CHAPTER ONE
INTRODUCTION

1.1 Background

Modern society has relied consistently on electrical power, requiring higher demands of power stability and power quality. High-power rapid impact loads, rapid growth of asymmetrical impact loads, e.g. electrified railway, increase in distributed wind power generation equipment, connections/disconnections of large load and inevitable power system faults, are adverse factors which can lead to considerable reactive disturbances in power system and affect power stability, power quality and economy of power grid operation. The over current and overvoltage sequences caused by these disturbances may damage the associated electrical apparatus.

To solve this problem, it is essential to adjust reactive power in the power grid expeditiously to achieve a reasonable power flow distribution, which is also very important in phase modulation, voltage regulation and overvoltage restriction [1].

Flexible AC Transmission Systems (FACTS) have been evolving to a mature technology with high power ratings. The technology proven in various applications became a first-rate, highly reliable one. FACTS, based on power electronics, have been developed to improve the performance of weak AC systems and to make long distance AC transmission feasible. FACTS can also help solve technical problems in the interconnected power systems [2].

Some of important possible benefits for FACTS controllers in restructure multi-machine power system Environments are listed below [3].

- The flow of power within the existing power system can be maintained as per the contract or as per the demand of the utilities.
- Secure loading of transmission lines nearer to their thermal limits.

- Increased dynamic and transient grid stability.
- Allows more active power in present lines by reducing reactive power flow in the line.
- Access to lower production cost.
- Environmental benefits.
- FACTS gadgets furnishes secure tie line connection with neighboring utilities by diminishing generally speaking crop save prerequisites on either sides.
- Operation speed of whole power system get improved with help of FACTS devices.
- Interconnection of renewable and distributed generation and storages.

Static Var compensators are a fast and reliable means of controlling voltage on transmission lines and system nodes .The reactive power is changed by switching or controlling reactive power elements connected to the secondary side of the transformer. Each capacitor bank is switched ON and OFF by thyristor valves (TSC). Reactors can be either switched (TSR) or controlled (TCR) by thyristor valves.

From the view point of power system, a SVS is equivalent to a shunt capacitor and a shunt reactor, both of which can be adjusted to control reactive power at its terminals (of nearby bus) in a prescribed manner. Ideally, a SVC should hold constant voltage (assuming that this is the desired objective) posses unlimited var generation or absorption, capability with no active and reactive losses and provides instantaneous response. Practically SVC consists of a controllable reactor and a fixed capacitor [4].

A Static Var Compensator mainly consists of following components [1]

1- Step down transformer

The static var compensator is normally installed at low voltage side of main transformer otherwise a step-down transformer is needed to reduce the voltage.

2-Medium Voltage switchgear

The medium voltage switchgear typically includes isolating switches, grounding switches and transformers. It can be installed indoor or outdoor.

3-Linear (Air-core) reactor

The air-core reactor in static var compensator has high stability and high linearity. It is used to absorb reactive power under the control of thyristors. Usually the air-core reactor is series connected to the thyristor valve in delta-connection and then connect the delta bridge to power grid.

4-Thyristor valve

The thyristor valve is the main control part in a SVC system. It is composed of several series/paralleled connected thyristors and its auxiliary components. The thyristors are triggered by electrical lighting system and it adopts water cooling as the main cooling method.

5-Capacitor/filter banks

The capacitor/filter banks can supply sufficient capacitive reactive power to power grid and filter the harmful harmonics.

The filter is composed of capacitors, reactors and resistors, providing capacitive reactive power to the entire system. In practical, the capacitor/filter banks are divided into several sub-banks which can be switched-in/switched-off by mechanical breakers or other electrical switches according to the actual situation.

6-Water cooling system

The heat produced by thyristor valve will be harmful to thyristors if the heat is not dissipated in time. The de-ionized water cooling system is sufficient for the thyristor valves which have a high operating voltage. The cooling system uses the de-ionized pure water for internal cooling and regular industrial recycling water for external cooling.

7- SVC control and protection system

The key functions of SVC control and protection system are:

- Generating the control pulses to the valve at suitable time to fire the thyristors
- Monitoring the SVC system to provide operation condition, fault record or self checking information.
- Switching in/out the FC in order protecting each component to ensure the safe operation of SVC.
- Friendly Human-Machine Interface.

The basic task of the SVC fault clearance system is to detect a specified class of power system faults and abnormalities and to disconnect the associated item of plant from the rest of the power system. By definition the protection system consists of instrument transformers, protection equipment, auxiliary supply, tripping circuit including the circuit breaker trip coil and all necessary wiring. The fault clearance system is the protection system together with circuit breakers. Independent of the high performance and quality the protection equipment may have, it is of no use if any of the other components in the fault clearance system fails [5].

The fault clearance system in the station must fulfit certain basic requirements originating from the power system. Simplified the requirements can be expressed as follows. The fault clearance system shall perform with high reliability, speed, selectivity and sensitivity.

Security takes precedence over dependability in the protection system for an SVC. The plants are installed to improve the voltage stability in the grid during and following major network disturbances. They must not trip when they are needed the most unless major faults appear in the main circuit. Only required protective functions, such as short circuit detection shall be employed. In case other functions are added they should be significantly time delayed [6].

1.2 Problem Statement

The SVCs (Static Var Compensator) are needed the most during network disturbances. At these occasions they may make the difference between a network collapse and successful continued operation, The basic task of the SVC fault clearance system is to detect a specified class of power system faults and abnormalities and to disconnect the associated item of plant from the rest of the power system, The fault clearance system shall perform with high reliability, speed, selectivity and sensitivity.

1.3 Objectives

The focus of this thesis is to study the schemes used for protection of the Static Var Compensation (SVC) units, these schemes which classified in to protections found in the control system of the SVC and others which protect each component of the SVC's components.

1.4 Methodology

The protection system is integrated with the control system to make the protection system able to detect the faults which give small current at large firing angle and vice versa such faults cannot be detected by the traditional protection relays. By this integration the SVC control system supplies the protection system by the reference setting as the firing angle change. This makes the protection system more stable, selective, sensitive and reliable.

1.5 Thesis Layout

This thesis is consisting from six chapter and details as follows:

Chapter one : introduction and it's involve Background, problem statement, objective and methodology.

Chapter Two: provides Introduction to TCR protection and protections in the control system, and how different faults accrue in the TCR can be detected and protected.

Chapter Three: provides Introduction to fixed capacitor bank and harmonic filters protection and how different faults accrue in them can be detected and protected.

Chapter Four: provides Introduction to Power transformer protection and how different faults accrue in it can be detected and protected.

Chapter Five: shows the simulation results of different types of faults applied in the TCR of LOCAL MARKET substation SVC and how the protection system located in the control system detects them and trip the main C.B.

Chapter Six :Conclusion and Recommendations

CHAPTER TWO

TCR PROTECTION AND CONTROL BASED PROTECTIONS

2.1 Introduction

A thyristor-controlled reactor (TCR) is a reactance connected in series with a bidirectional thyristor valve as shown in figure 2.1. The thyristor valve is phase-controlled, which allows the value of delivered reactive power to be adjusted to meet varying system conditions. Thyristor-controlled reactors can be used for limiting voltage rises on lightly loaded transmission lines. The current in the TCR is varied from maximum [7] (determined by the connection voltage and the inductance of the reactor) to almost zero by varying the firing delay angle.

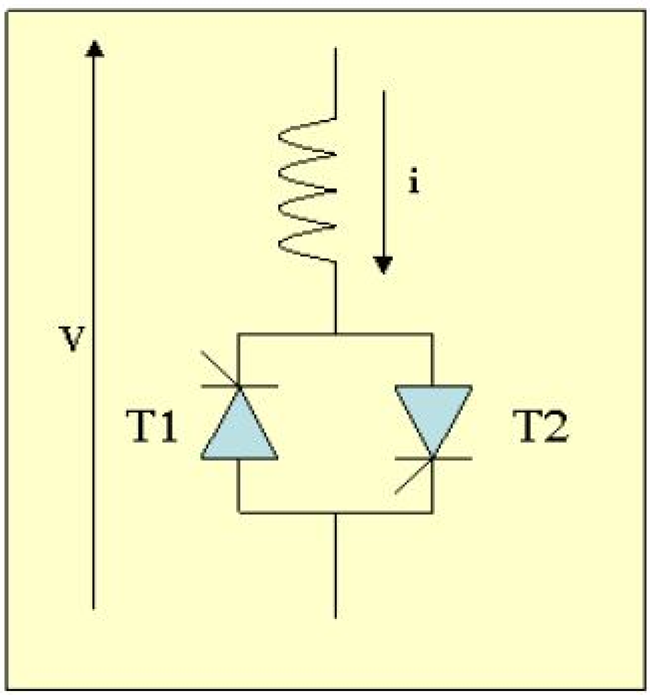


Figure 2.1: TCR components

The thyristor does not conduct if gate pulses are not provided. In such a case, the effective susceptance is zero. On the other hand if thyristors are always on, the effective susceptance is equal to that of the inductor.

Now if the each thyristor is fired at a delay angle (as measured from the point where it gets forward biased) between 90 and 180 degrees, the resulting current waveform is as shown on Figure 2.2.

The figure shows the current waveform for various values of delay angle note that this waveform is obtained by integrating the voltage from the point at which the thyristor switches on using the rule:

$$L * i = \int v\,dt \qquad (2.1)$$

The thyristor switches off when the current through it falls to zero. The reverse connected thyristor behaves similarly for the other half cycle. The instantaneous current i over half a cycle is given by

$$i = \frac{\sqrt{2}V}{X_l}(\cos 2\alpha - \cos \omega t) \qquad (2.2)$$

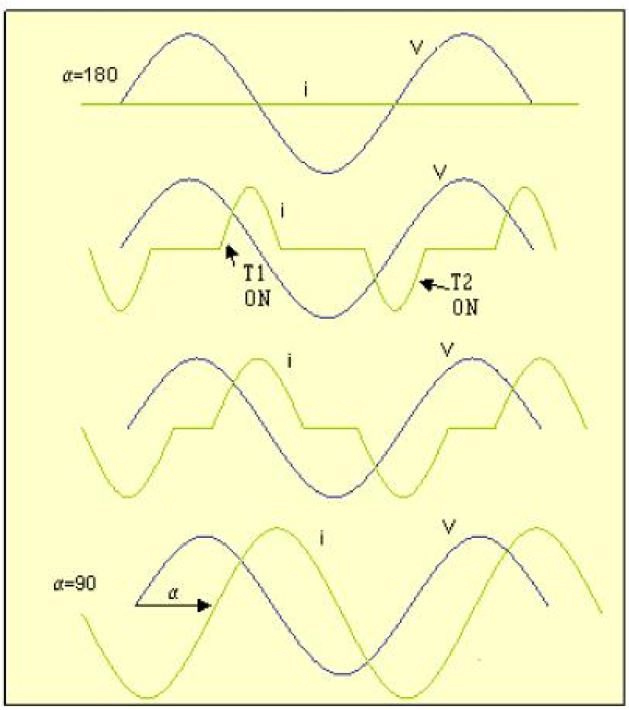


Figure 2.2: current waveform for various values of delay angle

2.2 TCR protection

In SVC a TCR branch is delta connected where each phase consists of a thyristor valve and two reactor stacks. The thyristor valve is electrically located between the reactors. By combining one line Current Transformer (CT) with two branch CTs, a protective zone encompassing two reactor halves and a thyristor valve is created in a main differential protection. By permutation, three such zones are aggregated in the TCR to provide detection and clearance of inter-zone faults [8].

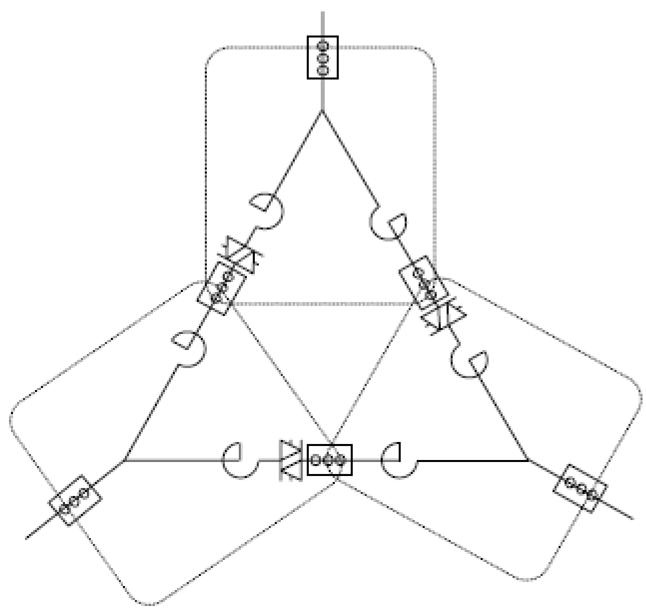


Figure 2.3: Typical arrangements for TCR in SVC unit and protective zones

2.2.1 Differential protection of TCR

Differential protection can be of high or low impedance type. The protection serves as the main protection for short circuits between the different protective zones. The protection is unaffected by SVC energization and any valve misfiring. Differential protection of low impedance type will have higher requirements on CT's compared to high impedance types. Low impedance types of differential protection needs to be blocked during SVC energization, if energization is performed with fully conducting TCR valves. Large DC components, with long time constant will be present in the TCR current at full conduction. Due to the large DC component and very long primary time constant false differential current exists. Restraint criteria's are generally not fulfilled and will not stabilize the protection.

High Impedance differential protection of TCR

Also known as unbiased differential protection only one actuating relay quantity (current) required for operation. It is assumed with these schemes that a certain degree of CT saturation is possible under throughfault conditions.

This leads to a spill current which could operate the relay.

Stabilization is achieved by means of a stabilizing resistor,R_s intended to raise the operating voltage of the system.

Fault current through R_s could lead to dangerous overvoltages voltage limiters are required. Relatively easy to set but it requires identical CT s (identical magnetization characteristics) in order to minimize the spill current with normal load [9].

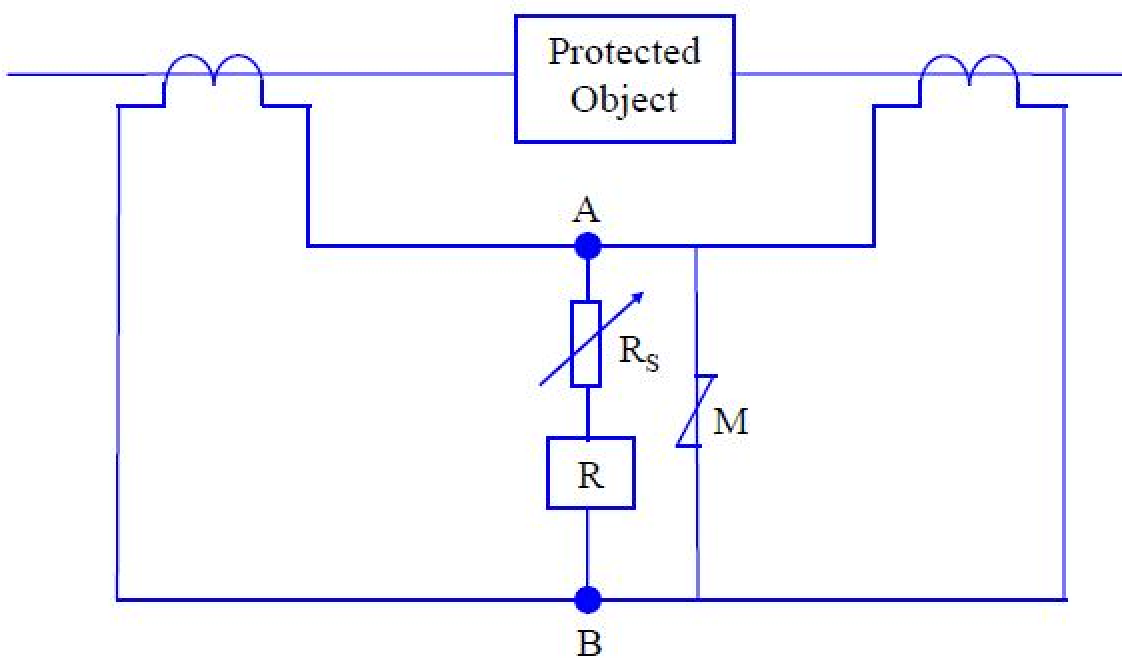


Figure 2.4: High Impedance differential schemes

The general requirement on the function values of the high impedance differential protection is that at maximum through fault current for an external faults the relay wont maloperate even with one CT fully saturated.

For a reactor the dimensioning criteria will be for the inrush current, since a reactor only will give a through fault current equal to rated current, at an external earth-fault[10].

The maximum inrush current for a reactor is approximately two times the rated current. If no specific requirement concerning at what current the relay should be stable exists, five times the rated current is used when operating voltage is selected.

This rather high value is set in order not to get problem at reactor breaker openings. As the CB is chopping the current at opening, a high frequency current (1-12 kHz) will oscillate between the reactor reactance and the circuit leakage capacitance. This oscillating current could lead to maloperation of the Differential relay. If there are maloperation problems at opening of the CB, the remedy for this is to connect a capacitor in the relay circuit.

The function value of the relay should be chosen:

$$U_{function} \geq In(R_{ct} + 2R_l) \qquad (2.3)$$

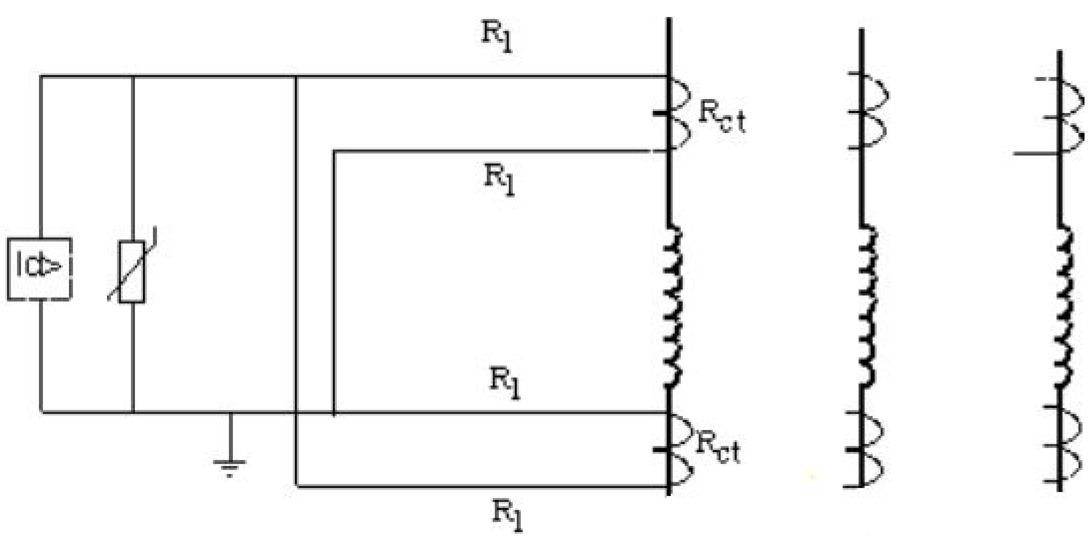


Figure 2.5: High Impedance differential schemes in reactor

Low impedance differential protection:

Differential protection, as its name implies, compares the currents entering and leaving the protected zone and operates when the differential between these currents exceeds a pre-determined magnitude.

The principle is shown in Figure 2.6. The CTs are connected in series and the secondary current circulates between them. The relay is connected across the midpoint thus the voltage across the relay is theoretically nil, therefore no current through the relay and hence no operation for any faults outside the protected zone. Similarly under normal conditions the currents, leaving zone A and B are equal, making the relay to be inactive by the current balance. Under internal fault conditions (i.e. between the CTs at end A and B) relay operates. This is basically due to the direction of current reversing at end B making the fault current to flow from B to A instead of the normal A to B condition in the earlier figure.

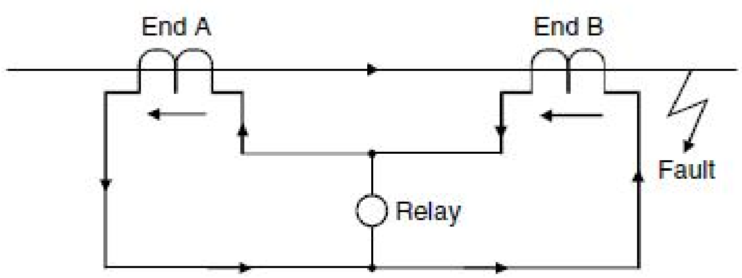


Figure 2.6: Differential protection operation during external faults

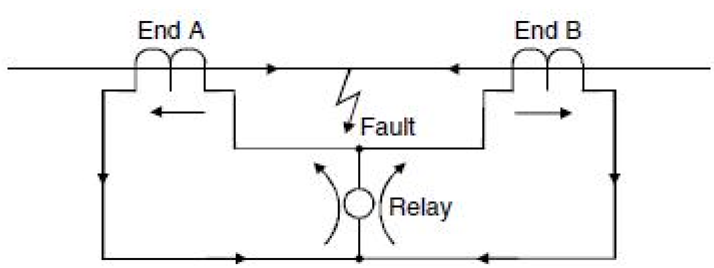


Figure 2.7: Differential protection operation during internal faults

The spill current in the differential relay due to the various sources of errors is dependent on the magnitude of the through current. Hence it is necessary to consider the setting of the differential relay to be more than or proportional to the worst spill current likely to occur under through-fault conditions. Because of the wide range of fault current magnitudes, it is not always satisfactory to make the relay insensitive to lower-spill current values. This problem had been overcome by adjusting the operating level of the relay according to the total amount of fault current. This was done originally by providing a restraining winding or electromagnet which carries the total fault current while an operating electromagnet was allowed to carry only the differential current. This principle of bias is applied to circulating current protection to ensure proper operation under all fault conditions.

If the two zone boundary currents are $I1$ and $I2$, then

Operating quantity: $K1\ (I1 - I2)$

Biasing quantity: $K2\ (I1 + I2)$

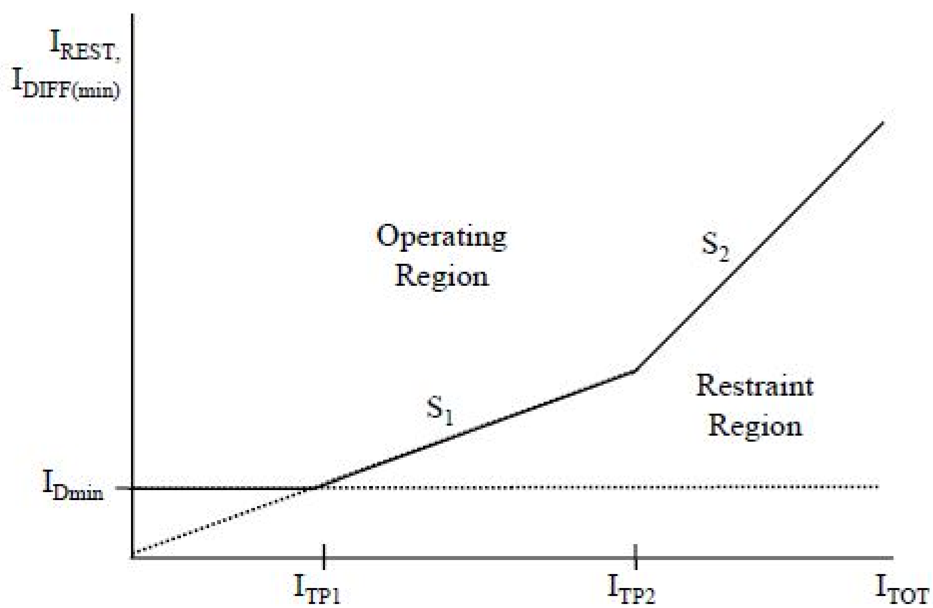


Figure 2.8: low impedance differential protection tripping characteristics

2.2.2 Over current protection of TCR:

Time delayed over current relays, with an added instantaneous step sensing the branch currents are generally used as back-up. The reactors are protected by thermal overload relays. The split arrangement of the reactors in each phase provides extra protection to the thyristors in event of a reactor fault, i.e. fault current is limited and the risk for steep front voltage surges eliminated. The valves are also protected against thermal overload by a specific function (TCR current limiter) in the SVC control system [8].

With this characteristic, the time of operation is inversely proportional to the fault current level and the actual characteristic is a function of both ‘time’ and 'current' settings. Figure 2.9 illustrates the characteristics of two relays given different current/time settings. For a large variation in fault current between the two ends of the feeder, faster operating times can be achieved by the relays nearest to the source, where the fault level is the highest. The disadvantages of grading by time or current alone are overcome.

The selection of overcurrent relay characteristics generally starts with selection of the correct characteristic to be used for each relay, followed by choice of the relay current settings. Finally the grading margins and hence time settings of the relays are determined. An iterative procedure is often required to resolve conflicts, and may involve use of non-optimal characteristics, current or time grading settings.

