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Protection of Distribution Networks with Distributed Generation

by

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ABSTRACT

FACULTY OF ENGINEERING, SCIENCE AND MATHEMATICS

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Doctor of Philosophy

PROTECTION OF DISTRIBUTION NETWORKS WITH DISTRIBUTED GENERATION

by Babar Hussain

The share of electric power from small scale Distributed Generation (DG) connected to low voltage distribution networks (DNs) is increasing in the electricity market day by day as this technology is not only becoming cheaper relative to other resources but is also environmentally friendly. However, along with these benefits, DG can also have an adverse impact on operation of the power systems. For example, voltage regulation, power system stability and protection coordination can be affected due to connection of DG to DNs. The purpose of this dissertation is to investigate the potential impact of DG on the protection setup of DNs and to suggest solutions to solve these problems for safe integration of DG.

The thesis analyzes the potential impacts of DG on DN protection with the help of a case study of DG installation in a typical DN. The issues discussed include increase in the fault current level, blinding of protection, sympathetic tripping, reduction in reach of a distance relay, lack of detection of single-phase to ground (1LG) fault with ungrounded utility side interconnection transformer configuration and failure of a fuse saving scheme. In respect of the case study, practical and effective solutions that rely on conventional protection devices and practices, for example, instantaneous overcurrent relay, zero sequence voltage detection and transfer trip scheme are proposed.

A novel protection strategy that combines the characteristics of both the time and instantaneous overcurrent elements along with a simple algorithm for adaptively changing the setting of the latter is proposed to ensure proper recloser-fuse coordination even in the presence of DG.

Conventional protection schemes face serious challenges when they are considered for protecting an islanded microgrid having an inverter interfaced DG unit and need major revision in order to detect and isolate the faulty portion, as fault currents are very limited in such systems. Protection coordination issues including lack of sensitivity and selectivity in isolation of a fault can occur in a microgrid, especially in an islanded mode of operation. The thesis presents and critically reviews traditional and state of the art protection strategies in respect of a microgrid protection.

Total harmonic distortion (THD) based islanding detection schemes that measure the output current THD of the inverter interfaced DG (IIDG) are discussed and the role of various factors like uncertainties in filter parameters, variations in the utility THD and the utility impedance on the performance of these schemes is investigated. The simulation results show that the THD in the inverter output current may be affected (depending upon the design of the controller) by the variations in the utility THD and the utility impedance. Consequently, the working of THD based schemes may suffer if these factors are not taken into consideration while selecting the trip threshold. A large L_2 (the inductor of the LCL filter facing the grid) can make the output current THD of the inverter less sensitive to variations in the utility impedance and, thus, makes the selection of the trip threshold easier. Moreover, through simulations it is shown that electromagnetic compatibility (EMC) capacitors can also affect the islanding detection schemes used for IIDG as they can introduce a large increase in the output current THD of the inverter.

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DECLARATION OF AUTHORSHIP

I, Babar Hussain,

declare that the thesis entitled

"Protection of Distribution Networks with Distributed Generation"

and the work presented in the thesis are both my own, and have been generated by me as the result of my own original research. I confirm that:

- this work was done wholly or mainly while in candidature for a research degree at this University;
- where any part of this thesis has previously been submitted for a degree or any other qualification at this University or any other institution, this has been clearly stated;
- where I have consulted the published work of others, this is always clearly attributed;
- where I have quoted from the work of others, the source is always given. With the exception of such quotations, this thesis is entirely my own work;
- I have acknowledged all main sources of help;
- where the thesis is based on work done by myself jointly with others, I have made clear exactly what was done by others and what I have contributed myself;
- parts of this work have been published as:

1-"Integration of distributed generation into the grid: protection challenges and solutions" *The 10th IET International Conference on Developments in Power System Protection (DPSP 2010),* Manchester, 29 March – 1 April 2010.

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Signed:
Date:

بسم الله الرحمن الرحيم

"In the name of Allah, most Gracious, most Compassionate"

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All praise is due to Allah, the Lord of all worlds. And may peace and blessings be upon the most honourable of the Messengers (Muhammad صلى الله عليه وسلم) and upon his family and companions, and all those who followed them in righteousness, until the day of Judgement.

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LIST OF ABBREVIATIONS

CB	Circuit Breaker
C&P	Control and Protection
CT	Current transformer
CTI	Coordination Time Interval
DG	Distributed Generation
DN	Distribution Network
DRs	Distributed Resources
DSP	Digital Signal Processor
EMI	Electromagnetic Interference
FCL	Fault Current Limiter
GPS	Global Positioning System
IEEE	Institute of Electrical and Electronic Engineers
IGBT	Insulated Gate Bipolar Transistor
IIDG	Inverter Interfaced Distributed Generation
k	Outer Feedback Loop Proportional Gain
k_c	Minor Feedback Loop Proportional Gain
LL	Phase to Phase
LLG	Phase-to-Phase-to-Ground
LLL	Three-Phase
LOG	Loss of Grid
LOM	Loss of Mains
1LG	Single Phase to Ground Fault
3LG	Three Phase to Ground Fault
MCC	Maximum Coordination Current
MM	Minimum Melt
OC	Overcurrent
PCC	Point of Common Coupling
PE	Power Electronics
PMUs	Phasor Measurement Units
PWM	Pulse Width Modulation

LIST OF ABBREVIATIONS

RFC	Recloser- Fuse coordination
RP	Reference Point
SCs	Short Circuits
TCC	Time Current Characteristics
THD	Total Harmonic Distortion
VSI	Voltage Source Inverter
ZSV	Zero Sequence Voltage

CHAPTER 1

INTRODUCTION

1.1 GENERAL BACKGROUND

Distributed Generation (DG) involves electricity generation from generators which rely on non-conventional and renewable energy sources like wind, solar, tidal, or small-scale hydro and are either connected to the low voltage distribution network (DN) or to the loads directly. The structure which evolves as a result of the direct connection of the DG to loads is often named as a microgrid. DG is becoming more and more important as it relies mostly on renewable sources of energy i.e. wind, solar, tidal, etc as compared to the traditional generation which is heavily dependent on fossil fuels. Factors like scarcity of fossil fuels, ever increasing prices of oil and gas, environmental implications of thermal generation and hydro dams, are pushing the world towards DG which relies mainly on renewable energy sources. Availability of high tech generators have made the generation of electricity using renewable sources quite competitive. Moreover, due to the availability of different interfacing units in the market, it is now possible to connect DG to the main grid safely and effectively. Among other favorable factors for the use of DG are, reduction in transmission and distribution costs as DG is located close to load centers, availability of highly efficient plants having capacity from 10KW to 15MW, quick installation and less space requirement for installation, the liberalization of the electricity market that is attracting new players in the power generation sector, flexibility to choose from different combinations of cost and reliability, reduction in investments for grid upgrade, etc. All these factors are encouraging energy experts to make more rigorous efforts to investigate and explore DG as a viable option to meet the future energy needs of the world.

DG offers many technical, economical and environmental benefits both when connected to the main grid as well as when supplying independent loads in the form of a microgrid. The benefits offered by DG in grid connected mode among others include provision of emergency backup in case of utility outages, increased reliability, reduction in voltage sags, energy savings through peak shaving and relieving the utility from the burden of investing in generation for future needs. While operating in the form of a microgrid, DG can help on several fronts e.g. control of reactive and active power, mitigation of voltage sag, and correction of the system imbalance. A typical DG connection to a DN is shown in the Fig. 1.1. When circuit breaker B1 is closed, DG is operating in grid connected mode of operation whereas when circuit breaker B1 is open, DG is operating in islanded mode of operation. An island is formed when a portion of a grid is energized solely by DG while that portion of the grid is electrically separated from the rest of the power system. An intentional islanded mode of operation of DG may be referred to as microgrid operation.

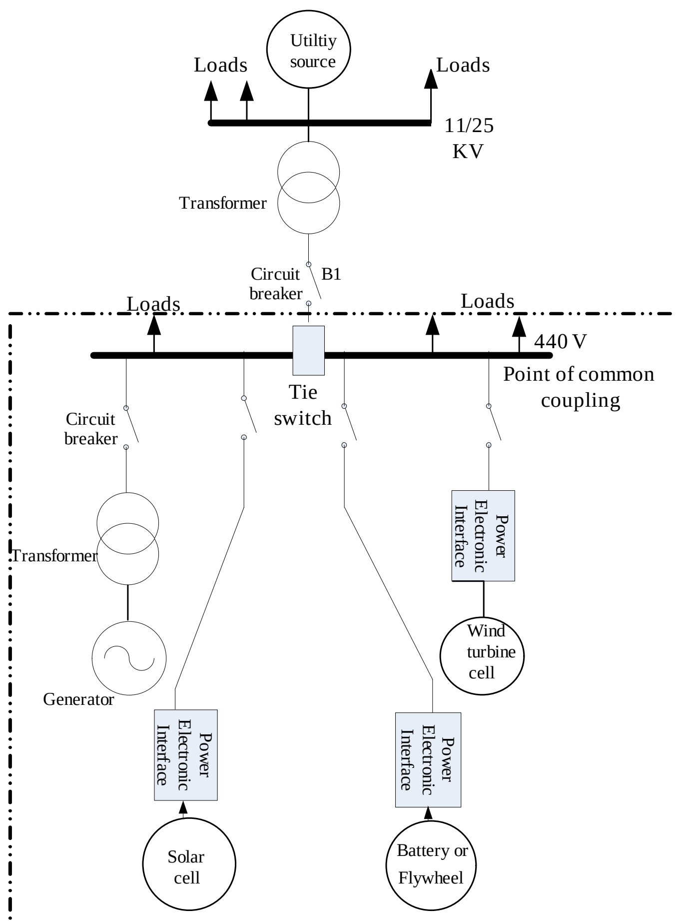

Figure 1.1: A typical DG connection to a DN

1.2 MOTIVATION

The share of electric power from DG is increasing in the electricity market day by day as this technology is not only becoming cheaper relative to the other resources but is also environmentally friendly. But uncertainty still exists about the potential impact of DG if connected to an existing DN and about potential solutions to problems that may arise as a result of that connection. Along with these benefits, DG can also have an adverse impact on operation of the power systems e.g. voltage regulation, power system stability and existing protection coordination can suffer due to the connection of DG. For an effective integration of DG into DNs, extensive research aimed at understanding all aspects of DG connection/operation is needed.

Due to the crucial role of a protection system in the safe operation of a power system, an investigation of the impact of DG on existing protection schemes is very important. Effective DG integration calls for a review of traditional power system protection concepts and strategies. New protection solutions are required to cope with the new challenges caused by active DNs i.e. DNs that are capable of bidirectional power flow. In the aforementioned perspective, the present research work was undertaken.

1.3 AIMS AND OBJECTIVES OF THE RESEARCH

The main purpose of this dissertation is to investigate the potential impacts of DG on the protection setup of a typical DN and to suggest effective and practical solutions employing traditional protection practices for the safe integration of DG into DNs. The objectives of the thesis can be summarized as below:

- To identify important protection issues and the scenarios in which these issues can arise when DG is connected to existing DNs.
- To identify the limitations of traditional protection practices in coping with the new protection challenges.
- To suggest effective and practical solutions employing traditional protection techniques and methods to solve these problems.

- To critically review protection challenges and their solutions specific to microgrid operation.
- To investigate the performance of the total harmonic distortion (THD) based islanding detection schemes with respect to the inverter interfaced DG (IIDG).

1.4 CONTRIBUTIONS OF THE THESIS

The contributions of the thesis can be summarized as below:

- Practical solutions involving existing protection practices and protective equipment are proposed to solve the protection coordination problems resulting from DG installation in a typical DN.
- A new protection strategy is proposed that combines the characteristics of both the time and instantaneous overcurrent (OC) elements along with a simple algorithm for adaptively changing the setting of the latter to ensure proper recloser-fuse coordination even in the presence of DG.
- The limitation of the THD based islanding detection schemes in respect of the IIDG is identified.
- The impact of electromagnetic compatibility (EMC) capacitors on the performance of a voltage source grid connected inverter is identified.

1.5 OUTLINE OF THE THESIS

The thesis is organized as follows:

Chapter 2 investigates the potential protection challenges, based on a simulation case study of a DG installation in a typical DN, which provides practical insight into DG integration issues and their solutions. The discussion reflects on long established rules for the design and coordination of protective relays in a power system i.e. selectivity, redundancy, grading, security, and dependability. In light of the simulation results, effective and practical solutions employing traditional protection practices are proposed to address the identified protection issues.

Chapter 3 explores the potential impacts of DG on recloser-fuse coordination (RFC) through simulations of different fault scenarios with different DG configurations. An alternative protection strategy is proposed that benefits from the characteristics of both time and instantaneous OC elements for maintaining RFC in a practical DN. Moreover, a simple algorithm is described to adaptively change the setting of the instantaneous OC element to ensure proper recloser-fuse coordination (i.e. fuse saving) under the worst fault conditions.

Chapter 4 discusses the challenges which conventional protection schemes may face when they are considered for protecting an islanded microgrid with an IIDG. Protection coordination issues such as lack of sensitivity and selectivity in isolation of a fault can occur in a microgrid especially in an islanded mode of operation due to the availability of a limited short circuit current. The chapter presents and critically reviews traditional and state of the art protection strategies in respect of microgrid protection.

In chapter 5, THD based islanding detection schemes i.e. schemes that measure the output current THD, for the IIDG are discussed and the role of various factors like uncertainties in filter parameters, variations in the grid (utility) THD and the grid impedance on the performance of these schemes is investigated. The simulation results show that the THD in the inverter output current may be affected (depending upon the design of the controller) by the variations in the utility THD and the utility impedance and, consequently, the working of THD based schemes may suffer if these factors are not taken into consideration while selecting the trip threshold. A large L_2 (the inductor of the LCL filter facing the grid) can make the output current THD of the inverter less sensitive to variations in the utility impedance.

Moreover, interactions between electromagnetic compatibility (EMC) capacitors and grid impedance are also discussed and their impact on performance (behaviour of the output current) of a voltage source grid connected inverter is also investigated through simulations. These simulations show that EMC capacitors can also affect the islanding detection schemes used for IIDG as they can introduce a large increase in the output current THD of the inverter. The identification of the impact of EMC capacitors on the performance of an inverter is a novel contribution of this thesis.

Finally, chapter 6 describes the conclusions and future work.

In the reference section, an extensive list of the relevant literature is included in chronological order to guide the reader to the relevant material.

CHAPTER 2

DISTRIBUTED GENERATION: PROTECTION ASPECTS OF THE GRID CONNECTED MODE OF OPERATION

2.1 INTRODUCTION

The integration of Distributed Generation (DG) into distribution networks (DNs) calls for a review of traditional power system protection concepts and strategies. New protection solutions are required to cope with the new challenges caused by the activeness of DNs (i.e. being capable of bidirectional power flow). Uncertainty still exists about potential DG impacts if connected to an existing DN and about potential solutions to problems that may arise as a result of that connection. Coordination problems between different protective devices e.g. between a circuit breaker, an autorecloser and a fuse, can occur due to changes in the magnitude and direction of the fault current [1]. The level of penetration of DG and the type of interfacing scheme i.e. whether the DG system is based on direct coupling of rotating machines like synchronous or induction generators or it is interfaced through a power electronic converter with electronic current limiting, have a fundamental impact on the protection scheme as these determine the level of short circuit current in the system. The key protection issues caused by DG connection to a DN are: modifications in fault current level, failure of traditional device discrimination strategies, reduction in reach of overcurrent (OC) and impedance relays (i.e. blinding of protection), bi-directionality of fault current resulting in sympathetic tripping, unintentional islanding of DG, miscoordination between a breaker, an autorecloser and a fuse causing failure of a fuse saving scheme, and mal-operation of an autorecloser.

These protection issues have been discussed in literature since the 1980s and an exhaustive list of relevant literature [1-116] is included in References in chronological order. Most of the literature only identifies issues without proposing any solutions. However, some papers e.g. [52, 60, 92], have also discussed potential solutions. In order to have a better insight into the issues and their solutions based on traditional protection practices, further investigation is needed. Moreover, as the protection issues caused by connection of DG may differ from network to network (depending upon size, type and location of DG, and network topology), so do the solutions i.e. the solutions are unique for different DNs.

This chapter investigates the potential protection challenges based on a simulation case study of a DG installation in a typical DN, providing practical insight into DG integration issues and their solutions. The discussion reflects on long established rules for the design and coordination of protective relays in a power system i.e. selectivity, redundancy, grading, security, and dependability [113]. In light of the simulation results, effective and practical solutions employing traditional protection practices are proposed to address the identified protection issues. Section 2.2 describes rules for the design and coordination of protective relays in a power system. Section 2.3 presents a brief overview of conventional protection principles and practices for DNs. Section 2.4 introduces the case study. In section 2.5, important protection issues including;

- fault current level increase,
- blinding of protection,
- sympathetic tripping,
- reduction in reach of a distance relay,
- lack of detection of single-phase to ground (1LG) with ungrounded utility side interconnection transformer configurations,
- failure of a fuse saving scheme

and scenarios in which they can arise in the presence of DG, are analyzed with the help of the case study. Section 2.6 explores different possible solutions to address these issues. Finally, section 2.7 summarizes the chapter.

2.2 RULES FOR THE DESIGN AND COORDINATION OF PROTECTIVE RELAYS IN A POWER SYSTEM

The rules that a good protection system should embody are [113]:

2.2.1 Selectivity

Selectivity means that a protection system, in case of fault, should isolate only the faulty part or the smallest possible part containing the fault.

2.2.2 Redundancy

In order to improve reliability, a protection system needs to take into account redundant function of relays. In a system, redundant functionalities are properly planned as a backup protection. Redundancy is achieved by combining different protection principles together, for example combining distance and differential protection in the case of transmission lines.

2.2.3 Grading

Grading of relay characteristics ensures clear selectivity and redundancy. This measure helps in achieving high redundancy without disabling the selectivity.

2.2.4 Security

This is the ability of a protection system to ensure that all power system events and transients that are not faults are rejected so that healthy parts of the system are not disconnected unnecessarily.

2.2.5 Dependability

This is the ability of a protection system to detect and disconnect all faults within the protected zone.

2.3 A TYPICAL PROTECTION SETUP FOR A RADIAL DISTRIBUTION FEEDER

The basic objective of protection coordination in power systems is to achieve selectivity i.e. to switch off only the faulted component and to leave the rest of the power system in service in order to minimize discontinuity of supply and to ensure stability. Proper coordination ensures that there is neither a maloperation of protective devices nor a duplication of their operation. A typical protection set up for a radial distribution feeder is shown in Fig. 2.1. Traditional distribution systems have a simple protection scheme as they carry unidirectional current [11]. A circuit breaker (CB) or recloser equipped with instantaneous and time OC protection elements is located at the beginning of the radial feeder to provide protection against phase and ground faults. The laterals usually employ fuses with inverse-time OC characteristics for protection against faults.

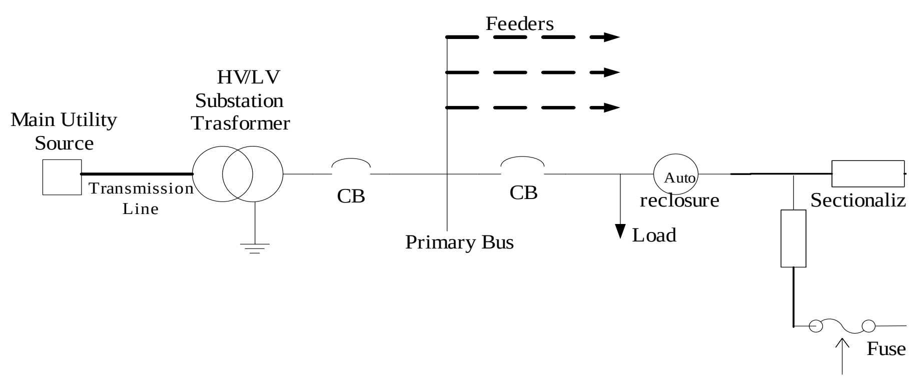

Figure 2.1: A protection set up for a simple radial feeder.

The traditional time coordination between a circuit breaker, a recloser and a lateral fuse for a radial distribution feeder is shown in Fig. 2.2 [31, 70, 110-113]. To achieve selectivity in the isolation of a fault, protective devices in series are time coordinated such that the upstream device electrically closest to the short circuit or overload opens first to isolate the faulty section. This minimizes the damage caused by a fault or overload while allowing upstream protective devices to remain closed and to continue to carry the normal load current. An autorecloser, in its fast mode of operation, is set to operate earlier than the lateral fuse to avoid turning a temporary fault into a permanent one. This practice is known as fuse saving. The feeder headend circuit breaker provides an overall back-up protection since its characteristic curve lies above all the other curves.

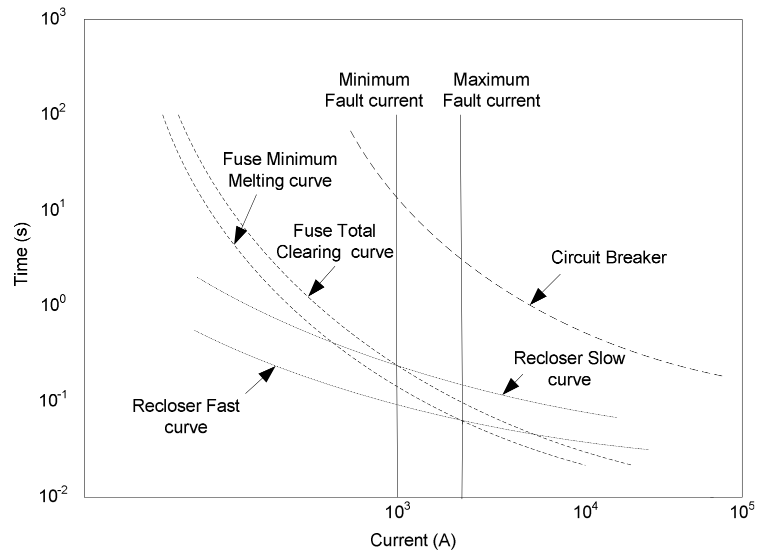

Figure 2.2: A typical time-current coordination of a circuit breaker, a recloser and a lateral fuse.

Appropriate protective device (relay) coordination is ensured by a relay pickup current setting ($I_{pick\text{-}up}$) of 50% of the minimum line end phase-to-phase (LL) fault current (I_{LL}). Relay current settings of 125-200% of full load current (I_{load}), i.e., $I_{pick\text{-}up}$ >125-200% I_{load}, prevents unnecessary tripping of the feeder when it is overloaded. An instantaneous element with a setting of four to six times of I_{load} or 125% of the three-phase fault current (I_{LLL}) at the first downstream protective device is used to protect the system against severe disturbances [110-113]. However, this time coordination will be lost if a change occurs either in the magnitude or direction of a fault current flowing through any of these protective devices.

2.4 THE CASE STUDY

Fig. 2.3 shows a single line diagram of a typical distribution network section which is henceforth referred to as the test system [117]. This test system is simulated to demonstrate and investigate the impact of DG on DN protection. A typical 25 kV distribution network is configured down stream of a 69/25 kV substation named as main substation. The utility grid upstream of the substation is represented by a Thevenin equivalent of a voltage source and a series impedance with short circuit (SC) level of 637 MVA and X/R ratio of 8.38 at the 69 kV input bus. The network is equipped with a 69 /25 kV, 15 MVA substation load tap-changing transformer, with a delta-wye grounded configuration. The transformer has a series equivalent impedance of 7.8% and connects the DN to the 69 kV subtransmission system. The DN is modelled by two load feeders, named as LF1 and LF2, emanating from the 25 kV bus. The system loads are considered as constant impedances that make no contribution to the fault current.

Twenty wind turbines with a total rated capacity of 33 MW are connected to the 25 kV bus through two 25 kV collector feeders named as CF1 and CF2. The DG unit is an actual wind power plant. The wind-turbines use induction generators with a rated capacity of 1.65 MW each (with a power factor of 0.95 lagging) and are connected to the network through 0.6/25 kV, 1.8 MVA step up transformers. Based on geographical distribution, ten wind turbines are grouped together and are modelled as an equivalent single machine, designated as DG 1 in Fig. 2.3, with a total capacity of 16.5 MW. The location of all the generators of DG1 is such that their contributions to different faults are almost the same. Similarly, the remaining ten wind-turbines are grouped together and are modelled as an equivalent single machine, named as DG 2 in Fig. 2.3, with a total capacity of 16.5 MW.

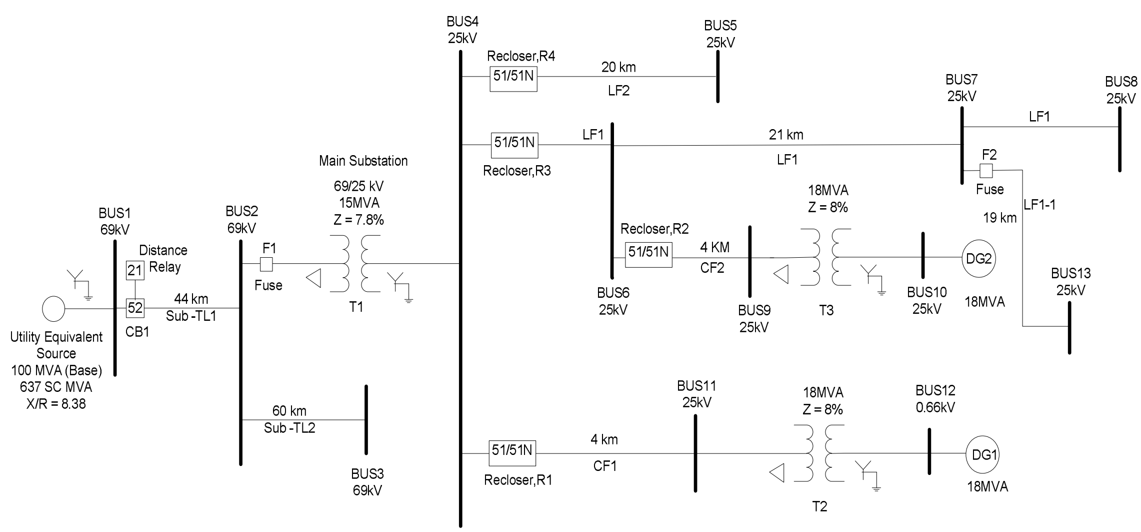

Figure 2.3: Single line diagram of a section of a typical DN with DG where Sub-TL stands for sub-transmission line, CF and LF represent collector and load feeders respectively. IEEE/ANSI designated protective device numbers are used [118].

The contributions of DG2 units to different faults are also assumed to be the same. Each generator is provided with capacitor banks at its terminal for reactive power compensation. The total reactive power required by each induction generator at full generation and 1 per unit voltage is about 740 kVAR.

IEEE/ANSI designated protective device numbers are used in this thesis [118]. A description of these numbers is given in Appendix A. A distance relay (i.e. 21) (SEL 321-mho type) is installed at the bus 1 end of the Sub-TL1 to protect against faults at Sub-TL1 and Sub-TL2 and to provide back up protection for some parts of the DN shown in Fig. 2.3. An OC fuse F1 (SS-PM 34-200) is installed on the high voltage side of transformer T1 to provide protection against transformer internal faults and backup protection against feeder faults. Load and collector feeders are equipped with reclosers R1, R2, R3, and R4 that contain time OC phase and ground fault relays (i.e. 51/51N) for protection against phase and ground faults. The autoreclose feature is disabled for the reclosers R1and R2. The impedance values of the sub-transmission lines (Sub-TLs) and the feeders along with pickup current settings ($I_{pick\text{-}up}$) of the various protective devices are shown in Tables 2.1 and 2.2 that are given in Appendix A. IEEE/ANSI designated protective device numbers are used in Fig. 2.3 [118]. A description of these numbers is also given in Appendix A. A commercial software package (ASPEN OneLiner) is used to simulate different faults to determine short circuit levels and to investigate their impact on protection coordination including the reach of the distance relay.

2.5 KEY PROTECTION CHALLENGES FOR DNs WITH DG

2.5.1 Fault current level modification

The connection of a single large DG unit or a large number of small DG units that use synchronous or induction generators to the DN will alter the fault current level as both types of generator contribute to it. The contribution of DG units to fault current is determined by their location, type, size, type of interface with the grid, grid impedance and network configuration [56, 60]. For example, if the fault location in the test system is at bus 8 i.e. downstream of the point of common coupling (PCC) of DG2 with the grid, then total fault current at the fault location will be

$$I_{F\text{-}T} = I_{F\text{-}G} + I_{F\text{-}DG1} + I_{F\text{-}DG2} \tag{2.1}$$

where I_{F-T} represents the total fault current at the fault location whereas I_{F-G}, I_{F-DG1} and I_{F-DG2} stand for fault current contributions from the grid, DG1 and DG2 respectively.

Fig. 2.4 shows the change in fault current for a three phase to ground (3LG) fault and a single phase to ground (1LG) fault for different DG configurations for the test system. It is clear from Fig. 2.4 that after the introduction of DG, the fault current (transient) has increased by 28.5% in the case of a 3LG at bus 2, by 51% in the case of a 3LG at bus 4 and by 22.6% in the case of a 3LG fault at the bus 8. Similarly, an increase in fault current also occurs in the case of a 1LG fault as is clear from Fig. 2.4.

This change in fault current level can disturb fuse-fuse, fuse-recloser and relay-relay coordination [29]. Moreover, all DNs, by design, have a characteristic short-circuit capacity. The selection of protective switchgear and equipment is based on this short-circuit capacity. Due to the fault current contribution by DG, this short-circuit limit can be exceeded and thus the thermal and mechanical endurance of switchgear and other network equipment can be endangered.

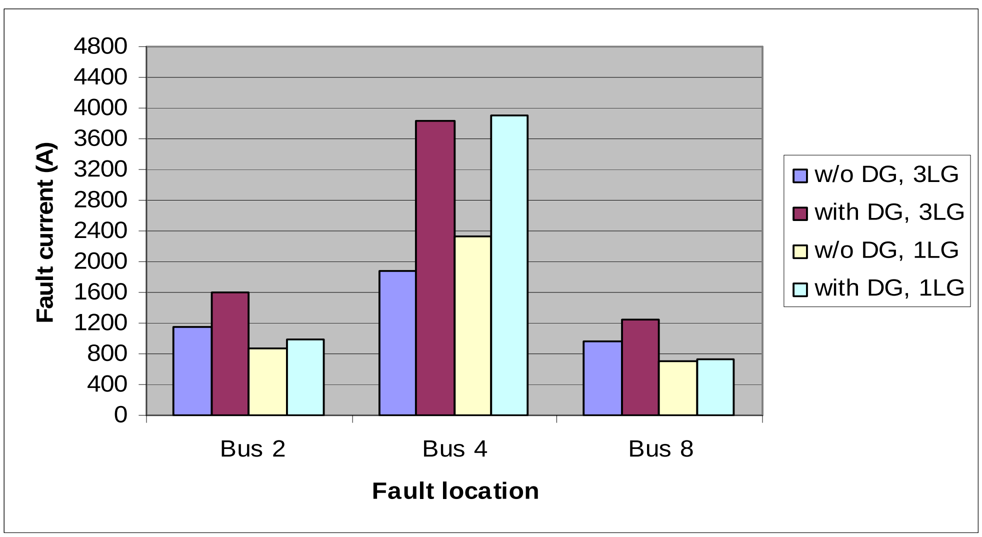

Figure 2.4: Fault current at different network buses with and without DG for the test system.

