltage needed to generate enough current circulation during the test.

Using three-phase portable generators is another solution. These generators can be rented on a daily or weekly basis and delivered to the job site. They are available in a wide range of voltage and kVA ratings. The weekly rental cost for a 250 kVA portable generator is around $1,100 (U.S.).

When the equipment under test involves a large MVA transmission-type power transformer, the test supply voltage may exceed 480 V. In this case, a large kVA rating, 480 V portable generator can be rented along with a suitable step-up transformer and connection cables. A 1000 kVA, 480 V generator, a 1000 kVA step-up transformer (480 V delta, 4160 V wye), and connection cables could be rented weekly for $6,200 (U.S.).

IV. Analysis of Results

One of the great advantages of three-phase primary injection tests is that all primary and secondary values of current circulating through the CTs can be calculated before the test. The calculated values include magnitude and phase angle at various measuring locations.

During execution of the test, all primary values of current magnitude and phase angle are registered and compared to the calculated values. Small discrepancies in phase current magnitude may occur due to internal voltage drop across the test source. Small phase angle differences, on the order of 1 to 5 degrees, may also occur. This is due to the fact that transformers are considered to have a 100 percent inductive characteristic for test calculation purposes, which is not true.

The testing procedure also indicates various locations for measurement of the secondary currents circulating through the CTs, accompanied by their expected values of magnitude and phase angle.

When digital relays and power meters are connected to the secondary circuits of the CTs, it is possible to interrogate these devices through their front-panel interfaces and to trigger reports that include values of current magnitude and phase angle.

Upon completion of the test, all measured values should match the calculated values. Any discrepancies should be analyzed, and if errors are found, they should be corrected and a new test performed to prove the correction was effective.

V. Case 1

A. Overview

The application of multifunction digital relays to protect medium-voltage power transformers has become a common industrial practice. Unlike utility transformers, industrial transformers frequently use neutral grounding resistors to limit ground current during faults to the 200 to 400 A level on medium-voltage systems.

Fig. 4 shows an example of a delta-wye-connected transformer with a grounding resistor connected across the neutral of the wye winding and the ground. A transformer differential relay (87) provides the main protection against internal faults, computing currents from the H and X bushing CTs. The relay can also provide 87GD protection against faults located close to the neutral of the wye winding. For this purpose, the relay computes currents from the neutral CT and X bushing CTs.

In transformer differential protection, the protected zone is determined by the location of the CTs and may include only the transformer, as shown in Fig. 4, or both the high-side and low-side circuit breakers, as shown in Fig. 5.

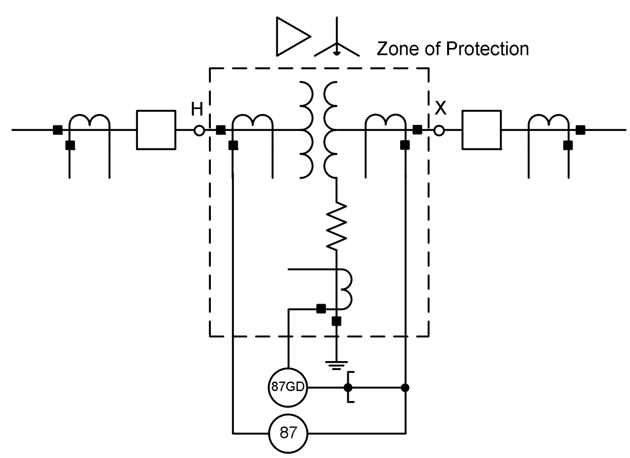

Fig. 4. Transformer differential relay zone of protection including only the transformer

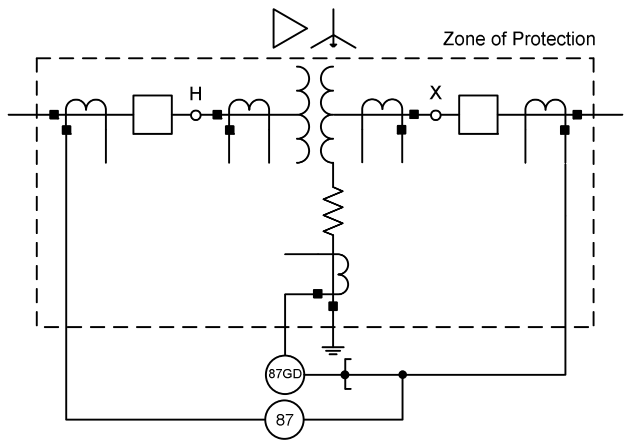

Fig. 5. Transformer differential relay zone of protection including circuit breakers

During commissioning, the connections from all the CTs to the 87 relay must be proved by primary injection, but the balance of the high-side CTs with the low-side CTs, also known as differential protection stability, has to be proved when three-phase current is flowing through the transformer. This is achieved by using a reduced-voltage, three-phase power supply as a source of test current. A portable generator, variable transformer, or even station auxiliary power could be used as a reduced-voltage power supply.

Two types of faults, three phase and phase to ground, are applied in turn to the low side of the transformer, while the high side is connected to the three-phase source. The three-phase fault test proves all CTs connected in series with the transformer windings and the stability of the differential protection. The phase-to-ground fault test proves the CTs located in the neutral of the wye winding and the stability of the 87GD protection [2].

B. Planning

The CTs to be tested provide protection for a 16.8 MVA Dy1 (ANSI standard delta-wye) transformer with characteristics as shown in the transformer nameplate in Fig. 6. CTs located in the neutral bushing provide operating current for 87GD relays. CTs located in the H and X bushings provide the main protection for internal faults.

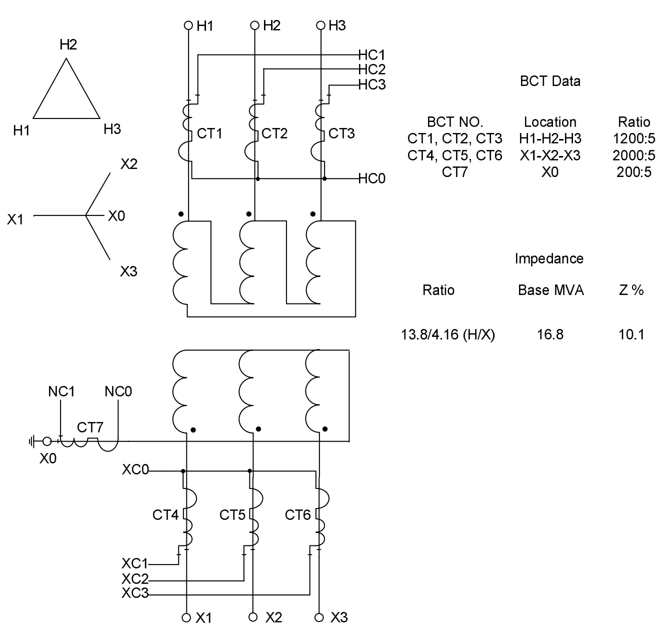

Fig. 6. Transformer nameplate information

The voltage and kVA rating of the reduced-voltage power supply are determined early in the planning stage. These values are directly proportional to the impedance of the transformer, the minimum circulating current during the test, and the voltage level of the transformer windings. Availability and cost also play a role in the selection process of the reduced-voltage power supply.

In this example, a three-phase, 208 V source was selected and produces approximately 15 percent of the transformer nominal current during the three-phase fault test. The reduced-voltage power supply will be connected to the H winding, and the faults will be applied to the X winding. If the same 208 V power supply was connected to the X winding and the short applied to the H winding, approximately 50 percent of the transformer nominal current would circulate during the three-phase test, requiring a power supply with a greater kVA rating.

Digital phase angle meters are typically used to measure both the magnitude and phase angles of the primary and secondary currents. The minimum circulating current for the test will most likely be determined by the minimum current the phase angle meter requires for correct phase angle measurement.

When test switches or sliding links are not available for secondary current measurement, miniature ac current clamps combined with power analyzers or phase angle meters may be used instead. Again, the minimum test current will be determined by the minimum current required for correct phase angle measurement.