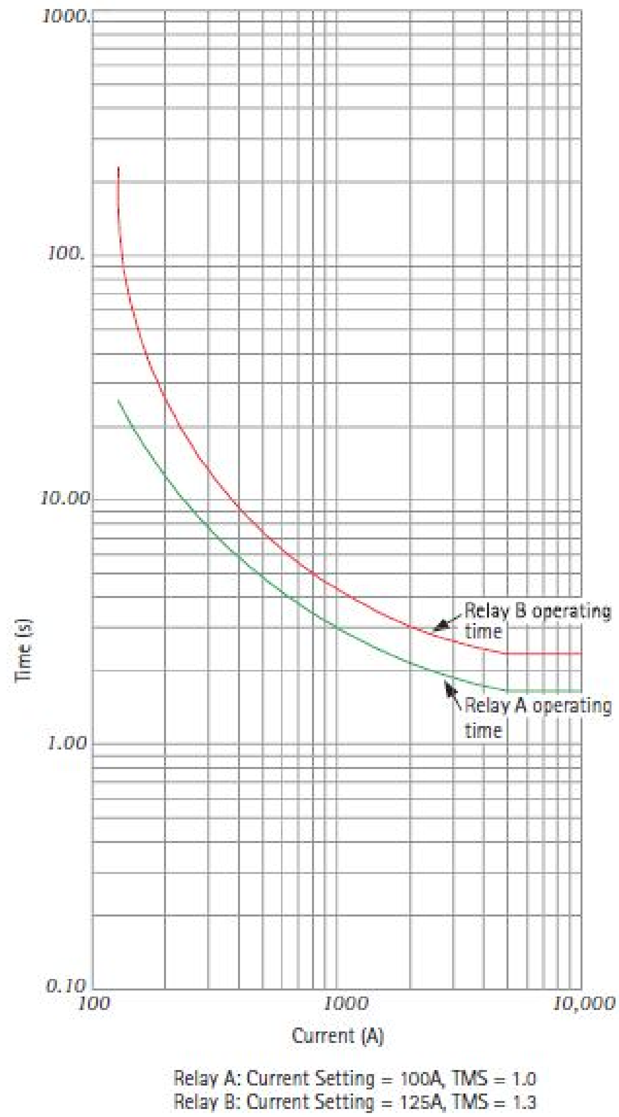


Figure 2.9: relay characteristics for different settings

The current/time tripping characteristics of IDMT relays may need to be varied according to the tripping time required and the characteristics of other protection devices used in the network. For these purposes, IEC 60255 defines a number of standard characteristics as follows:

- Standard Inverse (SI)
- Very Inverse (VI)
- Extremely Inverse (EI)
- Definite Time (DT)

Table 2.1: Relay characteristics according to IEC 60255

Relay Characteristic	Equation (IEC 60255)
Standard Inverse (SI)	$t = TMS * \frac{.14}{I_r^{.02} - 1}$
Very Inverse (VI)	$t = TMS * \frac{13.5}{I_r - 1}$
Extremely Inverse (EI)	$t = TMS * \frac{80}{I_r^2 - 1}$
Long time standard earth fault	$t = TMS * \frac{120}{I_r - 1}$

Table 2.2: North American IDMT relay characteristics

Relay Characteristic	Equation (IEC 60255)
IEEE Moderately Inverse	$t = \frac{TD}{7} * \left\{\frac{.0515}{I_r^{.02} - 1} + 0.14\right\}$
IEEE Very Inverse	$t = \frac{TD}{7} * \left\{\frac{19.61}{I_r^2 - 1} + 0.491\right\}$
Extremely Inverse (EI)	$t = \frac{TD}{7} * \left\{\frac{28.2}{I_r^2 - 1} + 0.1217\right\}$
US CO8 Inverse	$t = \frac{TD}{7} * \left\{\frac{5.95}{I_r^2 - 1} + 0.18\right\}$
US CO2 Short Time Inverse	$t = \frac{TD}{7} * \left\{\frac{0.02394}{I_r^{0.02} - 1} + 0.01694\right\}$

Where

$I_r = \frac{I}{I_r}$

I_s = relay setting current

TMS = Time multiplier Setting

TD = Time Dial setting

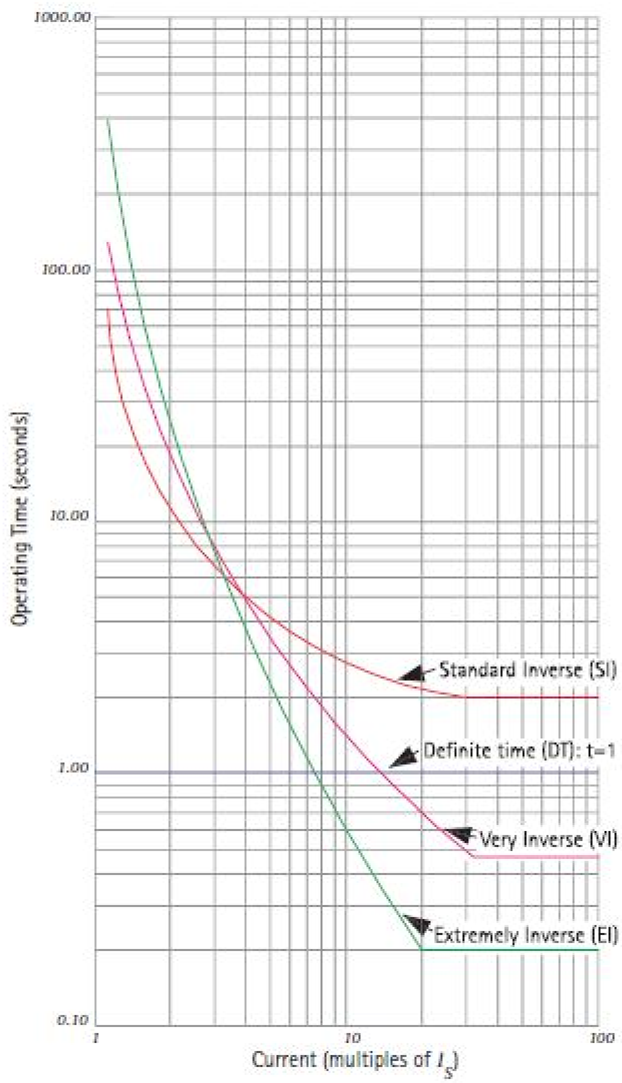


Figure 2.10: Relay characteristics to IEC 60255

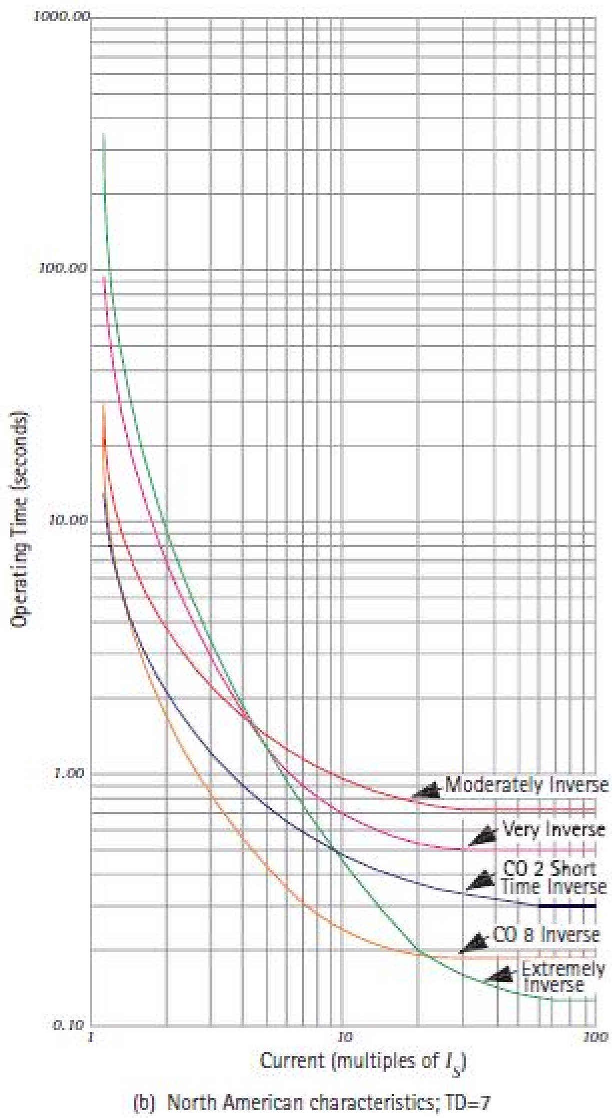


Figure 2.11: Relay characteristics according to North American standard

2.2.3 Protection against Unsymmetrical operation of TCR

Unsymmetrical TCR operation and turn to turn faults can also be detected by a negative phase sequence protection. However, turn to turn faults are extremely difficult to detect. The small unbalances and sequence currents associated with turn to turn faults generally are smaller than the existing tolerable unbalances in the system, i.e. unbalances due to negative sequence, component tolerances, etc. Consequently there seems to be no reliable handle to distinguish between the intolerable and tolerable conditions. As the turn to turn fault spreads to more turn, the current will increase. Negative sequence relays must consider conditions mentioned above, the settings are generally high which makes the relay insensitive. The relay should be time delayed to avoid operation on system transients and external faults.

2.2.4 Thermal overload protection of TCR

The valves are also protected against thermal overload by a specific function (TCR current limiter) inthe SVC control system, see section 9. The selective protection simulates the temperature inside thereactor and works with the time constant of the reactors. For some installations this protection isinstalled in the SVC control system. Experience from hundreds of SVC's has also shown that it is veryrare that this protection operates since the TCR current will be limited by protective control featuresimplemented in highly reliable SVC control systems.

2.3 Control-based protection TCR control system

Fundamental frequency current or voltage overload in any TCR is prevented by the control system. There are control functions making sure that the current in the TCR cannot become higher than the component ratings. The voltage on the TCR terminal is also controlled to make sure it cannot exceed its design value.

DC current in the TCR is actively suppressed by a control function manipulating the thyristor firing instants. When it comes to detecting malfunctions in the plant the most important function is to compare the actual currents in thyristor controlled branches with currents simulated in the control system. The simulation is based on measured system voltage and actual firing orders to the thyristors. In case there is a deviation between the two values exceeding a limit the plant is considered faulty. There are also a number of self-supervision functions and hardware checks making sure the control system is working properly.

2.3. 1 Over-voltage protection

The over-voltage strategy employed for TSC legs is usually to block firing for small over-voltages (typically up to 5% above the maximum continuous voltage specified). Only the SVC coupling transformer high side voltages are monitored. For higher over-voltages, the strategy is to trip the SVC if the overvoltage and time duration exceed to customer specification. The Entergy overvoltage specification for the two SVC systems required the SVC to ride through an inverse time Overvoltage envelope. This resulted in values of time delays for the trip setting of 100 ms for an over-voltage of 1.35-1.4 pu and 5 seconds for an over-voltage of 1.15 pu. At over-voltages above 1.6 pu, an instantaneous trip command is issued. The delay time periods are usually determined from off line studies and confirmed/adjusted by Transient Network Analysis (TNA).

2.3.2 Under-voltage protection

The most commonly used strategy for dealing with undervoltage conditions is to block firing of TSC valves because the valves do not have sufficient forward voltage to safely turn on. In addition, blocking the TSC valves prevents the occurrence of large transients that would occur if the voltage happens to recover at that instant. The stability controller (the gain-supervision control or the dead-band control) is also usually blocked during the undervoltage condition. After the system voltage recovers, the stability controller is deblocked after a suitable time delay.

2.3.3 Over-current protection

Transient over-currents caused by valve misfiring and thyristor junction heating caused by increased switching and conduction losses at maximum continuous current are the two main concerns while developing the strategy for control-based TSC over-current protection. A misfire event combined with maximum valve blocking voltage (under worst system overvoltage) with a precondition of maximum steady state junction temperature caused the most severe stresses to the valve. When the thyristor valve current exceeds an over-current threshold (usually around 4 pu rated current), a misfire is assumed to have occurred. The misfire over-current protection strategy is then decided by the particular application.

CHAPTER THREE

FIXED CAPACITOR BANK AND HARMONIC FILTERS PROTECTION

3.1 Introduction

Protection engineering for shunt capacitor banks requires knowledge of the capabilities and limitations of the capacitor unit and associated electrical equipment including individual capacitor unit, bank switching devices, fuses, location and type of voltage and current instrument transformers.

A capacitor unit, Figure 3.1, is the building block of any SCB. The capacitor unit is made up of individual capacitor elements, arranged in parallel/series connected groups, within a steel enclosure. The internal discharge device is a resistor that reduces the unit residual voltage allowing switching the banks back after removing it from service. Capacitor units are available in a variety of voltage ratings (240V to 25kV) and sizes (2.5kVAr to about 1000kVAr) [12].

Capacitors are intended to be operated at or below their rated voltage and frequency as they are very sensitive to these values; the reactive power generated by a capacitor is proportional to both of them ($kVar \approx 2\pi f V^2$). The IEEE Std 18-1992 and Std 1036-1992 specify the standard ratings of the capacitors designed for shunt connection to ac systems and also provide application guidelines [13].

These standards stipulate that:

a) Capacitor units should be capable of continuous operation up to 110% of rated terminal rms voltage and a crest voltage not exceeding 1.2 x √2 of rated rms voltage, including harmonics but excluding transients. The capacitor should also be able to carry 135% of nominal current.

b) Capacitors units should not give less than 100% nor more than 115% of rated reactive power at rated sinusoidal voltage and frequency.

c) Capacitor units should be suitable for continuous operation at up to 135%of rated reactive power caused by the combined effects of:

- Voltage in excess of the nameplate rating at fundamental frequency, but not over 110% of rated rms voltage.
- Harmonic voltages superimposed on the fundamental frequency.
- Reactive power manufacturing tolerance of up to 115% of rated reactive power.

All applications of power capacitors require the same basic protection objectives, including system short circuits between phases or to ground within the bank, and element overvoltages, caused by power system overvoltages or by the failure of other elements within the bank. Since the failure modes differ between capacitor types, the performance of protection schemes will also vary [14].

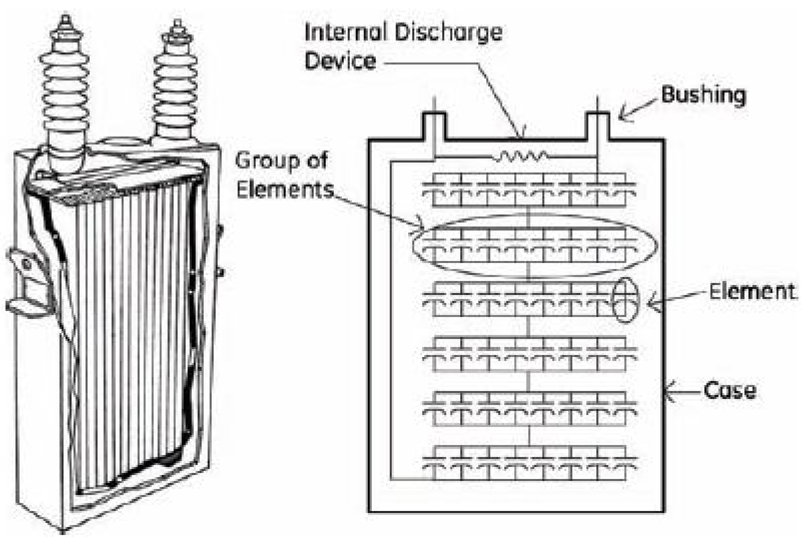


Figure 3.1: Capacitor unit

3.2 Capacitor Bank Types

There are generally four types of the capacitor unit designs to consider:

3.2.1 Externally fused capacitors

An individual fuse, externally mounted between the capacitor unit and the capacitor bank fuse bus, protects each capacitor unit. The capacitor unit can be designed for a relatively high voltage because the external fuse is capable of interrupting a high-voltage fault. However, the kilovar rating of the individual capacitor unit is usually smaller because a minimum number of parallel units are required to allow the bank to remain in service with a capacitor can out of service. A SCB using fused capacitors is configured using one or more series groups of parallel-connected capacitor units per phase.

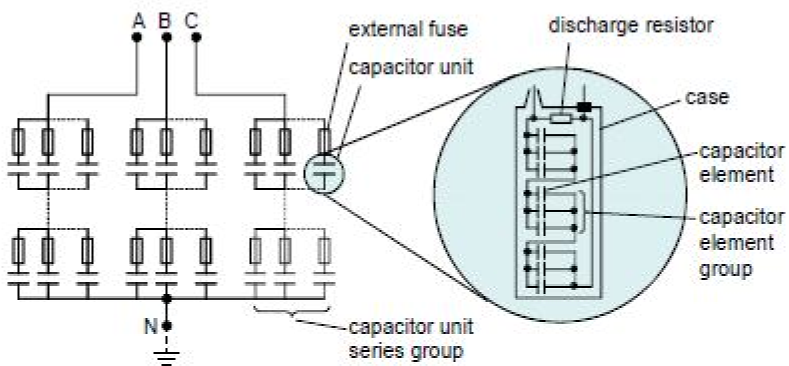


Figure 3.2: Externally fused capacitors

3.2.2 Internally Fused Capacitors

Each capacitor element is fused inside the capacitor unit. A “simplified” fuse is a piece of wire sized to melt under the fault current, and encapsulated in a wrapper able to withstand the heat produced by the arc during the current interruption. Upon the capacitor failure, the fuse removes the affected element only. The other elements, connected in parallel in the same group, remain in service but with a slightly higher voltage across them.

Figure 3.3 illustrates a typical capacitor bank utilizing internally fused capacitor units. In general, banks employing internally fused capacitor units are configured with fewer capacitor units in parallel and more series groups of units than are used in banks employing externally fused capacitor units. The capacitor units are built larger because the entire unit is not expected to fail.

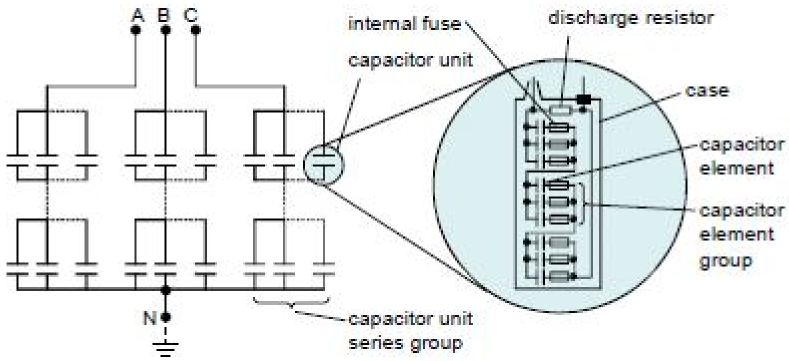


Figure 3.3: Internally Fused Capacitors

3.2.3 Fuseless Capacitors

Fuseless Capacitor Bank designs are typically the most prevalent designs in modern day. The capacitor units for fuseless capacitor banks are connected in series strings between phase and neutral, as shown in Figure 3.4. The higher the voltage for the bank, the more capacitor elements in series.

The expected failure of the capacitor unit element is a short circuit, where the remaining capacitor elements will absorb the additional voltage. For example, if there are 6 capacitor units in series and each unit has 8 element groups in series there is a total of 48 element groups in the string. If one capacitor element fails, this element is shorted and the voltage across the remaining elements is 48/47 of the previous value, or about 2% higher. The capacitor bank remains in service; however, successive failures of elements would aggravate the problem and eventually lead to the removal of the bank.

The fuseless design is usually applied for applications at or above 34.5kV where each string has more than 10 elements in series to ensure the remaining elements do not exceed 110% rating if an element in the string shorts.

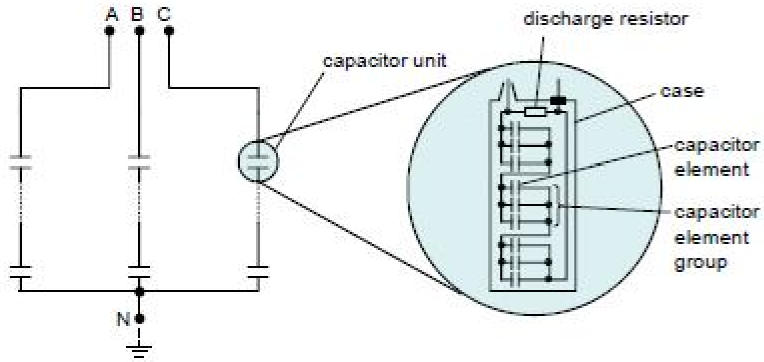


Figure 3.4: Fuseless Capacitors

3.2.4 Unfused Capacitors

Contrary to the fuseless configuration, where the units are connected in series, the unfused shunt capacitor bank uses a series/parallel connection of the capacitor units. The unfused approach would normally be used on banks below 34.5kV, where series strings of capacitor units are not practical, or on higher voltage banks with modest parallel energy. This design does not require as many capacitor units in parallel as an externally fused bank.

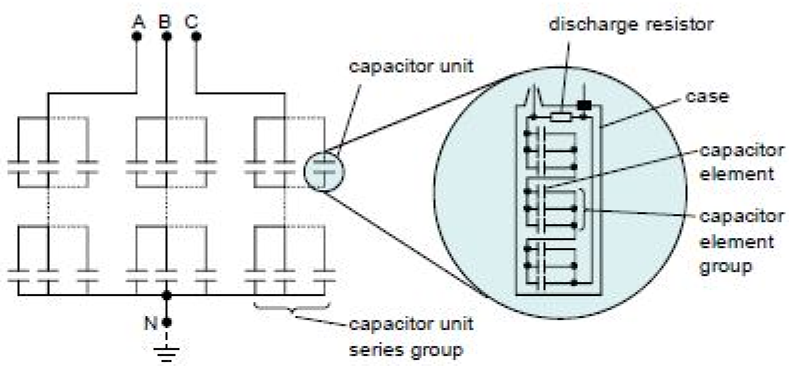


Figure 3.5: Unfused Capacitors

3.3 Capacitor Bank Design

The optimum connection for a SCB depends on the best utilization of the available voltage ratings of capacitor units, fusing, and protective relaying. Virtually all substation banks are connected wye. Distribution capacitor banks, however, may be connected wye or delta. Some banks use an H configuration on each of the phases with a current transformer in the connecting branch to detect the unbalance.

3.3.1 Grounded Wye-Connected Banks

Grounded wye capacitor banks are composed of series and parallel-connected capacitor units per phase and provide a low impedance path to ground. Figure 6 shows typical bank arrangements.

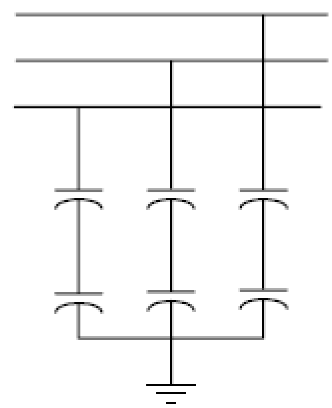


Figure 3.6: Grounded Wye-Connected Banks

Advantages of the grounded capacitor banks include:

- Its low-impedance path to ground provides inherent self-protection for lightning surge currents and give some protection from surge voltages. Banks can be operated without surge arresters taking advantage of the capability of the capacitors to absorb the surge.
- Offer a low impedance path for high frequency currents and so they can be used as filters in systems with high harmonic content. However, caution shall be taken to avoid resonance between the SCB and the system.
- Reduced transient recovery voltages for circuit breakers and other switching equipment.

Some drawbacks for grounded wye SCB are:

- Increased interference on telecom circuits due to harmonic circulation.
- Circulation of inrush currents and harmonics may cause misoperations and/or over operation on protective relays and fuses.

- Phase series reactors are required to reduce voltages appearing on the CT secondary due to the effect of high frequency, high amplitude currents.

3.3.2 Multiple Units in Series Phase to Ground – Double Wye

When a capacitor bank becomes too large, making the parallel energy of a series group too great (above 4650 kvar) for the capacitor units or fuses, the bank may be split into two wye sections. The characteristics of the grounded double wye are similar to a grounded single wye bank. The two neutrals should be directly connected with a single connection to ground.

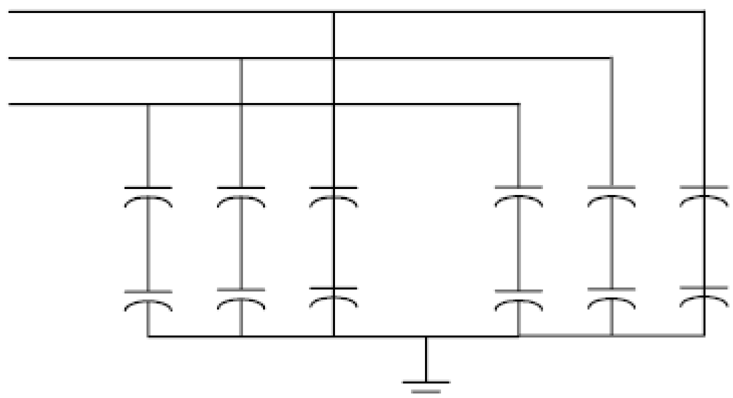


Figure 3.7: Multiple Units In Series Phase To Ground – Double Wye

3.3.3 Ungrounded Wye-Connected Banks

Typical bank arrangements of ungrounded Wye SCB are shown in Figure3.8 Ungrounded wye banks do not permit zero sequence currents, third harmonic currents, or large capacitor discharge currents during system ground faults to flow. (Phase-to-phase faults may still occur and will result in large discharge currents). Other advantage is that overvoltages appearing at the CT secondaries are not as high as in the case of grounded banks. However, the neutral should be insulated for full line voltage because it is momentarily at phase potential when the bank is switched or when one capacitor unit fails in a bank configured with a single group of units. For banks above 15kV this may be expensive.

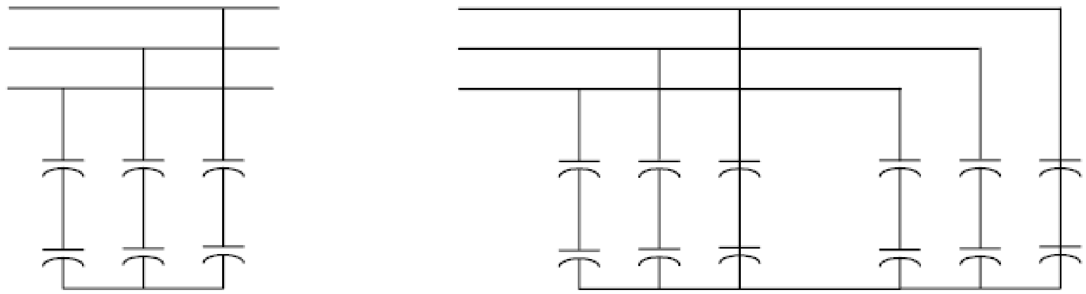


Figure 3.8: Ungrounded Wye-Connected Banks

3.3.4 Delta-connected Banks

Delta-connected banks are generally used only at distributions voltages and are configured with a single series group of capacitors rated at line-to-line voltage. With only one series group of units no overvoltage occurs across the remaining capacitor units from the isolation of a faulted capacitor unit. Therefore, unbalance detection is not required for protection and they are not treated further in this paper.

3.3.5 H Configuration

Some larger banks use an H configuration in each phase with a current transformer connected between the two legs to compare the current down each leg. As long as all capacitors are normal, no current will flow through the current transformer. If a capacitor fuse operates, some current will flow through the current transformer. This bridge connection can be very sensitive. This arrangement is used on large banks with many capacitor units in parallel.

3.4 Protection of capacitor banks

3.4.1 Voltage Differential (87V)

With reference to Figure 9, this function is based on a voltage divider principle – a healthy capacitor string has a constant and known division ratio between its full tap (typically the bus voltage) and an auxiliary tap used by the protection. The principle could be used on both grounded (Figure 5a) and ungrounded Figure3.5b banks. In the latter case the neutral point voltage (VX) must be measured by the relay, and used to derive the voltage across the string.

The function uses the following operating signal:

For grounded system.

$$V_{op(A)}=|V_{1A}-k_A*V_{2A}| \quad (3.1)$$

For ungrounded system

$$V_{op(A)}=|V_{1A}-k_A*V_{2A}- V_x*(k_A-1)| \quad (3.2)$$

Where kA is a division ratio for the A-phase of the bank. Identical relations apply to phases B and C.

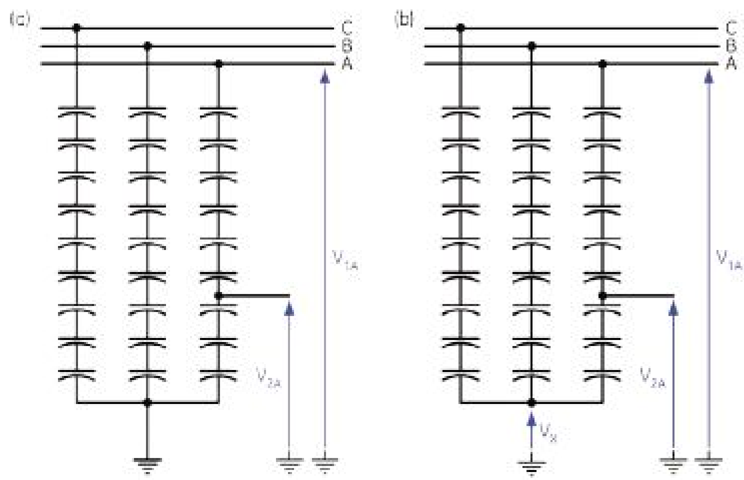


Figure 3.9: Voltage differential application to grounded (a) and ungrounded (b) banks.

3.4.2 Unbalanced protection for single capacitor ungrounded why bank

The simplest method to detect unbalance in single unearthed wye banks is to measure the bank neutral or zero-sequence voltage. If the capacitor bank is balanced and the system natural unbalance equals zero, the neutral voltage will ideally be zero as well. A change in any phase of the bank will result in a change in the neutral or zero-sequence voltage. Figure 3.10 shows a method that measures the voltage between capacitor neutral and earth using a VT and an overvoltage protection function. The voltage measurement can also be done by a resistive divider. This scheme is simple but the disadvantage is that the system unbalance and the natural unbalance of the bank are present in the measurement.

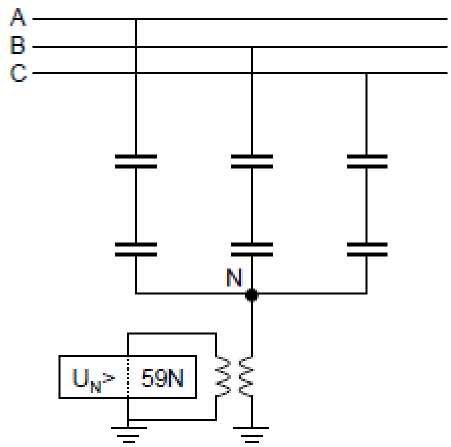


Figure 3.10: unbalanced protection for ungrounded capacitor bank

3.4.3 Unbalanced Protection For Single Capacitor Grounded Why Bank

Figure 3.11 shows a scheme used with earthed single-wye SCBs based on a current transformer installed on the connection between the capacitor bank neutral and earth. Unbalance in the bank causes a current to flow between the neutral and earth. This scheme is simple but the disadvantage is that again the system unbalance and the natural unbalance of the bank create an unbalance current to flow. Additionally, system faults with earth connection cause the corresponding earth fault current component to flow in the bank neutral requiring coordination between the bank protection and system earth fault protection. The scheme can be implemented with a sensitive overcurrent protection function, or an overvoltage protection function together with a small shunt resistor can be applied instead.

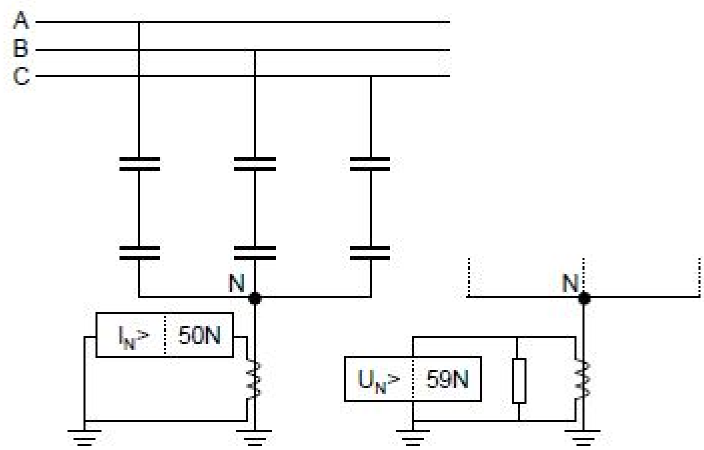


Figure 3.11: unbalanced protection for grounded capacitor bank

3.4.4 Unbalanced Protection For Ungrounded *Double-Wye Banks*

Typically, a double-wye-type of bank allows a secure unbalance protection with a simple uncompensated function, because any system zero-sequence component affects both wyes equally, but a failed capacitor unit will appear as an unbalance between the neutrals. This is also an advantage in case of earthed SCBs because coordination with the system earth-fault protection is not required which allows fast operation of the unbalance protection.