2.5.2. Blinding of protection

Although DG increases the fault current levels, the fault current seen by the upstream protection devices decreases when DG is located between the fault point and the feeding station. For example, if the fault location in the test system is downstream of the PCC of DG2 with the grid, the recloser R3 will only see the fault current supplied by the upstream sources i.e. utility source and DG1. Since this is only one part of the actual fault current, upstream protection devices may not function properly i.e. blinding of protection (delayed tripping, reduction in reach of a relay or no tripping at all) and other coordination problems may occur. The blinding of protection is most likely to happen in case of a high impedance fault point [37, 43, 56]. In the test system, delayed tripping of the recloser R3 equipped with OC element with inverse time characteristics (51) is witnessed in case of a 3LG fault at 90% of the feeder LF1 length with DG connection as shown in Table 2.3. It is clear from the table that in the case of the said fault, the 51 element operated in 0.11s when no DG was connected and it operated in 0.13s when either both DG1 and DG2 or only DG2 was connected.

Table 2.3: Operating times of protection devices in case of a 3LG fault at 90% of the feeder LF1 length with DG and without DG connection

Configuration of the test system	**Operating time (s)**		
	OC relay at LF1	OC relay at CF 1	OC relay at CF 2
W/O DG	0.11	N/O	N/O
With DG 1	0.09	0.24	N/O
With DG 2	0.13	N/O	0.24
With both DGs	0.13	0.32	0.32

To observe underreaching of an OC relay due to DG presence, an instantaneous OC element (i.e. 50) is added to the recloser R3. $I_{pick\text{-}up}$ of the 50 element is selected as 1300A to ensure that it operates only against high magnitude faults occurring either on the feeder LF1 or on the feeder LF1-1.With this setting, as can be seen from Table 2.4, the 50 element will operate for 3LG faults occurring upto 25% of the feeder LF1-1 length with no DG connection. But when DG is connected to the network, the OC relay will only operate for close in faults at the feeder LF1-1. Thus reach of the relay has been reduced due to presence of DG in the network.

Table 2.4: Fault currents in the case of a 3LG fault at different locations of the feeder LF1. I_{F-R3} stands for fault current through the recloser R3

No. of units at DG1	No. of units at DG2	Fault location (% of feeder length)	I_{F-T} (A)	I_{F-R3} (A)
0	0	close in	1551	1551
0	0	10	1450	1450
0	0	25	1320	1320
0	10	close in	2358	1421
0	10	10	2133	1285
0	10	25	1863	1123

2.5.3. Sympathetic tripping

Sometimes DG can contribute to a fault on a feeder fed from the same substation or even to a fault at higher voltage levels resulting in unnecessary operation of a protective device for faults in an outside zone, i.e., a zone that is outside its jurisdiction of operation. [42, 52, 60, 64, 65, 84]. An unexpected contribution from a DG unit can lead to a situation when a bidirectional relay operates with another relay which actually sees the fault. Thus, the protection scheme will no longer be selective and may result in unnecessary isolation of a healthy feeder or a DG unit. For example, the recloser R1 at CF1 can unnecessarily operate for a high resistive 3LG fault at the feeder LF1 as a result of infeed to the fault from DG1 through the substation bus bar as shown in Fig. 2.5.

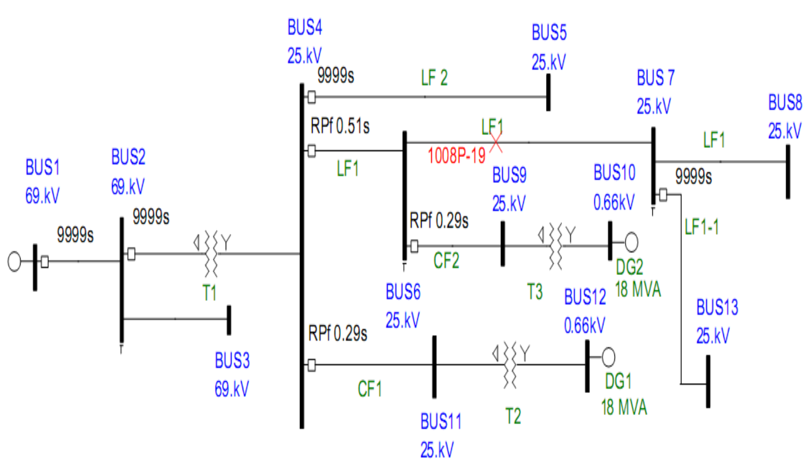

Figure 2.5: Sympathetic tripping scenario when relay at CF1 opens for a high resistive 3LG fault at 30% of the feeder LF1 length with both DG1 and DG2.

2.5.4. Reduction in the reach of a distance relay

The reach of a distance relay (also known as impedance relay) is the maximum fault distance that causes the relay to trigger in a certain impedance zone, or in a certain amount of time depending upon its configuration. The fact that line impedance is proportional to the line length is used by the distance relay for calculating the distance from the relay location to the fault. When the measured apparent impedance (Z), which is the ratio of applied voltage to current acquired at relay location, is less than impedance setting (Z_{set}), i.e. $Z < Z_{set}$, which mostly happens in case of faults, the relay will operate to clear the fault. Due to the presence of DG, a distance relay may not operate according to its defined zone settings. When a fault occurs downstream of the PCC of DG with the utility, the impedance measured by an upstream relay will be higher than the real fault impedance (as seen from the relay) as is clear from the following mathematical derivation [64,114].

The voltage U_r measured by the relay at its location is;

$$U_r = I_{F-G} Z_{upstream} + (I_{F-G} + I_{F-DG}) Z_{downstream} \tag{2.2}$$

The impedance Z_r, measured by the relay at its location is;

$$Z_r = U_r / I_{F-G} = Z_{upstream} + Z_{downstream} + (I_{F-DG} / I_{F-G}) Z_{downstream} \tag{2.3}$$

where $Z_{upstream}$ is the impedance between the relay location and the PCC, $Z_{downstream}$ is the impedance between the PCC and the fault point f and I_{F-DG} is the fault current contribution from DG.

The value Z_r from Eq. 3 is equivalent to an apparently increased fault distance and is due to increased voltage resulting from an additional infeed at the PCC. This can affect the grading of the relays (i.e. relay zone settings) and, consequently, the relays may not operate in the desired zone. Table 2.5 shows the original zone settings for the distance relay installed at the Sub-TL1 with no DG connection and the reduced zone settings for the same relay with DG connection for a 3LG and a 1LG fault in the test system. It is clear from the table that in the case of a 3LG fault, the range of zone 2 decreases to 67%

with DG connection, down from 79% when no DG was connected. Similarly, reductions in reach of other zones can also be noticed. The distance relay is set to operate with a time delay of 0.6s in case of a fault in zone 2. Normally, induction generators will stop feeding the faults occurring in zone 2 by that time. However, there is a possibility (i.e. in case of worst fault scenario) that the induction generators, due the presence of either the capacitor banks or the stray capacitances, may feed a fault in zone 2 for 0.6s or even longer. A good protection practice is to design the system for the worst fault scenario.

Table 2.5: Operating zones of the distance relay with and without DG in case of a 3LG and 1L G

Zones	**Relay settings (% of line length)**	**Distance relay operating range**			
		3 phase fault		1 phase fault	
		w/o DG	with DG	w/o DG	with DG
Zone 1	40	40	40	39	39
Zone 2	80	79	67	79	74
Zone 3	110	100	96	100	100

In Figs. 2.6, 2.7 and 2.8, the reduction in range of zone 2 due to DG infeed is shown with the help of an RX Diagram. The said diagram represents the area of resistance and reactance covered by each of the relay zones and the position of a fault relative to the relay zones. The magnitude of the impedance is shown by the length of the radius vector whereas the phase angle is represented by the position of the vector.

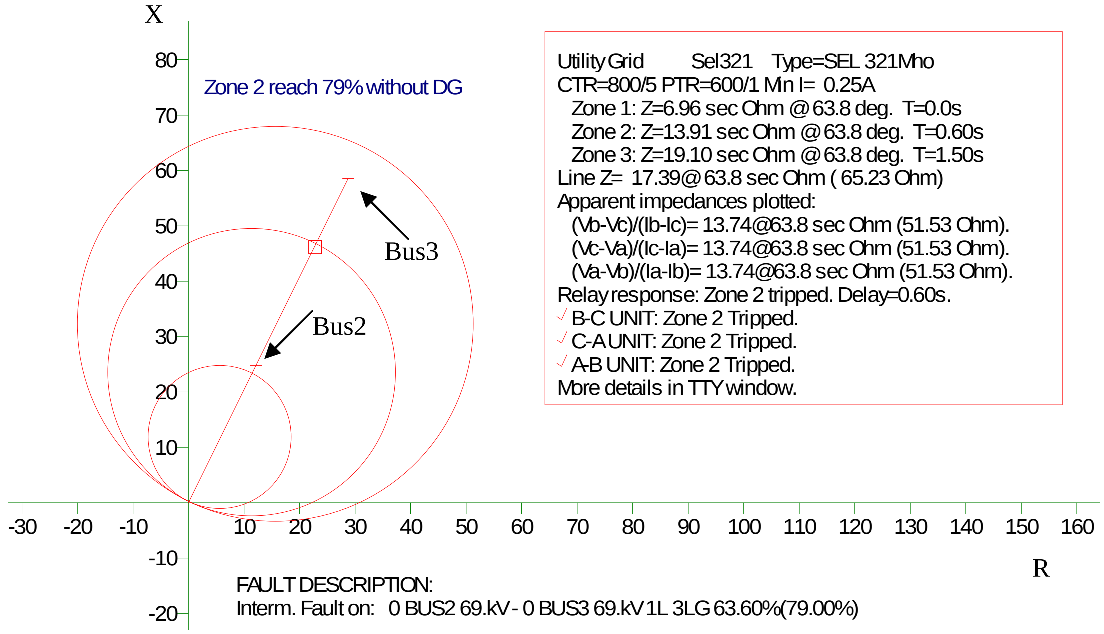

Figure 2.6: Distance relay zone settings and operation of the relay in zone 2 for a 3LG fault at 79% of the line with no DG connection. The impedance of the line (in primary ohms) is shown as a slanted line from the origin. The fault impedance (V/I) is plotted as a point on the complex plane.

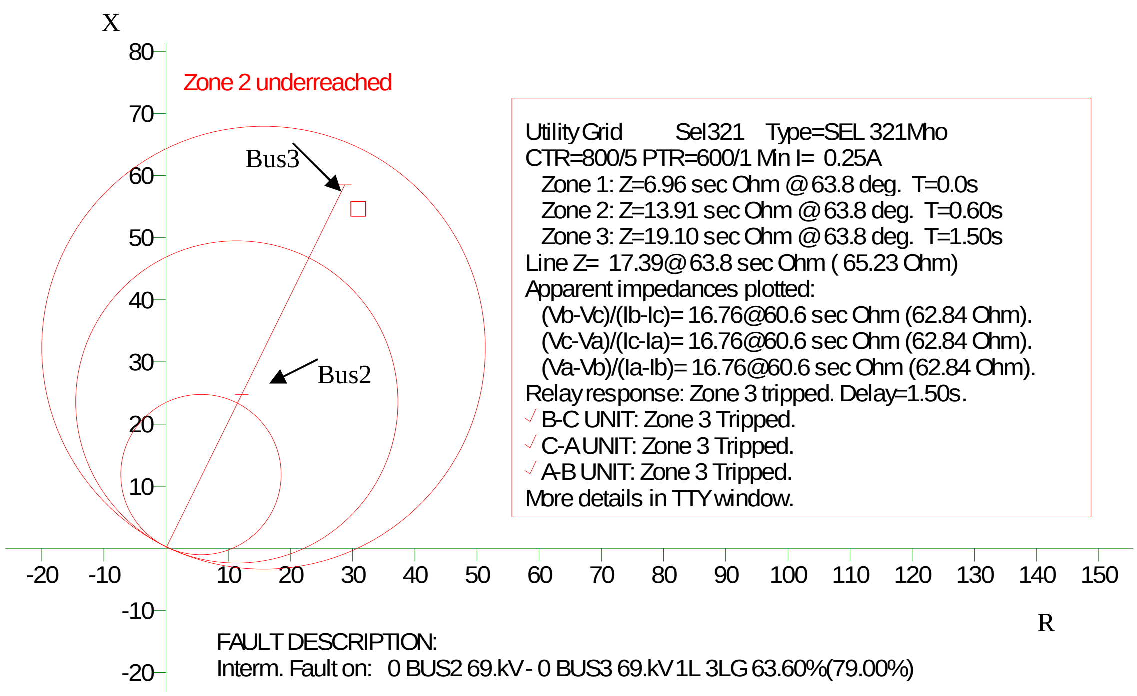

Figure 2.7: Failure of the distance relay to operate in zone 2 for a 3LG fault at 79% of the line with DG connection.

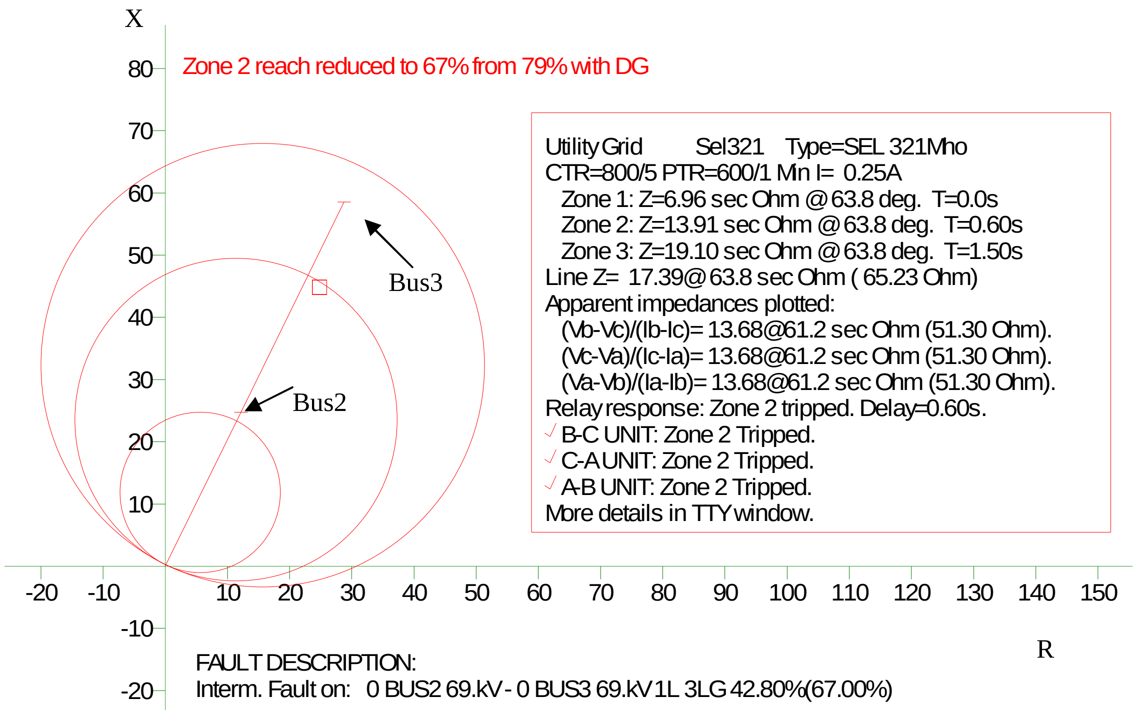

Figure 2.8: Operation of the distance relay in zone 2 for a 3LG fault occurring maximum at 67% of the line with DG connection.

2.5.5. Selection of a suitable interfacing transformer configuration

The interaction of DG with the grid is to a great extent determined by the connections of the interfacing transformer. Transformer configuration and grounding arrangements selected for DG connection to the grid must be compatible with the grid to save the system from voltage swells and overvoltages, and consequent damage [29]. According to IEEE 1547 standard, the grounding scheme of the DG interconnection should not cause overvoltages that exceed the ratings of equipment connected to the area electric power system and should not disrupt the coordination of ground fault protection on the area electric power system [115]. Among the five commonly used interconnection transformer connections are, delta (primary or high voltage side) - delta (secondary or low voltage side), delta (primary) - wye grounded (secondary), wye ungrounded (primary) - delta (secondary), wye grounded (primary) - delta (secondary), wye grounded (primary) - wye grounded (secondary) [29, 42, 52,116].

The transformer with delta or ungrounded wye on the utility side does not act as a ground source for the system i.e. there is no zero sequence path between the utility and DG. So this configuration would not allow any zero sequence current (i.e. from the DG side) to disturb the utility ground relay coordination as can be established by comparing results shown in Figs. 2.9 and 2.10. The results in both these figures are for the test system shown in Fig. 2.3. Fig. 2.9 shows fault currents when both DG1 and DG2 are connected through a delta (primary) - wye grounded (secondary) interconnection transformer whereas Fig. 2.10 represents fault currents when a wye grounded (primary) - delta (secondary) interconnection transformer is used. Also, ground faults on the utility side would not affect loads on the DG side (if any) if a delta primary configuration is used. This is not true when a wye grounded primary configuration is employed.

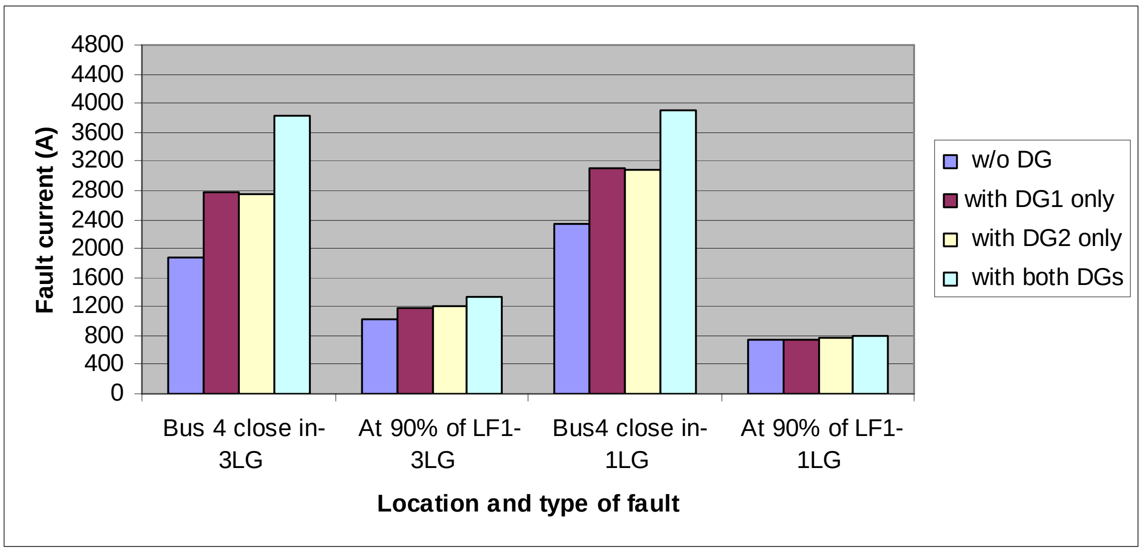

Figure 2.9: Fault currents with different DG configurations with delta primary transformer configuration.

An interconnection transformer with a wye grounded primary configuration provides a ground source for the system which ensures that utility side ground faults are detected easily. Also, there would be no overvoltages due to ground faults on the utility side. However, the presence of zero sequence current sources will increase the ground fault current level on the utility side as is shown in Fig. 2.10. This could have an adverse impact on ground relay coordination of the utility. It could, depending upon the ratio of DG source impedance to the substation ground impedance, short out some of the zero sequence fault current (I_0) from the substation ground relays. In some cases, the magnitude of the diverted I_0 could be large enough to restrain the substation ground fault relays from operation. Moreover, reduction in I_0 as seen from substation relays can also reduce the reach of these relays, which may result in failure of fuse saving schemes.

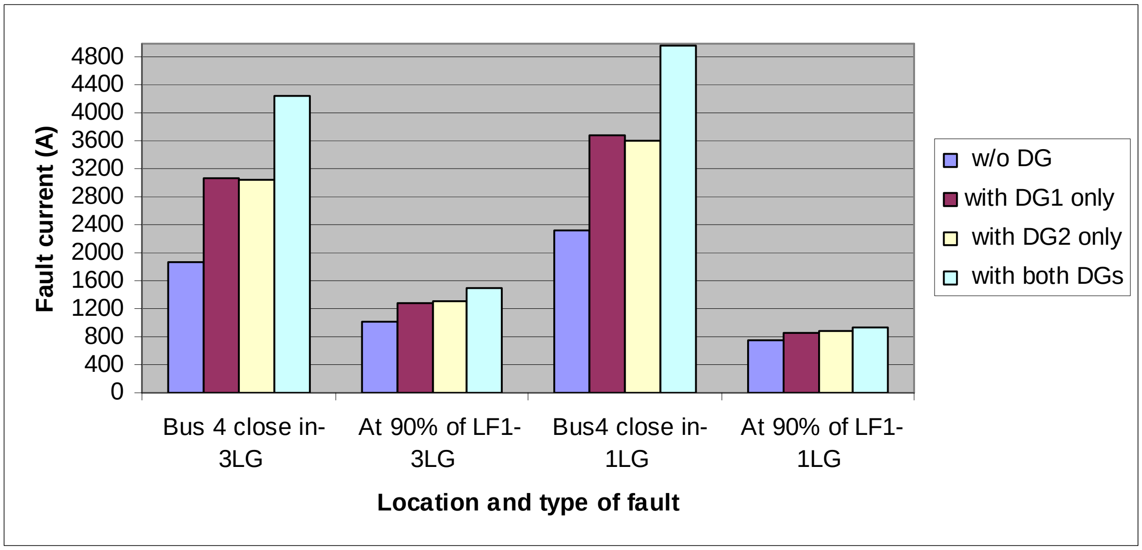

Figure 2.10: Fault currents with different DG configurations with a wye grounded primary transformer configuration.

One serious implication of interconnection transformers with a delta primary configuration is that with this configuration, detection of utility side 1LG faults becomes difficult. This drawback can have serious implications when the utility CB opens in response to a 1LG fault on the utility feeder while the DG unit is still connected. As the resultant system lacks a grounding path because the utility ground source is separated by the opening of utility CB, line to neutral voltages (V_{LN}) on the open ended healthy phases can approach line to line voltages (V_{LL}). To investigate this phenomenon, the test system understudy is modelled in PSCAD/EMTDC. A sustained 1LG fault is applied on sub-TL1 and the circuit breaker CB1 is opened at 0.11s. When the breaker opens, voltage on open ended healthy phases rises to 1.8 per unit (p.u) as is clear from Fig. 2.11. This happens especially when at the time of opening of circuit breaker CB1, DG nearly matches the capacity of the load on the feeder. This can subject the line to neutral connected equipment to severe overvoltages and damages i.e. saturation of connected distribution transformers.

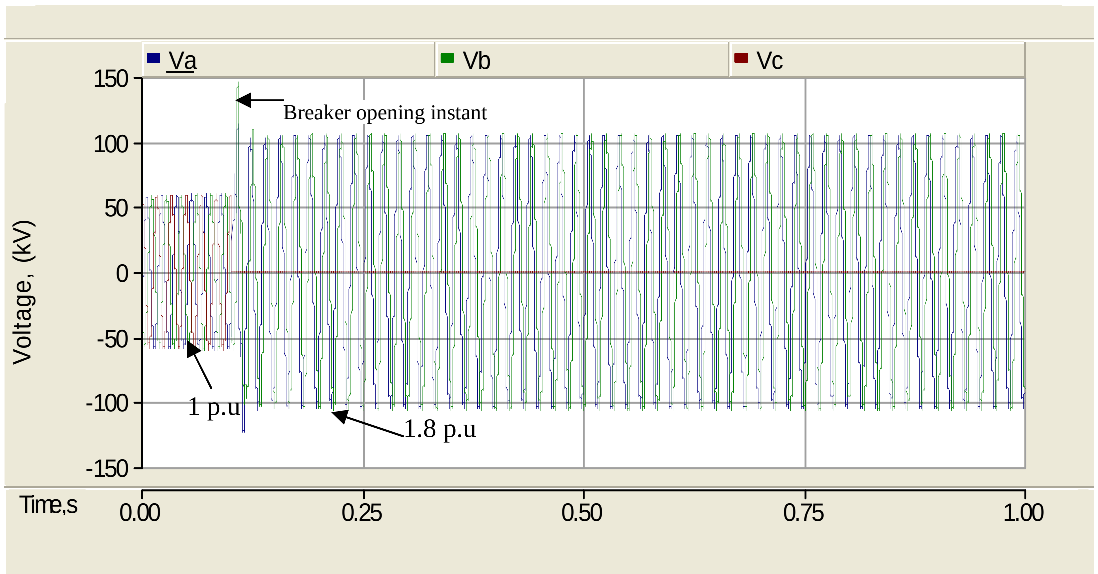

Figure 2.11: Voltage rise scenario in the test system due to 1LG fault on phase C of Sub-TL1.

2.6 RECOMMENDATIONS

In this section, a solution is proposed based on traditional protection tools and practices. The basic philosophy behind the proposed solution is to design an effective protection strategy that is practical, selective and reliable i.e. utilizes traditional or commercially available protective devices, techniques and communication channels. To reduce the implementation cost, the proposed solution makes use of an optimal number of protective devices but, of course, without sacrificing selectivity and reliability. In accordance with IEEE Standard 1547 [115], islanded operation of DG units is not considered. The following modifications and additions are recommended for implementation on the interconnection point (point of common coupling) and on the 69 kV line:

- To stop DG units from feeding faults on the 25 kV bus or beyond:
  - Nondirectional overcurrent relays enclosed in the reclosers R1 and R2 should be replaced by directional OC units (67/67N). The pick up settings of these relays should be set greater than the normal rated currents of DG1 and DG2 so that no operation takes place under normal working conditions. On detection

of a fault current flowing in a reverse direction i.e. towards the 25 kV bus, the directional units will trip the respective reclosers R1 and R2 to disconnect DG from the network.

- Even with the introduction of a directional unit at the recloser R1, the issue of blinding of protection and sympathetic tripping may not be solved completely. Blinding of the recloser R3 can still occur as, in the case of a fault on the load feeder LF1 beyond the bus 6, the recloser R3, in order to see the full fault current flowing through it, will have to wait for the disruption of the fault current infeed from DG2 by the recloser R2. So its operation will be a bit slower than its operation in the absence of DG2. Similarly, sympathetic tripping may occur in the case of some high impedance faults at the feeder LF1 even with the addition of a directional unit at the recloser R1.
- To solve the problem of blinding of protection, one option is to select new time current characteristics (TCC) for the 51 element of the recloser R3 by taking into consideration contributions from DG. But in this case, maloperation of the recloser R3 might occur when the system is working without DG. The problem of sympathetic tripping can be solved by selecting new TCC for the 51 element of the recloser R1 with a time delay. However, this needs great care; if the selected time delay is too large, DG1 may keep on feeding faults for an extended period even when the utility source is separated from the network by the opening of the coupling breaker. An alternate solution is to upgrade the recloser R3 with the addition of an instantaneous element (50). The 50 element with a careful current pickup setting and with a total response time of a couple of cycles can solve both of these problems. Moreover, this 50 element is also essential for ensuring fuse saving in the presence of DG as is discussed in the next chapter.
- To ensure continuity of supply to the load feeders LF1 and LF2 from the utility source in the case of faults on collector feeders CF1 and CF2, the reclosers R1 and R2 should be set to operate faster than any other protection of the network.

- A multifunction voltage relay (MVR1) along with three voltage transformers (VTs) is proposed for the 25 kV bus to monitor abnormal conditions i.e. islanding due to the tripping of proposed circuit breaker CB2 or 1LG fault on the 25 kV network fed by the DG units. The multifunction voltage relay will include the following functions; under, over, instantaneous and zero sequence voltage (ZSV) measurement functions (i.e. 27, 59, 59I, 59N (3V0)) and under, over, and rate of change of frequency (ROCOF) measurement functions (i.e. 81U/O/R). For detection of 1LG faults, the relay will rely upon the ZSV (i.e. 3V0) detection principle i.e.

$$3V_0 = V_a + V_b + V_c \tag{2.4}$$

  where V_a, V_b *and* V_c are three phase to ground voltages. The 3V0 voltages will be derived from VTs broken delta secondary configuration whose primaries would be connected line to ground. On detection of an islanding condition or 1LG fault, the relay will trip the relcoser R1 and R2 and thus effectively separate DG from the network.

- A multifunction protective relay (MPR1) with functions 50/50N, 51/51N, 67/67N and a 25 kV circuit breaker CB2 is recommended for installation on the downstream side of the transformer T1. This relay will provide fast interruption of fault currents that will feed the transformer faults. It will also provide primary protection for the 25 kV bus which has become a load cum generation bus after the connection of DG units. Moreover, it will act as a local back up in the event of failure of the reclosers R1, R2, R3 and R4.

- Islanding can occur in the test system if DG units continue to energize the network in spite of the opening of the circuit breaker CB1. The solution includes;

  - Application of a suitable anti-islanding protection scheme

    An addition of multifunction voltage relay (MVR2) along with three voltage transformers (VTs) on the 69 kV side of the transformer T1 would ensure anti-islanding protection and fast detection of 1LG faults being fed from the DG units. It will also fix the problem of voltage rise on open ended healthy phases of the 69 KV line in the event of the opening of CB1. The multifunction voltage relay will include 27, 59, 59I, 59N (3V0) functions. For detection of 1LG faults, the relay will rely upon the ZSV detection principle. ZSV which is otherwise zero in a balanced system will rise when the 69 kV line becomes ungrounded as circuit breaker CB1 opens for a 1LG fault which is being fed by DG. To observe this phenomenon, the test system was modelled in PSCAD/EMTDC software. A sustained 1LG fault was applied on sub-TL1 and the circuit breaker CB1 was opened at 0.11s. The simulation results are shown in Fig. 2.12 which clearly show a significant rise in ZSV 'V0' (which otherwise is very low) at the instant when the circuit breaker CB1 opens. For ZSV detection, the primaries of VTs will be wye connected between terminals of the transformer T1 and ground, whereas secondaries will be connected in the open delta configuration. In the case of a 1LG fault on the 69 kV line, the relay, by measuring ZSV from open delta secondaries, will send trip signals to the circuit breaker CB2 and to the reclosers R1 and R2, to isolate the DG units and to inhibit islanding. A trip signal to the circuit breaker CB2 and the recloser R1 can be arranged locally, whilst any suitable communication channel e.g. fiber optics, power line carrier, radio or microwave can be used for tripping the recloser R2.

