Lessons Learned Through Commissioning and Analyzing Data From Transformer Differential Installations

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Abstract—**Ensuring correct setting and installation of a transformer differential relay is critical. A transformer differential relay must detect internal faults, damaging overloads, and through-fault currents while remaining secure against misoperation. The ability to use wye-connected CTs with microprocessor-based relays has simplified installations, and these relays provide better commissioning tools than those available with traditional relays. However, installations and commissioning remain complicated. Installation and settings errors continue to be widespread, implying a need for more rigorous commissioning tests. Even with greater commissioning effort, occasional wiring problems develop over time, and these can best be resolved through analysis of relay event report data. In the interest of reducing transformer differential misoperations, we share in this technical paper practical lessons we have learned through experience with commissioning and relay event report analysis.**

I. Introduction

In many ways, microprocessor-based transformer differential relays have simplified installations. These relays perform internal mathematical computations for phase-angle compensation and zero-sequence filtering. One can use these relays with lower burden wye-connected CTs regardless of transformer winding connections and can accommodate virtually any transformer application. Built-in metering displays secondary current magnitude and phase angle. Relay metering also displays operate and restraint quantities useful in commissioning exercises.

Despite advanced technology, however, a multitude of potential mistakes and problems conspire to make the installation of differential relays challenging. There can be wiring errors such as rolled phase wires, reversed polarity, and incorrect CT taps. Phase-angle compensation and zero-sequence filtering settings errors continue to be widespread. System phase rotation, phase-to-bushing connections, CT secondary wiring, and mobile transformer arrangements can all complicate installations. Installers must also overcome challenges from power system events that include inrush, overexcitation, external faults with CT saturation, and operating conditions that bypass CTs.

Engineers and technicians have seen a number of proposed solutions that attempt to reduce the complexity of transformer differential relay installation and commissioning. Primary injection tests attempt to find problems before transformer energization. Commissioning worksheets and process checklists help engineers and technicians step through in-service metering checks and troubleshooting methodically. Software tools graphically display currents, operate and restraint quantities, and harmonics. Relays also offer the promise of automated or relay-assisted commissioning.

Commissioning tests are intended to find wiring and settings mistakes before protection schemes go into service. However, mistakes continue to go unnoticed. These mistakes result from improper or incomplete tests, the lack of sufficient load current during in-service meter readings, misinterpretation of in-service readings, or the lack of complete testing altogether. Relay-assisted commissioning may not be able to uncover more than single-contingency installation errors [1]. Unfortunately, multiple-contingency errors are not uncommon.

Even perfect commissioning during initial installation does not prevent problems from developing over time. Such problems include CT wiring short circuits and loose connections. Event report analysis provides the best way to identify these problems.

Despite advances in relay technology, the application of transformer differential relays remains challenging. Proper application requires careful settings development and thorough commissioning. Technology has not yet replaced the invaluable contribution of a knowledgeable and experienced engineer and technician. Collective experience in helping troubleshoot misapplications and determine the root cause of misoperations provides practical lessons that we share in this technical paper with the goal of reducing the number of transformer differential misoperations.

II. Transformer Differential Review

Transformer differential protection is deceivingly simple in concept. A transformer differential relay compares current entering the transformer to current leaving the transformer. If the currents are not nearly equal, we assume an internal fault. Because the relay responds to difference current, rather than to total current through the transformer, we can set it to be quite sensitive. Because CT locations define the zone of protection, the relay is highly selective and can operate with no coordination time delay.

We can use a simple instantaneous overcurrent relay such as Fig. 1 illustrates to visualize the behavior of the differential relay for an external fault (or through-load). Assume for now that the protected equipment is a bus, with no voltage transformation or phase shift. If the CTs are ideal and identical, the currents on both sides of the protected equipment are equal and have opposite polarity. Therefore, the overcurrent relay detects no current; i.e., the difference current is zero for an external fault. If, however, the fault is internal to the CTs, the currents have the same phase angle, add together, and pass through the overcurrent relay; i.e., the relay measures difference current for an internal fault.

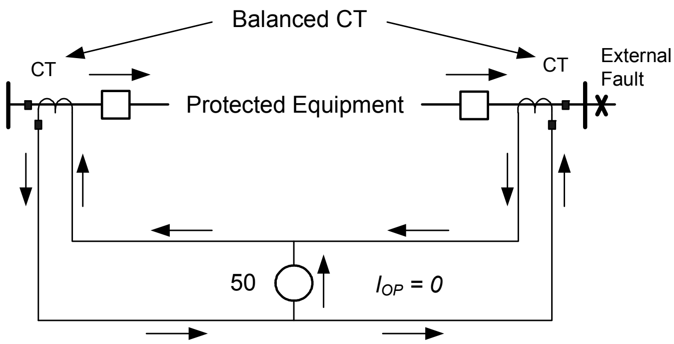

Fig. 1 Differential relay concept

In a microprocessor-based differential relay, there is no overcurrent operate coil such as in Fig. 1. Instead, the relay samples and extracts the fundamental instantaneous magnitude and phase angle of the currents. From these values, the relay mathematically calculates the phasor sum of the currents, which we call operate or difference current. Fig. 2 shows a percentage-restraint differential relay. Instead of comparing the operate current to a simple threshold or pickup, the relay calculates the ratio of operate current to a restraint quantity. When the ratio of operate-to-restraint current exceeds a certain percentage, the relay operates. In addition, the relay has a variable sensitivity dependent on restraint. Relay design determines what constitutes restraint current, but it typically is the scaled scalar sum of the CT currents, for example the average of the current magnitudes.

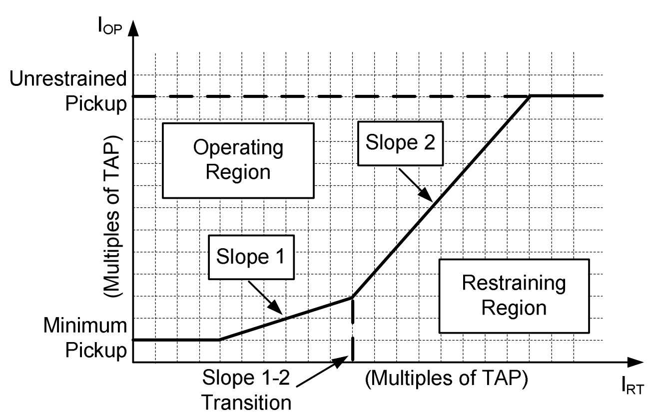

Fig. 2 Percentage-restraint concept

The area above the Slope 1 and Slope 2 line represents the operating region. The area below this line represents the restraining region, where no trip occurs. The lowest horizontal portion of the trip threshold represents the minimum sensitivity of the relay. This minimum setting is typically 30 percent or 0.3 per unit and is necessary to deal with errors at very low magnitudes of current and tap changer operations. Because CT error resulting from saturation is most likely to be a problem at higher current levels, the slope of the characteristic provides increased security as currents increase. The highest horizontal portion of the trip threshold is the unrestrained or instantaneous trip, whose purpose is to react quickly to very heavy current levels that clearly indicate an internal fault.

In practice, many power system challenges make the design and application of transformer differential relays difficult [2]. Unequal CT performance, resulting predominantly from CT saturation, causes the relay to measure operate current. The percentage-restraint characteristic adds security during external faults with CT saturation. It is important to note that the ANSI accuracy class or C-rating of a multiratio CT applies only to the full winding of the CT; any tap selection less than full winding will degrade CT performance.

Transformers can introduce phase-angle shifts. These phase shifts, if unaccounted for, introduce operate current for through-load or fault conditions. Traditionally, transformer wye windings incorporated delta-connected CTs to remove the phase-angle shift the power transformer introduced. A microprocessor-based relay accounts for the transformer phase shift mathematically by applying appropriate phase-angle compensation. This feature of microprocessor-based relays makes it possible to use wye-connected CTs in all instances.

Wye-connected CTs present a lower burden than do delta-connected CTs. Burden can be as much as three times less, depending on fault type. With wye CTs, one can use zero-sequence overcurrent elements from the same relay CT inputs. Drawings and connections are easier to understand. Wye CTs provide easier phase overcurrent coordination with downstream feeders (no $\sqrt{3}$ pick-up adjustment to remember) than do delta-connected CTs. Lastly, metering data match those from other equipment, such as bus main or feeder relays that typically use wye CTs.

The internal phase-angle compensation capability of microprocessor-based relays makes available numerous benefits obtained from using wye-connected CTs. However, one must take great care in setting phase-angle compensation correctly; errors with this setting are some of the most common mistakes installers make with differential relays.

In discussions of phase shift across a transformer, it is common to hear a transformer described as an ANSI standard. This description means that the high-side phase currents lead the low-side phase currents by 30 degrees. These transformers are also called DABy or Dy1, where the capital letters represent high voltage and lowercase letters represent the low side. DAB refers to a high-voltage delta connected polarity of A to a nonpolarity of B. A “y” refers to a wye winding. The “1” indicates that the low side lags the high side by “1 hour on the clock,” or 1 increment of 30 degrees. Either way, these shorthand notations express that one might expect a transformer high-side phase current to lead the corresponding low-side phase current by 30 degrees. This *primary* phase relationship across the transformer determines phase-angle compensation settings.

See Fig. 3 for an important but easy-to-overlook observation. The current the relay detects on the secondary of the CT on Winding 2 will be 180 degrees out of phase with the current on the primary of the CT. When one takes phase-angle measurements during commissioning for a through-load condition on the transformer we have been discussing, the relay secondary terminal block will detect the low-side current *leading* the high-side current by 150 degrees*. This is normal and expected.*

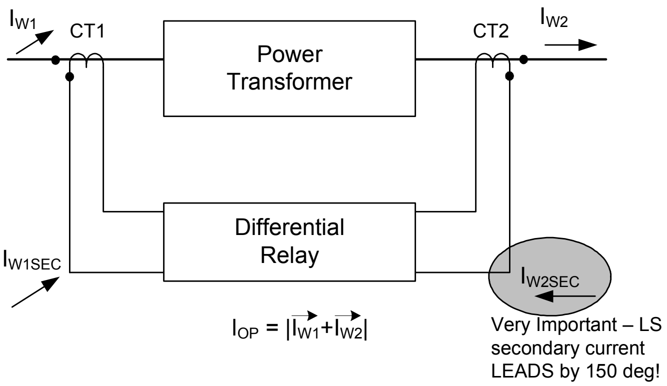

Fig. 3 Phase-angle shift across a transformer

Available CT taps can cause current magnitude mismatch errors. With a transformer that has a 10:1 voltage transformation ratio, one would ideally choose CT ratios that had a 1:10 ratio. Choosing such CT ratios is not always possible, given the existing taps on the CTs. This inability to obtain the proper ratio leads to current magnitude mismatch. The differential relay corrects these errors with a tap setting. Tap is defined as the current, in amps, that flows in the CT secondaries at the maximum transformer power rating. Through use of a tap setting for each winding, the relay converts all currents into per unit, while accounting for any current magnitude mismatch.

Let us now consider zero-sequence current sources. Consider a typical two-winding power transformer that is delta-connected on the high side and grounded-wye connected on the low side. A low-side phase-to-ground fault will result in zero-sequence current flowing through the low-voltage CTs without a corresponding zero-sequence current flowing through the high-voltage CTs. The fault is external, so the secondary currents the relay detects must be equal in magnitude and 180 degrees out of phase after current magnitude and phase-angle correction. Therefore, to prevent relay misoperation, we must remove the zero-sequence current the low-voltage CTs detect. One can typically accomplish this removal by selecting the correct phase-angle compensation setting in the relay. Thus, internal phase-angle compensation corrects both phase-angle and zero-sequence source errors. Any phase-angle compensation that performs the mathematical equivalent of a delta CT eliminates the zero-sequence current component.

Fig. 4 shows the development of operate and restraint quantities after tap and phase-angle compensation.

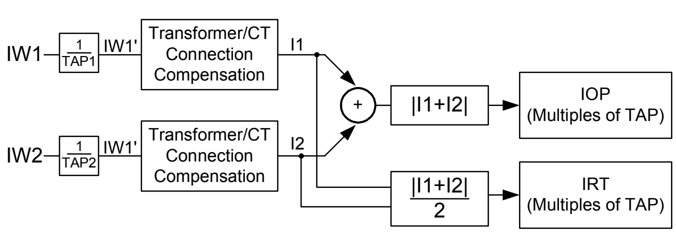

Fig. 4 Development of operate and restraint

The differential relay must also remain secure in the presence of magnetizing inrush current. Only one winding detects this current during transformer energization, so the relay detects an obvious difference current. Fortunately, the relay can take advantage of harmonics and dc offset, typical components of the current waveform during inrush. Relays can employ any or all of a variety of different means to provide security during inrush, including second- and fourth-harmonic blocking, second- and fourth-harmonic restraint, independent or common harmonic blocking, and dc ratio blocking. Reference [3] provides an excellent discussion of inrush restraint methods.

There are a great number of other factors to consider when developing transformer protection. We mention some of these factors here as a review. Restricted earth fault or zero-sequence differential can provide detection of phase-to-ground faults near the neutral on wye-connected windings. The slope characteristic of the normal phase differential element causes relay sensitivity to decrease as load current increases. Therefore, at maximum transformer loading, the phase differential element may be unable to detect ground faults near the neutral until the fault evolves. Zero-sequence differential or restricted earth fault elements are immune to balanced load, so one can set these elements more sensitive for this type of fault. In autotransformer applications, use a neutral CT for the reference current. For these applications, do not use CTs in the delta tertiary.

In some installations, devices such as sudden pressure relays, gas-accumulator relays, or combination Buchholz relays monitor sudden pressure change or the accumulation of combustible gases within a transformer. These devices can detect turn-to-turn faults deep inside a winding that produce little current difference at the transformer bushing.

It is common to interface indicating contacts from these relays to a microprocessor-based relay for tripping, trip seal-in, event report triggering, and SCADA indication. One must take great care, however, when implementing direct trip applications; sudden pressure relays have a reputation for poor security and lack of dielectric strength. As Fig. 5 illustrates, use both the normally open and normally closed contacts from these devices to indicate a trip. Also use debounce delays on any digital relay inputs monitoring these devices, to provide necessary security.

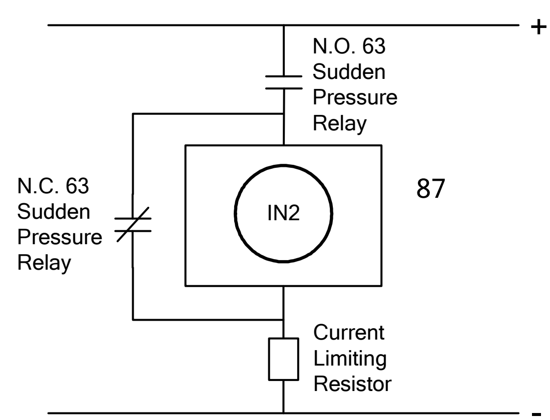

Fig. 5 Interface to sudden pressure relay

Operating conditions that bypass CTs are a common threat to differential relay security. Consider the one line diagram in Fig. 6. If the bus main breaker is in need of maintenance, it is possible to bypass the breaker by closing the parallel switch. However, possibly as soon as current switches from the bus main breaker, and definitely when the bus main breaker opens, the transformer differential relay will trip. Before and during this maintenance, therefore, one must isolate the differential relay from the lockout relay it operates.

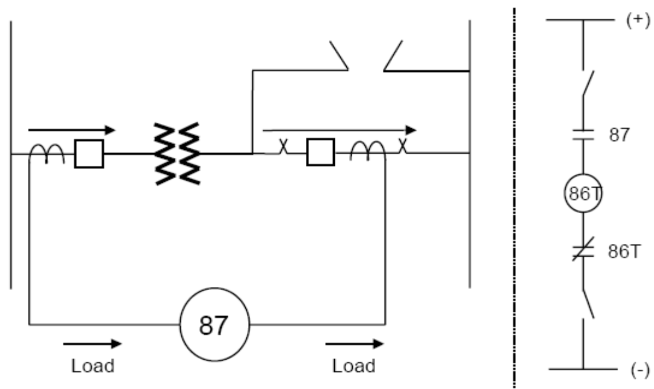

Fig. 6 Bus main breaker with breaker bypass switch

How the scheme in Fig. 6 returns to normal has great importance. Differential relays can have a trip-latching mechanism that, once a relay activates a trip, holds the trip asserted until the disappearance of all current. If so, the trip remains active throughout the maintenance period because load current likely exceeds the minimum current supervision. Even when the bypass switch opens and the balance of current returns, the trip may still be active because there was never any loss of load current through Winding 1. The local technician must take great care in remembering to reset the differential manually, before returning the differential relay to service, or the lockout will inadvertently trip. Most microprocessor-based relays provide for customization of the trip unlatch condition. In this example, allowing the trip to reset when the differential condition extinguishes would be more appropriate.

Special cases, such as mobile transformer installations, require extra attention. With mobile transformers, the system phase rotation or the phase-to-bushing connections may vary at each installation location. However, it is likely that the physical connections from the CTs to the relay do not change. A-phase on the system may not be connected to A-phase of the relay. While not ideal, this type of connection is commonplace. One must in such situations adjust relay settings, particularly those for phase-angle compensation.

Damage because of overexcitation results from excess flux seeking a path through structural steel that is not designed to handle the resulting eddy currents and localized heating. The flux density in the core of a transformer is a function of the volts-per-turn applied and the frequency. Therefore, a volts-per-hertz element provides the best overexcitation protection. If a relay does not have a voltage input, one can monitor the fifth-harmonic content of the currents. Generally, the time necessary to respond to an overexcitation condition is relatively slow, so it is common to use the overexcitation element to block the high-speed differential element, while at the same time alarming through SCADA.

Overcurrent and overload protection is a key component of transformer protection. Differential relays include backup overcurrent elements, and one should set these to protect the transformer damage curve for through faults. Because through-fault damage is cumulative, it is also helpful to monitor and alarm for accumulated I^2t over time. During peak demand periods, thermal modeling and monitoring can warn against insulation damage.

