

Transformer Tank Rupture – A Protection Engineer’s Challenge

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Introduction

According to a recent draft IEEE PC 57.156 Guide for Tank Rupture Mitigation of Liquid Immersed Power Transformers and Reactors published by the IEEE PES Transformer committee “There are combinations of arc energy, location, and duration which overwhelm the capacity of the standard pressure relief to protect the tank. It has also been demonstrated, theoretically and from field tests, that for low impedance faults with energy levels susceptible to cause the rupture of the tank, the rate of pressure rise is too high and the Pressure Relief Device (PRD) have, at best, little effect in preventing the rupture.” Later in the document, in Annex B, titled “Other Items Relating to Prevention of and Responses to Arcing Rupture”, under the heading Transformer and System Design Considerations it states.. “Inclusion of an appropriately rated protective relay may allow for prompt isolation from the energy source of the fault.” The ball seems to be in the protective relay engineer’s court.

Expensive, and in many cases unrepairable, ruptures of power transformer tanks are caused by lengthy clearing of internal faults which can be avoided with the choice of the correct protection algorithm. Insulation of power transformer winding can break down at any time, causing significant ground fault current, especially in strong and solidly grounded power systems, as is the case with most power transmission systems. Slow clearing of the internal fault can lead to tank rupture, and potentially spilling tens of thousands of gallons of oil causing fire, and a horrendous environmental cleanup. If this happens, many power companies generally prefer to replace the faulty transformer, rather than attempt to fix the tank with an unpredictable result. Both replacement and repair are costly.

This paper will review the tank rupture phenomena, present a protection method to help alleviate tank rupture, and use real world operational data from the same power system both before and after application of the proposed protection. Applying the protection algorithm can be expected to produce a significant drop in tank rupture, in comparison to applying the traditional differential protection scheme.

Tank Rupture

The power transformers are cooled by mineral oil to dissipate heat loss generated from core and winding parts into the outside air. If the oil or the other insulation material loses its dielectric properties due to oil pollution or ionization, an electrical arc may occur in an oil-filled transformer and a large volume of gas is generated by the arc decomposing the oil under high heat, this results in the rapid increase of tank pressure [4]. The pressure rise generates pressure waves that propagate inside the oil and interact with the tank structure. This wave and structure interaction eventually leads to the tank rupture and possible transformer explosion. These explosions make an outflow of a large amount of oil and may also cause a fire by the contact of hot combustible gas with oxygen in outside air, which will have serious consequences to environment. Very deep concerns about public hazards exist because many substations are located very close to residences and underground substations are increasing in the urban areas. The most effective way for preventing tank explosion is to provide sufficient tank strength in order to withstand the initial dynamic pressure peak and to equip the tank with multiple and fast acting pressure relief devices in order to discharge the developed pressure rapidly.

Electrical faults may occur anywhere in the tank when the oil and insulation material lose dielectric insulation function. The fault vaporizes the surrounding oil and creates a gas bubble due to the huge heat exchange

between the fault and the liquid oil. The growth of the bubble causes a pressure increase near the fault that propagates in the tank. The internal pressure of the tank increases continually until tank rupture takes place at the weakest position from the near of fault location.

Tank rupture is a very complex phenomenon to investigate - arc testing is cost-prohibitive and, moreover, random in nature. An important R&D program was therefore initiated in 1985 with an aim to develop a fundamental understanding of the rupture mechanisms, the efficiency of pressure reduction devices and the feasibility of containment measures. This resulted, among other things, in a sophisticated explicit dynamic calculation methodology that has been successfully applied to transformers of different sizes and designs, and continuously improved in the process. The main conclusions from this investigation were published in 1994 [5] and led more recently in 2008 to the implementation of a new arc-containment specification.

Meanwhile, the subject had been on CIGRÉ's preferential subject list in 1988-1989 and two important papers [3,4] from Japan shed considerable light on pressure venting for power transformers. Finally, in 1995, EPRI [6] released the results of an equally important research effort. It is worth pointing out that these three independent studies, although they did not have identical scopes, are in excellent agreement on all major conclusions which are:

- Pressure and deformation are significantly higher in the fault area than at a remote distance.
- The containment capabilities of present tank designs can be significantly improved by increasing flexibility and correcting weak points.
- Further improvement can be achieved but only at the expense of very large venting ducts, high-volume gas cushions and specially reinforced tanks.

Arc Energy

Pressure build-up inside the tank that eventually leads to rupture is caused by the high amount of energy released by the arc in the form of heat, which decomposes the oil into gases. The amount of gas generated has been observed to vary linearly (60-100 cc/kJ) with arc energy in experiments up to 2.64 MJ [8]. Arc energy (E_{arc}) is therefore the prime parameter in the evaluation of rupture risk. It can be calculated by the expression:

$$E_{arc} = 0.9 V I t \quad (1)$$

Where: V , I , and t are the arc voltage, current, and duration respectively. The factor 0.9 is introduced due to take into account the arc voltage typically has a square waveform.

For most systems, arc current can easily be evaluated by the short-circuit levels, and duration by the type of protection (relay and breaker) but difficulties arise in the evaluation of arc voltage. In a paper written by Hydro Quebec (7) The paper suggests the simple estimate of 100V/cm is too low for arc voltage. After numerous tests they concluded that the arc voltage for internal faults under oil reached values greater than 40kV. This higher values was attributed to the increased pressure due to gas generated during the arc. A more accurate expression for the arc voltage was proposed to be:

$$V = 55L\sqrt{P} \quad (2)$$

Where P is the absolute pressure (Atm), and L is the arc length in cm.

Containment

Pressure buildup following an arc inside a transformer depends on the volume of gas generated by the arc and the tank expansion characteristics. A simplified expression was first proposed by [3]; it is based on the conservative assumption of an isothermal expansion of the gas bubble. Equation (3) and Figure 2 present a modified version which includes different arc parameters and a more elaborate dynamic amplification factor than the single value suggested in (4)

$$Ps = F \left[100 \sqrt{\frac{1+KE}{4}} - 50 \right] \frac{100C}{V}$$

Where:

Ps: calculated tank pressure (kPa)
 E: fault energy level to withstand (kJ)
 k: arc energy conversion factor ($=5.8 \times 10^{-4} \text{ m}^3/\text{kJ}$)
 C: tank expansion coefficient (m^3/kPa)
 V: volume of oil in main tank (m^3)
 F: dynamic amplification factor (Figure 2)

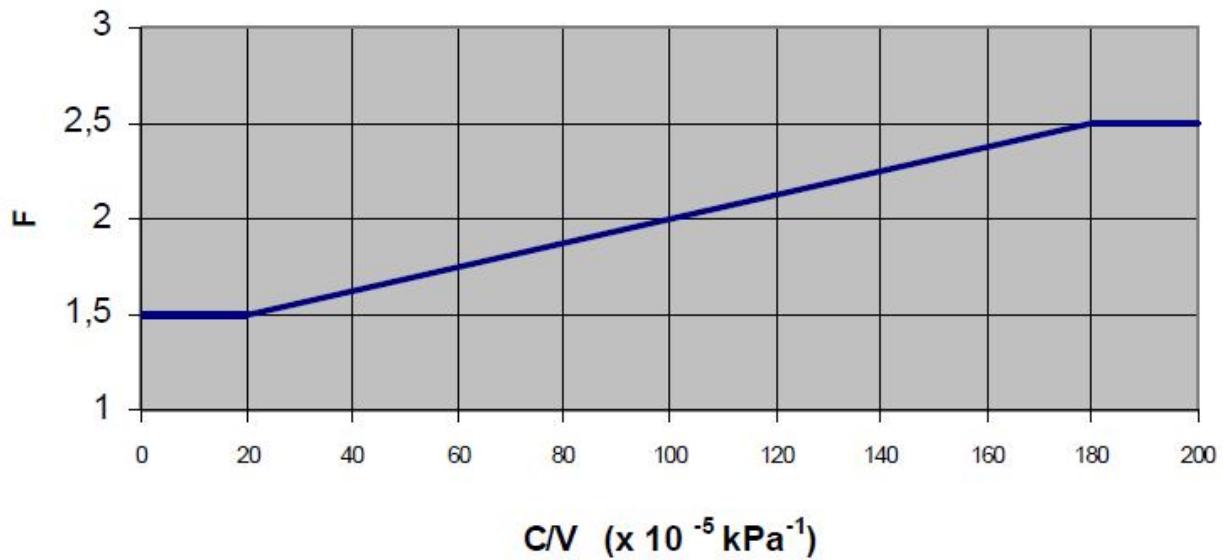


Figure 2 Calculation of Maximum internal pressure [5]

Factor k is based on experiments [7] which suggest a gas generation rate of 85 cc/kJ at an average temperature of 2000°K. This represents about 24% of arc energy transferred into enthalpy of the gas bubble. Given that all tanks are designed to withstand about 100 kPa (vacuum) without plastic deformation, one can evaluate the ultimate rupture pressure somewhat above 200 kPa.

Voltage (kV)	Lower	Upper
735 three phase	4.0	10
735 single phase	3.0	7.0
315	3.5	8.0
230	3.5	6.5
161	3.0	6.0
120	2.0	4.0

Figure 3
Approximate range of arc energy containment for conventional transformer tank designs [7]

Venting

Many transformers are equipped with pressure relief devices to prevent accidental overpressure during the oil-filling process. Their efficiency in the event of an internal failure has often been questioned and it is generally accepted that, for low-impedance power faults, they are of little use.

While a detailed calculation of the efficiency of a pressure venting device requires much effort, a simple analysis with conservative assumptions can easily give a theoretical upper bound for the venting efficiency. If we assume that:

- the venting aperture is some distance from the arc such that only oil is vented;
- the discharge area is fully open at arc ignition;
- the discharge velocity reaches the maximum theoretical velocity instantaneously at arc ignition and remains maximum throughout the duration of the fault.

Then one can easily compute the vented oil volume and compare it to the volume of gases generated by the arc. Using the pressure equation described previously to compute the pressure levels for both vented and non-vented cases, the efficiency of venting can be expressed in terms of % of peak internal pressure reduction. For example, a typical 100-MVA modern tank design (flexibility C = 0.0066 m³/kPa) and an arc duration of 3 cycles has been considered for different venting apertures and arc energies below. Maximum theoretical peak pressure reductions that can then be achieved by venting are summarized in Figure 4.

