DESIGNING A PROTECTION COORDINATION LOSS ASSESSMENT TECHNIQUE FOR DG INTEGRATED MV NETWORKS

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Degree of Master of Science

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Dissertation submitted in partial fulfillment of the requirements for the degree Master of Science in Electrical Engineering

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Declaration

I declare that this is my own work and this dissertation does not incorporate without acknowledgement any material previously submitted for a Degree or Diploma in any other University or institute of higher learning and to the best of my knowledge and belief it does not contain any material previously published or written by another person except where the acknowledgement is made in the text.

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The above candidate has carried out research for the Masters Dissertation under my supervision.

Signature of the supervisor: Date:

Dr. Lidula N. Widanagama Arachchige

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Abstract

Conventional distribution system is generally passive, which means power flow is unidirectional, from its grid substation to the loads. With addition of Distributed Generation (DG) in to the system, several issues, such as power flow bi-directionality and increase of fault current in the system influence the existing protection scheme, which is originally designed for a passive network, which has limitations. Protection issue may become a crucial factor and more attention is required in designing the protection system at increased DG penetration levels. If it is possible to calculate loss of protection coordination quantitatively, utility can clearly identify the measures to be taken on their protection system in advance.

The objective of this research study is to introduce a technique, which can be used to assess the protection coordination loss quantitatively, for a DG integrated network. Study is focused on the typical Medium Voltage (MV) network, mainly 33 kV and 11 kV in Sri Lanka. MV distribution system of Mawanella area of Ceylon Electricity Board (CEB), Sri Lanka is selected for the case study where, a total capacity of 6.4 MW of mini-hydro plants is integrated to the system.

Fault current contribution to the system heavily depends on DG type, capacity and location. The effect of these decisive factors on the protection system is analyzed using the Power World Simulator. A tabulation method is used to record the data. Based on the table, decision on protection coordination loss in the system is segregated, protection coordination is maintained or not. Using the segregated data, protection coordination loss percentage is presented to get an overall idea for the system.

The proposed technique can be used to analyze the loss of protection coordination quantitatively for existing networks where DGs are already in operation. The same can also be used as a powerful tool at planning stage at the time of studying new DG proposals. The proposed technique can be integrated as a new dimension to the currently practicing tools of over voltage check and short circuit capacity check.

Key words – Distributed Generation, Protection Coordination, Protection Coordination loss, Distribution System Planning, Fault Level

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List of Abbreviations

Abbreviation	Description
AR	Auto Recloser
CB	Circuit Breaker
CEB	Ceylon Electricity Board
CIGRE	International Council on Large Electricity Systems
DD	Distribution Division
DG	Distributed Generation
DOE	Department of Energy
EPRI	Electric Power Research Institute
GSS	Grid Substation
HV	High Voltage
IEA	International Energy Agency
IEEE	Institute of Electrical and Electronics Engineers
IPP	Independent Power Producers
LBS	Load Break Switch
LV	Low Voltage
MHP	Mini Hydro Plant
MV	Medium Voltage
NCRE	Non-Conventional Renewable Energy
PSS	Primary Substation
RES	Renewable Energy Sources
TR	Transformer
USA	United States of America

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CHAPTER 1

INTRODUCTION

1.1 Distributed Generation

Distributed generation (DG), which is also called on-site generation, dispersed generation, embedded generation, or decentralized generation, generates electricity from many small energy sources [1].

Most countries generate electricity in large centralized facilities, such as fossil fuel (coal, gas powered), nuclear, large solar power plants or hydropower plants. These plants have excellent economies of scale, but usually transmit electricity long distances and can negatively affect the environment. Distributed generation allows collection of energy from many sources and may give lower environmental impacts and improved security of supply.

In scientific literature there is not a common, clear consensus about the definition of DG. Several different definitions have been used to distinguish DG from the central, large power generation. A brief overview of main definitions used at international level is as follows:

- The institute of Electrical and Electronics Engineers Inc. (IEEE) defines the DG as generation of electricity by facilities sufficiently smaller than central plants, usually 10 MW or less, so as to allow interconnection at nearly any point in the power system [2]
- The International Council on Large Electricity Systems (CIGRE) defines DG unit as a generation unit that is not centrally planned, not centrally dispatched, usually connected to the distribution network and smaller than 50 -100 MW [3]
- The International Energy Agency (IEA) defines DG as generating plant serving a customer onsite or providing support to a distribution network, connected to the grid at distribution level voltages [4]

- The US department of Energy (DOE) defines DG as modular electric generation or storage located near the point of use. The DOE considers distributed power systems to typically range from less than a kilowatt to tens of megawatts in size as DG unit [5]
- The Electric Power Research Institute (EPRI) treats small generation units from a few kilowatt up to 50MW and/or energy storage devices typically sited near customer loads or distribution and sub-transmission substations as distributed energy resources [6]

Ceylon Electricity Board (CEB), Sri Lanka defines the DG as a single generator or a group of generating plants of total installed capacity up to 10 MW, connected to the CEB distribution system at 33 kV or below (11 kV & 400 V) [7].

1.2 Increasing Penetration of DGs

Following factors and trends in the power sector in general are driving the widespread penetration of DGs:

- Increased use of RES (Renewable Energy Sources), which are particularly suitable for distributed power generation, rather than concentrated.
- Restructuring of the utility industry, purchasing of power from Independent Power Producers (IPP) allowing open access to the market
- Advances in technology
- Limitations of transmission and distributed capacities
- Trends in sustainable development
- National energy policy movements for security and diversity of energy supply

1.3 Network Planning and Operations Issues

For many years electric power industry has been driven by a paradigm where almost all electricity was generated by large, central power plants, delivered to the consumption areas over transmission lines, and distributed to the consumers through the passive distribution infrastructure at lower voltage levels. In this system, power flows were in one-direction. Now this model is changing to a bidirectional distributed generation network. However, existing network design standards and regulatory frameworks are based on the old unidirectional model.

The operation of a distribution system with a large amount of distributed generation raises a number of issues [8], [9], [10]:

- Voltage profiles change along the network, leading to a behavior different from that of a typical unidirectional network
- Voltage transients may appear as a result of connection and disconnection of generators or even as a result of their operation
- Short circuit levels are increased
- Load loses change as a function of the production and load levels
- Congestion in system branches is a function of the production and load levels
- Power quality and reliability may be affected
- Utility protection system coordination may get affected and as a result, modifications to the coordination between the existing protection scheme or a complete replacement of some of the protection devices may be required
- Existing distribution planning practices are required to be revised to account DGs
- Unwanted power islanding need to be addressed
- A DG installation changes the traditional routine of distribution planning and engineering by increasing the scope and complexity of what must be considered. Many traditional rules of thumb and guidelines may no longer be valid.

1.4 Present Status of Sri Lanka

Dominating type of distributed generation technology in Sri Lanka at present is mini-hydro and there are some other emerging DG technologies.

Most of them are Non-Conventional Renewable Energy (NCRE) sources and commonly used types are as follows:

- Mini Hydro
- Wind
- Solar
- Biomass

Table 1.1 shows projects, which are already commissioned and connected to the CEB grid, and which are still in agreement stage as at 31st December 2013. Installed DG capacity to the CEB 33kV system is 367 MW approximately.

Table 1.1: Summary of DG projects, which are already completed and connected to the grid, and which are at proposal stage [11]

No	Description	Project Type	No. of Projects	Capacity (MW)
01	Commissioned Projects	Mini Hydro Power	128	270.932
		Biomass-Agricultural & Industrial Waste Power	2	11.000
		Biomass-Dendro Power	2	5.500
		Solar Power	4	1.378
		Wind Power	10	78.450
		Total-Commissioned	146	367.260
02	Standardized Power Purchase Agreements (SPPA) Signed Projects	Mini Hydro Power	55	134.64
		Wind Power	5	41.100
		Biomass-Agricultural & Industrial Waste Power	2	4.000
		Biomass-Dendro Power	10	56.770
		Biomass-Municipal Solid Waste	1	10.000
		Total - SPPA Signed	73	246.510

Figure 1.1 shows the NCRE capacity additions to the date of 31 December 2013 and Figure 1.2 shows the annual energy contribution from NCRE to the year 2012.

According to these two figures, it is obvious that the future trend is of increasing penetration of DGs.

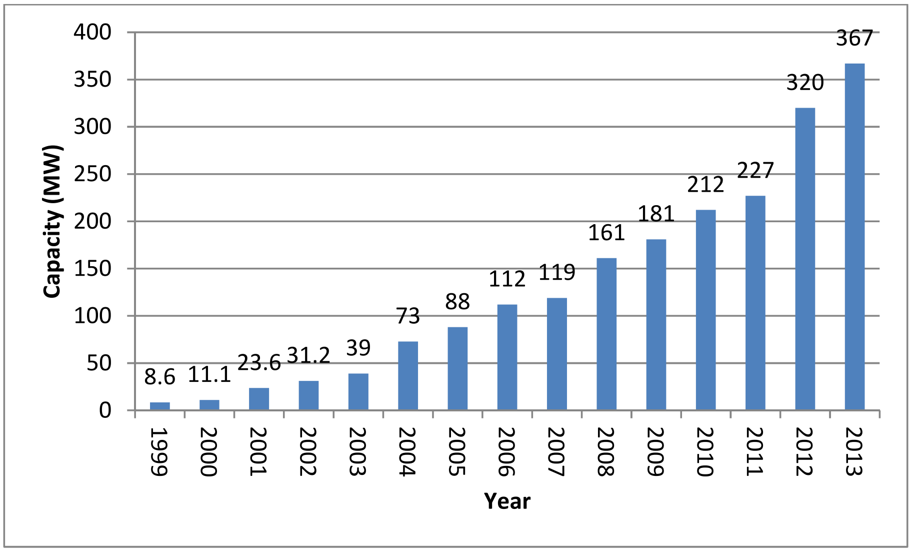


Figure 1.1: NCRE capacity additions to the date of 31 December 2013 [11]

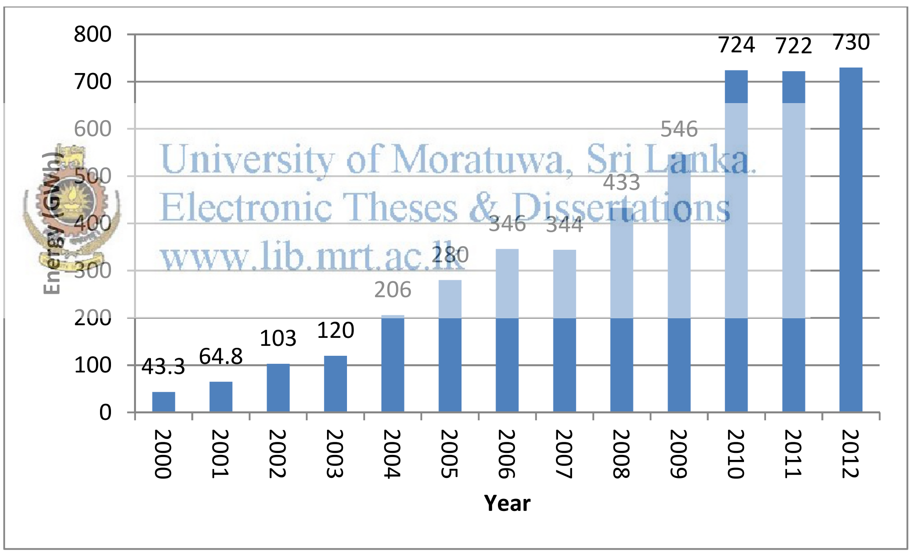


Figure 1.2: Annual energy contribution by NCRE to the year 2012 [11]

1.5 Current Practice for DG Integration in Sri Lanka

When a new DG interconnection proposal is received for the analysis of technical feasibility, the following two regular technical evaluations are conducted by the distribution system planning division of the CEB:

- System over voltage

  When, 25% of grid substation maximum load is connected to the network to represent off-load condition, over voltage is checked within the limit of 6% throughout that particular medium voltage network. Synergy is used as the simulation software.

- Grid substation cumulative fault level

  Fault level at the grid substation 33 kV bus is calculated with the presence of DGs and it is checked whether this value is below the rated switchgear capacity at the relevant grid sub-station. The most widely used switchgear rating in the CEB MV level is 25 kA.

1.6 Problem Statement

Conventional distribution network is generally passive, which means power flow is unidirectional from its grid substation to the distribution loads. Electricity distribution network is generally either radial or ring in its physical arrangement and intends unidirectional power flow. Commonly used protection schemes are over current and earth fault and it is normally designed considering the unidirectional power flow.

When DGs are present in the network, power flow becomes bidirectional deviating from its simplicity to a complex system. Fault level in the system increases and magnitude and direction of fault current flow also get affected. DGs are being added to these distribution networks even though they were not designed to host power generators. Most studies confirm that the electricity distribution networks can easily absorb 10-15% penetration of DGs without requiring major structural changes, although integration will need to be carefully controlled [8].

Current practice of CEB is to connect and run the DGs without specifically evaluating effect of DG integration on protection coordination.

The real question is that, should DGs need to be considered as an important element in protection planning & designing. If it is a real matter and still not considered at planning stage, it may cause nuisance trippings in the utility network resulting unnecessary frequent disconnection of DGs affecting possible power system stability, reliability, safety and cost issues. A stern attention has not been still given to this area.

The following points indicate the requirement of a specific analysis in the area of distribution system protection with increasing penetration of DGs:

- Under low integrated capacity of DGs, it may not create serious issues to the network protection system, and could possibly be neglected. But, with the increased capacity, contribution of fault current from DGs at various points of the network may get drastically increased affecting the system protection. At a fault, network current flow is not simple unidirectional anymore, but complex bidirectional.

- CEB Grid Code on "*Guide for Grid Interconnection of Embedded Generators, Part-1 & Part-2*" [7] has been formulated and published in year 2000 and integrated DG capacity to the system at that time was only 11.1 MW (Figure-1). Therefore, having more than 365 MW of DG capacity integrated to the system, it is important to revise the DG integration practices including power system protection aspects.

- Although it is not very frequent, occasional nuisance trippings are reported in the networks with high DG penetration levels. A co-relation between DGs and network protection system can be highly anticipated.

- Even with simple basic electrical engineering concepts at the first glance, it can be shown that there will be a fault current contribution to the system due to the presence of DGs. The decisive factors are the amount of fault current injected to the system at a particular fault, and the effect on system protection scheme.

- There have been a lot of studies done and research papers are published on this area saying that, "presence of DGs may cause a serious problem to the protection system". Most studies propose solutions to cater this problem, but they are either not practical to implement or high cost protection system rehabilitations. Summary of some of the proposed studies are as follows:

  Girgis and Brahma in [12] have proposed a solution based on replacing relays and reclosers in the distribution network by microprocessor based devices. In this solution, the proper recloser curve should be selected from predefined curves so that coordination can be re-attained. The solution is not economical and also impractical.

  Tailor and Osman in [13] have proposed a scheme based on the disconnection of all DGs instantly at a fault to restore radial nature of the system. Protection scheme originally designed for the radial system works well and isolate the fault. Disconnection of all DGs even at a temporary fault is a disadvantage here.

  Girgis and Brahma in [14] have proposed a scheme based on dividing the system into zones controlled by remotely operated breakers. The faulty zone is isolated by tripping the suitable breaker with a microprocessor based intelligent system. The solution is not economical and requires high cost infrastructure changes.

