Impacts of Transformer Inrush Current on CT Performance and Residual Ground Overcurrent Protection

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Abstract*—Residual ground overcurrent elements are widely used to provide ground fault protection on low-impedance grounded power systems. In these applications, these elements require sensitive pickups in order to provide reliable protection. They are commonly applied with a time delay to provide coordinated tripping throughout the system. However, these elements also can be applied in high-speed protection schemes such as Zone Selective Interlocking (ZSI) for protection of medium-voltage buses and cable sections. Transformer inrush currents can cause saturation of current transformers due to their monopolar nature. Inrush induced saturation does not affect each phase CT equally, which causes residual current to flow on the CT secondaries. This residual current can cause ground overcurrent elements to pick up until the CTs begin to pull out of saturation resulting in unintended operation of ZSI schemes for non-fault conditions. Analyzing the response of CTs to transformer inrush can be difficult when applying commonly used steady state analysis software. This paper provides an overview of transformer inrush and its impacts on CT performance. A real-world event is presented demonstrating a case of ZSI misoperation due to CT saturation caused by inrush currents. Several commonly available mitigation techniques are presented including harmonic blocking, residual overvoltage supervision, and directional element supervision. Each of these mitigation techniques will be evaluated with the aid of Real Time Digital Simulation. Best practices are presented for providing sensitive, secure ground overcurrent protection on low-impedance grounded systems.

I. INTRODUCTION

The sources for medium voltage electrical systems in industrial facilities are commonly grounded through a neutral grounding resistor (NGR). This is done to limit the amount of fault current available for single-line-to-ground faults on the system. The NGRs are connected to the neutrals of the source transformers as well as generators. When a single-line-to-ground fault occurs, the system line-neutral voltage is impressed across the NGR. The resistance of the NGR, coupled with the system nominal voltage, dictates the maximum amount of ground fault current that can flow during a fault. The let-through current can be approximated as shown in Equation (1).

$$I_{SLG} = \frac{V_{LLnom}}{\sqrt{3}*R_{NGR}} \qquad (1)$$

where:

I_{SLG} is the maximum ground fault current in amps.

V_{LLnom} is the nominal system line-line voltage in volts.

R_{NGR} is the resistance of the grounding resistor in ohms.

The ground fault current for low-impedance grounded systems is limited to 50 amps or more [1]. These values of fault current reduce the amount of damage incurred due to the fault while still providing enough fault current to allow for selective tripping to isolate the faulted piece of equipment. The sizing of the NGR must account for the sensitivity of the ground protection relaying applied on the system. A typical approach is to design the ground fault protection systems to be capable of operating for fault currents in the range of 5-20% of the grounding resistor let-through current [1]. This sensitivity is required to protect the NGR from thermal damage during low magnitude faults.

As an example, for coordinating NGR size with the protection system capabilities, consider the simple system illustrated in Figure 1 below.

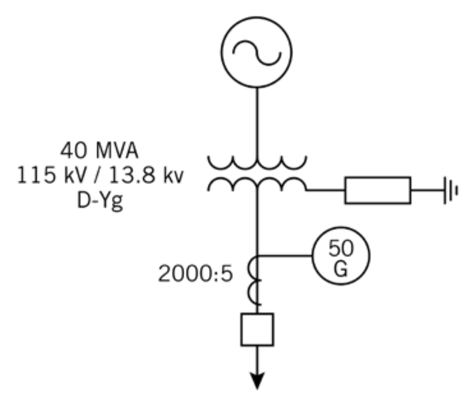

Fig. 1. Simplified Medium Voltage System Oneline

For systems employing residual ground overcurrent elements, the minimum sensitivity to ground faults is dictated by the phase current transformer (CT) ratios and the minimum allowable ground fault pickup setting of the protective relays. For systems with large continuous current ratings, the ground fault pickup may be very low in relation to load current. For example, on a 13.8 kV system with 2000:5 CTs and a minimum relay pickup of 0.25 amps-secondary, the minimum ground element sensitivity is 100 amps. The NGR for this application should be sized between 4 and 16 ohms to allow a let-through current between 500 and 2000 amps. Note that for this application, the ground element sensitivity could be as low as 5% of rated full-load current which increases the susceptibility of the residual overcurrent element to pick up due to measurement errors, particularly during high-current events such as faults and inrush.

II. Transformer Inrush

A. Theory

When transformers are energized, they draw magnetizing inrush current. These high currents are caused by a mismatch between residual flux, or lack of flux, in the transformer's iron core and the steady state flux required by the voltage applied across the transformer winding. The relationship between voltage and flux is shown in (2) and (3) below. The voltage across the transformer winding is directly proportional to the rate of change of flux in the core. Conversely, we can say that the flux in the core is the integral of (or area under) the applied voltage waveform.

$$v(t) = N\frac{d\Phi}{dt} \tag{2}$$

$$\Phi(t) = \frac{1}{N}\int_0^t v\,dt \tag{3}$$

Equation (2) also shows us that the instantaneous value of flux will be at its maximum when the voltage sine wave crosses zero. Let's assume that the voltage at breaker closing (energization) is at a zero crossing and increasing to a positive peak and that the remnant flux in the core of the transformer is zero. For this voltage condition, the core flux would normally be at a negative peak during steady state operation. When energized the flux will start at zero and continue to increase to a positive peak as the voltage completes its positive half cycle. This will drive the flux level to twice it's normal steady state value. This saturates the iron core of the transformer.

Significantly higher excitation current is required to build the magnetic field around the transformer windings when the core is saturated. Thus, transformers can draw inrush currents that are 8-12 times nominal, decaying until a steady state has been reached and the core has come out of saturation. As can be seen in Figure 2, transformer inrush current is asymmetrical and monopolar in nature. It can also be high in harmonic content (second and fourth, specifically). The inrush current magnitude is not the same in all three phases.

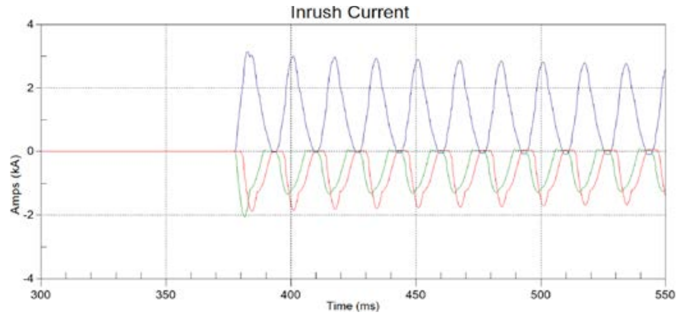

Fig. 2. Inrush Current

B. Effects on Current Transformers

Current transformers rely on time-varying flux through their core to induce voltage on the secondary to drive proportionally smaller current through their secondary circuit.

