Diagnosing CT Polarity Issues in Transformer Earth Fault Protection

David Quashie
Snohomish County PUD

Sumit Sawai, John Hostetler, Aditya Parhad, and Pratheek Annamdevula
Schweitzer Engineering Laboratories, Inc.

Revised edition released August 2026

Originally presented at the
15th Annual Australian Protection Symposium, August 2026

Diagnosing CT Polarity Issues in Transformer Earth Fault Protection

Sumit Sawai, John Hostetler, Aditya Parhad, and Pratheek Annamdevula, *Schweitzer Engineering Laboratories, Inc.*
David Quashie, *Snohomish County PUD*

***Abstract*—A neutral current transformer (CT) polarity error can compromise both the security and dependability of restricted earth fault (REF) and ground directional overcurrent (67N) protection. The resulting measurement error is normally latent during balanced load and many switching conditions. Visual wiring checks alone are not sufficient to verify REF or 67N integrity. This paper presents a structured diagnostic approach for identifying incorrect neutral CT polarity in REF and 67N applications. The approach progresses from indirect methods that use relay metering and event records to direct verification methods performed during an equipment outage.**

The proposed diagnostic framework is demonstrated through field event captures from multiple in-service transformers and validated through primary field testing and event records on a 230/115 kV autotransformer. These examples demonstrate how multiple independent analytical checks can isolate the neutral current path as the source of error, guide corrective action, and support improved commissioning practices for grounded transformer applications.

I. Introduction

Transformer protection schemes rely on accurate current measurements at the boundaries of the protected zone. When these measurements correctly reflect system conditions, protection elements, such as phase differential (87) and restricted earth fault (REF), provide fast, sensitive, and secure fault detection [1].

Directional neutral overcurrent elements (67N) applied to lines connected to a grounded-wye winding use transformer neutral current as the polarizing quantity. REF and 67N element performance depends on correct neutral current magnitude and polarity.

An incorrect current transformer (CT) polarity connection is a simple wiring error, but it can invalidate the measured quantities and compromise the underlying protection principles. This can result in reduced dependability for internal faults and decreased security during external disturbances.

Fig. 1 presents a typical protection arrangement for a delta-wye grounded transformer and directional ground protection for a line on the wye side. The 87 and REF elements provide protection for the transformer, while a 67N element protects the line connected to the grounded-wye winding. Fault F1 represents a fault on the line, and F2 represents a fault within the transformer zone.

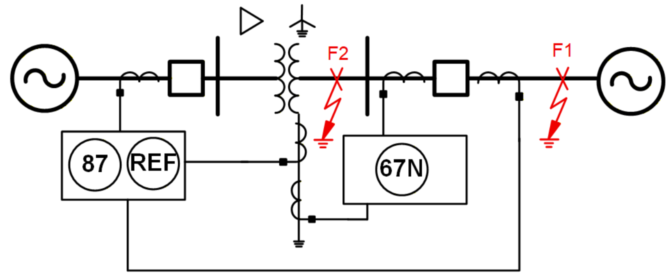

Fig. 1. Typical REF and 67N application.

The REF element provides sensitive detection of ground faults within a restricted zone that may not produce sufficient phase current to operate the differential element [2] [3]. This includes faults near the neutral point of solidly grounded windings and faults across a significant portion of a low-impedance grounded-wye winding. REF implementations commonly use either:

- A directional element (32I) that evaluates the direction of an operate quantity measured from the neutral CT (IN) with respect to a reference residual quantity derived from the terminal CTs (3I0), or
- A low- or high-impedance zero-sequence differential scheme using terminal CTs and neutral CT.

Although the diagnostic signatures described later in Section II apply equally to directional, low-impedance, and high-impedance REF schemes, the remainder of this paper focuses on the directional REF implementation to illustrate the impact of CT polarity errors.

In directional implementations, the operating principle can be expressed as (1):

$$32I_{REF} = \overrightarrow{_{3I0}} \bullet \overrightarrow{_{IN^*}} \qquad (1)$$

The directional REF element evaluates the product of two phasors: 3I0 and the complex conjugate of IN, denoted by IN*. In practice, modern relays implement a slightly expanded characteristic to account for applications with a neutral grounding resistor. Fig. 2 shows the expanded characteristic of the directional REF element, with the shaded area indicating the external-fault region. Additionally, the directional REF element includes special logic to handle internal fault cases where only IN is measured without any residual (3I0) current, resulting in $32I_{REF} \approx 0$. The absence of residual current may occur due to open breakers or radial system configurations. In such cases, the presence of neutral current without corresponding residual current is treated as an indication of an internal fault, allowing the use of a sensitive, but secure, neutral overcurrent element.

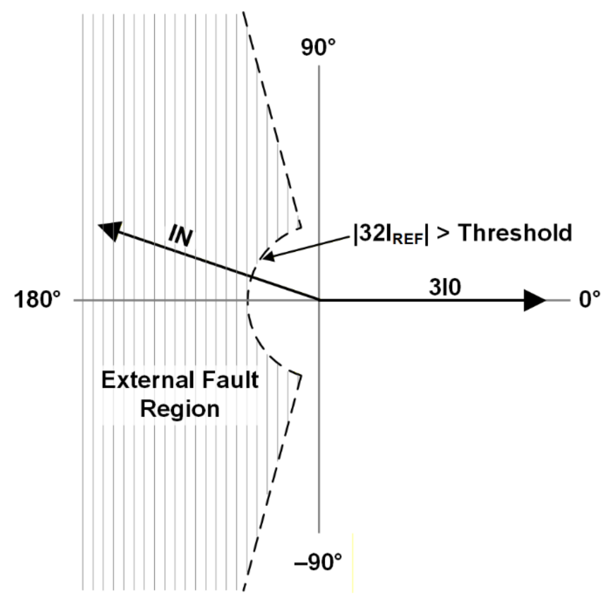

Fig. 2. Directional REF characteristic.

The 67N element provides directional ground fault protection by evaluating the phase relationship between residual current 3I0, measured by the line CTs, and a polarizing quantity IN, measured by the neutral CT. The operating principle governing 67N is the same as that of the directional REF element shown in (1); the key difference is that the 3I0 used in 67N applications is measured by the line CTs whose polarity is oriented opposite to that of the REF terminal CTs measuring 3I0, as shown in Fig. 1. The 67N element declares faults on the line as forward and faults behind the relay location as reverse.

Both REF and 67N elements depend directly on the correct magnitude and polarity of residual and neutral currents. As a result, errors in CT polarity directly affect their directionality response and operating characteristics, with the resulting effects of a neutral CT polarity error summarized in Table I and Table II.

TABLE I
FAULT AT F1 IN FIG. 1

Element	Correct Neutral CT Polarity	Incorrect Neutral CT Polarity
REF	External	Internal
67N	Forward	Reverse

TABLE II
FAULT AT F2 IN FIG. 1

Element	Correct Neutral CT Polarity	Incorrect Neutral CT Polarity
REF	Internal	External
67N	Reverse	Forward

Field experience shows that several wiring and configuration errors can affect REF and 67N performance, including:

- Reversal of neutral CT secondary leads.
- Reversal of one or more phase CT polarities.
- Incorrect CT ratio selection.
- Incorrect assignment of the neutral CT in REF applications with multi winding arrangements, such as a YNyn configuration or paralleled transformers.

Among these errors, reversal of the neutral CT polarity is the most common and difficult to identify due to lack of proper commissioning practices. Visual inspection can confirm consistency with drawings but cannot guarantee correctness of CT polarity or wiring implementation.

