New Methods for Protection of Future Power Networks Incorporating High Penetrations of Distributed Generation

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Abstract

Due to initiatives such as the EU (European Union) 2020 target of 20% of final energy consumption from renewable sources [1], and a target to reduce greenhouse gases from energy production by 80-95% by 2050 [2], the number of renewable generators being connected to power systems is increasing. Many modern renewable generators are inverter-interfaced [3] and many of these are being connected at the distribution level within power systems. This increase in generation at this level of the system can affect the operation of network protection, and with the continuing increase in generation, the impact on protection operation is expected to grow. In this thesis, the growing impact of inverter-interfaced generation on distribution network protection is investigated.

Initially, protection problems resulting from increasing DG (Distributed Generation) penetration are investigated and the work of others in this domain is reviewed. A description of the development of an empirical model of an inverter, incorporating fault behaviour, is presented. The model is based on observations of laboratory testing and is developed to accurately model inverter fault behaviour. Three problems are subsequently considered and evaluated using simulation: protection "blinding", loss of protection coordination and sympathetic tripping. Sympathetic tripping is found to be the most 'imminent' problem and a comprehensive simulation based investigation is undertaken to evaluate the extent of sympathetic tripping for typical penetrations of distributed generation.

In the latter sections of the thesis, a number of potential solutions are evaluated to ascertain their effectiveness in reducing or preventing the occurrence of protection problems such as sympathetic tripping. Firstly, it is demonstrated that sympathetic tripping can be avoided in most circumstances by modifying the settings specified in the UK Energy Networks Association's G59/2 recommendation. Secondly, the development and operation of an optimisation based technique is described – this can significantly improve the speed of protection operation and thus avoid the occurrence of sympathetic tripping; improvements in protection speed of up to 42 % are achieved with this method. Finally, a communication based blocking scheme is described which employs IP/MPLS (Internet Protocol Multiprotocol Label Switching) communication technology. The operation of this scheme is demonstrated

via laboratory testing and it is shown that the selected technology may be effective when adopted within this blocking scheme.

The thesis concludes with an overview of future work that is required to further advance the concepts demonstrated.

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Finally, thanks to my parents Ian and Janice, I would not have completed this PhD if it weren't for their support.

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Glossary of Abbreviations

AC	Alternating Current
ADC	Analogue to Digital Converter
BARON	Branch And Reduce Optimisation Navigator
CB	Circuit Breaker
CHP	Combined Heat and Power
CT	Current Transformer
DC	Direct Current
DG	Distributed Generation
DNO	Distribution Network Operator
EI	Extremely Inverse
EN	Egress Node
EU	European Union
FACTS	Flexible Alternating Current Transmission System
FCL	Fault Current Limiter
FRR	Fast Re-Route
GAMS	General Algebraic Modelling System
GOOSE	Generic Object Oriented Substation Event
GPC	Giga-Processing Card
GPRS	General Packet Radio Service
GSM	Global System for Mobile Communications
GTIO	Giga-Transceiver Input Output
GTNET	Giga-Transceiver Network Communication Card
HV	High Voltage
IDMT	Inverse Definite Minimum Time
IDNO	Independent Network Operator
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronic Engineering
IP	Internet Protocol
IP/MPLS	Internet Protocol Multiprotocol Label Switching
ISP	Internet Service Provider
LDP	Label Distribution Protocol
LER	Label Edge Router
LOM	Loss of Main
LSP	Label Switched Path
LSR	Label Switching Router
LTSEF	Long Time Standby Earth Fault
LV	Low Voltage
MCB	Miniature Circuit Breaker
MINLP	Mixed Integer Nonlinear Programming
NGC	National Grid Code
NGET	National Grid Electricity and Transmission
OC	Overcurrent
Ofgem	Office of Gas and Electricity Markets
OS	Operating System
PCC	Point of Common Coupling
PLC	Power Line Communication
PMAR	Pole Mounted Auto Recloser

PSCAD	Power System Computer Aided Design
PV	Photo Voltaic
RSCAD	Real Time System Computer Aided Design
RSVP-TE	Resource Reservation Protocol with Traffic Engineering
RTDS	Real Time Digital Simulator
SAR	Signal Aggregation Router
SI	Standard Inverse
SP	Scottish Power
SPF	Shortest Path First
SSE	Scottish and Southern Energy
TM	Time Multiplier
TMS	Time Multiplier Setting
TSO	Transmission System Operator
UKGDS	United Kingdom Generic Distribution System
UV	Under Voltage
VI	Very Inverse
VT	Voltage Transformer
WiMAX	Worldwide Interoperability for Microwave Access

Chapter 1 Introduction

1.1 Introduction to the research

With the 2020 European Union target of 20 % of renewable energy from renewable sources [1] and a 80-95 % reduction in greenhouse gases from energy production by 2050 [2], it is likely that the number of DG units employing renewable energy resources being connected to the power system will continue to increase in the future. The majority of modern DG units connected to the power system are inverter-interfaced i.e. nearly all photovoltaics, most modern fully inverter-interfaced wind turbines and nearly all emerging wave and tidal power technologies [3]. This increasing penetration of DG (both inverter-interfaced and directly connected) has the potential to significantly disrupt the operation of traditional protection schemes. Both the academic and industrial communities have voiced specific concerns over network protection discrimination, coordination and speed of operation [4-6]. Furthermore, the protection of the DG interface is also subject to investigation, with researchers reporting problems relating to the ability of the DG interface to operate correctly under all encountered scenarios, with protection discrimination, selectivity, ride through, reduction of unnecessary disconnection and finally, the ever-present concern over loss of mains protection, all being cited as potential problems [7-10].

For the purposes of this thesis, DG units are defined as any generator unit connected at the distribution level; in the UK distribution systems are the power systems where line voltages are less than 132 kV [11]. DG units often employ renewable energy sources but can also be supplied from non-renewable sources e.g. small scale CHP (Combined Heat and Power) plants connected at the distribution level can be powered from natural gas and standby petrochemical based generation. This is often used when large scale generation is insufficient in capacity, or prohibitively expensive. The breakdown of DG by fuel and plant type in the UK is shown in Figure 1.

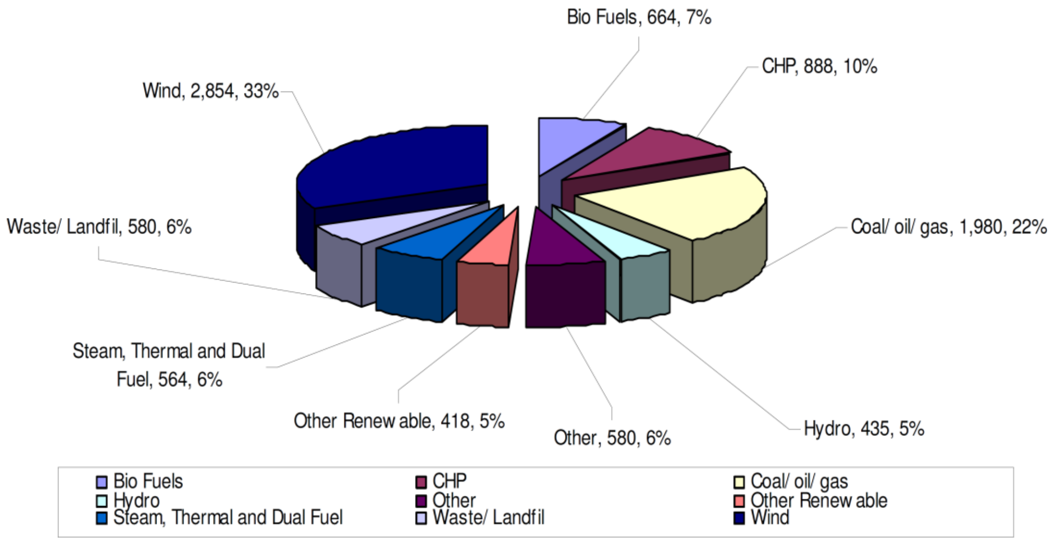


Figure 1: DG breakdown by fuel type in the UK in 2012 [12]

Appendix 1 provides an overview of the potential UK and global renewable energy resources by fuel type. The findings from Appendix 1 show that wind technology is presently the most utilised renewable energy resource in the UK but that by employing other renewable technologies such as solar, marine, hydroelectric, CHP and landfill generation, an estimated 332.6 TWh/year from renewable energy sources could be achieved. With a UK annual demand of 323 TWh/year in 2011 this equates to more than 100 % of demand met from renewable sources.

With waning oil reserves and a desire to produce 'cleaner' energy, there has never been greater motivation for developing the UK's renewable based DG resource. This is reflected in the recorded and predicted growth of renewables in the future. However, there are many obstacles to widespread development of DGs. The biggest hurdles to overcome include the costs associated with installing DG units; the variability of supply from renewable based generators and the network and protection implications of changing from traditional forms of power generation to distributed forms of generation. It is the network and protection implications that will be explored in the following chapter and developed throughout this thesis.

1.2 Research context

In the UK and the majority of the developed nations, power distribution networks are typically structured according as shown in Figure 2.

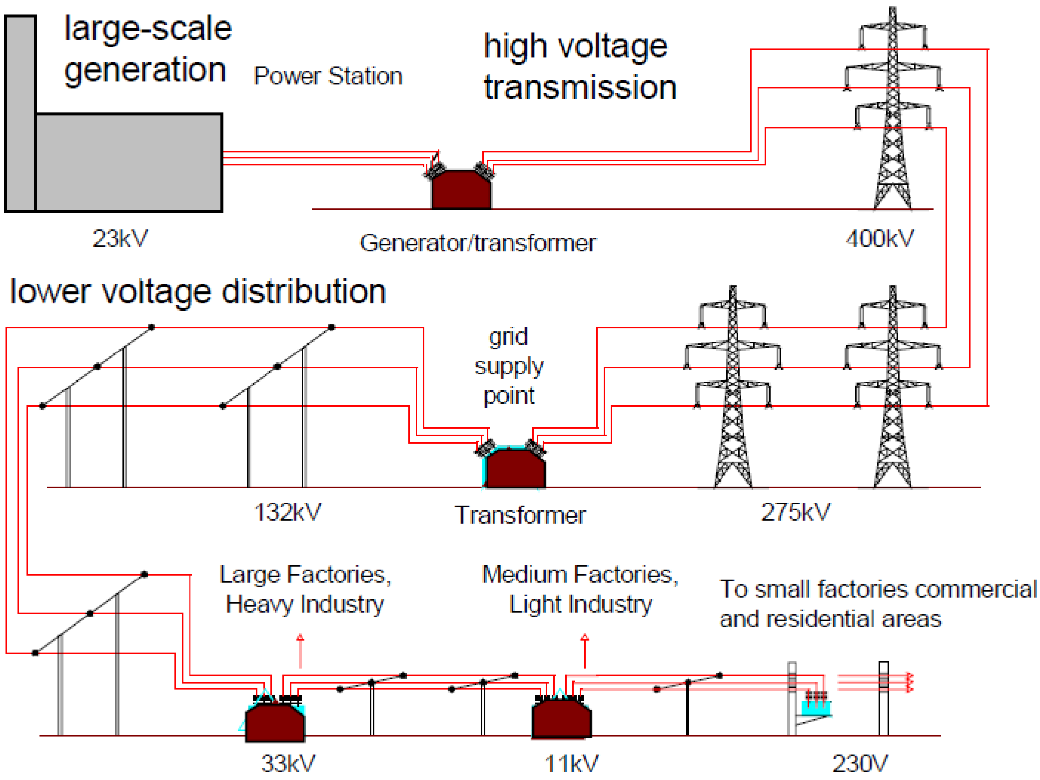


Figure 2: Traditional UK power system architecture [11]

As shown in Figure 2, traditional UK Power systems were supplied from a small number of large scale power stations – typically coal, gas or nuclear fuelled. Bulk power was transferred over long distances via the 400-275 kV transmission network to distribution networks where the voltage was then stepped down to lower levels as required by consumers. Transferring large amounts of power at high voltage levels reduces overall energy losses compared with transmitting at lower voltages (although insulation costs are increased at higher voltages). As the number of DGs (and transmission-connected renewables, such as large scale offshore wind) on the network increases the number of new connections and transmission links has to be increased to enable the power from renewable generators to be transmitted to load centres. Networks are evolving from that shown in Figure 2 to the architecture shown in Figure 3.

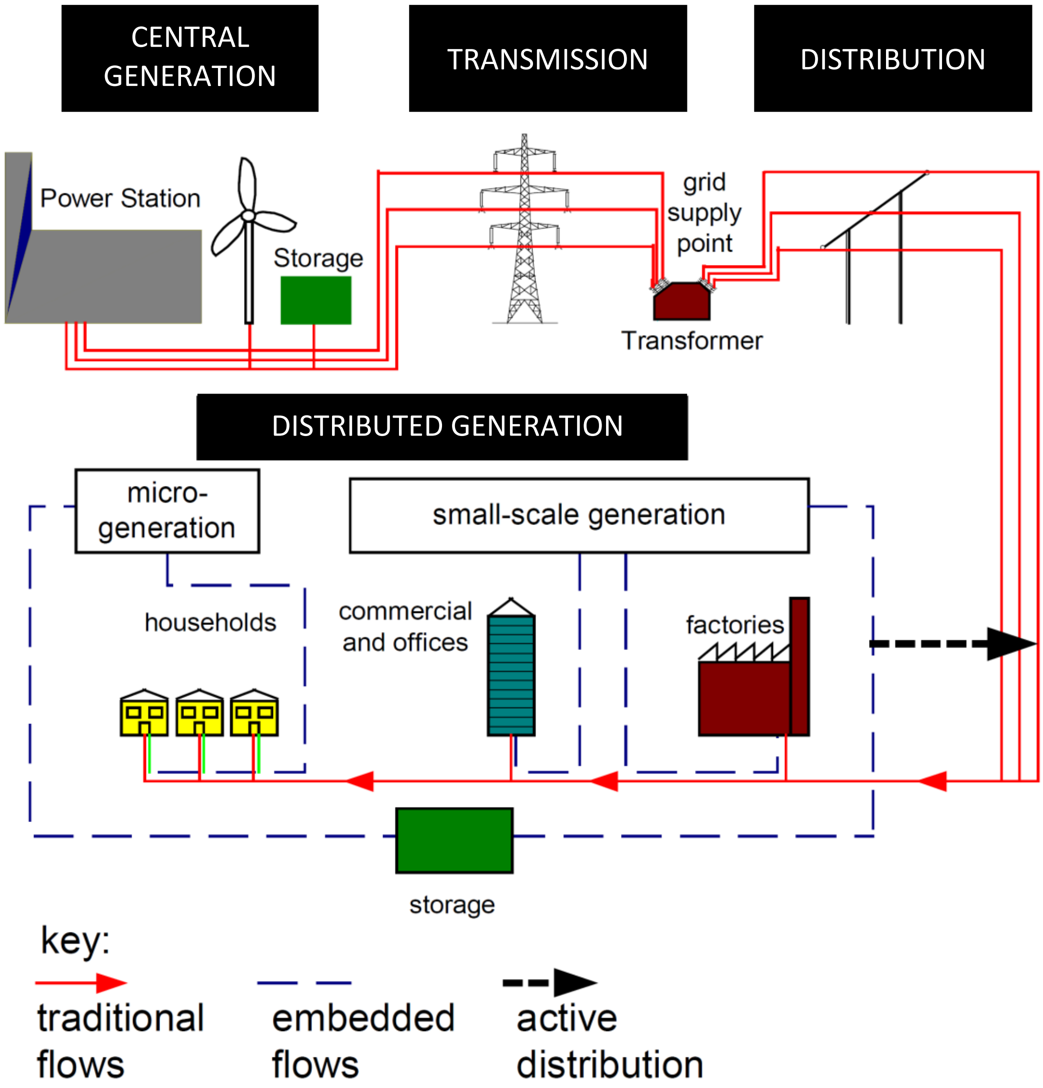


Figure 3: System with increasing DG penetration [11]

Figure 3 illustrates that large scale power plants are supplemented, and in some cases replace by renewable generation on a large scale, connected at both transmission and distribution level. In the UK context, renewables are predominantly in the form of large scale wind farms, but in lower latitude countries, large scale photovoltaic power stations may be used. Energy storage systems are also being included at both 'ends' of the network. At the distribution level, DG has been installed at factory, commercial and residential level (the lowest capacity generators installed at the residential level are often referred to as microgeneration). The energy output of many renewable generators varies (often in a non-controllable fashion) with time, in the case of wind farms the energy output is a function of wind speed and with photovoltaics the output is a function of solar irradiation. As the proportion of supply from renewable generators increases it becomes more difficult to accurately match supply and demand using the controllable generators (i.e. large scale plant, which in future may decrease in number). This has led to increased interest in energy storage technology by network operators. Energy storage allows grid operators to successfully meet demand when supply from renewables falls and also to store excess supply when generation exceeds demand. Traditionally the largest energy storage systems in the UK were pumped hydro storage schemes, but other forms of energy storage are now being investigated including: heating water for residential and industrial purposes; flywheel and supercapacitor storage; compressed air storage in large underground spaces; and various forms of battery storage [13, 14].

It is clear from Section 1.1 that the use of renewables is growing and will continue to do so. Increasing renewable generation, the introduction of storage, and the required investment of additional transmission infrastructure has implications for network operation and protection performance. Some of the main problems relating to network operation and protection performance are discussed below.

1.2.1 Islanding

Islanding occurs when part of the network is disconnected, often due to a network fault, and generation in the part of the network that is now 'islanded' continues to supply loads within the island. This can be detrimental to power system performance and safety for several reasons. The islanded system may not be earthed and therefore the risk of electric shock within the island is increased (as shown in Figure 4). Due to the earthing arrangement of the power system shown in Figure 4, when CB (Circuit Breaker) B opens, the 11 kV feeder no longer has deliberate connection to earth. If the DG doesn't disconnect on islanding protection, the risk of undetected earth faults and consequent risks of electric shock in this part of the network increases. The voltage and frequency of the island may also deviate from nominal values and potentially damage loads within the island. The fault level within the island is likely to change resulting in delayed or non-operation of protection schemes for faults within the islanded network [3]. One of the most dangerous and potentially damaging results of islanding, is unsynchronised reclosing of the (presumed) "dead" part of the network to the main network. This may happen if part of a power system becomes islanded from the network and generators within the island continue to supply loads within the island. The frequency of the generators within the island tends to drift from the grid frequency and when the island and the grid are reconnected the result is typically arcing at the breaker, and potential damage to generators in the island (and other generators) due to large torque pulsations and energy swings [15].

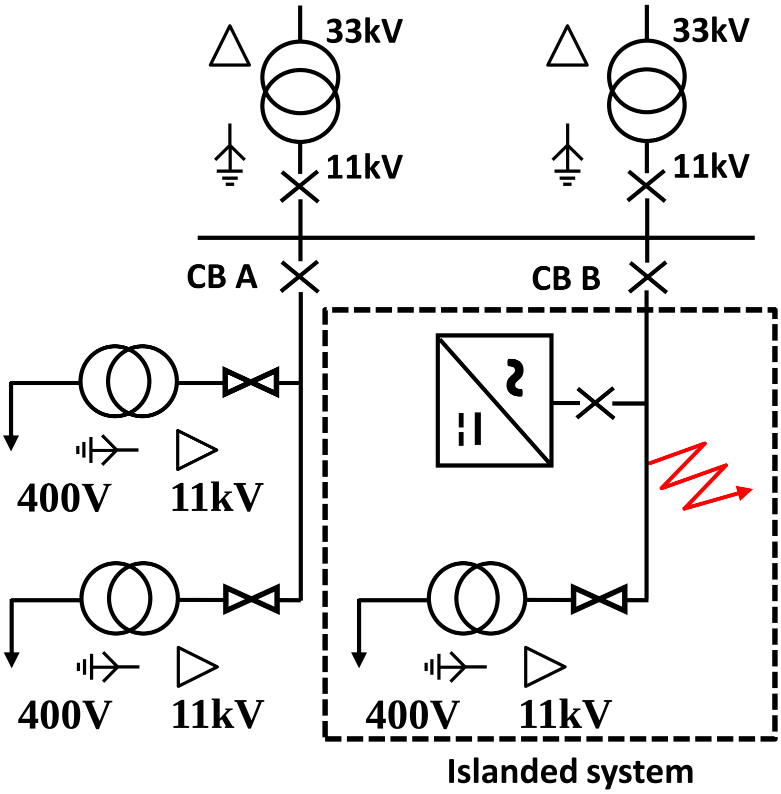


Figure 4: Example of islanded power system

Though islanding is normally not desirable, intentional islanding is allowed in some circumstances e.g. when a feeder to a geographic island is faulted, when a network with essential loads is islanded, or for privately owned networks that are designed to operate in an islanded state [16]. In each of these instances, appropriate earthing is connected when the island is separated from the network; sufficient generation is installed to meet predicted loads (this ensures voltage and frequency remain within desired levels) and the protection scheme of the island is switched to a low fault level mode for the duration of the islanded condition. Present practice in the UK is to disconnect all islanded DGs either through protection with settings as specified in G59/2 [17] or via an intertripping signals that are sent when any circuit breaker(s) that is/are capable of forming the island opens. However, with the growing penetration of DGs, it has been suggested that intentional islanding should be permitted in future and that DG units should be allowed to continue to supply loads within their respective islands [18]. Areas of the network that would be permitted to run in an islanded mode would need to be evaluated for fault level, earthing, and the overall impact on protection. The radical changes that islanding would bring to network performance during faults would undoubtedly lead to issues for presently adopted protection systems; this is a clear area of future work and islanded networks would most likely require communicating and adaptive protection solutions.

1.2.2 Variations in fault level

Another impact of increasing DG penetration is the fact that they can act to change network fault levels. Fault level is the potential maximum apparent power that will flow in a faulted circuit and is calculated from the nominal pre-fault voltage and the maximum three-phase fault current, normally assuming a “bolted” short circuit to reflect worst case conditions [3]. It is an abstract variable in the sense that the voltage and the current in the calculation do not occur simultaneously. It is however a useful indicator for rating circuit breakers to be able to withstand the maximum potential fault current. When DGs are added to the network they may increase the fault level at that point in the network. The increase in fault level is dependent on the type of DG. Synchronous generators typically provide a fault current of up to five times their nominal load current [19], whereas a converter-interfaced DG unit may typically only provide 120 % of its nominal load current and may not provide this for a sustained period of time (as discussed in Chapter 3). If converter-interfaced generators replace traditional synchronous or induction generators on a large scale basis, then the fault level of the network will decrease in future. In extreme cases (and perhaps in other countries) the grid infeed to a distribution network could be supplied solely from converter-interfaced sources, such as photovoltaic power stations or a converter-interfaced wind farm. Increasing or decreasing fault levels can cause problems for network protection. Increasing fault levels may mean switchgear will no longer be rated to withstand the new, higher fault current contribution from DG units. Decreasing fault level can result in the protection scheme being unable to detect the fault. The low fault contribution of the grid infeed makes it difficult for traditional overcurrent based protection techniques to be coordinated effectively and new methods of fault detection may be required.

1.2.3 The impact of DG on fault behaviour and detection of faults

As has already been shown in Figure 2, traditional power systems involve uni-directional power flow, emanating from a relatively small number of large scale power stations. As DG units are added at the distribution level and power is supplied from multiple locations power flow becomes bi-directional in certain parts of the system, and unpredictability in terms of fault current flow directions (and magnitudes) during faults. This can lead to a number of network operation problems. Blinding of protection may occur when DG units are connected upstream of the fault and downstream of the protection device; as shown in Figure 5, the DG fault current contribution is not measured by the protection device. As the contribution of fault current from the DG increases (e.g. due to increased numbers or capacities of DG), the fault current from the HV (High Voltage) grid infeed may be reduced, as shown for transmission systems in [20].

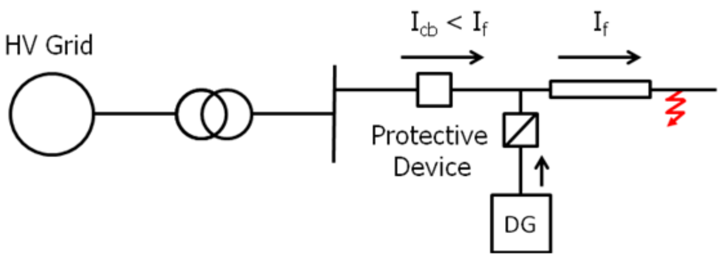


Figure 5: Example of Blinding of Protection

Referring to Figure 6, false tripping occurs when DG is connected directly to line 1 and a fault occurs on line 2. The DG will supply fault current, via the common bus, to the fault. If it is assumed that the protective devices on lines 1 and 2 are both overcurrent relays with similar time and plug settings and that they both measure the same fault current (the DG on line 1 is assumed to be supplying a large proportion of the fault current, thereby reducing the contribution from the HV grid infeed) selectivity becomes a significant problem. It is unclear which protective device will operate first; protective device 1 may operate before 2 resulting in the unnecessary disconnection of line 1 [21, 22].

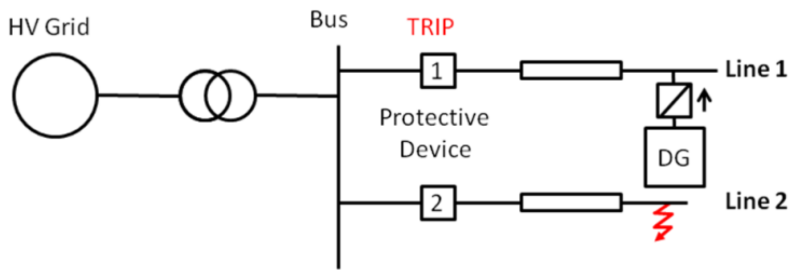


Figure 6: Example of False Tripping

At the distribution level, there are five main types of protection coordination problem that may result from increasing DG penetration: fuse to fuse, overcurrent relay to fuse, overcurrent relay-overcurrent relay, overcurrent relay-PMAR (Pole Mounted Auto Recloser) and PMAR-fuse [23]. The addition of DG to a power system has the potential to change the magnitudes and paths of fault currents, as shown above, and may affect the grading margin between different protection devices on the network [24].

1.2.4 Other factors

Generators and loads have the potential to distort the network voltage waveform. A recognised source of harmonics in power systems is from imperfections in small-scale power supplies found in computers, televisions etc. [3, 25]. Badly configured synchronous and inductions generators could add harmonic content to the system but in reality modern generators are designed such that harmonic content is negligible. The more likely source of harmonics is from converter-interfaced generators [3]. However, like modern synchronous and induction generators, modern converter technologies should also be able to conform to IEEE (Institute of Electrical and Electronic Engineering) requirements on harmonic injection [3]. Harmonic injection is not likely to be as significant a problem as the other issues discussed above due to the high specifications required for modern generators. However, with increasing penetrations of DG units the injection of harmonic content needs to be evaluated to avoid unwanted heating, damage to sensitive loads and potentially protection relay failure [26, 27].

The widespread connection of DG (and transmission-connected renewables) will also act to change voltage levels throughout the system, and may have detrimental effects on system voltage and frequency stability, due to the reduced overall levels of system inertia arising from inverter-connected renewable energy sources.

1.2.5 Research context summary

It is clear from Section 1.2 that there is a requirement to fully investigate the impact that increased levels of DGs (and storage) will have on network protection. This will involve investigating and quantifying the nature and extent of the introduced problems, and investigating, proposing and demonstrating solutions to specific problems; all of which represent the main objectives of this research work. The next section summarises the outcomes and contributions from the research work reported in this thesis.

1.3 Research Contributions

A number of contributions can be identified from the work reported here. These contributions are summarised below.

1. Development and reporting of a laboratory test facility that has been used to investigate the performance of actual inverter devices connected to networks under a variety of fault conditions.
2. Following on from the previous contribution, the research has delivered an inverter model that is based upon a combination of theoretical inverter performance, but modified by the observations from the laboratory experiments, thereby providing an inverter model that can be used with a relatively high degree of confidence within the subsequent studies undertaken in this research project.
3. Using the developed laboratory facilities and inverter models, knowledge and understanding of the behaviour of both the inverter and the network protection within networks incorporating varying penetrations of distributed generation has been provided. The key findings and individual contributions are listed below:
    a. Investigation and quantification of the protection blinding problem – it has been established that protection blinding, though theoretically possible, would only occur for extremely large penetrations of DG and as a result is not likely to occur in the UK at present levels of DG penetration. It is also extremely unlikely in the future as DG with a capacity in excess of 7.2 MVA at 11 kV is likely to be needed to cause blinding [28].

b. Investigation and quantification of protection coordination problems – There several different types of protection coordination problem that can occur at the distribution level. A critical review of the literature in this area is presented, along with a comprehensive simulation study that reviews the relationship between overcurrent relay, PMAR and inverter interface protection operation for various levels of penetration and locations of DG.
c. Investigation and quantification of the sympathetic problem – in a typical UK distribution network with standard protection settings, sympathetic tripping has been observed to occur at even very low penetrations of DG. As the penetration of DG increases, sympathetic tripping is likely to detrimentally impact upon supply availability and customer interruptions – the investigation quantifies this problem and this is a key contribution of the work.

4. Development and demonstration of an optimisation technique that reduces both primary and backup protection operation times for a network with varying amounts of DG has been developed – this may act to reduce or even eliminate the aforementioned sympathetic tripping problem.
5. Investigation, demonstration and testing of candidate communications technologies that could provide a cost effective and reliable communicating protection solution for networks of the future with high penetrations of DG.
6. A critical review of a range of other candidate protection solutions considered by both the author and other researchers in this field.

1.4 Publications

The publications relating to the work undertaken and reported in this thesis are listed below.

1.4.1 Conference publications

- **K. I. Jennett** and C. D. Booth, "Protection of Converter Dense Power Systems," presented at Universities Power Engineering Conference (UPEC), 2010 45th International, Cardiff, UK, 2010.
- **K. I. Jennett**, C. D. Booth and M. Lee, "Analysis of the Sympathetic Tripping Problem for Networks with High Penetrations of Distributed

Generation," presented at the International Conference on Advanced Power System Automation and Protection, Beijing, 2011.

- **K. I. Jennett**, F. Coffele, and C. D. Booth, "Comprehensive and quantitative analysis of protection problems associated with increasing penetration of inverter-interfaced DG," presented at the 11th International Conference on Developments in Power System Protection, Birmingham, UK, 2012.

1.4.2 Journal publications

- **K. I. Jennett**, C. D. Booth, F. Coffele and A. J. Roscoe, "Sympathetic tripping of inverter-interfaced distributed generation and protection solutions" IEEE Transactions on Smart Grids. *Successfully passed 1st round of reviewing.*

1.4.3 Letter publications

- **K. I. Jennett**, C. D. Booth, V. R. Pandi and H. H. Zeineldin, "Optimal Protection Coordination with Distributed Generation considering Multiple Relay Characteristics," IEEE transactions on Power Delivery. *Successfully passed 1st round of reviewing.*

1.5 Thesis structure

An outline of the work presented in this thesis is provided below.

In Chapter 2 a background review on distribution network architectures, the applied protection systems as used in UK power systems and an overview of typical DG technologies is presented. The application of communication systems to protection is discussed and the capabilities of IP/MPLS (Internet Protocol Multiprotocol Label Switching) technology for teleprotection applications are investigated.

In Chapter 3 the fault testing of a commercially available inverter (used for PV (Photo Voltaic) interfacing) in the laboratory is reported. An empirical fault model for an inverter, based on the findings from the laboratory investigations, is then presented. This model is used within power system simulation studies in later chapters. In this chapter the laboratory setup and testing procedures are described; the inverter fault response is evaluated for compliance with relevant standards, the empirical inverter fault model is explained and the response of the empirical inverter fault model is validated. The model was validated by modelling the laboratory test in simulation and comparing the simulated inverter response to the response recorded in the laboratory tests.

In Chapter 4 a literature review of work concerned with the detrimental impact of DGs on network protection operation is presented. A simulation study is then reported which investigates three of the most common forms of protection failure resulting from increasing DG penetration. Three potential solutions to these protection problems are then evaluated: adaptive protection, FCL (Fault Current Limiter) technology and protection optimisation.

In Chapter 5 the sympathetic tripping problem, introduced in Chapter 4, is investigated using a model of a UK rural/urban network. A large number of simulations, covering variations in network fault level, DG penetration and fault location, are reported. This simulation uses the empirical inverter model developed in Chapter 3. Two different solutions that can assist in preventing the occurrence of sympathetic tripping are investigated. The first solution involves changing traditional protection settings and also changing the settings specified in the related G59/2 recommendation. The second solution involves the use of a communications based blocking scheme that employs IP/MPLS communication technology. IP/MPLS communication technology is then evaluated for latency requirements for the blocking scheme (and also for general teleprotection requirements) using test equipment in the laboratory.

In Chapter 6 an optimisation technique is investigated and then demonstrated, using optimisation simulation software, that can be used to improve overall protection scheme operation times and thus address many of the problems investigated in Chapter 3 and Chapter 4.

Chapter 2 Overview of Modern Power Distribution Networks

In order to describe the protection of distribution systems within a wider context, this chapter provides a high level overview of power system operation, based on the UK situation.

The second part of this chapter reviews protection theory relevant to the problems investigated later in this thesis, including an introduction to power system faults, the principles of power system protection, the devices used for power system protection and the prevailing standards relating to power system protection.

The third part of this chapter reviews the use of communication systems in protection schemes. This includes the criteria significant in communication schemes used for teleprotection and a background review of IP (Internet Protocol) and the potential merits of using IP/MPLS based communication for protection scheme applications. An IP/MPLS based communication system is presented as a candidate solution that can reduce or eliminate sympathetic tripping in Chapter 4.

2.1 Generation, Transmission and Distribution

The operation of the electricity industry in the UK is dependent on several organisations and functions. The TSO (Transmission System Operator) is responsible for managing the operation of the high voltage electricity networks in Scotland, England and Wales. The TSO ensures that generation output is matched to demand in real time to maintain power system security and stability and ensure that power system voltage and frequency are kept within acceptable levels [29]. In the UK the TSO is NGET (National Grid Electricity and Transmission) plc. and it owns the transmission system in England and Wales. In Scotland the transmission network is jointly owned by SSE (Scottish and Southern Energy) and SP (Scottish Power). The ownership of the UK transmission networks is shown geographically in Figure 7.

Voltage levels in excess of 132 kV are normally defined as transmission (though in Scotland 132 kV is considered as transmission level) and in England and Wales, distribution networks are defined as any power system with a voltage level of 132 kV and below. The role of the TSO is regulated by Ofgem (Office of Gas and Electricity

Markets) [11] and regulation involves: ensuring that the transmission system is developed, operated and maintained to be efficiently operated and economically viable; ensuring that competition is maintained between electricity suppliers and generators to reduce costs to consumers; ensuring that the installation of transmission equipment does not detrimentally impact the local city or landscape and limiting the impact on the environment from pollutants as a by-product of electricity transmission.

In the UK the TSO matches generation and demand in real time through a balancing mechanism. Suppliers buy energy from generators to meet the predicted demand from their customers. If the prediction is incorrect and there is a corresponding imbalance between supply and demand, then the TSO intervenes to maintain system integrity. The TSO (NGET in the UK) intervenes by accepting bids from generators to increase or decrease their output (while taking into account network constraints). This expense is then recouped from the party responsible for the imbalance. For example, if a supplier has contracted surplus generation then the supplier becomes responsible for the cost of reducing generator output to correct the supply/demand imbalance. Another instance where NGET may be required to intervene is due to a network constraint. For example, if the majority of suppliers were to purchase energy from wind farms in the north of Scotland it is unlikely that there will be sufficient transmission capacity to transmit that energy to the major load centres in the south of England. In this case the NGET has to accept bids from generators in the area of surplus energy (i.e. the north of Scotland) to decrease their output and accept bids from generators in the area with the deficit to increase their output (i.e. the south of England). In this way competition is maintained between generators. NGET is also incentivised by Ofgem to ensure that costs incurred while balancing supply and demand are minimised.

The distribution networks of the power system are used to carry power from the transmission system and generators to industrial, commercial and domestic loads [30]. The industrial, commercial and domestic customers buy electricity from suppliers who in turn pay the owners of the distribution electrical network (DNOs) for use of their networks. Suppliers recoup this cost from the customers [30].

The electrical distribution networks in the UK are separated into regions as shown in Figure 7. DNOs own and operate the electrical distribution network within these regions. There are fourteen licensed DNOs owned by six different groups and four IDNOs (Independent Network Operators) who run smaller networks within these regions [30]. Many of the regions shown on the map are aggregated zones i.e. disparate DNO (Distribution Network Operator) zones have been grouped together. That is why there are fourteen licensed zones but only nine regions shown in Figure 7. DNOs are also regulated by Ofgem and are required to connect any customer that wishes to be connected to the distribution network. They are also required to maintain distribution network services within their area of operation.

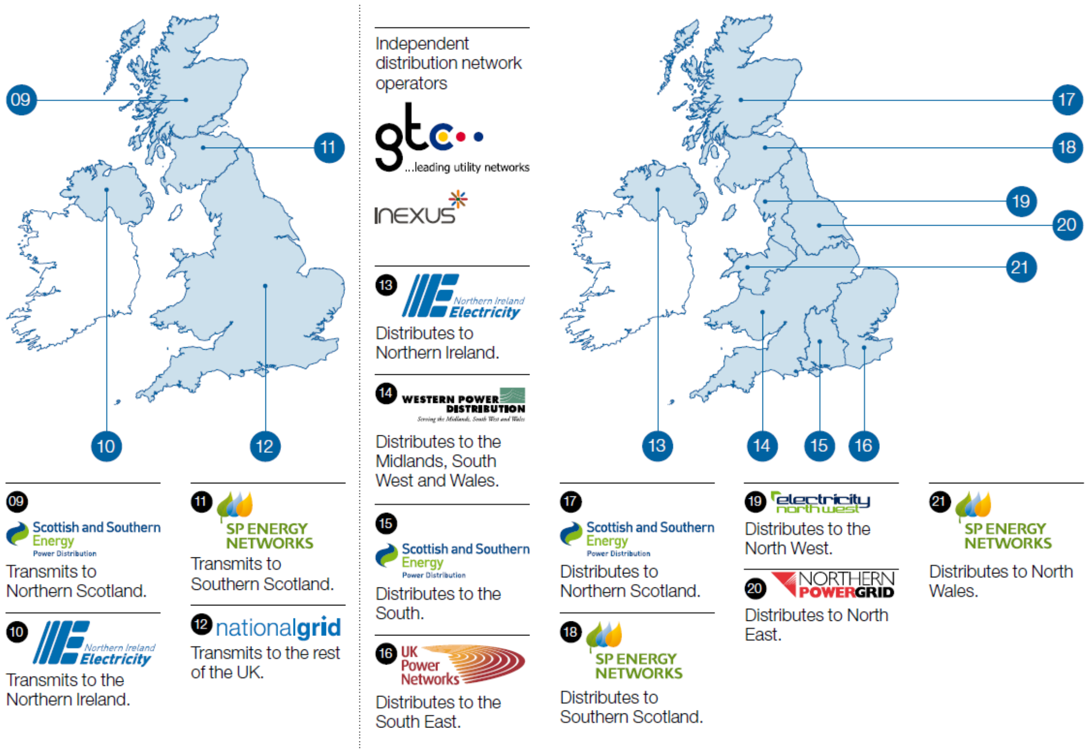


Figure 7: Distribution network operators in the UK power system (2013) [31]

The traditional UK power system architecture is characterised by uni-directional bulk power transfer over relatively long distances from a small number of large scale power stations. This architecture is representative of the power system architectures found in many developed nations throughout the world. Future power systems are likely to be characterised by relatively smaller scale power transfers over relatively shorter distances, with a reduced emphasis on centralised large scale generators and a very significant increase in distributed generation resources. The total demand supplied from large scale power stations is decreasing and is expected to continue to decrease in the future. Unless protection and generator dispatch schemes are modified to accommodate for increasing penetration of DGs, it is likely that the risk of the power system becoming generally less stable will increase. Faults, loss of generators/lines, significant load changes and other abnormal operating conditions may have increasingly severe consequences if the design and operation of system protection and control schemes are not modified to take into account the changing nature of the power system.

2.2 Protection of distribution networks

Power system protection is a universal requirement for electrical power systems. Power system protection detects faults and other abnormal operating conditions that can result in loss of supply and damage to equipment and customers and reacts quickly (usually by opening circuit breakers to isolate the fault) in the event of such conditions being detected. When power system protection fails to operate, there can be serious consequences for power system operation and in extreme cases, large scale system blackouts may be experienced [32].

The distinction between faults and abnormal operating conditions is often unclear. Typically faults fall into the category of short circuits (where a current carrying conductor comes into contact with the earth or another conductor) and open circuits (where a current carrying conductor is severed). Short circuits typically result in current magnitudes ('fault currents') far in excess of typical load currents. Faults can also be intermittent (e.g. when conductors clash together in high winds) or sustained (e.g. when a tree falls onto a transmission line). 'Abnormal operating conditions' covers a wide variety of undesirable power system conditions. For some abnormal conditions the protection scheme should not operate; for example, when a motor starts up there is a transitory inrush current that can be mistaken for a fault event. However, other abnormal conditions do require intervention via the protection scheme (e.g. when part of the network becomes islanded). A large part of on-going research in protection technology involves discerning when an abnormal condition is benign and when it requires intervention.

The ability of system designers, manufacturers of equipment, or operators to totally prevent faults is limited. Typical events that lead to power system faults include lightning strikes, human error, ageing equipment and debris coming into contact with equipment or power lines. These events can be managed but not prevented entirely. It is for this reason that protection systems are designed for managing the impact of faults rather than fault prevention. Typically faults can be detected from the resulting changes in current, voltage and frequency.

This section of the thesis provides an introduction to the main principles of power system protection and gives an overview of the main types of protection equipment used on modern power systems. The aim of this chapter is to place the content discussed in later chapters in context, not to provide a comprehensive guide to protection engineering. For more detailed information on protection engineering principles refer to [15, 24].

2.2.1 Short circuits on the power system

Short circuits occur when the insulation around a current carrying conductor breaks down. This results in the current in the conductor being diverted from its intended load. This breakdown of insulation can be caused by many factors including: ageing of insulation, temperature changes in the conductor and/or insulator, precipitation, pollution, foreign objects coming into contact with the conductor, etc. This breakdown of insulation can be transitory or sustained. From the point of view of a generator, a fault is effectively another load on the power system and the magnitude of the fault current resulting from a fault is dependent on the impedance of the fault path and the type of generators connected to the network. In the case of a highly resistive short circuit, the fault can be difficult to distinguish, or even indistinguishable, from load conditions. When the fault resistance is low (e.g. as would be the case where a conducting foreign object connects two conductors) the fault current (assuming synchronous or induction based generation) will be very high and this excessive current can cause overheating and damage to electrical equipment. Short circuits typically result in electrical arcing leading to further deterioration of insulation and, if uninterrupted, can lead to generators becoming unstable and overall power system instability.