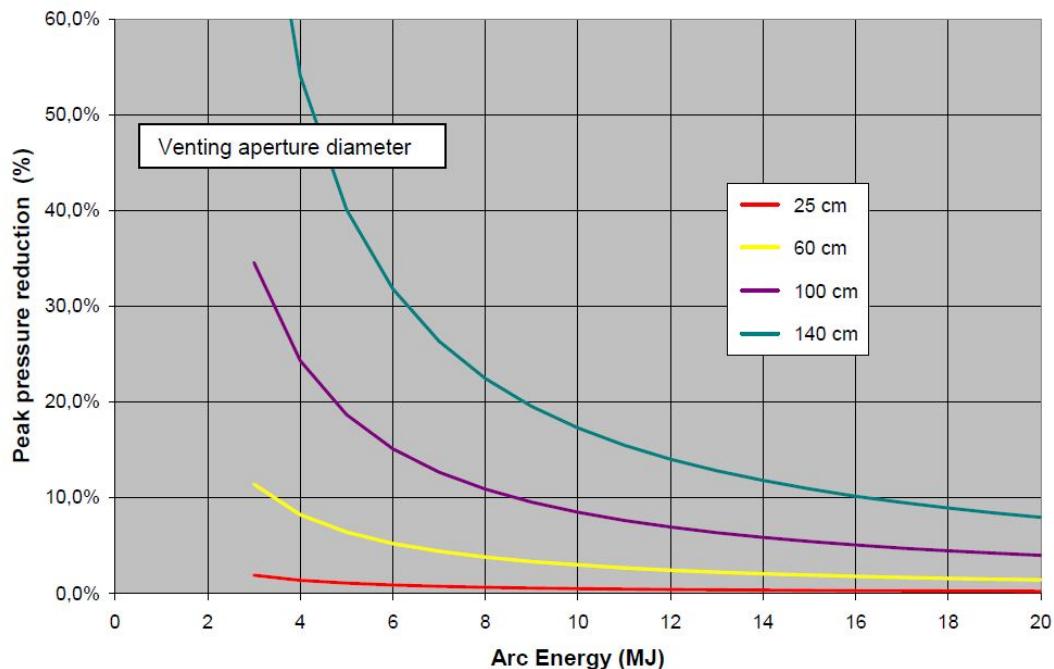


Figure 4
Upper bound of pressure reduction for different aperture diameters

It can be seen that for this typical power transformer in its estimated range of containment capability (3-7 MJ):

- Required aperture for a significant pressure reduction (say 30%) should be at least 140 cm.
- Pressure reduction that can be expected from a 25-cm aperture is less than 3%.

Flexible Transformer

Another method to reduce the chance of tank rupture is to modify the tank such that it is flexible and can withstand the rise in pressure from an internal fault and subsequent gas generation.[8] The example below show a 20 M joule arc energy event. The risk of tank rupture is mitigated by much lower tank stresses with a flexible tank versus a rigid tank.

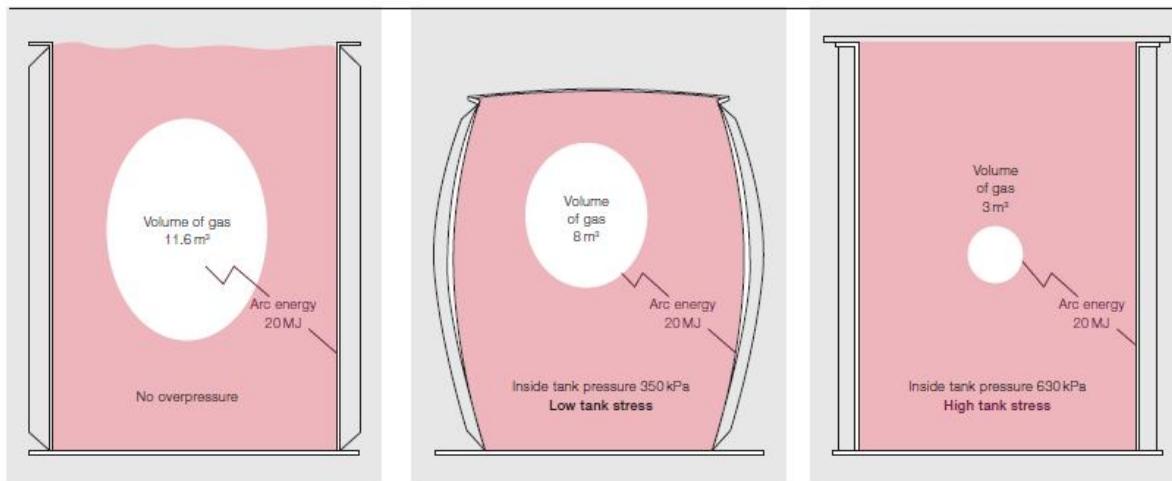


Figure 5a
Open tank

Figure 5b
Flexible tank

Figure 5c
Rigid tank

The idea behind this concept is to absorb a certain arc energy in a deformation of the tank figure 5. The tank is designed to rupture above this defined energy level. For safety reasons, the

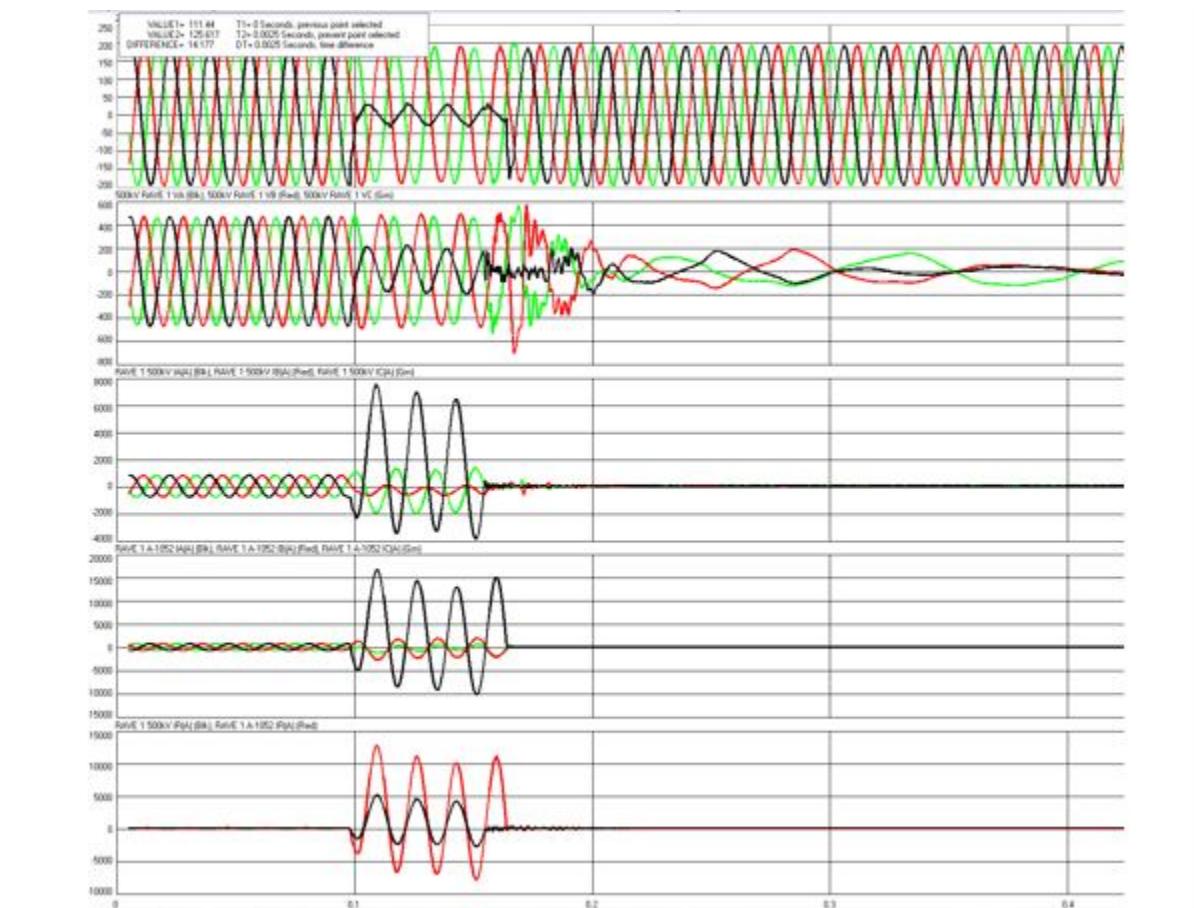
point of rupture is typically arranged to be at the edge of the cover, making dangerous ejections and major oil spills less likely.

The flexible tank solution is better than a pressure venting approach – eg, rupture disc or large-volume expansion chamber as it became clear from studies that even a large venting area of 1.0 to 1.5 m² would reduce the peak pressure by only 10 to 30 percent during an internal arcing fault – insufficient to mitigate the tank rupture risk under normal circumstances. [7]

Tank rupture mitigation with protective relays

Now that we've looked at what can mechanically done to help mitigate tank rupture, let's look at what can be done from a protection engineer's perspective. There are several methods that have been used to detect faults in a power transformer; overcurrent, differential, and impedance relays to name a few. For brevity, let's limit the discussion to the transformer differential relay (87T), and the Restricted Earth Fault (REF) which have promise to give us the greatest chance to clear the fault in enough time to mitigate tank rupture. The sensitivity and security of both types of relays will be reviewed for 2, 3 winding transformers, and autotransformers.

When the tank rupture phenomena was introduced in this paper, it was said there is a direct correlation between the time the arc lasts and the chances of tank rupture. The following example for BPA illustrates this. The t fault was cleared by high speed relays and a high speed breaker. The A phase to ground fault was cleared in slightly more than three cycles. There was no bulging of the tank.



BPA Experience with Tank Rupture

From BPA's perspective, they had numerous catastrophic failures of large transformers in the past. These were usually caused by slow clearing times. Coincidentally starting in the 1990's BPA started an aggressive program to change out older circuit breakers. Some of the urgency was driven by seismic damage to live tank breakers after an earth quake. BPA started installing faster dead tank breakers. The newer 500kV breakers begin contact parting about 17ms after a trip command is given. The 230kV and 115 kV breakers are about 1 cycle slower. These faster clearing times allowed BPA the capability of reducing the total energy that is dissipated in a transformer tank during a fault. The only obstacle was the protective relay. In parallel to the breaker upgrades BPA also started testing and installing faster transformer protection relays. BPA started with some of the earliest electronic relays that had trip times in the order of 1 to 1.25 cycles. They transitioned to microprocessor based relays in large numbers only after the tripping speed was improved to match the electronic relays. Since this time BPA has had several high magnitude internal tank faults; most commonly near the base of the bushings. BPA has had no catastrophic tank failures when the transformer was protected by newer breakers and faster relays. BPA recently had catastrophic failures of a couple of shunt reactors and one large transformer. None of these had high side breakers. The two reactors had bushing faults and the fault current appeared to bypass the bushing current transformers. The transformer was tapped on a 500kV line. It had slower differential relays and needed to open four high side breakers by a transfer trip scheme at two remote terminals to clear the fault. High side breakers have been added to each of these installations and the new differential relays overlap to the breakers such that the bushings are in the differential zone of protection.

REF Protection Scheme principle

In general REF is in nature a Zero component Differential protection scheme known as 87N able to successfully handling ground faults inside protected object as grounded winding of power transformers, reactors or even more complex overall autotransformers.