This paper presents a structured approach for identifying neutral CT polarity errors in REF and 67N protection applications. It first establishes the expected current relationships for internal and external ground faults, then shows how those relationships change when neutral CT polarity is reversed. It then demonstrates indirect diagnostic methods using relay metering and event data, followed by direct verification techniques and a field validation case.

II. CHARACTERIZING INTERNAL VERSUS EXTERNAL TRANSFORMER GROUND FAULTS

The diagnostic methods described in this paper are based on the fundamental difference in zero-sequence current flow for internal and external ground faults on a grounded transformer winding. This section develops that distinction and shows why the relationship between terminal residual current and neutral current is a reliable polarity indicator.

A. External Ground Fault

Fig. 3 shows an example power system with a Dyn1 transformer connected between two equivalent sources, V_S and V_R, represented by their respective source impedances, Z_S and Z_R. The delta-connected side is connected to the local system, while the grounded-wye side is connected to the remote system. An external single-line-to-ground fault is applied on the line outside the transformer REF protection zone.

The lower portion of the figure shows the corresponding symmetrical component networks for the external-fault condition. The positive-, negative-, and zero-sequence networks are connected in series at the fault location.

Z1S, Z2S, and Z0S represent the positive-, negative-, and zero-sequence impedances of the source connected to the delta side (local system).

Z1R, Z2R, and Z0R represent the positive-, negative-, and zero-sequence impedances of the source connected to the grounded-wye side (remote system).

Z1T, Z2T, and Z0T represent the transformer positive-, negative-, and zero-sequence impedances. In the zero-sequence network, the grounding impedance is represented as $3 \cdot R_{NGR}$. The fault resistance is represented as $3 \cdot R_F$.

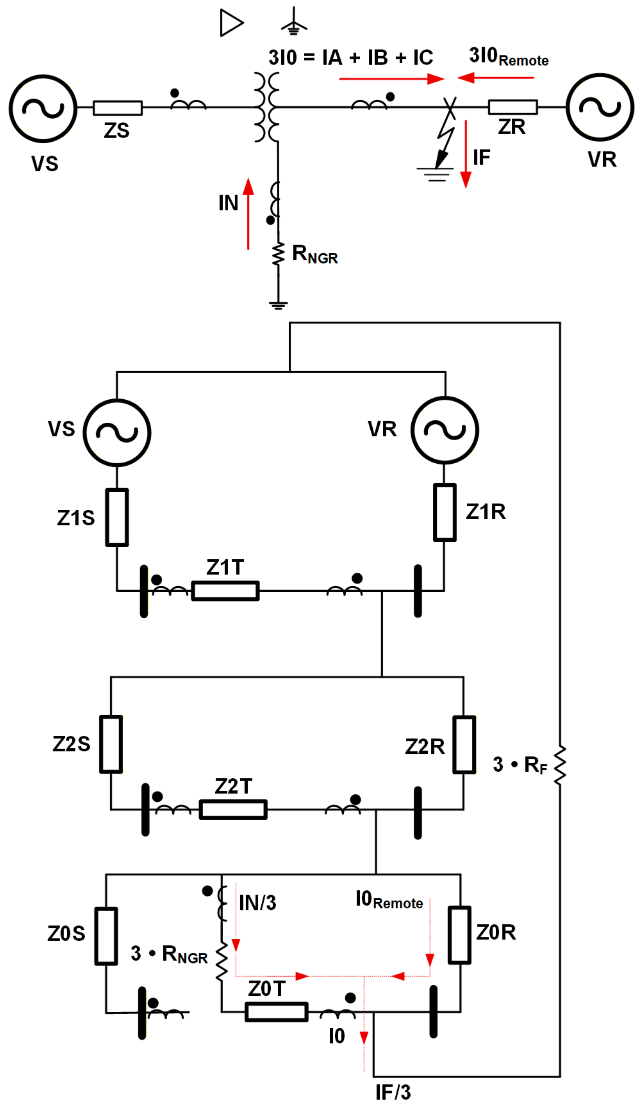

Fig. 3. External ground fault on a transformer and corresponding sequence networks.

For an external ground fault, the fault is outside the REF zone of protection. The zero-sequence current follows a single path through the protected zone: it enters from the neutral and exits the wye-connected bushings before returning to the fault. The same fault current is being measured by both the neutral CT and phase bushing CTs.

Applying Kirchhoff's current law (KCL) results in (2):

$$3\mathrm{I0} = -\mathrm{IN}(\text{external fault}) \tag{2}$$

Thus, the terminal residual current and neutral current are equal in magnitude and opposite in polarity for an external ground fault, assuming negligible measurement error and no significant CT saturation. This relationship is imposed by the zero-sequence network topology and is the restraining condition for REF.

B. Internal Ground Fault

Fig. 4 shows the same system as that of Fig. 3, but with the internal fault now located on the transformer bushing, within the REF zone of protection.

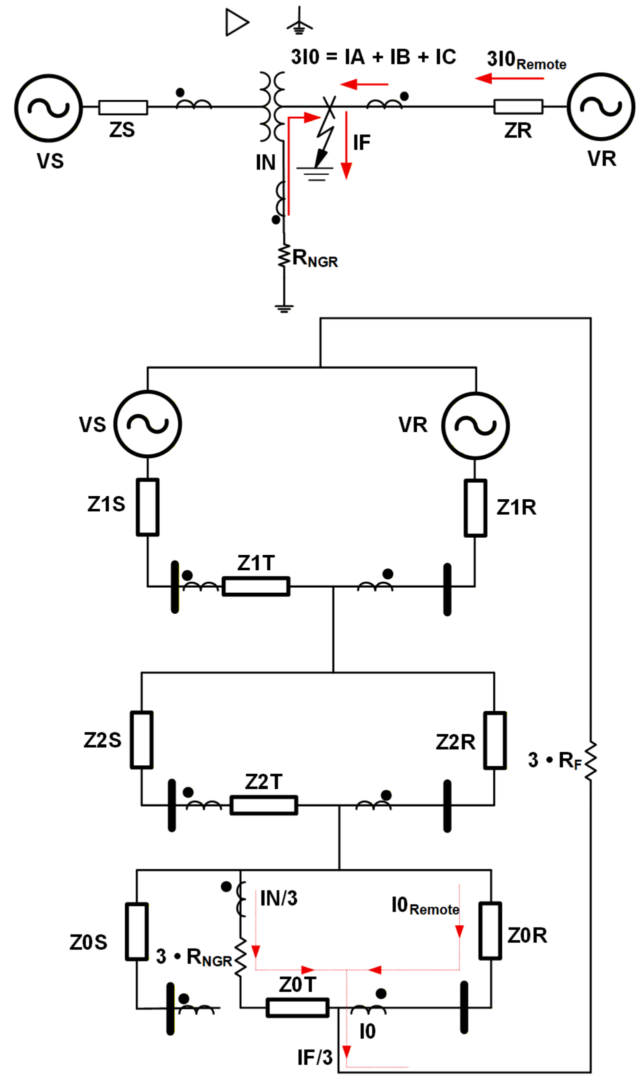

Fig. 4. Internal ground fault on a transformer and corresponding sequence networks.

An internal fault introduces a new current path within the winding. As a result, the zero-sequence current is no longer confined to a single route within the zone. Instead, it divides between:

- the neutral grounding path (measured by the neutral CT), and
- the system path (measured by the terminal CTs).

