ANALYSIS OF A DIFFERENTIAL AND OVERCURRENT OPERATION ON A 345KV HIGH VOLTAGE LINE REACTOR

Authors:

Eric Schroeder P.E., Cross Texas Transmission, Amarillo, Texas

Jerry Burton, Cross Texas Transmission, Amarillo, Texas

Luke Hankins, SynchroGrid, College Station, Texas 77845

Joe Perez P.E., SynchroGrid, College Station, Texas 77845

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Eric Schroeder P.E., Cross Texas Transmission, Amarillo, Texas eschroeder@crosstexas.com
Jerry Burton, Cross Texas Transmission, Amarillo, Texas jburton@crosstexas.com
Joe Perez P.E., SynchroGrid, College Station, Texas, jperez@synchrogrid.com
Luke Hankins, SynchroGrid, College Station, Texas, lukeh@synchrogrid.com

I. INTRODUCTION

High voltage line reactors are used in long transmission lines to mitigate the high voltage levels created by the line charging capacitance. The application of line reactors should be studied carefully since an incorrect operation can isolate not only the reactor but also the transmission line itself. This type of application comes with challenges concerning the system and protective relays. Reactors present difficulties to differential algorithms during in-rush situations. This is because reactors will experience the same amount of currents on both the high and low sides. As a result, the differential current magnitude could be zero, leaving no magnitudes to extract the second harmonic waveform used for blocking of the 87 function. The protection engineer must understand the protection function and operation algorithms of the relays being applied in order to properly protect the reactor and avoid mis-operations during in-rush conditions. This paper describes the analysis of a reactor in-rush event where the backup relay tripped on differential during energization whereas the primary relay did not trip on differential. In addition, this paper describes in detail the protection algorithm concepts, waveform behavior, and differential characteristics of the primary and backup relays. This will allow us to see how the two algorithms differ in security, reliability, and sensitivity.

II. SYSTEM ONELINE

Figure 1 shows the system oneline of the line reactors configuration. The normal reactor operation is done through the use of a circuit switcher. The reactor is protected by a redundant system using two different differential relays from different manufacturers. Manufacturer A will be referred to as the primary and manufacture B will be referred to as the backup. The differential zone is bounded by CTs within the reactor's high side and low side, as shown in figure 2. If a fault is detected inside the zone of protection, the differential relays send a transfer trip signal via GOOSE to the line relays to open local and remote line breakers. The circuit switcher opens 30 cycles after the line breakers open.

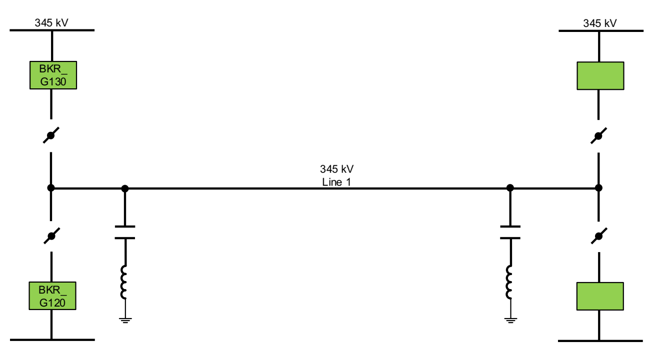

Figure 1: System Oneline

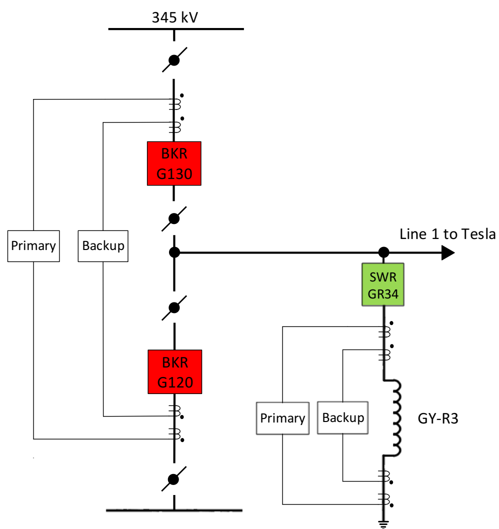

Figure 2: Reactor Differential Protection

III. SEQUENCE OF EVENTS

Table 1 shows a summarized version of the sequence of events that occurred during this event. As shown below, operators are told to close the reactor at 09:26:30.887. Five cycles after closing the circuit switcher, the line relays receive a transfer trip signal via GOOSE from the backup reactor differential relay. Two cycles after the differential trip was issued, the local line breakers are opened. 21 cycles later, the primary relay trips on ground instantaneous overcurrent. Finally, 34 cycles after the initial differential trip, the circuit switcher opens.

Description	Time Stamp Value (hrs:min:sec:ms)
Circuit Switcher GR34 closes	**09:26:30.887**
(5 cycles later) backup relay operates on B Phase Differential	09:26:30.972
1/4 of a cycle after diff trip, line relays receive transfer trip from the reactor backup differential relay	09:26:30.974
2 cycles after diff trip, breakers G13 & G12 open	**09:26:31.005**
20 cycles after diff trip, the primary reactor differential issues a trip on ground instantaneous overcurrent	09:26:31.308
21 cycles after diff trip, the backup reactor differential issues a trip on ground instantaneous overcurrent	09:26:31.324
34 cycles after diff trip, R34 opens	**09:26:31.537**

Table 1. Sequence of Events

The summary of the sequence of events tells us that there are quite a few events happening that need further investigation. We can see that only the backup relay detects a differential fault. This already raises several questions about these operations. Is there an internal fault in the reactor? Why didn't the primary relay see an internal fault? Why do both relays operate on instantaneous ground overcurrent?

The first step in analyzing an event is to check the relay settings that are in service. This procedure can be laborious since it requires that all settings be recalculated. This allows us to uncover errors that might have slipped during initial commissioning. The next section digs deeper in the analysis of the relay settings and description of its use.

IV. DIFFERENTIAL RELAY SETTINGS

This reactor application, as shown in the system oneline, uses two redundant current differential relays for primary and backup protection. In addition, two different relay manufacturers are utilized where the protection algorithms are calculated differently. A summary of the settings from the primary relay used to protect the reactor is shown in table 2.

