

IMPROVEMENTS IN PROTECTION AND COMMISSIONING OF DIGITAL TRANSFORMER RELAYS AT MEDIUM VOLTAGE INDUSTRIAL FACILITIES

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Paper No. PCIC-AN84

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Abstract— The application of multifunction digital relays to protect medium voltage power transformers has become a common industrial practice. Industrial transformers, unlike utility transformers, frequently use neutral grounding resistors to limit ground current during faults to 200-400A range on medium voltage systems. This paper will discuss why these types of transformers require sensitive ground differential protection. The paper will also discuss the basics of transformer protection including: phasing standards, through-fault withstand capability, differential/fusing/overcurrent protection, slope, CT requirements, harmonic restraint, and communicating these requirements properly when programming and commissioning new digital relays. The rationale for providing transformer overexcitation protection on all major transformers within industrial facilities is also addressed.

Advancements in digital technology have allowed relay manufacturers to include more and more relay functions within a single hardware platform as well as address more and more transformer winding configurations. This has resulted in digital transformer relays requiring an experienced protection engineer to set and an experienced relay testing technician to commission. Since there are fewer experienced professionals among us now, the next generation of transformer relays needs to concentrate on this complexity issue in addition to technical improvements. This paper addresses these issues that the author believes are the major shortcomings of existing digital transformer protective relays.

Index Terms – multifunction digital relay, low resistance grounding, ANSI, IEC, slope, inrush, harmonic restraint, overexcitation, V/Hz, electro-mechanical relays.

I. INTRODUCTION

A. Transformer Protective Zones

Traditionally, the protection of medium voltage power transformers at industrial facilities has been relegated to the application of transformer phase differential and backup overcurrent relays to provide short-circuit protection. With the advent of modern multifunction transformer relay packages, phase differential and overcurrent are only two of the many protection functions that are incorporated into these relays.

Fig. 1 illustrates the various protection zones that can be part of a digital transformer protection relay.

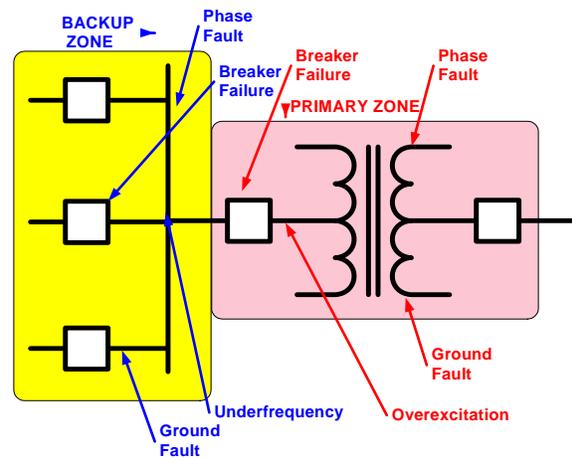


Fig. 1 Transformer Zone Protection

This flexibility and added functionality has added to the complexity resulting in complicated relays to set and commission. Also, the failure of the hardware platform typically results in loss of all protective functions within the relay package and must be considered in the design of the protection system to maintain the concept of primary and backup protection. This paper addresses these issues and provides practical solutions. These shortcomings, however, are far outweighed by the many advantages of digital relays. Users also have seen the many benefits of digital relays with almost all new installations using this technology.

B. Reasons for Transformer Failure

Contrary to popular belief, transformers do experience short circuits and abnormal electrical conditions that result in their failure. As transformers become older, the likelihood of failure increases as insulation begins to deteriorate. An example of one such abnormal condition is overexcitation. Many industry experts have concluded that overexcitation and through-faults are more detrimental to transformer life than load-associated aging [1].