Short circuits are categorised according to the path of conduction causing the short circuit. For example, when the insulation between a single phase and the earth breaks down it is referred to as a phase-earth fault. Likewise, if the insulation between two of the phases is breached it is defined as a phase-phase fault. Table 1 shows the different fault types possible in a power system, the probability of each type and the resulting severity in terms of fault current magnitude and damage to power system operation.

Table 1: Probability and severity of fault with respect to fault type [24]

Fault type	Probability of occurrence (%)
Phase-earth	85%
Phase-phase	8%
Phase-phase-earth	5%
Phase-phase-phase	2%

A single line diagram of one phase of a faulted three phase power system is shown in Figure 8. In this case the fault is a single phase earth fault on line 2. The impedance of the power system equipment is typically much lower than the impedance of the loads. The fault impedance is also typically much lower than impedance of the loads. At fault inception the fault provides a return path from the generator to the earth that bypasses the higher impedance return path of any of the loads. This causes a high fault current to flow in line 1 and line 2 and only a very small proportion of the total current to flow in loads 1, 2 and 3. The short circuit current in this case is only limited by the short circuit current capabilities of the generator and the impedance to the fault (Z_{line1} and Z_{line2}). If the power system has a solid earthing connection and the impedance of the fault and the impedance of the earth path are low then the voltage at the point of fault will be close to zero.

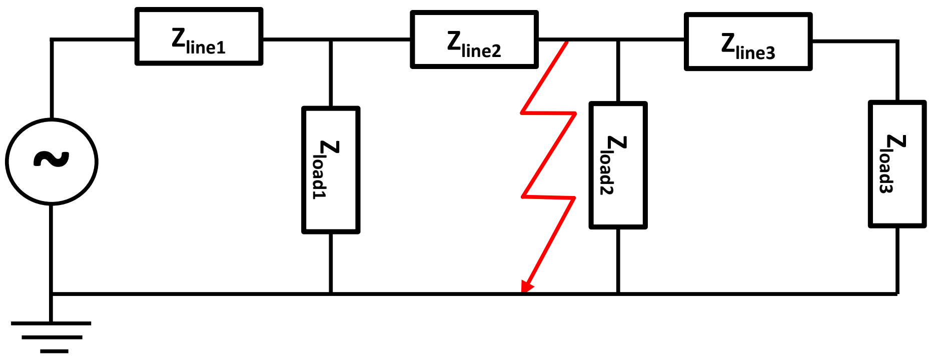


Figure 8: Single line diagram of a single phase to earth fault

2.2.2 Fault detection on the power system

Fault detection is typically achieved by measuring current, voltage or frequency at different points on the power system. CTs and VTs step down and convert the measured current or voltage to a level that can be readily processed by protection relays. The measurement transformers also serve another function in that they electrically isolate the protection relays from the network so that during fault conditions the sensitive relay components are not damaged. Based on the input signal from the transformer, the protection relay effectively “decides” on an appropriate course of action. If the input to the relay is indicative of a fault the protection relay will normally be configured to output a tripping signal. This tripping signal is sent to one or more CBs which open to isolate the area of the network in which the fault has been detected. Modern protection relays are microprocessor based but are still configured to operate on the same principles as their older electro-mechanical and electronic counterparts. This allows protection engineers to operate modern microprocessor relays in conjunction with older electromechanical and electronic relays (there are still many electromechanical/electronic relays in operation, especially in MV (Medium Voltage and LV (Low Voltage) networks).

CTs and VTs are typically designed to have standardised transformation ratios. CTs normally step down to a secondary transformer current of 1 A or 5 A and VTs normally have a secondary transformer rating of 110 V phase-phase. The primary rating of CTs and VTs depends on the thermal line rating and the voltage level of the network within which they are installed. For example, a CT (Current Transformer) installed on a line with a rating of 80 A may have a primary rating of 100 A to accommodate an overload of 25 % and a VT (Voltage Transformer) installed on an 11 kV distribution network will have a primary rating of 11 kV line-line. Both CTs and VTs are subject to ratio and phase angle errors which need to be accounted for when designing the protection scheme. It is worth noting that protection CTs are different to metering CTs; metering CTs saturate at current levels that would cause damage to the transformer whereas protection CTs are configured to transform the highest possible fault current with a high degree of fidelity to ensure correct protection operation. Measurement transformers typically still operate on the same electro-mechanical principles as power transformers, however, due to the advantages of optical sensing based technology [33], future protection schemes are likely to employ optical based current and voltage measurement transformers.

The main components of a protection system are shown in Figure 9. Depending on the protection relay being used, CTs and/or VTs will continuously send current and/or voltage signals to the relay. If the relay detects a fault to which it should react, it will send a tripping signal to the CBs to open and isolate the faulted area of the network. Also, depending on the nature of the protection scheme, the protection relay may communicate with other protection relays to transfer measurement data or to control a remote circuit breaker(s) or to record fault data and send alarm signals.

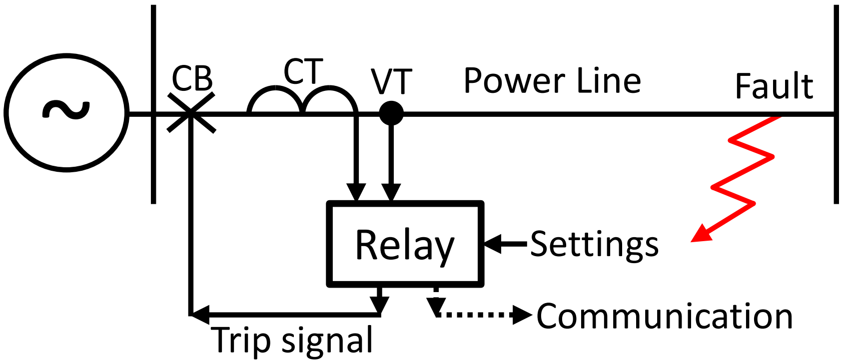


Figure 9: Components of power system protection [24]

2.2.3 Isolating faults on the power system

At the transmission level power flow is not unidirectional. Transmission lines are interconnected to the extent that CBs at both ends (or all ends in the case of a multi-terminal arrangement) of the line must be opened in order to isolate a transmission line in the event of a fault. Due to the critical nature of power system components at the transmission level, dedicated power system protection is also provided for generators, busbars and power transformers.

Traditionally, at the distribution level power flow was uni-directional i.e. power flowed from the ‘upstream’ transmission grid infeed ‘downstream’ to customers. For this form of uni-directional power flow a fault could be isolated by opening the nearest CB upstream from the fault without having to open a corresponding downstream CB. Now that DG units are being installed at the distribution level, the power flow in the distribution system is no longer uni-directional and more sophisticated, costly protection systems are required to ensure adequate protection.

The increasing penetration of DGs also impacts on the fault level of the system and can lead to issues with protection such as loss of coordination between protection devices, non-operation of network protection devices and spurious protection operation. This is an area of on-going research in protection engineering and is investigated in detail in Chapter 4**.**

2.2.4 Requirements of protection systems

The effectiveness of a protection system in quickly isolating faulted areas of a power system in order to achieve minimum disruption to generators and consumers is typically evaluated using four inter-related criteria – sensitivity, selectivity, speed, reliability and dependability [15].

1. Sensitivity – a protection scheme must be able to detect the smallest fault current that may be encountered. A very sensitive protection scheme is able to detect very small fault currents without mistaking them for load currents. Protection relays must also be sensitive enough to detect faults on other parts of the system in order to be able to operate as backup protection in the event that the main protection on the faulted equipment fails.
2. Selectivity (discrimination) – the protection system should be able to isolate the section of the network that is faulted and allow 'healthy' parts of the network to remain operational. A selective protection system is able to isolate all faulted areas of the network to minimise system disruption and to refrain from operating when there is no fault on the network (or when the fault is outside the remit of the protection scheme). Fault detection is typically maintained through monitoring current, voltage and frequency. For some fault conditions a single monitored parameter is insufficient to ensure appropriate discrimination e.g. a resistive fault may cause a fault current equal to or lower than load current. A protection scheme must be able to discriminate between non-fault and fault conditions by using alternative forms of fault detection; in the case of a resistive fault, phase imbalance may be used for fault identification, but this may compromise selectivity.
3. Speed (operating time) – the longer the fault remains on the system, the more damage will occur and the greater the likelihood that the system will become unstable. If the protection system operates quickly the damage is reduced and the risk of network instability is lowered. However, a time delay is integral to most types of protection scheme for two reasons 1) it is required when discriminating between main and backup protection (discussed later in this chapter) and 2) a time delay is required to gather

sufficient voltage, current or frequency data to accurately predict whether a fault condition exists i.e. there is a minimum time required for measurement and decision making.

4. Reliability and dependability – protection equipment should operate in the same way consistently for the same fault type and fault location so that protection equipment coordination can be maintained. However, all equipment has a predictable level of failure and to account for the predicted failure of the first level of protection (main protection) redundant (backup protection) relays are employed in protection schemes to operate on a time delay if the main protection relay fails to operate. For transmission systems, two (or even three) main protection systems may be used, in addition to other backup systems.

2.2.5 Protection system philosophies

All protection systems can be categorised as either being a form of unit protection or non-unit protection.

A unit protection scheme only operates for faults within a predefined area and should never operate for faults outside that zone. Typically unit protection schemes incorporate measurement devices at the boundaries of the protected zone. A relay or multiple relays compare the measured quantities (normally current or voltage magnitudes and/or phases) and when the comparison of measured quantities indicates a fault, CBs at the boundaries of the protected zone are opened to isolate the fault. Typically, transmission line unit protection schemes require some form of communication between the relays at the ends of the protected zone to facilitate comparison of measured values.

The main drawbacks of unit protection are the costs associated with the communication system, the potential for failure in the communications link and the lack of provision of backup protection for faults outside the protected zone. To address these drawbacks, unit protection is typically only used in critical systems where the costs associated with installing unit protection are justified. Usually, redundant communication links and additional non-unit protection schemes are installed to provide backup in the event of failure of a communications link and to provide backup for faults outside the protected zone.

Non-unit protection differs from unit protection in that non-unit schemes do not protect a clearly defined zone of the network, but cover a not specifically defined area, with backup protection being provided for adjacent plant items and circuits. The area a non-unit protection scheme can provide protection to is referred to as its 'reach' and is normally defined by the relay settings. Normally, the further a fault is located from a non-unit relay, the longer the delay period before the relay will operate. The purpose of the relationship between fault location and relay operation time is illustrated in Figure 10. For the fault shown in Figure 10, relay 2 will operate after a minimum time delay. If relay 2 fails to operate, relay 1 must operate to ensure the fault is removed from the system, but it should never operate before relay 2. To ensure correct operation, relay 1 is configured to operate with a time delay in excess of the predicted operation time of relay 2 for a fault as shown. Overcurrent protection makes use of the principle that the fault current flowing to a fault from a measurement location (between the source of fault current and the fault) decreases as the impedance between the measurement point and the fault increases. This principle can be used to ensure that the relay closest to the fault location normally operates fastest – the principles of overcurrent protection are discussed in more detail in Section 2.2.6.

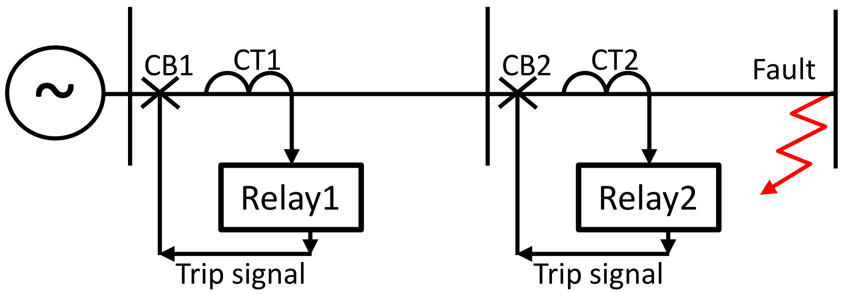


Figure 10: Non-unit protection operation

The main disadvantage of non-unit protection when compared to unit protection is that non-unit protection does not provide as high a level of discrimination. An example of discrimination failure is shown in Figure 11. In this example, protection device 2 should operate for the fault on line 2, but if the fault contribution from the DG is large enough and protection relay 1 is non-directional, protection relay 1 may operate incorrectly.

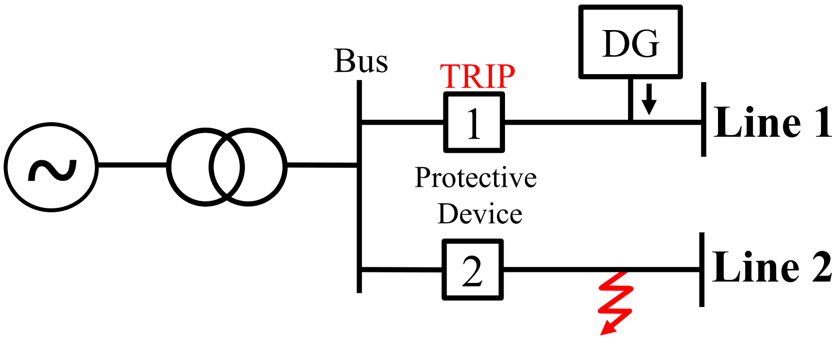


Figure 11: Example of protection discrimination failure

Examples of both unit and non-unit protection techniques are discussed in the following sections of this chapter.

2.2.6 Overcurrent protection

A relay is similar in its function to a fuse, a relay measures the current travelling in the conductor and when the fault current exceeds the limits established for normal load operation the relay interprets this condition as a fault. In a fuse the fault current causes the fuse material to heat up and eventually break down; when the fuse material breaks down, the path of conduction is broken and the fault is isolated from the system. The rate at which the fuse breaks down is dependent on the fault current magnitude and the *electrothermal* properties of the fuse material. In a relay the fault detection time is dependent on the *electromechanical* configuration of the relay, or in the case of a modern microprocessor based relay, it is dependent on the settings applied within the relay's software, which normally mimics the operation of an electromechanical device in terms of the relationship between measured current and tripping time. On detecting a fault, the relay sends a signal to a circuit breaker(s) on the faulted conductor to isolate the fault.

Conceptually, the simplest form of modern relay protection is an instantaneous overcurrent relay. This relay operates as soon as the current in the conductor exceeds the designated fault current setting ('pickup current') to isolate the fault. There are two inter-related limitations of instantaneous overcurrent protection:

1. If the pickup current setting of the relay is too low, then it may operate for transient power fluctuations caused by sudden load changes (e.g. motor start-up).

2. If the pickup current is set too high, then the relay may not operate for distant faults or high resistance faults that result in relatively low fault currents.

The solution to this problem is to add a time delay into the relay operation time; this is implemented in definite time overcurrent relays. In a definite time overcurrent relay, the relay delays its operation for a fixed time before operating when the current exceeds the threshold. This means that the pickup current can be set lower than would be feasible in an instantaneous overcurrent relay. If there is a transient overcurrent the relay will not operate immediately and if the transient dissipates within the time delay period, then the relay will not operate. This type of relay operation is also flawed because the relay will always operate with the same time delay no matter the magnitude of fault current. Ideally, a relay should operate faster as the magnitude of the fault current increases. This is implemented by using relays with inverse time characteristics as shown in Figure 12.

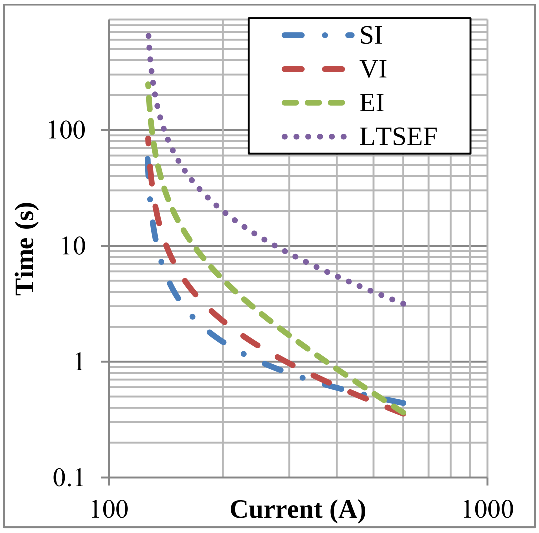


Figure 12: Various overcurrent protection relay characteristics [15]

Relays with inverse time characteristics operate faster as the fault current increases in magnitude. This is a desirable characteristic, as the fault current measured by the relay decreases with distance to the fault from the relay location due to the increased line impedance between the fault current source and the fault location. The two parameters that define the relays operation time for a given characteristic are the 'pickup current' and the 'time multiplier.' The pickup current defines the horizontal location of the relay characteristic and the time multiplier defines the vertical location of the relay characteristic, as shown in Figure 13 (in this case the plug setting and time multiplier are shown in the context of a definite time overcurrent relay characteristic).

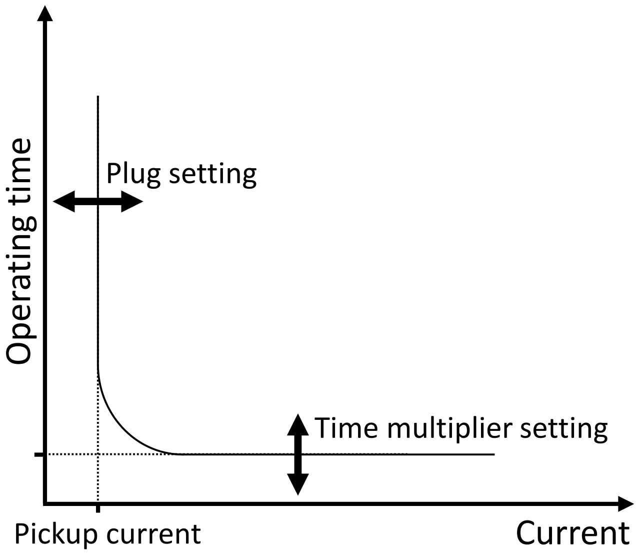


Figure 13: Plug setting and time setting for a definite time overcurrent relay characteristic

The time multiplier setting and plug setting of the relays will be chosen to ensure an adequate grading margin time for all possible fault currents so that even if both relays measure the same fault current, relay 2 will still operate more quickly than relay 1. The pickup current is typically set so that the relay only begins to operate when the current exceeds 125-150 % of the line's thermal rating – this allows a margin for overloading the line before the protection will begin to operate. The downstream relay is configured to operate as fast as possible, while taking into account coordination with further downstream protection (e.g. other overcurrent relay protection and/or fuse protection devices).

The characteristics shown in Figure 12 originate in traditional electromechanical relays. These relays rely on physical properties of the mechanical components within the relays to define protection characteristics. Modern micro-processor relays can define the protection characteristic in software and are therefore capable of implementing any type of characteristic required by the protection engineer. However, for typical protection schemes, the characteristics shown in Figure 12 are normally used to maintain standardisation and to simplify the process of time grading between modern microprocessor relays and older electromechanical relays.

An example of overcurrent protection grading is shown in Figure 14. The relays begin to operate when the fault current exceeds the pickup current. The two relays have been assigned different pickup currents so that relay 1 will provide backup protection for relay 2 in the event that relay 2 fails to operate.

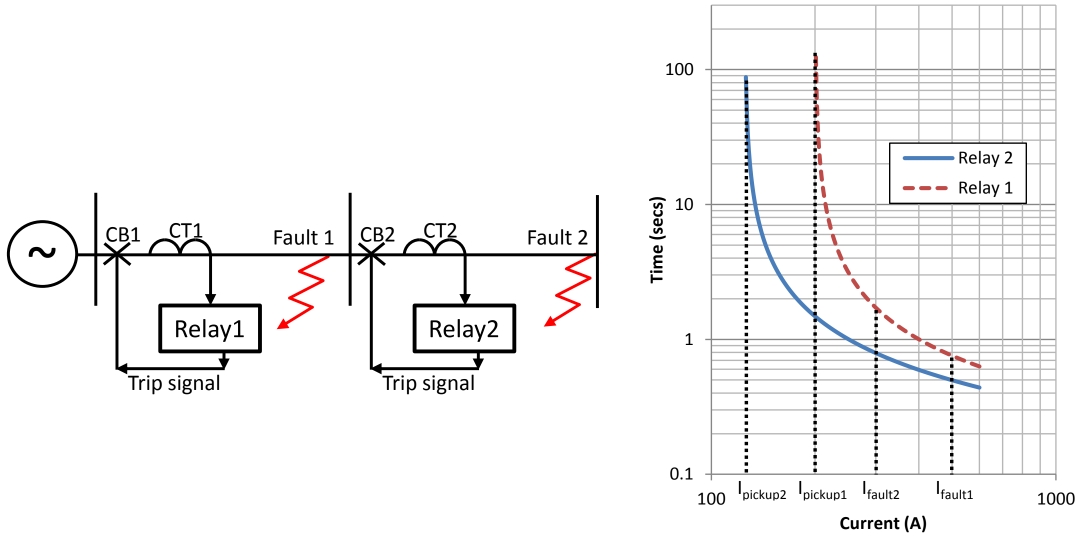


Figure 14: Overcurrent relay protection grading

The disadvantage of inverse time overcurrent protection is that as the fault moves closer to the source the operation time of the protection relays increase. This is not a problem on short feeders as the increase in time is negligible. However, on long feeders that employ multiple relays, the pickup current and time multiplier of the next upstream relay has to be greater than that of the immediately downstream relay to ensure sufficient grading. For example, in Figure 14, for fault 1, relay 1 will operate slightly slower than relay 2 would operate for fault 2. The increase in time is slightly offset due to the increased fault current measured by relay 1 due to the fault being closer to the source. However, in order to provide sufficient grading between the relays, relay 1 will still operate slower than relay 2 for a fault at an equivalent distance from the relay. If more relays were connected upstream of relay 1, the delay in operation of the upstream relays would be increased. This problem is further compounded by the increasing fault current i.e. as the fault current increases, the risk of overheating and damage to equipment increases.

To address this issue, inverse time overcurrent protection is often used in combination with instantaneous protection (discussed at the start of this section). The instantaneous protection function is typically employed within the protection characteristic as shown in Figure 15. The instantaneous element of the characteristic is set so that the relay (in this case relay 1) will operate instantaneously for faults that are definitely within its protection zone and with a time delay for faults that may be within its zone of protection (i.e. close to the end of the feeder or highly resistive faults) or as backup protection for faults outside its area of protection (e.g. fault 2). For I_{fault1} as shown in Figure 15 the relay will operate instantaneously, but for I_{fault2} (assuming relay 2 fails to operate) relay 1 will operate with a time delay. To ensure the instantaneous element of the relay characteristic does not operate outside its zone of protection, instantaneous overcurrent protection is limited to networks that have relatively large changes in fault level between relay locations. The instantaneous pickup setting is typically set to 130 % of the maximum fault current at the next downstream relay to ensure the instantaneous element only operates for faults on its protected line. When inverse time overcurrent protection is used in combination with instantaneous protection the instantaneous setting is sometimes referred to as the 'high set' value.

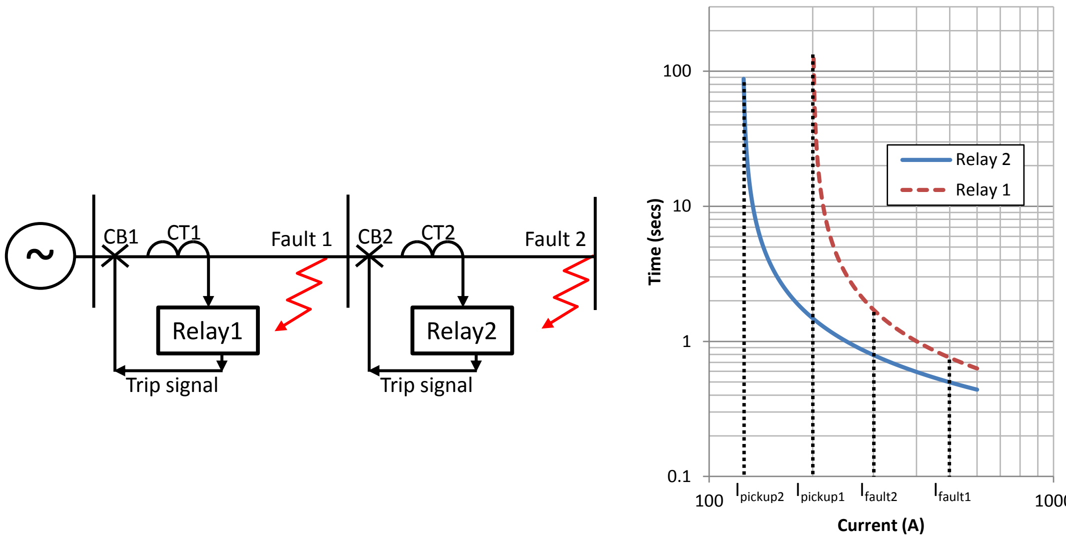


Figure 15: Instantaneous overcurrent protection grading

Inverse time overcurrent protection is the most common type of relay based protection at the distribution level in the UK. However, due to economic constraints, relay and circuit breaker protection cannot be cost effectively used to protect all sections of the distribution network. Typically overcurrent protection is used in coordination with PMARs, fuses and sectionalisers as shown in Figure 16.

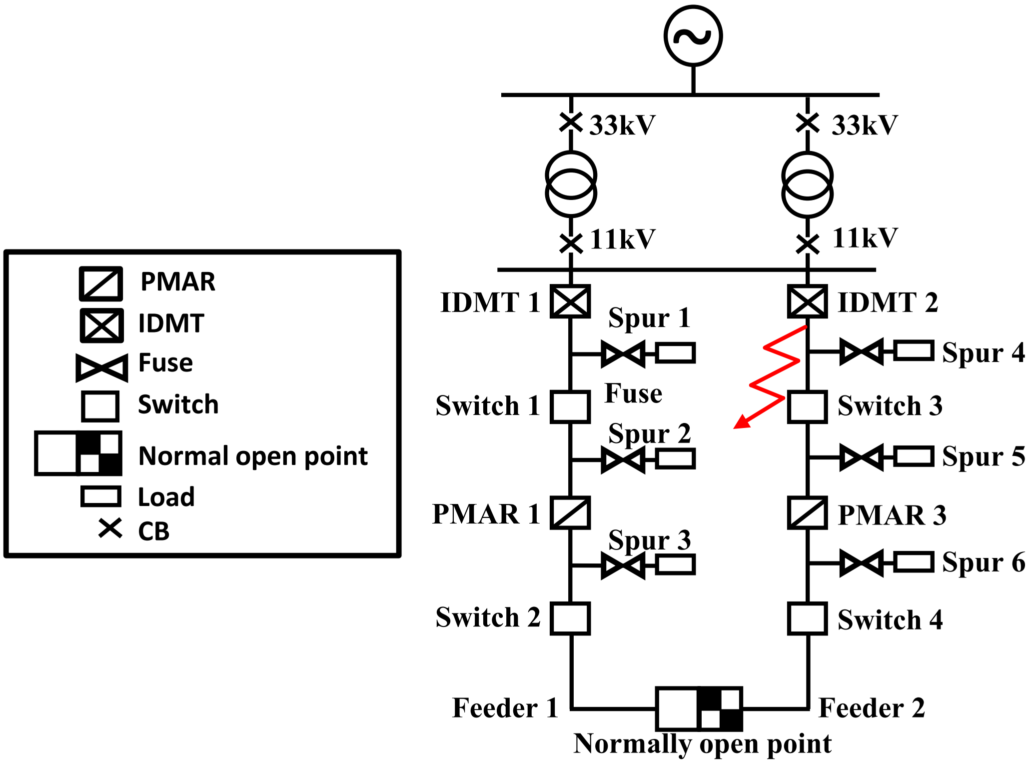


Figure 16: Typical distribution level protection scheme

Figure 16 shows a distribution network with two feeders connected via a switch. Under normal operating conditions the switch connecting the two feeders will remain open, however under abnormal operating conditions the switch can be closed to provide an alternative supply path (e.g. IDMT (Inverse Definite Minimum Time) 2 trips its breaker for a permanent fault on feeder 2, switch 3 is opened, the normally open point is closed and the loads on spurs 5 and 6 are back-fed through feeder 1). The switches on the network are not capable of fault (and sometimes load) current interruption and are only used when the line is isolated to modify the network configuration.

The IDMT relays on each feeder coordinate with the downstream PMAR and fuse protection on the spurs. In modern protection schemes, fuse protection on the spurs may be replaced by section switches. The advantage of section switches is that they only operate (to open and isolate a downstream fault) after a pre-defined number of recloser attempts by the PMARs. Therefore, if reclosing manages to clear the fault, the spur will remain in service. If reclosing does not clear the fault (e.g. for a permanent short circuit) the section switches will then operate to isolate the spur and the fault, and the recloser will subsequently successfully reclose and restore supply to other loads on the feeder.

The order of operation of a protection system incorporating fuse, PMAR and IDMT protection devices is shown in Figure 17. If it is assumed that the fault is permanent, the order of protection operation will be as follows: PMAR 1 will attempt multiple reclosures to clear the fault (the fault is permanent so the PMAR will be unsuccessful in reclosing); during one of the unsuccessful reclosures the fuse will melt and isolate the fault. If the fuse failed to operate the recloser would try to reclose (typically three times [15]) and then remain in the open position to isolate the fault. If the PMAR failed to isolate the fault the IDMT would operate on backup protection. If the fault was transient, then the PMAR may be able to clear the fault (before the fuse melts) during an auto-reclose and the system would then return to normal operation.

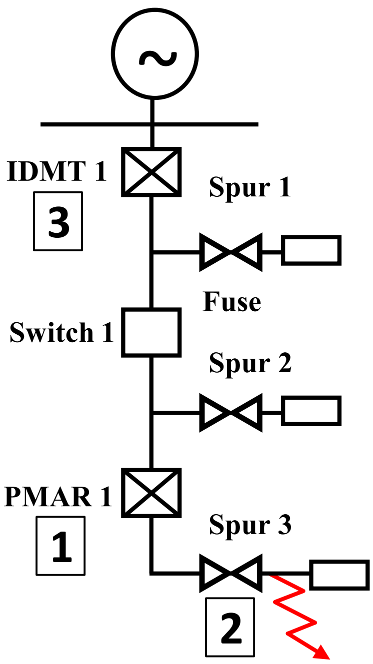


Figure 17: Protection coordination with fuses, PMARs and IDMTs

The act of reclosing can remove temporary arcing faults and, in some cases, faults caused by foreign objects on the conductor (which can sometimes be cleared – effectively burned away – by repeated reclosures). If a fault can be removed by reclosing instead of human intervention, it reduces the time that the affected circuit is out of service and hence the amount of time that customers are without supply. If the insulation around a conductor is reduced, it can cause an arc to form, this can be caused by conductors clashing together in high winds, lightning strikes, vegetation or wildlife causing short circuits, etc. When the recloser operates it initially interrupts the current flowing in the conductor, this interrupts the arc and (in the case of air insulated equipment) allows the air to deionise and the air insulation to re-establish around the conductor. In the case of small obstructions (e.g. fallen branches) on the conductor, the act of reclosing causes a pulse (or "shot") of current to pass through the obstruction which may physically throw the obstruction from the line or burn the obstructions sufficiently to clear the fault. Typically on distribution networks, reclosing is attempted three times before the recloser is permanently opened and a visual inspection of the faulted section of the network is required. At transmission level reclosing is typically only attempted once due to the more critical nature of the systems and the stress (physical and from a network stability perspective) that repeated interruptions and reclosures would place on the system.

At the transmission level, the costs associated with installing relatively more sophisticated and reliable protection (compared to MV distribution and LV protection) is justified due to the relatively severe consequences of faults, and particularly faults that are not cleared correctly. For completeness, the protection systems used at the transmission level are discussed in the remaining sections of this chapter.

2.2.7 Distance (impedance) protection

Distance protection uses voltage and current phasor measurements to calculate the apparent system impedance from the relay's perspective. Faults cause the measured impedance to fall and thus can be detected by distance protection. The closer the fault is to the measurement point, the larger the drop in measured impedance and hence distance protection can also be used to approximate the fault location. An example of a distance protection scheme is shown in Figure 18.

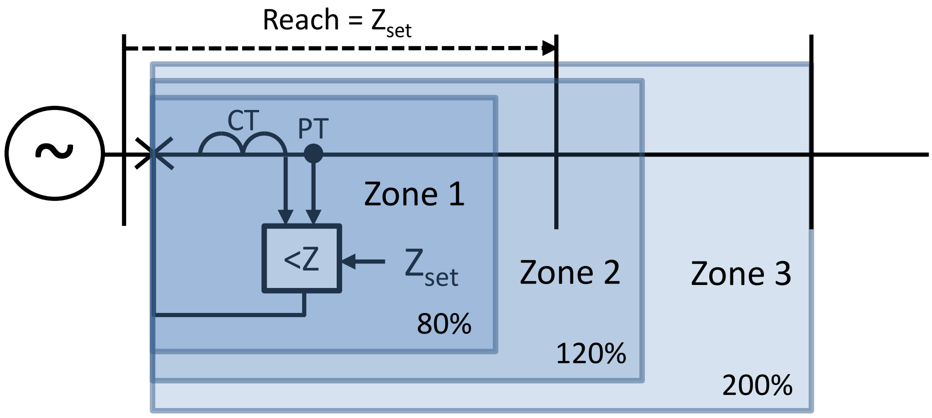


Figure 18: Distance protection scheme

CT and VT measurement errors and unpredictable variations in fault resistance mean that the accuracy of distance protection in predicting the fault location is limited. To accommodate for this lack of accuracy, distance relays are configured to operate instantaneously only for faults that can be proven to definitely be inside the distance relays zone of protection [24]. This is achieved by setting the instantaneous protection to operate for impedances that equate to 80 % of the impedance of the protected zone. Not operating instantaneously for the remaining 20 % of the protected zone accounts for errors in voltage and current measurements, errors in relay calculation and errors in predicted line impedance (the cumulative total of these errors typically amounts to an impedance error of less than 20 % of the first protected line's impedance) [15]. The distance relay is also configured to provide protection with a time delay for faults outside 80 % of the protected line. This has two benefits: 1) the distance protection provides backup protection in the event that the other protection schemes on the network fail to operate and 2) in the event that the relay 'under-reaches' (i.e. does not instantaneously react to a fault in the remaining 20 % of the protected line), the distance protection will still operate after a time delay. Distance relays are therefore configured to operate instantaneously for a fault detected within 0-80 % of the line (defined as zone 1 protection); with a time delay for a faults detected within 80-120 % of the line impedance (defined as zone 2 protection) and with a further time delay for faults detected within 120-200 % of the original line impedance (defined as zone 3 protection) [24]. When setting the backup protection i.e. zone 2 and zone 3, the relay must be configured so that it does not operate for lines outside the desired protection area. For example, if a distance protection scheme protects a short transmission line that connects to a distribution network, zone 3 protection could operate for faults on the distribution system. This is an undesirable operation as the distance protection scheme will interfere with the operation of the distribution protection system. To compensate for situations where distance protection might interfere with other protection schemes the extents of zone 2 and zone 3 may be modified. As distance protection provides backup protection for faults outside its main zone of protection and its zone of protection cannot be exactly defined, it is classed as a non-unit category of protection scheme – although it can be modified to operate as a unit scheme with the assistance of communications [15].

Figure 19 shows the distance protection scheme of Figure 18, but represented on the *R*-*X* plane (this example assumes the line has almost equal resistive and reactive components: in reality a transmission overhead line is likely to be more reactive than resistive). The circular characteristic is useful for detecting faults of varying impedance. A more resistive fault (e.g. an arcing fault [24] instead of a bolted short circuit) will have a larger resistive component than the line impedance and will therefore not fall on the dark line representing the line impedance shown in Figure 19. An example of a resistive fault is shown as a small circle in Figure 19. Due to the circular boundary characteristics, the resistive fault will still be detected by zone 1 protection; this would not be the case if the protection boundary characteristic more closely followed the line characteristic.

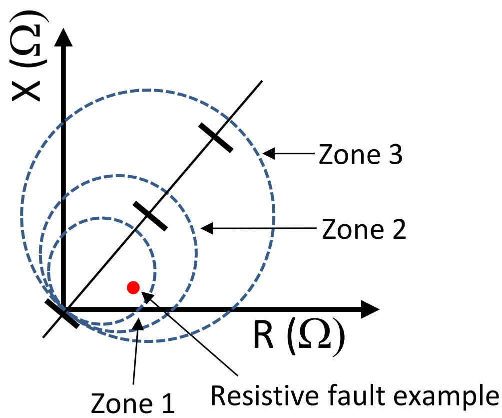


Figure 19: Distance relay protection characteristic on *R*-*X* plane

Modern microprocessor based relays can calculate both the magnitude and phase of the measured voltage and current and are therefore able to calculate the resistive and reactive components of the measured impedance. They can also implement a boundary characteristic to provide protection appropriate for the equipment that is being protected; typical characteristics are shown in Figure 20.

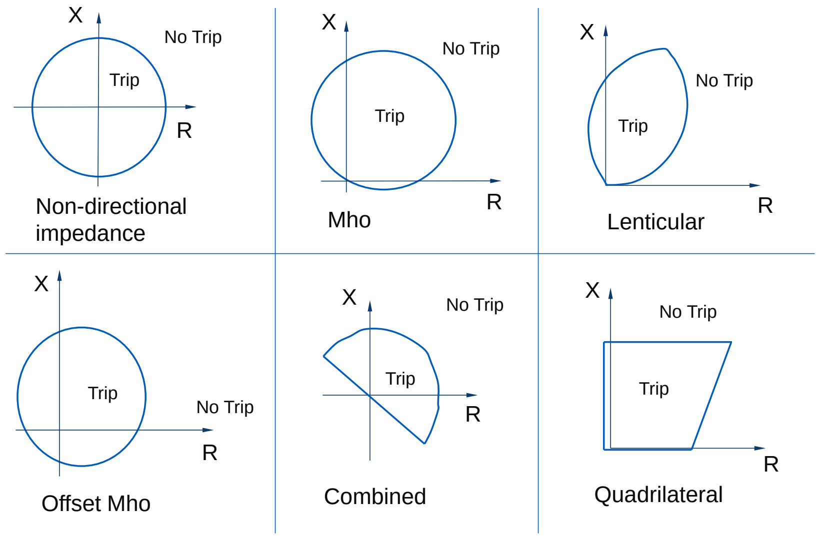


Figure 20: Typical modern distance relay protection characteristics

There are a variety of techniques that can be used to compensate for the fact that zone 1 does not encompass the entirety of the protected line in distance relays. All of these techniques require distance relays to be installed at each end of the feeder with overlapping zones of protection; a communication system is typically used to coordinate the operation of the two distance relays.

In the transmission network distance protection is used for main (and backup) protection of transmission line, and provides backup protection of transformers, generators and busbars. On the distribution network distance protection is often used to provide main and backup protection.

2.2.8 Differential protection

Differential protection operates according to the principle whereby if there is a fault within electrical equipment, then the vector summation of the individual currents entering and leaving the equipment will be non-zero (i.e. Kirchhoff's current law will not be obeyed). The relative magnitude and phase of the currents can be compared and a fault condition can be determined if the difference between them (i.e. the residual or differential current) is greater than a given threshold (this threshold takes into account measurement error in the CTs). Differential protection is a form of unit protection as it only protects a specific piece of equipment or area of the network. Differential protection requires at least two measurements (normally current measurements), normally taken at the boundaries of the protected zone. In the case of a dual relay differential protection scheme (shown in Figure 22), a communication link is also required to transfer the measured signals between the relays for comparison and decision making.

An example of a single relay circulating current differential scheme is shown in Figure 21 – this is normally used for protection of transformers, busbars or short lines. The two measured signals (in this case currents) are taken from the boundaries of the protected area. The CTs that the relay uses to measure the currents are connected in such a way that the vector sum of the currents is zero for non-fault conditions and non-zero for fault conditions inside the protected zone. There are several combinations of situations where the relay has to correctly identify whether to react to the fault, for example, the fault can be inside or outside the protected zone and the system may have fault current infeed from both ends of the feeder (typical of transmission systems) or from only one (typical of distribution systems). If the fault is external (i.e. at 1 or 3 in Figure 21) then the fault currents measured by both CTs should be identical. For a fault at 1, the current measured in both CTs will decrease (or zero in some cases) and for a fault at 3 both currents will increase from nominal levels. In both cases the phases of the currents will be the same and the magnitude of the current presented to the relay will be zero (I_{relay}=0), therefore, the relay will not operate. If the fault is internal (i.e. within the protected zone) a proportion of the current will be lost to the fault. I_a and I_b will therefore not be equal, the relay (I_{relay}) will measure a non-zero current and operate to isolate the protected zone. If the fault is external but the load in Figure 21 is replaced by a generator then for an external fault (i.e. at 1 or 3) I_a and I_b will be equal in magnitude and phase. The current measured by the relay will be zero (I_{relay}=0) and the relay will not operate. If the load in Figure 21 is replaced by a source of current and the fault is internal there is a very small potential for the magnitude of I_a and I_b to be equal. However, I_a and I_b will be 180^o out of phase, the relay will measure a non-zero current and therefore operate to isolate the protected zone. Depending on the equipment to be protected, the differential scheme will be configured to compare different parameters: some only compare magnitude, some only phases and some compare both.

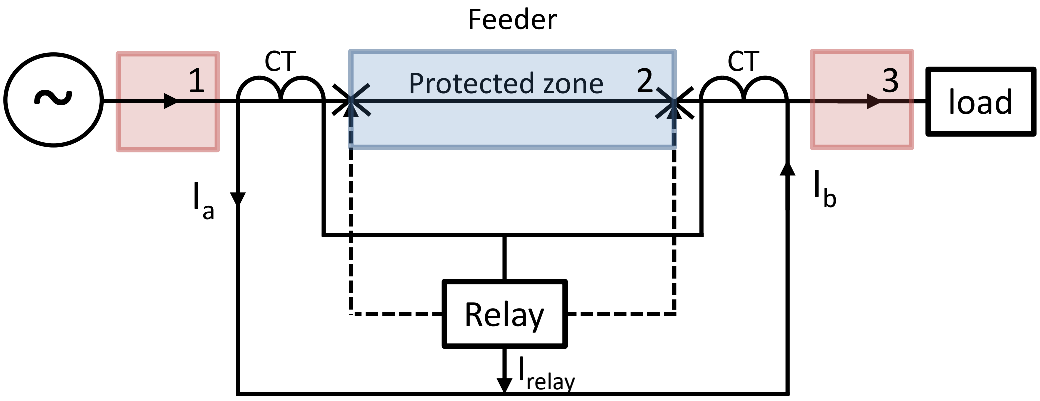


Figure 21: Example of single relay current based differential protection scheme

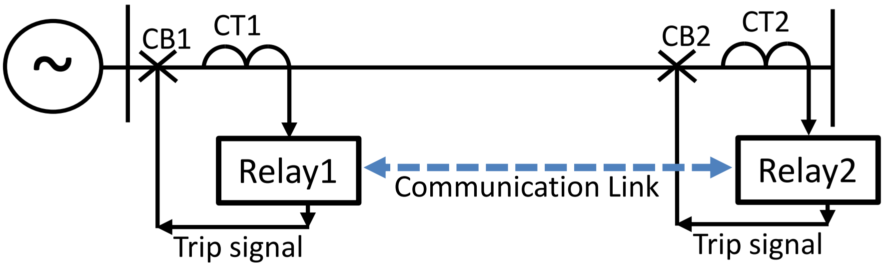


Figure 22: Example of dual relay current differential scheme

As differential protection is a form of unit protection, it does not discriminate with other protection relays, as would be the case in an overcurrent scheme (discussed in Section 2.2.6). This means there is normally no intentional time delay associated with the protection scheme operating (other than any short delay which may be incorporated within the algorithm to avoid spurious tripping for fast non-fault transients); it can therefore operate to clear a fault very quickly compared to other forms of protection.

