Impact of Incipient Faults on Sensitive Protection

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Abstract — Incipient faults first represent a challenge for the detection of such fault by the primary protection. These faults could last few milliseconds only, being intermittent in nature and possibly evolving eventually over time to a complete insulation breakdown, creating a permanent fault. However, these undetected "ghost" faults may have inadvertent impact on the sensitive protection for adjacent protection zones, compromising its security.

This paper will focus on the impact of such faults on the sensitive protection, including transformer restricted ground fault (RGF) and sensitive ground fault protection. Incipient faults create DC offset in currents, which may drive CTs into a light saturation. This paper reviews a real field application case where a repetitive intermittent fault on a 22-kV underground cable was undetected for a long period of time, leading to the transformer neutral CT saturation and to the incorrect operation of two transformer RGF schemes in the substation. The gradual process of CT saturation is explained in detail.

Referring to the transformer low impedance restricted ground fault, scheme security is accomplished by the specific algorithm with some additional supervisory features. Particular attention is dedicated to improving the security of the RGF scheme and other affected sensitive protections for this type of external incipient faults, without jeopardizing dependability and speed of operation.

Index Terms — Incipient Faults, Sensitive Protections, CT Saturation

I. An Interesting Field Case

On September 15, 2016, the Restricted Ground Fault (RGF) in a transformer relay incorrectly operated. As a result of this event, the substation experienced a temporary loss of supply.

This substation is connected to the network via three 66 kV subtransmission lines which feed several 22 kV feeders via four power transformers. One transformer is rated 20/32 MVA and the other three are connected as a Group and rated 10/16 MVA each. In the Group two transformers out of three were in service at the time of the event and the third one used as spare. The transformers are star ungrounded on the HV side and star grounded with a neutral grounding resistor on the LV side. The Neutral Grounding Resistor (NGR) is common for the substation. Delta tertiary winding is also present in all the transformers. The NGR limits the maximum fault current of the substation to 1587 A. Low impedance restricted ground fault is applied on the LV side of the transformer, one RGF for T4 and one RGF for the Group. Refer to Figure 1 for further details.

The captured fault record revealed that one of the 22 kV cable feeders experienced a series of incipient faults in phase-A due to a defective cable joint recently commissioned. It is suspected that the fault was present for a period of time prior to the event with a fault current peak value varying between 200 to 600 A.

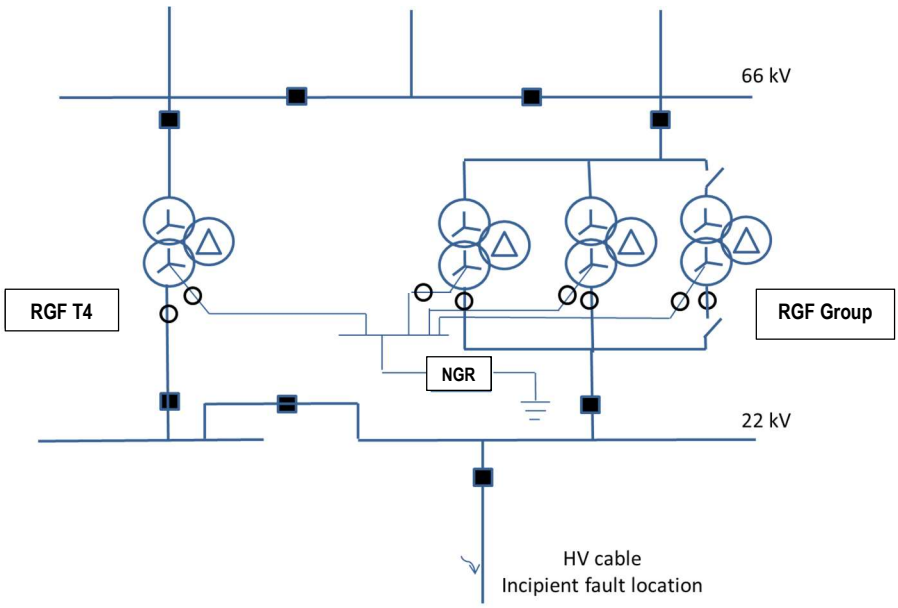

Figure 1. Simplified substation single line diagram

The current signature is typical for an incipient fault. Each insulation breakdown has a short time length of about 1/4 cycle which appears at the peak of the voltage, self-clears at current zero-crossing or before, and can repeat every three to ten cycles as shown in the figure below.

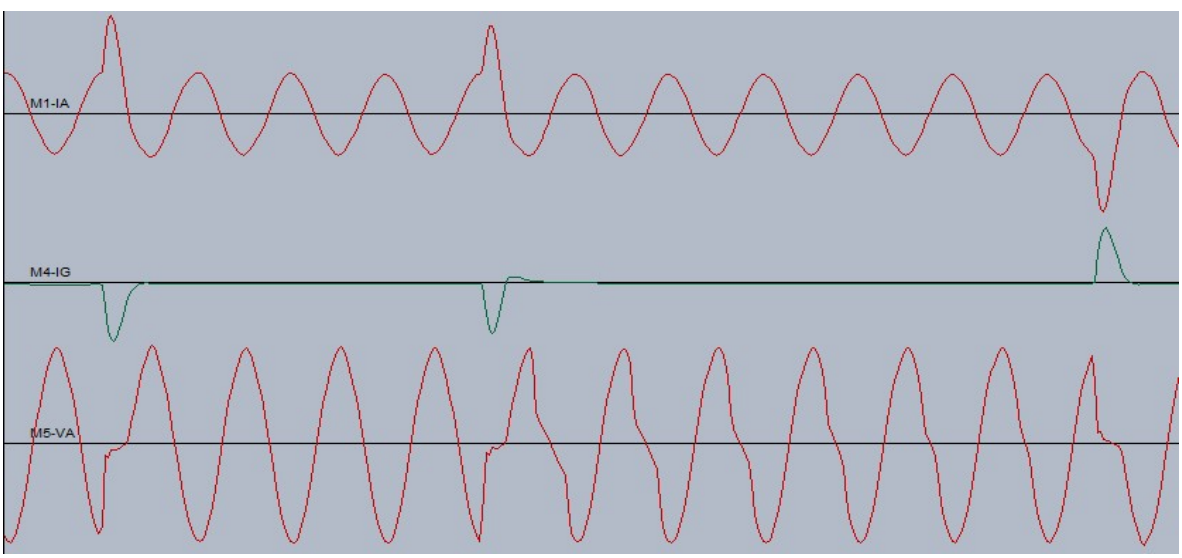

Figure 2. Fault data from T4

There are no other faults or transients at the moment of the relay operation. It is interesting to note that the incipient faults on a downstream cable would cause a misoperation of an upstream transformer protection.

The protection engineers would then ask the questions like following:

- What happened? Why did a series of incipient faults result in the operation of RGF?
- Will it affect other sensitive protection functions?
- What solution can be applied to improve relay security, but without jeopardizing relay dependability?

In the following sections, the fundamental of incipient fault is introduced, the above questions are discussed in detail, the field case is further analyzed, and solutions are provided and explained.

II. INCIPIENT FAULTS

Faults in a power system are due to insulation breakdown such as mechanical, thermal, electrical and environmental/chemical damage on the insulating material. Faults could be transient in nature, like a lightning strike on a transmission line, or permanent such as a physical damage in the XLPE insulation of an HV cable. At the same time, a fault could develop instantaneously or could take some time to generate considerable fault current, large and long enough to be detected and cleared by the protection relay.

Faults that are intermittent in nature present a menace to the power system because they are typically very short, sporadic and generally random in magnitude. Incipient faults could last 1/2 cycle or less, remain in this condition for an extended period and evolve eventually over time to a complete insulation breakdown. It is expected that the prediction and location of these self-clearing and transitory faults will be critical for utilities in the next decades to improve the reliability of the power supply. Reducing incipient faults will reduce the likelihood of a permanent fault which could develops days or weeks after the first events, at the most unexpected and unwelcomed time, for instance during other faults or major plant outages.