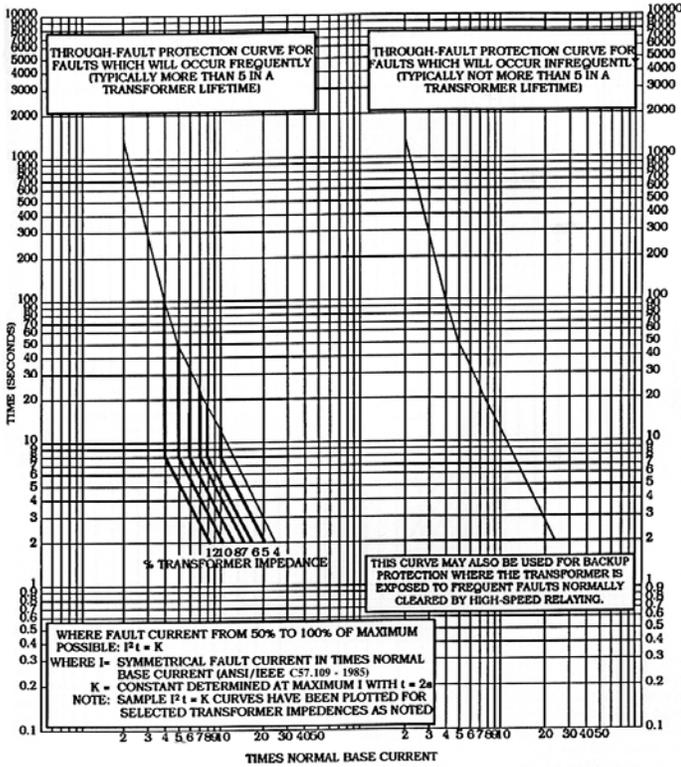


Fig. 2a IEEE Category III Transformer – 5 to 30 MVA

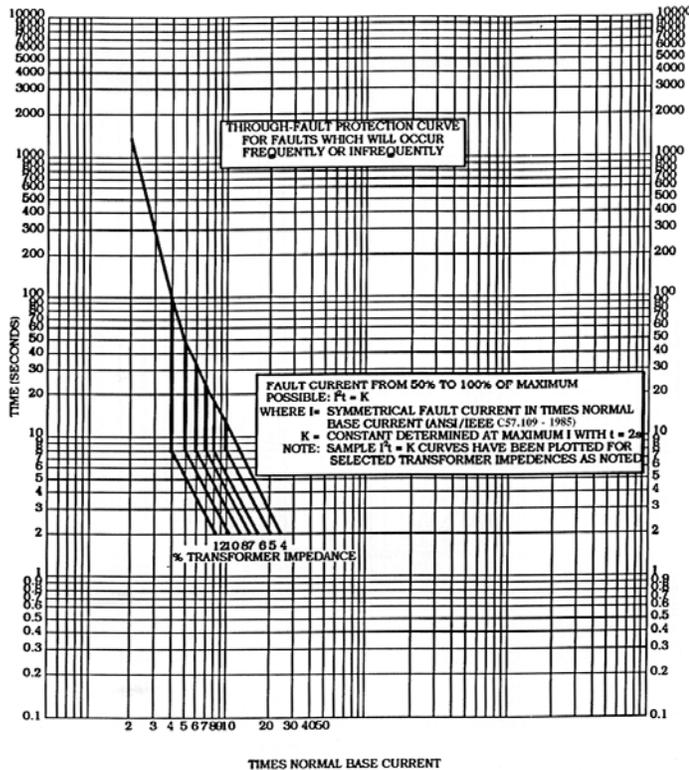


Fig. 2b IEEE Category IV Transformers – above 30 MVA

Through-fault failures were a major industry concern in the U.S. during the late 1970's and 1980's when the industry experienced an unusually large number of through-fault failures due to design deficiencies. As a result, the IEEE Transformer Committee developed guidelines (C57.12.00-2000) for duration and frequency of transformer through-faults. The requirements for Category III (5-30 MVA) and Category IV (above 30 MVA) transformers are depicted in Figs. 2a and 2b. The smaller Category III transformers through-fault standards are defined by two sets of curves—one for frequent faults and one for infrequent faults. This was done because of the use of this size transformer for utility distribution substation applications, which subject these transformers to frequent through-faults and multiple automatic reclosing attempts. The multiples of normal current in Figs. 2a and 2b are based on the self-cooled rating of the transformer being 1.0 base current. These curves should be used when developing transformer time overcurrent relay settings.

The through-fault effects on transformer failure are somewhat mitigated at medium voltage industrial installations because most through-faults are line-to-ground faults and fault current is limited through 200-400A grounding resistors in the transformer neutral. A detailed analysis of transformer failures conducted by a major electrical equipment insurer breaks down the causes of transformer failures based on the transformers they insure. Table 1 shows the insurer's breakdown of the causes of failure from 1990-2002 which included approximately 8,000 insured transformers. One of the insurer's conclusions is that whatever the cause of failure, age compounds the problem. Therefore, the proper protection of aging transformers warrants careful attention from industrial facility engineers.

TABLE 1 [2]
CAUSE OF TRANSFORMER FAILURES

Cause	% of Failures
Insulation Failure	26%
Manufacturing Problems	24%
Unknown	16%
Loose Connections	7%
Through Faults	5%
Improper Maintenance	5%
Oil Contamination	4%
Overloading	4%
Fire/Explosions	3%
Lighting	3%
Floods	2%
Moisture	1%

II. TRANSFORMER BASICS

Transformer grounding and winding configuration (wye or delta) play a large role in the development of the protection for a specific transformer.

A. Transformer Grounding and Winding Configurations

At most medium voltage industrial facilities, the main incoming transformer that provides the tie to the utility system is generally configured to be a delta primary – wye grounded secondary transformer. The secondary wye winding is generally grounded through a grounding resistor. Typically, these resistors reduce ground current to between 50 to 800 amps and are dependent on client preference and system charging currents. There are three major reasons for use of a secondary grounding resistor to reduce industrial system ground current:

1. Reducing ground current reduces damage at the point of fault.
2. Reducing ground current reduces the fault current level that industrial equipment (transformers, cables, etc.) must carry during line-to-ground fault clearing.
3. Reducing ground current minimizes the voltage dip on the industrial system for a line-to-ground fault.

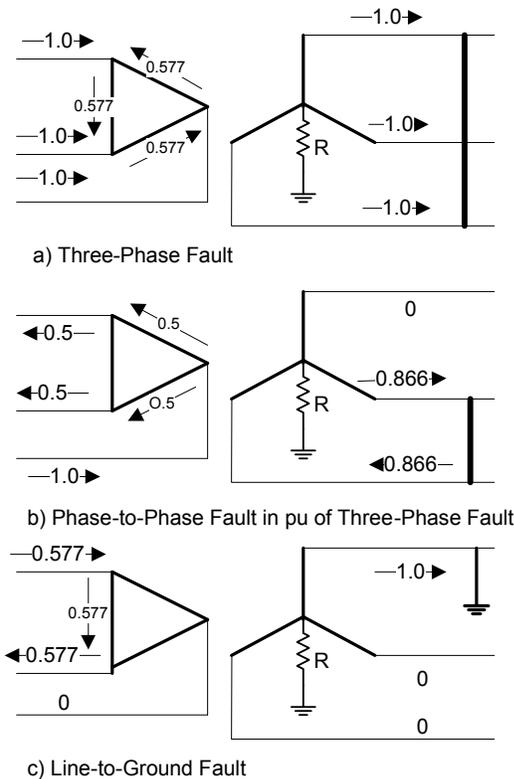


Fig. 3 Delta-Wye Transformer Fault Current Distribution

The use of a delta-wye transformer introduces a rearrangement of fault current on the primary side of the transformer for secondary faults that effect protection when overcurrent devices such as overcurrent relays or fuses are

used. Fig. 3 illustrates how the secondary fault currents are redistributed for various types of faults when viewed from the primary side of the transformer. Fault currents are shown in per unit (pu). The use of fuses, which are commonly used by utilities to protect solidly-grounded transformers 10 MVA and smaller cannot be used to protect transformers that are grounded through grounding resistors as shown in Fig. 3. As an example, if the secondary ground fault current is limited to 400 A on a 10 MVA 138/13.8 kVA transformer, a bolted secondary ground fault would only produce 23 A (see Fig. 3c) of fault current on the primary of the transformer which is less than the 42 A of full load current. Thus, it is not possible to fuse such a transformer because the fuses are not sensitive enough to detect secondary ground faults. These transformers must be protected by relays.