III. Setting Examples and Concerns

System phase rotation is important for several reasons. The relay must have system phase rotation information to properly calculate symmetrical components and to properly set phase-angle compensation settings. We define system phase rotation as the sequence in which system phases proceed as they rotate in a counter-clockwise direction. We express this rotation either as ABC or ACB. Positive rotation is synonymous with an ABC system, while negative describes an ACB system. Some interchange CBA for ACB. ABC, BCA, or CAB indicates a positive or ABC system phase rotation, and ACB, CBA, or BAC indicates a negative or ACB system phase rotation.

Understanding which system phase is connected to which transformer bushing is the next critical step in setting the differential relay correctly. We define phase-to-bushing connection as the order or sequence in which the system phases land on the transformer bushings. For example, system phase A can be physically connected to transformer bushings H1, H2, or H3. It is common to use the terminology of “ABC to H1-H2-H3” or “positive” phase connections to H1-H2-H3, in which case the implication is that A-phase is connected to H1, B-phase is connected to H2, and C-phase is connected to H3. In fact, ABC, BCA, or CAB connected to H1-H2-H3, respectively, all indicate a positive or ABC system phase-to-bushing connection. ACB, or CBA, or BAC connected to H1-H2-H3, respectively, all indicate a negative or ACB system phase-to-bushing connection.

One may generally assume, but should verify in the field, that each transformer winding has the same phase-to-bushing connection sequence and system phase rotation. One can also assume an ABC to H1-H2-H3 phase-to-bushing connection on transformer nameplate drawings. Again, this assumption may have no relationship to actual field connections.

An installation can have a positive or ABC system phase rotation but a negative or ACB to H1-H2-H3 phase-to-bushing connection. This has tremendous impact on the phase-angle shift across the transformer and, therefore, on required phase-angle compensation settings. Do not rely on the nameplate diagram alone. One must have a verified three-line diagram to set the relay.

It is a requirement that the transformer nameplate show how each winding is connected. Through use of the nameplate, the system phase rotation, and the phase-to-bushing connections, one can quickly sketch the phase-angle relationship one should expect between transformer windings.

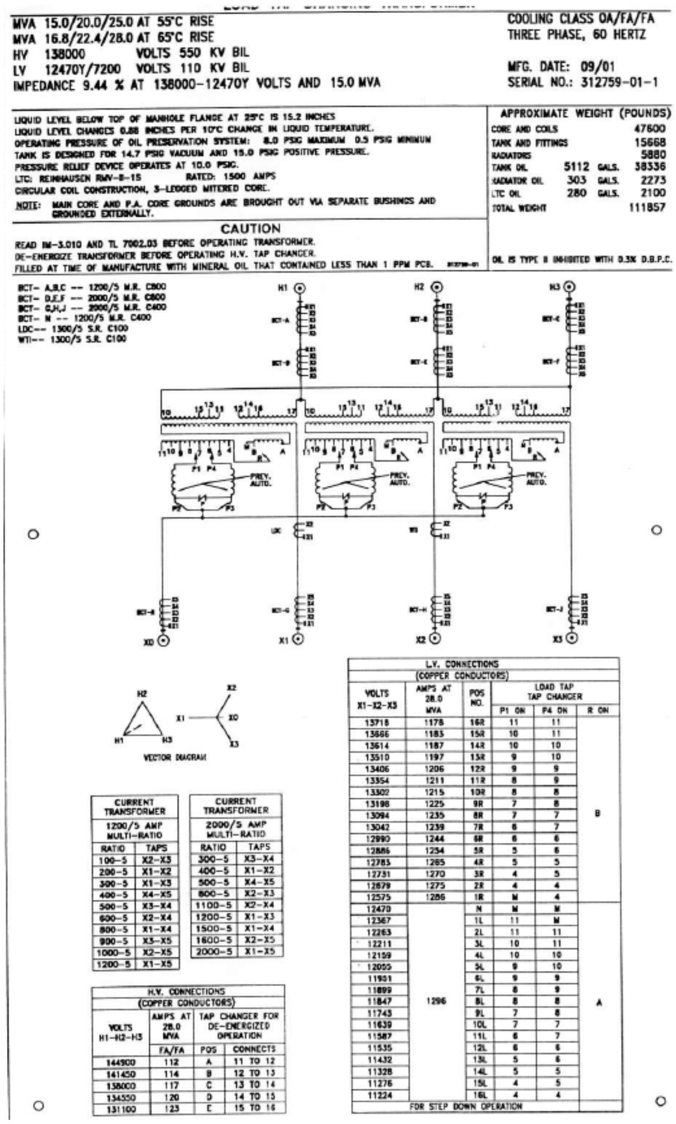

Fig. 7 Example transformer nameplate

Assume that we are developing settings for the transformer shown in Fig. 7. In this first example, our system phase rotation is ABC. The system phase-to-bushing connections are B-to-H1, C-to-H2, and A-to-H3. Recognize that BCA phase-to-bushing connections are the same as a positive or ABC connection sequence. Combination of the nameplate and the phase-to-bushing information produces the simplified three-line diagram in Fig. 8.

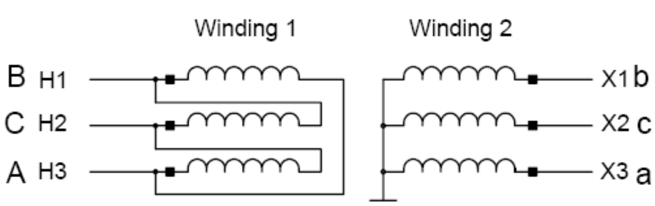

Fig. 8 Simplified three-line diagram

To determine the phase-angle shift across the transformer, draw a balanced three-phase set of phasors in the proper system phase rotation that represents the high-side phase currents. See Fig. 9. Through the use of the phase-to-bushing connections, and the transformer nameplate information in Fig. 8, one can determine the phase angles of the currents inside the delta windings on the high side. The current passing through the winding at the top left in Fig. 8 is a delta current, or the difference between the system B-phase and the system A-phase (1.73 p.u. @ –150 degrees). This winding corresponds to the low-side winding shown at the top right in Fig. 8, so you can transpose this phasor (1.73 p.u. @ –150 degrees) to the low-side X1 bushing of the transformer.

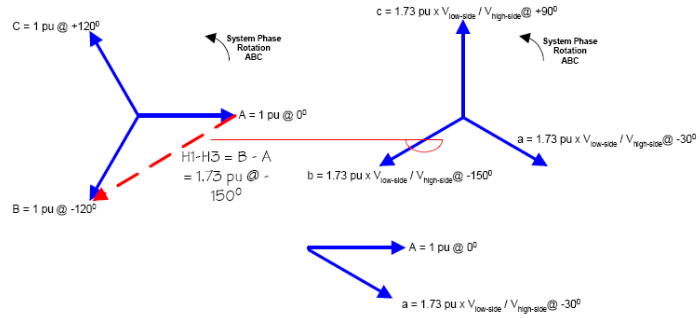

Fig. 9 Derivation of phase-angle relationship (1)

Continue this process until you have completed the balanced three-phase set of low-side phasors. You now know the angle relationship between the high side and the low side of the transformer. As the nameplate suggests, in this example, the high-side phase currents lead the low-side phase currents by 30 degrees.

It does not take a great deal of effort to derive the actual phase-angle relationship. It is critical that this derivation of the phase-angle relationship occur before any attempt to set the relay, so that internal phase-angle compensation settings can be set correctly.

Different phase-angle relationships result from different system phase rotation or phase-to-bushing connections with the exact same transformer. Connected to a system with ACB system phase rotation, and with A-to-H1, B-to-H2, and C-to-H3 phase-to-bushing connections, the low-side phase currents will actually *lead* the high-side by 30 degrees, contrary to the nameplate diagram. Similarly, it can be shown that use of the same transformer, connected to a system with ABC system phase rotation, and with A-to-H1, C-to-H2, and B-to-H3 phase-to-bushing connections, will cause the low-side phase currents to actually *lead* the high side by 30 degrees, contrary to the nameplate diagram.

The next important part of the design we must understand before we can set the relay correctly is how the system phase currents connect to the relay inputs. We recommend using wye-connected CTs and connecting A-phase of the system to A-phase of the relay, B-phase of the system to B-phase of the relay, and C-phase of the system to C-phase of the relay. We previously discussed the benefits of wye-connected CTs. Wiring the relay inputs to the appropriate system phase ensures that metering, involved-phase fault targets, and analog channels in event reports match the power system.

With mobile transformers, we may not want to rewire the CTs at each installation. However, not rewiring the CTs can lead to situations where the system phase is not properly connected to the corresponding relay phase. Connection of the system phase to the corresponding relay phase is one of the basic recommended practices for CT wiring to any microprocessor-based relay. It is impossible to develop one set of phase rotation and phase-angle compensation settings suitable for every conceivable mobile installation. While not an ideal situation, relay settings, phase-angle compensation settings particularly, must be adjusted. This is one instance where installing a relay with multiple settings groups is ideal. Such an installation would make it possible to preload different settings to match all configurations. During mobile transformer installation, a technician could move a group selector switch to the appropriate position for the installation.

Now that we have all the appropriate information (system phase rotation, phase-to-bushing connections, transformer nameplate, and CT secondary wiring), we can set phase-angle compensation settings for the relay. Most microprocessor-based relays apply some form of matrix mathematics to the measured phase currents to correct for transformer and CT phase-angle shifts and zero-sequence sources. A complete example will be helpful to demonstrate how this works.

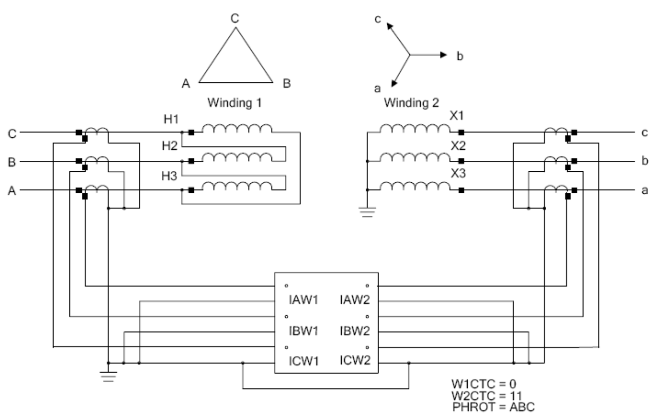

Fig. 10 Complete connection example

Assume that a power system with system phase rotation ABC incorporates the transformer with the nameplate shown in Fig. 7. The phase-to-bushing connections are C-to-H1, B-to-H2, and A-to-H3. The CT secondaries are wired such that the system phases connect to the corresponding relay inputs: A-phase on the system to A-phase on the relay, B to B, C to C. Fig. 10 shows the complete three-line diagram. Follow the process we discussed previously for developing the phase-angle relationship across the transformer, as shown in Fig. 11.

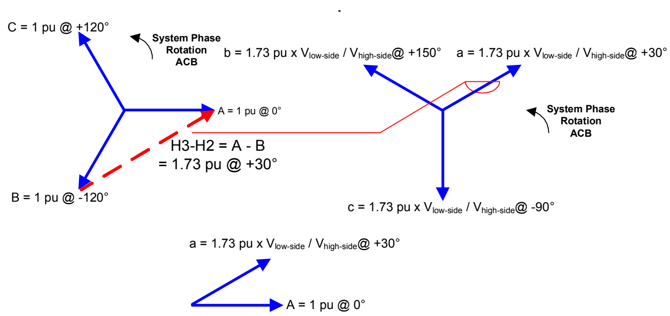

Fig. 11 Development of phase-angle relationship (2)

Because of the phase-to-bushing connections, the low-side currents will now *lead* the high-side currents by 30 degrees, contrary to the transformer nameplate.

When setting the relay, we choose a connection compensation matrix from the list shown in Fig. 12 for each winding. When multiplied by the phase currents, the compensated currents should produce zero operate current for external load or faults. One available choice, the identity matrix or compensation matrix M0, does not appear in Fig. 12; this is the one matrix that does not change the phase currents in any way.

$$[\mathrm{CTC}(1)] = \frac{1}{\sqrt{3}} \bullet \begin{bmatrix} 1 & -1 & 0 \\ 0 & 1 & -1 \\ -1 & 0 & 1 \end{bmatrix} \qquad [\mathrm{CTC}(2)] = \frac{1}{3} \bullet \begin{bmatrix} 1 & -2 & 1 \\ 1 & 1 & -2 \\ -2 & 1 & 1 \end{bmatrix}$$

$$[\mathrm{CTC}(3)] = \frac{1}{\sqrt{3}} \bullet \begin{bmatrix} 0 & -1 & 1 \\ 1 & 0 & -1 \\ -1 & 1 & 0 \end{bmatrix} \qquad [\mathrm{CTC}(4)] = \frac{1}{3} \bullet \begin{bmatrix} -1 & -1 & 2 \\ 2 & -1 & -1 \\ -1 & 2 & -1 \end{bmatrix}$$

$$[\mathrm{CTC}(5)] = \frac{1}{\sqrt{3}} \bullet \begin{bmatrix} -1 & 0 & 1 \\ 1 & -1 & 0 \\ 0 & 1 & -1 \end{bmatrix} \qquad [\mathrm{CTC}(6)] = \frac{1}{3} \bullet \begin{bmatrix} -2 & 1 & 1 \\ 1 & -2 & 1 \\ 1 & 1 & -2 \end{bmatrix}$$

$$[\mathrm{CTC}(7)] = \frac{1}{\sqrt{3}} \bullet \begin{bmatrix} -1 & 1 & 0 \\ 0 & -1 & 1 \\ 1 & 0 & -1 \end{bmatrix} \qquad [\mathrm{CTC}(8)] = \frac{1}{3} \bullet \begin{bmatrix} -1 & 2 & -1 \\ -1 & -1 & 2 \\ 2 & -1 & -1 \end{bmatrix}$$

$$[\mathrm{CTC}(9)] = \frac{1}{\sqrt{3}} \bullet \begin{bmatrix} 0 & 1 & -1 \\ -1 & 0 & 1 \\ 1 & -1 & 0 \end{bmatrix} \qquad [\mathrm{CTC}(10)] = \frac{1}{3} \bullet \begin{bmatrix} 1 & 1 & -2 \\ -2 & 1 & 1 \\ 1 & -2 & 1 \end{bmatrix}$$

$$[\mathrm{CTC}(11)] = \frac{1}{\sqrt{3}} \bullet \begin{bmatrix} 1 & 0 & -1 \\ -1 & 1 & 0 \\ 0 & -1 & 1 \end{bmatrix} \qquad [\mathrm{CTC}(12)] = \frac{1}{3} \bullet \begin{bmatrix} 2 & -1 & -1 \\ -1 & 2 & -1 \\ -1 & -1 & 2 \end{bmatrix}$$

Fig. 12 Phase-angle compensation matrices

Process for Determining Internal Phase-Angle Compensation Settings

Step 1: Choose one of the primary winding currents as a reference.

It is best to develop a consistent practice. Here, we choose Winding 1, the high side, as our reference current. Because this is a delta-connected winding, and there is no zero-sequence source between the CTs and the transformer, we can choose a compensation setting of zero for this winding, or matrix M0 (the identity matrix).

The M0 matrix applies no phase-angle shift or zero-sequence trap to the phase currents. For autotransformers, wye-connected windings, or delta windings that include a zig-zag transformer or other zero-sequence source, choose a compensation setting other than zero to apply a zero-sequence trap.

Step 2: For an ABC system phase rotation, count the number of 30-degree increments, moving in a counter-clockwise rotation, to line up Winding 2 with the reference Winding 1.

Because in Fig. 11 the low side will lead the high side by 30 degrees, we must move the low-side Winding 2 current 330 degrees or 11 increments of 30 degrees in the counter-clockwise direction to get it to line up with the reference Winding 1. Therefore, we choose a compensation setting of 11, or matrix M11, for this winding. Note that M11, as with any matrix other than M0, introduces a phase shift and a zero-sequence trap.

$$[\mathrm{CTC}(11)] = \frac{1}{\sqrt{3}} \bullet \begin{bmatrix} 1 & 0 & -1 \\ -1 & 1 & 0 \\ 0 & -1 & 1 \end{bmatrix}$$

that is,

$$\mathrm{IAWnC} = \frac{(\mathrm{IAWn} - \mathrm{ICWn})}{\sqrt{3}}$$

$$\mathrm{IBWnC} = \frac{\mathrm{IBWn} - \mathrm{IAWn}}{\sqrt{3}}$$

$$\mathrm{ICWnC} = \frac{(\mathrm{ICWn} - \mathrm{IBWn})}{\sqrt{3}}$$

Fig. 13 Matrix 11 manipulation of phase currents

When we multiply low-side currents by matrix M11, the resulting phasors are in phase with their high-side counterparts. Keep in mind that the secondary currents for Winding 2 are actually 180 degrees out of phase with the primary, as a result of through load or fault current flowing out of the CT. Multiplication of the low-side currents by matrix M11 produces a compensated secondary current that is 180 degrees out of phase with the high side. Operate or difference current is therefore zero. Nothing is fundamentally different here. A traditional differential scheme would have required delta-connected CTs on the low side. We accomplish the same result through the use of wye CTs on all windings.

References [4] and [5] provide more useful examples for the interested reader. Note that for the example shown in Fig. 8 and Fig. 9, we set the Winding 1 compensation matrix to M0 and Winding 2 to M1. We can show that a large number of matrix choices would be valid (W1CTC = 3, W2CTC = 4 for example); developing a consistent process for choosing a reference is helpful. And, as we discussed previously for an ACB system phase rotation, count the number of 30-degree increments, moving in a *clockwise* rotation, to line up Winding 2 with the reference Winding 1.

IV. Recommended Differential Test Procedures

We can classify the activities involved in the commissioning of a new transformer differential protection scheme into three major groups: hardware, functional, and in-service or commissioning testing.

