Incorrect transformer differential operation due to System Grounding

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Abstract – Power system grounding is a key component of power system design and can have adverse effects to protection schemes. Particular protection functions that can be impacted are phase, neutral and negative sequence overcurrent, directional overcurrents, restricted ground fault and Transformer differential protection.
This paper discusses LV power system grounding, impacts of a solidly grounded generator to the system with a solidly grounded wye transformer winding and how this caused the transformer percentage differential to incorrectly operate.
Additional security measures added to the percentage differential are also presented to enhance transformer differential security against temporary system grounding events causing circulating currents, ensuring correct percentage differential operation.

Index Terms — Transformer Differential (87), Percentage Transformer Differential, CT Saturation, Directionality Check, Instantaneous overcurrent (IOC or 50), time overcurrent (TOC or 51), Directional Overcurrent (67), Ground Fault Protection (GFP), Modified Differential Ground Fault, Intelligent electronic device (IED).

I. INTRODUCTION

Power system grounding should be regarded as the connection of the three-phase AC power system to the mass of the earth, which is usually via the neutral terminal, to accomplish the following:

1. Provide a reference to ground for the power system
2. Stabilize the voltage during normal system operation
3. Limit the voltage rise on the power system occurring during abnormal system conditions such as ground faults, surges, lightning, unintentional contact with a higher voltage system or other abnormal system events
4. Safeguard against undue voltage stress on power system primary component insulation, such as cables, transformers, generators, motors.

A simple single ground on a power system typically would be grounded as follows:

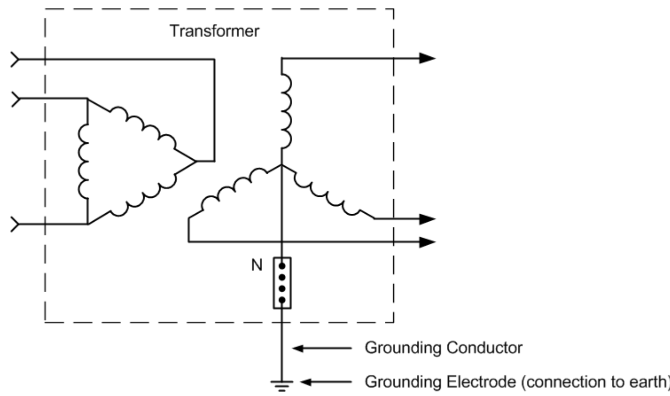

Fig. 1: Simple Single Ground of LV Power System

All LV power system components must be electrically bounded and connected to ground to ensure interconnection of conductive materials enclosing electrical conductors and equipment must establish an equipotential plane such that the possibility of a potential difference between the exposed non-current carrying metal parts is minimized, ensuring all LV power system components are safe, Connections are typically as follows: (3-phase 4-wire LV power system)

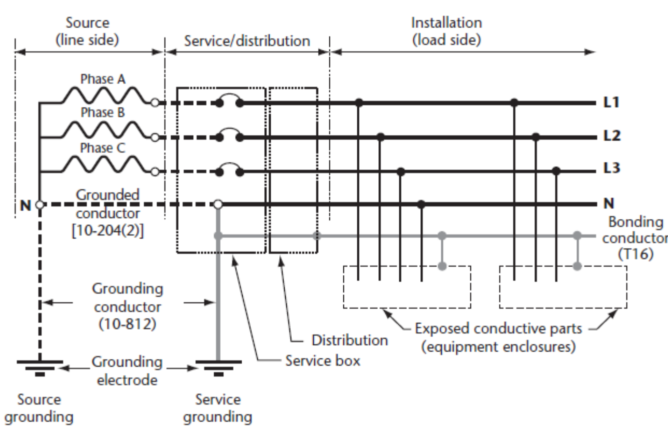

Fig 2: LV Bonding System and its Connection to Ground

The objective of equipment grounding and bonding is:

1. To provide adequate current-carrying capability in the ground fault return path for the duration of a ground fault without any equipment risk, e.g. overheating and fire
2. To provide a low-impedance path for ground fault current to facilitate the operation of overcurrent protective devices, including its coordination time
3. To reduce the risk of electric shock hazard to personnel

There are numerous standards addressing grounding, bonding and protection requirements of LV power systems. Some examples for single or multiple source LV 3-phase power systems are:

1. Canada: CSA C22.1-15
2. Canadian Electric Code CEC Rule 10-206
3. Canadian Electric Code CEC Rule 10-204
4. Canadian Electric Code CEC Rule 14-102
5. IEEE Green Book Std 142-1991
6. IEEE Orange Book Std 446-1995
7. USA National Electric Code NEC 230.95
8. USA National Electric Code NEC 250.24
9. USA National Electric Code NEC 250.30
10. USA National Electric Code NEC 250.5
11. USA National Electric Code NEC 250.21
12. USA National Electric Code NEC 250.23
13. USA National Electric Code NEC 250.26

II. HISTORY OF LV POWER SYSTEM GROUNDING

Here's a brief history of LV power system grounding:
As electrical energy was first discovered and developed in DC form, it is not unusual that its early applications employed low voltage DC for communications, lighting, and power transmission. The first low voltage distribution system covering any appreciable distance was DC; it was established in 1882 over the 57 km link between the German cities of Munich and Miesbach. Multiphase AC systems were soon to follow, driven by the possibility of converting voltage through transformers.

