Event Analysis of 4.16 kV Generator Differential Misoperation

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Generator differential protection has been used for about a century and has proven to be very secure for external faults, energization, load pickup and dependable for detecting internal faults. Since the development of Intelligent Electronic Devices (IEDs), the traditional percentage differential algorithm has been greatly refined and improved with rare cases of misoperation.

This paper discusses a percentage differential misoperation of a 1.55 MW, 4.16 kV generator shortly after synchronization and during loading of the generator, what caused the operation and how it was fixed.

Additional security measures added to the percentage differential and enhancements to the inrush inhibit is also presented to enhance generator differential security against large load energization events.

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Index Terms — Generator Differential (87), Percentage Generator Differential, CT Saturation, Directionality Check, Instantaneous overcurrent (IOC or 50), time overcurrent (TOC or 51), Directional Overcurrent (67), Intelligent electronic device (IED)

I. Introduction

Generator protection was originally covered initially by fuses, then as protection components developed, by overcurrent electromechanical relays. These original protection schemes were not very selective and could not reliably determine if faults were internal to the generator or on the generator step-up transformer or external bus or feeders. Current and/or time coordination was used for selectivity; however, this had the consequence that for internal generator faults, the fault would not be cleared instantaneously with much more transformer damage as a result.

Generator protection evolved to be more sensitive, secure and caters today for various generator types, sizes, and applications.

Today, typical generator protection schemes, consist of some or all of the following protection functions:

1. Distance (21) (Typically applied as backup protection)
2. Volts-per-Hertz (24)
3. Undervoltage (27)
4. Third harmonic undervoltage (27^{TH})
5. Inadvertent energization (50/27)
6. Reverse power (32)
7. Loss-of-field (40)
8. Stator unbalanced current (46)
9. Stator thermal (49)
10. Breaker failure (50BF)
11. Timed and instantaneous phase overcurrent (50/51)
12. Timed and instantaneous ground overcurrent (50G/51G)
13. Percentage differential
14. Time-overcurrent, detection of turn-to-turn faults (51)
15. Voltage controlled or restrained time-overcurrent (51V)
16. Exciter or DC generator relay (53)
17. Overvoltage protection (59)

18. Zero-sequence overvoltage for detection of ground faults in ungrounded generators (59BN)
19. Zero-sequence overvoltage for detection of stator turn-to-turn fault protection (59N)
20. Third harmonic instantaneous overvoltage (59TH)
21. Third harmonic instantaneous voltage differential (59THD)
22. Voltage balance or loss of potential (60)
23. Breaker failure timer (62B)
24. Fault pressure for transformer (63)
25. Rotor ground fault voltage (64F)
26. 100% stator ground fault with sub-harmonic injection (64S)
27. Directional ground overcurrent (67N)
28. Transformer oil/gas level (71)
29. Loss of synchronism (78)
30. Frequency, both under and over (81)
31. Hand-reset lockout (86)
32. Differential for bus (87B)
33. Differential for generator stator (87G)
34. Sensitive differential for generator stator (87GN)
35. Differential for generator step-up and/or unit transformers (87T)
36. Differential for overall generator and transformer (87O)
37. Self-reset auxiliary relay (94)

The number and quantity of protection elements needed depends on factors such as generator size (MVA), voltage levels, type of core, type of windings, cooling type (hydrogen, air or other).

II. History of Percentage Differential

The first unit transformer protection function developed is the transformer differential protection consisting only of differential overcurrent and not any restraint, which was not very secure during transformer energization or through-fault events, since current transformers (CTs) did not have the same performance. The same differential was initially deployed in generator protection.

Initially, overcurrent relays were used to measure the differential current.

This overcurrent protection was initially used for differential protection by having the CT secondary currents matched (same secondary current magnitudes and phase angles) and summed to measure the differential current as follows:

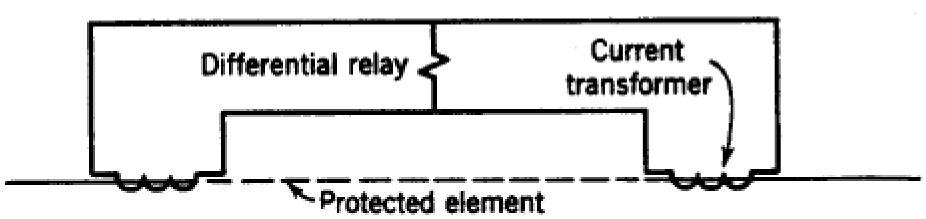


Fig 1: Simple Differential using a Current-Balanced Relay

External faults would then only see the current circulate as follows:

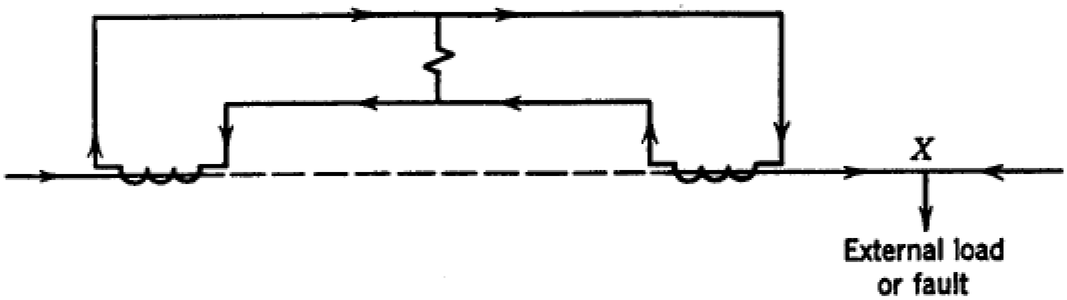


Fig 2: External Fault on a Current-Balanced Relay

Internal faults, the two currents could flow from both sides and would be summed and provide a differential current as follows:

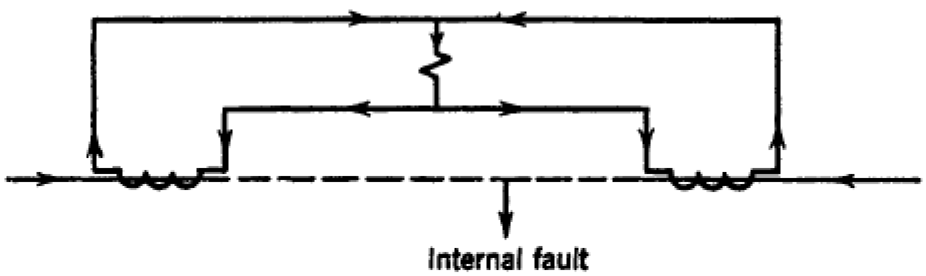


Fig 3: Internal Fault on a Current-Balanced Relay

It was only in the early 1900's that differential relaying with restraint was developed, comprising of a balanced beam, two current coils with core and a control spring as indicated in figure 4.

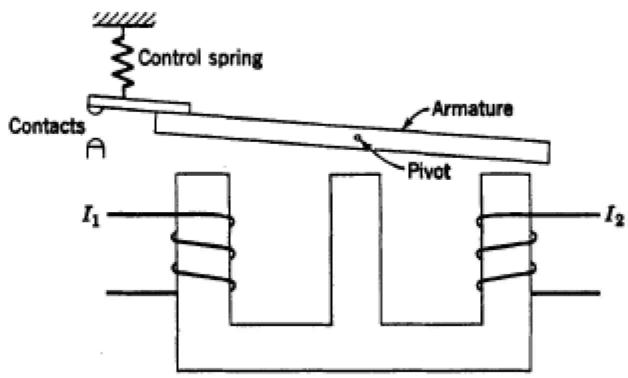


Fig 4: A Balanced Beam type of Current-Balanced Relay

In this case, I_1 produces positive torque and is hence the "operating" quantity where I_2 produces negative torque, or the "restraining" quantity, and the total torque can be given as:

$$T = K_1I_1^2 – K_2I_2^2$$

When the relay is at the verge of operation, the net torque is zero and:

$$K_1I_1^2 = K_2I_2^2$$

Therefore, the operating characteristic is:

$$\frac{I_1}{I_2} = \sqrt{\frac{K_2}{K_1}} = \text{constant}$$

The operating characteristic of this current-balanced relay is:

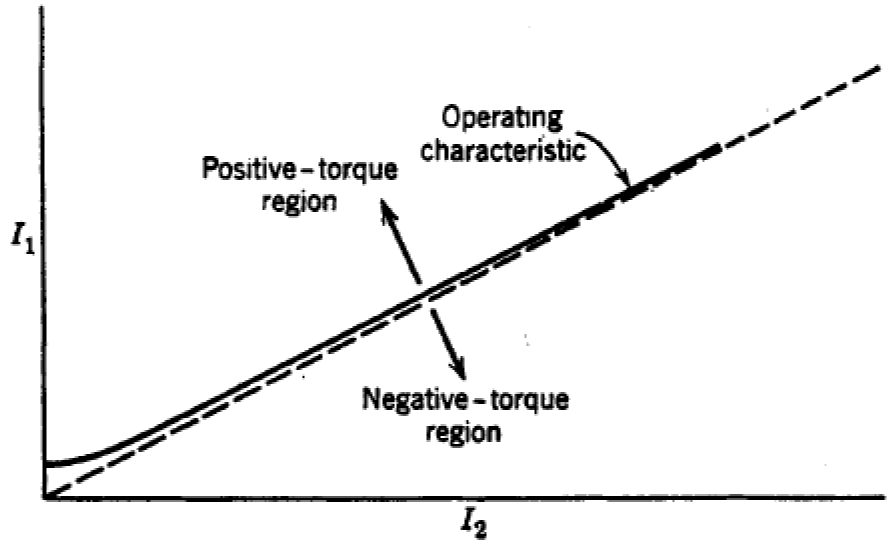


Fig 5: Operating Characteristic of a Current-Balanced Relay

The purpose of the control spring is to ensure the operate quantity I_1 won't cause an operation when the restraint quantity I_2 is zero, however has much less of an effect as current magnitudes increase. Operation occurs in the positive-torque region and restraint in the negative-torque region.

The operating characteristic is hence based on the ratio between I_1 and I_2, and as such can be expressed as the percentage between I_1 and I_2. The characteristic or "percentage slope" can be altered by changing the number of turns of the coils proportionally for I_1 and I_2.