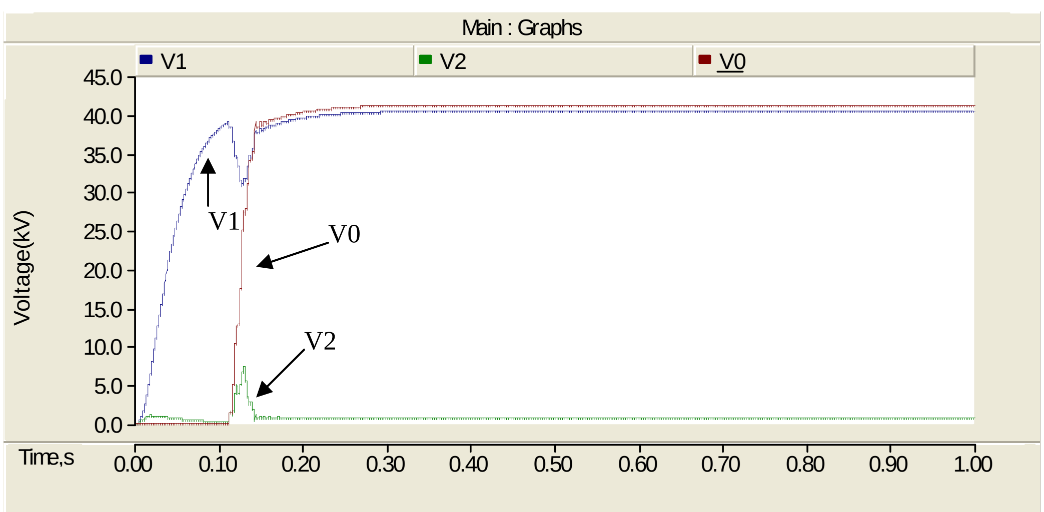

Figure 2.12: Zero Sequence Voltage (V0) rise scenario in the test system due to 1LG fault on Sub-TL1. V1 and V2 stand for positive sequence and negative sequence voltages respectively.

- Use of a transfer trip (TT) scheme

Use of a direct transfer trip (TT) scheme from the circuit breaker CB1 to the reclosers R1 and R2 can also avert islanding. Simultaneously, with the opening of the circuit breaker CB1, a trip signal will be sent to the reclosers R1 and R2 to disconnect the DG units from the network and thus forestall islanding. Any suitable communication channel as mentioned earlier can be used for transmitting the signal.

Both of the above mentioned schemes will ensure instantaneous trip of the DG units from the system.

- In case of opening of the reclosers R1 or R2, the individual wind induction generators that are equipped with common islanding detection functions i.e. 27/59, 81U/O, will trip.

- So far as the underreaching of the distance relay (i.e. 21) installed at the bus1 end of the Sub-TL1 is concerned, readjustment of zone settings or addition of an extra zone can make the relay operate in the correct zone. For example, if the impedance setting of zone 2 is increased from 13.91 ohm to 16.91 ohm, then it will cover 79% of the line even in presence of DG as shown in Fig. 2.13. However, the distance relay can over reach if the DG units are disconnected. Therefore, these conditions should be checked to ensure that there is no miscoordination with the adjacent zone 2.

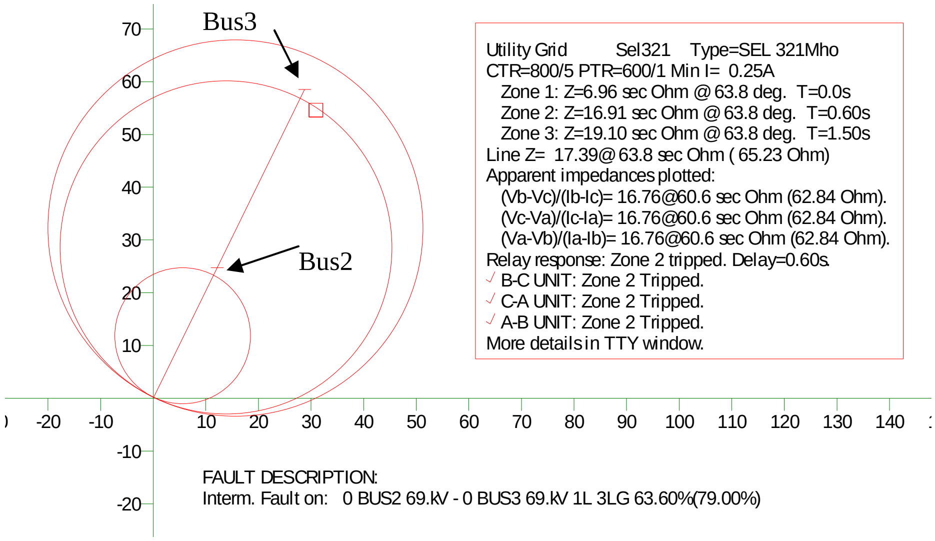

Figure 2.13: Operation of the distance relay in zone 2 for a 3LG fault occurring at 79% of the line with modified settings of zone 2 with DG connection.

- Another solution for the problems of blinding of protection, relay underreach, and failure of the fuse saving scheme is to set the relays i.e. the 51 units of the reclosers R1 and R3, and the distance relay at Sub-TL1 for two groups of settings; one group for operation without DG and the other group for operation with DG. Any suitable communication link e.g. fiber optics or microwave, can be provided between the relevant relays and the DG units so that the former can update their settings according to the status of the latter. This will help to avoid the need of very delicate settings for the relays and potential danger of maloperations.

The complete protection setup for the test system is shown in Fig. 2.14.

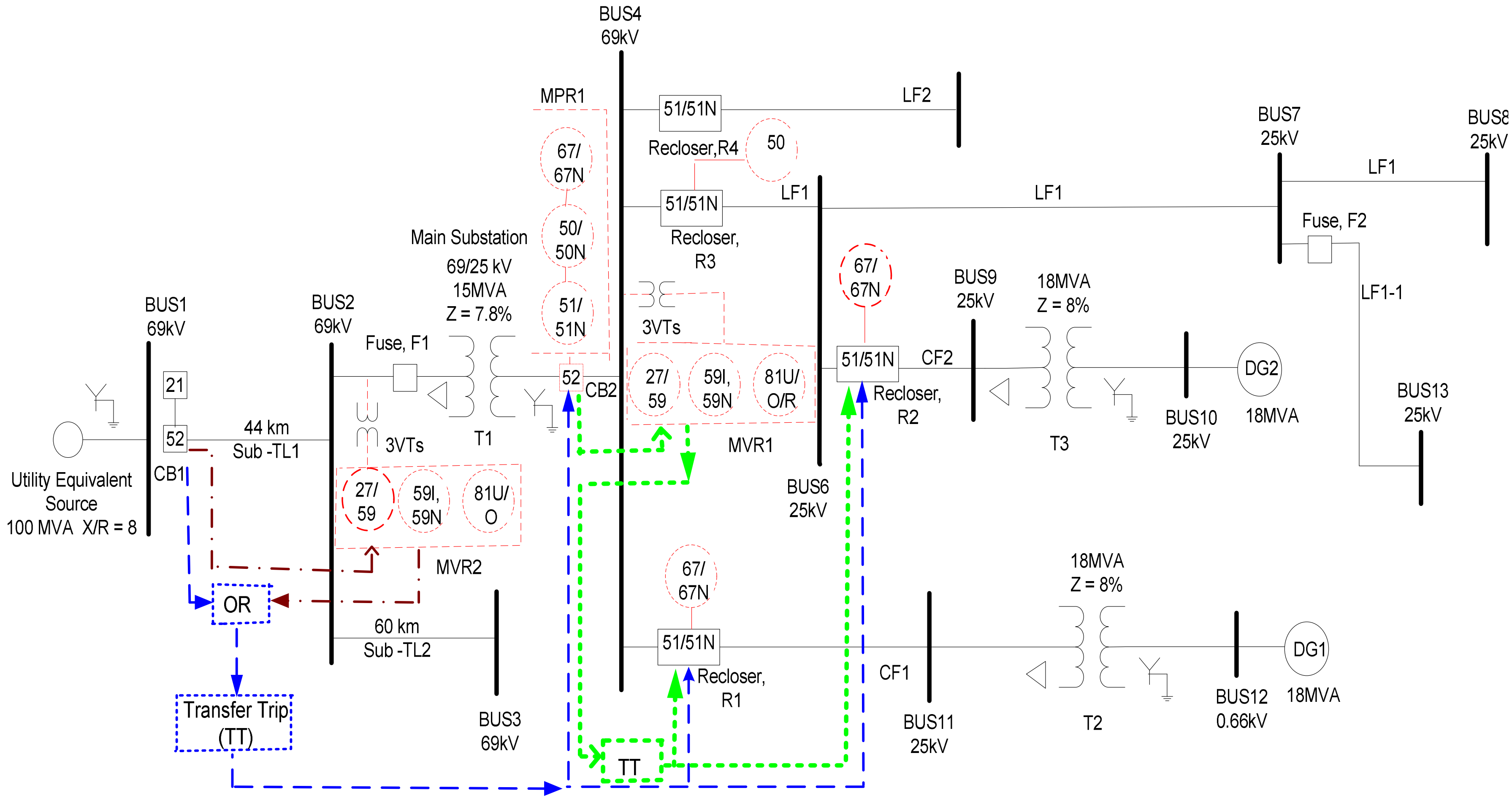

Figure 2.14: Complete protection scheme for the test system shown in Fig. 2.3 to ensure safe integration of DG. Broken lines show transfer trip (TT) scheme from the circuit breaker CB1 to the circuit breaker CB2, the reclosers R1 and R2 whereas dotted lines represent TT scheme from the circuit breaker CB2 to the reclosers R1 and R2.

2.7 SUMMARY

The chapter has analyzed the potential impact of DG on DN protection with the help of a case study involving DG installation in a typical DN. Different scenarios, such as sympathetic tripping or underreaching of a distance relay, where an existing protection setup can fail to safely accommodate DG have been discussed and reinforced by simulation results from the case study. These scenarios should be considered to determine whether or not to upgrade the current protection system to ensure reliability and selectivity of the protection scheme even after DG connection. A practical solution that relies on conventional protection practices has been proposed in respect of the case study. The proposed solution ensures reliable, high-speed protection and minimizes the negative impacts of DG on the protection set up of the DN. The point is made that a properly designed protection scheme with careful selection and setting of protective devices can allow safe connection of DG to existing DNs to reap the full benefits of DG.

CHAPTER 3

FUSE SAVING STRATEGY IN THE PRESENCE OF DISTRIBUTED GENERATION

3.1 INTRODUCTION

To ensure reliability of supply i.e. to avoid prolonged discontinuity of service due to temporary faults, utilities normally employ a fuse saving strategy. Through this strategy, utilities try to 'save' the fuse on the circuit following temporary faults by de-energizing the line with the fast operation of an upstream interrupting device (i.e. recloser) before the fuse has a chance to be damaged. The interrupting device then recloses and restores power beyond the fuse. This is achieved through properly coordinating time current characteristics (TCC) curves of a recloser and a fuse. This is a useful practice as it saves expensive fuse replacement and unnecessary extended consumer service interruption which otherwise could be quite burdensome as temporary faults constitute 70 to 80% of faults occurring in distribution networks (DNs). However, in the case of a permanent fault beyond the fuse, upon completion of recloser fast mode shots, the fuse blows to clear the fault while the recloser is waiting to operate on its slow curve. However, installation of DG on distribution circuits may affect the timing coordination between substation relaying and the fuse due to additional fault current contribution from the distributed resource. Due to miscoordination caused by DG infeed to the fault, the fuse could blow first or both the fuse and interrupting device could operate at the same time.

This chapter describes an alternative protection strategy that benefits from the characteristics of both time and instantaneous OC (51 and 50) elements for maintaining recloser-fuse coordination (RFC) in a practical DN. Moreover, a simple algorithm is proposed to adaptively change the setting of the 50 element to ensure fuse saving under the worst fault conditions. Section 3.2 explains the importance of a fuse saving practice.

In section 3.3, various solutions proposed in the literature for maintaining RFC in DNs with embedded DG have been critically reviewed. In section 3.4, the potential impacts of DG on RFC are investigated in the case of the test system through simulations of different fault scenarios with different DG configurations. The results are analyzed for developing a solution strategy. In section 3.5, a scheme is proposed to restore proper RFC for fuse saving even in the presence of DG. A reclosing strategy for the feeder with DG is described in section 3.6. In section 3.7, some observations are made in respect of the application and implementation of the proposed strategy. Finally, section 3.8 gives a summary of the chapter.

3.2 WHY FUSE SAVING MAY FAIL IN DNs WITH DG

As shown in Fig. 2.2 in chapter 2, the coordination between a recloser and a fuse will be valid only if the fault current is between the minimum fault current of the feeder ($I_{F\text{-}min}$) and the maximum fault current of the feeder ($I_{F\text{-}max}$) and if there is some margin between the operating times of these two devices. This is because between $I_{F\text{-}min}$ and $I_{F\text{-}max}$, the recloser fast characteristic curve lies below the minimum melt (MM) characteristic of the fuse and the recloser slow characteristic curve lies above the total clearing (TC) characteristic of the fuse. However, integration of distributed generation (DG) into DNs, depending upon the size, type and location of DG, may affect the recloser-fuse coordination (RFC) [8, 31, 112-113]. The RF miscoordination can occur when the fault current becomes greater than $I_{F\text{-}max}$ due to the additional fault current contribution from DG. It can also happen, when due to the location of DG, the fault current seen by a recloser is less than the current that passes through a fuse even when fault current is between $I_{F\text{-}min}$ and $I_{F\text{-}max}$. As a result, the fuse could blow first or both the fuse and the recloser could operate at the same time.

3.3 LITERATURE REVIEW

Various measures proposed in the literature for maintaining protection coordination in power systems, particularly for maintaining RFC in DNs with DG, can be broadly divided into two categories: preventive and remedial. Preventive measures are those which aim at limiting the contribution of DG to such an extent that the original RFC of the network is not disturbed as proposed in [27, 70, 87, 30, 120-127]. Remedial measures are those which recommend changes in settings of protective devices to maintain RFC in the presence of DG as discussed in [8, 45, 52, 54, 55, 128-150].

3.3.1. Preventive measures proposed in literature

In [5], the authors recommend that protection selectivity should be checked whenever a new DG unit is connected to a DN and settings of overcurrent (OC) devices should be recalculated to maintain it. In [120, 70, 87, 121-122], a method based on the mathematical equations of characteristics of protective devices is described for determination of the maximum size of DG that can be integrated into the system without causing RF miscoordination. In [30] miscoordination between protective devices has been investigated for different DG sizes and locations with the help of an actual distribution network. It is suggested that, generally, the only way to maintain coordination without modifying the protection scheme in the presence of DG is an instant disconnection of all DG connected to the system in the case of a fault. Once DG is offline, the original protection coordination i.e. the one prior to the DG connection, will be restored. But this scheme can't work in certain conditions where the fault level is such that the coordination margin between operating times of recloser and fuse is almost negligible i.e. by the time the DG is disconnected, the fuse would already had blown. The use of a fault current limiter (FCL) for maintaining protection coordination when DG is connected to the DN is discussed in [123-127]. But there are some issues/drawbacks associated with the use of FCLs:

- FCL is a relatively new device and needs more practical testing and field experience to become a reliable solution for fault current limiting in electric networks.
- In a DN with a high level of DG penetration, optimal location of a fault current limiter and selection of its best impedance may be challenging.
- Due to decreased fault current with the application of an FCL, readjustment of a recloser I_{pickup} settings or change of a fuse may be necessary to restore recloser-fuse coordination.
- Power losses in electrical networks under normal operation are increased by FCLs.

- Standardized testing protocols are not developed yet.

3.3.2. Remedial measures proposed in literature

3.3.2.1 Miscellaneous

By showing the impact of different DG types and sizes on fuse melting time, reference [8] proposes the change of fuse size, or the selection of faster relays or recloser settings with fuse change outs as the most likely option for ensuring recloser-fuse coordination. Changes in the type of fuse or its size are proposed in [128] when it is not possible to save the fuse over the entire fault current range. In circumstances where it is not possible to save a fuse due to a high fault contribution from DG, the use of sectionalizers is discussed in [52] as a potential solution.

Reference [45] proposes modifying the TCC of the recloser fast curve for maximum possible fault current on the basis of the fuse to recloser ratio i.e. ratio of the fuse current I_F to the recloser current I_R i.e. (I_F/I_R) and then coordinate it with the fuse curve. To this end, the use of an adaptive microprocessor based recloser is recommended. The curves of both phase and ground units need to be modified separately. When the system is restored by the recloser fast mode operation, the original settings of the recloser fast curve again become valid, as in accordance with current utility practice, the DG should have already been removed before the recloser closes for the first time. Through simulation results, it is shown that the scheme can maintain RF coordination against all sorts of faults.

In [129], it is proposed to modify the TCC of the recloser fast curve based on the minimum value of I_R/I_F to ensure RFC even in the presence of DG. To accomplish this, the use of a microprocessor based recloser is recommended. It is shown that the revised characteristic curve is valid even when DG is disconnected as $I_{F\text{-}min}$ is calculated on the basis of no DG connection and $I_{F\text{-}max}$ is calculated with DG connection. The curves of both phase and ground units need to be modified separately. Through simulation results, it is shown that the scheme can maintain RFC against all sorts of faults. However, the schemes discussed in [45, 129] may not be very effective when it comes to maintaining coordination in the worst fault conditions as will be discussed later in the chapter.

Mindful of the fact that recloser-fuse coordination has its limitations at higher fault levels i.e. for fault currents above a certain level, recloser operation can occur simultaneously with fuse blowing, an intelligent fuse saving scheme is described in [130]. An optimized TCC curve is developed that allows both fuse-blowing and fuse-saving in accordance with the fault current level. To this end, the custom fuse-save curve is truncated at the maximum coordination current (MCC) which is defined as the current where fuse saving can no longer be guaranteed by the recloser. According to this scheme, the fuse-saving TCC curve will be active only for a partial range of the available fault currents i.e. upto MCC. Tripping on the recloser fuse-saving curve will take place only when it can ensure fuse saving. In circumstances where fuse saving is not possible, the fast tripping operation of the upstream recloser shifts to a delayed curve to allow the fuse to operate. Thus, for a fault beyond the fuse and with the fault level greater than MCC, only the fuse will operate. This will ensure that the recloser and fuse don't operate for the same fault. If a high magnitude fault is on the main line i.e. on feeder LF1-1 in the network studied in this thesis, instead of being beyond a fuse, then a trip will be triggered on the delayed TCC curve of the recloser.

The scheme has its merits but it has a down side too i.e. it will ensure fuse saving only over a partial range of available fault currents. The MCC will not be fixed as it will change depending upon the size, type and location of DG i.e. for the network studied in this thesis, MCC will vary depending upon number of the DG units at DG1 or DG2. Moreover, high magnitude faults on the main line will put more stress on the network components as they will be cleared by the recloser delayed curve instead of the fast curve.

3.3.2.2 Adaptive relaying

Adaptive protection is as an online activity that modifies the preferred protective response to a change in system conditions or requirements in a timely manner by means of externally generated signals or control action. References [131-133, 55, 134-140] discuss strategies relying on an adaptive I_{pickup} of OC relays to detect faults (normal or high impedance) in DNs that otherwise remain undetected due to fixed settings of OC relays or due to introduction of DG into the network. Most of these strategies rely on modifying relay settings in real time as operating conditions of the system change i.e. I_{pickup} is updated according to currently available short circuit current and actual loading conditions.

Adaptive protection schemes described in [54, 141], propose dividing the DN into various zones with a reasonable balance of load and DG in each zone. The schemes aim at maintaining protection coordination while keeping most of the DG online during a fault by allowing islanded operation of DG. But due to the location of DG units with respect to the loads and the fluctuating nature of power from these units as well as of utility loads, it might not be possible to establish zones that fulfill the required criteria. Moreover, provision for islanded operation of DG is not desirable as according to present utility practice, islanding is not allowed.

A scheme is proposed in [142] to keep protection coordination intact during a fault without creating an island or DG disconnection whilst ensuring that the conventional overcurrent protection devices i.e. OC relays, reclosers or fuses, don't lose their proper coordination. But this scheme is intended only for meshed networks.

3.3.2.3 Expert systems and agent based schemes

Expert systems have been used to solve protection coordination problems in distribution systems in [143-145]. In [146], an expert system is applied as a decision tool to identify coordination problems when DG is connected to the network and to modify the settings of protection devices for improving the coordination in the new scenario. The principle of expert systems, which essentially mimics human experts, is to solve complicated problems by using knowledge base and inference processes whereas other approaches use data and programs. The expert system feeds input data using a graphical user interface and develops coordination settings based on power flow and short-circuit analyses.

A multi-agent approach for achieving proper protection coordination in power systems in the presence of DG has been discussed in [147-149]. More simulation results will be helpful to evaluate the feasibility of the approach. In [150], an adaptive agent based self healing protection strategy is proposed and through simulation results of a power system with DG, it is shown that its performance is better than a traditional protection scheme.

These schemes based either on expert systems or on multiagent systems are claimed to be effective in achieving proper protection coordination in power systems with embedded DG. However, these systems are expensive as well as difficult to realize and maintain due to their complexity. Moreover, due to lack of traditional experience with these systems, it will take time before they get practical acceptance.

3.4 THE CASE STUDY: SIMULATION RESULTS AND DISCUSSION

To illustrate the impact of DG on the fuse saving scheme, the time coordination between the recloser R3 and the fuse F2 (150K) of the test system shown in Fig. 2.3 and described in section 2.4 has been investigated. The coordination is based on the TCC of the recloser and MM and TC characteristics of the fuse as shown in Fig 3.1 (a mathematical description of the TCC is given in Appendix B). Two reclosing attempts i.e. one in fast mode and one in slow mode, are planned. The coordination holds well for different faults with no DG connection. For example, in the case of a three-phase (LLL) close in fault at the feeder LF1-1, the recloser fast curve operates in 0.07s, whereas MM time (MMT) for the fuse is 0.29s as shown in Fig. 3.1. The relay current and operating time is shown both as points on the curves and as text within the description boxes.

However, when DG is connected to the test system, then depending upon the DG size, type, location, and the nature and location of fault, there is a real chance of RF miscoordination i.e. fuse blowing, even in case of temporary faults. It can be noticed from Fig. 3.1 that chances of RF miscoordination are maximum when the fault current is high. Generally, maximum fault current is expected in the case of a bolted LLL fault (which is hence forth mentioned as an LLL fault). So to investigate the RFC limitations i.e. the conditions where it is not possible to save the fuse, an LLL fault has been simulated at different lengths of LF1-1 with different DG configurations.

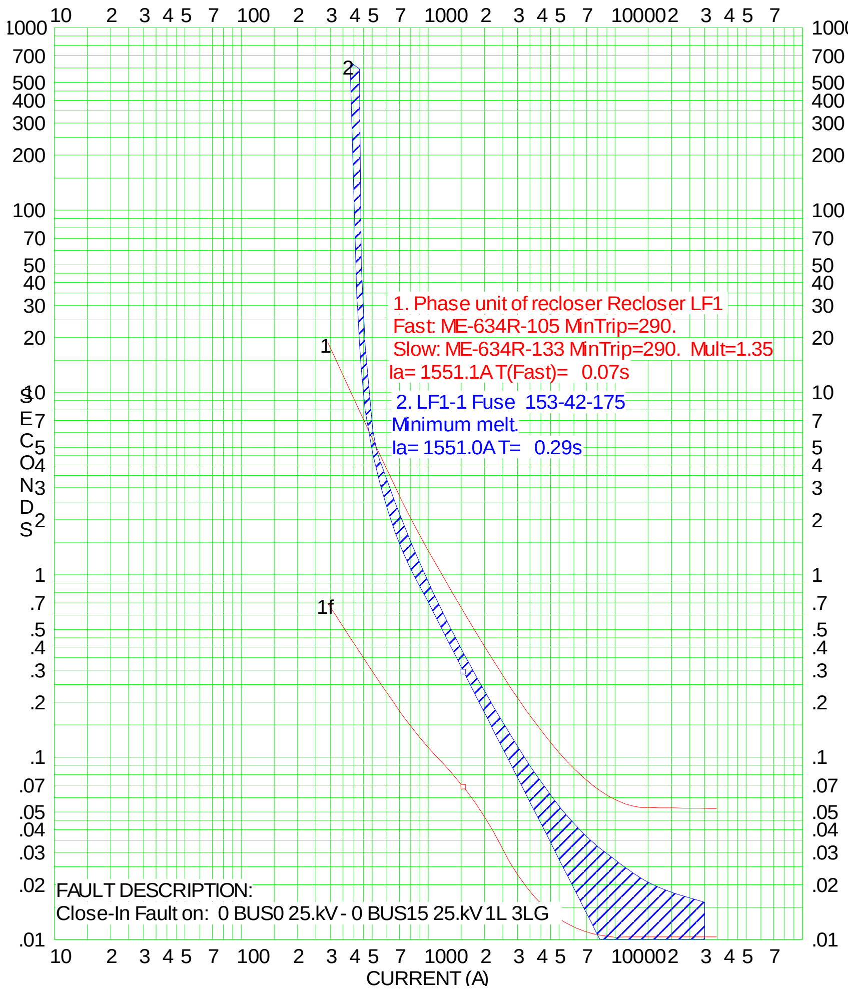

Figure 3.1: Proper coordination between the recloser R3 and the fuse F2 for an LLL (i.e. 3LG with zero ground resistance) close in fault at LF1-1 without DG. '1_f' and '1' stand for the recloser fast and slow characteristics curves respectively while '2' represents the fuse characteristics curve. The relay current and operating time is shown both as points on the curves and as text within the description boxes.

The total fault currents and the fault currents seen by the recloser and the fuse obtained by simulating an LLL fault at different lengths of the feeder LF1-1 are shown in Fig 3.2. The results are for different values of M and N, where M and N are numbers of DG units at DG1 and DG2 respectively. It is clear from the figure that the fault currents seen by the recloser R3 and the fuse are different. This is because the recloser is not seeing the fault current contribution from DG2 as the latter is connected downstream of the former. This is not true in case of the fuse i.e. the fuse sees the whole fault current.

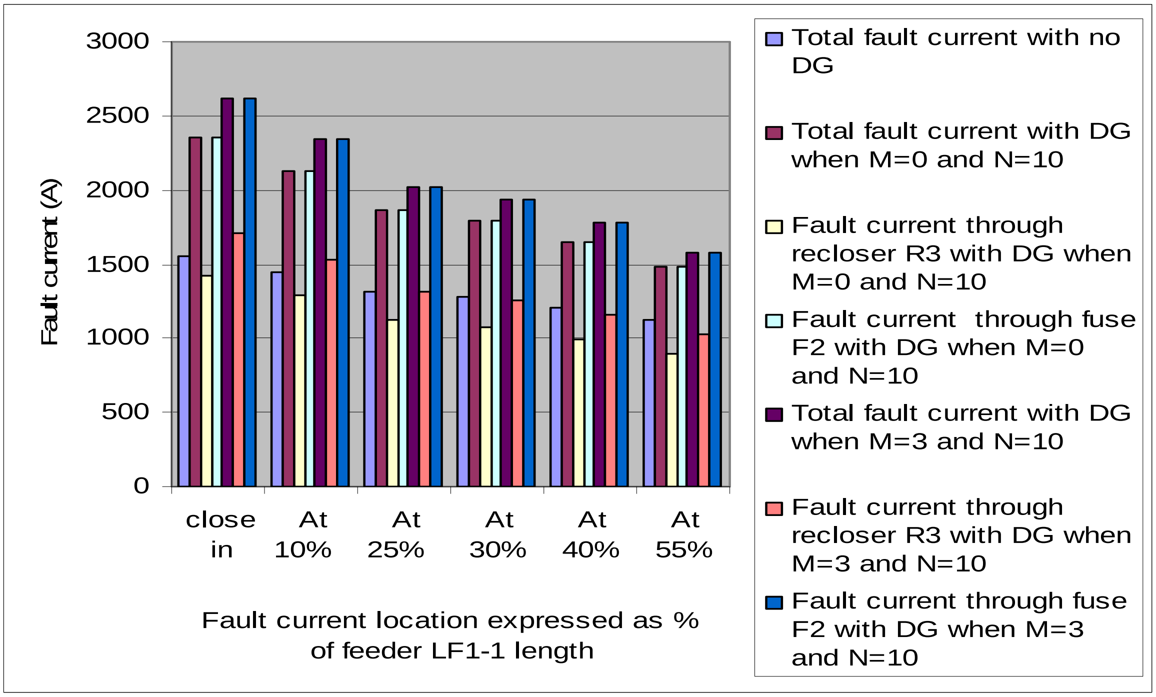

Figure 3.2: Fault current magnitudes for a LLL fault at different lengths of LF1-1 for different values of M and N where M and N are numbers of DG units at DG1 and DG2 respectively.

The operating times (T_{op}) of the recloser time OC phase element i.e. 51 and MMTs of the fuse for fault currents presented in Fig. 3.2 are shown in Figs. 3.3 to 3.6. A coordination time interval (CTI) of 0.1s (i.e.100 ms) is assumed to account for CB opening time, errors and tolerances in CTs and relays. This CTI seems reasonable as modern reclosers are capable of opening their contacts within two cycles. As described in [112], depending upon the size of the fuse, its melting time can be reduced upto 75% of its original melt time in case of repeated recloser operations. But since in the case understudy, only one reclose attempt is allowed, the phenomena of heat accumulation due to repeated recloser operations is not necessarily of concern here. Results for cases when M=1or 2 and N=10, are not included as in these cases conclusions are the same. Moreover, results for single-phase to ground or two-phase to ground faults are also not considered here as they are cleared by the recloser R3 ground OC time element i.e. 51N, without causing RF miscoordination.

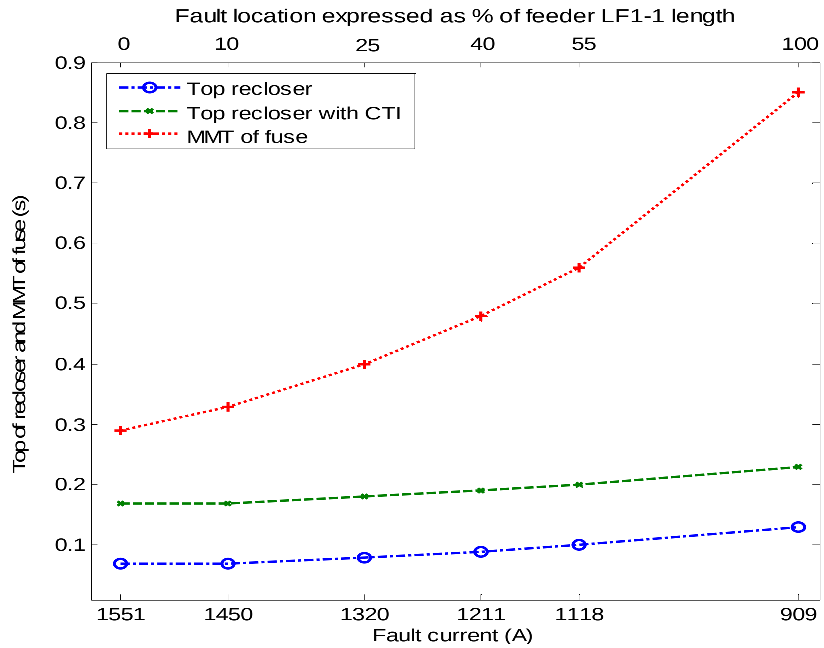

Figure 3.3: T_{op} of the recloser and MMTs of the fuse for an LLL fault at different lengths of the feeder LF1-1 with no DG connection.