The base principle of REF differential protection is shown below on Figure 6 using a typical YnD power transformer as an example.

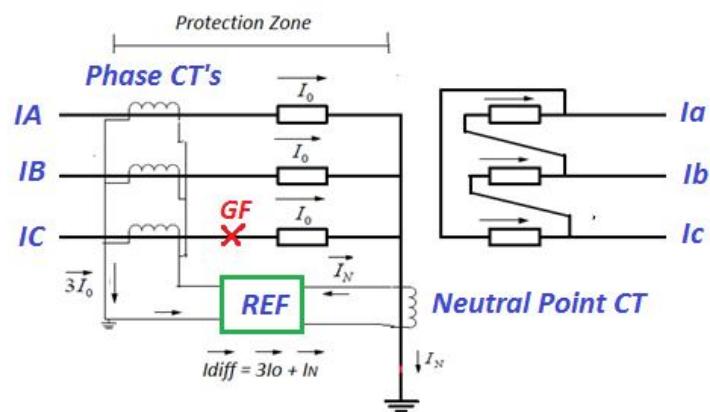


Figure 6
Restricted Earth Fault Protection Scheme

REF differential protection zone is defined/restricted by three phase CT's and a single CT in neutral point. Residual current $3Io$ is a vectorial summation of winding Phase currents.

$$3Io = IA + IB + IC$$

Physically vectorial summation is done using zero sequence filter made by connecting phase CT's secondaries in parallel. Neutral point current IN is current flowing between power transformer neutral point and station ground.

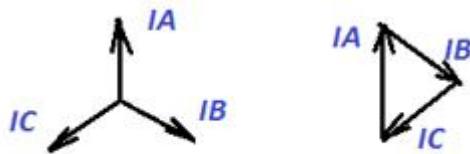
REF protection scheme operation under typical power system conditions.

Normal load condition.

REF protection system continuously performs vectorial summation of residual current $3Io$ and current through the neutral point, IN . The result of this summation is the differential/operating current, $IdiffREF$. Under normal load conditions at power system is perfectly balanced residual current, $3Io = IA + IB + IC = 0$. If no ground fault neutral point current is zero, $IN = 0$. As result differential current is zero

$$IdiffREF = 3Io + IN = 0$$

Symmetrical Load $3Io = IA + IB + IC$



As we see symmetrical load will not influence REF operation, it is insensitive on load.

External Ground Fault Condition – Ideal CT

Under external ground fault condition at the point of the ground fault Zero Voltage V_0 source will generate Zero sequence currents Io toward protected transformer and Iox toward the power system. The magnitude of these currents is dependent on the equivalent zero system impedance from both side of the fault.

From our example we can see the same zero current Io will flow through the each phase windings and its vectoral sum is equal to the residual current magnitude, $3Io$. The same current will flow through the neutral point to ground, and it is equal to the residual current $3Io$.

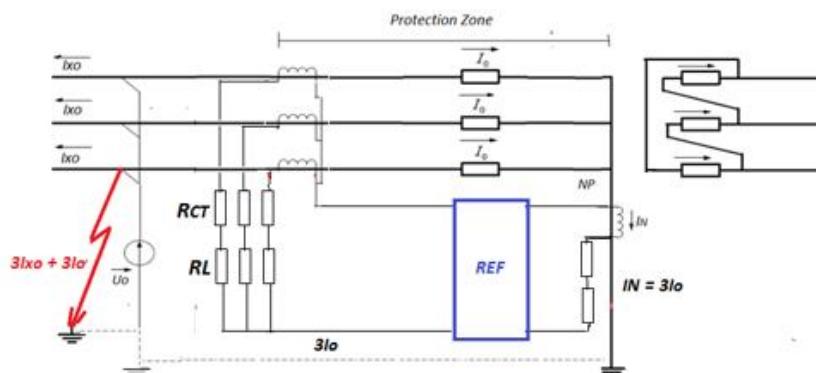


Figure 7

External Fault

With no CT saturation, both currents residual and neutral point current are equal in magnitude but are shifted for 180 degree.

$$3Io = Io + Io + Io = 3Io = IN, \text{ then}$$

REF differential current, $IdiffREF$ is equal to vector summation of both these currents,

$$IdiffREF = 3Io + IN = 0$$

Under this condition $IdiffREF$ is equal zero and REF relay will not operate.

Internal Ground Fault condition

During ground fault inside protected/restricted zone, as for external ground fault, zero source V_0 will generate zero current, I_{ox} toward power system and toward the winding neutral point neutral current, Io . These currents are different and their magnitudes are dependent on the zero sequence network impedances from both sides of the ground fault/source V_0 .

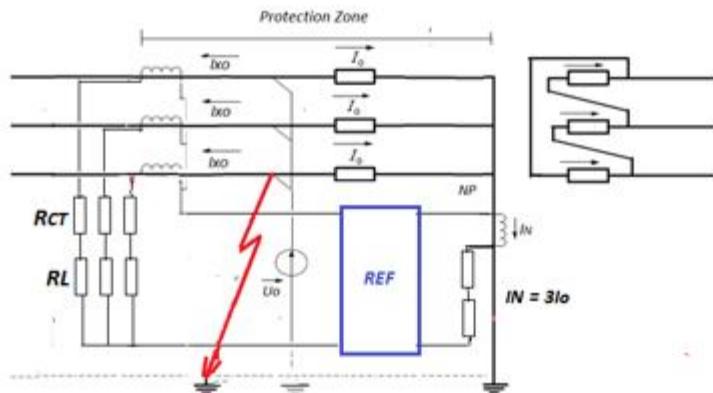


Figure 8
Internal fault

Residual current summed from phase CT's is equal to:

$$3Ix_o = Io_x + Io_x + Io_x ,$$

Neutral point current is equal to:

$$IN = Io + Io + Io = 3Io$$

Note that under this condition (Internal fault) the angle between these currents is zero.

Vectorial summation of both these currents represent REF differential current, its magnitude is:

$$IdiffREF = 3Ix_o + 3Io = 3Ix_o + IN \gg 0$$

The REF Differential element will operate.

The above analysis is true for primary currents, or if the current transformers do not saturate.

REF differential relay is a simple solution. It can be done using an Instantaneous Overcurrent Current element IOC 50 >>, set for desired sensitivity Idmin, and will be extremely fast. However, the situation is significantly changed when we consider current transformer saturation.

False Differential Currents, FDC

Iron –core current transformers generate errors in the form of excitation current over the entire operating range. It is very low under normal load conditions and in the extreme case during heavy external fault when current transformers saturate, its error reaching maximum. As error increase CT secondary output current become smaller and smaller and at saturation, CT secondary current is practically zero. As a result CT's in any differential protection scheme Including REF will always cause False Differential Current (FDC) as shown in diagram below.

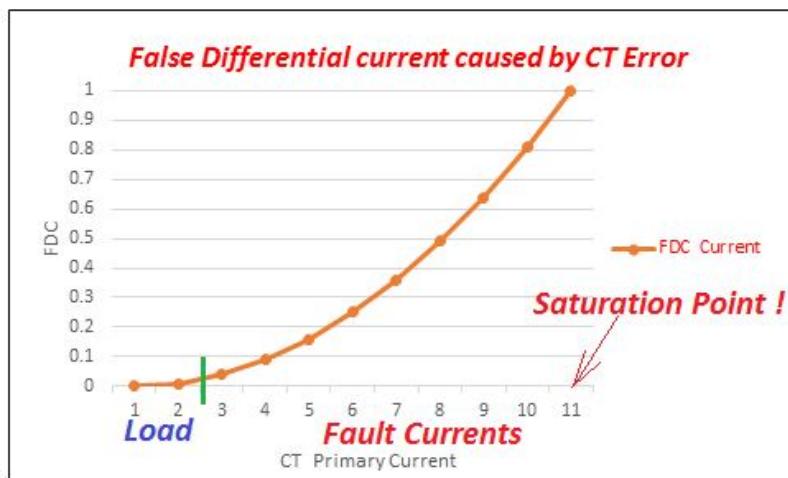


Figure 9
False differential currents due to current transformer saturation

Figure 9 shows the problem of any differential protection scheme including REF. The differential protection scheme needs to recognize current transformer saturation.

Current transformer saturation makes instantaneous overcurrent relay implementation of the REF scheme unsuitable solution. It will misoperate for any external fault when FDC become above Idmin setting. .

REF Operating Scheme/Methods

There are three distinct restrain principle/approaches/methods used to deal/solve this False Differential Current FDC problem:

- High Impedance differential method, HID
- Low Impedance Differential method, LID and
- Phasor Comparison method, PC (Fault Discriminator)

Selection of which method will be used for REF protection scheme is dependent on the application, utility practice, and the experience of protection engineers. The goal is to choose a method which be able successfully deal with FDC currents offering an optimal solutions between sensitivity and stability. This task is not easy since sensitivity and stability are highly opposed features, increasing sensitivity will decrease stability and vice versa it is simple a teeter –tauter behavior.

Phase Angle Comparison is relatively new method for application for differential protection schemes. This method is based on phase angle comparison between residual $3Io$ and neutral current IN . This method is also known as the fault discriminator as it discriminates between an internal and external fault by relative phase positions of the differential currents.

It is discussed and proposed by authors that negative sequence based phase comparator method become fully self-sustained method for REF protection scheme, rather than as supervision condition for Low Impedance Differential LID method.

REF, share all pros and cons as any other typical differential protection scheme.

All three methods will be described in the coming text, analyzing its behavior under worst case scenario CT saturation.

REF Sensitivity versus 87T differential protection scheme

For sensitivity calculation two typical two and three winding power transformers are used.

Two winding power transformer analysis

Model used for calculation is shown below.

For calculating minimum winding ground fault currents power transformer secondary circuit breaker (PCB) is open, no contribution to the ground fault current from secondary side of the power transformer.

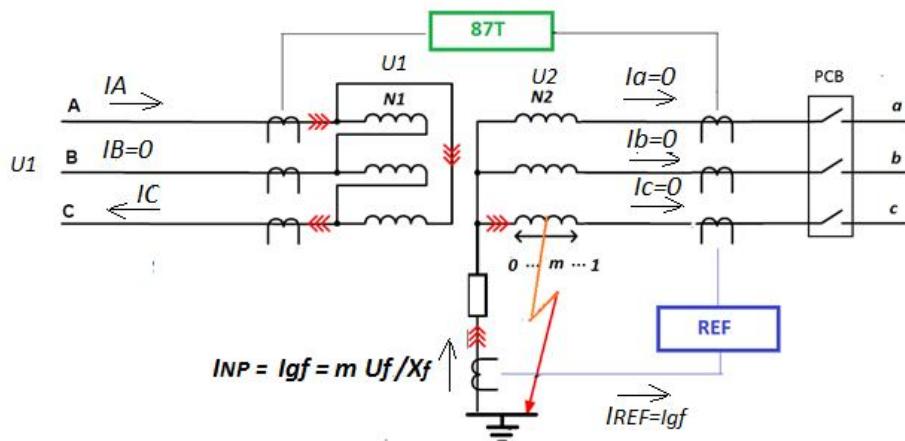


Figure 11
2 winding transformer REF

For simulated ground faults from transformer neutral point to the end of its bushing, $0 < m < 1$, Differential currents are calculated for both REF and 87T differential protection scheme using procedure shown below.