Following points indicate possible reasons for this issue not being addressed in practice yet in Sri Lanka:

- If the case is really serious, there should be frequent nuisance trippings in the DG connected networks, and it should be heavily highlighted through operational staff and reliability indices.
- Still the current integrated capacity of DGs may not be enough to make such protection coordination problems in the system

If a technique can be developed to calculate the possible protection coordination loss quantitatively for a particular DG integrated network assuming that a mis-coordination (protection coordination loss) occurs in the system, a judgment can be clearly made on above two ends. Such a technique can be applied for the following cases as well.

- It can be used as a tool in DG interconnection planning to check any possible protection mis-coordination in the network, as a result of integrating the proposed DG. It is similar to the current techniques described in Section 1.5 (to check over voltage and fault level) used in the CEB.

- It can be used as a tool for reviewing the status of protecting coordination in DG integrated networks routinely and decide the required possible solutions.

- The technique can be used as a tool of justification of a decision taken at a time of decisive network protection scheme change, protection setting change or rehabilitation.

- The tool can be used for solving specific protection issues, which may arise in DG integrated networks in some cases.

Considering all the points noted here, objectives of the research study have been formulated.

1.6.1 Possible coordination problems

Protection system of MV distribution network is designed considering the fact that the grid substation feeds its downstream network. DG units are connected to this passive network and existence of DGs is not specifically considered at the initial protection scheme design. Protection units are coordinated in such a way that the unit closest to the fault isolates the fault while upstream units providing backup protection to the downstream unit. Protection units are either, fuses, Auto Reclosers (ARs) or grid substation Circuit Breakers (CBs). Possible protection coordination problems, which may arise with the integration of DGs are summarized below [10]:

- Coordination range of two adjacent protection units may get disturbed by DG fault current contributed to the network, driving for a possible mis-coordination

- Downstream protection units may unnecessarily get operated for upstream faults, when a significant amount of fault current is contributed by DGs connected to that end

- The addition of DGs to the system might reduce fault current level drawn from the grid substation. This may reduce the ability to “see” the faults at the corresponding protection units.

The impact of DGs to the protection coordination system of a particular network may get changed by several key factors:

- DG Capacity
- DG Type
- Location

1.7 Objectives of the Study

The objectives of the study are as follows:

Objective-1:

To propose a protocol for DG integration, which facilitate identification of required rehabilitation on existing protection scheme

Objective-2:

To decide the maximum DG capacity, which can be connected to a particular location without changing the existing protection scheme

Objective-3:

To assess the loss of protection coordination in the system to decide the best location to integrate a DG for a particular MV network from protection point of view

1.8 Scope of Work

The scope of the research study is on designing a mechanism to evaluate the protection coordination with the DGs connected to the 33 kV network of the CEB, Sri Lanka. Since the typical arrangement of the 33 kV network of CEB in the whole country is analogous, it was decided to select a particular 33 kV network which already has DGs, as the case study. Mawanella area was selected for this purpose.

The technique developed here, based on the MV network of Mawanella area, can be used for any other cases, with specific slight changes specially when applied to MV underground cable networks and 11kV networks.

The study is mainly focused on mini-hydro plants, which are mainly synchronous generators. The same technique can be applicable for other types of DG technologies (induction and power electronic convertor) as well.

Power World Simulator is used as the software for simulation purposes of faults in the modeled network. Using the software, different types of faults at different nodes in the network are created and fault current can be recorded at any required location very easily.

MV distribution network of Mawanella area is selected as the case study here due to following advantageous reasons:

- The MV distribution network of Mawanella area is very much analogous to the typical arrangement of the 33 kV network of CEB, where Kiribathkumbura grid substation feeds the Mawanella Gantry and then switched to several sub feeders through auto reclosers at the gantry point
- The network is solely 33 kV
- Author's accessibility to the network, making data collection fast and easy
- Three DGs (all mini-hydro plants) are already connected to the network at various points with a total capacity of 6.4 MW
- Since geospatial data are readily available for the network, a reasonable accurate modeling could be guaranteed
- MV distribution network is quite reasonably small enough; otherwise very large networks are difficult to model in the simulator used due to limitations associated with the license.

CHAPTER 2

MV DISTRIBUTION ARCHITECTURE IN SRI LANKA

2.1 Typical Power System Network

A schematic diagram of typical power system architecture in Sri Lanka is shown in Figure 2.1.

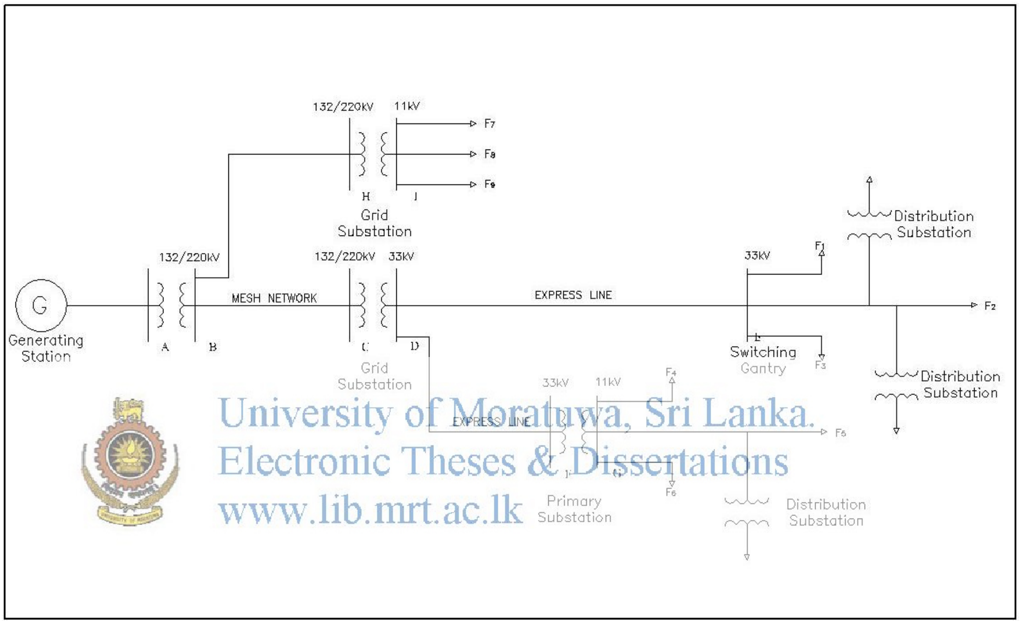


Figure 2.1: Typical power system architecture in Sri Lanka

At the generating station, the voltage is stepped up to the transmission voltage, typically 132/ 220 kV and power is transmitted in a mesh network. At the grid substation, transmission voltage is stepped down to 33 kV and feeds to the switching gantries or primary substations trough express lines. There is no voltage conversion in a switching gantry and it switches the express line into several sub feeders delivering power to distribution substations. In a primary substation, voltage is stepped down to 11 kV and output is switched into several other sub feeders to deliver power. In some cases, transmission voltage is directly stepped down to 11 kV and feeds to the distribution substations.

2.2 MV Distribution Network Architecture

2.2.1 Feeder arrangement

The voltages of 33 kV and 11 kV are used for MV distribution in CEB and it is either radial or ring. In case of ring networks, although the network physical arrangement is a loop, only unidirectional power flow is allowed. Paralleling of two grid substation feeders is not allowed in system operation. A typical schematic diagram of a MV network is shown in Figure 2.2.

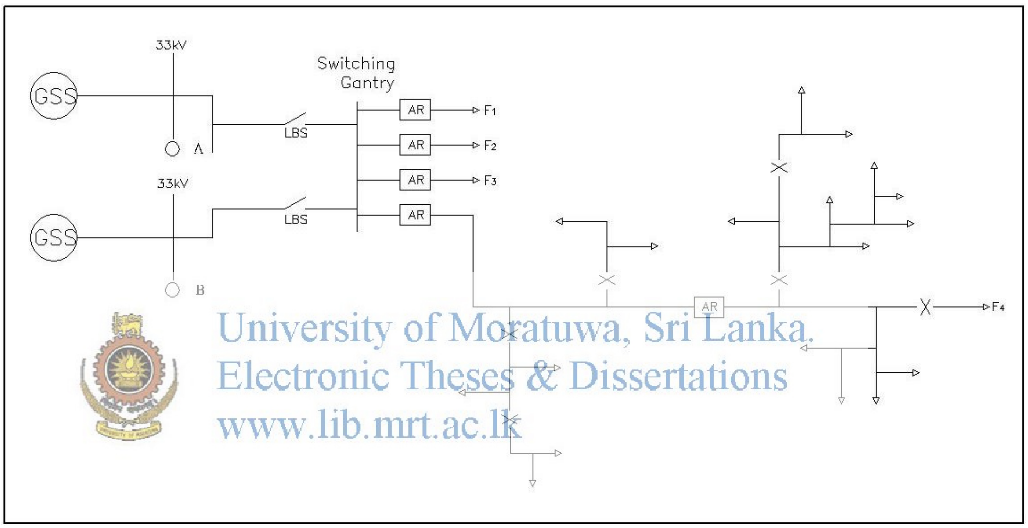


Figure 2.2: MV distribution network architecture

2.2.2 Switching gantry

Typical function of a gantry is, switching of the incoming express line, which comes from the grid substation in to sub feeders through auto reclosers. Depending on the planning requirements, sub feeders can contain several other auto reclosers at downstream, generally maximum three in series.

The advantage of a switching gantry is that, it improves the system reliability and reduces unnecessary outages drastically, mainly due to the following reasons:

- Alternating feeding arrangement is possible, due to the ability of feeding from more than one grid substation to the gantry
- Occurrence of grid substation feeder trippings get reduced, due to the existence of auto reclosers in sub feeders

Typical arrangement of a gantry is shown in Figure 2.3;

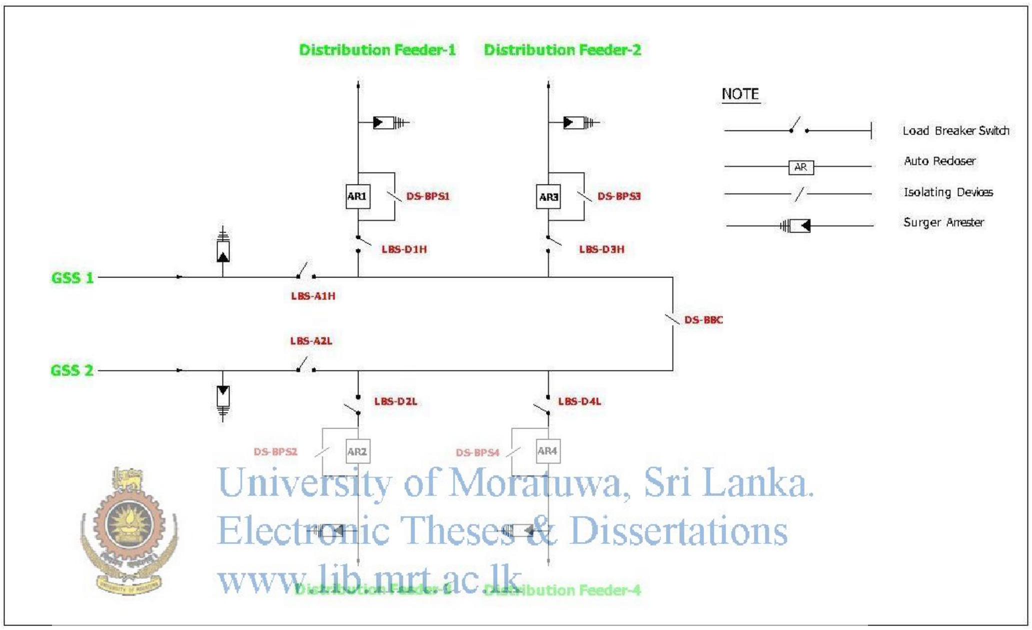


Figure 2.3: Typical arrangement of a gantry

2.2.3 Protection system

Protection system in MV distribution networks is quite simple and commonly used equipment are, circuit breakers (at grid substation), auto reclosers, sectionalizers and line fuses. From these, sectionalizers are still rarely used in the CEB MV networks.

Overcurrent, earth fault and sensitive earth fault are the general schemes used in the network protection. It is simply designed for a passive network with unidirectional power flow.

Typical function of an auto recloser is described below [15]-[16]:

An auto recloser is a circuit-breaker with an electronic controller providing measurement, communication, protection and auto reclosing capabilities. Auto reclosing is the ability to automatically reclose the recloser after a protection trip.

Auto reclosing is very useful on overhead networks where most faults are caused by transient events (such as lightning, insulator flashover, conductor clashing, birds and animals causing faults). When such a fault occurs, the electronic controller trips the circuit-breaker, and then automatically recloses it after a time delay. Auto reclosing is not usually appropriate for underground networks where faults are more likely to be of a non-transient nature.

The number of recloses and the time delay between tripping and reclosing are user configurable. Typically, it can be configured up to three recloses (up to four protection trips). A series of protection trips followed by automatic recloses is called a Reclose Sequence.

If the recloser has automatically reclosed the configured number of times, but the fault is still present (such as a line down on the ground), then it will stop reclosing and the circuit-breaker will remain open. This is called lockout.

2.3 Location for DG Interconnection

Depending on physical location of the plant, capacity, technical and other practical issues, and viability of the project, a DG can be possibly connected to one of the following points in a MV distribution network:

- Directly to the grid substation feeder bay
- To the express line between the grid substation and gantry
- To the gantry point
- To a main distributor or a spur line

CHAPTER 3

MV NETWORK MODELING FOR FAULT SIMULATION

Modeling of MV distribution network of Mawanella area for fault simulation contains the following key components:

- MV distribution network
- Grid substation -132kV bus
- Grid substation -132/33kV power transformer
- Grid substation -33kV earthing transformer
- Distributed generators and generating transformers

The Power World Simulator, Version 12_GSO Educational Version software package was used for simulations, and the main reasons for using it in this study are as follows:

- Network modeling and simulation is quite fast and easy
- It has a user-friendly, highly interactive graphical user interface
- The educational version of the software is freely available

3.1 Modeling of MV Distribution Network for Fault Analysis

3.1.1 Conversion of real network in to a simplified model

The geospatial map of MV distribution network of Mawanella area is shown in Figure 3.1.

Magellan Vantage Point V2.32 software tool was used for analyzing geospatial data for building the simplified model of the network for simulations. Line lengths were accurately calculated through this software.

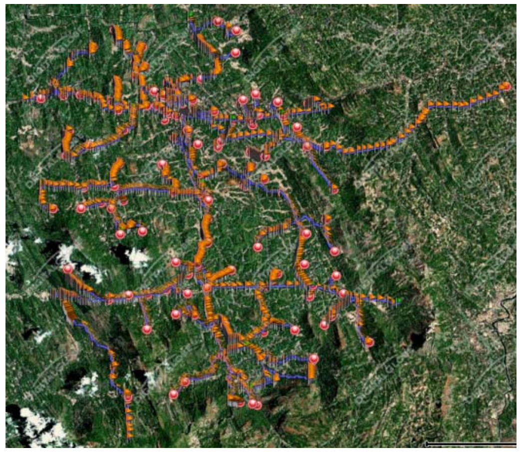


Figure 3.1: Geospatial map of MV distribution network of Mawanella

The developed simplified network model is shown in Figure 3.2.