As a safety precaution, all secondary current measuring instruments (phase angle meter, ammeter, etc.) should not be internally or externally fused. Refer to the equipment instruction manual, and confirm that the current inputs are not fused. Personnel injury and equipment damage may occur due to open CT circuits caused by blown fuses.

Before inserting the test plug into the test switch measurement point (see Fig. 7), execute a continuity check across the test plug terminals to confirm the existence of a continuous path.

Fig. 7 shows the convention for secondary current measurement when test switches are available. All the expected values of secondary current phase angles will be derived based on this convention.

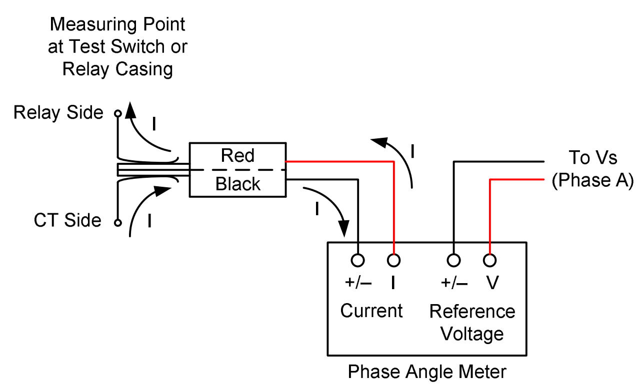

Fig. 7. Secondary current measuring convention

Fig. 8 illustrates how primary current can be measured using an ac current clamp and a phase angle meter.

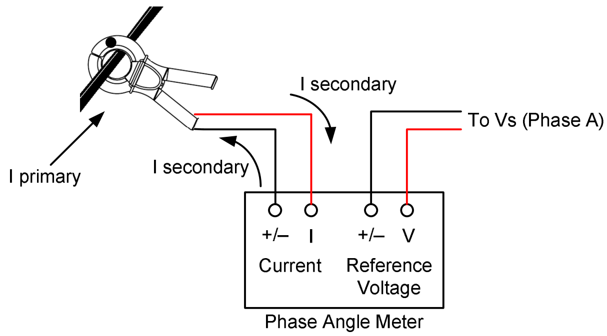

Fig. 8. Primary current measurement technique

Note that all phase angle measurements (primary or secondary) must use the same reference voltage, typically the A-phase voltage of the reduced-voltage power supply, Vs. To avoid an accidental short circuit of the reference voltage, a low-current-rated fuse or circuit breaker should be installed as close as possible to the reduced-voltage power supply, as shown in Fig. 9.

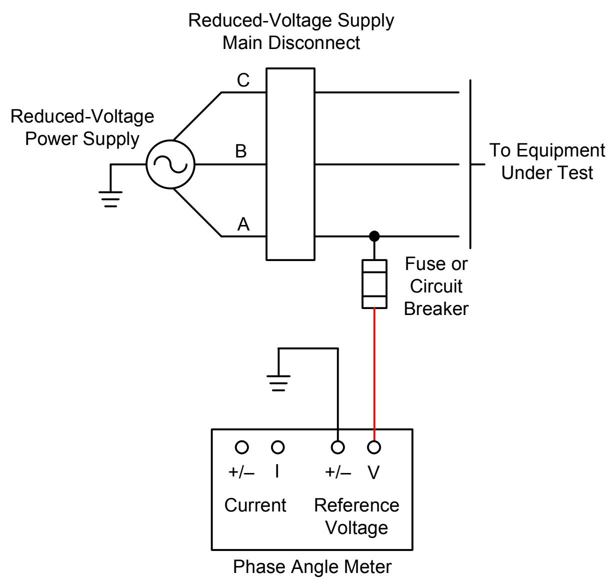

Fig. 9. Reference voltage connection

The one-line diagram in Fig. 10 illustrates the direction of the currents flowing through the primary and secondary circuits when the reduced-voltage power supply is applied to the H bushings of the transformer and the X bushings are all shorted to ground. The primary current flows from the power supply to the short circuit. The direction of the secondary currents is determined based on the orientation of the CTs and the direction of primary current flow.

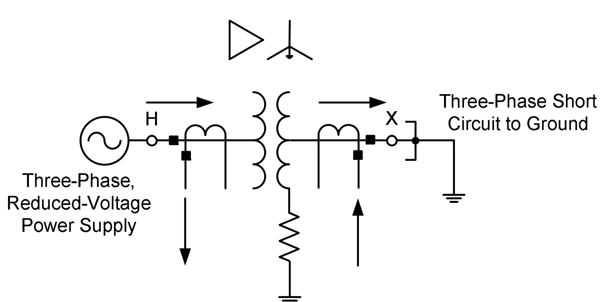

Fig. 10. Current flow direction on primary and secondary circuits

It is important to note that there is a phase angle shift between the currents circulating through the primary and secondary bushings of a delta-wye transformer. The phase angle shift is determined by the connection of the transformer windings and by the phase rotation of the reduced-voltage power supply.

For a transformer with the characteristics shown in Fig. 6, ABC rotation applied to H1-H2-H3 bushings, and test setup shown in Fig. 10, the currents circulating through the X bushings lag the currents circulating through the H bushings by 30 degrees.

C. Execution

At this stage, a simple diagram should be drawn to form part of the commissioning log. It should show CT locations, the testing transformer, and the position of the test leads in the circuit. A typical diagram is shown in Fig. 11.

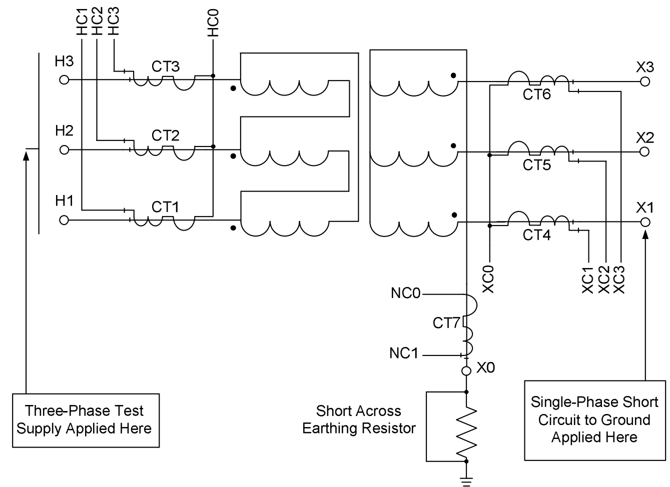

Fig. 11. Connections for through fault on 87GD protection

As mentioned before, it is possible to obtain a larger test current by applying the three-phase power supply to the low side of the power transformer. It should be noted that the primary currents flowing will be small, so that the secondary currents will only be in the order of milliamps.

Because power transformers can be fitted with tap-changing gear, some differential current may appear in the overall protection when the three-phase, short-circuit test is performed. Therefore, this test should initially be done on the nominal-ratio tap of the transformer and be repeated, if desired, on the extreme tap positions [2].

The 13.8 kV and 4.16 kV currents will be 105 A and 348 A, respectively, and the currents in the delta windings of the transformer will be 60.6 A. Appendix A shows all the calculations necessary to determine the values of the testing currents. The primary currents are balanced in the three phases for the first through-fault test, as shown in Fig. 12.

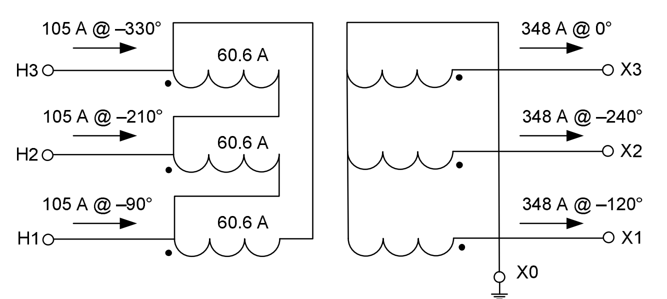

Fig. 12. Three-phase, through-fault values

When a variable transformer is used as the source for the test, it is advisable to switch on at a low value of current and increase it slowly, in case there are any open-circuit or incorrectly connected CTs [2]. If the test results differ appreciably from those expected, reduce the current, and switch off while the matter is investigated.