By the 1890s, ungrounded 3-phase systems were available, although they remained ungrounded in part due to the delta configuration of the transformer secondaries. This was intentional, as most electrical loads were squirrel cage induction motors, also connected in a delta fashion. The perception was that leaving the system ungrounded reduced the personnel hazards associated with ground fault incidents. However, single phase-to-ground faults could not be reliably detected. Only when escalation to multi-phase faults had occurred was detection – and subsequent protective action – possible. The result was actually an increased hazard. The lack of a neutral reference plane resulted in uncontrolled phase-to-ground voltages which often initiated insulation faults; it also created a significant risk of exposure to higher – possibly lethal - voltages for personnel.

By the 1920s, a lot of loads required 1-phase 120/240V ("high-leg delta") and 208Y/120V, 3-phase. This was solid grounded with better ground fault detection.

In the 1940s, loads demanded more power, hence was 480V and 600V 3-phase systems developed. This was solidly grounded to prevent escalating system voltage to ground (5-6 times rated) during intermittent arcing ground faults in large LV systems from stray capacitance to ground.

In the 1950s, solidly-grounded 4-wire, wye 600Y/347V and 480Y/277V systems were developed to cope with fluorescent lighting that came in use, which produced much less heat than incandescent lighting, however at this time, fluorescent lighting required more than 120V to operate.
Service entrance ratings were increased from 600A to 4000A as load demand started to increase.
To meet this increase of load demand, utilities changed from delta to wye secondaries on power transformers and started to deploy 277V and 347V line-to-neutral voltages while still providing 480V and 600V as delta.
Today, 90% of LV power systems uses this convention which are solidly grounded 4-wire wye.

In the 1960s, devastating electrical equipment burn-downs on solidly grounded 480Y/277V and 600Y/347V systems occurred. This caused lots of fires, injuries and death, even though affected equipment were configured and protected in accordance with the CEC and NEC standards. A lot of these events occurred due to arcing ground faults that escalated into destructive three-phase arcing faults and because fuses and thermal magnetic circuit breakers used at this time did not interrupt the three-phase faults fast enough to protect primary equipment and personnel.

In 1971, the NEC added requirement for ground fault protection at service entrances, as per 230.95 (revised 2014) which is still in affect today. This state:
230.95 Ground-Fault Protection of Equipment. Ground-fault protection of equipment shall be provided for solidly grounded wye electrical services of more than 150 volts to ground but not exceeding 1000 volts phase-to-phase for each service disconnect rated 1000 amperes or more.

In 1972, the CEC added similar requirements as per 14.102 (revised 2012) also still in affect today. This state:
14-102 Ground fault protection

(1) Ground fault protection shall be provided to de-energize all normally ungrounded conductors of a faulted circuit that are downstream from the point or points marked with an asterisk in Diagram 3 in the event of a ground fault in those conductors as follows:
    (b) For circuits of solidly grounded systems rated more than 150 volts-to-ground, less than 750V phase-to-phase and 1000A or more; and
    (c) For circuits of solidly grounded systems rated 150V or less to ground and 2000A or more.

III. Multiple Sources with Solid Neutral Grounds

The CEC and NEC rules require each source transformer of a LV power system to have a solidly grounded neutral (or neutral path). When it comes to the connection of a generator set to the LV power system, it might meet the requirements as a separately derived source and then its neutral must be solidly connected to that of the preferred source.

If a separately derived source meeting the requirements of NEC 250.20(B) includes an alternate power source whose neutral conductor is solidly connected to that of the preferred source, the alternate source neutral is considered grounded through the ground at the preferred source service disconnect. This means that, sometimes the neutral of a genset power source will be grounded at the genset neutral; other times, it won't. (To see what must be considered before deciding when to ground the neutral, see "When You Should Ground and Switch the GenSet Neutral" sidebar on page 31 and "When You Should Not ground the GenSet Neutral" sidebar on page 32.) of the NEC standard.

Grounding of a generator requirements are thus not clear-cut and must be reviewed.

Two major problems arise if the transformer and generator neutrals are grounded and tied together as per standard when using a 3-pole transfer switch or breaker:

1. Incomplete ground-fault sensing with a separate solidly grounded utility transformer and generator.
   Two neutral currents paths, due to the two separate grounds, will have each a neutral circulating current for single-phase-to-ground faults, as below:

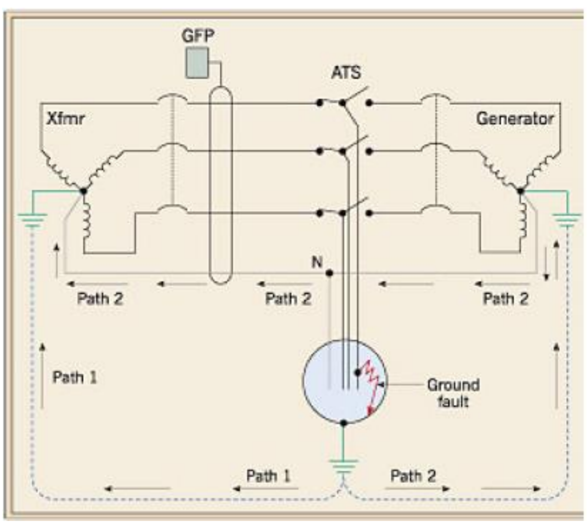

Fig 3: Circulating Ground-Gault currents for Transformer and Generator grounded separately

Path 1 is directly back to the transformer via the grounded-wye of the transformer.

Path 2 is along the solidly grounded neutral of the generator, then along the neutral conductor back to the transformer neutral. So, in this case, the transformer ground fault sensor (GFP) will see path 2 as if it is load current, and the zero-sequence GFP will sense only the fault current flowing from path 1. As a result, incomplete sensing of the total ground fault current is observed.