Description	Setting	Value
Diff. Element Operating Current Pickup (p.u.)	O87P	0.5
Slope 1 Setting (%)	SLP1	35
Slope 2 Setting (%)	SLP2	75
Unrestrained Element Current Pickup (p.u.)	U87P	1.00
Incremental Operate Current Pickup (p.u.)	DIOPR	1.2
Incremental Restraint Current Pickup (p.u.)	DIRTR	1.2
Enable Harmonic Blocking Differential Element	E87HB	Y
Enable Harmonic Restraint Differential Element	E87HR	N
Second-Harmonic Percentage (%)	PCT2	10

Table 2: Primary Relay Differential Settings

The settings are composed of a minimum pickup differential 087P along with a high instantaneous U87P setting. The 087P setting offers a very sensitive threshold that allows the relay to isolate internal faults very quickly. The U87P is an instantaneous setting where the restraint current is not taken into consideration, making it suitable for high magnitude internal faults. It operates directly as the summation of the filtered differential currents. We noticed that harmonic blocking and harmonic restraint settings are also available with harmonic restraint not being used. The second harmonic setting is set to 10% of the fundamental. This means that if the relay detects a second harmonic content above 10%, the relay will block the differential element from operating. Harmonic blocking and restraint are used in order to increase the security and dependability of the algorithm during in-rush or external fault events.

The slope characteristic for this relay is shown in figure 3 . This relay uses one of two slopes as part of the differential characteristic. The relay's internal algorithms decide which slope to use based on the behaviors of the currents. Slope 1, set at 35%, is typically used to increase the restrain of the relay in order to avoid operations due to CT errors, transformer losses, high load conditions, etc. Slope 2, set at 75%, gives the relay more security by increasing the restrain region of the differential plane and is used for high-through faults, high close-in external faults, CT saturation, etc. Increased restrain is necessary when dealing with errors of a higher magnitude.

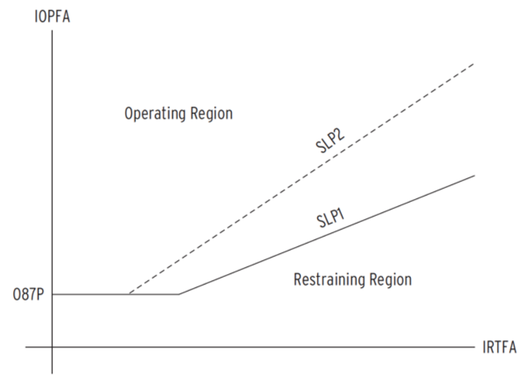

Figure 3: Primary Relay Differential Plane

The backup relay uses similar settings to the primary relay. A summary of the settings from the backup relay used to protect the reactor is shown in table 2.

Description	Setting	Value
PERCENT DIFFERENTIAL	Function	Enabled
PERCENT DIFFERENTIAL	Pickup	0.100 pu (0.5A)
PERCENT DIFFERENTIAL	Slope 1	25 %
PERCENT DIFFERENTIAL	Break 1	1.570 pu
PERCENT DIFFERENTIAL	Break 2	7.840 pu
PERCENT DIFFERENTIAL	Slope 2	98 %
PERCENT DIFFERENTIAL	Inrush Inhibit Function	Adapt. 2nd
PERCENT DIFFERENTIAL	Inrush Inhibit Mode	2-out-of-3
PERCENT DIFFERENTIAL	Inrush Inhibit Level	10.0 % fo
PERCENT DIFFERENTIAL	Function	Enabled
PERCENT DIFFERENTIAL	Block	OFF

Table 3: Backup Relay Differential Settings

This relay also has minimum and high operating pickup settings that are set to the same pickup as the primary relay. Even though the same pickup criteria is used for both relays, the settings themselves appear to be different because each relay calculated the per unit value differently. This relay uses harmonic blocking and an inhibit in-rush setting called adaptive second harmonic. Similar to the previous relay, the second harmonic is set to 10% of the fundamental. In addition, the second harmonic value as compared to the fundamental must be higher than the settings in at least 2 out of 3 phases in order for the differential to be blocked. This will be very important information that will be visually explained in the waveform analysis section.

The slope characteristic of the backup relay is shown in figure 4. This relay also uses the dual slope characteristic to improve the security of the relays. However, unlike the previous relay, the slopes are fixed for both internal and external faults.

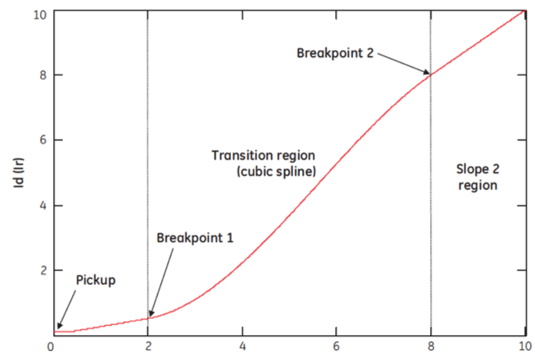

Figure 4: Backup Relay Differential Plane

V. PROTECTION ALGORITHMS

In order to understand the reasons behind the reactor differential relay operation, it is necessary to understand how each individual relay algorithm works. Each manufacturer has its own preferred method of protection algorithm that either makes them more secure and less sensitive or less secure and more sensitive. Below is a review on how both relays establish the operate IOP and restrain IRT currents along with the harmonic restraint and blocking that are needed in differential applications.

Operate and Restraint Currents:

The primary calculates the operate and restraint currents on a per phase basis. The formulas for A Phase differential for the high (IAT) and low side (IAW) of the reactor phasor currents are shown in equations 1 and 2 below.

$$\mathrm{IOPA} = |\mathrm{IAT} + \mathrm{IAW}| \quad (1)$$

$$\mathrm{IRTA} = |\mathrm{IAT}| + |\mathrm{IAW}| \quad (2)$$

The backup calculates the operate and restraint currents for A Phase as shown below:

$$\mathrm{IOPA} = \mathrm{IAT} + \mathrm{IAW} \quad (3)$$

$$\mathrm{IRTA} = \mathrm{MAX}[(|IAT|), (|IAW|)] \quad (4)$$

Notice that in both relays, the differential currents IOPA is calculated by adding the phasor currents that are protecting the reactor. The absolute value of a phasor calculation results in taking magnitudes only and not the angles. The major noticeable difference is how the restraint current is calculated. This will be shown visually in section VII. In either case, both sets of current differential methods have to overcome the restrain current along with the slope setting in order for the relay to operate as shown in equation 5.

$$\mathrm{IOP} > \mathrm{IRT} * \mathrm{SLP} \quad (5)$$

<u>**Harmonic Restraint and Blocking:**</u>

Both relays offer extra security algorithms for in-rush conditions. The primary relay has the ability to apply harmonic restraint and blocking before the differential function issues a trip.

<u>Harmonic Restraint:</u> When the primary relay is set to harmonic restraint, the operating current is calculated as follows:

$$\mathrm{IOPA} > (|\,\mathrm{IAT} + \mathrm{IAW}|) * Slope + K2 * (IOPAph2) + K4 * (IOPAph4) \quad (6)$$

K2 and K4 are the 2nd and 4th harmonic settings and IOPAph2 and IOPAph4 are the 2nd and 4th harmonic values found in the operate current or current differential summation. Equation 6 shows that the operating current IOPA “must overcome the combined effects of the restraining current, IRTA, and the harmonics of the operating current for the element to assert a trip output. Any measurable harmonic content provides some benefit toward the goal of preventing differential relay operation during in-rush conditions” [1]. Harmonic restraint is generally slower, but has improved dependability when energizing a faulted transformer or reactor. Also, because the harmonics are summed, harmonic restraint is more secure during in-rush conditions. The restraint method is shown in figure 5 below.