Hardware tests begin with validation of the transformer turns ratio, or TTR. Upon completion of a TTR test, we know the transformation ratio, proper bushing designation, and vector diagram of the transformer and use this to verify the nameplate information.

The next hardware tests involve verifying CT ratios. In the case of multiratio current transformers, it is important to determine the intermediate tap ratios and confirm accurate wiring of these taps to terminal blocks per the equipment wiring diagrams. We must verify CT polarity and compare this information against the equipment nameplate data and wiring diagrams. We must measure and compare excitation current with the published curves from the CT manufacturer. The obtained excitation curve reveals the ANSI relay accuracy class voltage of the CT under test. Insulation resistance tests are important in proving the existence of a single ground point in the CT circuit. We compare CT burden measurements with expected design values and perform wiring tests to identify equipment locations and interconnections and to verify that these are all according to design drawings. Of particular importance is ac wiring verification, where we compare actual equipment location, bus phasing identification, equipment bushing identification and primary polarity orientation of the CTs with the three-line current and potential drawings, wiring schematics, and secondary wiring. During ac circuit verifications, it is important to verify the correct operation of all isolation and shorting devices.

The next hardware test involves validation of the protective relay itself and its installed settings. Among the most important tests with digital relays are comparisons of meter data with injected analog signals, proof of dc input and output functionality, and verification of self-test status. Settings must match all the information validated in previous tests.

To best represent the as-installed application, it is important to perform relay testing with settings and wiring left undisturbed. Follow all recommended testing and commissioning procedures from relay manufacturers, and validate that the relay operates as expected and as set for expected scenarios.

Functional testing activities include ac and dc control checks, or trip tests. We inject ac signals and observe whether the protective relay operates appropriate breakers and lockouts. These tests are intended to verify the interaction of all the different protective and control devices, and to ensure that design drawings truly match what exists in the field.

AC Primary Current Injection Test

Balanced three-phase current injection verifies primary and secondary ac current circuits [6]. While this test may require that a small portable generator be onsite, or that we use a station service transformer, primary injection provides installers the benefit of discovering problems before transformer energization. Installers can validate test CT and transformer ratios, polarity, connections and wiring, as well as related transformer protective relay settings. The verification involves temporarily connecting a reduced-voltage, three-phase power supply to one of the windings of the transformer and applying to the remaining winding a three-phase short circuit to ground. Balanced three-phase current will circulate through the transformer windings. The circulating current magnitude, which we can calculate, is proportional to the applied voltage and transformer impedance. We can measure secondary current magnitude and angle, as well as operate and restraint quantities, at test switches, terminal blocks, meters, and relays.

To illustrate the procedure, we calculate a test plan for the transformer application shown in Fig. 14.

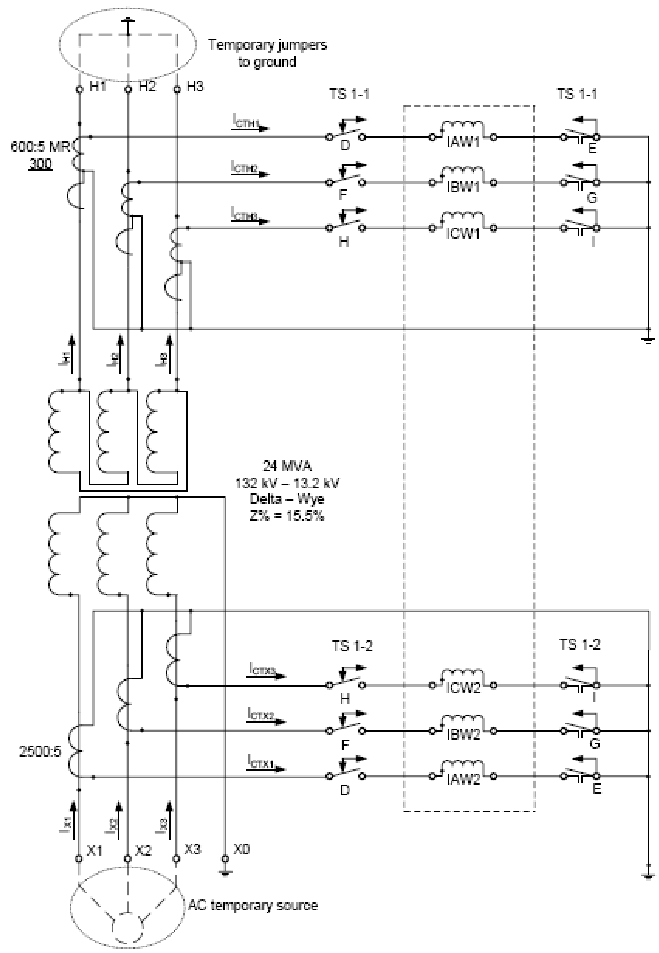

Fig. 14 Three-line diagram

Assume a transformer is rated for 24 MVA, with a primary winding voltage of 132 kV (delta connected), a secondary winding voltage of 13.2 kV (wye connected), and an impedance of 15.5 percent at 24 MVA.

Step 1: Calculate one p.u. of the transformer high-side and low-side primary current:

$$1 \text{ p.u. at } 132 \text{ kV} = 24 \text{ MVA} / (\sqrt{3} \cdot 132 \text{ kV}) = 105 \text{ A}$$

$$1 \text{ p.u. at } 13.2 \text{ kV} = 24 \text{ MVA} / (\sqrt{3} \cdot 13.2 \text{ kV}) = 1050 \text{ A}$$

Step 2: Calculate the p.u. values of current for different power supply voltage levels (240 V shown here) applied to the low side:

$$I_{@240V} \text{ (p.u.)} = (240 \text{ V} / 13.2 \text{ kV}) / (0.155) = 0.1173 \text{ p.u.}$$

Step 3: Calculate high-side and low-side currents in amps for different power supply voltage levels (240 V shown here):

$$I_{HS\ PRI} = 105 \text{ A} \cdot 0.1173 \text{ p.u.} = 12.32 \text{ A}$$

$$I_{HS\ SEC} = 12.32 \text{ A} / 60 = 205.3 \text{ mA}$$

$$I_{LS\ PRI} = 1050 \text{ A} \cdot 0.1173 \text{ p.u.} = 123.2 \text{ A}$$

$$I_{LS\ SEC} = 123.2 \text{ A} / 500 = 246.4 \text{ mA}$$

Step 4: Select the appropriate ac source voltage level.

Reference [1] recommended a typical minimum current of 250 mA secondary for load tests. In this particular case, we can select an ac source voltage of 240 V because it provides almost 250 mA at the secondary of both CTs, and one can obtain a capable generator easily at a commercial rental facility.

Step 5: Calculate the minimum kVA rating for the power supply:

$$\text{Power} = (240 \text{ V} \cdot \sqrt{3} \cdot 123.2 \text{ A}) / 1000 = 51.21 \text{ kVA}$$

We can select a 75 kVA portable generator for the test.

Step 6: Calculate expected magnitude and phase angles of the through current.

All the angles are referenced to A-phase voltage of the test source. We apply ABC system phase rotation (or positive-sequence current) to bushings X1, X2, and X3, respectively. The transformer is a DABy, or Dy1, where the high-side current phase angle leads the low side by 30 degrees. Because the transformer has a highly reactive impedance, we can assume that the current lags the source voltage by 85 degrees.

$I_{X1} = 123.2 \text{ A} @ -85°$
$I_{X2} = 123.2 \text{ A} @ -205°$
$I_{X3} = 123.2 \text{ A} @ +35°$
$I_{H1} = 12.32 \text{ A} @ -55°$
$I_{H2} = 12.32 \text{ A} @ -175°$
$I_{H3} = 12.32 \text{ A} @ +65°$

Step 7: Calculate the expected magnitude and angle of the currents leaving the current transformer polarity marks and going to the relay. Note that if either CT had been connected in delta, we would need to account here for the magnitude and phase-angle adjustment necessary for the delta CT.

$I_{CTX1} = 246.4 \text{ mA} @ -85°$
$I_{CTX2} = 246.4 \text{ mA} @ -205°$
$I_{CTX3} = 246.4 \text{ mA} @ +35°$
$I_{CTH1} = 205.3 \text{ mA} @ +125°$
$I_{CTH2} = 205.3 \text{ mA} @ +5°$
$I_{CTH3} = 205.3 \text{ mA} @ -115°$

Step 8: Prepare a table containing the current values we expect to measure during the test.

Measuring points will include current flowing into transformer bushings X1, X2, X3, current leaving transformer bushings H1, H2 and H3, current passing through test switches TS 1-2 and TS 1-1 test jacks, and current the protective relay measures.

Step 9: Connect the power supply to the 13.2 kV transformer terminals, apply to the 132 kV transformer terminals a three-phase short circuit to ground, and turn on the temporary power supply.

Confirm correct phase rotation of the temporary power supply. Measure current at all test points and compare current values you measure to the current values you expected. Interrogate the transformer differential relay for instantaneous metering and operate and restraint values. Turn off the temporary power supply and analyze the results. After proper primary injection tests, no misoperation is expected from wiring errors or incorrect phase angle compensation settings.

Commissioning or In-Service Tests

Analysis of current injection test results, in-service measurements, or commissioning tests follows the same process. The benefit of doing a current injection test is that one can uncover some errors before energizing the transformer "for real." One can, therefore, leave the transformer differential relay in service during initial transformer energization.

Through these tests, we can observe currents and relay behavior during a balanced out-of-section or through-load event. The following checks are common to any commissioning test [7].

Step 1: Check the phase rotation and angle of the currents. If the magnitude of the test currents is too small, the phase-angle accuracy cannot be trusted; a typical minimum current of 250 mA secondary is recommended for load tests. Ensure that the currents are balanced and 120 degrees apart. Ensure also that the phase rotation matches the expected system rotation and relay setting (ABC or ACB). There should be positive-sequence current, but there should be no negative-sequence or zero-sequence current. The presence of significant negative-sequence current is a good indicator of rolled phase wires, improper phase sequence, and incorrect CT taps.

Step 2: Check that expected secondary current magnitudes match actual measurements. Compare the metering in the transformer differential to another device, or ensure that power into the transformer equals the power out of the transformer. If secondary currents do not equal expectations, the cause is most likely a CT tapped at an unexpected value, one that does not match the relay settings.

Step 3: Check that the relationship of high-side to low-side currents matches expectations. Remember that, for a through-load condition, one of the CT secondary currents will be 180 degrees out of phase with its primary current (as you can see in *Step 7* of the previously discussed primary current injection test). Compare the observed phase angles to the phase-angle compensation settings in the relay, and ensure that those settings are appropriate.

Step 4: Check that each differential element detects nearly zero per-unit operate current. You can expect a small amount of operating current if commissioning occurs while the transformer tap position does not correspond with the rated or nominal voltage you used when calculating the relay tap settings. If any operate current exists, check that the mismatch, or the ratio of operate current to restraint current, is less than 10 percent. If the mismatch is greater than 10 percent, you must perform further testing and troubleshooting to determine the cause of the operate current. Suspect an incorrect phase-angle compensation setting in the relay if operate current is high and all checks to this point have been normal.

Software tools such as MathCAD® or relay-assisted commissioning features are helpful at this point. You can read in relay current measurements or event data, and these software tools can automatically calculate the results of every possible phase-angle compensation matrix or setting. These tools can help you verify that you have chosen and installed correct settings, those that produce the lowest mismatch. Be careful using these tools, however, because these tools may be incapable of resolving multiple-contingency errors. Triggering an event report and using event analysis software to view the waveforms and phasors present during commissioning is also an invaluable tool in determining root cause.

V. Recommended Event Report Analysis Procedure

During commissioning tests, you can trigger relay event reports to document the procedure. After a fault or field event, event reports become invaluable tools for finding root cause and solving problems. The following process is handy when analyzing event report data from relays.

Step 1: Understand what is expected to happen for given conditions. To understand what you can expect, you must look at settings, installation drawings, reference texts, and instruction manuals.

Step 2: Collect all relevant information, including eyewitness testimony, any available information about the fault, sequence-of-events records, trip targets, and relay event data.

Step 3: Gather available analysis tools, such as instruction manuals, reference texts, and event analysis software.

Step 4: Compare the actual operation to expectations. If there are any differences, resolve these differences by determining root cause. Do not waste time analyzing unused elements or settings. Focus, instead, on trip logic and output contact programming. Do not forget to look at prefault information, and use data from prefault information to perform an "offline" commissioning test to prove that system installation is correct. Before and during the analysis process, save data intelligently, naming files in a coherent way.

Step 5: Document your findings, proposed solutions, and test results. When you have validated a correct operation, or determined root cause and developed a proven solution for an incorrect operation, you are done.

VI. Loose Terminal In CT Secondary Wiring

A 69 kV delta high-side, 12.47 kV grounded wye low-side power transformer was installed and operating correctly for some time. Then, the residual ground time-overcurrent element (51N1) on the delta high-side winding began triggering a number of event reports. See Fig. 15. There was no corresponding change in low-side currents during each of these events, only balanced three-phase load flow. Therefore, we could rule out a power system fault. We would not expect to see any zero-sequence current on the high-side delta of the transformer, except for a fault between the Winding 1 CTs and the transformer bushings, or possibly as a result of CT saturation during a fault.

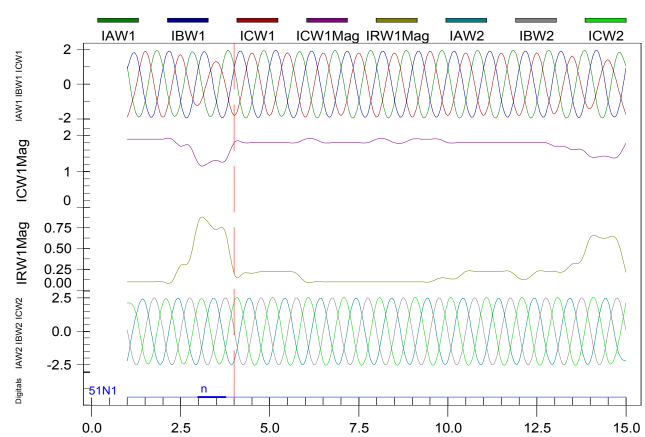

Fig. 15 Residual ground element asserting briefly

In this case, the residual current resulted not from an increase of phase current, as one might expect for a fault, but rather from momentary decreases in C-phase Winding 1 current ($3I0_{WDG1} = IA_{WDG1} + IB_{WDG1} + IC_{WDG1}$). In one event, shown in Fig. 16, the 51N1 element eventually times out and trips.

What field condition could cause a decrease of one phase current? A short circuit, either in the CT secondary wiring or internal to the relay, could cause this decrease. By checking the relay status, and testing the relay analog input metering, we could rule out the relay as the root cause. Suspecting the CT wiring, we inspected the C-phase Winding 1 circuit and found a short circuit-to-ground. There was a loose terminal connection in the junction box on the top of the transformer, with evidence of considerable arcing. Every time the loose connection arced, C-phase current from the CT shunted away from the relay to ground. This caused the residual 3I0 ground current we measured at the relay.

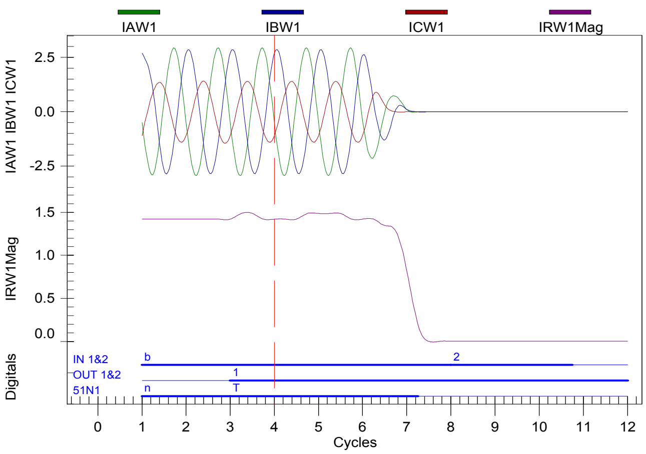

Fig. 16 Residual ground element times out and trips

Lesson Learned – A pattern of momentary loss or decrease in current at the relay location can indicate an upstream short-circuit or arcing condition in the CT secondary wiring. Despite our best efforts during commissioning, wiring problems can develop over time and can best be identified with event report analysis.

VII. Short Circuit in CT Secondary Wiring

An unusual series of misoperations plagues a generator step-up transformer. The transformer 137.5 kV voltage side is grounded-wye connected, and is connected to Winding 1 of the differential relay. The 11.5 kV side is delta connected, and two generators are connected to independent windings of the relay, Windings 2 and 3. The transformer nameplate indicates that the high side should lead the low side by 30 degrees. However, the system phase rotation is ABC, and the phase-to-bushing connections are A-to-H1, C-to-H2, and B-to-H3, so the high side lags the low side by 30 degrees.

Once installed, the transformer differential relay operated as expected for several months. An event report triggered during normal balanced power flow is available, and we used this report for "offline" commissioning to validate that settings and phase-angle compensation appeared correct. Suddenly, the relay experienced several unexpected trips.

One event shows a trip during what appears to be balanced load flow when the generators were online. Another event shows a trip during a phase-to-ground high-side transmission line fault when generation was offline. Healthy relay status rules out a malfunctioning relay as the root cause. We therefore suspected a wiring problem that developed since installation.