2. Nuisance tripping due to unbalanced load.
   Again, the system will have two current paths due to an unbalanced load as below:

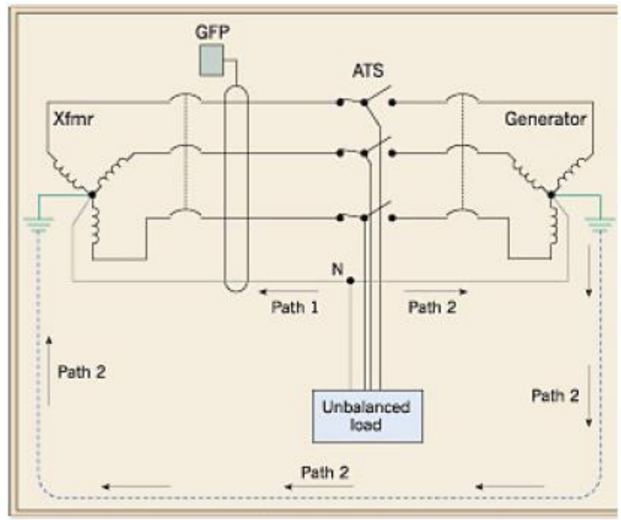

Fig 4: Circulating Neutral Unbalanced currents for Transformer and Generator grounded separately

Path 1 will be directly to the service neutral of the solidly grounded wye of the transformer and path 2 is the generator neutral current, circulating back to the transformer wye via the grounding of the generator metallic enclosure, conduit, fittings etc.

The path 2 current would have the same effect on the transformer GFP as a ground-fault current, therefore, an unbalanced load would have the same effect as a ground fault on the transformer GFP, even if there are no faults on the system.

The multiple paths of neutral currents can also be described as follows:

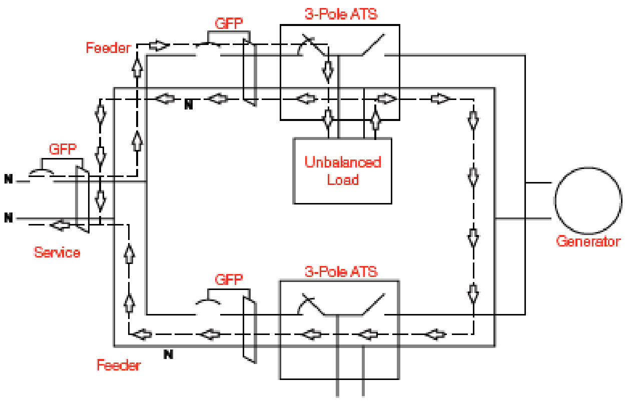

Fig 5: Multiple Paths for Neutral Currents on System with Multiple Grounds

Unbalanced currents due to generator paralleled with utility supply.
When a generator is operated in parallel with a Utility source, the voltage waveforms are likely to be somewhat dissimilar between the utility supply and generator and therefore result in neutral circulating current [5]. This can occur in either permanently paralleled applications or during closed transition transfers in peak shaving or back-up generation applications. Also, other sources of distributed generation, such as wind turbines, solar panels, fuel cells, microturbines, etc., can have excessive circulating neutral currents when paralleled with the Utility in 4-wire systems.

A solution to these separate circulating currents, is to use a 4-pole transfer switch by opening the neutral and to not ground the neutral a second time at the generator or ground the generator neutral and not connect the normal distribution and generator neutrals together. Switching of the neutral eliminates the extra neutral path. This is not always feasible for standby or emergency generator supplies.

Since there is no solid interconnection with the service-supplied neutral, the generator is considered a separately-derived system and its neutral must be grounded.

If the system has an emergency generator which is rated 277/480 or 347/600 wye, and the generator main disconnecting means is rated 1000 amps or more, NEC Article 700.7 (D) will require a ground fault indication on the generator. Note that this requirement is for an indication (alarm) only, and circuit interruption is not required. The NEC does not require that sensing ground fault current cause a trip that would result in a loss of power to emergency systems involving life safety. While ground fault indication is required by NEC above 1000 amps, it can be and often is provided on smaller systems below 1000 amps as well.

Sometimes the NEC requirement of 230.95 for ground fault protection on high capacity services is interpreted to apply to emergency standby generators as well. However, the NEC states in 700.26 that ground fault protection of emergency services that would include a trip shall not be required. Providing ground fault protection that includes circuit interruption may be contrary to the intent of codes for essential electrical systems. The codes suggest that higher priority be given to continuity of service than to the protection of essential electrical system equipment, except where equipment protection is required to prevent a greater hazard than lack of essential electrical service. In general, it is not recommend using ground fault protection that includes tripping off critical emergency service or feeders.

Another solution to mitigate and reduce the neutral circulating currents is to have an impedance installed between the generator neutral path connected to the transformer neutral.

To mitigate the ground fault protection, a modified differential ground fault scheme can be used as described in [1].

The impact of the two paths of neutral circulating currents due to two grounds on the system can also be seen on the differential protection of the main station transformer, as per below analysis.

IV. Analysis of 13.8kV/600 V Transformer Differential Incorrect Operation

A. Introduction

The University of Alberta's main utility transformers, standby generator and emergency supply looks as indicated in Fig A-1, with emphasis on the transformer differential connections.

The system consists of two utility transformers LU023-T1 and LU23-T2 feeding two supplies each, however of importance is the emergency supply Renewal SG which is also connected to a 3.125MVA 2 pole-pair 2.5MW backup, neutral solidly grounded diesel generator. The generator is intended for backup supply during emergency system outages and not to be permanently synchronized, however, is synchronized during maintenance runs and testing.