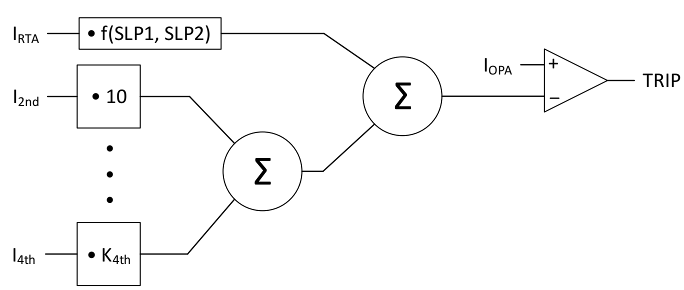

Figure 5: Primary Relay Harmonic Restraint Supervision

<u>Harmonic Blocking:</u> When the primary relay is in the harmonic block mode, the IOPA operating current is “independently compared with the restraint current and the selected harmonics.” [3] The harmonic logic is shown in figure 6. We see that the operate current still has to overcome the restraint and slope setting as shown in equation 7.

$$\mathrm{IOPA} > (|\,\mathrm{IAT} + \mathrm{IAW}|) * Slope \quad (7)$$

Before a differential trip is declared, the amount of second harmonic content is checked within the operate current. If the 2nd harmonic measured value is greater than the percent setting, the differential trip is blocked. For example, for a 2nd harmonic setting of 10%, when the fundamental operate current has a value of 10A and the 2^{nd} harmonic found in the unfiltered operate current has a value of 1A, the relay differential element will be blocked. “When the harmonic content is below the specified threshold, the harmonic blocking has no effect.” [3]

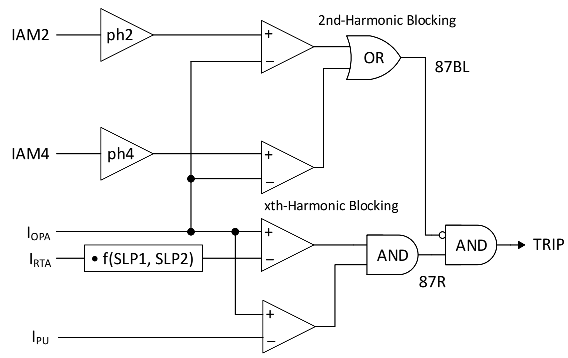

Figure 6: Primary Relay Harmonic Blocking

In addition, the primary relay uses common cross blocking which blocks the differential of any 2^{nd} harmonic phase that is above the given setting. This is shown in figure 7 below.

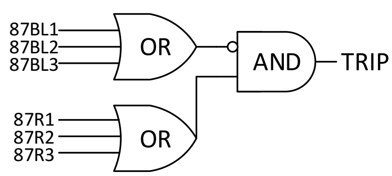

Figure 7: Primary Relay Harmonic Cross Blocking

The backup relay does not offer a restraint harmonic blocking feature. However, it does offer two types of harmonic blocking techniques: traditional and adaptive 2^{nd} harmonic blocking. The traditional 2nd harmonic restraint responds to the ratio of magnitudes of the 2nd harmonic and fundamental frequency components. If the 2^{nd} harmonic content found in the differential current is higher than the given settings, the relay blocks the differential setting. This is similar or the same as the harmonic blocking technique of the primary relay. The adaptive 2nd harmonic restraint responds to magnitudes and phase angles of the 2nd harmonic and the fundamental frequency component. The backup relay manufacturer claims that the adaptive harmonic restraint algorithm successfully restrains tripping when faced with low levels of second harmonic current during an in-rush event [3]. The harmonic blocking logic offered by the backup relay is shown in figure 8.

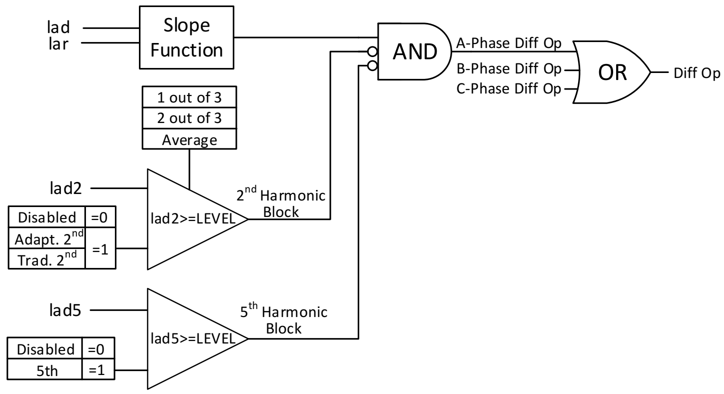

Figure 8: Backup Relay Harmonic and Cross Blocking

Since the second harmonic is calculated on a per phase bases, the relay offers 4 different modes of harmonic blocking.

1. Per-phase: In per-phase mode, the relay performs in-rush restraint individually in each phase.

2. 2-out-of-3: In 2-out-of-3 mode, the relay checks the second harmonic level in all three phases individually. If any two phases establish a blocking condition, the remaining phase is restrained automatically.

3. Averaging: In averaging mode, the relay first calculates the average second harmonic ratio and then applies the inrush threshold to the calculated average.

4. 1-out-of-3: In 1-out-of-3 mode, all three phases are restrained when a blocking condition exists on any one phase. 1-out-of-3 mode typically reverts back to per-phase mode after a short time delay to allow tripping in case an internal fault occurs during energization.

VI. WAVEFORM ANALYSIS

This section will use the information that was explained above to determine the behavior of the two differential relays during the reactor in-rush.

Figure 9 shows a COMTRADE record of the reactor in-rush that was observed during energization captured by the backup relay. Equal phases have been superimposed with each other in order to show their angle separation.

