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Enhance arc flash safety with Eaton's Cooper Power™ series Arc Reduction Vacuum Fault Interrupter (AR-VFI) transformer

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Integrated Transformer Vacuum Fault Interrupter (VFI) technology coupled with secondary overcurrent sensing, arc-light sensing and modern relaying significantly reduces secondary incident arc energy. Pre-designed and factory-tested, the AR-VFI transformer protection system utilizes this method to provide integral overcurrent protection on secondaries up to 6000 A.

I. Introduction

As defined by the National Fire Protection Association (NFPA), arc flash is an electric current that passes through air when insulation or isolation between electrified conductors is no longer sufficient to withstand the applied voltage. Arc flash events could be triggered due to insulation degradation or spontaneously due to an operational error. The flash is immediate, but the result of these incidents lasts much longer and can cause equipment damage and severe injury including burns, concussion and death. Each year more than 2,000 people in North America are treated in burn centers with severe arc flash injuries [1]. It is the purpose of an electrical system protection scheme to sense these anomalies in the system and react quickly enough to limit the damage caused by the explosive release of energy. Critical loads at hospitals, entertainment arenas, continuous process facilities, and commercial and industrial facilities require dependable, high uptime power delivery. Advancing safety in the design of medium-voltage substations plays a critical role in improving the reliability and maintainability of these facilities, and subsequently the longevity of the facility and the safety of its workforce.

When performing an arc flash system study, evaluators will often start at the furthest downstream or most readily serviced equipment. Typically, this investigation begins begins with low-voltage panelboards, switchboards or switchgear and works its way upstream until the identified incident energy requirements have been met or the study can go no further with the technology available. In many cases, lack of a cost-practical solution forces the arc flash study to come to a halt. This roadblock in the pursuit of arc energy reduction often results in the transformer secondary and low-voltage bus / cabling lacking sufficient protection. The result of which is a significant arc flash hazard zone from the transformer secondary to the next downstream protective device. The secondary of the transformer has always been a place of notably high incident energy and a difficult amount of energy to affordably overcome. Due to this obstacle, the transformer is often located outdoors, far away from serviceable gear, or cordoned off by 'WARNING: Arc Flash Hazard' signs. Many system designers have understood this condition as an inherent danger in the application of transformers, with solutions which are often either too costly or too complex, forcing system designers to forgo attempts to further mitigate the arc energy. Instead, relying on signage, proper-practice, and 'good training' to keep personnel safe from the hazard. Fortunately, advances in control systems coupled with advances in transformer design can allow this hazard to be reduced to much more acceptable levels.

The adaptation of the transformer into a safe and serviceable piece of equipment also allows an electrical system designer to drastically rethink the way they form their system topology. For example, by bringing higher voltages closer to the building or even indoors, reducing the need for high amperage copper buswork throughout a facility, and integrating smart inter-equipment controls and diagnostics into the transformer to maximize asset management capability. As we will explore further in this paper, advances in equipment safety can allow for significant impacts on total system cost, overall layout and installation complexity.

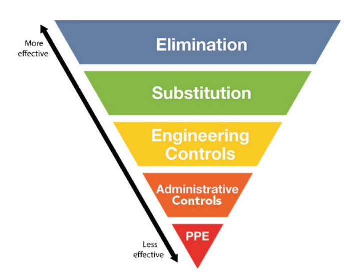

Figure 1 – NFPA 70E, Hierarchy of Controls
The ANSI defined Hierarchy of Risk Controls provides basic guidance and perspective on how to design electrical systems to enhance safety.

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When planning, implementing or upgrading any electrical system, it is vital to take a total systems approach. Advancements in factory-engineered systems allow the application of technology in switchgear / transformer lineups to yield significant improvements in fault clearing time and arc flash safety with minor financial investment. In this paper, we'll explore how modern approaches to protection with integrated sensing and controls can address the first three categories of risk controls (Figure 1) to impact overall distribution system design.

II. Traditional protection methods

Distribution transformers can experience overcurrent events due to a variety of system anomalies. Divided into two broad categories, faults that cause an overcurrent can be quantified as either permanent or temporary. A permanent fault on a transformer or in downstream equipment is most often the result of insulation failure. This can be due to thermal cycling, vibration, localized heating, overloading, inadequate cooling, or a variety of operational stresses the transformer or equipment may have experienced. A temporary fault on the other hand would result from an accidental or spontaneous shorting from phase-to-ground or phase-to-phase, perhaps due to collision of conductive parts, a tree branch on an overhead line, dust or corrosion accumulation on conductors or simply a mistake made with a tool during energized maintenance. In any event, whether the fault condition is internal to the transformer, or on the secondary side of the unit, the fault is typically sensed and interrupted by the primary device. Traditional transformer protection uses primary fusing or a primary power circuit breaker installed on the line side of the transformer. (Examples of primary protective devices shown in Figures 2 and 3)

Figure 2 – Example of pad-mount transformer with primary bayonet style fusing.

This form of primary protection can be physically mounted in the transformer tank or enclosure or in another enclosure on the primary side, either directly coupled to the transformer or in a piece of gear further upstream.

Figure 3 – Examples of traditional primary breakers, interrupters and reclosers.