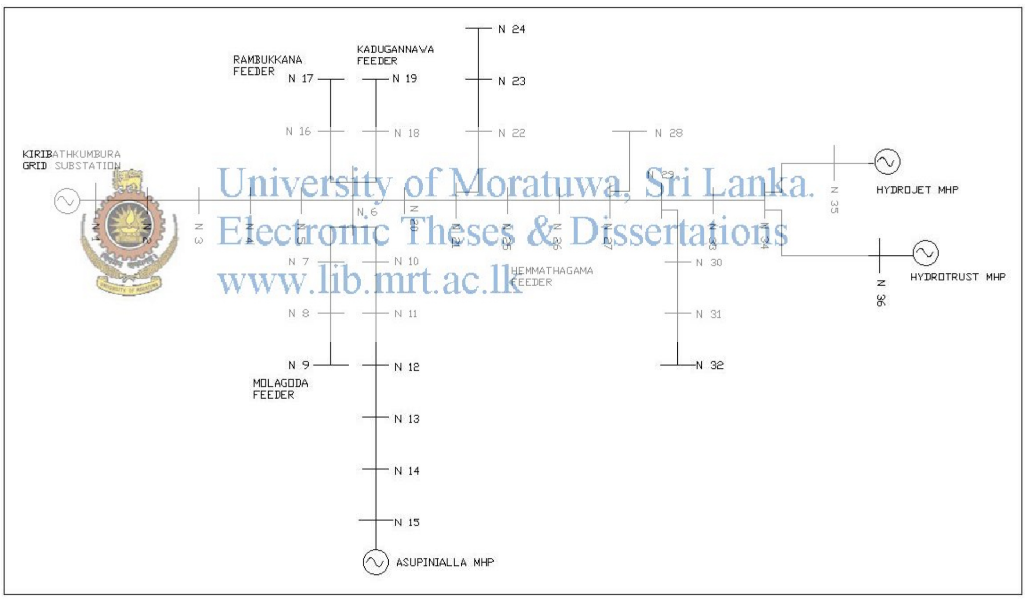


Figure 3.2: MV network model developed for simulation

Mawanella gantry which is shown by node N6 in Figure 3.2 is fed by Feeder-14 of Kiribathkumbura grid. Length of this incoming express line is approximately 15.1 km in length. Two Mini-Hydro Plants (MHPs), Hydro Jet and Hydro Trust are connected at the end of Hemmathagama feeder. Asupinialla mini-hydro plant is directly connected to the gantry with a dedicated 18.1 km long Lynx line.

Plant capacities connected to the network are shown in Table 3.1.

Table 3.1: Integrated plant capacities

Name of the Plant	Capacity
Asupinialla MHP	3.8 MW
Hydrojet MHP	1.1 MW
Hydrotrust MHP	1.5 MW

In formulating the simplified model of the above distribution system, the following points were noted and applied:

- The simulation software used in this study is an educational version and can only model 40 network nodes. Number of network nodes defined here is 36. The distance between any nearest two nodes is approximately 3 km. The length of each section and type of conductor used are shown in Table 3.2.

Table 3.2: Length of each section and conductor type

No.	Section	Length (km)	Conductor Type
1	N1-N2	3.02	Lynx
2	N2-N3	3.02	Lynx
3	N3-N4	3.02	Lynx
4	N4-N5	3.02	Lynx
5	N5-N6	3.02	Lynx
6	N6-N7	2.67	Racoon
7	N7-N8	2.67	Racoon
8	N8-N9	2.67	Racoon
9	N6-N10	3.02	Lynx
10	N10-N11	3.02	Lynx
11	N11-N12	3.02	Lynx
12	N12-N13	3.02	Lynx
13	N13-N14	3.02	Lynx
14	N14-N15	3.02	Lynx
15	N6-16	3.85	Racoon
16	N16-N17	3.85	Racoon
17	N6-N18	2.85	Racoon
18	N18-N19	2.85	Racoon
19	N6-N20	2.84	Racoon

20	N20-N21	2.84	Racoon
21	N21-N22	2.67	Weasal
22	N22-N23	2.67	Weasal
23	N23-N24	2.67	Weasal
24	N21-N25	2.84	Racoon
25	N25-N26	2.84	Racoon
26	N26-N27	2.84	Racoon
27	N27-N28	2.20	Racoon
28	N27-N29	2.10	Racoon
29	N29-N30	3.57	Racoon
30	N30-N31	3.57	Weasal
31	M31-N32	3.57	Weasal
32	N29-N33	2.75	Racoon
33	N33-N34	2.75	Racoon
34	N34-N35	1.60	Racoon
35	N34-N36	2.80	Racoon

- Main 33 kV distributors from the gantry were considered in the model and the total length is approximately 102 km.
- Spur lines from the main lines were omitted from the model and majority of spur lines are less than 3 km and it is shown in Figure 3.3. Spur line number is shown in the X-axis of the graph.

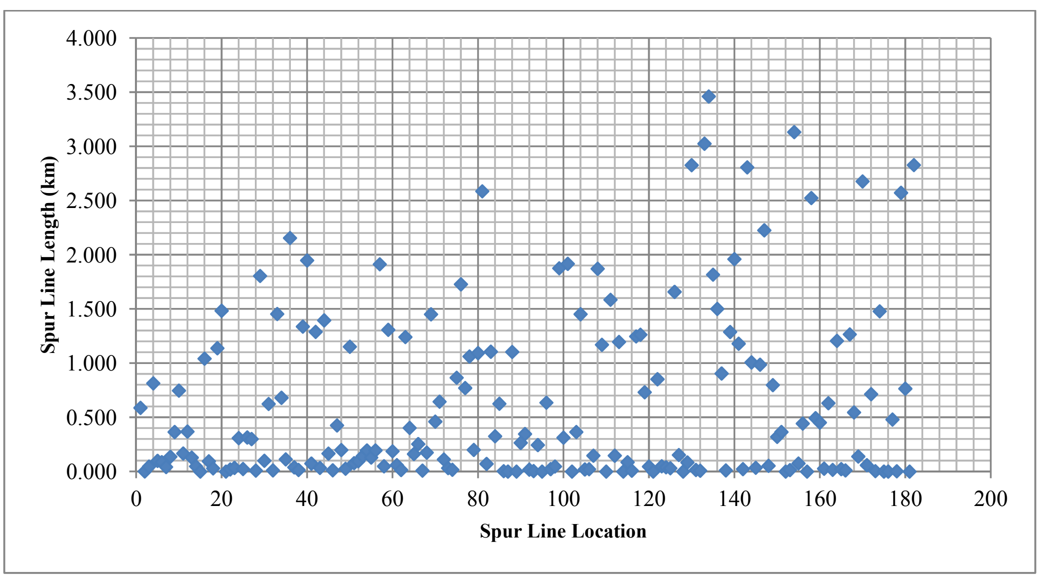


Figure 3.3: Graph of spur line lengths

- The network is assumed to be in its normal configuration
- Single circuit horizontal line formation is considered

The network shown in Figure 3.2 is modeled in the simulation environment and shown in Figure 3.4.

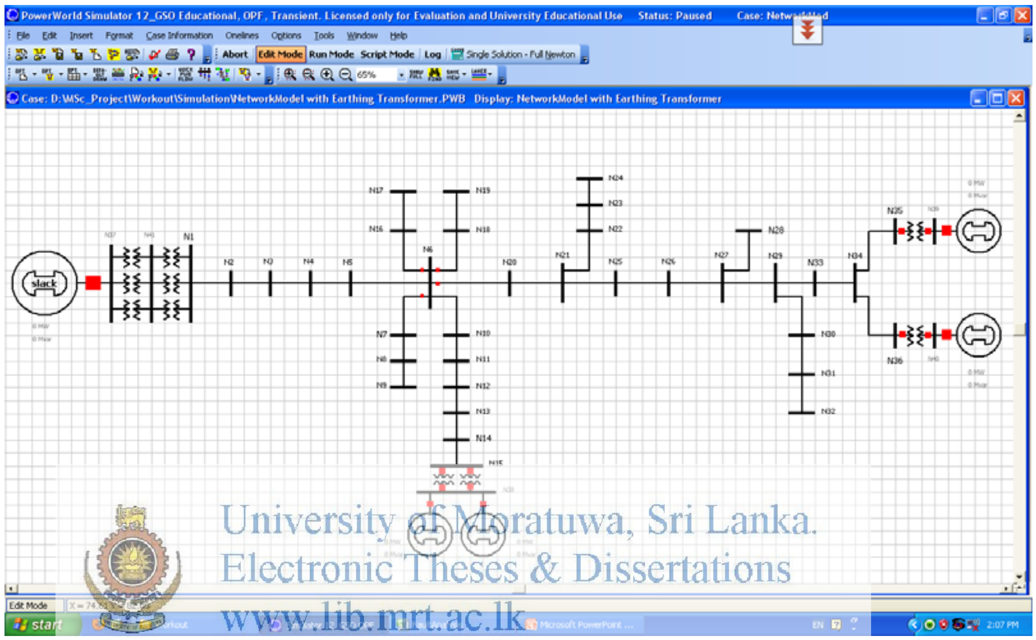


Figure 3.4: The network modeled in the Power World Simulator

3.1.2 Calculation of line parameters for each section

Standard parameters used for different types of conductors are shown in Table 3.3.

Table 3.3: Standard parameters used for different types of conductors [17]

Conductor Type	Positive Sequence Impedance (Z_1) per km (Ω)	Zero Sequence Impedance (Z_0) per km (Ω)
Lynx	0.177 + j0.313	0.326 + j1.588
Racoon	0.431 + j0.375	0.580 + j1.651
Weasal	1.100 + j0.403	1.249 + j1.679

Calculation of line parameters for each section of the network is shown in Table 3.4. Three phase base values of S_{base} = 100 MVA, V_{base} = 33 kV and Z_{base} = 10.89 Ω are used in calculation of per-unit impedance values.

Table 3.4: Calculation of per-unit impedance values for each section of the network

No	Section	Zo (Ω)		Z1 (Ω)		Zo,pu		Z1,pu	
		Real	Im	Real	Im	Real	Im	Real	Im
1	N1-N2	0.985	4.796	0.535	0.945	0.0904	0.4404	0.0491	0.0868
2	N2-N3	0.985	4.796	0.535	0.945	0.0904	0.4404	0.0491	0.0868
3	N3-N4	0.985	4.796	0.535	0.945	0.0904	0.4404	0.0491	0.0868
4	N4-N5	0.985	4.796	0.535	0.945	0.0904	0.4404	0.0491	0.0868
5	N5-N6	0.985	4.796	0.535	0.945	0.0904	0.4404	0.0491	0.0868
6	N6-N7	1.549	4.408	1.151	1.001	0.1422	0.4048	0.1057	0.0919
7	N7-N8	1.549	4.408	1.151	1.001	0.1422	0.4048	0.1057	0.0919
8	N8-N9	1.549	4.408	1.151	1.001	0.1422	0.4048	0.1057	0.0919
9	N6-N10	0.985	4.796	0.535	0.945	0.0904	0.4404	0.0491	0.0868
10	N10-N11	0.985	4.796	0.535	0.945	0.0904	0.4404	0.0491	0.0868
11	N11-N12	0.985	4.796	0.535	0.945	0.0904	0.4404	0.0491	0.0868
12	N12-N13	0.985	4.796	0.535	0.945	0.0904	0.4404	0.0491	0.0868
13	N13-N14	0.985	4.796	0.535	0.945	0.0904	0.4404	0.0491	0.0868
14	N14-N15	0.985	4.796	0.535	0.945	0.0904	0.4404	0.0491	0.0868
15	N6-16	2.233	6.356	1.659	1.444	0.2051	0.5837	0.1524	0.1326
16	N16-N17	2.233	6.356	1.659	1.444	0.2051	0.5837	0.1524	0.1326
17	N6-N18	1.653	4.705	1.228	1.069	0.1518	0.4321	0.1128	0.0981
18	N18-N19	1.653	4.705	1.228	1.069	0.1518	0.4321	0.1128	0.0981
19	N6-N20	1.647	4.689	1.224	1.065	0.1513	0.4306	0.1124	0.0978
20	N20-N21	1.647	4.689	1.224	1.065	0.1513	0.4306	0.1124	0.0978
21	N21-N22	3.335	4.483	2.937	1.076	0.3062	0.4117	0.2697	0.0988
22	N22-N23	3.335	4.483	2.937	1.076	0.3062	0.4117	0.2697	0.0988
23	N23-N24	3.335	4.483	2.937	1.076	0.3062	0.4117	0.2697	0.0988
24	N21-N25	1.647	4.689	1.224	1.065	0.1513	0.4306	0.1124	0.0978
25	N25-N26	1.647	4.689	1.224	1.065	0.1513	0.4306	0.1124	0.0978
26	N26-N27	1.647	4.689	1.224	1.065	0.1513	0.4306	0.1124	0.0978
27	N27-N28	1.276	3.632	0.948	0.825	0.1172	0.3335	0.0871	0.0758
28	N27-N29	1.218	3.467	0.905	0.788	0.1118	0.3184	0.0831	0.0723
29	N29-N30	2.071	5.894	1.539	1.339	0.1901	0.5412	0.1413	0.1229
30	N30-N31	4.459	5.994	3.927	1.439	0.4095	0.5504	0.3606	0.1321
31	M31-N32	4.459	5.994	3.927	1.439	0.4095	0.5504	0.3606	0.1321

32	N29-N33	1.595	4.540	1.185	1.031	0.1465	0.4169	0.1088	0.0947
33	N33-N34	1.595	4.540	1.185	1.031	0.1465	0.4169	0.1088	0.0947
34	N34-N35	0.928	2.642	0.690	0.600	0.0852	0.2426	0.0633	0.0551
35	N34-N36	1.624	4.623	1.207	1.050	0.1491	0.4245	0.1108	0.0964

Figure 3.5 illustrates an example case of entering per-unit positive sequence impedance and zero sequence impedance values in simulating the line section “N5-N6”.

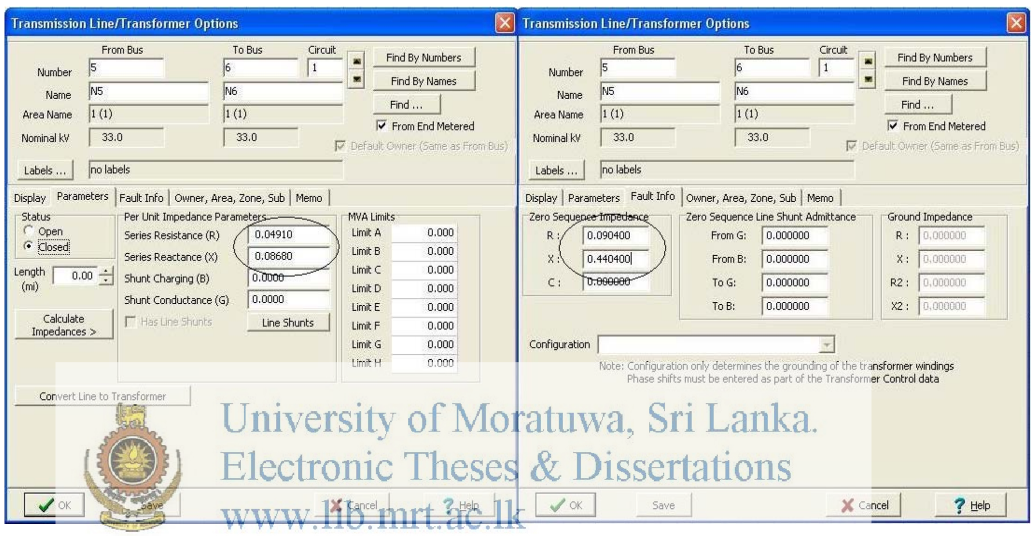


Figure 3.5: Modeling of section N5-N6 with line parameters in the simulator

3.2 Modeling the Grid Substation 132 kV Bus

Fault level of 132 kV bus of Kiribathkumbura grid substation is taken as 10 kA (-75 deg) [18]. Grid substation 132 kV bus is modeled as a single large generator in the simulator and parameters calculated are shown in Table 3.5.