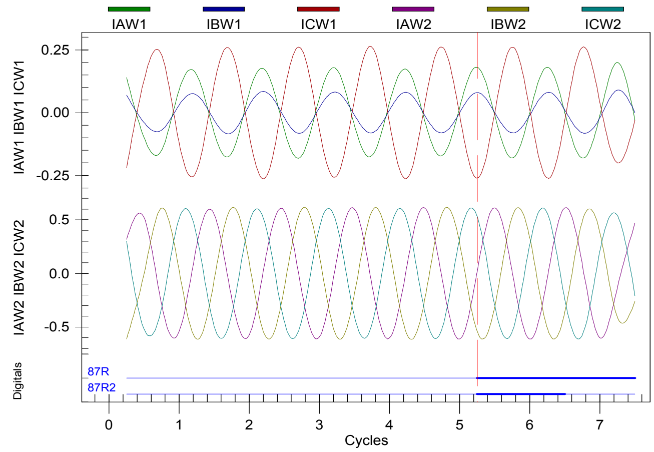

Fig. 17 Differential element trips with balanced load

Fig. 17 shows the trip during balanced load. The restrained differential element 87R2 caused the trip. The high-side currents look strange, while the low-side or generator-side currents look normal and balanced. Because we have verified proper commissioning, and the relay status is OK, we again suspect a wiring failure.

Consider the Winding 1 currents in Fig. 17. IAW1 and IBW1 are in phase, but have different magnitudes, while ICW1 is 180 degrees out of phase. A closer inspection of the magnitudes and angles indicates that IAW1+ IBW1= – ICW1.

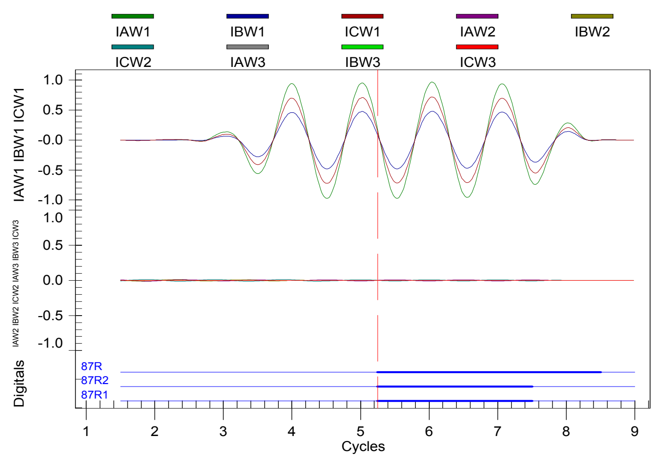

Fig. 18 High-side line-to-ground fault with no generation online

The event shown in Fig. 18 shows no low-side current, and all three phases on the high side are in phase, or have the same phase angle. The zero-sequence source on the transformer high side makes the event look almost like what we would expect for a phase-to-ground fault on the high-side power system, with all generation offline. The fact that all three phase magnitudes are not identical in magnitude, however, is unexpected. We can rule out at least one potential wiring problem, the lack of a CT neutral connection, because ICW1 cannot be returning through IAW1 and IBW1.

The detective work to resolve this problem consists of coming up with wiring problem theories that would explain the behaviors Fig. 17 and Fig. 18 exhibit. The simplest theory is to imagine the polarity of IAW1 and the polarity of IBW1 shorting together in the CT wiring somewhere upstream of the differential relay. For balanced load, IAW1 and IBW1 would physically add up at the point of the short to result in the -ICW1 for balanced load. The currents would then divide according to downstream wiring and burden from connected devices. For an external ground fault, the initial three phase currents are all of equal magnitude and in phase. IAW1 and IBW1 would physically add up at the point of the short, maintaining the same phase angle, and would then divide according to downstream wiring and connected-device burden. This would result in our measuring unequal magnitudes at the relay location. In both events, IAW1 has about twice the magnitude of IBW1, so the A-phase circuit impedance and connected-device burden must be about half that for the B-phase circuit impedance and connected-device burden.

By physically inspecting the wiring from the CT to Winding 1 of the relay, we discovered a short in the high-side wiring between A-phase and B-phase. A meter in the CT circuit had frayed wires at the terminal block connections, with several strands of the A-phase wire touching a few strands of the B-phase wire.

Lessons Learned – When currents, during load or faults, do not match expectations, suspect a wiring problem. Because the problem is continuous, not momentary as in the previous example, we can suspect a solid short or other problem.

While this is a challenging problem to diagnose, even with the data we collected, imagine trying to analyze and troubleshoot this problem with electromechanical relays! The value of relay event report data is overwhelming.

VIII. Incorrect CT Tap

A single line-to-ground fault occurred on the low side of a delta-wye power transformer. The fault was external to the differential zone of protection, but the differential relay tripped. We would expect a correctly installed relay to restrain for an out-of-section fault. The high-side delta winding of the transformer was connected to Winding 1 of the relay, and the low voltage grounded-wye side of the transformer was connected to Winding 2 of the relay. In Fig. 19, the low voltage single-phase-to-ground fault appears correctly as a phase-to-phase fault on the high side.

We would expect the restraint current to increase significantly during the fault, but we would expect the operate current to not increase or to increase only slightly. Instead, in Fig. 20, we note that the operate current in two differential elements increased substantially. Before the fault, however, we also notice that significant operate current exists in all three differential elements (the ratio of operate to restraint in each element exceeds 66 percent).

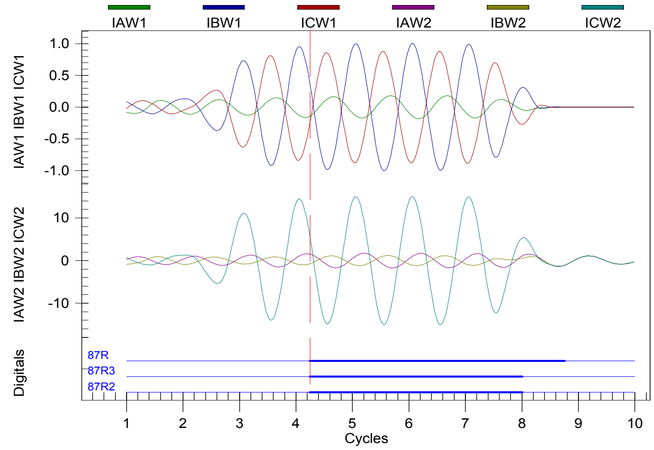

Fig. 19 C-Gnd fault on wye side of delta-wye bank

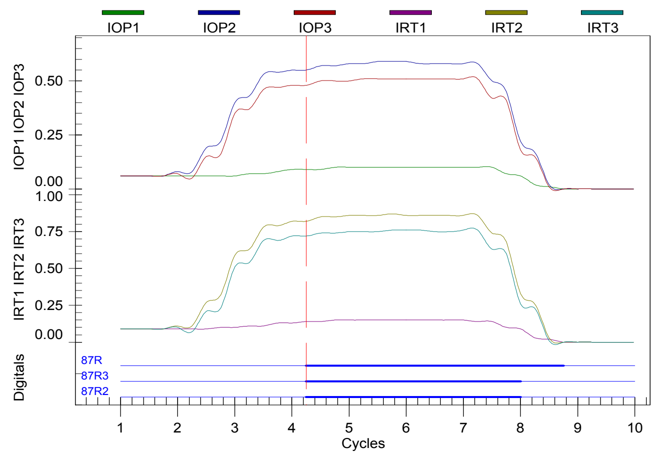

Fig. 20 Operate current increases for external fault

The C-phase low-side current produces fault current flow in B and C phases on the high side. The settings for the relay use phase angle compensation Matrix 0 for Winding 1, and Matrix 1 for Winding 2. According to these matrices, the high-side B and C phase currents and the low-side C phase current are involved in the calculation of differential elements 87R2 and 87R3, both of which operated.

When a relay captures event data, it stores several cycles of prefault information. One can use the prefault data to perform an “offline” commissioning test. We can see prefault phasors in Fig. 21.

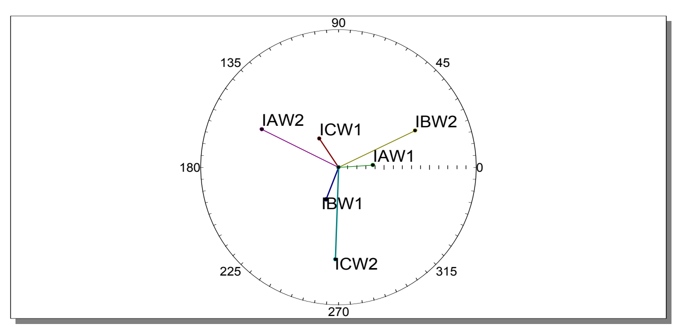

Fig. 21 Prefault phasors show expected angles

The relay also stores the settings that were active during the fault. From those settings, we can expect the high side (IAW1) to lead the low side (IAW2) by 30 degrees. Remembering that the low-side Winding 2 secondary current will be 180 degrees out of phase with its primary current for through-load or fault current, we can see that the prefault phase-angle relationships are as expected; if you were to "flip" IAW2, for example, it would lag IAW1 by 30 degrees.

During commissioning, we ordinarily check that the expected current magnitudes match actual meter readings. With this event, we had no information from any other device, such as a power meter, against which we could compare values. We can, however, calculate the power into the transformer and compare that to the power out of the transformer. From the phasor information, we gathered the measured prefault currents. From the relay settings, we obtained the nominal transformer voltages (115 kV high side and 12.47 kV low side) and expected CT ratios (200:5 on the high side and 400:5 on the low side).

$$\text{Power In} = \sqrt{3} \cdot 0.1\ \text{A} \cdot 40 \cdot 115\ \text{kV} = 796\ \text{kVA}$$

$$\text{Power Out} = \sqrt{3} \cdot 0.9\ \text{A} \cdot 80 \cdot 12.47\ \text{kV} = 1.6\ \text{MVA}$$

A transformer is effectively a constant power device, so we know that there is likely a problem with the actual CT taps. If we assume that the low-side power calculation is correct, substitute the 1.6 MVA value for Power In, and solve for the actual CT ratio on the high side, we calculate a 400:5 tap (instead of 200:5 as expected). If we assume that the high-side power calculation is correct, substitute the 796 kVA value for Power Out, and solve for the actual CT ratio on the low side, we calculate a 200:5 tap (instead of 400:5 as expected). Either CT tap error was possible according to available CT taps. Field inspection verified the existence of an incorrect CT tap, 400:5, on the high side.

Lesson Learned – Use prefault data from the differential relay to perform an "offline" commissioning test. It is possible to verify phase-angle relationships, and a simple power in versus power out calculation can help reveal incorrectly tapped CTs.

If current at the relay is less than expected, suspect a CT with a higher tap than the relay settings intended. If current at the relay is lower than expected, suspect a CT with a lower tap than the relay settings intended. Commissioning tests discussed previously should identify this problem before a transformer and scheme go into service.

IX. One Phase of a CT Incorrectly Tapped

An 87R element causes a delta-wye power transformer differential relay to trip for a low-side feeder fault. We confirm the location of the fault by looking at the feeder relay-generated event data, shown in Fig. 22. According to data time stamps, both the feeder relay and the transformer differential relay operated at the same time.

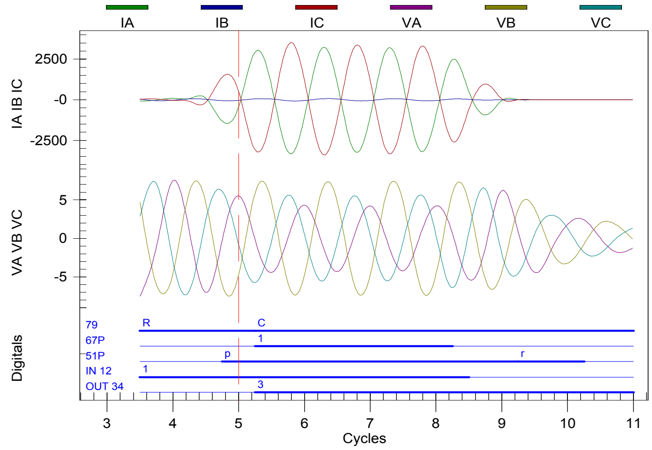

Fig. 22 Downstream feeder relay confirms fault out-of-section to the Transformer differential

We suspect that the feeder relay operated correctly, but that the transformer differential relay should not have tripped. In Fig. 23, the transformer low-side Winding 2 currents agree with the feeder relay in indicating that the fault was an A-phase-to-C-phase fault. The high-side delta winding currents, however, produce unexpected results. There is residual ground current present on the delta side of the transformer for a low-side fault. The presence of this current implies a CT wiring problem.

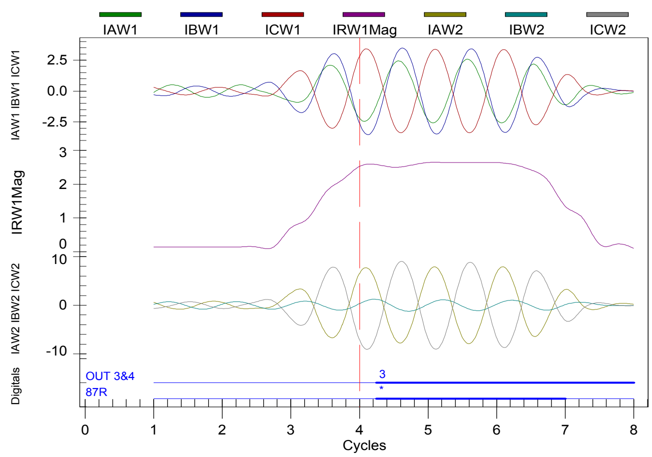

Fig. 23 Transformer differential trip for out-of-section feeder fault

An A-phase-to-C phase fault on the low side of a delta-wye transformer should produce a high-side C-phase current equal to the sum of, and 180 degrees out of phase with, the A-phase and B-phase currents. The A-phase and B-phase currents should be about the same magnitude. In other words, IAW1+ IBW1= – ICW1. In Fig. 23, notice that the C-phase current angle appears to be correct, but the C-phase magnitude is less than we would expect.

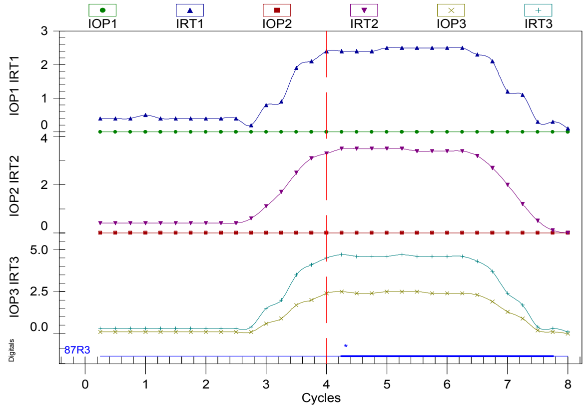

Fig. 24 Only 87R3 sees operate current during fault

Fig. 24 presents more evidence that the problem lies solely with ICW1. First, the prefault ICW1 magnitude is noticeably less than IAW1 and IBW1. Second, prefault IOP1 and IOP2 are zero, while the ratio of IOP3 to IRT3 is 33 percent, far greater than our commissioning rule of thumb of 10 percent. The settings for the relay use phase angle compensation Matrix 0 for Winding 1, and Matrix 1 for Winding 2. For a transformer in which the high side leads the low side by 30 degrees, the phase-angle compensation settings isolate ICW1 as the only current that would affect only the 87R3 differential element while not affecting the other two differential elements. During the fault, only the 87R3 element shows increased operate current. Third, the residual current we measured on the transformer high side during the fault is exactly 180 degrees out of phase with ICW1. This implies that the residual ($3I0_{WDG1} = IA_{WDG1} + IB_{WDG1} + IC_{WDG1}$) compensated for insufficient current from the CT circuit on ICW1. Settings indicate an intended CT ratio of 600:5 on the high side. We inspected the CT wiring and found that the C-phase of the high-side CT was tapped at 1200:5.

Lessons Learned – Use event data from adjacent relays to confirm fault type and location. Understand what to expect for a given fault before analyzing the relay data.

Use differential operate and restraint quantities, and knowledge of phase-angle compensation mathematics, to understand why only one or two, but not all, differential elements operated.

As with the previous example, a higher-than-expected CT tap produced less-than-expected current at the relay. In this case, only one phase of a three-phase CT was incorrectly tapped and wired. Commissioning tests discussed previously should identify this problem before the transformer and scheme go into service.

X. Incorrect CT Polarity

As load increases during first-time energization of a new transformer, the transformer differential relay trips. The low current magnitudes and balanced conditions, shown in Fig. 25, confirm that there was no system fault. The power transformer is 69 kV delta to 12 kV grounded-wye, with ABC system phase rotation and ABC phase-to-bushing connections. We would expect the high side to lead the low side by 30 degrees for this transformer, and the phase-angle compensation to be W1CTC = 0 or 12 and W2CTC = 1.

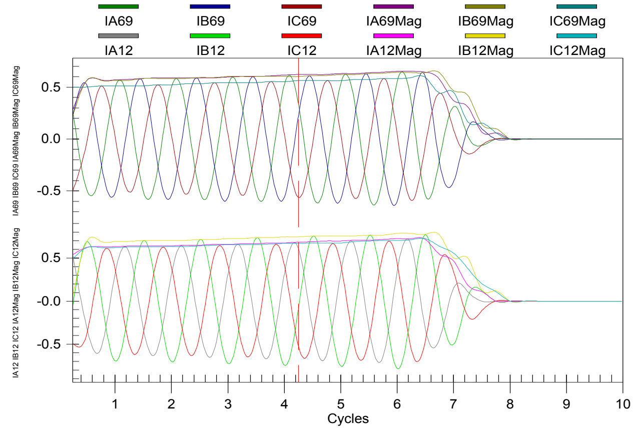

Fig. 25 Differential relay trips while balanced load in steadily increased

Fig. 26 shows the current phase angles at cycle two of the event data. The high side does indeed lead the low side by 30 degrees, but we expect this only on the primary of the CTs. Remember, as Fig. 3 demonstrated, that we would expect the secondary current from the low-side CT to be 180 degrees out of phase for a through-load condition. Therefore, the relay should observe low-side currents leading high-side currents by 150 degrees. We can use the operate currents from differential event reports to confirm that this is a problem involving all three phases. Upon inspection of the low-side CTs, we found that these CTs had been connected with reverse polarity.