While this form of protection does offer a means of fault interruption for downstream events, it often cannot act fast enough to reduce energy levels to a safe, practical value. Primary protection on transformers is generally sized to protect the primary side and the windings, often with a smaller expulsion fuse for secondary faults. Larger secondary overloads should otherwise be interrupted by the secondary low-voltage main breaker or feeder breaker much nearer the fault location. Additionally, secondary arcing faults are often not large enough to elicit a fast response from the primary side protective device. This means that anything from the transformer secondary terminals to the low-voltage protective device is at a high arc energy level. Depending on the size of this zone and typical operator proximity, that may be an extreme arc flash hazard. (Hazard Zone – shown below, Figure 4)

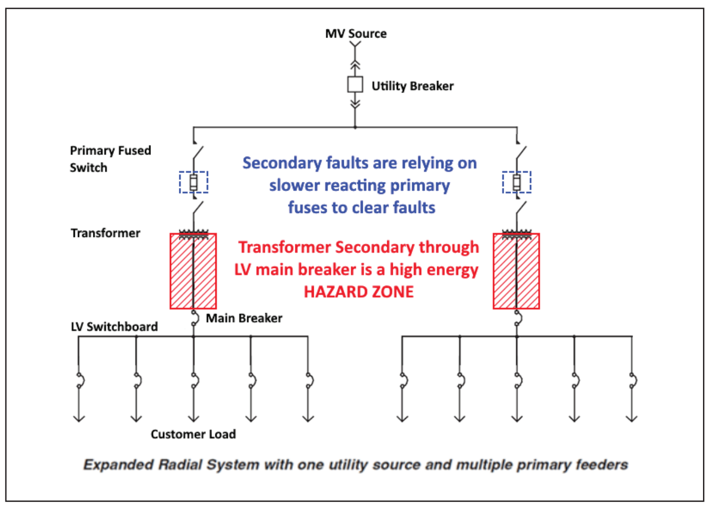

Figure 4 – Hazard zone

For many transformers, the area from the conductor or bussing off the transformer secondary bushings to the line side of the low-voltage main breaker will have incident energy in the 'Dangerous' zone (>40 cal/cm²) as defined by NFPA 70E [4]. While higher energy personal protective equipment (PPE) does exist (up to 100 cal/cm²), energized work above this level is prohibited. If the line side of secondary main breaker is not isolated with barriers to prevent propagation to the load side, this applies to the entire low-voltage gear.

III. Drawbacks of primary protection alone

While a primary protective device does offer an eventual means of interruption for secondary overcurrent events in this "Hazard Zone," they typically cannot operate fast enough to reduce the fault energy to a desired level. The primary device will result in longer trip times because it (fuse or breaker) must be set high enough to allow transformer inrush current to flow without nuisance operating on initial energization. Because of the higher trip current requirement of a primary device, secondary arcing faults transposed through the transformer are too small in comparison to cause the primary protection to react fast enough.

As shown on the time-current characteristic curve in Figure 5, typical primary devices must be coordinated to the right/above the transformer inrush curve in order to avoid operation upon initial energization. This necessary coordination creates a limiting factor for the primary device that restricts the operational curve from being sufficiently sensitive to the small amount of current pulled through the primary side during a secondary fault, forcing the fault to worsen before the primary device can react.

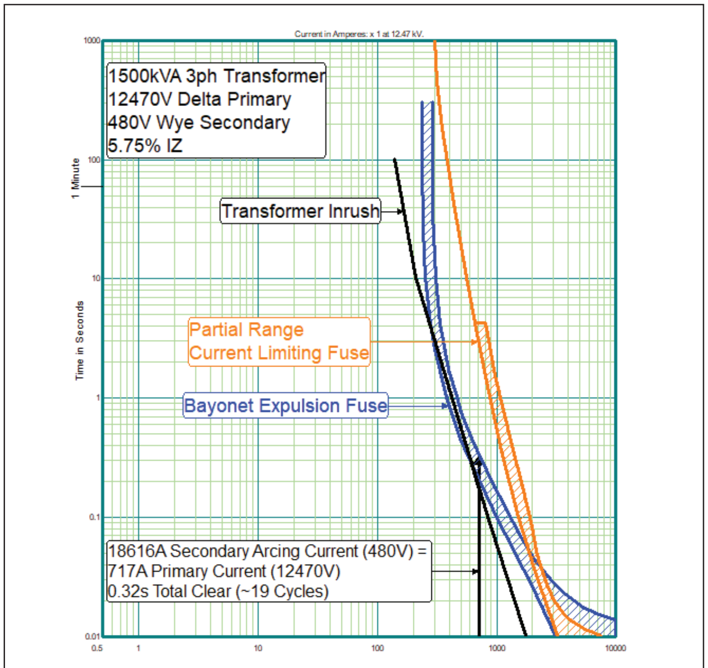

Figure 5 – Basic bayonet fuse coordination. Note bayonet fuses and Partial Range Current Limiting Fuses (PRCLFs) must be coordinated to the right of the transformer inrush curve to avoid operation on startup.

Furthermore, arcing events are inherently lower current than a bolted fault condition due to the inclusion of the through-air-impedance (typically Iarc = 30%-60% of Ibolted-fault) [2]. In some cases, this lower magnitude current can have difficulty in pulling a high enough current to operate fuses on the primary side of the transformer, especially if the coordination inclusive of inrush is loose. Primary fuses can react even more slowly to secondary line-to-ground arcing faults in a Delta-Wye transformer due to the resultant low magnitude circulating current in the primary Delta winding. This is due to current being pulled through only one phase on the secondary (Wye) side of the transformer, which consequently, pulls current in all phases (circulates current) on the primary (Delta) side. The resultant line current will be only 58% [or 1/sqrt (3)] of what a corresponding secondary fault current would produce on a Wye primary transformer. Much like poor (or loose) coordination, low magnitude circulating currents can cause an unnecessary increase in duration as the arc event must increase in severity until the current is high enough to melt the fuse and clear the fault; in some cases, taking several seconds.

Over the years, workarounds for required loose coordination due to inrush have been incorporated into microprocessor-based relays used with primary interrupters, such as the so-called 'inrush restraint' setting. This type of setting bypasses the protection settings for an allotted amount of time during initial energization then afterward moves the curve back to a tighter setting. This function can work, however commissioning (initial energization) can often be one of the most prevalent times for arc flash events to occur [3], so this solution is not ideal, as it is critical protective systems are functional during start-up. Another clever solution to avoid the problem of loose inrush coordination would be to engage a type of harmonic blocking within the control relay to effectively 'ignore' the initial inrush current. Harmonic blocking, while effective in many cases, can be very difficult to properly set and varies by transformer, relying on evaluation of the inductive and reactive components in the system to avoid causing nuisance operations or improperly blocking genuine trip signals. More recent advancements in primary overcurrent control equipment have allowed use of a much tighter instantaneous overcurrent setting (ANSI Device 50) that can be activated to drastically tighten the curve and offer a much faster secondary fault clearing time. This ability to temporarily change settings groups is referred to as "Energy Reducing Maintenance Switches" or "ERMS" per the NEC. This can be highly effective but still suffers from two major drawbacks: the setting must be switched on or activated in order to work and the secondary fault current still must reflect through the transformer losing speed and magnitude in the process, causing the primary device to respond more slowly. These extra manual steps rely on human intervention to be effective and the speed is still limited by forcing the fault current to reflect to the line side of the transformer. Additionally, this means that a 'maintenance mode' switch can suffer from some of the same issues seen with lock-out/tag-out procedures, improper personnel training or sudden fault events due to equipment degradation over time.

