Impact of distributed generation on distribution system

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A Dissertation Submitted to

the Faculty of Engineering, Science and Medicine, Aalborg University

in Partial Fulfilment for the Degree of

Master Graduate

June 2011

Aalborg, Denmark

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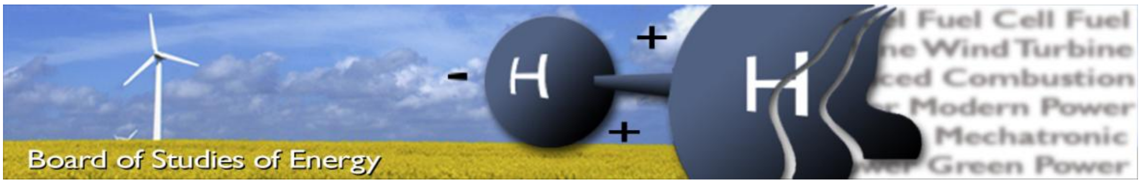
Printed in Denmark by Aalborg University



Title: **Impact of Distributed Generation on Distribution System**

Semester: **10th**

Semester theme: **EPSH 4**

Project period: **Spring - 2011**

ECTS: **30**

Supervisor: **Pukar Mahat**

Project group: **1001**

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Copies: 2

Pages, total: 107

Appendix: 1

SYNOPSIS: As the yearly electric energy demand grows, there is a significant increase in the penetration of distributed generation (DG) to fulfil this increase in demand. Integration of a DG into an existing distribution system has many impacts on the system, with the power system protection being one of the major issues. Short circuit power of a distribution system changes when its state changes. Short circuit power also changes when some of the generators in the distribution system are disconnected. This may result in elongation of fault clearing time and hence disconnection of equipments in the distribution system or unnecessary operation of protective devices. In this thesis, the effect of DG penetration on the short circuit level has been analyzed in a distribution system with wind turbine and gas turbine generators. Different cases have been studied. Location and technology of the DG sources are changed to study the effect that these changes may have on the coordination of protective directional over-current relays.

By signing this document, each member of the group confirms that all participated in the project work and thereby that all members are collectively liable for the content of the report.

To my family and friends

Acknowledgement

I would like to express my deep gratitude and appreciation to my supervisor Assistant Professor Pukar Mahat for his suggestions, patience and encouragement throughout the period of this work. His support, understanding and expertise have been very important in completing this research.

I want to take this opportunity to thank my parents and family for their love, constant support and their precious advice through my life.

Abstract

As the yearly electric energy demand grows, there is a significant increase in the penetration of distributed generation (DG) to fulfil this increase in demand. Interconnecting DG to an existing distribution system provides various benefits to several entities as for example the owner, utility and the final user. DG provides an enhanced power quality, higher reliability of the distribution system and can peak shaves and fill valleys. However, the integration of DG into existing networks has associated several technical, economical and regulatory questions. Penetration of a DG into an existing distribution system has many impacts on the system, with the power system protection being one of the major issues. DG causes the system to lose its radial power flow, besides the increased fault level of the system caused by the interconnection of the DG. Short circuit power of a distribution system changes when its state changes. Short circuit power also changes when some of the generators in the distribution system are disconnected. This may result in elongation of fault clearing time and hence disconnection of equipments in the distribution system or unnecessary operation of protective devices. Therefore, new protection schemes for both DG and utility distribution networks have been developed in the recent years but the issue has not been properly addressed. In this thesis, the effect of DG penetration on the short circuit level has been analyzed in a distribution system with wind turbine and gas turbine generators. Different cases have been studied. Location and technology of the DG sources are changed to study the effect that these changes may have on the coordination of protective directional over-current relays (DOCR). Results are compared to that of the normal case to investigate the impact of the DG on the short circuit currents flowing through different branches of the network to deduce the effect on protective devices and some conclusions are documented.

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Chapter 1

Introduction

1.1 Traditional Concept of Power Systems

Currently, most of the power systems generate and supplies electricity having into account the following considerations [1],[2]:

- Electricity generation is produced in large power plants, usually located close to the primary energy source (for instance: coil mines) and far away from the consumer centres.
- Electricity is delivered to the customers using a large passive distribution infrastructure, which involves high voltage (HV), medium voltage (MV) and low voltage (LV) networks.
- These distribution networks are designed to operate radially. The power flows only in one direction: from upper voltage levels down-to customers situated along the radial feeders.
- In this process, there are three stages to be passed through before the power reaching the final user, i.e. generation, transmission and distribution.

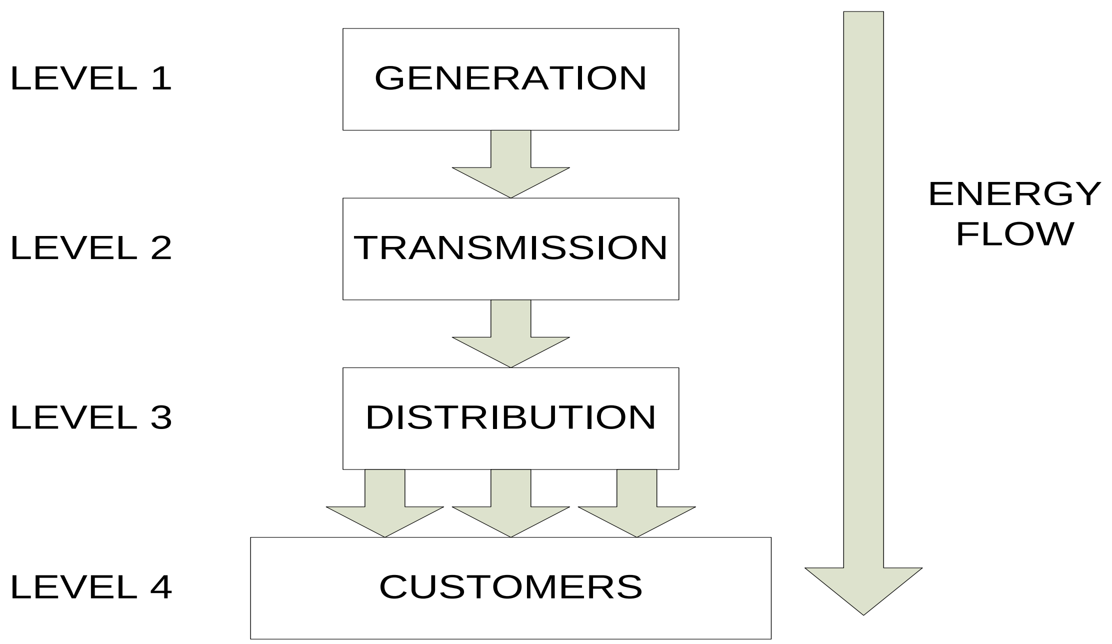

Fig. 1.1 Traditional industrial conception of the electrical energy supply

In the first stage the electricity is generated in large generation plants, located in non-populated areas away from loads to get round with the economics of size and environmental issues. Second stage is accomplished with the support of various equipments such transformers, overhead transmission lines and underground cables. The last stage is the distribution, the link between the utility system and the end customers. This stage is the most important part of the power system, as the final power quality depends on its reliability [2].

The electricity demand is increasing continuously. Consequently, electricity generation must increase in order to meet the demand requirements. Traditional power systems face this growth, installing new support systems in level 1 (see figure 1.1). Whilst, addition in the transmission and distribution levels are less frequent.

1.2 New Concept of Power Systems

Nowadays, the technological evolution, environmental policies, and also the expansion of the finance and electrical markets, are promoting new conditions in the sector of the electricity generation [2].

New technologies allow the electricity to be generated in small sized plants. Moreover, the increasing use of renewable sources in order to reduce the environmental impact of power generation leads to the development and application of new electrical energy supply schemes.

In this new conception, the generation is not exclusive to level 1. Hence some of the energy-demand is supplied by the centralized generation and another part is produced by *distributed generation*. The electricity is going to be produced closer to the customers.

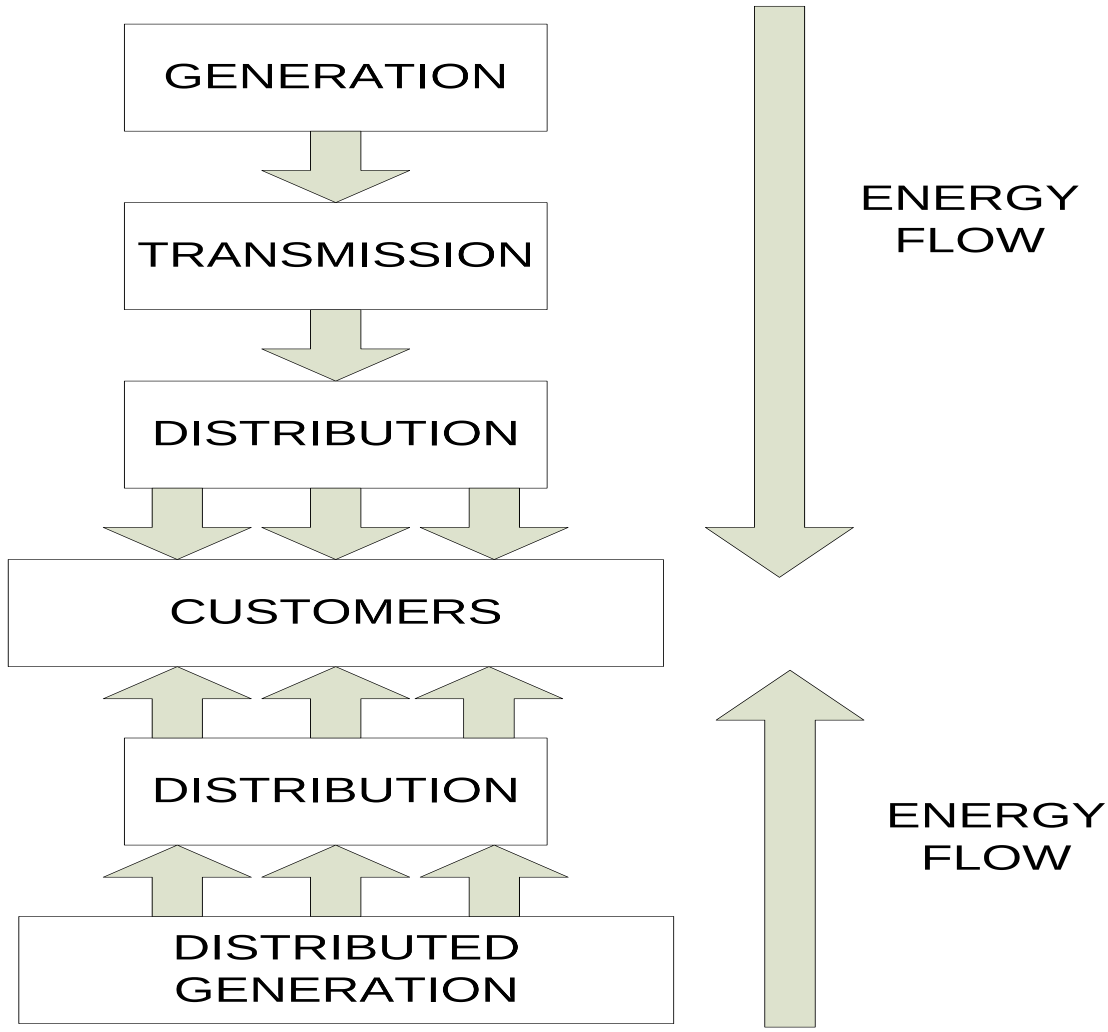

Fig. 1.2 New industrial conception of the electrical energy supply

1.3 Distributed Generation

Large scale integration of distributed generators at either LV or MV is at the present the trend followed in power systems to cover the supply of some loads. These generators are of considerable smaller size than the traditional generators (thermal, nuclear, etc…) [3].

An overview of some common benefits and drawbacks of the DG are presented below:

1) *Benefits* [4]

- Connection of DG is intended to increase the reliability of power supply provided to the customers, using local sources, and if possible, reduce the losses of the transmission and distribution systems.

- The connection of DG to the power system could improve the voltage profile, power quality and support voltage stability. Therefore, the system can withstand higher loading situations.

- The installation of DG takes less time and payback period. Many countries are subsidizing the development of renewable energy projects through a portfolio obligation and green power certificates. This incentives investment in small generation plants.

- Some DG technologies have low pollution and good overall efficiencies like combined heat and power (CHP) and micro-turbines. Besides, renewable energy based DG like photovoltaic and wind turbines contribute to the reduction of greenhouse gases.

2) *Drawbacks* [4]

- Many DG are connected to the grid via power converters, which injects harmonics into the system.

- The connection of DG might cause over-voltage, fluctuation and unbalance of the system voltage if coordination with the utility supply is not properly achieved.

- Depending on the network configuration, the penetration level and the nature of the DG technology, the power injection of DG may increase the power losses in the distribution system.

- Short circuit levels are changed when a DG is connected to the network. Therefore, relay settings should be changed and if there is a disconnection of DG, relay should be changed back to its previous state.

1.4 Problem Statement

Nowadays, the power electricity demand is growing fast and one of the main tasks for power engineers is to generate electricity from renewable energy sources to overcome this increase in the energy consumption and at the same time reduce environmental impact of power generation. The use of renewable sources of energy has reached greater importance as it promotes sustainable living and with some exceptions (biomass combustion) does not contaminant. Renewable sources can be used in either small-scale applications away from the large sized generation plants or in large-scale applications in locations where the resource is abundant and large conversion systems are used [5].

Nevertheless, problems arise when the new generation is integrated with the power distribution network, as the traditional distribution systems have been designed to operate radially, without considering the integration of the this new generation in the future. In radial systems, the power flows from upper terminal voltage levels down to customers situated along the radial feeders [4].Therefore, over-current protection in radial systems is quite straightforward as the fault current can only flow in one direction. With the increase of penetration of DG, distribution networks are becoming similar to transmission networks where generation and load nodes are mixed (“mesh” system) and more complex protection design is needed. In this new configuration, design considerations regarding the number, size location and technology of the DG connected must be taken into account as the short circuit levels are affected and miss coordination problems with protection devices may arise [7], [8].

This research addresses some of the issues encountered when designing the over-current protection coordination between protection devices, in case that a number of DG sources are connected to a radial system.

1.5 Thesis Objectives

- The main objective of this thesis is to investigate the impact that different configurations and penetration levels of DG may have on the protection of distribution systems.
- The second objective is to develop possible solutions for issues with protection in presence of a significant number of DG.

1.6 Scope and Limitations

The scope and limitations of this research are as follows:

- Only the major technical issues with over-current protection coordination of a distribution system are covered.

- The DG technologies have been limited to gas turbine generators (GTG), which are based on synchronous generators and fixed speed wind turbines (WTG), which are based on induction generators.

- In case of combined heat and power plants, which consists of gas turbines, heat generation is not considered. The electricity is considered as the main output of the plant.

- Models have been developed in DIgSILENT/Power Factory and many of the standard models available in DIgSILENT have been used.

1.7 Outline of the Thesis

This thesis contains 5 chapters and one appendix. It is organized as follows:

Chapter 1: Introduction

This chapter gives a brief introduction to the concept of distributed generation reflecting the importance of DG systems to both the utility network and customers, besides the drawbacks occurring if DG is connected to the distribution systems.

Chapter 2: Literature Review

This chapter is divided into six sections: the first section is a brief introduction and a definition of DG, followed by the second section which discusses the various types of distributed generation technologies and their nature. The impacts of DG on power system grids are discussed in the third section. Section four high lights one of the most important issues to maintain a safe operation of the DG, the protection coordination. Section five is an overview of one of the major problems, islanding, that miss-protection can lead to and causes difficulties in system restoration. Finally the last section discusses the impact of DG penetration on the distribution feeder protection and the miss-protection problems arising from the interconnection of DGs.

Chapter 3: Over-current Protection of Distributed Systems

This chapter is divided in four sections: the first section gives a brief introduction to over-current protection technique and some examples of protection devices used in distribution systems. The second section describes the types of over-current relays and some of their main features. Section three explains the model of the over-current relay created in DIgSILENT used throughout this thesis. Finally, in section four a practical application example using a small test distribution system and the proposed relay model is given. Some simulations are carried out using the test system and the main problems encountered in protection coordination of relays, both with and without distributed generation installed in the system are shown.

Chapter 4: Modelling and Simulation results

In this chapter, simulations results with different DG configurations are presented. The chapter is divided into five sections: the first section describes the modelling of the distribution system. In the second section, design of the over-current relay protection is explained, illustrating two main cases: firstly in Case 1, the test system is analyzed without the presence of DG, it is the base case that results are compared to. Then, in Case 2, the test network topology is modified introducing DG at different locations, as well as, changing the DG technology, showing the effect on the level of short circuit currents. In the section three, it is described the modelling of the modified distribution system. Section four, describes the design of the over-current relays protection for this modified system, several case are analyzed for different levels of penetration of DG. A small discussion on the results is made at the end of each case and some conclusions are drawn. The last section presents, some solutions that may be implemented to overcome the issues found with over-current protection of distributed system.

Chapter 5: Conclusion

Some conclusions are presented in this chapter. The chapter ends naming some of the works that can be done in the future with reference to the work presented in this research.

Appendix

It presents data for test systems, generators, excitation system and speed governor.

Chapter 2

Literature Review

2.1 Introduction

Distributed Generation (DG) is one of the new trends in power systems used to support the increased energy-demand. There is not a common accepted definition of DG as the concept involves many technologies and applications. Different countries use different notations like “embedded generation”, “dispersed generation” or “decentralized generation”.

Furthermore, there are variations in the definition proposed by different organizations (IEEE, CIGRE…) that may cause confusion. Therefore in this thesis, the following definition is used [8]:

Distributed generation is considered as an electrical source connected to the power system, in a point very close to/or at consumer´s site, which is small enough compared with the centralized power plants.

To clarify about the DG concept, some categories that define the size of the generation unit are presented in Table 2.1.

Table 2.1

Size of the DG [10]

Type	Size
Micro distributed generation	1Watt < 5kW
Small distributed generation	5kW < 5 MW
Medium distributed generation	5 MW < 50MW
Large distributed generation	50MW < 300MW

The different DG technologies and impacts of distributed generation are introduced in this chapter; besides, islanded operation and the impact of DG on distribution feeder protection are presented.

2.2 Types of Distributed Generation

DG can be classified into two major groups, inverter based DG and rotating machine DG. Normally, inverters are used in DG systems after the generation process, as the generated voltage may be in DC or AC form, but it is required to be changed to the nominal voltage and frequency. Therefore, it has to be converted first to DC and then back to AC with the nominal parameters through the rectifier [10].

In this chapter, some of the DG technologies, which are available at the present: photovoltaic systems, wind turbines, fuel cells, micro turbines, synchronous and induction generators are introduced.

2.2.1 Photovoltaic Systems

A photovoltaic system, converts the light received from the sun into electric energy. In this system, semiconductive materials are used in the construction of solar cells, which transform the self contained energy of photons into electricity, when they are exposed to sun light. The cells are placed in an array that is either fixed or moving to keep tracking the sun in order to generate the maximum power [9].

These systems are environmental friendly without any kind of emission, easy to use, with simple designs and it does not require any other fuel than solar light. On the other hand, they need large spaces and the initial cost is high.

In Fig. 2.1, a photovoltaic panel is shown.

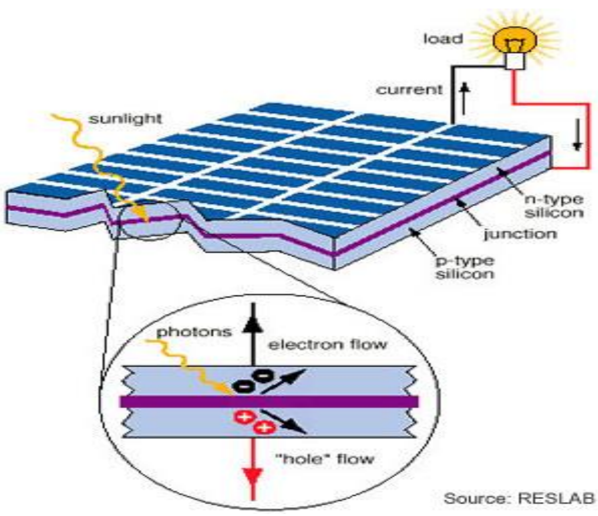

Fig. 2.1 Schematic diagram of a photovoltaic system [11]

PV systems generate DC voltage then transferred to AC with the aid of inverters. There are two general designs that are typically used: with and without battery storages.

2.2.2 Wind Turbines

Wind turbines transform wind energy into electricity. The wind is a highly variable source, which cannot be stored, thus, it must be handled according to this characteristic. A general scheme of a wind turbine is shown in Fig. 2.2, where its main components are presented [9].

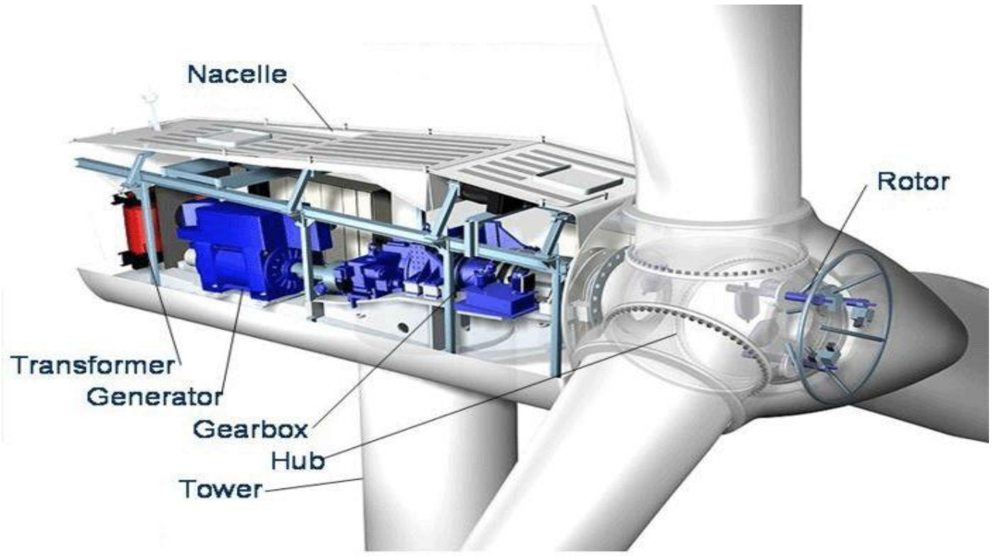

Fig. 2.2 Schematic operation diagram of a wind turbine [12]

The principle of operation of a wind turbine is characterized by two conversion steps. First the rotor extract the kinetic energy of the wind, changing it into mechanical torque in the shaft; and in the second step the generation system converts this torque into electricity.

In the most common system, the generator system gives an AC output voltage that is dependent on the wind speed. As wind speed is variable, the voltage generated has to be transferred to DC and back again to AC with the aid of inverters. However, fixed speed wind turbines are directly connected to grid [9].

2.2.3 Fuel Cells

Fuel cells operation is similar to a battery that is continuously charged with a fuel gas with high hydrogen content; this is the charge of the fuel cell together with air, which supplies the required oxygen for the chemical reaction [9].

The fuel cell utilizes the reaction of hydrogen and oxygen with the aid of an ion conducting electrolyte to produce an induced DC voltage. The DC voltage is converted into AC voltage using inverters and then is delivered to the grid.

In Fig. 2.3 the operation characteristics of a fuel cell are presented.

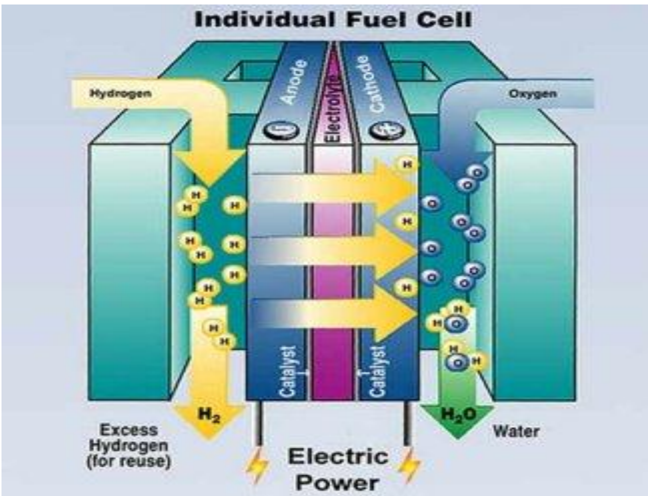

Fig. 2.3 Schematic diagram of a fuel cell [13]

A fuel cell also produces heat and water along with electricity but it has a high running cost, which is its major disadvantage. The main advantage of a fuel cell is that there are no moving parts, which increase the reliability of this technology and no noise is generated. Moreover, they can be operated with a width spectrum of fossil fuels with higher efficiency than any other generation device. On the other hand, it is necessary to assess the impact of the pollution emissions and ageing of the electrolyte characteristics, as well as its effect in the efficiency and life time of the cell [10].

2.2.4 Micro-Turbines

A micro-turbine is a mechanism that uses the flow of a gas, to covert thermal energy into mechanical energy. The combustible (usually gas) is mixed in the combustor chamber with air, which is pumped by the compressor. This product makes the turbine to rotate, which at the same time, impulses the generator and the compressor. In the most commonly used design the compressor and turbine are mounted above the same shaft as the electric generator. This is shown in Fig. 2.4.

