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MODELLING AND SIMULATION OF THE IMPACTS OF DISTRIBUTED GENERATION INTEGRATION INTO THE SMART GRID

by

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DECLARATION

I, Onwunta Emea Kalu Onwunta, declare that the contents of this thesis represent my own unaided work, and that the thesis has not previously been submitted for academic examination towards any qualification. Furthermore, it represents my own opinions and not necessarily those of the Cape Peninsula University of Technology.

Signed **Date**

ABSTRACT

Distributed generation (DG) has been reincarnated after its demise by centralised generation. While economy of scale and efficiency are the advantages of the latter, deregulation of the electricity market, environmental concerns and the need to arrest dwindling reserve margins have necessitated the rebirth of the former. Indeed, a full circle has therefore evolved with generation being ‘embedded’ in distribution systems and ‘dispersed’ around the system rather than being located and dispatched centrally or globally. This development is in tandem with the history of industrial revolutions that started from energy and moved through services and communication and back to energy.

South Africa is not immune to the global energy, especially tertiary energy, challenge phenomenon. At the peak of the 2007-2008 energy crisis, her generation net reserve margin fell below 10% – well below conventional industry benchmark of at least 15%. Also South Africa is Africa’s largest emitter of CO_2 contributing over 40% of Africa’s total CO_2 emissions. Therefore, DG’s relevance to South Africa is quite obvious.

However, DG integration into distribution networks leads to a number of challenges. For instance, with significant penetration of DG power flow reversal may be experienced and the distribution network will no longer be a passive circuit. This underscores the crucial role of ICT in active distribution network occasioned by DG and especially the emergent of “*prosumerism*” (a hitherto consumer also becoming a producer). Therefore, a smart grid and similar phrases have all been used to describe a “digitised” and intelligent version of the present-day power grid.

There are immense benefits derivable from modelling and simulation. Consequently, a typical radial distribution network model has been developed to evaluate the considerable impacts of DG integration. The modelling and simulation of the network are accomplished using the DIgSILENT PowerFactory simulation package. Impacts of DG on voltage profile, fault level, voltage stability and protection coordination have been investigated and their possible mitigation measures proferred. The results reveal that for a particular DG type its impacts depend mainly on its capacity and point of connection relative to a given load type. Smart grid technology addresses some of these impacts through its inherent capability which includes peer-to-peer relay communication for protective devices on the distribution feeder as well as communication to the DG facility.

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DEDICATION

To my parents of blessed memory – Mr & Mrs Emea Kalu Onwunta,

My darling wife – Mrs Ngozi Kalu Onwunta, and

Son – Chidiebere Emea Onwunta.

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GLOSSARY OF ACRONYMS

AAAC – All Aluminium Alloy Conductors

ACSR – Aluminium Conductor Steel Reinforced

APS - Arizona Public Service Company

ASI – Australian Solar Institute

BRICS – Brazil, Russia, India and South Africa

CDMA – Code Division Multiple Access

CERTS – Consortium for Electric Reliability Technology Solutions

CISPR – Comité International Spécial des Perturbations Radioélectriques (Special international committee on radio interference)

CLEEN – Cluster for Energy and Environment

CMTS – Cable Modem Termination System

CO_2 - Carbon Dioxide

CSPA – Concentrating Solar Power Alliance

D:EA&DP – Department of Environmental Affairs and Development Planning

DER – Distributed Energy Resources

DG – Distributed Generation

DIgSILENT – DIgital SImuLator for Electrical NeTwork

DoE - Department of Energy

DSL – Digital Subscriber Line

DSLAM – DSL Access Multiplexer

DSM – Demand Side Management

DSSS – Direct Sequence Spread Spectrum

DTI – Department of Trade and Industry

EAC - Electricity Advisory Committee

EASAC – the European Academies Science Advisory Council

EC – European Commission

ETP - European Technology Platform

EURELECTRIC – Union of the Electricity Industry

GHGs - Greenhouse Gases

GIZ – German Society for International Cooperation

GOOSE – Generic Object Oriented Substation Event

GPON – Gigabit Passive Optical Network

GTZ – German Technical Cooperation

GWEC – Global Wind Energy Council

HDR – High Data Rate

HFC – Hybrid Fibre-Coaxial

HOMER - Hybrid Optimisation Model for Electric Renewables

ICT - Information Communication and Technology

IEA - International Energy Agency

IEA-ETSAP - International Energy Agency-Energy Technology Systems Analysis Programme

IEA-PVPS - International Energy Agency-Photovoltaic Power System Program

IEIA - International Energy Information Administration

INSEL – Integrated Simulation Environment Language

IPC – Intergovernmental Panel on Climate Change

IRENA – International Renewable Energy Agency

ISM – Industrial, Scientific and Medical

JUCCCE – Joint US China Co-operation on Clean Energy

LDR – Low Data Rate

MTSO – Mobile Telephone Switching Office

NERC – North American Electric Reliability Corporation

NERSA – National Energy Regulator of South Africa

NETL – National Energy Technology Laboratory (USA)

NIST – National Institute of Standards and Technology (USA)

NSP – Network Service Provider

OECD – Organisation for Economic Co-operation and Development

OLT – Optical Line Terminal

ONT – Optical Network Terminal

PCC – Point of Common Connection (Coupling)

PSCAD/EMTDC – Power Systems Computer Aided Design/Electro-Magnetic Transients including DC

PSS/E – Power System Simulator for Engineering

PUC – Point of Utility Connection

REIPP – Renewable Energy Independent Power Producer

RPP – Renewable Power Plant

RSA – Republic of South Africa

SAIC – Shanghai Automotive Industry Corporation

SANDI – Energy Development Institute

SASGI – South Africa Smart Grid Initiative

SASTELA – Southern Africa Solar Thermal and Electricity Association

SCADA – Supervisory Control and Data Acquisition

SIMPOW – SIMulation of POWer systems

SPICE – Simulation Program with Integrated Circuit Emphasis

TRNSYS – TRaNsient SYstem Simulation Program

TWACS – Two-Way Automatic Communication systems

UNIDO – United Nations Industrial Development Organisation

WEC – World Energy Council

CHAPTER 1
INTRODUCTION

1.1 Background

Power systems were originally developed in the form of local generation supplying local demands, the individual systems being built and operated by independent companies (Jenkins *et al.*, 2000). This is exemplified by the lighting of the Harbour Board of the City of Cape Town whose installation was commissioned on 3 October 1882, the lamps being supplied by generating plant installed in a building in St Andrew's Square. According to Palser (*n.d*), it is recorded that these lights "proved of great service, not only in minimising accidents, but also in facilitating the working of vessels at night". During the early years of development, small generating station supplying local loads proved quite sufficient. In other words, the electric system was composed of multiple but isolated generation plants (Galli *et al*., 2011). For instance, initially 4000 individual electric utilities in the U.S. owned local grids and operated in isolation (Jin, 2010). However, it was soon recognised that an integrated system, planned and operated by a specific organisation, was needed to create an effective system that was both reasonably secure and economic (Jenkins *et al.*, 2000). This in the view of EPRI (2000) means that centralised power systems evolved in the first place because of the various economic and reliability advantages associated with large-scale interconnected power systems.

Modern electrical power systems have developed over a period of about 70 years (Jenkins *et al.*, 2010) based on economy of scale and efficiency. This is because modern society is very much dependent on the availability of cheap and reliable electricity (Bollen and Hassan, 2011) which warranted the replacement of small generating stations with large centralised generators. However, the economic and reliability advantages of 50 years ago may no longer apply today due to new technical and economic factors that have arisen in the past few decades (EPRI, 2000). In the view of Clark (2010) while some fossil fuels, like coal, are still cheap today, they are the major American and global atmospheric polluters. Therefore, if the human and environmental impacts of coal were calculated into its costs, then the real cost of coal energy generation for power would soar. The bulk of global electricity is generated in large (> 500 MW) power stations at around 20 kV (Freris and Infield, 2008). This is then stepped up by transformers to an extra high voltage (EHV) level such as 400 kV and carried by the transmission system to the bulk supply points, where it is stepped down to a high voltage (HV) level of around 100 kV. The 400 kV high voltage interconnected transmission network, according to Jenkins *et al.* (2010), is common in most of Europe and 750 kV in North America and China.

In South Africa the generators in the power stations produce electricity at about 20 kV and frequency of 50Hz. The high voltage transmission system in Eskom comprises a 132 kV, 275 kV, 400 kV and 765 kV (Eskom, 2010a). The difference in the transmission voltages is because of differences in (Casazza and Delea, 2010):

- the locations of generating units and stations in relation to the load centers,
- the sizes and types of generating units,
- geography and environmental conditions, and
- the time that the transmission systems were built.

All the high voltage lines plus the big transformers and related equipment form the transmission system, also known as the National Grid (Eskom, 2012b).

Eskom is the state-owned national utility that provides electricity to South Africa as well as to a number of Southern African countries. Eskom is an integrated monopoly, generating 95% of the country's electricity, as well as approximately 45% of the electricity used in Africa. It operates and owns the national transmission system which is made up of more than 300 000 km of power lines, of which 27 000 km constitutes the national transmission grid. Ninety two percent of electricity is produced from 24 coal fired power stations. South Africa has one nuclear power station, the only one on the African continent, two gas turbine generators, two conventional hydroelectric plants and two pumped storage stations. Eskom exports electricity to Botswana, Lesotho, Mozambique, Swaziland, Namibia and Zimbabwe (ERC, 2009).

The implication of the aforementioned integrated monopoly is that Eskom generates, transmits and in some cases distributes electricity to industrial, mining, commercial, agricultural and residential customers and redistributors. Additional power stations and major power lines are being built to meet rising electricity demand in South Africa (Eskom, 2013).

Figure 1.1 shows a diagrammatic layout of a typical electrical power system from the point of generation to the point of consumption. The figure depicts a coal fired power station as this represents the majority of world stations. For example, Eskom produces electricity at power stations, most of which are grouped near coal mines in Mpumalanga and the Northern Province. However, the big “load” centres are in places like Gauteng, the Western Cape and KwaZulu Natal (Eskom, 2012b). This is because according to Keyhani (2011), historically power plants are located away from heavily populated areas and such locations are where water and fuel (often supplied by coal) are available.

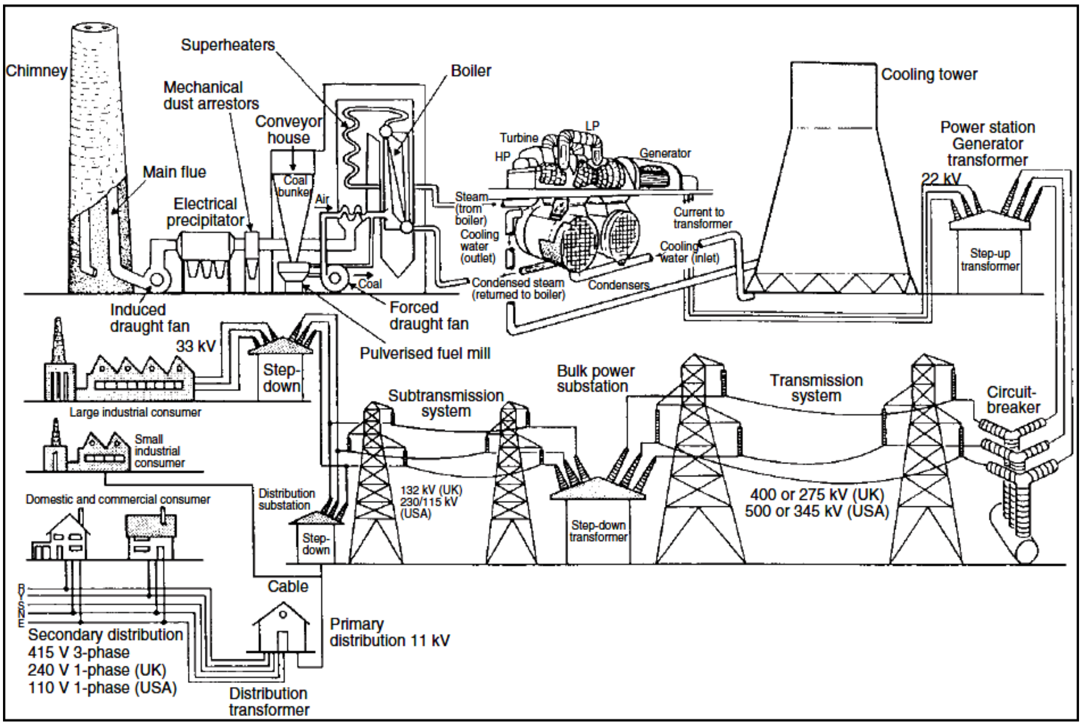

Figure 1.1: Pictorial view of the components of a large power system (Freris and Infield, 2008)

Obviously, change axiomatically is the only constant because – according to Jenkins *et al.* (2010) – from around 1990 there has been a revival of interest in connecting generation to the distribution network. But Power System Relay Committee (PSRC) of IEEE (2004) asserts that the use of distributed resources has increased substantially since 1998 because of the potential to provide increased reliability and lower cost of power delivery to customers. Bollen and Hassan (2011) view this as the introduction of new types of production into the power system. This is equivalent to a return to the early days of electricity supply. As observed by Jenkins *et al.* (2000) a full circle has therefore evolved with generation being ‘embedded’ in distribution systems and ‘dispersed’ around the system rather than being located and dispatched centrally or globally. This development is in tandem with the history of industrial revolutions that started from energy and moved through services and communication and back to energy as shown in Figure 1.2.

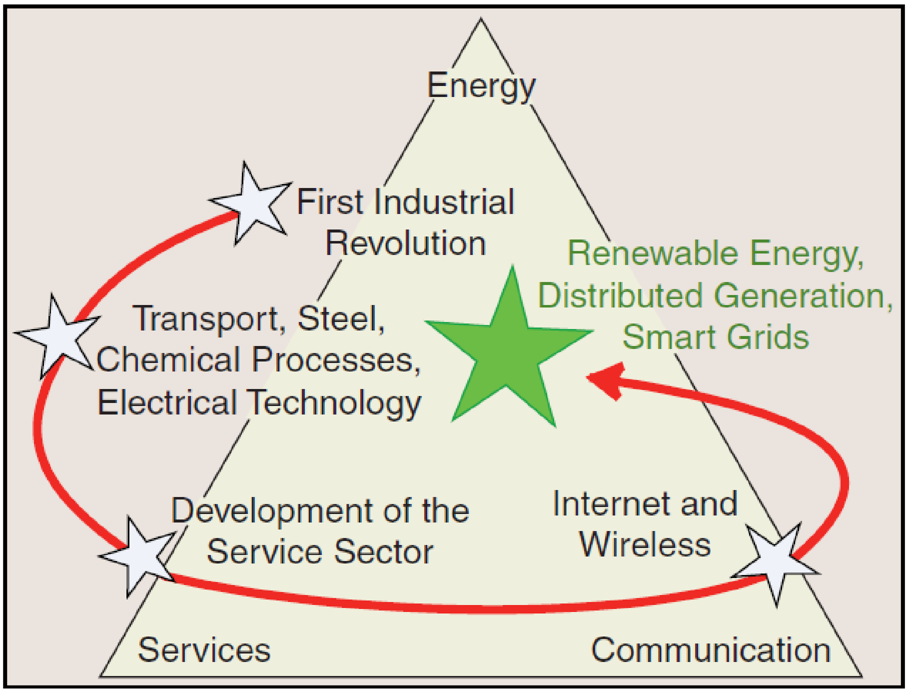

Figure 1.2: Visual history of industrial revolutions (Liserre *et al*., 2010)

Some of the reasons necessitating this full circle are basic while others are regionally or nationally dependent. For instance from the OECD countries' perspectives the reasons are (IEA, 2002; Pepermans *et al*., 2005):

- Electricity market liberalisation,
- Developments in DG technology,
- Constraints on the construction of new transmission lines,
- Increased customer demand for highly reliable electricity, and
- Concerns about climate change.

But in the view of Bollen and Hassan (2011) these reasons are:

1. The open electricity market that has been introduced in many countries since the early 1990s has made it easier for new players to enter the market. Enabling the introduction of new electricity production is one of the main reasons for the deregulation of the electricity market.
2. Another reason for introducing new types of production is environmental. Several of the conventional types of production result in emission of carbon dioxide with the much-discussed global warming as a very likely consequence. Therefore, changing from conventional production based on fossil fuels, such as coal, gas, and oil, to

renewable sources, such as sun and wind, will reduce the emission. Nuclear power stations and large hydropower installations do not increase the carbon dioxide emission as much as fossil fuel does, but they do impact the environment in different ways.

3. Introduction of new production, of any type, is justifiable because the margin between the highest consumption and the likely available production – reserve margin – is very small. This is obviously an important driving factor in fast-growing economies such as Brazil, South Africa, and India. Also in North America and Europe the margin is getting rather small for some regions or countries.

Currently, environmental and energy security – evidenced by reduced reserve margin – concerns are potential compelling factors for South Africa to return to the beginning of electricity generation mode (Onwunta and Kahn, 2013). Therefore, second and third reasons by Bollen and Hassan (2011) are quite relevant to South Africa. Firstly, South Africa is the largest emitter of greenhouse gasses (GHGs) in Africa and one of the most carbon emission-intensive countries in the world, annually emitting some 7 tonnes of CO_2 per capita (RSA, 2009) as shown in Figure 1.3. Greenhouse gasses are primarily water vapour, carbon dioxide, carbon monoxide, ozone, and a number of other gasses (Keyhani, 2011).

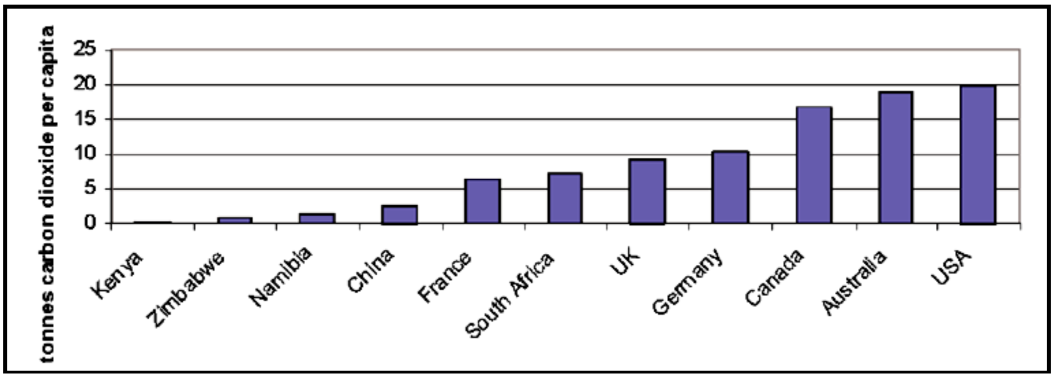

Figure 1.3: Carbon dioxide emission per capita (RSA, 2009)

South Africa's energy intensive economy and high dependence on coal for primary energy are responsible for her emission status. Data for this analysis was based on IEA 2001 report. Due to its high dependence on coal the South African electricity grid is one of the most carbon intensive in the world with a grid emission factor of 1.01 tCO2e/MWh (Sa and Paul, 2013)

According to an IEIA 2009 study, South Africa's per capita emissions are 9.18 tonnes of CO_2 per capita (Urban Earth, 2012). The study estimated that South Africa is the 12th highest CO_2

emitter globally with China as the greatest contributor while USA is in second position. While South Africa only contributes 1.49% to global CO_2 emissions, its per capita emissions are high relative to many countries. Figure 1.4 below shows South Africa's per capita CO_2 emissions in relation to other BRICS member countries and the USA. It is evident from the figure that South Africa exceeds the world average of 4.49 tonnes of CO_2 per capita and is higher than China, Brazil and India. The study further re-echoes that South Africa is Africa's largest emitter contributing over 40% of Africa's total CO_2 emissions. Also the African country with the second highest emissions is Egypt who contributes 17% of the continents emissions.

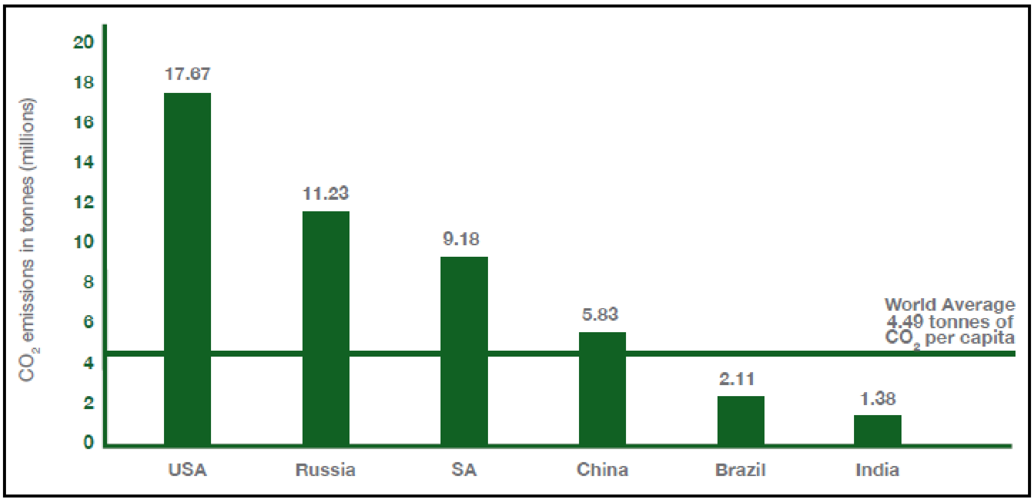

Figure 1.4: South Africa's per capita CO_2 emissions relative to other BRICS member countries and the USA (Urban Earth, 2012)

Carbon dioxide being a major component of greenhouse gas (GHG) emissions explains South Africa's global GHG emissions status. According to OECD (2013), South Africa is towards the upper end of the international range in terms of GHG emissions per capita, and among the most emission-intensive middle-income countries as shown in Figure 1.5. Of the 134 countries for which IEA data are available, South Africa ranked 47th in 2008 in per capita greenhouse gas emissions, with 10.3 tonnes of CO_2 equivalent, 43% above the global mean. Even compared to upper-income countries, South Africa is close to the average: 11 of 34 OECD countries have lower greenhouse gas emissions per capita.

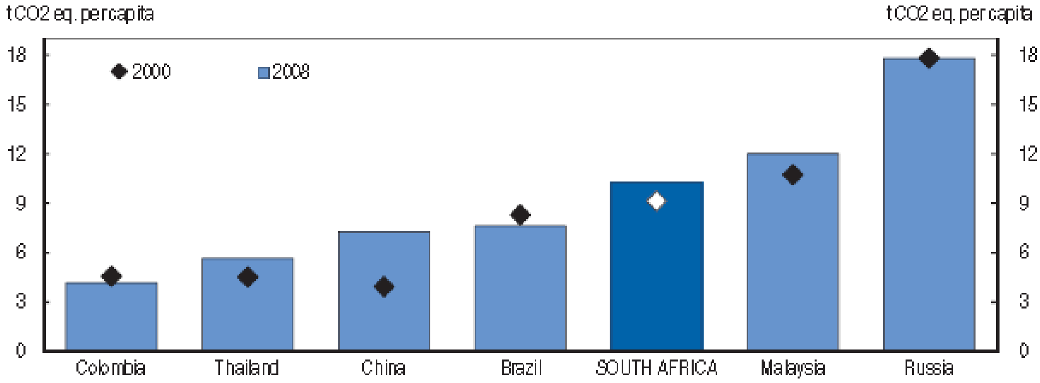

Figure 1.5: Greenhouse gas emissions per capita (OECD, 2013)

Secondly, the electricity supply industry in South Africa is confronted with many challenges. Amongst these challenges are (de Beer, 2012a):

- Shortage of generation capacity
- Poor performing networks
- A significant infrastructure investment backlog
- Ageing infrastructure
- Ageing workforce
- Inability to effectively introduce renewable energy options into the grid
- Inability to introduce effective demand response strategies

The challenge posed by reduced reserve margin – due to shortage of generation capacity – in South Africa's power system really manifested recently. Reserve margin is a deterministic criterion, which provides a measure of system security (Miketa and Merven, 2013) and it is defined as the difference between the operable capacity and the peak demand for a particular year as a percentage of peak demand. According to Weedy *et al*. (2012) reserve margins are allowed in the total generation plant that is constructed to cope with unavailability of plant due to faults, outages for maintenance and errors in predicting load or the output of renewable energy generators. Also when traditional national electricity systems were centrally planned, it was common practice to allow a margin of generation of about 20% over the annual peak demand. They also believe that a high proportion of intermittent renewable energy generation leads to a requirement for a higher reserve margin.

Since 2007, Eskom has experienced a lack of capacity in the generation and reticulation (distribution) of electricity (Inglesi and Pouris, 2010) which resulted in the first quarter of 2008 blackouts experienced in the country and the resultant South Africa's economic damage. In their view the economic growth of the first quarter of 2008 fell to 1.57% from 5.4% in the last quarter of 2007. The coincidence of South Africa's energy crisis with the economic meltdown in 2008 was a double tragedy, to say the least. At the peak of the crisis, the generation net reserve margin fell below 10% – well below conventional industry benchmark of at least 15%. The main reason for the 2007-2008 energy crisis was the imbalance between electricity supply and demand. This, according to Inglesi and Pouris (2010), is attributable to:

- The delayed decision (in 2004) by government to fund the building of a new power station which failed to give Eskom enough time to prevent the crisis.

- The increase (50%) of electricity demand in the country between 1994 and 2007 which might have been partially a consequence of the implementation of the Free Basic Electricity Policy in 2001. Coupled to this was the expansion of the economy after the lifting of the sanctions.

Also ERC (2009) posits that over the last decade the reserve margin has fallen significantly as a result of growth in demand of around 3% per year and a very limited amount of new capacity commissioned. The impact of the 2008 electricity shortage in South Africa which resulted in load shedding could have been reduced or even avoided if the utility network had more DG connected to it (Mollo *et al*., 2012). Equally, increase in consumption of electricity in industrialized countries since about 1980 has been no more than 2% per year due largely to the contraction of energy-intensive industries (e.g. steel manufacturing) combined with efforts to load manage and to make better use of electricity.

However, South Africa has maintained a serious commitment in tackling her energy challenges. One of such concerted efforts is the government's overarching policy on energy as set out in its *White Paper on the Energy Policy of the Republic of South Africa (1998)*. This white paper encourages the entry of multiple players into the generation market. A supplement to this is the *White Paper on Renewable Energy (2003)*, which recognises that the medium and long-term potential of renewable energy is significant. There is also the *National Energy Efficiency Strategy (2005)* which highlights the role of energy efficiency in addressing energy and environmental issues. And most recently the *Integrated Resource Plan (2010)* which has laid out the proposed generation new build fleet for the period 2010 to 2030. Undoubtedly, with an increasing demand in energy predicted and growing environmental concerns about fossil fuel based energy systems, the development of large-scale renewable energy supply schemes is strategically important for increasing the diversity of domestic energy supplies and avoiding energy imports while minimising the environmental impacts (RSA, 2004).

Evidently, South Africa has joined the current international trend towards the generation of “clean” energy in response to the threat of climate change and to meet the commitments of the Kyoto Protocol. According to RSA (2004), the Kyoto Protocol was introduced in 1997 at the third Conference of Parties. The conference resulted in a consensus decision to adopt a Protocol under which industrialised countries (Annex 1 countries) will reduce their combined GHG emissions by at least 5% compared to 1990 levels by the period 2008 to 2012. South Africa acceded to the Kyoto Protocol in March 2002. The Kyoto Protocol does not commit the non-Annex 1 (developing) countries, like South Africa, to any quantified emission targets in the first commitment period (2008 to 2012). Also, RSA (2004) noted that although South Africa is not committed to a specific timeframe to reduce GHG emissions, it has a window of opportunity to utilise international funding for the penetration of renewable energy into South Africa’s energy mix.

Sa and Paul (2013) have noted that to address the climate change concerns related to its carbon intensity South African government has pledged to reduce its total annual GHG emissions by 34% below its business-as-usual trajectory by 2020. Consequently, based on global best practices the South African government has developed a suite of instruments that will either penalise industry and/or consumers for emitting GHGs or reward industry and/or consumers for reducing their GHG emissions. One of the carrot instruments the government has put in place to realise this objective is the so-called REIPPP which provides independent power producers with an advantageous electricity tariff for their renewable electricity. The program is designed as a competitive bidding process whereby the lowest bidders are awarded long term power purchase agreements at an offered price in R/MWh for the renewable energy their projects supply to the South African grid.

According to Singh (2011), South African Department of Energy has published its Integrated Resource Plan (IRP) that will guide the development of the future energy mix. Integrated resource planning is a public planning process and framework in which the costs and benefits of both demand- and supply-side resources are considered to develop a least-cost mix of resource options (Basso, 2009). The IRP is proposing that coal contributes 46% to the energy mix by 2030, renewable energy 26%, nuclear 13%, open cycle gas turbines 8%, pumped storage 3%, combined cycle gas turbines 3%. A diagrammatical representation of this future energy mix is depicted in Figure 1.6. The IRP aims to balance affordability with the need to reduce carbon emissions and ensure security of supply.

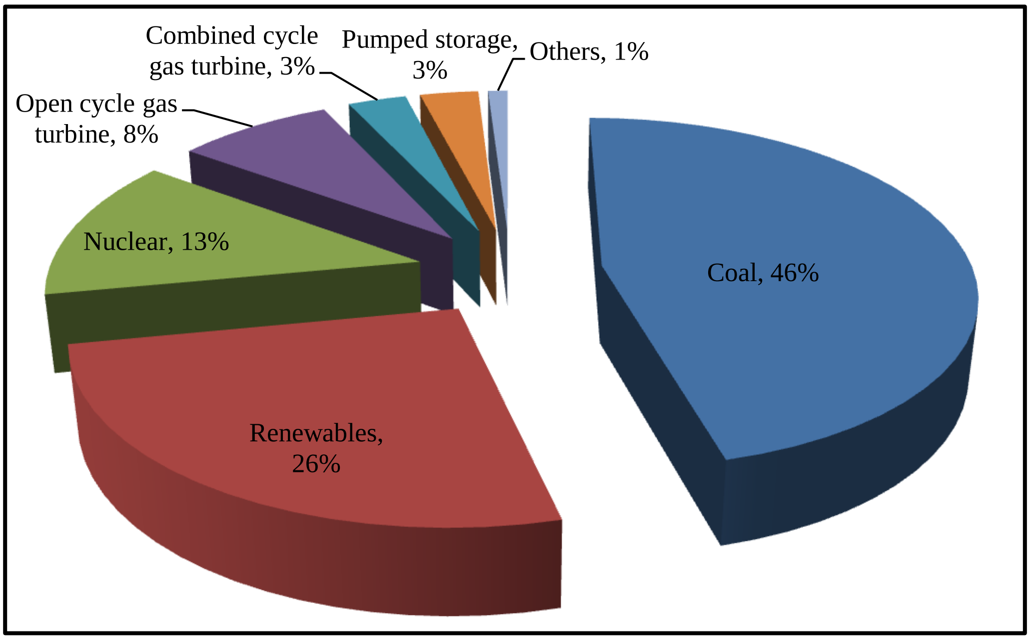

Figure 1.6: South Africa's future energy mix by 2030 (Singh, 2011c)

The International Energy Agency (IEA) defines energy security as the uninterrupted availability of energy sources at an affordable price (Miketa and Merven, 2013). Energy security has many aspects. Long-term investment is mainly linked to timely investments to supply energy in line with economic developments and environmental needs. Short-term energy security focuses on the ability of the energy system to react promptly to sudden changes in the supply-demand balance. There is no single indicator for energy security but some aspects that are commonly looked at include:

- Diversity of the supply mix
- Reliability criteria
- Reliance on imports from a single source
- The impact of droughts in hydro systems

Interestingly South Africa had been cited by Petrie *et al*. (2001), based on an EPRI report, as an excellent example of the focus on distributed generation. Approximately 20% of South Africa's rural population was not expected to get utility grid electricity for at least the next 20 years. The South African government recognising the importance of distributed generation and renewable energy technologies had approved the use of photovoltaic systems for the electrification of 2000 clinics and 16,800 schools. Photovoltaic systems were eventually expected to electrify an estimated 2.5 million homes and 100,000 small businesses in a comprehensive South African grid electrification program.

In summary and according to GWEC (2012), South Africa has the world's seventh largest coal reserves, so it is no surprise that more than 90% of South Africa's electricity comes from coal fired power stations with the attendant high CO_2 and GHG emissions. While Eskom produces the bulk of this with in excess of 34,000 MW of coal fired capacity, South African municipalities own another 2,400 MW, and an additional 860 MW is privately held. But the non-coal electricity generated by Eskom includes:

- one nuclear power station at Koeberg (1,930 MW);
- two gas turbine facilities (342 MW);
- six conventional hydroelectric plants (600 MW);
- and two hydroelectric pumped storage stations (1,400 MW).

Eskom's three previously mothballed coal-fired facilities (3,800 MW) at Camden, Grootvlei and Komati have been refurbished. Reserve margins are razor thin, and South Africa has recently been plagued by blackouts and rolling brownouts during peak periods. Therefore, need for rapid capacity additions, as well as the government's policy to stop the growth in greenhouse gas emissions by the middle of next decade, bodes well for renewable distributed generation power development.

1.2 Research Topic

Modelling and simulation of the impacts of distributed generation integration into the smart grid

Section 1.1 has established that distributed generation deployment is quite relevant to South Africa. But a pertinent question to ask is "How will distributed generation integration affect the operation of South Africa's power system given that it was designed for a centralised generation?" The connection of generation sources to distribution networks leads to a number of challenges because these circuits were designed to supply loads with power from the higher to the lower voltage circuits. According to Jenkins *et al.* (2010), conventional distribution networks are passive with few measurements and very limited active control. They are designed to accommodate all combinations of load with no action by the system operator. However, with significant penetration of distributed generation the power flows may become reversed and the distribution network will no longer be a passive circuit supplying loads but an active system with power flows and voltages determined by the generation as well as the loads. Ackermann *et al*. (2001) believe that this large variety of options for grid connection of distributed generation makes the analysis of grid integration issues very complex. Furthermore, that local network conditions have an important influence on the relevant integration issues. Hence, each network will require a detailed analysis

According to IEC (2010) it is a great challenge to interconnect renewable energy generation to power systems. Therefore, one important task of Smart Grid is to provide a dynamic platform for free and safe interconnection of renewable energy generation to power systems. This means that smart grid technology can address some of the problems of interconnecting DGs at the distribution level.

Equally, a worthwhile question is "What is the status of the communication system between consumers and South Africa's electricity behemoth?" because generation through distributed generation results to a hitherto consumer also becoming a producer. A parlance for this producer-consumer phenomenon is "*prosumer*". This participation by energy end users has been called the "democratization of energy" (Keyhani, 2011). It has similarities to the debate as to whether it is better for individual computers to hold their own software or to use it from a central source as required (Jenkins *et al.*, 2010). ICT plays a crucial role in the emergent active distribution network occasioned by distributed generation.

Thirdly, "Is it possible to proffer acceptable solutions to distributed generation challenges through computer software?" Computer based analysis is highly educational because there is no fear of damage due to fault or abnormal operation. Technically, simulation is a virtual or software representation of a physical circuit or system (Bose, 2006).

1.3 Research Objectives

The primary objective of this research work is to conduct a study on the impacts of distributed generation integration given the emergence of smart grid concept. Therefore, this work aims at evaluating the potential effects of DG on the operation of electric power system with particular reference to the distribution system.

Actualisation of this objective hinges on:

1. Extensive and intensive literature review,
2. Selection of appropriate simulation software,
3. Development of a distribution network model, and
4. Simulations to investigate DG impacts.

1.4 Research Scope and Limitations

This research work focuses on DG integration into medium voltage distribution network.

The most interesting smart grid's applications currently are wind power and solar applications, but hydroelectric power remains under research and development (Elgargouri *et al*., 2013). So this research limits itself to energy from sun and wind without being unmindful of other DG technologies.

This work is limited to the steady state concerns of DG integration because a smart grid communication infrastructure is extremely complex. However, the crucial role of communication in electric power system will receive due attention while avoiding its modelling complexities.

1.5 Thesis Organisation

This thesis is organised as follows:

- Chapter 1 Introduction
- Chapter 2 Distributed Generation Concept and Technology
- Chapter 3 Distributed Generation Integration Issues
- Chapter 4 Smart Grid: Concept, Development and Lessons for South Africa
- Chapter 5 Modelling and Simulation
- Chapter 6 Conclusion and Recommendations

CHAPTER 2
DISTRIBUTED GENERATION CONCEPT AND TECHNOLOGY

2.1 Introduction

This chapter commences with distributed generation concept which embodies definition, classifications and environmental friendliness of distributed generation. This is followed by a brief review of sun and wind based generation as typical technology examples. The approach to these reviews includes history, classifications and operating principles.

2.2 Distributed Generation Concept

Distributed generation is not a new concept because originally, all energy was produced and consumed at or near the process that required it (Borbely and Krieder, 2001). According to them a fireplace, wood stove, and candle are all forms of “distributed” – small scale, demand-sited – energy. So is a pocket watch, alarm clock, or car battery. However, the key to today’s energy revolution involves turning the resource clock backwards (from large power plants hundreds or thousands of miles away to a “heat engine” in the building) by riding the rapidly accelerating technology wave forward. Therefore, distributed generation is a fairly new concept in the economics literature about electricity markets, but the idea behind it is not new at all (Singh and Parida, 2012).

2.2.1 Definition of Distributed Generation

The reasons for the death and rebirth of distributed generation have been highlighted in Chapter 1. Many terms have emerged to describe power that comes from sources other than from large, centrally dispatched generating units connected to a high-voltage transmission system or network (Sotkiewicz and Vignolo, 2007). In fact, according to them, there is no clear consensus as to what constitutes distributed generation. However, there appears to be an apparent consensus that basically the connection of generation sources to the distribution network has come to be known as distributed power generation system (DPGS) – most simply as distributed generation (DG) – or the use of distributed energy resources (DER). The term distributed energy resources includes both distributed generation and controllable load (IEEE, 2003; Jenkins *et al.*, 2010). This means that DG is a subset of DER.

The term distributed generation can be considered to be synonymous and interchangeable with the terms embedded generation and dispersed generation, which are now falling into disuse (Jenkins *et al.*, 2010; Puttgen *et al*., 2003). The term ‘embedded generation’ comes from the concept of generation embedded in the distribution network while ‘dispersed generation’ is used to distinguish it from central generation (Freris and Infield, 2008; Jenkins *et al.*, 2000). Ackermann *et al*. (2001) had suggested the term *embedded distributed generation* if the power output of distributed generation is used only within the local distribution network. Furthermore, a regional coloration to these synonyms has been noted by Ackermann *et al*. (2001) as follows:

Anglo-American countries often use the term ‘embedded generation’, North American countries the term ‘dispersed generation’, and in Europe and parts of Asia, the term ‘decentralised generation’ is applied for the same type of generation.

But according to Sallam and Malik (2011) the production of electricity by some consumers using their own generation sources with the goal of feeding their loads or as backup sources to feed critical loads in case of emergency and utility outage is defined as “distributed generation” (DG) in North American terms and “embedded generation” in European terms. Distributed generation is a common term in South Africa although Eskom uses embedded generation in its documentations such as DISTRIBUTION STANDARD FOR THE INTERCONNECTION OF EMBEDDED GENERATION in which an Embedded Generator refers to the item of generating plant that is or will be connected to the Distribution network. This definition includes all types of connected generation, including co-generators and renewables.

Keyhani *et al*. (2010) assert that distributed generation entails using many small generators of 2 to 50 MW output, situated at numerous strategic points throughout cities and towns, so that each provides power to a small number of consumers nearby and dispersed generation refers to use of even smaller generating units, of less than 500 kW output and often sized to serve individual homes or businesses. In their view later publications tend to combine the two categories into one (i.e., distributed generation), to refer to power generation at customer sites to serve part or all of customer load or as backup power, or, at substations, to reduce peak load demand and defer substation capacity reinforcements.

Also EPRI (2000) has noted that there are other terms that are commonly used and have certain legal ramifications per utility normal practice, state, and federal regulations. Terms such as non-utility generator (NUG), independent power producer (IPP), and qualifying facility (QF) are examples. Others are self-generation, on-site generation, cogeneration, and "inside the fence generation" (Schienbein and Dagle, 2001) and small-scale generation (Bollen and Hassan, 2011).

Irrespective of the aforementioned interchangeability, some authors believe distributed generation and dispersed generation are not the same though same acronym – (DG). Their disagreement hinges on capacity as shown in Table 2.1.

Table 2.1: Difference between distributed generation and dispersed generation based on capacity (Onwunta and Kahn, 2013)

Distributed Generation	**Dispersed Generation**	**Authors**
15 – 10,000kW	10 – 250kW	Willis and Scott (2000)
2 – 5MW	<500kW	Kothari and Nagrath (2003)
10 – 10,000kW	1 – 100kW	Farret and Simões (2006)

Therefore, the different terms often refer to different aspects or properties of the new types of generation (Bollen and Hassan, 2011).

2.2.2 Distributed Generation Classifications

One of the classifications of DGs is based on capacity or output power rating as shown in Table 2.2. The units installed on distribution systems will typically be no larger than 1 or 2 MW (Dugan and McDermott, 2002).

Table 2.2: Distributed generation capacities (Ackermann *et al*. 2001; El-Khattam and Salama, 2004)

Class	**Power Range**
Micro distributed generation	~ 1W – 5kW
Small distributed generation	5kW – 5MW
Medium distributed generation	5MW – 50MW
Large distributed generation	50MW – 300MW

Another basis for classification of DGs is the type of technology involved in the power generation. Therefore, distributed generation technologies can be categorised as renewable and non-renewable as depicted in Table 2.3.

Table 2.3: Distributed generation technologies (Puttgen *et al*., 2003)

Renewables	**Non-renewables**
Solar	Internal combustion engine (ICE)
Wind	Combined cycle
Geothermal	Combustion turbine
Ocean	Microturbine
	Fuel cell

Non-renewable energy is obtained from sources at a rate that exceeds the rate at which the sources are replenished (Fanchi, 2004). For example, if the biogenic origin of fossil fuels is correct, fossil fuels could be consider renewable over a period of millions of years, but the existing store of fossil fuels are being consumed over a period of centuries. Because fossil fuels are being consumed at a rate that exceeds the rate of replenishment, fossil fuels are considered non-renewable. Also renewable energy is energy obtained from sources at a rate that is less than or equal to the rate at which the source is replenished. In the case of solar energy, Fanchi (2004) asserts that because the remaining lifetime of the sun is measured in millions of years, many people consider solar energy as an inexhaustible supply of energy. In fact, solar energy from the sun is finite, but should be available for use by many generations of people. Therefore, solar energy is considered renewable and other energy sources that are associated with solar energy, such as wind and biomass, are also considered renewable.

Distributed generation technologies could also be grouped according to their dispatchability namely dispatchable and non-dispatchable. This is because, according to Petrie *et al*. (2001), one of the primary elements in a distributed generation management system is the dispatch strategy: the aspect of control strategy that pertains to the sources and destinations of energy flows. The key difference between the two categories is the controllability of electric power (Kateeb *et al*., 2011). The dispatchable resources, in general, have the energy stored, and could therefore be called upon at any given time to produce power. This implies that dispatchable units such as conventional generator sets, fuel cells, and microturbines, can be controlled by a central intelligence and relied on to generate according to the needs of the power system (Petrie *et al*., 2001). The non-dispatchable resources, on the other hand, inherently do not have any control of the input energy for later use when needed. This means that non-dispatchable technologies generate not as a function of power system needs, but rather as a function of intermittent availability of their energy source. From the foregoing it can adduced that while non-renewable DG technologies are dispatchable the renewable DG technologies consist of dispatchable and non-dispatchable resources. Hydroelectric, biomass and geothermal are dispatchable resources, whereas, wind, solar and tidal waves would be classified as non-dispatchable resources – most or common renewable energy systems are non-dispatchable.

Variable renewable power plants, in this case non-dispatchable DGs, rely on resources that fluctuate on the timescale of seconds to days, and do not include some form of integrated storage (IEA, 2008). Output from such plants fluctuates upwards and downwards according to the resource: the wind, cloud cover, rain, waves, tide, etc. Such technologies are often referred to as intermittent, but this term is misleading because the output, aggregated at the system-wide level, does not drop from full power to zero or vice versa, but rather increases and decreases on a gradient as weather systems shift. It is measured in terms of *ramp rate* – the increase / decrease in output as well as the period over which this occurs. Ramp rates may on occasion be steep: wind plants for example are designed to cut out in storm conditions when a certain wind speed is reached, but meteorological forecasting can provide notice of such events. Therefore, the challenge with variable renewable energy is not so much its *variability,* but rather its *predictability*. In other words, if output could be forecast with 100 % certainty the only challenge would be to meet the ramp rates.

APS (2012) defines distributed generation as any type of electrical generator, static inverter or generating facility interconnected with the distribution system that has the potential either

- for feeding a consumer load, where this load can also be fed by, or connected to, the utility electrical distribution system, or
- for electrically paralleling with, or for feeding power back into the utility's electrical distribution system.

This results in yet another classification of DG as either a separate system or parallel system. A separate or stand alone system is one in which there is no possibility of electrically connecting or operating the consumer's generation in parallel with the utility's system. The consumer's equipment must transfer load between the two power systems in an open transition or non-parallel mode. If the consumer claims a Separate System, the utility may require verification that the transfer scheme meets the non-parallel requirements. But in a Parallel or Interconnected System (grid-connected), a generator is connected to a bus common with the utility's system, and a transfer of power between the two systems is a direct result. A consequence of such interconnected operation is that the consumer's generator becomes an integral part of the utility system that must be considered in the electrical protection and operation of the utility system. Parallel generators encompass any type of distributed generator or generating facility that can electrically parallel with, or potentially backfeed into the utility system.

2.2.3 Distributed Generation and Environmental Friendliness

Keen public awareness of the environmental impacts of electric power generation (Chiradeja, and Ramakumar, 2004) and efforts to mitigate climate change are crucial to DG renaissance. For instance, fossil fuelled power plants produce sulphur oxides, particulate matter, and nitrogen oxides (Weedy *et al*., 2012). Of the former, sulphur dioxide accounts for about 95% and is a by-product of the combustion of coal or oil. The sulphur content of coal varies from 0.3 to 5%. According to these authors, it should be noted that although sulphur does not accumulate in the air it does so in the soil.

Unfortunately some distributed generation technologies could, if fully deployed, significantly contribute to present environmental problems. Therefore, the technologies that can be used for distributed generation cannot be described in general as environmentally friendly. But regarding the main current environmental issue, the increased greenhouse effect, all DG technologies lead to significantly lower emissions than coal-based technologies (Ackermann *et al*., 2001). According to Crappe (2008) the contribution of the capital goods to the emissions from fossil fuel power plants is negligible (<5%). On the contrary, in the case of the so-called "zero emission" generation systems, though direct emission due to combustion is zero, indirect emissions linked to construction, maintenance and dismantling have to be considered. This is the case with nuclear power plants, windmills, photovoltaic generators, hydroelectric power plants and power plants using biomass.

Ackermann *et al*. (2001) consider indirect emissions as emissions that occur during the manufacturing of the power unit and the exploration and transport of the energy resources and maintain that the emissions from typical DG technologies are significantly lower than those from coal power stations. They have also noted that combined cycle gas turbines (CCGT) and large hydro units, too, have significantly lower SO_2 and CO_2 emissions than coal power stations. In their view biomass is seen as being CO_2 neutral, as the amount of CO_2 emitted into the atmosphere when biomass is burnt is equal to the amount of CO_2 absorbed during its growth. According to them NOx (nitrogen oxides) emissions of combustion of bio-fuels were reported to be 20 - 40% lower than that of fossil fuel plants, and SO_2 emissions were reported to be insignificant. Also battery storage as well as fuel cells has no direct emissions besides the emissions occurring during the manufacturing process. However, the fuel mix used for the production of the electricity stored in the batteries must be considered in the calculations of the indirect emissions of battery storage. Furthermore, in the case of fuel cells, the indirect emissions also depend on the energy mix that is required to produce hydrogen, as hydrogen cannot be easily exploited in the same way as conventional fossil fuels.

GIZ *et al*. (2011) agree that renewable energies, such as wind energy, allow electricity production without consuming fossil resources and without any direct carbon dioxide emissions. Therefore, just by producing electrical energy, the use of these sources is justifiable and represents in many locations an economical alternative to the use of fossil resources such as coal or oil.

Wikipedia (2013) has cited a 2006 study of 3 installations in the US Midwest that found the CO_2 emissions of wind power ranged from 14 to 33 tonnes (15 to 36 short tons) per GWh of energy produced. Most of the CO_2 emission came from producing the concrete for wind-turbine foundations.

To add credence to a holistic or life cycle assessment of environmental friendliness of not just DGs but any other product, UNIDO (2006) has approached this from standardisation perspective. Accordingly it submits that environmental protection is an important aim of standardisation: the focus here is on preserving nature from damage that may be caused during the manufacture of a product or during its use or disposal after use. For example, the domestic use of a washing machine should generate only a minimum of pollutants

Two different methods of analysis have been applied to study the life cycle of 'emission-free' power generation facilities (Crappe, 2008):

- analysis of the process chain which calculates the total energy utilisation and the corresponding emissions for all the materials used (steel, concrete, plastic, etc.);
- input/output analysis which divides a product according to its economic elements while the life cycle is defined as a set of economic activities.

According to Crappe (2008) a study conducted by Voorspools *et al*. (2000) has led to retaining the orders of magnitude of Table 2.4 linked to capital goods. Unfortunately, the authors failed to explain why wind power (coast) has less indirect CO_2 emissions than wind power (interior).

Table 2.4: Indirect greenhouse gas emissions from "zero emission" power plants (construction, maintenance, demolition of plants, complete life cycle) (Crappe, 2008; Voorspools *et al*., 2000)

Type of construction	**Duration of life (years)**	**Indirect emissions of CO_2 (gCO_2/kWhe)**	**Use of primary energy (kJprim/kWhe)**	**kJprim/kJe (%)**
Nuclear	40	3	40	1.11
Wind power (coast)	20	9	120	3.33
Wind power (interior)	20	25	350	10.00
Photovoltaic 1996	20	130	3,000	83.33
Photovoltaic 2005	25	60	1,500	41.66
Pumped storage plant	40	8	110	3.06
Micro-hydraulic power plant	40	15	200	5.56
Wood gasification	15	15	260	7.14
Co-combustion of sludge	30	3	40	1.11

Table 2.4 shows that PV cells' indirect CO_2 emissions are higher than those of wind power. This is in agreement with the comparison executed by Jin (2010) of the environmental friendliness between wind turbines and PV cells with a conclusion that wind turbine manufacturing is cleaner than the volume production of solar PV cells. Therefore, wind power makes good sense environmentally and economically. This is because turbine components are generally either recyclable or inert to the environment.

2.3 Distributed Generation Technology

This section considers the technologies deployed in the generation of electrical power from the sun and wind as typical examples of distributed generation technology. The choice of these two sources without any prejudice to other sources such as microtubines, fuel cells, geothermal and internal combustion engines is because of their relevance to the Western Cape Province.

2.3.1 Solar Energy System

Typically, an informed discussion about solar energy is limited by various and confusing notions of what the term *solar energy* actually describes (Bradford, 2006). In his view broadly speaking, *solar energy* could be used to describe any phenomenon that is created by solar sources and harnessed in the form of energy, directly or indirectly – from photosynthesis to photovoltaics.

According to Farret and Simões (2006), the sun is a perennial, silent, free, and non-polluting source of energy and is responsible for all life forms on the planet. This means that sun is of great importance for the planet earth and the ecosystem of our society. Succinctly put, when the sun disappears from the universe, we will cease to exist (Kayhani, 2011). Therefore, solar energy is the most abundant energy resource on earth but only a minuscule fraction of the available solar energy is used (Luo and Ye, 2013). The solar energy that hits the earth's surface in one hour is about the same as the amount consumed by all human activities in a year (IEA, 2010a; Kroposki *et al.*, 2009). The total solar energy absorbed by the earth's atmosphere, oceans and land masses is approximately 3,850,000 exajoules (EJ) per year (Luo and Ye, 2013; Zhong and Hornik, 2013). According to Luo and Ye (2013) the amount of solar energy reaching the surface of the planet is so vast that in 1 year it is about twice as much as will ever be obtained from all of the Earth's nonrenewable resources of coal, oil, natural gas, and mined uranium combined. Consequently, solar energy appears to be easy alternative next to conventional sources, like electricity, coal and fossil fuels (Singh, 2011b). For instance it is estimated that by 2050, PV (photovoltaic) will provide around 11% of global electricity production and avoid 2.3 gigatonnes (Gt) of CO2 emissions per year (IEA, 2010a). Also by 2050, with appropriate support, CSP (concentrating solar power) could provide 11.3% of global electricity, with 9.6% from solar power and 1.7% from backup fuels (fossil fuels or biomass) (IEA, 2010b).

Solar energy reaches the earth in the form of electromagnetic waves (radiation). Rays emitted by the sun, gamma rays, reach the terrestrial orbit a few minutes after they leave the sun surface, crossing approximately 150 million kilometres (Farret and Simões, 2006). Clouds reflect about 17% of sunlight back into space, 9% is scattered backward by air molecules, and 7% is actually reflected directly off the surface back into space. Therefore, eventually the radiation at earth's surface decreases to about 35% less than the level in the stratosphere. At noon on a clear day, the luminous power at the ground level is approximately 1000 W/m^2. Therefore, many factors affect the amount of radiation received at a given location on earth. These factors are (Keyhani, 2011):

- season
- humidity
- temperature
- air mass, and
- the hour of the day

Also according to Keyhani (2011) insolation refers to exposure to the rays of the sun, i.e., the word insolation has been used to denote the solar radiation energy received at a given location at a given time. The phrase incident solar radiation is also used; it expresses the average irradiance in watts per square meter (W/m^2) or kilowatt per square meter (kW/m^2).

2.3.1.1 Brief History and Early Solar Energy System Applications

Literature is replete with historical perspective of solar energy system. Solar energy is the oldest energy source ever used and the sun was adored by many ancient civilizations as a powerful god (Kalogirou, 2009). Keyhani (2011) asserts that from the beginning of recorded history humans have worshipped the sun and the first king of Egypt was Ra, the sun god. The sun god of justice for the Mesopotamia was Shamash. In Hinduism, the sun god, Surya, is believed to be the progenitor of mankind. Apollo and Helios were the two sun divinities of Ancient Greece. The sun also figured prominently in the religious traditions of Zoroastrianism (Iran) and Buddhism (Asia), as well as in the Aztec (Mexico) and Inca (Peru) cultures.

Solar energy, radiant light and heat from the sun has been utilised since ancient times using a range of ever-evolving technologies (Zhong and Hornik, 2013). Based on the account of Kalogirou (2009) the first known practical application of solar energy was in drying for food preservation. Probably the oldest large-scale application was the burning of the Roman fleet in the bay of Syracuse by Archimedes, the Greek mathematician and philosopher (287 – 212 B.C.). Scientists discussed this event for centuries and authors made reference to this event, although later it was criticized as a myth because no technology existed at that time to manufacture mirrors. Amazingly, the very first applications of solar energy refer to the use of concentrating collectors, which are, by their nature (accurate shape construction) and the requirement to follow the sun, more “difficult” to apply. During the 18th century, solar furnaces capable of melting iron, copper, and other metals were being constructed of polished iron, glass lenses, and mirrors. The furnaces were in use throughout Europe and the Middle East. One of the first large-scale applications was the solar furnace built by the well-known French chemist Lavoisier, who, around 1774, constructed powerful lenses to concentrate solar radiation. This attained the remarkable temperature of 1750 ° C. The furnace used a 1.32 m lens plus a secondary 0.2 m lens to obtain such temperature, which turned out to be the maximum achieved for 100 years. Another application of solar energy utilisation during that century was carried out by the French naturalist Boufon (1747 – 1748), who experimented with various devices that he described as “hot mirrors burning at long distance”.

Furthermore, according to Bradford (2006), solar-energy technology saw a burst of new practical applications during the late-nineteenth-century industrial revolution, driven by three solar energy inventors on different continents. The first of the solar inventors was William Adams, a former British patent officer and engineer. In Bombay, India, in the 1860s and 1870s, he conducted various solar-energy experiments and created practical devices such as a solar cooker to help ease energy shortfalls and depletion of local wood fuel in colonial India. Around the same time period, Augustin Mouchot, a French school teacher and inventor, attempted to develop solar-energy generators. John Ericsson, the third solar inventor, was a Swede who moved to the United States in 1839, earning fame and fortune as the designer of the iron-clad Union ship the *Monitor,* which is credited with altering the course of the U.S. Civil War. After the war, Ericsson turned his attention to solar energy and began extensive experiments in the 1870s that continued until his death in 1889. He developed a solar-power engine using hot air to run pistons, an efficient design that limited energy waste.

The use of sun for energy generation can be direct or indirect. Indirect solar energy is related primarily to wind power, hydropower, photosynthesis, sea tidal energy, and to the microbiological conversion of organic matter into liquid fuels (Farret and Simões, 2006). Direct conversion of sunlight into electricity in PV cells is one of the three main solar active technologies, the two others being concentrating solar power (CSP) and solar thermal collectors for heating and cooling (SHC) (IEA, 2010a). PV is a commercially available and reliable technology with a significant potential for long-term growth in nearly all world regions.

2.3.1.2 Photovoltaic System

Photovoltaics (PV) ("photo" meaning "light" and "voltaic" referring to electricity) is the direct conversion of sunlight into an electrical potential (a photovoltage) that can be used to provide electric power (Roop, 2007). A material or device that is capable of converting the energy contained in photons of light into an electrical voltage and current is said to be *photovoltaic* (Masters, 2004). Therefore, the photo-voltaic effect is the process by which an electric potential difference (voltage) is created in a material exposed to light (electromagnetic radiation), which then leads to the flow of electric current (NERC, 2010). This process is directly related to the photo-electric effect, but distinct from it in that in the case of the photo-electric effect electrons are ejected from the material surface upon being exposed to high enough frequency (energy) light, whereas in the photo-voltaic effect the generated electrons are transferred across a material junction (e.g., PN junction in a photo-diode) resulting in the buildup of a voltage between two electrodes and the flow of direct current electricity. In other words, the energy supply for a solar cell is photons coming from the sun (Fonash, 2010). A photon with short enough wavelength and high enough energy can cause an electron in a photovoltaic material to break free of the atom that holds it. If a nearby electric field is provided, those electrons can be swept toward a metallic contact where they can emerge as an electric current. The PV photon cell charge offers a voltage of 1.1 up to 1.75 electron volt2 (eV2) with a high optical absorption (Keyhani, 2011).

Masters (2004) and Roop (2007) concur with other myriad authors that the PV effect itself was discovered in 1839 by a 19-year-old French physicist, Edmund Becquerel, who observed that a photocurrent would flow between two electrodes in a solution when the apparatus was exposed to light. Almost 40 years later, the effect was noticed in selenium by William Adams and Richard Day, and the first solid-state solar cells were made from selenium by Charles Fritts and Werner Siemens. However, many investigators were sceptical about these devices because the quantum physics required to explain the observed effect were not known yet. It was not until Max Planck's proposal of the quantum nature of light in 1900 that the theoretical foundations for understanding PV were established. They were able to build cells made of selenium that were 1% to 2% efficient. Selenium cells were quickly adopted by the emerging photography industry for photometric light meters. According to Masters (2004), as part of his development of quantum theory, Albert Einstein published a theoretical explanation of the photovoltaic effect in 1904, which led to a Nobel Prize in 1923. About the same time, in what would turn out to be a cornerstone of modern electronics in general, and photovoltaics in particular, a Polish scientist by the name of Czochralski began to develop a method to grow perfect crystals of silicon. By the 1940s and 1950s, the Czochralski process began to be used to make the first generation of single-crystal silicon photovoltaics, and that technique continues to dominate the photovoltaic (PV) industry today (Masters, 2004). Then, in 1954, Calvin Fuller and Gerald Pearson were working on new silicon rectifier diode technology at Bell Laboratories, and during one experiment they found that their device produced a significant photocurrent when strongly illuminated (Roop, 2007). At that same time, Daryl Chapin was working on selenium solar cells. When Pearson alerted Chapin to his silicon discovery, Chapin immediately abandoned his selenium work and switched to silicon, and after significant effort but a relatively short time, the result was the achievement of 6% conversion efficiency. However, the energy cost for PV, which is the critical figure of merit for PV systems (usually expressed in $/kWh), was nearly a thousand times that of competing alternatives at that time. Although technically successful, PV was still too expensive to be useful.

Surprisingly, Keyhani (2011) records that solar cells, also called photovoltaic (PV) cells, were developed by Carlson and Wronski in 1976.

But as long as 120 years ago, visionaries looking through the soot and smoke of the early industrialising world saw the need for a renewable and environmentally acceptable energy source (Fonash, 2010). Writing in 1891, Appleyard foresaw “the blessed vision of the Sun, no longer pouring his energies unrequited into space, but, by means of photo-electric cells and thermo-piles, these powers gathered into electrical storehouses to the total extinction of steam engines, and the utter repression of smoke.” It is interesting to note Appleyard’s specific mention of what he calls photo-electric cells. This energy conversion approach was known even then due to Becquerel’s discovery of photovoltaic action in 1839.

2.3.1.3 Photovoltaic Energy Conversion

Photovoltaic energy conversion is the direct production of electrical energy in the form of current and voltage from electromagnetic (i.e., light, including infrared, visible, and ultraviolet) energy (Fonash, 2010). A solar cell is a large-area semiconductor diode (Krauter, 2006). It consists of a *p-n* junction created by an impurity addition (doping) into the semiconductor crystal (consisting of four covalent bonds to the neighboring atoms for the most commonly used silicon solar cells). According to (Farret and Simões, 2006), semiconductor materials have bands of allowed and forbidden energy in their spectrum of electronic energy (the energy gap). Inside the allowed band, there are valence and conduction bands, separated by such an energy gap. The electrons occupy the valence band and can be excited in the conduction band by thermal energy or by absorption of photons with energy quantum higher than the energy gap. The bandwidth of the energy gap is characteristic for each semiconductor. So, when an electron passes from one band to other, it leaves in its place a hole that can be considered a positive charge. When voltage is applied across the semiconductor, the electrons and their holes contribute to the electrical current, since the presence of that electric field makes those particles move in opposite directions with respect to each other. Therefore, an electrostatic potential inside the material is created to separate positive from negative charges. Whenever the semiconductor is illuminated, it behaves like a battery; in other words, the charges accumulate in opposite areas of the chip. When a load is applied, a current flows through it, and electrical power is dissipated as shown in Figure 2.2.

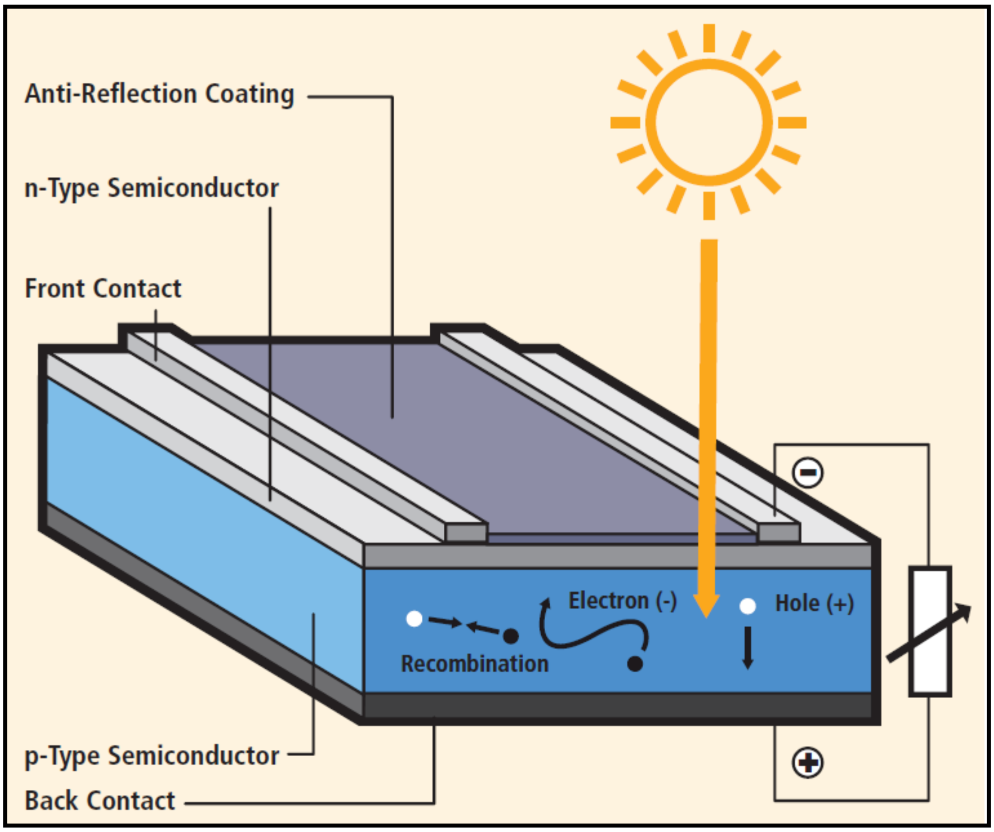

Figure 2.1: Generic schematic cross-section illustrating the operation of an illuminated solar cell (IPCC, 2011)

Consequently, the basic four steps needed for photovoltaic energy conversion are (Fonash, 2010):

- a light absorption process which causes a transition in a material (the absorber) from a ground state to an excited state,
- the conversion of the excited state into (at least) a free negative- and a free positive-charge carrier pair, and
- a discriminating transport mechanism, which causes the resulting free negative-charge carriers to move in one direction (to a contact that we will call the cathode) and the resulting free positive-charge carriers to move in another direction (to a contact that we will call the anode).

The energetic, photogenerated negative-charge carriers arriving at the cathode result in electrons which travel through an external path (an electric circuit). While traveling this path, they lose their energy doing something useful at an electrical "load," and finally they return to the anode of the cell. At the anode, every one of the returning electrons completes the fourth step of photovoltaic energy conversion, which is closing the circle by

- combining with an arriving positive-charge carrier, thereby returning the absorber to the ground state.

In some materials, the excited state may be a photogenerated free electron– free hole pair. In such a situation, step 1 and step 2 coalesce. In some materials, the excited state may be an exciton, in which case steps 1 and 2 are distinct.

Kroposki *et al*. (2009) have noted that this "photovoltaic" effect requires no moving parts and does not use up any of the material in the process of generating electricity. The most attractive features of solar panels are the nonexistence of movable parts, very slow degradation of the sealed solar cells, flexibility in the association of modules (from a few watts to megawatts), and the extreme simplicity of its use and maintenance Farret and Simões (2006). As shown in Figure 2.2, a typical solar cell consists of a glass or plastic cover or other encapsulant, an antireflective surface layer, a front contact to allow electrons to enter a circuit, a back contact to allow the electrons to complete the circuit, and the semiconductor layers where the electrons begin and complete their journey.

2.3.1.4 Classification of Photovoltaics

There are a number of ways to categorize photovoltaics based mainly on the different types of technologies currently used to manufacture them. One dichotomy is based on the thickness of the semiconductor. Conventional crystalline silicon solar cells are, relatively speaking, very thick – of the order of 200–500µm (Masters, 2004). An alternative approach to PV fabrication is based on thin films of semiconductor, where "thin" means something like 1–10µm. Thin-film cells require much less semiconductor material and are easier to manufacture, so they have the potential to be cheaper than thick cells. The first generation of thin-film PVs were only about half as efficient as conventional thick silicon cells; they were less reliable over time, yet they were no cheaper per watt, so they really weren't competitive. Currently, however, about 80% of all photovoltaics are thick cells and the remaining 20% are thin-film cells used mostly in calculators, watches, and other consumer electronics.

According to Zhou *et al*. (2011), the so-called 1st generation of solar cells based on e.g. bulk crystalline and polycrystalline silicon is still dominating the PV market. However, so-called 2nd generation solar cells mainly consisting out of thin film solar cells based on CdTe, Copper Indium Gallium Selenide (CIGS), and amorphous silicon has currently gained distribution of 25% in market share worldwide. It is expected that this number will increase significantly within the next years. While for the 1st and 2nd generation solar cells commercial solar panels are available with decent power conversion efficiencies (PCEs) and lifetimes, the emerging 3rd generation solar cells such as OPV (organic PV) and DSSCs (dye-sensitized solar cells) technologies are still in the development phase. IPCC (2011) is in agreement with Zhou *et al*. (2011) that these emerging PV technologies are still under development and in laboratory or (pre-) pilot stage, but could become commercially viable within the next decade. According to IPCC (2011), they are based on very low-cost materials and/or processes and include technologies such as dye-sensitized solar cells, organic solar cells and low-cost (printed) versions of existing inorganic thin-film technologies. However, contrary to the position of IPCC (2011) on the commercial viability of these emerging PV technologies, Zhou *et al*. (2011) assert that some commercially available products have recently entered the market such as e.g. solar bags representing niche products, which are so far not suitable for competing with traditional large scale applications of solar panels of the 1st and 2nd generations. In traditional solar panels the differences between best solar cell and average solar cell efficiencies are much smaller than for the emerging solar cell technologies with the consequence that modules of 3rd generation solar cells still suffer from very low performance.

Photovoltaic technologies can also be categorized by the extent to which atoms bond with each other in individual crystals as follows (IEA, 2010a; Masters, 2004):

- *single crystal* , the dominant silicon technology;
- *multicrystalline*, in which the cell is made up of a number of relatively large areas of single crystal grains, each on the order of 1 mm to 10 cm in size, including multicrystalline silicon (mc-Si);
- *polycrystalline*, with many grains having dimensions of the order of 1 µm to 1 mm, as is the case for cadmium telluride (CdTe) cells, copper indium diselenide (CuInSe2,) and polycrystalline, thin-film silicon;
- *microcrystalline* cells with grain sizes less than 1 µm; and
- *amorphous*, in which there are no single-crystal regions, as in amorphous silicon (a-Si).

Another way to categorize photovoltaic materials is based on whether the *p* and *n* regions of the semiconductor are made of the same material (with different dopings, of course)—for example, silicon. These are called *homojunction* photovoltaics. When the *p*–*n* junction is formed between two different semiconductors, they are called *heterojunction* PVs. For example, one of the most promising heterojunction combinations uses cadmium sulfide (CdS) for the *n*type layer and copper indium diselenide (CuInSe2, also known as "CIS") for the *p*-type layer.

Other distinctions include multiple junction solar cells (also known as cascade or tandem cells) made up of a stack of *p*–*n* junctions with each junction designed to capture a different portion of the solar spectrum. The shortest-wavelength, highest-energy photons are captured in the top layer while most of the rest pass through to the next layer. Subsequent layers have lower and lower band gaps, so they each pick off the most energetic photons that they see, while passing the rest down to the next layer. Very high efficiencies are possible using this approach.

Figure 2.3 shows the classification of solar cells adapted from Singh (2011b) with emphasis on the current technological developments. However, the figure presents a minor confusion by having organic solar cells as a subdivision of the same organic solar cells. Perhaps this is a means to highlight that among organic solar cells some are purely organic and others inorganic.

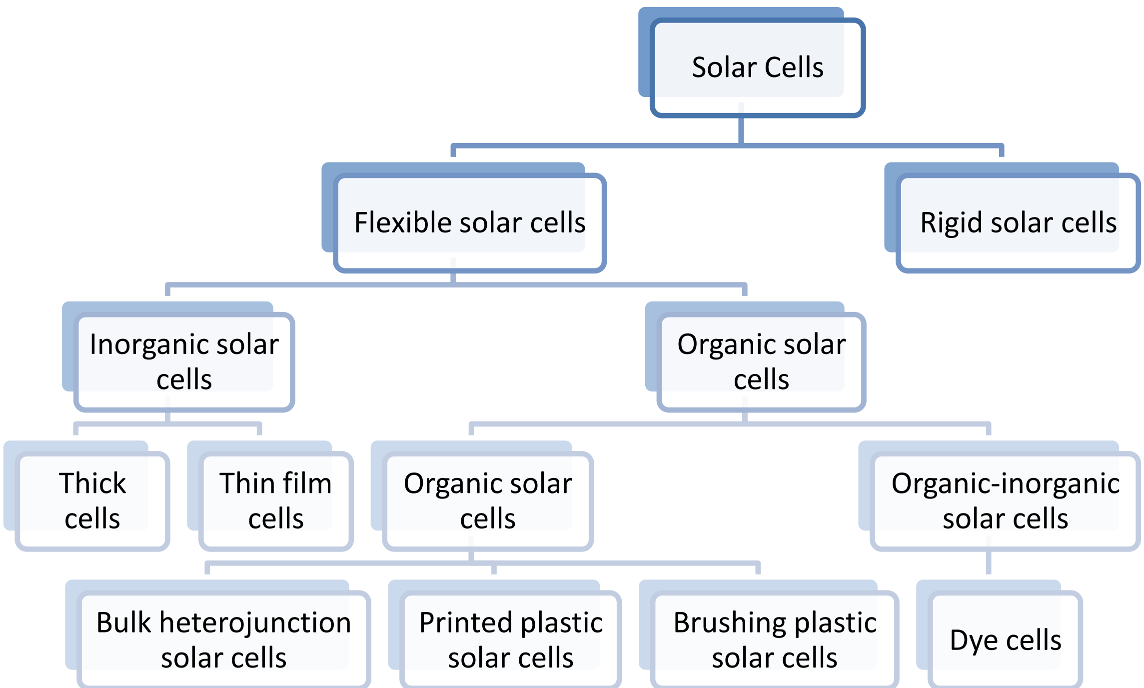

Figure 2.2: Classification of Solar cells (Singh, 2011b)

According to Farret and Simões (2006) PVs are capable of converting incident solar energy into dc current, with efficiencies varying from 3 to 31%, depending on the technology, the light spectrum, temperature, design, and the material of the solar cell. Therefore, they have compared the performances of the commonest materials used in PV modules for certain sizes as depicted in Table 2.5.

Table 2.5: Commonest Materials Used in PV Modules (Farret and Simões, 2006)

Type	Theoretical Efficiency		Practical Tests,	Modules	
	cm^2	η (%)	η (%)	cm^2	η (%)
Monocrystalline silicon (Si)	4	29	23	100	15 - 18
Polycrystalline silicon (Si)	4	---	18	100	12 - 18
Amorphous silicon (a-Si)	1	27	12	1000	5 - 8
Gallium arsenide (GaAs)	0.25	31	26	---	---
Copper indium-selenide (CIS)	3.5	27	17	---	---
Cadmium telluride (CdTe)	1	31	16	---	---

Similarly Zhou *et al.* (2011) have extended the power conversion efficiency (PCE) comparison to include the 3rd generation PVs as shown in Table 2.6. According to them it should be noted that especially for the emerging new PV technologies the average efficiencies are significantly lower than the results of the best cells.

Table 2.6: Comparison of best and average PCE values of single solar cells and modules of different PV technologies (Zhou *et al*., 2011)

PV Technology	Best cell PCEs	Average cell PCEs	Best module PCEs	Average module PCEs
Si (bulk)	25.0% (monocrystalline) 20.4% (polycrystalline) 10.1% (amorphous)	---	22.9% (monocrystalline) 17.55% (polycrystalline)	14 – 17.5% (monocrystalline) 13 – 15% (polycrystalline) 5 – 7 % (amorphous)
CIGS (thin film)	20.3%	---	15.7%	10 – 14%
CdTe (thin film)	16.7%	---	10.9%	~ 10%
DSSC	11.2	5 – 9%	5.38%	---
OPV (thin film)	8.3% and 8.5%	3 – 5%	3.86%	1 – 3%

Cells are the building block of PV systems and a silicon cell produces 0.5 volts (Hughes, 2008). Since an individual cell produces only about 0.5 V, it is a rare application for which just a single cell is of any use. Instead, the basic building block for PV applications is a *module* consisting of a number of pre-wired cells in series, all encased in tough, weather-resistant packages (Masters, 2004). Multiple modules, in turn, can be wired in series to increase voltage and in parallel to increase current, the product of which is power. Such combinations of modules are referred to as an *array*. Figure 2.4 shows this distinction between cells, modules, and arrays.

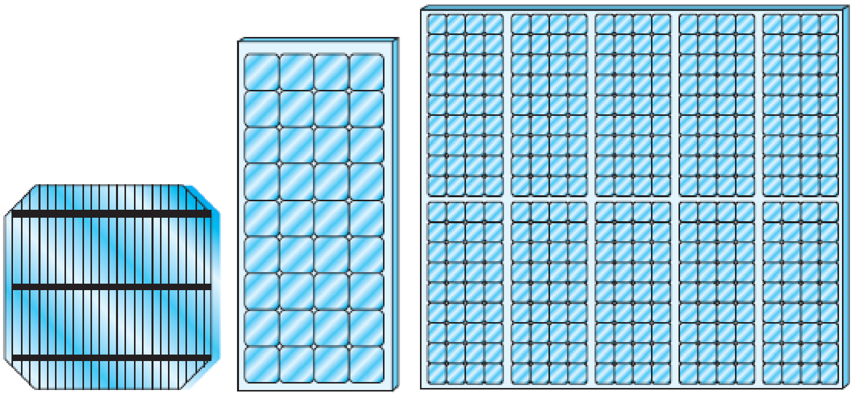

Figure 2.3: Distinction between cells, modules, and arrays (Hughes, 2008)

2.3.1.5 Grid Connection of Photovoltaic Systems

As stated in the preceding section, the basic elements of a PV system are the modules that are usually series-connected and a series of PV modules is usually called a PV string. But several components are needed to construct a grid connected PV system to perform the power generation and conversion functions (Khalifa, 2010), as shown in Figure 2.5. Depending on the number of the modules, the PV array converts the solar irradiation into specific DC current and voltage (Man, 2012).

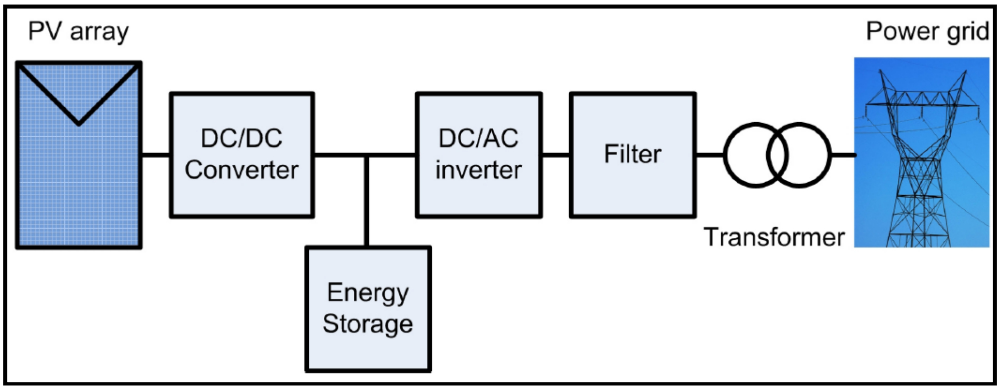

Figure 2.4: Components of a grid connected PV system (Khalifa, 2010; Man, 2012)

If the voltage of the PV string is always higher than the peak voltage of the grid the PV converter does not require a step-up stage (Lorenzani *et al.*, 2009). In this case higher efficiency can be obtained because a single stage full-bridge converter can be used. Otherwise, a DC-DC boost converter or a transformer must be added for voltage amplification but it reduces efficiency. However, energy storage devices can be included in order to store the energy produced in case of grid support connection (Khalifa, 2010; Man, 2012). A three-phase inverter performs the power conversion of the array output power into AC power suitable for injection into the grid. Pulse width modulation control is one of the techniques used to shape the magnitude and phase of the inverter output voltage.

Teodorescu *et al*., (2011) have noted that the PV inverter is the key element of grid-connected PV power systems and the main function is to convert the DC power generated by PV panels into grid-synchronized AC power. High frequency harmonics in the output current due to power semiconductors switching are reduced by the filter. An interfacing transformer is connected after the filter to step up the output AC voltage of the inverter to match the grid voltage level. The power transformer is used only for galvanic isolation between the PV system and the utility grid (Man, 2012). Khalifa (2010) adds that protection relays and circuit breakers are used to isolate the PV system when faults occur to prevent damage to the equipment if their ratings are exceeded. Therefore, according to Lorenzani *et al*. (2009) a PV system is the combination of PV fields and the related power converters.

Historically the first grid-connected PV plants were introduced in the 1980s as thyristor-based central inverters (Teodorescu *et al*., 2011). According to them, the first series-produced transistor-based PV inverter was PV-WR in 1990 by SMA. Moreover, since the mid 1990s, IGBT and MOSFET technology has been extensively used for all types of PV inverters except module-integrated ones, where MOSFET technology is dominating.

In PV plants applications, various technological concepts are used for connecting the PV array to the utility grid as shown in Figure 2.6 and explained as follows.

Module Inverters

Module Inverters shown in Figure 2.6a consists of single solar panels connected to the grid through an inverter (Ma *et al*., 2014; Man, 2012) and no DC wirings are needed between PV modules (Lorenzani *et al*., 2009). They are typically in the 50 – 400 W range for very small PV plants (one panel) (Teodorescu *et al*., 2011) although Ma *et al*. (2014) believe they are normally less than 300W. The advantage of this configuration is that there are no mismatch losses, due to the fact that every single solar panel has its own inverter and MPPT control, thus maximising the power production (Ma *et al*., 2014). Therefore, the power extraction is much better optimised than in the case of string inverters. According to them, one other advantage is the modular structure, which simplifies the modification and maintenance of the whole system because of its ‘‘plug & play’’ characteristic.

However, due to the low power ratings of PV modules, large voltage amplification units for grid connection are required thereby making it difficult for the whole system to achieve high efficiency (Ma *et al*., 2014; Man, 2012). Moreover, the price per watt achieved is still high compared to the previous configurations. Lorenzani *et al*. (2009) believe that despite their simple use and installation the low power level of AC modules leads to higher cost per watt. According to them, the major issue of this solution is the lifetime of the actual converters that is smaller than the lifetime of a PV module (20 years and more). They, therefore, conclude that when it will be comparable this solution will become interesting. In view of those demerits, this inverter configuration has not been widely adopted even for small or medium-scale PV systems (Ma *et al*., 2014).

String Inverters

The configuration presented in Figure 2.6b entered on the PV market in 1995 with the purpose of improving the drawbacks of central inverters (Ma *et al*., 2014; Man, 2012). String inverters are typically in the 0.4–2 kW range for small roof-top plants with panels connected in one string (Teodorescu *et al*., 2011). Compared to central inverters, in this topology the PV strings are connected to separate inverters, single- or three-phase (Ma *et al*., 2014), and so does not employ the parallel connections of the strings (Lorenzani *et al*., 2009; Man, 2012). If the PV string terminal voltage is high enough – no voltage boosting is necessary (single-stage), an improvement of the overall system efficiency can be achieved (Ma *et al*., 2014). Moreover, fewer PV panels for each string can also be used, but then a DC–DC boost converter, a DC-ACDC high-frequency transformer-based converter, or a line frequency transformer is required as the boosting stage, comprising the efficiency performance. The configuration allows individual MPPT for each string thereby making them completely independent from each other (Lorenzani *et al*., 2009; Man, 2012). Consequently, the reliability of the system is improved because the system is no longer dependent on only one inverter compared to the central inverter topology. Therefore, according to Lorenzani *et al*. (2009) it is easy to build PV systems with different orientations, shading conditions and number of PV modules for each string. Also, the need for string diodes is eliminated leading to total loss reduction of the system. In summary the advantages compared to the central inverter are as follows (Ma *et al*., 2014):

- no losses in string diodes (no diodes needed),
- individual MPPT for each string,
- better yield, due to separate MPPTs,
- lower price due to the mass production.

However, a disadvantage of string-converters in comparison to central converters is the higher price per kW (Lorenzani *et al*., 2009). According to them, string converters are often built only as single-phase converters due to the low power level. A very common classic topology is the full-bridge with a line frequency transformer on the AC-side for galvanic isolation and for voltage step-up.

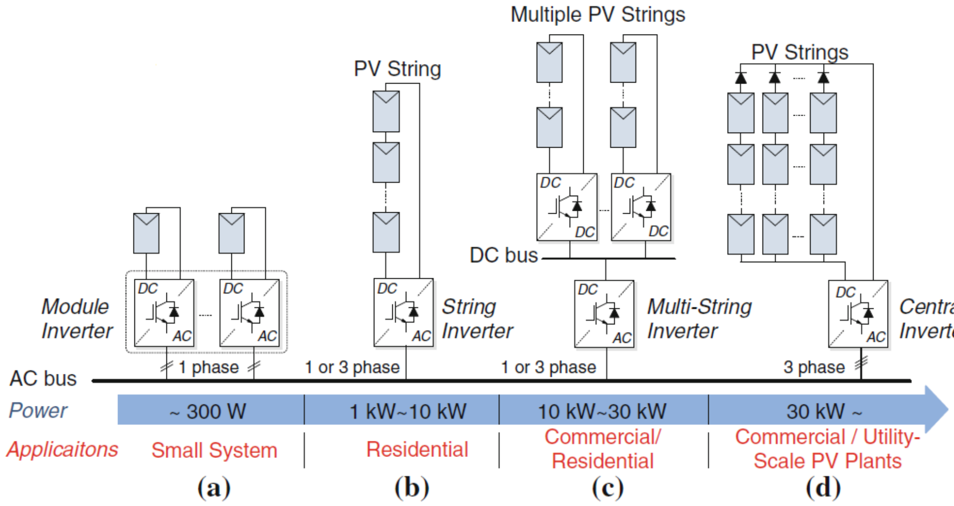

Figure 2.5: Different grid-connected PV inverter structures: a) Module Inverters; b) String Inverters; c) Multi-String Inverters; d) Central inverters (Ma *et al*., 2014)

Multi-String Inverters

The multi-string inverter configuration presented in Figure 2.6c became available on the PV market in 2002 being a mixture of the string and module inverters (Man, 2012). Multi-string inverters are an intermediate solution between string inverters and central inverters (Ma *et al*., 2014). Therefore, a multi-string inverter combines the advantages of both string-inverters (high energy production due to individual MPPT control) and central-inverters (low cost), by having many DC–DC converters with individual MPPTs, which feed energy into a common DC-AC inverter. In this way, no matter what the nominal data, string size, PV module technology (e.g. crystalline or thin film), orientation, inclination or weather conditions (e.g. partial shading) of different PV strings are, they can be connected to one common grid-connected inverter. They authors have noted that the multi-string concept is a flexible solution, having a high overall efficiency of power extraction, due to the fact that each PV string is individually controlled. Moreover, the major feature of a multi-string inverter is the multiple DC–DC stages connected in parallel to the DC-link. So, transformerless PV inverter technology can also be adopted in the multi-string inverter systems.

Man (2012) agrees that the topology allows the connection of inverters with different power ratings and PV modules with different current-voltage (I-V) characteristics. Moreover, MPPT is implemented for each string and implies that an improved power efficiency could be obtained. Similarly, Lorenzani *et al*. (2009) have noted that the multi-string converter manages two or three strings, and provides independent MPPT by different DC-DC converters. In their view, through these additional DC-DC stages – used also in some string converters – it is possible to obtain a very wide input voltage range which gives to the user big freedom in designing of the photovoltaic field.

According to Man (2012) the power ranges of this configuration are maximum 5 kW and the strings use an individual DC-DC converter before the connection to a common inverter. However, based on Teodorescu *et al*. (2011) multistring inverters are typically in the 1.5 – 6 kW range for medium large roof-top plants with panels configured in one to two strings. Furthermore, Ma *et al*. (2014) have put the power range at 10kW – 30kW as shown in Figure 2.6c.

Central Inverters

For this architecture, presented in Figure 2.6d, the PV arrays are connected in parallel to one central inverter. The central inverter, typically three-phase, is the most widely alternative for large-scale or utility-scale PV power plants, which have high power ratings between 10-1000 kW (Ma *et al*., 2014; Man, 2012; Teodorescu *et al*., 2011) and modular design for large power plants ranging to tenths of a MW and typical unit sizes of 100, 150, 250, 500 and 1000 kW (Teodorescu *et al*., 2011). Such inverters (e.g. 750 kW SMA Central Inverter) have to be equipped with ancillary service functions, like fault ride-through and reactive power injection due to the high power ratings (Ma *et al*., 2014). They contend that adoption of a central inverter is the simplest way to concentrate a large PV plant with low construction cost.

The main advantages of central inverters are the high efficiency (low losses in the power conversion stage) and low cost due to usage of only one inverter (Lorenzani *et al*., 2009; Man, 2012). However, the disadvantages of this configuration are also significant and they are as follows (Ma *et al*., 2014; Man, 2012):

- need for high DC-link voltage (550–850 V) and very long DC cables between PV strings and the central inverter,

- power losses due to a common MPPT applied to the central inverter,
- power loss due to module mismatch,
- losses in the string diodes (blocking diodes), and
- reliability of the whole system depends only on one inverter.

The lack of individual MPPT for each string does not permit to harvest the maximum electric power from PV modules, especially when shading or different orientation of modules occurs (Lorenzani *et al*., 2009). According to them, this major shortcoming results in avoiding this simple topology in newer photovoltaic system designs.

Besides, based on Teodorescu *et al*. (2011) Mini central inverters are typically > 6 kW with three-phase topology and modular design for larger roof-tops or smaller power plants in the range of 100 kW and typical unit sizes of 6, 8, 10 and 15 kW.

2.3.1.6 Concentrating Solar Power System

The term 'Concentrating Solar Power' is often used synonymously around the world with 'Concentrating Solar Thermal Power' (Lovegrove *et al*., 2012). Consequently, in their study the term has been used in a more general sense to include both solar thermal and photovoltaic (PV) energy conversion. However, this current research has limited the meaning of Concentrating Solar Power (CSP) to Concentrating Solar Thermal (CST) systems while acknowledging the importance of Concentrating Photovoltaic (CPV) systems.

As highlighted in Section 2.3.1.1, the very first applications of solar energy refer to the use of concentrating collectors. Therefore, the principles of concentrating solar radiation to create high temperatures and convert it to electricity have been known for more than a century but have only been exploited commercially since the mid 1980s (Richter *et al*., 2009). According to them, the first large-scale CSP stations were built in California's Mojave Desert. Kearney and ESTELA (2010) have recorded the key CSP historical milestones from 1970's to 2010.

Concentrating Solar Power (CSP) plants use mirrors to concentrate sunlight onto a receiver – by various methods – which collects and transfers the solar energy to a heat transfer fluid that can be used to supply heat for end-use applications or produce heat and steam to generate electricity via a conventional thermodynamic cycle such as conventional steam turbines and pistons (IEA-ETSAP and IRENA, 2013; IPCC, 2011; Lovegrove *et al*., 2012). Other concepts are being explored and not all future CSP plants will necessarily use a steam cycle

(IRENA, 2012). Large CSP plants can be equipped with a heat storage system to allow for heat supply or electricity generation at night or when the sky is cloudy. The four main elements or functionalities required for the operation of a CSP, in gray, and the nine steps involved in CSP electricity production are as shown in Figure 2.7 (Kearney and ESTELA, 2010; Richter *et al*., 2009) The four main elements are:

- a concentrator,
- a receiver,
- some form of transport media or storage, and
- power conversion.

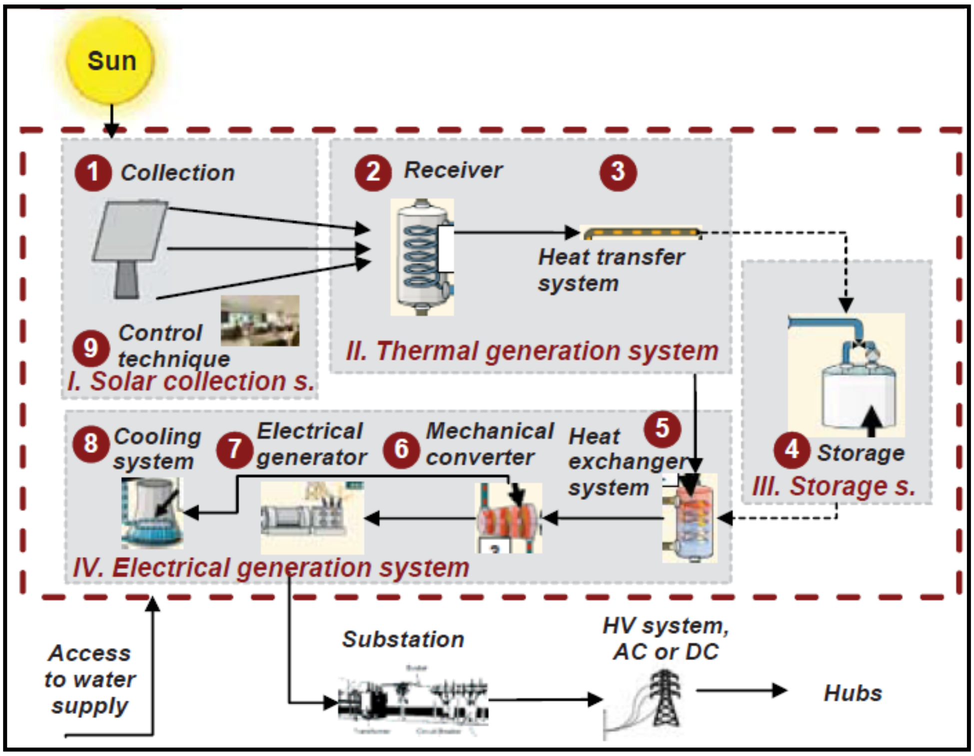

Figure 2.6: The nine steps of Solar Thermal Electricity (Kearney and ESTELA, 2010)

Large-scale CSP plants most commonly concentrate sunlight by reflection, as opposed to refraction with lenses (IPCC, 2011). PV and CSP technologies both use the sun to generate electricity, but they do it in different ways (Kroposki *et al*., 2009). PV – or solar electric – systems use semiconductor solar cells to convert sunlight directly into electricity. In contrast, CSP – or solar thermal electric – systems use mirrors to concentrate sunlight and exploit the sun's thermal energy. Simply put, PV uses the sun's light to generate electricity directly, whereas CSP uses the sun's heat to generate electricity indirectly.

