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Protection of a 138/34.5 kv transformer using SEL 387-6 relay

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PROTECTION OF A 138/34.5 KV TRANSFORMER USING SEL 387-6 RELAY

by

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ABSTRACT

Schweitzer Engineering laboratories (SEL) donated the SEL 387, SEL 311L, and SEL 351S relays and the SEL AMS to Missouri University of Science and Technology. This thesis documents the demonstration approach to set the SEL 387 relay to protect a grounded wye-grounded wye transformer and then test these settings by injecting fault currents into the relay using the SEL AMS. This thesis explains the approach to set the differential element of the SEL 387 relay to protect a transformer against internal faults and the overcurrent element of the SEL 387 relay to protect transformer against external faults. A radial power system model is assumed and modeled using ASPEN Oneliner and Power Flow software. Fault currents obtained from ASPEN model are injected to the relay using the SEL AMS. Separate tests are performed for the differential element and the overcurrent element. The objective of testing the differential element is to show that it is tripping for internal faults and restraining for external faults. The approach used by the SEL 387 differential relay to make trip decisions is theoretically calculated. These theoretical results are verified with results obtained from the relay fault event reports. The instantaneous and time overcurrent elements are tested by running various types of faults at four different locations. The objective of testing the overcurrent elements is to show that the instantaneous overcurrent elements are tripping only for transformer primary side faults and to show that primary side time overcurrent element is coordinating with the secondary side time overcurrent element.

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1. INTRODUCTION

Schweitzer Engineering laboratories (SEL) donated the SEL 387, SEL 311L, and SEL 351S relays and the SEL AMS to Missouri University of Science and Technology. This thesis documents the demonstration approach to set the SEL 387 relay to protect the transformer and then test these settings by injecting fault currents into the relay using the SEL AMS. This is intended to provide additional documentation to better use the relays for a hands on experience on setting relays in a classroom setting.

The basic components of power systems are generators, transformers, high voltage transmission lines, and distribution lines. The damage to any of these equipment components may result in a system outage. The main cause of damage in power system is a short circuit or fault. A fault is caused due to conditions such as lightening, earthquakes, wind, contact of animals with equipment etc. [1]. During a fault condition, abnormal conditions such as high currents, over voltages, low voltages, and over/under frequency may exist in the system. These abnormal conditions often exceed the rating of the equipment and lead to equipment damage.

A fault may be a single phase to ground, a double phase to ground, phase to phase or a three phase fault. A single phase to ground fault occurs the most frequently of all faults. The desirable response to a single phase to ground fault is to disconnect the faulted part momentarily until the fault clears to prevent cascading. This disconnection is accomplished by means of a circuit breaker controlled by the protective relays.

A protective relay or relay is defined by IEEE Standard C37.90 as ‘‘an electric device that is designed to respond to input conditions in a prescribed manner and, after specified conditions are met, to cause contact operation or similar abrupt change in associated electric control circuits." The electronic device refers to the relay that opens the contacts of the circuit breaker (known as tripping) when there exists an abnormal condition such as high currents, over voltages, or low voltages. In the same manner, it is should not respond to normal operating conditions or load conditions. The relays are usually given inputs from current transformers (CT), voltage transformers (VT), or both. These CTs and VTs are known as instrument transformers. These instrument transformers usually step down the currents and voltages of the primary or main circuit to lower values that can be safely applied to the relays.

The relay may be either electromechanical or a digital. Electromechanical relays use the electromagnetic principle which converts electrical quantities such as current and voltage to mechanical quantities such as torque. The digital relays are built with microprocessors, digital signal processors, and A/D converters to convert electrical quantities to digital signals. Reliability, speed, low burden, multifunctional capability features available in digital relays have made them more dependable than electromechanical relays. Digital usage over the past two to three decades has increased and many industries are replacing their electromechanical relays with digital relays.

Based on the logic of protection, relays can be classified as overcurrent relays, differential relays, distance relays, or directional relays. For example, an overcurrent relay operates if the current through the relay exceeds the pickup value. A distance relay operates if the ratio of voltage to current is below a preset value. The relay under consideration, SEL 387, is a multifunctional digital relay which includes differential protection, overcurrent protection, restricted earth fault protection, and transformer thermal protection as functionalities.

2. BACKGROUND

2.1. TRANSFORMER BASICS

According to ANSI C57.12.80, a transformer is defined as “a static electric device consisting of a winding, or two or more coupled windings, with or without a magnetic core, for introducing mutual coupling between electric circuits. Transformers are extensively used in electric power systems to transfer power by electromagnetic induction between circuits at the same frequency, usually with changed values of voltage and current.” A simple single phase transformer consists of two coils, known as the primary and secondary windings, wound on an iron core separated electrically but linked magnetically. When an ac voltage V1 is supplied to primary winding, a small current, known as the exciting current, is produced in this primary winding and an alternating flux is produced in the iron core. This flux is transferred to the secondary coil through the iron core which in turn induces voltage V2 in the secondary, as shown in Figure 2.1.

The voltage is stepped up or down based on the number of primary and secondary winding turns. The voltage is proportional to number of turns. If number of primary turns is greater than secondary turns, the voltage is stepped down. If the number of primary turns is less than secondary turns, the voltage is stepped up.

In power systems, the transformer is the most important component used to step up or down different voltage levels. According to ANSI C57.12, transformers with a high side voltage or low side voltage ratings greater than 69kV are used at transmission levels. Small transformers with a high side voltage rating less than 69kV are classified as distribution transformers and are used at distribution levels. The transformers used in

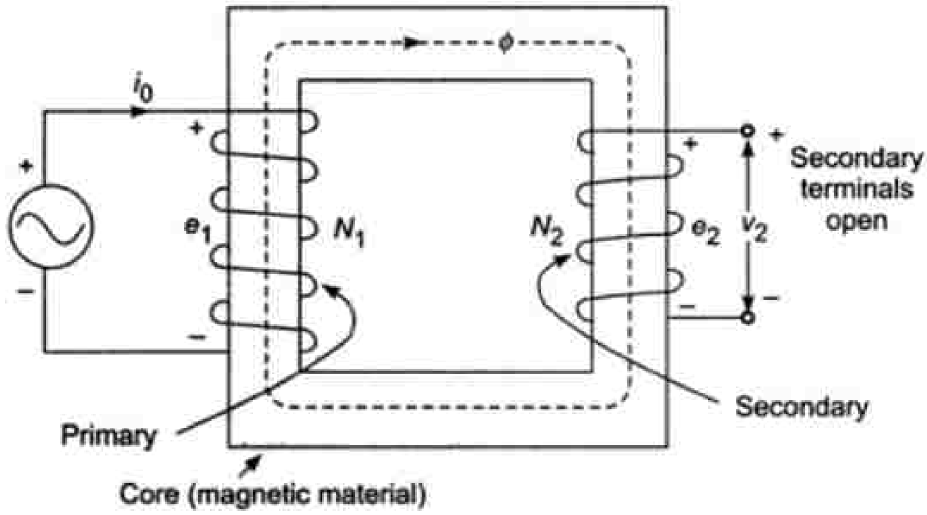


Figure 2.1. Basic structure of a transformer under no load [12]

power systems may be of two windings or three windings. The transformer windings are usually connected in delta or wye connection. Different combinations of two winding transformer connections are shown in Figure 2.2. Auto transformers are also a common connection type in power systems.

2.2. TRANSFORMER PROTECTION

The main objective of transformer protection is to detect transformer internal faults with high sensitivity and restrain for the faults on the system for which tripping of the transformer is not required [1]. The transformers have to be protected for internal faults, external faults, overexcitation, and overload conditions. Overexcitation protection is provided mostly for generator step up unit (GSU) transformers as these transformers are operated under the control of automatic voltage regulator of generator during start up or shut down [9]. Transformers at distribution levels are protected against internal and

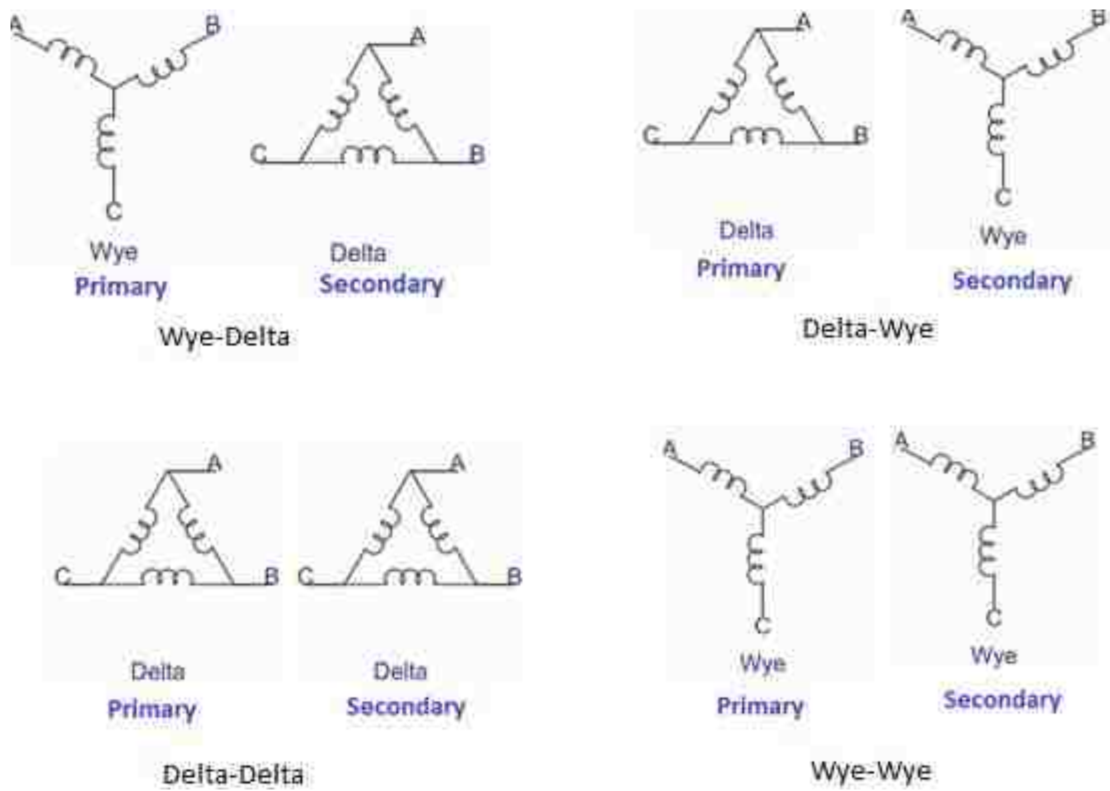


Figure 2.2. Winding configurations of transformers

external faults. Overload protection may also be included for these transformers. In general, transformers with ratings greater than 10MVA are protected using a differential relay [1]. Transformers rated less than 10MVA, which are mainly distribution transformers, are protected using fuses on their high side. Transformers with low ratings are relatively inexpensive and therefore differential protection, which is expensive, is not feasible. Fuses are less expensive as they do not make use of a circuit breaker. Therefore the protection of small transformers with fuses is more economically feasible. The conditions for which transformers have to be protected are discussed under sections 2.2.1. to 2.2.4.

2.2.1. Internal Faults. Faults in the transformer zone are internal faults. Internal faults are due to transformer insulation breakdown. Insulation breakdown occurs due to following factors:

- ageing of insulation due to overtemperature
- contaminated oil
- partial discharges in the insulation
- transient overvoltages

Breakdown of insulation leads to severe earth faults, short circuit faults, turn to turn faults, core faults, and tank faults. The occurrence of any of these faults results in severe damage to transformer. Differential protection is commonly used to protect the transformer from internal faults.

2.2.2. External Faults. Faults external to the transformer zone are external or through faults. External faults impose severe stress on transformers if these faults are not cleared by their corresponding primary protection devices. Stress on transformer causes transformer overheating and damage. External fault protection is provided by overcurrent relays or fuses. These protection devices serve as backup to downstream devices.

2.2.3. Overexcitation. An overexcitation fault is caused by an increase in voltage or decrease in frequency. As per IEEE C37.91 "Overexcitation of a transformer can occur whenever the ratio of the per unit voltage to per unit frequency (V/Hz) at the secondary terminals of a transformer exceeds its rating of 1.05 per unit (PU) on the transformer base at full load, 0.8 power factor, or 1.1 PU at no load" [9]. The transformer core saturates and increases the iron loss during overexcitation. The volts per hertz (V/hz) protection is provided to protect against overexcitation. This protection is usually provided for generator and GSU transformer together based on the combined generator and transformer overexcitation capability.

2.2.4. Overload Faults. An overload increases copper losses and causes temperature rise. Thermal protection is usually provided to transformer to protect against this condition. Generally an alarm is used for protection instead of tripping.

The transformer under consideration in this demonstration is a 138/34.5 kV, 80MVA grounded wye-grounded wye power transformer. The SEL 387 relay is used to protect this transformer. The differential element of this relay is used to provide protection for internal faults. To provide protection for external faults, the overcurrent element is used.

Figure 2.3 shows the one line diagram of the transformer protection scheme using the SEL 387 relay. ANSI device number 87 represents the differential relay. CT1 and CT2A are the CTs located on the high side and low side, respectively, and are used for differential protection. ANSI device numbers 51P and 51G represent the phase and ground overcurrent relays respectively. ANSI device numbers 50P and 50G represents the phase and ground instantaneous overcurrent relays respectively. ANSI device number 52 represents a circuit breaker. Circuit breaker 52-1 is on the high side of the transformer. Circuit breaker 52-2 is on the low side of the transformer. For testing purpose, differential element and time overcurrent elements have been used.

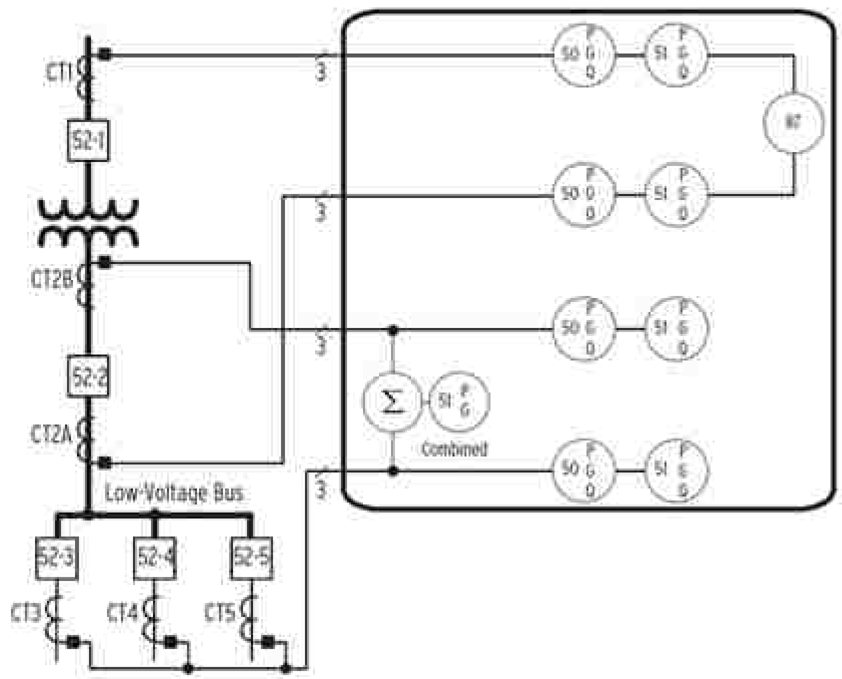


Figure 2.3. One line diagram for the protection of a 138/34.5 kV transformer using the SEL 387 relay

2.3. TRANSFORMER PROTECTION FOR INTERNAL FAULTS USING DIFFERENTIAL RELAY

Differential protection is the best protection technique due to selectivity [1]. Selectivity is the ability of the relay to trip for internal faults and restrain for external faults. The differential relay is used to provide instantaneous protection to a specific component such as a generator, transformer, line, or bus without the need for coordination with the relays protecting other equipment outside the zone of equipment under consideration. Other commonly used protection relays, such as distance relays or overcurrent relays that extend their protection to adjacent zones, need to be coordinated with the devices protecting the zone adjacent to transformer zone. The transformers with ratings greater than 10 MVA are protected by differential relays. For transformers with higher ratings, differential relays are used because they provide instantaneous protection to internal faults.

The working principle of a differential relay is based on Kirchhoff's current law according to which current flowing into a node is equal to current flowing out of a node. The net current entering the protection zone through the CTs secondary is calculated by the relay. Under ideal non fault or external fault conditions, the net current in the protection zone is zero. Under non-ideal conditions, current flows through the protection zone even under normal conditions due to transformer excitation currents, CT error, and relay error [1]. This condition is shown in Figure 2.4.

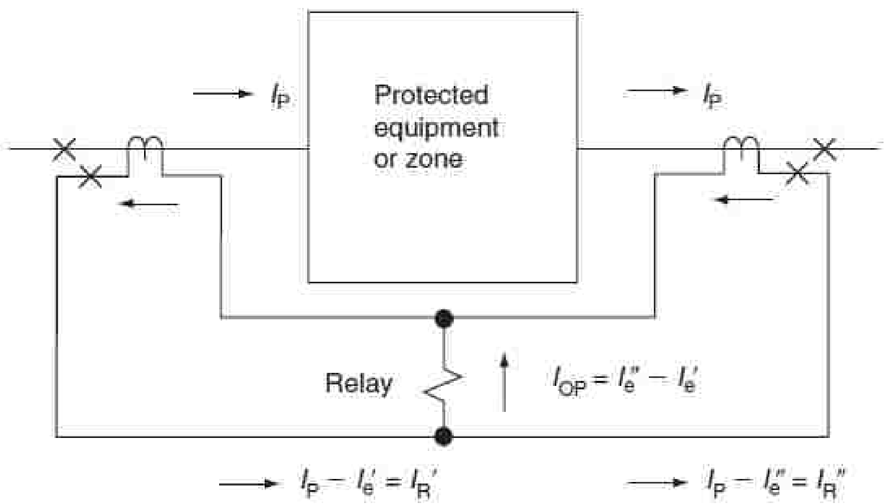


Figure 2.4. Normal operating conditions, $I_{op} = I_e'' - I_e'$ [1]

When there is an internal fault, the fault currents from both the windings will be flowing into the protection zone in opposing directions as shown in Figure 2.5. The relay trips if currents flowing in the protection zone exceed the pickup value. The pickup of a differential relay is set based on the transformer inrush current, CT errors, relay errors, and other factors.

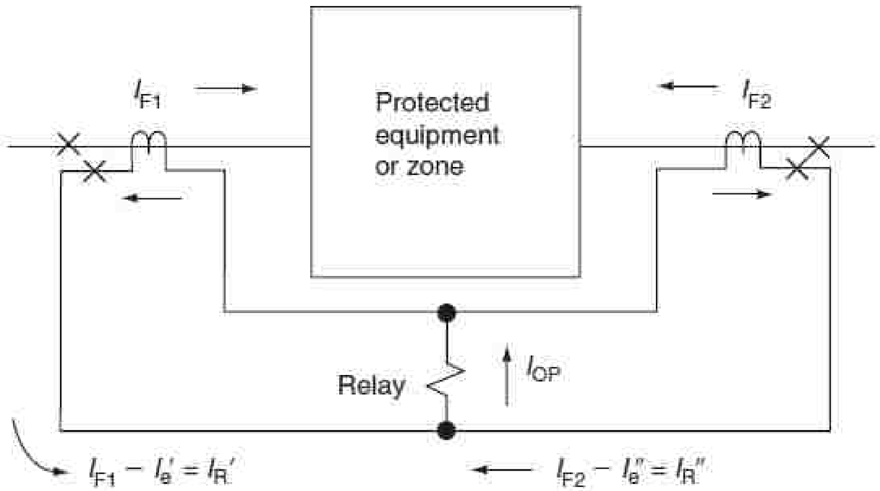


Figure 2.5. Internal fault condition $I_{OP} = I_{F1} + I_{F2} - I_e'' - I_e'$ [1]

2.3.1. Percentage Restraint Differential Relay Scheme. The SEL 387 relay uses a percentage restraint differential relay scheme. This scheme operates on the ratio of the magnitudes of pick up to restraint currents or the value of slope of the curve as shown in Figure 2.6. The operating current is defined as the phasor sum of all currents flowing into the protection zone. The restraint current has many definitions. It can be defined as follows

$$I_{RST} = K\left(|I_{W1}| + |I_{W2}| + |I_{W3}| \ldots..\right) \text{ or} \tag{2.1}$$

$$I_{RST} = \text{Max}\left(|I_{W1}|, |I_{W2}|, |I_{W3}| \ldots..\right) \tag{2.2}$$

where I_{W1}, I_{W2}, I_{W3}, … are the secondary currents flowing in winding 1, winding 2, and winding 3, etc., and K is a constant defined by the relay manufacturers. For the SEL 387 relay, the restraint current is defined as the average of currents flowing through the two windings as shown in equation 2.3.

$$I_{RST} = \frac{|I_{W1}|+|I_{W2}|}{2} \tag{2.3}$$

If the operate-to-restraint current ratio exceeds the value of slope, the relay trips [3]. The relay trip and operate regions are as shown in Figure 2.6. A single slope or a dual slope characteristic can be used with a minimum pickup setting.

From the slope characteristics, it is evident that the percentage restrained differential scheme provides more sensitive protection for low levels of current and less sensitive protection for high current levels. It is designed to differentiate between differential currents flowing due to internal faults from the differential currents flowing due to external faults as a result of CT saturation. This scheme is designed based on the fact that the higher currents are due to CT saturation which occurs as result of high external faults.

2.3.2. Factors To Be Considered While Setting A Differential Relay. There are several factors to be taken into consideration while setting a differential relay. All these factors have to be considered carefully to avoid relay misoperation.

2.3.2.1. Power transformer phase shift. When a two winding transformer is used in power systems, it is typically a grounded wye-grounded wye configuration or a delta-wye configuration. In a grounded wye -grounded wye configuration, there is no phase shift between the primary and secondary of the transformer. If the transformers are connected with a delta-wye configuration, there is ±30˚ phase shift between the primary and secondary. If this phase shift is not compensated, differential current will flow through the protection zone. The phase shift between the primary and secondary of the power transformer can be compensated by using proper CT connections. The traditional way to provide compensation is to connect a wye CT for a delta winding and a delta CT for a wye winding. This connection compensates for the delta-wye phase shift of the power transformer. For a wye connected winding, a delta connected CT is used to remove zero sequence currents. Zero sequence current has to be eliminated to avoid misoperation of the differential relay due to line to ground faults on the wye side of a delta-wye connected transformer. In digital relays, delta-wye phase shift compensation and zero sequence current elimination can be attained by providing appropriate settings to the relay. With the availability of this feature, any configuration can be chosen for the CTs.

2.3.2.2. Tap compensation mismatch. Power transformers have different voltage ratings for primary and secondary windings. CT ratios of primary and secondary windings should be selected in such a way that same secondary current flows through the CTs of both windings. As the CT ratio selection should take the maximum load current into account to avoid CT saturation, it may not be possible to select CT ratios whose primary purpose is to make the same secondary currents to flow through the CTs of both windings. To compensate for the difference in secondary currents, electromechanical relays are provided with tap settings. Because of availability of only a limited taps in electromechanical relays, there exists a mismatch between these secondary currents. The tap compensation mismatch error can be calculated using equation 2.4.

$$\text{mismatch\%} = \frac{\dfrac{I_1}{\text{TAP}_1} - \dfrac{I_2}{\text{TAP}_2}}{\min\left(\dfrac{I_1}{\text{TAP}_1}, \dfrac{I_2}{\text{TAP}_2}\right)} \times 100 \tag{2.4}$$

where I_1 and I_2 are transformer full load secondary currents in winding 1 and winding 2 CTs respectively. TAP_1 and TAP_2 are the taps selected from the available taps to minimize the mismatch error.

However in digital relays, there is no tap compensation mismatch error and thus this error can be assumed to be zero. The relay tries to automatically adjust the tap to make mismatch error zero.

2.3.2.3. Load/No load tap changer. Transformers are usually provided with on load/no load tap changers to regulate the voltage based on system load conditions. The tap changer changes the transformer turns ratio, and thus the voltage of the primary or secondary winding. The transformer's on load tap changers are used when voltage regulation can be performed on load without interruption to power. On the other hand, no load tap changers are used when voltage regulation has to be done while the transformer is on no load. The relays settings are usually made considering the transformer primary and secondary fixed rated voltages. But these voltages vary in accordance with load conditions. An error of ±5% for a no load tap changer and an error of ±10% for a load tap changer can be considered in differential relay settings to account for transformer tap changes due to load conditions [3].

2.3.2.4. Inrush current. The transformer inrush current is the high magnitude current flowing through the transformer at three instances: during energization of the transformer, during the transformer voltage recovery after an external fault is cleared, and during parallel operation of two or more transformers [4]. Any condition that causes instantaneous change of the transformer flux linkages can cause large inrush currents to flow. As the duration of flow of these currents is very short, they do not cause any fault.

But these currents may cause the differential relay to operate. The relationship between the flux produced in the core of the transformer and the applied voltage in general is given by equations 2.5 and 2.6.

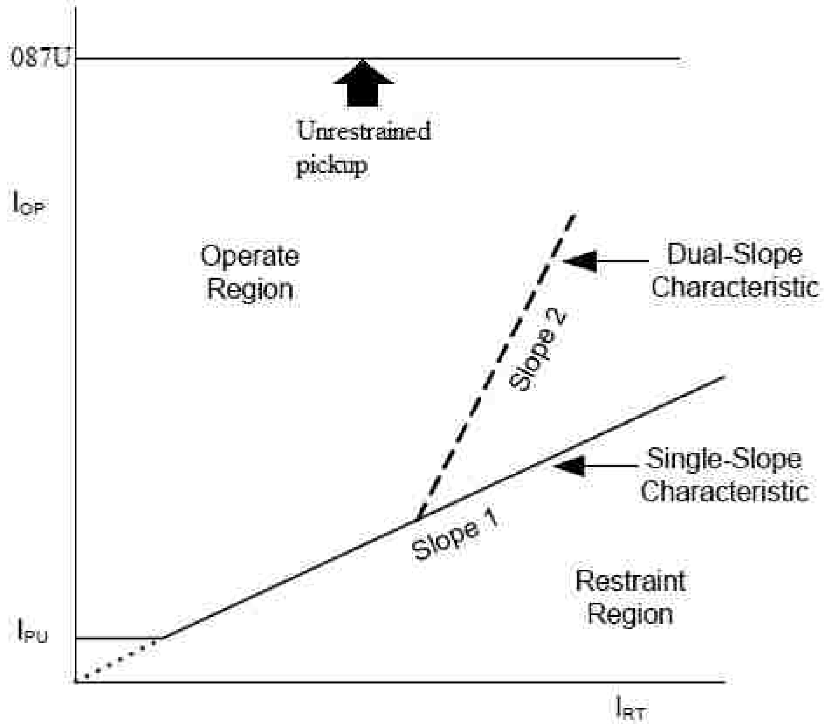


Figure 2.6. Percentage differential relay slope characteristics [3]

$$V(t) = \frac{d\phi(t)}{dt} \tag{2.5}$$

$$\phi(t) = \int v(t) + K \tag{2.6}$$

If $V(t) = V_m sin(\omega t)$, then $\Phi(t)$ will be a cosine function. From equations (2.5)-(2.6), it is evident that the applied voltage and core flux are in quadrature with each other. However, if the transformer is energized at the instant the voltage is zero, the core flux at this particular instant is also zero. The value of flux obtained after the first half cycle of voltage, when the flux and voltage together start from zero can be calculated as follows,

$$\begin{aligned}\phi(\pi) &= \int_0^{\pi} V_m \sin(\omega t)dt \\ &= \frac{V_m}{\omega}\int_0^{\pi} \omega \sin(\omega t)dt \\ &= \varphi_m \int_0^{\pi} \sin(\omega t)d(\omega t) = 2\varphi_m\end{aligned} \tag{2.7}$$

where $\frac{V_m}{\omega} = \varphi_m$ is the maximum value of flux. The flux at the end of first half cycle of voltage becomes as high as twice the maximum value of flux, $2\Phi_m$. The core begins to saturate when the value of flux reaches its maximum value Φ_m. A large amount of current is drawn from the system to produce the remaining flux after the core saturates. This is the magnetizing inrush current and is as high as ten times the current rating of the transformer. These large currents are responsible for tripping differential relays.

Inrush currents are characterized with even harmonic content at large levels. This fact can be used to distinguish an inrush current from a fault current. The SEL 387 relay is equipped with harmonic blocking and harmonic restraint feature to provide security to relays against high inrush currents which are rich in 2^{nd} and 4^{th} harmonic content [4]. If the harmonic blocking setting is enabled, the differential relay is blocked when the ratio of second or forth harmonic operating current and fundamental frequency operating current exceeds a preset second or forth harmonic threshold. Enabling the harmonic restraint setting in relay increases the slope of the relay. As shown in Figure 2.7, the slope is increased by adding a harmonic restraint constant *C*. This can be mathematically represented as follows:

$$\text{IOP} = \text{SLP1*IRT} + C \tag{2.8}$$

$$C = \frac{100}{PCT2}\sum IW_n C2 + \frac{100}{PCT4}\sum IW_n C4 \tag{2.9}$$

where

IOP: operating current

IRT: restraint current

SLP1: value of slope without harmonic restraint

PCT2: 2nd harmonic threshold

PCT4: 4th harmonic threshold

ΣIW_nC2: sum of 2nd harmonic currents through all the windings

ΣIW_nC4: sum of 4th harmonic currents through all the windings [5].

2.3.2.5. Overexcitation. Transformer overexcitation is caused due to increase in voltage or decrease in frequency as the magnetic flux inside the transformer is directly proportional to the applied voltage and inversely proportional to frequency [5]. Due to overstressing the transformer with high flux, overexcitation results in core saturation that causes a higher magnitude current to flow into transformer primary winding than out of transformer secondary winding. The differential relay might interpret this incorrectly as a fault current and trip. Large overexcitation currents might be undesirable as they cause transformer heating and ultimately damage the transformer. But differential protection cannot reliably detect overexcitation currents as the relay characteristics do not match with the transformer overexcitation capability limit [1]. Instead, a separate protection scheme such as Volts/hertz must be used to protect transformer from high overexcitation currents.

The overexcitation currents are abundant in odd harmonic content, mostly third or fifth, whereas in fault currents, the content of these harmonics is comparatively low. This fact can be used to differentiate an overexcitation current from the fault current and prevent the operation of differential relay for overexcitation currents [4]. Third harmonic content cannot be used to detect overexcitation condition as it is eliminated with a delta winding similar to how a zero sequence current is eliminated using delta winding. Using a mechanism to eliminate fifth harmonic content can prevent differential relay from tripping for overexcitation conditions. The SEL 387 relay has 'harmonic blocking' feature that blocks the relay if the fifth harmonic content exceeds a specified limit. When the ratio of fifth harmonic operating current and fundamental frequency operating current exceeds a preset fifth harmonic threshold, the differential relay is blocked.

2.4. TRANSFORMER THROUGH FAULT PROTECTION USING OVERCURRENT RELAYS

The differential relay can provide instantaneous protection to internal faults. To protect a transformer against external faults, an overcurrent relay can be used. For transformers rated less than 10MVA, where differential protection is not used, a fuse on the high side of transformer can provide external fault protection [1]. When a differential protection is used, overcurrent elements are generally used as local backup to the differential relay and at the same time provide protection for transformer external faults. An instantaneous overcurrent element is used as a backup for a differential relay. Time overcurrent elements are used exclusively to provide protection for external faults in case downstream relays fail to operate. The objectives of using a time overcurrent relay on primary and secondary of transformer can be summarized as follows:

- The primary function of the overcurrent relay on the primary side is to provide primary backup protection for the secondary side relays and thereby protect the transformer against external faults. The relay settings should be selected to coordinate with the transformer damage curve while coordinating with its upstream and downstream devices. The relay curve should lie to the left of the transformer damage curve for all faults.

- The primary function of the overcurrent relay on the secondary side of the transformer is to provide backup protection for downstream relays and protect transformer from external faults. This can be achieved by coordinating the secondary side relay with the transformer damage curve. This relay has to coordinate with primary side relay as well as downstream relays.

2.4.1. Description Of Overcurrent Relays. Overcurrent relays respond to faults by tripping if the magnitude of the current sensed by the relay exceeds the pickup setting. The pickup setting of the relay is the minimum current at which relay starts to operate. Non-directional overcurrent relays are often used for protecting radial systems. In a radial power system, the flow of power is only in one direction from the substation to the loads. In the absence of distributed generation, there will be no fault current contribution from the downstream system in such a system. It is important to use directional overcurrent relays if the system is of the network or ring type where flow of power may be from multiple directions. The choice of directional relays for such systems enables good selective operation for faults.

The overcurrent relays are classified based on the trip duration as either instantaneous overcurrent relays or time overcurrent relays. Instantaneous overcurrent relays trip for faults without any time delay. They are usually set to act instantaneously for the faults in the zone they are primarily protecting without overreaching. Time overcurrent relays are often used to trip with time delay to provide primary protection for the faults in the zone they are protecting and backup protection for faults in the adjacent zones. This time delay is provided to coordinate with upstream and downstream relays and thereby avoid misoperation. The operation time of time overcurrent relays decreases as the magnitude of the current increases. A separate protection is provided for phase faults and ground faults. Ground fault currents are usually small in magnitude compared to phase fault currents. So separate ground fault relays are needed which are set more sensitively for ground fault protection.

2.4.2. Overcurrent Relay Coordination. A fault needs to be cleared quickly before the equipment it is protecting is damaged. At the same time, the faulted area has to be isolated with as much little load outage as possible. For a particular fault, the device near the fault must operate first to isolate as many loads as possible from outage. This is the main idea behind coordinating relays. For every relay in power systems, there is usually a backup relay to operate if the primary relay fails to operate for a fault in its zone. Coordination has to be attained with this backup relay to interrupt power to few loads as possible in the process of clearing a fault. In a radial system, such as the system under consideration, a minimum coordinating time interval of 0.3 seconds has to be maintained to avoid misoperation. This 0.3 seconds time interval includes

- Relay operating time - 1 cycle
- Lockout relay operating time - 1 cycle
- Breaker operating time - 3 cycles

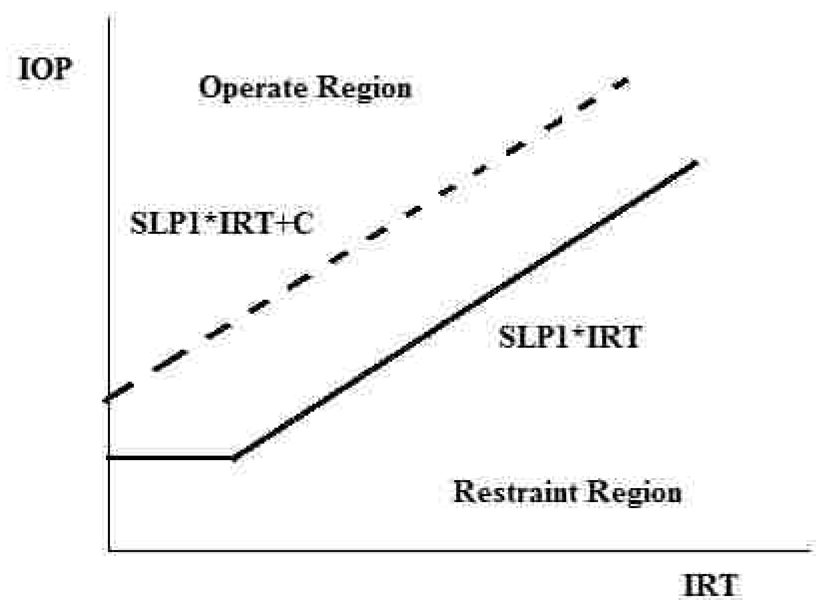


Figure 2.7. Slope change when the harmonic restraint setting is enabled

- Breaker failure time - 10 cycles if a breaker failure scheme exists, otherwise is zero
- Margin - 10 cycles margin is typical

All these factors sum to 24 cycles. To be more conservative, a coordinating time interval of 18 cycles or 0.3 seconds is considered in a radial system.

The overcurrent relay pickup setting is selected based on load conditions, load imbalances, and fault conditions. Setting the time overcurrent phase and ground relay requires selection of the time dial and curve. The parameters relay curve and time dial are selected in such a way that 0.3 seconds coordinating time interval is maintained between a primary relay and its next upstream or downstream relay. Time current curves (TCC) are usually provided by the relay manufacturers. There are 4 different types of curves for any relay: extremely inverse, very inverse, inverse, and moderately inverse curves. To attain good coordination, relays in the downstream are usually assigned curves that are more inverse than curves assigned to upstream relays in a typical radial system as the one shown in Figure 2.8.

The SEL 387 relay has two types of curves: the US standard curves (U1, U2, U3, U4) and the IEC curves (C1, C2, C3, C4). Curves U1, U2, U3, and U4 respectively are US moderately inverse, inverse, very inverse, and extremely inverse curves whereas C1, C2, C3, and C4 respectively are the IEC class A or moderately inverse, IEC class B or inverse, IEC class C or very inverse, and IEC class D or extremely inverse curves. Any curve that attains good coordination with upstream and downstream devices can be chosen. US curves coordinate well with ABB and GE's electromechanical relays. IEC curves coordinate well with European relays or relays of many other countries.

A sample family of US extremely inverse curves is shown in Figure 2.9. The curves are governed by the equations 2.10 and 2.11, where T_P is the operating time, T_R is the reset time, TD is the time dial setting, and M is the multiple of pickup current.

$$T_p = TD\left(0.0352 + \frac{5.67}{M^2 - 1}\right) \tag{2.10}$$

$$T_R = TD\left(\frac{5.67}{1 - M^2}\right) \tag{2.11}$$

2.4.3. Setting An Overcurrent Relay. The following sub sections describe the approach to set phase and ground overcurrent relays.

2.4.3.1. Phase time overcurrent (51P). A phase time overcurrent element can be used to protect lines, transformers, or feeders with a time delay. The relay should not trip for load conditions. The 51P can be set from 1.15 times to 2 times the load current. It should be time coordinated with its upstream and downstream devices. Also, a minimum fault detection margin of 2 for an end of line minimum fault (usually phase to phase fault) has to be maintained. The relay curve and time dial setting must be selected to maintain a minimum of 0.3 seconds coordinating time interval with the consecutive upstream or downstream devices to avoid relay misoperation.

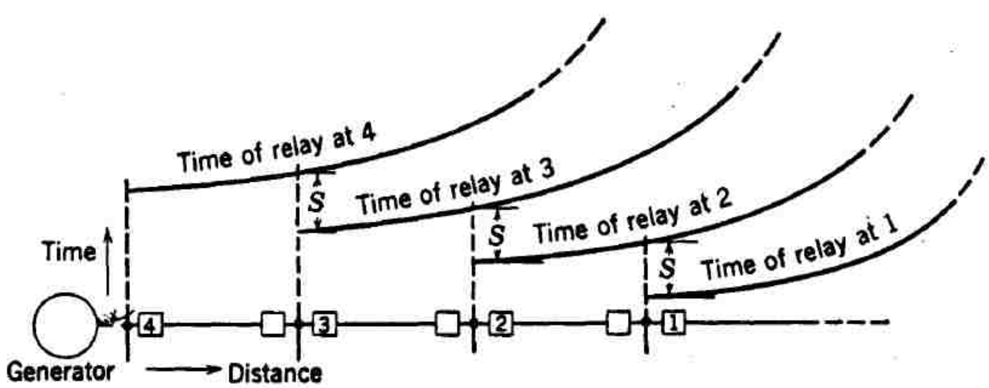


Figure 2.8. Relay typical TCC curves in a radial system [13]

2.4.3.2. Ground time overcurrent (51N). A ground time overcurrent element can be used to provide ground fault primary or backup protection. It can be set with utmost sensitivity as its operation is independent of load conditions. However, they have to be set above minimum expected imbalance. Similar to a phase overcurrent relay, a ground relay curve and time dial setting has to be selected to maintain a minimum of 0.3 seconds coordinating time interval with the next upstream or downstream device to avoid relay misoperation.

2.4.3.3. Phase/ground instantaneous elements (50P/50N). Phase/ground instantaneous elements are used to trip instantaneously for the faults in the line or transformer zone they are primarily protecting. Their protection should not over reach the zone they are primarily protecting to avoid misoperation. A phase instantaneous element is set with a margin 1.5 to 2 above the remote bus maximum fault (mostly 3 phase fault). A ground instantaneous element is set similarly at a pickup of 1.5 to 2 times the remote bus line to ground fault.