Applying KCL at the fault point in Fig. 4 yields (3):

$$\frac{\mathrm{IF}}{3} = \frac{\mathrm{IN}}{3} + \mathrm{I0} \tag{3}$$

Applying current division, the neutral current component is given by (4), where the current division factor α is defined in (5):

$$\frac{\mathrm{IN}}{3} = \frac{\mathrm{IF}}{3} \bullet \frac{\mathrm{Z0R}}{\mathrm{Z0R} + \mathrm{Z0T} + 3\mathrm{R}_{\mathrm{NGR}}} \tag{4}$$

$$\alpha = \frac{\mathrm{Z0R}}{\mathrm{Z0R} + \mathrm{Z0T} + 3\mathrm{R}_{\mathrm{NGR}}} \tag{5}$$

Substituting (5) into (4) yields (6):

$$\frac{\mathrm{IN}}{3} = \frac{\mathrm{IF}}{3} \times \alpha \tag{6}$$

The terminal zero-sequence component is expressed by (7) and (8):

$$\mathrm{I0} = \frac{\mathrm{IF}}{3} - \frac{\mathrm{IF}}{3} \bullet \alpha \tag{7}$$

$$\mathrm{I0} = \frac{\mathrm{IF}}{3}(1-\alpha) \tag{8}$$

Dividing (6) by (8), gives (9):

$$\frac{\mathrm{IN}}{3\mathrm{I0}} = \frac{\alpha}{(1-\alpha)} \tag{9}$$

From (9), it is conclusive that there is no value of α that would yield the same current phase relationship as an external fault, as shown in (10):

$$3I0 = -\mathrm{IN} \text{ or } \frac{\mathrm{IN}}{3\mathrm{I0}} = -1 \tag{10}$$

Additionally, achieving 3I0 = IN (same magnitude and phase angle) for internal faults is highly improbable as it requires the condition shown in (11):

$$\alpha = 0.5 \text{ or } \mathrm{Z0R} = \mathrm{Z0T} + 3\mathrm{R_{NGR}} \tag{11}$$

In typical power-system installations, Z0R is much smaller than $\mathrm{Z0T} + 3\mathrm{R_{NGR}}$. Furthermore, because Z0R and Z0T are complex valued impedances, the condition $\alpha = 0.5$ requires a match of both magnitude and phase angle and is therefore seldom encountered in practice.

Therefore, a REF event record showing 3I0 approximately equal to IN in both magnitude and phase during an external fault is a diagnostic signature of a CT polarity inversion.

Fig. 5 illustrates a field event in which the REF element operated during an external ground fault on a 250 MVA, 345 kV/34.5 kV, YNyn transformer with a buried delta tertiary. Field verification confirmed reversed polarity of the neutral CT. This is evidenced by condition 3I0 = IN observed, indicating a CT polarity issue.

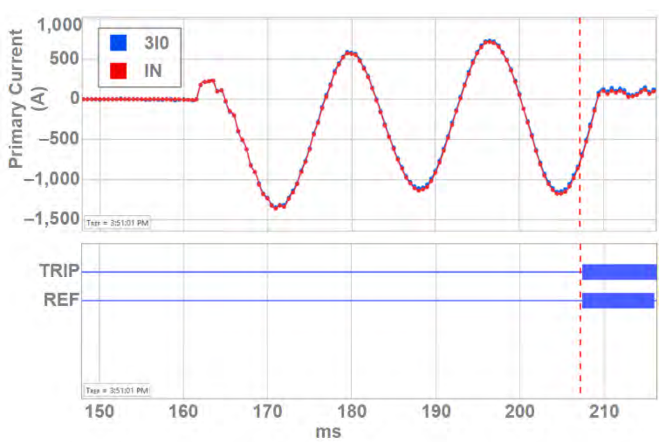

Fig. 5. 3I0 and IN during an external ground fault with inverted neutral CT polarity.

Although this analysis for internal ground fault is developed for an internal bushing-to-ground fault on a Dyn1 transformer, the conclusion applies to any turn-to-ground fault within the REF zone. The relationship depends on the zero-sequence network topology, not on the exact fault location along the winding. Therefore, an internal fault produces a measurable difference between terminal residual current and neutral current. The analysis applies equally to autotransformer applications, with one essential distinction: for autotransformers, the terminal zero-sequence current 3I0 must be defined as the phasor sum of the zero-sequence currents measured at all terminals of the galvanically connected windings. Reference [3] addresses the autotransformer REF application in detail.

A 67N application that uses autotransformer neutral current as a polarizing quantity requires careful consideration. Unlike REF protection, a feeder 67N element cannot generally use the summation of zero-sequence currents from all galvanically connected transformer terminals. As a result, the polarizing source must be selected and validated based on the specific system topology and grounding configuration [4]. In practice, this approach is not generally recommended because it demands a thorough understanding of network parameters and system configurations to ensure secure and dependable operation.

III. Commissioning Practices Overview

Modern transformer commissioning practices have evolved through accumulated field experience to verify protection system performance and wiring integrity before energization [5] [6]. International standards and industry guides provide a structured basis for test plans that address critical CT and voltage transformer (VT) wiring, relay logic, and end-to-end functional checks [7] [8] [9]. Advances in primary and secondary injection test equipment have also improved the ability to detect configuration and wiring errors when the full measurement chain is tested.

Transformer protection commissioning is a staged verification process that starts at the switchyard CT and VT installations and concludes at the protective relay terminals, where current and voltage phasors are checked for correct magnitude and phase angle [10]. Fig. 6 shows a typical test configuration and delineates the switchyard and control room boundaries in which the associated test equipment and interfaces are located.

A typical transformer protection test program includes the following verification steps [6]:

1. CT ratio and polarity verification at the transformer: This preliminary switchyard test confirms each bushing or external freestanding CT ratio using a local ac voltage injection source (Transformer Ratio Test). CT polarity is then checked against the design drawings and, where applicable, verified using a dc flick test [11] [12].
2. Wiring continuity to the switchgear room: This step traces each CT secondary circuit from the transformer yard, through marshaling kiosks or junction boxes, to the cable terminations leading to the relay terminals via a terminal block/test switch. It is supported by drawing reviews and correct identification of cable cores for each phase; in Fig. 6, this path is represented by the solid wiring route.