Table 3.5: Kiribathkumbura GSS 132 kV bus fault parameters

Kiribathkumbura Grid Substation – 132 kV Bus (S_{base} = 100 MVA, V_{base} = 132 kV, I_{base} = 0.437 kA)	
Fault level of 132 kV bus	10 kA (-75deg)
$I_{sc,pu}$	22.883 (-75deg)
Z_{pu}	0.01131 + j0.04221

Parameters entered in the simulator for 132 kV bus are shown in Figure 3.6.

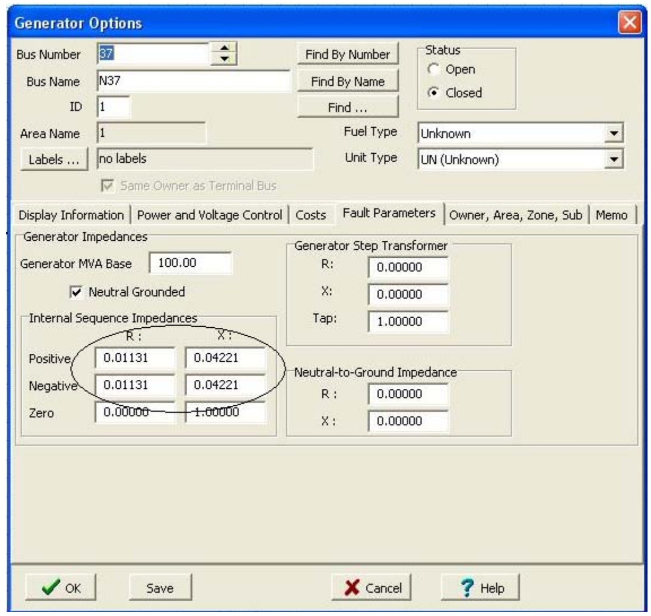


Figure 3.6: Modeling of GSS 132kV bus in the simulator

132 kV bus of the Kiribathkumbura Grid substation is defined as the "slack bus," representing the rest of the power system. It is also a requirement that one bus being defined as a slack bus in the simulator [19]. Features of a slack bus as defined in the simulator are as follows:

- It provides an angle and voltage reference
- It must be a bus with a generator
- Voltage angle and magnitude are fixed
- Real and reactive output of the generator is free to vary

3.3 Modeling of GSS Power Transformers and Earthing Transformers

3.3.1 Modeling of power transformers

Number of power transformers in the Kiribathkumbura grid substation is three and their capacities are 31.5 MVA each. Vector group is YNd1. The summary of name plate data is shown in Table 3.6. Base values are 100 MVA and 33 kV.

Table 3.6: Kiribathkumbura GSS power transformer data

Power Transformer-Kiribathkumbura GSS	
MVA Rating	31.5
Voltage ratio	132,000 / 33,000
Impedance	11.02
Z_{pu} (at 100 MVA)	0.3498
Vector group	YNd1

Transformer HV side (132 kV) is star connected and solidly grounded, and LV side (33 kV) is delta connected which is naturally ungrounded.

Grounded wye-delta configuration is used in the simulator and generator information dialog box is shown in Figure 3.7.

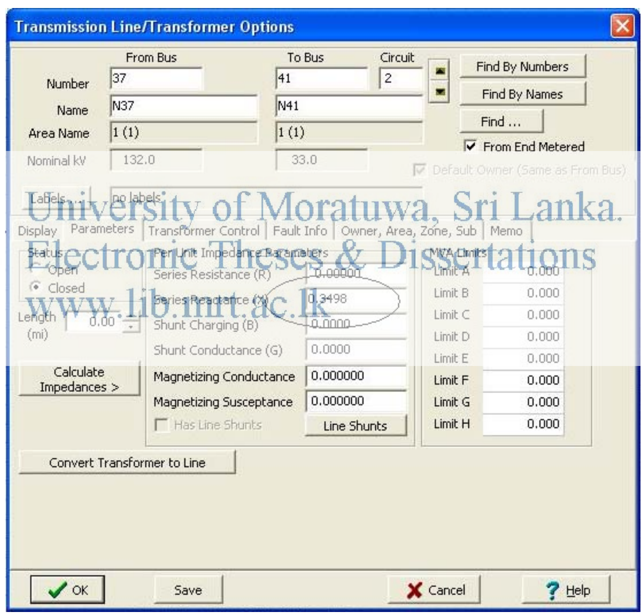


Figure 3.7: Modeling of GSS power transformers in the simulator

3.3.2 Modeling of earthing transformers

The earthing transformers are used for grounding of 33 kV bus at the grid substation. It is a Zig-Zag transformer, which can provide a high impedance path to zero sequence current and low impedance path to positive and negative sequence currents [20].

Main objectives of having earthing transformers in the grid substation are:

- Grounding 33 kV distribution network at the grid substation end
- Creating a high impedance path for earth fault current in the 33 kV system

The summary of name plate data of earthing transformers in Kiribathkumbura grid substation is shown in Table 3.7.

Table 3.7: Kiribathkumbura GSS earthing transformer data

Earthing Transformer-Kiribathkumbura GSS	
MVA Rating	0.2 MVA
Voltage	33,000 kV
Zero sequence Impedance	78.03 Ω
Z_{base}	5,445.0 Ω
Z_{pu}	0.014330579 Ω
Z_{pu} (at 100 MVA)	7.165 Ω

Typical arrangement of power transformer, auxiliary transformer and earthing transformer of a grid substation is shown in Figure 3.8 in single line form.

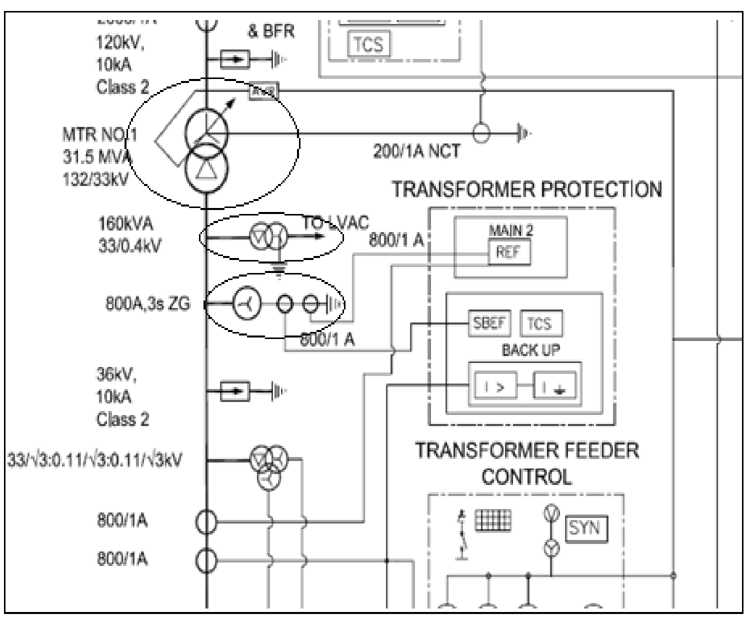


Figure 3.8: Single line diagram of a grid substation

There is no direct component to model the earthing transformer in the Power world Simulator and an equivalent model representing its characteristics was developed as the solution. The equivalent model was validated using both the simulator and manual calculation.

For an earthing transformer:

$$I_n = \frac{\sqrt{3}\, E}{Z_s}$$

$$I_n = \frac{\sqrt{3}\ \times 33{,}000}{78.03}$$

$$I_n = 732.5\ A$$

Where,

E = Line to line voltage in volts

Z_s = Zero sequence impedance per phase in ohms

I_n = Neutral current in amperes

Zero sequence equivalent circuit for the power transformer and earthing transformer is shown in Figure 3.9 and it was used for modeling in the simulator.

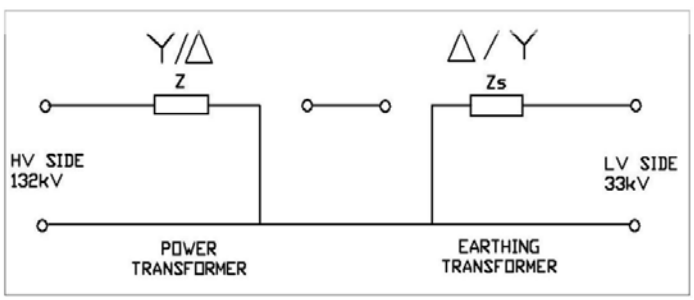


Figure 3.9: Equivalent model used in the simulator representing power tranformer and earthing transformer

In the simulator, earthing transformer is modeled using delta-grounded wye power transformer. Positive sequence impedance (transformer impedance) is set as zero and zero sequence impedance is set as 7.165 Ω (earthing transformer per-unit zero sequence impedance per phase).

Values entered in the simulator are shown in Figure 3.10.

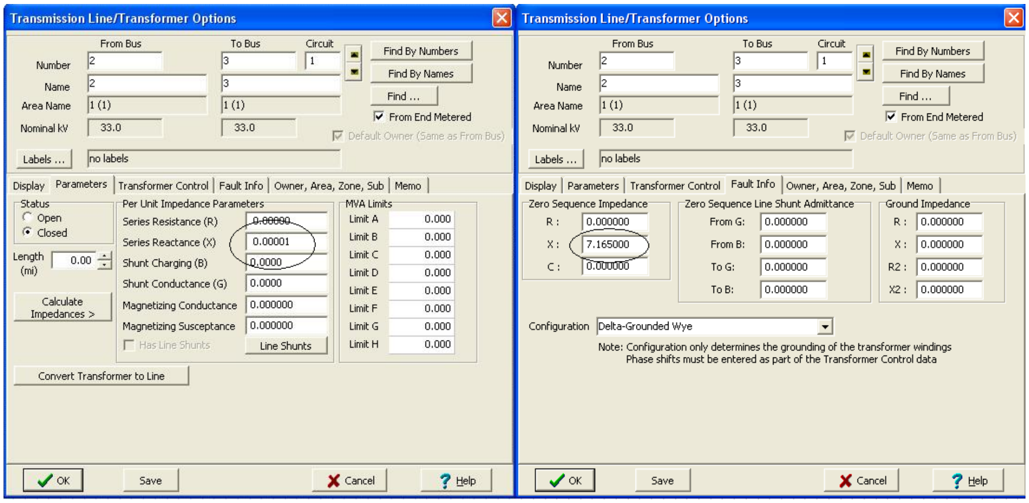


Figure 3.10: Modeling of earthing transformer in the simulator

By setting internal reactance values of bulk generator to zero, which represents the 132 kV bus as a 1 pu source, and power transformer reactance to zero, a single line to ground fault is simulated in the 33 kV bus to check with the manual calculation. Simulated earth fault current and calculated value is equal and therefore, model is guaranteed to be correct. A screen shot of simulated result is shown in Figure 3.11.

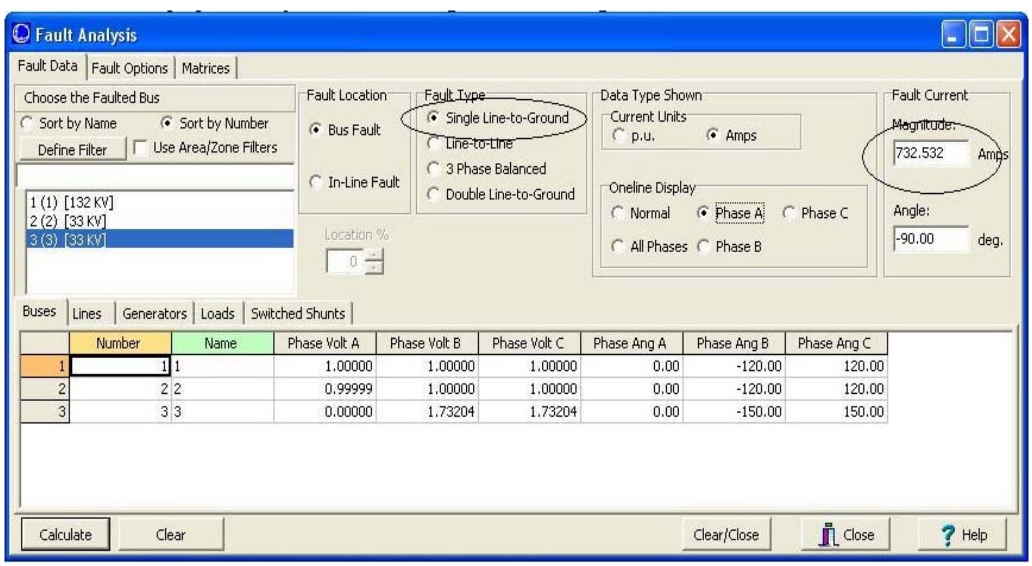


Figure 3.11: Simulated results for earthing transformer to guarantee its accuracy of modeling in the simulator

3.4 Modeling of Distributed Generators and Generating Transformers

3.4.1 Electrical characteristics of DG units

The ability of the DG units to feed external faults depends strongly on the technology of the generator. Accordingly, generators used for DG integration can be categorized into three types of technologies considering their electrical characteristics:

- Synchronous generators
- Induction generators
- Power electronic converter based sources

The impact on the protection of the distribution system is dependent on whether the interfacing scheme is based on direct coupling of rotary machines, such as synchronous generators or induction generators, or whether the DG system is interfaced via a power electronic converter. Power electronic converters have the minimum fault current feeding capacity compared to the other technologies [10].

All three technologies can be modeled by a single driving voltage source in series with equivalent impedance for short circuit studies [10].

3.4.2 Modeling of mini-hydro plants

Generators in all three power plants, Asupinialla, Hydrojet and Hydrotrust are synchronous generators and modeled with their internal reactances.

Number of generators in Asupinialla is two and others are having only a single machine. The summary of name plate data of Asupinialla and other parameters [21] are shown in Table 3.8. Base values are 100 MVA and 33 kV.

Table 3.8: Name plate data of synchronous generators at Asupinialla

Generator Name Plate Data-Asupinialla MHP		
MVA Rating	2.5 MVA	
V_{out}	3,300 kV	
MVA Base	2.5 MVA	100 MVA
X''_d	0.119	4.76
X_2	0.123	4.92
X_o	0.026	1.04

Generator capacities of Hydrojet MHP and Hydrotrust MHP are 1.875 MVA and 2.5 MVA respectively. Internal impedance values of Asupinialla MHP are used for other two plants too, since their internal impedance data are not available.

3.4.3 Modeling of generating transformers

The summary of name plate data of generating transformers in the three MHPs is shown in Table 3.9. Base values are 100 MVA and 33 kV.