2.4.4. Transformer Through-Fault Withstand Capability Curve. The transformer through current or external faults produce physical forces which cause thermal and mechanical damage to the transformer if the external fault is not isolated before the transformer is damaged. As discussed previously, to provide backup for downstream relays and to protect the transformer from external faults, overcurrent relays are used. But overcurrent elements are usually associated with a time delay as they are required to coordinate with downstream devices. The time delay provided to set overcurrent elements also should conform to the transformer through-fault withstand capability curve. Through fault withstand capability curves provide information about short circuit currents that a transformer can withstand for a specified time period. Overcurrent relays located downstream to the transformer should operate before the transformer becomes damaged. The relay on the primary side of the transformer provides backup to downstream relays for transformer external faults. Transformer withstand capability curve properties differ for different transformer categories. As per IEEE

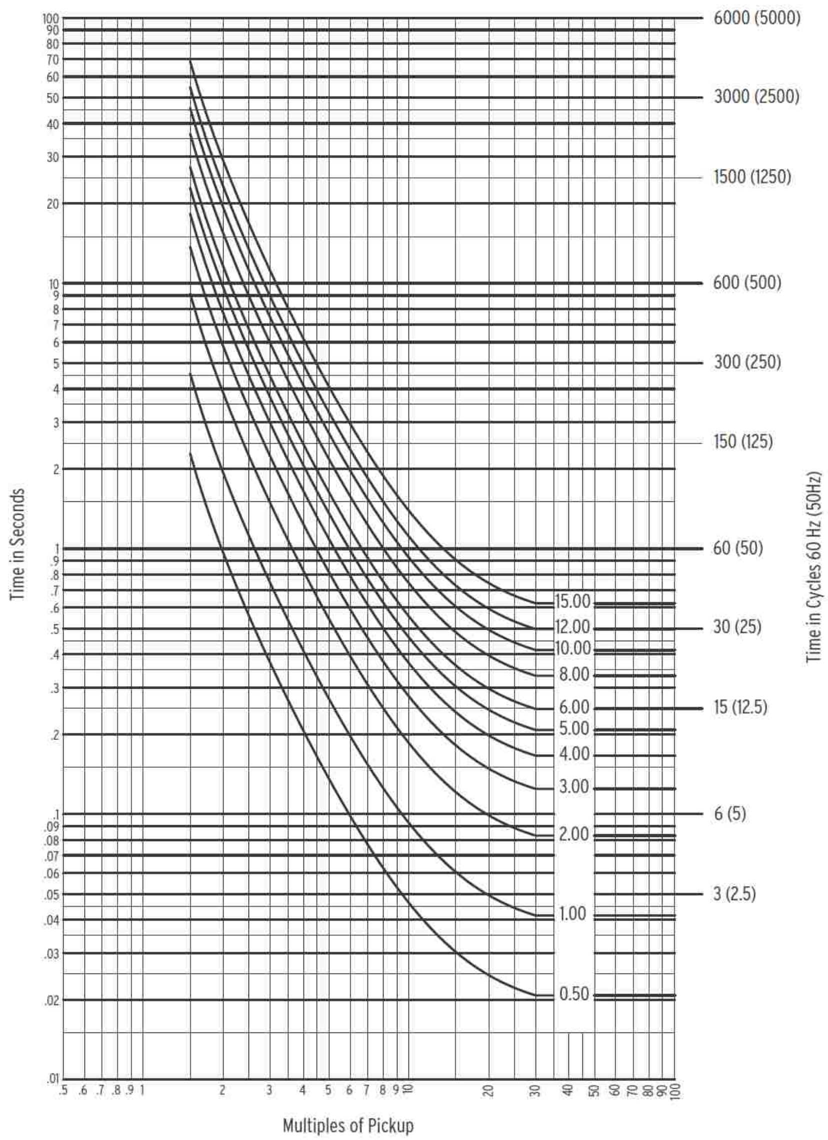


Figure 2.9. US Extremely inverse curve U4 [5]

C57.12.00, transformers are categorized as shown in Table 2.1 according to kVA ratings. The duration of short circuit of Category I transformers can be determined by the equation 2.12, where *t* is duration in seconds and *I* is the symmetrical short-circuit current in multiples of normal base current.

$$t = \frac{1250}{I^2} \tag{2.12}$$

For Category II, III, and IV transformers, the duration of the short circuit is limited to 2 seconds. Symmetrical short circuit currents for Category I and II transformers are calculated based on transformer impedance. The symmetrical short circuit current for Category III and IV transformers is calculated based on transformer impedance [9].

A different through-fault protection curve is applied for different transformer applications i.e., there is separate through-fault withstand capability curve for transformers subjected to infrequent faults and transformers subjected to frequent faults. For example, transformers typically found in industrial, commercial and institutional power systems with secondary side conductors enclosed in conduit or isolated are subjected to faults less frequently. On the other hand, transformers found in utility distribution substations with overhead lines connected to secondary windings are subject to frequent faults. If a transformer is subjected to faults infrequently, the transformer is typically protected only against thermal damage. A transformer subjected to faults frequently has to be protected against both thermal and mechanical damage. The through-fault withstand capability curve selected should reflect both possibility of thermal damage and mechanical damage. The TCC relay curves on the primary and secondary of the transformer along with downstream relays for which transformer relays are providing backup should lie to the left of transformer damage curve to properly protect transformer for low side uncleared faults. For Category I transformers, only a thermal protection curve can be considered as shown in Figure 2.10. This curve can be used for both frequent and infrequent faults of category I transformers. For category II and III transformers with infrequent faults, the thermal protection curve as shown in Figure 2.10 is used. For transformers with frequent faults, the mechanical damage curve must be considered. For a Category II transformer with frequent faults, the curves as shown in Figure 2.11 with mechanical damage curves represented with dotted line can be considered. The choice of curve is based on transformer impedance (% Z). For Category III transformers with frequent faults, the curve as shown in Figure 2.12 is used. This curve reflects both thermal and mechanical damage. For Category IV transformers, the same curve as shown in Figure 2.12, which reflects both thermal and mechanical damage, can be considered for both frequent and infrequent faults [9].

2.4.5. Transformer Through-Fault Withstand Capability Curve Shift. When there is a delta winding, the line currents are different from the phase currents for different fault types. This difference must be considered when coordinating relays with the transformer through-fault withstand capability curve. For example, consider a fault scenario on the secondary side of a delta-wye two winding step down transformer. In this transformer configuration, the primary side (delta) leads the secondary side (grounded wye) by 30˚. Fault currents distribution for secondary side three phase, phase to phase, and phase to ground faults are shown in Figure 2.13. In these figures, the largest phase current is designated as 1.0 per unit. Unlike a wye-wye transformer which has comparable per unit fault currents flowing through both the windings for all types of faults, a delta-wye transformer has different values of currents flowing through the primary and secondary. For a wye side three phase fault, 1.0 per unit line currents flow through both primary and secondary windings. While for a wye side phase to phase fault, the primary side phase A, B, C currents are 0.5 per unit, 1.0 per unit, and 0.5 per unit respectively, and the secondary side phase A, B, C currents are 0.0, 0.866 per unit and 0.866 per unit, respectively. For a secondary side phase A to ground fault, the line

Table 2.1. Transformer categories [9]

Category	Single phase (kVA)	Three phase (kVA)
I	5 to 500	15 to 500
II	501 to 1667	501 to 5000
III	1668 to 10000	5001 to 30000
IV	Above 10000	Above 30000

currents on the delta side are 0.577 per unit. The secondary side phase to ground fault is seen as a phase to phase fault by the relay on a delta winding. If it is desired to shift the relay curves from the primary side to the secondary side, the shift factor includes the turns ratio in addition to the multiplication factor. For example, if a primary side relay curve is shifted to the secondary side, the relay curve shift factor is obtained by multiplying the turns ratio with a multiplication factor of $\sqrt{3}$ or 1.732.

The winding currents of delta windings are different from the line currents. The through-fault withstand capability curve has to be shifted to accommodate this difference in winding and line currents. For a secondary side three phase fault, the line currents are

1.0 per unit whereas the winding currents are 0.577 per unit. This implies that the line currents are 1.732 times winding currents. Therefore the through-fault withstand

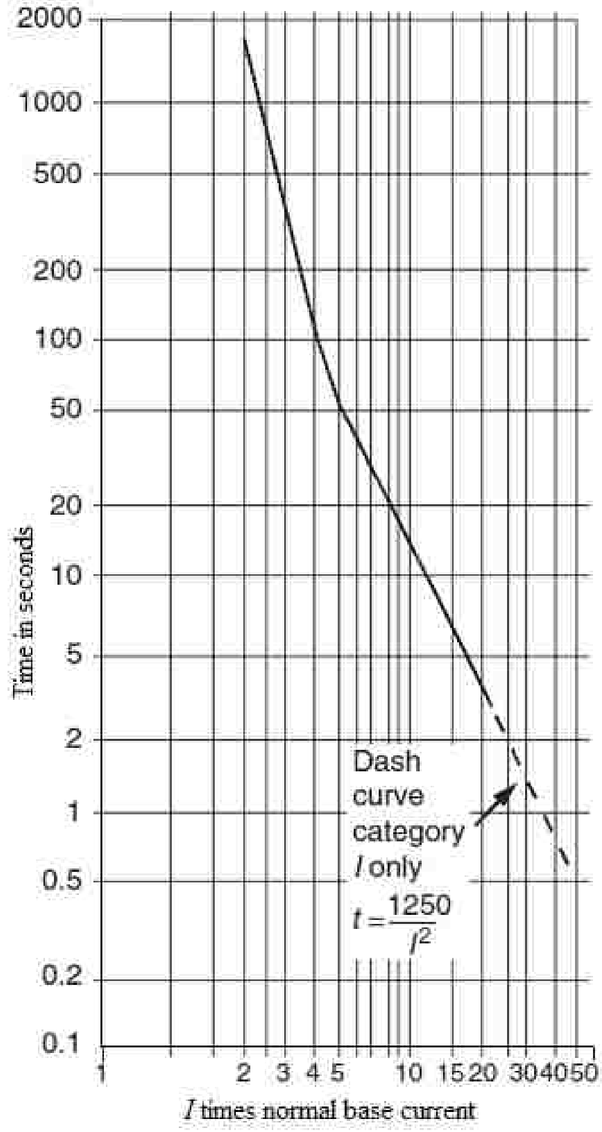


Figure 2.10. Through-fault withstand capability curve for frequent and infrequent faults of Category I transformer and for infrequent faults of Category II and III transformers [1]

capability curve has to be shifted by a factor 1.732 towards the right. For a secondary side phase to phase fault, the line currents are for the A, B, C phases respectively are 0.5, 1.0, and 0.5 per unit respectively. The winding currents are 0.5, 0.5, and 0.0 per unit. The through-fault withstand capability curve has to be shifted by a factor of 2 towards the right.

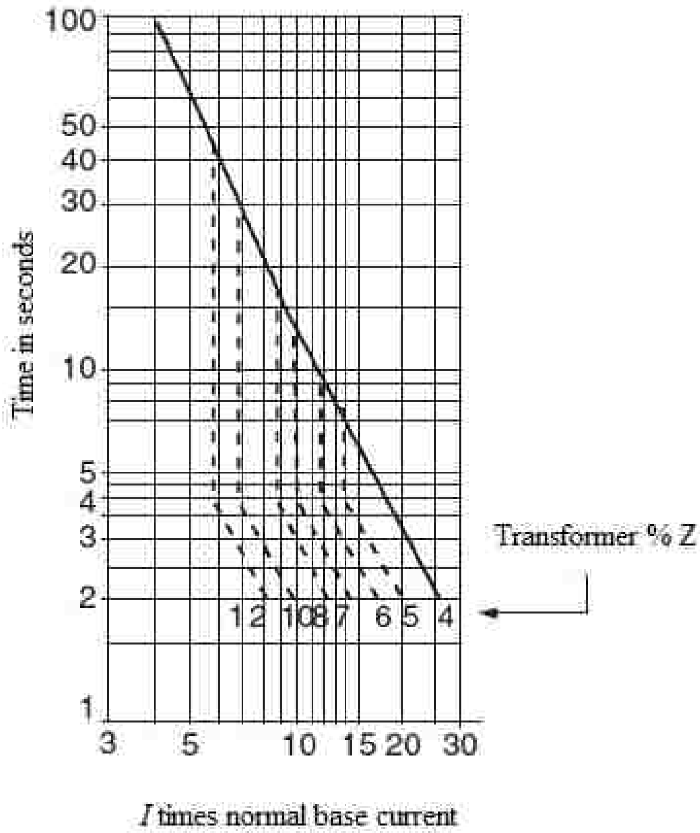


Figure 2.11. Through-fault withstand capability curves for frequent faults of Category II transformer [1]

2.5. GROUND FAULT PROTECTION OF TRANSFORMER

For a grounded wye-grounded wye transformer, the differential relay can provide protection for internal ground faults if their current magnitudes are high. If the ground currents are of low magnitude, which is the most common scenario, the ground overcurrent elements can be used to provide transformer protection. An instantaneous

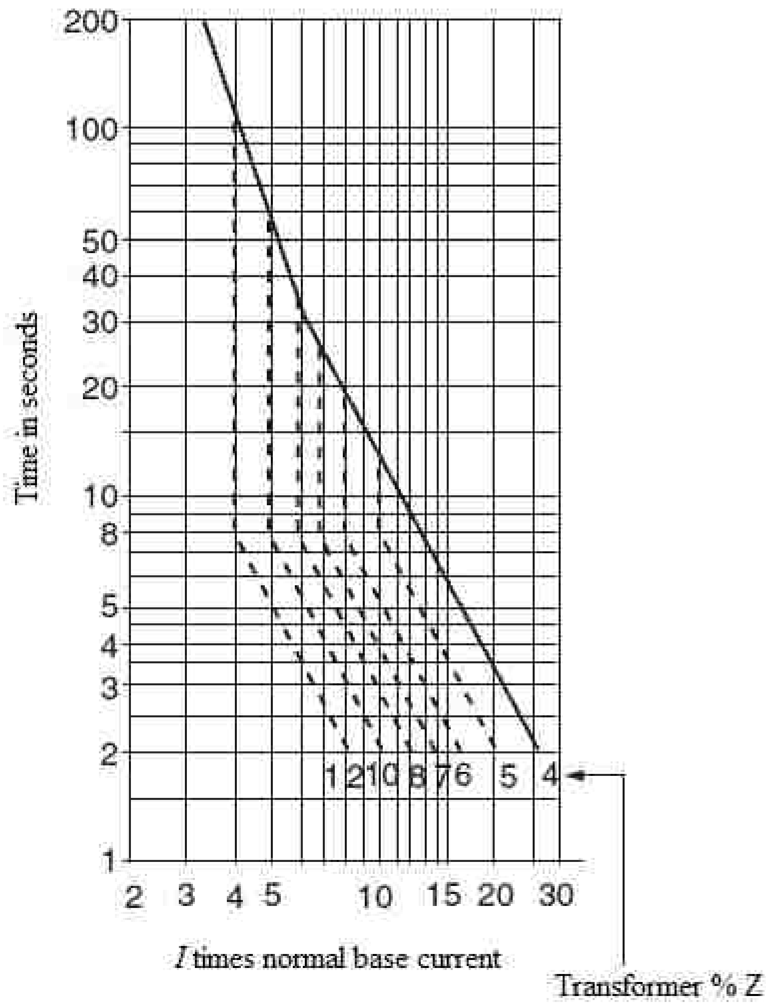


Figure 2.12. Through-fault withstand capability curve for frequent faults of Category III transformer and for infrequent or frequent faults of Category IV transformers [1]

ground (50N) overcurrent relay on primary side can be used to protect transformer for primary side faults. Time overcurrent ground relays (51N) can be used on the primary side and secondary side of a grounded wye-grounded wye transformer to provide time delayed ground fault protection of the transformer and to provide back up ground fault protection for downstream relays. A ground differential relay or a restricted earth fault (REF) element can be used on secondary side to protect wye windings. It detects a fault only if current flows through the neutral of the grounded wye winding.

For a delta grounded-wye connected transformer, the 51N relay on the primary side cannot see the faults on the secondary side as the delta winding traps zero sequence currents. To provide ground fault protection to a delta-grounded wye transformer, the 51N on the delta side should be supplemented with a ground differential protection on the wye side. The 51N on the primary side can only detect ground faults on the primary side [9]. Ground differential protection can be replaced with a 51N and/or 50N in the neutral of the grounded wye transformer. This relay not only provides protection for ground faults close to the transformer neutral, but also provides back up protection for downstream ground overcurrent relays [15].

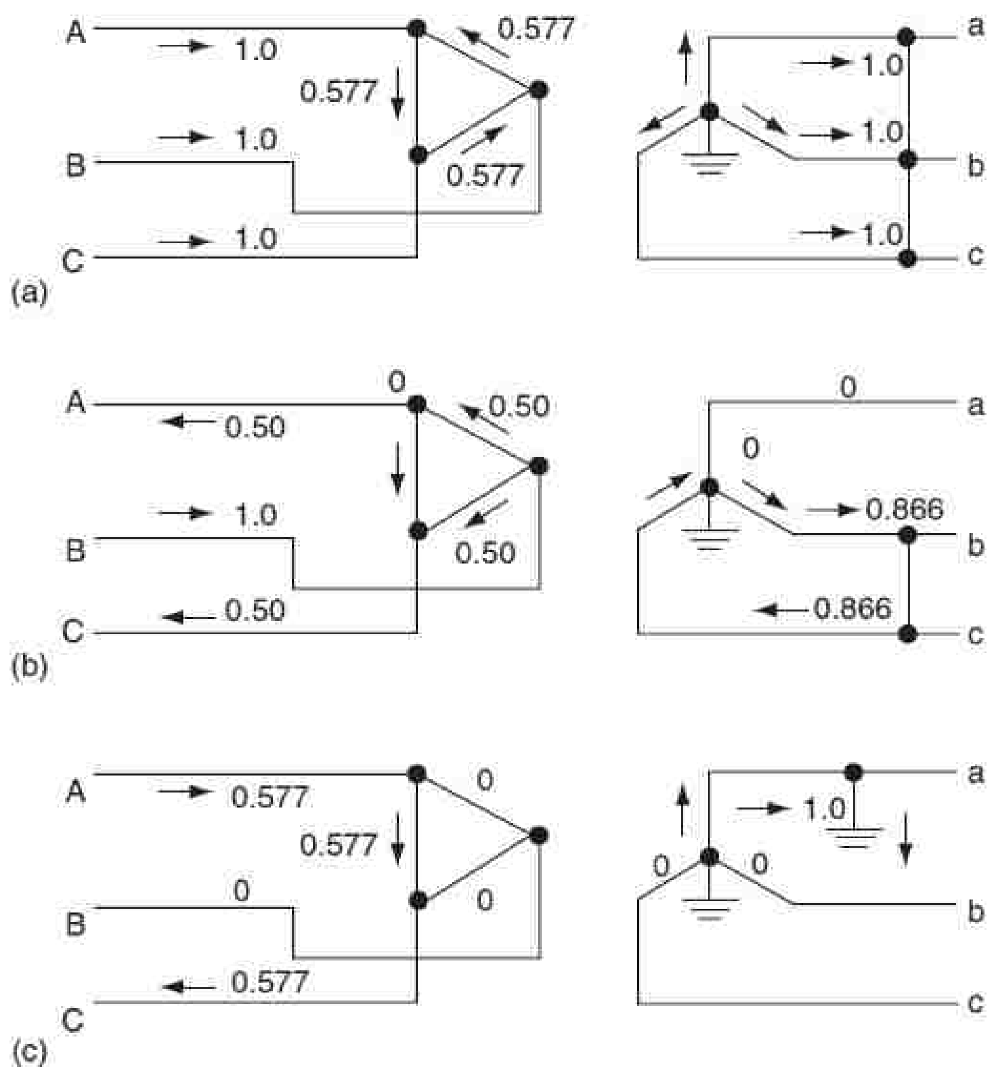


Figure 2.13. Current distribution in a delta-wye transformer for secondary side faults [1]

3. SEL 387-6 RELAY SITING – THEORETICAL DESCRIPTION

3.1. CT RATIO (CTR)

Current transformers are used to scale down the primary currents to small magnitudes so that they can be safely applied to protective relays. Figure 3.1 represents an equivalent circuit of a current transformer. The impedance across the secondary winding, Z_E, has nonlinear characteristics. Its value depends on the excitation voltage E_s. The maximum value of E_s that a CT can sustain is given by equation 3.1.

$$V_s = 4.44 f \times A \times N \times B_{\max} \tag{3.1}$$

where f is the system frequency, A is the cross sectional area of the core in square inches, N is the number of secondary turns, and $B_{\max}$ is the maximum flux density of the core in lines per square inch.

In Figure 3.1, R_s represents the secondary winding resistance, X_L represents the leakage reactance, and Z_B is the sum of the input impedance of relay and lead resistance.

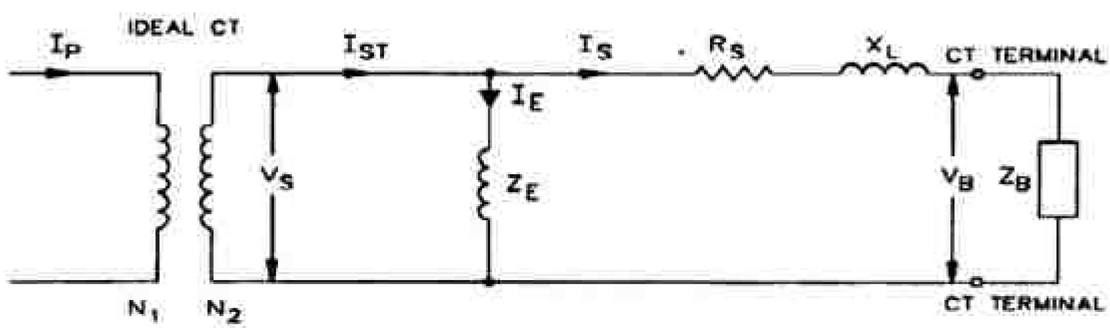


Figure 3.1. Equivalent circuit diagram of current transformer [16]

The curve drawn relating the excitation voltage V_S and the excitation current I_E is the CT excitation curve. Figure 3.2 represents the CT excitation curves for a multi-ratio class C CT. When the voltage developed across the CT burden increases due to an increase in burden, the primary fault current, the presence of a DC component in the primary fault current, and the flux in the CT core, will increase. The excitation current I_E increases, consequently the secondary current I_S decreases. If the increase in current does not increase the excitation voltage, this indicates that the CT is saturated. In Figure 3.2, when the operating point reaches the horizontal line, the CT is said to saturate. When the CT saturates, the primary current is not reproduced in the secondary. The knee, or effective point of saturation indicated by point A, is defined as the point at which the tangent to the excitation curve makes a 45˚ angle with the abscissa for a CT with a non-gapped core and an angle of 30˚ with the abscissa for a CT with a gapped core.

3.1.1. CT Accuracy Class [1][10]. CTs can be categorized based on levels of accuracy. CT standard classes are C, T, and K for relaying purposes. Class C designates a CT that has negligible leakage flux. For C class CTs, the excitation characteristics can be used to determine the CT performance. A K class CT is similar to a C class CT and has a knee point voltage of at least 70% of the secondary terminal voltage rating. T class CTs have significant leakage impedance. Performance is not easily calculated for T class CTs, therefore manufacturer test curves are used. A CT is designated by its class type followed by a number which represents the secondary terminal voltage rating. The number indicates the secondary terminal voltage (VB) that the transformer can deliver to a standard burden at 20 times the rated secondary current without exceeding the 10% ratio correction. For relaying, standard voltage burdens are 100, 200, 400, and 800 V with standard burdens designated with B-1, B-2, B-4, and B-8 respectively at 0.5 power factor. The standard burdens are in ohms (Ω) obtained by dividing voltage by 20 times rated current. The standard rated secondary CT current is 5 amperes in the USA. For a class C400 CT, the C represents the CT class, and the 400 indicates a VB of 400V. The standard burden for this CT can be obtained as follows:

$$\text{standard burden} = \frac{\text{secondary terminal voltage}}{20 * \text{CTsecondary rated current}} \tag{3.2}$$

$$= \frac{400}{20*5} = 4\Omega$$

Hence the standard burden for C400 CT is given as B-4.

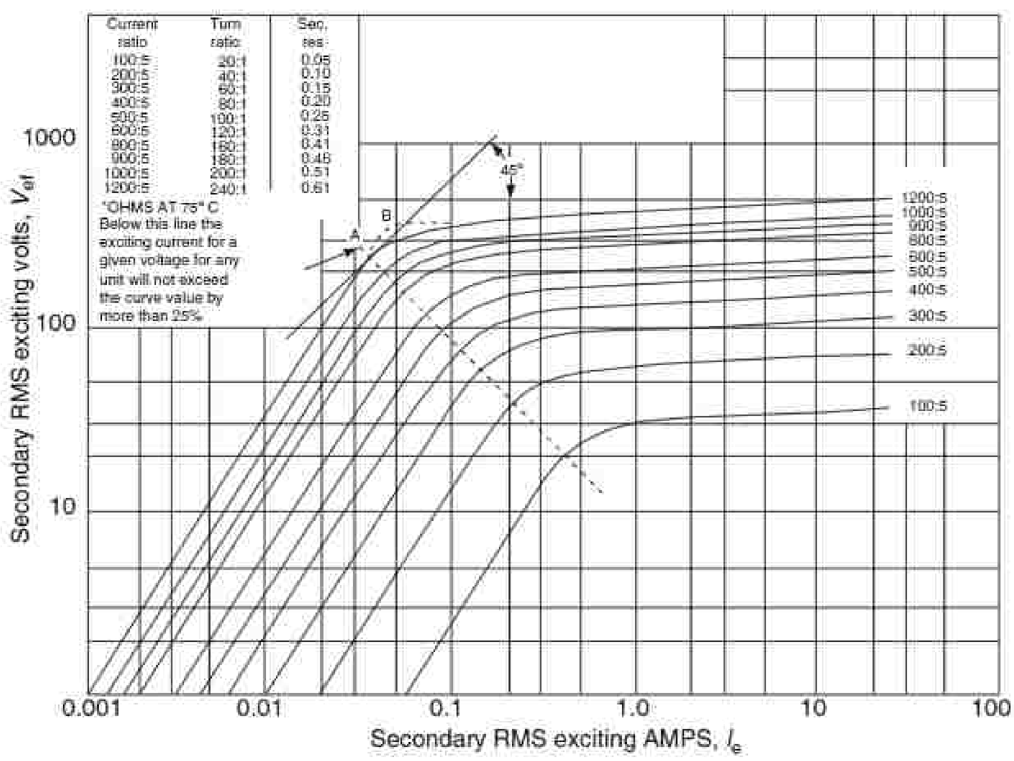


Figure 3.2. Typical excitation curves for a multi ratio C class transformers [1]

3.1.2. CT Saturation Considerations For Setting Protective Relays. During CT saturation, the secondary current waveform becomes distorted. The secondary current will have short duration peaks as shown in Figure 3.3. The peak current is less than the actual primary current divided by the CT ratio value. The secondary RMS current value is typically 5 to 8% of the primary current divided by the turns ratio value. For example, a fault current in primary amperes is 10,000 applied to a CT with ratio of 100:5 will yield a CT secondary current 500 A. But the CT can only tolerate a current up to 20 times the CT standard secondary rating i.e., 100 amperes. Hence this results in CT saturation. The CT saturation can cause the secondary current to be as low as 8% of the peak value that is expected. For the above example, the secondary peak current obtained due to CT saturation is given by $0.08*500*\sqrt{2} = 56.6$ A. This reduction in current will interfere with normal relay operation. Because the relay receives a reduced current, the operating time of the relay is much longer than it would be without any CT saturation. An upstream relay with a higher CT ratio might trip for such a fault [17]. Instantaneous overcurrent relays are preferred for correct operation since their tripping time is less than the time taken by CT to enter into saturation [16]. In case of a differential relay, unequal saturation of CTs during external faults results in false differential current flowing in the protection zone. This is handled by percentage differential scheme with variable or dual slope.

The two main factors to be considered for CT selection are avoiding CT saturation and ensuring that the sensitivity of the relay is maintained. The CT ratio has to be carefully selected to avoid CT saturation. Selecting a CT with the primary rated above the maximum full load primary current is suggested. This selection ensures that nearly 5 amperes current flows through the secondary for full load current. If the CTR is set too high to avoid saturation, then it can have a negative impact on the overall sensitivity of the relay [19].

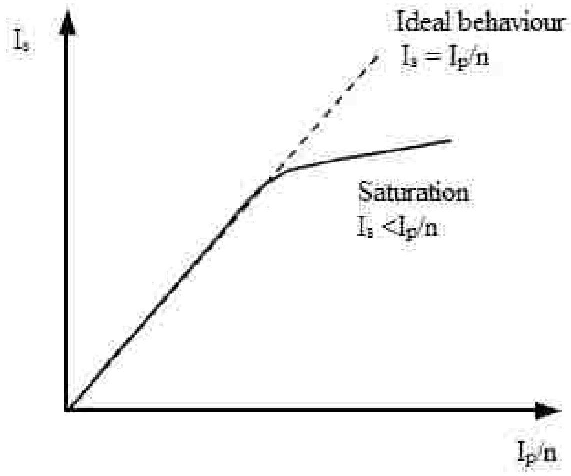


Figure 3.3. Decreases in secondary current than the expected primary current divided by turns ratio value due to CT saturation [10]

If the following inequality holds, then the CT is not in saturation [10]:

$$20 \geq \left(\frac{X}{R}+1\right) \times I_f \times Z_b \tag{3.3}$$

where I_f is the maximum fault current in per unit of CT rating, Z_b is the CT burden in per unit of standard burden, and X/R is the X/R ratio of the primary fault circuit.

3.1.3. CT Ratio Calculation For 138/34.5 KV Transformer.

MVA rating of transformer = 80 MVA

Maximum current rating = MVA/√3*kV = 334.7A primary

= 1338.8 A secondary

The primary side CT ratio can be selected as 500:5 or 100 and the secondary side CT ratio as 1500:5 or 300 to avoid saturation.

3.1.3.1. Checking the 500:5 CT on the 138kV winding for saturation.

Step 1: The X/R ratio can be obtained from ASPEN by running a close-in three phase fault (maximum fault). The result can be viewed on the TTY window as shown in Figure 3.4. The X/R ratio of 8.54 is indicated.

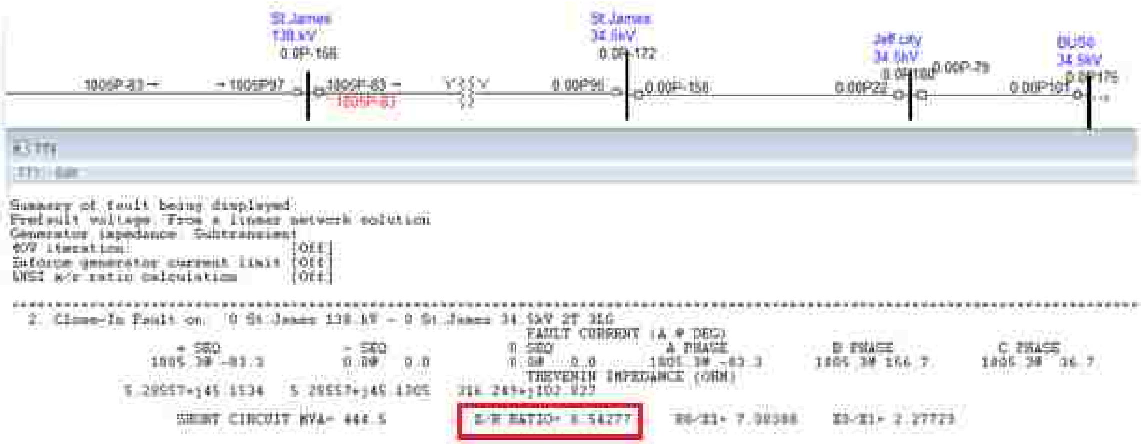


Figure 3.4. Screen shot of TTY window in ASPEN showing the X/R ratio for a high side close-in three phase fault

Step 2: I_f = maximum fault current as obtained from ASPEN/ CT primary rating

I_f = 1805/500= 3.61 pu.

Step 3: The available CT is a C200, 600:5 multiratio CT with a 500: 5 tap selected. Figure 3.5 shows the excitation curve for the 600:5 multiratio CT for which the following values are used: CT burden = 0.279 Ω, Resistance of leads= 0.252, and relay resistance = 0.0108 which can be obtained from the manual as shown in Figure 3.6.

The total burden is the sum of the CT burden, resistance of leads, and relay resistance:

= 0.279+0.252+0.0108 = 0.5418 **Ω**. The standard burden for the C200 accuracy class CT is 2**Ω**, and since we are using 500:5 tap, the standard burden is scaled as 2*(500/600) = 1.67**Ω**. Therefore, Z_b in per unit on standard burden base is 0.5418/1.67 = 0.324.

Step 4: Substituting these values into equation (3.3) yields:

$$(1+8.54)*3.61*0.324 = 11.16 < 20$$

Hence, a CT ratio selection of 500:5 will not cause saturation.

3.1.3.2. Checking the 1500:5 CT on the 34.5kV winding for saturation.

Step 1: The X/R ratio can be obtained from ASPEN by running a close-in three phase fault (maximum fault). The results can be viewed on TTY window as shown in Figure 3.7 yielding an X/R ratio of 11.01.

Step 2: I_f = maximum fault current as obtained from ASPEN/ CT primary rating

I_f= 4472/1500 = 2.98 pu.

Step 3: The available CT is a C400, 2000:5 multiratio CT with a 1500:5 tap selected. Figure 3.8 gives the excitation cure for a 2000:5 multiratio CT. CT burden = 1.003 **Ω**, the resistance of leads = 0.252, and the relay resistance = 0.0108. The total burden is 1.003+0.252+0.0108 = 1.2658 **Ω** and the standard burden for a C400 accuracy class CT = 4**Ω**. Since the CT has a 1500:5 tap, the standard burden is scaled as 4*(1500/2000) = 3**Ω**, and Z_b in per unit on standard burden base = 1.2658/3 = 0.4219.

Step 4: Substituting into equation (3.3) yields

(1+11.0143)*2.98*0.4219 = 15.1 < 20

Hence, the CT ratio selection of 1500:5 will not cause saturation.

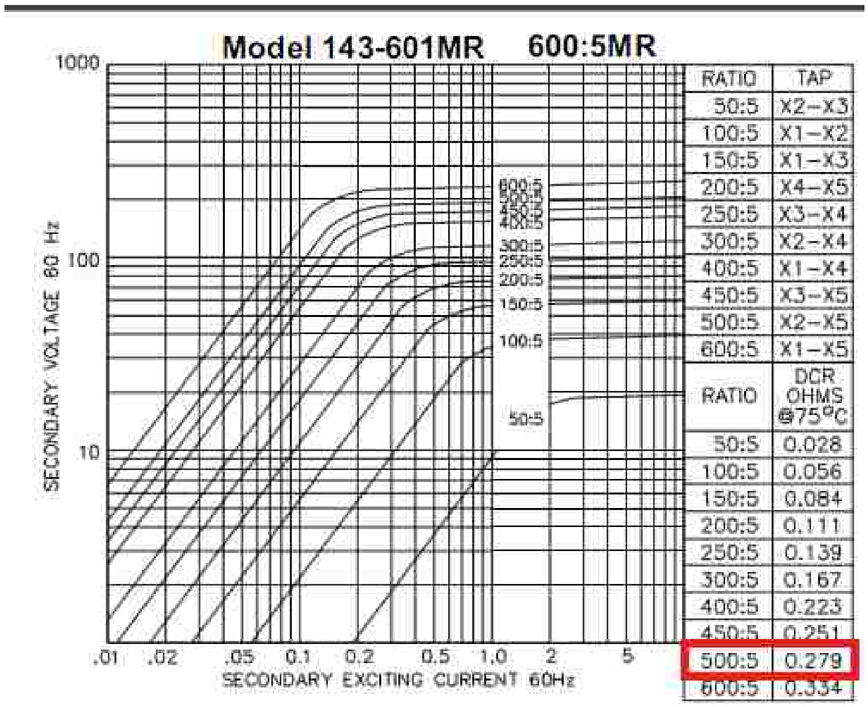
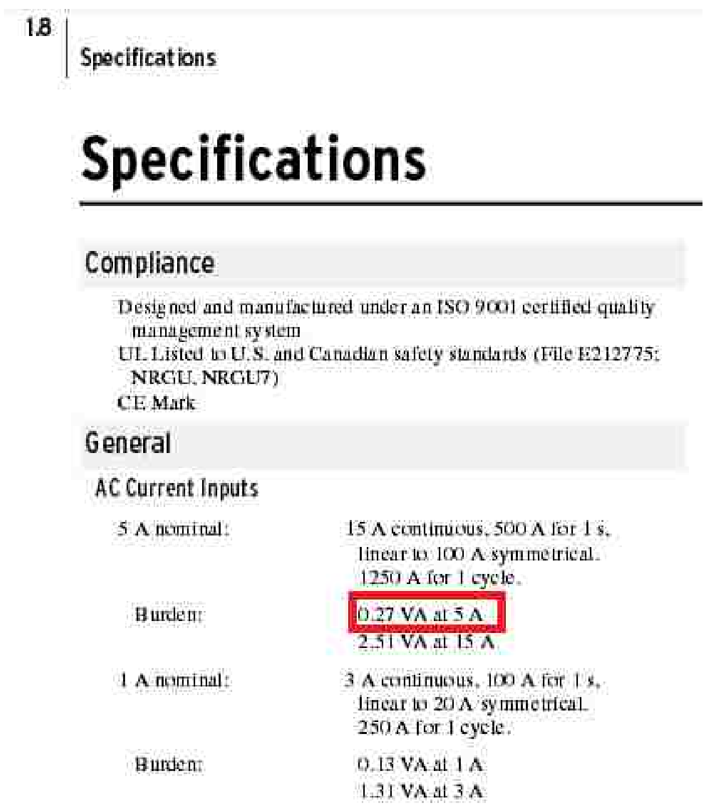


Figure 3.5. 600:5 multiratio CT curve

3.2. CONNECTION COMPENSATION (WnCTC)

As discussed in Section 2.3.2.1, the phase shift between the primary and secondary windings of the transformer must be considered while setting a differential relay. If this phase shift is not compensated, a false differential current flows through the protection zone, which may cause the relay to misoperate. In the SEL 387 relay, proper selection of values for WnCTC (n is 1 for winding 1, 2 for winding 2, so on) provides compensation for the primary-secondary phase shift as well as helps to remove zero sequence currents. Zero sequence currents flowing through one winding may not flow through the other winding during fault conditions such as a line to ground fault on low side of delta-wye transformer. It is important to remove the zero sequence currents by assigning appropriate values to WnCTC. The main idea behind compensation is to make the phase difference between the secondary currents of both windings to be 180˚. Under normal operating conditions or through-fault conditions, the current will enter the line from one side and will leave the secondary side as shown in the Figure 3.9. Currents leaving are considered to be 180˚ out of phase with currents entering under normal or through-fault conditions. If there is 30˚ phase shift between the primary and secondary due to the presence of a delta winding, the currents in primary and secondary winding are 180˚±30˚ out of phase with each other. In the SEL 387-6 relay, the general expression of current compensation is given by Equation 3.4. In this equation, IAWn, IBWn, and ICWn are the three phase currents entering terminal n of the relay, IAWnC, IBWnC, and


1.8 Specifications

Specifications

Compliance

Designed and manufactured under an ISO 9001 certified quality management system
UL Listed to U.S. and Canadian safety standards (File E212775; NRGU, NRGU7)
CE Mark

General

AC Current Inputs

5 A nominal:	15 A continuous, 500 A for 1 s, linear to 100 A symmetrical, 1250 A for 1 cycle.
Burden:	0.27 VA at 5 A 2.51 VA at 15 A
1 A nominal:	3 A continuous, 100 A for 1 s, linear to 20 A symmetrical, 250 A for 1 cycle.
Burden:	0.13 VA at 1 A 1.31 VA at 3 A

Figure 3.6 Specifications of the SEL 387-6 relay

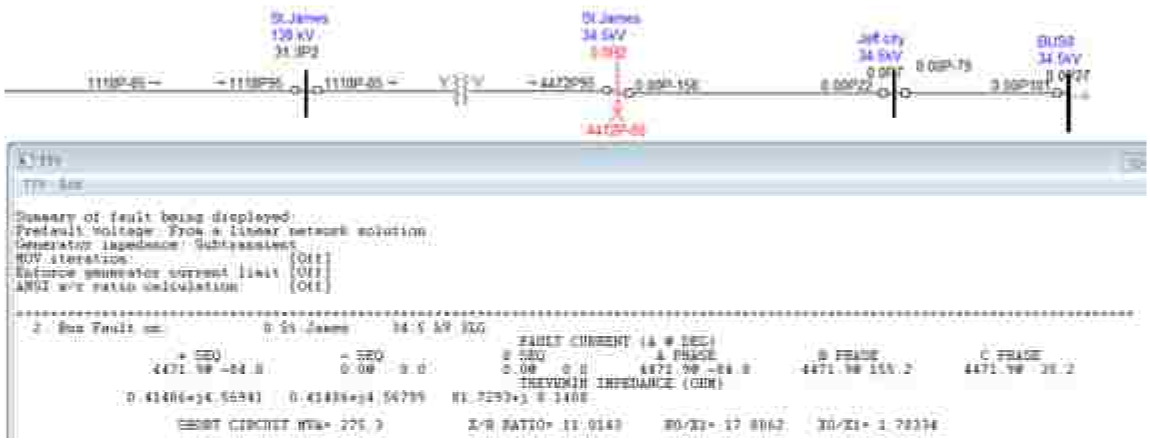


Figure 3.7. Screen shot of TTY window in ASPEN showing X/R ratio for low side three phase fault

ICWnC are the corresponding three phase currents after compensation, and CTC(m) is the compensation matrix, m=0,1,2….,12.

$$\begin{pmatrix} \text{IAWnC} \\ \text{IBWnC} \\ \text{ICWnC} \end{pmatrix} = [\text{CTC(m)}] \begin{pmatrix} \text{IAWn} \\ \text{IBWn} \\ \text{ICWn} \end{pmatrix} \tag{3.4}$$

The phasors are rotated by ±30m˚. A balanced set of ABC current phasors will be rotated in counter clockwise direction when multiplied with CTC(m). A balanced set of ACB phasors will be multiplied in counterclockwise direction when multiplied with CTC(m) [5].