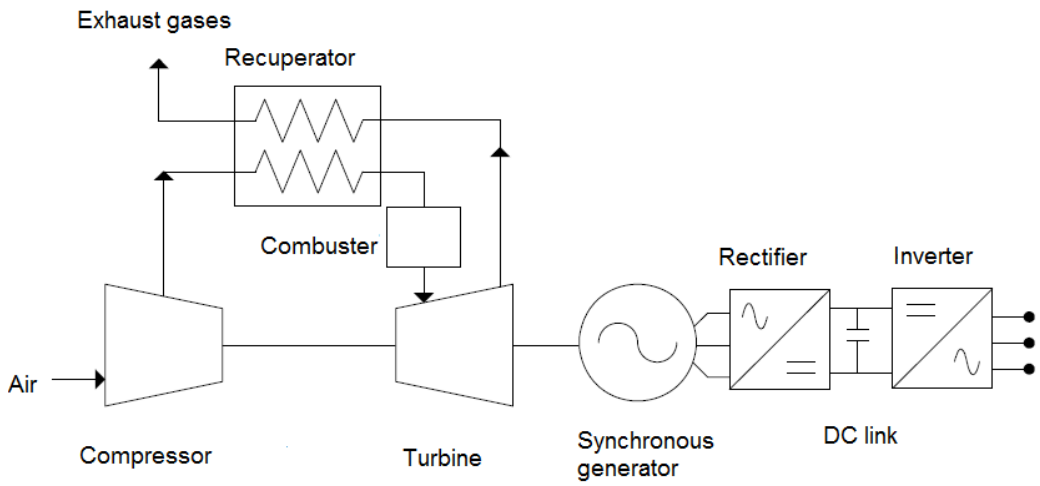

Fig 2.4 Schematic diagram of a micro-turbine [10]

The output voltage from micro-turbines cannot be connected directly to the power grid or utility, it has to be transferred to DC and then converted back to AC in order to have the nominal voltage and frequency of the utility.

The main advantage of micro-turbines is the clean operation with low emissions produced and good efficiency. On the other hand, its disadvantages are the high maintenance cost and the lack of experience in this field. Very little micro-turbines have been operated for enough time periods to establish a reliable field database. Furthermore, methods of control and dispatch for a large number of micro turbines and selling the remaining energy have not been developed yet [10].

2.2.5 Induction and Synchronous Generators

Induction and synchronous generators are electrical machines which convert mechanic energy into electric energy then dispatched to the network or loads.

Induction generators produce electrical power when their shaft is rotated faster than the synchronous frequency driven by a certain prime mover (turbine, engine). The flux direction in the rotor is changed as well as the direction of the active currents, allowing the machine to provide power to the load or network to which it is connected. The power factor of the induction generator is load dependent and with an electronic controller its speed can be allowed to vary with the speed of the wind. The cost and performance of such a system is generally more attractive than the alternative systems using a synchronous generator [14].

The induction generator needs reactive power to build up the magnetic field, taking it from the mains. Therefore, the operation of the asynchronous machine is normally not possible without the corresponding three-phase mains. In that case, reactive sources such as capacitor banks would be required, making the reactive power for the generator and the load accessible at the respective locations. Hence, induction generators cannot be easily used as a backup generation unit, for instance during islanded operation [14].

The synchronous generator operates at a specific synchronous speed and hence is a constant-speed generator. In contrast with the induction generator, whose operation involves a lagging power factor, the synchronous generator has variable power factor characteristic and therefore is suitable for power factor correction applications. A generator connected to a very large (infinite bus) electrical system will have little or no effect on its frequency and voltage, as well as, its rotor speed and terminal voltage will be governed by the grid.

Normally, a change in the field excitation will cause a change in the operating power factor, whilst a change in mechanical power input will change the corresponding electrical power output. Thus, when a synchronous generator operates on infinite busbars, over-excitation will cause the generator to provide power at lagging power factor and during under-excitation the generator will deliver power at leading power factor [15]. Thus, synchronous generator is a source or sink of reactive power. Nowadays, synchronous generators are also employed in distribution generator systems, in thermal, hydro, or wind power plants. Normally, they do not take part in the system frequency control as they are operated as constant power sources when they are connected in low voltage level. These generators can be of different ratings starting from kW range up to few MW ratings [16].

2.3 Impact of Distributed Generation on Power System Grids

The introduction of DG in systems originally radial and designed to operate without any generation on the distribution system, can significantly impact the power flow and voltage conditions at both, customers and utility equipment.

These impacts can be manifested as having positive or negative influence, depending on the DG features and distribution system operation characteristics [3].

The objective of this thesis, is to investigate the technical impact that the integration of DG have on the protection coordination of distributed power systems. A method to asses this impact, is based *on investigate the behaviour of an electric system, with and without the presence of DG*. The difference between the results obtained in these two operating conditions, gives important information for both, companies in the electric sector and customers.

In that sense, a general view of the main problems encountered in the integration of DG to the distributed network is presented.

2.3.1 Impact of DG on Voltage Regulation

Radial distribution systems regulate the voltage by the aid of load tap changing transformers (LTC) at substations, additionally by line regulators on distribution feeders and shunt capacitors on feeders or along the line. Voltage regulation is based on one way power flow where regulators are equipped with line drop compensation.

The connection of DG may result in changes in voltage profile along a feeder by changing the direction and magnitude of real and reactive power flows. Nevertheless, DG impact on voltage regulation can be positive or negative depending on distribution system and distributed generator characteristics as well as DG location [3].

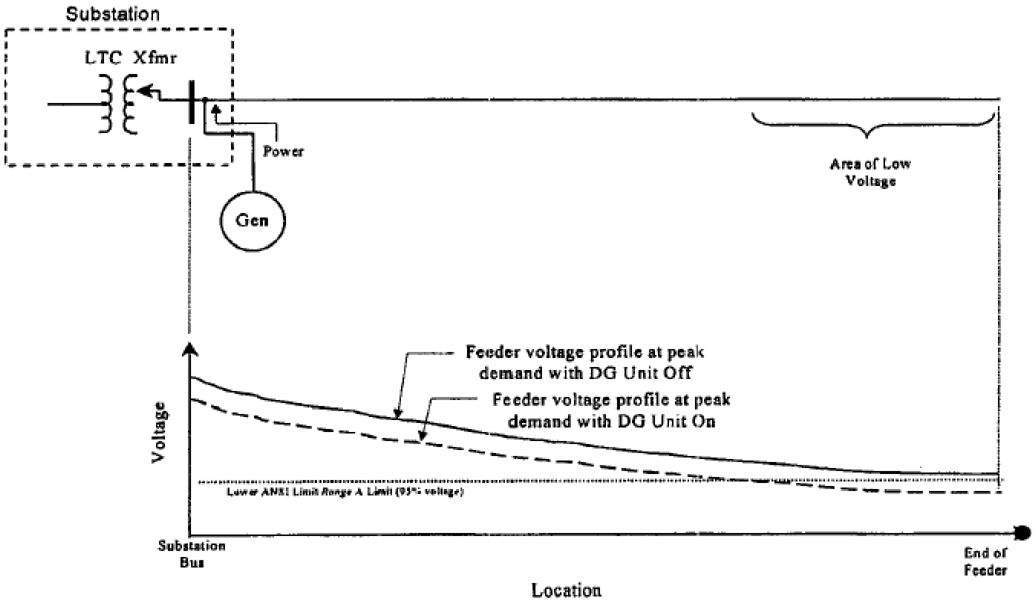

Fig. 2.5 Voltage profiles with and without DG [3]

In Fig. 2.5 the DG is installed downstream the LTC transformer which is equipped with a line drop compensator (LDC). It is shown that the voltage becomes lower on the feeder with DG than without the DG installed in the network. The voltage regulator will be deceived, setting a voltage lower than is required for sufficient service. The DG reduces the load observed from the load compensation control side, which makes the regulator to set less voltage at the end of the feeder. This phenomenon has the opposite effect to which is expected with the introduction of DG (voltage support) [3].

There are two possible solutions facing this problem: the first solution is to move the DG unit to the upstream side of the regulator, while the second solution is adding regulator controls to compensate for the DG output.

The installation of DG units along the power distribution feeders may cause overvoltage due to too much injection of active and reactive power. For instance, a small DG system sharing a common distribution transformer with several loads may raise the voltage on the secondary side, which is sufficient to cause high voltage at these customers [3]. This can happen if the location of the distribution transformer is at a point on the feeder where the primary voltage is near or above the fixed limits; for instance: ANSI (American National Standards Institute) upper limit 126+ volts on a 120 volt base.

During normal operation conditions, without DG, voltage received at the load terminals is lower than the voltage at the primary of the transformer. The connection of DG can cause a reverse power flow, maybe even raising the voltage somewhat, and the voltage received at the customer´s site could be higher than on the primary side of the distribution transformer.

For any small scale DG unit (< 10MW) the impact on the feeder primary is negligible. Nonetheless, if the aggregate capacity increases until critical thresholds, then voltage regulation analysis is necessary to make sure that the feeder voltage will be fixed within suitable limits [3].

2.3.2 Impact of DG on Losses

One of the major impacts of Distributed generation is on the losses in a feeder. Locating the DG units is an important criterion that has to be analyzed to be able to achieve a better reliability of the system with reduced losses [3].

According to [3], locating DG units to minimize losses is similar to locating capacitor banks to reduce losses. The main difference between both situations is that DG may contribute with active power and reactive power (P and Q). On the other hand, capacitor banks only contribute with reactive power flow (Q). Mainly, generators in the system operate with a power factor range between 0.85 lagging and unity, but the presence of inverters and synchronous generators provides a contribution to reactive power compensation (leading current) [15].

The optimum location of DG can be obtained using load flow analysis software, which is able to investigate the suitable location of DG within the system in order to reduce the losses. For instance: if feeders have high losses, adding a number of small capacity DGs will show an important positive effect on the losses and have a great benefit to the system. On the other hand, if larger units are added, they must be installed considering the feeder capacity boundaries [3]. For example: the feeder capacity may be limited as overhead lines and cables have thermal characteristic that cannot be exceed.

Most DG units are owned by the customers. The grid operators cannot decide the locations of the DG units. Normally, it is assumed that losses decrease when generation takes place closer to the load site. However, as it was mentioned, local increase in power flow in low voltage cables may have undesired consequences due to thermal characteristics [4].

2.3.3 Impact of DG on Harmonics

A wave that does not follow a "pure" sinusoidal wave is regarded as harmonically distorted. This is shown in Fig. 2.6.

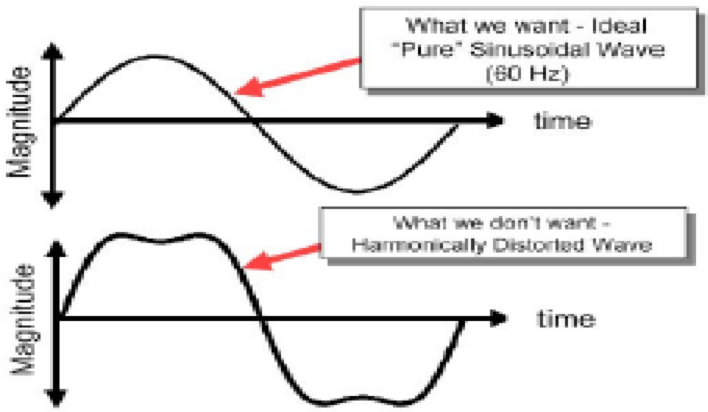

Fig. 2.6 Comparison between pure sinusoidal wave and distorted wave [17]

Harmonics are always present in power systems to some extent. They can be caused by for instance: non-linearity in transformer exciting impedance or loads such as fluorescent lights, AC to DC conversion equipment, variable-speed drives, switch mode power equipment, arc furnaces, and other equipment.

DG can be a source of harmonics to the network. Harmonics produced can be either from the generation unit itself (synchronous generator) or from the power electronics equipment such as inverters. In the case of inverters, their contribution to the harmonics currents is in part due to the SCR (Silicon Controlled-Rectifier) type power inverters that produce high levels of harmonic currents. Nowadays, inverters are designed with IGBT (Insulated Gate Bipolar Transistor) technology that use pulse width modulation to generate the injected "pure" sinusoidal wave. This new technology produces a cleaner output with fewer harmonic that should satisfy the IEEE 1547-2003 standards [17].

Rotating generators are another source of harmonics, that depends on the design of the generators winding (pitch of the coils), core non-linearity's, grounding and other factors that may result in significant harmonics propagation [3].

When comparing different synchronous generator pitches the best configuration encountered is with a winding pitch of 2/3 as they are the least third harmonic producers. Third harmonic is additive in the neutral and is often the most prevalent. On the other hand, 2/3 winding pitch generators have lower impedance and may cause more harmonic currents to flow from other sources connected in parallel with it. Thus, grounding arrangement of the generator and step-up transformer will have main impact on limiting the feeder penetration of harmonics. Grounding schemes can be chosen to remove or decrease third harmonic injection to the utility system. This would tend to confine it to the DG site only.

Normally, comparing harmonic contribution from DG with the other impacts that DG may have on the power system, it is concluded that they are not as much of a problem [3]. However, in some instants problems may arise and levels can exceed the IEEE-519 standard (these levels are shown in table 2.1). These problems are usually caused by resonance with capacitor banks, or problems with equipment that are sensitive to harmonics. In the worst case, equipment at the DG may need to be disconnected as a consequence of the extra heating caused by the harmonics.

Table 2.2

Harmonic current injection requirements for distributed generators per IEEE 519-1992. [3]

Harmonic order	**Allowed Level Relative to fundamental (odd harmonics)***
< 11th	4%
< 11th to < 17th	2%
< 17th to 23rd	1.5%
< 23rd to 35th	0.6%
35th or greater	0.3%
Total Harmonic Distortion	5%

*Even harmonics are limited to the 25 of odd values.

The design of a DG installation should be reviewed to determine whether harmonics will be confined within the DG site or also injected into the utility system. In addition, the installation needs to fulfil the IEEE-519 standard. According to [3], any analysis should consider the impact of DG currents on the background utility voltage distortion levels. The limits for utility system voltage distortion are 5% for THD (total harmonic distortion) and 3% for any individual harmonic.

2.3.4 Impact of DG on Short Circuit Levels of the Network

The presence of DG in a network affects the short circuit levels of the network. It creates an increase in the fault currents when compared to normal conditions at which no DG is installed in the network [3].

The fault contribution from a single small DG is not large, but even so, it will be an increase in the fault current. In the case of many small units, or few large units, the short circuits levels can be altered enough to cause miss coordination between protective devices, like fuses or relays.

The influence of DG to faults depends on some factors such as the generating size of the DG, the distance of the DG from the fault location and the type of DG. This could affect the reliability and safety of the distribution system.

In the case of one small DG embedded in the system, it will have little effect on the increase of the level of short circuit currents. On the other hand, if many small units or a few large units are installed in the system, they can alter the short circuit levels sufficient to cause fuse-breaker miss-coordination. This could affect the reliability and safety of the distribution system. Figure 2.7 shows a typical fused lateral on a feeder where fuse saving (fault selective relaying) is utilized and DGs are embedded in the system. In this case if the fault current is large enough, the fuse may no longer coordinates with the feeder circuit breaker during a fault. This can lead to unnecessary fuse operations and decreased reliability on the lateral [3].

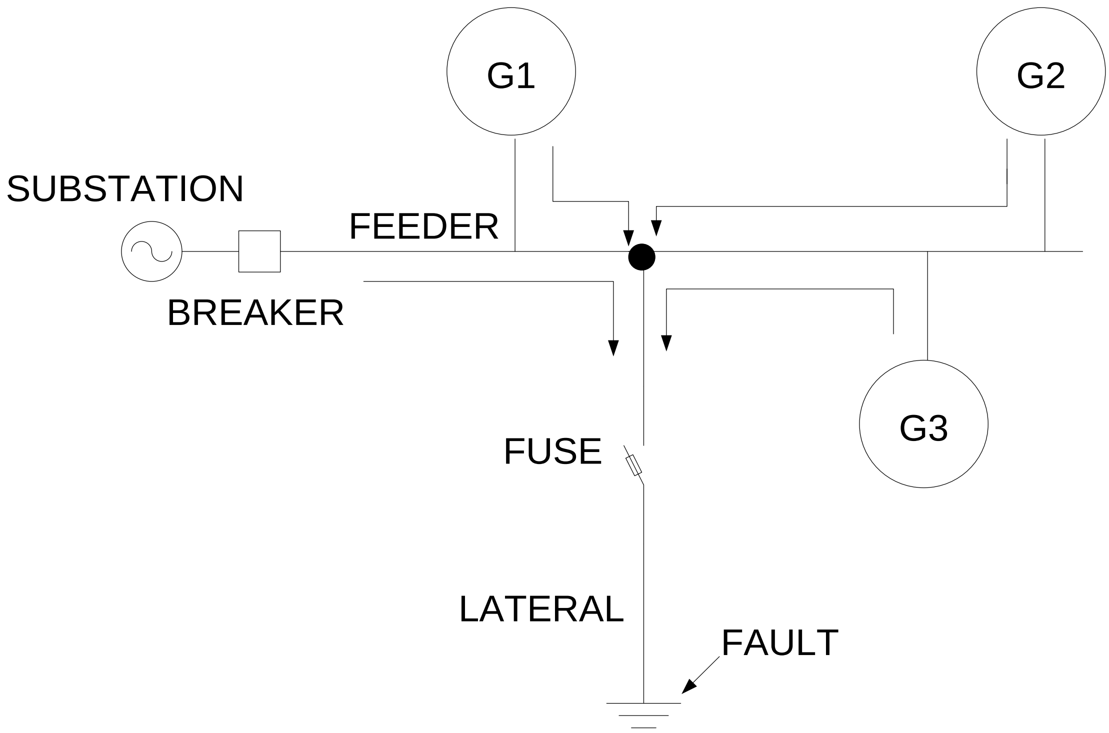

Fig. 2.7 Fault contributions due to DG units 1, 2 and 3 are embedded in the system. Fuse-breaker coordination may be no longer achieved

If the DG is located between the utility substation and the fault, a decrease in fault current from the utility substation may be observed. This decrease needs to be investigated for minimum tripping or coordination problems. On the other hand, if the DG source (or combined DG sources) is strong compared to the utility substation source, it may have a significant impact on the fault current coming from the utility substation. This may cause fail to trip, sequential tripping, or coordination problems [17]. Coordination problems concerning feeder protection will be detailed in section 2.6.

The nature of the DG also affects the short circuit levels. The highest contributing DG to faults is the synchronous generator. During the first few cycles its contribution is equal to the induction generator and self excited synchronous generator, while after the first few cycles the synchronous generator is the most fault current contributing DG type. The DG type that contributes the least amount of fault current is the inverter interfaced DG type, in some inverter types the fault contribution lasts for less than one cycle. Even though a few cycles are a short time, it may be long enough to impact fuse breaker coordination and breaker duties in some cases [18].

2.4 Protection Coordination

For DG to have a positive benefit, it must be at least suitably coordinated with the system operating philosophy and feeder design. DG is connected to the network through an interconnection point called the point of common coupling (PCC). The PCC has to be properly protected to avoid any damage to both sides, the DG equipment and the utility equipment, during fault conditions [19].

In the interconnection of the DG to the distribution utility grid, there are some protection requirements that are established by the utility. Adequate interconnection protection should consider both parties ensuring the fulfilment of the utility requirements. Interconnection protection is usually dependent on size, type of generator, interconnection point and interconnecting transformer connection [20].

DG generation must be installed with a transformer characteristics and grounding arrangement compatible with the utility system to which it is to be connected. If this requirement is not satisfied, overvoltages may arise which can cause damage in the utility system or customer equipment. The type of transformer selected has a major impact on the grounding perceived by the utility primary distribution system and for the generator to appear as a grounded source to the utility primary system. Therefore, it is demanded that the transformer allows a ground path (zero-sequence path) from the low voltage side to the high voltage side [3].

Literature review showed that there is not a universally “best” transformer connection accepted for all cases. In Fig. 2.8, some usual connections used are presented.

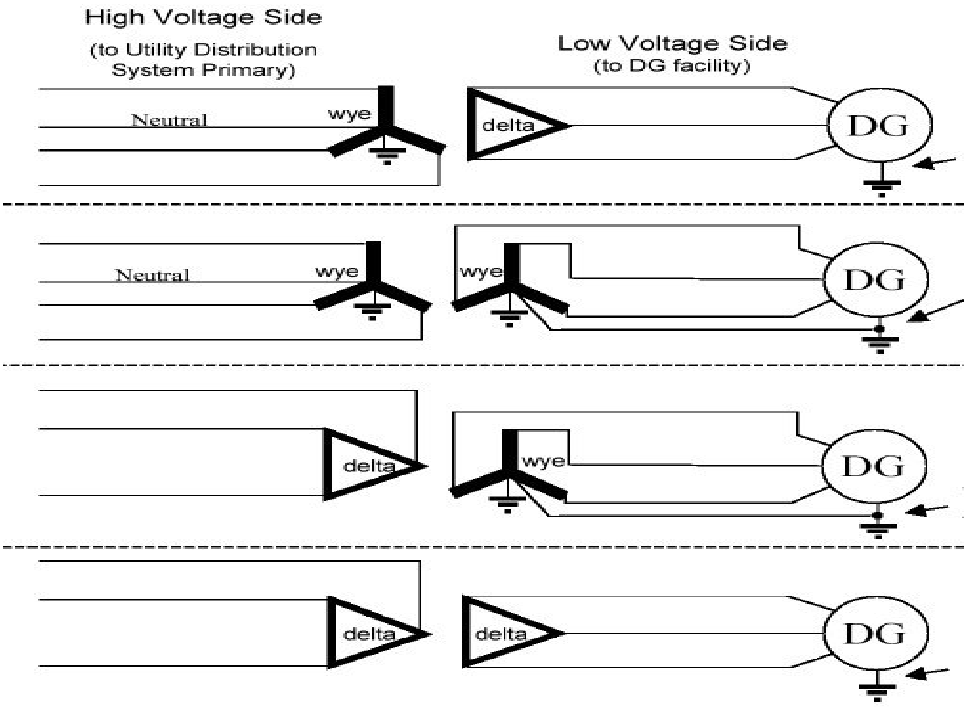

Fig. 2.8 Commonly transformer connections used with DG [17]

Each of these connections has advantages and disadvantages to the utility with both circuit design and protection coordination affected. The utility establish the connection requirements and determines which type of connection is appropriate [17].

In Fig. 2.8, the top two configurations can provide a grounded path to the primary. Moreover, to make the source appear as effectively grounded; the generator´s neutral must be grounded. The first arrangement is preferred for four-wired-multi-grounded neutral systems [17].

The two bottom configurations shows that, even though the source is properly grounded on the low voltage side of the transformer, the system may still appear to the utility primary to be ungrounded at the high voltage side. These two arrangements act as grounded sources and are preferred on three-wire ungrounded distribution systems [17].

To fulfil the desired safe scenario, the protection is based on the following factors [19], [21]:

1. Protection should respond to the failure of parallel operation of the DG and the utility.

2. Protecting the system from fault currents and transient over voltages generated by the DG during fault conditions in the system.

3. Protecting the DG from hazards it may face during any disturbance occurring in the system such as automatic reclosing of re-closers as this can cause damage depending on the type of the generator used by the DG.

4. Network characteristics at the point of DG interconnection. Considering the capability of power transfer at this point and the type of interconnection.

The generator protection is one of the most important devices, typically located at the generator´s terminals. Its function is to detect internal short circuits and abnormal operating conditions of the generator itself, for instance: reverse power flow, over excitation of the generator and unbalanced currents [20].

For the utilities to operate in a safe mode, some aspects have to be analyzed.

1. Configuration of the interconnecting transformer winding.
2. Current and voltage transformer requirements.
3. Interconnection relays class.
4. Speed of DG isolation to be faster than that of the utility system automatic reclosing during fault conditions to avoid islanding cases.

2.5 Islanding of a Power Network

According to [3] islanding occurs when the distributed generator (or group of distributed generators) continues to energize a portion of the utility system that has been separated from the main utility system. Moreover, islanding only can be supported if the generator(s) can self excite and maintain the load in the islanded area. This situation is shown in Fig. 2.9:

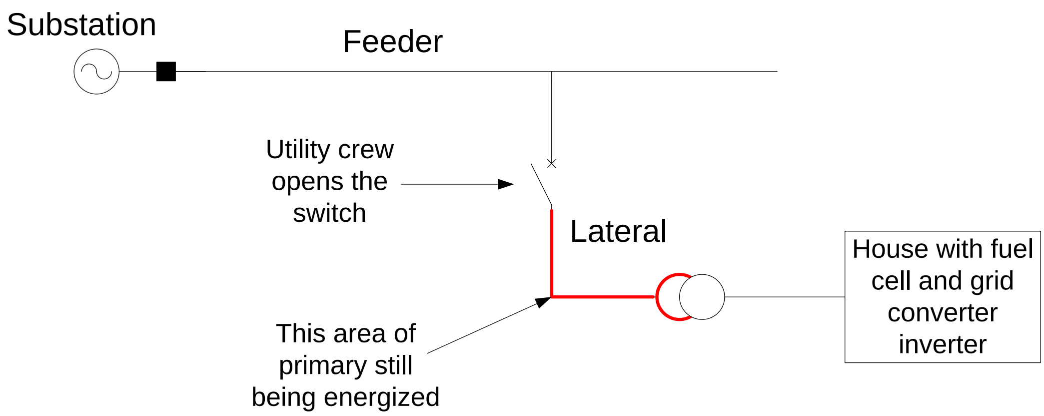

Fig. 2.9 Islanding of a DG system

This separation could be due to operation of an upstream breaker, fuse, or automatic sectionalizing switch. As it is shown in Fig. 2.9, manual switching or "open" upstream conductors could also lead to islanding. In most of the cases this is not desirable as the reconnection of the islanded part becomes complicated, mainly when automatic reclosing is used. Furthermore, the network operator is not able to assurance the power quality in the island (the DG is no more controlled by the utility protection devices and continues feeding its own power island). This increases the probability that DG sources may be allowed to subject the island to out of range voltage and frequency conditions during its existence and the fault level may be too low, so that the over current protection will not work the way it is designed. Therefore, the power quality supplied to customers is worsening [1].

