Hawassa University Institute of Technology

Department of Electrical and Computer Engineering

OPTIMAL COORDINATION OF PROTECTIVEDEVICES FOR DISTRIBUTION SYSTEM USING ANT LION OPTIMIZATION

(Case Study: Yirgalem Distribution Substation)

A Thesis Submitted in

Partial Fulfillment of the Requirements for the Degree of Master of Science in Power System and Energy Engineering

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Optimal Coordination of Protective Devices for Distribution System Using Ant Lion Optimization

(Case Study: Yirgalem Distribution Substation)

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Abstract

Coordination of protective device in power distribution system has vital importance for the smooth operation of power system in term of selectivity, avoiding mal-operation of protective relays thereby minimizing unnecessary power loss. Yirgalem distribution system contains several problems in term of its primary and secondary protection schemes. This includes short circuits, overloading and overlapping. Since protective devices in Yirgalem distribution system is missing proper coordination, there is unnecessary tripping, removal of healthy part of system, equipment damage due to protective relays are not sensing fault and power loss occurs. Therefore, to reduce such kind of problems, some mitigation methods are needed to be implemented. These are selecting proper setting of relays, selection of appropriate overcurrent protective device, optimal coordination of protective devices. This thesis presents optimal coordination of protective devices for Yirgalem distribution system by minimizing the operating time of relays in primary as well as back up protection. In this research we have utilized Electrical Transient Analyzer Program (ETAP) software to coordinate protective devices and observed that protective devices get coordinated but it missed the objective of the thesis that is, minimizing the operating time of relays. Therefore, to obtain the minimum operating time of relay we have used Nature-based algorithm called Antlion Optimization techniques and particle swarm optimization (PSO) techniques. Power system in distribution area mostly comprises of protection devices like fuse, circuit breakers, re closers and protective relays. For the sake of optimal operation of these devices, system design engineer should take care of weather the devices are operating in coordinated manner or not. Optimization is the process of obtaining optimal solution (minimum or maximum) from the set of possible solutions (a given search space). Therefore, based on Ant Lion optimization technique and particle swarm optimization (PSO), the distribution system protection system is coordinated and minimum operating time of relay is obtained for respective feeders at Yirgalem distribution system. Antlion optimization(ALO) is better since the obtained minimum operating time of relay by it is more less than that obtained from Particle swarm optimization (PSO).

***Key Words**: Ant Lion Optimization (ALO), Particle swarm optimization (PSO), Electric Transient Analyzer Program (ETAP) Protective devices, Protective device coordination, Selectivity*

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Nomenclature

ALO	Ant Lion Optimization
CB	Circuit breaker
CT	Current Transformer
CTR	Current Transformer ratio
CTI	Coordination time interval
DC	Direct current
ETAP	Electrical Transient Analyzer Program
FPC	First pole clear
IEEE	Institute of Electrical and Electrical Engineers
IEC	International Electrotechnical Commission
IDMT	Inverse definite minimum time
KW	Kilowatt
Kvar	Kilo-Volt ampere
MMT	Minimum melting time
MVA	Mega volt ampere
OC	Over current
OCPD	Over current protective device
OCR	Over current relay
OLF	Overload factor
OF	Objective function
PS	Plug setting
POC	Primary operating current
I_p	Pickup current
PDC	Protective device coordination
PPE	Personal protective element
PT	Potential transformer
PSM	Plug setting multiplier

RALF	Rated accuracy limiting factor
SF6	Sulphur hexafluoride
TSM	Time setting multiplier
TDS	Time dial setting
TCT	Total clearing time
TSM	Time setting multiplier
TCC	Time current curve
TDS	Time dial setting
TDM	Time discrimination margin

CHAPTER ONE

Introduction

1.1 Background

Faults and transients can occur in the power system. These will lead to over currents and over voltages, which can harm insulation and conductors which in turn result in equipment loss and system failure. Any power system network should be protected with protective relays that isolate the malfunctioning portion of the system as fast as possible in order to prevent equipment damage, operator injuries, and to ensure minimal system disruption while providing service to the working portion of the network. When primary relays fail, backup relays come on when enough time has passed to make a decision.

Yirgalem distribution system has encountered some problems regarding to protective device coordination. For example, protective relays are late enough to send trip signal to nearby circuit breakers to trip fault due to improper setting, miscoordination of relays which results in outage of healthy part of system, equipment damage due to relays not sensing fault and resulting in heating of protective relays.

Determining the configuration and rating of overcurrent protective devices from the load upstream to the power supply is the goal of a protective device coordination study. It increases power system selectivity while also assisting in preventing relay malfunctions and eliminating un required power outage in the power protection mechanism. During this period, the power protection system will activate the nearest fault site first when two or more series protective devices coordinate. In the event that one upstream device malfunctions, the remaining devices must cooperate to function sequentially and offer backup protection.

In order to limit damage to protection equipment and isolate the defective section of the system from the healthy portion, overcurrent relays must be properly coordinated with other protective devices in any power protection system. After enough time discrimination, backup relays function in the event that the primary relays fail. It should be possible for the over current relay to distinguish between normal and abnormal fault circumstances [2].

It is possible for the protective relays to differentiate in between normal, abnormal, and fault circumstances. The concepts of discrimination, selectivity and backup protection are included by the term relay coordination. Selectivity entails that in order to isolate the problem, the relay nearest to it must first turn on. At the time that the backup relays don't operate right away due to a fault, they ought to do so eventually. Selectivity ensures the least amount of downtime during fault clearing.

Protection devices, one of the many distribution system components, are of utmost importance since they work to maintain the physical integrity of the population as a whole as well as the system's equipment.

Safety equipment's including protective fuses, circuit breakers, and overcurrent relays are advanced nowadays. A sort of insurance is offered by the protective device for expensive electrical equipment. The size and length of the disturbance, plus the likelihood of equipment damage or physical danger, can all be decreased by protecting electrical power systems. If a protecting equipment is active, it does so in response to a systemic issue.

For the optimization of protective devices for distribution networks, algorithms and a computational tool were created, with an emphasis on coordination, selectivity, and device allocation.

Power system is designed to give service for different types of loads in safe and reliable manner. Effectively controlling short circuit current should be considered during designing power system. Knowing various type of load currents available, either it is normal or abnormal. Different kinds of currents are described below.

Normal Current

Normal current is a load current which is current expected to be consumed by load under normal working conditions.

Overloads

According to NEC, overload is the operation of equipment in excess of normal, full load rating, or of a conductor in excess of rated ampacity which if stays in system will cause equipment damage or dangerous overheating.

Overload current is a fault current greater in magnitude than full load current

Short circuit current

Short circuit current exceeds full load current in ranges of thousands of amperes. The system's maximum short-circuit current at the problem spot sets a limit on the maximum value. This type of current is classified as bolted and arcing short circuit currents.

- Bolted short circuit currents: This type of current originates when phase conductors solidly connected each other. This may be due to improper connection or metal objects are touching the conductor
- Arcing short circuit currents: This current result from loose connection or due to insulation failure. During this time an arc expected to sustain current to pass through loose connection. This means an arc generates impedance on the same way to the flow of current thereby small number of current flows into bolted fault.

Over currents

According to NEC, overcurrent is the current in excess of rated current of equipment of the ampacity of conductor. It is the result of overload, short-circuit, arc, or ground fault

Effects of overcurrent include fires, conductor insulation damage and equipment damage.

1.2 Statement of problem

Distribution systems are directly connected to power substation and that is why it needs special attention to protective device coordination. Yirgalem distribution system protective relay is not set properly which results in weak protection system in both primary as well as secondary protection scheme. Due to that, protective relays cannot sense faults and this results in overheating of protective devices and thermal breakdown of them, miss coordination, unnecessary tripping, service outage and equipment damage. In addition to this, due to weak coordination of protective devices at Yirgalem distribution system, there is loss of power.

At Yirgalem distribution system, both primary as well as secondary protection schemes are not set in standard which has been issue resulting in damaging of system protective equipment and loss of healthy part of system.15kv side (Feeder 1, Feeder 2 and Feeder 3) are vulnerable due to issue on its primary as well as secondary protection. Faults occurring on Feeder 1 results in total outages from 15kv side main breaker and this in turn results in power outage at customers on feeder 2 and feeder 3.

Here in this research, optimal setting and selection of protective device coordination is done using Antlion optimization techniques (ALO) and Particle swarm optimization (PSO), so that the operating time of protective relay is minimized.

1.3 Objectives of Research

1.3.1 General Objective

The General objective of this research is optimal coordination of protective devices for Yirgalem distribution system using Antlion optimization techniques.

1.3.2 Specific Objectives

- To determine minimum operating time of relay under a given constraint.
- To apply appropriate setting for protective relays at Yirgalem distribution system
- To study Yirgalem distribution system current fault analysis and protective device coordination
- To study coordination of protective device in term of load flow analysis and short circuit analysis using ETAP software.

1.4 Significance of thesis

Optimal coordination of protective device has vital importance in minimizing the operating time of protective relays so that the unnecessary outage of power and equipment damage at Yirgalem distribution system is minimized.

1.5 Scope

This research encompasses protective device coordination for distribution system by selecting different coordination techniques and selection of appropriate protective devices.

It includes:

- Selecting overcurrent protective relays and / or devices for coordination purpose
- Finding the operating time of relays using ETAP software even though it is not minimized until optimization method is applied.
- Applying the ALO optimization techniques and PSO to minimize the operating time of relay
- Studying the impact of poor coordinated power system in relation to Yirgalem distribution (like power loss, equipment damage, power outage)

1.6 Outline

This research contains the following activities:

- **Introduction Part**: Here it contains the introductory part about the general concept of faults and transients that happen on a given power system. Here the introductory part explains about the overview of protective devices over the past years and how they have been changed nowadays, types of currents that a given load may be suppressed of and related issues
- **Literature Review Part:** This part includes some journals, articles and papers written based distribution system, distribution system protection system, coordination of protective devices, protective devices deployed on a given power system and other related fields are investigated. Here nature of faults has been stated in clearly form and it has been dealt that how much they are sever enough. Power system qualities has been introduced in clear form.
- **Problem Identification:** This part of research identifies the statement of problem that the research is aimed to solve it. Identifying problem is first stage of mitigating issues to be raised. These problems identified are improper setting of protective relays which results in relay not to sense fault, failure of protective device coordination, latency of protective devices to trip fault, miscoordination and equipment damage.
- **Collecting Data:** Yirgalem Distribution substation has been used as case study for the project. We collected data need like interruption information, load analysis and related information from Yirgalem distribution system. This data includes feeder types, length of feeders in kilometers, type of conductor, system voltage level, current transformer ratio, number of circuit breakers, and transformers rating. This collected data is set to be analyzed to solve coordination problem of protective devices in existing distribution system.
- **Mathematical Modeling.** This part includes modeling system single line diagram, flow chart of protective relay coordination, relay coordination analysis, short circuit analysis, load flow analysis, mathematical expressions and calculations of protective relay coordination, ETAP software, how it works and ALO working principles
- **Simulation Result and Discussion:** This part includes result part and discussion on it. Here it includes short circuit simulation result, load flow analysis simulation, protective device coordination simulation for every feeder, operating time evaluation using both

ETAP and ALO, comparison of existing system and optimized system, calculating power loss of system and it states how protective devices has been coordinated using TCC.

CHAPTER TWO
LITERATURE REVIEW

2.1 Nature of Faults in Power System

Faults in power system is the defect in power system which is occurring due to current is distracted from the intended path of its normal way. This creates condition which is abnormal that reduces the insulation strength between conductors. Insulation strength is meant to be dielectric strength of materials which measures the strength of insulator. Fault current in a given power system releases enormous amount of thermal energy, which if not cleared rapidly could cause fire hazards, damage to power equipment and risk to human beings.[1]. Fault current the current flowing through electrical circuit during fault condition.

Problems in power system includes

- Short circuits
- Abnormal conditions
- Equipment failures

The above listed problems may be caused due the occurrences of one of the following factors

1. Poor grounding system: grounding play's vital role in smooth operation of power system, it should be solidly grounded, low resistance grounded (effectively grounded system)
2. Bad weather conditions: rainy season is the major cause of faults in power system due protective device breakdown.
3. Lightening: Many faults in overhead transmission system arises due to lightening
4. Man-made accidents like fires
5. Pollution: the accumulation of dust and other things on bare part of conductor, protective devices, power system components may result in short circuits
6. Conductor's types: we have both overhead and underground conductors in power system where faults could arise accordingly
7. Environmental issues: we have natural forests, trees and animal caused faults in power system

2.2 Types faults in power system

Symmetrical faults: Faults occurring in all three phases.

Unsymmetrical faults are Faults giving rise to asymmetrical current which is differing in both magnitudes and phases in all three phases are asymmetrical.

LG fault in distribution system, when one conductor drops to ground or comes in contact with neutral conductor, it causes insulation breakdown in between one of phases and ground which LG fault occurs.

LL fault: It is when short-circuiting occurs in between two phases of system.

LLG fault: It occurs when short-circuiting occurs between two phases along with the earth at the same time

LLL fault: In a 3-phase fault, all three phases are shorted together. This can occur in 3-wire or 4-wire systems. When this occurs, the three phases are all bridged together, but they are not bridged to ground

LLLG fault: A transmission crossarm breaks and drops all three phase wires to the ground.

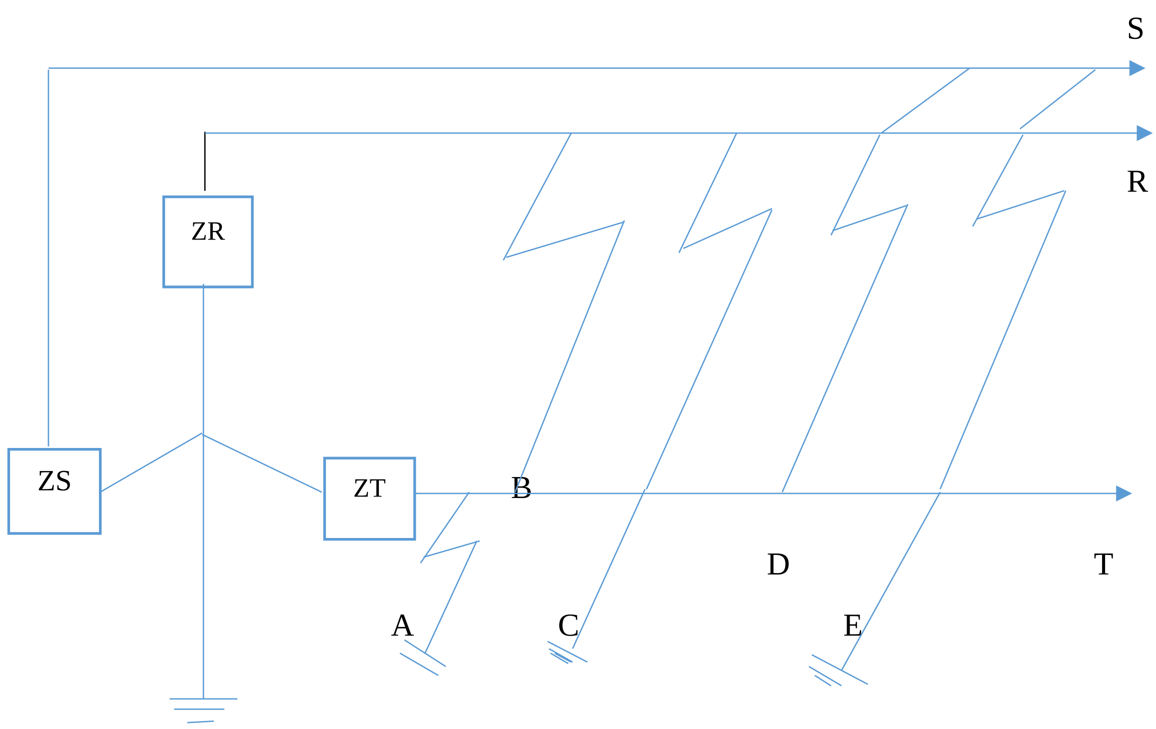

Fig 2.1 Types of faults in three phase power system

In above three phase power system, A represents LG fault, B represents LL fault, C represents LLG fault, D represents LLL fault and E represents LLLG fault.

ZR, ZS and ZT represents Impedance related to R, S and T respectively.

Fault statistics in power system in reference to fault type is described as below in tabular form

Table 2.1 Fault statistics related to type of fault [2]

Types of faults	Description	Chance of occurrence	Severity
LG	Insulation breakdown between one of phases and ground	85%	Least
LL	Insulation breakdown between two phases	8%	It is severe than LG
LLG	Insulation breakdown between two phases and ground	5%	It is severe than LL
LLL	Insulation breakdown between all three phases	5%	It is severe than LLG
LLLG	Insulation breakdown between three phases and ground	2%	Most

From the above table we can conclude following

- LG faults have high chance of occurring in power system, but is least sever among the other
- LLLG and LLL are more sever faults but having low chance of occurrence

2.3 Power System Protection and Coordination

An essential component of a power system that delivers electricity to consumers is the electrical power distribution system. But it requires safety measures like breakers, over-current relays, fuses, and re-closers. Comparing distribution systems to generation and transmission systems, distribution systems experience higher outages on average.

The minimization of the overall operation time of the devices to be protected is the goal of the optimization. Obtaining optimal pickup currents and time multiplier settings for the protection devices achieves the goal. Fastest feasible fault isolation is provided by this.

Due to complexity of non-linear optimal programming, the coordination of overcurrent relay is commonly performed by linear programming methods.

There are two approaches to coordinate protective devices in power system protection scheme. These are Optimal and Non-Optimal. This are described under the references [2] and [3]. It has been shown that relay setting in a power system can be optimized using linear optimal programming. [3]. The optimal coordination of protective device is linear-programing problem for minimizing the operating time of OCR. This is called objective function subject to the coordination constraints. Constraints are defining coordination criteria according to on primary and backup pair of relays [3] and [4]

Optimal Coordination

Selectivity and fast isolation of faulty portion of power system is achieved through optimal coordination between protective relays during faults. Optimal coordination includes two parameters to optimize. This are Time dial setting (TDS) and Plug setting multiplier (PSM) or pickup current setting (IP) with proper constraints. This is called optimal coordination.

Non-Optimal Coordination

Power system with improper protection scheme and protective relay setting results in miscoordination in protective device operation which hinders the selectivity of system and system disturbance as whole. The two parameters TDS and PSM in non-optimal coordination are not set properly which causes protective relays not sense fault in the system and which results in equipment damage. Yirgalem distribution system is non-optimally coordinated which results in frequent power outage since relays setting is not set properly.

2.4 Essential qualities of power system protection

A given protection system is intended to satisfy power system essential qualities in nature. Yirgalem distribution system has missed the below essential qualities of power system.

These are:

- Reliability
- Selectivity
- Speed
- Economics
- Sensitivity

2.4.1 Reliability

Yirgalem distribution system has problem in relation to power system reliability. Due to poor protection scheme and protective device coordination.

It lacks power system adequacy and system security. This research is planned to mitigate this issue by optimal coordination protective device coordination.

For example, there is loss of power at Yirgalem, which is not adequate enough to existing customer and the customers are getting power by shift.

2.4.2 Selectivity

At Yirgalem distribution system, due to protective relays are not set properly, healthy part of system gets removed when fault occurs on another feeder.

It is not selective, which results power outage at customer end on healthy part of system.

2.4.3 Speed

The operating time of relay at Yirgalem distribution system is not at minimum level which results in latency of relay operation.

For example, feeder 1 circuit breaker is frequently damaging due to relay operation latency.

Protective relays are needed to be fast due to the following cases

- Critical clearing time should not be exceeded.
- Electrical devices may be damaged if fault currents stay long

2.4.4 Sensitivity

We have said that, at Yirgalem distribution time of operation of relay is not set minimum which results the relays not to sense faults occurring. This results in equipment damage since faults are not sensed by respective relays.

The term "sensitivity" describes the size of the fault current that the power protection system detects.

Some modes of failures in protection coordination system at Yirgalem distribution system

- Failure of current or voltage signals to the relays
- DC supply failure
- Failure of relay itself due to relay hardware component, software failure, power supply failure
- Failure of fuse
- Failure of circuit breaker (tripping circuit or mechanism, or signal to trip the breaker
- Mis-coordination

2.5 Protective device coordination

In order to guarantee the continuity of service in the system, system protection coordination studies are crucial in power system networks. When higher current values than in a normal state flow into the system as a result of the short circuit, this is a fault or short circuit in the power system. Faults may occur in system due to natural disaster, lighting, faulty equipment and other related things. For the distribution system to operate effectively, faults in any component of the system must be avoided and isolated from the rest of the system as quickly as feasible. To do this, protective devices are utilized.

Circuit breakers, fuses, CT, and protective relays make constitute a team of protection devices. The proper sizing, positioning, and synchronization of protective devices is one of the key operational controls of any distribution system. To guarantee consistent system performance, proper protective device settings and relay coordination are necessary.

For distribution systems to experience the fewest interruptions and fastest restoration times, protective device cooperation is crucial.

In order to give optimum protection with the least amount of interruption for any kind of faults that may occur in the system, protective device coordination, which is a time sequence operation, is carried out to decide the tripping settings of each protective device in a power system.

The technique of selecting the "best fit" timing of current interruption when abnormal electrical situations occur is known as protective device coordination (PDC).

Overcurrent protection devices, including various types of relays, circuit breakers, re closers, and fuses, are the ones most frequently employed to protect distribution networks. They are referred to as coordinated with each other when two or more protection devices have a sequence of operations to isolate the fault.

The selection or setting of all series protective device from the load upstream to the power supply constitutes a coordination study. A comparison of all the devices operating times in response to various levels of overcurrent is done while selecting or setting these protection devices. Designing a selectively coordinated electrical power system is the goal, of course.

2.5.1 Purpose of Protective Coordination

- Protecting the public
- Improving system reliability
- Minimizing damage to system equipment
- Protecting overloads

What is power system protection?

It can be defined as complete arrangement of protective devices and other required devices to deliver desired power to load centers. This protection devices used for protection at distribution systems are fuses, relays, current transformers and circuit breakers.

It can be defined as an art and science of detecting problems with power system components and isolating these components.

When equipment failure, human errors, or lighting issues occur on any part of the system, a protective device is expected to reduce damage to the system and its components and shorten the length of service interruption. The overcurrent relay is sending signal to circuit breaker and then CB trips fault.

Protective devices are devices applied to a given power systems to identify abnormal situation and initiate appropriate corrective actions. These equipment's are like arresters, surge protectors, fuses, and relays with associated circuit breakers.

PPE, or personal protective equipment, shields its wearer from any physical risks or dangers that the working environment may bring. It is significant because it serves as a preventative strategy for sectors like manufacturing and mining that are known to be more dangerous. Short circuits must be separated using safety equipment that can detect abnormal current flow and remove the afflicted area from the system.

Protective devices are intended to perform the following tasks

1. Minimizing equipment damage
2. Safeguarding personnel
3. Minimizing power interruption
4. Delivering reliable power to the healthy part of system by disconnecting faulty section
5. Fastening restoration time of power after incident

In order to prevent the entire electrical system from being compromised, selectively coordinated overcurrent protective device (OCPD) is used to localize an overcurrent issue, restrict the outage to the particular equipment or circuit that is impacted, and ensure operational continuity.

A fault condition on a branch circuit should open the branch circuit OCPD, not the feeder OCPD. Likewise, a fault condition on a feeder should open the feeder OCPD, not the service OCPD

2.6 Protective devices deployed at distribution networks

Mostly used protective devices to be coordinated optimally at distribution area are:

- Fuses
- Overcurrent Relay
- Circuit Breakers
- Reclosers

Along with using the proper equipment, care must be given with how the equipment is used in order for the protection system to operate properly. This is necessary because several devices are connected to the same network, and if the order in which they operate does not match, unnecessary loads will be disconnected, endangering the system's reliability and possibly having a negative impact on the system distribution company's continuity indicators [6,7].

Knowing the devices involved is the first step in coordination and selectivity

Mostly used protective devices in distribution system are fuses, Circuit Breakers, Recloser and Relays of different types, mostly Overcurrent relay.

2.6.1 Fuses

Fuses are overcurrent protection equipment that operate directly by the heat produced by flowing current and have an inverse time characteristic. The current in the fault condition destroys current passage in these devices. Fuse is a thermal tripping device in an electric circuit whose operation is dependent on the thermal capacity of the fuse element, its melting temperature, and the current flow prior to the fault situation.

Description of Fuses

- Must be replaced after it has interrupted an overcurrent event.
- Has less initial cost
- No maintenance required
- Only opens on overcurrent events
- No capability for optional protective features

Being a fuse-type protection device, the operation is based on a metal link with certain time-versus-current characteristics, where the active element melts when the tolerable current is achieved, opening the circuit [8].

There are different types of fuses according to melting speed of the element to be fused. Most of the time fuses are used at beginning of laterals [11].

Information required for coordination of fuses

- Fuse continuous current rating
- Fuse time-current characteristics curve
- Fuse interrupting-current rating
- Time delay characteristics

Fuse to Fuse coordination

Fuse has two principal characteristics: these are Minimum Melting Time (MMT) and Total Clearing Time (TCT)

Minimum Melting Time (MMT) – gives time in which fuse can be damaged for a given value of fault current

Total Clearing Time (TCT) – gives fault clearing time of fuse for a given value of fault.

Coordination using Fuse can be done on two ways.

1) Based on selectivity ratio which manufacturer provides. The ratio of nominal current of F_1 to F_2 gives selectivity ratios. It works when all the fuses are from same company.
2) Fuses can be coordinated using characteristic curves too. It is the curve in between current melting time or total clearing time.

The main fuse should melt before the backup fuse for the same fault current level when two or more fuses are used consecutively. For the downstream of both fuses, total clearing time of main fuse should not exceed 75% of minimum melting time fuse used as back up protection [12].

The selectivity for fuse-to-fuse coordination is expressed mathematically as

$MCT_{Fm} \leq 0.75 \leq MMT_{Fb}$

Where, MCT_{Fm} is the minimum clearing time of main fuse and MMT_{Fb} is the minimum melting time of back up fuse.