The current-balanced relay was adopted for biased differential by changing the coil connections as follows:

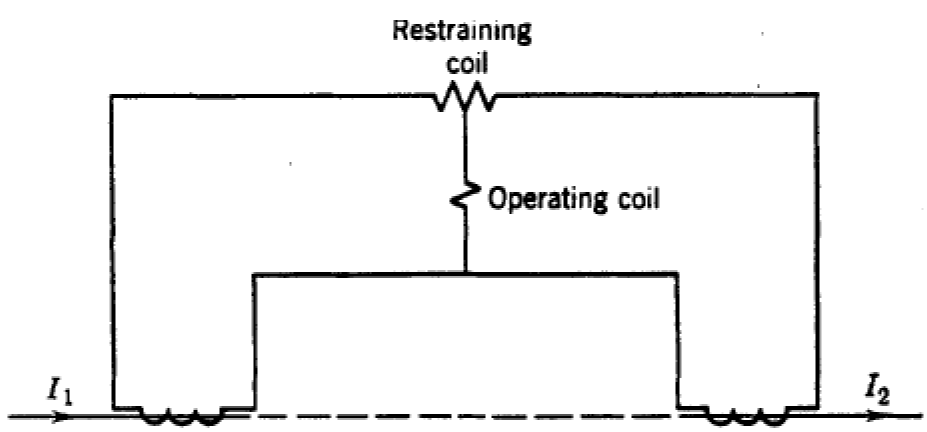


Fig 6: Percentage-Differential Relay for a two-winding transformer/generator

The differential current in the operating coil in this configuration is proportional to $I_1 – I_2$ and the equivalent current in the restraining coil is proportional to $(I_1 + I_2)/2$ if the operating coil is connected to the midpoint of the restraining coil. The operating/restraining characteristic of this relay is:

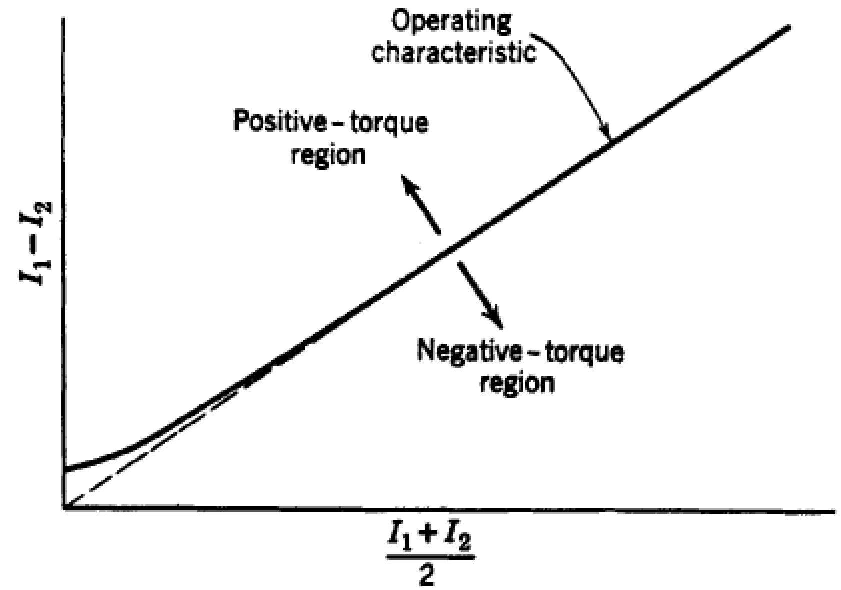


Fig 7: Percentage-Differential Relay Operating Characteristic

The ratio of the differential operating current to the average restraining current is a fixed percentage except at the minimum due to restraining spring; hence the name Percentage-differential protection.

The advantage of percentage differential was it was much more secure against incorrect operations during external faults than just a regular differential overcurrent, as compared in characteristics below:

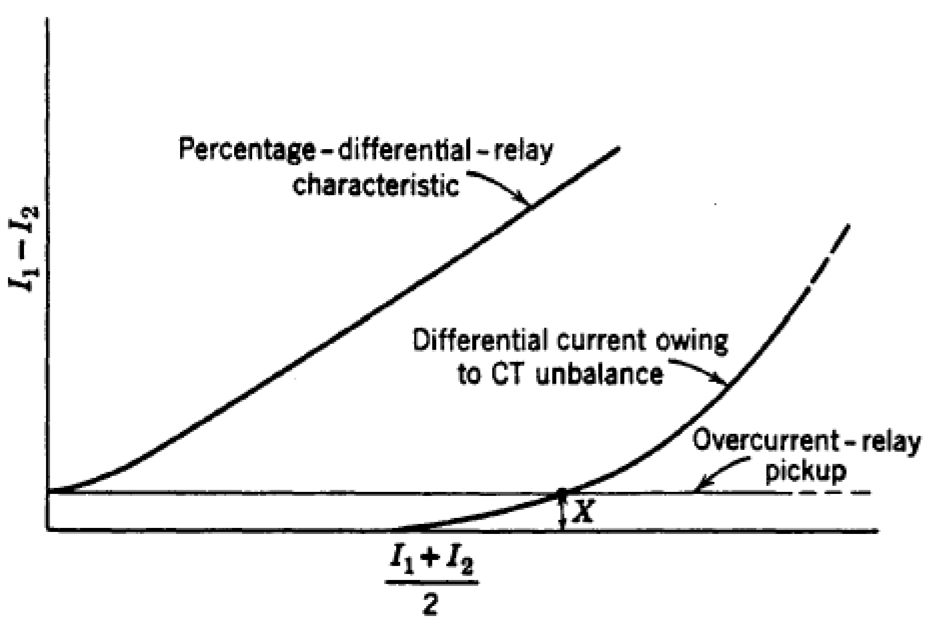


Fig 8: Percentage-Differential compared to Overcurrent-differential Characteristics

Due to a much more secure characteristic, percentage-differential became one of the key transformer and generator protection functions still widely used today.

III. Enhancements to Percentage Differential

The percentage-differential operating characteristic produced by the balanced-beam electromechanical relays as seen in figure 7, was secure for most external faults, however wasn't always sensitive during internal faults with low differential currents. The differential current can be low during high resistive faults, or due to high impedance grounding of the transformer or generator, hence the need to increase the sensitivity (or dependability) of the percentage-differential protection function.

Changing of the operating characteristic is not easily achievable in electromechanical relays, however is implemented in most transformer protection Intelligent Electronic devices (IEDs) today.

One of the most common characteristics for transformer percentage-differential deployed in IEDs today is:

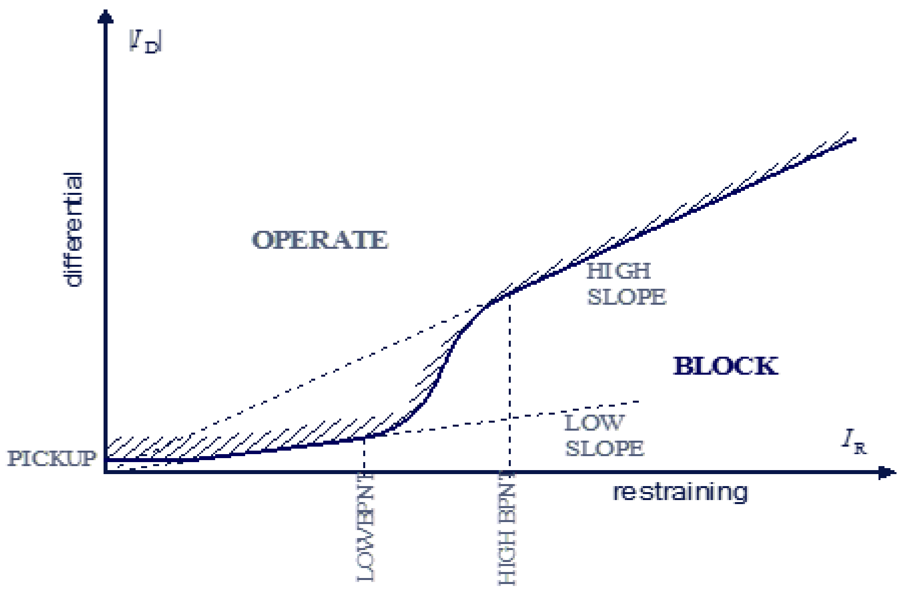


Fig 9: Percentage-Differential Characteristic in IED

This characteristic consists of minimum pickup, two slopes and two break points to allow transition from the low slope to the high slope, where the characteristic in Figure 7 consists only of the minimum pickup and one slope setting, depending on the capabilities of the balanced-beam eletromechanical relay.

The transition from low slope to high slope was initially a straight line, however was later improved to characteristic such as a cubic spline, which provides a much smoother transition.

This new improved percentage-differential caters much better for low differential currents, hence can the characteristic be split into two regions:

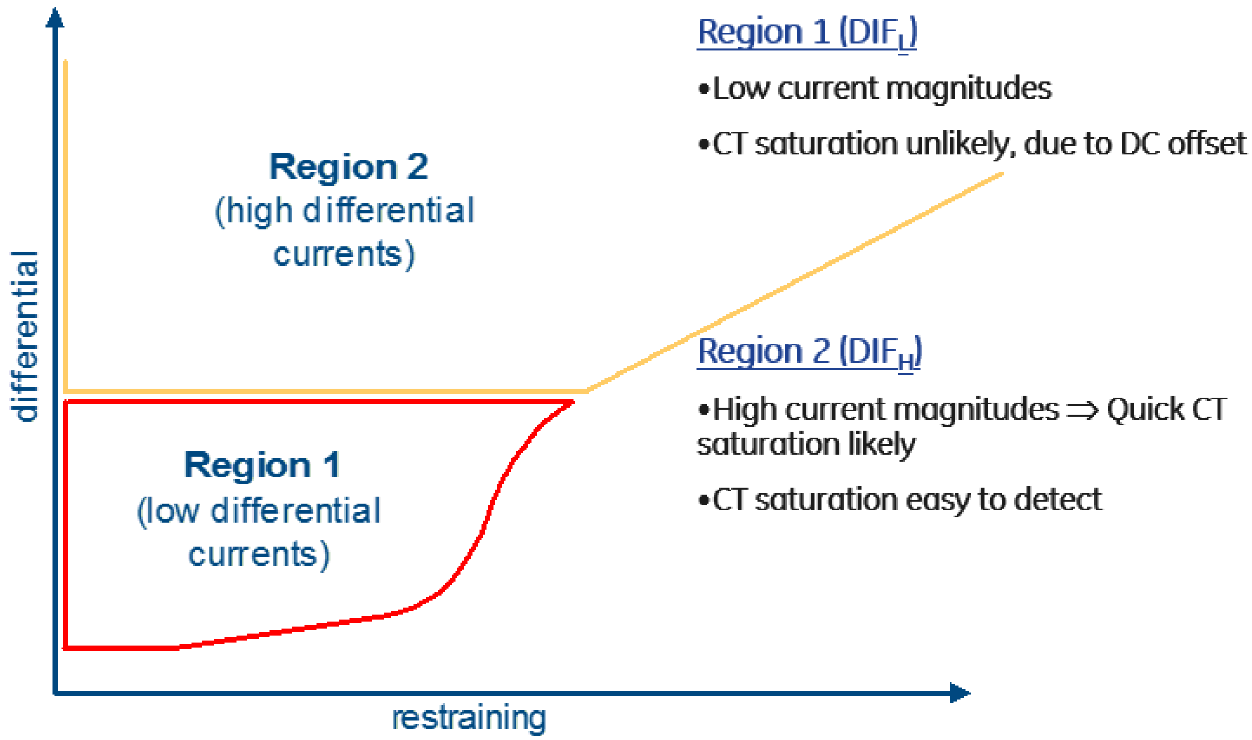


Fig 10: The Two Regions of the Percentage-Differential Characteristic

IV. Harmonic Restraint (Blocking) of Percentage-Differential

Percentage-differential still had the challenge of incorrect operations especially during transformer energization. As such, second harmonic inhibit has traditionally been used for transformer restraint (blocking) during magnetizing inrush conditions.