B. Transformer Phasing Standards

There are two major phasing standards used worldwide for transformers. The ANSI/IEEE standard was developed by North American transformer manufacturers and is used in the U.S., Canada and many other countries. The IEC phasing standard was developed by European transformer manufacturers and is used in Europe and countries worldwide whose electric system was influenced by European manufacturers. Transformer protective relays that are sold worldwide must be able to handle both phasing standards. Being able to handle both these phasing standards has added to the complexity of digital transformer relays. Properly communicating the phase shift introduced by delta-wye transformers to a digital relay is the biggest source of setting errors in digital transformer relays. The level of complexity required to communicate transformer phase shift to a digital relay is one of the design features that differentiates one relay manufacturer's product from another.

IEEE/ANSI phasing standards are shown in Fig. 4. For delta-wye or wye-delta transformers, the primary (H) current leads the secondary current (X) by 30 degrees.

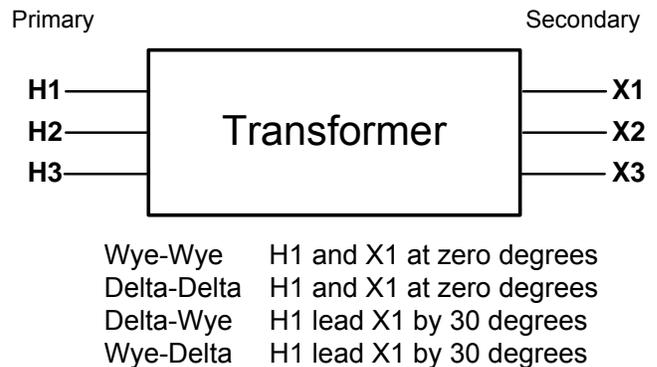


Fig. 4 IEEE/ANSI Phase Shifts

How the 30 degree phase shift is accomplished within the transformer is a mystery to many engineers. It is simply accomplished by how the delta winding is made up within the transformer. Fig. 5 and Fig. 6, respectively, show how this is done for a delta-wye and wye-delta transformers wound to meet IEEE/ANSI standards.

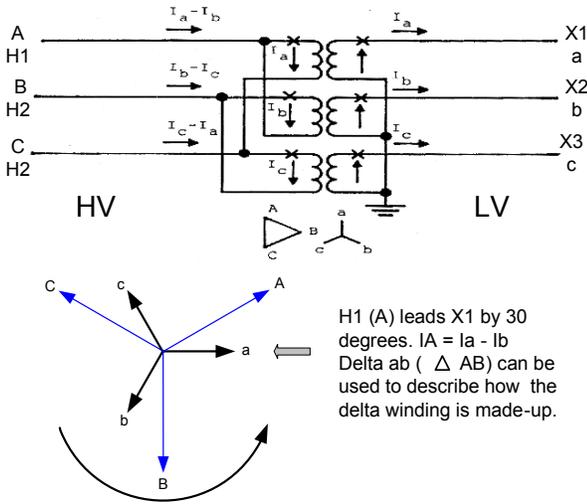


Fig. 5 IEEE/ANSI Delta-Wye Transformer Phasing

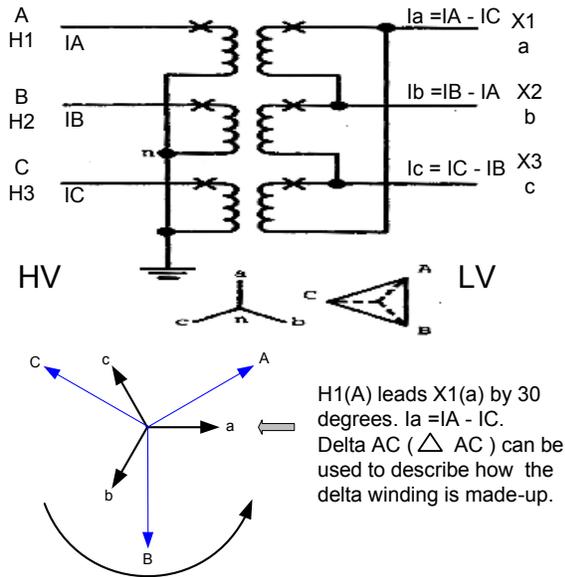


Fig. 6 IEEE/ANSI Wye -Delta Transformer Phasing

For IEEE/ANSI standard transformers, a simple way to communicate the phase shift is to determine how the delta winding is configured. One can look at a phasing diagram for the delta winding and easily determine if the A phase delta is a delta AB ($I_a - I_b$) or AC ($I_a - I_c$) configured. The delta AB shifts the phase angle 30 degrees in the positive direction with the delta current leading the wye current. The delta AC shifts the phase angle 30 degrees in the negative direction with the delta current lagging the wye current. Using this simple convention, it is possible to communicate the phase shift to a digital relay for IEEE/ANSI standard delta-wye transformers.

IEC phasing standards cannot use the method described above to communicate the phasing to a digital transformer relay. The Euro-designation uses a clock system with each hour a 30 degree increment of lagging phase angle from the X1 bushing to the H1 bushing. The clock is divided into 12 segments. Each segment number indicates the number of 30 degree increments the phase angle is shifted (Example: $1=30^\circ$ and $11=11 \times 30^\circ = 330^\circ$). The letter D is used to designate a delta winding and the letter Y a wye winding. The letter that is capitalized is the primary or H winding of the transformer. Fig. 7 illustrates the clock concept and the standard IEC phasing examples.