In cases of spontaneous faults where there was no time to engage a tighter maintenance mode protection setting prior to the fault occurring, this feature becomes essentially ineffective. Moreover, there are better ways to address this issue that can provide reliable protection in an 'always-on' mode.

IV. Enhanced protection with secondary sensing

Vacuum fault interrupter (VFI) technology has been used for decades and is often found in many critical commercial and industrial facilities. It has been proven to provide high interrupting capability as well as offer an integral means of electronic trip that is required for more sophisticated protection schemes. Compared to a traditional overcurrent device like a primary fuse, a VFI utilizes a local control that contains adjustable overcurrent settings. These settings often take the form of either a basic solid-state control with a few pre-defined protection curves, or more flexible overcurrent curve settings that can be modified or shaped for the application, a function like those found in modern microprocessor-based relays. The drastic difference between a modern interrupter and a primary device with a static protection curve like a fuse is the ability to dial in specific protection settings and electronically issue a trip signal. The trip signal itself most often triggers some type of solenoid or release mechanism that allows stored mechanical energy to be released or the VFI plunger to be magnetically actuated at high speed, opening the contacts within the vacuum bottle, and interrupting the fault current passing through. A variety of vacuum interrupter options that fit this description can be used on the primary of the transformer: metal-clad switchgear with vacuum circuit breaker, metal-enclosed vacuum breakers, pad-mounted VFI switchgear, or pole mounted vacuum reclosers are a few examples as shown in figure 3.

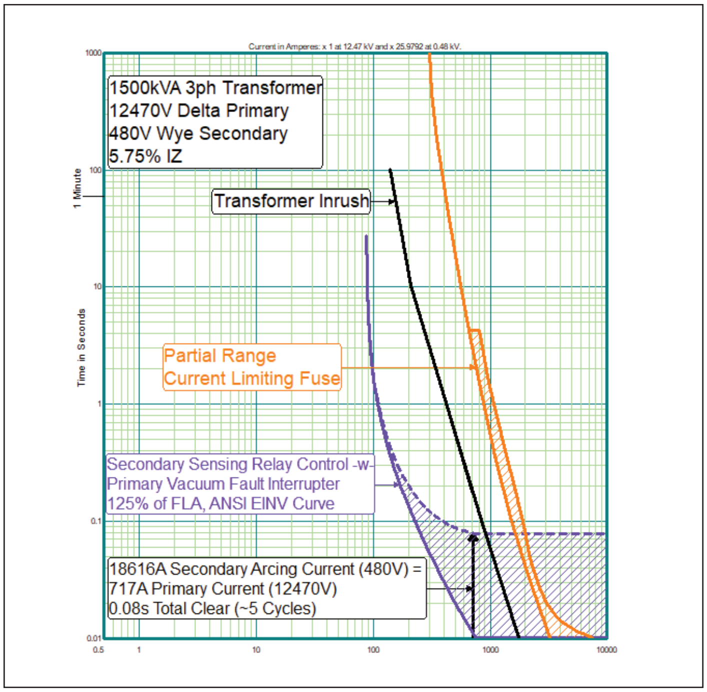

Figure 6 – TCC with secondary sensing curve, settings show relation to transformer inrush curve. Note that the interrupt curve for the 50/51 relay can be set far to the left of the transformer inrush curve.

Settings may be temporarily altered or tightened as described with inrush restraint, harmonic blocking or maintenance mode settings, but when left alone any of the above primary vacuum interrupter options can suffer the same outcome as a primary fuse. An alternative and much faster reacting approach is to add a means of secondary sensing and relaying into the equation. By adding in a simple 50/51 overcurrent relay and current transformers to the secondary side of the transformer the overall secondary fault clearing time can be drastically reduced. The secondary overcurrent settings do not have to be coordinated for transformer inrush as they are located downstream of the core/coil and therefore may have a much tighter level of protection that can be continually active.

As shown in Figure 6, the secondary overcurrent protection curve can be placed far to the left of the transformer inrush curve, allowing the arc flash event to be picked up more quickly. Once the overcurrent is commutated from the secondary cable / bus to the CT and to the 50/51 relay, a signal can then be sent to the primary interrupter to open and clear the fault. This entire operation can be achieved in a fraction of the time it would take waiting for the primary device alone.

This high-speed sensing and fault clearing operation can be even further enhanced by incorporating arc light sensing technology in the low-voltage cabinet or service entrances. Eaton Arc Flash Relays (EAFR) utilize fiber optic arc light sensors to detect the presence of an arc event and send the trip signal to the primary VFI in a sub-cycle manner (<8 ms). Arc flash relays can be incorporated with the overcurrent protection relay to ensure operation is due to a current surge and arc light to avoid nuisance tripping on light alone. The combination creates an extremely reliable and ultra-fast acting sensing system. This reduces clearing times from seconds for traditional systems to milliseconds, significantly lowering incident energy levels for minimal financial investment [5].