For instance, if an island is developed on a feeder during standard reclosing operations, the islanded DG units will be quickly out of phase respect to the utility system during the "dead period". Then, the reclose occurs and unless reclose blocking into an energized circuit is provided at the breaker control, the islanded DG will be connected out of phase with the utility. This can lead to damage of utility equipment, the DG supporting the island and customer loads, which decrease the reliability of the whole network [3].

The last drawback encountered with islanded operation is the safety problems to maintenance crews. Personnel working on the line maintenance work or repairing a fault may mistakenly consider the load side of the line as inactive, where distributed sources are indeed feeding power to utilities [22].

Islanding has two forms: unintentional islanding, it can be expressed in other words as “the loss of mains”. It is a situation when the distributed generator is no more operating in parallel with the utility. And intentional islanding that is performed on purpose by the utility to increase the reliability of the network.

2.5.1 Intentional Islanding

There are cases where the reliability of the power network can be increased if DG units are configured to support “backup- islands” during upstream utility source outages. For this configuration to be effective, reliable DG units like gas turbine generators and careful coordination of utility disconnection and protection equipment are required [3].

In this situation, the switch must open during upstream faults and the generators must be able to support the load demand on the islanded section maintaining suitable voltage and frequency levels in the islanded system. If a static switch is not employed, this scheme would usually result in a momentary interruption to the island since the DG would necessarily trip during the voltage disturbance caused by the upstream fault. It is desired that a DG assigned to support the island must be able to restart and carry the island load after the switch has opened. Furthermore, the switch will need to sense if a fault has happened downstream of the switch location and automatically send a signal to disconnect the DG if fault has occurred within the islanded area [3].

When utility power is restored on the utility side, the switch must not close the utility and island, if they are not in synchronism. This synchronism is performed by measuring the voltage, phase and frequency on both sides of the switch and transmitting that information to the DG unit, supporting the island, to change its power to bring these parameters within limit for synchronization of islanded system to main grid.

2.5.2 Islanding Detection

At the present, the methods or techniques used in detecting islanding situations are based on measuring the output parameters of the DG and a decision is taken to decide whether these parameters define an islanding situation or not. These islanding detections techniques may be classified into two major groups which are basically, remote and local techniques. Local techniques are further divided in passive and active detection techniques [22], [23].

Remote islanding detection technique is based on communication between utilities and DGs. Remote detection techniques have higher reliability than local detection techniques, but they are expensive to implement in many distribution system.

Local detection techniques are based on the measurement of the system parameters at the DG location, like voltage, frequency, etc.

Active methods directly interact with the power system operation, whilst passive methods are based on identifying the problem on the basis of measured system parameters [22].

Passive detection methods monitor the variations occurring in the power system parameters such as the short circuit levels, phase displacement and the rate of output power as in most cases of utility disconnection the nominal network voltage, current and frequency are affected. A passive method utilises these changes to decide and react to an islanding situation. When the DG is connected to the utility, there will be a negligible change in the frequency or power flow and it will not be sufficient for the initiation of the protective relay that is responsible for the DG isolation. On the other hand, if the DG is not connected to the utility network, the changes in the frequency and output power will be sufficient enough to energise the relay resulting in the disconnection of the DG preventing the occurrence of an islanding situation [24].

Passive detection methods are fast and do not introduce disturbance in the system, but they have a large non detectable zone (NDZ). For instance, it will not be efficient in the case of a balance between the loads connected and generation in an islanded part of the network as there will be a NDZ. NDZ is the region in an appropriately defined space in which the islanding detection scheme under test fails to detect islanding [24].

Active methods detect islanding even under perfect balance between generation and load, which is not possible with passive detection schemes. Active methods directly interact with the power system operation by introducing small perturbations. The idea behind the method is that the perturbation will be negligible if DG is connected to the grid, while it will result in a significant change in the system parameters if the DG is islanded. Active methods are expensive than passive methods [22].

One of the direct and efficient islanding detection methods is by monitoring the trip status of the main utility circuit breaker and as soon as the main circuit breaker trips, an instantaneous signal is sent to the circuit breaker at the interconnection between the DG and the utility system to trip the interconnection circuit breaker preventing the occurrence of islanding. Even though this method seems to be easy and direct, its implementation is difficult due the distribution of DGs in a large geographic range that will require special comprehensive monitoring techniques with committed systems [22].

2.6 Impact of DG on Feeder Protection

One of the principal features of distribution systems is that the power flows radially, from the main generating station down to the feeders to support all loads. In this design, protection devices are placed on feeders and laterals of the distribution network, in order to maintain continuous supply to all loads and to protect equipment and different appliances of the system from power outages [17].

During the design of these protection equipments, some characteristics have to be taken into consideration, keeping in mind that it is not possible to protect the entire network straight from the substation. Normally, in large networks the protection is provided by the use of various protection devices based on the fact that any protection device has a reach or maximum distance to cover. Moreover, when designing the protection scheme of a network, coordination between the mentioned protection devices must be considered to be able to reach a highly reliable network that will isolate only the faulted zones and will maintain the healthy parts energised. This purpose increases the global reliability of the network [17].

The introduction of DG in the radial configuration causes a number of problems with the protective device coordination. For example in the traditional system, when using over current protection, it is possible to assume that the fault current only flows in one direction, whilst, this is not always true if there are DG embedded in the network.

The presence of DG in a network will have a great impact on the coordination of the protective device, thus it affects the distribution feeder protection. It also has a great impact on the utility protection devices. In the following section the impacts of DG on the protection devices are discussed.

2.6.1 Mal-Trip and Fail to Trip

The penetration of DG in an existing distributed network results in a general increase in the fault levels for any fault location in the whole network and in some cases this increase is of a considerable magnitude in some specific parts of the network. This increase causes a lot of problems to the existing protection devices in the network. The type of protection depends on the situation of the DG and where it is placed in the network as the penetration of DG changes the configuration of the network parameters.

The protection systems can fail in two different ways: by unnecessarily removing a non-faulted component (mal-trip); or by not removing a faulted component (fail-to-trip). A mal trip ("Sympathetic tripping") is the case in which one of the protection devices trips instead of the other. This tripping occurs due to one protective device detecting the fault while it is outside of its protection zone and trips before the required tripping device. Fig. 2.10a shows that this type of failure occurs when the DG unit feeds an upstream fault. Moreover, this type of tripping causes the isolation of the healthy part of the network whilst it is not required. Therefore, the reliability of the distribution network is reduced [25].

In contrast, fail to trip occurs for downstream faults. In this case the fault current is principally formed by the current originated from the DG unit. Consequently, the fault current through the over current protection device can be below the setting for which it was designed and the protection remains passive, hence the faulty feeder will not be disconnected. In Fig. 2.10b, this situation is presented.

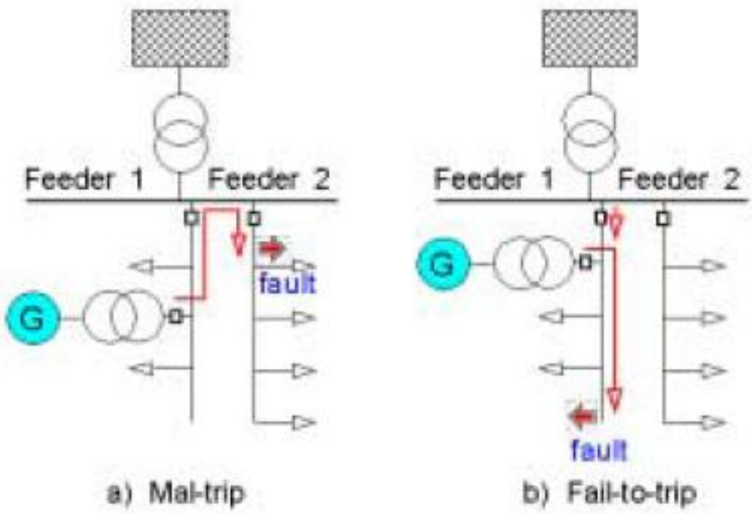

Fig. 2.10 Mal trip and fail to trip [25]

In Fig. 2.10a, when the fault occurs, the relay/breaker at feeder 2 is the prime device that should trip to isolate the faulted branch leaving all the healthy parts operating normally. In this situation, relay/breaker at feeder 1 should be the backup of relay and breaker in feeder 2, but it will trip first. This tripping is a result of the additional current injected by the DG to the fault which was not taken into consideration during the original feeder protection design. Thereby, relay/breaker in feeder 1 will sense the rise in current flowing through it and interpret it as a fault condition and in consequence a trip takes place [25].

2.6.2 Reduction of Reach of Protective Devices

The presence of a DG in the distribution network may cause a protection deficiency called “reduction of reach”. If a large production unit or several small ones are connected to the distribution network, the fault current seen by the feeder protection relay may be reduced, which can lead to improper operation for the over current relays.

This problem is illustrated in Fig. 2.11. When the DG is embedded in the network, its contribution to the fault current (I_k) reduces the current seen by the feeder relay (I_1). If the unit is larger, the fault current injected will be higher, as well as, if the unit is located near to the grid, higher I_1 will be seen, as the impedance of the line will be lower. Therefore, it can be also concluded that the impact increases with the size of the unit and the distance between the feeder and the DG system [1]. This is the failure of the protection devices to cover its designed protective distance, as the DG causes a decrease in the sensitivity of these protection devices, thus decreasing the distance protected [26].

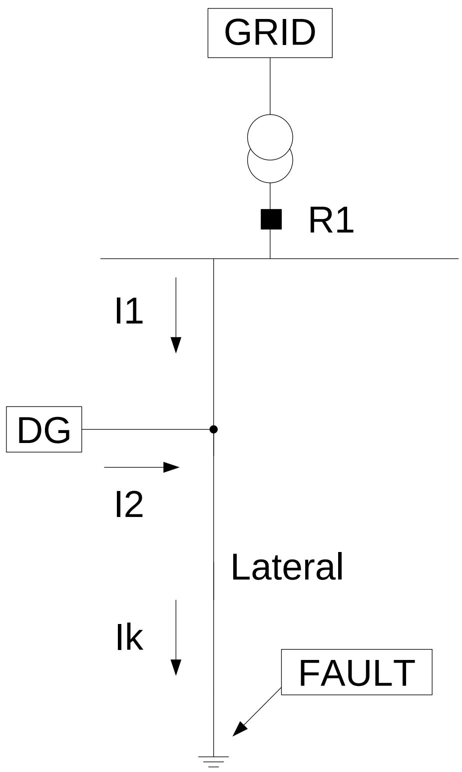

Fig. 2.11 Reduction of reach of protective devices

R1 is set up to cover the whole line, but the presence of the DG will cause a change in the apparent impedance of the line which causes a miss-estimation of R1. When the fault is at the end of the line the impedance of the line will be higher and R1 will not be able to sense the fault due to the less fault current from the grid.

2.6.3 Failure of Fuse Saving Due to Loss of Recloser-Fuse Coordination

Usually, electricity is supplied to loads in distribution networks through radial distribution systems and then through laterals and transformers to the customers. To be able to protect the system components and loads providing the desired safety, protection equipment must be placed along the network at various places according to the function of each appliance. The most common protection technique for protecting laterals in distribution networks is by using a fuse, which is coordinated with other protection equipment of the network like recloser. This coordination is required in order to be able to save the fuse from blowing out in case of temporary faults. The purpose is to reduce power outages as it is not required to interrupt the system during temporary faults due to the fact that these faults are considered to be around 70 to 80 percent of the total faults. An example of these faults is lightning, which is an instantaneous phenomena and then it disappears. Fig 2.12 shows an example of a part of a distribution network involving recloser and fuse without the presence of DG [27].

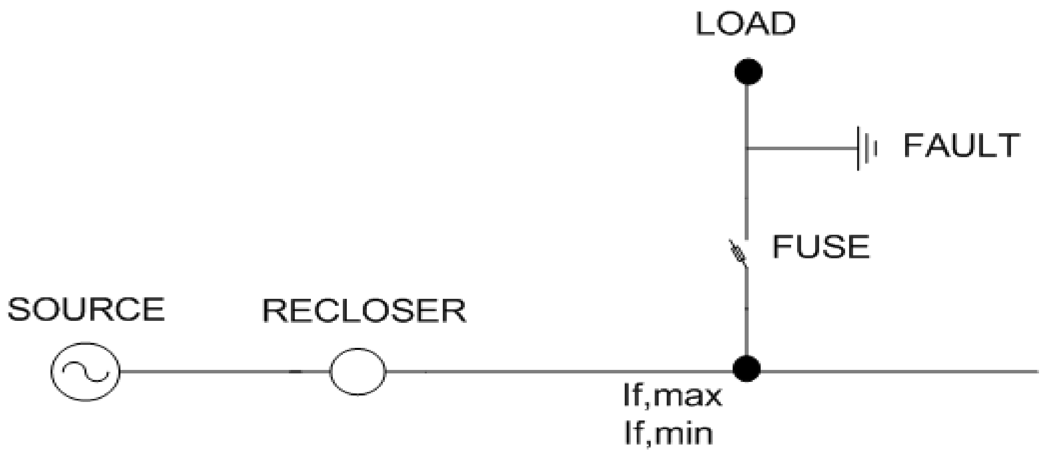

Fig. 2.12 Part of a distribution network including relay and fuse

In this figure, it is noticed that the current flowing through the recloser is the same as through the fuse, for the illustrated fault condition. These devices must coordinate for all values of fault currents on the load feeder [27].

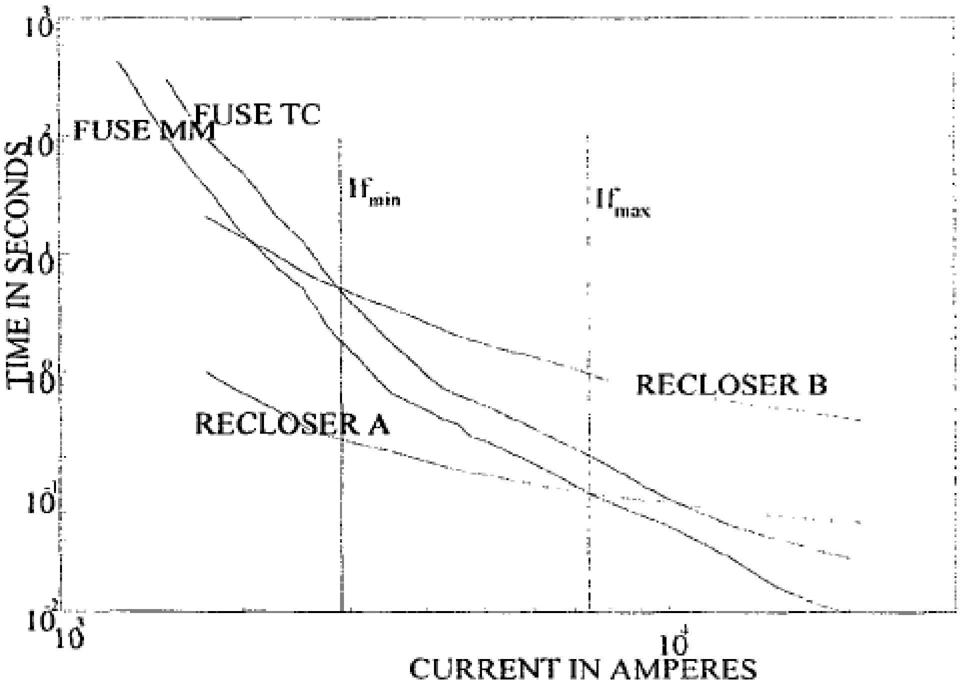

Fig. 2.13 Coordination between recloser and fuse for the case shown in figure 2.12

A recloser has two operating modes to either clear a temporary fault or locking open for permanent fault if the fuse does not blow for permanent faults. In Fig. 2.13, “RECLOSER A” represents the fast operation curve of the recloser, while “RECLOSER B” represents the slow curve of the recloser. The operating mode of a recloser is “F-F-S-S”, where “F” is the fast operating mode and “S” is the slow operating mode. The recloser attempts two consecutive trials with a difference time interval assumed as one second, if the fault is a temporary fault it is expected to be cleared after the first strike of the recloser, if it strikes again the total time is now 2 seconds (second fast operation) and the fault still exists then the fault is regarded to be a permanent fault and the fuse has to operate to cut it off [27].

A fuse has two characteristics, minimum melting ,”FUSE MM”, gives time in which fuse can suffer damage for a given value of fault current. And the other characteristic is total clearing, “FUSE TC”, gives the fault clearing time of fuse for a given value of fault current. The procedure followed is that the fuse should only operate for permanent fault on the load feeder. If the fault is temporary, recloser should give a fault a chance to clear, disconnecting the circuit with fast operation. In this way, the load feeder is not disconnected for every temporary fault. Moreover, recloser provides a backup protection to fuse through slow mode. In Fig 2.13, it can be noticed that for a permanent fault the TC of the fuse lies below the “B” curve within the range of $I_{f.min}$ and $I_{f,max}$ .Hence, for a permanent fault, fuse will operate before the recloser. If the fuse fails to clear the fault, the recloser attempts two trials (slow mode) before it is locked out.

The main purpose of coordination between fuse and recloser is to result in insolating only the faulted area, leaving the healthy parts of the network energized and therefore increasing the reliability of the network. The coordination described above only hold in the range between $I_{f,min}$ and $I_{f,max}$, therefore, it is required that any type of fault along the load feeders lie between these two limits [27].

On the other hand, the penetration of DG in the network will change the power characteristics of the network, contributing to fault currents which increase the fault current values and may cause failure of fuse – recloser coordination. In Fig. 2.14, the same network as before is shown, but with the DG embedded in the system.

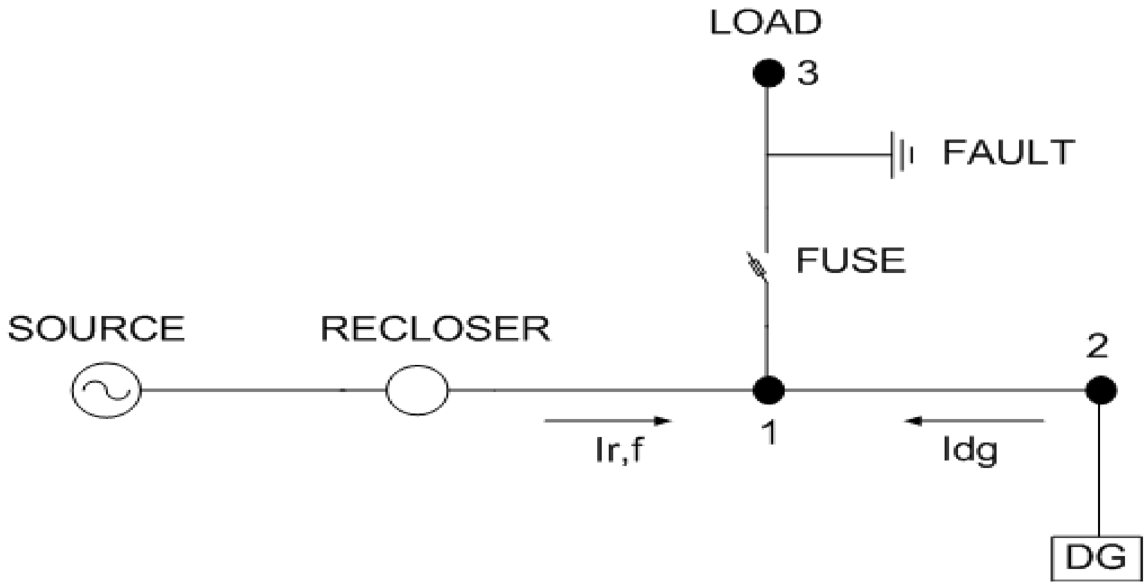

Fig. 2.14 Network example with embedded generation

In this case, the fault current flowing through the recloser is only contributed by the substation (source), whilst the fault current flowing through the fuse is a sum of both the current contributed from the DG to the fault and the fault current contributed from the substation. The increase in the fault current flowing through the fuse could be sufficient to initiate the blowing of the fuse before the recloser operation [27].

Fault current must lie between $I_{f,min}$ and $I_{f,max}$ for coordination to hold. Then, two possible situations may arise: if the fault current for a fault on load feeders exceeds the current limits, coordination is lost, as “FUSE MM” characteristic of fuse lies below the “RECLOSER A” curve. In the other case, if fault current lies within the allowed limits, there is a margin.

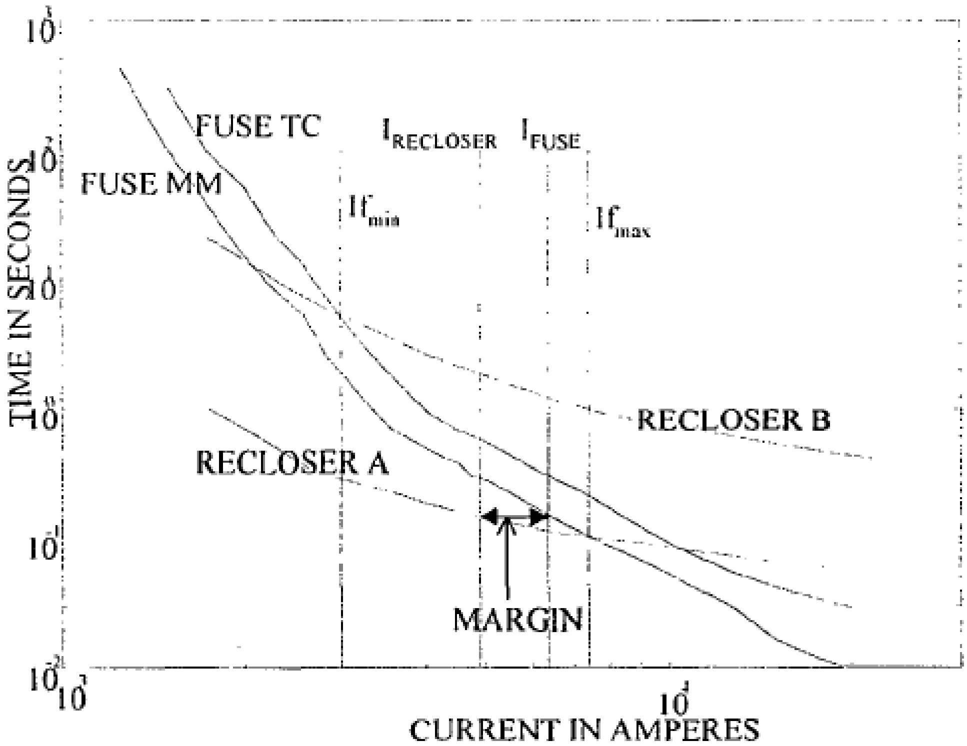

Fig. 2.15 Coordination margin between fuse and recloser

In Fig. 2.15, "$I_{RECLOSER}$" is the fault current seen by the recloser and "I_{FUSE}" is the fault current seen by the fuse. The disparity of these currents will depend on the size, type and location of the DG in the main feeder. Larger size, more fault current injection and location of the DG closer to load feeder will result in greater disparity and vice-versa. If for a given fault current, the difference between $I_{RECLOSER}$ and I_{FUSE} is more than the margin shown in Fig. 2.15, fuse will be damaged before recloser operates in fast mode, thus coordination will be lost [27].

A concern point is that when recloser closes after the first (and subsequent) open interval, it would be energizing a dead system if DG is not connected to the system. If DG is embedded in the system, this assumption is no longer valid. Reclosing will connect two live systems together and if this is done without proper synchronizing, then damage to the DG unit may be caused.

Chapter 3

Over-current Protection of Distributed Systems

3.1 Introduction

Faults generally results in high current levels in electrical power systems. These currents are used to decide the occurrence of faults and require protection devices, which may differ in design depending on the complexity and accuracy necessary. The ordinary type of protection devices are thermo-magnetic switches, moulded-case circuit breakers (MCCBs), fuses, and over-current relays. Amongst these types, over-current relay is the most common protection device used to counteract excessive currents in power systems [7].

Over-current protection is principally intended to operate only under fault conditions and therefore, over-current relays should not be installed merely as a way to protect systems against over-loads. Nevertheless, relay settings are often selected taking both into account, over-load and over-current circumstances.

An over-current protection relay is a device able to sense any change in the signal, which it is receiving normally from a current and/or voltage transformer and carry out a specific operation in case that the incoming signal is outside a predetermined range. Usually the relay operates closing or opening electrical contacts, as for example the tripping of a circuit breaker [7].

3.2 Types of Over-current Relays

Concerning the relay operating characteristics, over-current relays may be classified into three major groups: definite current, definite time, and inverse time.

3.2.1 Definite Current Relay

This type of characteristic makes the relay to operate instantaneously when the current reaches a predetermined value. This feature is shown in Fig. 3.1:

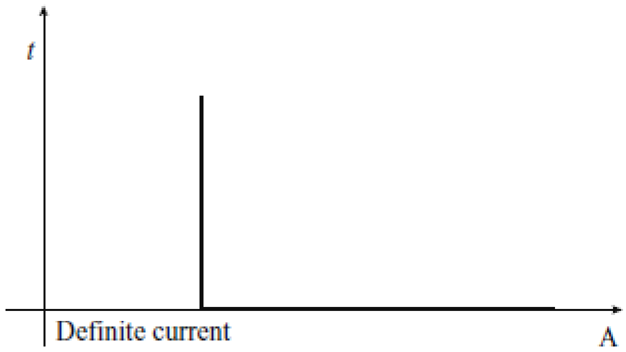

Fig. 3.1 Definite current characteristic of over-current relays [7]

The setting is chosen in such a way that the relay, which is installed at the furthest substation away from the source, will operate for a small current value and the relay operating currents are gradually increased at each substation, moving towards the source. Thereby, the furthest relay from the source operates first disconnecting the load in the neighbouring site of the fault [7].