Incipient faults on HV cable are often the result of a gradual aging process which damages the insulation by creating channels and trees in the cable. The void or deficient point in the insulation material will have a stronger electric field with a higher risk to be conductive. Partially discharge activities will eventually starts to develop in these areas of the cable. From a partial discharge to a permanent fault is then a matter of time. An example of water tree and electrical tree in a cable is shown in Figure 3.

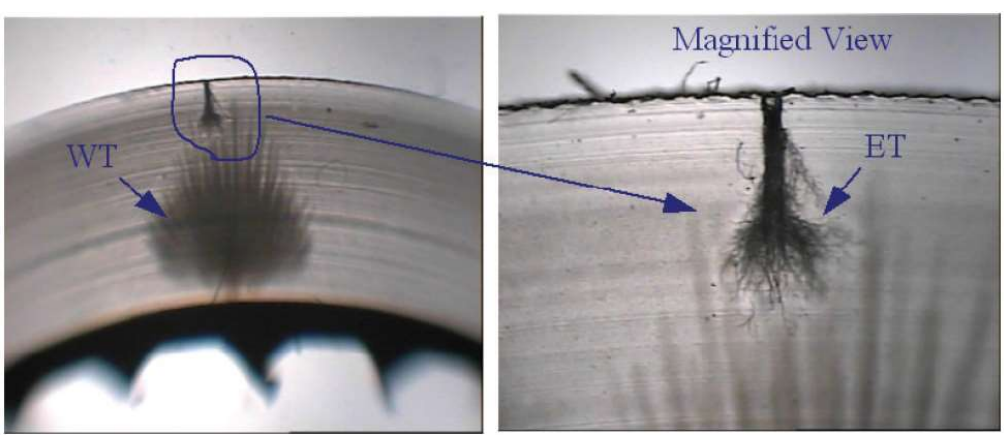

Figure 3. Illustrations of water tree (WT) and electrical tree (ET) [1]

Incipient faults have very clear signatures such as the occurrence near a voltage peak which creates the insulation breakdown. Spike frequency increases over time, from sporadic events in a day to several events within one second. These faults challenge protection relays as the digital signal processing and protection algorithm targets events that are longer than 1/2 cycle. Typically, field experiences show that these events are less than a quarter of a cycle during the spike period. Due to this specific signature, traditional overcurrent detection might not operate fast enough to detect these faults. In recent years, more studies and research have been made available within the industry to develop protection algorithms to detect this type of faults [2].

Incipient faults are initially self-clearing as the power system returns to the normal behavior after few events. For its nature, these faults are more common in HV cable or primary equipment such as transformer or circuit breaker rather than overhead transmission lines. The causes of these faults in HV cables could be a defective cable joint with penetration of water in the splice itself. The accumulation of water within the joint evolves quickly to a fault and subsequent arc fault. The heat generated by the arc causes a quick evaporation of the water itself with a temporary insulation recovery with could extinguish the arc fault.

Incipient faults on cable joint can be also generated by poor quality of the joint work or some defect in the material used for the joint. Other fault locations include cable terminations that traditionally are one of the weak points in underground power system. Last, the elbow of the cable is another sensitive point as the water can penetrate more easily into the cable insulation.

Incipient faults represent a challenge for power protection for the following reasons:

- Fault detection. These faults can last very few milliseconds and evolve in a permanent fault very slowly, and this can create confusion and misunderstanding within the protection relay. Very short disturbances could be considered power system natural transients or noise with an associated low level of confidence for the protection element.
- Protection coordination for the upstream protection schemes such feeder overcurrent and feeder ground fault protection as the phasor measurement could have large errors and differ from relay to relay.
- Protection stability due to CT saturation for the other unit scheme. For instance, for the line differential scheme or transformer RGF. Further details for the RGF are elaborated in the following Sections.
- Location of such incipient fault.

III. Restricted Ground Fault Protection

A. Techniques and security

Transformer winding neutral point can be connected to ground solidly or via an impedance as a method to reduce the ground fault current. In a solidly grounded star winding, the fault current is limited only by the leakage reactance of the winding, which varies in a complex manner with the position of the fault. For the majority of the winding the fault current is in the magnitude range between two to five times transformer nominal current. In an impedance grounded transformer, the fault current is limited by the grounding resistor. The source impedance can be generally

disregarded due to its relative small magnitude compared to the magnitude of the neutral grounding resistance (NGR), or reactance (NGX).

It is well known that restricted ground fault protection provides sensitive ground fault detection for faults close to the neutral point of a star winding transformer. The magnitude of the fault current for this type of fault depends on the grounding type of the system. Sensitivity of the RGF is also dependent if the current comes from one or two sides of the transformer.

Figure 4 shows the relationship between the fault current and the distance of fault from neutral for a delta star transformer with fault current only derived from the delta side [3]. Fault Current refers to the current measured in the neutral connection of the transformer and Primary Current refers to the current measured by the phase CT on the delta side of the transformer. With no star winding contribution to the fault and a fault close to the neutral of the transformer, the overall transformer differential is not sensitive enough to detect the fault.

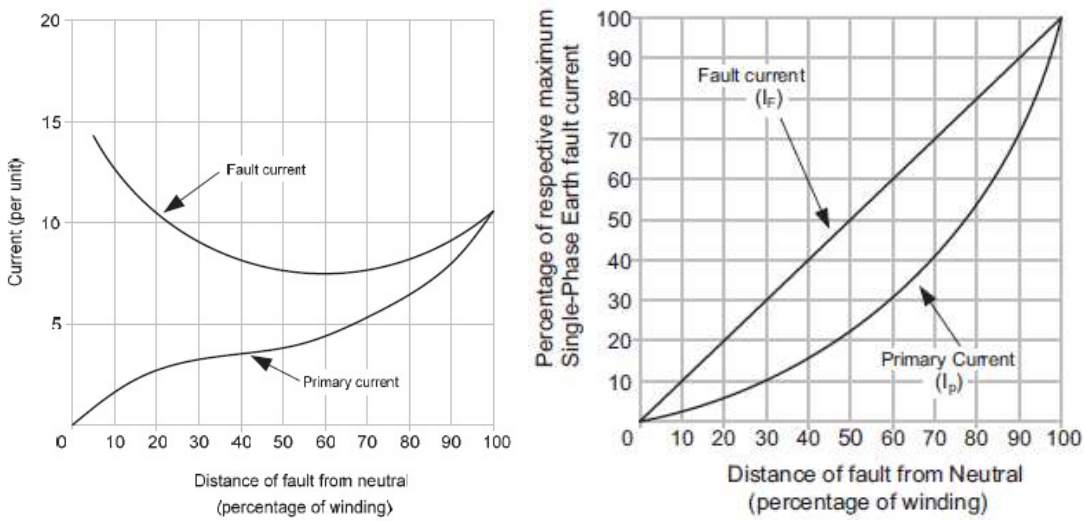

Figure 4. Fault current in solidly grounded (left) and impedance grounded (right) star winding

This study focuses on the low impedance RGF scheme. This scheme is now becoming more popular than the high impedance scheme which applies the well-known Mertz-Price circulating current principle.

Low impedance scheme requires a definition of the operating and restraining signal. For the RGF scheme, the operating current and required sensitivity is usually represented by the summation of the neutral current as measured by the summation of the phase CTs, I_N, and the current measured by the CT on the ground connection of the transformer, I_G. However, some algorithms only use the ground CTs and use the neutral current to differentiate between internal and external faults.