The transformers are two-winding 3MVA delta/wye 13.8kV/600V, however differential protection is configured as a three-winding delta/wye/wye 13.8kV/600V/600V to allow separation of the loads feeding the emergency supply Renewal SG and regular supply Infill SG.

A closer look at transformer LU23-T2's connections to the Renewal SG emergency supply bus, diesel generator and its differential connections are as indicated in Fig A-2.

Grounding and the modified differential ground fault topology are indicated in Fig A-3.

This highlights the grounding path and the possibility of neutral circulating current between the generator and the transformer neutrals.

The transformer percentage-differential protection function of transformer LU023-T2 had an undesired operation during a test run of the standby generator while it was synchronized and picking up load.

The load currents were very low, with some harmonics mostly in the Renewal winding indicated above, which is tied to the Renewal SG bus and diesel generator. Unfortunately, the exact load of the generator and loads on bus Renewal SG at the moment of trip is not known.

This transformer protection was installed and commissioned in 2011 and has been in service since then.

The waveforms captured from the transformer differential protection IED is indicated in Fig A-4

Upon first review, there was clearly no fault and it appears that the polarity of the C-phase winding is reversed in the Renewal winding, however it has been operating correctly for years.

The waveforms of the same transformer during normal operating conditions without the generator is indicated in Fig A-5.

On the IED operating characteristic it was observed that the differential operated; well within the load region.

The transformer differential thus operated on the C-phase.

B. Investigation

Upon further review and comparing the transformer IED waveforms between the trip condition with the generator synchronized (figure 9) and normal conditions without the generator running (figure 10), the following differences are observed:

1. The Renewal winding phasing seems to have polarity issues in figure 9. Its phases should be very similar to the Infill winding of the transformer since both windings are on the 600V wye side of the transformer i.e. graphs 3 and 4 should be very similar. In figure 10, these two windings are very similar as expected.
2. The sequence components differences of the Delta and Renewal winding with the generator running and not running are: (Loads are a little different)

TABLE I

Sequence Components	Generator Running		Generator Not Running	
	Prim 13.8kV	Renewl 600kV	Prim 13.8kV	Renewl 600V
I1	26.51A∠-151.1°	416.87A∠8.3°	26.46A∠-45.8°	497.20A∠101.8°
I2	1.37A∠87.9°	230.37A∠151.5°	0.3A∠114.4°	11.06A∠-69.8°
I0	0.02A∠59.4°	263.06A∠143.1°	0.14A∠-97.7°	0.98A∠-162.1°

3. The Renewal winding neutral current In with the generator running is about 800A, and without the generator running it is 0A.
4. The Renewal winding is very unbalanced with the generator running, compared to when the generator is offline:

TABLE II

Phase	Generator Running	Generator Not Running
	RMS Currents	RMS Currents
Ia	322A	498A
Ib	586A	508A
Ic	664A	508A
In	791A	0A

This high neutral current is due to the neutral circulating current from the generator to the utility neutral.

The transformer differential settings are as follows, which is correct compared to transformer ratings:

PARAMETER	CT F1	CT M1	CT M5
Phase CT Primary	200 A	5000 A	3000 A
Phase CT Secondary	5 A	5 A	5 A
Ground CT Primary	200 A	5000 A	3000 A
Ground CT Secondary	5 A	5 A	5 A

PARAMETER	SOURCE 1	SOURCE 2	SOURCE 3
Name	Prim.	Renewl	Infill
Phase CT	F1	M1	M5
Ground CT	F1	M1	M5
Phase VT	F5	None	None
Aux VT	None	None	None

SETTING	PARAMETER
Operating Characteristc Graph	View
Function	Enabled
Pickup	0.150 pu
Slope 1	15 %
Break 1	2.000 pu
Break 2	8.000 pu
Slope 2	98 %
Inrush Inhibit Function	Trad. 2nd
Inrush Inhibit Mode	Average
Inrush Inhibit Level	20.0 % fo
Overexcitation Inhibit Function	Disabled
Overexcitation Inhibit Level	10.0 % fo
Block	OFF
Target	Latched
Events	Enabled

Fig 6: Percentage-Differential and Transformer Settings

C. Analysis

From the above waveforms, it is clear that there is a significant neutral circulating current from the generator to the transformer neutral when the generator is synchronized. This level of circulating current increases as generator load increases.

The main question is; was the transformer differential operation correct?

Transformer settings for the Renewal winding do have the connection as Wye and grounding as “Within Zone”, which is correct based on transformer configuration and grounding. All other winding settings are also correct based on transformer info, ratings and CT ratios.

Based on these settings, the transformer differential algorithm should remove zero sequence currents in the differential calculation, however, percentage-differential did operate.

Calculation of the differential currents are as follows:

1) Rated current and CT margin

The rated current for each winding as calculated using:

$$I_{rated}[w] = \frac{P_{rated}[w]}{\sqrt{3} \times V_{nom}[w]}$$

CT margin for each winding is calculated:

$$I_{margin} = \frac{CT\ primary[w]}{I_{rated}[w]}$$

TABLE III

Winding	Rated Current	CT Margin
Primary	125.51A	1.59
Renewal	2886.71A	1.73
Infill	2886.71A	1.04

The reference winding selection is set to “Automatic Selection”, hence the winding with the lowest CT margin (or closest to 1) will be selected as the reference winding, hence the winding associated with Infill.