The physical size of the CT core determines the amount of flux that can flow through it, and in doing so, limits the magnitude of primary winding current that can be accurately transferred to a secondary current. When the maximum possible amount of flux is induced in the CT's core, we say the CT is "saturated." The blue trace on Figure 3 shows the CT flux during inrush. The flattening of the curve indicates the core has reached maximum flux density and become saturated.

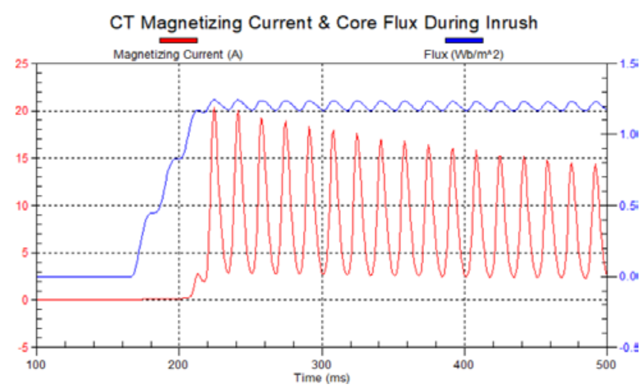

Fig. 3. CT Core Magnetizing Current & Flux During Inrush

After the point of saturation has been reached, an increase in primary current flowing into the CT will not result in a proportionally increased secondary current, because the magnetizing current required to induce additional flux becomes very large. This physical limitation is shown in (4) below, which takes (3) and relates flux to the physical parameters of the CT.

$$\Phi \cdot N \;=\; B \cdot A \cdot N = \int_0^t v\,dt \tag{4}$$

where B is the flux density and A is the cross-sectional area of the CT core (see [3] for detailed discussion of CT saturation).

For our purposes, it is important to understand that the monopolar nature of inrush will cause a CT to saturate at lower primary current magnitudes than a bipolar current would. Bipolar current will result in a flux that moves up and down the hysteresis curve as the current alternates from positive to negative. When alternating current is monopolar, the flux moves up the hysteresis curve, but does not move back down to the opposite side of the curve. The lack of zero crossings for the CT secondary voltage causes flux to accumulate in the core eventually driving the CT core into saturation as shown in Figure 3. Bipolar fault currents can still cause saturation, but it takes a higher magnitude to push the CT past the knee point of the core's excitation curve.

It is also important to know that a saturated CT will produce a distorted output waveform and inaccurate phase current readings. Figure 4 below shows the A-phase primary (blue) current being accurately reproduced as a secondary current (red) for about 2.5 cycles at which point the CT core saturates and the secondary becomes distorted. The CTs on individual phases may not distort the secondary currents identically when saturated, so a residual element that operates on a summation of those currents will see false residual current from the imbalance of unevenly saturated CTs. This can cause misoperation of elements operating on residual current.

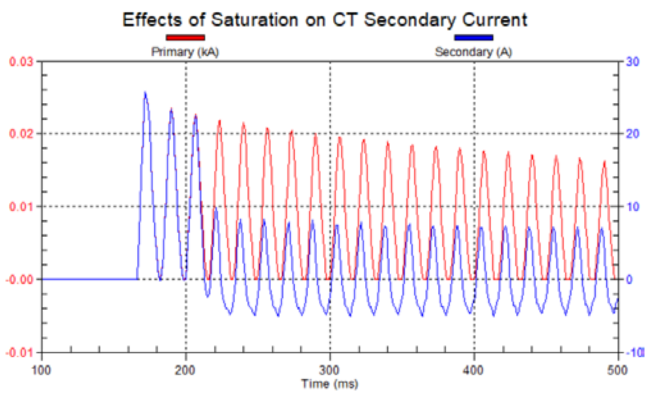

Fig. 4. Inrush Current (Primary & Saturated Secondary)

III. CT Saturation Impacts on Ground Overcurrent Elements

A. *Residual Ground Elements*

As discussed at the end of Section II, unevenly saturated phase CTs can cause protective relays to see false residual current. As shown in Figure 5, a residual ground element takes the individual phase CT inputs and sums them together either physically external to the relay (common in electromechanical applications) or mathematically internal to the relay (microprocessor-based relays).

Under ideal conditions, the three phase currents will be equal in magnitude and 120 degrees out of phase. The vector sum of the A-, B-, and C-phase currents will be zero, however, in practice some small amount of imbalance will exist. For unbalanced ground faults, the sum of the phase current vectors will result in zero-sequence or ground current measured by the relay. Instantaneous, definite-time, and time-overcurrent residual elements are all commonly applied to provide protection against ground faults. Residual ground elements can typically be set much more sensitively than phase elements as we expect zero-sequence (3I0) current to be near zero during normal operation. This does, however, make the residual elements more susceptible to false tripping if the relay CTs saturate during the high current, unfaulted conditions of transformer inrush. Since transformer inrush current magnitude is not equal in all three phases, the CTs will saturate unevenly producing a false residual current.

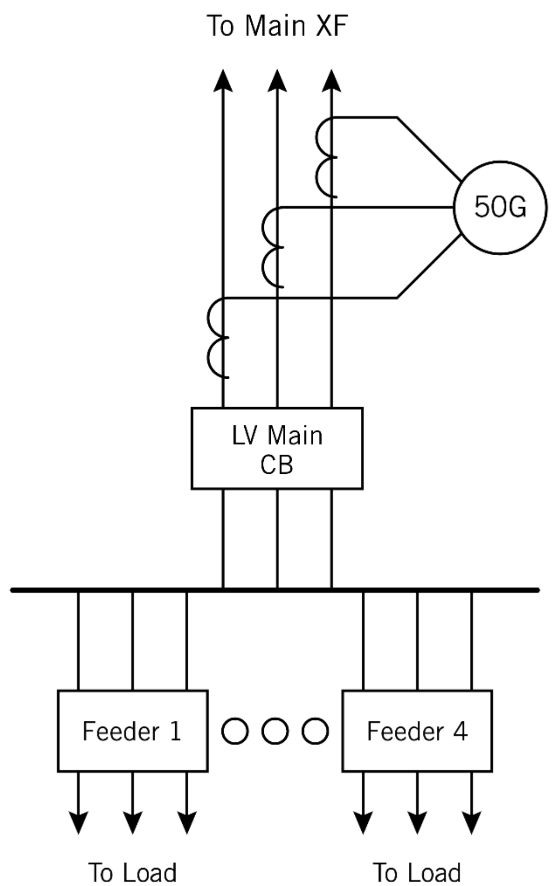

Fig. 5. Example CT Connection for a Residual Ground Element

B. *Core Balance CTs*

A seemingly simple solution to the problems caused by saturation when applying residual ground elements is to apply core balance CTs. Core balance CTs, also known as zero-sequence CTs, have a single core that encompasses all three phases. A secondary winding is wrapped around the core and connected to the protective relay (see Figure 6). By passing all three phases through a single core, the CT is performing a physical summation of all three currents. The output of the CT is proportional to the zero sequence primary current. A core balance CT is immune to false residual current caused by unevenly saturating CTs, because there is only one core. Inrush is a balanced phenomenon, so flux induced in the single core by the high phase currents will cancel and no zero-sequence current will flow on the CT secondary.