Calculation of REF and 87T differential currents

Winding ground fault current is in linear relation with fault EMF, $mxU2$ and it is the same linear relation with number m of winding turns/coils involved in the fault.

$$Igf = m \times U2ph / Zf = 3x (U2 / (Zo + Z1 + Z2)) = 3Io$$

Maximum ground fault current is at end of secondary winding N2, and it has value

$$I_{gfmax} = m \times U_{2ph}/Z_f, \text{ for } m=1$$

U_{2ph} - N2 winding phase voltage, and

Z_f - total fault impedance ($Z_0 + Z_1 + Z_2$)

Winding ground fault current as a function of its maximum value can be express as,

$$I_{gf}(m) = m \times I_{gfmax}$$

Ground fault current has a linear relation with turns m involved in the ground fault.

The same current is flowing through the neutral point due to the secondary PCB open. The contribution to this ground fault current from the secondary side is zero.

Under above conditions REF differential current is equal to this ground fault current. Current as vectorial summation is calculated as below

$$I_{dif\ REF} = I_{NP} + 3I_0 \quad \text{at} \quad 3I_0 = 0$$

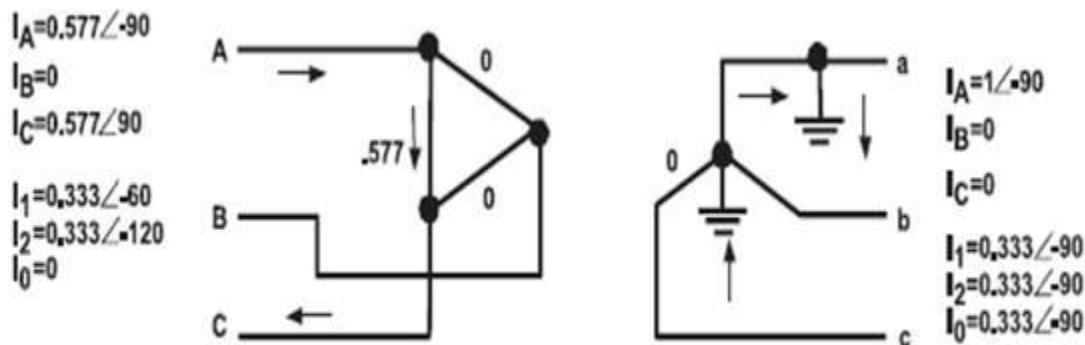
$$I_{dif\ REF} = I_{NP} = I_{gf}(m) = m \times I_{gfmax}$$

Using single CT in neutral point will connect this secondary current to REF relay.

Further, applying Ampere-Turn law we will determine current distribution through power transformer during this ground fault simulation.

$$N_1 \times I_A = m \times N_2 \times m I_{gfmax}$$

The primary winding N_1 is connected in Delta. It's two phase fault currents must compensate for single phase ground fault on the Y winding, as shown below.



Reference for current phase angles: $V_a, sec = 1∠0$, $Z_1 = Z_2 = Z_0 = 1∠90$, giving $I_{3PH}, A = 1∠-90$

Also, the relation between phase current and line current at Delta winding is $1/\sqrt{3} = 0.57$ we can write following Ampere-turn equations

$$N_1 \times I_A = m \times N_2 \times m I_{gfmax}$$

Both line currents I_A and I_B are equal and they will calculate as:

$$I_A = I_B = 0.57 \times N_2/N_1 \times I_{gfmax} \times m^2$$

These line currents, IA and IB through phase CT's are connected to 87T differential relay.

In the same time these IA and IB currents are also differential currents IdiffA and IdiffB because secondary side currents $I_a = I_b = I_c = 0$, PCB is open.

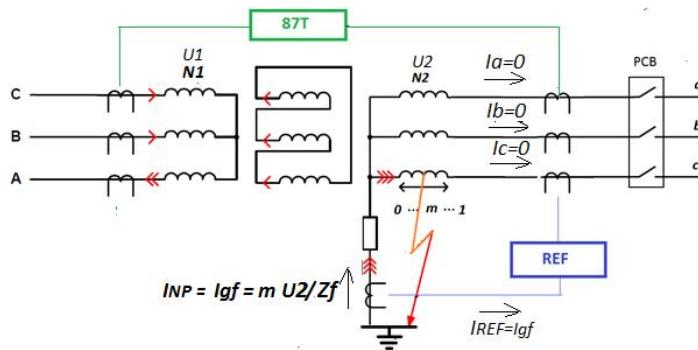
$$Idiff_{87T} = IdiffA = IdiffB = IA = IB = 0.57 \times N2/N1 \times Igfmax \times m^2$$

$$Idiff_{87T} = k \times m^2$$

As we see from above equation 87T differential current is in a quadratic relation with number of winding turns m involved in the fault.

Three winding power transformer sensitivity analysis

The similar differential current analysis is conducted on three winding transformer. The model we used is shown below.



Applying ampere-turn law it is evident following: ground fault current through $mxN2$ portion of secondary Wye winding is balanced by $2/3$ primary current through Delta winding N1 and $1/3$ by current flow through tertiary winding N3. Having PCB on secondary side open. Phase differential currents measured by 87T and REF differential relays are:

$$IdiffA = 2/3 \times (m \times N2/N1) \times m \times Igfmax =$$

$$IdiffA = 2/3 \times N2/N1 \times Igfmax \times m^2$$

$$IdiffB = 1/3 \times N2/N1 \times Igfmax \times m^2 \quad \text{and,}$$

$$IdiffC = 1/3 \times N2/N1 \times Igfmax \times m^2$$

As for two winding transformer phase Differential currents are in quadratic relation with place, m of the ground fault. Differential current measured by REF relay is the same as for two winding transformer and it is in linear relation with m ,

$$IdiffREF = m \times Igfmax$$

The above equations show significant REF relay sensitivity based on its linear relation with number of turns m involved in the fault. On other hand 87T relay sensitivity is still in quadratic relation with turns, m , but slightly increased by contribution of zero component flowing in tertiary winding.

The results for both two and three winding power transformers are presented in a graphical form shown below in figure 12. Also, presented results are shown in normalized per unit form.

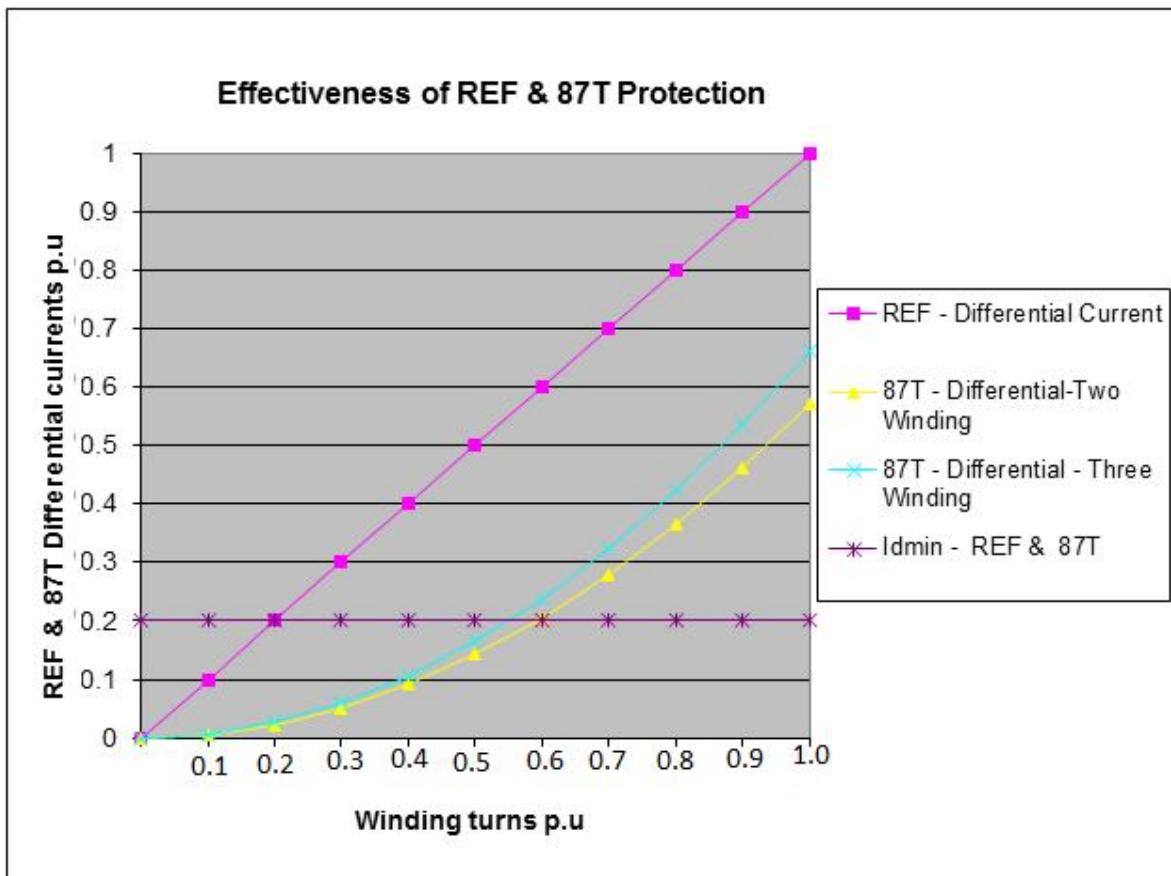


Figure 12
Effectiveness of 87T vs REF Differential relays for different fault locations

Differential currents REF – Differential (Red), 87T- Differential currents of three winding power transformer (Blue) and 87T Differential current for three winding power transformer (Yellow) are expressed in relation of winding ground faults place, practically of winding turns m (p.u.).

REF – Differential Current is linearly dependent from winding turns, and 87T Differential current is quadratic dependency from winding turns

REF and 87T pick-up value is set to 0.2 p.u. (Purple).

Results of above sensitivity analyze for both two and three winding power transformers

If both differential relays REF and 87 T are set to operate at the same operating value $Id_{min}=0.2$ pu from diagram above the following is evident.

1. REF will cover 80% of winding.
2. 87T will cover only 40 % of winding.
3. If 87T is set as typical to $Id_{min} = 0.25-0.40$ pu, then coverage will be drop to less than 30% of winding.

4. If REF is set to its maximum sensitivity $id_{min} = 0.05$ pu it will cover 95% of protected winding.
5. A three winding transformer has slightly improve sensitivity, about 50% of protected winding.