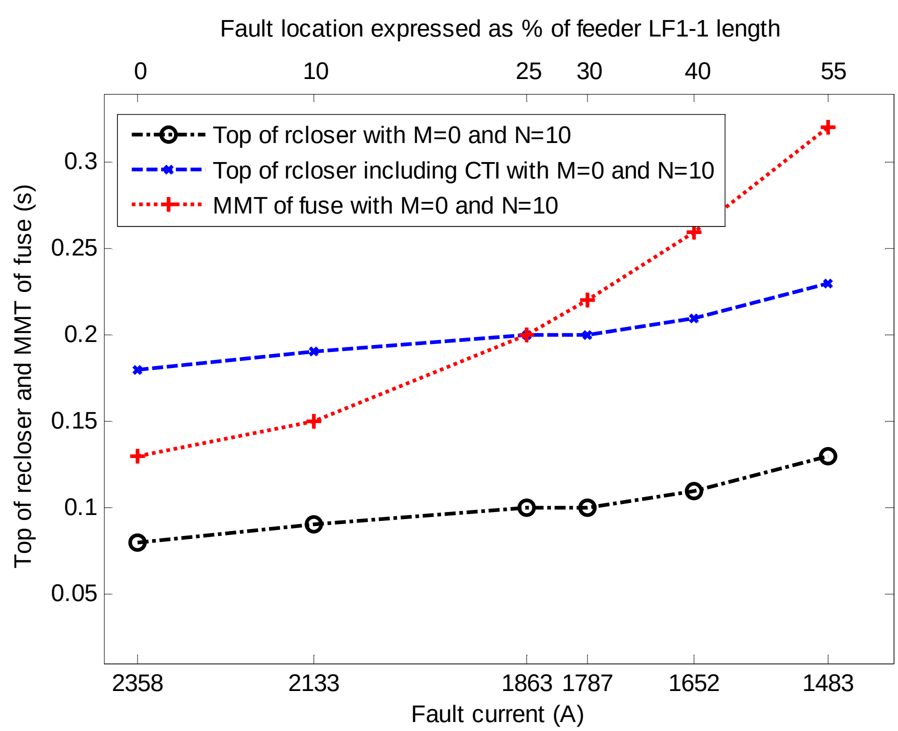

Figure 3.4: T_{op} of the recloser and MMTs of the fuse for faults shown in Fig. 3.2 when M=0 and N=10.

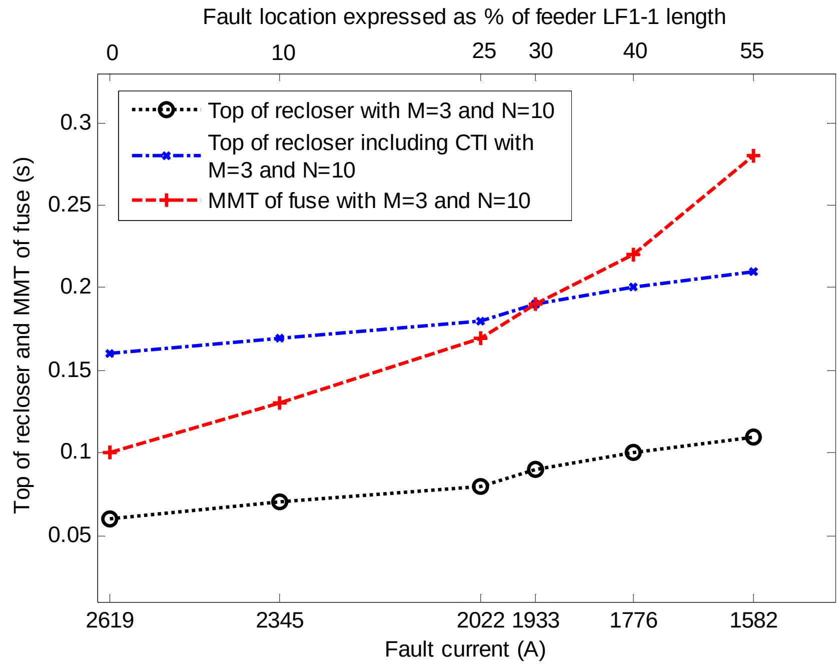

Figure 3.5: T_{op} of the recloser and MMTs of the fuse for faults shown in Fig. 3.2 when M=3 and N=10.

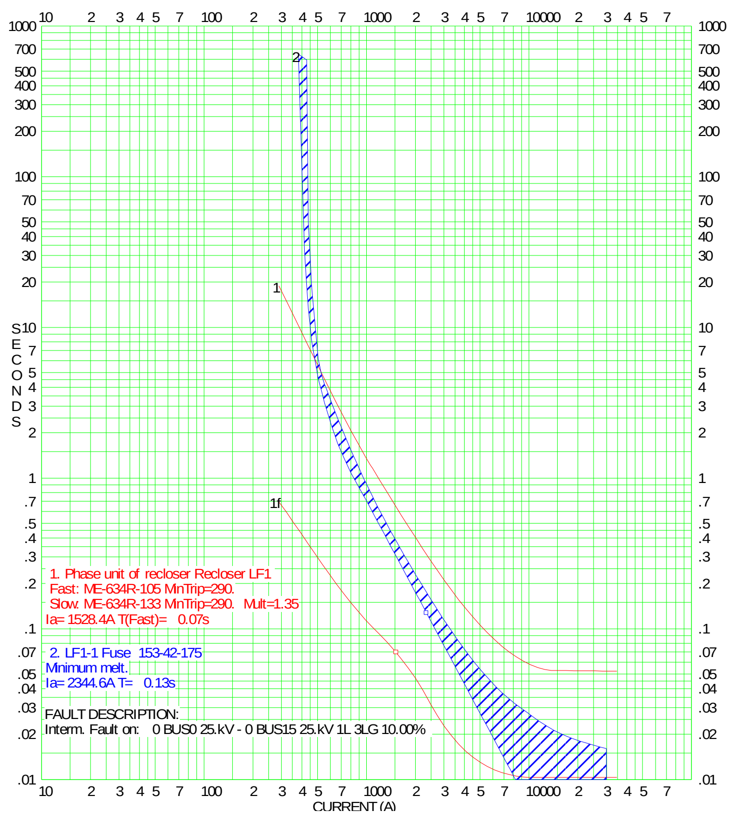

Figure 3.6: Loss of the fuse-recloser coordination between the recloser R3 and the fuse F2 for an LLL fault at 10% of LF1-1 length when M= 3 and N =10.

A comparison of T_{op} of the recloser R3 i.e. 51 element, with MMTs of the fuse as shown in Figs. 3.3 to 3.5 makes it clear that;

- Fuse saving will be ensured by the recloser against all phase faults i.e. phase to phase (LL) and LLL faults, over the entire length of the feeder LF1-1 when no DG is connected to the network.
- When DG is connected to the network, it may not be possible to ensure a CTI of 100 ms between operation of the recloser fast curve and the fuse in case of LLL faults upto 25% of the feeder LF1-1 length when $M \leq 3$ and $N = 10$ i.e. fuse saving can not be ensured in that case.

From now onwards, an LLL fault upto 25% of the feeder LF1-1 length will be referred to as the reference fault and the location corresponding to 25% of the feeder LF1-1 length will be referred to as the reference point (RP).

3.5 Fuse Saving Strategy

As discussed in the previous section (on the basis of Figs. 3.3 to 3.5), a recloser equipped with a 51element can ensure fuse saving only against low fault currents in the presence of DG. That is to say, against phase to phase and high impedance LLL over the entire length of LF1-1 and against bolted LLL faults only beyond the reference point (RP). This is due to the fact that in case of low fault currents, enough time margins are available for a recloser to operate before the fuse has any chance to blow. This is not true in the case of high fault currents e.g. for bolted faults upto the RP. The increased fault currents along with the down stream location of DG make it difficult for a recloser to operate before a fuse with a safe time margin.

Therefore, modification of the TCC of the recloser is necessary to save the fuse in the event of temporary faults when DG is connected to the network. One way to do it is to follow the procedure described in [45, 129] i.e. modification in the fast curve of the recloser on the basis of the ratio of I_R and I_F, as mentioned earlier. However, here, this method does not give the desired results. The minimum CTI for the test system is 0.04 s in the case of an LLL close in fault at the feeder LF1-1 when M= 3 and N =10. By modifying the recloser fast curve as described in [45, 129], the new CTI for the same fault will be 0.073s whereas for a fault at 10% of the feeder LF1-1 length for the same case, it will be 0.096s. In both cases, it is less than the required margin of 0.1s. Moreover, with the application of this method, the whole of the recloser fast curve is modified. This is undesirable as in the case of the test system, RF miscoordination is witnessed only over a quarter of the feeder LF1-1 i.e. up to the RP. In addition, the recloser also sees faults on LF1 where fuse saving is not a matter of concern. In these cases, upgrading the recloser R2 with an instantaneous directional OC element (i.e. 67) with a suitable trip threshold, which has a total response time (relay operating time plus CB opening time) of 2.5 to 5 cycles, may not work. As time margins in the scenarios discussed above are very small, the fuse might get damaged before the recloser R2 completes its operation to separate DG2 from the network.

Alternatively, the use of the 50 element along with the 51 element is proposed here. CTI for the aforementioned faults can be increased if a recloser having an instantaneous OC phase element (50) in addition to the 51 element is used. The 50 element with an operating time of 0.015s when a fault current exceeds its $I_{pick\text{-}up}$ will clear all phase faults occurring upto the RP with a reasonable time margin. If the operating time of the 50 element is compared with fuse blowing times shown in Figs. 3.3 to 3.5, it can be found that most of the faults will be cleared with a CTI of more than 100ms. Even in cases where it is not possible to have CTI of 100 ms i.e. for an LLL close in fault at LF1-1 when M= 3 and N =10, a recloser with a 50 element will ensure a CTI of .085s and for a fault at 10% of the feeder LF1-1 length for the same case, it will ensure a CTI of 0.115s. This shows an improvement in CTI in comparison to results obtained by following the technique described in [45, 129].

3.5.1 Options and considerations for the selection of $I_{pick\text{-}up}$ of the 50 element

$I_{pick\text{-}up}$ of the 50 element should be such that it operates only against high magnitude faults that are unlikely to be cleared by a 51 element safely. It is undesirable to set the 50 element to operate against the low magnitude faults i.e. fault occurring beyond RP. As if set too low, it may maltrip when the current momentarily rises in some conditions without a fault, e.g., due to transformer inrush current or cold load start conditions. Its setting should be such that it operates only for faults upto the RP irrespective of the number of DG units connected. $I_{pick\text{-}up}$ of the 50 element can be based either on fault currents calculated without considering DG contribution or on fault currents determined with DG contribution, as discussed in the following subsections.

3.5.1.1 $I_{pick\text{-}up}$ of the 50 element based on fault currents with no DG

If the setting of the 50 element is done without considering the contribution from DG, it will underreach i.e. the area protected by the relay will reduce if, subsequently, DG is connected downstream of the recloser. For example, in the case study, $I_{pick\text{-}up}$ of 1290A for the 50 element will ensure that the recloser will operate for the reference faults without DG connection as can be noticed from Fig. 3.3. With this setting, when DG is connected downstream of the recloser, then the latter, depending upon number of DG units connected, may not operate in the case of all the reference faults. It will operate only for faults occurring below the RP. For example, when M = 0 and N = 2, the fault current seen by the recloser for an LLL fault at the RP is only 1262 A, whereas the total fault current is 1486 A. In this case, the recloser will underreach.

3.5.1.2 $I_{pick\text{-}up}$ of the 50 element based on fault currents with DG connection

If the setting of the 50 element is done with DG contribution taken into account, it will overreach if, subsequently, DG which is connected downstream of the recloser is disconnected from the circuit. For example, in the case study, $I_{pick\text{-}up}$ of 1095A for the 50 element will ensure that the relay will operate for reference faults with DG connection. With this setting, when downstream connected DG units are disconnected, the 50 element, depending upon number of DG units disconnected, may operate for faults occurring beyond the RP and thus encroach into the area of the 51 element operation. For example, when all the DG units are disconnected, then the 50 element with $I_{pick\text{-}up}$ of 1095A will operate for faults upto 55% of LF1-1 length as can be noticed from Fig. 3.3 i.e. it will overreach.

Thus, a fixed $I_{pick\text{-}up}$ of the 50 element based either on fault current with no DG connection or based on fault current with DG connection, has its limitations. To overcome this problem, an adaptive setting of the 50 element needs to be adopted. The strategy is to set the initial $I_{pick\text{-}up}$ of the element either on the basis of fault current with no DG connection or on the basis of fault current with DG connection, then later on adaptively change the setting when a DG unit is connected or disconnected from the network. In this chapter, the reference (i.e. initial) $I_{pick\text{-}up}$ of the 50 element is based on the fault current calculated at the RP in the case of an LLL fault with no DG connection. This setting is adaptive, i.e. it will change when ever a DG unit is added or removed from the network to ensure that the recloser with the 50 element operates for all reference faults with a CTI of 100 ms.

Keeping in mind the proposed adaptive change in settings, a multifunctional microprocessor based recloser is necessary so that it can be programmed as required. Therefore, replacement of the existing recloser with a microprocessor based recloser with communication capabilities that incorporates both the instantaneous and time OC elements is recommended. A microprocessor based recloser, that is capable of communicating with DG, can adaptively change its settings online in accordance with different DG configurations. Moreover, due to the availability of discrete pick up current settings and numerous built in time-current curves, it is possible to incorporate the TCC of both the 50 and 51 elements in one unit.

3.5.2 Adaptive algorithm

To enable the 50 element to adaptively modify its $I_{pick\text{-}up}$, a simple algorithm is developed that can be programmed into the recloser control logic along with some essential data that can be stored in a data base. The algorithm is shown in Fig. 3.7 in the form of a flow chart. In the flow chart,

M and N stand for number of DG units connected at DG1 and DG2 respectively,

I_{set} stands for the reference $I_{pick\text{-}up}$ of the 50 element. It can have four different values depending upon values of M while N = 0,

I_{red} is the reduction in fault current flowing through the recloser R3 in the case of faults at the feeder LF1-1 when a single DG unit is connected at DG2; its value is different for different combinations of M and N,

I_p stands for $I_{pick\text{-}up}$ of the 50 element when $M \geq 0$ and $N \geq 1$, subscripts a, b, c, and d are defined on the basis of I_{red} for various combinations of M and N.

The data that is required to be stored in a relay data base includes different possible values of I_{set} and I_{red}. I_{set} is calculated on the basis of the fault currents that result from a LLL fault at 25% of the feeder LF1-1 length for different combinations of M and N. The magnitudes of these fault currents are shown in Table 3.1 given in Appendix B. To implement this algorithm, a communication link is necessary between the recloser and various DG units so that the former can update its setting when the latter are connected or disconnected from the network. It can be accomplished easily as modern reclosers have remote communication capability.

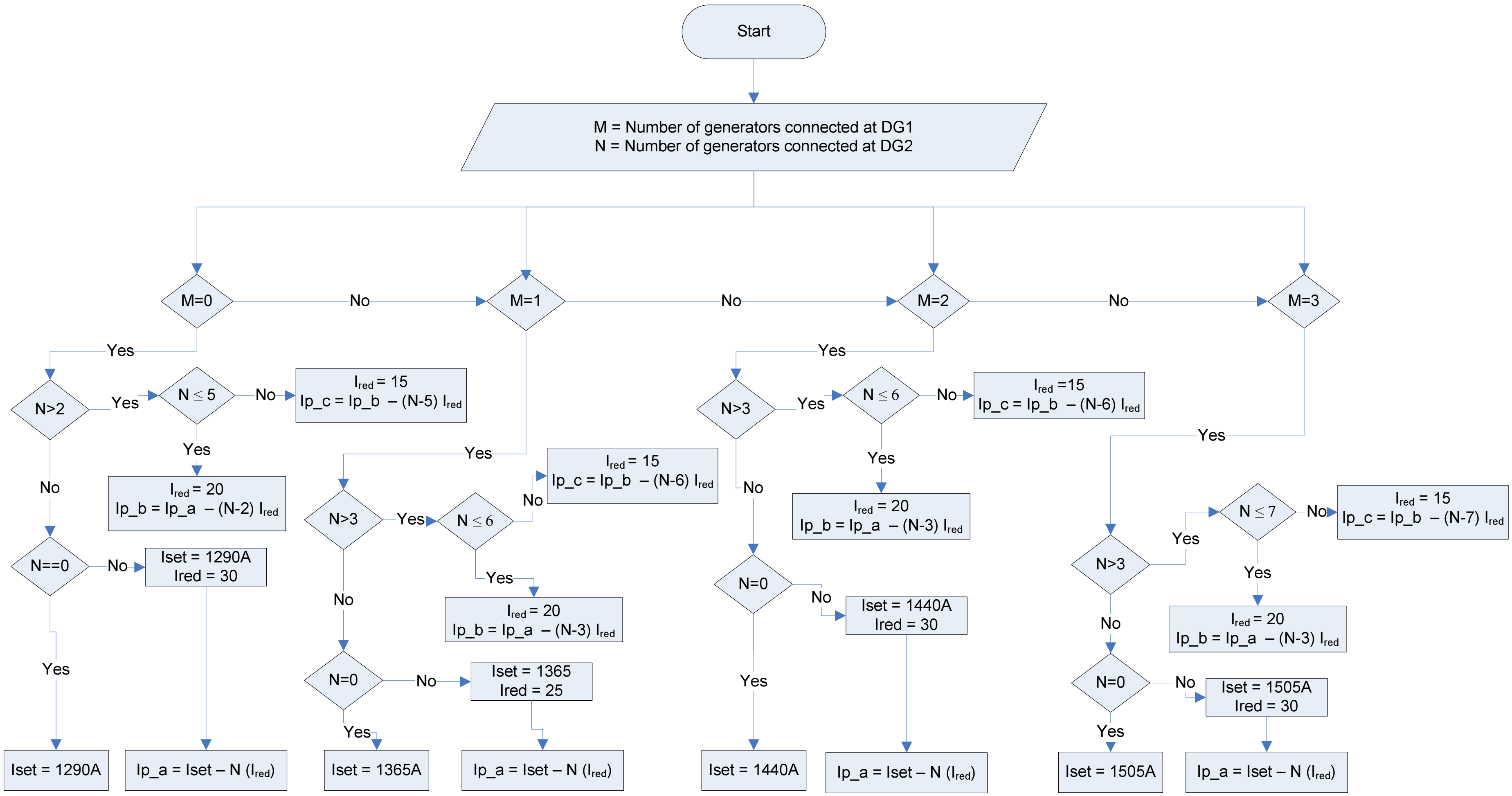

Figure 3.7: Adaptive algorithm for modifying $I_{pick\text{-}up}$ of the instantaneous element when a DG unit is connected or disconnected from the network.

3.5.2.1 Description of the algorithm

I- Through fault analysis of the test system, fault currents due to an LLL fault at different locations of the LF1-1 with no DG connection i.e. M=0 and N=0, are found and corresponding operating times of the 51 element and fuse are noted.

II- The same step is repeated with all DG units connected. A fault location farthest from the fuse end of the feeder where it is not possible to have a CTI of 100ms with a 51 element (i.e. 25% of the feeder LF1-1 length) is selected as a reference location to use as a basis for selecting $I_{pick\text{-}up}$ of the 50 element.

III- Fault current due to an LLL fault at the reference location when no DG is connected i.e. M=0 and N=0, is obtained from the step I.

IV- The reference $I_{pick\text{-}up}$ (i.e. I_{set}) of the 50 element when M=0 i.e. 1290 A, is based on the fault current magnitude obtained in step III.

- Whenever a unit is added at DG2 or subsequently removed after connection i.e. the value of N changes while M= 0, "$I_{pick\text{-}up}$ of the 50 element is reset adaptively. This is done by finding the corresponding reduction or increase in utility fault current contribution (I_{red}) flowing through the recloser R3 in the case of an LLL fault occurring at the reference location and then adding or deducting it from the reference setting. Thus when a DG unit is connected or disconnected at DG2, $I_{pick\text{-}up}$ of the 50 element also decreases or increases accordingly".

V- If DG1 is online and has one unit connected i.e. M= 1, then irrespective of the number of DG units at DG2, the reference $I_{pick\text{-}up}$ (i.e. I_{set})of the 50 element will depend upon the fault current that will result in the case of an LLL fault at the reference location with M=1 and N=0. If the reference $I_{pick\text{-}up}$ of the element is not changed from when M=0 and N=0, then, subsequently, when M=1 and N=0, it will operate for an LLL fault occurring approximately upto 35% of LF1-1 length, as in that case, fault current at that point will be about 1290 A.

- Whenever a unit is added at DG2 or subsequently removed after connection while M=1, the process described in IV is repeated but with M=1 for updating settings of the 50 element.

VI- If DG1 is online and has two units connected i.e. M= 2, then irrespective of the number of DG units at DG2, the reference $I_{pick\text{-}up}$ (i.e. I_{set}) of the 50 element will depend upon the fault current that will result in the case of LLL at the reference location with M=2 and N=0.

- Whenever a unit is added at DG2 or subsequently removed after connection, while M=2, the process described in IV is repeated but with M=2 for updating settings of the 50 element.

VII- If DG1 is online and has three units connected M=3, then irrespective of number of DG units at DG2, the reference $I_{pick\text{-}up}$ (i.e. I_{set}) of the 50 element will depend upon the fault current that will result in the case of LLL at the reference location with M=3 and N=0.

- Whenever a unit is added at DG2 or subsequently removed after connection while M=3, the process described in IV is repeated but with M=3 for updating settings of the 50 element.

Fig. 3.8 shows the new TCC for the 50 and 51 elements of the recloser R3 of the test system obtained in accordance with the proposed algorithm for the cases when M=0 while N= 0 or 10 and when M=3 and N=0 or 5. As can be noticed from these figures, $I_{pick\text{-}up}$ of the 50 element will be different for each of these cases i.e. it is modified according to the values of M and N. It will be 1290A when M= 0 and N= 0 while it will be 1095A when M= 0 and N= 10. Similarly, it will be 1500A when M= 3 and N= 0 while it will be 1370A when M= 3 and N= 5. TCC for the 50 and 51 elements for other combinations of M and N can also be achieved by following the procedure described above.

To evaluate the effectiveness of the proposed scheme, an LLL close in fault and an LLL fault at 10% of feeder LF1-1 length were modelled with the recloser R3 settings modified in accordance with the proposed algorithm when M= 3 and N =10. Both of the faults were cleared by the recloser 50 element with a CTI of 0.085s and 0.115s respectively as shown in Figs. 3.9 and 3.10.

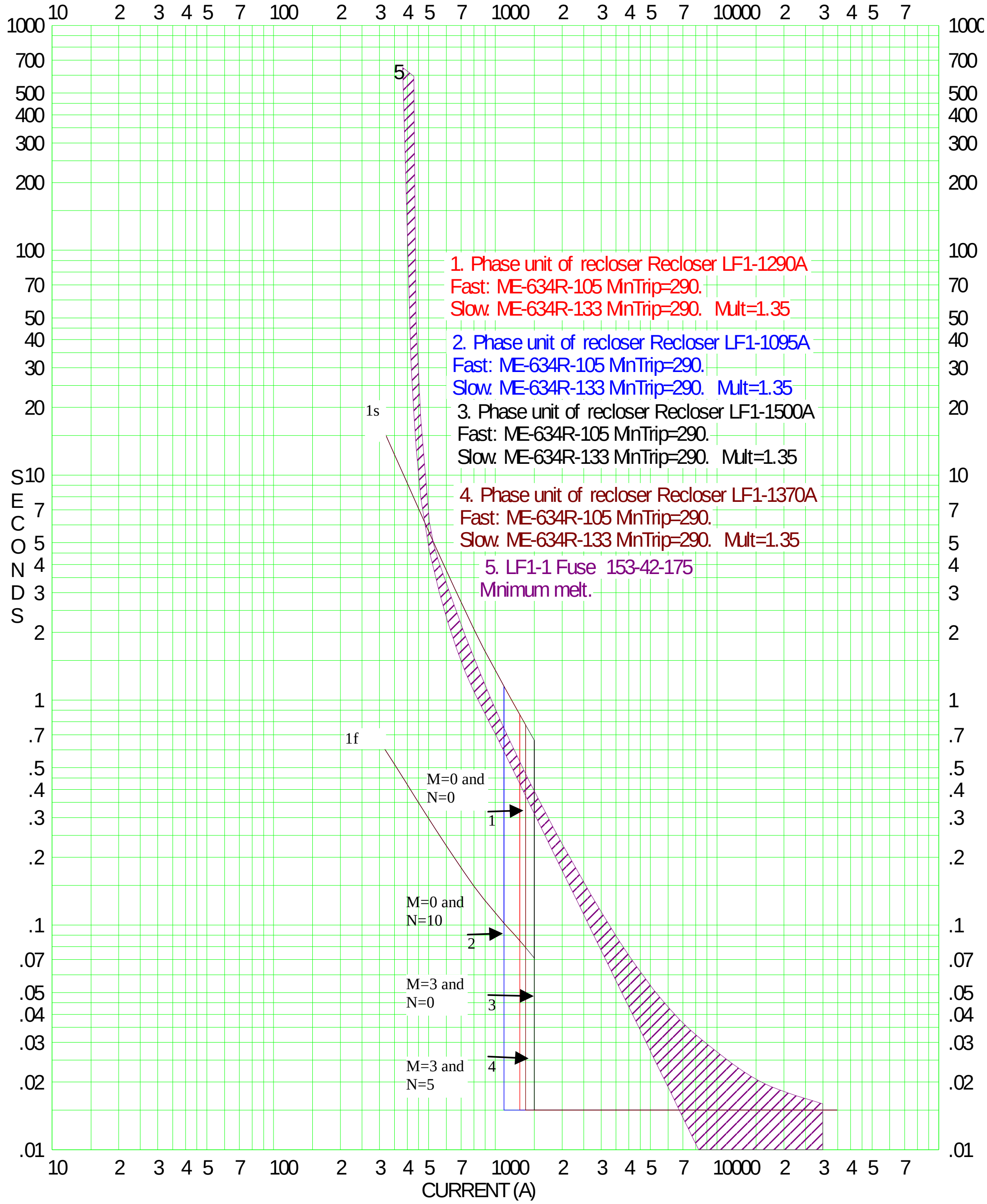

Figure 3.8: The proposed TCC for the recloser instantaneous and time OC elements when M=0 and N= 0 or 10, and when M=3 and N= 0 or 5. ‘1f’ and ‘1s’ are the fast and slow characteristic curves of the recloser whereas ‘5’ is the fuse characteristic curve.

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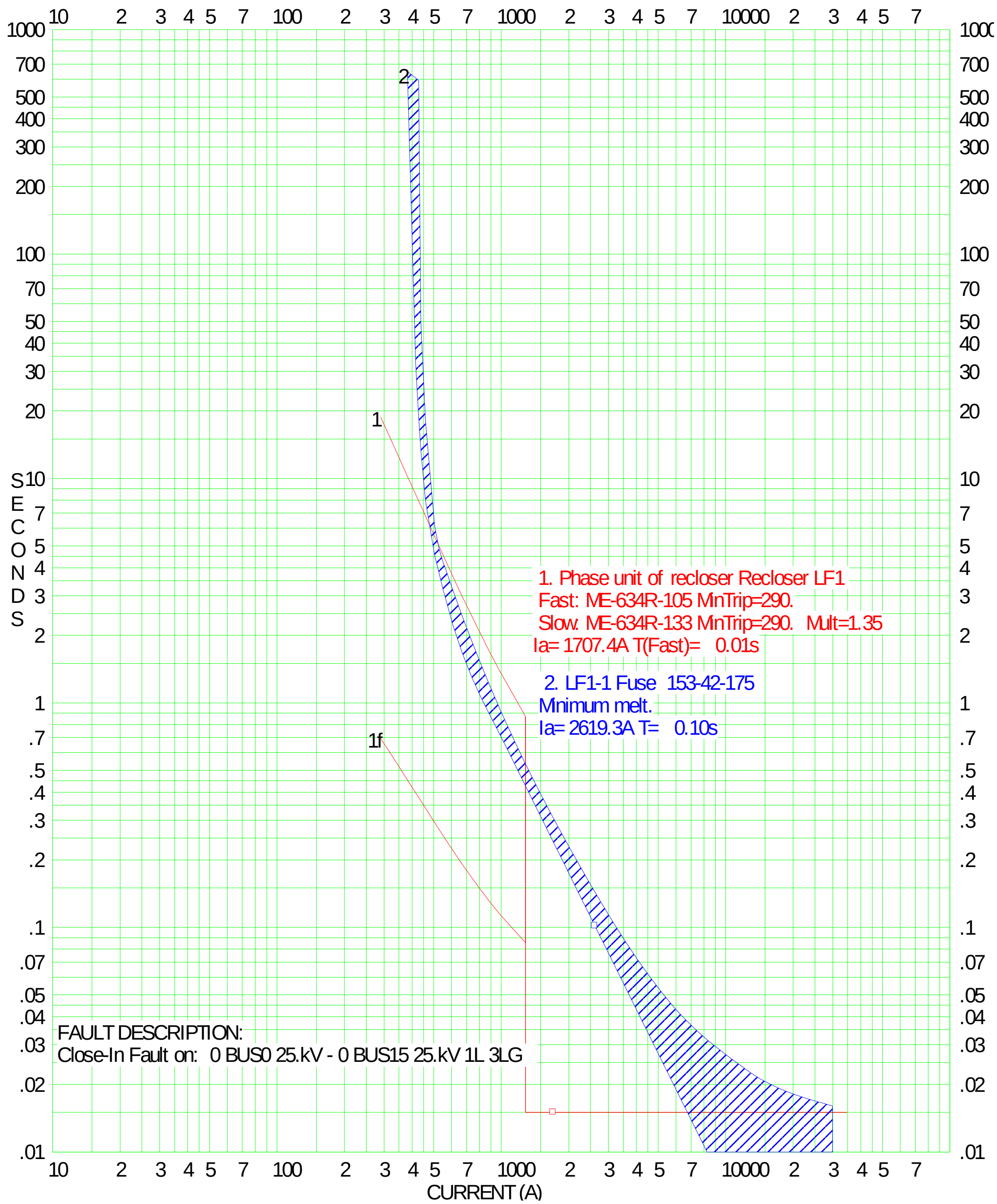

Figure 3.9: T_{op} of the recloser R3 with the modified settings and the fuse F 2 for a close in LLL fault at feeder LF1-1 when M= 3 and N =10.