Specifying and installing core balance CTs does make life for a protection engineer easier. However, tradeoffs come in the form of physical limitations, installation quality, and cost. In our example system specifically, several cables were required

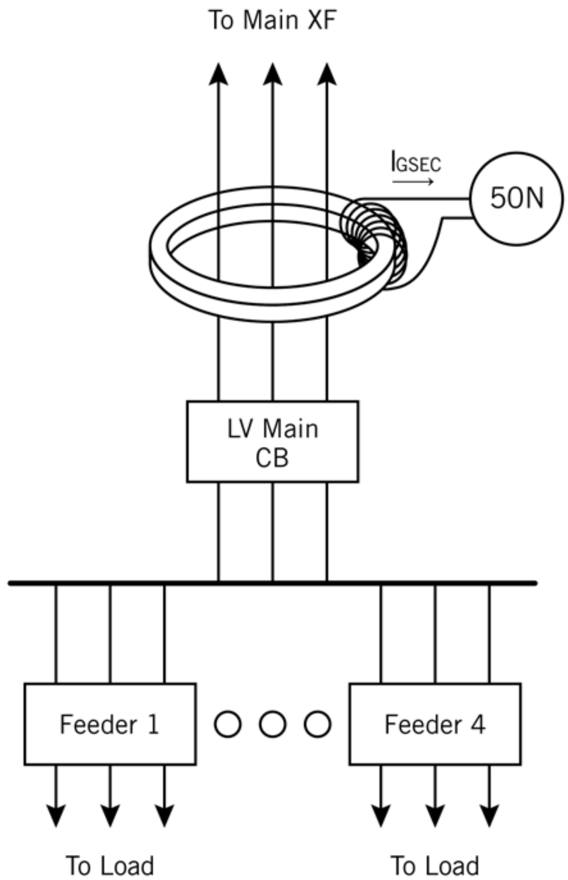

Fig. 6. Example CT Connection for a Core Balance CT

per phase to meet ampacity requirements on the mains and feeders. Routing all the cables through the window of a core balance CT can be difficult or impossible. When installing a core balance CT around cable terminations, care must be taken to not damage a medium voltage cable shield and to properly route it back through the CT when making field terminations. One solution is to move the core balance CT around the breaker bushings inside the switchgear rather than around the cable terminations. However, bushing mounted core balance CTs are generally custom made and the switchgear manufacturer might not be able to physically accommodate them. Retrofitting a core balance CT can be challenging or impossible if false residual current due to inrush is not considered in the design phase of a site. Finally, there is a potential for cost savings by securing residual ground elements within the protective relays. If an architecture is repeatedly deployed without core balance CTs, there could be savings in not having to purchase the CTs but also an increase in quality of installation by moving toward a scalable software solution. Scalable mitigation solutions are discussed in Section IV below.

C. Real-World Example

During commissioning with 13.8 kV primary power applied, the customer's testing team witnessed firsthand the impacts of transformer inrush on CT performance and residual ground overcurrent protection. Before describing what was seen, there are four key aspects of the system architecture that must be understood:

- First, the power system design called for sixteen (16), relatively small, 1.8 MVA, Dy1 transformers to connect to a bus radially fed by a single, relatively large, main breaker.
- Second, applying a traditional bus differential scheme across the large bus was undesirable from a wiring quantity and quality standpoint. Instead, a communication-based system using blocking signals was applied. The blocking scheme, also known as zone selective interlocking (ZSI) works by setting an overcurrent element in the main and feeder relays reasonably above load or imbalance current. If any feeder perceives a fault, it sends a block upstream to the main preventing it from tripping the whole bus. If the main sees a fault, but no block signal is received, the fault is assumed to be on the bus and the main relay issues a trip after a short delay to account for communication delays of the block signal. While traditional differential schemes operate roughly 2-3 cycles faster, the blocking scheme is still much faster than time-coordinated overcurrent elements and greatly reduces the wiring required.
- Third, an NGR was applied to limit the single-line-to-ground fault currents, which in turn means ground overcurrent elements are set relatively sensitive when compared to the phase overcurrent elements.
- Fourth, zero-sequence CTs were not applied at incoming main breakers to avoid the hassles and quality concerns of routing power cables through a window-style CT in the field. Therefore, only the three phase CTs were wired to the main relay to allow the relay to internally sum the phase currents to calculate the ground current value.

When the testing team began executing multiple open transition transfer functionality checks further upstream in the system, the intended transfer would fail more than 30% of the time because the main relay (which was not involved in the transfer sequence) would issue a protective trip. The waveform capture from the main relay is shown in Figure 7. The top plot in Figure 7 shows the phase currents, the middle plot shows the measured residual current, and the bottom plot shows (from top to bottom) the relay trip and ground overcurrent pickup word bits. The event capture showed normal inrush waveforms but the DC offset eventually caused its CTs to saturate and thus caused the relay to calculate a false residual current great enough to exceed the sensitive ground setting. Since the feeder CTs didn't saturate, no block signal was sent and the main relay issued a trip. Due to the random nature of transformer inrush, the main CTs would not always saturate severely enough to cause a trip, hence the intermittent failures of the transfer scheme.

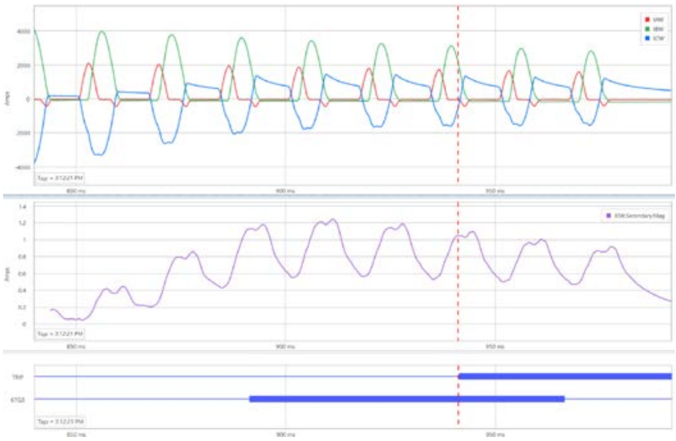

Fig. 7. Event Capture from Real-World Misoperation

This phenomenon was seen at two different sites using a similar architecture design but spread apart in construction schedule by a few months. When the problem was first encountered, finding a resolution quickly was a high priority. The first thought was to apply second harmonic blocking to supervise the scheme, but that feature wasn't supported by the relay applied. As shown later in this paper, this turned out to be a blessing in disguise due to the unreliability of second harmonic blocking in certain cases. The first site decided the quickest route would be to install a core balance CT and modify the relay settings to leverage the new CT accordingly. After further investigation, research, and testing, the second site applied a software approach using the zero-sequence voltage polarized directional elements described in Section IV. Both sites continue to operate with no further trouble.