The scheme of Figure 3.12 (top) uses a current transformer on the connection of the two neutrals and a simple overcurrent protection function. Figure 3.12 (bottom) uses a voltage transformer connected between the two neutrals and an overvoltage protection function. The effect of system voltage unbalance is avoided in both schemes, but the effect of natural unbalance of the bank is not, which causes circulating current or voltage between the neutral points in the healthy state. Therefore, if a very sensitive protection is required, the scheme must be completed with natural unbalance compensation function.

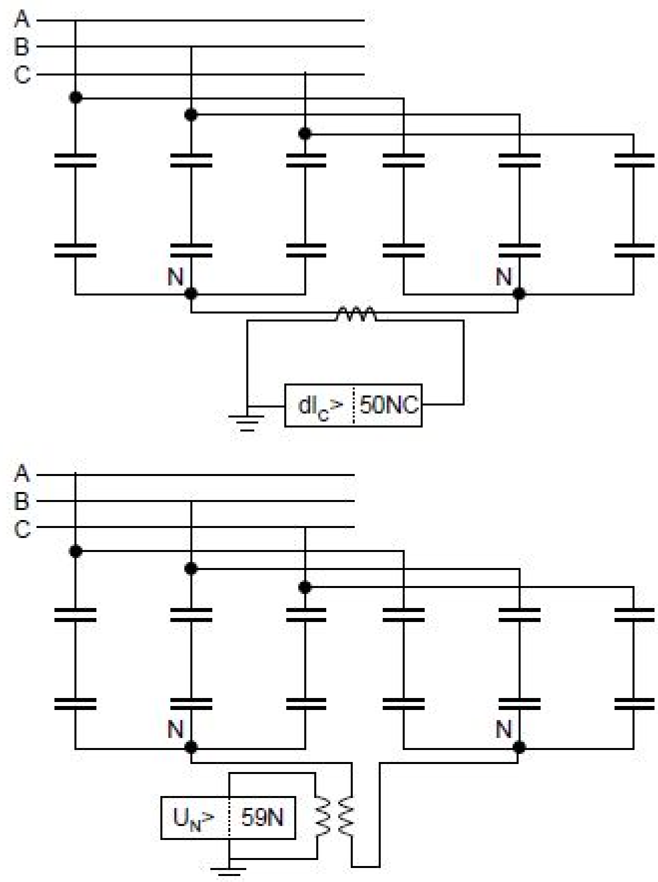


Figure 3.12: unbalanced protection for ungrounded Double-Wye Banks

3.4.5 Unbalanced Protection For Grounded Double-Wye Banks

Figure 3.14 shows a scheme for an earthed double-wye SCB, where a current transformer is installed on each neutral of the two sections of a double-wye. The neutrals are connected together and earthed from one point. The current transformer secondaries are cross-differentially connected to an overcurrent protection function, so that the scheme is insensitive to any outside system condition that affects both sections of the capacitor bank in the same way, for example, in case of an outside earth fault-equal zero-sequence current flows in the neutrals of both sections, but ideally the function measures zero current due to the CT connection. Alternatively, the connections from neutral to earth from the two wyes may be in opposite directions through a ring core current transformer, Figure 14 (bottom).

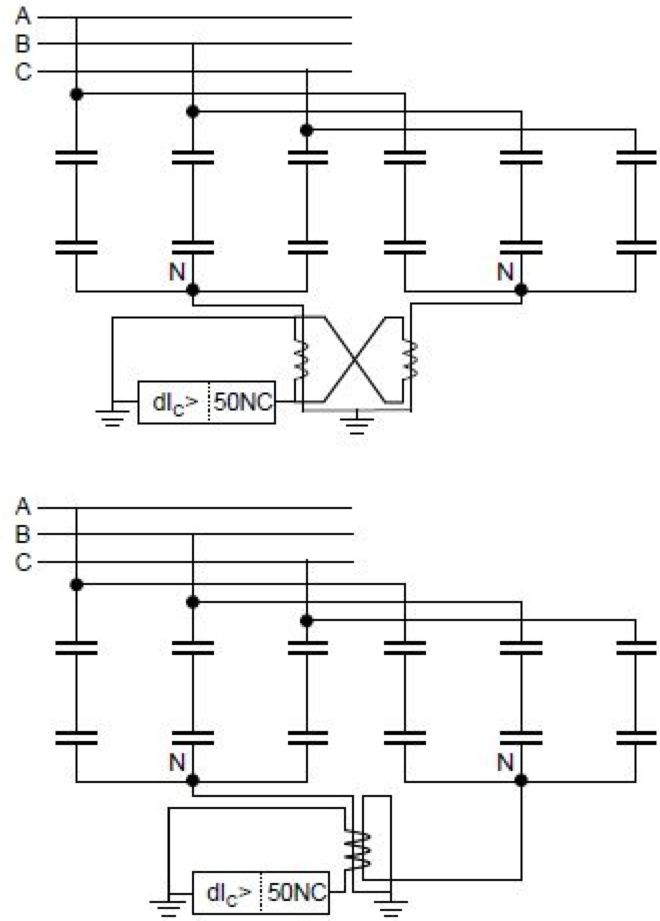


Figure 3.13: unbalanced protection for grounded Double-Wye Banks

3.4.6 Unbalanced Protection of H Configuration Capacitors

Larger SCBs use an H-configuration in each phase with a current transformer connected between the two legs, Figure 3.14. The unbalance protection is based on the measurement of the current between the legs.

As long as all the capacitors are healthy, no current will flow through the current transformers. If a capacitor element or unit fails, some current will flow through the current transformer. The advantage of this scheme is that it is insensitive to system unbalance, but the effect of the natural unbalance of the bank causes circulating current to flow between the legs. In addition, in case of an earthed H-configuration, any system zero-sequence component affects similarly all legs and therefore ideally no current will flow through the leg CTs in this case. If the natural unbalance compensation function is in use, the H-configuration allows a very sensitive and fast unbalance protection, and this is why it is mostly used on large banks with many capacitor units in parallel.

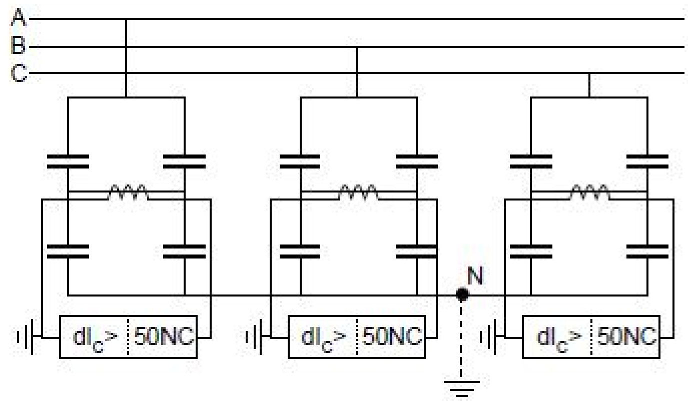


Figure 3.14: **unbalanced protection of H configuration capacitors**

3.4.7 Short Circuit and Earth-Fault Protection

Protection against flashovers between phases and flashovers to neutral and to earth must be provided. To fulfill this requirement, a two-stage overcurrent and earth-fault protection is typically applied. The high-set stages are used to provide protection against faults between the SCB terminals and the circuit breaker. The time-delayed low-set stages are used to detect faults within the bank for which greater sensitivity is required. Time-delayed overcurrent stages can be applied with normal settings without encountering false operations due to inrush currents. The desirable minimum starting level is 135% of nominal phase current for the earthed wye banks or 125% for unearthed banks. High-set stages, if applied, should be set high enough to override inrush or outrush transient currents. Successful operation of modern IEDs may be obtained by setting the high-set overcurrent stages at three to four times the capacitor rated current to override back-to-back bank switching [15].

3.4.8 Negative-Sequence Overcurrent Protection

If the phases of the bank are constructed in distinct separate structures, a flashover within the capacitor bank will begin as a short circuit fault over of a single-series group. Such a fault produces very little phase overcurrent. For this type of fault, fast protection is provided by the unbalance protection. However, depending on the applied scheme and the fault type, the unbalance current may be out of the normal reliable operating range of the unbalance protection. For example, if a flashover occurs across the entire limb, the current in the neutral connection can be very high. Also for certain capacitor bank configurations, some faults within the bank will not cause an unbalance signal and will remain undetected, for example rack-to rack faults for banks with two-series groups connected phase-over-phase and using neutral voltage or current for unbalance protection, and rack-to-rack faults for certain H-bridge connections. Therefore, if the unbalance protection fails to operate, the initial fault may spread until it becomes severe enough to operate the short circuit protection resulting to considerable damage. For these reasons, a backup protection. For the unbalance protection is recommended. The negative-sequence overcurrent protection can be used for this purpose to complement the scheme securing the tripping in the above cases.

3.4.9 Undervoltage and Undercurrent Protection

Once disconnected from the system, the SCB cannot be reconnected immediately due to the trapped charge within the capacitor units. Otherwise, catastrophic damage to the circuit breaker may occur. To discharge the bank, each individual capacitor unit has a resistor to discharge the trapped charge within 5 minutes. Under voltage or undercurrent protection function with a time delay is used to detect the bank going out of service and prevent closing the breaker until the set time has elapsed. This delay prevents tripping of the bank for system faults external to the bank. The under voltage or Undercurrent function should be set so that it will not operate for voltages that require the capacitor bank to remain in service.

3.4.10 Overvoltage Protection

The SCB may be subjected to overvoltages resulting from abnormal system operating conditions. If the system voltage exceeds its normal limit, the bank becomes overloaded and other system equipments become stressed. To limit the effects of overvoltage to a safe level, the bank should be removed from service in due time. The tripping of the bank lowers the voltage in the vicinity of the bank, reducing also the overvoltage on other system equipment. Therefore, this function operates also as a system protection. Definite time or inverse time-delayed three-phase overvoltage protection measuring the bus voltage is typically used. Overvoltage protection needs to be coordinated with the dedicated current-based overload protection providing also backup protection functionality.

3.5 Harmonic Filters

For most SVC installations harmonic filters are connected. Harmonic filters perform the dual task of providing reactive power generation at fundamental (grid) frequency and performing the harmonic filtering needed to take care of the harmonics generated by the TCR. Filter banks for SVC applications are generally divided into two parallel banks in Y-Y connection with ungrounded neutrals tied together. Internal fuses protect the capacitor units [16]. Increasing concern over the harmonic (voltage or current distortion) problem stems from the growing numbers and power ratings of the highly non-linear power electronic devices used in controlling power apparatuses in industrial distribution systems. Harmonic in power systems shortens the equipment’s life expectancy and can interfere with communication lines and sensitive equipment [17]. Passive filters consisting of capacitors, inductors and/or resistors can be classified into tuned filters and high-pass filters. They are connected in parallel with nonlinear loads such as diode/thyristor rectifiers, ac electric arc furnaces, and so in. Figures 1 and 2 show circuit configurations of the passive filters on a per-phase base [18].

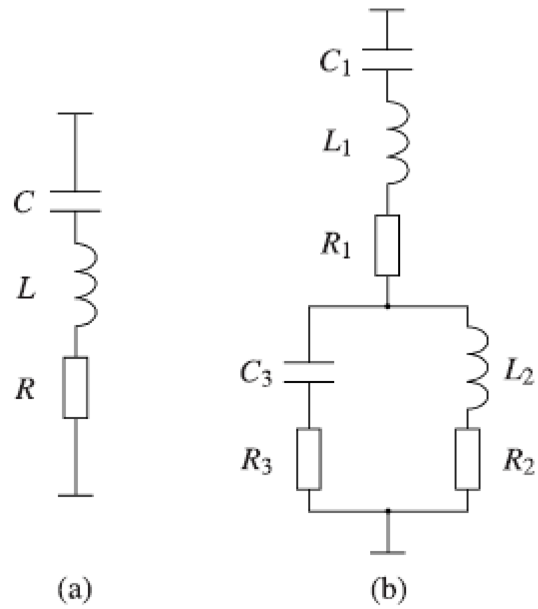


Figure 3.15: Passive tuned filters: (a) single tuned, and (b) double tuned

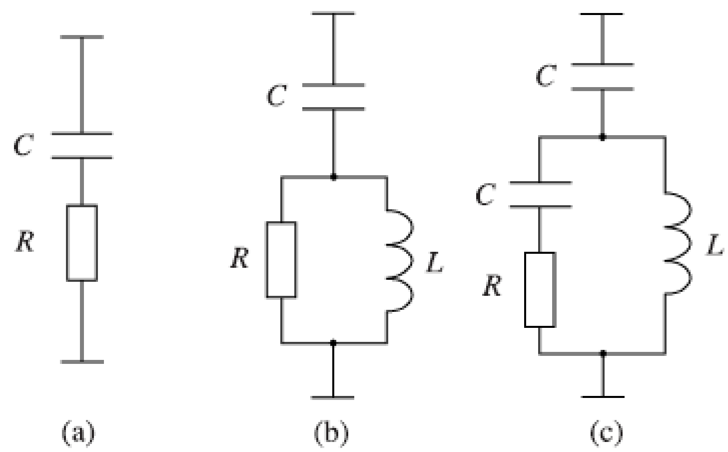


Figure 3.16: Passive high-pass filters: (a) first-order, (b) second-order and (c) third-order.

3.6 Protection of harmonic filters:

The protection of a harmonic filter is different than that of a shunt capacitor bank. Typically shunt capacitor banks are protected for case rupture by expulsion or current limiting fuses. For metal-enclosed capacitor banks, full-range current limiting fuses are used since they expel no gas during interruption and they limit fault damage. In addition to case rupture protection, ungrounded capacitor banks are typically protected by a sensitive unbalance protection system that protects the remaining good capacitors from overvoltages (due to neutral voltage shift) that result when a capacitor fuse blows. The above capacitor protection concerns also apply to harmonic filters, but filters have additional overcurrent protection concerns for the tuning reactor(s) [19].

The figure below shows a comprehensive harmonic filter bank protection system. The figure shows a filter bank feeder breaker connected to an ungrounded-wye connected harmonic filter bank. Several different relays are shown with their ANSI number designation

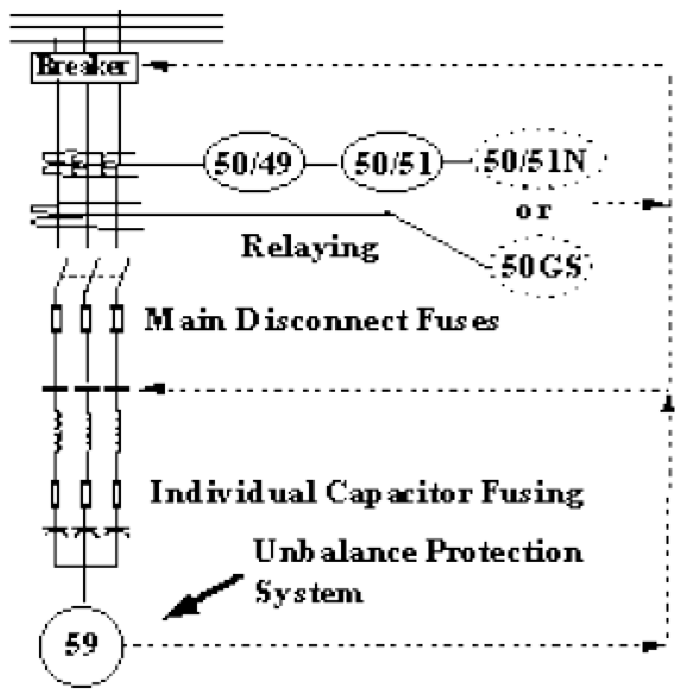


Figure 3.17: Typical harmonic filter protection system

The following points can be made in regards to figure 3.17.

- Resistive grounded systems may have low ground fault current levels and may not be detected by standard phase overcurrent relays or the main disconnect fuses. Therefore 50/51N or 50GS relays may be necessary.
- An upstream feeder breaker or an integral roll-out vacuum circuit breaker within the metal-enclosed filter bank will provide current interruption for faults

on the line side of the capacitors and may eliminate the requirement for the main disconnect fuses and switch.

The protection of a filter bank can be divided into two parts, capacitor protection, and reactor protection:

Reactor Protection

The tuning reactor should be protected for both faults and overloads. Overloads may occur for any of the following reasons:

- The addition of harmonic producing devices on the industrial system or nearby utility distribution system.
- An increase in the ambient harmonic voltage distortion.
- The malfunctioning of a non-linear load.
- A change in tuning point due to a blown capacitor fuse.
- An over voltage condition.

The overload protection is best achieved by a thermal overcurrent relay (Device 49) mounted in each phase of the filter bank. This relay is sensitive to RMS current and ambient temperature and can be set to trip at RMS current values that will cause damage to the reactor. This sensitive protection is not achievable with fuses and is more sensitive than a regular 51 relay. The thermal relay(s) should be wired to trip the filter bank by either the internal filter bank vacuum switches (for multi-stage banks with independent stage protection) or the upstream circuit breaker.

In addition to overload protection, the reactors should also be protected for phase and ground faults. Protection against phase faults can be achieved with current limiting fuses on the main disconnect switch or by 50/51 relays on the filter bank supply. If relays are to be used, they should be wired to trip the feeder breaker or the next upstream device since most filter bank capacitor switches (either oil switches, vacuum breakers, and vacuum contactors) are not rated to interrupt fault currents.

If the reactor is iron-core (enclosed filter banks usually are), consideration should be given to installing the current limiting fuses on the main disconnect even if a feeder breaker or integral breaker exist. The primary concern is the bracing of the iron-core reactor. During a load side reactor fault, full voltage is applied across the iron-core reactor, and it saturates to its low, air-core reactance. If this saturation affect is not accounted for in the original design (usually it is not due to cost), current limiting fuses should be considered.

Ground fault protection is not required on solidly grounded systems since they can be detected by the phase fault protective devices. For resistive grounded systems, however, a 50/51N or 50GS device is usually required. These devices can detect low level ground faults and can be wired to trip either the upstream breaker or the filter bank switches if the resistor rating is low enough.

Capacitor protection:

The filter capacitors should be protected against case rupture (due to internal capacitor faults) and overvoltages from blown capacitor fuses. In addition, the filter bank capacitors should be taken off line if one of the main disconnect fuses blow. This protection function is achieved with single ungrounded wye-connected capacitor banks with neutral unbalance protection systems."Individual capacitor fusing" is almost always necessary in ungrounded filter banks since a failed capacitor only draws three times the banks rating. In addition, high rated full range current limiting fuses are expensive. The fuses should have a voltage rating equal to the line-line voltage unless they are tested for voltages that exceed their normal rating. These capacitor fuses should be coordinated with the upstream disconnect fuses, thermal relays, and over current relays .In addition to the above protection system, it may be desirable to have overvoltage protection on the filter bank if the electrical system is not equipped with one. The main concern here is over voltages that can occur during light load and ground fault conditions.

CHAPTER FOUR

POWER TRANSFORMER PROTECTION

4.1 Introduction

Utility SVCs normally make use of a power transformer between the power grid and the SVC medium voltage (MV) busbar. On this bus harmonic filters, thyristor controlled reactors and capacitors are connected. In many cases, an auxiliary power transformer is also connected to this bus. It is important to note that the power transformer is the only connection of this bus to the mains. There are never several in feeds or more than one power transformer in the circuit. SVC transformers are, like generator transformers, made with a large turn ratios. The voltage on the SVC MV bus is typically in the span of 15-30 kV irrespective of the voltage level on the mains. A very normal transformer turn ratio is 400/25 kV. This large ratio results in very high short circuit currents on the MV bus, it is frequently in the range of 50-90 kA (rms symmetrical). The transformer current in its MV bushings also become large due to large power and low voltage, 5-15 kA are normal values. The large fault and load current currents must be considered when designing the protection system [20].

SVC transformers are made with large magnetic cores. The saturation voltage is typically as high as 120-125% of nominal voltage. This figure is derived from the large voltage variation on the SVC MV bus. The transformer impedance is normally close to 15% on its power rating. As the current through the transformer is purely reactive (inductive or capacitive) the voltage on the MV bus will vary +/- 15% when the SVC goes from fully capacitive to fully inductive operation. Typically the voltage reference for the SVC controller is settable between 100% and 110% voltage on the mains. Totally the voltage on the MV bus will vary from +25% to -15%. The power transformer must be designed not to saturate at maximum continuous voltage on this bus.

4.2Transformer faults

4.2.1 Faults within the transformer tank

These may comprise phase-to-earth, phase-to-phase, or inter turn faults on the windings, inter winding faults, tap changer faults, insulator bushing failure and core overheating due to failure of core insulation. The possibility of damage is high for these faults as is the risk of fire and short fault clearance times are advantageous. The connections of the power transformer and the method of earthing play an important part in determining current magnitude available for relay operation, and each case requires separate consideration.

For a resistance earthed, star-connected winding, a winding-to-earth fault will give rise to a current dependent on the value of the earthing resistor and the distance of the fault from the neutral end of the winding. The effective ratio of transformation between the primary winding and the short circuited portion of the secondary winding varies with the fault position. The current flowing through the transformer terminals is therefore, for all practical purposes, proportional to the square of the percentage of the winding short circuited as shown in Figure 4.1

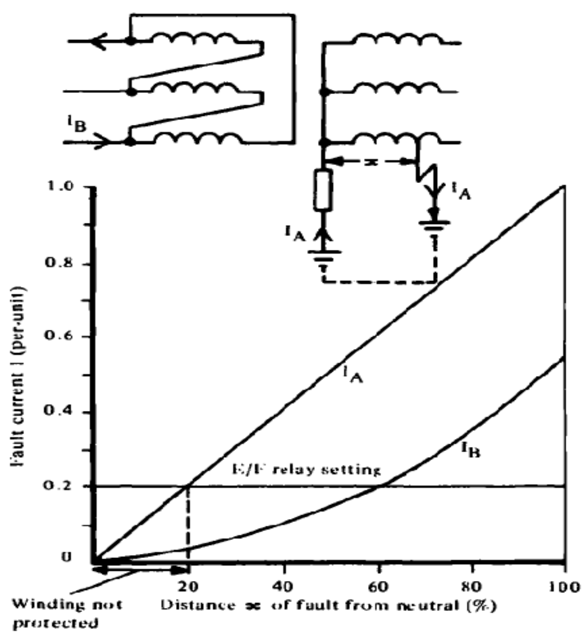


Figure 4.1: Transformer fault current for resistance earthed transformer star winding

For a solidly earthed star winding, the fault current bears no simple relationship to the distance of the fault from the neutral end since the effective reactance of the fault path changes with fault position. Figure 4.2 shows that the minimum value of fault current occurs for a fault 30 to 40% from the neutral end.

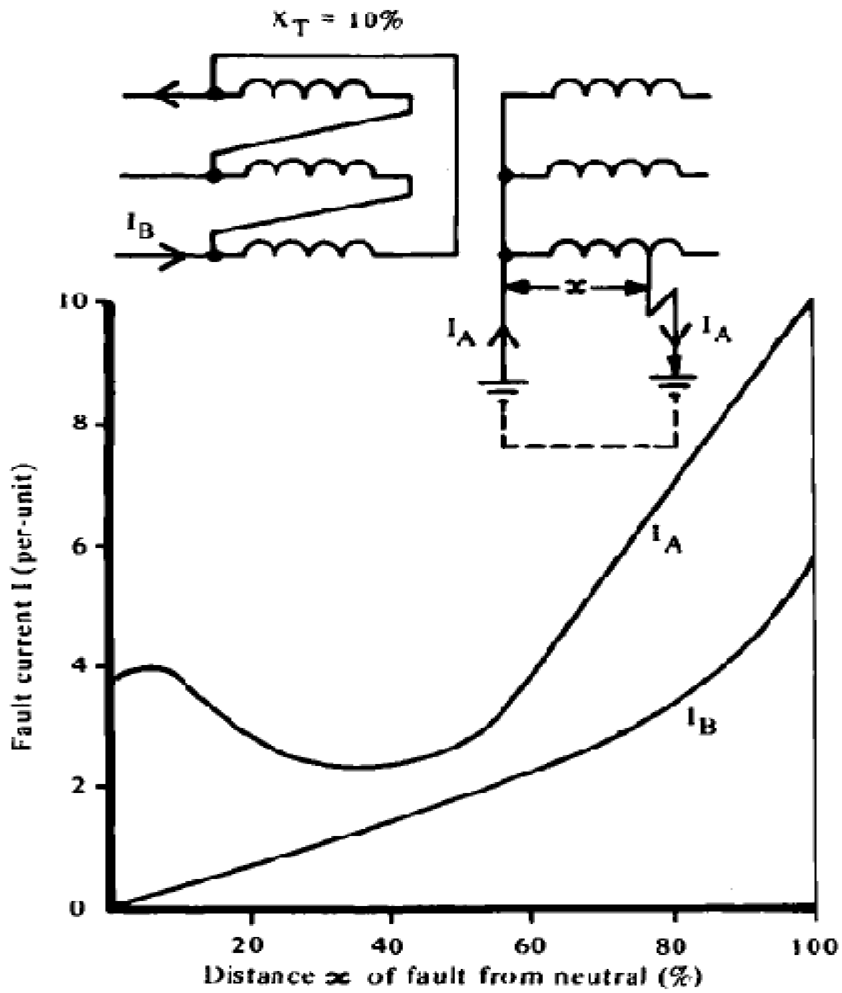


Figure 4.2: Transformer fault current for solidly earthed transformer star winding

For a delta connected winding the minimum voltage on the delta winding is at the centre of one phase and is 50% normal phase-to-earth voltage, and an illustration of the approximate method of calculation is given in Figure 4.3 The range of values of fault current varies less than with the star connected winding.

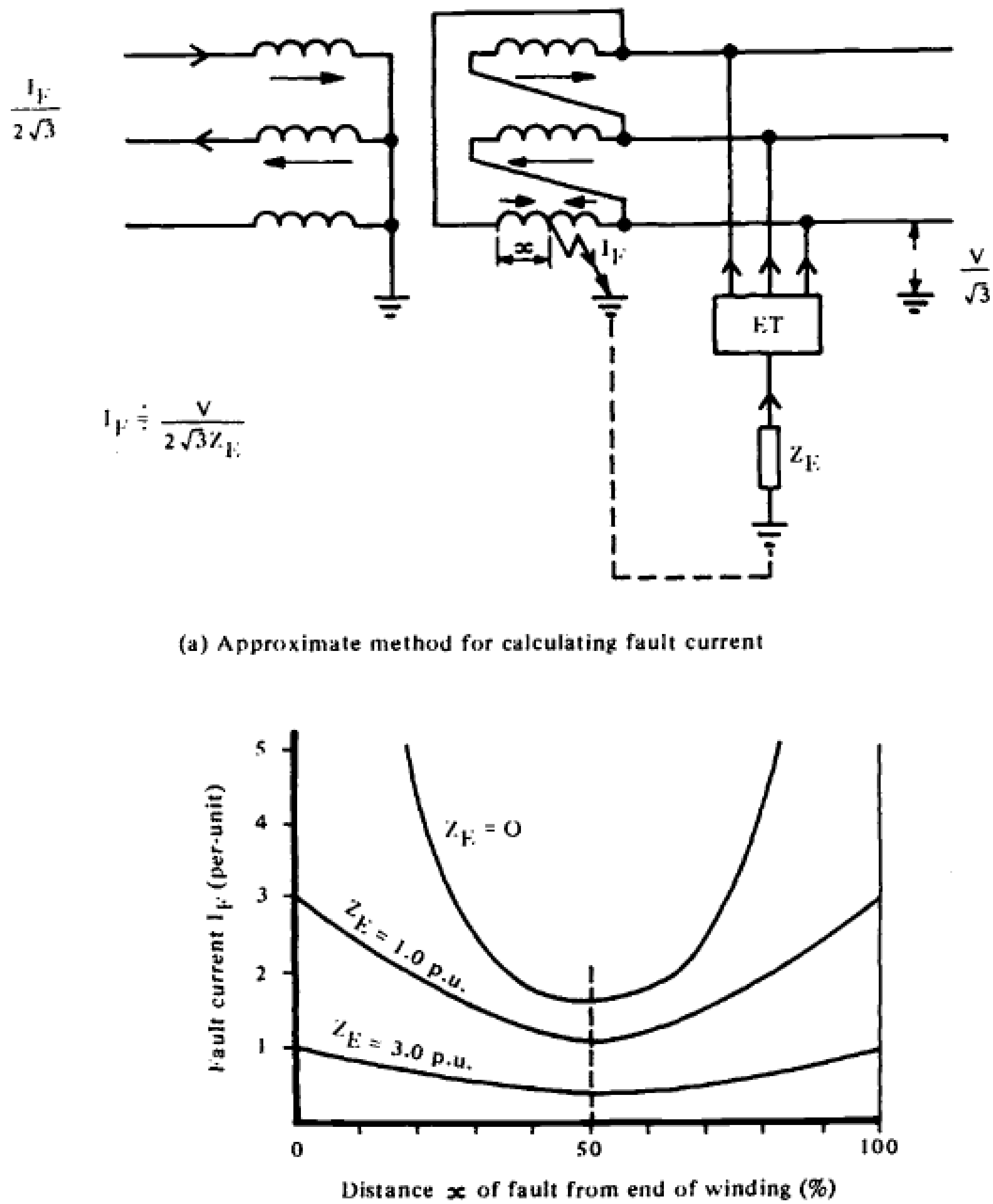


Figure 4.3: Transformer fault current for transformer delta winding

Phase-to-phase faults rarely occur on a power transformer. Clearly such faults will give rise to large currents. Interturn faults are more likely to occur than phase-to-phase faults. The interturn insulation on a power transformer is not as great as the interwinding insulation, and the possibility exists of breakdown between turns.