Also, since 87T differential equations are dependent from ratios N2/N1 and if N1 increases, the situation will be worse. Less of the winding will be cover by 87T differential protection.

The REF differential is independent from ratio N2/N1.

For ground faults close to the neutral point, the main protection, 87T, become insensitive and the REF becomes transformer main protection.

Due to the REF significant sensitivity and reduced operating speed versus 87T it is recommended that REF protection should be implemented in overall protection scheme of power transformers to deal and prevent worst case scenario of power transformer its rupture.

REF protection scheme for autotransformer

Figure 13 shows a typical CT's locations at an autotransformer and its connection to REF and 87T protection scheme.

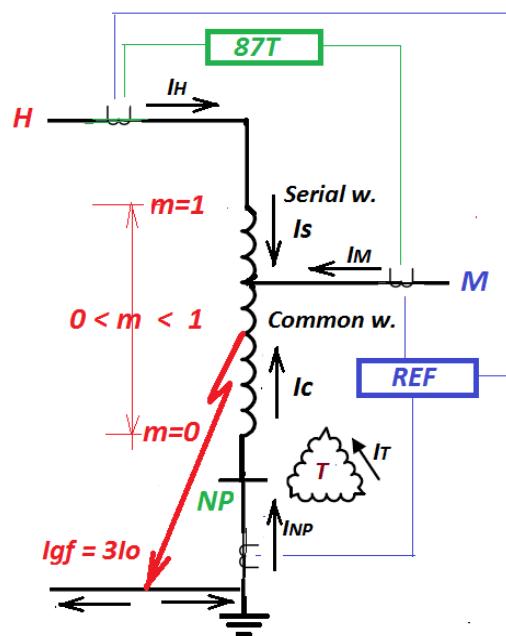


Figure 13
Autotransformer 87T and REF Protection

Restricted ground fault protection zone of autotransformer is defined by the phase CT's on High and Medium voltage side and one single CT in neutral point. Tertiary CT's are not used for REF protection scheme, even though Tertiary winding has key role in ground fault current distribution and direction through the autotransformer.

Speaking about currents distribution through the autotransformer its series, common and tertiary windings including neutral point can be very controversial but after all is true because it is simply based on transformer Ampere-turn law.

$$I_H * n_s + I_c * n_c + I_T * n_T = 0$$

Below is the theoretical background of REF protection scheme application for autotransformer, this was base for creating RTDS model we used for testing.

Vectorial summation of both side phase currents of the autotransformer will obtain residual currents $3I_{0H}$ and $3I_{0M}$ as,

$$3IHo = (IA + IB + IC) \text{ and } 3IMo = (Ia + Ib + Ic)$$

REF Relay itself will numerically calculate differential current as vectorial summation of both side residual current 3IH₀ and 3IM₀ including neutral point current IN according the following equation;

$$\text{Idiff REF} = 3\text{IH}_0 + 3\text{IM}_0 + \text{IN} = \\ = (\text{IA} + \text{IB} + \text{IC}) + (\text{Ia} + \text{Ib} + \text{Ic}) + \text{IN}$$

Analytical calculation of above fault currents and their distribution regarding ground faults simulations along series and common windings of autotransformer is a hard task, and for investigation of REF sensitivity and operation including other relevant protection devices especially which required directional criterion, it is highly recommended use numerical fault-calculation programs, RTDS model, etc..

Network Sequence connection diagram of the power system model we used for analysis/testing is shown in Figure 14. Specifically it is used for ground fault analyze at Medium side of AT.

By definition all network impedance are connected in series, and zero component current is calculated as,

$$I_0 = I_1 = I_2 = \frac{U_{ph}}{(Z_{1Eq} + Z_{2Eq} + Z_{0Eq})}$$

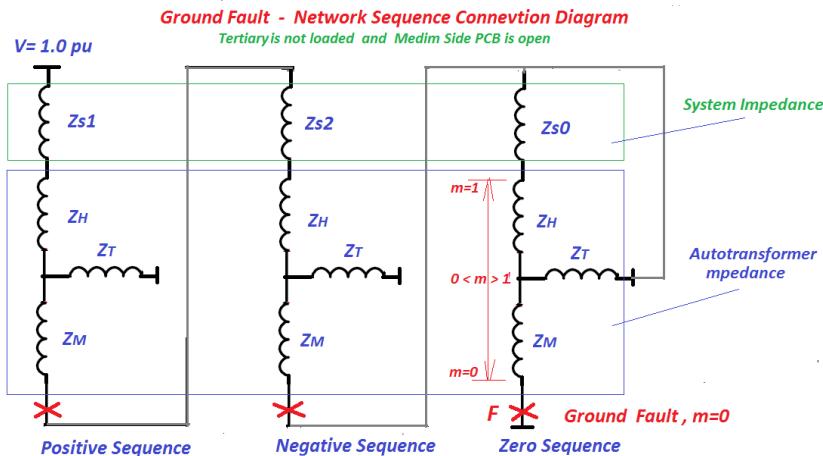


Figure 14
Autotransformer Sequence Network

For REF operation of interest is the zero current distribution through autotransformer and we will focusing our analysis on Zero sequence network in more details as shown in Figure 15.

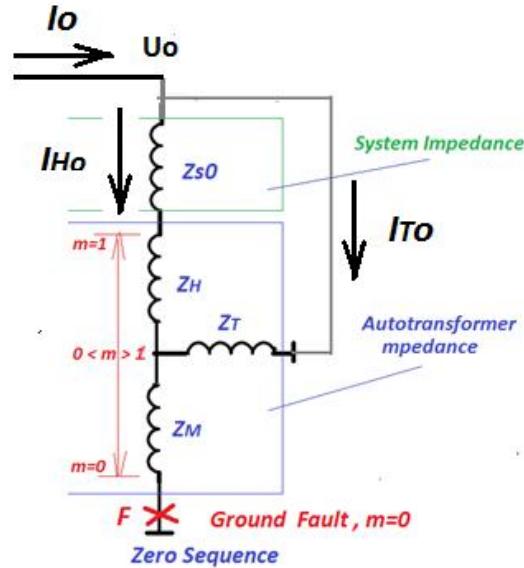


Figure 15
Autotransformer zero sequence network

Above Z_H , Z_M and Z_T are equivalent impedances of autotransformer T scheme calculated as shown below.

$$Z_H = \frac{(Z_{HM} + Z_{HT} - Z_{MT})}{2}$$

$$Z_M = \frac{(Z_{HM} + Z_{MT} - Z_{HT})}{2}$$

$$Z_T = \frac{(Z_{HT} + Z_{MT} - Z_{HM})}{2}$$

Dependent from percentage input impedance equivalent impedance can be even less than zero.

Z_{so} impedance is equivalent zero sequence impedance of power system.

Using above zero sequence scheme we can define both currents through series and tertiary winding dependent from I_0 .

$$I_{H0} = \left(\frac{Z_T}{Z_{so} + Z_H + Z_T} \right) * I_0$$

$$I_{T0} = \left(\frac{Z_{S0} + Z_H}{Z_{S0} + Z_H + Z_T} \right) * I_0$$

Also, current through nutral point will calculate as,

$$I_N = I_{M0} - I_{H0}$$

$$I_N = \left(1 - \frac{Z_T}{(Z_{S0} + Z_H + Z_T)} \right) * I_{M0}$$

Brief analysis of both equations will showing following:

- Tertiary current and Neutral point current can be zero
- Both current I_T an I_N can flow in any direction dependent from impedance Z_H and Z_{so} .

These controversial results are reasons why is critical conduct a detailed fault study. Similarly are define other sequence currents positive and negative. Using calculated sequence currents we are able create phase currents and relay differential currents for both REF and 87T. Summary of above testing methodology/algorithim is outlined in a flow diagram shown below in figure 16.

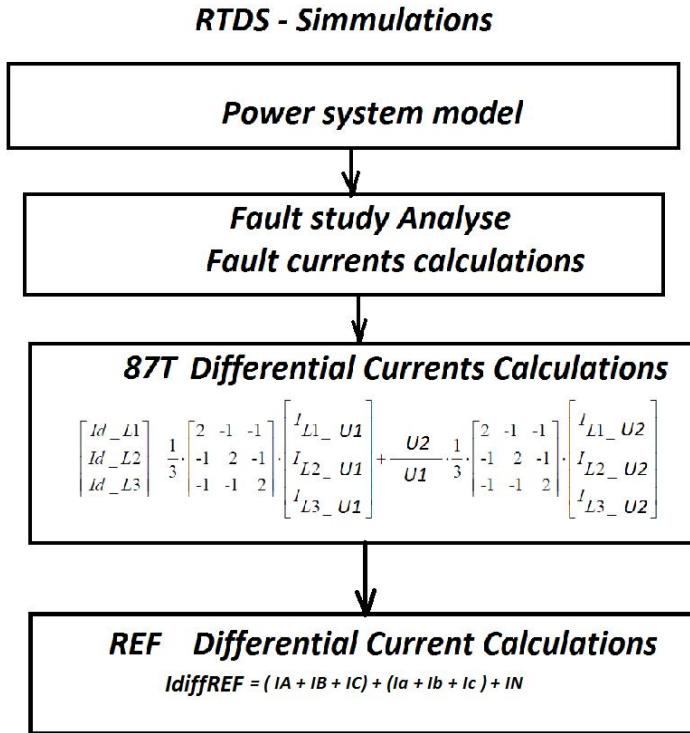


Figure 16
Flow Diagram for study

Test Results based on above testing algorithm are shown in figure 17.

Diagram in figure 17 shows REF sensitivity versus 87T for autotransformer derived from RTDS testing.