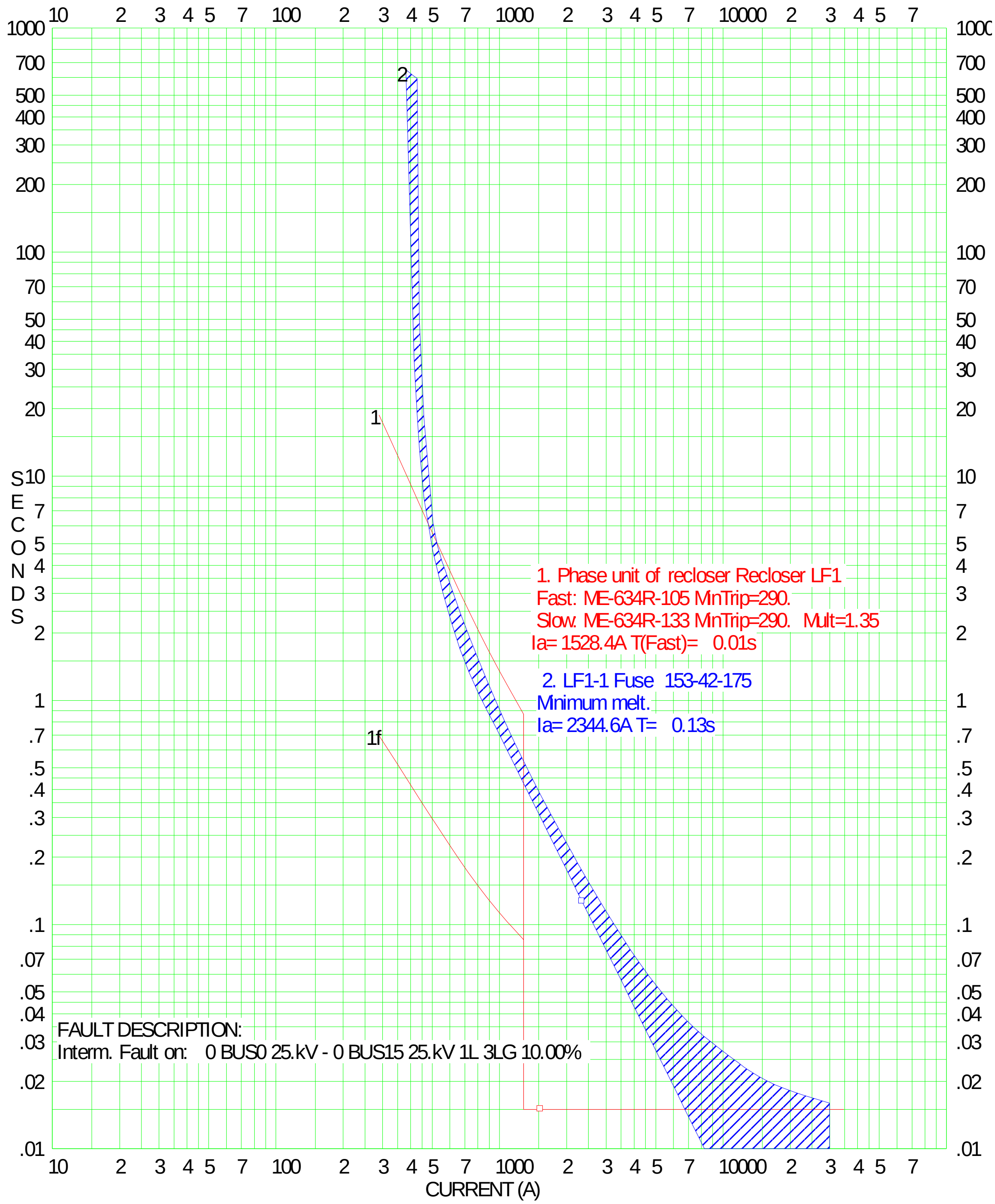

Figure 3.10: T_{op} of the recloser R3 with the modified settings and the fuse F 2 for an LLL fault at 10% of the feeder LF1-1 length when M= 3 and N =10.

Figs. 3.11 and 3.12 show the fault currents, corresponding T_{op} of the 50 and 51 elements, and MMTs of the fuse in the case of an LLL fault at the RP for different combinations of M and N. For the results shown in these figures, the settings of the 50 element were obtained by implementing the proposed algorithm in Matlab, while the required input data for the algorithm was found by simulating an LLL fault at the RP with different possible values of M and N.

From the results presented in Figs. 3.11 and 3.12, it is clear that the proposed algorithm is valid and the recloser with $I_{pick\text{-}up}$ modified in accordance with the proposed algorithm can ensure fuse saving with an acceptable time margin in the presence of DG even in the worst fault conditions.

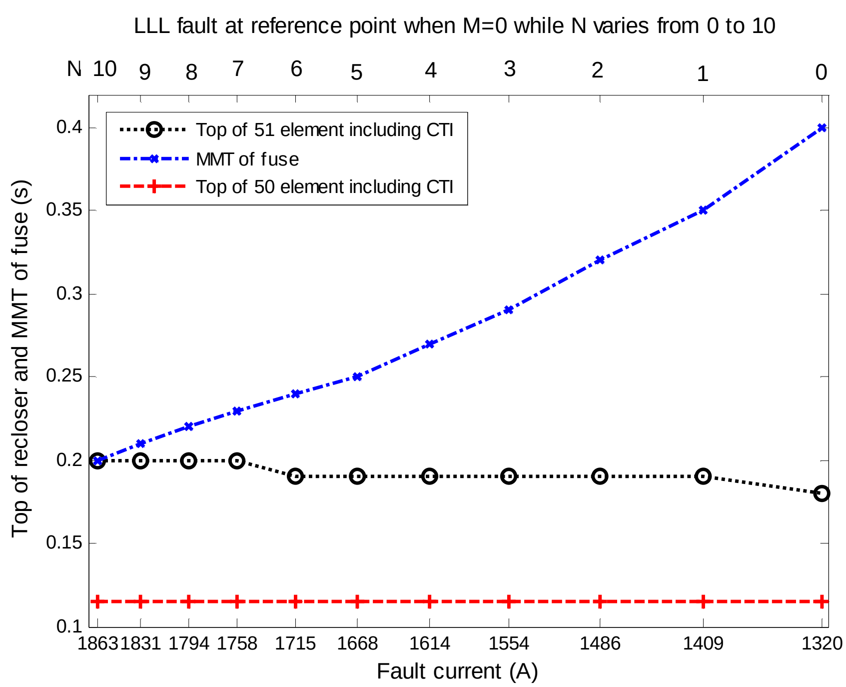

Figure 3.11: T_{op} of the 50 and 51 elements of the recloser and MMTs of the fuse for an LLL fault at the reference point when M=0 while N varies from 0 to 10.

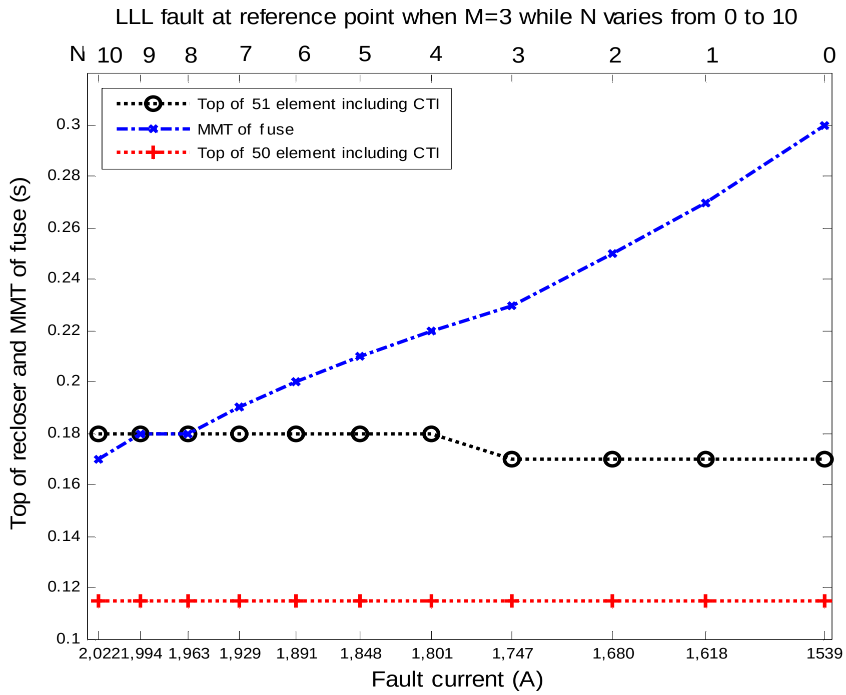

Figure 3.12: T_{op} of the 50 and 51 elements of the recloser and MMTs of the fuse for an LLL fault at the reference point when M=3 while N varies from 0 to 10.

3.6 HOW RECLOSING WILL BE APPLIED

The role of an auto reclosure is very important in restoring the system after a fault that lasts for a very short interval. However, in the case of a DN with DG, two main problems may result from automatic reconnection of the utility after a short interval [29, 52]. The first problem is that the automatic reclosure attempt may fail as a result of feeding of the fault from the DG. The second problem is that due to active power unbalance, a change in frequency may occur in the islanded part of the grid. In this scenario, an attempt at reclosing the switch would couple two asynchronously operating systems which can cause serious damages to distributed generators as well as give rise to high voltages and currents in the DN. Moreover, conventional reclosers are designed to reconnect the circuit only if the substation side is energized and the opposite side is unenergized. However, in the case of DG, there would be active sources on both sides of the recloser, thus hampering its working.

The reclosing scheme in the case of the test system is planned while taking care of the above mentioned factors. Ideally, whenever the recloser R3 operates due to a trigger from either of the 51 or 50 elements, a trip signal should be sent simultaneously to reclosers R1 and R2 to disconnect DG1 and DG2 from the network. This is in accordance with IEEE standard 1547 that requires DG to be disconnected under abnormal system conditions so that its fault contribution can not disturb the existing protection coordination [115]. However, due to the location of DG1, it is not desirable to separate it from the network in case of a fault either on the feeder LF1 or on the feeder LF1-1. If it remains connected, it will continue to feed loads on the feeder LF2 along with the utility source. So disconnection of only DG2 is recommended whenever the recloser R3 trips in case of a fault either on the feeder LF1 or on the feeder LF1-1. This will not only stop formation of an undesirable island but also avert out of phase synchronization and subsequent potential damage to DG equipment. When DG2 is separated from the network, a reclosing attempt will be made by the fast curve of recloser R3 to restore the supply. To ensure that the reclosing attempt is successful, instead of an instantaneous reclosing attempt, delayed reclosing is recommended i.e. an increase of the reclose interval from the usual 0.3 s to 1s should be considered. If this attempt is successful, DG2 will be reconnected to the system with proper synchronization. If the attempt is unsuccessful, then if the fault is at LF1-1, it will be cleared by the fuse. If it is at LF1, then it will be cleared by the recloser R3 slow curve. When the recloser R3 closes for the first time and the fault is cleared, the original network along with initial settings of the recloser R3 i.e. settings for operation without DG2, will be restored. The settings of the recloser R3 will be updated when, subsequently, units of DG2 are reconnected according to the proposed algorithm.

3.7 OBSERVATIONS

Although, the protection strategy is described for a particular network, it can be successfully applied to restore RFC in similar networks. Algorithms for adaptively changing $I_{pick\text{-}up}$ of a recloser in response to varying network configurations can be derived by following the method introduced in section 3.5. As RF miscoordination due to single-phase to ground or two-phase to ground faults is not observed in the test system, it is not discussed here. However, in networks where it does happen, a strategy similar to the one described in this chapter may be adopted.

Protection schemes requiring communication links between various protection devices are unpopular due to their high cost. But thanks to technological developments in communications and availability of wireless communication channels, such schemes can be implemented in a cost-effective manner. Moreover, multifunctional microprocessor based reclosers are already in use for power system protection. So, this scheme could be practical and may successfully be implemented in actual power networks.

3.8 SUMMARY

In this chapter, the impact of DG on RFC (i.e. on a fuse saving scheme) of a traditional DN has been investigated. Various solutions proposed in the literature to ensure fuse saving even in presence of DG have been reviewed. Through simulation results it is shown that fuse saving might not be possible in certain circumstances when DG is connected to the network. Limitations of time delayed and instantaneous overcurrent (OC) relays (i.e. 50 and 51) in respect of fuse saving when DG is connected to the network have been discussed. Moreover, it is shown that it may not be possible to ensure fuse saving with different DG sizes and configurations if the 50 element has a fixed $I_{pick\text{-}up}$. To compensate for this drawback, a simple algorithm is proposed for an online adaptive change of $I_{pick\text{-}up}$ of the 50 element in response to different DG configurations. The method to derive adaptive relay settings is also described in detail. The simulation results obtained by adaptively changing relay settings in response to changing DG configuration confirm that the settings selected theoretically in accordance with the proposed strategy hold well in operation. The method to apply reclosing is also discussed. Assumptions made during the analysis are justified and it is shown that the suggested solution is general in nature. The salient feature of the proposed scheme is that it is practical as it combines the characteristics of both the 51 and 50 elements along with a simple algorithm for adaptively changing the setting of the latter to ensure fuse saving in the presence of DG.

CHAPTER 4

MICROGRID PROTECTION

4.1 INTRODUCTION

For the purpose of this discussion, microgrids comprise of low voltage distribution systems with small distributed generation (DG) sources and controllable loads and are capable of operating either in the grid connected mode or islanded mode. The concept of the microgrid is becoming popular as microgrids are expected to provide environmental and economic benefits to end customers, utilities and society. However, for their effective operation, potential technical challenges related to protection and control need to be addressed. Protection coordination issues, such as lack of sensitivity and selectivity in the isolation of a fault, can occur in a microgrid especially in an islanded mode of operation. This chapter discusses protection issues and challenges arising when a microgrid is operating in an islanded mode. It presents and critically reviews traditional and state of the art protection strategies in respect of a microgrid protection.

Section 4.2 explains why protection coordination problems occur in a microgrid. Section 4.3, describes the possible solutions to key protection challenges in an islanded microgrid. Finally, section 4.4 concludes the chapter.

4.2 PROTECTION COORDINATION PROBLEMS IN MICRORIDS

Most of the micro-sources and energy storage devices are not suitable for direct connection to the grid and are, therefore, interfaced to the grid through power electronics (PE) interfaces i.e. converters. However, a PE converter leads to a number of protection related challenges in a microgrid, especially in an islanded mode of operation. Availability of a sufficient level of short-circuit current is not guaranteed when a microgrid is working in an islanded mode since this level may drop down substantially after disconnection from the stiff medium voltage grid. This becomes even worse in the case of a microgrid where most of the microsources are connected by means of a converter that has a built-in fault current limitation. In most cases, the contribution of converter based microsources to fault current may be limited to twice the load current or even less than that [151]. Some of the overcurrent (OC) relays will be unresponsive to this low level of fault current; others that might respond will be delayed in their operation. The undetected fault situation can lead to high voltages not withstanding the low fault currents. Moreover, if the fault remains undetected for too long, it can spread through the entire system and can cause damage to equipment.

In traditional power systems that have a generation source at one end of the network, the fault current decreases as the distance from the source increases. This happens as the impedance offered to the fault current increases as the distance of a fault from the source increases. This phenomenon is used for discrimination of devices that use fault current magnitude. However, in the case of an islanded microgrid having an inverter interfaced distributed generation (IIDG) unit, as the maximum fault current is limited, the fault level at different locations along the feeder will be almost constant. Hence, the traditional current based discrimination strategies would not work.

In a microgrid, there are multiple DG sources located at different locations with respect to the loads, so the direction and amplitude of short circuit currents will vary. In fact, operating conditions of a microgrid may be constantly changing because of the intermittent microsources (wind and solar) and periodic load variation. Also, a network topology may be regularly changed for loss minimization or for other economic or operational reasons. Moreover, controllable islands of different size and content may be formed as a result of faults in the main grid or inside a microgrid. In such circumstances, loss of relay coordination may occur due to variation in direction and amplitude of a short circuit current. A general OC protection with a single setting group may become inadequate, i.e. it may fail to ensure selectivity in isolation of a fault.

Thus, in order to cope with issues of bidirectional power flow and low short-circuit current level, in a microgrid dominated by microsources that are interfaced through PE interfaces, new fault detection and protection strategies are required.

4.3 POSSIBLE SOLUTIONS TO KEY PROTECTION CHALLENGES IN MICROGRIDS

Conventional protection schemes face serious challenges when they are considered for protecting islanded microgrids with an IIDG unit and need major revision in order to detect and isolate the faulty portion in presence of limited fault currents in such systems. The various possible solutions to cope with the problem can be broadly divided into three categories:

- Uprating of a PE inverter i.e. use of inverters having high fault current capability [152].

- Introduction of an energy storage device in a microgrid that is capable of supplying large current in case of a fault [153].

- In depth analysis of the fault behaviour of an islanded microgrid with an IIDG unit to comprehend the behaviour of system voltages and currents [154,155]. This will in turn help in defining alternative fault detection and alternative protection strategies that, instead of relying on a large fault current, depend on other parameters like change in voltage of a system due to a fault [156].

4.3.1. Use of differential protection scheme

In [157] the authors have proposed a differential protection scheme to overcome the problem of low fault currents in the case of an isolated microgrid having IIDG. A protection scheme based on differential relays is selected as its operation is independent of the fault current magnitude as opposed to the overcurrent relays. No new algorithm has been developed in this particular study, but it certainly shows a new application of differential protection which is traditionally used for transformer protection. Of course, this scheme solves the problem of low fault current in the case of an IIDG, but a lot of other issues are neglected. The proposed protection scheme might not be able to differentiate between a fault current and an overload current. Nuisance tripping might result whenever the system is overloaded. Traditional differential protection schemes, in some instances, are unable to differentiate correctly between internal faults and other abnormal conditions. Moreover, mismatch of the current transformers can also be a source of malfunction.

For the coordinated clearing of a fault in an isolated microgrid to ensure selectivity, it is important that different distributed resources (DRs) can effectively communicate with each other. To this end, evolving a distribution system version of the pilot wire line differential scheme (pilot wire is used to pickup fault conditions at a remote location) may be the need of the hour [151].

4.3.2 Use of a balanced combination of different types of DG units for grid connection

Another way to ensure the proper protection of a isolated microgrid is to use DG systems with synchronous generators or to use inverters having high fault current capability or to use a proper combination of both type of DG units so that conventional protection schemes can be properly used. This combination will ensure large fault currents that can be detected by conventional protection schemes. Of course, for the large size inverter, you need large size power electronic switches, inductors and capacitors, etc, thus making the system expensive. It may be added that in the case of low voltage circuits, fault current should be at least three times greater than the maximum load current for its clearance by overcurrent relays.

Directional relays can be used to clear the fault within the microgrid provided they see the fault current exceeding the maximum load current in their tripping direction. However, this is not always true as in the case of microgrids, faults are fed from different directions [151].

The protection scheme for an islanded microgrid is heavily dependent on the type of the controller used for the inverter, as the controller actively limits the available fault current from an IIDG [158,159]. This fact has been shown in the said literature, where two different controllers i.e. one using dq0 (direct axis, quadratic axis and zero sequence) coordinates and the other using three-phase(abc) coordinates, are employed to control a standalone four leg inverter supplying a microgrid. In both the cases, the fault current is quite small but its magnitude is different. As a result of reduced fault current, the overcurrent based protection schemes become less effective as they require more time to detect and, subsequently, clear the fault and the selectivity of protection scheme is reduced [156]. That's why it is important to analyze the fault behavior of an IIDG system to understand the behavior of network voltages and currents so that a suitable protection scheme can be selected. One of the options to detect a fault in such a system is to make use of voltage sequence components. It is possible to calculate the values of voltage source components for different types of faults since the theory of the interconnection of equivalent sequence networks in the event of a fault is applicable here [158].

4.3.3 Voltage based detection techniques

Another method to detect low magnitude fault current is to make use of the large depression in network voltage in the event of a fault [160]. However, keeping in mind the small size of a microgrid (i.e. electrically small), the voltage depression might not have a sufficient gradient to allow for discrimination of the protection devices. This calls for measurement of some other parameter/s to supplement the undervoltage based fault detection. Simple device discrimination can be achieved by current detection along with definite time delays.

This scheme, if adopted in a conventional system, will clearly subject the system to high stresses due to delayed clearance time (resulting from definite time delays) in the presence of a large fault current. However, as in the case of an islanded microgrid with IIDG, the fault current would be restricted, the definite time delay would not pose any serious problems. The duration of delays can be set on the basis of sensitivity of loads or generation to undervoltage. Adequate discrimination paths can be set up for possible networks that can exist within a microgrid by selecting different delays for forward and reverse direction flow of the fault current. Moreover, this protection scheme doesn't require any communication between the relays for its implementation.

The literature [156] proposes various voltage detection methods to protect networks with a low fault current. One of the suggested methods makes use of the Clarke and Park transformations [161] to transform a set of instantaneous three phase utility voltages into a synchronously rotating two axis coordinate system. The resultant voltage is compared with a reference value to detect the presence of the disturbance. In the case of an unsymmetrical fault, the utility voltage ‘dq’ components have a ripple on top of the DC term. These components are first notch filtered and then compared with a reference for the detection of the disturbance.

Another voltage detection method makes use of the fact that the sum of two squared orthogonal sinusoidal waveforms is equal to a constant value [162]. The necessary 90 degree phase shift is achieved by passing each phase voltage through an all pass filter. The output is obtained by summing the squared values of the two signals for each phase and then compared with the reference after filtration to detect any disturbance.

The above mentioned schemes have their limitations. The performance of the schemes can suffer due to time delays and filtering actions. The time required for detection of faults in each case is different as it depends upon the type of the fault as well as on the magnitude of the voltage at the faulty feeder at the moment of the occurrence of the fault. Time delay is also introduced by filtering action.

A novel scheme based on current traveling waves and bus voltages is proposed in [163] for the protection of a microgrid. In the said scheme, current traveling waves are used to identify a faulted feeder while the bus bar voltages are used to determine whether an event is caused by a fault or a switch operation. However, simulation results necessary to evaluate the authenticity of the scheme are missing.

4.3.4 Employing adaptive protection schemes

Adaptive protection schemes are presented as a solution for microgrid protection working either in grid connected or islanded mode. The basic philosophy behind these schemes is automatic readjustment of the relay settings when the microgrid changes from grid connected to isolated mode and vice versa. In the case of islanded microgrid, the adaptive protection strategy can be used by assigning different trip settings for different levels of fault current which, in turn, are linked to different magnitudes of system voltage drops resulting from a disturbance in the system. Also, relay settings must be updated in response to changes in a microgrid. Otherwise, relays may maloperate or in the worst case scenario, may fail to operate when required [164].

A protection strategy for a micro-grid operating either in an islanded mode or parallel mode is described in [165]. The sample microgrid is divided into four protection zones with the help of circuit breakers. Different fault conditions i.e. single phase to ground and phase to phase faults, are simulated in different zones, and results are presented to confirm the validity of the scheme. However, this scheme has its downside. For selective clearance of the faults occurring in different zones, up-to-date knowledge of the loads and status of various zones of the microgrid is needed. As without this knowledge, the relay settings can’t be modified in accordance with the changing system conditions.

As discussed earlier, a fault in the system can result in severe voltage depression in the entire network (due to low impedances within the network) in the case of an islanded microgrid with an IIDG unit. In such a scenario, selectivity can’t be assured with the use of voltage measurement alone. A possible solution may be the use of a voltage restrained overcurrent technique [156]. The logic scheme of that technique is shown in Fig. 4.1. A large depression in voltage (which happens mostly in the case of a short circuit as opposed to an overload) will result in the selection of a lower current threshold, this would effectively move the time-current characteristic down and thus tripping time would be reduced. In contrast to this, tripping times would be longer in the case of overloads, as small voltage depression would not be able to switch the scheme to the lower setting. Thus the system would retain the longer time setting corresponding with long-term characteristics.

This scheme, although looking promising, has its drawbacks. It is not clear how the scheme will perform if there is little difference in magnitude of a voltage depression resulting from short circuit and overload conditions. The scheme seems to make use of the principle of relays with inverse time characteristics i.e. the larger the fault current, the smaller the response time. Also, long clearing times in case of faults causing small voltage drops pose the risk of fault currents spreading in the entire network. This can cause stress in the network.

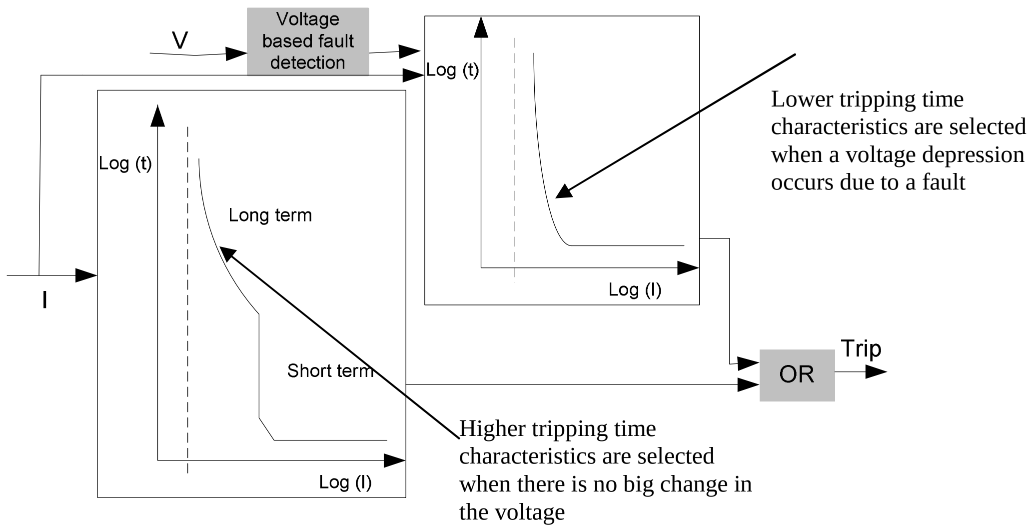

Figure 4.1: voltage restrained overcurrent protection scheme logic circuit

4.3.5. Protection based on symmetrical and differential current components

The literature [166] suggests the detection of a single phase to ground (1LG) and a phase to phase (LL) fault by making use of symmetrical current components. Symmetrical components consist of positive, negative, and zero-sequence quantities. Basically, positive-sequence quantities are those present during balanced, three-phase conditions. Positive sequence quantities make up the normal voltages and currents observed on power systems during typical, steady-state conditions. Negative-sequence quantities are a measure of the amount of unbalance existing on a power system. Mostly, zero-sequence quantities are associated with ground being involved in an unbalanced condition. Since negative- and zero-sequence quantities are usually present in substantial levels only during unbalanced, faulty conditions on a power system, they are often used to determine that a faulty condition exists on a power system. Negative-sequence can be used to detect LL, 1LG, and phase-to-phase-to-ground (LLG) faults. Zero-sequence can be used to detect 1LG and LLG faults. A threshold is assigned to each of the symmetrical current components to prevent the microgrid protection operating under unbalanced load conditions.

4.4 SUMMARY

Different protection issues that may occur in a microgrid operating in an islanded mode of operation i.e. lack of protection sensitivity and selectivity, have been discussed in this chapter. These issues should be taken into account for designing a reliable protection scheme for a microgrid. Traditional and state of the art protection strategies in respect of microgrid protection have been critically reviewed. Techniques and strategies, such as, analysis of current using digital signal processing for characteristic signatures of faults [167], development of a real-time fault location technique having the capability of determining exact fault locations in all situations, impedance methods, zero sequence current and/or voltage detection based relaying, and differential methods using current and voltage parameters [151], have the potential for developing more robust protection schemes to cope with the new challenges.

CHAPTER 5

ISLANDING DETECTION FOR THE INVERTER INTERFACED DISTRIBUTED GENERATION

5.1 INTRODUCTION

According to current technical recommendations e.g. G83/1, G59/1, G75, ETR-113/1, IEEE-1547, distributed generation (DG) should be automatically disconnected from a distribution network (DN) when the utility's main source is disconnected from the network. This is ensured through a protection scheme which is commonly known as anti-islanding protection or loss of mains (LOM) protection. To adhere to existing standards and regulations, an anti-islanding feature such as an islanding detection algorithm, is incorporated as a mandatory feature in the controller of commercially available inverters that are used to connect distributed energy sources such as fuel cells, photovoltaic, microturbines and wind turbines to the grid. These algorithms are used as the local protection functions to prevent energization of a local network from DG when islanding occurs as well as to prevent any out-of-synchronism reclosure of DG units [168].

The various existing islanding detection strategies may broadly be divided into three categories; active, passive and communication based strategies. Passive islanding detection techniques are based on measuring a system parameter(s) and comparing it with a preset threshold. Variations in various parameters such as voltage, frequency and total harmonic distortion (THD) of current or voltage are continuously monitored at the interconnection point of DG with the grid. When islanding occurs, generally, a significant change occurs in values of these parameters. This property is used as an indication that islanding has occurred. In the active islanding detection schemes, disturbances such as low frequency inter-harmonic currents are injected locally into the system and responses of these disturbances are used to detect islanding conditions. The communication-based schemes use telecommunication means to alert and trip DG when islands are formed. These schemes include power line signaling and transfer trip. A comprehensive survey of these strategies is given in literature [169-172].

In this chapter, THD based islanding detection schemes i.e. schemes that measure the output current THD, for the inverter interfaced DG (IIDG) are discussed and the role of various factors like uncertainties in filter parameters, variations in the grid (utility) THD and the grid impedance on the performance of these schemes is investigated through simulation. To this end, the test system i.e. a three phase PWM voltage source inverter (VSI) with a two-loop feedback structure connected to the grid (utility) through an LCL filter, has been modelled in Matlab/Simulink. The simulation results obtained from the test system show that THD in the inverter output current may be affected (depending upon the design of the controller) by the variations in the utility THD and the utility impedance. Consequently, the working of THD based schemes may suffer if these factors are not taken into consideration while selecting the trip threshold. Moreover, interactions between EMC capacitors and grid impedance are also discussed and their impact on the performance of a voltage source grid connected inverter i.e. deterioration of working of the inverter, is also investigated through simulations. These simulations show that EMC capacitors can also affect the islanding detection schemes used for inverter interfaced Distributed Generation (IIDG) as they can introduce a large increase in the output current THD of the inverter. This phenomenon has not yet been taken into consideration by researchers while investigating the performance of an inverter.

Section 5.2 discusses the working principle of THD based islanding detection methods. Section 5.3 explains why it is difficult to select a trip threshold for THD based islanding detection methods. Section 5.4 explains about the importance and selection of simulation software. Section 5.5 describes the test system topology that comprises of a VSI along with its controller which is connected to the grid through an LCL filter. In section 5.6, linear analysis of the controller is presented. Section 5.7 describes the impact of various factors like uncertainties in the filter parameters, variations in the utility THD and the utility impedance on the output current THD of the inverter, that has a simple proportional controller, with the help of the Simulink model. Section 5.8 investigates the affect of EMC capacitors on the performance (behaviour of the output current) of the inverter in grid connected mode of operation. Finally, section 5.9 concludes the chapter.