3.2.1. Procedure To Select Values For WnCTC [5]. Step 1. Establish the phase direction for the terminal-A line current for each three-phase winding of the transformer. (This step requires transformer nameplate drawings and/or internal connection diagrams). For a transformer with a delta winding, a ±30˚ phase shift is required. In delta connections there is a 30˚ phase shift between line currents and winding currents. If the transformer winding contains a delta winding with an ABC rotation, then phasor A is rotated 30˚ in the counterclockwise (CCW) direction. If the transformer winding contains a delta winding with an ACB rotation, phasor A is rotated 30˚ in the clockwise (CW) direction. If the winding of transformer is connected in wye, there is no need to make any rotation as there is no phase shift between line currents and winding currents. These adjustments are required to achieve a common reference for all transformer windings with respect to line currents. This is summarized in the Figure 3.10. Here DAB represents delta winding with ABC rotation while DAC represents delta winding with ACB rotation.

Step 2: Adjust the terminal-A line current direction by the phase shift (if any) of the current transformer connection. The same principle can be applied here. If the transformer winding contains a delta-winding with ABC rotation, rotate phasor A 30˚ in counter clockwise direction. If the transformer winding contains a delta winding with ACB rotation, rotate phasor A 30˚ in counterclockwise direction. If the winding of transformer is connected in wye, there is no need to make any rotation.

Step 3: Choose a setting for WnCTC for each set of winding input currents. This setting is the number of 30-degree increments needed to adjust each nonreference winding to line it up with the reference. This number will range from 0 to 12 increments. For ABC phase rotation, begin at the winding direction and proceed in a CCW direction

Step 4: If any winding needs no phase correction, but is a grounded-wye winding having wye-connected CTs, choose WnCTC = 12 for that winding, rather than WnCTC = 0. This setting will remove zero-sequence current components from the relay currents to prevent false differential tripping on external ground faults. All non-zero values of

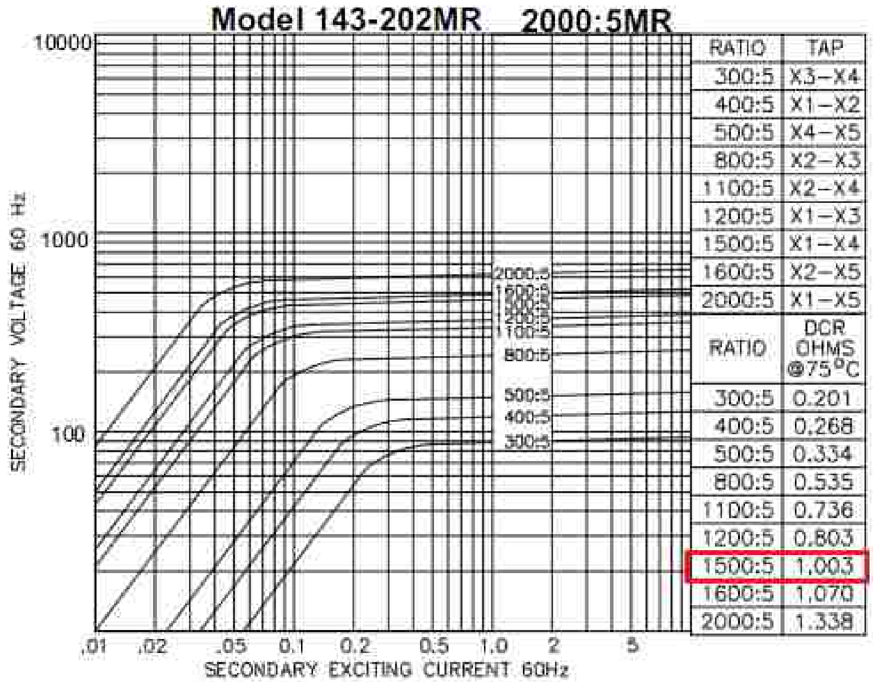


Figure 3.8. 2000:5 multiratio CT curve

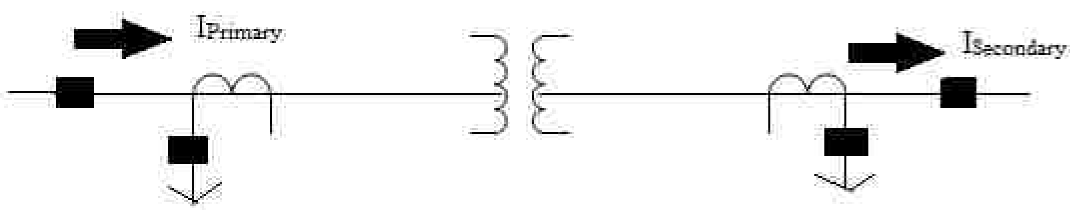


Figure 3.9. Currents going into the primary side and out on the secondary side

WnCTC remove zero-sequence current. More detailed explanations with examples have been discussed in [5].

3.2.2. Winding Compensation For 138/34.5 kV Transformer. A 387-6 relay is used to protect a grounded wye-grounded wye transformer with wye CTs as shown in Figure 3.11. The rotation for both the windings is ABC, therefore there is no need for compensation. To remove zero sequence component: W1CTC = W2CTC = 12.

Additionally, W1CTC = W2CTC= 0 to achieve the correct results for line to ground faults.

3.3. PERCENTAGE DIFFERENTIAL RELAY SETTINGS

Figure 3.12 summarizes the settings required for a percentage differential scheme. Explanation about each of these settings is discussed under sections 3.3.1 to 3.3.5.

3.3.1. Restrained Element Operating Current Pickup (087P) [5]. The minimum pickup 087p should be set as sensitively as possible while considering the steady state CT error and excitation current. A setting of 0.2 to 0.3 times the tap setting can be used. The setting must satisfy equation 3.5.

$$087P \geq (0.1 * I_N / TAP_{MIN}) \tag{3.5}$$

3.3.2. Restrained Element Slope 1 Settings (SLP1) [3]. The restraint element slope 1 can be set considering the following factors:

Excitation current = 2 percent

CT accuracy = 3 percent

NLTC = 5 percent

LTC = 10 percent

Tap mismatch = 0 percent

Relay accuracy = 5 percent

All of these percentages sum to 25 %, thus a setting of 25% can be used.

3.3.3. Restrained Current Slope 1 Limit (IRS1) [5]. This setting is necessary when 2 slopes are set. This set defines the point where 2 slopes intersect. A setting of 3 times the tap as suggested in the SEL 387-6 manual can be used.

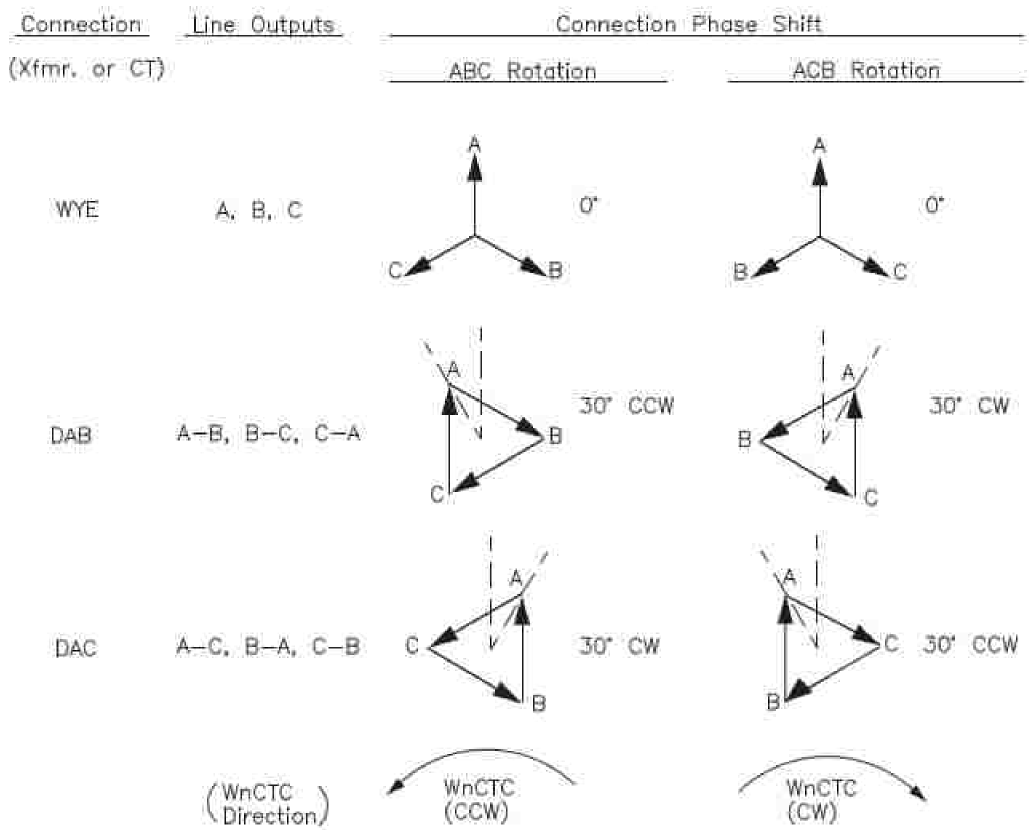


Figure 3.10. Winding connections, phase shifts and compensation direction [5]

3.3.4. Restrained Element Slope 2 Settings (SLP2). The selection of slope 2 is optional. Slope 2 is needed if the CT performance becomes a concern due to poor CT accuracy class, very high X/R ratio, or high fault levels. A setting of 50 % for slope 2 covers all of these situations.

3.3.5. Unrestrained Element Pickup (87U) [5]. The instantaneous unrestrained current element is intended to react quickly to very high internal faults. A pickup setting of 10 times the tap is suggested. This setting must be high enough so as not to trip for high inrush currents. This is set to reliably operate the relay for high internal faults in which CT saturation results in harmonic distortion. The unrestrained differential element only responds to the fundamental frequency component of the differential operating current.

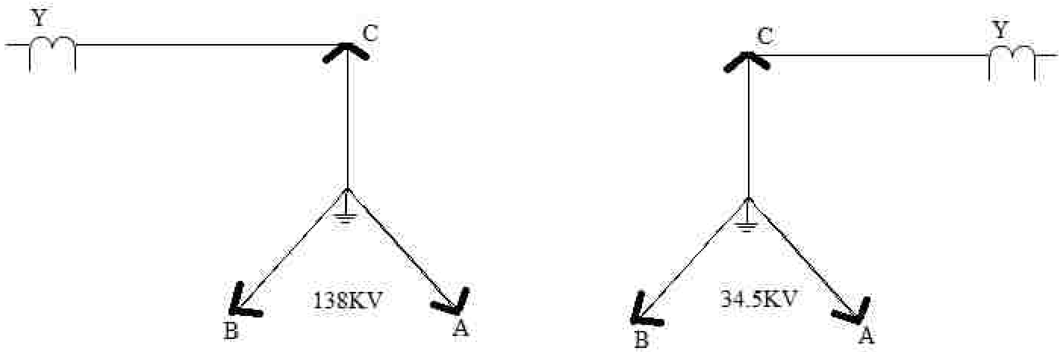


Figure 3.11. 138/34.5 kV wye-wye transformer under consideration

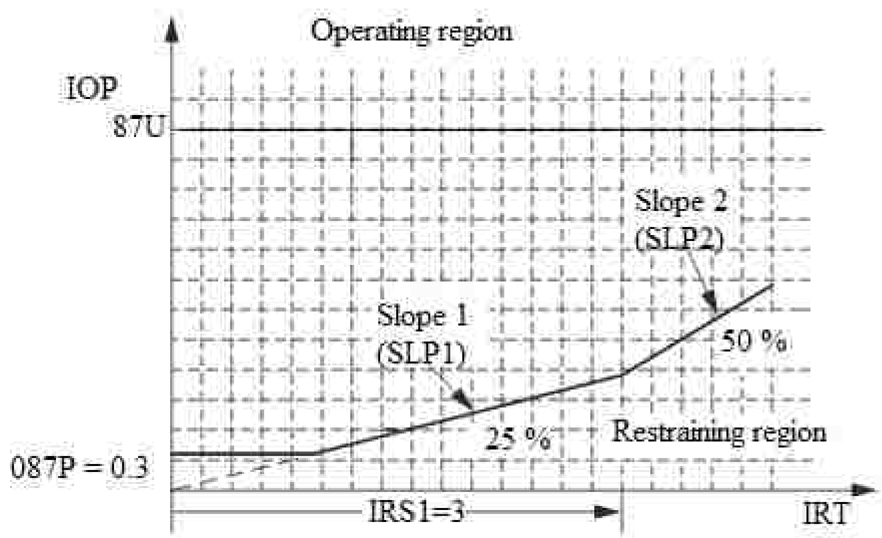


Figure 3.12. SEL 387-6 relay differential element settings [5]

3.4. SEL 387-6 RELAY DIFFERENTIAL ELEMENT TRIP LOGIC [5]

The relay trips if the operating point is in the operating region shown in Figure 3.12. The line defined by slope 1 (SLP1) is the line passing through the origin. The percentage differential prevents the SLP1 line from passing through the origin by introducing the 087P pickup for the relay security. The line defined by slope 2 (SLP 2) does not pass through the origin. The operating current (IOP) and restraint currents (IRT) are calculated as shown in Figure 3.14.

The input currents IAWn, IBWn, ICWn, where n is the winding number, are filtered and split into fundamental frequency, second harmonic, and forth harmonic currents as shown in Figure 3.13. Each of these currents are converted into per unit values on their respective tap base. The value of tap for a particular winding is automatically calculated by the relay using equation 3.6.

$$\mathrm{TAPn} = \frac{\mathrm{MVA}}{\sqrt{3} \times \mathrm{kV} \times \mathrm{CTRn}} \tag{3.6}$$

The per unit currents obtained are compensated by multiplying by the corresponding CTCn matrix. The final tap scaled, compensated fundamental frequency currents I1WnC1, I2WnC1, I3WnC1, second harmonic currents I1WnC2, I2WnC2, I3WnC2, forth harmonic currents I1WnC4, I2WnC4, I3WnC4 are used for IOP and IRT computation. The calculation of IOP1 (operating current for 87-1 element), IRT1 (restrained current for 87-1 element), IHRT1 (harmonic restraint), I1HB2 (second harmonic), and I1HB4 (fourth harmonic) quantities for the 87-1 element is shown in Figure 3.14. IOP1 is generated by summing the winding currents in a phasor addition. IRT1 is generated by summing the magnitudes of the winding currents in a simple scalar addition and dividing by two. The 87-2 and 87-3 quantities are calculated in a similar manner.

Figure 3.15 shows how the differential element quantities are used to generate the unrestrained 87U*n* (87U1 or 87U for phase A, 87U2 or 87U for phase B, 87U3 or 87U for phase C) and restrained 87R*n* (87R1 or 87R for phase A, 87R2 or 87R for phase B, 87R3 or 87R for phase C) elements. These elements are combined to form differential element targets (87-1, 87-2, 87-3).

The following four cases illustrates how the relay makes the decision to trip 87U or 87R elements:

Case 1**:** IOP > U87P

If the operating current is greater than the unrestrained element pickup, the relay trips the 87U element.

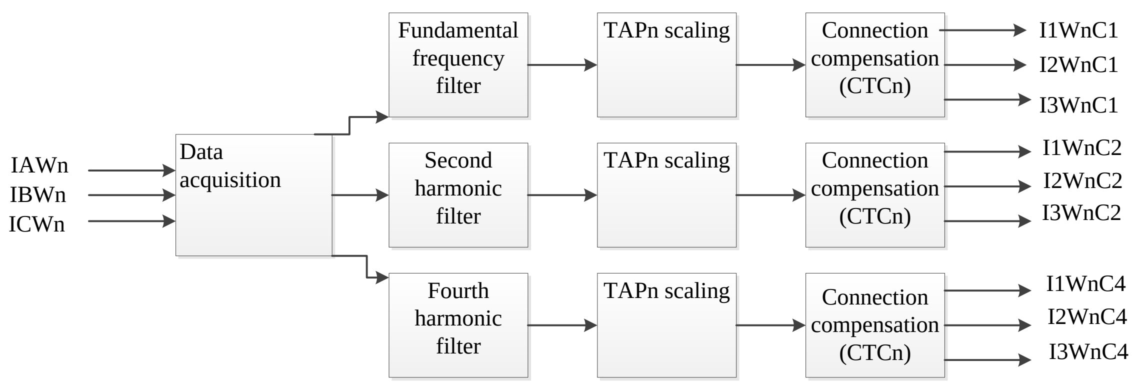


Figure 3.13. Winding n currents used to calculate IOP and IRT

Case 2**:** $\mathrm{IRT}<\dfrac{087\mathrm{P}*100}{\mathrm{SLP1}}$

This case indicates the region before slope 1 begins. The relay trips if IOP> 087P.

Case 3**:** IRT< IRS1

Slope 1 begins at the point $\mathrm{IRT}=\dfrac{087\mathrm{P}*100}{\mathrm{SLP1}}$ and ends at IRT = IRS1.

The following conditions have to be satisfied for 87R to trip for case 3:

1. $\frac{IOP}{IRT} > \frac{SLP1}{100}$ and

2. IOP > 087P

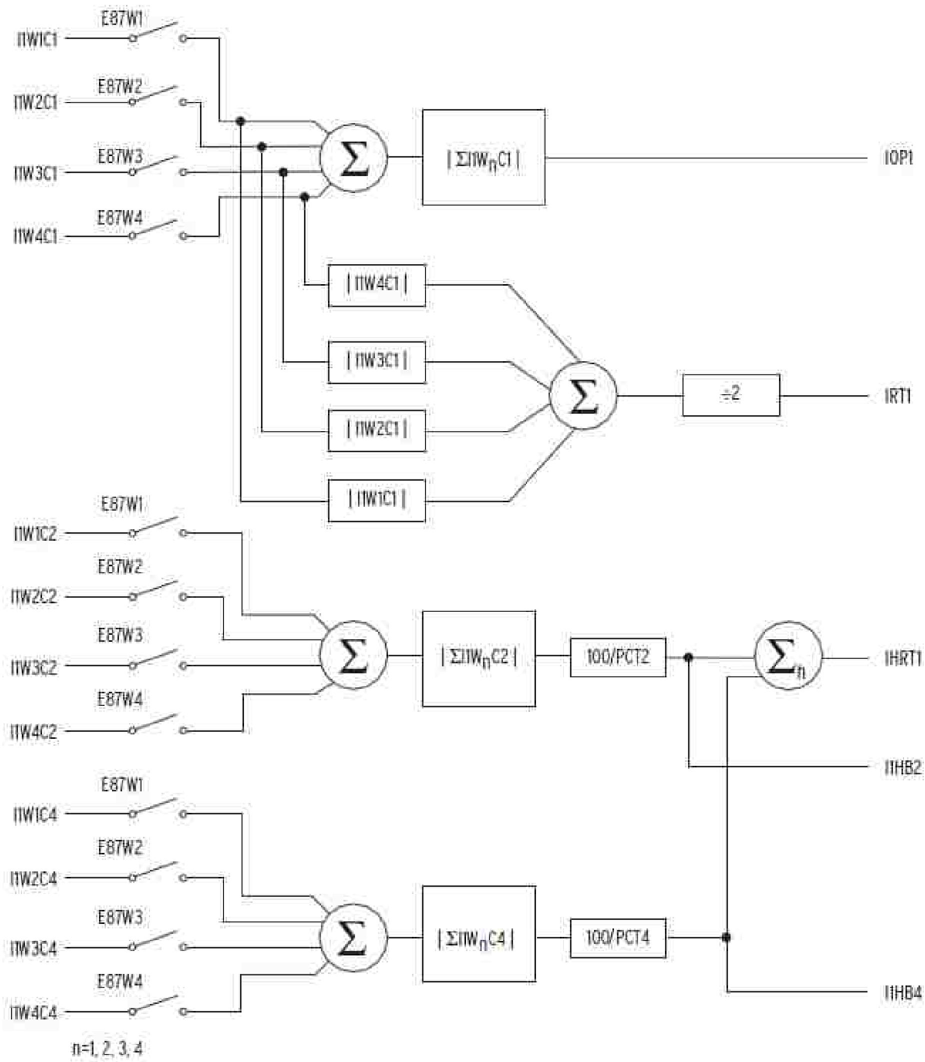


Figure 3.14. Differential element 87-1 quantities [5]

Case 4**:** IRT>IRS1

The 87R element asserts if the operate current satisfies following two conditions for case 4:

1. $IOP > \frac{SLP2}{100} * IRT + (\frac{SLP1 - SLP2}{100}) * IRS1$ and

2. IOP > 087P

3.5. OVERCURRENT ELEMENT SETTINGS

For setting overcurrent elements, it is required to perform a fault analysis for the power system. This can be accomplished using the ASPEN one line power flow software.

3.5.1. Power System Model-Using ASPEN. A radial system is considered and its one line diagram as shown in Figure 3.16 is set up in the ASPEN software. The parameters of the one line diagram considered have been listed in the Table 3.1.

3.5.2. Setting Of Overcurrent Relays. Overcurrent relays have been placed at 6 different locations as shown in Figure 3.16. The relay pickup, curve used, timedial, and coordinating time interval with consecutive upstream device have been tabulated for each relay in Table 3.2. The phase time overcurrent pickup has been selected based on the maximum load conditions. A minimum load margin (calculated using equation (3.7)) of 1.15 is maintained for these relays. A minimum fault detection margin (calculated using equation (3.9)) of 2 for minimum end of line (EOL) fault (usually phase to phase fault) is attained. Ground overcurrent relays are set at minimum of 50 % above load unbalance. The pickup setting is also chosen to attain a fault detection margin between 2 to 10 for EOL line to ground fault. A 10% unbalance is assumed in all cases. Phase instantaneous relays have been used at locations 4 and 6. Phase instantaneous relay at location 4 is set at 40% above the maximum remote bus fault to protect 85% of line from St. James 34.5kV to Jeff city. Phase instantaneous relay at location 6 (the high side of 138-34.5 kV transformer) is set at a margin of 30 % above the low side maximum fault and is used to detect only high side faults instantaneously. A ground instantaneous relay at location 6 set at 30% above low side maximum phase to ground fault is used to trip for high side ground faults instantaneously. The time dial and curve is selected to attain a minimum CTI of 0.3 seconds between upstream and downstream devices.

$$\text{Load Margin for phase relays} = \frac{\text{Pickup}}{\text{Maximum load}} \tag{3.7}$$

$$\text{Margin over laod unbalance} = \frac{\text{Pickup}}{\text{Maximum load unbalance}} \tag{3.8}$$

$$\text{Fault detection margin} = \frac{\text{Minimum EOL fault current}}{\text{pickup}} \tag{3.9}$$

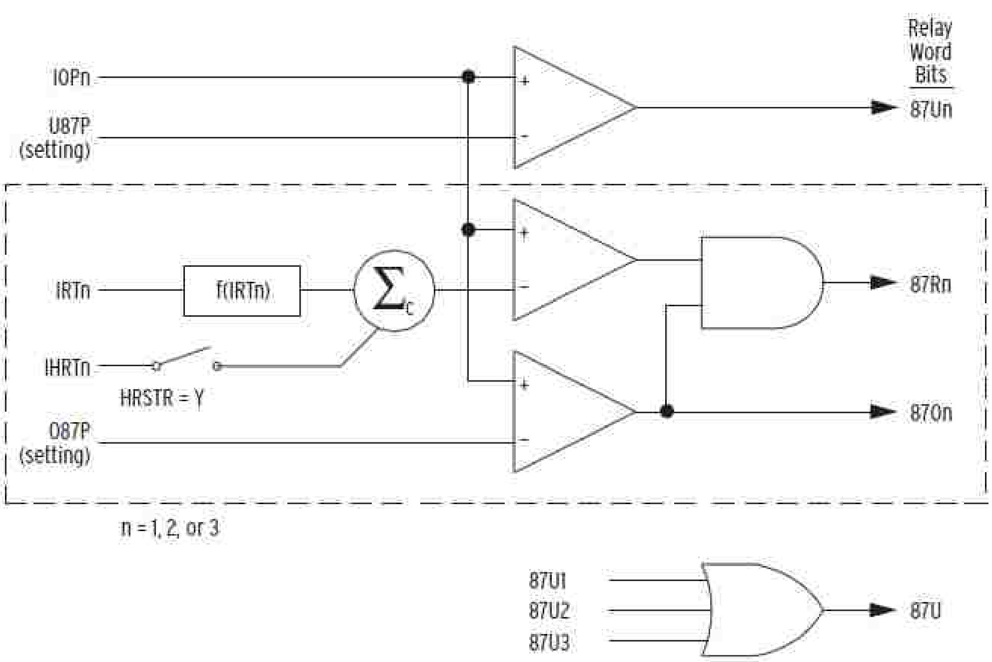


Figure 3.15. Differential element 87-1 quantities [5]

3.5.3. Time Current Curves (TCC). The TCC curves give information about the time required by a relay to trip for a particular value of fault current. Curves on the high side of the transformer or on the 138 kV are drawn on a 138 kV voltage base. Curves on the low side of the transformer or on the 34.5 kV are drawn on a 34.5 kV voltage base. The x-axis of the graph represents the current in amperes (on the corresponding voltage base) and the y–axis represents time in seconds.

3.5.3.1. Curves for phase overcurrent relays. The TCC curves shown in Figure 3.17 are obtained for phase overcurrent relays placed at locations 1 to 6. The curve number indicates the location. For example, curve 1 is for the relay located at location 1. Location 1 is downstream from location 6 or high side of transformer. The curves of relays on low side of transformer are drawn with a 34.5 kV voltage base while curve 6 of relay located on high side of transformer is drawn with 138 kV voltage base. For a downstream relay at location 1, the SEL 351S U4 curve which is an extremely inverse curve is used. For the upstream relay at location 6, the U1 curve is used.

3.5.3.2. Curves for ground overcurrent relays. Ground overcurrent relay curves are obtained in a similar manner way to the phase overcurrent relays with small pickup settings as shown in Figure 3.18.

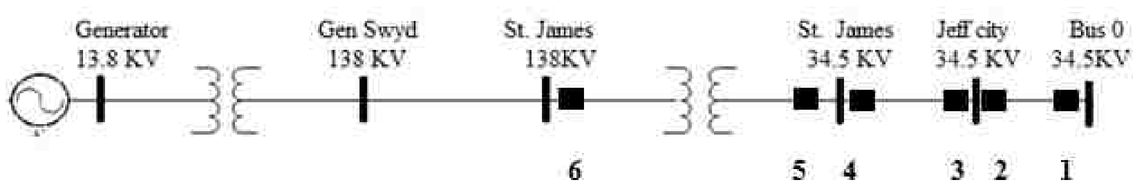


Figure 3.16. One line diagram for model under consideration

3.5.3.3. Transformer damage curve. The downstream devices must be coordinated with the transformer damage curve to give protection for through faults.

From Figure 3.19, it can be seen that the downstream curves are coordinated with the TCC curve as they lie to the left of the TCC curve. The transformer damage curve in Figure 3.19 is drawn with respect to the low side voltage 34.5 kV. The high side relay must be coordinated with the transformer damage curve drawn with respect to high side currents to give protection for upstream faults. In Figure 3.20, the high side relay is drawn with respect to the high side 138 kV voltage coordinating with the transformer damage curve drawn with respect to high side 138 kV voltage.

Table 3.1 Parameters of the power system model

Generator	Reference angle= -30˚ Generator MVA = 500 Reactances on generator MVA Subtransient reactance = 0.0625+j0.1755 pu Transient reactance = 0.0425 +j0.2016 pu Synchronous reactance = 0.0425 +j1.76 pu Negative sequence reactance = 0.0625 +j0.1749 pu Zero sequence reactance = 0.00424 +j0.0973 pu Neutral impedance = 200Ω
GSU tranformer	Configuration: Delta wye transformer/Delta lagging Voltage rating: 13.8/138 KV MVA = 300 MVA Z= Z_0 = 0.00671 +j0.16438 pu on 100 MVA base Neutral grounding impedance = 0
Line from Gen swyd to St.James 138KV	Z= 0.00854+j0.0376 pu on 100MVA Z_0= 0.0881 +j0.357661 pu on 100MVA
138 to 34.5 KV transformer	Configuration: Grounded Wye-Grounded Wye Voltage rating: 138/34.5KV MVA =80 MVA Z= Z_0 = 0.0071+j0.1468 pu on 100 MVA base Neutral grounding impedance = 0 Z_{g1}= 10Ω Z_{g2}= 20Ω

Table 3.1 Parameters of the power system model(Cont.)

Line- St. James 34.5KV to Jeff city	Z= 0.045+j0.1118 pu on 100MVA Z_0= 0.3071 +j0.7989 pu on 100MVA Emergency rating of line= 900A
Line- Jeff city to Bus 0	Z= 0.08+j0.1718 pu on 100MVA Z_0= 0.6071 +j0.9949 pu on 100MVA Emergency rating of line= 400A

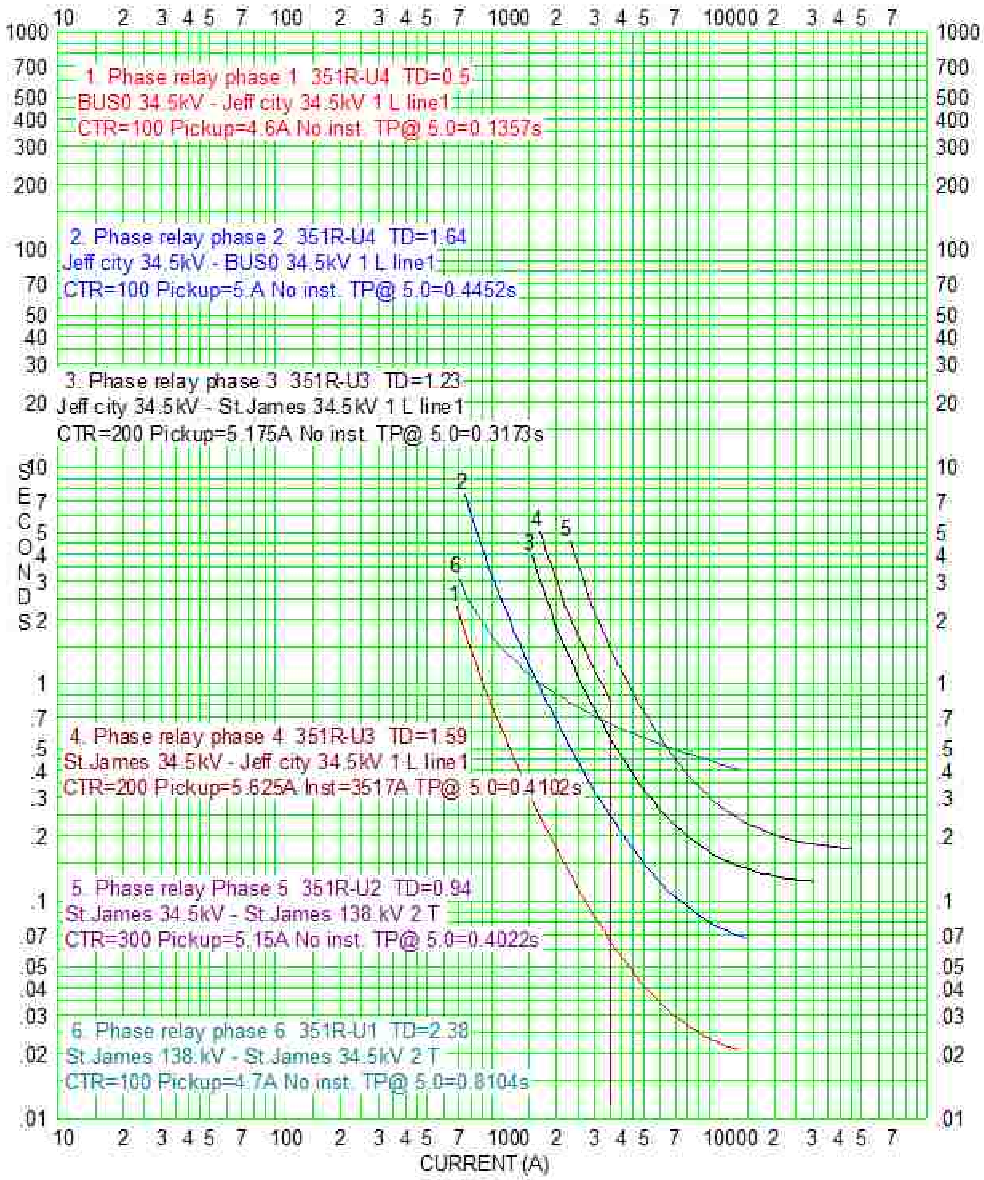


Figure 3.17. TCC curves for phase overcurrent relays

Table 3.2 Overcurrent relay settings in ASPEN

S.No	Relay	Pickup in secondary Amps	Load margin (Load unbalance margin for ground relays)	Fault Detection Margin for minimum EOL fault (EOL phase to phase fault for phase and LG for ground relays)	Curve used (SEL US)	Time dial	CTI with the next upstream device for maximum fault
1.	Phase OC 1 CTR=100	4.6	1.15	4.72	U4	0.5	0.32
2.	Phase OC 2 CTR=100	5	1.25	4.35	U4	1.64	0.34
3.	Phase OC 3 CTR=200	5.175	1.15	2.87	U3	1.23	0.30
4.	Phase OC 4 CTR=200	5.625	1.25	2.64	U3	1.59	0.36
5.	Phase OC 5 CTR= 300	5.15	1.15	2.50	U2	0.94	0.543
6.	Phase OC 6 CTR=100	4.7	1.4	2.57	U1	2.38	---
1.	Ground OC 1	1.5	1.5	9.94	U4	0.5	0.31
2.	Ground OC 2	1.3	2	7.45	U4	5.35	0.30
3.	Ground OC 3	1.2	1.34	5.64	U3	4.83	0.30
4.	Ground OC 4	1	1.79	4.23	U3	6.74	0.30
5.	Ground OC 5	1	1.34	4.05	U2	5.12	0.483

Table 3.2 Overcurrent relay settings in ASPEN (Cont.)

6.	Ground OC 6	1	1.91	9.7125	U1	5.85	---
7.	Phase Inst 6	14.53 (1.3 times max LS fault)					
8.	GND INST 6	10.1 (1.3 times max LS fault)					
9.	Phase Inst 4	17.584 (protects 85% of line instantaneously)					

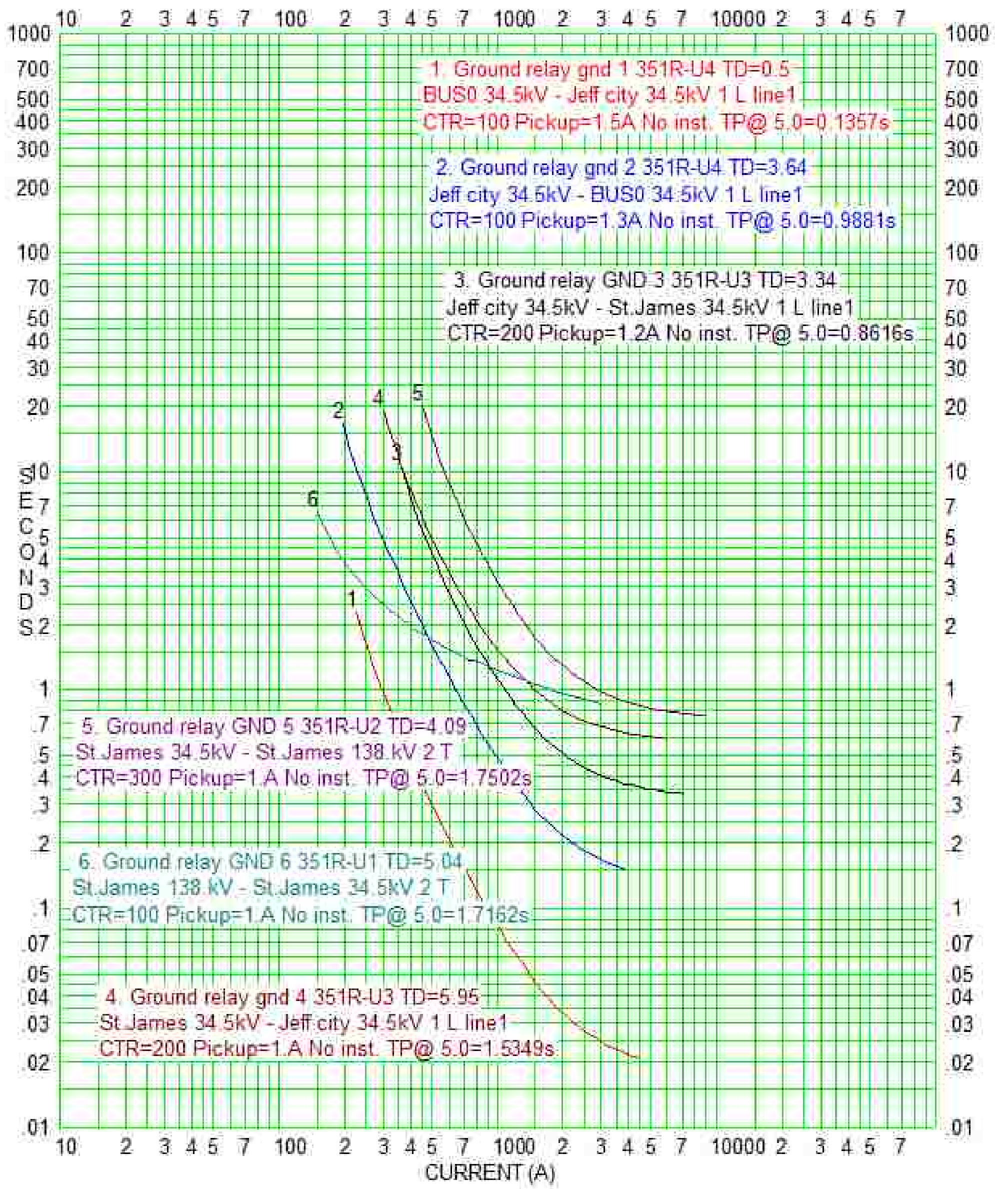


Figure 3.18. TCC curves for ground overcurrent relay

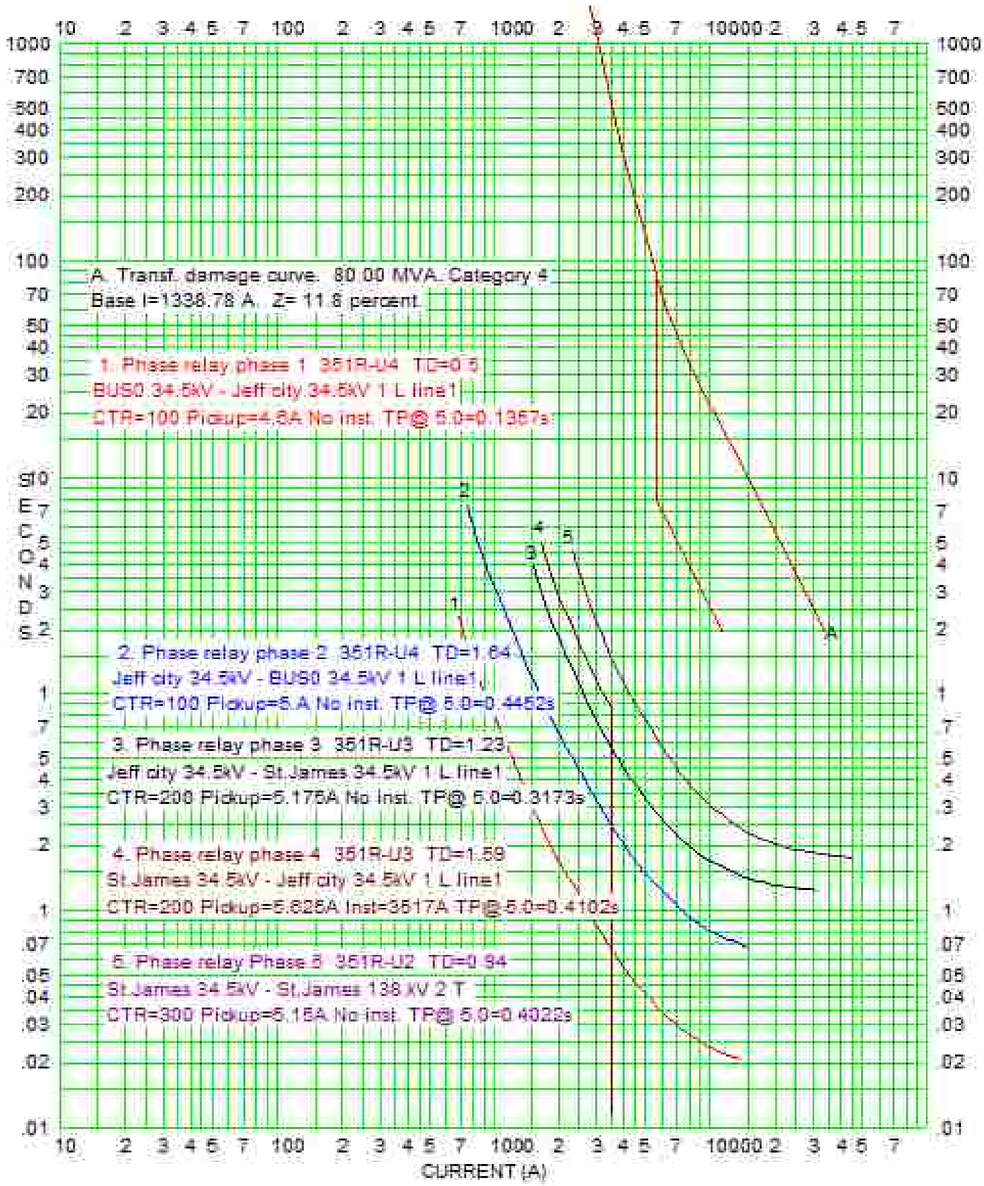


Figure 3.19. TCC curves on the low side of the transformer coordinating with the transformer damage curve drawn with respect to the low side 34.5 kV voltage

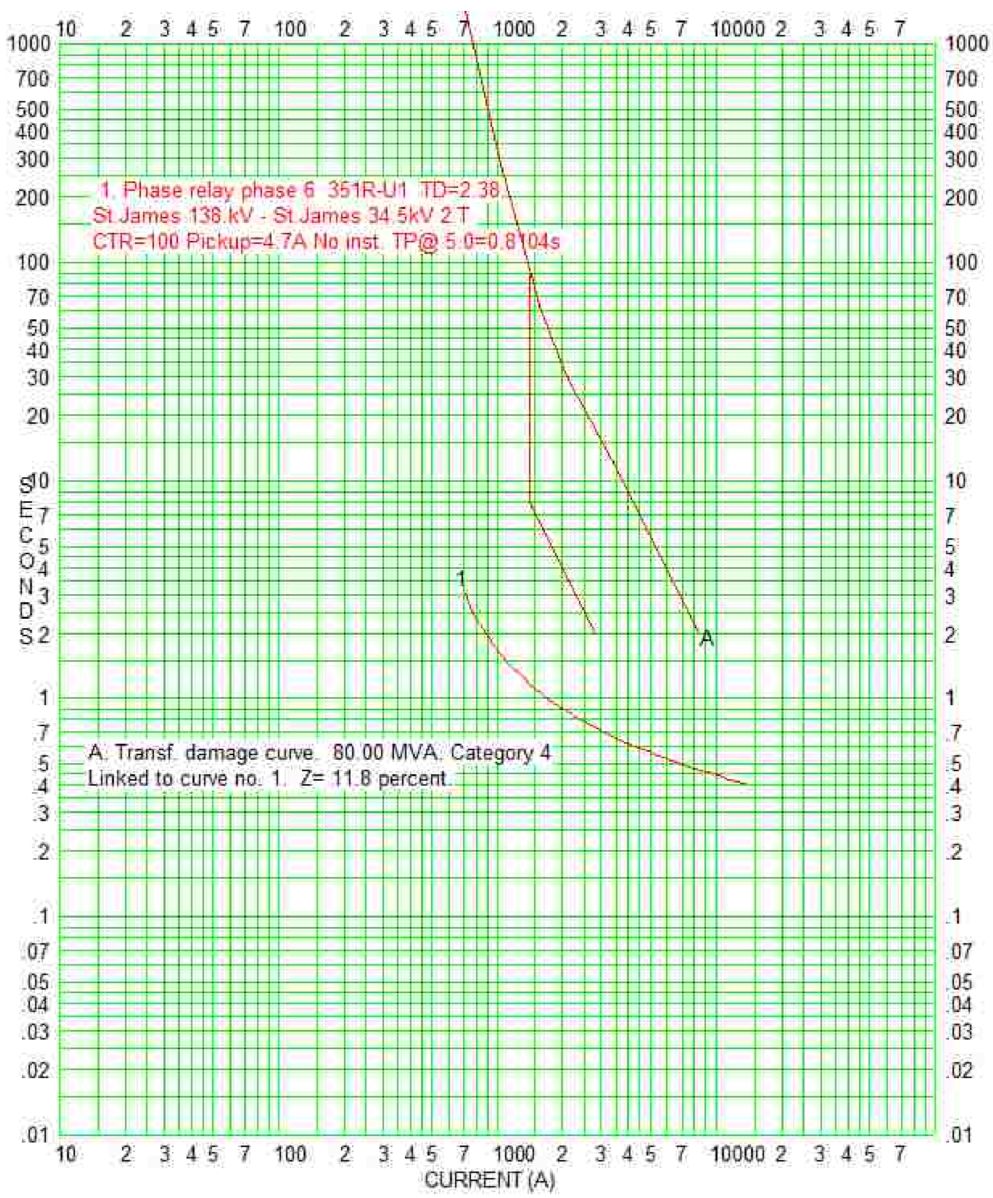


Figure 3.20. The TCC curve on the high side of the transformer coordinating with the transformer damage curve drawn with respect to the high side 138 kV voltage

4. SETTING RELAY USING SEL 5030 SOFTWARE

4.1. CONFIGURATION SETTINGS

The Relay Identifier (RID) and Terminal Identifier (TID) settings typically are used to identify the equipment protected by the relay or the identifier of the circuit breakers controlled by the relay.