V. Difficulties of integration

Conceptually, the addition of secondary sensing systems to trip a primary interrupting device is a relatively straightforward method to reduce downstream incident energy levels. Used in many industries in some form or another for at least a decade, this type of protection scheme is well-established and offers a highly effective solution for low-voltage overcurrent and fault protection. Implementation of these schemes, however, can prove to be quite cumbersome, often adding lead time and high field service costs. Challenges such as:

- Sizing and selection of primary interrupter
- Coordination of primary interrupter equipment and transformer connections
- Choice of protective relay and its location in the system
- CT ratio, burden and accuracy
- CT location and wiring to relay
- Wiring of the trip signal from the relay to the primary protection device
- Addition and placement of arc light sensors and arc flash relay (when necessary)
- Reliable power supply for the protective relay
- Settings development (system study) and relay programming
- Overall testing of protection scheme

While history has revealed the usefulness of VFIs as a great tool for arc flash mitigation, these obstacles can increase the risk of error in design or set up and if structured incorrectly can quickly render a protection system ineffective.

Further discussion with field engineers, electrical contractors and end users has offered more insight into these difficulties. Initial design intent for VFIs are typically to act as the means of overcurrent interruption for faults both on the line side (or internal to the transformer tank) and load side of the transformer, however as we explored earlier, like a primary fuse, a primary VFI alone is not quick enough to result in practical secondary energy levels. VFIs paired with transformers typically utilize some means of 50/51 relaying whether it be an older electromechanical relay, a custom solid-state control with timing card, or more advanced microprocessor relay. Regardless of the control style, the ability to remotely trip in the event of a secondary arc flash is what allows the VFI to work as an extremely effective protection device. While the controller can be highly reliable, the remote trip functions are not often self-powered by the transformer directly or do not function while the transformer is de-energized. This means the user is required to wire both the trip output signal, and a power cable to the controller, not including the type and placement of overcurrent sensing (CTs) in the scheme. This may not always pose a significant problem, however often control power is not readily accessible nor is it always located in close proximity to the sensing equipment or arc flash hazard zone. This distance between controller, power supply, sensors and hazard zone can create immense difficulty in integration, also making the set up and maintenance of the protection scheme a feat in and of itself.

Supplemental difficulties arise even after the system design, component selection and physical installation of protection system components is complete. Challenges such as correctly testing the protection scheme and validating the energy levels are as expected. All are necessary steps and must be done without compromising the integrity of the equipment or safety of the commissioning crew. As many are becoming aware, the recent revision of IEEE 1584 standard – "guide for performing arc flash hazard calculations" [6] released in late 2018 has increased the number of variables significantly. While the new model is more accurate than it was previously, these new variables can increase the difficulty in coming up with an energy level value to note on the equipment hazard label (i.e. determining the real energy value in cal/cm2). This is due to the dynamic nature of arc faults and how they propagate from various electrode orientations within enclosure sizes and conductor arrangements. Calculating the energy of this dynamic event takes complex equations coupled with an iterative process that proves troublesome to most. This may create difficulty in performing arc flash studies as many of the variables are specific to the equipment installation, cable lengths between gear, sensor placement, interrupter placement, etc. Moreover, utilizing standardized, pre-integrated, and pre-tested protection system packages can greatly decrease the difficulty in system design, integration, and validation and significantly benefit the overall project complexity and resultant equipment reliability.

VI. Pre-integrated and pre-tested solution as a novel approach

This protection approach can be greatly simplified by integrating the VFI, sensing and controls directly into a standardized transformer apparatus. Eaton's Cooper Power series product engineers combined this approach with the methods investigated earlier regarding secondary sensing and primary interruption to result in the Arc Reduction VFI (AR-VFI) transformer (shown below in Figure 7).

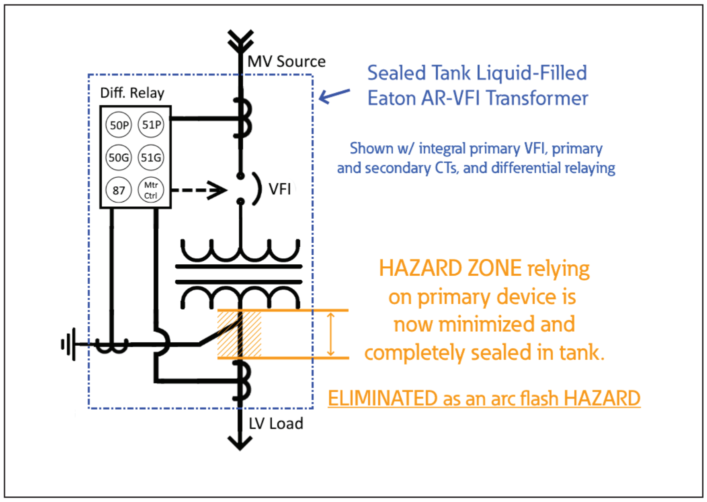

Figure 7 – AR-VFI transformer setup

The inclusion of modern microprocessor-based relaying and under-oil sensing equipment into existing VFI transformer technology allows the protection scheme to be fully contained within the footprint of the transformer package. The resultant standardized design offers:

- Significant space reduction of the lineup (60% reduction in space as compared to Dry-Type + MV Interrupter + LV Main)
- Manufacturer standardized relay selection (Eaton E-Series ETR or equivalent)
- Single local controller (differential relay) provides primary and secondary 50/51, plus differential 87 protection
- Highly adjustable primary and secondary protection settings
- Ability to trip primary interrupter device from secondary sensing minimizing overcurrent event reaction time
- Manufacturer provided/selected CT and sensors
- Dedicated CTs minimize burden and reduce cost, size and weight
- Ideal CT location internal to tank with secondary 50/51 protection maximizing zone of protection
- Pre-wired CT connections from primary and secondary sides of transformer to local relay
- Ideal selection and location of arc-flash light sensors
- Minimized signal proximity for sensors, relay and trip unit
- Reliable power from an integrated instrument transformer and local battery backup power
- Properly sized and protected PTs to provide power and optional voltage/power monitoring.
- Consistent variables for performing arc flash hazard calculations based on standardized equipment design, increasing equipment reliability

All the above factors come into play when designing a transformer protection system. By creating a pre-integrated solution, the complex field work and respective cost can be minimized. This approach ultimately simplifies the assembly and validation of the protection scheme, thereby shrinking the impact on the overall project budget and timeline.