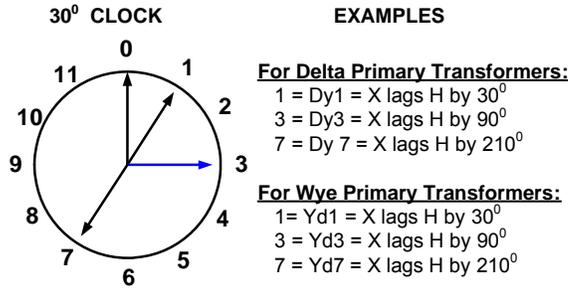


Fig. 7 IEC Transformer Phasing

To be able to handle both these phasing standards, relay manufacturers have used various techniques. Some have chosen to diagram every possible transformer phasing connection, which results in more than 250 three-line phasing diagrams. The number of specific cases is increased because of the fact that delta-connected CT must be considered. Others have chosen to adopt the Euro clock, which can be used to describe IEEE/ANSI standard transformers as well as IEC transformers. One manufacturer has chosen to use the software to allow users to select either the IEEE/ANSI or IEC standard.

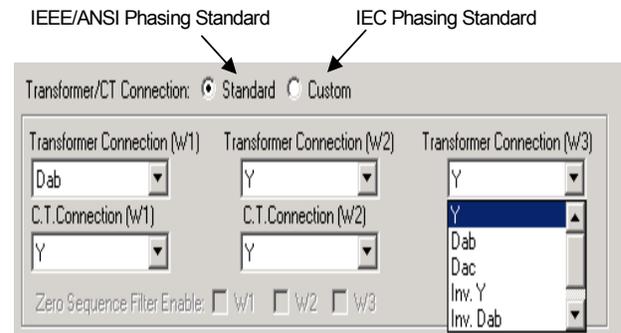


Fig. 8 Programmable Phasing Standard Selection

This method allows North American users to define phase shift by the simple method of how the delta is made up on A-phase (Delta AB or Delta AC). If the relay is being used to protect an IEC standard transformer, a custom mode can be selected that uses the 30° clock described above. This results in a less complicated method to communicate transformer phase shift to a digital relay for standard IEEE/ANSI phasing application while still providing the flexibility to address IEC transformers. Fig. 8 illustrates this software.

III. TRANSFORMER DIFFERENTIAL PROTECTION

Transformer differential protection is typically installed on transformers that are 10 MVA or larger [5]. At medium voltage industrial facilities where the transformer wye windings are grounded through a grounding resistor, smaller transformers are generally protected by differential relays due to the sensitivity issues described in Section II of this paper. Transformer differential protection is a challenge to apply because of factors such as: current magnitude and phase angle balancing, inrush and overexcitation restraint and CT performance. Digital relays have allowed manufacturers to improve many of the design elements that comprise transformer differential protection. Transformer differential protection can be divided into two categories: phase and ground.

A. Phase Differential (87T) Protection

Current magnitude balancing within a differential relay is accomplished through the selection of the appropriate transformer tap settings within the relay. Older technology E-M (electromechanical) relays used five or six discrete tap settings to balance current magnitudes on the primary and secondary of the transformer. They could balance a current mismatch of approximately 3 to 1. Digital relays have continuous settable tap settings and can balance a 10 to 1 current mismatch—making them more accurate and providing the flexibility to handle larger mismatches. Typically, the tap settings on the primary and secondary are selected by determining the full load current at the ONAN rating of the transformer and then checking to make sure the relay current coil ampere rating is not exceeded under emergency loading conditions.

Phase angle compensation is discussed fully in Section II of the paper. E-M transformer relays balance phase angle externally through the connection of the input CTs. Wye transformer winding CT inputs are connected in delta and delta winding CT inputs are connected in wye to balance the 30° phase shift. Frequently, in the case of older transformers that are being upgraded with digital protection, it is easier to retain the delta CT's connections. The magnitude of the delta CT currents under normal balanced load conditions is 1.73 higher than the individual line current for each of the CT's phases being subtracted to form the delta – i.e. $I_a - I_c = 1.73 I_a = 1.73 I_c$. Many digital relays do not compensate for the increase in current magnitude so that overcurrent relaying within the digital relay package being supplied from these same CT's must be compensated by setting the relays 1.73 higher. Relay metering also is incorrect by the same value. This has been a source of confusion in some applications. There are, however, manufacturers that do compensate and provide overcurrent and metering with correct magnitude line currents.

Percentage restraint slope is a concept that is universally used in both E-M and digital relays to provide security against false operation during through-faults. It is recognized that the higher the through-fault current, the greater the possibility is that mismatch in CT performance will cause a false differential error current. In percentage restraint differential relays, the higher the through-fault current, the greater the value of differential current it takes to operate the relay. Fig. 9

illustrates this concept for a digital relay. The operating current (I_o) is the vector sum of the primary and secondary per unit currents. Per unit current (pu) in differential relays is the CT current on the primary and secondary divided by the relay tap setting for that winding. The differential relay pickup must be set above steady-state transformer magnetizing current and generally is set in the 0.2 – 0.3 pu range.