IEA-ETSAP and IRENA (2013) have noted that unlike solar photovoltaic (PV), CSP uses only the direct component of sunlight and provides heat and power only in regions with high DNI

(Direct Normal Irradiance) – Sun Belt regions – such as North Africa, the Middle East, the southwestern United States and southern Europe. These are typically arid and semi-arid regions at latitudes between 15° and 40° North or South of the Equator, but equatorial regions are usually too cloudy. They further posit that high DNIs can also be available at high altitudes where scattering is low. Sunlight consists of direct and indirect (diffused) components, and the direct component (i.e. DNI) represents up to 90% of the total sunlight during sunny days but is negligible on cloudy days. CSP plants can provide cost-effective energy in regions with DNIs > 2000 kWh/m^2-yr, and in the best regions (DNIs > 2800 kWh/m^2-yr) the CSP generation potential is 100-130 GWh_e/km^2-yr. This is roughly the same electricity generated annually by a 20 MW coal-fired power plant with a 75% capacity factor. CSP plants can be equipped with a heat storage system to generate electricity even under cloudy skies or after sunset. Therefore, thermal storage can significantly increase the capacity factor and dispatchability of CSP compared with PV and wind power (Kearney and ESTELA, 2010). It can also facilitate grid integration and competitiveness.

According to GIZ *et al*. (2013) the direct normal irradiation (DNI) of South Africa is high, particularly in the Northern Cape region around Upington where the annual sum of DNI reaches almost 2800 kWh/m^2 making this region one of the most attractive for CSP in the world. This high DNI value is comparable to other key CSP countries as shown in Table 2.7.

Table 2.7: Average annual sum of DNI (GIZ *et al*., 2013)

Country	**Average annual sum of DNI**
Italy Spain/Portugal Tunisia	2000 kWh/m^2 2200 kWh/m^2 2400 kWh/m^2
U.S (Nevada)	2500 kWh/m^2
Saudi Arabia	2500 kWh/m^2
South Africa	2800 kWh/m^2
Chile	2900 kWh/m^2

GIZ et al. (2013) affirm that DNI is the most important factor which influences the design of a CSP plant because a higher DNI value results in lower costs for the electricity production, assuming the same frame conditions. Frame conditions are all factors that have a direct or indirect influence on the design of the CSP plant like the cooling method, installation costs, soil conditions, and grid connections. Their conclusion is that this impressive DNI provides South Africa with an optimal starting point for the integration of CSP technology into its energy mix.

Swartz (2013) and de Vries (2013) have decried the poor attention accorded CSP relative to wind and PV by South African government despite the immense benefits of CSP. Swartz (2013) based on CSPA (2012) has noted that there is a growing belief in South Africa that government is close to missing an opportunity to save billions of tax payers Rands by overlooking a lower total cost electricity generating solution such as concentrated solar thermal energy or CSTP. He has also remarked that in the integrated resource plan (IRP) of 2010, CSTP has been allocated only 1200 MW of capacity up to 2030 which is approximately 4% of the total new generation capacity, whereas wind and PV have been allocated more than 9% each. However, de Vries (2013) is of the view that government's IRP procurement allocation of only 1200 MW of CSP up to 2030, against 9200 MW of wind and 8400 MW of solar PV is based solely on price, with wind currently at R0,89/kWh and solar PV at R1,65/kWh against CSP at R2,51/kWh. According to him the use of OCGT plants to provide peaking power is a major cause of concern among CSP developers, as it should be to consumers. The reason is that a CSP plant can deliver peaking power at a price 60% lower than an OCGT plant, and provide additional benefits, such as baseload capacity, foreign exchange savings from avoiding diesel imports, and substantial carbon emissions reductions. Therefore, his conclusion is "Judge CSP on its value, not only on its price". Furthermore Swartz (2013) has observed that the IRP document does not discuss the potential for hybridisation of CSP with coal and gas which could potentially save billions of Rands in ongoing payments for continually rising coal, diesel and gas prices as well as other external costs such as water, health and road infrastructure costs

Accruable benefits from CSP especially with thermal energy storage to South Africa include (CSPA, 2012; GIZ et al., 2013; de Vries, 2013; Swartz, 2013)

- provision of energy and ancillary services and enhanced capacity credits,
- avoidance of system integration costs incurred by intermittent renewable resources such as wind and solar photovoltaics,
- support for power quality, and
- possible additional benefits, such as improved long-term reductions in greenhouse gas emissions when compared to portfolios without dispatchable clean resources

In past years, the installed CSP capacity has been growing rapidly in keeping with policies to reduce CO_2 emissions (IEA-ETSAP and IRENA, 2013). For instance in 2012, the global installed

CSP capacity was about 2 GW (compared to 1.2 GW in 2010) with an additional 20 GW under construction or development. In their view while CSP still needs policy incentives to achieve commercial competitiveness, in the years to come technology advances and deployment of larger plants (i.e. 100-250 MW) are expected to significantly reduce the cost, meaning that CSP electricity could be competing with coal- and gas-fired power before 2020. The consequence of this is an astronomical increase or gain in CO2 savings as shown in Figure 2.8.

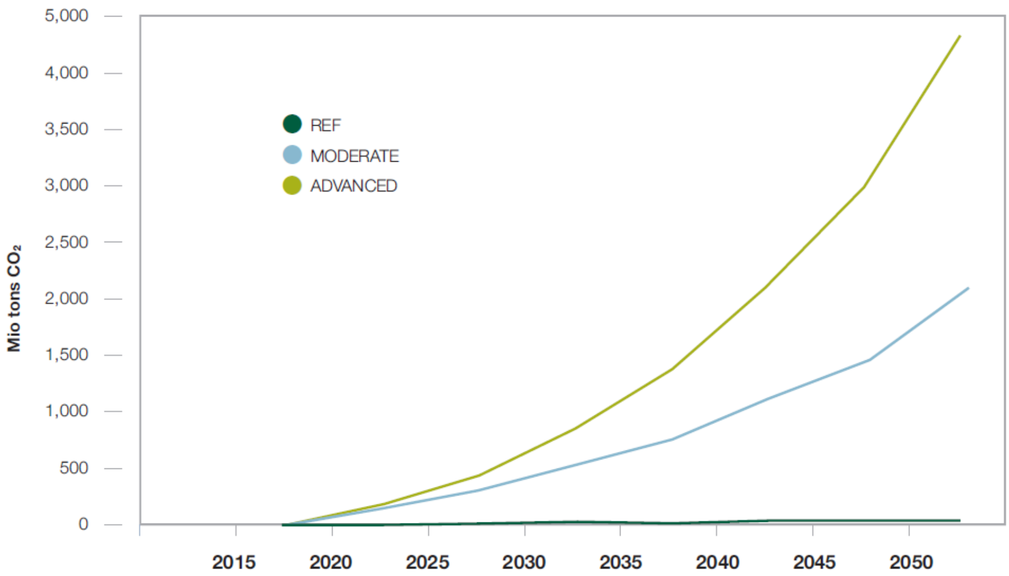

Figure 2.7: Annual CO_2 savings from CSP Scenarios (Richter *et al*., 2009)

2.3.1.7 CSP Technologies

CSP plants are mostly defined or described by their solar collection system technology. There are various CSP technologies with different advantages and disadvantages, and CSP plants need to be designed to optimally meet local and regional conditions (EASAC, 2011). There are four CSP plant variants, namely: ***Parabolic Trough***, ***Fresnel Reflector***, ***Solar Tower*** and ***Solar Dish,*** which differ depending on the design, configuration of mirrors and receivers, heat transfer fluid used and whether or not heat storage is involved. Solar concentration is either to a line (linear focus) as in trough or linear Fresnel systems or to a point (point focus) as in central-receiver or dish systems (IEA-ETSAP and IRENA, 2013; IPCC, 2011). According to IEA-ETSAP and IRENA (2013), the first three types are used mostly for power plants in centralised electricity generation, with the parabolic trough system being the most commercially mature technology. Also solar dishes are more suitable for distributed generation. Although PTC technology is the most mature CSP design, solar tower technology occupies the second place and is of increasing importance as a result of its advantages

(Zhang *et al*., 2013). But IEA-ETSAP and IRENA (2013) believe that solar tower system is presently under commercial demonstration, while Fresnel reflector and solar dish systems are less mature. The salient features of these technologies are shown in Figure 2.10 and briefly highlighted in the following sections.

2.3.1.8 Parabolic Trough

The first systems were installed in 1912 near Cairo in Egypt to generate steam for a pump that delivered water for irrigation (Richter *et al*., 2009). At that time, this plant was competitive with coal-fired installations in regions where coal was expensive.

In parabolic trough concentrators, long rows of parabolic reflectors concentrate the solar irradiance by the order of 70 to 100 times onto a heat collection element (HCE) mounted along the reflector's focal line. The troughs track sun continuously around one axis, with the axis typically being oriented north-south (IPCC, 2011; Richter *et al*., 2009). The HCE comprises a steel inner pipe (coated with a solar-selective surface) and a glass outer tube, with an evacuated space in between. Heat-transfer oil, mostly synthetic thermal oil, is circulated through the steel pipe and heated to about 400°C. The hot oil from numerous rows of troughs is pumped through a series of heat exchangers to produce superheated steam at high pressure. The steam is converted to electrical energy in a conventional steam turbine generator (Rankine cycle), which can either be part of a conventional steam cycle or integrated into a combined steam and gas turbine cycle. According to Richter *et* al. (2009) the thermal oil has a top temperature of about 400°C, which limits the conversion efficiency of the turbine cycle, so researchers and industry are also developing advanced heat transfer fluids (HTFs). One example is direct generation of steam in the absorber tubes, another using molten salt as the HTF. Prototype plants of both types are currently being built. Equally IPCC (2011) has noted that alternative heat transfer fluids to the synthetic oil commonly used in trough receivers, such as steam and molten salt, are being developed to enable higher temperatures and overall efficiencies, as well as integrated thermal storage in the case of molten salt.

Land requirements are of the order of 2km^2 for a 100-MWe plant, depending on the collector technology and assuming no storage (IPCC, 2011) while the output of the power plant is between 25MW and 200MW of electricity, at its peak (EC, 2007). With storage systems, the plant can keep working at a constant load. Also with high performance and low electricity production costs, the outlook for parabolic trough power plants is very good (EC, 2007). A typical parabolic trough CSP plant layout is as shown in Figure 2.9.

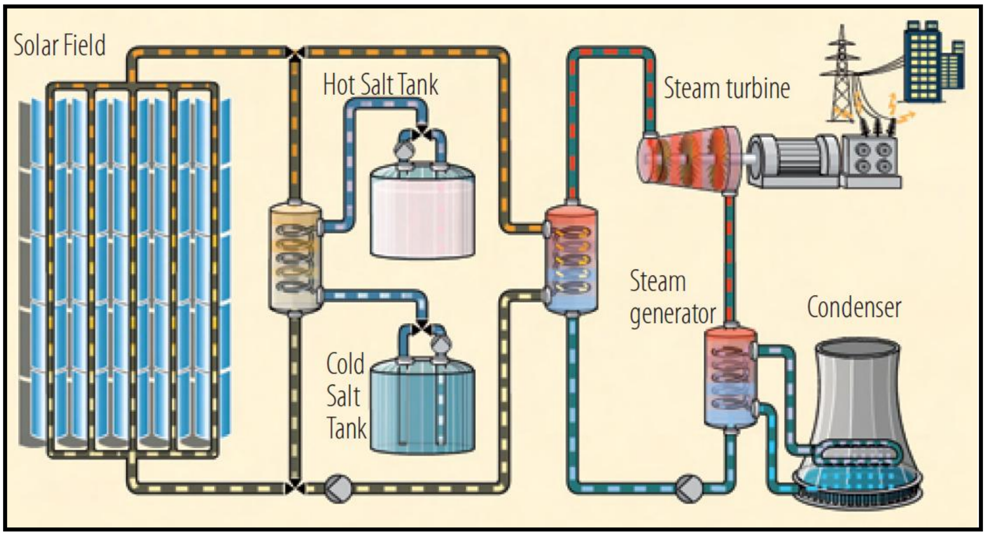

Figure 2.8: A parabolic trough CSP plant (EC, 2007)

According to Fenyves (2013) in South Africa the first large scale parabolic trough CSP installation (KaXu Solar One at Pofadder/Northern Cape) owned by a consortium of Abengoa (Spain) and CMI (Belgium) will have 100 MW rated electrical output and three hours of thermal storage capacity. Another station in South Africa, using this technology which is in project phase is Bokpoort CSP (Groblershoop, Northern Cape), a 50 MW, parabolic trough type, similar to KaXu, but with 9,5 hours of storage, so that the plant will be able to supply power around the clock. The Saudi-Arabia based ACWA Power International Group and also portions of IDC and local communities will enjoy 40% of ownership.

2.3.1.9 Fresnel Reflector

Linear Fresnel reflectors (LFR) approximate the parabolic shape of the trough systems (Richter *et al*., 2009; Zhang *et al*., 2013) by using long rows of flat or slightly curved mirrors to reflect the sunrays onto a downward facing linear receiver. According to IPCC (2011) the use of these long lines of flat or nearly flat mirrors allows the moving parts to be mounted closer to the ground, thus reducing structural costs. It has also noted that in contrast, large trough reflectors presently use thermal bending to achieve the curve required in the glass surface. The receiver is a fixed structure mounted over a tower above and along the linear reflectors (Zhang *et al*., 2013). The receiver being a fixed inverted cavity could have a simpler construction than evacuated tubes of the parabolic troughs and be more flexible in sizing

(IPCC, 2011). The reflectors are mirrors that can follow the sun on a single or dual axis regime.

The main advantage of LFR systems is that their simple design of flexibly bent mirrors and fixed receivers requires lower investment costs and facilitates direct steam generation, thereby eliminating the need for heat transfer fluids and heat exchangers. Therefore, the technology is seen as a potentially lower-cost alternative to trough technology for the production of solar process heat (Richter *et al*., 2009) especially because its installed costs on a per square metre basis can be lower than for trough systems (IPCC, 2011). Linear Fresnel reflector plants are however less efficient than parabolic trough collector and solar tower collector in converting solar energy to electricity (IEA, 2010b; IPCC, 2011; Zhang *et al*., 2013). It is moreover more difficult to incorporate storage capacity into their design.

According to IEA (2010b) and Zhang *et al*. (2013) a more recent design, known as compact linear Fresnel reflectors (CLFR), uses two parallel receivers for each row of mirrors and thus needs less land than parabolic troughs to produce a given output. Zhang *et al*. (2013) assert that the first of the currently operating LFR plants, Puerto Errado 1 plant (PE 1), was constructed in Germany in March 2009, with a capacity of 1.4 MW. The success of this plant motivated the design of PE 2, a 30 MW plant to be constructed in Spain. Furthermore, a 5 MW plant has recently been constructed in California, USA.

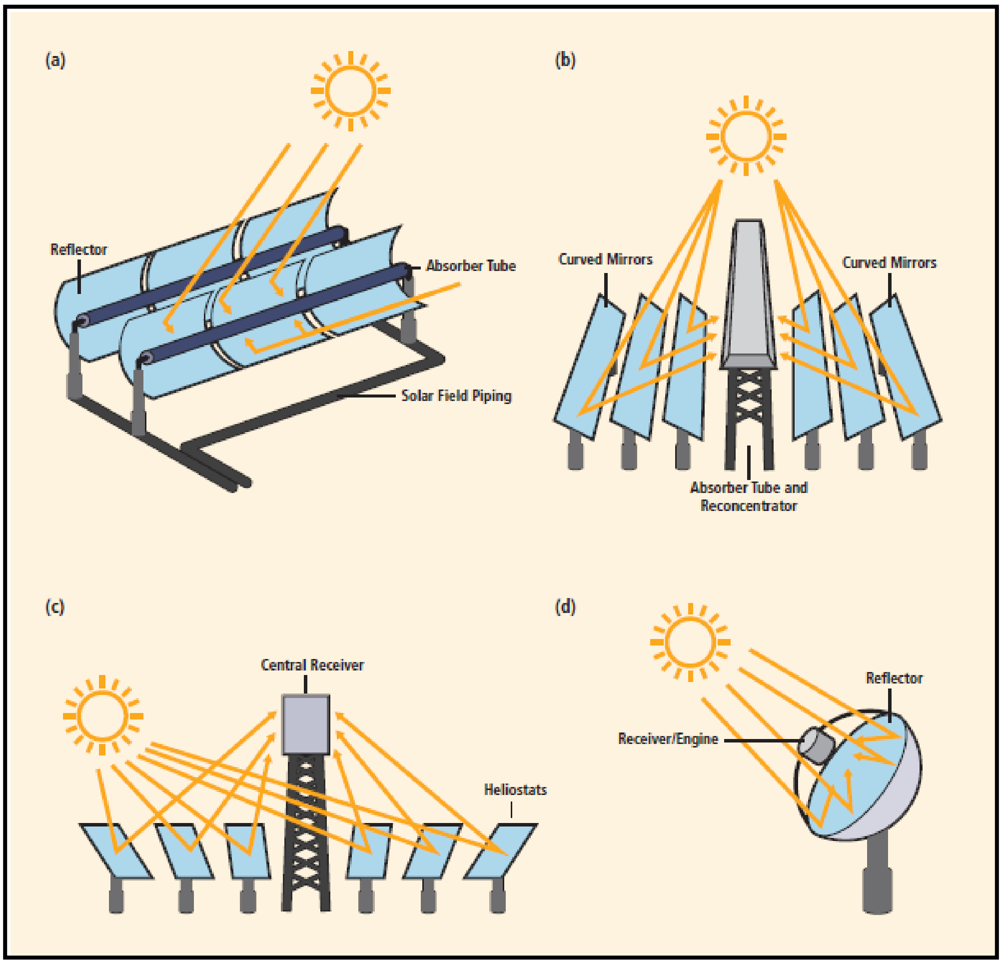

Figure 2.9: Schematic diagrams showing the underlying principles of four basic CSP configurations: (a) parabolic trough, (b) linear Fresnel reflector, (c) central receiver/power tower, and (d) dish systems (IPCC, 2011; Richter *et al*., 2009)

2.3.1.10 Solar Tower

This is also known as central receiver, solar central tower, power tower or solar power tower.

Solar Tower, one type of point-focus collector, is able to generate much higher temperatures than troughs and linear Fresnel reflectors, although requiring two-axis tracking as sun moves through solar azimuth and solar elevation (IPCC, 2011). This system uses a field of distributed mirrors – heliostats – that individually track the sun and focus the sunlight on the top of a tower. Heliostats are flat or slightly concave mirrors that follow the sun in a two axis tracking (Zhang *et al*., 2013). The number of heliostats will vary according to the particular receiver's thermal cycle and the heliostat design (EC, 2007). By concentrating the sunlight 600 – 1000 times, they achieve temperatures from 800°C to well over 1000°C (IPCC, 2011; Richter *et al*., 2009). In the central receiver, the solar energy is absorbed by a heat transfer fluid (HTF) and then used to generate superheated steam to power a conventional turbine.

According to Richter *et al*. (2009) in over 15 years of experiments worldwide, power tower plants have proven to be technically feasible in projects using different heat transfer media (steam, air and molten salts) in the thermal cycle and with different heliostat designs. Also if pressurised gas or air is used at very high temperatures of about 1,000°C or more as the heat transfer medium, it can even be used to directly replace natural gas in a gas turbine, making use of the excellent cycle (60% and more) of modern gas and steam combined cycles.
The high temperatures available in solar towers can be used not only to drive steam cycles, but also for gas turbines and combined cycle systems. Such systems in their view can achieve up to 35% peak and 25% annual solar electric efficiency when coupled to a combined cycle power plant.

IEA (2010b) and Zhang *et al*. (2013) assert that some commercial tower plants now in operation use direct steam generation (DSG), others use different fluids, including molten salts as HTF and storage medium. They concur that concentrating power of the tower concept achieves very high temperatures, thereby increasing the efficiency at which heat is converted into electricity and reducing the cost of thermal storage. In addition, the concept is highly flexible, where designers can choose from a wide variety of heliostats, receivers and transfer fluids. They have also noted that some plants can have several towers to feed one power block. Figure 2.11 is an illustration of a typical scheme of a solar tower CSP plant.

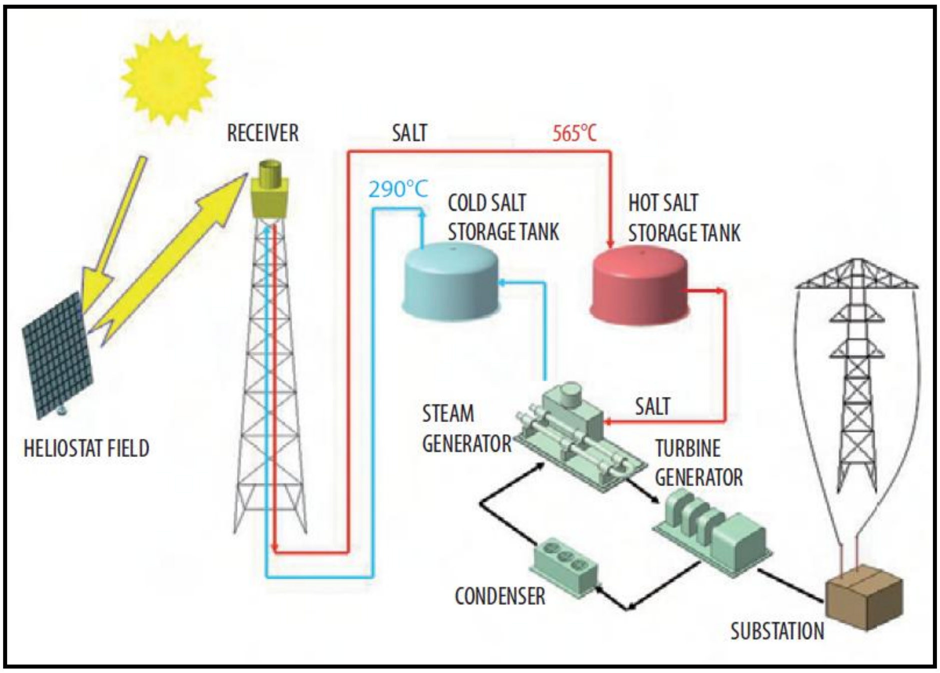

Figure 2.10: A solar tower CSP plant (EC, 2007)

According to Fenyves (2013) in South Africa the first large scale solar power tower CSP installation (Khi Solar One at Upington/Northern Cape), owned by a consortium of Abengoa

(Spain) and CMI (Belgium) will have 50 MW rated electrical output, 2 hour thermal storage using molten salt and will use a superheated steam turbine with air cooling. He has put the combined investment value of Khi and KaXu at R10-billion.

2.3.1.11 Solar Dish

A parabolic dish-shaped reflector concentrates sunlight on to a receiver located at the focal point supported above the centre of the dish (Richter *et al*., 2009; Zhang *et al*., 2013). The entire system tracks the sun – usually one axis, predominantly north–south (Richter *et al*., 2009), with the dish and receiver moving in tandem. This design eliminates the need for a heat transfer fluid and for cooling water (IEA, 2010b). The concentrated beam radiation is absorbed into a receiver to heat a fluid or gas (air) to approximately 750°C (Richter *et al*., 2009) but dishes have been used to power Stirling engines at 900°C (IPCC, 2011). This fluid or gas is then used to generate electricity in a small piston or Stirling engine (an engine which uses external heat sources to expand and contract a fluid) or a micro turbine, attached to the receiver.

According to IEA (2010b) and Zhang *et al*. (2013) parabolic dish collectors offer the highest transformation efficiency of any CSP system but are expensive and have a low compatibility with respect to thermal storage and hybridization. However, promoters claim that mass production will allow dishes to compete with larger solar thermal systems. They assert that each parabolic dish has a low power capacity (typically tens of kW or smaller), and each dish produces electricity independently, which means that hundreds or thousands of them are required to install a large scale plant like that built with other CSP technologies. Therefore, because of their size, they are particularly well-suited for decentralised power supply and remote, stand-alone power systems (EC, 2007; Richter *et al*., 2009).

Several dish/engine prototypes have successfully operated over the last 10 years, ranging from 10kW (Schlaich, Bergermann and Partner design), 25kW (SAIC) to over 100kW (the 'Big Dish' of the Australian National University). Like all concentrating systems, they can additionally be powered by fossil fuel or biomass, providing firm capacity at any time. There is now significant operational experience with dish/Stirling engine systems, and commercial rollout is planned. In 2010, the capacity of each Stirling engine was small – of the order of 10 to 25kWe while the largest solar dishes have a 485m^2 aperture and are in research facilities or demonstration plants (IPCC, 2011). Maricopa Solar Project is the only operational parabolic dish collector plant, with a net capacity of 1.5MW (Zhang *et al*., 2013). The plant began operation on January 2010 and is located in Arizona, USA.

2.3.2 Wind Energy System

Wind energy relies, indirectly, on the energy of the sun. A small proportion of the solar radiation received by the Earth is converted into kinetic energy, the main cause of which is the imbalance between the net outgoing radiation at high latitudes and the net incoming radiation at low latitudes (IPCC, 2011). The Earth's rotation, geographic features and temperature gradients affect the location and nature of the resulting winds (Burton et al., 2011). The use of wind energy requires that the kinetic energy of moving air be converted to useful energy. As a result, the economics of using wind for electricity supply are highly sensitive to local wind conditions and the ability of wind turbines to reliably extract energy over a wide range of typical wind speeds.

According to IEA (2013) wind power deployment has more than doubled since 2008, approaching 300GW of cumulative installed capacities, led by China (75GW), the United States (60GW) and Germany (31GW). Wind power now provides 2.5% of global electricity demand – and up to 30% in Denmark, 20% in Portugal and 18% in Spain. Its roadmap targets 15% to 18% share of global electricity from wind power by 2050, a notable increase from the 12% aimed for in 2009. It has therefore set a new target of 2 300GW to 2 800GW of installed wind capacity will avoid emissions of up to 4.8 Gt of CO_2 per year.

Wind is South Africa's cheapest renewable energy source. Smit and Smit (2003) contend that South Africa has a more moderate wind resource along the coastline. The expected average wind speed is lower than northern Europe and United States. The South African wind resource is currently estimated between 500 to 1 000MW. According to them Eskom executed its first case study and derivable experiences on wind energy at Klipheuwel Wind Farm, the first wind farm in sub-Sahara Africa. Klipheuwel is about 50km north of Cape Town. The wind farm consists of a Danish Vestas V47 660kW, V66 1.75MW and one French Jeumont J48 750kW wind turbines with a combined capacity of 3.16 MW. It was formally opened on 21 February 2003. An early estimate for Klipheuwel capacity factor was 22% which compares favourably with rural Germany and California where average estimates are also around 22% to 23%.

South Africa is blessed with excellent wind resources and her wind power has moved from the planning to the execution phase, and is becoming one of the most vibrant new wind markets globally. After taking a decade to install the first 10 MW of wind power, the industry in South Africa is currently developing between 3,000 MW and 5,000 MW of wind power, of which 636 MW is under construction and a further 562 MW approaching financial close. In addition, there is a long term energy blueprint giving wind a significant allocation, about 9,000 MW of new capacity in the period up to 2030 (GWEC, 2012). Figure 2.12 illustrates the trend of wind power installation in South Africa.

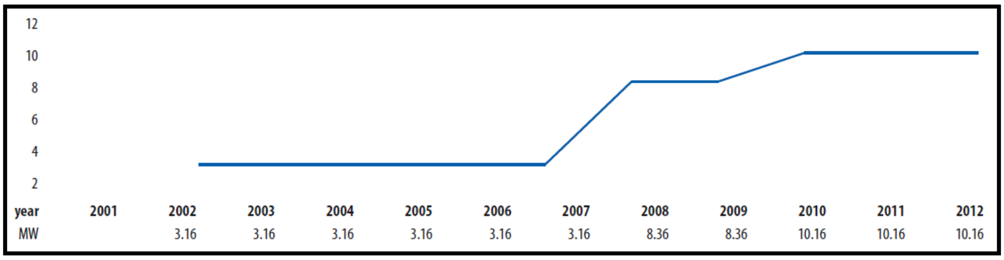

Figure 2.11: Total installed wind power capacity (GWEC, 2012)

Blaine (2014) has reported that Eskom's Sere wind farm, near Vredendal on the West Coast (Western Cape Province), has erected three of its planned 46 turbines and is on track to deliver first power by the end of 2014. Once completed, the plant will add 100MW to the national grid and contribute to saving nearly 6Mt of GHG emissions over 20 years. The completed wind farm would have 46 Siemens 2,3VS-108 turbines, each generating 2.3MW and positioned over an area of 16km^2.

2.3.2.1 Brief History and Early Wind Energy System Applications

The idea of using wind, a natural source, is not new because people have used technology to transform the power of the wind into useful mechanical energy since antiquity. Along with the use of water power through water wheels, wind energy represents one of the world's oldest forms of mechanised energy (Redlinger *et al.*, 2002). According to them though solid historical evidence of wind power use does not extend much beyond the last thousand years, anecdotal evidence suggests that the harnessing of mechanised wind energy pre-dates the Christian era. Stiebler (2008) concurs that the history of windmills goes back more than 2000 years. Indeed, humans have been using wind energy in their daily work for some 4000 years (Molina and Alvarez, 2011). But Patel (1999) contend that the first use of wind power was to sail ships in the Nile some 5000 years ago. The use of wind power is said to have its origin in the Asian civilisations of China, Tibet, India, Afghanistan and Persia

(Redlinger *et al*., 2002). In their view the first written evidence of the use of wind turbines is from Hero of Alexandria, who in the third or second century BC described a simple horizontal-axis wind turbine. It was described as powering an organ, but it has been debated as to whether it was of any practical use other than as a kind of toy. They also assert that more solid evidence indicates that the Persians were harnessing wind power using a vertical-axis machine in the seventh century AD and from Asia the use of wind power spread to Europe.

The Europeans used wind power to grind grains and pump water in the 1700s and 1800s while the first windmill to generate electricity in the rural USA was installed in 1890 (Patel, 1999). In 1700 BC, King Hammurabi of Babylon used wind powered scoops to irrigate Mesopotamia. Some other civilizations, like the Persians (500-900 AD), used the wind to grind grain into flour, while others used the wind to transport armies and goods across oceans and rivers. Sails revolutionized seafaring, which no longer had to be done with muscle power. More recently, mankind has used the power of the wind to pump water and produce electricity (Molina and Alvarez, 2011).
They have been used predominantly for grinding cereals and for pumping water. Important examples of more recent times are the Dutch Windmills which appeared in different variants and were erected in large numbers in the 17th and 18th century in Europe. Another memorable development of the 19th century was the Western Mill, found in rural areas especially in the USA up to the present day. Modern constructions of wind energy converters were developed in the 1920s, but it was not before the 1980s that they found professional interest as a prominent application of renewable energies (Stiebler, 2008). Today, large wind-power plants are competing with electric utilities in supplying economical clean power in many parts of the world (Patel, 1999).

2.3.2.2 Modern Wind Turbine

According to Molina and Alvarez (2011) the beginning of modern wind turbine development was in 1957, marked by the Danish engineer Johannes Juul and his pioneer work at a power utility (SEAS at Gedser coast in the Southern part of Denmark). His R&D effort formed the basis for the design of a modern AC wind turbine – the well-known Gedser machine which was successfully installed in 1959. With its 200kW capacity, the Gedser wind turbine was the largest of its kind in the world at that time and it was in operation for 11 years without maintenance. The robust Gedser wind turbine was a technological innovation as it became the hall mark of modern design of wind turbines with three wings, tip brakes, self-regulating and an asynchronous motor as generator. Foreign engineers named the Gedser wind turbine as 'The Danish Concept'. The so-called "Danish concept" that was very popular in the eighties, refers to the transformation of wind energy into electrical energy using a simple squirrel-cage induction machine directly connected to a three-phase power grid (Molina and Mercado, 2011).

Wind turbines come in two broad categories: the horizontal-axis turbine whose blades appear similar to aeroplane propellers, and the vertical-axis turbine whose long curved blades are attached to the rotor tower at the top and bottom and have the appearance of an eggbeater (Redlinger *et al*., 2002). Vertical-axis turbines have not lived up to their early promise, and today virtually 100 per cent of existing turbines use the horizontal-axis concept.

Figure 2.13 shows the components in a modern wind turbine with a gearbox; in wind turbines without a gearbox, the rotor is mounted directly on the generator shaft. The rotor is the heart of a wind turbine and consists of multiple rotor blades attached to a hub (Molina and Alvarez, 2011). It is the turbine component responsible for collecting the energy present in the wind and transforming this energy into mechanical motion.

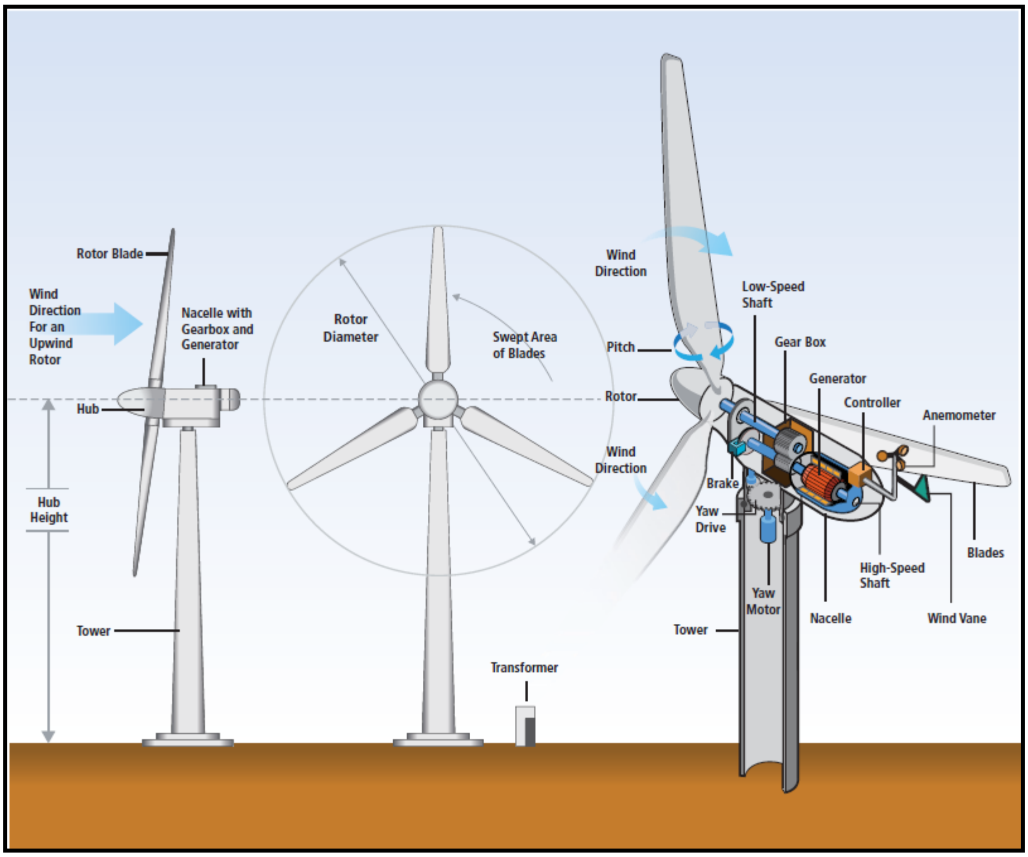

Figure 2.12: Basic components of a modern, horizontal-axis wind turbine with a gearbox (IPCC, 2011)

Modern wind turbines, which are currently being deployed around the world, have three-bladed rotors with diameters of 70m to 80m mounted atop 60m to 80m towers (Lindenberg *et al.*, 2008), as illustrated in Figure 2.13. But according to Molina and Alvarez (2011), currently most rotors have three blades, a horizontal axis, and a diameter of between 40 and 90 meters. In addition to the currently popular three-blade rotor, two-blade rotors are also used to be common in addition to rotors with many blades, such as the traditional wind mills with 20 to 30 metal blades that pump water. They have also noted that over time, it was found that three-blade rotor is the most efficient for power generation by large wind turbines. In addition, the use of three rotor blades allows for a better distribution of mass, which makes rotation smoother and also provides for a “calmer” appearance

The three blades are attached to a hub and main shaft, from which power is transferred (sometimes through a gearbox, depending on design) to a generator. The main shaft and main bearings, gearbox, generator and control system are contained within a housing called the nacelle.

2.3.2.3 Basic Design and Operating Principles of Wind Turbines

Rotor blades being a crucial and basic part of a wind turbine means that the design of the individual blades also affects the overall design of the rotor. Generating electricity from the wind requires that the kinetic energy of moving air be converted to mechanical and then electrical energy, thus the engineering challenge for the wind energy industry is to design cost effective wind turbines and power plants to perform this conversion (IPCC, 2011). Molina and Alvarez (2011) posit that the rotor blades take the energy out of the wind; they “capture” the wind and convert its kinetic energy into the rotation of the hub. The profile is similar to that of airplane wings. Rotor blades utilise the same “lift” principle: below the wing, the stream of air produces overpressure; above the wing, the stream of air produces vacuum. These forces make the rotor rotate.

The amount of kinetic energy in the wind that is theoretically available for extraction increases with the cube of wind speed (IPCC, 2011; Lindenberg *et al*., 2008). This means that a 10% increase in wind speed creates a 33% increase in available energy. However, a turbine only captures a portion of that available energy as shown in Figure 2.14.

Modern large wind turbines typically employ rotors that start extracting energy from the wind at speeds of roughly 2.5 to 4m/s (cut-in speed). The Lanchester-Betz limit provides a theoretical upper limit (59.3%) on the amount of energy that can be extracted (Burton *et al*., 2011). A wind turbine increases power production with wind speed until it reaches its rated power level, often corresponding to a wind speed of 11 to 15m/s. According to Abad *et al*. (2011) wind turbines are designed to produce electrical energy as cheaply as possible and to yield maximum output at wind speeds around 15 meters per second. In their view it does not pay to design turbines that maximize their output at stronger winds, because such strong winds are rare. But in the case of stronger winds, it is necessary to waste part of the excess energy of the wind in order to avoid damaging the wind turbine. Therefore at still-higher wind speeds, control systems limit power output to prevent overloading the wind turbine, either through stall control, pitching the blades, or a combination of both (Abad *et al*., 2011; Burton *et al*., 2011). Most turbines then stop producing energy at wind speeds of approximately 20 to 25 m/s (cut-out speed) to limit loads on the rotor and prevent damage to the turbine’s structural components.

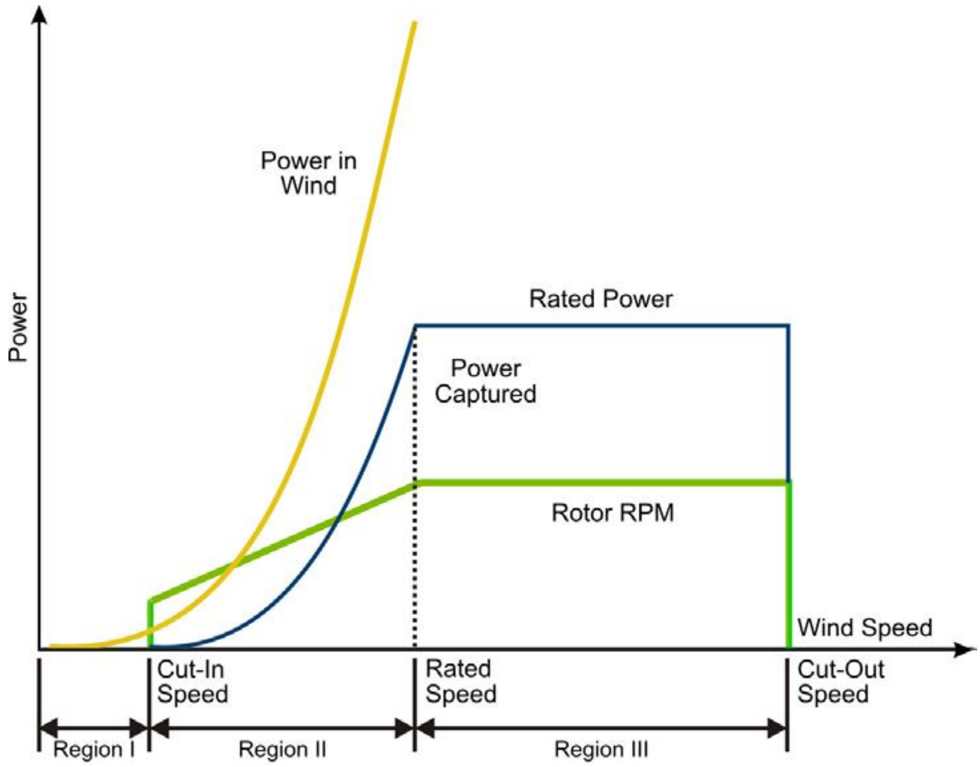

Figure 2.13: Typical power output versus wind speed curve (IPCC, 2011; Lindenberg *et al*., 2008)

Wind turbine design has centred on maximizing energy capture over the range of wind speeds experienced by wind turbines, while seeking to minimize the cost of wind energy. According to IPCC (2011) as described generally in Burton *et al*. (2011), increased generator capacity leads to greater energy capture when the turbine is operating at rated power (Region III). Larger rotor diameters for a given generator capacity, meanwhile, as well as aerodynamic design improvements, yield greater energy capture at lower wind speeds (Region II), reducing the wind speed at which rated power is achieved. Variable speed operation allows energy extraction at peak efficiency over a wider range of wind speeds (Region II). Finally, because the average wind speed at a given location varies with the height above ground level, taller towers typically lead to increased energy capture.

According to Molina and Alvarez (2011) the maximum wind speed (or survival speed), above which wind turbines are destroyed, is in the range of 40 to 70m/s. Also the most common survival speed of commercial wind turbines is around 60 m/s. The foregoing shows that wind turbines have three modes of operation namely:

- Below rated wind speed operation
- Around rated wind speed operation (usually at nominal capacity)
- Above rated wind speed operation

If the rated wind speed is exceeded the power has to be limited. Therefore, all wind turbines are designed with a power control that achieves this goal and avoids a run-away situation. Consequently, the power limitation may be done by some of the three following methods (Hansen, 2005; Molina and Mercado, 2011), namely:

- stall control (the blade position is fixed but stall of the wind appears along the blade at higher wind speed),
- active stall (the blade angle is adjusted in order to create stall along the blades) or
- pitch control (the blades are turned out of the wind at higher wind speed).

Figure 2.15 shows a generic qualitative power curve for a variable-speed pitch-controlled wind turbine, with four zones and two areas. The rated power P_r of the wind turbine (that is, the actual power supplied to the grid at wind speed greater than V_r) separates the graph into two main areas. According to Camacho *et al*. (2011) below rated power, the wind turbine produces only a fraction of its total design power, and therefore an optimization control strategy needs to be performed. Conversely, above rated power, a limitation control strategy is required to forestall the inherent damage.

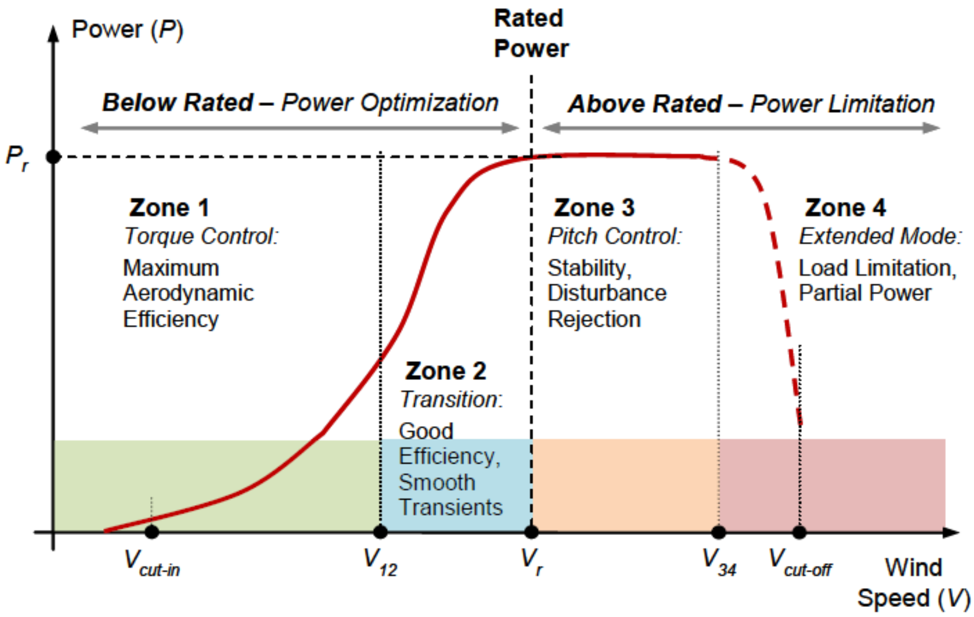

Figure 2.14: Power curve of a wind turbine and control zones (Camacho *et al.*, 2011)

Therefore, Camacho *et al*. (2011) have highlighted the different wind turbine power limitation measures or controls as follows:

- For passive-stall-controlled wind turbines, in which the rotor blades are fixed to the hub at a specific angle, the generator reaction torque regulates rotor speed below rated operation to maximize energy capture. Above a specific wind speed, the geometry of the rotor induces stall. In this manner, the power delivered by the rotor is limited in high wind conditions courtesy of a particular design of the blades that provokes loss of efficiency.

- In pitch control, the power delivered by the rotor is regulated either by pitching the blades toward the wind to maximize energy capture or by pitching to feather to discard the excess power and ensure that the mechanical limitations are not exceeded. At rated operation, the aim is to maintain power and rotor speed at their rated value. To achieve this, the torque is held constant and the pitch is continually changed following the demands of a closed-loop rotor speed controller that optimizes energy capture and follows wind speed variations. In contrast, below rated operation there is no pitch control; the blade is set to a fine pitch position to yield higher power capture values while the generator torque itself regulates the rotor speed.
- Active stall control is a combination of stall and pitch control. It offers the same regulation possibilities as the pitch-regulated turbine but uses the stall properties of the blades. Above rated operation, the control system pitches the blades to induce stall instead of feathering. In this technique, the blades are rotated only by small amounts and less frequently than for pitch control.

Generally according to Lindenberg *et al*. (2008) the speed of the wind increases with the height above the ground, which is why engineers have found ways to increase the height and the size of wind turbines while minimizing the costs of materials. The increase in wind speed with elevation is referred to as wind shear. They authors have noted that there has been a long-term drive to develop larger turbines as a direct result of the desire to improve energy capture by accessing the stronger winds at higher elevations. Although the increase in turbine height is a major reason for the increase in capacity factor over time, there are economic and logistical constraints to this continued growth to larger sizes.

2.3.2.4 Classification of Wind Energy Systems

Wind energy systems could be classified based on several criteria such as position of rotational axis of the turbine, power output (capacity), speed, type of coupling between the mechanical and electrical parts, the nature of the rotor and stator, and even method of integration unto the grid.

Based on axis position, wind turbines are classified as the horizontal axis and vertical axis turbines. Horizontal axis wind turbines (HAWTs) are more common than vertical axis wind turbines (VAWTs). The horizontal axis turbines have a horizontally positioned shaft, which helps ease the conversion of the wind's linear energy into a rotational one.

In terms of capacity modern wind turbine technology can be classified into three main categories: large grid-connected turbines, intermediate-sized turbines in hybrid systems, and small stand-alone systems (Khaligh and Onar, 2010; Redlinger *et al*., 2002). According to them large grid-connected wind turbines, in the size range of 150 kW and above, account for by far the biggest market value among wind turbines. The size of commercially available grid-connected wind turbines has evolved from 20 – 50kW range in the early 1980s to the 500 – 800kW range most common in the late 1990s. Turbines in the 1 – 2MW size range have been commercially available since 1997. Also intermediate-sized or medium wind turbines in the 1 – 150kW range can operate in hybrid energy systems combined with other energy sources such as diesel, small-scale hydro, photovoltaics, and/or storage systems. According to Khaligh and Onar (2010) medium wind turbines usually provide between 20 and 300kW installed power having a blade diameter of 7–20 m, and the tower is not higher than 40 m. They are usually used to supply either remote loads that need more electrical power or commercial buildings and are directly connected to the load through DC/AC power electronic inverters. Furthermore, small 'stand-alone' wind turbines of less than 1kW for water pumping, battery charging, heating and so on represent the third turbine category. The most commercially successful in this category are very small wind turbines in the 25–150 watt range with rotor diameters of 0.5 to 1.5 metres. They are designed for low cut-in wind speeds of generally 3–4 m/s (Khaligh and Onar, 2010). Such small wind turbines are widely used for battery charging at remote telecommunication stations. Yachts also often carry a very small (less than 1 kW) wind turbine for battery charging which can be used for television sets, communication systems and small refrigerators. However, Lindenberg *et al*. (2008) posit that until recently, three-bladed upwind designs using tail vanes for passive yaw control dominated small wind turbine technology (turbines rated at less than 10 kW). They have noted that U.S. manufacturers are world leaders in small wind systems rated at 100 kW or less, in terms of both market and technology. Also turbine technology begins the transition from small to large systems between 20 kW and 100 kW.

Figure 2.16 illustrates the relationship between turbine output power and respective diameters. In other words the figure gives an idea of the normal rotor sizes of wind turbines: if the rotor diameter is doubled, one gets an area which is four times larger (two squared) (Wagner and Mathur, 2009). This means that four times as much power output from the rotor will also be obtained. However, according to them, rotor diameters may vary somewhat from the values given in the figure because many manufacturers optimise their machines to local wind conditions: a larger generator, of course, requires more power (strong winds) to turn at all. So if one installs a wind turbine in a low wind area, annual output will actually be maximised by using a fairly small generator for a given rotor size (or a larger rotor size for a given generator). They believe the reason why more output is available from a relatively smaller generator in a low wind area is that the turbine will be running more hours during the year.

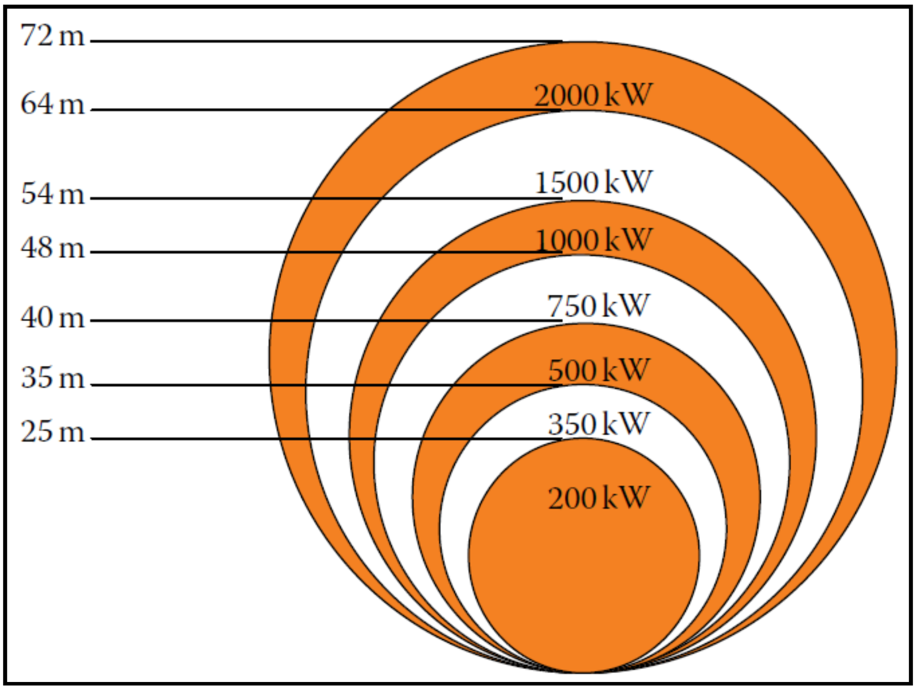

Figure 2.15: Turbine output power for different wind turbine diameters (Khaligh and Onar, 2010; Wagner and Mathur, 2009)

In consideration of speed wind energy systems are either fixed or variable while the coupling between the mechanical and electrical parts could be with or without a gear-box as shown in Figure 2.17. The following are the meanings of the abbreviations in Figure 2.17

- SCIG – Squirrel-cage Induction Generator
- WRSG – Wound Rotor Synchronous Generator
- PMSG – Permanent-Magnet Synchronous Generator
- WRIG – Wound Rotor Induction Generator

- DFIG – Doubly-Fed Induction Generator

According to Wu *et al*., (2011) while fixed-speed SCIG has no power converter, reduced-capacity power converter is applicable to DFIG and WRIG + variable rotor resistance. Also WRSG, PMSG and indirect drive SCIG make use of full-capacity power converter.

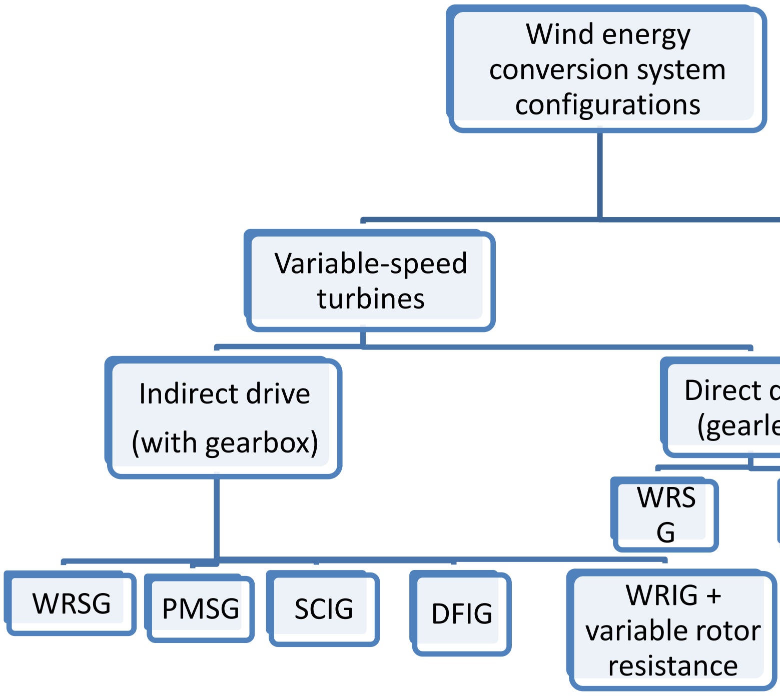

Figure 2.16: Classification of wind energy system configurations (Wu *et al*., 2011)

A technological roadmap starting with wind energy/power and converting the mechanical power into electrical power is shown in Figure 2.18. Therefore, Iov *et al*. (2008) have highlighted the crucial role of power electronics in the integration of wind energy systems into the grid. In this case a power converter is used to interface the wind energy system to the grid.

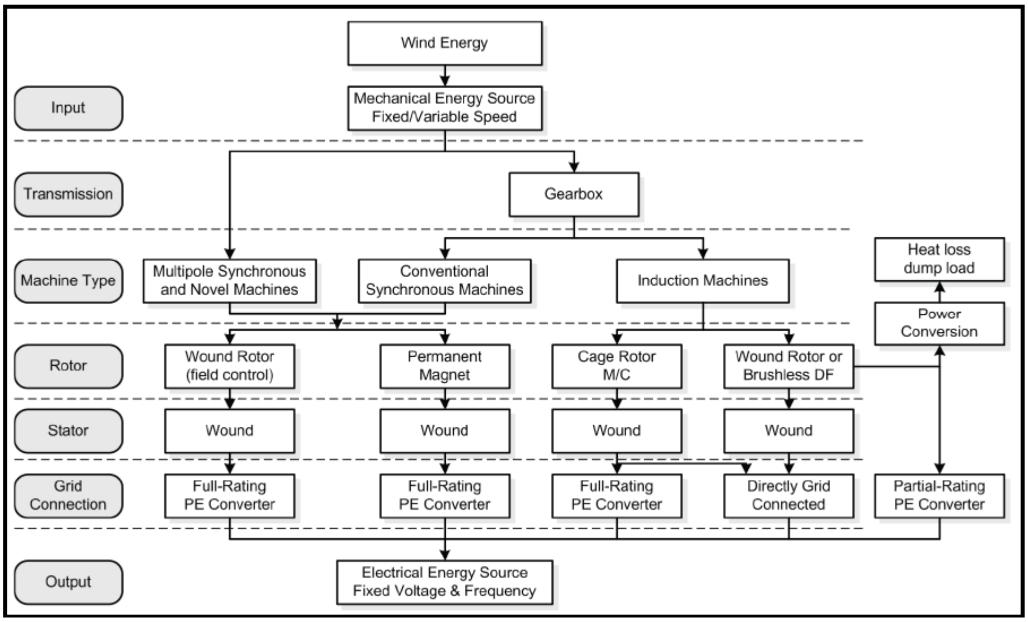

Figure 2.17: Technological roadmap for wind turbine's technology (Iov *et al*., 2008)

The most commonly applied wind turbine designs can be categorized into four wind turbine concepts (Iov *et al*., 2008; Molina and Mercado, 2011). According to Iov *et al*., 2008 the main differences between these concepts are related to the generator type and therefore the layout of the power electronic interface as well as to the way in which the output power is limited above its rated value in order to prevent overloading. However, there is one other machine type that will be referred to as Type 5 in which a mechanical torque converter between the rotor's low-speed shaft and the generator's high-speed shaft controls the generator speed to the electrical synchronous speed (Camm *et al*., 2009). This type of machine then uses a synchronous machine directly connected to the medium voltage grid. These configurations are briefly explained and illustrated as follows:

The first type is a constant-speed wind turbine system with a standard squirrel-cage induction generator (SCIG) directly connected to the electric grid using a step up power transformer, as depicted in Figure 2.19. In order to limit the output power this concept uses currently the active stall control. Fixed speed systems have the advantage of simplicity and low cost; however, the main drawbacks of this concept include the inability of supporting speed control, the requirement of a stiff grid (fixed voltage and frequency), and the necessity of a robust mechanical structure in order to support the high mechanical stress caused by wind gusts.

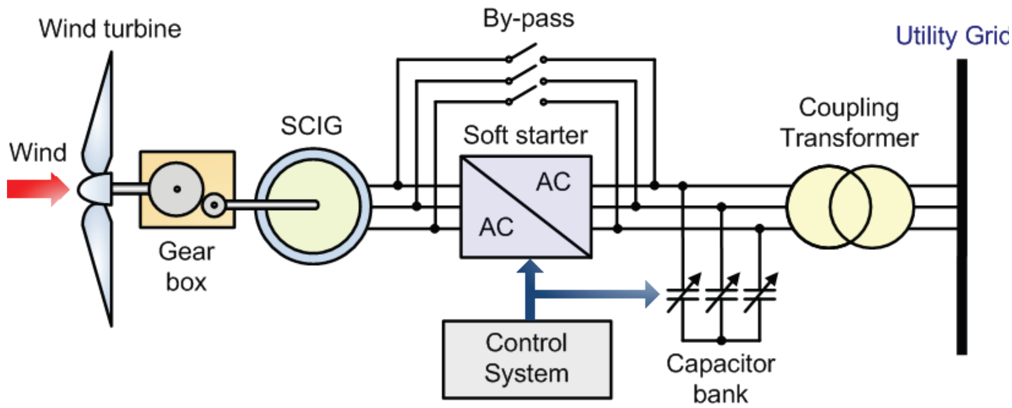

Figure 2.18: Fixed speed wind turbine directly connected to the electric grid via a squirrel cage induction generator (Molina and Mercado, 2011)

Furthermore and according to Camm *et al*. (2009) a major drawback of the induction machine is the reactive power that it consumes for its excitation field and the large currents the machine can draw when started “across-the-line.” Consequently, to ameliorate these effects the turbine typically employs a soft starter and discrete steps of capacitor banks within the turbine.

The second topology corresponds to the limited variable speed controlled wind turbine with variable rotor resistance. The basic structure of this wind turbine is shown in Figure 2.20. It uses a wound rotor induction generator (WRIG) and it has been used by the Danish manufacturer Vestas Wind Systems since the mid 1990s.

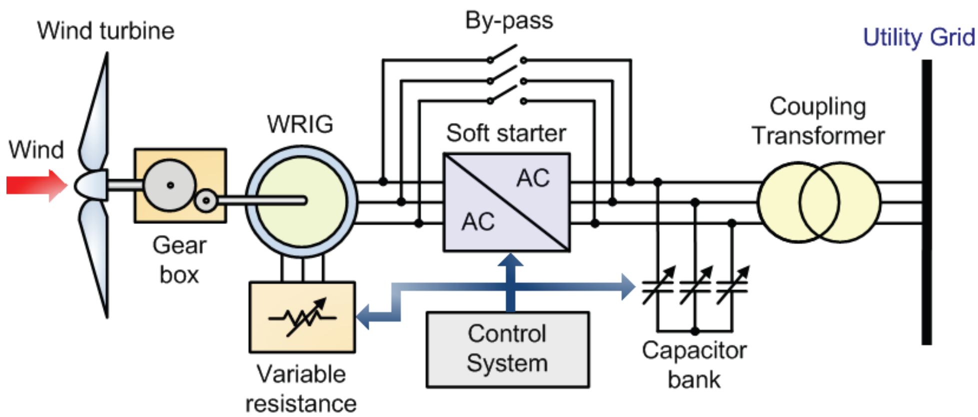

Figure 2.19: Partial variable speed wind turbine directly connected to the electric grid via a wound rotor induction generator with variable rotor resistance (Molina and Mercado, 2011)

The stator windings of the generator are directly connected to the grid. The rotor winding of the generator is connected in series with a controlled resistance that defines the range of the variable speed (typically 0 – 10% above synchronous speed). Thus, by varying the total rotor resistance the generator speed and thus the output power are controlled. By adding resistance to the rotor circuit, the real power can be “stretched” to the higher slip and higher speed ranges (Camm et al., 2009). That is to say, according to them, that the turbine would have to spin faster to create the same output power, for an added rotor resistance. This allows some ability to control the speed, with the blades' pitching mechanisms and move the turbines operation to a tip speed ratio (ration of tip speed to the ambient wind speed) to achieve the best energy capture. However, power is lost as heat in the rotor resistance.

The third type is a variable speed wind turbine system with a doubly fed induction generator (DFIG) as depicted in Figure 2.21. The power electronic converter feeding the rotor winding has a power rating of approximately up to 30% of the rated power; the stator winding of the DFIG is directly connected to the grid. However, its main drawbacks are the use of slip rings, which needs brushes and maintenance, and the complex protection schemes in the case of grid faults.

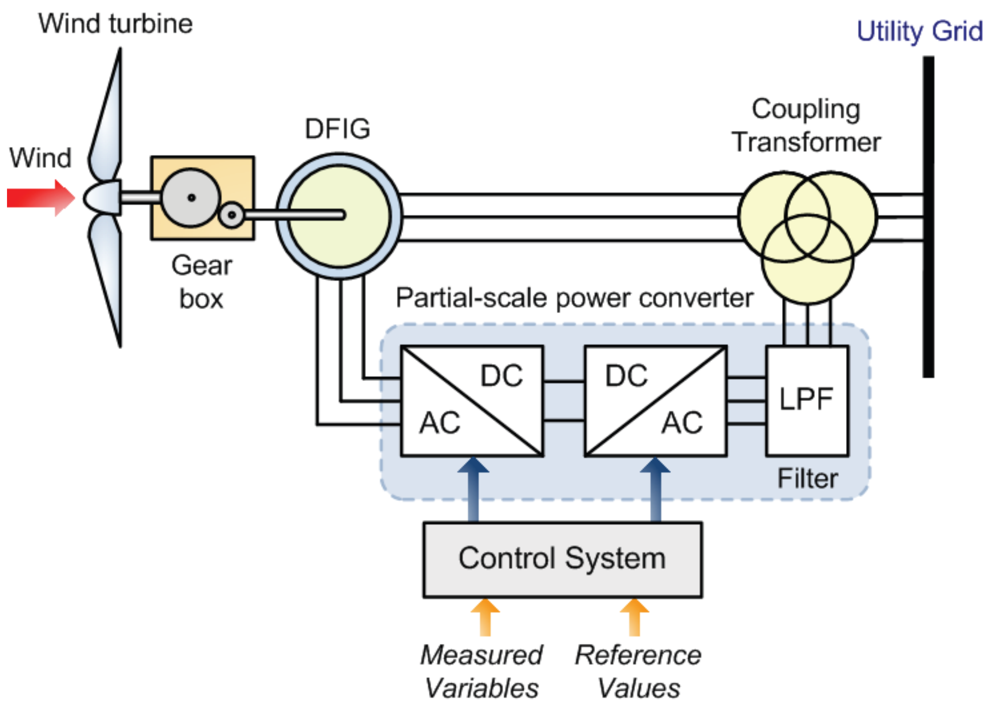

Figure 2.20: Variable speed wind turbine directly connected to the electric grid via a doubly-fed induction generator controlled with a partial-scale power converter (Molina and Mercado, 2011)

The greatest advantage of the DFIG is that it offers the benefits of separate real and reactive power control, much like a traditional synchronous generator, while being able to run asynchronously (Camm *et al*., 2009). They have noted that the field of industrial drives has produced and matured the concepts of vector or field oriented control of induction machines. Therefore, using these control schemes, the torque producing components of the rotor flux can be made to respond fast enough that the machine remains under relative control, even during significant grid disturbances. Indeed, while more expensive than the Type 1 or 2 machines, the Type 3 is becoming popular due to its advantages.

The fourth type is a variable speed wind turbine with full-rated power electronic conversion system and a synchronous generator or a SCIG as illustrated in Figure 2.22. The generator can be electrically excited (wound rotor synchronous generator, WRSG) or permanent magnet excited type (permanent magnet synchronous generator, PMSG). Direct-in-line variable speed wind turbines have several drawbacks with respect to the former variable speed DFIG concepts, which mainly include the power converter and output filter ratings at about 1 p.u. of the total system power. This feature reduces the efficiency of the overall system and therefore results in a more expensive device. However, as the full scale power converter decouples entirely the wind turbine generator from the utility grid, grid codes such as fault ride through and grid support are easier to be accomplished, as required from modern applications.

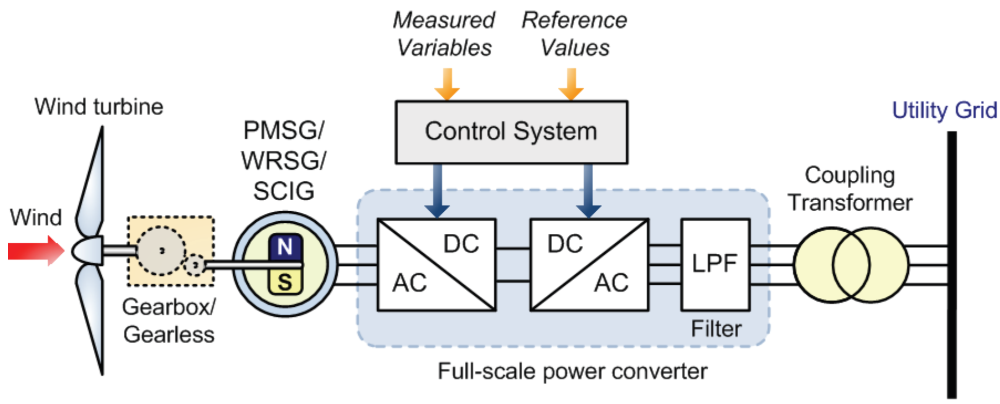

Figure 2.21: Direct-in-line variable speed wind turbine connected to the electric grid through a full-scale power converter (Molina and Mercado, 2011)

Type 5 wind turbines are not as widely reported in the literature as the preceding ones. However, as shown in Figure 2.23, they consist of a typical wind turbine generator (WTG) variable-speed drive train connected to a torque/speed converter coupled with a synchronous generator (Camm *et al*., 2009). According to them, the torque/ speed converter changes the variable speed of the rotor shaft to a constant output shaft speed.

Then the closely coupled synchronous generator, operating at a fixed speed (corresponding to grid frequency), can be directly connected to the grid through a synchronising circuit breaker.

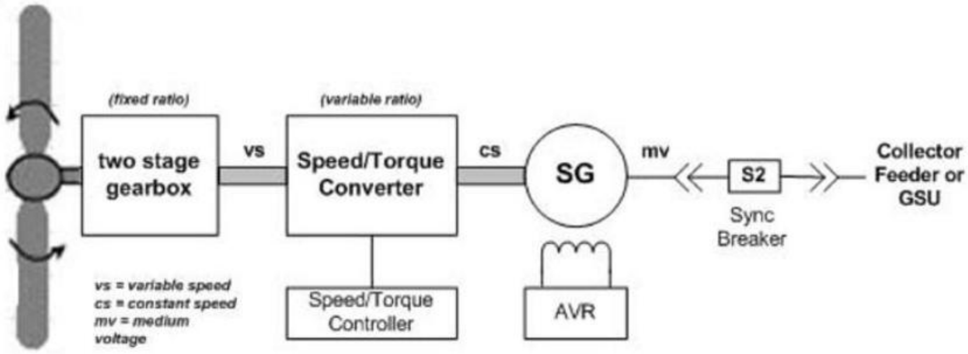

Figure 2.22: Typical Configuration of a Type 5 WTG (Camm *et al.*, 2009)

The synchronous generator can be designed appropriately for any desired speed (typically 6 poles or 4 poles) and voltage (typically medium voltage for higher capacities). The authors have noted that this approach requires speed and torque control of the torque/speed converter along with the typical voltage regulator (AVR), synchronizing system, and generator protection system inherent with a grid-connected synchronous generator.

2.4 Conclusion

This chapter has reviewed the various definitions of DG and its two typical technology examples. This has shown that irrespective of its various terms or definitions DG is a fairly new concept in the economics literature about electricity markets, but the idea behind it is not new at all. Basically the different terms often refer to different aspects or properties of the new types of generation. Also there is a strong overlap between the terms, but there are some serious differences as well. Therefore, in this work the term “distributed generation” refers to production units connected to the distribution network especially production units based on renewable energy sources.

From Section 1.1, the two main reasons necessitating South Africa’s deployment of renewable DG are CO_2 emission curtailment and improvement of Eskom’s wafer thin reserve margin. These are achievable by increasing the attention accorded CSP, if not bringing it at par with wind and PV, given the country’s impressive DNI although renewable energy electricity generation is not absolutely “zero-emission”. Unfortunately, South Africa’s electricity network was not designed for this kind of generation. Therefore, appropriate questions to ponder about are the probable consequences of the integration of this “new” type of generation and this is the focus of next chapter.

CHAPTER 3
DISTRIBUTED GENERATION INTEGRATION ISSUES

3.1 Introduction

The aim of this chapter is to review the inherent issues of DG integration. It begins with a deeper consideration of the DG renaissance. Thereafter the threat or challenges posed by DG integration will be highlighted.

3.2 Distributed Generation Renaissance

A lot has been written concerning the rebirth of DG. As was noted in Section 1.1 some of the reasons adduced are location or region based for instance electricity generation issues in OECD countries are different from BRICS countries.

According to Chiradeja and Ramakumar (2004) the impending deregulated environment faced by the electric utility industry and recent advances in technology, several DG options are fast becoming economically viable. They have listed a multitude of recent events that have created a new environment for the electric power infrastructure leading to an upsurge in interest in the development and utilisation of DG as follows:

- Deregulation of the electric utility industry and the ensuing breakup of the vertically integrated utility structure.
- Public opposition to building new transmission lines on environmental grounds.
- Keen public awareness of the environmental impacts of electric power generation.
- Rapid increases in electric power demand in certain regions of the country.
- Significant advances in several generation technologies that are much more environmentally benign (wind-electric generation, microturbines, fuel cells, and photovoltaics) than conventional coal, oil, and gas-fired plants.
- Increasing public desire to promote "green" technologies based on renewable energy sources.
- Awareness of the potential of DG to enhance the security of electric power supply, especially to critical loads, by creating mini- and micro-grids in the case of emergencies and/or terrorist acts, and/or embargoes of energy supplies.

While commenting on the value of distributed generation Petrie *et al*. (2001) have noted that where there is no power, any source of power generation is, of course, of significant value to the end-user, to the regional government, and to the prospective energy service company. According to them, from the electricity industry perspective, DG is attractive because it has multiple other values which include the following:

- The generator can be sited close to the end-user, thus decreasing transmission and distribution costs and electrical losses.
- Sites for small generators are easier to find.
- Distributed generators offer reduced planning and installation time.
- Because the DG units are distributed, the “system” may be more reliable. One unit can be removed for maintenance or service with only a moderate effect on the rest of the power distribution system. This is especially important for new technologies where the long-term reliability is not proven.
- Newer distributed generation technologies offer an environmentally clean and low noise source of power.
- Newer distributed generators can run on multiple types of fuels. This allows flexibility and reduction in cost of the infrastructure required to get the fuel to the generator. The preferred fuel source differs in various parts of the world. However, the required quality of the selected fuel may be more important for certain new DG technologies.
- Newer distributed generators can run on fuels generated from biogasification. Biomass (e.g., wood, hog waste, agricultural byproducts) is a truly renewable source of fuel in most developing countries and especially in agricultural regions.

Equally from the end-user perspective, DG is also attractive for several reasons such as:

- Power is readily available and the power has improved quality and reliability over power produced from central generating stations.
- Depending on the nature of fuel used, electricity prices are often lower than power from central plants.
- Some DG technologies provide cogeneration possibilities, which allow site recovery of heat and / or hot water. This has the potential to raise energy efficiency to around 90%. In rural villages, the recovered heat can be used for hot water, space heating, industrial processes and even space cooling (adsorption air conditioners)

Chiradeja and Ramakumar (2004) posit that the key element of this new environment is to build and operate several DG units near load centres instead of expanding the central-station power plants located far away from customers to meet increasing load demand. Therefore, according to Sallam and Malik (2011), the overall trend is concerned with efficient utilisation of DG in:

- supplying electricity to small loads in remote locations where it may be more economic than establishing a new line to the load site;
- supplying heat energy and steam to hospitals and some industries from cogeneration systems;
- providing high power quality for electronic and sensitive equipment;
- backup power source during utility outages, in particular, for loads requiring uninterrupted power supply such as hospitals, banks, and data centres;
- peak-shaving programs where DG can be used during high - cost periods to supply consumers participating in the programs resulting in reduction of overall power cost;
- reduction of air emissions by using renewable energy sources;
- avoiding distribution system investments;
- providing excess capacity to utilities;
- dispatching DG to achieve most economical operation taking into account the priority of supplying independent producers; and
- reducing transmission and distribution (T & D) losses.

Most of the benefits of employing DG in existing distribution networks have both economic and technical implications and they are interrelated (Chiradeja, and Ramakumar, 2004). While all the benefits can be ultimately valuated in terms of money, some of them have a strong technical flavour than others. As such, they have proposed to classify the benefits into two groups – technical and economic. The major technical benefits are:

- reduced line losses;
- voltage profile improvement;
- reduced emissions of pollutants;
- increased overall energy efficiency;
- enhanced system reliability and security;
- improved power quality;
- relieved transmission and distribution congestion.

Also the major economic benefits are:

- deferred investments for upgrades of facilities;
- reduced operation and maintenance costs of some DG technologies;
- enhanced productivity;
- reduced health care costs due to improved environment;
- reduced fuel costs due to increased overall efficiency;
- reduced reserve requirements and the associated costs;
- lower operating costs due to peak shaving; and
- increased security for critical loads.

These benefits are deemed as the positive impacts. However, distributed energy resources add new challenges to the distribution system design process in the areas of safety, fault sensing, and protection, among others. This is because traditionally the distribution network is designed and operated assuming that the electricity is brought in from the Grid Supply Point (Dai, 2010). The specifications of network components of both plant gears and control gears and operation arrangements are therefore based on this assumption. The penetration of distributed generators into distribution network voids the conditions on which the network designs and operations are based. Consequently, distribution-system engineers are currently divided between DG advocates and adversaries, each having their own valid reasons (Targarona and Morcos, 2007). One of the main reasons for this conflict is just "fear of what could happen" due to the lack of practical knowledge on traditional power systems having a high level of DG penetration. According to them, still fresh in the minds of many engineers is the wrong approach that has been taken in the past by large computer manufacturers when they underestimated the growing market of personal computers; an analoguey with the present DG situation that is easy to make.

There are concerns about the compliance of the generator connection with the standards and practices of network design and operation. The requirements (and, therefore, the complexity and cost) of protection and control systems for distributed resource systems, beyond the requirements of various standards, codes, and required certifications, depend primarily on (Ortmeyer *et al*., 2008; Schienbein and Dagle, 2001):

- The size of the DG system with respect to the minimum total customer load on the feeder
- The number, size, and location of other DG units on the feeder

- The purpose of the DG — grid-connected or primarily grid-independent operating mode
- The type of DG — diesel generator, gas turbine generator, fuel cell, etc.
- The specific configuration of the feeder system (including laterals to the loads), including the size, location, operating mode, type of relays, breakers, and fuses, the feeder voltage, and the location, size, and configuration of all transformers
- Network operator requirements specific to that network (possibly as a result of experience with unique and unusual loads) and any additional safety requirements of local jurisdictions
- The DG penetration level, and
- The strength of the system at the point of DG connection.

3.3 Distributed Generation Integration

In considering the positive and negative impacts of distributed generation it could be proper to ask "Is it *integration* or *interconnection* of distributed generation?" This appears crucial because of their interchangeability by some authors while some maintain their individuality.

According to Basso (2009) interconnection in IEEE 1547 is defined as "the result of the process of adding a DR unit to an area EPS (electric power system)," A technical barrier to the interconnection of DR is its effect on the area EPS – referred to as system impacts. Siira (2014) asserts that interconnection is a widely known concept and the fundamental area covered by the IEEE 1547 series of standards. He has noted that generally it deals with all equipment and functions used to interconnect a distributed energy resource unit with an area electric power system (distribution system).

Integration specifically means the physical connection of the generator to the network with due regard to the secure and safe operation of the system and the control of the generator so that the energy resource is exploited optimally (Freris and Infield, 2008). They maintain that proper integration of any electrical generator into an electrical power system requires knowledge of the well-established principles of electrical engineering. Also the integration of generators powered from renewable energy sources is fundamentally similar to that of fossil fuelled powered generators and is based on the same principles, but, renewable energy sources are often variable and geographically dispersed.

According to EPRI (2000) both terms are not synonymous. It asserts that the term "integration" is much broader than simply the interconnection of DR, because integration considers the entire electric power system and how DR influences it. Consequently, it posits that there are three key elements associated with integration of DR into the electric power system namely:

- Interconnection practices
- System design and operation impacts
- Communications and control possibilities

Interconnection practices are those matters dealing with the types of control relays, transformer interfaces, disconnect switches, and other-site specific DR hardware required for successful operation of the DR. *System design and operation impacts* deal with the broader scope of how the electric power system is affected by the DR. This includes impacts such as voltage regulation, flicker, harmonics, and reliability. These types of impacts may involve studies such as load flow, harmonic, and short-circuit analysis. *Communication and control possibilities* address the need for data and control signals to be transferred to and from DR equipment to other electric power system equipment and/or control centers as is required for safe and effective operation of DR.

It further notes that it is important to recognise that all three of these areas are closely inter-related. For example, the voltage impacts of DR on the power system are influenced by DR interconnection practice and the controls employed.

From the forgoing and given IEEE (2003) definition of interconnection as the result of the process of adding a DR unit to an Area EPS, it may be proper to conclude by concurring with EPRI (2000) that interconnection is a subset of integration: an analoguey to DER and DG. Therefore, interconnection and integration could be accorded a cause-effect relationship.

3.3.1 Distributed Generation Interfaces

According to Little (1999) interfaces are the point of interaction between DG and the energy infrastructure as shown in Figure 3.1. The physical interfaces include a DG unit's interaction with the fuel and electrical infrastructure. Physical interfaces are mainly concerned with issues such as safety, protocols, system impacts, reliability, standards, and metering. Some forms of DG will involve a communications interface with a central entity that controls and/or monitors the DG system. The market interface covers how the DG unit or its owner interacts or competes with other suppliers in the marketplace. The market interface includes concerns over dispatch, tariffs, pricing signals, response, and business and operational decisions.

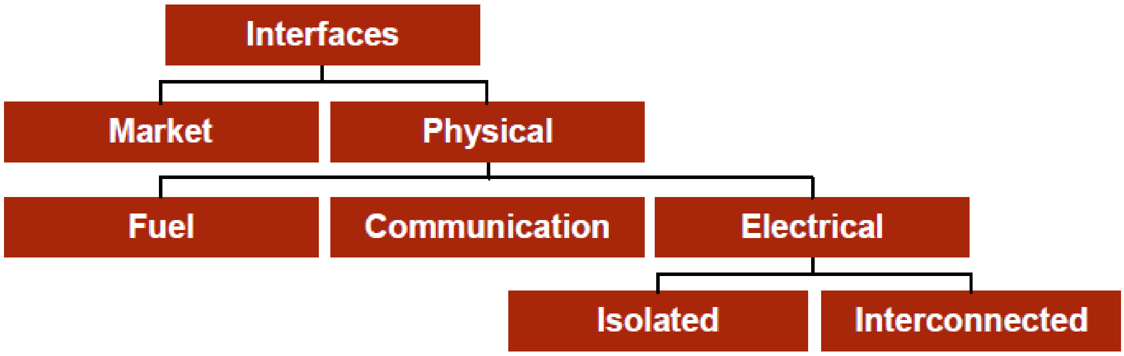

Figure 3.1: Distributed generation interfaces (Little, 1999)

Little (1999) has noted that while there are issues surrounding all of these interfaces, the most important issues in the short term are on the electrical interface. Also that the most contentious issues in the electrical interface are those involving DG interconnected to the grid.

The electric power system interface is the means by which the DG unit electrically connects to the power system outside the facility in which the unit is installed. Little (1999) asserts that depending on the application and operation of the DG unit, the interface configuration can range from a complex parallel interconnection, to being non-existent if the DG unit is operated in isolation. Therefore, the electrical interface determines the status of the DG as either grid-connected or standalone (isolated). However, the complexity of the interface increases with the level of interaction required between the DG unit/owner and the electrical grid/distribution company.

Grid interconnection is the most complex electrical interface configuration and the source of many issues involving DG. For most customers, DG systems are most cost-effective and efficient when they are interconnected with the utility grid (de Almeida and Moura, 2007). According to them, in simple terms, “interconnected with the grid” means that both the DG system and the grid supply power to the facility at the same time. Paralleled systems offer added reliability, because when the DG system is down for maintenance, the grid meets the full electrical load, and vice versa. The term “interconnection” is often used synonymously with the terms “synchronized operation” or “parallel operation” (Little, 1999). In this configuration, the DG unit is connected to the electric grid system while it generates electricity.

Consequently, distributed generation systems can be designed to keep a facility up and running without an interruption if the grid experiences an outage. Also, as noted by de Almeida and Moura (2007), grid-interconnected systems can be sized smaller to meet the customer's base load as opposed to its peak load. Not only is the smaller base-load system cheaper, it also runs closer to its rated capacity and, therefore, is more fuel efficient and cost-effective. Therefore, they believe that two different types of grid interconnection are possible: parallel or roll-over. With the parallel operation, the DG system and the grid are interconnected and both are connected to the load. In the rollover operation, the two sources are interconnected, but only one is connected with the load. In their view a typical interconnection system includes three kinds of equipment:

- Control equipment for regulating the output of the DG
- A switch and circuit breaker (including a "visible open") to isolate the DG unit
- Protective relaying mechanisms to monitor system conditions and to prevent dangerous operating conditions

3.3.2 Impacts of Distributed Generation

While discussing the reasons for the resurgence of distributed generation in Section 3.2, those advantages or benefits of DG were deemed as the positive impacts. That was quickly and briefly followed by the disadvantages because of the divergent views of its proponents and opponents. Consequently, the focus of this section is on some of the negative effects of DG integration.

Firstly, the following impacts are some of the major "planning and design" concerns of utilities when DG is interconnected to the grids (Tran and Vaziri, 2005).

- Harmonic distortion
- Loading concerns
- Voltage flicker
- Voltage regulation

But according to Coster *et al*. (2011) large scale integration of DG units in the distribution grid not only affects the grid planning but also has an impact on the operation of the distribution grid. Therefore, they posit that aspects which are influenced by the connection of DG units are as follows:

- voltage control;
- power quality;
- protection system;
- fault level; and
- grid losses.

They have also noted that the effect of DG units on these quantities strongly depends on the type of DG unit and the type of the network.

Therefore, there are many technical issues that must be considered when connecting a generating scheme to the distribution system, such as (Masters, 2002):

- thermal rating of equipment
- system fault levels
- stability
- reverse power flow capability of tap-changers
- line-drop compensation
- steady-state voltage rise
- losses
- power quality (such as flicker, harmonics)
- protection.

Whatever the reason, we will increasingly find DG being installed to operate in parallel with the distribution system which results to several potential operating conflicts that have been addressed since the early 1980s (Dugan and Mcdermott, 2002). A few of these conflicts are:

- overcurrent protection
- instantaneous reclose
- ferroresonance
- reduced insulation
- transformer connections and ground faults.

According to Sallam and Malik (2011) some of the problems that may be faced in connecting DG systems to the existing distribution network are technical and some are economical. Therefore, they have noted the technical problems are as follows:

- Some on-load tap changer transformers are not designed for reverse power flow.
- Increase of fault levels.
- Protection of distribution systems is not designed for reverse power flow.
- Nuisance tripping of some healthy parts in distribution systems.
- Existing networks are not designed for high voltage rise. So, voltage reduction schemes and network voltage control schemes are adversely affected by DG, especially if operating under voltage control, or if generator output changes rapidly.
- Metering equipment and communication system between meters and the data centre should be modified.

The economic problems resulting from the connection of distributed generation to the existing distribution network could be considered as the "disruptive threats of distributed generation". The current clamour for DG and by extension DER based on their benefits appears to overlook their financial implications to retail energy business (Onwunta and Kahn, 2013). According to IEA (2002) distributed generation is a "disruptive technology" that could fundamentally alter the organisation of the electricity-supply industry. A disruptive innovation is defined as (Kind, 2013): *"an innovation that helps create a new market and value network, and eventually goes on to disrupt an existing market and value network (over a few years or decades), displacing an earlier technology. The term is used in business and technology literature to describe innovations that improve a product or service in ways that the market does not expect, typically first by designing for a different set of consumers in the new market and later by lowering prices in the existing market".* Technically DG has a disruptive effect on distribution network previously planned for passive or unidirectional operation. Also it is disruptive to the utility whose revenues are directly correlated to customer levels or sales.

Figure 3.2 is an illustration of the interplay amongst technology innovation, government program and behavioural changes. The financial risks created by disruptive challenges include declining utility revenues, increasing costs, and lower profitability potential, particularly over the long-term. As DER and DSM programs continue to capture "market share," for example, utility revenues will be reduced. For instance, energy-saving technologies like smart grids in North America are challenged by a traditional business model where the main driver is increasing energy sales (WEC, 2012). Adding the higher costs to integrate DER, increasing subsidies for DSM and direct metering of DER will result in the potential for a squeeze on profitability and, thus, credit metrics. While the regulatory process is expected to allow for recovery of lost revenues in future rate cases, tariff structures in most places call for non-DER customers to pay for (or absorb) lost revenues. As DER penetration increases, there is a cost-recovery structure that will lead to political pressure to undo these cross subsidies and may result in utility stranded cost exposure.

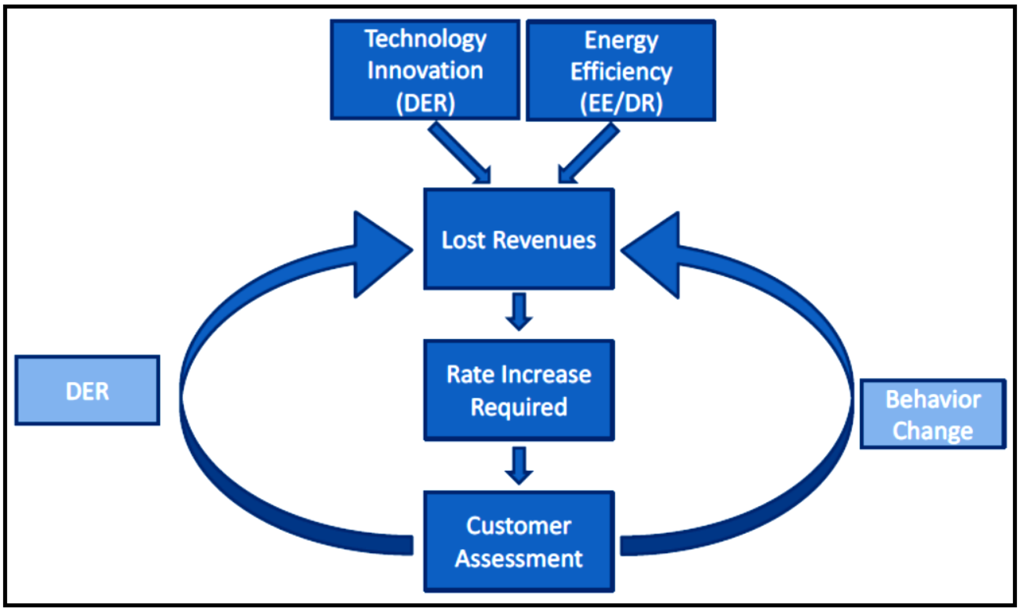

Figure 3.2: Vicious cycle from disruptive forces (Kind, 2013)

According to Kind (2013) in a cost-of-service rate-regulated model, revenues are not directly correlated to customer levels or sales but to the cost of providing service. However, in most jurisdictions, customer rates are a function of usage/unit sales. In such a model, customer rate levels must increase via rate increase requests when usage declines, which from a financial perspective is intended to keep the company whole (i.e., earn its cost of capital). He posits that this may lead to a challenging cycle since an increase in customer rates over time to support investment spending in a declining sales environment (due to disruptive forces) will further enhance the competitive dynamics of competing technologies and supply/demand efficiency programs. His conclusion is that this set of dynamics can become a vicious cycle that, in the worst-case scenario, would leave few(er) customers remaining to support the costs of a large embedded infrastructure system, some of which may be stranded investment but most of the costs will continue to be incurred in order to manage the flows between supply and customers.

Some of the distributed generation integration technical problems are highlighted in the following sections beginning with interconnection transformer connections.

3.3.2.1 Interconnection Transformer Connections

Transformer connections play a key role in DR interconnection and the type of winding configuration and connection can affect how the DR impacts the area electric power system (Basso, 2009). Therefore, understanding distribution transformer characteristics, configurations, and applications is critical to understanding the issues of integrating DR to the system (EPRI, 2000). This is because the vast majority of DR installations involve some sort of existing distribution transformer interface. Unfortunately, many existing distribution transformers are not suitable even for DR applications since the criteria upon which they were originally selected had nothing to do with generation at the customer site. According to EPRI (2000) many transformer arrangements used in practice are problematic for power flow from the customer system back to the primary.

The selection of the interconnection transformer connection has a major impact on how the distributed generator will interact with the utility system and there is no universally accepted "best" connection (Khan, 2008; Mozina, 2001; Mozina, 2010; PSRC, 2004). However, many utility engineers believe the best transformer connection for DG is grounded wye-delta, with the grounded wye side connected to the utility side, just like central station generation connected to the transmission grid (Dugan and Mcdermott, 2002). This is because the protective relaying for this connection is well understood from decades of experience with central station generation and single line-to-ground faults are relatively easy to detect from the phase-to-phase voltages on the DG side. According to them, other fault conditions are also relatively easy to detect. For instance, if the DG accidentally becomes isolated in an island, the utility side still appears to be effectively grounded, although somewhat less so than before the island formed. Also there are fewer strange resonant conditions that can occur and ferroresonance is considerably less likely. Furthermore, they have noted that triplen harmonics produced by the machines are blocked by the delta winding (very important for some machines) and there are probably other benefits not mentioned.

While Khan (2008) believes that four connections are commonly used, the rest of the authors differ with him maintaining that there are five commonly used connections as shown in Figure 3.3. Each of these connections has advantages and disadvantages to the utility with both circuit design and protection coordination affected depending on the type of DR and distribution system (Basso, 2009). Consequently, they posit that each connection should be addressed by the utility as they establish their interconnect requirements. Specifically, Khan (2008) has noted that the type of transformer employed has an impact on the grounding perceived by the utility primary system and for the generator to appear as a grounded source to the utility primary distribution systems, the transformer must be able to pass a ground path from the low voltage to the high voltage side, which is commonly called as zero-sequence path.

The utility and DG owner have only two basic choices in selecting the primary winding configuration of the interconnection transformer (Mozina, 2010):

1. unground primary windings (delta or wye ungrounded) and risk possible overvoltages
2. ground the primary windings (wye grounded) and potentially disrupt feeder relay ground coordination through the injection of unwanted ground current.

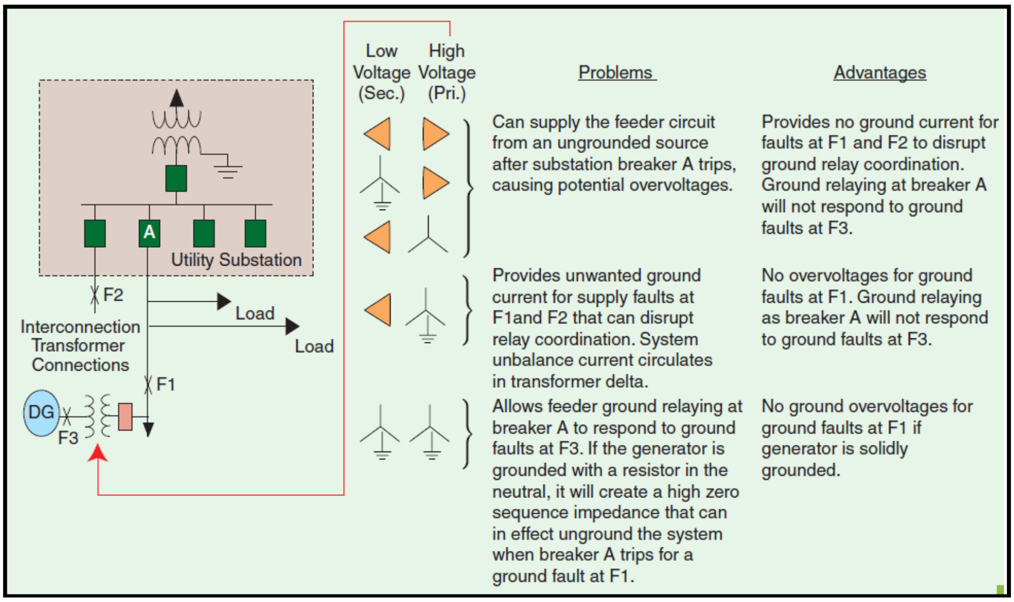

Figure 3.3: Interconnection transformer connections (Mozina, 2010)

3.3.2.2 Ungrounded Transformer Primary Windings

The three connections under this group are: Delta (HV)/Delta (LV), Delta (HV)/Wye-Gnd (LV) and Wye-Ungnd (HV)/Delta (LV) – High Side Delta or Ungrounded Wye – where (HV) indicates the primary winding and (LV) indicates the secondary winding. According to Mozina (2001) and PSRC (2004) the major concern with these connections is in the area of circuit design, but an advantage of this connection is that there is no source of zero sequence current to impact the utility ground relay coordination. However, coordination problems can arise for fused multiphase laterals and for back feed of phase faults on adjacent feeders. Referring to Figure 3.3, for ground faults at F1 and F2, all of the fault current will come from the utility. In addition, any ground fault on the secondary of the transformer at F3 will not be detected at the breaker A location. If breaker A is tripped for a ground fault at F1, the utility breaker may trip with the generator still connected and the resulting system is not effectively grounded. This means that with the ungrounded connection, phase faults will have two sources of fault currents. Line to neutral voltages on the unfaulted phases approach the normal line to line voltages which can cause a severe overvoltage of line to neutral connected equipment. If the insulation of the connected equipment has not been selected for those voltage levels, the result will be serious damage to the equipment. The connected distribution transformers will become saturated and damaged, insulators and lightning arrestors will likely flash over and the breaker bushings may fail. It is generally accepted that if the connected generator is rated at less than half of the minimum load on the circuit, it will be unable to sustain more than line to ground voltages. Therefore, they have advised that the ungrounded primary connections should only be considered if the distributed generator is rated at less than half of the load on the circuit. Also, if this type of transformer connection is used, voltage relays must trip the DR for an overvoltage condition. They have noted that minimum load data on a feeder may not be readily available and special data may need to be obtained for this evaluation.