Continuing with the phase-to-ground through fault, the expected values are shown in Fig. 13.

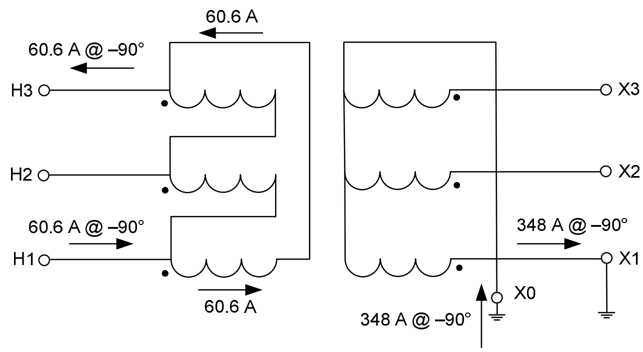

Fig. 13. Phase-to-ground, through-fault values

The following are the step-by-step instructions for the execution of the test:

1. Verify that all safety precautions were taken.
2. Visually inspect the connections between the reduced-voltage power supply and the transformer H bushings.
3. Visually inspect the three-phase short circuit applied to the transformer X bushings and ground.
4. Verify, with a phase-sequence meter, the phase rotation of the reduced-voltage power supply.
5. Visually confirm that ABC rotation is being applied to the H1-H2-H3 bushings of the transformer.
6. Connect the reference voltage of the phase angle meter to the same phase applied to the H1 bushing of the power transformer, typically Phase A.
7. Energize the transformer with the reduced-voltage power supply, and quickly inspect the primary connections and CT secondary connections. Look for any indication of open CTs.
8. Using an ac current clamp, measure the magnitude and phase angle of the currents flowing into the H bushings of the transformer. The obtained values should be very close to the calculated ones, as shown in Fig. 12. The phase angle measurements may be a few degrees different than the calculated ones. This is due to the fact that the transformer does not have 100 percent inductive impedance.
9. Using an ac current clamp, measure the magnitude and phase angle of the currents leaving the X bushings of the transformer. The obtained values should be very close to the calculated ones, as shown in Fig. 12.
10. Measure all the secondary currents at the different measuring points (test switches), and compare them with the expected values calculated in Appendix A.
11. If panel meters and digital relays are part of the secondary circuits of the CTs under test, verify they are correctly displaying the primary current values.
12. Verify the stability of the differential protection. This task can be easily verified when digital transformer differential relays are used. These relays can display both the operating and restraint quantities of the differential elements, providing an immediate validation of a few relay settings and CT circuits. Fig. 14 in the following section is an example of the type of information provided by a digital transformer differential relay.
13. If any discrepancies are found, immediately stop the test and address the problem.
14. Disconnect the reduced-voltage power supply from the transformer.
15. Following all safety precautions, uninstall the three-phase short circuit from the X bushings. Install a single-phase short circuit from X1 bushing to ground.
16. Following all the safety precautions, install a bypass jumper across the terminals of the neutral resistor, as shown in Fig. 11.
17. Energize the transformer with the reduced-voltage power supply, and quickly inspect the primary connections and CT secondary connections. Look for any indication of open CTs.
18. Repeat Steps 8 through 13 for the CT circuits that were not proved during the three-phase test.
19. Disconnect the reduced-voltage power supply from the transformer, and remove the single-phase short from the X1 bushing and the bypass jumper across the grounding resistor.
20. Restore all test switches to their operational state.
21. Remove all connections between the power transformer and the reduced-voltage power supply.

D. *Interpretation of Results*

Once both tests are complete, it is time to check the results. The tools available to accept or reject the results are the various reports obtained from digital relays and the measured values of the currents (magnitude and phase angle) circulating through the secondary of the CTs. Although no actual load is flowing through the transformer, the operating current measured by the differential relay should be zero.

Fig. 14 through Fig. 19 illustrate the reports obtained from the digital transformer relay used to protect the transformer shown in Fig. 11. The reports were triggered during both the three-phase, short-circuit test and single-phase, short-circuit test. Relay connections are shown in Appendix A as part of the test values calculation.

Fig. 14 shows a report triggered during the three-phase test. IAW1, IBW1, and ICW1 are the currents measured by the relay that correspond to the currents circulating through the H bushings of the transformer. IAW2, IBW2, and ICW2 are the currents measured by the relay that correspond to the currents circulating through the X bushings of the transformer. 3I2W1 and 3I2W2 are the negative-sequence currents circulating through the H and X bushings, respectively. IGW1 and IGW2 are the values of 3I0 calculated by the relay for each of the windings. IN is the current circulating through the neutral of the transformer wye winding.

The obtained results of phase and neutral currents exactly match the calculated magnitude and phase angles for the three-phase test.

```
=>>MET

RID                                    Date: 01/12/2009   Time: 15:22:26
TID                                        Time Source: Internal

                     IAW1     IBW1     ICW1     IGW1     3I2W1    IAVW1
Wdg1 Mag (A pri.)    104.8    105.9    107.8      5.4      0.4    106.2
Wdg1 Angle (deg)       0.0   -121.5    120.0    145.3    -23.6      0.0

                     IAW2     IBW2     ICW2     IGW2     3I2W2    IAVW2
Wdg2 Mag (A pri.)    352.2    346.2    346.3      7.6      4.7    348.2
Wdg2 Angle (deg)     149.4     29.7    -90.5    140.9    132.7      0.0

                         IN
Neutral Mag (A pri.)      0.1
Neutral Angle (deg)     156.9
```

Fig. 14. Metering from digital transformer relay: primary currents displayed

Fig. 15 shows a report also triggered during the three-phase test. This report displays the operating and restraint quantities for the percentage restrained differential elements 1, 2, and 3. IOP1, IOP2, and IOP3 are the operating currents for each one of the differential elements. IRT1, IRT2, and IRT3 are the restraint quantities for each one of the differential elements.

```
=>>MET DIF

RID                                    Date: 01/12/2009   Time: 15:23:15
TID                                        Time Source: Internal

                     IOP1     IOP2     IOP3
Operate      (pu)    0.00     0.01     0.00

                     IRT1     IRT2     IRT3
Restraint    (pu)    0.30     0.30     0.29
```

Fig. 15. Metering from digital transformer relay: differential element quantities displayed

During normal operation without any faults within the differential zone, it is expected that very small amounts of IOP and strong values of IRT are measured by the relay. The values obtained from the report definitely show the absence of operating current IOP, indicating the differential element is stable. The values of IRT are identical and match the expected value of 0.3 pu.

The analysis of the reports shown in Fig. 14 and Fig. 15 indicates the following:

- The differential element is stable.
- The CTs are set at the correct ratio according to the relay settings.
- All CT wiring is correct in terms of phasing and polarity.
- The phase rotation setting of the relay matches the ABC rotation applied to the H1, H2, and H3 bushings.
- The relay winding compensation settings are correct.