- Relay identifier RID= XFMR 1
- Terminal identifier TID = station A

Winding 1 and Winding 2 are enabled while winding 3 and winding 4 are disabled for a two winding transformer. Also, Overcurrent elements for two transformer windings are enabled.

- E87W1=Y
- E87W2=Y
- E87W3= N
- E87W4= N
- EOC1=Y
- EOC2 =Y
- EOC3 =N
- EOC4 =N

All other settings that are not used can be disabled by a selecting N

- EOCC =N
- ETHER =N

- ELS1= N
- ELS2 =N

4.2. GENERAL DATA

A 387-6 relay is used to protect a 80 MVA grounded wye-grounded wye 138/34.5 kV transformer. The CTs of both the windings are wye connected with the CTR on the primary = 100 and the CTR on the secondary = 300.

- W1CT=Y
- W2CT=Y
- CTR1 = 100
- CTR 2= 300
- MVA = 80

The internal compensation for the wye-wye transformer with a wye-wye CT can be set to 12 to remove the zero sequence currents. However, selecting 12 may give incorrect results for internal ground faults, so it is advisable to set the CT compensation to 0 for both the windings for the purpose of experiments.

- W1CTC = 0
- W2CTC = 0

The voltages for winding 1 and 2 are 138kV and 34.5kV, respectively.

- VWDG1 = 138
- VWDG2 = 34.5

4.3. DIFFERENTIAL ELEMENT SETTINGS

The tap settings are automatically made by the relay based on the MVA.

Percent restraint slope settings:

- 087P = 0.3- Minimum pick up setting
- SLP1 =25- Slope 1 setting
- SLP2 =50- Slope 2 setting
- IRS1 =3- restraint current slope 1 limit
- U87P= 10- Unrestrained element pickup

The following settings relate to the harmonic blocking and harmonic restraint:

- PCT2 = 15
- PCT4 = 35
- TH5P= OFF
- IHBL= N
- E32I= 0

4.4. OVERCURRENT ELEMENT SETTINGS

The overcurrent settings are calculated using the ASPEN model. All of the settings are in secondary amperes. All of the negative sequence overcurrent elements have been disabled (OFF) as they are not used. The torque control for all these overcurrent elements can be set as 1 to make them trip without any external condition. The SEL relay has 4 levels of instantaneous overcurrent elements. The level 1 elements can be used for tripping by assigning the proper setting. The level 2 and level 3 instantaneous overcurrent elements can be used to unlatch trip by setting them as low as

0.5 A. It is important to set the level 4 phase instantaneous elements of both the windings at their factory setting value of 4 A. OCA or OCB or OCC bits are monitored by corresponding the 50Pn4 (phase instantaneous winding n level 4 element). For example, relay word bit OCA indicates an A-phase overcurrent during the fault. It is derived by first checking which winding "W*n*" LED is lit, and then <u>if the associated 50A*n*4 overcurrent element bit is asserted</u>, or if the magnitude of the IAW*n* phase current is greater than or equal to the magnitudes of IBW*n* and ICW*n*. The same action is taken by the OCB and OCC bits.

The winding 1 overcurrent element settings are

- 50P11P (winding 1 level 1 phase instantaneous element pickup) = 16.77
- 50P11D (winding 1 level 1 phase instantaneous element delay) = 0
- 50P11TC (winding 1 level 1 phase instantaneous element torque control) = 1
- 50P12P = 0.5 (used for unlatching)
- 50P13P = 0.5 (used for unlatching)
- 50P14P = 4
- 51P1P (winding 1 phase time overcurrent pickup) = 4.7
- 51P1C (winding 1 phase time curve) = U1
- 51P1TD (winding 1 phase time overcurrent dial) = 2.38
- 51P1RS (winding 1 phase time overcurrent electromechanic reset) = N
- 51P1TC (winding 1 phase time overcurrent torque control) = 1
- 50N11P (winding 1 level 1 ground instantaneous element pickup) = 11.65
- 50N11D (winding 1 level 1 ground instantaneous element delay) = 0
- 50N11TC (winding 1 level 1 ground instantaneous element torque control) = 1

- 50N12P = OFF
- 51N1P (winding 1 ground time overcurrent pickup) = 1
- 51N1C (winding 1 ground time curve) = U1
- 51N1TD (winding 1 ground time overcurrent dial) = 5.85
- 51N1RS (winding 1 ground time overcurrent electromechanic reset) = N
- 51N1TC (winding 1 ground time overcurrent torque control) = 1

The winding 2 overcurrent element settings are:

- 50P21P (winding 2 level 1 phase instantaneous element pickup) = OFF
- 50P22P = OFF
- 50P23P = 0.5 (Used for unlatching)
- 50P24P = 4
- 51P2P (winding 2 phase time overcurrent pickup) = 5.15
- 51P2C (winding 2 phase time curve) = U2
- 51P2TD (winding 2 phase time overcurrent delay) = 0.94
- 51P2RS (winding 2 phase time overcurrent electromechanic reset) = N
- 51P2TC (winding 2 phase time overcurrent torque control) = 1
- 50N21P (winding 2 level 1 ground instantaneous element pickup) = OFF
- 50N22P = OFF
- 51N2P (winding 2 ground time overcurrent pickup) = 1
- 51N2C (winding 2 ground time curve) = U2
- 51N2TD (winding 2 ground time overcurrent time dial) = 5.12
- 51N2RS (winding 2 ground time overcurrent electromechanic reset) = N
- 51N2TC (winding 2 ground time overcurrent torque control) = 1

4.5. TRIP EQUATIONS

Trip equations are used to set conditions for a breaker to trip. For the example considered, first trip equation or Tr1 given by equation 4.1 is used to trip the breaker if any of the winding 1 or winding 2 overcurrent elements assert. Second trip equation or Tr2 given by equation 4.2 is used to trip a breaker if any of the restrained or unrestrained differential elements assert. Tr2 asserts if either the differential restrained element or the unrestrained element trips.

$$Tr1= 51P1T+51P2T \tag{4.1}$$

$$Tr2=87U+87R \tag{4.2}$$

4.6. UNLATCH TRIP EQUATIONS

A trip bit remains asserted until the unlatch trip bit asserts. The unlatch trip asserts when the ultr1/ultr2 bit asserts or the target reset button on the relay front panel is pushed. When the unlatch trip asserts, the trip bit drops.

ULTR1= !50P13

ULTR2= !50P23

The unlatch asserts when these word bit values drop below their settings, which is usually assumed 0.5 Amps. The close and unlatch close logic can be left at their factory settings as no breakers are wired to the relay outputs.

4.7. EVENT REPORT

The event report includes all the relay word bits that are included in the trip equations. Equation 4.3 is used to generate event report. Event report is generated if any of the differential relay bits 87U or 87R or any of the overcurrent relay bits 50P11 or 51P1 or 51P2 or 50N11 or 51N1 or 51N2 change from state ‘0’ to state ‘1’. The symbol ‘/’ in equation 4.3 indicates raising edge of a bit.

$$ER = /87U + /87R + /50P11 + /51P1 + /51P2 + /50N11 + /51N1 + /51N2 \qquad (4.3)$$

The length of an event report (LER) can be changed using the ‘SET G’ command. The maximum limit for an LER is 60 cycles. The pre-fault event cycle ‘PRE’ setting is also included in ‘SET G’ command. The pre-fault event cycle length can be any value less than 60 cycles.

4.8. OUTPUT EQUATIONS

Each trip equation can be assigned to a particular output. The circuit breaker contacts are usually wired to these output contacts:

OUT101= Tr1

OUT102=Tr2

4.9. SEL 387 RELAY SETTINGS- SCREEN SHOTS

Figure 4.1 and 4.2 are the screen shots of the settings in the SEL 5030 software. The setting sreen appears after ‘SET 1’ ommand is typed. The following settings can be left at their factory settings:

- Demand metering elements
- Miscellaneous timers

```
RID     =XFMR 1 S/N 2001289073
TID     =SEL 387 STATION A
E87W1   = Y          E87W2   = Y          E87W3   = N          E87W4   = N
EOC1    = Y          EOC2    = Y          EOC3    = N          EOC4    = N
EOCC    = N          ETHER   = N          ESLS1   = N          ESLS2   = N
ESLS3   = N

W1CT    = Y          W2CT    = Y          W3CT    = Y          W4CT    = Y
CTR1    = 100        CTR2    = 300        CTR3    = 100        CTR4    = 120
MVA     = 80.0       ICOM    = Y
W1CTC   = 0          W2CTC   = 0
VWDG1   = 138.00     VWDG2   = 34.50

TAP1    = 3.35       TAP2    = 4.46
O87P    = 0.30       SLP1    = 25         SLP2    = 50         IRS1    = 3.0
U87P    = 10.0       PCT2    = 15         PCT5    = 35
TH5P    = OFF        IHBL    = N


E32I    =0

Press RETURN to continue

50P11P  = 14.53      50P11D  = 0.00       50P11TC =1
50P12P  = 0.50       50P12TC =1

50P13P  = 0.50       50P14P  = 4.00
51P1P   = 4.70       51P1C   = U1         51P1TD  = 2.38       51P1RS  = N
51P1TC  =1

50Q11P  = OFF        50Q12P  = OFF
51Q1P   = OFF
50N11P  = 10.10      50N11D  = 0.00       50N11TC =1
50N12P  = OFF
51N1P   = 1.00       51N1C   = U1         51N1TD  = 5.85       51N1RS  = N
51N1TC  =1

DATC1   = 15         PDEM1P  = 7.00       QDEM1P  = 1.00       NDEM1P  = 1.00
```

Figure 4.1. Screen shot of SEL 387 relay settings

```
50P21P  = OFF       50P22P  = OFF
50P23P  = 0.50      50P24P  = 4.00

Press RETURN to continue
51P2P   = 5.15      51P2C   = U2        51P2TD  = 0.94      51P2RS  = N
51P2TC  =1

50Q21P  = OFF       50Q22P  = OFF
51Q2P   = OFF
50N21P  = OFF       50N22P  = OFF
51N2P   = 1.00      51N2C   = U2        51N2TD  = 5.12      51N2RS  = N
51N2TC  =1

DATC2   = 15        PDEM2P  = 7.00      QDEM2P  = 1.00      NDEM2P  = 1.00

TDURD   = 9.000     CFD     = 60.000

TR1     =51P1T + 51P2T + 51N1T + 51N2T
TR2     =87U + 87R
TR3     =0
TR4     =0
TR5     =0
ULTR1   =!50P13
ULTR2   =!50P23

Press RETURN to continue
ULTR3   =!50P33
ULTR4   =!(50P13 + 50P23 + 50P33)
ULTR5   =0
52A1    =IN101
52A2    =IN102
52A3    =IN103
52A4    =0
CL1     =CC1 + LB4 + /IN104
CL2     =CC2 + /IN105
CL3     =CC3 + /IN106
CL4     =0
ULCL1   =TRIP1 + TRIP4
ULCL2   =TRIP2 + TRIP4
ULCL3   =TRIP3 + TRIP4
ULCL4   =0
ER      =/87U + /87R + /50P11 + /51P1 + /51P2 + /50N11 + /51N1
          + /51N2
OUT101  =TRIP1
OUT102  =TRIP2
OUT103  =TRIP3

Press RETURN to continue
OUT104  =TRIP4
OUT105  =CLS1
OUT106  =CLS2
OUT107  =CLS3
```

Figure 4.2. Screen shot of SEL 387 relay settings

5. EXPERIMENTS

5.1. TEST FOR DIFFERENTIAL ELEMENT

Aim:

i) To test the differential element and show that it is tripping for internal faults while restraining for external faults.

ii) To hand calculate the values of IOP and IRT and verify with those values obtained in the event report.

iii) To theoretically derive which of the differential elements (87U1, 87U2, 87U3, 87R1, 87R2, 87R3) would trip.

Experimental Setup:

- For the assumed ASPEN model, 4 fault scenarios are considered as shown in Figure 5.1. The faults at locations 1 and 2 are internal faults, whereas the faults at locations 3 and 4 are external faults to the differential relay.
- The fault currents are obtained from ASPEN by running faults at these locations.
- The fault currents are injected to the relay using the SEL AMS and a check is made if the differential element is tripping correctly for internal faults and restraining for external faults.
- Event reports are obtained using the Synchrowave 2015 software. The values of IOP and IRT are hand calculated and verified with those values obtained in the event report. The expected 87 bits that will trip for these faults are derived theoretically and then verified with results from event reports.

- The following trip equations are used

$$Tr1= 51P1T+51P2T \tag{5.1}$$

$$Tr2= 87U+87R \tag{5.2}$$

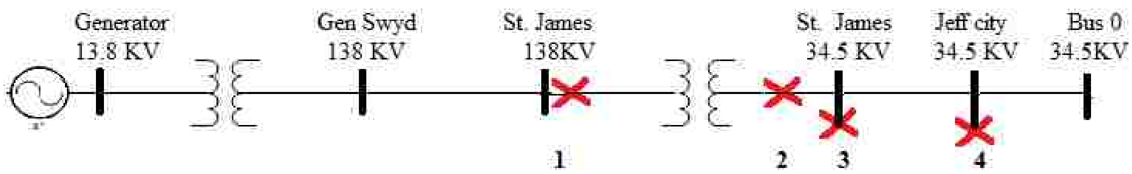


Figure 5.1. Four fault scenarios considered for experiment

5.1.1. Three Phase Fault At Location 1. A three phase fault is considered at location 1 which is on primary side of transformer. The current phasors seen by the relays on primary and secondary of transformer for this fault are shown in Figure 5.3. The pre fault, fault and post fault currents in secondary amperes injected to the relay using SEL AMS are shown in Figure 5.4. Figure 5.5 and Figure 5.6 are the event reports generated for this fault. In Figure 5.5, the third waveform which indicates the changed relay word bits by a solid blue line show that output contact OUT102 assigned to trip2 asserted as relay bits 87R1, 87R2 and 87R3 have tripped. Tripping of 87R1, 87R2, 87R3 indicates that the differential element's restrained element picked up for a three phase fault. Differential event report in Figure 5.6 gives information about operate current and restrained current magnitudes for all three phases during fault.

From Figure 5.6,

IOP1= 5.4, IOP2 = IOP3= 5.38

IRT1= IRT2= 2.7, IRT3 = 2.69

Theoretical calculations:

$$\vec{I1W1C1} = \frac{\vec{IAW1}}{TAP1} = \frac{18.05\angle -83.3^\circ}{3.35} = 5.38\angle -83.3^\circ$$

$$\vec{I2W1C1} = \frac{\vec{IBW1}}{TAP1} = \frac{18.05\angle 156.7}{3.35} = 5.38\angle 156.7$$

$$\vec{I3W1C1} = \frac{\vec{ICW1}}{TAP1} = \frac{18.05\angle 36.7}{3.35} = 5.38\angle 36.7$$

$$\vec{I1W2C1} = \frac{\vec{IAW2}}{TAP2} = 0$$

$$\vec{I2W2C1} = \frac{\vec{IBW2}}{TAP2} = 0$$

$$\vec{I3W2C1} = \frac{\vec{ICW2}}{TAP2} = 0$$

$$IOP1 = \left|\vec{I1W1C1} + \vec{I1W2C1}\right| = \left|5.38\angle -83.3 + 0\right| = 5.38$$

$$IOP2 = \left|\vec{I2W1C1} + \vec{I2W2C1}\right| = \left|5.38\angle 156.7 + 0\right| = 5.38$$

$$IOP3 = \left|\vec{I3W1C1} + \vec{I3W2C1}\right| = \left|5.38\angle 36.7 + 0\right| = 5.38$$

$$IRT1 = \frac{\left|\vec{I1W1C1}\right| + \left|\vec{I1W2C1}\right|}{2} = \frac{\left|5.38\angle\text{-}83.3\right| + 0}{2} = 2.69$$

$$IRT2 = \frac{\left|\vec{I2W1C1}\right| + \left|\vec{I2W2C1}\right|}{2} = \frac{\left|5.38\angle 156.7\right| + 0}{2} = 2.69$$

$$IRT3 = \frac{\left|\vec{I3W1C1}\right| + \left|\vec{I3W2C1}\right|}{2} = \frac{\left|5.38\angle 36.7\right| + 0}{2} = 2.69$$

Implementation of differential logic:

Minimum pickup 087P intersects slope 1 at the value of restraint current given by

$$IRT = \frac{087P*100}{SLP1} = \frac{0.3*100}{25} = 1.2$$

Since 1.2 < (IRT1 = IRT2 = IRT3 = 2.69), from Section 3.4, case 3 can be applied to determine which of the differential elements would trip:

Condition 1: $(\frac{IOP1}{IRT1} = \frac{IOP2}{IRT2} = \frac{IOP3}{IRT3}) = 0.5 > (SLP1 = 0.25)$

Condition 2: (IOP1 = IOP2= IOP3 = 5.38) > (087P = 0.3)

Hence the differential restrained elements 87R1, 87R2, 87R3 elements are expected to trip. The approximate operating point is marked 1 in Figure 5.2.

5.1.2. Phase To Phase Fault At Location 2. A phase to phase fault is considered at location 2 or on secondary side of transformer. The current phasors seen by the relays on primary and secondary of transformer for this fault are shown in Figure 5.7. The pre fault, fault and post fault currents in secondary amperes injected to the relay using SEL AMS are shown in Figure 5.8. Figure 5.9 and Figure 5.10 are the event reports generated for this fault. In Figure 5.9, the third waveform which indicates the changed relay word bits by a solid blue line show that output contact OUT102 assigned to trip2 asserted as relay bits 87R2 and 87R3 have tripped. Tripping of 87R2, 87R3 indicates that the differential element’s restrained element picked up for a phase B to C fault. Differential event report in Figure 5.10 gives information about magnitudes of operate and restrained currents for all three phases during fault.

From figure 5.10,

IOP1= 0, IOP2 = 3.04, IOP3= 3.01

IRT1=0, IRT2= 1.52, IRT3 = 1.51

Theoretical Calculations:

$$I1W1C\vec{1} = \frac{IAW\vec{1}}{TAP1} = 0$$

$$I2W1C\vec{1} = \frac{IBW\vec{1}}{TAP1} = \frac{10.19\angle 168.2}{3.35} = 3.04\angle 168.2$$

$$I3W1C\vec{1} = \frac{ICW\vec{1}}{TAP1} = \frac{10.07\angle 22.4}{3.35} = 3\angle 22.4$$

$$I1W2C\vec{1} = I2W2C\vec{1} = I3W2C\vec{1} = 0$$

$$IOP1=0$$

$$IOP2=\left|I2W1C\vec{1}+I2W2C\vec{1}\right|$$

$$= 3.04 \text{ pu}$$

$$IOP3=\left|I3W1C\vec{1}+I3W2C\vec{1}\right|$$

$$= 3 \text{ pu}$$

$$IRT1= 0 \text{ pu}$$

$$IRT2=\frac{\left|I2W1C\vec{1}\right|+\left|I2W2C\vec{1}\right|}{2}$$

$$= 1.52$$

$$IRT3=\frac{\left|I3W1C\vec{1}\right|+\left|I3W2C\vec{1}\right|}{2}$$

$$= 1.5 \text{ pu}$$

Implementation of differential logic:

Minimum pickup intersects slope 1 at the value of restraint current given by

$$IRT=\frac{087P*100}{SLP1} = \frac{0.3*100}{25} = 1.2$$

Since 1.2 < (IRT2 = IRT3 = 1.52), from Section 3.4, case 3 can be applied to determine which of the differential elements would trip:

Condition 1: $(\frac{IOP2}{IRT2} = \frac{IOP3}{IRT3} = 0.5) > (SLP1 = 0.25)$

Condition 2: (IOP2= 3.04, IOP3 = 3) > (087P = 0.3)

Hence the differential relay restrained elements 87R2, 87R3 elements are expected to trip. The approximate operating point is marked 2 in Figure 5.2.

5.1.3. Three Phase Fault At Location 3. A three phase fault is considered at location 3 which is external to transformer. The current phasors seen by the relays on primary and secondary of transformer for this fault are shown in Figure 5.11. The pre fault, fault and post fault currents in secondary amperes injected to the relay using SEL AMS are shown in Figure 5.12. Figure 5.13, Figure 5.14 and Figure 5.15 are the event reports generated for this fault. In Figure 5.13, changed relay word bits indicated by solid blue line show that winding 1 phase time overcurrent element 51P1 and winding 2 phase time overcurrent element 51P2 picked up. In Figure 5.14, the third waveform shows that output contact OUT101 assigned to trip1 asserted as relay bit 51P2T tripped and differential element restrained. Tripping of OCA (phase A overcurrent), OCB (phase B overcurrent), OCC (phase C overcurrent), indicates that overcurrent elements of phase A,B,C tripped. Differential event report in Figure 5.15 gives information about the magnitudes of operate and restrained currents for all three phases during fault.

From Figure 5.15,

IOP1= IOP2 = IOP3= 0

IRT1= IRT2= IRT3 = 3.34

Theoretical calculations:

$$I1W1C\vec{1}=\frac{IAW\vec{1}}{TAP1}=\frac{11.18\angle -84.8}{3.35}=3.34\angle -84.8$$

$$I2W1C\vec{1}=\frac{IBW\vec{1}}{TAP1}=\frac{11.18\angle 155.2}{3.35}=3.34\angle 155.2$$

$$I3W1C\vec{1}=\frac{ICW\vec{1}}{TAP1}=\frac{11.18\angle 35.2}{3.35}=3.34\angle 35.2$$

$$I1W2C\vec{1}=\frac{IAW\vec{2}}{TAP2}=\frac{14.9\angle 95.2}{4.46}=3.34\angle 95.2$$

$$I2W2C\vec{1}=\frac{IBW\vec{2}}{TAP2}=\frac{14.9\angle -24.8}{4.46}=3.34\angle -24.8$$

$$I3W2C\vec{1}=\frac{ICW\vec{2}}{TAP2}=\frac{14.9\angle 144.8}{4.46}=3.34\angle 144.8$$

$$IOP1=\left|I1W1C\vec{1}+I1W2C\vec{1}\right|=\left|3.34\angle -84.8+3.34\angle 95.2\right|=0$$

$$IOP2=\left|I2W1C\vec{1}+I2W2C\vec{1}\right|=\left|3.34\angle 155.2+3.34\angle -24.8\right|=0$$

$$IOP3=\left|I3W1C\vec{1}+I3W2C\vec{1}\right|=\left|3.34\angle 35.2+3.34\angle 144.8\right|=0$$

$$IRT1=\frac{\left|I1W1C\vec{1}\right|+\left|I1W2C\vec{1}\right|}{2}=3.34$$

$$IRT2=\frac{\left|I2W1C\vec{1}\right|+\left|I2W2C\vec{1}\right|}{2}=3.34$$

$$IRT3=\frac{\left|I3W1C\vec{1}\right|+\left|I3W2C\vec{1}\right|}{2}=3.34$$

Implementation of differential logic:

IOP1= IOP2= IOP3= 0

The operate point plots on X-axis as marked approximately by point 3, which is in restraint region in Figure 5.2. So differential element is not expected to trip.

5.1.4. Phase To Phase Fault At Location 4. A phase to phase (B to C phase) fault is considered at location 4 which is external to transformer. The current phasors seen by the relays on primary and secondary of transformer for this fault are shown in Figure 5.16. The pre fault, fault and post fault currents in secondary amperes injected to the relay using SEL AMS are shown in Figure 5.17. Figure 5.18, Figure 5.19 and Figure 5.20 are the event reports generated for this fault. In Figure 5.18, changed relay word bits indicated by solid blue line show that winding 1 phase time overcurrent element 51P1 and winding 2 phase time overcurrent element 51P2 picked up. In Figure 5.19, the third waveform shows that output contact OUT101 assigned to trip1 asserted as relay bit 51P2T tripped and differential element restrained. Tripping of OCB, OCC, indicates that overcurrent elements of phase B,C tripped. Differential event report in Figure 5.20 gives information about magnitudes of operate and restrained currents for all three phases during fault.

From Figure 5.20,

IOP1= IOP2 = IOP3= 0

IRT1= IRT2= IRT3 = 2.22

Theoretical calculations:

$$\mathrm{I1W1C}\vec{1} = \frac{\mathrm{IAW}\vec{1}}{\mathrm{TAP1}} = 0$$

$$\mathrm{I2W1C}\vec{1} = \frac{\mathrm{IBW}\vec{1}}{\mathrm{TAP1}} = \frac{7.43\angle -170.8}{3.35} = 2.22\angle -170.8$$

$$\mathrm{I3W1C}\vec{1} = \frac{\mathrm{ICW}\vec{1}}{\mathrm{TAP1}} = \frac{7.43\angle 9.1}{3.35} = 2.22\angle 9.1$$

$$I1W2C\vec{1} = \frac{IAW\vec{2}}{TAP2} = 0$$

$$I2W2C\vec{1} = \frac{IBW\vec{2}}{TAP2} = \frac{9.91\angle 9.2}{4.46} = 2.22\angle 9.2$$

$$I3W2C\vec{1} = \frac{ICW\vec{2}}{TAP2} = \frac{9.91\angle -170.8}{4.46} = 2.22\angle -170.8$$

$$IOP1 = \left| I1W1C\vec{1} + I1W2C\vec{1} \right| = 0$$

$$IOP2 = \left| I2W1C\vec{1} + I2W2C\vec{1} \right| = \left| 2.22\angle -170.8 + 2.22\angle 9.2 \right| = 0$$

$$IOP3 = \left| I3W1C\vec{1} + I3W2C\vec{1} \right| = \left| 2.22\angle 9.1 + 2.22\angle -170.8 \right| = 0$$

$$IRT1 = \frac{\left| I1W1C\vec{1} \right| + \left| I1W2C\vec{1} \right|}{2} = 2.22$$

$$IRT2 = \frac{\left| I2W1C\vec{1} \right| + \left| I2W2C\vec{1} \right|}{2} = 2.22$$

$$IRT3 = \frac{\left| I3W1C\vec{1} \right| + \left| I3W2C\vec{1} \right|}{2} = 2.22$$

Implementation of differential logic:

IOP1= IOP2= IOP3= 0

The point plots on X-axis as marked approximately by point 4 in Figure 5.2. So differential element is not expected to trip.

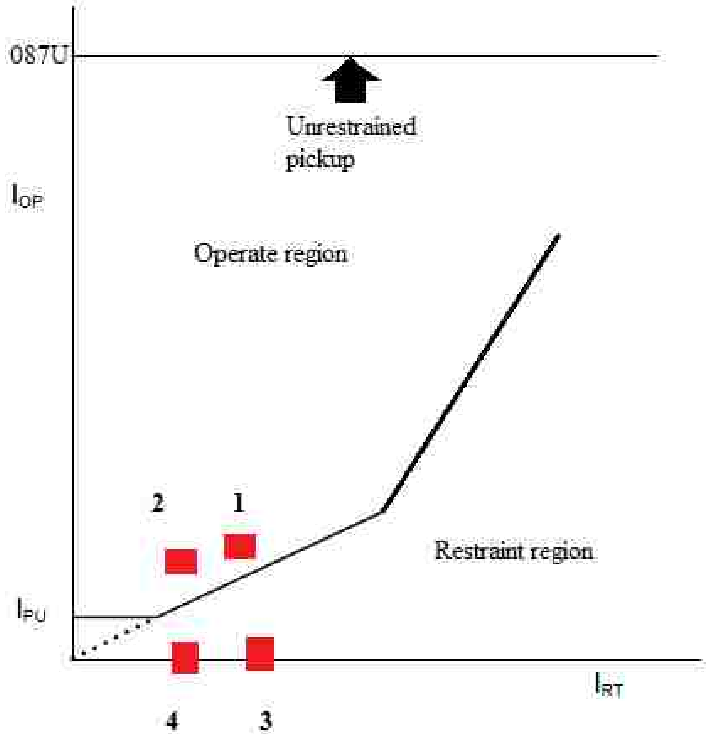


Figure 5.2. Approximate location of operating points for the considered faults

5.2. TEST FOR OVERCURRENT ELEMENTS

Aim:

To show that

i) Instantaneous phase and ground overcurrent elements are tripping instantaneously for primary side faults and restraining for secondary side faults

ii) Primary side overcurrent relay is coordinating with secondary side overcurrent relay.

Experimental setup:

- Faults are injected to relay by using SEL AMS. Fault currents are obtained by running faults in ASPEN model. Faults at 4 locations shown in figure 5.1 are used for testing.

- The phase instantaneous elements are tested by running three phase, phase to phase faults on primary side and three phase fault on secondary side of transformer. Ground instantaneous element is tested by running line to ground fault on primary and secondary sides of transformer.
- Coordination of primary side phase time overcurrent relay with secondary side phase time overcurrent relay is verified by injecting three phase fault currents to relay. Coordination of primary side ground time overcurrent relay with secondary side ground time overcurrent relay is verified by injecting single line to ground fault currents to relay.
- The following trip equations are used

$$\text{Tr1} = \text{51P1T} + \text{51N1T} + \text{51N2T} + \text{51P2T} \tag{5.3}$$

$$\text{Tr2} = \text{50N11T} + \text{50P11T} \tag{5.4}$$

5.2.1. Three Phase Fault At Location 1. A three phase fault is considered at location 1 which is on the primary of transformer. The current phasors seen by the relays on primary and secondary of transformer for this fault are shown in Figure 5.3. The pre fault, fault and post fault currents in secondary amperes injected to the relay using SEL AMS are shown in Figure 5.4. Figure 5.21, is the event report generated for this fault. In Figure 5.21, changed relay word bits indicated by solid blue line show that phase instantaneous winding 1 overcurrent 50P11T element tripped, OUT102 assigned to trip2 asserted as relay bit 50P11T tripped. Tripping of OCA, OCB, OCC indicates that overcurrent elements of phases A, B,C tripped.

5.2.2. Phase To Phase Fault At Location 1. A phase to phase fault is considered at location 1 which is on the primary of transformer. The current phasors seen by the relays on primary and secondary of transformer for this fault are shown in Figure 5.22.

The pre fault, fault and post fault currents in secondary amperes injected to the relay using SEL AMS are shown in Figure 5.23. Figure 5.24 is the event report generated for this fault. In Figure 5.24, changed relay word bits indicated by solid blue line shows that phase instantaneous winding 1 overcurrent 50P11T element tripped, OUT102 assigned to trip2 asserted as relay bit 50P11T tripped. Tripping of OCB, OCC indicates that overcurrent elements of phases B,C tripped.

5.2.3. Three Phase Fault At Location 2. A three phase fault is considered at location 2 which is on the secondary of transformer. The current phasors seen by the relays on primary and secondary of transformer for this fault are shown in Figure 5.25. The pre fault, fault and post fault currents in secondary amperes injected to the relay using SEL AMS are shown in Figure 5.26. Figure 5.27 and Figure 5.28 are the event reports generated for this fault. In Figure 5.27, changed relay word bits indicated by solid blue line show that winding 1 phase time overcurrent element (51P1) picked up. In Figure 5.28, the third waveform shows that output contact OUT101 assigned to trip1 asserted as relay bit 51P1T or winding 1 phase time overcurrent element tripped. Tripping of OCA, OCB, OCC, indicates that overcurrent elements of phases A, B,C tripped.

5.2.4. Three Phase Fault At Location 3. A three phase fault is considered at location 3. The current phasors seen by the relays on primary and secondary of transformer for this fault are shown in Figure 5.11. The pre fault, fault and post fault currents in secondary amperes injected to the relay using SEL AMS are shown in Figure 5.12. Figure 5.29, Figure 5.30 are the event reports generated for this fault. In Figure 5.29, changed relay word bits indicated by solid blue line show that winding 1 phase time overcurrent element 51P1 and winding 2 phase time overcurrent element 51P2 picked up. In Figure 5.30, the third waveform shows that output contact OUT101 assigned to trip1 asserted as relay bit 51P2T tripped. Tripping of OCA, OCB, OCC indicates that overcurrent elements of phase A,B,C tripped.

5.2.5. Three Phase Fault At Location 4. A three phase fault is considered at location 4. The current phasors seen by the relays on primary and secondary of transformer for this fault are shown in Figure 5.31. The pre fault, fault and post fault currents in secondary amperes injected to the relay using SEL AMS are shown in Figure 5.32. Figure 5.33, Figure 5.34 are the event reports generated for this fault. In Figure 5.33, changed relay word bits indicated by solid blue line show that winding 1 phase time overcurrent element 51P1 and winding 2 phase time overcurrent element 51P2 picked up. In Figure 5.34, the third waveform shows that output contact OUT101 assigned to trip1 asserted as relay bit 51P2T or winding 2 phase time overcurrent element tripped. Tripping of OCA, OCB, OCC indicates that overcurrent elements of phase A,B,C tripped.

5.2.6. Single Line To Ground Fault At Location 1. A single line to ground fault is considered at location 1 which is on the primary of transformer. The current phasors seen by the relays on primary and secondary of transformer for this fault are shown in Figure 5.35. The pre fault, fault and post fault currents in secondary amperes injected to the relay using SEL AMS are shown in Figure 5.36. Figure 5.37 is the event report generated for this fault. In Figure 5.37, changed relay word bits indicated by solid blue line shows that instantaneous winding 1 ground overcurrent element 50N11T tripped, OUT102 assigned to trip2 asserted as relay bit 50N11T tripped. Tripping of OCA indicates that overcurrent element of phase A tripped.

5.2.7. Single Line To Ground Fault At Location 2. A single line to ground fault is considered at location 2 which is on the secondary of transformer. The current phasors seen by the relays on primary and secondary of transformer for this fault are shown in Figure 5.38. The pre fault, fault and post fault currents in secondary amperes injected to the relay using SEL AMS are shown in Figure 5.39. Figure 5.40 and Figure 5.41 are the event reports generated for this fault. In Figure 5.40, changed relay word bits indicated by solid blue line show that winding 1 ground time overcurrent element 51N1 picked up. In Figure 5.41, the third waveform shows that output contact OUT101 assigned to trip1 asserted as relay bit 51N1T tripped and differential element restrained. Tripping of OCA indicates that overcurrent element of phase A tripped.

5.2.8. Single Line To Ground Fault At Location 3. A single line to ground fault is considered at location 3. The current phasors seen by the relays on primary and secondary of transformer for this fault are shown in Figure 5.42. The pre fault, fault and post fault currents in secondary amperes injected to the relay using SEL AMS are shown in Figure 5.43. Figure 5.44 and Figure 5.45 are the event reports generated for this fault. In Figure 5.44, changed relay word bits indicated by solid blue line show that winding 1 ground time overcurrent (51N1) and winding 2 ground time overcurrent (51N2) elements picked up. In Figure 5.45, the third waveform shows that output contact OUT101 assigned to trip1 asserted as relay bit 51N2T tripped. Tripping of OCA indicates that overcurrent element of phase A tripped.

5.2.9. Single Line To Ground Fault At Location 4. A single line to ground fault is considered at location 4. The current phasors seen by the relays on primary and secondary of transformer for this fault are shown in Figure 5.46. The pre fault, fault and post fault currents in secondary amperes injected to the relay using SEL AMS are shown in Figure 5.47. Figure 5.48 and Figure 5.49 are the event reports generated for this fault. In Figure 5.48, changed relay word bits indicated by solid blue line show that winding 1 ground time overcurrent (51N1) and that winding 2 ground time overcurrent (51N2) elements picked up. In Figure 5.49, the third waveform shows that output contact OUT101 assigned to trip1 asserted as relay bit 51N2T tripped. Tripping of OCA indicates that overcurrent element of phase A tripped.