IV. Mitigation Techniques for Securing Residual Ground Elements

This section describes how residual overvoltage, zero-sequence directional elements, and harmonic blocking can be applied to supervise residual ground overcurrent elements against misoperation for transformer inrush. Settings calculation examples are also included based on the sample system shown in Figure 8 below.

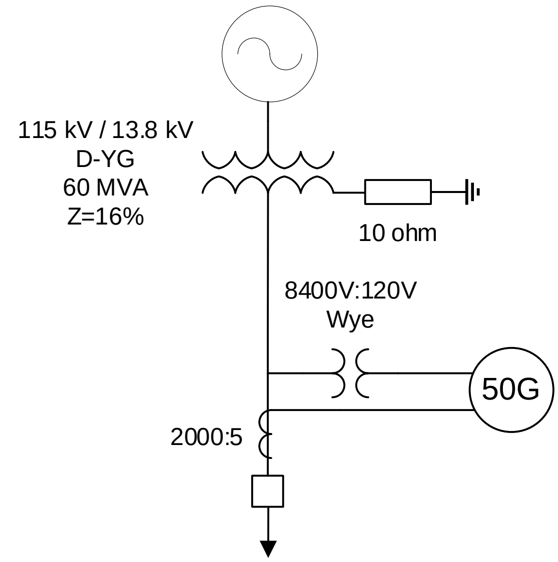

Fig. 8. Example System One-Line

A. *Residual Overvoltage Torque Control*

Residual voltage (3V0) is calculated as the sum of the three phase-to-neutral voltages. When system voltages are at steady state, 3V0 will ideally be zero volts but in practice will be some small value due to system imbalance and measurement error. Transformer inrush does not introduce additional 3V0 to the system, thus making 3V0 a secure method to supervise sensitive ground elements at risk of unintended operation. Systems utilizing neutral grounding resistors to limit ground fault current will see substantial 3V0 during ground faults due to the relatively high zero-sequence source impedance. This makes 3V0 an effective method to indicate a ground fault exists on the system. To supervise sensitive ground overcurrent elements with 3V0, a residual ground overvoltage element (59G) can be used as torque control. The 59G element should be set with some margin below the 3V0 observed for the minimum ground fault current that can be detected by the relay. It also should be set above the standing 3V0 due to system imbalance and measurement errors during steady-state operation.

As an example of calculating the required 59G set-point, let's assume the residual overcurrent relay shown in Figure 8 has a pickup of 100 amps. The 3V0 observed during a ground fault can be calculated using (5).

$$3V0_{Fault} = 3I0 * 3 * ZNGR \tag{5}$$

For a 100 amp ground fault on the example system, the 3V0 observed by the relay would be 3000 volts-primary, or 42.85 volts-secondary. The 59G pickup should be set with some margin below this value to ensure adequate sensitivity to allow the residual overcurrent element to trip during faults at minimum pickup, while still being above the standing 3V0 due to measurement errors and system imbalance. For the test cases described later in this paper, the 59G pickup was set to 50% of the 3V0 seen during the minimum detectable ground fault.

B. Directional Element Supervision

Directional elements are used to supervise overcurrent elements to ensure they operate only for faults in a desired direction. One style of zero-sequence voltage polarized directional element (32V) uses the zero-sequence voltage (3V0) and zero-sequence current (3I0) quantities to calculate an apparent zero-sequence impedance (6).

$$Z0 = \frac{Re[3V0*Z0ANG*3I0]^*}{|3I0|^2} \tag{6}$$

Using the calculated Z0, the relay compares Z0 against the forward and reverse thresholds, to determine fault direction. The 32V element is enabled when the ratio of zero-sequence current to positive-sequence current is greater than the positive-sequence restraint factor (a0), the residual current (3I0) is greater than the forward or reverse directional residual current fault detector pickup (50GF or 50GR respectively), and a loss-of-potential condition does not exist[5]. The operating characteristic for this element is shown in Figure 9.

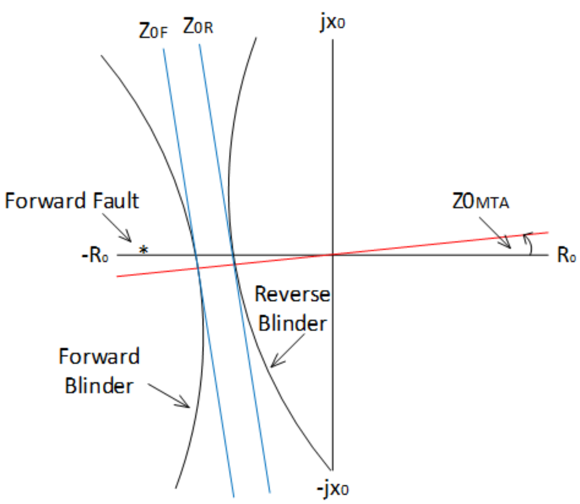

Fig. 9. Directional Element Characteristic – RX Diagram

Zero-sequence voltage polarized directional elements (32V) are a good choice to supervise sensitive ground overcurrent elements (67G) in low resistance grounded systems because they check for expected voltage imbalances for a given residual current magnitude. As stated previously, ground faults on low-impedance grounded systems produce a large amount of 3V0 which makes zero-sequence voltage a good polarizing quantity for the directional determination.

The following example provides some settings guidelines for zero-sequence voltage polarized elements supervising fast-operating, ground overcurrent elements. See Figure 8 for the example system one line with the following additional parameters.

Max Load: 1,958A
67G Pickup: 0.25Asec

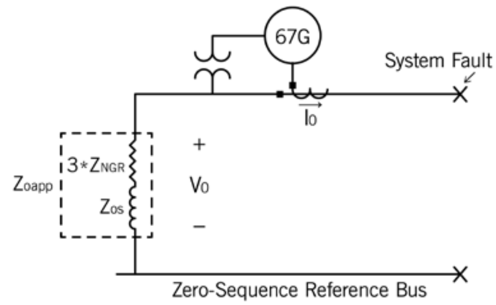

Fig. 10. Example Zero-Sequence Network

Using the system parameters above, the apparent zero-sequence impedance seen by the relay during a downstream ground fault can be calculated as follows (note that the zero sequence impedance of the transformer, Z_{0S}, is neglected since it is much smaller than the NGR impedance):

$$Z0app = -\frac{CTR}{PTR} * 3 * ZNGR \tag{7}$$

$$Z0app = -\frac{400}{70} * 3 * 10\Omega = -171.4\ \Omega_{sec}$$

Because the zero-sequence network is primarily resistive due to the NGR, the zero-sequence max torque angle Z0MTA can be set to the minimum available setting. For the relay used in this example, this angle is set to 5 degrees. This will effectively make the zero-sequence blinders Z0F and Z0R resistive blinders.