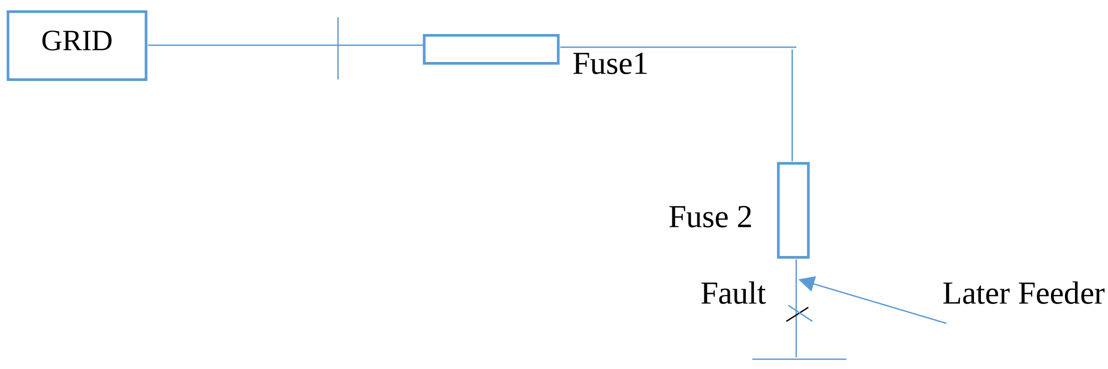

Fig.2.2 Fuse to Fuse coordination

Here in the above diagram, fuse 1 cleans fault before fuse 2 which occurs on feeder1. But for fault occurring at later feeder, fuse 2 cleans fault before fuse 1

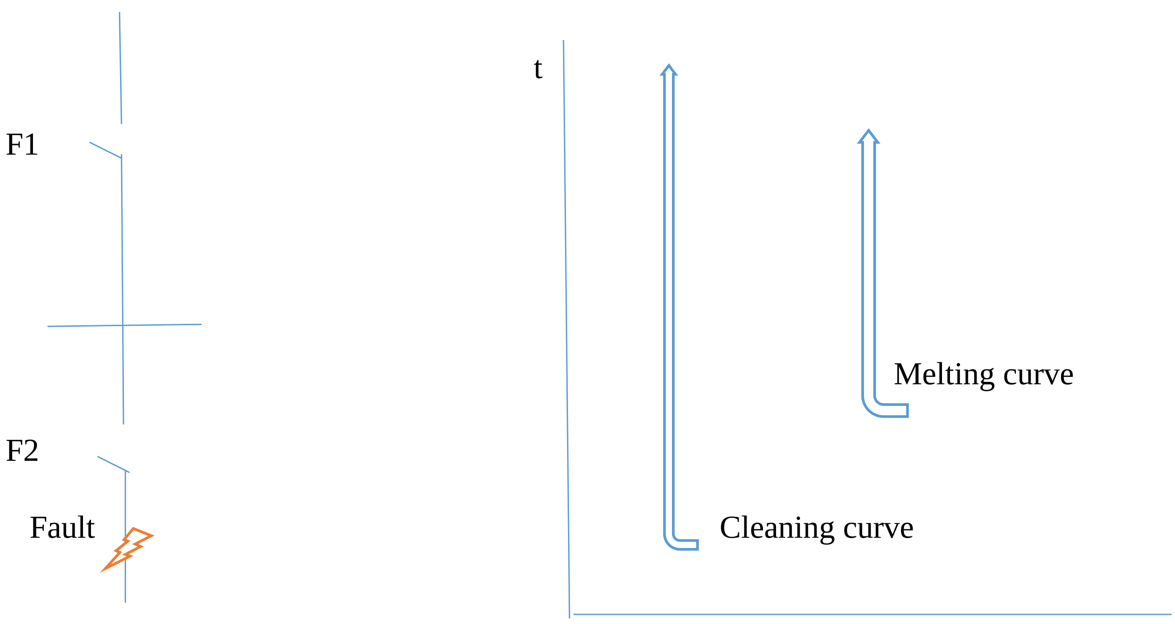

Fig.2.3 Coordination of Fuses using characteristic curve

2.6.2 Relays

Protective relays are electrical devices which monitor the current of system by using Current Transformer (CT) and Voltage of system by using Potential Transformers (PT).

It is electromechanical device that uses electromagnet to close and open electrical contacts. It controls high power circuit with low power signal in the form of current and voltage.

- Relays control electrical circuit remotely and /or isolate one circuit from another
- Relays are utilized for switching and controlling purpose
- They use small signal level voltage and current values to circuit breaker in order to trip during fault

Current Transformers (CT)- it is a device which transforms large primary values of current in power system to safe secondary values. The secondary current will be proportional to primary current.

Potential Transformers (PT)- it is a device which transforms large primary voltages of system into safe secondary values.

Protective relays are used for quick elimination of faulty part of electrical power system from healthy one. Overcurrent relay is one of major overcurrent protective relays. Overcurrent relays (OCR) are applied in power system to prevent short circuits, overcurrent, phase failures. They are designed for diminishing damage to power transformers, electrical devices, and give support to reliable operations of power distribution system.

When a power system component experiences a short circuit or begins to act abnormally in any way that could harm it or otherwise interfere with the efficient running of the rest of the system, protective relaying is used to prompt its removal from service.

Relay to Relay coordination

The coordination of overcurrent relay is same as that of fuses but the basis was, time current characteristics. Here the pickup current and time multiplier settings are considered in setting of overcurrent relays. The upstream relay R2 should be coordinated with downstream relay R3 and the grading between the two relays will take place at the maximum fault current at R3. For any fault at Line 3, the relay R3 must operate before relays R2 and R3 operate

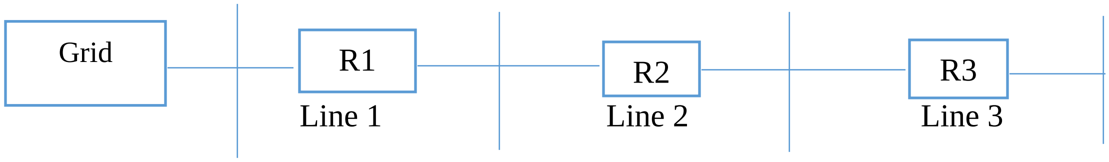

Fig.2.4 Relay to Relay coordination

Relay is expected to differentiate in between normal and fault conditions. Coordination of relay covers selectivity, discrimination and back up protection. For relay setting, maximum fault current is calculated at fault location first. Then plug setting multiplier (PSM) and time setting multiplier (TSM) selected and relay coordination is checked by time current curve (TCC). The operating time of relay for identified fault is current is determined by time setting and plug setting multipliers.

Relay to Fuse coordination

For all phase faults occurring in lateral feeder as shown as in the below diagram, the fuse should clean fault before first function (phase to phase function) of OC relay. On the other hand, for the ground fault the fast ground function (third function) must operate before the fuse to avoid its destruction during the fugitive ground fault.

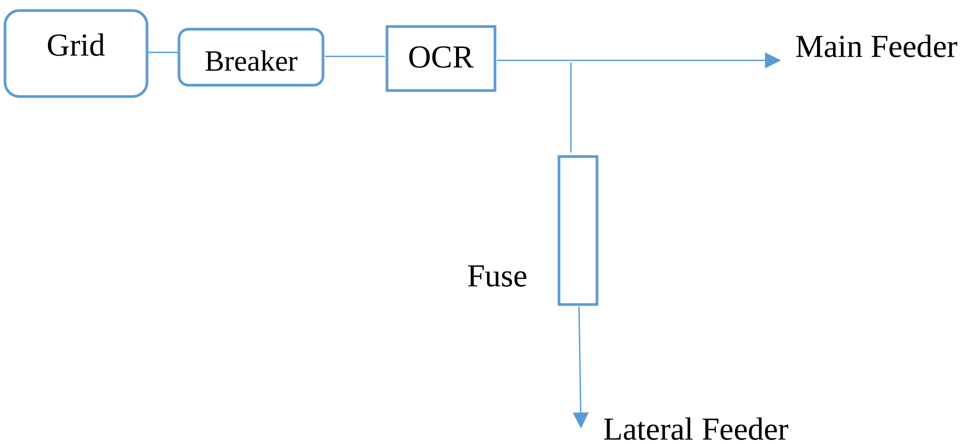

Fig.2.5 Relay to Fuse coordination

Parameters for calculating relay operating time

- Time/PSM curve of the relay
- Plug setting
- Time setting
- Current Transformer ratio (CTR)
- Fault current of the system

2.6.3 Overcurrent Relays

Overcurrent relay is one of protective device in power system which depends on fault current to operate. These components are usually deployed in distribution networks in the substation at the beginning of the main feeder as the circuit's primary protection.

Overcurrent relays are classified as

- **Instantaneous**
- **Definite time**
- **Inverse time** but here for this paper we will focus on inverse time overcurrent relay types. These kinds of overcurrent relays are categorized into three common groups: standard inverse, very inverse, and extremely inverse, and their operating times are inversely proportional to the fault current. It has two types of settings. These are time delay setting and current setting

Current setting – it is also called as pick up setting which determines the pick-up current of relay. Here the pick-up current is expressed mathematically as

$$I_{pickUp} = OLF*I_{nom} \tag{2.1}$$

Where, $I_{pickUp}$is the relays pickup current, *OLF* is Over load factor and $I_{nom}$is nominal current at the relay location.

Plug Setting Multiplier (*PSM*) – It is the ratio of fault current to pick-up current, which determines the operation of relay at fault condition. It is expressed mathematically as,

$$PSM = \frac{\text{Fault current}}{\text{pickup current}} \tag{2.2}$$

Where, *PSM* is plug setting multiplier, $I_{relay=}$ fault current and $I_{pickUp}$is the relay pick-up current.

Here the important thing to be considered is adjusting time delay setting. Time delay setting (*TDS*) is adjusting the delay time for operation of relay for coordination purpose. It is commonly called Time Dial Setting (*TDS*).

There are two settings for overcurrent relays

A. Plug Setting: plug setting is decided on the following conditions

- The relay shall reach at least up to the end of next protective zone. This is for back up protection
- The plug setting must not less than maximum normal load including permissible continuous overload unless monitored by under voltage relay

B. Time setting

- Time setting multiplier is selected to give lowest possible time for the relay at the end of the radial feeder.
- Time multiplier setting should allow not only for the time of the breaker but also for the overshoot of relay and allowable time errors in the time of operation of successive relays.
- It is common practice to take fixed selective interval of 0.25 second between the successive relays. We can express plug setting using percentages of rated current or current setting. Usually, it is taken as 1 to 5 amps as current setting. Multiple of pickup current is termed as plug setting multiplier (PSM).

$$\text{Plug setting (PS)} = \frac{\text{Disired pickup current}}{\text{CT ratio}} \tag{2.3}$$

$$\text{Primary operating current (POC)} = \text{CT ration*PS} \tag{2.4}$$

$$\text{Plug setting multiplier (PSM)} = \frac{\text{Fault current}}{\text{Actual POC}} \tag{2.5}$$

$$\text{Time setting multiplier (TMS)} = \frac{\text{Desired operating time}}{\text{operating time at selected PSM and TMS}} \tag{2.6}$$

Time discrimination margin (TDM or t_{margin}) between the operation of downstream device and relay is vital for coordination of relay with other time/current devices. This will ensure the selectivity of protective device coordination. This could be represented mathematically as

$$t_{relay} - t_{device} < t_{margin}$$

Where, t_{relay} is representing relay operating time, t_{device} denotes the operating time of downstream device.

2.6.4 Circuit Breakers

An electrical circuit breaker is a switching device that can be used to control and protect an electrical power system both manually and automatically. It breaks the system when sensing a large draw of current flow due to overloading or short circuit. It can safely close & open a circuit to protect it from damage.

- It can be re used after interrupting an overcurrent event
- It has a higher initial cost
- Requires maintenance
- Optional protective features (i.e. ground fault)

A circuit breaker is a device that enables both manual opening and closing of a circuit as well as automatic opening of a circuit in response to overcurrent. Power circuit breaker of low voltage is equipped with electromechanical trip devices. But modern solid-state devices are replacing electromechanical trips.

Role of circuit breakers in power protection system

- It interrupts the flow of current after it is sensed by relays
- It safely breaks open circuit
- It quickly extinguishes the arc
- It prevents arc from re-striking
- Its terminals should with stand voltage after breaking

Information needed for coordination

- Circuit breaker continuous current rating
- Circuit breaker interrupting rating
- Circuit breaker time-current characteristics curves
- Circuit breaker ratings

2.6.5 Re-Closers

Re closers are overcurrent devices that often have an inverse time characteristic. Since transformer and cable faults are typically not transient in nature, automatic reclosing systems shouldn't be used when these sorts of loads are being protected. When applied to permanent faults in transformer or cable loads, automatic reclosing schemes can cause equipment damage and provide safety risks to people**.** The re closers typically have multiple trip modes with varying speeds, including fast and delayed trip modes. Downstream fuses are protected against transients by fast trip mode, and delayed trip mode is set as backup protection for them

Re closers are more expensive than fuses, but they are more sophisticated and have broader protection, measurement, automation, and control capabilities. Electric power distributors have been using re closers more and more recently as a result of the device's potential for control and communication [9]. Because the reclosers allow timed automatic reclosures, it is possible to reduce power interruptions caused by transient defects [10], such as contact with trees.

Re Closers can be located in distribution networks as

- At substations near the start of the main feeder as the circuit's primary protection.
- At main feeder for section long lines for better protection
- At the branches

Reclosers are more expensive than fuses, but because of the measurement, automation, and control options, these devices are more advanced and provide a larger range of protection capabilities. Due to the reclosers' potential for control and telecommunication, electric power distributors have been using them more frequently. These features enable real-time network control and allow movements for a variety of purposes, assisting in the development of the smart grid [13].

2.7 Coordination and Selectivity

Between the fault point and the power supply, if there are two or more series protective devices, these devices must be coordinated so that the one closest to the fault point will operate first. In order to provide backup protection in the event that one device fails to operate, the other upstream devices must be designed to function sequentially. The term for this is selective coordination.

A coordination study requires selection of all protective devices in the network right from the power supply to the downstream load side. A comparative analysis of the operating times of all protective devices in the coordination process will be made in response to the various levels of fault current in the network and the direction of fault current flow in the case of directional overcurrent protection. Relay coordination is meant to be the relay nearest to the point of fault operates, but if this relay fails, back relay operates. Along with using the correct equipment, care must be given with how the equipment is used in order for the protection system to operate properly. This is necessary because several devices are connected to the same network, and if the order in which they operate does not match, unnecessary loads will be disconnected, endangering the system's reliability and possibly having a negative impact on the system distribution company's continuity indicators. [15, 16].

2.7.1 Selective Coordination/Unit Coordination

Selective coordination is also known as Discrimination, which is defined as the ability of protective devices to isolate faulty part of system thereby minimizing fault on power system.

Selective coordination can be achieved when the following requirements are satisfied.

- Devices which are used for sensing or measuring should be installed at each end of protected equipment.
- Communication should be there between the devices at each end, for comparing electrical conditions and detect fault whenever it occurs.

Non-selective coordination **Selective coordination**

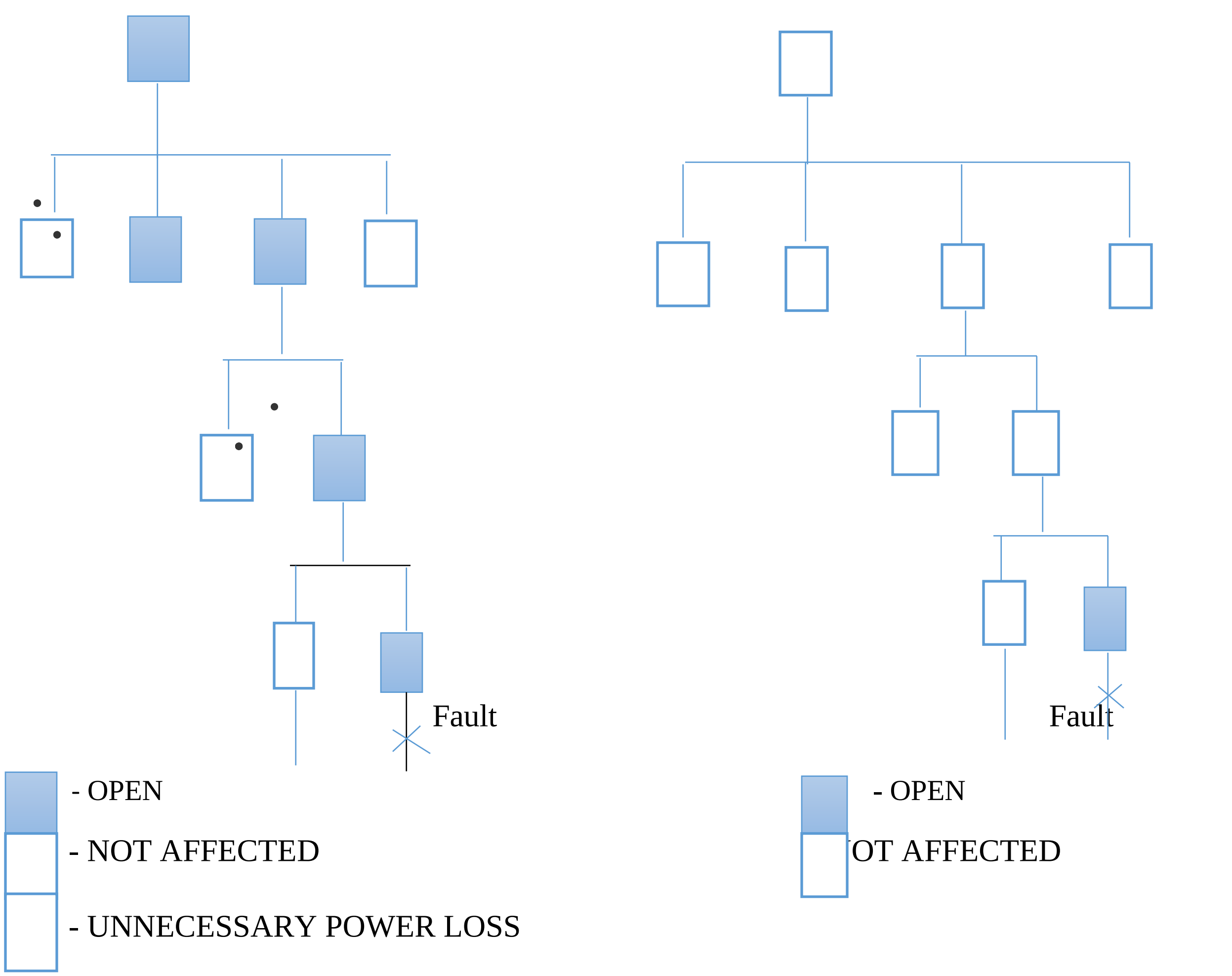

Fig.2.8 Selective Coordination vs Non-Selective Coordination

Main Advantages of Unit Protection

- There is minimum disruption in power system due to only faulty part is being disconnected
- It results in minimum damage to system equipment and danger to human life due to unit protection operates very fast.
- It is stable
- It is reliable
- It is very sensitive.

Main Disadvantages of Unit Protection

- Unit protection is expensive
- It requires communication of relays at installed at either end

Non-unit protection's inherent discriminating abilities are not absolute because the relay operates independently and often activates whenever it detects a fault, regardless of where the fault is. Therefore, to achieve discrimination in non-unit protection scheme, it requires principle of grading.

2.7.2 Classification of discrimination methods/Techniques

According to type of relay and application, power companies use different methods of grading. Most commonly used methods of gradings are grading by time, current and combination of both current and time [34]

Discrimination by Time

Time discrimination operates in such a way that, closer the relay is to the source, the longer the time delay**.** Here the current is measured at various points along current path like at source, intermediate location and consumer end. The tripping time at this location is graded in such a way that a circuit breaker or fuse nearest to the fault operate first, providing primary protection [35]

The major drawback of this method is more severe faults are cleared by longest operating time

Discrimination by Current

Current discrimination is based on the fact that, further the fault is from the source, the weaker is fault current. Drawback of discrimination by current is that it can be applied only where there is appreciable impedance between the two circuit breakers applied.

Discrimination by both Time and Current (IDMT)

To mitigate such problems imposed by using either time or current coordination, the inverse time overcurrent relay characteristic is chosen where time of operation is inversely proportional to fault current level and actual time of operation is function of both 'time multiplier setting" and 'fault setting''

Grading margin depends upon various factors

- The fault current interrupting time of circuit breaker
- Relay timing error
- The overshoot error of relay
- CT ratio errors

Let us consider the below illustration to understand grading in unit protection schemes.

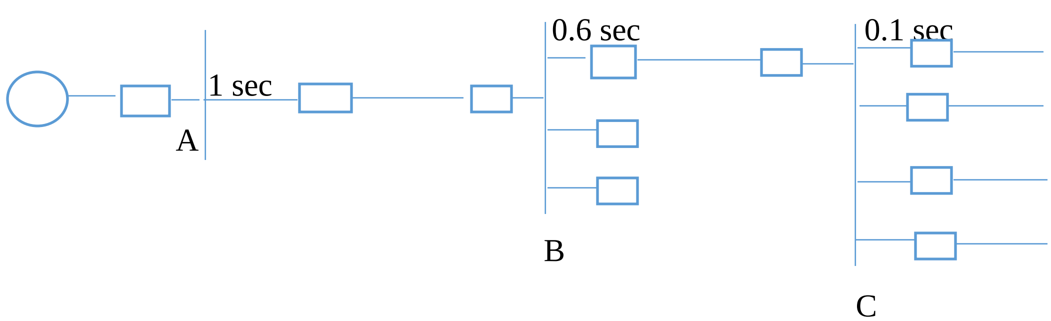

Fig.2.9Time grading

From the above illustration we can understand that, tripping time at station C, B and A are graded in a way that fault beyond circuit breaker at C operates first as primary protection. Circuit breaker at B operates only when Circuit breaker at C does not.

2.7.3 Primary and Backup Protection

Primary protection is also known as main protection, which is the essential protection provided for protecting power system. The primary protection should take immediate action initially if a problem arises in the protected area. The backup protection activates and removes the faulty component from the health system if the primary protection is ineffective.

Advantages of Back up protection

- If main protection(primary) fails, backup protection overtakes the protection
- Main protection may fail if one of system component like relay, current transformer, potential transformer, auxiliary relay, so that at this time Back up protection serves the system
- when Primary protection is inoperative for maintenance purpose or testing, back up protection acts as primary protection.

2.8 Coordination Study

The selection or configuration of each series protective device from the load upstream to the power supply constitutes a coordination study. The operating times of all the devices in response to various levels of overcurrent are compared while selecting or setting these protection devices. The objective was designing selectively coordinated electrical power system.

2.8.1 Time-current characteristics

Calculation of the estimated relay settings in terms of both current and time is necessary for the proper coordination of over current relays in a power system.

In all time-current characteristics curve, time is plotted in vertical axis and current is plotted in horizontal axis.

In order to use characteristic curves to a coordination study, one must choose or adjust the various protection devices in such a way that the curves are arranged on a composite time-current graph from left to right without crossing over. When applying characteristic curves to a coordination study, it is necessary to choose or configure the different protective devices so that the characteristic curves of the series devices from the load to the source are situated on a composite time-current graph from left to right with no overlap of curves.

2.8.2 Data required for coordination study

- Single line diagram of a system
- System voltage level
- Incoming power supply data
- Impedance and MVA of a given system
- X/R ratio
- Transformer setting and impedance data
- Protective device rating
- Time current characteristics curves of protective devices
- CT ratio
- Conductor sizes and lengths
- Short circuits and load current data
- Maximum load currents
- Transformer protection points
- Existing protection system including relay device numbers and settings, CT ratios and time current characteristics curve
- Data on the system under study
- Maximum and minimum momentary short circuit currents at major buses

2.8.3 Coordination Procedures

When carrying out protection coordination, one should do the following procedures.

- Select fault current expected at lowest convenient voltage base and convert all ampere values to these values. Here we have options like common MVA base or separate current scale for each system voltage.
- Indicating Short circuit currents on horizontal axis(X-axis) and relay operating time in Y-axis
- Indicate largest (worst case) load ampacity on horizontal axis.
- Specify protection pints
- Protective relay pickup ranges should be indicated
- Starting from largest load at the lowest voltage level, plot the curve for this device on the extreme left side of graph.

- Ensure the non-overlapping of the curves by tracing the curve for all protective devices.
- Coordination time intervals. To ensure the correct sequential operation of the devices, specific time intervals between the curves of different protection devices must be maintained when plotting coordination curves. The intervals are required due to relays have over-travel and curve tolerances.

In addition to the above procedures, it is usually preferable to utilize relays that are connected in series upstream and downstream of the network because they may have the same operational characteristics and the farthest downstream relay will have current settings that are equal to or lower than the upstream relays.

The right selection of the grading time and current largely determines how selective the protection is. The time interval between two successive rounds of protection is known as the grading period. It is important to keep an appropriate margin to ensure selectivity while not delaying the relay's operating time during a heavy fault current condition. In order to achieve the appropriate relay coordination in the power system network, the grading margin principles are used.

2.8.4 Relay Coordination

Tripping of protective relays in sequential or orderly manner is the concept of relay protection. It is one of critical task of engineers during designing of relay in power system distribution. It is required to isolate faulty part of power system from healthy one with minimum relay and circuit breaker operation.

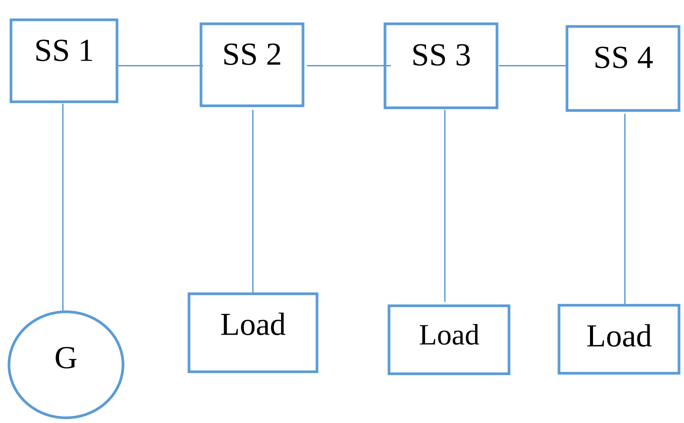

Fig.2.10 Substation Relay coordination

Here in the above relay coordination concept, the operating time of relay is designed as operating time of Substation 1> Substation 2 > Substation 3 > Substation 4

If we consider substation 1 as generation station and 2, 3, 4 are distribution substations, if fault occur in substation 4, relay 4 should operate. If rather relay 1 operating means the relay designed system is said to be poorly coordinated which results in total power system shutdown or tripping of unnecessary zones. Therefore, in order to mitigate such problems, we have to use relay coordination concept.

2.8.5 Standard IDMT Overcurrent Relay

In this type of overcurrent relay, the operating time is inversely proportional to current. So, high current will operate overcurrent relay faster than lower ones. We have standard inverse, very inverse and extremely inverse type of IDMT overcurrent relay types [17]. They are also called inverse definite minimum time relay.

The operating time of relay can be made up by adjusting the time dial setting (TDS). The lowest (fastest operating time) time dial setting is **0.5 sec and the slowest is 10sec**.

- Operates when current exceeds its pickup value
- Operating time depends on magnitude of current
- It gives inverse time characteristics at lower values of fault current and definite time characteristics at higher values of fault current.
- It is widely used for protection in distribution lines

Standard relay characteristics are important since they are standard for adjusting the time of Overcurrent (OC) relay functions. We have two main standards which are used as standard for obtaining relay functions. These are IEEE which is stated at [18] and International Electrotechnical Commission (IEC) which is stated at [19].

Table 2.2 Constants of Characteristics curve for IEC and IEEE standards.

Standard	Curve	A	B	C
IEC	NI VI EI	0.14 13.5 80	0.02 2 2	0 0 0
IEEE	NI VI EI	0.0515 19.61 28.2	0.02 2 2	0.114 0.491 0.1218

Where NI stands for Normal inverse, VI is very inverse and EI stands for extremely inverse. Whereas A, B, C are time curve characteristics curves constants.