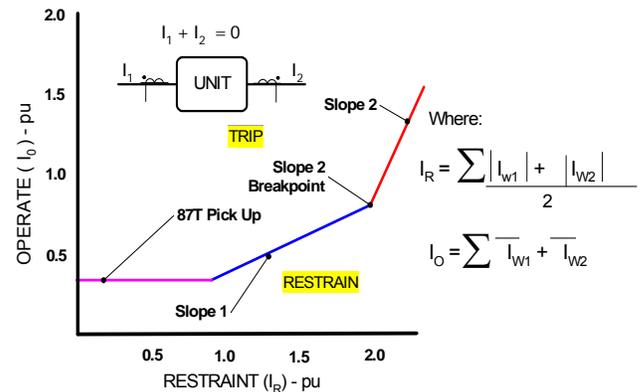


Fig. 9 Digital Relay Dual Slope Characteristic

As shown in Fig.9, the higher the through-fault current, the higher the value of the restrain current which is the sum of the primary and secondary pu current magnitudes divided by two. Some relay designers use the larger of the two winding currents rather than the average of the two windings as the restrain current. The higher the restrain current the more operating current it takes to cause the differential unit to trip. Almost all digital transformer differential relays use the dual slope approach. At a settable breakpoint (usually 2.0 pu restrain current), the slope is increased from slope 1 to slope 2. Slope 1 is set based on expected CT error (typically 10% for C class CTs), LTC tap range (usually 10%), magnetizing losses (about 1%) and a safety margin (about 5%). Thus, for a transformer without LTC, the slope 1 setting is typically 15-20%. For LTC transformers, the slope 1 setting is set higher to accommodate the ratio change with typical settings of 25-30%. The slope 2 setting is usually double the slope 1 setting. The quality of the CTs used to supply transformer differential relays generally requires that they operate in their linear range for worst case symmetrical through-faults. A CT burden calculation can be done to verify linear operation. In addition, manufacturers generally provide specific guidance on minimum CT quality based on through-fault current levels.

Harmonic restraint is used within transformer differential relays to provide both inrush and overexcitation restraint. Inrush restraint is required when a transformer is energized. The transient magnetizing current to energize the transformer can be as high as 8-12 times the transformer rating. With high current in the primary winding and no current in the secondary windings, a high differential current will result. The transformer differential relay sees this unbalance as a trip condition. The magnitude of inrush current depends on the residual magnetizing flux in the transformer core, the source impedance and the point on the voltage wave when the circuit breaker contact closes. When the circuit breaker closes, all

three phase contacts close at approximately the same time. The three-phase voltages, however, are displaced from each other by 120°. Thus, two of the phase voltages will be near maximum while one is near zero voltage. This imbalance in voltages results in inrush currents being unsymmetrical in each of the three phases. Inrush current is not entirely 60 Hz sinusoidal current but comprised of a significant level of even harmonics—the most dominant being the 2nd harmonic. For over 50 years, relay designers have used 2nd harmonic restraint to prevent false differential operation on transformer energizing. Most digital relay designers also used 2nd harmonic for inrush restraint. Digital relays are also designed so that the 2nd harmonic in all three phases are combined in some manner to restrain the differential.

Today, newer transformers are being built with low loss steel cores, which result in much less 2nd harmonic current on energizing. This has caused differential relay tripping during energizing. At least one digital relay designer has reinforced the 2nd harmonic restraint by also adding the 4th harmonic which is typically around 40% of the 2nd harmonic.

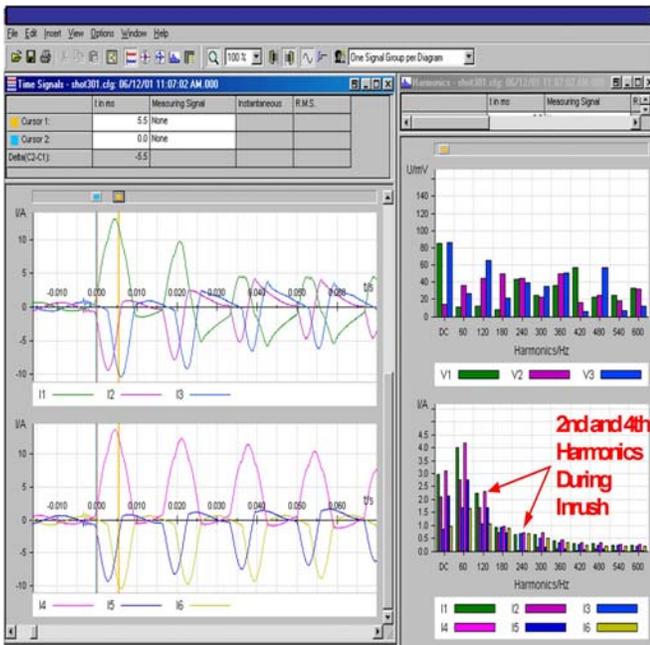


Fig. 10 Typical Transformer Inrush and Harmonics

This design improved inrush restraint for low loss steel core transformers. Fig. 10 shows inrush current for a typical transformer and the relative level of 2nd and 4th harmonic content. Programming a digital relay with too low an inrush restraint setting, risks the relay restraining for an internal fault because CT saturation can also produce significant levels of even harmonics. Transformer relays are equipped with a non-harmonically restrained high set differential element (87H) that provides protection for high current magnitude internal faults where CT saturation can occur. This element is set above the expected inrush current.

Harmonic restraint is also used to prevent the transformer differential relay from operating during overexcitation events. Overexcitation occurs when the volts per hertz (V/Hz) level rises significantly, resulting in transformer saturation. Transformer core flux is proportional to voltage and inversely

proportional to frequency. Overexcitation events can occur at an industrial facility during major system disturbances when industrial load is isolated from the utility system and is supplied from on-site generation. When a transformer is saturated, excitation current, which is normally very low, increases and unbalances the differential causing it to operate. Protection is required for overexcitation events, but the differential relay operation occurs so quickly that power system voltage control devices, such as generator automatic voltage regulators (AVR's), are not given enough time to operate to correct the problem. When a transformer is overexcited, a significant amount of 5th harmonic current is generated. This harmonic is used to restrain the differential from operating. Most digital relay manufacturers block relay operation when the 5th harmonic exceeds a specific value—generally around 30%. Because the transformer is under stress during overexcitation, one manufacturer thought it more prudent to desensitize the relay rather than block its operation. This is done by raising the pickup when the 5th harmonic exceeds a specific value, which is settable in the relay. Fig. 11 illustrates how the relay's slope is modified during overexcitation conditions.