A short circuit of a few turns of the winding will produce a heavy current in the faulted loop and a very small terminal current. In this respect it has some similarity to a neutral end fault on a solidly earthed star winding.

Core faults can occur due to lamination insulation becoming short circuited. This can cause serious overheating due to eddy current losses. Core clamping bolts must always be insulated to prevent this trouble. If core insulation becomes defective (due, possibly, to the failure of core bolt insulation or debris in the tank), it must be detected quickly.

4.2.2 Faults on transformer connections

These may comprise any type of normal system fault on open copper work connections or flashover of co-rdinating gaps. Damage due to such faults is not usually great though they may constitute a serious hazard to power system stability if not cleared quickly. Faults between the current transformers and the associated circuit breaker have to be included in this category.

4.2.3 *Overheating*

Failure of the cooling system will cause overheating and consequent danger of damage to the windings.

4.2.4 Faults external to the transformer zone

These will be of the usual range of system earth and phase faults to be cleared by appropriate external protection systems. They will affect, therefore, only the requirement of transformer back-up protection.

4.3Protection Schemes of Power Transformer

4.3.1differential Protection

Differential protection, as its name implies, compares currents entering and leaving the protected zone and operates when the differential current between these currents exceed a pre-determined level. The type of differential scheme normally applied to a transformer is called the current balance or circulating current scheme.

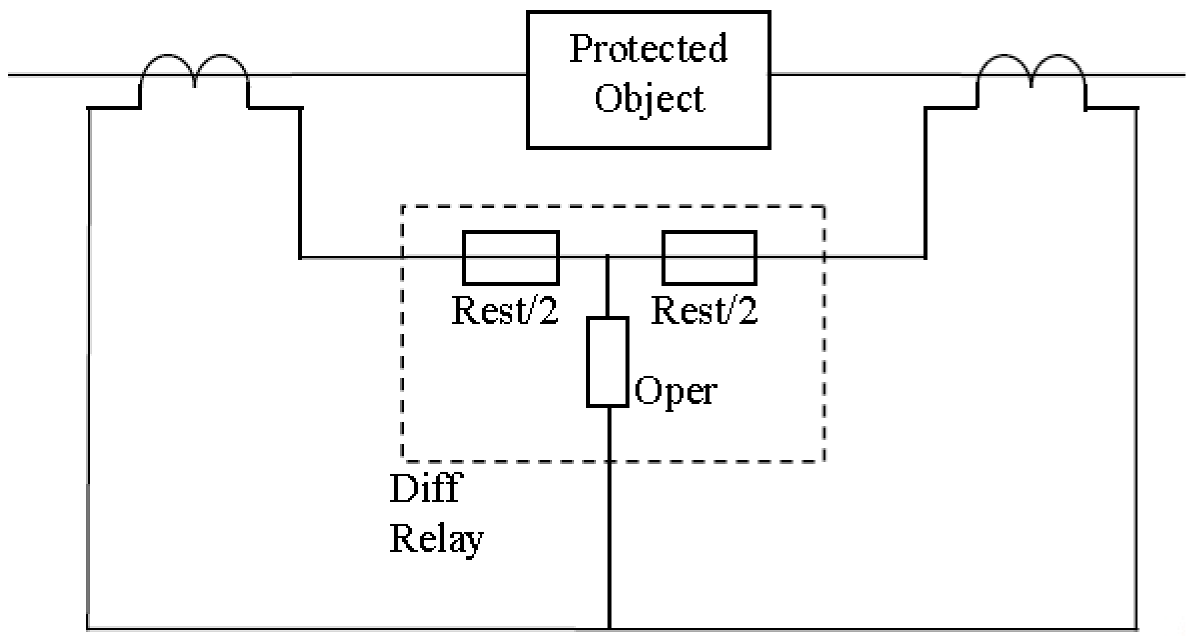


Figure 4.5: Differential protection scheme

This part of the research describes how to calculate the settings for two-winding power transformer differential protection [21].

4.3.1.1 Starting ratio

Under ideal circumstances, and when there is no fault inside the protection zone, the differential current is zero. However, due to CT inaccuracies and varying tap changer positions (power transformer applications); the differential current deviates from zero in practice. An increasing the load current cause the differential current to grow at the same percentage rate. The Starting ratio setting affects the slope of the relay operating characteristics between the 1st (fixed 0.5

x In) and the 2nd turning-point (Turn-point 2): an increase in the load current causes the differential current required for tripping to increase with the set percentage.

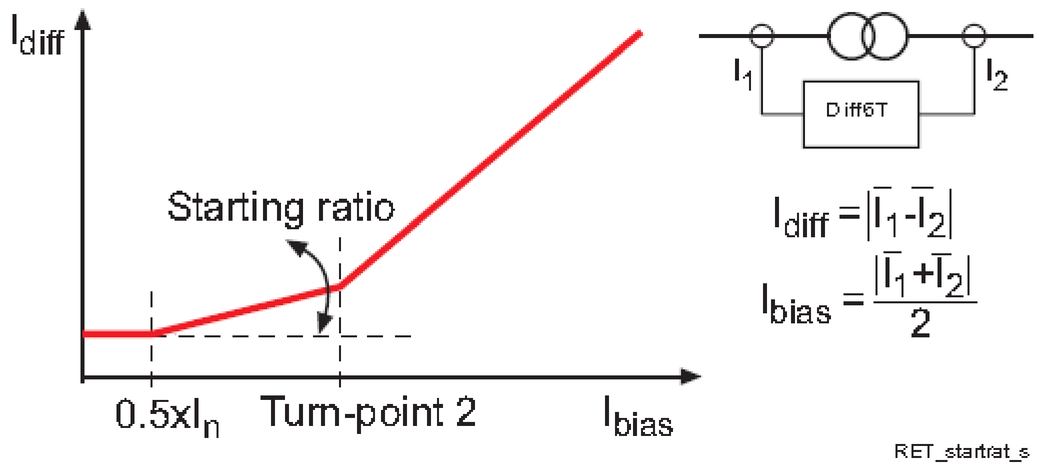


Figure 4.5: Setting parameters of the differential relay

4.3.1.2 Basic setting

The Basic setting defines the minimum sensitivity of the protection. Basically, it allows for the no-load current of the power transformer, but it can also be used to influence the overall level of the operation characteristic. At rated current the no-load losses of the power transformer are less than 1 per cent at rated voltage. Should, however, the supply voltage of the transformer suddenly increase due to operational disturbances, the magnetizing current of the transformer increases as well. In general, the magnetic flux density of the transformer is rather high at rated voltage and a voltage rise of a few per cent will cause the magnetizing current to increase by tens of per cent. This should be considered in the Basic setting.

Basic setting = 0.5 x Starting ratio + P’ (4.1)

Where P’ represents the no-load losses of the transformer at maximum voltage. Typically, P’ = 10% is used if the actual value is unknown.

4.3.1.3 Turn-point 2

The 2nd turning-point defines the point in the operation characteristics at which the influence of the starting ratio ends and a constant 100% slope begins. Beyond this point, the increase in the differential current is equal to the corresponding increase in the stabilizing current.

Finding settings for the differential protection is always balancing between stability and sensitivity. The smaller the 2nd turning-point setting is the more stable and less sensitive the protection is. And vice versa, the higher the setting is, the more sensitive and less stable the protection is.

4.3.1.4 Instantaneous differential current stage (Inst.setting)

The Inst.setting is set high enough to prevent the differential function from tripping when the transformer is energized. Normally, the peak value of the asymmetric inrush current of the transformer is considerably higher than the peak value of the symmetric inrush current. Typically, the amplitude of the fundamental frequency component is only half of the peak value of the inrush current. Thus the instantaneous setting can be set below the peak value of the asymmetric inrush current. In power transformer protection the setting value of the instantaneous differential current stage is typically 6...10.

It is recommended to use the instantaneous tripping limit (Inst.setting) together with the low-set stage, because, in the event of a serious fault, it will provide faster protection than the low-set stage. Further, it will not be blocked by harmonics.

4.3.1.5 Second harmonic blocking (Ratio I_2f/I_1f>)

Power transformers are ferromagnetic devices. At the moment of energization, the power transformer draws a magnetizing inrush current, which is perceived by the differential protection relay solely as a differential current.

Because the transformer magnetizing impedance is non-linear, the inrush current contains a lot of second order harmonics. A well-known principle is to detect an inrush situation from the content of the 2nd order harmonics and block the differential protection relay (low-set stage) for the time of the inrush.

The recommended setting for the second harmonic blocking is 15% in power transformer protection.

4.3.2 Restricted earth fault protection:

A simple over current and earth fault relay will not provide adequate protection for winding earth faults. Even with a biased differential relay installed, the biasing desensitizes the relay such that it is not effective for certain earth faults within the winding. This is especially so if the transformer is resistance or impedance earthed, where the current available on an internal fault is disproportionately low. In these circumstances, it is often necessary to add some form of separate earth fault protection. The degree of earth fault protection is very much improved by the application of unit differential or restricted earth fault systems as shown in Fig6.

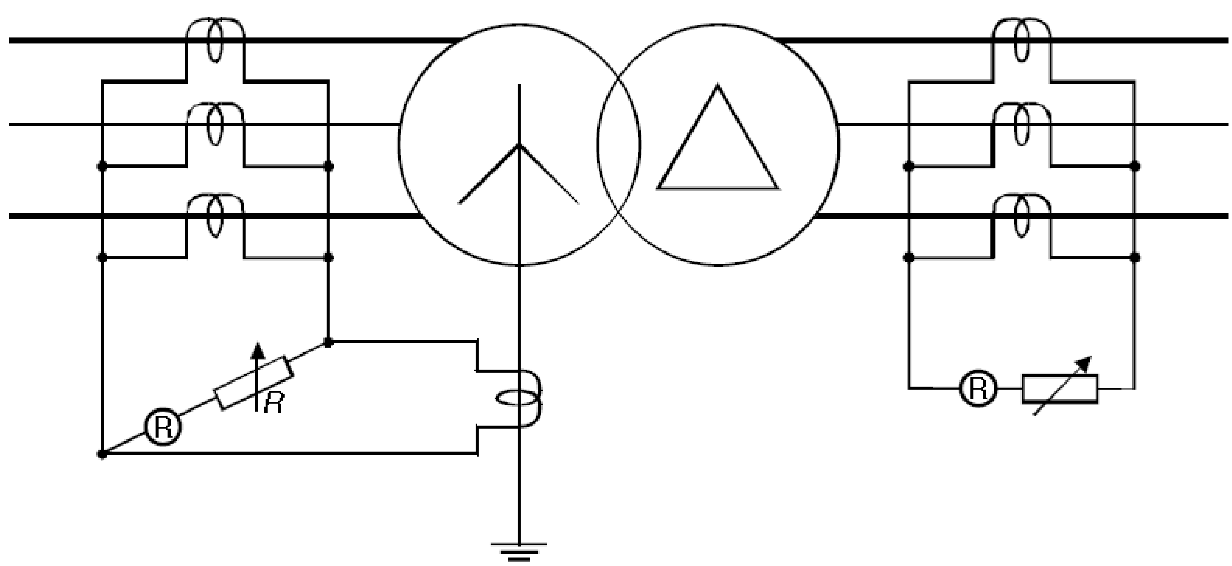


Figure 4.6: restricted earth fault protection

The restricted earth-fault protection is designed to detect high-resistance earth faults within the protection zone of power transformers. There are two operation principles available, i.e. the biased differential scheme and the phase comparison scheme. The biased differential scheme can be used, if the actual accuracy limit factor of the CT is sufficient for the application. In the case of heavy CT saturation, the phase comparison scheme is recommended to be used instead, to avoid unwanted tripping[20].The relay is connected to the current transformers in such a way as to measure the difference in earth fault current 'entering' the protected zone with that 'leaving' the protected zone. Where no internal earth fault occurs and the CTs transform perfectly the differential current is zero.

High impedance differential protection must

1- Guarantee stability for all load and through fault conditions. Note that due to transient CT errors (e.g. CT saturation) the CTs may not transform perfectly.

Stability of the protection is achieved by using a relay operating voltage that is greater than the maximum voltage which can appear across the relay under given through fault conditions.

2- Guarantee operation for internal fault conditions. The minimum primary operate current is defined as the 'fault setting'.

The relay fault setting is calculated taking into account: the required operate level for in-zone earth faults.

The following the research describes how to calculate the settings for two-winding power transformer restricted earth fault protection [22].

4.3.2.1 Operate voltage setting

The minimum required relay operate voltage setting (Vs) is given by:

$$V_s > I_f * (R_{ct} + R_l) * T \qquad (4.2)$$

Where

Vs is relay operate voltage setting

I_f Is the maximum assigned through fault current for transformer?

R_{ct} is ct resistance

R_l is terminal resistance

T is ct turns ratio

To ensure high speed relay operation the relay circuit operating voltage should be selected in accordance with the stability requirement above (equation 1), also, the operate voltage should not exceed 0.5 x CT knee point voltage (V_k).

$$V_s \leq \frac{V_k}{2} \qquad (4.3)$$

4.3.2.2 Primary operate current (fault setting)

For internal faults the relay will operate at the calculated 'Voltage SettingV_s'. This operating voltage will also be applied across the CT secondary windings of all the CT secondaries connected in parallel with the relay. This voltage will drive a magnetizing current in each of the CT secondary windings and this must be added to the relay operate current when calculating the operate current of the high impedance protection scheme.

$$P.O.C = \frac{(I_S + I_{NLR} + \sum I_{MAG})}{T} \qquad (4.4)$$

Where

P.O.C = Primary operate current (fault setting)

I_{MAG} = Secondary magnetising (exciting) current of current transformer at V_s

I_{NLR} = Non-linear resistor (Metrosil) current.

Is = Relay setting current

4.3.2.3 Series stabilizing resistance

When fully saturated the CT secondary provides no current and it behaves as a resistance in the secondary circuit. Differential current in the secondary circuit will flow either through this 'resistance' or through the relay. A 'stabilizing' resistance is added in series with the relay input to ensure that the operate voltage at the current setting is greater than the maximum voltage which can appear across the element/stabilizing resistor during the maximum assigned through fault current. It is assumed that any earthing resistor can become short-circuit.

$$V_s = I_s \, x \, R_{stab} \tag{4.5}$$

4.3.3 Over current and earth fault protection

It is a common practice to install an IDMT over current and earth fault relay on the HV side of a transformer. The inherent time delay of the IDMT element provides back-up for the LV side. High-set instantaneous over current is also recommended on the primary side mainly to give high-speed clearance to HV bushing flashovers. Care must be taken, however, to ensure that these elements do not pick-up and trip for faults on the LV side as discrimination is important. For this reason, it is essential that the HSI element should be of the low-transient overreach type, set approximately to 125% of the maximum through-fault current of the transformer to prevent operation for asymmetrical faults on the secondary side.

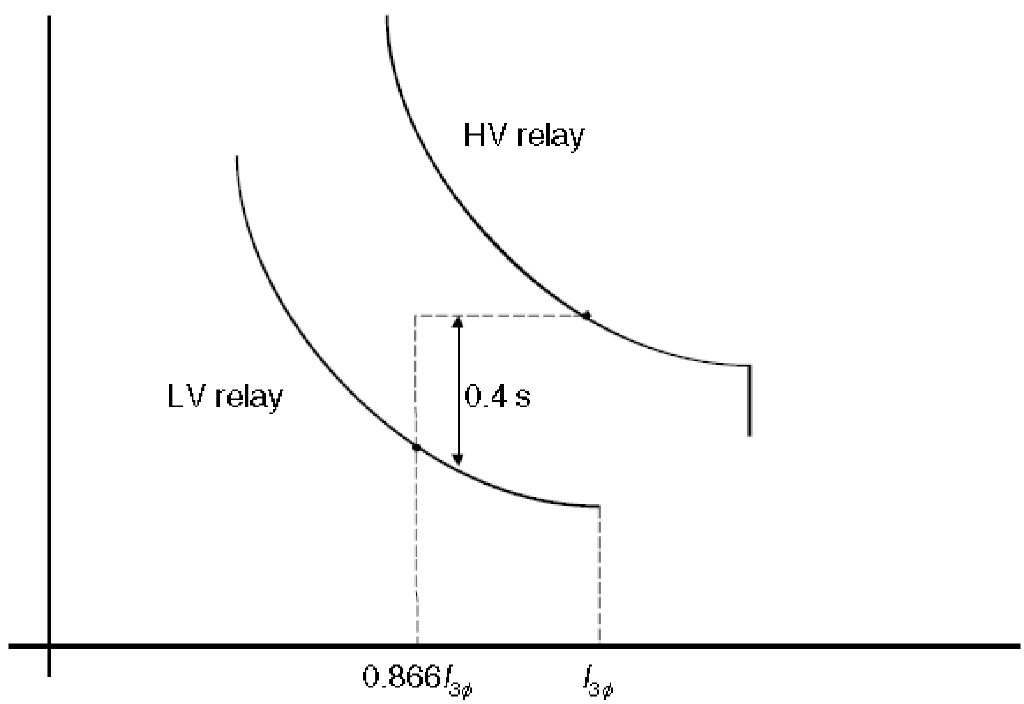
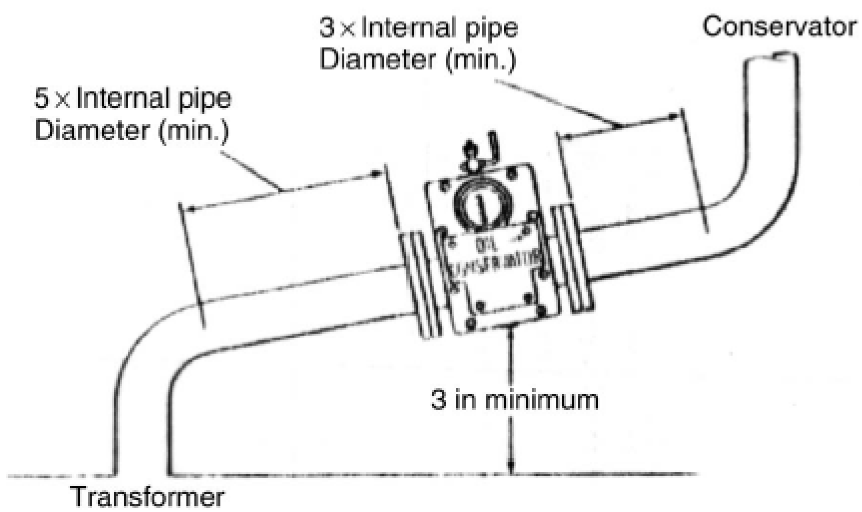


Figure 4.7: setting of the over current protection for the transformer

4.3.4 Buchholz protection

Failure of the winding insulation will result in some form of arcing, which can decompose the oil into hydrogen, acetylene, methane, etc. Localized heating can also precipitate a breakdown of oil into gas.

Severe arcing will cause a rapid release of a large volume of gas as well as oil vapor. The action can be so violent that the build-up of pressure can cause an oil surge from the tank to the conservator. The Buchholz relay can detect both gas and oil surges as it is mounted in the pipe to the conservator Figure 4.8.



4.8: Buchholz relay in the transformer

4.3.6 Overloading

A transformer is normally rated to operate continuously at a maximum temperature based on an assumed ambient. No sustained overload is usually permissible for this condition. At lower ambient it is often possible to allow short periods of overload but no hard and fast rules apply, regarding the magnitude and duration of the overload. The only certain factor is that the winding must not overheat to the extent that the insulation is cooked, thereby accelerating ageing. A winding temperature of 98 °C is considered to be the normal maximum working value, beyond which a further rise of 8–10 °C, if sustained, is considered to half the life of the transformer. Oil also deteriorates from the effect of heat. It is for these reasons that winding and oil temperature alarm and trip devices are fitted to transformers.

Typical settings (e.g. Eskom) normally adopted (unless otherwise recommended by the manufacturers) are as follows:

Winding temperature alarm = 100 °C

Winding temperature trip = 120 °C

Oil temperature alarm = 95 °C

Oil temperature trip = 105 °C

On the larger transformers, cooling fans and pumps are employed to control the temperature. In many cases, normal practice seems to be to use IDMT over current relays for overload protection, CT ratios being chosen on the basis of the transformer full load current.

CHAPTER FIVE

SIMULATION AND RESULTS

5.1 Background

There are nine substations in SUDAN, and every substation will be equipped one set of SVC. Considering the different electrical condition, the capacity of SVC settled in the substation is also different. This simulation is done to verify the characteristic of protection system of single SVC. According to the configuration, here we choose LOCAL MARKET substation. The substation diagram of LOCAL MARKET and The single-line diagram of SVC are shown in appendix (A). The single-line diagram of TCR is shown in Figure5.1.

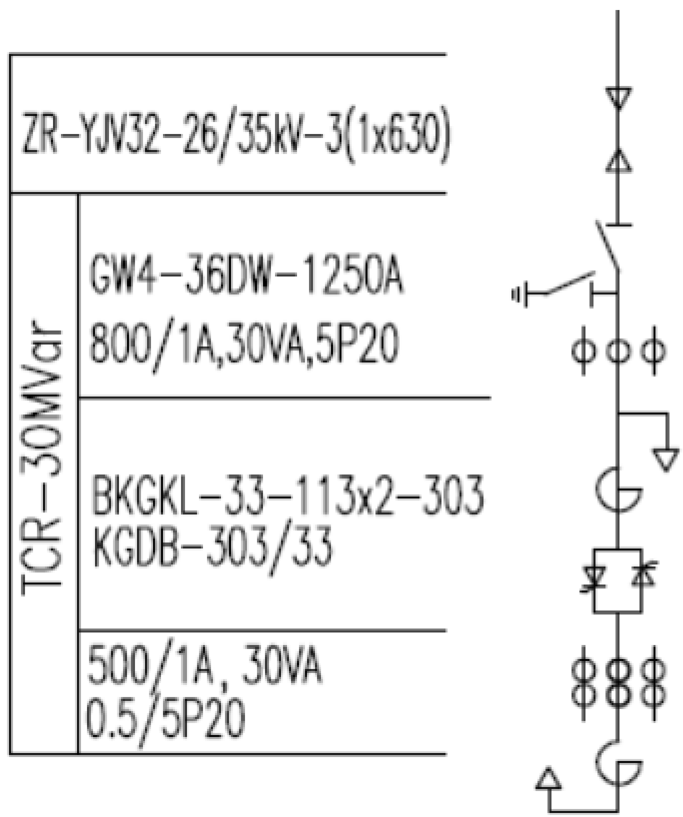


Figure 5.1:single line diagram of TCR of Local Market substation

5.2 System Simulation Based

The system is simulated in MATLAB SIMULINK software environment using the operational data given in Figure5.1 this module is designed to be used for the protection of the SVC in the control system of the SVC. The following figures show the components of the model.