In this case the protection setting is based on maximum fault level conditions (three phase short circuit current), when a fault level is lower, these settings may not be appropriated as the fault will not be cleared until it reaches the protection setting value. Therefore, clearing the fault will take some time during which equipment can be damaged. In consequence, definite current relay protection has slight selectivity at high values of short-circuit currents. On the other hand, if the settings are based on lower value of fault current, may result in some needless operation of breakers as the fault level increase. Due to these disadvantages, definite current relays are not used as a single over-current protection, but their use as an instantaneous component is very common in combination with other types of protection [7].

3.2.2 Definite Time Relay

In this type of relay the setting may be changed to deal with different levels of current by using different operating times. The settings can be attuned in such a way that the relay, which is installed at the furthest substation away from the source, is tripped in the shortest time, and the remaining relays are tripped in sequence having longer time delays, moving back in the direction of the source [7].

Definite time protection is more selective as the operating time can be set in fixed steps. However, faults close to the source, which results in higher currents may be cleared in a relatively long time. This relay allow setting of two independent parameters, the pickup setting and the time dial setting. The pickup setting define the current value necessary to operate the relay and the time dial sets the exact timing of the relay operation. In Fig. 3.2, the characteristic curve of a definite time relay is shown [7]**.**

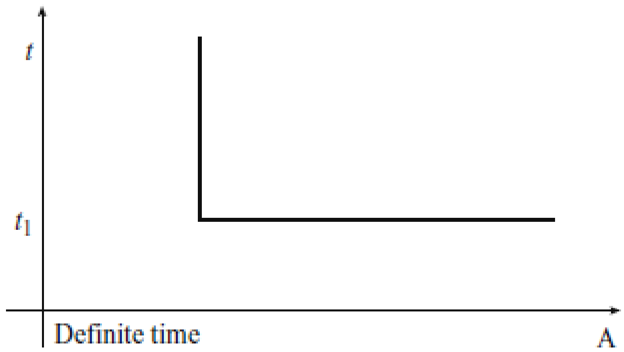

Fig. 3.2 Definite time/current or definite time characteristic of over-current relays

3.2.3 Inverse Time Relays

These relays operate in a time that is inversely proportional to the fault current. Inverse time relays have the advantage of that shorter tripping times can be achieved without risking the protection selectivity. These relays are classified based on their characteristic curves, which define the speed of operation as inverse, very inverse or extremely inverse. Their defining curve shape is shown in Fig. 3.3.

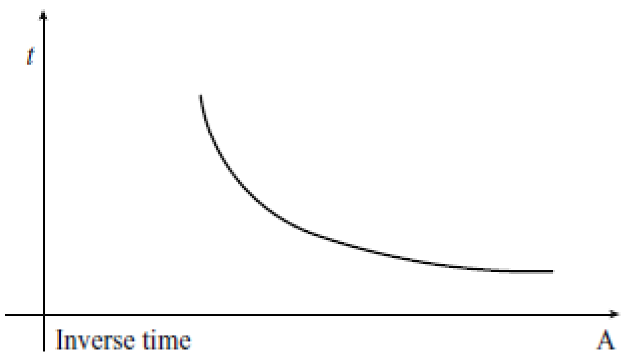

Fig. 3.3 Inverse time/ current characteristic of over-current relays [7]

3.3 Model of an Over-current Relay

Over-current relays are modelled in DIgSILENT/Power Factory combining the definite time and inverse time characteristic as better protection selectivity is achieved.

Furthermore, it has to be taken into account that when distributed generation is connected to a distribution system, the protection topology has to be changed as fault currents can circulate in both directions throughout a system device (see Fig. 3.4). Therefore, directional over-current relays should be used to guarantee a safe operation scenario.

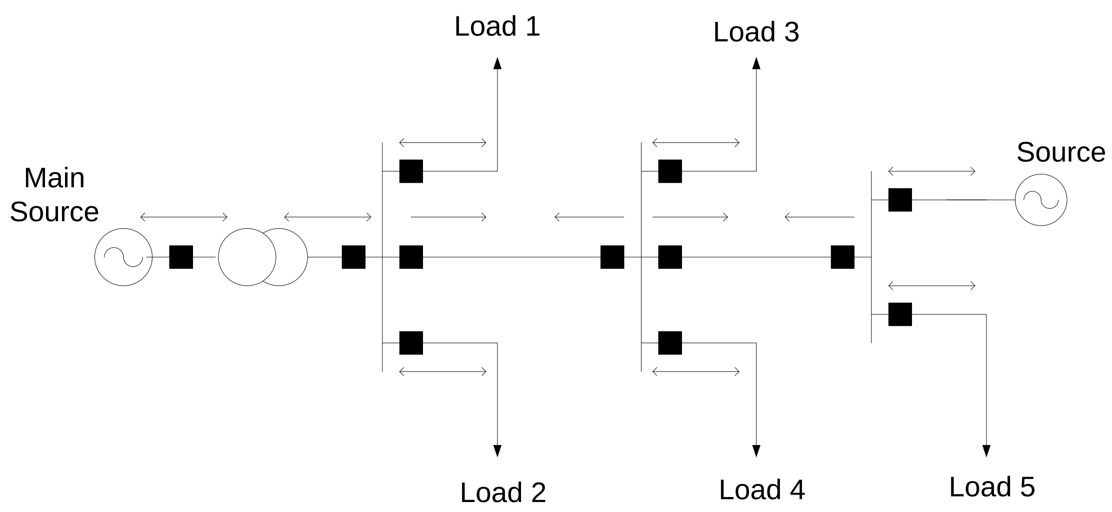

Fig. 3.4 Application of directional over-current relays in multi-source networks

Directional over-current relays are formed by adding a directional block on an over-current unit, which determines the direction of the power flow in the associated distribution element. The directional unit typically requires a reference signal to determine the angle of the fault to decide if the relay should operate. The reference signal is provided by voltage and current transformers [7]. In Fig 3.5, the blocks used to model the relay in DIgSILENT are shown**.**

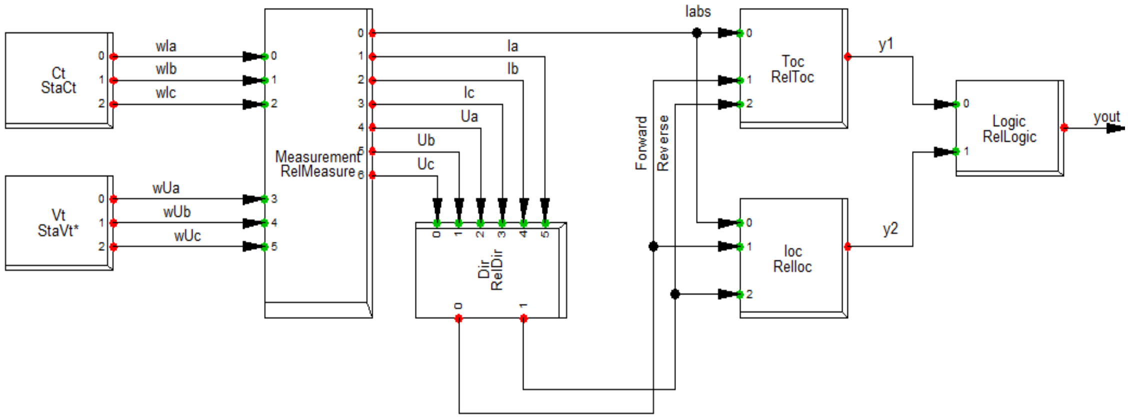

Fig. 3.5 Block diagram of directional over-current relay

The current transformer (Ct) and voltage transformer (Vt) sense the currents and voltages, respectively, which are measured by the *RelMeasure* block. Once the measurements are carried out, signals are sent to the *RelDir* detection block, which determines if the current is flowing in a reverse or forward direction and send the appropriate signal to the time over-current block (RelToc) and to the instantaneous over-current block (RelIoc). If the current is higher than the instantaneous pick up current (I_{inst}) then the *RelIoc* block gives trip signal. If the current is lower than I_{inst} but higher than the pickup current (I_p), a trip signal is produced depending on the characteristic curve of the *RelToc* block. Any of these signals can activate relay pick up (OR operation), which is represented by the logic block (RelLogic).

3.4 Directional Over-current Relay Protection Coordination

Directional over-current relaying (DOCR) is simple, economic, have the possibility to choose different tripping characteristics and therefore is commonly used as primary power system protection in distribution systems. A primary protection should operate every time a protection element detects a fault on the power system. Also, back up relay protection should be provided to operate when, for whatever reason, the primary protection does not work. The backup protection should be designed with a time-delay to postpone the operation of the relay and give time for the primary protection to operate first [7].

The major problem with this type of protection is the complexity in performing the relays coordination, mainly in multi-source networks. New relay settings are implemented as load, generation level or system topologies changes. Changes in the system are detected by identifying the operation scenario. Two different operation scenarios are studied and analyzed in this chapter and they are: distributed system without and with DG connected. To protect the system, digital over-current relays are used, as they have the possibility for using different tripping characteristics (several setting groups) [28].

3.4.1 Relay Protection Coordination of Radial Systems

In Fig. 3.6, a simple radial distribution system is shown, where TS is the transmission system, A, B, C and D are the buses of the system, their correspondent loads are load1, load2, load3 and load4, respectively and R1, R2 and R3 are the over-current relays. When a fault occurs in the network over-current protection takes place.

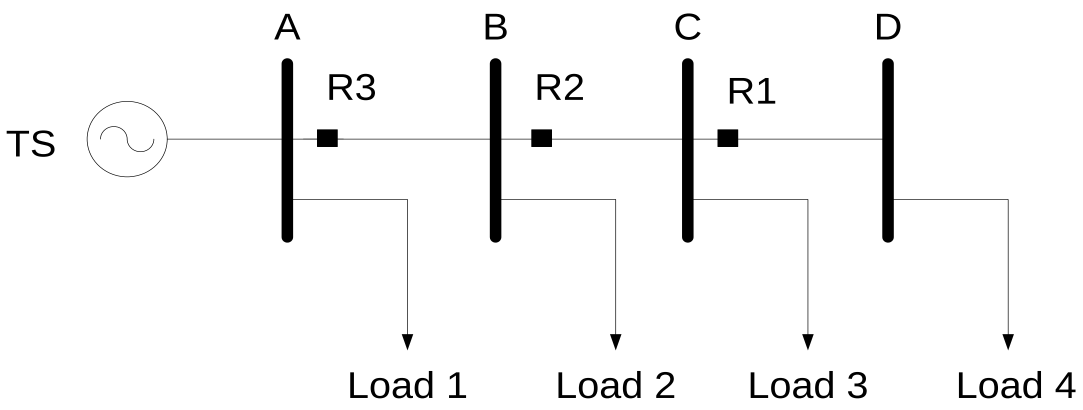

Fig. 3.6 Distribution system without distributed generation

The relays characteristic are based on IEC 255-3 standard (nearly inverse), which is expressed by the following equation [29]:

$$t_i = \frac{0.14TD}{\left(\frac{I_{fi}}{I_{pickup_i}}\right)^{0.02} - 1} \qquad (3.1)$$

Where:

TD = time dial setting of relay i. It is designed taking into account that the upstream relay provides a backup function to the downstream relay.

I_{fi} = fault current seen by relay i.

I_{pickup_i} = pick up current of relay i.

In the network shown in Fig. 3.6, relay 2 also act as the backup of relay 1, and relay 3 also act as the backup of relay 2. The minimum difference between the operation times of primary/ backup protection is called coordination time interval (CTI). The CTI depends on a number of factors such as the circuit breaker operation time, delay and return time of the measuring element, etc. The TD settings are set in such a way that the farthest relay (relay 1) has the lowest TD. As for relay 2, if a fault happen in line CD, its operation time should be larger than that of relay 1 at least by the CTI. For relay 3 the same philosophy is followed [29].

3.4.2 Relay Protection Coordination with Distributed Generation

The coordination of the relays is changed with the presence of DG depending on number, capacity and location of these units. In this section the following cases are considered [29].

- *Single DG interconnected*

In Fig. 3.7, DG1 is connected to bus A. If a downstream fault occurs, for instance in line CD, relay 1, 2 and 3 will sense the downstream fault current, which it is greater than without DG due to the current contribution from the DG1. Then, relay 1 will clear the fault and the sensitivity will be enhanced because of the greater fault current. On the other hand, if a fault current is higher than permissible current limit, coordination between relays 1 and 2 may not hold [29].

If fault current is higher than permissible current limit, difference between the operating times of main and backup relay protection will be lower than the CTI and coordination may not hold [30].

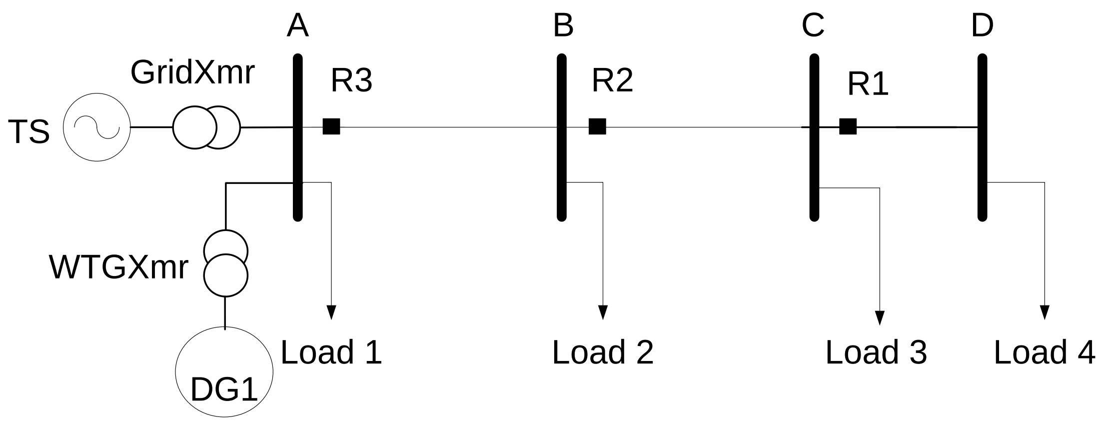

Fig. 3.7 Single DG connected to bus A

The line data for the test system in Fig. 3.7 is given in Appendix Table AI. The type of DG used in the simulations are wind turbines, which are modelled as induction generators, using standard models available in the DIgSILENT library; their data is given in Appendix Table AII. Induction generators are connected to their respective buses through transformers (WTGXmr). Moreover, the distribution system is connected to the transmission network through another transformer (GridXmr). Their data is given in Appendix Table AIII and the transmission system data is presented in Table AIV. The load values are collected in Appendix Table AV.

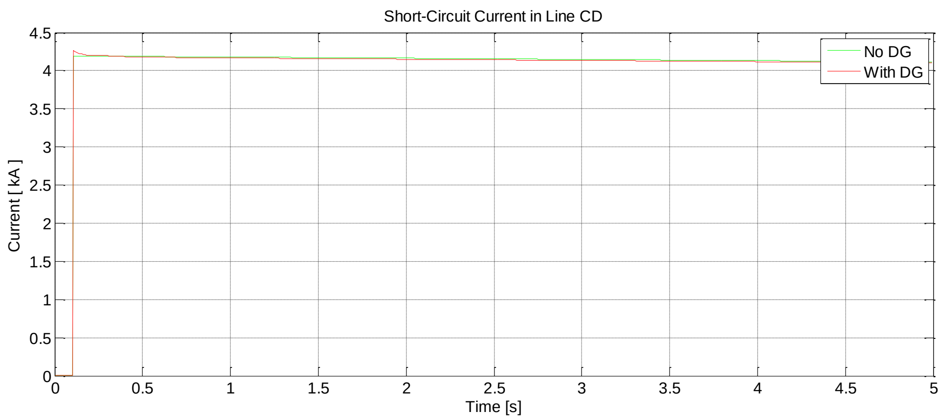

Fig. 3.8 Short circuit current in line CD with and without DG1

In Fig. 3.8, the short circuit currents for a three phase fault in line CD, with and without DG1 connected to bus A, are shown. It can be seen from the Fig. 3.8 that the short circuit current contribution from the DG1 is negligible and the short circuit levels remain within the allowable margin defined for the case with no DG connected in the system.

The I_p of all relays is set 1.5 times maximum normal current. The current values are chosen from design study shown in Fig. 3.7. Instantaneous pick up times (T_{inst}) are set as *50ms*. The TD for each relay is calculated using equation (3.1) and taking into account that clearing of fault takes around *70ms* after the picking up of the relay and upstream relay reset time is well within *30ms*. This gives enough time for R1 to pickup and to send the tripping signal to the correspondent circuit breaker to open and clear the fault before R2 picks up. Relays 2 and 3 are designed similarly. The pickup currents, time dial setting and the instantaneous pick up current for each relays R1, R2 and R3 are shown in Table 3.1.

Table 3.1

Time over-current characteristics of relays R1, R2 and R3 with DG1

Relay	**I_p (A)**	**TD (s)**	**Instantaneous pickup current (A)**
R1	285	0.019	4300
R2	300	0.223	4800
R3	330	0.259	4990

Fig. 3.9 shows the time over-current characteristic plot of relays R1, R2 and R3. It can be noticed that selectivity between relays holds as the curves are not crossing each other.

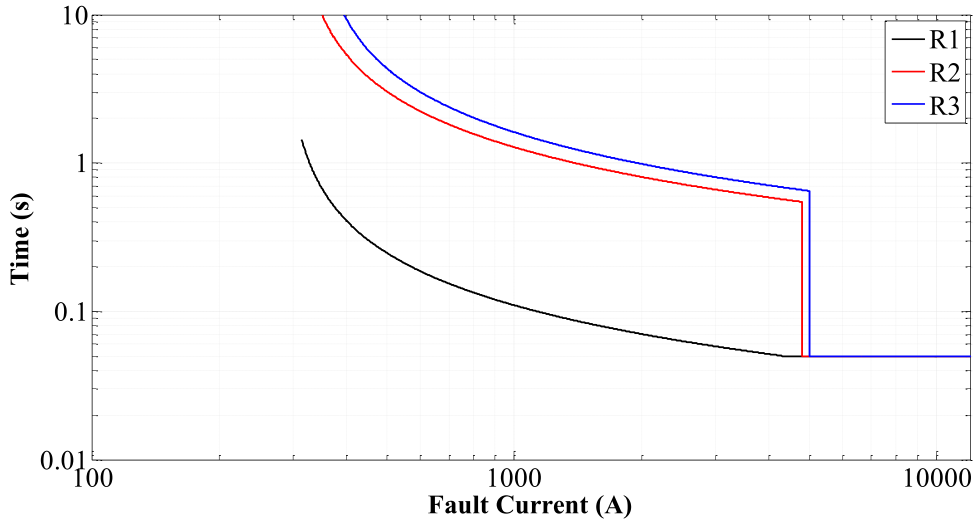

Fig. 3.9 Time over-current plot of relays R1, R2 and R3.

Fig. 3.10 shows the clearing time for a three phase fault in line CD after relay picks up and the corresponding opening trip signal is sent to the circuit breaker. The relay is clearing the fault within the setting time *(50ms)*.

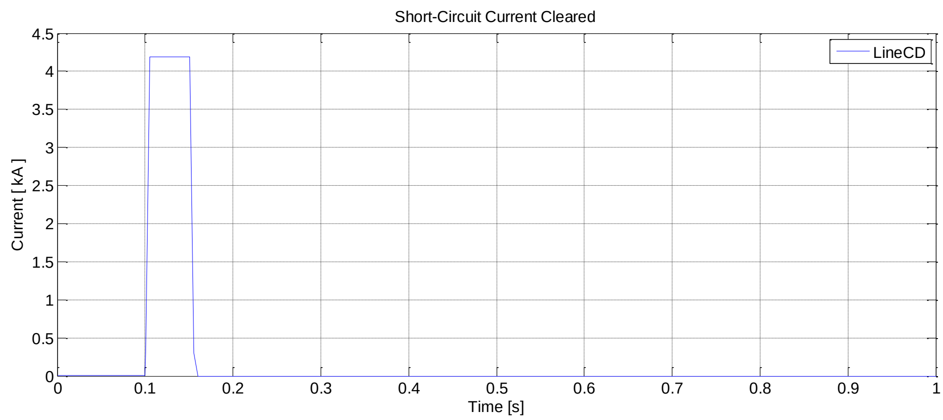

Fig. 3.10 Fault cleared after the relay picks up time

In Fig. 3.11, a single DG with the same characteristics as DG1 is connected to bus B. In this case, for a fault in section AB with relays characteristics same as in the previous case, relays 2 and 1 will not see the upstream fault current. Meanwhile relay 3 will sense the downstream fault current and if this current is higher than the set value, relay 3 operates and hence, DG2 and the downstream loads will form an island [30].

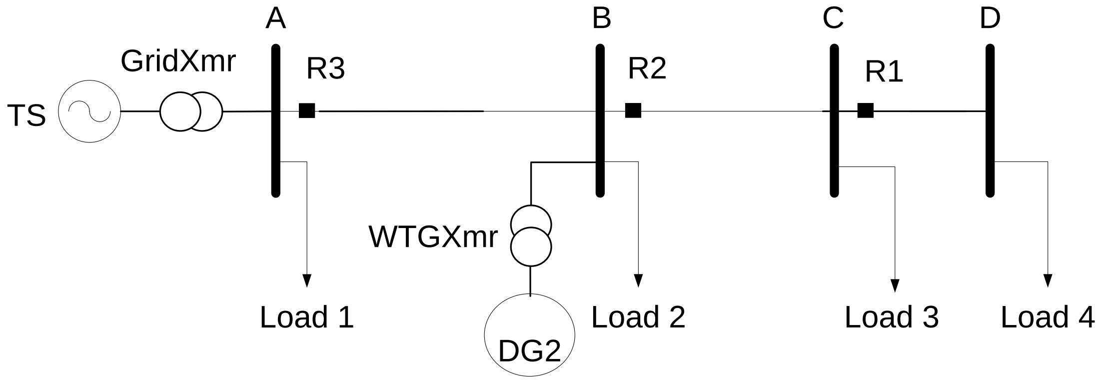

Fig. 3.11 Single DG connected to bus B.

In Fig. 3.12, the short circuit currents for a three phase fault in line CD when DG2 is connected to bus B and without DG, are shown. It can be seen that the short circuit current level in this line is roughly the same as in the previous case since DG2 is providing very little short circuit current to the fault.

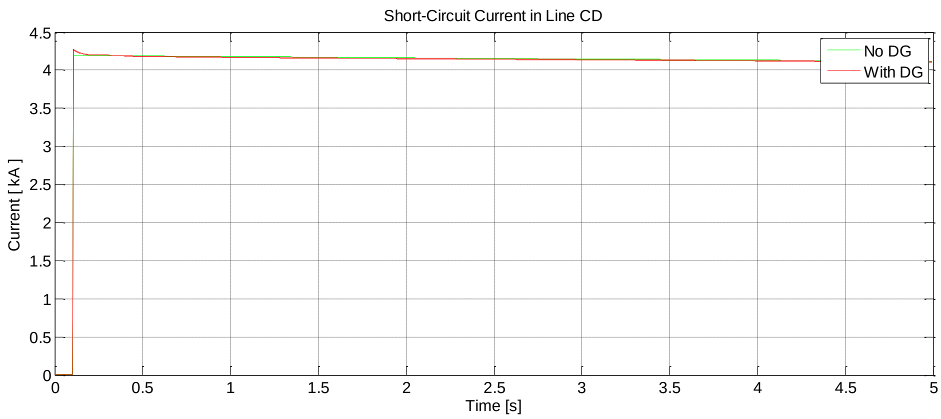

Fig. 3.12 Short circuit current in line CD with DG2 connected

Relay settings are the same as in the previous case. If an island is formed, the protection scenario changes and therefore setting relays must adapt to the new limits. When the system is islanded the short circuit current seen by the relays is less compared to the case when the distribution system is connected to the transmission grid. As a proposed solution adaptative protection relays can be used [32]. These relays are able to update the trip characteristics by detecting the operating states and the faulted section.

- *Multiple DGs interconnected to radial systems*

Fig 3.13 shows, DG2 and DG3 (same characteristics as DG2) connected at bus B and bus C, respectively. For a downstream fault from DG3 the coordination of relays is the same as in the previous case and selectivity between them will hold if the fault is lower than the permissible current limit. For a fault in line BC, relay 2 operates before relay 3 and for a fault in line AB relay 3 should trip while the loads, DG2 and DG3 will form an island. The proper coordination of the relays depends on the amount of fault current, which is increased when DG is connected to the system and should not exceed the predetermined current set range of the relays, if not, coordination may be lost. It can be said that with a downstream fault of DG, selectivity and coordination holds and sensitivity is improved as long as the fault current does not exceed the permissible limits. Whilst for an upstream fault the coordination is probable lost [30].

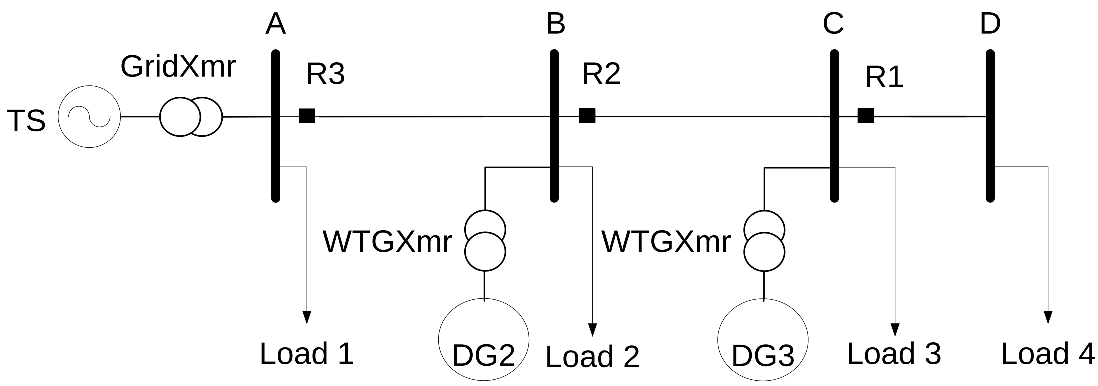

Fig. 3.13 Multiple DGs connected to radial systems

In Fig. 3.14, the short circuit current for a three phase fault in line CD when DG2 and DG3 are connected to bus B and bus C and when they are not is shown. As in the two previous cases not appreciable difference between the short circuit current with and without DG is noticed. However, a slight decrease in the short circuit current when DG it is connected is noticeable in Fig. 3.15. This is a contradictory to the situation experienced before.