Due to the unavoidable measurement error of CTs at all current magnitudes a tolerance level is added when I_a and I_b are compared. However, as the CT measurement error increases with current magnitude, the differential current tolerance must also increase. If the tolerance does not increase, the relay may operate for external faults when the measured currents are greater than nominal and a differential current is detected due to the CT measurement errors. The technique of increasing the tolerance with measured current is known as biasing and is shown in Figure 23.

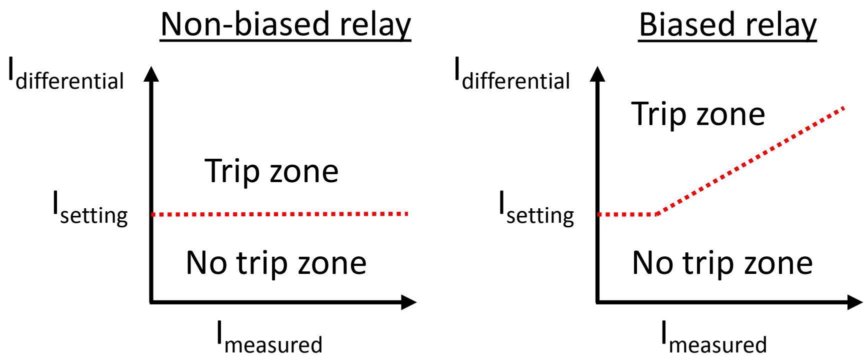


Figure 23: Relay biasing to improve the selectivity of differential protection

It can be seen in the second graph of Figure 23 that as the measured current increases the bias (the tolerance on the setting of the differential current) is increased to compensate for the increased CT error at higher currents. Increasing the bias reduces the relay sensitivity to low fault currents associated with highly resistive faults, but more significantly, it reduces the risk of spurious tripping when the fault is outside the protected zone. The unbiased component of the trip characteristic shown in the second graph in Figure 23 is used to account for relatively small differential currents that could be caused by line charging errors. Line charging errors are caused by a capacitive leakage of current on the line [29]. This capacitive leakage current causes the current measured at the end of the line to be smaller than the current measured at the start of the line and can result in the differential protection operating incorrectly. Differential protection relays are configured to accommodate for the leakage current by calculating the expected current loss. This is done by calculating the expected leakage current from the measured line voltage and known line capacitance [29].

Modern microprocessor relays instigate biasing within software; older electromechanical relays passed the measured current through a winding that acted to restrain operation. As the current in the winding increased the electromechanical restraining force from the winding would also increase to provide a biasing force.

2.2.9 Summary of typical UK protection schemes

2.2.9.1 Low voltage/consumer level (400 V in UK)

Fuses may be used for LV line and plant protection at this voltage level; however, in modern power systems MCBs (Miniature Circuit Breakers) are often used on LV networks instead of fuses. MCBs have an advantage over fuses in that they can be reset after a fault has been cleared. On LV networks residual current devices are used to detect for earth faults. An earth fault causes a proportion of the supply current to return through the earth conductor instead of the neutral. Residual current devices use this effect by comparing the currents measured in the live and neutral conductors to detect for earth faults.

Non-unit protection at higher voltages (normally overcurrent relay protection) also provides backup protection to faults on the LV network.

2.2.9.2 Distribution voltage level (11/33/132 kV in UK)

As discussed in Section 2.2.6, overcurrent relay, PMAR, fuse and section switch protection are all used at this voltage level. Typically 11 kV feeders connected to 33 kV or 11 kV substations will be protected with overcurrent relays at the head of the feeder. In the case of long feeders where a single overcurrent relay may not be sufficient to provide the minimum required protection clearance time PMARs or an additional overcurrent relay may be installed downstream of the original protection device.

In the UK the choice of protection equipment used on 132 kV power systems is dependent on the nature of the power system. Main protection may use distance and/or differential protection and backup protection may use distance and/or overcurrent protection.

2.2.9.3 Transmission voltage level (275/400 kV in UK)

Due to the critical nature of the transmission network, there are at least two and sometimes three levels of main protection system redundancy and protection is configured to operate extremely quickly (normally within only 70-80 ms of fault inception). Backup protection also operates very quickly at the transmission level, normally in 200 ms or less. Employing both redundant protection and ensuring fast protection operation reduces the risk of widespread system failure to acceptable levels. Differential and distance protection are used as main protection, with redundant communications systems. Dedicated circuit breaker fail (where backup circuit breakers are tripped via dedicated communications in the event of the failure of a circuit breaker to open when instructed) and overcurrent protection are also used as backup to the main systems.

2.2.10 Protection of DG

In the UK, the standards that define the protection and fault behaviour requirements of DG units are categorised based on the capacity of the DG and the voltage level of the network that the DG is connected to. For the lowest capacity DGs, connected at LV networks, the standard that defines protection requirements and required fault behaviour is G83 [15, 34]. G83 defines the requirements for inverter-interfaced sources with a capacity of less than 16 A per phase and/or connected at a voltage level less than or equal to 230/400 V AC (Alternating Current). For DGs connected at the distribution level (greater than 400 V and less than 132 kV) G59/2 is the relevant standard [17]. For generators connected at the transmission level (at 132 kV and above) the UK grid code defines the generator protection and fault behaviour requirements [35]. As the generator capacity increases, the protection and fault behaviour (or "ride through") requirements defined in the standards relating to the generator become more rigorous and greater emphasis is placed on the generator actively contributing to the support of grid stability.

As discussed in Chapter 1, the number of DG units on the UK power system is increasing. This has led to an increase in the impact that DG has on network stability and performance during faults. To accommodate for this increase the level of specification in terms of fault behaviour and protection requirements specified in the standards has also been increased.

This thesis considers the impacts of increasing DG penetration at the distribution level and will therefore mainly be concerned with the guidance provided in G59/2. G59/2 focuses on the protection of the generator/network interface and provides guidance on:

1. LOM (Loss of Main)
2. Main and backup short circuit overcurrent protection
3. Reverse power protection
4. Under/over voltage
5. Under/over frequency
6. Phase unbalances
7. Synchronising specifications

LOM protection ensures that DGs do not continue to supply power to an islanded power system. LOM protection normally uses frequency measurements (but some other techniques are available that monitor the relative phase of the voltage and detect shifts which may be indicative of islanding) to determine if the system is islanded, as the frequency of the island will normally tend to deviate from network frequency when it becomes isolated. Islanding protection is required for three reasons

- If an islanded system is out of synchronism with the rest of the network and is then reconnected to the network it can cause damage to the reclosing CB and generators on both the islanded network and the larger network as a whole
- The islanded system may not have sufficient earthing when disconnected from the network; this increases the risk of non-detection of short circuits within the islanded network.
- Fault levels in the island may be reduced; this can cause protection schemes to operate incorrectly.

2.3 Introduction to communication in protection schemes

Protection schemes employing communication (normally used for signalling) are referred to as teleprotection schemes. As already discussed in Section 2.2.5, teleprotection is used in unit protection schemes, and for this application teleprotection is often referred to as protection signalling. Another use of teleprotection is controlling the operation of remote circuit breakers for local events, for this application teleprotection is referred to as intertripping [15]. The data being transferred using teleprotection schemes can be commands (e.g. block, trip, etc.) or measured data (e.g. voltage, current, frequency etc.). The communication link used to transfer the teleprotection data is chosen based on the application, the distance being communicated over and the nature of the available communication links already in place. Typical communication links include: private pilot wires, rented pilot wires, high frequency carrier channels over the power line, very or ultra high frequency radio and optical fibres [15]. In later sections of this chapter the use of IP/MPLS based communication will be reviewed for its viability for teleprotection.

The most significant criteria in teleprotection systems are security, dependability and speed as shown in Figure 24. The significance of each of these criteria varies between applications. For example, in a blocking scheme security, it is less important than it would be for a direct intertrip scheme. If communication fails in a blocking scheme, it does not result in protection failing to operate when a fault occurs. However, in an intertrip-based scheme, communication failure can result in the protection scheme failing to operate [15]. The blocking scheme proposed in Chapter 4 is different to standard blocking schemes, in that speed is not as significant an issue due to the relatively large delay in inverter undervoltage protection operation.

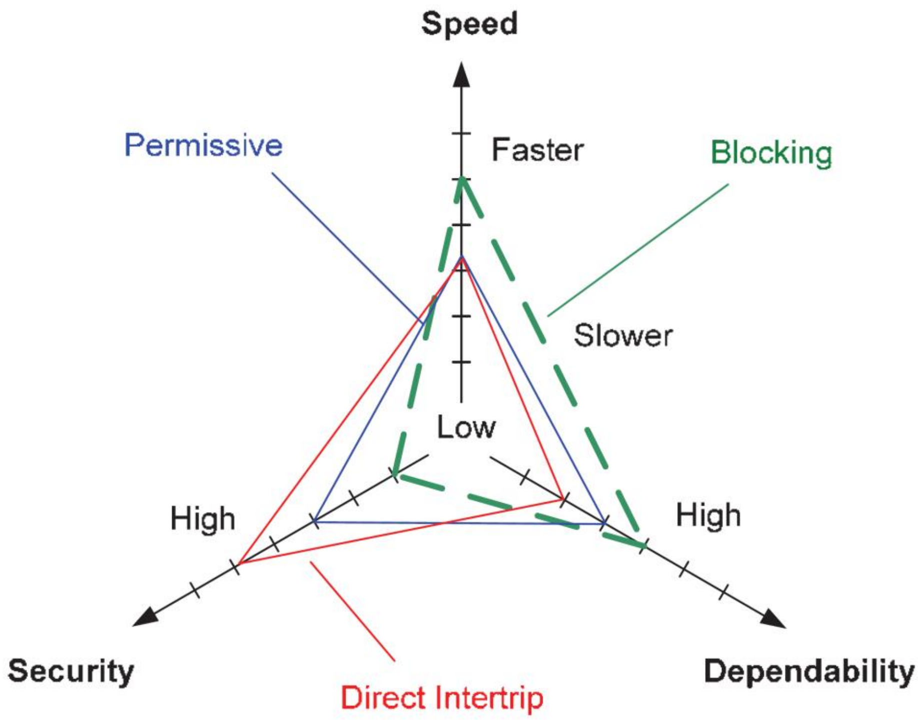


Figure 24: Teleprotection trade off triangle [15]

In a traditional protection scheme employing communications, overall fault clearance time is the sum of signalling time, protection relay operating time, trip relay operating time and circuit breaker operating time [15]. Typical protection operating times range from 4 to 40 ms depending on the application [15] and typically modern protection relays have a failure rate of 1 per 10,000 operations [36].

Typically protection communication schemes are permitted a maximum of one incorrect trip per 500 equipment years and less than one failure to trip per 1000 attempts; a delay of more than 50 ms should also not occur more than once for every ten equipment years [15].

The following sections in this chapter review the use of IP based communication for protection applications. In the first part of this section, the IP is introduced and the process the IP uses for data transfer is reviewed. In the second part of this section, the merits of IP/MPLS based communication over traditional IP communication are discussed. In the final part of this section, specific advantages of IP/MPLS communication are demonstrated with specific case studies focusing on jitter and communication failure handling capabilities presented. IP/MPLS is investigated further in Chapter 4 as a candidate technology for assisting in reducing or eliminating the occurrence of sympathetic tripping.

2.3.1 Internet protocol

All forms of communication are based on rules that govern how information is conveyed. The rules that govern communication between people are defined by language and culture. The rules that define communication between computers are governed by protocols [37]. The remit of a protocol is to define how data being transferred is sequenced, the syntax of the data and how the data should be recovered if communication is corrupted. Several protocols are often used simultaneously when data is being transmitted between computers, as different protocols are applied for communication over different media. This section will consider the protocol applied to internet communication i.e. the IP. An apt analogy for the IP is postal delivery, shown in Figure 25.

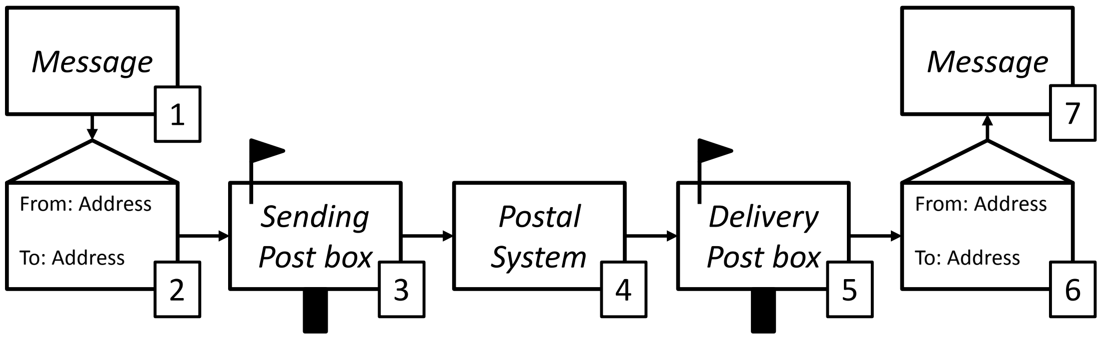


Figure 25: Postal delivery analogy for IP [37]

The IP follows similar conventions to the postal delivery system shown in Figure 25. The stages involved in this process are as follows:

1. The letter content is prepared and written
2. The ‘from’ and ‘to’ addresses are added to the envelope containing the letter
3. The envelope is deposited in the sending post box
4. The envelope is processed by the postal system
5. The enveloped is deposited in the delivery (or arrival) post box

6. The letter is removed from the envelope that it has been transported in
7. The letter is read

This analogy can be mapped directly onto the IP network communication as shown in Figure 26.

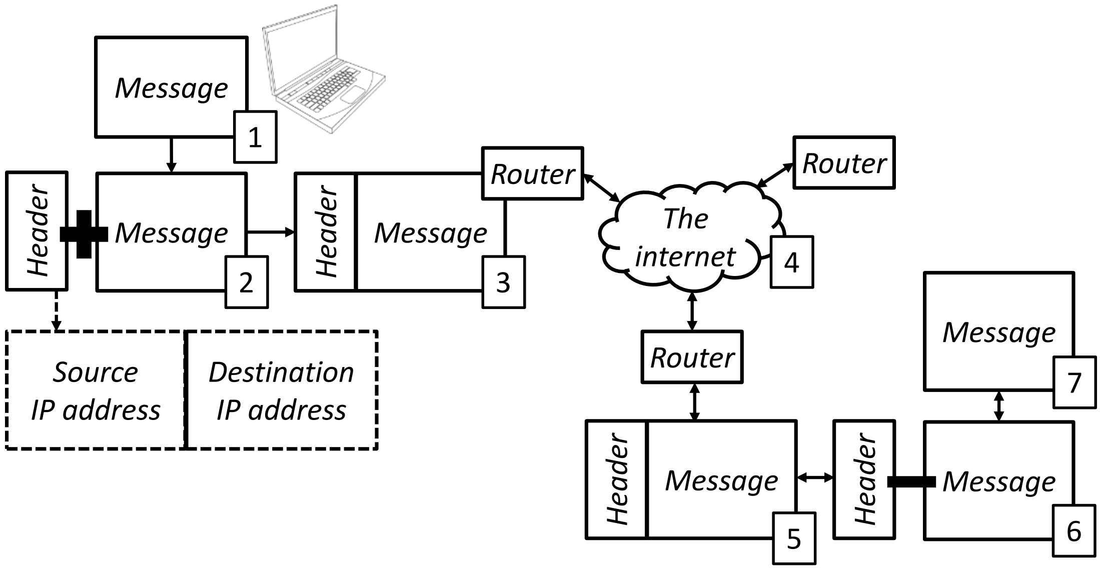


Figure 26: IP communication [37]

In this system the following steps are observed:

1. Creation of the message. In this case instead of being written as a letter the data that constitutes the message is generated on a computer.
2. The message is 'enveloped' in a data packet (in this case an IP packet). The IP packet contains the message and an IP header. The IP header is like an envelope, it contains the 'from' (or source) IP address and the destination IP address.
3. The IP packet is then sent via a router. The router is the interface between the computer and the internet and replaces the post box in the previous analogy.
4. The IP packet is sent from the local router to the Internet via an ISP (Internet Service Provider). Routers within the Internet forward the IP packet until it arrives at the destination router. Each router within the chain (between source and destination forwards) determines where to forward the IP packet by comparing the header in the IP packet to an IP lookup table.
5. The router arrives at the destination computer and is then forwarded to the destination computer.

6. After the IP packet arrives in the destination computer the header is removed so that the message can be read by the destination application.

2.3.2 IP/MPLS communication technology

In a traditional IP network, when a router receives a data packet it determines where the packet should be sent by performing an IP lookup function. The router references a pre-defined routing lookup table to determine the next router that the packet should be forwarded to. Each router in the communication network performs the same independent lookup function for packet forwarding [38].

IP/MPLS differs from traditional IP communication by using 'label switching' [39]. In an IP/MPLS network the first router in the network to receive the data packet performs the same routing lookup as in a traditional IP network. However, instead of finding the next router in the communication chain, the first router determines the final destination router and maps the optimum route from itself to the final destination (taking into consideration network and bandwidth constraints). The first router than appends a 'label' or 'header' to the data packet that allows routers further down the chain to forward the packet without having to perform an IP lookup. Once the destination router receives the data packet the label is removed and the packet can be processed using normal IP routing techniques [40].

In traditional IP networks all the routers from the first router to receive the data packet to the destination router have to perform the IP lookup function. This adds additional computation to heavily utilised routers in the core of the network that already route significant amounts of traffic. In IP/MPLS networks only the first router in the link (normally routers on periphery of the network) has to perform the IP lookup. This helps redistribute the work load away from routers that handle the majority of network traffic. This advantage has been somewhat reduced with the advent of modern, cheap ASICs (application-specific integrated circuit) hardware in routers that are capable of processing many millions of IP routing lookups every second [41].

Another advantage of IP/MPLS is the ability to control traffic routing. This allows the networking operator to prioritise specific traffic and also prevent congestion [42]. Traditional IP protocols do not employ traffic engineering, instead a metric cost is assigned to each communication link and a SPF (Shortest Path First) algorithm is used to determine the communication path. Traffic engineering, employed in IP/MPLS systems, takes the SPF algorithm and adds further constraints to improve traffic control. For example, when a communication path's total bandwidth has been allocated, it is removed as an option for other traffic. This improves the speed at which the data pack is sent and improves the operation speed of the entire communication network (as traffic is not assigned to congested links) [43].

IP/MPLS also has improved resiliency over traditional IP networks due to the IP/MPLS FRR (Fast re-route) protocol [44]. In a traditional IP network, a new optimum path is calculated if a failure occurs. There is a time delay associated with determining a new path and a further time delay to update the relevant routers of the new path. The fast reroute IP/MPLS protocol determines backup paths in advance so that when a failure occurs the delay in transferring to the new path is short and packet loss is kept to a minimum [45].

2.3.3 IP/MPLS applications

The high predictability, resilience, low latency and jitter of IP/MPLS schemes makes them suited to many applications [46].

IP/MPLS communication systems are being used to upgrade mobile telecommunication networks. IP/MPLS communication technology provides greater bandwidth than many existing communication systems, in many cases it is more cost effective than existing systems and it also lends itself to next generation mobile services [47]. These advantages are becoming more significant as the growing demand for mobile internet access is creating a "bottleneck" at existing mobile tower connections [47].

IP/MPLS communication networks are also being used in business and mission critical traffic in rail systems extensively, for example by the Banverket rail operator in Sweden [48]. The high resilience and predictability (in terms of network traffic handling capability, latency and jitter) of IP/MPLS technology makes it an ideal communication solution for safety critical communication for rail operation. IP/MPLS provides a cost effective solution that improves on the bandwidth of older communication networks. The type of data being transferred is agnostic to IP/MPLS communication so older, disparate systems can be unified into one IP/MPLS network without incompatibility issues. IP/MPLS is therefore used for train signalling, alarm systems, ticketing information, video surveillance, traffic management etc.

Alcatel Lucent is also promoting the use of IP/MPLS communication networks for smart grid solutions at the transmission, subtransmission and distribution levels [46]. Many of the attributes of IP/MPLS technology that make it suitable for critical systems in the rail network also make it suitable for mission critical solutions in power systems. IP/MPLS communication systems' high resilience, scalability, security (to cyber-attack) and ability to accommodate different data types on the same network makes it suited to providing a unified communication network for different power system applications. The traffic control capability of IP/MPLS allows it to transmit and prioritise critical data such as IEC (International Electrotechnical Commission) 61850 substation control communication and still have the bandwidth capability to accommodate less time critical information such as metering data.

2.3.4 Operation of IP/MPLS scheme

One of the key aspects of IP/MPLS communication is the LSP (Label Switched Path) configured between routers [49, 50]. The LSP is effectively a unidirectional route between the origin and destination routers in an IP/MPLS network. Without establishing a LSP route the IP/MPLS network can't forward data packets using the labelling method discussed in the previous section. The IP/MPLS signalling protocol maps LSPs to specific labels so that when a data packet is assigned a label it corresponds to a specific LSP route. There are multiple types of IP/MPLS protocol: LDP (Label Distribution Protocol) and RSVP-TE (Resource Reservation Protocol with Traffic Engineering). LDP is simpler to implement than RSVP-TE, however, RSVP-TE allows traffic engineering (discussed in previous section). In reality most networks use a combination of both protocols.

There are three key router categories in an IP/MPLS network, as shown in Figure 27 [38].

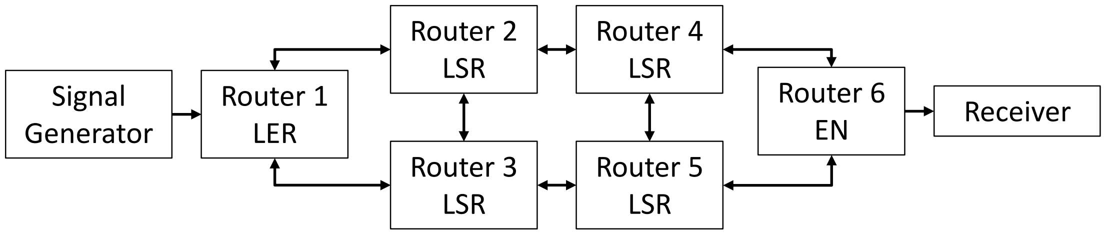


Figure 27: IP/MPLS router roles (categorisation)

The LER (Label Edge Router) defines the initial path for the data pack by appending the IP/MPLS 'label'. It also adds the packet to the LSP.

The LSR (Label Switch Router) does not perform IP lookup but transmits the packet onto the next router. This router is a 'bridge' in the middle of a LSP between the LER and the destination router.

The EN (Egress Node) is the destination router that removes the IP/MPLS label so that the data packet can be processed using traditional IP communication.

2.3.5 Communication system capabilities

The main criteria that are typically used in evaluating the viability of IP/MPLS technology are listed below [51]. These criteria are generic for all communication applications; the criteria most pertinent to protection application have been emboldened:

1. Synchronisation – the ability to distribute a high quality clock signal throughout the communication network for synchronising equipment
2. **Predictability** – the quality of the communication system must be consistent in terms of its ability to cope with network traffic, failure, latency and jitter.
3. **Resiliency** – the communication network must be able to continue to operate within acceptable parameters for failures on the network e.g. communication link failure or denial of service.
4. Security – the communication network must be resistant to cyber attacks.
5. Easy Management – the communication system must be intuitive to maintain and troubleshoot.
6. **Low Latency and Jitter** – the latency (or delay in sending/receiving a signal) must be within acceptable parameters and the jitter (the variability of packet latency in sending/receiving) must be consistent and low.

The communications ability to accommodate with jitter and its resiliency in terms of communication link and node failure will be discussed below.

2.3.5.1 Jitter (variability of latency)

As has already been discussed jitter is the variability of latency. The magnitude of jitter is dependent on the amount of network traffic and can increase if there's a sudden burst of traffic on the network. This can cause communication congestion. Jitter is demonstrated graphically in Figure 28 and Figure 29. In Figure 28 the top graph shows a clock pulse of fixed duration. The bottom graph is the return signal of the clock pulse after it has travelled through a communication network. The return signal has a fixed latency of half a cycle applied on the initial signal. This is perhaps representative of a fixed communication network with a constant level of network traffic. Latency is constant therefore jitter is zero.

In Figure 29 the top graph is a clock pulse with fixed duration (the same as the top graph in Figure 28). The middle graph is the return signal of the clock pulse after it has travelled through a communication network. The return signal has variable latency i.e. in some cases it arrives before the initial clock pulse and in some cases it arrives after. This is perhaps representative of a communication system in flux (i.e. the communication path is dynamically changing) or a communication system with variable amounts of traffic vying for priority. The bottom graph is an illustration of how the jitter changes between cycles.

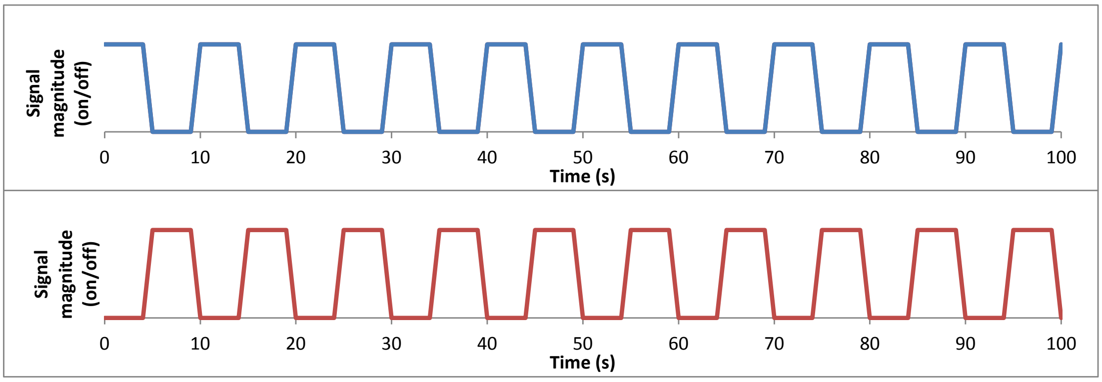


Figure 28: Example of fixed latency - no jitter

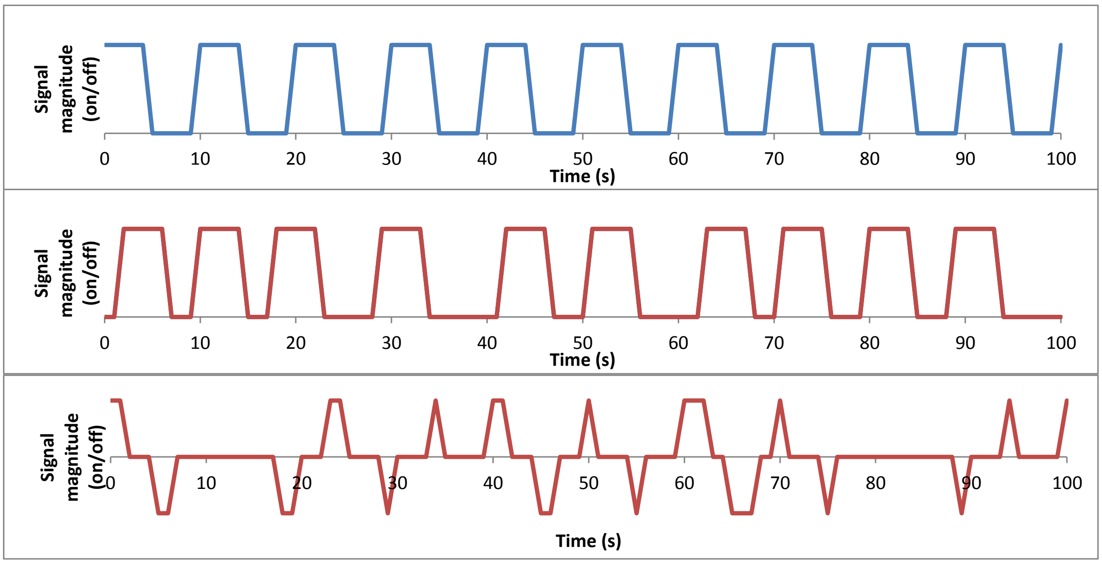


Figure 29: Example of variable latency - jitter present [52]

The IP/MPLS communication network accommodates for jitter on the network by buffering data and then re-transmitting it at a constant rate. If the jitter on the network increases the size of the jitter buffer must be increased to accommodate. Jitter is also reduced by applying appropriate traffic engineering (as discussed in Section 2.3).

The router jitter buffer operation is shown in Figure 30. If there is jitter in the input signal the receiving SAR (Signal Aggregation Router) holds several clock pulses worth of traffic in a buffer. The SAR then transmits re-transmits the traffic at a constant rate to remove the jitter from the signal. The delay associated with holding the traffic in the buffer is what adds latency to the signal.

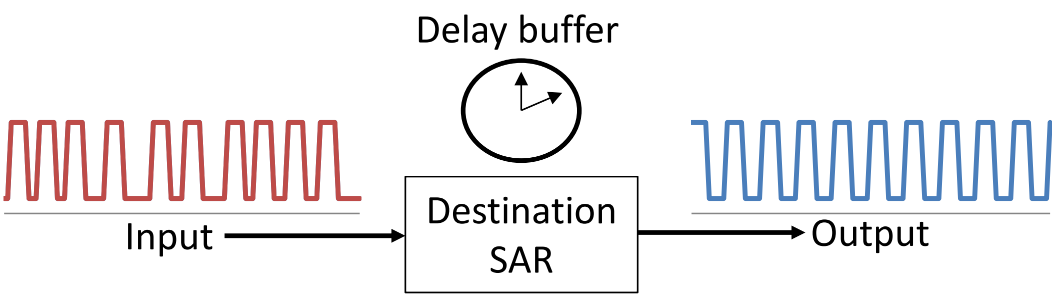


Figure 30: Router jitter buffer operation

The IP/MPLS communication network has been tested for jitter tolerance by adding additional jitter onto the network using the network emulator as shown in Figure 31 [53].

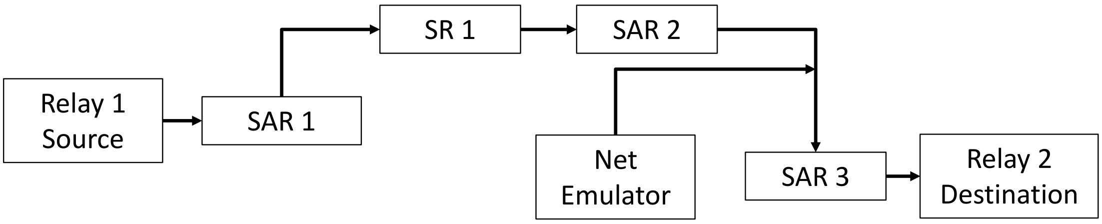


Figure 31: Laboratory test of IP/MPLS jitter handling capabilities [53]

The network emulator introduced varying levels of jitter based on a Gaussian distribution as shown in Figure 32. It was demonstrated that the relays (Toshiba GRL 100 Line Differential Protection Relays) were capable of operating up to a jitter level of 0.8 ms (peak to peak), this corresponds to a latency resulting from the jitter buffer in excess of 187μs [53]. Beyond this level of jitter the relays do not function correctly. This is a hardware limit of this specific relay and does not reflect the jitter handling capability of the IP/MPLS technology.

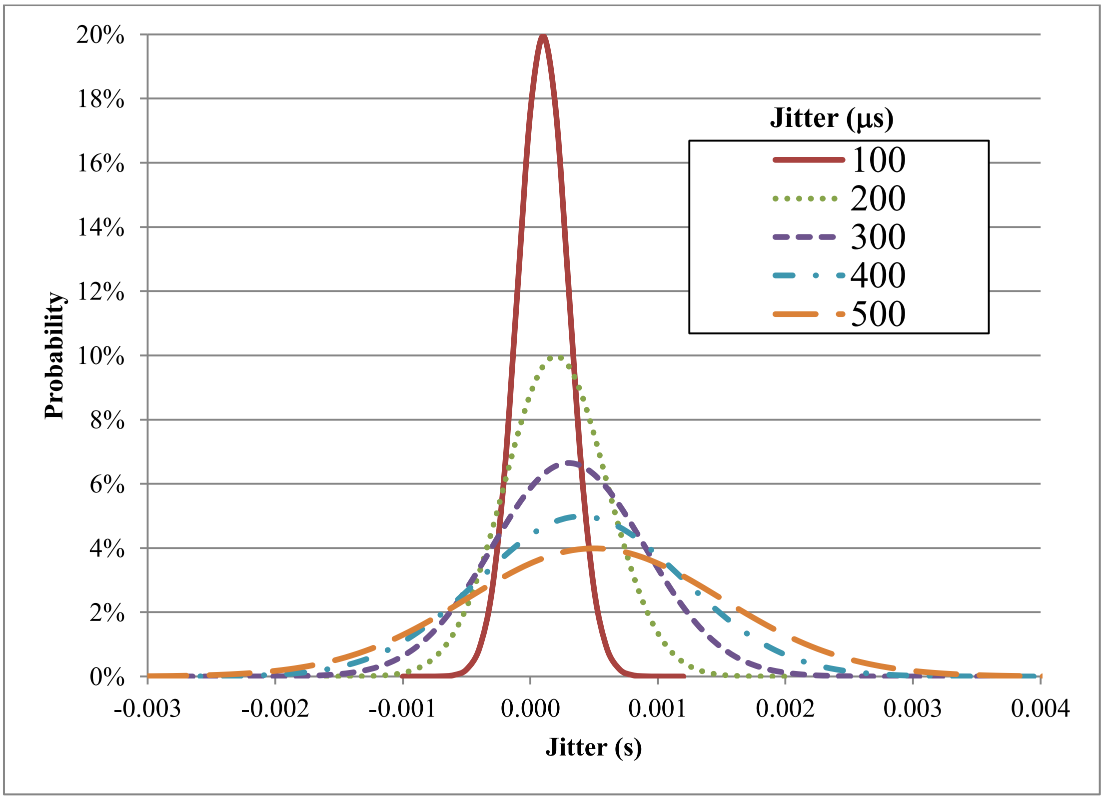


Figure 32: Gaussian distribution of jitter

2.3.5.2 Communication link or node failure

In the event of a communication link failure, the IP/MPLS communication scheme must continue to operate. The communication scheme does this by re-routing traffic via an alternative route. For the blocking scheme proposed in Chapter

4, providing backup communication links to provide communication redundancy is unlikely to be cost effective. However, if the blocking scheme were implemented as part of a wider communication network used for multiple applications, or if the IP/MPLS scheme were used for high priority traffic, then redundant communication channels may be required. Many “smart grid” functions of the future will require communications, so the economic argument against use of communications may become less of a barrier in the future.

The ability of IP/MPLS to accommodate link and node failure has been tested using the laboratory setup shown in Figure 33 [53]. In Figure 33, one of the SARs is remotely controlled to disconnect, while in Figure 34 a cable is manually disconnected. As already discussed in Section 2.3, IP/MPLS uses FRR technology to find an alternative communication path in the event of link failure.

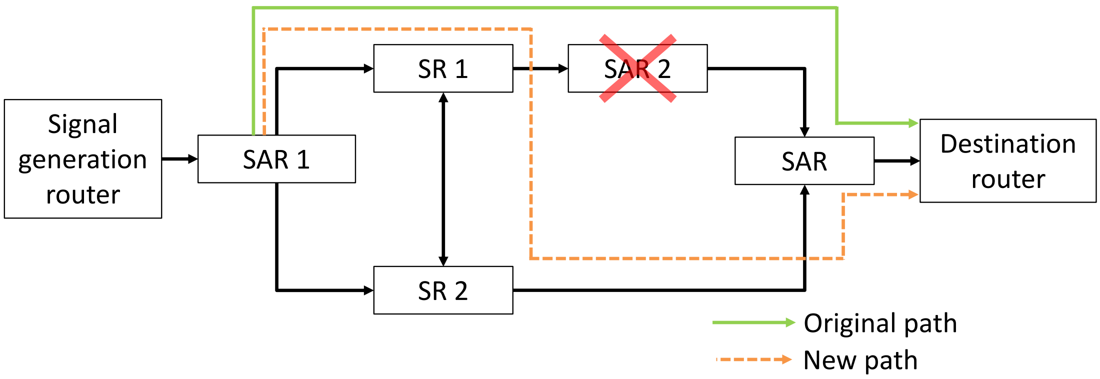


Figure 33: Laboratory test of IP/MPLS fast re-route capabilities – node failure

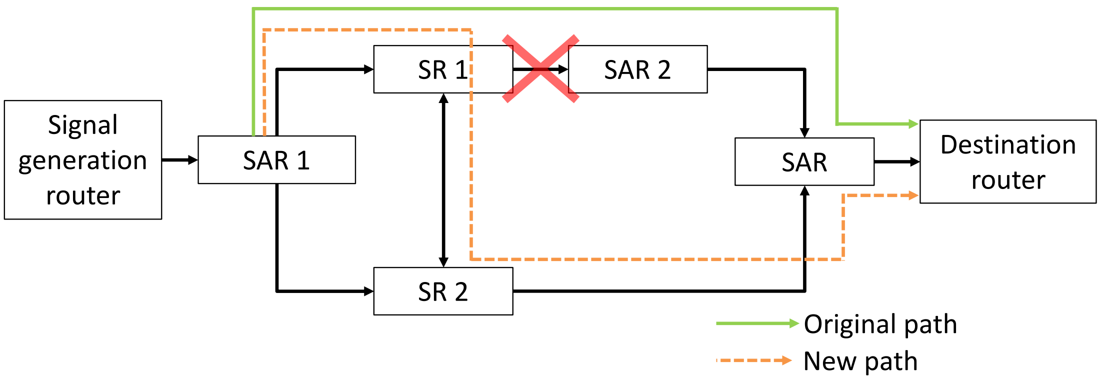


Figure 34: Laboratory test of IP/MPLS fast re-route capabilities – link failure

In both cases the FRR (Fast Re-Route) function operates and finds an alternative communication path. In Figure 33 (node failure), the re-route function causes a delay of 34 ms before the fault is detected and the path is re-routed; in Figure 34 (link failure) the re-route function causes a delay of 47 ms. As already discussed, total fault clearance time using teleprotection should typically be less than 50 ms [15]. This leaves very little time for other protection operations if a re-route operation is required. However, without link or node failure the communication system has been shown to operate with a latency of 1.5 ms and with proper management of the system, it is extremely unlikely that node/link failure will coincide with a power system fault event. Once the communication system fault is cleared, the IP/MPLS scheme returns to the default LSP. The change back to the original LSP is scheduled to cause minimum disruption to communication and therefore typically results in a latency of only 1 ms [15].

2.4 Chapter summary

In the first part of this chapter a basic overview of the operation of the UK power system has been presented. Topics that have been discussed include: ownership of the power system; regulation of the power system and the balancing mechanism used to balance generation and demand. This basic overview puts the work presented later in the thesis into a wider context i.e. how the results from this thesis contribute to the power industry as a whole.

In the second part of this chapter protection theory relevant to the topics discussed later in the thesis has been presented. These topics include fault detection, fault isolation, requirements of a typical protection, an overview of protection relaying devices and a summary of the protection requirements for DG protection.

In the third part of this chapter the role of communication technology in protection applications has been discussed. The capabilities of IP/MPLS for use in protection have also been evaluated with specific case studies on jitter and handling of communication failure presented. The role of IP/MPLS as a candidate technology for stopping the occurrence of sympathetic tripping is investigated in more detail in Chapter 4.

Chapter 3 Laboratory testing and development of an empirical inverter fault model

In this thesis, the primary focus of the research is the impact of inverters on distribution network operation. To accurately evaluate this impact, an inverter fault model has been developed based on observations of inverter fault behaviour recorded during laboratory testing of a commercially available 3 kW single phase inverter used for PV applications. Based on industrial guidance this inverter is typical of PV inverters presently being installed on the UK power system.

The first part of this chapter describes the fault test procedure using a 3 kW single phase PV interface inverter within the microgrid lab facility at the University of Strathclyde. The second part of this chapter presents the results from the laboratory testing and reviews the inverter's fault response and its compliance with relevant standards (G83 [34], G59/2 [17] and the National Grid Code [35]). The third and final part of this chapter explains how the inverter's observed fault responses have been used to develop an empirical inverter fault model for investigating the impact of inverter-interfaced DG on distribution protection operation. The inverter model is used to investigate the impact of inverters on distribution protection using PSCAD (Power System Computer Aided Design) power system simulations in Chapter 4 and Chapter 5.

3.1 Objective of laboratory testing

The objective of the laboratory tests was to quantify the inverter's fault response for different impedances to the fault. The laboratory test involved applying faults on the microgrid network with various amounts of impedance inserted between the terminals of the inverter and the fault location and logging the inverter's tripping time (or non-tripping), fault current contribution and terminal voltage.

3.2 Laboratory setup

An overview of the laboratory setup is shown in Figure 35. In the microgrid, faults were placed on to the system in the vicinity of the inverter; the magnitude of the voltage depression at the inverter's terminals was influenced via an inductor bank as shown in Figure 35. The voltages and current were recorded on each phase of the lines supplying the fault and at the terminals of the single phase inverter interface using current and voltage transformers.