VII. Simulations

Initial validation of the integrated protection scheme began with calculation of the secondary arc energy values based on the recently released IEEE 1584-2018 standard. The bulk of this process was spent identifying the key variables that drive the total length of the fault clearing sequence based on the physical layout of the transformer secondary cabinet (Hazard Zone) and protection system components. The variables considered for total fault clearing time were:

a. Arcing current magnitude

b. Commutation of phase overcurrent to CT

c. Arc-flash light sensor pick up (if included)

d. Relay pick-up time

e. Relay contact close time

f. Vacuum interrupter open/clear time

The above components of the total fault clearing time depend on several constraints as well such as CT burden and/or sensor distance from relay, type of relay and location relative to interrupter, and speed and capability of the interrupter itself.

One of the major benefits of integrating the necessary components directly into the transformer structure and design standardization of this complexity is the minimization of variance in device location, programming and timing. With CTs and light sensors placed in a controlled and consistent location within the low-voltage termination section, the arc energy modeling process could be greatly simplified. CTs are located under-oil within the transformer tank such that the 50/51 zone of protection is maximized and covers anything downstream of the low-voltage terminals as they leave the tank. Arc-flash light sensors are placed at a uniform distance from the low-voltage bushings or termination point with negligible difference in fiber optic cable distance for all sizes of distribution transformer cabinets. In all scenarios, it was assumed that the CTs would be appropriately sized with correct ratio and accuracy class for protective relaying (C100 minimum, ratio based on 1.5x full load amperage). Locking in these variables acted as the control for comparing primary sensing / interruption alone to the primary interruption with the addition of secondary sensing to trip the primary interrupter. Modeling the integrated solution for IEEE 1584-2018 standard also necessitated picking a few physical characteristics that highlight the size and layout of the transformer secondary: most importantly, the electrode configuration and enclosure size. Through significant testing for the revision of IEEE 1584-2018 standard it was determined that some factors can make the arc energy much worse as seen by the user. These factors include a deeper enclosure, horizontal electrodes protruding at the user (referred to as "HCB" by IEEE 1584-2018 standard [6], and, of course, the overall let-though energy for the transformer in question. If the factors above are taken to be worst case scenario, that is, a maximum energy phase-to-phase arc fault occurring on horizontal electrodes placed within a deep small enclosure, the resultant incident energy can be devastating. As it so happens, these factors are very common to occur all at once at the transformer secondary. Most often in a pad-mounted transformer or unit substation transformer scenario, the bushings are within a deep enclosure and are horizontally protruding at the user or adjacent gear. In order to factor these values into the simulation and subsequent testing, Eaton's engineers utilized a consistent enclosure size and electrode configuration in order to control the variation of the results and highlight the difference in energy based on the addition of secondary sensing systems. For the simulation, the chosen variables were as follows:

Transformer ratings/construction:

a. Transformer size range: 1500 kVA

b. Transformer secondary L-L voltage: 480 V

c. Transformer impedance: 5.75%

d. Transformer enclosure size: 72" h x 30" w x 24" d

e. Electrode configuration: HCB

f. Working distance: 18"

Individual component timing:

- 50/51 relay pickup time including CT pickup: 24 ms (1.5 cyc) *fault magnitude dependent
- 50/51 Relay trip contact close time: 8 ms (0.5 cyc)
- Arc-flash light sensor pickup:<1 ms (<0.0625 cyc)
- Arc light relay contact close time: 7 ms (0.44 cyc)
- Vacuum interrupter open/clear time: 43 ms (2.6 cyc)
- Bayonet fuse sense/operate/clear time: 69.8 ms (52.2 cyc)

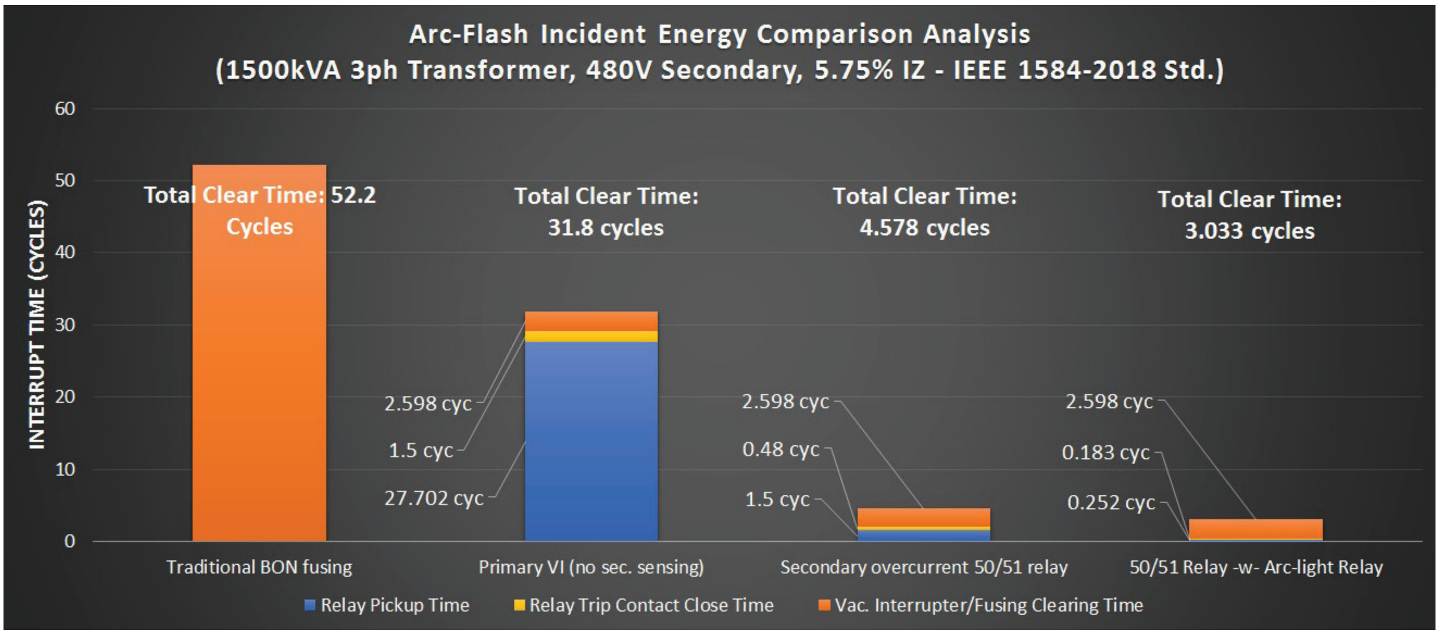

Figure 8 – Comparison of clearing times for traditional fusing, primary interruption alone and primary interruption coupled with secondary sensing systems.