2) Magnitude compensation factors

The magnitude compensation factors are calculated using:

$$M[w] = \frac{I_{primary}[w] \times V_{nom}[w]}{I_{primary}[w_{ref}] \times V_{nom}[w_{ref}]},$$

TABLE IV

Winding	Compensation Factor
Primary	1.53
Renewal	1.67
Infill	1

3) Phase and zero-sequence compensation equations

The compensated currents can then be calculated based on the transformer type of Dy-1:

Delta:

TABLE V

Φ_{comp}[w]	Grounding[w] = “Not within zone”
0°	$I_A^P[w] = I_A[w]$ $I_B^P[w] = I_B[w]$ $I_C^P[w] = I_C[w]$

Wye: (Grounding within zone)

TABLE VI

330° lag	$I_A^P[w] = \frac{1}{\sqrt{3}}I_A[w] - \frac{1}{\sqrt{3}}I_B[w]$ $I_B^P[w] = \frac{1}{\sqrt{3}}I_B[w] - \frac{1}{\sqrt{3}}I_C[w]$ $I_C^P[w] = \frac{1}{\sqrt{3}}I_C[w] - \frac{1}{\sqrt{3}}I_A[w]$

4) Magnitude, phase angle and zero-sequence compensation equations

The total compensated current for each phase is calculated using:

$$I_A^C[w] = M\,[w] \times I_A^P[w]$$

$$I_B^C[w] = M\,[w] \times I_B^P[w]$$

$$I_C^C[w] = M\,[w] \times I_C^P[w]$$

The secondary currents of each winding captured at differential operation, was as follows: (From figure 9)

TABLE VII

Winding	I_A^C	I_B^C	I_C^C
Primary	0.65A∠-153.7°	0.65A∠-268.5°	0.7A∠-31.1°
Renewal	0.33A∠-269.9°	0.58A∠-127.9°	0.66A∠-245.8°
Infill	0.1A∠-246.8°	0.11A∠-9.7°	0.1A∠-128.7°

Using all the above equations, the compensated currents for each winding comes to:

TABLE VIII

Winding	I_A^C	I_B^C	I_C^C
Primary	0.99A∠-153.7°	0.99A∠-269.9°	1.07A∠-31.1°
Renewal	0.83A∠-299.7°	1.02A∠-94.7°	0.37A∠-45.1°
Infill	0.1A∠-36.7°	0.1A∠-6.2°	0.099A∠-277.7°

5) Differential and restraining current calculation:

Differential currents are calculated:
$Id_A = I_A^C[1] + I_A^C[2] + I_A^C[3]$
$Id_B = I_B^C[1] + I_B^C[2] + I_B^C[3]$
$Id_C = I_C^C[1] + I_C^C[2] + I_C^C[3]$

Restraining currents are calculated:
$Ir_A = \max |I_A^C[1]|, |I_A^C[2]|, |I_A^C[3]|$
$Ir_B = \max |I_B^C[1]|, |I_B^C[2]|, |I_B^C[3]|$
$Ir_C = \max |I_C^C[1]|, |I_C^C[2]|, |I_C^C[3]|$

Differential and restraint currents in A:

TABLE IX

	I_A	I_B	I_C
Diff	0.741A.∠-210.9°	0.035A.∠-227.3°	0.754A.∠-31.2°
Restraint	0.99A	0.99A	1.07A

Differential and restraining currents in p.u.

TABLE X

	I_A	I_B	I_C
Diff	0.148p.u.∠-210.9°	0.007p.u.∠-227.3°	0.151p.u.∠-31.2°
Restraint	0.20p.u.	0.20p.u.	0.21p.u.
Trip/ No-trip	No-trip	No-trip	Trip

The differential in C-phase is right at the edge just above the differential/restraint characteristic (minimum setting is 0.15p.u.) and operates which can also be seen in figure 11. A-phase is just below the operating point where B-phase has very little differential current.

Analysis thus confirms that the percentage-differential operation was correct for this particular system conditions.

Two algorithms that adds additional security to the percentage-differential are the directionality check and CT saturation detection.

The directionality check, described in section V, will secure a differential operation against such events.

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:

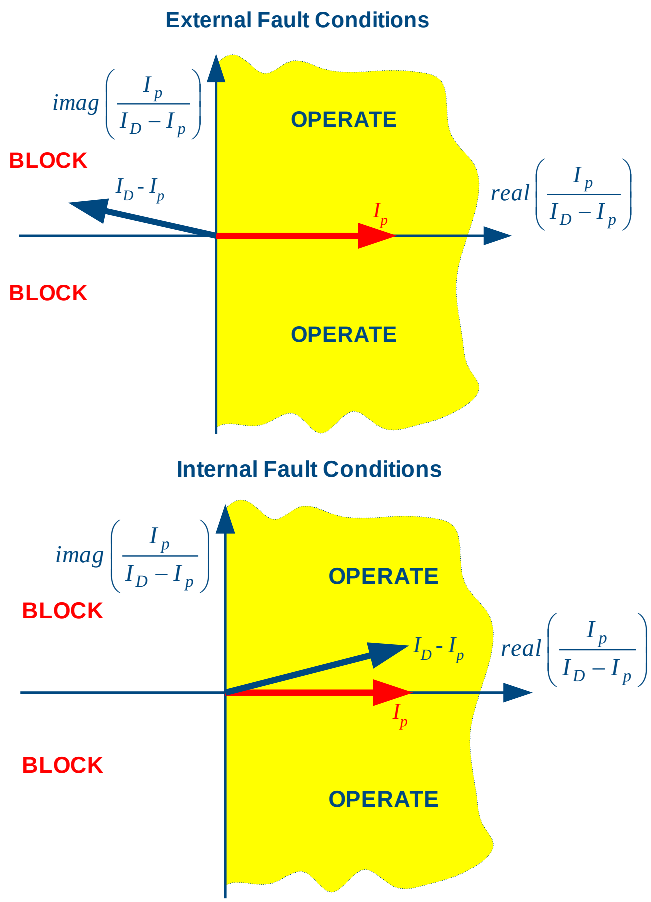

Fig 7: Directionality Check of Current Angles

Allowed-To-Live" timer for each of the data unit messages expected to be received. This timer is reset to the "Time-Allowed-To-Live" value received in each data message containing that data unit. A loss of connection is declared if this timer ever times out, and the FLS initiates a communications trouble alarm, sets status operands to "On" and sets the data unit power value to zero in the event that communications was lost with an end-unit. The FLSC uses the values of the communications trouble alarm and the resulting change of offline status to "On" (i.e. declare it as unavailable) to inhibit a contingency, hence ensuring no shedding due to loss of communications. Remote device off-line and or communications trouble alarm could be used to annunciate FLS scheme trouble conditions, and perhaps even to block the FLS scheme.

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:

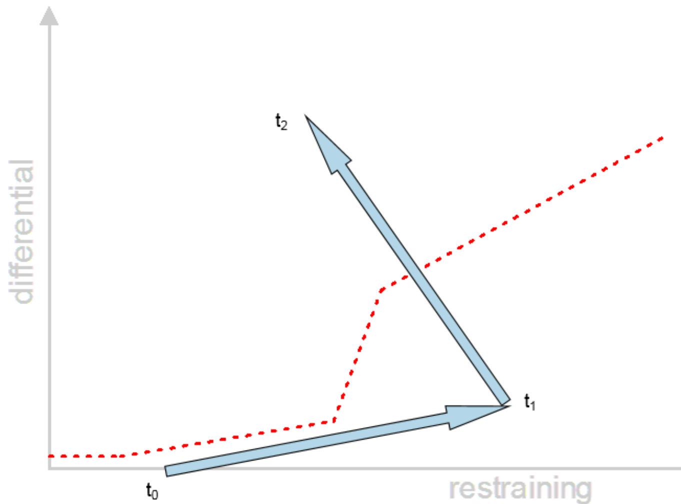

Fig 8: Percentage-Differential Characteristic During CT Saturation

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. Conclusion

LV power system neutral currents can be significantly impacted by the presence of two grounds from dissimilar sources such as a utility transformer and standby generator. In this particular case it was due to the synchronization of a solidly grounded backup diesel generator, which is not intended to be synchronized continuously, connected to two utility transformer solidly grounded wye-winding neutrals. The ground fault protection scheme did not operate since a Modified Differential Ground Fault scheme [1] is deployed, which is adapted for scenarios like this, however, the impact of this neutral circulating current on the transformer differential should be considered. Utilizing the directionality check of the transformer percentage-differential would mitigate this particular operation, however the presence of the neutral circulating current and reducing it is being reviewed.

An unusual percentage-differential operation is covered during system running conditions, highlighting the need to have all power system operating conditions reviewed and its possible impacts on the protection performance.

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VIII. Vitae

David Roh is the Utilities Services Manager, Electrical at the University of Alberta, Utilities department. David is a graduate of the Red River Community College in Winnipeg, MB and has over 36 years' experience in electrical equipment application, sales and service and Consulting Engineering. He has been with the University of Alberta for over 13 years and now serves as Utility Services Manager.

Lorne Clark, P. Eng is the Utilities Services Engineer at the University of Alberta, Utilities department, He received the degree of Bachelor of Science in Electrical Engineering from the University of Alberta in 2000. Mr. Clark has 19 years of engineering experience: 5 years with GP Technologies Ltd. as a consultant and 14 years with the University of Alberta Utilities department as the Utilities Services Engineer. He specializes in power systems distribution operations and maintenance support as well as project management. He is a member of IEEE.

JC (Jacobus) Theron is Technical Applications Engineer for Grid Automation division of GE Grid Solutions. He received the degree of Electrical and Electronic Engineer from the University of Johannesburg, South Africa in 1991. Mr. Theron has 27 years of engineering experience; 6 years with Eskom (South Africa) as Protection / Control and Metering Engineer, 14 years with GE Multilin (Canada) as Technical Applications Engineer / Product / Technical support / Protective Relaying Consultant/Protection and Systems Engineer leading the Project and Consulting Engineering team and as Product Manager, 2 years with Alstom T&D (USA) as Senior Systems Engineer and 5 years with Hydro One as Operations Assessment Engineer / P&C Technical

Services Manager. He specializes in transmission, distribution, bus and rotating machines protection applications support and Fast Load Shed Systems, system designs and transient system testing. He is member of IEEE.