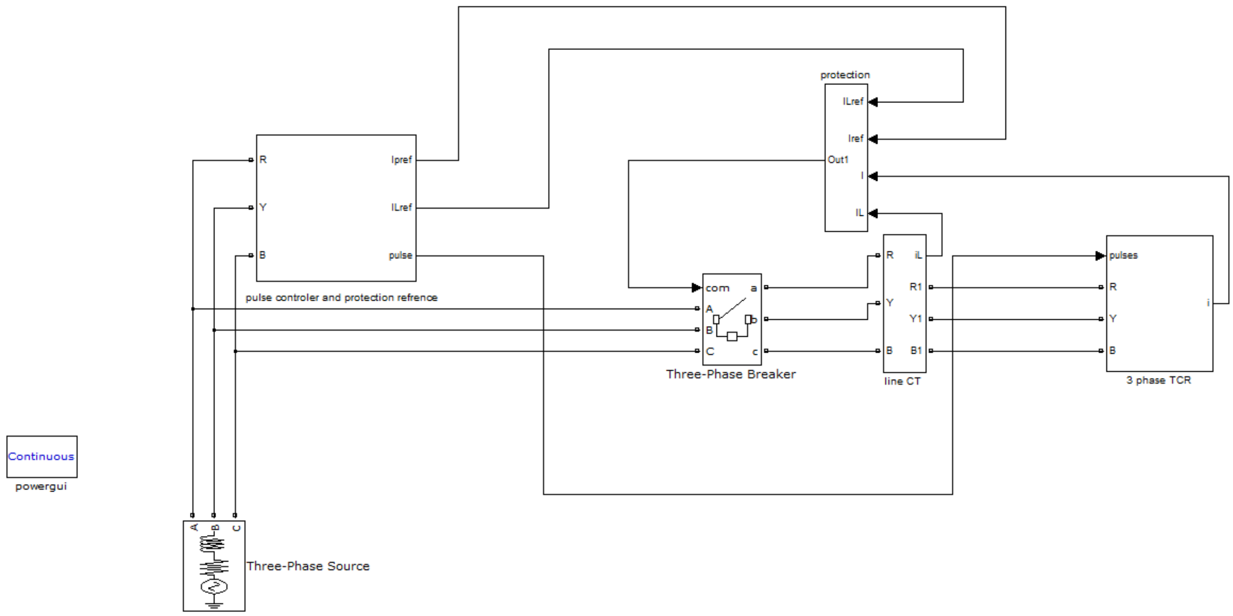


Figure 5.2: Model in MATLAB SIMULINK

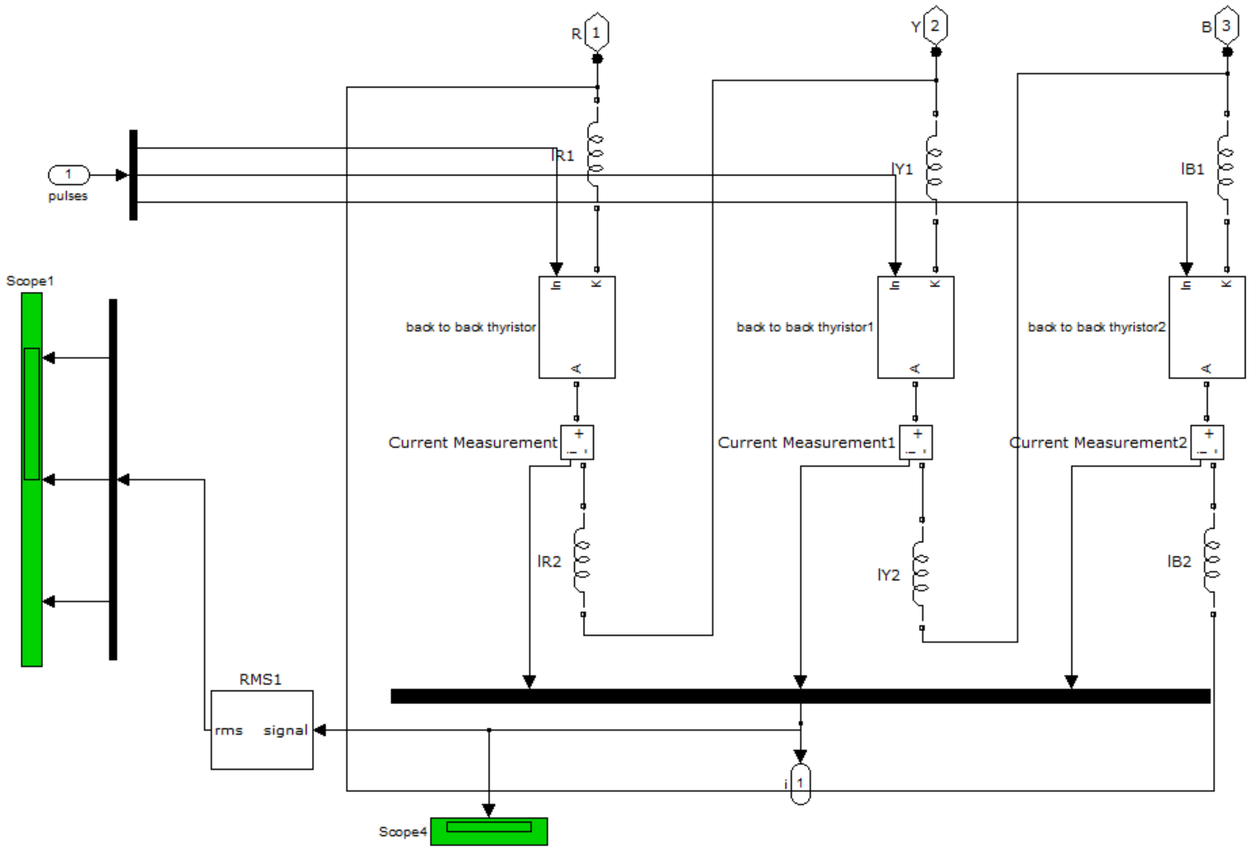


Figure 5.3: TCR model

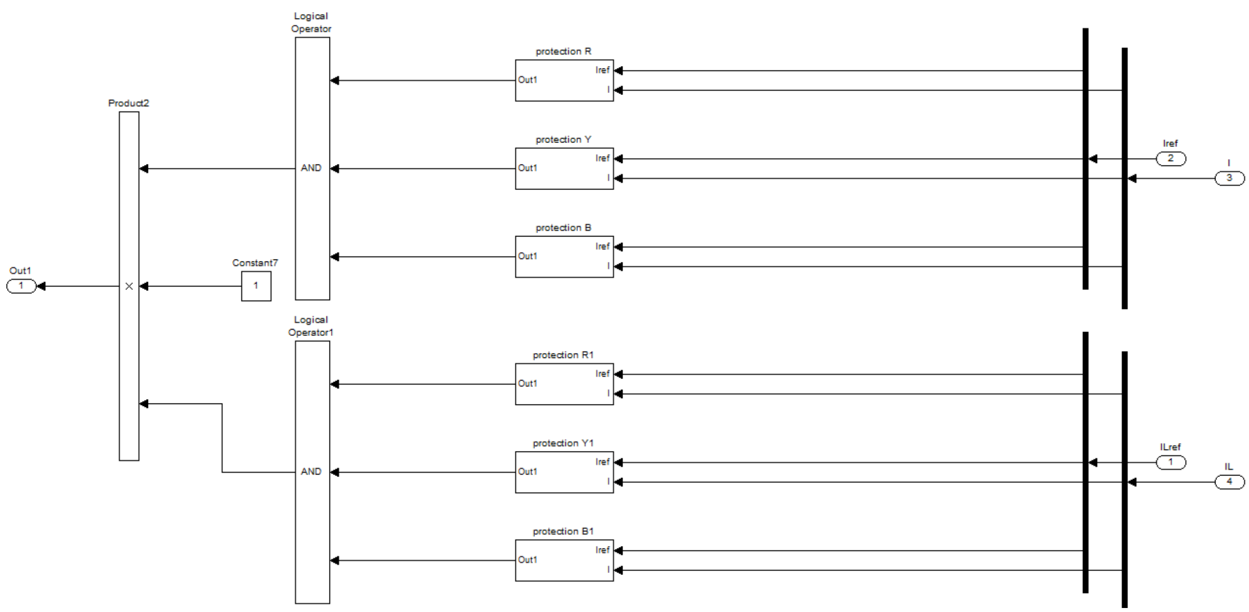


Figure 5.4: protection control subsytem

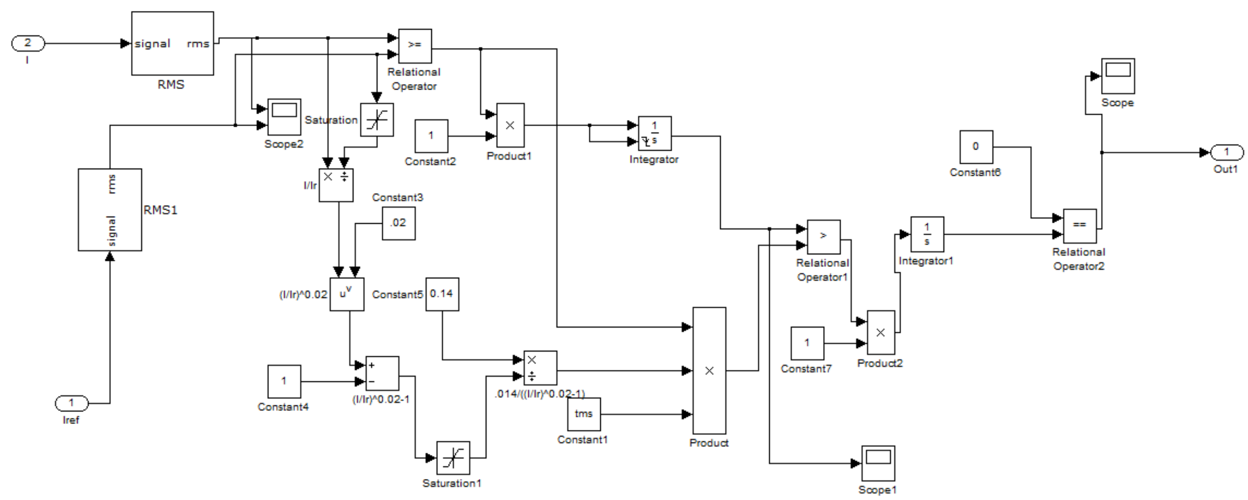


Figure 5.5: protection control sytem

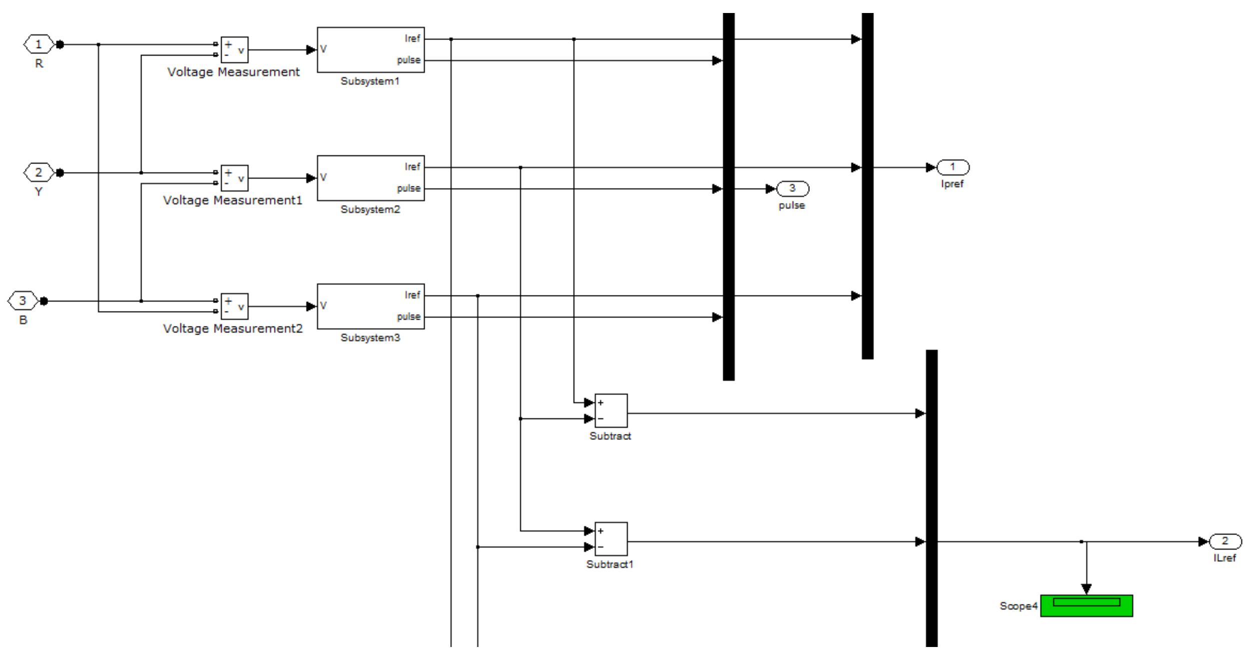


Figure 5.6: Pulse Control and protection reference subsystem

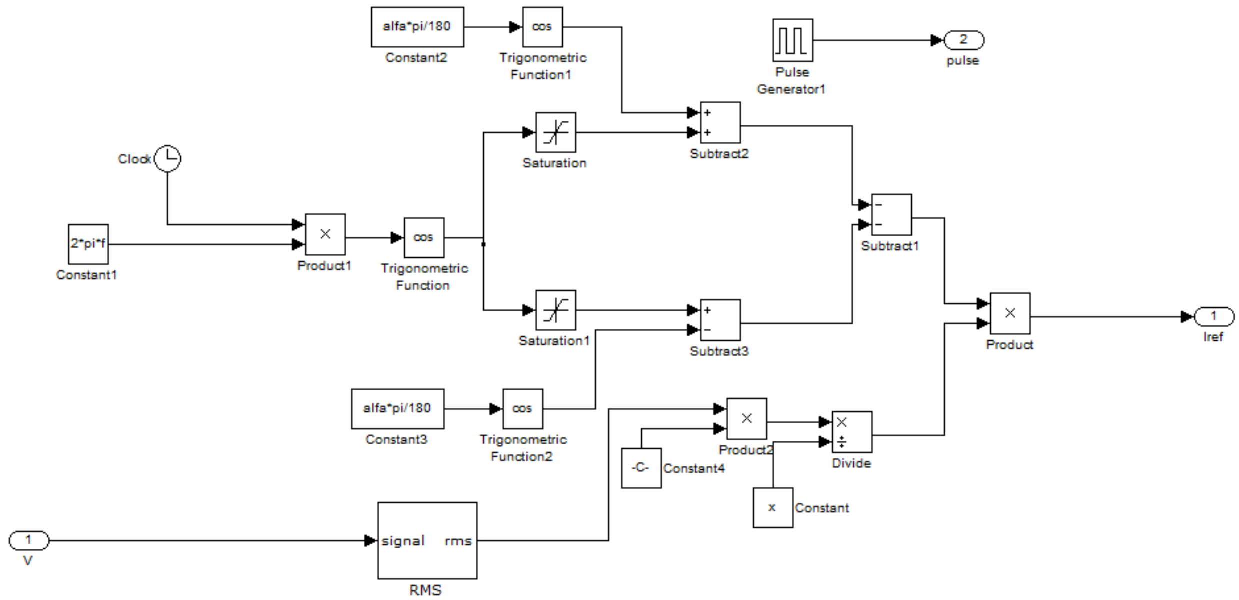


Figure 5.7: Pulse Control and protection reference subsystem

5.3 Normal operation of SVC without faults

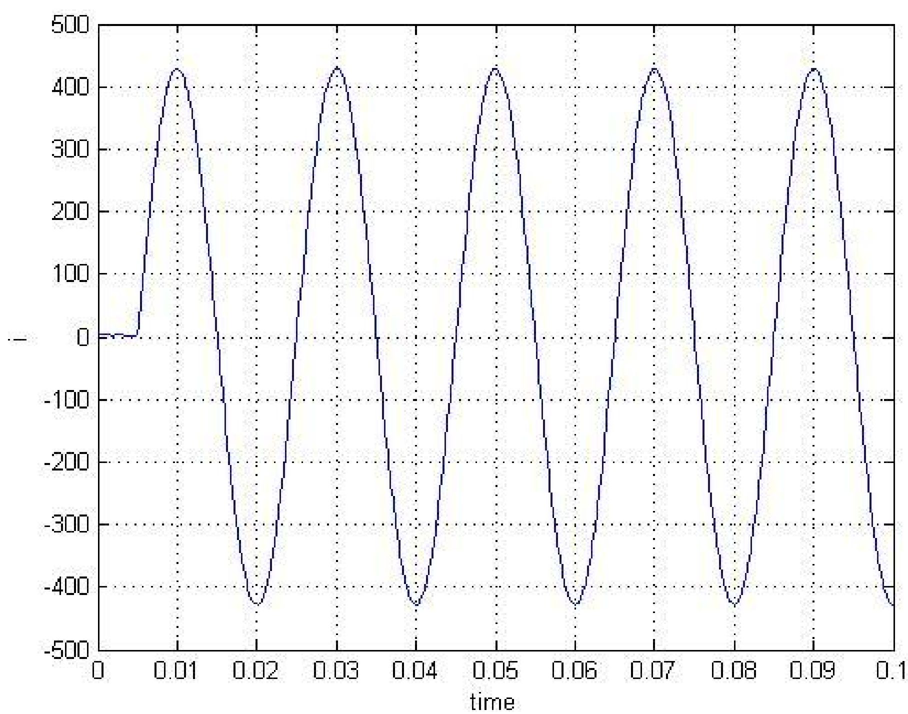


Figure 5.8: Phase currents when $\alpha = 90$

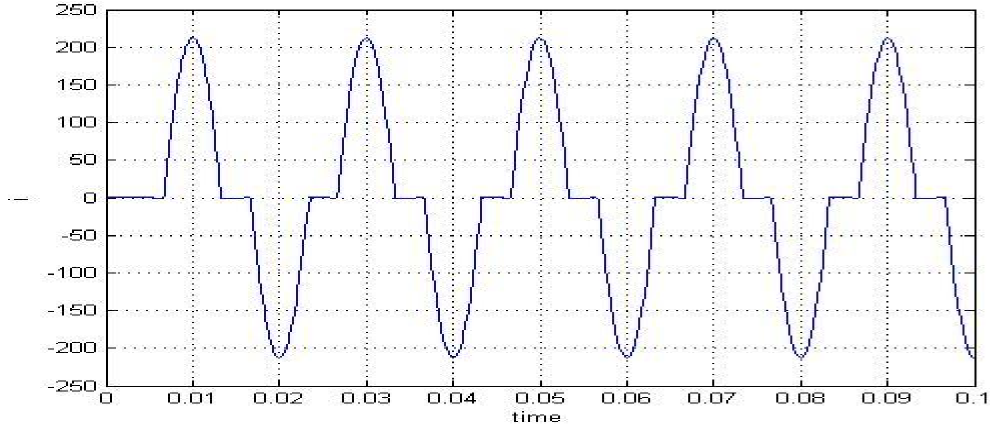


Figure 5.9: Phase currents α = 120

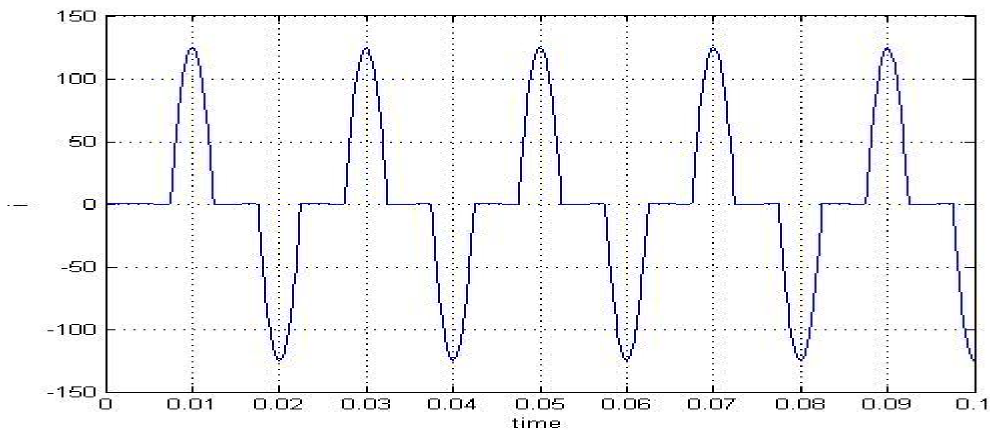


Figure 5.10: Phase currents α = 135

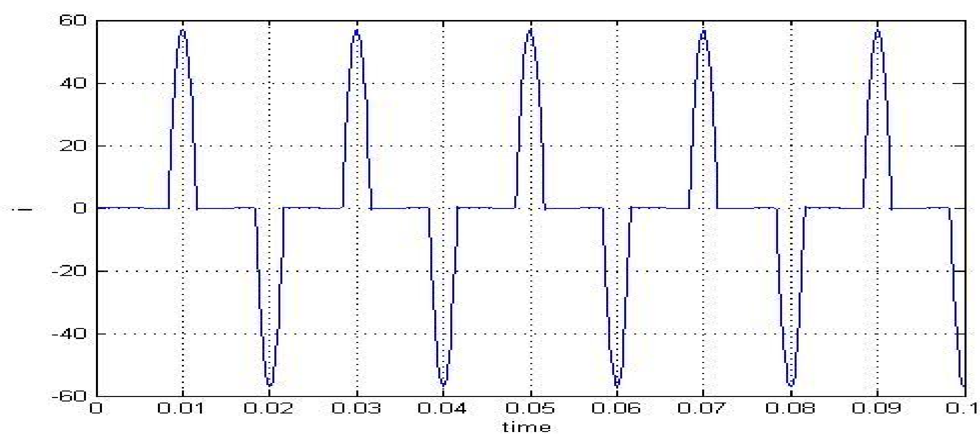


Figure 5.11: Phase currents α = 150

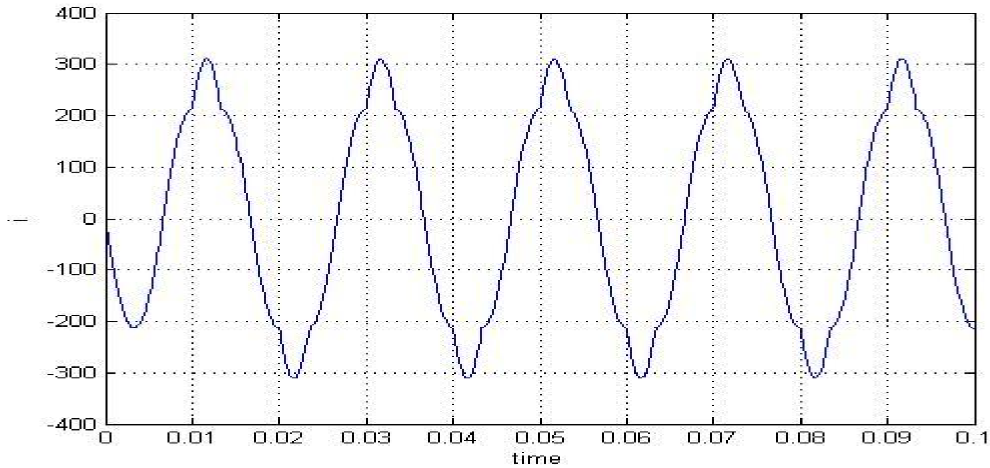


Figure 5.12: Line currents α = 120

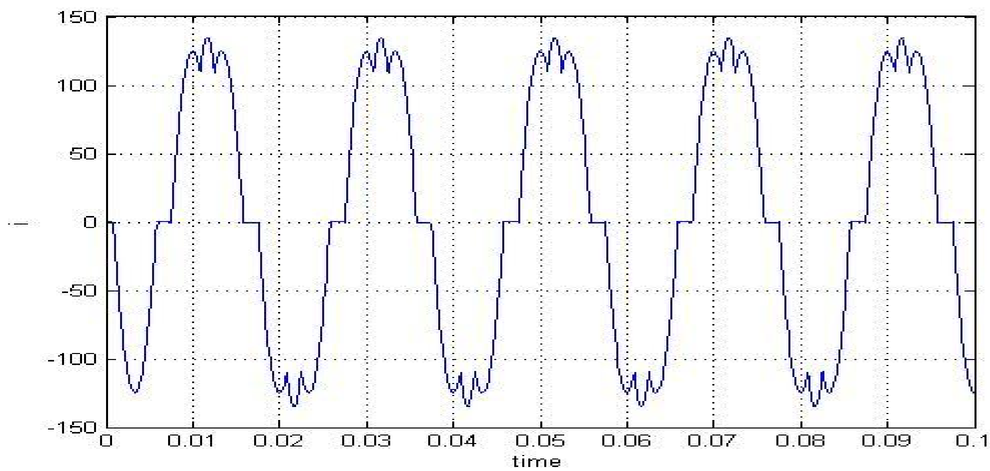


Figure 5.13: Line currents α = 135

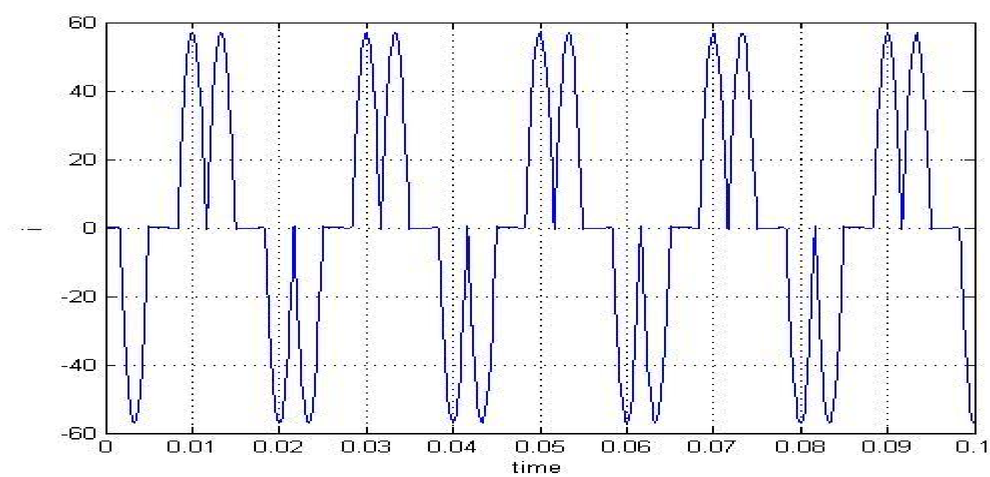


Figure 5.14: Line currents α = 150

Table (5.1): line and phase currents for different firing angles.

Firing angle (α)	MVAR	Phase wave			Line wave		
		I_{peak}	I_{RMS}	Harmonic Distortion	I_{peak}	I_{RMS}	Harmonics Distortion
90	30	429.4A	303A	0%	744.1A	524.7A	0%
120	12.31	213.1A	124.4A	39.76%	308.6A	201.3A	9.71%
135	6.3184	124.6A	63.82A	60.8%	134.6A	95.53A	15.2%
150	2.3661	56.95A	23.9A	95.77%	56.95A	33.78A	52.65%
180	0	0	0	100%	0	0	100%

During normal operation of TCR each line and phase currents proportionally affected by change in firing angle from rated current when $\alpha = 90$ to zero when $\alpha = 180$ this variation in current affect in the reactive power absorbed by the TCR. Which varies from 30MVAR when $\alpha = 90$ to zero when $\alpha = 180$. Also harmonics produced by the TCR increase with the increase in firing angle. From the results we find that total harmonic distortion of the wave of line current is less than that of wave of phase current this because TCR is delta connected so the line current wave does not contains the third order harmonic.

5.4 short-circuit at the terminal of one of two reactors in TCR

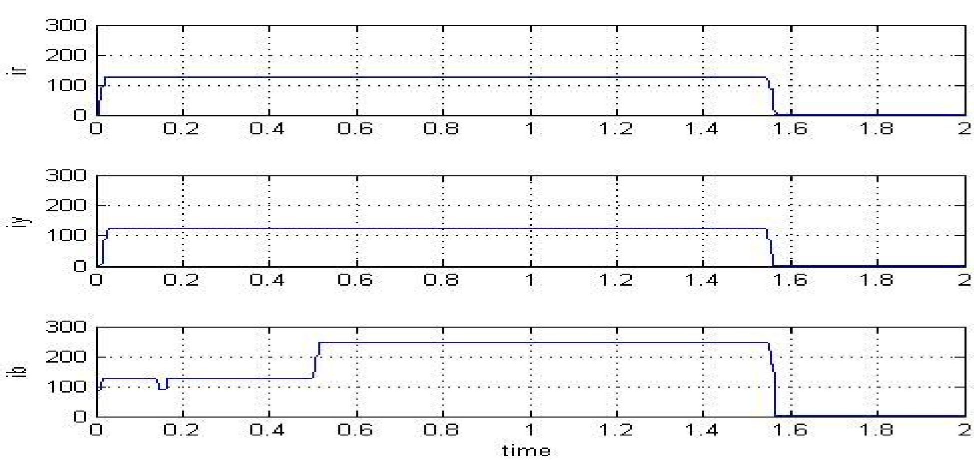


Figure 5.15: RMS of phase currents during a short circuit in the terminal of one of the reactors $\alpha = 120$

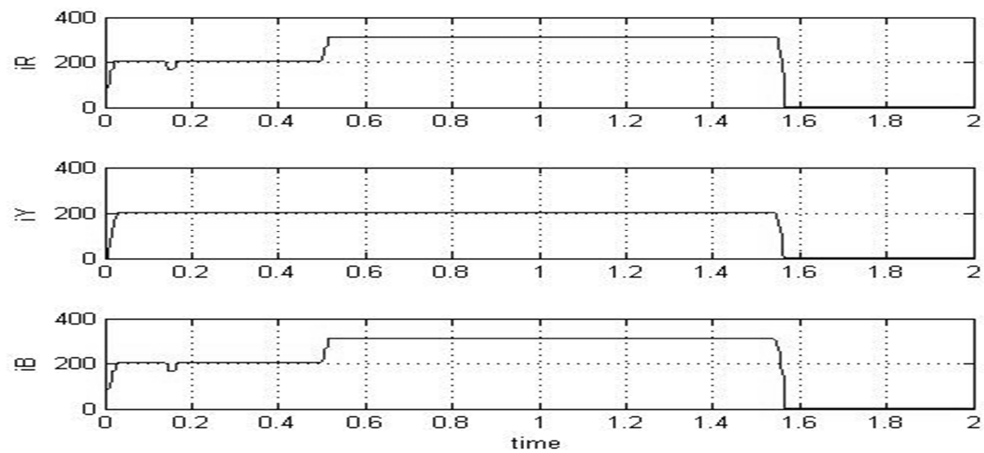


Figure 5.16: RMS of line currents during a short circuit in the terminal of one of the reactors α = 120

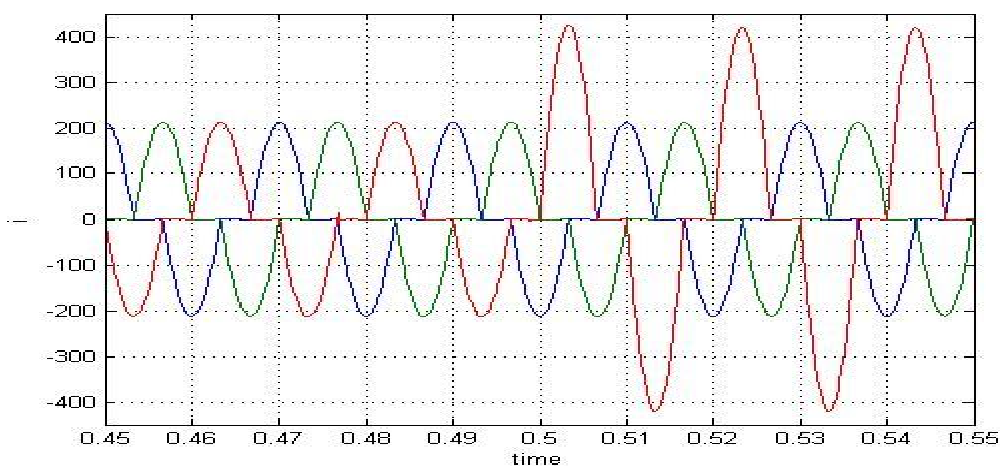


Figure 5.17: phase currents during a short circuit in the terminal of one of the reactors α = 120

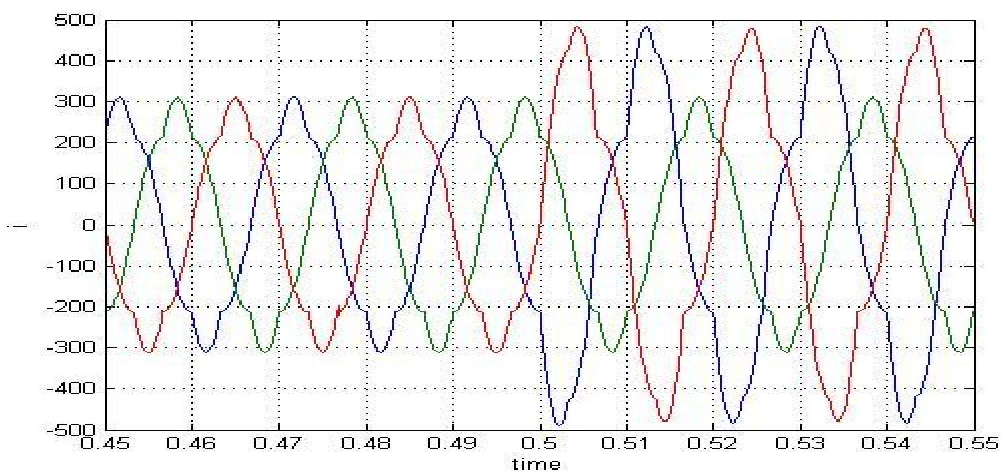


Figure 5.18: line currents during a short circuit in the terminal of one of the reactors α = 120

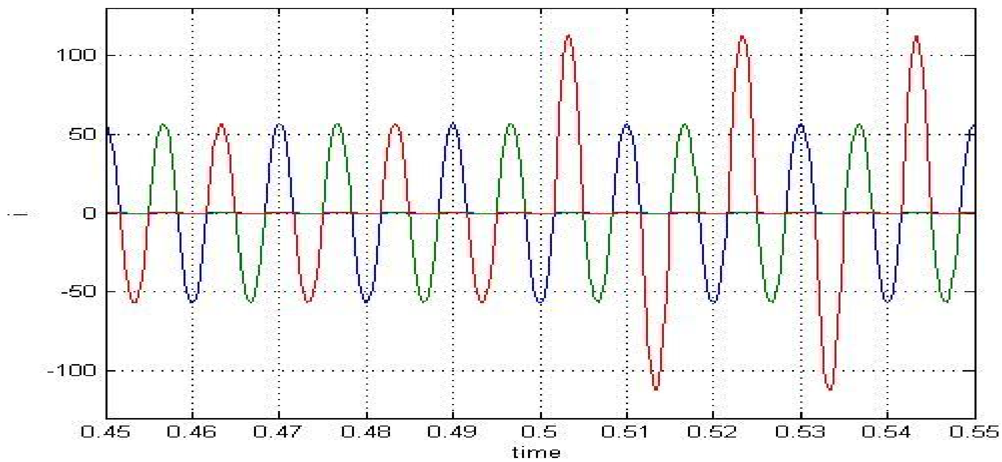


Figure 5.19: phase currents during a short circuit in the terminal of one of the reactors α = 150