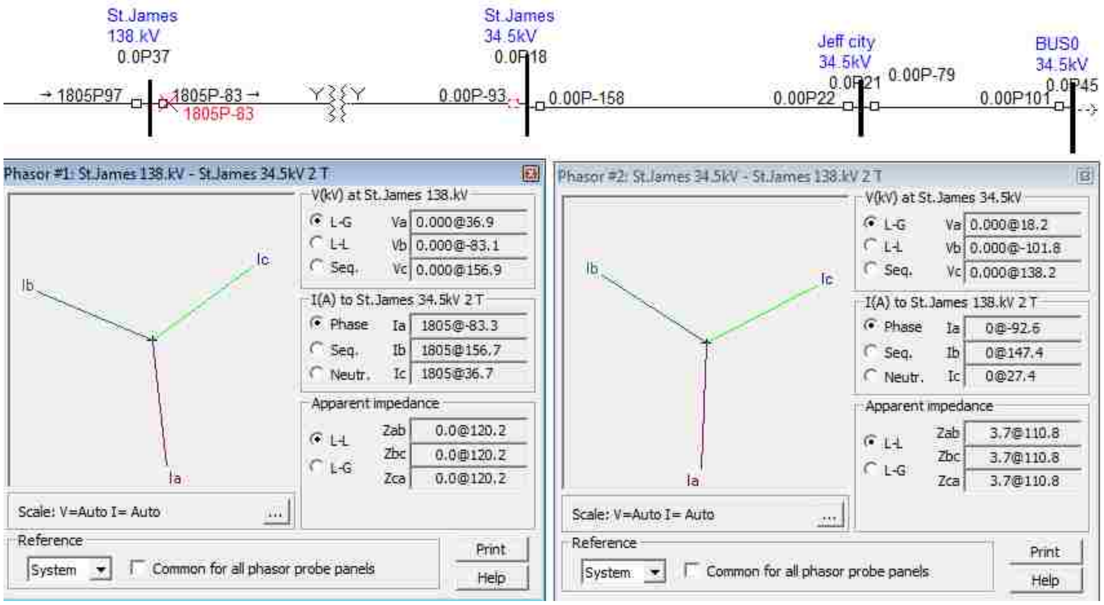


Figure 5.3. Fault currents obtained from ASPEN for three phase fault at location 1

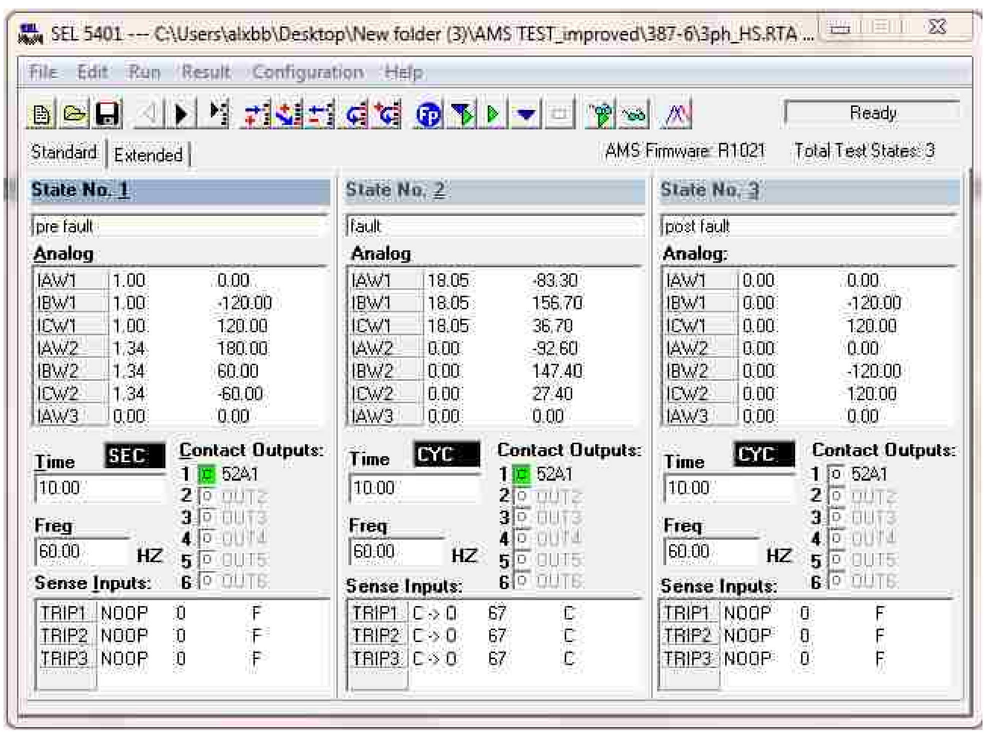


Figure 5.4. SEL AMS setting for three phase fault at location 1

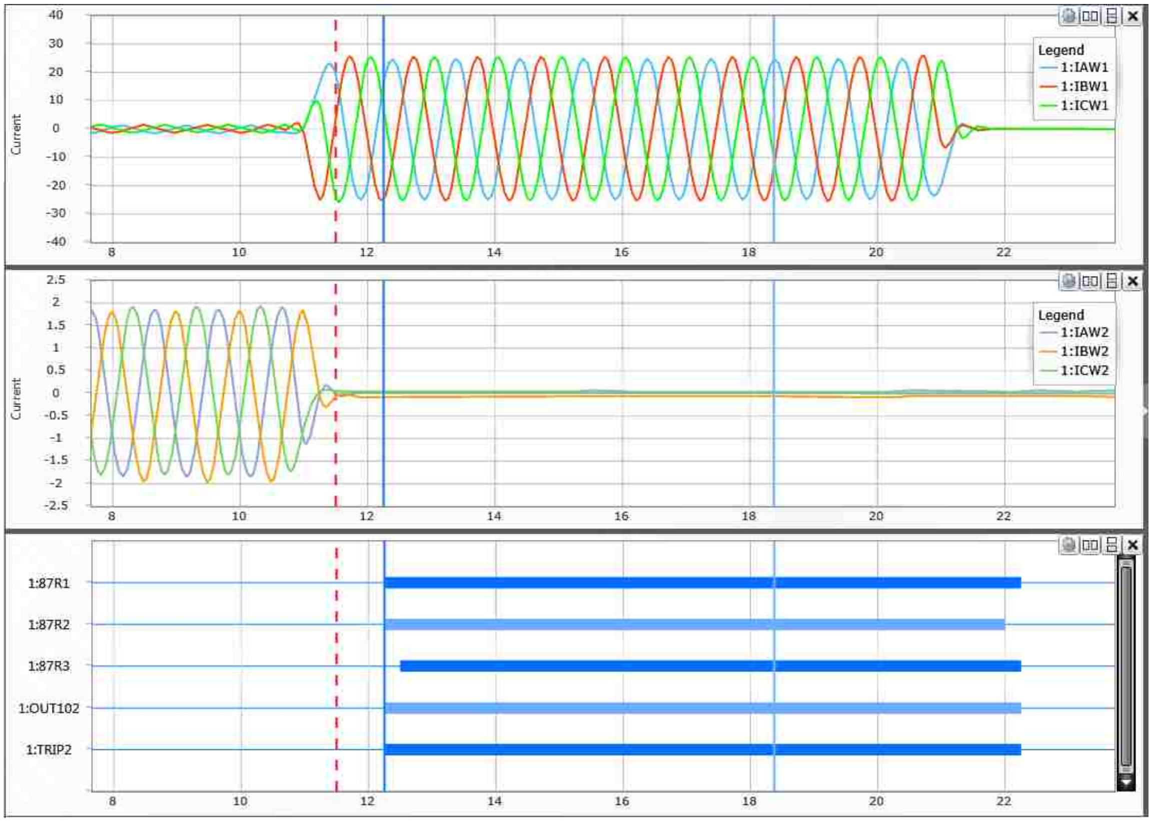


Figure 5.5. Event report for three phase fault at location 1

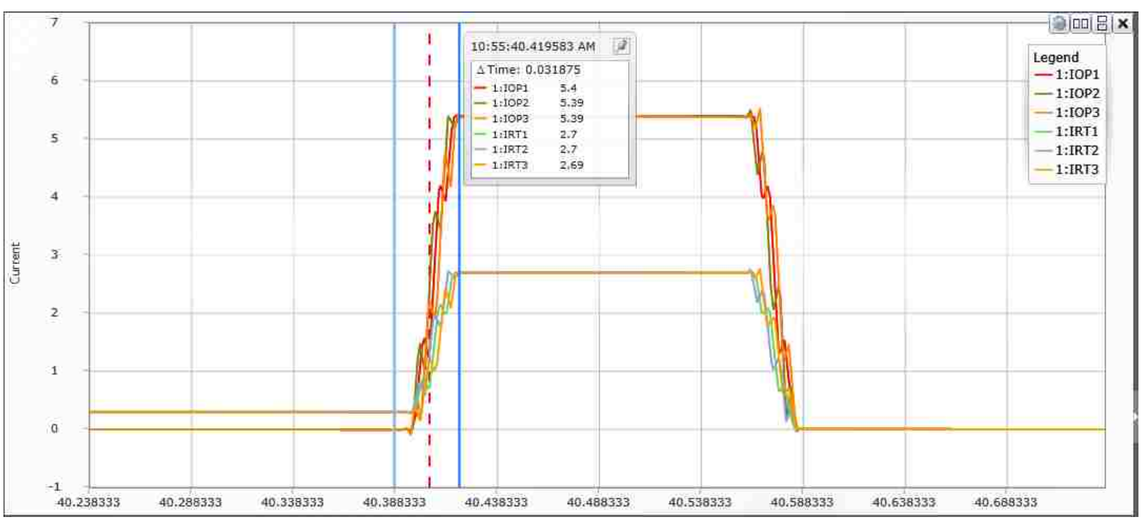


Figure 5.6. Differential event report for three phase fault at location 1

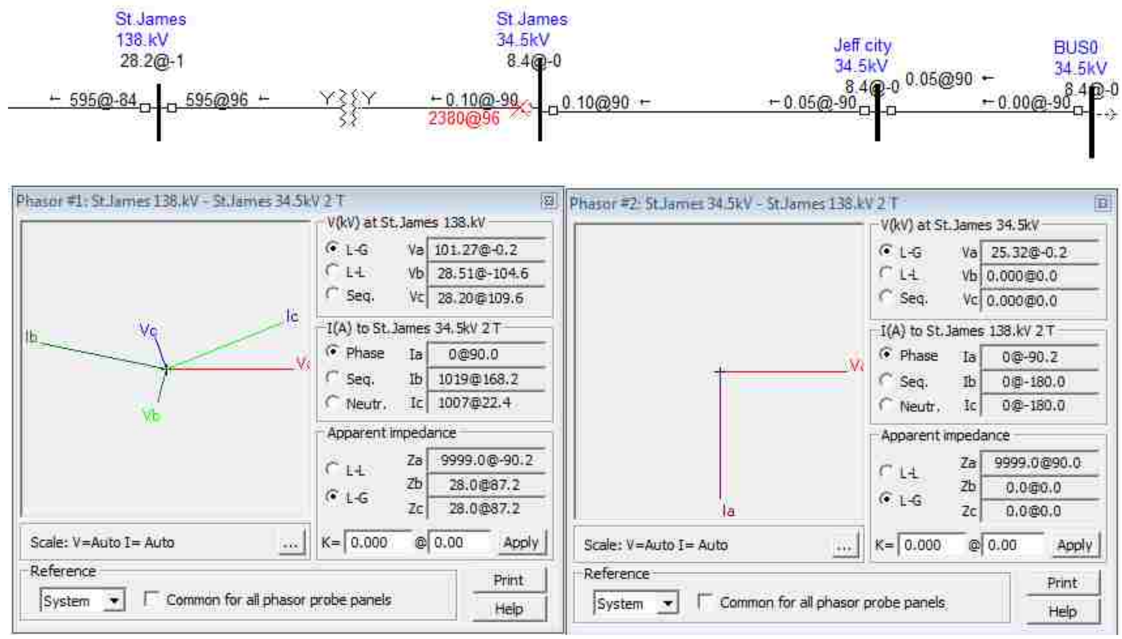


Figure 5.7. Fault currents obtained from ASPEN for phase to phase fault at location 2

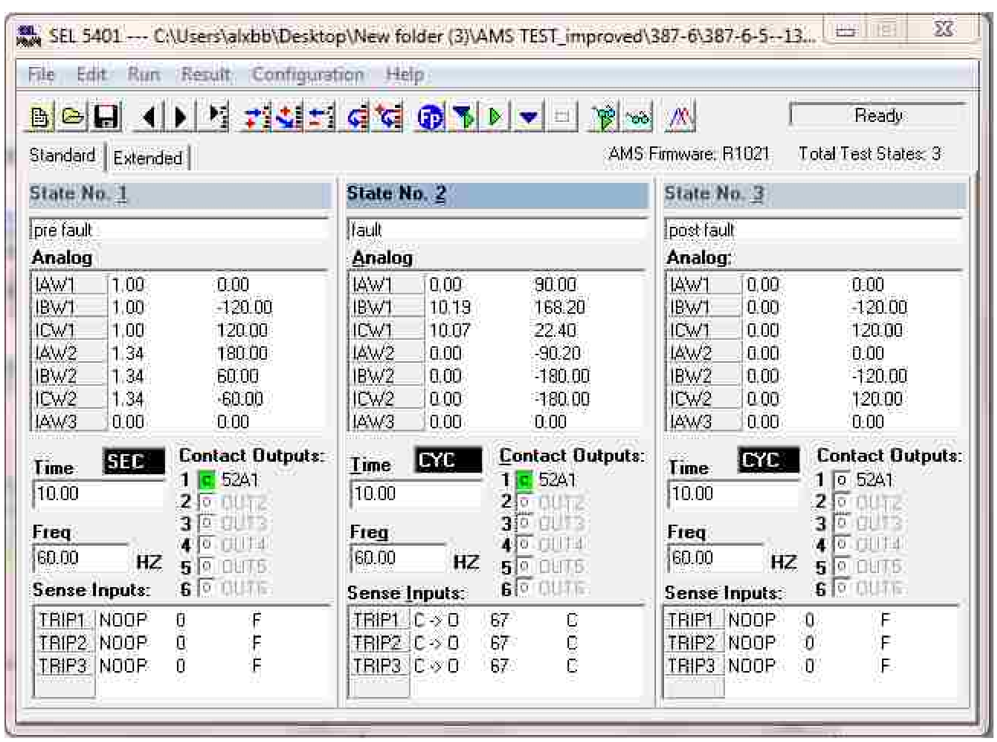


Figure 5.8. SEL AMS setting for phase to phase fault at location 2

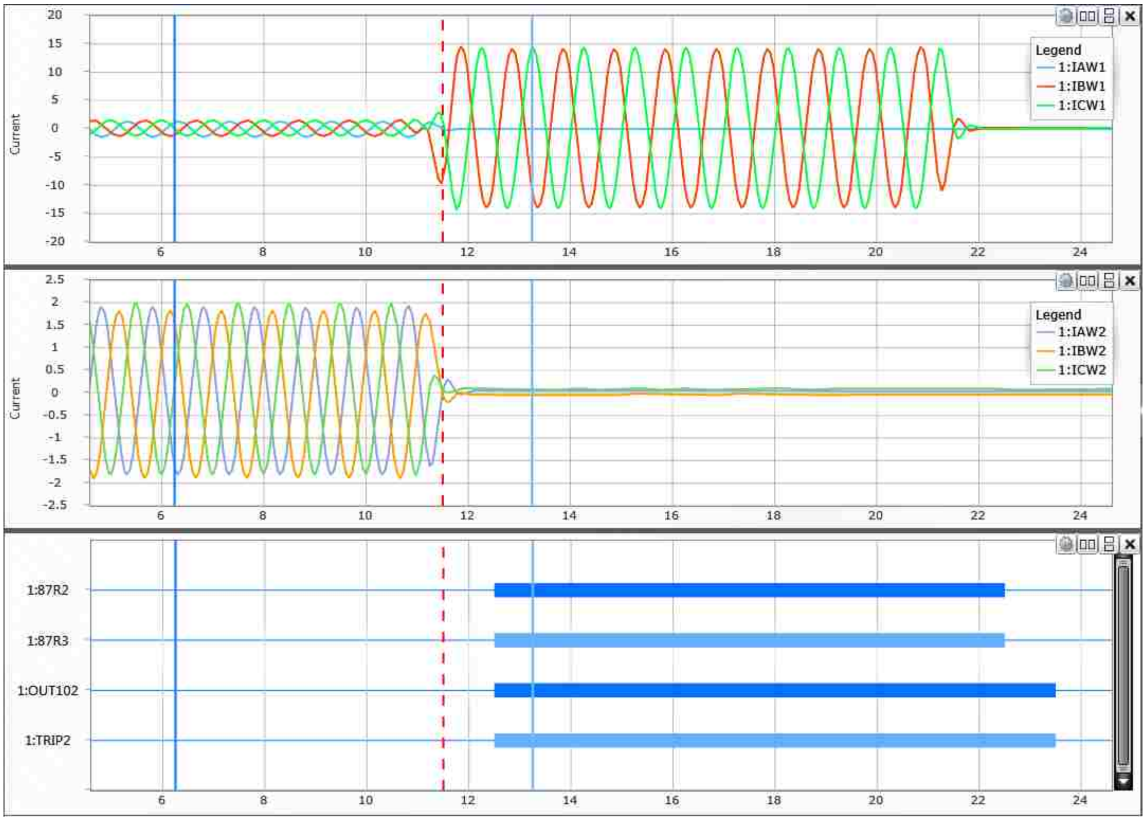


Figure 5.9. Event report for phase to phase fault at location 2

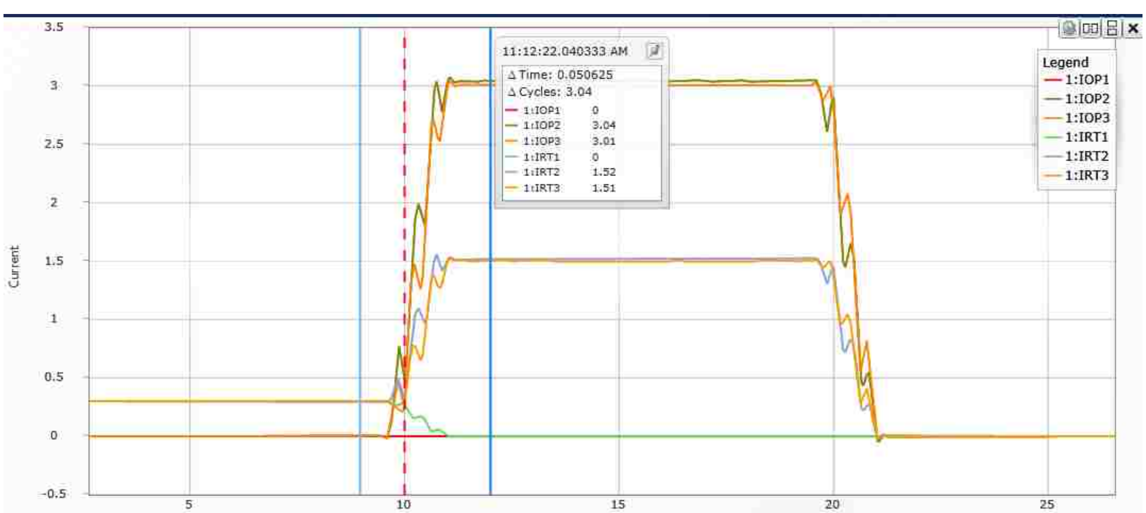


Figure 5.10. Differential event report for phase to phase fault at location 2

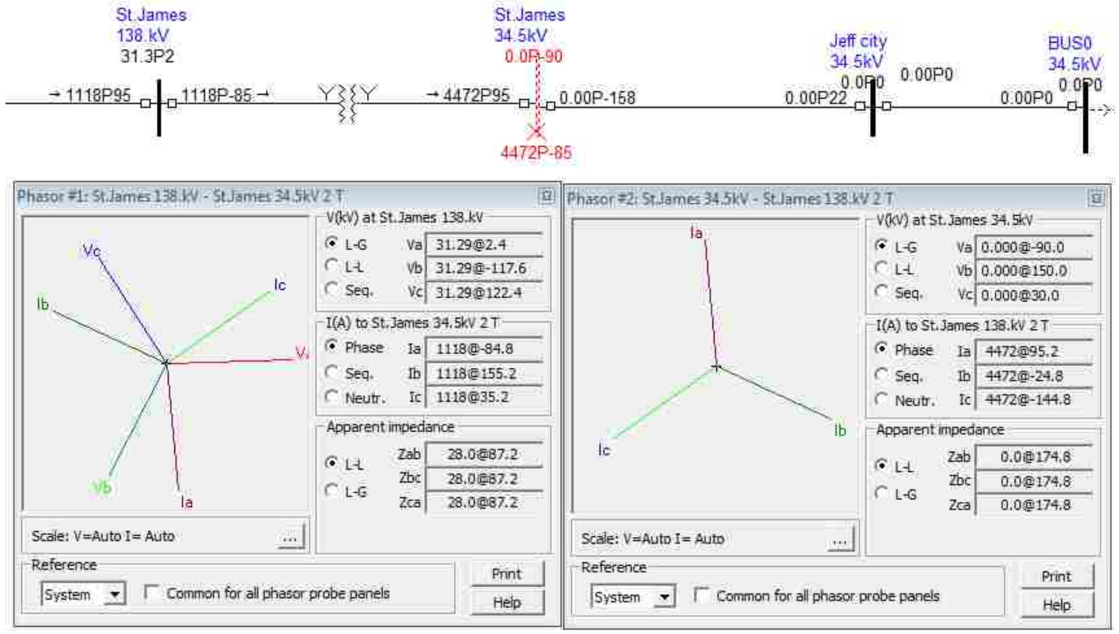


Figure 5.11. Fault currents obtained from ASPEN for a three phase fault at location 3

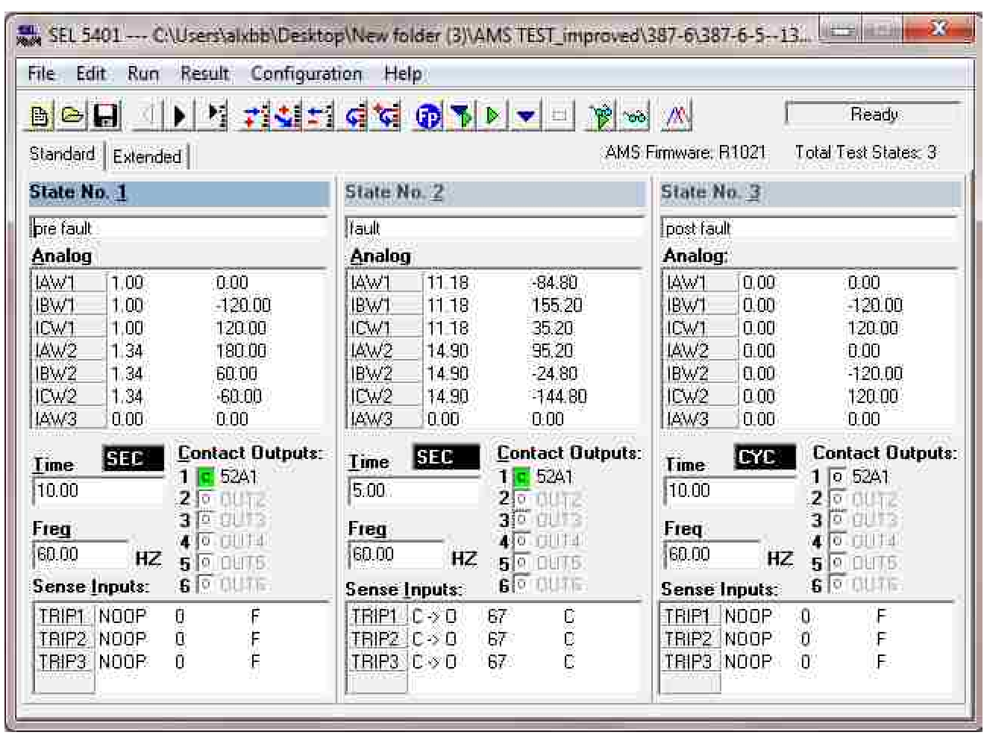


Figure 5.12. SEL AMS setting for three phase fault at location 3

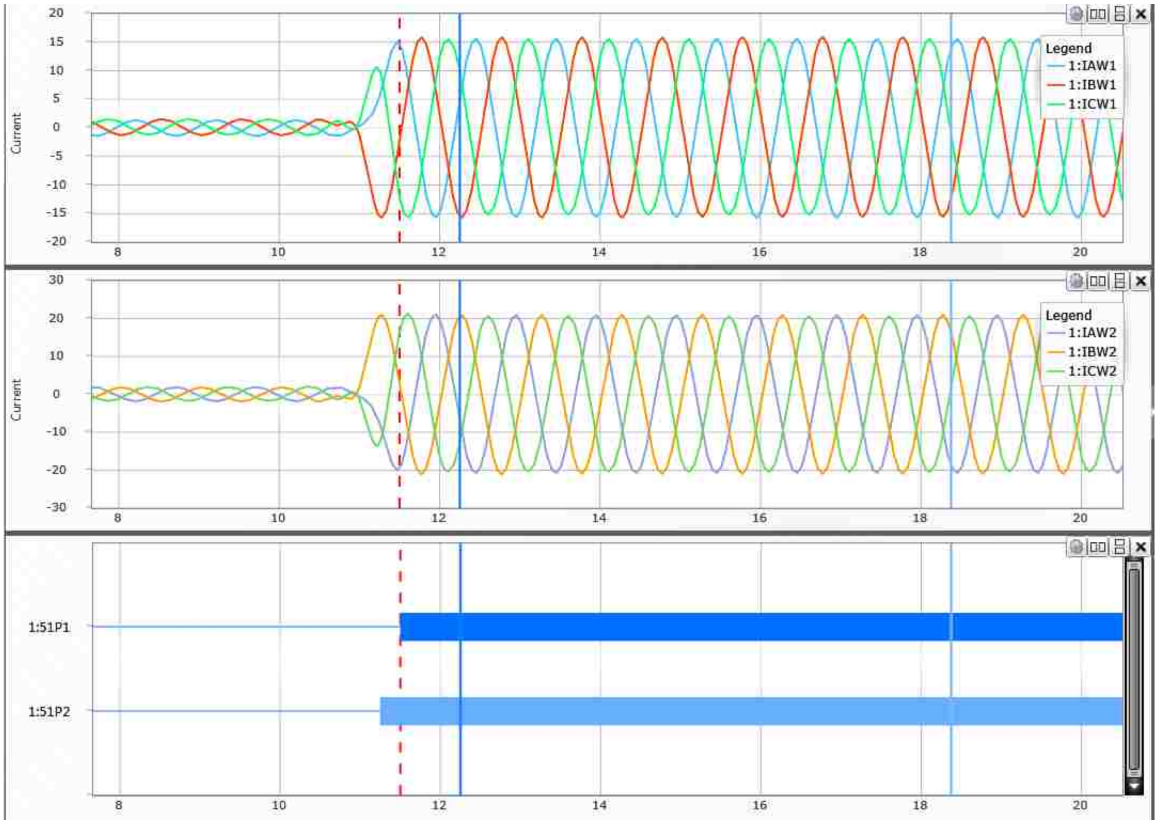


Figure 5.13. Event report showing pickup of relay bits for a three phase fault at location 3

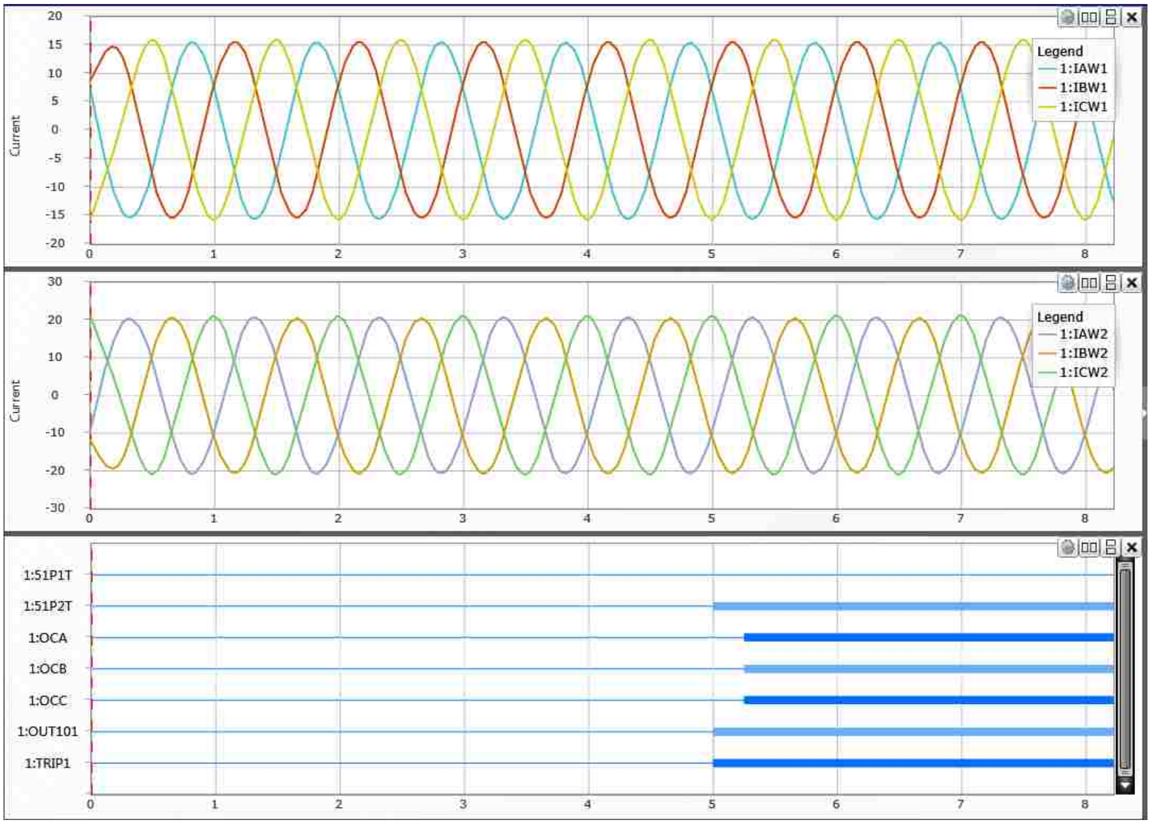


Figure 5.14. Event report showing tripping of overcurrent element for three phase fault at location 3

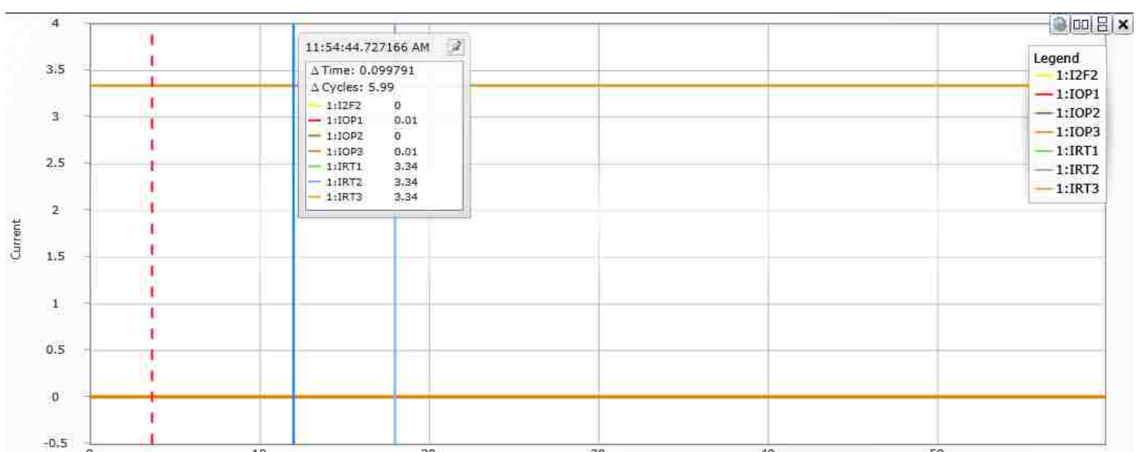


Figure 5.15. Differential event report for three phase fault at location 3

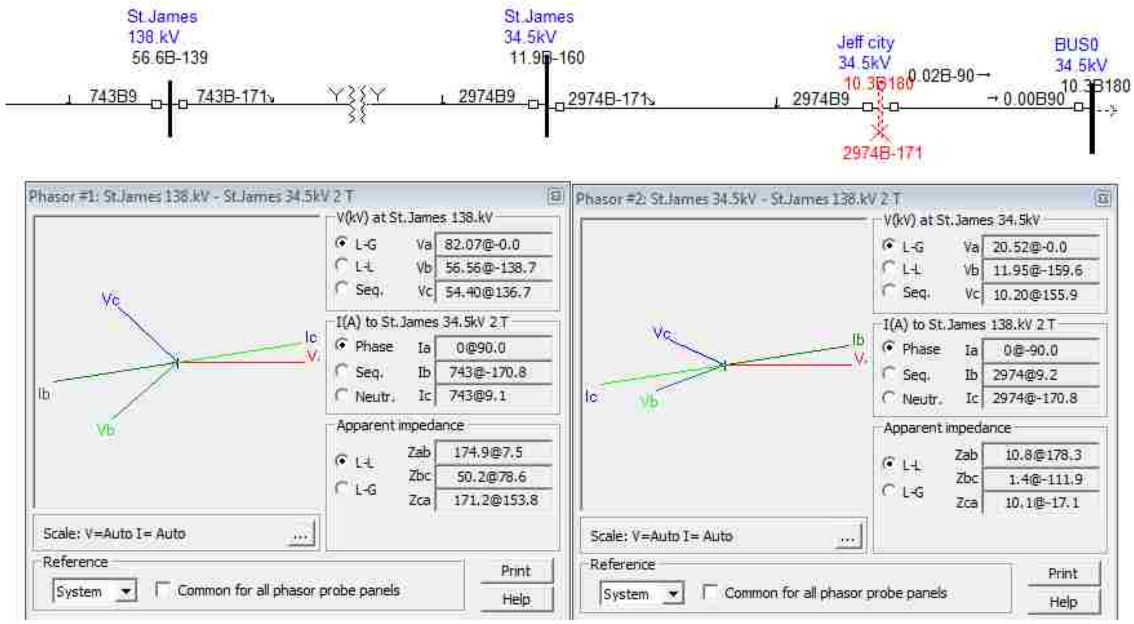


Figure 5.16. Fault currents obtained from ASPEN for phase to phase fault at location 4

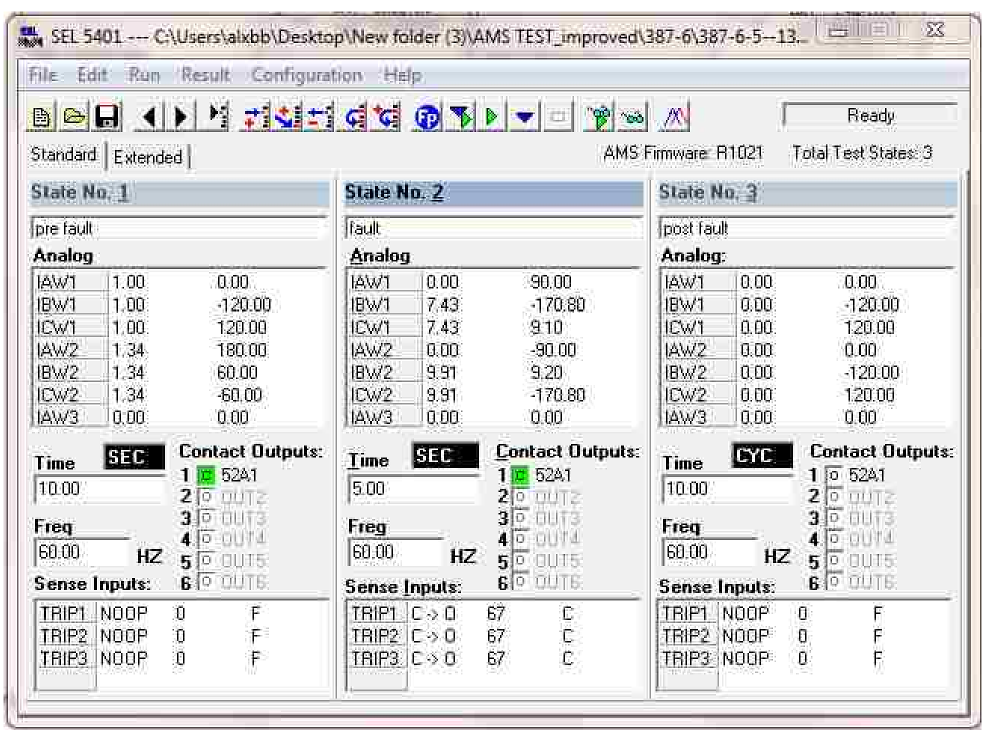


Figure 5.17. SEL AMS setting for phase to phase fault at location 4

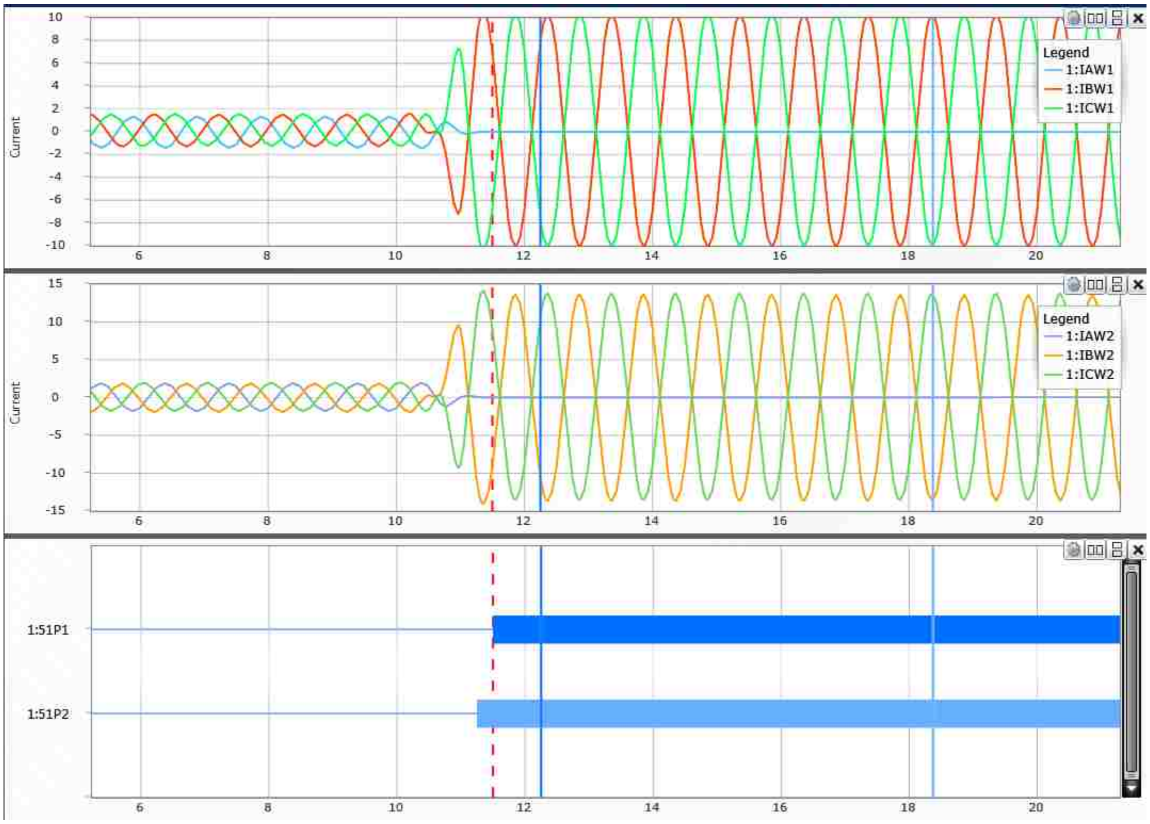


Figure 5.18. Event report showing pickup of overcurrent element for phase to phase fault at location 4

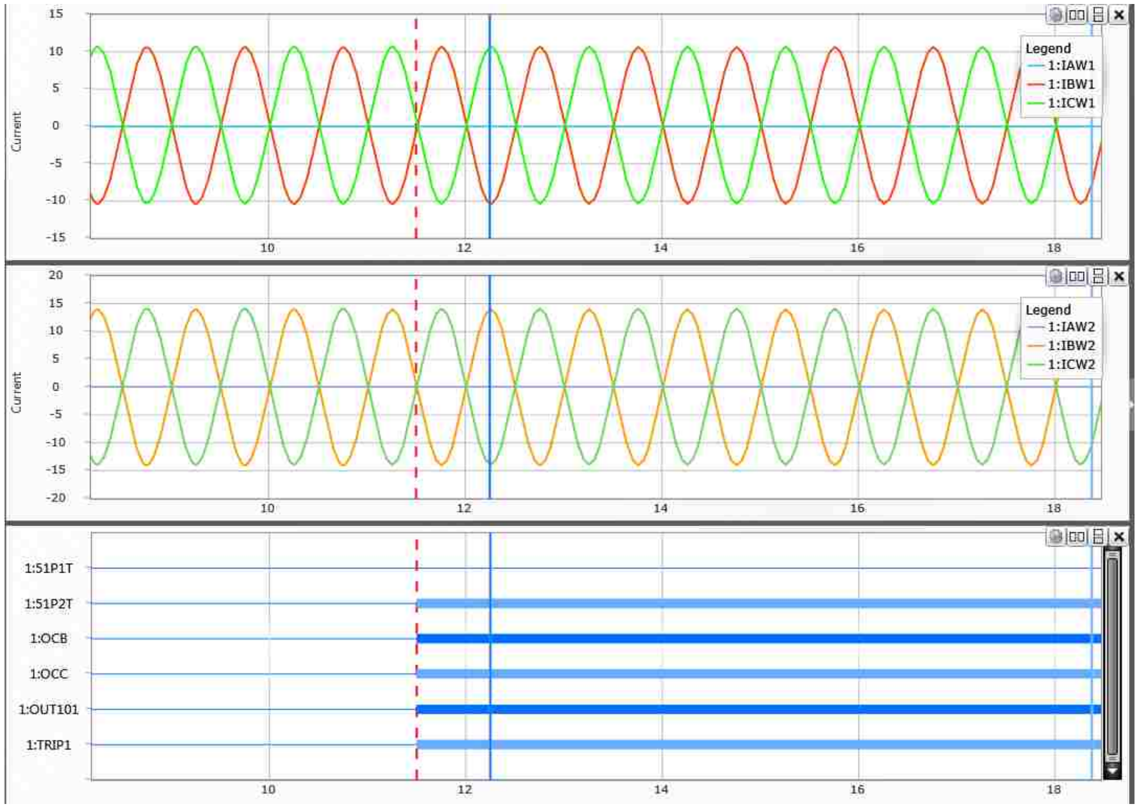


Figure 5.19. Event report showing tripping of overcurrent element for phase to phase fault at location 4