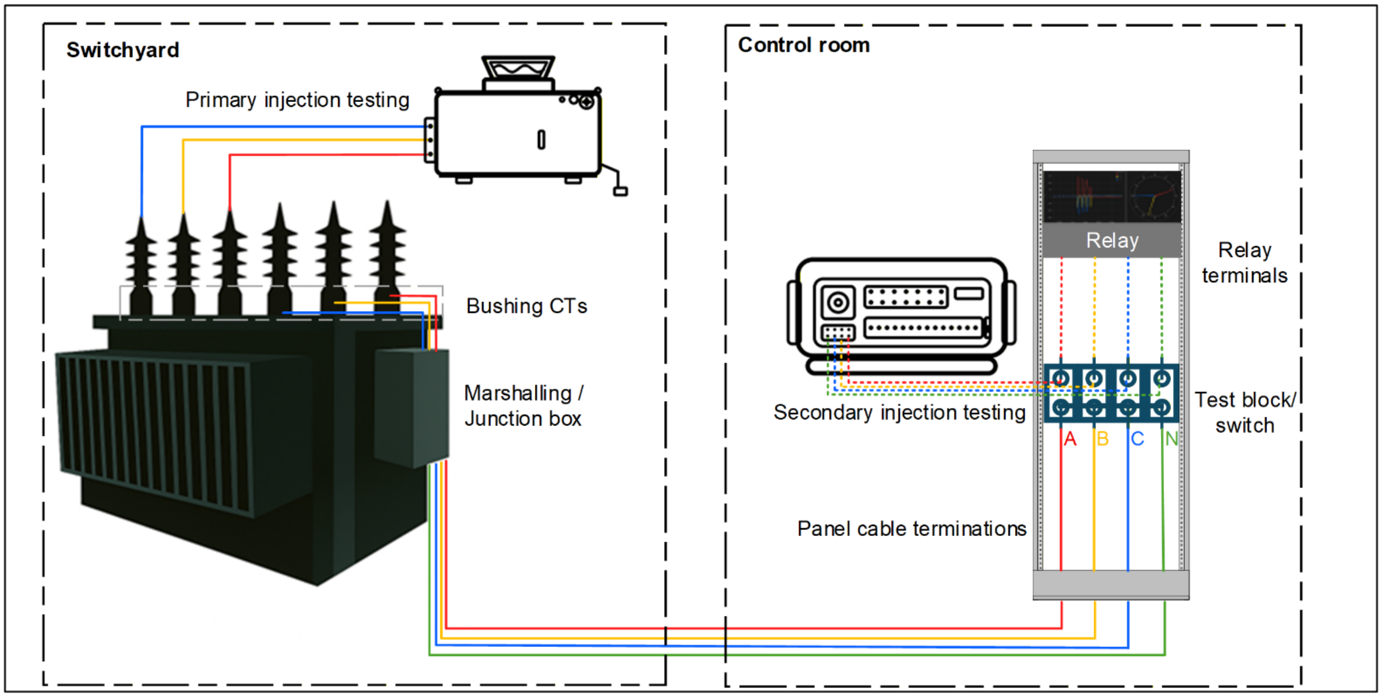

Fig. 6. Typical staged approach for transformer protection commissioning.

3. Secondary system testing: This stage checks the control room wiring between the test block/test switch and the relay. A secondary injection test set is used to confirm correct terminations and wiring integrity at the relay panel before any end-to-end primary tests are performed. This is shown using dotted lines in Fig. 6.
4. End-to-end primary injection testing: Once the full connection from the transformer terminals to the relay is complete, a primary injection source (shown in Fig. 6) with sufficient capacity is used for end-to-end verification. A known primary current is applied, and the relay measurements are checked for correct magnitude, phase angle, and polarity, providing confidence that the complete measurement chain is correct [6].
5. In-service verification: After energization and first load, correct differential-element behavior is confirmed by reviewing the relay differential metering and event records. This provides final confidence that the scheme is stable and operating as intended under normal conditions.

Rigorous execution of all stages reduces the risk of an undetected polarity error to a negligible level. In practice, however, the full sequence is not always completed due to scope reductions or time constraints, which can result in immediate or latent protection issues [13].

A. *Practical Constraints That Limit Commissioning Effectiveness*

Several practical constraints can limit the effectiveness of the commissioning process. The following items, based on field experience, describe conditions that can prevent full end-to-end polarity verification.

1. Staggered equipment delivery: In many projects, switchyard equipment (transformers and yard CTs) and control room equipment (protection panels and relays) are delivered and installed at different stages of construction. This results in a segmented commissioning approach in which components are tested individually rather than as an integrated system. As shown in Fig. 6, the CT secondary circuit traverses multiple physical interfaces, including the CT terminal box, junction box or marshaling kiosk, panel cable terminations, relay test blocks, and finally the relay terminals. Each interface introduces a potential source of wiring errors, such as phase transposition or polarity inversion. Where end-to-end testing cannot be performed as a single continuous activity, overall circuit integrity relies on accurate documentation and consistent labeling across all interfaces.
2. Multiple vendors and fragmented accountability: In many utility and industrial installations, primary switchyard equipment, secondary wiring, relay configuration, and commissioning tests are delivered by different parties. Critical information, such as CT polarity conventions, terminal designations, and relay input/channel assignments, may not be transferred accurately across organizational boundaries [13]. These information gaps create conditions where a polarity error can be introduced at one interface and then carried through later stages without being detected.
3. Tight outage windows: In many industrial plants, the economic cost of extended transformer outages creates a persistent incentive to shorten commissioning activities. Primary injection testing of the REF element requires the transformer to be fully isolated, with current circulated through the neutral grounding path

and, in many installations, temporary shorting of the neutral grounding resistor. When outage windows are compressed, some of these tests are deferred, leaving the REF element commissioned only through secondary injection or visual wiring verification [14].

4. Limitations of primary CT polarity and ratio tests: For yard CTs, secondary voltage injection is often used to verify CT ratio and polarity by applying a known ac voltage to the CT secondary and measuring the induced voltage at the primary terminals. Polarity is checked by confirming the expected instantaneous current relationship defined by the polarity marks: when primary current enters the marked primary terminal, the corresponding secondary current leaves the marked secondary terminal [15]. For example, a 2000:5 CT (400:1), applying 10 V ac to the secondary produces only 25 mV at the primary. At such low levels, electromagnetic interference, capacitive coupling, and instrument noise may be comparable to or exceed the signal, leading to ambiguous results. The test also requires strong isolation of the primary conductors to avoid stray coupling (e.g., via the core, bus capacitance, or adjacent phases), which can introduce unwanted voltages and corrupt measurements. Since injection levels, acceptable readings, and isolation requirements vary by CT design and application requirements [16] [17], manufacturer-stated procedures should be followed. In practice, achieving sufficient isolation and measurement fidelity is often difficult for bushing and neutral CTs, so the test may be omitted despite its importance to REF integrity.
5. Secondary test limitations: Secondary injection testing verifies relay logic and settings at the relay input terminals, but it does not verify CT primary polarity or upstream wiring interfaces. As a result, the REF element may still pass secondary injection at the relay terminals even if the neutral CT polarity is reversed. Only primary injection testing, or a controlled in-service check, verifies the full chain from the primary system through the CTs and wiring to the relay [18].

B. *The Insidious Nature of REF Polarity Issues*

What distinguishes a neutral CT polarity reversal from many other commissioning defects is that it can remain hidden during normal operation.

Under balanced load conditions, the residual current (3I0) measured by the terminal CTs may be small due to low unbalance. As a result, the REF operating quantity remains below set pickup regardless of neutral CT polarity. The polarity reversal here produces no alarm, no abnormal metering, and no visible deviation in relay behavior.

During transformer energization from the delta side, the magnetizing inrush current has no zero-sequence component. The REF element therefore sees essentially no operating current and provides no indication of a polarity reversal.

During transformer energization from the grounded-wye side, the inrush current includes a zero-sequence component. This zero-sequence current is transient and decaying in nature, but it may provide enough signal for a polarity comparison even when it is not sufficient to cause an REF operation due to wrong polarity. If the energization record is not deliberately reviewed, the polarity issue may remain unnoticed during commissioning energization.

These practical constraints lead to an important commissioning lesson: some transformer REF applications enter service without definitive verification of neutral CT polarity. When that occurs, protection engineers need reliable methods to evaluate polarity from available relay data before an outage can be obtained.

To address this problem, the following sections present a systematic step-by-step procedure, beginning with noninvasive assessment using relay metering, event reports, and historical fault records, and progressing to direct primary verification when an outage becomes available.

IV. Methodologies to Identify CT Polarity Issues

This section presents diagnostic methods arranged from indirect, noninvasive checks to direct primary tests. The indirect methods use information available from modern microprocessor-based relays, including event reports, metering captures, and oscillography, to evaluate the equipment while it remains in service [19].

A. *Indirect Methods*

1) *Energization Captures From the Grounded Side*

When a transformer is energized from its wye-grounded side, the magnetizing inrush current draws zero-sequence current through the winding. This inrush current flows from the source, through the phase CTs at the terminal, into the winding, and returns through the neutral to ground. When a grounded transformer winding is energized, the neutral and zero-sequence current relationship will look identical to an external fault. The key diagnostic relationship is:

$$3I0 = -IN \text{ (correct polarity)}$$

$$3I0 = IN \text{ (reversed polarity)}$$

This verification can be performed in either the time domain (comparing instantaneous waveforms) or the phasor domain (comparing magnitude and angle from the relay metering or event report at each sample point). If the relay captures an energization event through an automatic trigger during a scheduled switching operation, the engineer can examine the 3I0 and IN relationship without requiring any additional outage.