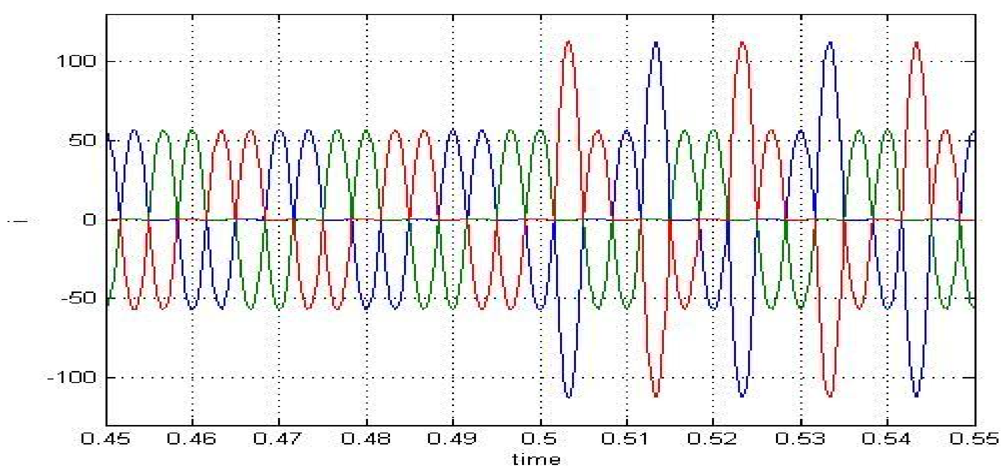


Figure 5.20: line currents during a short circuit in the terminal of one of the reactors α = 150

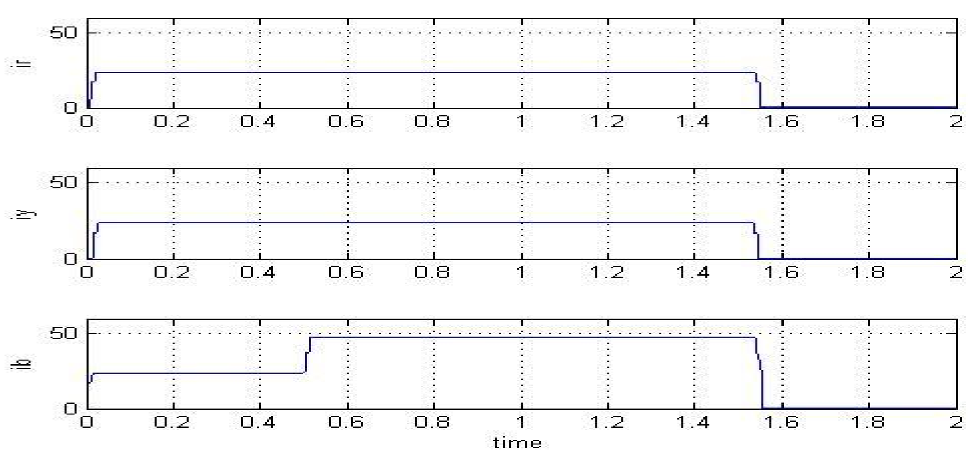


Figure 5.21: RMS of phase currents during a short circuit in the terminal of one of the reactors α = 150

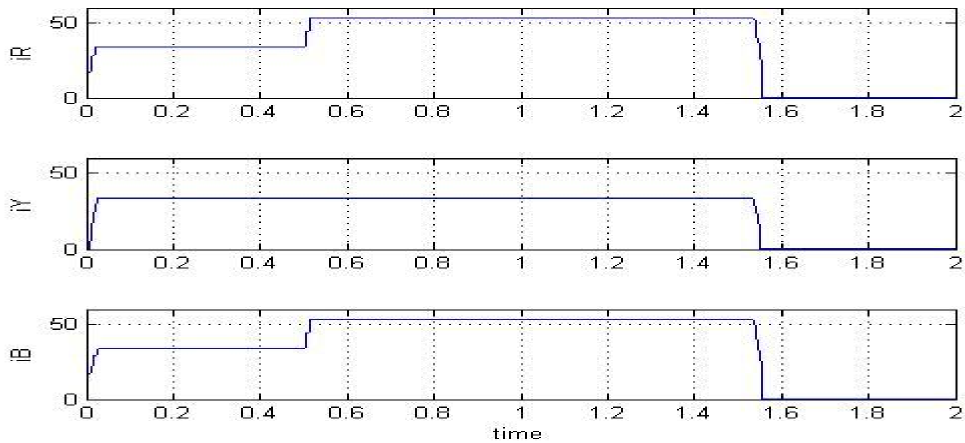


Figure 5.22: RMS of line currents during a short circuit in the terminal of one of the reactors $\alpha = 150$

Table (5.2): currents during a short circuit in the terminal of one of the reactors

	$\alpha = 90$	$\alpha = 120$	$\alpha = 135$	$\alpha = 150$
Phase Normal current	301.5A	125.13A	63.8A	23.9A
Phase Fault current	592.7A	247.8A	125.9A	47.4A
Line Normal current	521.9A	204.0A	95.5A	33.8A
Line Fault current	797.1A	311.3A	147.7A	53.0A
Tripping time of C.B	1 s	1 s	1 s	1 s

From the results it is clear that when a fault accurse at the terminal of one of the two reactors the line and currents during the fault become two times of the normal currents without faults this is because the total fault impedance is half of total inductance of the two reactors.

Also the fault current decrease proportionally with the increase in firing angle this is because the time of connection between the reactor and the voltage source decrease with the increase in firing angle.

The time of tripping of the fault for all cases is the same because the protection system compares between the fault current and the normal operation current while it has the same ratio for firing angles the tripping time is the same.

5.5 phase faults inside and outside of the TCR

5.5.1 3 phase fault inside the TCR

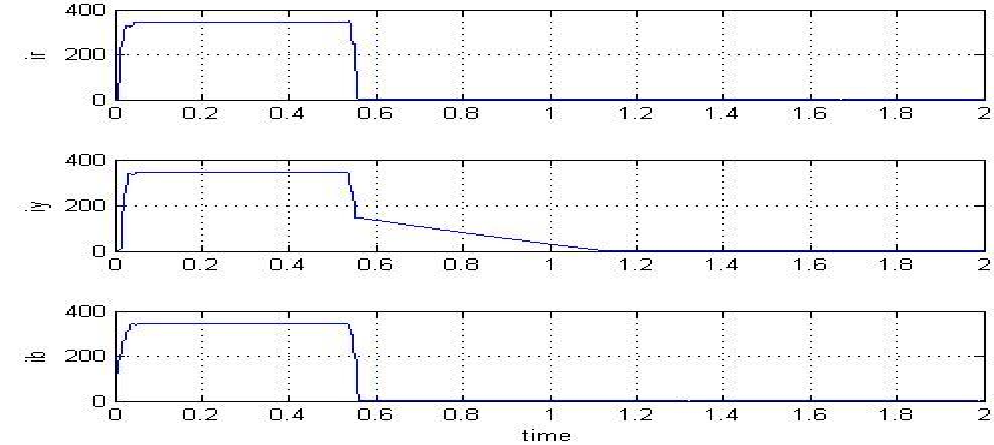


Figure 5.23: RMS of phase currents during 3 phase fault inside the TCR when $\alpha = 120$

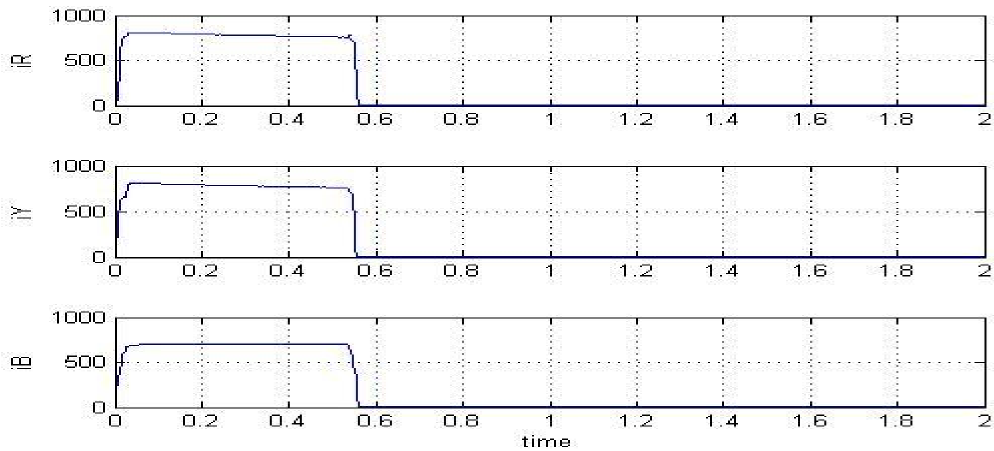


Figure 5.24: RMS of line currents during a 3 phase fault inside the TCR when $\alpha = 120$

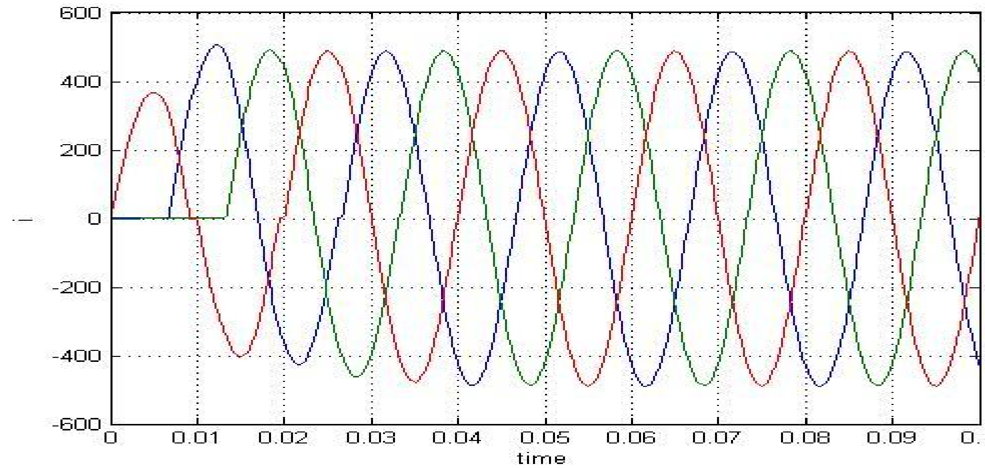


Figure 5.25: phase currents during a 3 phase fault inside the TCR when α = 120

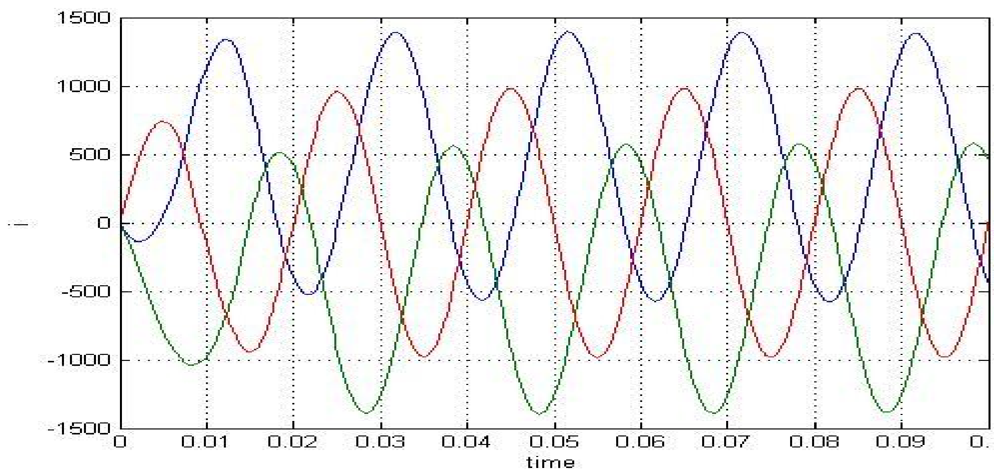


Figure 5.26: line currents during a 3 phase fault inside the TCR when α = 120

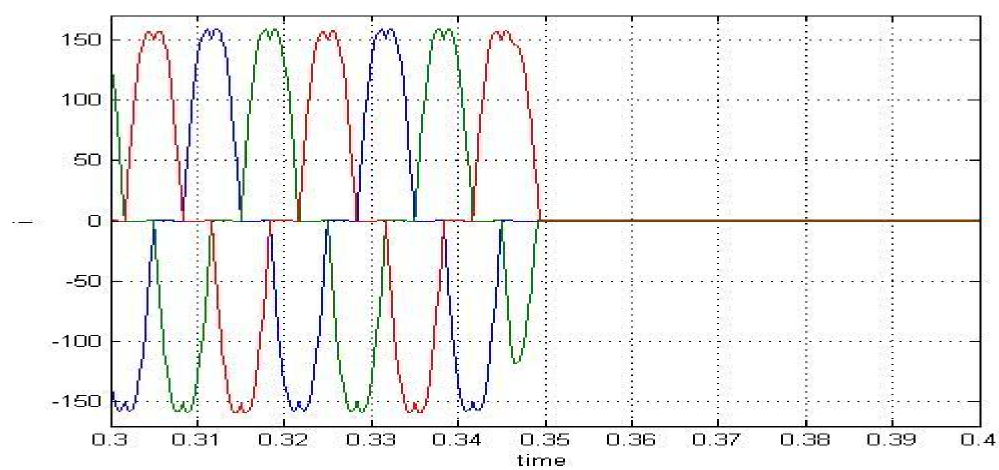


Figure 5.27: phase currents during a 3 phase fault inside the TCR when α = 150

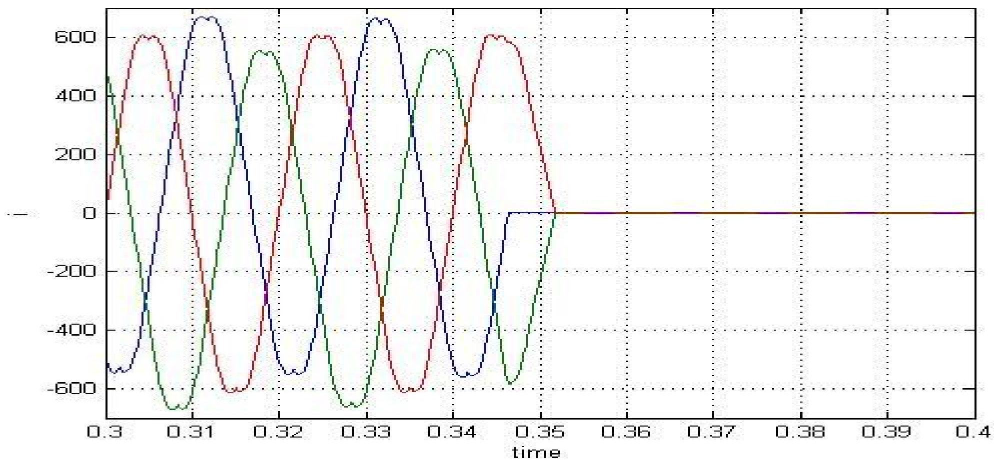


Figure 5.28: line currents during a 3 phase fault inside the TCR when α = 150

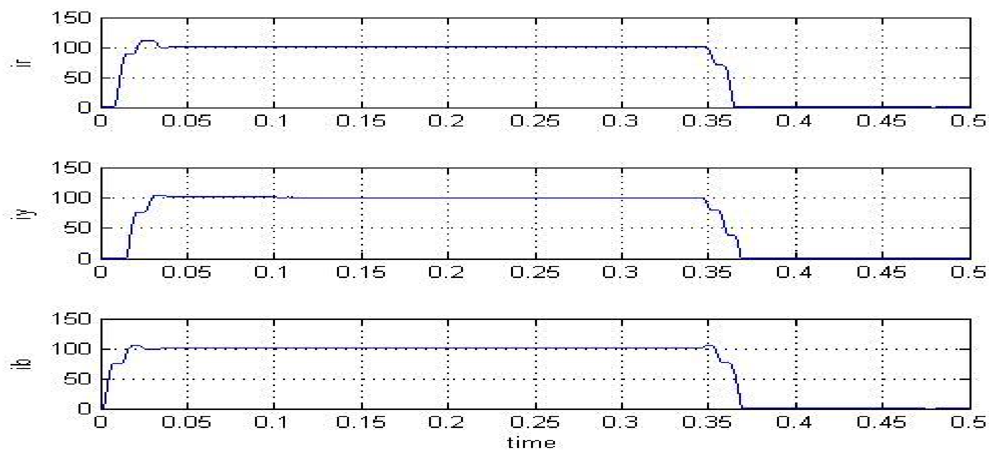


Figure 5.29: RMS of phase currents during a 3 phase fault inside the TCR when α = 150

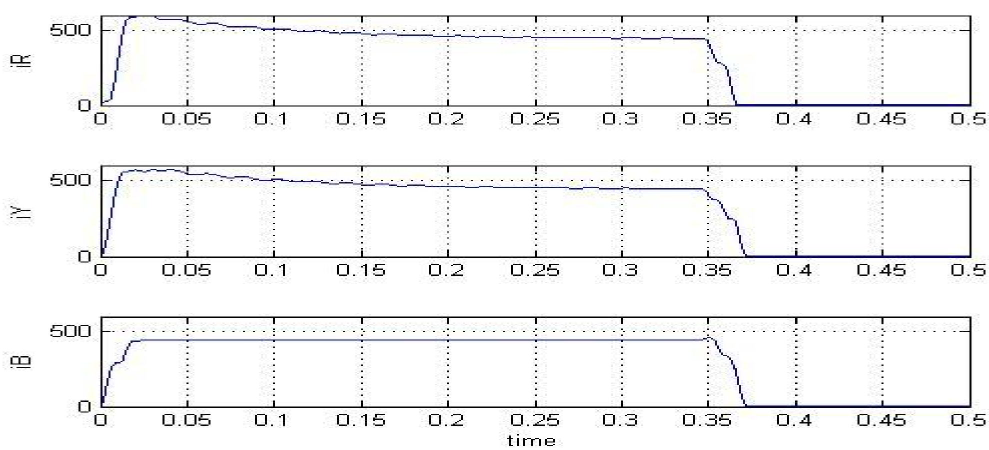


Figure 5.30: RMS of line currents during a 3 phase fault inside the TCR when α = 150

5.6.2 3 phase fault outside of the TCR

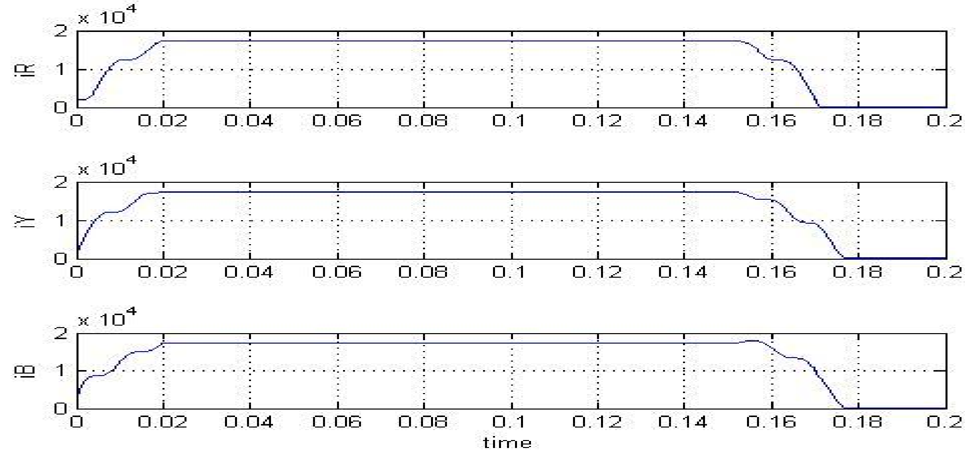


Figure 5.31: RMS of line currents during a 3 phase fault outside the TCR $\alpha = 120$

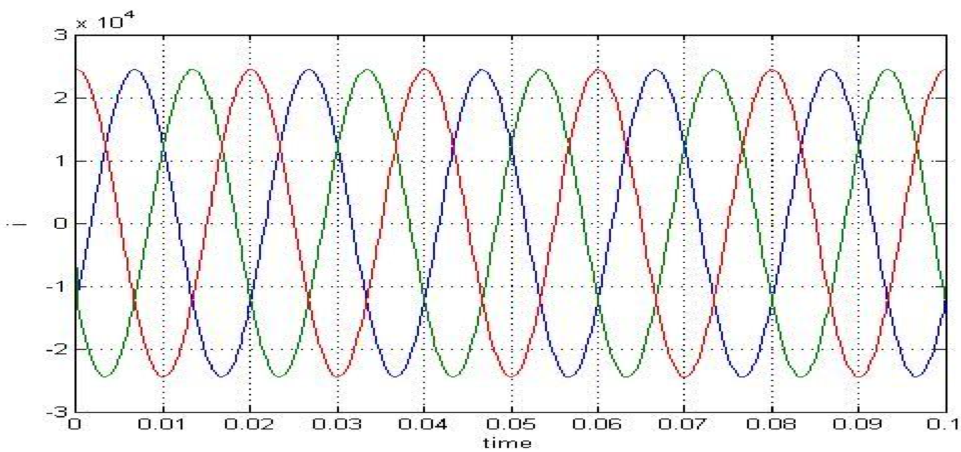


Figure 5.32: line currents during a 3 phase fault outside the TCR $\alpha = 120$

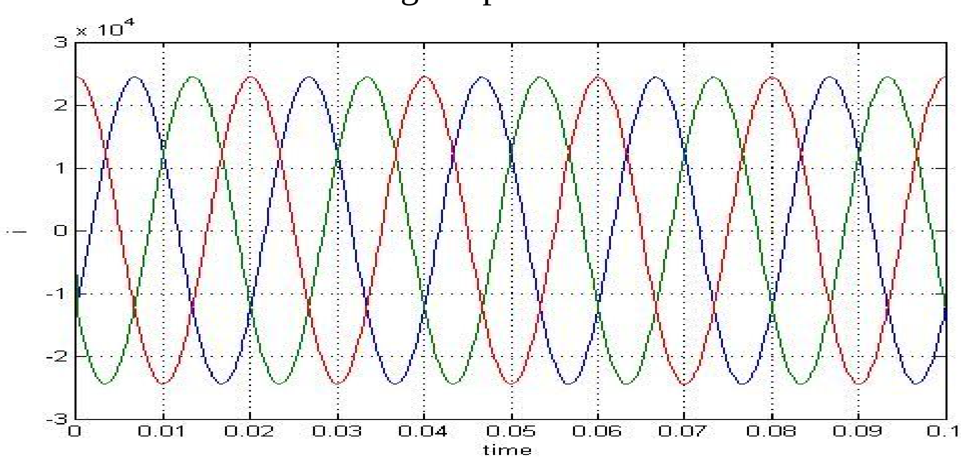


Figure 5.33: line currents during a 3 phase fault outside the TCR $\alpha = 150$

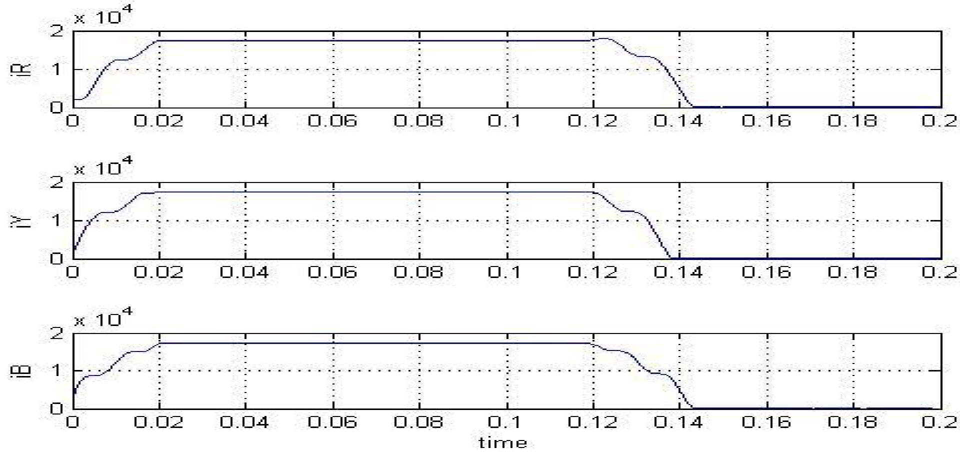


Figure 5.34: RMS of line currents during a 3 phase fault outside the TCR α = 150

Table (5.3): currents during 3 phase faults inside the TCR

	α = 90	α = 120	α = 135	α = 150
Phase Normal current	301.5A	125.13A	63.8A	23.9A
Phase Fault current	386.8A	345.2A	215.4A	104.7A
Line Normal current	521.9A	204.0A	95.5A	33.8A
Line Fault current	790A	695A	560A	462A
Tripping time of C.B	1.663 s	0.491 s	0.4s	0.349 s

Table (5.4): currents during 3 phase fault outside of the TCR

	α = 90	α = 120	α = 135	α = 150
Phase Normal current	301.5A	125.13A	63.8A	23.9A
Phase Fault current	279.6A	113.5A	58A	21.6A
Line Normal current	521.9A	204.0A	95.5A	33.8A
Line Fault current	17.4kA	17.4kA	17.4kA	17.4kA
Tripping time of C.B	0.2193s	0.1714s	0.1532s	0.1432s

From the results it is clear that when a 3 phase fault accurse inside or outside of the TCR all currents of the three phases are proximately equal hence all currents of the three lines are also equal.

The fault current during the fault become two times of the normal currents without faults this is because the total fault impedance is half of total inductance of the two reactors.

In the case of 3 phase faults inside the TCR the fault current decrease proportionally with the increase in firing angle this is because the time of connection between the reactor and the voltage source decrease with the increase in firing angle, in spite of this the tripping time decrease with the increase of firing angle because as firing angle increase the ratio between the fault current and normal operation current increase.

In the case of 3 phase faults outside of the TCR the fault current does not affected by the change in firing angle this is because the fault current doesn't pass through the thyristor, in spite of this the tripping time decrease with the increase of firing angle because as firing angle increase the ratio between the fault current and normal operation current increase.

The time of tripping of the fault for 3 phase faults outside of the TCR is too small because the fault current is too large and hence if it doesn't trip quickly it will damage the equipment.

The signals come from CTs in the phase circuit can be used to detect the faults inside the thyristor but cannot used to detect the fault outside the TCR. These outside faults can be detected by the signals came from the line CTs.