According to EPRI (2000) DR units using a delta-high-side winding need to include robust anti-islanding protection and fast tripping to help limit the duration of overvoltage problems should they develop.

Many utilities use ungrounded interconnection transformers only if a 200% or more overload on the DG occurs when breaker A trips (Mozina, 2001; Mozina, 2010). During ground faults, this overload level will not allow the voltage on the unfaulted phases to rise higher than the normal line to neutral voltage, avoiding pole-top transformer saturation and potential lightning arrester failure. For this reason, ungrounded primary windings should generally be reserved for smaller DGs, where overloads of at least 200% are expected upon islanding.

In South Africa the preferred neutral earthing philosophy for MV-connected generators or generator transformers is that the MV neutral point be left un-earthed (Eskom, 2008b). This will serve to avoid issues of earth fault relay desensitization, as well as avoiding "circulating" zero sequence or triplen (i.e. 3rd, 6th, 9th etc.) harmonic currents between the distant earth connections.

3.3.2.3 Grounded Primary Transformer Windings

This consists of Wye-Gnd (HV)/ Delta (LV) – High Side Grounded Wye/Low Side Delta – and Wye-Gnd (HV)/ Wye-Gnd (LV) – Wye-Wye.

According to PSRC (2004) the Wye-Gnd (HV)/ Delta (LV) establishes a zero sequence current source for ground faults on the distribution system, which could have a significant impact on the utility's ground relay coordination. As Figure 3.4 shows, for a ground fault at F1, the zero sequence fault current will be divided between breaker A location and the grounded neutral of the distributed generator interconnection transformer. The distribution of this fault current will be dependent on the circuit and transformer impedances.

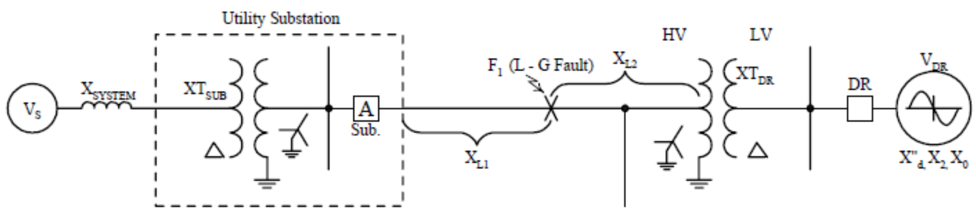

Figure 3.4: Single-line diagram for Wye-Grounded (HV) / Delta (LV) interconnection transformer (PSRC, 2004)

Figure 3.5 is the symmetrical component equivalent circuit for this connection. Due to the presence of the delta secondary configuration, the zero sequence current source is independent of the status of the generator and the generator breaker. In addition, any unbalanced load on the distribution circuit would normally return to ground through the utility transformer neutral. With the addition of the generator interconnection transformer this unbalance will be divided between the utility transformer neutral and the generator interconnect transformer. The load unbalance is the sum of the unbalance currents on all feeders connected to the same bus as the DG feeder (Mozina, 2001; Mozina, 2010). They assert that there are utilities that install a neutral reactor in the wye winding to reduce the ground current from the DG. Therefore, their advice is that the reactor must be selected such that the feeder remains effectively grounded when the source breaker A trips. In South Africa, Eskom's MV networks are resistively earthed at the source substation so as to limit earth fault currents to the typical ranges: less than 720A (Rural networks) and less than 1600A (urban networks) (Eskom, 2008b).

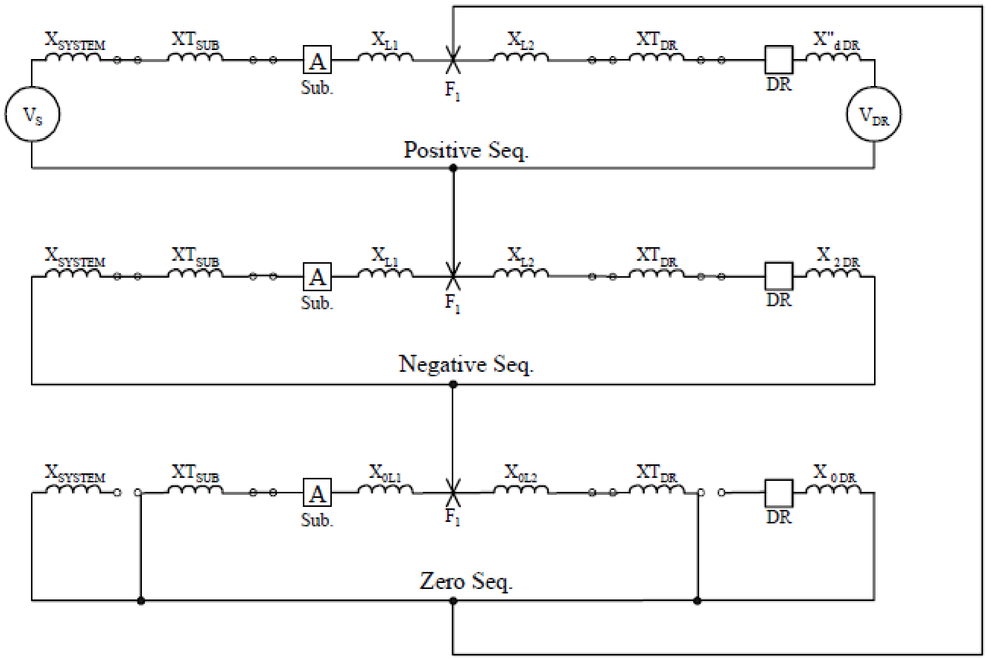

Figure 3.5: Symmetrical component circuit for Wye-Grounded (HV) / Delta (LV) interconnection transformer (PSRC, 2004)

During serious unbalance conditions such as a blown lateral fuse, the load carrying capability of the interconnection transformer can be reduced (PSRC, 2004). It was noted that the advantages are that the relaying at breaker A will not see a ground fault at location F3 in Figure 3.3 and no overvoltage problems are associated with this connection.

The last interconnection transformer connection to be considered is the Wye-Gnd (HV)/ Wye -Gnd (LV). This connection establishes a zero sequence current source as in the previous example if the generator is wye connected with a grounded neutral. According to (PSRC, 2004), ground relay coordination at breaker A is impacted and unbalance can be a problem as described in the case of High Side Grounded Wye/Low Side Delta. Also, the absence of a delta connection to circulate the zero sequence currents adds additional complexities for the relay engineer. Referring to Figure 3.6, sensitive settings on ground overcurrent relays at breaker A can detect and trip for ground faults at F3. According to Mozina (2010) if a wye–wye transformer connection is used, the ground relays at breaker A can respond to a ground fault at location F3 that requires coordinating the ground protection at breaker A with local ground protection at the DG.

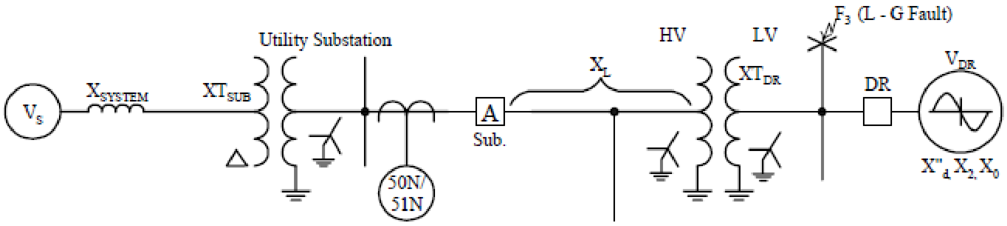

Figure 3.6: Single-line diagram for Wye-Grounded (HV) / Wye-Grounded (LV) interconnection transformer (PSRC, 2004)

An analysis of the symmetrical components circuit, as shown in Figure 3.7, for this connection demonstrates that the zero sequence contribution to ground faults on the distribution system is dependent on the status of the generator. When the generator is off line, there is no zero sequence source for ground faults on the distribution circuit. With this connection, there are no problems with overvoltage.

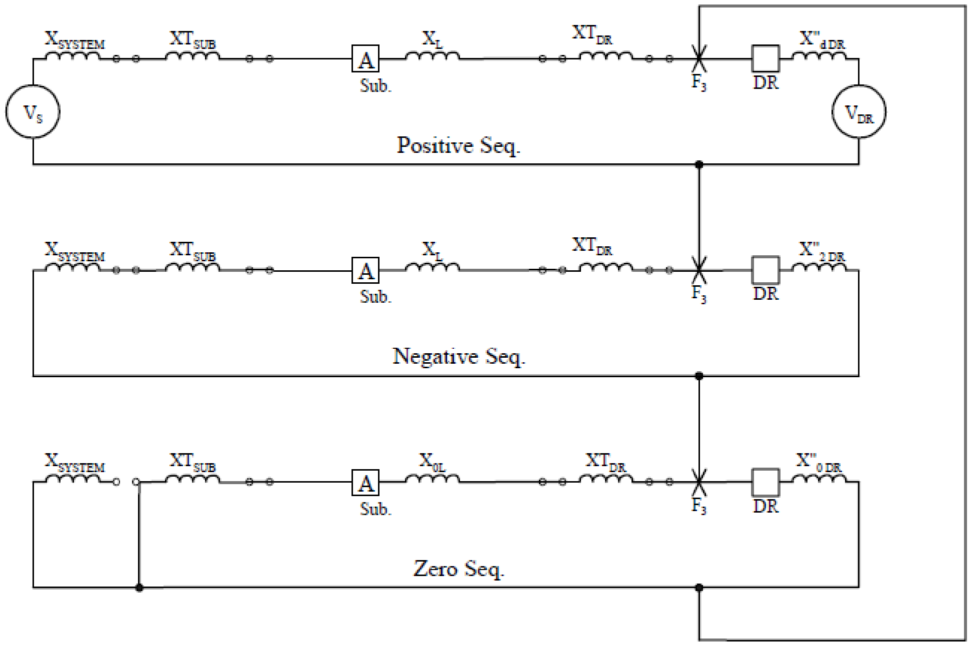

Figure 3.7: Symmetrical component circuit for Wye-Grounded (HV) / Wye-Grounded (LV) interconnection transformer (PSRC, 2004)

It is the general practice at industrial and commercial medium-voltage facilities to ground generator neutrals with a resistor to limit the ground current between 200 and 400 A which causes a large zero sequence impedance (Mozina, 2010). Therefore, he posits that for a permanent feeder supply ground fault (F1), the voltage shift on the unfaulted phase will shift to line to line voltage, similar to an ungrounded primary winding case.

IEEE 1547 addresses the question of overvoltages and relay coordination that can be caused by a DG operating in parallel with the utility distribution system with a single sentence that states, “the grounding scheme of the DG interconnection shall not cause overvoltages that exceed the rating of the equipment connected to the area electric power system and shall not disrupt the coordination of the ground fault protection on the area electric system." The considerations to do this are not spelled out in the standard and are a major shortcoming of the document. However, ground concerns are covered in greater depth in the IEEE 1547.2 guide.

According to Eskom (2008b) the neutral points of generator transformer windings galvanically connecting the EG (Embedded Generator) to a Distributor at HV shall be solidly/effectively earthed, while those of MV connected generators/transformers will not be earthed. Also where used, the winding configuration of the generator transformer (e.g. Delta-Star, Star-Delta etc.) shall be such that zero sequence currents on the Distributor's network and EG systems are decoupled from one another.

Therefore, generally, the transformer connection offering the best performance will depend on the system (EPRI, 2000). Also, the ideal transformer configuration will depend heavily on the size and type of DR application.

3.3.2.4 Voltage Rise and Control Due to Distributed Generation

Voltage rise is typically the main constraint for the connection of EGs to LV and MV networks (Eskom, 2008). The main technical barrier to DG on distribution networks has been found to be voltage rise due to significant active power injections from DG. It is mainly an issue on rural networks due to their high impedance and low X/R ratio (Keane *et al*., 2011). This constraint or technical barrier arises because voltage magnitudes at service locations must be maintained within specified ranges. Consequently, to transmit power from an l l kV primary substation to a typical low voltage connected customer some distance away will require the voltage at the primary substation to be higher than the voltage at the point of connection of the customer to the 11 kV system. The maintenance of system voltages within permitted limits is accomplished in both fixed designs of the system (e.g., conductor selection, substation and distribution transformer tap settings and fixed capacitor banks) and by voltage control equipment such as automatic load tap changers, step-type voltage regulators (SVR), and switched capacitors (Masters, 2002; Walling *et al*., 2008). According to Walling *et al*. (2008) capacitors (switched and fixed) compensate reactive current, reducing the current from the source to the capacitor location, resulting in reduced line voltage drop. However, capacitors will cause a current increase in feeders if the capacitor size is greater than the load reactive demand due to overcompensation. This will also happen if the capacitor size meets the reactive demand of the total distributed load connected to a feeder, but is installed at a location where it compensates more than the downstream reactive power demand, resulting in voltage increase.

But conventional large scale generation which is dispatchable and used for voltage control is being displaced by DG which in many cases is non-dispatchable and does not have voltage control enabled (Keane *et al*., 2011). They have noted that a consequence of this is increasing demand for reactive power at distribution network interfaces, below which DG is connected. Therefore, this new additional reactive power demand is placing a strain on transmission system voltage resources and resulting in lower voltages at times of high DG output.

Interconnection of DG results in changes in power flows and the voltage profile of the feeder, and generally results in overvoltages under low load or high (DG) production conditions (Rajapakse *et al*., 2009). According to them in weak networks, the DG capacity is generally determined by the voltage limits. Furthermore, the connection status of a DG is not controlled by the utility. This implies that disconnection of a DG during the high load can cause undervoltages, while re-connection of a DG under low load conditions may cause overvoltages. Incidentally, this may lead to poor power quality situation and may result in operation of under/over voltage relays.

When a generator is to be connected to the distribution system, the distribution network oeprator will consider the worst case operating scenarios and ensure that their network and customers will not be adversely affected. Typically, these scenarios are (Masters, 2002):

- no generation and maximum system demand
- maximum generation and maximum system demand
- maximum generation and minimum system demand.

He posits that it is the voltage rise during periods of no/minimum demand that limits how much generation can be connected.

Equation 3.1 is the formula for evaluating the maximum steady-state voltage variation at the PCC of a DG interconnected with a power system (Chen *et al*., 2010; Papathanassiou and Hatziargyriou, 2001).

$$VR = \frac{S_G}{S_S}\cos(\varphi_S + \varphi_G) = \frac{1}{R}\cos(\varphi_S + \varphi_G) \leq 0.03$$

(Equation 3.1)

Where,

VR is the voltage variation at PCC.

S_G is the apparent power of a DG.

S_S is the short-circuit capacity at the PCC.

φ_S is the phase angle of the system impedance at PCC.

φ_G is the phase angle of the DG's output power.

$R = S_S/S_G$ is the short circuit ratio at the PCC.

According to Papathanassiou and Hatziargyriou (2001) the 3% limit imposed (Germany and other European national regulations impose an even more stringent 2% limit) is strict for two reasons. First, the grid voltage levels are determined by the aggregate effect of all connected consumers and generators and hence no single connection or user could be allocated the full variation limit. Second, in order to achieve a ± 10% variation limit at the LV level, the MV grid voltage should be more narrowly bounded. Furthermore they assert that Equation 3.1 is accurate enough for most practical purposes (its error being less than 0.5% for R ≥ 215*)*. Depending on the grid angle φ_S and the power factor angle φ_G of the installation, short-circuit ratios down to 15 or even lower may be acceptable. In practical situations, Equation 3.1 will yield a voltage increase due to the active power flow on the resistive part of the network impedance, which may be significant in case of weak grids (Papathanassiou, 2007). He notes that for this reason, slightly inductive power factor values are usually preferred ($Q < 0$). Moreover, since voltage variations are the aggregate effect of generating facilities and network loads, more detailed evaluation involves load flow calculations in the network, taking into account the actual network configuration and loads. Therefore, by solving the load flow for the four combinations of max/min load/generation, the maximum and minimum voltages,*U*max and *U*min, are determined for each node (usually, min load/max gen yields maximum voltages and max load/min gen minimum voltages): these voltages must then be appropriately bounded.

Rearranging Equation 3.1 yields the formula for calculating the maximum allowable capacity (rated apparent power) of a DG under a voltage variation limit as shown in Equation 3.2 (Chen *et al.*, 2010).

$$S_G = \frac{VR \times S_S}{\cos(\varphi_S + \varphi_G)}$$

(Equation 3.2)

However, they have noted that the evaluation of the maximum allowable capacity of a DG is not very precise because Equation 3.2 does not involve the uncertainty of feeder loading.

According to Masters (2002) the level of generation that can be absorbed onto the distribution system is determined by many factors, such as:

- voltage level
- voltage at the primary substation
- distance from the primary substation
- size of conductor
- demand on the system
- other generation on the system
- operating regime of the generation.

Unfortunately Equation 3.2 does not consider some of the issues raised by Masters (2002) such as distance from the primary substation and size of conductor. Therefore, relying on the work by van Zyl and Gaunt (2005a) based on a 2-node network theory, a simple algebraic method can be used as a guide to determine the maximum rating of DG that can be connected at a particular location before the upper voltage regulation limit on the network is exceeded as shown in Equation 3.3 (Eskom, 2008):

$$P_{DG} = \left[\frac{V_{std}\left(V_{std} - V_{setpoint}\right)}{r \times d}\right] + \left[S_{min}\left(1 - \frac{d}{2 \times L}\right)(\cos\theta + \sin\theta)\right] - \left[\frac{x}{r} Q_{DG}\right]$$

(Equation 3.3)

Where:

P_{DG} = Maximum exported DG power [MW]

V_{std} = Upper voltage regulation limit on the network (usually 1.05 p.u.) [p.u.]

$V_{setpoint}$ = OLTC setpoint voltage (usually 1.03 p.u.) [p.u.]

r + jx = Impedance per km of the line connecting the EG and the source busbars [ohms/km]

d = Distance of the DG from the source substation [km]

L = Backbone length of the feeder [km]

S_{min} = Minimum feeder load apparent power [MVA]

$\cos\theta$ = power factor of feeder minimum load

$\sin\theta = \sqrt{1-\cos^2\theta}$

Q_{DG} = Reactive power exported by the DG into the network [MVar] = 0. Assume the generator will operate at unity power factor.

The three terms of Equation 3.3 represent the following respectively (van Zyl and Gaunt, 2005a):

1. A term that is independent of feeder load and which varies in proportion to the allowable voltage rise and inversely with the conductor resistance. The "No-load" term is hyperbolic with respect to "d", the distance of the DG from the source substation.
2. A "Load" term that is linear with respect to d, and which varies with the load magnitude, location, power factor and the X/R ratio of the feeder.
3. A "Reactive Power Generation" term that is constant with respect to d and which varies with the reactive power generation by the DG, and the X/R ratio of the feeder.

Eskom (2008) has noted that the total length is the sum of all MV lines on the feeder including all tee-offs. In this case, "L" is the backbone length of the feeder. Also, this formula is only a guide and it is still essential to do a load flow study to determine the effect of the DG on voltage rise.

According to Bollen and Hassan (2011) the connection of a generator to the distribution network will result in a voltage rise at the terminals of the generator and the approximate relative voltage rise is given by Equation 3.4:

$$\frac{\Delta U}{U} = \frac{R \times P_{gen}}{U^2}$$

(Equation 3.4)

Where:

R = source resistance at the terminals of the generator,

*P*gen = injected active power, and

U = nominal voltage.

They assert that this approximation holds for all practical cases at distribution level and the same relative voltage rise as according to Equation 3.4 is experienced by all customers connected downstream of the generator, as shown in Figure 3.8, where the generator is connected to the medium-voltage feeder.

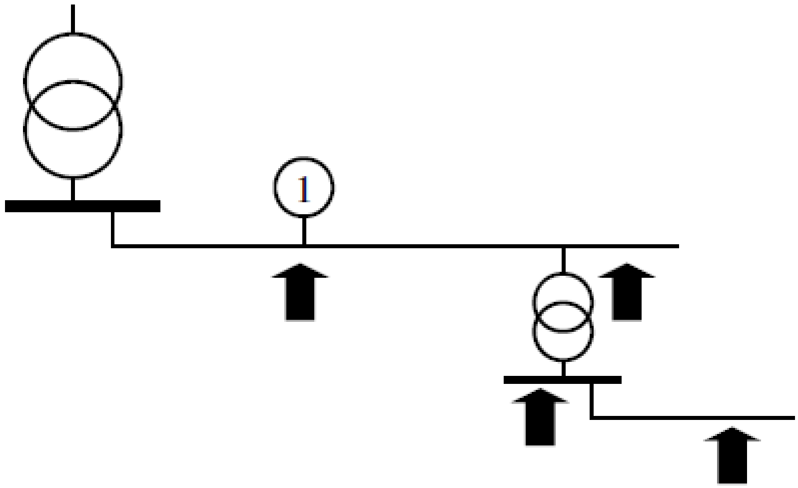

Figure 3.8: The relative voltage rise due to the generator is the same for all indicated positions (Bollen and Hassan, 2011)

This implies that when, for example, the voltage rise is 2.5% at the point where the generator feeds into the medium-voltage feeder, all customers at the indicated positions in Figure 3.8 will also experience a voltage rise equal to 2.5% due to the power injected by the generator. Bollen and Hassan (2011) have equally highlighted that what matters for the voltage rise experienced by a given customer owing to a generator at a given location is the source resistance at the point-of-common coupling between the generator and the customer. The points-of-common coupling are shown in Figure 3.9 for a fixed customer location (somewhere along a low-voltage feeder) and five different generator locations (1–5). The point-of-common coupling between the generators 1–5 and the indicated customer location is at location A–E, respectively. The point-of-common coupling is an important point because it is the resistive part of the source impedance at the point-of-common coupling that determines the voltage rise experienced by a given customer due to a given generator (Bollen and Hassan, 2011).

It is this resistance that is used in Equation 3.4 to calculate the voltage rise. When the HV/MV transformer is equipped with automatic tap changers, as is typically the case, the voltage at the main MV bus (i.e., on MV side of the HV/MV transformer) is kept constant. In that case, the resistance *R* in Equation 3.4 is the resistance between the point-of-common coupling and the main MV bus.

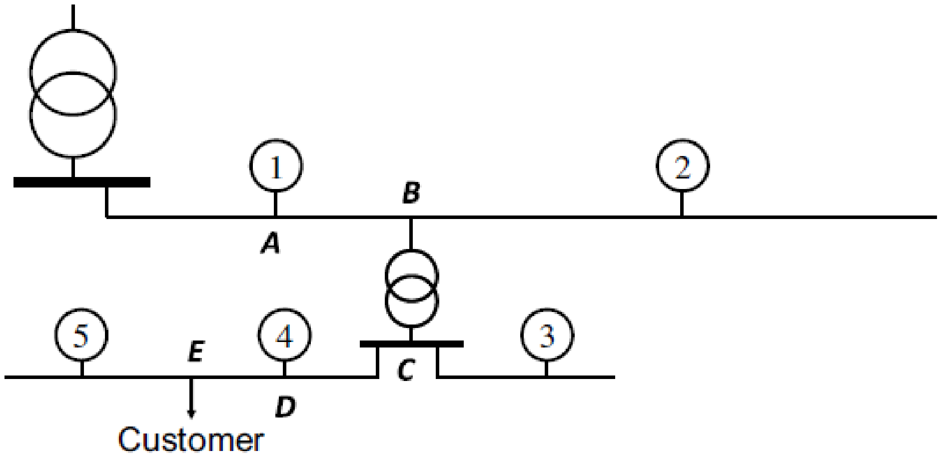

Figure 3.9: Points-of-common coupling (A–E) between a customer and generators at five different locations (1–5) (Bollen and Hassan, 2011)

According to Keane *et al*. (2011) a range of planning and operational methods have been proposed to alleviate the voltage rise barrier. A number of active voltage control schemes have also been proposed utilising power factor control and tap changers in both a centralized and distributed manner. They have emphasised that the issues of voltage rise on the distribution network and reactive power demands on the transmission system are conflicting. This because the selection of a fixed inductive power factor by the distribution network operator, as shown in Equation 3.3, serves to alleviate the distribution voltage rise issue, however the result is a large reactive power demand being made on the transmission system.

But if the connection of a generator to an 11 kV overhead line causes an excessive voltage rise, there are several techniques that can be employed to alleviate the situation, for example (Masters, 2002):

- reduce the primary substation voltage
- allow the generator to import reactive power (reducing the RP + XQ term)
- install auto transformers, or voltage regulators as they are often called, along the line (resetting the voltage along the line)
- increase the conductor size (reducing the resistance)
- constrain the generator at times of low demand (reducing the transmitted power)
- a combination of the above.

While commenting on DR impact on the system voltage Walling *et al*. (2008) have noted that in general, an attempt by a DR to regulate distribution system voltage can conflict with existing voltage regulation schemes applied by the utility to regulate the same or a nearby point to a different voltage reference. According to them even if DR does not actively control the system voltage, DR can cause a voltage increase or decrease along the feeder depending on the DR type, control method, its delivered power and feeder parameters and loading. This is because the incremental flow of real power, interacting with feeder resistance, will tend to make the voltage at the DR location rise. Equally injection of reactive power by the DR will increase the voltage rise and consumption of reactive power will tend to offset the voltage rise caused by the real power flow.

Furthermore concerning interaction of DR and voltage regulator operations Walling *et al*. (2008) have highlighted that the line drop compensation (LDC) feature, which is an integral part of the SVR control, estimates the line voltage drop and performs voltage corrections based on line current, line R and X parameters, and load side voltage. It is inherently assumed that current flow downstream of the regulator is roughly proportional to current at the regulator location, with the constant of proportionality steadily decreasing with increasing downstream distance from the regulator. Consequently, during reverse power flows, the LDC must have adequate control algorithms to properly perform voltage corrections. The reverse power flow may result from switching operations that reconfigure the feeder, or it may be due to DR supplying power back to the substation. There are several modes of operation presently available in modern SVR controls and the impact of DR is different on each.

For a normal bidirectional mode, an SVR control determines the direction of operation (forward or reverse) based on the direction of real power flow. According to Walling *et al*. (2008) this mode of operation may not be suitable for applications on feeders with DR connected as illustrated below.

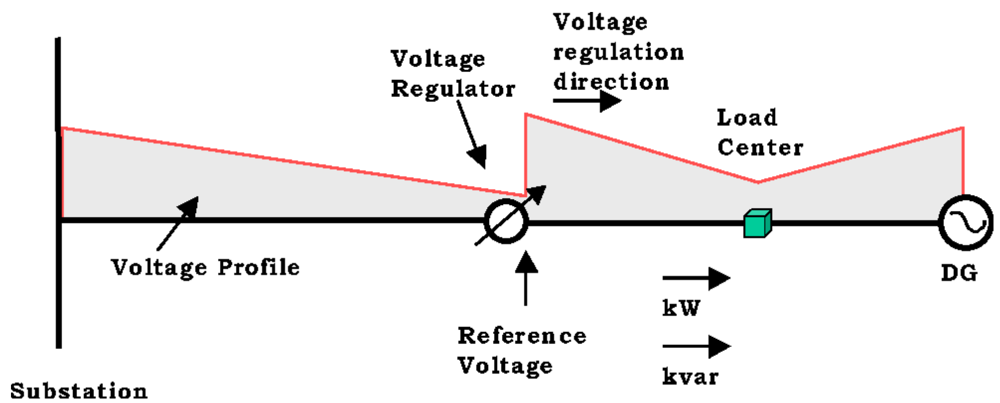

Figure 3.10: Normal bidirectional mode (forward mode) (Walling *et al*., 2008)

In Figure 3.10, the DR generates less real power than the feeder load downstream of the SVR. The real power flow through the SVR is from left to right (from substation to DR). With normal bidirectional sensing the regulator will be in Forward Mode, regulating the voltage on the DR side. This control mode is acceptable during these system conditions.

However, when DR real power (kW) generation exceeds the customer demand between the SVR and the DR, the real power flow through the SVR is from DR to substation and the regulator will operate in Reverse Mode and regulate the voltage on the substation side. This is the case in Figure 3.11.

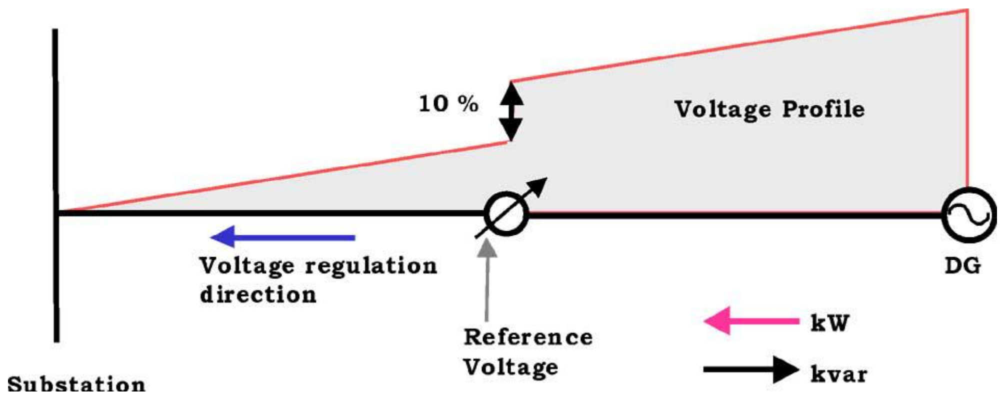

Figure 3.11: Normal bidirectional mode (reversed mode) (Walling *et al*., 2008)

If the source side voltage (substation side) is greater than the SVR set-point voltage, the SVR will tap down in an attempt to lower the voltage. But since the substation voltage is "fixed," the net effect is to raise the voltage on the DR side. This sequence will continue until the regulator taps to minimum tap, resulting in a 10% (or greater) overvoltage on the DR side of the SVR. Therefore, this control mode is unacceptable for system operation with DR (Walling *et al*., 2008).

Selection of appropriate tap settings for the distribution transformers becomes difficult with the increased penetration of DG. This is especially difficult when the DGs are not equally distributed among the feeders supplied by the same transformer (Rajapakse *et al*., 2009; Uchida *et al.*, 2007). Such a situation is illustrated in Figure 3.12 where there are two feeders supplied by the same transformer, but DGs are concentrated on only one of them. Generally, when the DGs are connected, the net current flow through the transformer is reduced because the DGs provide the power to the nearby loads (Rajapakse *et al*., 2009). Consequently, the transformer tap needs to be changed to the light load setting. The resulting decline of the sending voltage can cause a voltage violation at the far end of the feeder without DGs as shown in Figure 3.12.

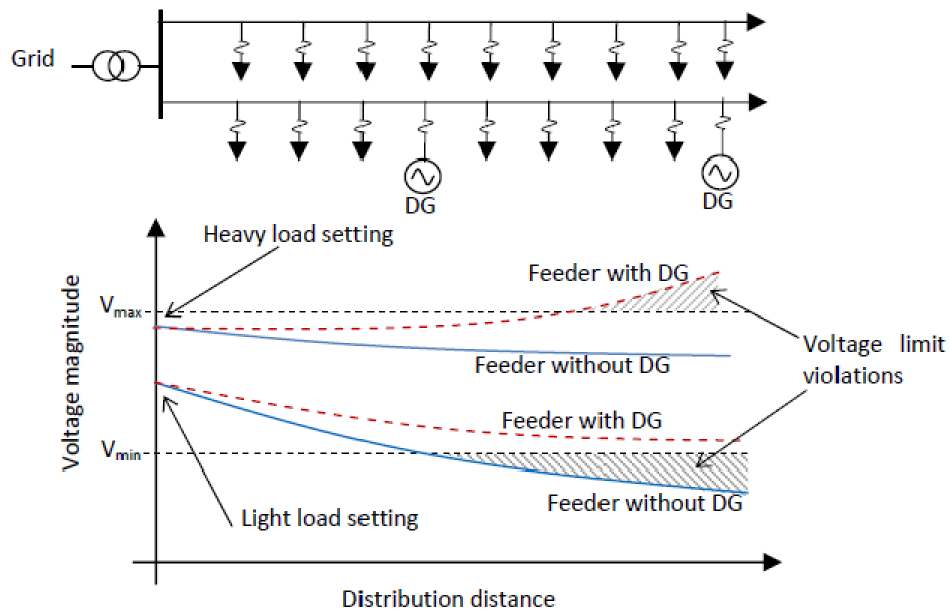

Figure 3.12: Possible DG interconnection configurations (Rajapakse *et al*., 2009)

Leaving the transformer tap at the heavy load setting risks overvoltages on the feeder with DGs. Switched capacitors and static VAr compensators can be used to control the feeder voltages, but these solutions are often too costly. According to Rajapakse *et al.* (2009) another issue that affects the operation of DGs at distribution level is the unbalanced voltage profile. As shown in Figure 3.13, the loads as well as DGs can be either three-phase or single-phase. Interconnection of single phase sources will increase the system unbalance.

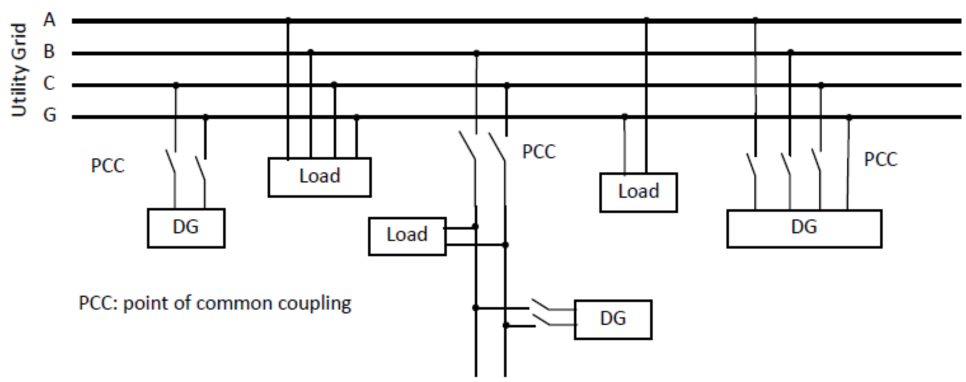

Figure 3.13: Possible DG interconnection configurations (Rajapakse *et al*., 2009)

On the other hand, inherently unbalanced distribution systems can pose problems for the three-phase DGs connected to it: the resulting unbalance currents in the DG can cause overheating and frequent shutdowns.

3.3.2.5 Protection Issues

The main objectives of a protection system are to detect and respond to all possible types of fault conditions that could occur, while affecting the minimum number of customers, and not limiting the capability of the system to carry load current (Comech *et al*., 2010). According to them since attempting to accomplish some of these objectives makes it impossible to accomplish others, compromises need to be made. The limits of these compromises are the criteria used to determine locations for the fault-interrupting devices, and the sensitivity and operating speed of the fault detecting devices.

Traditionally, power-system protection has been designed assuming that central generation feeds the distribution network and thus fault current always flows from the higher to the lower voltage levels (Jenkins *et al*., 2010). However, with the introduction of distributed generation, both central and distributed generators feed current into a fault. Their assertion is that this multi-directional flow of fault currents requires the rechecking of existing protection coordination and reach. Coster *et al*. (2010) strongly believe that connection of DG not only alters the load flow in the distribution grid but can also alter the fault current during a grid disturbance. According to them the rate of change of the fault currents strongly depends on the ability of the DG to contribute to the fault current.

Distributed generation impacts the protection of distribution networks in a number of ways (Bollen and Hassan, 2011). Some impacts are due to an increase in fault current because of the generator and other impacts occur because the fault current contribution from a generator is too small. They posit that the impact of distributed generation on protection strongly depends on the fault current contribution and thus on both the size and type of the interface. For instance, synchronous generators deliver a continuous short-circuit current because a synchronous generator typically would inject 4 to 8 times its rated output current for 5 to 7 cycles during a fault (EPRI, 2000). This drops off to roughly 2 to 5 times the rated current after 60 to 120 cycles into the event. It notes that these decaying fault levels are due to transition from the machines sub-transient to transient reactance.

According to Bollen and Hassan (2011) induction generators contribute during one or two cycles in case of a three-phase fault and longer in case of a non-symmetrical fault. This is due to the fact that this type of generator gets its excitation from the mains, it is not able to maintain the short-circuit currents for a relatively long time (Targarona and Morcos, 2007). But units with power electronics interface have none or a very limited contribution to the fault current. Inverter-based DR may supply twice rated current for a brief period (Walling *et al*., 2008). Furthermore, Bollen and Hassan (2011) have noted that one of the widely discussed consequences of distributed generation impacts on the protection of distribution networks is the risk of non-controlled island operation. This is because a fault on the distribution system may result in a distributed generator being disconnected together with some loads, thus creating a power island (Jenkins *et al*., 2010). As the fault current from a distributed generator can be very low, a subsequent fault on the islanded system may not be detected. In addition, depending on the design of the network, the connection of the system neutral to earth (ground) may be lost during islanding. Both conditions are undesirable. Additionally the creation of power islands leads to difficulties with the use of auto-reclose on distribution networks as well as posing safety issues for maintenance staff. Therefore, according to them, the protection philosophy of a distributed generator should determine when it should stay connected, supporting the main power system, and when it should be tripped off to ensure safety.

Consequently Comech *et al*. (2010) submit that the connection of DG in distribution networks must take into account the following subjects:

- Protection behaviour (coordination problems)
- Adequate ratings of power equipments
- Islanding
- Detection problems
- Operation procedures

These problems strongly depend on the applied protective system and consequently on the type of distribution grid.

However, according to Coster *et al*. (2011) the main protection problems posed by the integration of distributed generation to the distribution grid are:

- prohibition of automatic reclosing;
- unsynchronized reclosing;
- fuse-recloser coordination;
- islanding problems;
- blinding of protection;
- false tripping.

The application of DR on the electric power system will have an influence on the operation of various overcurrent-protective devices (EPRI, 2000). According to it some common typical impacts from integration of DR include:

- Nuisance fuse blowing, particularly related to fuse-saving schemes affected by the added current supplied by the DR.
- False tripping operations by upstream breakers, reclosers, sectionalizers, or fuses due to downstream DR generation.
- Failure of sectionalizers to operate when they should because the DR keeps a line energized.
- Desensitization of breakers and reclosers due to unplanned DR currents.

3.3.2.5a Fault Current Contribution from a Synchronous Generator

As stated earlier and according to Bollen and Hassan (2011) the impact of distributed generation on protection strongly depends on the fault current contribution and thus on both the size and type of the interface. However, in distribution networks with DG, the requirement of not exceeding the design short-circuit capacity should be satisfied at every point of the network, under maximum fault current conditions (Boutsika and Papathanassiou, 2008). In typical radial networks, fed by a HV/MV (or MV/LV) substation, this condition normally needs to be checked at the MV (or LV) busbars of the substation, because the upstream grid provides the dominant contribution, which rapidly diminishes downstream the network due to the series impedance of the lines. The contribution of individual DG sources, on the other hand, reduces to a much smaller degree at remote network nodes, because their internal impedance is relatively high compared to the impedance of the network lines. Therefore, short-circuit current calculations normally need to be performed at the secondary busbars of the substation, regardless of the adopted DG interconnection scheme (connection to an existing feeder or directly to the busbars via a dedicated line). According to them, the resulting fault level is the phasor sum of the maximum fault currents from the upstream grid, through the step-down transformer, and the various generators (and possibly motors) connected to the distribution network. The grid contribution is easily calculated according to IEC 60909. The contribution of many novel DG source types, on the other hand, is not addressed in the Standard and several assumptions need to be made.

Consequently, the fault current contribution from a synchronous machine can be calculated as follows (Eskom, 2008). According to Ohm's Law (with the voltage taken at 110%), the fault contribution from the generator, I_{kG}, can be calculated using:

$$I_{kG} = \frac{c \times V_{Gen}}{\sqrt{3} \times Z_{Gen}}$$

(Equation 3.5)

Normal generator capability:

$$S_{Gen} = \sqrt{3} V_{Gen} I_{Gen}$$

(Equation 3.6)

Also

$$S_{base} = \frac{V^2{}_{base}}{Z_{base}}$$

(Equation 3.7)

Therefore

$$Z_{Gen} = \left|(R_g + jX_d^{"})\right| \times Z_{base} = \left|(R_g + jX_d^{"})\right| \times \frac{V^2{}_{Gen}}{S_{Gen}}$$

(Equation 3.8)

The fault contribution from a synchronous machine (generator and/or motor) depends on the size, output voltage and impedance of the generator (and the step-up generator transformer if applicable). Therefore, the fault contribution from the synchronous generator, at the generator terminals, can be expressed as:

$$I_{kG} = \frac{c \times V_{Gen}}{\sqrt{3}} \times \frac{S_{Gen}}{\left|(R_g + jX_d^{"})\right| \times V^2{}_{Gen}}$$

$$= \frac{c \times S_{Gen}}{\sqrt{3} \times \left|(R_g + jX_d^{"})\right| \times V_{Gen}}$$

(Equation 3.9)

Where:

I_{kG} = Fault contribution from the generator (kA)

c = Voltage factor. For all distribution networks above 1 kV, the voltage factor is 1.1 (IEC60909)

S_{Gen} = MVA rating of generator

X_d'' = Sub-transient reactance of generator (p.u.)

R_g = Generator stator resistance (p.u.)

V_{Gen} = Output voltage of the generator (kV)

It should be noted that Equation 3.9 calculates the fault level contribution of the generator at the generator terminals. However, the fault level contribution at a particular point in the network is also dependent on the impedance of the network between that point and the generator. Therefore, detailed fault level studies including models of both the customer and utility network are required to calculate fault levels at particular points in the network. The typical fault current rating of isolators on 11 kV and 22 kV feeders are about 7.5 kA (Eskom, 2008). So in MV distribution networks a fault contribution of less than 6 kA at 11kV or 22kV should not be problematic though further investigation is required.

The establishment of DG penetration limits based on fault levels and source impedance angles has been considered by van Zyl and Gaunt (2005b). Their conclusion is that an approximate expression for the DG penetration limit at a given network location can be derived from the three phase fault level at that point and an assumed lowest source impedance angle that will be encountered. From Equation 3.3, the maximum penetration of DG, operating at unity power factor that can be accepted at a point on an un-loaded radial distribution network can be calculated using the formula (van Zyl and Gaunt, 2005a):

$$P_{DG} = \left[\frac{V_{Max}\left(V_{Max} - V_{Setpoint}\right)}{R}\right]$$

(Equation 3.10)

Where all quantities are expressed in per-unit, and:

V_{Max} = the upper voltage regulation limit on the network,

$V_{Setpoint}$ = the On-Load Tap Change setpoint voltage at the upstream substation, and

R = the branch resistance from the DG busbar to the upstream voltage-controlled busbar.

According to van Zyl and Gaunt (2005b), the source resistance, R_{Source}, seen from the DG busbar can be expressed in terms of the per-unit three-phase fault level, S_{Fault} and source impedance angle, φ, at the DG busbar as follows:

$$R_{Source(pu)} = \frac{\cos \varphi}{S_{Fault(pu)}}$$

(Equation 3.11)

Equation 3.11 can be substituted into Equation 3.10 to yield an approximate formula for the DG penetration limit:

$$P_{DG} \approx \left(\frac{k}{\cos \varphi}\right) \times S_{Fault(pu)}$$

(Equation 3.12)

Where:

k = a constant: $V_{Max}(V_{Max} - V_{Setpoint})$

As is common in South Africa, for networks with a 1.03pu voltage setpoint, and a maximum allowable busbar voltage of 1.05pu, k = 0.021. A similar k-factor will apply to networks elsewhere where a 2% voltage rise is permitted.

The authors have noted that the DG penetration limit expressed in Equation 3.12 is more pessimistic than that from Equation 3.10 since the former includes the resistance from the DG busbar back to the infinite source (including HV networks and HV/MV transformers). Also in practice, the resistances of upstream HV networks are negligible when compared to that of even moderately long MV distribution lines.

Therefore, Equation 3.12 can be used to understand the stipulation in some countries that the DG penetration must not exceed one twenty-fifth of the three-phase fault level at that location. In Equation 3.12, this amounts to assuming a fault level angle of 58^{o} with k = 0.021. The more lenient stipulation in Spain, that DG penetration can be as high as 10% of the fault level, is equivalent to assuming a fault level angle of 78^{o}. Given a 1.03pu voltage setpoint, maximum allowable busbar voltage of 1.05pu, and k = 0.021 the source impedance angles in the characteristically weak distribution networks in South Africa could be averaged at 55^{o}. This suggests that, when expressed using Equation 3.12, DG penetration on MV networks in

South Africa should be limited to one twenty-seventh of the fault level at the point of connection.

To analyse the effect of a synchronous generator DG on the fault current in a distribution feeder, a generic feeder is taken as a reference as shown in Figure 3.14 based on Coster *et al*. (2010). At distance *d* a DG-unit is connected and at the end of the feeder a three-phase fault is present. According to Bollen and Hassan (2011) it should be noted that the reason for discussing three-phase faults first is not because these faults are most common or most severe. But the calculations for three-phase faults are easier and, therefore, more suitable to illustrate the calculation methods.

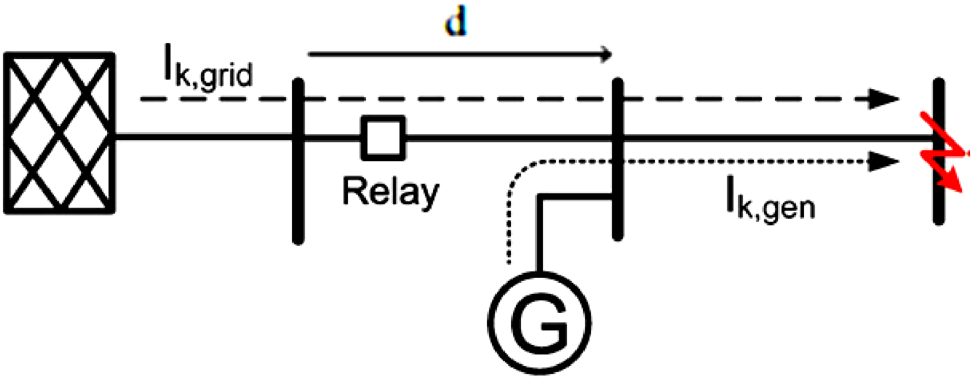

Figure 3.14: Short-circuit current contribution of both grid and DG-unit (Coster *et al*., 2010)

For the analysis it is convenient to use a distance parameter to indicate the location of the DG which is relative to the total feeder length. This parameter is defined as:

$$l = \frac{d}{d_{tot}}$$

(Equation 3.13)

Where:

d = distance to the DG-unit and

d_{tot} = total feeder length.

An electric equivalent of the feeder shown in Figure 3.14 is given in Figure 3.15.

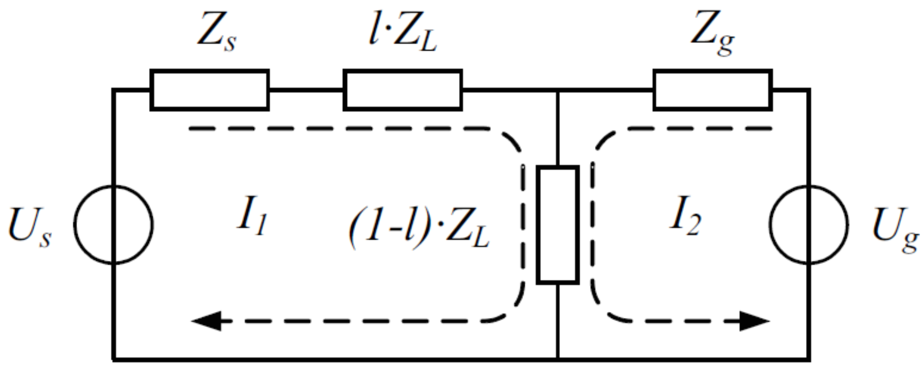

Figure 3.15: Network equivalent of Figure 3.14 (Coster *et al.*, 2010)

Where:

Z_L = total line impedance,

Z_g = generator-impedance and

Z_s = source-impedance

U_s = grid voltage

U_g = generator voltage

I_1 = grid contribution $I_{k,grid}$ to the total fault current

I_2 = DG-contribution, $I_{k,gen}$ to the total fault current

Defining the mesh currents I_1 and I_2 and applying the Kirchhoff Voltage Law (KVL) for U_s and U_g can be found:

$$\begin{bmatrix} U_s \\ U_g \end{bmatrix} = \begin{bmatrix} Z_s + Z_L & (1-l).Z_L \\ (1-l).Z_L & Z_g + (1-l).Z_L \end{bmatrix} \cdot \begin{bmatrix} I_1 \\ I_2 \end{bmatrix}$$

(Equation 3.14)

An analytical expression for I_1 and I_2 can be found by solving Equation 3.14. Because of the strong relation with the IEC60909 fault-analysis method, Thevenin's Theorem is applied on the network of Figure 3.14 to find an analytical expression for $I_{k,grid}$ and $I_{k,gen}$. In Figure 3.16 the Thevenin equivalent of the network of Figure 3.15 is shown.

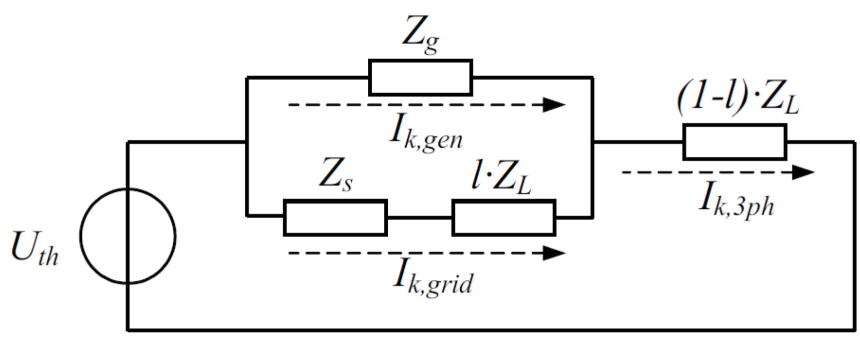

Figure 3.16: Thevenin equivalent of Figure 3.15 (Coster *et al.*, 2010)

For this figure the Thevenin impedance is:

$$Z_{th} = \frac{(Z_s + l.Z_L).Z_g}{Z_s + l.Z_L + Z_g} + (1 - l).Z_L$$

(Equation 3.15)

Where:

$Z_s = jX_s$ is the grid impedance,

$Z_g = jX_g$ is the generator impedance and

$Z_L = R_L + jX_L$ is the total line or cable impedance.

l = relative generator location as defined in Equation 3.13.

The total three-phase short-circuit current can be calculated by:

$$I_{k,3ph} = \frac{U_{th}}{\sqrt{3}.Z_{th}}$$

(Equation 3.16)

Combining Equation 3.15 and Equation 3.16 yields:

$$I_{k,3ph} = \frac{U_{th}.\left(Z_s + l.Z_L + Z_g\right)}{\sqrt{3}\left[Z_L.Z_g + Z_s.Z_g + Z_s.Z_L + l.Z_L(Z_L - Z_s) - l^2 {Z_L}^2\right]}$$

(Equation 3.17)

For the grid contribution holds:

$$I_{k,grid} = \frac{Z_g}{\left(Z_s + l.Z_L + Z_g\right)}.I_{k,3ph}$$

(Equation 3.18)

Substituting Equation 3.17 in Equation 3.18 gives for the grid contribution:

$$I_{k,grid} = \frac{U_{th}.Z_g}{\sqrt{3}\left[Z_L.Z_g + Z_s.Z_g + Z_s.Z_L + l.Z_L(Z_L - Z_s) - l^2 {Z_L}^2\right]}$$

(Equation 3.19)

The total short-circuit current, $I_{k,3ph}$, is determined by Equation 3.17 which is a non-linear equation, so $I_{k,grid}$ is non linear as well. In case of a weak grid, Z_s can be as large as Z_g and due to the contribution of the generator, the grid contribution to the short-circuit current decreases. Equation 3.19 describes the grid contribution to the fault current in a distribution feeder including a synchronous generator. This equation shows that the grid contribution will be determined by the total feeder impedance, the local short-circuit power at the substation, the generator size and location.

3.3.2.5b Point of Maximum Impact of Fault Current Contribution from a Synchronous Generator

Coster *et al*. (2010) have also considered the point of maximum impact of synchronous DG's short-circuit current contribution. The maximum DG impact on the grid contribution to the short-circuit current occurs when the grid contribution is the minimum. Hence the minimum of Equation 3.19 has to be determined. This is done by taking the derivative of Equation 3.19 which leads to:

$$\frac{dI_{k,grid}}{dl} =$$

$$\frac{jX_g\left(R_L{}^2 - X_L(X_L - X_s) - 2l\left(R_L{}^2 - X_L{}^2\right) + j\left(R_L(2X_L - X_s)\right)\right)}{-X_g(X_L + X_sR_L) - l^2\left(R_L{}^2 - X_L{}^2\right) + j\left(X_g\left(R_L - X_s\left(X_g - X_L\right)\right) + lR_L(2X_L - X_s) + 2l^2R_LX_L\right)^2}$$

(Equation 3.20)

The minimum of $I_{k,grid}$ can be found with:

$$\frac{dI_{k,grid}}{dl} = 0$$

(Equation 3.21)

Which yields for *l*:

$$l = \frac{1}{2}.\frac{R_L{}^2 - X_L(X_L - X_s) + jR_L(2X_L - X_s)}{\left(R_L{}^2 - X_L{}^2\right) - 2jX_LR_L}$$

(Equation 3.22)

With Equation 3.22 the location of maximum generator impact can be calculated which can be helpful at the planning stage.

An important impact of DG short circuit current contribution on distribution protection system is the blinding phenomenon.

3.3.2.5c Blinding of Protection

This is also called protection underreach (Coster *et al*., 2011; Kauhaniemi and Kumpulainen, 2004) and fail-to-trip (Bollen and Hassan, 2011). Figure 3.17 is an illustration of the concept of “reach” in a utility protective relaying system and how it is affected by DG interconnection. Utility breakers and reclosers are set to “see” a certain distance down the radial feeder and this is sometimes referred to as the “reach” of the device (Dugan and McDermott, 2002). The reach is determined by the minimum fault current that the device will detect.

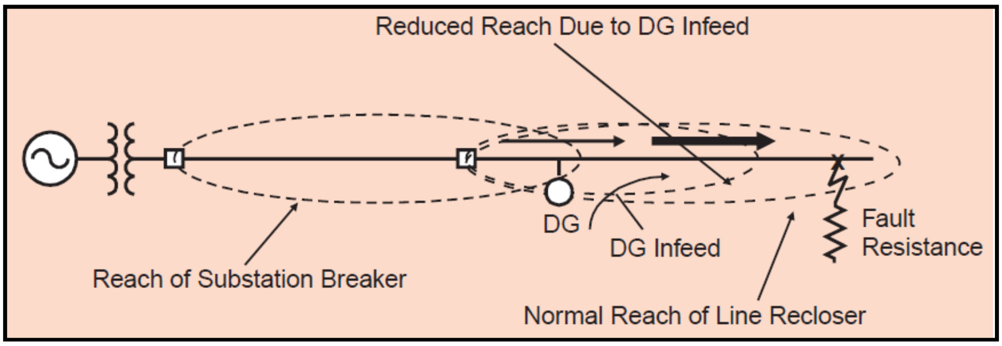

Figure 3.17: The generator infeed reduces the reach of utility relaying (Dugan and McDermott, 2002)

At peak loading, when the DG is likely to be interconnected, the relaying is actually fairly sensitive – the reach is large – and does not take much additional current to trip the breaker. However, the DG infeed, as shown, can cut sharply into that reach. That is, there is a significantly increased risk that faults with high resistance will go undetected until they burn into larger faults. The obvious result is that there will be more damage to the utility physical plant than without the DG. There is also more risk of sustained interruption to customers. Therefore, while there is the perception that DG will bring more reliability to the system, that is generally true only for the entity that owns the generator, assuming it can be operated as backup generation as well as cogeneration. For the example shown, the net effect on the utility distribution system reliability is probably slightly negative.

According to Mäki (2007) protection blinding phenomenon is a sensitivity problem. Sensitivity problems are possible in cases in which the initial feeder relay settings are not checked as DG is installed in the network. Sensitivity problem means that a fault is not detected at all or is tripped slower than in the initial scheme. It is obvious that this may result in severe safety problems. Additionally, relay operation delays may result in exceeding the thermal limits of network components. It is essential to note, that the overall short-circuit currents will increase due to the DG integration, which makes the operation delays more crucial. Also blinding takes place in all short-circuit situations in which DG is present.

However, the significance of the phenomenon is strongly dependent on the network, generator type, and the fault location.

A very simplified situation for consideration is shown in Figure 3.18 to illustrate blinding phenomenon based on Mäki *et al*. (2005) and Mäki (2007). To simplify the presentation of blinding a point called "common feed point" has been defined in the figure. According to them, a common feed point (CFP) is here defined as the point closest to the fault, which is yet fed in parallel by the DG unit and the feeding network. Therefore, CFP is not a fixed point rather it can be found in various locations for different fault situations. For faults on the same branch, the CFP is, however, common. In some cases the fault can be located directly in the CFP, meaning the Z_{fault_b} will be equal to zero. Common feed point is important because the intensity of blinding is dictated by the ratio of impedances between the CFP and other parts of the network.

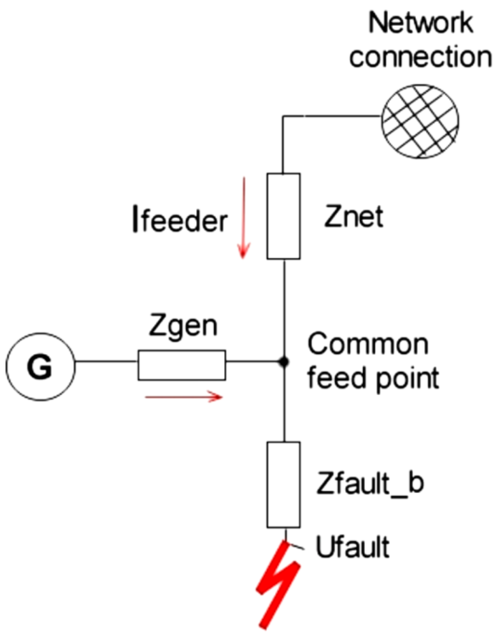

Figure 3.18: Simple network presenting the network impedances during a fault in the presence of DG (Mäki *et al*., 2005)

Reasoning for blinding can be found using normal fault current calculation applying thevenin's impedances. Firstly, if the DG unit is ignored, the fault current I_{feeder} for a symmetrical short-circuit fault can be calculated as follows:

$$I_{feeder} = \frac{U_{fault}}{Z_{net} + Z_{fault\_b}}$$

(Equation 3.23)

Where:

U_{fault} = the pre-fault voltage of the fault point.

Znet = impedance of the grid and primary transformer

Z_{fault_b} = total branch impedance between the common feed point and the fault including also the fault impedance.

With the DG unit connected to the network as shown in Figure 3.23 and assuming the impedance of the DG unit connection line and the unit itself is Z_{gen} then the thevenin impedance for the parallel connection of feeding network and the DG unit can be calculated simply as follows:

$$Z_{th} = Z_{fault\_b} + \left(\frac{Z_{gen}Z_{net}}{Z_{gen} + Z_{net}}\right)$$

(Equation 3.24)

Further, calculating the total fault current with reduced parallel impedance and dividing the fault current for feeder branch gives:

$$I_{feeder} = \left(\frac{Z_{gen}}{Z_{gen} + Z_{net}}\right)\left(\frac{U_{fault}}{Z_{th}}\right)$$

(Equation 3.25)

Substituting for Z_{th} in Equation 3.25 gives,

$$I_{feeder} = \left(\frac{Z_{gen}}{Z_{gen} + Z_{net}}\right)\left(\frac{U_{fault}}{Z_{fault\_b} + \frac{Z_{gen}Z_{net}}{Z_{gen} + Z_{net}}}\right)$$

(Equation 3.26)

$$I_{feeder} = \left(\frac{Z_{gen}}{Z_{fault\_b}\left(Z_{gen} + Z_{net}\right) + Z_{gen}Z_{net}}\right)U_{fault}$$

(Equation 3.27)

which can be further simplified to:

$$I_{feeder} = \left(\frac{1}{Z_{fault\_b} + \frac{Z_{fault\_b}Z_{net}}{Z_{gen}} + Z_{net}}\right)U_{fault}$$

(Equation 3.28)

Equation 3.28 shows that with faulted branch impedance equal to zero, the current measured at the relay will remain the same as without the DG unit installed. It is important to notice that the faulted branch impedance Z_{fault_b} here includes also the branch between the common feed point and the fault. Thereby Z_{fault_b} equal or near to zero would be possible mostly on main line between the DG unit and the substation with a theoretical fault with no impedance. Thus blinding practically always occurs during the fault to some extent, but the intensity of the phenomenon is dictated by the location of fault, in other words the impedance Z_{fault_b} and its relation to the other impedances.

Similarly, it's easy to see that a situation with DG unit temporarily disconnected also results in the initial form of Equation 3.23. This can be seen as the open breaker at the DG connection point can be presented as infinite Z_{gen}. Thus the disconnected DG unit has no effect on protection, which is evident.

Assuming Z_{fault_b} as well as Z_{gen} greater than zero and Z_{gen} remaining in finite limits it could easily be shown that:

$$\frac{U_{fault}}{Z_{fault\_b} + \frac{Z_{fault\_b} Z_{net}}{Z_{gen}} + Z_{net}} < \frac{U_{fault}}{Z_{net} + Z_{fault\_b}}$$

(Equation 3.29)

Which in other words means:

$$I_{feeder,with\_DG} < I_{feeder,without\_DG}$$

(Equation 3.30)

Equation 3.30 is basically the criterion for the phenomenon called protection blinding. It should be noted that the pre-fault voltage U_{fault} may also be increased due to the DG unit depending on unit's voltage control system. However, the effect of short-circuit impedances is usually greater and the current measured by the relay therefore decreases. If the resultant fault impedance between the DG source and fault point is considerably higher than the fault impedance between the source and the substation, then under strong DG source the faults occurring beyond the source may not be switched off by protective relays of the connecting line (Rojewski *et al.*, 2009). But after switching the DG source the correct operating conditions of protective relays of the connecting line are brought back.

According to Kauhaniemi and Kumpulainen (2004) for the ratio between the feeder relay current ($I_{feeder,with\_DG}$) I_1 in the situation shown in Figure 3.18 and the current ($I_{feeder,without\_DG}$) I_k the following formula can be derived:

$$\frac{I_1}{I_k} = \frac{Z_{gen}\left(Z_{net} + Z_{fault\_b}\right)}{Z_{net}\left(Z_{fault\_b} + Z_{gen}\right) + Z_{fault\_b}Z_{gen}}$$

(Equation 3.31)

The short-circuit impedance of the generator can he expressed using the short-circuit impedance of the feeding network as $Z_{gen} = aZ_{net}$. Analogueically the impedance of the line (to the fault location) can he expressed as $Z_{fault\_b} = bZ_{net}$. Therefore, Equation 3.31 can be re-written as

$$\frac{I_1}{I_k} = \frac{aZ_{net}(Z_{net} + bZ_{net})}{Z_{net}(bZ_{net} + aZ_{net}) + aZ_{net}bZ_{net}}$$

(Equation 3.32)

The ratio of the currents with and without generator can then be simplified:

$$\frac{I_1}{I_k} = \frac{a + ab}{a + b + ab}$$

(Equation 3.33)

Equation 3.33 presents the impact of the coefficients *a* and *b* on the ratio I_1/I_k. The authors have noted that in all practical cases the impact is such that the ratio is less than one, which means that the contribution from the generator reduces the current seen by the feeder relay. So their conclusion is that the impact of the production unit increases with the size of the unit (larger unit implies lower coefficient *a*) and with the length of the line section between the production unit and the fault (larger coefficient *b*).

It can be analytically shown that although integration of generating units increases the total short circuit duty at any point of the system, it tends to decrease contributions from each of the sources (Vaziri *et al.*, 2010). This decrease in contribution from any source is known as "Relay Desensitization". For this reason, fault contributions at the end of the protective zones for each protective device between the utility and the DR must be checked to ensure that End of Line (EOL) Protection from each source is maintained. If any protective device is desensitized such that it no longer protects, its zone ends, then additional protective equipment is required.

From Equations 3.23 and 3.28 it can be seen that the network reinforcements to decrease the impedances Z_{net} and Z_{fault_b} naturally result in higher fault currents at the relay regardless of the state of DG unit (Mäki *et al*., 2005). Therefore, the blinding problem could be avoided by applying reinforcements between the substation and the CFP, or similarly between the CFP and the worst-case fault location. However, reinforcement of the branch that connects the DG unit to the CFP results in a more severe blinding problem. This is also evident, as the contribution of DG unit increases due to the stronger connection to the CFP. Unfortunately other aspects such as voltage or power flow often require reinforcing the network particularly in the vicinity of the DG unit. Worthy of note is that trying to solve blinding of protection may introduce false tripping (Coster *et al*., 2011).

3.3.2.5d Fault Ratio Factor

The subtraction of Equation 3.28 from Equation 3.23 produces the DG short circuit contribution as follows:

$$I_{DG} = \left(\frac{U_{fault}}{Z_{net} + Z_{fault\_b}}\right) - \left(\frac{U_{fault}}{Z_{fault\_b} + \frac{Z_{fault\_b}Z_{net}}{Z_{gen}} + Z_{net}}\right)$$

(Equation 3.34)

$$I_{DG} = \frac{Z_{net}Z_{fault\_b}U_{fault}}{(Z_{net} + Z_{fault\_b})(Z_{fault\_b}Z_{gen} + Z_{fault\_b}Z_{net} + Z_{gen}Z_{net})}$$

(Equation 3.35)

The ratio of Equation 3.23 ($I_{feeder,without\_DG}$) to Equation 3.35 (I_{DG}) is given in Equation 3.36

$$\frac{I_k}{I_{DG}} = \frac{Z_{fault\_b}Z_{gen} + Z_{fault\_b}Z_{net} + Z_{gen}Z_{net}}{Z_{fault\_b}Z_{net}}$$

(Equation 3.36)

Where, $I_k = I_{feeder,without\_DG}$ = available utility fault current

Equation 3.36 is the Fault Ratio Factor (also called Short Circuit Contribution Ratio: SCCR) which is simply available utility fault current divided by DG fault contribution in the affected area (Barker, 2012). In other words, Short Circuit Current Ratio (SCCR) is the ratio of the short circuit current contribution of the Generating Facility to the short circuit current contribution of the Distribution System at the PCC (Vaziri *et al*., 2010). Barker (2012) has noted that it is among some of the useful penetration ratios for screening analysis of DGs. It is useful for overcurrent device coordination and overcurrent device ratings. According to him its suggested penetration level values are >100 for very low penetration, 100 – 20 moderate penetration, and less than 20 for higher penetration. Other example ratios (or definitions) used to describe penetration levels for engineering analysis often includes the following (Barker, 2012; Coddington *et al*., 2010):

- Minimum Load to Generation Ratio – this is the annual minimum load on the relevant power system section divided by the aggregate DG capacity on the power system section
- Stiffness Factor – the available utility fault current divided by DG rated output current in the affected area
- Ground Source Impedance Ratio – ratio of zero sequence impedance of DG ground source relative to utility ground source impedance at point of connection

Barker (2012) notes that these ratios are based on the aggregate DG sources on the system area of interest where appropriate. Also these ratios are often used along with a host of other criteria as trigger points, to establish when detailed studies are necessary to evaluate the impact of DG systems on the utility grid (Coddington *et al*., 2010).

In terms of system protection and reliability short circuit current contribution requirements are meant to show that the generating facility has a small enough impact such that it is unnecessary to perform a short circuit contribution analysis (Vaziri *et al*., 2010). According to them, at high voltage side of the dedicated (or the interconnection) distribution transformer, the sum of the Short Circuit Contribution Ratios (SCCR) of all generating facilities on the distribution system circuit may not exceed 0.1. This is a cumulative criterion on a first come-first serve basis. Once the cumulative SCCR of 0.1 has been surpassed, additional fault detecting schemes must be added at PCC. The schemes are to enable the new interconnecting facility detect and clear faults occurring on the area EPS system. Furthermore they submit that for customers that are metered at the low voltage (secondary) levels of a shared distribution transformer, the short circuit contribution of the proposed generating facility must be less than or equal to 2.5% of the interrupting rating of the utilities service equipment.

3.3.2.5e Sympathetic Tripping

This is also known as false-tripping (Bollen and Hassan, 2011; Coster *et al*., 2011) and mal-tripping (Bollen and Hassan, 2011). DG-related selectivity issues include two typical problems; the possibility of unnecessarily disconnecting the DG feeder (also called *sympathetic tripping*) and the possibility of nuisance tripping of DG units (Mäki, 2007). He asserts that neither of these events causes an actual safety hazard, but they are of great harm to both producer and network operator. However, in both cases, IPP suffers a certain amount of energy not produced due to the missing network connection. In the case of sympathetic tripping, the customers of the whole feeder experience a totally unnecessary interruption, which results in reduced reliability from the DNO's point of view. Also the nuisance tripping of DG results in voltage variations and reduced quality of power supply. False tripping (also known as sympathetic tripping) may occur when a DG unit contributes to the fault in an adjacent feeder connected to the same substation (Coster *et al*., 2011). This means that the DG contributes to the fault by feeding a short-circuit current upwards towards the substation and further towards the fault (Mäki, 2007). According to them the generator contribution to the fault current can exceed the pickup level of the overcurrent protection in the DG feeder – if the feeder relay does not detect the direction of current – causing a possible trip of the healthy feeder (nuisance tripping) before the actual fault is cleared in the disturbed feeder. A typical situation during which sympathetic tripping is possible is shown in Figure 3.19.

The DG unit provides a major contribution to the fault current when the DG unit and/or the fault are located near the substation (Coster *et al*., 2011). They have noted that false tripping can easily occur especially in weak grids with long feeders protected by definite-time overcurrent relays. In this case, the settings of the protection relays have to ensure that faults at the end of the feeder are also detected which leads to a relatively low pickup current.

Directional overcurrent relay offers a straightforward solution for this problem (Mäki, 2007) but unfortunately the existing equipment is usually of a non-directional type. Therefore, allocating the costs of equipment replacements may be problematic and may constrain the economical viability of DG. In his view it must be noted that relay upgrading can also offer other benefits apart from the DG-related ones, for instance faster feeder protection.

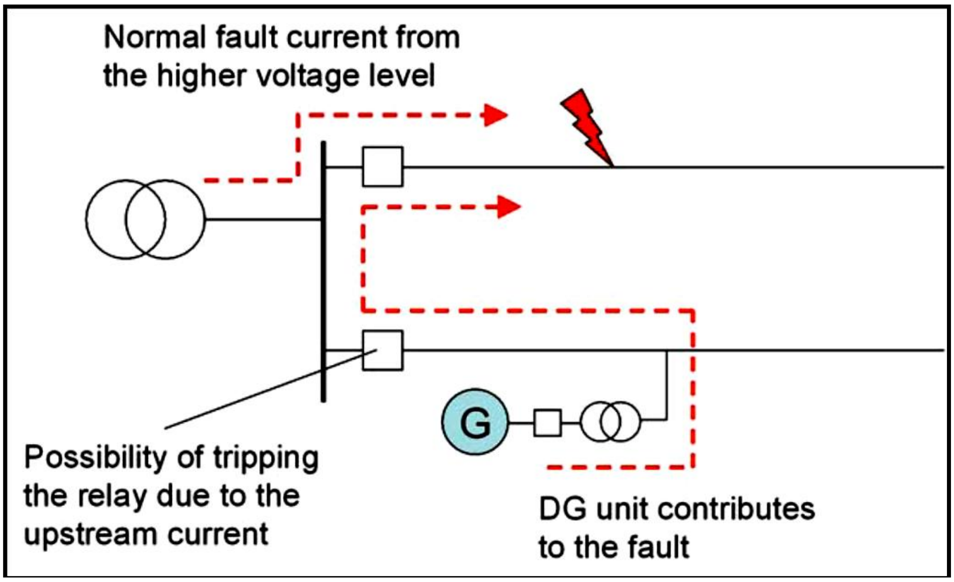

Figure 3.19: Upstream contribution of DG and the possibility of tripping nondirectional relay (Mäki, 2007)

Also sympathetic tripping can be avoided by coordinating the operation times of feeder relays. If the faulted adjacent feeder is tripped faster than the DG feeder, the sympathetic tripping should not occur. Presently a quite common practice is to apply same overcurrent protection characteristics on similar adjacent feeders and this could enable the possibility of sympathetic tripping. However, it is not always possible to modify the relay operation times in order to avoid sympathetic tripping as other factors may constrain this possibility.

Furthermore, Mäki (2007) has highlighted that nuisance tripping of DG unit can occur under similar circumstances as sympathetic tripping. Faults can be located on adjacent feeder, on higher voltage level or at the substation. Due to the protection operation times for these fault locations, short-circuit on an adjacent feeder is most likely to cause problems. For instance the deviation of voltage or frequency at the PCC may be great enough to trip the DG unit. Consequently, the DG protection settings should be assessed for the worst-case faults outside the DG feeder. These faults can be found near the substation but also in areas where the operation of feeder relay with specified-time operation characteristics shifts from one operation mode to another. Sensitivity problems such as blinding of protection may be in conflict with the nuisance tripping problems as they may require opposed protection setting modifications.

It should be noted that blinding of protection and false tripping are independent of the type of feeder (Coster *et al*., 2011).

3.3.2.5f Fuse-Recloser Coordination

A special case of protection coordination occurs when autoreclosing is used together with a practice called "fuse saving." The fuse is chosen such that it will not be impacted by the fault current under the fast stage of the recloser (Bollen and Hassan, 2011). One of the first things utility engineers expect to be sacrificed as the amount of DR on a distribution feeder increases is the ability to save fuses for temporary faults (Walling *et al*., 2008). This is a difficult task without the extra infeed from DR. DR contributes additional current to the fuse and slightly reduces the current seen by the breaker. This tightens the already slim timing margin available in this process. An automatic recloser is a protection device typically applied in distribution grids consisting of overhead lines (Coster *et al*., 2011). Fuse-recloser coordination is used for overhead medium-voltage feeders in remote areas and the recloser is equipped with an overcurrent relay, which opens the recloser with minimum delay (Bollen and Hassan, 2011). According to them, any delay needed would be to accommodate for load starting, transformer energizing, and so on. The delay time on the initial reclose attempt can be very short, nominally 0.5 s but can be on the order of 0.2 s open-close cycle time, if an "instantaneous" setting is used (Dugan and McDermott, 2002; Walling et al., 2008).

Most faults on these lines only last a short period of time, therefore it is not necessary to switch the line off permanently. Temporary faults constitute 70% to 80% of faults occurring in distribution system (Girgis and Brahma, 2001). The automatic recloser switches off the line for a short period of time to allow the arc to extinguish. Because about 80% of faults on overhead distribution lines are of a transient nature, so a simple reclosing action is sufficient to remove the fault (Bollen and Hassan, 2011). For instance a falling branch of a tree causes a momentary short-circuit fault which may be cleared during the automatic reclosing sequence. After a brief time delay the line is energized again by the automatic recloser. When the fault is removed the line can stay in service otherwise the automatic recloser switches off the line again. In case of a permanent fault the line is switched off permanently after three or four unsuccessful reclosing actions.

Automatic reclosing in overhead medium voltage networks has been a very powerful means to enhance the quality of supply. Majority of faults can be cleared by automatic reclosing, which is not just prevalent both in European and American networks (Kumpulainen and Kauhaniemi, 2004) because overhead line feeders are widely used in the world (Coster *et al*., 2011).

Figure 3.20 is an illustration of the fuse-recloser concept. The figure shows a distribution line where the main feeder is protected by a recloser and the load feeder is protected by a fuse. In this configuration the recloser has to act against temporary faults and the fuse against permanent ones.

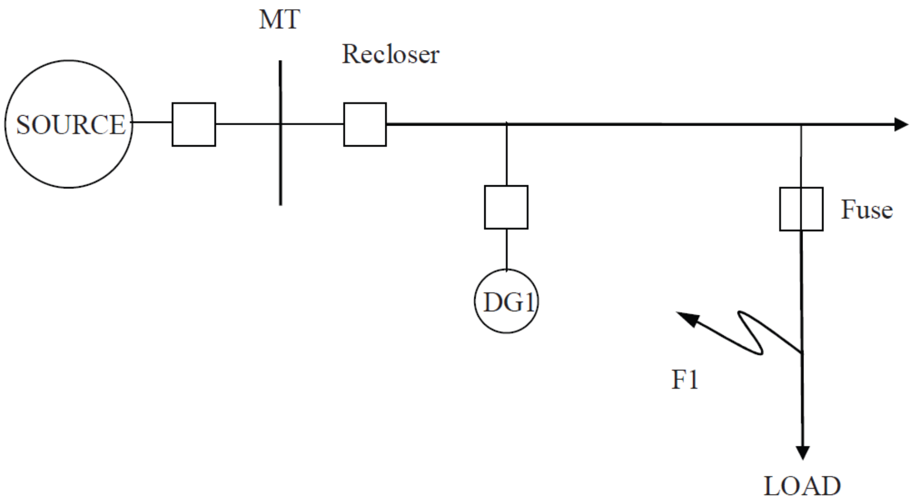

Figure 3.20: Fuse saving scheme (Comech *et al*., 2010)

For the analysis of this configuration, a recloser actuation sequence Fast-Fast-Slow-Slow is supposed (Comech *et al*., 2010). According to this sequence, if faults occur in the load feeder, the recloser acts opening the feeder breaker according to its fast overcurrent curve. The feeder breaker stays in this state for a defined time until the recloser orders to close it, allowing temporary faults to be cleared. If the fault persists, the recloser acts again. If after the second fast actuation of the recloser the fault is not cleared, the fault is assumed to be permanent. Therefore, after the second fast actuation of the recloser, it changes its overcurrent curve to the slow one, so that the fuse acts faster than the recloser. For the correct performance of the described scheme, the recloser and the fuse must be coordinated, as it is shown in Figure 3.21. In the figure the fuse characteristics are depicted as MM (Minimum Melting) and TC (Total Clearing). The Minimum Melting characteristic gives the time in which fuse is melted for a given value of fault current and Total Clearing characteristic gives the fault clearing time of fuse considering fault arc extinction for a given value of fault current (Girgis and Brahma, 2001). Also, the two vertical lines indicate the maximum and the minimum fault current for a fault downstream of the fuse. It is for this range of currents that the curves should be coordinated (Bollen and Hassan, 2011; Comech *et al*., 2010). This means that the system will be coordinated if the fault current for a fault in the load feeder is inside the limits (Ifmin and Ifmax).

Bollen and Hassan (2011) have noted that the coordination between the fuse and the recloser is somewhat complicated and the following coordination rules apply:

- The minimum melting time of the fuse should be longer than the clearing time of the fast stage of the recloser. A certain minimum distance between the curves should be maintained. Minimum factors recommended are: 1.25 times for the single reclosing, 1.35 for two fast reclosings with a reclosing time of 1 second or more, 1.8 times for two fast reclosings with a reclosing time of one half second.
- The maximum clearing time of the fuse should be shorter than the clearing time of the slow stage of the recloser.

Figure 3.21 shows that in that range of current, fast recloser curve is faster than MM fuse and that the slow recloser is slower than TC fuse. Therefore, if the fuse fails in its actuation, the slow recloser would act as a backup protection. Therefore, when DG is not connected the currents seen by the recloser and the fuse for faults in the load feeder being the same while current fault is inside the coordination range (Ifmin and Ifmax), then the system is coordinated as shown in this figure.

The presence of a generator on the distribution feeder will impact the coordination in a number of ways (Bollen and Hassan, 2011). The main impact is that the current through the fuse is no longer the same as the current through the recloser. The current through the fuse will increase, whereas the current through the recloser will decrease. The different currents seen by the recloser and by the fuse depend on the size, location and type of DG (Comech *et al*., 2010). Consequently, the minimum and maximum fault currents for a fault in load feeder are modified because of the presence of DG thereby causing possible coordination problems. This is because if fault level increases due to DG, it could happen that fault currents are outside the coordination range which could make the fuse to act before the fast recloser actuation for a temporary fault. This is a typical case of failure to clear which means that some of the utility's customers will now see a sustained interruption when they should have been subjected to only a momentary one and the reliability of the power delivery system is slightly degraded (Dugan and McDermott, 2002).

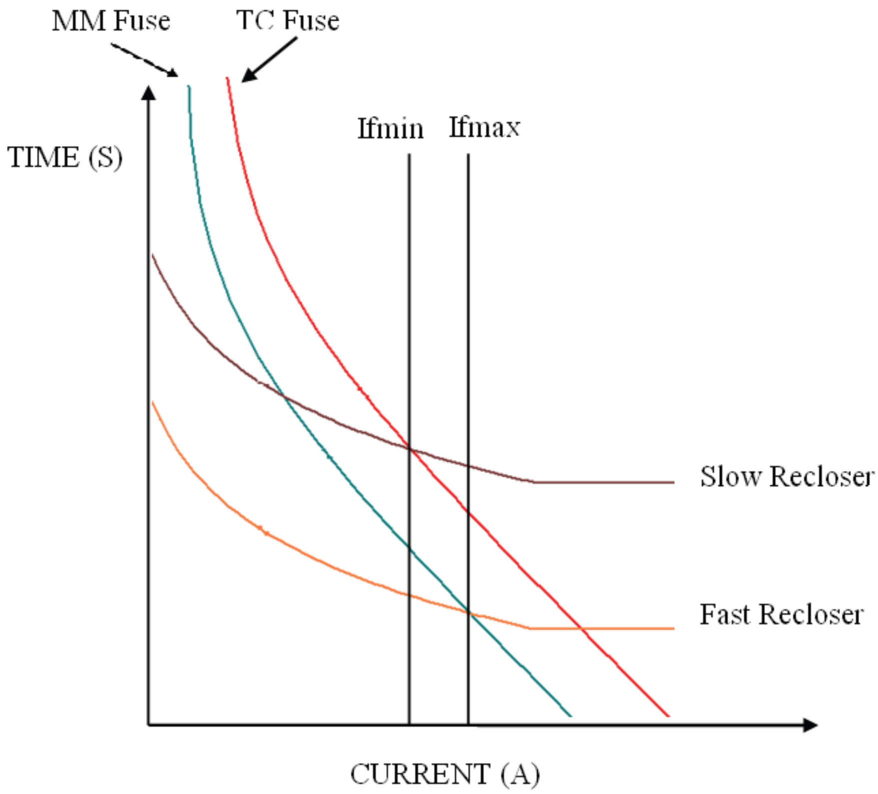

Figure 3.21: Characteristics of the fuse (TC and MM) and the recloser (Fast and Slow) for a coordinated system (Comech *et al*., 2010)

Also when the resultant fault current is less than the recloser pickup current a failure to clear could also result with significant consequences. A clearing failure means that there will be prolonged arcing and the utility transformers will experience another “through fault” and either can mean shortened life and expensive repairs to utility equipment (Dugan and McDermott, 2002).

Another coordination problem arises if a DG connected to the downstream side of the breaker or recloser is not removed prior to the reclose, the reclose can be into an energized system which is not synchronized with the system on the source side of the switchgear (Walling *et al*., 2008). According to them it is possible that the two systems are 180 out of phase and if an out-of-phase reclosing occurs, a very severe transient is produced. If the DG is still connected upon reclosing, the DG equipment itself is subject to damage. For a rotating machine, which is the most common type of generator, owners can expect damage to the shaft, coupler, and prime mover due to out-of-phase switching (Dugan and McDermott, 2002). In one instance from their experience, a piece of insulation detached from the rotor winding, presumably from either the electrical forces or the mechanical shock. They have noted that solid-state inverters have much less inertia and would normally be less susceptible to the out-of-phase reclose, assuming proper protection against current surges.

While such a reclose is often considered only a threat to the DG, it can also have severe impact on the local distribution system and its customers (Walling *et al*., 2008). According to them the utility and customer impacts of out-of-phase reclosing include:

1) A severe switching surge, with voltage magnitude ideally approaching 3 p.u. in a lightly damped system.
2) Large simultaneous inrush currents into transformers and motors, which could cause nuisance operation of fuses and other overcurrent protective devices on the utility system and within customer facilities.
3) Severe torque transients on motors and their mechanical loads.

The foregoing shows that reclosing and some types of DG are fundamentally incompatible (Dugan and McDermott, 2002). Therefore, for the reclose to be successful there must be sufficient time between shots for the fault arc to dissipate and clear. This places a responsibility on any DG on the system to detect the presence of the fault and disconnect early in the reclose interval. Consequently, concerning auto-reclose dead-time settings on networks with Embedded Generation, Eskom (2008b) stipulates that auto-reclose dead-time settings on all circuit-breakers between the PUC (Point of Utility Connection – between DG transformer and PCC and it is likely to be CB) and the SSP (Secure Supply Point) shall be increased from the standard 3 seconds to at least 5 seconds so as to provide additional margin for the detection and isolation of possible power islands.

3.3.2.5g Loss-of-Mains

One of the consequences of failed reclosing of autoreclosers is that the DG will energise the system if it is not disconnected when the recloser opens. Therefore the protection system should be able to detect mains failure and disconnect the DG as quickly as possible. This phenomenon of a distributed generator energising the remainder of the power system when part of the network is disconnected from the mains is known as Islanding. It is also known as loss of grid and could equally be caused by scheduled and unscheduled load shedding, maintenance outages and/or equipment failure (Chowdhury *et al*., 2008).

A first, and very important, distinction is between “controlled island operation” and “noncontrolled island operation” (Bollen and Hassan, 2011). According to them controlled island operation is a method to improve the reliability of supply involving one or more generators that are equipped with the proper control and protection equipment to guarantee a reliable and safe operation. Controlled or intentional island operation is used among others to obtain high reliability in industrial installations, hospitals, and data centers that require a higher reliability than that can be offered by the public supply. Generally the presence of distributed generation enables a wider scale use of controlled island operation and this is often mentioned as an important advantage of distributed generation. This is because a generator or cluster of generators operating as an island (microgrid) may be able to supply a part of the local load when grid supply is not available (Rajapakse *et al.*, 2009). According to them numerous technical issues have to be addressed to make intentional islanded operation a reality such as:

- The Power balance needs to be maintained between production and consumption.
- An effective protection coordination must be maintained under both grid connected and islanded modes.
- In order to reach such a high level of local autonomy, it requires solving advanced control and protection functions.

In South Africa intentional islanding of a generator with part of the Eskom network is not permitted unless specifically agreed to with Eskom (Eskom, 2008b).

Conversely, the term noncontrolled island operation is used when one or more generators power one or more loads, without a galvanic connection to the rest of the grid, and when this situation is unintended. Whenever the situation is unintended it remains non-controlled island operation even when control equipment is available to maintain all parameters within their appropriate range. Non-controlled island operation is a serious concern and should be avoided whenever possible.

Furthermore, Bollen and Hassan (2011) have noted that it is important to distinguish between "short-time island operation" and "long-time island operation" or "sustained island operation". The latter requires a sustained balance between the production and the generation, both for active and reactive powers. Such is not very likely, unless dedicated control systems are used or when control systems installed for other purposes unintentionally take over the control during island operation. Short-time island operation is more likely (Kumpulainen and Kauhaniemi, 2004) and it is this that causes the problems with autoreclosing and that might result in dangerous overvoltages. Personnel safety is, however, more concerned with the long-time island operation.

In Figure 3.25 an island situation occurs, for example, when recloser C opens and DG1 will feed into the resultant island in this case. As discussed in the previous section the most common cause for a recloser to open is a fault in the downstream of the recloser. A recloser is designed to open and re-close two to three times within a few seconds. The intention is to re-connect the downstream system automatically if the fault clears by itself. In this way, temporary faults will not result in the loss of downstream customers. An island situation could also happen when the fuse at point F melts. In this case, the inverter based DG will feed the local loads, forming a small islanded power system.

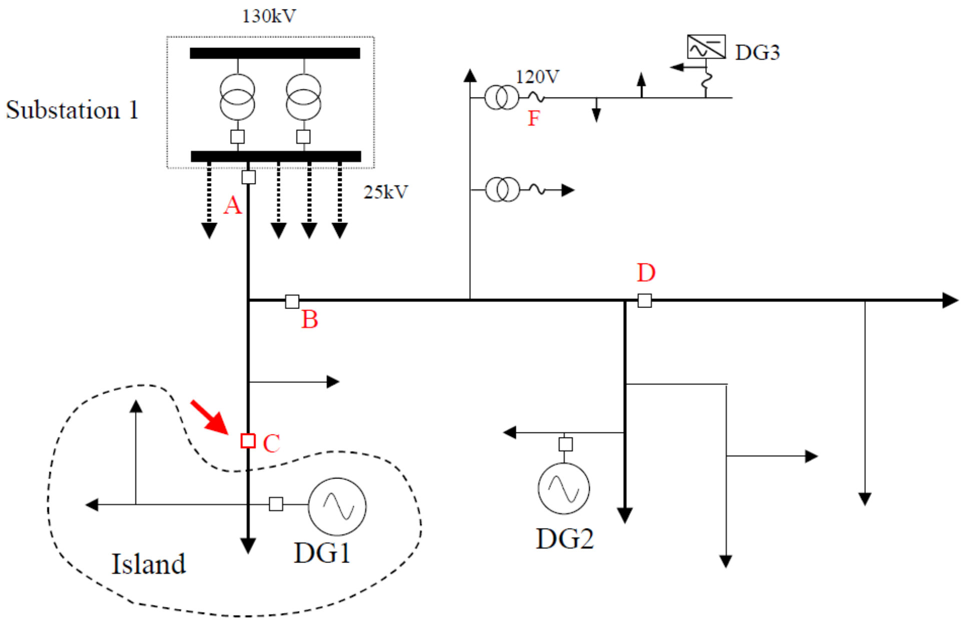

Figure 3.22: Typical distribution system with distributed generators (Xu *et al.*, 2004)

The island is an unregulated power system and its behaviour is unpredictable due to the power mismatch between the load and generation coupled with the lack of voltage and frequency control (Xu *et al.*, 2004). The main concerns associated with such islanded systems or why they should be avoided are (Bollen and Hassan, 2011; Xu *et al.*, 2004):

- The voltage and frequency provided to the customers in the islanded system can vary significantly if the distributed generators do not provide regulation of voltage and frequency and do not have protective relaying to limit voltage and frequency excursions, since the supply utility is no longer controlling the voltage and frequency, creating the possibility of damage to equipment in the network, end-user equipment, and endanger personal safety in a situation over which the utility has no control. Utility and DG owners could be found liable for the consequences.
- Islanding may create a hazard for utility line-workers or the public by causing a line to remain energized that may be assumed to be disconnected from all energy sources.

This is because opening a breaker in a radial network will no longer guarantee that the downstream network is indeed de-energized.

- The distributed generators in the island could be damaged when the island is reconnected to the supply system. This is because the generators are likely not in synchronism with the system at the instant of reconnection. Such out-of-phase reclosing can inject a large current to the generators. It may also result in re-tripping in the supply system.
- Islanding may interfere with the manual or automatic restoration of normal service for the neighbouring customers because the protection of the distribution network is not designed for island operation: a fault, therefore, might not be cleared or cleared too slow.
- Harmonic resonance or even ferroresonance may occur during the island operation; as the source is weak, a small amount of capacitance can give a low resonance frequency.
- The network operator may still be responsible for the voltage delivered to the customers, but without any possibility to control this voltage.

Therefore, to guard against these consequences of islanding an important requirement to interconnect a DG to power distribution systems is the capability of the generator to detect island conditions and subsequently be disconnected. The current industry practice is to disconnect all distributed generators immediately after the occurrence of islands (Xu *et al*., 2007). According to them, a distributed generator should typically be disconnected within 100 to 300 ms after loss of main supply. To achieve such a goal, each distributed generator must be equipped with an islanding detection device, which is also called anti-islanding device. The basic requirements for a successful detection are (Xu *et al*., 2004):

- The scheme should work for any possible formations of islands because there could be multiple switchers, reclosers and fuses between a distributed generator and the supply substation. Opening of any one of the devices will form an island. Since each island formation can have different mixture of loads and distributed generators, the behaviour of each island can be quite different. Therefore, a reliable anti-islanding scheme must work for all possible islanding scenarios.
- The scheme should detect islanding conditions within the required time frame. The main constraint here is to prevent out-of-phase reclosing of the distributed

generators. A recloser is typically programmed to reenergize its downstream system after about 0.5 to 1 second delay. Ideally, the anti-islanding scheme must trip its DG before the reclosing takes place.