The signal shown in Fig. 7 is an example of a 50 MVA, 132/11 kV delta-wye grounded transformer energized from the wye side. The top plot shows the phase currents of the wye side; the bottom plot shows the corresponding zero-sequence current and measured neutral current. A clear 3I0 = –IN relationship can be observed, indicating proper polarity for REF protection.

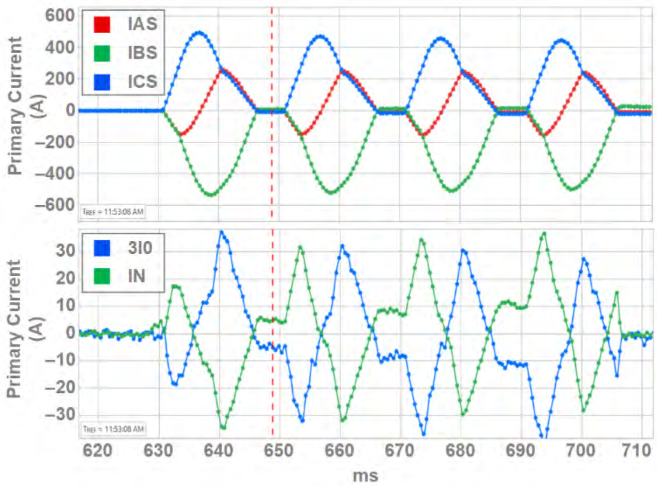

Fig. 7. Energization with correct CT polarity.

The signals shown in Fig. 8 are a clear example of a CT polarity issue. The energization waveform was captured from a 250 MVA 345/34.5 kV YNyn transformer with a buried delta tertiary, energized from the 345 kV side. While the neutral and zero-sequence currents have the expected equal magnitudes, they are clearly phase-aligned, indicating an issue with CT polarity.

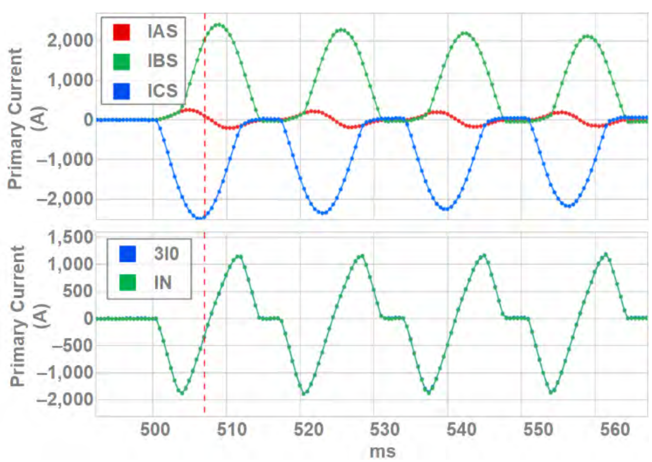

Fig. 8. Energization with incorrect CT polarity.

2) Unbalanced-Load Analysis

Any degree of load unbalance on the power system generates zero-sequence current that flows through the grounded transformer winding. This small but measurable zero-sequence current must enter through the terminal phase CTs and exit through the neutral CT (or vice versa), satisfying the same relationship as an external fault:

$$3I0 = -IN$$

Zero-sequence load current is typically small and difficult to measure, containing a large amount of high-frequency noise. This makes phase comparison challenging; however, by focusing on the fundamental frequency content, a phase relationship can be determined for most systems, even if the signals are well below the most sensitive specified accuracy range of the relay.

The signal shown in Fig. 9 is an example of zero-sequence load current measured from a 50 MVA 110/13.8 kV YNyn step-down transformer. The top plot shows the raw primary transformer neutral current with the zero-sequence 13.8 kV load current. The middle plot shows the same data in secondary amperes with dc and all higher harmonics removed. The third plot shows the angle of the neutral current relative to the zero-sequence terminal current.

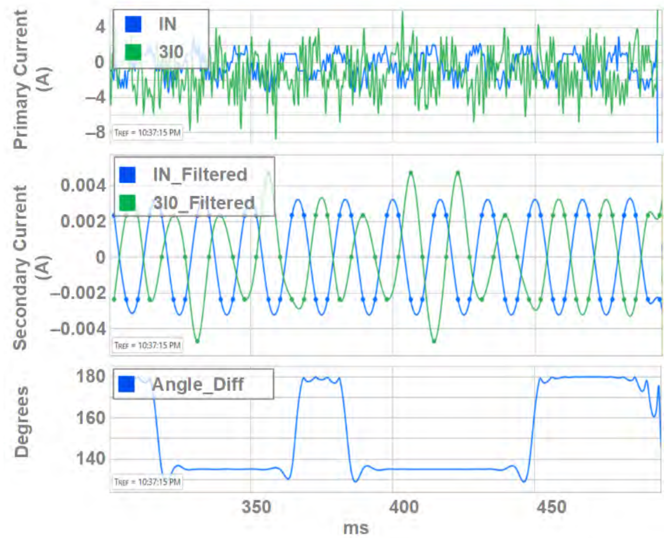

Fig. 9. Load current analysis with correct CT polarity.

What initially appears to be noise often contains a surprising amount of useful information once isolated to the fundamental frequency. The relay in this example is only presented with 2 mA of secondary current, but that is enough to establish that the neutral current and zero-sequence load current have approximately the same magnitude and are 180 degrees apart in phase, within a margin of ±45 degrees.

Using the zero-sequence terminal current as a reference, the measured neutral current falls within the normal load region shown in Fig. 10. The agreement in magnitude provides further confirmation that the terminal CTs and neutral CT are connected with the correct relative polarity for REF protection.

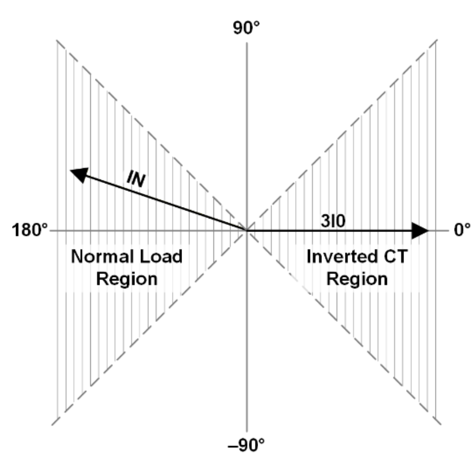

Fig. 10. Load current CT polarity characteristic.

3) *External-Fault Events and Differential-Element Behavior*

If historical event records exist for external faults, the behavior of the phase differential (87) and negative-sequence differential (87Q) elements can be compared with the REF element to help determine the cause of CT polarity issues. During an external fault with proper CT configuration:

- The 87 and 87Q elements should indicate restraint (low operating current, high restraint current) because they use phase CTs that are unaffected by neutral CT polarity.
- The event report should show IN = –3I0 if the neutral CT polarity is correct.
- If the REF element trips while 87 and 87Q correctly restrain, this is strong evidence that the issue is isolated to the neutral current path.

The external fault can also be independently confirmed by checking adjacent device operations. For instance, a line distance relay operating for a ground fault in Zone 1 on the adjacent line confirms the fault was external to the transformer zone.