$$Z0MTA = 5\ degrees$$

For a ground fault on the protected system, the relay will see an impedance equal to the impedance of the NGR. The ground fault will establish a voltage drop measured by the relay (-V0) and a current flow into the protected system (+I0), resulting in a negative impedance calculated by the relay (-Z0). During inrush conditions, very little zero-sequence voltage will be established at the relay, resulting in a low calculated apparent impedance. Considering this, the zero-sequence blinder forward threshold Z0F can be set to some small percentage of the of the NGR impedance. In this example, Z0F is set to 10% of the NGR impedance. The zero-sequence blinder reverse threshold Z0R should be set greater than the forward threshold with the minimum default offset in radial applications. In applications with bi-directional fault current flow, the Z0R threshold can be determined using a similar method to that outlined for Z0F, but considering the remote zero sequence source impedance.

$$Z0F = 10\% * -Zapp = -17.14\ \Omega_{sec}$$

$$Z0R = Z0F + 0.1 = -17.04\ \Omega_{sec}$$

The positive-sequence restraint factor a0 (I0/I1) should be based on the ratio of the 67G element pickup (3I0) to the max load.

$$a0 = \frac{67G * CTR\ A}{3 * I_{load}} \tag{8}$$

$$a0 = \frac{0.25 * 400\ A}{3 * 1{,}958\ A} = 0.017$$

After configuring the zero-sequence, voltage-polarized directional element for the system, supervise the fast-operating ground element using the 32V element as a torque control condition. If the relay loses its voltage reference due to a blown PT fuse, the fast-operating ground element should be blocked from tripping. Internal relay logic may include loss-of-potential supervision for the directional element.

C. *Harmonic Blocking*

Harmonic blocking is another method considered to secure sensitive overcurrent elements during transformer inrush. The presence of second harmonics can be used to identify transformer inrush currents and block residual overcurrent elements from operating until inrush has subsided. Second harmonic blocking logic compares the ratio of harmonic content to fundamental current on a per-phase basis. Historically, studies indicated that the second harmonic component of the transformer magnetizing inrush current was 15% or more of the fundamental current. With newer transformers, there have been improvements in core steel and design resulting in lower inrush current harmonics with the possibility of the second harmonic being as low as 7% [6].

A typical setpoint for the percent second harmonic pickup (HBL2) to block overcurrent elements during inrush is 10%. This pickup was suitable for the transformer used for the testing conducted for this paper as it produced second harmonic content well above 15% in the primary waveform. When the percent second harmonic content is greater than the HBL2 setpoint for a particular phase, a relay blocking word bit for that phase will assert. This relay blocking word bit can be used as a torque controlling element to supervise and block sensitive ground overcurrent elements from operating during transformer inrush.

D. *Speed and Sensitivity Considerations*

Additional mitigation techniques for residual ground definite-time overcurrent elements such as decreasing sensitivity or increasing time delay, have long been considered simple and acceptable practices to avoid misoperation due to transformer inrush. While these methods provide simple solutions, the tradeoff in speed of operation must be considered.

Transformer inrush can cause false residual current on the CT secondaries for well over one second. For medium voltage power distribution systems, it is common that a zone-selective-interlocking (ZSI) scheme will be used to improve fault clearing speed as compared to time-coordinated overcurrent protection and as a more cost-effective means to implementing bus and line differential protection. The pickup time for the ZSI scheme is typically set to a few cycles. The improvements in clearing time due to implementation of a ZSI scheme are lost if the ground overcurrent elements are delayed longer than inrush. For time-coordinated overcurrent protection, additional delay may be acceptable to ride out inrush. However, this will cascade into sacrificing fault clearing speed of ground overcurrent elements upstream. For time-delayed protection, other mitigation options such as use of inverse-time overcurrent elements can also be used. However, to avoid sacrificing ground overcurrent element fault clearing speed, one of the previously discussed mitigation techniques should be considered.

Decreasing the sensitivity of ground overcurrent elements to be set above the false residual current due to CT saturation during inrush is often not possible for low-impedance grounded systems with limited available ground fault current. The worst-case magnitude of false residual current is also difficult to estimate in practical applications. However, the pickup settings can be increased toward 20% of the NGR rating, which will decrease the duration of 50G pickup during inrush.

V. Simulation Setup

A. *Model Power System Description*

Several mitigation techniques for dealing with false residual current due to CT saturation were described in the previous section. Protection hardware-in-the-loop (HIL) testing was used to verify the performance of these security measures for a variety of system conditions. A simulator capable of modeling the performance of power system components, including instrument transformers, and exchanging digital and analog signals with a protective relay in real-time was used for the HIL testing. Figure 11 illustrates the set-up of the test equipment.

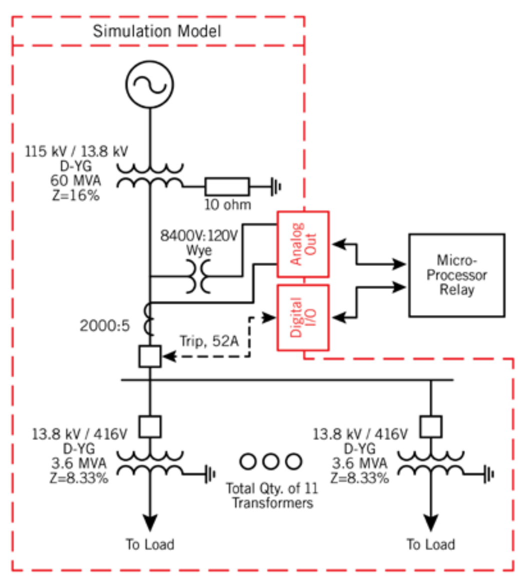

Fig. 11. HIL Simulation Overview

The model power system was configured to be representative of a 13.8 kV industrial power system. The source transformer was modeled with a 10-ohm NGR to provide 800 amps of ground fault current. The 115 kV source was configured such that the available fault current could be varied between 2 kA and 20 kA with the X/R ratio also variable from 5 to 40. Eleven 3.6 MVA load transformers were included in the model. These transformers were modelled based on factory acceptance test data provided by a manufacturer. Several inrush tests were performed at the factory and the results of these tests were used to validate the power system model. It should be noted that the full load current for the main transformer is higher than the continuous rating of the downstream loads, but for these simulations, the authors were more concerned with providing fault currents in a range typical of these types of installations.

Three different styles of 2000:5 CTs were modelled based excitation characteristics provided by their manufacturer. Two sets of C200 CTs (of different design) were modelled along with a set of C400 CTs. The output of the CTs was provided to the low-level test interface of a microprocessor-based relay via analog outputs on the simulator.