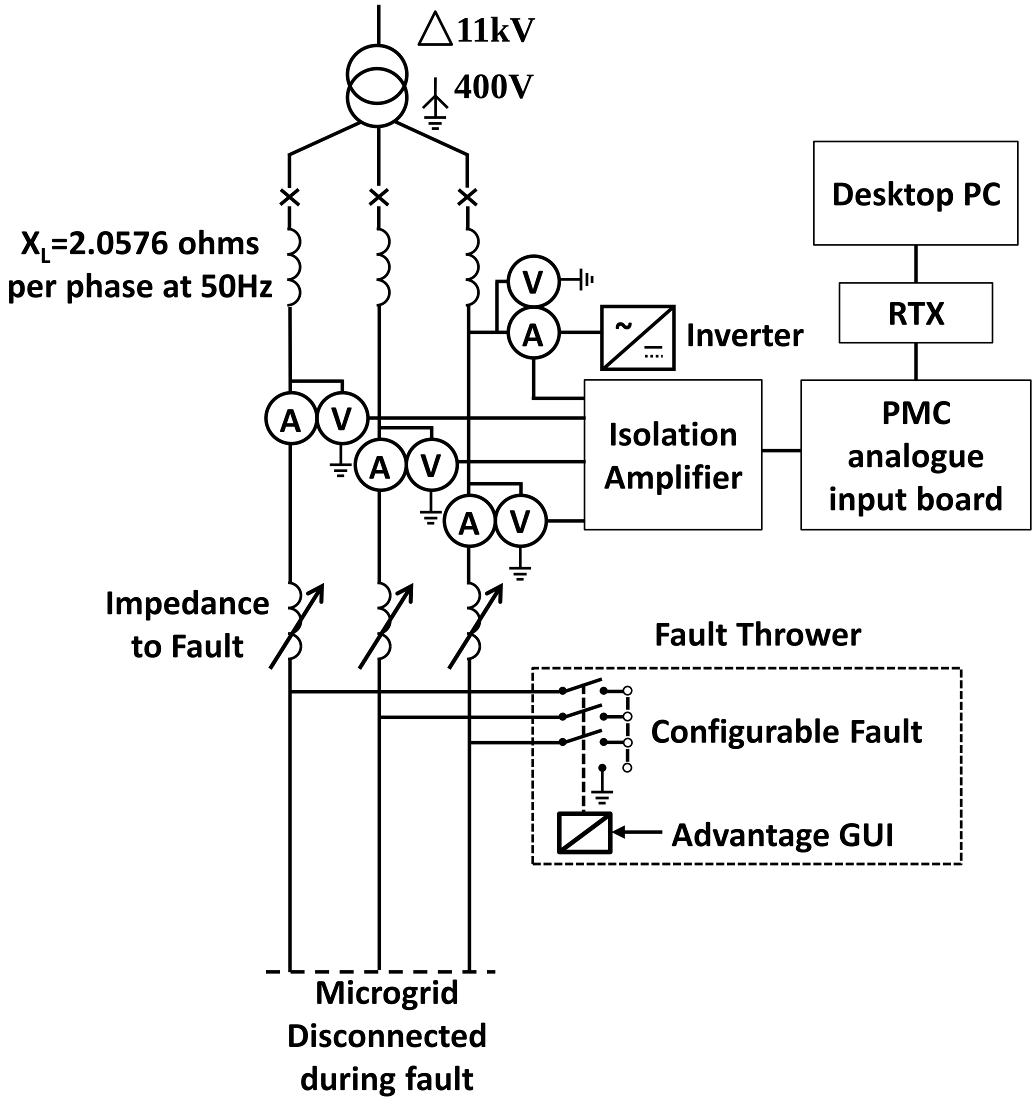


Figure 35: Experimental arrangement to test inverter's response to network faults

3.2.1 Fault thrower

A schematic of the fault thrower, constructed at Strathclyde, is shown in Figure 36. The fault thrower is capable of applying: three-phase, phase-phase, phase-earth, phase-phase-earth, three-phase-earth faults. The fault type is configured manually while the fault thrower is offline and disconnected from the microgrid. For the purposes of this study three-phase faults were used to evaluate the inverter's fault behaviour. Three phase faults are the most severe fault type (in terms of voltage depression) and were chosen in order to evaluate the inverter's behaviour under worst case conditions. It is worth noting that there are some unique conditions at which single phase faults can cause greater fault currents and voltage depression. Larger fault currents and voltage depressions can occur for single phase faults when the fault is close to the wye side of delta-wye (grounded) transformers.

There is negligible fault impedance associated with the fault thrower – impedance to fault is defined externally from the fault thrower in the line impedance between the inverter and the fault. The fuses, miniature circuit breakers and surge arresters shown in the schematic were installed to prevent damage to other electrical components within the microgrid when the fault was applied. As can be seen from the diagram the contactors that apply the fault are controlled using a software interface via the local area network within the microgrid laboratory.

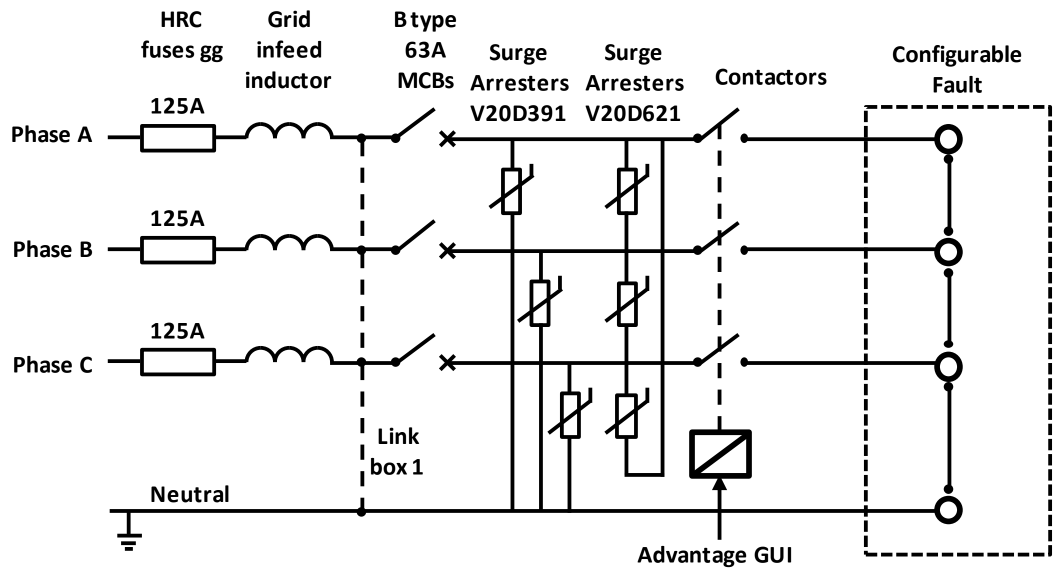


Figure 36: Fault thrower schematic

3.2.2 Measurement equipment

Several stages of measurement equipment were required to accurately measure the inverter's fault response, as shown in Figure 37.

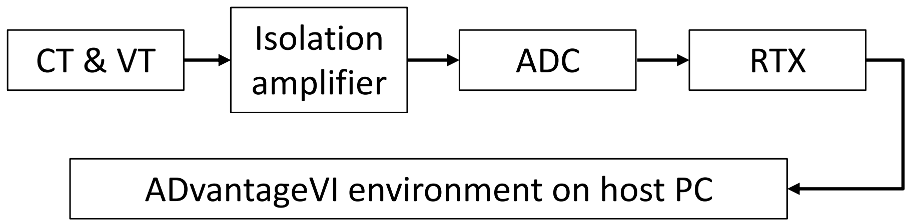


Figure 37: Measurement equipment block diagram

The voltage output from the measurement transformers is isolated, clamped (within acceptable limits), filtered and scaled by the isolation amplifiers [54]. The ADC (Analogue to Digital Converter) digitises the analogue voltage from the isolation amplifiers. The rtX simulator [55] calibrates and converts the data for interfacing to the host PC. The voltage and current data is interpreted by the host PC and displayed (in real time) and stored (for later analysis) using the ADvantageVI [56] run time environment as shown in Figure 38. A Simulink model was developed to further calibrate and account for errors in the data sent from the rtX. The ADvantage run time environment is also used to control the operation of the fault thrower.

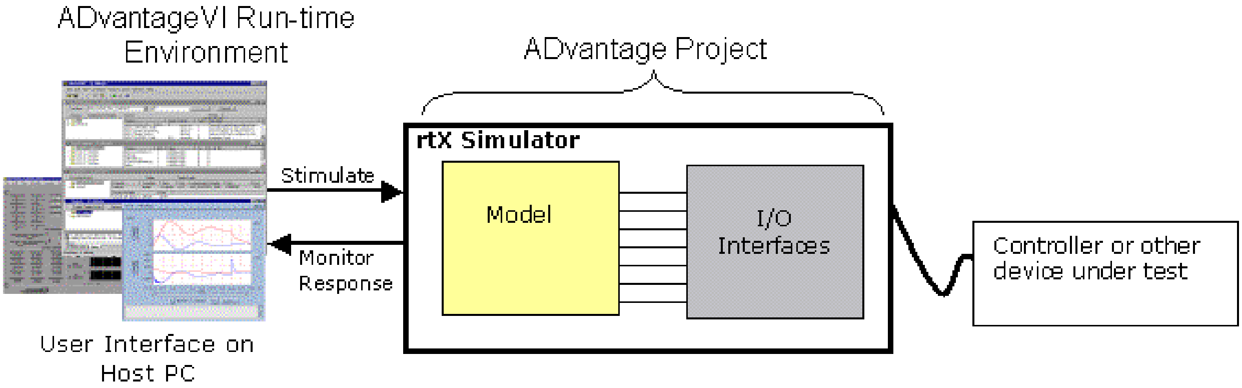


Figure 38: ADvantage Virtual Interface run time environment [56]

3.2.3 Inverter test arrangement

The inverter is a single phase 3000 VA commercial inverter designed for photovoltaic applications and extensively used within the UK at present. Based on industry consultation, this inverter behaviour is typical of single phase inverters being used at present for low voltage photovoltaic applications. For reasons of confidentiality the inverter manufacturer cannot be named, however the inverter specification is provided in Table 2 and Table 3.

Table 2: Input and output data of test inverter

INPUT DATA	
DC max. power for cos φ=1	3,170 W
Max. input current	13.8 A
Max. input voltage	600 V
MPP voltage range	230 - 500 V
OUTPUT DATA	
AC nominal output for cos φ=1	3,000 W
Max. output power	3,000 VA
Max. output current	13.0 A
Max. efficiency	95.70%
Euro. efficiency	94.80%
MPP adaptation efficiency	> 99.9 %
Grid connection	1~NPE 230 V
Frequency	50 Hz / 60 Hz
Harmonic distortion	< 3 %
Power factor	0.75 - 1 ind./cap
Night consumption	app. 1 W

Table 3: General and safety data of test inverter

GENERAL DATA	
Dimensions (height x width x depth)	673 x 434 x 250 mm
Weight	23.8 kg
Degree of protection	IP 54
Inverter concept	HF transformer
Cooling	Regulated air cooling
Installation	indoor and outdoor installation
Ambient temperature range	from -20°C to +55°C
Permitted humidity	0 % to 95 %
SAFETY EQUIPMENT	
DC insulation measurement	Warning/shutdown (depending on country setup) at Riso < 500 kΩ
Overload behaviour	Operating point shift, power limiter
DC disconnect	integrated

This capacity of inverter is configured to comply with present G83 standards; however, later in this chapter the inverter's ability to comply with more stringent standards relating to higher capacity inverter's is also investigated. It was connected to a single phase 3.3 kW programmable DC (Direct Current) power supply [57] in the microgrid laboratory. A DC power supply is an idealised representation of the energy source in a photovoltaic inverter application. It is probable that in 'real-world' applications, the energy sources (i.e. the solar radiation and the PV panel in the case of a photovoltaic installation), would not have the capacity to provide such a large step change in power delivery as that provided by the DC supply used in this study. By using a DC power supply to represent the energy source these results effectively reflect the largest fault current response that the inverter can achieve. During the fault test the other devices on the microgrid (other than the inverter) were disconnected to avoid the potential for damage.

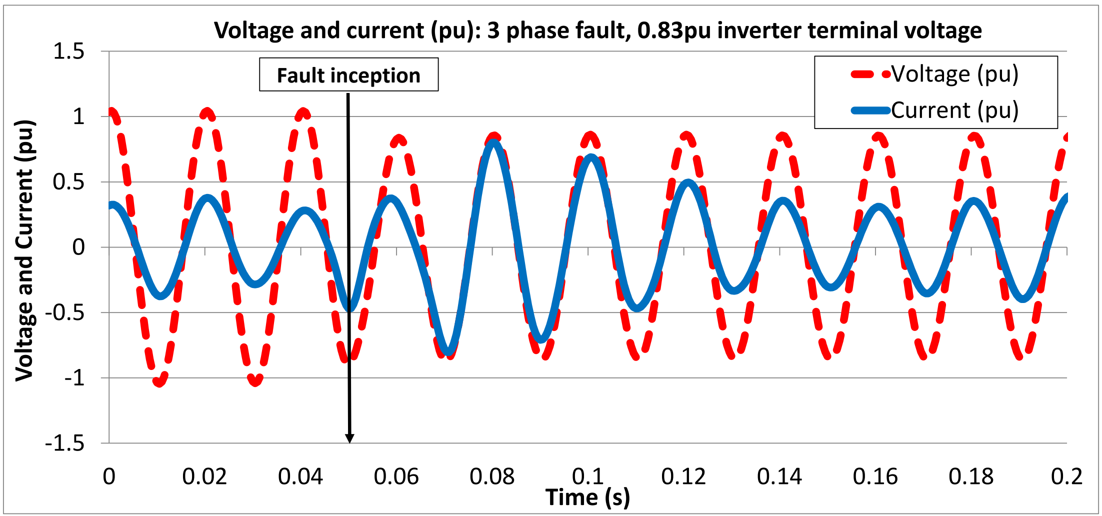
3.3 Testing procedure and fault response

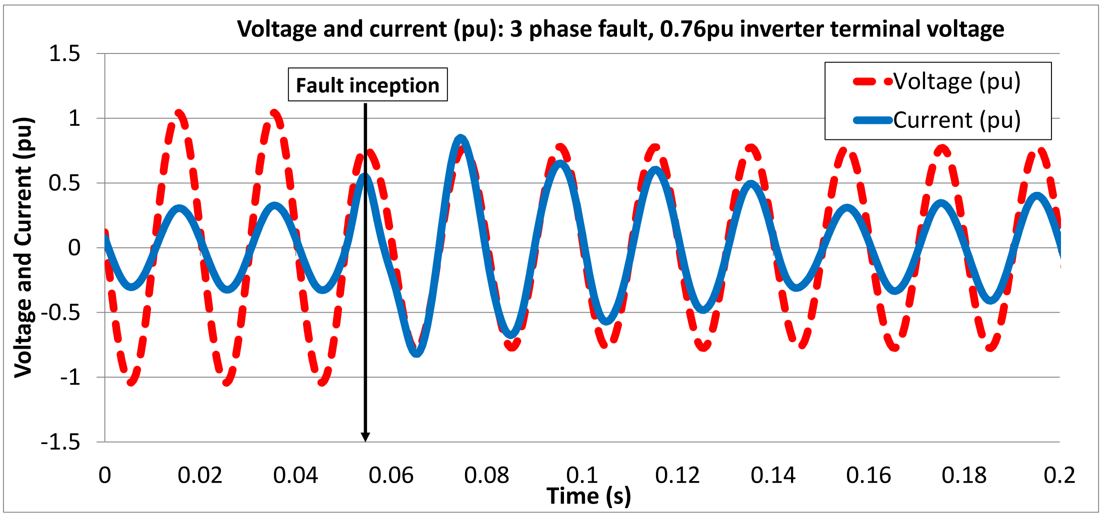
Five experiments were conducted, with inverter terminal voltages of 0.83 pu, 0.66 pu, 0.47 pu, 0.22 pu and 0.15 pu being produced at the inverter's terminals using the aforementioned impedance to fault arrangement, a summary of the inverter's fault response is given in Table 4.

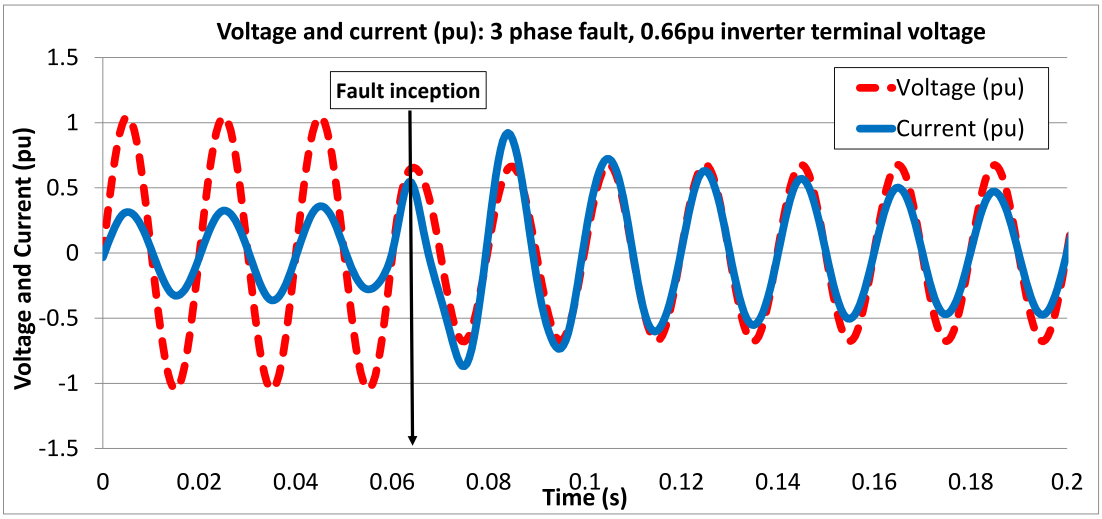
As one would expect, the inverter's fault current contribution varies in terms of both magnitude and phase as the impedance to the fault is varied (as shown in Figure 39). It is interesting to note that the fault current magnitude and phase angle do not remain constant during the fault, as evidenced by the inverter's response to faults where the voltage is 0.22 pu and 0.15 pu at the inverter's terminals during the fault (as shown in the final two graphs in Figure 39). At these terminal voltages, the phase angle between the supplied voltage and current is larger than for the higher voltages of 0.83 pu, 0.66 pu and 0.47 pu.

The maximum recorded fault current from the inverter was 1.08 pu rms when the terminal voltage level was 0.15 pu. The per unit value of current is 13 A rms (for a 3kW power rating at a single phase voltage of 230 V rms). This fault current is actually lower than that assumed and suggested in the majority of the literature: for example, [58] suggests 2 pu fault current could be supplied by a three phase 15 kVA inverter-interfaced DG, [59] states that 2 pu is typical as a "rule of thumb" for industry, but records a 4-5 pu fault current in a laboratory test of an inverter and [60] states that 1.6 pu is typical for inverters employed in shipboard applications. The difference between the recorded results and the results in the literature may be due to the application to which the inverter is being applied. Higher rated switches capable of withstanding fault currents greater than the rating of the inverter tend to be more expensive. It is therefore economically inadvisable to design the inverter to be capable of producing fault currents in excess of its rating. Many of the fault tests in the literature are performed on specialised inverter equipment that may be overrated for shipboard [60] or research applications [58]. It can be observed from Figure 39 that the pre-fault inverter current is lower than expected (0.3729 peak pu instead of 1 peak pu if operating at rated current). This is due to the Max Power Point Tracker within the inverter being switched off. In order to use the inverter with a DC supply instead of a PV panel (or PV panel emulator) the manufacturer advised that the Max Power Point Tracker must be disabled. An appropriate PV panel or PV panel emulator was not available for the purposes of this test.

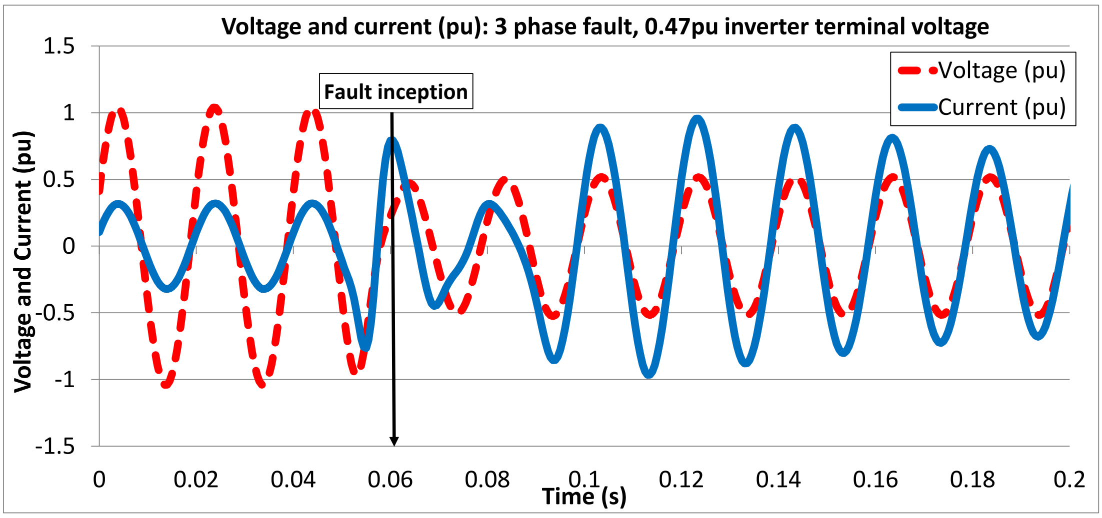
As the inverter terminal voltage decreases (as would be the case for faults progressively closer to the inverter's location), the fault current supplied by the inverter increases. It can be observed from Figure 39 that the reactive component of the inverter's fault contribution becomes more significant at lower voltages.



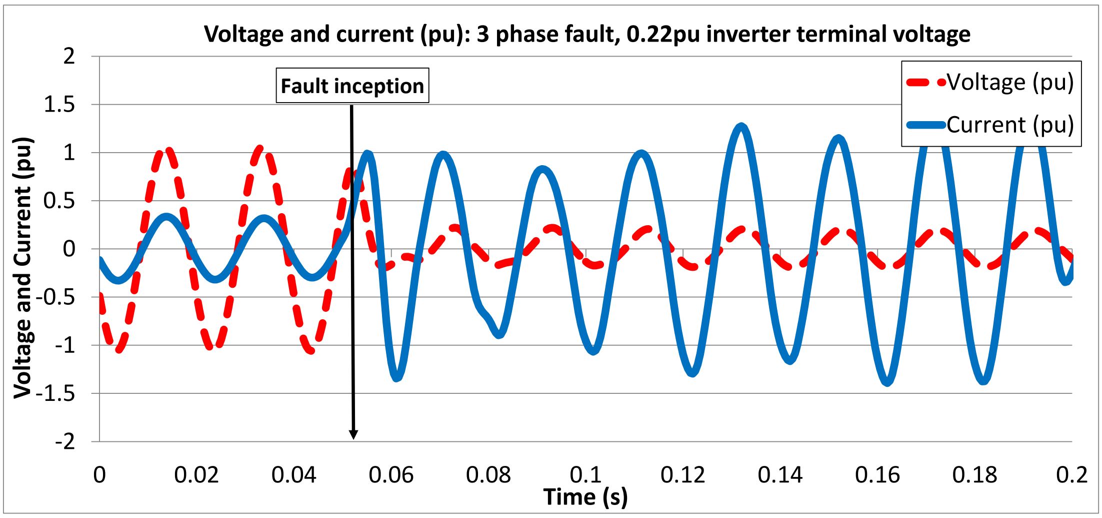




Voltage and current (pu): 3 phase fault, 0.66pu inverter terminal voltage
Fault inception
Voltage (pu)
Current (pu)
Voltage and Current (pu)
Time (s)



Voltage and current (pu): 3 phase fault, 0.47pu inverter terminal voltage
Fault inception
Voltage (pu)
Current (pu)
Voltage and Current (pu)
Time (s)



Voltage and current (pu): 3 phase fault, 0.22pu inverter terminal voltage
Fault inception
Voltage (pu)
Current (pu)
Voltage and Current (pu)
Time (s)

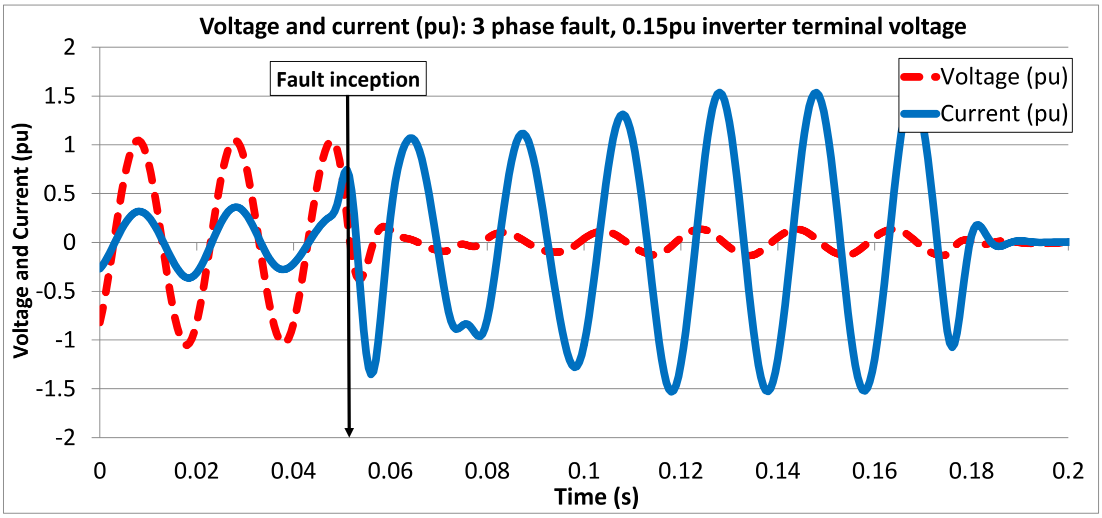
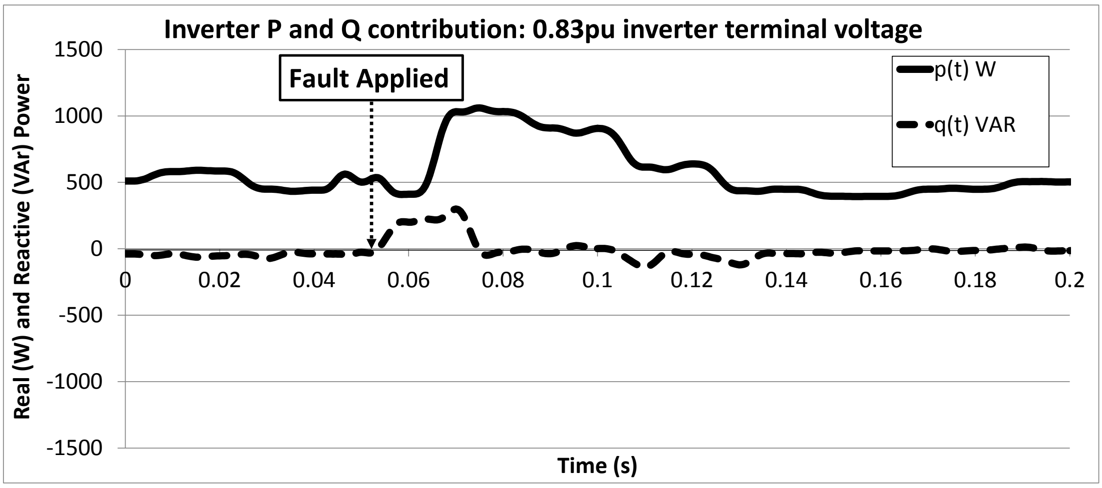


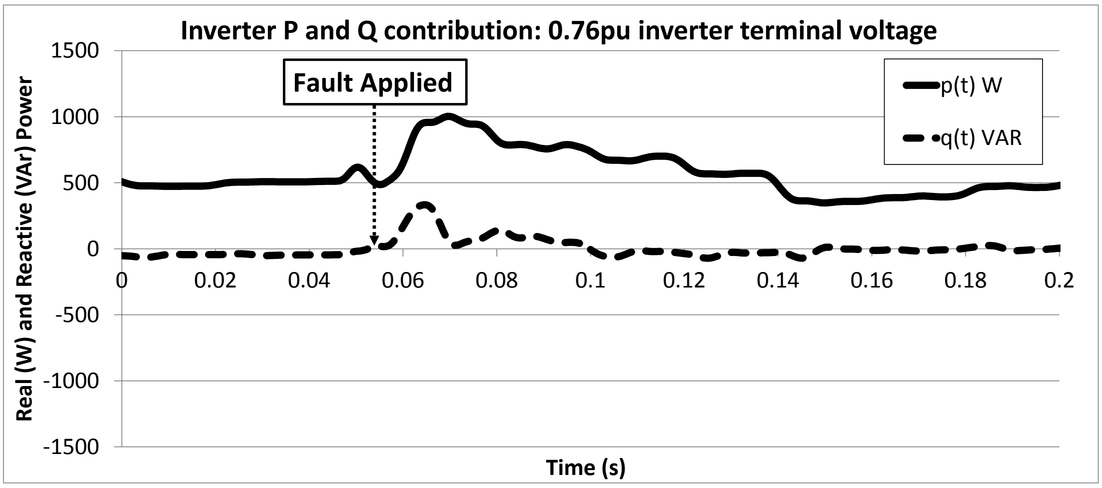
Figure 39: Inverter's voltage and current fault response during network faults

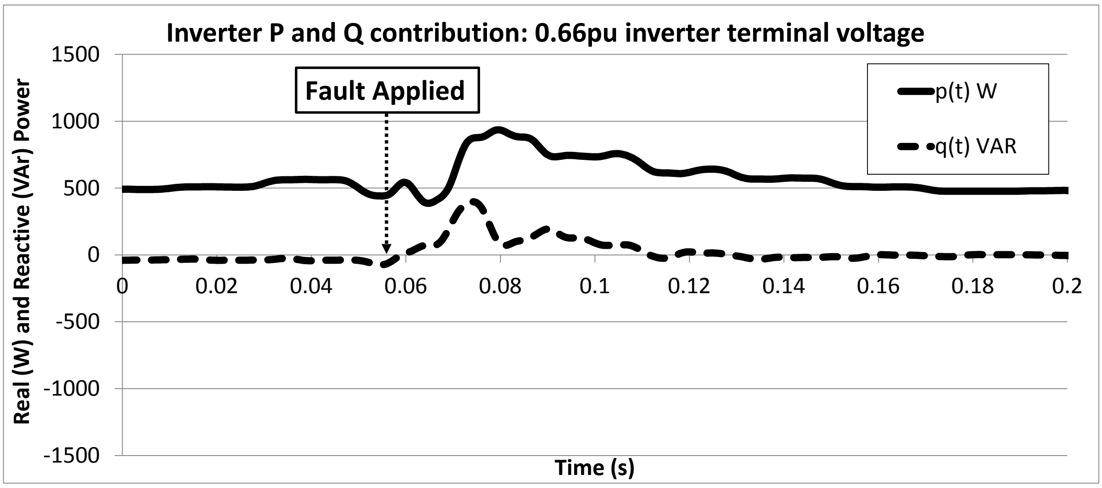
Table 4: Summary of inverter laboratory fault response

Inverter terminal voltage during fault (rms pu)	Maximum inverter fault current (rms pu)
0.83	0.5664
0.76	0.6010
0.66	0.6522
0.47	0.6757
0.22	0.9777
0.15	1.086

The inverter's corresponding real and reactive power contributions, for the same range of impedances to fault as shown in Figure 39, are shown in Figure 40. The values for P and Q were calculated from the measured voltages and currents in Figure 39, using the method presented in [61]. As anticipated from Figure 39 (due to the increasing phase angle) the reactive inverter power contribution increases at lower voltages. In contrast, the active power contribution from the inverter decreases at lower voltages. The reason the active power decreases is because the voltage depression resulting from the fault is greater than the increasing current contribution from the inverter. More severe voltage depressions are representative of physically closer and/or lower impedance faults.


Inverter P and Q contribution: 0.83pu inverter terminal voltage
Fault Applied
p(t) W
q(t) VAR
Real (W) and Reactive (VAr) Power
Time (s)
1500
1000
500
0
-500
-1000
-1500
0
0.02
0.04
0.06
0.08
0.1
0.12
0.14
0.16
0.18
0.2


Inverter P and Q contribution: 0.76pu inverter terminal voltage
Fault Applied
p(t) W
q(t) VAR
Real (W) and Reactive (VAr) Power
Time (s)
1500
1000
500
0
-500
-1000
-1500
0
0.02
0.04
0.06
0.08
0.1
0.12
0.14
0.16
0.18
0.2


Inverter P and Q contribution: 0.66pu inverter terminal voltage
Fault Applied
p(t) W
q(t) VAR
Real (W) and Reactive (VAr) Power
Time (s)
1500
1000
500
0
-500
-1000
-1500
0
0.02
0.04
0.06
0.08
0.1
0.12
0.14
0.16
0.18
0.2

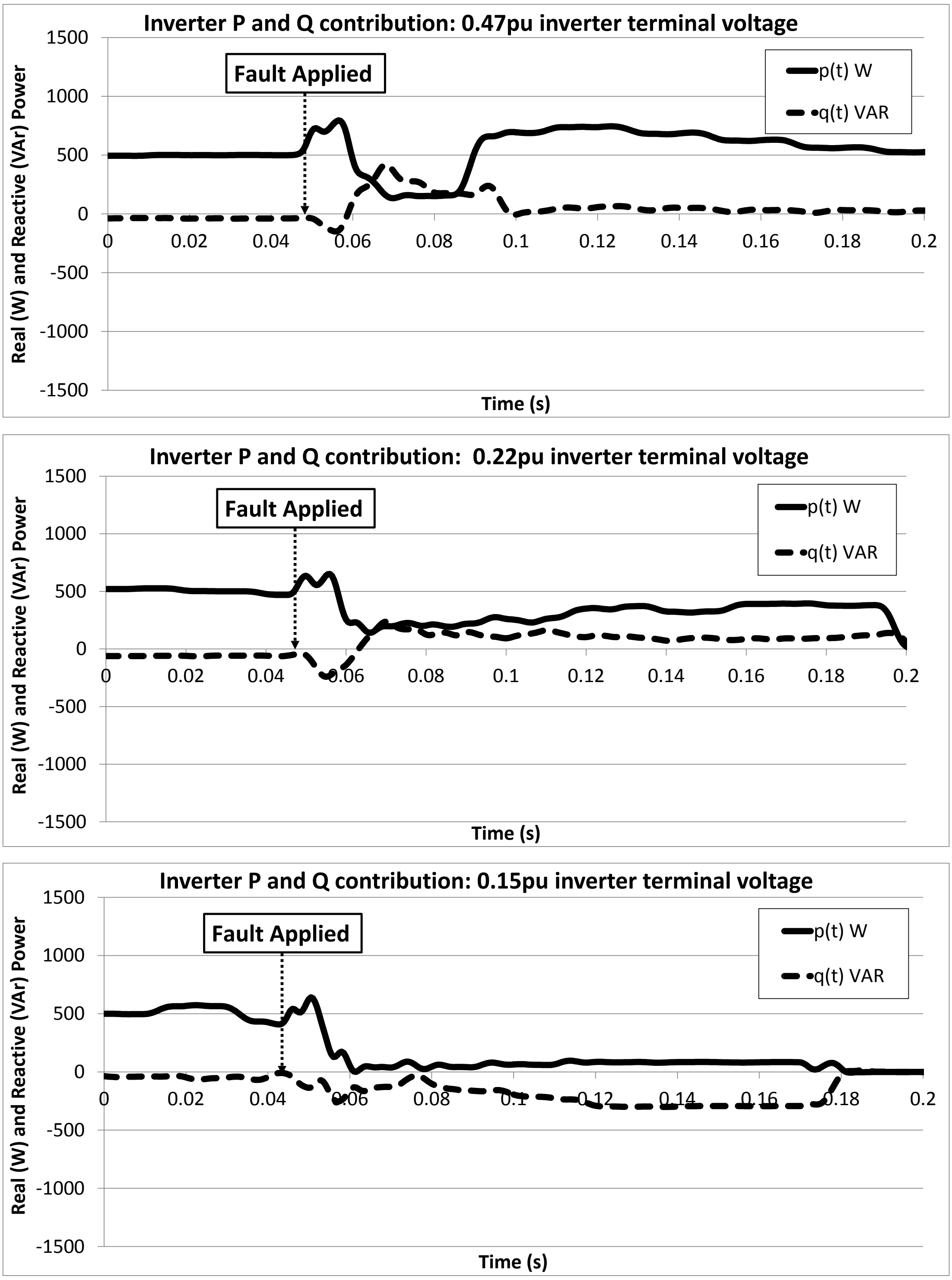


Figure 40: Inverter's real and reactive power fault response during network faults

3.4 Compliance with relevant inverter standards

The relevant standards relating to inverter fault behaviour are summarised in Table 5. At present this capacity of inverter must only comply with standard G83. In order to determine whether the inverter's fault protection would need to be updated if G83 requirement were changed; in this section the inverter's capability of meeting G59/2 and UK grid code requirement is evaluated. The results suggest that at present the inverter would not be able to meet all G59/2 or G83 requirements; however, it is probable that the inverter would be able to meet these requirements if its control software was updated.

Table 5: Generator undervoltage protection requirements

Standard	**Rating of Generators**	**Undervoltage Requirements**
G83	<16 A per phase ≤400 V	-10 % trip within 1.5 s
G59/2	Small and medium power stations	-20 % trip after 0.5 s -13 % trip after 2.5 s
UK Grid Code	Large power stations	See Figure 43 for characteristic

Based on the capacity and voltage rating of the tested inverter, the relevant prevailing standard for the inverter is G83 [34]. It is worth noting that at the distribution level there are presently no standards or recommendations that define what such an inverter's current contribution should be during a fault. The inverter's fault response with respect to the G83 fault response requirements is shown in Figure 41. It can be observed that for the voltage depressions applied in this laboratory test, the inverter complies with all G83 requirements i.e. for faults that result in a voltage of less than 0.9 pu at the inverter terminals, the inverter disconnects within 1.5 s. During non-fault operation (i.e. V~1 pu) the inverter remains connected indefinitely. It can therefore be assumed that the inverter undervoltage protection begins to operate at some voltage level between 1 pu and 0.76 pu as required in G83.

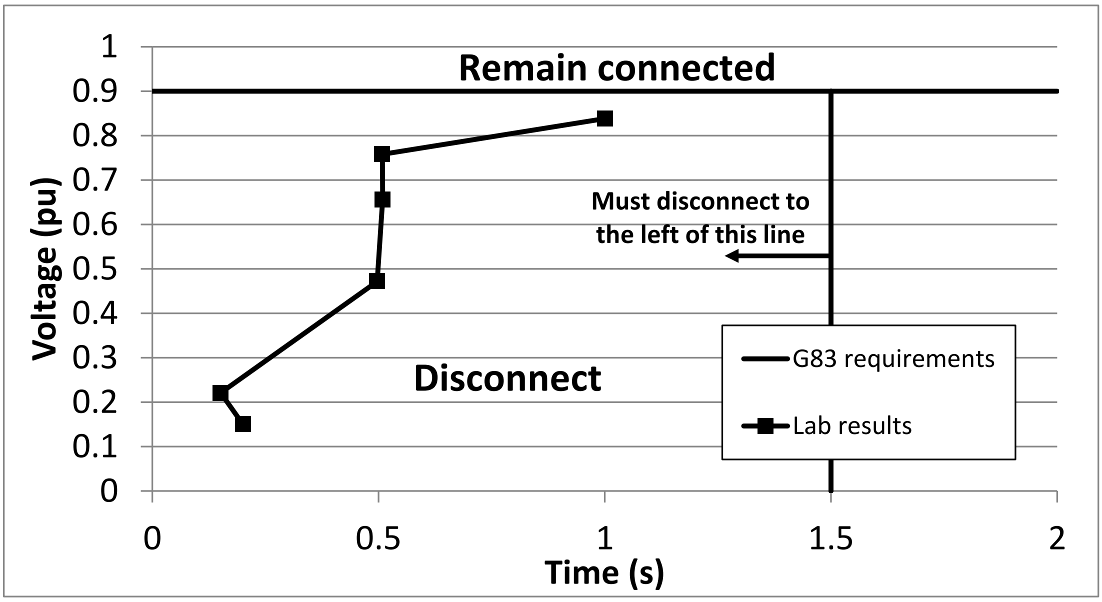


Figure 41: Inverter disconnection time for a range of undervoltages - G83 undervoltage threshold also illustrated

Based on dialogue with industry representatives, it is anticipated that G83 will be updated in the near future to incorporate the more rigorous undervoltage protection requirements specified in G59/2 [17]. This update is likely to be due to the growing penetration of small scale inverters (presently required to comply with G83) on the power system. As this penetration increases the aggregated impact of these inverters on power system operation also increases. This update to the standards ensures that the growing aggregated response of small scale inverters complies with the more stringent fault response standards presently limited to higher capacity inverters. This ensures the negative impact of the aggregated fault response of small scale inverters on power system operation is reduced. G59/2 presently only refers to inverter-interfaced sources greater than 16 A per phase and/or connected at a voltage level higher than 230/400 V AC. Accordingly, the inverter's fault response has been evaluated with respect to G59/2 so that the inverter's compliance with future standards could be quantified. G59/2 states that inverter-interfaced DG units must remain connected for 0.5 s when the measured phase-phase voltage is less than 80 % of nominal, and must remain connected (or "ride-through") for a duration of 2.5 s when the measured phase-phase voltage lies between 80 % and 87 % of nominal, as shown in Table 7.

The inverter's connection time, terminal voltage and the boundary that defines G59/2 requirements are shown in Figure 42. It can be seen that at low voltages, the inverter tends to disconnect faster than the 0.5 s requirement in G59/2.

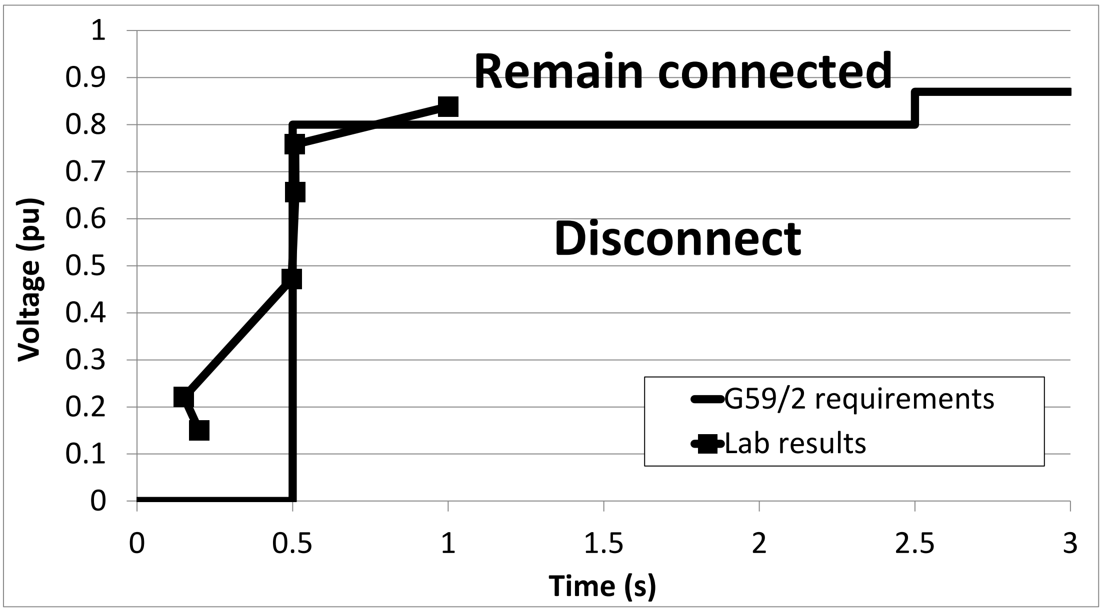


Figure 42: Inverter disconnection time for a range of undervoltages - G59/2 compliance threshold also illustrated

As the voltage level increases the fault response specified in the relevant inverter standard becomes more prescriptive. In order to demonstrate that small scale inverters are unable to comply with the more prescriptive fault response specifications required at higher voltage levels, the inverter's fault response has been compared to the grid code requirements in Figure 43. The NGC (National Grid Code) specifies a characteristic that large scale inverter-interfaced power stations must comply to. It can be seen that the inverter approximates the connection requirements imposed by the NGC but not to the same level of fidelity. This is expected as NGC requirements only apply to large inverter-interfaced power stations where the fault response is more heavily regulated due to the larger impact of the power station's response on power system operation.