Therefore, relay operating time for given short circuit current and pick up current is

$$t = \left[\frac{A}{(\frac{If}{IP})^{B}-1}\right]\times \text{TDS, for IEC standard and } t = \left[\frac{A}{(\frac{If}{IP})^{B}-1}+c\right]\times\text{TDS, for IEEE standard}$$

According to IEC, Time can be calculated using the following equation

Table 2.3 Relay Characteristics

Relay characteristic	**Equitation**
Standard inverse	$T = \left[\frac{0.14}{(\frac{If}{IP})^{0.02}-1}\right]\times \text{TDS}$
Very inverse	$T = \left[\frac{13.5}{(\frac{If}{IP})^{0.02}-1}\right]\times\text{TDS}$
Extremely inverse	$T = \left[\frac{80}{(\frac{If}{IP})^{0.02}-1}\right]\times \text{TDS}$

2.9 Literature Review

There are so many researchers in recent years regarding about protective device coordination in power system. Specially most of researchers published paper on overcurrent protection coordination currently rather than earth fault protection since they think that earth fault has no impact on interruption. The main problem they feared of using both earth fault and overcurrent protection coordination is that difficulty in relay coordination if a system is multi network type. Most used methods for relay coordination are trial and error method, topological analysis and optimization techniques.

In research paper stated at [30] protective coordination is based on parameter optimization techniques for large interconnected power systems using above 30 buses.

At research paper [31], protective relay coordination for both radial and parallel feeder is provided based on time current characteristics.

There are other research papers which uses protection coordination by time [33], where an evolutionary algorithm applied a constraint optimization tool to search for the optimal relay setting by linear programing to obtain minimized objective function of time. But this method has drawback that most sever faults are cleared by longest operating time [34]

Trial and error methods are used by protection engineers at substation based on their past history about setting relay pickup current according to load current of system

Here is the overview of research papers to solve protective relay coordination problem in below table.

Table 2.4 Overview of literature review

Proposed Methods	Defining characteristics	Advantages	Disadvantages
Linear optimization techniques [24]	It is used as basis for formulation of relay coordination problem	TMS is Linear programming optimized for any fixed pickup current value	Initial value of pickup current become mired in a local minimum if the operator is inexperienced in tuning the value
Non-Linear optimization techniques [25]	Here overcurrent relay characteristics formulation presented in non-linear programming form	Plug setting current is optimized in tandem with TMS	It is time consuming technique, because of iteration of non-linear programming
Trial and error method [26],[27]	The transparent plate has been trimmed to fit the current and time of relays	Simple and power network friendly	In large networks are time consuming, and has low convergence rate and large TDS of relay and engineers use their experience to set pickup current based on load current of system
Curve fitting technique [28]	For a given relay, time operating curves, both linear and non-linear functions, time inverse operating characteristics are derived	Easy to establish relays	It is erroneous for currents less than 1.3 times pickups current threshold
Graph theory [29]	Determining relays optimal breakpoints	It satisfies proper coordination	But relay operating time is not minimum

2.10 Antlion Optimization (ALO)

2.10.1 Antlion optimizer

Antlion optimization techniques, has been selected from other optimization techniques, since it is simple, easy to converge, has low input parameters and it avoids local optima.

Antlions belong to the Myrmeleontid family and Neuropteran order (net-winged insects). Its lifecycle contains two stages namely, larva and adult. Larva lifecycle longs up to 3 years but adults long up to 3-5 weeks.

Ant Lion Optimization (ALO) is a new field of artificial intelligence that was introduced in 2015 by Mirjalili [21]. It is recent swarm intelligence based meta-heuristic algorithm which models the interaction of Ants and antlions in nature [21]. There are two main stages in the life of antlion optimization. These are larva and adult stages. The adult phase lasts only up to 3-5 weeks which is used for reproduction. On the other hand, larva stage which is prolonged phase of lifecycle is used for hunting the prey(ants). The hunting mechanism for antlion larva is unique. The move along the circular path and throw out the sands with their huge jaws to make small funnel-shaped pits on the sandy soil for trapping ants. They hide beneath the bottom of pits and wait for an ant or tiny insects for trapping. Ant lion then trays to keep any escaping attempt of the prey by throwing sands through the outer edge of the trap. Insects sliding into the bottom of the pit finally consumed by the antlion. The remaining prey are thrown out of the pit. The higher the level of hunger in antlions, the larger the traps they dig.

In nature, ants move at random in search of foods. This stochastic movement of ants over search space is modeled by using [21] by using cumulative sum function and random function applied over different iteration.

2.10.2 Steps in the ALO algorithm

The ALO simulates six main important operation of hunts in larva.

1. The random walking of ants
2. Building Ant Lion traps
3. Entering of the Ants into traps
4. Sliding of ants towards antlion
5. Catching the pray and re-building traps

6. Elitism

1. Random walking of Antlions

The random motion of Ant is modeled as below

$$X(t) = [0, Cumsum(2r(t_1) - 1), Cumsum(2r(t_2) - 1), \ldots Cumsum(2r(t_n) - 1)] \quad .. \qquad .(2.7)$$

Where n refers to the maximum number of iterations, Cumsum represents Cumulative sum, t denotes the step of iteration and r(t) is random function represented as

$$r(t) = \begin{cases} 1, & if\ rand > 0.5 \\ 0, & if\ rand \leq 0.5 \end{cases} \qquad (2.8)$$

where *rand* is the random number produced using uniform distribution in the interval [0,1] and t shows step of random walk, or iteration in this research

2. Building Ant Lion traps

For entrapping of the prey(ant) the antlion prepares trap(pit). The outer edge of pit was so Sharpe so that the tinny ants easily fall into the pit. The depth of the pit depends up on the hunger behavior of antlion. It is assumed that ants are trapped in only one selected antlion [21]

Around the selected antlion, the ants walk at random in the hypersphere formed by the vectors c & d. The antlion's pits' mathematical formula is as follows:

The random walk of Antlion needs to be converted into position in actual search space based on upper and lower boundary. It can be modeled using equation:

$$Y_i = \left(\frac{Xi - ai}{bi - ai}\right) \times (d_i - c_i) + c_i \qquad (2.9)$$

The ants' movements are affected by antlions 'traps' and this can be described as

$$c = c' + Antlion, \text{ and } d = d' + Antlion \qquad (2.10)$$

$AntLion^t_j$ demonstrates the position of the antlion j^{th} at the iteration t^{th}

3. Entering of the Ants into traps

Ant Lion is the sit down of the pit and waiting for the prey. ALO uses Roulette wheel operator. Roulette operator is used for selecting antlion based on their fitness value. Ant lions dig their pits in proportion to the fitness value to catch the prey. This is modeled in [21].

4. Sliding of ants towards antlion

Once the antlions knows that ants are trapped and tries to escape, the sliding process of ants with decreasing radius occurs.

When an ant is in its trap, the antlion starts throwing the sands outward the center of pit to slide the escaping ants [21].

5. Catching the pray and re-building traps

An ant is eventually caught in the antlions jaw when it is slipped to the bottom of the pit. This process of catching prey is simulated by assuming that the ant has become fittest than corresponding antlion. So that, the antlion updates its position of hunted and catches new prey. It is modeled under [21].

6. Elitism

Elitism is need to adopted in the algorithm. It means that best solution obtained during each generation and the fittest antlion obtained until now in each iteration is to be saved and considered as elite antlion. The movement of this elite antlion influences the movement of all the ants during the iteration. The position update of each ant depends on random walk around antlion selected by roulette wheel and the elite. It can be modeled as

The location or position of ant is described as

$$M_{ant} = \begin{bmatrix} ant1,1 & ant1,2 \dots & ant1,d \\ ant\ 2,1 & ant2,2 \dots & ant2,d \\ . & . & . \\ . & . & . \\ ant\ n,1 & ant\ n,2 .. & ant\ n,d \end{bmatrix} \tag{2.11}$$

Matrix M_{ant} is considered to save the position of each ant. The objective function is employed during optimization and the following matrix saves the fitness value of each ant

2.11 Flow chart of Antlion Optimization

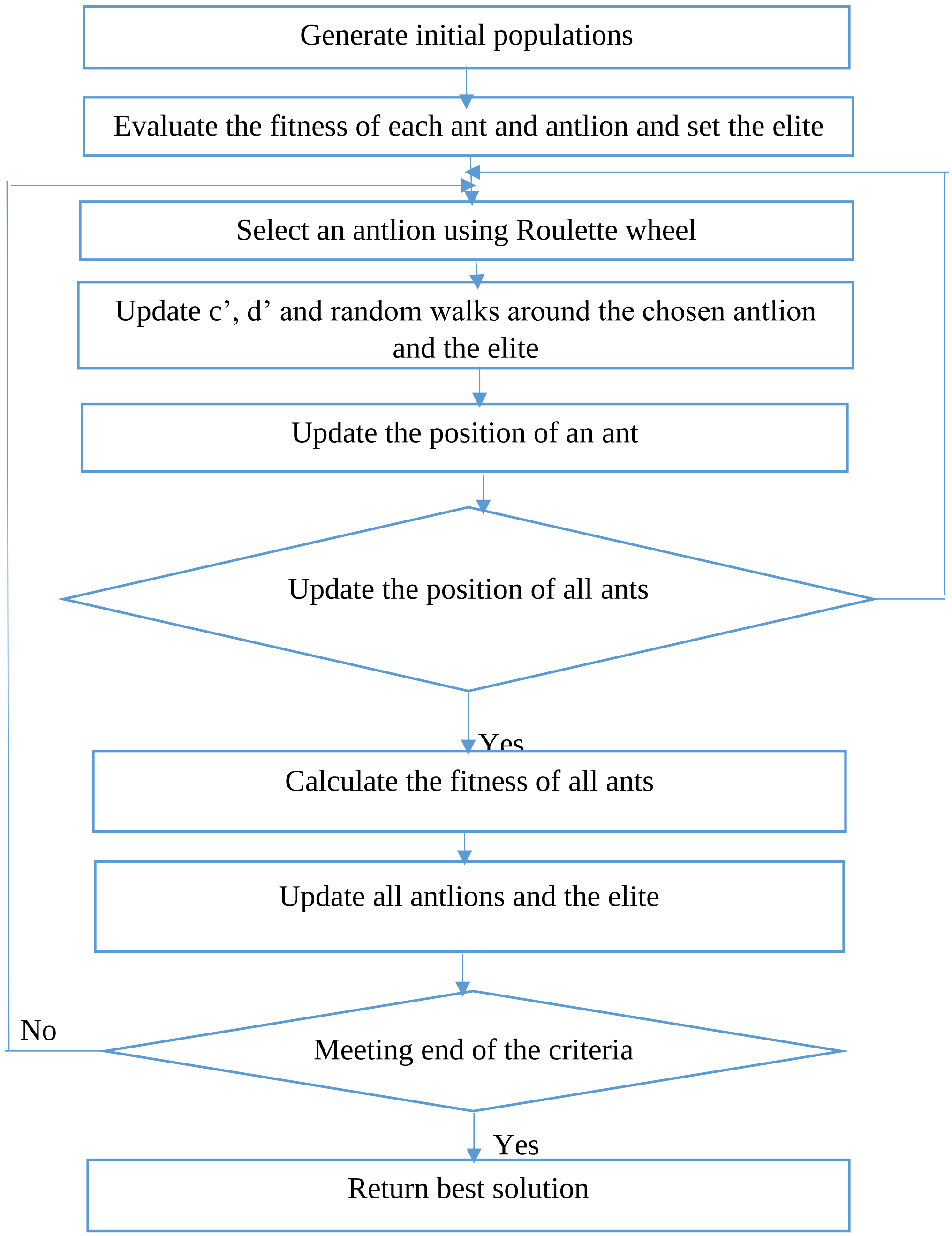

Fig 2.11 Flow chart of Antlion optimization

2.12 Particle Swarm Optimization

Particle swarm optimization (PSO) is one of the bio-inspired algorithms and it is a simple one to search for an optimal solution in the solution space. In this research, particle swarm optimization (PSO) method is used to obtain minimum operating time of overcurrent relay [36].

Particle Swarm Optimization (PSO) was proposed by Kennedy and Eberhart in 1995. Sociobiologists believe a school of fish or a flock of birds that moves in a group "can profit from the experience of all other members". In other words, while a bird flying and searching randomly for food, for instance, all birds in the flock can share their discovery and help the entire flock get the best hunt.

While we can simulate the movement of a flock of birds, we can also imagine each bird is to help us find the optimal solution in a high-dimensional solution space and the best solution found by the flock is the best solution in the space. This is a heuristic solution because we can never prove the real global optimal solution can be found and it is usually not. However, we often find that the solution found by PSO is quite close to the global optimal.

Research paper at [37] presents PSO for overcurrent relay coordination problem. Particle swarm optimization is used to solve miscoordination problems and reduce the operation time of the relays. The simulation outcomes have shown that the particle swarm optimization algorithm is set to minimize the total operation time of relays and to solve the miscoordination problem in the power protection system.

Steps of Particle swarm optimization (PSO)

Step 1: Initialization of population of particles (initialize algorithm constants)

Step 2: Initialize the solution from the solution space (initial values for position and velocity)

Step 3: Evaluate the fitness of each particle

Step 4: Update individual and global bests (g_{best} and P_{best})

Step 5: Update the velocity and position of each particle

Step 6: Go to step 3 and repeat until the termination condition (it converges)

2.13 Flow chart of Particle swarm optimization

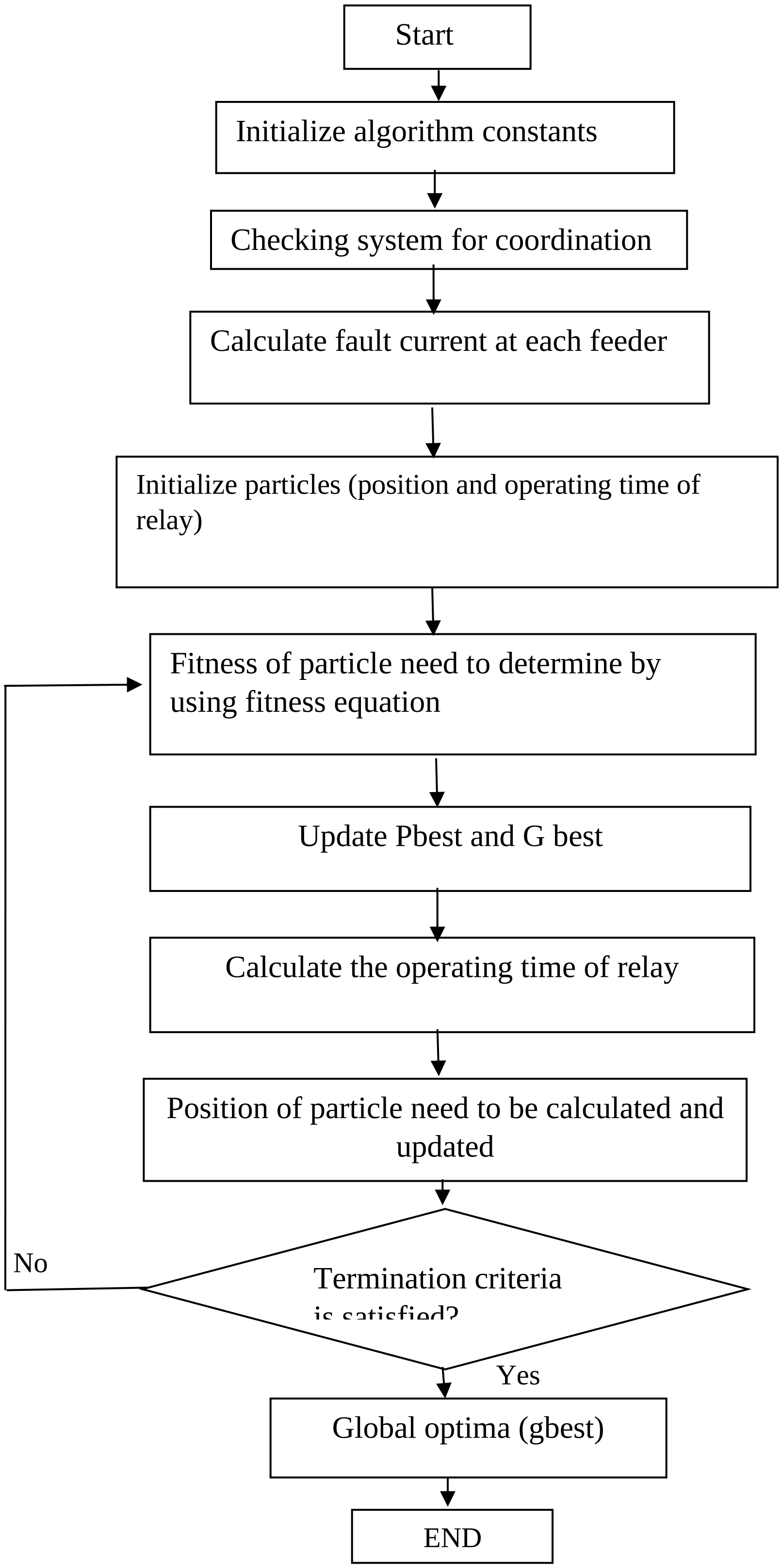

Fig 2.12 Flow chart of Particle swarm optimization (PSO)

CHAPTER THREE

METHODOLOGY AND MODELING OF PROTECTIVE DEVICE COORDINATION

3.1 Flow Chart of Protective Device Coordination

Protective device coordination problem should follow some rules in order power system to be operated in proper way. Unless other way, we may lose entire power system functionality which could result in equipment damage, service interruption from customer perspective and even hazards to humans nearby.

Basic rules for proper relay coordination are listed as follows:

- Use relays with same operating characteristics in series with each other
- Time setting of relays furthest from source should be equal to or less than time setting of relays closest to source or behind it

Flow chart designed for proposed algorithm of optimal coordination of overcurrent relays is explained as below

- We should have a given power system, it may be transmission system, distribution system or substation level. For our case we consider Yirgalem distribution substation
- Conducting short circuit analysis and load flow analysis to determine fault current flowing through it to design protective device and determine either power system is adequately designed for satisfying the performance criteria or not respectively
- Overcurrent protective relay and its setting should be selected
- Overcurrent relay should be connected to distribution feeder and protective coordination should be done based on short circuit analysis
- Applying a Network to fault and verifying the result
- Coordination should be checked by using ETAP, if it meets the coordination criteria we will proceed, other ways relay setting should be rechecked
- Applying Antlion optimization technique (ALO) to find optimal coordination in order to minimize the operating time obtained by using ETAP
- Recording the result

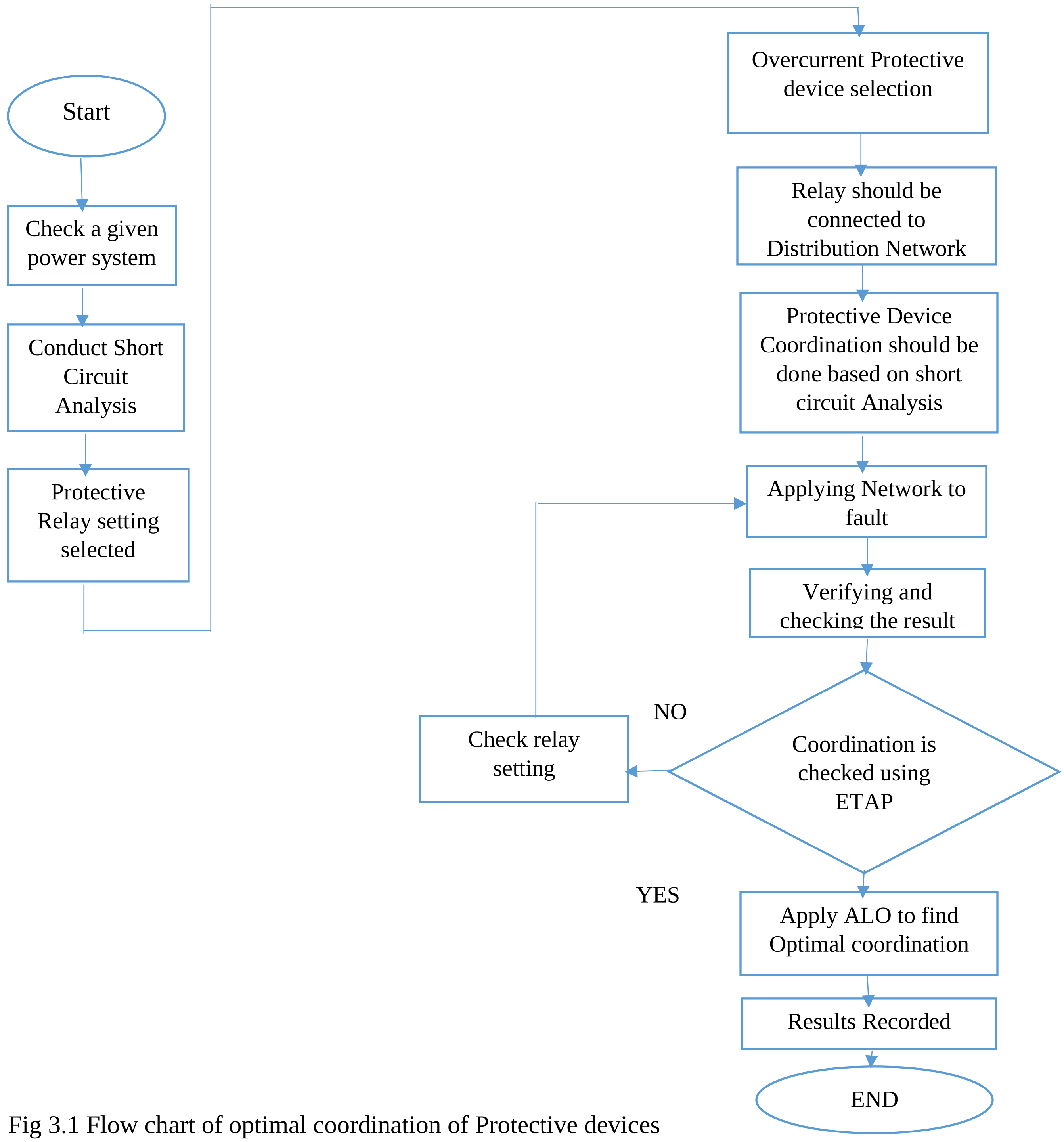

Fig 3.1 Flow chart of optimal coordination of Protective devices

3.2 Relay Coordination Analysis

In a given designed system, we need to consider the following points for relay coordination

- Load flow analysis
- Short circuit analysis
- CT selection
- Relay coordination

3.2.1 Short Circuit Analysis

Short circuit currents are the currents that introduce large amount of destructive energy in the form of heat and magnetic force in power system. The reliability as well as safety in a given electrical power system is based on knowledge of short circuit currents that exist in a system. Most of power systems are not protected from this short circuit current which may result in equipment damage.

During performing short circuit analysis, we have to consider the following issue

- Protective device to be coordinated should be differentiated
- Maximum and minimum fault currents for distribution system should be determined
- Fault current in power distribution system at each protective device should be calculated

Short circuit analysis is required to guarantee that existing and new equipment ratings are sufficient to withstand the available short circuit energy at each point in the electrical system. By determining the right interrupting ratings of protective devices, a short circuit analysis will help to ensure that persons and equipment are protected (circuit breaker and fuses) [22].

Determining fault current for protective devices in power system is the key point to be considered during protection device coordination study. Carrying short circuit analysis in distribution system is must to find out both maximum and minimum fault current existing in power system.

$$Z_{pu} = \%Z \times \frac{base\ MVA}{transformer\ rating(MVA)} \tag{3.1}$$

$$Fault\ MVA = \frac{base\ MVA}{Z\ pu} \tag{3.2}$$

$$Fault\ current = \frac{Fault\ MVA}{\sqrt{3} \times line\ voltage} \tag{3.3}$$

For Relay coordination

$$\text{FPC} = \frac{voltage\ between\ healthy\ and\ faulty\ phase}{normal\ phase\ voltage} \tag{3.4}$$

$$\text{Plug setting} = \frac{desired\ pickup\ current}{CTR} \tag{3.5}$$

$$\text{Primary operation current} = \text{CTR}\times\text{PS} \tag{3.6}$$

$$\text{Plug setting multiplier} = \frac{FI}{actual\ POC} = \frac{fault\ current}{plug\ \ setting \times rated\ current\ of\ \ CT} \tag{3.7}$$

Where, FPCstands for first pole clear, POC is primary operation current, CTR stands for current transformer ratio, PS stands for plug setting

3.2.2 Load Flow Analysis for Distribution System

Load flow analysis is carried out using ETAP software which simulates the actual steady state power system operating condition enabling the evaluation of bus voltages, real and reactive power flow and losses.

Conduting Load flow analysis is helpful for determining whether the power system is adequately designed for satisfying the performance criteria or not.

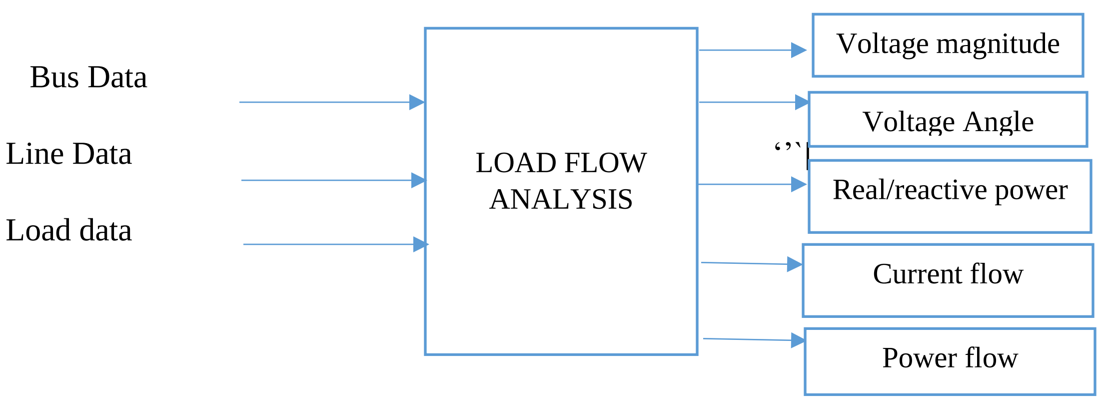

Fig. 3.2 Load flow analysis

Load flow analysis is key for determining how electrical system is performing during normal and abnormal operating condition and provides the information needed to:

- Optimize circuit usage

- Develop practical voltage profiles
- Minimize Kw and Kvar losses
- Develop equipment specification guidelines
- Identify transformer tap setting

3.3 Modeling of Yirgalem Distribution system using ETAP software

3.3.1 Electrical Transient Analysis Program (ETAP)

Electrical Transient Analysis Program (ETAP) is a graphical enterprise package which operates in different Microsoft windows operating systems to model and enhancement of electrical power system. It is analytical engineering solution provider specialized in simulation, design, monitoring, control, optimizing and automating power systems.

Electrical Transient Analysis Program (ETAP) operates by utilizing real time data to advanced monitoring, real time simulation, system of energy management and efficient load shedding.

Power systems experts utilize the Electrical Transient Analyzer Program (ETAP), a modeling and simulation tool for electrical networks, to build an "electrical digital twin" and examine the dynamics, protection, and transients of electrical power systems.