Table 3.9: Name plate data of generating transformers

Description	**Asupinialla MHP**	**Hydrojet MHP**	**Hydrotrust MHP**
Capacity	2 x 2.5 MVA	2.0 MVA	2.8 MVA
Voltage ratio	33,000/ 3,300 V	33,000/ 6,600 V	33,000/ 415 V
Impedance	6.35 %	6.52 %	7.81 %
Per-unit impedance	2.54 Ω	3.26 Ω	2.7893 Ω
Vector group	Dyn11	YNd11	Dyn11

CHAPTER 4

SIMULATION & RESULTS

4.1 Three Phase Fault Current Contribution by DGs

Three phase faults were simulated in each node from N1 to N36 for the following two cases to identify the current contribution by three DGs:

- DGs are connected to the network
- DGs are not connected to the network

In the case with DGs, it was assumed that all DGs are running at their maximum rated capacities, none of the DGs are taken for outages, and all DGs are connected to the network. The worst case scenario was assumed.

In order to calculate the fault current for a three-phase short circuit in the network, the following assumptions were made [22]:

- The power system operates under balanced steady state conditions before the fault occurs.
- Pre-fault load current is neglected
- MV lines are represented by their equivalent series reactances & resistances. Shunt admittances are neglected.
- Transformers are represented by their leakage reactances. Winding resistances, shunt admittances, and Delta-Why phase shifts are neglected.
- Synchronous machines are represented by constant voltage sources behind subtransient reactances. Armature resistance, saliency and saturation are neglected.
- All rotating and non-rotating loads are neglected.

Table 4.1 shows fault current contribution in each case, with DGs and without DGs.

Table 4.1: Fault current contribution, with DGs and without DGs

Node	3 Ph Fault Current without DGs (A)	3 Ph Fault Current with DGs (A)	Difference (A)
1	11,792	12,435	643
2	7,218	7,888	670
3	5,151	5,840	689
4	3,994	4,704	710
5	3,258	3,992	734
6	2,750	3,509	**759**
7	2,287	2,800	513
8	1,949	2,314	365
9	1,695	1,966	271
10	2,379	3,049	670
11	2,096	2,711	615
12	1,873	2,452	579
13	1,692	2,249	557
14	1,544	2,086	542
15	1,419	1,952	533
16	2,125	2,563	438
17	1,721	2,001	280
18	2,260	2,761	501
19	1,911	2,260	349
20	2,262	2,893	631
21	1,913	2,466	553
22	1,516	1,858	342
23	1,240	1,461	221
24	1,042	1,194	**152**
25	1,654	2,159	505
26	1,455	1,928	473
27	1,298	1,750	452
28	1,197	1,577	380
29	1,201	1,643	442
30	1,066	1,407	341
31	883	1,117	234
32	749	915	166
33	1,095	1,526	431
34	1,005	1,429	424
35	959	1,360	401
36	928	1,316	388

Maximum current difference observed between the two cases is 759 A at node N6 of the network. The above value is with 6.4 MW of capacity of DGs, interconnected to the network. When integrated capacity increases, the current difference could get further increased.

The two cases are also graphically illustrated in Figure 4.1. A screen shot of simulation of fault current at node N6 is shown in Figure 4.2.

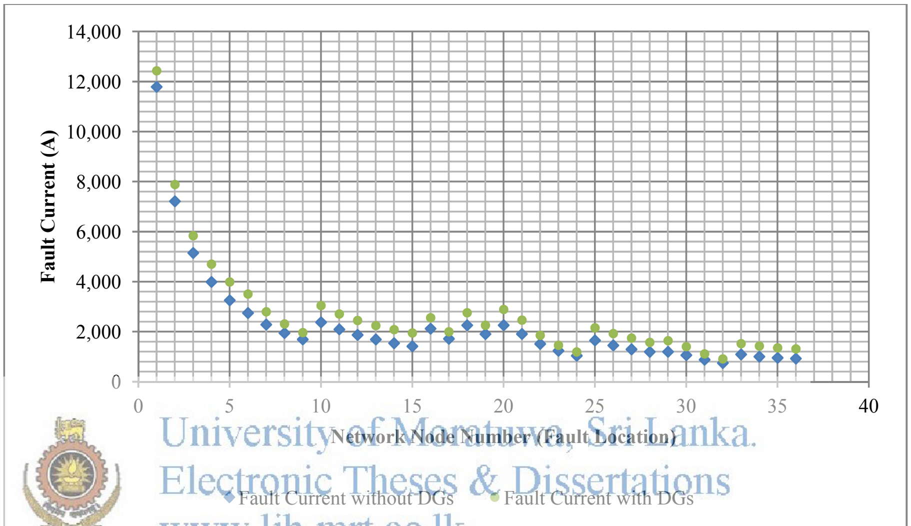


Figure 4.1: Fault current contribution, with DGs and without DGs

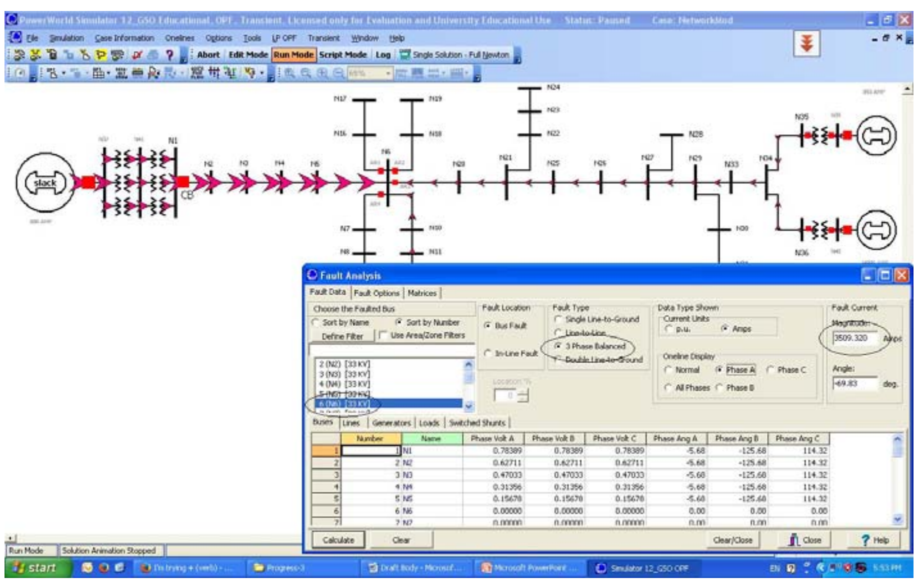


Figure 4.2: Simulation of fault current at node N6

4.2 Identification of Fault Isolation Time of Protection Units

All the protection units available in the network are shown in Figure 4.3 and their individual characteristics are given in Appendix-A.

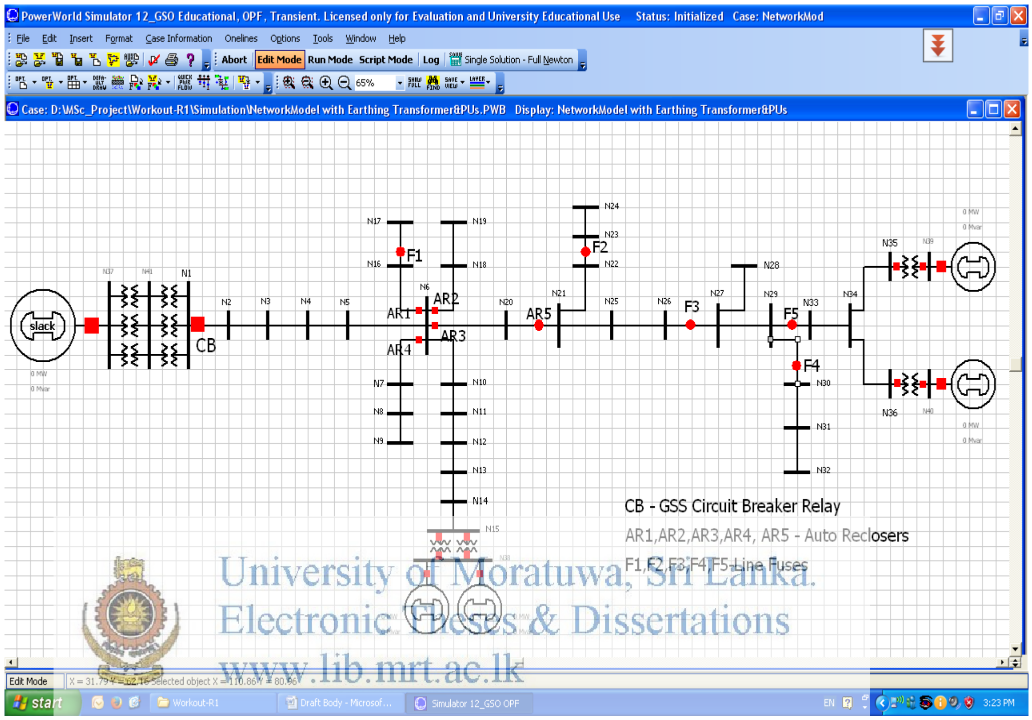


Figure 4.3: Protection units available in the network

Overcurrent and earth fault protection schemes are available in the grid substation feeder bay relays and auto reclosers (AR1, AR2, AR3, AR4 and AR5) and fuses (F1, F2, F3, F4 and F5) are located in the network as shown in Figure 4.3.

Operating time of grid substation feeder breaker and auto reclosers are calculated using their overcurrent characteristics curves. Minimum melting time curves are used in calculating fusing time. Three phase balanced faults were created at each node of the network and fault current trough each and every protection units were recorded respectively in each case. Relevant operating time was also calculated using characteristics curves of the protection units and results are tabulated in Table 4.2.

Table 4.2: Fault current through protection devices and their operating times

Fault At		CB	AR1	AR2	AR3	AR4	AR5	F1	F2	F3	F4	F5
N2	I_f (A)	7,217	0	0	314	0	314	0	0	314	0	314
	t (s)	0.00			15.80		7.90			7.00		2.00
N3	I_f (A)	5,151	0	0	326	0	326	0	0	326	0	326
	t (s)	0.00			14.01		7.00			5.00		0.96
N4	I_f (A)	3,994	0	0	339	0	339	0	0	339	0	339
	t (s)	0.00			12.48		6.24			4.50		0.90
N5	I_f (A)	3,258	0	0	353	0	353	0	0	353	0	353
	t (s)	0.00			11.17		5.58			4.00		0.80
N6	I_f (A)	2,750	0	0	367	0	367	0	0	367	0	367
	t (s)	0.00			10.10		4.95			3.50		0.70
N7	I_f (A)	2,194	0	0	293	2,800	293	0	0	293	0	293
	t (s)	1.51			20.34	0.00	10.61			8.00		2.70
N8	I_f (A)	1,814	0	0	242	2,314	242	0	0	242	0	242
	t (s)	1.91			67.50	0.00	37.13			35.00		6.60
N9	I_f (A)	1,541	0	0	206	1,966	206	0	0	206	0	206
	t (s)	2.37			na	0.00	inf			150.00		15.00
N10	I_f (A)	2,339	0	0	312	0	312	0	0	312	0	312
	t (s)	1.39			16.14		8.25			7.00		2.10
N11	I_f (A)	2,034	0	0	271	0	271	0	0	271	0	271
	t (s)	1.65			29.12		29.70			15.00		3.50
N12	I_f (A)	1,799	0	0	240	0	240	0	0	240	0	240
	t (s)	1.93			74.25		37.13			6.40		6.60
N13	I_f (A)	1,613	0	0	215	0	215	0	0	215	0	215
	t (s)	2.23			inf		inf			80.00		11.00
N14	I_f (A)	1,461	0	0	195	0	195	0	0	195	0	195
	t (s)	2.54			inf		inf			300.00		20.00
N15	I_f (A)	1,336	0	0	178	0	178	0	0	178	0	178
	t (s)	2.88			inf		inf			inf		50.00
N16	I_f (A)	2,009	2,563	0	268	0	268	0	0	268	0	268
	t (s)	1.68	0.00		30.94		14.85			15.00		3.50
N17	I_f (A)	1,568	2,001		209		209	2,001	0	209	0	209
	t (s)	2.32	0.00		inf		inf	0.05		150.00		15.00
N18	I_f (A)	2,164	0	2,761	289	0	289	0	0	289	0	289
	t (s)	1.53		0.00	21.52		10.61			10.00		2.70
N19	I_f (A)	1,772	0	2,260	236	0	236	0	0	236	0	236
	t (s)	1.97		0.00	92.81		37.13			6.40		6.60
N20	I_f (A)	2,212	0	0	2,531	0	376	0	0	376	0	376
	t (s)	1.49			0.00		4.64			3.20		0.68
N21	I_f (A)	1,839	0	0	2,105	0	2,105	0	0	389	0	389
	t (s)	1.88			0.00		0.00			3.00		1.00

N22	I_f (A)	1,386	0	0	1,586	0	1,586	0	0	291	0	291
	t (s)	2.74			1.09		0.54			10.00		2.70
N23	I_f (A)	1,089	0	0	1,246	0	1,246	0	1,461	229	0	229
	t (s)	3.92			1.45		0.72		0.10	50.00		8.00
N24	I_f (A)	890	0	0	1,019	0	1,019		1,194	187	0	187
	t (s)	5.51			1.86		0.95		0.15	inf		30.00
N25	I_f (A)	1,670	0	0	1,796	0	1,796	0	0	396	0	396
	t (s)	2.13			0.94		0.47			2.50		0.94
N26	I_f (A)	1,367	0	0	1,564	0	1,564	0	0	406	0	406
	t (s)	2.79			1.10		0.56			2.30		0.90
N27	I_f (A)	1,210	0	0	1,384	0	1,384	0	0	1,384	0	416
	t (s)	3.33			1.28		0.63			0.11		0.84
N28	I_f (A)	1,090	0	0	1,248	0	1,248	0	0	1,248	0	375
	t (s)	3.91			1.44		0.72			0.15		1.10
N29	I_f (A)	1,115	0	0	1,275	0	1,275	0	0	1,275	0	424
	t (s)	3.78			1.41		0.69			0.13		0.84
N30	I_f (A)	955	0	0	1,093	0	1,093	0	0	1,093	1,407	363
	t (s)	4.86			1.70		0.84			0.18	0.07	1.30
N31	I_f (A)	758	0	0	867	0	867	0	0	867	1,117	288
	t (s)	7.54			2.30		1.14			0.30	0.11	2.70
N32	I_f (A)	621	0	0	711	0	711	0	0	711	915	236
	t (s)	12.22			3.02		1.52			0.45	0.16	6.60
N33	I_f (A)	1,010	0	0	1,156	0	1,156	0	0	1,156	0	1,156
	t (s)	4.43			1.59		0.80			0.15		0.09
N34	I_f (A)	923	0	0	1,056	0	1,056	0	0	1,056	0	1,056
	t (s)	5.16			1.78		0.89			0.18		0.11
N35	I_f (A)	873	0	0	999	0	999	0	0	999	0	999
	t (s)	5.71			1.91		0.95			0.22		0.13
N36	I_f (A)	839	0	0	961	0	961	0	0	961	0	961
	t (s)	6.15			2.00		1.00			0.24		0.15

4.3 Differentiation of Successful Coordination

With identification of operating time of each protection unit, the next step is to discriminate it; whether the faulty section is isolated successfully or not. If only the faulty section is isolated, it can be identified as a successful coordination. If it is not only the faulty section but also healthy sections are isolated, then it can be identified as a coordination failure.

The concept is based on the simple condition that the protection unit nearest to the fault should operate first and only the faulty section should be isolated. It should not include any healthy section.