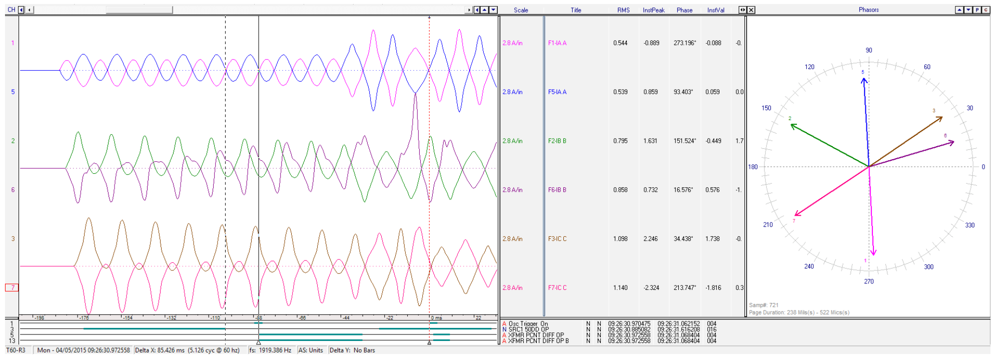

Figure 9: Reactor In-Rush Currents from Backup Relay

As can be seen, the waveform signature and phase vectors indicate that each equal phase is 180 degrees from each other. For example, the high side and low side of phase A are 179.7 degrees apart, indicated by channels 1 and 5 respectively. The B phases are 135 degrees apart and the C phases are 179 degrees apart. An internal fault is declared when the angle between the common phases are less than 90 degrees. It is clear that there is no internal fault based on the waveform analysis. However, the backup relay declares a differential operation on the B Phase. This results in tripping the line breakers and 345kV line out of service. The primary relay does not see a differential operation during the energization.

Let's evaluate the performance of each relay by looking into the operate, restraint, and 2nd harmonic blocking functions by using the formulas outline in the protection algorithms section.

In order to calculate the operate or current differential of this relay, one must first filter the currents using a Fast Fourier or Cosine Filter. This is done in order to extract all harmonic components from the waveform except the 60Hz signal. Relays operate only on the fundamental signal for all protection functions. Using Wavewin, we can easily filter the fundamental signal for our analysis.

1. Take the fundamental of each phase current.
2. Calculate the operate current for each phase differential.

$$\mathrm{IOPA} = |\mathrm{IAT} + \mathrm{IAW}|$$
$$\mathrm{IOPB} = |\mathrm{IBT} + \mathrm{IBW}|$$
$$\mathrm{IOPC} = |\mathrm{ICT} + \mathrm{ICW}|$$

3. Take the RMS of each operate current.

Since the B phase is the current that operated, the IOPB was calculated first. Figures 10 and 11 show the IOPB originally given by the primary and backup relay records along with the IOPB calculated by Wavewin. Notice that the original IOPB waveforms are slightly different from the ones calculated by Wavewin. This is because of the sampling rate of each relay. In addition, the backup relay cuts off its measurement when the currents value falls below 0.1A. Any value below 0.1A is not taken into account in protection functions. Nevertheless, the Wavewin-calculated values simulate the original relay signals very well.

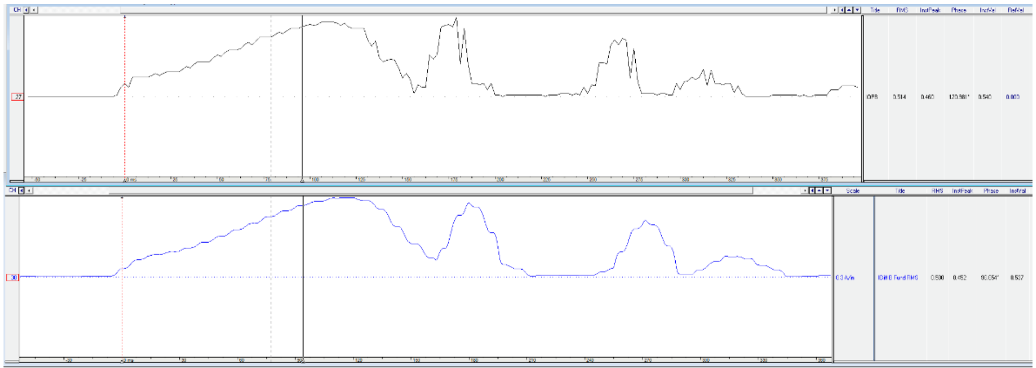

Figure 10: IOPB Current Differential for Primary Relay

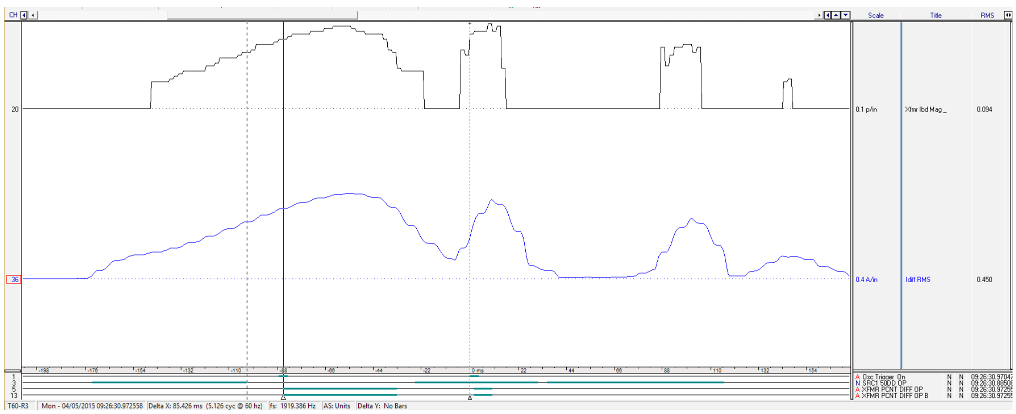

Figure 11: IOPB Current Differential for Backup Relay

The minimum operate current of both relays are set to trip at a 0.5A secondary. Based on the information seen in Figures 10 and 11, both relays IOPB reached beyond the setting point of 0.5A secondary. The primary relay shows a value of 0.51 amps and the backup relay shows a value of 0.45 amps or 0.095 p.u. These small discrepancies are most likely due to the sampling rate of the relay done for the protection functions.

This proves that the current differential level did go above the operate setting. However, the relays have to check the 2nd harmonic content of the waveform before it declares an internal trip. This was explained in the protection algorithm section. In a similar manner, we are going to use Wavewin to check the harmonic content of each differential current for each relay.

1. Take the fundamental of each phase current.
2. Calculate the operate current for each phase differential.

$$\mathrm{IOPA} = |\mathrm{IAT} + \mathrm{IAW}|$$
$$\mathrm{IOPB} = |\mathrm{IBT} + \mathrm{IBW}|$$
$$\mathrm{IOPC} = |\mathrm{ICT} + \mathrm{ICW}|$$

3. Extract the 2nd harmonic signal of each unfiltered operate phase differential.

Figures 12 and 13 below show the ratio of the second harmonic content as compared to the fundamental IOPB signal. Figure 12 shows the ratio calculated by the relay and Wavewin shown as IHB2 and the 2nd Harmonic ratio for the primary relay shown as IB. Figure 13 shows the harmonic spectrum showing the same result. It can be seen that the harmonic ratio shown in both signals is around 50% which is above the relay setting of 10%. Since the harmonic ratio is above 10%, the differential element will be blocked for the primary relay. In addition, since this relay uses harmonic cross blocking, all three phase differential functions will be blocked.