Over the past several years, anti-islanding protection for DG has emerged as one of the most challenging technical barriers for DG interconnection, especially for synchronous generators connected at medium voltages (Bollen and Hassan, 2011; Xu *et al*., 2007). Therefore, many anti-islanding techniques have been proposed and a number have been implemented in actual DG projects or incorporated into the controls of inverters used in utility-interactive DG applications (Xu *et al*., 2004) to solve the problem worldwide (Xu *et al*., 2007). According to Xu *et al*. (2004), it is important to consider the characteristics of the distributed generators when selecting an anti-islanding scheme. Generally, loss-of-main detection techniques can be divided into three groups according to their operation principles (Kumpulainen and Kauhaniemi, 2004; Mäki, 2007; Rajapakse *et al*., 2009):

- ***Passive methods*** are based on measuring the state of the PCC. The passive islanding detection methods make decisions based on measured electrical quantities such as voltage and frequency. For instance the reactive power imbalance between production and consumption, which occurs after the loss of mains, leads to a change in the voltage level. Therefore, the voltage magnitude measured at the DG can be used to detect the island and trip signals are generated if the measured voltage shows abnormal variation over a predefined period of time. Normally, voltage relays respond to both under-voltage and over-voltage situations. Voltage Surge relay (also known as Voltage Vector Shift relay or Voltage Phase Jump relay) is one of the methods used for fast detection of islands. Also under-frequency can occur if the grid connection is lost at a situation where the local load exceeds the production of the generator, whereas over-frequency situations can arise if there is a surplus production at the time of grid disconnection. So, the frequency relays can take decisions based on the frequency of the voltage at the DG. The over-frequency or under-frequency elements are used to trip the generator from the system. If the real power in the island is almost balanced, the change of frequency of the islanded section will be low, making the relay ineffective. Rate of change of frequency (ROCOF), which is the time derivative of the frequency, is also frequently used to detect power islands. ROCOF relays are popular as they response much faster than the frequency relays.

- ***Active methods*** are constantly trying to force the state of the PCC outside its normal operation area. This is conducted by continuously making small changes in the PCC state and monitoring the response. In other words in the active detection methods, disturbances are injected into the network and islands are detected based on system responses to the injected disturbance. During islanding, the response will be greater and thereby detectable. Reactive error export, fault level monitoring, system impedance monitoring and frequency-drift are some of the active island detection methods. The reactive error export method controls the DG excitation current to generate a known value of reactive current. The frequency drift loss of mains detection method is specifically used in inverter interfaced DGs. Active schemes are based on active island de-stabilization, monitoring the response of the system to a change created by the anti-islanding protection equipment. Active methods have been criticized for being often only suitable for inverter-based systems and for deteriorating power quality.
- ***Communication methods*** are based on communication between the DG unit and the power system. The telecommunication-based methods use communicated circuit breaker status signals to alert and trip DGs when islands are formed. Their performance is independent of the type of distributed energy resources involved. Telecommunication based systems can be implemented in conjunction with SCADA systems. In this approach, the states of the circuit breakers in the grid are continuously tracked. The circuit breaker state information can be used to determine whether a part of the system has become an island, using predetermined logic. Transfer tripping schemes can be considered as a decentralized version of the SCADA based system. In transfer trip schemes, a logic circuit uses information of circuit breaker states to determine if a part of the grid has been islanded. Comparison of rate of change of frequency (COROCOF) at the substation and the DG location is another telecommunication-based method. The rate of change of frequency is measured at the substation and if it exceeds a certain limit, a block signal is sent to the DG end. If the rate of change of frequency at DG is greater than a set point, and if there is no block signal received from the substation end, the DG will be tripped. Telecommunication based anti-islanding methods are superior to passive methods,

because they don't have nondetection zone (NDZ). They have so far been applied mostly with large DG units because of high costs.

However according to Xu *et al*. (2004) these techniques can be broadly classified into two types according to their working principles as shown in Figure 3.23. The first type consists of communication-based schemes and the second type consists of local detection schemes. These are equally divided into sub-types as shown and are as described above by (Kumpulainen and Kauhaniemi, 2004; Mäki, 2007; Rajapakse *et al*., 2009). But the disadvantage with any so-called “passive method” is that it can detect island operation only when there is an unbalance between production and consumption in the island (Bollen and Hassan, 2011). Therefore, when both the active and the reactive power demand by the load is covered by the generators connected to the island, no passive method can detect the difference between island operation and grid-connected operation. According to them such a “perfect balance” can be due to the pure coincidence or due to the control system of one or more of generators creating the right conditions. Consequently, the so-called “active methods” for islanding detection have the advantage that they can detect any island operation, even when both active and reactive powers are in perfect balance.

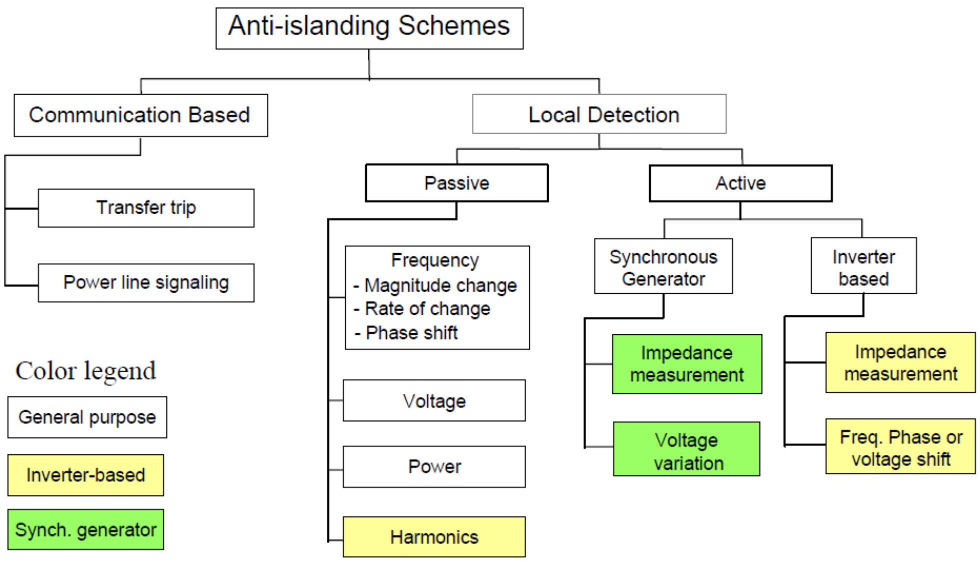

Figure 3.23: Classification of anti-islanding schemes (Xu *et al*., 2004)

Xu *et al*. (2004) have noted that the active method is widely used by inverter-based DGs due to its ease of implementation on such systems. Also although some of the local detection schemes can be applied to both types of DGs, their performances can differ as they are dependent on the operating characteristics of the DGs involved. Equally they posit that these loss-of-mains protection methods and techniques are constantly improved although many are intrinsically limited. According to them this is why there is a need to compromise between cost and simplicity, or between maximizing reliability of islanding detection methods and maximizing DG power availability (for example, limiting nuisance tripping). However, out of the above described methods under/over voltage, under/over frequency, rate of change of frequency (ROCOF) and voltage vector surge (VVS) relays are the most widely used methods for anti-islanding protection (Rajapakse *et al.*, 2009). In their view one of the main disadvantages of these methods is the possibility of nuisance tripping of DGs during other system disturbances such as load switching and faults.

Timbus *et al*. (2010) have compared the different islanding methods based on their main features as shown in Table 3.1.

Table 3.1: Comparison of islanding detection methods (Timbus *et al*., 2010)

Method Type	Strengths	Weaknesses	Grid Friendly
Passive	- grid friendly - easy and cheap to implement	- NDZ larger compared to others	yes
Active	- low NDZ - some easy to implement	- can create power quality problems - can lead to nuisance trip - some difficult to implement - possible interaction between converters in the same grid	- suitable for a finite number of generators
Communication based	- reliable - some easy to implement - theoretically no NDZ	- expensive to implement - need communication infrastructure - need involvement of utility	- yes

According to them, passive methods constitute the basic islanding protection package of every distributed generator connected to utility grid though active methods are preferred due to their low non-detection zone. However, they have noted that one of the main drawbacks which may contribute to a shift from using active methods is their negative contribution to the quality of power in the grid. And also future availability of a communication network for the power grid combined with more interest from utilities to monitor the assets in the grid may facilitate a move towards the use of communication based methods for islanding detection.

Common standards for performance of islanding detection techniques and testing procedures to verify the performance of the detection means in detecting islands are needed to reduce the obstacles to grid connection of distributed energy resources (Xu *et al.*, 2004). They submit that national and international standards bodies have developed such standards and test procedures, initially for photovoltaic inverters but more recently for all DG sources that connect to low voltage portions of the distribution network. Global standardization authorities such as IEC and IEEE are the main divers for standardizing requirements and testing conditions for islanding detection. However, there are also country specific regulations which may differ from both IEC or IEEE approaches and which complicate the development of a general solution for the global market. Japan, Germany, Austria and more recently Spain and Italy are known for applying different requirements for connecting DGs to the utility grid (Timbus *et al*., 2010). Unfortunately, the lack of harmonization in the standards makes it more costly and time-consuming for manufacturers to develop and certify inverters or other DG equipment that can be sold into multiple markets (Xu et al., 2004). As a result, costs for inverters and other DG equipment are higher than they need to be.

According to Xu *et al*. (2004) standards developed in the early and mid 1990's often specify use of a specific detection method or the use of more than one detection method. For example the German standard requires the use of a "Mains Monitoring Unit" that incorporates both active impedance detection and passive over/under voltage and frequency detection as well as redundant disconnect means. Similarly, Japanese standards have required the use of at least one passive and one active method. However the current trend is to have performance based standards that specify the performance of the islanding detection and disconnection means and the test procedure to verify performance, but do not call for use of any particular technique. They have noted that the performance based standard normally specifies that the DG source must detect and disconnect within a specified time after an island is created, and that it can only reconnect after the grid reconnects to the island, and voltage and frequency have remained within normal limits for a specified time. However, the allowable time intervals vary among standards, depending on differing assumptions about the importance of rapid detection and disconnection to avoid interfering with the action of automatic reclosers.

But the unintentional islanding section, Section 4.4.1, of IEEE (2003) stipulates that for an unintentional island in which the DR energizes a portion of the Area EPS through the PCC, the DR interconnection system shall detect the island and cease to energize the Area EPS within two seconds of the formation of an island. Some examples by which this requirement may be met are:

1. The DR aggregate capacity is less than one-third of the minimum load of the Local EPS.

2. The DR is certified to pass an applicable non-islanding test.
3. The DR installation contains reverse or minimum power flow protection, sensed between the Point of DR Connection and the PCC, which will disconnect or isolate the DR if power flow from the Area EPS to the Local EPS reverses or falls below a set threshold.
4. The DR contains other non-islanding means, such as a) forced frequency or voltage shifting, b) transfer trip, or c) governor and excitation controls that maintain constant power and constant power factor.

Two inputs from the utility and energy regulator exist on the issue of unintentional islanding in South Africa. For instance, no EG shall continue to energise any portion of the network that has been unintentionally islanded on a section of the Distributor's network (Eskom, 2008b). According to it, disconnection shall occur at the PUC upon detection of an unintentional island with the primary concern being for human safety, plant protection and power quality, in that order. The philosophy to be applied is that the detection of an islanding condition shall take precedence over the continuity of the generator's grid connection (via the PUC). Therefore, the generator must be disconnected from the distribution network upon reasonable suspicion of islanded operation. Generators of capacity greater than 50MVA will typically include more definitive islanding detection methods (e.g. communication-assisted intertripping schemes); so as to further avoid nuisance tripping for nonislanding events. Furthermore, dedicated loss-of-grid protection will be applied at the PUC in all applications. However, an EG may be exempted from this requirement in the event that it is prohibited from exporting real power to the distribution network by a suitable reverse power relay. The loss-of-grid protection may take the form of Rate-of-Change of Frequency (ROCOF) or Voltage Vector Shift protection with the typical settings as shown in Table 3.2. But where ROCOF or Voltage Vector Shift protection is not deemed suitable, a communication-based direct transfer trip scheme may be applied such as to disconnect the EG in the event of an island developing (Eskom, 2008b).

Table 3.2: Typical settings for loss-of-grid protection (Eskom, 2008b)

ROCOF	Δf	0.2 – 1.0Hz/s (0.4Hz/s typical)
	Δt	40ms – 2s
	Time delay	200ms – 500ms
Voltage Vector Shift	ΔV	6^{o} – 12^{o} (6^{o} typical, 12^{o} on weak networks)

According to NERSA (2012) the RPP of category A (0 – 1 MVA (Only LV connected RPPs)) shall be equipped with effective detection of islanded operation in all system configurations and capability to shut down generation of power in such condition within 0.2 seconds. Also the RPP of category B (1 MVA – 20 MVA and RPPs less than 1 MVA connected to the MV) and C (20 MVA or higher) shall be equipped with effective detection of islanded operation in all system configurations and capability to shut down generation of power in such condition within 2 seconds. In all islanded operation with part of the transmission or distribution system is not permitted unless specifically agreed with the NSP.

Given the crucial role controlled or intentional island operations can play, IEEE in 2011 published IEEE Std 1547.4-2011. This document covers intentional islands in electric power systems (EPSs) that contain distributed resources (DRs) and is intended to provide an introductory overview and address engineering concerns of DR island systems. Therefore, it is relevant to the design, operation, and integration of DR island systems. According to IEEE (2011b) the term *DR island systems,* sometimes referred to as *microgrids,* is used for these intentional islands. It notes that DR island systems can be either local EPS islands or area EPS islands and DR island systems are EPSs that:

1. have DR and load,
2. have the ability to disconnect from and parallel with the area EPS,
3. include the local EPS and may include portions of the area EPS, and
4. are intentionally planned.

As stated earlier one of the main concerns associated with unintentional islanded systems or why they should be avoided is that harmonic resonance or even ferroresonance may occur during the island operation: as the source is weak, a small amount of capacitance can give a low resonance frequency (Bollen and Hassan, 2011; Xu *et al*., 2004). However, ferroresonance could still happen in the absence of a DG. The ferroresonance associated with DG differs from the traditional ferroresonance caused by single-phase switching in that no unbalanced condition is necessary (Mozina, 2010).

3.3.2.5h Ferroresonance

The term *ferroresonance* can be found in technical literature dating as far back as 1920 referring to an oscillating phenomenon between a nonlinear inductance and a capacitor (Escudero *et al*., 2004). According to them despite available extensive literature, ferroresonance still remains widely unknown and is feared by Power Systems Operators as it seems to occur randomly, possibly resulting in the catastrophic destruction of plant equipment. This general lack of knowledge means that ferroresonance is normally overlooked at the planning and design stages or, on the contrary, held responsible for “inexplicable” equipment failures. However, situations conducive to ferroresonance are occurring increasingly frequently in modern MV networks due to environmental constraints leading to the use of underground cable on short spurs supplying MV/LV distribution transformers in the range 100 to 1000 kVA (Dugan and McDermott, 2002; Eskom, 2008c). It notes that it is a standard practice that MV networks are earthed at source and that the MV windings of distribution transformers must be unearthed and, in most cases, connected Dyn.

Ferroresonance is a special form of series resonance between the magnetizing reactance of a transformer and the system capacitance (EPRI, 2000; Short, 2004). According to them a common form of ferroresonance occurs during single phasing of three-phase distribution transformers especially on cable-fed transformers because of the high capacitance of the cables. Also the transformer connection is also critical for ferroresonance because an ungrounded primary connection (as shown in Figure 3.24) leads to the highest magnitude ferroresonance. They have equally noted that during single phasing (usually when line crews energize or deenergize the transformer with single-phase cutouts at the cable riser pole) a ferroresonant circuit between the cable capacitance and the transformer’s magnetizing reactance drives voltages to as high as 5 per unit on the open legs of the transformer. According to Eskom (2008c) the typical range of overvoltage experienced during the ferroresonant conditions, is in the order of 2 per unit. But in some more severe cases, 3 or 4 per unit voltages are met. The voltage waveform is normally distorted and often chaotic.

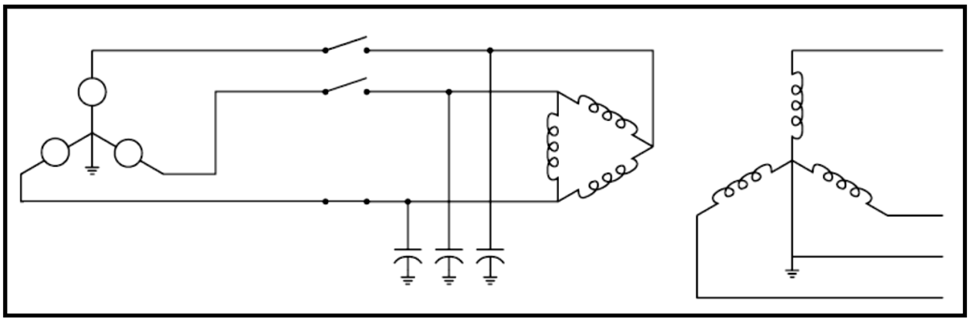

Figure 3.24: Ferroresonant circuit with a cable-fed transformer with an ungrounded high-side connection (EPRI, 2000; Short, 2004)

Generally in linear circuits, resonance occurs when the capacitive reactance equals the inductive reactance at the circuit source frequency, resulting in large currents and voltages.

Unlike linear resonance, ferroresonance is not so easy to predict and several steady state solutions may exist for a particular excitation and range of circuit parameters due to the non-linearity (Escudero *et al*., 2004).

Ferroresonance is a function of the cable capacitance and the transformer no-load losses. The lower the losses relative to the capacitance, the higher the ferroresonant overvoltage can be (Short, 2004). According to Escudero *et al*. (2004) ferroresonant systems are very sensitive to initial conditions: remnant flux in the magnetic cores, switching instant, circuit losses and charge in the capacitances are the key variables that determine the steady state response. Therefore, it is possible that a system disturbance causes the circuit that was operating in a normal steady-state condition to jump into another stable operation point with very high currents and/or voltages. In other words ferroresonance has either transient or steady state effects (Eskom, 2008c). For transformer configurations that are susceptible to ferroresonance, ferroresonance can occur approximately when (EPRI, 2000; Short, 2004):

$$B_C \geq P_{NL}$$

(Equation 3.37)

Where:

B_C = cable kvar/transformer kVA = percent capacitive susceptance or capacitive reactive power per phase, VAr

P_{NL} = percent core loss on the transformer nameplate base = core loss per phase, W

According to EPRI (2000) if the condition above is exceeded, then a more complicated evaluation may be warranted. This would require knowing the cable capacitance, transformer configuration, capacitance, and core characteristics, as well as the arrester size, type, and location.

Also the capacitive reactive power on one phase (B_C) depends on the voltage and the capacitance as given by Equation 3.38

$$B_C = \frac{{V_{kV}}^2}{3} 2\pi f C$$

(Equation 3.38)

Where:

VkV = rated line-to-line voltage, kV

f = frequency, Hz

C = capacitance from one phase to ground, μF

It could be deduced from Equations 3.37 and 3.38 that ferroresonance can happen at any voltage level with the appropriate combination of capacitance, non-linear inductance and low losses.

Eskom (2008c) has proposed measures to avoid overvoltages detrimental to consumers' appliances. According to it in situations where the capacitive reactance of the cable is greater than 1.6 times the normal transformer inductive reactance, ferro-resonance will not occur. In these cases, special measures are unnecessary. It has noted that although resonance is avoided when the limiting cable lengths are not exceeded, and transformer LV voltage will not exceed 1.06 per unit, overvoltage will still occur on the cables connected to the open phase(s) and on the end(s) of the winding(s). However, the maximum MV voltage that occurs, with the full limiting length of cable, is less than 1.65 per unit. It is considered that transformer and cable insulation will not be significantly affected by such voltages because of the limited durations likely to occur. But if other more vulnerable apparatus such as surge arresters were connected, 1.65 per unit could not be permitted. Therefore, to calculate the permitted cable length, the capacitive reactance must be at least 1.6 times the winding reactance (X_m) of the transformer. Equation 3.39 is for a delta connected winding,

$$X_m = \frac{3V^2 1000}{S}\left(\frac{100}{I_m\%}\right)$$

(Equation 3.39)

Where:

X_m = winding reactance

I_m = No-load core magnetising current as a percentage of the rated line current

S = apparent power in kVA

V = nominal primary voltage in kV

For example, the magnetizing current of a 200 kVA 11 kV/400 V Dy transformer is 1.48%, resulting in: X_m = 123kΩ and the limiting capacitive reactance being 1.6 × X_m = 197kΩ. In situations where there is more than one transformer and more than one cable length, the equivalent value of X_m is calculated from the individual values of X_m in parallel. But the total cable capacitive reactance must be at least 1.6 times the equivalent value of X_m. Eskom also has a policy concerning when cable lengths exceeding the permitted length which requires ensuring the prevention of single-phasing as far as possible. As a result single-phase fuses and switching devices must not be used at the tee-off position. Of course, unforeseen events such as broken jumpers cannot be entirely eliminated.

Ferroresonance is more likely with (Escudero *et al*., 2004; Short, 2004):

1. A non-linear inductance. This appears in a transformer ferromagnetic core. Unloaded transformers provide typical non-linear inductances. Therefore, ferroresonance disappears with load as little as a few percent of the transformer rating.
2. A capacitance. This can appear in the form of voltage grading capacitors in HV circuit breakers, conductor inter-phase capacitances, capacitance to ground of cables and long lines, series capacitors or shunt capacitor banks.
3. Low Losses. These are present in very lightly loaded transformers combined with modern low losses magnetic cores. And in smaller transformers because they have smaller no-load losses.
4. A voltage or current source. Shorter cable lengths are required for ferroresonance and resonance is more likely even without cables, just due to the internal capacitance of the transformer. With higher voltages, the capacitances do not change significantly (cable capacitance increases just slightly because of thicker insulation), but VArs are much higher for the same capacitance.

Normally, ferroresonance occurs on three-phase transformers, but ferroresonance can occur on single-phase transformers if they are connected phase to phase, and one of the phases is opened either remotely or at the transformer (Short, 2004). He posits that ferroresonance normally occurs without equipment failure if the crew finishes the switching operation in a timely manner and that occasionally, ferroresonance is severe enough to fail a transformer. Ferroresonant overvoltages may also fail customer's equipment from high secondary voltages with small end-use arresters being particularly susceptible to damage. However, from an operational point of view, ferroresonant oscillations can represent a hazard to the plant equipment integrity (Escudero *et al*., 2004). Therefore, the systems engineer's challenge is to predict whether ferroresonance can arise in a particular circuit and to determine a good operational safety margin.

The phenomenon of ferro-resonance may be encountered in power systems in a number of situations, most of which are easy to eliminate (Eskom, 2008c). Studies and field experience have shown that certain power system configurations are more susceptible to ferroresonance than others (Escudero *et al.*, 2004). According to them the most frequent cases are:

- Voltage Transformers energized through grading capacitors of open circuit breakers.
- Voltage Transformers connected to an isolated or resonant neutral system (distribution networks).
- Power Transformers energized in only one or two phases.
- Lightly loaded Power Transformers connected to a cable network with low short circuit power.
- Single phase switching (fuse blowing) in distribution networks.

Ferroresonance drove utilities to use three-phase transformer connections with a grounded-wye primary, especially on underground systems (Short, 2004). Consequently, to avoid ferroresonance on floating wye – delta transformers, some utilities temporarily ground the wye on the primary side of floating wye – delta connections during switching operations. Table 3.3 shows transformer primary connections susceptibility to ferroresonance.

Table 3.3: Transformer primary connections susceptible to ferroresonance (EPRI, 2000; Short, 2004)

Susceptible Connections	**Not Susceptible**
Floating-wye Delta Grounded-wye with 3,4, or 5-legged core construction Line-to-line connected single-phase units	Grounded-wye made of three individual units or units of triplex construction Open wye – open delta Line-to-ground connected single-phase units

Solutions to ferroresonance include (EPRI, 2000; Short, 2004):

- Using a higher-loss transformer
- Using a three-phase switching device instead of a single-phase device
- Switching right at the transformer rather than at the riser pole
- Using a transformer connection not susceptible to ferroresonance
- Limiting remote switching of transformers to cases where the capacitive VArs of the cable are less than the transformer's no load losses. This means limiting the cable length feeding the transformer to meet the criteria given above.

The preceding discussions on ferroresonance on a traditional distribution system could be worsened by the presence of distributed generators through unintentional islanding. According to Mozina (2013) the ferroresonance associated with DG differs from the traditional ferroresonance caused by single phase switching in that no unbalanced condition is necessary. Ferroresonance is a phenomenon that may be encountered in the interconnection of DR and extreme overvoltages can develop when the DR is connected to a section of the distribution circuit that has been isolated from the utility (PSRC, 2004). For example when a riser-pole fuse on a cable-fed transformer blows, and the DG is required to disconnect at the first sign of trouble, it will leave the service transformer isolated without load and served with an open phase. This scenario, a classical ferroresonance condition, is illustrated in Figure 3.25 with a delta-wye grounded service transformer (Dugan and McDermott, 2002). In other words when a DG is islanded with pole-top distribution system capacitor banks, a unique form of ferroresonance and overvoltages of over 3.0 per unit can occur (Mozina, 2010). The ferroresonance effects can result in significant overvoltages where peak voltage can reach 3 to 4 per unit (Vaziri *et al*., 2010). Mozina (2010) posits that the discharging and charging of the system capacitance through nonlinear magnetizing reactance of the DG interconnection transformer produce these overvoltages. But according to Vaziri *et al*. (2010) during islanding conditions ferroresonance can occur with DR acting as the driving source in the circuit.

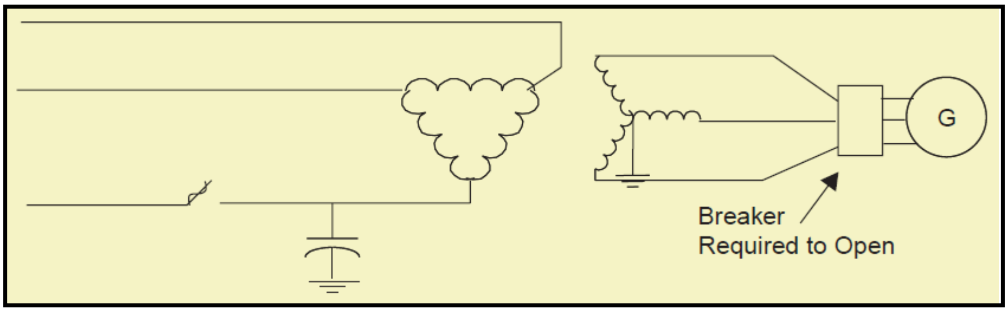

Figure 3.25: A riser-pole fuse blowing on a cable-fed transformer leads to ferroresonance (Dugan and McDermott, 2002)

Ferroresonance is known for its high voltage magnitudes (3 per unit is not uncommon) and for its highly distorted and irregular voltage and current waveforms (Bollen and Hassan, 2011) as depicted in Figure 3.26.

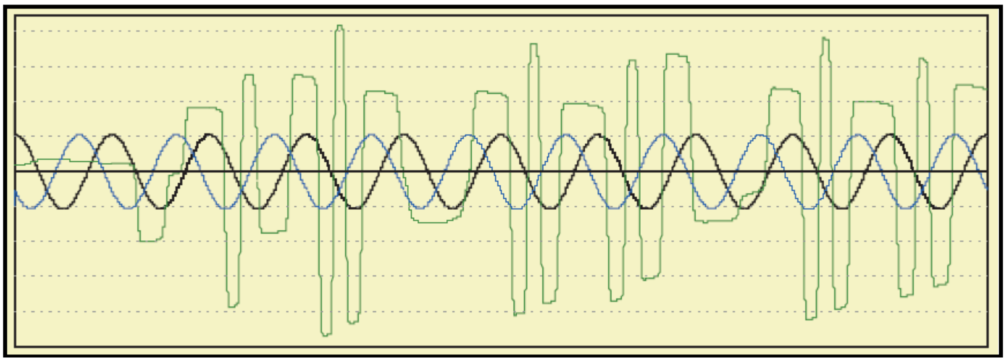

Figure 3.26: An example of ferroresonant overvoltages for delta primary with one phase open. Scale is 1 p.u. per vertical division (Dugan and McDermott, 2002)

The phenomenon of self-excitation of induction generators has been known for many years and it occurs when an isolated generator is connected to a system having capacitance equal to or greater than the magnetizing reactance requirements (Mozina, 2010). He however notes that the ferroresonance is not confined to induction generators but can also occur on synchronous machines. Both synchronous and induction generators can be involved in ferroresonance and a combination of the two can make things worse (Bollen and Hassan, 2011). They posit that self-excitation of induction generators is a related phenomenon that can result in overvoltages of 1.5 – 2 per unit. According to Walling *et al*. (2008) islanding a rotating generator DR with a portion of a distribution system having excess capacitive compensation can result in high overvoltages due to self excitation of the machine. This is because saturation of transformers in the isolated subsystem introduces large harmonic current components which can resonate in the circuit formed by the DR and the capacitive compensation. Furthermore, although saturation reduces the fundamental overvoltage to some degree, the potentially large harmonic voltage components can result in very high peak overvoltages. This type of ferroresonance can occur with both induction and synchronous generators, and it can occur with all three phases connected (single-phasing is not a requirement) (EPRI, 2000; Vaziri *et al*., 2010).

There are four conditions necessary for DR islanding ferroresonance to occur (Bollen and Hassan, 2011; EPRI, 2000; Mozina, 2010; Mozina, 2013; Vaziri *et al*., 2010):

1. The generator must be operating in an islanded state.
2. The generator must supply more power than there is load on the island. A rule of thumb is that the load should be less than three times the generator rating.
3. Sufficient capacitance must be available on the island to resonate (typically 30 – 400% of the generator rating). This can be due to utility capacitor banks or from DR

capacitor banks. Some authors believe the range in capacitance resulting in ferroresonance is 25 – 500% of the generator rating.

4. A transformer must be present on the island to serve as the non-linear reactance

According to EPRI (2000) solutions to this type of ferroresonance include changing the distribution system characteristics to change the criteria given above (limit or expand the area that could be islanded or remove or change the size of the capacitor bank). In proffering solutions or techniques for mitigating the resulting overvoltages Mozina (2010) has noted that studies have shown that both induction and synchronous generators are susceptible. Also, all types of interconnection transformer connections (wye–delta, delta– wye, wye–wye, and delta–delta) are susceptible. So it does not matter what the DG interconnection transformer is, although the overvoltage will be worse if the ferroresonance occurs simultaneously with a neutral shift on an ungrounded island (EPRI, 2000). Surge arresters will clip the peaks of the overvoltage but will not suppress the ferroresonance condition and may be damaged in the process (Mozina, 2010) especially with arresters rated only slightly above the normal RMS voltage (EPRI, 2000). According to Mozina (2010) metal-oxide arresters have an increased ability to survive longer, but they can also be damaged. Therefore, the most practical solution is to trip the DG to remove the driving source during an overvoltage condition through overvoltage relaying (EPRI, 2000; Mozina, 2010; Mozina, 2013). However, this is not as simple as it sounds, since the voltage wave-shape for this resonance condition is nonsinusoidal (Mozina, 2010; Mozina, 2013).

It should be noted that the impacts of ferroresonance is the same as highlighted earlier with or without DG.

3.3.2.5i Power Quality

Connection of the dispersed generation of renewable energy to distribution grid can have both positive and negative effects to the power quality (Vaimann *et al.*, 2012). Bollen and Häger (2005) agree that DER units may have an adverse influence on several power-quality disturbances noting that the most discussed issue is the impact on voltage variations. Also increased levels of harmonics and flicker are mentioned as potential adverse impact of DER units. But according to them DER units can also be used to mitigate power-quality variations especially through power-electronic interfaces that can be used to compensate voltage variations, flicker, unbalance and low frequency harmonics. Unfortunately, the use of power-electronic interfaces will however lead to high frequency harmonics being injected into the system which could pose a new power-quality problem in the future. However, Vaimann *et al*. (2012) contend that the realisation of these impacts depends on possibilities of information and communication systems to control and maintain voltage in the feeders, turn the loads in or out and replace lost power with the reserves. Also, power quality can be controlled and improved in whatever point of the electric system beginning from the mains in the system or the grid and ending with single devices at the consumer level.

Consequently, this section considers only the adverse contributions of DGs to the electric power systems power quality. A number of different definitions of power quality exist in the literature, but none of them is generally accepted (Bollen and Häger, 2005). According to some definitions, only equipment mal-operation is part of power quality, whereas other definitions incorporate all deviations from an ideal voltage and/or current waveform. The inducing effect due to the presence of current harmonics in overhead lines and cables is in some countries also considered as a power quality phenomenon. Another point of disagreement is whether power quality includes interruptions or not. But Bollen and Häger (2005) are of the view that power quality covers all deviations from the ideal voltage and current waveform (a constant-magnitude non-distorted sine wave of nominal frequency and magnitude, with current in phase with the voltage) including interruptions – though this viewpoint has been criticized as being far too wide – and almost any aspect of power systems. Therefore, according to them, the term power quality refers to the electrical interaction between the electricity grid and its customers or equipment connected to it, and consists of two parts: the voltage quality concerns the way in which the supply voltage impacts equipment; the current quality on the other hand concerns the way in which the equipment current impacts the system. This means that the actual power quality (i.e. the disturbance levels) results from the interaction between the network and the connected equipments (Agarwal and Tsoukalas, 2011). The capability of the power system to absorb the power quality disturbances is depending on the fault level at the point of common coupling (Golovanov *et al*., 2013). Bollen and Häger (2005) have noted that most of the recent emphasis is on voltage quality, with voltage dips and interruptions being dominant.

(NERSA, 2012) views power quality as the characteristics of the electricity at a given point on an electrical system, evaluated against a set of reference technical parameters. These characteristics include:

- voltage or current quality, i.e. regulation (magnitude), harmonic distortions, flicker, unbalance;
- voltage events, i.e. voltage dips, voltage swells, voltage transients;
- (supply) interruptions;
- frequency of supply

Therefore, EGs are required to operate within legal power quality limits because Eskom and the Municipalities are held liable for deviations from legal power quality limits that their customers may experience (Eskom, 2008b).

Power quality covers two groups of disturbances: variations and events. While variations are continuously measured and evaluated, events occur in general unpredictable manner and require a trigger action to be measured (Agarwal and Tsoukalas, 2011). According to Chang *et al*. (2012) power quality events are those occurred disturbances with a beginning and an ending in time, which are different from those steady or quasi-steady disturbances which require continuous measurements. Important variations are: slow voltage changes, harmonics, flicker, and unbalance. Important events are rapid voltage changes, dips or voltage sags, swells and interruptions (Agarwal and Tsoukalas, 2011; Chang *et al*., 2012). There are many advanced methods proposed to perform the analysis of power quality events (Chang *et al*., 2012). According to them the analysis for the power quality events can be roughly grouped to two categories: detection (or triggering) and classification. The detection process is designed to identify the occurrences of events and trigger the corresponding automation and protection mechanisms. The classification process is mainly used to identify the types of events according to different properties of power quality disturbances.

The foregoing shows that the effect of the integration of the DG on power quality concerns three major aspects (Coster *et al*., 2011):

- dips and steady-state voltage rise;
- voltage flicker;
- harmonics

Distributed generators do not result in any significant direct increase in the number of voltage dips (Bollen and Hassan, 2011). They assert that the only possible impact is the voltage dip due to the connection of the generator to the grid which is comparable to the effect of motor starting or transformer energizing and capacitor energizing transients. According to them this is of concern only for generation with rotating machine interface, and even in this case, typically a soft starting is used to limit the voltage drop. The authors have noted that the presence of distributed generation, however, impacts the number of dips in several indirect ways as follows:

- Distributed generation connected to the distribution system will locally strengthen the grid, which will result in a decrease of the number of dips experienced by local customers.
- Replacement of large conventional power stations by distributed generation will weaken the transmission grid, which will result in an increase of the number of dips experienced by the customers.
- Large penetration of distributed generation will require enforcement of the power system in the form of new cables or overhead lines, especially the integration of large wind parks into the subtransmission system which has been reported to require significant amounts of new lines. These lines will result in more voltage dips for customers connected close to these lines. This may especially impact large industrial customers that have traditionally been most sensitive to voltage dips.
- The weakening of the transmission system may also result in a longer fault clearing time and thus longer voltage dips. Distance protection and differential protection are not much impacted by the fault level, over a broad range of fault levels. But overcurrent protection, sometimes used in subtransmission system, may be impacted.
- After fault clearing, rotating machines take a large reactive power. In a weak system, this will pull down the voltage after the fault and result in longer voltage dips.
- The power electronics converter, with which many distributed generators are equipped, can be used to maintain the voltage for the local load. Two different approaches are being discussed: temporary island operation of the generator with its local load and injection of reactive power during the dip, while remaining connected to the grid.

Figure 3.27 is an illustration of a voltage sag or dip occasioned by DG disconnection for fault clearing. According to Dugan and McDermott (2002) before a fault occurs, the DG will help support the voltage and may be large enough to actually raise the voltage as suggested in the top diagram. Therefore, in one sense, the DG improves the reliability of the distribution system by allowing it to serve more loads at a good voltage than without the DG. But should the load be increased to the point where the feeder is actually *dependent* on the DG to support the load, there could be significant operational difficulties when the inevitable fault occurs. In order for the utility system fault protection scheme to operate, the DG must disconnect and remains disconnected until it can be determined that the utility voltage has stabilized (usually a few minutes). However, if the load is too great, the voltage will sag too low and the utility will not be able to successfully serve the load upon reclosure. Consequently, changes in operating procedure will be required to restore power and it will take longer to restore power to some customers. Dugan and McDermott (2002) have noted that in that sense, the reliability of the power delivery system might appear to have worsened slightly, although the DG may actually be mitigating a voltage regulation problem under normal conditions.

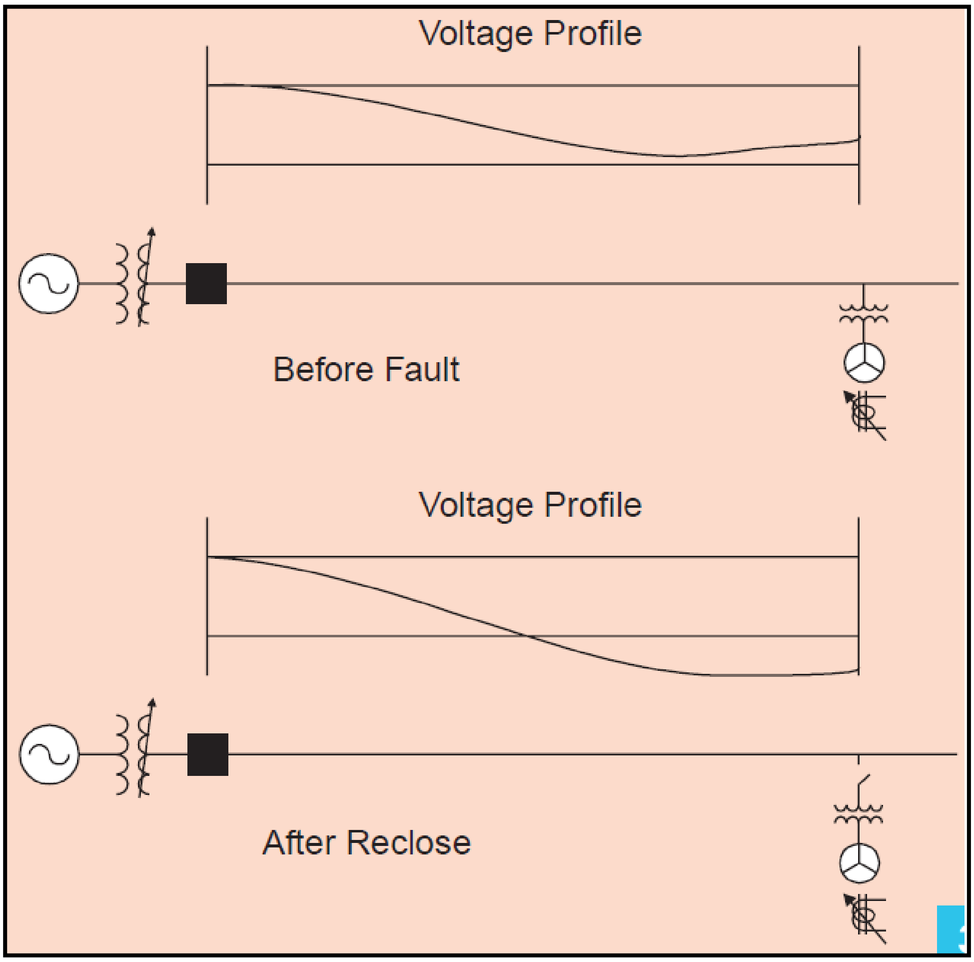

Figure 3.27: The voltage sags too low after generators are disconnected to clear a fault (Dugan and McDermott, 2002)

The issue of steady-state voltage rise which strongly depends on the X/R ratio, feeder load, and injected power by the DG unit (Coster *et al*., 2011) is as contained in Section 3.3.2.4 where it is shown that connecting the DG to a lightly loaded feeder can result to power flow reversal and the concomitant voltage rise at the DG connection point. This means that the supply voltage for customers connected nearby DG units starts to rise as well, which is a steady-state voltage rise effect. However, the DG can also have a transient effect on the voltage level (Coster et al., 2011). This is because a rapid load current variation of a DG unit causes a sudden increase or decrease of the feeder current and resultantly an effect on the feeder voltage. For instance, when the wind starts to blow, the wind turbine output rapidly increases until the rated power of the wind turbine is reached. The rapid output change of the wind turbine changes the power flow in the feeder and can cause a voltage transient. A sudden change in the output power can also occur when the wind exceeds a certain upper limit (25 m/s). At that point, the wind turbines have to be protected against overload and strong mechanical forces, and are disconnected and shut down. This disconnection can cause an increase in the feeder current and consequently a dip or a drop in the supply voltage as highlighted earlier.

Voltage sag is almost universally considered as "a nonpermanent voltage reduction with values between 10% and 90% of the rated voltage and duration between 1/2 cycle and a few minutes" (Targarona and Morcos, 2007). According to them, voltage reduction of more than 90% or applied voltage less than 10% are considered as an interruption, while voltages with durations shorter than three minutes correspond to the phenomenon known as microinterruption. Also, the ability of sensitive equipment (SE) to withstand voltage sags without dropout is called the *ride-through capability*.

Voltage fluctuations can produce annoying flickers to lamps, deteriorating the performance of some electric devices that are sensitive to voltage fluctuations (Chang *et al*., 2012). The introduction of DER units will generally lead to an increase of the voltage magnitude experienced by the customers (Bollen and Häger, 2005). According to them with highly variable sources of energy (like wind and sun) the voltage magnitude will also show a higher level of changes over a range of time scales. They submit that the term "voltage fluctuations" is used to cover a wide range of changes in the voltage magnitude while noting that there is a significant overlap with the term "voltage variations". However, they have limited the use of the term "voltage fluctuations" to those changes in voltage magnitude that (potentially) lead to light flicker with incandescent lamps, as defined in the IEC flickermeter standard (IEC 61000-4-15). To improve the voltage quality of the power system, it is important to precisely track the components of voltage fluctuations. And in general, the voltage fluctuations can be expressed as the amplitude modulated (AM) signal as follows (Chang *et al.*, 2012):

$$v(t) = \left[A_0 + \sum_{i=1}^{m} A_i \cos\left(\omega_{fi} t + \phi_{fi}\right)\right] \cos(\omega_0 t + \phi_0) = A_{En} \cos(\omega_0 t + \phi_0)$$

(Equation 3.40)

where A_0, ω_0, ϕ_0, A_i, ω_{fi} and ϕ_i are amplitudes, angular frequencies, and phase angles of the fundamental and flicker components, respectively, and *m* is the expected number of flicker signals. The authors have noted that many methods have been proposed to evaluate the envelope A_{En} of the AM signal.

The severity of voltage fluctuations is quantified through the "short-term flicker severity" (symbol P_{st}) and the "long-term flicker severity" (symbol P_{lt}) (Bollen and Häger, 2005). According to them the definition of the short-term flicker severity is such that a level of 1.0 will lead to disturbing levels of flicker being noticed by most observers with standard incandescent lamps, and fast variations in generated power may lead to voltage fluctuations. Obviously, these pose a concern for those sources for which the available power strongly varies with time: notably wind and solar power. For instance, wind turbines produce a continuously varying output. Concerning limitation of flicker induced by the DR, IEEE (2003) holds that the DR shall not create objectionable flicker for other customers on the Area EPS. According to it flicker is considered objectionable when it either causes a modulation of the light level of lamps sufficient to be irritating to humans, or causes equipment misoperation

Harmonics are voltage and current frequencies in the electrical system that are multiples of the fundamental frequency (Arrillaga and Watson, 2003; WEG, 2010) as shown in Figure 3.28. This fundamental frequency is 60 Hz in USA and 50 Hz in European and South African power systems.

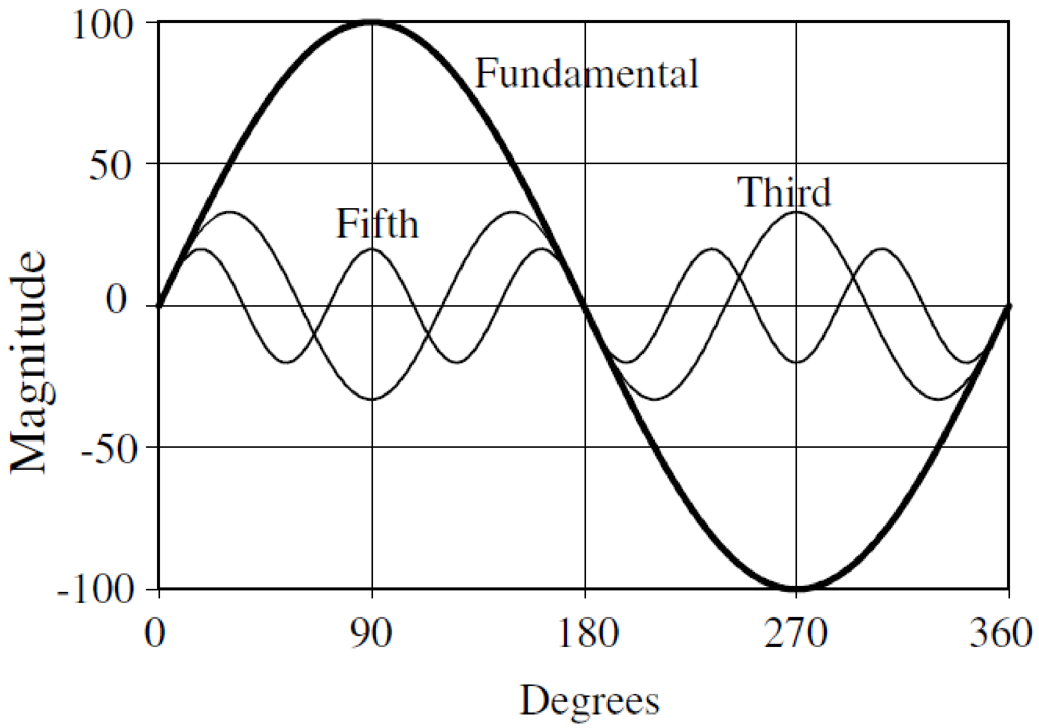

Figure 3.28: Fundamental, third, and fifth harmonics (Galli *et al.*, 2002)

On the issue of harmonic emissions of non-linear loads into power grid, Luszcz (2013) has noted that harmonics content defined for currents and voltages is an effect of its non sinusoidal wave-shape. This is because power electronics switching devices – like diodes, thyristors and transistors – used in power conversion process change their impedances rapidly according to line or PWM commutation pattern and produce non sinusoidal voltages and currents which are required to perform the power conversion process properly. Unfortunately, these non sinusoidal currents are also partly injected into the power grid as an uninvited current harmonic emission. Therefore, non sinusoidal load currents charged from power grid produce voltage harmonic distortions in power grid which can influence all other equipment connected to that grid because of the existence of grid impedance. According to Luszcz (2013) this mechanism results to non-linear current of an equipment being harmful to other equipment supplied from the same grid and also for the grid itself, such as transformers and transmission lines. Bollen and Häger (2005) accept that the power-electronic interfaces of DER units contribute to waveform distortion. They posit that the current waveform contains frequency components at integer multiples of the power-system frequency and at integer multiples of the switching frequency. They have referred to the former as "low frequency harmonics" and to the latter as "high-frequency harmonics". Harmonic distortion emission is commonly understood as harmonics produced by non-linear loads, usually power electronics converters in the frequency range up to 2 kHz which are strongly related to some of the power quality indices (Luszcz, 2013). Furthermore, harmonic distortion emission in the frequency range above 2 kHz can be named as high frequency harmonics emission.

Therefore, the characteristic low frequency harmonics generally produced by power electronic switching devices, especially the rectifier, on the power line are considered to be of the order given by Equation 3.41

$$h = np \pm 1$$

(Equation 3.41)

where, h = order of the harmonics present; n = an integer (1, 2, 3, 4, 5...); p = number of pulses or rectifiers. For most applications, it is sufficient to consider the harmonic range from the 2^{nd} to the 25^{th}, but most standards specify up to the 50^{th} (Arrillaga and Whatson, 2003).

Voltage-source converters are known as a source of high-frequency harmonics with the switching frequency and multiples of the switching frequency (1 kHz and up) appearing in the spectrum of the current (Bollen and Häger, 2005). According to Luszcz (2013) typical carrier frequencies used in AC-DC PWM boost converters are within a range from single kHz for high power application up to several tens of kHz for small converters. In other words, pulse-width modulation leads to groups of frequency components around the integer multiples of the switching frequency (Bollen and Häger, 2005). Also hysteresis control, used in smaller converters, leads to a noise-like frequency spectrum around an "average switching frequency" determined by the design of the converter. Therefore, if the switching frequency is close to a system resonance it causes a large high-frequency ripple on the voltage. Important part of conducted emission spectrum generated by those types of converters is located in frequency range below 2 kHz normalised by power quality regulations and above 9 kHz normalised by low frequency EMC regulation (especially CISPR A band 9kHz-150kHz) (Luszcz, 2013). Also a frequency spectrum range of harmonic distortions introduced into power grid can be exceedingly wide, nevertheless the maximum frequency range which is usually analysed is defined by CISPR standard as 30MHz. Furthermore, between 9kHz and 30MHz two frequency sub-bands are defined as CISPR A up to 150kHz and CISPR B above 150kHz as shown in Figure 3.29.

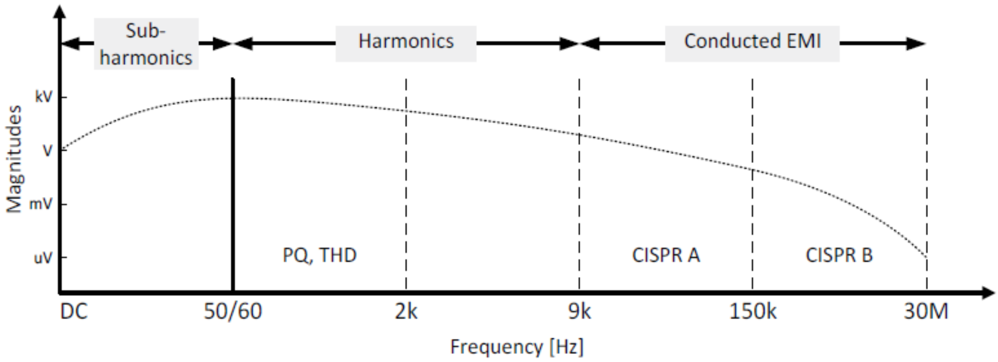

Figure 3.29: Harmonic distortions frequency sub-ranges (Luszcz, 2013)

According to Bollen and Häger (2005) an increasing penetration of DER with power-electronic interfaces, will lead to an increasing level of high-frequency harmonics. Unfortunately, they have noted that the full consequences of this remain unclear.

The frequency map of different harmonic emissions, usually considered as conducted type emissions which are mainly propagating by conduction process along power lines, is presented in Figure 3.30.

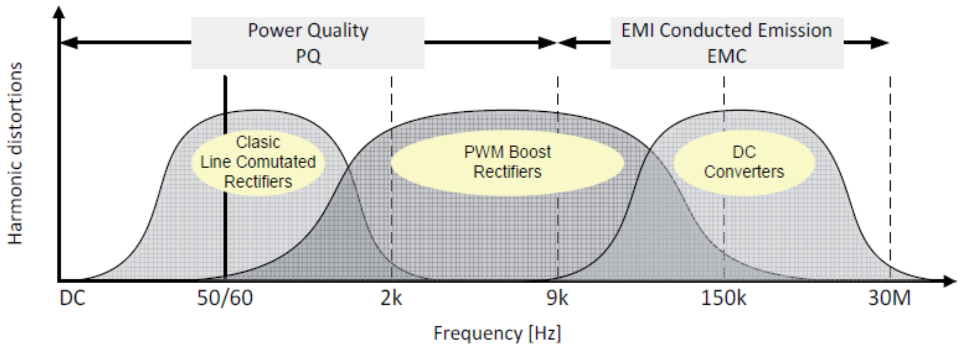

Figure 3.30: Characteristic distribution of harmonic emission spectra for different types of power electronics converters (Luszcz, 2013)

From this prospective, three primary types of harmonic distortion emission of typical sources which can be associated to particular power electronics converters topologies and technologies can be distinguished. These are (Luszcz, 2013):

- classic PQ frequency range up to 2kHz, where the main sources of harmonic distortions are usually line commutated rectifiers used in single- and multi-phase topologies using as power switches diodes or thyristors,
- high frequency harmonic distortion emission in the frequency range 2 − 9kHz, where mainly PWM boost rectifiers, as a relatively new topology, are generating harmonic components correlated to the used PWM carrier frequency which depending on the

topology and rated power of the converter is usually located between a few kHz and tens of kHz,

- conducted EMI emission in frequency range (9kHz − 30MHz), which is primarily an effect of DC voltage conversion by switching mode methods where power transistor switching processes are key sources of high frequency conducted emission which can easily propagate also towards AC power lines.

According to Jasinski and Kazmierkowski (2011) the recommended voltage distortion limits, is usually expressed by THD index, where THD is total root sum square (RSS) harmonic voltage in percent of nominal fundamental frequency voltage. This term has come into common usage to define either voltage or current distortion factor (DF) as shown in Equation 3.42. The DF is the ratio of the RSS of the harmonic content to the RMS value of the fundamental quantity, expressed as a percent of the fundamental.

$$THD = \sqrt{\frac{\sum_{h=2}^{50} {U_L}^2_{(h)}}{{U_L}^2_{(l)}}} 100\%$$

(Equation 3.42)

where: $U_{L(h)}$ = harmonic voltage; $U_{L(l)}$ = nominal fundamental frequency voltage

However, Equation. 3.43 shows a common formula for THD

$$THD = \sqrt{\sum_{h=2}^{\infty} \left(\frac{A_h}{A_l}\right)^2}$$

(Equation 3.43)

where: A_h = rms values of the non-fundamental harmonic components; A_l = rms value of the fundamental component

Harmonics generated by consumer’s appliances must not cause voltage rise in the connection point. Therefore, fixing limits may become important before using numerous harmonics emitting devices together (Vaimann *et al*., 2012). According to them in some papers measurements with nonlinear loads are done when 5% current´s total harmonic distortion value at connection point is followed. For example most of the common compact fluorescence lamps have the total harmonic distortion over 100 %. Harmonic currents injected from individual end users on the system should be limited. This is because these currents propagate toward the supply source through the system impedance, creating voltage distortion. So by limiting the amount of injected harmonic currents, the voltage distortion can be limited as well. They have noted that this is the basic method of controlling the overall distortion levels proposed by IEEE Standard 519-1992.

IEEE (2003) stipulates that when the DR is serving balanced linear loads, harmonic current injection into the Area EPS at the PCC shall not exceed the limits stated in Table 3.4. The harmonic current injections shall be exclusive of any harmonic currents due to harmonic voltage distortion present in the Area EPS without the DR connected.

Table 3.4: Maximum harmonic current distortion in percent of current (I) (IEEE, 2003)

Individual harmonic order h (odd harmonics)	h < 11	11 ≤ h < 17	17 ≤ h < 23	23 ≤ h < 35	35 ≤ h	Total demand distortion (TDD)
Percent (%)	4.0	2.0	1.5	0.6	0.3	5.0

The current (I) equals the greater of the Local EPS maximum load current integrated demand (15 or 30 minutes) without the DR unit, or the DR unit rated current capacity (transformed to the PCC when a transformer exists between the DR unit and the PCC). Equally, even harmonics are limited to 25% of the odd harmonic limits above.

Section 2.3.1.5 highlighted that PV inverter is a key element of grid-connected PV power systems and the main function is to convert the DC power generated by PV panels into grid-synchronized AC power. Also it noted that the high frequency harmonics in the output current due to power semiconductors switching are reduced by the filter. An inverter could be either a voltage-source or current-source. Currently, inverters are not required to be characterised as being voltage-source or current-source and hence it is very difficult for purchasers of equipment to select a particular type (Passey *et al.*, 2011). According to them, even when a voltage-source inverter is used to help correct poor harmonic voltage, and so the inverter produces harmonic currents to assist in correcting the grid voltage, its energy output is reduced. This is equitable provided the owner of the inverter is also the cause of the harmonics on the grid and so they are assisting with correction of their own problem. However, the owner of the inverter may be experiencing high harmonic flows, and so reduced energy output, because of the poor harmonic performance of other customers on the power system. This is another reason why current-source inverters are common – their output is not generally affected by the grid's voltage harmonics.

Harmonics can also be eliminated using passive and active filters, which are generally cheaper than inverters. Passive filters are composed of passive elements such as capacitors or reactors, and absorb harmonic current by providing a low-impedance shunt for specific frequency domains. They come in two forms: tuned filters (which are targeted to eliminate specific lower-order harmonics) and higher-order filters (that can absorb entire ranges of higher-order harmonics). Active filters detect harmonic current and generate harmonics with the opposite polarity for compensation. Active filters are better than passive filters because (IEA-PVPS, 2009; Passey *et al*., 2011):

- they can eliminate several harmonic currents at the same time,
- they are smaller and quieter, and
- they do not require a system setting change even when a change occurs in the grid.

In summary and according to Passey *et al*. (2011), while the most common type of inverters (current-source) does not create harmonic distortion, it also does not provide the harmonic support required from the grid. In contrast, voltage-source inverters can provide harmonic support but do so at an energy cost and there are a variety of harmonic compensators that are likely to be cheaper.

3.4 Conclusion

This chapter has reviewed the inherent issues of distributed generation integration commencing with a highlight of DG renaissance. It has shown that DG interconnection and integration and not synonymous though used interchangeably by some authors. Also highlighted in this chapter are some of the technical challenges posed by DG integration.

Chapters 2 and 3 have focused on DG with little or no reference to smart grid. Therefore the next chapter is devoted to smart grid concept, development and possible lessons for South Africa.

CHAPTER 4
SMART GRID: CONCEPT, DEVELOPMENT AND LESSONS FOR SOUTH AFRICA

4.1 Introduction

The focus of this chapter is on the current clamour for a modernised electric power system in tandem with the prevailing digitisation of every aspect of global life or system. For instance, for over half a century, society has used language such as ‘computer revolution’ or ‘computer age’ and more recently, it is common to find references to the ‘information revolution’ or the ‘digital revolution’ (Care, 2010). Currently, according to the author, the word ‘digital’ is a familiar cultural keyword and phrases such as ‘digital culture’, ‘digital society’, or ‘digital economy’ are commonly used. He therefore concludes that implicit in this rhetoric is the idea that, as a society, we are moving from an analogue ‘world’ into a digital one.

To realise this objective consideration will be given to the needs for grid modernisation, smart grid neologism or coinage; smart grid concept, components and definitions; smart grid developments and the relevant lessons for South Africa.

4.2 Need for Grid Modernisation

As stated above in recent times virtually every aspect of global life or system has witnessed a form of modernisation called digitisation. Examples of such systems include telecommunication, control systems, entertainment and even economies. For instance, looking at the communication industry, one observes how drastically the communication horizon has changed. From letters to e-mails and SMS, from phone calls to video chat and live conferencing, from phone booths to smart phones: since the digitisation of communication, a new era of consumer choice has been inaugurated (Khattak *et al*., 2012). In their view the potential exists for similar transformation and opportunity in the provision of electricity, embodied in a concept known as the “smart grid.” It is note worthy that digitisation thrives in the presence of electricity but it had progressed without electricity being digitised.

Therefore, prior to the introduction of smart grid electric power system had remained analogueous to a sign post that directs to a destination without reaching that destination.

However, electricity symbolised by the electric grid was cited by the National Academy of Engineering as the supreme engineering achievement of the 20th century (Wulf, 2000) because if *any* of its elements were removed our world would be a very different place – and a much less hospitable one. Although the grid has witnessed many innovations and improvements over the last century, its basic design has remained the same from the days of Edison and Tesla in the 1880s: centralised generation through a one-way transmission and distribution system to consuming devices that have no information about the cost of electricity or whether the grid is overloaded (Arnold, 2011). According to him, reliable and high quality electric power is becoming increasingly important given the pervasive application of electronics and microprocessors. This in his view justifies the urgent need to modernise the grid.

In modernising the grid the first question we have to answer is how "dumb" our grid is at present and which parts of it need to be made "smart" (Kurth, 2013). He contends that the transmission system is relatively intelligent and controlled on the basis of reliable data. This can be seen looking at the sharp increase in renewable energy which has so far been handled in Germany and Europe without any significant blackouts. Medium and low-voltage grids, on the other hand, are "as dumb as dumb can be" and are controlled virtually "blind." We must therefore consider it a top priority to make these grids smarter, glean more information about their condition and load level and indeed be able to control them actively at all. To achieve this, not a single smart meter is necessary, however, since the amount of electricity entering or leaving each consumer's premises is of less importance. Only the big industrial customers are relevant—yet their consumption is already measured accurately today. Kurth (2013) holds that currently lacking are meter and control devices actually in the grid and possibly a few reference measurements for wind and photovoltaic. For instance, smart metering could significantly improve knowledge of what is happening in the distribution grid, which nowadays is operated rather blindly (IEC, 2010). Equally, for the transmission grid an improvement of the observability of system-wide dynamic phenomena is achieved by Wide Area Monitoring and System Integrity Protection Schemes.

Efforts to completely modernise the grid or make parts of it smarter, based on the argument of Kurth (2013) and other authors, are motivated by several goals such as (Arnold, 2011):

- To make the production and delivery of electricity more cost-effective.

- To provide consumers with electronically available information and automated tools to help them make more informed decisions about their energy consumption and control their costs.
- To help reduce production of greenhouse gas emissions in generating electricity by permitting greater use of renewable sources.
- To improve the reliability of service.
- To prepare the grid to support a growing fleet of electric vehicles in order to reduce dependence on oil.

In the United States and many other countries, modernisation of the electric power grid is central to national efforts to (NIST, 2012):

- increase energy efficiency,
- transition to renewable sources of energy,
- reduce greenhouse gas emissions, and
- build a sustainable economy that ensures prosperity for current and future generations.

The need to improve the environment, especially through reduction if not elimination of GHG emissions from centralised large generating plants, and energy efficiency has resulted to considerations for smarter or better methods of handling the grid. Through this means a cleaner energy supply that is more energy efficient, more affordable and more sustainable will be developed. Succinctly put, Smart grids are essential for achieving energy security, affordable energy and climate change mitigation – the three elements of the "energy trilemma" (WEC, 2012). Therefore, the core drivers for the current global move towards smart grid technology, as shown in Figure 4.1, are (ETP, 2006):

- Need for better or healthier environment
- Security and quality of energy supply
- Market evolution and efficient regulatory framework

According to IEC (2010), the key market smart grid drivers are:

- Need for more energy
- Increased usage of renewable energy resources
- Sustainability
- Competitive energy prices

- Security of supply
- Ageing infrastructure and workforce

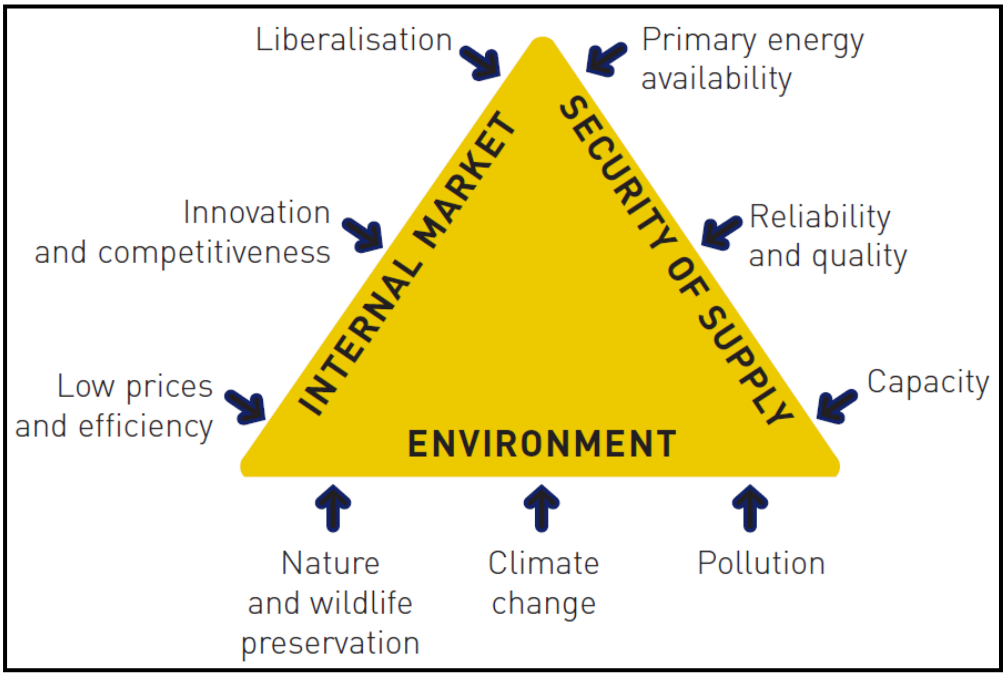

Figure 4.1: Driving forces in the move towards smart grids (ETP, 2006)

EURELECTRIC (2012) believes there are some universally accepted benefits of smart grid and a 'benefit' being an impact (of a smart grid project) that is of value to any regulated or commercial body, energy consuming households or society at large. To gauge their magnitude and facilitate comparison, benefits should be quantified and expressed in monetary terms. For smart grid systems, it is well accepted that there are four fundamental categories of benefits (EPRI, 2010; EURELECTRIC, 2012). But according to EPRI (2011) smart grid benefits can be categorised into five types:

1. Power reliability and power quality. The Smart Grid provides a reliable power supply with fewer and briefer outages, "cleaner" power, and self-healing power systems, through the use of digital information, automated control, and autonomous systems.
2. Safety and cyber security benefits. The Smart Grid continuously monitors itself to detect unsafe or insecure situations that could detract from its high reliability and safe operation. Higher cyber security is built in to all systems and operations including physical plant monitoring, cyber security, and privacy protection of all users and customers.
3. Energy efficiency benefits. The Smart Grid is more efficient, providing reduced total energy use, reduced peak demand, reduced energy losses, and the ability to induce end-users to reduce electricity use instead of relying upon new generation.

4. Environmental and conservation benefits. The Smart Grid facilitates an improved environment. It helps reduce greenhouse gases (GHG) and other pollutants by reducing generation from inefficient energy sources, supports renewable energy sources, and enables the replacement of gasoline-powered vehicles with plug-in electric vehicles.
5. Direct financial benefits. The Smart Grid offers direct economic benefits. Operations costs are reduced or avoided. Customers have pricing choices and access to energy information. Entrepreneurs accelerate technology introduction into the generation, distribution, storage, and coordination of energy.

The first four benefits are the ones referred to by EPRI (2010) and EURELECTRIC (2012). But notably within each of the broad categories, there are several types of benefit and by definition they are mutually exclusive in terms of accounting for different benefit categories (EPRI, 2010; EURELECTRIC, 2012). They assert that smart grid functionalities that lead to one type of benefit can also lead to other types of benefits. For example, improvements that reduce distribution losses (an economic benefit) mean that pollutant emissions are reduced as well (which is an environmental benefit).

Having identified the achieved benefits, it is very important to identify the beneficiaries in the process. In general, benefits are reductions in costs and damages, whether to generators, distribution system operators, consumers or to society at large (EURELECTRIC, 2012). Broadly speaking there are three groups of beneficiaries or primary stakeholder groups (EPRI, 2010: EPRI, 2011; EURELECTRIC, 2012)

- Utilities are the suppliers of power and include electric utilities that generate power as well as the transmission and the load serving entities that deliver it (and integrated utilities that do all three). Many of the benefits (and of course the costs) to utilities are passed on to ratepayers, though the exact portion that is passed on varies from case to case. Utilities can provide more reliable energy, particularly during challenging emergency conditions, while managing their costs more effectively through efficiency and information which can be used for more effective infrastructure development, maintenance and operation.
- Customers are the end-users or consumers of electricity. They are ratepayers who benefit from changes in rates and services offered by utilities, as well as from improvements in reliability and power quality. The benefits to customers are reduced

electricity bills, reduced damages from power interruptions and improved power quality. Consumers can balance their energy consumption with the real-time supply of energy. Variable pricing will provide consumer incentives to install their own infrastructure that supports the Smart Grid. Smart grid information and communication infrastructure will support additional services not available today.

- Society in general is the recipient of externalities of the Smart Grid – effects on the public or society at large – which can be either positive or negative in nature. In general, the benefits in this category are reductions in negative externalities such as pollutant emissions. Positive externalities are generally more difficult to identify. Societal welfare benefits associated with efficiency improvements are not entirely reflected in the price of electricity; there are indirect, macroeconomic benefits such as job creation as well. There are also benefits to, and damages borne by society at large that are not externalities in the strict sense of the formal definition, but which are linked to other types of market failures (e.g., oil security benefits). So basically society benefits from more reliable power for governmental services, businesses, and consumers sensitive to power outage. Renewable energy, increased demand efficiencies, and Plug-In Electric Vehicle (PEV) or other distributed storage support will reduce environmental costs, including society's carbon footprint.

Identifying these groups of beneficiaries enables one to distinguish *who* (which group in general) is benefiting from which types of smart grid investments (EPRI, 2010). A benefit to any one of these stakeholders can in turn benefit the others (EPRI, 2011; EURELECTRIC, 2012). For example, those benefits that reduce costs for utilities could lower prices, or prevent price increases, for customers. However in such cases it is vital to ensure that benefits transferred from one party to another are not double counted (EURELECTRIC, 2012). Lower costs and decreased infrastructure requirements enhance the value of electricity to consumers. Reduced costs increase economic activity which benefits society. Societal benefits of the smart grid can be indirect and hard to quantify, but cannot be overlooked. According to EPRI (2011) and EURELECTRIC (2012) other stakeholders also benefit from the smart grid. For instance, regulators can benefit from the transparency and audit-ability of smart grid information. Furthermore, vendors and integrators benefit from business and product opportunities around smart grid components and systems. Therefore, total benefits of smart grid are the sum of the benefits to utilities, consumers and society at large.

NIST (2012) notes that around the world, billions of dollars are being spent to build elements of what ultimately will be “smart” electric power grids. In other words, around the globe countries are undertaking massive investments in modernising their energy infrastructure (Noam *et al*., 2013). The aim is to create a networked, automated, distributed, market- and service-promoting ICT-enhanced energy system in which new optimisation potentials and business models can emerge. But according to Camacho *et al*. (2011) the term *smart grid* implies that the existing grid is dumb, which is far from true. They believe that the current grid structure reflects carefully considered trade-offs between cost and reliability.

A smart grid whose sobriquets include “intelligent grid or intelligrid,” “modern grid,” “grid of the future or future grid,” “energy internet” and so on is deemed to be an improvement of the 20th century power grid. The current grid is a relic of the past, designed to meet the needs of a different industry in a bygone era with outdated technologies that are incapable of meeting today's requirements, let alone those of the future (Sioshansi, 2012). Therefore, a smart grid and similar phrases have all been used to describe a “digitized” and intelligent version of the present-day power grid. The traditional grid is built on the following five premises (Santacana *et al*., 2010):

1) The components are predominantly dumb conductors and are not controllable.
2) Even if they are controllable, they cannot react quickly enough.
3) There is no energy storage; an interruption on the transmission or distribution grid means an interruption of service.
4) Customer demands are not controllable, and the grid can only react passively to the change in demands with centralized control.
5) The grid can only react to the changes by continuously balancing the output of the central power plants in order to remain in a dynamic equilibrium.

The improvement derivable through smart grid hinges on the two-way flows of electricity and information aimed at creating an automated and distributed advanced energy delivery network, in contrast to the one-way flow of a traditional grid. A brief comparison between traditional grid and a smart grid is given in Table 4.1. From the foregoing, transformation from a centralised, producer controlled network to the one that is less centralised and more consumer-active has become imperative. This transformation promises (Agarwal and Tsoukalas, 2011):

1. To change the industry's entire business model and
2. Its relationship with all stakeholders involving and affecting utilities, regulators, energy service providers, technology and automation vendor, and all consumer of electric power.

Table 4.1: The smart grid compared with the existing grid (Farhangi, 2010)

Existing Grid	**Intelligent Grid**
Electromechanical	Digital
One-way communication	Two-way communication
Centralised generation	Distributed generation
Hierarchical	Network
Few sensors	Sensors throughout
Blind	Self-monitoring
Manual restoration	Self-healing
Failures and blackouts	Adaptive and islanding
Manual check/Test	Remote check/Test
Limited control	Pervasive control
Few customer choices	Many customer choices

However, this transformation is not without a technical cost to utilities such as Eskom. Therefore, utilities have to master the following challenges (IEC, 2010):

- High power system loading
- Increasing distance between generation and load
- Fluctuating renewable
- New loads (hybrid/e-cars)
- Increased use of distributed energy resources
- Cost pressure
- Utility unbundling
- Increased energy trading
- Transparent consumption and pricing for the consumer
- Significant regulatory push

Agarwal and Tsoukalas (2011) have observed that a complete realisation of the smart grid presents several challenges. According to them one of the several challenges that cannot be ignored is the need to ensure highest level of power quality. They assert that it is desirable to consider power quality not only from the electronic components usage in electrical network but also for the design of regulatory system for electrical networks. But a key challenge is explaining in simple terms what a smart grid is, and more importantly, the direct benefits customers will incur with a massive deployment of all the necessary technologies (McKinsey, 2010; WEC, 2012). In his testimony before the House Committee on Energy and Commerce on 3rd May 2007, Yeager (2007) asserted: "The biggest impediment to the smart electric grid transition is neither technical nor economic. Instead, the transition is limited today by obsolete regulatory barriers and disincentives that echo from an earlier era". Generally, the challenges facing smart grid development as highlighted by US-EAC (2008) are:

- Regulatory challenges
- Utility business model
- Lack of a coordinated strategy
- Cost
- Consumer impacts
- Key infrastructure issue
- Security
- Credit crisis impacts

Interestingly, Bipath (2010) has identified the challenges responsible for the slow emergence of smart grid in South Africa and also proffered solutions namely:

- Fundamentally**,** no single business owns or operates the grid. Individual players have little incentives to risk a major change. With so many players in the grid system, Eskom and 187 municipalities, finding a common vision for change is difficult but imperative.
- Smart grid benefits are so broad and far reaching that perhaps only government can account for the cumulative societal value. Therefore, longer term financial incentives are needed to enable the larger infrastructure investments required for the Smart Grid
- Solutions to the regulatory and legislative barriers include changes in statutes, policy, and regulation to eliminate those that inhibit progress, and create those that encourage progress. The aim is to create a "win-win" scenario for all stakeholders
- Overcoming culture and communication challenges requires increasing the understanding and awareness of stakeholders on the value of the Smart Grid and

encouraging them to embrace the needed changes within their organisational cultures

- Industrial barriers require defining the case for change, the "burning platform", and providing the necessary incentives to engage industry on the smart grid. Industry will respond when it understands there is a profitable market for smart grid technologies and services. However, the solutions cannot be overseas based and South Africa cannot be a net importer of technology. It must create jobs back home otherwise it will get very little support.
- There is a need to increase the speed of research, development and deployment as a solution to technical barriers. This involves:
  - Increase in funding to support research, development and deployment for those technologies that are needed for the Smart Grid
  - Working more closely with academia to develop the new human resources with skill needed for the Smart Grid
  - Applying more priority and resources to the development of needed standards and universally acceptable system architecture.
  - Clarifying the pathway to the Smart Grid by developing a transition plan that shows the intermediate milestones for achieving its vision

According to IEA (2011) smart grid investments are likely to be deployed more rapidly in vertically integrated utilities where the business case can more easily be made. In the many areas where this is not possible, more strategic co-operation between distribution system operators and transmission system operators is needed. The implication of this is that it is worthwhile for Eskom, being a vertically integrated utility, to consider making the necessary investments for an immediate smart grid deployment given its enormous benefits.

4.3 Smart Grid Neologism

There is an apparent confusion on who coined the phrase "smart grid" and the date but this is common in science and technology. Consequently smart grid historical perspective should be devoid of the historians' holistic approach because of the seeming differences in the dates of some of the major scientific or technological feats, as noted by Gottlieb (1997):

> *Historians like to assign definite dates to mark the occurrence of significant events. This is not quite so easy to do in science and technology as it is in, say,*

politics. When one studies the birth and evolution of notable achievements in either theoretical or applied science a great deal of fuzzy logic is encountered in attempts to date the sudden emergence of the event, and more 'originators', inventors, discoverers and improvers are usually involved than given deserved credit. Moreover, there are inevitably earlier workers in the field who laid down the basic intellectual tools for demonstrable ideas and devices.

For instance, Schneidewind (2009) and Parish (2009) assert that the term "Smart Grid" was coined by Andres E. Carvallo on April 24, 2007 at an IDC Energy Conference in Chicago. But Carvallo and Cooper (2011) posit that Andres Carvallo defined smart grid on March 5, 2004 and with John Cooper built the very first smart grid in the United States at Austin Energy – what they now call a first generation smart grid, or Smart Grid 1.0 – and have documented their unique experiences from 2003 to 2010.

However, literature is replete with credits being given to Dr. Massood Amin for smart grid neologism without a consensus on the date. According to Wikipedia (2012), the term smart grid has been in use since at least 2005, when it appeared in the article "Toward a Smart Grid" by Amin and Wollenberg. And that the term had been used previously and may date as far back as 1998. The dates mostly cited are 2003, 2004 and 2005 (Kateeb *et al*., 2011; Simões *et al*., 2012; Keyhani, 2012) and credit being given to Amin and Wollenberg.

However, smart grid concept emerged in Europe but was named in USA Energy Act 2007 and as Obama stimulus package (Hill, 2010). The US Energy Independence and Security Act (EISA) of 2007 passed by the US Congress, particularly with article XIII, started the era of an official use of the term "smart grid" or brought the term *smart grid* into the public vocabulary to designate future expansion of the electricity grid (Kezunovic *et al*., 2012; Nordell, 2012). According to Nordell (2012) the EISA mandate assumes that existing electrical system of USA is antiquated and in disrepair and needs urgent help to meet emerging demands. In fact, the author asserts that the creation of the smart grid really began more than 100 years ago with the early development of interconnected power systems. However, he also notes that there is ample opportunity under the EISA mandate to make the power systems of USA "smarter,"

Therefore, over the last several years, the term ''smart grid'' has taken the electric power industry by storm, with its use being further cemented in the power industry lexicon with the launch of the IEEE *Transactions on Smart Grid Journal* in 2010 (Glover *et al*., 2012).

4.4 Smart Grid Concept

Virtually every decade or generation has its own buzzword such as Great Depression of the 1930s, energy efficiency since 1973, and lately economic recession since 2007. Such fads and trends have abounded in the electric utility industry (Brown, 2008). According to him, the result of a concept or catch phrase catching the attention and imagination of people is a wave of talk, buzz, papers, presentations, and self-proclaimed experts. Sometimes these concepts validate themselves and are gradually integrated into standard business practices. Alternatively, these concepts fade away and make room for the next big thing. In recent time the world has been inundated with smart systems courtesy of ICT. One of such systems is the Smart Grid. The Smart Grid has seen major hype over the past few years with many considering Smart Grid as a cliché in the utility industry (Borlase *et al*., 2012). In their view, what was initially given the name of "intelligent grid" (maybe that implied too much) and is currently interpreted a hundred and one different ways, Smart Grid has gained worldwide recognition, and the "smart" catchphrase seems to have carried over into other industries – for good reasons or not. Consequently, almost everything is dubbed "smart" in the electric system, even down to the "smart bolt" on a transmission tower.

Smart grid is a concept not a computer system or some sort of hardware (Sallam and Malik, 2011). According to IEC (2010) smart grids can have multiple shapes because there is no single unified concept of what constitutes a "Smart Grid". While there are many facets to the concept, smart grid is really about three things: distributed intelligence, digital communications, and decision software (Collier, 2010). Therefore, it is about an intelligent electric delivery system that responds to the needs of and directly communicates with consumers. Sallam and Malik (2011) assert that one of smart grid driving factors is the need to understand and manage the technical challenges and opportunities for integrating new generation technologies into grids. "Smart Grid" is one of the major trends and markets which involve the whole energy conversion chain from generation to consumer (IEC, 2010). It notes that the power flow will change from a unidirectional power flow (from centralized generation via the transmission grids and distribution grids to the customers) to a bidirectional power flow. Also, the way a power system is operated changes from the hierarchical top-down approach to a distributed control. Furthermore, one of the main points about Smart Grid is an increased level of observability and controllability of a complex power system. However, this can only be achieved by an increased level of information sharing between the individual components and sub-systems of the power system. It contends that standardization plays a key role in providing the ability of information sharing which will be required to enable the development of new applications for a future power system.

According to NIST (2012), the smart grid is a complex system of systems, serving the diverse needs of many stakeholders. However, the broad spectrum of entities and stakeholders covered by the smart grid is evident from the conceptual model of Figure 4. 2. The domains and actors in Figure 4.2 are highlighted in Table 4.2.

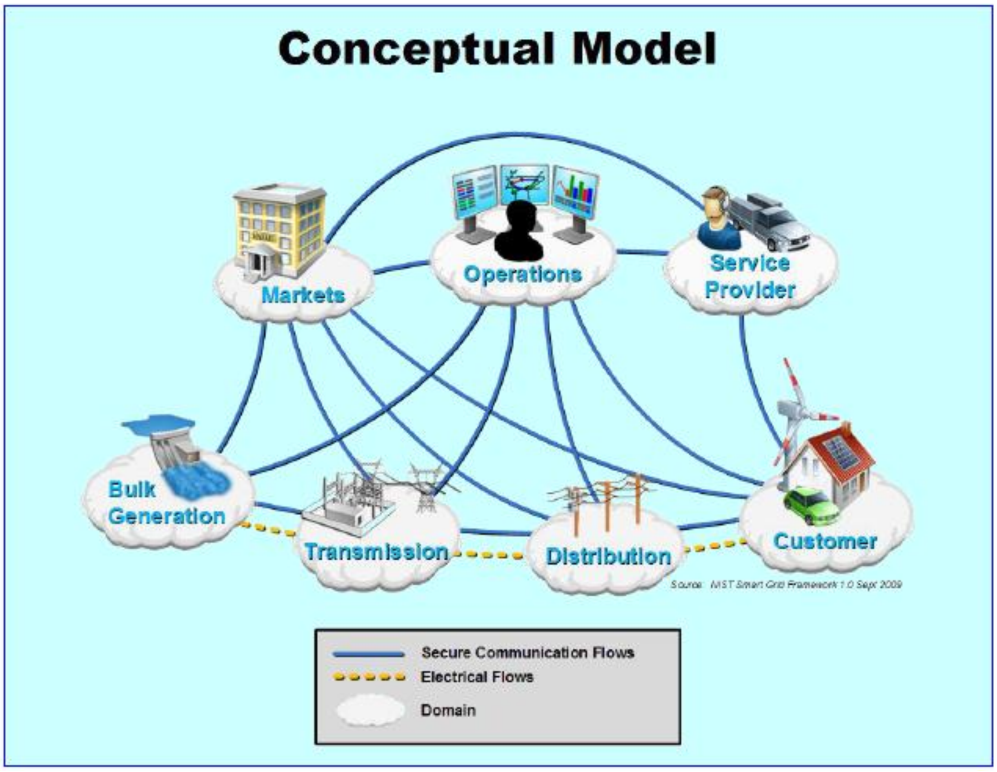

Figure 4.2: NIST smart grid conceptual model (Camacho *et al*., 2011; NIST, 2012)

Worthy of note in Figure 4.2 is the interaction of actors in different smart grid domains through secure communication. Therefore, the smart grid further broadens the already highly distributed nature of power systems by extending control to the consumer level (Camacho *et al*., 2011). They submit that the smart grid can be conceptualised as an extensive cyber-physical system that supports and significantly enhances controllability and responsiveness of highly distributed resources and assets within electric power systems. Also, the responsiveness achievable through smart grid concepts will play a vital role in achieving large-scale integration of new forms of generation and demand. For instance, renewable generation will make an increasingly important contribution to electric energy production into the future.

Table 4.2: Domain and actors in the smart grid conceptual model (NIST, 2012)

S/N	Domain	Actors in the Domain
1	Customer	The end user of electricity. May also generate, store, and manage the use of energy. Traditionally, three customer types are discussed, each with its own domain: residential, commercial, and industrial.
2	Markets	The operators and participants in electricity markets
3	Service Provider	The organisations providing services to electricity customers and to utilities
4	Operations	The managers of the movement of electricity
5	Bulk Generation	The generators of electricity in bulk quantities. May also store energy for later distribution
6	Transmission	The carriers of bulk electricity over long distances. May also store and generate electricity
7	Distribution	The distributors of electricity to and from customers. May also store and generate electricity

However, integration of these highly variable, widely distributed resources will call for new approaches to power system operation and control. Likewise, new types of loads, such as plug-in electric vehicles and their associated vehicle-to-grid potential, will offer challenges and opportunities. Consequently, they contend that establishing a cyber infrastructure that provides ubiquitous sensing and actuation capabilities will be vital to achieving the responsiveness needed for future grid operations. But they also note that sensing and actuation will be pointless without appropriate controls. Another conceptual model of smart grid or smart grid vision that captures the issues raised by Camacho *et al*. (2011) is shown in Figure 4.3. Similarly, a smart grid concept based on European Technology Platform is shown in Figure 4.4.

According to ETP (2006), the operation of future grid will be shared between central and distributed generators. Control of distributed generators could be aggregated to form microgrids or 'virtual' power plants to facilitate their integration both in the physical system and in the market as shown in Figure 4.4. This figure clearly shows that smart grids are composed of complex and integrated systems which are often built on proven advanced technologies with a provision for further technological developments.

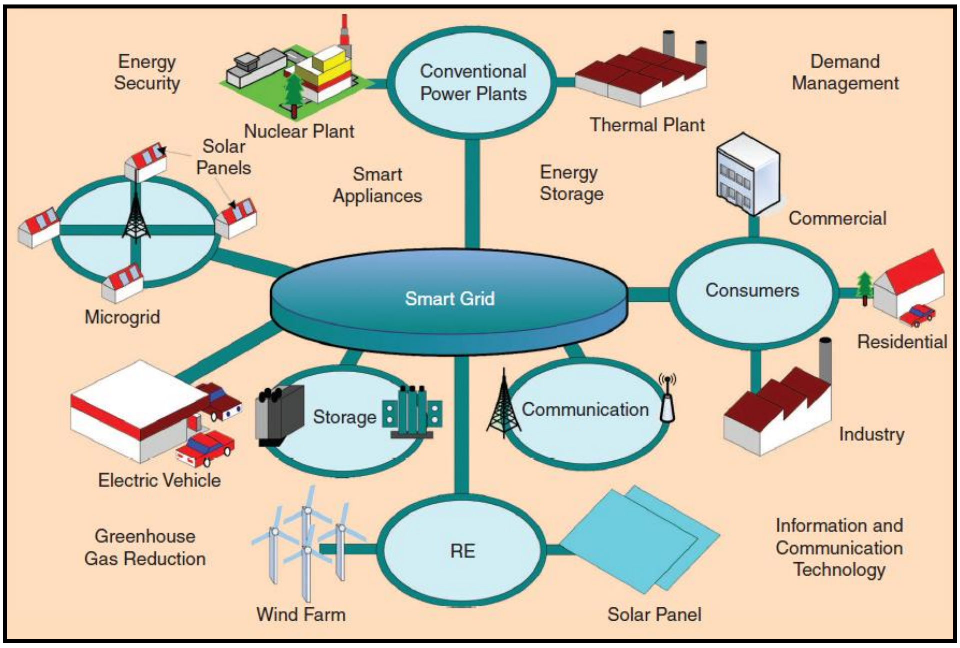

Figure 4.3: The future electric grid (Yu *et al*., 2011)

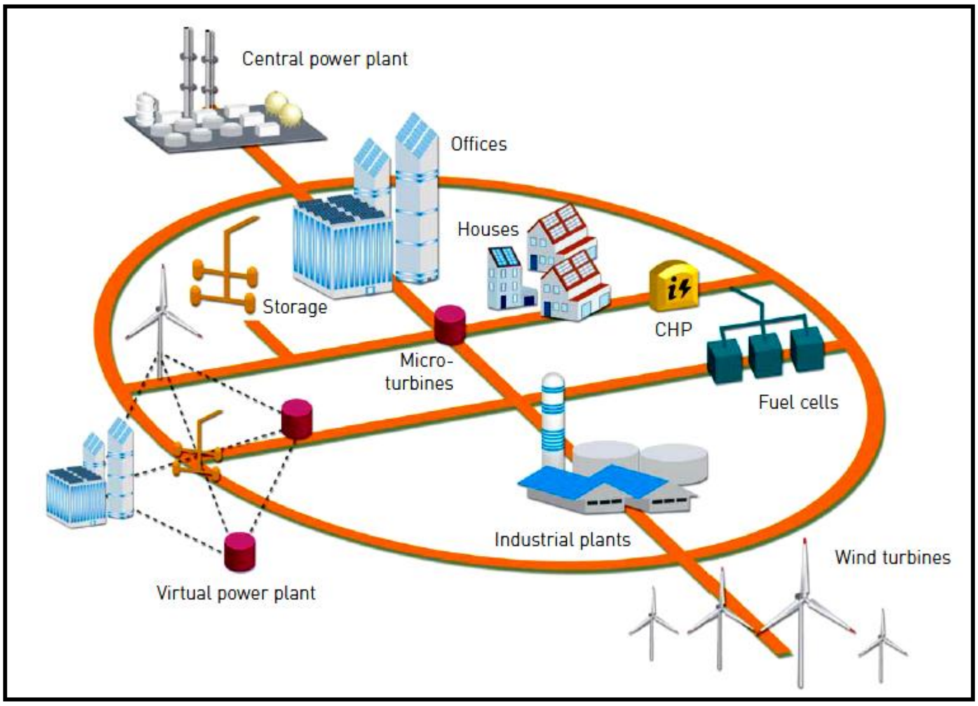

Figure 4.4: Future grid composition (ETP, 2006)

The vision of smart grids promises to make transformation in transmission, distribution, and conservation of energy possible by bringing philosophies and technological concepts that enabled internet to the utility and the electric grid (Agarwal and Tsoukalas, 2011). They have noted that smart grid employs digital technologies to improve transparency and to increase reliability as well as efficiency of electrical network.

The introduction of smart grid concept means that the era when national grid (the transmission system) or just grid referred to all the high voltage lines plus the big transformers and related equipment is over. This is because smart grid transcends the hitherto transmission system and incorporating non-conventional means of electricity generation as shown in Figure 4.5. A power system grid is therefore a network of transmission and distribution systems for delivering electric power from suppliers to consumers (Keyhani, 2011).

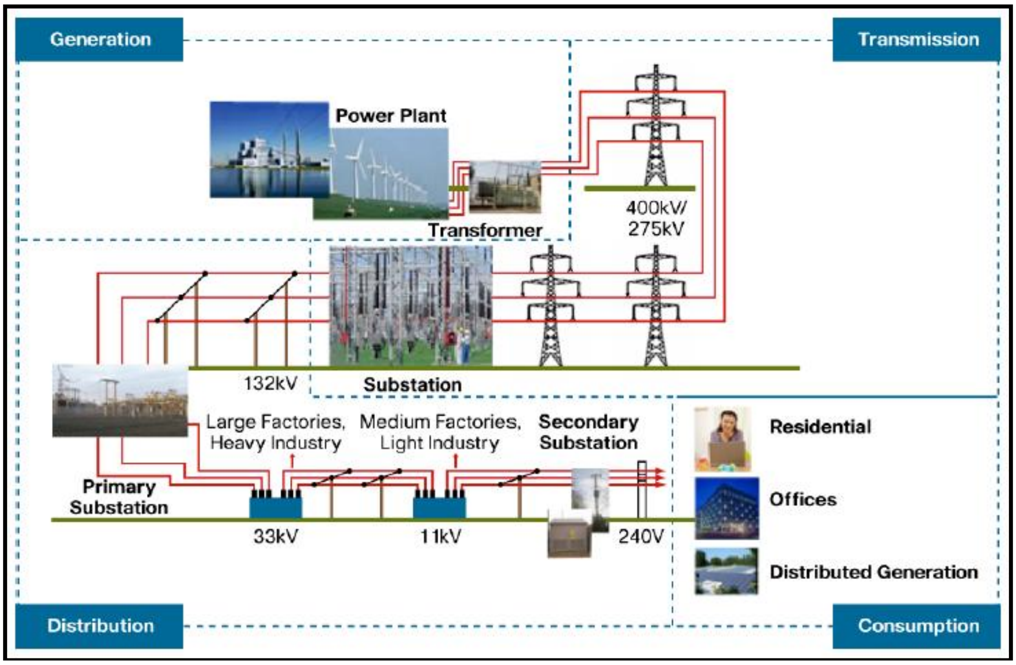

Figure 4.5: Physical view of a typical smart grid power infrastructure (Pothamsetty and Malik, 2009)

4.5 Smart Grid Components

But according to Popović-Gerber *et al.* (2012), the concept of smart grid involves the future evolution of the entire power network much more than adding ICT and smart metering to the existing grids. It will do this by continuing to deploy three fundamental building blocks: distributed intelligence, digital communications, and decision software (Collier, 2010). Consequently, Santacana *et al.* (2010) have proposed the representation of the four essential building blocks of the smart grid using a layered diagram as shown in Figure 4.6. According to them, an analoguey can be drawn between these layers and those that make up the human body. The bottom layer is analogueous to the body's muscles; the sensor/actuator layer corresponds to the body's sensory and motor nerves, which perceive the environment and control the muscles; the communication layer corresponds to the nerves that transmit perception and motor signals; and the decision intelligence layer corresponds to the human brain.