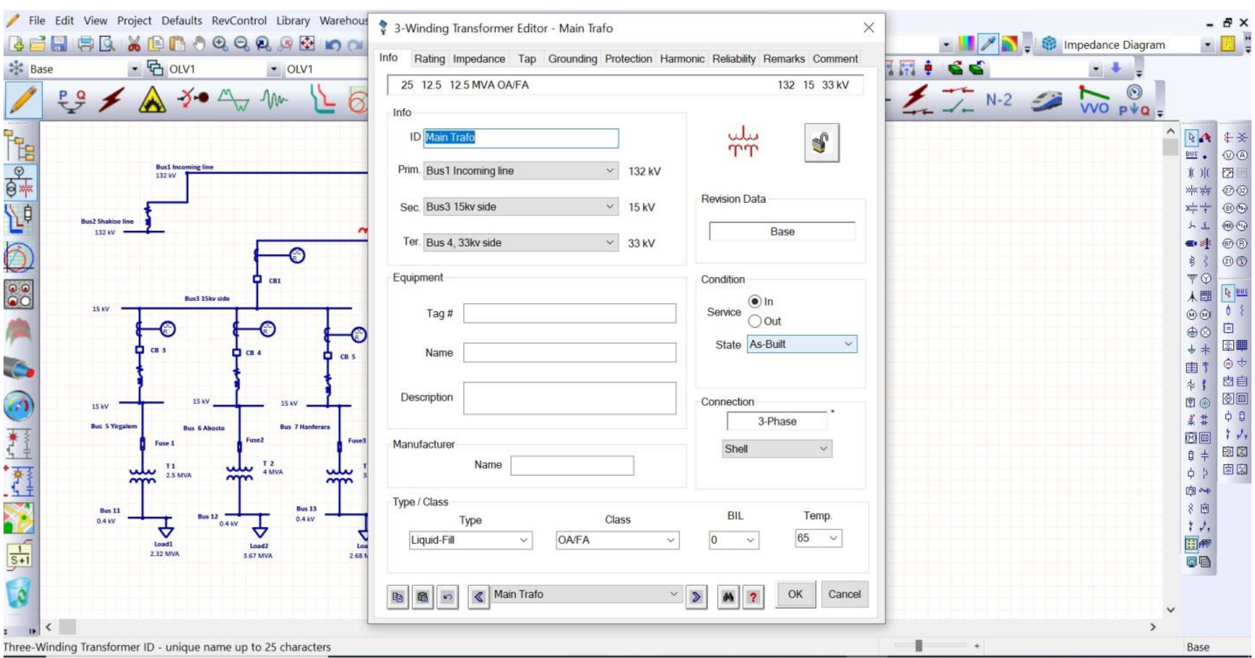

Fig 3.3 Modeling of Yirgalem substation using ETAP software

3.3.2 Case Study Area

This research has been caried out in Sidamo region, Yirgalem substation. It is located 314km from Ethiopian capital city Adis Abeba and it is about 42km from regional city, Hawassa. Yirgalem distribution substation has one 132kv line incoming and 6 feeders from which three are 15kv and the rest three are 33kv lines. It is rated with transformer rating as 132kv/33kv and 132kv/15kv.

3.4 Yirgalem Distribution System

Yirgalem distribution substation has one incoming 132kv busbar and the other outgoing busbar called Shakiso busbar which has voltage rating of 132kv. The distribution system currently working with six (6) feeders. Three of them are 15kv and the rest three are 33kv lines. The three 15kv radial feeders are named as feeder 1 as Yirgalem feeder, Feeder 2 as Abosto feeder and Feeder 3 is named as Hanferara Feeder. The rest three are 33kv feeders and named as feeder 4 as Bensa Daye feeder, Feeder 5 as CZA Chipud factory feeder and Feeder 6 as Kura Chanco.

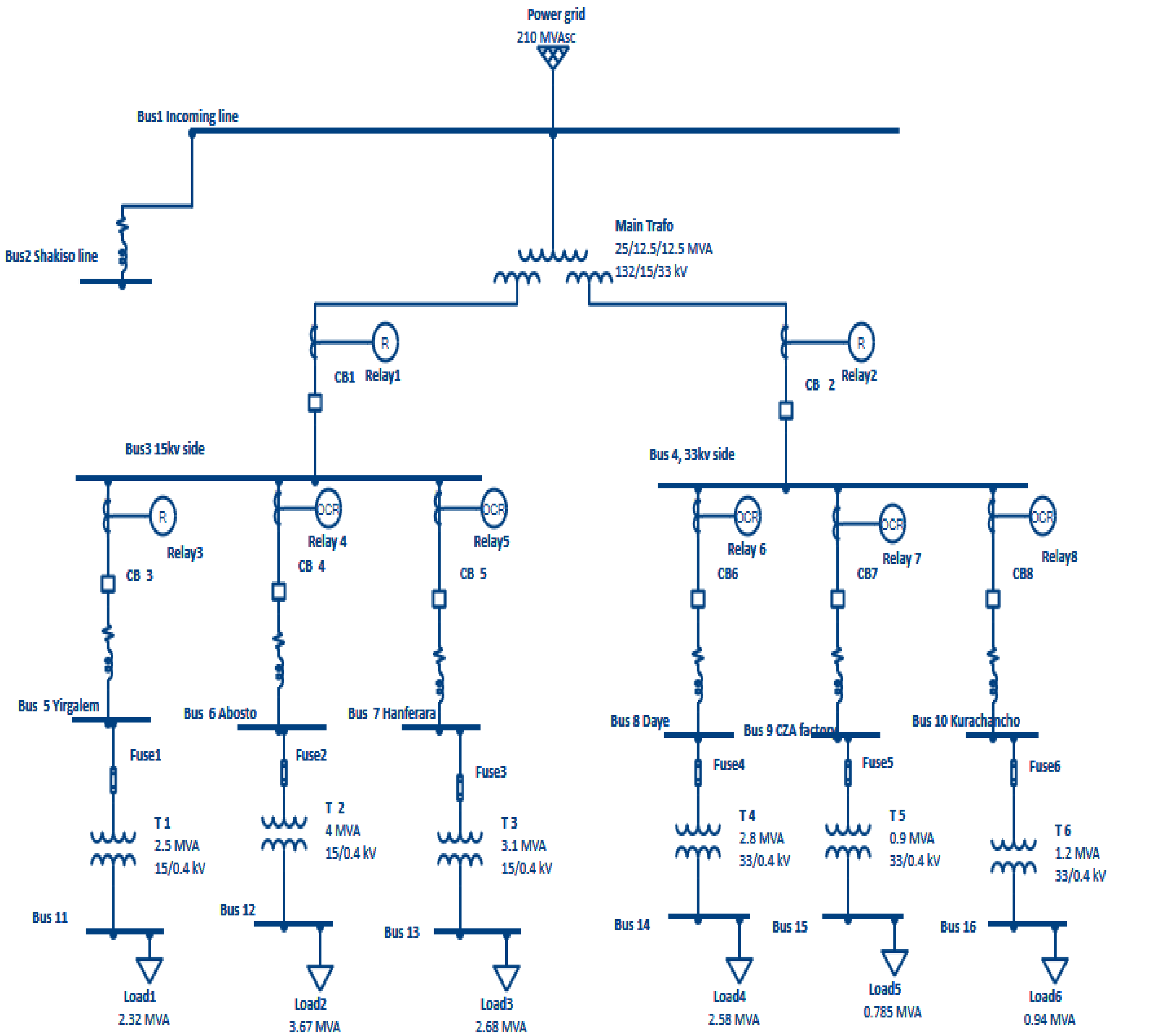

Fig 3.4 Single line diagram of Yirgalem distribution system

For the research purpose, we need to consider the following parameters at Yirgalem Distribution system

- Current Transformer Ratio
- Peak load
- Transformer Rating
- Impedance value
- Conductor type

- Circuit breaker, Relay and Fuse specification
- Duration of interruption
- Length of feeder

3.4.1 Peak load of Yirgalem Distribution system

Table 3.1 Peak load at Yirgalem distribution system, 2014/2022 data

	Peak load of Yirgalem Distribution system in MW, 2014/2022 data											
FEEDER	MONTHS											
	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG
Feeder 1	3.5	3.6	3.6	3.4	3.5	3.8	3.2	3.7	4.2	3.8	3.8	3.8
Feeder 2	1.6	2.0	1.5	1.5	1.3	1.3	1.3	1.2	1.4	1.2	1.3	1.2
Feeder 3	2.0	2.0	2.0	2.0	2.0	2.0	2.1	1.8	2.0	1.8	1.7	1.9
Feeder 4	3.5	4.0	3.2	3.5	3.2	3.1	3.3	3.5	3.7	3.4	3.6	3.7
Feeder 5	3.4	3.8	3.2	3.10	3.0	2.9	3.2	3.4	3.5	3.1	3.5	3.5
Feeder 6	3.2	3.5	3.1	3.0	2.9	2.8	3.2	3.3	3.4	3.0	2.9	3.3

Total load in the system is calculated as dividing the sum of each feeder to 12 months

$$\text{Total load} = \frac{sum\ of\ each\ feeder}{12\ Months} \tag{3.8}$$

Feeder 1 = $\frac{3.5+3.6+3.6+3.4+3.5+3.8+3.2+3.7+4.2+3.8+3.8+3.8}{12} = \frac{43.9}{12} =$ 3.65

Feeder 2 = $\frac{1.6+2.0+1.5+1.5+1.3+1.3+1.3+1.2+1.4+1.2+1.3+1.2}{12} = \frac{16.8}{12} =$ 1.4

Feeder 3 = $\frac{2.0+2.0+2.0+2.0+2.0+2.0+2.1+1.8+2.0+1.8+1.7+1.9}{12} = \frac{17.3}{12} =$ 1.4

Feeder 4 =$\frac{3.5+4+3.2+3.5+3.2+3.1+3.3+3.5+3.7+3.4+3.6+3.7}{12} = \frac{41.7}{12} =$ 3.5

Feeder 5 = $\frac{3.4+3.8+3.2+3.1+3.0+2.9+3.2+3.4+3.5+3.1+3.5+3.5}{12} = \frac{39.6}{12} =$ 3.3

Feeder 6 = $\frac{3.2+3.5+3.1+3.0+2.9+2.8+3.2+3.3+3.4+3.0+2.9+3.3}{12} = \frac{37.6}{12} =$ 3.13

By using power factor of 0.98Yirgalem distribution system, we can calculate both real and reactive power demand as follows.

Table 3.2Peak load data of Real and Reactive power demand

Feeder Name	Feeder 1	Feeder 2	Feeder 3	Feeder 4	Feeder 5	Feeder 6
Real power, MW	3.65	1.4	1.44	3.47	3.3	3.13
Reactive power, MVA	3.72	1.42	1.47	3.54	3.36	3.19
Load Current in A	140.5	53.9	55.4	61	57.7	57.7

3.4.2CT and VT ration

Table 3.3CT and VT Ratio

Feeder Name	CT Ratio	VT Ratio
Feeder 1	300/1	15kv/100
Feeder 2	300/1	15kv/100
Feeder 3	200/5	15kv/100
Feeder 4	150/1	33kv/100
Feeder 5	150/1	33kv/100
Feeder 6	150/1	33kv/100

3.5 Mathematical Modeling of Protective Device Coordination

Here we are going to calculate mathematical modeling for Yirgalem distribution system protective device coordination.

Mathematical Expression for some system parameters is discussed as following

$$Z_{pu} = \%Z \times \frac{base\ MVA}{transformer\ rating(MVA)} \tag{3.9}$$

$$Fault\ MVA = \frac{base\ MVA}{Z\ pu} \tag{3.10}$$

$$Fault\ current = \frac{Fault\ MVA}{\sqrt{3} \times line\ voltage} \tag{3.11}$$

$$Load\ current\ I_L = \frac{KVA}{\sqrt{3} * KV} \tag{3.12}$$

Now, short circuits on each feeder is to be calculated.

Total short circuit = short circuit 1 + short circuit 2 + short circuit 3 + short circuit 4 + short circuit 5 +short circuit 6

Here the main objective of calculating short circuit on primary and secondary of transformer is to obtain selective rating f overcurrent protective devices which should interrupt fault current.

Transformer Rating and Impedance of feeders

Table 3.4 Transformer rating and impedance value

Feeder V level	Main Transformer Rating	Impedance level
15kv Side	12.5MVA	68.4Ω
33kv Side	12.5MVA	576Ω

Therefore, based on the above impedance and transformer rating value in addition to total load data of Yirgalem distribution system, we can conduct short circuit analysis for a given distribution system

3.5.1 Short Circuit Analysis of 15kv Voltage side (15kv feeder)

1. Yirgalem Feeder(15kv) Transformer (MVA) = 2.5 Z actual= 68.4ohm, Z_{PU} = 0.76 and Z_{pu} = $Z\times\frac{MVAbase}{KV*KV}\times\frac{1}{1000}$ = $68.4\times\frac{2.5MVA}{15KV\times15KV}\times\frac{1}{1000}$ = 171/225 = 0.76 , Transformer 1 MVA_S = $\frac{Base\ MVA}{Z\ pu}$ = $\frac{2.5}{0.76}$ = 3.3MVA , Impedance Z1MVA = $\frac{KV*KV}{Z}$= 15*15/0.76 = 296MVA, Resultant MVA on same feeder= Inv($\frac{1}{Z1MVASC}$ + $\frac{1}{T1MVASC}$) = INV($\frac{1}{296}$ + $\frac{1}{3.3}$) = 3.26MVA. Fault current MVASC2 = $\frac{load1MVA*KVA}{\sqrt{3}*0.4KV}$ = $\frac{2.32*1000}{0.6928}$ = 3348.8A Fault current MVA = (MVA resultant1 *KVA)/radical 3 * 15kv = (3.26*1000)/1.732*15= 125.48A. I resultant = 3348.8 + 125.48 = 3474.28A = 3475A

2.Abosto Feeder (15kv)

Transformer 2 (MVA) = 4, Z actual = 68.4, Z pu = $Z\times\frac{MVAbase}{KV*KV}\times\frac{1}{1000}$ = $68.4\times\frac{4}{15\times15}\times\frac{1}{1000}$ = $\frac{273.6}{225}$ =1.216. Transformer 2 MVA_{SC2} = $\frac{MVA*100}{\%Z}$ = $\frac{4*100}{\%68.4}$ = 585MVA, Impedance Z2MVA= $\frac{KV*KV}{Z}$ = $\frac{15*15}{1.216}$ = 185MVA. Resultant MVA on same feeder = Inv($\frac{1}{Z2MVASC}$ + $\frac{1}{T2MVASC}$) = INV ($\frac{1}{185}$ + $\frac{1}{585}$) = 13.3MVA. Load is connected to 0.4KV. therefore, Faut current MVASC2 = $\frac{load2MVA*KVA}{\sqrt{3}*0.4KV}$= $\frac{3.67*1000}{\sqrt{3}*0.4KV}$=$\frac{3670}{0.6928}$ = 5297A. Fault MVASC resultant = $\frac{\text{MVA resultant2 *KVA}}{\sqrt{3}*15kv}$= $\frac{13.3*1000}{\sqrt{3}*15kv}$ = 512A. Therefore, Resultant Fault current = 5297+512 = 5809A

3.Hanferara Feeder

Transformer 3.(MVA) = 3.1, Z actual 68.4, Z pu = Z×$\frac{MVAbase}{KV*KV}$ ×$\frac{1}{1000}$ = 68.4×$\frac{3.1}{15\times15}$ × $\frac{1}{1000}$= $\frac{212.04}{225}$ = 0.99424. Transformer 3 MVA_{SC3} = $\frac{MVA*100}{\%Z}$ = $\frac{3.1*100}{\%68.4}$ = 453MVA, Impedance Z3MVA= $\frac{KV*KV}{Z}$ = $\frac{15*15}{0.99424}$ = 226 MVA. Resultant MVA same feeder = Inv($\frac{1}{Z3MVASC}$ + $\frac{1}{T3MVASC}$) =

INV ($\frac{1}{453}$ + $\frac{1}{226}$) = 150MVA. Load is connected to 0.4KV. therefore, Faut current MVASC3 = $\frac{load3MVA*KVA}{\sqrt{3}*0.4KV}$= $\frac{2.68*1000}{\sqrt{3}*0.4KV}$=$\frac{2680}{0.6928}$ = 3868.4A. Fault MVASC resultant = $\frac{\text{MVA resultant3 }*\text{KVA}}{\sqrt{3}*15kv}$= $\frac{150*1000}{\sqrt{3}*15kv}$ = 5774A. Therefore, Resultant Fault current = 3868.4+5774 = 9642A

3.5.2 Short Circuit Analysis of 33kv Voltage side (33kv feeder)

4.Bensa Feeder(33kv)

Transformer 4. (MVA)=2.8, Z = 576Ω. By using equation 3.11, we can calculate per unit impedance pu = Z×$\frac{MVAbase}{KV*KV}$ ×$\frac{1}{1000}$ = 576×$\frac{2.8}{33*33}$ × $\frac{1}{1000}$= $\frac{1612.8}{1089}$ = 0.148

Transformer 4 MVA_{SC4} = $\frac{MVA*100}{\%Z}$ = $\frac{2.8*100}{\%576}$ = 48.6MVA. Impedance Z4MVA= $\frac{KV*KV}{Z}$ = $\frac{33*33}{0.148}$ = 7358MVA. Resultant MVA same feeder = Inv($\frac{1}{Z4MVASC}$ + $\frac{1}{T4MVASC}$) = INV ($\frac{1}{48.6}$ + $\frac{1}{7358}$) = 48.3MVA. Load is connected to 0.4KV. therefore, Faut current MVASC4 = $\frac{load4MVA*KVA}{\sqrt{3}*0.4KV}$= $\frac{2.58*1000}{\sqrt{3}*0.4KV}$=$\frac{2580}{0.6928}$ = 3724A. Fault MVASC resultant = $\frac{\text{MVA resultant4 }*\text{KVA}}{\sqrt{3}*15kv}$= $\frac{48.3*1000}{\sqrt{3}*33kv}$ =$\frac{4830}{57.157}$84.5A. Therefore, Resultant Fault current = 3724+84.5 = 3808.5A

5.CZA Chipud Factory(33kv)

Transformer 5. (MVA) = 0.9, Z actual = 576

Z pu = Z×$\frac{MVAbase}{KV*KV}$ ×$\frac{1}{1000}$ = 576×$\frac{0.9}{33*33}$ × $\frac{1}{1000}$= $\frac{518.4}{1089}$ = 0.476

Transformer 5 MVA_{SC5} = $\frac{MVA*100}{\%Z}$ = $\frac{0.9*100}{\%576}$ = 15.6MVA

Impedance Z5MVA= $\frac{KV*KV}{0.476}$ = $\frac{33*33}{0.476}$ = 2288MVA. Resultant MVA same feeder = Inv($\frac{1}{Z4MVASC}$ + $\frac{1}{T4MVASC}$) = INV ($\frac{1}{15.6}$ + $\frac{1}{2288}$) = 15.5MVA. Load is connected to 0.4KV. Therefore, Fault current

MVASC5 = $\frac{load5MVA*KVA}{\sqrt{3}*0.4KV}$= $\frac{0.875*1000}{\sqrt{3}*0.4KV}$=$\frac{875}{0.6928}$ = 1263A. Fault MVASC resultant = $\frac{\text{MVA resultant5*KVA}}{\sqrt{3}*33kv}$= $\frac{15.5*1000}{\sqrt{3}*33kv}$ = $\frac{15500}{57.157}$= 271A. Therefore, Resultant Fault current = 1263+271 = 1534.2A

6. Kurachancho Feeder (33kv)

Transformer 6. (MVA) = 1.2, Z actual = 576. Z pu = Z×$\frac{MVAbase}{KV*KV}$ ×$\frac{1}{1000}$ = 576×$\frac{1.2}{33*33}$ × $\frac{1}{1000}$= $\frac{691.2}{1089}$= 0.635

Transformer 5 MVA_{SC5} = $\frac{MVA*100}{\%Z}$ = $\frac{1.2*100}{\%576}$= 208.3MVA. Impedance Z4MVA= $\frac{KV*KV}{Z}$ = $\frac{33*33}{0.635}$ = 1715MVA. Resultant MVA same feeder = Inv($\frac{1}{Z4MVASC}$ + $\frac{1}{T4MVASC}$) = INV ($\frac{1}{1715}$ + $\frac{1}{208.3}$)= 186MVA. Load is connected to 0.4KV. therefore, Fault current MVASC6 = $\frac{load6MVA*KVA}{\sqrt{3}*0.4KV}$= $\frac{0.94*1000}{\sqrt{3}*0.4KV}$=$\frac{940}{0.6928}$ = 1359A. Fault MVASC resultant = $\frac{\text{MVA resultant6 *KVA}}{\sqrt{3}*33kv}$= $\frac{186*1000}{\sqrt{3}*33kv}$ = $\frac{186000}{57.157}$= 3254A. Therefore, Resultant Fault current = 1359+3254 = 4613.2A

Therefore, total fault current on 15kv feeder side is the sum short circuits on three Transformers and total fault current on 33kv feeder side is the sum of short circuits on three Transformers.

15kv side = short ckt1 + short ckt2 + short ckt3 = 3475+ 5809+ 9642 = 18926A= 18.926KA

33kv side = short ckt4 + short skt5 + short ckt6 = 3808.5 + 1534.2 + 4613.2 = 9955.9A= 9.9559KA

Circuit breaker rating = 1.5 *short circuit current, Fuse Rating = 1.25*Short circuit current

Table 3.5 Summary of fault currents on feeders

Feeder name	Short Circuit Current	Selection of Protective device rating	
		Circuit Breaker Rating (ampere)	Fuse Rating (Kilo ampere)
Feeder 1	3475	5212	4344
Feeder 2	5809	8714	7261
Feeder 3	9642	14463	12053
Feeder 4	3808.5	5713	4761
Feeder 5	1534.2	2301	1917
Feeder 6	4613.2	6919.8	5766.5

3.6 Overcurrent Relay Setting calculation

In overcurrent protection case, we use three phase faults current to design short circuit calculation and use 120% of load current based on EEP standard

1. **Feeder 1**

CT Ration: 300/1, Relay nominal current 100%(1Amps). pickup current = Load current ×120% = 140.5×1.2= 168.6A, Relay secondary current = Ip/CTR = 168.6/300 = 0.562A. PSM =(If/Ip) ^0.02 = (3475/168.6) ^0.02 = 1.06

Time multiplier setting T = $\frac{0.14*TMS}{{3475/_{168.6}}^{0.02}-1}$ = 2.244* TMS 1

1. **Feeder 2**

CT Ration: 300/1, Relay nominal current 100%(1Amps). Pickup current = Load current ×120% = 53.9×1.2= 64.68A, Relay secondary current = Ip/CTR = 64.68/300 = 0.2156A. PSM =(If/Ip) ^0.02 = (5809/64.68) ^0.02 = 1.09

Time multiplier setting T = $\frac{0.14*TMS}{5809/_{64.68}{}^{0.02}-1}$ = 1.487* TMS 2

2. **Feeder 3**

CT Ration: 200/5, Relay nominal current 5 Amps. Pickup current = Load current ×120% = 55.4×1.2= 66.48A, Relay secondary current = Ip/CTR = 66.48/40 = 1.662A. PSM =(If/Ip) ^0.02 = (9642/66.48) ^0.02 = 1.105

Time multiplier setting T = $\frac{0.14*TMS}{9642/_{66.48}{}^{0.02}-1}$ = 1.337* TMS 3

3. **Feeder 4**

CT Ration: 150/1, Relay nominal current 100%(1Amps). Pickup current = Load current ×120% = 61×1.2= 73.2A, Relay secondary current = Ip/CTR = 73.2/150 = 0.488A. PSM =(If/Ip) ^0.02 = (3808/73.2) ^0.02 = 1.082

Time multiplier setting T = $\frac{0.14*TMS}{3808/_{73.2}{}^{0.02}-1}$ = 1.703* TMS 4

4. **Feeder 5**

CT Ration: 150/1, Relay nominal current 100%(1Amps). Pickup current = Load current ×120% = 57.7×1.2= 69.24A, Relay secondary current = Ip/CTR = 69.24/150 = 0.4616A. PSM =(If/Ip) ^0.02 = (1534/69.24) ^0.02 = 1.064

Time multiplier setting T = $\frac{0.14*TMS}{1534/_{69.24}{}^{0.02}-1}$ = 2.19* TMS 5

5. **Feeder 6**

CT Ration: 150/1, Relay nominal current 100%(1Amps). Pickup current = Load current ×120% = 57.7×1.2= 69.24A, Relay secondary current = Ip/CTR = 69.24/150 = 0.4616A. PSM =(If/Ip) ^0.02 = (4613/69.24) ^0.02 = 1.087

Time multiplier setting T = $\frac{0.14*TMS}{4613/_{69.24}{}^{0.02}-1}$ = 1.598* TMS 6

The **objective function** to be minimized is T=2.244*TMS1+1.487*TMS2+1.337*TMS3+ 1.703*TMS4+2.19*TMS5+1.598*TMS6

Table 3.6 Relay setting

FEEDER	CT	PICKUP	PSM	OBJECTIVE OF TMS
F-1	300/1	168.6	1.06	2.244
F-2	300/1	64.68	1.09	1.487
F-3	200/5	66.48	1.105	1.337
F-4	150/1	73.2	1.082	1.703
F-5	150/1	69.24	1.064	2.19
F-6	150/1	69.24	1.087	1.598

The above table 3.6 shows the pickup current and plug setting multiplier of overcurrent relay of six (6) feeders. We can see that PSM is within the acceptable value ($0.1 \leq PSM \leq 1.2$)

3.7 Problem Formulation of Protective Device Coordination

Since Overcurrent relay (OC) coordination problem relays in interconnected power system, it is stated as constrained optimization problems where the primary objective is minimizing the operating time of both primary and backup relays [20].

3.7.1 Objective functions

Minimizing of relay operating time is the major objective of optimal coordination. As a result, an objective function for the best coordination can be thought of as the minimal total duration of operation of all overcurrent relays.

$$Min(F) = \sum_{i=1}^{n} w_i * f(Ip, I_i) * TDS \tag{3.13}$$

$$Min(F) = \sum_{i=1}^{n} w_i * t_{i,k} \tag{3.14}$$

Where $t_{i,k}$ indicates the operating time of relay at i for near end fault and n is the number relays. TDS represents time dial setting, $f(Ip, I_i)$ depends on relay setting, fault current and relay characteristics. The coefficient W_i is weight assigned for the operating time of the relay R_i.

The function $f(Ip, I_i) = \frac{\beta}{M^\alpha} + C$ where α, β and C are constants given on above table 2.1and M is plug setting multiplier

The pickup current value Ip, the maximum short circuit current I flowing through the relay, and the time setting multiplier TSM or time dial setting TDS all determine how quickly an overcurrent relay (OCR) operates.

Ideally, all primary relay should operate at minimum possible time but this can't be achieved because it is difficult to keep back up protection properly coordinated.

3.7.2 Relay setting Constraints

Two parameters, TSM and pickup current, should be set for each relay. The TMS of relay has significant effect on operating time of relay. It has its own constraint inequality [32]

$$0.1 \leq TMS \leq 1.1$$

Relay bounds based on operating time and pickup settings

The bounds on TMS and PS are described below.

$$TDS_{min} \leq TDS_i \leq TDS_{max}$$

$$PS_{min} \leq PS_i \leq PS_{max}$$

Where, TDS_{min} and TDS_{max} are the minimum and maximum Time dial setting of relays respectively, and PS_{min} and PS_{max} are the minimum and maximum plug settings of relays respectively.

3.7.3 Coordination criteria

Based on primary relay operating time for near and far end fault, and backup relay operating time similarly for near and far end fault. It differs based on type of relays. For electromagnetic relays CTI is in between 0.3 to 0.4s but for digital and numerical relays CTI is in between 0.1 to 0.2s.

$$T_b - T_p \geq CTI$$

Where, T_b is backup relay operating time for near and end fault, T_p is primary relay operating time for near and far end fault and CTI stands for coordination time interval.