Fig. 16 and Fig. 17 show the same type of reports for the same three-phase, short-circuit test, but in this case, the secondary polarity of the CT connected to the IAW1 input of the relay was intentionally swapped. Note from the reports how the operating current IOP1 increased to 0.29 pu, the negative-sequence current 3I2W1 increased to 212.4 A, and the zero-sequence current IGW1 increased to 213.2 A. All these values are very close to zero in the reports shown in Fig. 14 and Fig. 15.

```
=>>MET

RID                                    Date: 01/12/2009   Time: 15:26:02
TID                                        Time Source: Internal

                     IAW1     IBW1     ICW1     IGW1     3I2W1    IAVW1
Wdg1 Mag (A pri.)    106.2    108.8    104.2    213.2    212.4    106.4
Wdg1 Angle (deg)       0.0     59.9    -59.9      1.1     -1.1      0.0

                     IAW2     IBW2     ICW2     IGW2     3I2W2    IAVW2
Wdg2 Mag (A pri.)    347.1    345.3    346.9      4.4      2.4    346.4
Wdg2 Angle (deg)     -30.1   -150.7     89.5     55.0     13.6      0.0

                         IN
Neutral Mag (A pri.)      0.2
Neutral Angle (deg)     126.1
```

Fig. 16. Metering from digital transformer relay: primary currents displayed

```
=>>MET DIF

RID                                    Date: 01/12/2009   Time: 15:26:42
TID                                        Time Source: Internal

                     IOP1     IOP2     IOP3
Operate      (pu)    0.29     0.00     0.00

                     IRT1     IRT2     IRT3
Restraint    (pu)    0.29     0.30     0.29
```

Fig. 17. Metering from digital transformer relay: differential element quantities displayed

The reports shown in Fig. 18 and Fig. 19 were obtained during the single-phase, short-circuit test.

```
=>>MET

RID                                    Date: 01/12/2009   Time: 15:32:52
TID                                        Time Source: Internal

                     IAW1     IBW1     ICW1     IGW1     3I2W1    IAVW1
Wdg1 Mag (A pri.)     58.9      2.3     62.1      5.8    105.3     41.1
Wdg1 Angle (deg)       0.0    142.8    178.5    148.5    -30.6      0.0

                     IAW2     IBW2     ICW2     IGW2     3I2W2    IAVW2
Wdg2 Mag (A pri.)    353.2      0.4      1.0    354.0    353.2    118.2
Wdg2 Angle (deg)     179.0    125.6    125.6    178.9    179.2      0.0

                         IN
Neutral Mag (A pri.)    349.8
Neutral Angle (deg)      -0.6
```

Fig. 18. Metering from digital transformer relay: primary currents displayed

```
=>>MET DIF

RID                                    Date: 01/12/2009   Time: 15:33:38
TID                                        Time Source: Internal

                     IOP1     IOP2     IOP3
Operate      (pu)    0.00     0.00     0.00

                     IRT1     IRT2     IRT3
Restraint    (pu)    0.17     0.00     0.17
```

Fig. 19. Metering from digital transformer relay: differential element quantities displayed

The measured values displayed in Fig. 18 match the expected values. Currents circulating through the H1 and H3 bushings have the same magnitude but opposite phase angles. Currents circulating through the X1 and X0 bushings also have the same magnitude but opposite phase angles.

Because this is a fault outside the differential zone, the relay calculated insignificant amounts of operating currents IOP (see Fig. 19).

The information obtained from the reports displayed in Fig. 14, Fig. 15, Fig. 18, and Fig. 19 indicates the CTs under test are properly oriented and connected to the relay. They also indicate the relay settings related to CT ratio, phase rotation, and winding compensation are correct.

The reports provided by the digital relay should be attached to the commissioning documentation.

VI. Case 2

A. Overview

The final step before energizing new substation bus sections is the through-fault test. This test forces a calculated primary current through the CT primaries and measures and compares secondary values to calculated values. Calculations are based on CT ratios, dot (polarity) convention, and transformer impedance, if necessary. Only when all secondary values are verified in magnitude and direction with the actual measured primary current can the tester be highly confident that bus differential protection schemes will work as designed.

This test is only performed when all secondary tests are complete. These secondary tests consist of proving station as-built prints using electrical methods to verify that the protective circuits are connected according to the design and that the CT secondary circuits are continuous with a single ground path. Secondary injection tests of the CTs are inadequate to fully check current circuits in an installation. Currents must circulate through the CT primary and secondary windings, and measurements must be made to verify phasing, ratio, and polarity. The through-fault test requires enough primary current to flow through the equipment under test so that test equipment can measure secondary currents and verify phase angle displacement, based on a known voltage reference. This section focuses on applying a through-fault test to prove bus differential protection.

B. Planning

The example scenario is a brand-new distribution substation consisting of a 138/12 kV transformer (TR1), two feeder circuit breakers (FDR1 and FDR2), and a bus-tie circuit breaker (BT 1-2). Fig. 20 illustrates the one-line schematic of the substation along with the designed orientation of the CTs.

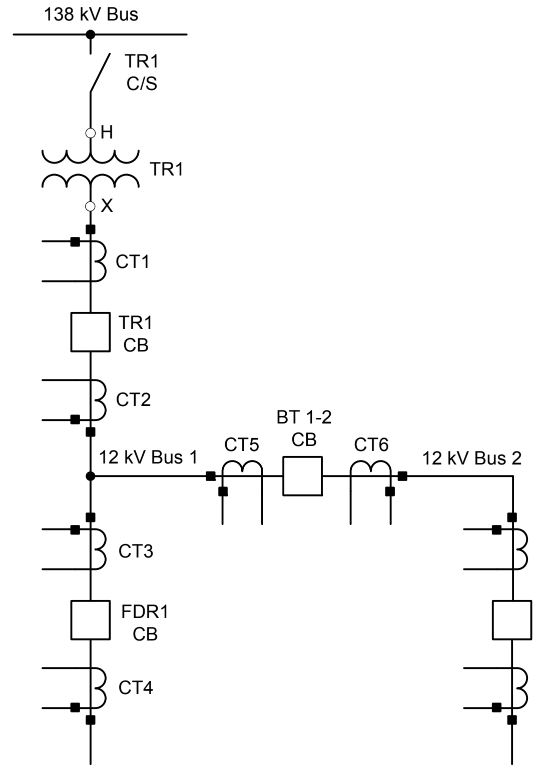

Fig. 20. One-line diagram of example distribution substation

Two 12 kV bus sections of this substation need to be tested. After the acceptance testing of the individual protective relays and CTs, a primary test current needs to flow through the bus sections to prove the proper ratio and orientation of the CTs. In a typical bus differential protection scheme, the CTs overlap the individual equipment protection, so the CTs under test are on the line side of the circuit breakers [3]. For example, to test the Bus 1 CTs, test CT1, CT4, and CT6. Likewise, to test the Bus 2 CTs, test CT5 and CT8. Other CTs in Fig. 20 are used for equipment protection and are not covered in this section. These CTs can be used to compare magnitude and direction with the bus differential CTs.

The impedance of TR1 limits the primary current flowing through the bus. The calculations of the fault current through a transformer were illustrated in a previous example. For the sake of simplicity, assume 100 A of primary fault current for this example.

Fig. 21 shows the three-line diagram of the Bus 1 differential circuit. Each CT has a set of shorting test switches that are used to short the CT and remove its contribution to the Bus 1 differential relay (87B1). The shorting test switches are TS 1-1 for CT1, TS 2-1 for CT4, and TS 3-1 for CT6. The difference should be measured at the bus differential relay at TS 3-2 as the primary current divided by the shorted CT ratio. In this case, all CTs have a 2500:5 ratio. With 100 A of primary current, the secondary current expected at the bus differential relay should be 0.2 A.

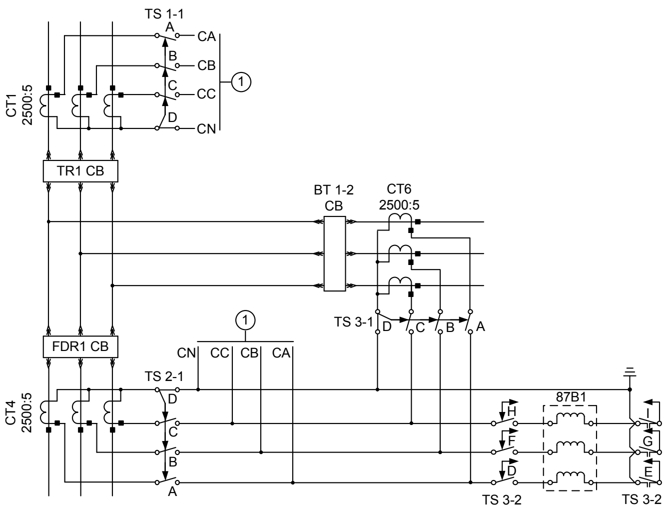

Fig. 21. Three-line diagram of Bus 1 differential circuit

Another consideration in bus differential through-fault testing is the polarity, or direction, of the CTs. In some cases, the shorting switches are linked so that each phase cannot be independently verified. To verify individual phases of the CTs, use a three-phase source. After establishing a voltage reference and sequence rotation from the test source, test the polarity of the CTs. If applying a three-phase voltage source to perform this test, the testing engineer should expect the nonreference phases to be 120 degrees apart from one another. The angles should be consistent for every CT tested. Note that the bus CTs for FDR1 are opposite in polarity to the bus CTs of TR1. Using a consistent test procedure and maintaining a standard test reference, the test equipment should display 180-degree angle shifts between the two CTs.