Harmonic restraint is not always implemented in Generator differential since it's not typically exposed to transformer energization events, however, should be used in an overall differential scheme.

Electromechanical relays and early microprocessor-based relays (IEDs), use either tuned transactors or Fourier transforms to estimate (measure, calculate) the second harmonic ratio. Values above a setting of typically fixed 20% (magnitude of 2^{nd} harmonic component/ magnitude of fundamental component of current) are classified as inrush cases; lower values allow the differential element to operate and trip the breakers. Modern transformers may cause problems for this traditional approach. In these transformers, the amount of 2nd harmonic may be as low as 7 to 10% for long periods of time during inrush conditions, jeopardizing the security of transformer differential protection. This is due to improved core material, core laminations, winding wound improvements and better insulation materials being used in more modern transformers.

Magnetizing inrush current in transformers results from any abrupt change of the magnetizing voltage. Although usually considered a result of energizing a transformer, the magnetizing inrush may be also caused by:

1) occurrence of an external fault,
2) voltage recovery after clearing an external fault,
3) change of the character of a fault (for example when a phase-to-ground fault evolves into a phase-to-phase-to-ground fault), and
4) out-of-phase synchronizing of a connected generator.
5) Saturation of current transformers during inrush
6) Inrush during removal of a fault
7) Sympathetic inrush (energization of a parallel transformer)

Since the magnetizing branch representing the core appears as a shunt element in the transformer equivalent circuit, the magnetizing current upsets the balance between the currents at the transformer terminals and is therefore experienced by the differential relay as a “false” differential current. The relay, however, must remain stable during inrush conditions. In addition, from the standpoint of the transformer life-time, tripping-out during inrush conditions is a very undesirable situation (breaking a current of a pure inductive nature generates high overvoltage that may jeopardize the insulation of a transformer and be an indirect cause of an internal fault).

For these reasons, the traditional harmonic inrush inhibit of 20% magnitude is not always adequate and the harmonic restraint needs to be improved.

One improvement is to take the phase angle differences of 2nd harmonic compensated to fundamental vs fundamental phase angle into account. The 2nd harmonic component rotate twice the speed of the fundamental, hence must the inhibit (blocking) algorithm take this into account, but this is easily overcome as described in [3].

Other means of securing the inhibit (blocking) algorithm, is by allowing the inhibit to be selectable on a per-phase basis (Inhibit for each phase of the transformer inrush is calculated and inhibit is applied separately), 2-out-of-three (if 2 of the three inhibits are above threshold, percentage-differential will be inhibited for all 3 phases) or 1-out-of-three (if 1 of the three inhibits are above threshold, percentage-differential will be inhibited).

Other means of inrush inhibit refinement made was to allow the 2nd harmonic inhibit level to be adjustable to levels other than the traditionally fixed 20% level.

The percentage-differential can also be vulnerable to incorrect operations due to transformer saturation events, which could occur during overexcitation conditions. The 5th harmonic is typical present during transformer overexcitation conditions, and the 5th harmonic vs fundamental ratio can also be used to secure percentage differential.

V. SECURING PERCENTAGE-DIFFERENTIAL USING DIRECTIONALITY CHECK AND CT SATURATION DETECTION

The percentage-differential function can be secured additionally for external through-faults or CT saturation, using the following newer algorithms:

A. Directionality Check

The directionality check compares the current angles between all windings and a main or reference winding, for CT’s connected in Wye and polarities as per Figure 14.
Voltages are NOT used for this directionality check.

This directionality check can be used to supervise percentage-differential against incorrect operations for any external fault during severe CT saturation, CT or CT wiring issues or failures.

For external faults, at least one of the current phase angles will be between +90 to +270 degrees i.e. more than 90 degrees to the reference, and for all internal faults, all current phase angles will be within 90 degrees to the reference, as per below:

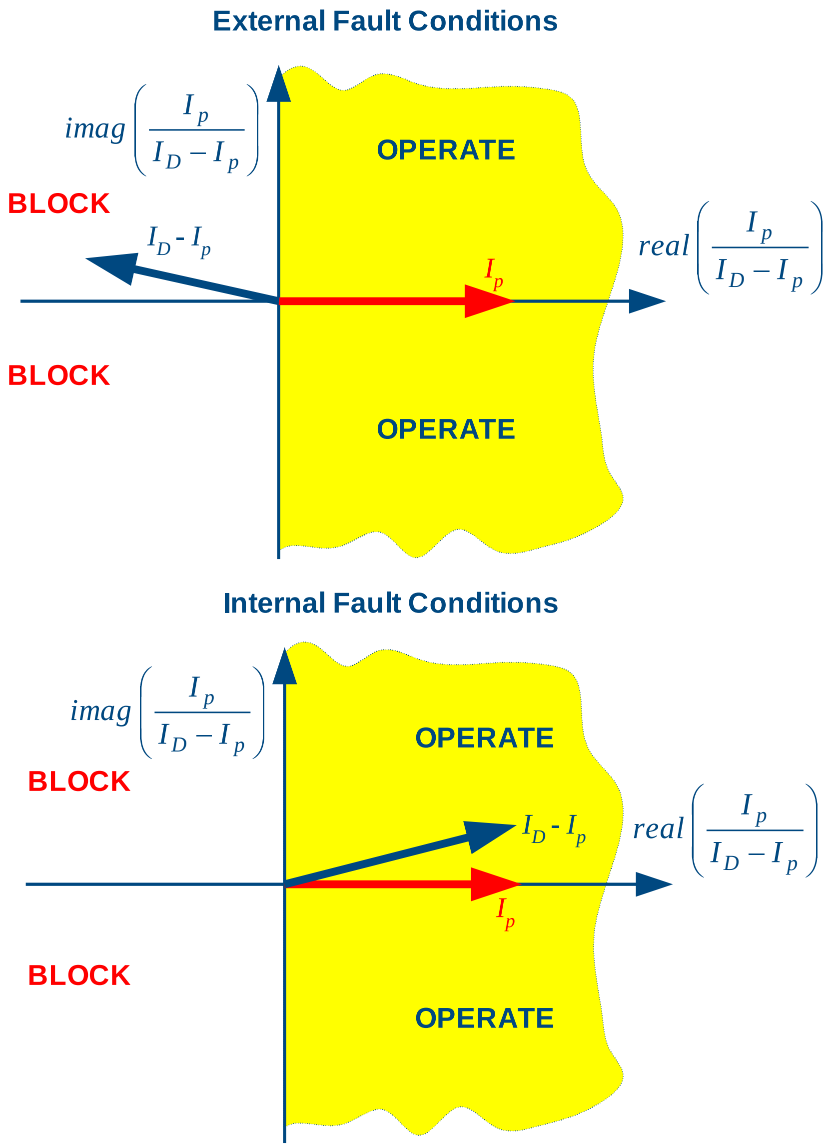


Fig 11: Directionality Check of Current Angles

B. CT Saturation Detection

During CT saturation events, the CT will typically provide unsaturated current for a brief period of 2 – 4 ms. This can be used to detect CT saturation based on the movement of the percent-differential characteristic as follows:

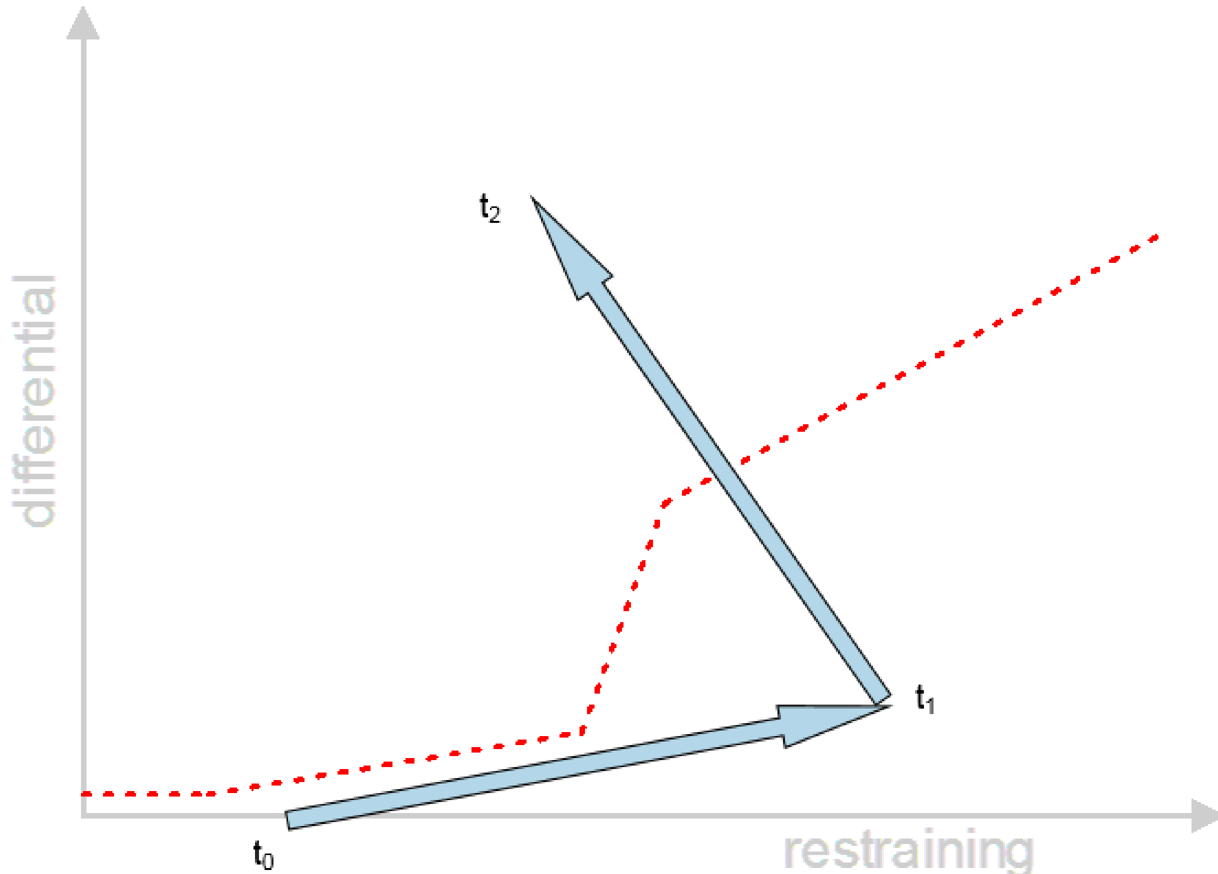


Fig 12: Percentage-Differential Characteristic During CT Saturation

At t_0, the external fault occurs. At t_1, the weakest CT starts to saturate and at t_2 the CT fully saturated.