As per the other unit schemes, security during external faults is mainly provided by the restraining current. One RGF algorithm [4] proposes a combination of different equations and conditions to guarantee that the restraining signal is large enough during CT saturation conditions.

$$I_{REST} = \max(I_{R0}, I_{R1}, I_{R2}) \tag{1}$$

The equation considers any type of external faults with and without CT saturation and are related to zero, negative, and positive-sequence currents of the three phase CTs. The zero-sequence component targets security for external ground faults, the negative sequence component considers security for external phase to phase faults, and last, the positive sequence component aims security for load conditions, and external three-phase balanced and near-balanced faults.

$$I_{R0} = |IG - IN| = |IG - (IA + IB + IC)| \tag{2}$$

The equation above brings an advantage of generating the restraining signal of twice the external ground fault current, while reducing the restraint below the internal ground fault current.

$$I_{R2} = |I\_2| \; or \; I_{R2} = 3 \times |I\_2| \tag{3}$$

The multiplier of 1 is used by the relay for first two cycles following complete de-energization of the winding (all three phase currents below 5% of nominal for at least five cycles). The multiplier of 3 is used during normal operation; that is, two cycles after the winding has been energized. The lower multiplier is used to ensure better sensitivity when energizing a faulty winding.

$$\begin{array}{ll} 1 & If \; |I\_1| > 2pu, then \\ 2 & \quad If \; |I\_1| > |I\_0|, then \; I_{R1} = 3 \times (|I\_1| - |I\_0|) \\ 3 & \quad else \; I_{R1} = 0 \\ 4 & else \; I_{R1} = |I\_1|/8 \end{array} \tag{4}$$

Under load-level currents (below 200% of nominal), the positive-sequence restraint is set to 1/8th of the positive-sequence current (line 4). This is to ensure maximum sensitivity during low-current faults under full load conditions. Under fault-level currents (above 200% of nominal), the positive-sequence restraint is removed if the zero-sequence component is greater than the positive-sequence (line 3), or set at the net difference of the two (line 2).

The raw restraining signal in Eq. (1) is further post-filtered for better performance during external faults with heavy CT saturation and for better switch-off transient control.

$$I_{gr}(k) = \max(I_{REST}(k), \alpha \times I_{gr}(k-1)) \tag{5}$$

where k represents a present sample, k-1 represents the previous sample, and α is a factory constant (α<1). The equation above introduces a decaying memory to the restraining signal. Should the raw restraining signal (*Irest*) disappear or drop significantly, such as when an external fault gets cleared or a CT saturates heavily, the actual restraining signal (*Igr(k)*) will not reduce instantly but will keep decaying, decreasing its value by 50% each 15.5 power system cycles.

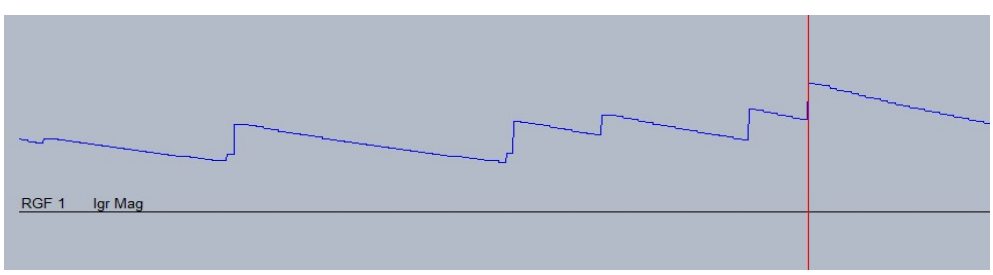

Figure 5. Example of RGF controlled restraining current

An alternative algorithm provides enhanced security by applying a triple slope biased characteristic. The last slope is recommended to be 150% to provide enough security during heavy external faults. The restraining current which is the typical summation of the neutral and ground current is reduced to 50% to provide sensitivity for internal faults without affecting the security of the scheme.

Security of the scheme can be also enhanced by applying a pickup time delay to the RGF, based on the fact that the scheme should target sensitive winding faults with current magnitude limited to less than 2-3 pu and let the overall transformer differential scheme look after heavy fault conditions. This delay will help to cater for unexpected and uneven CT saturation, but the delay may not prevent misoperation during CT saturation and fault lasting longer than delay. Similarly, it is worth noting that one algorithm enables the RGF only if the maximum phase current is below two per unit.

B. Cause of misoperation

Back to the field case as described in Section I, the cause of misoperation is explained in this section.

There were five incipient faults recorded in the relay, where the last one caused the RGF function to operate. The differential current, biased restraint current (slope=24% as per the user-setting), measured ground current and calculated neutral current are illustrated in Figure 6.

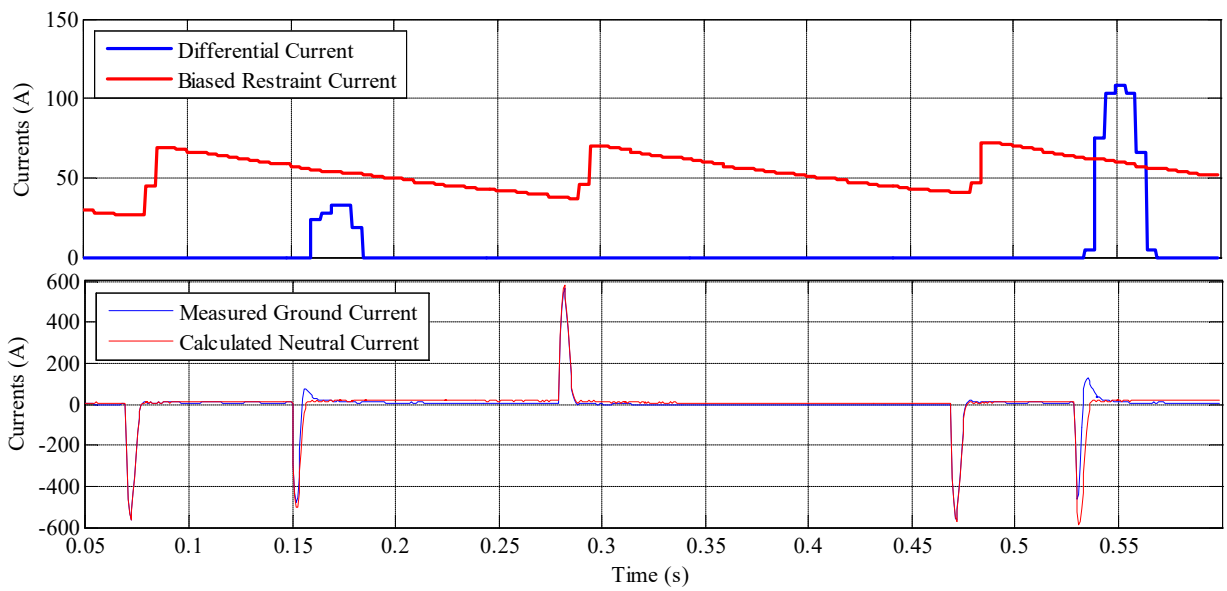

Figure 6. Differential, biased restraint, measured ground and calculated neutral currents

The zoomed-in details of five spikes are shown in Figure 7, where the peak value is referred to the calculated neutral current (red color). It can be found that the neutral-side CT experienced CT saturation on the second and fifth incipient faults as shown in the recorded data. The saturation caused by the fifth spike is more severe such that the larger erroneous differential current was induced and then the RGF function operated incorrectly.

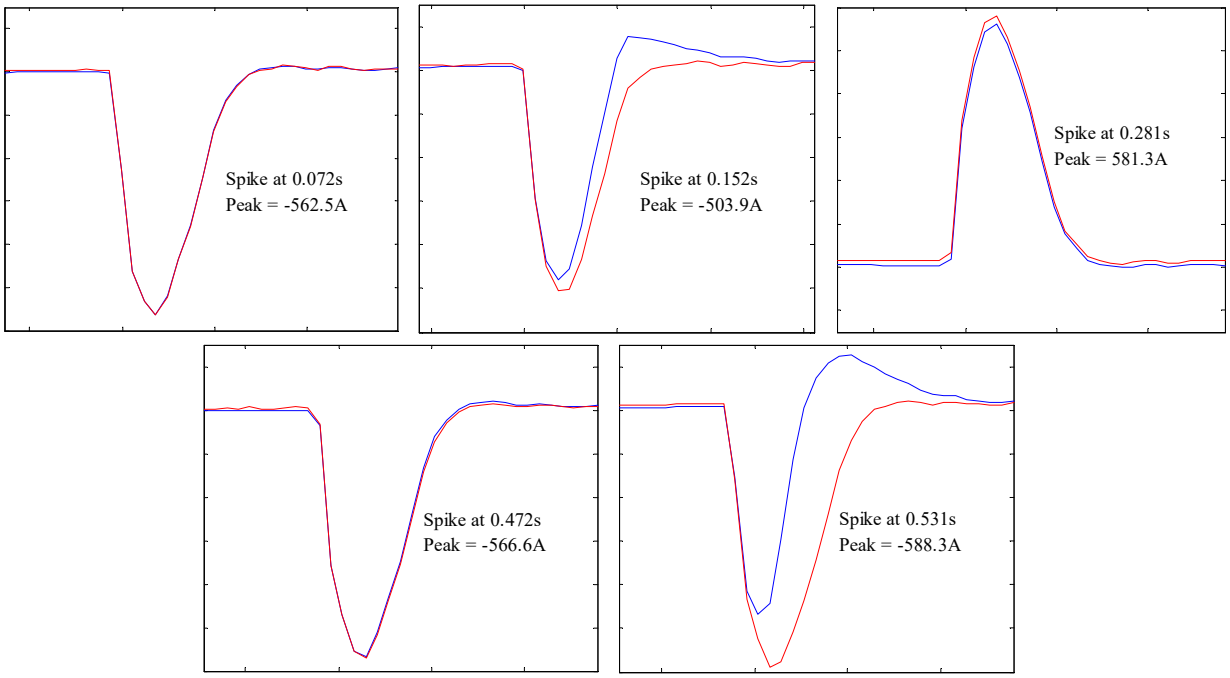

Figure 7. Measured ground current (blue) and calculated neutral current (red) of five spikes