4) *Power or Current Flow Comparison With Adjacent Devices*

Comparing the metering (current or power-flow direction and magnitude) on the transformer differential relay with metering on neighboring devices, such as line protection relays on adjacent circuits, can help distinguish whether a potential CT polarity issue lies with the terminal CTs or the neutral CT. If the terminal CT metering on the transformer relay has the expected direction relative to the adjacent line relay and approximate magnitude, the terminal CTs are likely of correct polarity, and the polarity error is on the neutral CT side. Conversely, if there is a directional mismatch, the terminal CTs may be at fault.

It is important to note that when comparing current metering between two devices, the angles must use a common reference, such as bus voltage; alternatively, power flow can be compared because power direction already embeds a voltage reference.

B. Direct Methods

Various direct methods are used across the industry to verify CT polarity, including primary ac injections, primary dc injection (often referred to as a dc flick test or dc kick test), and proprietary CT polarity test devices [20]. The appropriate method depends on equipment availability, site constraints, and utility practices. For a broader discussion of direct methods, see [21]. This paper focuses on the dc flick test because it was used in the field validation case discussed later.

In a dc flick test, a dc source (typically a lantern battery) is momentarily applied across the CT primary winding. The resulting magnetic flux within the CT core produces a pulse in its secondary that can be observed using a D'Arsonval meter. When the dc source is removed, the collapsing magnetic flux generates a pulse in the opposite direction [21].

By observing the direction of the meter deflection caused by the initial pulse, the secondary polarity of the CT can be identified relative to the applied primary polarity. When a positive pulse is applied to the primary CT winding, the analog meter needle will swing in the positive direction if the CT polarity is correct. A D'Arsonval meter with a needle that can freely move in either direction is well suited for this test because it provides a clear visual indication of pulse direction. Digital multimeters are more common, and some models include fast minimum/maximum capture with time-stamp capability; however, the instrument must be capable of capturing the transient response reliably.

Repeatedly applying dc voltage can leave residual flux in the CT core, which can affect the shape of subsequent pulses. It is recommended to demagnetize the CT if flick tests are performed. Demagnetization can be performed by applying a slowly decreasing ac voltage to the CT secondary, as described in [17].

V. Field Validation

This section applies the methodology from Section IV to an unintended REF operation at a 230/115 kV autotransformer substation operated by Snohomish County PUD in the northwest United States.

A. Background and Event History

The substation houses the only 230/115 kV autotransformer, operated by the utility, which interconnects with the regional 230 kV transmission system. The transformer is protected by microprocessor-based transformer differential relays. The relays provide phase differential, negative-sequence differential, and REF transformer protection. The high-side currents are measured from CTs in Breaker U. The low side of the transformer feeds a breaker-and-a-half bus where current is measured from CTs in Breakers S and T, as shown in Fig. 11.

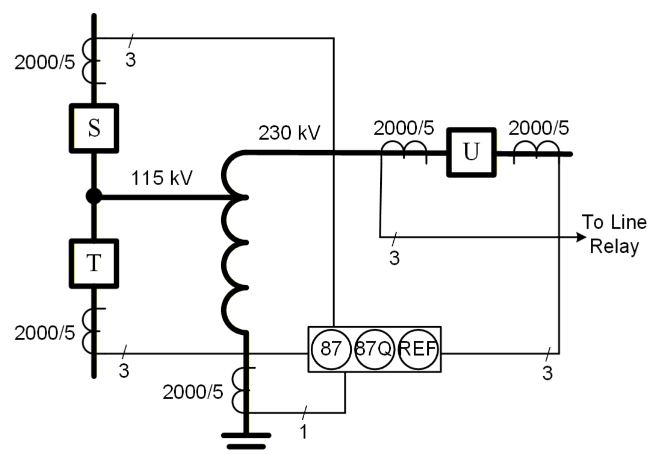

Fig. 11. Snohomish autotransformer REF protection.

On September 3, 2020, the primary relay operated and tripped the autotransformer. The event was later confirmed to be an external C-phase-to-ground fault on the 230 kV line. An adjacent line distance relay independently confirmed the external fault with a Zone 1 ground distance operation. The event record from the line relay shows the complete fault clearance and breaker opening sequence, confirming the fault was on the line and external to the transformer zone.

The engineering team of the relay manufacturer analyzed the event data and concluded that the neutral CT polarity was reversed. Supporting observations included:

1. The phase differential (87) and negative-sequence differential (87Q) elements showed correct through-fault restraint behavior, while only the REF element operated, indicating the issue was isolated to the neutral current path.
2. The neutral current magnitude during the fault was approximately equal to the sum of the terminal zero-sequence currents. As shown in Section II, a true internal ground fault within the REF zone would not produce this external-fault magnitude relationship.
3. Pre-fault data confirmed that the zero-sequence load current was in phase with the neutral current. For normal load unbalance, the terminal residual current and neutral current should be approximately 180 degrees apart when the neutral CT polarity is correct.
4. Event playback on an identical relay with the neutral CT polarity reversed produced correct restraint behavior, with the REF external-fault restraint bit properly asserting.

Initial field verification confirmed that the CT secondary wiring matched the available drawings. This verification created an apparent contradiction: relay event analysis indicated reversed polarity, while point-to-point wiring checks appeared correct. Until a thorough conclusion was presented via diagnostic methods and an opportunity of a planned outage allowed direct primary verification, the utility disabled the REF elements from service and relied on the remaining transformer protection elements.

B. *Application of REF Diagnostic Methods*

1) Metering Data Comparison

Metering data were collected from the transformer relay and an adjacent line protective relay during normal load conditions, as shown in Table III. The data showed consistent current flow between devices.

TABLE III
PHASE A METERING COMPARISON DURING STEADY-STATE LOAD

Location	Device	Measurement
Breaker S (LV)	Transformer Relay	338 ∠–175° A
Breaker T (LV)	Transformer Relay	260 ∠–176° A
Breaker U (HV)	Transformer Relay	291 ∠4° A
Breaker U (HV)	Line Relay	290 A ∠–177°

The high-voltage current at Breaker U should equal the vector sum of the low-voltage currents measured at Breakers S and T after those currents are adjusted for the transformer ratio, as shown in (12) and (13).

$$IA_{U_{Expected}} = \frac{115}{230} \bullet (IA_S + IA_T) \tag{12}$$

$$IA_{U_{Expected}} = 299 \text{ A } \angle{-175°} \tag{13}$$

The expected high-voltage current approximately equals the high-voltage current recorded by the line relay and is 180 degrees out of phase with the high-voltage current measured by the transformer relay. This phase relationship is expected because the transformer relay and line relay use opposite Breaker U CT reference directions. The comparison confirms the polarity and tap position of the phase CTs at Breakers S, T, and U. Therefore, any remaining polarity discrepancy is isolated to the neutral CT circuit.

2) Reviewing Event Oscillography

The September 3 event oscillography shown in Fig. 12 illustrates that the neutral current is approximately equal to the summed zero-sequence current measured at Breakers S, T, and U. Equal magnitudes between 3I0 and IN are consistent with an external fault. However, the fact that 3I0 and IN are also in phase is inconsistent with the expected external-fault restraint relationship discussed in Section II. The combined magnitude and angle evidence is consistent with reversed neutral CT polarity.

A closer look at the highlighted pre-fault region of the event in Fig. 12 reveals the 3I0 to IN phase relationship during normal load conditions.

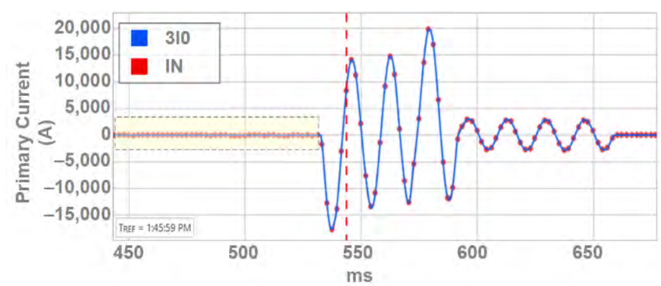

Fig. 12. Utility external ground fault event.