This movement from load region to beyond breakpoint 2 and then towards the operating region is used to determine the fault is external and CTs are saturating; hence can the percentage-differential be blocked to remain secure.

VI. SETTINGS OF PERCENTAGE-DIFFERENTIAL

The balanced-beam type of percentage-differential relays needed the secondary currents to be of equal magnitude and phase angle, hence was it necessary that CTs of the generator neutral and line ends be of the same ratio, type, and preferably same manufacturer, and connected as follows:

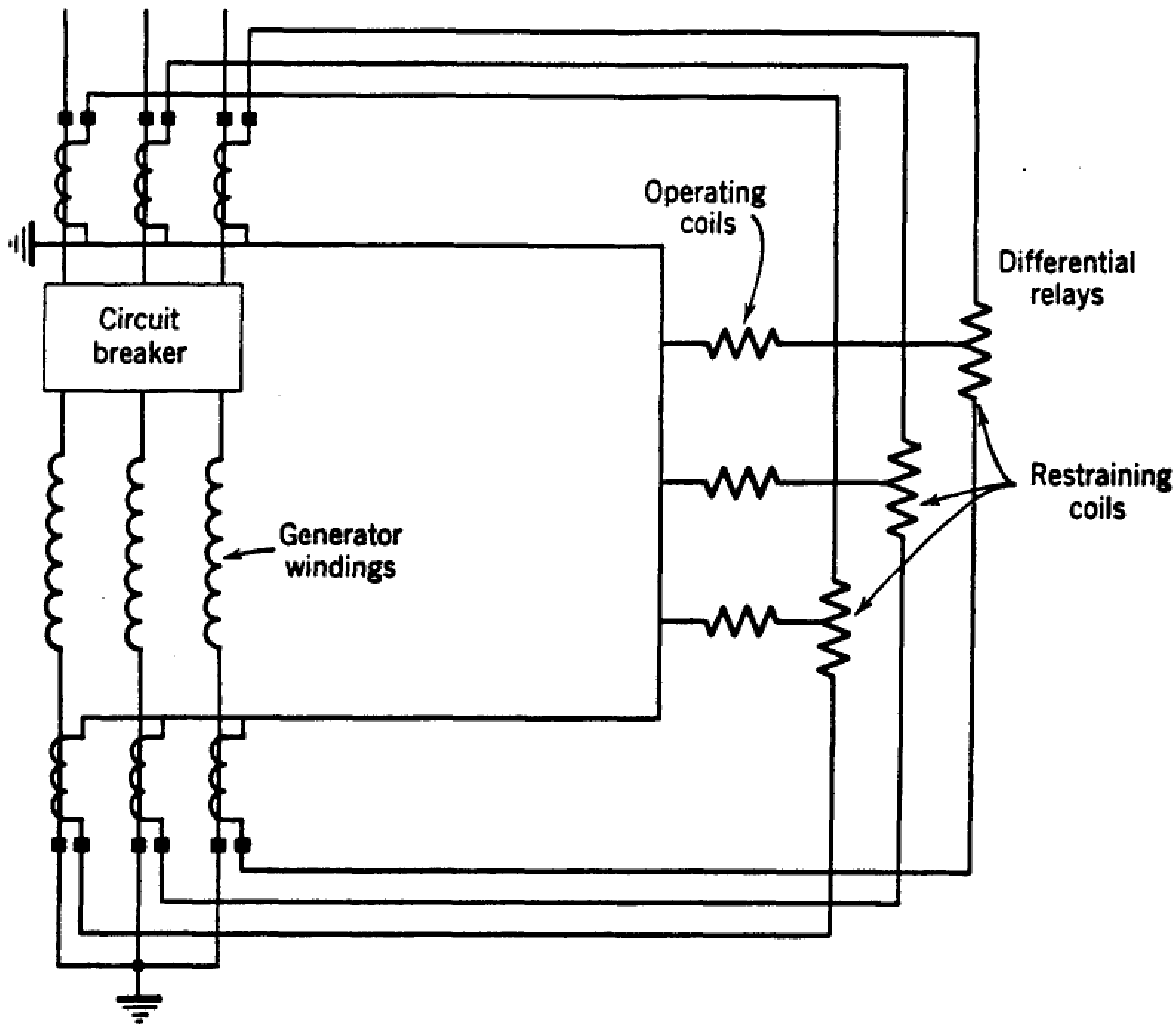


Fig 13: Connection Diagram for Balanced-Beam Generator Percentage-Differential Relay

If the current magnitudes could not be precisely matched, auxiliary CTs would be needed for current matching, which occasionally occurs in large generators. This of course add complexity and inaccuracies to the overall differential scheme, and the minimum differential current and slope had to be calculated on resultant differential, CT and auxiliary CT performance. CTs with similar performance is thus needed for most secure percentage-differential performance, especially when electromechanical relays are deployed.

Today's IED-type percentage-differential relays perform magnitude and phase angle compensation numerically, hence can CT ratios and types be different with all CT connections be wye as follows:

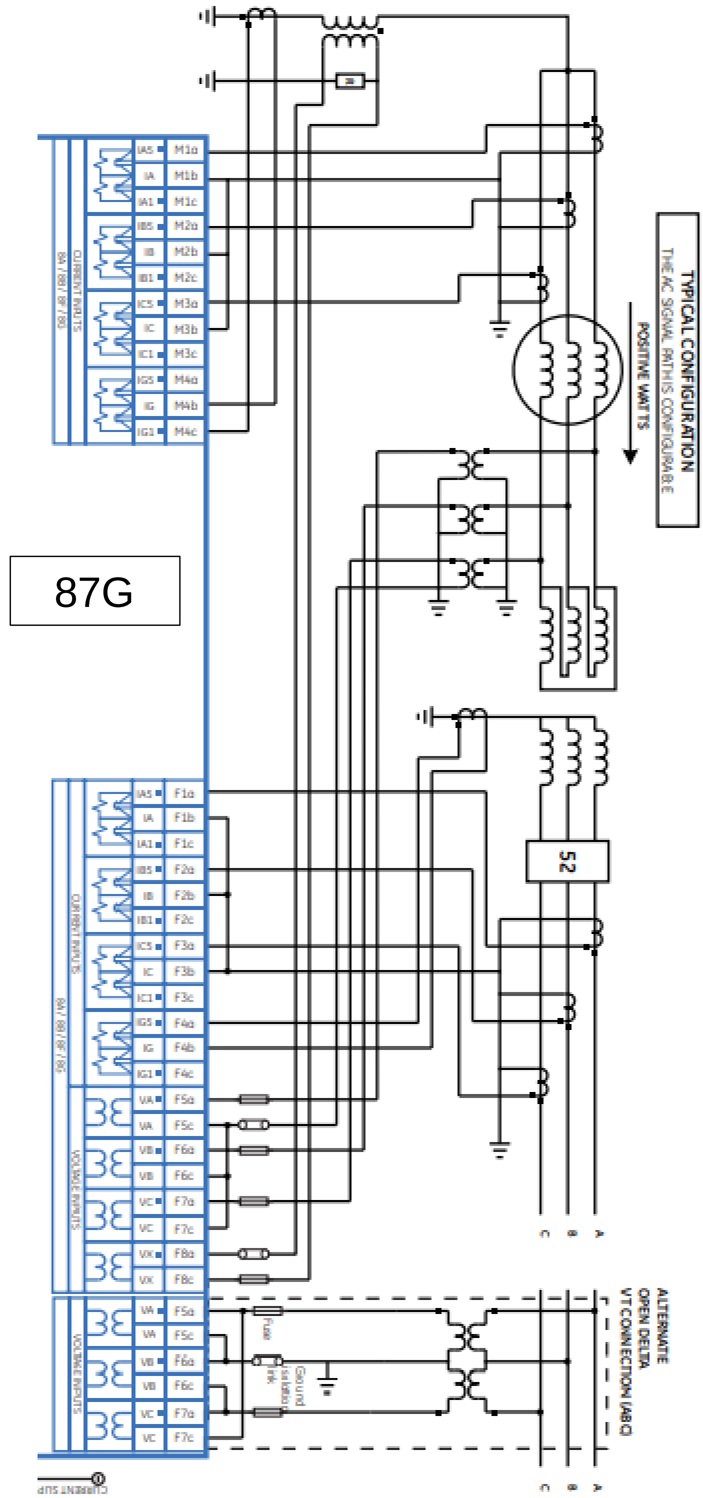


Fig 14: Connection Diagram for generator IED with overall Percentage-Differential Relay

The following settings must be entered for the generator and transformer (overall differential) and each CT bank:

1) CT ratio's and secondary current

2) Number of windings (if overall differential is used)

3) Phase compensation (Internal if IED needs to calculate or External if CT wiring compensates for overall differential)

4) Rated MVA (if overall differential is used)

5) Nominal phase-to-phase voltage (if overall differential is used)

6) Grounding (Overall differential: if winding is grounded within the zone eg. Grounded wye or ungrounded eg. Delta)

7) Angle with regards to winding 1 (if overall differential is used)

These settings are needed by the IED to determine equivalent differential current based on CT ratios, voltage ratio of transformer, zero sequence subtraction if internally grounded.