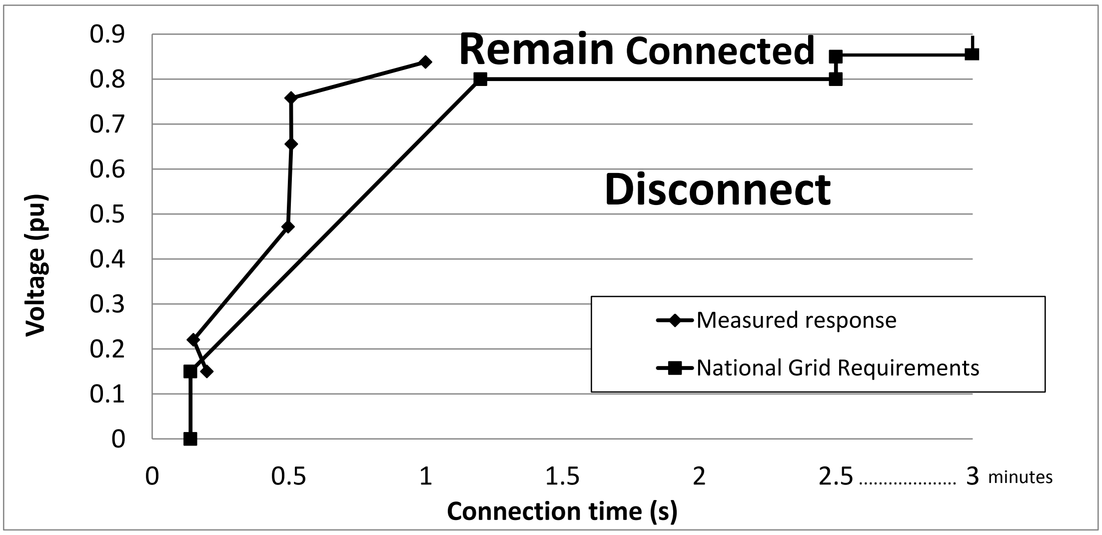


Figure 43: Inverter disconnection time for a range of undervoltages - NGC compliance threshold also illustrated

3.5 Empirical Inverter Fault Model

The inverter manufacturer advised that the inverter must turn off quickly to avoid internal damage when severe undervoltages are encountered. This safety mechanism prevents the inverter from complying with G59/2 when the voltage is particularly depressed (this can be observed in Figure 39 at voltage 0.22 pu and 0.15 pu) [62]. The inverter manufacturer also confirmed that the inverter will not produce higher than 1.2 pu rms fault current, even for a bolted short circuit at the inverter terminals [62]. The maximum fault current capability of the inverter (i.e. for a fault at the terminals of the inverter) could not be tested. This was at the request of the industrial partner supplying the inverter. They did not want to risk damaging the inverter unit by applying a fault on the inverter's terminals, it also micro-grid laboratory protocol not to apply a fault at the terminals of a machine. Based on this information, the inverter fault response was approximated as shown in Figure 44 for subsequent use in simulation. It can be observed that the assumed maximum rms current of 1.2 pu (1.7 pu peak) fits the fault current linear trend seen between voltage levels 0.15 pu and 0.22 pu. Figure 44 shows the maximum recorded rms fault current and the corresponding rms inverter terminal voltage for each fault test based on the results shown in Figure 39. It is assumed that the inverter transits from being compliant with G59/2 to being non-compliant at the midpoint between data point (0.22, 0.98) and (0.47, 0.68), corresponding to a voltage of approximately 0.35 pu. The phase angle between the voltage and current of the inverter's fault response was simulated as the averaged phase angle over the duration of the fault as seen in Figure 39. The inverter's connection time was modelled as shown in Figure 42.

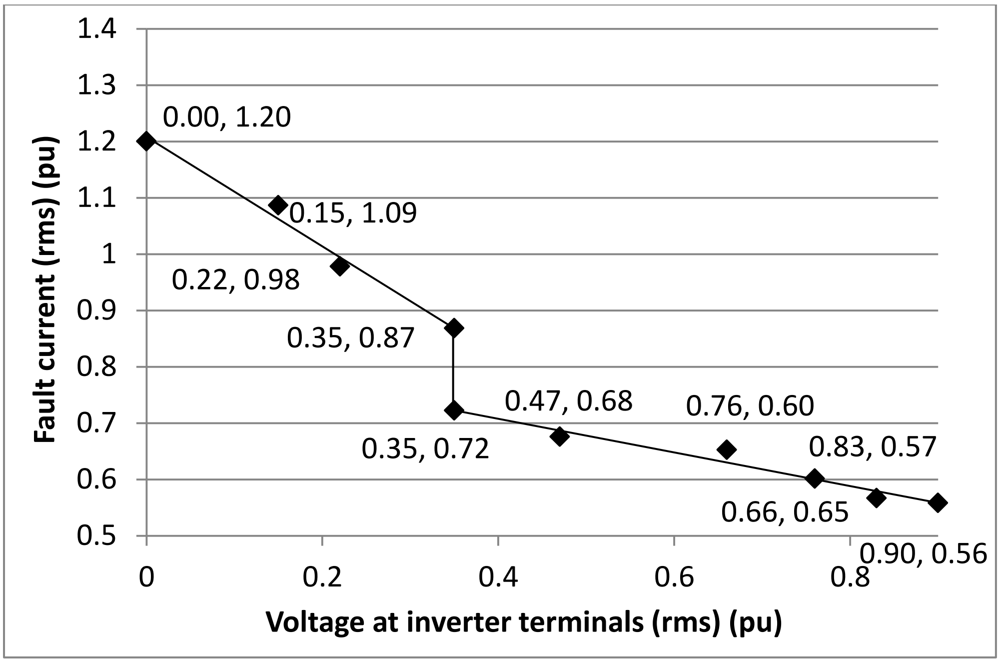


Figure 44: Modelled inverter fault response

The empirical inverter model's control block diagram used to implement the inverter fault behaviour is shown in Figure 45. The control diagram demonstrates how the inverter monitors its terminal voltage and outputs an I_d and I_q setting value to the three phase current source. The I_d and I_q values are based on the fault current response shown in Figure 44. This inverter fault model is based on the inverter control diagram discussed in [63]. The inverter inductive filter impedance is set to 0.1 pu (between 0.05-0.15 is typical for inverters [63]).

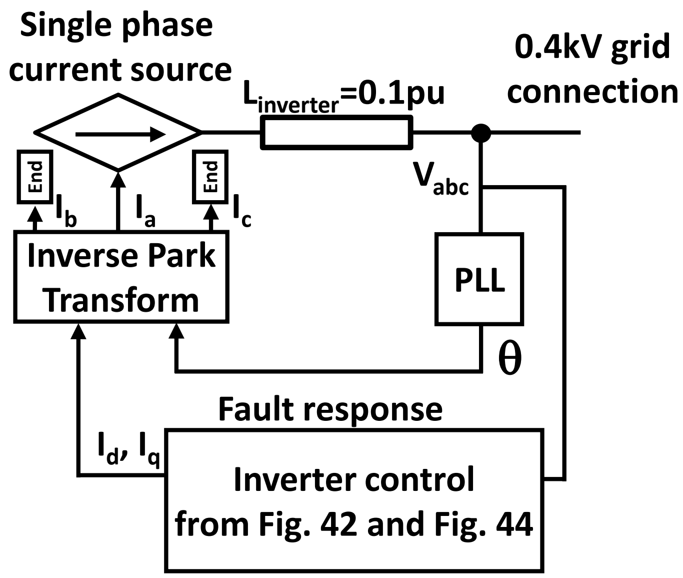


Figure 45: Control diagram for single phase inverter model's fault response

The laboratory inverter fault tests were repeated in simulation to evaluate and validate the fidelity and accuracy of the simulated inverter model. For comparison, the simulated inverter fault response and the laboratory fault response are shown in Figure 46 (for a fault resulting in a voltage of 0.83 pu at the inverter's terminals). To simplify the model, the inverter outputs zero current before the fault is applied. This simplification does not influence the investigation of protection blinding, coordination deterioration or sympathetic tripping considered in Chapter 4 and Chapter 5 as pre-fault current has a negligible impact on the protection response. In order to evaluate the impact of setting the pre-fault voltage to zero, the simulations in Chapter 4 were repeated with the inverter pre-fault current controlled to provide rated current (i.e. 13 A per inverter). This increased the voltage at the inverter terminals pre-fault but had negligible impact on the protection operation time or inverter terminal voltage pre-fault. The simulation results presented in Chapter 4 were therefore not impacted by the increased inverter current pre-fault.

The model is configured to continuously output the maximum fault current recorded over the duration of the fault in the laboratory test. This idealised response was chosen in order to evaluate the maximum potential impact the inverter could have on protection operation – in terms of fault current and voltage support. In Figure 39 it can be seen that for some faults the inverter fault current increases with time and for others it decreases. This may be due to the point on wave at which the fault occurs [64]. The point of wave impact on inverter fault response was not evaluated in this test, however, future studies in this area should run a larger number of fault tests to determine the impact this may have.

In order to evaluate the 'worst case' scenario i.e. the maximum possible fault current contribution of the inverter, the inverter model was controlled to output the maximum fault current observed in the laboratory fault test for a time interval corresponding to G59/2 requirements.

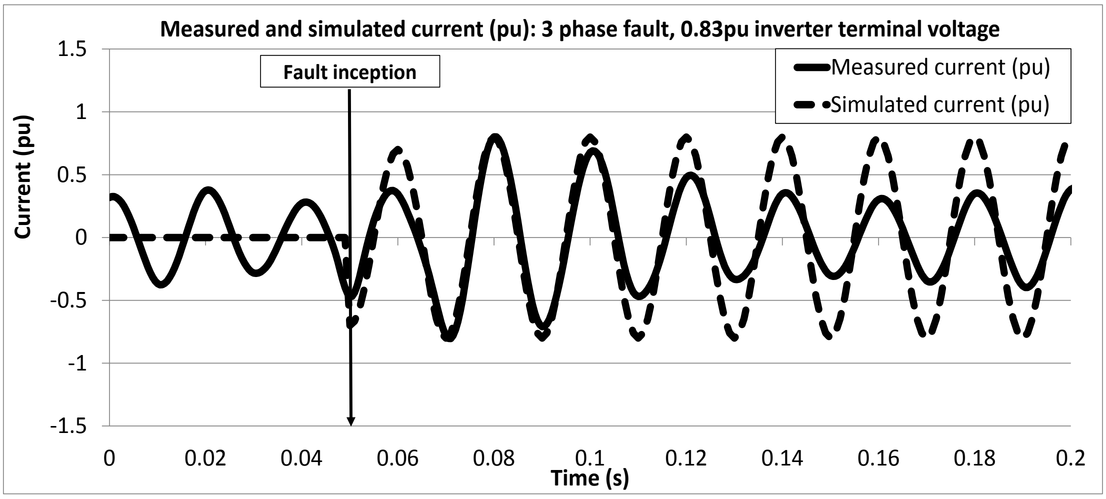


Figure 46: Comparison between inverter's simulated and laboratory fault response

It can be observed from Figure 46 that the simulated response shows a good matching when compared to the laboratory obtained response. As discussed above, the simulated response is controlled so as not to provide current pre-fault inception or have the DC decay observed in the laboratory. However, in all other regards the simulated response accurately emulates the laboratory response.

Figure 39, Figure 40 and Figure 46 have been shown over a 0.2 s time interval. With fault inception being applied at approximately 0.05 s in all cases this equates to approximately 0.15 s of fault response. This timescale was chosen to capture the transitory behaviour after the fault. At higher voltage levels e.g. 0.83 pu to 0.66 pu this captures the inverter's fault response transitioning to a steady state and at lower voltage levels 0.22 pu to 0.15 pu this time interval captures the inverter disconnecting due to internal inverter protection. At lower distribution levels, in some cases, faults can remain on the power system for extended periods of time (i.e. beyond 0.2 s). For the purposes of this study it has been assumed that the inverter model will maintain a fault current contribution as specified in Figure 44 and comply with G59/2 fault requirements for the duration of the fault. To avoid increasing simulation complexity by modelling three single phase inverters in simulation the single phase inverter model shown in Figure 45 was scaled to a three phase inverter model as shown in Figure 47. Each single phase controlled current source in the three phase model is controlled to output the same fault response as the single phase current sources in the previous model. As the fault response is dictated by the three phase voltage measured at the PCC (Point of Common Coupling) all three current sources will be controlled to supply fault current even for single phase faults. This operation is correct in this case as only three phase faults are considered in this thesis, however, if single phase faults were to be considered in future studies each single phase current source would need to be assigned a control loop. Also, to decrease simulation complexity when the number of inverters in simulation is increased instead of adding multiple inverter models the inverter capacity is scaled appropriately i.e. two, 9 kW three phase inverters would be represented by one 18 kW three phase inverter. The inverter inductive filter is scaled appropriately as the inverter rating is increased. The transformer characteristics are based upon industry supplied data and are shown in Table 6 and it is assumed there is no line impedance between the inverter PCC and 0.4 kV side of the transformer.

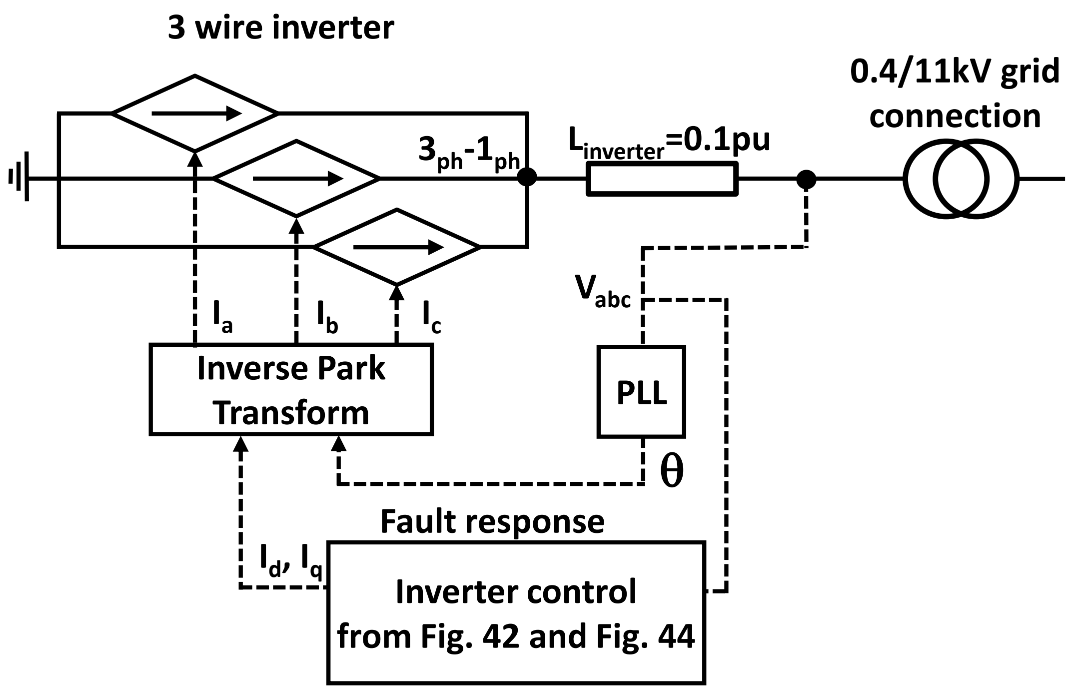


Figure 47: Control diagram for three phase inverter model's fault response

Table 6: 11/0.4kV transformer characteristics

Transformer characteristic	Setting	Units
Capacity	1	MVA
Winding 1 type	Star	-
Winding 2 type	Delta	-
Earthed winding	Secondary	-
Primary voltage	11	kV
Secondary voltage	0.433	kV
Delta lags or leads Y	Lags	-
Positive sequence leakage reactance	0.0475	pu
Copper losses	11.97	kW
Tap changer	Yes	-
Tap changer	HV	-
Minimum	-5%	-
Maximum	5%	-

3.6 Chapter summary

In the first part of this chapter the laboratory testing used to evaluate the fault behaviour of a 3 kW inverter used for photovoltaic applications has been presented. The laboratory results have been analysed and the inverter's response has been compared to expected fault behaviour discussed in the available literature. It has been shown that the fault behaviour of the laboratory tested inverter differs from that of the fault behaviour discussed in the literature, possible reasons for this discrepancy are discussed.

In the second part of this chapter the inverter's compliance with the relevant standard G83 has been evaluated and found to full comply with all requirements. The inverter is also evaluated for its ability to meet the more stringent requirements of standards for inverters at higher voltage levels. The inverter complies with G59/2 requirements at voltage levels above 0.47 pu but not with UK grid code requirements. However, it should be noted that the inverter is only required to meet G83 requirements and with modifications to the inverters control software it may be possible to make it compliant with these other standards.

In later chapters this inverter model is used to investigate protection problems resulting from distribution generation on the network. This addresses a gap in the literature as previous studies of these problems primarily consider only the impact of synchronous and induction based generators [28, 65-68].

Chapter 4 The impact of renewable generation on distribution protection operation

From this chapter onwards, the focus of this thesis is on the behaviour and protection of distribution systems, as this is the main application area considered in this research. Three protection problems relating to increasing DG penetration have been identified in the literature: blinding of protection, loss of protection coordination and sympathetic tripping of inverters. In this chapter the literature relating to these three problems is critically reviewed. Each problem is then investigated and quantified via simulation and potential solutions to the problems are evaluated.

4.1 Distribution network architecture

This thesis is primarily concerned with the impact of DG on distribution networks (as opposed to the impact at the transmission level). The distribution network models that are used in this thesis include the UKGDS (United Kingdom Generic Distribution System) [69] large rural network model, IEEE 30 bus power system [70] and a distribution network supplied by a UK DNO. The UKGDS network model architecture is shown in Section 4.2.1 and is used in this chapter to investigate blinding, protection coordination and sympathetic tripping. The IEEE 30 bus networks are used in Chapter 6 to evaluate an optimisation based protection solution. The distribution network supplied by a UK DNO is used in Chapter 4 for a study that evaluates and quantifies the extent of the sympathetic tripping problem. The IEEE 30 bus network and the DNO supplied distribution network are introduced below.

The IEEE 30 bus system was created for research purposes and was designed to be representative of distribution networks employing directional overcurrent protection. The network architecture of the 30 bus network is shown in Figure 48 below. For the purposes of the optimisation solution reported in Chapter 6 of this thesis only the 11kV section of the network is simulated as shown in Figure 79.

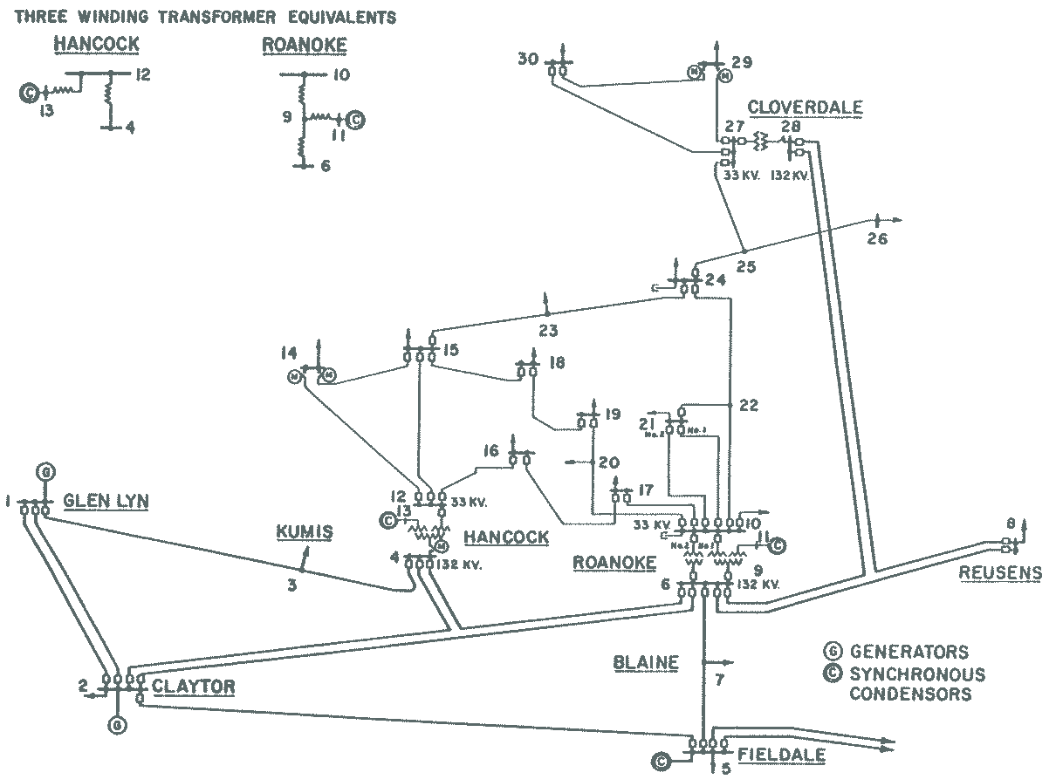


Figure 48: IEEE-30 bus distribution system [70]

The distribution network supplied by a UK DNO is shown in Figure 49. Feeder 1 is supplying a rural network and feeder 2 is representative of an urban network. Rural networks are typically fed from overhead lines and urban networks are normally fed from underground cables. As shown in Figure 49, urban networks are typically characterised by higher customer densities than rural networks. Though not obvious from Figure 49, urban networks also typically have much shorter feeders than would be found in an equivalent rural network. This network was chosen for evaluating the impact of the sympathetic tripping problem as it includes the two main types of network found in the UK.

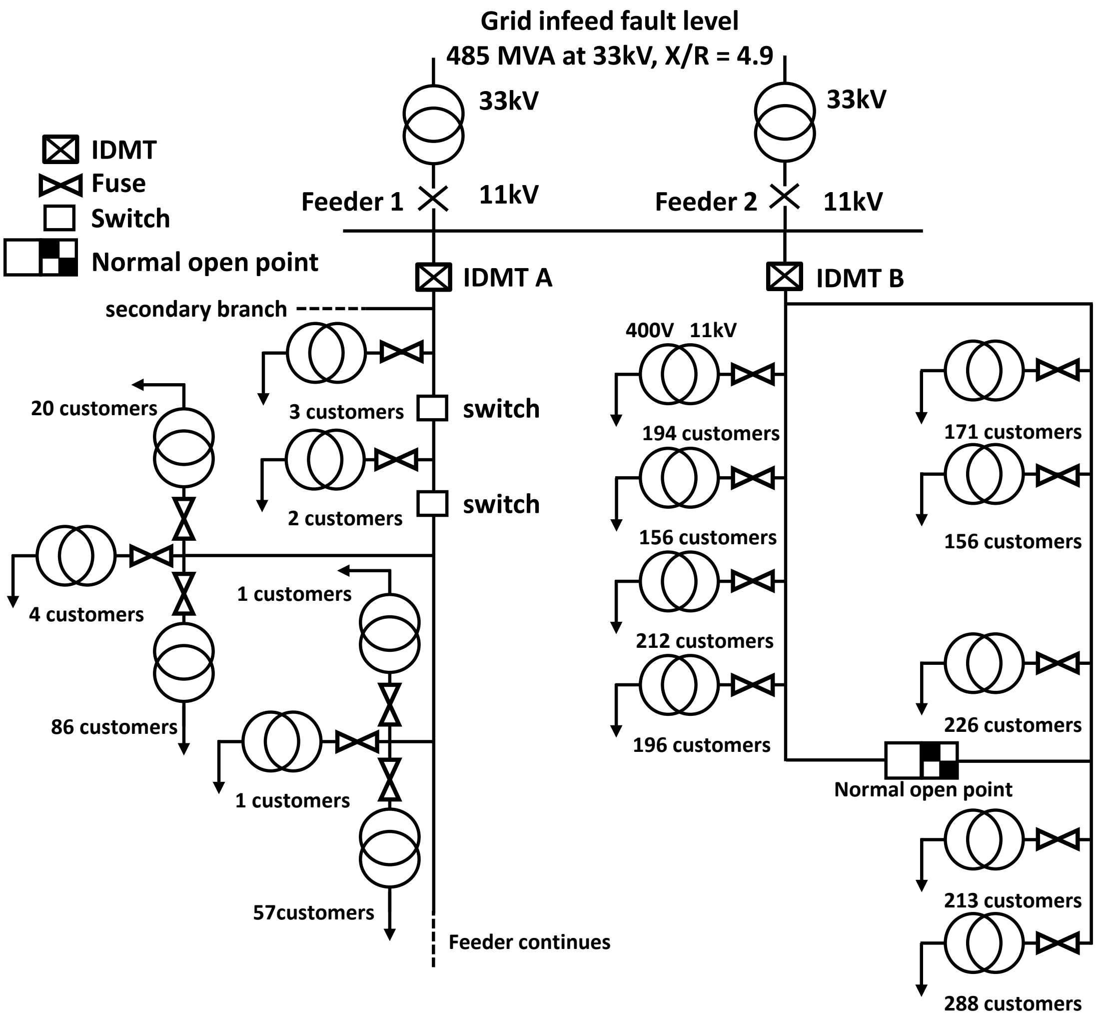


Figure 49: UK DNO 11kV distribution network architecture

4.2 Test case network

Each of the three main categories of potential protection problem introduced by DG (blinding, coordination problems, sympathetic tripping) above are investigated in this chapter using the UKGDS [69] large rural network model. The UKGDS is an online resource containing several power system models that are representative of typical power system types found in the UK. Available power system models include rural, radial urban, meshed urban, radial suburban and meshed suburban. This power system database was produced by several UK universities for research purposes so as to provide power system network data that is representative of UK power systems.

4.2.1 Network characteristics

The rural UKGDS network used in this investigation comprises two 33/11 kV transformers and three main feeders, as shown in Figure 50. Each feeder has between four and eight spurs with several secondary spurs. For the purposes of this investigation two feeders connected from node 201 were modelled as shown in figure 51. The grid infeed fault level has been assumed to range from 20 to 900 MVA and an average X/R ratio of 2 has been assumed for the rural network – these values were taken from [71, 72]. As will be discussed later in this chapter, the DG is modelled as an inverter-interfaced DG unit. The inverter model behaviour is based on laboratory testing of a commercially available PV inverter, which enhances the fidelity and validity of the model. More details of the laboratory testing and behaviour of the inverter model are available in Chapter 3.

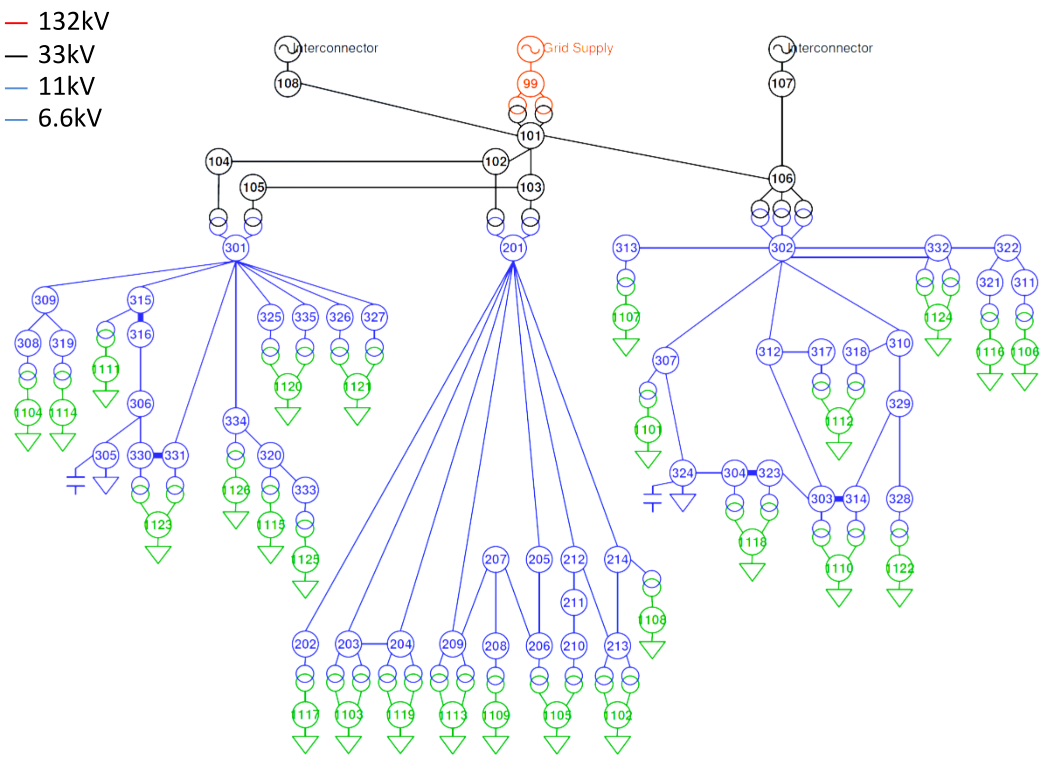


Figure 50: UKGDS large rural network [69]

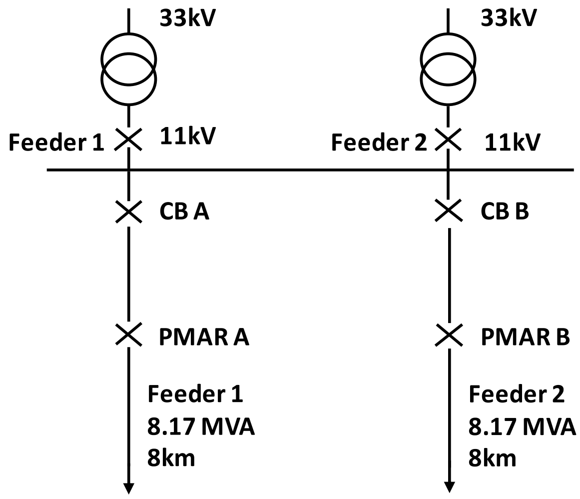


Figure 51: Test case 11 kV rural overhead line network model

4.2.2 Protection settings

The protection settings are based on utility settings policies and theoretically calculated protection settings [24]. For feeder protection, a standard inverse overcurrent protection relay with a primary pickup current of 480 A and a TM (Time Multiplier) of 0.15 was used. This provided an overcurrent margin of approximately 15 % on maximum feeder capacity. To investigate blinding and loss of coordination (discussed in Section 1.2.3) a second protection device was required. A PMAR is therefore included at a distance of 4 km from the 11 kV bus with a standard inverse characteristic, a primary pickup current of 250 A and a TM of 0.1. This is consistent with UK DNO protection setting policy for both urban and rural feeders.

The required UV (Under Voltage) protection settings of inverter-interfaced DG are specified in G59/2 [17]. This standard refers to all inverter-interfaced sources greater than 16 A per phase and/or connected at a voltage level higher than 230/400 Volts AC. G59/2 states that inverter-interfaced DG units must remain connected for 0.5 s for a phase-phase voltage of less than 80 % and 2.5 s for a phase-phase voltage between 80 % and 87 %. The G59/2 recommendation does not specify current or power output limits during the fault. The relevant G59/2 protection settings are shown in Table 7.

Table 7: G59/2 protection settings

Prot Function	Small Power Station				Medium Power Station	
	LV Connected		HV Connected			
	Setting	Time	Setting	Time	Setting	Time
U/V st 1	Vφ-n† -13%	2.5s*	Vφ-φ‡ -13%	2.5s*	Vφ-φ‡- 20%	2.5s*
U/V st 2	Vφ-n† - 20%	0.5s	Vφ-φ‡ - 20%	0.5s		
O/V st 1	Vφ-n† + 10%	1.0s	Vφ-φ‡ + 10%	1.0s	Vφ-φ‡ + 10%	1.0s
O/V st 2	Vφ-n†+ 15%	0.5s	Vφ-φ‡ + 13%	0.5s		
U/F st 1	47.5Hz	20s	47.5Hz	20s	47.5Hz	20s
U/F st 2	47Hz	0.5s	47Hz	0.5s	47Hz	0.5s
O/F st 1	51.5Hz	90s	51.5Hz	90s	52Hz	0.5s
O/F st 2	52 Hz	0.5s	52Hz	0.5s		
LoM (Vector Shift)	K1 x 6 degrees		K1 x 6 degrees#		Intertripping expected	
LoM (RoCoF)	K2 x 0.125 Hz/s		K2 x 0.125 Hz/s#		Intertripping expected	

K1=1.0 (for low impedance networks) or 1.66-2.0 (for high impedance networks)

K2=1.0 (for low impedance networks) or 1.66 (for high impedance networks)

4.2.3 Fault resistance

A limitation in other papers that evaluate blinding, loss of coordination and sympathetic tripping is the lack of justification when defining fault resistance. This chapter considers a fault resistance of 0-10 Ω based on the research relating to arc resistance discussed in [28].

4.2.4 Transformer characteristics

The 0.4/11 kV transformer characteristics given in Table 6 are used for the LV transformer considered in this chapter. The 33/11 kV transformer characteristics are based upon industry supplied data and are shown in Table 8.

Table 8: 33/11kV transformer characteristics

Transformer characteristic	Setting	Units
Capacity	12	MVA
Winding 1 type	Delta	-
Winding 2 type	Star	-
Earthed winding	Secondary	-
Primary voltage	33	kV
Secondary voltage	11	kV
Delta lags or leads Y	Lags	-
Positive sequence leakage reactance	0.14148	pu
Copper losses	22.67	kW
Tap changer	Yes	-
Tap changer	HV	-
Minimum	-15%	-
Maximum	5%	-

4.3 Blinding of protection

4.3.1 Introduction to the problem

Blinding of protection occurs when a protection device is unable to detect a fault due to fault current not being detected by its measurement transformer [21, 22]. Another term for blinding of protection that is used in the literature is 'reduction of protection reach' [73-75]. The principle of protection blinding is shown in the context of an 11 kV distribution network in Figure 52. As the contribution of fault current from the DG unit increases, the contribution of fault current from the grid infeed will decrease. The DG supports the grid voltage and therefore the voltage depression 'seen' by the grid infeed is reduced and therefore less fault current will be supplied from the grid. If the protection device is not configured to account for the fault contribution of the DG unit, the protection device may be unable to detect the fault in certain cases, or will operate more slowly than desired.

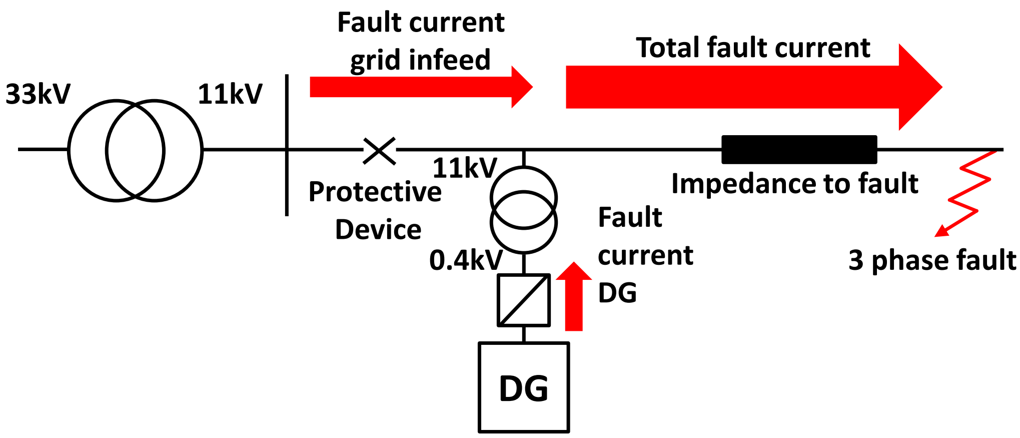


Figure 52: Example of protection blinding

Many of the papers on protection blinding introduce it as a concept [22, 23, 76] or demonstrate it through simple numerical examples [21, 65, 73]. There are several limitations to the approach taken in these papers.

The choice of network characteristics in these papers is often not justified. In [77] protection blinding is demonstrated on a 20 kV network; however, the network characteristics are not supplied. Often, fault resistance is not considered [21, 22] or if it is considered the choice of fault resistance is not justified. In [73] fault resistances in excess of 15 Ω are simulated whereas [28] uses established principles to determine that phase faults with a resistance in excess of 10 Ω are unlikely. In the majority of papers, the DG interface protection is not implemented. This could have a significant impact on the occurrence of protection blinding. For example, in the case of an inverter, the interface protection may operate in 0.5 s, removing the inverter's contribution to protection blinding. Based on these limitations in the literature many of the conclusions drawn about the severity and conditions at which protection blinding occurs are limited.

Those papers that evaluate protection blinding via simulation or numerical analysis attempt to identify the circumstances (or boundary conditions) at which it will occur. Reference [73] evaluates how the reach of an overcurrent relay changes when DG is installed on a seven bus feeder. The authors attempt to identify the point at which protection blinding occurs by identifying how high the fault resistance has to be before the fault becomes undetectable. In [78], a numerical and simulation analysis of protection blinding on a 22 kV distribution network is carried out. The authors vary the level of DG connected to the network between 0-6 MVA in order to identify if blinding will occur. The authors conclude that for typical DG penetration, the fault current contribution remains within acceptable limits and hence blinding does not occur. [28] investigates blinding of protection on a more sophisticated network model than that used in the previously discussed references. This paper implements protection hardware in the loop as part of the protection blinding analysis and considers DG interface protection and a realistic range of fault resistances. In contrast to many of the papers on blinding, it concludes that protection blinding is unlikely to occur under realistic worst case scenario conditions.

The majority of the literature on protection blinding focuses on the impact of synchronous or induction based DG [28, 65]. This is normally because inverter-interfaced DG units do not supply the same magnitude of fault current and therefore do not contribute to protection blinding to the same extent. The magnitude of fault current from synchronous and induction based generation is typically in excess of five times load current [76]; the fault current magnitude of inverter interfaced DG quoted in the literature varies between one to four times load current [58-60, 76]. In this this inverter-interfaced generation is considered to address this gap in the literature at the request of the industrial sponsor.

The fault current magnitude of directly connected synchronous and induction based generators is defined by the physical properties of the generator and its associated prime mover. These properties are fairly consistent between generators and therefore fault current contribution is generally predictable. In contrast, an inverter's fault response is limited by the physical properties of the inverter's semi-conductor switches, the capability of the associated energy source and the inverter control. As the associated energy source is often variable in terms of its output (in the case of wind or solar) and the inverter control algorithm often varies between manufacturers, the fault response of an inverter is less predictable than that of synchronous and induction generators.

This section of the thesis aims to address a gap in the literature by evaluating the impact of inverter-interfaced DG on protection blinding for a justified ranged of fault resistances, using verified network characteristics, using industry informed protection settings and implementing DG interface protection as specified in G59/2.

4.3.2 Simulation of protection blinding

The simulated network configuration used to investigate the occurrence of protection blinding is shown in Figure 53. In the simulated scenario the grid infeed fault level is varied between 20 MVA and 900 MVA, the fault location is at the end of feeder 1, the fault resistance is varied between 0 Ω and 10 Ω [28], the location of the inverter-interfaced DG is at 75 % of the length of the feeder, while the capacity of the DG is varied between 0 and 3 MVA. This inverter capacity was chosen based on a typical 11 kV feeder rating. A typical urban 11 kV feeder with capacity 400 A, as stated in [79], which equates to an apparent power rating of 7.6 MVA, is selected for illustrating the analysis. An inverter of 3 MVA is equivalent to installing a generator that supplies approximately half of the feeder's total rating. As DGs are typically connected at distributed points along the feeder instead of being aggregated at one point, 3 MVA was considered a realistic maximum capacity.

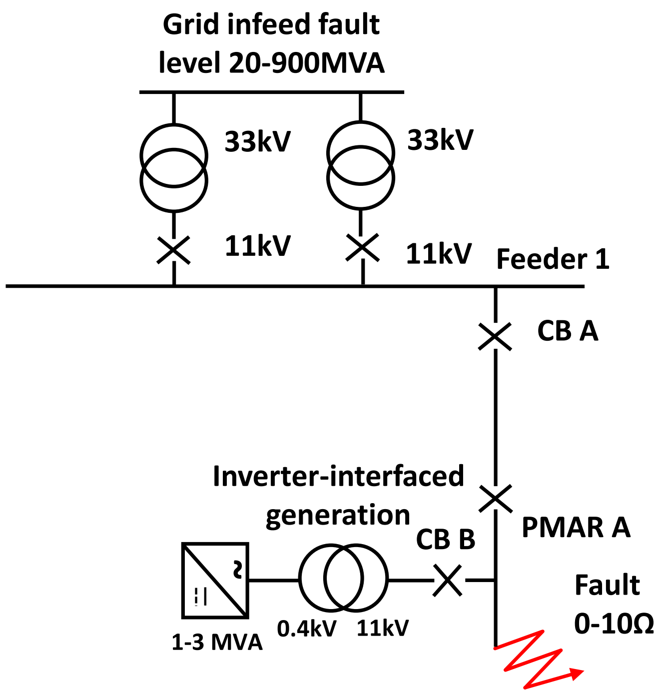


Figure 53: Blinding of OC (Overcurrent) protection simulation diagram

4.3.3 Simulation results

Figure 54 shows the protection operating time of the PMAR in the simulated scenarios when there is no DG connected to the network.

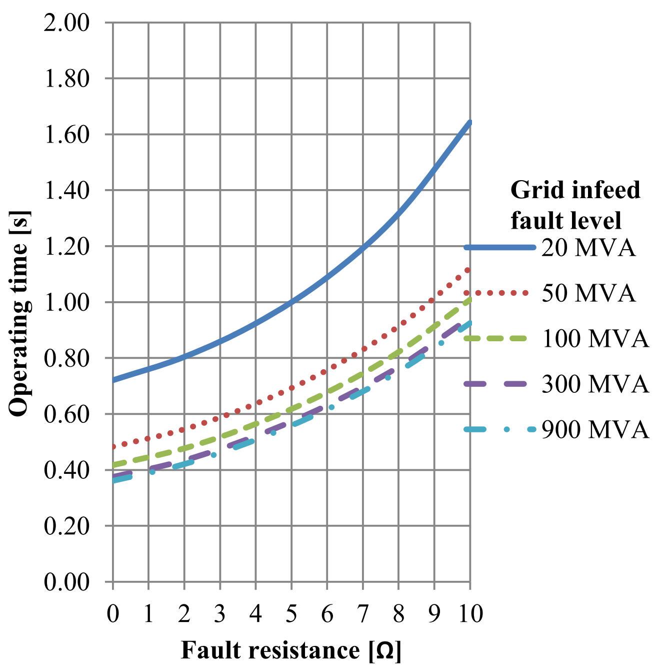


Figure 54: PMAR operating time without DG

The maximum operating time of the PMAR occurs when the grid infeed fault level is low (20 MVA) and the fault resistance is high (10 Ω). As the grid infeed fault level is increased, the protection scheme operates faster. It can be observed from Figure 54 that the PMAR operating time increases from 0.93 s to 1.64 s as the fault level decreases from 900 MVA to 20 MVA (for a fault resistance of 10 Ω).