Before applying a primary current through any equipment, pay attention to other CTs that are in the path of the fault current. In this case, the CTs on the bus side of each breaker protect their associated equipment. A good practice is to isolate any breaker failure trips to avoid causing inadvertent automatic operations—especially in the case of in-service equipment in the station.

A test data sheet should be created listing all points to be tested during the through-fault test. An example is shown in Appendix B. Primary current measurements are done using a clamp-on ammeter of appropriate range. Secondary current measurements are made using a test stabber properly connected to a phase angle meter able to display voltage, current, and angle at test switch locations on the relay panels. The stabber has a “red/black” designation, and a color should be chosen to always face up, or into the relay (see Fig. 7). This establishes a standard test equipment orientation and makes analysis of phase angles simpler. The test data sheet should identify the test switch locations in preparation for the actual test. For Bus 1, TS 3-2 E, G, and I should show 0 A if all bus CTs are unshorted. When CT1 is shorted with TS 1-1, TS 3-2 should measure 0.2 A with the appropriate angle. Unshort the CT, and verify that TS 3-2 E, G, and I return to 0 A. As a quick check, stab into FDR1 relay protection test switches, and compare the magnitudes and angles to the Bus 1 differential CTs. Check and compare the CT orientation between the bus and line protection CTs, and make sure they match the three-line schematic.

CT6 located at BT 1-2 is also used in the Bus 1 differential protection scheme but requires the test source to be moved from FDR1’s line side to FDR2’s line side. This test setup also covers testing the Bus 2 differential CTs, streamlining the physical process of through-fault setup. Be aware of primary current flowing through CT5 in BT 1-2, which protects Bus 2. In cases where one bus is in service, it is critical to include a step in the through-fault procedure to isolate the in-service bus differential trips, to avoid unintended operations.

Fig. 22 shows the three-line diagram of the Bus 2 differential circuit. The tests are the same as Bus 1, but only CT5 and CT8 are tested. The CT shorting test switches are TS 3-3 for CT5 and TS 4-1 for CT8. Both CTs have ratios of 2500:5, so secondary current magnitudes measured at the Bus 2 differential relay (87B2) should remain the same as Bus 1. Using the same voltage reference and rotation, results of this test should be similar to the Bus 1 values. As mentioned in the Bus 1 test, even though both sections of bus should be out of service, it is good practice to isolate the Bus 1 differential trips to avoid any unintended operation.

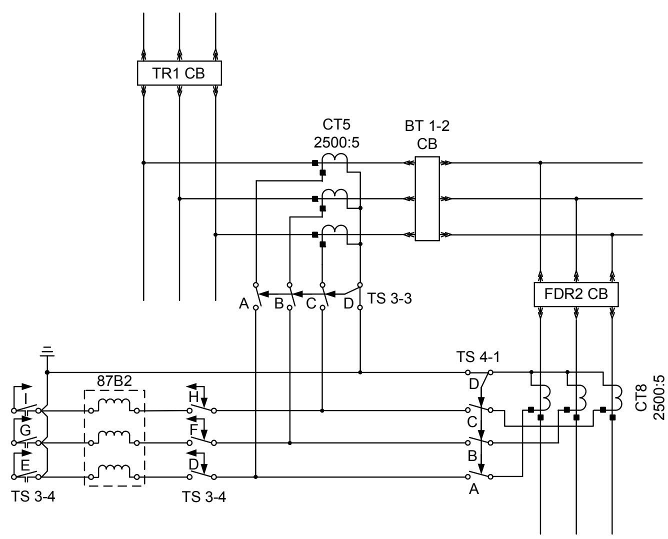

Fig. 22. Three-line diagram of Bus 2 differential circuit

C. Execution

Fig. 23 shows the one-line diagram of the test setup for a Bus 1 through fault.

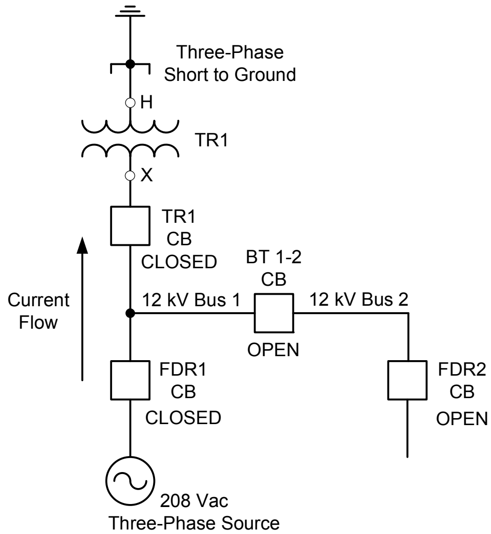

Fig. 23. One-line diagram of Bus 1 differential test setup

For this example, a zone of protection must be established so that personnel are safe and equipment under test are not inadvertently energized. A zone of protection is typically accepted by the tester from a designated authority (i.e., load dispatcher or industrial plant operator). In this example, the 138 kV side disconnect switch should be open and uncoupled, and the 12 kV feeders should have their feeder cables lifted and grounded to prevent backfeed. All primary equipment should be connected together within the zone of protection, and in the case of metal-clad switchgear, all circuit breakers must be racked to the "connect" position and initially open.

An example through-fault procedure is listed in Appendix B. A short and efficient procedure helps simplify the process, especially for personnel not associated with the planning of the through-fault test.

Short-circuit the 138 kV bushings of the transformer, and connect a three-phase source to the feeder side of the FDR1 circuit breaker. Current flows from the 12 kV line side of the feeders to TR1's 138 kV side, basically creating a backfeed condition of TR1.

The three-phase source, for example, could be the station's auxiliary power transformer with a heavy-duty safety switch. The transformer should have enough kVA capacity to maintain the calculated fault current. Select the proper test cables to run from the safety switch to the feeder side of FDR1. Before connecting test cables to the safety switch, check the voltages and rotation of the auxiliary transformer, and establish a phase reference. Use the reference as A-phase. In the case of positive-sequence rotation, use B-phase as the phase lagging A-phase by 120 degrees and C-phase as the remaining phase. Color-code the test cables for easy identification of each phase. Connect the test cables to the feeder side of FDR1; then connect the test cables to the open safety switch. Check that all connections are tight, and clear unnecessary personnel from the testing area. Begin the test by closing the safety switch and checking for proper voltage at FDR1 circuit breaker terminals. Close the TR1 circuit breaker, and then close the FDR1 circuit breaker. Record values taken from the appropriate test switches, as listed on the data sheet, while keeping a consistent voltage reference and stab direction. When all test values are recorded, shut down the test by opening the FDR1 circuit breaker and then opening the safety switch. Lock and tag the safety switch open, and move the test cables to the feeder side of FDR2. The three-phase test grounds remain on the 138 kV side of TR1. When the test cables are connected, inspect the equipment, and begin the test. Repeat the procedure from the previous test, closing the FDR2 circuit breaker to initiate fault current flow. The fault current will be the same as the first test. Record the test results, and compare actual to calculated values. If any of the values do not match, investigate the problem further. Possible mismatches in values could be a result of incorrect wiring not caught during secondary CT continuity checks.

Fig. 24 shows the test setup one-line diagram for a Bus 2 through fault. The primary fault current will remain the same at 100 A, so secondary currents will remain at 0.2 A for 2500:5 CT5 and CT8. When running this test, verify the polarity of the bus differential CTs is 180 degrees out of phase between FDR2 and TR1's bus differential CTs, as illustrated by the polarity convention in Fig. 20. Also verify the individual phases are separated by the proper phase difference, and match the phases to the test switch label. When all values are recorded, shut down the test, and remove all test cables and grounds.