APPENDIX A (Figures in larger format)

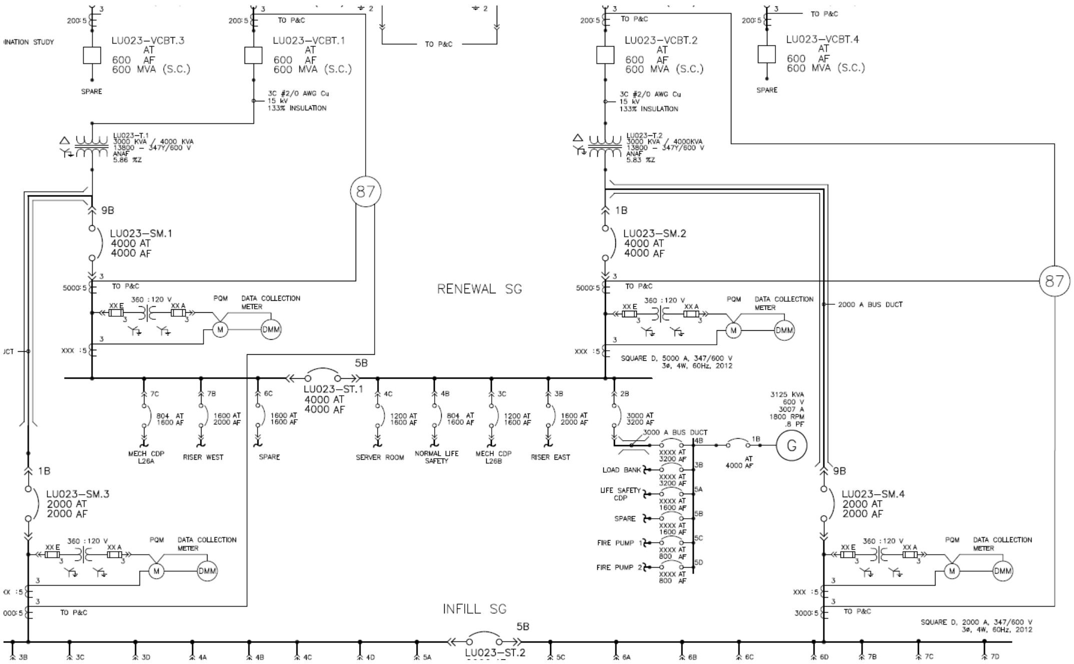

Fig A-1: University of Alberta Utility Transformers, Backup Generator and Emergency Supply