When a DG unit of 1MVA is connected to the feeder, the operating time of the PMAR increases, as shown Figure 55. This change is negligible at low values of fault resistance but becomes more pronounced as the fault resistance is increased. In the presence of DG, the PMAR operating time increases from 0.92 s to 1.1 s for a 10Ω fault when the grid infeed fault level is 900 MVA. When the grid infeed fault level is decreased to 20 MVA with the same fault resistance, the PMAR operating time increases from 1.64 s to 1.73 s.

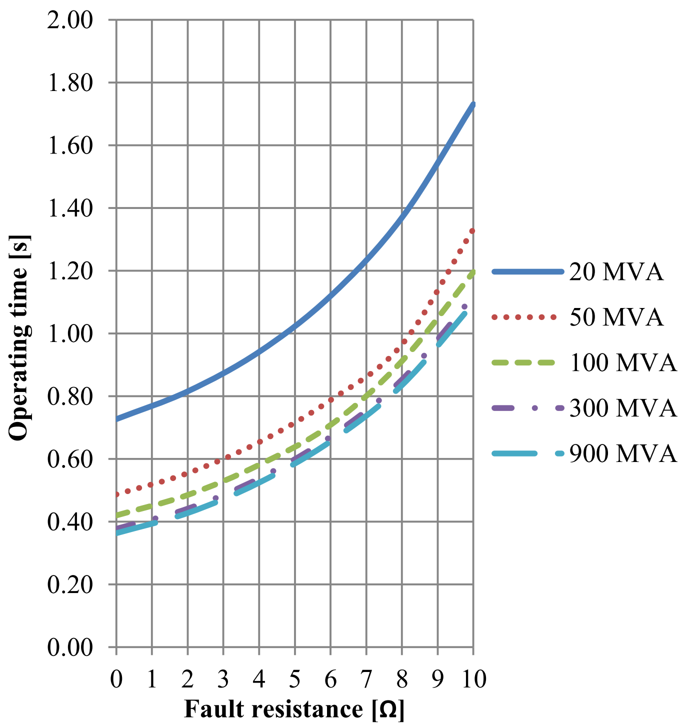


Figure 55: Protection operating time with DG of 1 MVA

If the DG unit rating is increased to 3 MVA, the variation in the operating time of the PMAR is still negligible for low resistance faults. The change in operating time becomes more evident as the fault resistance increases, as shown in figure 56.

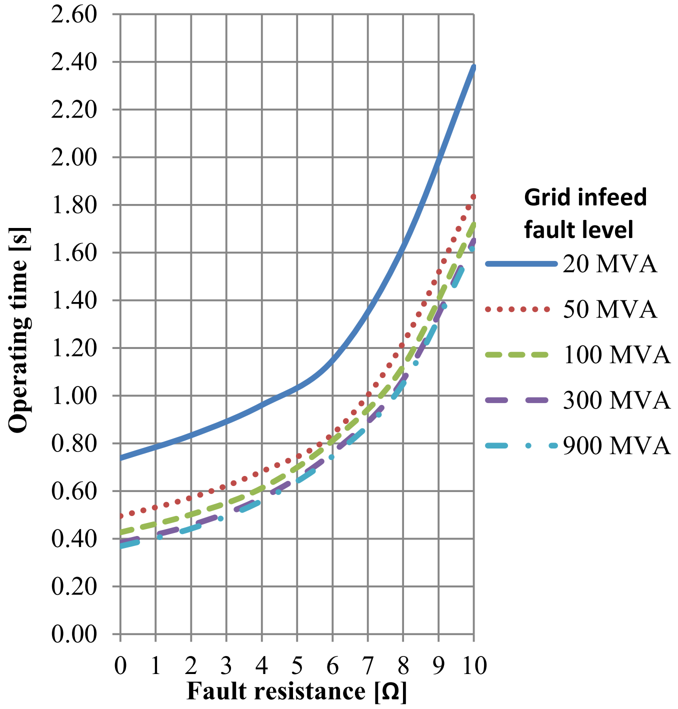


Figure 56: Protection operating time with DG of 3 MVA

Comparing figure 54 (no DG) to figure 56 (3 MVA DG), the operating time increases from 0.92 s to 1.63 s for a 10 Ω fault when the grid fault level is 900 MVA. When the grid fault level is 20 MVA, it increases from 1.64 s to 2.38 s.

The simulation results show that inverter-interfaced DG has an impact on overcurrent protection operating time and in the worst case scenarios, presented in figure 56, leads to significantly longer protection operating times. It is worth noting that the 20 MVA fault level considered in this scenario is representative of an extremely weak grid connection; this would be unusual in the UK. Also, even for this extremely weak grid infeed scenario, the PMAR is still able to detect the fault, albeit with an undesirably long protection operation time. These findings suggest that for present levels of DG penetration, blinding of the overcurrent protection seems to be very unlikely to occur on UK power systems. Power systems with longer feeders, slower protection responses and significantly larger penetrations of DG may be more susceptible to blinding, but it is not deemed to present a significant risk in the UK.

4.4 Loss of protection coordination

4.4.1 Introduction to the problem

At 11 kV, there are five possible instances where coordination can be compromised due to increased DG penetration: fuse to fuse, overcurrent relay to fuse, overcurrent relay-overcurrent relay, overcurrent relay-PMAR and PMAR-fuse [23]. The addition of DG to a power system has the potential to change fault current magnitudes and paths, and may impact upon the coordination time (or current) margins between different protection devices on the network [24]. The interaction between the DG interface protection and the existing protection scheme can also impact on the coordination of the distribution protection scheme. In the network investigated in this thesis, the potential for coordination problems between an overcurrent relay, a PMAR and an inverter's interface protection is evaluated.

An example of a loss of protection coordination shown in the context of an 11 kV distribution network in Figure 57 [23]. In this case, two protection devices have been installed on the 11 kV feeder. The devices would be coordinated so that faults downstream of protection device 2 would cause protection device 2 to operate first and if it failed to operate protection device 1 would operate on backup protection after a time delay. However, in the scenario shown in Figure 57 the contribution of fault current from the DG would change the grading between the two protection devices so that protection device 2 would operate much faster than protection device 1. In this case the grading margin has changed but not necessarily in a negative way. In this case protective device 2 operates faster and protective device 1 operates slower (when operating as backup protection). In terms of the correct order of operation, coordination is maintained. However, if protective device 2 were to fail, protection device 1 would operate slower than expected and this could lead to a risk of protection blinding (already discussed in Section 4.3.2).

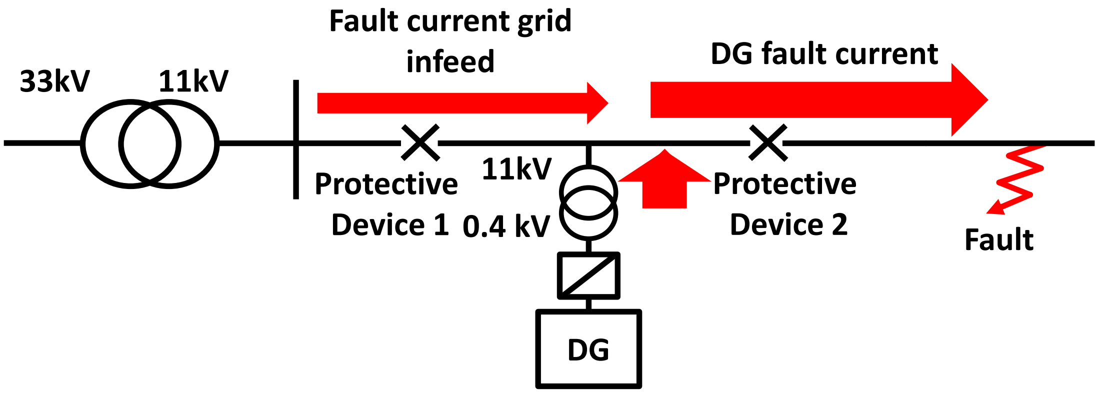


Figure 57: Example 1 loss of protection coordination

Another example of loss of protection coordination is shown in Figure 58 [80]. The protective device characteristics and grading margins are shown in Figure 59. In this case, the device characteristics have an instantaneous element so that when the fault is detected to definitively lie within the device's zone of protection (typically covering the 80 % of the protected line from the relay location [24]) the device will operate instantaneously without any time delay. Under normal operation with no DG, for the fault shown in Figure 58, device 3 will operate instantaneously. If it fails to operate, device 2 will operate after a time delay. When DG is added to the network as shown in Figure 58, the fault current measured by devices 2 and 3 will change. If the DG supplies a large enough fault current, it could change the fault current measured as shown in Figure 59, causing both device 2 and 3 to operate instantaneously for the same fault. This is an undesirable protection operation, as it isolates a larger part of the power system than is required to clear the fault.

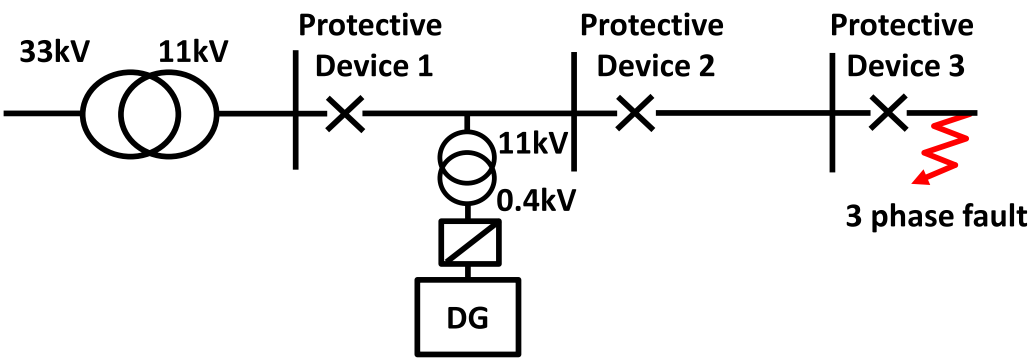


Figure 58: Example 2 loss of protection coordination

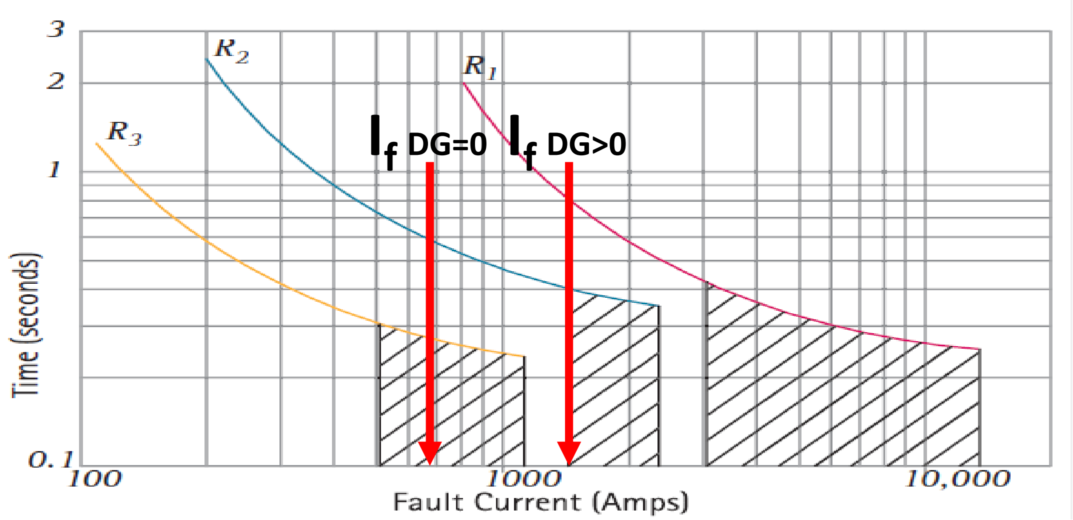


Figure 59: Relay characteristic coordination [15]

There are many different examples of loss of protection coordination that can result due to the presence of DG. Many of the problems can cause unwanted protection operation (maloperation as shown in Figure 58) or cause protection to fail to operate when it is required. The diversity of power system configurations and protection scheme designs means that the number of possible loss of coordination scenarios is vast. This chapter will critically review the literature in this area and report on a simulation study that reviews the relationship between overcurrent relay, PMAR and inverter interface protection operation for increasing DG penetration.

Many of the same limitations evident in the literature regarding protection blinding are also apparent in the literature investigating loss of protection coordination. Many of the papers introduce the problem conceptually [21, 75, 81], or provide simple numerical examples to demonstrate the problem [22, 82, 83], but do not simulate or perform quantifiable laboratory tests to fully investigate or demonstrate the problem. Other papers evaluate the problem with respect to synchronous or induction DG units [66-68], whereas many of the DG units now being connected to the network are inverter interfaced [3]. Furthermore, several papers consider the problem but do not fully justify the choice of network characteristics [84, 85], protection settings [83, 86], DG interface protection [23] or fully the range of fault resistances [87, 88]. The overriding message from the literature is that DG does result in protection coordination failure if the DG penetration is relatively high; however, the point at which coordination fails is highly dependent on the protection scheme, network architecture and type of DG.

The next section of the thesis will evaluate protection coordination between an overcurrent relay, a PMAR and the DG interface protection using a laboratory verified empirical inverter-interfaced DG model, using network characteristics provided by industry, industry-verified protection settings, justified fault resistances and justified protection settings.

4.4.2 Simulation of loss of protection coordination

The simulated network configuration used to investigate the occurrence of loss of protection coordination is shown in Figure 60. As with the other simulations in this chapter this network is based on the UKGDS model discussed in Section 4.1. In the simulated scenario, the grid infeed fault level is maintained at 300 MVA at 33 kV (100 MVA at 11 kV), the fault location is varied between 25 % and 100 % of the length of feeder 1, the fault resistance is varied between 0 Ω and 10 Ω [28], the location of the inverter-interfaced DG is varied between 25 % and 75 % of the length of feeder 1 and the capacity of the DG is varied between 1 and 3 MVA.

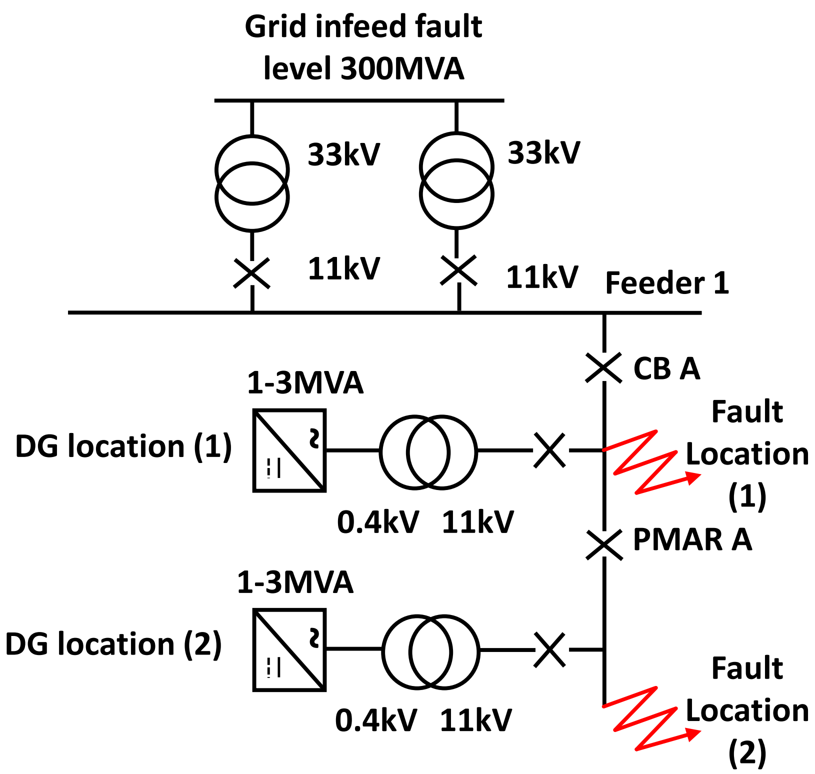


Figure 60: Simulation arrangement for investigation of loss of protection coordination

The following scenarios have been simulated:

A. DG location (1) and fault location (2)
B. DG location (2) and fault location (2)

The scenarios that were not considered in this investigation are: DG location (1)/fault location (1) and DG location (2)/fault location (1). In both of these scenarios, the coordination between the two protection devices is not affected by the combination of DG unit and fault location. Scenario A is similar to the protection blinding problem investigated in the previous section; however, in this scenario the impact of protection blinding is more severe. This is because the grading margin between the two protection devices renders the protection at CB A more sensitive to changes in fault current. This is demonstrated in more detail in the following section.

4.4.3 Simulation results

4.4.3.1 Scenario A: DG location (1) and fault location (2)

In scenario A, the fault current contribution of the DG reduces the operating time of PMAR A (as already demonstrated in Figure 57), thus increasing the grading margin between CB A and PMAR A. Table 9 presents the simulated protection operation time for scenario A and Table 10 presents the corresponding grading margins without DG and with DG of 1 and 3 MVA capacities. It can be observed that when DG is connected and the fault resistance is high, the protection at A never operates. This is similar to the blinding scenario investigated in Section 4.3. However, in Section 4.3 the protection device was always able to detect the fault, even at very high fault resistances. In this scenario, the protection at A does not detect the fault due to the required grading margin between the protection devices at high fault resistances.

Table 9: Protection operating time in seconds in scenario A

R fault (Ω)	Protection time (s)					
	No DG		DG=1MVA		DG=3MVA	
	Main	Backup	Main	Backup	Main	Backup
0	0.3733	0.8719	0.3684	0.8313	0.359	0.8586
2	0.4328	1.019	0.4257	1.049	0.412	1.1121
4	0.5194	1.380	0.5094	1.542	0.491	2.0918
6	0.6292	1.995	0.6148	2.493	0.589	5.6386
8	0.7665	3.208	0.7455	5.385	0.708	-
10	0.942	6.671	0.911	-	0.919	-

Table 10: CB A – PMAR A grading margin in scenario A

R fault (Ω)	Protection grading margin (s)		
	No DG	DG=1MVA	DG = 3 MVA
0	0.44	0.46	0.50
2	0.59	0.62	0.70
4	0.86	1.03	1.60
6	1.37	1.88	5.05
8	2.44	4.61	-
10	5.73	-	-

4.4.3.2 Scenario B: DG location (2) and fault location (2)

In scenario B, the fault current contribution of the DG decreases the operation time of both CB A and PMAR A at different rates, thus increasing the grading margin between the devices. This is demonstrated in Figure 61, the fault current measured by both protection devices decreases due to the fault contribution from the DG, therefore, the margin between the two protection devices increases (as shown by the double ended arrow in Figure 61). Table 11 presents the simulated protection operation time for scenario B and Table 12 presents the simulated grading margin without DG and with DG of 1 and 3 MVA ratings. It can be observed that this fault/DG configuration generates similar grading margins as observed in Scenario A.

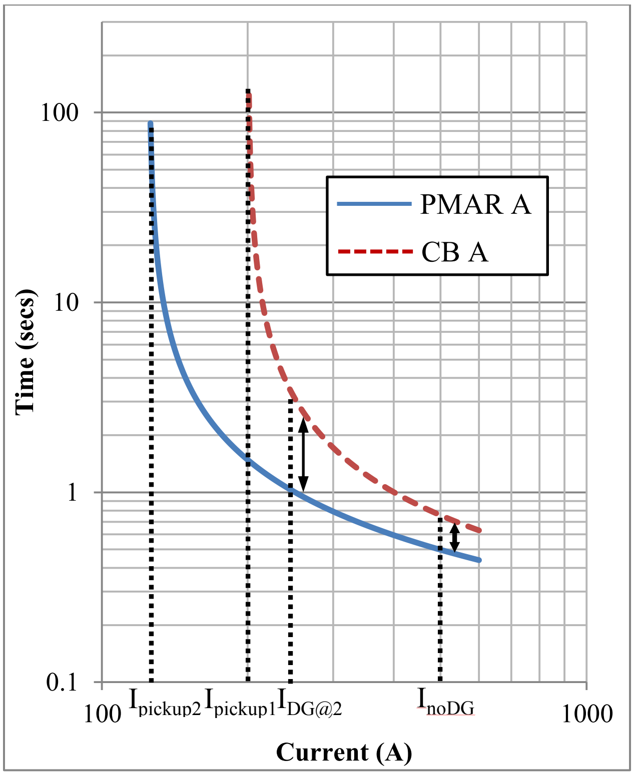


Figure 61: Change in grading margin due to DG at (2)

Table 11: Protection operating time in seconds in scenario B

R fault (Ω)	Protection time (s)					
	No DG		DG=1MVA		DG=3MVA	
	Main	Backup	Main	Backup	Main	Backup
0	0.3733	0.8719	0.3755	0.8223	0.38	0.83105
2	0.4328	1.019	0.4396	1.032	0.4533	1.056
4	0.5194	1.380	0.5360	1.409	0.5672	1.436
6	0.6292	1.995	0.6686	2.278	0.7549	3.087
8	0.7665	3.208	0.8497	3.897	1.058	-
10	0.942	6.671	1.114	-	1.631	-

Table 12: Grading margin between CB A and PMAR A in scenario C

R fault (Ω)	Protection grading margin (s)		
	No DG	DG = 1 MVA	DG = 3 MVA
0	0.44	0.45	0.45
2	0.59	0.59	0.60
4	0.86	0.87	0.90
6	1.37	1.61	2.33
8	2.44	3.05	-
10	5.73	-	-

The simulation results show that the connection of inverter-interfaced DG changes the grading margin between protection devices. However, it has been demonstrated that the grading margin is not changed to the extent that protection begins to operate incorrectly.

In scenario A, the grading margin between the protection devices increases. If the main protection device were to fail then backup protection operation would be delayed and the fault would remain be on the system for longer. Scenario B is similar to scenario A, in that the grading margin between the protection devices increases. If the main protection device were to fail then the backup protection operation would be delayed.

In neither of the scenarios (A or B) did protection grading deteriorate such that the grading margin reduced below the minimum grading time (typically 0.3 s [15]). However, the scenarios have demonstrated that the relationship between the protection devices is not straightforward and that DG adds greater complexity to the coordination of the protection scheme.

4.5 Sympathetic tripping

4.5.1 Introduction to the problem

The premise of the sympathetic tripping problem is illustrated in figure 62. Based on the UV requirements specified in G59/2 and discussed in Section 2, if the fault on feeder 2 results in a voltage of 80 % or less at the terminals of the inverter and the protection time delay on feeder 2 is longer than 0.5 s, then the protection on the inverter interface will trip. As the penetration of DG on the network increases, the potential loss of generation resulting from inadvertent undervoltage protection operation will continue to increase. In extreme situations, if large amounts of feeder-connected DG are 'hiding' load (that is, offsetting load that would be added to the feeder if the DG were not supplying power), then when the DG disconnects, the previously 'hidden' load will be 'seen' by the network. This could impact the operation of the voltage controller on the grid infeed transformer and potentially cause further voltage fluctuations on the 11kV network. Inverters on other feeders that have not already disconnected on the original fault event may then operate on undervoltage protection due to this voltage fluctuation. This may not be likely in the near term, but as the number of DGs on the network increases the risk of such a situation increases when significant amounts of DG are removed from the system. While not evaluated further in this thesis, this risk must be recognised and should be the subject of future studies. Avoidance of sympathetic tripping would reduce this risk and this is studied in detail in this chapter.

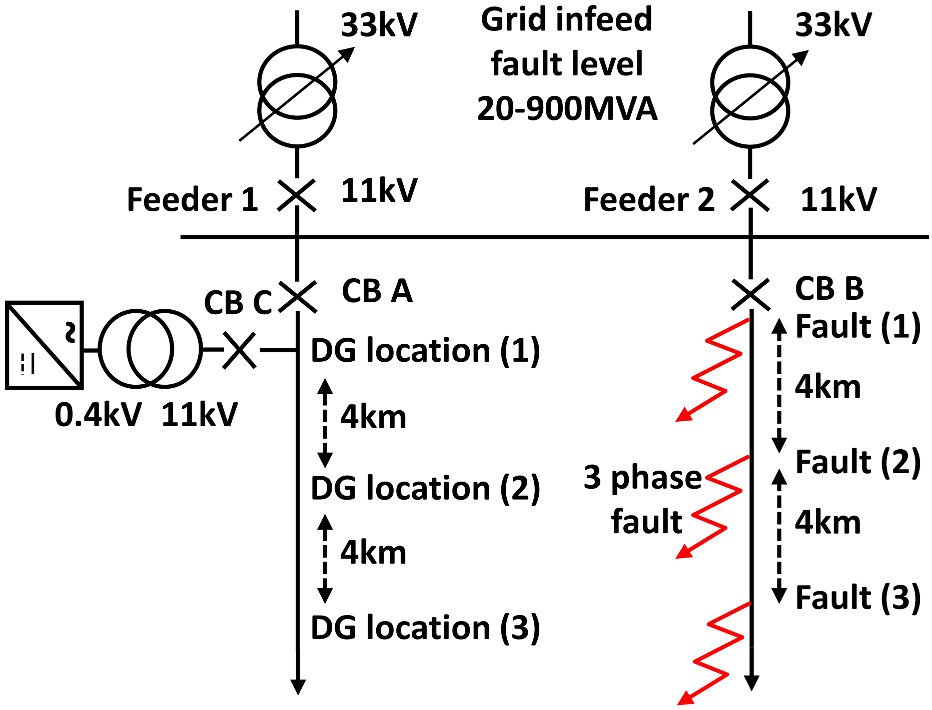


Figure 62: Sympathetic tripping simulation diagram

It is worth noting that the term 'sympathetic tripping' is sometimes also used to describe a delayed voltage recovery sympathetic tripping problem [89]. This occurs when faults cause induction motors loads to lose speed during voltage depressions. This large load is often a result of the aggregated loads of residential air conditioners. When the motors lose speed they draw more current and this overcurrent as they accelerate can cause the protection scheme to operate. This aspect of sympathetic tripping is not considered further, but should be studied as future work.

In the literature sympathetic tripping (sometimes referred to as false tripping) is often introduced conceptually with little or no quantification [90, 91] and often for the purposes of applying a novel solution to the problem [74, 92-95]. It is also often referred to (again conceptually) as part of a wider review of protection implications due to increasing DG penetration [96, 97]. Sympathetic tripping is widely quoted as representing a challenge for protection of networks with DG, however there appears to be a lack of objective and quantitative studies of this problem. This chapter addresses this shortcoming in the literature by simulating sympathetic tripping on a UK power network with great accuracy, using experimentally derived and validated models.

4.5.2 Simulation of sympathetic tripping

The impact of variations in grid infeed fault level (20-900 MVA), the fault location (1-3), the location of the inverter-interfaced DG (1-3) and the capacity of the DG (1-3 MVA) are evaluated with respect to the sympathetic tripping problem in the following section. In order to determine the most severe fault response, the fault was assumed to be a three phase fault (R=0 Ω) for all scenarios considered in this chapter. G59/2 undervoltage protection settings (as discussed in Section 4.5.1) have been applied to the DG undervoltage protection.

4.5.3 Simulation results

4.5.3.1 Impact of grid infeed fault level

The effect of grid infeed fault level on sympathetic tripping was evaluated using the following network configuration: setting the inverter location to (2), the inverter capacity to 3 MVA and the fault location to (2). This network configuration (with the inverter and fault in the middle of the feeders) was chosen to be representative of an 'average' scenario. More extreme responses, in terms of sympathetic tripping, would occur at other locations i.e. both inverter and fault at the heads of their respective feeders, or both inverter and fault at the end of the feeders. The inverter capacity of 3 MVA was also chosen to represent an 'average' scenario as the maximum capacity of DG likely to be connected at this voltage level is 6 MVA (discussed in Section 4.2.2). Exhaustive testing incorporating a range of fault locations, DG locations and DG capacities is investigated in more detail in later sections of this chapter and also in Chapter 4.

It was found that with a grid infeed fault level of 20 MVA at 33 kV (it is worth noting that this fault level is extremely small by present standards and is more representative of a future power system where traditional generation has been replaced by solar only), the protection at CB B operates with a time delay of 0.6103 s, and for a grid infeed fault level of 900 MVA (high), it operates with a delay of 0.3684 s. For all fault levels from 20-900 MVA the voltage at the inverter terminals is always less than 80 %. However, at higher fault levels, the protection at CB B operates quickly enough to avoid sympathetic tripping i.e. less than 0.5 s.

4.5.3.2 Impact of DG capacity

The impact of the inverter-interfaced DG's capacity on sympathetic tripping was evaluated using the following network configuration (referring to figure 62): setting the inverter location to (2), varying the inverter capacity and the fault location and determining the required grid infeed fault level to avoid sympathetic tripping. As in the previous scenario, this inverter location was once again chosen to be representative of an average scenario. The fault location and inverter capacity were varied to evaluate the combined impact they have on changing inverter capacity. The results of this simulation are shown in Table 13.

Table 13: Inverter capacity impact on sympathetic tripping

Scenario	Inverter capacity (MVA)	Fault location	Minimum grid infeed fault level to avoid sympathetic tripping (MVA)
1	1	1	80
2	1	3	680
3	3	1	60
4	3	3	140

It can be observed that, as the inverter capacity is increased, the required grid infeed fault level to avoid sympathetic tripping reduces. The decrease in required grid infeed fault current, when moving from scenario 1 to 3, is due to the marginally higher fault contribution from the inverter. This increased fault contribution causes the protection at CB B to operate quicker, i.e. before the inverters sympathetically trip on under voltage protection. Therefore, in scenario 3, sympathetic tripping is avoided at a lower grid infeed fault level than in scenario 1. In scenarios 2 and 4 sympathetic tripping is avoided because the voltage at the inverter terminals is higher than 87 % of nominal. Scenario 4 does not require as high a fault level as scenario 2 because the inverter capacity is higher therefore the fault contribution from the inverter results in a terminal voltage greater than 87 % at a lower grid infeed fault level. The large step change in 'minimum grid infeed fault level to avoid sympathetic tripping' between scenario 2 and scenario 4 is due to the voltage cut-offs specified in G59/2 i.e. (0.8 pu and 0.87 pu). In order to determine how this step change occurs the simulation was repeated for a larger number of fault locations and inverter capacities, shown in Table 15. This table shows the required grid infeed fault level to avoid sympathetic tripping for different inverter capacities and fault locations. Cells marked as NSZ (No safe zone) do not have a fault level (between the tested limits 0-900 MVA) that avoids sympathetic tripping for that given inverter capacity and fault location. In the scenarios marked (A) sympathetic tripping is avoided because the protection relay at the start of the faulted feeder operates before the undervoltage protection on the inverter. In the scenarios marked (B) sympathetic tripping is avoided because the voltage at the inverter terminals is not depressed beyond the limits specified in G59/2 (0.87pu). The NSZ scenarios correspond to fault locations where the protection relay operates after the inverter undervoltage protection and the inverter terminal voltage is below the limits specified in G59/2.

Table 14: Required grid infeed fault level to avoid sympathetic tripping for varying inverter capacity and fault location (NSZ = No safe zone)

		Inverter at (2)			
		Inverter Capacity (MVA)			
		1	2	3	
Point of fault (km)	0	80	80	60	(A)
	0.5	80	80	80	(A)
	1	80	80	80	(A)
	1.5	100	100	100	(A)
	2	120	100	100	(A)
	2.5	140	120	120	(A)
	3	160	160	140	(A)
	3.5	200	180	180	(A)
	4	280	260	240	(A)
	4.5	460	420	380	(A)
	5	NSZ	NSZ	NSZ	
	5.5	NSZ	NSZ	NSZ	
	6	NSZ	NSZ	720	(B)
	6.5	NSZ	NSZ	480	(B)
	7	NSZ	640	380	(B)
	7.5	NSZ	480	300	(B)
	8	680	380	240	(B)

4.5.3.3 Impact of distance to fault

The effect of the relative distance between the DG and the fault on sympathetic tripping was evaluated using the following network configuration: setting the inverter-interfaced DG capacity to 3 MVA and varying the DG and fault location as described in Table 15.

Table 15: Effect of DG and fault location on sympathetic tripping

Scenario	DG location	Fault Location	Minimum required grid infeed fault level to avoid sympathetic tripping (MVA)
1	1	1	60
2	1	2	240
3	1	3	780
4	3	1	60
5	3	2	240
6	3	3	140

At fault locations 1 and 2, the protection at CB B operates in less than 0.5 s so sympathetic tripping is always avoided. At fault location 3 the voltage at the inverter terminals is greater than 87 % so sympathetic tripping is also avoided in this case. Scenario 6 requires a lower grid infeed fault level than in scenario 3. This is because the inverters are further away from the fault in scenario 6, therefore the relative impedance between the inverter and the fault is higher. Accordingly, the inverter terminal voltage in scenario 6 will always be higher than the inverter terminal voltage in scenario 3 for the same grid infeed fault level. The large change in required grid infeed fault level in Scenario 6 when compared to Scenario 3 is similar to that seen in the previous simulation, Table 13. To evaluate this large step change the simulation was repeated for a greater number of fault locations and inverter capacities as shown in Table 16. The same trend as observed in Table 14 can be observed.

Table 16: Required grid infeed fault level to avoid sympathetic tripping for varying inverter capacity and fault location (NSZ = No safe zone)

		Inverter at (1)			Inverter at (2)			
		Inverter Capacity (MVA)			Inverter Capacity (MVA)			
		1	2	3	1	2	3	
Point of fault (km)	0	80	80	60	80	80	60	(A)
	0.5	80	80	80	80	80	80	
	1	80	80	80	80	80	80	
	1.5	100	100	100	100	100	100	
	2	120	100	100	120	100	100	
	2.5	140	120	120	140	120	120	
	3	160	140	140	160	160	140	
	3.5	200	180	180	200	180	180	
	4	280	260	240	280	260	240	
	4.5	460	420	380	460	420	380	
	5	NSZ	NSZ	NSZ	NSZ	NSZ	500	(B)
	5.5	NSZ	NSZ	NSZ	NSZ	840	340	
	6	NSZ	NSZ	NSZ	NSZ	540	260	
	6.5	NSZ	NSZ	NSZ	NSZ	400	220	
	7	NSZ	NSZ	NSZ	780	320	180	
	7.5	NSZ	NSZ	NSZ	560	260	160	
	8	NSZ	NSZ	780	440	220	140	

The simulation results have demonstrated that the grid infeed fault level has a significant impact on the risk of sympathetic tripping being experienced. A "strong" grid can avoid the problem by causing line protection to trip faster than the required 0.5 s. A higher capacity DG unit is less likely to result in sympathetic tripping. However, if the DG's inverter protection does sympathetically trip, the consequences could be more severe. The load 'hidden' by the inverter would be larger and the load 'seen' after sympathetic tripping would therefore be greater, possibly leading to tripping of the feeder protection on overload. If the fault is close to the terminals of the inverter, sympathetic tripping is more likely. If the inverter is connected at the end of the feeder, the probability of sympathetic tripping occurring is reduced.

Chapter 4 builds on the results from this section by evaluating the problem over a larger range of fault levels, inverter locations, inverter penetrations and fault locations using the 'real-world' distribution network supplied by a UK DNO (Section 4.1).

4.6 Potential solutions to blinding, loss of protection coordination and sympathetic tripping

In this chapter, it has been demonstrated that protection blinding is unlikely to be a problem for present levels of inverter-interfaced DG on UK power systems. Several examples of loss of protection coordination have been identified and it has been demonstrated that in some cases they do not negatively impact upon protection operation. However, it *has* been shown that at anticipated future levels of penetration of inverter-interfaced DG (approximately half of the feeder's rated capacity, as discussed in Section 4.2.2), sympathetic tripping is likely to become a problem. At extreme levels of DG unit penetration, on networks with long feeders and/or for networks with relatively slower acting network protection schemes, protection blinding may also start to cause difficulties. Many of the solutions discussed in the literature are equally applicable to protection blinding, loss of protection coordination and sympathetic tripping. The effectiveness of the solutions proposed in the literature is evaluated in this section.

4.6.1 Adaptive protection

In [5, 94, 98, 99] adaptive protection is considered as a solution to mitigate the negative impact of DG on protection scheme operation. These papers propose modifying the settings of a distribution protection scheme to account for the fault contribution being supplied from DG units connected to the power system. This technique has the potential to stop the occurrence of both protection blinding and loss of protection coordination but its impact on sympathetic tripping is likely to be limited unless protection operation speed is significantly improved.

One of the limits of some adaptive protection solutions, particularly the solution proposed in [5], is that the adaptive protection scheme requires more protection equipment to operate than standard protection schemes. In [5] several additional CBs are required to isolate the distribution system into protection system zones. This is however not true for all adaptive protection schemes, for example [100, 101] do not require additional equipment, but instead control and configure existing protection equipment more effectively to improve the collective protection system response.

Adaptive protection also typically requires a communication system to update individual protection devices to conform to an overriding protection strategy while maintaining inter-relay coordination. The adaptive solution requires a communication scheme in [5, 98] for updating protection device settings and in [94] for blocking sympathetic tripping of DG. The specification of the required communication system or an explanation of how the protection scheme should continue to operate in the event of a communication failure is not provided in these papers. Reference [99] suggests that existing 'smart grid' communication technologies could be employed for the necessary inter-protection communication; however, the required specification of the communication system is not defined nor is the limitation of existing smart-gird communication media investigated.

From a financial viewpoint, without significant motivation from increasing DG penetration, the addition of extra protection equipment and communication may not be cost effective for distribution level protection. Presently, in the UK, dedicated communication systems are only widely applied at higher voltage levels [15] where the increased cost of the communication system is justified by the greater potential of damaging sensitive equipment or losing electrical supply to a larger customer base. In future power systems communication networks may be more prevalent, IP/MPLS communication is discussed as a candidate technology for future systems in Section 5.4.2, this technology may apply to the communication systems proposed in the above papers.

Another limitation to the adaptive protection solutions discussed in these papers is that they do not take into account DG availability. The fault contribution of DG will vary with respect to the energy supply; in the case of wind or solar generation this is continuously variable. The cumulative fault contribution from DG will also vary when some DG units are out of service and the adaptive protection scheme would be required to take this into account – this is not considered in any of the papers discussed above. The optimisation solution presented in Chapter 6 of this thesis considers varying DG availability when optimising protection settings. This is an important consideration for any solution that is being applied as a result of increasing DG penetration.

A more comprehensive evaluation of an adaptive protection scheme's requirements is considered in [102] and [103]. However, [102] evaluates adaptive protection's capability in modifying protection reach to accommodate a quadrature booster transformer being added to the network and [103] determines if adaptive protection can be used to modify protection characteristics to maintain protection coordination for changing network configurations. In both cases the proposed techniques accommodates the changing network characteristic, but the techniques may prove less effective when applied to blinding, loss of protection coordination or sympathetic tripping and are perhaps not generically applicable, being targeted at specific scenarios and problems.

4.6.2 Fault current limiters

Another technique that has been evaluated in the literature as a tool for solving protection issues resulting from DG penetration is the use of FCLs to limit DG fault contribution [75, 104, 105]. Passive FCLs can permanently limit fault current limits but they cause additional voltage drops and hence power losses. Active FCLs do not have this limitation, they remain in a low impedance mode until fault current is detected and then switch to a high impedance mode to block the fault current. The potential benefit of FCLs to reduce fault currents in marine electrical applications is being researched extensively [106-109]. Due to the power dense, low voltage nature of shipboard networks, fault currents have the potential to be extremely high, therefore FCL solutions are extremely attractive from a protection viewpoint. A comprehensive guide to the various merits of different FCL technologies is available in [110]. The first commercially available FCL (developed by GridOn) is being installed in Newhaven, East Sussex, UK in 2013 [111]. The objective of this equipment is to limit fault current contribution from mid to large scale DG plant e.g. wind farms [112]. This technology allows DNOs to maintain existing fault levels and hence continue to existing protection schemes (and most importantly, from a cost perspective circuit breakers) when DG is installed – the use of FCLs also helps to ensure that the current withstand capabilities of all current carrying equipment is not violated during faults. However, the aggregated contribution of micro-DG units can also interfere with protection operation. Unless the connection of micro-DG to the network was to be directed through a common connection point it would be impractical and prohibitively expensive to install FCLs at every DG/network interface. As micro-DG is typically installed on individual residences; installing FCLs at a PCC (Point of Common Coupling) would be impractical. One solution to this method may be to group communities containing DG units into FCL protected zones and limit the DG fault contribution from an entire community onto the feeder, as show in Figure 63. This has the potential to avoid blinding of protection and loss of protection coordination for micro-DG fault contribution.

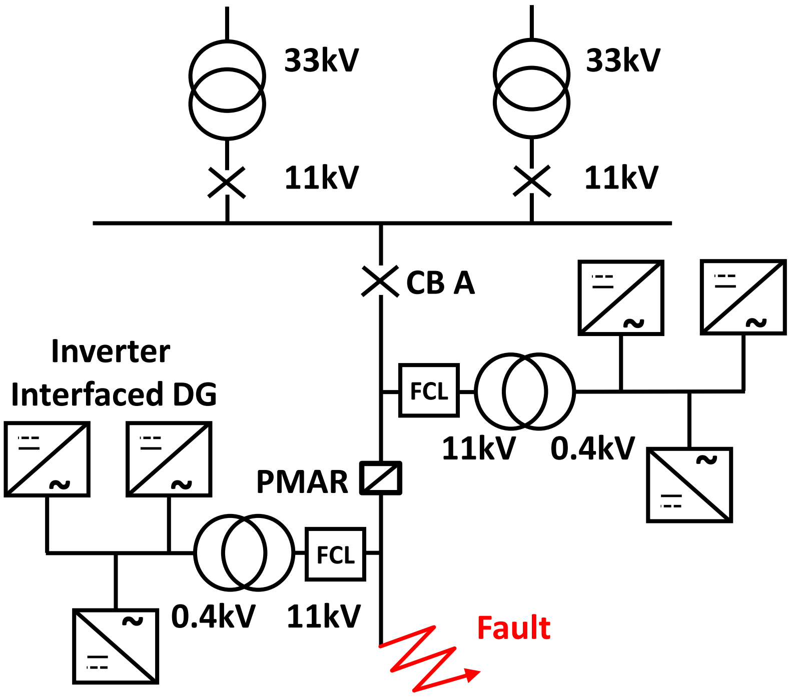


Figure 63: FCL implementation on distribution network

In [113], an optimisation technique for defining the optimal size of FCLs to ensure correct protection operation while minimising the loss of supply to customers is proposed. It is shown that by installing optimally sized FCLs, protection relay settings can be found that satisfy both islanded and grid connected modes. This technique may prove an effective method as FCLs become more commercially available. The effectiveness of this solution in reducing the impact of blinding, loss of protection coordination and sympathetic tripping was not investigated within the paper. The merits of optimisation solutions for different application are discussed in more detail in the following section.