For example, if winding 2 has a 30degree lag with regards to winding 1, the equivalent currents calculated for the differential calculation is:

Φ_{comp}[w]	Grounding[w] = "Not within zone"	Grounding[w] = "Within zone"
30° lag	$I_A^P[w] = \frac{1}{\sqrt{3}} I_A[w] - \frac{1}{\sqrt{3}} I_C[w]$ $I_B^P[w] = \frac{1}{\sqrt{3}} I_B[w] - \frac{1}{\sqrt{3}} I_A[w]$ $I_C^P[w] = \frac{1}{\sqrt{3}} I_C[w] - \frac{1}{\sqrt{3}} I_B[w]$	$I_A^P[w] = \frac{1}{\sqrt{3}} I_A[w] - \frac{1}{\sqrt{3}} I_C[w]$ $I_B^P[w] = \frac{1}{\sqrt{3}} I_B[w] - \frac{1}{\sqrt{3}} I_A[w]$ $I_C^P[w] = \frac{1}{\sqrt{3}} I_C[w] - \frac{1}{\sqrt{3}} I_B[w]$

Fig 15: Phase and Zero Sequence Compensation for 30Degrees phase shift

The differential current is calculated based on this compensated current:

$$I_d = \overrightarrow{i_{1(comp)}} + \overrightarrow{i_{2(comp)}}$$

Different definitions of restraint signals are used in the industry.
Here are a few examples:

$$i_R = |i_1| + |i_2| + |i_3| + \ldots + |i_n|$$ "sum of"

$$i_R = \frac{1}{n}\left(|i_1| + |i_2| + |i_3| + \ldots + |i_n|\right)$$ "scaled sum of"

$$i_R = \sqrt[n]{|i_1| \cdot |i_2| \cdot |i_3| \cdot \ldots \cdot |i_n|}$$ "geometrical average"

$$i_R = Max\left(|i_1|, |i_2|, |i_3|, \ldots, |i_n|\right)$$ "maximum of"

The most common are "Sum Of" and "Max Of". Here is a comparison:

"Sum Of" Approach

- More restraint on external faults; less sensitive for internal faults
- "Scaled-Sum Of" approach takes into account number of connected circuits and may increase sensitivity
- Breakpoint settings for the percent differential characteristic more difficult to set

"Max Of" Approach

- Less restraint on external faults; more sensitive for internal faults
- Breakpoint settings for the percent differential characteristic easier to set
- Better handles situation where one CT may saturate completely (99% slope settings possible)

Most commonly used is the "Max Of" restraint, which the following guidelines are based on.

Based on Figure 9, the percentage-differential has the following settings, and must be calculated accordingly:

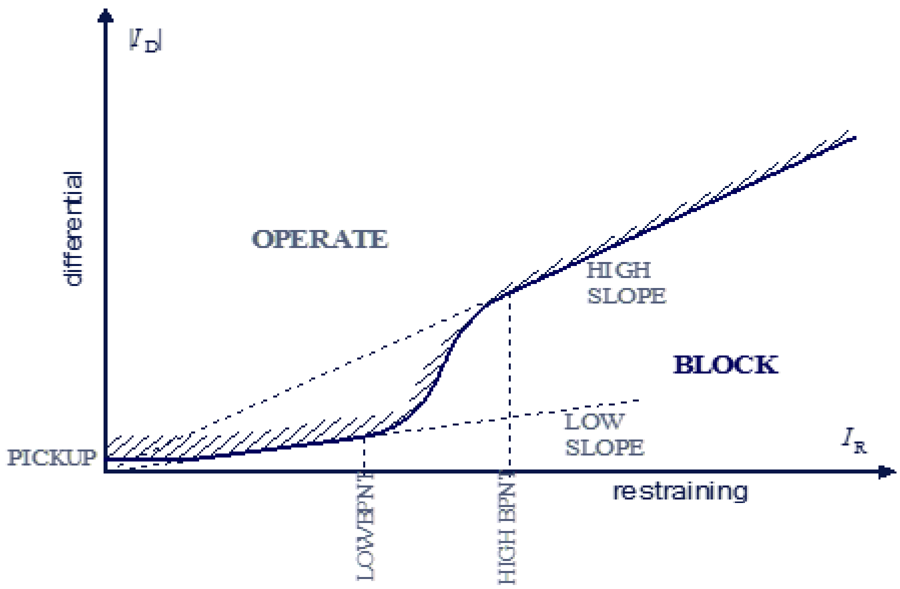


Fig 9 (Repeated): Percentage-Differential Characteristic in IED

I. Minimum Pickup

1) Defines the minimum differential current required for operation of the Percentage-Differential element.

2) Calculate based on CT errors during load conditions and low currents.

3) Must be set above maximum leakage current not zoned off (not measured by the differential) in the percentage-differential zone (VTs for example)

II. Low Slope

1) Defines the percent bias for the restraint currents from I_{REST}=0 to I_{REST}=Low Breakpoint

2) Setting determines the sensitivity of the differential element for low-current internal faults

3) Must be set above maximum error introduced by the CTs in their normal linear operating mode

4) Include errors introduced by a tap changer

5) Errors due to relay accuracy, excitation/losses of transformer, maximum leakage currents as in VI.

6) Based on performance of all CTs during linear operation and above factors, the slope can be calculated as:

$$\text{Slope} = \frac{\Delta I_d}{\Delta I_r} \times 100\% \ \text{(in pu)}$$

7) The maximum differential current can be calculated by using the IEEE PSRC CT saturation calculator [4], based on the weakest (lowest performance/class) CT saturating:

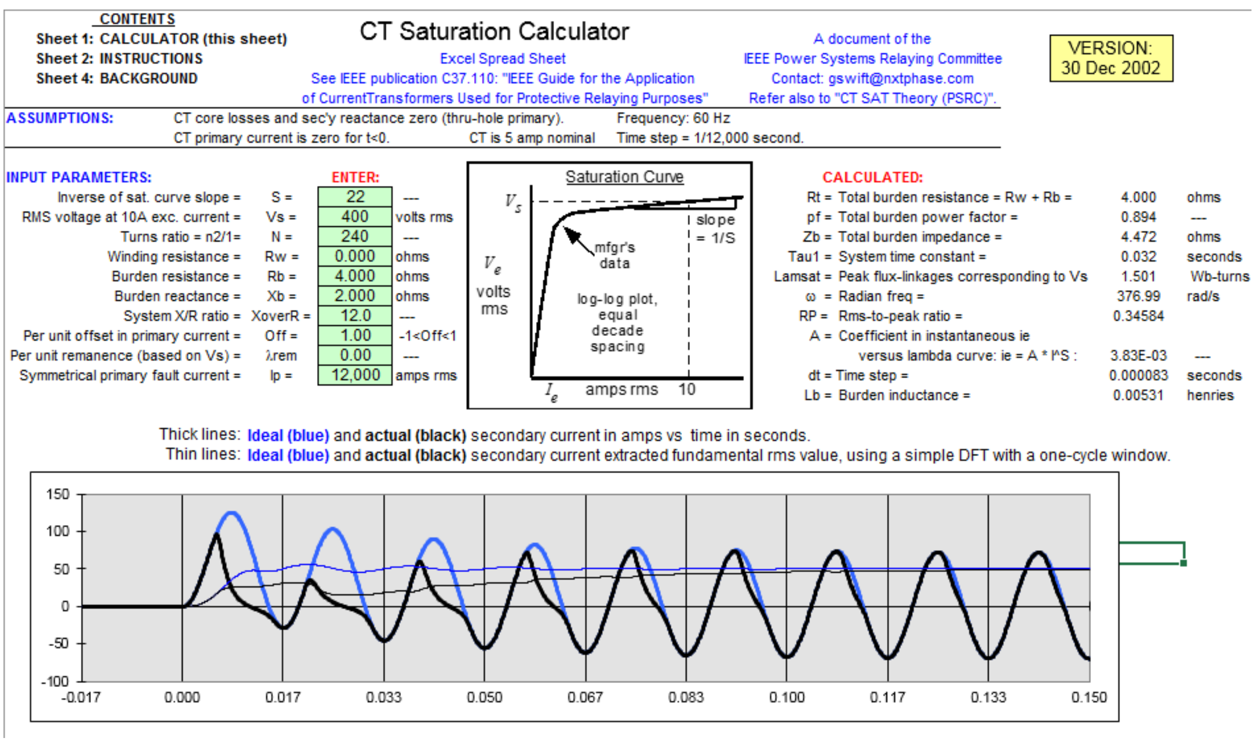


Fig 16: IEEE PSRC CT Saturation Calculator

III. Low Breakpoint

1) Defines the upper limit to restraint currents that will be biased according to the Low Slope setting

2) Should be set to be above maximum load but not more than maximum current where CTs still operate linearly (including residual/remanence flux)

3) Assumption is that CTs will be operating linearly (no significant saturation up to 80% residual flux) up to the Low Breakpoint setting. Again, to be calculated using [4].

IV. High Breakpoint

1) Defines the minimum restraint currents that will be biased according to the High Slope setting

2) Should be set to be below the minimum current where the weakest CT will saturate with no residual flux. Again, to be calculated using [4].

V. High Slope

1) Defines the percent bias for restraint currents larger than high breakpoint

2) Setting determines stability of differential element for high current external faults

3) Should be high enough to tolerate spurious differential current during saturation of CTs on heavy external faults

4) Setting can be relaxed in favor of sensitivity and speed as CT saturation and directional principle can be used for security if used.

VII. Analysis of 4.16 kV Generator Differential Incorrect Operation

A. Introduction

The generator percentage-differential protection function operated incorrectly after the generator was synchronized and loaded to 1.1 MW with no faults on the system. This occurred during two separate incidents.

During both incidents differential currents were observed in both A and B-phases (nothing in C-phase), which would fluctuate until the differential current increase above the minimum pickup setting of 0.3 p.u. in A-phase, which is the trigger point of the waveforms in Figure 17.

These currents are well in the load region, hence is no CT saturation suspected.
The phasors of the neutral currents were stable; however the line currents phase angles were fluctuating when comparing waveforms in figure 18, and did contain more harmonics (especially 2nd).

Very little negative and zero sequence currents are observed.

This IED did not include the directionality check or CT saturation detection algorithms as was discussed earlier.