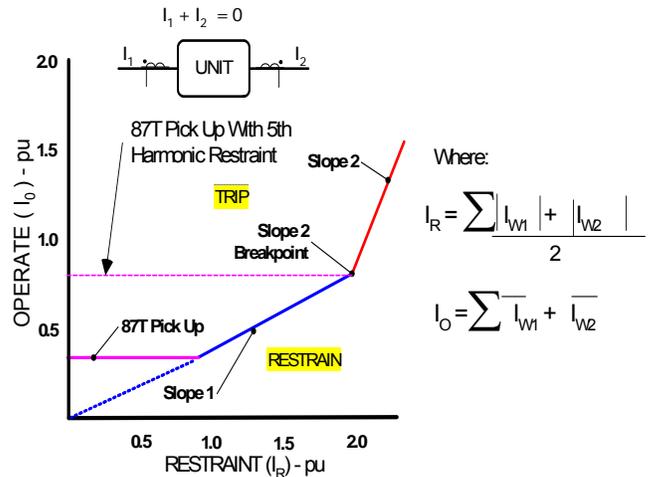


Fig. 11 5th Harmonic Slope Modification

Overexcitation of a transformer can damage the transformer if the event is allowed to persist. Overexcitation results in excessive core flux resulting in a high interlamination core voltage, which, in turn, results in iron burning. Also, at this high flux level, the normal magnetic iron path designed to carry flux saturates and flux begins to flow in leakages paths not designed to carry it, again causing damage. Fig. 12 illustrates this flux path.

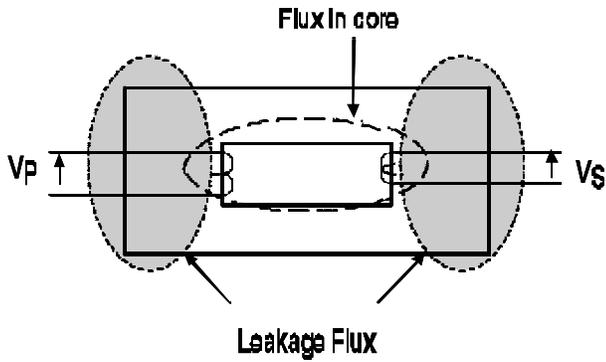


Fig. 12 Overexcitation Transformer Core Flux

The continuous overexcitation V/Hz transformer capability is specified in IEEE C57.12.00 standard [3] developed by the IEEE Transformer Committee. It specifies a 1.05 pu (on the transformer secondary base) at rated load and 0.8 PF or greater for loaded transformers. The short time capability varies based on transformer design.

Protection for overexcitation is provided by relay function (24) within a digital relay. This function measures the ratio of V/Hz. It is important that this function be implemented when protecting transformers with a digital package since digital relay differentials, unlike earlier E-M relays, are designed not to operate for an overexcitation event leaving the transformer unprotected. E-M relays provided only discrete time element V/Hz protection. Digital relays offer an inverse time curve that closely matches most transformer overexcitation capability curves as illustrated in Fig. 13.

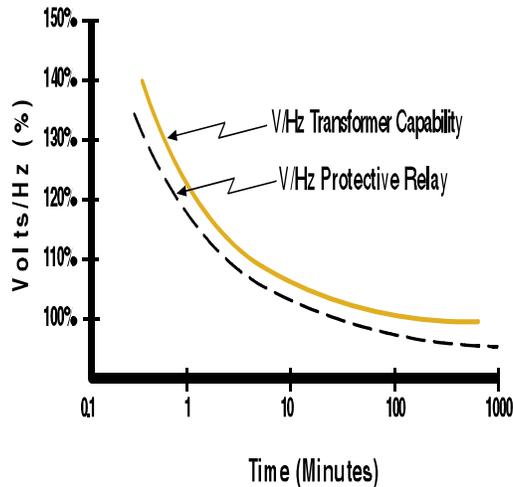


Fig. 13 Typical Transformer V/Hz Short-Time Capability

B. Ground Differential (87GD) Protection

Industrial transformers are generally grounded through a resistor in the transformer wye neutral as described in Section II. Many industrial transformers rely solely on the phase differential (87T) to provide ground fault protection. Some industrial engineers do not understand that phase differential protection alone does not provide the level of sensitivity to detect faults over the entire wye winding. A significant portion of the wye winding near the neutral will not

be protected if only phase differential is applied. Even for ground faults on the transformer wye terminal, additional sensitivity is required where ground fault current is limited to 200-400A range. Consider the following example shown in Fig. 14.

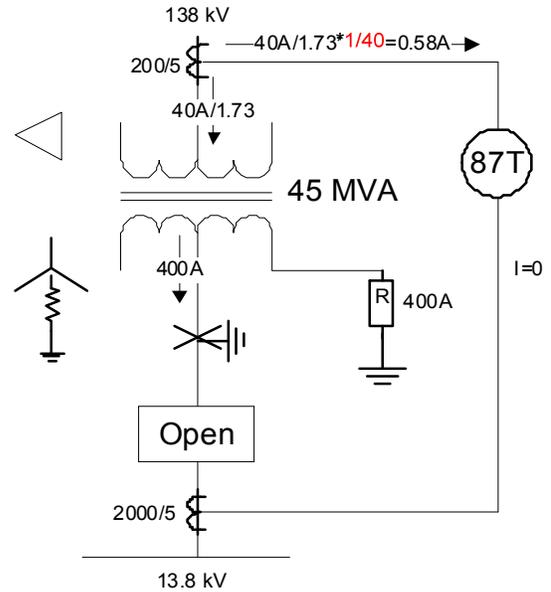


Fig.14 Example of Secondary Ground Fault

Example: A 45 MVA, 138/13.8 kV transformer with 200/5 138 Kv CTs and a typical 87T relay pickup of 0.3 pu. Fig. 3 illustrates the current distribution for a delta-wye transformer ground fault. The relay tap is set at the 45 MVA transformer rating (Tap = 4.71 A secondary amps) and can only respond to a fault of 1.41 A (4.71 A X 0.3 = 1.41 A). The ground fault current (0.58 A) is below the threshold of operation of the 87T phase differential. Sensitive detection of secondary ground faults can be substantially increased through the addition of an 87GD ground differential relay, which uses a product approach, utilizing the following equation. The relay-operating characteristic is:

$$I_{OPP} = (-3I_0) / N \cos \Theta$$

Where:

- 3I₀ = residual current from the bus side CTs
- N = transformer neutral current
- Θ = phase angle between the currents

The ground differential sensitivity is very low and will operate for an In current of 0.2 A. Fig. 15 illustrates the zone of operation where the 87T relay cannot detect ground faults. In many cases, the 51G neutral time overcurrent relay provides time delay protection for faults in this zone.

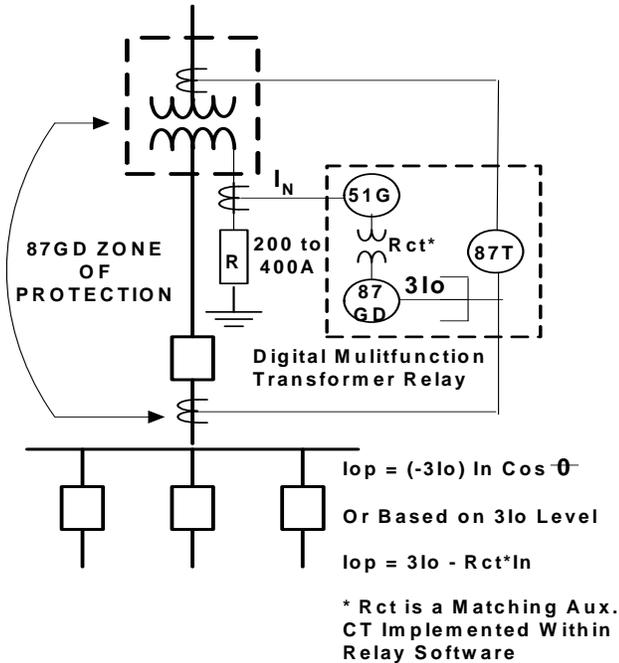


Fig. 15 Transformer Digital Ground Differential Relay

High-speed protection can be provided by use of a product type ground differential relay described above. The concept was available in E-M technology and is now available in digital transformer protection packages. For faults external to the protective zone, the net operating quantity is negative and the relay will restrain from operating. For low values of $3I_o$, the relay automatically switches from a product to a balancing algorithm ($3I_o - R_{ct} I_n$). This allows it to detect internal faults when the low-side transformer breaker is open as in Fig. 14. R_{ct} is a ratio matching auxiliary CT, which is provided as part of the software algorithm in digital relays as opposed to being an actual CT as it was in E-M technology. This scheme provides excellent security against mis-operations for external, high-magnitude faults, even for cases where the phase CTs saturate. There are, however, some digital relay manufacturers that try to employ only a simple differential ($I_n - 3I_o$). This method is prone to mis-operate during high magnitude through-faults. Transformer ground differential relaying substantially improves transformer ground fault sensitivity and is recommended in the Buff Book [4]. The example described above actually occurred at a paper mill where the fault was caused by a human contact. High-speed protection for this event was extremely important and was provided by the digital ground differential that was recently installed on the transformer.

IV. APPLICATION AND COMMISSIONING OF DIGITAL TRANSFORMER RELAYS

Multifunction transformer digital relays have features that were not available on electromechanical or static relays. These include: oscillography and event recording; multiple setting groups; multiple output and input contacts; metering; monitoring of external inputs/outputs; communications; self-monitoring and diagnostics and programmable logic. These

are the features that make digital relays the technology of choice for the protection of transformers. Many of these features also add to the complexity of setting and commissioning of these relays.

The design of modern digital relays is such that all voltage and current inputs are multiplexed through common components. If a component fails, generally all protective functions within the multifunction relay are inoperative. The industrial facility engineer must be aware of this fact in deciding the level of redundancy for a particular application. For the protection of important generators or transformers, the effect on the system of removing these components from service for a relay failure may be unacceptable. In those cases, dual digital relays are used. A typical dual protection scheme for a transformer is shown in Fig. 16. Full input redundancy can be achieved by using separate CT and VT inputs for both primary and backup relays. Because of practical limitations, many users supply both primary and backup relays from the same CT and VT circuits. Using the multiple digital output contacts to trip the high and lowside breakers directly and also trip the lockout relay can provide output redundancy. This provides tripping even if the lockout relay fails. Also, some users reduce the functionality of the backup relay. An example of this is the use of overcurrent relaying as backup for transformer protection rather than fully redundant differential relaying as illustrated in Fig. 16.

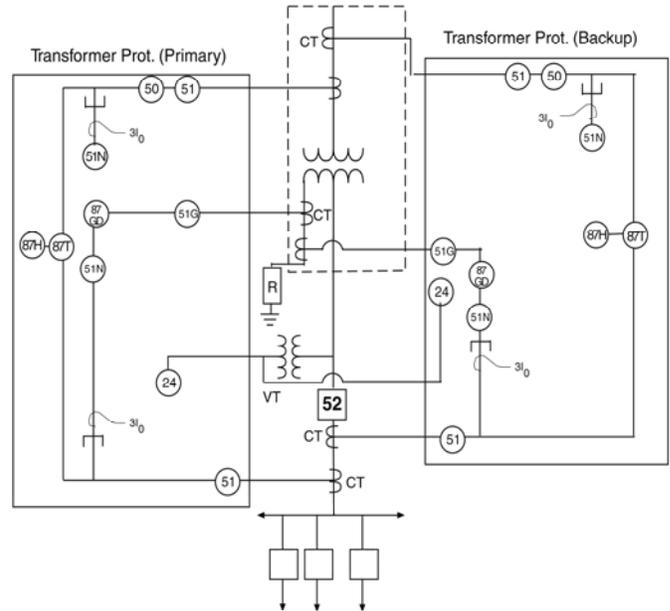


Fig.16 Dual Relay Transformer Protection

A. Testing Digital Relays

Testing multifunction digital transformer relays offers some unique challenges to the user. Multifunction relays have protective functions that interact with each other, making testing more complicated. They can also be programmed to do control logic, which must be verified. In addition, digital relays can have multiple setting groups that may be switched to address varying system conditions. This flexibility