Since it is looking from protection point of view at the distribution network, it is assumed that the distributed generators are continuously feeding the fault current without tripping until the grid supply is lost. Minimum time gap considered for successful coordination check between two protection units is considered as 100 ms.

The methodology is described using a simple radial MV distribution system with integrated DGs as shown in Figure 4.4.

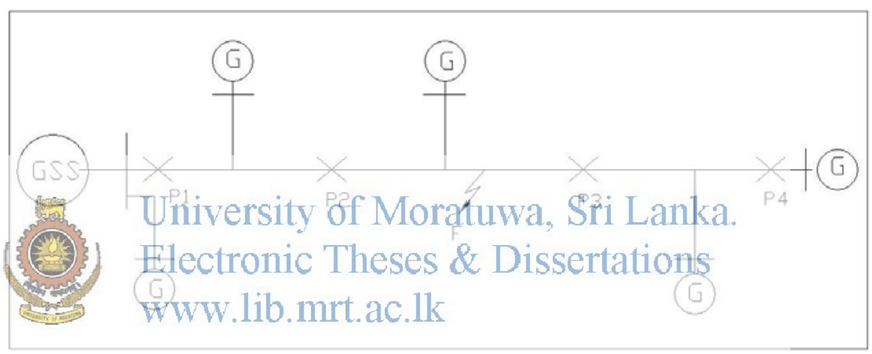


Figure 4.4: Example MV distribution network with DGs

P1, P2, P3 and P4 are the protection units. For fault *F*, protection units P2 and P3 should operate first to isolate the faulty section. Any probable operating times of the other protection units should be well beyond 100 ms.

The above criterion was used in classifying successful coordination and coordination fail for the MV distribution system shown in Figure 4.3. Successful coordination is denoted by “1” and if the coordination is failed, it is denoted by “0”. The result with application of above criterion is tabulated in Table 4.3.

Table 4.3: Differentiation of successful coordination

Fault		CB	AR1	AR2	AR3	AR4	AR5	F1	F2	F3	F4	F5	Result
N2	I_f (A)	7,217	0	0	314	0	314	0	0	314	0	314	**1**
	t (s)	0.00			15.80		7.90			7.00		2.00	
N3	I_f (A)	5,151	0	0	326	0	326	0	0	326	0	326	**1**
	t (s)	0.00			14.01		7.00			5.00		0.96	
N4	I_f (A)	3,994	0	0	339	0	339	0	0	339	0	339	**1**
	t (s)	0.00			12.48		6.24			4.50		0.90	
N5	I_f (A)	3,258	0	0	353	0	353	0	0	353	0	353	**1**
	t (s)	0.00			11.17		5.58			4.00		0.80	
N6	I_f (A)	2,750	0	0	367	0	367	0	0	367	0	367	**1**
	t (s)	0.00			10.10		4.95			3.50		0.70	
N7	I_f (A)	2,194	0	0	293	2,800	293	0	0	293	0	293	**1**
	t (s)	1.51			20.34	0.00	10.61			8.00		2.70	
N8	I_f (A)	1,814	0	0	242	2,314	242	0	0	242	0	242	**1**
	t (s)	1.91			67.50	0.00	37.13			35.00		6.60	
N9	I_f (A)	1,541	0	0	206	1,966	206	0	0	206	0	206	**1**
	t (s)	2.37			na	0.00	inf			150.00		15.00	
N10	I_f (A)	2,339	0	0	312	0	312	0	0	312	0	312	**1**
	t (s)	1.39			16.14		8.25			7.00		2.10	
N11	I_f (A)	2,034	0	0	271	0	271	0	0	271	0	271	**1**
	t (s)	1.65			29.12		29.70			15.00		3.50	
N12	I_f (A)	1,799	0	0	240	0	240	0	0	240	0	240	**1**
	t (s)	1.93			74.25		37.13			6.40		6.60	
N13	I_f (A)	1,613	0	0	215	0	215	0	0	215	0	215	**1**
	t (s)	2.23			inf		inf			80.00		11.00	
N14	I_f (A)	1,461	0	0	195	0	195	0	0	195	0	195	**1**
	t (s)	2.54			inf		inf			300.00		20.00	
N15	I_f (A)	1,336	0	0	178	0	178	0	0	178	0	178	**1**
	t (s)	2.88			inf		inf			inf		50.00	
N16	I_f (A)	2,009	2,563	0	268	0	268	0	0	268	0	268	**1**
	t (s)	1.68	0.00		30.94		14.85			15.00		3.50	
N17	I_f (A)	1,568	2,001		209		209	2,001	0	209	0	209	**0**
	t (s)	2.32	0.00		inf		inf	0.05		150.00		15.00	
N18	I_f (A)	2,164	0	2,761	289	0	289	0	0	289	0	289	**1**
	t (s)	1.53		0.00	21.52		10.61			10.00		2.70	
N19	I_f (A)	1,772	0	2,260	236	0	236	0	0	236	0	236	**1**
	t (s)	1.97		0.00	92.81		37.13			6.40		6.60	
N20	I_f (A)	2,212	0	0	2,531	0	376	0	0	376	0	376	**1**
	t (s)	1.49			0.00		4.64			3.20		0.68	
N21	I_f (A)	1,839	0	0	2,105	0	2,105	0	0	389	0	389	**0**
	t (s)	1.88			0.00		0.00			3.00		1.00	

N22	I_f (A)	1,386	0	0	1,586	0	1,586	0	0	291	0	291	**1**
	t (s)	2.74			1.09		0.54			10.00		2.70	
N23	I_f (A)	1,089	0	0	1,246	0	1,246	0	1,461	229	0	229	**1**
	t (s)	3.92			1.45		0.72		0.10	50.00		8.00	
N24	I_f (A)	890	0	0	1,019	0	1,019		1,194	187	0	187	**1**
	t (s)	5.51			1.86		0.95		0.15	inf		30.00	
N25	I_f (A)	1,670	0	0	1,796	0	1,796	0	0	396	0	396	**1**
	t (s)	2.13			0.94		0.47			2.50		0.94	
N26	I_f (A)	1,367	0	0	1,564	0	1,564	0	0	406	0	406	**1**
	t (s)	2.79			1.10		0.56			2.30		0.90	
N27	I_f (A)	1,210	0	0	1,384	0	1,384	0	0	1,384	0	416	**1**
	t (s)	3.33			1.28		0.63			0.11		0.84	
N28	I_f (A)	1,090	0	0	1,248	0	1,248	0	0	1,248	0	375	**1**
	t (s)	3.91			1.44		0.72			0.15		1.10	
N29	I_f (A)	1,115	0	0	1,275	0	1,275	0	0	1,275	0	424	**1**
	t (s)	3.78			1.41		0.69			0.13		0.84	
N30	I_f (A)	955	0	0	1,093	0	1,093	0	0	1,093	1,407	363	**1**
	t (s)	4.86			1.70		0.84			0.18	0.07	1.30	
N31	I_f (A)	758	0	0	867	0	867	0	0	867	1,117	288	**1**
	t (s)	7.54			2.30		1.14			0.30	0.11	2.70	
N32	I_f (A)	621	0	0	711	0	711	0	0	711	915	236	**1**
	t (s)	12.22			3.02		1.52			0.45	0.16	6.60	
N33	I_f (A)	1,010	0	0	1,156	0	1,156	0	0	1,156	0	1,156	**0**
	t (s)	4.43			1.59		0.80			0.15		0.09	
N34	I_f (A)	923	0	0	1,056	0	1,056	0	0	1,056	0	1,056	**0**
	t (s)	5.16			1.78		0.89			0.18		0.11	
N35	I_f (A)	873	0	0	999	0	999	0	0	999	0	999	**0**
	t (s)	5.71			1.91		0.95			0.22		0.13	
N36	I_f (A)	839	0	0	961	0	961	0	0	961	0	961	**0**
	t (s)	6.15			2.00		1.00			0.24		0.15	

In a similar manner, same steps were applied again to the network, without considering the DGs. Table 4.4 shows the summary of two cases, “with DGs” and “without DGs”, and percentage of coordination loss is also shown.

As discussed above, “1” in the table implies that the right protection units are operated to isolate the faulty section only and “0” represents the cases where mis-coordination takes place.

Table 4.4: Percentage of coordination loss, with DGs and without DGs

Fault Location	N2	N3	N4	N5	N6	N7	N8	N9	N10	N11	N12	N13	N14	N15	N16	N17	N18	N19
Without DGs	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
With DGs	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	1	1
Fault Location	N20	N21	N22	N23	N24	N25	N26	N27	N28	N29	N30	N31	N32	N33	N34	N35	N36	Result
Without DGs	1	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	3%
With DGs	1	0	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	17%

It shows that for 97% of the faults, protection coordination in the network is successful without DGs, and only at 3% of the faults the protection coordination is lost. But, in the case of 'with DGs', it shows that the protection coordination loss has been increased to 17%. The protection coordination loss value calculated is the maximum probable mis-coordination to be taken place in the system to represent the worst case scenario.

4.4 Analyzing the Network for Earth Fault Current

The modeled MV distribution system of Mawanella area was analyzed for earth faults to identify the earth fault current contribution from DGs. Following assumptions were made [22]:

- The system operates under balanced steady state conditions before the fault occurs. Therefore the zero-, positive-, and negative-sequence networks are uncoupled before the fault occurs. During unsymmetrical faults they are interconnected only at the fault location.
- Pre-fault load current is neglected. Because of this, the positive sequence internal voltages of all machines are equal to the pre-fault voltage, say VF. Therefore, the pre-fault voltage at each bus in the positive-sequence network equals VF.
- Transformer winding resistances and shunt admittances are neglected.
- MV lines are represented by their equivalent series reactances & resistances. Shunt admittances are neglected.
- Synchronous machine armature resistance, saliency and saturation are neglected.
- All rotating and non-rotating loads are neglected.

Single-line-to-ground faults were simulated at each node of the network N1 to N36 and results are tabulated and shown in Table 4.5 and Figure 4.5. Simulation was carried out for both cases: “with DGs” and without DGs”.

Table 4.5: Single-line-to-ground fault currents, with DGs and without DGs

Node	**Single Line to Ground Fault Current without DGs (A)**	**Single Line to Ground Fault Current with DGs (A)**	**Difference (A)**
1	1,955	1,966	**11**
2	1,588	1,607	19
3	1,335	1,360	25
4	1,150	1,181	31
5	1,010	1,045	35
6	900	939	**39**
7	810	843	33
8	736	763	27
9	674	697	23
10	811	849	38
11	738	775	37
12	677	713	36
13	626	661	35
14	581	617	36
15	543	578	35
16	776	806	30
17	681	704	23
18	805	837	32
19	727	754	27
20	805	843	38
21	728	765	37
22	653	685	32
23	589	616	27
24	535	557	22
25	663	700	37
26	609	645	36
27	563	598	35
28	531	563	32
29	533	568	35

30	488	518	30
31	440	466	26
32	399	422	23
33	498	533	35
34	467	503	36
35	451	485	34
36	439	473	34

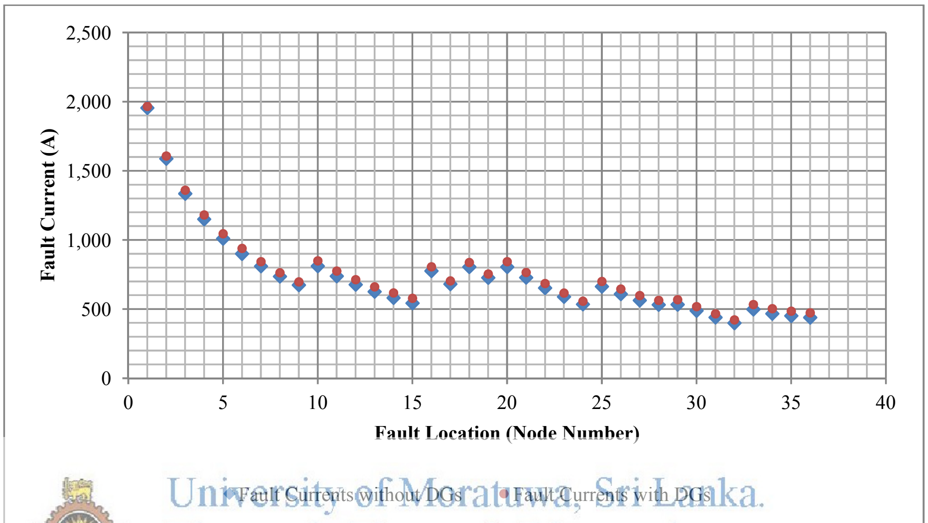


Figure 4.5: Single-line-to-ground fault currents, with DGs and without DGs

Variation of earth fault current is negligible and DGs are not playing a significant role in contributing earth fault currents.

This provides an important conclusion, that one can analyze the network for earth faults, totally dis-regarding the DGs, and by only considering the passive network. Protection settings can be calculated and set without considering the DGs as usual for any other passive network and complexity that could arise due to the presence of DGs in the network can be totally ignored.

The reason why the DGs are not contributing to the earth fault currents is due to the fact of the earthing arrangement of HV side (utility side) of generating transformers. It is normally delta which means ungrounded and isolates the zero sequence network of the DG from the utility network.

CHAPTER 5

FORMULATION OF THE TECHNIQUE & ACHIEVING OBJECTIVES

The techniques developed to achieve each objective are basically slight alterations of the basic steps followed in previous chapters.

The techniques are shown and summarized under each objective in a flow chart for clear understanding. Steps illustrated in the flow chart are already followed in previous chapters for analyzing the network.

5.1 Achievement of Objective-1:

The objective-1 of the study is, "to propose a protocol for DG integration, which facilitates identification of required rehabilitation on existing protection scheme".

Figure 5.1 shows the flow chart representation of achieving objective-1 of the study.

Start with modeling the particular MV distribution network to be studied for simulation. This shall include, bulk network to represent 132/220 kV bus of the grid substation, power transformers and earthing transformers of grid substation, overhead lines of the MV network, and DGs and their generating transformers. Network faults shall be represented by nodes defined as shown in Chapter 4 and care shall be taken to represent them with reasonable accuracy.

Create a three phase fault at node-1 and enter the current values flowing through the protection units in the table.

Calculate operating time of each using their characteristics curves. Decide events as a successful coordination or not and put "1" or "0" in the table as per the conditions for coordination check.

Then go to the next node and repeat the same until all nodes are completed.

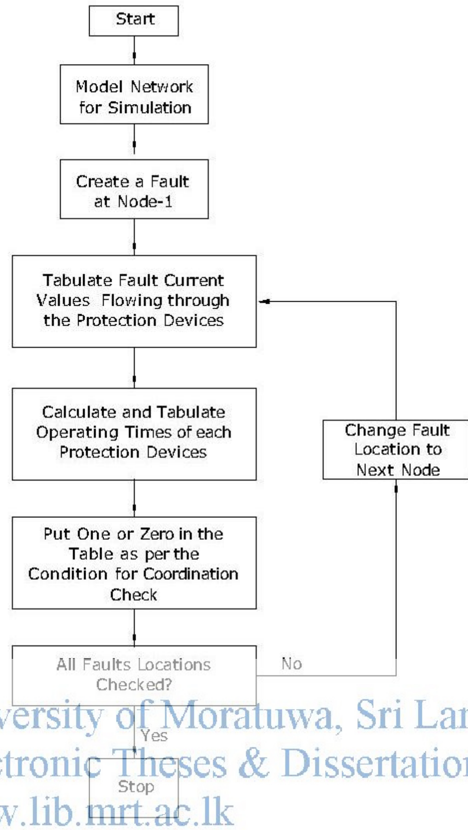


Figure 5.1: Flow chart representation for achieving objective-1

At the end the percentage of protection coordination loss (or probable percentage of mis-coordination) to be taken place in the network can be calculated.