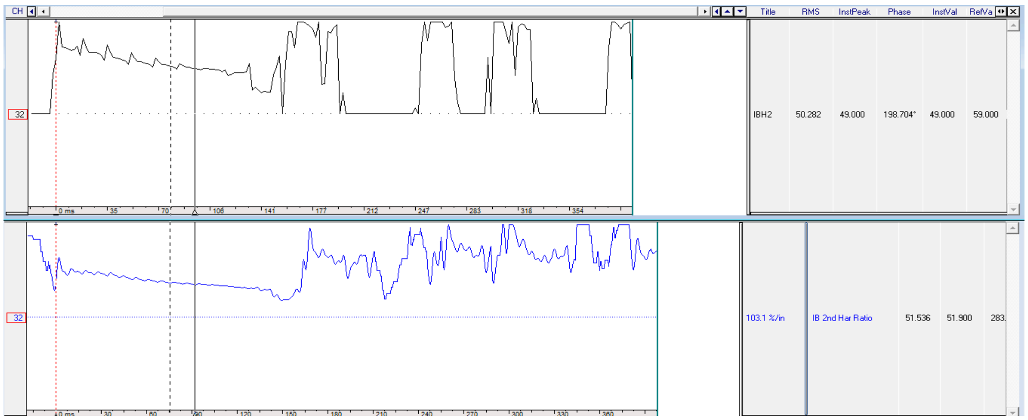

Figure 12: Primary Relay Ratio of 2nd Harmonic and Fundamental for IOPB

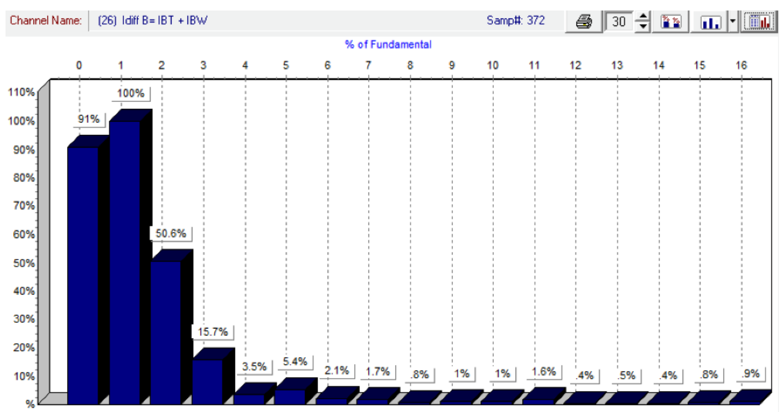

Figure 13: Primary Relay Harmonic Content of Unfiltered IOPB

Figures 14 shows the 2nd harmonic ratio as compared to the fundamental calculated by the backup relay and Wavewin. Based on the waveform, we can observe that the ratio is about 50% which is similar to what the primary relay calculated. Figure 15 shows the harmonic spectrum showing the same result.

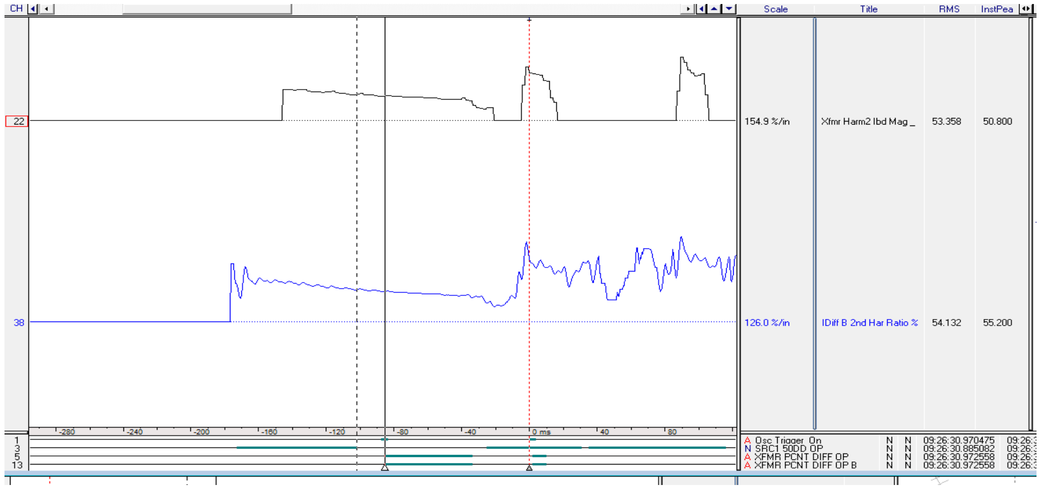

Figure 14: Backup Relay Ratio of 2nd Harmonic and Fundamental for IOPB

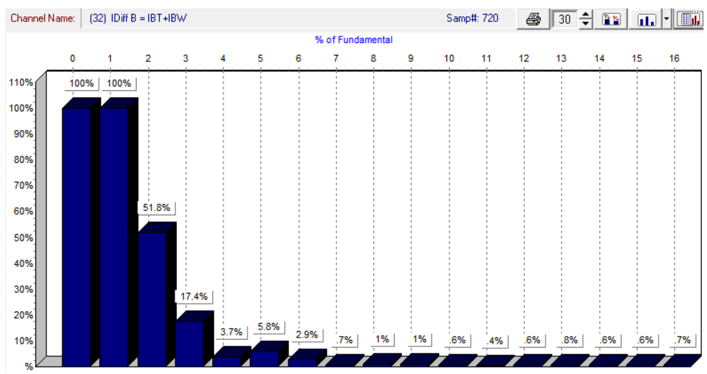

Figure 15: Primary Relay Harmonic Content of Unfiltered IOPB

Based on this analysis, the B phase differential produced enough harmonic content to block the differential function from operating. So why did the differential function still operate? Let's look at the other two phases' 2nd harmonic content and see what the relay calculated.

Figures 16 and 17 show the harmonic content of the A phase differential. Notice that the 2nd harmonic content calculated by the relay is zero. Our calculation shows a content of 29%. The challenge with this signal is that the high and low sides of phase A are almost identical. So when you add the two signals to get the differential magnitude, the result produces almost no current. As a result, there is no 2nd harmonic signal to extract. In addition, the actual current values are so small that they go below the threshold cutoff of the relay. At that point, the relay interprets that there is no current to be measured.