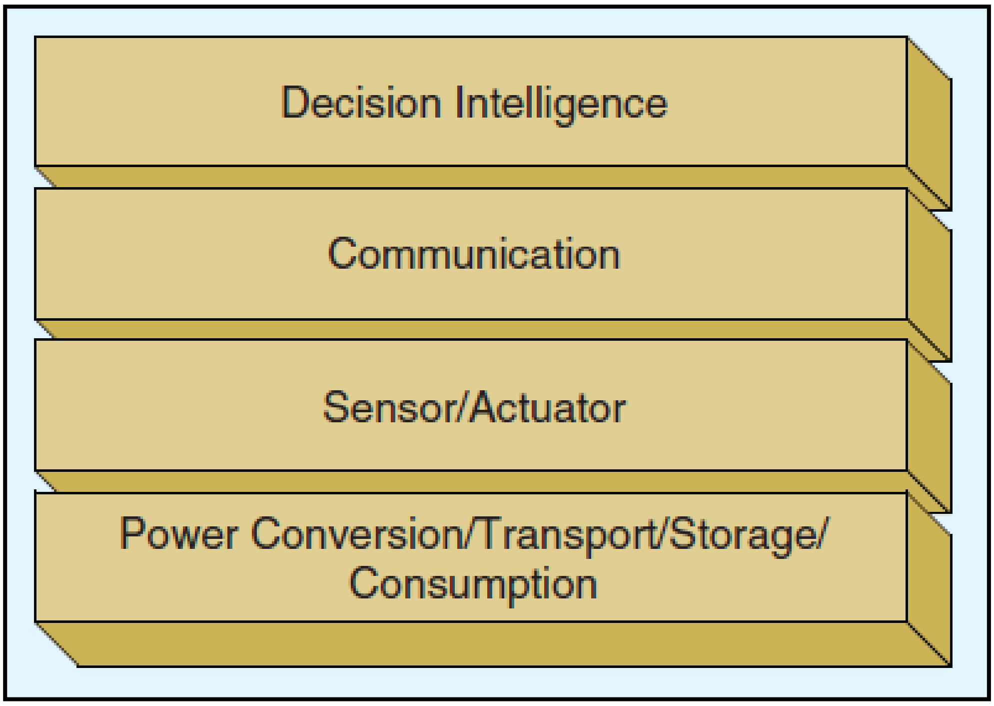

Figure 4.6 Smart grid technology layers (Santacana *et al*., 2010)

Gao *et al*. (2012) agree with Santacana *et al*. (2010) on the four major components of smart grid but disagree on the individual composition of these groups as shown in Figure 4.7. Therefore, according to Gao *et al*. (2012) smart grid is composed of:

- Sensing and Measurement
- Advanced Control Methods
- Improved Interfaces and Decision Support
- Advanced Components

The crucial role played by advanced control methods in smart grid through integrated communications (IC) is very clear from Figure 4.7. According to IEC (2010) common to most of the Smart Grid technologies is an increased use of communication and IT technologies, including an increased interaction and integration of formerly separated systems. Equally Noam *et al*. (2013) submit that an essential building block of smart grids is a communications and control system integrated with the existing power grid which enables end-to-end communication and thus improved coordination. Furthermore, through the use of broadband networks, sensors, smart meters, and software, this layer enables the two-way flow of electricity and information to provide superior performance at lower costs. At the same time, greenhouse gas emissions would be reduced as an improved coordination of energy supply and demand increases efficiency.

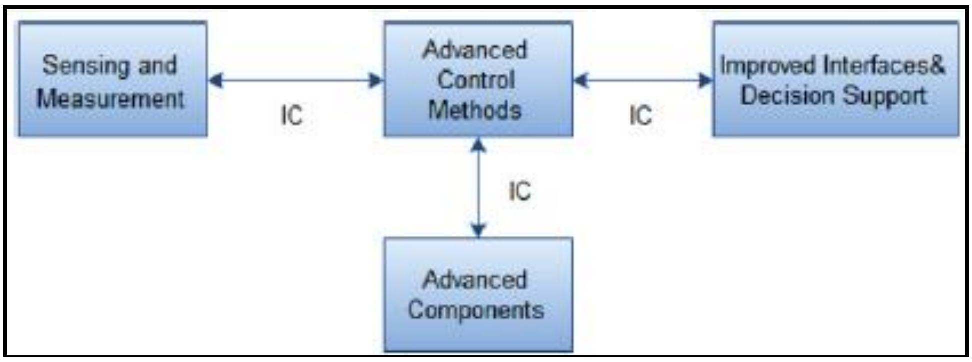

Figure 4.7: Smart grid key technology areas (Gao *et al*., 2012)

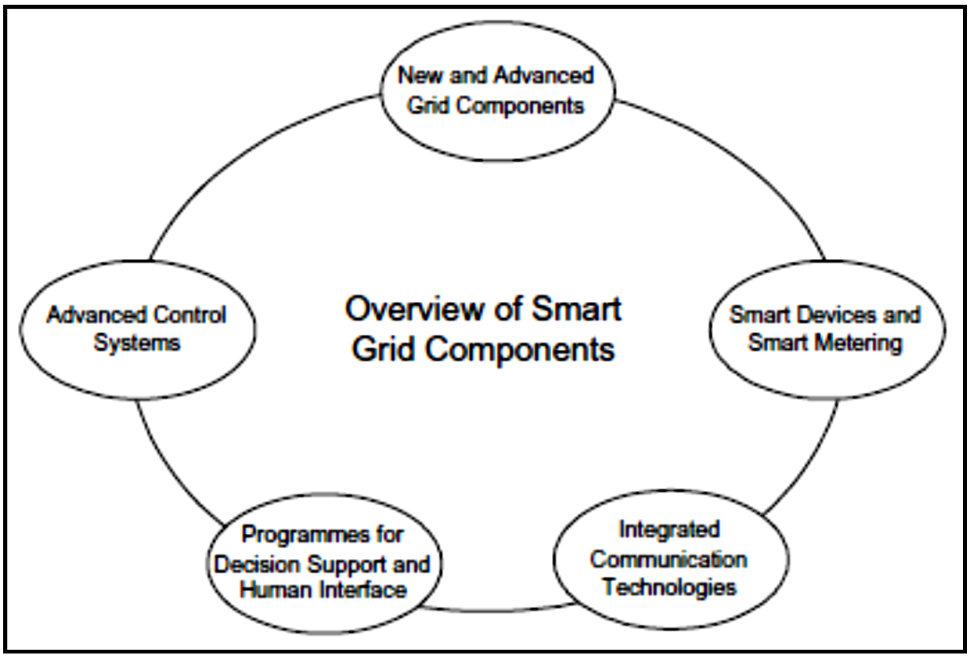

Figure 4.8: Main component of a smart grid (Agarwal and Tsoukalas, 2011)

From a technical components perspective, the smart grid is a highly complex combination and integration of multiple digital and non-digital technologies and systems (Agarwal and Tsoukalas, 2011). The authors have noted that these individual grid components do not need to be centralised, but can have more control stations and be more highly integrated. Figure 4.8 shows the five key technology areas emerging to achieve the principal characteristics of smart grid. According to NETL (2007) these technologies have been proven in other industries and are essential to realising the modern grid vision. They are briefly explained as follows (Agarwal and Tsoukalas, 2011; NETL, 2007; US-DOE, 2012):

- Fully integrated two-way, and possibly high-speed, communication technologies will make the modern grid a dynamic, interactive “mega-infrastructure” for real-time information and power exchange. Open architecture implementation of these technologies will create a plug-and-play environment that securely networks grid components to talk, listen and interact. Such technologies include Broadband over Power Line (BPL), digital wireless communications or hybrid fibre coax;

- Sensing and measurement, including advanced protection systems, wireless, intelligent system sensors for condition information on grid assets and system status, and Advanced Metering Infrastructure (AMI). These technologies will enhance power system measurements and enable the transformation of data into information. They evaluate the health of equipment and the integrity of the grid and support advanced protective relaying; they eliminate meter estimations and prevent energy theft. They also enable consumer choice and demand response, and help relieve congestion;
- Advanced components play an active role in determining the grid's behaviour. The next generation of these power system devices will apply the latest research and development in materials, superconductivity, energy storage, power electronics, microelectronics, Unified Power Flow Controllers (UPFC), Plug-in Hybrid Electric Vehicles and Direct Current micro-grids. This will produce higher power densities, greater reliability and power quality, enhanced electrical efficiency producing major environmental gains and improved real-time diagnostics;
- Advanced control methods will involve application of new methods to monitor essential components, enabling rapid diagnosis and timely, appropriate response to any event to ensure high quality supply and for Smart Grids to become self-healing. They will also support market pricing and enhance asset management and efficient operations. Such technologies include advanced Supervisory Control and Data Acquisition (SCADA) systems, load and short-term weather forecasting, and distributed intelligent control systems;.
- Improved interfaces and decision support: In many situations, the time available for operators to make decisions has shortened to seconds. Thus, the modern grid will require wide, seamless, real-time use of applications and tools that enable grid operators and managers to make decisions quickly. Decision support with improved interfaces will amplify human decision making at all levels of the grid to reduce significant amounts of data to actionable information. These include online transmission optimisation software, enhanced GIS mapping software and support tools to increase situational awareness.

Berst (2009) has represented the smart grid as a sector chart as shown in Figure 4.9. He has clumped core technologies at the top as a group because he believes the Smart Grid starts with those core technologies and they deserve more visibility in all considerations. According to him the chart serves at least one important purpose: it underscores the value and role of core technologies. Most high-tech industries have understood this for decades and they treat core technologies as foundations or “platforms.” Once the platform is in place, they amortize its cost by building as many applications on top of it as possible.

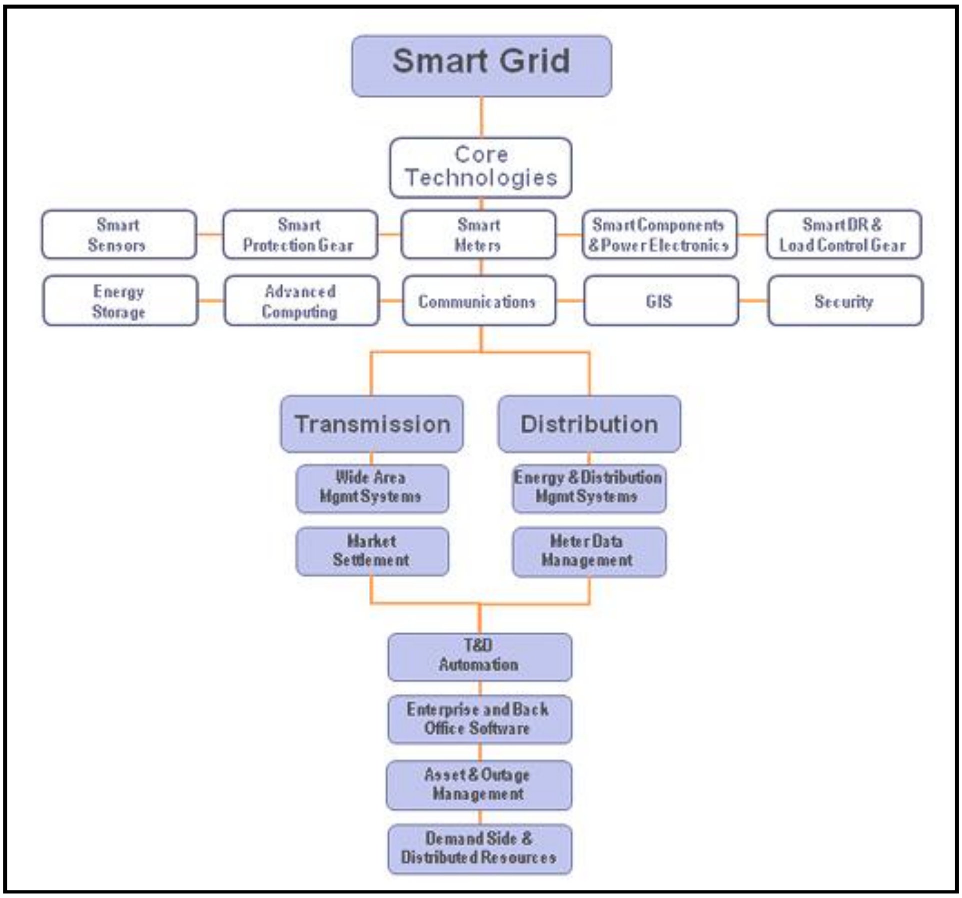

Figure 4.9: Smart Grid sector chart (Berst, 2009)

Berst (2009) relying on the fact that in reality, the pinnacle of intelligence is the ability to express complex ideas in simple terms – a lesson preached for at least the last 2,400 years by notables ranging from Aristotle to Abraham Lincoln to Albert Einstein – is convinced that consumers will never ask for something until they understand it. So in his opinion to make the case to consumers, we must simplify and he believes the best approach is to describe the Smart Grid as three pieces:

- Smart devices
- Two-way communications
- Advanced control systems

Santacana *et al*. (2010) have noted that the objective of transforming the current power grid into a smart grid will be achieved through the application of a combination of existing and emerging technologies for energy efficiency, renewable energy integration, demand response, wide-area monitoring and control, self-healing, HVDC, flexible ac transmission systems (FACTS), and so on. According to IEC (2010) HVDC and FACTS – both are actuators, e.g. to control the power flow – improve the controllability of the transmission grid. It notes that the controllability of the distribution grid is improved by load control and automated distribution switches. Devices and systems developed independently by many different suppliers, operated by many different utilities, and used by millions of customers, must work together (EC, 2010; NIST, 2012) to provide a smart power system (EC, 2010). Moreover these systems must work together not just across technical domains but across smart grid "enterprises" as well as the smart grid industry as a whole (NIST, 2012). For such a system to operate and the desired services and functionalities to be provided, these components will need to be linked together. In this context, interoperability becomes of major importance, not least in the interest of ensuring greater competition. However, the relationship between interconnection and interoperability is often a source of confusion for engineers just as between interconnection and integration as explained in Section 3.3. According to Siira (2014) during the development of the IEEE 2030-2011 Smart Grid standard, it was a personal struggle for him to "get" the concept of interoperability and how it related to power systems interconnection until he understood the perspectives of Information Technology (IT) and Communication Technology (CT). Then he realised that the systems-of-systems view employed and recommended in the IEEE 2030-2011 Smart Grid guide standard was extremely powerful.

Based on EC (2010) interoperability can be defined as the ability of a system or a product to work well with other systems or products. It notes that while there are many ways to achieve interoperability, one common way is via interface standards. A good example of this is the set of standards developed for the World Wide Web, including TCP/IP, HTTP and HTML, by which information is seamlessly exchanged over the Internet between devices of all sorts and brands, for the benefit of users and businesses. Equally, interoperability can be achieved through standardisation of communications in terms of interfaces, signals, messages and workflows. However, this does not mean unifying all data protocols or applications to a single technology but defining them in a detailed and unambiguous manner and agreeing on the usage and interpretation of standards in such a way as to ensure interoperability between systems and devices.

NIST (2012) and IEEE (2011b) have proffered solutions to interoperability challenges. Particularly IEEE (2011b) focuses on a systems-level approach to understanding and the guidance for *interoperability* components of communications, power systems, and information technology platforms as shown in Figure 4.10. Besides, there exist other factors frustrating smart grid transition as highlighted in Section 4.2. Siira (2014) asserts that the most recent developments that lay a path to improving interoperability are included in the IEEE 2030 series of standards, with IEEE 2030-2011 being the cornerstone. This guide standard introduces the Smart Grid Interoperability Reference Model (SGIRM) that organizes all the functions and interconnections of a Smart Grid in terms of three separate perspectives that together comprise the Smart Grid:

- The Power Systems (PS-IAP) Perspective defines the Smart Grid in terms of power entities and their interoperability.
- The Communications Technology (CT-IAP) Perspective defines the Smart Grid in terms of communications paths.
- The Information Technology (IT-IAP) perspective describes the Smart Grid in terms of information flows, entities, and protocols used to exchange that information.

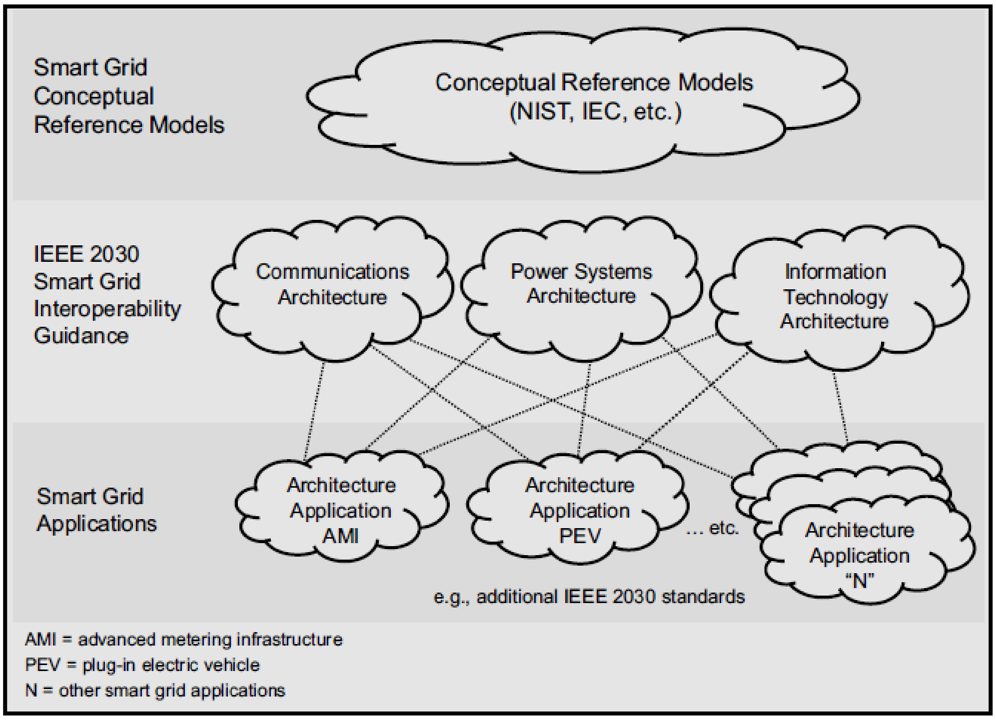

Figure 4.10 Evolution of smart grid interoperability (IEEE, 2011b)

Therefore, according to him interoperability is the capability of multiple networks, systems, devices, applications, or components to exchange and use information securely and effectively.

But, the standardisation of solutions and interoperability of technologies will help reduce deployment costs, essential to establish a positive business case (WEC, 2012). Therefore, interoperability between devices and equipment is crucial, as the introduction of smart grids and smart metering should not create a barrier to competition or unnecessary cost (EC, 2010).

4.6 Smart Grid Definitions

It is extremely difficult to present a unique definition of smart grids as the concept involves various components and concepts (Agarwal and Tsoukalas, 2011). This is because the smart grid concept combines a number of technologies, end-user solutions and addresses a number of policy and regulatory drivers (Glover *et al*., 2012). An attempt was made to characterise some key features of future grid development, such as the introduction of extensive communication, computational and sensing capabilities. Also there was a particular emphasis on expanding the ability of humans, whether in the role of grid operators or users of electricity, to be able to receive new information concerning grid conditions and to respond to this additional information with various actions at their disposal. As the attributes of the new grid were expanded, it became more difficult to capture all of this in simple terms; thus many interpretations of what smart grid really means have emerged (Hill, 2010). It is probably safe to say that there are as many definitions of "smart grid" as there are smart grid projects, experts, or practitioners (Sioshansi, 2012). Similarly, the many interpretations of "Smart Grid" depend on the perspective of those talking about Smart Grid – the utility, vendors, consultants, academics, and consumers (Borlase *et al*., 2012). Also, Khattak *et al*. (2012) have noted that the meaning of smart grid is usually multifaceted to variable audiences. According to them the gamut of workshops, online resources, and awareness campaigns that involve the deployment of smart grids and its associated benefits makes it difficult for end users and other stake holders to identify exactly what it is or understand the potential advantages and concerns. The definition of a smart grid also varies owing to the complexity of power systems (Yu *et al*., 2012). Another challenge in defining "smart grid" is that it is today used as a marketing term, rather than a technical definition (IEC, 2010). For this reason there is no well defined and commonly accepted scope of what "smart" is and what it is not. However, it notes that smart technologies improve the observability and/or the controllability of the power system. Therefore, smart grid technologies help to convert the power grid from a static infrastructure to be operated as designed, to a flexible, "living" infrastructure operated proactively.

According to Collier (2010), here is the problem with the smart grid, "Nobody knows exactly what it is". This means that "smart grids" is a term that defies a clear definition and yet it is essential to differentiate precisely to avoid misunderstandings (Kurth, 2013). The import of this differentiation stems from some aspects being directly linked to the grid, while others are far wider and barely affect the grid at all. Therefore, unfortunately as it may sound, despite the widespread embrace of the smart grid concept there is no universal definition of what smart grid encompasses. In other words, we cannot say there is an aligned definition of smart grid which is used worldwide (JUCCCE, 2007) as evidenced by the following examples. "Smart Grid" is a broad term used to include the application of secure, two-way communications and information technology to electrical power grids (IEEE, 2011). This means that smart grid is the integration of power, communications, and information technologies for an improved electric power infrastructure serving loads while providing for an ongoing evolution of end-use applications. Smart grid has also been defined by IEA (2011) as an electricity network that uses digital and other advanced technologies to monitor and manage the transport of electricity from all generation sources to meet the varying electricity demands of end-users. It also notes that the "smartening" of the electricity system being a revolutionary process – it is not a one-time event – is already happening. In other words smart grids are not an instant revolution, but a steady evolution which has to include the customer as well as energy suppliers and producers (EURELECTRIC, 2011a).

The term "smart grid" refers to an electricity transmission and distribution system that incorporates elements of traditional and cutting-edge power engineering, sophisticated sensing and monitoring technology, information technology and communications to provide better grid performance and to support a wide range of additional services to consumers (JUCCCE, 2007). It adds that a smart grid is not defined by what technologies it incorporates, but rather by what it can do. Consequently, it views a smart grid as the combination of devices, network and software which are designed to improve energy efficiency, reduce environmental impact, improve reliability and visibility and reduce electricity theft. A smart grid means that an electric utility can determine in real time the status and characteristics of every component part of the grid and be able to actively manage every controllable device (Collier, 2010). IEC (2010) defines Smart Grids as the concept of modernizing the electric grid. It considers smart grid simply as integrating the electrical and information technologies in between any point of generation and any point of consumption.

For Sioshansi (2012), smart grid is defined as any combination of enabling technologies, hardware, software, or practices that collectively make the delivery infrastructure or the grid more reliable, more versatile, more secure, more accommodating, more resilient, and ultimately more useful to consumers. But, a useful definition of the smart grid must encompass its ultimate applications, uses, and benefits to society at large. It should be noted that smart grid can be defined in multiple ways including by its technologies, its functionality, and its benefits (Giordano and Bossart, 2012). Like the telecommunications and the genesis of the Internet, technology holds the key to the smart grid and its realisation (Khattak *et al*., 2012). However, Agarwal and Tsoukalas (2011) maintain that smart grid can be defined in two different ways: it is either defined from a solution perspective ("What are the main advantages of the grid?") or from a components' perspective ("Which components constitute the grid?"). Below are smart grid definitions by European Union (EU) and US respectively (Giordano and Bossart, 2012):

- A Smart Grid is "an electricity network that can intelligently integrate the behaviour and actions of all users connected to it – generators, consumers and those that do both – in order to efficiently ensure sustainable, economic and secure electricity supply"
- A Smart Grid uses digital technology to improve reliability, security, and efficiency (both economic and energy) of the electric system from large generation, through the delivery systems to electricity consumers and a growing number of distributed-generation and storage resources.

A comparison of the above definitions shows that EU defines smart grid based on its composition which have been highlighted earlier. But from US perspective, a smart grid is not defined by what technologies it incorporates, but rather by what it can do (functionality, characteristics or solution perspective). Smart grid characteristics are defined as prominent attributes, behaviours, or features that help distinguish the grid as "smart" (EPRI, 2011).

Therefore, the key attributes or characteristics of the 21st century grid are (Agarwal and Tsoukalas, 2011; US, 2007; US-DOE, 2010b):

- Increased use of digital information and controls technology to improve reliability, security, and efficiency of the electric grid.
- Enables active participation by consumers. It achieves this by enabling real-time communication between the consumer and utility so consumers can tailor their energy consumption based on individual preference like price.
- Accommodates all generation and storage options. This refers to its ability of accepting energy from virtually any fuel source including solar and wind as easily and transparently as coal and natural gas; capable of integrating all better ideas and technologies e.g. energy storage technologies.
- Enables new products, services, and markets. It has the potential of creating new opportunities and markets by means of its ability to capitalise on plug-and-play innovation wherever and whenever appropriate.
- Provides power quality for the digital economy. This means that it is capable of delivering the necessary power quality free of sags, spikes, disturbances, and interruption. In other words it is quality focused.
- Optimises asset utilisation and operates efficiently. So it is capable of meeting increased consumer demand without adding infrastructure.
- Anticipates and responds to system disturbances (self-heals). Its intelligence will make it capable of sensing overloads and rerouting power to prevent or minimize a potential outrage.
- Operates resiliently against attack and natural disaster. This implies that it will become increasingly resistant to attack and natural disaster as it becomes decentralised and reinforced with smart grids security protocols.
- Development of standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid.
- Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services.

In China smart grid is defined as an integration of renewable energy, new materials, advanced equipment, information technology, control technology and energy storage technology, which can realise digital management, intelligent decision making and interactive transactions of electricity generation, transmission, deployment, usage and storage (Yu *et al*., 2012). Smart grid is perceived or interpreted as a strong and robust electric power system.

The various definitions of smart grid account for its many sobriquets which include “intelligent grid or intelligrid”, “modern grid,” “grid of the future or future grid”, “energy internet”, “perfect power grid”, and “empowered grid”.

A distinction exists between “smart grid” and “advanced smart grid” and also between “smart grid” and “smarter grid” based on 2009 US-DOE smart grid handbook (Carvallo and Cooper, 2011). Consequently, a smart grid is defined as follows: “The smart grid is the integration of an electric grid, a communications network, software, and hardware to monitor, control, and manage the creation, distribution, storage and consumption of energy. The smart grid of the future will be distributed, it will be interactive, it will be self-healing, and it will communicate with every device.” Also an advanced smart grid is defined as follows: “An advanced smart grid enables the seamless integration of utility infrastructure, with buildings, homes, electric vehicles, distributed generation, energy storage, and smart devices to increase grid reliability, energy efficiency, renewable energy use, and customer satisfaction, while reducing capital and operating costs.” By the reasoning of US-DOE, “smarter grid” is achievable with today’s technologies, while “smart grid” is more of a vision of what will be achievable as a myriad of technologies come on line and as multiple transformations reengineer the current grid.

Definitions and terminology vary somewhat, but whether called “Smart,” “smart,” “smarter,” or even “supersmart,” all notions of an advanced power grid for the 21st century hinge on adding and integrating many varieties of digital computing and communication technologies and services with the power-delivery infrastructure (NIST, 2012). It posits that bidirectional flows of energy and two-way communication and control capabilities will enable an array of new functionalities and applications that go well beyond “smart” meters for homes and businesses. Unfortunately, people sometimes confuse the smart grid with smart meters and advanced metering infrastructure (AMI) or with interoperability in communications (Santacana *et al*., 2010). To address the confusion that exists when discussing smart meters and smart grids, WEC (2012) has noted that it is important to highlight that smart meters are part of a smart grid, while a full smart grid includes many more technologies than just smart meters.

Smart meters are the visible face of a new ICT infrastructure promoted by governments in many regions and countries of the world to improve energy efficiency (IEC, 2010). They allow electricity consumers to play an active role in the functioning of the electricity markets, and allow distribution networks to play an active role in the functioning of electricity systems, becoming "Smart Grids". Smart metering systems represent the gateway for customer access to the new grid and, together with new, value-added energy services they may have a critical and positive effect on energy and power demand, demand response / load management and integration of distributed energy generation. Society as a whole may benefit through less and more efficient energy usage and the integration of distributed / renewable energy sources. Smart metering is a revolutionary development that will radically change the way electricity markets work and generation and distribution are managed. The concept of Automatic Meter Reading (AMR) is rapidly evolving towards Smart multi-energy metering / multi-functional Advanced Multi-Metering Infrastructure (AMI). Smart metering systems will cover at least the following key applications:

- remote data retrieval for billing and other metrological or fiscally relevant purposes concerning energy usage and, where available, energy generation;
- collection of additional data regarding the operation of the meter and the network, including power quality, outage information, technical and non-technical losses;
- sending configuration data to energy end-users, including contractual parameters, tariff schedules, pricing and operational information, time synchronization, firmware updating etc.;
- supporting advanced tariff and payment options;
- remote enabling / disabling of supply, including flexible load limitation where and when system conditions require;
- communication towards in-home systems, including appliances and local generation units, for the purposes of load management, cost control etc.;
- interface to home automation systems.

On the other hand, Advanced Metering Infrastructure (AMI) integrates smart grid infrastructure with smart metering. AMI refers to systems that measure, collect, analyze and control energy distribution and usage, with the help of advanced energy distribution automation devices such as distribution network monitoring and controlling devices, network switching devices, load/source-shedding devices, electricity meters, gas meters and/or water meters, through various communication media on request or on a pre-defined schedule (IEC, 2010). This infrastructure includes hardware, software, communications, energy distribution-associated systems, customer-associated systems and meter data management (MDM) software. Concerning systems requirements for AMI, smart grid infrastructure must meet the following functions:

- Distribution network monitoring
- Power quality monitoring
- Fraud detection
- Load levelling
- Demand response functions
- New business models
- Record capacity utilisation
- Minimization of down time
- Load/source-shedding
- Management & control of energy (re)sources
- Remote Switching procedures
- Customer information
- Asset Management

According to IEC (2010), in addition the usual security and quality of the supply must be maintained.

However, the core idea of smart grids can be expressed quite concisely (Watson *et al*., 2010; Noam *et al*., 2013):

Energy + Information < Energy

Consequently, Watson *et al*. (2010) have proposed the need to develop a new subfield of Information Systems (IS), called ***energy informatics*** that recognises the role that IS can play in reducing energy consumption, and thus CO_2 emissions. According to them, energy informatics is concerned with analysing, designing, and implementing systems to increase the efficiency of energy demand and supply systems. This requires collection and analysis of energy data sets to support optimisation of energy distribution and consumption networks..

According to Khattak *et al*. (2012) the expression "Using megabytes of data to move megawatts of energy," from a document prepared for the U.S. Department of Energy, coins the essence of the smart grid perfectly.

In summary, the ideal Smart Grid has been defined in terms of characteristics in the US and in terms of services in the European Union as shown in Table 4.3. Although there is some debate on what specifically constitutes a smart grid, a consensus is forming regarding its general attributes (Santacana *et al*., 2010) as highlighted earlier. Pretty much everybody agrees that we need it for various reasons and to varying degrees (Collier, 2010). Also there is a seeming agreement that smart grid can impact all aspects of the electric power system from generation to transmission to distribution to consumer, and can impact power delivery, communications, and marketplace (Giordano and Bossart, 2012). Similarly, one thing is clear that Smart Grid is a definite change in the way people are thinking about the generation, delivery, and use of electric energy (Borlase *et al*., 2012). Therefore, the "Smart Grid" has become an essential component to addressing the energy demand, security, and environmental challenges we face.

Table 4.3: Smart Grid services and characteristics to define the ideal Smart Grid (Giordano and Bossart, 2012)

<table>
<tr><th rowspan="9">Smart Grid services/characteristics</th><th>European Union (Services)</th><th>USA (Characteristics)</th></tr>
<tr><td>Enabling the network to integrate users with new requirements</td><td>Accommodate all generation and storage options</td></tr>
<tr><td>Enabling and encouraging stronger and more direct involvement of consumers in their energy usage and management</td><td>Enable active participation by customers</td></tr>
<tr><td>Improving market functioning and customer service</td><td>Enable new products, services, and markets</td></tr>
<tr><td>Enhancing efficiency in day-to-day grid operation</td><td rowspan="2">Optimize asset utilisation and operate efficiently</td></tr>
<tr><td>Enabling better planning of future network investment</td></tr>
<tr><td rowspan="2">Ensuring network security, system control and quality of supply</td><td>Provide the power quality for the range of needs</td></tr>
<tr><td>Operate resiliently to disturbances, attacks and natural disasters</td></tr>
</table>

4.7 Smart Grid Developments

Smart grid development just as the definition lacks a unified pattern. For instance, given that smart grid concept emerged in EU but was named in US Energy Act 2007 (Hill, 2010), a difference in developmental approaches to smart grid should be expected between EU and US. According to Asmus (2006), J. Antonoff summed up the differences between the U.S. and European approach to developing a smart grid in this way: "On the technology side, the U.S. is the leader. We are great here in the U.S. at technology gadgets and figuring out how to fix things. The Europeans are much more focused on strategy and policy and how to introduce behavioural changes. They see a problem, develop a policy to address it, and assume the technologies will follow".

Consequently, the priority of local evolutionary drivers, challenges, motivations and path followed by each region and country towards the implementation of smart grid are unique. Reasons for this uniqueness in each local situation include:

- differences in terms of energy mix,
- environment,
- legislation,
- regulation,
- market, and
- customer response.

Therefore, some of the goals for modernising the grid are more important than others in some countries (Arnold, 2011). For example, in industrialised countries the load demand has decreased or remained constant in the previous decade, whereas developing countries have shown a rapidly increasing load demand (IEC, 2010). According to WEC (2012) most of the growth in energy consumption is expected to occur in the emerging economies, where demand for electric power is driven by strong, long-term economic growth, and the aspirations of a rapidly growing middle class. But aging equipment, dispersed generation as well as load increase might lead to highly utilised equipment during peak load conditions (IEC, 2010). So it notes that if the upgrade of the power grid should be reduced to a minimum, new ways of operating power systems have be found and established.

The main reasons for adopting smart grid in developed countries are the reduction of losses, system performance and resource optimisation, the integration of renewables, energy efficiency and a rapid-response mechanism to demand (de Nigris and Coviello, 2012). But, according to them, in developing countries there are other new factors. For instance, the quality and reliability of electricity supply are fundamental for supporting an expanding economy, and can be achieved relatively rapidly and sustainably by designing, planning and developing a modern electricity infrastructure that is forward-looking from the outset. Similarly, IRENA (2013) has observed that renewable energy considerations in developing countries are very different to those in developed countries. It notes that while the technologies may be, and usually are, the same, their implementation and requirements are often driven by different needs and issues.

In the EU, the smart grid strategy is motivated by concepts of innovation with regard to social and environmental reforms for an interactive economy (Simões *et al*., 2012). Heiles (2012) submits that in Europe smart grid is driven by the energy policy of the European Commission and Parliament to have a 20% cut in greenhouse gas emission, 20% energy share from renewable resources and 20% increase in energy efficiency by 2020 (20-20-20). But in the U.S. the smart grid activities are driven by the US Energy Independence and Security Act of 2007. Also the evolution of the smart grids in the US may be traced to several innovations in the transmission grid, such as (Simões *et al*., 2012):

- Wide-area measurement and fast controls
- Installation of power system stabilisers – phase shifting transformers, flexible ac transmission system devices
- Installation of phasor measurement units (PMUs)
- Advent of advanced control room visualisation
- Public awareness and concomitant push for more renewable energy sources in the grid

Giordano and Bossart (2012) contend that the overarching policy objective for the deployment of smart grids in the Europe is to provide a more sustainable, efficient and secure electricity supply to consumers. To this end, it is acknowledged that Smart Grids are instrumental in the transition to a low-carbon economy, facilitating demand-side efficiency, increasing the shares of renewables and distributed generation, and enabling electrification of transport.

Another important policy driver is the set-up of an internal European energy market. Smart Grids are considered as a key enabler to strengthen cross-border energy transactions, support retail competition and open the market to new services and players in the interest of consumers.But the principal policy objective for implementation of smart grids in the US is to provide affordable, reliable, secure and sustainable supply of electric power. According to WEC (2012) in North America, the emphasis is on creating a more efficient system by eliminating manual meter readings, reducing theft, detecting outages faster, and upgrading old equipment. And in Europe, as well as replacing an ageing infrastructure and developing interconnected networks among countries, the integration of decentralised and intermittent renewable energy sources is the major driver in the development of the grid's infrastructure. Furthermore, smart grid standards are not intended to be requirements or mandates in US unlike EU. This is corroborated by IRENA (2013) having asserted that the reason for developing standards, adhering to them is voluntary; i.e. countries, organisations, and individuals are not legally obliged to follow them. However, if particular standards are referenced in regulation, legislation, contract law, or as part of a referenced certification requirement (as normative references), they then operate in a context that is no longer voluntary, even though the standards themselves remain voluntary (i.e. the compulsory instrument cannot be called a "standard"). It notes that European standards, even when developed under a mandate and for European legislation, remain voluntary in their use. But this appears contradictory to the view of Giordano and Bossart (2012). According to IRENA (2013) Mandated Standards are particularly prevalent in Europe where in certain circumstances regional legislative bodies or organisations request the provision of standards that directly support legislation and regulation. It notes that various reasons for the issuance of mandates include:

- promotion of technologies,
- environmental issues,
- safety/consumer protection,
- requests from industry,
- harmonisation of national legislation,
- EU directives, or CE marking (EU).

Undoubtedly, standards are an ideal instrument to achieve a number of objectives such as (Giordano and Bossart, 2012; IRENA, 2013):

- Seamless interoperability,
- Harmonised data models,
- Compact set of protocols,
- Communication and information exchange,
- Improved security of supply in the context of critical infrastructure,
- Robust information security, data protection and privacy adequate safety of new products and systems in the smart grid

The use of standards is proving particularly important in the field of renewable energy and energy efficiency since, in an emerging and fast-growing market, the harmonised approach provides confidence in what is being installed (IRENA, 2013).It further contends that there still appears to be a large requirement to demystify what standards are, and what they can do for stakeholders, external to the standards-making process, particularly at the level that helps individuals or companies to either utilise the appropriate standards or to support their engagement in the development process.

However and interestingly too, EU and US smart grid experts share similar views on the main components and functions of the smart grid as highlighted in the preceding sections.

In the Latin America and Caribbean (LAC) regions, a very wide range of energy mix situations and market environments exist. The main unifying idea for smart grid is the urgent necessity to reduce system losses and increase the electricity system efficiency (de Nigris and Coviello, 2012). Countries of the same economic bloc have similar, if not the same, main drivers in smart grid development. While low carbon and energy efficiency are paramount for OECD countries, green economy growth agenda is a priority for OECD Asian countries. Also for emerging countries (eg BRICS) fast growth infrastructure is outstanding. The smart grid environment is extremely dynamic and changes rapidly, with emerging economies playing an increasingly important role (WEC, 2012). It further notes that non-technical losses in the power sector are small in advanced economies. For example, Japan’s electricity grid is among the most efficient and reliable in the world with average distribution losses of less than 5% (2000–2010). In other words, Japan’s existing electricity network is already considered to be reliable, and so Japan's objective is more focused – to enable further introduction of renewable energy and create a new infrastructure for EVs and new services through the utilisation of smart meters and ICT network (EC, 2010). In contrast, the situation tends to be significantly different in developing countries. Therefore the priorities for India and Brazil are to build a grid able to carry enough capacity for the rising demand for electricity, as well as reducing the high levels of electricity losses. Specifically, the Indian power system is characterized by high inefficiency because of high losses (technical as well as very high non-technical losses) (IEC, 2010). However, smart grids can help control and expand these grids by optimising the operation and improving the efficiency of the network through enhanced automation, more monitoring devices, protection and real time operation, as well as faster fault identification (WEC, 2012).

Japan's main objective is to achieve a total shift from fossil fuels to renewable energy, generating a low-carbon society (WEC, 2012; Ling *et al*., 2012) aiming at reducing CO_2 emissions by 25% compared with the level in 1990 (EC, 2010). US focuses on businesses and infrastructure, whereas Japan is striving to move toward a low-carbon society by developing the smart grid system (Ling *et al*., 2012). Reliability improvement is much less important in Japan, where power outages at the distribution level average only about 16 min per year per customer, than it is in the US where such outages exceed two hours per year per customer (Arnold, 2011). So, Japan has developed an initial standards roadmap for the smart grid and has also formed a Smart Community Alliance, which has extended the concept of the smart grid beyond the electric system to encompass energy efficiency and intelligent management of other resources such as water, gas and transportation.

The main drivers for a smart grid in South Korea are similar to those for US and EU – reduce greenhouse gas (GHG) emissions significantly, improve energy efficiency, and increase the share of renewable energy (WEC, 2012). South Korea aims to build the world's first nationwide smart grid system to reduce its emissions by monitoring energy use more carefully (EC, 2010). It notes that the grid, to be set up by 2030, is part of the country's $103bn initiative to increase its generation of green energy from the current 2.4 % of total power to 11 % in the next two decades. Resultantly, South Korea could lower its greenhouse gas emissions by 40 million tonnes annually with a national smart grid, reduce overall energy use by 3 % and lower the peak load for electric power by about 6 %. The electricity savings would be equal to the output of seven 1GW nuclear power reactors.

Both United Kingdom (UK) and China stress the upgrade and renovation of the infrastructure of the present power system and changes to its operation but with different emphases (Sun *et al.*, 2010). The UK has paid most attention to the electric power distribution system, energy consumption and renewable generation, whilst China also focuses on strengthening the transmission system for their smart grid development. Therefore, comparing with US and Europe, the Chinese smart grid appears to be more transmission-centric (Pazheri *et al.*, 2011). But in China the smart grid concept focuses on all sections of the power system, including smart power generation, transmission, deployment, usage and storage (Yu *et al.*, 2012). Equally IEC (2010) believes that China is promoting the development of smart grid because of the high load increase and the need to integrate renewable energy sources. Therefore, the requirements there are for a stronger and smarter grid with massive investments focused on increasing capacity, reliability, efficiency and integration of renewable (EC, 2010).

Another worthy aspect of comparison of smart grid development is the financing mechanisms. So several financing mechanisms to drive forward the development of smart grid technologies and incentivise private sector investment have been established in various countries. Available financing mechanisms include:

- Public funding
- Private funding
- Regulatory incentives
- External grants

It is of fundamental importance to involve national regulatory authorities in the early stage of smart grid development, as this will allow them to better understand the benefits of the technologies and provide appropriate regulatory mechanisms to support their full deployment (WEC, 2012). Accordingly in the United States, alongside federal financing, smart grid technologies and developments are financed by private investments. However, in emerging countries, the cost of financing the development of smart grid technologies is for the most part borne by government finances or external grants. For example, the State Grid Chinese Corporation has been carrying out pilot projects by means of independent investment and public tendering. Similarly, smart grid projects in India are being implemented on a pilot basis and are mostly funded by government finances or external grants. Also South Korea's investment plan provides a total fund of USD 25 billion until 2030, which will be used for the most advanced key technology development and the successful deployment of South Korea's smart grids. Even though the initial investment sources came from the government, the higher share of the financial burden will be borne by the private sector. In summary Table 4.4 shows the available smart grid financing mechanisms for some countries and regions.

Table 4.4 Overview of available financing mechanisms (WEC, 2012)

Country/Region	**Financing Mechanism**
US	Public and Private funding
EU	Public funding and Regulatory incentives
South Korea	Public and Private funding
Brazil	Regulatory incentives
China	Public funding
Japan	Public funding and Regulatory incentives
India	Public funding, Regulatory incentives and External grants

Furthermore, to fully utilise the benefits of smart grids technological as well as daunting financial challenges have to be overcome and it is of uttermost importance that policymakers and industry work closely together and include the wider public in their efforts (WEC, 2012). Therefore, for industry it is important to elaborate a positive business case with a precise definition of how investments are paid for, reflecting the fact that benefits are incurred to a wide range of stakeholders. This is crucial because the development of smart grids is a long-term process that binds capital over many years and therefore requires strong commitment from all stakeholders and a positive business model.

There are also diverse consumer involvements in these smart grid initiatives and the resultant varying responses from consumers. These varying responses from consumers may be related to the emphasis of their respective smart grid initiatives. For example, the emphasis is on smart metering and dynamic pricing in the US (Mah *et al*., 2012). In contrast, EU places emphasis on decentralised electricity systems in which consumers have become ‘‘prosumers’’ who both produce and consume electricity. Those ‘‘prosumers’’ can sell electricity that they generate from micro-generation technologies such as wind and solar power at household and community levels. Therefore, EU appears to involve consumers better than US in its smart grid developments. This could account for the most reported smart grid opposition occurring in US. For example For example, in California (United States), some customers of the utility Pacific Gas & Electric have been opposed to smart meters being installed in their homes due to privacy, health, and safety concerns (WEC, 2012). It notes that the same issue had surfaced in the states of Maine and Illinois, where customers have opposed smart meter rollouts. Consequently, the respective states’ public utility commissions have to consider smart meter opt-out options, where consumers pay an initial fee and monthly charge for choosing to opt out. However, similar trends of mistrust are emerging elsewhere such as in Korea and Australia (Mah *et al*., 2012). While consumers in places such as Ontario are highly positive, negative consumer responses have been recorded in many places, in various forms and with different impacts. The result of such negative responses could include some local people blocking the development, requiring of opt-out arrangements or even moratoria. Notable issues of concern to consumers include:

- costs,
- health and safety,
- data-sharing, privacy,
- fairness,
- involuntary remote disconnection,
- uneven distributional effects, and
- the impacts on vulnerable groups such as the elderly or people who are less familiar with IT.

The path to successfully turning the consumer into an active energy customer revolves around the concept of engagement (Gangale *et al*., 2013). A first necessary step towards consumer engagement is raising awareness and providing information about newly introduced smart technologies or mechanisms. This could be executed by means of brochures, energy consultancy services and fairs. Following the delivery of this information to customers, the next steps involve exploring ways of securing continuous consumer engagement by means of tailored tools and strategies. In order to change consumer behaviour, consumers need to be aware of their energy use, understand its impacts on the environment and on energy security, and realise the potential for energy and money savings. Generally, the amount of energy use and its impact on the system are largely abstract concepts and for most consumers, especially in the household sector, it may be difficult to link these values to daily energy-using activities.

4.8 Smart Grid Development in South Africa and Lessons

South Africa Smart Grid Initiative (SASGI), an initiative of and under South African National Energy Development Institute (SANDI), was launched on 22 May 2012 and is a representative electricity industry institute. Prior to this South Africa’s interest in smart grid could be evidenced in the development of the following standards by Standards Bureau of South Africa (SBSA):

- Advanced Meter Reading for Large Power Users, NRS071:2004(SANS473:2006)
- Advanced Metering Infrastructure, NRS049-1:2010

The establishment of SASGI is considered as a major step towards the realisation of the smart grid opportunities in the country. The scope of work of SASGI is expected to include (de Beer, 2012a):

- Assessment of smart grid related developments within the South African electricity supply industry
- Applicable technology consideration
- Directing standards and specifications
- Identification and motivation of enablers to promote smart grids in SA

SASGI has identified the following focus areas to ensure that technology is optimally deployed and that the grid is modernised to meet the 21st century grid requirements (de Beer, 2012b):

- Reliability
- Security
- Economy
- Efficiency
- Environment
- Safety

But the immediate focus of SASGI and the work groups are to address the following areas (SASGI, 2012):

- Improvement in network availability.
- Improved network security.
- Facilitation of energy management.
- Improved productivity.
- Ability to accommodate renewable energy sources.

Based on SASGI (2012) South Africa's Smart Grids Vision is captured as follows:

> *The Smart Grid aims to revolutionise the South African electricity system by 2030 by integrating 21st century technologies to achieve seamless*

generation, delivery and end-use that is effective, scalable and adaptable and benefits the South Africa nation. It is an economically evolved, technology enabled, electricity system that is intelligent, interactive, flexible and efficient and will enable South Africa's energy use to be sustainable for future generations.

Below are brief explanations on the meaning of some key words in the vision statement:

- **Economically Evolved** – affordable electricity system that meets growing needs of the country
- **Technology enabled** – fit for the purpose of ICT, processes, sensors, systems and applications
- **Intelligent** – from data to knowledge
- **Interactive** – ability to monitor, control and manage using two way communications throughout the value chain
- **Flexible** – appropriate, scalable and adaptable based on common standards
- **Electricity system** – the complete value chain of all interconnected equipment and components from generation to end use
- **Sustainable** – optimised and affordable from environmental and economic perspectives

Eskom has started deploying a hybrid smart grid model that supports its legacy time division multiplexing management system, while gradually introducing an Internet Protocol (IP) packet communication system, which will enable smart demand-side management, automatic correction and the connection of variable, renewable-energy generation capacity (Burger, 2012). This agrees with the position of Collier (2010) that utilities can begin using existing and emerging technologies and applications to create something known as an agile grid, on their way to creating a smart grid. According to him many utilities already have deployed, or are planning, key elements or components of an agile grid. Equally, smart grids will not be rolled out in a single swoop, instead their implementation is an incremental and continuous step-by-step learning process, characterised by different starting points (EURELECTRIC, 2011a). However, Burger (2012) notes that Eskom is focusing too much on the technology and not necessarily the reasons for implementing the technology. A possible counter to this assertion is that the concept of intelligent infrastructure will continue to evolve, but utilities have tangible choices now, and they do not have to wait passively to provide practical solutions as smart grid develops (Collier, 2010). As part of the technological focus Eskom has implemented smart grid technologies successfully on parts of its 400 000 km of lines and has rolled out fibre-optic cables to most of its larger distribution substations, using a technique called Skywrap that winds the cables along the earth conductor of existing power lines, and has microwave and general packet radio service (GPRS) communication with its more remote distribution substations. According to Budka *et al.* (2014) *Skywrap®* (a registered trademark of AFL Telecommunications LLC, Alcoa Fujikura Limited.) technology provides for deployment of fibre over existing transmission lines by wrapping the fibre (strands) helically around the ground wire or around the phase wires, thereby making it possible to deploy fibre along existing transmission lines. A pertinent lesson is that the technology choices should not be made in silos, or only as pilot projects, but in a holistic fashion, aiming for a fully deployed smart grid. Electric utilities make use of both wholly owned and operated networks and third-party networks (Collier, 2010), and so collaboration between utilities and ICT companies is important to extend grid visibility and control to include customers (Burger, 2012).

While Europe presents a vital lesson to South Africa on perfection of strategies, policies and how to introduce behavioural changes, USA offers a typical example of smart grid technology deployment and the inherent benefits in the absence of strategy and policy perfections. South Africa should also avoid consumers' negative responses as witnessed in US by ensuring active engagement of stakeholders especially consumers. This is important because smart grids are not an instant revolution, but a steady evolution which has to include the customer as well as energy suppliers and producers (EURELECTRIC, 2011a). The European Commission (EC) Smart Grid Task Force is currently using the NIST Conceptual Model as a basis for the definition of a Smart Grid reference architecture, which is being used for the Analysis of Standardisation gaps, cyber-security threats and options for future market models in Europe (Giordano and Bossart, 2012). According to them and as shown in Figure 4.11, to fit the European context, the EC Smart Grid Task Force (in particular the Expert Group working on standardization3) has extended the NIST model by including the Distributed Energy Resources domain (in blue in the picture).

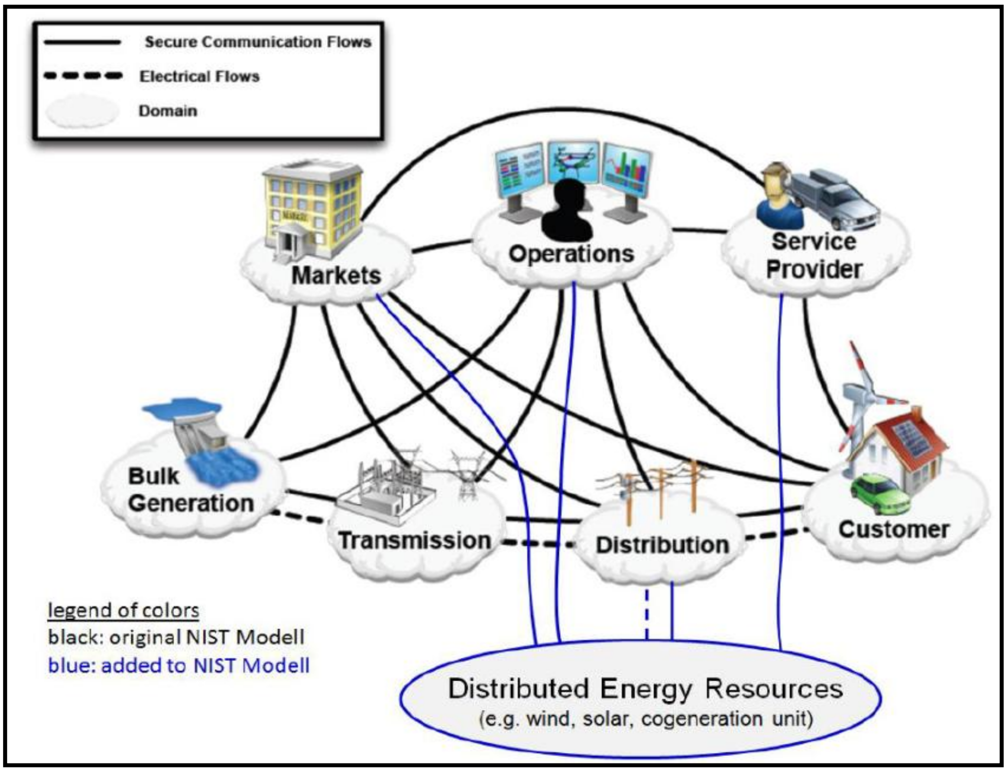

Figure 4.11: Original NIST Smart Grid conceptual model and adaptation to the EU context (in blue) (Giordano and Bossart, 2012)

Worth mentioning also is that in steps 2 (Identify the functions) and 4 (Map each function onto a standardized set of benefit types) of the original EPRI Cost Benefit Analysis methodology (EPRI, 2010), EPRI functions have been replaced by (European) functionalities by the EC Smart Grids Task Force. So, Giordano and Bossart (2012) submit that it is worth stressing that functions and functionalities cannot be directly compared. Functions have a very strong technical dimension (e.g. fault current limiter, Feeder Switching). Functionalities represent more general capabilities of the Smart Grid and do not focus on specific technology thereby providing an intuitive description of what the project is about. Therefore, South Africa could learn from Europe by adapting existing models, standards and even technologies to suit her local context.

A vital lesson from India is the utilisation of all financing mechanisms but one. But South Korea's approach could be adopted where though the initial investment sources came from the government, the higher share of the financial burden will be borne by the private sector. Eskom as a vertically integrated company should be the main promoter and executor of smart grid applications like Solid Grid Corporation of China – China's largest power network operating company. But according to EURELECTRIC (2011b) investments in Europe's distribution grids will hence need to be incentivised by national energy regulators. Once this critical condition is met and DSOs dispose of favourable investment conditions, they will face two options:

1. They can follow the **"fit and forget approach"**, often referred to as the "copper-plate scenario". This approach entails heavy investments in additional distribution lines in order to prepare distribution grids for a large intake of RES electricity. This means over-sizing the distribution grid to avoid congestion during the few periods of strong wind or sunshine – comparable to building four- or five lane automobile highways to avoid potential congestion hours.
2. Alternatively, DSOs can follow the **"smart grids approach"** which consists of investing in Information and Communication Technologies (ICT) that will help them to better manage the electricity flows and limit the need for new lines. By using ICT (including smart metering) to monitor, control and automate the distribution grid, DSOs can optimise the use of current assets.

While the "smart grids approach" provides a better allocation of resources in the long run, it is very likely to result in higher capital expenditures (mainly in ICT) in the short and medium term, compared to the "fit and forget approach" (EURELECTRIC, 2011b). However, the "smart grids approach" will also bring about many benefits to other actors such as energy suppliers and, most importantly, to customers. Therefore, Europe offers a good lesson to South Africa because NERSA has a crucial investment role to play in conjunction with Eskom and municipalities.

South Africa could also benefit from Japan's approach to smart grid concept especially by extending it beyond the electric system to encompass energy efficiency and intelligent management of other resources such as water, gas and transportation. This is because Smart Grid deployment must include not only technology, market and commercial considerations, environmental impact, regulatory framework, standardisation usage, ICT and migration strategy but also societal requirements and governmental edicts (IEC, 2010).

Education is vital in South Africa's target for sustainable electricity generation and consumption. To avoid the negative responses experienced in some places, South Africa needs to intensify efforts in healthy engagement with her electricity customers. One of such efforts is educating the customers on the fundamental meaning of smart grid and the accruing benefits. Also advanced countries such as US and UK have veritable lessons for

South Africa's tertiary education sector regarding the restructuring of Electrical Engineering curricula to reflect the required training for this 21st century and beyond grid.

Therefore, South Africa is well positioned to learn from the developments in the rest of the world. Since South Africa does not have to go through the full technology development cycle, it is possible to select through the required applied research and establishment of standards the most appropriate Smart Grid options for the South Africa (SASGI, 2012).

4.9 Conclusion

Undoubtedly electric grid cannot remain a proverbial sign post in the scheme of digitalisation and the derivable benefits from grid modernisation could justify the required huge investments. Irrespective of who receives the credit for smart grid neologism and the exact date, diverse composition and definitions, a seemingly consensus has been formed on the characteristics and benefits of smart grid. This is because smart grid remains a core concept in sustainable electricity generation and consumption. Therefore, South Africa's strategic position in electricity generation in Africa with the attendant positive impact on the economy and environment stands undermined without smart grid. US, EU, China, Japan and others especially BRICS members could serve as appropriate reference. Consequently, South Africa is presented with the opportunity to "leap-frog" and enhance the relevant proven applicable smart grid solutions.

CHAPTER 5
MODELLING AND SIMULATION

5.1 Introduction

This chapter aims at investigating some of the issues raised in Section 3.3.2. However, the chapter commences with a review of the modelling of PV devices, CSP and wind power systems. Thereafter, DIgSILENT PowerFactory software is deployed for the investigations on a developed model because Kaberere *et al*. (2005), Lund *et al*. (2005) and other authors have performed various comparative studies with DIgSILENT PowerFactory. They have confirmed it as being a versatile commercial power system program. Besides, DIgSILENT has set standards and trends in power system modelling, analysis and simulation for more than 25 years (DIgSILENT, 2013). The proven advantages of the PowerFactory software are its overall functional integration, its applicability to the modelling of generation-, transmission-, distribution- and industrial grids, and the analysis of these grids' interactions. This software provides a library of standard electrical components or models such as transformers, machines, and transmission lines. Therefore, the modelling and simulations are executed using DIgSILENT PowerFactory Version 14.1.3.

5.2 Modelling of PV Devices

Many models can be utilised to emulate the characteristics of a PV cell (Lyden *et al*., 2012), the basic unit of a PV generator (Yazdani *et al*., 2011). These models however vary in complexity, accuracy and adaptability to modelling varying environmental conditions (Lyden *et al*., 2012). According to them, the output characteristics of a PV cell are highly non-linear due to the p-n junction, and subsequently are usually modelled using a diode as an equivalent circuit element to model diffusion and recombination currents. Moreover, the PV cell current-voltage (I-V) characteristic is dependent on the irradiance energy and the temperature, which means that model parameters at Standard Test Conditions (STC), that is, 25°C, 1000W/m^2, deviate when compared to actual variable operating conditions. Therefore, this creates a need for accurate modelling mechanisms to demonstrate PV cell operation under unpredictable environmental conditions. Different equivalent circuits of a PV cell have been proposed in the literature (Yazdani *et al*., 2011). The simplest class of models fall into the category of single diode models which include, in order of complexity, Ideal Single Diode Model (ISDM), Simplified Single Diode Model (SSDM) and Single Diode Model (SDM) (Lyden *et al*., 2012; Mahmoud *et al*., 2012). However, Lyden *et al*. (2012) have noted that other models include additional diodes (referred to as Double Diode Models (DDM)) to model the complexities of recombination current, which are dominant at low voltage and low irradiance (Yazdani *et al*., 2011), and sometimes neglect resistances. Eventually, for small-size PV cells, a three-diode circuit has been proposed to include also the effect of large leakage current through peripheries (Yazdani *et al*., 2011). The equivalent circuits for the ISDM, SDM and SSDM are shown in Figure 5.1, where R_s and R_{sh} are the series and shunt resistance respectively, I_{ph} is the light-generated (photon) current, while I and V are the load current and voltage respectively.

Various numerical methods and method relying on artificial intelligence techniques or linearisation and Thevenin equivalents are described in the literature for modelling PV cells (Lyden *et al*., 2012). According to them, despite the number and diversity of techniques proposed, of the analytical methods, for the modelling of PV characteristics the SDM is generally accepted to have the best balance between accuracy and simplicity. Similarly, Yazdani *et al*. (2011) have noted that the single-diode circuit is the most commonly used model in power system simulation studies, since it offers a reasonably good trade-off between simplicity and accuracy, and can be efficiently included in many power system simulation platforms. Despite its simplicity, the ideal single-diode model (ISDM) does not guarantee an accurate characteristic at the MPP (Mahmoud *et al*., 2012). They concur that the single-diode model (SDM) is most commonly used for conducting PV studies due to its accuracy. Furthermore, for such an approach, five parameters are essential to develop the PV simulation model. The parameters are determined by solving five nonlinear equations iteratively (Mahmoud *et al*., 2012), or by tuning the value of some parameters such that the I–V characteristic coincides with the three operating points given by the datasheet (Mahmoud *et al*., 2012; Villalva *et al*., 2009). Implementing a simulation model for such a method requires a numerical solver because I = f (V, I) and V = f (I, V) (Mahmoud *et al*., 2012; Villalva *et al*., 2009). Mahmoud *et al*. (2012) have noted that to reduce the complexity, some studies eliminate the shunt resistance, as shown in Figure 5.1(c). Although the complexity is reduced, it exhibits deficiencies when subjected to temperature variations and still requires a numerical solver.

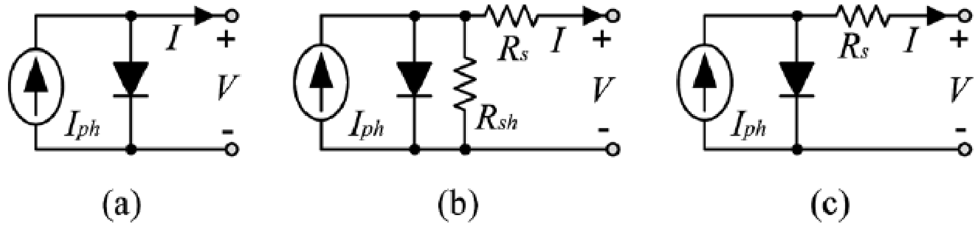

Figure 5.1: Equivalent circuits for PV: (a) ISDM; (b) SDM; (c) simplified singlediode model (SSDM) (Mahmoud *et al*., 2012)

Figure 5.1(a) shows the equivalent circuit of the ideal PV cell. The basic equation from the theory of semiconductors that mathematically describes the *I–V* characteristic of the ideal PV cell is (Villalva *et al*., 2009):

$$I = I_{ph,cell} - \underbrace{I_{0,cell}\left[exp\left(\frac{qV}{akT}\right) - 1\right]}_{I_d} \qquad \text{(Equation 5.1)}$$

Where:

$I_{ph,cell}$ = current generated by the incident light (it is directly proportional to the Sun irradiation),

I_d = Shockley diode equation,

$I_{0,cell}$ = reverse saturation or leakage current of the diode,

q = electron charge ($1.60217646 \times 10^{-19}$ C),

k = Boltzmann constant ($1.3806503 \times 10^{-23}$ J/K),

T (in Kelvin) = temperature of the *p-n* junction, and

a = diode ideality constant.

A typical *I-V* curve originating from Equation 5.1 is shown in Figure 5.2 with I_{ph} as I_{pv}.

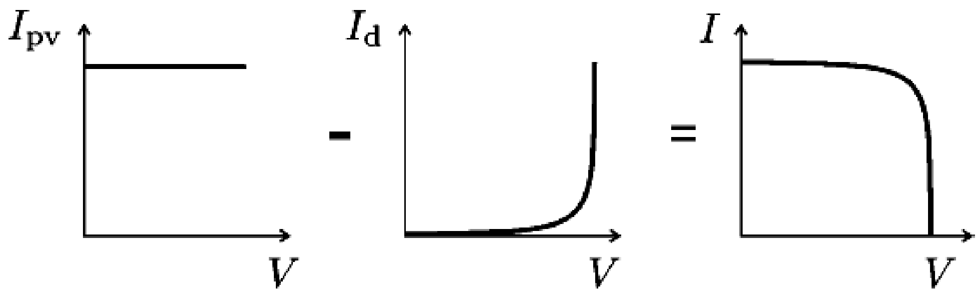

Figure 5.2: Characteristic I–V curve of the PV cell. The net cell current I is composed of the light-generated current Ipv and the diode current Id (Villalva *et al*., 2009)

As highlighted in Chapter 2 and according to Chatterjee *et al.* (2011) a PV source is commercially available in the form of a module in which a number of cells are connected in series. However, for large power and voltage applications, a combination of these modules is needed. A number of modules are connected in series, called a string, to give a higher voltage. Likewise, to increase the current rating of the source, these strings are connected in parallel to form an array. But the basic equation of the elementary PV cell, Equation 5.1, does not represent the *I–V* characteristic of a practical PV array. Therefore, because practical arrays are composed of several connected PV cells, the observation of the characteristics at the terminals of the PV array requires the inclusion of additional parameters to the basic equation (Villalva *et al.*, 2009) as shown in Equation 5.2.

$$I = I_{ph} - I_0 \left[exp\left(\frac{V + R_s I}{V_t a} \right) - 1 \right] - \frac{V + R_s I}{R_p}$$

(Equation 5.2)

Where:

I_{ph} and I_0 are the PV and saturation currents, respectively, of the array and

R_s = equivalent series resistance of the array

R_p = equivalent parallel resistance

$V_t = N_s kT/q$ is the thermal voltage of the array with N_s cells connected in series. If the array is composed of N_p parallel connections of cells the PV and saturation currents may be expressed as $I_{ph} = I_{ph,cell} N_p$ and $I_0 = I_{0,cell} N_p$.

Equation 5.2 produces the *I–V* curve shown in Figure 5.3, where three *remarkable points* are highlighted: short circuit ($0, I_{sc}$), MPP (V_{mp}, I_{mp}), and open circuit ($V_{oc}, 0$).

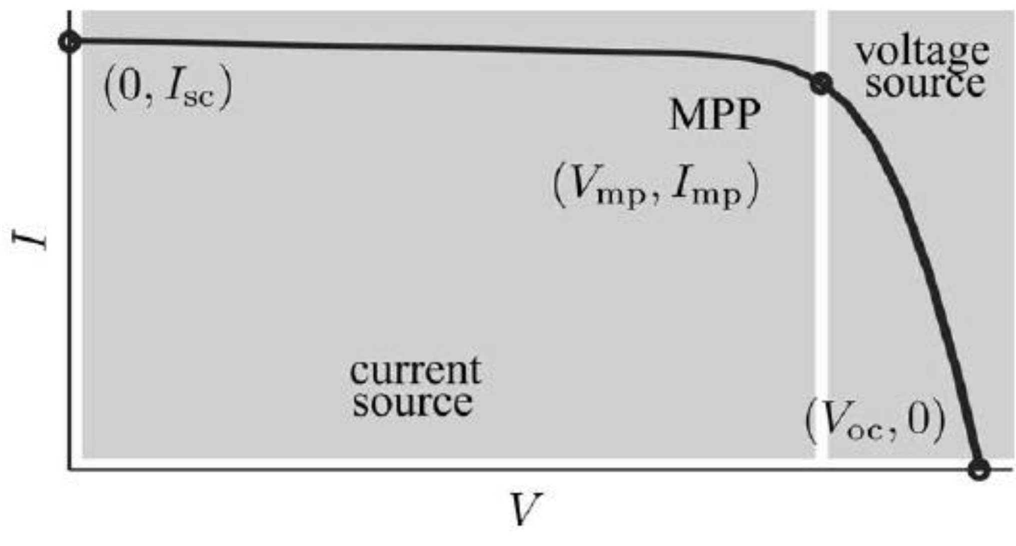

Figure 6.3: Characteristic I–V curve of a practical PV device and the three remarkable points (Villalva *et al.*, 2009)

Similarly, Figure 5.4 shows a typical load matching for a photovoltaic PV panel with a given insolation level.

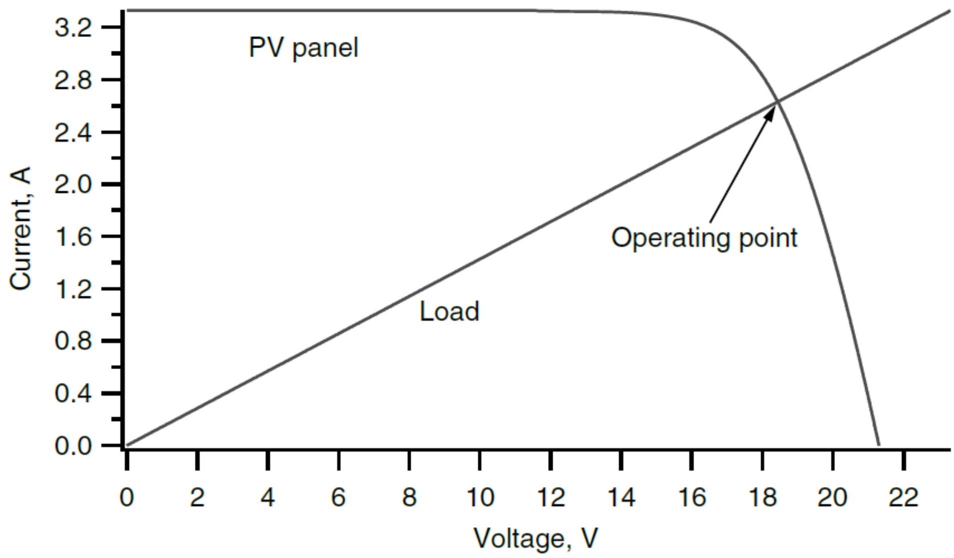

Figure 5.4: Load matching for a photovoltaic PV panel with a given insolation level (Manwell *et al*., 2009).

5.3 Modelling Concentrating Solar Power Systems

As explained in part of Section 2.3.1 the steam by CSP systems is normally converted to electrical energy in a conventional steam turbine generator (Rankine cycle), which can either be part of a conventional steam cycle or integrated into a combined steam and gas turbine cycle. Therefore, from an electrical grid perspective, the models needed to simulate the steady-state, short-circuit and transient time-domain dynamics of such a generating unit, are typically no different from standard synchronous generating units for fossil fuel plants (NERC, 2010). For a typical conventional synchronous generator, the rotational speed is fixed – no slip; and the flux is controlled via exciter winding (Muljadi *et al*., 2013). Consequently, the magnetic flux and the rotor rotate synchronously.

5.4 Modelling of Wind Power Systems

Wind turbines are designed to capture the kinetic energy present in wind and convert it to electrical energy. An analogy can be drawn between wind turbines and conventional generating units which harness the kinetic energy of steam (Singh, 2011a; Vyas *et al*, 2013). According to them, from a modeling standpoint, a fixed-speed wind turbine consists of the following components:

1. Turbine rotor and blade assembly (prime mover)

2. Shaft and gearbox unit (drive-train and speed changer)
3. Induction generator
4. Control system

The interaction between each of these components determines how much kinetic energy is extracted from the wind. Modelling of the electrical subsystems is fairly straightforward, as power system modeling software usually includes a built-in induction machine model. Induction machines are popular as generating units due to their asynchronous nature, since maintaining a constant synchronous speed in order to use a synchronous generator is difficult due to variable nature of wind speed (Singh, 2011a). Power electronic converters may be used to regulate the real and reactive power output of the turbine. However, modeling of the aerodynamics and mechanical drive-train is more challenging because these components are modelled based on the differential and algebraic equations that describe their operation.

Modeling of wind turbine generator systems (WTGS) can be broadly classified into (Vyas *et al*, 2013):

1. Static modelling
2. Dynamic modeling

The authors acknowledge that static models of WTGS can be used for steady state analysis or quasi-steady state analysis such as load flow studies, power quality assessment, short circuit calculations whereas a dynamic model of WTGS is needed for various types of system dynamic analysis including stability study, control system analysis and optimisation techniques. Moreover, the static models of WTGS are characterised by a simple voltage source (V), a voltage and real power source (V, P) or a real and reactive power source (P, Q). Therefore, the choice of model used depends on specific application and the type of WTGS. The tree diagram of Figure 5.5 shows the model types and their applications.

However, the mechanical power extracted from the wind by a wind turbine is a complex function of the wind speed, blade pitch angle, and shaft speed (Vittal and Ayyanar, 2013) and it is given by Equation 5.3.

$$P_m = \frac{1}{2}\rho {v_w}^2 \pi r^2 C_p(\lambda)$$

(Equation 5.3)

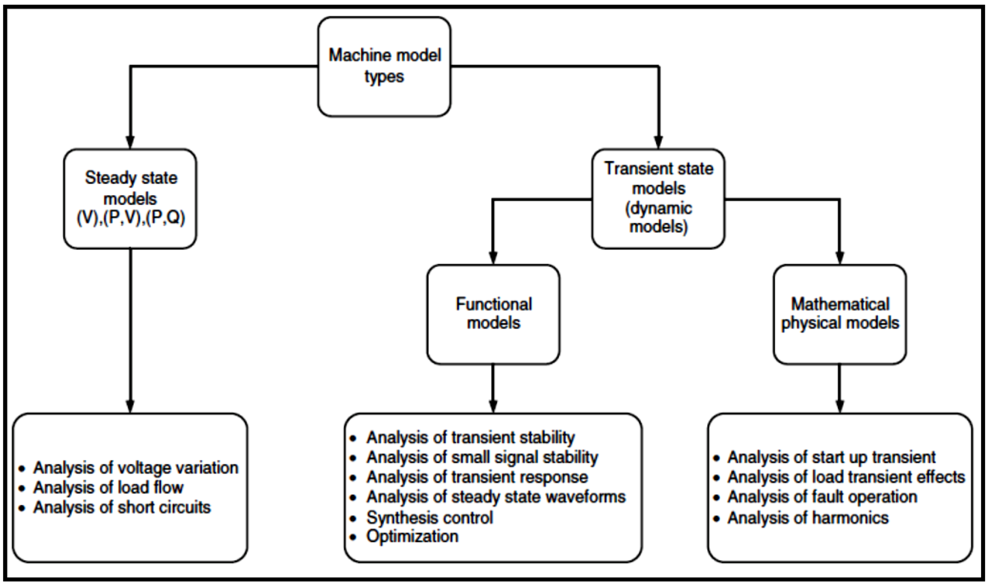

Figure 5.5: Model types and their applications (Vyas *et al.*, 2013)

Where:

Pm = the power extracted from the wind, in watts

ρ = the air density, in kg/m3

r = the radius swept by the rotor blades, in m

v_w = wind speed, in m/s

Cp = the performance coefficient (ratio of power extracted from the rotor to the power available from wind, also known as rotor performance coefficient and sometimes referred as Betz factor) defined (since, Pextracted < Pwind) as follows:

$$C_p = \frac{P_{extracted}}{P_{wind}}$$

(Equation 5.4)

λ = the tip speed ratio (the ratio of turbine blade speed to that of the wind)

$$\lambda = \frac{\omega_t r}{v_w}$$

(Equation 5.5)

Where:

ω_t = mechanical rotor speed, radians/s

From Equation 5.3 it is noted that the air density, the wind speed, and the radius swept by the blades are not quantities that can be controlled. Therefore, the only parameter that can be controlled in order to maximise the energy output from the wind is the performance coefficient Cp, which has a theoretical maximum governed by Betz's law of 0.593.

However, according to Wu *et al*. (2011) and as can be observed from Equation 6.3, there are three possibilities for increasing the power captured by a wind turbine: the wind speed vw, the power coefficient *Cp,* and the sweep area *A.* They posit that since wind speed cannot be controlled, the only way to increase wind speed is to locate the turbines in regions with higher average wind speeds. An example is the offshore wind farm, where the wind speed is usually higher and steadier than that on land. Equally, as the captured power is a cubic function of the wind speed, doubling the average wind speed would increase the wind power by eight times. Secondly, the wind turbine can be designed with larger sweep area (i.e., longer blades) to capture more power and the sweep area is given by $A = \pi l^2$ *,* where / is the blade length. It should be noted that an increase in the blade length has a quadratic effect on the sweep area and the captured power. This explains the trend of increasing the rotor diameter experienced during the last decade. Finally, the third way of increasing the captured power is by improving the power coefficient of the blade through a better aerodynamic design.

The performance coefficient Cp for a given blade pitch angle and rotation speed is nonlinearly related to the wind speed. Cp typically peaks at a given turbine tip speed to wind speed ratio and then drops off again to zero at higher tip speed ratios. Worthy of note is that the Cp characteristic is manufacturer-specific and varies for turbines provided by different manufacturers. A typical plot of Cp versus the tip speed ratio k is shown in Figure 5.6, where the change of Cp as pitch angle (β) is adjusted is also shown.

A wind turbine obtains its power input by converting the force of the wind into torque (turning force) acting on the rotor blades (Wagner and Mathur, 2009). However, the amount of energy which the wind transfers to the rotor depends on the density of the air, the rotor area, and the wind speed. Moreover, the energy in the wind is in the form of kinetic energy and kinetic energy is generally characterised by the Equation 5.6:

$$E = \frac{1}{2}mv^2$$

(Equation 5.6)

But the change in energy is proportional to the change in mass, where

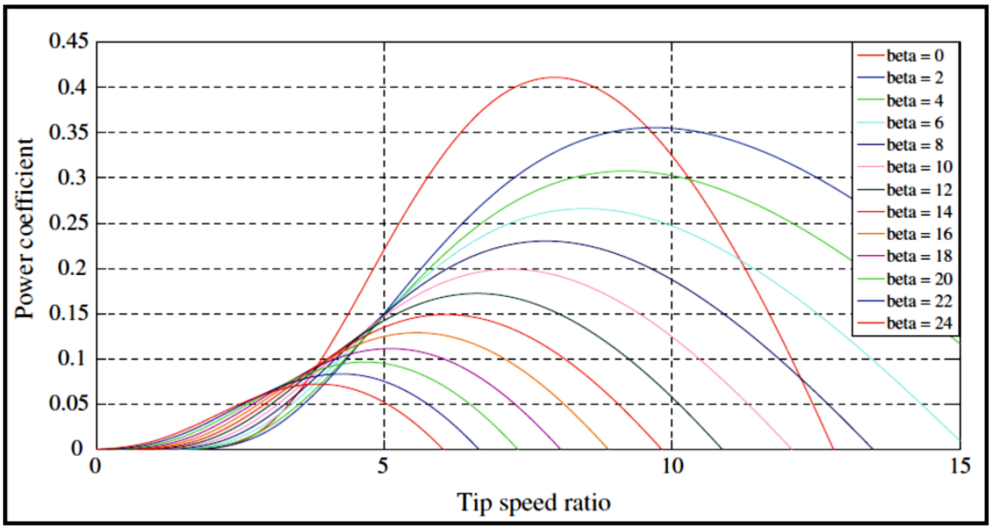

Figure 5.6: Power coefficient as a function of tip speed ratio (Vyas *et al.*, 2013)

$$m = V\rho_a$$

(Equation 5.7)

and ρ_a is the specific density of the air. Therefore, substituting for V and m yields

$$E = \frac{1}{2}A\rho_a v^3 t$$

(Equation 5.8)

From the previous equation it can be seen that the energy in the wind is proportional to the cube of the wind speed, v^3. The power P is defined as

$$P = \frac{E}{t} = \frac{1}{2}A\rho_a v^3$$

(Equation 5.9)

Therefore, Equation 5.9 shows that power in wind is proportional to v^3 as highlighted in Section 2.3.2.3 with particular reference to Figure 2.14. According to Wagner and Mathur (2009) it is more profitable to place a wind energy converter in a location with occasional high winds than in a location where there is a constant low wind speed. Moreover, measurements at different places show that the distribution of wind velocity over the year can be approximated by a Weibull-equation. This means that at least about 2/3 of the produced electricity will be earned by the upper third of wind velocity.

A typical set of output power-speed curves as a function of turbine speed and wind speed is shown in Figure 5.7. In this figure, the electric power output and turbine speed are normalised using their respective rated quantities.

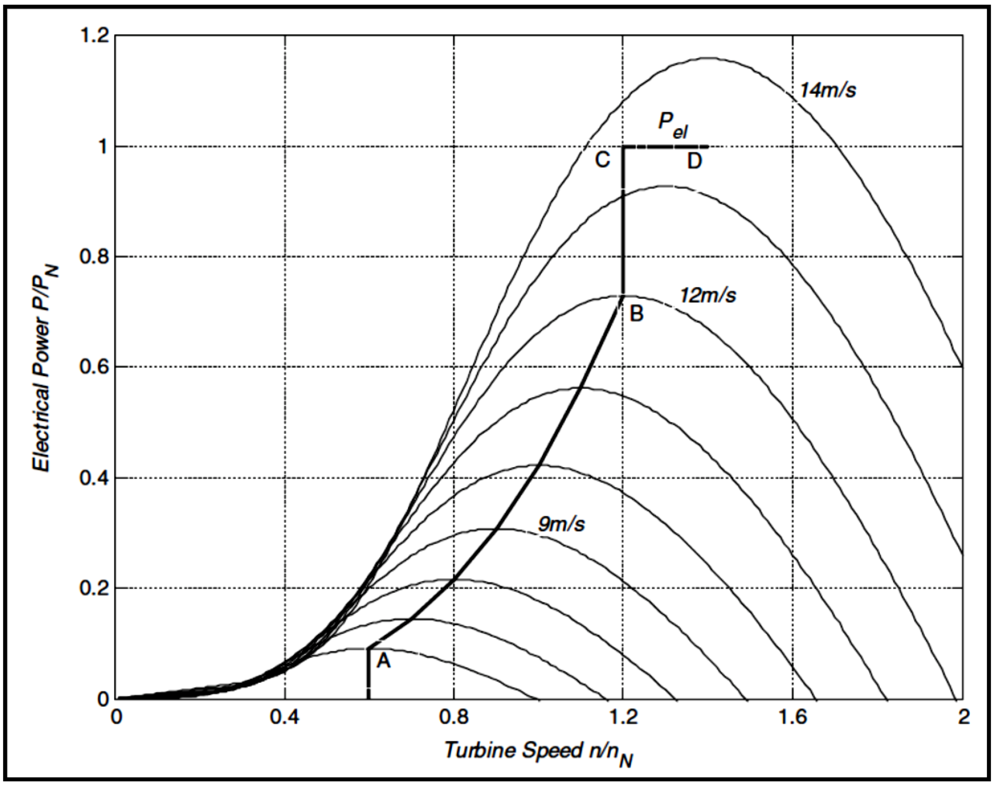

Figure 5.7: Plot of electrical output power as a function of wind turbine speed (Vittal and Ayyanar, 2013)

5.5 Investigations Model Development and Simulations

The development of an appropriate distribution network model is the focus of this section. This model will then be utilised through simulations in investigating some of the impacts of DG integration into the distribution network. The scope of the investigations is outlined in Section 5.5.1; the modelling in Section 5.5.2; and the simulation results in Section 5.5.3.

5.5.1 Scope

The investigations are limited to the steady state phenomena such as short circuit contribution, voltage variation and protection coordination because issues such as transient stability are usually not critical factors at the distribution level (Boutsika and Papathanassiou, 2008) especially for radial feeders (Alstom, 2011).

Distribution network being the emphasis for this work, these investigations are limited to medium voltage distribution not exceeding the substation. However, the author is aware that DG can impact on the transmission network and vice versa.

Most urban networks in Southern Africa are characterised by short (<5km) MV feeders usually operated at 11kV, with “large” (200 to 1000kVA) three-phase distribution transformers supplying typically up to 200 LV customers (Eskom, 2012a). In contrast, traditional rural networks comprise long (20-100km) MV feeders, typically operating at 11, 22 or 33kV, supplying individual or small groups of customers through small (16-200kVA) distribution transformers. The standard practices and requirements for all MV overhead distribution lines up to 33kV include the use of bare conductors up to Hare (Oak) (Eskom, 2011). Conductors are predominantly ACSR types namely Squirrel, Fox, Mink and Hare, but AAAC conductor types such as Acacia, 35, Pine and Oak conductors are only used in high marine pollution areas. Different conductors and their properties are shown in Appendix A. Therefore, the investigations are based on 22kV radial distribution network and 60km feeder of Fox overhead lines.

5.5.2 Modelling

Standard component models have been chosen from DIgSILENT PowerFactory library in modelling the system for the investigations. Consequently, the equations describing the components have been ignored. The model being examined consists of an external grid (utility equivalent source) modelled as a Thevenin equivalent voltage source with a short circuit power of 650MVA and an X/R ratio of 3.7. A 20MVA, 132/22kV substation is modelled as a load tap-changing transformer, with delta-wye grounded configuration. The transformer has a series equivalent impedance of 9% and its vector group is Dyn1. Per unit impedances ($Z_{1,2}$ and Z_0) of the 60km Fox overhead line (feeder) are 0.86 + j0.39 Ωkm^{-1} and 0.78 + j1.56 Ωkm^{-1} respectively with a current rating of 155A. This basic model is as shown in Figure 5.8.

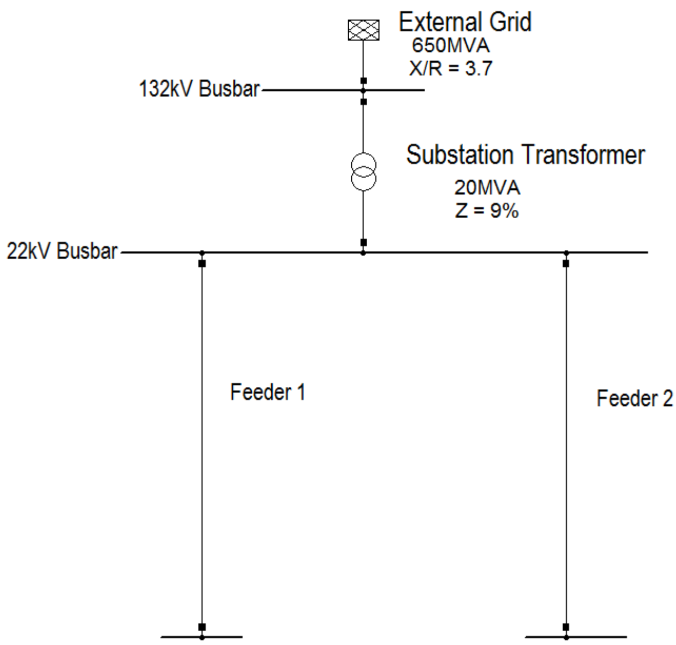

Figure 5.8: Basic distribution system model

To investigate the impacts of DG the feeder is modelled with 0.98 and 1.8MW loads – LD1 and LD2 – connected at 20km and 40km respectively as illustrated in Figure 5.9.

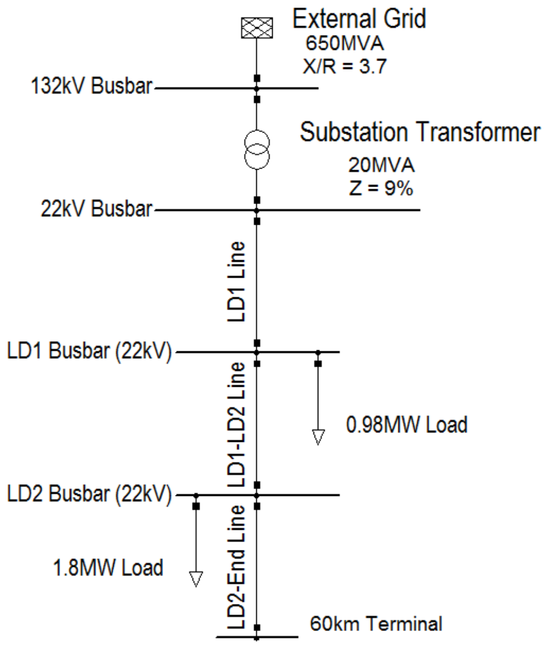

Figure 5.9: A 60km feeder model

The loads are general load types modelled as constant impedance and therefore do not contribute to the fault level. The DG is a synchronous generator, which can be used in thermal, hydro, or wind power plants. The DG is modelled as a Turbo Series 1 of IEC909/IEC60909 Machine Type and the excitation system control mode is constant power factor. Power factor control mode is aimed at maximising the active power production. Also it exempts the DG from participating in the system frequency control. In consequence, unitary power factor operation is adopted. In the absence of manufacturers' data, the DG parameters are the typical data from Eskom (2008a) as contained in Appendix B and the rating limited to 5MVA according to Eskom (2008b). It has a direct connection to the system because its nominal voltage is 22kV.

5.5.3 Simulation Results

The results of the investigations are presented as follows:

5.5.3.1 Impact of DG on Voltage Profile

The voltage level of distribution systems by requirement must be kept within a specific range which is well defined in international standards and the common range is 1 ± 0.5 p.u.This range is the default in DIgSILENT PowerFactory for the steady-state bus voltages. The investigation of the possible effects of DGs on the voltage profile along the feeder entails, firstly, ascertaining the feeder voltage profile in the absence of a DG – base case scenario. This necessitated the execution of a balance and positive sequence load flow simulation of the distribution model. The result reveals the voltages at the three reference points are 0.87, 0.79 and 0.79 p.u. respectively, as depicted in Figure 5.10, which violates the lower limit requirement.

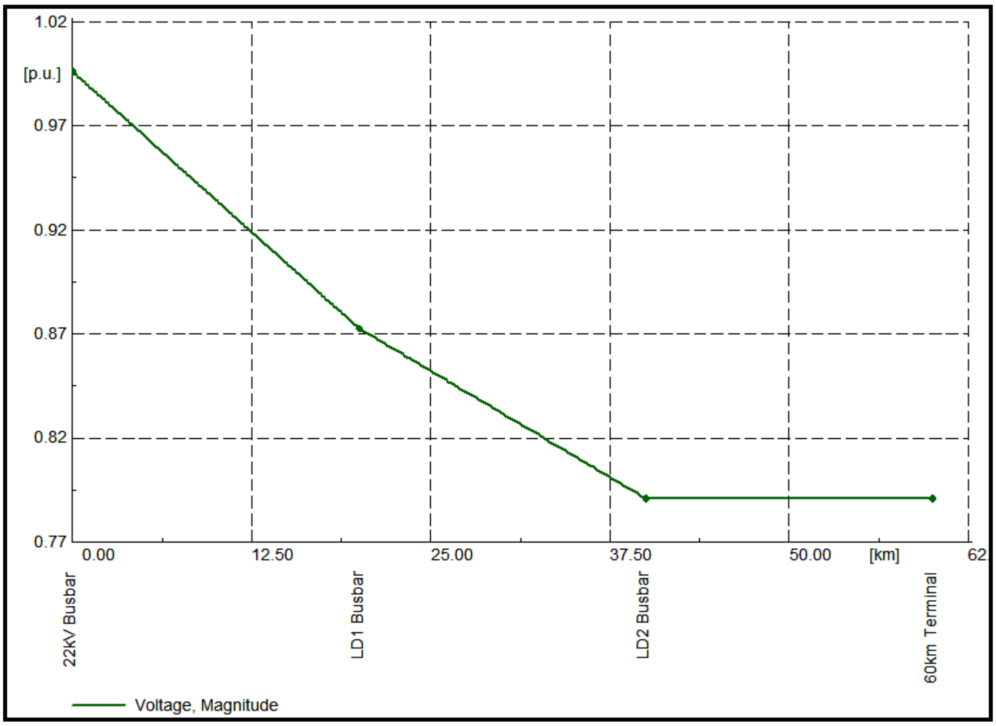

Figure 5.10: Feeder voltage profile without DG

As a solution to the voltage deterioration the 5MVA synchronous DG, having an installed capacity of 4.5MW, is modelled to dispatch 4MW and 2MW for the purpose of the investigations. Simulations of the distribution model are executed when each of these outputs is injected at the feeder end, LD2 Busbar and LD1 Busbar respectively. Figure 6.11 is a snapshot of the DG's element data load flow configuration when it dispatches 4MW.

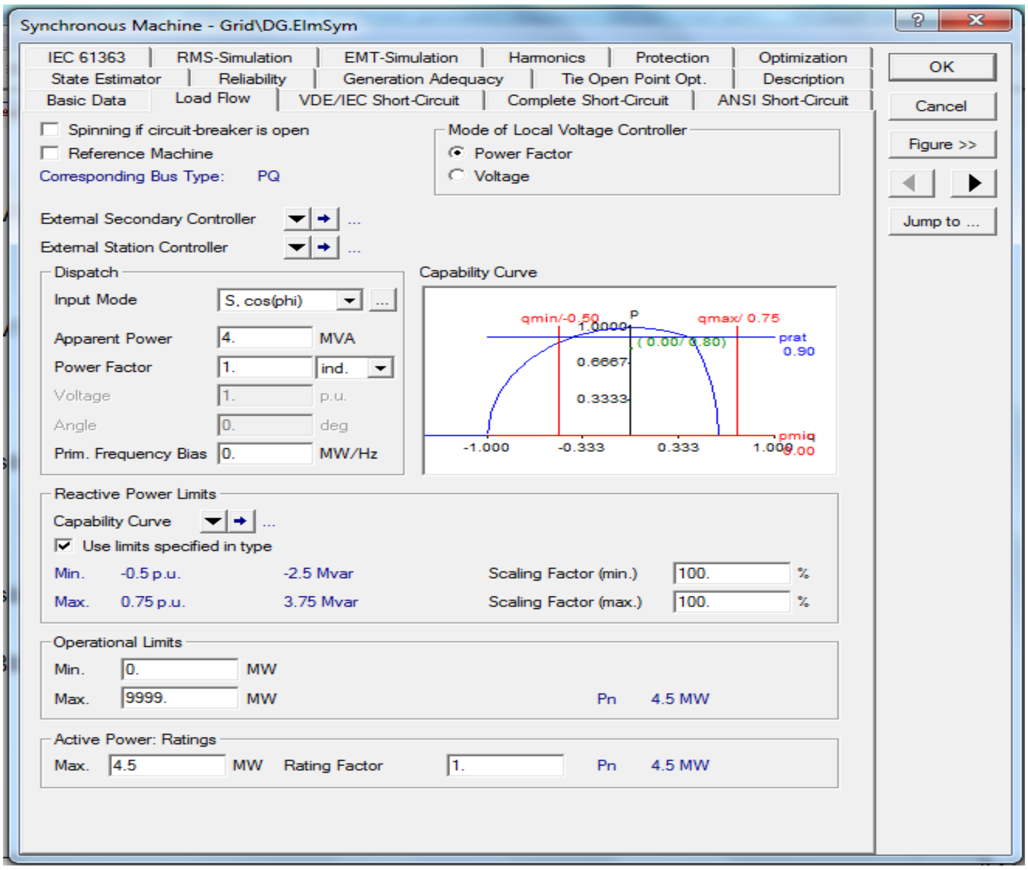

Figure 5.11: DG's element data load flow configuration for 4MW dispatch

With the DG dispatching 4MW and connected at the end of the feeder, the load flow simulation revealed an 80% loading of the DG. The resultant voltage profile, Figure 5.12, shows that the voltage at the 20km terminal is 1.02 p.u. and the second load experiences 1.07 p.u. voltage. Equally voltage at the end of the feeder (generator's POC) is 1.19 p.u. Therefore, there is a violation of the 1.05 p.u. voltage limit from 31km to the end of the feeder.