At first glance, the pre-fault data appears as noise, as shown in Fig. 13. Examining the same event filtered to remove dc and higher-harmonic content reveals a clear relationship between the neutral and zero-sequence terminal current, as shown in Fig. 14.

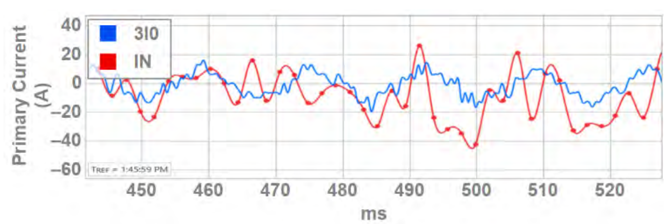

Fig. 13. Raw zero-sequence primary load current.

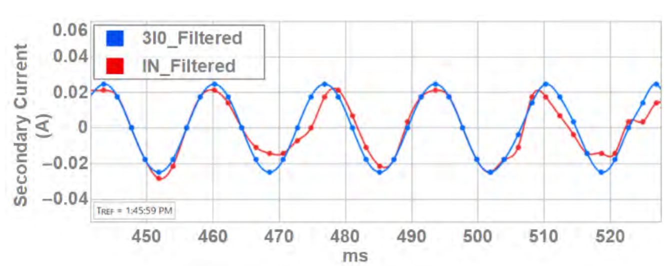

Fig. 14. Filtered zero-sequence secondary load current.

When zero-sequence load current is used as the reference for REF protection, the neutral current should plot in the external-fault region of the operating characteristic because load is outside the REF zone. In a correctly connected REF scheme, the zero-sequence load current is approximately 180 degrees out of phase with the neutral current. In contrast, Fig. 14 shows the zero-sequence load current and neutral current in phase, further indicating a neutral CT polarity inversion.

The data in Fig. 14 have also been scaled to secondary amperes to show what information is available to the REF protection element. The load unbalance is generating only 17 mA of secondary current, which is well below the specified accuracy limits of the relay manufacturer. Even though the absolute accuracy of these data is unknown, it is more than sufficient to determine whether correct polarity was used in the REF zone of protection.

3) *DC Flick Test*

The indirect methods provided consistent evidence of a neutral CT polarity inversion. Direct primary testing was then performed during a scheduled outage to confirm the diagnosis and support corrective action.

The setup used for the test is shown in Fig. 15. A 9 V lantern battery was used as the dc source. The polarity of the lantern battery terminals was verified using a calibrated meter to confirm the correct identification of the positive and negative terminals. The safety ground switch was closed on the high side of the transformer, and the low-side transformer bushings were bypassed.

When the dc source was momentarily applied, the needle of the analog meter deflected in the opposite direction from the expected response (see Fig. 15). The dashed needle in Fig. 15 represents the rest position of the needle in the analog meter. This result confirmed that the neutral CT secondary polarity presented to the relay was opposite to the required protection reference direction.

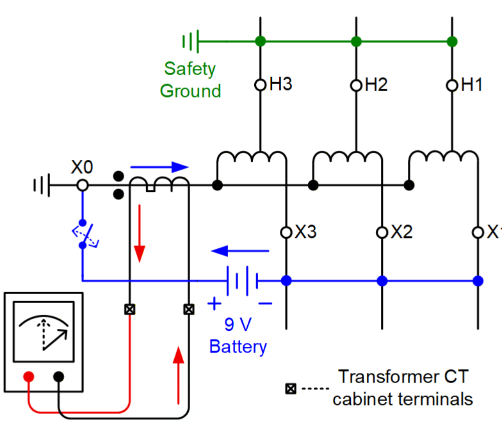

Fig. 15. Expected deflection in analog meter.

4) *Post-Correction Energization Verification*

Following the results of the dc flick test, the neutral CT secondary leads were flipped at the relay terminal block end. The transformer was successfully re-energized and an energization event was captured, with no REF element assertions recorded.

A snapshot of the energization event is provided in Fig. 16. The event report indicates that the zero-sequence current (3I0) and the neutral current (IN) are equal in magnitude and opposite in phase, confirming that the polarity of the neutral CT is now correctly oriented.

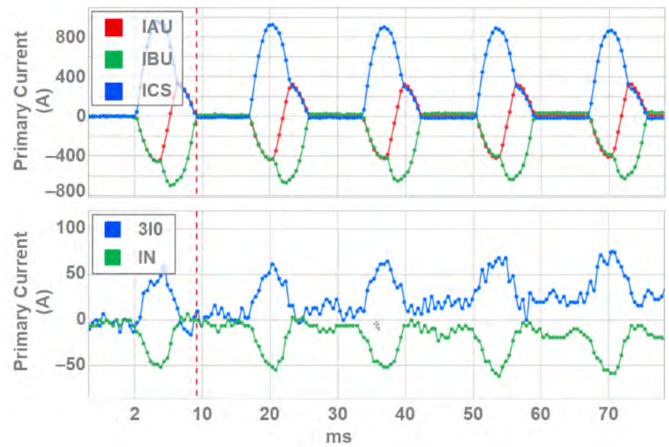

Fig. 16. Utility post-correction energization record.

C. *Root-Cause Analysis*

The issue was caused by a mismatch between the physical polarity of the neutral CTs and the polarity convention used in the secondary wiring. At some point, the CT orientation and wiring reference no longer matched. As a result, wiring checks showed correct continuity and drawing compliance, but the relay received the neutral current with reversed polarity. This is believed to have occurred because the CTs were physically flipped without relabeling the leads and reconnected as before; however, the actual confirmation required an internal examination of the transformer tank and was not possible at the time.

As a result, external ground faults were seen as internal faults by the REF element. This case shows that CT polarity must be verified across the full measurement path from primary current through CT orientation, relay inputs, and logic, not just by checking wiring continuity.

VI. Discussion and Lessons Learned

This investigation required both noninvasive analysis and direct primary testing. The investigation highlights several practical lessons for commissioning and post-event analysis:

1. Physical wiring verification is necessary but not sufficient. A wiring check confirms only that field terminations match the available documentation. It does not independently verify CT physical polarity orientation or the complete current reference direction applied to the relay. Therefore, independent analytical or primary verification methods are required for conclusive diagnosis.
2. Indirect methods can diagnose polarity issues without outages. For critical assets where outage scheduling is difficult, indirect methods (energization captures, unbalanced-load analysis, power or current flow comparison, and differential-element behavior during

faults) provide strong diagnostic evidence using information already available from the relay.

3. Multiple independent methods build confidence. No single indirect method is definitive by itself. However, when steady-state metering, event oscillography, differential-element behavior, and adjacent relay operations all support the same conclusion, the cumulative evidence can justify corrective planning before an outage is available.
4. Energization events are powerful diagnostic tools. The relationship between 3I0 and IN during transformer energization provides a clear, physics-based signature of correct or incorrect polarity. Modern protective relays with high-resolution data acquisition (e.g., 16-bit or higher analog-to-digital converters) can automatically capture these events and provide sufficient information to determine CT polarity.
5. Primary verification remains the definitive method for confirming CT polarity. A dc flick test provides direct confirmation of CT polarity and should be performed whenever possible. Complementary verification methods further improve commissioning confidence. Primary ac injection or system energization, when evaluated with relay measurements, provides end-to-end validation of the installation; however, these methods alone may mask errors if multiple issues offset each other. Secondary injection testing verifies the wiring from the test switch to the relay and confirms correct relay configuration and measurement scaling. In addition, point-to-point wiring checks validate the accuracy of connections from the CT secondary terminals to the test block. Application of all four verification methods, dc polarity testing, primary injection or energization checks, secondary injection, and wiring verification, provides a comprehensive approach that ensures accurate and reliable commissioning.
6. Commission with polarity verification in mind. During initial commissioning, engineers should not rely solely on visual wiring checks. A dc flick test on neutral CTs, or a deliberate load or energization capture with 3I0-to-IN comparison, should be incorporated into the commissioning plan for REF applications.