The RGF scheme was connected to phase and ground CTs respectively specified as per Table 1. Calculations show that on each incipient fault, the secondary voltage developed on the CT secondary is quite below the CT knee point, hence, CT saturation should not have appeared at all. Absence or minor CT saturation should have guaranteed correct stability of the RGF scheme.

Table 1. CT data and calculations during incipient faults

CT	Phase CT	Ground CT
Ratio	1200:5A	300:5A
Total burden (ohm)	1.95	1.61
Knee point voltage (V)	100	50
Average current seen by CT (primary, rms, A)	450.9	221.8
Maximum current seen by CT (primary, rms, A)	475.8	238.4
Maximum secondary voltage (rms, V)	3.9 (3.9% of Vk)	6.4 (12.8% of Vk)
Maximum current seen by CT (primary, peak, A)	1006	588.3
Maximum secondary voltage (peak, V)	8.2 (8.2% of Vk)	15.8 (31.6% of Vk)

It is important to mention that a CT may experience saturation even the secondary voltage does not exceed the knee point voltage, due to the presence of CT remanence. The fact in this case is that the ground CT truly experienced saturation upon some of negative current spikes, especially,

it occurs after another negative spike. The positive spike right after a negative spike does not cause the CT saturation, and similarly for a negative spike following a positive spike. What did it happen? The reason is explained in the following section.

IV. CT Saturation Caused by Incipient Faults

Before concluding the cause of the CT saturation during incipient faults, three scenarios are simulated to examine the ground CT performance during three emulated incipient faults. The IEEE PSRC CT model [5] is applied in the simulations below. The initial remanence is set to zero.

The incipient fault experienced on the ground CT is simulated by a 0.44 cycle pulse, the same as the first spike in Figure 7, and repeated every 100 ms.

A. Scenario 1

The first pattern of the simulated incipient faults is to repeatedly inject a positive pulse, followed by a negative pulse, both having the same magnitude. As shown in Figure 8, expectedly, there is not any saturation observed, and the primary current and secondary current are perfectly matched in per unit.