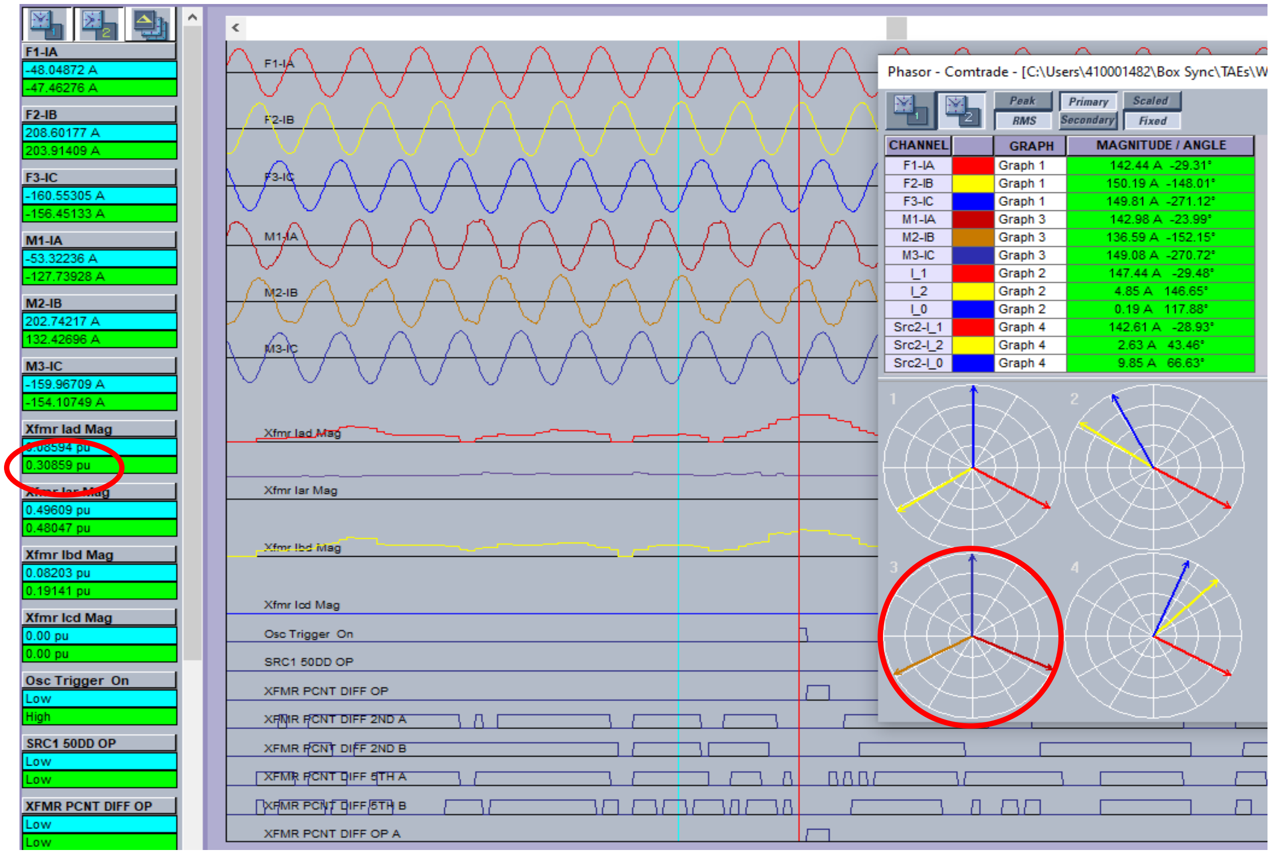


Fig 17: Incorrect Percentage-Differential Operation Waveforms (1)

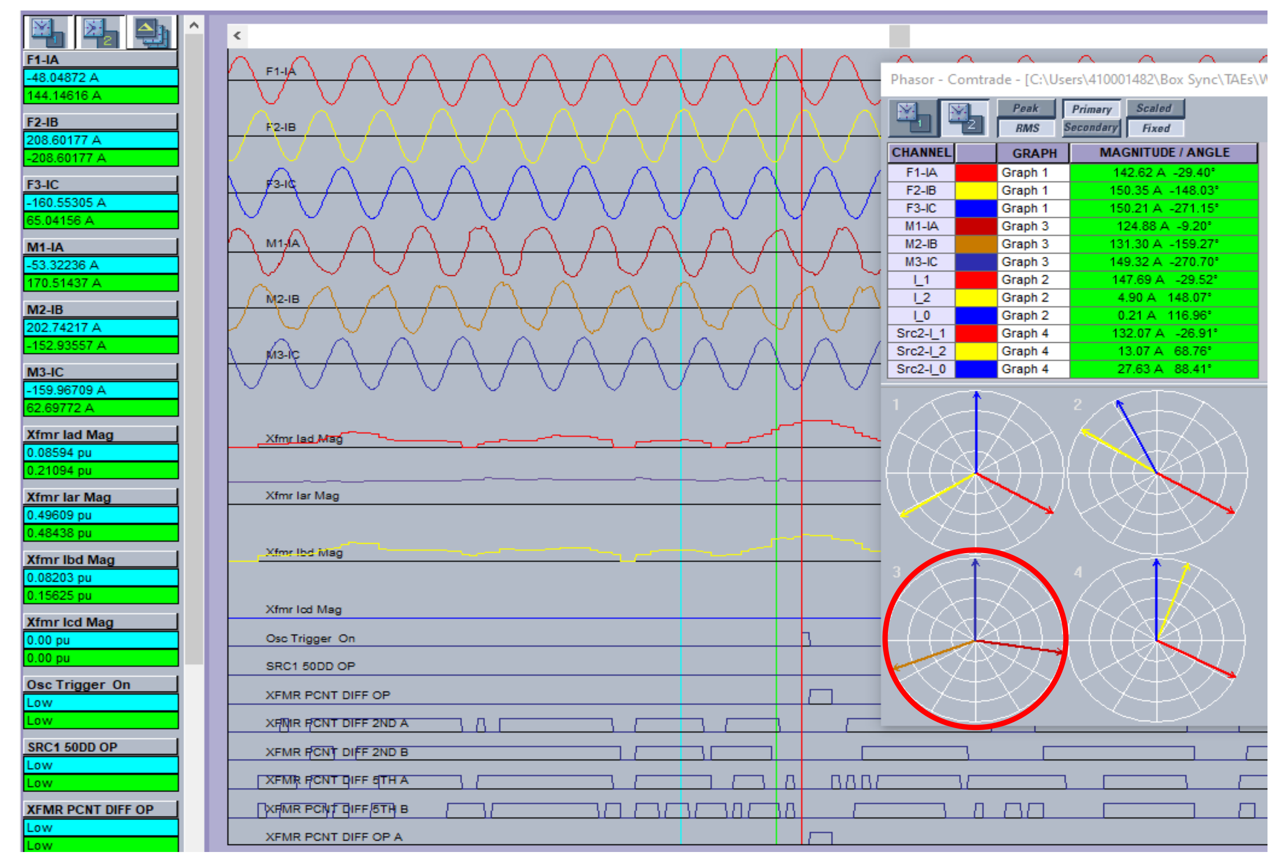
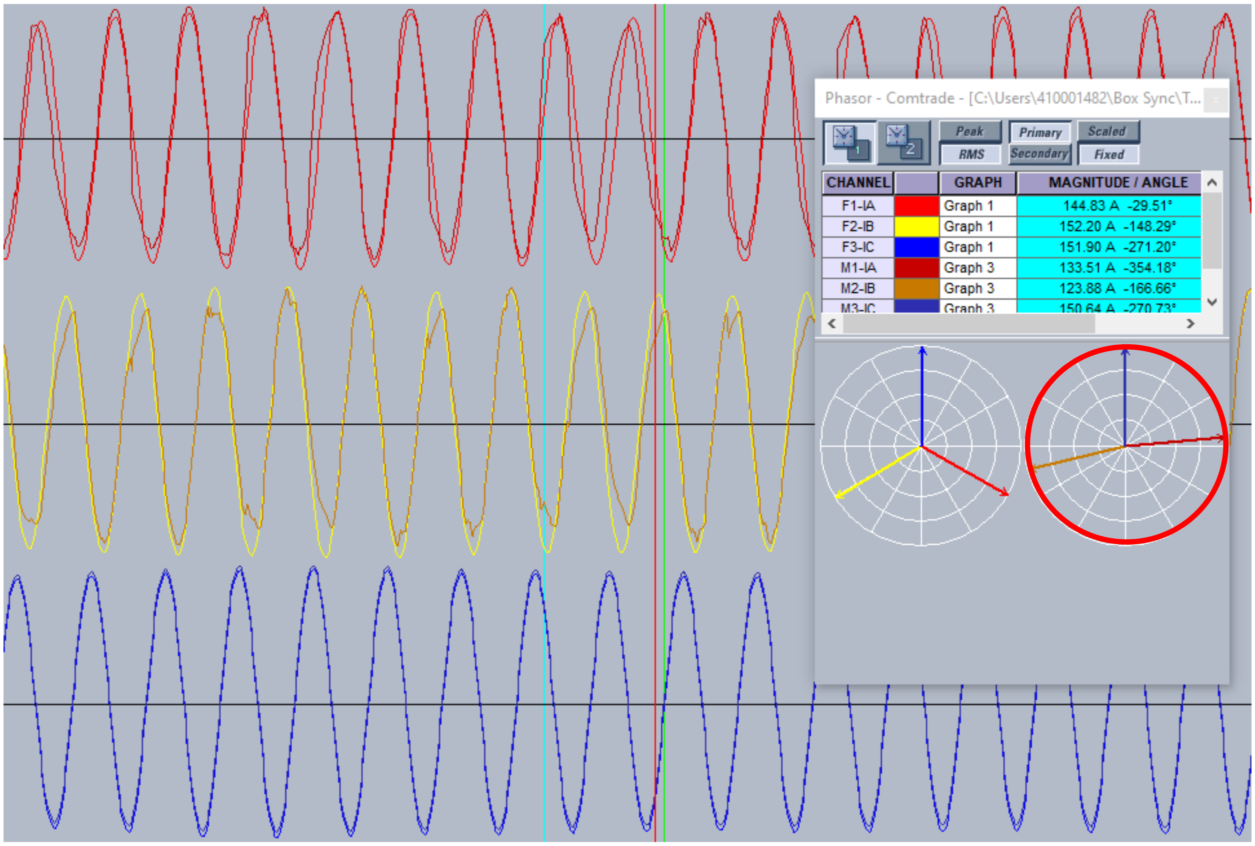


Fig 18: Incorrect Percentage-Differential Operation Characteristic (2)

The neutral and line currents had a difference more than expected, especially when comparing A and B phase currents. They are expected to be much closer to each other since CTs are of the same ratio and type, and no CT saturation expected. This difference is much more than expected maximum CT errors.

The troubling part is the neutral A and B-phase currents seem to be somewhat distorted; see below when currents are put on top of each other, especially the phasors: (C-phase currents are very similar, hence no C-phase differential current)



.Fig 19: Comparing Line and Neutral Currents

B. Investigation

1) Possible internal fault in the generator windings?