Three-phase potentials were also provided to the relay via the low-level test interface. The relay could trip the main breaker within the simulation and could also monitor the 52a status of the breaker via I/O from the simulator. This test setup allowed for multiple transformer energization and fault cases to be performed to validate the performance of the supervisory logic employed for the residual ground overcurrent elements in the relay. The 13.8 kV main circuit breaker was equipped with point-on-wave closing control so that the severity of the inrush current could be controlled. The simulator also has the capability of performing COMTRADE playback to the relay.

Three residual ground overcurrent elements were enabled in the relay with each supervised by one of the following: residual overvoltage, zero-sequence directional, or harmonic blocking. The settings for the supervisory elements were selected as described in the previous section. The pickup of the 50G element was set to 0.25 amps-secondary and the time delay was set to 2.5 cycles, which is typical for a zone selective interlocking scheme. The performance of the feeder CTs during these inrush tests was not considered.

B. Test Cases

The supervisory logic for the residual ground overcurrent elements was tested to verify that the elements were secure for non-fault conditions such as inrush, high-magnitude three-phase fault conditions, and to verify that the elements would still provide reliable detection of single-line-to-ground faults. The first test was an event playback of the real-world example described in Section III. Following successful completion of the event playback, inrush cases were run with varying numbers of load transformers being energized at a time. Source strength and X/R ratio were also varied for these cases to get a diverse set of results. Each of these cases were run with one vendor's microprocessor-based relay interfaced with the simulator.

VI. Simulation Results

A. Real-World Event Playback

Several event reports were captured during the on-site open-transition transfer testing described in Section III. These events were captured in COMTRADE format which made them available for play-back in a laboratory setting. One of these event reports, which resulted in a trip in the field, was played back to a relay similar to the one installed in the field. The relay in the lab was equipped with residual overvoltage, zero-sequence voltage polarized directional, and harmonic blocking supervision for its residual ground overcurrent elements. The response of the relay can be seen in Figure 12. The top plot in Figure 12 shows the filtered phase currents recorded by the relay during playback. The center plot shows the calculated zero-sequence current magnitude which is steadily increasing as the CTs begin to saturate. The digital plot at the bottom of Figure 12 shows (from top to bottom) the residual ground element pickup, harmonic blocking, zero-sequence directional element, and residual overvoltage elements. The harmonic blocking signal asserts very early in the event due to the high harmonic content of the inrush waveform. Once the CTs have begun to saturate a few cycles after energization, the residual overcurrent element picks up. Note that the directional element and residual overvoltage element do not assert for this event. For this case, the harmonic blocking, directional, and residual overvoltage supervision methods would have prevented the residual ground overcurrent function from issuing a trip.

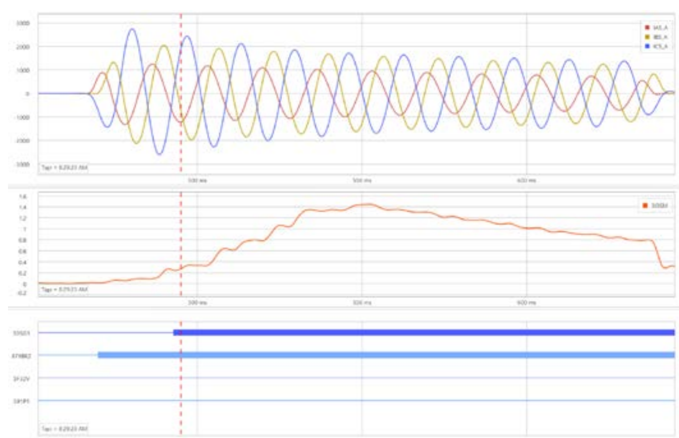

Fig. 12. Relay Event Capture from COMTRADE Playback

B. Inrush Simulations

As mentioned above, several load transformer inrush events were simulated and the response of the CTs and residual ground overcurrent elements on the main breaker were studied. Cases were run for the energization of one, two, six, and eleven transformers at a time. For these tests, the main breaker was used to energize the downstream transformers. Several cases were performed with each of the three current transformer types that were modelled in the simulation.

The unsupervised residual ground overcurrent element picked up for all but two of the test cases. When the residual ground element did pick up, it was blocked from tripping by the residual overvoltage and zero-sequence directional elements. The harmonic blocking function performed as-intended for all the energization cases. Time to saturation and subsequent pickup of the residual overcurrent element ranged from 16 milliseconds to 380 milliseconds depending on the type of CT used, the number of transformers energized, and the breaker closing angle. For several of the simulations, the residual overcurrent element remained picked-up for over one second. An example case showing the response of a 2000:5, C400 CT to the energization of eleven transformers is shown in Figure 13 below. The top plot shows the filtered phase currents measured by the relay. The center plot shows the residual current magnitude. The digital plot at the bottom of Figure 13 shows (from top to bottom) the residual ground element pickup, harmonic blocking, zero-sequence directional element, and residual overvoltage element. The CTs begin to saturate about 125 milliseconds after energization giving rise to an increase in calculated residual current causing the residual ground overcurrent element to pick up. The harmonic blocking function asserts very early in the event due to the high harmonic content of the phase currents. As the inrush magnitude decays, the residual current decays as well until the residual overcurrent element drops out after timing for approximately 1.3 seconds. Since the voltages were well balanced during the event, the residual overvoltage and zero-sequence directional elements restrained.

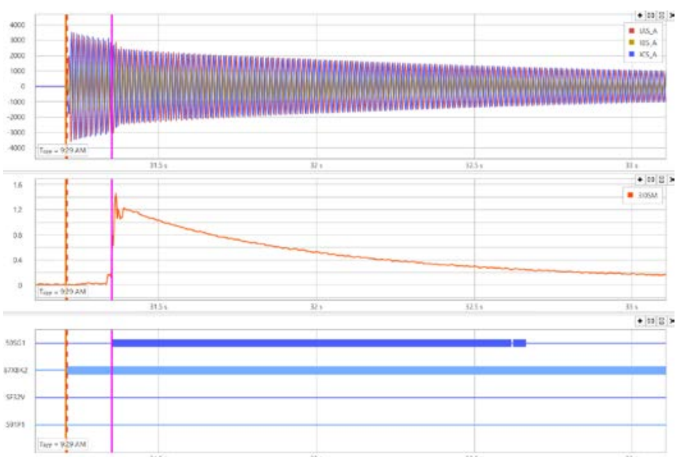

Fig. 13. Relay Response to Energization of Eleven Transformers

While the case of energizing eleven transformers through the main breaker provides a worst-case for inrush current in the simulations performed for this paper, it would be unusual to perform switching this way in practice. Additional cases were performed to create a more realistic energization waveform. A tie breaker was added to the model so that six transformers could be energized while five transformers were already in service and under load. This was done to provide a realistic representation of an open-transition transfer for a main-tie-main switchgear lineup. Results of this test case with a 2000:5, C200 CT are shown in Figure 14. The top plot shows the unfiltered phase currents measured by the relay. The center plot shows the unfiltered residual current magnitude. The digital plot at the bottom of Figure 14 shows (from top to bottom) the residual ground element pickup, harmonic blocking, zero-sequence directional element, residual overvoltage element, and relay trip response. The capture in Figure 14 was taken approximately two seconds after the transformer was energized. The inrush current magnitude has decayed significantly at this point, but the current transformers were still saturated which caused the residual overcurrent element to remain asserted. The decreased harmonic distortion in the phase currents resulted in the harmonic blocking function dropping out, which permitted the residual overcurrent element to issue a trip. Since the voltages remained balanced throughout this event, the residual overvoltage and zero-sequence directional elements remained secure.