At Yirgalem distribution substation, relays are numerical types (Micom). These types of relays are widely used in substation because they respond quickly to clear fault.

3.7.4 Relay time and current setting

Each and every relay has its own TMS and PS settings. PS setting is selected based on maximum load current and minimum fault current observed by relay. TMS limit is based on available relay current-time characteristic.

$PS_{min} \leq PS \leq PS_{max}$

$TMS_{min} \leq TMS \leq TMS_{max}$

$T_{min} \leq T \leq T_{max}$

Where, PS is plugging setting, TMS stands for Time multiplier setting and T is for time.

3.7.5 CT Selection

Current Transformer is a measurement for transformer which is designed to produce alternative current in the secondary winding which is proportional to measured current in primary winding.

CT reduce Currents of high voltage systems to a much lower value which is convenient to smooth operation. Secondary winding holds current rating of 1A or 5A usually.

Important points for selecting CT

- Current Transformer output
- Conductor size
- Load size or Amperage range
- Accuracy rating
- Form factor
- Regulatory requirements

3.7.6 Selection of Overcurrent Relay

Relay operates when the current passing through the operating coil exceeds the preset threshold value. There are three types of operating characteristics of overcurrent relays.

1. Definite (instantaneous) current protection
2. Definite time protection
3. Inverse time protection

1. **Definite (instantaneous) current protection**

Here the relay operates as soon as fault current exceeds the threshold value. There is no intentional delay time. The relay located furthest from source, operates for lower fault current. This type is disadvantageous due to its poor coordination trend and little selectivity at high level of short circuits, incase if there is feeder with small impedance, it could be difficult to differentiate fault currents at both ends.

2. **Definite time protection**

Here two conditions must meet for protection(tripping) operation. Current must exceed the setting value and fault must be continuous for at least time equal to time setting of relays. Here its s difficult to coordinate and requires changes with the addition of load and that the short circuit fault close to source may be cleared in long time in spite of its high current value.

3. **Inverse time operation**

Here the operating time is inversely changed with respect to current. So high currents operate overcurrent relay faster than lower ones. This type is standard inverse, very inverse and extremely inverse.

Inverse time relays also known as inverse definite minimum time (IDMT) relays where the operating time is based on the way that the relay closer to the fault operated before than the other protection. This is known as time grading.

CHAPTER FOUR

RESULT AND DISCUSSION

4.1 Load Flow Analysis

Load flow analysis is performed using ETAP computer software that simulates the actual steady-state power system operating conditions. Conducting load flow analysis enables us ensuring the power system is designed adequately to satisfy performance scenario. Load flow analysis determines how electrical system will perform during normal and contingency operating conditions.

Here in below figure 4.1, we see the flow of current and power at each and every feeder. It shows steady state operating condition of power system.

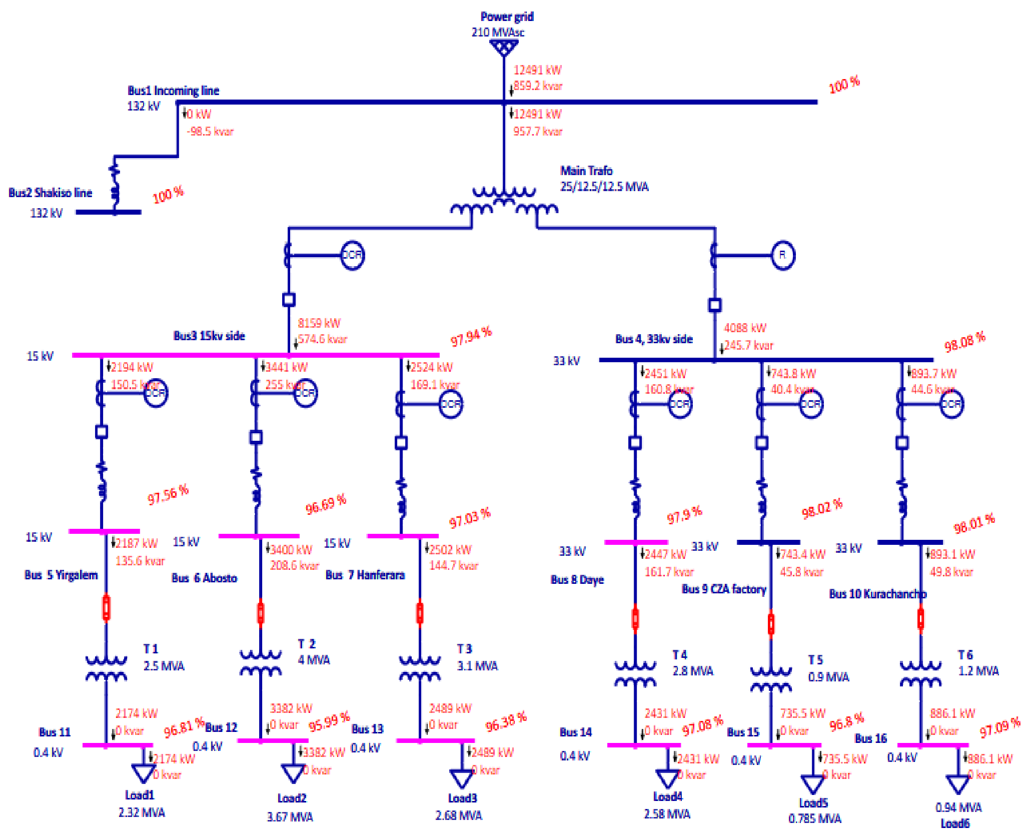

Fig 4.1 Load flow analysis simulation

4.2 Short Circuit Analysis

The goal of conducting short circuit analysis is to find maximum fault current present in power system.

Short circuit studies are conducted to determine the magnitude of fault currents in the system. This information is crucial for selecting protective devices and setting their coordination to ensure the safety of equipment and personnel

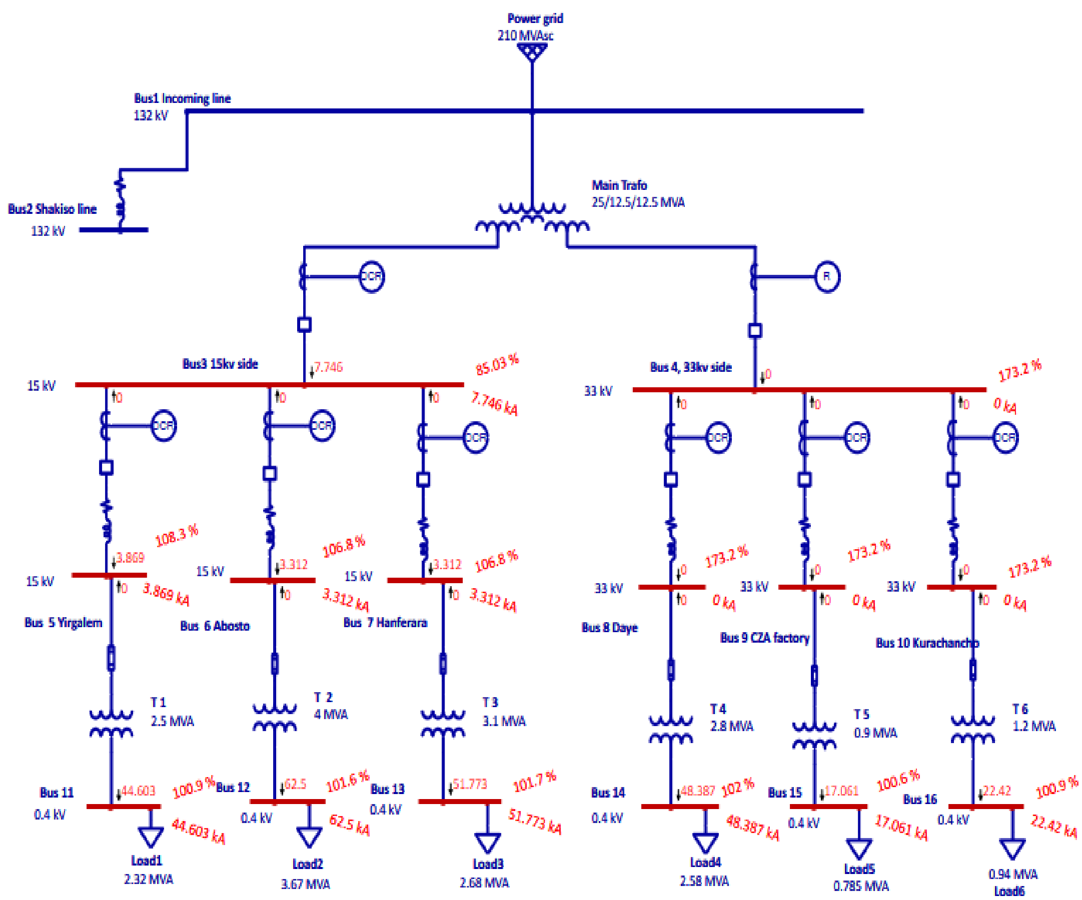

Fig 4.2 Short circuit simulation using ETAP software

Table 4.1Short circuit summary report

Short-Circuit Summary Report

1/2 Cycle - 3-Phase, LG, LL, & LLG Fault Currents

Prefault Voltage = 100 % of the Bus Nominal Voltage

Bus		3-Phase Fault			Line-to-Ground Fault			Line-to-Line Fault			*Line-to-Line-to-Ground		
ID	kV	Real	Imag.	Mag.	Real	Imag.	Mag.	Real	Imag.	Mag.	Real	Imag.	Mag.
Bus3 15kv side	15.000	4.731	-3.202	5.713	6.504	-4.207	7.746	2.773	4.098	4.947	-7.952	-1.059	8.022
Bus 4, 33kv side	33.000	2.000	-1.408	2.446	0.000	0.000	0.000	1.219	1.732	2.118	1.219	1.732	2.118
Bus 5 Yirgalem	15.000	2.753	-2.723	3.872	2.488	-2.963	3.869	2.358	2.384	3.353	1.265	3.958	4.155
Bus 6 Abosto	15.000	2.501	-2.145	3.294	2.337	-2.348	3.312	1.857	2.166	2.853	0.786	3.427	3.516
Bus 7 Hanferara	15.000	2.501	-2.145	3.294	2.337	-2.348	3.312	1.857	2.166	2.853	0.786	3.427	3.516
Bus 8 Daye	33.000	1.712	-1.287	2.142	0.000	0.000	0.000	1.115	1.483	1.855	1.115	1.483	1.855
Bus 9 CZA factory	33.000	1.712	-1.287	2.142	0.000	0.000	0.000	1.115	1.483	1.855	1.115	1.483	1.855
Bus 10 Kurachancho	33.000	1.712	-1.287	2.142	0.000	0.000	0.000	1.115	1.483	1.855	1.115	1.483	1.855
Bus 11	0.400	11.167	-39.451	41.001	9.967	-43.475	44.603	34.166	9.671	35.508	30.154	33.706	45.226
Bus 12	0.400	21.229	-50.123	54.433	19.987	-59.217	62.500	43.407	18.385	47.140	35.292	53.831	64.369
Bus 13	0.400	15.954	-43.402	46.241	14.510	-49.698	51.773	37.587	13.817	40.046	31.846	42.455	53.071
Bus 14	0.400	12.636	-43.352	45.156	10.979	-47.125	48.387	37.544	10.943	39.106	33.255	36.549	49.413
Bus 15	0.400	3.888	-16.191	16.651	3.642	-16.667	17.061	14.022	3.367	14.420	12.340	11.945	17.174
Bus 16	0.400	4.891	-21.167	21.725	4.451	-21.974	22.420	18.331	4.236	18.814	16.364	15.638	22.635

The above short circuit summary report shows maximum3-phase fault, L-G fault, L-L fault and L-L-G fault. When we see L-G fault on 15kv side, Bus11, current magnitude is 44.603, bus 12 is 62.500 and bus 13 is 51.773. When we are comparing those three fault currents, magnitude of fault current occurred at bus 12 is larger which is 62.500.

When we are seeing maximum fault current at 33kv side, bus 14 is 48.387, bus 15 is 17.061 and bus 16 is 22.420. when compared, fault current at bus 14 is larger than the other two.

Therefore, from15kv feeders feeder 2 is experiencing large fault current which needs care during overcurrent relay designing and from 33kv side, feeder 4 is experiencing large fault current and needs care on designing relays

4.3 Selective Protective device coordination

Whenever fault occurs at a given power system, the faulty part of system should be disconnected and healthy part should operate to provide reliable power to end customers. Protective relays sense the fault and sends trip signal to circuit breaker to open the faulty section. Incase if primary protective fail to operate, backup protection does the operation

4.3.1 Primary Protection coordination for fault at feeder 1 (15kv side)

To talk about coordination of protective devices, we should start at downstream side not upstream side. When fault occurs at Yirgalem feeder (Yirgalem load), there is fuse at downstream side but it does not control fault. Relay 3 sense fault and sends trip signal to CB 3. Then Relay 4 senses faut and trip signal to CB4 and CB4 takes tripping action. There is Relay 5 which senses fault and sends again trip signal to CB5.

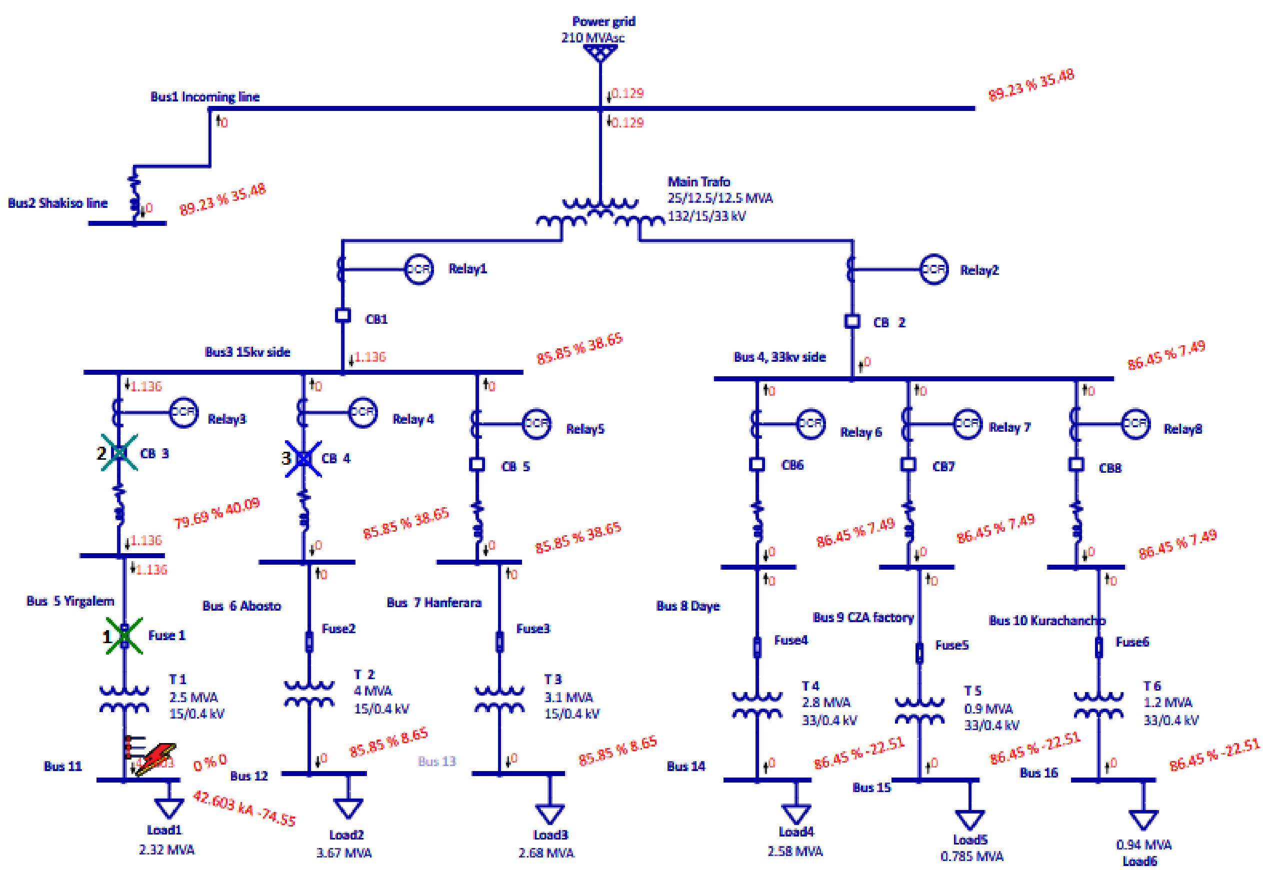

Fig 4.3 Primary protection for fault at feeder 1(Yirgalem Feeder)

Therefore, we can see the sequence of operation for fault occurred during Primary protection at feeder 1 as below.

Table 4.2 Sequence of operation of event summary report

Time(ms)	Protective device selected	Fault current (KA)	Time 1(ms)	Condition
19.8	Fuse1	1.136	<19.8	
39.3	Relay3	1.136	59	Phase-OC1-51
1230	CB3		33.3	Tripped by Relay3 Phase-OC1-51
59	Relay 4	0.462	59	Phase-OC1-51
1420	CB4			Tripped by Relay 4
78.6	Relay 5	0.324	78.6	
1620	CB 5			Tripped by Relay 5

From the above table, we can understand that when fault occurs at feeder 1, it must be sensed by downstream protective relays and circuit breaker at downstream side should trip the faulty section. Downstream side fuse has time of operation of 19.8 ms but it cannot control fault and it burns out. At this time relay next to it (R3) sense's fault and sends trip signal to CB3 with time of operation 83ms. Then R4 sense's fault and sends trip signal for CB4 with 59ms. Now R5 then sends trip signal to CB5 with 78.6ms and if with all these protective devices fail to control the fault, secondary protection is taking the operation.

4.3.2 Secondary Protection Coordination for fault at Feeder 1 (15kv side)

If CB3 fails to operate, it is must that secondary/backup protection should take the action to clear fault. In this case CB 1 trips if CB 3 fails to trip fault at Yirgalem feeder load side.

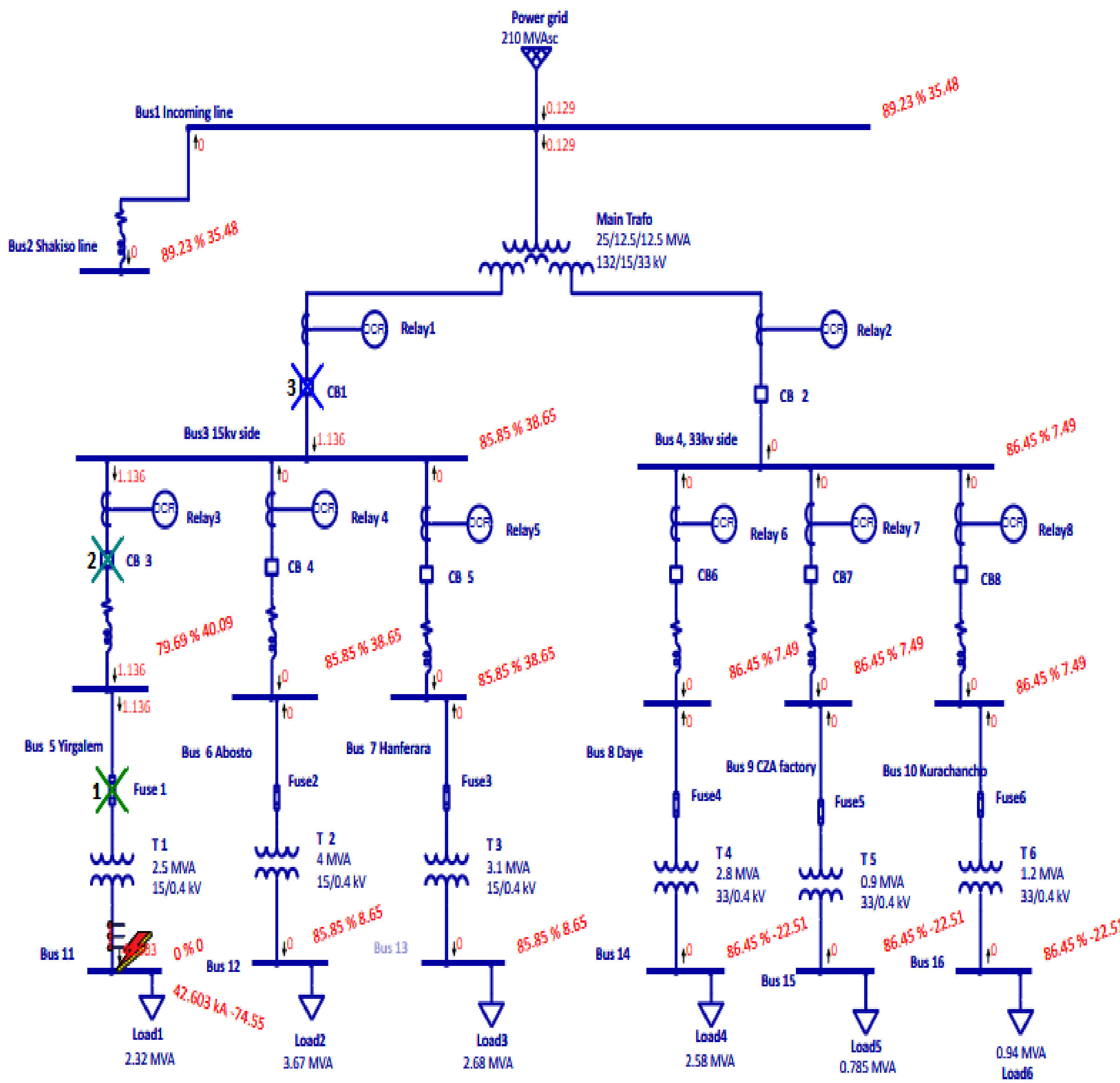

Fig 4.4 Secondary Protection for fault at Feeder 1(Yirgalem Feeder)

Sequence of operation for fault occurred at feeder 1 during secondary protection is represented in tabular form as below.

Table 4.3 Sequence of operation for fault at feeder 1

		Sequence of operation event summary report			
		Fault at Yirgalem Feeder (Feeder 1)			
Time(ms)	Protective device selected	Fault current (KA)	Time 1(ms)	Time 2(ms)	Condition
19.8	Fuse1	1.136	<19.8	<19.8	
39.3	Relay3	1.136	<39.3		Phase-OC1-51
1230	CB3		33.3		Tripped by Relay3 Phase-OC1-51
98.3	Relay 1		<98.3		
1820	CB1	1.452	89		Tripped by Relay 1

The above table illustrates that, fault occurred at feeder 1 is not mitigated by CB3 of R3 and it extended beyond primary protection. In this time, it is must that backup protection should take protection work. R1 sends trip signal to CB1 with time of operation 89ms and controls fault.

4.3.3 Primary Protection Coordination for fault at Feeder 4 (33kv side)

Consider short circuit has been occurred at 33kv Feeder side at Daye Bensa side (F4), at instant of fault occurrence Fuse 4 gets burn out since it cannot control fault current. Then Relay 6 sends trip signal to CB6 and CB6 takes trip action. In the same manner Relay 7 senses fault and sends trip signal to CB7 to take tripping action. Then Relay 8 sends trip signal to CB8 and clears fault. This is illustrated using single line diagram below.

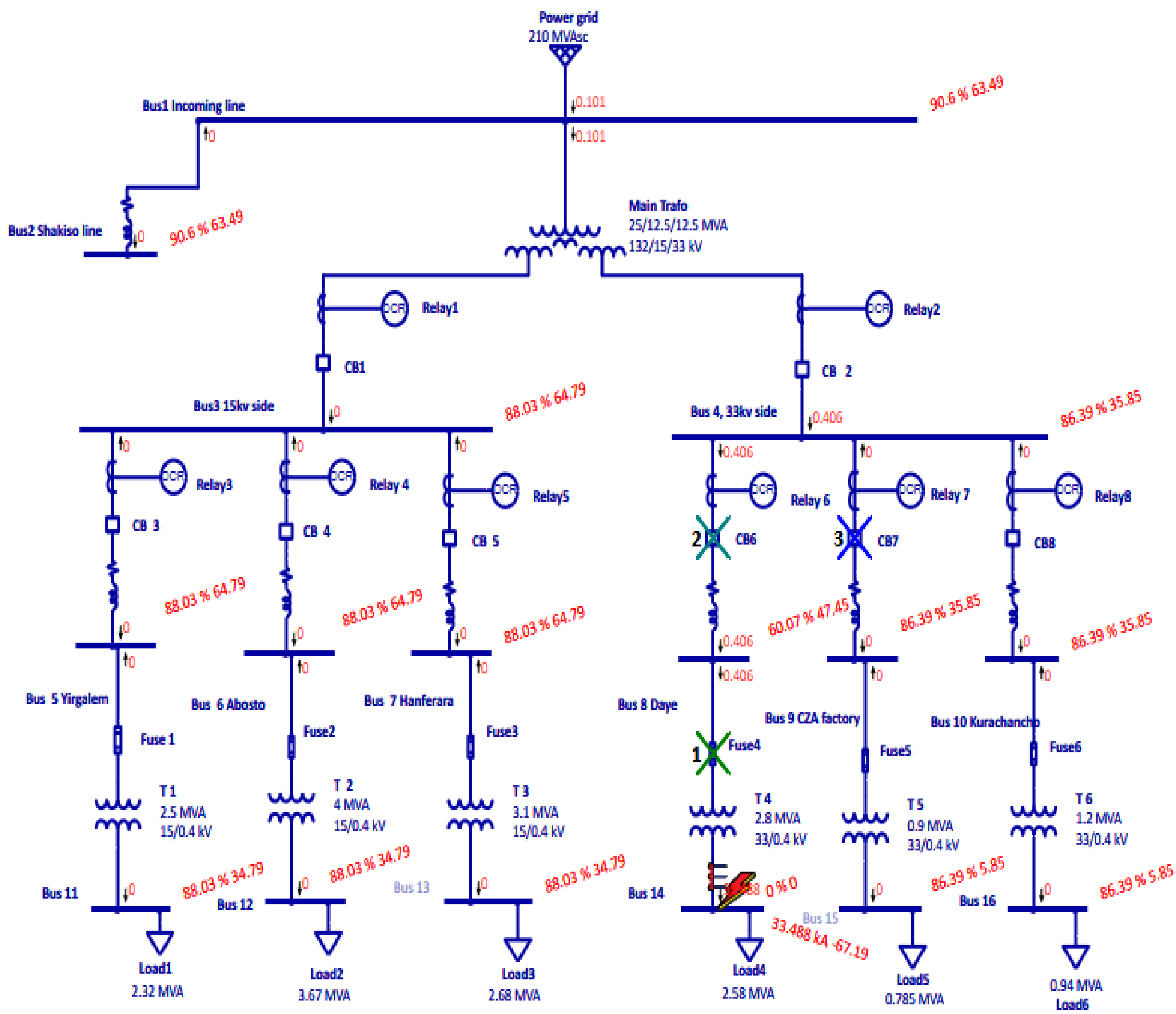

Fig 4.5 Primary protection for fault at 33kv side (Bensa feeder)

Primary protection devices on 33kv side are Fuse 4, Fuse 5, Fuse 6, Relay 6 Relay 7, Relay 8, CB6, CB7, and CB8.

This protection scheme is coordinated as in below tabular form.