increases the commissioning complexity. These relays also have significant input monitoring capability that can greatly assist the user in determining whether these relays are properly connected to their CT and VT inputs, helping to verify that the relay is functioning properly.

Digital relays also have self-diagnostics that check the health of the relay that can immediately detect internal failures. This is perhaps the most important single feature in digital relays. The ability to detect a failure before the protection system has to operate contrasts with traditional protection where a failed or defective relay remains undetected until it does not operate correctly during a fault or until the next maintenance test. It is important that the completeness of self-diagnostics be considered in developing a maintenance/test program for multifunction digital relays and that relay failure be alarmed to a manned location so that personnel can immediately take appropriate action.

B. Commission Testing

Commission testing of digital transformer relays still requires the test engineer to verify the proper setting, internal logic and operation for a new installation or verify a setting/logic/control change at an existing installation. This typically requires:

1. Injection of current and voltage into the relay to verify relay setting and timing
2. Verification of proper relay inputs and outputs
3. Verification of proper relay logic
4. Verification of tripping and targets

Clearly communicating settings to the relay is the first step in the field commissioning process. Simple and straightforward setting screens are important and not all relay manufacturers provide setting screens that clearly show how the desired setting should be communicated to the relay. Section II of this paper discusses communication of the phase shift. Problems in properly communicating the desired setting to the relay are a frequent source of errors.

Relay screens can also be used to provide valuable information to the field test engineer to confirm that the relay is connected to trip the proper outputs and all protective functions that have been specified to be in service are, in fact, programmed to be in service.

Summary screens are particularly important because, during the injection testing processes, it is necessary to temporarily disable interfering functions to test the desired function. These screens provide positive feedback that all desired functions have been returned to service after testing.

Determining that the phasing and current balancing of the phase differential 87T is correct is a major part of commissioning a digital transformer relay. Again, graphics in the relay can provide major help to determine if the relay is wired correctly or that the settings are resulting in proper balancing of input and output currents. Fig. 17 illustrates “built in” digital phase angle meters within the relay that look at both the input currents as well as the internally compensated currents. These meters provide positive indication that the relay is properly set and wired. If there is a problem, it will point the commissioning engineer to the root cause: wiring external to the relay or improper setting within the relay. This

is a powerful commissioning tool that has proven its value in numerous installations.

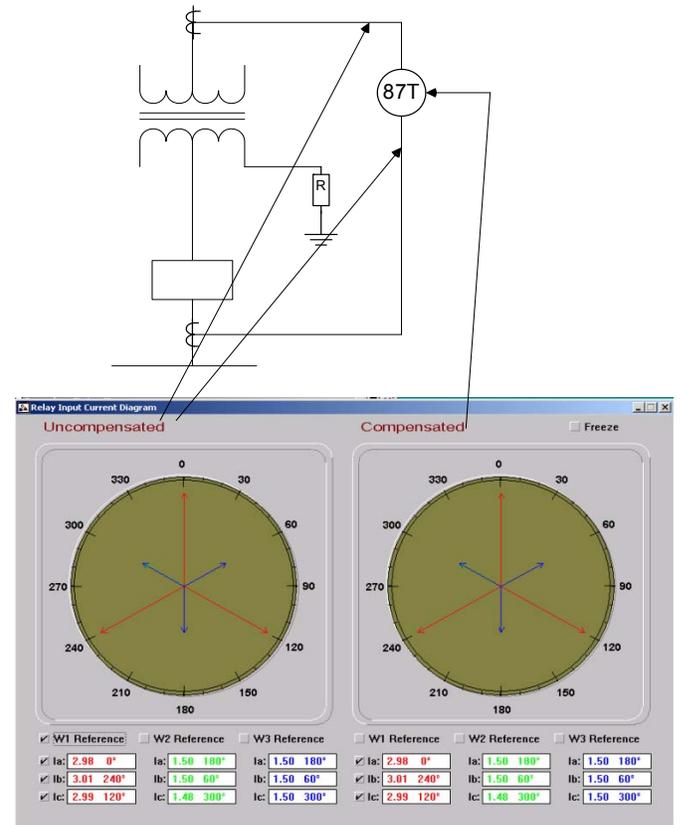


Fig. 17 Relay Phase Angle Measurements

The commissioning tools cited above are one of the major advantages of digital relays and the graphics used to communicate to the user is a major difference between manufacturers with some doing a better job than others. Clear, user-friendly graphics reduce the relay complexity, commissioning and setting errors.

V. CONCLUSIONS

Selecting, setting and commissioning of new multifunction transformer digital relays offer unique challenges to the user. The advantages of numerous relay functions being available in a single hardware platform are offset to some extent by the need to provide for the failure of that platform. Also, it makes testing more difficult.

Digital relays reduce external control wiring required by E-M and static relay technologies by incorporating control logic within the relay itself. This, however, results in more complex relay testing to verify proper relay control logic. These shortcomings, however, are far outweighed by the many advantages of digital relays cited in this paper. Users also have seen the many benefits of digital relays with almost all new installation using this technology.

VI. REFERENCES

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VII. VITA

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