5.2 Achievement of Objective-2:

The objective-2 of the study is, "to decide the maximum DG capacity which can be connected to a particular location without changing the existing protection scheme".

Figure 5.2 shows the flow chart representation of achieving objective-2 of the study.

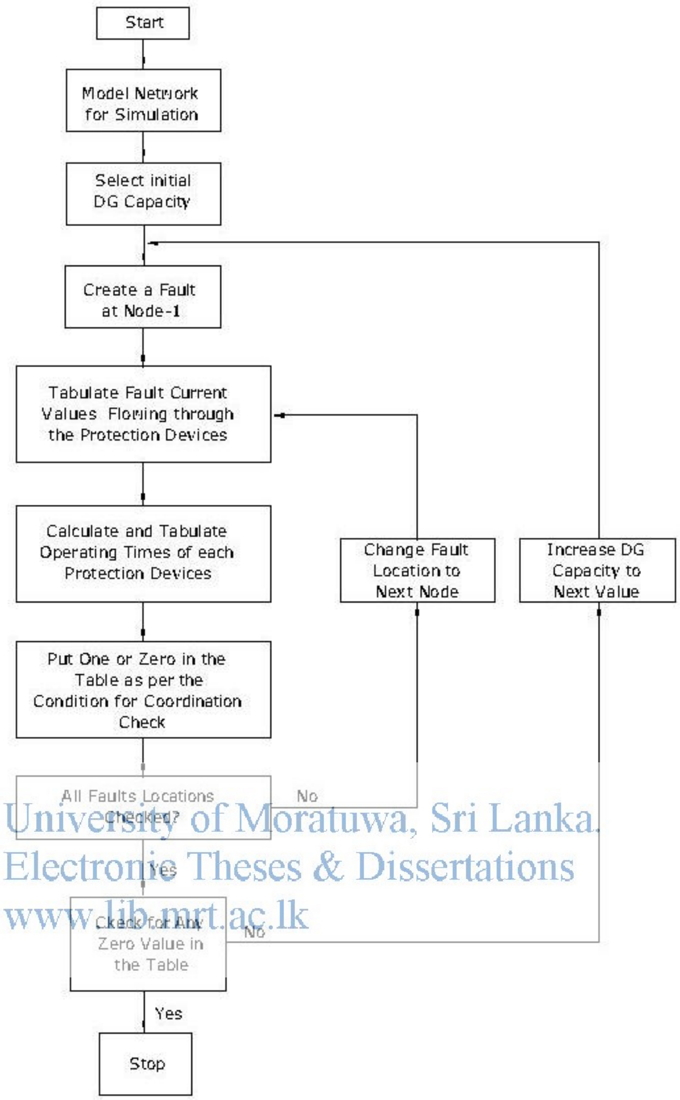


Figure 5.2: Flow chart representation for achieving objective-2

Start with modeling the network to be studied for simulation. Select the required location to decide the maximum DG capacity, which can be connected without changing the existing protection scheme. It should be checked that the existing protection scheme is fully coordinated prior to start with the technique.

Select initial DG capacity and create a fault at node-1. Enter current values in the table and calculate respective operating time of protection units. Put “1” or “0” in the table as per the condition for coordination check. Repeat the same for the other nodes and if any zero value appears in the table, stop further simulation. If not, then increase the capacity to next step and repeat the same.

In practice, 2.5 MW will be a good step to increase the capacity. Generators representing 2.5 MW (as in the case with Asupinialla MHP) can be paralleled one by one at each step to the connection point and simulated. It should be kept in mind that maximum capacity here is limited to a particular DG technology, either synchronous, induction or converter.

5.3 Achievement of Objective-3:

The objective-3 of the study is, “to assess the loss of protection coordination in the system to decide the best location to integrate a DG for a particular MV network area from protection point of view”.

To illustrate this, it is assumed that a 5 MW MHP is to be connected to the system. Protection coordination loss is calculated after plant is connected to node N1. Steps present in the flow chart shown in Figure 5.1 are followed. A screen shot for the simulation for the case where 5 MW of DG unit is connected to the node N1 is shown in Figure 5.3.

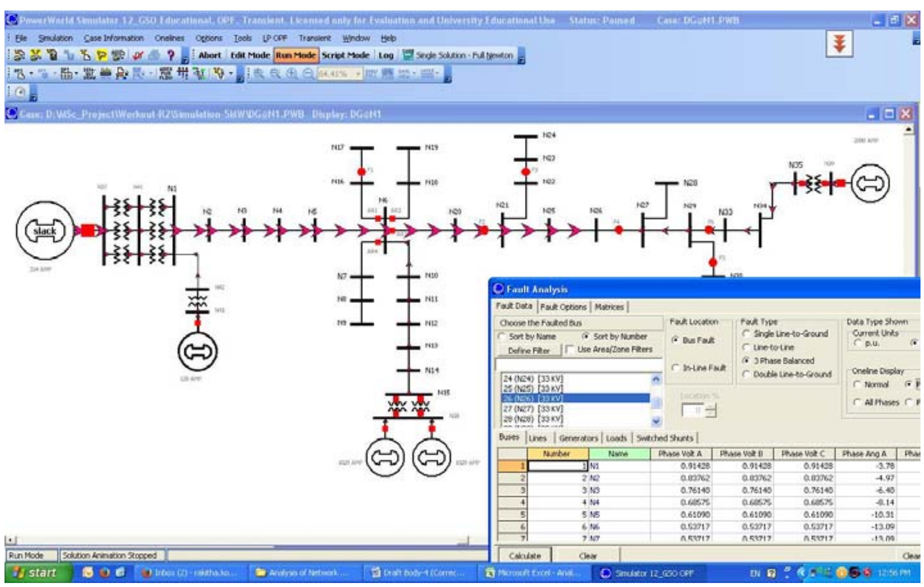
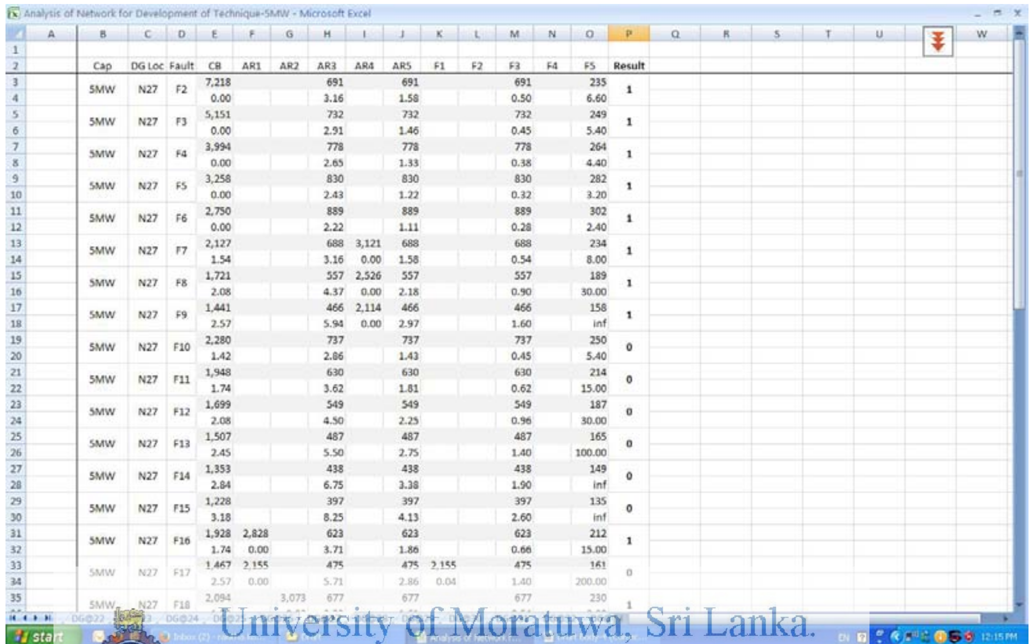


Figure 5.3: Simulation with 5 MW of DG unit connected to node N1

Same steps can be repeated for other nodes as well and protection loss can be calculated at each case. Figure 5.4 shows the results when DG is connected to the node N27.


Analysis of Network for Development of Technique-5MW - Microsoft Excel

Cap	DG Loc	Fault	CB	AR1	AR2	AR3	AR4	AR5	F1	F2	F3	F4	F5	Result
5MW	N27	F2	7,218			691		691			691		235	1
			0.00			3.16		1.58			0.50		6.60	
5MW	N27	F3	5,151			732		732			732		249	1
			0.00			2.91		1.46			0.45		5.40	
5MW	N27	F4	3,994			778		778			778		264	1
			0.00			2.65		1.33			0.38		4.40	
5MW	N27	F5	3,258			830		830			830		282	1
			0.00			2.43		1.22			0.32		3.20	
5MW	N27	F6	2,750			889		889			889		302	1
			0.00			2.22		1.11			0.28		2.40	
5MW	N27	F7	2,127			688	3,121	688			688		234	1
			1.54			3.16	0.00	1.58			0.54		8.00	
5MW	N27	F8	1,721			557	2,526	557			557		189	1
			2.08			4.37	0.00	2.18			0.90		30.00	
5MW	N27	F9	1,441			466	2,114	466			466		158	1
			2.57			5.94	0.00	2.97			1.60		inf	
5MW	N27	F10	2,280			737		737			737		250	0
			1.42			2.86		1.43			0.45		5.40	
5MW	N27	F11	1,948			630		630			630		214	0
			1.74			3.62		1.81			0.62		15.00	
5MW	N27	F12	1,699			549		549			549		187	0
			2.08			4.50		2.25			0.96		30.00	
5MW	N27	F13	1,507			487		487			487		165	0
			2.45			5.50		2.75			1.40		100.00	
5MW	N27	F14	1,353			438		438			438		149	0
			2.84			6.75		3.38			1.90		inf	
5MW	N27	F15	1,228			397		397			397		135	0
			3.18			8.25		4.13			2.60		inf	
5MW	N27	F16	1,928	2,828		623		623			623		212	1
			1.74	0.00		3.71		1.86			0.66		15.00	
5MW	N27	F17	1,467	2,155		475		475	2,155		475		161	0
			2.57	0.00		5.71		2.86	0.04		1.40		200.00	
5MW	N27	F18	2,094		3,073	677		677			677		230	1

Figure 5.4: Calculation of coordination loss with DG connected to N27

Table 5.1: Protection coordination loss at each node, N1 to N35

Fault Location		N2	N3	N4	N5	N6	N7	N8	N9	N10	N11	N12	N13	N14	N15	N16	N17	N18	N19	N20	N21	N22	N23	N24	N25	N26	N27	N28	N29	N30	N31	N32	N33	N34	N35	Result
5MW	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	1	1	1	0	1	1	1	0	1	1	1	1	1	1	1	0	0	0	18%
5MW	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	1	1	1	0	1	1	1	0	1	1	1	1	1	1	1	0	0	0	18%
5MW	3	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	1	1	1	0	1	1	1	0	1	1	1	1	1	1	1	0	0	0	18%
5MW	4	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	1	1	1	0	1	1	1	0	1	1	1	1	0	1	1	0	0	0	21%
5MW	5	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	1	1	1	0	1	1	1	0	1	1	1	1	0	1	1	0	0	0	21%
5MW	6	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	1	1	1	0	0	1	1	0	0	1	1	1	0	1	1	0	0	0	26%
5MW	7	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	1	1	1	0	0	1	1	0	0	1	1	1	0	1	1	0	0	0	26%
5MW	8	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	1	1	1	0	0	1	1	0	0	1	1	1	0	1	1	0	0	0	26%
5MW	9	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	1	1	1	0	0	1	1	0	0	1	1	1	0	1	1	0	0	0	26%
5MW	10	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	1	1	1	0	0	0	1	0	1	1	1	1	0	1	1	0	0	0	26%
5MW	11	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	1	1	1	0	0	1	1	0	1	1	1	1	0	1	1	0	0	0	24%
5MW	12	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	1	1	1	0	1	1	1	0	1	1	1	1	0	1	1	0	0	0	21%
5MW	13	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	1	1	1	0	1	1	1	0	1	1	1	1	0	1	1	0	0	0	21%
5MW	14	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	1	1	1	0	1	1	1	0	1	1	1	1	0	1	1	0	0	0	21%
5MW	15	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	1	1	1	0	1	1	1	0	1	1	1	1	0	1	1	0	0	0	21%
5MW	16	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	1	1	1	0	0	1	1	0	0	1	1	1	0	1	1	0	0	0	26%
5MW	17	1	1	1	1	1	1	1	1	0	0	0	0	1	1	1	0	1	1	1	0	0	1	1	0	0	1	1	1	0	1	1	0	0	0	38%
5MW	18	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	1	1	1	0	0	1	1	0	0	1	1	1	0	1	1	0	0	0	26%
5MW	19	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	1	1	1	0	0	1	1	0	0	1	1	1	0	1	1	0	0	0	26%
5MW	20	1	1	1	1	1	1	1	1	1	0	1	1	1	1	1	0	1	1	1	0	1	1	1	1	1	1	1	1	0	1	1	0	0	0	21%
5MW	21	1	1	1	1	1	1	1	1	0	0	0	1	1	1	1	0	1	1	1	0	1	1	1	1	1	1	1	1	0	1	1	0	0	0	26%
5MW	22	1	1	1	1	1	1	1	1	0	0	0	1	1	1	1	0	1	1	1	0	1	1	1	1	1	1	1	1	0	1	1	0	0	0	26%
5MW	23	1	1	1	1	1	1	1	1	0	0	0	0	0	1	1	0	1	1	1	0	1	1	1	1	1	1	1	1	0	1	1	0	0	0	32%
5MW	24	1	1	1	1	1	1	1	1	0	0	0	0	1	1	1	0	1	1	1	0	1	1	1	1	1	1	1	1	0	1	1	0	0	0	29%
5MW	25	1	1	1	1	1	1	1	1	0	0	0	1	1	1	1	0	1	1	1	0	1	1	1	0	1	1	1	1	0	0	1	0	0	0	32%
5MW	26	1	1	1	1	1	1	1	1	0	0	1	1	1	1	1	0	1	1	1	0	1	1	1	0	1	1	1	1	0	0	1	0	0	0	29%
5MW	27	1	1	1	1	1	1	1	1	0	0	0	0	0	0	1	0	1	1	1	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	24%
5MW	28	1	1	1	1	1	1	1	1	0	0	0	0	0	0	1	0	1	1	1	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	24%
5MW	29	1	1	1	1	1	1	1	1	0	0	0	0	0	0	1	0	1	1	1	0	1	0	1	1	1	1	1	1	1	1	1	1	1	1	26%
5MW	30	1	1	1	1	1	1	1	1	0	0	0	0	0	1	1	0	1	1	1	0	1	1	1	0	0	1	1	1	1	1	1	1	1	1	26%
5MW	31	1	1	1	1	1	1	1	1	0	0	0	0	0	1	1	0	1	1	1	0	1	1	1	0	0	1	1	1	1	1	1	1	1	1	26%
5MW	32	1	1	1	1	1	1	1	1	0	0	0	0	0	1	1	0	1	1	1	0	1	1	1	0	0	1	1	1	1	1	1	1	1	1	26%
5MW	33	1	1	1	1	1	1	1	1	0	0	0	0	0	0	1	0	1	1	1	0	0	1	1	0	0	1	1	1	1	1	1	0	0	0	41%
5MW	34	1	1	1	1	1	1	1	1	0	0	0	0	0	0	1	0	1	1	1	0	0	1	1	0	0	1	1	1	1	1	1	0	0	0	41%
5MW	35	1	1	1	1	1	1	1	1	0	0	0	0	0	0	1	0	1	1	1	0	0	1	1	0	0	1	1	1	1	1	1	0	0	0	41%

The summary of protection coordination loss at each node is shown in Table 5.1 and same is shown in a graphically in Figure 5.5. As discussed earlier, “1s” represent successful coordination and “0s” represent the cases of failures.