Table 4.4 Sequence of operation summary report

Time(ms)	Protective device selected	Fault current (KA)	Time 1(ms)	Condition
19.8	Fuse 4	0.406	<19.8	
39.3	Relay 6	0.406	39.3	Phase-OC1-51
1520	CB6		152	Tripped by Relay 6
78.6	Relay 7	0.197	78.6	Phase-OC1-51
1620	CB7		162	Tripped by Relay 7
98.3	Relay 8	0.196	98.3	Phase-OC1-51
1820	CB8		182	Tripped by Relay 8

From the above table we can understand that fault occurred at feeder 4, it must be sensed by downstream protective relays and circuit breaker at downstream side should trip the faulty section. Downstream side fuse has time of operation of 19.8ms but it cannot control fault and it burns out. At this time relay next to it (R6) sense’s fault and sends trip signal to CB6 with time of operation 152ms. Then R7 sense’s fault and sends trip signal for CB7 with 162ms. Now R8 then sends trip signal to CB8 with 182ms and if with all these protective devices fail to control the fault, secondary protection is taking the operation.

4.3.4Secondary Protection Coordination for fault at Feeder 4 (33kv side)

For a fault current occurred at feeder 4, it is expected that fault should be tripped with the action of primary protective devices deployed at downstream side. If primary protection failed to operate, secondary/backup protection is applied.

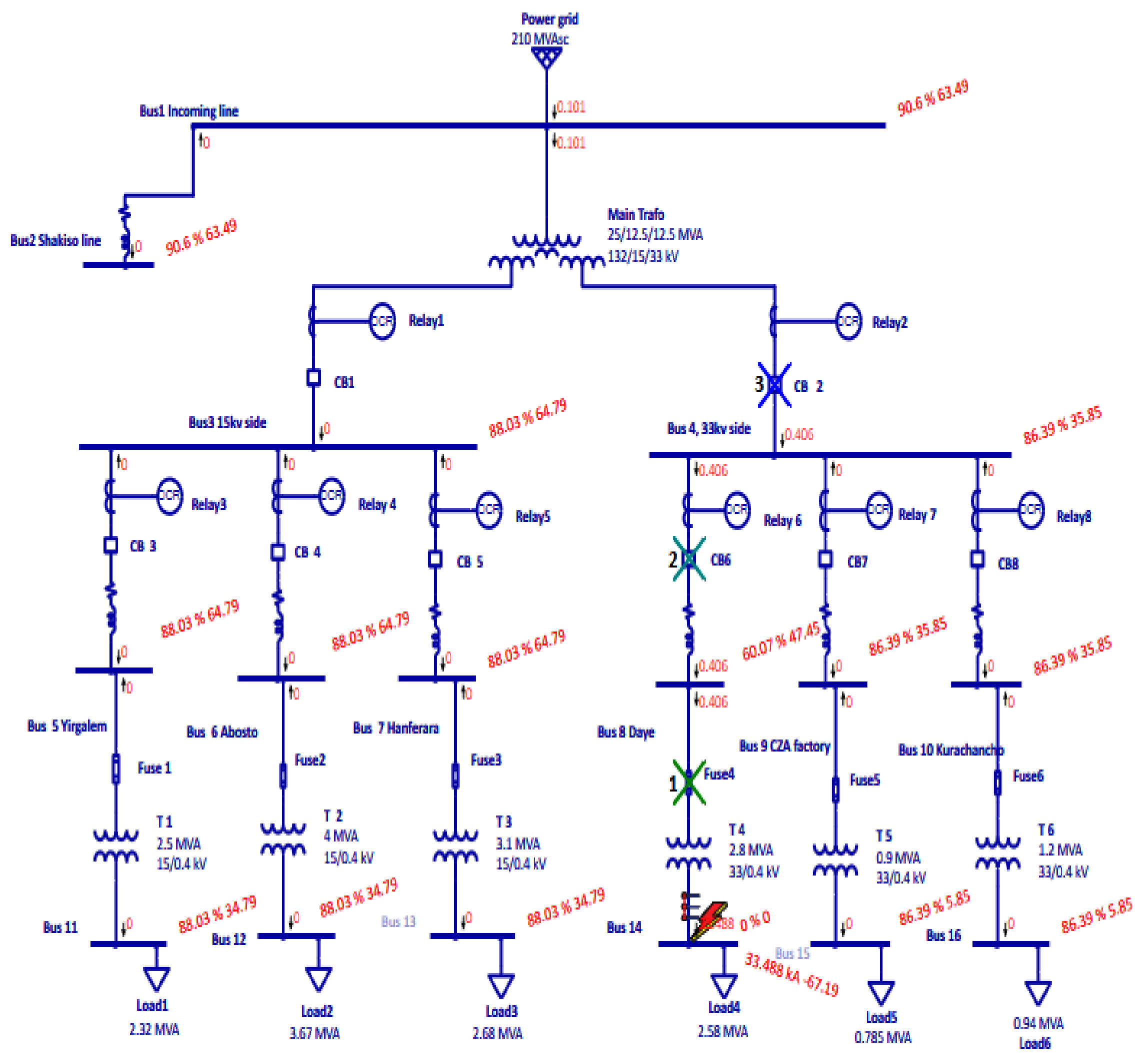

Fig 4.6 Secondary protection for fault at feeder 4 (33kv side)

Here in below table, we can see the time operation of protective devices for fault during secondary protection

Table 4.5 Sequence of operation for secondary protection occurred at feeder

Time	Protective device selected	Fault current (KA)	Time 1(ms)	Condition
19.8	Fuse 4	0.406	<19.8	
49.1	Relay 6	0.406	49.1	Phase-OC1-51
1520	CB6		132	Tripped by Relay 6
78.6	Relay 2	0.406	78.6	Phase-OC1-51
1620	CB2		162	Tripped by Relay 7

The above table shows secondary protection on feeder 4, in case if CB6, CB7 and CB8 fail to trip the fault, secondary protective device R2 sends trip signal to CB2 with time of operation 162ms.

4.3.5 Total operating time of relay (Circuit breaker tripping time) by using ETAP

Table 4.6 Total operating time of relay (Circuit breaker tripping time)

Feeder Name	Relay Name	Relay Type	Tripping CB	Time(ms)	Time (s)
Feeder 1	Relay 3	Primary	CB3	1230	1.23
Feeder 2	Relay 4	Primary	CB4	1420	1.42
Feeder 3	Relay 5	Primary	CB5	1620	1.62
Feeder 4	Relay 6	Primary	CB6	1520	1.52
Feeder 5	Relay 7	Primary	CB7	1620	1.62
Feeder 6	Relay 8	Primary	CB8	1820	1.82
At 15kv side	Relay 1	Backup	CB1	1820	1.82
At 33kv side	Relay 2	Backup	CB2	1620	1.62

The above tables show total operating time of protective devices from both primary as well as secondary protection side. This time of operation satisfies protective device coordination but it misses the objective of this thesis. It is primary concern to minimize the operating time of relays with a proposed optimization algorithm. We will see it in the next sections.

4.4 ALO Simulation result for minimized CB tripping time

As we have seen from our short circuit analysis part, fault occurs at each feeder. From below table we can see that the minimized optimal value of time of operation for each and every feeder. As we see, at feeder 1, total operating time of relay 3 is 0.10657s. At feeder 2, the operating time of relay is 0.12827s. At feeder 3, the operating time of relay 5 is 0.16032s. At 33kv side, feeder 4 operating time of relay 6 is 0.15812s. At feeder 5, the operating time of relay 7 is 0.15967s. At feeder 6, the operating time of relay 8 is 0.18129s.

Table 4.7 Optimal Operating time of relay after optimization

	ALO optimized Minimum Operating time of Relay (MOTR)							
	Primary Protection						Secondary Protection	
Fault Numbers	R3	R4	R5	R6	R7	R8	R1	R2
At Feeder 1	0.10657						0.16941	
At Feeder 2		0.12827					0.17157	
At Feeder 3			0.16032				0.18177	
At Feeder 4				0.15812				0.16549
At Feeder 5					0.15967			0.17735
At Feeder 6						0. 18129		0.20861

The above table shows that the ALO simulation result for operating time of each relay with minimum result. We have 3 overcurrent relays R3, R4 and R5 at 15kv side and 3 relays R6, R7 and R8 at 33kv side. Those listed relays are primary relays. But we have secondary relays too, R1 at 15kv side and R2 at 33kv side. The relays operating time are in ascending order from left to right. This can be described as MOTR3 < MOTR4 < MOTR5 and MOTR6 <MOTR7 <MOTR8.

4.5 Comparison of Existing system with ALO optimized system

It has been shown that existing system has greater latency in relay Operation during short circuit condition which results in equipment damage as well as total system disturbance as whole. The main objective of this project was to minimize this operating time to minimum value.

Table 4.8 Comparison of Existing and ALO optimized system

	Existing system (before optimization) operating time of Relay							
	Primary Protection						Secondary Protection	
Fault Numbers	R3	R4	R5	R6	R7	R8	R1	R2
At Feeder 1	1.230						1.820	
At Feeder 2		1.420					1.820	
At Feeder 3			1.620				1.820	
At Feeder 4				1.520				1.620
At Feeder 5					1.620			1.620
At Feeder 6						1.820		1.620

	ALO optimized Minimum Operating time of Relay (MOTR)							
	Primary Protection						Secondary Protection	
Fault Numbers	R3	R4	R5	R6	R7	R8	R1	R2
At Feeder 1	0.10657						0.16941	
At Feeder 2		0.12827					0.17157	
At Feeder 3			0.16032				0.18177	
At Feeder 4				0.15812				0.16549
At Feeder 5					0.15967			0.17735
At Feeder 6						0.18129		0.20861

From the above table we can observe that even though existing system protective relays coordinated, its time of operation is yet to be minimized. So, by using ALO optimization technique, we minimized the operating time relays.

4.5.1 ALO Simulation result at feeder 1

The below result is obtained from Antlion optimization tool box, where optimal value of TMS is recorded. The minimum value of operating time of relay for a given fault is 0.10657s. Here we can see that time of operation of relay (in our case R3) before optimization is 1.23 and after ALO optimization is carried out, it has been minimized to 0.10657s. ALO optimization result for TMS is in acceptable range of its inequality constraints

$0.1 \leq TMS \leq 1.1$, for our case, $0.1 \leq 0.10657 \leq 1.1$

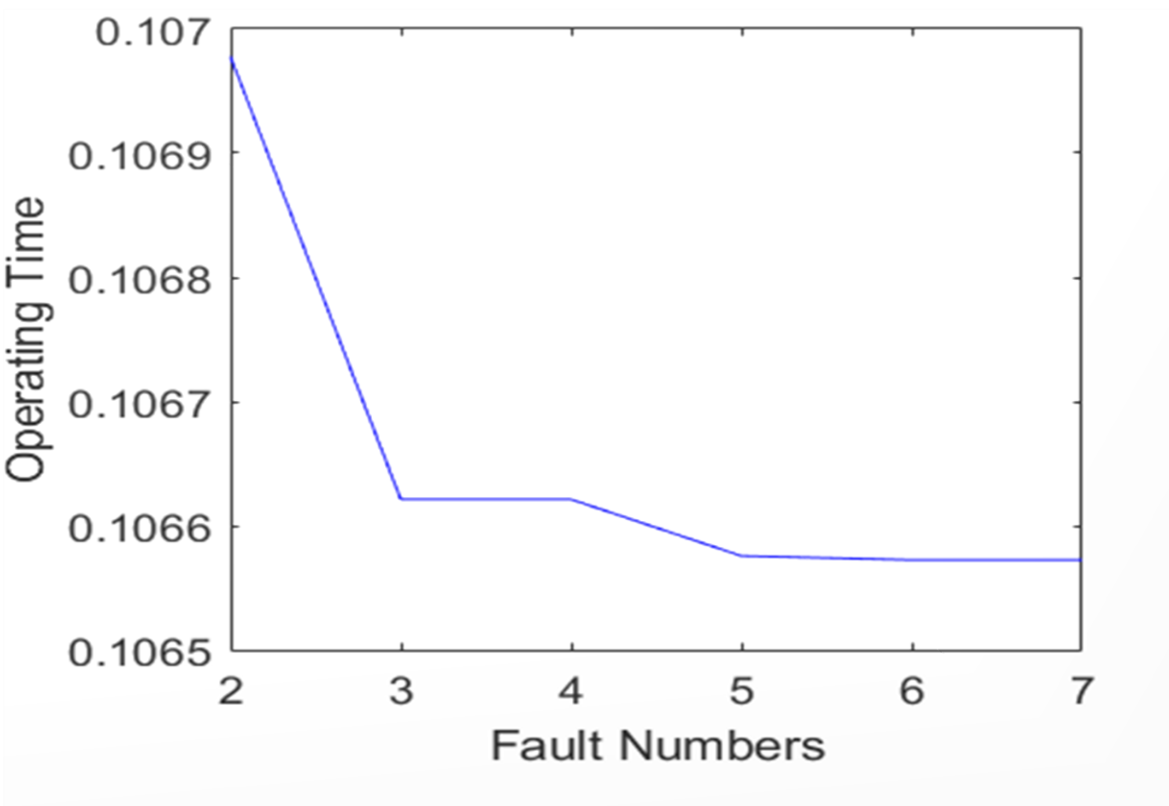

Fig. 4.7 ALO Simulation for Feeder 1

4.5.2 ALO Simulation result at Feeder 2

From Antlion optimization toolbox, we have obtained minimum operating time of relay (in our case R4) as 0.12827s. Operating time of relay at existing system is 1.42s. If we observe the difference, relay operating time has been minimized from1.42s to 0.12827s.

The inequality constraint is satisfied as below.

$$0.1 \leq TMS \leq 1.1 \text{ to } 0.1 \leq 0.12827 \leq 1.1$$

At feeder 2, minimum operating time of relay obtained by ALO is 0.12827s

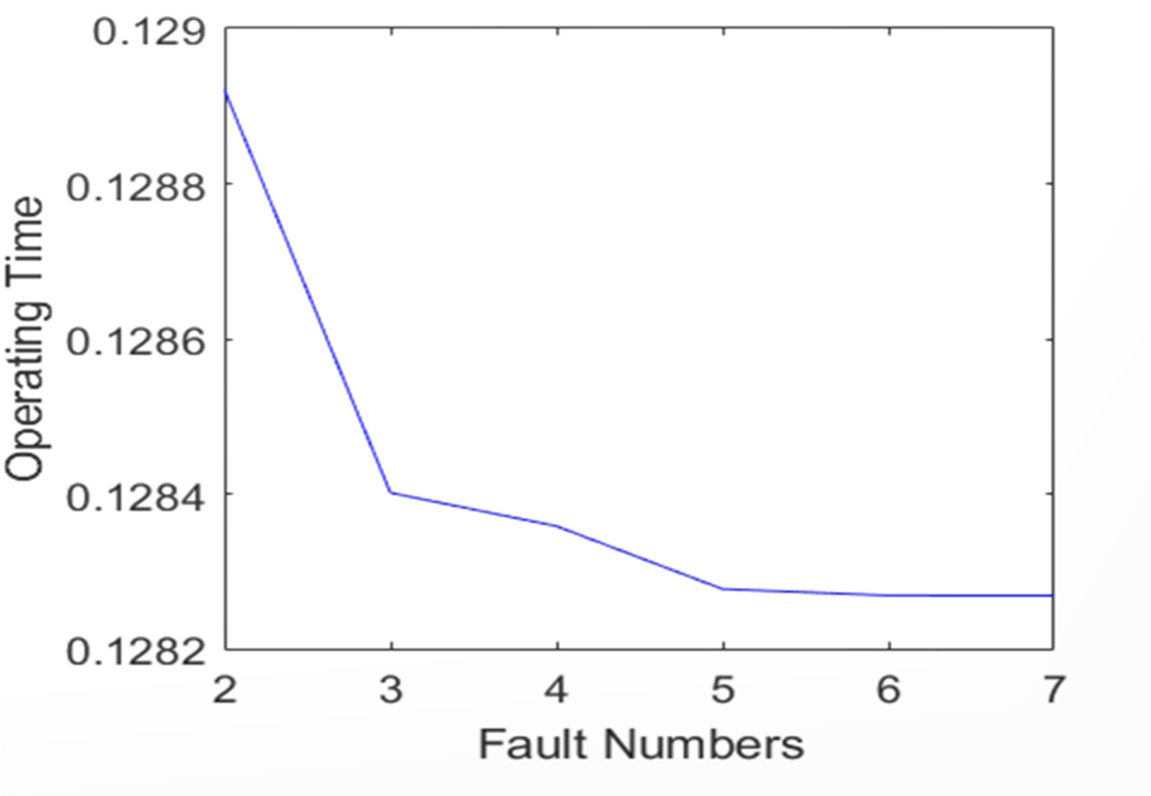

Fig. 4.8ALO simulation for feeder 2 operating time

4.5.3 ALO Simulation result at feeder 3

Here at feeder 3, we have R5 as protective device and its operation of time during existing time was 1.62s and after applying ALO from its toolbox the operating time of relay was 0.1603s. it can be said that time of operation has been reduced from 1.62s to 0.1603s.

The inequality constraint has been satisfied as below

$$0.1 \leq TMS \leq 1.1 \text{ as } 0.1 \leq 0.1603 \leq 1.1$$

At feeder 3, total operating time of relay from optimization toolbox is 0.16032s

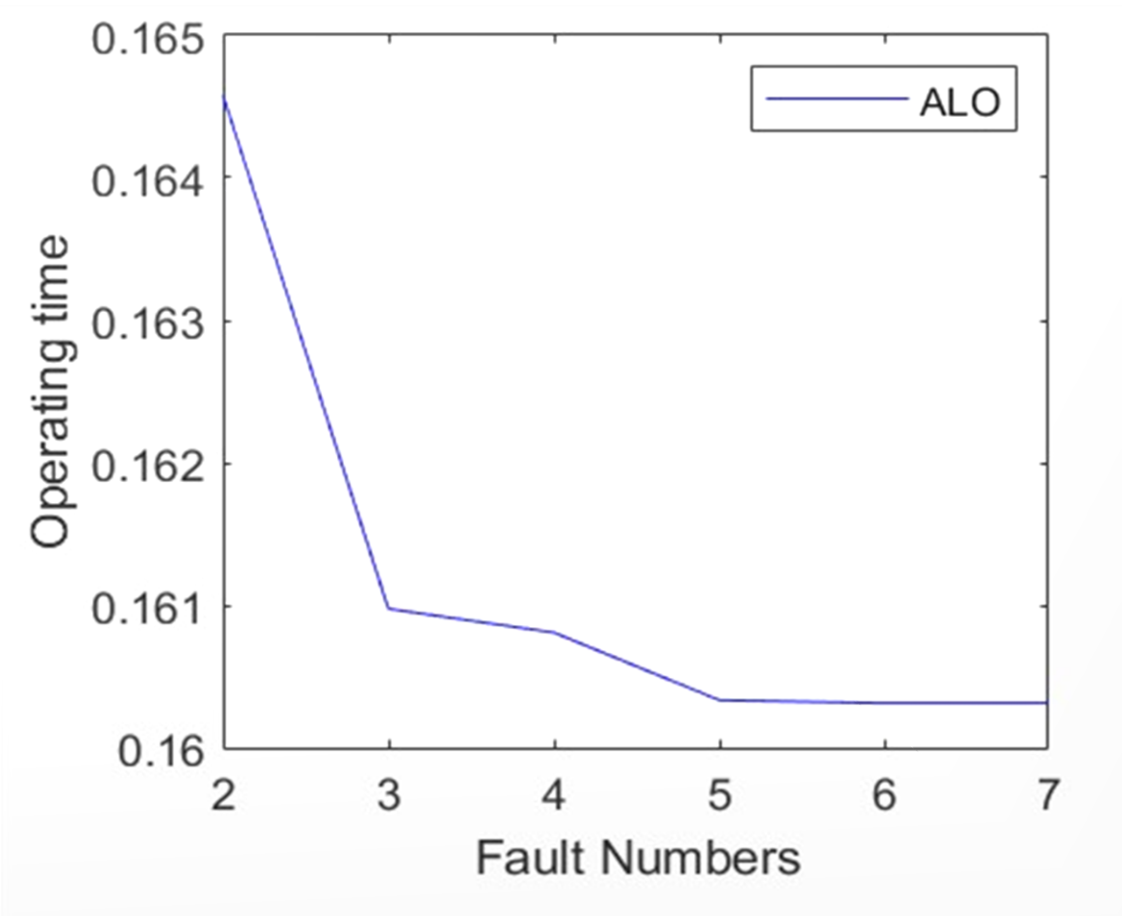

Fig 4.9ALO Simulation for feeder 3 operating time

4.5.4 ALO Simulation result for feeder 4

At feeder 4, we have relay R6 and its operating time of operation before optimization was 1.52s. This number need to be minimized by using optimization. Using ALO toolbox, it has been reduced to 0.15812s.

Inequality constraint condition satisfied as below

$$0.1 \leq TMS \leq 0.1,\ 0.1 \leq 0.15812 \leq 1.1$$

At Feeder 4, the minimized operating time of relay is 0.15812s.

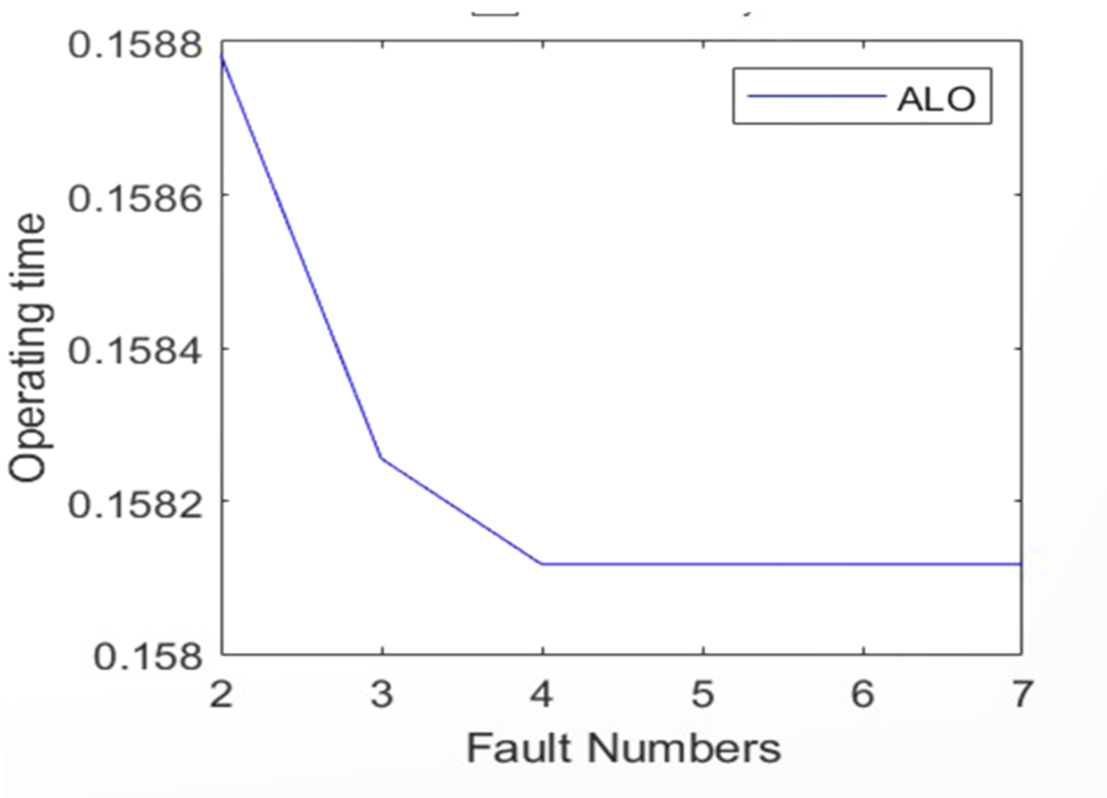

Fig 4.10 ALO simulation for feeder 4 operating time

4.5.5 ALO Simulation result for feeder 5

At feeder 5, existing system time of operation is larger number, 1.62s. With the help of ALO optimization toolbox, this number has been reduced to 0.15967s.

This minimized value is within acceptable inequality constraint as below

$$0.1 \leq TMS \leq 1.1 \text{ to } 0.1 \leq 0.15967s$$

Here the minimum time of operation of relay is 0.15967s

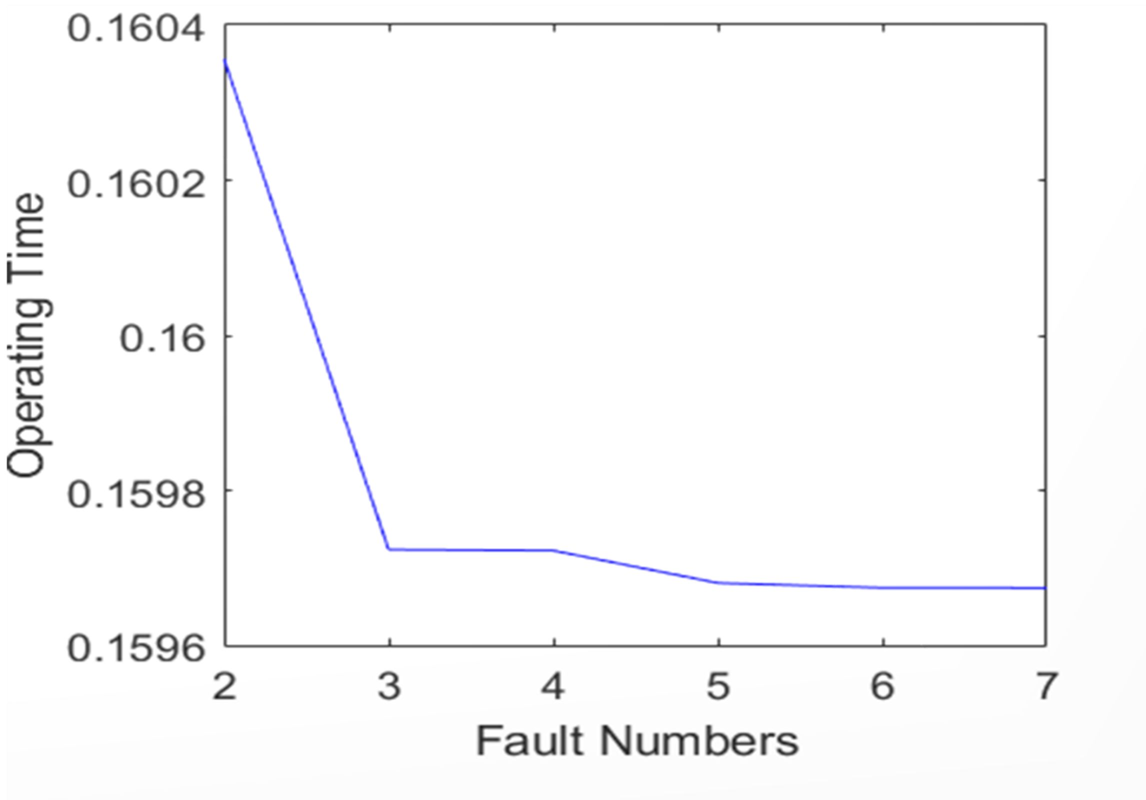

Fig 4.11ALO simulation for feeder 5 operating time

4.5.6 ALO Simulation result at Feeder 6

At feeder 6, the existing system time of operation time need to be minimized. Before optimization applied time of operation of relay is 1.82s. It has been minimized to 0.18129s by using ALO optimization toolbox

It is within the inequality constraint condition as below

$$0.1 \leq TMS \leq 1.1 \text{ to } 0.1 \leq 0.18129 \leq 1.1$$

At feeder 6, minimized operating time of relay is 0.18129s.