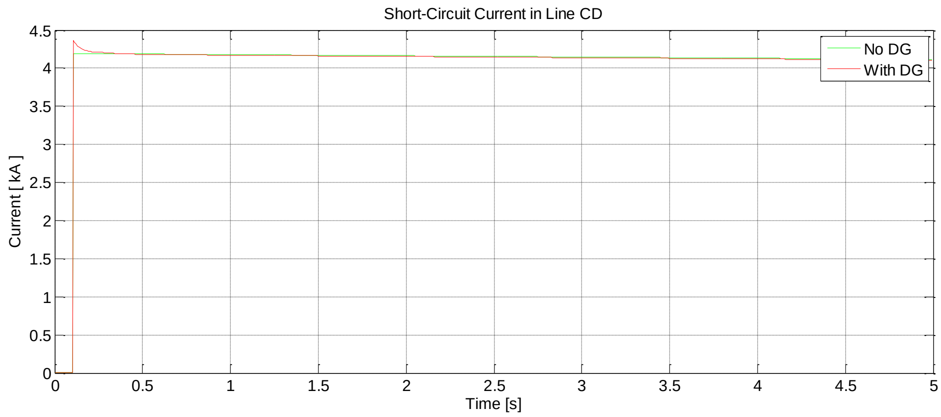

Fig. 3.14 Short circuit current in line CD with DG2, DG3 connected and without DG

The decrease in the short circuit current level when DG is connected to the system is caused by an increase on the impedance seen by the fault. Before the DG is connected, the radial system has less impedance and therefore the current seen by the fault is higher. On the other hand, the connection of DG increases the impedance of the whole system in a proportion defined by the impedance provided by the DG technology, which in this case is wind turbines [1],[17].

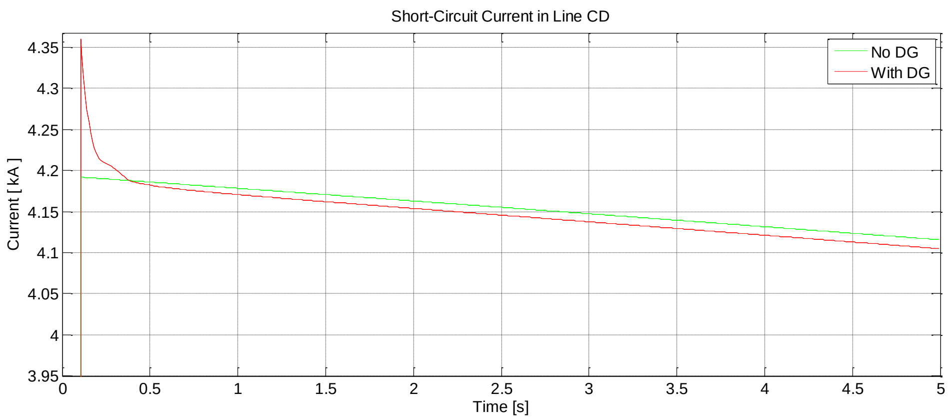

Fig. 3.15 Zoom in area of Fig. 3.14

Relay settings are the same as the previous cases and it was observed that coordination between relays hold and the fault was cleared in the expected time as it is shown in Fig. 3.16.

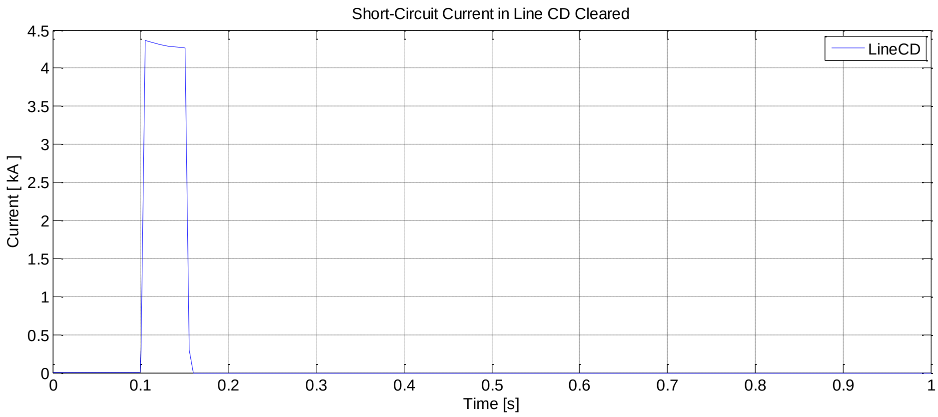

Fig. 3.16 Clearing fault when DG2 and DG3 are connected to the system

As a conclusion it can be said that as long as the fault current does not exceed the permissible current limits, the presence of DG in a system may enhance the coordination between relays by increasing the fault current, but, on the other hand, the DG may also cause a decrease in fault current from the transmission system. Both situations are possible when DG is connected into a radial system and they need to be investigated for minimum tripping or coordination problems. Furthermore, relays operation may lead to islanding (if the DG technology can support the island, for example: synchronous generators), which also needs to be investigated in order to set the proper protection coordination.

Chapter 4

Modelling and Simulation results

4.1 Modelling of distribution system

In this thesis, a 20 kV distribution network in mid Himmerland (Denmark), owned by Himmerlands Elforsyning (HEF) has been chosen. The single line diagram of the distribution system is shown in Fig. 4.1. The network is formed by 11 radial feeders, namely SØRP, STNO, STKV, STSY, JUEL, STK1, HJOR, FLØE, REBD, MAST and STCE. There is also a combined heat and power (CHP) plant with 3 gas turbine generators (GTGs) in feeder STK. The distribution system also has 3 fixed speed wind turbine generators (WTGs) at the end of feeder SØRP.

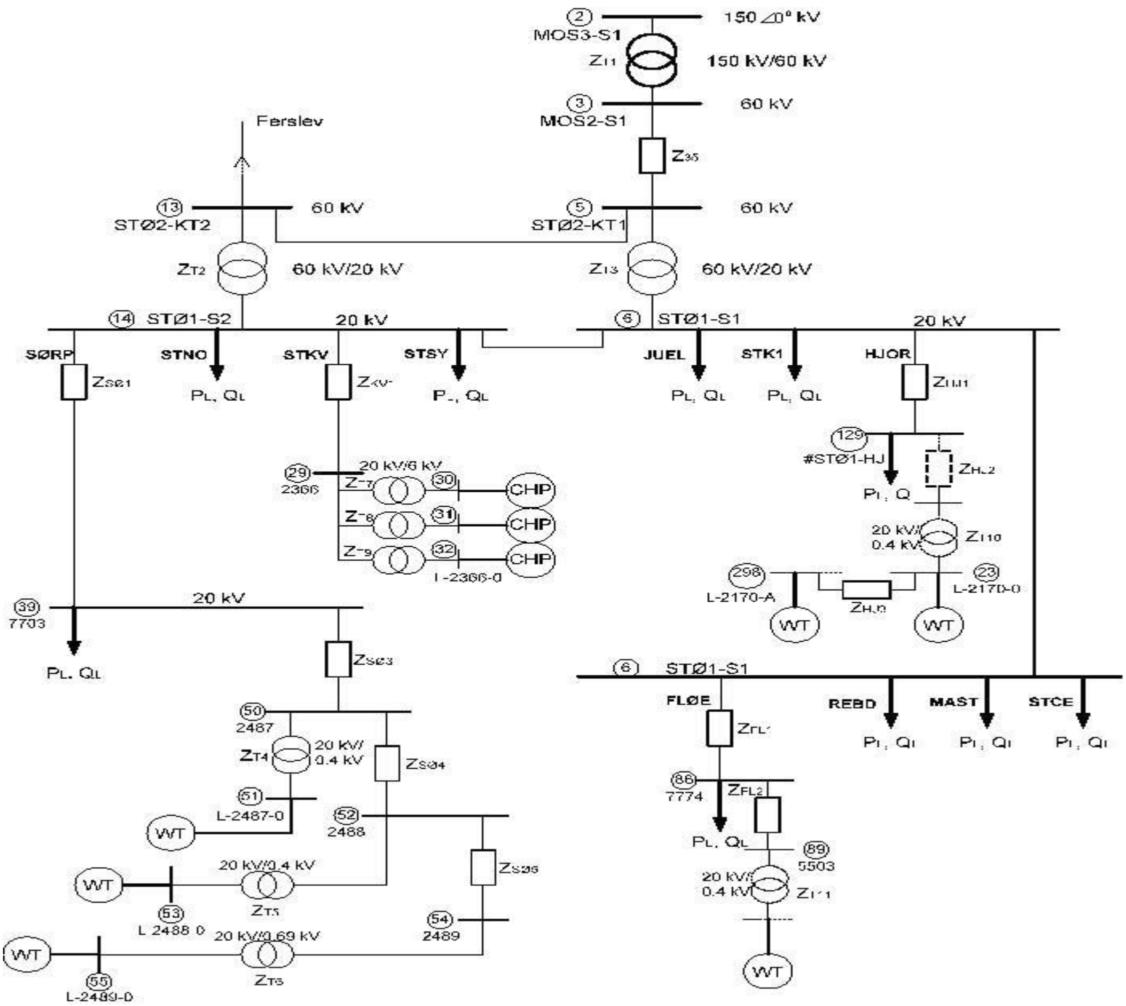

Fig. 4.1 Local distribution network at Støvring in Nordjylland [31]

Feeders STNO, STSY, JUEL, FLØE, MAST and STCE are modelled as an aggregated load connected at Bus 05 named Load 05. Feeders SØRP, STKV, STNO, STSY, JUEL, FLØE, MAST and STCE are the feeders included in the study and analysed. SØRP is modelled as 8 line sections from Bus 05 to Bus 14. The distribution system is modelled as shown in Fig. 4.2. The line data for the test system is given in Appendix Table AVI. All GTGs have the same specifications. They are synchronous generator based and their data is given in Appendix Table AVII. GTGs are connected to Bus 06 through transformers (GTGXmr). The WTGs are induction generator based and their data is given in Appendix Table AII. They are connected to their respective buses through transformers (WTGXmr). The distribution system is connected to the transmission network at Bus 05 through a circuit breaker (CB) and a transformer (GridXmr). The transmission grid is represented by 'Tran Grid' in Fig. 4.2. The data for the transformers are given in Appendix Table AIII and the transmission system data is presented in Table AIV. Capacitor banks are also installed at Bus 12, Bus 13 and Bus 14 to cancel out the reactive power drawn by the WTGs.

The whole test distribution system is modelled in DIgSILENT/Power Factory 14.0.524. For the purpose of this study the GTGs are modelled as synchronous generators and the WTGs as induction generators, using standard models which are available in DIgSILENT. The data for the load and generation is given in Appendix Table AVIII.

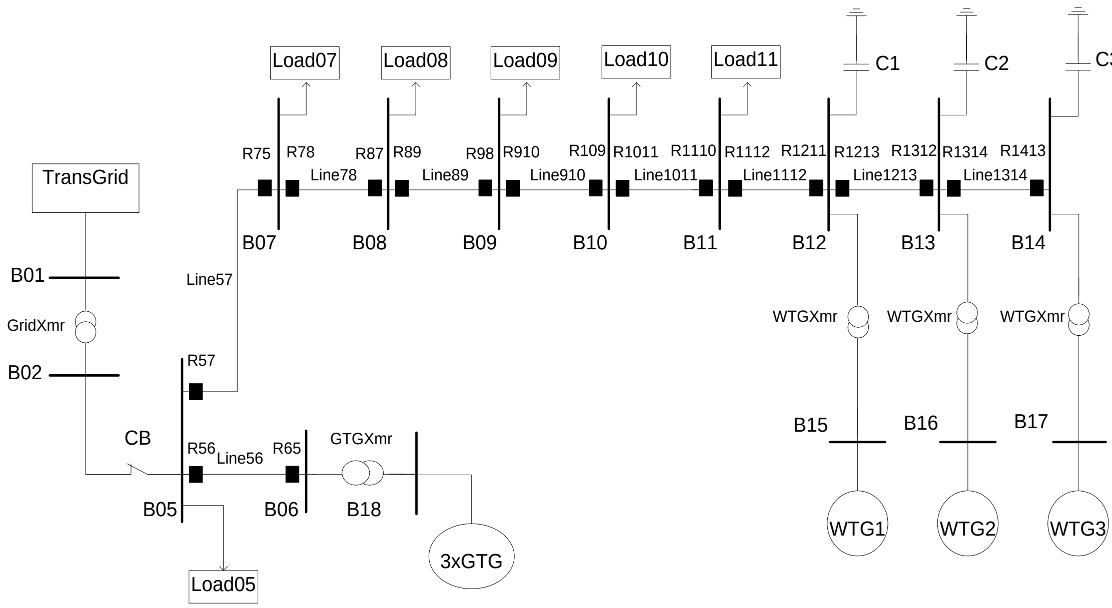

Fig. 4.2 Model of the test distribution network

4.2 Design of over-current relays for the test distribution system

The protection coordination of relays, for the test distribution system, is designed based on the condition of the distribution system. Two cases are simulated and they are:

- Case1 is the normal situation without the presence of DG.
- Case2 is the situation where DG is installed in the system.

Digital directional over-current relays are used for the protection of the radial distribution system to facilitate its operation with DG. Fig. 4.3 is modified form of Fig. 4.2 without any DG. The relays are represented by '**R**' in Fig. 4.2 and Fig. 4.3 with numbers describing the buses that define the beginning and the end of a protection zone.

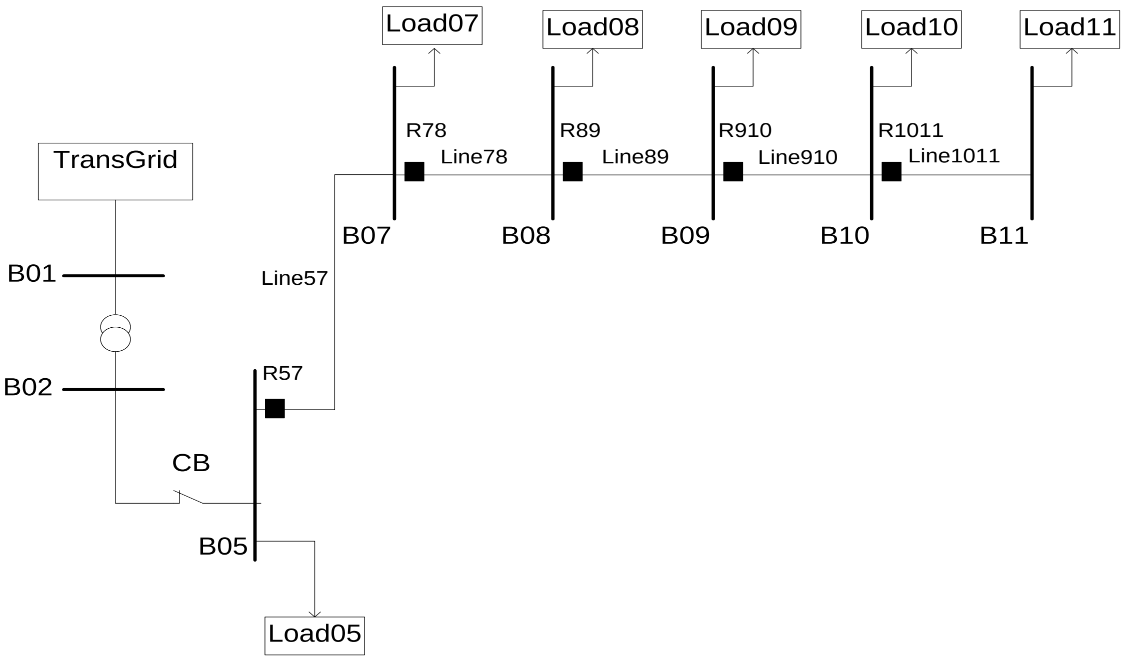

Fig. 4.3 Modified radial distribution system for Case1

Relay R1011 only see forward current when there is a fault in its protection zone and therefore it is designed to trip for smaller current. Relays are set as explained in the previous chapter in section 3.4.1, taking into account that if a fault occurs in Line1011 close to Bus 10, relay R1011 will trip first to clear the fault and relay R910 will provide the backup function. Relays R89, R78 and R57 are designed similarly. The current values are chosen from design study of the test distribution system.

Table 4.1

Time over-currents characteristics of relays R1011, R910, R89, R78 and R57 for Case1

Relay	I_p (A)	TD (s)	Instantaneous pickup current (A)
R1011	150	0.022	3090
R910	200	0.221	3680
R89	250	0.239	4230
R78	325	0.242	4620
R57	410	0.245	4850

The pickup currents, time dial settings and instantaneous pick up currents for the individual relays are listed in Table 4.1.

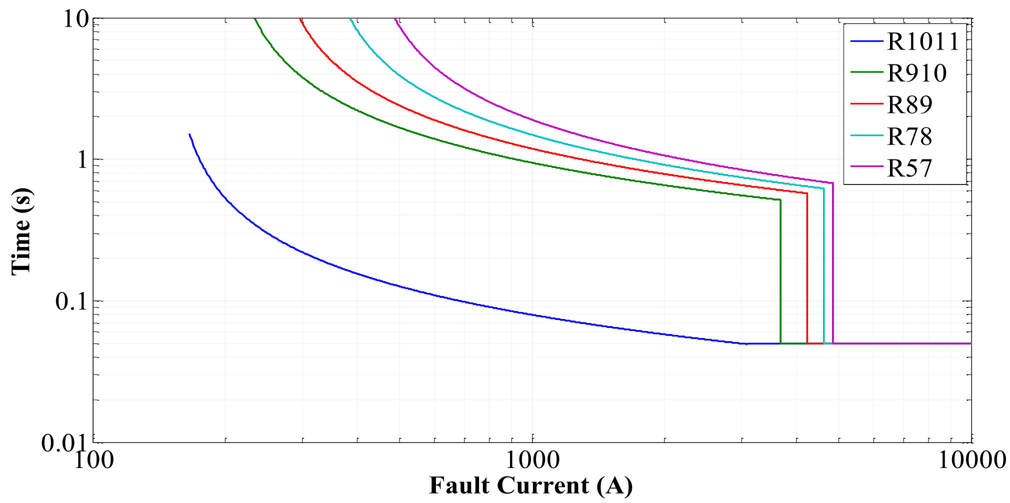

Fig. 4.4 Time over-current characteristic plot of relays R1011, R910, R89, R78 and R57 for Case1

Fig. 4.4 shows the time over-current plots of relays R1011, R910, R89, R78 and R57 for Case1. It is noticed that the proper coordination between relays is achieved.

A three phase fault, with a resistance of *0.05*Ω*,* is simulated in Line1011 close to Bus 10, when the DG is not connected to the system. Fig. 4.5 shows the breaker status; 1 represents that the breaker is closed and 0 represents that it is open. The relay´s time over-current characteristics are as in Fig. 4.4. It can be appreciated from the figure that the fault is cleared by opening the breaker for R1011, *150ms* after the fault, due to the activation of instantaneous pickup.

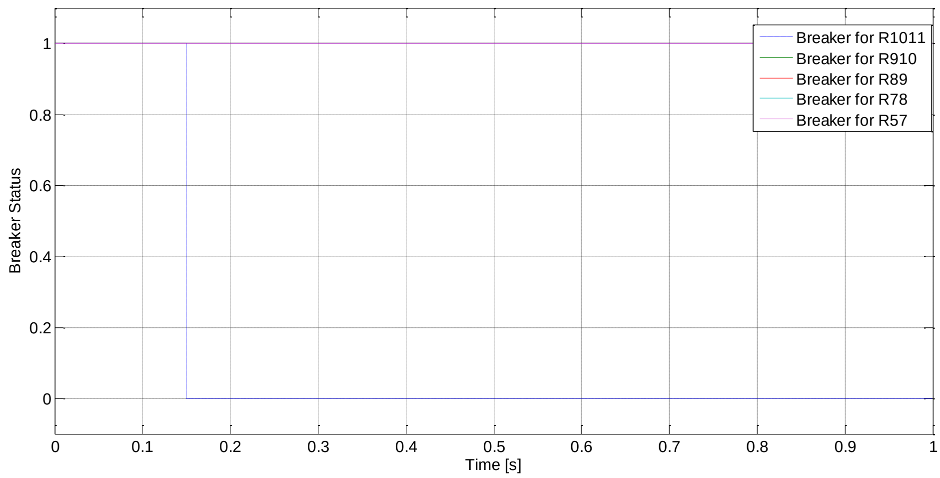

Fig. 4.5 Status of circuit breaker for a three phase fault in Line1011 for Case1 when relays are setting according to Fig. 4.4

Now the DG is interconnected in the system and the same fault is simulated again. Fig. 4.6 shows the breaker´s status. As it can be seen all breakers are opening at the same time, *t=150ms* to clear the fault. This situation is not desirable as the coordination purpose is to isolate only the faulted zone. Moreover, R57 is not tripping and all the current coming from the transmission system and the CHP (three synchronous generators) is supplied to Load07. This may cause high currents and hence, damage for this load.

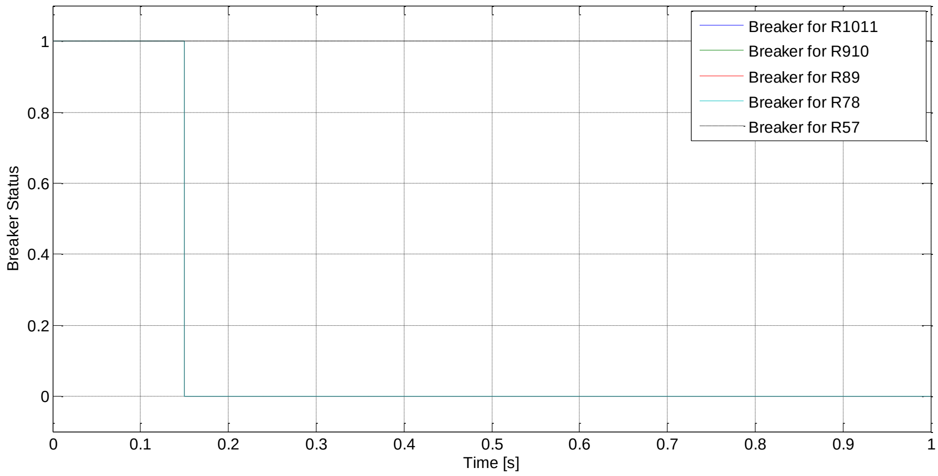

Fig. 4.6 Status of circuit breaker for a three phase fault in Line1011 for Case2 when relays are setting according to Fig. 4.4

There is a significant difference in fault current when the distribution system changes the state from "radial" system to "mesh" type system and hence, coordination may not be attained if the same relay settings are used when DG is interconnected in the system. Fig. 4.7 shows the different currents seen in Line1011 when a three phase fault is simulated near to Bus 10 for the case where DG is not considered in the system (see Fig. 4.3) and for the case with DG connected in the system (see Fig. 4.2). It is observed that this increase in the current is from the contribution of the DG installed in the test system.

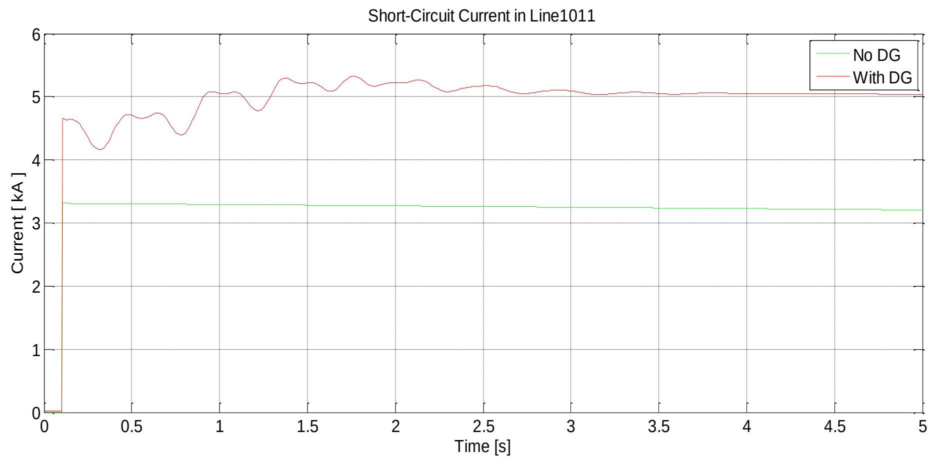

Fig. 4.7 Short circuit current comparison in Line1011 for Case1 and Case2

Therefore, the trip characteristics of relays R1011, R910, R89, R78 and R57 are calculated for the "mesh" condition as well. In Fig. 4.2 the whole system with the DG connected is shown. If a fault occurs in Line1314 close to Bus 13 relay R1314 picks up after *50ms* (instantaneous pickup) to clear the fault. If it fails, then R1213 picks up *500ms* after fault for $I^{1213}_{max1314}$ (current seen by the R1213 when a fault occurs in Line1314). It is assumed that clearing of a fault takes around *70ms* after the picking up of the relays and the reset time is well within *30ms* [31]. Relays R1112, R1011, R910, R89, R78, R57 and R65 are designed similarly for their respective currents seen when a fault occurs in Line1314. The sources of the fault current for a fault in Line1314 are WTG1, WTG2, GTG and the transmission grid. Relay R1314 see only forward current when there is a fault in its protective zone and, consequently, it is designed to trip for smaller current.