5.2 WORKING PRINCIPLE OF THD BASED ISLANDING DETECTION METHODS

Islanding detection methods based on THD measurement of either the output voltage or the output current of the inverter are discussed in the literature [173-181]. In these methods, the inverter monitors the THD of either the inverter terminal voltage or the output current and shuts down if this THD exceeds the trip threshold. The rationale is that, in normal operation, the DN acts as a stiff (low impedance) voltage source, maintaining a voltage with low distortion (THD) on the inverter terminals. In the case of islanding, two mechanisms are expected to cause an increase in voltage THD. Firstly, the impedance at the inverter terminals increases due to disconnection of the low impedance DN and only the local load (with much higher impedance than the grid) remains connected to DG. As a result, the inverter output current harmonics may cause increased levels of voltage harmonics in the terminal voltage. Secondly, non-linear loads within the island e.g. distribution step-down transformers, may be excited by the output current of the inverter [173]. Due to current excitation, the voltage response of the non-linear loads can be highly distorted [175,176,182].

5.3 WHY SELECTION OF A TRIP THRESHOLD IS DIFFICULT

Selection of an appropriate trip threshold that provides reliable islanding protection, but does not lead to nuisance tripping of the inverter, is an issue with passive islanding detection schemes including those based on THD measurement [176]. It is clear that the selected trip threshold should be higher than the THD that can be expected in the grid voltage but it should be lower than the THD that will be produced during islanding. However, this threshold is difficult to select practically due to a number of reasons.

To maintain power quality, standards like ANSI/IEEE 519 and IEEE 1547 [183, 115], stipulate that for utility connection mode, total harmonic distortion (THD) of the output current of the inverter should be a maximum of 5%. To meet this criterion with some safety margin, the inverters are usually designed to have lower distortion than the standard. However, the DN voltage may have voltage THD of 5% or more if there are significant local non-linear loads on high impedance lines. Moreover, when THD in the output current of the inverter is 5% (the maximum allowable limit), it is possible in the presence of RLC loads that the THD in the voltage measured at the common node of the load and utility is 5%. This is due o the fact that the parallel RLC circuit can exhibit low-pass characteristics that attenuate the higher frequencies. In this case, it is clear that the THD threshold will have to be set lower than 5% [174]. In addition, the distortion level may change rapidly as nonlinear loads are switched on and off.

THD in the output current of the inverter, depending upon the design of the controller, is also influenced by grid impedance. This is because in grid connected mode, along with the filter components, the resonance frequency of the system is also determined by the grid impedance [181,184]. The resonance frequency without taking into consideration the grid impedance is given by the following equation;

$$f_{res} = \frac{1}{2\pi\sqrt{L_f C}} \qquad 5.1$$

When a stiff voltage such as the grid is connected, the resonance frequency will be modified according to the following equation;

$$f_{res} = \frac{1}{2\pi\sqrt{\left(\frac{L_f L_g}{L_f + L_g}\right)C}} \qquad 5.2$$

Where L_f and C represent inductance and capacitance of the filter whereas L_g represents the grid side impedance.

Due to changes in the resonance frequency caused by grid impedance, amplification of certain harmonics may take place which may result in mal-operation of a THD based islanding scheme, leading to unnecessary separation of DG from the system. Thus, if the THD trip threshold is selected for ideal condition (stiff grid case) it may be ineffective in weak grid conditions (high grid impedance). On the contrary, if the THD threshold has been selected for the worst condition (weak grid case), it may be ineffective when the system is working in stiff grid case. Moreover, THD in the output current of the inverter, depending upon the design of the controller, is also affected by the THD of the utility voltage. The last two phenomenons i.e. affect of utility impedance and utility voltage THD on the output current THD of the inverter have been investigated here with the help of simulation studies.

5.4 SELECTION OF SIMULATION SOFTWARE

Advances in the field of computer simulation and microprocessor technology have allowed various control schemes involving power electronics to be more flexible and easy to follow. Different computer simulation programs such as PSpice, Matlab, and Simulink help to investigate circuit waveforms, dynamic and steady-state behavior of control systems. This tool is very helpful to determine the behavior of a circuit before it is practically implemented. Thus, by simulation, it is easier to study the influence of different parameters on system behavior compared to the hardware experimentation in a laboratory which requires significant time and money. In the industrial sector, computer simulations are being used in combination with hardware implementation to optimize the design process.

Knowledge of the nature of simulation, its limitations and the assumptions that are made, is important to trust the accuracy of simulation results. It also helps in appreciating the problems associated with modeling and simulation process and consequently, making results more accurate. The complexity of the actual characteristics of switching devices is a major problem in their modeling in power electronic circuits. This is why accurate models of real switching devices are not always available. Magnetic components like inductors also suffer from this drawback. A clear evaluation of the objectives of simulation helps in obtaining the results without making the model of a circuit unnecessarily complex, thus saving precious modeling and computation times [185].

During their transition from one switching state to the other, switching circuits (both passive and active) exhibit extreme nonlinearity. This nonlinearity needs to be taken into account while deciding upon a suitable computer simulation tool. The software should be capable of performing this type of simulation. It should also have the capability to run the simulations with the appropriate resolution to represent the smallest time constant in the simulation model with acceptable accuracy. Switching circuit simulations normally take quite a long time due to the large difference between the smallest and the largest time constants in the circuit (which can be several orders of magnitude). So, software must be efficient in solving numerical problems. Simultaneously, this software should also represent the controller comfortably.

Since extensive programming is required for modeling the circuit and manipulating the results in high level languages like C or FORTRAN, it’s wise to use a package like Matlab, which is specifically developed with built-in convenient features. Matlab is a well-known computer package for high-performance numerical computation and visualization. It has an edge over programming languages like C and FORTRAN as it is user-friendly due to the convenient built-in features and various specialized toolboxes. As Matlab performs array and matrix manipulations easily, it solves numerical problems in a fraction of the time of other software packages like SPICE [186]. Simulink, an extension to Matlab, is a powerful graphical pre-processor developed specifically for simulations of dynamic systems. Circuit models in Simulink are available as block diagrams. In addition to block libraries containing various functions, which are supplied with the software, the users have the flexibility to create their own blocks with the use of S-function written in C or Matlab M-files. This flexibility is not available in circuit-oriented simulators. The Control System Toolbox and the Signal Processing Toolbox, available in Matlab along with other toolboxes, provide the tools for control system design and manipulation of results from the simulation. Of course, Matlab/Simulink has its downside too; it is not easy to model the inductor saturation phenomenon which becomes quite important at high power. However, it produces results that are accurate enough. That’s why Matlab is used to carry out computer simulation studies for this project.

5.5 SYSTEM TOPOLOGY AND DESCRIPTION

Utility connected power electronic inverters are used to connect renewable energy sources such as solar, wind, or marine to the distribution or utility grid. They convert variable frequency AC or DC into 50/60 Hz fixed frequency AC, to inject into the grid and/or to supply to local loads. The inverter is operated in current control mode when connected to the utility which dictates the output voltage. The output current of the inverter is controlled to have a low harmonic distortion. A good current quality is normally achieved by using a combination of a well designed pulse width modulated (PWM) inverter, an output filter and a robust feedback current control strategy. The results show that variations in utility impedance can make the system unstable due to reduced bandwidth or due to changes in the resonance frequency. To ensure robustness, the design of the controller should be for a large set of the utility impedances and the utility THD values, ensuring the controller will be stable in all grid conditions [187-197].

The circuit diagram of the test system is shown in Fig. 5.1. It comprises a three-phase VSI whose output is connected to the three-phase grid (utility) system via an LCL filter. The controller has a two-loop feedback structure i.e. an outer grid current loop and an inner filter capacitor current loop with a simple proportional controller in both the loops (similar to that described in [191]). It also incorporates a grid voltage feedforward loop to compensate for the effect of utility voltage harmonic disturbances. Classical control design methods are used to determine the nominal controller parameters. After the description of the controller, designed in Matlab/Simulink, the behaviour of the output current THD of the inverter has been investigated.

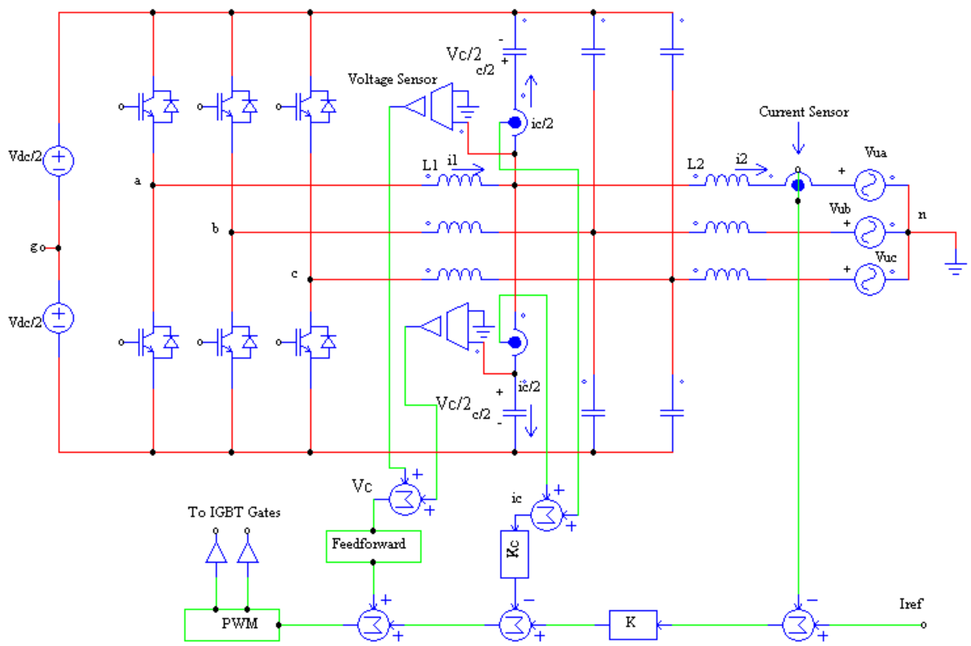

Figure 5.1: The test system comprising of a three-phase VSI whose output is connected to the three-phase grid (utility) system via an LCL filter. In Fig. k_c and k stand for proportional (P) gain in the inner and the outer feedback loops respectively.

Insulated gate bipolar transistors (IGBTs) are used as switches. As the output voltage is being dictated by the utility, the inverter is operated in current-control mode. The output current is controlled to be sinusoidal and in synchronism with the utility voltage so that the power flows from the dc side to the utility side.

The choice of the LCL filter is due to its superior performance as compared to LC and L filters. In systems where an LC filter is used, the resonance frequency of the filter is determined by the utility impedance. So the damping of the system is difficult due to utility impendence uncertainty. In systems where only coupling inductors are used, large size inductors are required to limit the di/dt and hence, the ripple current. In case of high rating devices, the losses in the inductors can't be ignored. Moreover, larger inductors are significantly more expensive than smaller ones. The LCL filter topology allows the use of smaller inductors, thus ensuring minimal losses, cost, size and weight of the whole system. Moreover, this configuration also offers a big advantage in high power systems where the switching frequency is limited [188,198]. However, this configuration has a down side, too.

It requires a carefully designed current controller, which is more complex and expensive, in order to avoid the problems caused by filter resonance.

The aim of the controller design is to achieve a specified output current THD (to improve power quality) at minimum cost. The selection of inverter power electronic devices is normally for a given system current and voltage rating. For a given filter topology, the dc link voltage is determined by the requirement to drive the current i_1 in the desired direction, e.g. in this case into the utility. The PWM switching frequency and maximum current ripple are determined by allowable losses in the power switches. The selection of the value of the inductor L_1 is based on the switching frequency, dc link voltage and maximum ripple current. The capacitance value is selected such that its impedance at the switching frequency is much lower than that of the inductor L_2. The inductor L_2 represents an actual inductance in the filter and is thus, separate from the utility impedance. The utility impedance can be modelled by changing the value of L_2. The inductor L_2 is important as it serves the following three purposes:

- It ensures the filtration of switching frequency current harmonics even if the impedance of a utility is lower than that of capacitors.
- It makes the controller performance less sensitive to variations in the utility impedance.
- It facilitates wireless paralleling of multiple systems connected to an isolated load (normally in voltage control mode).

The L_1 inductors are much larger and hence, more expensive as compared to L_2 inductors since the former has to carry both the fundamental and the high frequency ripple components of the current.

5.5.1. Elements of the Simulink model

The simulink model of the voltage source grid connected inverter is shown in Fig. 5.2. The model comprises of two main sections [191]:

- Electrical section comprising of dc-link, inverter, LCL filter, and the utility.

- Controller section comprising of current measurements, ADC's, PWM generator, reference currents, feedforward signals, summation operators and gains.

5.5.1.1 Three-phase inverter

The Universal Bridge Block is set up to be a three-phase inverter. IGBTs are selected as switching devices with diodes across them. The switching time is set to a typical IGBT switching time (0.2ms). The on-state voltage drop across the IGBTs and the diodes is set to be 1.5V.

5.5.1.2 PWM generator

A PWM generator block is available in Simulink. The modulating signal is compared with a triangular carrier signal to produce the switching commands: one for the upper switch and the other for the lower switch. The carrier frequency is chosen to be 8 kHz.

5.5.1.3 LCL Filter

A special configuration is used to connect filter capacitors to the DC link as shown in Fig. 5.3. For each phase, two capacitors of the value C/2 are connected to the dc-link (one to the +dc-link and one to the –dc-link). The capacitor current measurements for each phase will be the summation of the currents flowing in the two capacitors. The equivalent series resistances (ESR) of the inductors and the capacitors have been ignored because these resistances improve the resonance damping of the system and the simulation condition is to take the worst case scenario.

5.5.1.4 Utility system

With regard to the utility grid, the assumption is that it behaves like a three-phase stiff voltage source, which is not affected by the current injected into it. It is modelled as a balanced three-phase voltage with amplitude of 230 V_{rms} (line to neutral) and a frequency of 50Hz as shown in Fig. 5.4. The voltage harmonics are taken into account by adding the most dominant harmonics i.e. 3^{rd}, 5^{th}, 7^{th}, etc as voltage sources in series as shown in Fig. 5.5.

5.5.1.5 Analogue to digital converters (ADCs)

An Analogue to Digital Converter (ADC) is modelled by a sample and hold circuit (zero order hold) as shown in feedback loops in Fig. 5.2. The sampling frequency is set to 16 kHz.

5.5.1.6 Computational time delay

As digital signal processing needs some time to perform calculations, adding a time delay element in the system is important. This time delay has a great effect on the controller performance and has to be included in the computer simulation model. Computational time can be modelled by a transport delay block prior to the zero-order hold block so that all the measurements are delayed by computational time.

5.5.1.7 Reference Current

Reference current is a simple sinusoidal signal with amplitude of 100A as shown in Fig. 5.6.

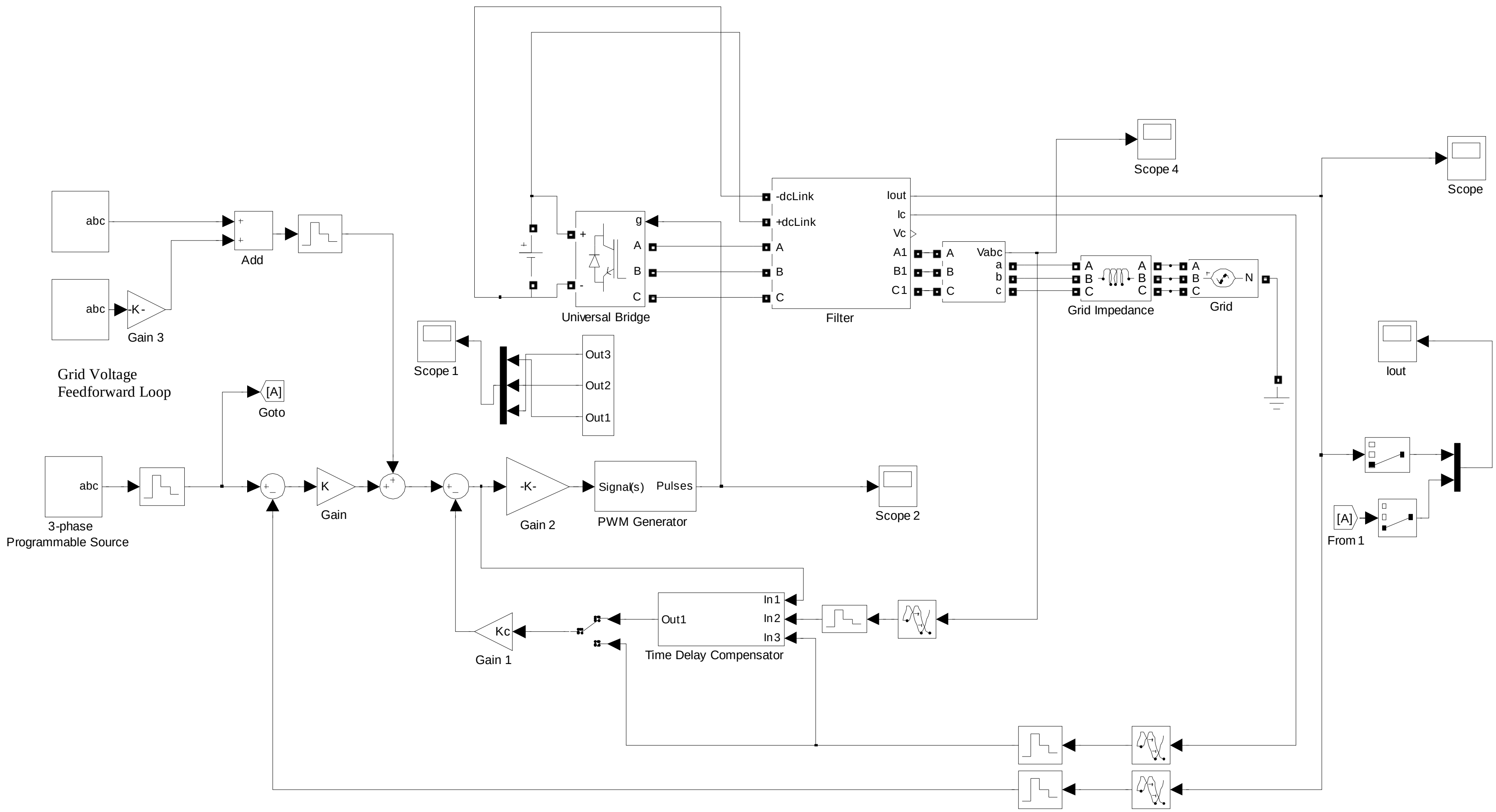

Figure 5.2: Three phase Simulink model of the test system shown in Fig. 5.1

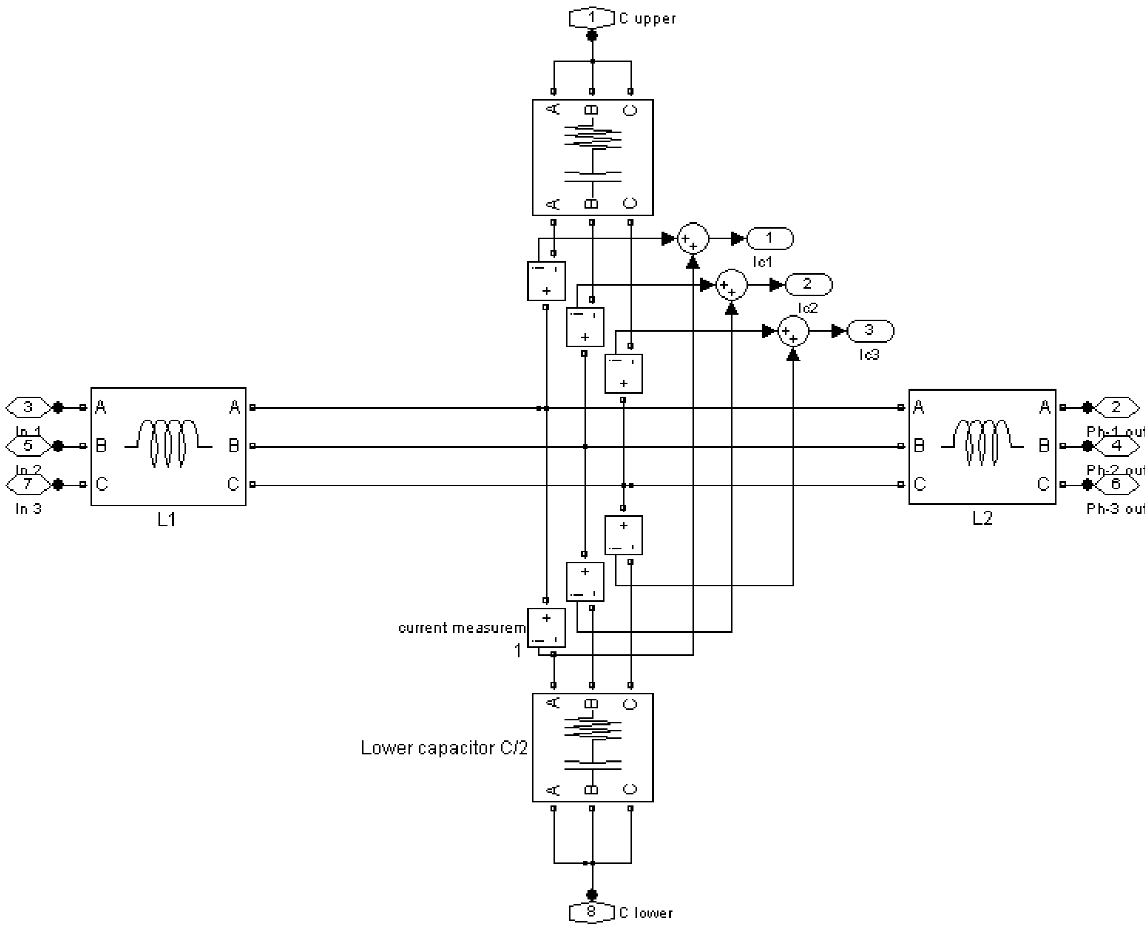

Figure 5.3: Simulink model of the LCL filter

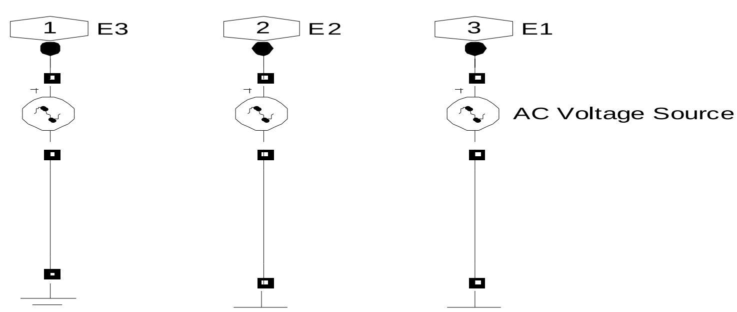

Figure 5.4: Simulink model of the utility system

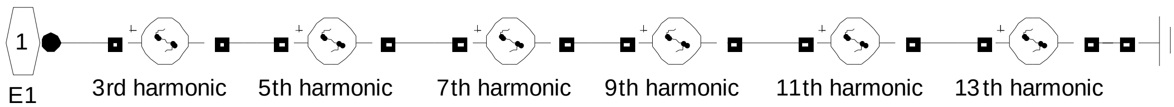

Figure 5.5: Simulink model of the utility voltage harmonics

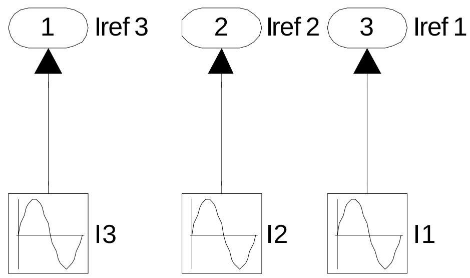

Figure 5.6: Simulink model of reference currents

5.6 LINEAR ANALYSIS OF THE CONTROLLER

The analysis and the design of the current controller is based on a single-phase equivalent circuit of the inverter and filter circuit as shown in Fig. 5.7. The circuit was first derived for star (or delta) connected filter capacitors in [199]. In Fig. 5.7, the voltage source v_{gn} stands for the voltage difference between the neutral point and the middle of the dc link and in control terms represent a source of disturbance caused by phase interaction which is given by;

$$v_{gn} = -\frac{v_{ag} + v_{bg} + v_{cg}}{3} \qquad 5.3$$

The above equation shows the dependence of the phase coupling voltage v_{gn} upon the switching state of all three phases. The value of the voltage v_{gn} jumps between the values of $-\frac{v_{dc}}{6}, -\frac{v_{dc}}{2}, +\frac{v_{dc}}{2}, +\frac{v_{dc}}{6}$.

The filter capacitors of the system shown in Fig. 5.1 are connected to the dc link instead of being connected in star or delta configuration. The essence of this filter topology is that it removes the phase interaction as proved in [191].

The following equations can be derived from the single phase equivalent circuit, shown in Fig. 5.7, assuming that v_{gn} is equal to zero.

$$v_{in} - v_c = L_1 \frac{di_1}{dt} \tag{5.4}$$

$$i_1 - i_2 = i_c \tag{5.5}$$

$$i_c = C \frac{dv_c}{dt} \tag{5.6}$$

$$v_c - v_u = L_2 \frac{di_2}{dt} \tag{5.7}$$

The block diagram of the single phase circuit based on the above equations is shown in Fig. 5.8. An expression for the output current of the circuit in the s domain can be derived as shown below [189];

$$I_2 = \frac{1}{(L_1L_2C)s^3 + (L_1 + L_2)s} V_{in} - \frac{L_1Cs^2 + 1}{(L_1L_2C)s^3 + (L_1 + L_2)s} V_u \tag{5.8}$$

The above equation can be represented in the block diagram form as shown in Fig. 5.9.

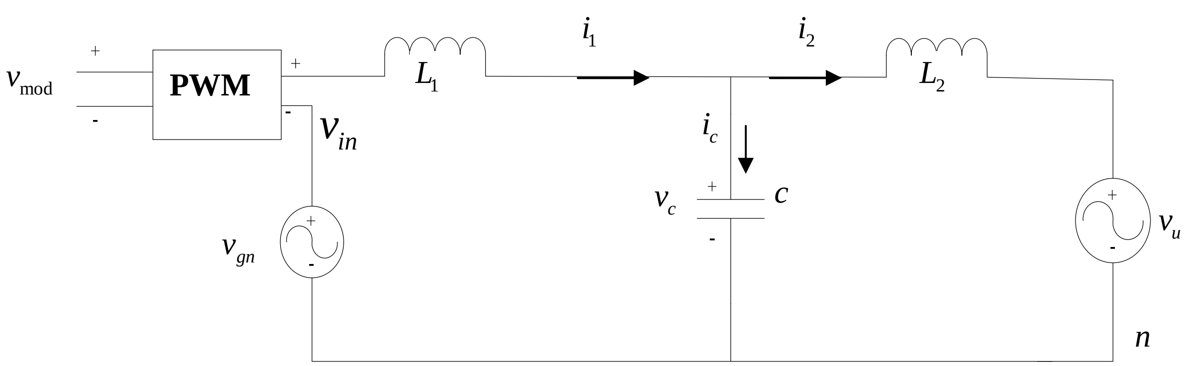

Figure 5.7: Single phase equivalent of the system shown in Fig. 5.1

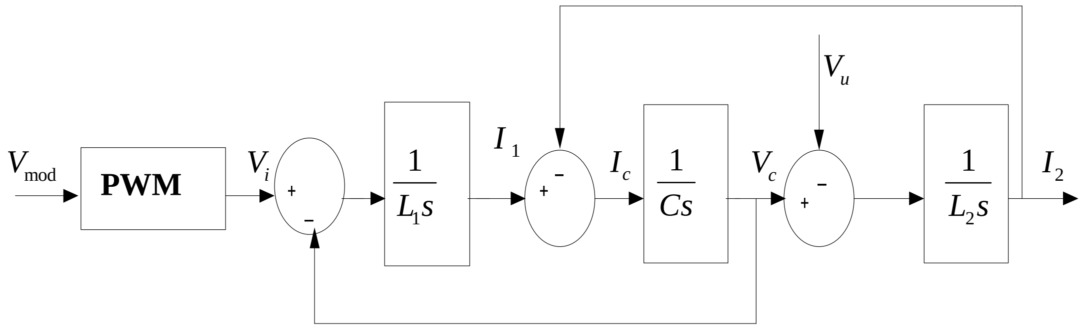

Figure 5.8: Block diagram of the single-phase equivalent circuit of the system

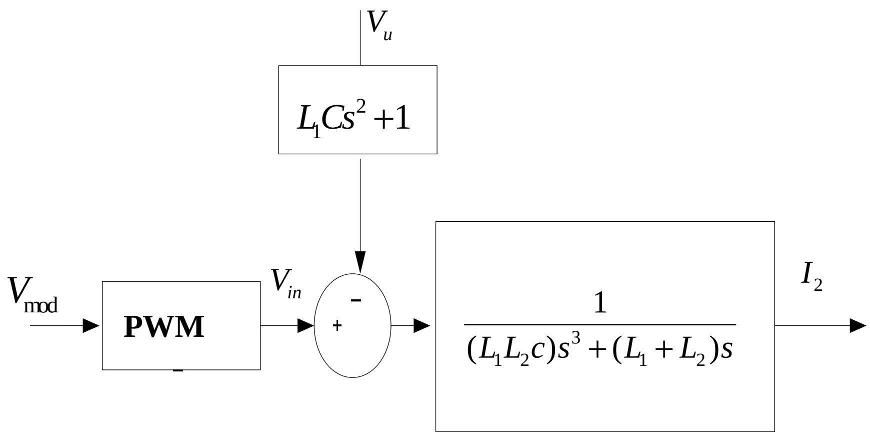

Figure 5.9: Simplified Block diagram of the single-phase equivalent circuit

In [191], the output current I_2 is used as the main feedback control signal and hence, is subtracted from the reference current. This structure is shown in block diagram form in Fig. 5.10.

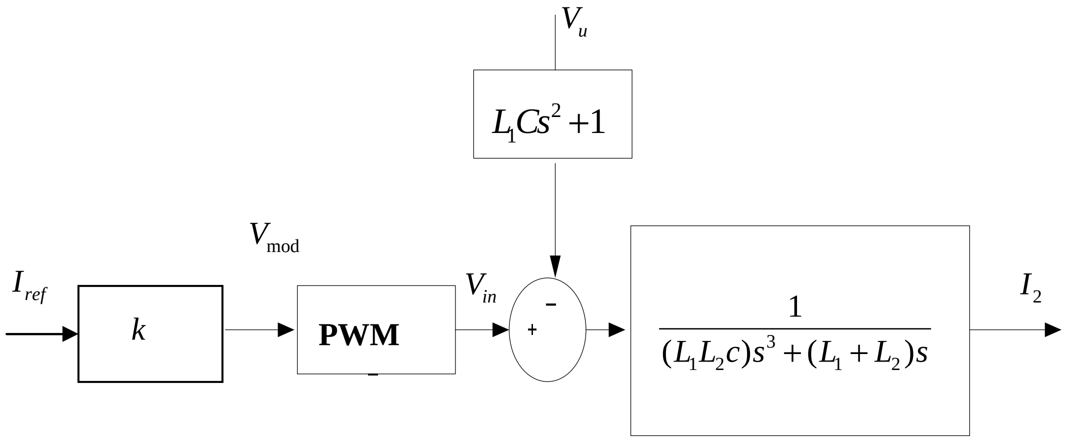

Figure 5.10: Single feedback loop structure of I_2.