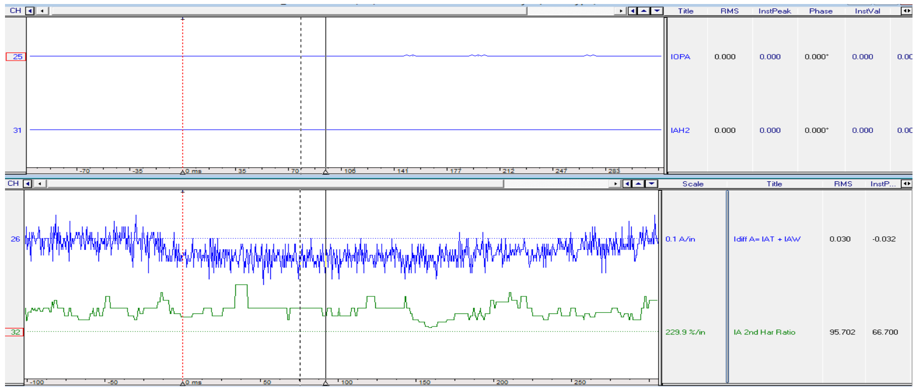

Figure 16: Primary Relay Ratio of 2nd Harmonic and Fundamental for IOPA

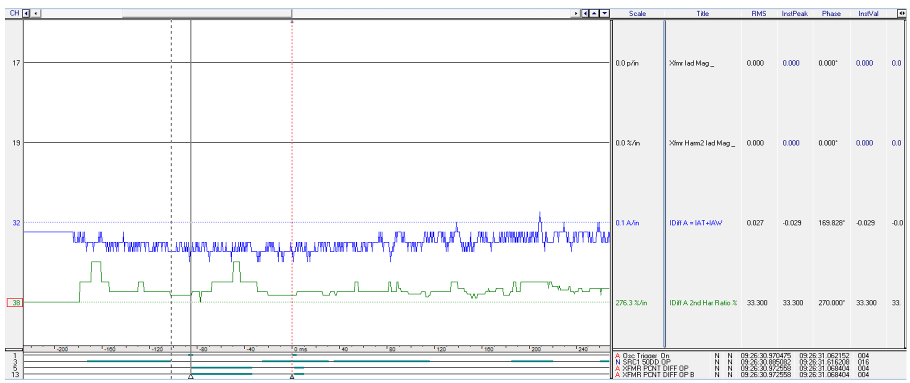

Figure 17: Backup Relay Ratio of 2nd Harmonic and Fundamental for IOPB

Figures 18 and 19 **Error! Reference source not found.**show the 2nd harmonic content of the C Phase. The measured value continues to be a challenge, but the signature reflects a much cleaner shape than the B phase. The 2nd harmonic value calculated by the relay is zero percent since the measured values were below the 0.1A threshold. Our calculated value gives a 2nd harmonic content of over 100%.

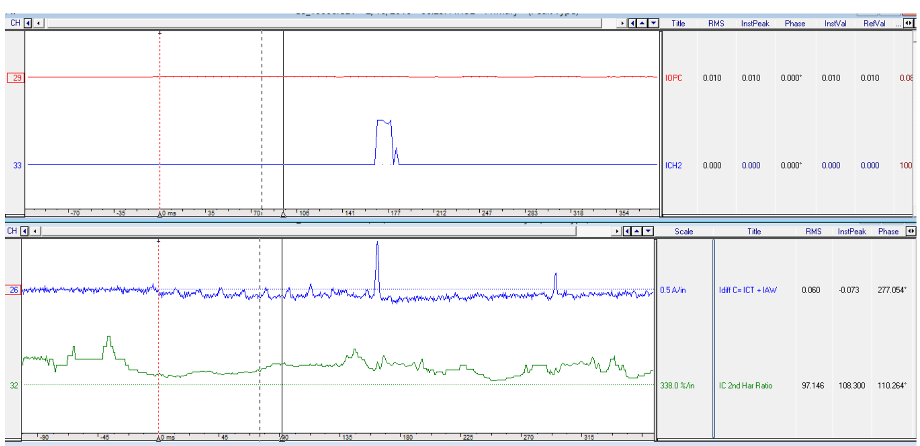

Figure 18: Primary Relay Ratio of 2nd Harmonic and Fundamental for IOPC

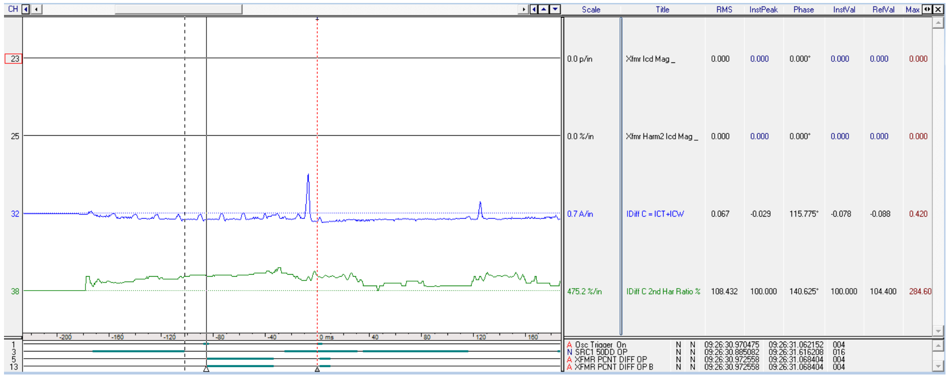

Figure 19: Backup Relay Ratio of 2nd Harmonic and Fundamental for IOPC

The second harmonic analysis of all three phases revealed that there was enough second harmonic content in all three phases. However, the A and C phases 2nd harmonic contents defaulted to zero due to the minimum measurement cutoff of the relays. That left the B phase as the only current with enough 2nd harmonic content to block the differential element on both relays. Since the primary relay uses harmonic cross blocking, the relay only needs to see one phase to block the differential. However, the backup relay needs at least two phases to block the differential. As a result, the backup relay tripped on differential.

CTT conducted in-rush testing of the original record by changing the following settings:

- Adaptive Blocking Mode for 2 out of 3
- Adaptive Blocking Mode per phase
- Traditional blocking Mode 2 out of 3
- Traditional blocking Mode Average

Table 4 shows the results for the in-rush performed by CTT. Each time the test was set to two out of three phases for harmonic blocking, the relay tripped during the in-rush.

Test Description	Trip
Adaptive Blocking Mode for 2 out of 3	Y
Adaptive Blocking Mode per phase	N
Traditional blocking Mode 2 out of 3	Y
Traditional blocking Mode Average	N

Table 4: In-rush Testing Results

Based on the tests above and harmonic analysis performed for this event, CTT decided to implement the per phase method using the traditional second harmonic setting.

VII. PRIMARY AND BACKUP RELAY DIFFERENTIAL PLANES

Figures 20 and 21 below show the differential behavior during the in-rush event for the primary and backup relays respectively. Each manufacturer has its own way of determining its operate and restraint currents. Referring back to equations 2 and 4, we can see that there is a major difference in how the relays calculate each phase's restraint current values. The primary relay adds the high and low side reactor phasor currents together whereas the backup relay uses whichever value is higher in magnitude.