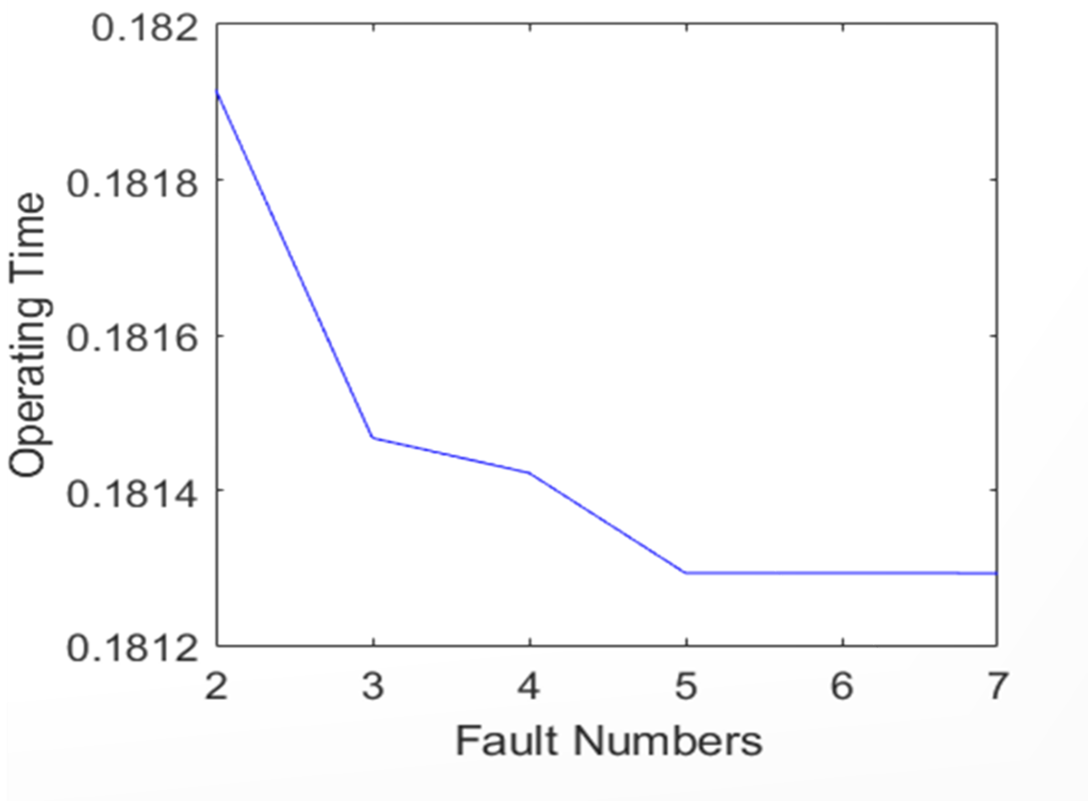

Fig 4.12 ALO simulation for feeder 6 operating time

4.6 Total operating time of relay by using PSO

The Particle swarm optimization is the algorithm that determines the ideal and suitable setting of the overcurrent relay, resulting in precise power protection system performance even though compared to ALO, it has some latency in operating time of relay.

4.6.1 PSO Simulation result at feeder 1

Here, at feeder 1 the operating time of relay by using PSO is 0.144578 s. The below figure has y-axis as the operating time of relay and x-axis as the number of faults in the number of feeders. The obtained value of TMS is much smaller than the existing system (1.23 s) but slightly greater than TMS value obtained by ALO (0.10657 s)

It is within the inequality constraint condition as below

$$0.1 \leq TMS \leq 1.1 \text{ to } 0.1 \leq 0.144578 \leq 1.1$$

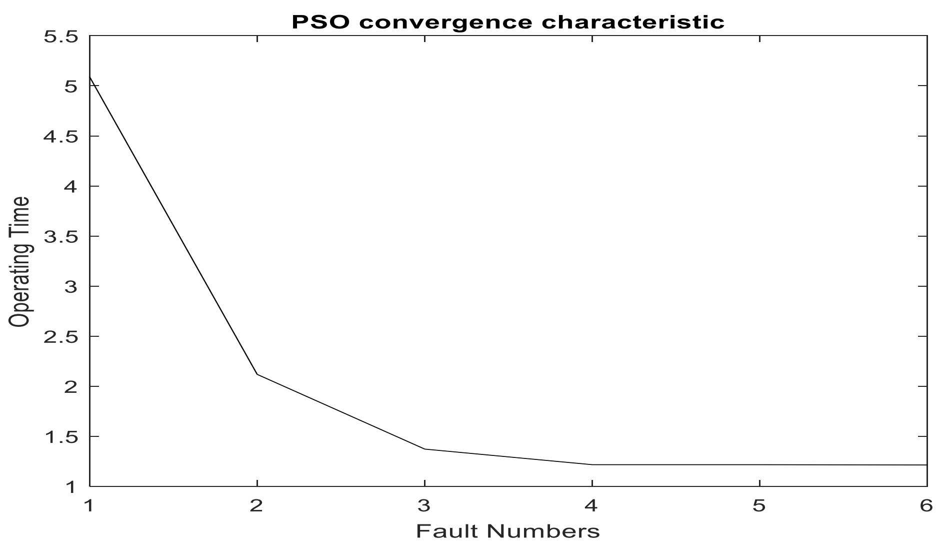

Fig 4.13 PSO simulation at feeder 1

4.6.2 PSO Simulation result at feeder 2

At feeder 2, the operating time of relay by using PSO is 0.180142s. The below figure has y-axis as the operating time of relay and x-axis as the number of faults in the number of feeders. The obtained value of TMS is much smaller than the existing system (1.42s) but slightly greater than TMS value obtained by ALO (0.12827s) It is within the inequality constraint condition as below

$$0.1 \leq TMS \leq 1.1 \text{ to } 0.1 \leq 0.180142 \leq 1.1$$

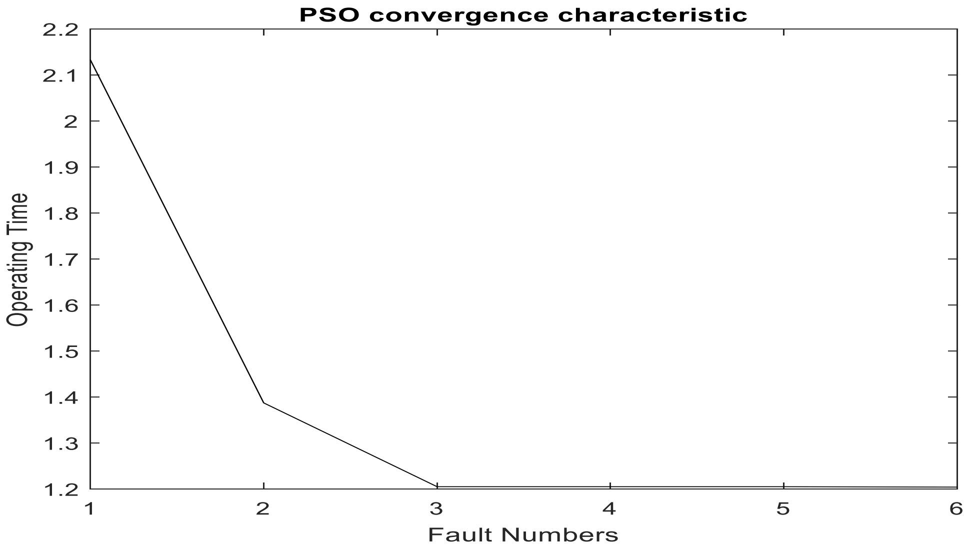

Fig 4. 14 PSO Simulation at feeder 2

4.6.3 PSO Simulation result at feeder 3

Here, at feeder 3 the operating time of relay by using PSO is 0.166550s. The below figure has y-axis as the operating time of relay and x-axis as the number of faults in the number of feeders. The obtained value of TMS is much smaller than the existing system (1.62s) but slightly greater than TMS value obtained by ALO (0.16032s). It is within the inequality constraint condition as $0.1 \leq TMS \leq 1.1$ to $0.1 \leq 0.166550 \leq 1.1$

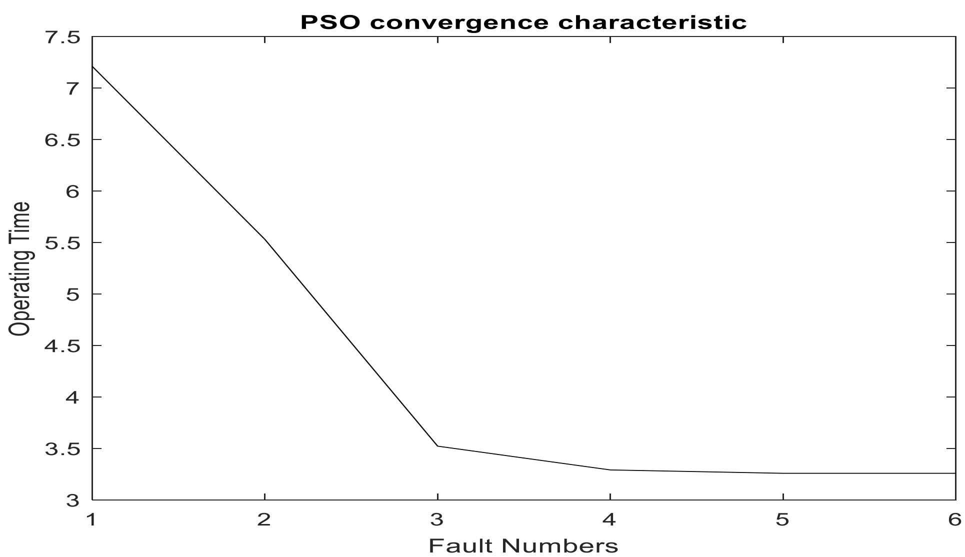

Fig 4.15 PSO simulation at feeder 3

4.6.4 PSO Simulation result at feeder 4

At feeder 4, the operating time of relay by using PSO is 0.188372. The below figure has y-axis as the operating time of relay and x-axis as the number of faults as the number of feeders. The obtained value of TMS is much smaller than the existing system (1.52s) but slightly greater than TMS value obtained by ALO (0.15812s) It is within the inequality constraint condition as below

$$0.1 \le TMS \le 1.1 \text{ to } 0.1 \le 0.188372 \le 1.1$$

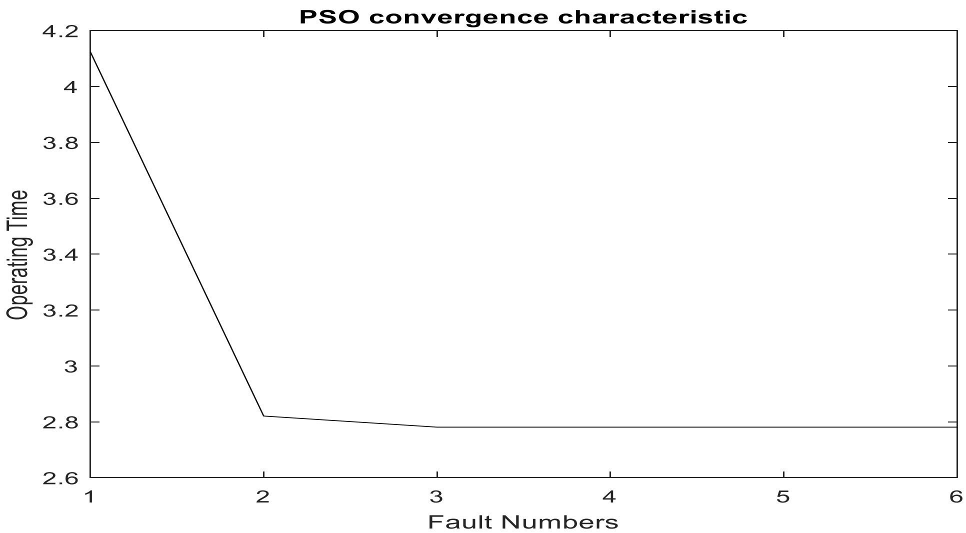

Fig 4.16 PSO simulation at feeder 4

4.6.5 PSO Simulation result at feeder 5

At feeder 5, the operating time of relay by using PSO is 0.188372. The below figure has y-axis as the operating time of relay and x-axis as the number of faults as the number of feeders. The obtained value of TMS is much smaller than the existing system (1.62s) but slightly greater than TMS value obtained by ALO (0.15812s) It is within the inequality constraint condition as below

$$0.1 \le TMS \le 1.1 \text{ to } 0.1 \le 0.188372 \le 1.1$$

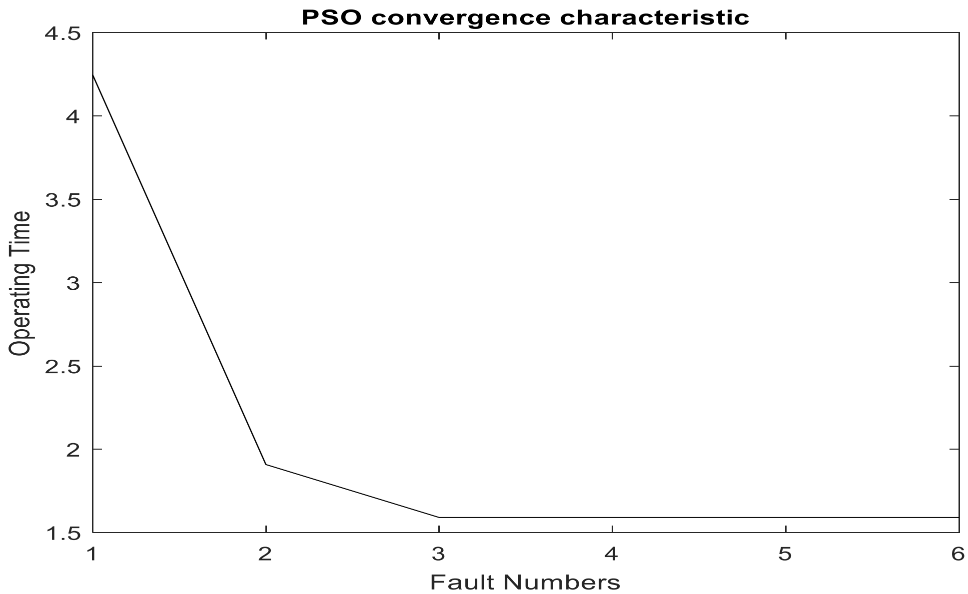

Fig 4.17 PSO simulation at feeder 5

4.6.6 PSO Simulation result at feeder 6

At feeder 6, the operating time of relay by using PSO is 0.193052s. The below figure has y-axis as the operating time of relay and x-axis as the number of faults as the number of feeders. The obtained value of TMS is much smaller than the existing system (1.82s) but slightly greater than TMS value obtained by ALO (0.18129s) It is within the inequality constraint condition as below

$$0.1 \leq TMS \leq 1.1 \text{ to } 0.1 \leq 0.193052s \leq 1.1$$

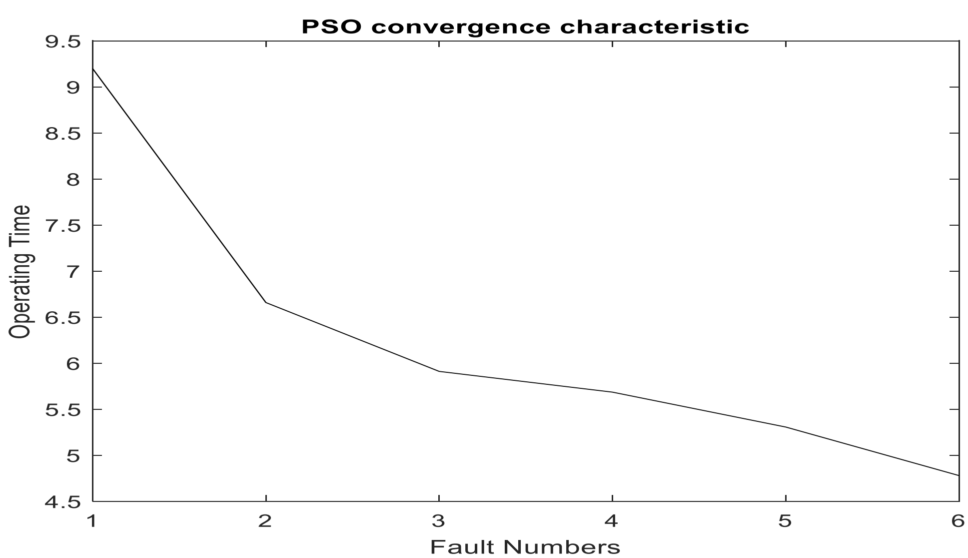

Fig 4.18 PSO simulation at feeder 6

4.7 Comparison of PSO with ALO optimized system

Table 4.9 Comparison between ALO and PSO optimized operating time of relay

	ALO optimized Minimum Operating time of Relay (MOTR)							
	Primary Protection						Secondary Protection	
Fault Numbers	R3	R4	R5	R6	R7	R8	R1	R2
At Feeder 1	0.10657						0.16941	
At Feeder 2		0.12827					0.17157	
At Feeder 3			0.16032				0.18177	
At Feeder 4				0.15812				0.16549
At Feeder 5					0.15967			0.17735
At Feeder 6						0.18129		0.20861

	PSO optimized Minimum Operating time of Relay (MOTR)							
	Primary Protection						Secondary Protection	
Fault Numbers	R3	R4	R5	R6	R7	R8	R1	R2
At Feeder 1	0.144578						0.172	
At Feeder 2		0.180142					0.345	
At Feeder 3			0.166550				0.192	
At Feeder 4				0.188372				0.235
At Feeder 5					0.188372			0.314
At Feeder 6						0.193052		0.236

Therefore, based on the above table comparing the operating time of relay obtained by applying ALO and PSO, operating time get from ALO has low latency than that of PSO. Therefore, we can conclude that, ALO is preferable optimization method for minimizing operating time of relay under protective device coordination problem. It is selectable due to simple, easily converging has small input parameters and it provides global optima solutions.

4.8 Time Current Curve (TCC) of Protective Devices

4.8.1 TCC of Fuses at 15kv sides

Fuses are Protective devices which are mostly deployed at distribution side with low voltages. Fuses burnout themselves in occurrence of faults and make power system safe.

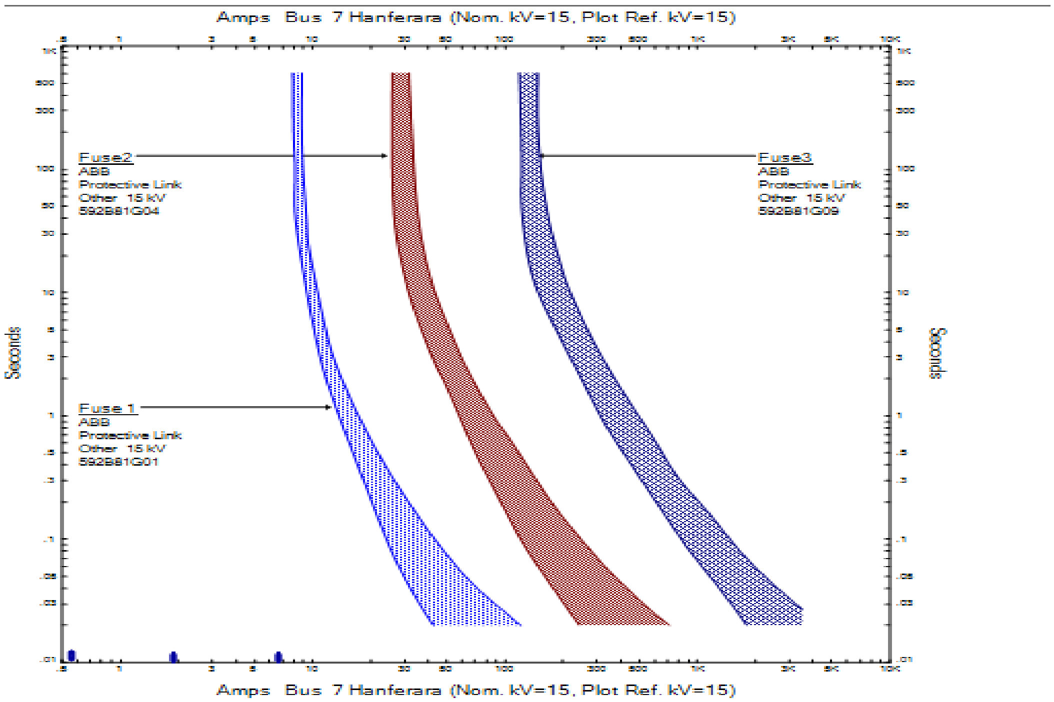

Fig.4.13 TCC of Fuses at 15kv side

The above picture shows that 3 fuses at low voltage sides during the occurrence of faults. Fuse 1 is at feeder 1, fuse 2 is at feeder 2 and fuse 3 is at feeder 3. Whenever we are talking about protective device coordination, if it is said to optimal coordinated system, the protection should start from downstream side of power system. So, at downstream side we get fuses. To say a given system is optimally coordinated, F1 should be exposed to fault before than F2 and F3. So TCC drawn for fuse coordination at 15kv side, fuses should be drawn from left to right for F1, F2, and F3 respectively.

4.8.2 TCC of Fuses at 33kv sides

Let us see TCC for fuse coordination at 33kv sides.

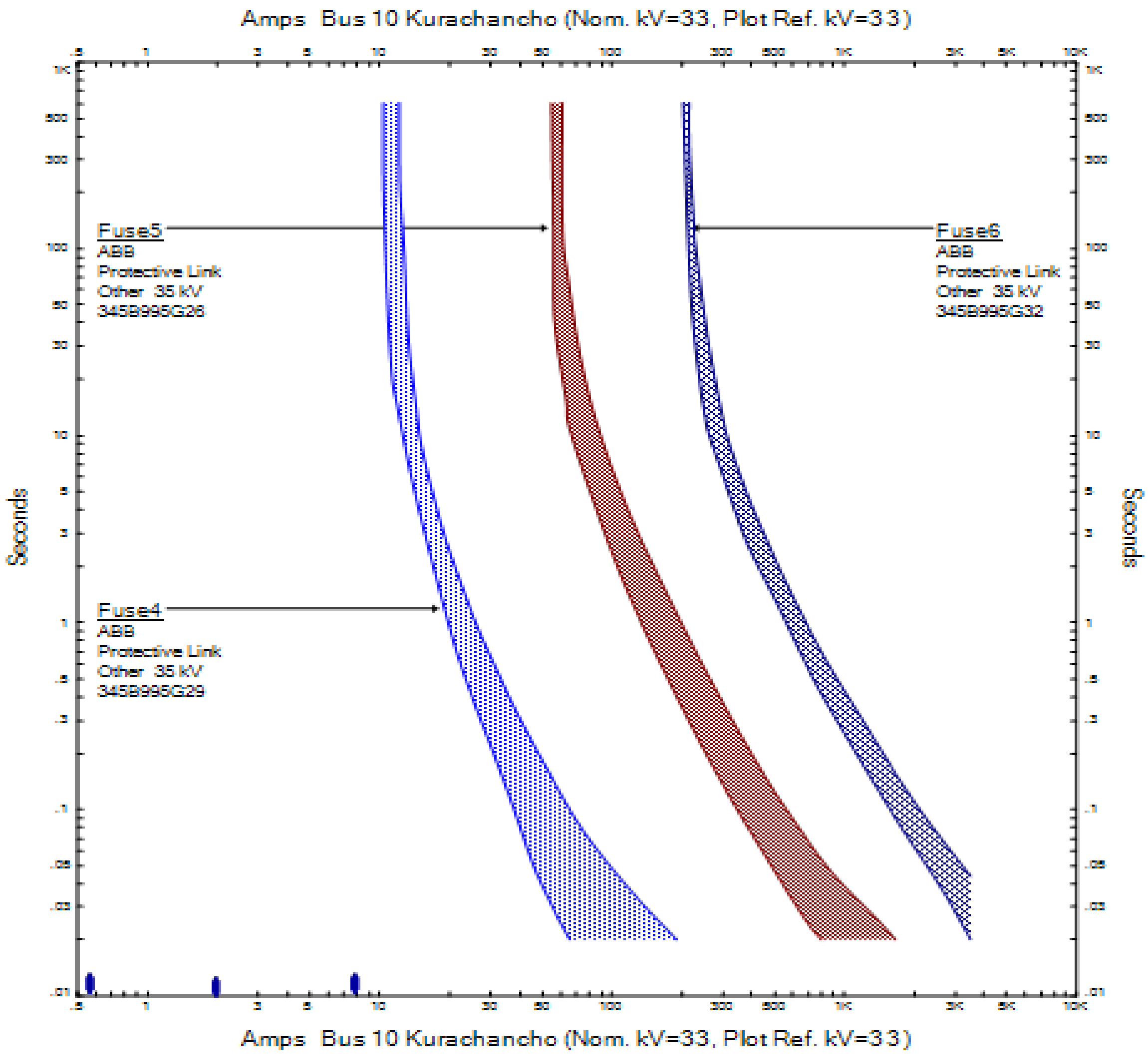

Fig.4.14 TCC of Fuses at 33kv sides

From above picture we can see that 3 fuses are there at 33kv side, low voltage sides during the occurrence of faults. Fuse 4 is at feeder 4, fuse 5 is at feeder 5 and fuse 6 is at feeder 6. Whenever if it is said to optimal coordinated system, the protection should start from downstream side of power system. So, at downstream side we get fuses. To say a given system is optimally coordinated, F4 should be exposed to fault before than F5 and F6. So TCC drawn for fuse coordination at 33kv side, fuses should be drawn from left to right for F4, F5, and F6 respectively.

4.8.3 TCC of Protective Relays at 15kv sides

Relays are protective devices which sense incoming power signals either in form of current and voltage with the help of CT and VT and sends it to circuit breaker so that, CB trips and disconnect faulty part of power system from healthy one.