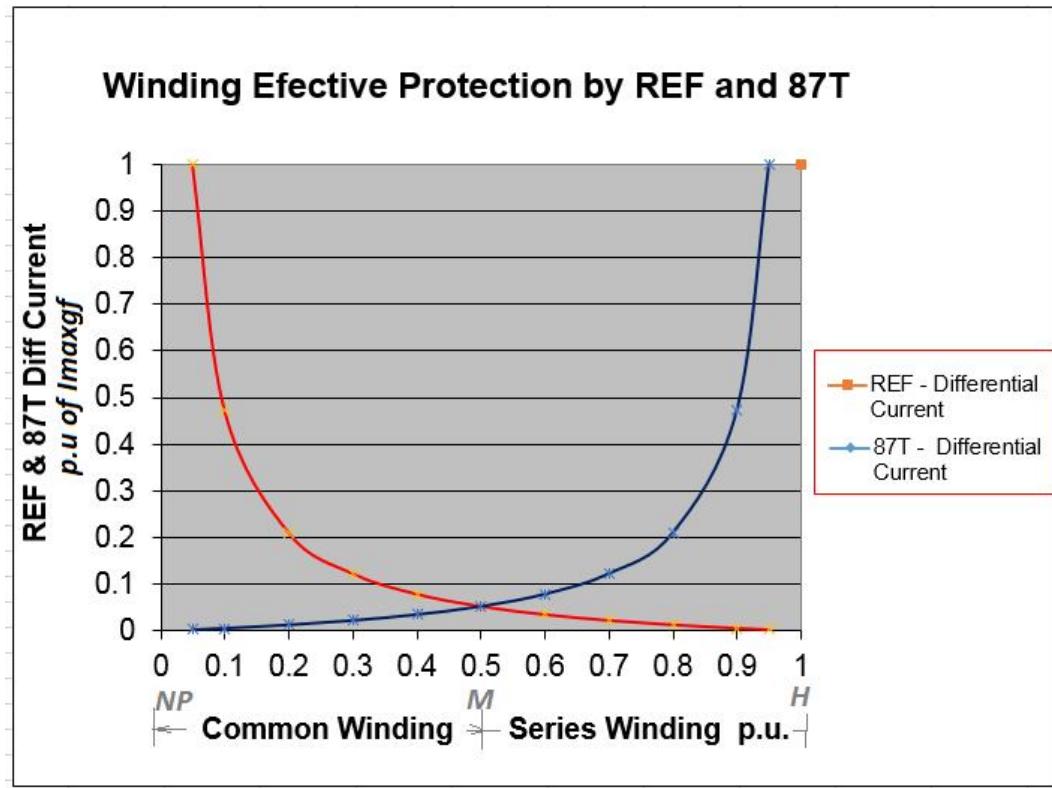


Figure 17
Sensitivity of REF vs 87T for Autotransformer

REF protection sensitivity of Autotransformer is different than for separate windings power transformer. Currents distribution through Series and Common winding are defined by Ampere-Turn balance law. Detail calculations/simulations must be based on fault simulator programs or RTDS. In a generalized p.u. diagram above is shown ground-fault sensitivity of both REF and 87T differential protections for an Autotransformer. REF protection is very sensitive along Common winding and it is reduced along Series winding. REF will very effectively protect Common winding. On other hand 87T is very sensitive for ground faults along Series winding. Phase currents are very high and 87T differential protection will easily detect and very effectively cover Series winding. Integrating both REF and 87T protection systems Autotransformer as Conventional Transformer will be optimally protected.

Autotransformer Model and its CT Connections to REF protection relay.

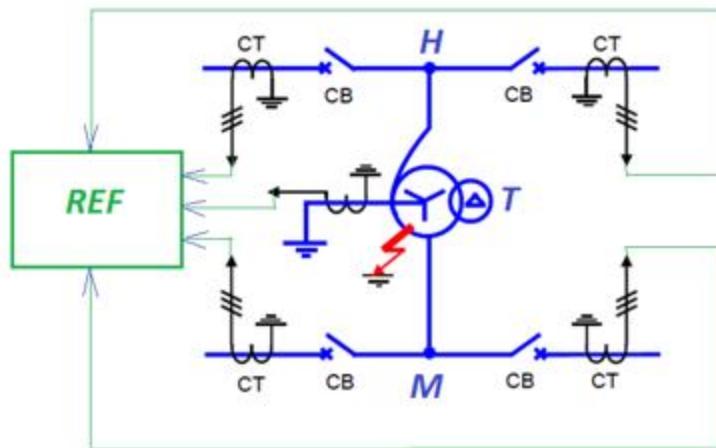
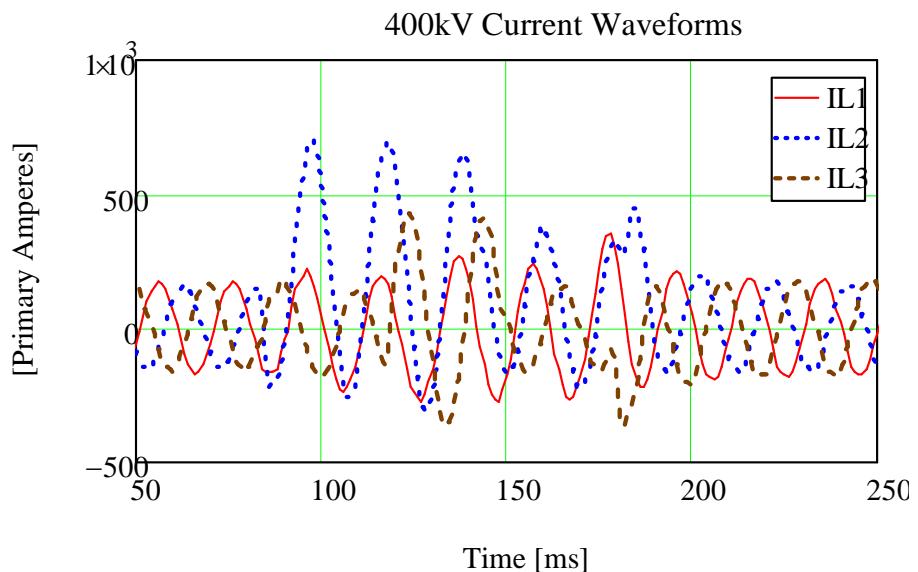


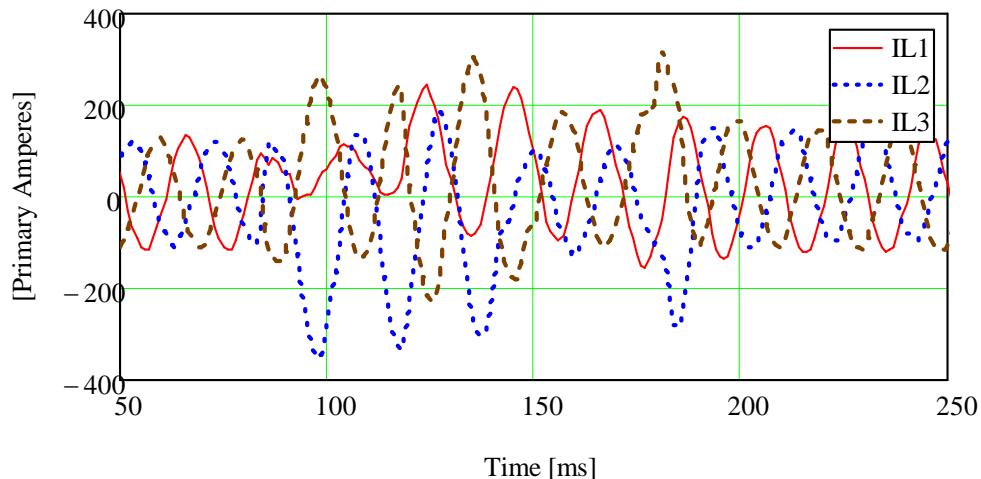
Figure 18
REF Protection for Autotransformer

RTDS DFR Records

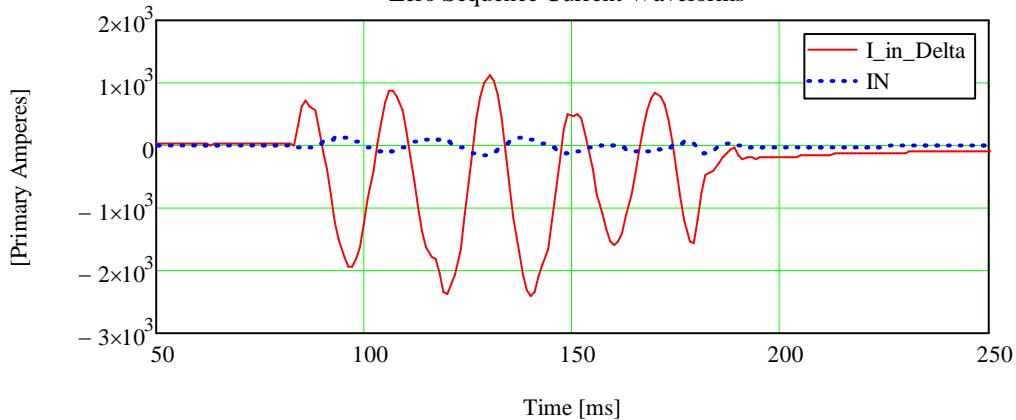
REF Protection Stability during External Ground faults



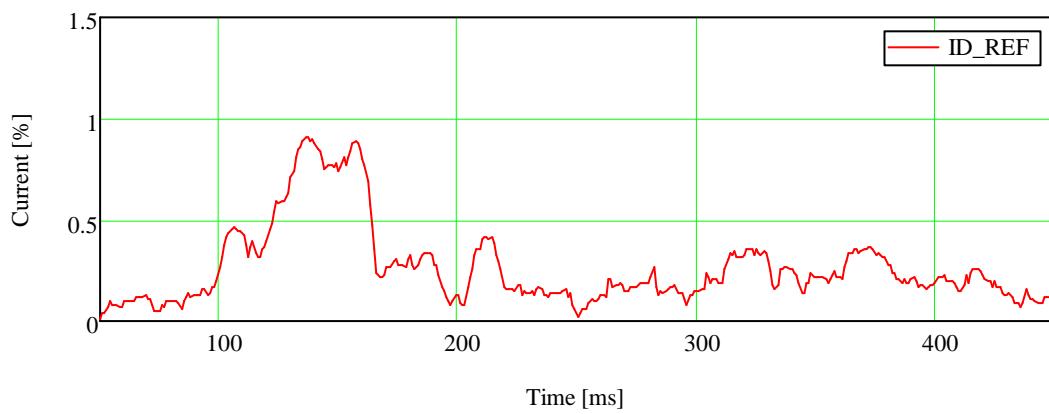
Common Winding Current Waveforms



Zero Sequence Current Waveforms



REF Function



From this record is evident stable operation with high accuracy of REF protection algorithm below 1 %.
Idmin was set on 5 % of Ibase.