Transformer secondary incident energy vs. transformer kVA

(Three-phase 480 V secondary ANSI standard impedance 5.75%, 18" working distance IEEE 1584—2018 calculations)

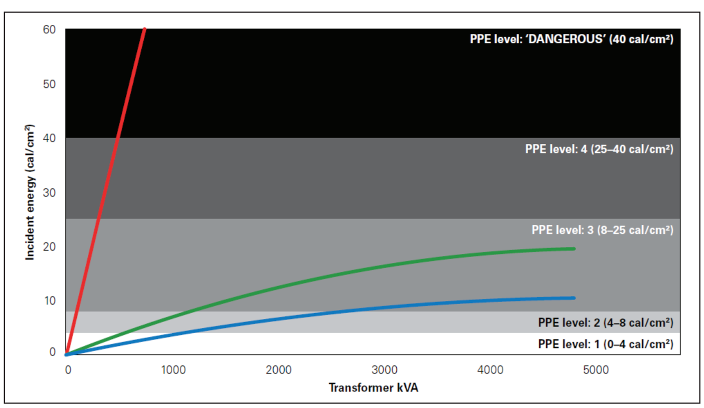

Figure 9 – Comparison of clearing times for traditional fusing, primary interruption alone and primary interruption coupled with secondary sensing systems.

Traditional primary OC protection

AR-VFI 50P design

AR-VFI arc-light sensing design

Shown on the left is a comparison of incident energy in the transformer secondary compartment as transformer kVA increases. Calculated values using the updated IEEE 1584-2018 standard show more accurate and stringent incident energy values for transformers. Designs highlighted in this study are traditional overcurrent protection, new AR-VFI design with 50P pickup and AR-VFI with arc-flash light sensing

In total, when comparing the clearing times on a similar unit for traditional fusing versus an AR-VFI transformer, we see a significant speed increase with secondary sensing systems. Based on the above parameters and variables looking specifically at a 1500 kVA pad-mount transformer as an example, the clearing time is reduced nearly 11.4 times with secondary current sensing alone, and nearly 17.5 times with arc-flash light sensing.

A graphical representation of clearing time comparison can be seen in Figure 8. These values were obtained by investigating the individual timing of each of the protection control apparatus and summating the duration of each to obtain a total duration. Taking the values obtained by summating the constituent components and inputting the clearing time values in an arc flash model with the revised IEEE 1584-2018 standard guidelines, it is well understood that reducing the total fault clearing time will reduce the incident energy value. But, in order to see just how much the energy is reduced for a given kVA the model was expanded to a range of transformer kVA values (45 – 5000 kVA) while holding the clearing time duration for each scheme. The model was applied across kVAs holding the same enclosure size and electrode configuration for each. While the enclosure size may vary more significantly in the real world than outlined in the initial simulation, it was determined that this would still allow practical interpretation of the benefit of reduced clearing time exclusively without allowing too many installation/arrangement variables to come into play. With that said, while this simulation is a good representation of 'before and after' the addition of secondary sensing, in all cases it is imperative to consider all variables before determining a true incident energy level. Noted in Figure 9 is a chart showing the reduction in secondary incident energy in the transformer low-voltage termination cabinet. This graph highlights the drastic reduction in secondary energy when adding a secondary sensing system, up to roughly 90% reduction with arc-flash light sensing.

Through the initial project simulations, Eaton engineers were able to validate the pursuit of an integrated solution and develop the standardized AR-VFI transformer. The functionality of secondary sensing systems is well proven by other studies and revalidated again through our modeling to still hold true given the IEEE 1584-2018 revisions. Understanding that the aim of integrating the solution is two-fold, 1) to allow the protection scheme to be pre-engineered and validated early in the process rather than in the field, and 2) the integrated solution allows the large number of variables required to calculate incident energy to be greatly simplified by providing consistent, known distances, trip times, signal types and relay settings on the transformer.

VIII. Real-world validation event

Proof of concept based on general theory, modeled system studies, and simulations evaluating theoretical clearing time and incident energy comparisons has been established. The next most pertinent form of validation would then be an actual arcing event that has taken place in a real-world circumstance. The following case study shows how the implementation of secondary sensing systems in transformers can provide drastically reduced clearing times: minimizing arc impact on equipment and maximizing personnel safety and equipment longevity.

The electrical design and ratings for the transformer under consideration can be noted on the nameplate (Figure 10). This transformer utilized an internal vacuum fault interrupter (VFI), primary and secondary current transformers, and primary and secondary overcurrent protection (50/51) relay. Physical testing and validation of the components and protection scheme prior to energization consisted of the following process checks:

- Validation of CT wiring, ratio and polarity (insulation resistance testing also performed to ensure proper installation)
- Validation of wiring of CTs to microprocessor-based relay
- Validation of wiring of trip signal from relay to vacuum interrupter trip contact
- Continuity checks on all protection scheme circuits
- Programming of relay and factory validation of system functionality

Once the AR-VFI transformer scheme was installed on site and verified to be wired correctly and send signals accordingly, the startup and commissioning process could take place. During the startup of this unit it was found that there was a large bolt (identified to be from a shipping bracket/support) that had come to rest across two phase conductors in a piece of downstream switchgear. The piece of hardware was unknowingly left within the gear across the A-B phase conductors during commissioning and was responsible for initiating the arcing event that we are reviewing in this case study. Shown in Figure 11 are the waveforms extracted from the overcurrent relay that was utilized to trip the primary VFI. As seen in the waveform plot, the duration from the moment the relay senses the overcurrent event from the CTs to moment of total fault clear is approximately 33 ms. This value must be added to the time taken to commutate the overcurrent surge from the phase conductor to the CT as well, which adds an additional ~0.25 – 0.33 cycles (4 – 5.3 ms) cycles, resulting in a total fault clearing time of ~2.22 cycles (37 ms). (Note: This fault interruption utilized the 50P, instantaneous, setting in the relay as maintenance mode was engaged for commissioning. Had the system utilized the 51P, time overcurrent setting, in an 'always on mode' as discussed earlier the clearing time would be extended by approximately 1.5 cycles (24 ms) minimum depending on coordination with downstream devices).