5.6 earth faults inside and outside of the TCR

5.6.1 Single line to ground fault inside and outside of the TCR

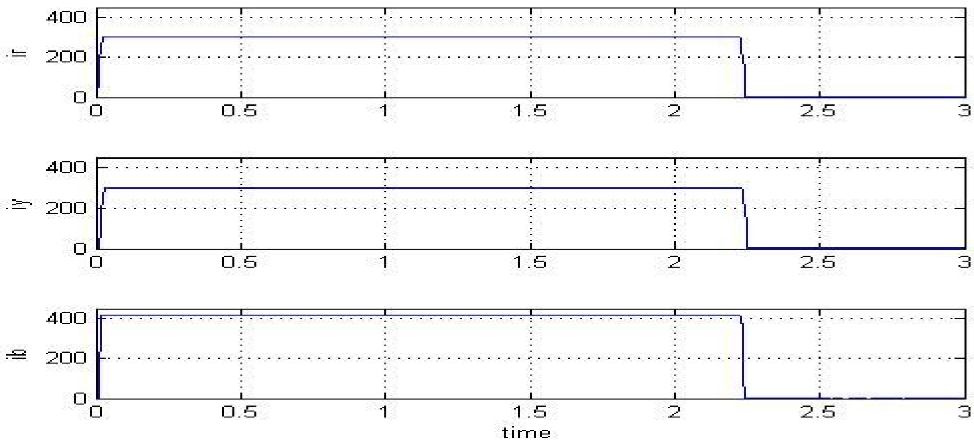


Figure 5.35: RMS of phase currents during a single line to ground fault inside the TCR $\alpha = 90$

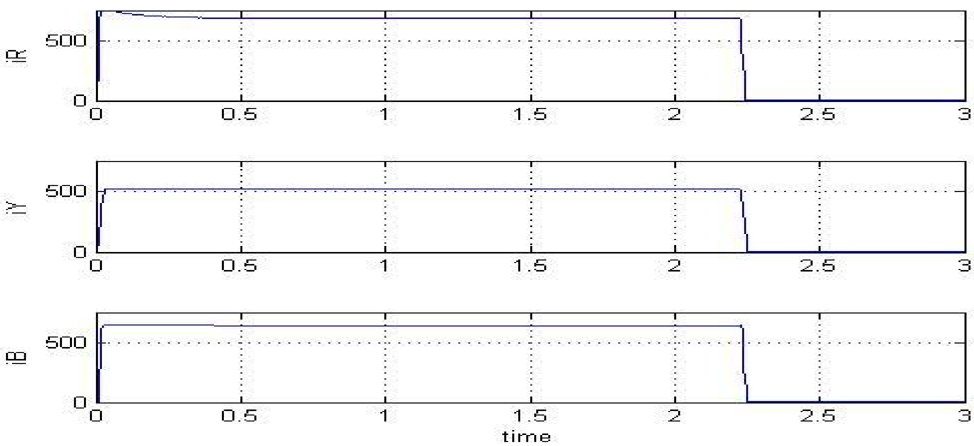


Figure 5.36: RMS of line currents during a single line to ground fault inside the TCR $\alpha = 90$

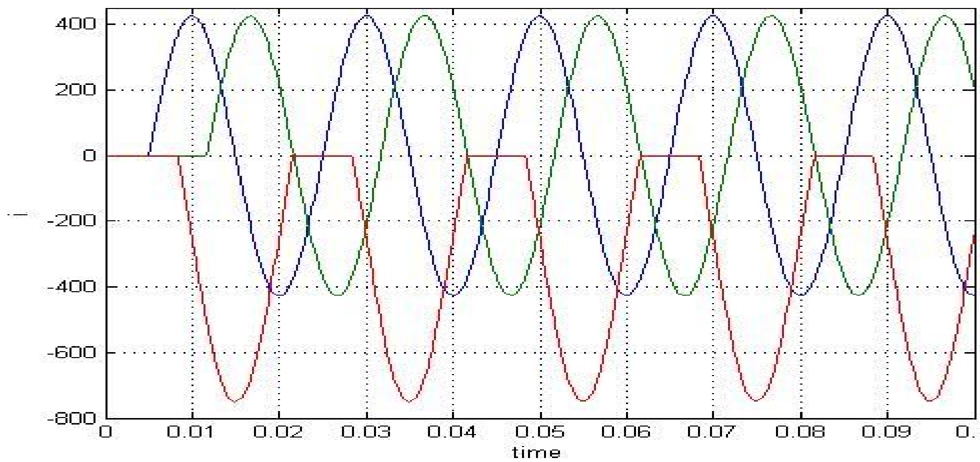


Figure 5.37: phase currents during a single line to ground fault inside the TCR
α = 90

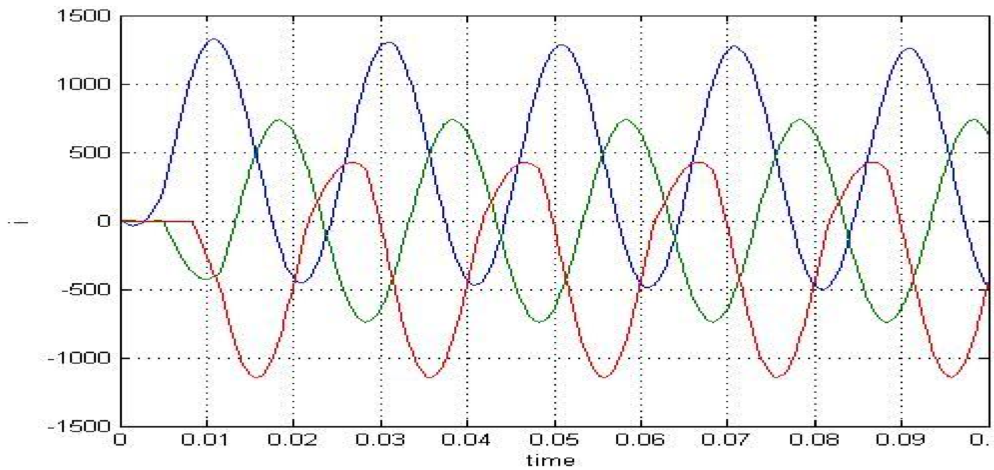


Figure 5.38: line currents during a single line to ground fault inside the TCR
α = 90

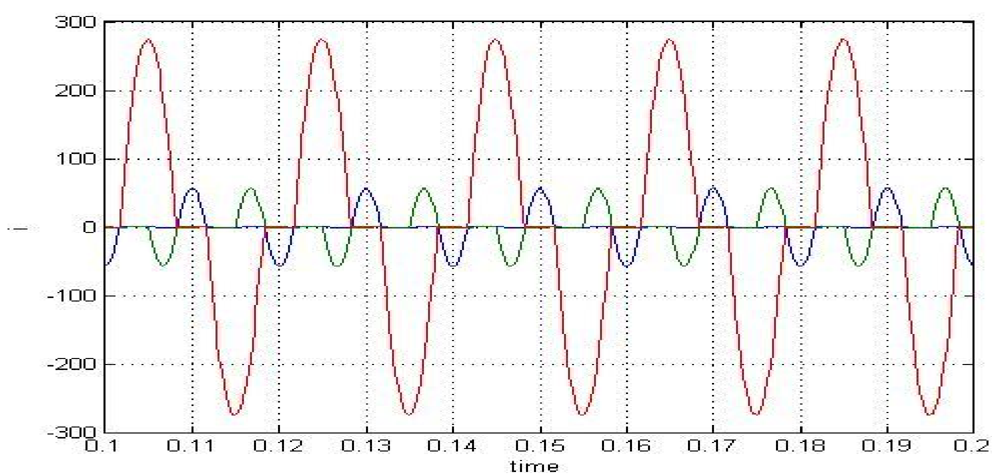


Figure 5.39: phase currents during a single line to ground fault inside the TCR
α = 150

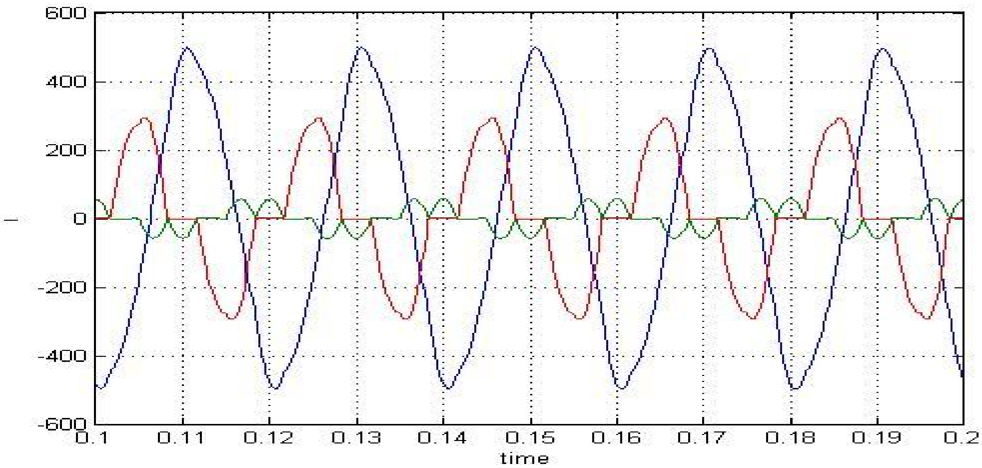


Figure 5.40: line currents during a single line to ground fault inside the TCR α = 150

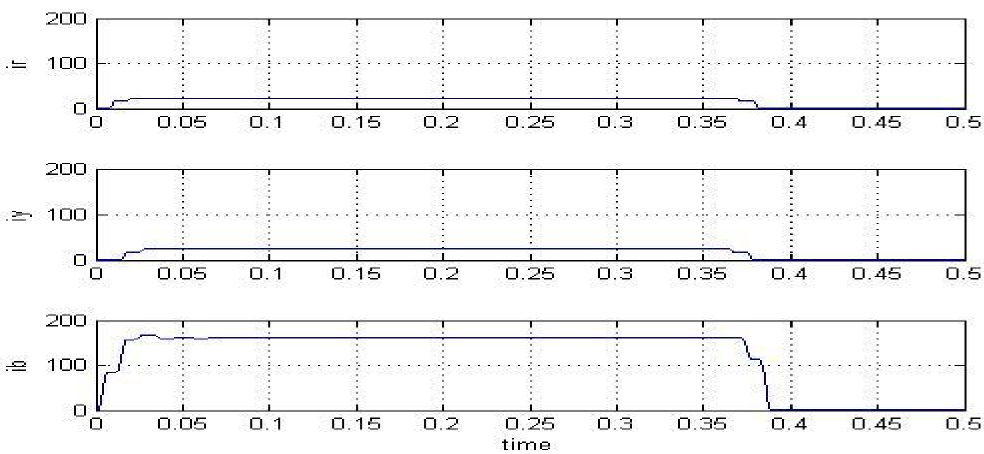


Figure 5.41: RMS of phase currents during a single line to ground fault inside the TCR α = 150

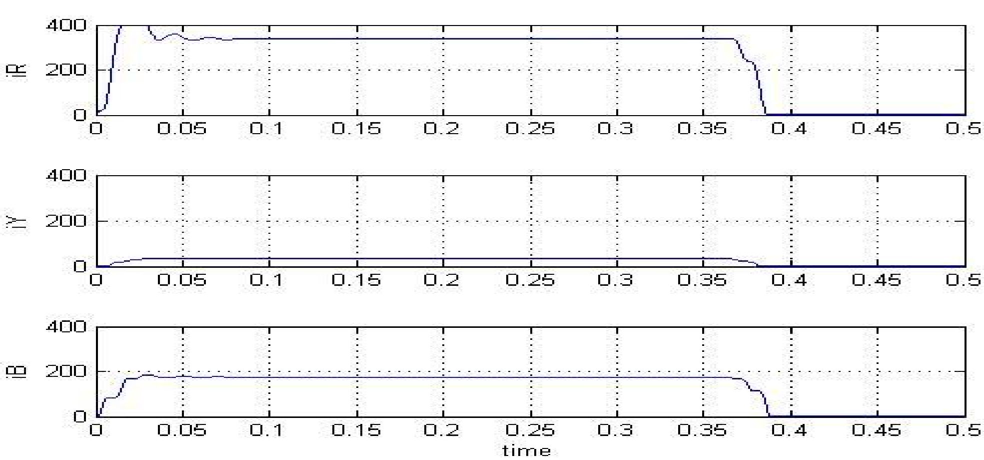


Figure 5.42: RMS of line currents during a single line to ground fault inside the TCR α = 150

5.6.2 Single line to ground fault outside of the TCR

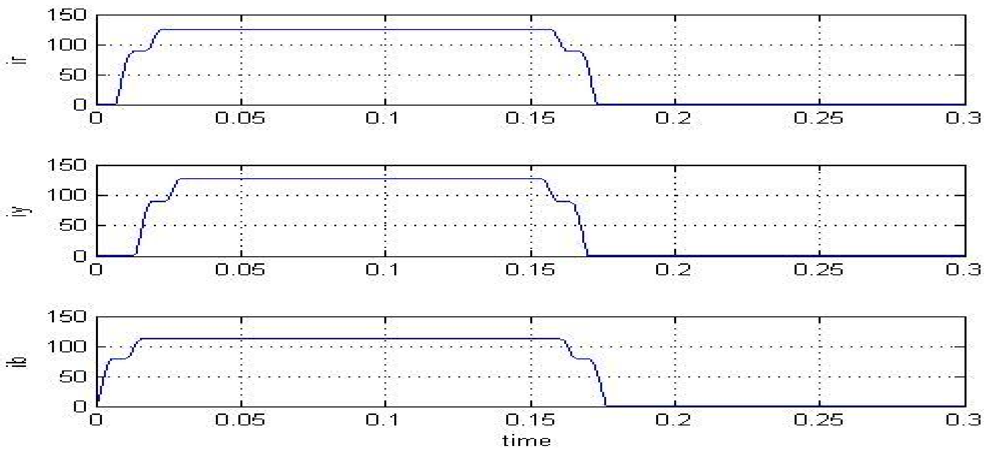


Figure 5.43: RMS of phase currents during a single line to ground fault outside the TCR α = 120

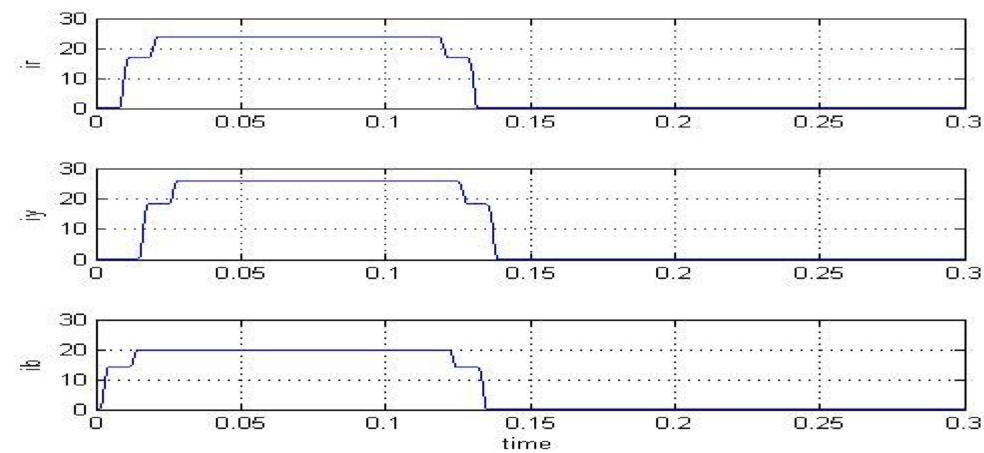


Figure 5.44: RMS of phase currents during a single line to ground fault outside the TCR α = 150

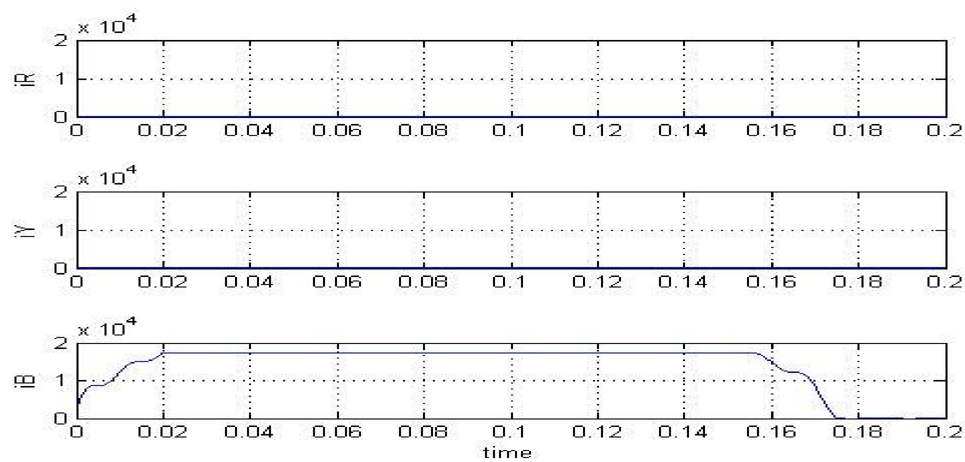


Figure 5.45: RMS of line currents during a single line to ground fault outside the TCR α = 120

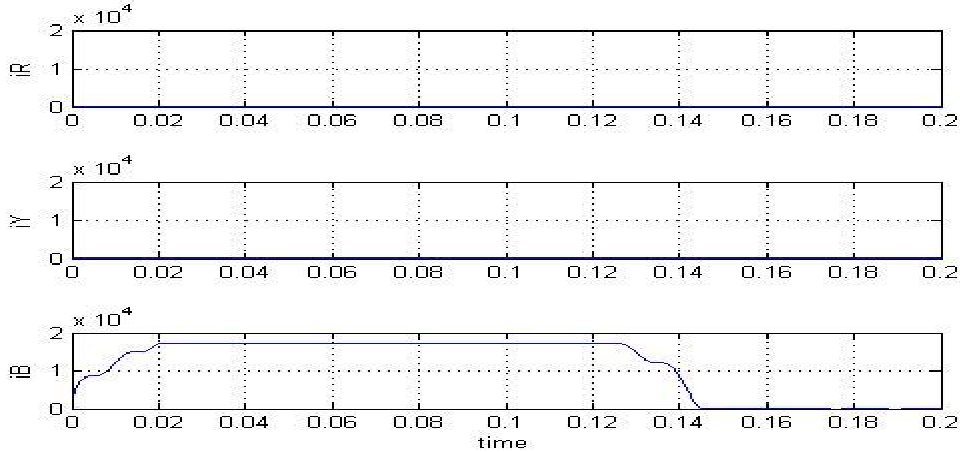


Figure 5.46: RMS of line currents during a single line to ground fault outside

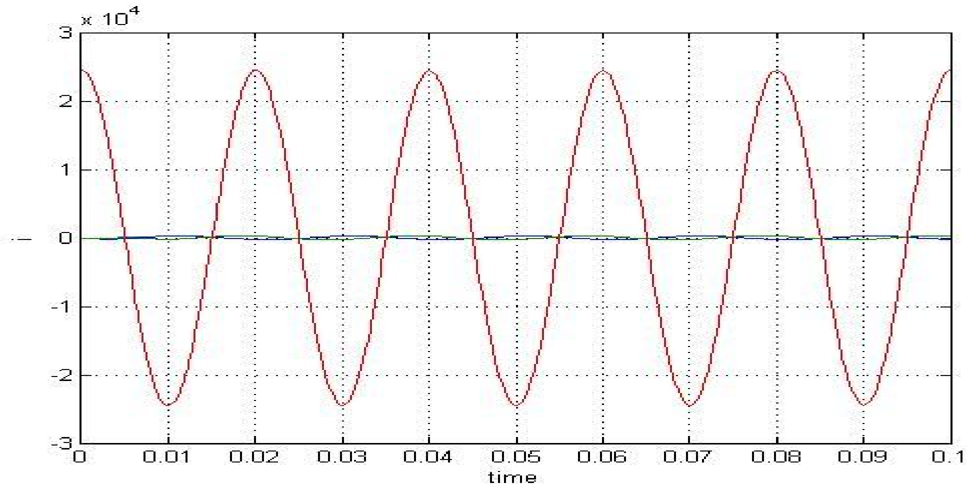


Figure 5.47: line currents during a single line to ground fault outside the TCR α = 120

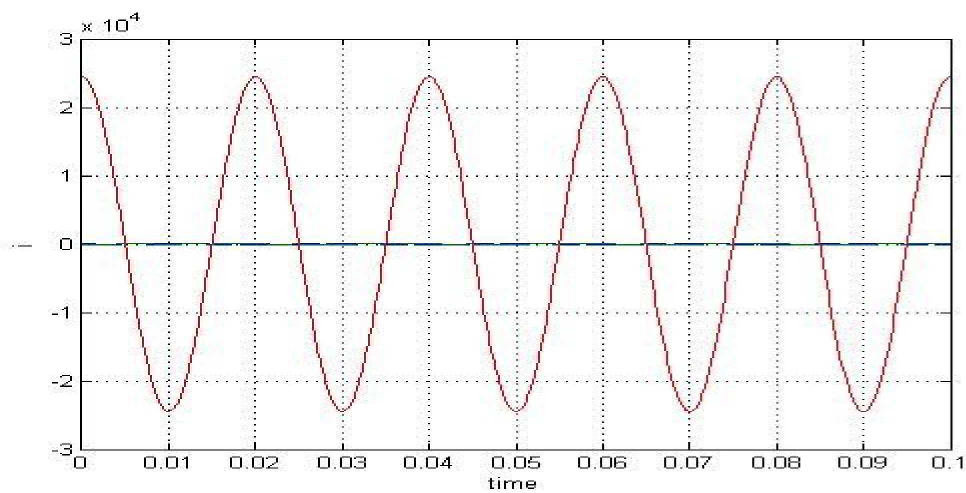


Figure 5.48: line currents during a single line to ground fault outside the TCR α = 150

Table (5.5): currents during single line to ground fault inside the TCR

	α = 90	α = 120	α = 135	α = 150
Phase Normal current	301.5A	125.13A	63.8A	23.9A
Phase Fault current	447A	353A	256.6A	167.5A
Line Normal current	521.9A	204.0A	95.5A	33.8A
Line Fault current	669A	455A	304.2A	182.62A
Tripping time of C.B	1.884s	0.7043s	0.5267s	0.3778s

Table (5.6): currents during 3 phase fault outside of the TCR

	α = 90	α = 120	α = 135	α = 150
Phase Normal current	301.5A	125.13A	63.8A	23.9A
Phase Fault current	279.4A	112.4A	55.8 A	19.9A
Line Normal current	521.9A	204.0A	95.5A	33.8A
Line Fault current	17.3kA	17.3kA	17.3kA	17.3kA
Tripping time of C.B	0.2144s	0.1748s	0.1549	0.1449

From the results it is clear that when single line to ground fault accurse outside of the TCR the faulty phase give a large increase in its current while the healthy phases are carry only their normal current. While in the case of the fault inside the TCR the faulty phase caries current more than the other phase and while the TCR is delta connected the lines which feed the faulty phase caries current more than the third one.

In the case of single line to ground fault inside the TCR the fault current decrease proportionally with the increase in firing angle this is because the time of connection between the reactor and the voltage source decrease with the increase in firing angle, in spite of this the tripping time decrease with the increase of firing angle because as firing angle increase the ratio between the fault current and normal operation current increase.

In the case of single line to ground fault outside of the TCR the fault current does not affected by the change in firing angle this is because the fault current doesn’t pass through the thyristor, in spite of this the tripping time decrease with the increase of firing angle because as firing angle increase the ratio between the fault current and normal operation current increase.

The time of tripping of the fault for single line to ground outside of the TCR is too small because the fault current is too large and hence if it doesn’t trip quickly it will damage the equipment.

The signals come from CTs in the phase circuit can be used to detect the faults inside the thyristor but cannot used to detect the fault outside the TCR. These outside faults can be detected by the signals came from the line CTs.