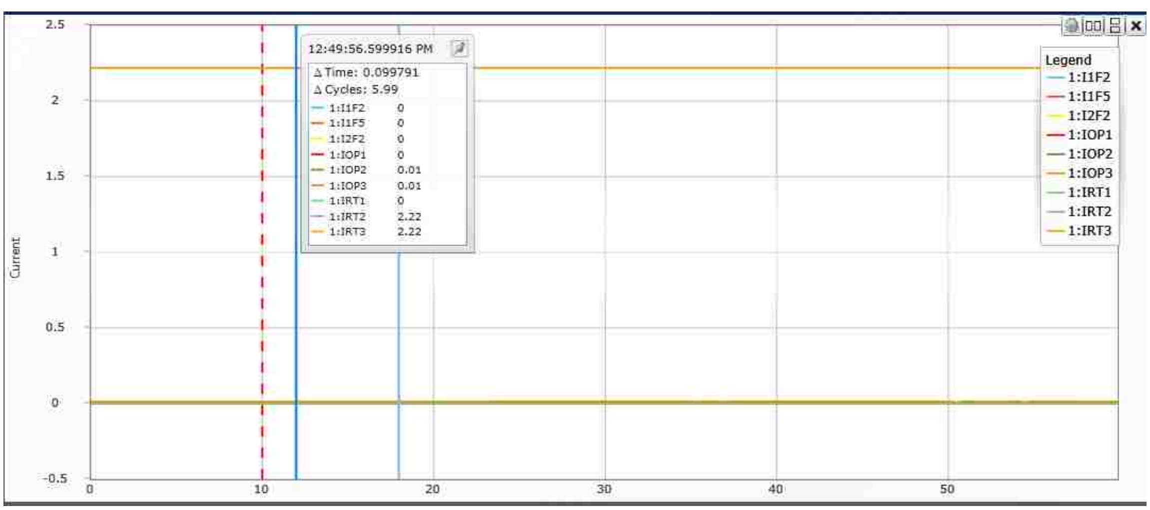


Figure 5.20. Differential event report for phase to phase fault at location 4

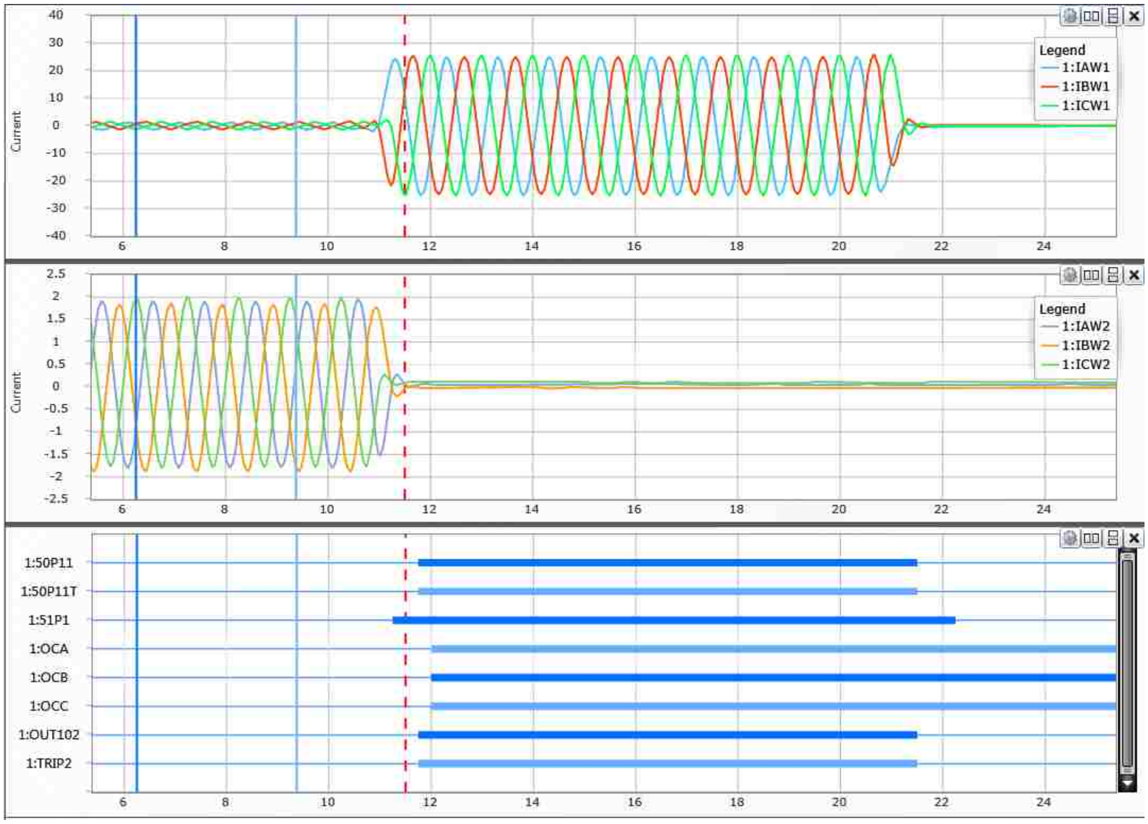


Figure 5.21. Event report showing tripping of overcurrent element for three phase fault at location 1

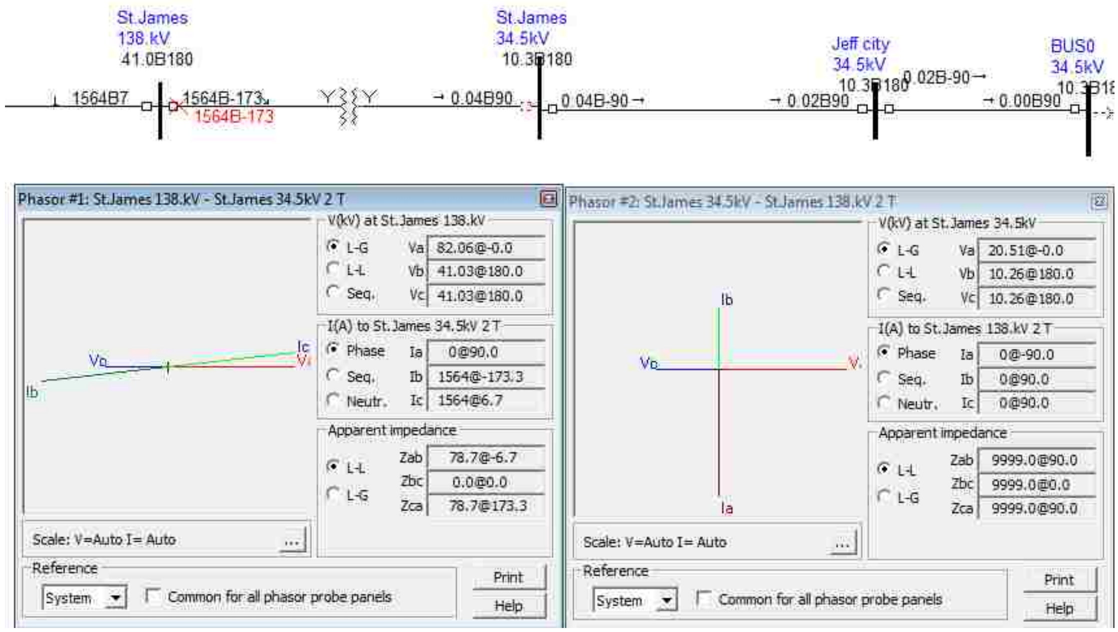


Figure 5.22. Fault currents obtained from ASPEN for phase to phase fault at location 1

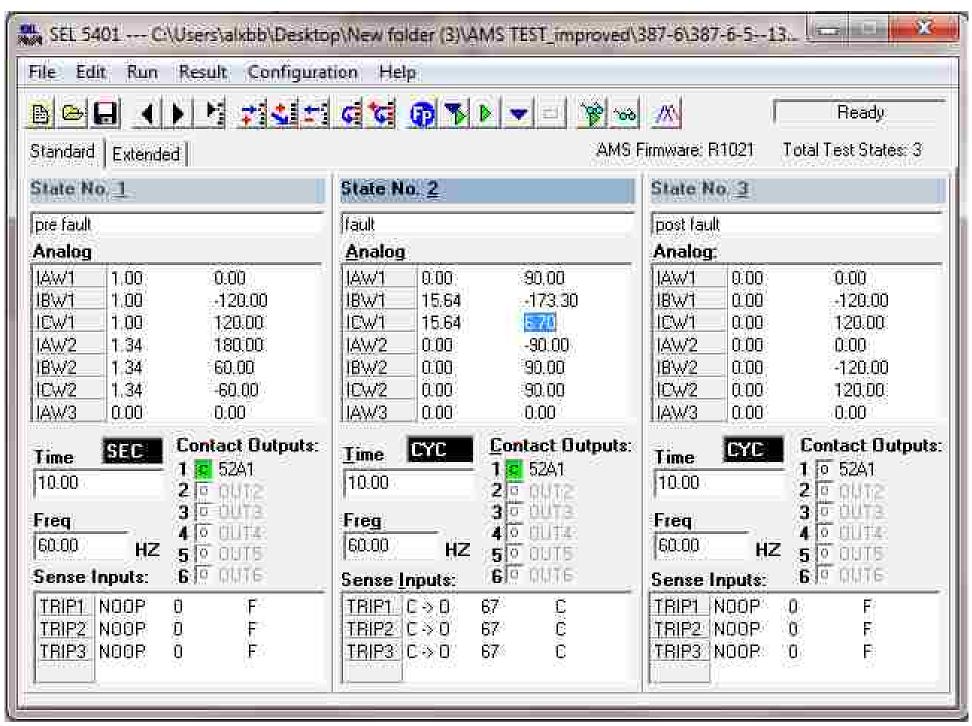


Figure 5.23. SEL AMS setting for phase to phase fault at location 1

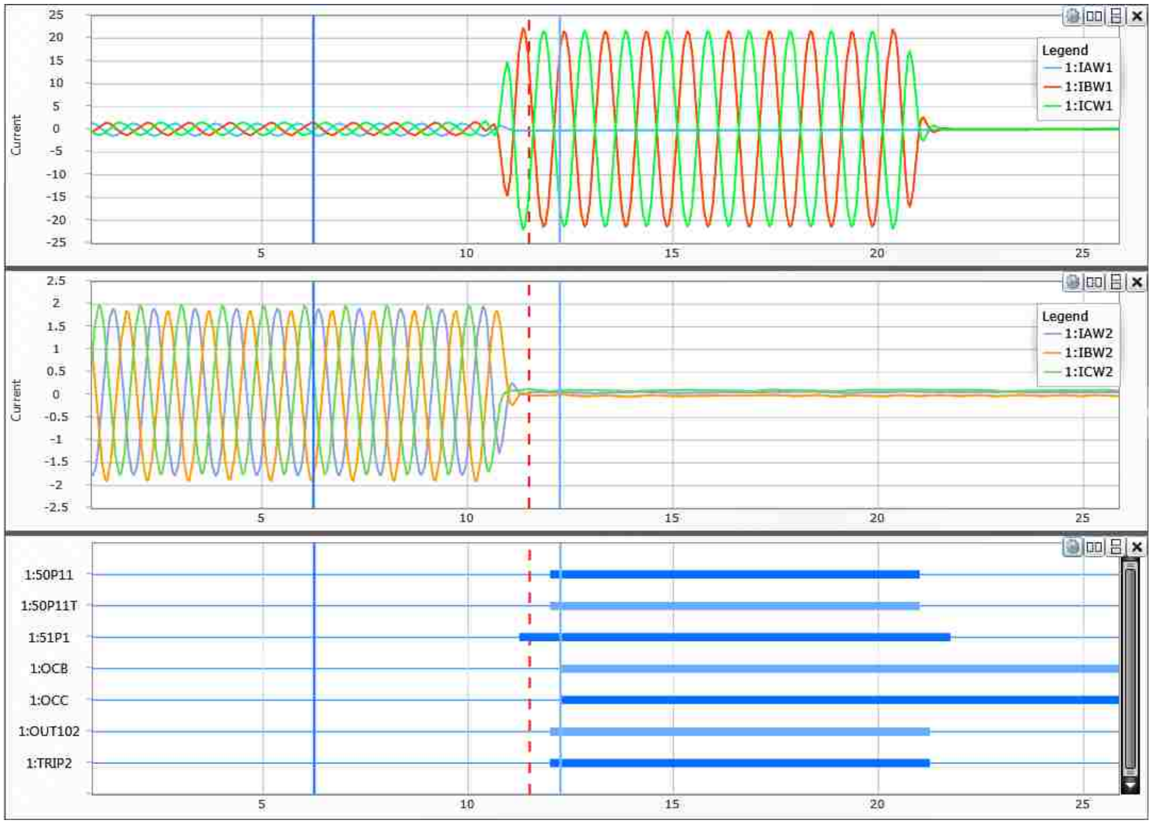


Figure 5.24. Event report showing tripping of overcurrent element for phase to phase fault at location 1

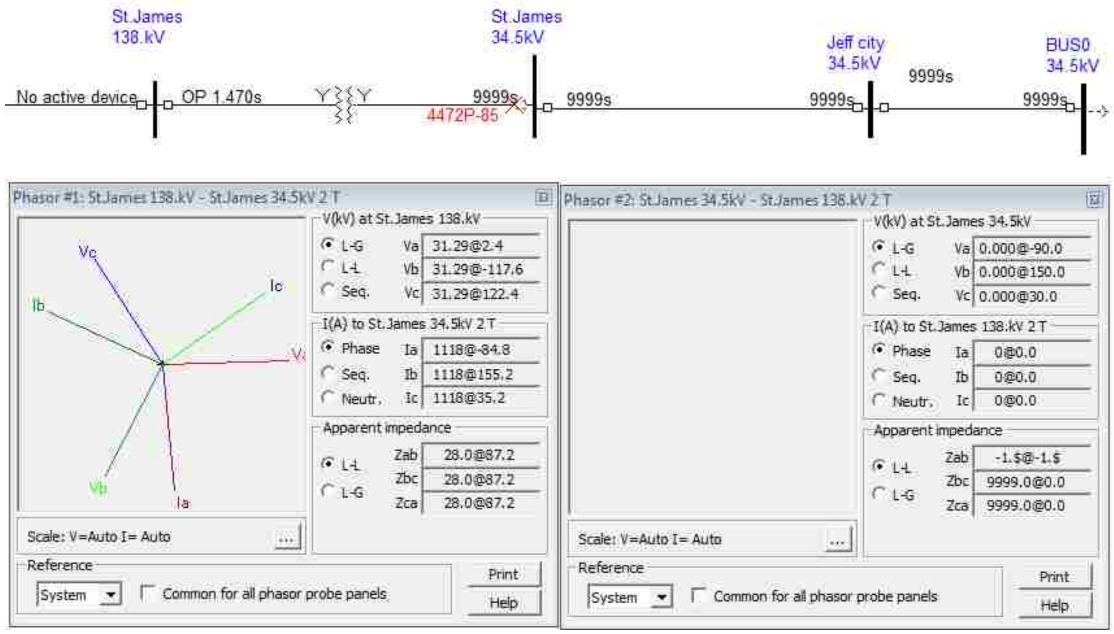


Figure 5.25. Fault currents obtained from ASPEN for three phase fault at location 2

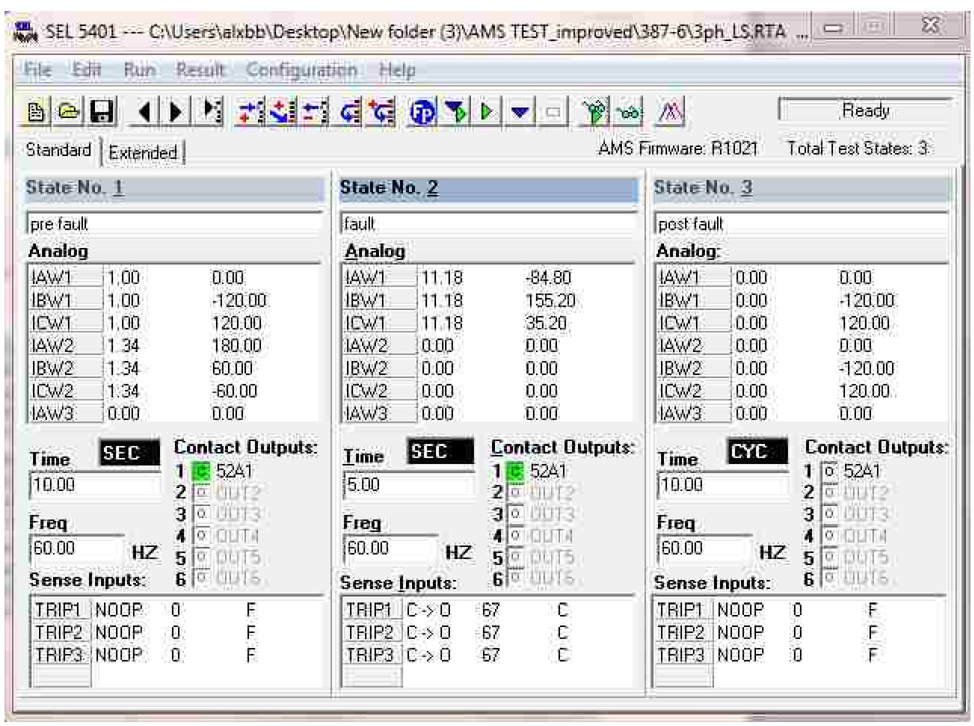


Figure 5.26. SEL AMS setting for three phase fault at location 2

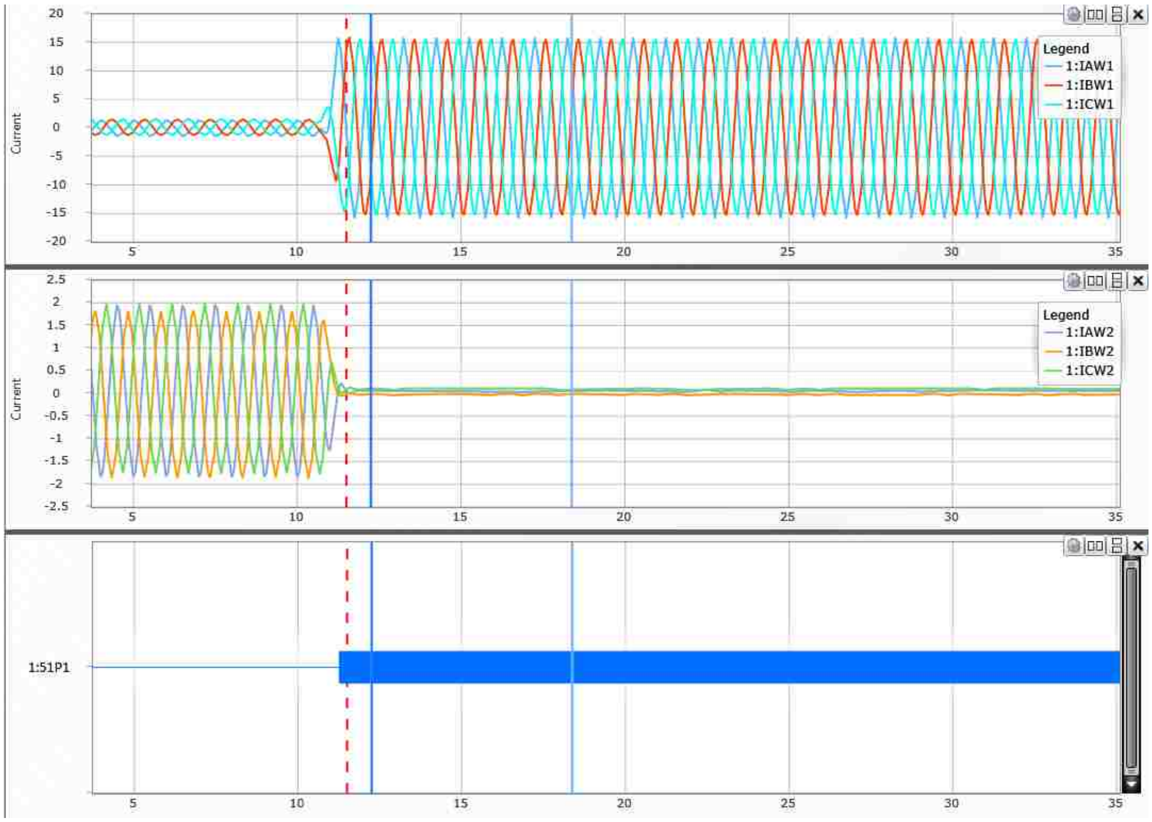


Figure 5.27. Event report showing pickup of overcurrent element for three phase fault at location 2

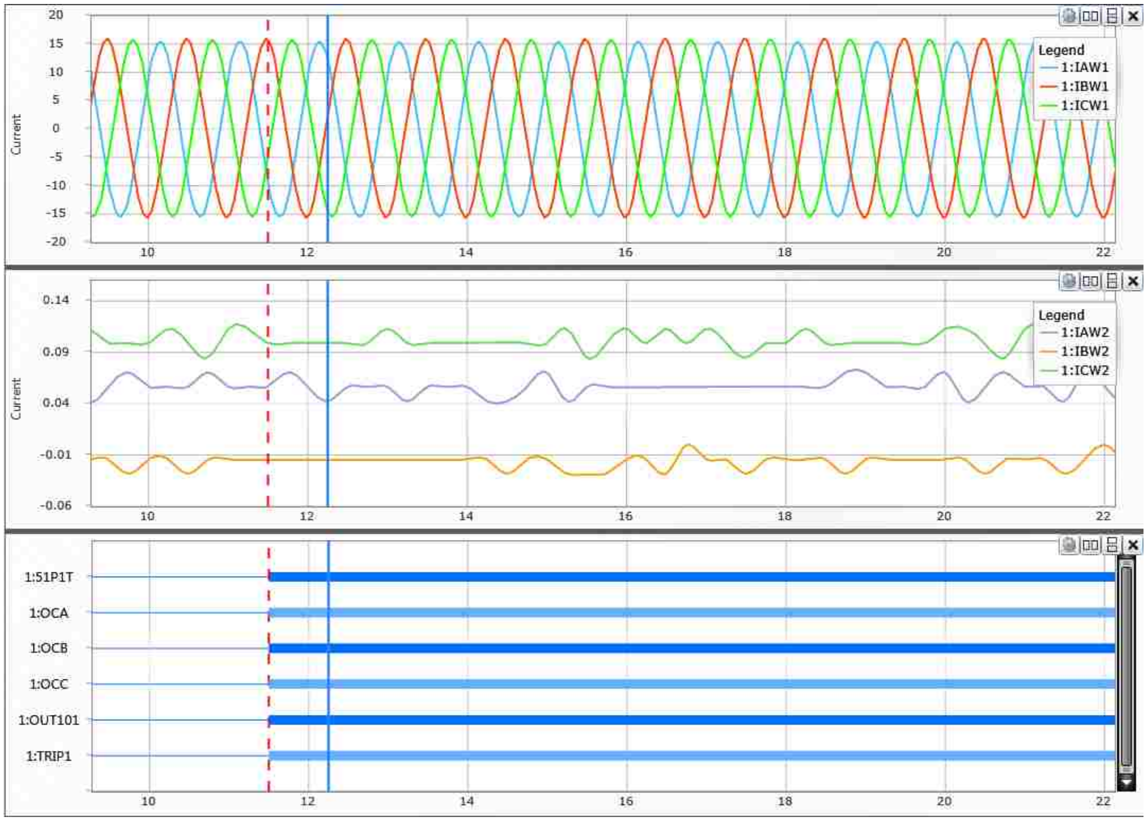


Figure 5.28. Event report showing tripping of overcurrent element for three phase fault at location 2

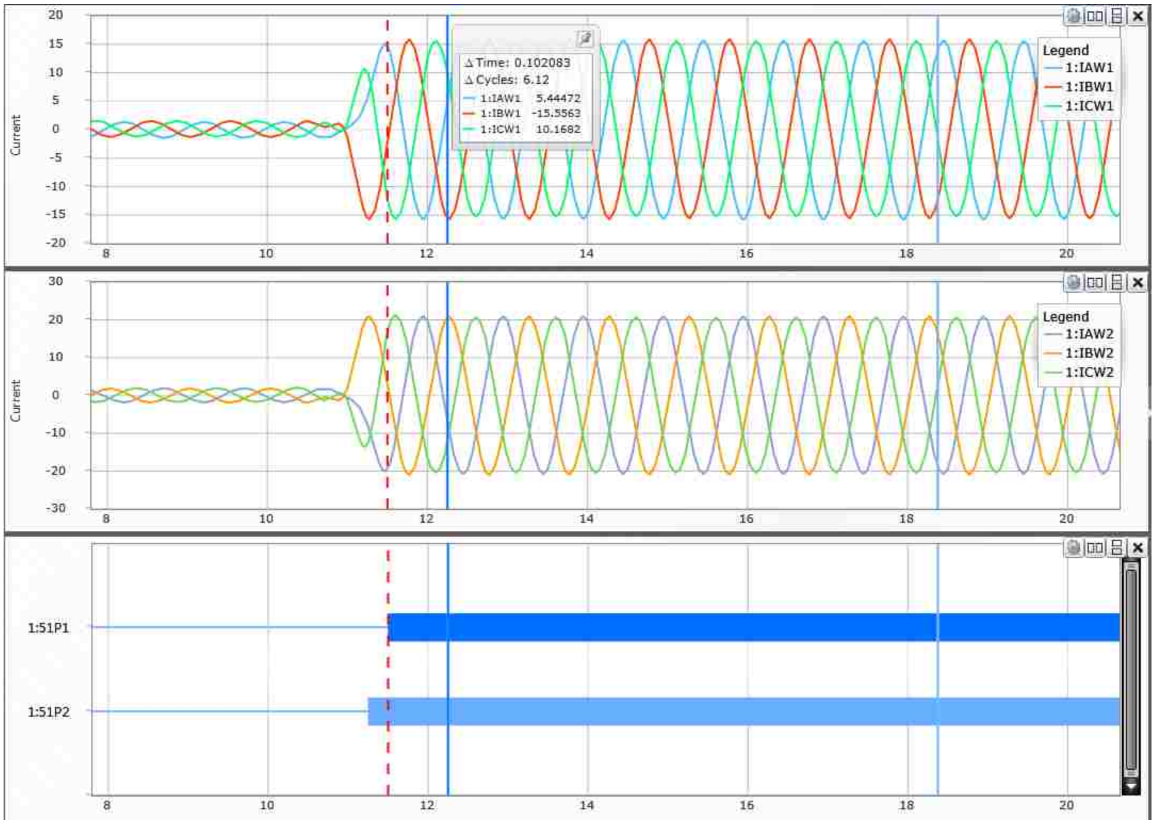


Figure 5.29. Event report showing pickup of overcurrent element for three phase fault at location 3

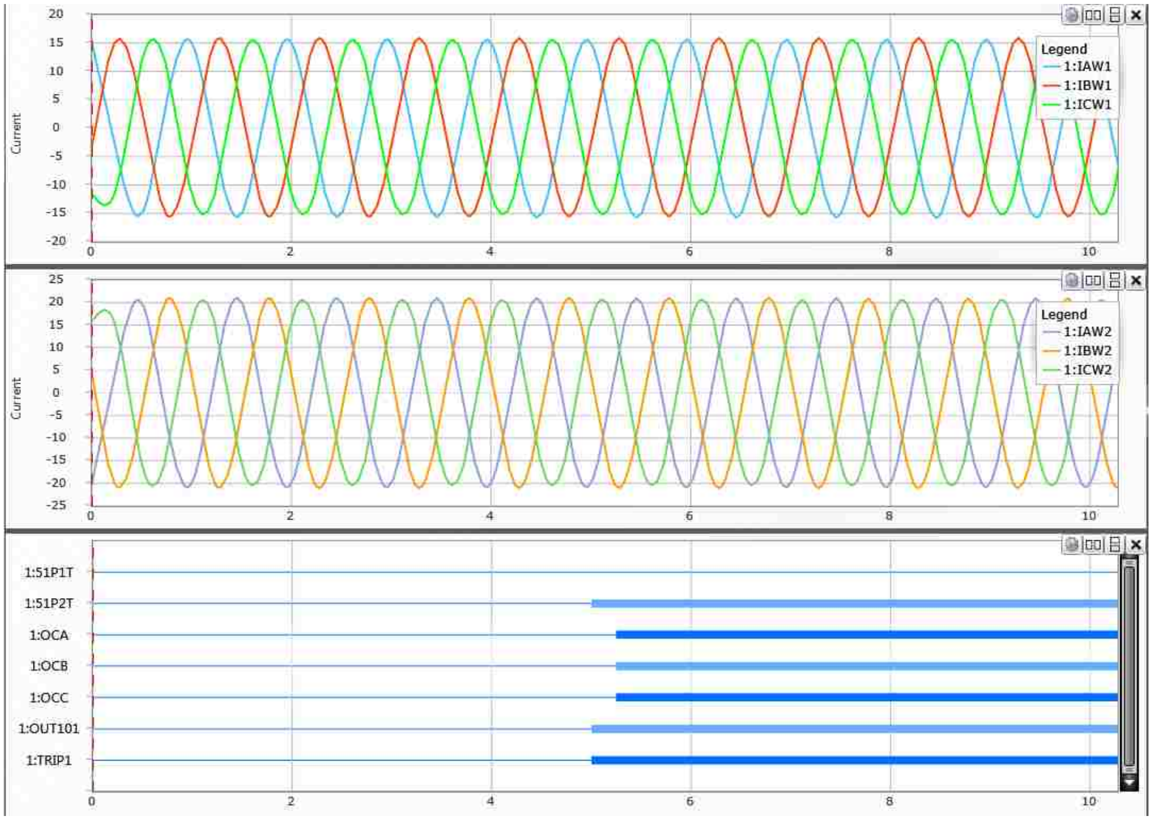


Figure 5.30. Event report showing tripping of overcurrent element for three phase fault at location 3

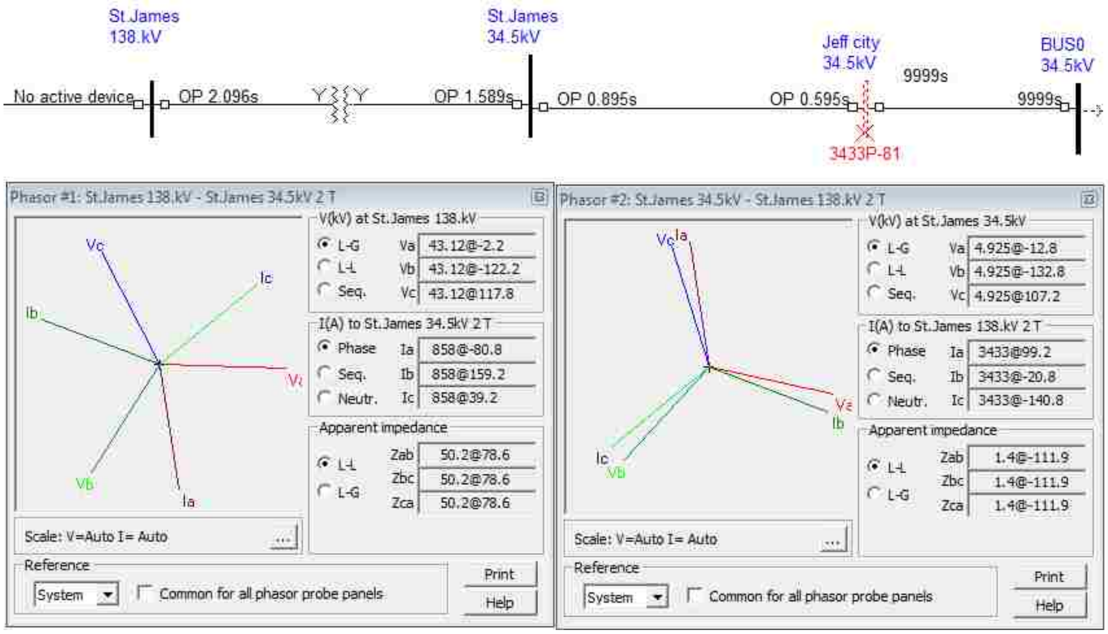


Figure 5.31. Fault currents obtained from ASPEN for three phase fault at location 4

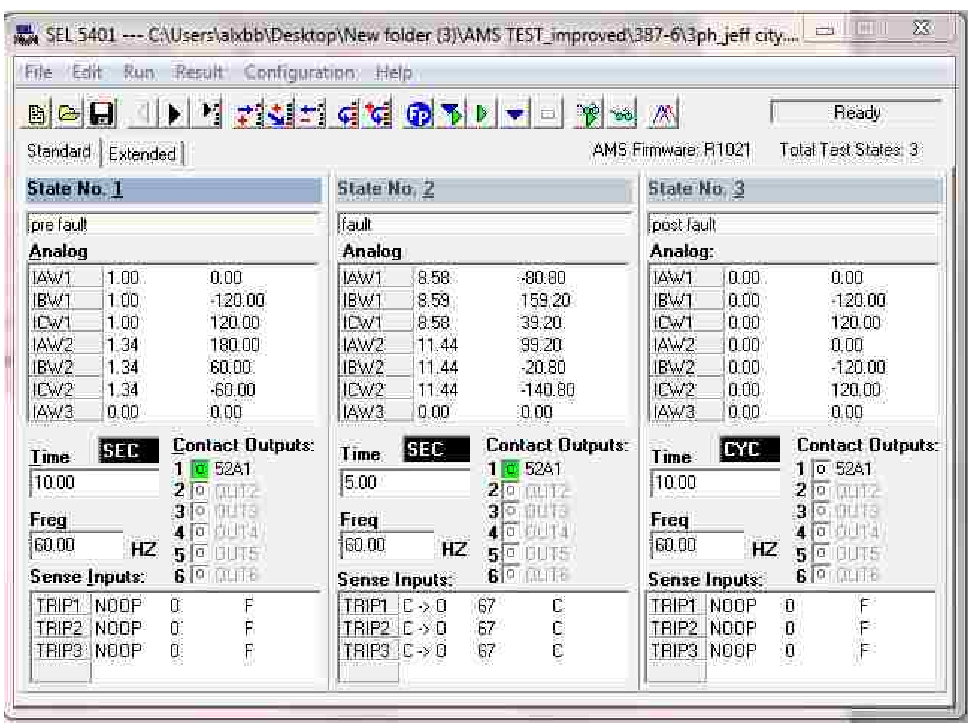


Figure 5.32. SEL AMS setting for three phase fault at location 4

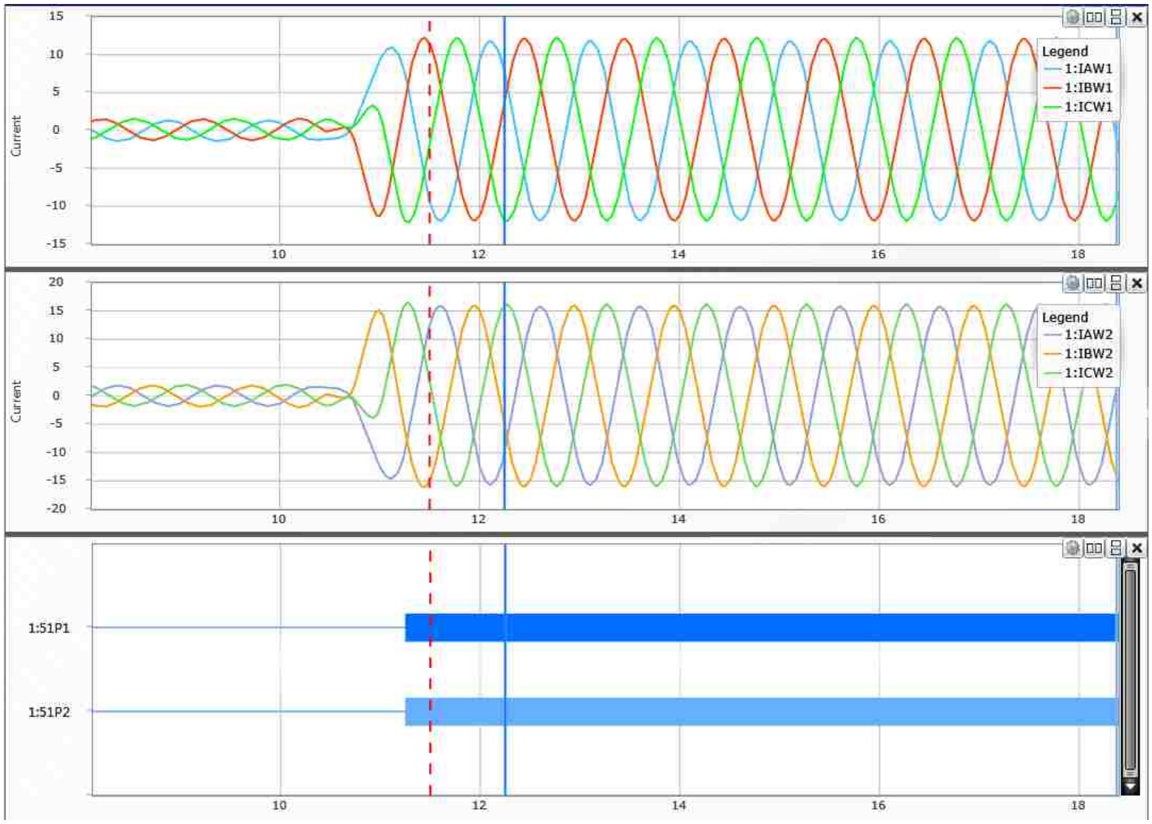


Figure 5.33. Event report showing pickup of overcurrent element for three phase fault at location 4

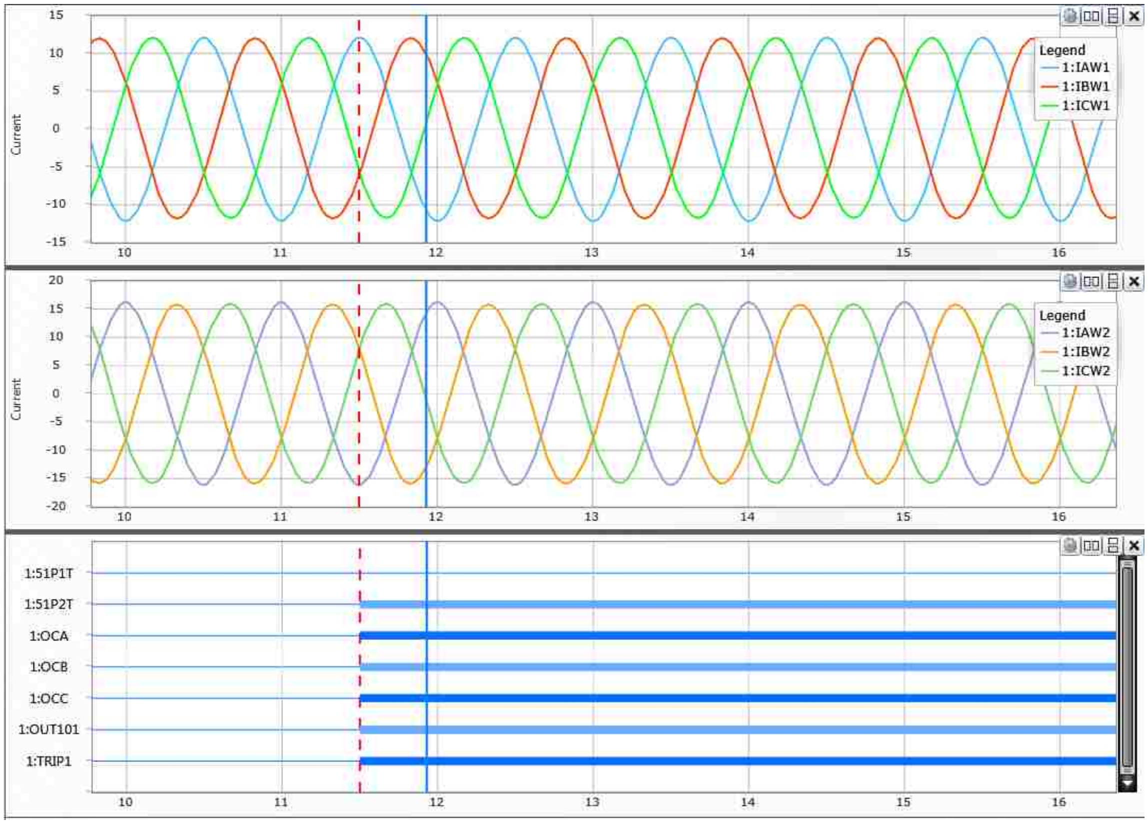


Figure 5.34. Event report showing tripping of overcurrent element for three phase fault at location 4