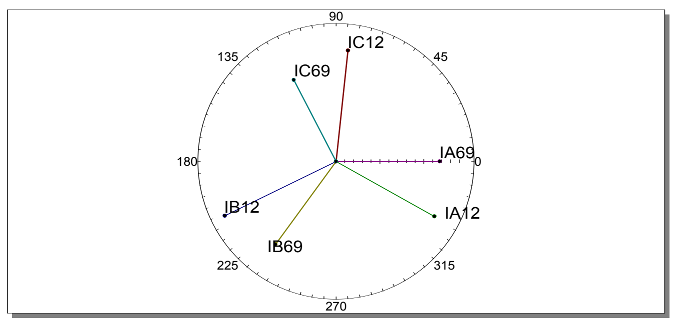

Fig. 26 Differential relay trips while balanced load is steadily increased

Lessons Learned – Use relay event report data to perform an "offline" commissioning test and identify CT polarity mistakes. Commissioning tests discussed previously should identify this problem before the transformer and scheme go into service.

One of the most common mistakes is to confuse expected phase angles on the primary versus the secondary side of a CT. Remember that the 30-degree high-side lead or lag relates to primary currents. For through-load or fault current, one of the CT secondaries will see current that is reverse polarity (current leaving the zone). For a transformer in which the high-side current leads the low-side current by 30 degrees, the secondary low-side current will lead the high-side current by 150 degrees.

XI. CT Secondary Phase Wires Rolled

A 33 MVA power transformer is connected 43.8 kV delta to 12.47 kV grounded-wye, with ABC system phase rotation and ABC phase-to-bushing connections. The high side leads the low side by 30 degrees.

There had been some difficulty with the relay during commissioning, so installers increased the minimum operate setting, O87P, from 0.3 to 1.0 per unit. This increased setting value kept the relay from operating during balanced load conditions, but the root cause of the problems remained unresolved.

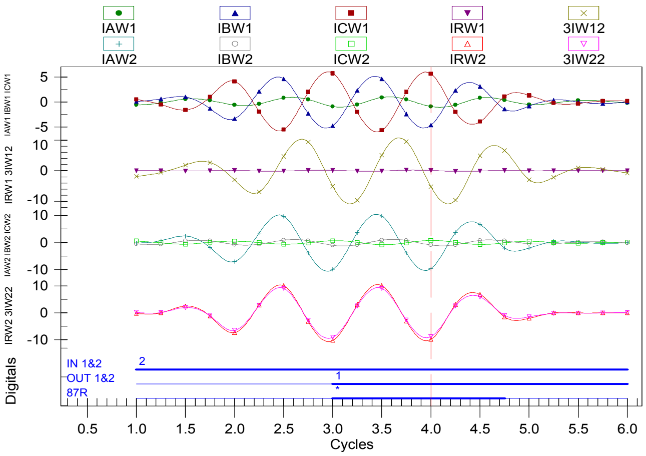

Fig. 27 Currents seen by differential relay for external phase-to-ground fault

Later, during a low-side A-phase-to-ground fault external to the differential zone of protection, the relay tripped. A low-side phase-to-ground fault appears as a phase-to-phase fault on the high side of the transformer. In Fig. 27, IAW2 increases on Winding 2, and IBW1 and ICW1 increase on Winding 1. While we can expect two currents to increase on the high side of the transformer (Winding 1), what is unusual is that we would expect A-phase and C-phase currents to increase, not B-phase and C-phase. Notice also that non-zero negative-sequence current exists on Winding 1 during the prefault period.

Fig. 28 shows the prefault current phasors. We immediately notice one problem. The Winding 1 phase rotation is ACB, while the Winding 2 phase rotation is ABC. The relay settings indicate that we should expect an ABC system phase rotation, so we suspect a wiring problem somewhere in the Winding 1 CT circuit.

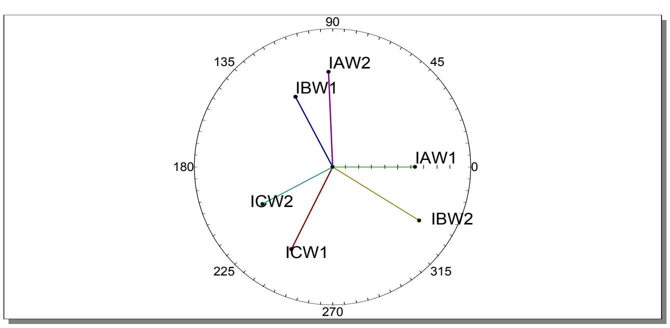

Fig. 28 Phase angles show different phase rotation

The relay uses the phase rotation setting to determine how to calculate symmetrical components. For example, for an ABC system phase rotation, $3I2_{WDG1} = IA_{WDG1} + a^2IB_{WDG1} + aIC_{WDG1}$. For an ACB system phase rotation, $3I2_{WDG1} = IA_{WDG1} + aIB_{WDG1} + a^2IC_{WDG1}$. Also, as this paper discussed previously, the system phase rotation is necessary for correct setting of relay phase-angle compensation. System phase rotation should always be the same on each side of the transformer.

The differential element information shown in Fig. 29 confirms that all three differential elements are affected and that all three elements operated.

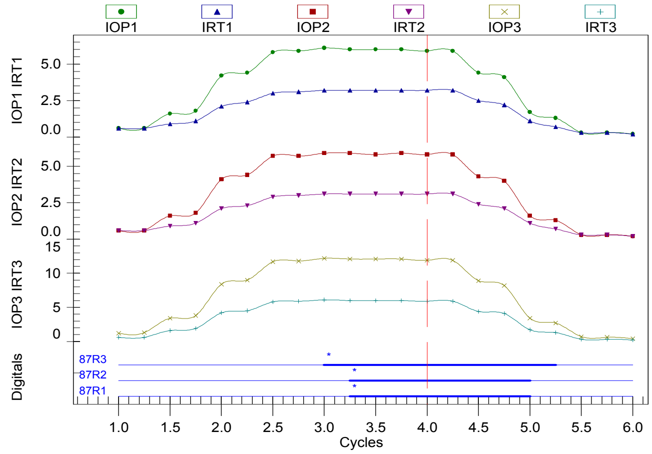

Fig. 29 All three differential elements see operate current

In fact, we can see during the prefault that the relay was already detecting huge mismatches. Before the fault began, the ratio of IOP1 to IRT1 and the ratio of IOP2 to IRT2 equaled 100 percent. The ratio of IOP3 to IRT3 was 200 percent! See Fig. 30.

The Winding 1 phase rotation definitely looks incorrect. For this transformer, we expect, on the primary side of the CTs, for the high side to lead the low side by 30 degrees. We expect to see the Winding 2 relay phase currents leading Winding 1 relay phase currents by 150 degrees. In Fig. 28, no phase-current pair exhibits this proper relationship.

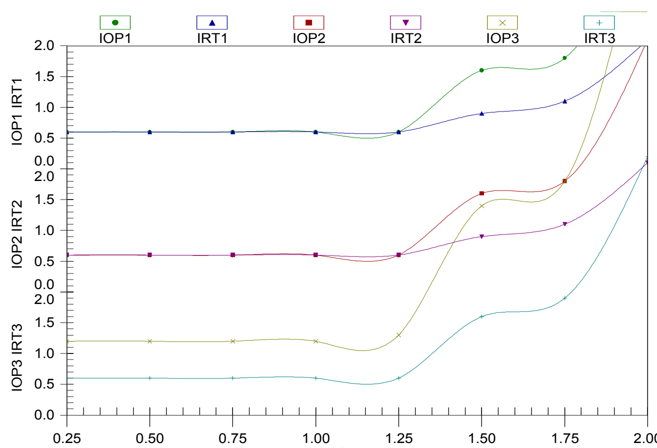

Fig. 30 Prefault data shows mismatch of 100 percent or more in all elements

We can, however, observe the current phase-angle relationships and work through wiring corrections that would result in the proper relationship. If we assume that the Winding 2 currents are correct and that we can use these currents as our reference, we can find it helpful to sketch on Fig. 28 where we would expect to see the Winding 1 currents. We would expect IAW1 to be in the fourth quadrant, opposite polarity of where IBW1 is shown. We would expect IBW1 at 180 degrees, opposite polarity of where the figure shows IAW1. We would expect ICW1 to be in the first quadrant, opposite polarity of where the figure presently shows this current.

We therefore suspect a multiple-contingency error. First, IAW1 and IBW1 appear to be rolled somewhere between the CT and the relay. Second, all three Winding 1 currents have the incorrect polarity. This is a complex theory, so we should test the theory by reexamining the fault data in Fig. 27. If it were indeed the case that IAW1 and IBW1 rolled, with all three currents at incorrect polarity, A-phase and C-phase on Winding 1 would have increased correctly (because of IAW1 and IBW1 being rolled). Also, after swapping the polarity of all three Winding 1 currents, IAW1 would be 180 degrees out of phase with IAW2, as we would expect for this fault. Field wiring inspections proved that rolled phases and incorrect polarity were the root causes for the problems we observed.

Lessons Learned – Never desensitize a relay setting to mask a problem.

An in-service mismatch reading greater than 10 percent indicates a problem that must be resolved. The phase rotation we observe on the high and low sides should match expectations and the relay setting. When phase rotation on the high side does not match that on the low side, suspect rolled phases, incorrect polarity, or both.

Multiple-contingency problems are rare, but not impossible. Commissioning tests discussed previously should identify this problem before the transformer and scheme go into service.

XII. Missing CT Secondary Neutral Connection

A single line-to-ground fault occurred on a 69 kV transmission line. Fig. 31 shows the event report the relay captured on that line. At the same time the fault occurred, a transformer differential relay misoperated. The differential relay protects a generator step-up transformer located behind or on the source side of the transmission relay. The step-up transformer is delta-connected on the generator low side, and those CT inputs are wye-connected to Winding 2 of the relay. The step-up transformer is grounded-wye connected on the high side, and those CT inputs are wye-connected to Winding 1 of the relay. The generator was online during the fault.

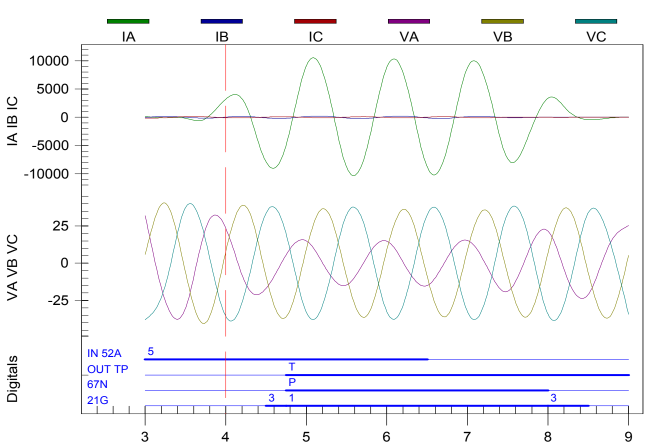

Fig. 31 AG fault on 69 kV transmission line

If the differential relay were installed correctly, we would expect it to restrain for this out-of-zone fault. The data from the transmission line terminal confirm that the fault was an out-of-zone fault for the differential relay. Fig. 32 shows the unexpected operation of the differential relay.

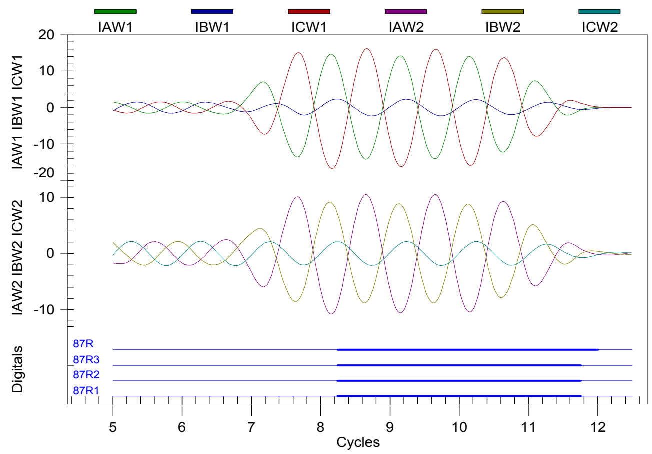

Fig. 32 Misoperation of generator step-up transformer differential relay

For a high-side line-to-ground fault on a grounded-wye transformer winding with the generator online, we would expect to see the faulted phase current magnitude increase dramatically relative to the other phase currents on Winding 1. We see, instead, an increase in magnitude for two currents on Winding 1. The fault should appear as a phase-to-phase fault on the low side, and it does. As we see in Fig. 32, however, the Winding 1 currents appear also as a phase-to-phase fault. The root-cause investigation found that the neutral wire was open-circuited, isolating the neutral of the wye-connected CT from the grounded neutral point at the relay. The CT had been changed from a delta to wye connection, but the addition of the neutral wire run back to the relay had been overlooked during commissioning tests.

Lesson Learned – If actual CT secondary currents do not match expectations for a system fault, investigate potential wiring errors that would provide the observed current flows. Such errors can include missing neutral connections, short circuits, lack of a ground, or multiple grounds.

XIII. CT Saturation

A distribution power transformer is connected high-side delta and low-side grounded-wye. Note that Winding 1 of a relay generally connects to the high-voltage side of a power transformer. This is an arbitrary association, however. In this application, Winding 2 of the transformer connects to the high-voltage delta side, and Winding 1 connects to the low-voltage wye side.

The transformer delta is connected polarity of H1-to-nonpolarity of H3. The system phase rotation is ABC. The phase-to-bushing connections are A-H1, B-H2, C-H3. We expect the low-side phase currents to *lead* the high-side phase currents by 30 degrees. Prefault phasors confirm that this relationship is as we expect.

The differential relay tripped for a distribution feeder phase-to-phase fault that was external to the differential zone of protection. The low-side fault was B-to-C phase. We would therefore expect IAW2 and IBW2 to be about equal on the high side (Winding 2) and in phase with ICW1 on the low side. The magnitude of ICW2 on the high side should equal the sum of IAW2 and IBW2, and the ICW2 phase angle should be opposite those two currents and in phase with IBW1 on the low side. In Fig. 33, these observed relationships match expectations.

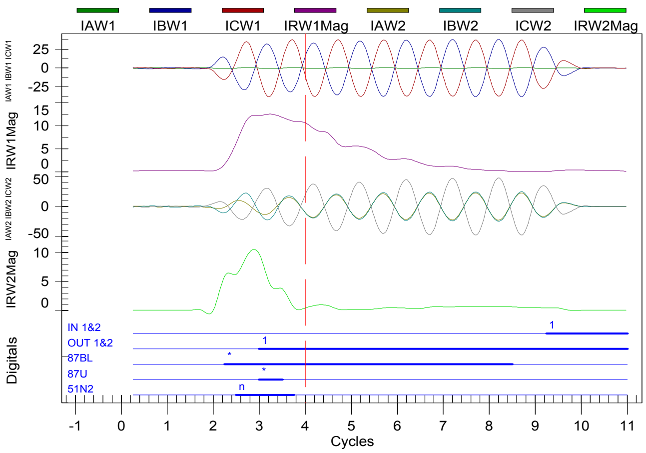

Fig. 33 Winding one (low-side) and winding two (high-side) currents for feeder fault

Fig. 33 shows four unexpected items. First, the unrestrained 87U element operated for an external fault. Second, second-harmonic blocking is asserted throughout the fault. Third, there is significant residual 3I0 ground current present on the low side (during a phase-to-phase fault) and on the high side (a delta-connected winding). Fourth, the residual current magnitude decreases over time, even while the fault persists. Similarly, in Fig. 34, there is significant operate current in all differential elements, but this operate current decreases over time even while the phase fault current persists.

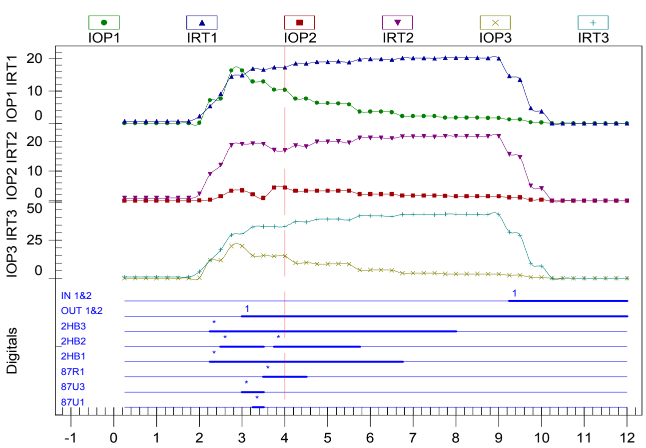

Fig. 34 Significant operate current exists for an external fault, but decays over time

Filtered 60 Hz phase currents remaining constant throughout a fault, while residual and operate currents decrease, indicate that the CTs experienced saturation. Harmonics are present when a CT saturates, which explains the second-harmonic blocking element asserting during the fault. This blocking element assertion prevented the 87R restrained-differential element from operating in this event. Note that the 51N1T high-side ground element tripped for a subsequent fault. Also, when a CT saturates, the replicated secondary current is not a true ratio current, diminished in magnitude and shifted in angle. Each CT phase behaves differently, resulting in calculated residual current (3I0 = IA + IB + IC). Over time, as the CT recovers, the false residual current subsides.

We suspect that saturating CTs are the root cause of the unexpected and diminishing zero-sequence and operating current. The only way to prove this theory, however, is to view the raw or unfiltered event data.