In order to rule out internal faults in the generator stator winding, several electrical tests were carried out:

i. Insulation Resistance IR, and Polarization Index PI of each stator phase winding and associated medium voltage cabling (PI values were average of 9)

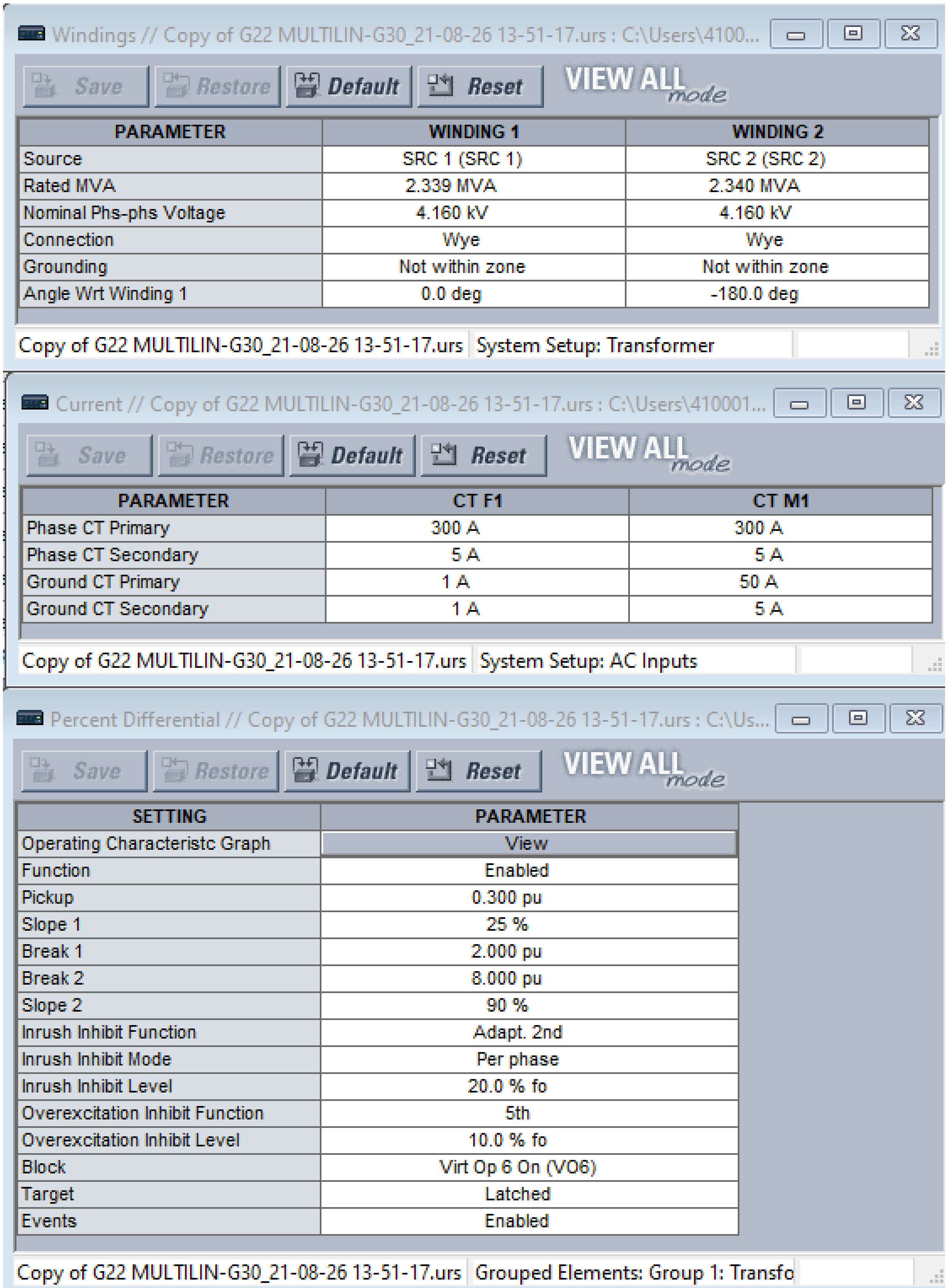
ii. DC winding resistance of each phase winding (average of 84.8mΩ @ 20°C)

With confidence that there was no problem inside of the generator, NTPC decided to increase the differential current from 0.2pu to 0.3pu before returning the unit back online. This resulted in the same outcome; the unit would trip around 1MW. It was then observed that the differential current would increase as the load on the unit increases. Around 1MW was when the differential pickpup was reached.

2) Possible Settings Error?

The second part of the investigation led to checking all settings, especially differential settings, CT ratio's, against the actual transformer, generator data and wiring diagrams.

Settings were correct and definitely not too sensitive for this application, which was correct as below:



Windings // Copy of G22 MULTILIN-G30_21-08-26 13-51-17.urs : C:\Users\4100...

Save | Restore | Default | Reset | VIEW ALL mode

PARAMETER	WINDING 1	WINDING 2
Source	SRC 1 (SRC 1)	SRC 2 (SRC 2)
Rated MVA	2.339 MVA	2.340 MVA
Nominal Phs-phs Voltage	4.160 kV	4.160 kV
Connection	Wye	Wye
Grounding	Not within zone	Not within zone
Angle Wrt Winding 1	0.0 deg	-180.0 deg

Copy of G22 MULTILIN-G30_21-08-26 13-51-17.urs | System Setup: Transformer

Current // Copy of G22 MULTILIN-G30_21-08-26 13-51-17.urs : C:\Users\410001...

Save | Restore | Default | Reset | VIEW ALL mode

PARAMETER	CT F1	CT M1
Phase CT Primary	300 A	300 A
Phase CT Secondary	5 A	5 A
Ground CT Primary	1 A	50 A
Ground CT Secondary	1 A	5 A

Copy of G22 MULTILIN-G30_21-08-26 13-51-17.urs | System Setup: AC Inputs

Percent Differential // Copy of G22 MULTILIN-G30_21-08-26 13-51-17.urs : C:\Us...

Save | Restore | Default | Reset | VIEW ALL mode

SETTING	PARAMETER
Operating Characteristc Graph	View
Function	Enabled
Pickup	0.300 pu
Slope 1	25 %
Break 1	2.000 pu
Break 2	8.000 pu
Slope 2	90 %
Inrush Inhibit Function	Adapt. 2nd
Inrush Inhibit Mode	Per phase
Inrush Inhibit Level	20.0 % fo
Overexcitation Inhibit Function	5th
Overexcitation Inhibit Level	10.0 % fo
Block	Virt Op 6 On (VO6)
Target	Latched
Events	Enabled

Copy of G22 MULTILIN-G30_21-08-26 13-51-17.urs | Grouped Elements: Group 1: Transfo

Fig 20: Transformer and Entered Settings

3) Possible Relay Algorithm Error?

The phasors observed by the relay were as below:

Phase	Trip Point	
	Line Currents	Neutral Currents
A	143.85A∠-29.48°	124.63A∠-348.94°
B	150.94A∠-148.21°	124.33A∠-168.54°
C	150.84A∠-271.08°	149.60A∠-270.61°

Since the CT ratios are the same and no transformer, the magnitude and phase compensation factors = 1.

$$I_d = m_1 \cdot \begin{bmatrix} IA_{1c} \\ IB_{1c} \\ IC_{1c} \end{bmatrix} + m_2 \cdot \begin{bmatrix} IA_{2c} \\ IB_{2c} \\ IC_{2c} \end{bmatrix}$$

Since the A-phase differential current was significantly higher than B-phase, we can calculate: differential current from above phasors:

$Id = 94.74A \ or \ 0.31pu$

Which is a significant differential current, not expected to be seen during normal load conditions!

Based on this, time to review and re-think what was observed:

- Settings seems correct
- Waveforms of A and B-phase line side currents are somewhat distorted without signs of saturation
- The differential current the relay calculated seems correct, however what is abnormal, the A and B-phase differential are higher than expected; C-phase differential currents were very close to 0.

4) Is this potentially a CT or wiring issue, or perhaps a relay hardware issue?

With the generator out of service, measuring resistance of the CT circuit at the relay, phases A and B had a higher resistance than phase C. The same was observed at the preceding shorting block. The CTs wiring were inspected, and the common conductor was found to be loose. This common conductor was made on the C-phase CT so that connection was good, it was the connection to A and B that was loose.

Below is the common conductor (after it was inspected for tightness, it came off)

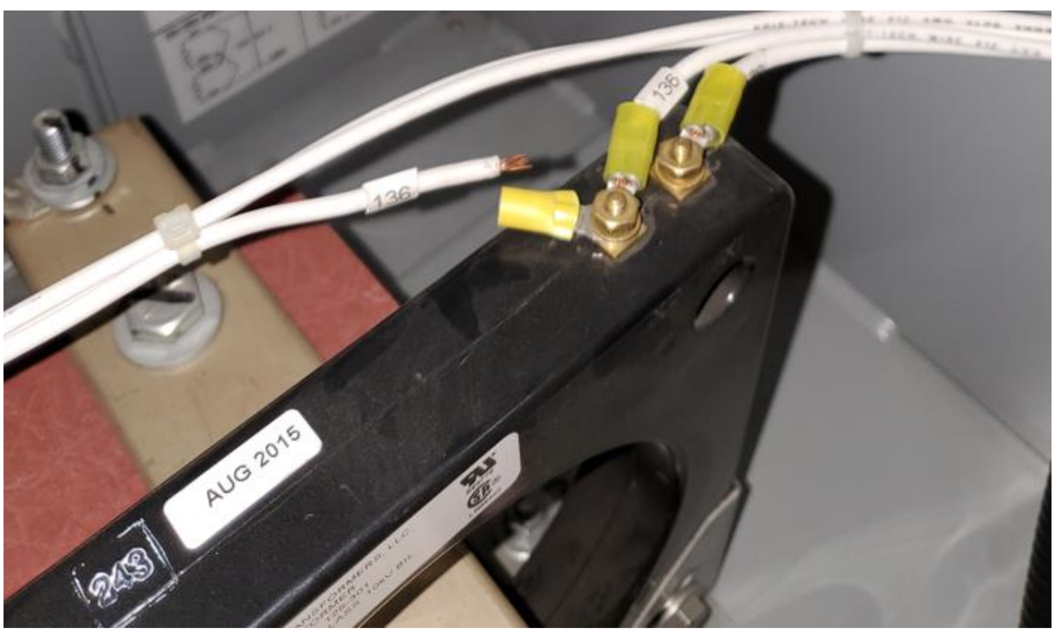


Fig 21: CT connections that came off

Evidence of arcing on the conductor strands (not clear), possible arcing on the insulation as well