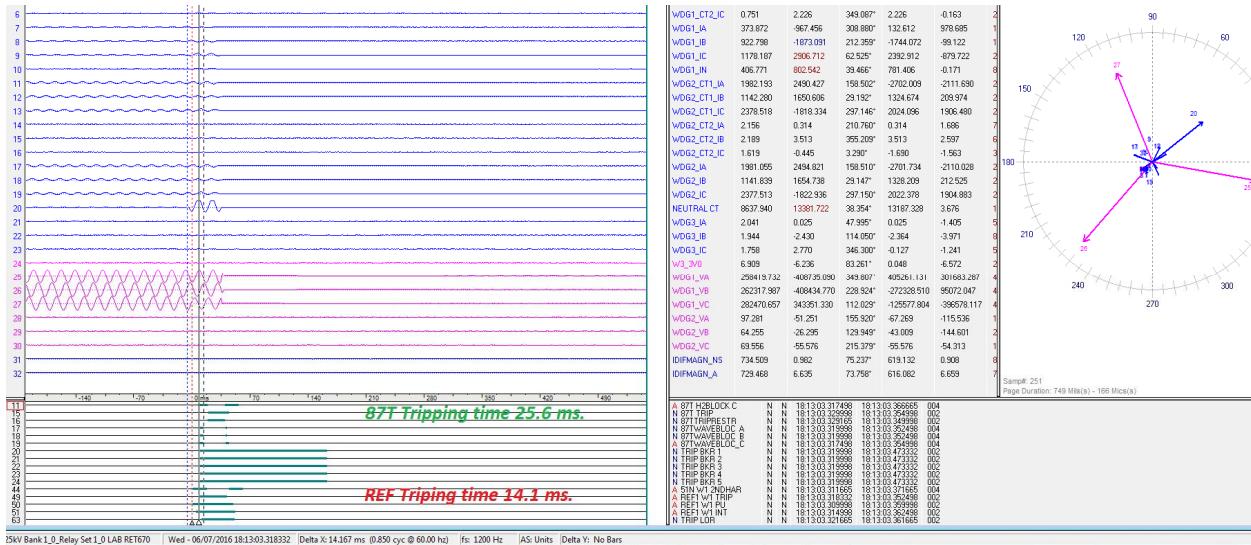


Figure 19
REF operation on Internal ground fault

From the DFR record REF is evident significant speed operating 13.4 ms and 87T under same condition 25.6 ms. REF speed is reduced based on its simplified algorithm.

High Impedance Differential scheme for REF

Ct Saturation

CT Saturation process under heavy fault currents (reach with longstanding DC component) is the most interesting natural transition scenario from an active current source to a passive resistive element RCT.

At full saturation ($d\text{flux}/dt = 0$) The impedance across the CT secondary terminal is equal to its winding resistance RCT. Its current output is practically zero at this point. In any differential scheme when one of its CT is saturated, False Differential Current (FDC) reaching the maximum. If it is not adequately restrained, REF will operate. This natural behavior of the CT at full saturation. This is the basis for HID protection scheme/ algorithm.

Stability of REF HID scheme

To make the explanation clearer, we will use an typical REF HID schematic diagram shown below in figure 20. This captures moment when one of phase CT is fully saturated, its output is zero, and across its terminal equivalent impedance is equal its resistance RCT. The resistance of secondary wiring conductor between CT terminal and REF relay is equal RL. Also, the Instantaneous overcurrent protection IOC 50 >> is an operate relay of REF protection scheme.

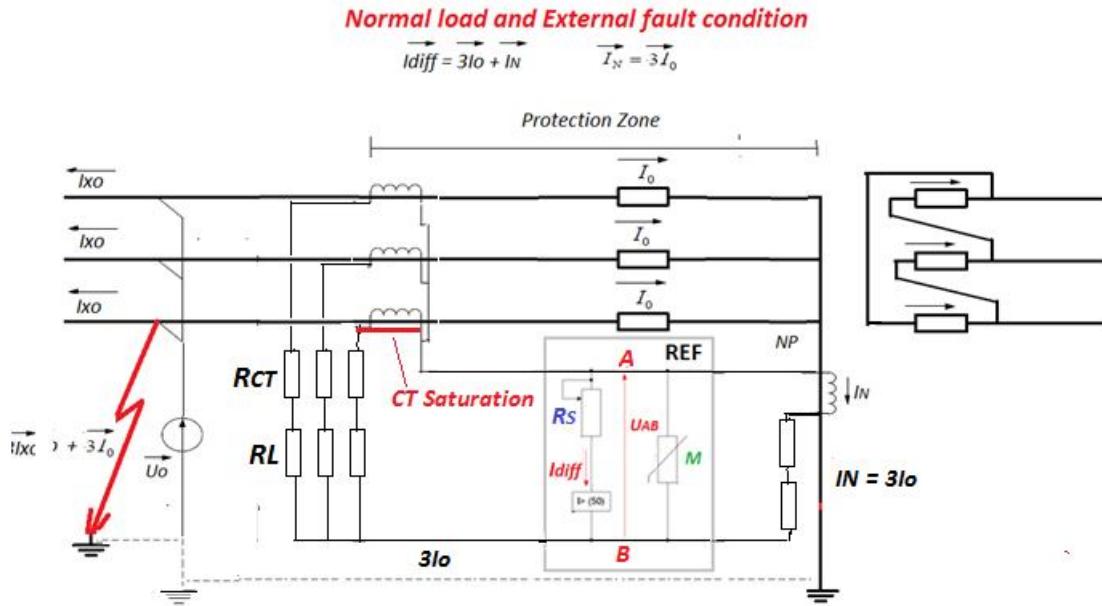


Figure 20
High Impedance REF Scheme

Taking the above into consideration, this false differential current FDC which equals:

$$I_{fmax} = Io = IN$$

will cause a rising potential between summation points A&B to its maximum value as

$$U_{ABmax} = I_{fmax} \times (RCT + RL) = IFDCmax \times (RCT + RL),$$

$$U_{ABmax} = Idiffmax \times (RCT + RL),$$

If the operating current:

$$I_{op} = U_{AB} / R_{REL} \text{ of IOC } 50\gg$$

is above its setting value I_{set} . REF will missoperate and will unnecessary trip healthy power transformer.

To prevent/restrain IOC relay from operating under this extreme condition at full CT saturation it is necessary insert an adequate stabilizing resistor R_s between the summation point A and B to make HID ultimately stable.

$$I_{op} < I_{st}$$

$$I_{op} = U_{AB} / (R_s + R_{rel}) = If \times (RCT + RL) / (Rs + R_{rel}) < I_{st}$$

To satisfy the above condition, the stabilization resistor value R_s will be calculated as shown below,

$$R_s > [If \times (RCT + RL) / I_{st}] - R_{rel}$$

For security, R_s value needs to increase for safety factor $sf = 1.05 - 1.1$ depending on the application.

As we see, the natural behavior of a saturated CT in its transformation from an active source to a passive resistive element is the fundamental basis of an REF HID scheme, and it is used to solve the most important and most difficult task of any differential protection scheme, to achieve its ultimate stability. That is, never operating during an external fault.

This scheme has huge advantage over both Low Impedance Differential, and Phase Comparison schemes. Other two methods; LID and PC, have difficulty in this area without other ct saturation detection means.

Sensitivity of REF HID scheme

The maximum sensitivity of an REF HID scheme is defined by its minimum differential/operating current known as I_{dmin} . The primary calculation is given by the formula below:

$$I_{dmin} = N_{CT} * (I_{op} + n * I_{\mu} * (U_{OP}) + I_M)$$

Where: $n= 4$, Three phase CT's and one single CT in Neutral point

$I_{\mu} * (U_{OP})$ is CT magnetization current at U_{OP}

I_{op} = I_{st} is IOC operating current equal I_{st}

I_M is current through metrosil (nonlinear resistor) at

U_{OP} voltage

The sensitivity of an REF scheme is directly dependent on the summation of all four CT magnetization currents at the operating point, U_{OP} .

Since this scheme required only 4 CT's, the sensitivity of REF can be set to a very low value, below 5% of total ground fault current, allowing 95% percent of winding be protected.

REF HID scheme for Autotransformer

Figure 21 shows an autotransformer REF HID secondary connection diagram, and using above calculation it will be define desired stabilizing resistor R_s for its associated REF protection.

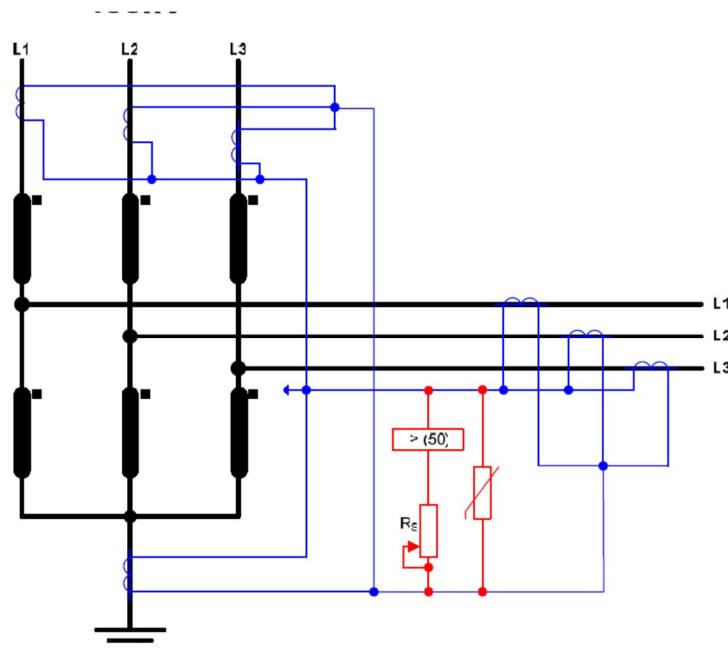


Figure 21
Autotransformer High Impedance Differential REF Connections

REF Low Impedance differential Scheme

REF Low Impedance Differential (LID) protection scheme chooses a direct approach to deal with False Differential Currents (FDC) by employing and deriving an operating/differential (biased, restrain, percentage) characteristic able to optimally compensate for false FDC in a wide range, from nominal load to maxim heavy ground fault current, or from minimal CT error to maximal at its saturation.

Logically, the LID operating characteristic follows the natural shape of the FDC characteristic, and obviously it must be set safely above FDC characteristic to prevent relay operation.

The LID scheme needs to employ and calculate additional restraint (biased) quantity because it optimizes the operating characteristic between sensitivity and stability.

One approach is to define the restraint value as maximum input current in the differential scheme which focuses more on stability, another as minimum input current which focuses on sensitivity, or the average values of all inputs currents.

Typical numerical operating characteristic of the LID REF protection is shown below in figure 22.

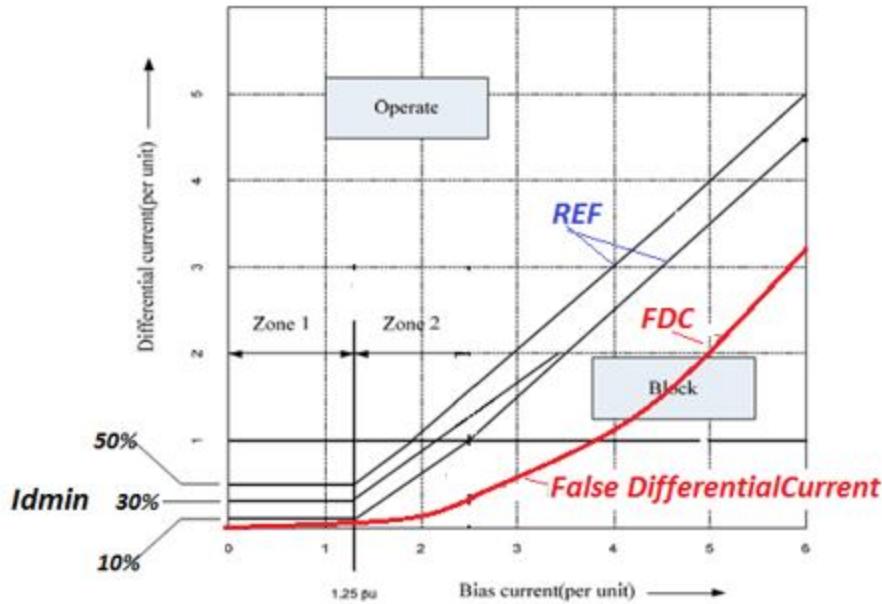


Figure 22
Typical Operating Characteristic for LID REF Scheme

The REF protection scheme shown in figure 23 will be used for the analysis. The current inputs to REF relay are; the residual current $3I_o$, as vectoral sum of phase currents, and the neutral point current derived by a single CT located between power transformer neutral point and ground.