5.7 thyristor damage after fault clearance

5.7.1 No damage in thyristor after fault clearance

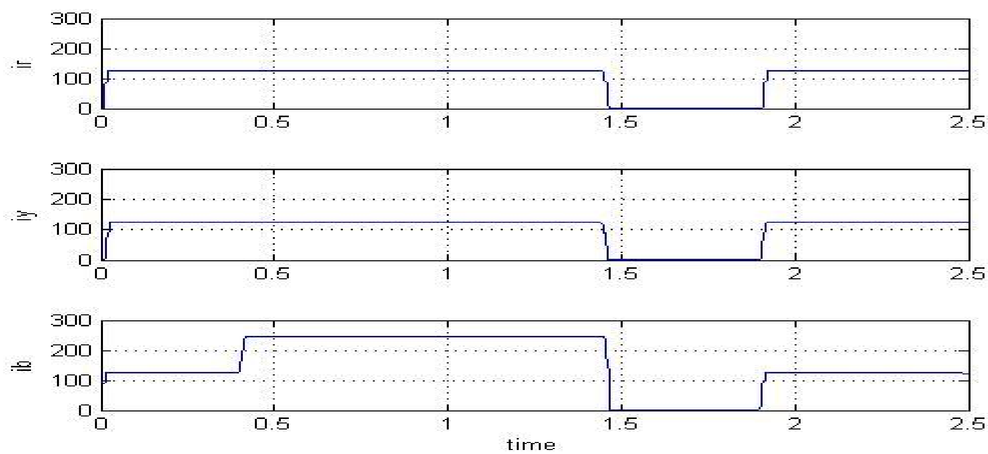


Figure 5.49: RMS values of Thyristors currents when the thyristor is healthy

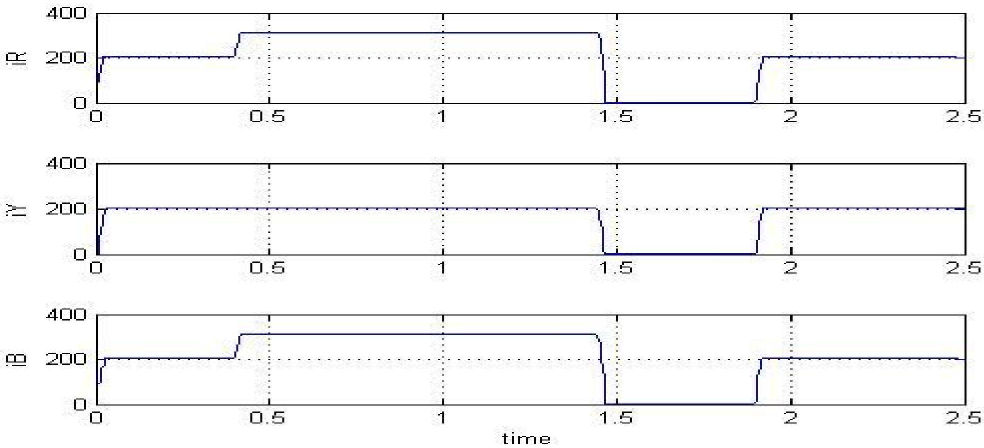


Figure 5.50: RMS values of lines currents when the thyristor is healthy

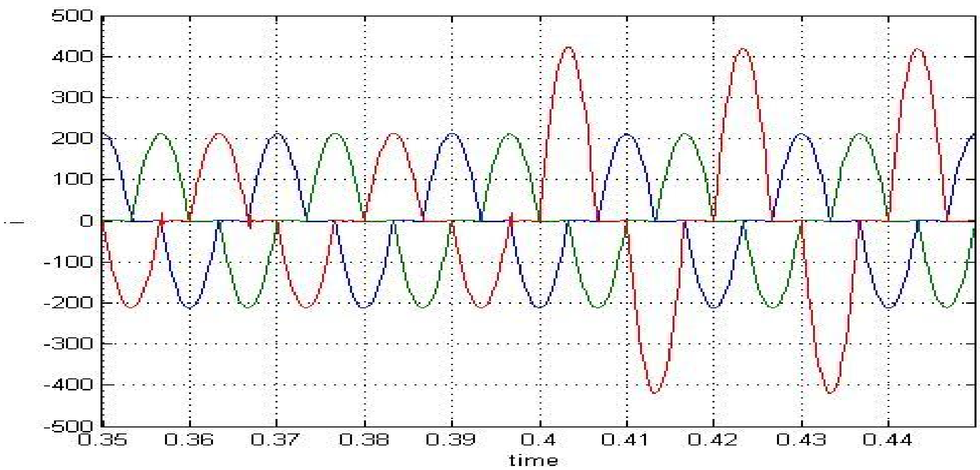


Figure 5.51: Thyristors currents during the fault when the thyristor is healthy

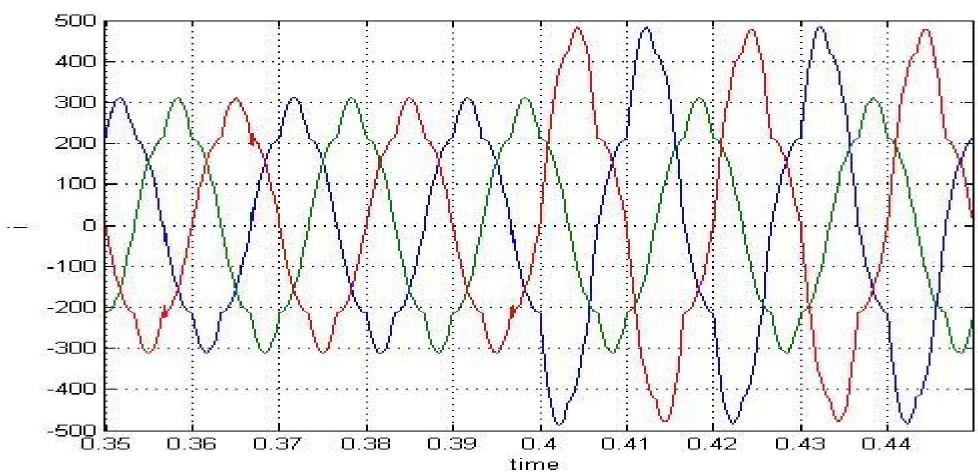


Figure 5.52: lines currents during the fault when the thyristor is healthy

5.8.2 Thyristor is short circuited after fault clearance

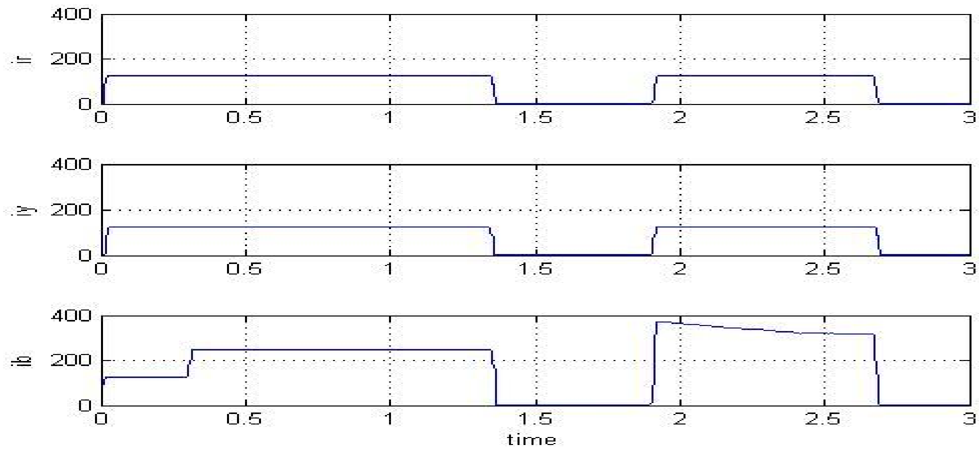


Figure 5.53: RMS values of Thyristors currents when the thyristor is shorted

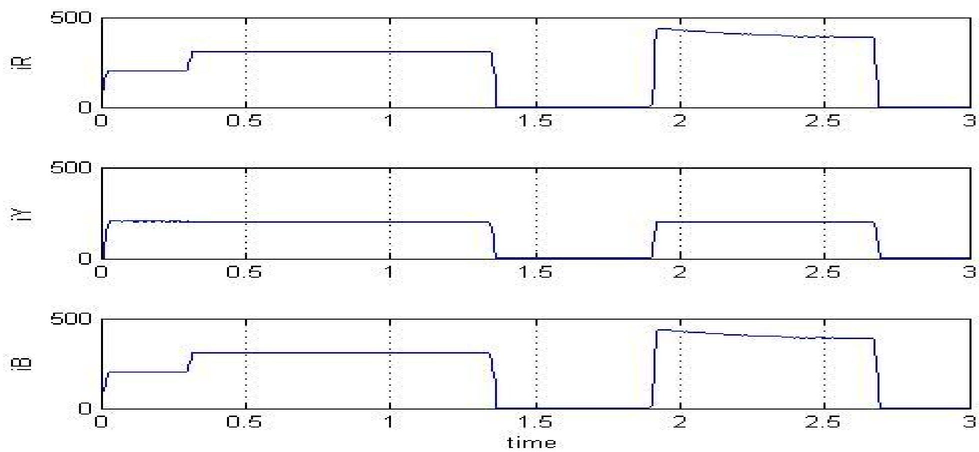


Figure 5.54: RMS values of lines currents when the thyristor is shorted

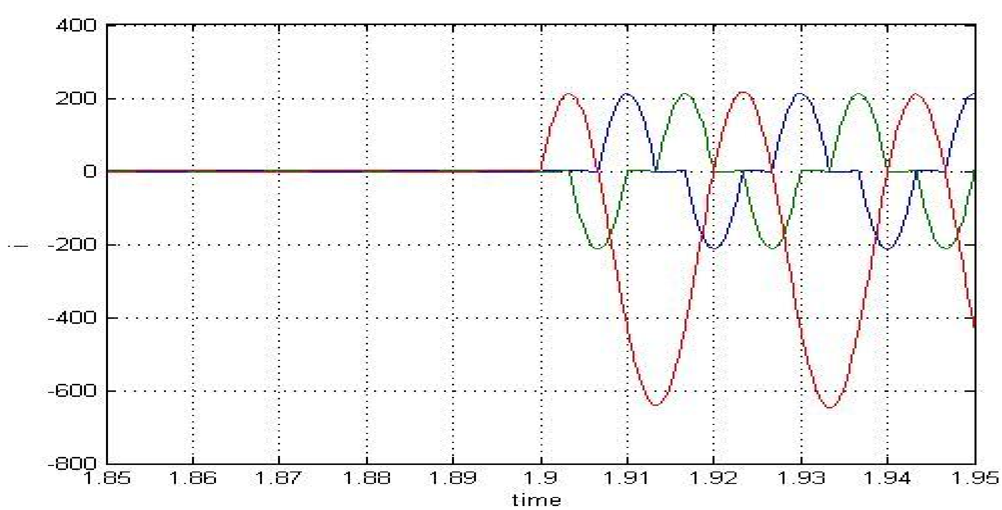


Figure 5.55: thyristors currents when the thyristor is shorted

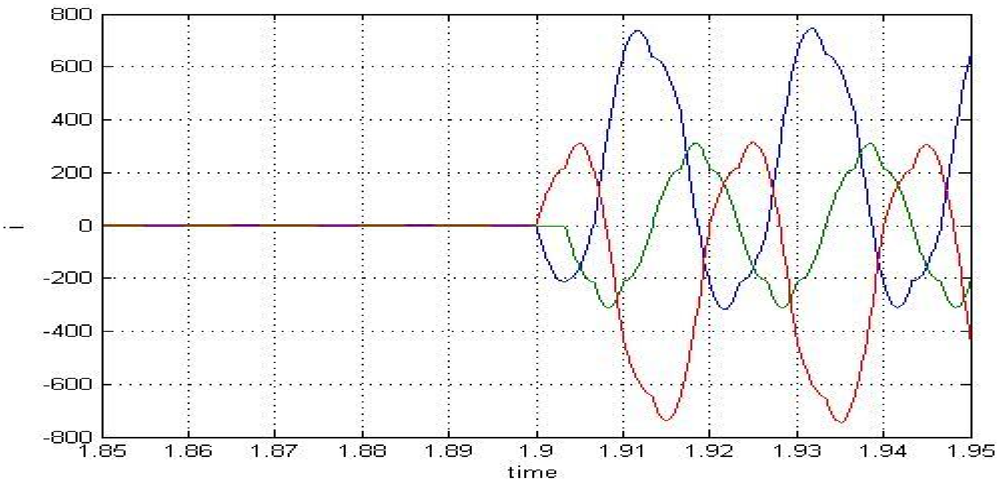


Figure 5.56: lines currents when the thyristor is shorted

5.8.3 Thyristor is open circuited after fault clearance

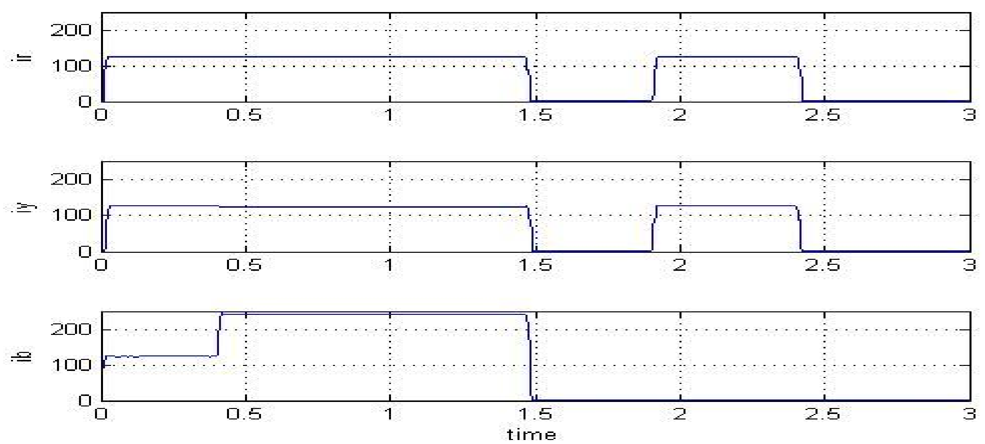


Figure 5.57: RMS of thyristor currents when the thyristor is opened

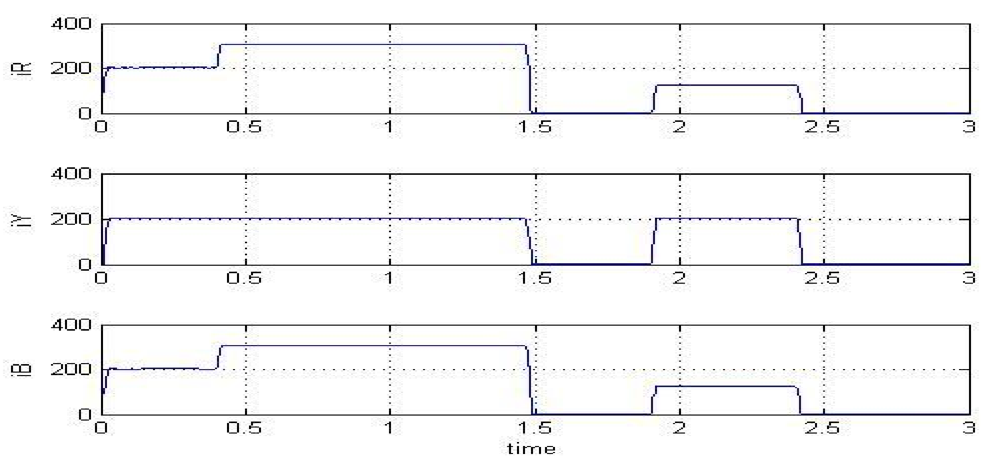


Figure 5.58: RMS of lines currents when the thyristor is opened

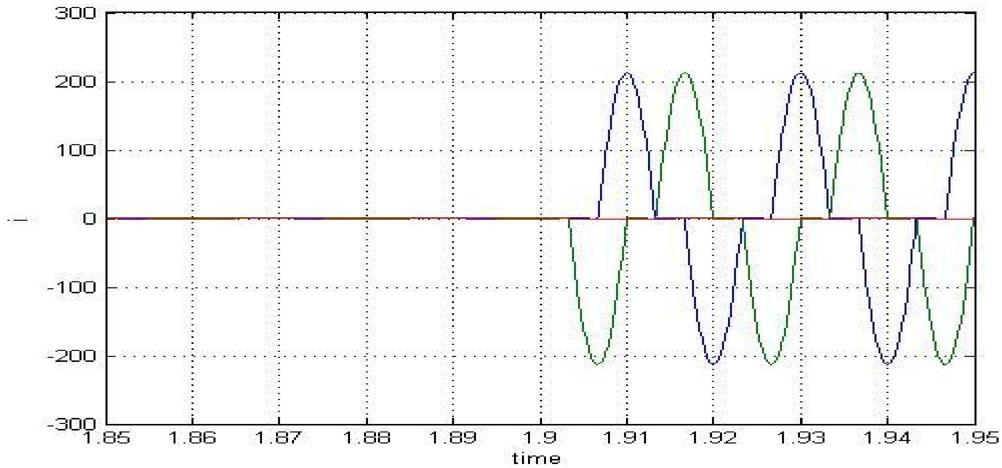


Figure 5.59: thyristors currents when the thyristor is opened

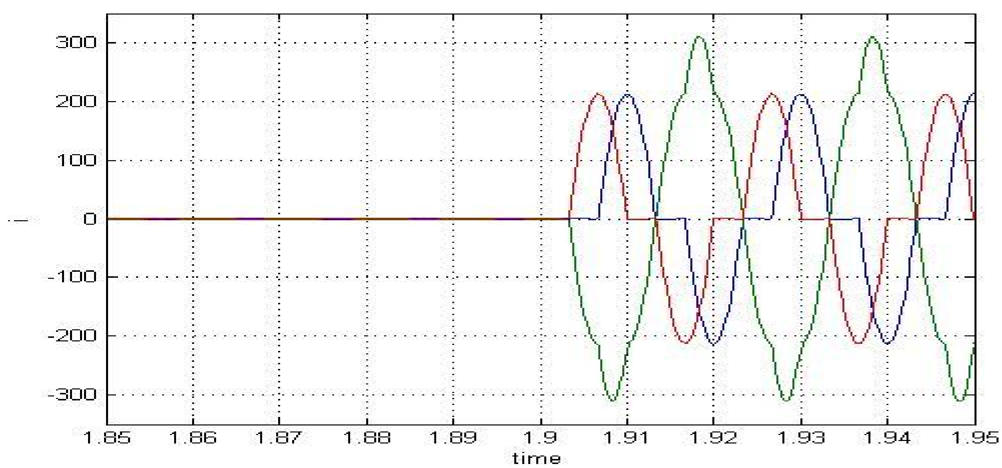


Figure 5.60: lines currents when the thyristor is opened

From the above results it is clear that if there is no damage in the thyristor the system back to its original state before the protection system detects the fault and clears it.

In the second case during normal operation all phases currents are equal and hence lines current are also equal, but during the fault faulty phase current become greater than the other phases, the protection system detect the fault and trip the main C.B after period of time, when the fault is cleared the thyristor damaged and became short circuited. If after the fault is cleared the thyristor damaged and became short circuited. And the main C.B is closed again the current at that phase increase and the protection system will detect that fault and trip the main C.B.

In the third case during normal operation all phases currents are equal and hence lines current are also equal, but during the fault faulty phase current become greater than the other phases, the protection system detect the fault and trip the main C.B after period of time, if after the fault is cleared the thyristor damaged and became open circuited. And the main C.B is closed again the current at that phase become zero and the protection system will compare between its actual current and the reference current and then it will trip the main C.B.

CHAPTER SIX

CONCLUSION AND RECOMMENDATIONS

6.1 Conclusion

In this work the control based over/under-current and thermal overload protection for the SVC relay-based protection included in the SVC installation is discussed.

The simulation shows how different types of faults which accrue in the model designed for LOCALMARKET SVC substation can be detected and cleared by the protection system of the SVC. The analysis is carried out using MATLAB SIMULINK software. And the results were discussed.

6.2 Recommendations

The recommended future work may be:

- Study the effect of firing angle on the metering devices (CTs and VTs) and if the uniform sine wave produced by the TCR can affect on their accuracy and tolerance.
- More integration in the control based protection system of SVC to eliminate the traditional protective relays.
- Study based protection system of other types of FACTS devices.

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APPENDIX (A)

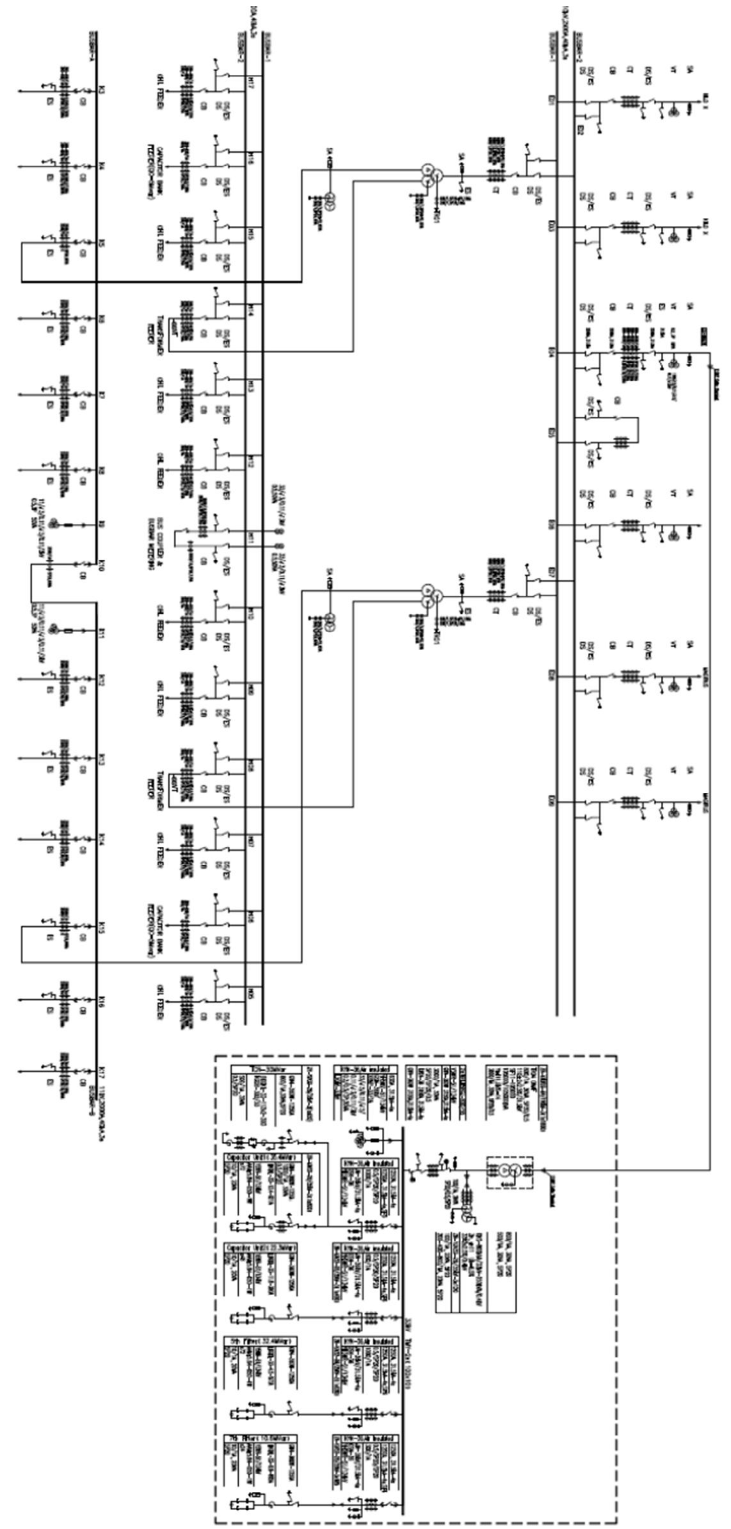

Figure 1:single line diagram of Local Market substation with SVC

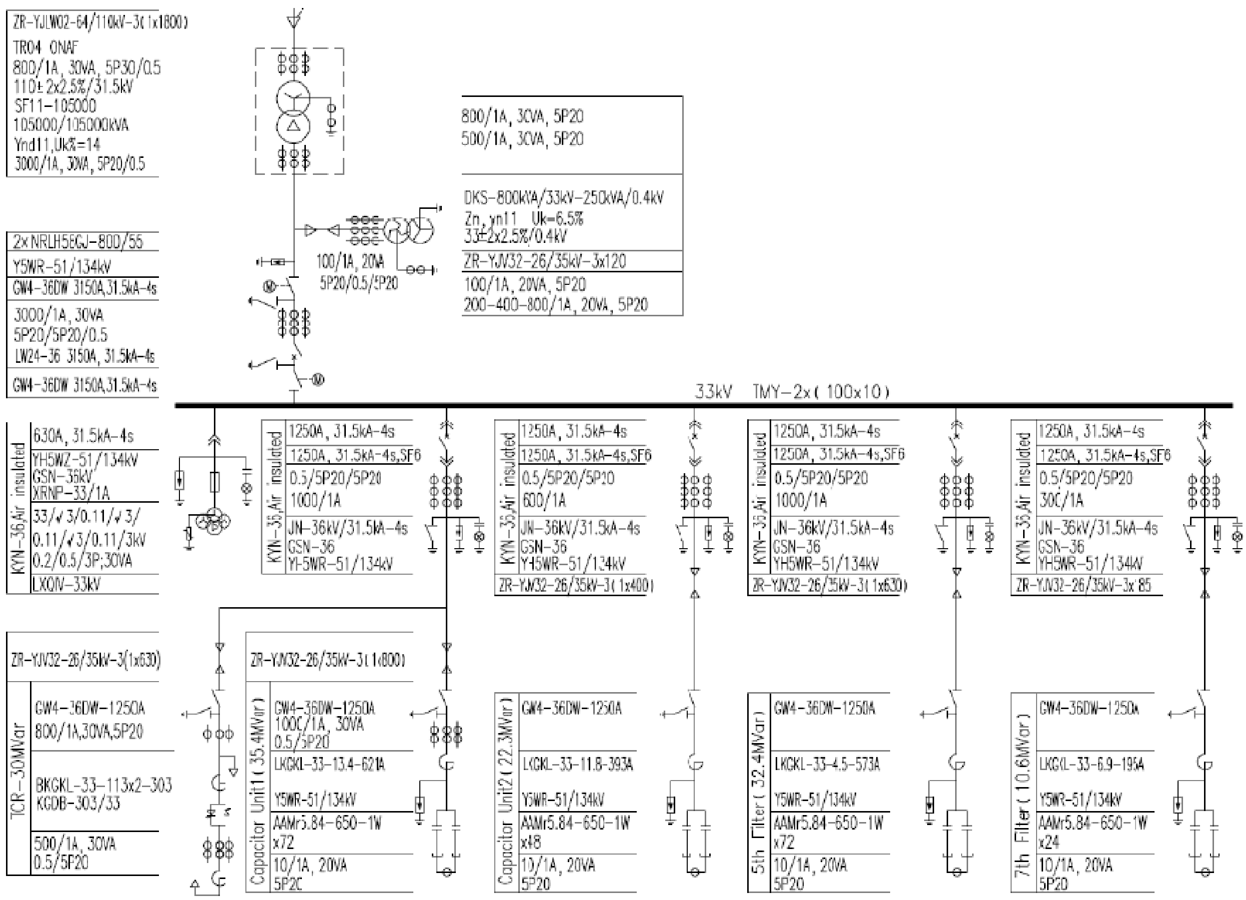

Figure 2 :SVC diagram of Alfarouq substation

APPENDIX (B)

Power Transformer protection setting for local LOCALMARKET SVC substation

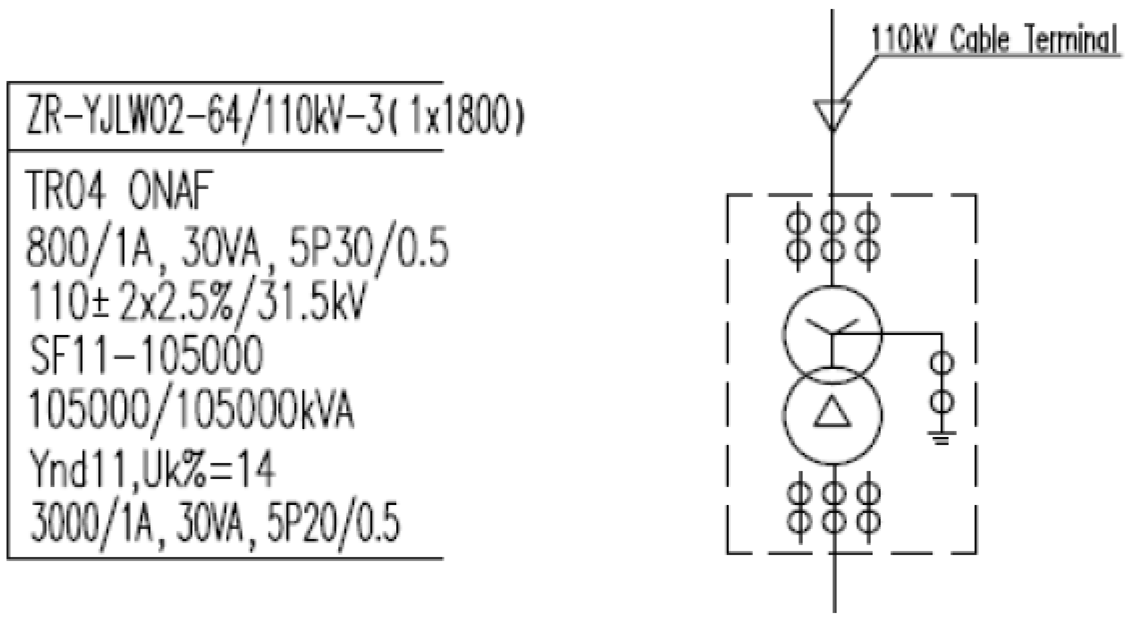

Figure 1: data of the power transformer

Differential protection setting

Correction of vector group

The power transformer vector group (Figure 1) is YNd11. The CT connections are as type II. Determine the correct settings.

CT connection = Type II

HV connection = YN

LV connection = d

Clock number = 11

Io elimination = not in use

Correction of CT turns ratio

High side full load current is

$$I_{nT} = \frac{105\ \text{MVA}}{110\ \text{kv} * \sqrt{3}} = 551.7\ \text{A}$$

$$\text{Scaling} = \frac{I_p}{I_{nT}} = \frac{800}{689} = 1.45$$

Low side full load current is

$$I_{nT} = \frac{105\ \text{MVA}}{33\ \text{kv} * \sqrt{3}} = 1839.2\ \text{A}$$

$$\text{Scaling} = \frac{I_p}{I_{nT}} = \frac{3000}{1839.2} = 1.631$$

Selection of starting ratio setting

The CT on both sides are rated 5P30 (i.e. the composite error is max. 5%) and the tap changer range is ± 2 × 2.5% (Figure 1). % CTs error approximately = 10%

% on load tap changer error =5%

From above the starting ratio can be calculated as

$$\text{Starting ratio setting}$$
$$= 5\%\ (\text{HV CT}) + 5\%\ (\text{LV CT}) + 2 \times 2.5\%\ (\text{tap changer})$$
$$+ 5\%\ (\text{relay}) + 5\%\ (\text{margin}) = 25\%$$

Selection of Basic setting

$$\text{Basic setting} = 0.5\ \text{x Starting ratio} + P' = 25\% * .5 + 10\% = 22.5\%$$

Selection of Turn-point 2

Its value chosen in range between 1.5 and 2

$$\text{Turn} - \text{point 2} = 1.75$$

Second slope

It is always chosen to be 100%

Instantaneous differential current stage

Its value chosen in range between 6 and 10

$$\text{Inst. setting} = 10$$

Inrush current blocking

$$\text{2. harm. block} = 15\%$$

Restricted earth fault protection setting

High voltage side

Data of ct

Knee Points:

Standard	V	I
IEC 60044-1	646.3V	19.62mA
IEC 60044-6	584.2V	20.90mA
ANSI 30	573.1V	14.95mA
ANSI 45	419.3V	10.14mA

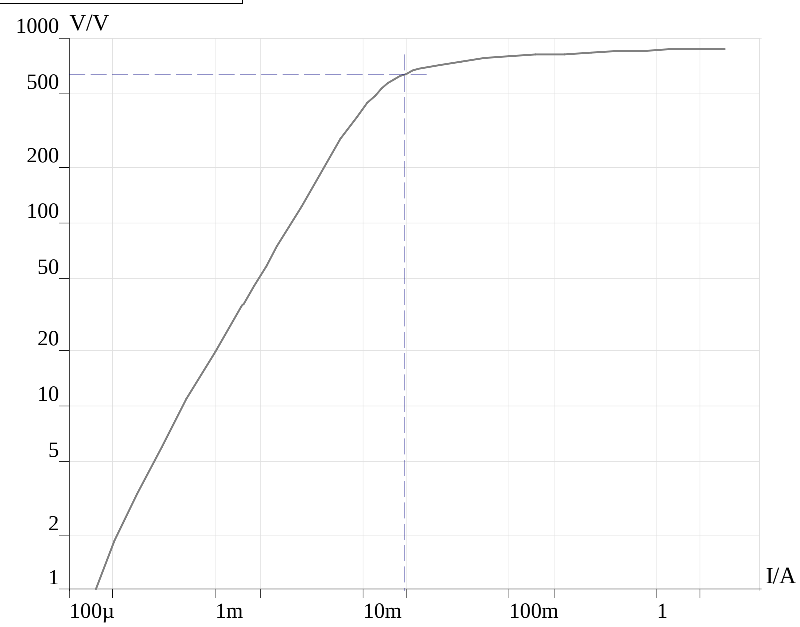

Figure 2: Magnetizing curve

Settings Requirements

Rated current $= I_{nT} = \frac{105\ \mathrm{MVA}}{110\ \mathrm{kv} * \sqrt{3}} = 551.7\ \mathrm{A}$

Assigned through fault current (rated stability limit) = 16 x rated current

$= 16 * 551.7 = 8.28\mathrm{KA}$

Primary Operate Current$(10 - 25\%$ of Irated$) = 55 - 137.9$

$= 80(.1$ A secondary $)$

Calculation of Required Stability Voltage Limits

$$V_s \geq I_F * (R_{ct} + R_L) * T$$

$$V_s \geq 8.28 * 1000 * (4.053 + 0.2) * \frac{1}{800} = 44.019V$$

$$V_s < \frac{V_k}{2}$$

$$V_s < \frac{419.3V}{2} = 209V$$

$$44.019 < V_s < 209$$

Calculation of Stabilizing Resistor Value

The required relay setting (Is) can be calculated from:

$$POC = \frac{4 * I_{MAGLCT} + Is}{T}$$

Therefore:

$$Is = POC * T - 4 * I_{MAGLCT} = \frac{20}{200} - 4 * I_{MAGLCT}$$

$$Is = 0.1 - 3 * I_{MAGLCT}$$

Say Vsprov = 100V (from requirement $44.019 < V_s < 209$)

From CT magnetizing curve (see Fig(1)) : At 100V $I_{MAGLCT} = 3.25mA$

$$Is = 0.1 - 4 * 0.00325 = 0.087A$$

say Is = 0.09A

$$Rstab = \frac{100}{.09} = 1111 \text{ Ohms}$$

Say 1000 Ohms giving Vs = 1000 x 0.09 = 90V

Stabilizing Resistor Specification

Continuous Power Rating

$$P_{con} = I_s^2 * R_{stab}$$

$$P_{con} = 0.09^2 * 1000 = 8.1 \text{ w}$$

Short Time Power Rating

$$P_{1sec} \geq \frac{{V_{Fint}}^2}{R_{stab}}$$

$$V_{Fint} > \sqrt[4]{V_k^3 * R_{stab} * I_{Fint}} * 1.3$$

$$I_{Fint} = \frac{8280}{800} = 10.35A$$

$$V_{Fint} > \sqrt[4]{419.3^3 * 1000 * 10.35} * 1.3 = 1214V$$

$$P_{1sec} \geq \frac{1214^2}{1000} = 1473w$$