4.6.3 Protection optimisation

There are a wide variety of papers that propose the use of optimisation techniques to improve power system operation. Applications for optimisation include improving economic generation dispatch [114], industrial facility parameter setting [115], active/reactive power control [116], optimal FACTS (Flexible Alternating

Current Transmission System) device placement [117], optimising protection settings for changing network topologies [118], optimising fault current limiter size/impedance to maintain relay co-ordination in networks with DG [105, 119] and investigating optimum DG placement in a distribution network to minimise protection relay operation time [120].

This section focuses on the application of optimisation techniques to improve protection operation settings to address blinding, loss of protection coordination and sympathetic tripping. By using optimal protection settings the protection operation speed can be improved and many of the protection problems that result from increasing DG penetration on the network can be solved.

There are many papers that optimise the protection settings of protection relays to improve the overall speed of the protection scheme [121-123]. The success of the proposed solutions is dependent on the complexity of the network modelled, the complexity of the network protection scheme and the choice of solver. A variety of solvers are used with varying degrees of effectiveness: [124] uses particle swarm optimisation, [125] uses a genetic algorithm approach, while others use hybrid approaches that combine different solvers [126, 127].

A large proportion of the literature investigates optimisation solutions for improving the protection settings for traditional networks with no DG [121-123]. However, there are also several papers that consider protection optimisation solutions for network protection to accommodate increasing DG penetration [128-130]. These papers demonstrate, with varying degrees of effectiveness, and using different solvers, that optimisation techniques can be used to re-establish correct protection coordination when DG units are installed on the network and the fault levels within the network consequently change. In each case [128-130], directly connected generators are used (synchronous in [113, 128] and induction in [130]) rather than inverter-interfaced generators. Synchronous/induction generators were chosen in these studies because they produce a much larger fault current than inverter-interfaced generators and therefore have a greater impact on protection operation.

The papers discussed thus far optimise protection settings but not protection characteristics (i.e. the relay characteristic curve shapes in overcurrent relays). There are far fewer papers that also consider protection characteristics as an optimisation variable. Those that do consider protection characteristics [131, 132] do not consider situations where DG is connected to the network. This is a solution that will be investigated and demonstrated in detail in Chapter 6. In Chapter 6 two aspects of protection optimisation are considered – optimising the relay *characteristics*, in addition to settings, and optimising performance for *varying penetrations and locations* of connection of DG.

4.7 Chapter summary

In this chapter, three protection problems that may potentially be caused by increasing DG penetration have been critically reviewed and then evaluated using simulation. It has been demonstrated that protection blinding is unlikely to be a problem for present levels of inverter-interfaced DG on UK power systems. Several examples of loss of protection coordination have been identified and it has been demonstrated that in some cases they do not negatively impact upon protection operation. However, it *has* been shown that at typical levels of inverter-interfaced DG (3 MVA per 11 kV feeder) sympathetic tripping is likely to become a problem in the future.

The second part of this chapter critically reviews three solutions that have been proposed in the literature as candidate solutions to stop protection blinding, loss of coordination and sympathetic tripping. All of the candidate solutions, adaptive protection, FCL technology and protection optimisation are found to have advantages and disadvantages in their ability to reduce or eliminate protection problems.

Adaptive protection can potentially address problems if the protection system can be 'adapted' to the correct configuration to avoid the problem within the necessary timescales. However, there are limitations in the solutions presented in the literature (such as a lack of consideration for DG availability) that need to be addressed before adaptive protection can be implemented effectively. Fault current limiter technology can also reduce the occurrence of many of the protection problems resulting from DG penetration by reducing the fault contribution from the DG. However, fault current limiters are only beginning to be trialled on power systems and it is unlikely that they could be cost effectively employed for small scale DG applications. Fault current limiters may prove more effective in reducing the fault current contribution from aggregated areas of the power system containing DG rather than being connected directly to DG interfaces. Protection optimisation can stop the occurrence of many protection problems by improving the speed of the protection system. The limitation of this solution is that it is not universally applicable. As will be shown in Chapter 6, optimisation techniques can result in significant improvements in protection operation speed for some networks. This is discussed further in Chapter 6.

Chapter 5 Investigation of the sympathetic tripping problem for changing network conditions

Chapter 4 investigated the sympathetic tripping problem on a UKGDS rural network and demonstrated that sympathetic tripping is likely to occur on power systems with growing penetrations of inverter-interfaced DG.

The first part of this chapter builds on the work of Chapter 4 by investigating the sympathetic tripping problem on a UK rural/urban network over a larger range of fault levels, inverter penetrations and fault locations, all using the empirical inverter model developed in Chapter 3 as the basis for representing the DG on the network. The impact of changing protection settings, relay characteristics (i.e. the nature of the characteristic curve shape for overcurrent relays) and inverter fault contribution are also investigated. This chapter demonstrates that sympathetic tripping will occur when presently adopted protection settings are used with expected future levels of DG penetration.

The second part of this chapter presents and evaluates two different solutions that can assist in preventing the occurrence of sympathetic tripping. The first solution involves changing protection scheme settings and changing G59/2 requirements. This is one of the most common methods suggested in the literature relating to sympathetic tripping [22, 90]. The second solution involves using a communications scheme to block inverter G59/2 operation during non-islanded conditions [15]. The feasibility of an IP/MPLS communication system is evaluated as a candidate technology for the proposed blocking scheme. The latency of IP/MPLS communication is evaluated using a laboratory test system. This chapter has two key findings – determination of the network conditions at which sympathetic tripping will occur and an evaluation of techniques to avoid it occurring in future networks.

5.1 Sympathetic tripping simulation

The premise of the sympathetic tripping problem has already been described in Chapter 4 and will not be repeated here. The sympathetic tripping problem is evaluated in this chapter, using the empirical inverter model developed in Chapter 3, on a typical UK power system incorporating a rural feeder and an urban feeder, shown in Figure 64 (feeder 1 is the rural feeder and feeder 2 is the urban feeder).

The network data and protection settings were provided by a UK DNO (see Section 5.1.2-5.1.3 for more information).

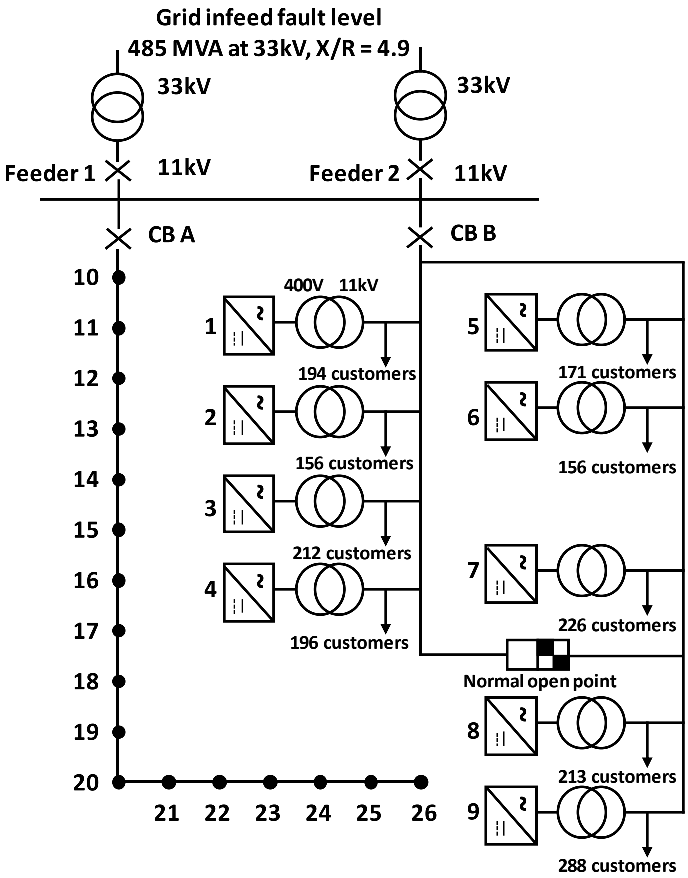


Figure 64: Simulation model for evaluating sympathetic tripping – based on rural (feeder 1) and urban (feeder 2) UK 11 kV distribution system (provided by UK DNO)

Faults were applied on feeder 1 at 17 locations corresponding to the 17 LV spurs (numbered 10-26 on the diagram) on feeder 1. The load on the spur and capacity of the inverter on each spur (1-9) were based upon the number of customers on each spur.

The maximum measured line current on feeder 2 was 160 A (equating to a three phase load of just greater than 3 MVA) and the minimum was 40 A (0.75 MVA) in the year 2011. The average load over the course of 2011 was 100 A (1.9 MVA); this load has been assumed to be distributed evenly across all customers on each LV spur. To evaluate the sympathetic tripping problem, the number of customers with 3 kW inverters installed on feeder 2 was varied. The combined fault contribution of the inverters on each spur was modelled as a single three-phase inverter unit with the response scaled appropriately and based on the developed empirical model, as discussed in Section 3.5. The penetration of inverters was scaled based on the max load, so that 100% penetration would equate to 3 MVA of generation. When the network loading is less than 3MVA this results in reverse power flow from the DG to the grid but total power transfer is kept within the feeders maximum capacity.

5.1.1 Feeder characteristics

The feeder impedance characteristics are given in Table 17 and Table 18 below.

Table 17: Feeder 1 characteristics

From	To	R (Ω)	X (Ω)
Feeder 1 bus	10	0.2417	0.1276
10	11	0.2395	0.1264
11	12	0.1092	0.0448
12	13	0.0494	0.0203
13	14	0.0272	0.0143
14	15	0.0005	0.0003
15	16	0.2223	0.0682
16	17	0.0013	0.0007
17	18	0.0595	0.0290
18	19	0.1692	0.0498
19	20	0.0238	0.0063
20	21	0.0589	0.0311
21	22	0.0026	0.0014
22	23	0.0509	0.0253
23	24	0.0658	0.0422
24	25	0.0020	0.0012
25	26	0.0871	0.0559

Table 18: Feeder 2 characteristics

From	To	R (Ω)	X (Ω)
Feeder 2 Bus	T-junction	0.5043	0.266219
T-junction	1	0.0018	0.0006
1	2	0.1723	0.0465
2	3	0.1484	0.0420
3	4	0.1699	0.0440
4	Normal open point	0.0252	0.0058
Feeder 2 Bus	T-junction	0.5043	0.2662
T-junction	5	0.1778	0.0486
5	6	0.0041	0.0025
6	7	0.0874	0.0256
7	Normal open point	0.0744	0.0182
7	8	0.0690	0.0183
8	9	0.0725	0.0252

5.1.2 Protection settings

The protection settings for feeders 1 and 2, supplied by the DNO, are given in Table 19.

Table 19: Feeder protection settings

Feeder protection settings	CB A	CB B
Primary pickup current (A)	400	400
Time multiplier	0.2	0.1

5.1.3 Transformer characteristics

The transformer characteristics used in this chapter are given in Table 8 and Table 6.

5.2 Simulation results

The network presented in Section 5.1 was simulated to evaluate the risk of inverters sympathetically tripping for faults on the adjacent feeder. The penetration of inverters was varied from 25 % to 100 % in 5 % increments to evaluate how the inverters' aggregated fault contribution impacts upon the risk of occurrence of sympathetic tripping.

5.2.1 Base Case

With the default network characteristics, protection settings and inverter fault response, defined in Section 5.1, the only condition when the feeder relay operated faster than the inverter's protection, i.e. sympathetic tripping did *not* occur, was at 100 % inverter penetration. At 100 % penetration, sympathetic tripping did not occur for faults at positions 10 and 26 but did occur for fault at positions 11-25. In the case of fault positions 10 and 26, two factors contributed to the avoidance of sympathetic tripping: the impedance (distance) from the inverters to the fault location was large enough that the voltage drop at the inverter terminals did not cause undervoltage protection operation; and the combined capacity of the inverters acted to support the system voltage at the inverter terminals to prevent undervoltage protection operation. This is shown in Table 20. Note that in Table 20 to Table 23 the following symbols are used: ✔ = inverter operates in 0.5 s and after the line relay, ✔ ✔ = inverter operates in 2.5 s and after the line relay, ✔ ✔ ✔ = inverter never operates, ✕ = inverter operates before relay (i.e. sympathetic tripping occurs). In Table 20, Table 21, Table 22 and Table 23the inverter response numbers in bold refer to the inverter positions shown in Figure 64.

Table 20: Protection (feeder 1) and inverter responses, with original TM (=0.2), inverter penetration of 100 %

Fault location	Line relay time (s)	Inverter response								
		1	2	3	4	5	6	7	8	9
10	0.44	✔	✔	✔	✔	✔	✔	✔	✔	✔
11	0.49	✕	✕	✕	✕	✕	✕	✕	✕	✕
12	0.51	✕	✕	✕	✕	✕	✕	✕	✕	✕
13	0.52	✕	✕	✕	✕	✕	✕	✕	✕	✕
14	0.52	✕	✕	✕	✕	✕	✕	✕	✕	✕
15	0.52	✕	✕	✕	✕	✕	✕	✕	✕	✕
16	0.56	✕	✕	✕	✕	✕	✕	✕	✕	✕
17	0.56	✕	✕	✕	✕	✕	✕	✕	✕	✕
18	0.57	✕	✕	✕	✕	✕	✕	✕	✕	✕
19	0.60	✕	✕	✕	✕	✕	✕	✕	✕	✕
20	0.60	✕	✕	✕	✕	✕	✕	✕	✕	✕
21	0.61	✕	✕	✕	✕	✕	✕	✕	✕	✕
22	0.61	✕	✕	✕	✕	✕	✕	✕	✕	✕
23	0.62	✕	✕	✕	✕	✕	✕	✕	✕	✕
24	0.63	✕	✕	✕	✕	✕	✕	✕	✕	✕
25	0.63	✕	✕	✕	✕	✕	✕	✕	✕	✕
26	0.65	✔✔	✔✔	✔✔	✔✔	✔✔	✔✔	✔✔	✔✔	✔✔

5.2.2 Impact of changing protection settings

By changing the feeder protection settings, the risk of sympathetic tripping can be reduced. Table 21 shows the protection operation times if the TM on the protection relay on feeder 1 is changed from 0.2 to 0.1 for an inverter penetration level of 25 %. It can be observed that in this instance the feeder protection operates before the inverter protection at all fault locations. At higher penetration levels, i.e. greater than 25 % the same response is observed – the feeder protection operates before the inverter protection. In this case, a small change to the feeder protection settings has removed the risk of sympathetic tripping. This is unlikely to be a viable solution in most protection schemes. Changing the TM of one protection relay will change the grading margin between protection devices and could potentially lead to loss of coordination between the feeder protection and downstream (or upstream) devices. This is demonstrated in Figure 65 where the TM of relay 2 has been changed from 0.1 to 0.2. In this case it can be observed that grading is lost for currents in excess of 400 A – relay 1 would begin operating faster than relay 2.

Table 21: Protection (feeder 1) and inverter responses, with reduced TM (=0.1), inverter penetration of 25 %

Fault location	Line relay time (s)	Inverter response								
		1	2	3	4	5	6	7	8	9
10	0.24	✔	✔	✔	✔	✔	✔	✔	✔	✔
11	0.26	✔	✔	✔	✔	✔	✔	✔	✔	✔
12	0.27	✔	✔	✔	✔	✔	✔	✔	✔	✔
13	0.27	✔	✔	✔	✔	✔	✔	✔	✔	✔
14	0.27	✔	✔	✔	✔	✔	✔	✔	✔	✔
15	0.27	✔	✔	✔	✔	✔	✔	✔	✔	✔
16	0.29	✔	✔	✔	✔	✔	✔	✔	✔	✔
17	0.29	✔	✔	✔	✔	✔	✔	✔	✔	✔
18	0.30	✔	✔	✔	✔	✔	✔	✔	✔	✔
19	0.31	✔	✔	✔	✔	✔	✔	✔	✔	✔
20	0.31	✔	✔	✔	✔	✔	✔	✔	✔	✔
21	0.32	✔	✔	✔	✔	✔	✔	✔	✔	✔
22	0.32	✔	✔	✔	✔	✔	✔	✔	✔	✔
23	0.32	✔	✔	✔	✔	✔	✔	✔	✔	✔
24	0.33	✔	✔	✔	✔	✔	✔	✔	✔	✔
25	0.33	✔	✔	✔	✔	✔	✔	✔	✔	✔
26	0.34	✔ ✔	✔ ✔	✔ ✔	✔ ✔	✔ ✔	✔ ✔	✔ ✔	✔ ✔	✔ ✔

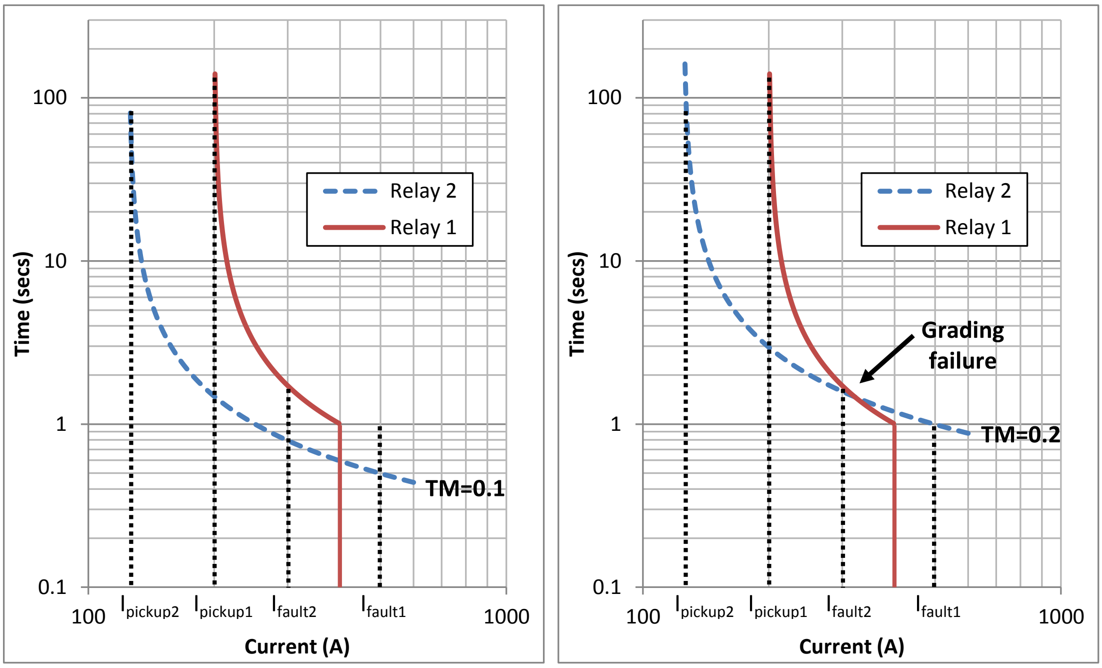


Figure 65: Example of grading changing as a result of changing TM

5.2.3 Impact of changing protection relay characteristic

A similar technique to modifying the protection settings is to modify the protection relay characteristic (or "curve"). Table 22 shows the protection operation times if the protection characteristic of the protection relay on feeder 1 was changed from SI (Standard Inverse) to EI (Extremely Inverse) for an inverter penetration level of 100 %. It can be observed that in this instance, the feeder protection operates before the inverter protection for all fault locations. In this case, changing the relay protection characteristic has removed the risk of sympathetic tripping. This is unlikely to be a viable solution in most protection schemes. Changing the protection characteristic curve of one protection relay may result in loss of coordination with other protection devices. For example, in Figure 66, the graph on the left shows two protective devices with SI characteristics. In this graph it can be observed that a sufficient grading margin is maintained for all fault currents. If the same pickup currents and TMs are used but the characteristic of relay 2 is changed to EI, then it can be observed on the graph on the right that the grading margin between the protection devices changes. In the case shown in Figure 66 the grading margin between the protection devices is zero for fault currents of magnitude I_{fault2}. These results differ from the results presented in Chapter 4 due to the different protection settings and network characteristics.

Table 22: Protection (feeder 1) and inverter responses, with extremely inverse characteristic, inverter penetration of 100 %

Fault location	Line relay time (s)	Inverter response								
		1	2	3	4	5	6	7	8	9
10	0.54	✔	✔	✔	✔	✔	✔	✔	✔	✔
11	0.56	✔	✔	✔	✔	✔	✔	✔	✔	✔
12	0.58	✔	✔	✔	✔	✔	✔	✔	✔	✔
13	0.58	✔	✔	✔	✔	✔	✔	✔	✔	✔
14	0.59	✔	✔	✔	✔	✔	✔	✔	✔	✔
15	0.59	✔	✔	✔	✔	✔	✔	✔	✔	✔
16	0.62	✔	✔	✔	✔	✔	✔	✔	✔	✔
17	0.62	✔	✔	✔	✔	✔	✔	✔	✔	✔
18	0.63	✔	✔	✔	✔	✔	✔	✔	✔	✔
19	0.67	✔	✔	✔	✔	✔	✔	✔	✔	✔
20	0.67	✔	✔	✔	✔	✔	✔	✔	✔	✔
21	0.68	✔	✔	✔	✔	✔	✔	✔	✔	✔
22	0.69	✔	✔	✔	✔	✔	✔	✔	✔	✔
23	0.70	✔	✔	✔	✔	✔	✔	✔	✔	✔
24	0.72	✔	✔	✔	✔	✔	✔	✔	✔	✔
25	0.72	✔	✔	✔	✔	✔	✔	✔	✔	✔
26	0.74	✔✔	✔✔	✔✔	✔✔	✔✔	✔✔	✔✔	✔✔	✔✔

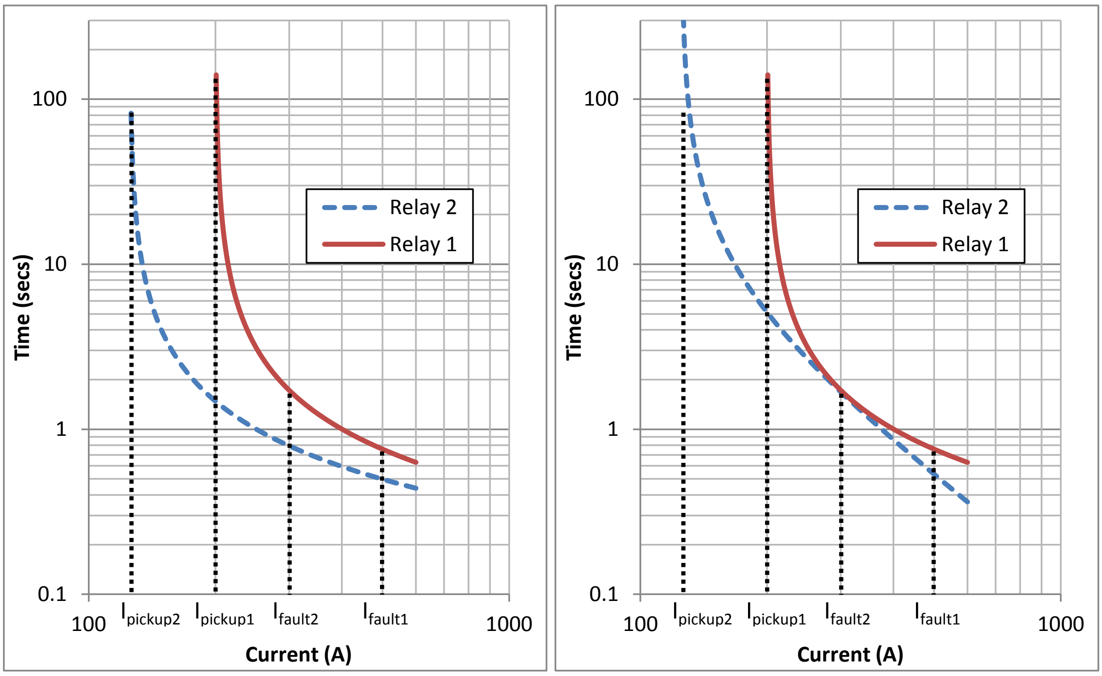


Figure 66: Example of grading problem as a result of using different relay characteristics

5.2.4 Impact of inverter response on simulation

The inverter fault response also has an influence on the risk of sympathetic tripping. To evaluate the impact of an inverter with an increased real and reactive fault current contribution, the simulation was repeated with an idealised inverter model capable of providing 2 pu rms fault current. This higher fault contribution is representative of the combined fault contribution from a mix of inverter interfaced generation and other more traditional generation such as synchronous generators. It is assumed that the inverter supplies 2 pu current for all voltages levels less than 0.9 pu and that the active and reactive components of the fault current were 1.6 pu and 1.2 pu respectively (i.e. in this scenario the inverter generates reactive power to support the grid voltage). The relative magnitudes of real and reactive power will depend on the impedance to fault and the inverter's controller action. It is also assumed that, unlike the previous inverter, this inverter complies with G59/2 with respect to operation time at all voltage levels. The feeder protection times (assuming 100 % inverter penetration) are shown in Table 23. In this case, the higher fault rating of the inverter means the inverter is better able to support its terminal voltage. Consequently, there are fewer fault locations that result in the inverter tripping before the feeder protection. At the electrically "closest" faults i.e. fault locations 10 and

11, the fault current is high enough to trip the feeder protection before the inverters disconnect. At 'distant' faults i.e. fault locations 16-18, the undervoltage at the inverter's terminals is between 0.8 pu and 0.87 pu, so the inverter disconnects according to the upper G59/2 setting of 2.5 s. At the locations furthest along the feeder, i.e. 19-26, the voltage at the terminals of the inverter remains above 0.87 pu, so the inverter will remain connected regardless of the fault duration. For fault locations 12-15, the voltage at the inverter terminals is below 0.8 pu, so the inverter operates within 0.5 s and before the feeder protection, i.e. a manifestation of the sympathetic tripping problem.

Increasing the inverter's fault current capacity will reduce the risk of sympathetic tripping as shown in Table 23. This could be achieved by increasing the number of inverters or by modifying the inverter control algorithm. In the latter case, the limiting factors in increasing the inverters fault current contribution would be the availability of the primary energy source supplying the inverter (in an urban network this is likely to be solar radiation) and the rating of the inverter and its internal components.

Table 23: Protection (feeder 1) and inverter responses – inverter with 2pu fault current contribution, inverter penetration of 100 %

Fault location	Line relay time (s)	Inverter response								
		1	2	3	4	5	6	7	8	9
10	0.46	✔	✔	✔	✔	✔	✔	✔	✔	✔
11	0.49	✔	✔	✔	✔	✔	✔	✔	✔	✔
12	0.51	✘	✘	✘	✘	✘	✘	✘	✘	✘
13	0.52	✘	✘	✘	✘	✘	✘	✘	✘	✘
14	0.53	✘	✘	✘	✘	✘	✘	✘	✘	✘
15	0.53	✘	✘	✘	✘	✘	✘	✘	✘	✘
16	0.56	✔✔	✔✔	✔✔	✔✔	✔✔	✔✔	✔✔	✔✔	✔✔
17	0.56	✔✔	✔✔	✔✔	✔✔	✔✔	✔✔	✔✔	✔✔	✔✔
18	0.57	✔✔	✔✔	✔✔	✔✔	✔✔✔	✔✔	✔✔	✔✔✔	✔✔✔
19	0.59	✔✔✔	✔✔✔	✔✔✔	✔✔✔	✔✔✔	✔✔✔	✔✔✔	✔✔✔	✔✔✔
20	0.59	✔✔✔	✔✔✔	✔✔✔	✔✔✔	✔✔✔	✔✔✔	✔✔✔	✔✔✔	✔✔✔
21	0.60	✔✔✔	✔✔✔	✔✔✔	✔✔✔	✔✔✔	✔✔✔	✔✔✔	✔✔✔	✔✔✔
22	0.60	✔✔✔	✔✔✔	✔✔✔	✔✔✔	✔✔✔	✔✔✔	✔✔✔	✔✔✔	✔✔✔
23	0.61	✔✔✔	✔✔✔	✔✔✔	✔✔✔	✔✔✔	✔✔✔	✔✔✔	✔✔✔	✔✔✔
24	0.62	✔✔✔	✔✔✔	✔✔✔	✔✔✔	✔✔✔	✔✔✔	✔✔✔	✔✔✔	✔✔✔
25	0.63	✔✔✔	✔✔✔	✔✔✔	✔✔✔	✔✔✔	✔✔✔	✔✔✔	✔✔✔	✔✔✔
26	0.64	✔✔✔	✔✔✔	✔✔✔	✔✔✔	✔✔✔	✔✔✔	✔✔✔	✔✔✔	✔✔✔

5.3 Analysis

The goal of this chapter is to identify the conditions at which the risk of sympathetic tripping is high, using a realistic and experimentally derived model for the inverters connected to the network. It is clear from the presented results that even at small penetrations of inverter-interfaced generation, sympathetic tripping can occur, independent of the location of the fault. It has also been established that small changes to protection settings, protection characteristics and inverter behaviour (which is likely to differ between manufacturers) has a large influence on the likelihood of sympathetic tripping occurring. This makes it difficult to predict the risk of sympathetic tripping without running a detailed simulation of a specific network with specific network protection settings. Due to the difficulty in predicting the occurrence of sympathetic tripping, a solution independent of the settings of the individual network protection scheme or the inverter penetration (or fault responses) is desirable, and candidate solutions will now be described.

5.4 Solutions to the sympathetic tripping problem

Several solutions that are equally applicable to protection blinding, loss of coordination and sympathetic tripping have been discussed in Chapter 4. This section will evaluate solutions specifically for reducing and/or avoiding the occurrence of sympathetic tripping.

The instances of sympathetic tripping could be reduced significantly through use of instantaneous feeder protection. However, for areas of the feeder that are not protected by instantaneous protection, e.g. at the end of feeders and for instances when backup protection operates, sympathetic tripping remains an unresolved issue. Furthermore, instantaneous protection is only applicable on long feeders where the fault level reduces significantly between feeder protection locations, so many feeders cannot use instantaneous relays.

In the short term (i.e. before the penetration of DG reaches significantly high levels), there are incremental solutions that can be used to reduce the occurrence of sympathetic tripping. These solutions include changing protection settings, changing the employed overcurrent protection characteristic curves and changing the relevant standards for DG interface protection (presently G83 but in the near future will be superseded by G59/2 for LV connections). However, as the amount of renewable generation on the power system increases, more radical solutions may be required; for example, solutions that require protection incorporating communications.

5.4.1 Solution option 1: Modified protection settings

As has already been shown in Section 5.2, changing the settings of the protection relay can prevent sympathetic tripping. This solution can be quickly applied to modern numerical relays by modifying the protection settings and protection characteristic via the software user interface [15]. In older electromechanical relays the protection settings can be modified mechanically, however, the protection characteristic cannot be changed without replacing the relay. Also, as has also been discussed, changing the settings of one relay within a protection scheme will most likely lead to loss of coordination between protection devices [124]. Also this solution would require the entire protection scheme to be updated to accommodate the addition of inverter-interfaced DG and this could lead to unacceptable fault clearance times [132]. Furthermore, the intermittent nature of DG might mean that the network protection system would not operate correctly for all operational scenarios.

An alternative solution could be to change the nature of the overcurrent protection relays' characteristic curves, which is readily achievable with modern numerical relays, where SI, VI and EI characteristics may be selected. Changing the protection characteristic can modify the speed of operation of the protection relay for a given fault current and act to reduce the risk of sympathetic tripping of DGs connected to the network. Changing the protection relay characteristic from SI to EI in this study avoided sympathetic tripping (as shown in Section 5.2.3). However, as already discussed, this solution can result in coordination problems between protection devices, so may not be viable in all cases.

Another solution would be to alter the G59/2 policy. If G59/2 were updated so that the time settings were delayed by 0.5 s, i.e. for voltages less than 80 % the inverter would be controlled to disconnect after 1s and for voltages between 80 and 87 % the inverter would be controlled to disconnect after 3 s, then the risk of sympathetic tripping could be reduced. The impact of relaxing the G59/2 time delay settings in increments of 0.1 s is shown in Figure 67. The solid black line in Figure 67 is the operation time of the protection relay on feeder 1 and is reflective of the duration of the presence of the fault (and hence the consequent undervoltage) on the system. It can be observed that as the fault moves further down the feeder, the protection relay takes longer to operate. For example, at fault position 10, the relay takes 0.47 s to operate and at position 25 the relay takes 0.65 s to operate to clear the fault. The results shown in Figure 67 are for a penetration level of 100 % and the times correspond to the behaviour of inverter 5. Due to the relatively small line impedance between the inverters, the undervoltage at the inverter terminals is effectively the same, at least to the extent of the limits defined in G59/2. For example, if all inverters experience a terminal voltage of less than 0.8 pu, then they will operate on undervoltage after 0.5 s. If they measure voltages of between 0.8 pu and 0.87 pu, then they will operate in 2.5 s. There is some variation in voltage between the inverter terminals, but because the impedance between the inverters is low this variation is marginal. In practice this means that the terminal voltage and hence operating time of one of the inverters is representative of the operating time of the other inverters. Inverter 5 was chosen arbitrarily as a representation of the typical operation time of most inverters. It can be seen that if both the lower and upper time settings of the G59/2 standard (i.e. 0.5 s for V<0.8 pu and 2.5 s for 0.8<V<0.87 pu) are increased by 0.1 s, then sympathetic tripping is avoided for fault positions 19-26. If the settings are increased by 0.2 s, sympathetic tripping is avoided at all fault positions. However, relaxing settings may have negative physical impact on the DG and/or inverter performance.

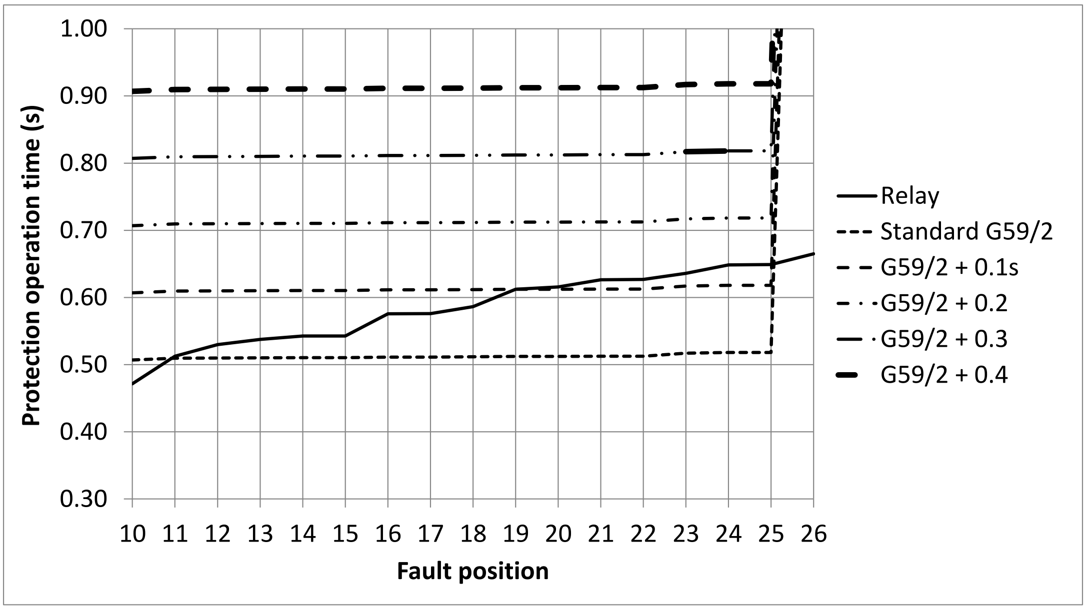


Figure 67: Impact of changing G59/2 settings on sympathetic tripping

5.4.2 Solution option 2: Use of communications

Protection systems employing communications are already widely used in transmission and sub-transmission systems [15] to improve performance. While presently not a cost effective means of protecting distribution systems, it may become a more viable solution as communication technology advances and the number of DGs on the distribution network increases.

A blocking scheme employed to instruct inverters to "ride through" undervoltage events, when it is ascertained that the inverters in question should not trip, could prevent sympathetic tripping occurring. If the fault location has been detected and the fault will be isolated by the nearest protection device, it is beneficial to the network if all DG units in the vicinity (but not downstream of the fault on the affected feeder) remain connected. Such a blocking scheme, which could be used to enhance DG ride through and avoid sympathetic tripping (and the potential for consequential cascade tripping of other DGs due to exacerbated undervoltage conditions when one or more DGs disconnect) is presented in Figure 68.

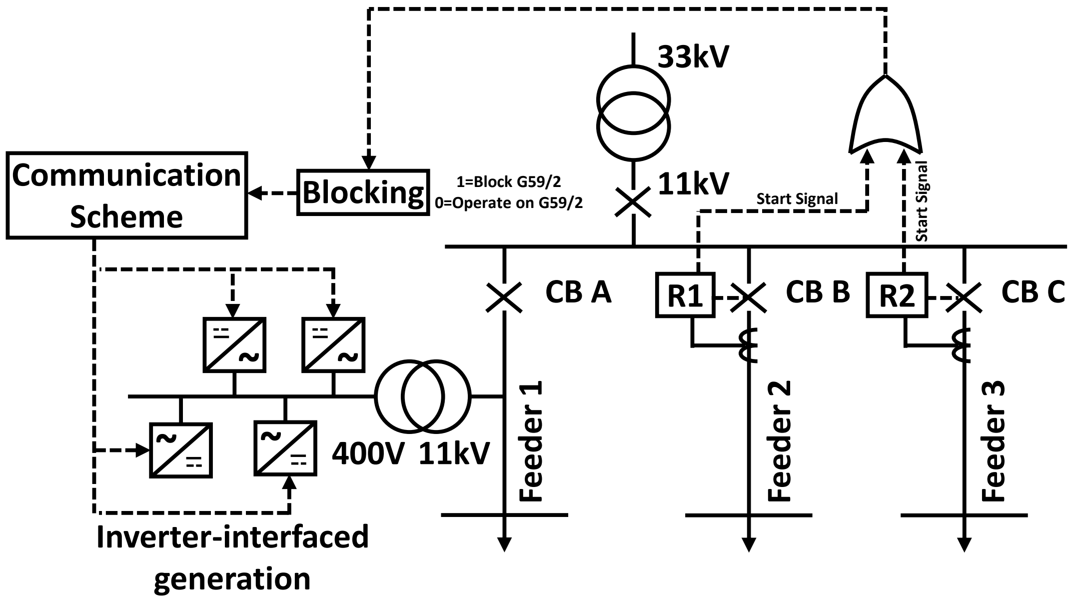


Figure 68: Blocking scheme for domestic level inverters

Traditional communication systems in HV power systems typically employ private or rented channels (or pilots), power line carrier, radio and optical fibre communication mediums [15]. These are expensive and it is unlikely that utilities would be able to justify their expense at LV now or in the future. An alternative form of communication that is potentially more cost effective is an internet based communication system. Household inverters used for photovoltaic applications are already being connected to the internet for remote system monitoring and reporting purposes [133]. It is probable that in the near future this same service could be extended to active control of the inverter. Assuming this was the case, a blocking scheme could be implemented. If the network was radial, as in Figure 68, a blocking signal from CB B could be sent to the inverters (on other feeders) to block their undervoltage protection when appropriate.

The proposed blocking scheme shown in Figure 68, makes use of the 'start signal' output from the relay which is generated when the relay detects an overcurrent event [134]. The 'start signal' is used as a blocking signal input to the inverter so that when an overcurrent event is detected on a feeder adjacent to the feeder containing the inverters the inverter's do not disconnect on G59/2 undervoltage protection. This solution is extendable to greater numbers of feeders and also to long feeders with multiple zones of protection by 'OR-ing' the blocking signal input to the inverter as shown in Figure 68. If the relay or communication system fails no signal would be sent and the undervoltage protection would operate on its default settings. Using the 'start signal' in this way ensures that the inverter G59/2 undervoltage operation is blocked (when appropriate) in the minimum possible time. Older electromechanical relays are unlikely to be equipped to output the 'start signal' on fault detection. In networks that use electromechanical relays an alternative solution may be to add additional instantaneous relays to output the blocking signal. These relays do not have to be used as part of the existing protection scheme and therefore selectivity is not as significant parameter in their setting. They can therefore be configured to 'trip' (send the blocking signal) at lower overcurrents than they would normally be configured to operate on. They could therefore be configured to provide 'blocking protection' in excess of 80 % of the feeder length (as previously discussed in Section 2.2.6. This blocking type scheme does not necessarily require fast communications, so concerns over latency are not overly pressing in this instance. If the communications were to fail, the inverters would default to the original G59/2 settings, meaning the protection functionality would still be provided, albeit with an increased risk of sympathetic tripping. Internet availability is continuously increasing – the percentage of UK households with internet access has increased from 61 % to 77 % from 2007 to 2011 [135]).

Internet based technologies that can provide the low latency, high security (and in some cases, deterministic latencies over packet-switched networks) required in protection applications are already available e.g. IP/MPLS [136-138]. IP/MPLS provides a connection orientated deterministic service which improves on the nondeterministic behaviour of traditional IP and Ethernet packet communication. The drawback of the IP/MPLS solution suggested in [136] is that it requires a private communication medium and standard enterprise routers are not capable of implementing IP/MPLS. This is not an obstacle in HV power system applications where it becomes cost effective to install a private communication infrastructure employing IP/MPLS capable routers but it does mean that IP/MPLS could not be used presently at the household level using existing household routers, but costs are continually reducing and market players such as Alcatel-Lucent are already promoting offerings based at LV smart grid applications [139, 140]. IP/MPLS could also become more economically viable as a solution to sympathetic tripping if it was implemented as a large network used for distribution and substation automation, fault and protection management, system management, smart metering, etc., in addition to the blocking scheme proposed in this chapter, as shown in Figure 69.