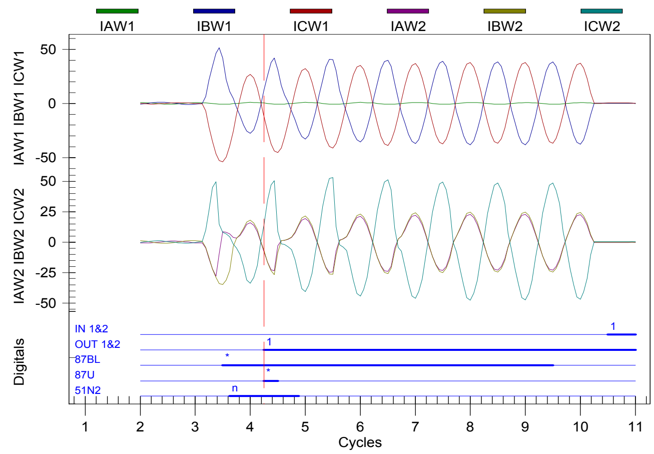

Fig. 35 CT saturation visible on both windings

Fig. 35 shows the raw event data, and we can see that the CTs, especially on the high side, saturated significantly. The low side had C400, 600:5 multiratio CTs, tapped at 100:5. Remember that the accuracy class here is for the full winding of the CT, so this CT is derated to approximately C67 performance (if such a CT existed). The CTs either need to be improved, or the tap must increase to access full CT capabilities.

Lastly, we found the 87U element to be too sensitive. A normal setting for this element would be in the range of 8 to 10 per unit of tap. In this case, the element had been set to 3 per unit. We therefore increased the 87U setting.

Lessons Learned – Decreasing residual or operate current over time, while filtered phase currents remain steady throughout a fault, is an indication of CT saturation. One can verify CT saturation only by looking at raw or unfiltered event data. The raw waveforms from Winding 2 in Fig. 35 are a perfect example of CT saturation. Commit these waveforms to memory, so that you can easily recognize these waveforms in the future.

Second-harmonic blocking prevented the 87R restrained-differential element from operating in this case, but one cannot rely on such restraining of the differential for all events involving CT saturation.

It is common to select CT taps based on expected load. However, one should check CTs to ensure that they will perform as necessary during faults [8]. Selecting lower taps on a multiratio CT derates CT performance.

XIV. Transformer Inrush Restraint

An ANSI standard 50 MVA power transformer is connected 69 kV delta to 12 kV grounded-wye. Upon first energization of the transformer, with the low side open, the differential relay tripped. Fig. 36 shows the digitally filtered 60 Hz phase currents on the high side during energization. The current magnitudes are low. We suspect a problem with inrush restraint settings.

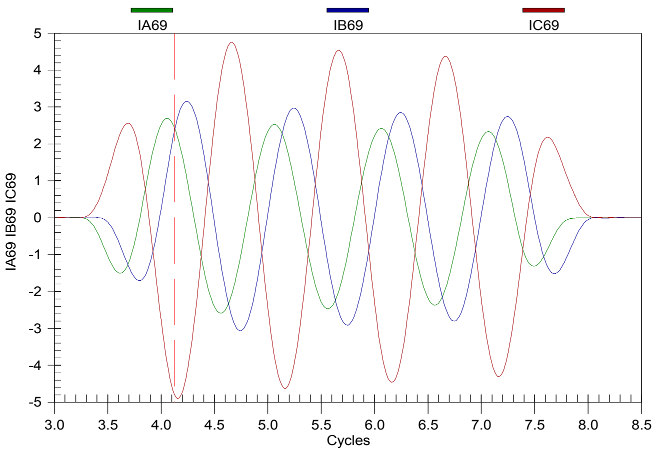

Fig. 36 Filtered 60 Hz high-side currents during energization

To verify our suspicion, we must analyze the raw data. The raw or unfiltered waveforms in Fig. 37 are textbook-perfect examples of magnetizing inrush current. Investigation of the installed settings finds that independent second-harmonic blocking was enabled as the inrush restraint. The second-harmonic threshold was set to 15 percent, a common value. Independent blocking means that second-harmonic content in excess of 15 percent of the fundamental frequency on A-phase will only block the 87R1 differential element. Likewise, B-phase second-harmonic content will block 87R2, and C-phase second-harmonic content will block 87R3. This mode emulates a traditional scheme of three discrete, or independent, differential relays.

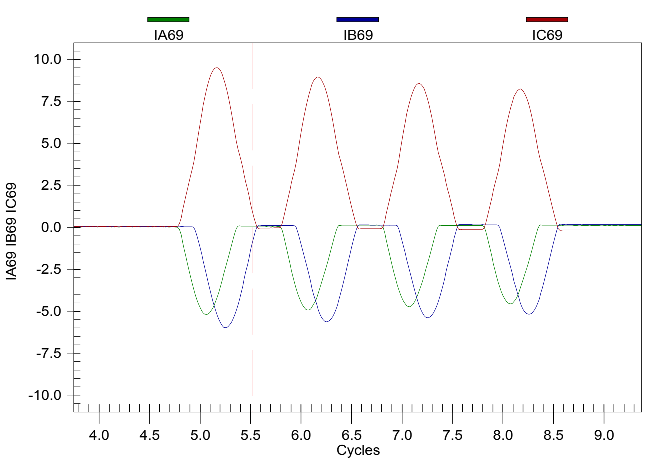

Fig. 37 Raw or unfiltered high-side currents during inrush

The waveforms in Fig. 37 obviously contain second-harmonic, but we must analyze the raw or unfiltered data further to determine how much second-harmonic exists on each phase. Event analysis software provides the tools by which we can view this information quickly. In Fig. 38, A-phase and B-phase had second-harmonic content at or above 30 percent of the fundamental, while C-phase had second-harmonic content just below 15 percent.

Modern event analysis software generates IEEE COMTRADE files from event data. The COMTRADE file is a standard way to represent field data so that a test set can replay the field event exactly.

We replayed this event in a lab to prove that a variety of settings solutions would solve the problem. Lab results showed that either common harmonic blocking, harmonic restraint, or dc ratio blocking would solve the problem and prevent a trip during inrush. It was easy to use settings in the existing relay to enable any or all of these elements.

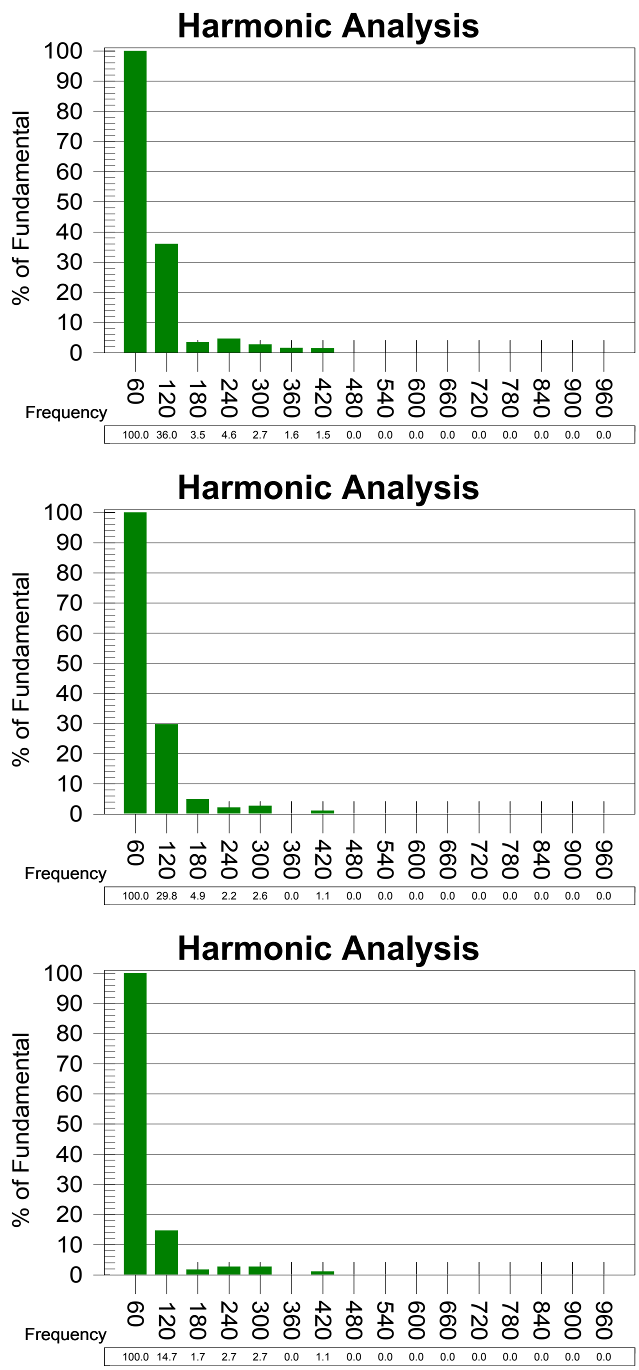

Fig. 38 C phase second-harmonic < 15 percent

Lessons Learned – A differential trip during energization, where current magnitudes are low and no other backup device operates, is likely the result of energizing inrush. One can best verify the existence of inrush current by viewing raw or unfiltered data. The raw waveforms in Fig. 37 are a perfect example of inrush. Commit these waveforms to memory, so that you can easily recognize these waveforms in the future.

Raw or unfiltered data is necessary for performance of harmonic analysis. Different phases of the transformer will produce different levels of harmonics during inrush.

When a wide variety of settings solutions are possible, convert the field event data to IEEE COMTRADE files, and replay the actual event into a relay in the lab with modified setting. Prove theories with real-world data before implementing these theories in the field.

XV. Incorrect Phase-Angle Compensation Settings

A 50 MVA power transformer is 69 kV delta to 12 kV grounded-wye, with ABC system phase rotation and ABC phase-to-bushing connections. We would expect the high side to lead the low side by 30 degrees for this transformer. We would also expect the phase-angle compensation to be W_{HS}CTC = 0 or 12 and W_{LS}CTC = 1 (or 30 degrees rotation in the counterclockwise direction to align with our reference high-side winding).

After being in service for some time, the differential relay trips during the external phase-to-phase fault shown in Fig. 39.

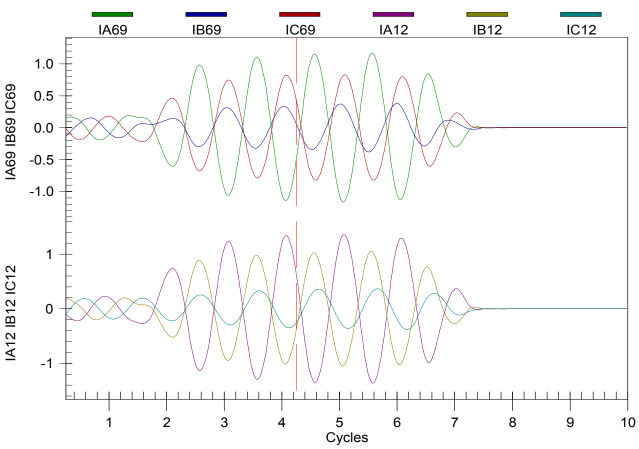

Fig. 39 External fault causes differential trip

Using the prefault data to perform an "offline" commissioning test, we find that phasor magnitudes, angle relationships, and rotation are as expected for through load. See Fig. 40. The 12 kV A-phase current, IA12, *leads* the 69 kV A-phase current, IA69, at the relay by 150 degrees. This corresponds to the 69 kV primary leading the 12 kV primary currents by 30 degrees.

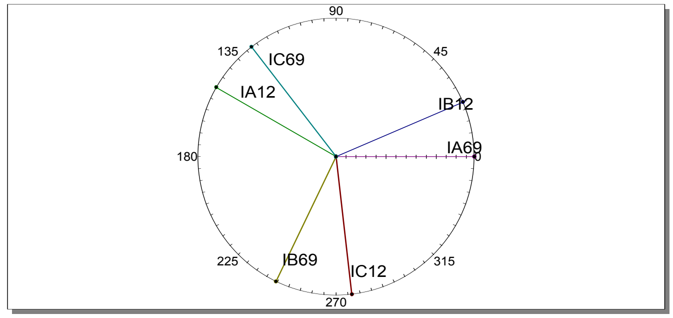

Fig. 40 High leads low side by 30 degrees as expected

An inspection of the relay settings uncovers an interesting mistake. In a previous example, we noted that Winding 1 of the relay most commonly connects to the high-voltage side of a power transformer. Again, the connection of Winding 1 to the high-voltage side is an arbitrary association by the design engineer. In that previous case, as in this one, the high-voltage side of the transformer connects to *Winding 2* of the relay. The settings shown for CT ratio and winding voltages reflect that Winding 1 is connected to the low-voltage side, and that Winding 2 is connected to the high-voltage side. However, the settings for phase-angle compensation reflect that the Winding 1 (in this case low-side) will lead the Winding 2 (in this case high-side) currents by 30 degrees, which is incorrect.

CTR1 = 3000:5 WYE
CTR2 = 600:5 WYE
WDG1 Voltage = 12.00 kV
WDG2 Voltage = 69.00 kV
WDG1 Phase-Angle Compensation = 12
WDG2 Phase-Angle Compensation = 1

A correct setting for the Winding 2 phase-angle compensation would be 0 or 12, and for the Winding 1 phase-angle compensation would be 1. We can assume that these settings were simply transposed in the settings process. Reversing the settings corrects the problem.

Lessons Learned - As many of these events demonstrate, it is critical to perform the previously discussed commissioning tests to identify this problem before putting the transformer and scheme into service. Verify that actual phase angles match expectations, and agree with phase-angle compensation settings selected. Insure that the operate current is less than 10% of the restraint current.

Verify CT wiring, and insure that transformer winding to relay connections are understood.

XVI. Lack of Zero-Sequence Trap

A 600 MVA, 345 kV-to-138 kV autotransformer is installed with wye-connected CTs on the high and low side. During a phase-to-ground fault external to the transformer on the 138 kV system, the differential relay trips.

Winding 1 and Winding 2 are each connected to 345 kV breakers on the high-side ring bus. Winding 3 is connected to a single 138 kV breaker on the low side. A CT in the transformer neutral is connected to a single-phase current input on Winding 4. Using the prefault data to perform an "offline" commissioning test, we find that phasor magnitudes, angle relationships, and rotation are as expected for through load. See Fig. 41.

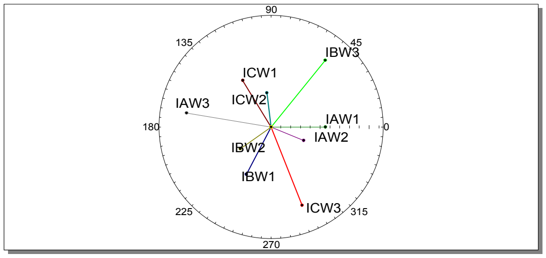

Fig. 41 Load current enters the autotransformer on Windings 1 and 2, and exits on Winding 3

Because there is no phase-angle shift between the high- and medium-voltage sides of the transformer, the engineer making the settings used no phase-angle compensation (identity matrix). The differential element, set in this way, simply compares A-phase on the high side with A-phase on the medium-voltage side (comparison of B and C phases occurs in the same way). The fault data, shown in Fig. 42, however, clearly indicate a single-line-to-ground fault. Each phase current consists of positive-sequence, negative-sequence, and zero-sequence components. The 345 kV system is a zero-sequence source, as is the transformer neutral. These combine or sum together to form the zero-sequence current leaving the medium-voltage winding. Because the differential element does not account for the zero-sequence contribution from the neutral CT, the medium-voltage currents appear larger than the high-voltage currents.

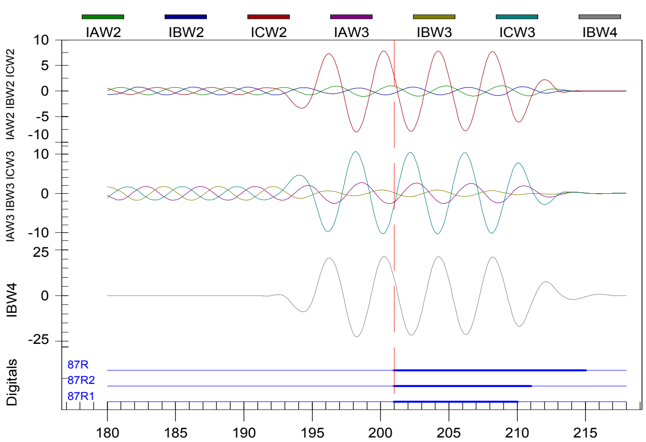

Fig. 42 Autotransformer neutral is a source of 3I0 current

For both the high-voltage and medium-voltage windings, one should have chosen any non-zero phase-angle compensation, taking care to set both high-voltage and medium-voltage compensation numbers the same. A non-zero compensation setting is essentially the same as physically installing a delta-connected CT on a wye winding, because this CT performs a phase-angle shift and introduces a zero-sequence trap, as shown below in the calculation of the delta current IAB, or IA minus IB.

$$I_a = I_1 + I_2 + I_0$$

$$I_b = \alpha^2 I_1 + \alpha I_2 + I_0$$

$$I_a - I_b = I_1 + I_2 + I_0 - \alpha^2 I_1 - \alpha I_2 - I_0$$

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

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

Lessons Learned–Eliminate zero-sequence currents from CTs connected to all grounded, wye-connected transformer windings or where a grounding transformer is installed on the delta winding within the differential zone. If CTs are wye-connected, the zero-sequence currents must be removed mathematically in the relay through the use of a non-zero compensation setting (the equivalent of a delta CT).

Commissioning and functional tests should include simulating through faults to ensure that the relay settings provide security against tripping for external faults.