This results in the primary relay restraining its differential currents on a much larger scale as compared to the backup relay. The increased restraint present in the primary relay allows it to operate correctly during an in-rush event such as reactor energization. This is the fundamental difference between the two algorithms that makes the primary relay more secure and reliable. On the other hand, the backup relay is faster and more sensitive during internal faults, but is also prone to misoperations due to the lower restraint quantities. It is very clear that the backup relay operated during the energization.

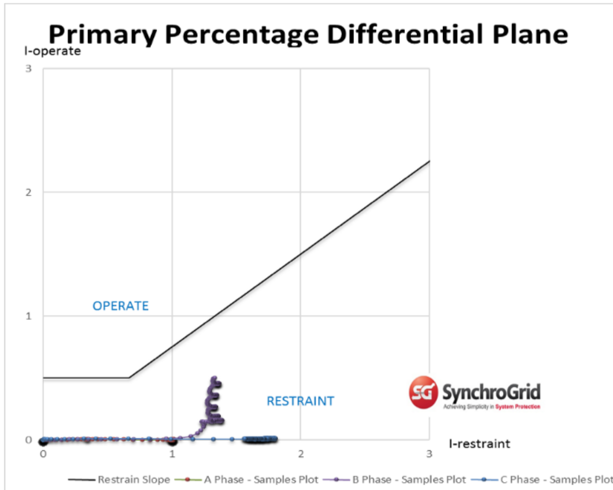

Figure 20: 2nd Harmonic Differential Plane for Primary Relay

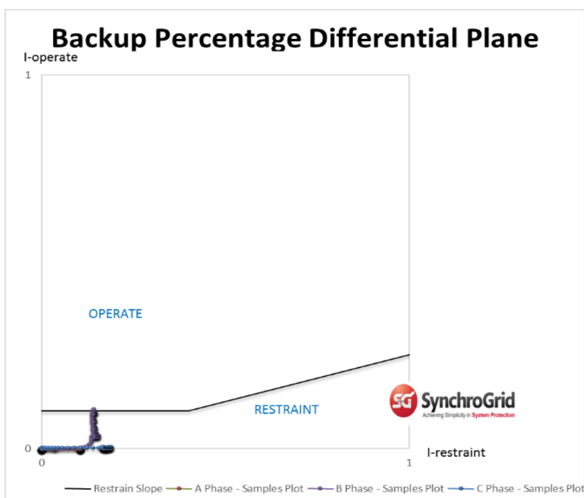

Figure 21: 2nd Harmonic Differential Plane for Backup Relay

VIII. RESONANCE EFFECT

Analyzing figure 22 below shows that the transmission line currents extinguished approximately 5 cycles after the reactor differential relay tripped. However, the reactor continued measuring currents on the high and low sides. Based on the SER, the circuit switcher remained closed for approximately 30 cycles after the reactor differential trip. The source of the currents being measured by the reactor relays is from the discharge energy from the 345kV line. This energy is built into the line capacitance properties for long lines.

Based on the waveform analysis in figure 23, there seems to be a resonance effect between the line capacitance and the reactor reactance oscillating around 47Hz. The voltages and currents start to oscillate at 47Hz, producing non-sinusoidal signals which make this short-term system highly unbalanced. The voltage levels on C Phase for a line to ground value reach as high as 326KV. This is almost as high as the phase to phase value of 345kV.