Figure 5.13 is the resultant feeder voltage profile when the DG's POC is LD2 Busbar leading to the p.u. voltages of the referenced points being 1.03, 1.10 and 1.10 respectively. The upper voltage limit violation commences from 24.6km to the end of the feeder.

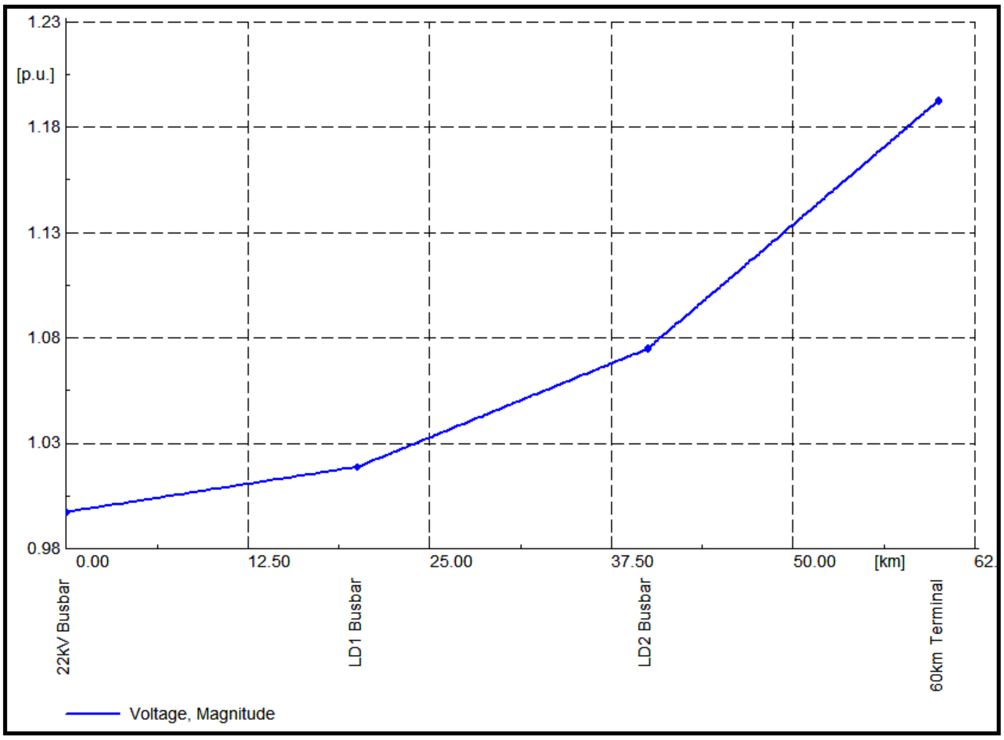

Figure 5.12: Feeder voltage profile with 4MW DG connected at the end of feeder

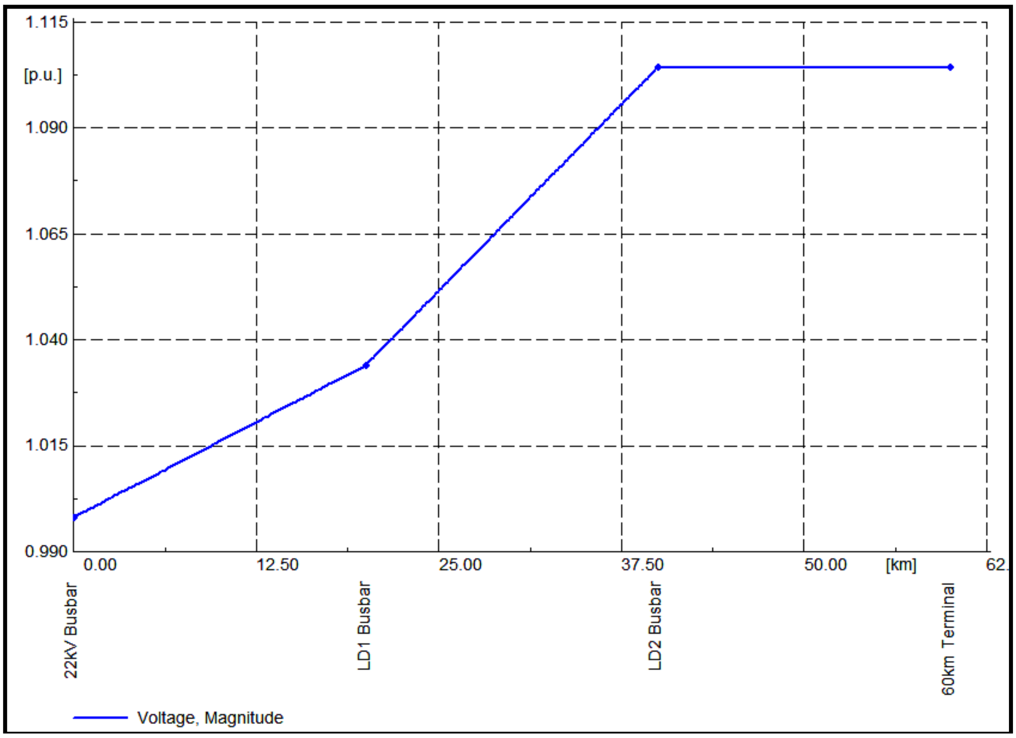

Figure 5.13: Feeder voltage profile with 4MW DG connected at LD2 Busbar

If the POC is at 20km from the substation – LD1 Busbar – the result is as depicted in Figure 5.14 with the p.u. voltages being 1.03, 0.97 and 0.97. Interestingly, there is no voltage limit violation at this point.

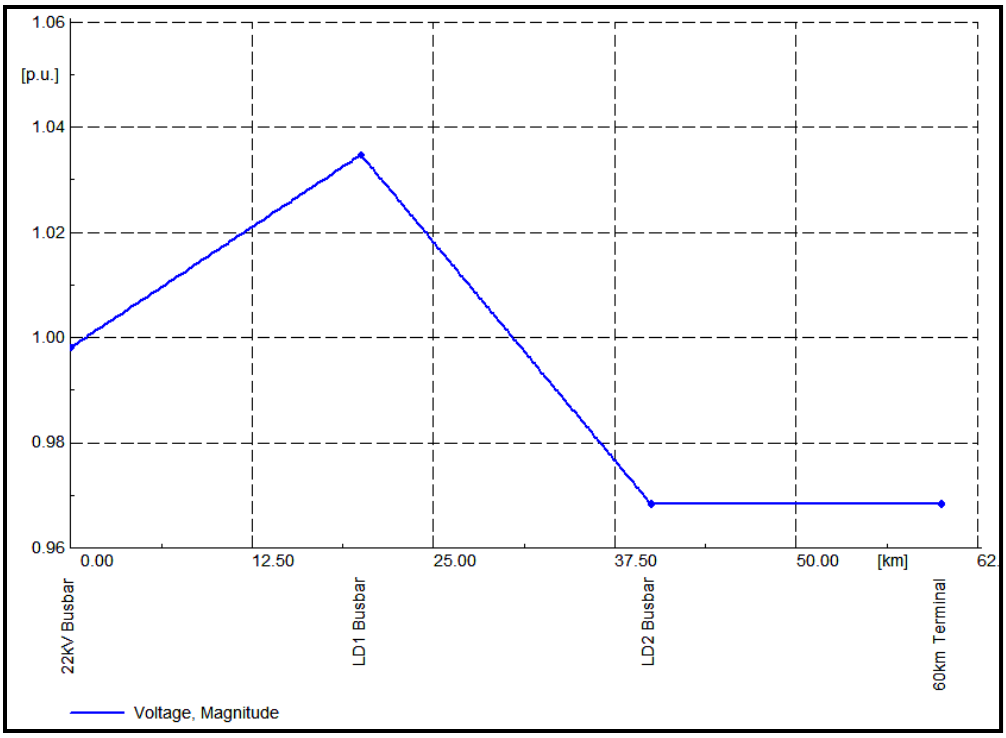

Figure 5.14: Feeder voltage profile with 4MW DG connected at LD1 Busbar

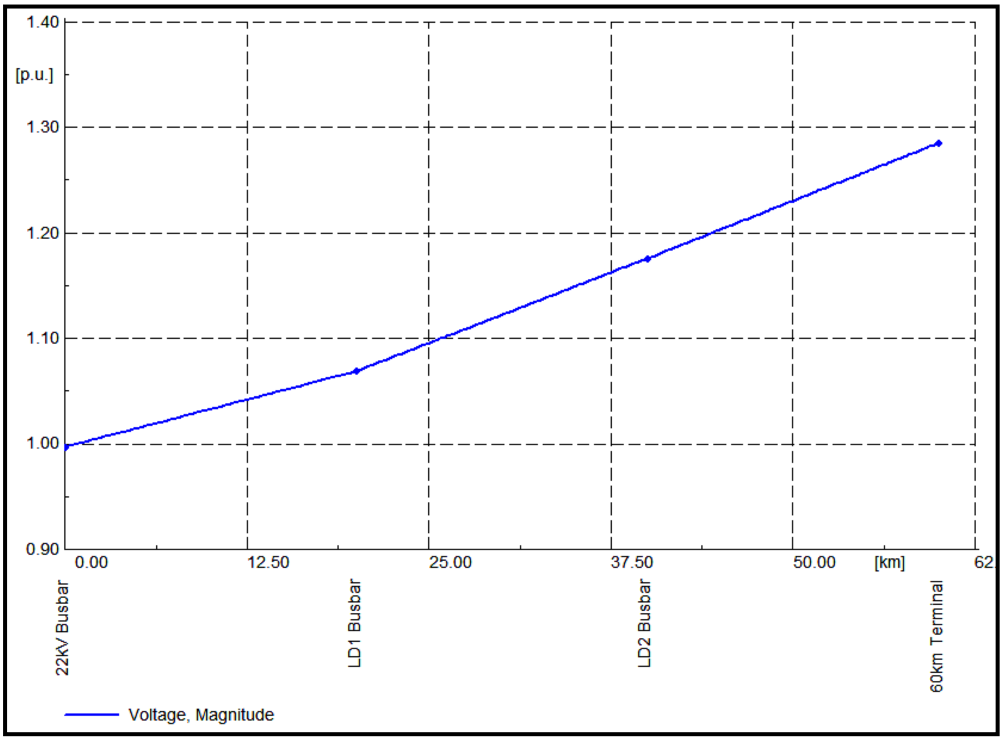

Figure 5.15: Minimum load feeder voltage profile with 4MW DG connected at feeder end

Figure 5.16 is a snapshot of the DG's element data load flow configuration for its 2MW dispatch.

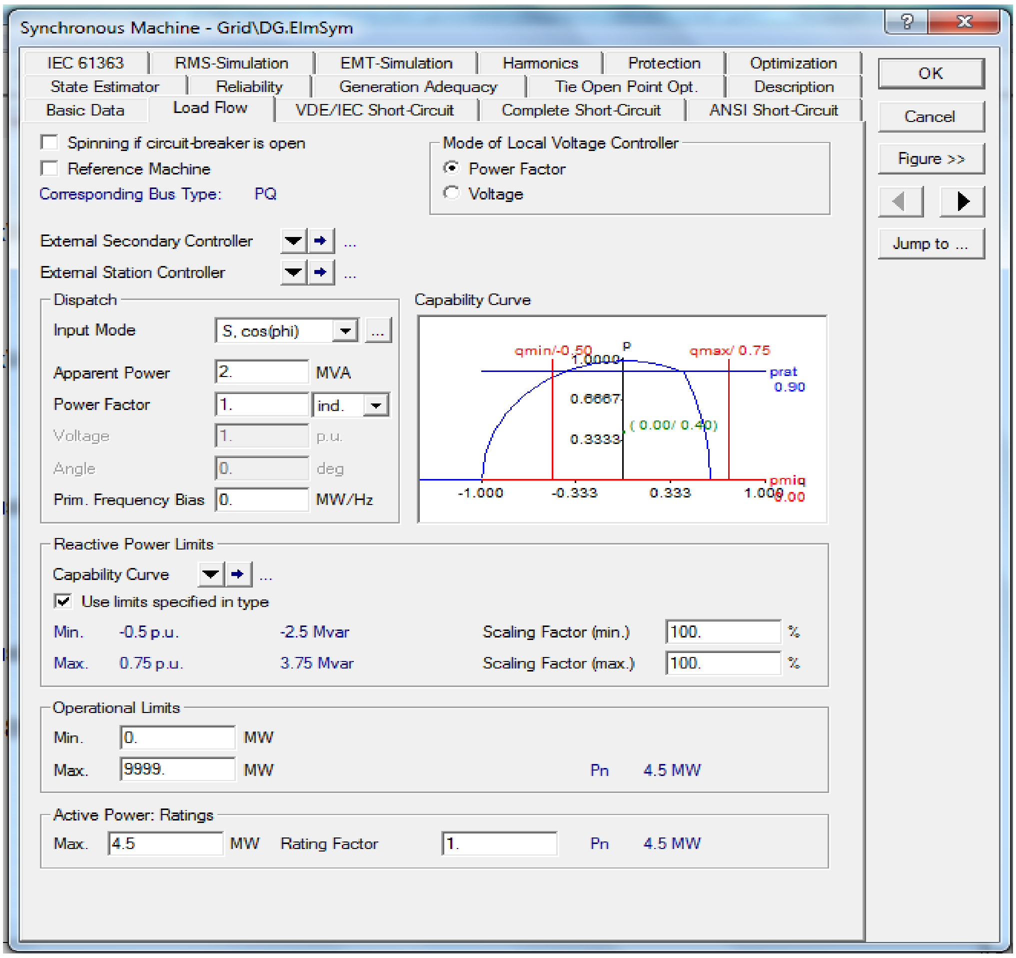

Figure 5.16: DG's element data load flow configuration for 2MW dispatch

With the DG connected at the end of the feeder and dispatching 2MW leaving a spinning reserve of 2.5MW, the resultant voltage profile is as shown in Figure 5.17.

While the DG experiences a 40% loading, the corresponding voltages are 0.96, 0.96 and 1.03 p.u. respectively. There is no voltage limit violation.

The voltage profile result of the DG injecting 2MW at LD2 Busbar is as shown in Figure 5.18 and the respective p.u. voltages are 0.97, 0.98 and 0.98. Again there is no voltage limit violation.

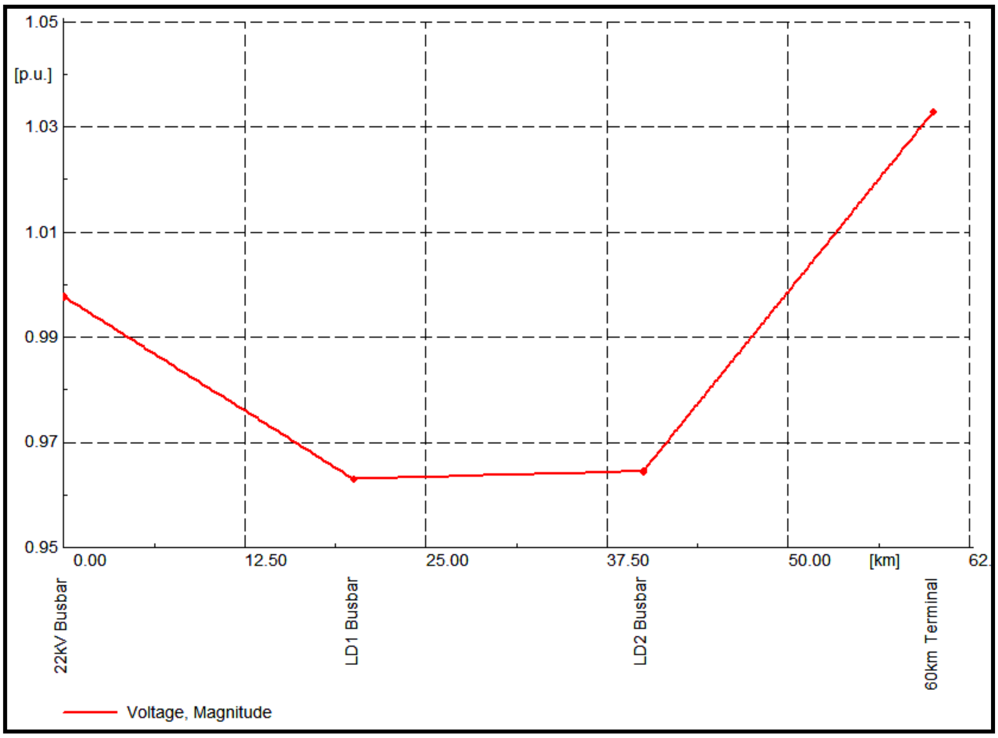

Figure 5.17: Feeder voltage profile with 2MW DG connected at the end of feeder

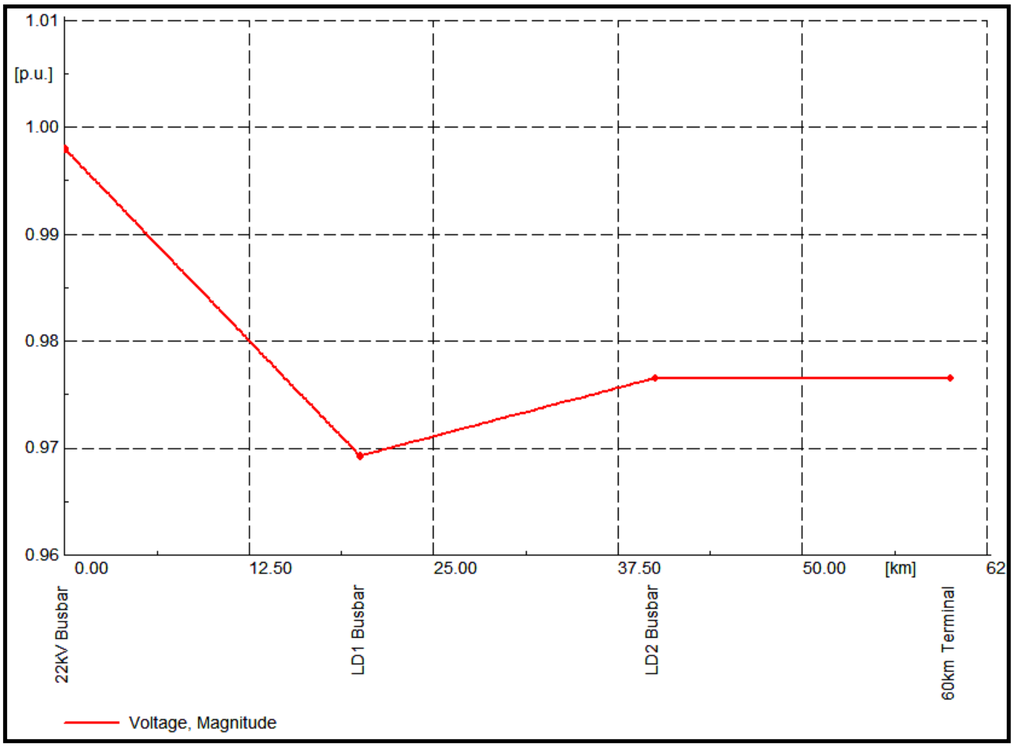

Figure 5.18: Feeder voltage profile with 2MW DG connected at LD2 Busbar

The DG's injection of 2MW at the LD1 Busbar produces a voltage profile as shown in Figure 5.19. The respective reference p.u. voltages are 0.96, 0.89 and 0.89 with a lower voltage limit violation from 23km to the end of the feeder.

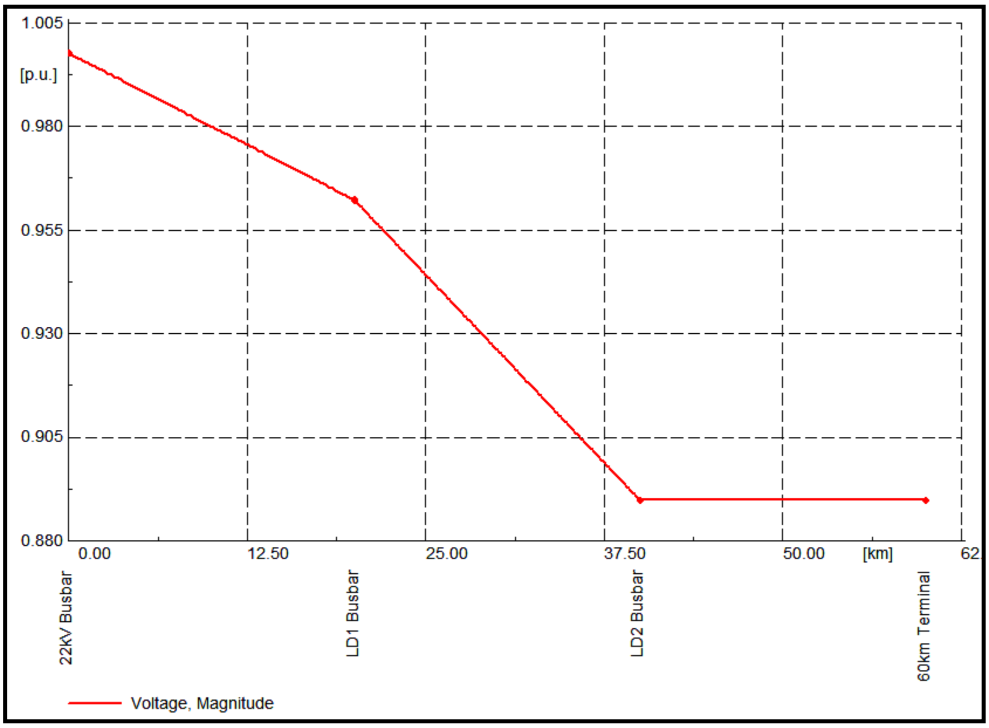

Figure 5.19: Feeder voltage profile with 2MW DG connected at LD1 Busbar

A possible minimum load scenario when the DG dispatches 2MW was created and investigated by putting LD2 out of service and also connecting the DG at the end of the feeder. The result is the voltage profile in Figure 5.20 which shows an upper limit voltage violation as from 28.5km.

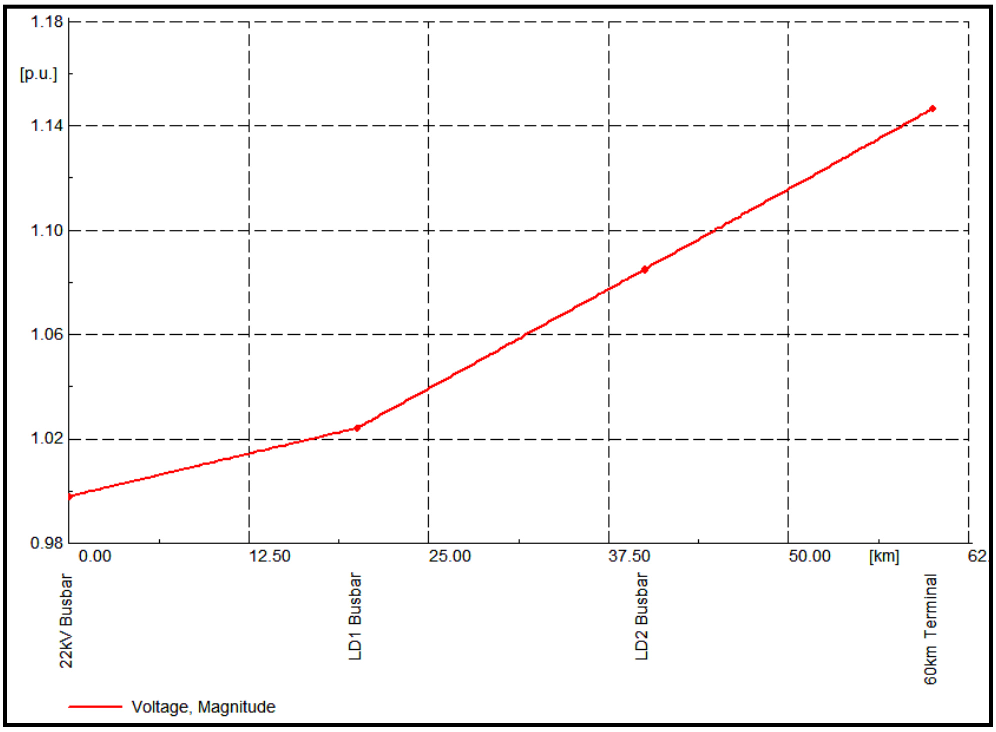

Figure 5.20: Minimum load feeder voltage profile with 2MW DG connected at feeder end

In summary the DG produces no voltage limit violation when it dispatches 4MW and connected at LD1 Busbar. Equally voltage limit violation is absent when the DG dispatches 2MW with feeder end and LD2 Busbar as its POCs. These results highlight the roles of location and capacity of DG on its effects on distribution network, for instance voltage profile, for a given load capacity. Particularly, the results show the importance of limiting DG capacity through careful study of the system to avoid overvoltages resulting from oversized generators. However, the cases without voltage limit violation typify highly loaded or weak networks where DGs can exert positive impacts thereby improving the network power quality. To limit the increased equipment voltage stress caused by violation of voltage limits, the DG overvoltage relay should be able to remove the DG during high voltages. The minimum load scenarios occasioned by sudden loss of loads result to greater upper voltage limit violations. Therefore, the deployment of smart devices to quickly disconnect the DG when an abnormality exits is of a necessity.

The two locations where voltage limit violations are absent – LD1 and LD2 Busbars – are considered the appropriate DG POCs for subsequent studies on the distribution network model.

5.5.3.2 Impact on Fault Level

One of the abnormalities of an electrical network is short circuit. Identification of the maximum fault current that will flow in the network under faulted conditions is the essence of short circuit studies prior to DG interconnection. This is because the maximum fault current is important in determining whether the existing equipment is adequately rated for the fault level – short circuit power. For instance, the maximum values of short circuit currents are calculated to determine the breaking capacity of the circuit breakers. From literature the two types of fault level conditions that should be studied are:

- Single phase to ground faults because they have highest rate of occurrence in distribution networks
- Three phase faults because of their severity – they produce maximum fault currents

Therefore, these short circuit studies have been executed on the developed model without and with DG interconnection. The conditions involving DG have been simulated based on the two power outputs – 4MW and 2MW – and connected on LD1 and LD2 Busbars respectively. Also the short circuit simulations on the line segments are on 50% line distance which is

10km. The short circuit method in this work is according to IEC60909 using a constant voltage factor which makes the fault level independant of the load. The maximum short circuit fault results are summarised in Table 5.1 for single phase to ground faults and Table 5.5 for three phase faults, and the values in each cell are the short circuit current (fault current) and fault level.

Table 5.1: Summary of results of single phase to ground faults

Connection Status	Short Circuit Current (kA) and Fault level (MVA)							
	132kV Busbar	22kV Busbar	LD1 Line	LD1 Busbar	LD1-LD2 Line	LD2 Busbar	LD2-End Line	60km Terminal
Without DG	2.89 220.29	6.04 76.72	1.04 13.20	0.56 7.15	0.39 4.90	0.29 3.72	0.24 3.00	0.20 2.52
With 4MW DG	2.94 224.20	6.47 82.20	1.72 21.88	1.91 24.23	0.76 9.70	0.47 6.00	0.34 4.33	0.27 3.39
With 2MW DG	2.92 222.59	6.26 79.51	1.37 17.38	1.00 12.76	1.06 13.41	1.58 20.04	0.72 9.12	0.46 5.79

Table 5.2 shows the complete simulation result of the single phase to ground short circuit on the busbars without DG. Tables 5.3 and 5.4 are the detailed results of the single phase to ground fault with the DG connected as described earlier. It should be noted that by default the single phase to ground fault occurs on the A (red) phase of the system.

Table 5.2: Result of single phase to ground short circuit without DG

```
-------------------------------------------------------------------------------------------------------------
| Fault Locations                                                                                            |
| Short-Circuit Calculation according to IEC60909                 Single Phase to Ground   / Max. Short-Circuit Currents |
-------------------------------------------------------------------------------------------------------------
| Asynchronous Motors                 | Grid Identification                | Short-Circuit Duration                  |
|    Always Considered                |    Automatic                       |    Break Time                    0.10 s |
|                                     |                                    |    Fault Clearing Time (Ith)     1.00 s |
|                                     | Conductor Temperature              | c-Voltage Factor                        |
|                                     |    User Defined            No      |    User Defined                  No     |
|                                     |                                    |                                         |
-------------------------------------------------------------------------------------------------------------
-------------------------------------------------------------------------------------------------------------
| Grid: Grid               System Stage: Grid        |                               | Annex:           / 1   |
-------------------------------------------------------------------------------------------------------------
|                   rtd. V                 Voltage              c-     Sk"          Ik"           ip      Ib      Sb  |
|                    [kV]  Phase  [kV]     [p.u.]     [deg]  Factor  [MVA]    [kA]    [deg]    [kA]    [kA]   [MVA] |
-------------------------------------------------------------------------------------------------------------
|132kV Busbar                                                                                                |
|  132kV Busbar     132.00  A     0.00     0.00      0.00    1.1   220.29    2.89   -76.87    5.80    2.89  220.29 |
|                           B    87.88     1.15   -117.57            0.00    0.00     0.00    0.00    0.00    0.00 |
|                           C    78.64     1.03    121.15            0.00    0.00     0.00    0.00    0.00    0.00 |
|                                                                                                            |
|22kV Busbar                                                                                                 |
|  22kV Busbar       22.00  A     0.00     0.00      0.00    1.1    76.72    6.04   -74.23   14.61    6.04   76.72 |
|                           B     9.84     0.77   -109.59            0.00    0.00     0.00    0.00    0.00    0.00 |
|                           C    15.29     1.20    102.45            0.00    0.00     0.00    0.00    0.00    0.00 |
|                                                                                                            |
|LD1 Busbar                                                                                                  |
|  LD1 Busbar (22k   22.00  A     0.00     0.00      0.00    1.1     7.15    0.56   -45.87    0.82    0.56    7.15 |
|                           B    17.87     1.41   -123.07            0.00    0.00     0.00    0.00    0.00    0.00 |
|                           C    13.42     1.06    136.58            0.00    0.00     0.00    0.00    0.00    0.00 |
|                                                                                                            |
-------------------------------------------------------------------------------------------------------------
-------------------------------------------------------------------------------------------------------------
| Grid: Grid               System Stage: Grid        |                               | Annex:           / 2   |
-------------------------------------------------------------------------------------------------------------
|                   rtd. V                 Voltage              c-     Sk"          Ik"           ip      Ib      Sb  |
|                    [kV]  Phase  [kV]     [p.u.]     [deg]  Factor  [MVA]    [kA]    [deg]    [kA]    [kA]   [MVA] |
-------------------------------------------------------------------------------------------------------------
|LD2 Busbar                                                                                                  |
|  LD2 Busbar (22k   22.00  A     0.00     0.00      0.00    1.1     3.72    0.29   -44.54    0.42    0.29    3.72 |
|                           B    18.27     1.44   -122.74            0.00    0.00     0.00    0.00    0.00    0.00 |
|                           C    13.25     1.04    138.23            0.00    0.00     0.00    0.00    0.00    0.00 |
|                                                                                                            |
|SingleBusbar                                                                                                |
|  60km Terminal     22.00  A     0.00     0.00      0.00    1.1     2.52    0.20   -44.08    0.29    0.20    2.52 |
|                           B    18.42     1.45   -122.62            0.00    0.00     0.00    0.00    0.00    0.00 |
|                           C    13.19     1.04    138.81            0.00    0.00     0.00    0.00    0.00    0.00 |
|                                                                                                            |
|                                                                                                            |
-------------------------------------------------------------------------------------------------------------
```

Table 5.3: Result of single phase to ground short circuit with 4MW DG

```
-----------------------------------------------------------------------------------------------------------------------------
| Fault Locations                                                                                                            |
| Short-Circuit Calculation according to IEC60909                          Single Phase to Ground   / Max. Short-Circuit Currents |
-----------------------------------------------------------------------------------------------------------------------------
| Asynchronous Motors                     | Grid Identification                    | Short-Circuit Duration                  |
|    Always Considered                    |    Automatic                           |    Break Time                   0.10 s  |
|                                         |                                        |    Fault Clearing Time (Ith)    1.00 s  |
|                                         | Conductor Temperature                  | c-Voltage Factor                        |
|                                         |    User Defined              No        |    User Defined                 No      |
|                                         |                                        |                                         |
-----------------------------------------------------------------------------------------------------------------------------
-----------------------------------------------------------------------------------------------------------------------------
| Grid: Grid                System Stage: Grid          |                                       | Annex:            / 1    |
-----------------------------------------------------------------------------------------------------------------------------
|                    rtd. V                   Voltage               c-      Sk"               Ik"          ip       Ib       Sb     |
|                    [kV]  Phase    [kV]     [p.u.]      [deg]   Factor   [MVA]       [kA]      [deg]    [kA]     [kA]    [MVA]   |
-----------------------------------------------------------------------------------------------------------------------------
|132kV Busbar                                                                                                                       |
|  132kV Busbar      132.00   A      0.00      0.00       0.00    1.1     224.20       2.94     -76.60    5.89     2.94   224.20   |
|                             B     88.45      1.16    -117.90              0.00       0.00       0.00    0.00     0.00     0.00   |
|                             C     78.73      1.03     121.69              0.00       0.00       0.00    0.00     0.00     0.00   |
|                                                                                                                                   |
|22kV Busbar                                                                                                                        |
|  22kV Busbar        22.00   A      0.00      0.00       0.00    1.1      82.20       6.47     -71.61   15.33     6.47    82.20   |
|                             B     10.06      0.79    -111.11              0.00       0.00       0.00    0.00     0.00     0.00   |
|                             C     15.23      1.20     103.63              0.00       0.00       0.00    0.00     0.00     0.00   |
|                                                                                                                                   |
|LD1 Busbar                                                                                                                         |
|  LD1 Busbar (22k    22.00   A      0.00      0.00       0.00    1.1      24.23       1.91     -68.76    4.58     1.91    24.23   |
|                             B     12.99      1.02    -100.48              0.00       0.00       0.00    0.00     0.00     0.00   |
|                             C     11.34      0.89     103.59              0.00       0.00       0.00    0.00     0.00     0.00   |
|                                                                                                                                   |
-----------------------------------------------------------------------------------------------------------------------------
□----------------------------------------------------------------------------------------------------------------------------
| Grid: Grid                System Stage: Grid          |                                       | Annex:            / 2    |
-----------------------------------------------------------------------------------------------------------------------------
|                    rtd. V                   Voltage               c-      Sk"               Ik"          ip       Ib       Sb     |
|                    [kV]  Phase    [kV]     [p.u.]      [deg]   Factor   [MVA]       [kA]      [deg]    [kA]     [kA]    [MVA]   |
-----------------------------------------------------------------------------------------------------------------------------
|LD2 Busbar                                                                                                                         |
|  LD2 Busbar (22k    22.00   A      0.00      0.00       0.00    1.1       6.00       0.47     -49.26    0.71     0.47     6.00   |
|                             B     16.77      1.32    -120.37              0.00       0.00       0.00    0.00     0.00     0.00   |
|                             C     12.84      1.01     131.53              0.00       0.00       0.00    0.00     0.00     0.00   |
|                                                                                                                                   |
|SingleBusbar                                                                                                                       |
|  60km Terminal      22.00   A      0.00      0.00       0.00    1.1       3.39       0.27     -46.58    0.39     0.27     3.39   |
|                             B     17.60      1.39    -121.45              0.00       0.00       0.00    0.00     0.00     0.00   |
|                             C     12.95      1.02     135.24              0.00       0.00       0.00    0.00     0.00     0.00   |
|                                                                                                                                   |
|                                                                                                                                   |
-----------------------------------------------------------------------------------------------------------------------------
```

Table 5.4: Result of single phase to ground short circuit with 2MW DG

```
-----------------------------------------------------------------------------------------------------------------------------
| Fault Locations                                                                                                            |
| Short-Circuit Calculation according to IEC60909                          Single Phase to Ground   / Max. Short-Circuit Currents |
-----------------------------------------------------------------------------------------------------------------------------
| Asynchronous Motors                     | Grid Identification                    | Short-Circuit Duration                  |
|    Always Considered                    |    Automatic                           |    Break Time                   0.10 s  |
|                                         |                                        |    Fault Clearing Time (Ith)    1.00 s  |
|                                         | Conductor Temperature                  | c-Voltage Factor                        |
|                                         |    User Defined              No        |    User Defined                 No      |
|                                         |                                        |                                         |
-----------------------------------------------------------------------------------------------------------------------------
-----------------------------------------------------------------------------------------------------------------------------
| Grid: Grid                System Stage: Grid          |                                       | Annex:            / 1    |
-----------------------------------------------------------------------------------------------------------------------------
|                    rtd. V                   Voltage               c-      Sk"               Ik"          ip       Ib       Sb     |
|                    [kV]  Phase    [kV]     [p.u.]      [deg]   Factor   [MVA]       [kA]      [deg]    [kA]     [kA]    [MVA]   |
-----------------------------------------------------------------------------------------------------------------------------
|132kV Busbar                                                                                                                       |
|  132kV Busbar      132.00   A      0.00      0.00       0.00    1.1     222.59       2.92     -76.57    5.85     2.92   222.59   |
|                             B     88.30      1.16    -117.73              0.00       0.00       0.00    0.00     0.00     0.00   |
|                             C     78.61      1.03     121.50              0.00       0.00       0.00    0.00     0.00     0.00   |
|                                                                                                                                   |
|22kV Busbar                                                                                                                        |
|  22kV Busbar        22.00   A      0.00      0.00       0.00    1.1      79.51       6.26     -72.10   14.99     6.26    79.51   |
|                             B     10.01      0.79    -110.47              0.00       0.00       0.00    0.00     0.00     0.00   |
|                             C     15.23      1.20     103.23              0.00       0.00       0.00    0.00     0.00     0.00   |
|                                                                                                                                   |
|LD1 Busbar                                                                                                                         |
|  LD1 Busbar (22k    22.00   A      0.00      0.00       0.00    1.1      12.76       1.00     -50.40    1.52     1.00    12.76   |
|                             B     16.82      1.32    -122.39              0.00       0.00       0.00    0.00     0.00     0.00   |
|                             C     13.37      1.05     132.30              0.00       0.00       0.00    0.00     0.00     0.00   |
|                                                                                                                                   |
-----------------------------------------------------------------------------------------------------------------------------
□----------------------------------------------------------------------------------------------------------------------------
| Grid: Grid                System Stage: Grid          |                                       | Annex:            / 2    |
-----------------------------------------------------------------------------------------------------------------------------
|                    rtd. V                   Voltage               c-      Sk"               Ik"          ip       Ib       Sb     |
|                    [kV]  Phase    [kV]     [p.u.]      [deg]   Factor   [MVA]       [kA]      [deg]    [kA]     [kA]    [MVA]   |
-----------------------------------------------------------------------------------------------------------------------------
|LD2 Busbar                                                                                                                         |
|  LD2 Busbar (22k    22.00   A      0.00      0.00       0.00    1.1      20.04       1.58     -75.80    3.98     1.58    20.04   |
|                             B     12.51      0.99     -99.54              0.00       0.00       0.00    0.00     0.00     0.00   |
|                             C     11.55      0.91     101.82              0.00       0.00       0.00    0.00     0.00     0.00   |
|                                                                                                                                   |
|SingleBusbar                                                                                                                       |
|  60km Terminal      22.00   A      0.00      0.00       0.00    1.1       5.79       0.46     -52.08    0.70     0.46     5.79   |
|                             B     16.26      1.28    -120.76              0.00       0.00       0.00    0.00     0.00     0.00   |
|                             C     13.05      1.03     129.64              0.00       0.00       0.00    0.00     0.00     0.00   |
|                                                                                                                                   |
|                                                                                                                                   |
-----------------------------------------------------------------------------------------------------------------------------
```

Table 5.5: Summary of results of three phase faults

Connection Status	Short Circuit Current (kA) and Fault level (MVA)							
	132kV Busbar	22kV Busbar	LD1 Line	LD1 Busbar	LD1-LD2 Line	LD2 Busbar	LD2-End Line	60km Terminal
Without DG	2.84 650	4.72 179.78	1.24 47.28	0.68 25.88	0.47 17.77	0.35 13.52	0.29 10.91	0.24 9.14
With 4MW DG	2.92 666.60	5.14 195.98	1.86 70.92	1.42 53.96	0.77 29.43	0.52 19.63	0.38 14.64	0.31 11.65
With 2MW DG	2.89 659.69	4.95 188.53	1.61 61.45	1.15 43.71	1.08 41.29	1.15 43.67	0.71 27.01	0.49 18.74

The detailed three phase short circuit simulation results of the respective scenarios are as shown in Tables 5.6, 5.7 and 5.8.

Table 5.6: Result of three phase short circuit without DG

Fault Locations Short-Circuit Calculation according to IEC60909		3-Phase Short-Circuit / Max. Short-Circuit Currents
Asynchronous Motors Always Considered Decaying Aperiodic Component (idc) Using Method B	Grid Identification Automatic Conductor Temperature User Defined No	Short-Circuit Duration Break Time 0.10 s Fault Clearing Time (Ith) 1.00 s c-Voltage Factor User Defined No
Grid: Grid	System Stage: Grid	Annex: / 1

	rtd. V [kV]	Voltage [kV]	[deg]	c-Factor	Sk" [MVA]	Ik" [kA]	[deg]	ip [kA]	Ib [kA]	Sb [MVA]	Ik [kA]	Ith [kA]
132kV Busbar												
132kV Busb	132.00	0.00	0.00	1.10	650.00	2.84	-73.30	5.70	2.84	650.00	2.84	2.86
22kV Busbar												
22kV Busba	22.00	0.00	0.00	1.10	179.78	4.72	-83.34	11.41	4.72	179.78	4.72	4.79
LD1 Busbar												
LD1 Busbar	22.00	0.00	0.00	1.10	25.88	0.68	-31.48	0.99	0.68	25.88	0.68	0.68
LD2 Busbar												
LD2 Busbar	22.00	0.00	0.00	1.10	13.52	0.35	-28.09	0.51	0.35	13.52	0.35	0.36
SingleBusbar												
60km Termi	22.00	0.00	0.00	1.10	9.14	0.24	-26.89	0.35	0.24	9.14	0.24	0.24

Table 5.7: Result of three phase short circuit with 4MW DG

Fault Locations Short-Circuit Calculation according to IEC60909		3-Phase Short-Circuit / Max. Short-Circuit Currents
Asynchronous Motors Always Considered Decaying Aperiodic Component (idc) Using Method B	Grid Identification Automatic Conductor Temperature User Defined No	Short-Circuit Duration Break Time 0.10 s Fault Clearing Time (Ith) 1.00 s c-Voltage Factor User Defined No
Grid: Grid	System Stage: Grid	Annex: / 1

	rtd. V [kV]	Voltage [kV]	[deg]	c-Factor	Sk" [MVA]	Ik" [kA]	[deg]	ip [kA]	Ib [kA]	Sb [MVA]	Ik [kA]	Ith [kA]
132kV Busbar												
132kV Busb	132.00	0.00	0.00	1.10	666.60	2.92	-72.83	5.82	2.91	664.94	2.88	2.92
22kV Busbar												
22kV Busba	22.00	0.00	0.00	1.10	195.98	5.14	-80.57	12.18	5.13	195.37	4.94	5.16
LD1 Busbar												
LD1 Busbar	22.00	0.00	0.00	1.10	53.96	1.42	-65.30	3.38	1.33	50.53	0.93	1.27
LD2 Busbar												
LD2 Busbar	22.00	0.00	0.00	1.10	19.63	0.52	-38.17	0.78	0.51	19.32	0.52	0.52
60km Termina	22.00	0.00	0.00	1.10	11.65	0.31	-32.52	0.45	0.31	11.65	0.31	0.31

Table 5.8: Result of three phase short circuit with 2MW DG

Fault Locations Short-Circuit Calculation according to IEC60909		3-Phase Short-Circuit / Max. Short-Circuit Currents
Asynchronous Motors Always Considered Decaying Aperiodic Component (idc) Using Method B	Grid Identification Automatic Conductor Temperature User Defined No	Short-Circuit Duration Break Time 0.10 s Fault Clearing Time (Ith) 1.00 s c-Voltage Factor User Defined No
Grid: Grid	System Stage: Grid	Annex: / 1

	rtd. V [kV]	Voltage [kV]	[deg]	c-Factor	Sk" [MVA]	Ik" [kA]	[deg]	ip [kA]	Ib [kA]	Sb [MVA]	Ik [kA]	Ith [kA]
132kV Busbar												
132kV Busb	132.00	0.00	0.00	1.10	659.69	2.89	-72.82	5.78	2.89	660.85	2.88	2.90
22kV Busbar												
22kV Busba	22.00	0.00	0.00	1.10	188.53	4.95	-81.01	11.86	5.01	190.90	4.92	5.05
LD1 Busbar												
LD1 Busbar	22.00	0.00	0.00	1.10	43.71	1.15	-40.30	1.75	1.09	41.47	0.91	1.05
LD2 Busbar												
LD2 Busbar	22.00	0.00	0.00	1.10	43.67	1.15	-73.50	2.90	1.00	38.17	0.60	0.94
60km Termina	22.00	0.00	0.00	1.10	18.74	0.49	-43.33	0.76	0.47	18.06	0.49	0.49

The above simulation results show that the connection of a DG to a distribution network increases the network fault levels and this effect is more pronounced close to the POC. This increment may result in the violation of equipment fault level ratings. Consequently, measures adopted in limiting fault levels which are widely documented include equipment upgrade, network splitting, and earthing of transformer and generator neutrals. Other measures are the use of series reactors, high impedance transformers, and extremely fast acting fuses or super conductive switches. However, each of these measures has its advantages and disadvantages.

5.5.3.3 Voltage Stability

Voltage stability refers to the ability of a power system to maintain steady-state voltage at all buses in the system after being subjected to a disturbance. Voltage stability is classified into steady-state and dynamic involving small and large disturbances respectively. To be investigated here are steady-state voltage stability pertaining to load increase and faults – small signal disturbances. This is because the voltage profile improvement from DG interconnection does not imply unlimited loading to avoid the system's failure to sustain the load. In general, the inability of the system to supply the required demand leads to voltage instability (voltage collapse) (Mansour and Cañizares, 2012). Moreover, voltage instability of radial distribution systems has been well recognised and understood for decades and was often referred to as load instability.

Voltage stability is usually represented by P-V curve and at the point of voltage collapse the voltage drops rapidly with an increase of the power load and consequently, the load flow simulation fails to converge beyond this limit. *P-V* curves have been traditionally used as graphical tools for studying voltage stability in electric power systems. Voltage stability analysis in DIgSILENT PowerFactory is performed by selecting the buses and the loads that are of interest, choosing the *Execute DSL scripts* and the selection of *U_P-Curve*. The resulting graphs are automatically displayed. Prior to voltage stability analysis the loads have unity scaling factors but DIgSILENT PowerFactory performs voltage stability analysis by gradually increasing the load, while keeping the power factor constant, of the preselected buses until they reach the power transfer limit.

The P-V curve of the developed model without DG is as shown in Figure 5.21. The maximum or total load before voltage collapse is 3.75MW made up of LD1 (1.32MW) and LD2 (2.43MW) – this is equivalent to 35% load increase from 2.78MW. Therefore, the loading margin to voltage collapse – for a current operating point, the total of increment of load in a specified pattern of load increase that would cause a voltage collapse – is 0.97MW. The 22kV Busbar p.u. voltage has dropped slightly to 0.99.

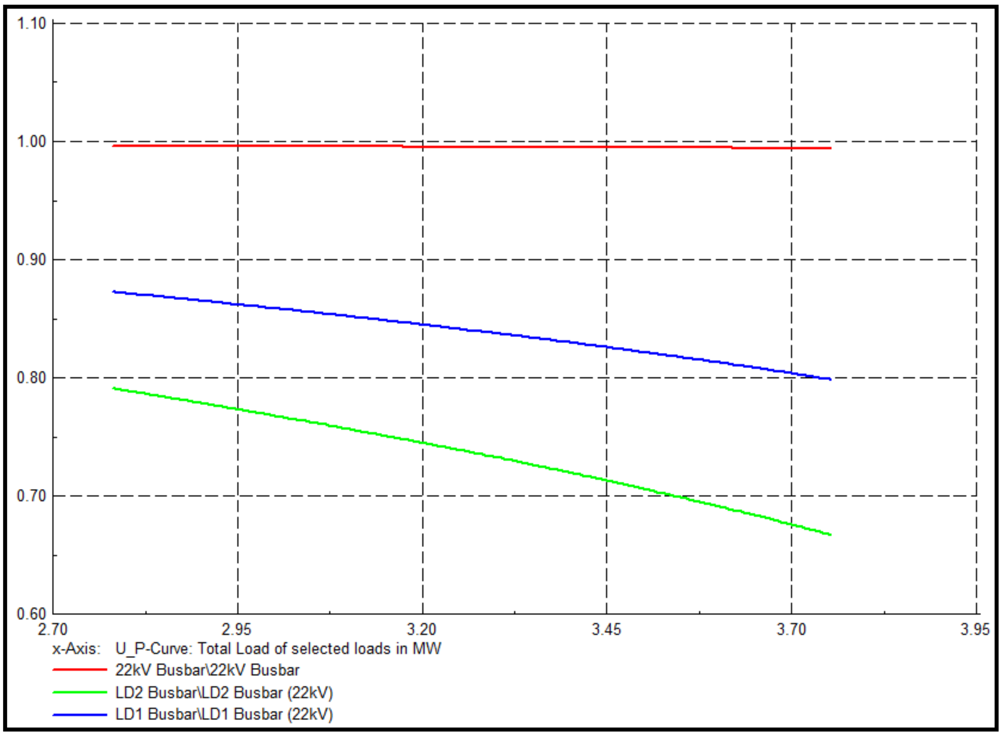

Figure 5.21: P-V curve without DG

But the resultant p.u. voltages at LD1and LD2 Busbars are 0.80 and 0.67 while that of the 60km Terminal is 0.67. Also LD1 Line's loading has risen to 89.69%. These values have violated their limits and so appear in red in Table 5.9. As a further investigation of the voltage stability a 50% load increment was simulated and this prompted an error message as shown in Figure 5.22. The output window message shows a failure in load flow convergence after 25 iterations as depicted in Figure 5.23.

Table 5.9: Result of voltage stability analysis without DG

Load Flow Calculation

AC Load Flow, balanced, positive sequence				
Automatic Tap Adjust of Transformers	No			
Consider Reactive Power Limits	No	Max. Loading of Edge Element	80.00 %
Automatic Model Adaptation for Convergence	No	Lower Limit of Allowed Voltage	0.95 p.u.
		Upper Limit of Allowed Voltage	1.05 p.u.

DIgSILENT PowerFactory 14.1.3 | Project: | Date: 10/2/2014

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Name	Type	Loading [%]	Voltage [p.u.]	Voltage [kV]	Station/Branch	Apparent Power [MVA]	Current [kA]	Current [p.u.]
Overloaded Elements								
60km Terminal	Term		0.67	14.67	Grid			
LD1 Busbar (22kV)	Term		0.80	17.57	LD1 Busbar			
LD2 Busbar (22kV)	Term		0.67	14.67	LD2 Busbar			
LD1 Line	Lne	89.69			22kV Busbar/22kV Bu..	5.26	0.14	0.90
					LD1 Busbar/LD1 Busb..	4.23	0.14	0.90

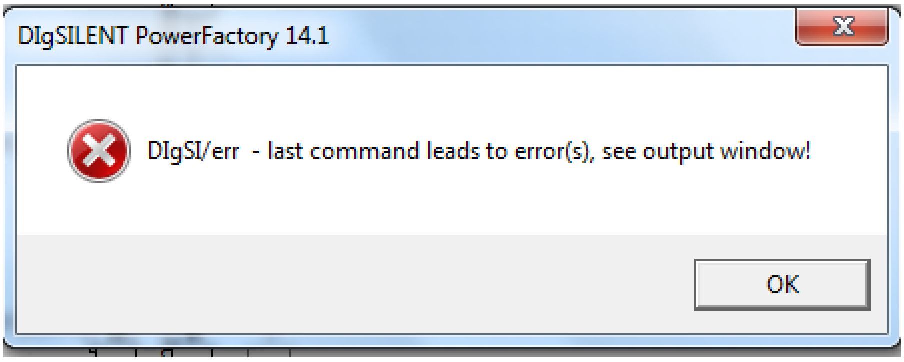

Figure 5.22: 50% load increment load flow error message

```
DIgSI/info - A calculation relevant object was changed!
DIgSI/info - The calculation results have been deleted.
DIgSI/info - Element ' External Grid' is local reference in separated area of '1'
DIgSI/info - Grid split into 3 isolated areas
DIgSI/info - Calculating load flow...
DIgSI/info - ------------------------------------------------------------------------
DIgSI/info - Start Newton-Raphson Algorithm...
DIgSI/info - load flow iteration: 1
DIgSI/info - load flow iteration: 2
DIgSI/info - load flow iteration: 3
DIgSI/info - load flow iteration: 4
DIgSI/info - load flow iteration: 5
DIgSI/info - load flow iteration: 6
DIgSI/info - load flow iteration: 7
DIgSI/info - load flow iteration: 8
DIgSI/info - load flow iteration: 9
DIgSI/info - load flow iteration: 10
DIgSI/info - load flow iteration: 11
DIgSI/info - load flow iteration: 12
DIgSI/info - load flow iteration: 13
DIgSI/info - load flow iteration: 14
DIgSI/info - load flow iteration: 15
DIgSI/info - load flow iteration: 16
DIgSI/info - load flow iteration: 17
DIgSI/info - load flow iteration: 18
DIgSI/info - load flow iteration: 19
DIgSI/info - load flow iteration: 20
DIgSI/info - load flow iteration: 21
DIgSI/info - load flow iteration: 22
DIgSI/info - load flow iteration: 23
DIgSI/info - load flow iteration: 24
DIgSI/info - load flow iteration: 25
DIgSI/err  - No convergence in load flow!
DIgSI/info - Load flow calculation not executed.
DIgSI/err  - last command leads to error(s), see output window!
```

Figure 5.23: 50% load increment load flow output window message

Figure 5.24 is the P-V curve when the DG injects 4MW resulting to a maximum load of 5.8MW before voltage collapse. This is approximately 109% increase and the resultant loading margin is 3.02MW. At the point of voltage collapse the p.u. voltages of the existing points of consideration on the feeder are 0.86, 0.65 and 0.65. Moreover, the percentage loading on LD1-LD2 Line rises to 97.86%. The parameter violations are depicted in Table 5.10.

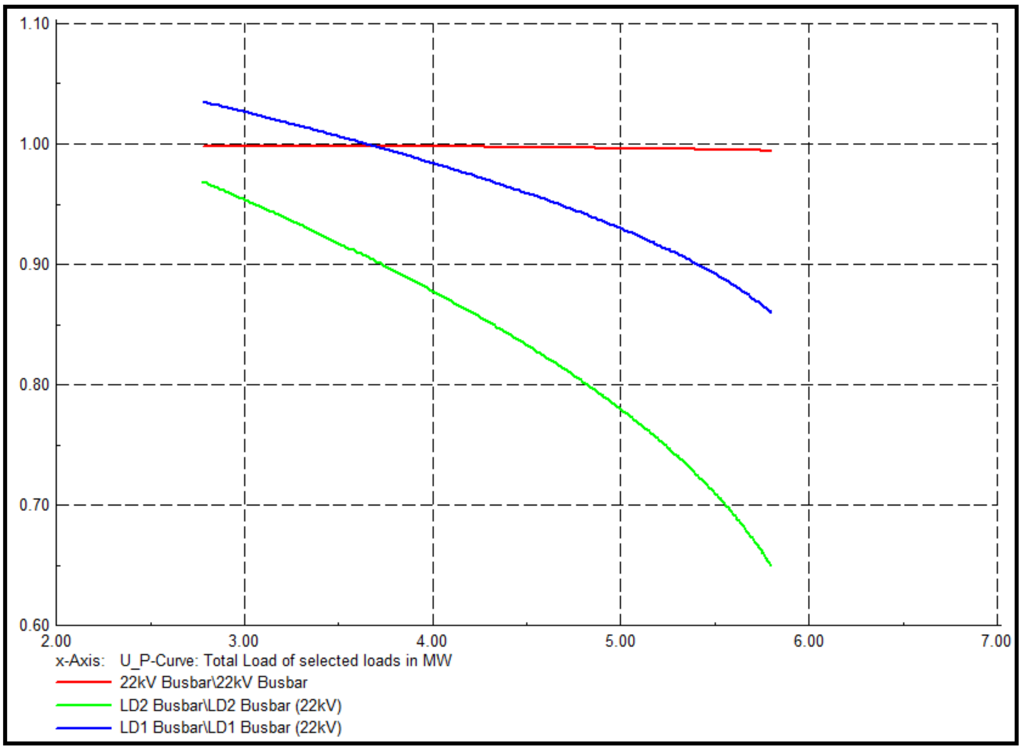

Figure 5.24: P-V curve with DG connected and injecting 4MW

Table 5.10: Result of voltage stability analysis when DG injects 4MW

Load Flow Calculation

AC Load Flow, balanced, positive sequence			
Automatic Tap Adjust of Transformers	No		
Consider Reactive Power Limits	No	Max. Loading of Edge Element	80.00 %
Automatic Model Adaptation for Convergence	No	Lower Limit of Allowed Voltage	0.95 p.u.
		Upper Limit of Allowed Voltage	1.05 p.u.

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Name	Type	Loading [%]	Voltage [p.u.]	Voltage [kV]	Station/Branch	Apparent Power [MVA]	Current [kA]	Current [p.u.]
Overloaded Elements								
60km Terminal	Term		0.65	14.29	Grid			
LD1 Busbar (22kV)	Term		0.86	18.92	LD1 Busbar			
LD2 Busbar (22kV)	Term		0.65	14.29	LD2 Busbar			
LD1-LD2 Line	Lne	97.86			LD1 Busbar/LD1 Busb..	4.97	0.15	0.98
					LD2 Busbar/LD2 Busb..	3.75	0.15	0.98

Also when the DG injects 2MW the resultant P-V curve is as shown in Figure 5.25. The maximum load before voltage collapse is 6.25MW which is equivalent to 125% load increase. The loading margin for this amounts to 3.46MW. Table 5.11 shows the respective p.u. voltages of LD1 and LD2 Busbars, and 60km Terminal including LD1 Line loading as 0.78, 0.67, 0.67 and 99.93%. Again they appear in red because of their limit violations.

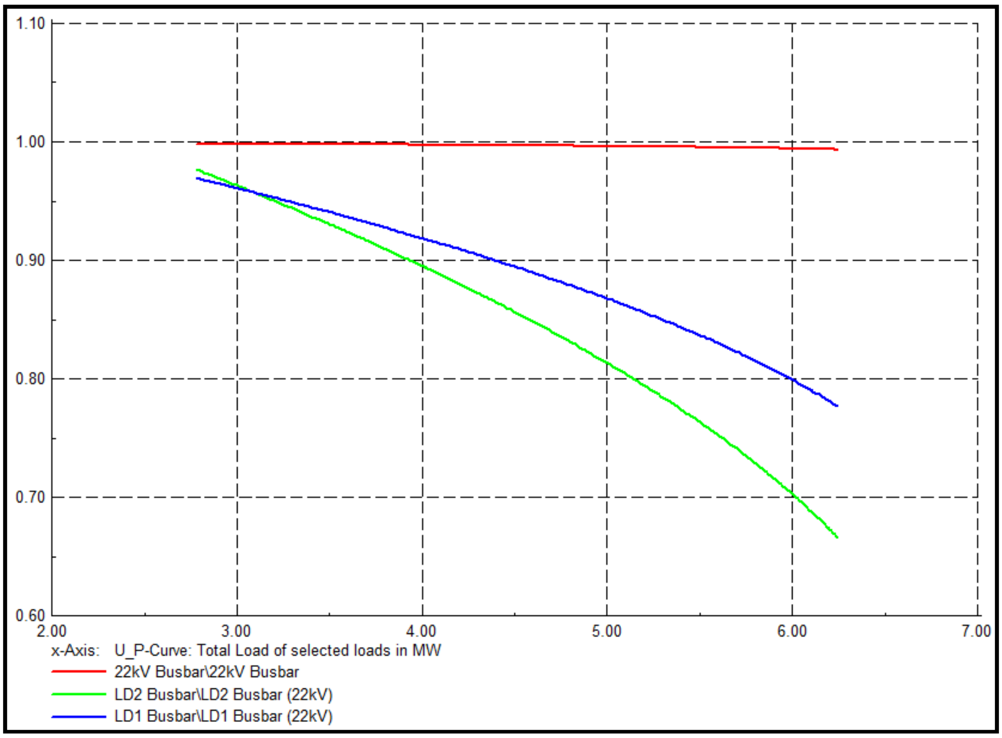

Figure 5.25: P-V curve with DG connected and injecting 2MW

Table 5.11: Result of voltage stability analysis when DG injects 2MW

Load Flow Calculation

AC Load Flow, balanced, positive sequence			
Automatic Tap Adjust of Transformers	No		
Consider Reactive Power Limits	No	Max. Loading of Edge Element	80.00 %
Automatic Model Adaptation for Convergence	No	Lower Limit of Allowed Voltage	0.95 p.u.
		Upper Limit of Allowed Voltage	1.05 p.u.

DIgSILENT PowerFactory 14.1.3 | Project: | Date: 10/3/2014

Study Case: Study Case | Annex: / 1

Name	Type	Loading [%]	Voltage [p.u.]	Voltage [kV]	Station/Branch	Apparent Power [MVA]	Current [kA]	Current [p.u.]
Overloaded Elements								
60km Terminal	Term		0.67	14.65	Grid			
LD1 Busbar (22kV)	Term		0.78	17.09	LD1 Busbar			
LD2 Busbar (22kV)	Term		0.67	14.65	LD2 Busbar			
LD1 Line	Lne	99.93			22kV Busbar/22kV Bu..	5.86	0.15	1.00
					LD1 Busbar/LD1 Busb..	4.58	0.15	1.00

The overall impact of a DG unit on voltage stability is positive. This is due to the improved voltage profiles as well as decreased reactive power losses (Hedayati *et al.*, 2008). A low voltage problem occurs when some system voltages are below the lower limit of viability but the power system is operating stably. Since a stable operating point persists and there is no dynamic collapse, the low voltage problem can be regarded as distinct from voltage collapse.

Voltage instability due to faults is a transient stability problem. In principle, transient stability problems might occur in distribution networks with DGs (Xyngi *et al.*, 2009). EMT-Simulation of DIgSILENT PowerFactory has been utililised in investigating single phase and three phase short circuits. The electromagnetic transient (EMT) simulation involves the definition of variables and events. In this case the variables are phase short circuit currents and and their corresponding voltages. Short circuit and its clearing on the selected busbars are the events. To investigate the transient stability of the developed model, self-clearing single phase to ground and three-phase short circuits are simulated. The simulation absolute run time is 0.2s with the short circuit introduced at 0.05s and cleared at 0.10s making it a three-cycle fault duration. Unlike the PV-curve an EMT-simulation plot is not automatically generated. The simulation results or plots are shown below and the disturbance including possible loss of symmetry in the power network systems when a fault occurs, especially single phase faults, is evident from the results. During the single phase to ground fault the voltage of the faulty phase rapidly falls to zero and may cause the voltages of the sound phases to rapidly increase. This portends danger and as has been reported in the literature could lead to a bolted short circuit between two sound phases. But during a three phase fault the phase voltages are the same and are at zero point.

Impact of DG on the short circuit current waveform could also be observed from the results. Again it has been widely published that synchronous generators have the most distinct impact on fault currents. In the first interval just after fault inception, the shape of fault current depends basically on the machine parameters. Then, the applied types of the exciter and the voltage regulator determine the shape.