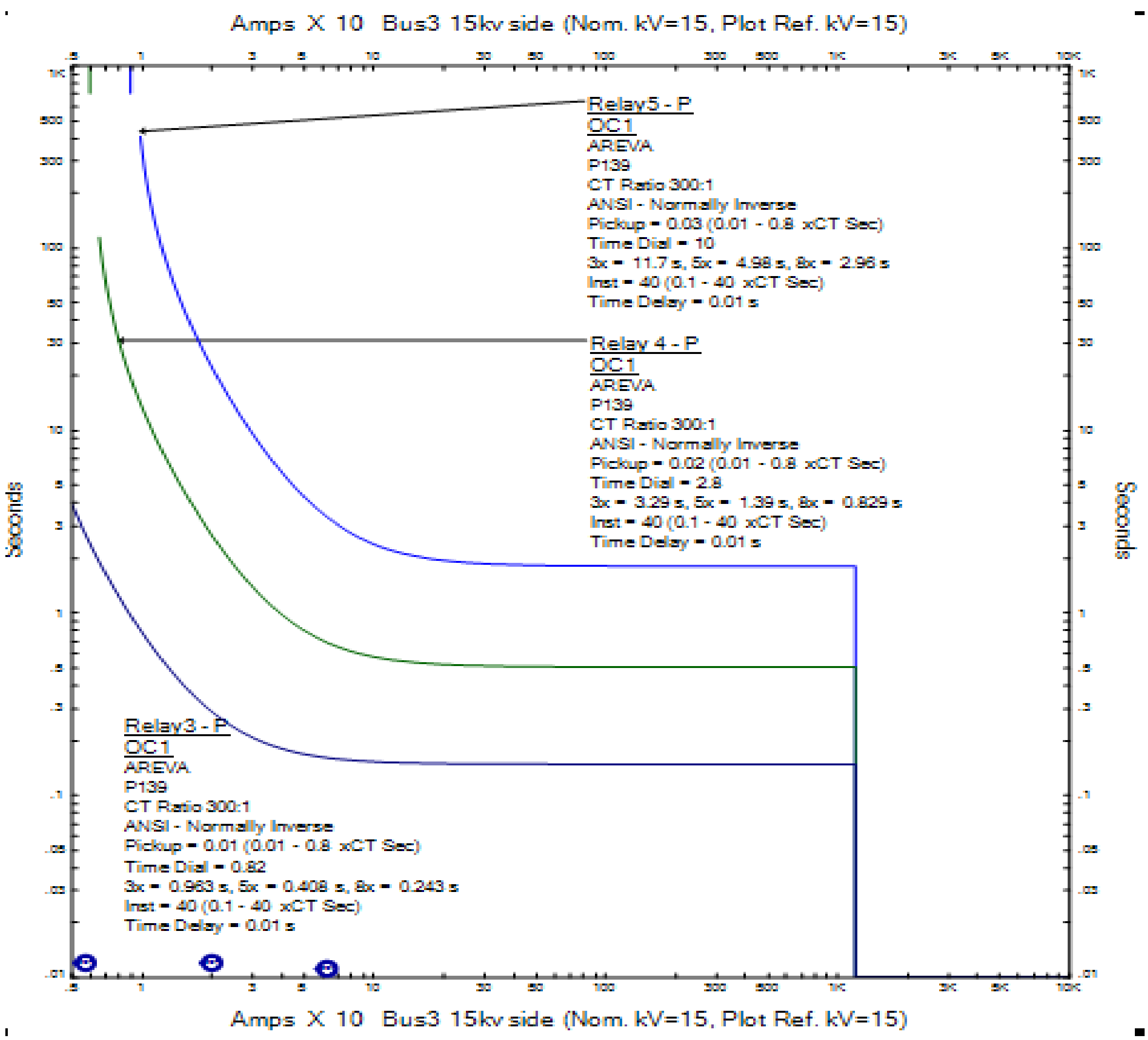

Fig.4.15 TCC of relays at 15kv sides

From the above picture, we have 3 overcurrent relays at 15kv side to be optimally coordinated. R3 is at feeder 1, R4 is at feeder 2 and R5 is at feeder 3. For fault occurring at feeder 1, R3 should operate before than R4 and R5. So TCC should be drawn from left to right for R3, R4 and R5. The are known to primary relays.

4.8.4 TCC of Protective Relays at 33kv sides

We have three primary protective relays with their own settings R6, R7 and R8 at 33kv side, and are coordinated as follows.

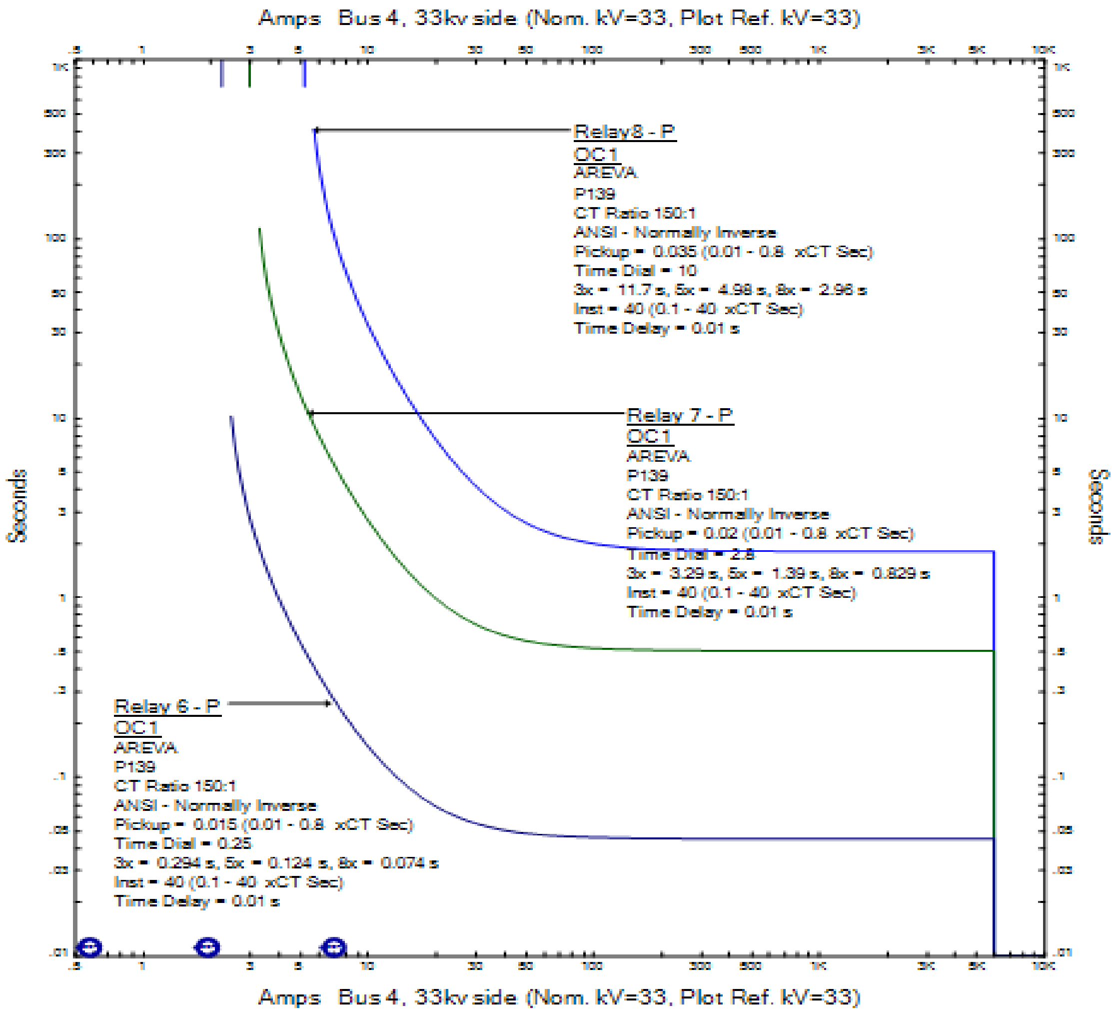

Fig.4.16 TCC of Relays at 33kv side

From the above picture, we have 3 overcurrent relays at 33kv side to be optimally coordinated. R6 is at feeder 4, R7 is at feeder 5 and R8 is at feeder 6. For fault occurring at feeder 4, R6 should operate before than R7 and R8. So TCC should be drawn from left to right for R6, R7 and R8.

4.8.5 TCC of Secondary Relays

R1 and R2 are the two relays in a given power system as secondary(backup) protection relays. They operate at a time when primary relays fail to operate.

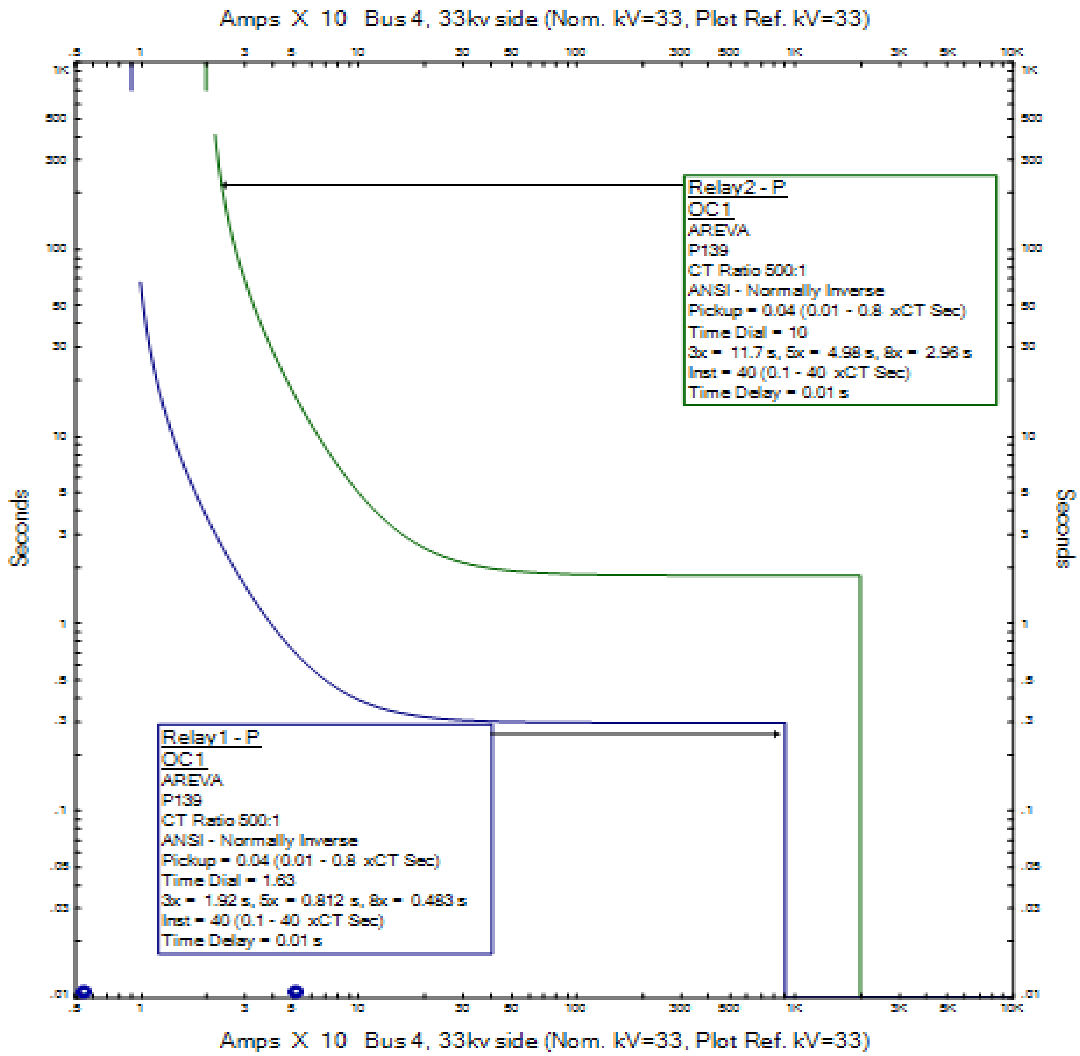

Fig.4.17TCC of primary relays

From the above picture, we have R1 and R2 as secondary relays. R1 is at 15kv side and R2 is at 33kv side. So TCC is drawn as from left to right for R1 and R2 respectively.

4.9 Evaluating Yirgalem distribution system branch power losses

4.9.1 Power losses before optimal coordination of protective devices

Before proper coordination of protective device in Yirgalem distribution system, power loss in term of real power is 1019.4kwbut after coordination of protective devices, it has reduced to 392.2kw that is a huge amount of power loss reduction.

When we see reactive power, before coordination we have 1273.0kvar power loss and after proper coordination of protective devices reactive power loss is reduced to 859.2kvar

4.9.2 Branch Losses Summary Report Before Optimal Coordination of Protective Devices

Table 4.9 Power loss before proper coordination of protective devices

	From-ToBus Flow		To-From Bus Flow		Losses		% Bus Voltage		%VDrop
Branch ID	MW	Mvar	MW	Mvar	KW	Kvar	From	To	Vmag
Line 1	0.000	-0.099	0.000	0.000	0.0	-98.5	100.0	100.0	0.00
Line 2	2.204	0.146	-2.200	-0.136	4.7	9.3	98.1	97.8	0.24
Line 3	2.934	0.587	-2.553	-0.157	380.8	430.4	98.1	83.8	14.28
Line 4	2.111	0.431	-1.815	-0.105	296.4	325.8	98.1	82.6	15.45
Line 5	2.401	0.142	-2351	-0.155	50.8	-13.0	98.2	96.0	2.22
Line 6	0.744	0.029	-0.743	-0.046	1.2	-17.0	98.2	98.0	0.17
Line 7	0.883	-0.081	-0.869	-0.048	13.7	-129.4	98.2	96.7	1.49
Main Trafo	11.485	1.372	-7.249	-1.164	206.8	117.7	100	98.1	1.92
T2	2.553	0.157	-2.540	0.000	13.7	156.7	83.8	83.2	0.61
T1	2.200	0.136	-2.187	0.000	12.8	136.4	97.8	97.1	0.76
T3	1.815	0.105	-1.805	0.000	9.2	104.9	82.6	82.1	0.56
T4	2.351	0.155	-2.336	0.000	14.6	155.4	96.0	95.2	0.80
T5	0.743	0.046	-0.735	0.000	7.9	45.8	98.0	96.8	1.23
T6	0.869	0.048	-0.862	0.000	6.8	48.5	96.7	95.8	0.91
					1019.4	**1273.0**			

We are going to compare it with power loss after optimal coordination of protective devices. It has shown in below table.

4.9.3 Branch Losses Summary Report after Optimal Coordination of Protective Devices

Table 4.10 Power loss after proper coordination of protective devices

	From-ToBus Flow		To-From Bus Flow		Losses		% Bus Voltage		%Vdrop
Branch ID	MW	Mvar	MW	Mvar	KW	Kvar	From	To	in Vmag
Line 1	0.000	-0.099	0.000	0.000	0.0	-98.5	100.0	100.0	0.00
Line 2	2.194	0.151	-2.187	-0.136	7.5	14.9	97.9	97.6	0.38
Line 3	3.441	0.255	-3.400	-0.209	40.8	46.3	97.9	96.7	1.25
Line 4	2.524	0.169	-2.502	-0.145	21.9	24.3	97.9	97.0	0.91
Line 5	2.451	0.161	-2.447	-0.162	4.3	-1.0	98.1	97.9	0.18
Line 6	0.744	0.040	-0.743	-0.046	0.4	-5.5	98.1	98.0	0.06
Line 7	0.894	0.045	-0.893	-0.050	0.6	-5.3	98.1	98.0	0.07
Main Trafo	12.491	0.958	-8.159	-0.575	243.0	137.4	100	97.9	2.06
T2	3.400	0.209	-3.382	0.000	18.3	208.6	96.7	96.0	0.07
T1	2.187	0.136	-2.174	0.000	12.7	135.6	97.6	96.8	0.75
T3	2.502	0.145	-2.489	0.000	12.7	144.7	97.0	96.4	0.65
T4	2.447	0.162	-2.431	0.000	15.2	161.7	97.9	97.1	0.82
T5	0.743	0.046	-0.735	0.000	7.9	45.8	98.0	96.8	1.23
T6	0.893	0.050	-0.886	0.000	7.0	49.8	98.0	97.1	0.92
					392.2	**859.2**			

The above result is compiled in tabular form as below.

Table 4.11 Power loss before and after proper coordination of protective devices

Selected protective devices	Real power in Kw	Energy in kwh	Reactive power in Kvar
Before coordination	1019.4	365*1019.4*24=8,929944wh	1273
After coordination	392.2	365*392.2*24=3,435672wh	859.2

4.9.4 Total loss of energy per year before and after coordination of protective devices

Before optimal coordination of protective device, real power loss is 1019.4kw. So, if we calculate energy for one annual year it comes = 365*1019.4*24 = 8,929,944wh

But after proper coordination of protective devices, real power is 392.2kw. Annual power loss in term of energy is calculated as= 365*392.2*24 = 3,435,672wh

4.10 Cost Analysis

Cost analysis of certain power system is key issue to be considered. This is because power system with unplanned cost will result in degradation of qualities in power system.

In our case, if we see the total power lost per year before optimal coordination of protective devices = 8, 929, 944kwh per year. If we convert it to birr

- ✓ Electric sell bill = 0.54 cent per kwh
- ✓ Power loss before coordination in Birr =8,929,944wh *0.54 = 4,929,169.76ETB
- ✓ Power loss in birr after proper coordination= 3,435,672wh *0.54 = 1,855,262.88ETB
- ✓ Saved energy in Birr = 4,929,169.76ETB - 1,855,262.88ETB = 2,966,907ETB

CHAPTER FIVE

CONCLUSION AND RECOMMENDATION

5.1 Conclusion

This Research focuses on protective device coordination specially on relay coordination for Yirgalem distribution substation. Optimal coordination of protective relay is aimed to obtain minimum operating time TMS. We need to determine pickup current Ip of relay which is non-linear function based international standards. Both TMS and Ip are used to do coordination system. ETAP is used for conducting short circuit and load flow analysis for proper selection of protective device and its rating. By using ETAP software, it is tried to do coordination of protective device. Even though coordination is done by using ETAP, it is unable to minimize the operating time of relay until some optimization technique is applied.

Antlion optimization (ALO) technique is used for minimizing operating time in MATLAB toolbox. Conventional system not only fails on proper coordination but also, it exposes substation to risk, frequent outage and equipment damage.

Therefore, it has been found critical that protective device in a given power system should be selectively coordinated so that the whole system operate in a proper way.

For this thesis different issues considered like conducting load flow analysis, short circuit analysis, protective device selection and its characteristics, TMS calculation on both existing and optimal way.

5.2 Recommendation

Based on the thesis outcome, it is found that some concerned sections need to be recommended.

- Power companies should give attention for protective device coordination. It should be done based on international standards.
- Power demand is dynamic in nature, so that load flow analysis and short circuit analysis should be conducted on specific period of time to balance load demand with existing generating capacity as well as optimal operation of power system.

- I recommend Yirgalem EEP to review current protective relay coordination system on substation since current protective coordination causes equipment damage due to its latency in operation.

5.3 FUTURE WORK

For future work

- Coordination of protective devices of Yirgalem Substation in presence of distributed generation (DG), using ALO optimization technique.

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Appendix

System Input data

1. Feeder data

Name of Feeder	Length in km	Conductor Type	Voltage level
Yirgalem Feeder	4	Al $50mm^2$	15kv
Abosto Feeder	5	Al $50mm^2$	15kv
Hanferara Feeder	7	Al $50mm^2$	15kv
Bensa Feeder	50	Al $50mm^2$	33kv
CZA feeder	3	Al $50mm^2$	33kv
Kurachancho Feeder	10	Al $50mm^2$	33kv

2. Transformer Rating

Feeder Name	Transformer Type	Transformer Rating	Impedance value	Transformer No
Main Line	Main Transformer	25MVA		1
F1	Distribution Transformer	2.5MVA		
F2	Distribution Transformer	4MVA		
F3	Distribution Transformer	3.1MVA		
F4	Distribution Transformer	2.8MVA		
F5	Distribution Transformer	0.9MVA		
F6	Distribution Transformer	1.2MVA		

3. Transformer CT Ratio

Feeder Name	15kv side	Feeder 1	Feeder 2	Feeder 3	33kv side	Feeder 4	Feeder 5	Feeder 6
CT ratio	500/1	300/1	300/1	200/1	500/1	150/1	150/1	150/1

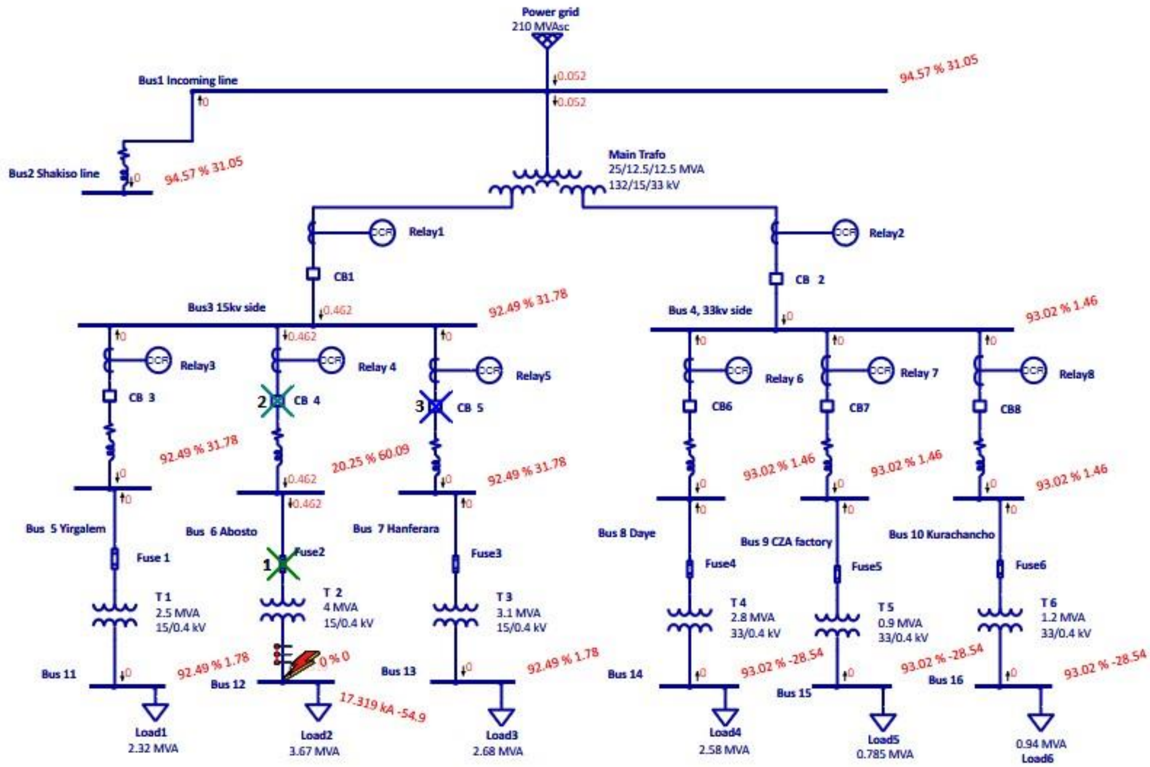
4. Peak load of Yirgalem Distribution system

Peak load of Yirgalem Distribution system in MW, 2014/2022 data												
FEEDER	MONTHS											
	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG
Feeder 1	3.5	3.6	3.6	3.4	3.5	3.8	3.2	3.7	4.2	3.8	3.8	3.8
Feeder 2	1.6	2.0	1.5	1.5	1.3	1.3	1.3	1.2	1.4	1.2	1.3	1.2
Feeder 3	2.0	2.0	2.0	2.0	2.0	2.0	2.1	1.8	2.0	1.8	1.7	1.9
Feeder 4	3.5	4.0	3.2	3.5	3.2	3.1	3.3	3.5	3.7	3.4	3.6	3.7
Feeder 5	3.4	3.8	3.2	3.10	3.0	2.9	3.2	3.4	3.5	3.1	3.5	3.5
Feeder 6	3.2	3.5	3.1	3.0	2.9	2.8	3.2	3.3	3.4	3.0	2.9	3.3

Feeder name	Short Circuit Current	Selection of Protective device rating	
		Circuit Breaker Rating (Ampere)	Fuse Rating (Ampere)
Feeder 1	3475	4170	5213
Feeder 2	5809	6971	8714
Feeder 3	9642	11570	14463
Feeder 4	3808.5	4570	5713
Feeder 5	1534.2	1841	2301
Feeder 6	4613.2	5536	6920

Appendix for Protection coordination

A. Primary protection coordination on Feeder 2 at 15kv side

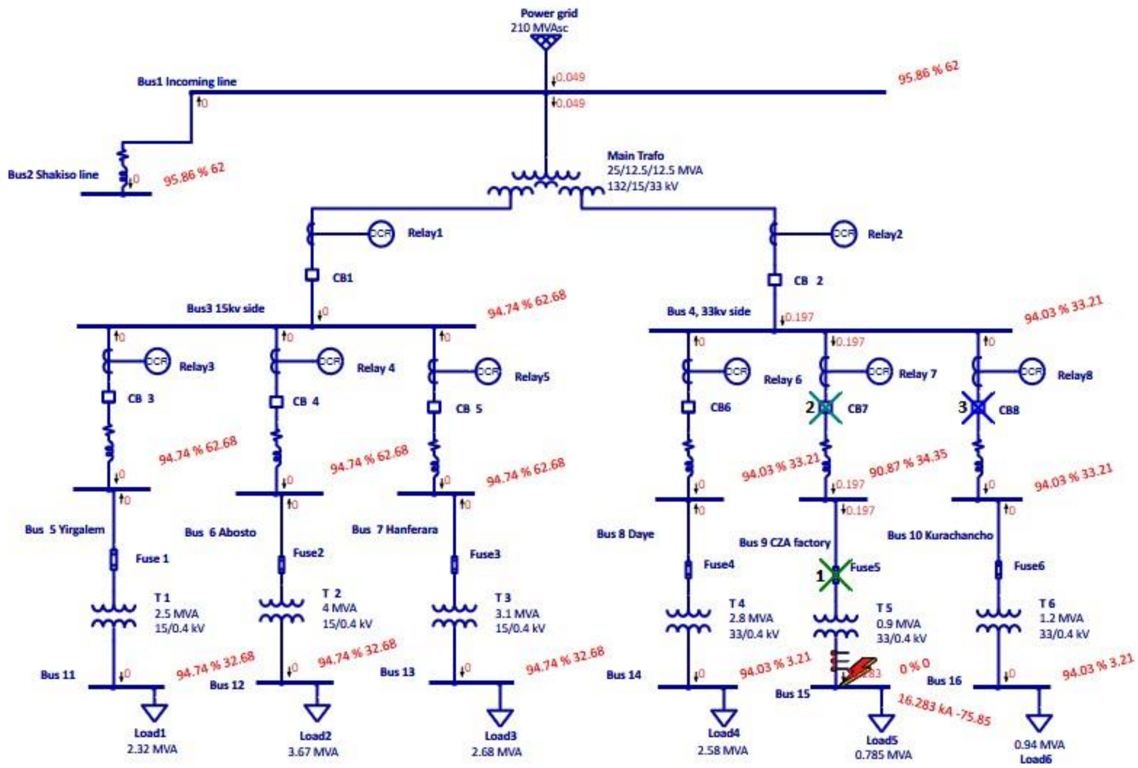


Sequence-of-Operation Event Summary Report

Symmetrical 3-Phase Fault at Bus 12.

Time (ms)	ID	If (kA)	T1 (ms)	T2 (ms)	Condition
36.3	Fuse2	0.462	<20.0	36.3	
98.3	Relay1	0.462	<98.3		Phase - OC1 - 51
153	Relay 4	0.462	153		Phase - OC1 - 51
236	CB 4		83.3		Tripped by Relay 4 Phase - OC1 - 51
236	CB 5		83.3		Tripped by Relay 4 Phase - OC1 - 51

B. Primary protection coordination on Feeder 5 at 33kv side



Sequence-of-Operation Event Summary Report

Symmetrical 3-Phase Fault at Bus 15.

Time (ms)	ID	If (kA)	T1 (ms)	T2 (ms)	Condition
19.8	Fuse5	0.197	<19.8		
59.0	Relay 7	0.197	<59.0		Phase - OC1 - 51
102	Relay2	0.197	102		Phase - OC1 - 51
142	CB7		83.3		Tripped by Relay 7 Phase - OC1 - 51
142	CB8		83.3		Tripped by Relay 7 Phase - OC1 - 51