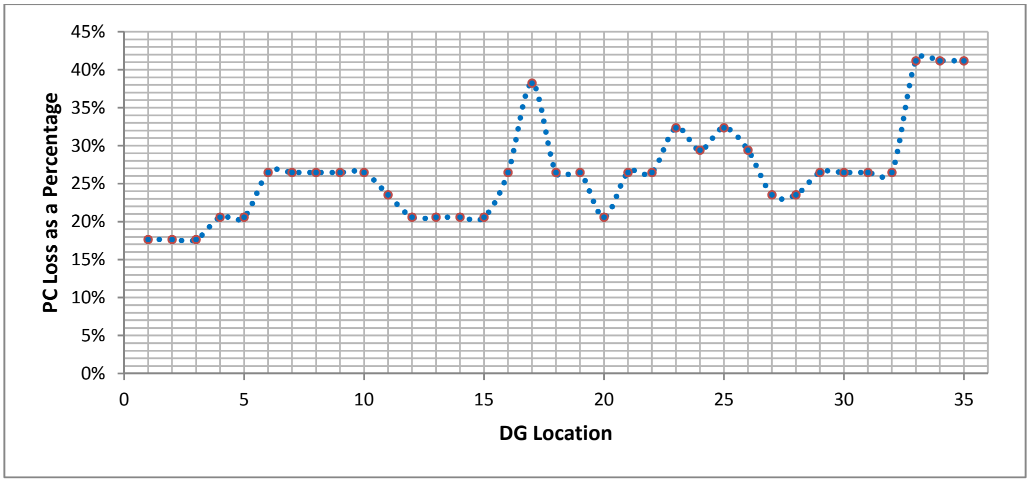


Figure 5.5: Protection coordination loss at each node, N1 to N35

It can be noted that when the DG is close to the grid substation (N1-N5), violation of coordination is minimum. That may be due to the fact that fault contribution pattern of DG is similar to the grid substation’s contribution and it doesn’t violate the initial power flow much. The amount of violation is also depended on the DG capacity as well. It can be noted that for some locations (N17 and N33-N35), coordination loss has reached almost 40%. Total DG capacity is 11.4 MW at this stage.

Figure 5.6 shows the flow chart representation of achieving objective-3 of the study.

Start with modeling the network to be studied for simulation. Select the DG capacity and connect the DG to the first node. Create a fault at node N1, find and enter the fault currents flowing through the protection units in the table and put “1” or “0” based on the conditions for coordination check. Repeat the procedure for faults at all other nodes. Then, connect the DG to the next node and repeat the same up to the final node.

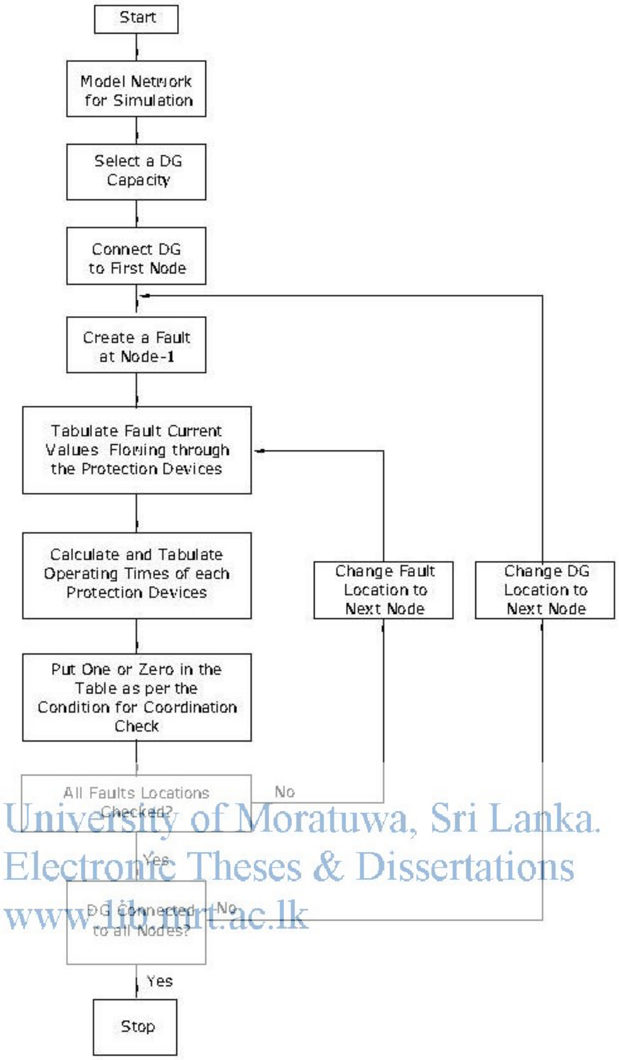


Figure 5.6: Flow chart representation for achieving objective-3

CHAPTER 6

CONCLUSION

Problems with protection coordination in CEB MV distribution system may increase with further integration of DGs to the system. Protection is another aspect that needs to be considered in integrating DGs.

It is depended on several factors, including DG type, capacity and location, and calculation of coordination loss quantitatively is very much system dependent. Due to the diversity of possible scenarios, a detailed study for a given system shall be carried out using the presented technique and guidelines proposed here. This can be used to clear uncertainties and increase protection based penetration limits as well.

With the present situation, a protection coordination loss may occur for phase over current faults in DG integrated MV networks in CEB, but not for earth faults. In general power system anatomy, the percentage of ground faults are in the range of 70-80% in overhead networks. Therefore, even if we totally forget over current protection in the system, it won't get much highlighted due to the reason that it is in the range of 20-30% of total faults. At low integrated capacities of DGs, this reflection would be further reduced. This may be the reason for not giving a specific attention in this area. But in real case, with high DG penetration levels, there can be a coordination loss in DG integrated networks and a specific attention is required in this area. Therefore, having low level of integrated DGs, current practice of CEB, of not giving a specific attention on protection coordination with DGs is somewhat logical, but not the best practice.

One can analyze a MV distribution network for earth faults, totally forgetting the integrated DGs, provided that the HV sides of generating transformers of the DGs are ungrounded. But for phase faults, it is not the case and DGs need to be taken as an important element. At any case, if the HV sides of generating transformers of the DGs are grounded, patterns of earth fault currents in the network would heavily get uneven and bigger. Therefore, there would be a major impact to the protection system of the network for earth faults in such a case.

The technique can be used to review MV networks of CEB where DGs are already in operation, to verify current protection coordination status. Due to the diversity of possible scenarios, a decision on revision or rehabilitation of protection schemes can be done based on the results of the analysis. The outcome would be:

- No revision is required
- There is a possible mis-coordination but, it is insignificant
- Mis-coordination is significant and attention is required to rectify the issue

The tool can be used to solve specific protection issues, which may arise in DG integrated networks in some specific cases as well.

Also, this type of analysis is very much useful for the cases where protection schemes have limitations such as, limits in coordination with upstream grid substation scheme. Since, transmission and distribution divisions of CEB are separate entities at the moment; dealing with such cases has limitations.

The technique can be used to show others, especially for top engineering managers, the amount of protection coordination loss quantitatively in a particular network area at a point of decisive network protection scheme rehabilitation. Output of this analysis is a valid justification in such an occasion.

The proposed method can be used to check and analyze protection coordination for phase over current at the planning stage at times of studying of technical feasibility of new DG proposals. It may not be required to do protection coordination reviews at each occasion and sometimes, it may not be practical too. Same as the current practices (overvoltage check and short circuit capacity check), proposed technique for coordination check can be incorporated into DG planning as a new dimension and can be used to identify possible coordination loss in the system at the proposal stage itself. If, a considerable coordination loss is expected as the result of the check, decision can be taken for a requirement for protection review or in the worst case, for possible protection system rehabilitation. Such costs can be even added to the interconnection cost as well.

Finally, it is also proposed to derive a standard benchmark MV system for the CEB in future to facilitate these types of studies to be carried out, which would be very much effective and helpful for the researchers. With future trends in dispersed generation resources, engineering involving in distribution system planning would become a real challenge and such a specific custom benchmark system to the CEB would make researchers more easy to carry out various types of analysis and simulations further.

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APPENDIX-A

PROTECTION DATA AND CHARACTERISTIC CURVES

Table A.1: Summary of protection data

Protection Unit	Description of the Characteristic
GSS CB Relay	Standard: IEC VI I_p = 400 A , TMS = 0.5 , I_{inst} = 2,400 A
AR1	Standard: IEC VI I_p = 220 A , TMS = 0.5 , I_{inst} = 1,800 A
AR2	Standard: IEC VI I_p = 220 A , TMS = 0.5 , I_{inst} = 1,800 A
AR3	Standard: IEC VI I_p = 220 A , TMS = 0.5 , I_{inst} = 1,800 A
AR4	Standard: IEC VI I_p = 220 A , TMS = 0.5 , I_{inst} = 1,800 A
AR5	Standard: IEC VI I_p = 220 A , TMS = 0.25 , I_{inst} = 1,800 A
F1	Rating: 100A , Type: K (Fast) , Minimum Melting Time-Current Characteristic
F2	Rating: 100A , Type: K (Fast) , Minimum Melting Time-Current Characteristic
F3	Rating: 100A , Type: K (Fast) , Minimum Melting Time-Current Characteristic
F4	Rating: 80A , Type: K (Fast) , Minimum Melting Time-Current Characteristic
F5	Rating: 80A , Type: K (Fast) , Minimum Melting Time-Current Characteristic

Acc. to IEC 60255-3 or BS 142, Section 3.5.2 (see also Figure 4-1 and 4-2)

NORMAL INVERSE (Type A)
$$t = \frac{0.14}{(I/I_p)^{0.02} - 1} \cdot T_p \ [s]$$

VERY INVERESE (Type B)
$$t = \frac{13.5}{(I/I_p)^{1} - 1} \cdot T_p \ [s]$$

EXTREMELY INV. (Type C)
$$t = \frac{80}{(I/I_p)^{2} - 1} \cdot T_p \ [s]$$

LONG INVERSE (Type B)
$$t = \frac{120}{(I/I_p)^{1} - 1} \cdot T_p \ [s]$$

For All Characteristics

- t trip time in seconds
- T_p setting value of the time multiplier
- I fault current
- I_p setting value of the pickup current

The tripping times for $I/I_p \geq 20$ are identical with those for $I/I_p = 20$.

For zero-sequence current read 3I0p instead of I_p and T_{3I0p} instead of T_p;
for ground fault read I_{Ep} instead of I_p and T_{IEp} instead of T_p

Pickup Threshold	approx. $1.10 \cdot I_p$

Figure A.1: TCC curves according to IEC

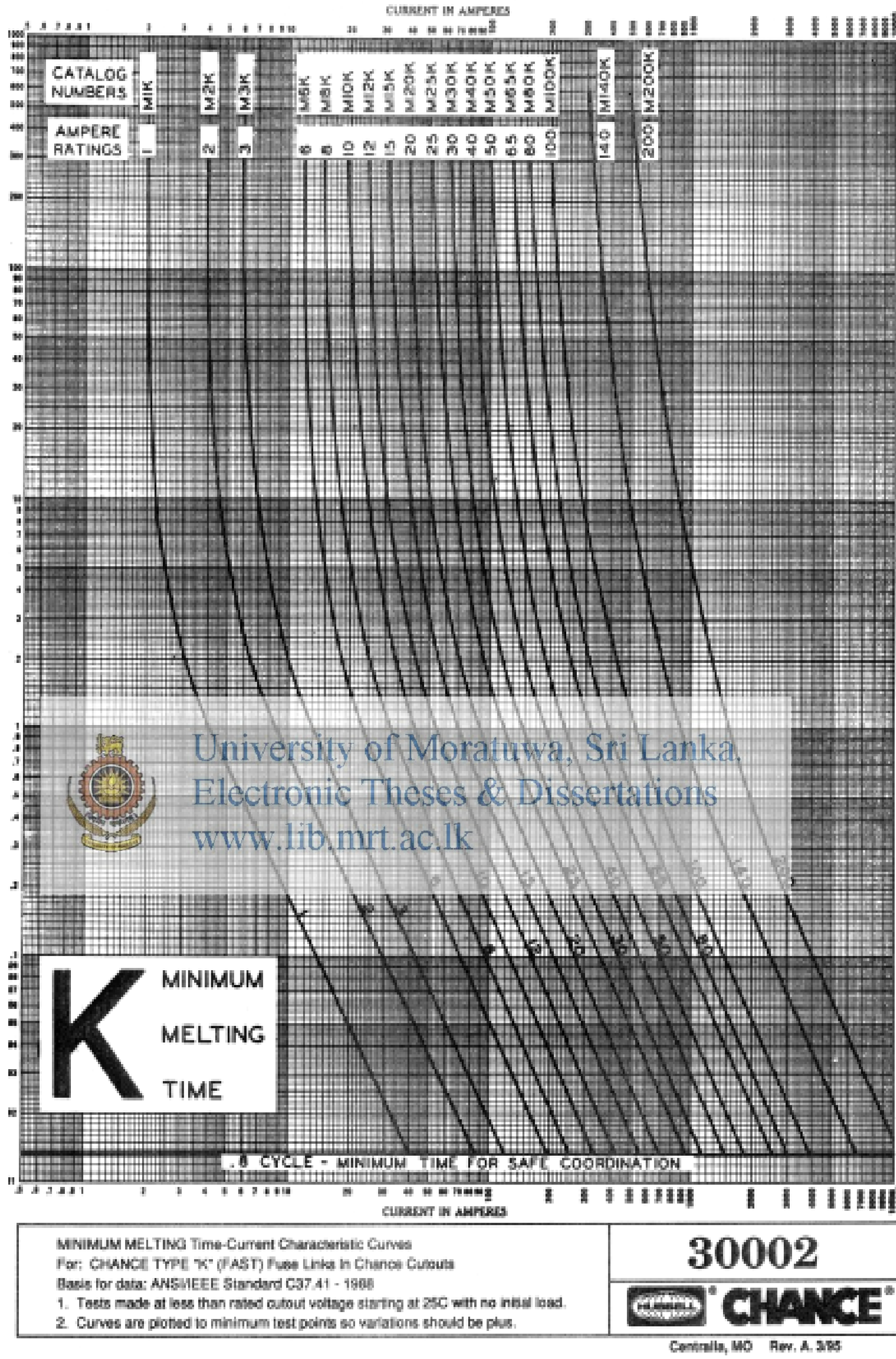

Figure A.2: Minimum Melting Time-Current Characteristics Curves, CHANCE TYPE "K" (FAST) Fuse Link, Data Sheet available at: http://www.hubbellpowersystems.com/switching/dist/fuselinks/fuse-curves/)