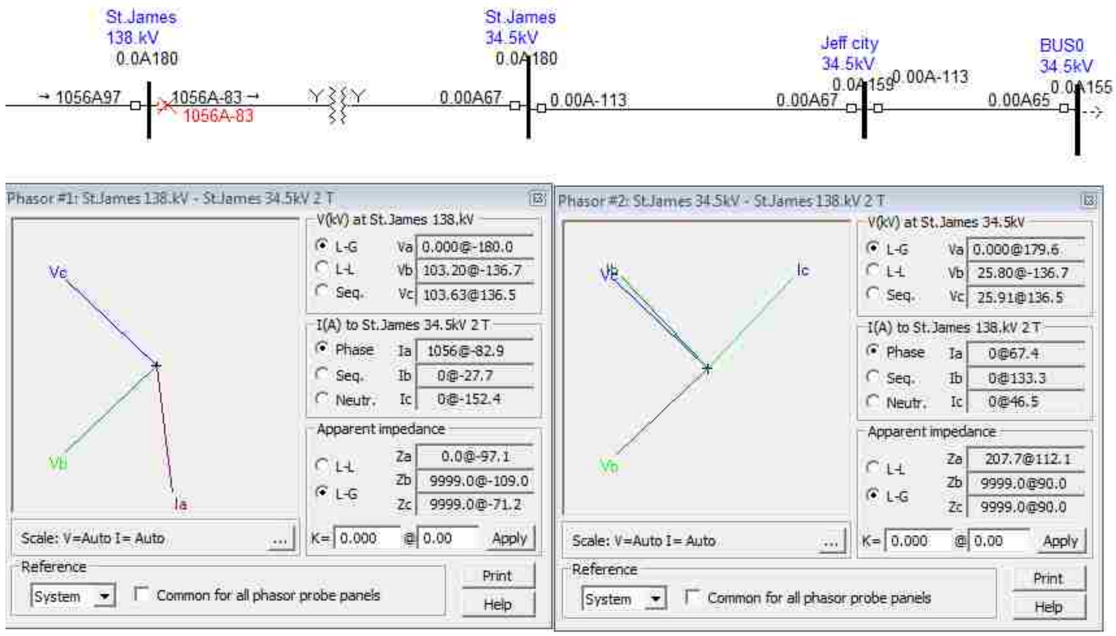


Figure 5.35. Fault currents obtained from ASPEN for single line to ground fault at location 1

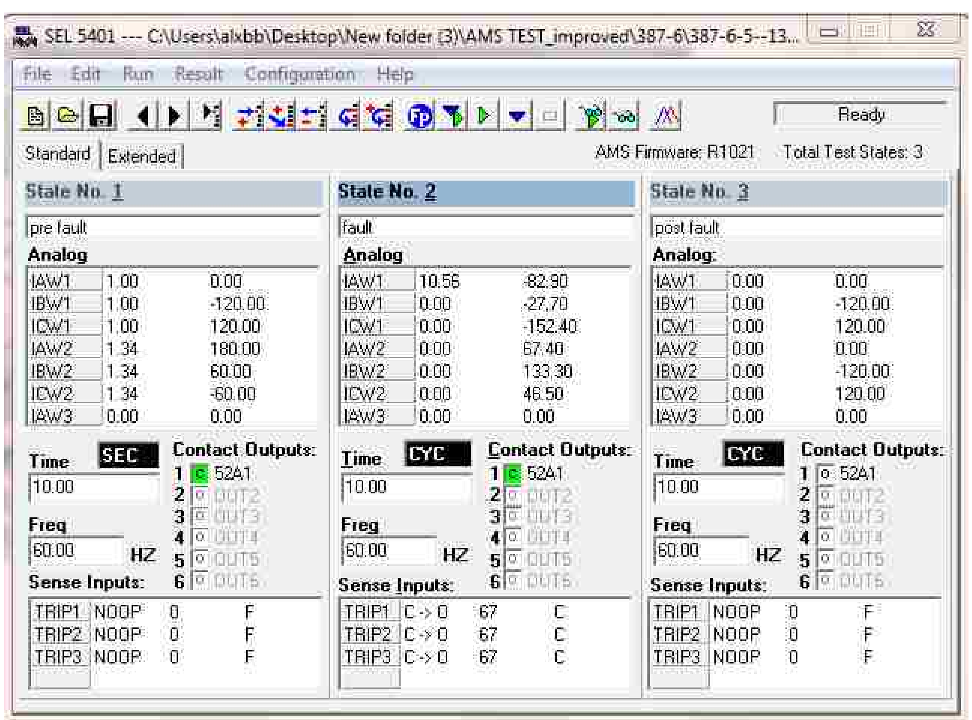


Figure 5.36. SEL AMS setting for single line to ground fault at location 1

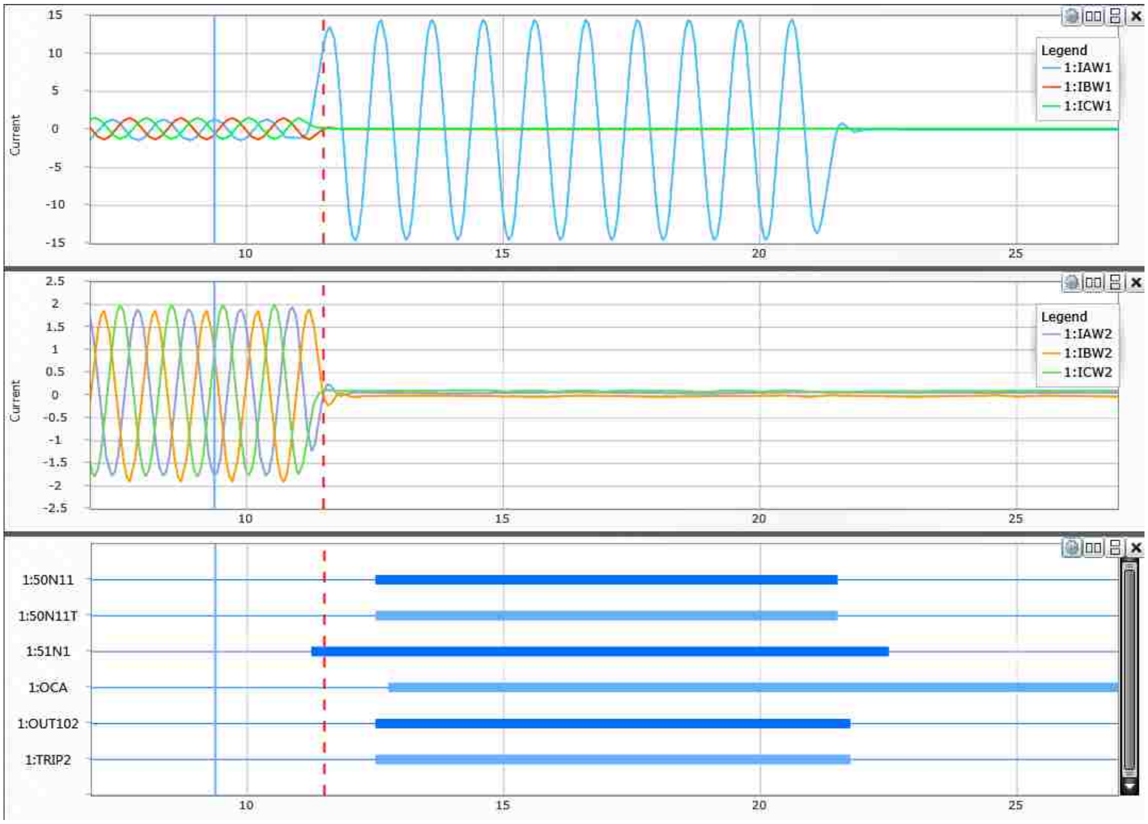


Figure 5.37. Event report showing tripping of ground overcurrent element for single line to ground fault at location 1

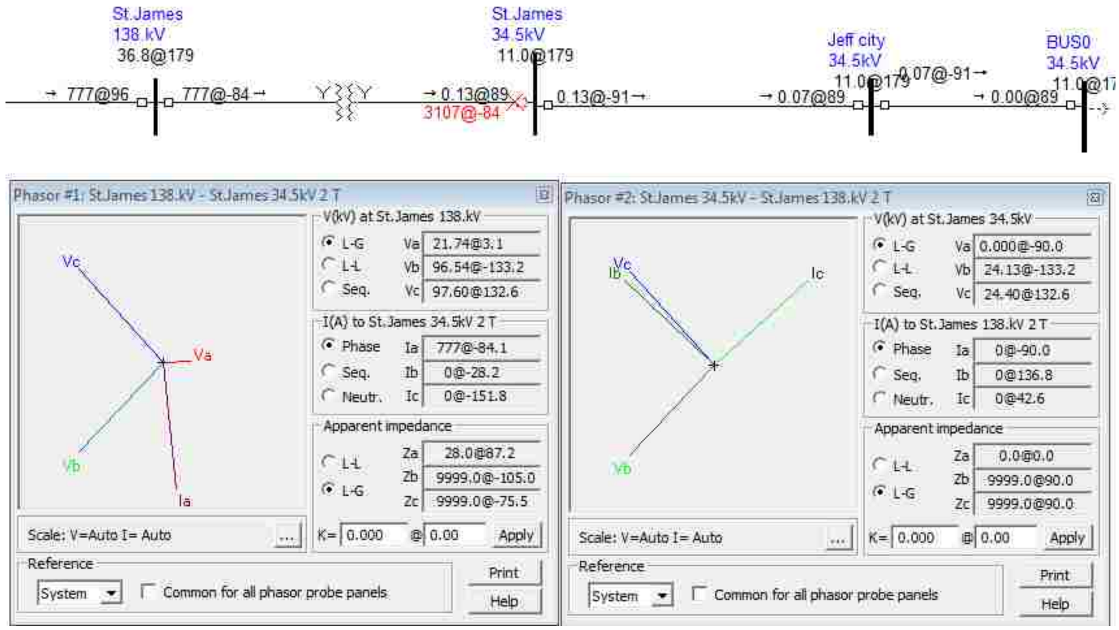


Figure 5.38. Fault currents obtained from ASPEN for single line to ground fault at location 2

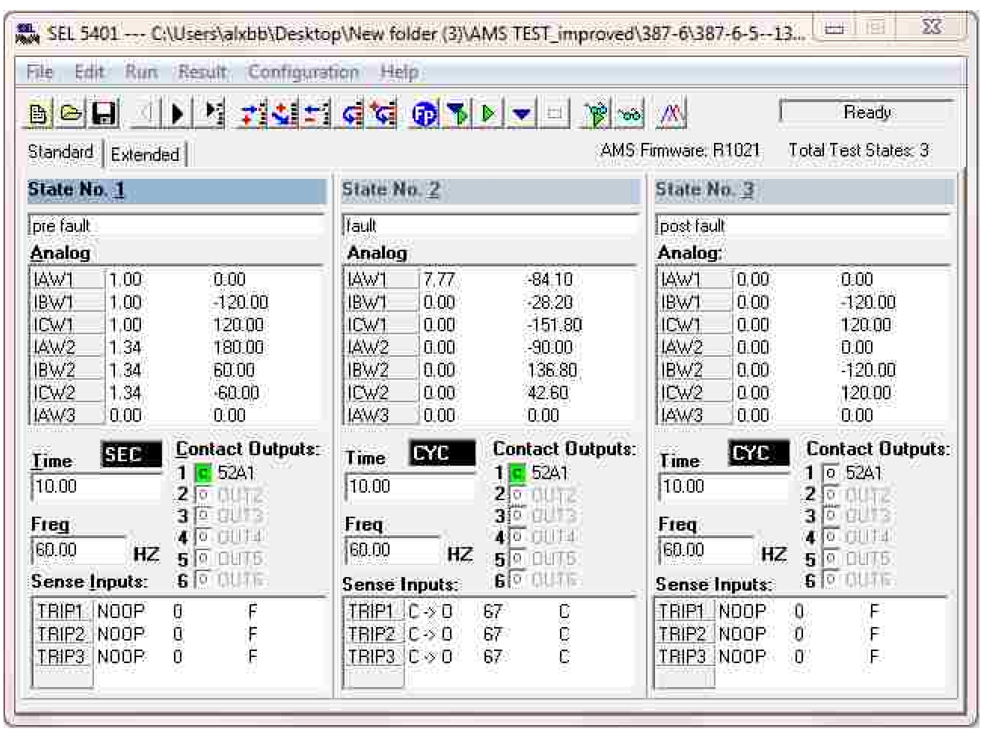


Figure 5.39. SEL AMS setting for single line to ground fault at location 2

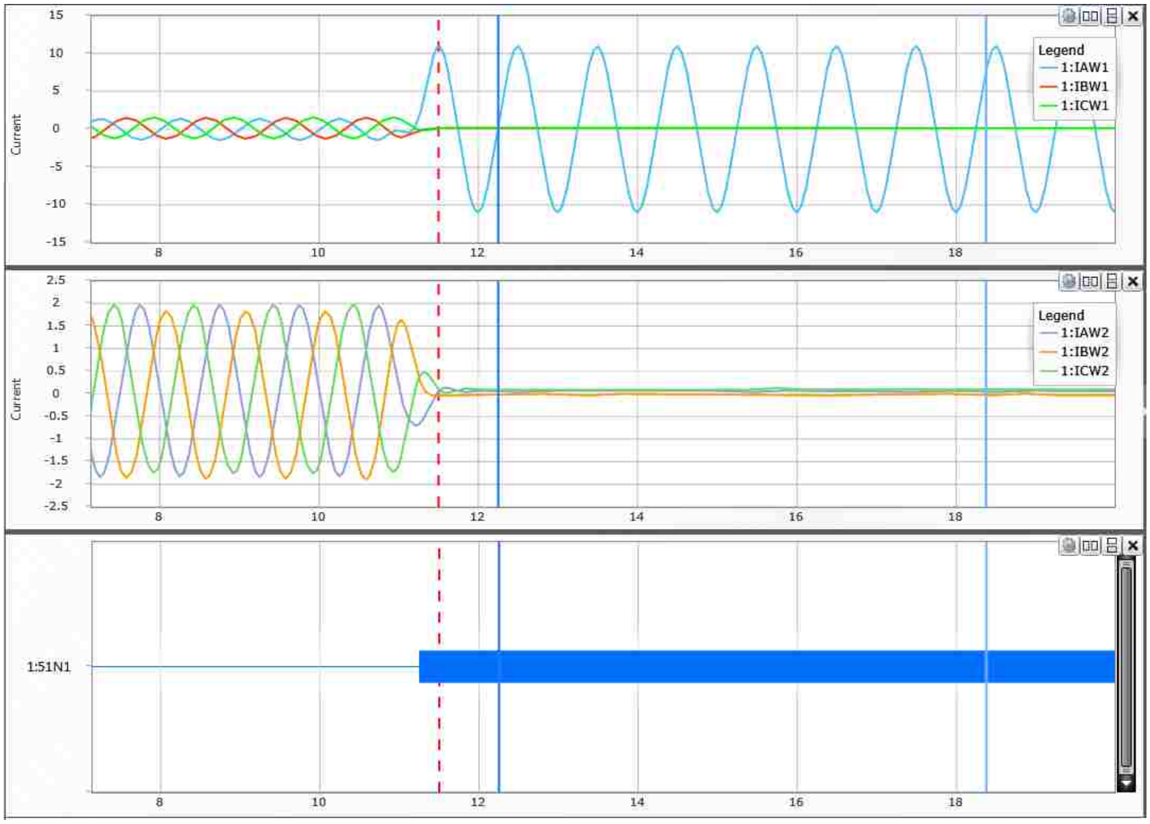


Figure 5.40. Event report showing pickup of ground overcurrent element for single line to ground fault at location 2

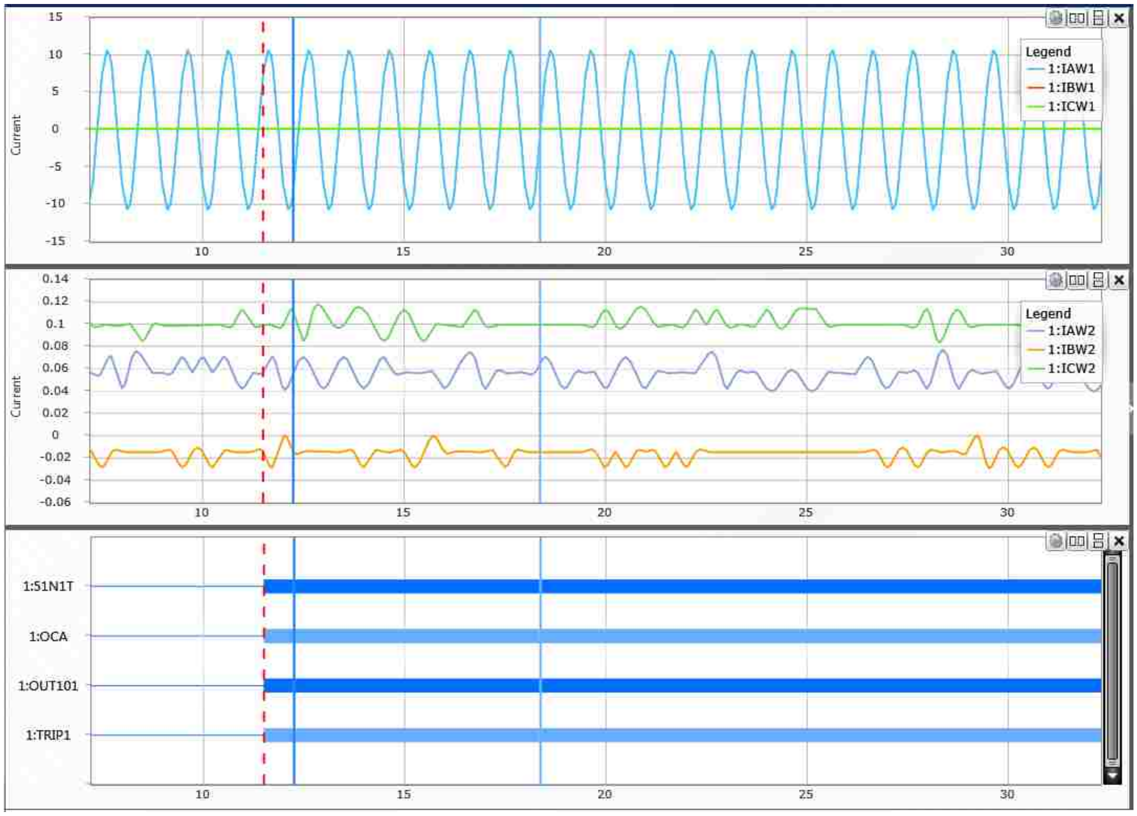


Figure 5.41. Event report showing tripping of ground overcurrent element for single line to ground fault at location 2

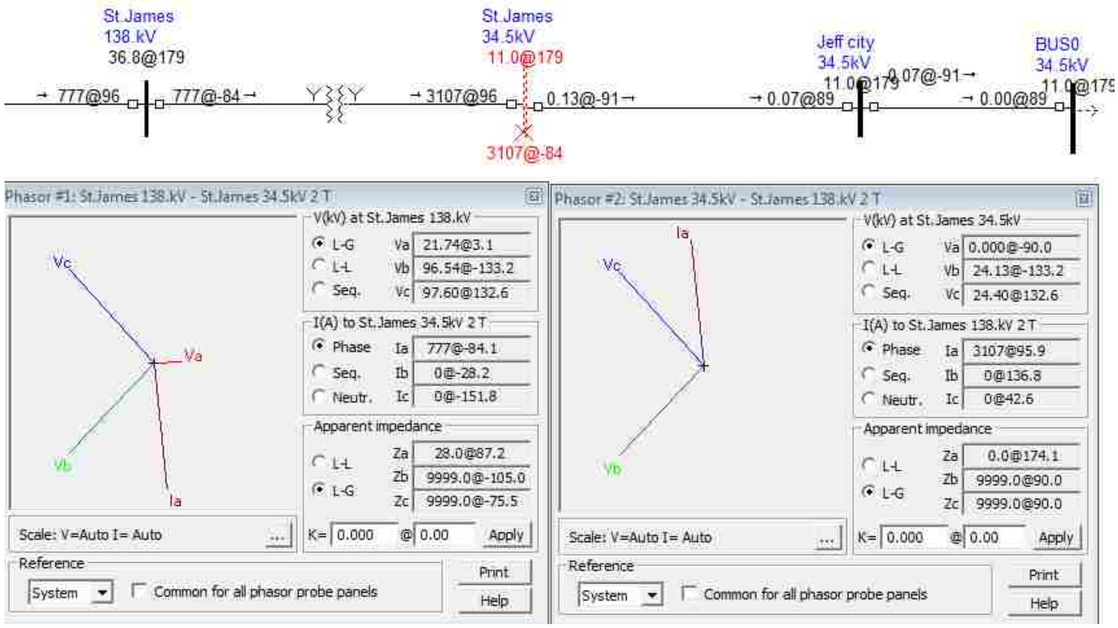


Figure 5.42. Fault currents obtained from ASPEN for single line to ground fault at location 3

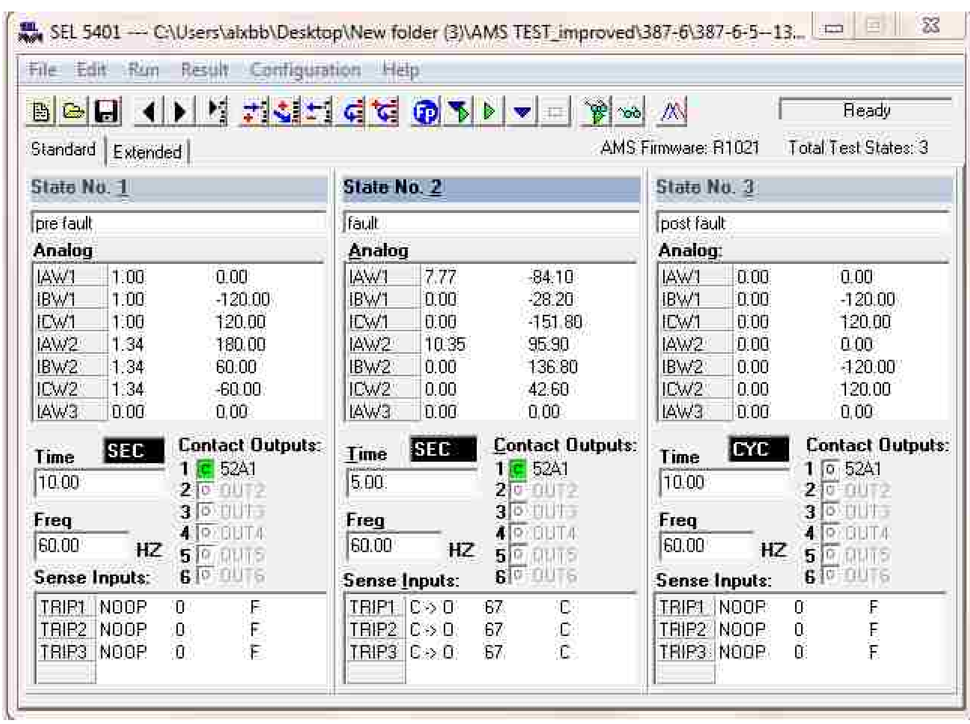


Figure 5.43. SEL AMS setting for single line to ground fault at location 3

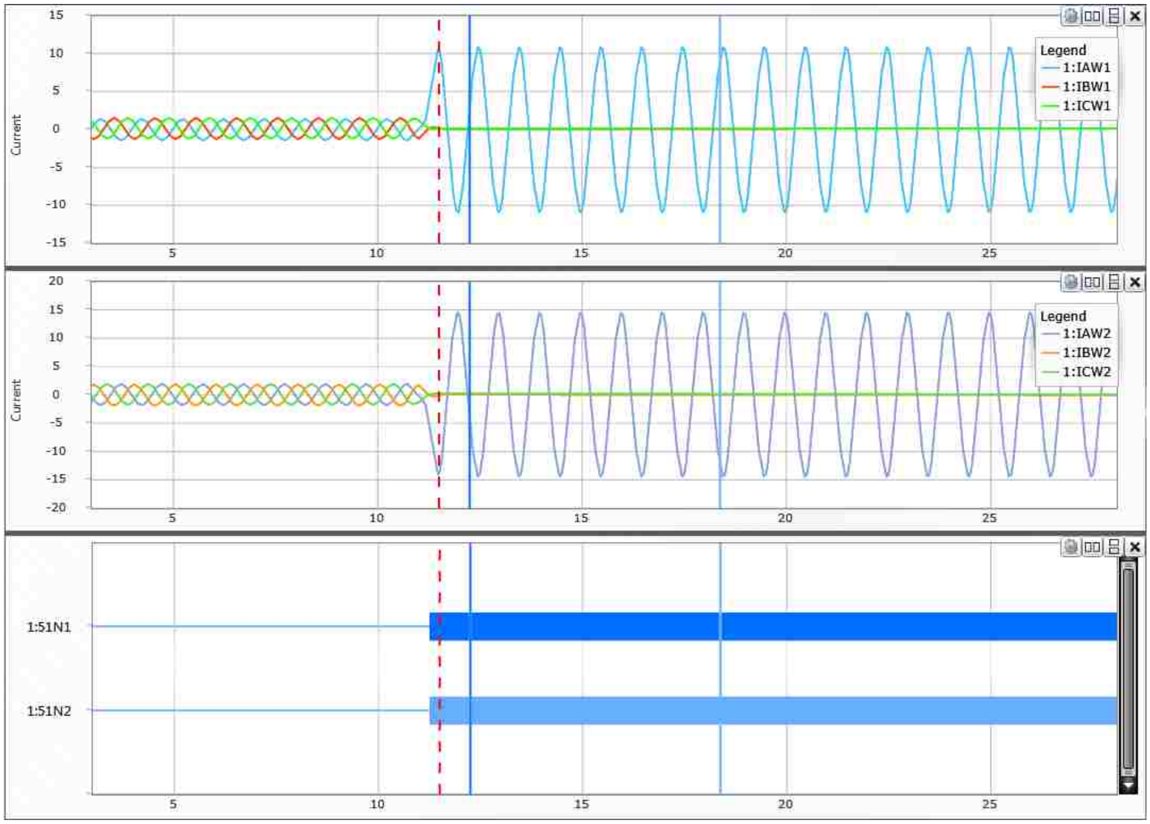


Figure 5.44. Event report showing pickup of ground overcurrent element for single line to ground fault at location 3

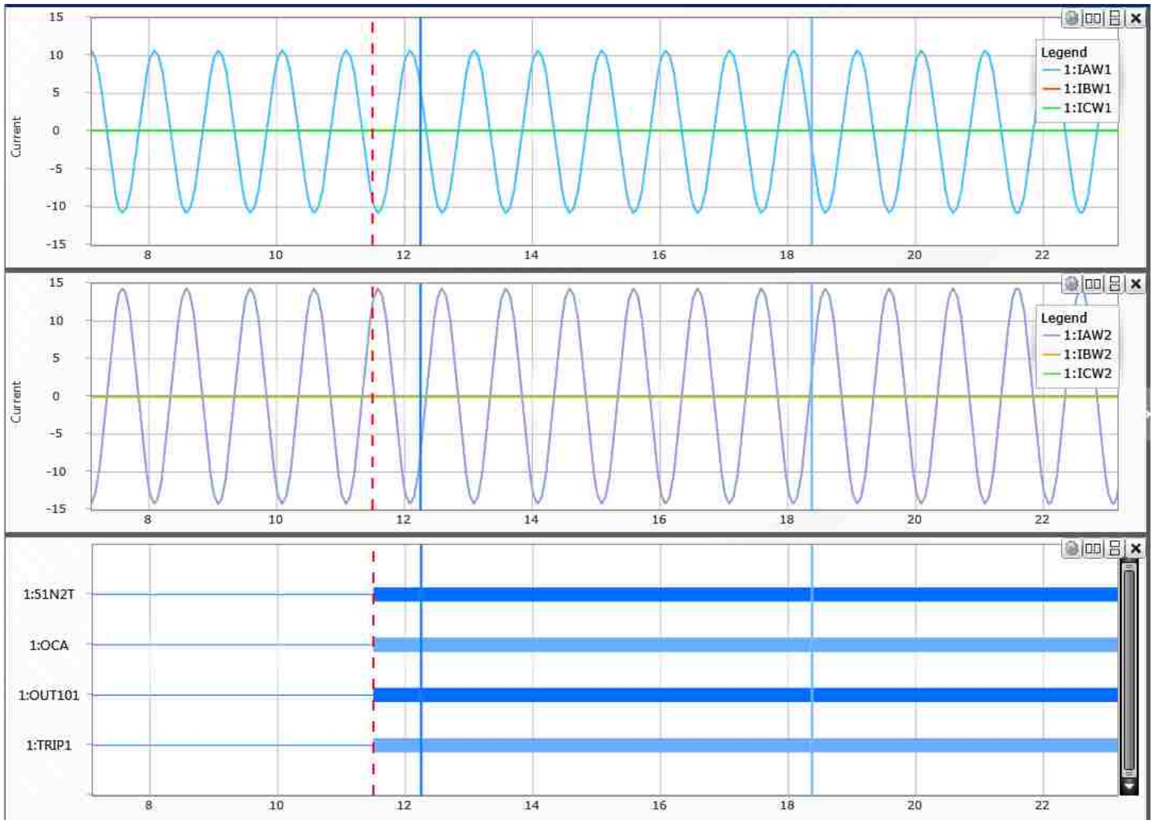


Figure 5.45. Event report showing tripping of ground overcurrent element for single line to ground fault at location 3

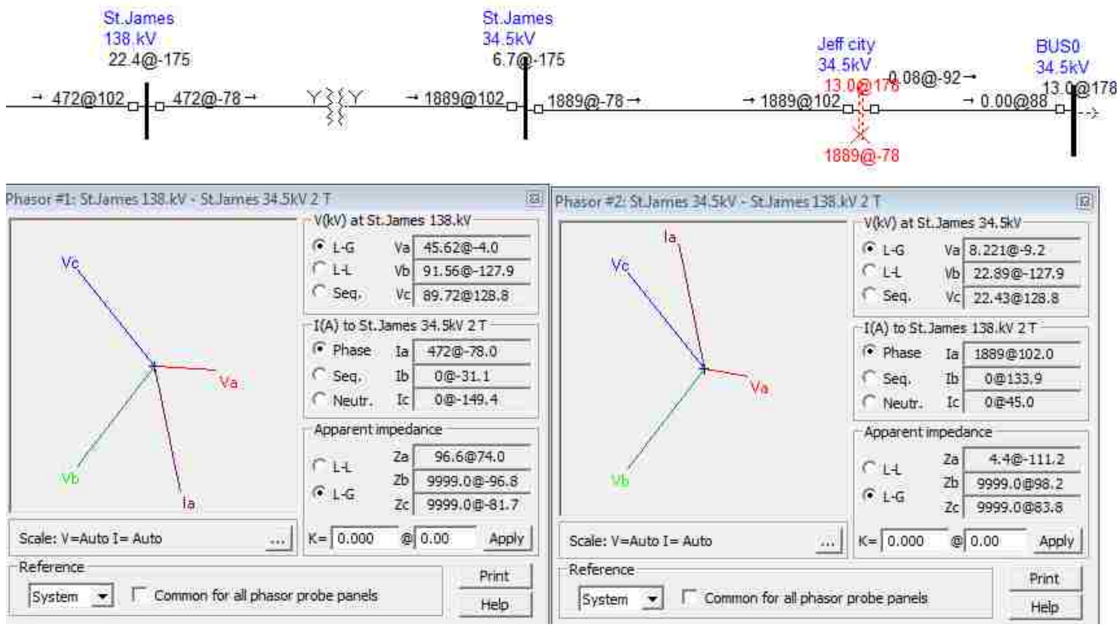


Figure 5.46. Fault currents obtained from ASPEN for single line to ground fault at location 4

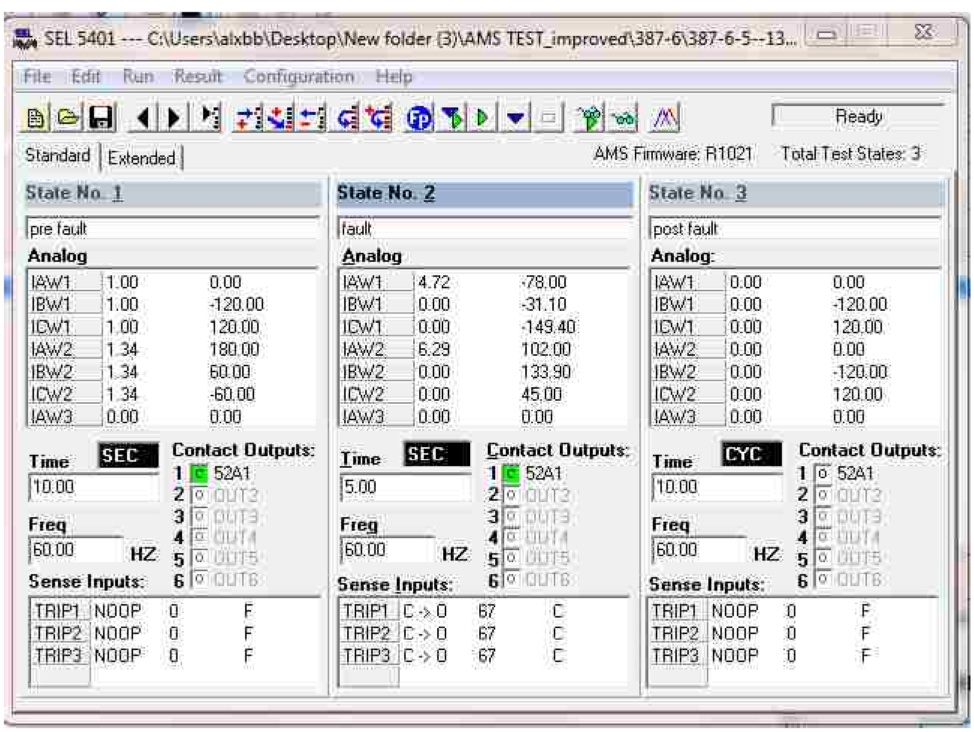


Figure 5.47. SEL AMS setting for single line to ground fault at location 4

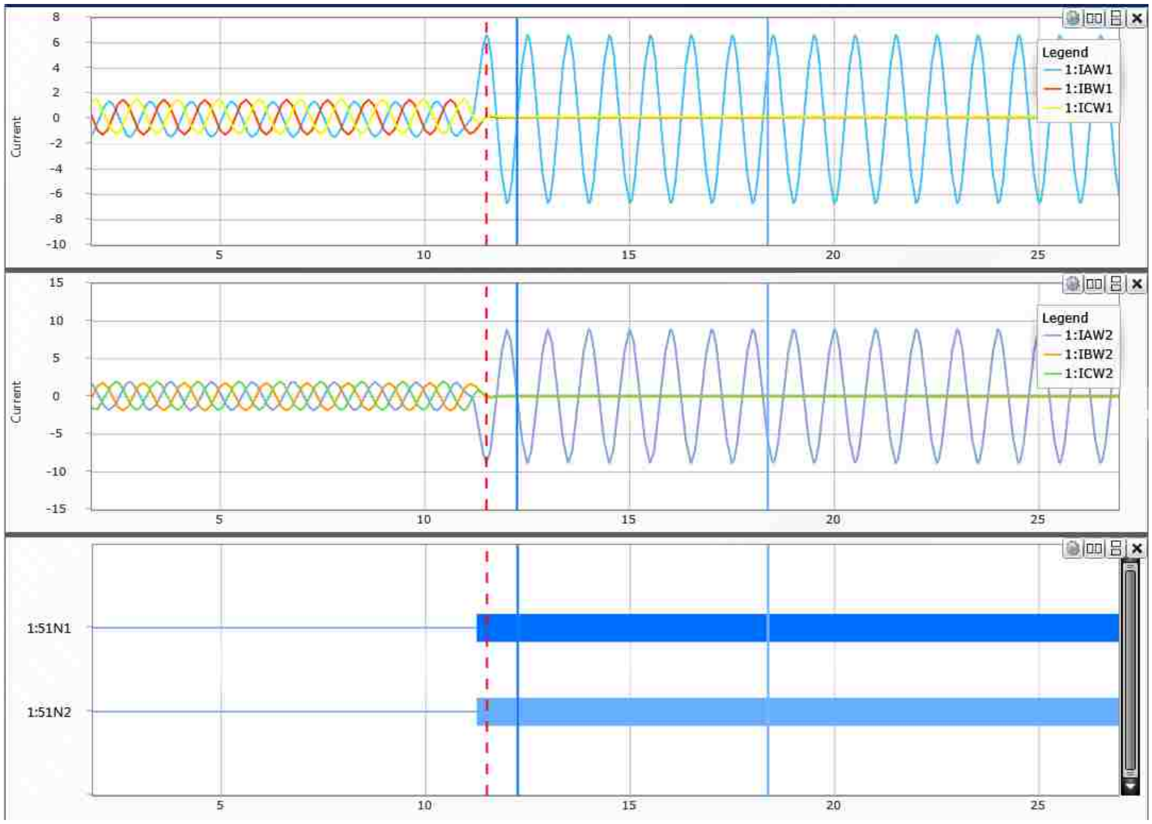


Figure 5.48. Event report showing pickup of ground overcurrent element for single line to ground fault at location 4

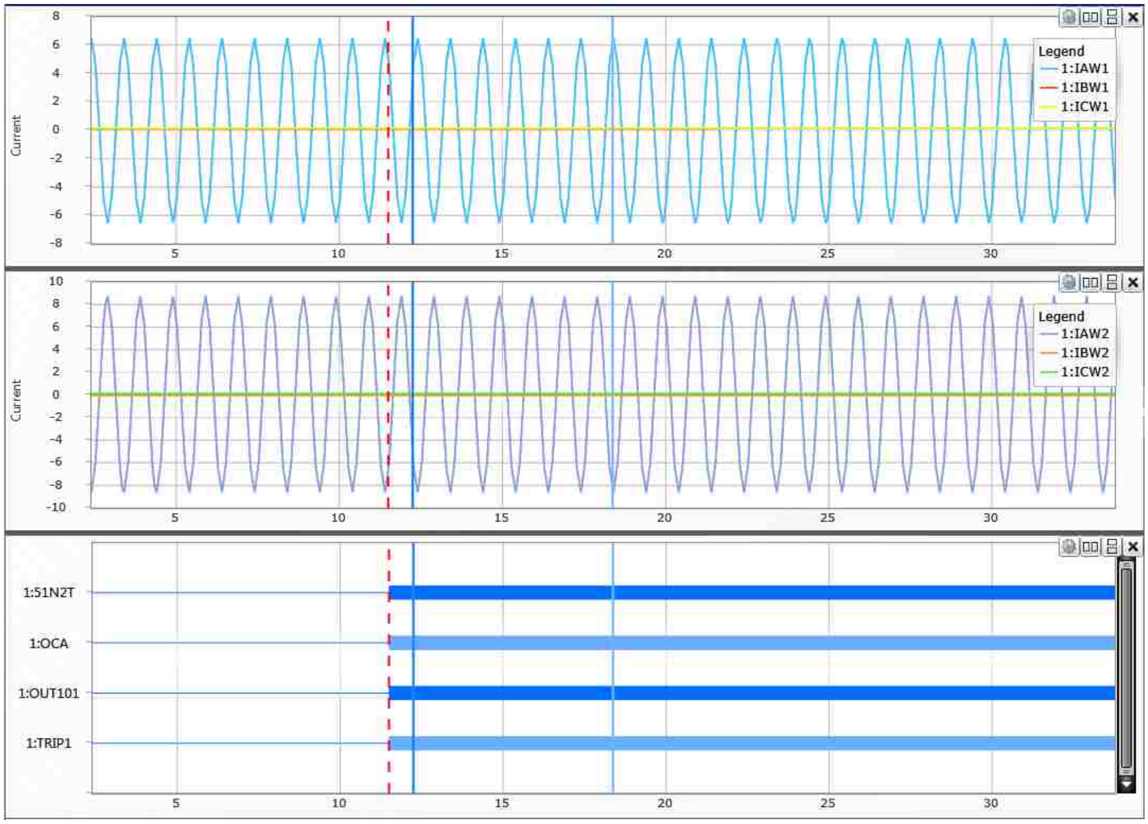


Figure 5.49. Event report showing tripping of ground overcurrent element for single line to ground fault at location 4

APPENDIX A- GETTING STARTED WITH ACSELERATOR QUICKSET

- Connect SEL C662 cable between the relay SERIAL PORT 3 and computer.
- Select SEL 5030 from the start menu.