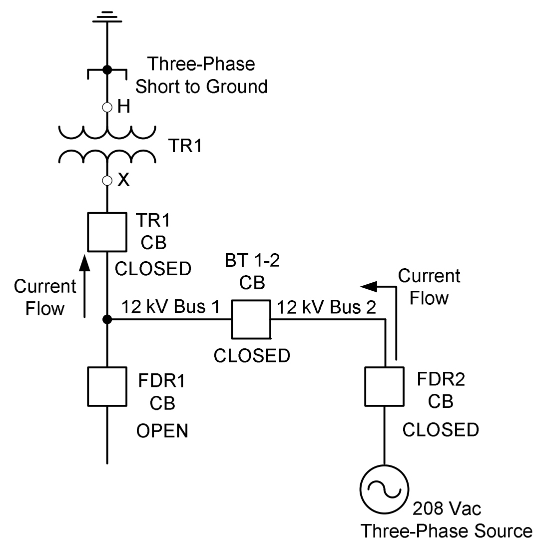

Fig. 24. One-line diagram of Bus 2 differential test setup

D. Interpretation of Results

The test results should show that actual values match up with calculated values. Actual source voltages, CT ratios, and transformer impedance should be taken into account regarding the tolerance of actual values. If the source is stable, the phase angles should be consistent according to the three-line current schematic. The magnitudes should be stable; any discrepancies should be investigated further with an inspection of secondary wiring and individual CT ratio tests. If all bus differential CTs are unshorted, the current measured at the bus differential relay should be 0 A. If this is not the case, identify which phase is in question, and retest the polarity of that CT.

VII. Conclusion

Through-fault testing is a major step in the commissioning process of any new substation equipment; bus sections are no exception. Simple calculations based on design schematics and equipment nameplates are required, along with adequate test equipment.

If through-fault testing is not performed, the equipment may misoperate and cause unnecessary investigation. This investigation requires testing personnel to recheck wiring, relamp dc schematic circuits, and relamp ac current/voltage circuits. This task is exhaustive and frustrating, since testing personnel are basically rechecking their work and delaying the energizing process. In the investigation process, support groups such as additional testers, substation construction workers, operators, planners, and other field personnel may be required. The cost of labor involved in the investigation process increases due to the time needed for testing. Additional through-fault tests may be required to prove any corrections made. The delay during investigation may cause further stress on project schedules.

Identifying these problems before the energizing process saves substation personnel time and stress. A complete test plan of commissioning new substation equipment installations should include a well-planned primary current injection test as the final step.

VIII. Appendix A

Appendix A demonstrates the calculation for Case 1.

Transformer nameplate data:

Ratio: 13.8/4.16 kV (H/X)

Base MVA: 16.8

Z1%: 10.1

Z1T = positive-sequence transformer impedance

Z2T = negative-sequence transformer impedance

Z0T = zero-sequence transformer impedance

Z1T = Z2T = Z1% = 10.1% = j 0.101 pu

Since the transformer nameplate only specified positive-sequence impedance, it is common practice to assume that Z0T is equal to Z1T.

Z0T = Z1T = Z1% = 10.1% = j 0.101 pu

Fig. 25 illustrates the positive- and negative-sequence networks for the transformer. Fig. 26 illustrates the zero-sequence network for the transformer.

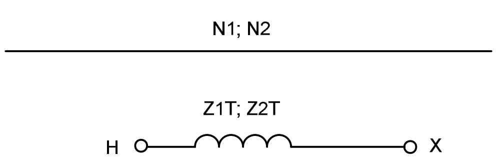

Fig. 25. Positive- and negative-sequence networks for a delta-wye transformer

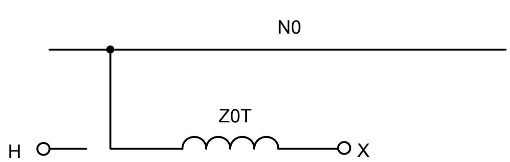

Fig. 26. Zero-sequence network for a delta-wye transformer

Calculate primary and secondary currents for Test 1: three-phase, reduced-voltage source applied to 13.8 kV winding and three-phase short circuit to ground applied to 4.16 kV winding.

Fig. 27 illustrates the sequence network for a three-phase fault applied to the 4.16 kV winding.

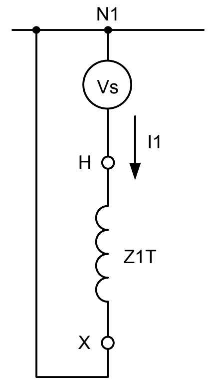

Fig. 27. Sequence network for a three-phase fault at 4.16 kV winding

Calculate Vs in pu:

Vs = 208 V/13,800 V = 0.0151 pu

Calculate I1 in pu:

I1 = Vs/Z1

Z1 = Z1T = j 0.101 pu

I1 = –j 0.1492 pu

13.8 kV level sequence quantities:

$I1_H = I1 = 0.1492 \angle{-90°}$ pu

4.16 kV level sequence quantities:

$I1_X = I1_H \bullet 1 \angle{-30°} = 0.1492 \angle{-120°}$ pu

Calculate primary currents in amperes:

1.0 pu current at 13.8 kV/16.8 MVA = 703 A

1.0 pu current at 4.16 kV/16.8 MVA = 2332 A

$|I_{AH}| = |I_{BH}| = |I_{CH}| = 0.1492 \bullet 703 = 105$ A

$|I_{AX}| = |I_{BX}| = |I_{CX}| = 0.1492 \bullet 2332 = 348$ A

$I_{AH} = I1_H = 0.1492 \angle{-90°}$ pu $= 105 \angle{-90°}$ A

$I_{BH} = a^2 \bullet I1_H = 1 \angle 240° \bullet 0.1492 \angle{-90°}$ pu $=$ $105 \angle{-210°}$ A

$I_{CH} = a \bullet I1_H = 1 \angle 120° \bullet 0.1492 \angle{-90°}$ pu $=$ $105 \angle{-330°}$ A

$I_{AX} = I1_X \bullet 1 \angle{-30°} = 1 \angle{-30°} \bullet -j\ 0.1492$ pu $=$ $348 \angle{-120°}$ A

$I_{BX} = a^2 \bullet I1_X = 1 \angle 240° \bullet 0.1492 \angle{-120°}$ pu $=$ $348 \angle 120°$ A

$I_{CX} = a \bullet I1_X = 1 \angle 120° \bullet 0.1492 \angle{-120°}$ pu $= 348 \angle 0°$ A

Calculate the secondary currents in amperes at the test switch locations, as shown in Fig. 28.

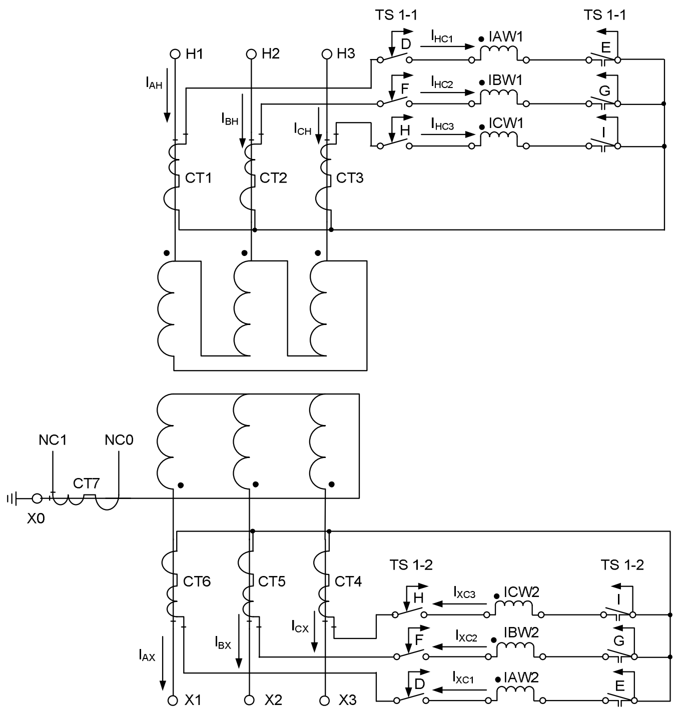

Fig. 28. Test switch locations and fault current distribution

All phase angles are measured in relationship to Phase A of the temporary reduced-voltage power supply, as shown in Fig. 7. The red side of the test plug always faces up.