The pickup currents, time dial settings and instantaneous pick up currents for the individual relays are listed in Table 4.2.

Table 4.2

Time over-current characteristics of relays R1314, R1213, R1112, R1011, R910, R89, R78, R57 and R65 for Case2

Relay	I_p (A)	TD (s)	Instantaneous pickup current (A)
R1314	250	0.020	2450
R1213	300	0.158	2600
R1112	450	0.160	2930
R1011	490	0.162	4870
R910	640	0.164	6370
R89	700	0.172	7700
R78	745	0.181	8510
R57	810	0.188	9820
R65	1140	0.155	6590

Fig. 4.8 shows the time over-current plots of relays R1314, R1213, R1112, R1011, R910, R89, R78, R57 and R65 for Case2. From a simple observation of Fig. 4.8 it looks like relays lose selectivity as the time over-current characteristic of R65 crosses the time over-current characteristics of other relays. Nevertheless, this is not the case, as R65 see forward current only from the GTG (see Fig. 4.2), whilst the other relays see current from both the GTG and the transmission grid for a fault beyond Bus 05.

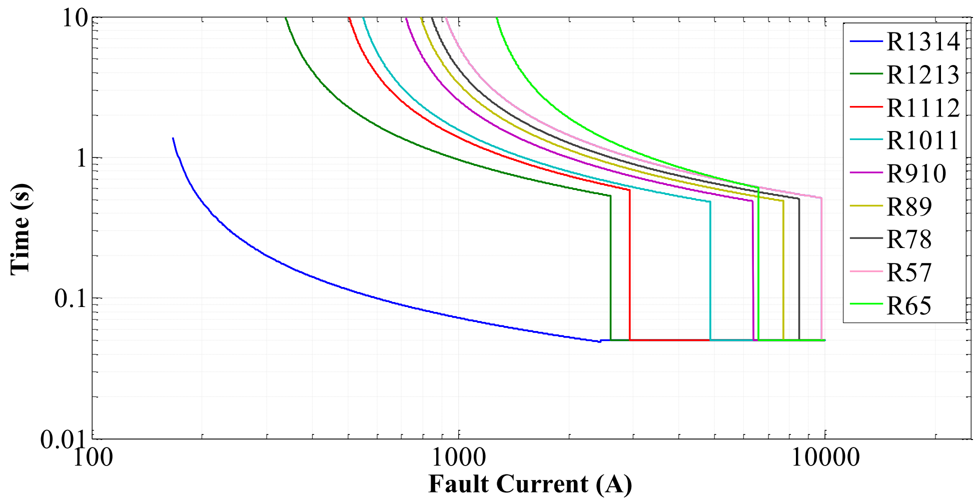

Fig. 4.8 Time over-current characteristics of relays R1314, R1213, R1112, R1011, R910, R89, R78, R57 and R65 for Case2

A three phase fault, with a resistance of *0.05*Ω*,* is simulated in Line1314 close to Bus 13, when the DG is connected to the system. The relay´s time over-current characteristics are as in Fig. 4.8. Fig. 4.9 shows the breaker status. It can be appreciated from the figure that the fault is cleared by opening the breaker for R1314, *150 ms* after the fault, due to the activation of instantaneous pickup.

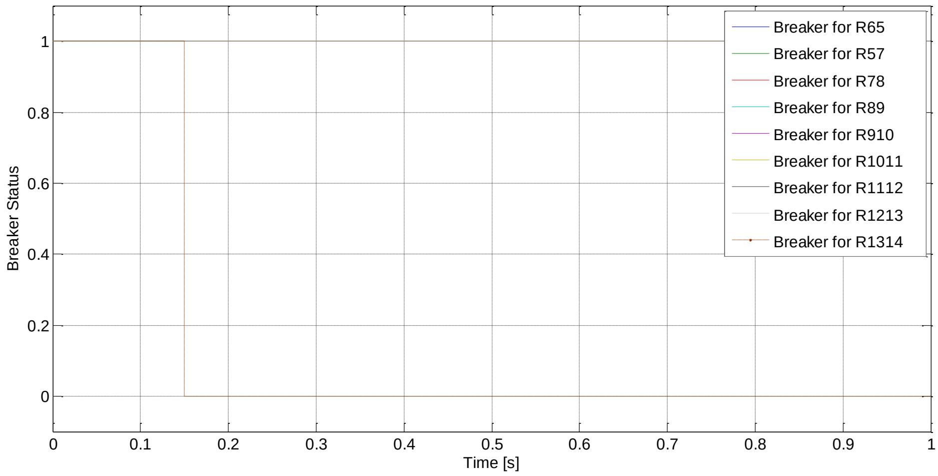

Fig. 4.9 Status of circuit breaker for a three phase fault in Line1314 for Case2 when relays are setting according to Fig. 4.8

In order to set the backward relays R1413, R1312, R1211, R1110, R109, R98, R87, R75 and R56, a three phase fault is simulated in Line56 near to Bus 05. The sources of the fault current are WTG1, WTG2, WTG3 and the transmission grid. The fault contribution from the wind turbines is very small, almost negligible and therefore R56 only sees the fault current coming from the transmission grid, which is the highest source of fault current in the distribution system. Even if the transmission grid is disconnected the fault current contribution from the wind turbines continue being insignificant (see Fig. 4.10).

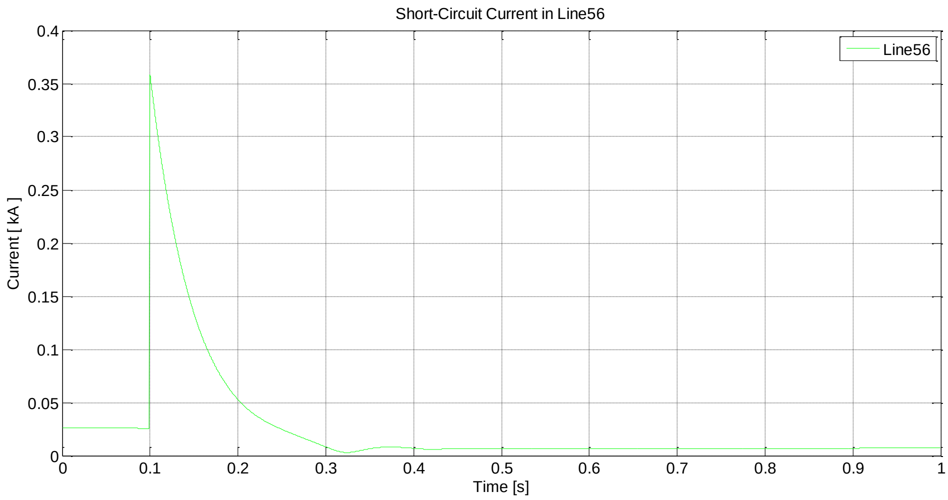

Fig. 4.10 Short circuit current seen in Line56

Fig. 4.11 shows the instantaneous pickup currents for each line of the distribution system when the transmission grid is disconnected and three phase short circuits are simulated in Line56 close to Bus 05, Line57 close to Bus 07, Line78 near to Bus 08, and so on. At the relays instantaneous pickup time (*50ms*) the fault currents are approximately the same and almost negligible for all lines. Therefore, selectivity between relays cannot be attained.

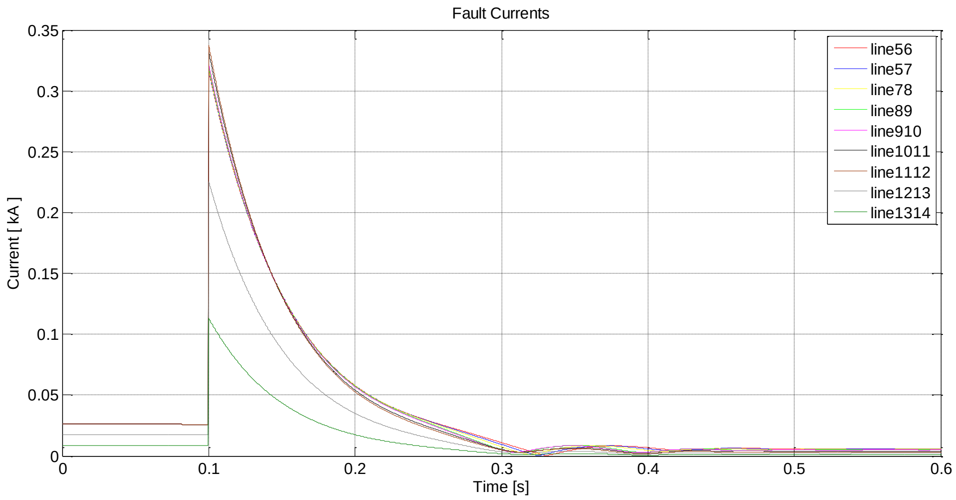

Fig. 4.11 Fault currents seen by relays R56, R75, R87, R98, R109, R1110, R1211, R1312 and R1413 for three phase faults in each line of the test system

In addition, in Fig. 4.12, the fault currents seen by all the relays are shown. It can be noticed that all relays sense the same fault current and that is almost zero.

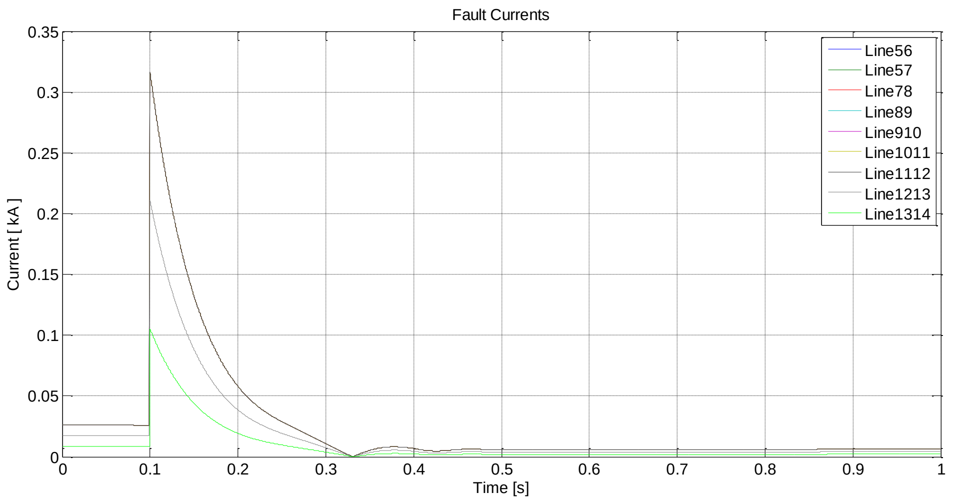

Fig. 4.12 Fault currents seen by the relays R56, R75, R87, R98, R109, R1110, R1211, R1312 and R1413 for a fault in Line56 near to Bus 05

The currents seen by these relays are almost negligible because of the fault current contribution from the CHP (formed by three GTGs) is larger than the fault current contribution from the three WTGs. Thereby, relays R56, R75, R87, R98, R109, R1110, R1211, R1312 and R1413 will see almost no fault current coming from the WTGs and coordination between them cannot be attained. If the currents seen by the relays and the instantaneous pickup currents sensed are considered as not dangerous for any equipment in the distribution system, relays R56, R75, R87, R98, R109, R1110, R1211, R1312 and R1413 may be removed from Fig. 4.2. Hence, the faulted part of the distribution system will be disconnected and fault will be supplied by the WTGs only. However, WTGs cannot sustain fault current and they are tripped by their own protection. The part upstream the fault would have been lost anyways as the WTGs cannot sustain the new islanded part. Hence by avoiding these extra relays for backward protection, hardly any compromise has been made.

Another scenario is simulated where the three wind turbines in Fig. 4.2 are replaced by three gas turbines generators. A three phase fault, with a resistance of 0.05Ω, is simulated in Line1314 close to Bus 13, when the WTGs have been replaced by GTGs. Fig. 4.13 shows the breaker status. The relay´s time over-current characteristics are as in Fig. 4.8. In Fig. 4.13 can be appreciated that the breaker for R1314 and for R1213 are opening at the same time while the rest of the breakers remain closed. This is not a desirable situation as for the same fault two different zones are isolated.

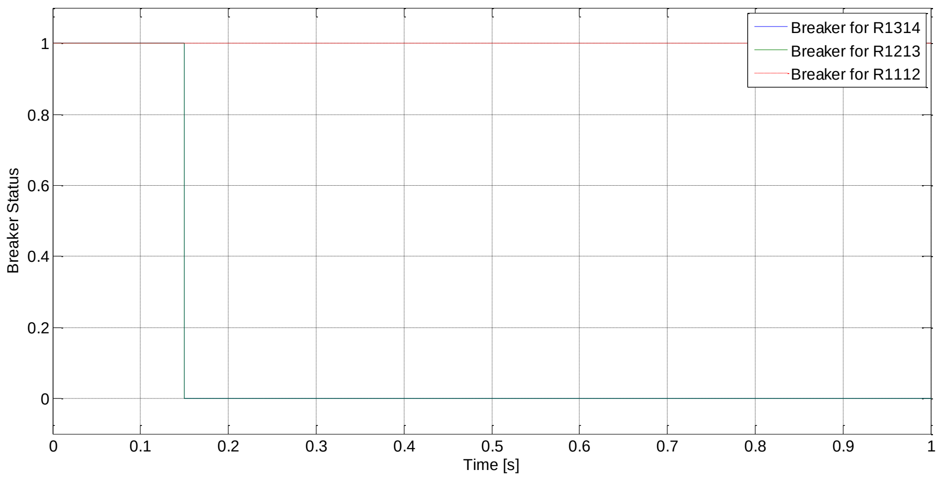

Fig. 4.13 Status of circuit breaker for a three phase fault in Line1314 for Case2 where the WTGs have been replaced by GTGs and relays are set according to Fig.4.8

Therefore, new relays settings needs to be implemented. Relay R56 only see forward current for a fault in its protective zone (see Fig. 4.2), and hence, it is designed to trip for smaller current. If fault occurs in Line56 near to Bus 05, R56 should trip first to clear the fault. If the fault is not cleared after *500ms* then, R75 should trip to clear the fault for $I^{56}{}_{75}$ (current seen by R75 for a fault in Line56 close to Bus 05). Relays R87, R98, R109, R1110, R1211, R1312 and R1413 are designed similarly. The pickup currents, time dial settings and instantaneous pick up currents for the individual relays are listed in Table 4.3.

Table 4.3

Time over-current characteristics of relays R56, R75, R87, R98, R109, R1110, R1211, R1312 and R1413 for the case where the WTGs have been replaced by GTGs

Relay	I_p (A)	TD (s)	Instantaneous pickup current (A)
R56	250	0.016	2200
R75	640	0.098	3360
R87	640	0.116	3500
R98	641	0.134	3134
R109	642	0.152	2918
R1110	644	0.170	2250
R1211	645	0.188	1950
R1312	430	0.201	783
R1413	214	0.214	4000

Fig. 4.14 shows the time over-current characteristic plot of relays R56, R75, R87, R98, R109, R1110, R1211, R1312 and R1413 for the case in which the three WTGs have been replaced by three GTGs.

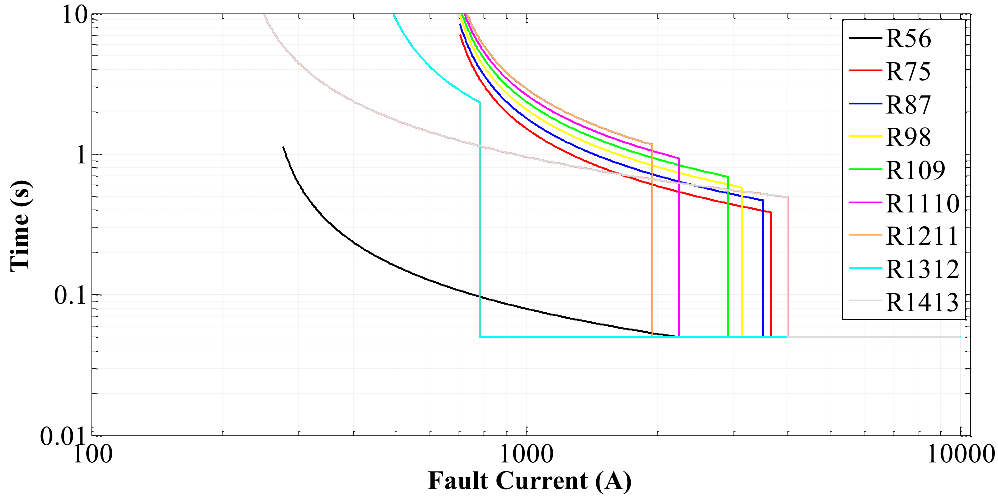

Fig. 4.14 Time over-current characteristics plot of relays R56, R75, R87, R98, R109, R1110, R1211, R1312 and R1413 for the case where the WTGs have been replaced by GTGs

From a simple observation of Fig. 4.14, relays have lost the capacity to be selective due to the presence of DG as the time over-current characteristics of the relays are crossing each other. Therefore, directional over-current relays are not suitable for the protection of the system with the presence of GTGs and another kind of protection should be used. Feasible solutions are presented in section 4.5.

4.3 Modelling of modified distribution system

The distribution test system shown in Fig. 4.2 is modified to illustrate more issues that may appear when DG is connected into radial systems. The three fixed speed wind turbines from the original test distribution system are replaced by two GTGs and a fixed speed wind turbine generator. The line data for the modified test system is given in Appendix Table AIX. The GTGs and WTG data are given in Appendix Table AVII and Table AII respectively. Load data and transformers data are collected in Appendix Table AX and Table AIII, respectively. The transmission grid is represented by 'TransGrid' and its data is given in Appendix Table AIV. Digital directional over-current relays are used for the protection of the radial distribution system to facilitate its operation with distribution generation. The relays are represented by '**R**' in Fig. 4.15 with numbers describing the buses that define the beginning and the end of a protection zone.

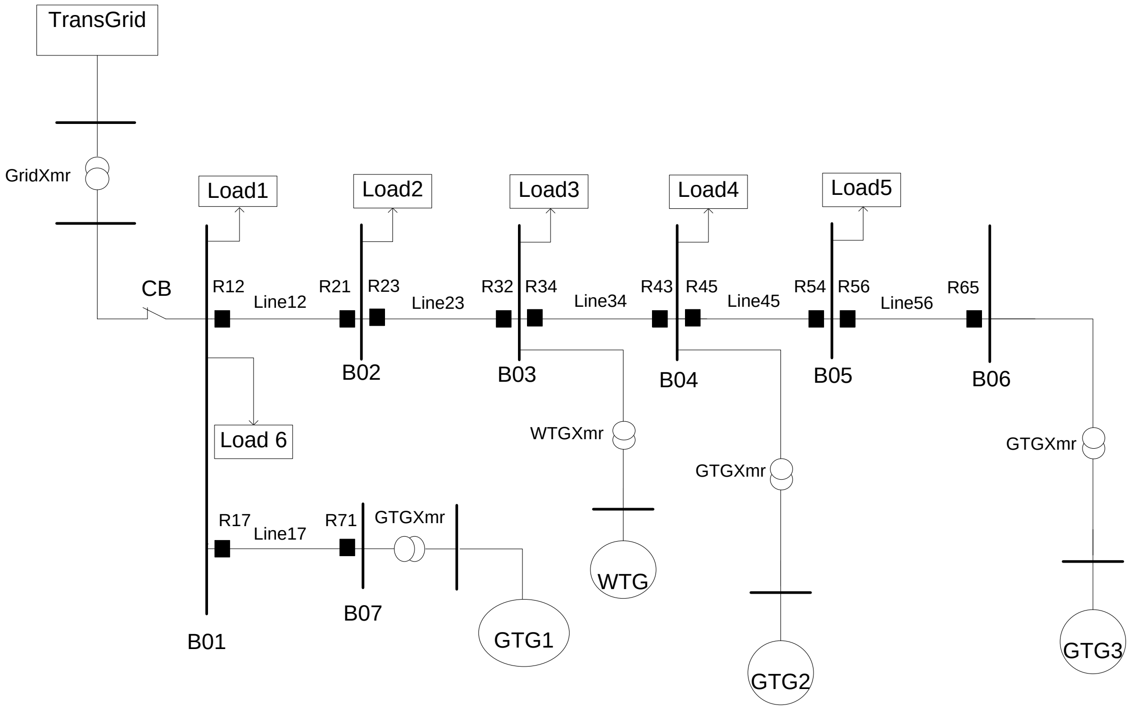

Fig. 4.15 Modified test distribution system

4.4 Design of over-current relays for the modified test distribution system

Firstly, the protection coordination for Case1 (no DG interconnected) is designed. Then, for Case2 each distributed source it is connected at a time, to analyze how the coordination between relays may be affected by increasing the penetration of DG.

The pickup currents, time dial settings and instantaneous pickup current for the individual relays for Case1 are listed in Table 4.4.

Table 4.4

Time over-current characteristics of relays R45, R34, R23 and R12 for Case1

Relay	I_p (A)	TD (s)	Instantaneous pickup current (A)
R45	150	0.016	3680
R34	168	0.280	4220
R23	172	0.299	4620
R12	210	0.330	4850

Fig. 4.16 shows the time over-current plot of relays R45, R34, R23 and R12 for Case1. As it can be appreciated in this figure coordination is achieved.

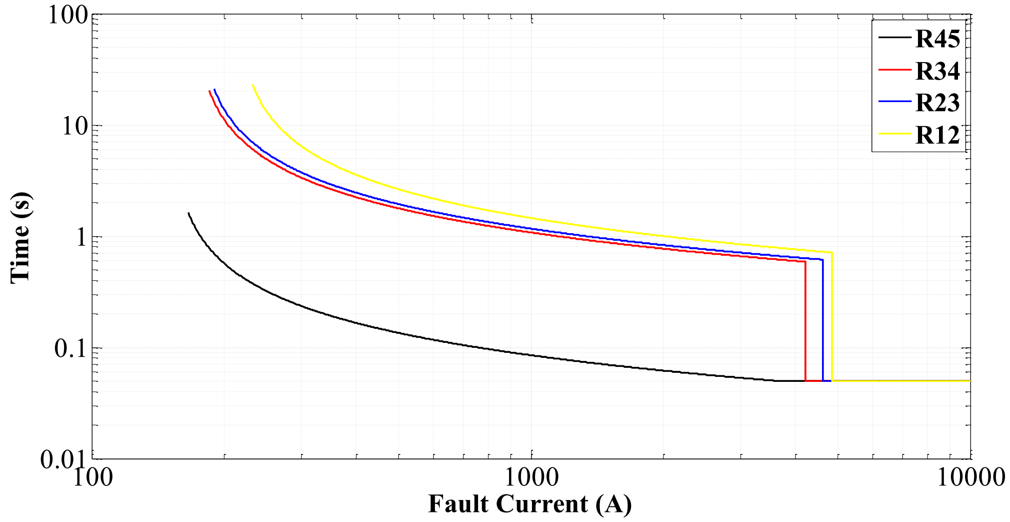

Fig. 4.16 Time over-current characteristics plot of relays R45, R34, R23 and R12 for Case1.

A three phase fault, with a fault resistance of *0.05* Ω, is simulated at the beginning of Line45, when there is not DG connected in the system. The relay´s time over-current characteristics are as in Fig. 4.16. Fig. 4.17 shows the breaker status. It can be seen from the figure that the fault is cleared by opening the breaker for R45, *150ms* after the fault, due to the activation of instantaneous pickup.

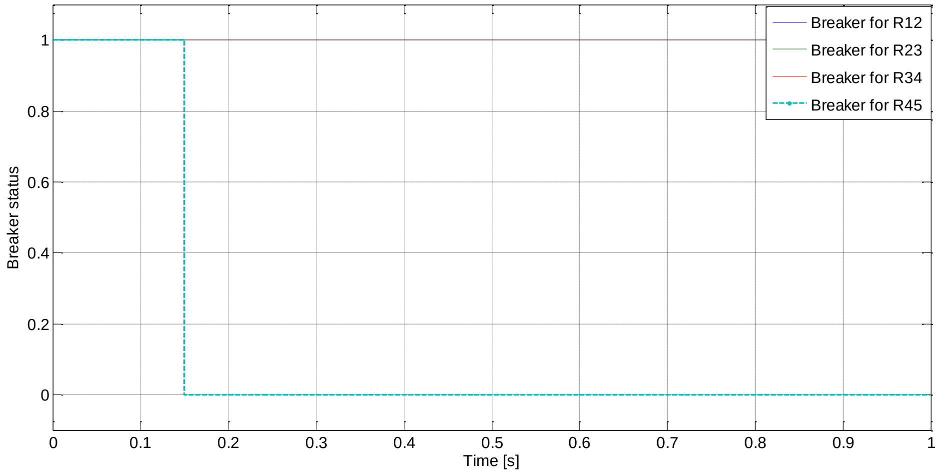

Fig. 4.17 Status of circuit breaker for a three phase fault in Line45 for Case1 and relays are set according to Fig. 4.16

Now the distribution system´s topology is modified by introducing DG sources in Bus 01 and Bus 06. DG in Bus 01 it is formed by three GTGs connected in parallel (CHP plant from Fig. 4.1) and is named as GTG1 for naming convention. The DG in Bus 06 is defined as one GTG with the same specifications as one GTG from the CHP plant and is named as GTG3 for naming convention (see Fig. 4.15).