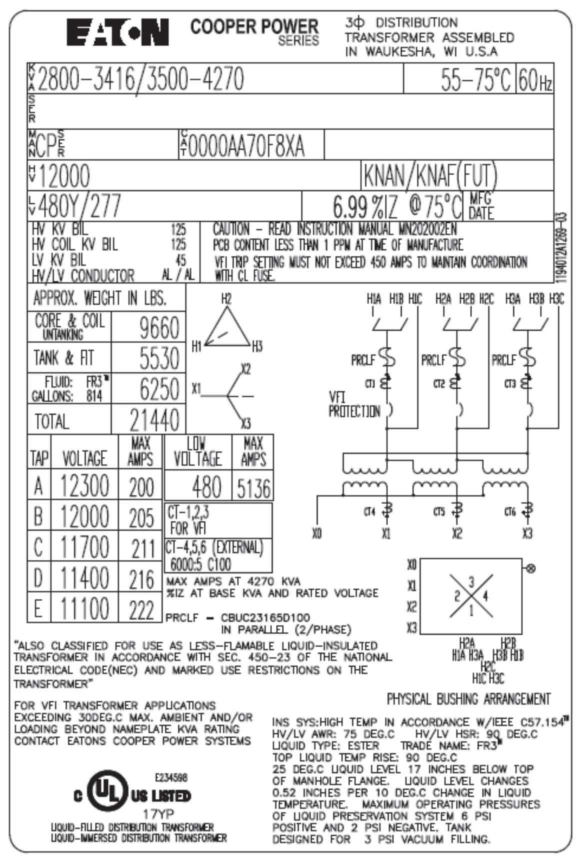

Figure 10 – Transformer nameplate showing unit ratings and schematic with integrated vacuum interrupter, line side and load side CTs and internal PRCLFs.

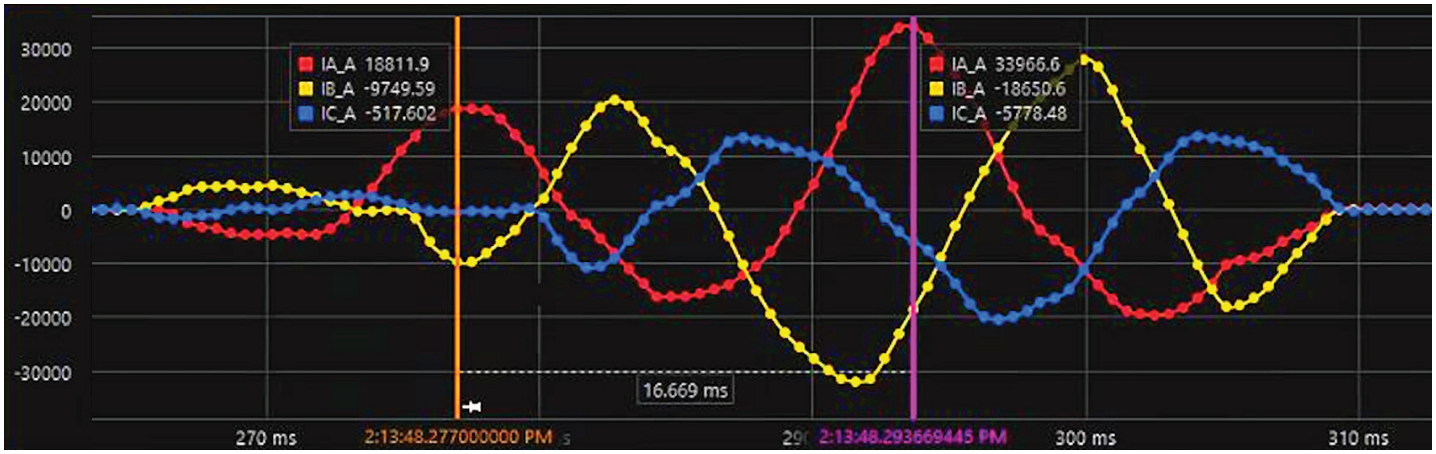

Figure 11 – 50/51 microprocessor relay waveforms from a secondary A to B phase fault event. Fault condition starts at approximately 273 ms, relay issues trip signal to vacuum interrupter at 277 ms, fault magnitude reaches peak value (34 kA) at 293 ms, fault is completely cleared by 310 ms. Total fault clearing time including CT pickup time 37 ms (~2.22 cycles)

The fault current magnitude reached a peak of 34 kA (~17 kA RMS) which was reached 1 cycle (16.66 ms) after the initial trip command was issued from the overcurrent protection relay. After the fault current reached its maximum the vacuum interrupter was then able to completely clear the arcing event within another cycle. This is an extremely fast clearing time. If an air-insulated breaker would have been used to clear the fault it would have likely taken at least 5 full cycles to clear the energy, however since the fault was cleared within vacuum it was significantly less. In this case, the fault initiated as a secondary A-phase to B-phase fault in the downstream switchgear then roughly 3 ms later (plotted at 280 ms on the waveform capture) the C-phase fault current initiated at a lesser magnitude. The C-phase fault here was likely due to the arcing temperature rise of the A-to-B-phase causing the air to ionize and become conductive (plasma) near the C-phase buswork in the gear. The lesser magnitude fault on C-phase is due to the lower temperature plasma near this fault path. After reviewing the clearing time for this arcing event, we can now review the approximate incident energy value. Utilizing the calculation methodology outlined in IEEE-1584 2018 standard [6] with horizontal electrodes in a box (HCB), and the default switchgear enclosure size of 20" h x 20" w x 20" d, bus gap of 1.25", and working distance of 24", we find that the energy level is reduced to ~1.9 cal/cm². This is an extremely significant energy reduction for such a large kVA unit and highlights the impact of the added secondary sensing with primary interruption scheme.