$I_{HC1} = I_{AH}/240 = 0.438 \angle{-90°}$ A

$I_{HC2} = I_{BH}/240 = 0.438 \angle{-210°}$ A

$I_{HC3} = I_{CH}/240 = 0.438 \angle{-330°}$ A

$I_{XC1} = I_{AX}/400 = 0.87 \angle{-120°}$ A

$I_{XC2} = I_{BX}/400 = 0.87 \angle{-240°}$ A

$I_{XC3} = I_{CX}/400 = 0.87 \angle 0°$ A

Table I shows the expected values of current magnitude and phase angle at different test switches. Note that currents I_{HC1}, I_{HC2}, and I_{HC3} flow into the red blade of the test plug, so the phase angle measurements at the test switch TS 1-1 coincide with I_{HC1}, I_{HC2}, and I_{HC3} phase angles. Currents I_{XC1}, I_{XC2}, and I_{XC3} flow into the black blade of the test plug, consequently causing the phase angle measurements at TS 1-2 to shift 180 degrees from I_{XC1}, I_{XC2}, and I_{XC3} phase angles.

TABLE I
EXPECTED VALUES OF CURRENT AT TEST SWITCHES

Test Switch Location	Expected Current
TS 1-1:E	0.438 ∠–90° A
TS 1-1:G	0.438 ∠–210° A
TS 1-1:I	0.438 ∠–330° A
TS 1-2:E	0.87 ∠–300° A
TS 1-2:G	0.87 ∠–60° A
TS 1-2:I	0.87 ∠–180° A

Calculate primary and secondary currents for Test 2: three-phase, reduced-voltage power supply applied to 13.8 kV winding and single-phase, short circuit to ground applied to 4.16 kV bushing X1.

Fig. 29 illustrates the sequence network for a single-phase fault (A-phase to ground) at the 4.16 kV winding.

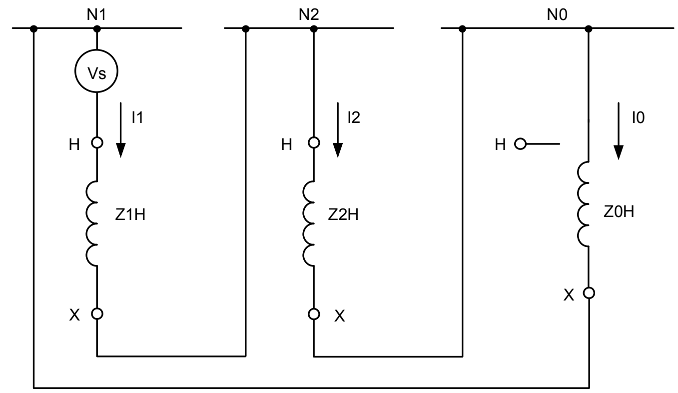

Fig. 29. Sequence network for a single-phase-to-ground fault at the 4.16 kV winding

Calculate Vs in pu:

Vs = 208 V/13,800 V = 0.0151 pu

Calculate I1, I2, and I0 in pu:

Z1 = Z1T = j 0.101 pu

Z2 = Z2T = j 0.101 pu

Z0 = Z0T = j 0.101 pu

I1 = I2 = I0 = Vs/Z0 + Z1 + Z2 = –j 0.0497 pu

4.16 kV winding sequence quantities:

$I0_X = -j\,0.0497$ pu $= 0.0497 \angle{-90°}$ pu

$I1_X = -j\,0.0497$ pu $= 0.0497 \angle{-90°}$ pu

$I2_X = -j\,0.0497$ pu $= 0.0497 \angle{-90°}$ pu

13.8 kV winding sequence quantities:

$I0_H = 0$

$I1_H = I1_X \bullet 1 \angle{+30°} = 0.0497 \angle{-60°}$ pu

$I2_H = I2_X \bullet 1 \angle{-30°} = 0.0497 \angle{-120°}$ pu

Calculate primary currents in amperes:

1.0 pu current at 13.8 kV/16.8 MVA = 703 A

1.0 pu current at 4.16 kV/16.8 MVA = 2332 A

$I_{AH} = I0_H + I1_H + I2_H = 0.0861 \angle{-90°}$ pu

$I_{AH} = 703 \bullet 0.0861 \angle{-90°} = 60.6 \angle{-90°}$ A

$I_{BH} = I0_H + a^2 \bullet I1_H + a \bullet I2_H = 0$

$I_{CH} = I0_H + a \bullet I1_H + a^2 \bullet I2_H = 0.0861 \angle 90°$ pu

$I_{CH} = 703 \bullet 0.0861 \angle 90° = 60.6 \angle 90°$ A

$I_{AX} = I0_X + I1_X + I2_X = 0.1491 \angle{-90°}$ pu

$I_{AX} = 2332 \bullet 0.1491 \angle{-90°} = 348 \angle{-90°}$ A

$I_{BX} = I0_H + a^2 \bullet I1_H + a \bullet I2_H = 0$

$I_{CX} = I0_H + a \bullet I1_H + a^2 \bullet I2_H = 0$

$I_N = 3 \bullet I0_X = 0.1491 \angle{-90°}$ pu

$I_N = 2332 \bullet 0.1491 \angle{-90°} = 348 \angle{-90°}$ A

Calculate the secondary currents in amperes at the test switch locations, as shown in Fig. 30.

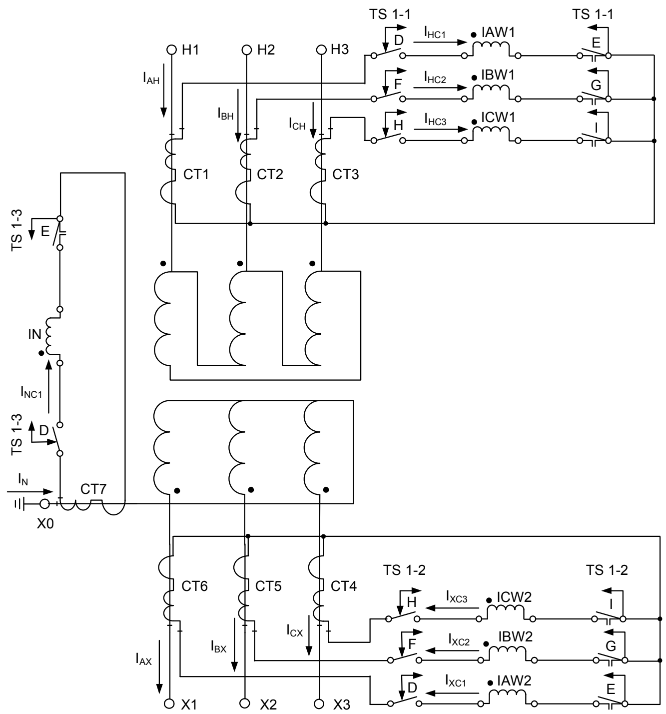

Fig. 30. Test switch locations and fault current distribution

All phase angles are measured in relationship to Phase A of the temporary reduced-voltage power supply, as shown in Fig. 7. The red side of the test plug always faces up.

$I_{HC1} = I_{AH}/240 = 0.253 \angle{-90°}$ A

$I_{HC2} = I_{BH}/240 = 0$ A

$I_{HC3} = I_{CH}/240 = 0.253 \angle{-270°}$ A

$I_{XC1} = I_{AX}/400 = 0.87 \angle{-90°}$ A

$I_{XC2} = 0$ A

$I_{XC3} = 0$ A

$I_{NC1} = I_N/40 = 8.7 \angle{-90°}$ A

Table II shows the expected values of current magnitude and phase angle at different test switches.