As it is evident from the figure, the output current can be calculated as

$$I_2 = \frac{k}{(L_1L_2C)s^3+(L_1+L_2)s+k} I_{ref} - \frac{L_1Cs^2+1}{(L_1L_2C)s^3+(L_1+L_2)s+k} V_u \qquad 5.9$$

where k stands for controller transfer function in the outer feedback loop.

According to linear control theory, the reference transfer function T(s) can be defined as;

$$T(\mathrm{s}) = \frac{k}{(L_1L_2C)s^3+(L_1+L_2)s+k} \qquad 5.10$$

and the disturbance transfer function S(s) can be defined as;

$$S(\mathrm{s}) = \frac{L_1Cs^2+1}{(L_1L_2C)s^3+(L_1+L_2)s+k} \qquad 5.11$$

The characteristic equation of both the transfer functions T(s) and S(s) is;

$$(L_1L_2C)s^3+(L_1+L_2)s+k=0 \qquad 5.12$$

As the above mentioned characteristic equation lacks the s^2 term, so the system is clearly unstable according to the Routh-Hurwitz Stability Criterion, which states that if any of the coefficients of the characteristic equation are zero or negative in the presence of at least one positive coefficient, then the system is unstable. To ensure that the system is stable and the resonance is damped, an s^2 term has to be introduced into the characteristic equation. A close examination of the system shows that expression of the capacitor current I_c contains the required s^2 term;

$$I_c = L_2 C s^2 I_2 + sCV_u \qquad 5.13$$

A minor feedback loop of I_c multiplied by the gain k_c (i.e. minor feedback loop gain) provides the required damping term for the system. For derivation of the transfer functions, the implementation of the minor feedback loop of $k_c I_c$ is represented in block diagram form as shown in Fig. 5.11. The simplified model is shown in Fig. 5.12. Let the open loop function $G_1(s)$ that relates the output current to the inverter voltage be defined as;

$$G_1(s) = \frac{1}{(L_1 L_2 C)s^3 + k_c L_2 C s^2 + (L_1 + L_2)s} \qquad 5.14$$

Similarly, let the disturbance transfer function be defined as,

$$D_1(s) = V_u (L_1 C s^2 + k_c C s + 1) \qquad 5.15$$

The closed loop transfer function relating the output current I_2 to the reference current I_{ref} (assuming the PWM inverter transfer function is unity) can now be expressed as;

$$I_2 = \frac{k(s)G_1(s)}{1 + k(s)G_1(s)} I_{ref} - \frac{G_1(s)}{1 + k(s)G_1(s)} D_1(s) V_u(s) \qquad 5.16$$

It is clear that the transfer function of the controlled plant $G_1(s)$ and the disturbance transfer function $D_1(s)$ are functions of the minor feedback loop gain k_c, meaning they are independent of the controller in the outer feedback loop. An increase in controller parameters adds an extra degree of freedom in designing the controller. The complete proposed per phase controller with the minor feedback loop of the capacitor current is shown in the Fig. 5.13. Hence, the plant transfer function G_1(s) and the disturbance transfer function D_1(s) are functions of the inner loop gain k_c only, and are independent of the outer loop gain *k*. The controllers in the inner and outer loop are designed to give good transient and steady state response, with good disturbance rejection capability [191].

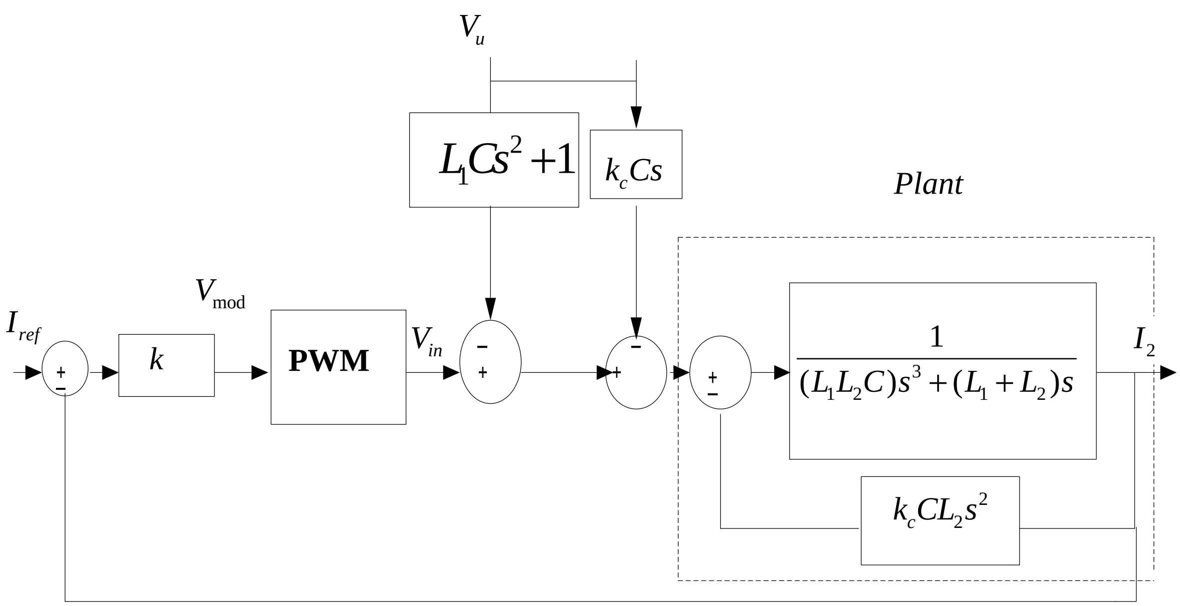

Figure 5.11: The control system with minor feedback loop of I_c. I_c is incorporated into the plant transfer function.

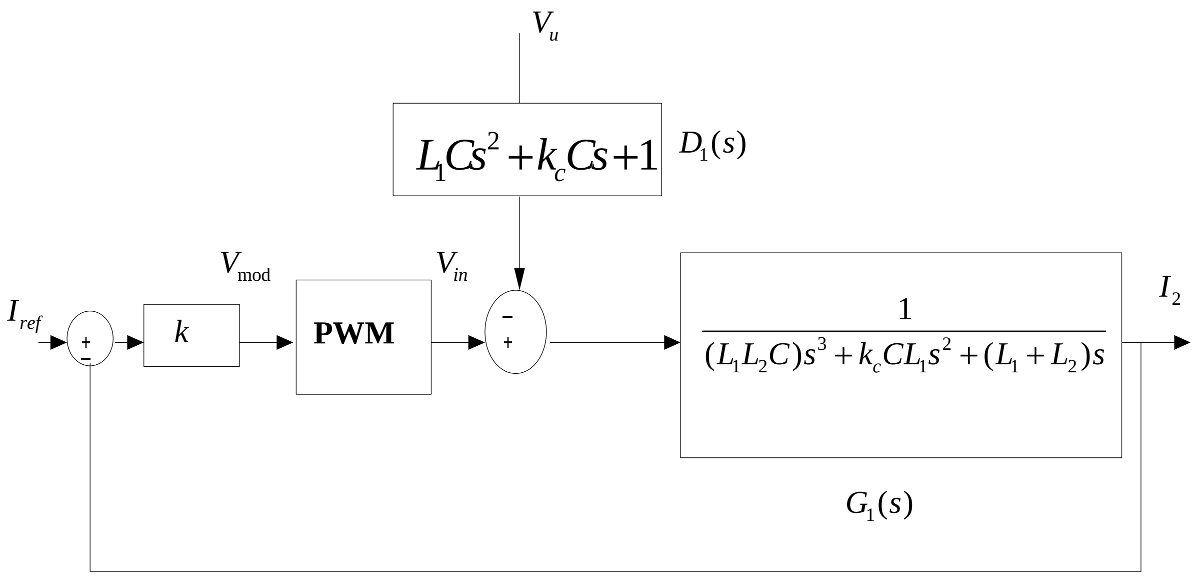

Figure 5.12: Simplified control system with minor feedback loop of I_c. I_c is incorporated into the plant transfer function.

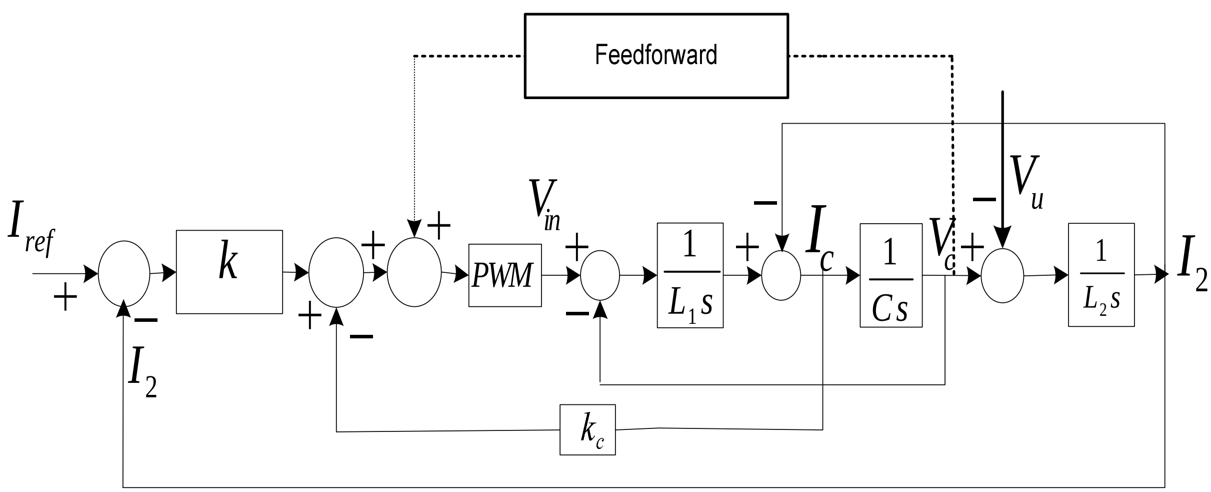

Figure 5.13: The proposed per phase controller.

The analysis of the open loop transfer function G_1(s) is used to select the loop gains. To determine the effect of the loop gains on the transient response of the system, the root locus of the open loop transfer function G_1(s) has been plotted for different values of the inner loop gain k_c as shown in Fig. 5.14. As expected, increasing the outer loop gain k will decrease the relative stability by pushing the closed loop poles to the right. However, increasing k_c improves the transient response by pushing the whole root locus to the left. Hence increasing k_c and decreasing k improve the transient response by increasing the stability margins and reducing the overshoot and settling time. Ideally, a higher value of k is required as it reduces the steady state error but it will compromise the relative stability as discussed earlier. On the other hand, a high value of k_c compromises disturbance rejection as is clear from Eq. 5.15. So the selection of loop gains is a compromise between transient stability and utility harmonic disturbance rejection. Bode plots for the transfer function $G_1(s)$ of the system with different values of k and k_c are shown in Fig. 5.15. The phase and gain margins for the system when k = 1.8 and k_c = 2.0 were calculated to be 25 degrees and 2.62 dB respectively as shown in Fig. 5.15.

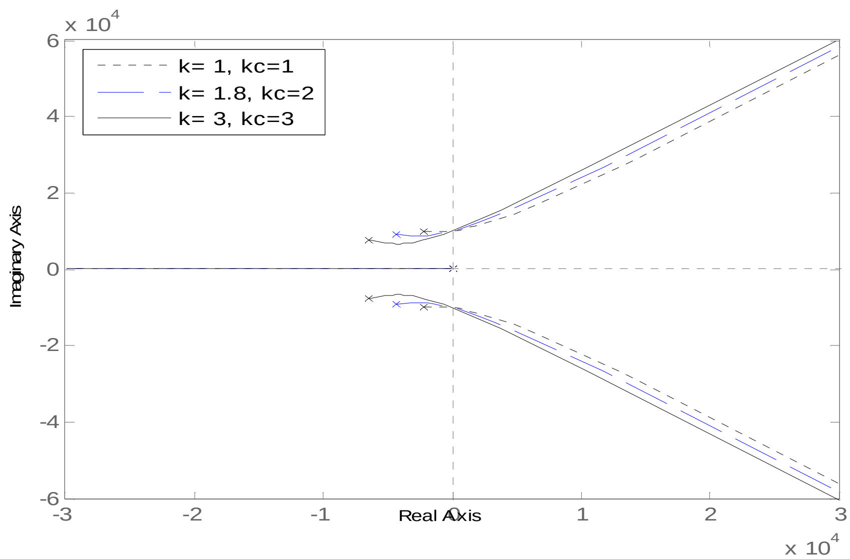

Figure 5.14: Root locus of the $G_1(s)$ for different values of inner loop gain k_c.

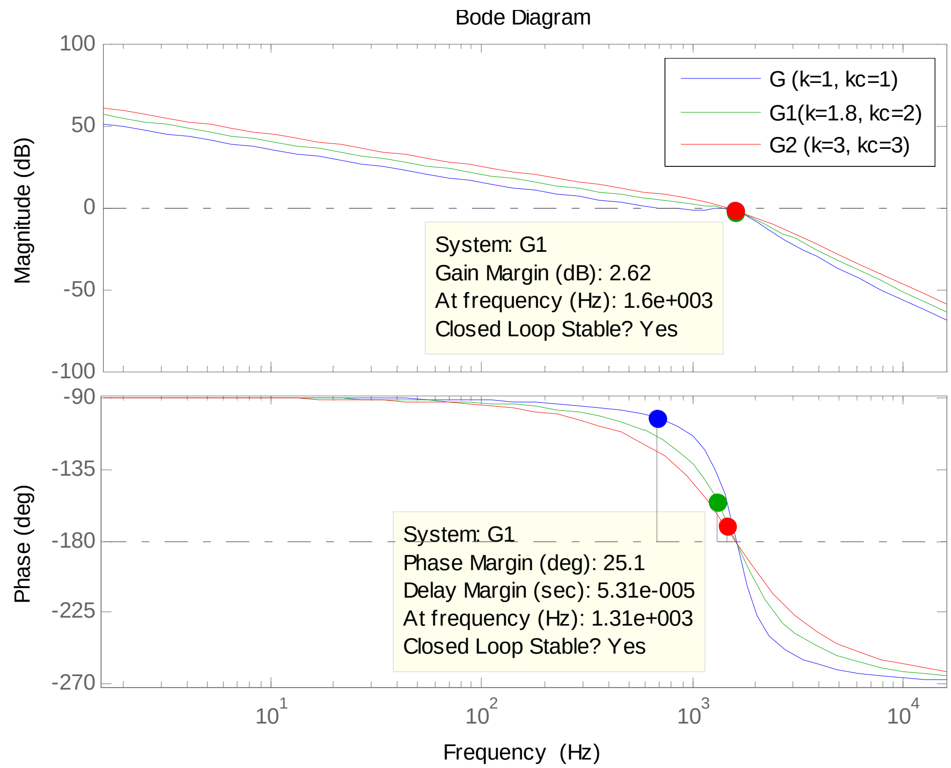

Fig. 5.15: Bode diagram of $G_1(s)$ for different values of K and K_C.

In addition to the two feedback loops, a feedforward loop of the capacitor voltage V_c as shown in Figs.5.1 and 5.13, is also implemented (with a positive sign) to compensate for the effect of the grid voltage disturbance. The capacitor voltage V_c is used in the feedforward loop instead of using the utility voltage as the latter is difficult to measure in practice. According to Eq. 5.15, the feedforward loop transfer function should be;

$$F(s) = L_1 Cs^2 + K_c Cs + 1 \tag{5.17}$$

The ideal feedforward transfer function involves differentiation of the utility voltage signal, which is undesirable in practice. This was overcome by implementing a slow feedforward loop that measures the steady state harmonics of the utility voltage and calculates the derivative by simply shifting the signal by 90 degrees and multiplying it by $2\pi f$ where f is the harmonic frequency. In fact, compensation for only the fundamental 50 Hz component provides satisfactory results for typical utility THD values [191].

5.7 ANALYSIS OF THE CONTROLLER WITH THE HELP OF SIMULINK MODEL

Power electronic inverters using an LCL filter for interfacing to the grid have better harmonic attenuation and high dynamic performance. However, due the LCL filter, these systems need complex current control strategies to maintain system stability. Moreover, these systems are more vulnerable to interference from grid background distortion due to resonance phenomena and due to the lower harmonic impedance offered to the grid [190,200-210]. The L_2 component shown in Figs. 5.1 and 5.2 is used to model changes in the utility impedance, which in general is unknown and may vary significantly as different loads are switched on and off. This, together with uncertainty in L_1 and C, arising from limited tolerances, can be a major challenge to the design of a controller. The normal practice is to design a controller using nominal parameter values. But in practice inverters are known to become unstable or to fail to meet THD specifications when installed at a different location (i.e. with different utility impedance and THD) or when certain loads are connected.

The behaviour of the output current THD has been investigated by using the system model shown in Figs. 5.1 and 5.2 by selecting different combinations of filter parameters, the utility impedance and the utility THD. These investigations were undertaken in order to gain an idea of the working of THD based islanding detection schemes in practical conditions. The operating parameters and the component values of the test system are shown in Table 5.1 given in Appendix C.

The output current THD of the inverter is examined while the system is connected to the utility grid that is modelled with different THD levels, i.e. 2.5%, 4.85%, and 7.5%. THD in the current is calculated according to the following formula;

$$THD = \frac{\sqrt{\sum_{h=2}^{\infty} I^2{}_h}}{I_1} \tag{5.18}$$

Where I_h and I_1 stand for rms values of the h harmonic current and the fundamental frequency current in the input current respectively [185].

Only the dominant odd harmonics up to 13^{th} are modelled. A predefined THD is used to look at the behaviour of the output current THD in the known distortion environment. Three cases have been examined:

- In the first case, filter parameters are assigned their nominal values as mentioned in Table 5.1.
- In the second case, uncertainties are introduced in filter parameters i.e. C changes by 20% and L_1 and L_2 change by 10% of their nominal values as given in Table 5.1.
- In the third case, different values are assumed for L_2 to account for utility impedance variations while other filter parameters retain their nominal values as shown in Table 5.1.

5.7.1. Simulation results

For correct results, the value of THD in the system output current was calculated using two methods i.e. a THD block and a Fast Fourier Transform (FFT) block. Both of these methods gave similar results. Therefore, measurements from THD block are included only.

5.7.1.1 THD in the output current for different levels of the utility THD

First of all, simulation case studies are carried out for the system with nominal values of the LCL filter components as is given in Table 5.1. The output current waveform and THD are shown in Figs. 5.16 and 5.17.

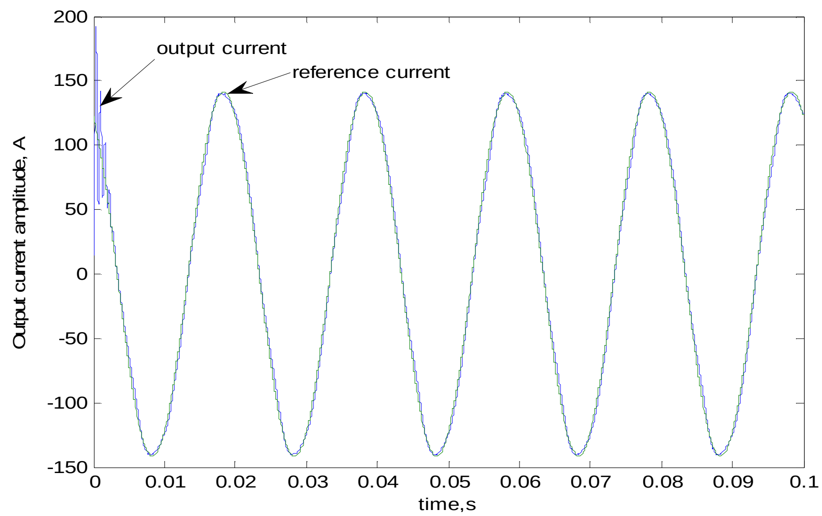

Figure 5.16: Waveform of the output current with nominal filter parameters and with 2.5% utility THD. Controller parameters are; k=1.8, k_c=2.

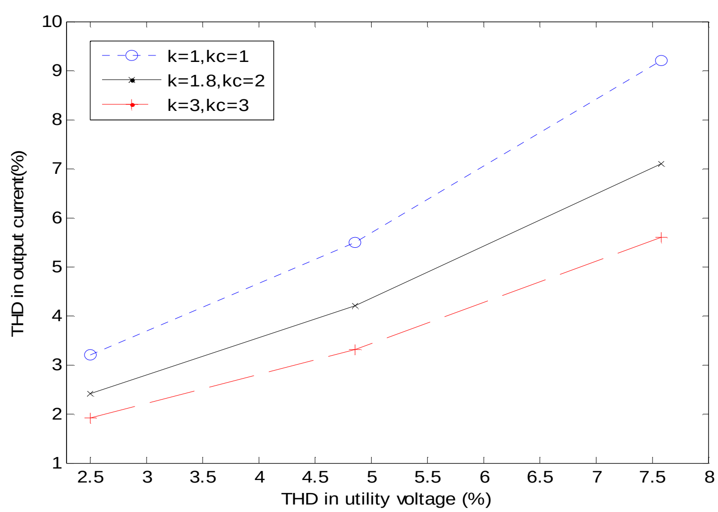

Figure 5.17: THD in output current with nominal filter parameters and with different utility THD levels.

5.7.1.2 THD in the output current when uncertainty in the filter parameters is taken into account

(1). THD in the output current for the maximum values of the filter parameters:

Secondly, simulation is done with all the filter parameters increased to the maximum of their uncertainty level i.e. inductance value (L) has been increased by 10% and capacitance value (C) has been increased by 20%. The final values for these parameters are, L_1= 253 μH, L_2= 55 μH, and C=288 μF. The output current THD is shown in Fig. 5.18.

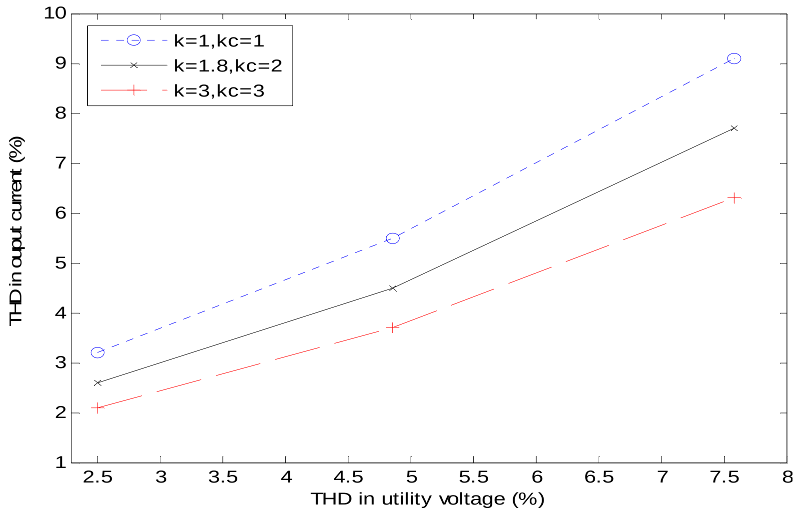

Figure 5.18: THD in output current with maximum values of filter parameters and with different utility THD levels.

(2). THD in the output current for the minimum values of the filter parameters:

Thirdly, the simulation is run with all the *filter* parameters decreased to the minimum of their uncertainty level i.e. inductance value (L) is decreased by 10% and capacitance value (C) is decreased by 20%. The final values for these parameters then are, L_1= 207 μH, L_2 = 45 μH, and C =192 μF. The output current THD is shown in Fig. 5.19.

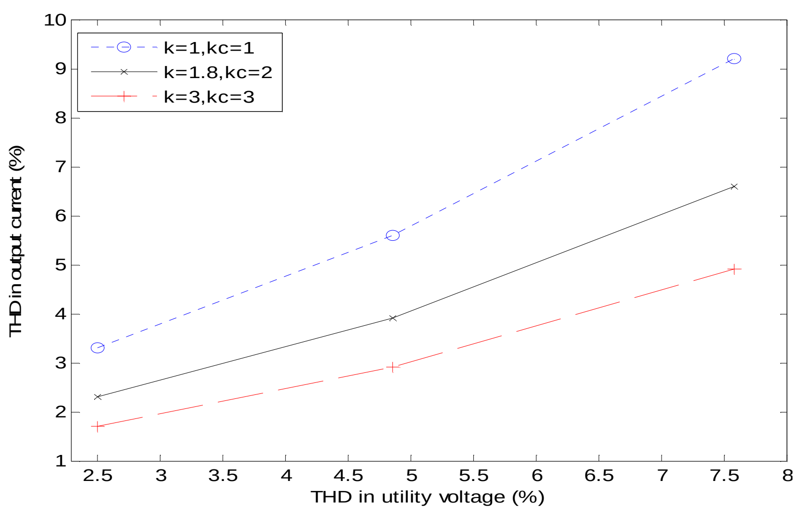

Figure 5.19: THD in output current with minimum values of filter parameters and with different utility THD levels.

(3). THD in the output current for the different values of L_2:

Another scenario is investigated by assigning different values to L_2 to account for variations in utility impedance while other filter parameters retain their nominal values. The results of these case studies are presented in Figs. 5.20 and 5.21.

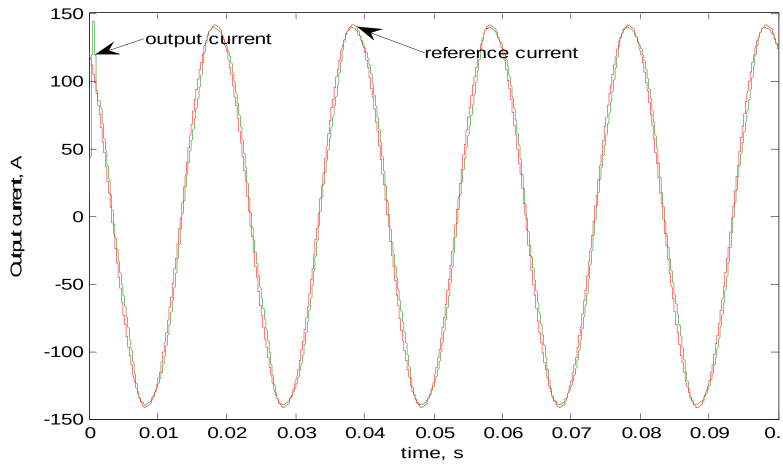

Figure 5.20: Waveform of the output current when L_2=200 uH. L_1 and C have their nominal values as given in Table 5.1. Utility THD is 2.5%. Controller parameters are; k=1.8, k_c=2.

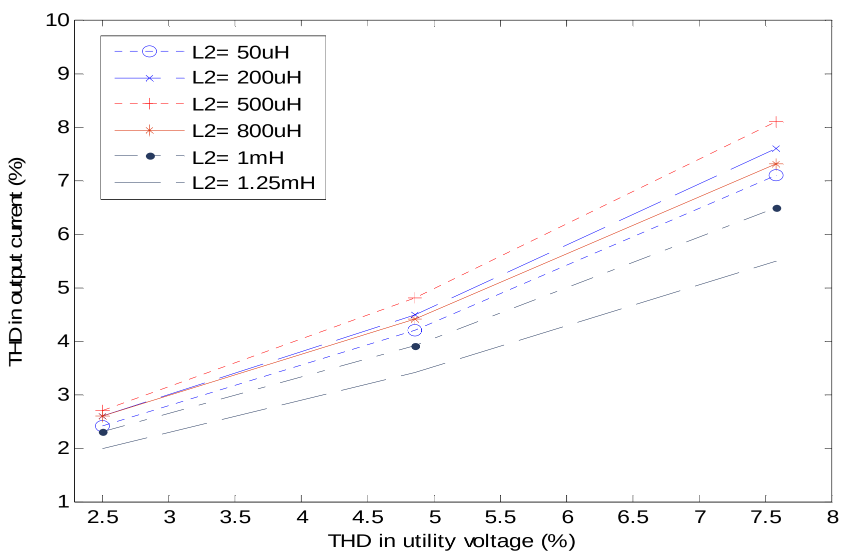

Figure. 5.21: THD in output current with different values of L_2 and with different utility THD levels. Controller parameters are; k=1.8, k_c=2.

Simulation results presented in Figs .5.17-5.19 and 5.21, show that for all the cases investigated, THD in the output current is less than 5% when utility THD is less than 5%

while filter parameter tolerances are taken into account. It is also clear from Fig. 5.21 that THD in the output current slightly increases as L_2 is increased upto 500 *u*H but it starts decreasing when L_2 is approximately equal to 800 *u*H or greater than that. Thus, output THD is affected due to variation in utility impedance. This can be explained by examining the disturbance-output relationship of the system. The disturbance-output function can be derived by setting I_{ref} =0 in Eq. 5.16, which gives;

$$N(s) = \frac{I_2(s)}{V_u(s)} = -\frac{G_1(s)}{1+k(s)G_1(s)} D_1(s) \qquad 5.19$$

Fig.5.22 shows the disturbance rejection plot for different values of utility impedance (L_2). It is clear from Fig. 5.22 that attenuation of harmonics upto the 3rd will be the same irrespective of the magnitude of L_2. However, as L_2 is increased upto 500 *u*H, attenuation of higher order harmonics i.e. higher than 3rd, will decrease as resonance peaks will be shifted to the left. In the worst case scenario, amplification of certain harmonics can also occur that will result in a very large THD. When L_2 is approximately equal to 800 *u*H or greater than that, attenuation of the harmonics will increase as the resonance peak becomes more damped as can be seen from Figs. 5.21 and 5.22.

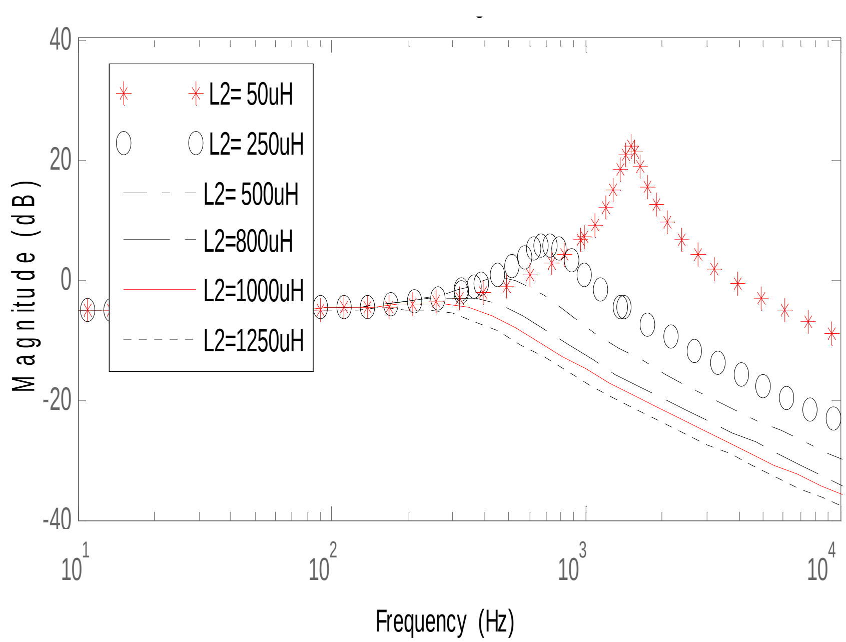

Figure 5.22: Frequency plot of N(s) for different values of utility impedance.