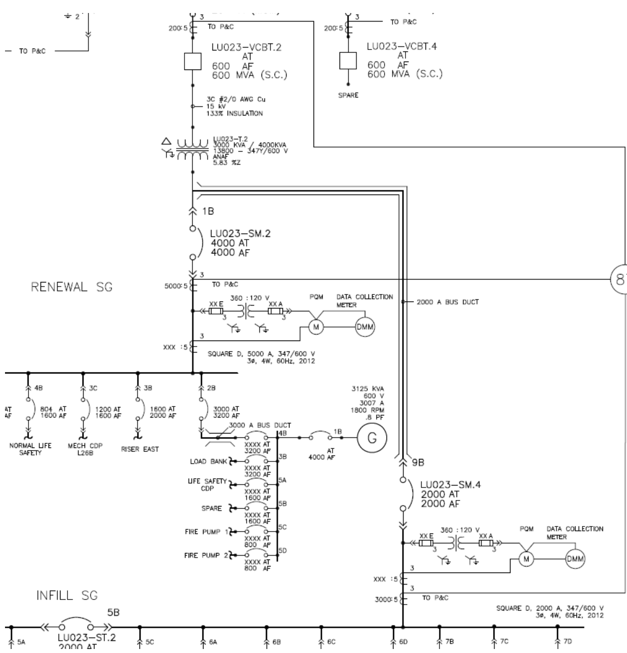

Fig A-2: Transformer LU023-T2 Connections

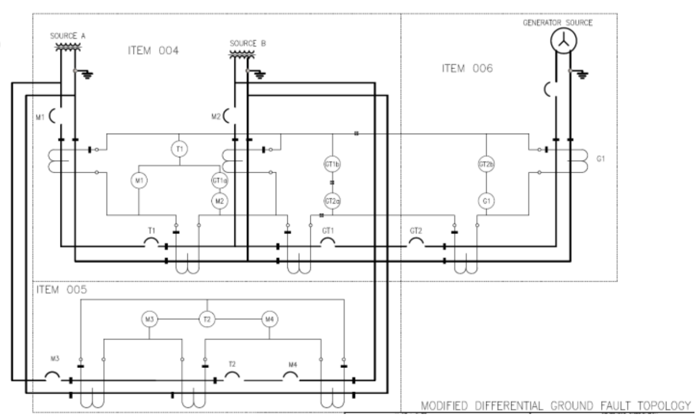

Fig A-3: Utility Transformers and Generator with Modified Ground

Fault Topology

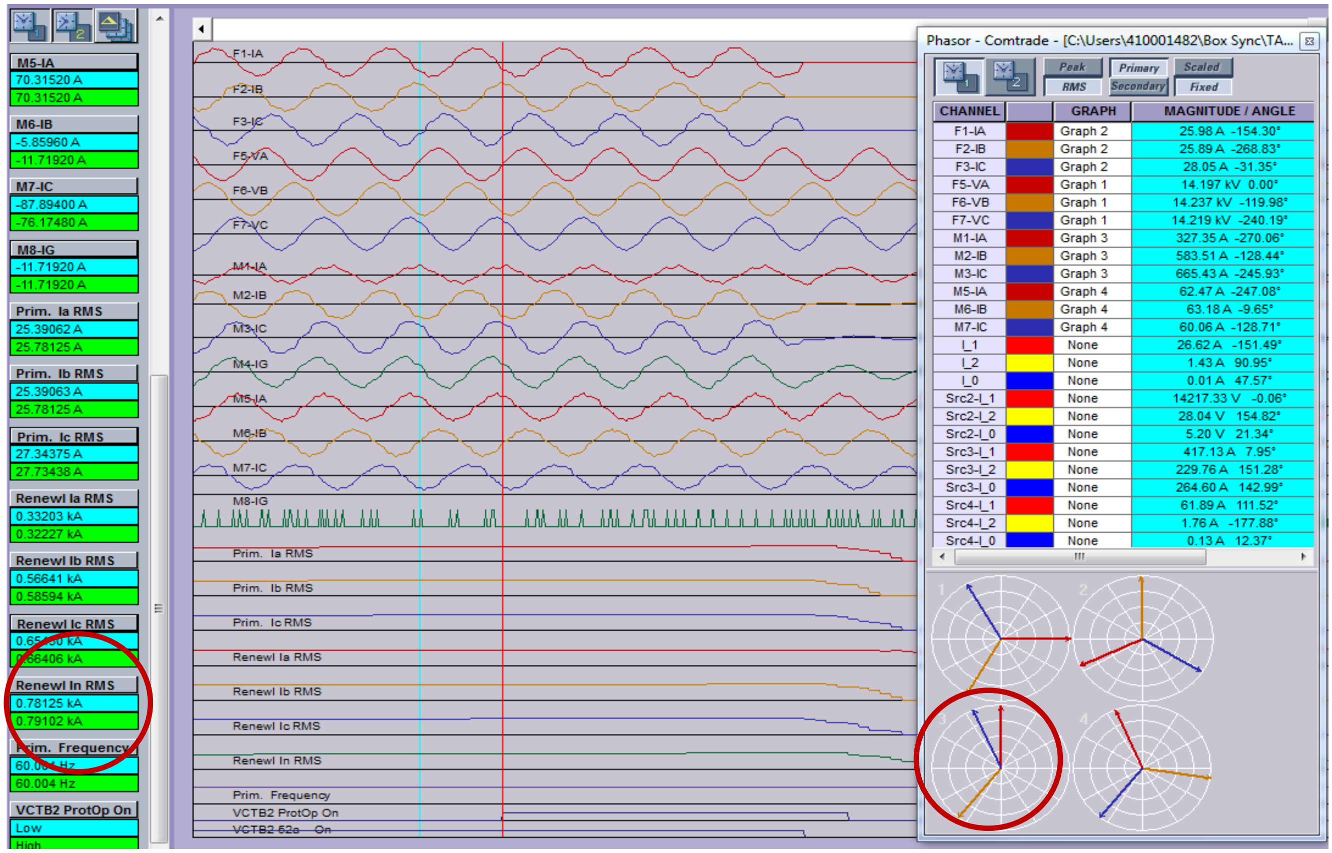

Fig A-4: Transformer Differential Operation Waveforms

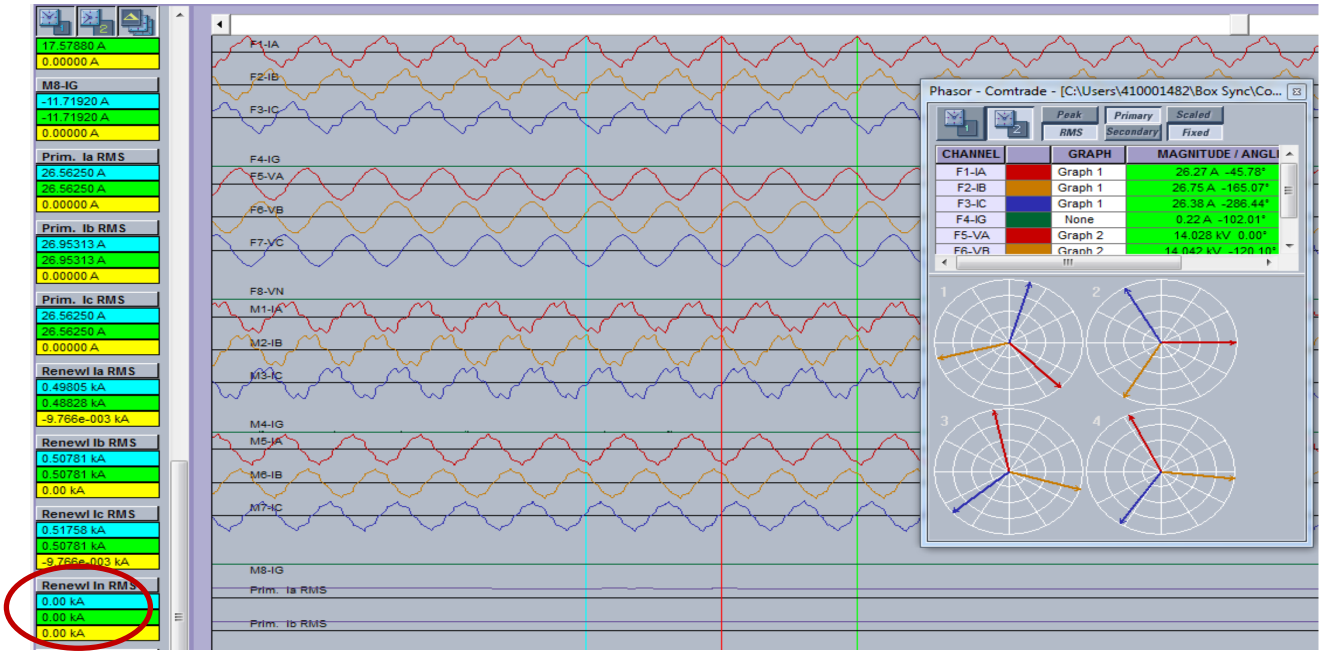

Fig A-5: Transformer Differential Normal Operation Waveform