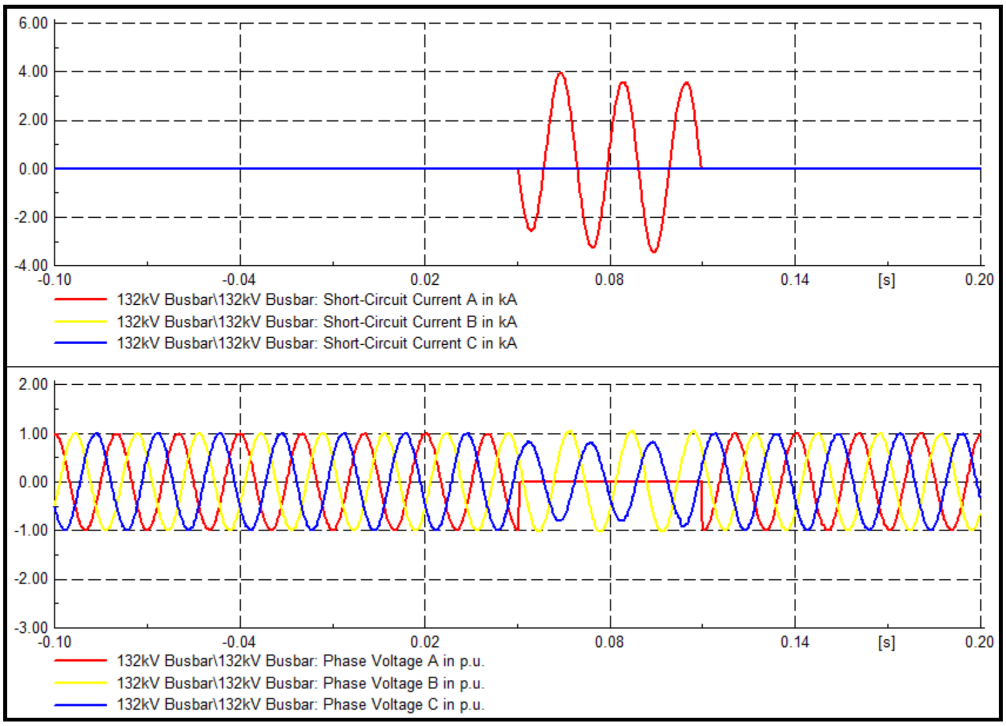

Figure 5.26: Single phase short circuit on 132kV busbar without DG

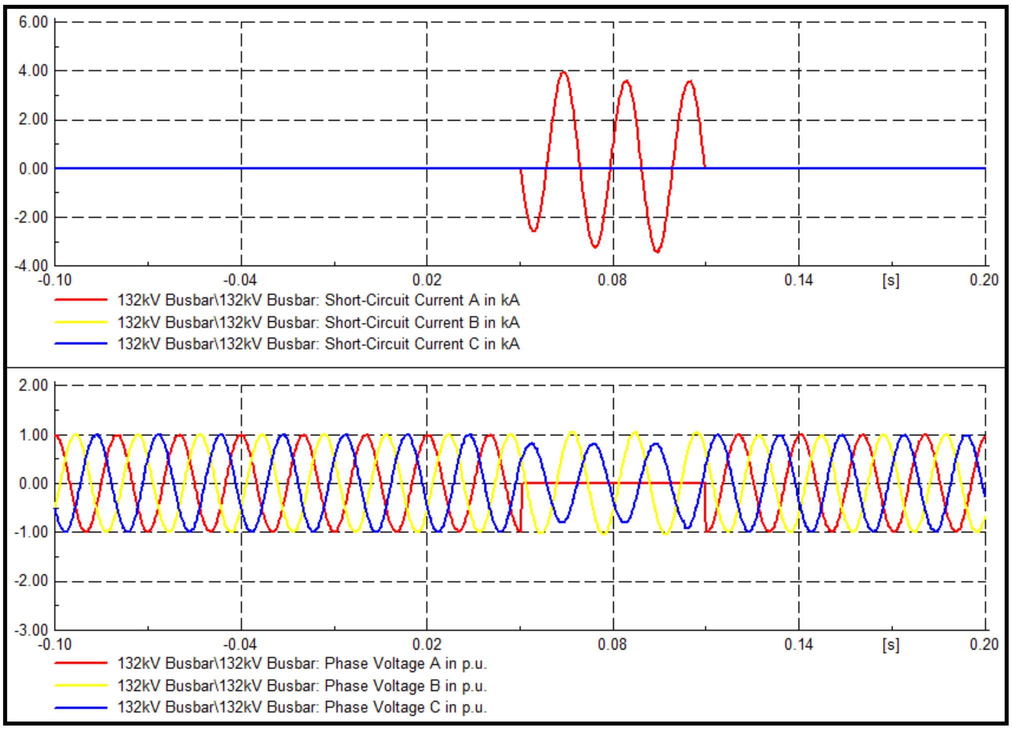

Figure 5.27: Single phase short circuit on 132kV busbar with 4MW DG connected

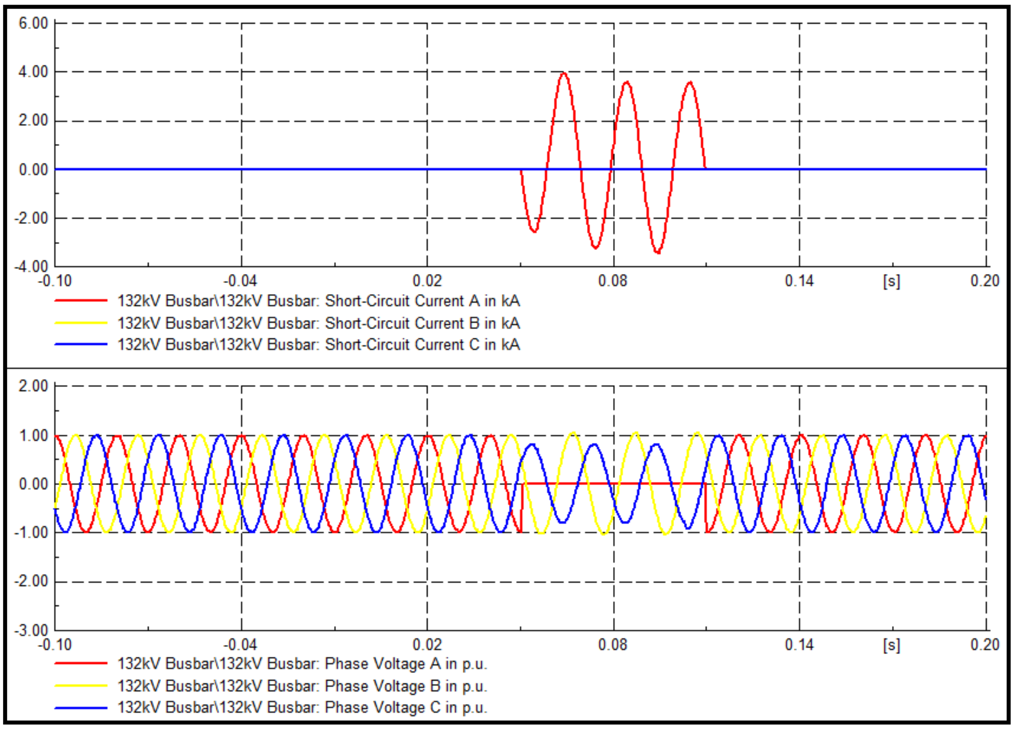

Figure 5.28: Single phase short circuit on 132kV busbar with 2MW DG connected

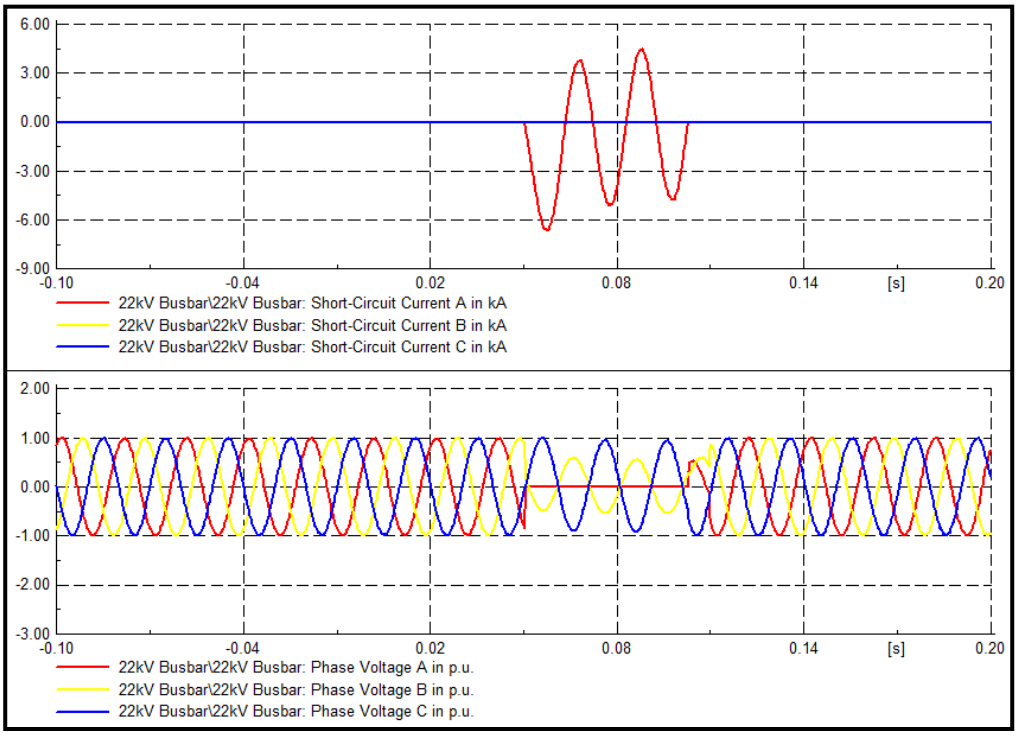

Figure 5.29: Single phase short circuit on 22kV busbar without DG

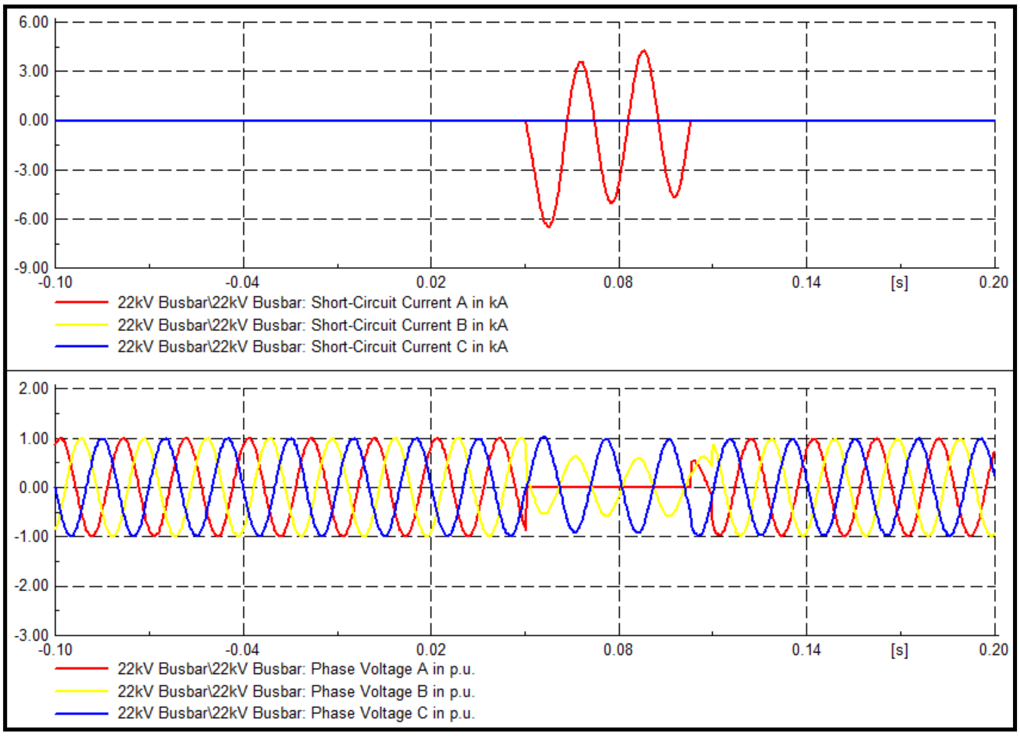

Figure 5.30: Single phase short circuit on 22kV busbar with 4MW DG connected

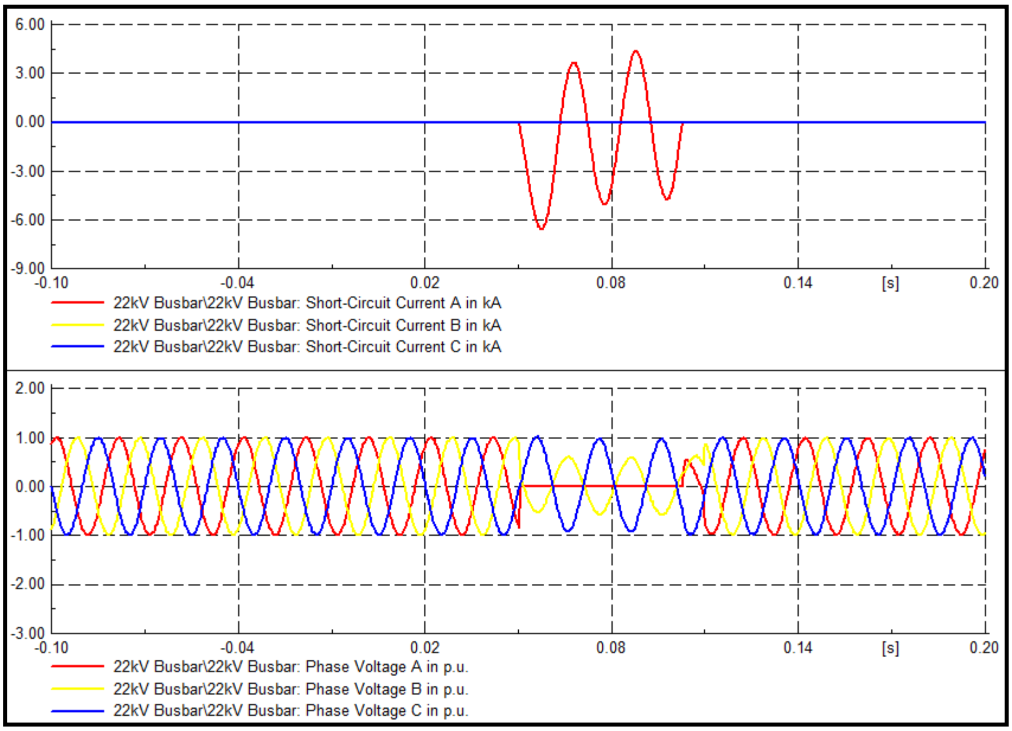

Figure 5.31: Single phase short circuit on 22kV busbar with 2MW DG connected

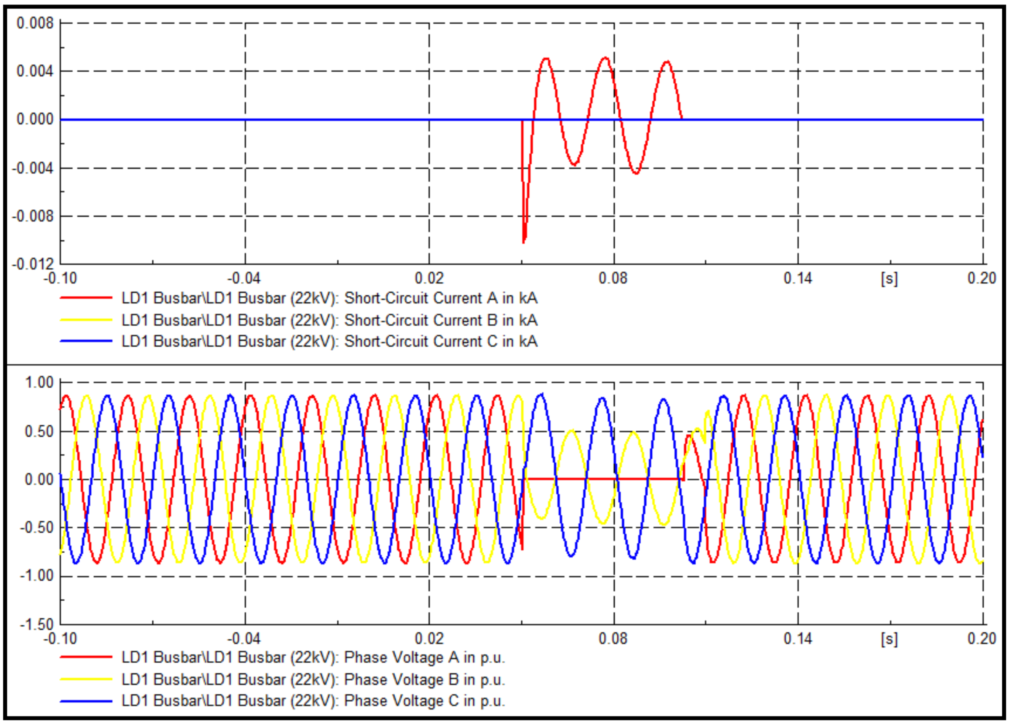

Figure 5.32: Single phase short circuit on LD1 busbar without DG

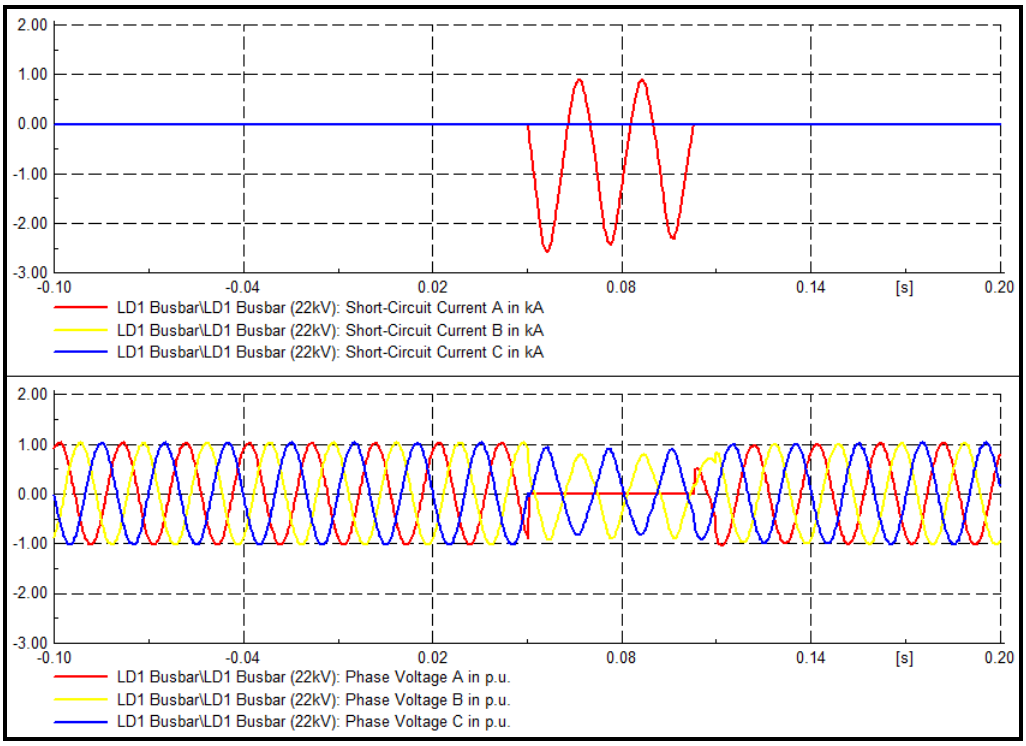

Figure 5.33: Single phase short circuit on LD1 busbar with 4MW DG connected

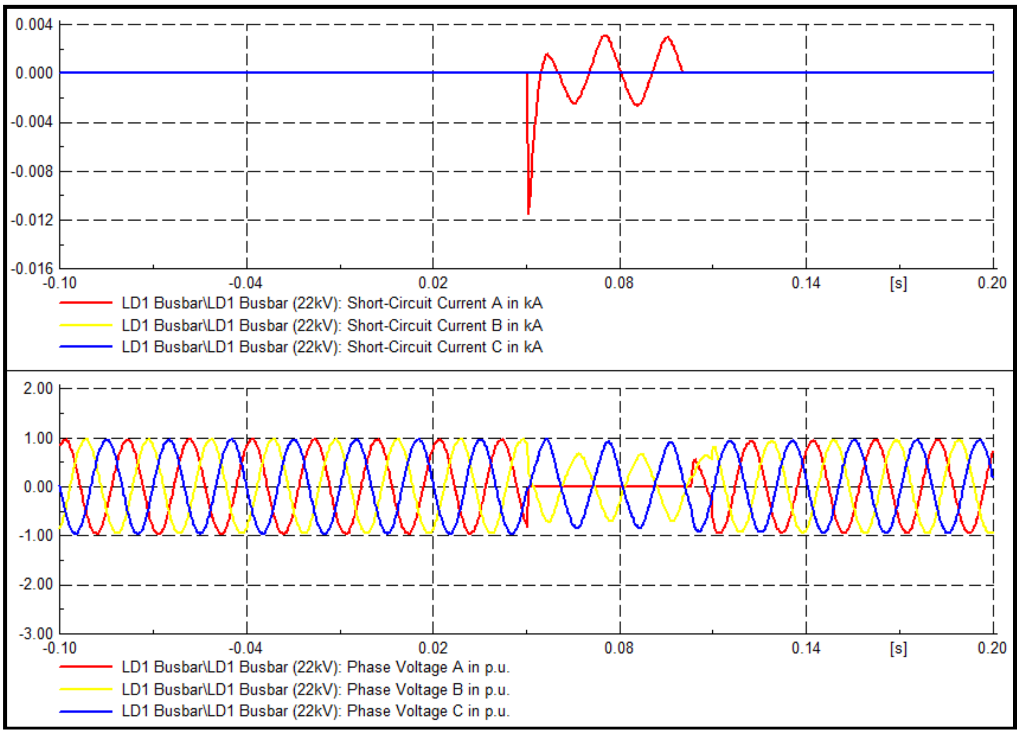

Figure 5.34: Single phase short circuit on LD1 busbar with 2MW DG connected

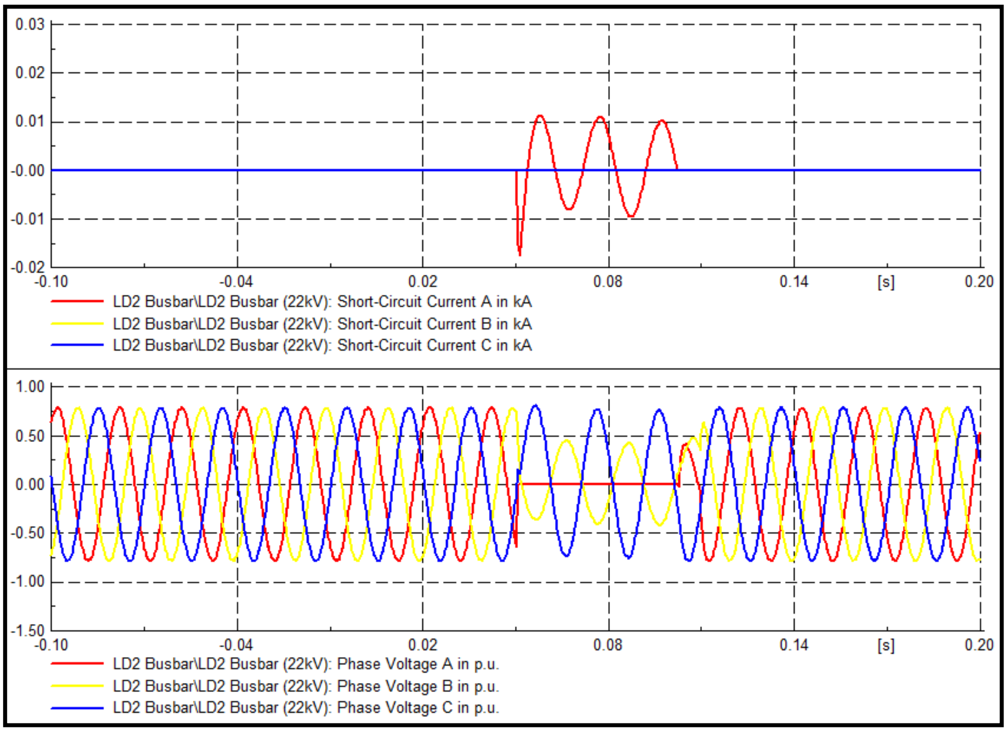

Figure 5.35: Single phase short circuit on LD2 busbar without DG

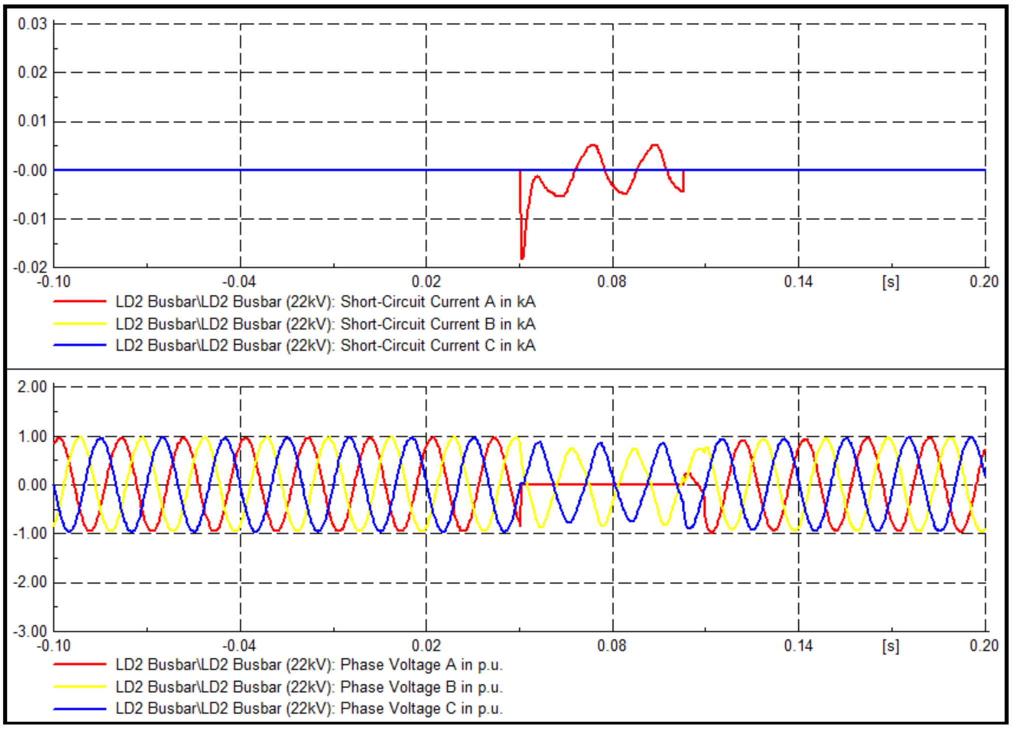

Figure 5.36: Single phase short circuit on LD2 busbar with 4MW DG connected

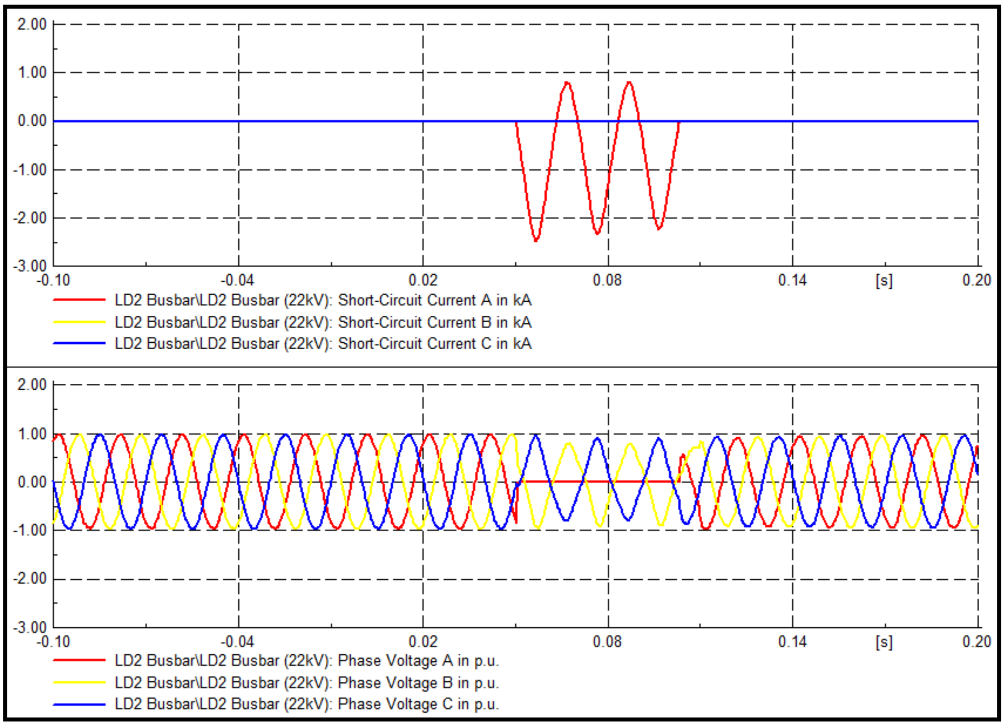

Figure 5.37: Single phase short circuit on LD2 busbar with 2MW DG connected

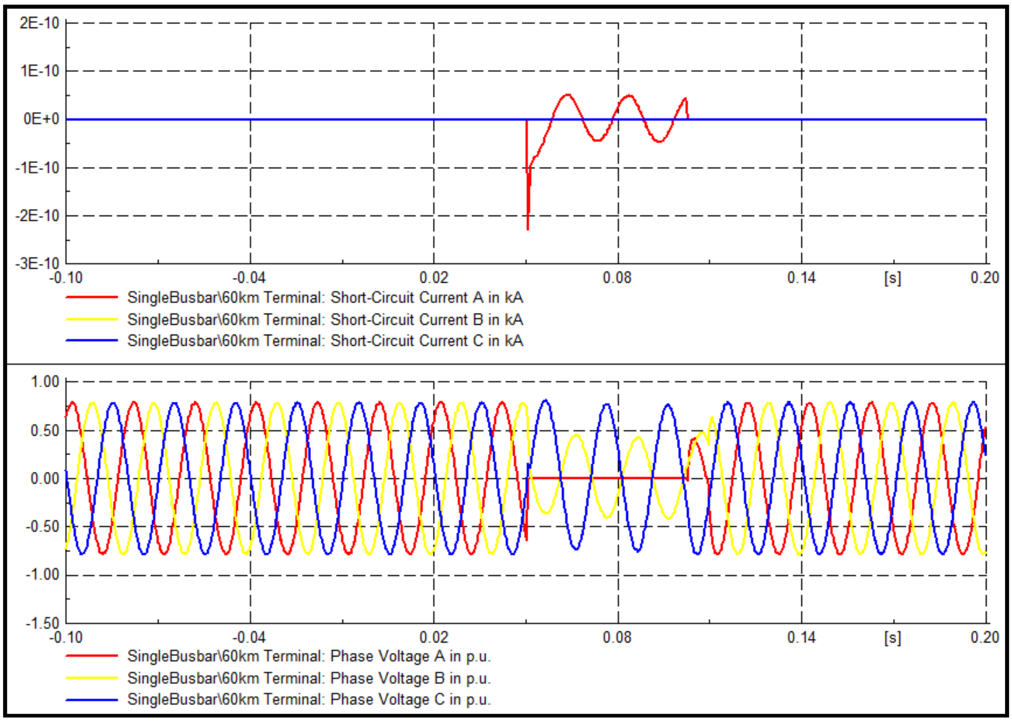

Figure 5.38: Single phase short circuit on 60km terminal without DG

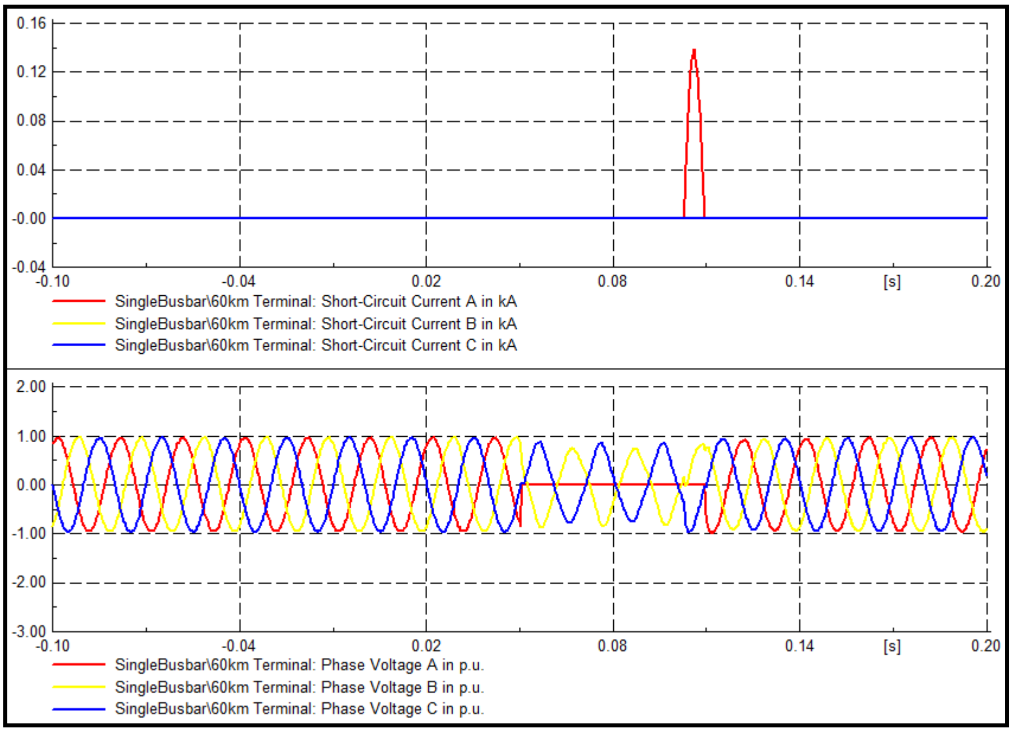

Figure 5.39: Single phase short circuit on 60km terminal with 4MW DG connected

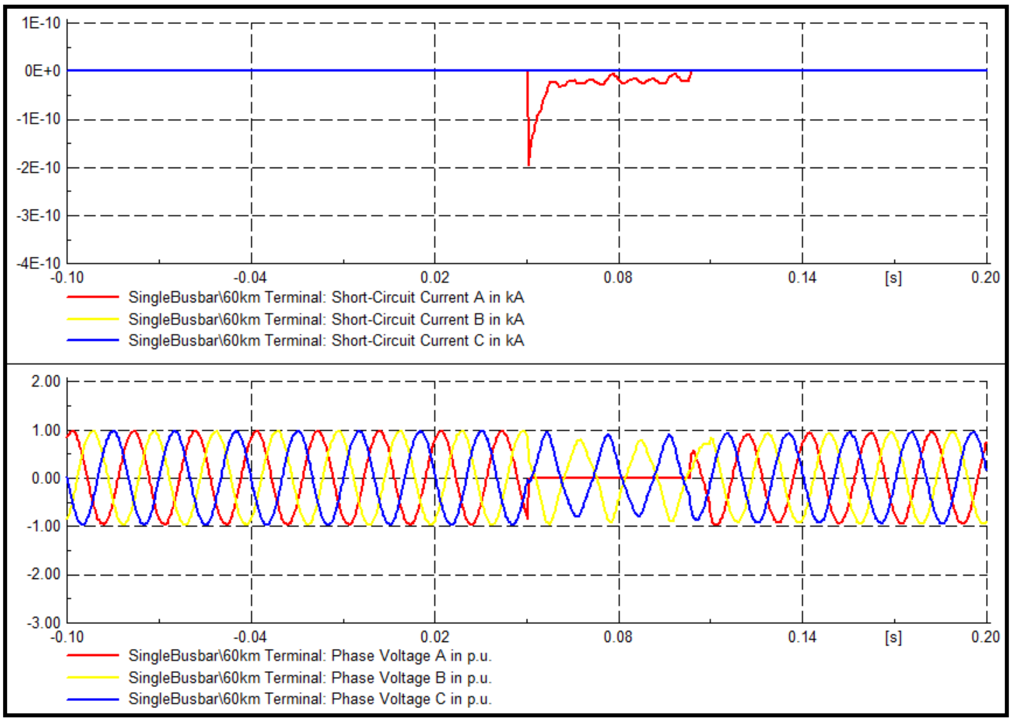

Figure 5.40: Single phase short circuit on 60km terminal with 2MW DG connected

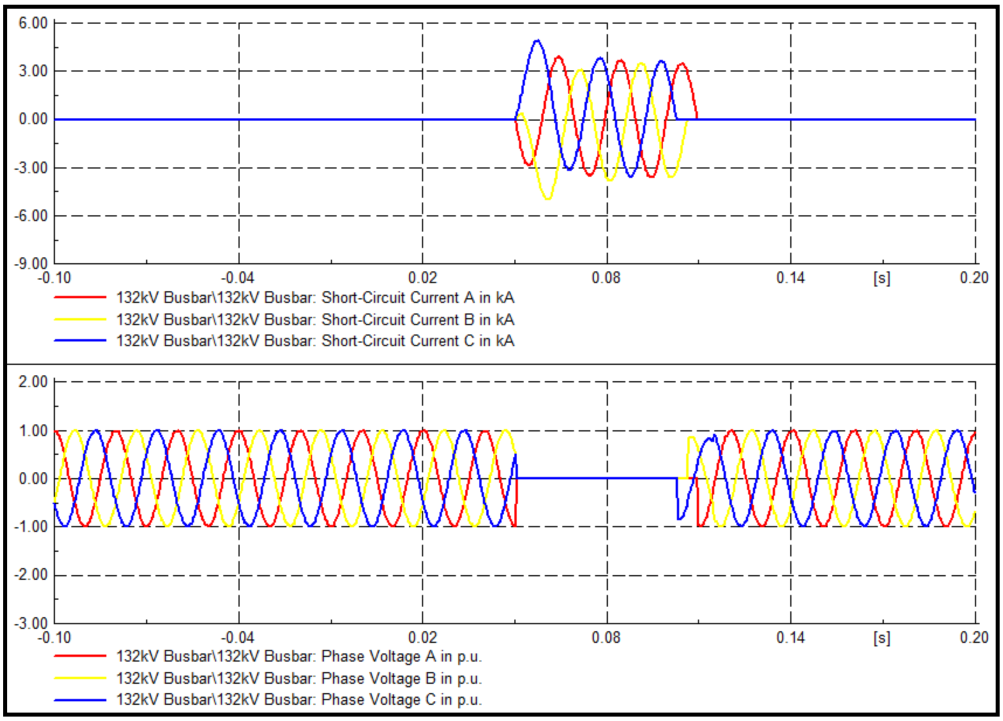

Figure 5.41: Three phase short circuit on 132kV busbar without DG

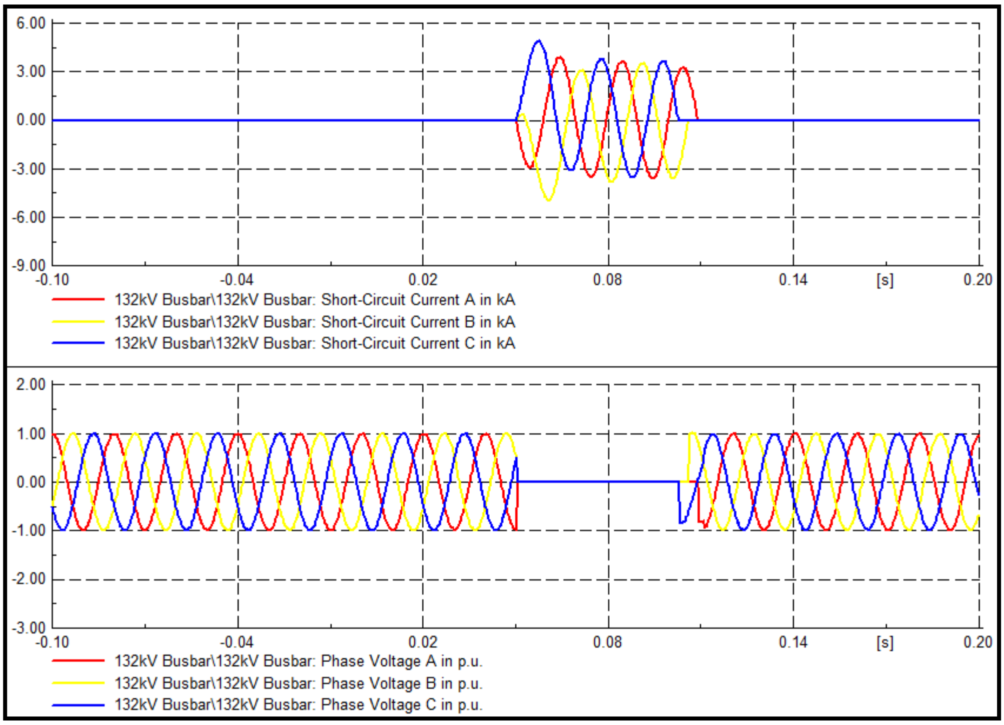

Figure 5.42: Three phase short circuit on 132kV busbar with 4MW DG connected

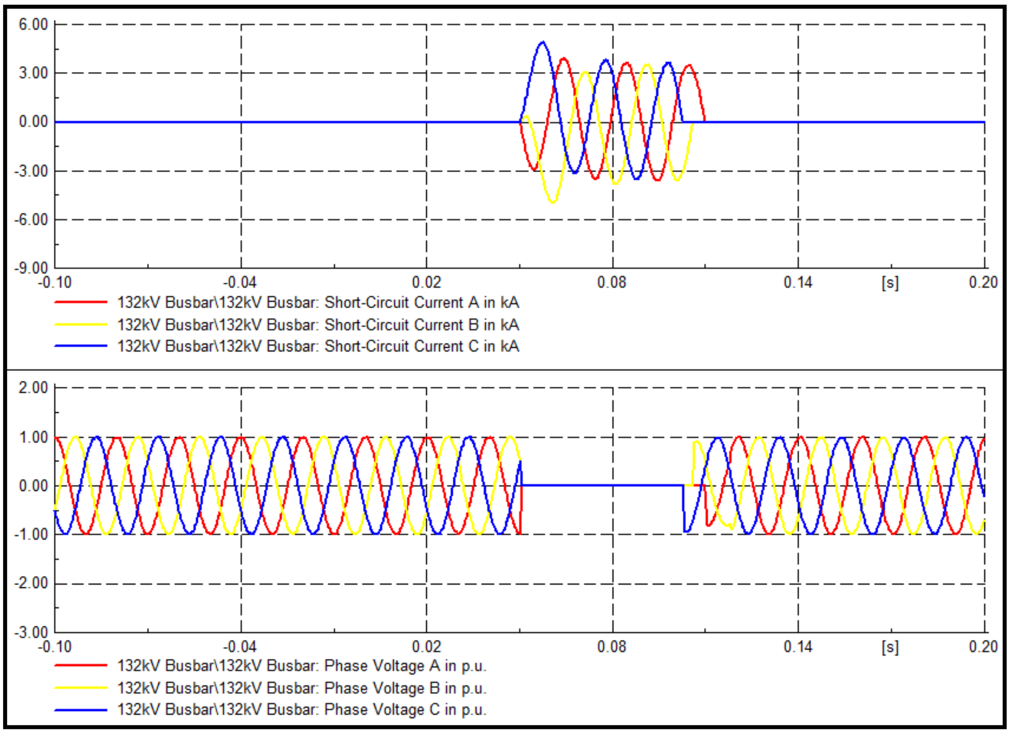

Figure 5.43: Three phase short circuit on 132kV busbar with 2MW DG connected

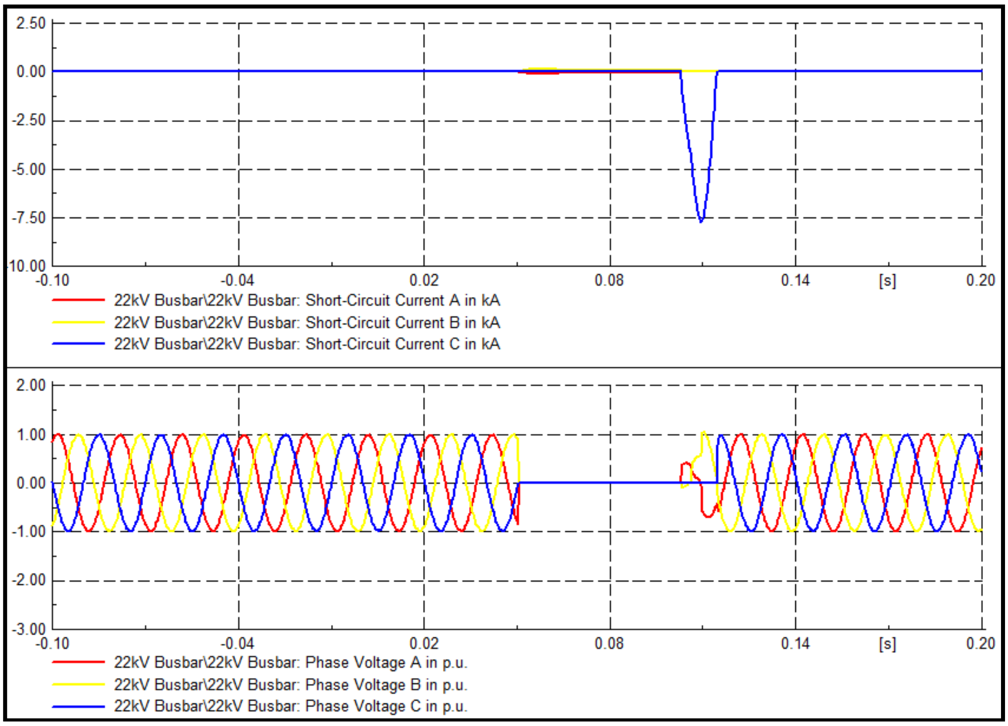

Figure 5.44: Three phase short circuit on 22kV busbar without DG

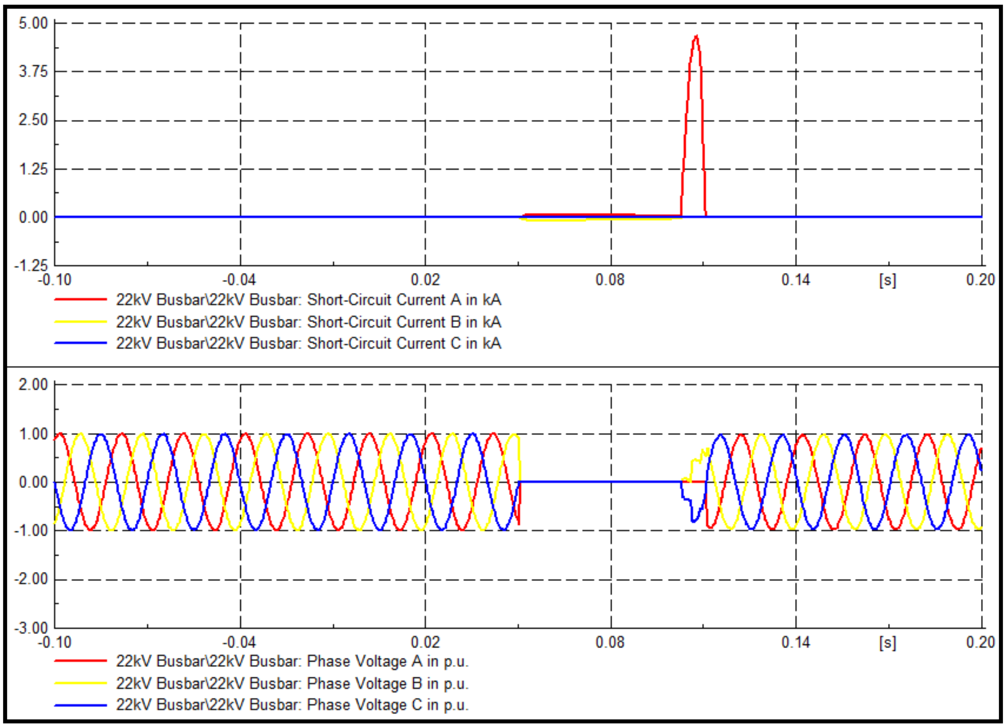

Figure 5.45: Three phase short circuit on 22kV busbar with 4MW DG connected

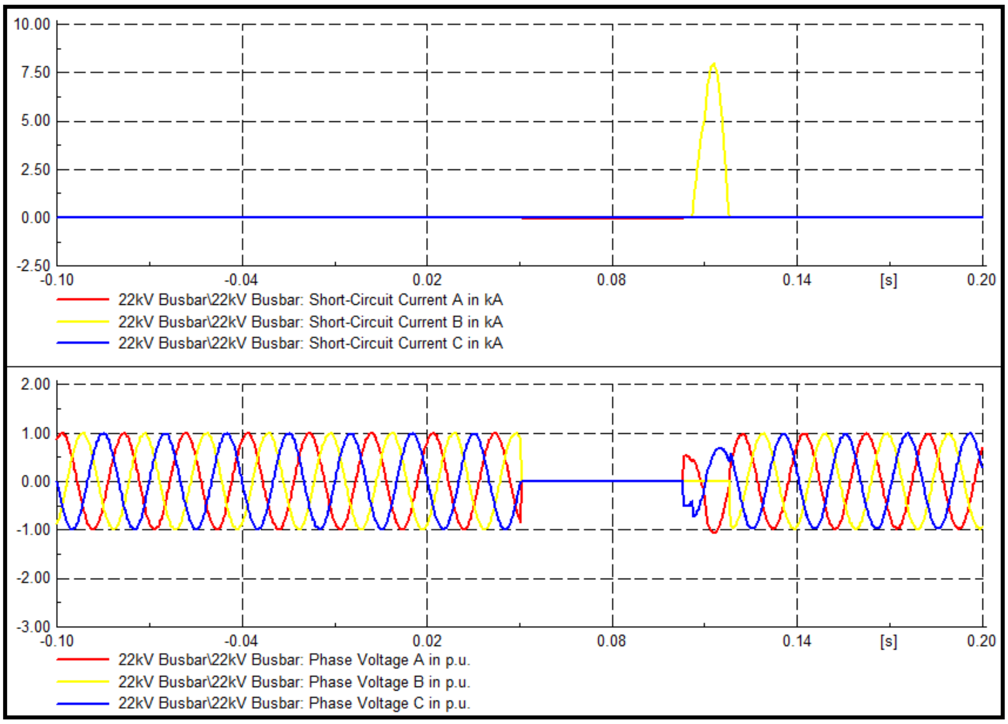

Figure 5.46: Three phase short circuit on 22kV busbar with 2MW DG connected

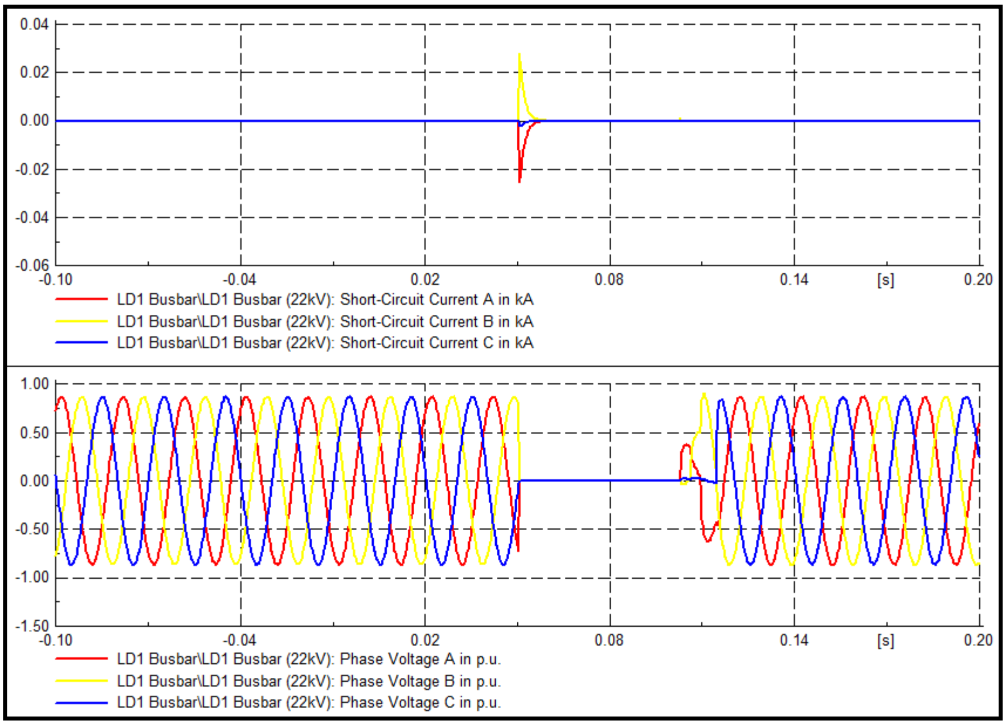

Figure 5.47: Three phase short circuit on LD1 busbar without DG

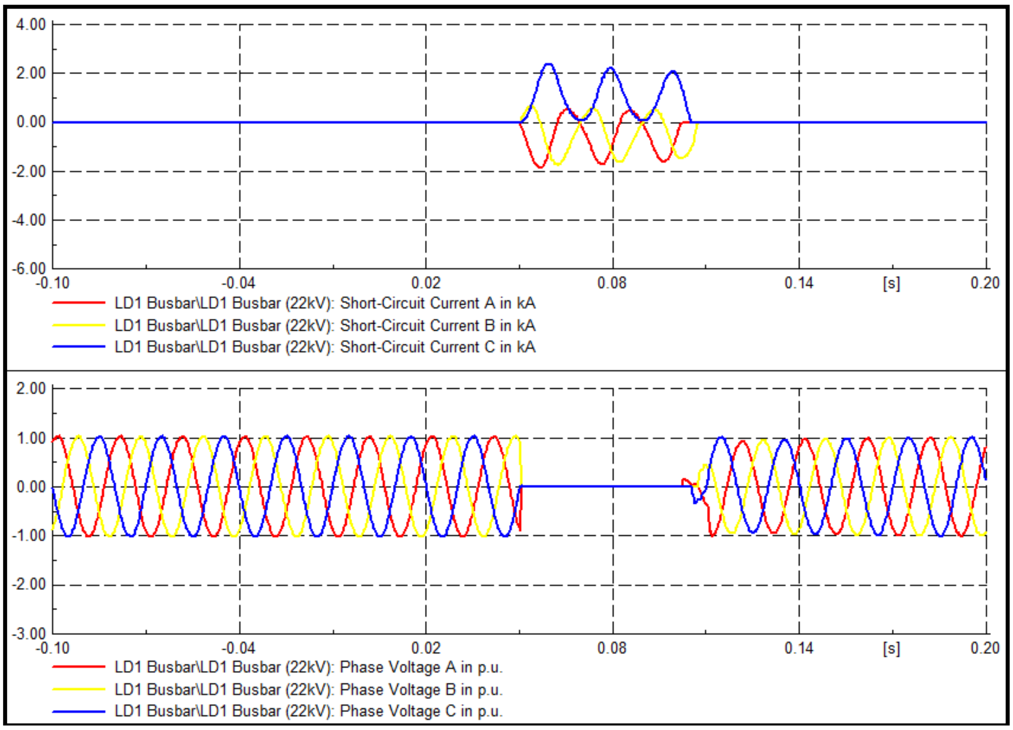

Figure 5.48: Three phase short circuit on LD1 busbar with 4MW DG connected

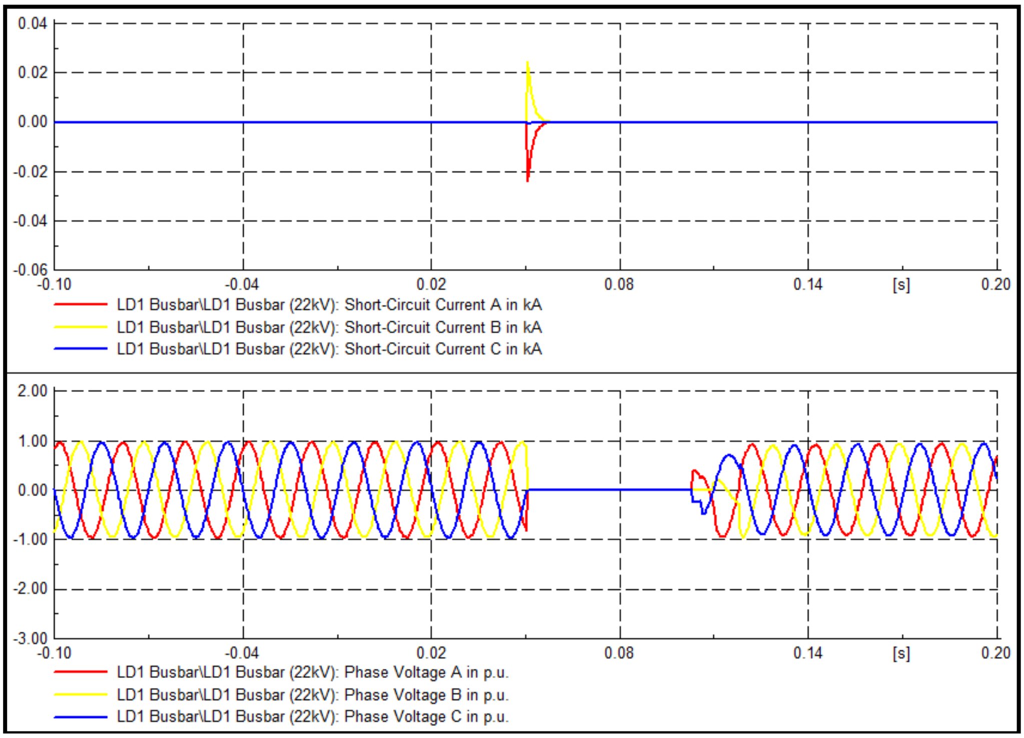

Figure 5.49: Three phase short circuit on LD1 busbar with 2MW DG connected

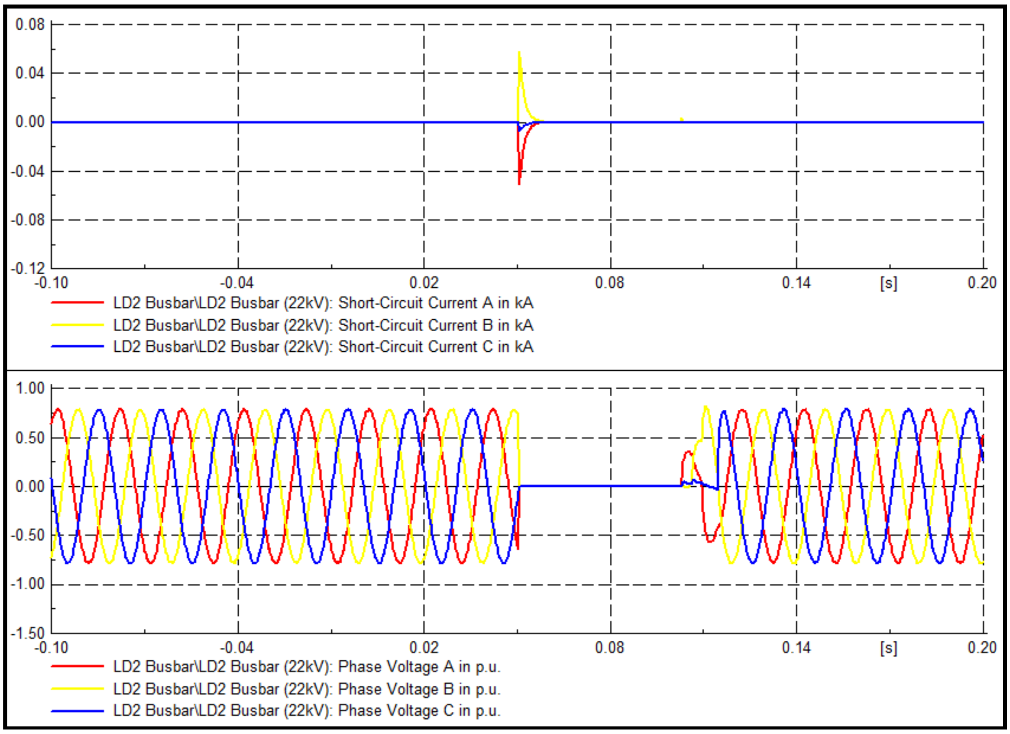

Figure 5.50: Three phase short circuit on LD2 busbar without DG

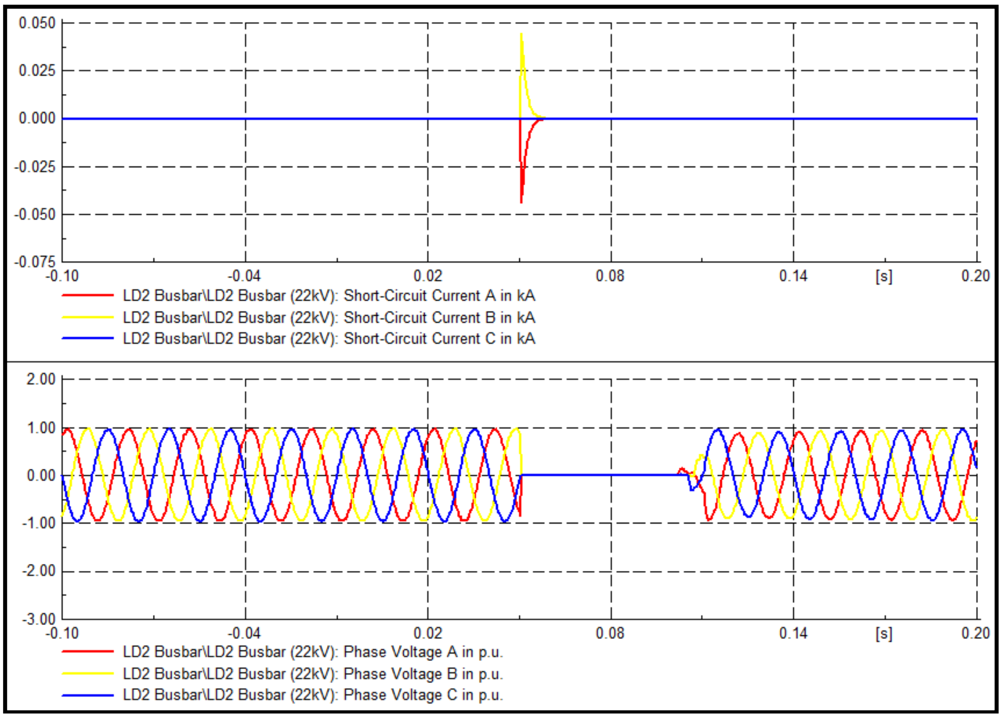

Figure 5.51: Three phase short circuit on LD2 busbar with 4MW DG connected

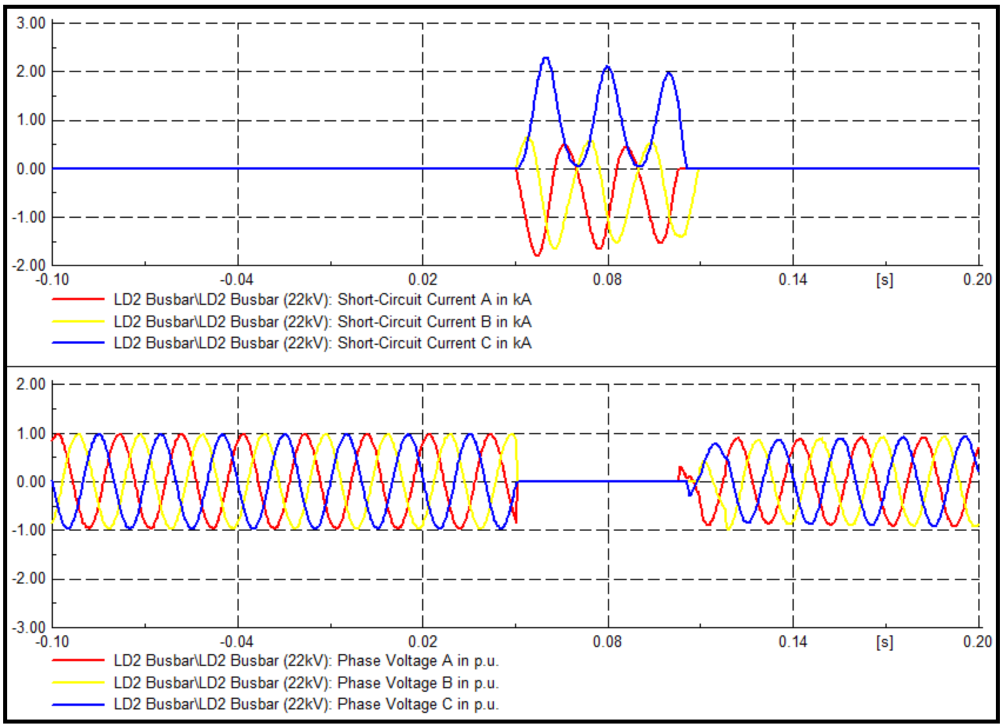

Figure 5.52: Three phase short circuit on LD2 busbar with 2MW DG connected

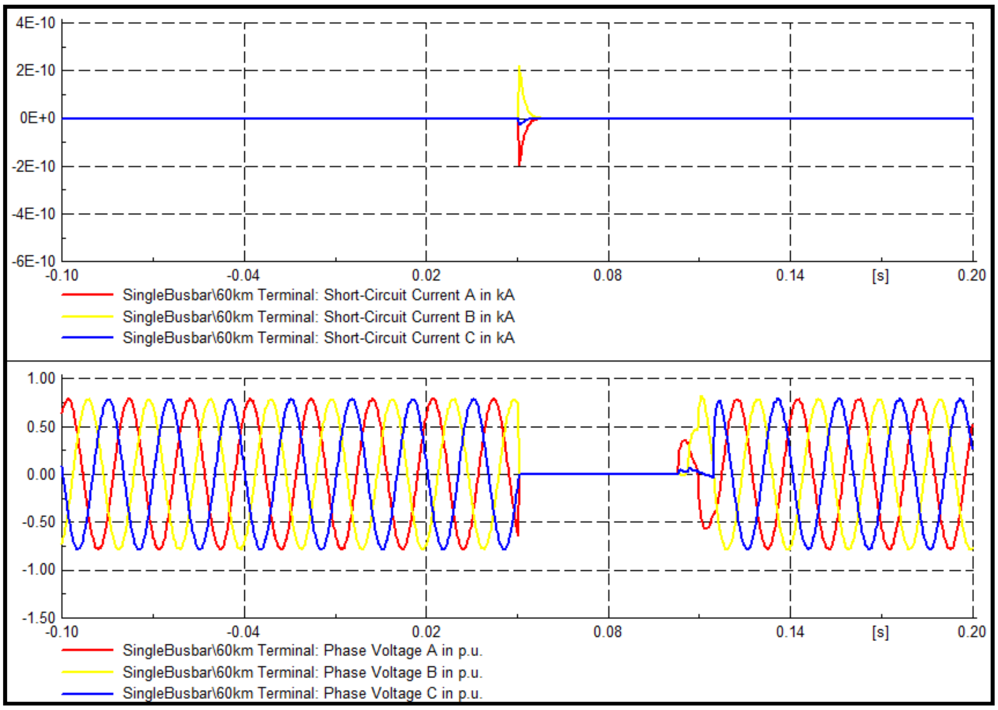

Figure 5.53: Three phase short circuit on 60km terminal without DG

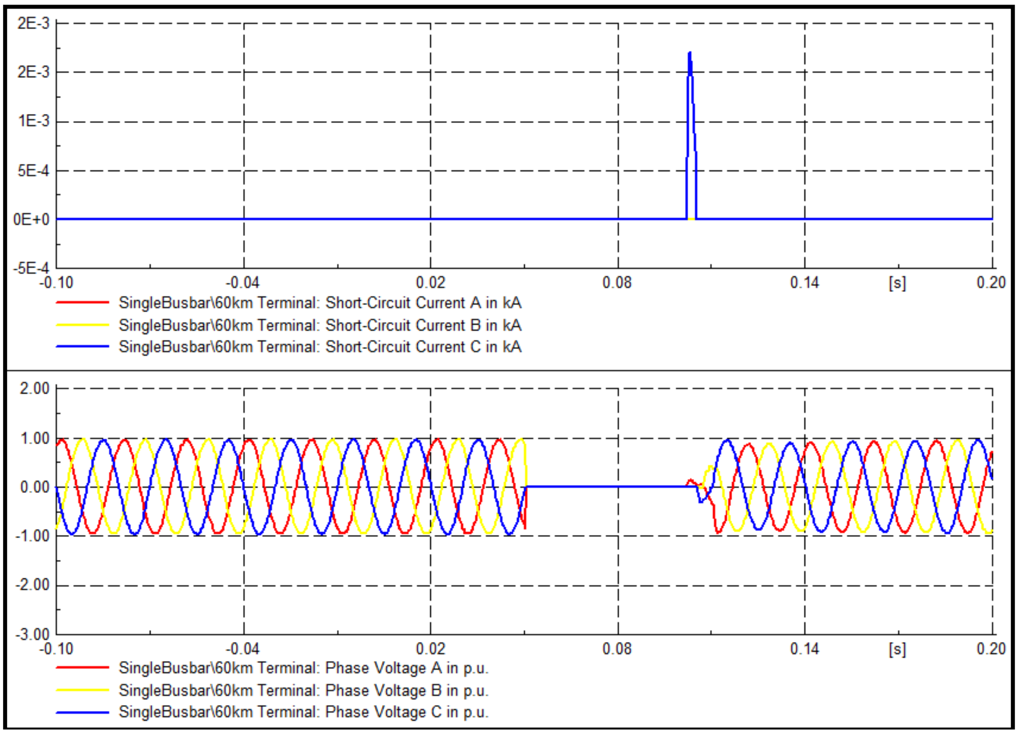

Figure 5.54: Three phase short circuit on 60km terminal with 4MW DG connected

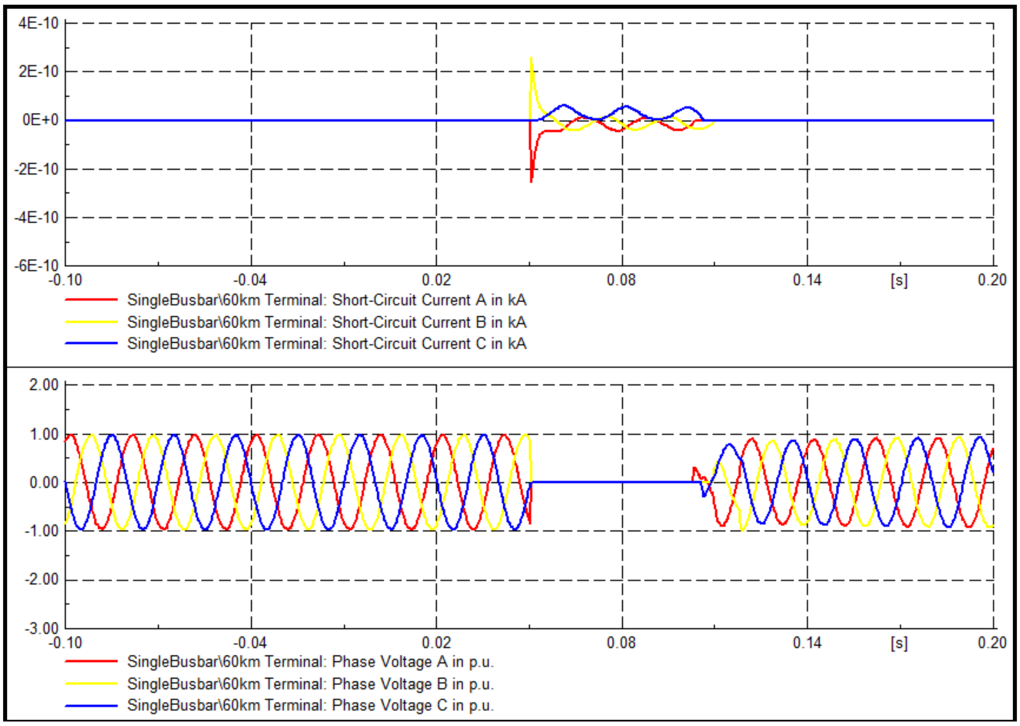

Figure 5.55: Three phase short circuit on 60km terminal with 2MW DG connected

The influence of a fault in the network on the stability of DGs and the effect of fault clearing time on the transient stability of DGs are beyond the scope of this work. But, for instance, several studies have been carried out to determine the effect of the clearing time of a fault on the transient stability of DGs (Xyngi *et al.*, 2009). However, the following plots show the behaviour of the DG during an external fault such as at its POC. The need for a clearer view of the speed and terminal voltage necessitated the increase in the simulation time to 1s while the simulation duration for both phase currents and voltages remained 0.2s. During an external fault to the DG its speed dips and rises momentarily above normal when the fault is cleared.

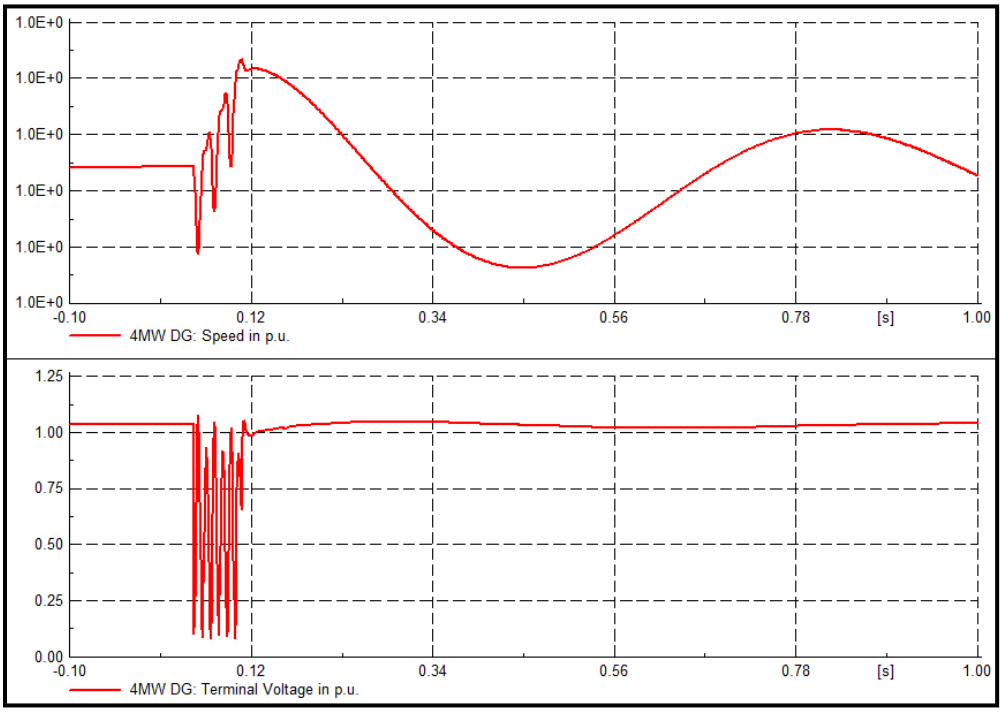

Figure 5.56: Speed and terminal voltage of 4MW DG during single phase short circuit

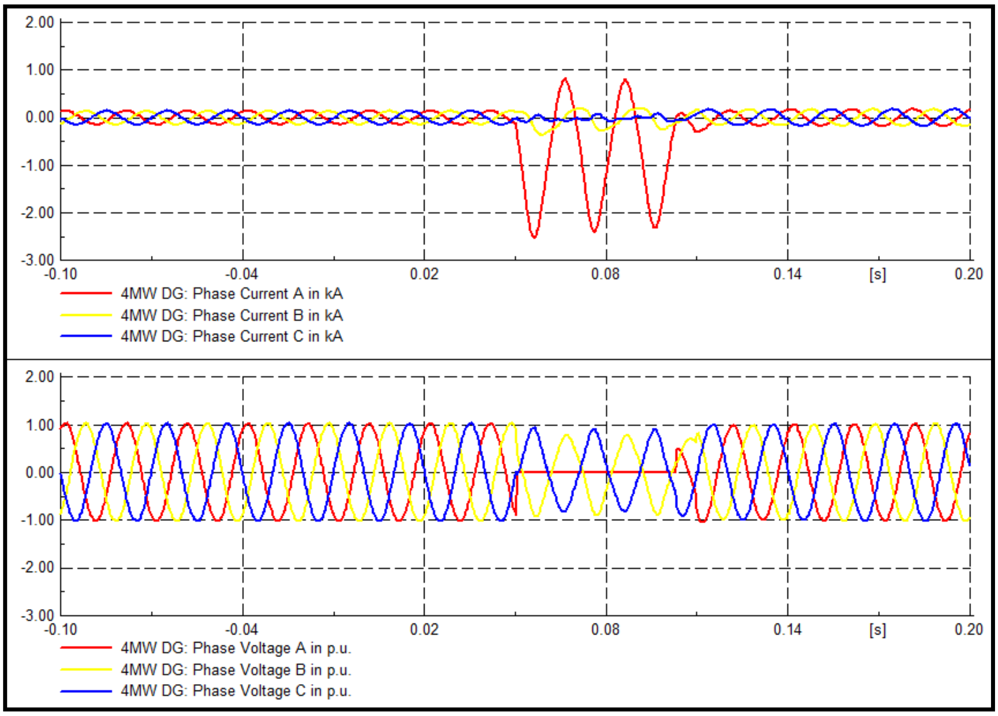

Figure 5.57: Phase current and voltage of 4MW DG during single phase short circuit

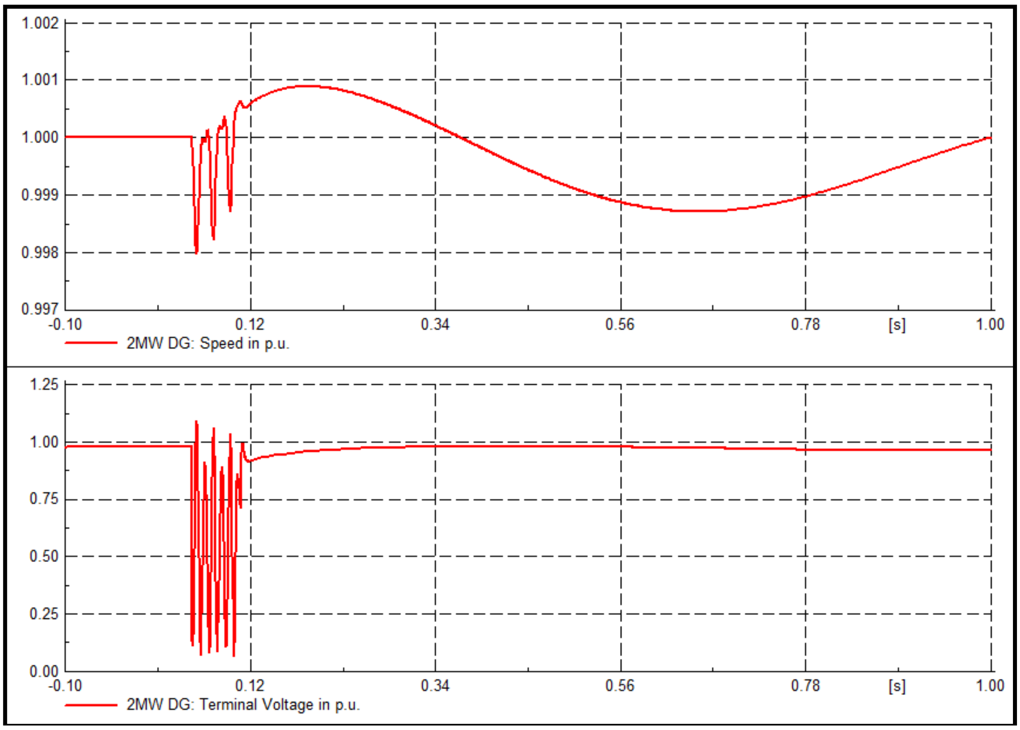

Figure 5.58: Speed and terminal voltage of 2MW DG during single phase short circuit

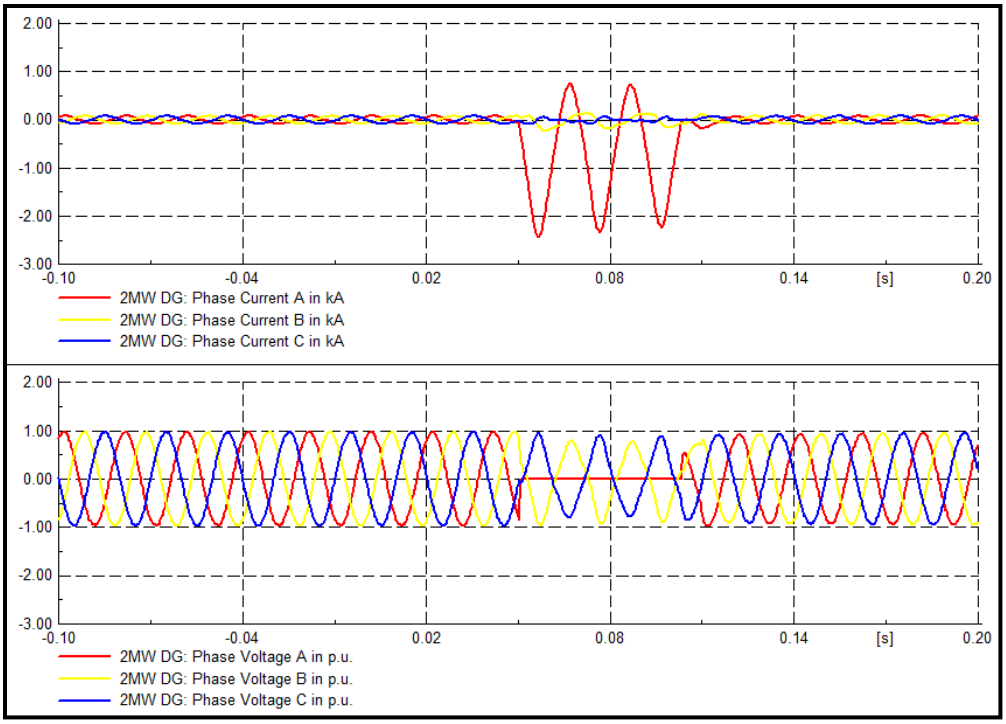

Figure 5.59: Phase current and voltage of 2MW DG during single phase short circuit

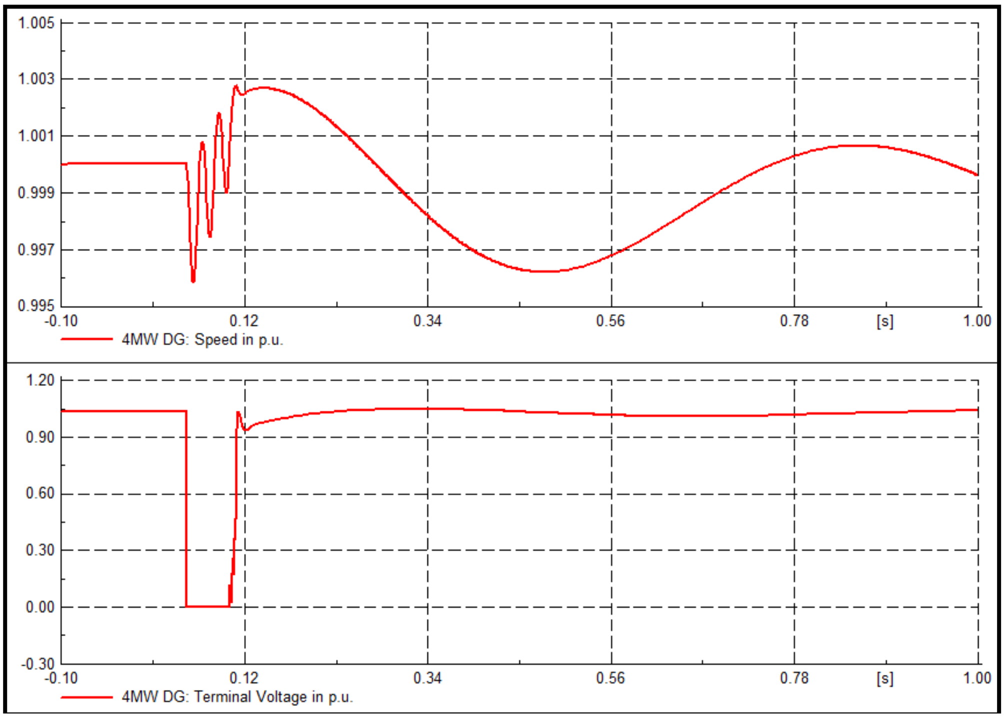

Figure 5.60: Speed and terminal voltage of 4MW DG during three phase short circuit

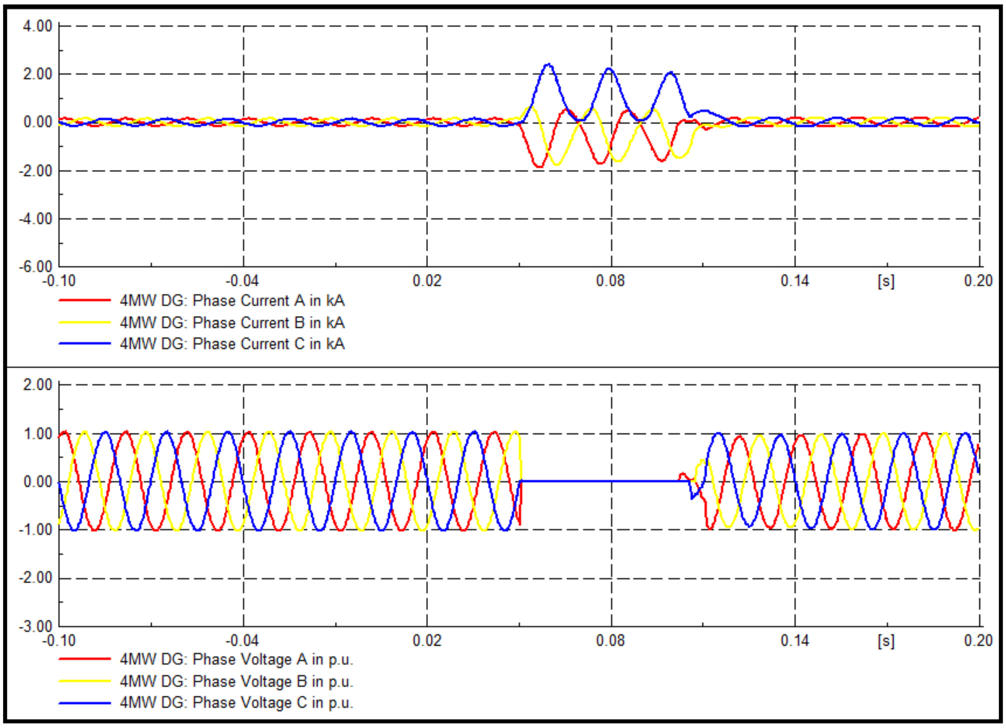

Figure 5.61: Phase current and voltage of 4MW DG during three phase short circuit

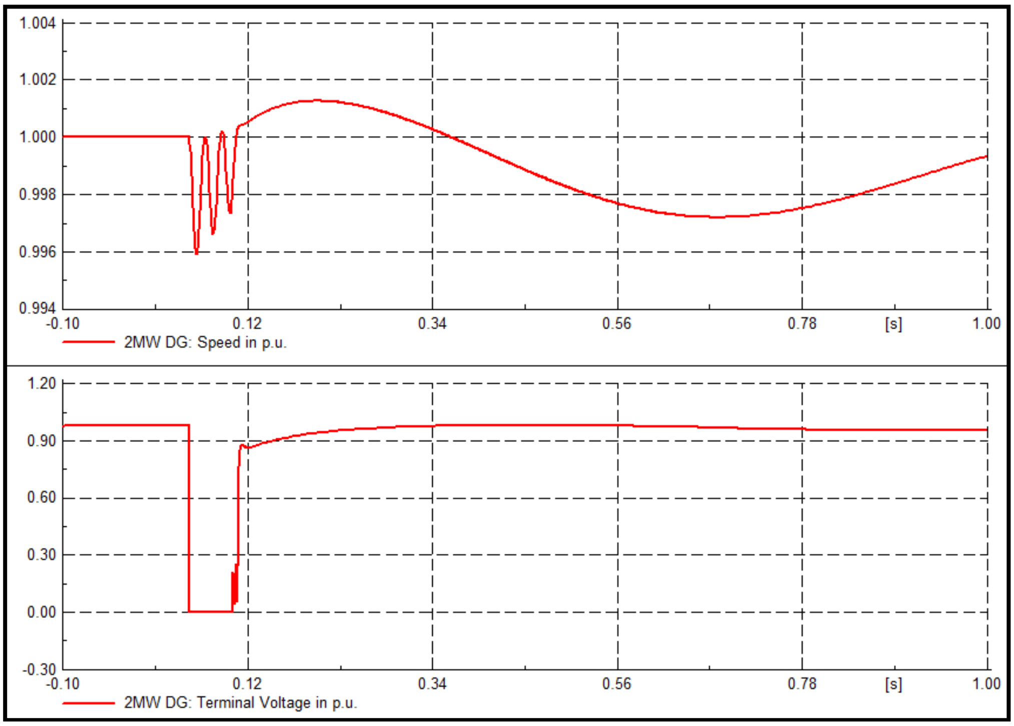

Figure 5.62: Speed and terminal voltage of 2MW DG during three phase short circuit

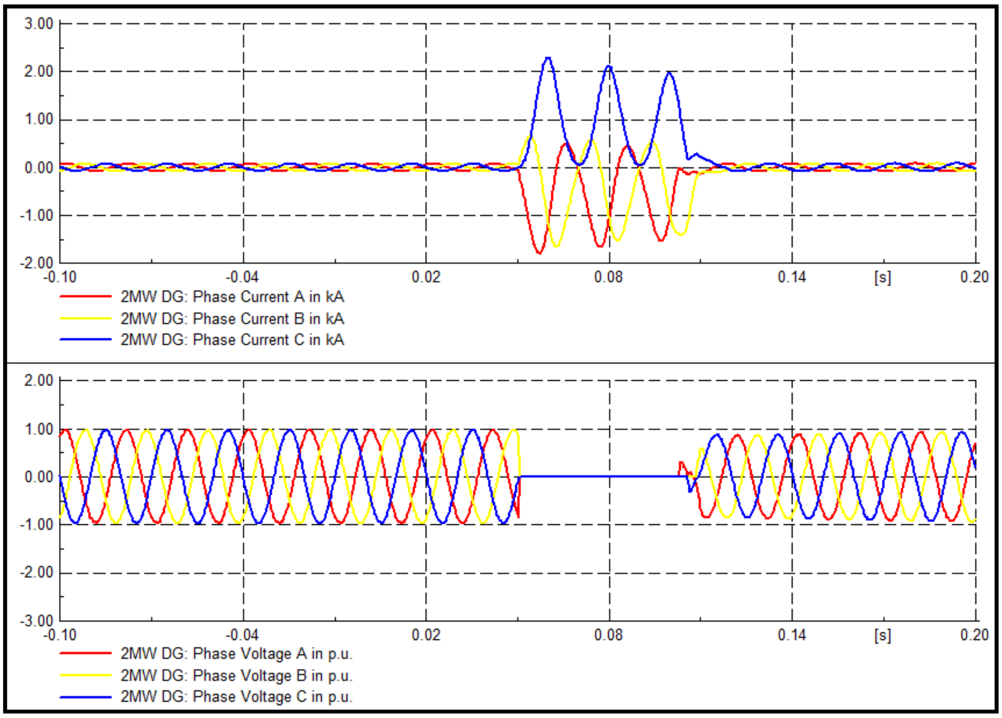

Figure 5.63: Phase current and voltage of 2MW DG during three phase short circuit

Transient instability is an important concern for the large-scale generators (Razzaghi *et al.*, 2013). In their view, to prevent transient stability problem for small-scale generators connected to the distribution networks, according to some existing grid codes, it is suggested to disconnect the DG units immediately after occurrence of a fault in the network. However, if DGs supply a significant share of the total load, extensive disconnections following the network faults will remarkably reduce the benefits expected from these energy sources. In addition, the sudden disconnection of a large block of DG could adversely affect the normal operation of the network.

5.5.3.4 Protection Issues

Investigation on some protection issues involving DGs has been carried out on the developed radial system model based on protection coordination. Types of over-current protective devices coordination include fuse-fuse coordination, fuse-relay coordination and relay-relay coordination. In the absence of laterals in the model relay-relay coordination has been chosen because the emphasis is on the feeder although the primary of the substation transformer is ideally protected with a fuse. Also DG protection or its isolation techniques are not considered.

The aim is to determine the impact of DG capacity and location on coordination of over-current relays in a radial distribution network. It is widely documented that in radial networks, selectivity of fault protection is achieved through time-current coordination of over-current relays. This is because for a particular fault, all the relays connected in the radial feeder see the fault current but are made to operate at different times. The coordination is based on the fact that the relay closest to the fault (primary relay) sees the largest fault current than those farther away (backup relays). Selection of different time current characteristics in the relay settings is the means of realising coordination. Two crucial relay settings are:

- Pickup or plug setting (tap setting)
- Time dial or time multiplier setting

From Tables 5.1 and 5.5 the fault currents along the feeder without DG are shown in Table 5.12. To ensure effective protection of the feeder, three General Electric overcurrent relays with inverse time characteristics are chosen from the DIgSILENT global library for the three segments. LD1 Line and LD1-LD2 Lines are protected by IAC51B828A respectively while IAC51A824A protects LD2-End section. Both relay models perform IDMT (Inverse Definite Minimum Time) and DT (Definite Time) or Instantaneous functions.

Table 5.12: Fault currents along feeder without DG

Fault Type	Busbar Fault Current (kA)			
	22kV	LD1	LD2	60km Terminal
$I_{3\varphi max}$	4.72	0.68	0.35	0.24
$I_{3\varphi min}$	4.14	0.53	0.27	0.19
I_{LGmax}	6.04	0.56	0.29	0.20
I_{LGmin}	5.32	0.46	0.24	0.16

The cable nominal current is 155A but the DIgSILENT PowerFactory 80% loading limit implies that the maximum load current is 124A. Therefore, this requires a current transformer (CT) whose ratio produces 5A secondary current for the maximum load (primary current):

$$CT\ ratio = \frac{124}{5} = 24.8\ \cong 25$$

(Equation 5.10)

The minimum value of current for which the relay must operate should be at least 1.5 times pickup, but not very much more (Burke, 1994). Therefore, the minimum primary pick up phase currents of the relays which define their reaches are:

$$R_1(LD2 - End\ Line\ relay) = \frac{0.19kA}{1.5} = 126.7A$$

(Equation 5.11)

$$R_2(LD1 - LD2\ Line\ relay) = \frac{0.27kA}{1.5} = 180A$$

(Equation 5.12)

$$R_3(LD1\ Line\ relay) = \frac{0.53kA}{1.5} = 353.3A$$

(Equation 5.13)

Respective secondary or relay pick up current settings are:

$$R_1 = \frac{126.7A}{25} = 5.1A$$

(Equation 5.14)

$$R_2 = \frac{180A}{25} = 7.2A$$

(Equation 5.15)

$$R_3 = \frac{353.3A}{25} = 14.1A$$

(Equation 5.16)

Furthermore, the respective maximum secondary pick up current settings are:

$$R_1 = \frac{0.35kA}{25} = 14A$$

(Equation 5.17)

$$R_2 = \frac{0.68kA}{25} = 27.2A$$

(Equation 5.18)

$$R_3 = \frac{4.72kA}{25} = 188.8A$$

(Equation 5.19)

Therefore, the relay pick up multiples are calculated as follows where

$$Pick\ up\ multiple = \frac{Maximum\ secondary\ pick\ up\ current}{Minimum\ secondary\ pick\ up\ current}$$

$$R_1 = \frac{14}{5} = 2.8$$

(Equation 5.20)

$$R_2 = \frac{27.2}{7} = 3.9$$

(Equation 5.21)

$$R_3 = \frac{188.8}{14.1} = 13.4$$

(Equation 5.22)

The time dial or time multiplier seetings ensure proper coordination amongst these relays. According to IEC 60255 and BS 142 standards, the operating time of a protection relay is calculated using Equation 5.23:

$$t = \frac{k\beta}{\left[\frac{I}{I_{\geq}}\right]^{\alpha} - 1}$$

(Equation 5.23)

Where:

k is an adjustable time multiplier

I is the measured phase current value

$I_{\geq}$ is the set start (pickup) current value

α and β are curve set-related parameters

From Equation 5.23 the time dial or time multiplier is derived as shown in Equation 5.24.

$$k = \frac{t\left(\left[\frac{I}{I_{\geq}}\right]^{\alpha} - 1\right)}{\beta}$$

(Equation 5.24)

However, for an electromechanical relay both I and $I_{\geq}$ are referring to the secondary current of the CTs. Therefore, the ratio $I/I_{\geq}$ is equivalent to the multiples of plug setting current as given by Equations 5.20 - 5.22.

Table 5.13 shows the characteristic referred to as 3/10 which means that the operating time is 3s at 10 times rated current. The times quoted in this table are for a time multiplier setting of 1.0 and therefore would be halved if a time multiplier setting of 0.5 is used (Christopoulos and Wright, 1999).

Table 5.13: Overcurrent relay 3/10 characteristic (Christopoulos and Wright, 1999)

Multiple of current setting	1.3	2	5	10	20 or more
Time (s)	∞	10	4.3	3.0	2.2

Therefore, assigning the least time dial of 0.5 to R_1 and given its multiple current setting of 2 results to an operating time of 5s. But the operating time of R_2 equals R_1 operating time plus the coordination time interval and in this case 0.3s is the discrimination margin. Substituting t = 5.3s and $I/I_{\geq}$ = 4 in Equation 5.24 gives the time multiplier of R_2 as

$$k = \frac{5.3([4]^{0.02} - 1)}{0.14} = 1.1 \cong 1$$

(Equation 5.25)

Similarly, the time dial of R_3 is calculated by substituting t = 5.6 (coordination time interval between R_2 and R_3 is 0.3s) and PSM (plug setting multiplier) of 13. The result is as given by Equation 5.26

$$k = \frac{5.6([13]^{0.02} - 1)}{0.14} = 2.1 \cong 2$$

(Equation 5.26)

The ground fault relay settings follow the same procedure. However, in both cases the maximum fault current values have been utilised in setting the instantaneous functions. The operating time of the phase and ground instantaneous elements are by default 0.03s. Therefore, the time-overcurrent plot of the relays is as shown in Figure 5.64. Table 5.14 is a summary of the single phase to ground fault and clearing time simulation results.

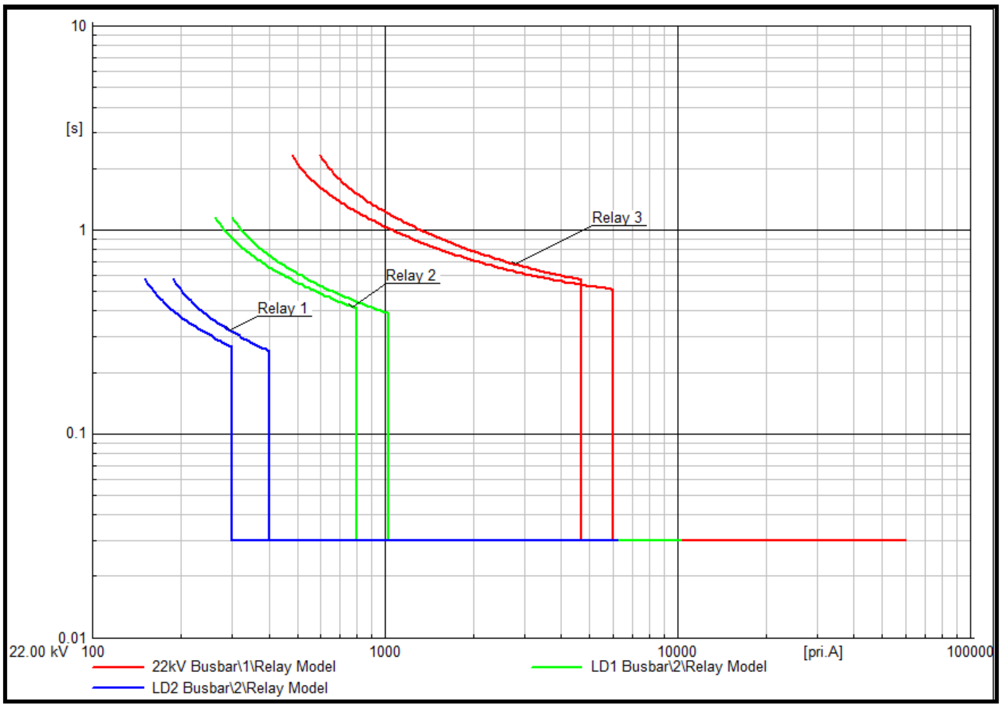

Figure 5.64: Time-overcurrent plot of the relays

Table 5.14: Single phase to ground fault and its clearing time

Fault Location	Fault Clearing Time (s)		
	No DG	With 4MW DG	With 2MW DG
60km Terminal	0.378	0.290/1.114	0.030
LD2-End Line	0.320	0.030/0.771	0.030
LD2 Busbar	0.938	0.575	0.928
LD1-LD2 Line	0.681	0.421	0.768
LD1 Busbar	1.749	1.989	2.024
LD1 Line	1.008	1.118	1.019
22kV Busbar	0.030	0.030	0.030

According to Harker (1998), it is worth noting that for a time-overcurrent relay incorporating phase and earth elements:

(i) the phase elements are responsive to positive-, negative- and zero-sequence currents;

(ii) the earth elements are responsive to zero-sequence current only.

Therefore, the responses of the phase elements due to earth faults are ignored in the following analyses except in cases they act before earth elements or the latter fail to operate. The result discussions of each location are as follows:

<u>60km Terminal</u>

Figure 5.65 shows that a single phase to ground fault on the 60km Terminal in the absence of DG is cleared by the earth element of R_1 in 0.0378s. But with 4MW DG connected the fault clearing time by R_1 is reduced to 0.290s and R_2 as a backup relay clears the fault in 1.114s should R_1 fail to operate, Figure 5.66. Likewise when 2MW DG is connected the fault is cleared by the instantaneous element of R_1 in 0.030s as shown in Figure 5.67. At this location impact of DG on protection coordination is negative.

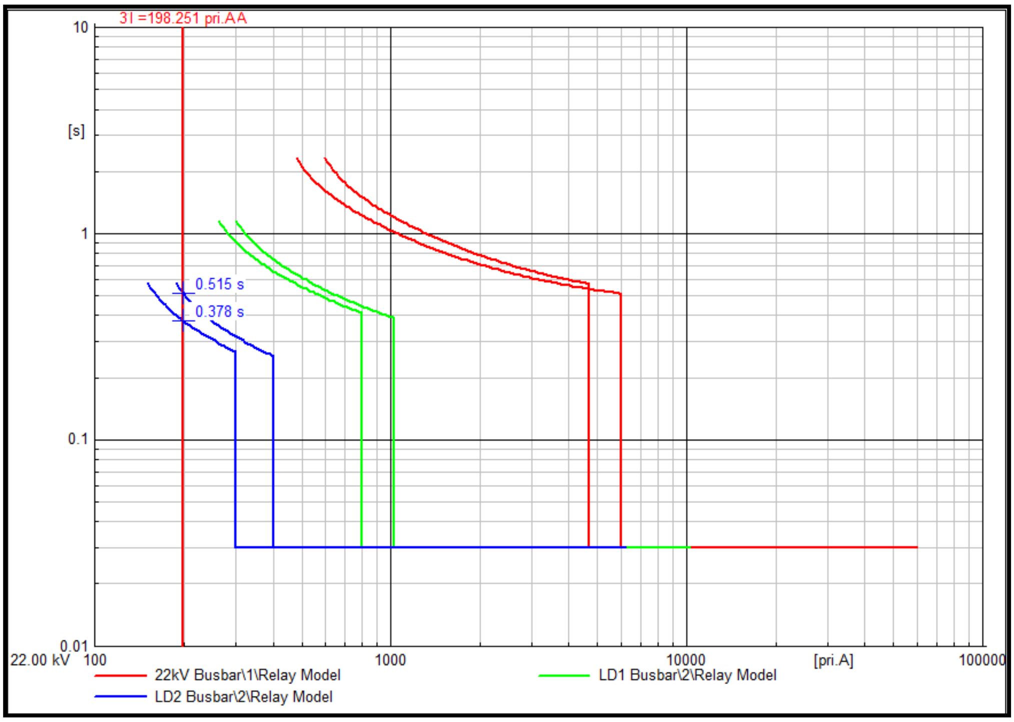

Figure 5.65: Plot of single phase to ground fault on 60km Terminal without DG

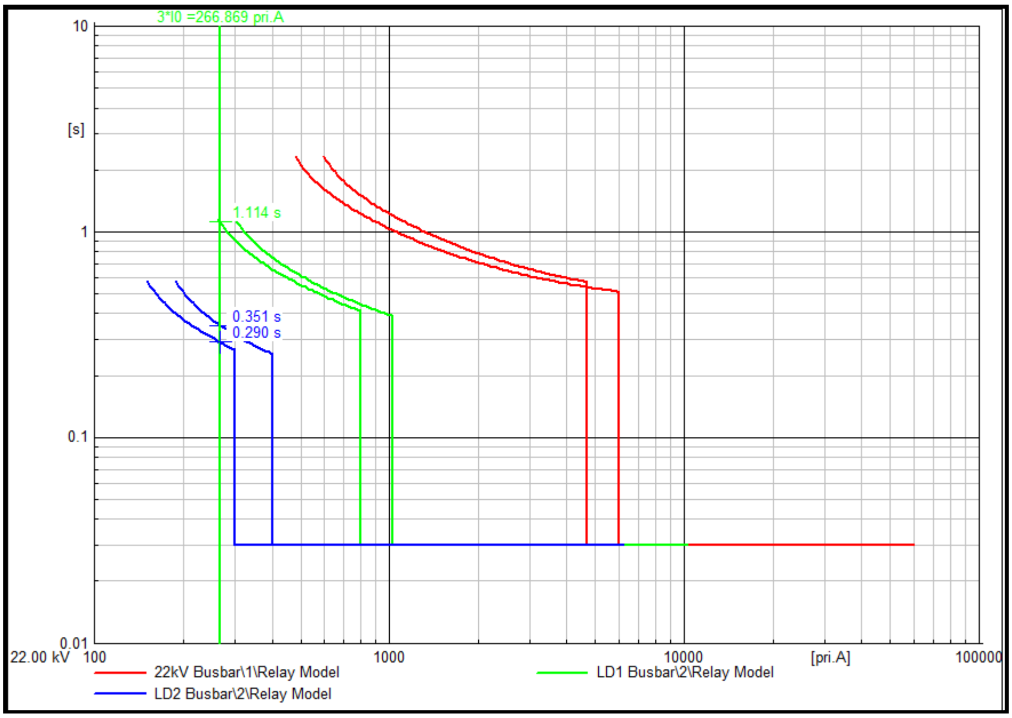

Figure 5.66: Plot of single phase to ground fault on 60km Terminal with 4MW DG connected

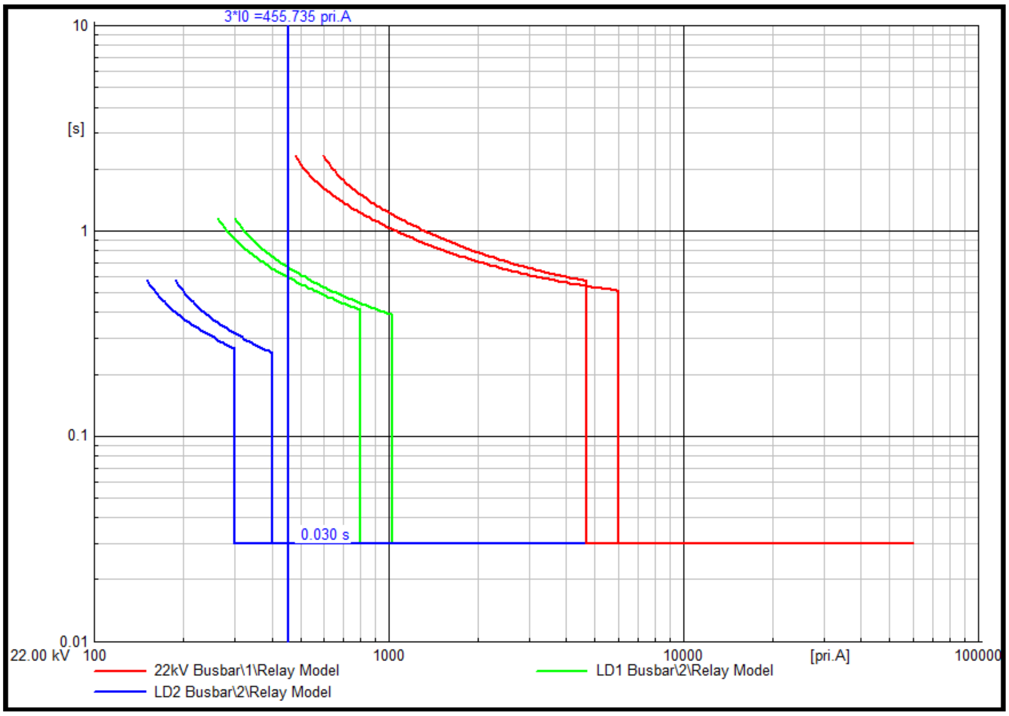

Figure 5.67: Plot of single phase to ground fault on 60km Terminal with 2MW DG connected

LD2-End Line

For the base case – without DG – an earth fault at the middle of LD2-End Line is cleared within 0.320s by R_1 as shown in Figure 5.68. As can be seen from Figure 5.69 the instantaneous element of R_1 ensures that the fault is cleared in 0.030s when the 4MW DG is connected. Otherwise R_2 clears the fault in 0.771s and the phase current is beyond the reach of R_3. But when the 2MW DG is connected R_1's instantaneous element clears the fault in 0.030s as depicted in Figure 5.70. Again, here the protection coordination is intact with DG connection.

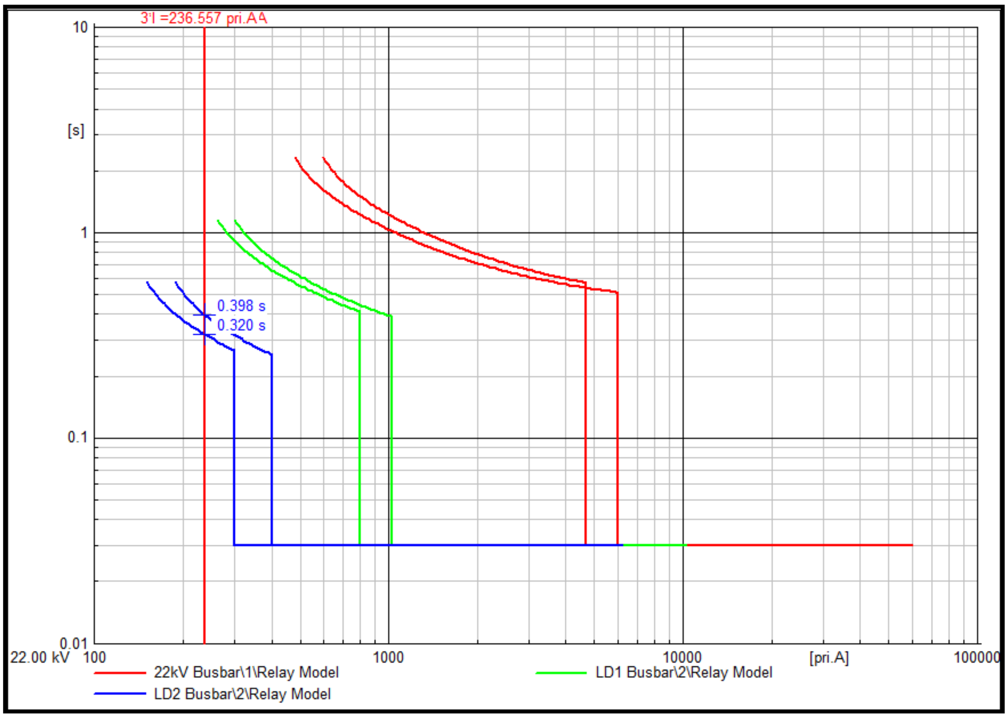

Figure 5.68: Plot of single phase to ground fault on LD2-End Line without DG

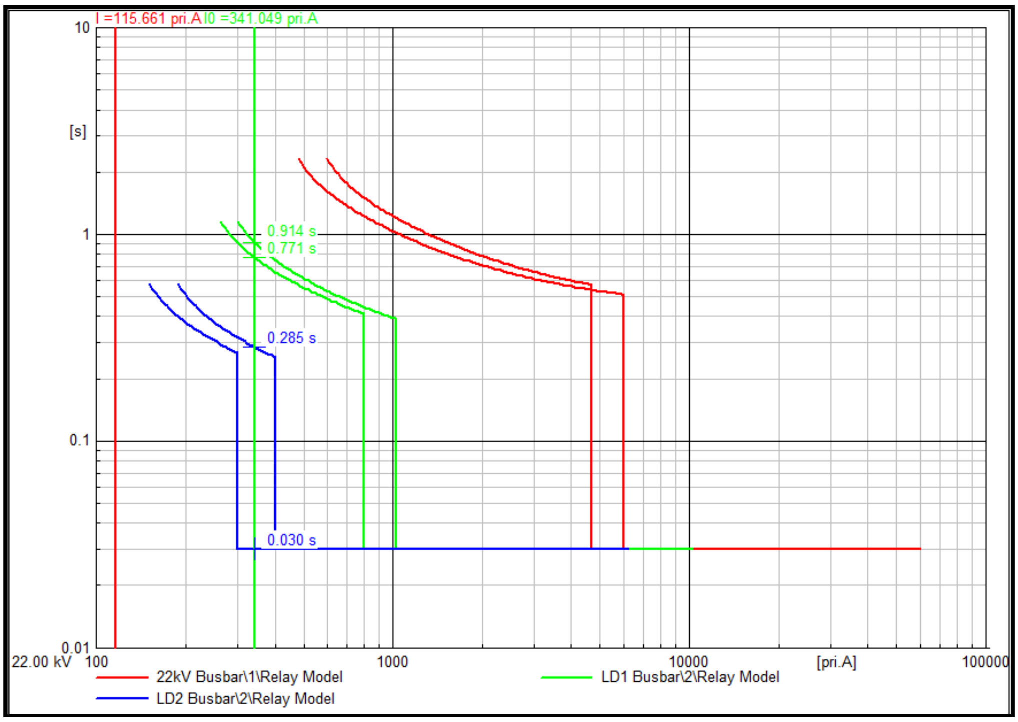

Figure 5.69: Plot of single phase to ground fault on LD2-End Line with 4MW DG connected

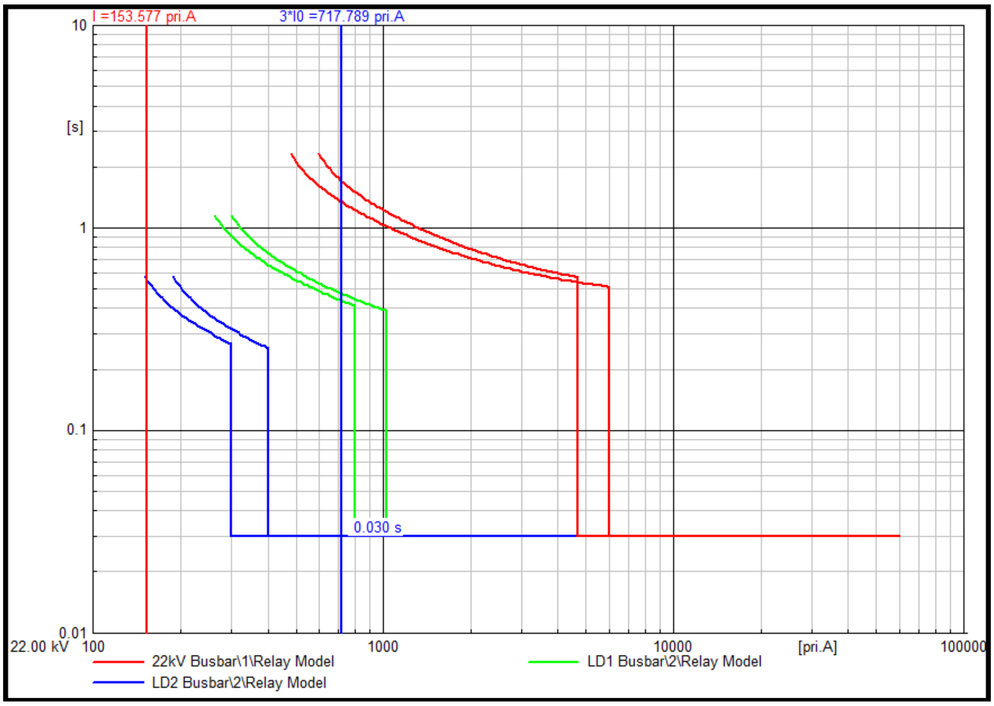

Figure 5.70: Plot of single phase to ground fault on LD2-End Line with 2MW DG connected

LD2 Busbar

According to Figure 5.71 the time for an earth fault on the LD2 Busbar to be cleared by R_2 is 0.938s for the base case. But the fault clearing time becomes 0.575s and 0.928s with the connection of 4MW and 2MW DG respectively (see Figures 5.72 and 5.73). Once again DG connection has no impact on the protection coordination.

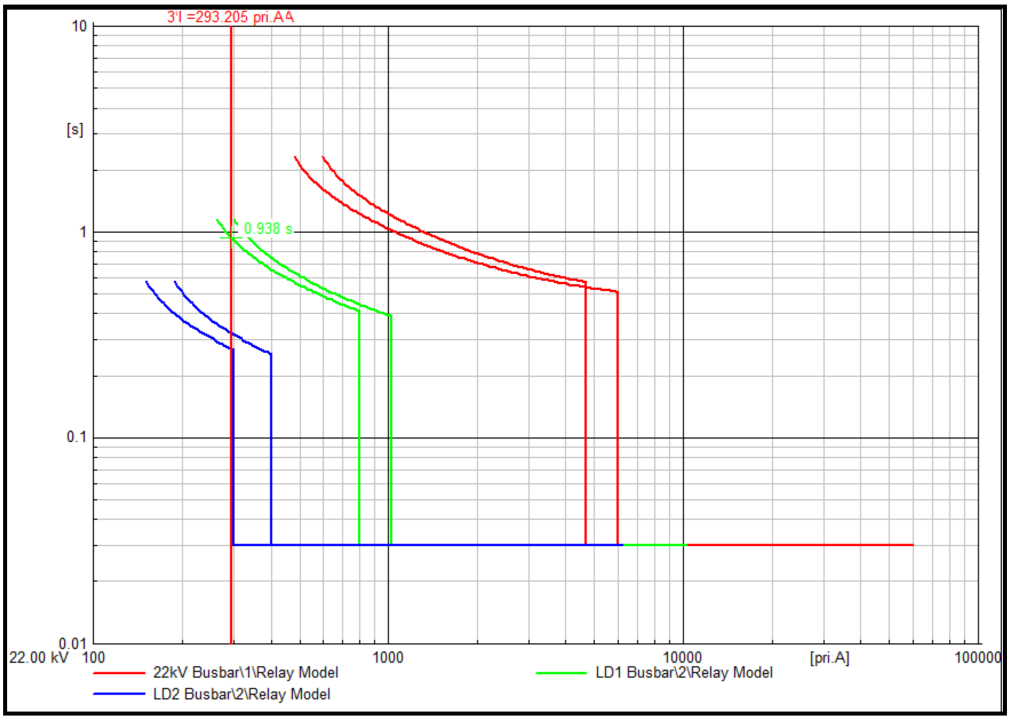

Figure 5.71: Plot of single phase to ground fault on LD2 Busbar without DG

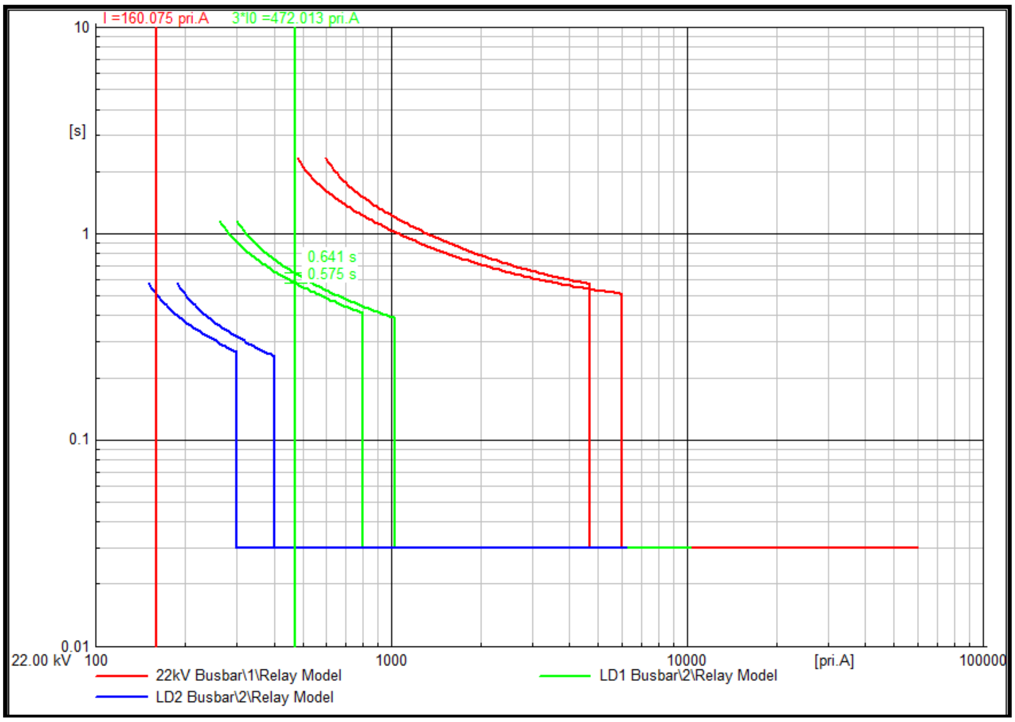

Figure 5.72: Plot of single phase to ground fault on LD2 Busbar with 4MW DG connected

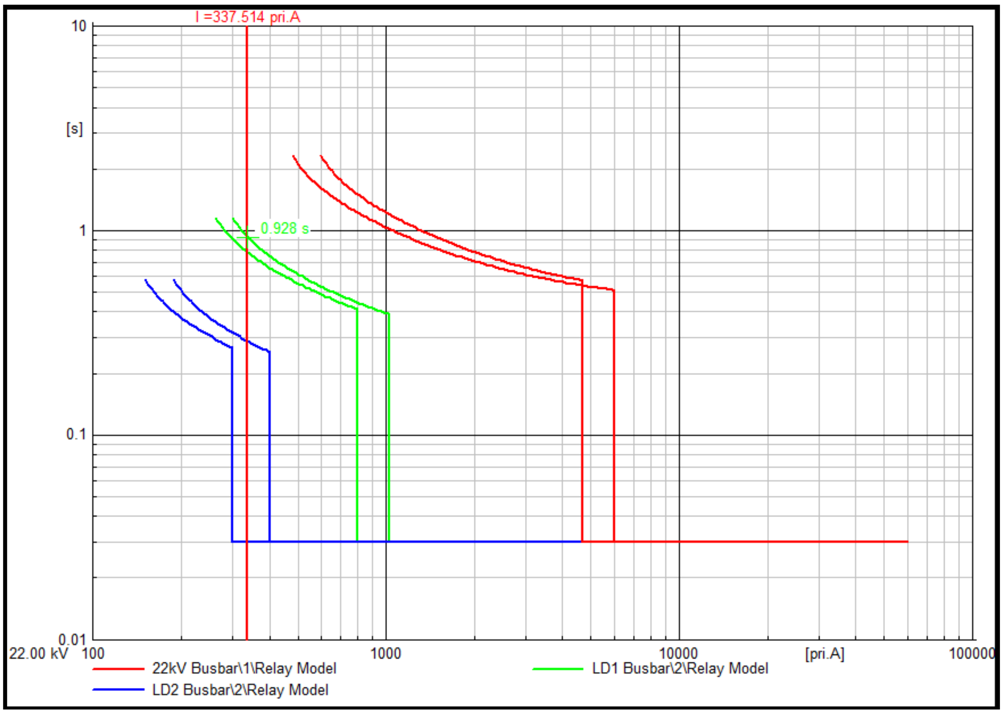

Figure 5.73: Plot of single phase to ground fault on LD2 Busbar with 2MW DG connected

LD1-LD2 Line

Ordinarily, an earth fault midway of LD1-LD2 Line is cleared by R_2 in 0.681s as contained in Figure 5.74. But Figure 5.75 shows that connection of the 4MW DG results to a fault clearing time of 0.421s. The fault is cleared in 0.768s by the phase element instead of 0.961s of the earth element when 2MW DG is connected as shown in Figure 5.76. It should be noted that this results to islanding scenario. Besides the protection coordination is not impinged upon by the presence of the DG.