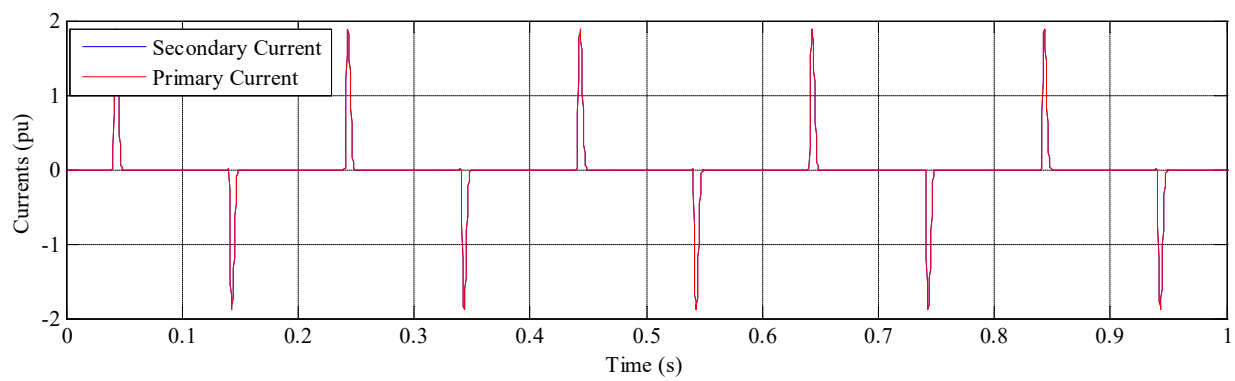

Figure 8. Primary and secondary currents – Pattern 1

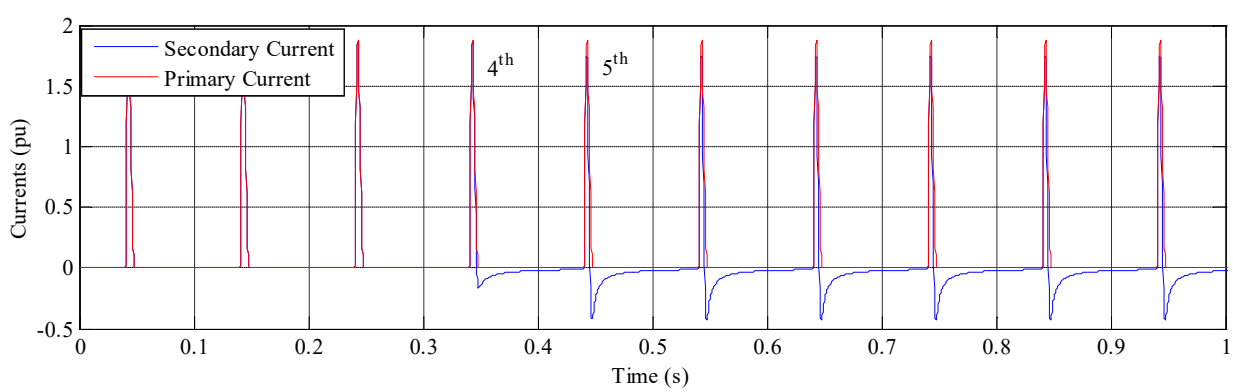

Figure 9. Primary and secondary currents – Pattern 2

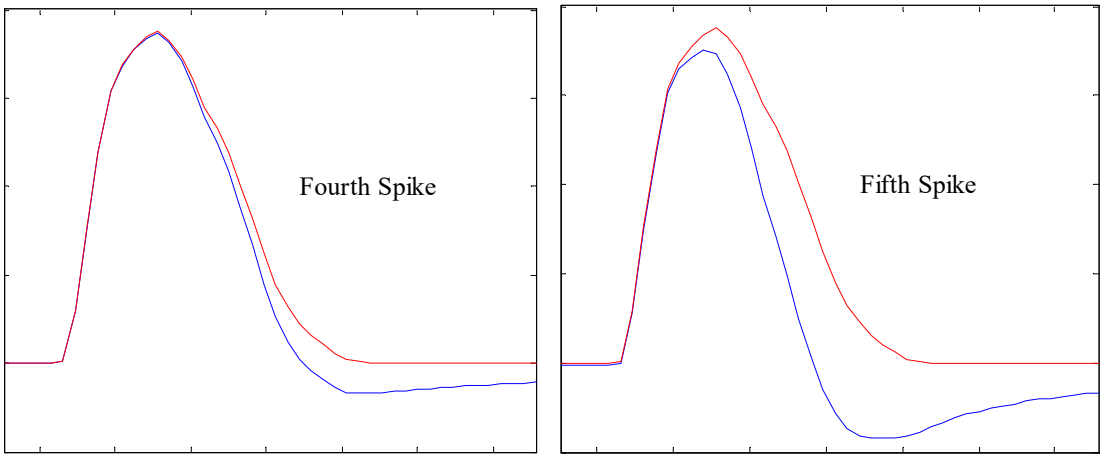

Figure 10. Details of the fourth and fifth spikes in Figure 9

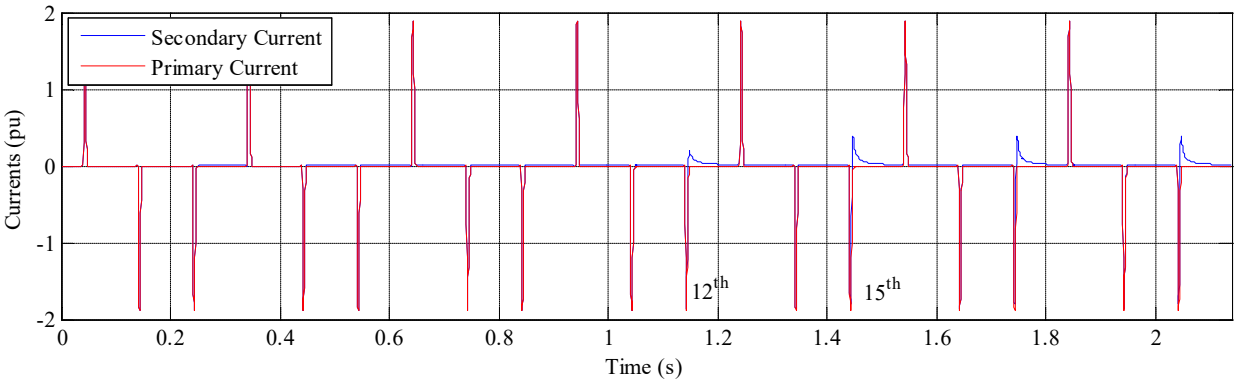

Figure 11. Primary and secondary currents – Pattern 3

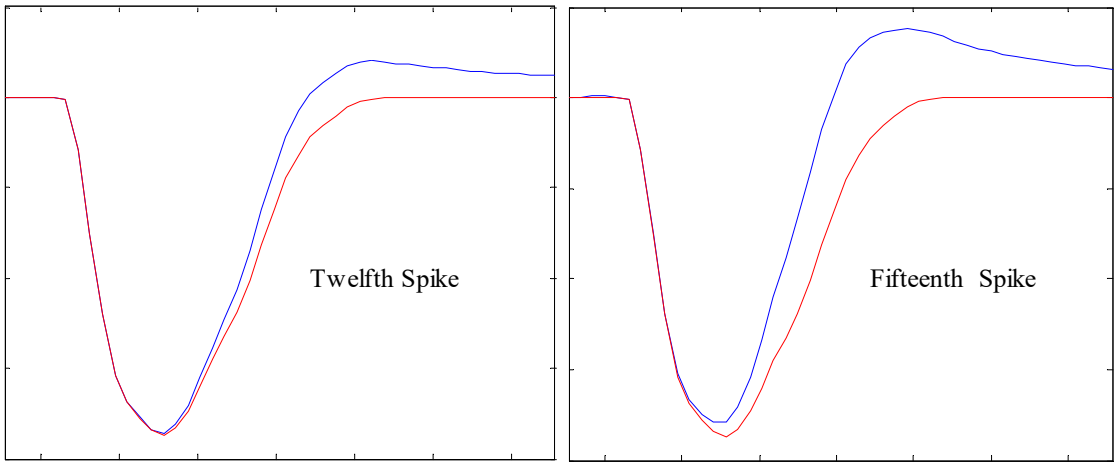

Figure 12. Details of the twelfth and fifteenth spikes in Figure 11

B. Scenario 2

The second pattern is always to inject a positive pulse, repeated every 100 ms. As shown in Figure 9, the ground CT starts saturation by the fourth incipient fault. The zoomed-in details of the fourth and fifth spikes are illustrated in Figure 10. It can be observed that,

- The fifth spike causes more severe saturation than the fourth spike.
- After the fifth spike, the CT saturation degree becomes stable.

C. Scenario 3

The third pattern is to inject one positive pulse, followed by two negative pulses, as shown in Figure 11. Apparently,

- There is no saturation in the positive spikes.
- There is no saturation in the negative spikes that follow the positive spikes.
- The negative spike following the other negative spike causes the ground CT to saturate since the 12th spike.
- After the 15th spike, the CT saturation degree becomes stable upon the occurrence of every second negative spike.

D. Analysis

Based on the simulations above, the incipient faults with some specific patterns would truly cause the ground CT saturation. Additionally, compared with the recorded spike in Figure 7, the simulated results closely match the recorded waveforms.

What did happen? Every time there is an insulation breakdown with subsequent fault current, magnetic flux in the CT is generated by the exciting voltage. As the spike interrupts, the magnetic flux does not reduce to zero but decreases to the remanence value due to the hysteresis of the magnetic material in the CT. In other words, some of the magnetic property is retained by the CT core. When the CT experiences a subsequent fault, the flux change will start from the remanence flux. For closed iron core CT like the PX type remanence flux can be removed by the demagnetizing methods as described in [6]. If this intermittent fault takes place in a distributed manner, one positive and one negative fault current, CT saturation would not appear as simulated in Figure 8, and therefore there is no impact on the RGF scheme stability.

Unfortunately, intermittent positive and negative faults might not balance in the short period. For instance, in a window of twenty consecutive faults, even a distribution of five spikes with one polarity and fifteen with the other could have an impact on the RGF security. Similarly, three consecutive insulation breakdowns with the same polarity will excessively increase the remanence flux in the core CT.

Referring to the available window data in Figure 6, the operations happened after several discharges with the same negative polarity.

It should be mentioned that in any unit scheme the best security is obtained if the CTs have similar performance. In this case CT saturation largely affected the ground CT rather that the

phase CT as the voltage experienced on the CT secondary winding as percentage of the CT knee point is more onerous on the ground CT mainly due to the lower CT ratio of 300/5A. It is noted that sometimes the ground CT is underrated. The distorted waveform also confirms the CT saturation on the ground CT.

The waveform at the time of the RGF operation also shows a CT subsidence effect on the ground CT. CT subsidence is the phenomena related to the CT secondary current released by the magnetic core upon primary current interruption. Following this interruption, the magnetic flux decreases to the residual flux level which releases a secondary CT current. This unipolar current is a mix of a DC component, harmonics and inter-harmonic even if the primary current event has disappeared. This appears in the I_G waveform as noted in the positive bump despite the discharge on phase A has ended.

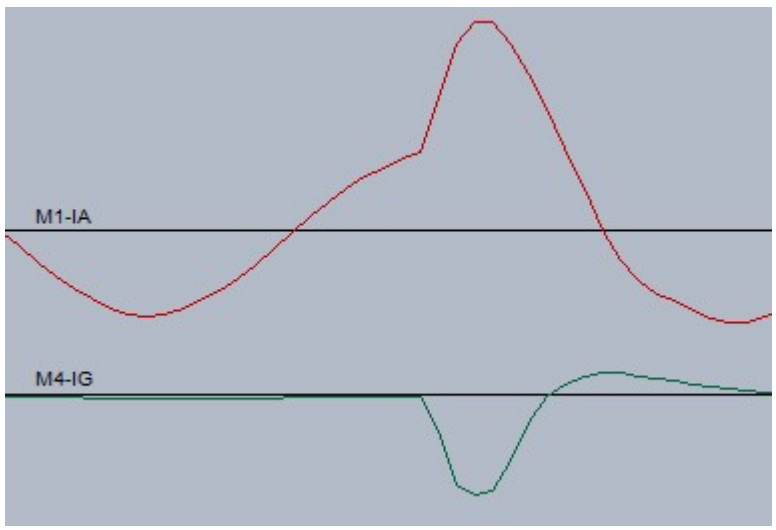

Figure 13. Waveform during CT saturation and CT subsidence on I_G

Taking the second simulation in Figure 9 as an example, also shown in Figure 14, the gradual process of CT saturation is explained below.