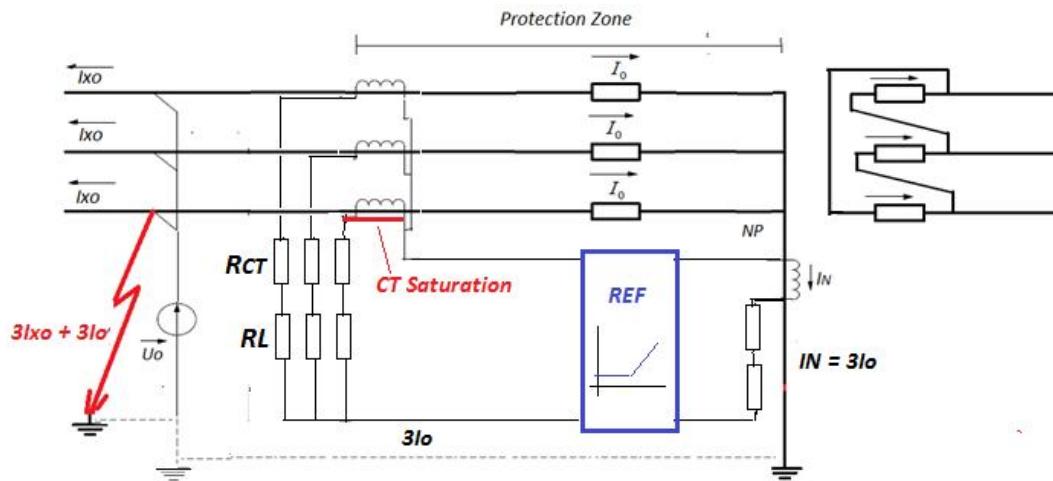


Figure 23
REF Protection scheme

The REF differential current is vectoral sum of residual and neutral point current.

$$Idiff_{REF} = 3I_o + IN$$

The restraint value for this application is selected as maximum input current, since this will yield the most stable operating characteristic safely set above FDC characteristic.

Then,

$$I_{restraint} = \text{Max of } (3I_o \text{ and } IN)$$

As we increase the REF stability, sensitivity is decreased, since it requires a higher differential current to operate. With respect to figure 15, the differential current must be above the REF characteristic for a given bias current for REF operation. Fortunately most internal faults are very strong and operating/differential current will be much higher than operating characteristic requires.

The REF operating characteristic itself is optimized and usually divided into three specific sections.

Section1: This section is the most sensitive part of the operating characteristics, it covers nominal load conditions. CT error and associated FDC current is minimal. This section is defined by minimum sensitivity I_{dmin} and zero slope, (0 %).

Section2: This section covers major overload and minor external faults, slope is moderate(30-40 %) and is able to compensate for increased FDC current. Sensitivity is directly dependent on the slope.

Section3: This section covers major external (through) fault conditions with substantial CT saturation, slope is set very high (60-80%) to compensate for substantial CT error and associated FDC current.

REF Operating Speed

REF Low Impedance Differential Scheme

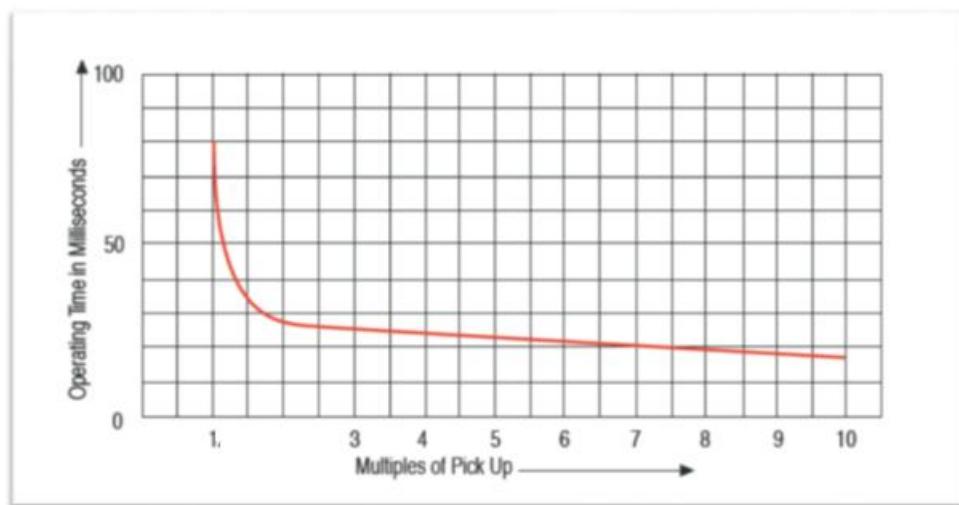
REF operating speed is 8 – 12 msec. Its overall algorithm is more simple than 87T it require less sub algorithms to execute. Number of sub algorithm as Harmonic restrain filtering contributing reduced operating time.

REF HID with numerical relay

Operating speed of numerical REF relay is on average 10 ms.

REF HID with electromechanical relay

REF HID operating speed with electromechanical relay is shown in figure 24, approximately 20 msec.



Time /current characteristics for electromechanical high impedance relay.

Figure 24
E/M High Impedance Differential Relay Operate Speed

Phase Comparator scheme

In cases where the LID scheme cannot determine whether the fault is external or internal due to heavy CT saturation, a phase comparator can be used for supervision. The phase comparator is not dependent on exact magnitude of residual current, $3I_0$ and neutral point current, I_N . Since a heavily saturated CT will still generate current minimum 3-5 % of its nominal value, that current can be used

to reliably define current phase angle. Input values for REF PC are residual and neutral point currents measured by CT on boundaries of protected zone/transformer. After calculating both current phasors angles, the phase comparator will define phase shift between these two currents, and will operate based on angular characteristic shown below in figure 25.

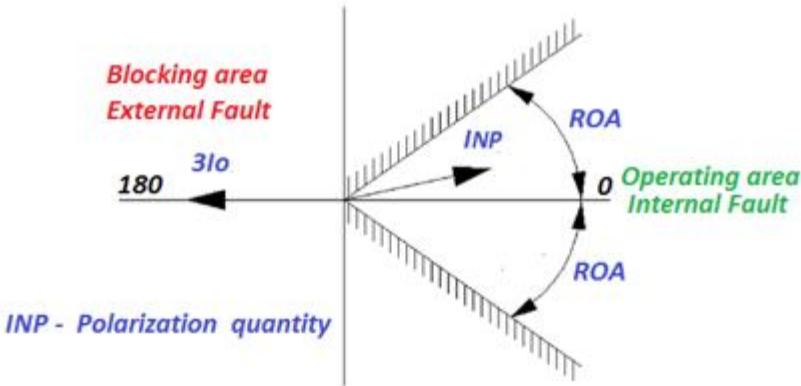


Figure 25
Phase Comparator Operating Characteristic

In ideal CT's any internal fault phase shift between those two currents is exact zero degrees. For external fault this shift is 180 degree. In reality with nonlinear CT's under heavy saturation, the measured shift angle between these two currents has some value and if it is still less than specified by relay operating angle (ROA), the phase comparator will declare the fault as Internal else, the fault is external.

PC is critical for overall operation of LID protection scheme and one needs to be very careful for setting operating angle ROA. The requirement is simple, ROA needs to be set so that during heavily saturated CT during an external fault, the phase comparator will not operate.

There are a few different PC mode dependent on which sequence current is used for its operation; zero or negative sequence. For two and three winding transformers, zero sequence current is used because the neutral point current doesn't change direction regardless if the fault is internal or external. For autotransformers, the situation is different since neutral point current can possibly change direction and can't be reliably used as reference value, especially current in tertiary winding. For autotransformers, a negative sequence PC is used.

Conclusions

In this paper we've described the transformer tank rupture phenomena and covered various means to help mitigate transformer tank rupture for internal faults. We've seen that what can be done mechanically is limited as it's not possible to put a pressure relief device large enough to expel enough oil to relieve the pressure prior to the tank rupturing from some faults. We've also shown that advances in the transformer tank design by letting the tank expand, and bracing critical areas can, if not prevent tank rupture, at least control where the tank ruptures to limit damage to the surrounding area.

From a protection perspective, we've shown that the Restricted Earth Fault relay (REF) has significant advantages over the transformer differential relay (87T) in both speed, and sensitivity. The REF has operating speed of around $\frac{1}{2}$ cycle, and can protect up to 95% of the winding. These factors lead us to conclude that the restricted earth fault relay is the best choice to help mitigate the chance of transformer tank rupture. Of course, a high speed relay must also be used with a high speed, two cycle circuit breaker to clear the fault as quick as possible.

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Biographies

Ilija Jankovic received a BSEE and MS in electrical engineering from the University of Sarajevo in the former Yugoslavia. He is a Ph.D. candidate in electrical power system stability and control at Moscow Power Engineering Institute in the Russian Federation. He is an electrical engineer with more than 35 years of experience in all aspects of electrical power system engineering, working with leading companies in Europe, the Middle East, Africa and North America on the design, manufacture, installation, commissioning and start-up of major power projects worldwide. He has special expertise in power system protection, control and stability.

Roger Hedding graduated with a BSEE from Marquette University, and a Master's degree in Electrical Engineering from the University of Pittsburgh. Roger is a recently retired Senior Consultant for ABB. He guides the application of relay products for the North American market. Roger is a IEEE Life senior member, and past Chair of the IEEE PES Power Systems Relay Committee. Roger has authored many papers in power systems protection.

Tom Roseburg received a BSEE from Washington State University in 1971. I began my career with Bonneville Power Administration in 1972 as a field engineer in the Branch of Substation Construction as a test engineer. In 1975 I became a field engineer in System Protection Maintenance where I worked in substations at various locations in the states of Washington and Idaho my main duties were setting, testing, and maintaining protective relays. I later became a District System Protection Maintenance supervisor in central Washington. In 1988 I transferred to BPA's Branch of System Protection Maintenance in Vancouver, Washington. My main duties include setting protective relays, developing setting criteria, and developing operational logic for protective relays. I also analyze fault operations and when protection problems occur I help isolate the problems and develop mitigation plans. I am currently working in that position.