A three phase fault is simulated in Line45 close to Bus 04, with a fault resistance of *0.05*Ω, when GTG1 and GTG3 are connected to the distribution system. The relay´s time over-current characteristics are as in Fig. 4.16. Fig. 4.18 shows the breaker´s status. It can be seen from the figure that the fault is cleared by opening the breaker for R45, *150ms* after the fault, due to the activation of instantaneous pickup. However, the breaker for R34 is opening at the same time and hence, two different zones are isolated for the same fault. Load4 will be unnecessarily disconnected. Moreover, GTG3 will be supplying Load5 operating in islanded mode, which may have associated problems as described in chapter 2 section 2.5.

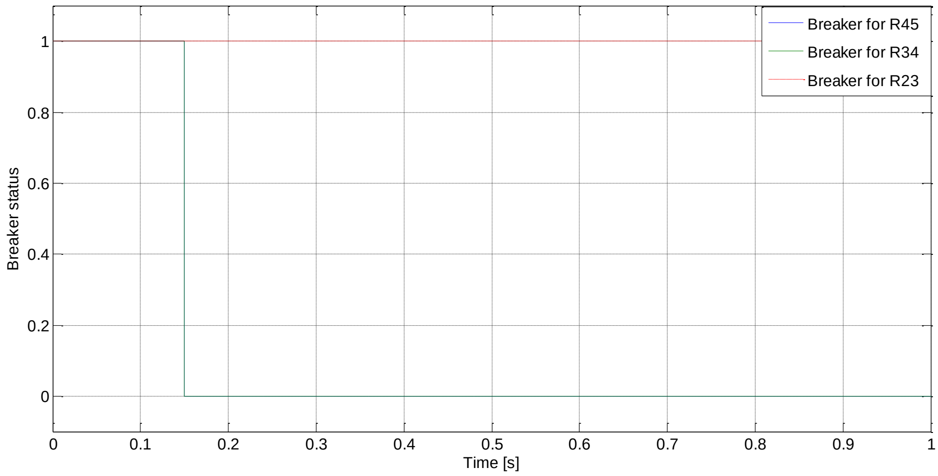

Fig. 4.18 Status of circuit breaker for a three phase fault in Line45 for Case2 when GTG1 and GTG3 are connected and relays are set according to Fig. 4.16

Fig. 4.19 shows the currents seen in Line45 for the same fault as in the previous case. It can be noticed that the change in the current level is caused by the DG installed in the system. Therefore, coordination may not be attained for the same relay settings.

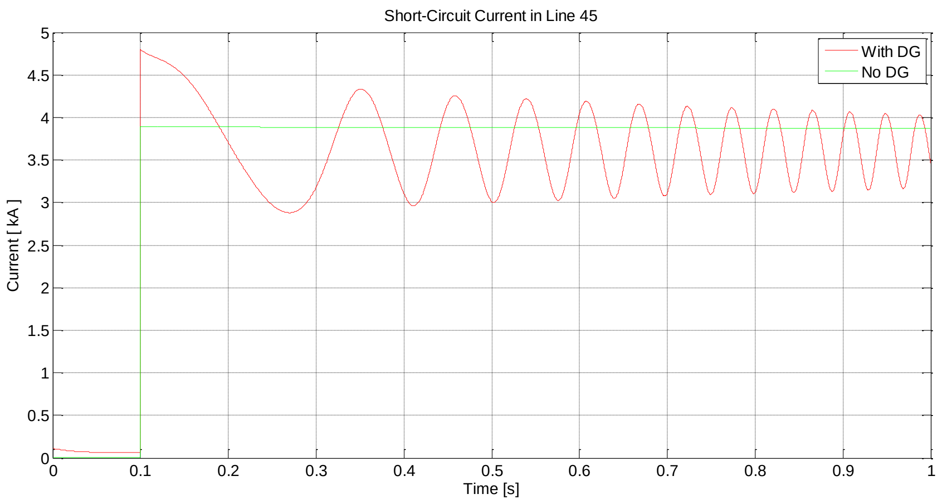

Fig. 4.19 Short circuit current comparison in Line45 for Case1 and 2

New relay settings are implemented. The pickup currents, time dial settings and instantaneous pickup currents for the individual relays for the case, in which GTG1 and GTG3 are connected, are listed in Table 4.5. Relay R56 see forward current only when there is a fault on its protective zone (see Fig. 4.15) and hence, it is designed to trip for smaller currents.

Table 4.5

Time over-current characteristics of relays R56, R45, R34, R23, R12 and R71 for Case2 when GTG1 and GTG3 are connected

Relay	I_p (A)	TD (s)	Instantaneous pickup current (A)
R56	250	0.017	3850
R45	350	0.172	4300
R34	350	0.202	4800
R23	350	0.227	5000
R12	400	0.240	5750
R71	1140	0.180	6550

Fig. 4.20 shows the time over-current plot of relays R56, R45, R34, R23, R12 and R71 for Case2 when GTG1 and GTG3 are connected.

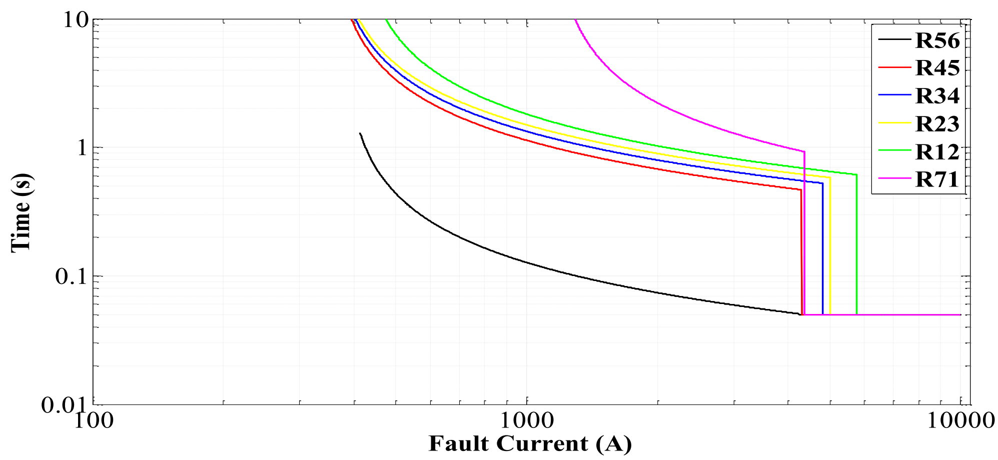

Fig. 4.20 Time over-current characteristics plot of relays R56, R45, R34, R23, R12 and R71 for Case2 when GTG1 and GTG3 are connected

From a simple observation of Fig. 4.20 it looks like relays lose selectivity as the time over-current characteristic of R71 crosses the time over-current characteristics of other relays. Nonetheless, this is not the case because of R71 only see forward current from the GTG1, whilst the other relays see current from both the GTG1 and the transmission grid for a fault beyond Bus 01 (see Fig. 4.15).

In order to set the relays R17, R21, R32, R43, R54 and R65, the transmission grid is disconnected from the system and a three phase short circuit is simulated in Line17 close to Bus 01. As it is shown in Fig. 4.21, all relays sense the same fault current and therefore, selectivity may be lost.

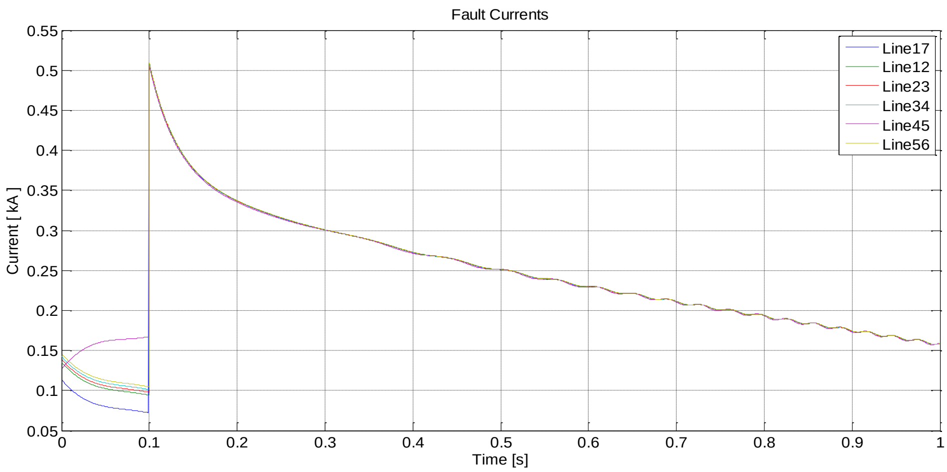

Fig. 4.21 Fault currents seen by the relays R17, R21, R32, R43, R54 and R65 for a fault in Line17 close to Bus 01 when GTG1 and GTG3 are connected

In addition, in Fig. 4.22, the instantaneous pick up currents for each line of the test system are shown. Three phase faults are simulated in Line56 close to Bus 06, Line45 close to Bus 05, Line34 close to Bus 04 and so on. At the relays instantaneous pickup time (*50ms*) the fault currents are roughly the same for all the lines. Therefore, selectivity between relays cannot be attained.

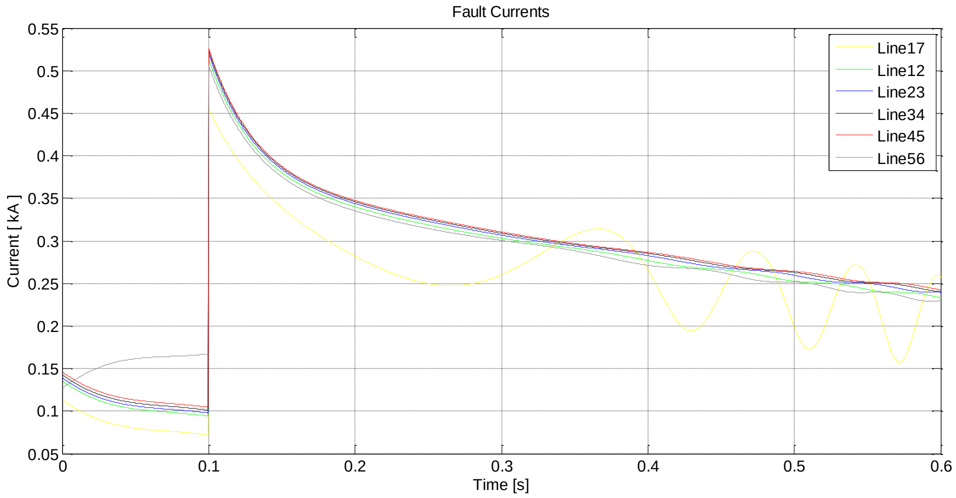

Fig. 4.22 Fault currents for Case2 when GTG1 and GTG3 are connected

Another scenario is simulated where GTG1 is removed from the system, GTG3 remains connected and GTG2 is connected to Bus 04 (see Fig. 4.15). GTG2 has the same specifications as GTG3. A three phase fault is simulated in Line45 close to Bus 04, with a fault resistance of *0.05*Ω, when GTG2 and GTG3 are connected to the distribution system. The relay´s time over-current characteristics are as in Fig. 4.20. The breaker for R45 is not clearing the fault. Moreover, the breakers of relays R34, R23 and R12 are opening and hence, coordination is not achieved. GTG2 and GTG3 are supplying loads Load4 and Load5 in islanded mode and some complications may arise as described in chapter 2 section 2.5. New relay settings are designed and presented below.

The pickup currents, time dial settings and instantaneous pickup current for the individual relays for the situation in which GTG2 and GTG3 are connected are listed in Table 4.6.

Table 4.6

Time over-current characteristics of relays R56, R45, R34, R23 and R12 for Case2 when GTG2 and GTG3 are connected

Relay	I_p (A)	TD (s)	Instantaneous pickup current (A)
R56	250	0.017	3850
R45	380	0.202	4100
R34	450	0.212	4400
R23	720	0.179	4700
R12	820	0.188	5000

Fig. 4.23 shows the time over-current plot of relays R56, R45, R34, R23 and R12 for Case2 when GTG2 and GTG3 are connected. As it can be appreciated in this figure coordination is attained.

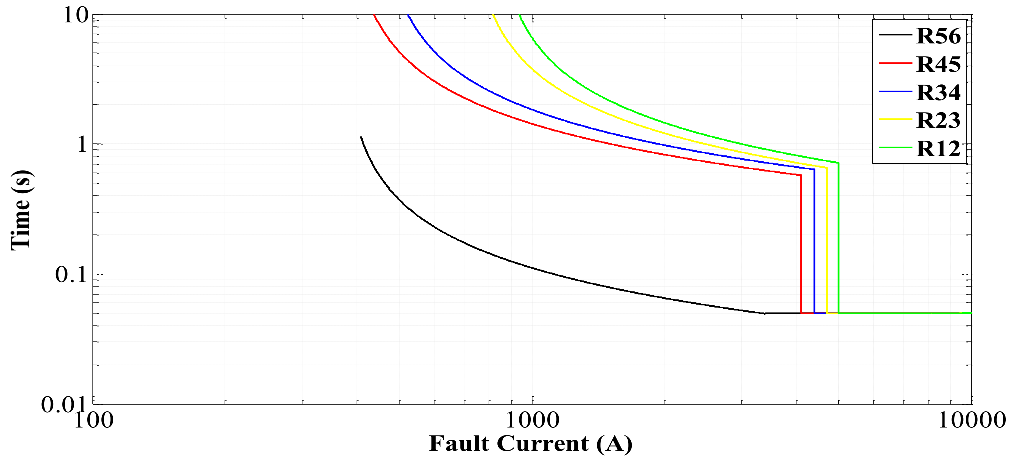

Fig. 4.23 Time over-current characteristics plot of relays R56, R45, R34, R23 and R12 for Case2 when GTG2 and GTG3 are connected

The tuning of the relays R21, R32, R43 and R65 is performed with the transmission grid disconnected and simulating a three phase short circuit in Line12 near to Bus 02.

As it can be seen in Fig. 4.24, relays R65 and R54 sense the same fault current coming from GTG3, then the fault current is increased in Line34 because of the fault current supplied by the GTG2 and relays R43, R32 and R21 see the same current. Therefore, coordination may not hold.

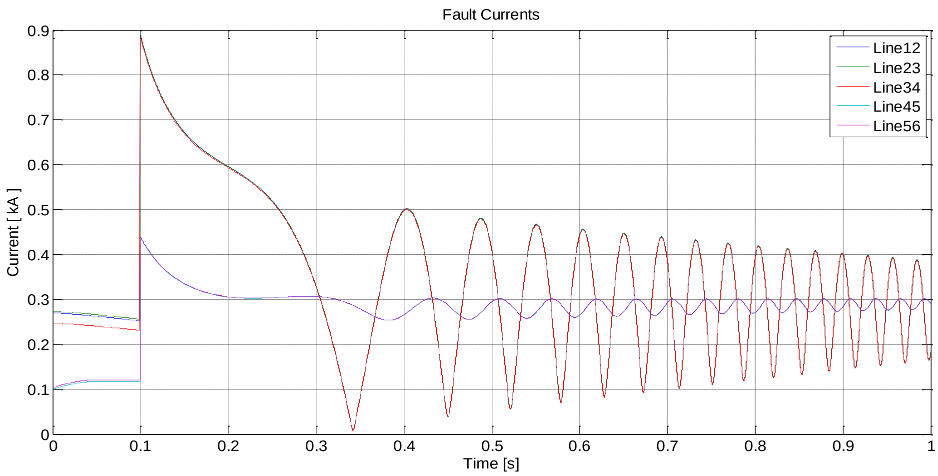

Fig. 4.24 Fault currents seen by the relays R21, R32, R43, R54 and R65 for a fault in Line12 close to Bus 02 when GTG2 and GTG3 are connected

As well, in Fig 4.25, the instantaneous pickup currents for each line of the distribution system are shown. Three phase faults are simulated in Line56 close to Bus 06, Line45 close to Bus 05, Line34 close to Bus 04 and so on. At the instantaneous pickup time selectivity between relays cannot be attained as the curves are crossing very close to each other.

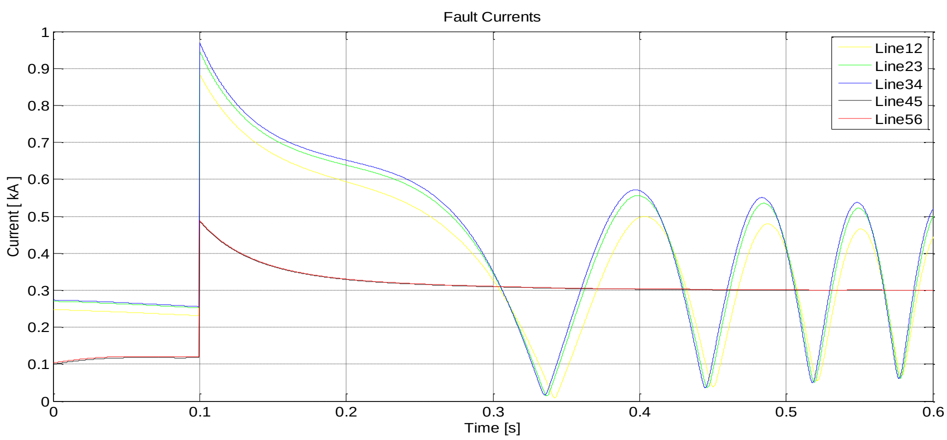

Fig. 4.25 Fault currents for Case2 when GTG2 and GTG3 are connected

A new scenario is simulated where GTG1, GTG2 and GTG3 are connected to the system. A three phase fault is simulated in Line45 close to Bus 04, with a fault resistance of *0.05*Ω, when GTG1, GTG2 and GTG3 are connected to the distribution system. The relay´s time over-current characteristics are as in Fig. 4.23. The breaker status are shown in Fig. 4.26. As it can be seen from this figure, the breaker for R45 is opening along with the breaker for R34 at *150ms* after the fault, due to the activation of instantaneous pickup time. Therefore, Load4 is unnecessarily disconnected and coordination is not attained. GTG2 is disconnected from the system but, GTG3 will operated in islanded mode supplying power to Load5.

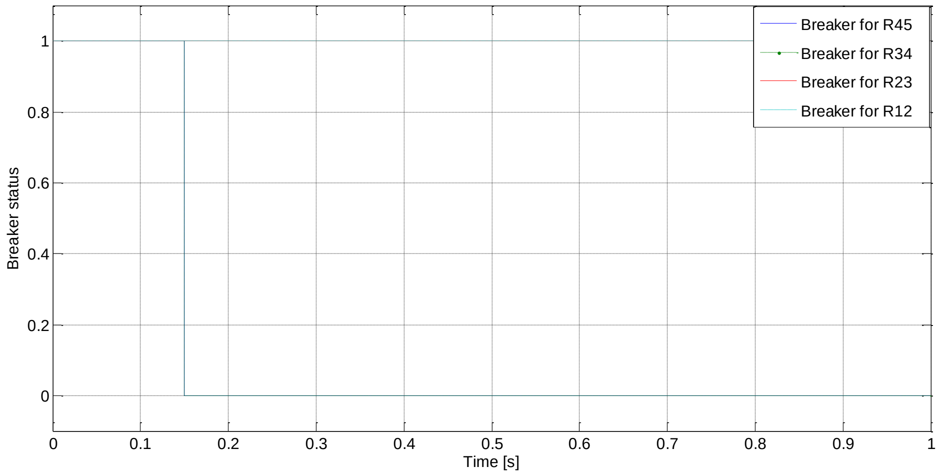

Fig. 4.26 Status of circuit breaker for a three phase fault in Line45 for Case2 when GTG1, GTG2 and GTG3 are connected and relays are set according to Fig. 4.28

New relays settings are calculated for the situation where GTG1, GTG2 and GTG3 are connected. The pickup currents, time dial settings and instantaneous pickup current for the individual relays for the situation in which GTG1, GTG2 and GTG3 are connected are listed in Table 4.7.

Table 4.7

Time over-current characteristics of relays R56, R45, R34, R23, R12 and R71 for Case2 when GTG1, GTG2 and GTG3 are connected

Relay	**I_p (A)**	**TD (s)**	**Instantaneous pickup current (A)**
R56	250	0.017	3850
R45	400	0.197	4650
R34	720	0.171	4800
R23	750	0.190	5300
R12	750	0.198	6100
R71	1140	0.180	6550

Fig. 4.27 shows the time over-current plot of relays R56, R45, R34, R23, R12 and R71 for Case2 when GTG1, GTG2 and GTG3 are connected. As it can be appreciated in this figure coordination is achieved.

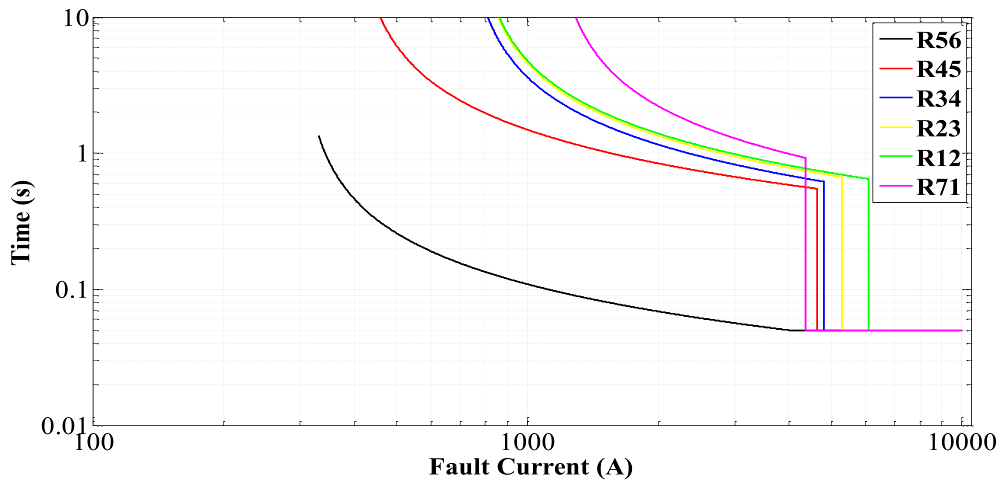

Fig. 4.27 Time over-current characteristics plot of relays R56, R45, R34, R23, R12 and R71 for Case2 when GTG1, GTG2 and GTG3 are connected

In order to set the backward relays, three phase faults are simulated in each line of the distribution system as explained in previous cases, without the transmission system connected. As it can be seen in Fig. 4.28 the instantaneous pickup currents in each line of the distribution system are crossing at *50ms* very close to each other. Relays R65 and R54 see the same current for the same type of fault in different protection zones. For a fault in Line65 close to Bus 06 relay R65 trips to clear the fault, but R54 also trips, disconnecting a healthy branch. Selectivity is lost and the main purpose of protection coordination, which is to isolate only the faulted zones.

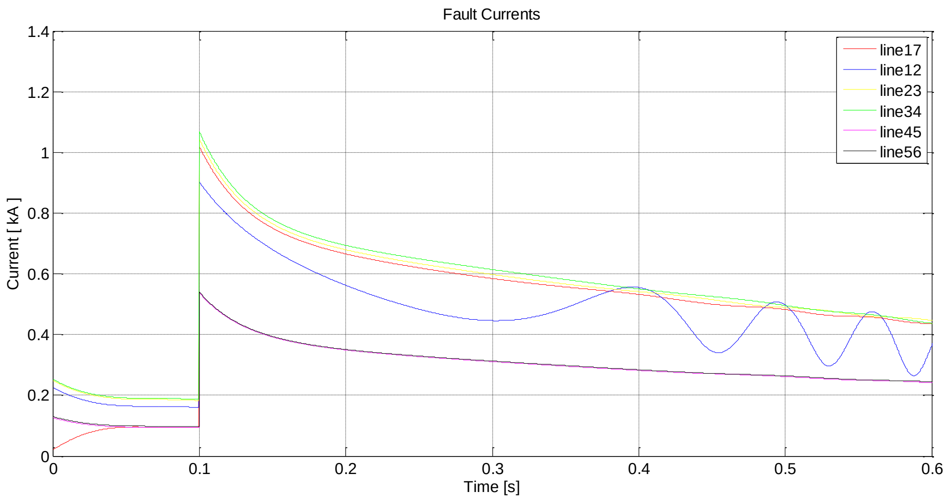

Fig. 4.28 Instantaneous pickup currents for Case2 when GTG1, GTG2 and GTG3 are connected

In Fig. 4.29 the currents seen by the relays for a three phase short circuit fault in Line17 near to Bus 01 are shown. Relays R65 and R54 see the fault current flowing from GTG3, which is increased in Line34 by GTG2, and hence, R43, R32, R21 and R17 will see more fault current.

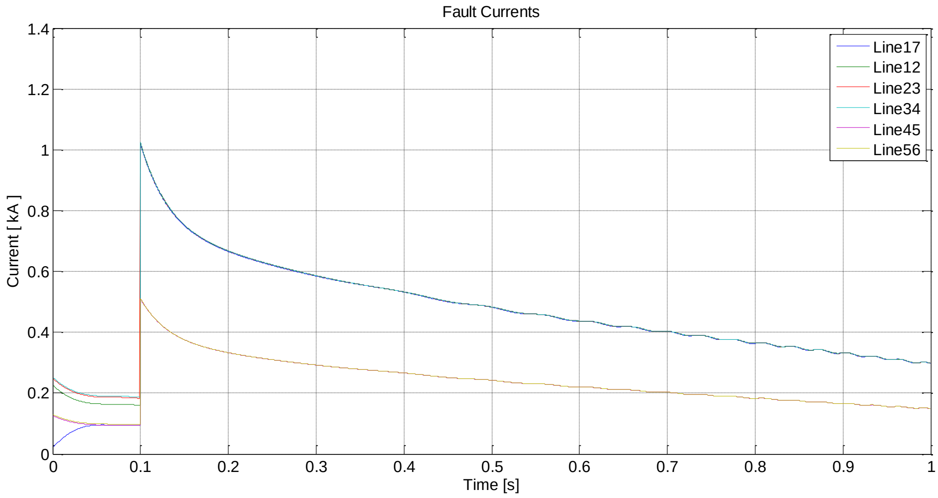

Fig. 4.29 Fault currents seen by the relays R21, R32, R43, R54 and R65 for a fault in Line45 close to Bus 05 when GTG1, GTG2 and GTG3 are connected

Another scenario is simulated where GTG1, GTG2, GTG3 and WTG are connected to the system. A three phase fault is simulated in Line45 close to Bus 04, with a fault resistance of 0.05Ω, when GTG1, GTG2, GTG3 and WTG are connected to the distribution system. The relay´s time over-current characteristics are as in Fig. 4.27. Fig. 4.30 shows the breaker status. It can be seen from the figure that the breaker for R45 is opening and breakers for relays R34, R23 and R12 remains closed. Therefore coordination is achieved for the same relays settings employed in the case where GTG1, GTG2 and GTG3 are connected to the distribution system.