XVII. Commissioning Multi-Winding Differentials

A 69 kV-to-12 kV power transformer is being installed for the first time. The high side is delta-connected, polarity of H1 to non-polarity of H2, and the low side is grounded-wye connected. Phase rotation is ABC, and phase-to-bushing connections are A-H1, B-H2, and C-H3. Winding 1 of the relay is connected to the high-side wye CT. Winding 2 and Winding 3 of the relay each connect to the load side of distribution feeder breakers. The transformer is energized, and we check in-service metering readings to determine if the differential relay is fit to go into service.

```
=>SHO
Group 1


E87W1   = Y        E87W2   = Y        E87W3   = Y        E87W4   = N
EOC1    = Y        EOC2    = Y        EOC3    = Y        EOC4    = N
EOCC    = N        ESLS1   = Y        ESLS2   = N        ESLS3   = N

W1CT    = Y        W2CT    = Y        W3CT    = Y        W4CT    = Y
CTR1    = 120      CTR2    = 240      CTR3    = 240      CTR4    = 1
MVA     = OFF      ICOM    = Y
W1CTC   = 0        W2CTC   = 1        W3CTC   = 1

TAP1    = 2.01     TAP2    = 5.55     TAP3    = 5.55
O87P    = 0.3      SLP1    = 40       SLP2    = OFF
U87P    = 8.0      PCT2    = 15       PCT5    = 35
TH5P    = OFF      IHBL    = N
```

Fig. 43 Transformer differential relay settings

```
=>METER


                 A         B         C         N         G
I MAG (A)     43.293    39.188    40.577    44.004     0.333
I ANG (DEG)    9.32   -111.80    133.36   -160.36    22.27

                 A         B         C         S
V MAG (KV)    41.278    41.093    41.498     0.002
V ANG (DEG)    0.00   -120.00    120.04    -63.36

                 A         B         C         3P
MW             1.763     1.594     1.639     4.996
MVAR          -0.289    -0.230    -0.388    -0.907
PF             0.987     0.990     0.973     0.984
               LEAD      LEAD      LEAD      LEAD

                 I1        3I2       3I0       V1        V2        3V0
MAG           40.989     6.953     0.333    41.290     0.123     0.338
ANG    (DEG)  10.29     -8.87     22.27      0.02    -88.50     97.61

FREQ (Hz)     60.01               VDC (V)     134.0
```

Fig. 44 Metering from high-side back-up relay

We collect current and power metering from the high-side backup overcurrent relay as a reference. In Fig. 44, the overcurrent relay is measuring about 40 A primary, per phase.

Three-phase power is about 5 MVA. Following proper commissioning test procedures, we calculate the expected current magnitudes that the differential relay should measure. At 5 MVA and 69 kV, the high side should measure about 40 A primary, or 0.33 A secondary (with a CTR of 120). At 5 MVA and 12 kV, the low side should detect about 240 A primary, or 1 A secondary (with a CTR of 240). In Fig. 45, we observe that the mismatch, or ratio of operate to restraint current, for each differential element is 10 percent or less.

```
=>MET DIFF
```

	Operate Currents			Restraint Currents		
	IOP1	IOP2	IOP3	IRT1	IRT2	IRT3
I (Mult. of Tap)	0.01	0.00	0.01	0.19	0.18	0.19
	Second Harmonic Currents			Fifth Harmonic Currents		
	I1F2	I2F2	I3F2	I1F5	I2F5	I3F5
I (Mult. of Tap)	0.00	0.00	0.00	0.00	0.00	0.00

Fig. 45 Operate and restraint currents

In Fig. 46, the Winding 1 currents match expectation, in terms of magnitude and phase rotation. We must add the Winding 2 and three phase currents to develop the total low-side current. Neither Winding 2 nor three currents, individually, lead Winding 1 currents by 150 degrees. Phase angle and magnitude measurement taken from either feeder individually will not make sense, because the total low-side load splits and flows down two feeders, each of which has a magnitude and power factor angle based upon downstream loads. By adding IAW2 and IAW3, we obtain 0.92 A secondary at 149 degrees. As expected, that magnitude is nearly one, and the phase angle leads IAW1 by nearly 150 degrees. The transformer is ready to go into service.

```
=>MET SEC
```

	Phase Currents			Sequence Currents		
Wdg1	IAW1	IBW1	ICW1	3I1W1	3I2W1	IRW1
I (A,sec)	0.37	0.33	0.35	1.05	0.04	0.02
Angle (deg)	0.00	-121.21	121.68	0.17	-16.28	35.88
Wdg2	IAW2	IBW2	ICW2	3I1W2	3I2W2	IRW2
I (A,sec)	0.29	0.29	0.37	0.94	0.14	0.19
Angle (deg)	-150.66	72.14	-17.73	-150.88	178.37	7.01
Wdg3	IAW3	IBW3	ICW3	3I1W3	3I2W3	IRW3
I (A,sec)	0.82	0.83	0.82	2.47	0.03	0.01
Angle (deg)	130.55	11.22	-109.91	130.62	-57.32	62.45
Wdg4	IAW4	IBW4	ICW4	3I1W4	3I2W4	IRW4
I (A,sec)	0.00	0.00	0.00	0.01	0.00	0.01
Angle (deg)	-72.55	107.45	17.45	-117.55	62.45	62.45

Fig. 46 Secondary current metering from differential relay

Lesson Learned – Phase-angle transformations across the transformer apply to the currents measured at the bushings. If CTs measure current at multiple downstream feeder locations, add the phasors before doing in-service reading checks.

In most cases, there is another relay handy against which you can reference metering information.

XVIII. Relay Failure

A differential relay trips a 20 MVA, 67 kV delta to 12.47 kV grounded-wye power transformer offline, and a technician travels to the substation to investigate. The relay had 51, C, and N target LEDs lit. As with most microprocessor-based relays, this differential relay has many other features, including backup overcurrent elements. Enabled in this relay is the residual ground overcurrent from Winding 2, the low side. This element provides time-coordinated backup for outgoing feeder relays and distribution bus protection. We observed no other relay targets. Fig. 47 shows relay event data that confirm the fault was an out-of-section ground fault, downstream of the low-side CTs. A visual inspection of the bus located no obvious trouble. We therefore re-energized the transformer about two hours later. The relay tripped within seconds.

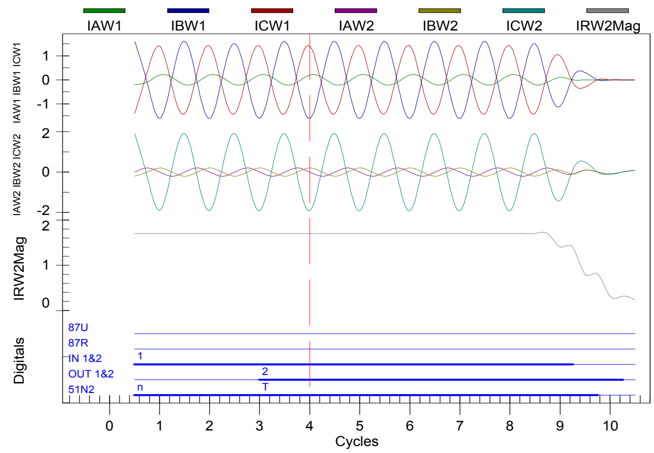

Fig. 47 Downstream C-ground fault confirmed

After the second trip, we suspected a miscoordination. We conducted a more thorough investigation and interrogated feeder relays to see if these relays had triggered event reports for any downstream faults. The history of all relays showed no triggered events, but we discovered that one of the feeder relays was disabled as a result of a self-test alarm. See Fig. 48.

```
=>HISTORY

SUBST.                Date: 07/18/05    Time: 10:30:18.634
BKR. SOUTH

#    DATE       TIME          EVENT   LOCAT   CURR  FREQ GRP SHOT TARGETS

1  06/03/05 00:00:22.234 BG T     20.40    571 59.96  1    0  11000010 00101010
.
.
.
29 04/01/04 11:18:31.184 AG      -0.00   1002 60.00  1    3  11000010 00110010

=>>STA

SUBST.                Date: 07/18/05    Time: 10:33:03.622
BKR. SOUTH


SELF TESTS

W=Warn    F=Fail

      IA       IB        IC        IN        VA        VB        VC        VS        MOF
OS   -1       -1         0         0        -2        -1         2         0        -1

      +5V_PS  +5V_REG  -5V_REG  +12V_PS  -12V_PS  +15V_PS  -15V_PS
PS     4.96    4.96    -4.98     12.02   -14.03F   14.90   -14.80

      TEMP     RAM       ROM       A/D      CR_RAM    EEPROM    IO_BRD
      36.4     OK        OK        OK       OK        OK        OK

Relay Disabled

=>>
```

Fig. 48 Transformer relay provided back-up for failed feeder relay for downed conductor

We found a downed conductor downstream of the failed feeder relay. The transformer relay had performed correctly, providing backup protection for this fault and relay failure.

Lessons Learned – Monitor self-test alarm contacts in real time. Investigate any failure immediately to improve the chance of fixing the problem before a fault occurs on the sys-

tem. SCADA, automatic messaging, or local annunciation are all options for highlighting a failed device.

A downed conductor was reenergized unnecessarily. Balance the desire to "get the lights back on" with the need to determine root cause prior to reenergization.

One can use event data from a healthy relay to piece together what happened with a failed relay and to determine probable fault location.

XIX. CT SATURATION RESULTING FROM DC OFFSET

A generator is online, but it is not synchronized to the power system. The breaker on the high side of the generator step-transformer is open. The step-up transformer is rated at 270 MVA, with a grounded-wye connected 345 kV high side, and a delta-connected 18 kV low side. System phase rotation is ABC, and phase-to-bushing connections are A-H1, B-H2, and C-H3. The delta is made with polarity-of-X1 connected to nonpolarity-of-X3. This type of connection forms a yDAC or yD1 transformer. The relay is set "y11D", with the Winding 2 delta side as the reference, and settings are correct.

A flashover occurs on the 345 kV side, causing a 345 kV C phase-to-ground fault. As we see in Fig. 49, the fault appears correctly as an A-to-C phase fault on the low side. We know from the event data that the fault was external to the differential zone, but the differential relay operated. The phase-angle relationships for the fault agree with what we would expect, given our transformer and settings. The event data show an unexpected 3I0 ground current on a delta winding and decaying 3I0 ground current magnitude (and operate current), despite the filtered faulted phase currents remaining constant. We therefore suspect CT saturation.

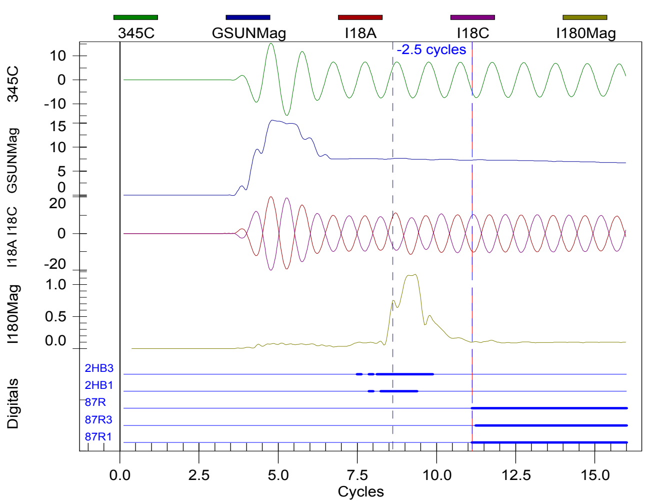

Fig. 49 Flashover on high-side caused differential trip

We need a raw event report to prove our theory. Fig. 50 shows the raw or unfiltered data. This saturated waveform looks very different from our earlier CT saturation example in Fig. 35. Rather than the "sawtooth" waveform of that figure, we see here heavy dc offset with a very noticeable long time-constant delay. This condition can arise commonly during external faults close in to generator step-up transformers [9]. We can also see from the filtered data in Fig. 49 the point at which there is a sharp spike of 3I0 current on the low side. This spike corresponds to the point where the dc offset of the two low-side currents has subsided and is nearly, but not completely, balanced. At a point 2.5 cycles later, when the differential element trips, it is evident that the high-side CT still has a good deal of offset. This dissimilar CT performance causes the differential misoperation.

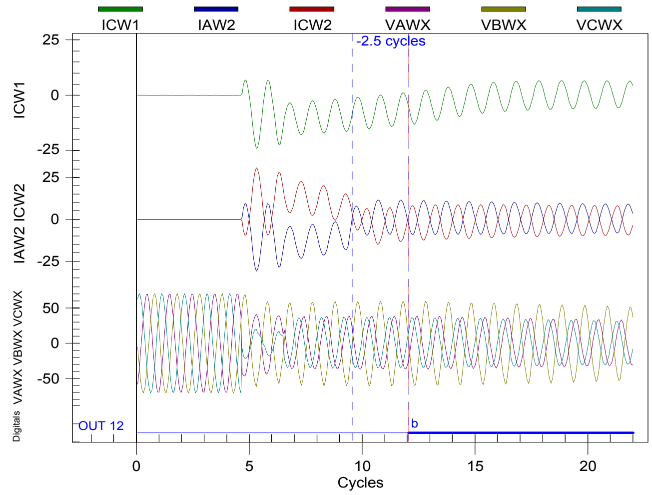

Fig. 50 Flashover on high-side caused differential trip

We must adjust the minimum operate setting O87P and the slope settings to make this application more secure.

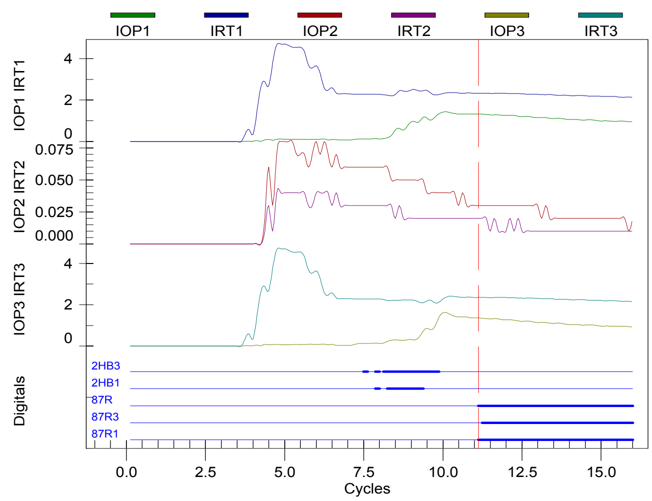

Fig. 51 Ratio of operate to restraint exceeds 50 percent in elements 87R1 and 87R3

Lessons Learned – Heavy dc offset is another contributor to CT saturation. We must have raw event data to see this offset.

Decreasing residual or operate current over time, while filtered phase currents remain steady throughout a fault, is an indication of CT saturation.

The raw waveforms from Winding 2 in Fig. 50 are a perfect example of a long time-constant delay, dc offset. Commit these waveforms to memory, so that you can easily recognize these waveforms in the future.

Check CTs to ensure acceptable performance during faults. Increasing minimum operate and slope settings increases security (while decreasing sensitivity).

XX. Restricted Earth Fault

A 20 MVA power transformer is installed as shown in Fig. 52. The relay issues a trip by restricted earth fault element, or ground differential. The ground differential zone encompasses the area between the neutral CT and the load side of the two distribution feeder breakers. Because the feeder relay in Fig. 53 also detected a ground fault, we suspect a misoperation of the restricted earth fault (REF) element. The relay perhaps operated for an out-of-section ground fault.

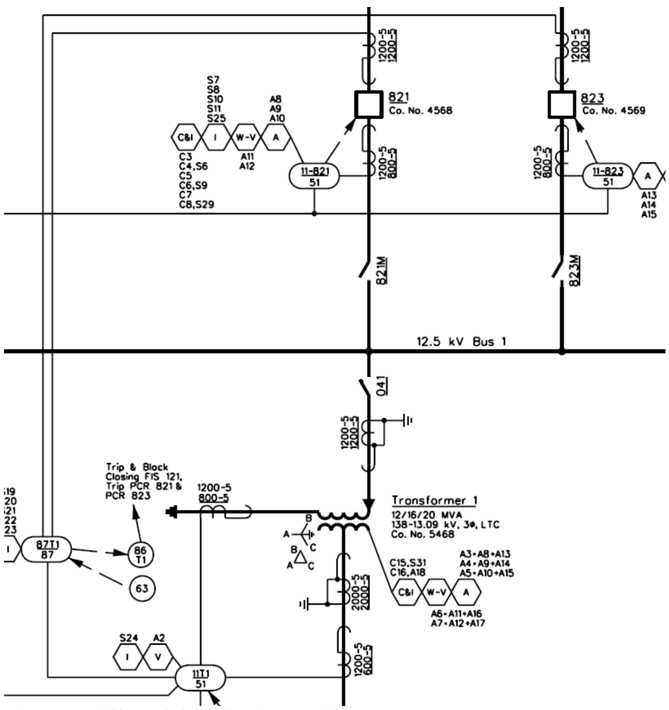

Fig. 52 Differential application oneline

It became evident upon further inspection that the feeder relay did not trip. The fault is definitely downstream of the feeder relay CT, but the ground fault current appears to dissipate before any trip or breaker operation. Such behavior could result from such an occurrence as a flashover across a dirty breaker bushing on a drizzly day. The fault appears to extinguish itself. The feeder relay was timing to trip, but it never did.

Fig. 54 shows data from the differential relay. The analog channels are named incorrectly, as a result of a label setting error. The top channel represents the high-side currents. The next two channels represent the two feeder breakers. The fourth channel represents the neutral ground current. The transformer high-side currents are not a textbook-perfect example of phase-to-phase for a low-side phase-ground fault, but they are close enough when one considers the presence of load. The neutral current magnitude matches that of the feeder relay; about 1000 A primary ground current. Notice, however, the absence of current imbalance on either distribution feeder CT. This tells us that the fault was between the source-side feeder CT (feeder relay CT) and the load-side differential CT (REF and 87T CT). Again, this indicates a breaker bushing flashover.

The feeder current magnitude data in Fig. 53 shows an A-phase fault in which the A-phase current lags the depressed A-phase voltage.