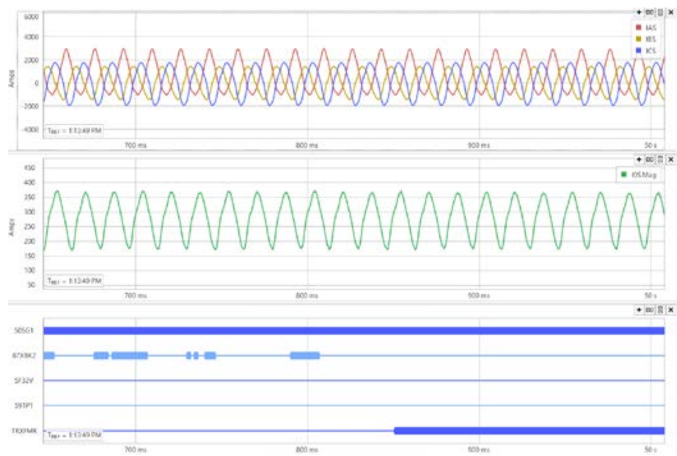

Fig. 14. Trip During Open-Transition Transfer Simulation

C. System Fault Conditions

Several fault cases were simulated including three-phase faults and single-line-to-ground faults during steady-state operation and single-line-to-ground faults during transformer energization. The three-phase fault test was intended to test the effectiveness of each supervisory condition for the residual ground element during fault-induced CT saturation. The single-line-to-ground fault tests were intended to challenge the reliability of the ground protection using each supervisory method.

Similar results were observed for each of the three-phase fault cases whether the fault was applied during steady state operation or as a switch-onto-fault condition. Figure 15 shows a case where a breaker was closed into a three-phase fault. The CTs saturated very quickly at the onset of the event which resulted in a large residual current being measured by the relay. The residual ground overcurrent element picked up. The residual overvoltage and zero-sequence directional elements remained secure during this event. The harmonic blocking function blocked correctly at the onset of the event, but unblocked as the CTs began to pull out of saturation, resulting in a trip.

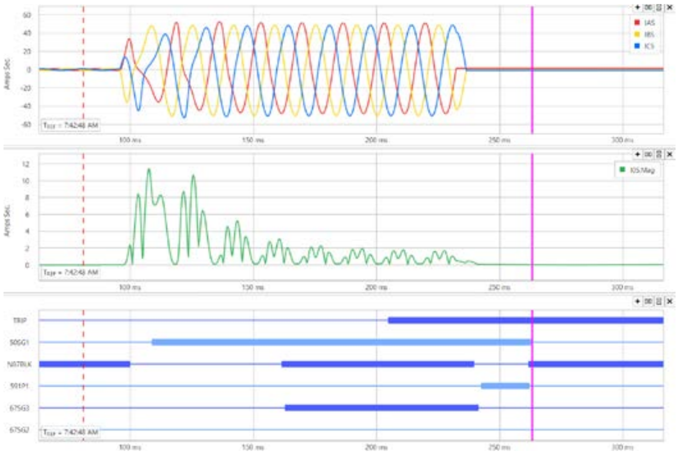

Fig. 15. Trip During Three-Phase Fault Simulation

A bolted single-line-to-ground-fault case was also simulated to demonstrate the intended operation of the residual ground element whether it was secured by residual overvoltage, harmonic blocking, or the zero-sequence directional element. An event capture for one of these simulations is shown in Figure 16 below. The residual ground elements supervised by residual overvoltage, zero-sequence directional, and harmonic blocking all correctly operated for this fault case. The residual overvoltage supervision provides a slight speed advantage compared to the directional element and added no more than a 4 millisecond delay to the total trip time in all the simulation cases. The directional element consistently operated 8 milliseconds slower than the non-supervised residual ground element. The harmonic blocking supervision typically added between 12-16 milliseconds of delay to the tripping decision.

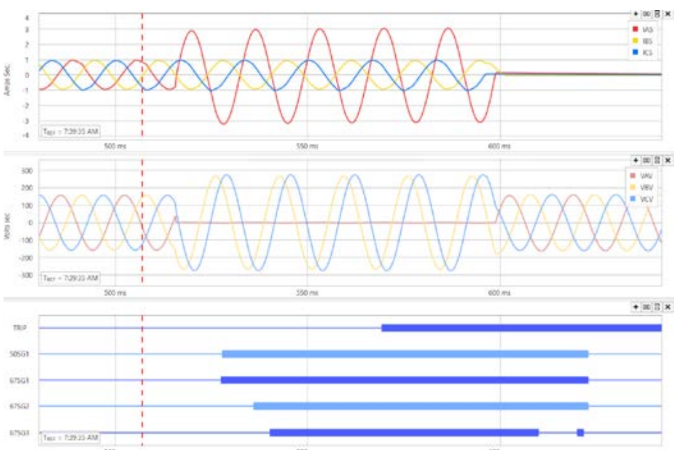

Fig. 16. Desireable Trip During Bolted Single-Line-to-Ground Fault

Bolted single-line-to-ground fault cases were also simulated during inrush to test the reliability of the residual elements supervised by residual overvoltage, harmonic blocking, or the zero-sequence directional element. An event capture for one of these simulations is shown in Figure 17. The top plot shows the phase currents measured by the relay. The center plot shows the response of the zero-sequence voltage polarized directional element. The red trace is the apparent Z0 calculated by the relay. The blue and green traces are the reverse and forward directional thresholds. The digital plot at the bottom of Figure 17 shows (from top to bottom) the residual ground element pickup, harmonic blocking, zero-sequence directional element, residual overvoltage element, and relay trip response. For this event, the breaker closing angle was adjusted to provide the worst-case inrush current. The residual overvoltage supervision performed well and correctly asserted to determine that there was a ground fault on the system. The harmonic blocking element prevented a trip due to the high harmonic content in the phase currents. The zero-sequence directional element operated 287 milliseconds slower than the residual overvoltage element. This delay in operation was due to the false residual current which decreased the magnitude of the Z0 calculated by the relay. As can be seen in the plot, the magnitude of the apparent Z0 begins to increase in magnitude as the CTs recover until it eventually crosses the forward directional threshold. The operation of the directional element could have been faster if the impedance thresholds for the directional element were decreased.