5.8 EFFECT OF THE ELECTROMAGNETIC COMPATIBILITY (EMC) CAPACITORS ON THE PERFORMANCE OF A GRID CONNECTED INVERTER

Electromagnetic compatibility (EMC) capacitors are introduced in the inverter circuit to provide a specific path to the switching frequency current components. If this path is not provided, then the current will flow through stray capacitances present in different parts of the system i.e. heat sink and chassis. This current (noise) will spread throughout the system and will affect the working of the components of the system like inductors and DC link capacitors. EMC capacitors prevent this noise from happening. However, with the introduction of the EMC capacitors, the otherwise stable system was found to become unstable for different values of filter parameters and utility impedance. This phenomenon, although quite important as it can affect the performance of an inverter, has not yet been taken into consideration by researchers investigating the performance (behaviour of the output current) of an inverter.

Here the behaviour of the system with EMC capacitors, as shown in Fig. 5.23, is analysed by assigning different values to system parameters. The standard values for the system are the same as mentioned in Table 5.1. The value of EMC capacitance is 5µF while controller parameters are; k=2 and k_c=2.

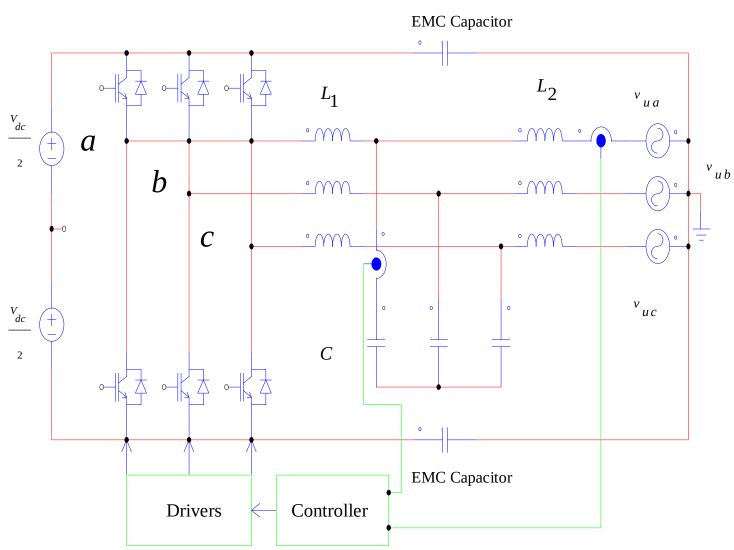

Figure 5.23: The system shown in Fig. 5.1 with EMC capacitors.

5.8.1. Simulation results for the system with EMC capacitors

5.8.1.1 When output voltage (V_{out}) is used in the feedforward loop

In all the simulation cases mentioned below, the THD in the utility voltage (V_u) is modelled as 4.8% and the output voltage (V_{out}) is used in the feedforward loop.

(**1**). The controller is stable without EMC capacitors as shown in Figs. 5.24. When L_2 = 120µH, the THD in output current (I_{out}) was 1.8%.

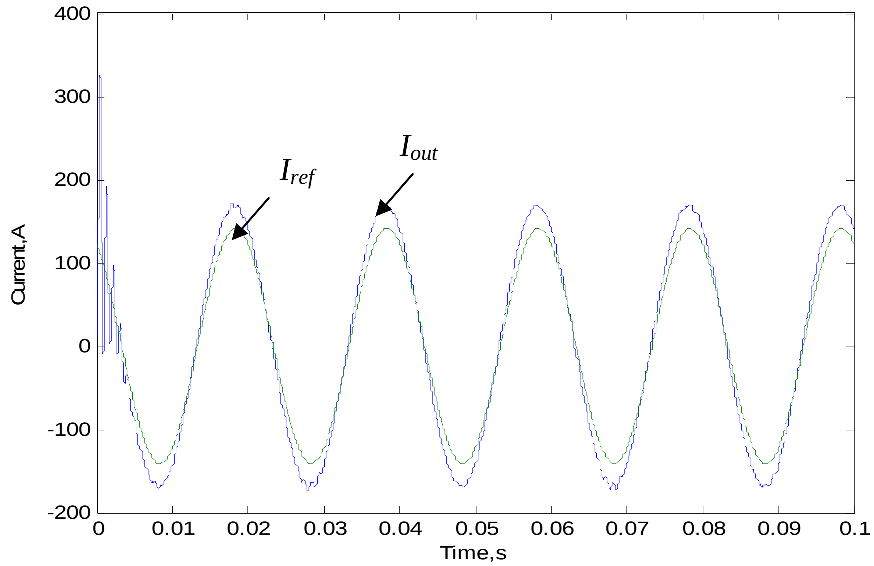

Figure 5.24: Waveform of the I_{out} and I_{ref} from the system without EMC capacitors when time delay is enabled while L_2 =120µH. I_{out} is the output current while I_{ref} is the reference current.

(**2**). The controller is unstable with EMC capacitors when time delay compensation is enabled as shown in Fig. 5.25 except when L_2=240µH as shown in Fig. 5.26. When L_2= 120µH, the THD in I_{out} was 18.6% and when L_2= 240µH, the THD in I_{out} was 0.16%.

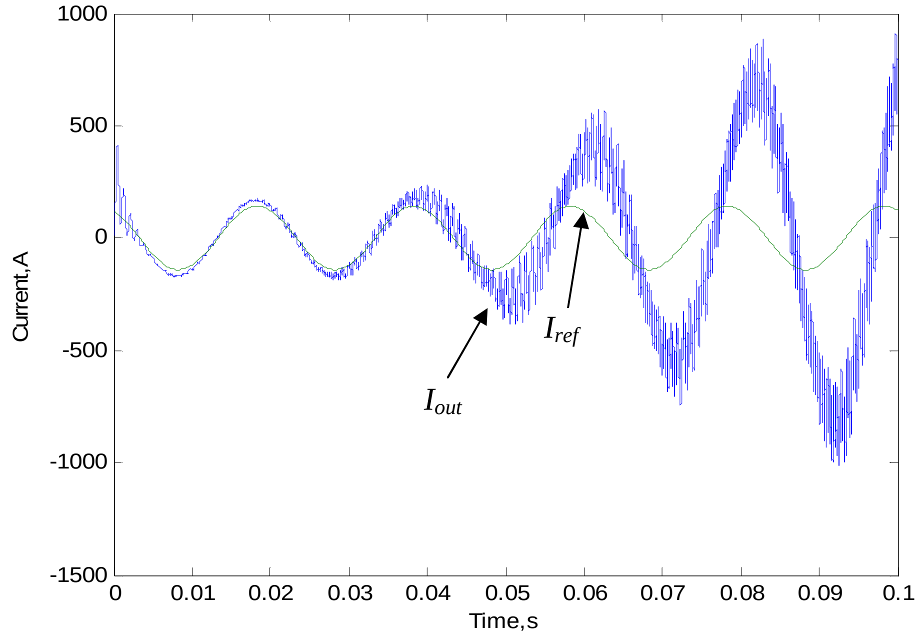

Figure 5.25: Waveform of I_{out} and I_{ref} from the system with EMC capacitors when time delay compensation is enabled while L_2 =120μH.

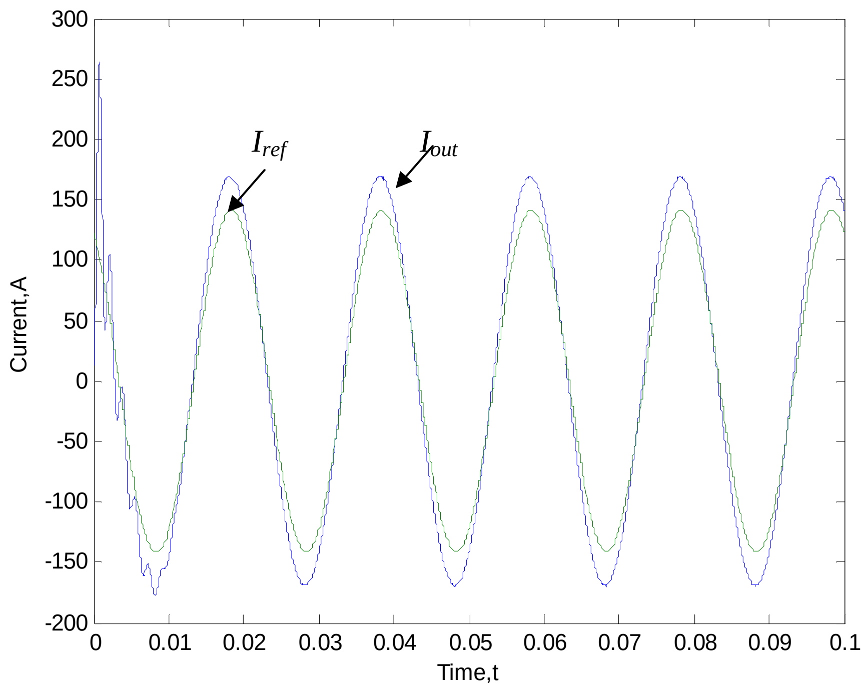

Figure 5.26: Waveform of I_{out} and I_{ref} from the system with EMC capacitors when time delay compensation is enabled while L_2 =240μH.

(**3**). The controller is unstable with EMC capacitors when time delay compensation is disabled while L_2 =120μH or 240μH, as shown in Fig. 5.27 for the case when L_2 =120μH.

However, it is stable when L_2=60uH as shown in Fig. 5.28. When L_2= 120μH, the THD in I_{out} was 43.6% and when L_2= 60μH, the THD in I_{out} was 0.9%.

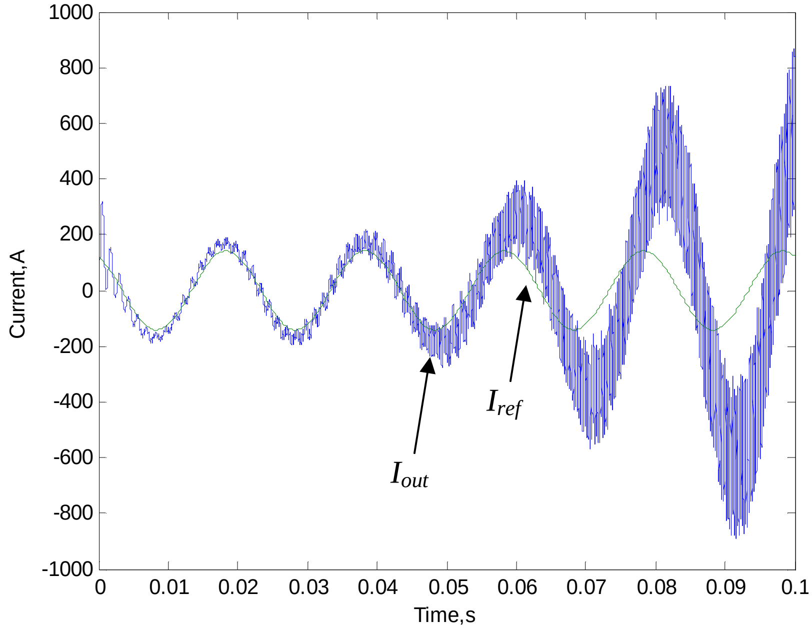

Figure 5.27: Waveform of I_{out} and I_{ref} from the system with EMC capacitors when time delay compensation is disabled while L_2 =120μH.

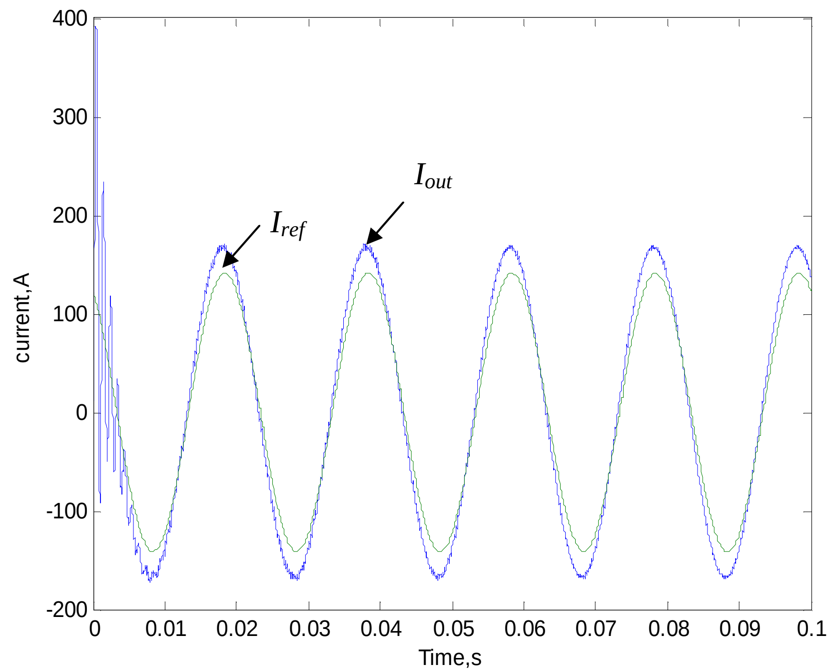

Figure 5.28: Waveform of I_{out} and I_{ref} from the system with EMC capacitors when time delay compensation is disabled while L_2 =60μH.

5.8.1.2 When an ideal sine wave is used in the feedforward loop

In all the simulation cases mentioned below, the THD in the utility voltage (V_u) was modelled as 4.8% and an ideal sine wave was used in the Feedforward loop.

(**1**). The controller is stable with EMC capacitors but the steady state error is very large when time delay is disabled and an ideal sine wave is used in the feedforward loop as shown in Fig. 5.29. Here L_2 =120µH while utility THD = 4.8%.

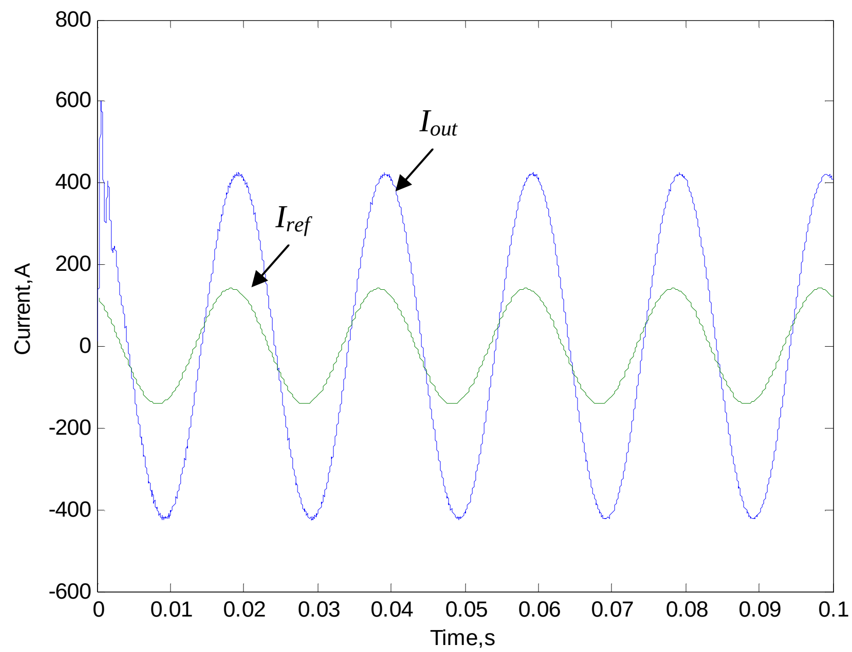

Figure 5.29: Waveform of I_{out} and I_{ref} from the system with EMC capacitors when time delay compensation is disabled and an ideal sine wave is used in feedforward loop. Here L_2 =120µH while the utility THD = 4.8%.

(**2**). The controller is stable with EMC capacitors when time delay is disabled and an ideal sine wave is used in the feedforward loop as shown in Fig. 5.30. Here L_2 =120µH while utility THD = 0.

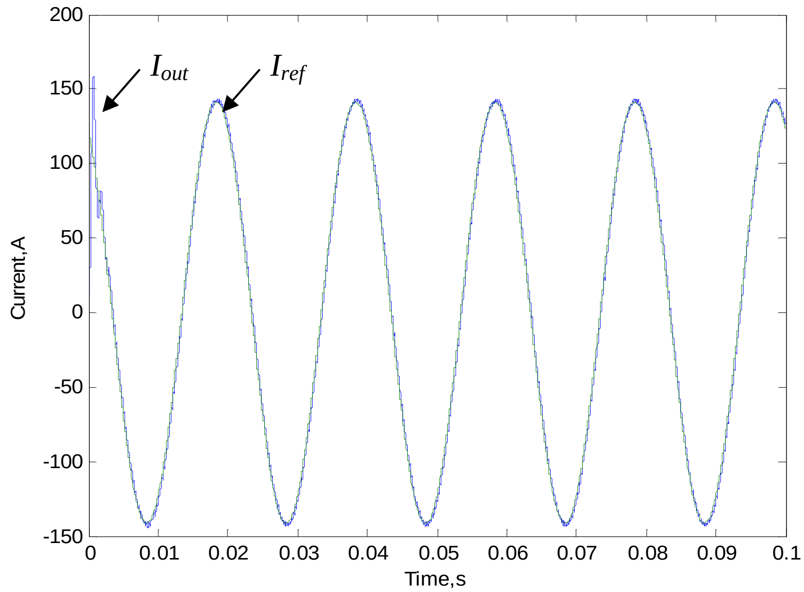

Figure 5.30: Waveform of I_{out} and I_{ref} from the system with EMC capacitors when time delay compensation is disabled and an ideal sine wave is used in feedforward loop. Here L_2 =120µH while the utility THD = 0.

5.8.2. Discussion of the results

From the results shown in Figs. 5.24 to 5.30, it seems that there is a relationship between grid impedance, time delay compensator and EMC capacitors. EMC capacitors and grid impedance cause some resonance frequencies to appear at the output voltage and if this voltage is used in the time delay compensator or in the feedforward loop, then the system becomes unstable. More investigations, i.e. mathematical modeling and simulations, are needed to understand the full significance of this phenomenon which is outside the scope of this thesis.

5.9 SUMMARY

This chapter has investigated the role of uncertainties in the filter parameters, the utility impedance and the utility THD on the performance of the THD based islanding detection schemes for the IIDG. The simulation results obtained from the test system i.e. VSI connected to the grid through an LCL filter, show that, depending upon the design of the controller, THD in the inverter output current may vary with changes in the utility impedance and the utility THD. Consequently, working of the THD based schemes may not be effective in islanding detection if these factors are not taken into consideration. A large L_2 can reduce the impact of grid impedance on resonance frequency and hence, makes THD in output current of the inverter less sensitive to variations in the utility impedance. Thus with a large L_2, the selection of THD threshold becomes relatively simple. Moreover, through simulations, it is shown that EMC capacitors can also affect the islanding detection schemes used for IIDG as they can introduce a large increase in the output current THD of the inverter. The identification of this phenomenon is novel and hence, further investigations are needed to appreciate its true significance.

CHAPTER 6

CONCLUSIONS AND FUTURE WORK

6.1 CONCLUSIONS

The thesis is concerned with the affects of Distributed Generation (DG) on protection of distribution networks (DNs). It identifies the potential problems that can arise when DG is connected to a DN and proposes some solutions for the safe integration of DG. Although the work has been focussed on the simulation of a case study involving DG installation in a specific DN, we can draw generic as well as some particular conclusions from the investigations of the case study.

The simulation results of the case study show that DG can cause various protection related issues including, increase in the fault current level, blinding of protection, sympathetic tripping, reduction in reach of a distance relay, lack of detection of 1LG with ungrounded utility side interconnection transformer configuration and failure of a fuse saving scheme.

These problems can be solved by a skillful and innovative application of the traditional protection practices and approaches as has been proved by designing a protection scheme for the case study. For example, the problems of blinding of protection and sympathetic tripping can be solved by upgrading the feeder head end recloser with the addition of an instantaneous overcurrent element (50). When a transformer with delta or ungrounded wye on the utility side is used for DG connection, a multifunction voltage relay that relies upon zero sequence voltage detection principles, can be used to detect abnormal conditions of islanding due to the tripping of the utility main circuit breaker or 1LG faults on the utility network being fed by the DG units.

Proper recloser-fuse coordination can be restored even in the presence of DG by making use of the novel fuse saving strategy (proposed in Chapter 3) that combines the characteristics of both the time and instantaneous OC elements (i.e. 51 and 50) along with a simple algorithm for adaptively changing the setting of the latter.

Although the proposed solutions work for the selected network, they may have their limitations when applied to more complex meshed networks. The setting of the trip threshold for the 50 element to solve the problems of blinding of protection and sympathetic tripping may be a delicate task, keeping in mind different inrush and starting currents of transformers and motors in a complex network. Similarly, it may be difficult, in practice, to adaptively set the 50 element to restore the recloser-fuse coordination (fuse saving scheme) as the difference between the various possible settings of the 50 element (depending upon the number of DG units connected) may be small for the conventional relay setting practice.

The solution of distance relay underreach (caused by DG connection) involving readjustment of the relay zone settings has its downside, too. The distance relay can over reach if the DG units are, subsequently, disconnected from the network. As the distance between the various protective devices involved in the transfer trip scheme (designed for the case study for antiislanding protection) is small, the use of the transfer trip scheme may be economical and reliable. However, the cost and reliability may be an issue when a transfer trip scheme is applied for antiislanding protection in large complex networks.

Protection coordination issues such as lack of sensitivity and selectivity in isolation of a fault, can occur in a microgrid due to the bidirectional flow of the fault current and the low short-circuit current level, especially in an islanded mode of operation. Conventional protection schemes are ineffective in protecting an islanded microgrid having an inverter interfaced DG (IIDG) and need major revision in order to detect and isolate the faulty portion in presence of limited fault currents in such systems. Innovative protection schemes and strategies relying on differential relaying, voltage detection techniques, adaptive relaying, and detection of symmetrical and differential current components may be used to solve these issues.

THD in the inverter output current may be affected (depending upon the design of the controller) by the variations in the utility THD and the utility impedance and, consequently, the working of the THD based islanding detection schemes may suffer, if these factors are not taken into consideration while selecting the trip threshold. A large L_2 (the inductor of the LCL filter facing the grid) can make the selection of the trip threshold more reliable and easier as it makes the output current THD of the inverter less sensitive to variations in the utility impedance. However, with a large L_2, the filter becomes expensive and bulky.

Electromagnetic compatibility (EMC) capacitors can have an impact on performance (behaviour of the output current) of a voltage source grid connected inverter as shown by the simulation results. There is a relationship between grid impedance, time delay compensator and EMC capacitors. EMC capacitors and grid impedance cause some resonance frequencies to appear at the output voltage, if this voltage is used in the time delay compensator or in the feedforward loop, then the system becomes unstable. This factor, if not taken into consideration, will affect the working of the THD based islanding detection schemes.

6.2 FUTURE WORK

Due to a continuous increase in industrial and domestic energy demands, power grids are expected to operate to their maximum capacity. The integration of DG in the grid has also raised some issues. That's why there is an increased need for new protection concepts, strategies and tools for accurate and better monitoring of a network, to ensure its safe working. Many areas of future work can be extended from the ideas and contents of this thesis.

More research is needed for the effective and practical implementation of the proposed fuse saving strategy. The hardware requirements for an efficient and reliable operation of the scheme should be studied. It needs to be determined how accurately the delicate current pickup settings for the instantaneous OC element of the scheme can be set. The accuracy of the current transformers needs to be examined. This issue is very important as the difference between various possible settings of the OC element (depending upon the number of DG units connected) may be small for the conventional relay setting practices.

Investigations are needed to determine whether or not it is possible to make use of the 50 element with adaptive current pickup settings (primarily proposed for solving the problems of blinding of protection, sympathetic tripping and recloser-fuse coordination) for protecting the microgrid (that will result if intentional islanding is allowed). If it is possible, then adjustments to the current pickup settings of the 50 element will have to be determined to enable it to work in coordination with other protective devices in the microgrid.

Instead of using a physical L_2 in an LCL filter which has its drawbacks, a virtual inductor can be introduced in the system to make the THD based islanding detection schemes more reliable by reducing the impact of utility impedance on the output current THD. The concept of virtual impedance is used in [211 -221], to mimick real impedance for control design purposes. It is shown in [215, 219] that an addition of an output current derivative feedback in the control algorithm is equivalent to including a virtual inductor in the circuit. Virtual L_2 may be an option but more research (including practical results) is needed to check the working of a THD based islanding detection scheme with a virtual inductor i.e. whether or not it reliably detects the islanding and to identify any issues that need to be taken care of to make it more reliable and practical. The working of the THD based islanding detection schemes also need to be investigated when multiple IIDG units with different control strategies are employed in a network. Moreover, the possibility of complementing THD measurements along with measurement of other parameters, like voltage or frequency, for islanding detection (i.e. a hybrid islanding detection scheme) should also be explored.

The possibility of using THD based islanding detection schemes/setups for fault detection in a microgrid mode of operation should also be considered. It may be possible that the islanding detection setup may well also be used as/or part of a protection scheme for a microgrid mode of operation. This will reduce the cost of the protection setup.

More investigations, involving mathematical modeling and simulations, are needed to appreciate the full significance of the relationship between grid impedance, time delay compensator and EMC capacitors and their impact on the performance (behaviour of the output current) of a grid connected inverter. This exercise will help in making the THD based islanding detection schemes more effective and reliable.

To solve the protection coordination issues caused by DG connection to meshed networks, that may not be solved by application of the traditional protection practices and approaches proposed in the thesis, modern ideas and techniques like;

- adaptive protection schemes,
- phasor measurement units (PMUs) that rely on a global positioning system (GPS) time signal for extremely accurate time-stamping of the power system information [222-223], and
- intelligent protection systems i.e. expert systems and multiagent systems [143-149],

need to be further explored (through simulations and practical applications) to increase their reliability and effectiveness, whilst also making them user friendly by reducing their complexity and cost.

The techniques and strategies involving analysis of current using digital signal processing for characteristic signatures of faults [167], development of a real-time fault location technique having capability of determining exact fault location in all situations, use of impedance methods, zero sequence current and/or voltage detection based relaying, and differential methods using current and voltage parameters [151] have the potential for developing more robust protection schemes and, therefore, need to be further explored to cope with the new challenges in the case of microgrid protection.

APPENDIX A

A1. Table 2.1: Impedances of feeders and Sub-TLs of the test system shown in Fig. 2.3

$Z^{+}_{25\ kV\ feeders}$	0.2138+j0.2880 Ω/km
$Z^{+}_{69\ kV\ Sub\text{-}TL}$	0.2767+j0.5673 Ω/km
$Z^{0}_{69\ kV\ Sub\text{-}TL}$	0.5509+j1.4514 Ω/km
$B^{+}_{Sub\text{-}TL}$	0.00803014065 Ω /km
$B^{0}_{Sub\text{-}TL}$	0.00481803678 Ω/km

A2. Table 2.2: Current settings of protection devices installed in the test system shown in Fig. 2.3

Protective equipment	Fuse F1	OC relay at LF1	OC relay at LF2	Earth fault relay at LF1	Earth fault relay at LF2	OC relay at CF1	OC relay at CF1	Fuse F2
Settings (A)	200	290	290	140	140	450	450	380

A3. List of IEEE/ANSI designated protective device numbers used in the thesis

27- Distance relay

50- Instantaneous overcurrent (OC) relay,

51- Time OC relay,

51N- Neutral time OC relay

59- Overvoltage relay

59I- Instantaneous overvoltage relay

59N- Neutral overvoltage relay

67- Directional OC relay

67N- Neutral directional OC relay

81U/O- Under and Over frequency relay

81R- Residual frequency relay

APPENDIX B

B1. Equations describing the general characteristics of a recloser and a fuse

The general characteristics of a recloser inverse time OC element can be mathematically expressed by the following equation [119].

$$t(I) = TD[\frac{A}{M^{p} - 1} + B] \tag{3.1}$$

Where *t* is the operating time of the device, *I* is the fault current seen by the device; TD is time dial setting; *M* is the ratio of I / $I_{pick\text{-}up}$ where $I_{pick\text{-}up}$ is device current set point, *A, B, p* are constants for selected curve characteristics.

Similarly, fuses also have inverse-time OC characteristics. Minimum melting (MM) and total clearing (TC) time for a fuse is usually represented by the straight line I^2t log-log plot. A better mathematical approximation of the fuse characteristic on the log–log curve, to be used in the protection setting, uses a second-order polynomial function. However, the interested range of the curve approaches a straight line within minimum and maximum values of the fault current (i.e. $I_{F\text{-}min}$ and $I_{F\text{-}max}$), which is known as the coordination range i.e. as long as the magnitudes of fault current are within the coordination range, the fuses are coordinated. Moreover, a linear equation greatly simplifies the calculations. Thus, fuse characteristic curve can be described by the general equation [121];

$$\log(t) = a.\log(I) + b \tag{3.2}$$

where t and I are the associated time and current, and the coefficients a and b can be found by curve fitting.

B2. Table 3.1: Fault currents for a 3LG fault at 25% of LF1-1 length for different combinations of M and N

M	N	$I_{F\text{-}Total}$ (A)	$I_{F\text{-}utility}$ (A)	$I_{F\text{-}DG1}$(A)	$I_{F\text{-}R3}$ (A)	$I_{F\text{-}DG2}$(A)
0	0	1320	1320	0	1320	0
1	0	1403	1288	118	1403	0
2	0	1476	1259	221	1476	0
3	0	1539	1233	311	1539	0

In the table, $I_{F\text{-}Total}$ is the total fault current; $I_{F\text{-}utility}$ is the fault current contribution from the utility source; $I_{F\text{-}DG1}$ and $I_{F\text{-}DG2}$ are the fault current contributions from DG1 and DG2 respectively; $I_{F\text{-}R3}$ is the fault current that flows through the recloser R3 i.e. the fault current seen by the 51 and 51 elements.

APPENDIX C

C1. Table 5.1: Parameters and component values for the system shown in Fig.5.1

Parameter	**Value**
Rated power	80kVA
Utility Phase voltage	230 V (rms)
DC Link Voltage	900 V(dc)
Inductor L_1	230 ± 23 µH
Inductor L_2	50 ± 5 µH
Capacitance C	240 ± 48µF
Switching Frequency	8 kHz

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