1. For the first three spikes, the flux linkage in the ground CT increases when a positive pulse is injected. Each pulse would boost the flux level by 0.0645 V-s.
2. For the first two spikes, when the injection disappears, the flux linkage would not decay because the accumulated flux (0.129 V-s) does not exceed the residual flux (around 0.156 V-s for the simulated CT). At the end of the third spike, the flux linkage is built up to 0.1924 V-s. After the interruption of the third spike, the flux linkage decays slowly towards the residual flux.
3. At the fourth spike, the ground CT enters the saturation because the accumulated flux linkage (0.2512 V-s) exceeds the saturation flux (0.24 V-s) of the B-H loop characteristic.
4. Once entering the saturation zone, the magnetic flux starts decaying to the residual flux level following primary current interruption. Right before a new spike is injected 91.2 ms after the previous interruption, the flux is decayed to 0.2212 V-s. During this decaying, the subsidence current is observed in the secondary current.

5. For the fifth spike and above, the process 3 and 4 above repeat. The saturation degree becomes stable because of the same current pattern and injection period.

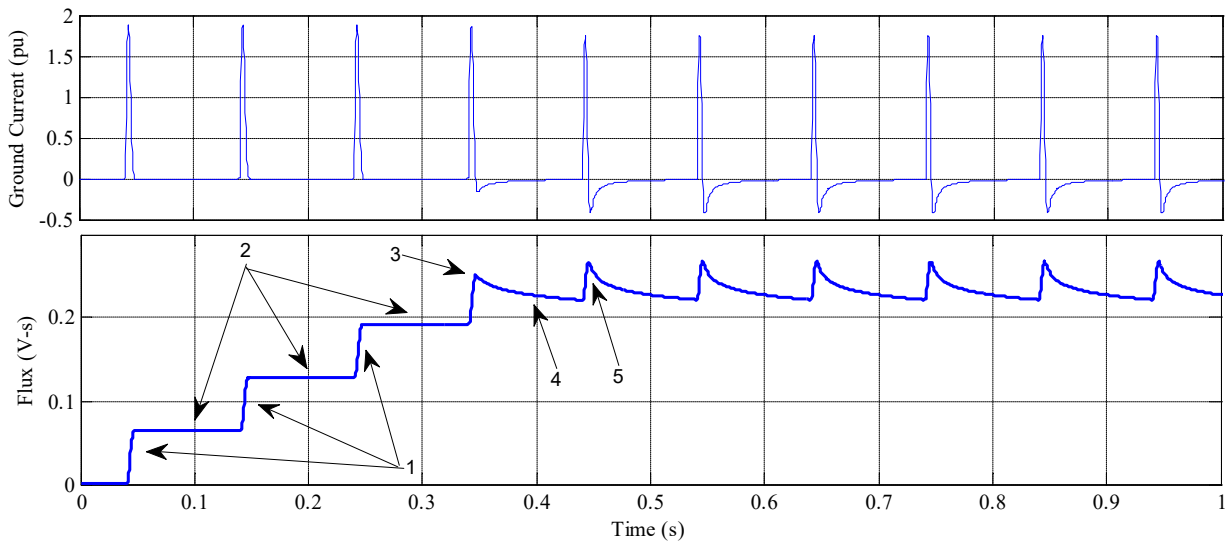

Figure 14. Secondary current and flux of ground CT

The core material of almost all relaying CTs are using cold-rolled and grain-oriented silicon steel, which is a type of isotropic material. For such material, the typical residual flux is about 50% to 80% of the saturation flux.

V. EFFECTS ON NEUTRAL DIRECTIONAL OVERCURRENT

The neutral directional overcurrent function is commonly used as a fast and sensitive directional indicator. Normally, the operating current selects the calculated neutral current (three-times the zero-sequence current) or measured ground current. The polarizing signal uses the zero-sequence voltage or calculated neutral current. Herein, the following three combinations are considered.

Table 2. Polarizing and operating signals

Polarizing signal	Operating signal	Comparator (Forward)	Comparator (Reverse)
V_0	I_0	$\lvert < -V_0 \bullet I_0 \times \angle ECA > \rvert < FWD\ LA$	$\lvert < -V_0 \bullet -I_0 \times \angle ECA > \rvert < REV\ LA$
V_0	I_G	$\lvert < -V_0 \bullet I_G \times \angle ECA > \rvert < FWD\ LA$	$\lvert < -V_0 \bullet -I_G \times \angle ECA > \rvert < REV\ LA$
I_G	I_0	$\lvert < I_G \bullet I_0 > \rvert < FWD\ LA$	$\lvert < I_G \bullet -I_0 > \rvert < REV\ LA$

Where, V_0 is the zero-sequence voltage, I_0 is the calculated zero-sequence current, I_G is the measured ground current, *ECA* is the element characteristic angle, *FWD LA* is the forward limit angle, *REV LA* is the reverse limit angle, and the operator < • > denotes the angle difference between the two input operands.

It should be mentioned that the analysis below is based on the traditional neutral directional scheme. The relay manufacturers may use the different method, and/or increase security by

applying security counts or other techniques. In the analysis, the *ECA* is set to 75 degrees and *FWD/REV LIMT ANGLE* to 90 degrees.

A. Polarizing V_0 and operating I_0

Normally, the fault component in the phase current, induced by incipient faults, is not large enough to cause the phase CT saturation. Therefore, the zero-sequence current calculated from the three-phase currents is usually not distorted. The neutral directional function should give the correct direction.

Regarding the field case in Section I, the neutral directional overcurrent indicates the correct downstream direction for all the five incipient faults, while using the polarizing signal (V_0) and operating signal (I_0).

B. Polarizing V_0 and operating I_G

It has been discussed that some incipient fault patterns may cause the ground CT to saturate. When ground current is used as the operating current, it is possible for the neutral directional function to give the incorrect direction, especially under the condition of the ground CT saturation.

It is confirmed that, during the second spike and fifth spike in Figure 7, the neutral directional overcurrent identified both of them as the internal fault after the CT entered saturation, as shown in Figure 15.

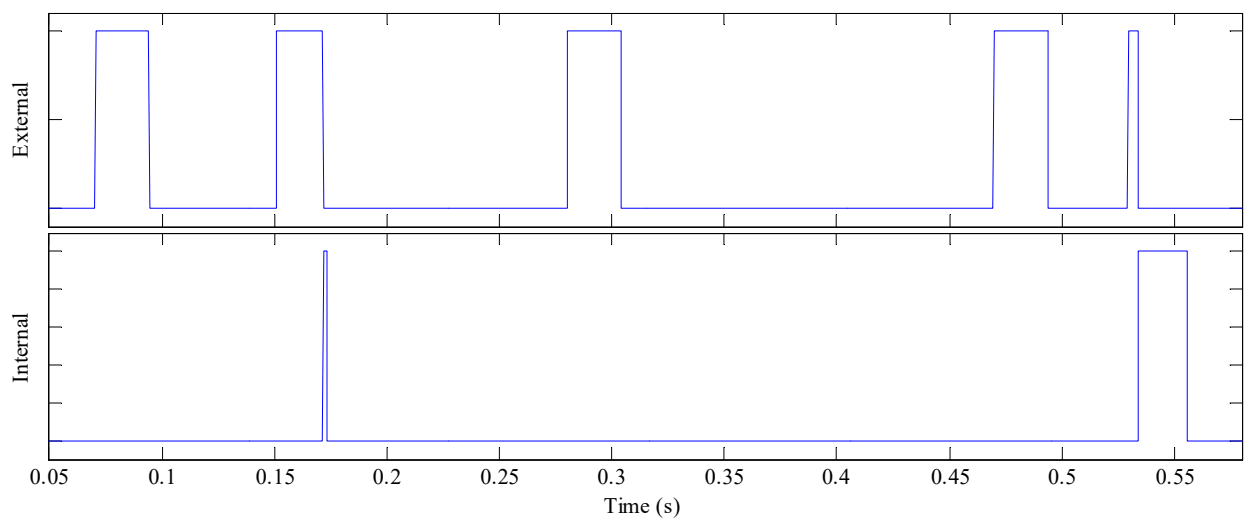

Figure 15. Indication of neutral directional during incipient faults – V_0 vs I_G

C. Polarizing I_G and operating I_0

When the ground CT is used as the polarizing signal, the neutral directional function may indicate the incorrect direction, mostly depending on the saturation degree. For example, among the five spikes in the field case, only the fifth spike gives the wrong direction for a very short duration at the very last moment, as shown in Figure 16.