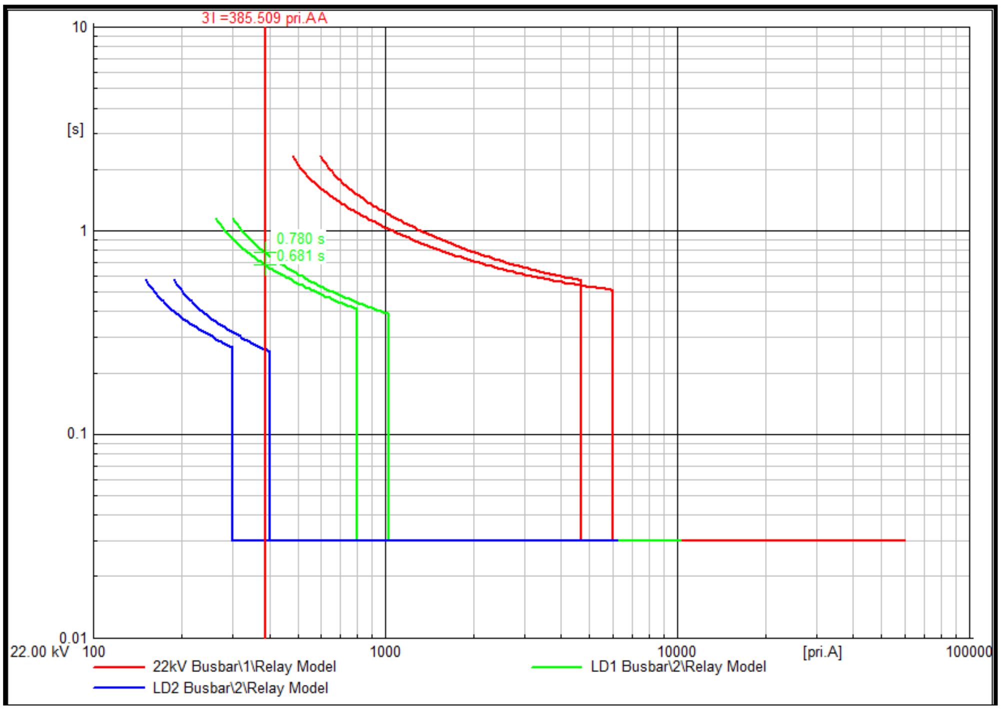

Figure 5.74: Plot of single phase to ground fault on LD1-LD2 Line without DG

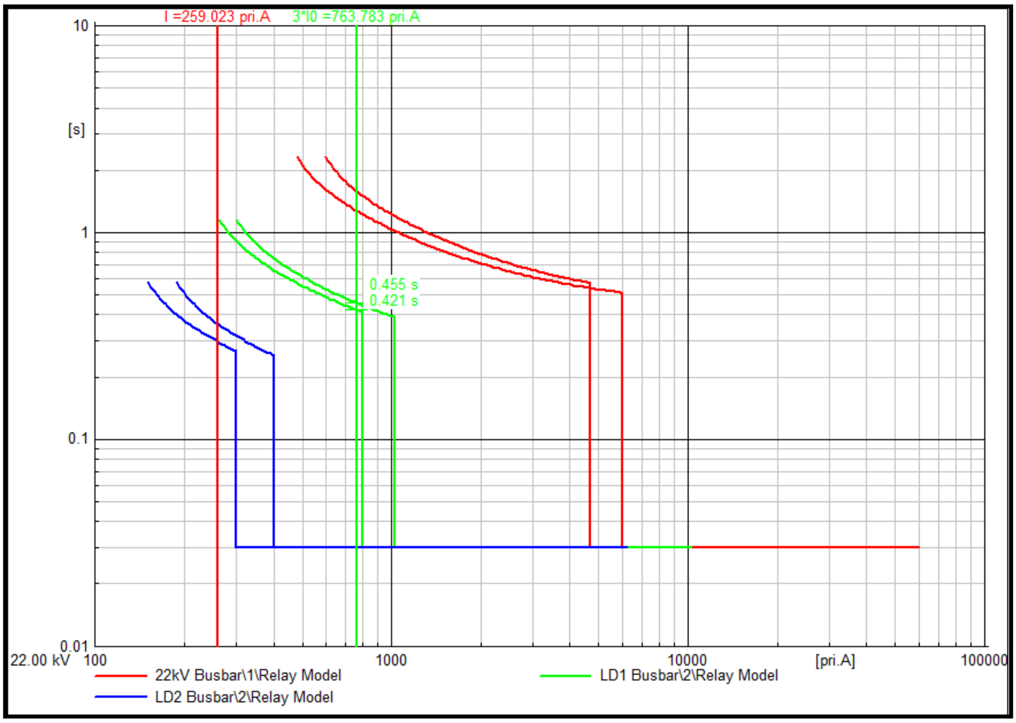

Figure 5.75: Plot of single phase to ground fault on LD1-LD2 Line with 4MW DG connected

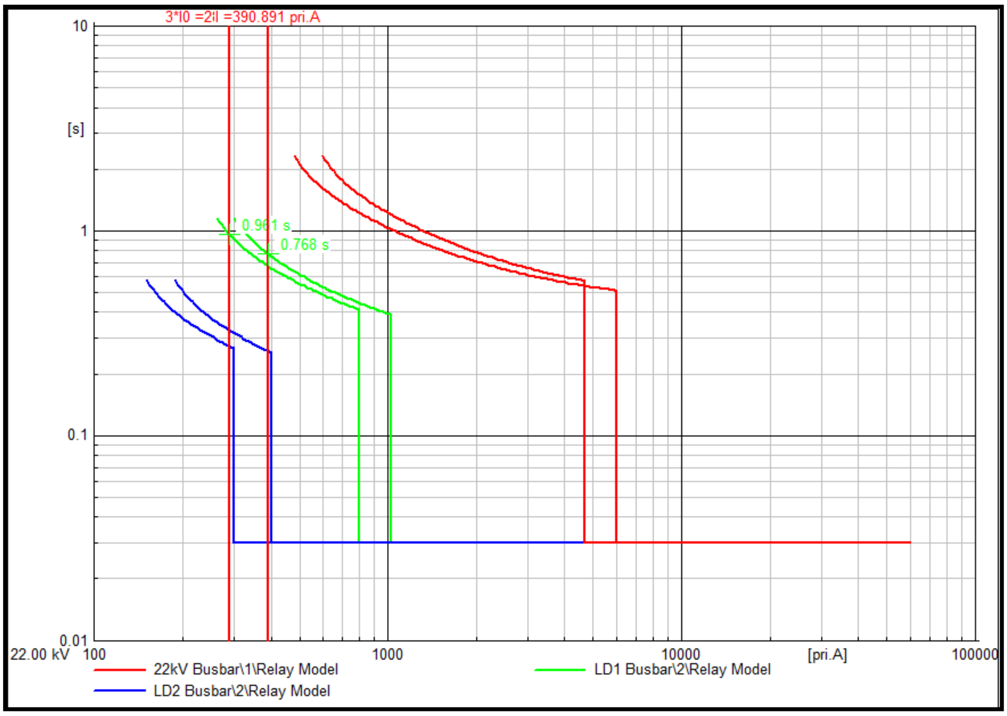

Figure 5.76: Plot of single phase to ground fault on LD1-LD2 Line with 2MW DG connected

LD1 Busbar

Figure 5.77 illustrates that an earth fault on the LD1 Busbar is cleared in 1.749s courtesy of R_3 in the base case. A typical case of protection blinding ensues with the connection of 4MW DG rendering the earth element inoperative while the phase element clears the fault in 1.989s as shown in Figure 5.78. Furthermore, a combination of nuisance tripping and protection blinding are the resultant effects when 2MW DG is connected. This is because LD2 and the DG are islanded by R_2 in 0.557s but the fault is cleared by R_3 in 2.024s (see Figure 5.79). Therefore, protection coordination is negatively impacted by the 2MW DG connection at this location.

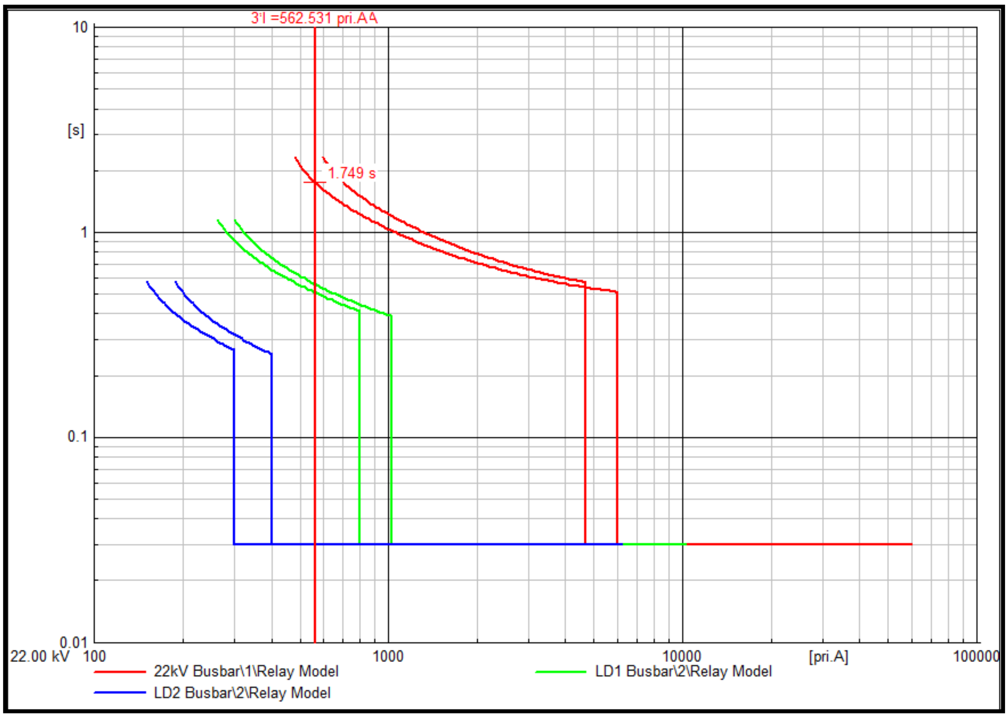

Figure 5.77: Plot of single phase to ground fault on LD1 Busbar without DG

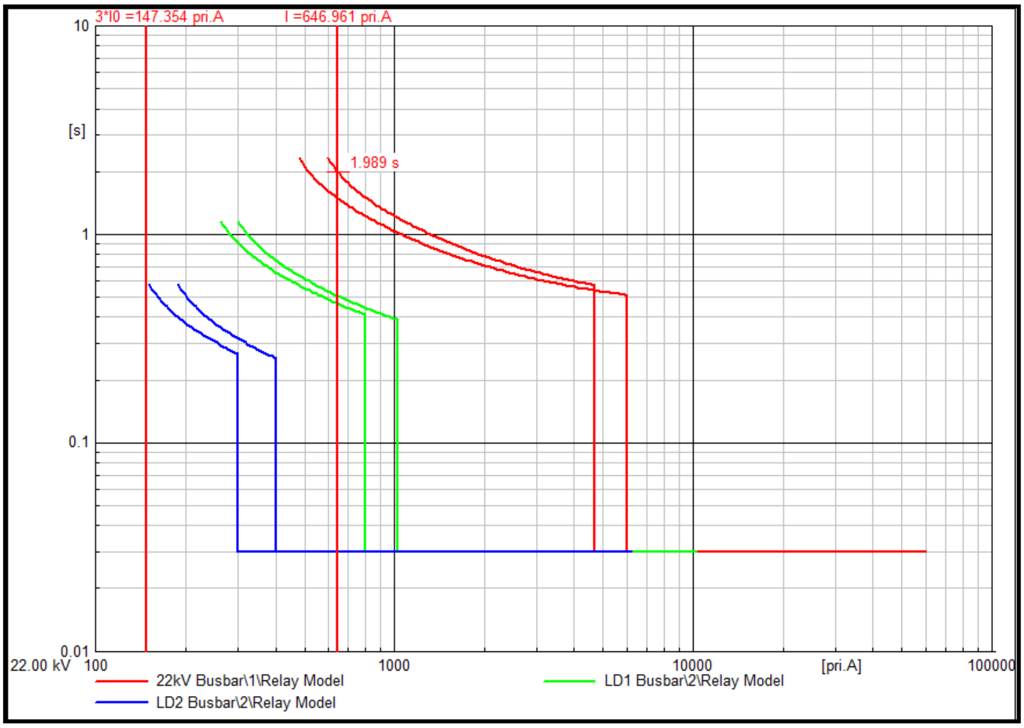

Figure 5.78: Plot of single phase to ground fault on LD1 Busbar with 4MW DG connected

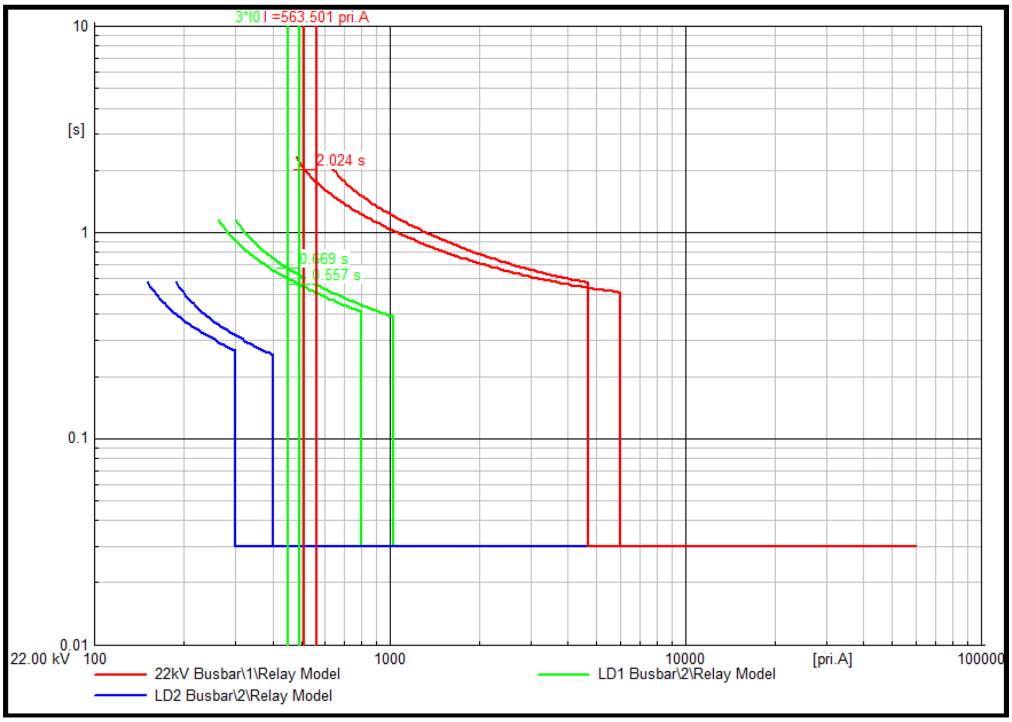

Figure 5.79: Plot of single phase to ground fault on LD1 Busbar with 2MW DG connected

LD1 Line

Figure 5.80 shows that without any DG connected, an earth fault at the middle of LD1 Line is cleared by R_3 in 1.008s. But when 4MW DG is connected R_3 clears the fault in 1.118s – a bit of protection blinding, Figure 5.81. An earth fault on LD1 Line with 2MW DG connected results to a combination of nuisance tripping and protection blinding. While R_2 isolates LD2 and the DG in 0.756s, R_3 clears the fault in 1.019s (see Figure 5.82). Undoudtedly, protection coordination has been compromised by 2MW DG connection.

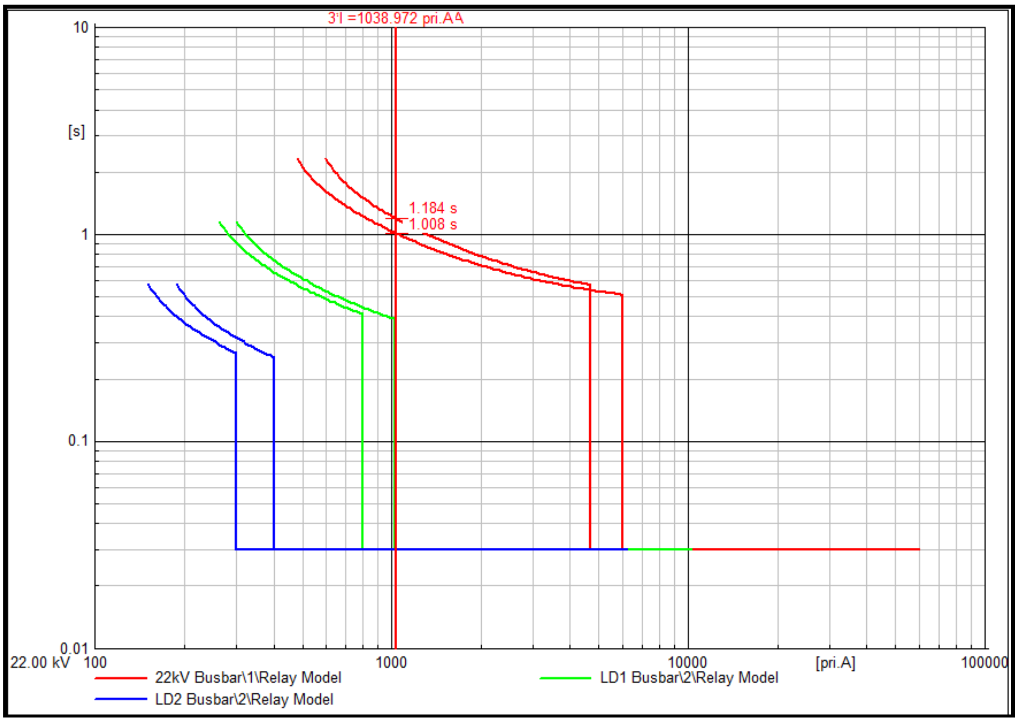

Figure 5.80: Plot of single phase to ground fault on LD1 Line without DG

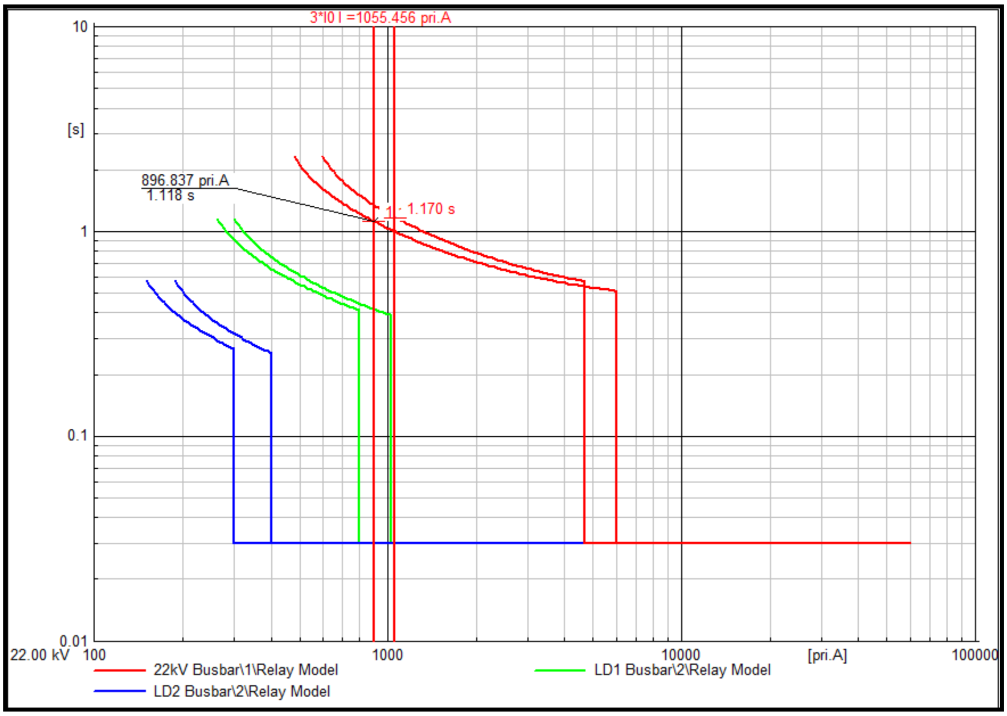

Figure 5.81: Plot of single phase to ground fault on LD1 Line with 4MW DG connected

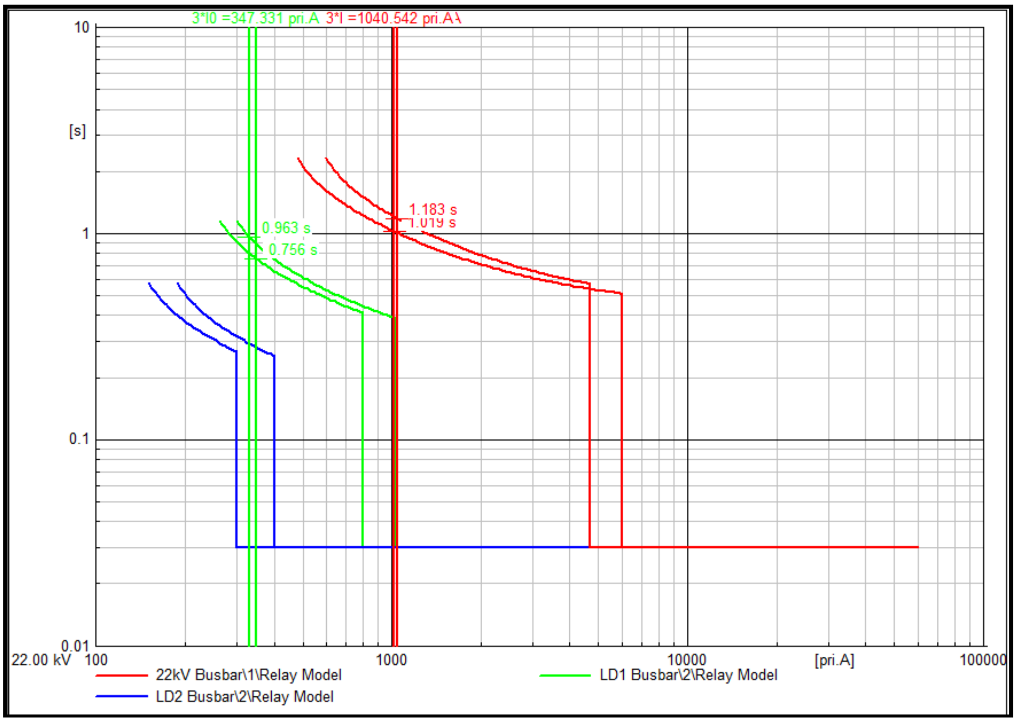

Figure 5.82: Plot of single phase to ground fault on LD1 Line with 2MW DG connected

22kV Busbar

Figures 5.83 to 5.85 show that in every scenario an earth fault on the substation busbar is cleared in 0.030s by the instantaneous element of R_3. However, this results to islanding in the presence of either DG.

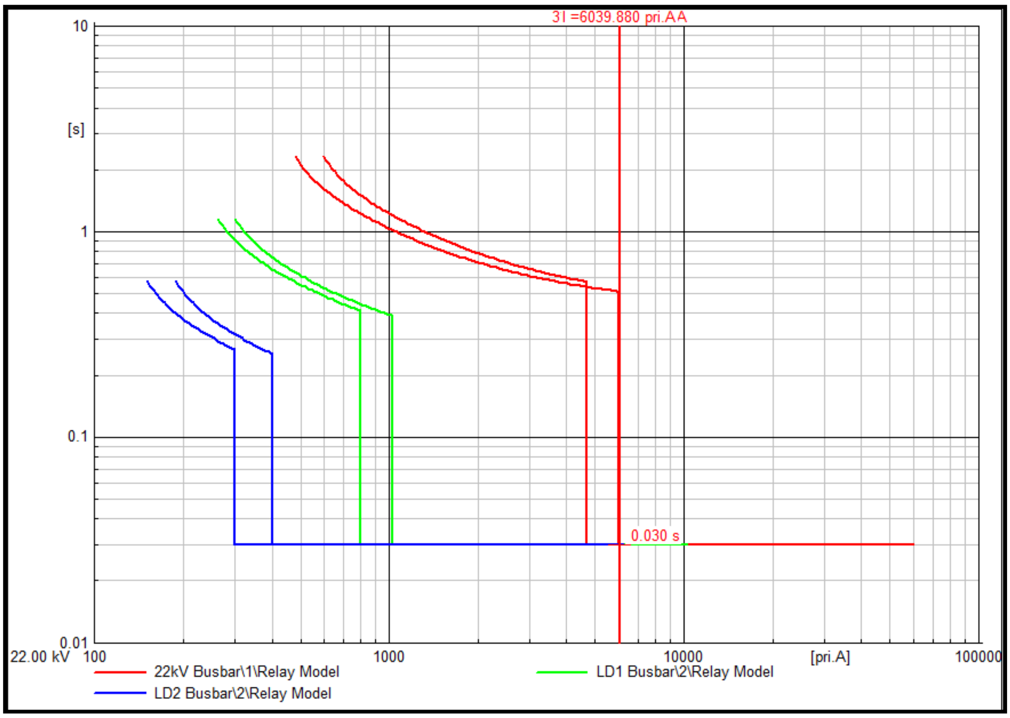

Figure 5.83: Plot of single phase to ground fault on 22kV Busbar without DG

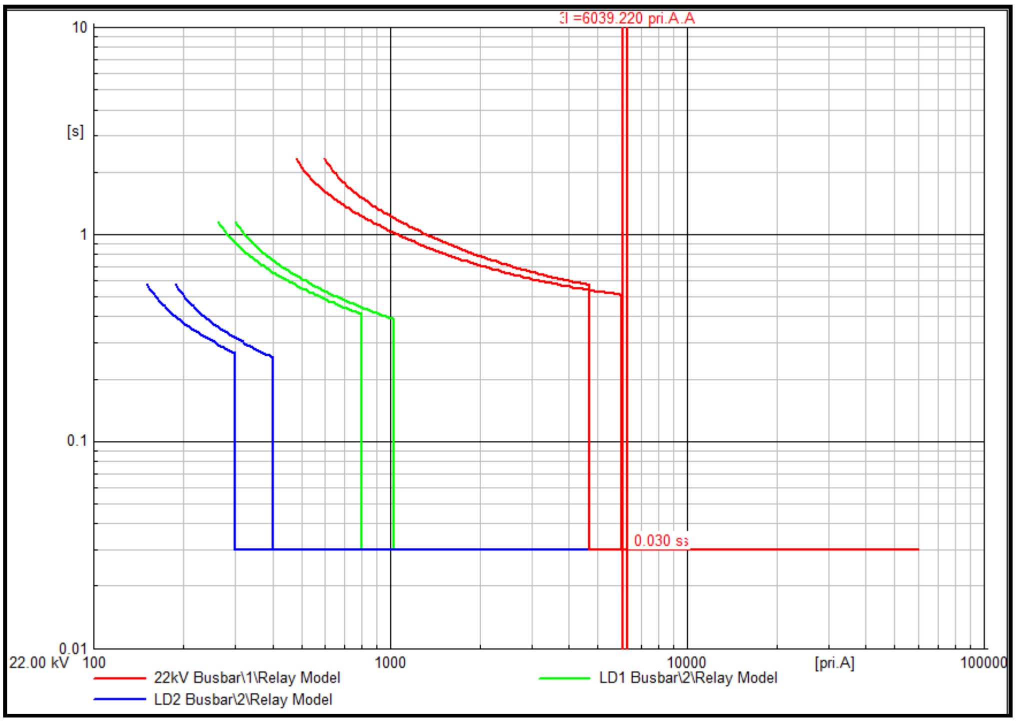

Figure 5.84: Plot of single phase to ground fault on 22kV Busbar with 4MW DG connected

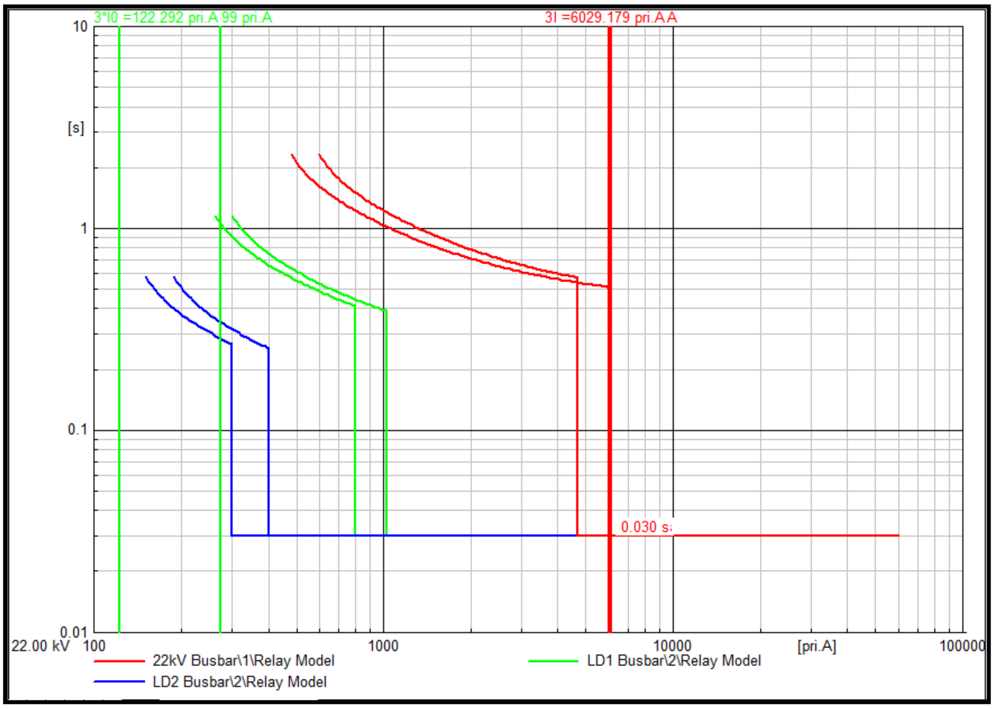

Figure 5.85: Plot of single phase to ground fault on 22kV Busbar with 2MW DG connected

A summary of the three phase short circuit fault and clearing time simulation results for the respective locations is shown in Table 5.15.

Table 5.15: Three phase fault and its clearing time

Fault Location	Fault Clearing Time (s)		
	No DG	With 4MW DG	With 2MW DG
60km Terminal	0.392	0.311/1.108	0.030
LD2-End Line	0.329	0.262/0.783	0.030
LD2 Busbar	0.864	0.596	0.864
LD1-LD2 Line	0.647	0.452	0.647
LD1 Busbar	1.839	1.839	1.839
LD1 Line	1.040	1.040	1.040
22kV Busbar	0.030	0.030	0.030

Result discussions of each location are as follows:

<u>60km Terminal</u>

The clearing of a three phase fault takes 0.392s by R_1 in the base case as depicted in Figure 5.86. Increase in fault current occasioned by 4MW DG connection reduces this time to 0.311s and R_2 clears the fault in 1.108s in the event that R_1 fails to operate as expected. This is shown in Figure 5.87. But R_1 clears the fault in 0.030s when the 2MW DG in connected as shown in Figure 5.88. The fault current when either DG is connected is beyond R_3's reach and so it remains inoperative. The results show that protection coordination is not affected by the DG connection at this location in the case of three phase fault.

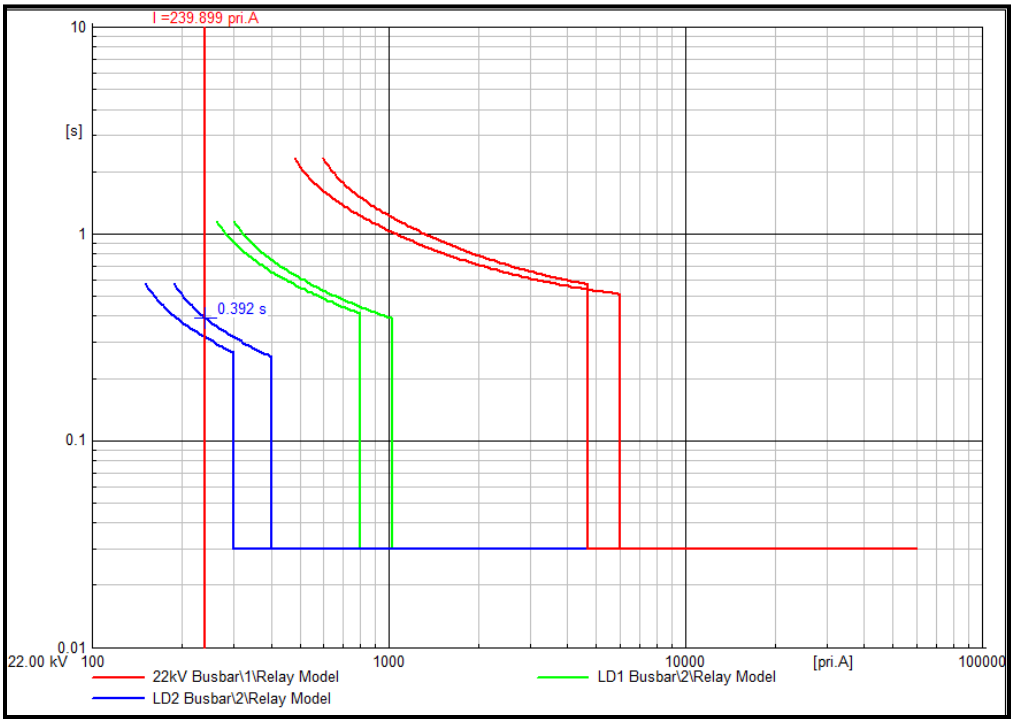

Figure 5.86: Plot of three phase short circuit on 60km Terminal without DG

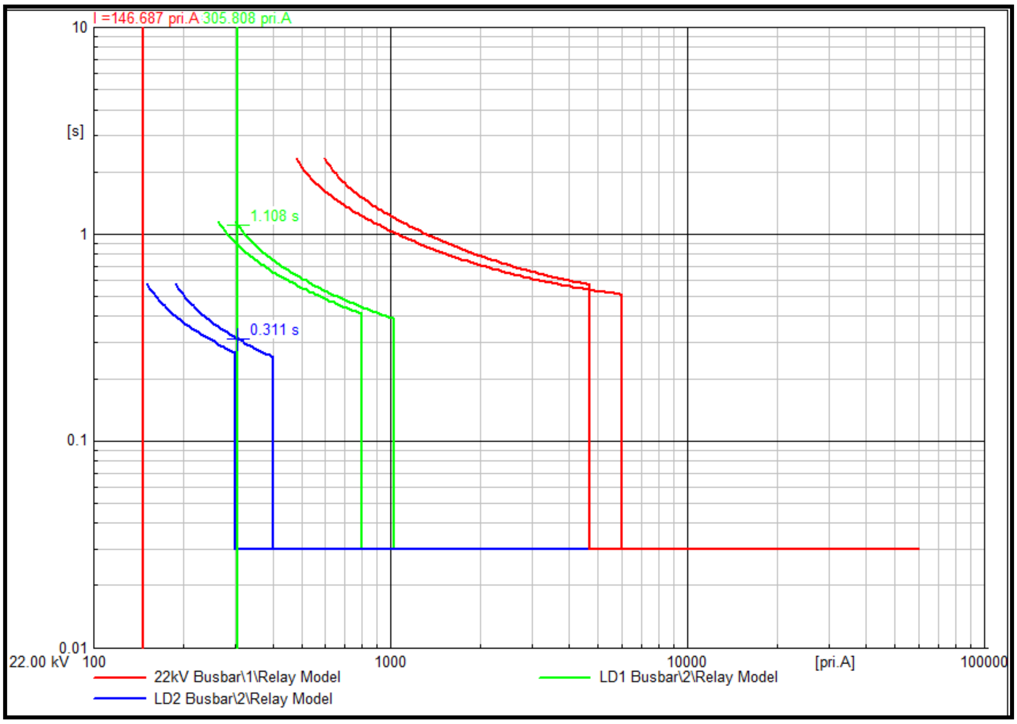

Figure 5.87: Plot of three phase short circuit on 60km Terminal with 4MW DG connected

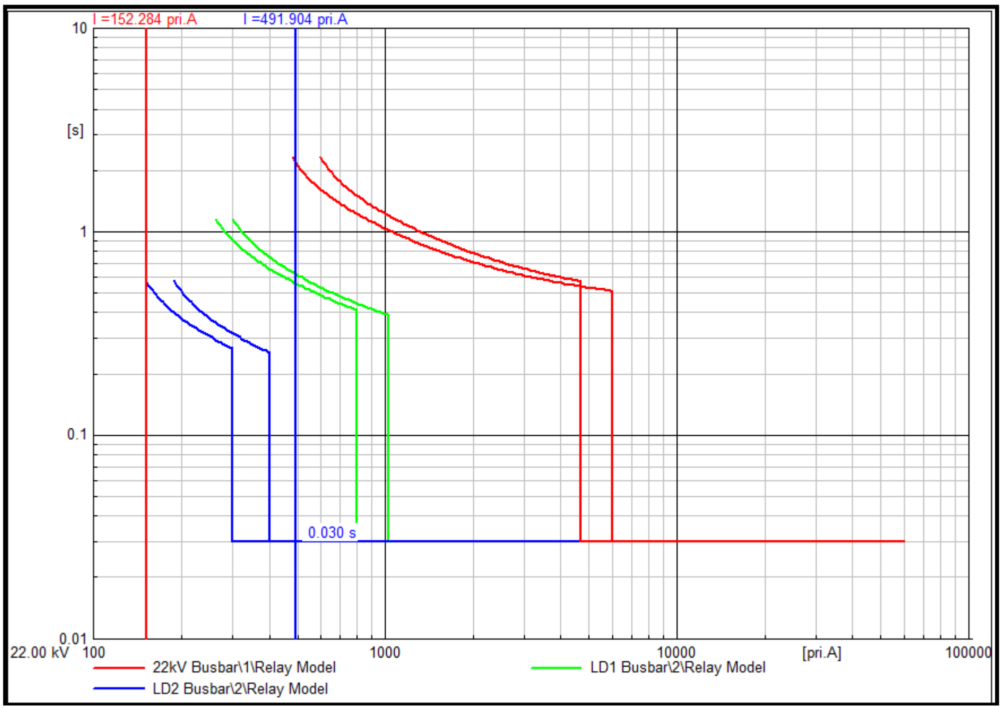

Figure 5.88: Plot of three phase short circuit on 60km Terminal with 2MW DG connected

LD2-End Line

R_1 clears a three phase fault occurring halfway of this line in the absence of a DG in 0.329s and this is shown in Figure 5.89. But with the connection of the 4MW DG, R_1 clears the fault in 0.262s while R_2 operates as a backup relay clearing the fault in 0.783s as depicted in

Figure 5.90. The instantaneous element of R_1 clears the fault in 0.030s when the 2MW DG is connected (see Figure 5.91). Again R_3 is idle because the current is beyond its reach. Equally, the protection coordination is unaltered.

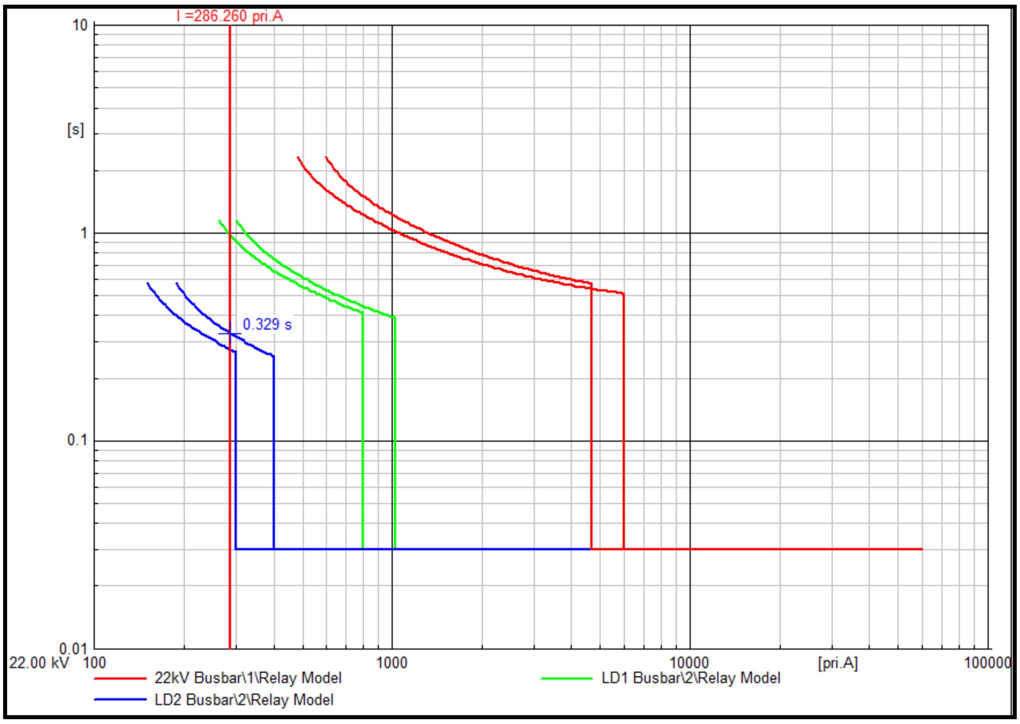

Figure 5.89: Plot of three phase short circuit on LD2-End Line without DG

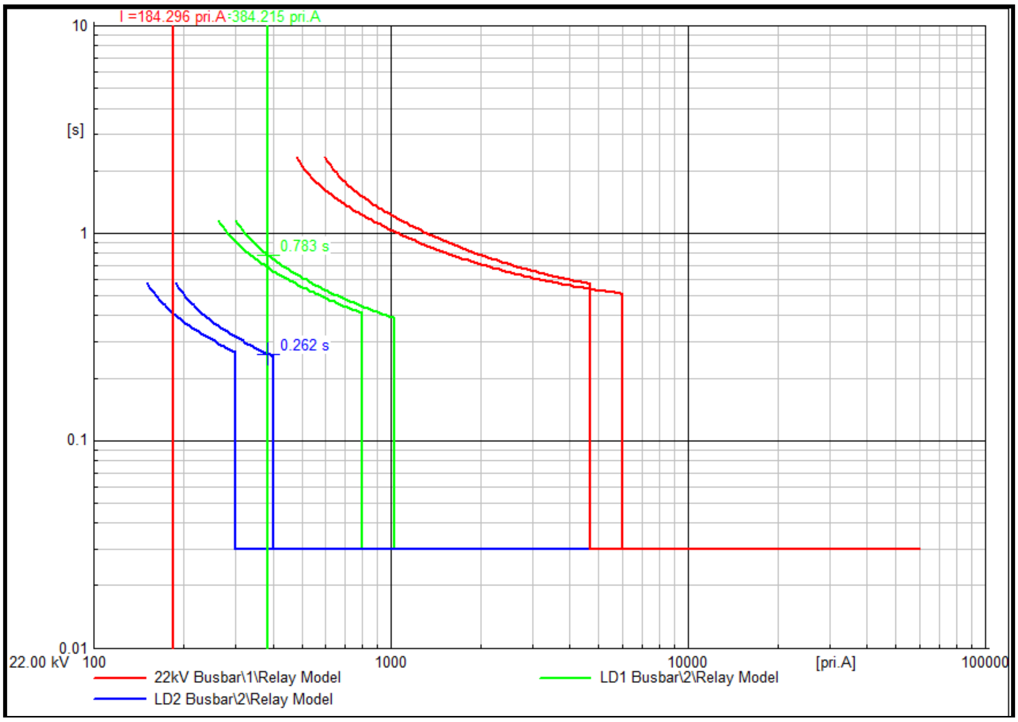

Figure 5.90: Plot of three phase short circuit on LD2-End Line with 4MW DG connected

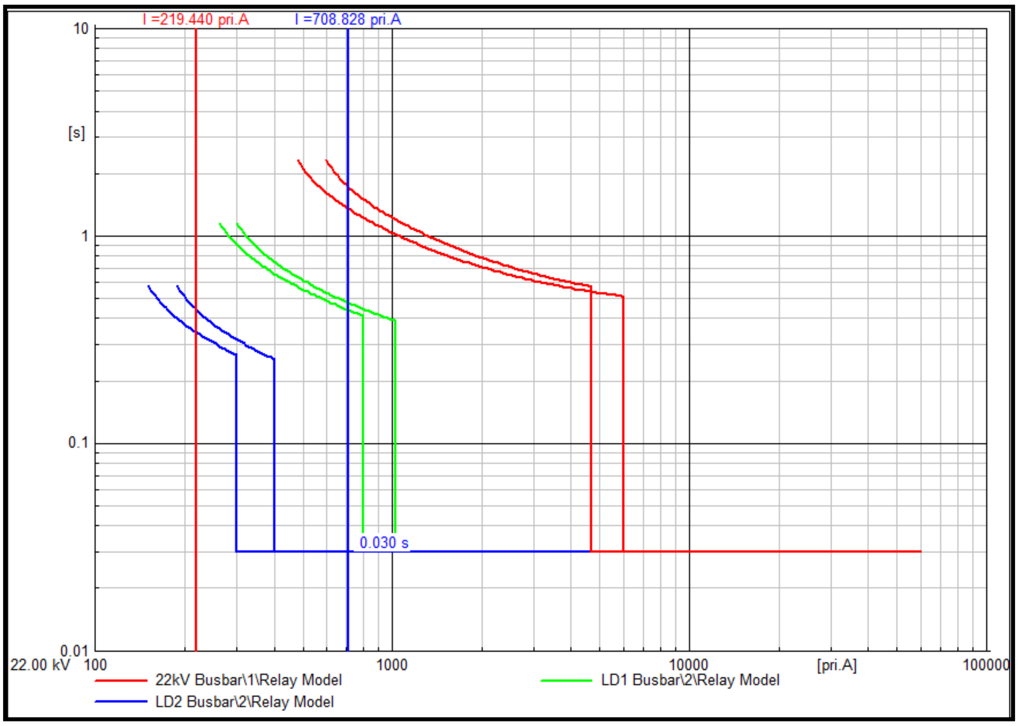

Figure 5.91: Plot of three phase short circuit on LD2-End Line with 2MW DG connected

LD2 Busbar

Here, R_2 clears a three phase fault in 0.864s in the absence of DG. With the connection of the 4MW DG the fault clearing time by R_2 reduces to 0.596s due to increased fault current. However, R_2 clears the fault in 0.864s when 2MW DG is connected with the resultant islanding of the DG and LD2. Once again R_3 is idle and the protection coordination is unaffected by the DG connections (see Figures 5.92 - 5.94)

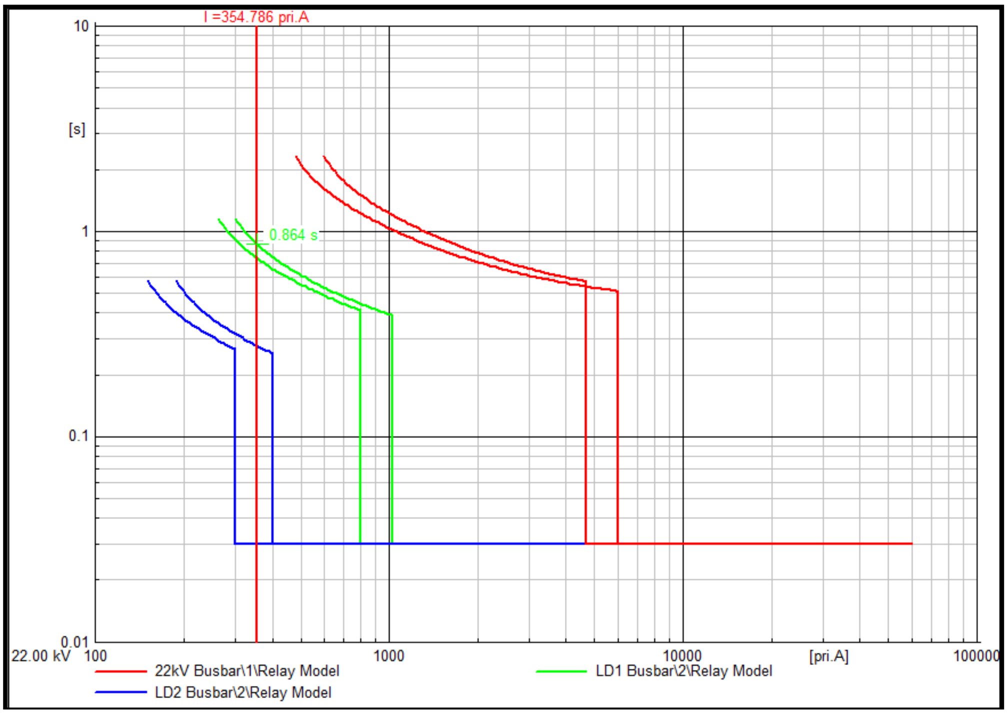

Figure 5.92: Plot of three phase short circuit on LD2 Busbar without DG

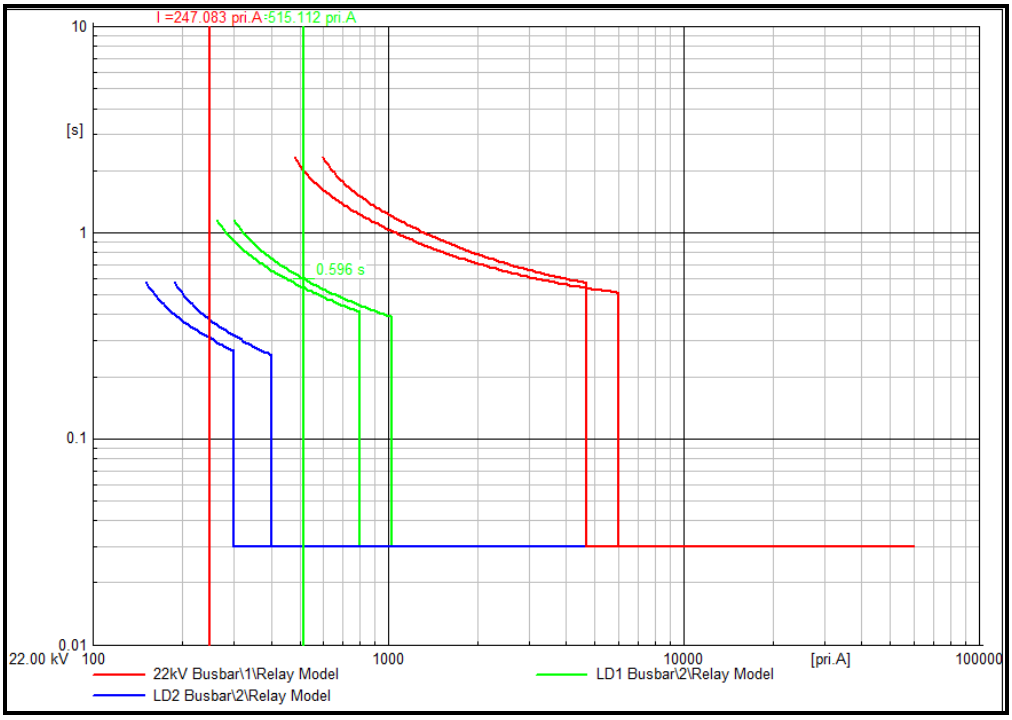

Figure 5.93: Plot of three phase short circuit on LD2 Busbar with 4MW DG connected

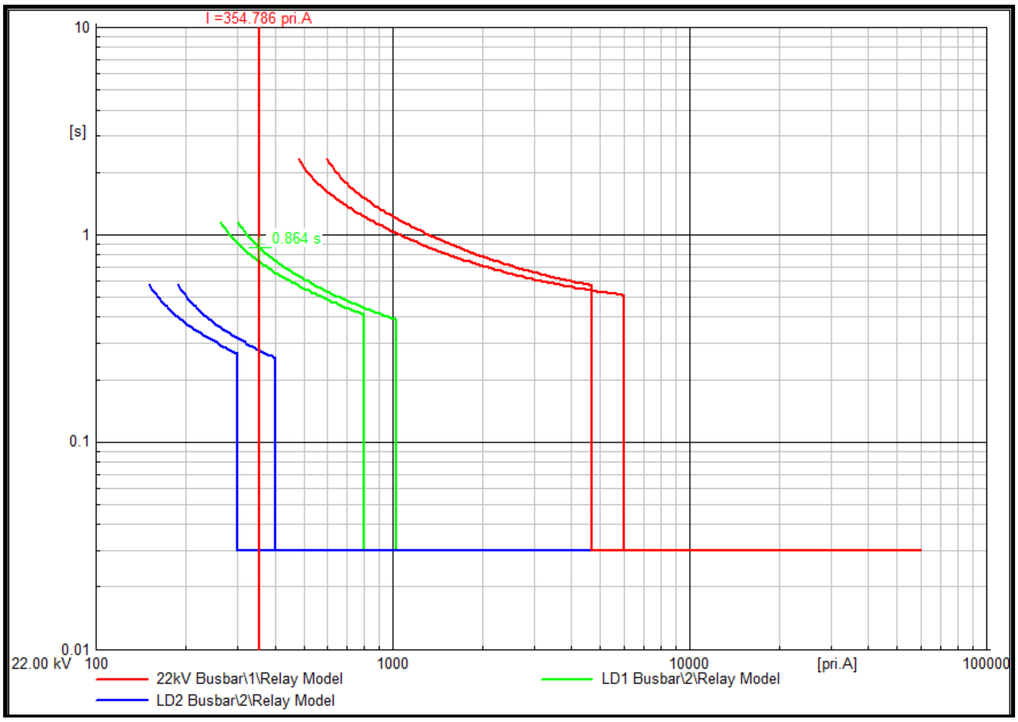

Figure 5.94: Plot of three phase short circuit on LD2 Busbar with 2MW DG connected

LD1-LD2 Line

In the base case a three phase fault at the middle of this line is cleared by R_2 in 0.647s as shown in Figure 5.95. However, Figure 5.96 shows that R_2 clears that same fault in 0.452s when a 4MW DG is connected. The fault is also cleared by R_2 in 0.647s if it occurs when the 2MW DG is connected as depicted in Figure 5.97. Therefore, at this point protection coordination is unaffected by DG connection.

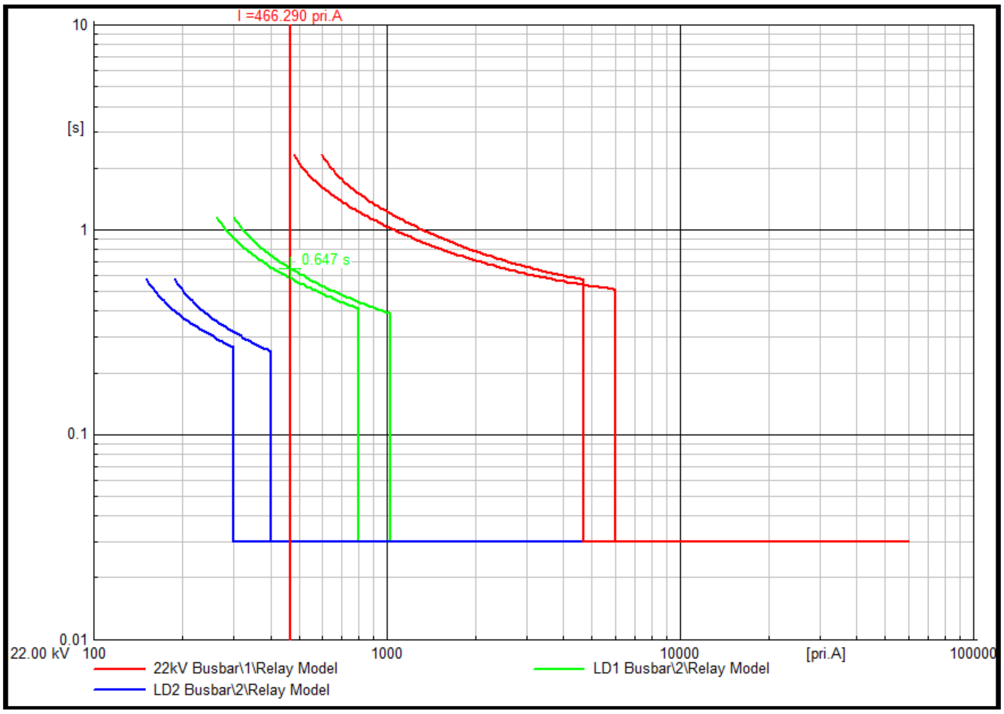

Figure 5.95: Plot of three phase short circuit on LD1-LD2 Line without DG

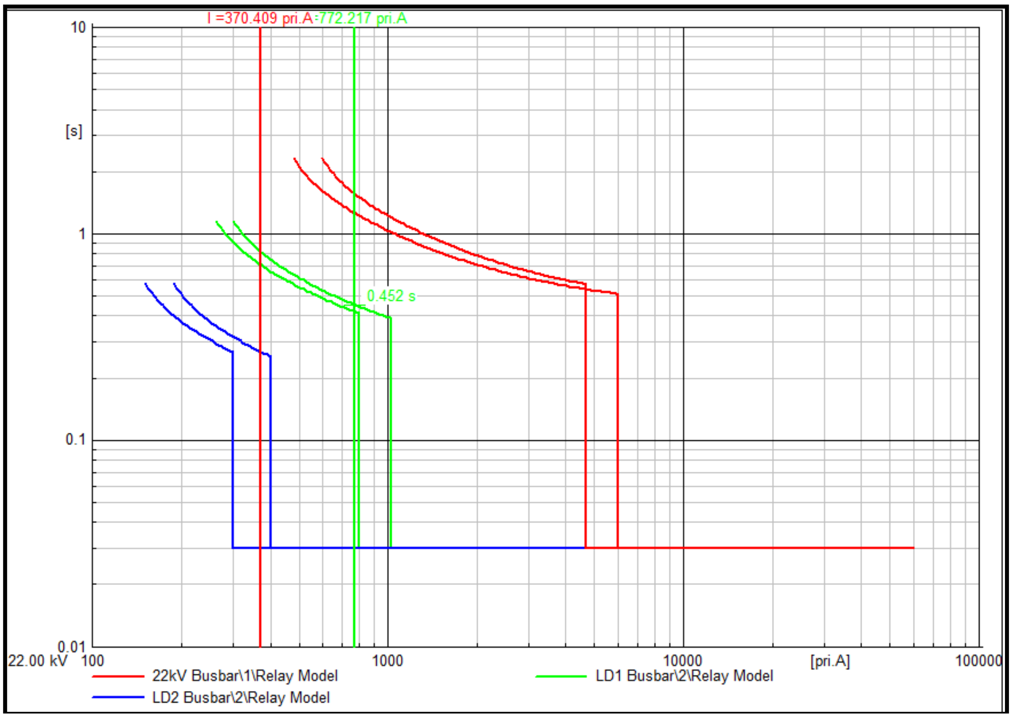

Figure 5.96: Plot of three phase short circuit on LD1-LD2 Line with 4MW DG connected

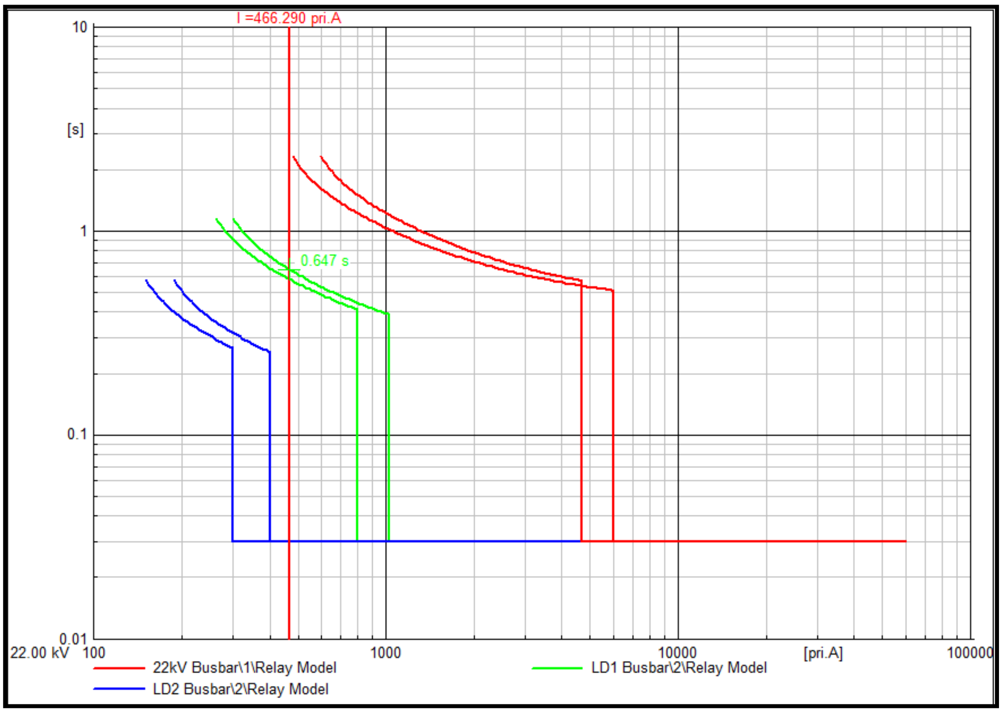

Figure 5.97: Plot of three phase short circuit on LD1-LD2 Line with 2MW DG connected

LD1 Busbar

The third relay, R_3, in the absence of a DG clears a three phase fault that occurs on this busbar in 1.839s. This fault clearing time is unchanged with the connection of the 4MW DG. However, the same fault in the presence of the 2MW DG leads to islanding of the DG with

LD2 in 0.624s by R_2 and the fault eventually cleared by R_3 in 1.839s. These are as contained in Figures 5.98 - 5.100. Therefore, the connection of the 2MW DG compromises the protection coordination during a three phase fault at this location.

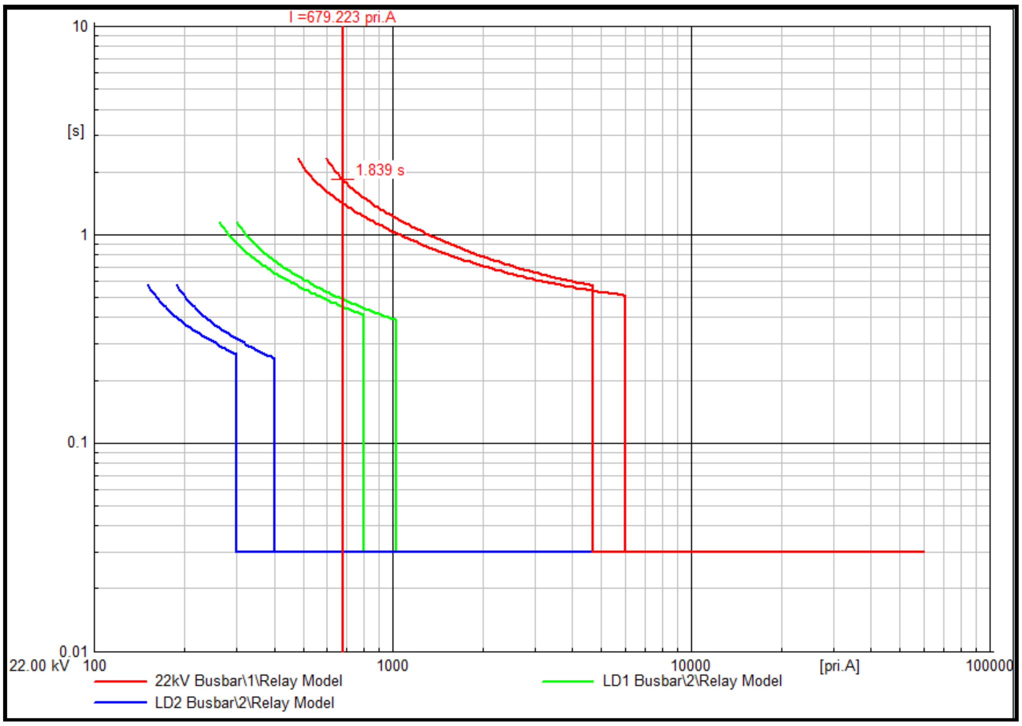

Figure 5.98: Plot of three phase short circuit on LD1 Busbar without DG

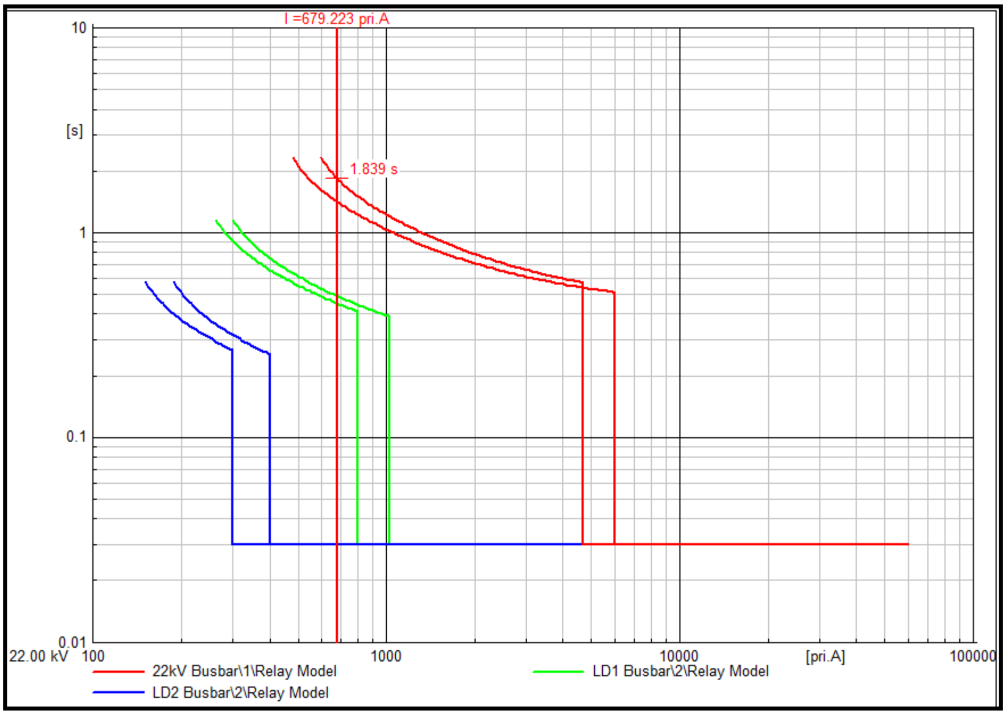

Figure 5.99: Plot of three phase short circuit on LD1 Busbar with 4MW DG connected

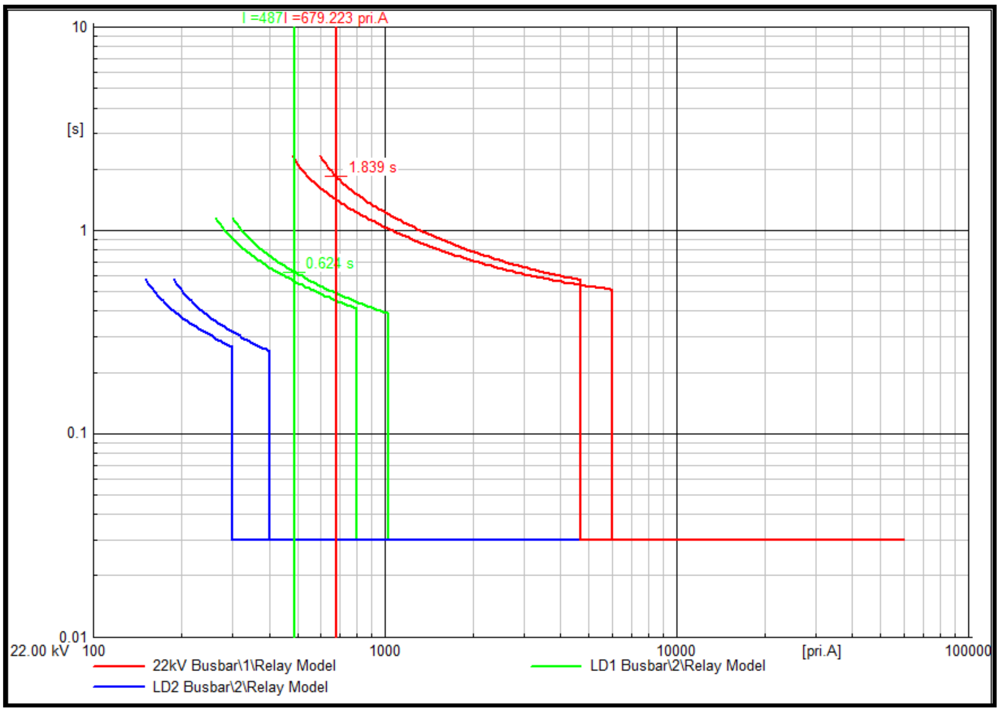

Figure 5.100: Plot of three phase short circuit on LD1 Busbar with 2MW DG connected

LD1 Line

A three phase fault occurring at the middle of this line is cleared by R_3 in 1.040s in the base case. The fault clearing time is also 1.040s when the 4MW DG is connected. But the occurrence of this fault when the 2MW DG is connected causes R_2 to isolate the DG and LD2 – a case of islanding – in 0.806s and thereafter, R_3 clears the fault in 1.040s (see Figures 5.101 - 5.103). Therefore, the protection coordination is violated when the 2MW DG is connected and a three phase fault occurs midway of LD1 Line.

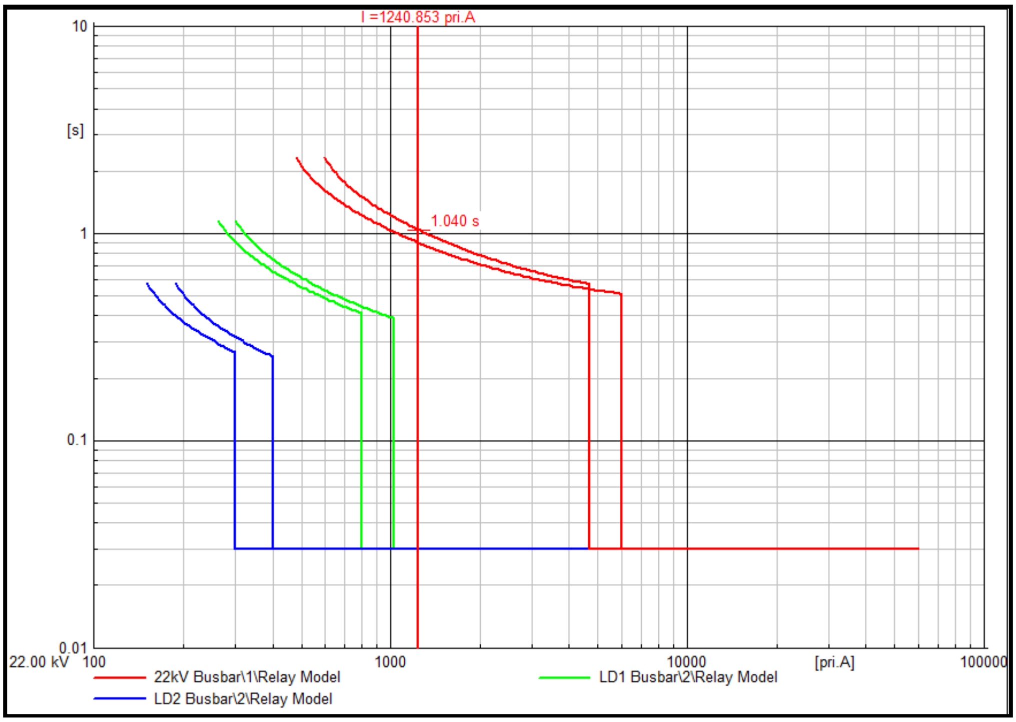

Figure 5.101: Plot of three phase short circuit on LD1 Line without DG

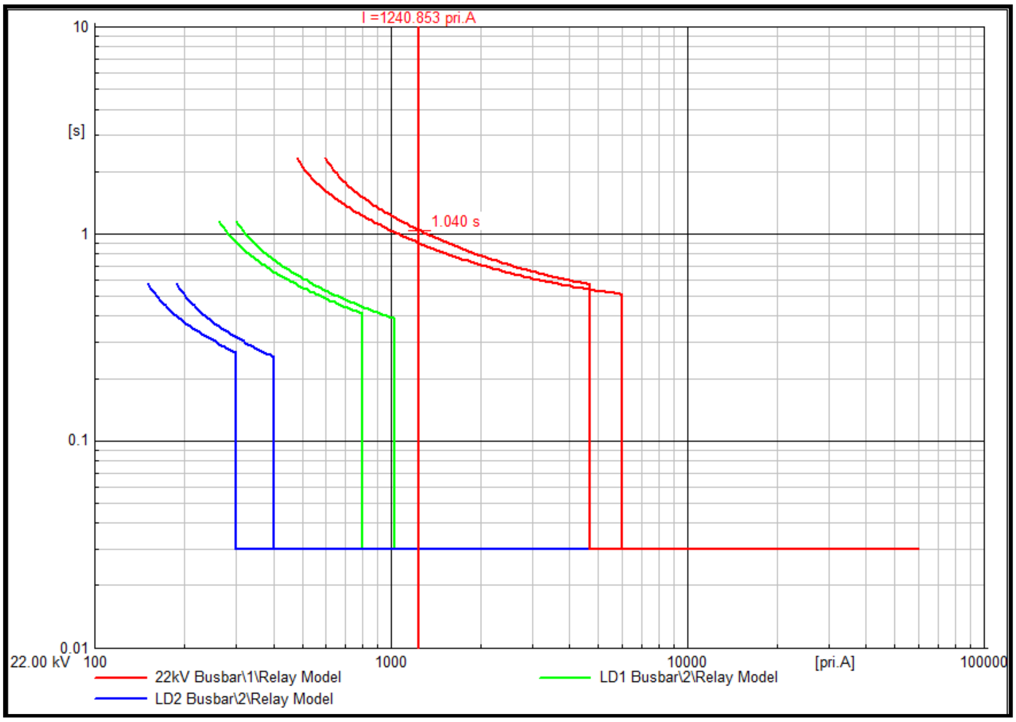

Figure 5.102: Plot of three phase short circuit on LD1 Line with 4MW DG connected

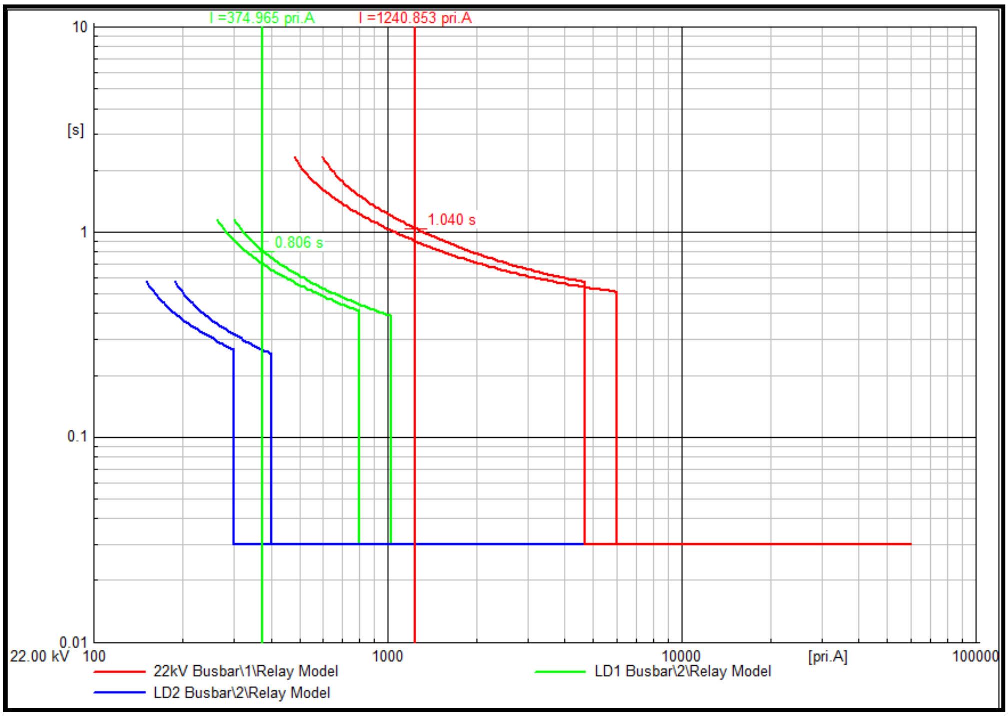

Figure 5.103: Plot of three phase short circuit on LD1 Line with 2MW DG connected

<u>22kV Busbar</u>

Figure 5.104 shows that the instantaneous element of R_3 clears a three phase fault on the 22kV Busbar in 0.030s when no DG is connected. The connection of the 4MW DG does not change this fault clearing time for the same fault as can be seen in Figure 5.105. However, when the 2MW DG is connected and a three phase fault exists at this location R_2 causes the DG to island with LD2 in 1.134s after R_3 has isolated the feeder in 0.030s. This is shown in Figure 5.106.

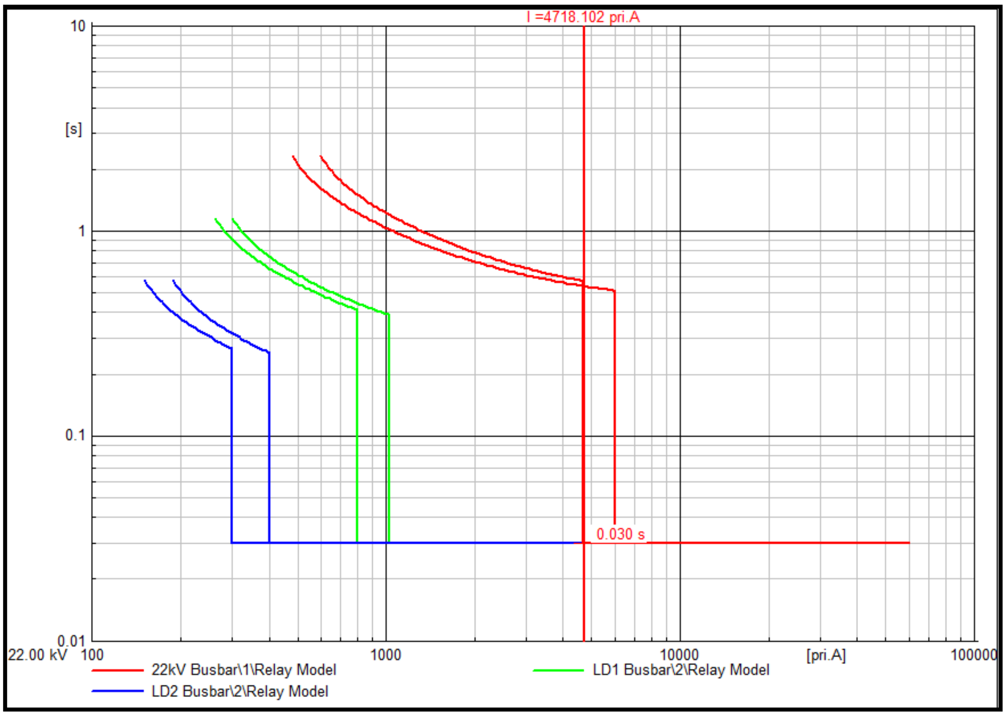

Figure 5.104: Plot of three phase short circuit on 22kV Busbar without DG

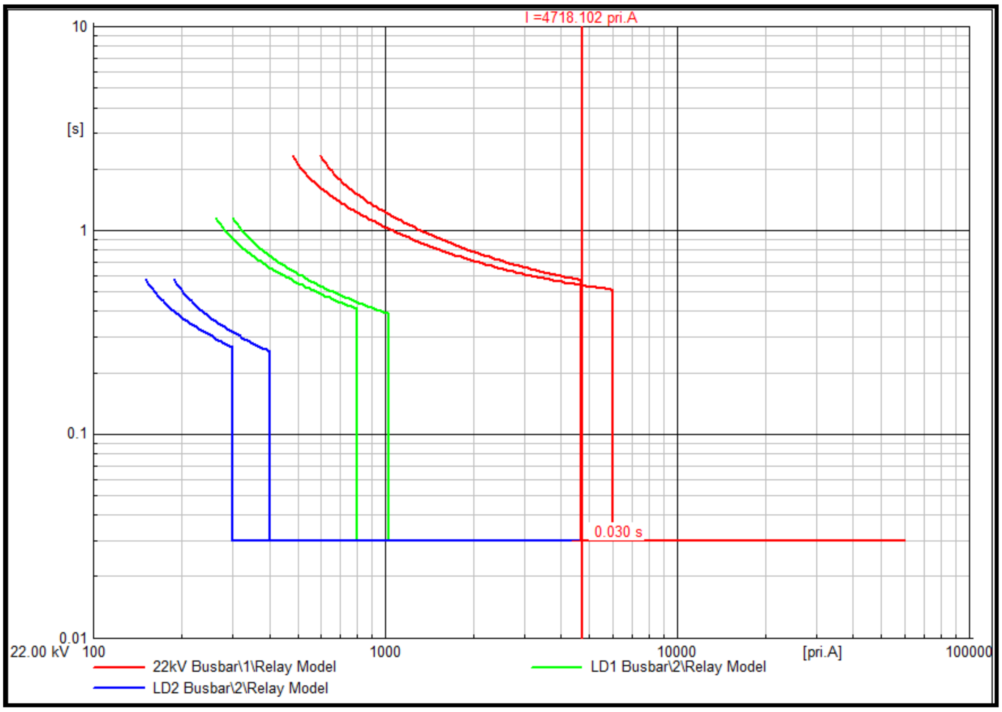

Figure 5.105: Plot of three phase short circuit on 22kV Busbar with 4MW DG connected

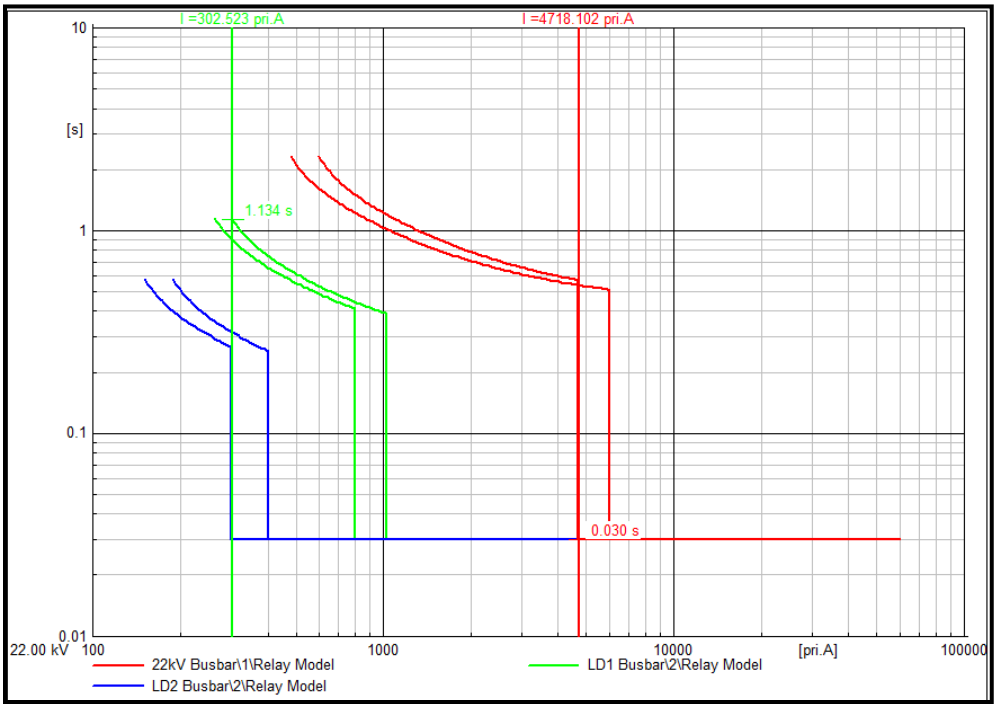

Figure 5.106: Plot of three phase short circuit on 22kV Busbar with 2MW DG connected

The protection coordination investigation on the developed model has highlighted some of the protection challenges of DG integration into the distribution network. These issues include nuisance tripping, relay desensitisation or blinding, and islanding. One of the solutions to nuisance tripping is the use of directional relays for the purpose of making the difference between the short-circuit current injected from a DG or from the main source of the feeder. Lowering of the reach of the relay being blinded is the quickest solution to relay desensitisation although could result to nuisance tripping. Unintentional islanding is undesirable and the DG should be disconnected as guided by established rules. Communication, a core component of smart grid, can effectively be deployed in disconnecting the DG through Intertripping (Direct Transfer Trip) during a fault.

Furthermore, the results show that DG location and capacity – and by extension number of DGs connected in the system – could impact negatively on relay coordination. However, smart grid concept incorporating intelligent devices such as microprocessor based multi-function relays possesses solutions to the above issues. This is because adjustment of relay settings would be easily implemented.

5.6 Conclusion

Some of the impacts of DG integration into the distribution network have been investigated based on the developed model. The investigations involving a directly connected synchronous DG have shown that for a particular DG type the impact on voltage profile depends on DG capacity and POC relative to the load. Therefore, proper sizing and location of DG ensure improvement in voltage profile. However, this improvement could lead to growth in load capacity which should be controlled to avoid the extreme case of voltage collapse. Voltage collapse as a steady state voltage stability problem negates the DG voltage profile improvement. Impacts of DG on system fault level and the attendant protection issues have also been investigated. The results show that DG connection could lead to protection miscoordination in a radial distribution network. Nuisance tripping, relay blinding and islanding are some of the protection issues resulting from DG integration into the distribution network. However, smart grid has the capability of handling most of the challenges posed by DG integration. This is because smart grid ensures that the distribution system becomes intelligent enough to identify such problems in real-time and take appropriate actions.

CHAPTER 6
CONCLUSION AND RECOMMENDATIONS

This work commenced with a highlight of the precarious state of South Africa's electricity supply and her high CO_2 emission status. Besides her political will – evinced by various policies – and international affiliations to challenge the status quo, it is believed that distributed generation is a worthy option. Indeed, this recourse to DG is a return to the beginning of electricity generation which started on very small scale. Succintly put, DG is a fairly new concept in the economics literature about electricity markets, but the idea behind it is not new at all. However, the relevant embedded generation – as it is known officially in South Africa – technologies that could assist South Africa combat her CO_2 challenge and readily be deployed especially in the Western Cape are sun and wind based such as PV, CSP and wind turbine. DG like every other technology has its merits and demerits which should receive proper considerations. These impacts, especially the technical ones, have been accorded due attention in Section 3.3.2. But worthy of note is the economic impact because South Africa has a vertically operated electricity establishment. Enough evidence abounds in the literature of the economic success of DG deployments in liberalised electricity markets. Therefore, deregulation of her electricity market will be another vital political move to improve on her electricity supply and CO_2 emission reduction.

Unfortunately and currently too, the electric grid consists of the generation, transmission and distribution which is the hierarchical order of current flow thereby making an end user a perpetual consumer. However, a paradigm shift is in the offing whereby a consumer becomes a customer because DG has an inbuilt concept of "prosumer" – producer-consumer. The decentralised nature and capacity of DG entails the need for proper and accurate information gathering and dissemination towards the realisation of this "prosumer" concept. This is because each DG can form a small grid, microgrid, but too small capacity-wise in a liberalised electricity market. Therefore, to be relevant in the electricity market DGs need to be aggregated to form virtual power plants. Consequently, another concept with a potential solution is "smart" grid. In other words, DG integration requires a smart grid to be feasible. While there is no agreement on who receives the credit for its neologism and exact date, smart grid has diverse definitions and conceptual approaches. Perhaps, this explains its different developmental perspectives in various climes. However, there appears a consensus on its functions and functionalities including the outstanding role of communications. One of them is the change in the meaning of an electric grid which now extends to the distribution level with the attendant bidirectional current flow. South Africa as a leader in the continent is championing this concept and should learn from other countries where smart grid has been successfully deployed. Key aspects of these lessons include financing, consumer engagement and restructuring of the electrical engineering curricula because of emerging concepts. Furthermore, South Africa’s proposed smart grid vision should receive urgent attention to properly guide smart grid deployment in the country.

As contained in Section 3.3.2 numerous obstacles exist for DG integration. Notably, smart grid has the ability to interconnect very large numbers of renewable energy resources and storage devices to complement the large generating plants and satisfy “plug-and-play” convenience. Therefore, smart grid technology can address some of the problems of integrating DGs at the distribution level through its inherent capability which includes peer-to-peer relay communication for protective devices on the distribution feeder as well as communication to the DG facility. For instance, selective trip transfer of the DG can be much more easily done at a lower cost since the communication channel will be justified for other smart grid requirements such as load control. Moreover, adaptive protection can be accomplished by automatically changing relay settings when the DG is not running or is switched to another feeder to optimise protection. It should be noted that these enhancements will improve relay coordination but will not address the overvoltage issues such as the ferroresonances. However, smart grid will handle such issues through its highly intelligent devices and communication. Generally, therefore, smart grid solves the possible problems that can affect the optimum behaviour of the system by operating the continuous information of the state of the different installations.

There are immense benefits derivable from modelling and simulation. Various power system programs exist but DIgSILENT PowerFactory 4.1.3 has been used to investigate the applicability of these programs in the study of DG integration. The design of a smart grid for studying how to provide rated voltage to loads of the system requires the steady-state model of power systems using the balanced system model. Therefore, the different equations or models relevant for DG integration impact studies have been evaluated. Standard inbuilt DIgSILENT PowerFactory electric power system models have been utilised in investigating some of the steady-state phenomena encountered in DG integration. The DG deployed for the study is a synchronous generator which can be used in thermal, hydro, or wind power plants. Some of the impacts of DG integration into the distribution network have been investigated based on the developed model. The investigations involving a directly connected synchronous DG have shown that for a particular DG type the impact on voltage profile depends mainly on DG capacity and POC relative to the load. A method to show how proper sizing and location of DG would ensure improvement in the voltage profile has been developed. The model allowed the study of load capacity growth with distributed generation which should be controlled to avoid the extreme case of voltage collapse. Voltage collapse as a steady state voltage stability problem negates the DG voltage profile improvement. Impacts of DG on system fault level and the attendant protection issues have also been investigated and the results analysed. The results show that DG connection could lead to protection miscoordination in a radial distribution network. This information would be of relevance to the current City of Cape Town's renewable energy integration and microgrid outlay plans of 2014. Nuisance tripping, relay blinding and islanding are some of the protection issues resulting from DG integration into the distribution network, and according to City engineers, modelling and simulation methods would assist in their efforts. The generation system which the city envisioned is limited to 3.26kW peak for a household with a single phase supply and 1MW for farming and industrial client. This is sufficient for the thesis model to handle. The model has been found to be useful to smart grid applications and has the capability of handling most of the challenges posed by DG integration. This is because smart grid ensures that the distribution system becomes intelligent enough to identify such problems in real-time and take appropriate actions.

Some aspects of getting more extensive distribution circuits from the Eskom supplier proved difficult. This was because they were considered as classified information for security reasons. The limited circuit model that was accessed with parameters from appropriate sources produced acceptable results.

Recommendation: The current thesis used a radial distribution circuit for the model development, but future work could include improvements to fit it for ring distribution networks including the single phase connections as outlined in the city's new 2020 plan.

The following are the publications from this research:

1. **Onwunta, O. E. K** and Kahn, M. T. E., 2013. Back to the beginning through smart grid. Energize (The independent power and energy journal of Southern Africa), December 2013, pp 31 – 35. Available online http://www.ee.co.za/wp-content/uploads/legacy/Energize_2013/07_TT_02_back-to.pdf
2. **Onwunta, O. E. K** and Kahn, M. T. E., 2013. Different perspectives on smart grid and lessons for South Africa. Proceedings of the Joint International Conference on Engineering Education and Research & International Conference on Information Technology (ICEE/ICIT-2013 Cape Town), 9 – 11th December, pp 100 – 110
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APPENDICES

A. Conductor Properties

Conductor properties for overhead lines up to 33kV (Eskom, 2011)

Conductor	Stranding	Copper	Mechanical properties					Coeff.	Electrical properties	
Code Name	and wire dia.	Equiv. Area	Overall Dia.	Total Area	Mass	Breaking Load	Final Modulus	of linear expansion	DC res. @ 20°C	Rating @ 75°C
	mm	mm^2	mm	mm^2	kg/km	kg	GPa	10^{-6} / °C	Ohm/km	A
Table A1 - ACSR (Aluminium Conductor Steel Reinforced) - Extra Strong										
Magpie	3/4/2,118	6,65	6,35	24,71	139,7	1893	133,76	13,68	2,707	78
Table A2 - ACSR (Aluminium Conductor Steel Reinforced										
Squirrel	6/1/2,11	12,9	6,33	24,48	85,2	818	80,4	19,31	1,3677	110
Fox	6/1/2,79	22,58	8,37	42,8	149	1340	80,4	19,31	0,7822	155
Mink	6/1/3,66	38,71	10,98	73,65	257	2230	80,4	19,31	0,4546	215
Hare	6/1/4,72	64,52	14,16	122,48	427	3670	80,4	19,31	0,2733	290
Table A3 - AAAC (Aluminium Conductor Aluminium Alloy reinforced)										
Acacia	7/2,08	13	6,24	23,79	65	682	61	23	1,39	110
35	7/2,77	22	8,31	42,18	115	1210	61	23	0,785	155
Pine	7/3,61	38	10,83	71,65	196	2060	61	23	0,462	215
Oak	7/4,65	63	13,95	118,9	325	3400	61	23	0,279	290
Table A4 - Galvanized Steel Wire										
3/3,35	3/3,35	–	7,35	26,44	215	2910	191	11,52	7,4	41
1/3.66	1/3.66	-	3.66	10.52	83	1431	196	11,52		

B. Generator Parameters

Field	Value
Nominal Apparent Power	5MVA
Nominal Voltage	22kV
Power Factor	1
Connection	YN
Synchronous reactance direct axis (saturated) Xd	0.6 p.u
Synchronous reactance quadrature axis (saturated) Xq	0.6 p.u
Reactive Power limits Minimum value	-0.6 p.u
Reactive Power limits Maximum value	0.75 pu
Zero sequence Resistance r0	0
Zero sequence reactance X0	0.03 p.u
Negative sequence Resistance R2	0
Negative sequence Reactance X2	0.14 p.u
Sub-transient reactance Xd’’	0.15 p.u
Stator resistance	0.002 p.u
Transient Reactance Xd’	0.2 p.u