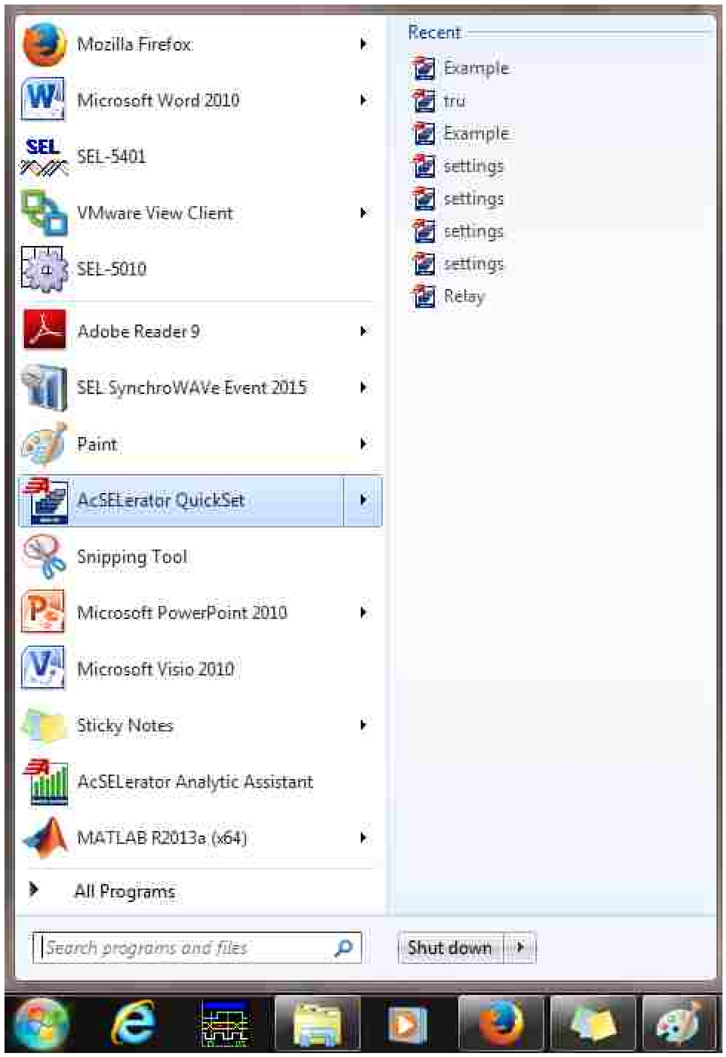


Figure A.1. Selecting AcSELerator Quickset from start

- Establish communication by selecting **communication** from home page.

Figure A.2. AcSELerator Quickset home page

- Select the parameters as shown in Figure A.3 for the SEL 387-6 relay. The password fields can be left empty. Communication will be established within few seconds.

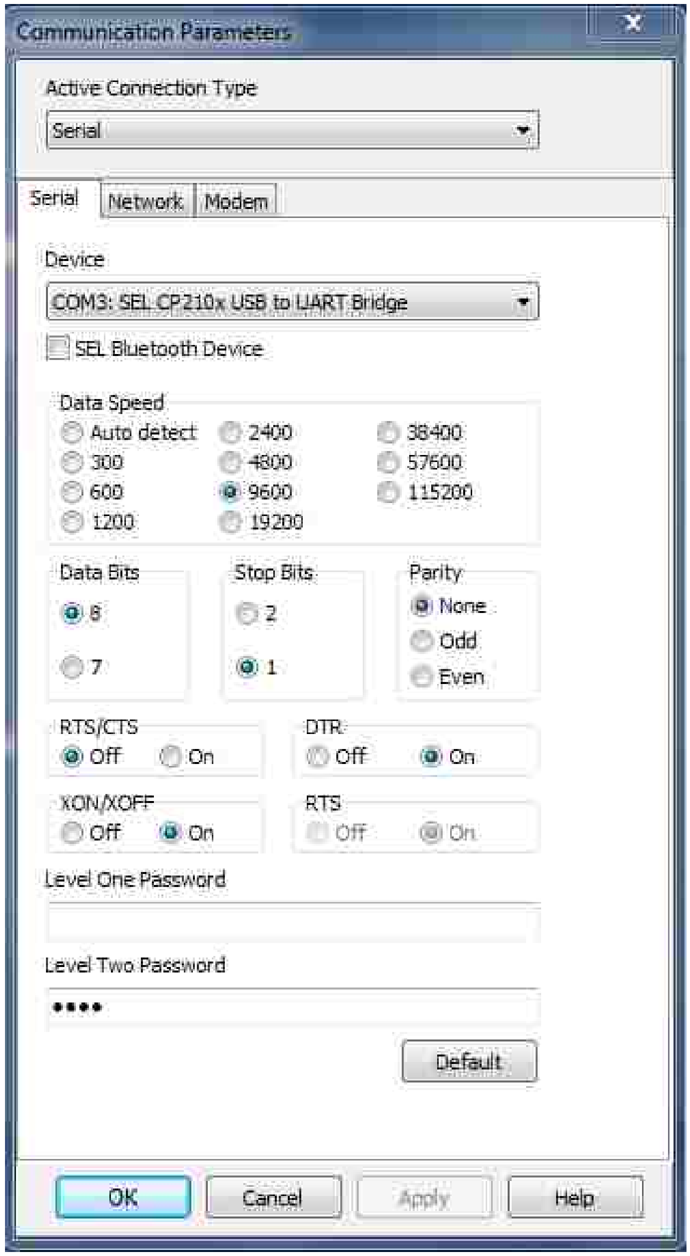


Figure A.3. Communication Parameters

- Click on terminal icon on the menu bar or type ctrl+T to open the work space used to program the relay.

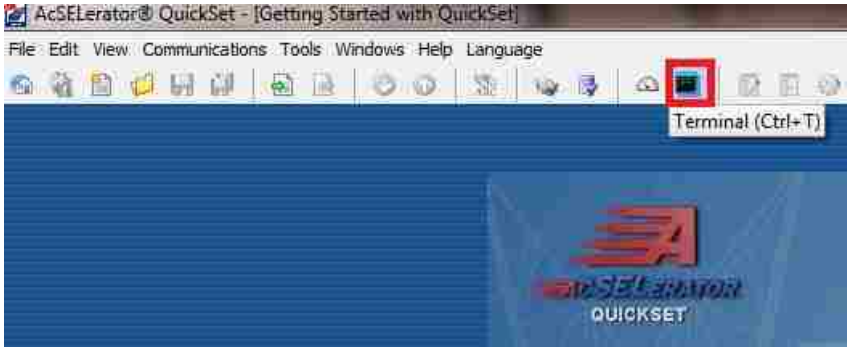


Figure A.4. ‘Terminal’ option highlighted on the menubar

- A terminal window gets opened. Use the password ‘power’ for level 1. All the relay commands need to access level 2. To go to access level 2 type ‘2acc<enter>’. The password is ‘power’.

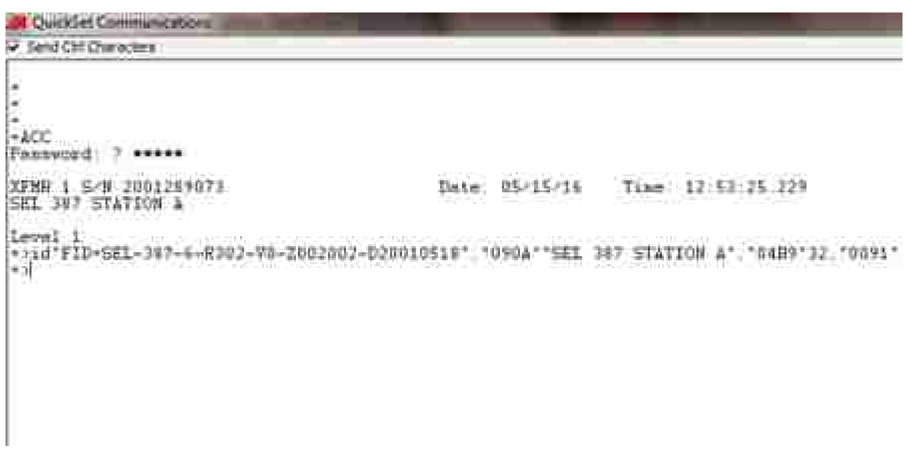


Figure A.5. Terminal window

- Type ‘set 1’ to begin programming the relay.

APPENDIX B- SEL AMS SETUP

- Connect the C750 ribbon cable from SEL 387-6 to the analog output of the SEL AMS. Connect the SEL C662 serial cable between the AMS and computer. These connections are shown in Figure B.1.

Figure B.1. Image showing connections of SEL AMS to SEL 387 relay

- Turn the relay ON. Plug in the SEL AMS power cable. Make sure that DC supply and main supply LEDs are ON.
- Select SEL- 5401 from the start menu.

Figure B.2. ‘SEL-5401’ option under start

- Select New from the topmost menu bar.

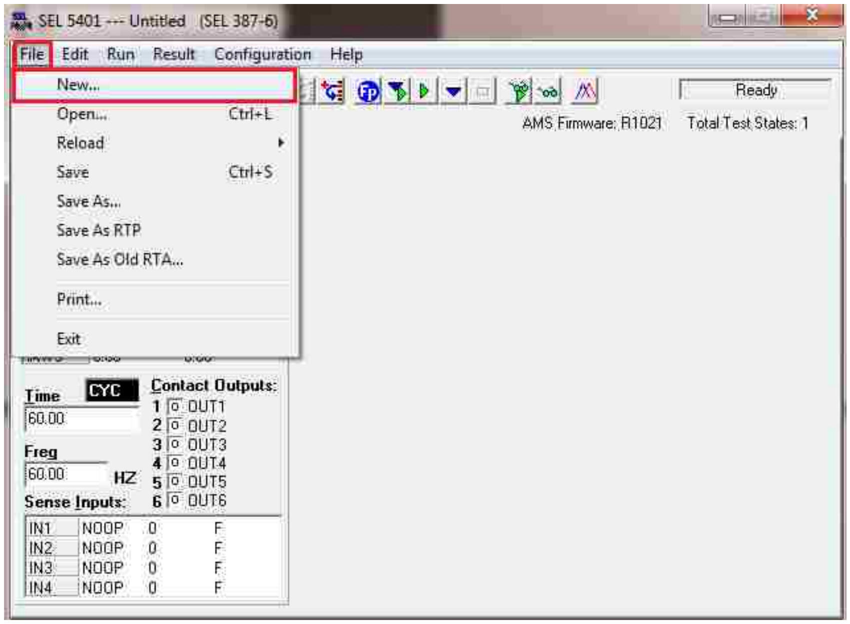


Figure B.3. Screen shot showing 'New' option on menubar

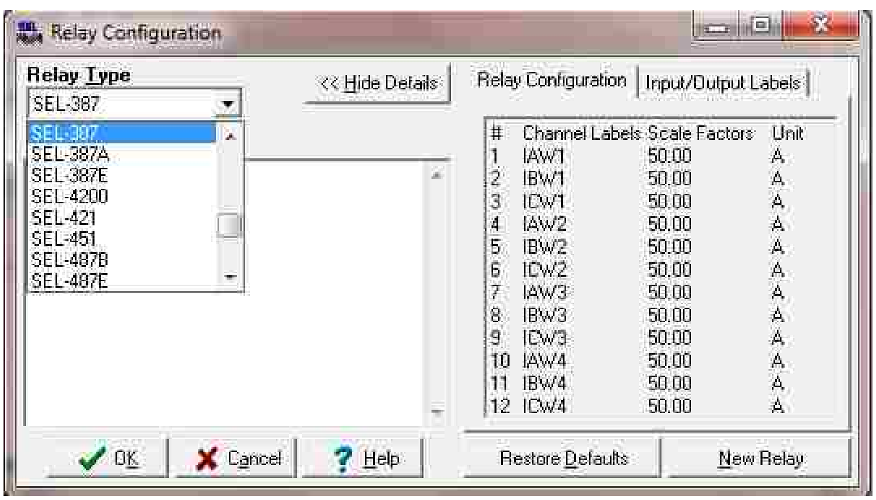


Figure B.4. Screen shot showing the relay type selection menu

- Select relay type as per the requirement.
- SEL 387 relay is not included in this software. It can be added by selecting new relay option at the bottom of relay configuration dialogue box.

- Assign the relay name as SEL 387-6.
- Assign the appropriate labels, scale factors, and units.

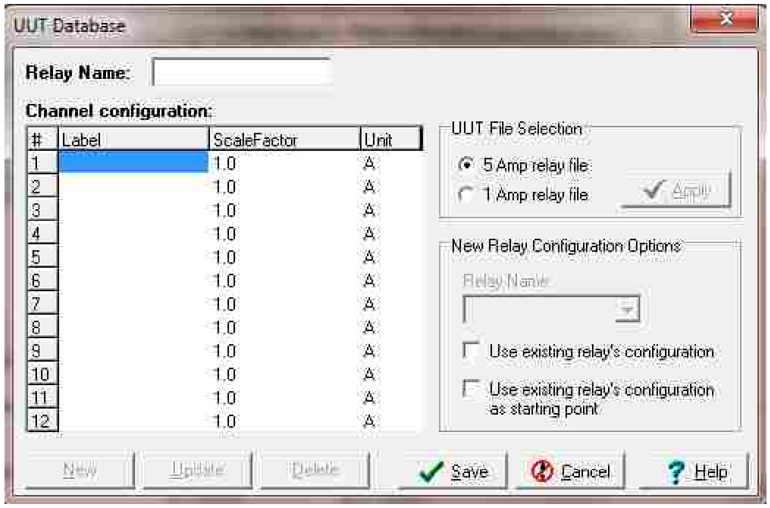


Figure B.5. Space area in SEL 5401 software to enter the configuration settings for a new relay

- Labels can be found at the back of relay.

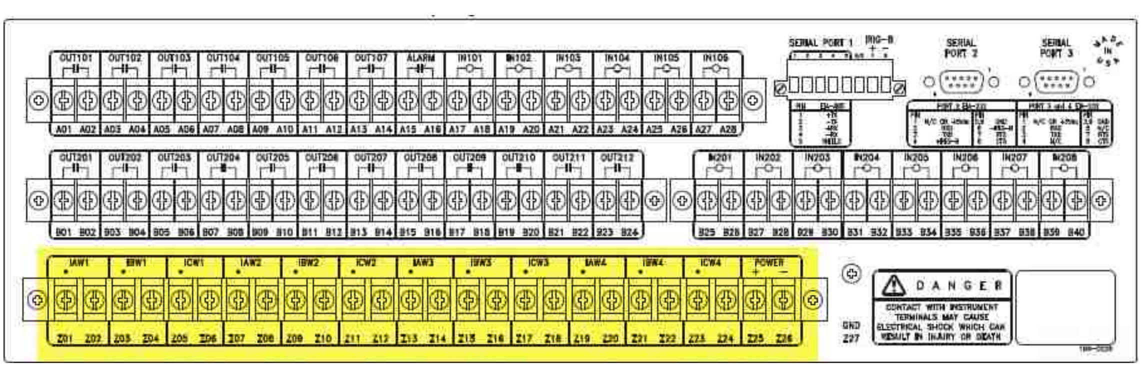


Figure B.6. Screen shot of rear view of relay showing labels [5]

- The scale factors can be obtained from relay input module. This is available in SEL 387 manual under Chapter 10 “Testing and trouble shooting.”

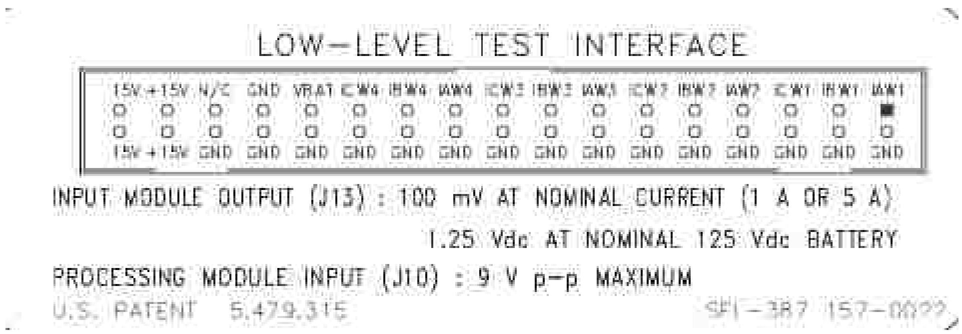


Figure B.7. Screen shot from SEL 387-6 manual showing scale factors

The scale factor = 5A/100mV = 50 for this particular relay.

B.1. SEL AMS TEST SETTINGS

Setting SEL AMS requires the settings for pre-fault, fault and post fault conditions

B.1.1. Pre-fault state. Enter the state name as pre fault

- Enter the winding 1 (primary) and winding 2 (secondary) pre fault current phasors. The magnitudes of primary and secondary currents can be chosen as low as 1 ampere and 1.34 (1*CTR of primary*transformer turns ratio/CTR of secondary winding) amperes respectively in secondary amperes.

- The currents in winding 1 will be going into the line and currents in winding 2 will be going out of line. Hence, for a grounded wye-grounded wye transformer there exists 180˚ phase shift between primary and secondary currents. So, phase angles of primary currents are 0, -120˚,+120˚ and secondary currents are 180˚, 60˚, -60˚ respectively for phases A, B, C. If there is a 30˚ delta wye phase shift between primary and secondary and if the primary delta winding leads secondary wye winding by 30˚, the phase angles of secondary currents will be 150˚, 30˚, -90˚ when the phase angles of primary currents are 0, -120˚,+120˚ respectively for phases A, B, C.

- Time of pre fault state can be set for 10 seconds.
- Set the contact outputs to closed or 'c' state. This change can be done using the space bar.
- Leave the sense inputs at NOOP or no operation state

B.1.2. Fault state. Enter the state name as fault

- Convert the currents obtained from ASPEN phasors into secondary currents for winding 1 and winding 2 by dividing each of them by corresponding CT ratios.
- Select the time in the range of 5 to 60 cycles if instantaneous operation (Instantaneous element or differential element trip) is expected. Otherwise if the relay is expected to trip in few seconds after it has picked up, select the time in the range of 3 to 10 seconds.
- Frequency is selected as 60 Hertz
- Contact output status is set as C or closed. If needed this can be changed to open by using spacebar on keyboard
- Set the sense inputs function as C→O, set delay as 67ms, TOS as C.

B.1.3. Post fault. Enter the state name as Post fault

- Assign 0 currents to all windings
- A 10 – 20 cycles time can be assigned

- Set the contact inputs as open
- Set the frequency as 60 Hertz
- Leave the sense inputs at NOOP or no operation state

Figure B.8. Pre fault state for a delta wye transformer with primary side leading secondary side by 30˚

To run a test, select ‘Download and run this test’ icon from the menu bar.

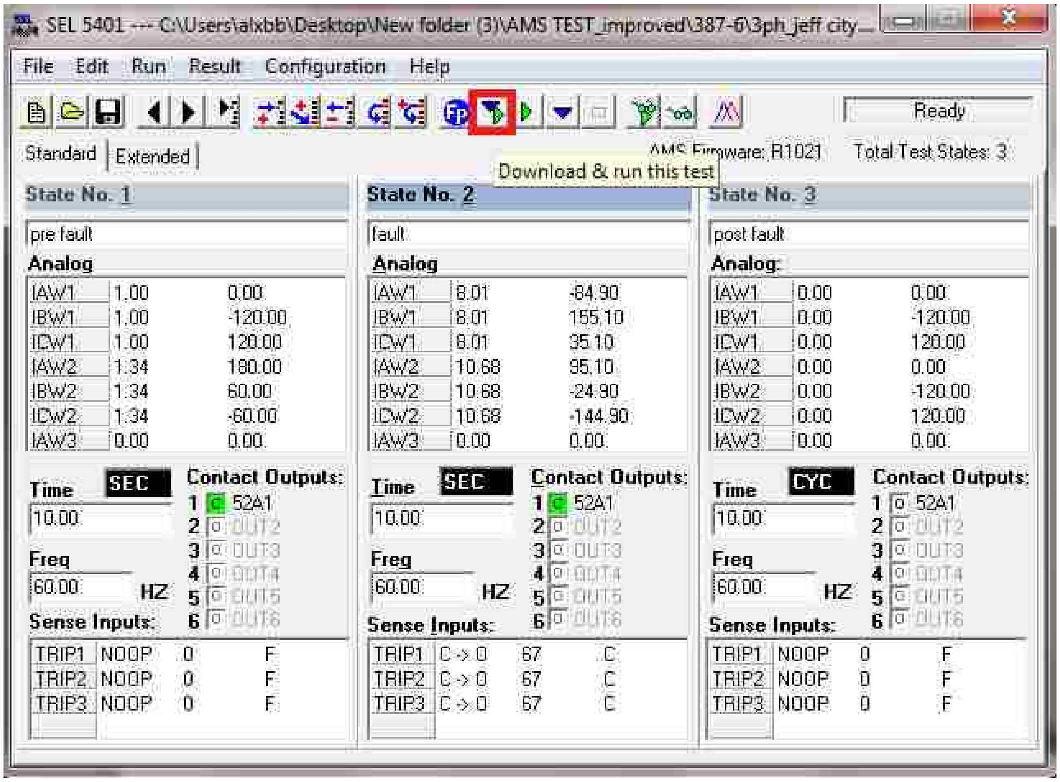


Figure B.9. Screen shot of pre fault, fault and post fault states entered into SEL 5401 software

APPENDIX C- PROCEDURE TO RETRIEVE EVENT REPORTS FROM RELAY

- From menu bar select events → get event files

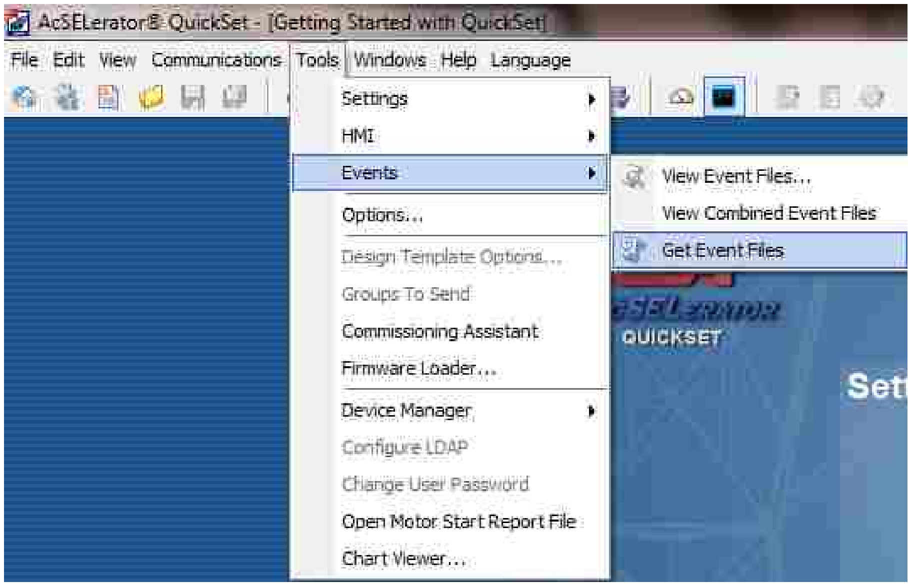


Figure C.1. Screen shot of AcSELerato Quickset screen to get event files

- Select the type of event. If a differential event report is required, select 8 samples/cycle-differential option. For a common type event report select any other option.   Enter the length of the event report as required. Maximum event length is 60 cycles.

Figure C.2. Screen shot showing list of event types in AcSELerator Quickset

- Check the box of the event which is to be retrieved. Click on 'get selected event report' option to get the event report. It usually takes a few minutes to get the event report retrieved depending on the number of cycles/number of samples. Once the event file is retrieved save this file to desired location with desired name.

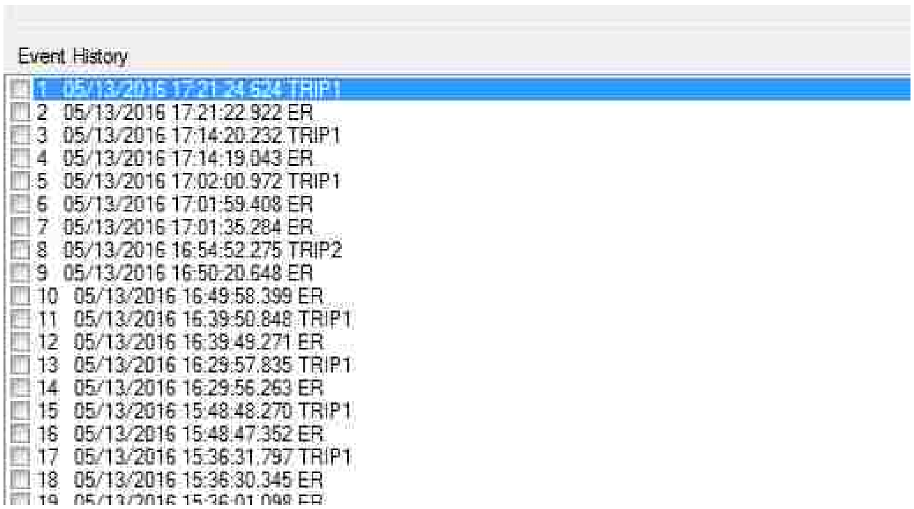


Figure C.3. Screen shot of AcSELerato Quickset Event History list

- Event report can be opened from menu bar by selecting → events →view event files.

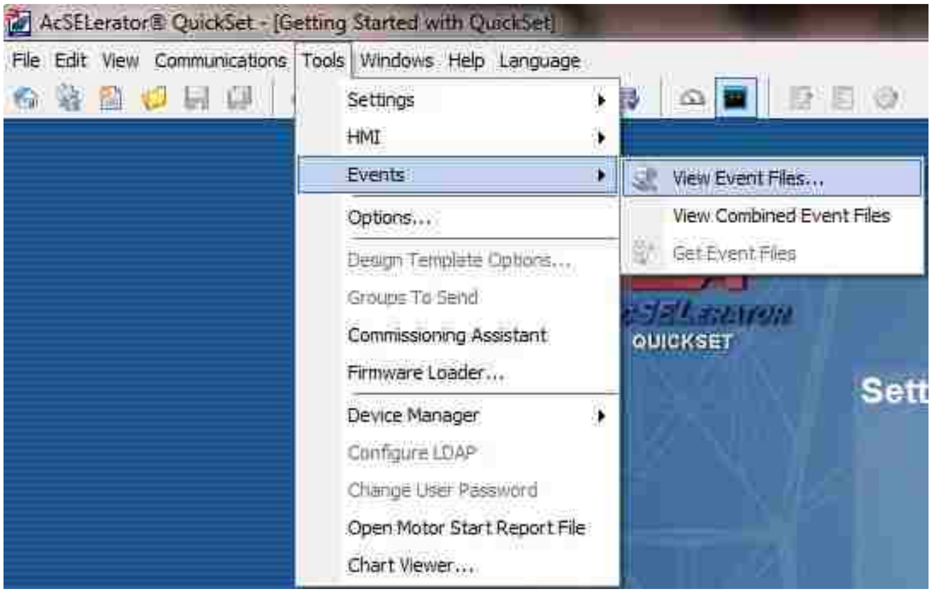


Figure C.4. Screen shot of AcSELerato Quickset screen to view event files

C.1. ANALYSIS OF DIFFERENTIAL EVENT REPORTS

Figures C.5 and C.6 show sample differential event reports. Figure C.5 shows the waveforms of operate currents IOP1, IOP2, IOP3 for phase A, B, C respectively and restraint currents IRT1, IRT2, IRT3 for phase A, B, C respectively. The peak value of graphs represents the operate current and restraint current magnitudes during faults.

In Figure C.6 changed relay word bits are indicated by a solid blue line. For example, the solid blue line next to 87R indicates that differential restraint element tripped during a fault event. Similarly, solid blue line next to trip2 indicates that trip2 bit asserted.

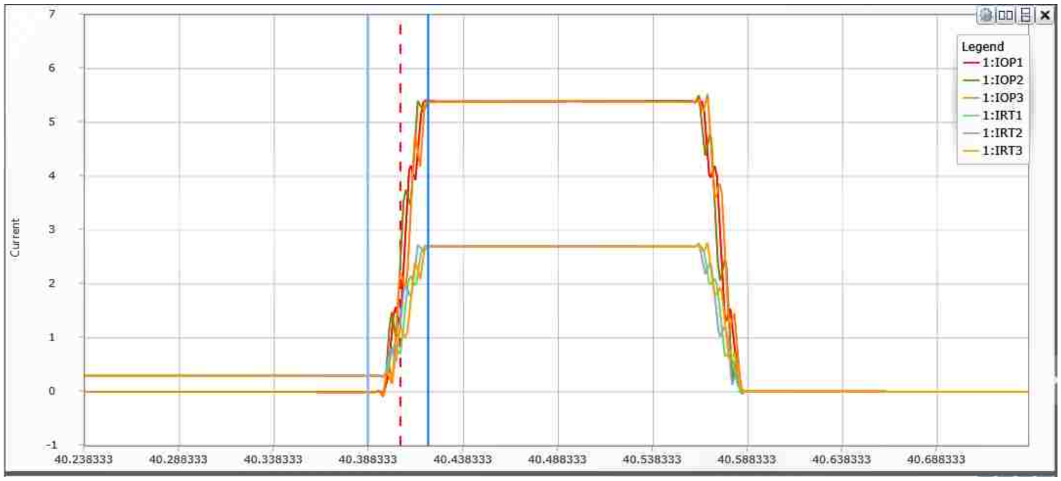


Figure C.5. Differential event report showing the waveforms of operate and restraint currents

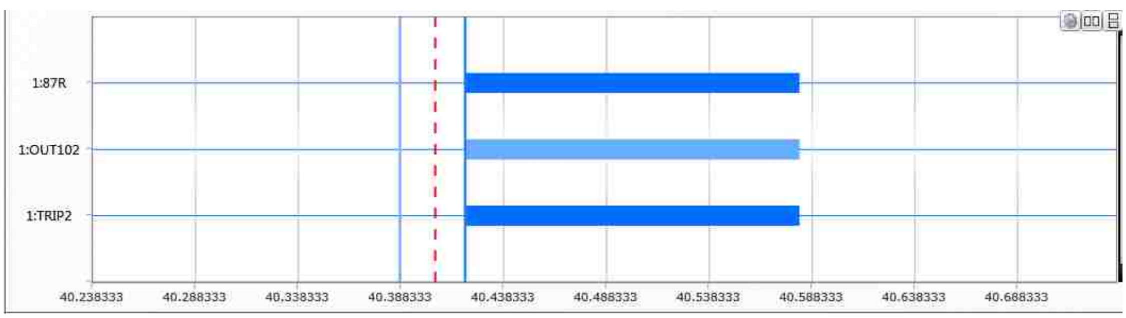


Figure C.6. Differential event report showing changed relay bits when a differential element tripped

C.2. ANALYSIS OF RAW/FILTERED EVENT REPORTS

This discussion applies to any type of raw/filtered event report with any number of samples per cycle.

Case 1: When the tripping is instantaneous

Differential element 87 or instantaneous element 50 will trip instantaneously with a time delay of less than 5 cycles. There is a 60 cycle limit to the length of event report. Because it takes less than 5 cycles to trip for these elements, the event reports can clearly show pre fault, fault and post fault states within this 60 cycles span. In Figure C.7, the upper wave form represents winding 1 or transformer primary current waveform. The lower wave form is winding 2 or transformer secondary current waveform. Figure C.8 shows the changed digitals or relay bits during relay operation. This active digitals column gives information about both picked up relay bits as well as tripped relay bits. For instance, in Figure C.8, 50P11 and 51P1 represents relay bits which picked up while 50P11T, OCB, OCC, OUT102, TRIP2 represents relay bits which were asserted or have changed to state ‘1’. It is not necessary for all the picked up bits to assert to ‘1’. For instance, in the same example, the 51P1 relay bit picked up but did not assert because the fault condition subsided before the time delay associated with this relay bit got expired. The dotted red line indicates the time at which a particular relay bit has picked up. The blue vertical line is a data line which can be moved anywhere to get the magnitude of current at that particular point.

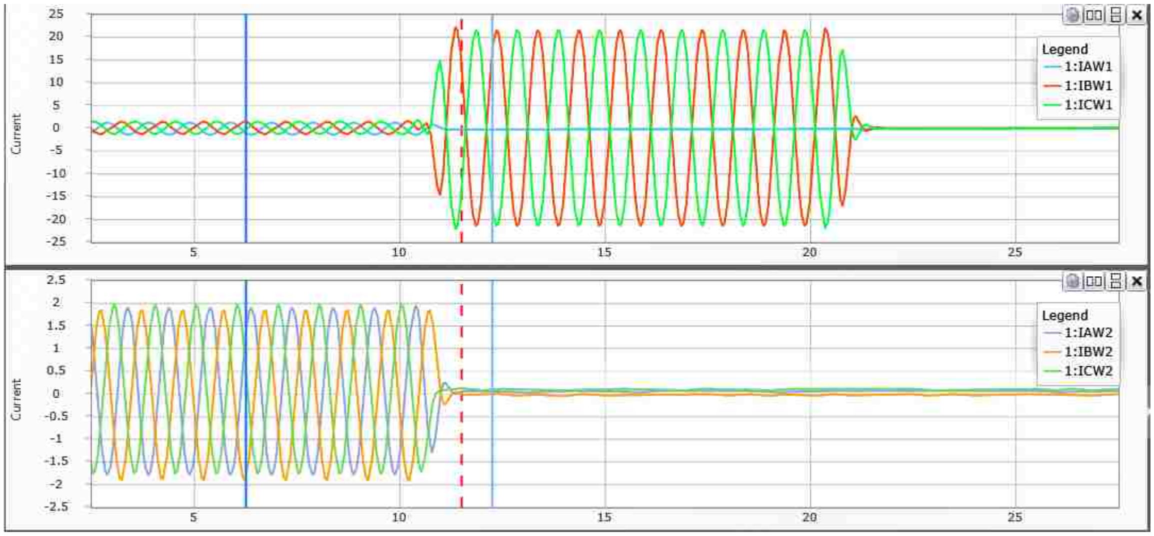


Figure C.7. Event report showing transformer primary and secondary currents

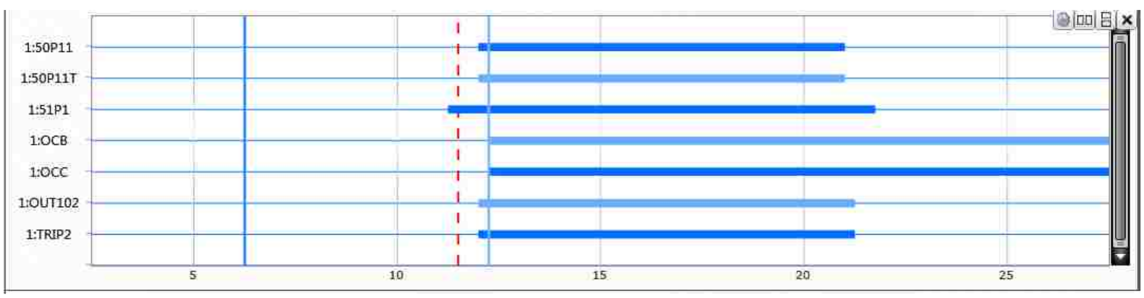


Figure C.8. Event report showing changed relay bits for a phase to phase fault

Case 2: Time overcurrent elements

For time overcurrent elements two event reports are generated. The first event report gives information about the relay word bits or elements which picked up. The second event report gives information about the elements which got asserted or reached state ‘1’. Figures C.9 and C.10 shows sample event reports for overcurrent elements which have tripped with a time delay.

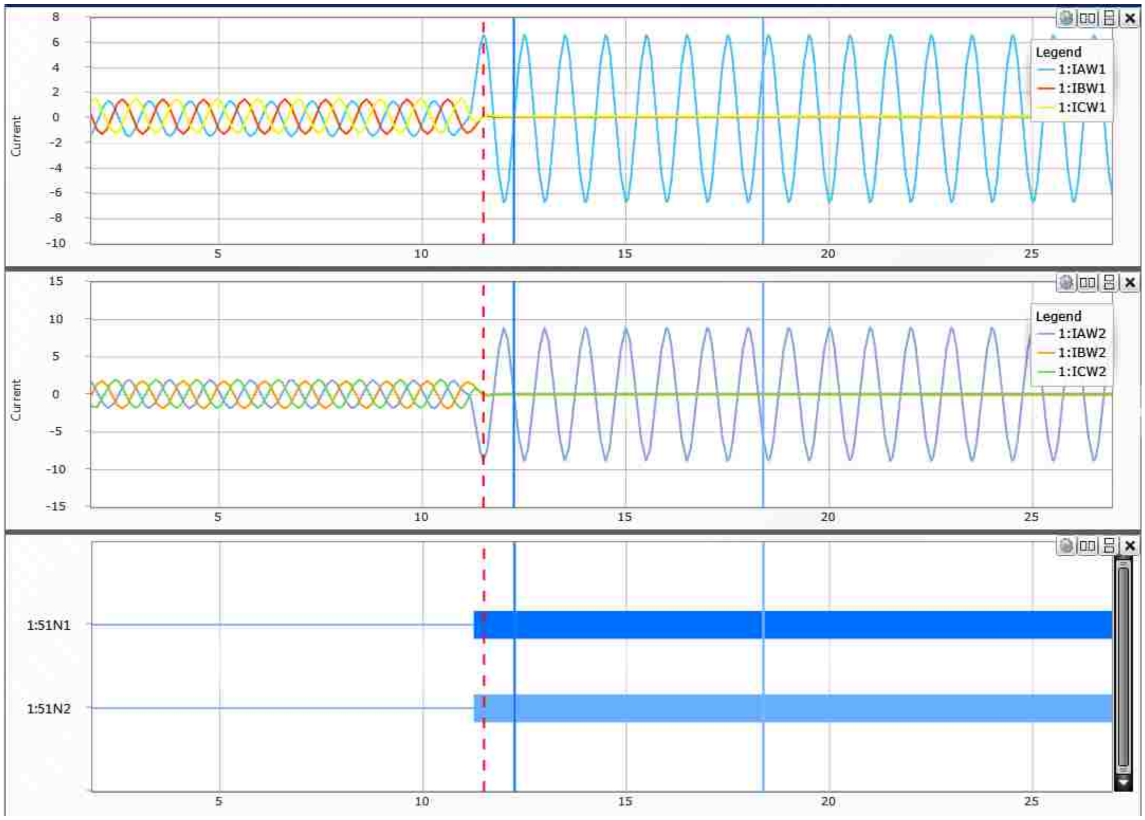


Figure C.9. Event report showing pickup of ground overcurrent element for single line to ground fault

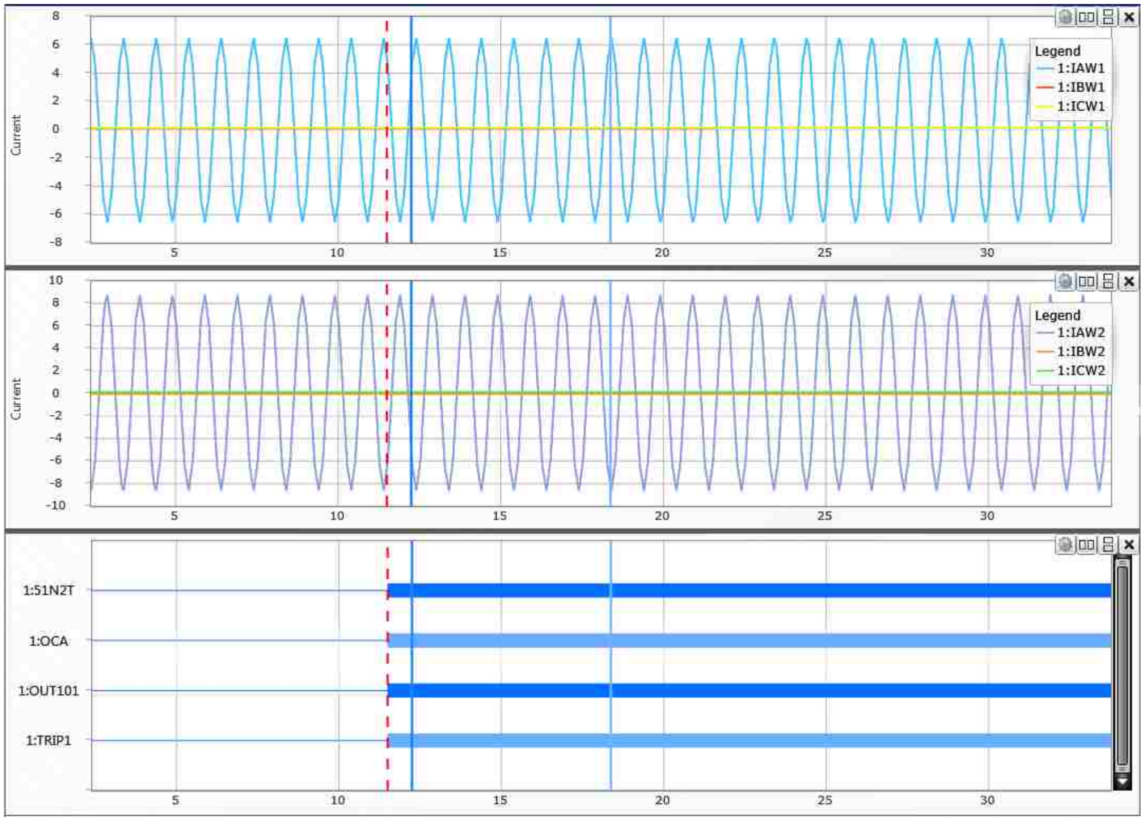


Figure C.10. Event report showing tripping of ground overcurrent element for single line to ground fault

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VITA

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