VII. Conclusion

This paper presented a structured diagnostic framework for identifying neutral CT polarity errors in REF and 67N protection applications. The framework progresses from indirect methods, including energization capture analysis, unbalanced-load verification, external-fault differential-element comparison, and power-flow cross-checking, to direct primary verification.

The framework was validated through a field case involving a 230/115 kV autotransformer where reversed neutral CT polarity caused a REF operation during an external ground fault. Indirect analysis of relay metering and oscillography isolated the neutral current path as the source of error, and direct verification through a dc flick test and post-correction energization capture confirmed the diagnosis and correction.

The methods presented provide practical guidance for commissioning personnel and protection engineers. They are particularly valuable for critical facilities where outage scheduling is constrained, because they allow polarity concerns to be evaluated from existing relay data before direct primary testing can be performed.

VIII. References

[1] B. Kasztenny, M. Thompson, and N. Fischer, “Fundamentals of Short-Circuit Protection for Transformers,” in Proc. 63rd Annual Conference for Protective Relay Engineers, College Station, TX, USA, 2010.

[2] S. Das, A. Hargrave, M. Taberer, and M. J. Thompson, “A Call to Action: Say YES to Restricted Earth Fault Protection,” in Proc. 76th Annual Conference for Protective Relay Engineers, College Station, TX, USA, Mar. 2023.

[3] N. Fischer, D. Haas, and D. Costello, “Analysis of an Autotransformer Restricted Earth Fault Application,” Schweitzer Engineering Laboratories, Inc., Pullman, WA, USA, Tech. Paper, 2010.

[4] E. Price, K. Kulasek, and G. Kobet, “The Negative Branch Impedance in the Transformer Sequence Circuit Model,” presented at the Western Protective Relay Conference, Spokane, WA, USA, 2014.

[5] K. Zimmerman, “Commissioning of Protective Relay Systems,” presented at the Annual Conference for Protective Relay Engineers, College Station, TX, USA, Apr. 2008.

[6] O. Peterson, R. Scharlach, and C. Baltazar, “Proper Testing of Protection Systems Ensures Against False Tripping and Unnecessary Outages,” presented at the IEEE Pulp and Paper Industry Technical Conference, Birmingham, AL, USA, Jun. 2009.

[7] IEEE Std C37.91-2021, *IEEE Guide for Protecting Power Transformers*.

[8] IEC 60255-187-1:2021, *Measuring Relays and Protection Equipment* – Part 187-1: Functional Requirements for Differential Protection – Restrained and Unrestrained Differential Protection of Motors, Generators and Transformers.

[9] AS 61869.2:2021, *Instrument Transformers* – Part 2: Additional Requirements for Current Transformers.

[10] M. Taberer, P. Iyer, and K. Zimmerman, “The Missing Link: How CT and VT Connection Errors Affect Protection,” presented at the Georgia Tech Protective Relaying Conference, Atlanta, GA, USA, May 2022.

[11] IEEE Std C37.110-2007, *IEEE Guide for the Application of Current Transformers Used for Protective Relaying Purposes*.

[12] IEC 61869-1:2023, *Instrument Transformers* – Part 1: General Requirements,” Available: https://webstore.iec.ch/en/publication/34049.

[13] North American Electric Reliability Corporation (NERC), “Lessons Learned: Misoperation of 87N Transformer Ground Differential Relays Causing Loss of Load,” Apr. 1, 2020.

[14] North American Electric Reliability Corporation (NERC), “Lesson Learned: Verification of Alternating Current Quantities during Protection System Commissioning,” Mar. 2, 2014.

[15] IEEE Std C57.13-2016, *IEEE Standard Requirements for Instrument Transformers*.

[16] J. Roberts and S. E. Zocholl, “Selecting CTs to Optimize Relay Performance,” in Proc. 23rd Annual Western Protective Relay Conference, Spokane, WA, USA, 1996.

[17] IEEE Std C57.13.1-2017, *IEEE Guide for Field Testing of Relaying Current Transformers*.

[18] D. Costello, “Lessons Learned Through Commissioning and Analyzing Data From Transformer Differential Installations,” *IEEE Trans. Ind. Appl.*, vol. 44, no. 4, pp. 979–1003, Jul./Aug. 2008.

[19] D. Costello, “Understanding and Analyzing Event Report Information,” in Proc. 27th Annual Western Protective Relay Conference, Spokane, WA, USA, 2000.

[20] D. Costello and K. Zimmerman, "CT Testing—What Every Relay Tester Should Know," in Proc. 67th Annual Conference for Protective Relay Engineers, College Station, TX, USA, 2014.

[21] M. Thompson, J. Hostetler, A. Hargrave, and S. Sawai, "Stop the Epidemic! Transformer Protection Misoperations," proceedings of the 48th Annual Western Protective Relay Conference, Spokane, WA, USA, October 2021.

[22] M. Kao, G. Kobet, and G. Pitts, "Considerations and Experiences in Implementing Ground Differential Protection for Transformer Protection," IEEE PES PSRC Report.

IX. Biographies

Sumit Sawai received his BS in electrical engineering from Sardar Patel College of Engineering, Mumbai, India, in 2011, and his MS in Electrical Engineering from Michigan Technological University, Houghton, Michigan, in 2015. He joined Schweitzer Engineering Laboratories, Inc. (SEL), in 2015 and currently serves as a senior power engineer in the Research and Development division. He is a licensed professional engineer in the state of Washington.

John Hostetler received his BS in electrical engineering from Washington State University in 2011 and his master of engineering degree in electrical engineering from the University of Idaho in 2020. Prior to joining Schweitzer Engineering Laboratories, Inc. (SEL), in 2011, John worked at Snohomish County Public Utility District. At SEL, he works as a senior product engineer in the Research and Development division.

Aditya Parhad received his BTech in electrical engineering at Veermata Jijabai Technological Institute (VJTI), India, in 2019, followed by an MS degree in electrical engineering from North Carolina State University, Raleigh, USA, in 2021. He joined Schweitzer Engineering Laboratories, Inc. (SEL), in 2021 through the Engineering Rotation Program. Aditya has since worked as an application engineer in the United States and currently supports customers across the Asia Pacific region.

Pratheek Annamdevula received his BTech degree in electrical and electronics engineering from GITAM University in Visakhapatnam, India, in 2014. He received his MS degree in electrical engineering from Michigan Technological University, Houghton, USA, in 2017. Pratheek joined Schweitzer Engineering Laboratories, Inc. (SEL), in 2017 and is presently an application engineer specializing in protection.

David Quashie received his BSEE from the University of Washington in 2007; he joined Northeast Utilities (currently known as Eversource) as a transmission protection and controls engineer the same year. He also worked for Bonneville Power Administration (BPA) as a protection field engineer. He is currently a transmission protection principal engineer in the System Planning and Protection Department at Snohomish County PUD. He is a registered professional engineer in the state of Washington and a member of IEEE.

20260806 • TP7274-01