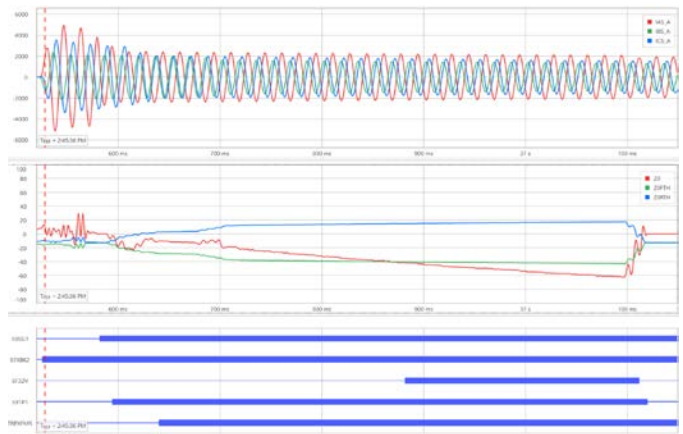

Fig. 17. Ground Fault During Worst-Case Inrush

Additional ground fault cases were run for less severe inrush conditions. Figure 18 shows an event capture for one of these cases. The CTs do not saturate initially during this event, so the apparent Z0 magnitude increases quickly after fault inception. There is a short delay between pickup of the 59G element and the 32V element, but it is only 30 milliseconds. The harmonic blocking function did not permit tripping for this event.

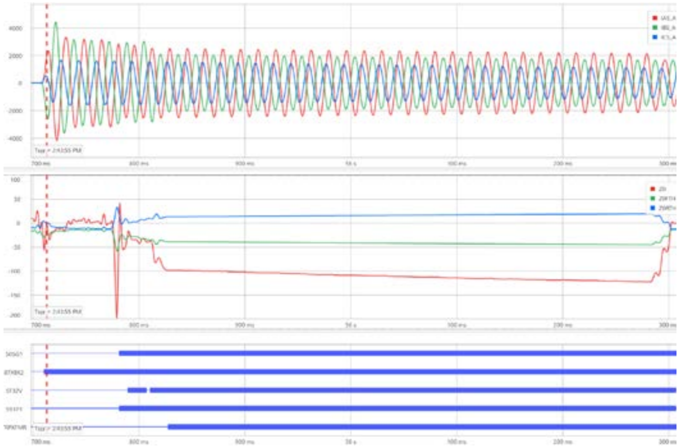

Fig. 18. Ground Fault During Less-Severe Inrush

VII. Conclusions

Transformer inrush currents cause saturation of current transformers due to their monopolar nature. Saturation of phase CTs during inrush leads to false residual current measured by the connected relay due to uneven saturation in each phase. This false residual current presents challenges for unsupervised residual ground overcurrent elements, particularly on low-impedance grounded systems where the ground elements must be set with enough margin below the let-through current of the NGR. This challenge is compounded when the residual ground elements are used in high-speed applications such as zone-selective interlocking.

Core balance CTs inherently provide security for ground overcurrent protection during transformer energization and high magnitude symmetrical faults. They also can present installation challenges in some applications due to physical constraints. Core balance CTs can be eliminated from the design through use of supervision within the protective relay for residual ground overcurrent elements. This settings-based solution is easily scalable and can save a substantial amount of time and money, particularly when a standardized design will be deployed across a large fleet of sites.

Residual overvoltage supervision is well-suited for securing residual ground elements on radial low-impedance grounded systems. During high-current events such as inrush or multi-phase faults, when the system voltages are balanced, the residual overvoltage element will not assert and will prevent the residual ground element from operating on false residual current. Residual overvoltage elements also permit the residual overcurrent element to operate if a single-line-to-ground fault occurs during transformer energization.

Zero-sequence voltage polarized directional elements are effective for securing residual ground elements. Similar to the residual voltage supervision, the directional element will only permit the residual ground overcurrent element to operate if there is sufficient zero-sequence polarizing voltage, indicating that there is a ground fault on the system. Directional elements add a small amount of delay compared to residual overvoltage elements during normal fault clearing. This delay in operation can increase for faults occurring during transformer inrush conditions if the CTs saturate heavily. The directional element can be made faster under inrush conditions by decreasing the magnitude of the impedance blinder setting. The zero-sequence directional element also provides the benefit of being suitable for power systems with bi-directional fault current flow.

Harmonic blocking is not as reliable as residual overvoltage or zero sequence directional elements for preventing residual overcurrent elements from operating during transformer inrush events. Harmonic blocking may not pick up during three-phase fault events where the CTs saturate slightly, yet still produce enough residual current to cause the residual overcurrent element to pick up. The harmonic blocking function may also add significant delay to tripping if a ground fault occurs during transformer energization. If the harmonic blocking thresholds are decreased to improve security during CT saturation, this delay will be increased.

By its nature, the harmonic blocking element only prevents operation of the residual overcurrent element if an event "might not be a fault." The zero-sequence directional and residual overvoltage supervision provide a more deterministic indication there is a ground fault on the system, which improves both the reliability and security of the residual overcurrent protection.

VIII. Future Work

For this paper, only a single manufacturer's relay was available for testing purposes. The harmonic blocking and directional element algorithms provided by other relay vendors may behave differently during inrush events. Other directional element implementations may require different settings criteria. Additional testing will need to be performed with other manufacturer's relays.

The settings criteria for the directional element studied as part of this paper could be further refined through additional testing to improve the relay response to faults during transformer energization while maintaining security.

A better understanding of the behavior of time-delayed backup protection will be beneficial to determine firm criteria that can be used for pickup sensitivity, timing characteristics, and time delays to secure these elements from unintentionally operating during inrush.

More testing to consider variables such as different transformer designs, CT remnant flux, and additional variations in source impedance will help to further refine the recommendations made in this paper.

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Biographies

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Tom Blooming, **P.E.** has spent his career working on power system studies, power quality issues, and all aspects of data center electrical design, most recently with Google. At Google Tom worked on new power system designs to suit the unique needs of large data centers. Prior to that he, was with Eaton Electrical in several roles. Most recently as an Application Engineer, supporting Eaton's power quality products, focusing on uninterruptible power supply application issues. Prior to that, Tom also handled application issues related to power factor correction capacitor banks, harmonic filters, static-switched capacitor banks, and active harmonic filters, as well as many power quality-related questions. Prior to that Tom performed numerous power systems measurements and studies in the Cutler-Hammer Engineering Services & Systems group. He has published technical papers and taught engineering workshops and training seminars on power quality issues. Tom received a B.S. in electrical engineering from Marquette University, an M.Eng. in electric power engineering from Rensselaer Polytechnic Institute, and an M.B.A. from Keller Graduate School of Management.