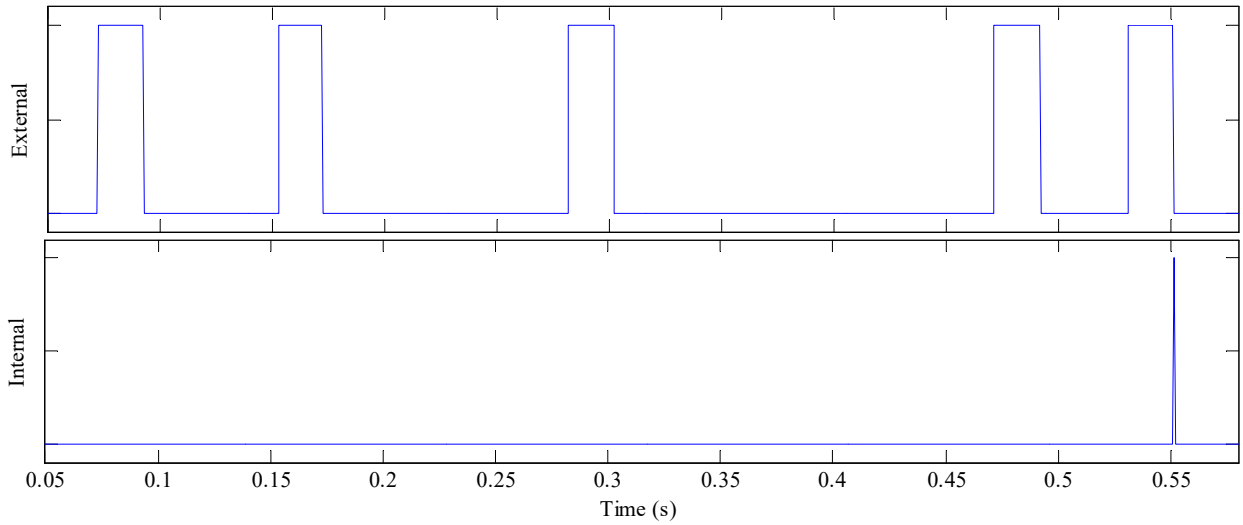

Figure 16. Indication of neutral directional during incipient faults – I_G vs I_0

VI. Options and Solutions

From a pure risk management point of view, the detection and clearance of such faults by the feeder primary protection would have completely solved the stability issue on the transformer RGF scheme.

Detecting incipient faults is not a straight-forward task. There is an extensive literature with proposed specific algorithms to recognize an intermittent fault. This investigation assumes that the feeder primary protection has not been able to quickly clear the event. As a result, enhancement of transformer RGF security is here reviewed.

This event was a combination of factors which are not usually associated with a typical protection operation:

- Low fault current
- CT saturation
- CT remanence

CT remanence is usually associated with high fault currents but this is not true for incipient fault as the flux builds up over time even with low current. The consequence of CT remanence is to push the CT core into saturation, or keep the core from going as deep into saturation. With consecutive faults with the same polarity the ground CT eventually saturated.

The DC component of the fault current deserves some attention:

- For a fault on a distribution cable is expected that the X/R is not excessively high, like near a large generator or for a transmission line in a high fault level region.
- As the fault appears towards the peak of the voltage, the DC component should have been effectively minor.
- The system is grounded via a resistor which should have decreased the X/R ratio.

Due to these factors the DC component should have been contained with a positive effect on CT saturation. This is not always the case, like in this event. A conservative X/R ratio of four has been used in this study.

From another point of view, CT saturation usually appears due to high fault current, heavy DC offset, large burden and CT remanence. Here only a large CT remanence was present. This interesting combination of factors driven by the incipient fault did challenge the RGF stability and makes this case particularly interesting. Here below the options considered in this study:

CT specifications

Because this operation involved CT remanence flux, the outcome of this review could include recommendations to give more consideration to these phenomena during protection design or upgrade of transformer RGF schemes. However, CT remanence is rarely involved in relay maloperation and there is already a conservative approach on the DC component by protection engineers which often consider the most onerous scenario in the design: A fault at voltage zero and the subsequent use of the full X/R ratio. Relay manufacturers are aware that CT requirements should be as reasonable as possible to allow CT specifications and avoid extra costs for utilities. For this reason, the authors do *not* suggest having a more stringent approach to CT performance and CT saturation checks.

Phase current magnitude check

In relation to relay design, some RGF algorithms are blocked if the phase current is higher than two or three times the nominal CT current. Due to the low fault current of the incipient fault, blocking the RGF would have *not* been effective. In this field case, it is also noted that the load during the maloperation is not critical. The load fed by the transformer was about 50 % of the nominal rating and 22 % of CT nominal and would have not altered the above consideration. In any case, the neutral ground resistor limits the fault current well below CT nominal current.

High RGF slope

During the investigation, it was found that the RGF slope was set too low. Slope on T4 was 24%, which is well below the minimum recommended setting of 40%. At the moment of the protection trip, the ratio of differential current to restraining current was respectively about 40% for T4. It is noted that in the event of a prolonged incipient fault CT saturation would have further worsen the impact on the RGF.

Based on the same considerations, it is also noted some limitations in RGF algorithms that apply a very high slope for restraining current above the nominal rating of the transformer or the CT nominal current of 1200/5 A. Transformer T4 has a nominal current on the LV side of 524A and the phase current (rms value) at the time of faults was varying between 414 and 476 A, which may *not* be covered by the high slope region.

Ground current check

It is also noted that supervising the RGF by using the current in the neutral of the transformer is *not* effective. The feature improves security during phase CT saturation, for instance during

transformer inrush current, but not during a genuine external incipient ground fault. As a result, other forms of security checks should be provided.

Permanent RGF time delay

Incipient faults are definitely short in nature. During a sub-cycle incipient fault, the maximum duration of the differential current is about 1.5 cycles. A simple method to increase the security could include a fixed RGF pick up delay of 2 cycles. The downside of this method is that it may be risky that the delay might *not* be sufficient during heavy CT saturation or faults lasting longer than the delay time. Permanent delay of the RGF could be also detrimental during a genuine fault in the transformer winding near the star point which requires faster operation, despite it is acknowledged that for a high fault current the overall transformer protection will operate instantaneously. It is also noted that a fixed RGF pick up delay might *not* be the prefered solution for some utilities.

DC component block

The unipolar waveform in the ground CT induced by incipient faults contains the sufficient DC component. Once the ratio of DC component to fundamental magnitude exceeds a threshold and the RGF scheme is picked up, the RGF operation is then delayed by two cycles or the user-setting delay, whichever is greater. However, only the user-selected delay is applied if the percentage of DC component is less than the threshold at the moment of the RGF pickup.

I_N and I_G angle difference supervision

The angle between I_N and I_G and how the angle difference evolves during the fault has been reviewed. As noted previously, the principle responds to a relative direction of the fault currents and declares the fault to be internal if the neutral and ground current flows in one direction. The angle difference between I_N and I_G was correctly 180 degrees during incipient faults with no CT saturation. If the saturation occurs, the angle difference typically decreases even to 140-160 degrees during each spike. However, during the last and critical insulation breakdown on transformer T4, the angle decreases to 65 degrees for a very short duration, as shown in Figure 17. This is below the 90 degrees threshold used in the typical directional check to maintain stability during CT saturation.