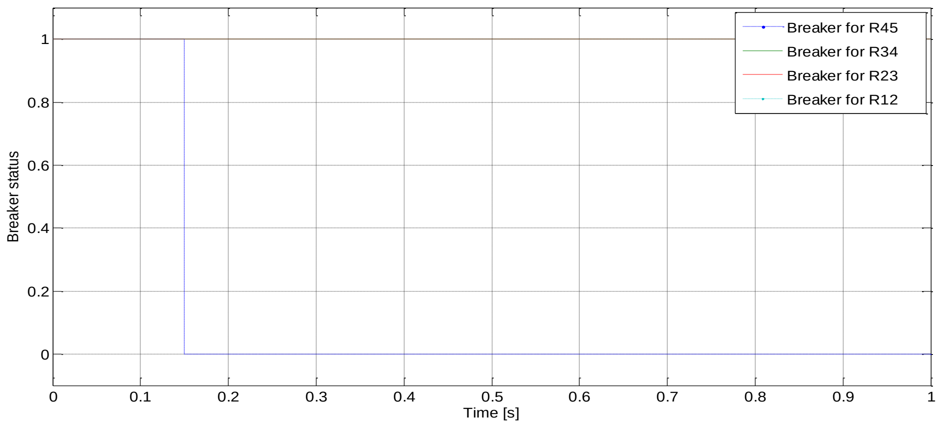

Fig. 4.30 Status of circuit breaker for a three phase fault in Line45 for Case2 when GTG1, GTG2, GTG3 and WTG are connected and relays are set according to Fig. 4.28

Fig. 4.31 shows the short circuit current levels in Line56 when all the GTGs and when all the DG (GTGs and the WTG) are connected in the system. The two curves are very close to each other as the fault current provided by the WTG is small. Therefore, the contribuetd current by the WTG does not affect the existing protection coordination.

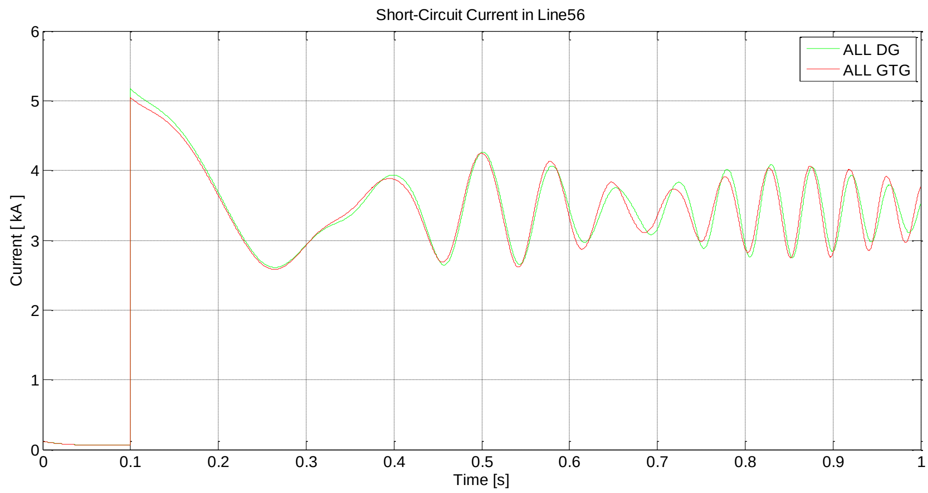

Fig. 4.31 Short circuit current comparison in Line56 for the condition in which all the DG are connected and with all the GTG

The setting of the backwards relays is performed as in previous cases. Fig.4.32 shows the instantaneous pickup currents in each line of the distribution system. It is noticed that the short circuit levels have increased by adding the WTG and that at *50ms* the curves are crossing very close to each other as in the previous situation. R17 will trip first for a fault in its protective zone, then R21 should trip for a fault in its protective zone, but the fault currents seen by R32, R43 and R65 will be the approximately the same as R21, hence, selectivity between them cannot be achieved.

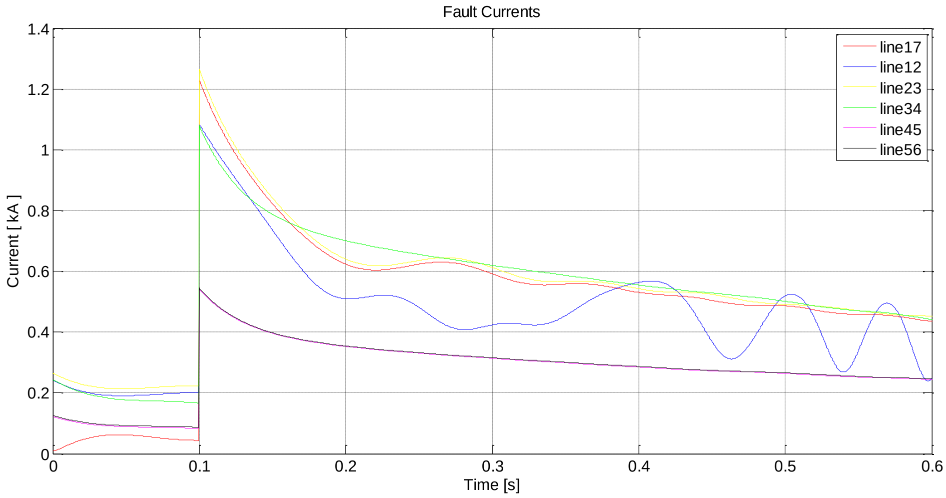

Fig. 4.32 Fault currents for Case2 when GTG1, GTG2, GTG3 and WTG are connected

In Fig. 4.33 the fault currents seen by the relays R17, R21, R32, R43, R54 and R65 when a three phase fault occurs in Line17 near to Bus 01 are shown. As in the previous case, relays R65 and R54 see the fault current flowing from GTG3, which is increased in Line34 by GTG2, and hence, R43, R32, R21 and R17 will see more fault current.

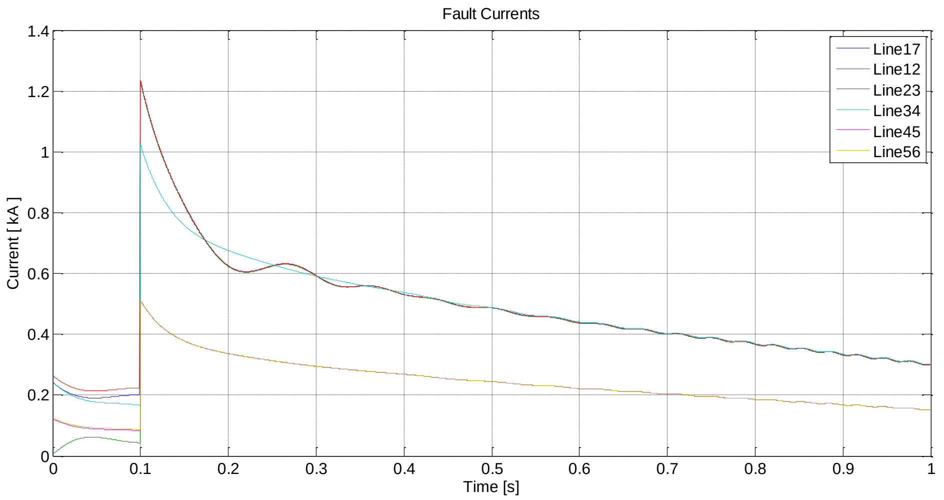

Fig. 4.33 Fault currents seen by the relays R21, R32, R43, R54 and R65 for a fault in Line17 close to Bus 01 when GTG1, GTG2, GTG3 and WTG are connected

4.5 Solutions for issues with protection in presence of a significant number of DG.

In sections 4.2 and 4.4, the main issues encountered with protection coordination when DG is interconnected to a radial system were presented. For the test system in section 4.2, selectivity between forward relays was achieved for the case in which WTGs were connected to the system. However, when these WTGs were replaced by GTGs, forward selectivity was lost, as well as, coordination between backward relays was not attained neither with WTGs nor with GTGs interconnected in the network.

The simulations performed in the modified test system in section 4.4 shows that coordination between forward relays could be achieved for different operating scenarios. Nevertheless, coordination for backward relays could not be attained in non of the cases.

The use of distance relays, differential relays and adaptive protection as feasible alternatives to over-current relays, are briefly discussed in the following sections.

4.5.1 Distance Relays

Distance relays have a balance between current and voltage, expressed in terms of impedance. When a line is protected against short circuits, the relation between the voltage at the relay´s location and the fault current flowing to the short circuit, is defined by an impedance. This impedance is proportional to the physical distance from the relay to the short circuit. Therefore, these relays achieve selectivity on the basis of impedance rather than current. If there is any abnormal situation, as for example more short circuit current flowing to the fault than which it is expected, the balance between the voltage at the relay´s location and the increased short circuit current will correspond to a impedance that does no longer represents the line distance between the relay´s location and the fault location and therefore relay will trip[32].

Distance relays are not so much influenced by changes in short circuit magnitude as for instance over-current relays are, and hence, are preferred to over-current relays as they are less affected by modifications in generation capacity and system topology. Distance relay setting is constant for a wide range of changes external to the protected line and should be used when over-current relay is slow or is not selective [32].

Distance relays are classified in impedance, reactance and admittance or MHO type depending on their application and operating characteristic.

The impedance relay does not have directional characteristic and its main application is as a fault detector [33].

The admittance relay is the most commonly used distance relay. It has directional characteristic and can be designed to correspond to the distribution line impedance. It is the tripping relay in pilot schemes and as the backup relay in step distance schemes [33].

The reactance relay is not directional and it responds only to the reactance of the protected line. It is used to complement the admittance relay making the overall protection independent of resistance [33].

Some of their main application cases are explained in [34, pg.306]. These relays may overcome the problems encountered with over-current protection as they are impedance selective, they trip depending on variations in the impedance defined by the relation between the voltage at the relay´s location and the short circuit current flowing to the fault. They do not depend on the current variations as much as over-current relays. Therefore, they are less affected by changes in current levels and hence, less influenced by variations on generation capacity or system´s topology.

4.5.2 Differential Relays

Differential relays may have several configurations based on the equipment that they protect and almost any type of relay can be made to operate as a differential relay, if it is connected in a determined manner [34]. In Fig. 4.34, a simple differential relay connection is shown.

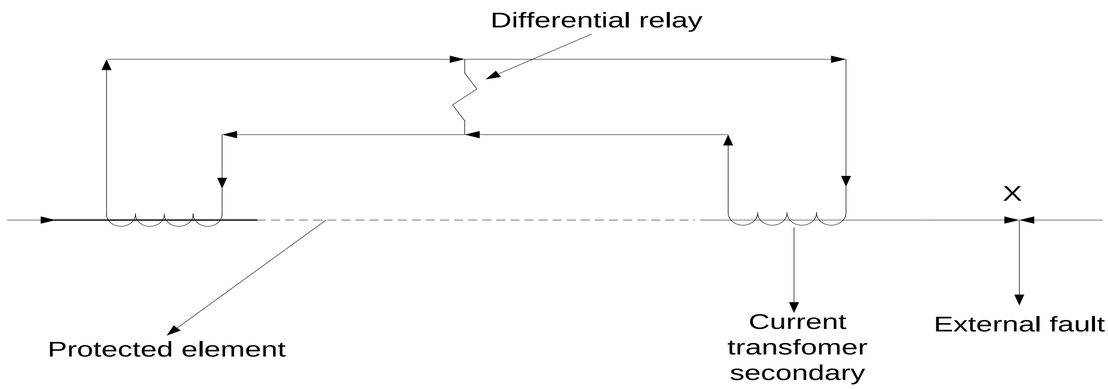

Fig. 4.34 Differential relay behaviour for an external fault

The protected element (dashed line) may be a line, a winding of a generator, etc. Current transformers are connected at both ends of the protected element. In addition, the current transformer secondary's are interconnected and an over-current relay is installed across the current transformer secondary circuit. If a fault occurs at X and the two current transformers have the same ratios, the currents will flow as indicated by the arrows (see Fig. 4.34) and no current will be seen by the differential relay.

However, if an internal fault occurs as shown in Fig. 4.35, differential current will flow as a result of the sum of the secondary currents. Fig 4.35 shows that the short circuit current is flowing to the differential relay from both transformer secondary´s, but, even if the short circuit current flows to the differential relay from only one transformer secondary, differential current will be seen. Differential relay will operate if the differential current exceeds a predetermined relay´s pickup value.

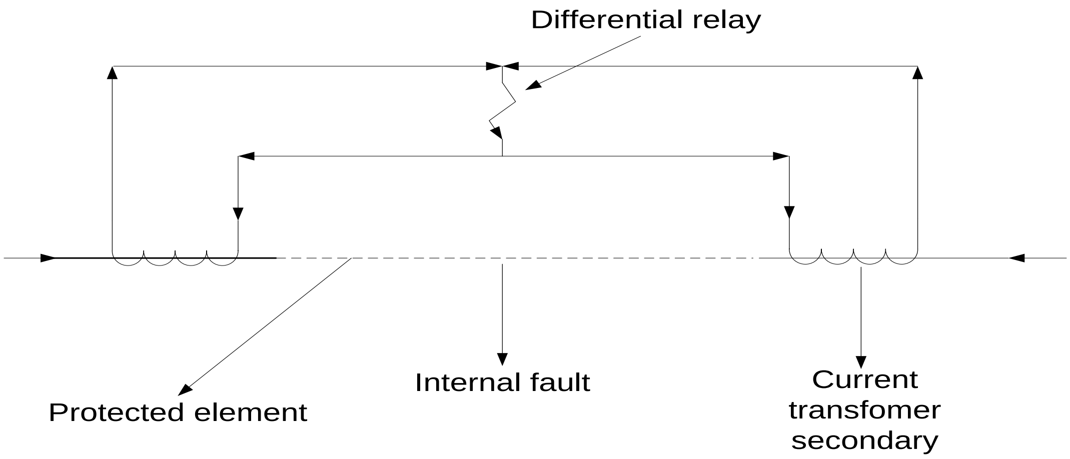

Fig. 4.35 Differential protection relay behaviour for an internal fault

According to [34] this type of protection is the most selective of all the conventional types, but each protected system element presents special problems that have made it impossible to develop a differential-relaying equipment having universal application.

As long as the fault occurs external to the protected element this relay will not see any fault and will not operate. It will only trip if a fault on its protective zone exceeds a predetermined value and hence, it will not be affected by external changes on system´s topology or variations in generation capacity. Thus, the problem with over-current protection can be faced by properly determination of differential relay´s connection scheme.

4.5.3 Adaptive protection

The previous protection philosophies assumes pre-determinism in their application. The normal and abnormal operation conditions are predetermined in order to set the coordination of over-current relays in such a way that relays respond to these predetermined conditions suitably. However, if a condition, which has not been taken into account in the analysis, arises, the response of the relays may not be adequate and the protection of the system is endangered. Moreover, it is very difficult to identify and analyze all the operating conditions of concern in first instance, as well as, it is impossible to determine the relay settings, which would be optimal for all normal and abnormal operating conditions [35].

The distribution system protection can be improved using an adaptative protection philosophy. According to [36] adaptive protection is “an online activity that modifies the preferred protective response to a change in system conditions or requirements in a timely manner by means of externally generated signals or control action". In other words, in adaptive protection, the relays should respond to the changing system conditions and adapt according to the actual system state. For the practical implementation of an adaptive protection some requirements have to be fulfilled [36]:

- Use of digital DOCR. Fuses or electromechanical and standard solid state relays are unsuitable. They do not provide the flexibility for changing the settings of tripping characteristics and they have no current direction sensitivity characteristic.

- Digital DOCR must have the possibility for using different tripping characteristics (several settings groups) that can be attuned locally or remotely and automatically or manually.

- Use of standard communication protocols, so that individual relays can communicate and exchange information with a central computer or between different individual relays fast and reliably to guarantee a required application performance.

Communication is a major activity in adaptive relaying system. Data networks capable of transferring data in a secure manner and with adequate latency are indispensable in this task. Data are needed in real time to achieve high speed control and protection and also in slower time to communicate system state data to substation based control and to prepare them for predictable abnormalities. Communication allows the relays to exchange information between them, with the station computers and between the station computers and the master computer [19], [37]. Some of the new trends in communication used in protection relaying as GPS or intranet, are illustrated in [37] and [38].

Adaptative protection can face the problems with over-current protection, by designing proper communication between relays in such a way that selectivity is attained for primary protection and backup protection is also accomplished. On the other hand, the implementation of a communication system is considerable complex, requires high cost and may be uneconomical for small distribution systems.

Chapter 5

Conclusion

5.1 Summary and Conclusion

The main objective of this thesis is to analyze the impact that different configurations and penetration levels of DG may have on the protection of distribution systems. Some of the DG technologies, generally used in Denmark, were utilized for this investigation. These technologies are different from the energy generation technologies normally used, mainly due to the primary source of energy is not controllable (photovoltaic's, wind turbine). A major classification can be done, regarding the type of connection with the main utility: generators directly connected, like synchronous or induction generators and those which use power electronic converters.

Synchronous generators are the highest contributing sources to faults. Induction generators contribute in less extent and they are highly damped. Finally, power electronic converters cannot hold high over-currents as their output it is limited to the rated current. Therefore, the power system is affected by the different technologies that are connected to it and hence, an analysis of the effect that each DG technology may have on the protection of the system needs to be assessed.

In this thesis, the network used is a 20 kV distribution network in mid Himmerland (Denmark), owned by Himmerlands Elforsyning (HEF). The grid was modelled in DIgSILENT/Power Factory 14.0.524. The main type of fault that is focused in this thesis is the worst fault that may arise in power systems, bolted three phase fault. The tested network was modified and analyzed for different situations, changing the location, technology and increasing the penetration of DG. Some general conclusions were extracted:

1) Penetration of any DG into a distribution system causes an increase in the fault level of the network at any fault location.

2) Penetration of a DG in the system causes it to lose its radial power flow characteristics.

3) Presence of the DG in a location close to the substation causes a decrease in the utility contribution to the fault but the fault current is still increased.

4) Increase in the level of DG penetration into the network causes a decrease in the contribution of the utility to faults.

5) As the distance between the DG and the fault location increases the value of the fault current decreases.

6) Loads and protective devices located downstream of the DG will not be exposed to the contributed fault current of the DG if a fault occurs upstream of the DG.

7) Presence of the DG causes a decrease in the short circuit current flowing through some branches which leads to the loss of sensitivity of the protective devices.

Furthermore, some feasible solutions to overcome the issues encountered in the protection of the distributed system, as adaptive protection or communication between relays were addressed.

5.2 Future Work

Although many aspects of over-current protection of the distribution system with DG have been covered by this dissertation, several other issues are interesting for future investigation. Some of the issues that are believed interesting are listed as follows:

- Integrating DG into existing distribution networks is a complex issue because data acquisition systems are not available. The installation of an information system such as the Supervisory Control and Data Acquisition (SCADA) system may help to solve many problems. The internet is already easily accessible; therefore it could be a great chance to utilize it for the purpose of power system operation.

- The implementation of adaptive protection is a challenging task since information which is normally not available in distribution networks is needed to update the relay settings.

- The simulations conducted in this thesis were performed using synchronous and induction generators; they can be repeated using an inverter type DG to investigate its impact on the short circuit level of the network.

- With significant penetration of power electronics interfaced DG units, over current protection may not work properly, as the short circuit current contribution is less than conventional synchronous machine based DG. Thus, protection of distributed systems with large penetration of inverter based DG needs to be investigated.

- In this thesis the size of the induction, as well as of the synchronous generators were considered equal for all simulations. Capacity of the DG sources may be increased to observe its impact on the short circuit levels and analyze if protection coordination can be attained.

- Solutions overcoming the issues with a significant presence of DG, were briefly described. These solutions could be implemented in DIgSILENT to analyze if the problems found in this thesis persist with the employment of another kind of system´s protection.

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Appendix

Table AI

Line data for section 3.4.2

From Bus	To Bus	Resistance (Ω)	Reactance (Ω)
A	B	0.1256	0.1404
B	C	0.1912	0.0897
C	D	0.4874	0.2284

Table AII

Wind turbine generator data

Parameters	WTG
Rated power	630 kW
Rated voltage	0.4 kV
Stator resistance	0.018 p.u.
Stator reactance	0.015 p.u.
Mag. Reactance	4.42 p.u.
Rotor resistance	0.0108 p.u.
Rotor reactance	0.128 p.u.
Inertia time constant	0.38 p.u.

Table AIII

Transformer data

Parameters	**CHPXmr**	**WTGXmr**	**GridXmr**
Rated power	3.3 MW	630 kVA	20 MVA
Rated voltage HV Side	6.3 kV	0.4 kV	60 kV
Rated voltage LV Side	20 kV	20 kV	20 kV
Copper losses	28 kV	8.1 kW	102.76 kW
No-load losses	4 kW	1.9 kW	10.96 kW

Table AIV

Transmission system data

Parameters	**Value**
Maximum short circuit power	249 MVA
Minimum short circuit power	228 MVA
Maximum R/X ratio	0.1
Maximum Z2/Z1 ratio	1
Maximum X0/X1 ratio	1
Maximum R0/X0 ratio	0.1

Table AV

Load data for section 3.4.2

Bus	PL (MW)	QL (MVAr)
A	7.6517	1.1607
B	0.4523	0.2003
C	0.7124	0.3115
D	0.1131	0.0501

Table AVI

Line data for the distribution system

From Bus	To Bus	Resistance (Ω)	Reactance (Ω)
5	6	0.1256	0.1404
5	7	0.1344	0.0632
7	8	0.1912	0.0897
8	9	0.4874	0.2284
9	10	0.1346	0.0906
10	11	1.4555	1.1130
11	12	0.6545	0.1634
12	13	0.0724	0.0181
13	14	0.7312	0.3114

Table AVII

Gas turbine generator data

Parameters	**Value**
Rated power	3.3 MW
Rated voltage	6.3 kV
Stator resistance	0.0504 p.u.
Stator reactance	0.1 p.u.
Synchronous resistance d-axis	1.5 p.u.
Synchronous reactance q-axis	0.75 p.u.
Transient reactance d-axis	0.256 p.u.
Sub-Tran. reactance d-axis	0.168 p.u.
Sub-Tran. reactance q-axis	0.184 p.u.
Transient time constant d-axis	0.53 s
Sub-Tran. Time constant d-axis	0.03 s
Sub-Tran. Time constant q-axis	0.03 s
Inertia time constant	0.54 s

Table AVIII

Load and generation data for the distribution system

Bus	PG (MW)	QG (MVAr)	PL (MW)	QL (MVAr)
05	0	0	7.6417	1.1607
06	8.9239	0	0	0.6446
07	0	0	0.4523	0.2003
08	0	0	0.7124	0.3115
09	0	2.5	0.1131	0.0501
10	0	0	0.1131	0.0501
11	0	0	0.1131	0.0501
12	0.31	0	0	0
13	0.31	0	0	0
14	0.31	0	0	0

Table AIX

Line data for the modified distribution system

From Bus	To Bus	Resistance (Ω)	Reactance (Ω)
1	7	0.1256	0.1404
1	2	0.1344	0.0632
2	3	0.1912	0.0897
3	4	0.4874	0.2284
4	5	0.1346	0.0906
5	6	1.4555	1.1130

Table AX

Load and generation data for the modified distribution system

Bus	PG (MW)	QG (MVAr)	PL (MW)	QL (MVAr)
Bus 01	0	0	0.4523	0.2003
Bus 01	0	0	7.6417	1.1607
Bus 02	0	0	0.7124	0.3115
Bus 03	0.31	0	0.1131	0.0501
Bus 04	8.9239	0	0.1131	0.0501
Bus 05	0	0	0.1131	0.0501
Bus 06	8.9239	0	0	0
Bus 07	8.9239	0	0	0

Table AXI

GTG governor data

Parameters	**Value**
Speed droop (p.u.)	0.05
Controller time constant (s)	0.4
Fuel system time constant (s)	0.1
Load limiter time constant (s)	3
Ambient temperature load limit (p.u.)	1
Temperature control loop gain (p.u.)	2
Controller minimum output (p.u.)	0
Controller maximum output (p.u.)	1
Frictional losses factor (p.u.)	0

Table AXII

Excitation system data

Excitation Model	**IEEE Type AC5A**
Parameters	**Value**
Tr Measurement delay (s)	0
Ka Controller gain (p.u.)	500
Ta Controller time constant (s)	0.02
Ke Exciter constant (s)	0.9
Kf Stabilization path gain (p.u.)	0.03
Tf1 1st stabilization path time constant (s)	0.6
Tf2 2nd stabilization path time constant (s)	0.38
Tf3 3rd stabilization path time constant (s)	0.058
E1 Saturation factor 1 (p.u.)	5.6
Se1 Saturation factor 2 (p.u.)	0.86
E2 Saturation factor 3 (p.u.)	4.2
Se2 Saturation factor 4 (p.u.)	0.5
V_{min} controller minimum output (p.u.)	-7.3
V_{max} Controller maximum output (p.u.)	7.3