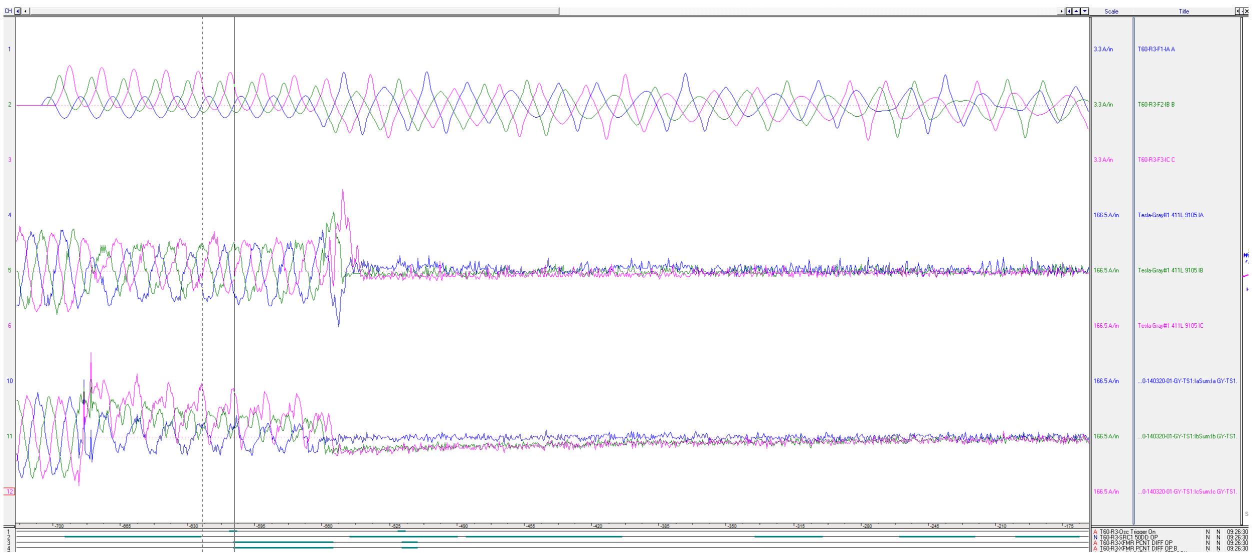

Figure 22: Record Showing T-Line Opened 5 cycles after Reactor Trip

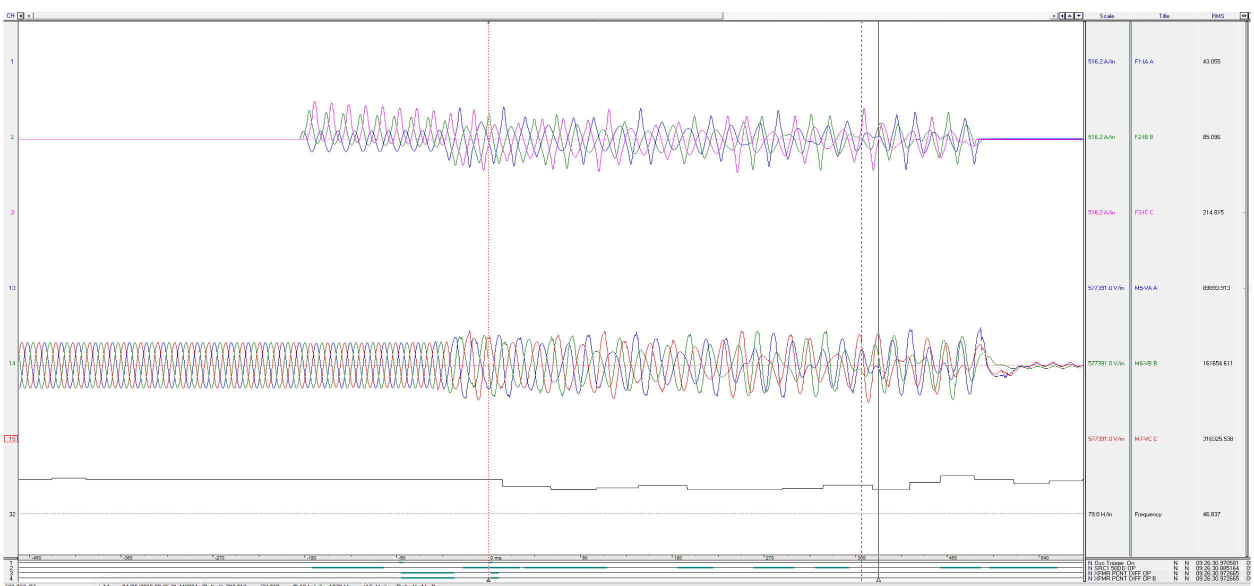

Figure 23: Resonance Effect due to Line Discharge

The resonance effect also affected the instantaneous and time overcurrent settings asserting a trip signal. The ground overcurrent waveform is shown in figure 24. The instantaneous ground 50G element in both the primary and the backup picked up 20 cycles after the initial differential trip. As a result, both relays sent signals to open both line breakers, locking the line out. However, the lines were already open due to the reactor differential lockout. This presents a challenge on reclosing for regular line to ground fault events since the circuit switcher will not open the currents after 30 cycles. The line will be locked out before the reclosing attempt is performed. It is important that the ground overcurrent elements do not pickup for the line discharge current and resonance effect when the line is tripped during normal line to ground faults.

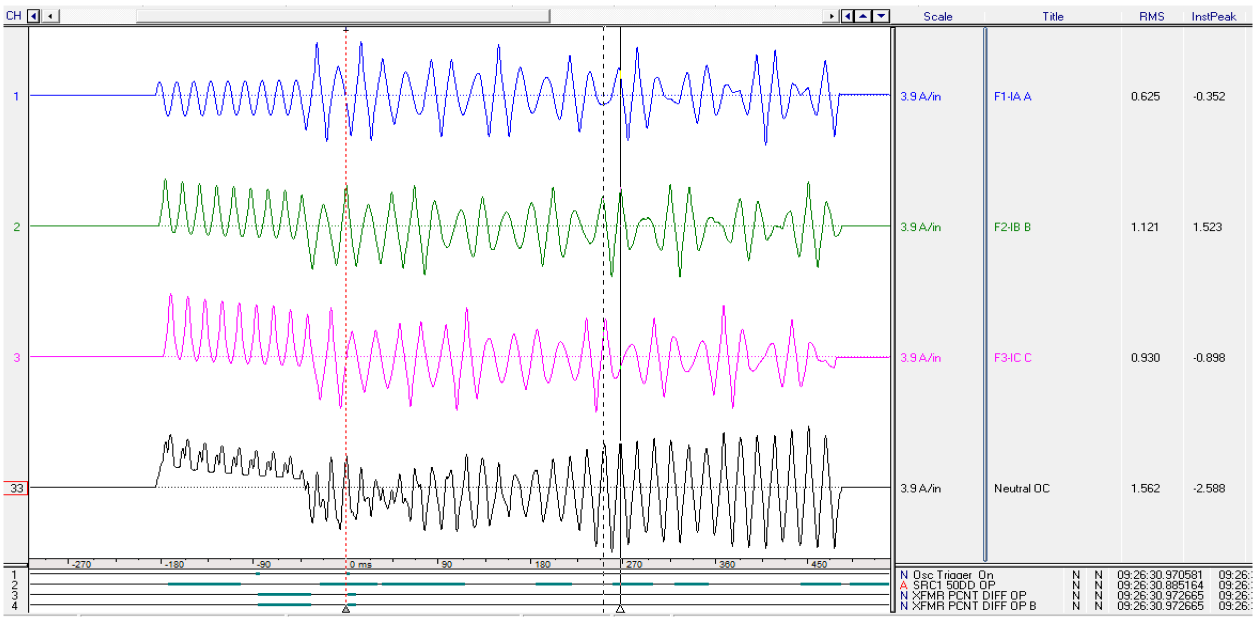

Figure 24: Resonance Effect on Ground Overcurrent Elements

IX. CONCLUSION

Since differential relays offer solutions for multiple applications, one can conclude that the relay engineer must deeply understand not only the element behavior, but also how each relay calculates its protection functions for the given application. This paper has described the behavior of a reactor energization and the response of two different differential relays. In addition, this paper has provided information that equips the customer and settings engineer with the necessary information to properly avoid operations during in-rush conditions.

X. REFERENCES

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XI. BIOGRAPHY

Eric Schroeder joined Cross Texas Transmission in January 2013 and has more than 20 years of experience managing electric transmission utilities and consulting in the power delivery industry. At Cross Texas Transmission, Eric is responsible for managing both field operations and control center operations. Prior to joining Cross Texas Transmission, Eric was an executive transmission manager at Texas Municipal Power Agency, overseeing the electric transmission business. Prior to that, he was a project engineer at POWER Engineers, a global consulting engineering firm. Eric also has owned his own business in the energy industry and is a regular speaker at energy and utility conferences. Eric holds a Bachelor of Science in electrical engineering from the University of Tulsa.

Jerry Burton joined Cross Texas Transmission in November 2013 and has over 18 years of experience in the electrical field on projects in the residential, commercial, oil and gas, process and generation/transmission industries. Mr. Burton has filled several positions from apprentice to general foreman, senior relay technician and most recently Substation Superintendent. Mr. Burton has a wide variety of knowledge as it pertains to relay testing, commissioning, preventive maintenance and substation construction. Mr. Burton currently holds a Texas Department of Licensing and Regulation Journeyman Electrician license and a Substation Journeyman Electrician certificate through the US Department of Labor.

Joe Perez received his B.S. degree in Electrical Engineering from Texas A&M University in 2003. Joe is the author of many relay application notes and has presented technical papers at WPRC, Texas A&M and Georgia Tech Relay Conferences. Joe is the owner of SynchroGrid, a registered professional engineer in the state of Texas and a member of PSRC, IEEE, and PES. Joe resides in the Bryan/College Station area. He can be contacted at jperez@synchrogrid.com

Luke Hankins is from Cleveland, Texas. He graduated from Texas A&M University with a Bachelor's of Science degree in Electrical Engineering. He is currently an E.I.T. and working for SynchroGrid as a Design Engineer. In addition to substation design, Luke is in charge of relay settings verification and mis-operation analysis. He also writes code in C++ and VBA that aid in company operation, automating tasks and improving efficiency.

XII. ACKNOWLEDGEMENT

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