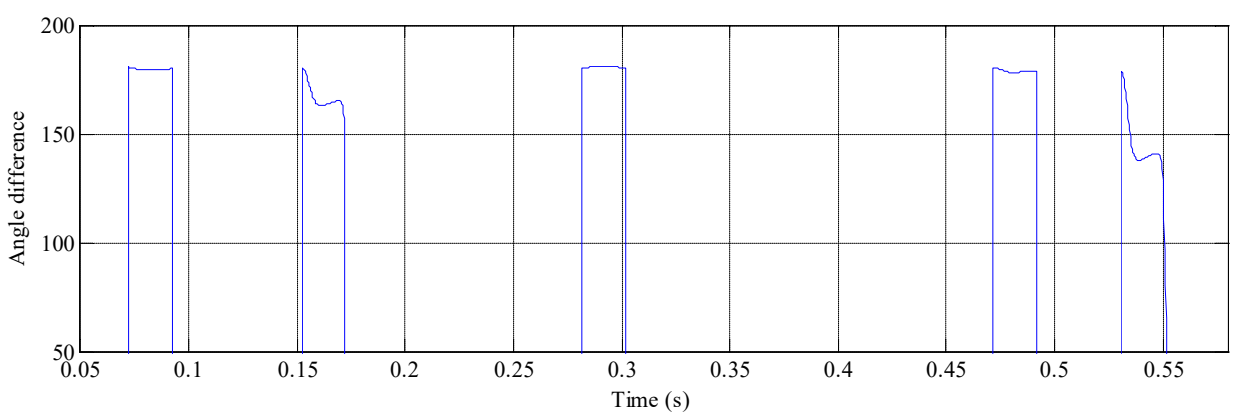

Figure 17. Angle difference between I_G and I_N during incipient faults

Better security performance could be obtained by restricting the I_G and I_N angle difference operating region from the typical ±90 to ±60 degrees or below with a marginal impact on dependability during internal faults and CT saturation. Or some security counts can be added to delay the operation. One more alternative method is to incorporate a transition logic: if the external direction is indicated for at least 0.75 of a power system cycle, the prospective internal indication is delayed by one cycle.

It should be mentioned that the valid angle difference shall be given when the magnitudes of I_G and I_N are greater than a threshold.

Neutral directional overcurrent check

The neutral directional overcurrent can be used to increase the security of the RGF scheme. As introduced in Section V, three polarizing methods are commonly used. In order to reduce the impact of the saturation of the ground CT and provide the better security, it is preferred to use the zero-sequence voltage as the polarizing signal and the zero-sequence current as the operating current. The polarizing combination of the zero-sequence voltage and measured ground current should be avoided due to its worse performance during the ground CT saturation, as is illustrated in Figure 15. The method of angle comparison between I_G and I_N is as per the above discussion.

While the zero-sequence voltage is used as the polarizing signal, the VT location needs to be considered. If the VT is isolated with the transformer when the LV-side circuit breaker is opened, the neutral directional overcurrent loses its reliability.

Transient restraining factor

One method to enhance the security of the RGF scheme could be achieved by adding a transient factor to the restraining current once an external fault is recognized, as shown in Figure 18. For instance, once the delta change of restraining current is above the pickup setting and the ratio of differential current to restraining current is less than a constant (*C1* in the figure below) for a duration of 1/8 cycle, which is a clear signature of an external fault, the algorithm could increase the calculated restraining by a 1.3 factor, expecting that the primary protection on the feeder will eventually detect and clear the fault. This increased retraining signal should be maintained until the external fault is cleared. The advantage of increasing the restraining current rather than blocking the scheme is to maintain the RGF scheme in service, acknowledging that the recognition of the incipient fault is indeed challenging due to the low current level involved.

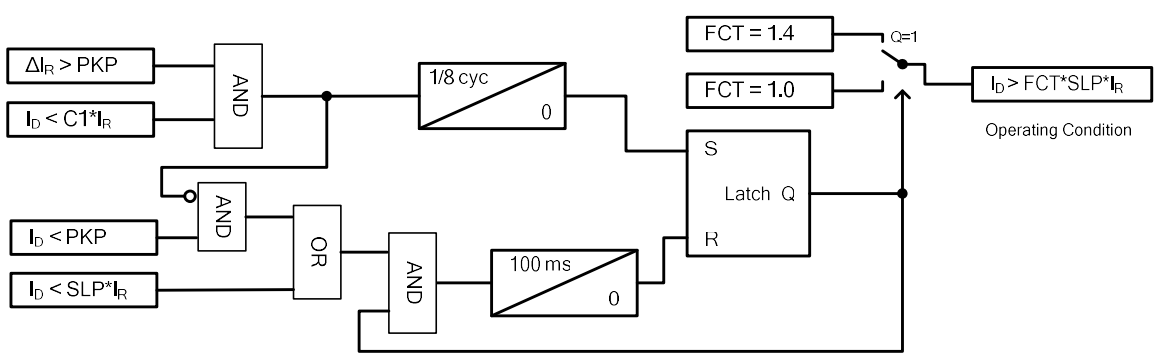

Figure 18. Simplified logic diagram of transient restraining factor

In the figure below, *PKP* is the pickup setting, *SLP* is the slope setting, *FCT* is the transient restraining factor, *C1* is a constant, I_D is the differential current, and I_R is the restraining current.

It should be highlighted that this option and the suggested 1.3 factor could have worked on this event but not in more serious CT saturation (for example, free saturation time is less than 2 ms). For an incipient fault, any reasonable RGF transient factor might not be secure enough to overcome the heavy CT saturation and CT remanence, especially in the ground CT if the fault on the feeder stays undetected for a longer period.

CT saturation detector

A clear sign that the RGF stability is at risk could be achieved by implementing a CT saturation detector based on the fact that any CT operates correctly for a short period of time after any fault. However, during an external event, the differential current after the event is very low for few milliseconds while the restraining current promptly increases. As the ground or phase CT saturates, the differential current will develop as well. In this case, due to the reduced maximum fault current it would be challenging to define a restraining current level to differentiate between an internal and external fault trajectory. Although this CT saturation detection method has been successfully adopted for generator, bus and transformer differential protection schemes, it may not be always effective to improve the RGF security during an incipient fault due to the low fault current level. A design solution could involve a slight compromise with the dependability of the scheme by reducing the excursion of the "External fault pattern" trajectory as shown in Figure 19.

The algorithm should delay the operation of the RGF scheme for a certain period of time, long enough to overcome onerous CT saturation and CT subsidence. A time delay of 100 ms could potentially fit the purpose.

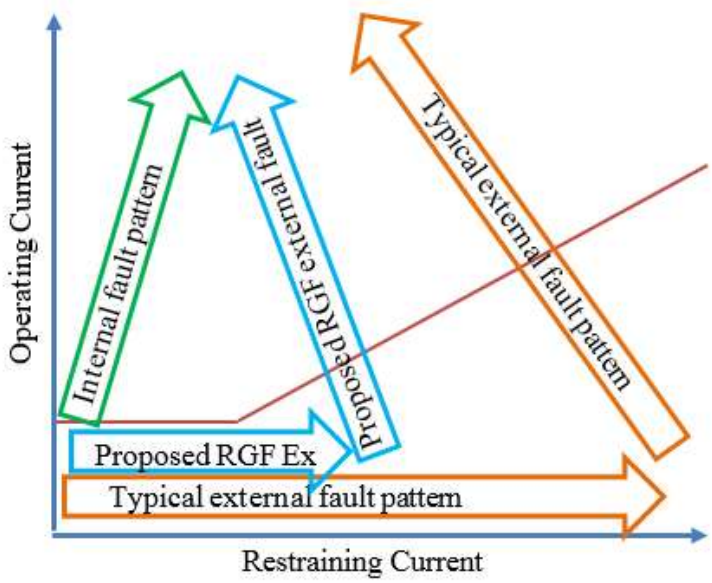

Figure 19. Proposed RGF external fault pattern to suit incipient faults

This solution appears to be robust and give sufficient flexibility to cater for a large series of incipient faults with different CT saturation scenarios.

VII. CONCLUSIONS

An undetected incipient fault will drive CTs into saturation and CT remanence has happened in this case where an intermittent fault on a 22-kV underground cable triggered two transformer RGF incorrect operations in the substation.

This paper has explained the root cause of CT saturation induced by incipient faults, investigated effects of incipient faults on sensitive protection functions, and proposed several options to improve the security of the RGF scheme. The findings suggest that a robust solution relies in the implementation of the directional comparison or the external fault recognition specifically designed for incipient faults. The neutral directional overcurrent and angle comparison between I_G and I_N can be utilized as the directional comparison logic. The transient restraining factor and CT saturation detector can be used to increase the security upon the detection of an external fault.

Any work to improve the RGF stability should consider that the development and deployment in large scale of feeder relays capable of detecting and clearing incipient faults is still far away. As a result, other effective forms to improve RGF stability in substations are required.

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IX. BIOGRAPHIES

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