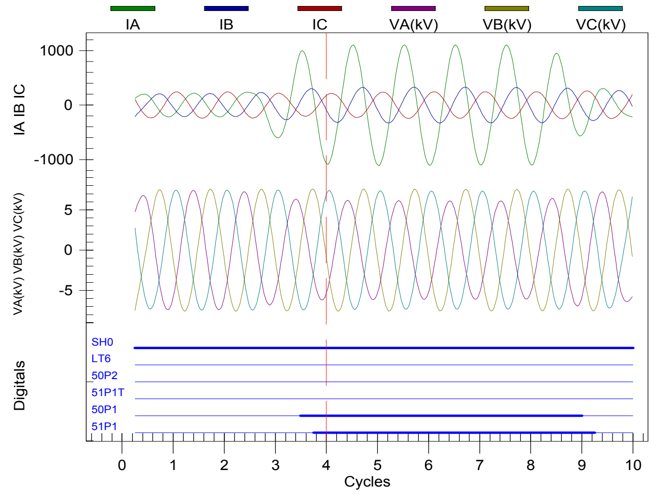

Fig. 53 Faulted feeder relay event data

Information from the transformer differential relay in Fig. 54, however, indicates that the fault was on C-phase. The high-side C-phase current is out of phase with the neutral current, and it is the largest high-side fault current, as we would expect if the fault involved the low-side C-phase current.

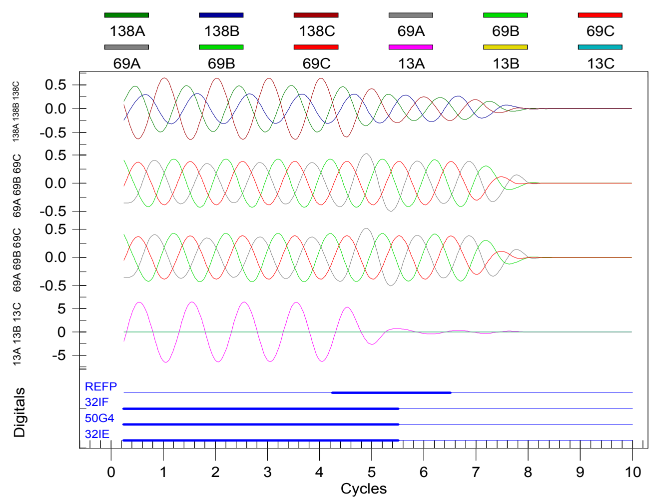

Fig. 54 Differential relay information

Data from the high-side backup relay, which also provides neutral time-overcurrent ground protection, corresponds to a C-phase low-side fault. See Fig. 55. This indicates the existence of a wiring discrepancy, in terms of phase labeling, between feeder relays and relays associated with the transformer. This complicates fault type determination and makes it difficult to correlate event data and metering.

Event analysis uncovered one last significant issue. There is a setting in the relay with which the user specifies the winding to be included in the REF zone. The as-set setting was to include only one feeder breaker CT. That means that, for any ground fault on the other feeder, the REF would be likely to misoperate [10].

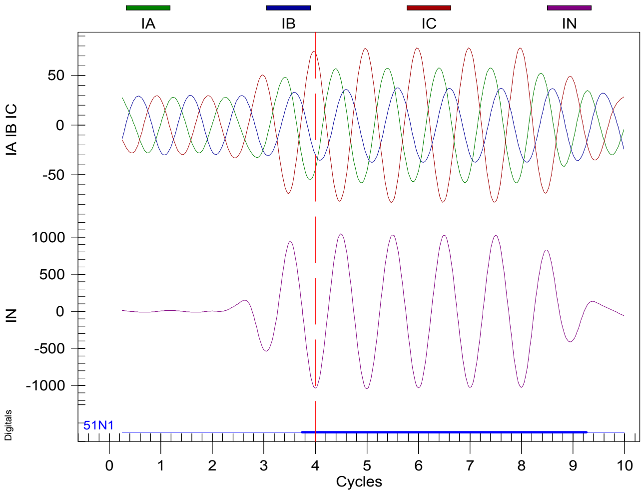

Fig. 55 High-side back-up relay information

Lessons Learned – Primary injection or other commissioning tests are valuable in ensuring consistent phasing throughout a substation. Discrepancies in phase wiring between the transformer and downstream feeders complicates metering and event analysis.

Commissioning tests on differential relays, including ground differential or REF elements, should test through load and external fault security on each winding to uncover setting mistakes, such as the inadvertent omission of a winding from the differential element.

On a radial feeder, one can use the presence of fault current in the feeder relay CT and concurrent absence of fault current in the differential CT to confirm that a fault was located between the two CTs, in each zone of protection.

XXI. Breaker Problem

A 9 MVA generator step-up transformer is delta-connected on the generator side and grounded-wye connected on the 69 kV system side. The generator is offline. However, the system is back feeding the step-up transformer to supply auxiliary loads. A line-to-ground fault occurs on the system, and the differential relay trips.

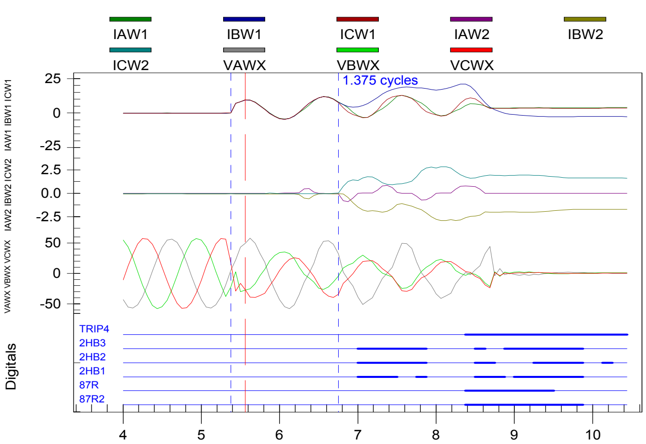

Fig. 56 Raw waveforms from differential relay

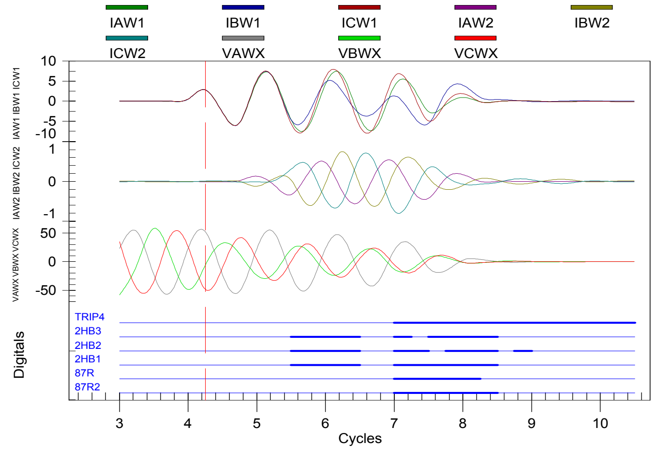

Fig. 57 Filtered waveforms from differential relay

The raw waveforms in Fig. 56 and the filtered 60 Hz waveforms in Fig. 57 begin as expected. For a single line-to-ground high-side fault with no generation, the step-up transformer supplies pure zero-sequence current to the system. All three phases are in phase until almost a cycle and a half into the fault, when the B-phase current no longer matches the others and loses symmetry. To determine if the problem is related to a local relay or CT, we compare these data to event reports from several upstream transmission line terminals.

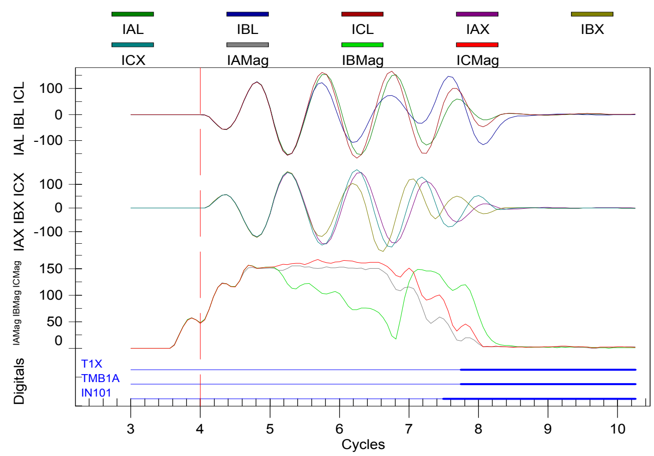

Fig. 58 Line current differential upstream

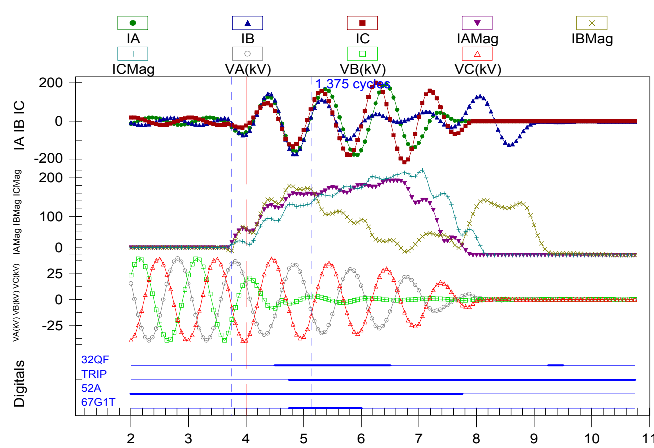

Fig. 59 Distance relay closest to fault

The data in Fig. 58 and 59 confirm that the local differential relay and CT are not the root cause. All three in-series terminals show the same B-phase current anomaly. From these data, we determine that the breaker closest to the fault needs inspection and maintenance. The B-phase interrupter appeared to open with a significantly different operating speed, and it possibly arced or flashed over during interruption.

Lessons Learned – Breaker arcing or flashover can cause current waveforms we measure at the relay to appear to lose symmetry, changing magnitude and angle. When one phase differs significantly from another, suspect a breaker problem.

When several relays in series experience the same fault current, compare data from these relays. The root cause will be downstream of the last incorrect waveform.

XXII. Overexcitation

An unloaded distribution substation transformer was deenergized by an upstream line switch. During the event, the transformer differential element tripped as a result of transient overvoltage. There would be no intentional deenergization of a loaded transformer with a line switch, so this event was a nuisance operation and not one that interrupted load.

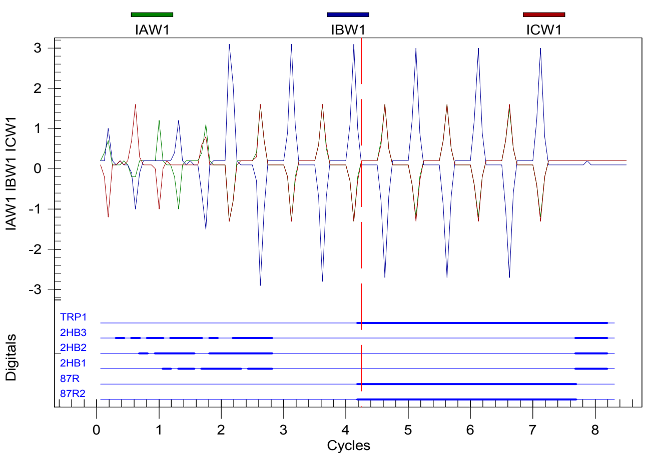

Fig. 60 Overexcitation waveform captured by relay

However, any operation of a differential relay causes concern and initiates troubleshooting efforts to determine if the transformer was indeed faulted. In this case, time and effort may have been wasted testing an unfaulted transformer.

For this event, no overexcitation blocking was in use. Harmonic analysis of the raw waveform shows that the fifth harmonic is roughly half the fundamental in the B and C phases. See Fig. 60. We converted the raw event data to IEEE COMTRADE format and replayed these data into a relay with 5th harmonic blocking enabled and proved that this would make the relay secure.

Lessons Learned – Fifth-harmonic blocking can prevent differential operations resulting from overexcitation. We can make troubleshooting easier if we enable fifth-harmonic elements to alarm, even if these elements are not enabled to block or trip.

Fig. 60 is a perfect example of an overexcitation condition, and can be committed to memory so as to be recognized in the future.

IEEE COMTRADE replay of field events is an excellent way to prove settings solutions.

XXIII. Motor Differential Application

A two-winding differential relay is installed to protect a motor. The differential relay trips during its first start attempt. Fig. 61 illustrates the phasors the relay captured during the event. We do not expect any phase-angle shift in a motor differential application. For starting or running current, the high-side currents should be out of phase with the low-side currents.

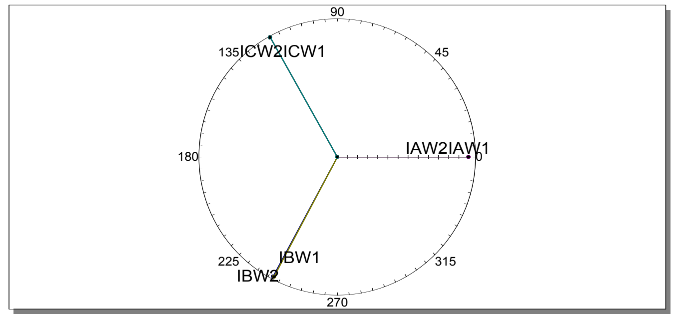

Fig. 61 High-side CT polarities found reversed

We found the high-side CT polarities to be connected with reverse polarity. After correcting the wiring error, we energized the motor again, only to have a differential element trip the motor immediately.

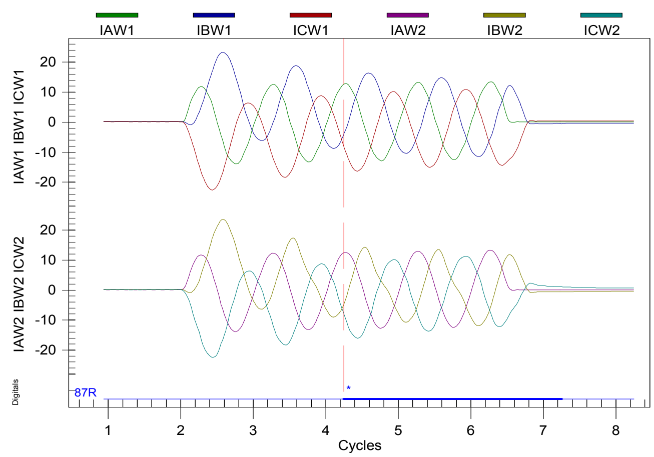

Fig. 62 Second trip shows some CT saturation

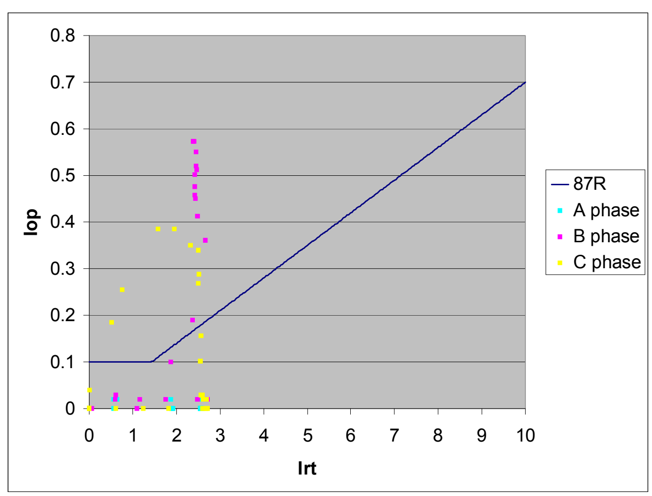

Fig. 63 Operate and restraint at all points in event

Fig. 62 shows the raw waveforms. DC offset and slight distortion is visible, so we suspect CT saturation and very sensitive pickup (0.1 per unit) and slope settings (7 percent) of playing a role in the second misoperation.

An empirical equation relates the CT saturation voltage to a secure slope setting in the relay [11]. Given the system X/R ratio, fault current, and CT burden, a more appropriate slope setting could be derived.

Alternatively, an engineer developed a software tool to plot operate and restraint quantities for each point through the recorded event data. See Fig. 63. Many points exceed the sensitive settings, so the relay operated. To compensate for the saturating CTs, we use an iterative process to find such values for pickup and slope that are secure for all points in the event data. We found that a minimum pickup of 0.3 per unit and a slope of 37 percent provided security for these fault data.

Lessons Learned – CTs can saturate during motor starts, causing false residual current and motor differential relays to misoperate.

CTs in industrial switchgear applications are commonly undersized or have low accuracy. Extremely sensitive settings, high security, and poor CTs are generally mutually exclusive.

Software tools help us visualize relay element performance and develop appropriate settings.

XXIV. Conclusions

Transformer differential relay installations remain complicated as a result of the impact many variables have on phase-angle relationships. These variables include system phase rotation, phase-to-bushing connections, and CT-to-relay wiring.

The reliance upon thorough commissioning tests to discover setting and wiring problems before a transformer goes into service, and the ensurance of electric power reliability, cannot be overstated.

Digital relays improve these installations in many ways. Most significantly, these relays accommodate virtually any transformer application, make available the universal use of wye-connected CTs, and provide advanced metering tools and event report data.

Event report data are critical to understanding and solving complex problems.

Technology has not yet replaced the invaluable contribution of a knowledgeable and experienced engineer and technician.

Developing proficiency with troubleshooting and event report analysis takes time, practice, and experience. Understanding real-world examples such as this technical paper provides should assist engineers and technicians facing root cause analysis in the future.

XXV. Acknowledgments

The author expresses his sincere appreciation for the experience and expertise shared by engineers at Schweitzer Engineering Laboratories, Inc. Bill Fleming, Brad Heilman, Matt Leoni, Ted Warren, and Karl Zimmerman contributed event report analysis examples. Rogerio Scharlach and Karl Zimmerman provided testing procedures. This paper would not have been possible without their significant contributions and prior work, much of which is presented here.

Event reports shared in this paper come from actual field installations. Any reference to the original user has been removed; the relevant information comes from the event data and what lessons these data provide. The continued sharing of these event data is invaluable, greatly appreciated, and makes coming to work fun.

XXVI. References

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XXVII. Biography

David Costello graduated from Texas A&M University in 1991 with a BSEE. He worked as a system protection engineer at Central Power and Light and Central and Southwest Services in Texas and Oklahoma. He has served on the System Protection Task Force for ERCOT. In 1996, David joined Schweitzer Engineering Laboratories, where he has served as a field application engineer and regional service manager. He presently holds the title of senior application engineer and works in Boerne, Texas. He is a senior member of IEEE, and a member of the planning committee for the Conference for Protective Relay Engineers at Texas A&M University.