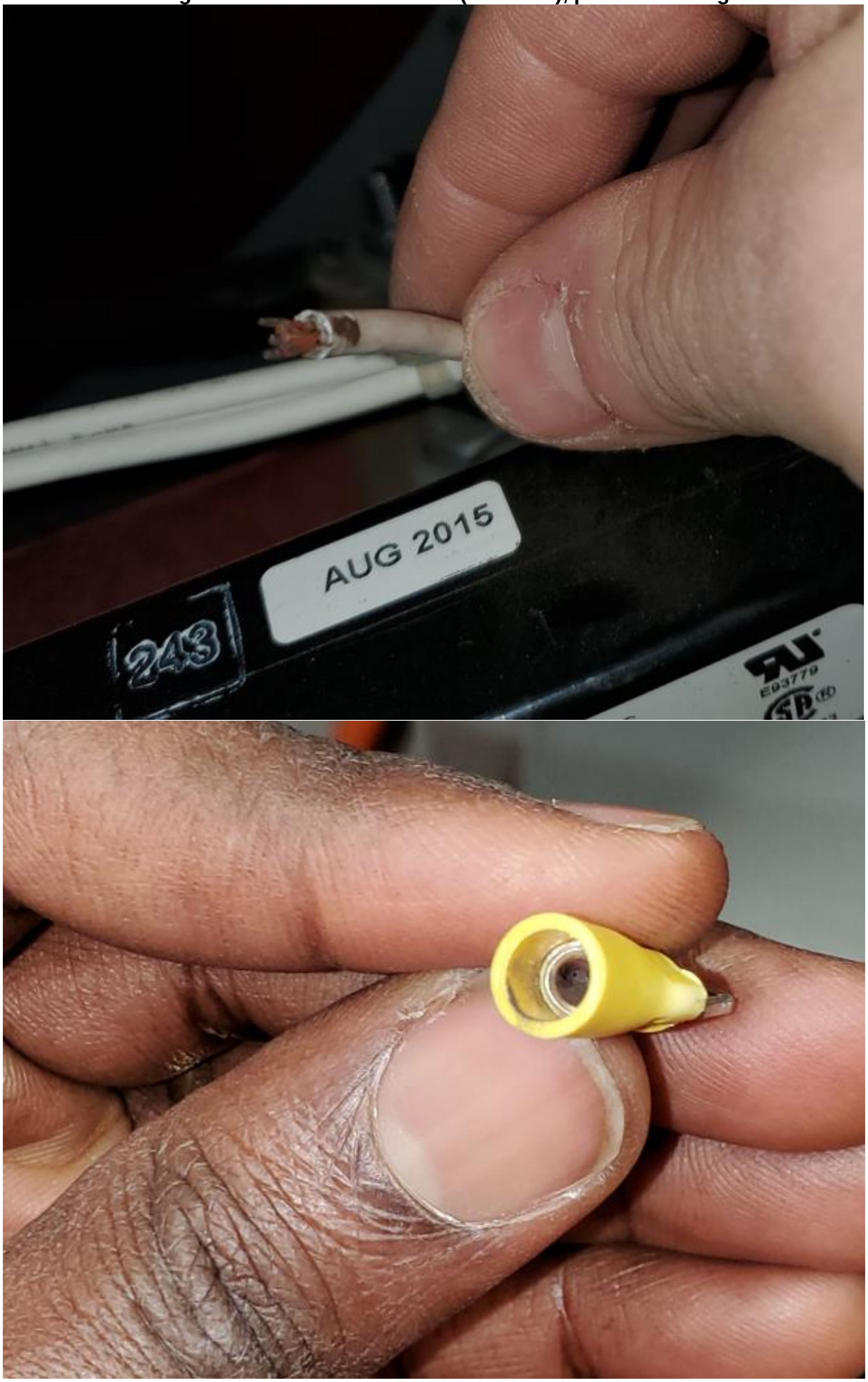


Fig 22: Arching of CT Wires/lug

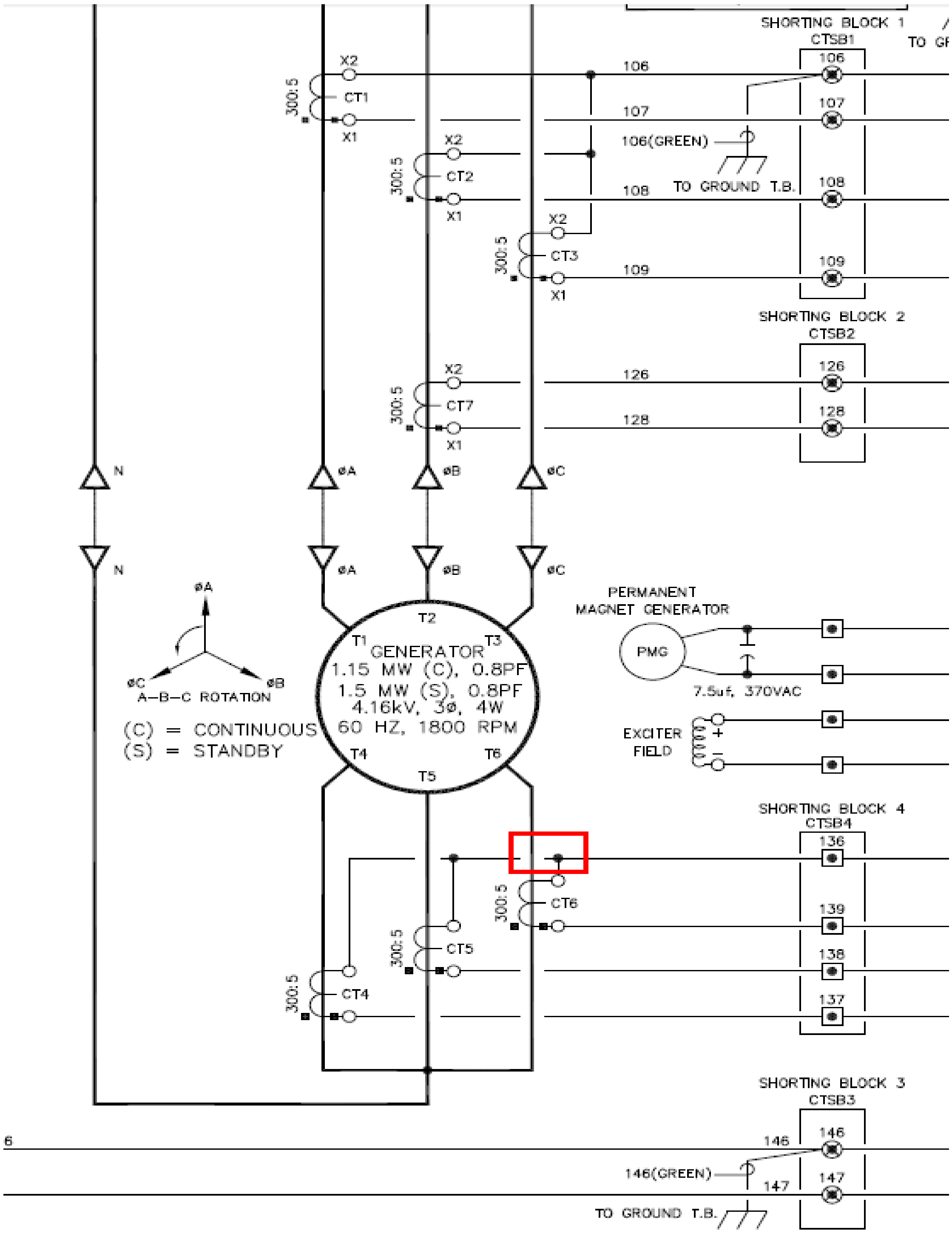


Fig 22: Loose connections to A- and B-phase Neutral CTs

After this CT wiring was fixed, re-terminated and connected, the generator was synchronized and loaded to about 1.1MW with the following results, indicating 0 differential currents and neutral and line currents identical:

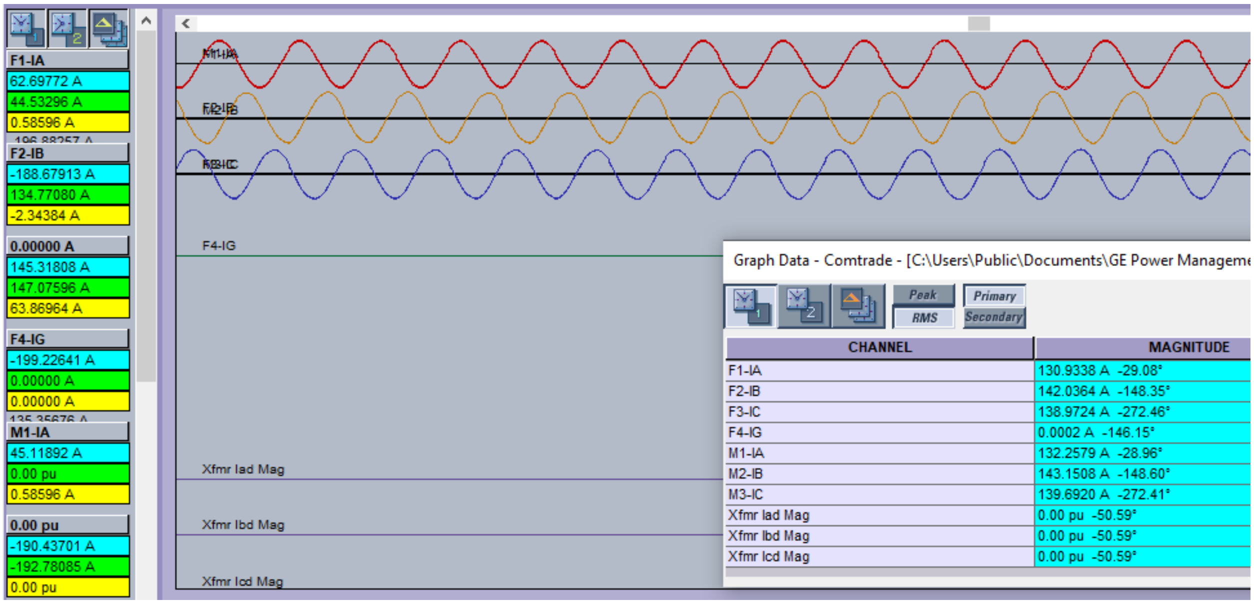


Fig 22: Generator Currents after correcting CT wiring

VIII. CONCLUSION

Percentage-differential is a fast, dependable and secure protection function and form an important part in generator and transformer protection. This function was enhanced and improved through the decades to cater for more demanding applications, better sensitivity and changing transformers that also evolved through the decades. Setting of this function reliably and securely is discussed, with a highlight of CT performance.
Many other enhancements were additionally introduced to the percentage-differential, such as CT saturation and directionality check.

An unusual percentage-differential incorrect operation is covered, highlighting that the whole protection system, including instrument transformers and its wiring, should be analyzed during such operations, utilizing analytical skills, literature, software analysis tools, consultation with manufacturers of primary equipment and IEDs. This highlighted that the instrument transformer wiring, in this case of 4.16kV generator CTs, was the cause of an unwanted differential protection operation.

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