Now to compare this clearing time in a 'what-if' scenario based on the identical situation where the transformer utilizes a primary vacuum fault interrupter (VFI), however now without the aid of secondary overcurrent sensing. The primary VFI trip curve (51P settings) must now be coordinated to withstand the transformer full load current and inrush current as previously discussed. In this case, the primary VFI pickup settings will be set at 325 A. Important to note again that the primary fault current is equal to the secondary fault current divided by the transformer ratio. This means the resultant primary through fault current would be only 680 A, based on the same secondary fault value of 17 kA. Given the same event parameters (34 kA peak, 17 kA RMS fault across A-and-B-phases), the VFI would operate and clear the fault event in about 2.4 sec (144 cycles), resulting in an incident energy of 125cal/ cm². Now given the fact that the fault clearing duration well exceeds the IEEE 1584-2018 standard recommended "2 second rule" [assuming some upstream protective device will operate, upstream equipment/cable failure would occur and stop the current, or the arc will self-extinguish within a 2 sec (120 cyc) timeframe] the clearing time was capped at 2 sec. Even capped at a 2 sec duration, this is still an eternity in arc flash terms. Given a fault extended for this duration and the same electrode configuration, and enclosure size parameters we had used with the previous secondary sensing analysis, this method of protection still results in an incident energy value of 103 cal/cm². This is an extremely significant difference in energy which if used in lieu of the secondary sensing method would pose a substantial arc flash hazard.

IX. Impact on electrical system topology

The reduction of secondary incident energy can be achieved in many ways, but not all are simplistic, cost saving or space saving, and many of these solutions still leave certain zones unprotected. Lack of protection can lead to increased equipment sizing/spacing and increased distance between critical areas or service entrances. This results in more buswork, increased maintenance complexity, more potential failure points, and larger unprotected (or less protected) "hazard zones". With the advent of pre-integrated, pre-tested solutions combined with proven Eaton VFI technology and modern relaying, electrical system designers can shrink overall footprint without compromising on electrical safety. The high-speed fault clearing time achieved with Eaton's AR-VFI transformer creates a safer piece of equipment from the transformer bushings all the way downstream (example AR-VFI transformers shown in Figures 12 and 13). This major advantage of lower incident energy levels at the transformer secondary allows it to be more readily treated as a serviceable piece of equipment where previously de-energization would have been required. With proven safer equipment, system designers can move the transformer secondary closer to or within buildings, or even connected by minimal cable or bus direct to the load. The removal of large amounts of low-voltage buswork in the system can eliminate significant capital cost from the project and points of potential failure. Eliminating the cable or bus also drastically simplifies the maintenance of said connections; no need to clean or inspect what is no longer present.

Furthermore, with a smart protective relaying system integrated into the unit and paired with a primary VFI, the transformer can be equipped with motor operation to facilitate remote control over the device for automated primary isolation or switching. Some of these features can be taken further and used in more advanced system protection or automation schemes as well to further isolate, restore or transfer sources. Overall, the purpose of reviewing a proven protection technology and understanding the benefits of a pre-integrated solution sheds light on the fact that standardized components used for customizable protection applications can be a major benefit to project simplicity, overall design schedule and cost.

Figure 12 – Eaton AR-VFI substation transformer

Figure 13 – Eaton AR-VFI compartmental padmount transformer

X. System considerations

It should be noted that while sensitive, high-speed protection can be an elegant solution to mitigate transformer and downstream arc flash, consideration should be given for what load is powered and the outcomes of spontaneous de-energization. Many large industrial facilities utilize large synchronous motors, induction furnaces and other continuous use machines that can suffer a great deal of damage when a sudden loss of power and/or rapid re-energization occurs. This section was included to briefly present awareness to caveats in the system. Whenever designing or upgrading an electrical system the system protection should be looked at, with all possibilities considered. Depending on the load, electrical system automation may be designed into the system so that power can be restored quickly, such as a data center or hospital. However, other facilities, such as those with synchronous motors, may suffer extreme damage from quick power restoration if out of phase. Moreover, when utilizing a pre-integrated / pre-validated protection system or piece of electrical equipment, it is imperative to understand all reaction times and automatic or semi-automatic functions of that equipment.

XI. Conclusions

With Eaton's AR-VFI transformer, dramatic improvements in fault clearing time, equipment reliability and personnel safety can be achieved without major investment. This approach not only can save space, time and money, but also comes with the benefit of added intelligence to support better outage recovery with fewer dispatches. Additionally, by taking a strategic, packaged approach to transformer and switchgear safety improvements, one can easily achieve a Total System Approach to improving substation operation. This includes:

- Creating a systematic / repeatable control
- Reducing fault clearing time
- Reducing the impact of faults
- Maximizing equipment functionality

The major benefits of a pre-integrated piece of equipment with known control components, known signal distances, known line-to-ground clearances, and known clearing times allows one to simplify arc flash hazard calculations and best design their system. The reduction in footprint of the integrated gear and minimization of low-voltage buswork in the system allows for decreased capital cost as well. Moreover, the intent of this study was to highlight the major benefits of secondary sensing technology paired with primary interruption and highlight the ease-of-use to the end user of a pre-integrated solution.

About Eaton

Eaton's mission is to improve the quality of life and the environment through the use of power management technologies and services. We provide sustainable solutions that help our customers effectively manage electrical, hydraulic, and mechanical power – more safely, more efficiently, and more reliably. Eaton's 2019 revenues were $21.4 billion, and we sell products to customers in more than 175 countries. We have approximately 93,000 employees. For more information, visit **Eaton.com.**

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