TABLE II
EXPECTED VALUES OF CURRENT AT TEST SWITCHES

Test Switch Location	Expected Current
TS 1-1:E	0.253 ∠–90° A
TS 1-1:G	0 A
TS 1-1:I	0.253 ∠–270° A
TS 1-2:E	0.87 ∠–27° A
TS 1-2:G	0 A
TS 1-2:I	0 A
TS 1-3:E	8.7 ∠–90° A

IX. APPENDIX B

A. Sample Test Data Sheet for Bus Differential Through-Fault Test

12 kV Bus Differential Thru-Fault Test DATE:

TEST METER USED:

		expected	measured
PRIMARY CURRENTS: 12 kV side	Aϕ =	100.00 A	
	Bϕ =	100.00 A	
	Cϕ =	100.00 A	

MEASURED VOLTAGES AT SOURCE:

A-B		V
B-C		V
C-A		V
A-G		V
B-G		V
C-G		V

MEASURED P-N VOLTAGE AT phase angle meter: <=reference

MAGNITUDES ARE IN mA; ANGLES ARE IN DEGREES

12 kV Bus Differential Thru-Fault Test Data

12 kV Bus 1 Differential

87B1 all CT contributions unshorted

		EXPECTED		ACTUAL	
CT Ratio: 500:1	TS 3-2	MAG	∠	MAG	∠
Aϕ	E	0.000	NA		
Bϕ	G	0.000	NA		
Cϕ	I	0.000	NA		

87B1 only TR 1 CT (CT-1); shorted FDR 1 contribution
FDR 1 SHORTING SWITCHES = TS2-1 A,B,C,D

		EXPECTED		ACTUAL	
CT Ratio: 500:1	TS 3-2	MAG	∠	MAG	∠
Aϕ	E	0.200			
Bϕ	G	0.200			
Cϕ	I	0.200			

87B1 only FDR 1 CT (CT-4); shorted TR 1 contribution
TR76 SHORTING SWITCHES = TS1-1 A,B,C,D

		EXPECTED		ACTUAL	
CT Ratio: 500:1	TS 3-2	MAG	∠	MAG	∠
Aϕ	E	0.200			
Bϕ	G	0.200			
Cϕ	I	0.200			

End test 1
move test source leads to FDR 2

87B1 all CT contributions unshorted

		EXPECTED		ACTUAL	
CT Ratio: 500:1	TS 3-2	MAG	∠	MAG	∠
Aϕ	E	0.000	NA		
Bϕ	G	0.000	NA		
Cϕ	I	0.000	NA		

87B1 only BT 1-2 CT (CT-6); shorted TR 1 contribution
BT 1-2 SHORTING SWITCHES = TS3-1 A,B,C,D

		EXPECTED		ACTUAL	
CT Ratio: 500:1	TS 3-2	MAG	∠	MAG	∠
Aϕ	E	0.200			
Bϕ	G	0.200			
Cϕ	I	0.200			

12 kV Bus 2 Differential

87B2 all CT contributions unshorted

		EXPECTED		ACTUAL	
CT Ratio: 500:1	TS 3-4	MAG	∠	MAG	∠
Aϕ	E	0.000	NA		
Bϕ	G	0.000	NA		
Cϕ	I	0.000	NA		

87B2 only FDR 2 CT (CT-8); shorted BT 1-2 contribution
BT 1-2 SHORTING SWITCHES = TS3-3 A,B,C,D

		EXPECTED		ACTUAL	
CT Ratio: 500:1	TS 3-4	MAG	∠	MAG	∠
Aϕ	E	0.200			
Bϕ	G	0.200			
Cϕ	I	0.200			

87B2 only BT 1-2 CT (CT-5); shorted FDR 2 contribution
FDR 2 SHORTING SWITCHES = TS4-1 A,B,C,D

		EXPECTED		ACTUAL	
CT Ratio: 500:1	TS 3-4	MAG	∠	MAG	∠
Aϕ	E	0.200			
Bϕ	G	0.200			
Cϕ	I	0.200			

B. 12 kV Bus Differential Through-Fault Test Procedure

1. Verify 138 kV TR1 C/S switch is open and uncoupled.
2. Verify positive-sequence rotation at Terminals 1, 2, and 3 of the reduced-voltage power supply safety disconnect switch. Also, measure phase-to-phase and phase-to-ground voltages at the same location. Refer to Fig. 31 for measuring points and connections.
3. Connect Terminals 4, 5, and 6 of the safety switch to Terminals A, B, and C of the FDR1 circuit breaker.
4. Verify source leads continuity from safety switch to the FDR1 circuit breaker.
5. Connect the reference voltage of the phase angle meter to the same phase connected to Terminal A of the FDR1 circuit breaker.
6. Apply a three-phase short circuit to the H bushings of Transformer T1.
7. Verify the TR1 circuit breaker is open.
8. Verify the FDR1 circuit breaker is open.
9. Verify the FDR2 circuit breaker is open.
10. Verify the BT 1-2 circuit breaker is open.
11. Verify that the Transformer TR1 load tap changer control is on manual mode and the tap changer is on neutral position.
12. Verify that the TR1 tank pressure gauge indicates positive pressure, and look for any strange objects connected to the H or X bushings of the transformer.
13. Identify and open the various current measuring switches involved in the test—TS 3-2: E, G, and I and TS 3-4: E, G, and I.
14. Perform a final inspection.
15. Perform three-phase, through-fault test from FDR1:
    a. Close safety switch.
    b. Close the TR1 circuit breaker.
    c. Close the FDR1 circuit breaker.
    d. Verify voltage at switch: record actual phase-to-phase and phase-to-ground voltages. Use an ac current clamp to measure the actual current on A-, B-, and C-phases and neutral.
    e. Take measurements using data sheet.
    f. Open the FDR1 circuit breaker.
    g. Open safety switch.
16. Check that source leads are dead, and move source leads to FDR2 LINE side.
17. Perform three-phase, through-fault test from FDR2:
    h. Close safety switch.
    i. Close the BT 1-2 circuit breaker.
    j. Close the FDR2 circuit breaker.
    k. Verify voltage at switch: record actual phase-to-phase and phase-to-ground voltages. Use an ac current clamp to measure the actual current on A-, B-, and C-phases and neutral.
    l. Take measurements using data sheet.
    m. Open the TR1 circuit breaker.
    n. Open the BT 1-2 circuit breaker.
    o. Open the FDR2 circuit breaker.
    p. Open safety switch.
18. Remove source leads and three-phase short circuit applied to the H bushings of Transformer T1.

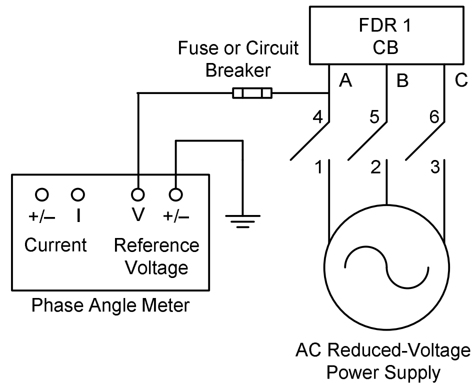

Fig. 31. AC connections to FDR1 circuit breaker

X. References

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XI. Vitae

Oliver Peterson is a senior engineer with the Testing Group for Commonwealth Edison (ComEd) in Chicago, IL. He has worked at ComEd for nine years, primarily commissioning, maintaining, and troubleshooting substation protective equipment. Prior to his work at ComEd, he received his BSEE from the University of Alaska-Fairbanks and an MSEE from the University of Wisconsin-Madison. Oliver is a registered Professional Engineer with the State of Illinois.

Rogerio Scharlach received his BSEE from the University Mackenzie, Brazil, in 1991. Upon graduating, he served nearly 13 years at Siemens in Brazil and the United States, where he worked as a commissioning and field service engineer in the areas of power generation, transmission, and distribution. He joined Schweitzer Engineering Laboratories, Inc. in 2005 as a field application engineer.

Cesar Baltazar earned his BSEE from the University of Texas-El Paso in 1998. He was then employed by Commonwealth Edison in Chicago as a field relay engineer, focusing on installing, testing, and applying different types of protective equipment commonly used in industrial plants and power systems. This included a variety of electromechanical, static, and digital multifunction relays. He joined Schweitzer Engineering Laboratories, Inc. in 2007 as a field application engineer. His responsibilities include providing application support and technical training for protective relay users.

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