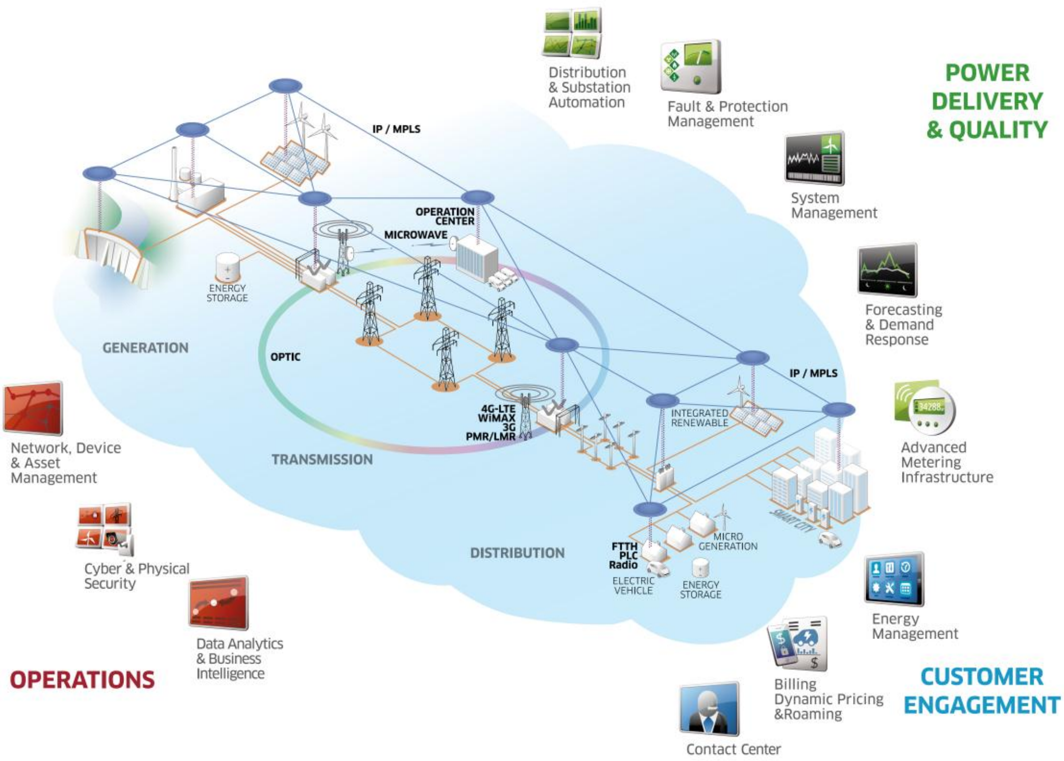


Figure 69: Potential for IP/MPLS in power system communication [141]

For households without an internet connection, alternative forms of communication could be used. Remote household energy monitoring and control is already being employed in smart metering and demand side management schemes. It is possible that this technology could be used for the purposes of controlling inverter undervoltage protection operation. There are several different communication technology that are used for transferring information between the smart meter and the point of central data processing/collection – Wi-Fi, GPRS (General Packet Radio Service), zigbee, power line carrier and bluetooth are some examples. There are also universal metering interfaces [142] available that are capable of interfacing meters to multiple communication protocols via peripheral devices. Further research would be required to determine if these forms of communication protocol could meet the requirements of the blocking scheme proposed in this chapter. This is investigated in more detail in the following section.

5.4.2.1 Laboratory testing of IP/MPLS communication system latency

Many of the criteria that are normally significant for communication systems are not as critical for the blocking scheme proposed in this chapter. For example, laboratory tests at the University of Strathclyde have demonstrated that latency associated with communications of greater than 6 ms can cause problems for some models of differential protection relay normally applied at transmission levels. In contrast, it is suggested that the blocking scheme proposed in this chapter could have a latency of significantly longer without the integrity of the protection scheme becoming severely compromised. G59/2 undervoltage protection operates on a timescale of 0.5 s to 2.5 s (dependent on the magnitude of undervoltage). It is probable that a marginal delay on this operation time due to latency in the blocking scheme would not adversely impact the inverter or the operation of the network protection scheme.

The laboratory setup for testing the latency of the IP/MPLS communication system is shown in Figure 70. The power system model used in the laboratory test is shown in Figure 71 – this is a simplified version of the rural/urban network used for the sympathetic tripping investigation in Chapter 4.

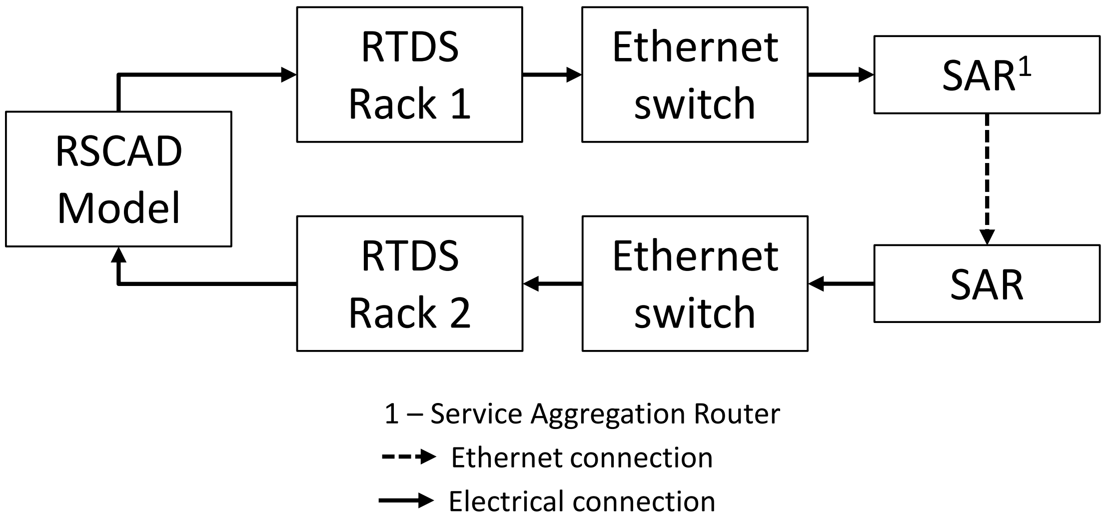


Figure 70: Laboratory configuration for IP/MPLS latency

The RSCAD (Real Time System Computer Aided Design) model runs on the RTDS (Real Time Digital Simulator) simulator and the RTDS simulator interfaces with hardware (e.g. control and protection devices) in real time through the I/O channels on the RTDS rack hardware. The SARs route the GOOSE (Generic Object Oriented Substation Event) data packets and add the IP/MPLS labels as discussed in Chapter 2. In an actual system, these routers would be the first in a chain of routers between the source and destination(s). SAR 1 in this case is the LER (Label Edge Router) and SAR 2 is the EN (Egress Node), there are no LSRs (Label Switching Routers) in this idealised network.

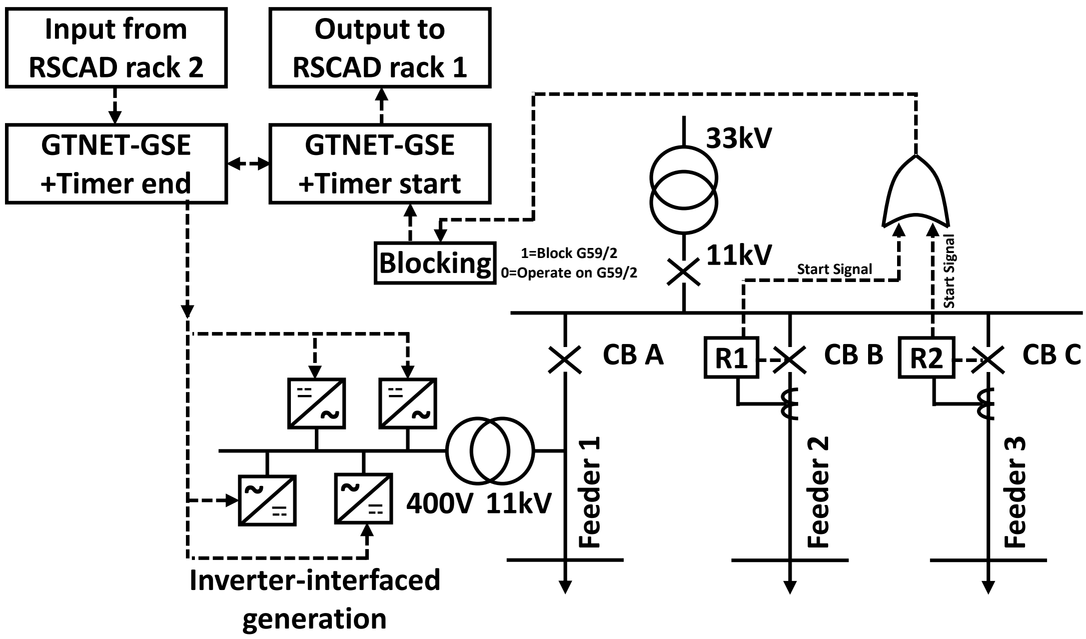


Figure 71: RSCAD model for testing IP/MPLS communication latency

The RSCAD model in Figure 71 contains two 11 kV feeders from a 33 kV grid infeed. When an overcurrent is detected on Feeder 2 a blocking signal is sent to the inverters stopping them from operating on undervoltage protection. When the overcurrent is no longer detected the blocking signal stops and the inverters are configured to return to G59/2 undervoltage protection behaviour. As discussed in Chapter 4, this ensures that the inverters do not operate for an undervoltage on the parallel feeder, but do operate when there is a fault on the feeder to which they are connected.

The RSCAD model also contains conversion blocks that generate GOOSE communication using the GTNET (Giga-Transceiver Network Communication Card) hardware as shown in Figure 72 [143]. The GPC (Giga-Processing Card) connects to the RTDS through a GTIO (Giga-Transceiver Input Output) port. GOOSE is a control model used in substation control networks. The final part of the RSCAD model is the timer. The timer begins counting when the CB opens and the blocking signal from CB B stops being sent. The timer stops counting when the signal travels around the communication loop (i.e. via the RTDS racks, ethernet switches and SARs shown in Figure 70) and is converted back from GOOSE to a blocking signal into the simulation using the GTNET hardware.

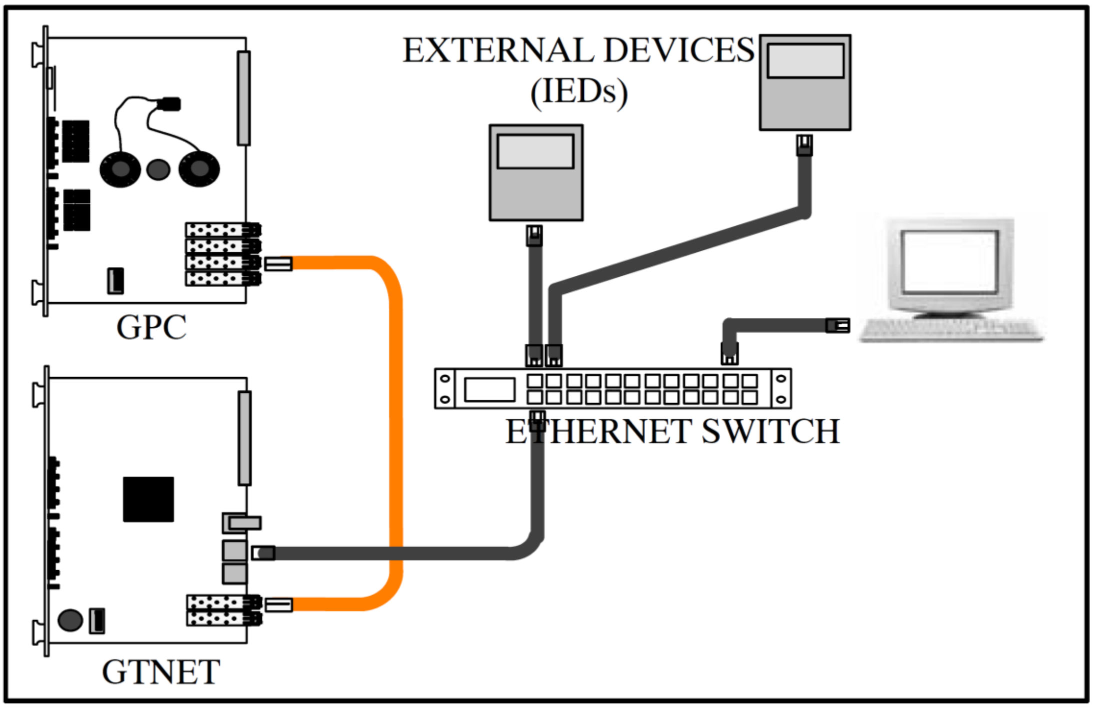


Figure 72: GTNET card connecting to RTDS through GPC [143]

The test results demonstrated a total latency of 1.5 ms as shown in Figure 73 and Figure 74. The fault was applied at 0.3 s and using the same protection settings as in Chapter 4, the overcurrent protection operated with a delay of 0.65 s. The latency between fault detection and the blocking scheme change of state propagating through the communication system was observed to be 1.5 ms. The relay has a latency of 50 ms between overcurrent detection and the 'start signal' being generated [144]. In a teleprotection application, the total latency is the contribution of telecom network latency and teleprotection equipment time. Telecom network latency is the contribution of router packetisation, network and router jitter buffer delay (discussed in more detail in Chapter 2).

In this laboratory experiment, the latency is the contribution of telecom network latency, the processing of the RTDS GPC and processing of the RTDS GTNET cards. The telecommunications network latency is variable and changes with the magnitude of the payload (the amount of data assigned to each packet before it is sent) and the amount of jitter [51]. However, as no jitter is being introduced into the communication link, and the payload size is pre-set at 2 Octets, then packetisation and jitter buffer delay are unlikely to be in excess of 0.25 ms [51]. The communication link is a short dedicated Ethernet cable and is unlikely to contribute significantly to total latency [51].

The laboratory setup utilises two GPCs and two GTNET cards as illustrated in Figure 71 and Figure 72. Each card contributes to overall latency.

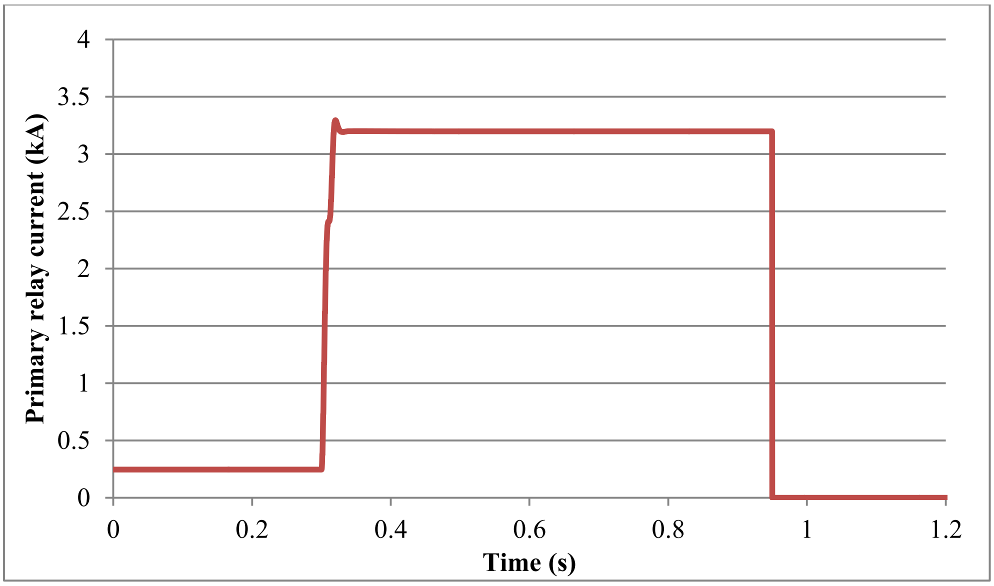


Figure 73: RMS primary relay current (kA)

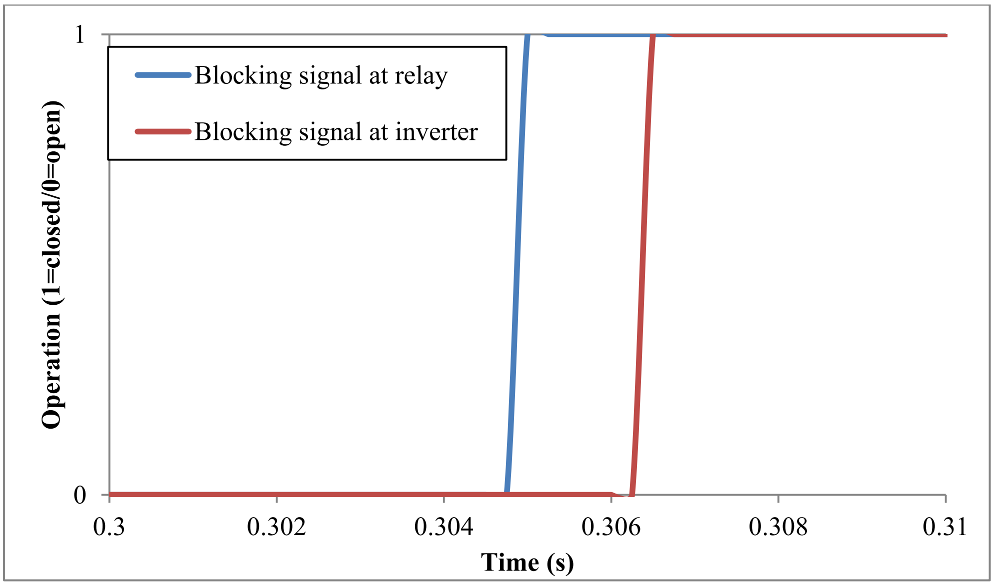


Figure 74: Breaker and blocking scheme operation time

Figure 75 and Figure 76 show the associated processing time of each RSCAD simulation block on the RTDS GPC, this processing time accounts for approximately 1.005 µs of delay. RTDS documentation [145] also provides an execution time for each simulation block and this agrees with the results shown in Figure 75 and Figure 76. Taking into account anticipated packetisation delay (0.25 ms) means that the majority of the delay is associated with processing within the GTNET cards (~1.1 ms).

Protection relays employing GOOSE messaging are likely to exhibit similar levels of latency to the RTDS operation delay recorded in this test. This assumption can be made on the basis that they employ a dedicated OS (Operating System) with comparable latency to the RTDS and a IEC61850 stack for generating GOOSE messages that has a comparable latency to the GTENT cards [146]. The latencies recorded in this test are within the requirements of the standards relating to IEC61850 communication; the most stringent standards relating to IEC61850 require a latency of less than 3 ms [147, 148]. The recorded latency is also well within the expected latency requirements of most teleprotection schemes (4-6 ms) [15].

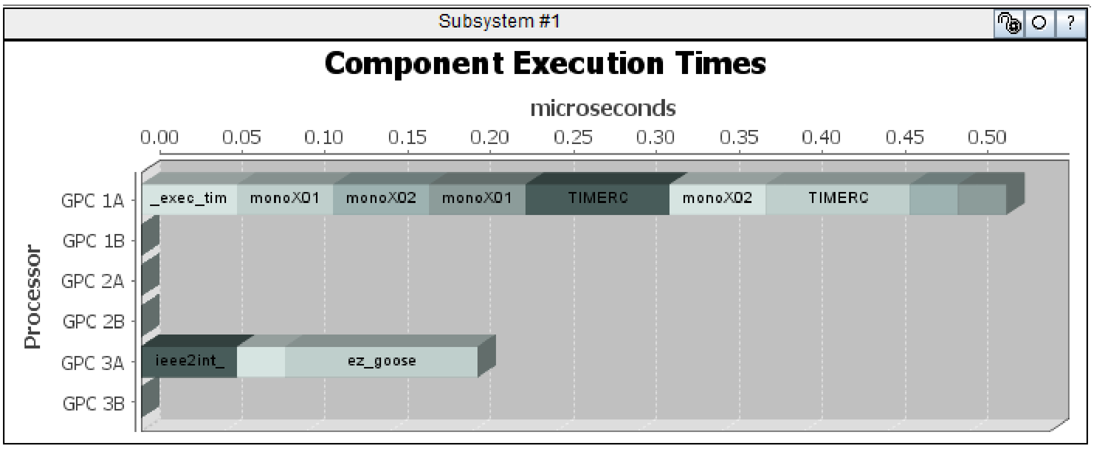


Figure 75: GPC latency – outbound from electrical system simulation

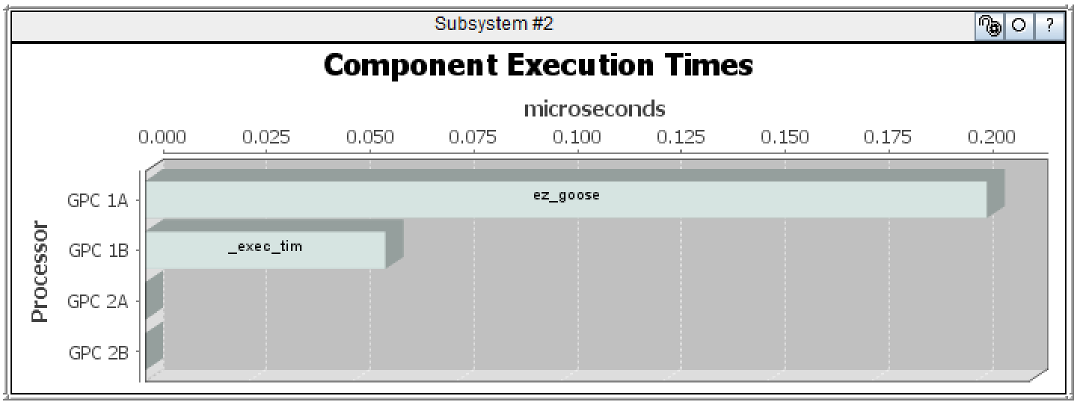


Figure 76: GPC latency – inbound from electrical system simulation

The communication network tested in Figure 70 is an idealised scenario, in that the communication link between the SARs is a dedicated Ethernet cable. In a 'real-world' scenario, the communication link would not be a dedicated cable and is more likely to be via a multi-hop network with shared traffic, with the consequence that there will be a reduction in available bandwidth and a potential increase in latency. Typically a protection scheme would employ a dedicated communication network or a rented communication channel with fixed limitations on available bandwidth. In the scheme proposed in Chapter 4, it is suggested that the blocking scheme could use the internet as the communications vehicle.

To evaluate the impact of decreasing communication bandwidth on protection scheme operation, the laboratory test shown in Figure 77 was performed. The bandwidth of the LSP was controlled via SAR 1. The bandwidth of SAR 1 was reduced from 2 MB/s to 1 MB/s in increments of 0.1 MB/s. The differential protection scheme entered an error state when the bandwidth fell below 1.5 MB/s. It should be noted that this is extremely unlikely to happen in a properly configured protection scheme. Teleprotection traffic would be labelled as high priority traffic and if there were a reduction in available bandwidth (e.g. as a result of congestion and/or communication link failure) it would be the lower priority traffic that would be delayed, not the high priority traffic. The communication scheme should be designed so that there is always enough available bandwidth for the maximum possible amount of high priority traffic.

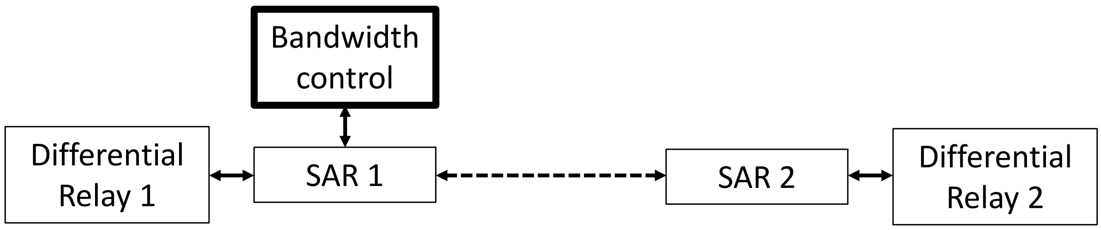


Figure 77: Impact of decreasing communication bandwidth

5.5 Chapter summary

In the first part of this chapter, the transition points at which sympathetic tripping occurs in terms of protection settings, inverter capacity and inverter fault behaviour have been identified. The effectiveness of changing protection settings, protection relay characteristic curves and G59/2 settings to prevent sympathetic tripping occurring has been evaluated. The undervoltage protection settings of G59/2 exist so that inverters do not continue to supply loads at a voltage outside normal operating conditions during a sustained undervoltage. The impact on generators and loads needs to be considered extensively before any changes are made to the present undervoltage protection settings.

In the second part of this chapter, two solutions to the sympathetic tripping problem are investigated. Changing protection settings and G59/2 standard requirements are evaluated as solutions to stop the occurrence of sympathetic tripping. Changing protection and G59/2 settings are shown to reduce, and in some cases stop, the occurrence of sympathetic tripping. However, modifying these settings can lead to a loss of protection coordination within the protection scheme, and changing G59/2 settings could potentially have a detrimental impact on the DG and inverter operation. The second proposed solution is a communication based blocking scheme that will prevent the inverter from operating on undervoltage protection during the appropriate conditions. IP/MPLS communication is evaluated as a candidate technology for this scheme, and is shown to meet the latency requirements of both standard teleprotection and the blocking scheme proposed in this chapter. This form of communication based blocking scheme could stop the occurrence of sympathetic tripping but may not be cost effective to apply unless it is incorporated into a larger communication network.

Chapter 6 Protection optimisation solution in the presence of variable amounts of distributed generation

The main premise of the solution presented in this chapter is that mitigation of risks to network protection performance from introduction of DG can be achieved if the speed of operation of the network protection is improved, without losing coordination and/or provision of backup. The key contribution of this chapter is the development and demonstration of a technique that can optimise network protection settings to minimise cumulative main and backup protection system operation times for all relays in a section of network. Case studies using variable numbers of DG units connected to the IEEE 14 and 30 bus distribution networks [70] are used to illustrate performance. The outcome of the chapter is a systematic method for optimisation of network protection settings to cater for a variety of DG penetration levels. It is demonstrated that improvements in cumulative main relay operation time of up to 42 % can be achieved on the IEEE-30 bus network.

6.1 Proposed protection coordination approach

In this chapter, the objective is to calculate the optimum values for the *TMS* (Time Multiplier Setting) and the I_p for each relay under varying penetration levels of DG. Furthermore, each relay's operating characteristic is optimised in order to minimise the cumulative operation time for all the relays in the network. The relay characteristics available include: standard, very and extremely inverse; and long-time standard earth fault (*SI, VI, EI* and *LTSEF*) [15]. The cumulative operating times are considered under both main and backup operation modes. There are a number of operational constraints, detailed later in this section, which must be obeyed by the optimiser. The objective function for the problem is shown in (1).

$$objective = \min \sum T_{ijk} \quad (1)$$

Where T_{ijk} indicates the operation time of relay R_i for a fault in location j and for DG configuration k, that is, a particular scenario where a number of DG units are connected at certain system locations. The individual operation times for every fault location are then added to give the total time. The ranges for i and j are obviously different for the 14 and 30 bus networks, while k is fixed for both case studies and represents one of the 8 DG configurations analysed. The constraints that must be considered in the optimisation study are described in the following sections.

6.1.1 Relay grading margin

The grading margin is the time delay between the operating time of the "local" relay, i.e. the closest relay to the fault in the direction towards the source of fault current, and the next "upstream" relay (i.e. the backup relay) operating in the event of the main protection failing to operate for some reason. The equation below defines the constraint relating to the grading margin between relays.

$$T_{njk} - T_{ijk} \geq \Delta T \tag{2}$$

Where T_{njk} is the operation time of relay R_n in backup mode for a fault in location j and for DG configuration k. ΔT is the relay grading margin between relays and is assumed to be 0.3 s, this is a typical grading margin for modern digital and numerical relays [15].

6.1.2 Limits on relay settings and operation times

The equations below define the limits on protection settings and relay operating time.

$$TMS_{i_{\min}} \leq TMS_i \leq TMS_{i_{\max}} \tag{3}$$

$$I_{pi_{\min}} \leq I_{pi} \leq I_{pi_{\max}} \tag{4}$$

$$T_{ijk_{\min}} \leq T_{ijk} \leq T_{ijk_{\max}} \tag{5}$$

In the above equations, TMS_i is the time multiplier setting, I_{pi} is the pickup current and T_{ijk} is the relay operating time. The minimum time multiplier is defined as 0.1 and the maximum as 3.2, this is consistent with [144]. The minimum pickup current is defined as twice the maximum load current, while the maximum pickup current is 25 times the maximum load current [144], although in practice, the actual settings applied will normally be well within these limits. These limits have been selected to accommodate normal load conditions and temporary overloads experienced due to transient conditions such as motor startup. The minimum relay operating time is defined as 0.02 s [149] and the maximum as 2 s (this is consistent with UK DNO requirements).

6.1.3 Relay characteristics

The protection devices used in this study are directional overcurrent relays. Due to the meshed network architecture directional relays were chosen in order to simplify the protection coordination configuration. If non-directional relays were used the number of relays that could potentially operate for the same fault would increase and coordinating the settings to ensure appropriate relay coordination would become more difficult. As part of the optimisation study the relays can be assigned a time-current characteristic from a choice of four [15]. The equation for the time-current curve is given below:

$$T_{ijk} = TMS_i * \frac{A}{I_r^{\ B} - 1} \tag{6}$$

$$I_r = \frac{I_{SC}}{I_{pi}} \tag{7}$$

Where T_{ijk} is the operating time in seconds referring to the relay R_i for a fault location j in the DG configuration k. TMS_i is the time multiplier setting of the relay R_i and is assumed to be continuously variable between 0.1 and 3.2. I_{sc} is the short circuit fault current flowing through relay R_i because of fault at location j. I_r is the multiple of relay current setting (in terms of multiples of the relay pickup current I_{pi}). A and B are constants that define the protection characteristic

The values of the constants A and B are shown in Table 24 for each of the four available relay characteristics [15]. The optimiser can be configured to establish a single optimum characteristic to be applied collectively to all relays, or it can find the optimum characteristic for each relay on an individual basis. The relay characteristics are presented graphically in Figure 78.

Table 24: Time-Current Curves

Curve	A	B
SI	0.14	0.02
VI	13.5	1
EI	80	2
LTSEF	120	1

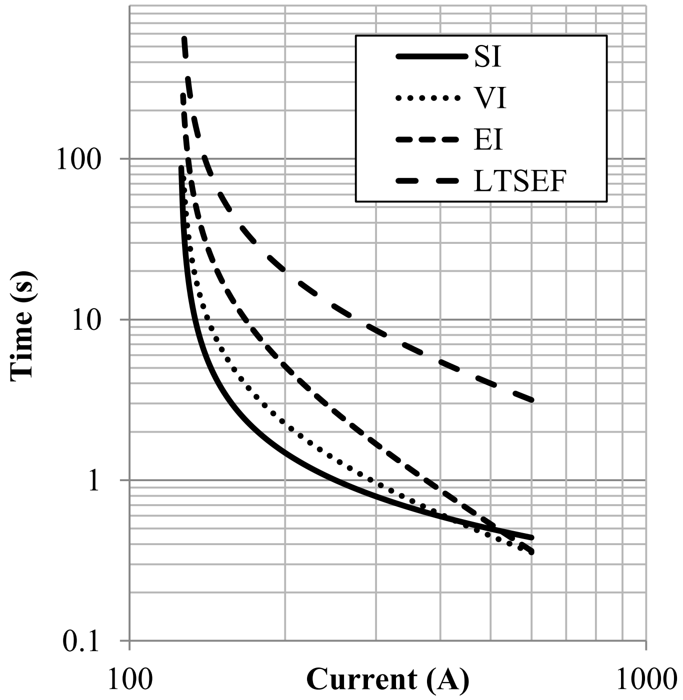


Figure 78: Alternative relay characteristics

To cater for the inclusion of different protection characteristics in the problem formulation, a binary variable is included in the problem definition – x_l. The A and B constants for each relay R_i are defined as the sum of each discrete variable multiplied by the binary variable as shown in (8) and (9) below:

$$A_i = 0.14x_{1_i} + 13.5x_{2_i} + 80x_{3_i} + 120x_{4_i} \tag{8}$$

$$B_i = 0.02x_{1_i} + 1x_{2_i} + 2x_{3_i} + 1x_{4_i} \tag{9}$$

Equations (8) and (9) can be re-expressed as follows:

$$A_i = \sum_l A_l x_{l_i} \tag{10}$$

$$B_i = \sum_l B_l x_{l_i} \tag{11}$$

Where A_l and B_l are the relay characteristic values for protection characteristic l, and x_{li} is equal to either 0 or 1.

Each relay should be assigned only one protection characteristic (i.e. only one x_l can be equal to 1 at any one time, with the other three being zero), this is achieved by applying the constraint as stated in (12).

$$\sum_{l} x_{li} = 1 \tag{12}$$

6.2 Power system details and optimisation implementation

The optimisation method has been applied to the distribution part of the IEEE-30 bus system, shown in Figure 79. This system has been modelled using both Matlab [150] and PSCAD [151] for comparison and verification of output results. The generator, transformer and transmission line data used in the models is available from [70]. In related literature [132], short circuit currents measured by each protection device have been calculated for faults at the midpoint of each feeder and have been used to calculate the protection device operation times and to carry out relay coordination calculations. Other coordination techniques use maximum fault currents to establish minimum protection operating times and to calculate settings; however, in this case the midpoint has been chosen to calculate the median fault current. This is more reflective of average protection operation times (as opposed to minimum times) and therefore allows the benefits of the optimiser to be more realistically stated. Maximum load currents have been used to define the minimum pickup current settings for each relay and these are used as constraints in the optimiser.

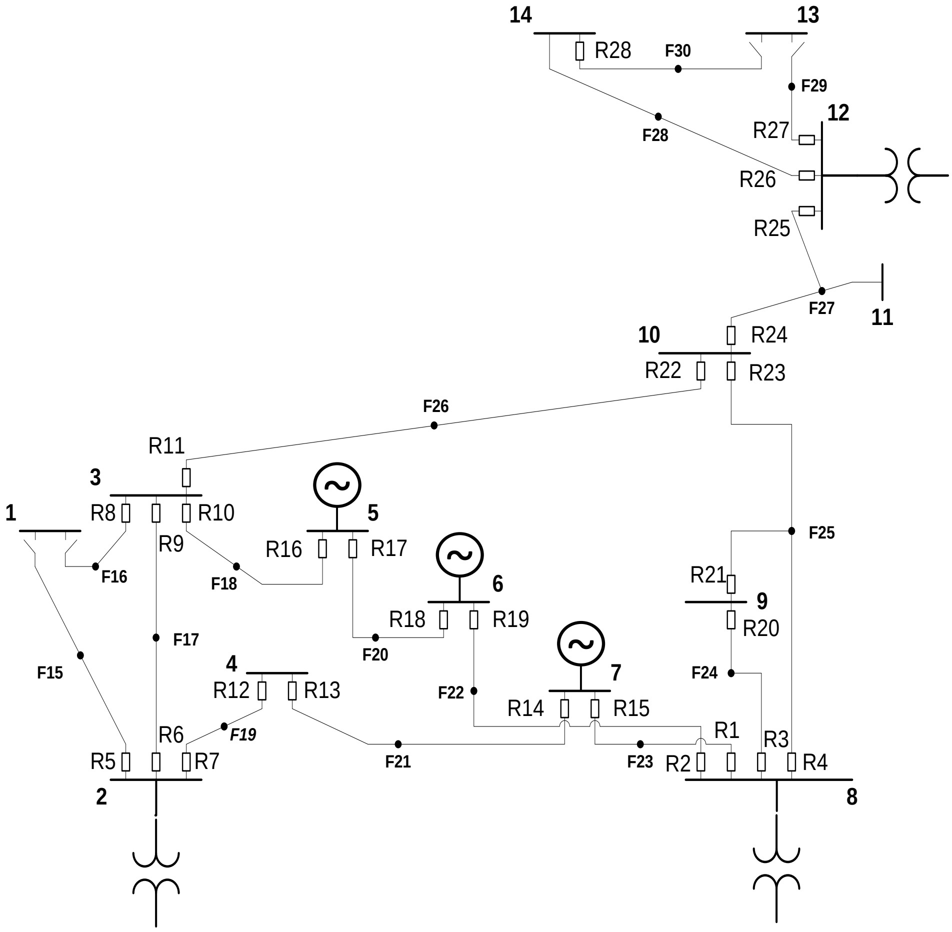


Figure 79: IEEE-30 bus distribution system - DG at buses 5, 6 and 7 [70]

The short circuit currents corresponding to all fault and relay measurement locations are calculated using the network data available from [70] and the positive sequence bus impedance matrix method [152]. Matlab has been used to execute these calculations and the results have been verified using the PSCAD power system modelling software. The error between the two methods has been found to be negligible (less than 0.005 % for all fault locations). Following calculation, the fault currents are uploaded in to the GAMS (General Algebraic Modelling System) [153] optimiser. Case studies 1 and 2, reported later in the chapter, consider situations where there is no DG and where DG is fixed at certain locations. Case study 3 considers different configurations of DG and therefore employs variable *k*, this adds a greater degree of complexity to the optimisation problem.

6.2.1 GAMS optimiser

GAMS is a high level modelling system for mathematical programming and large scale optimisation [153]. GAMS is designed for solving large, complex optimisation problems [153], making it an ideal application for the problem investigated in this chapter. There are two stages involved in the implementation of all optimisation techniques: formulation of the problem and solving the problem. In GAMS the problem is formulated in an algebraic text based structure. Optimisation terminology differs between disciplines, the convention in GAMS is that: indices are called sets, given data is called parameters, decision variables are called variables and constraints and the objective function are called equations [153]. The key components of a GAMS model are shown in Figure 80.

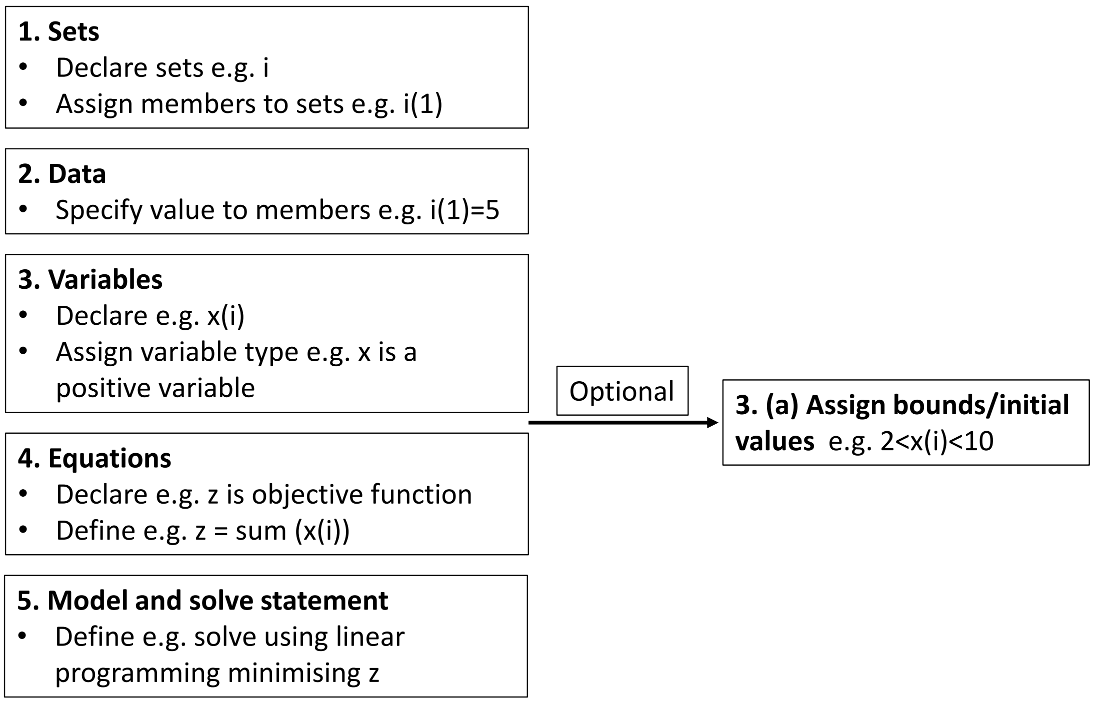


Figure 80: Key components of GAMS model [153]

1. Sets are the GAMS representation of algebraic indices. There are multiple ways of defining sets using the GAMS language, but all share the commonality that the sets and the members of the sets must be declared.
2. In GAMS data can be defined in three different ways: lists, tables or direct assignments. Each member of a set must have a value assigned to it.
3. Decision variable are not assigned values like members. They are instead quantities that GAMS will control (within given boundaries/constraints) to achieve the optimal solution for the objective function [154]. The objective function is a mathematical expression that combines one or more variables to express the goal of the optimisation. The objective function is either maximised or minimised based on the nature of the problem. Variables must

be assigned a type so that GAMS knows how to manipulate it. Examples of types include: positive (0 to + ∞) or negative (0 to - ∞).

   a. Bounds limit the range that GAMS can vary the value of the variables within. A properly bounded problem will increase the likelihood that the optimisation solver will be able to find a feasible solution because the 'search space' in which the solver has to look for a solution is smaller. A smaller search space will also improve the speed of the optimiser. Often a solver will start from the initial conditions of the variables when trying to find the optimal solution. The solver will then move from the initial conditions within the search space to find better solutions. In the same way that proper bounding improves the efficiency and effectiveness of the solver, if the initial conditions are defined so as to be close to the desired solution it will also improve the efficiency and effectiveness of the solver.

4. In the equations section of the problem formulation the equations are declared and the equation is defined with respect to the variables in the point (3).
5. The solve section defines what solver type should be used to solve the optimisation problem. The type of solver that can be used is defined by the type of optimisation problem that is being solved. A full list of GAMS solver types are listed below:
   a) Quadratic constraint programming
   b) Nonlinear programming
   c) Nonlinear programming with discontinuous derivatives
   d) Mixed integer programming
   e) Relaxed mixed integer programming
   f) Mixed integer quadratic constraint programming
   g) Mixed integer nonlinear programming
   h) Mixed complementarity problems
   i) Mathematical programs with equilibrium constraints
   j) Constrained nonlinear systems

Optimisation problems can be divided into two categories: constrained and unconstrained. In unconstrained problems the objective is to find the best (maximum or minimum) possible value of the objective function within the defined search space. In constrained optimisation the objective is still to find the best value but it has to be achieved within various constraints. The optimisation problem considered in this study is a constrained optimisation, it is also a MINLP (Mixed Integer Non Linear Programming) problem. Mixed integer means that some of the variables are real numbers and some of the variables are integer values [154]. In this study T_{ijk} is a real number variable and A and B are integer values. The optimisation problem in this case study is also nonlinear in that at least one of the equations is non-linear. In this case the relay operation time variable adds the non-linearity to the study due to the nature of the protection relay characteristic curves. Nonlinear problems are more difficult to solve than linear problems and therefore tend to increase the optimisation computation time of the solver [154]. In nonlinear problems it is also difficult to distinguish local solutions from global solutions [154]. This is particularly relevant to the study presented in this chapter because it makes it difficult to determine whether the solution generated by the solver could be improved with different starting points, bounds or greater solver computation time.

6.2.2 BARON solver

The BARON (Branch And Reduce Optimisation Navigator) [155] solver is used to obtain the optimal relay settings. This solver is one of the MINLP [155] solvers in GAMS. The other MINLP solvers available in GAMS were evaluated for their ability to solve the optimisation problem, however, Baron was consistently found to be the most successful at finding feasible solutions to this particular problem. The BARON solver is a branch-and-reduce optimisation navigator which is a subtype of the branch-and-bound optimisation technique. The branch and bound technique is based on the fact that the list of possible integer solutions in an optimisation problem has a tree structure [156]. Figure 81 shows all possible solutions for a three variable optimisation problem where each variable can have a value of 1 or 0. The nodes on the far right represent possible solutions which could be either feasible or infeasible. The intermediate nodes represent incomplete solutions e.g. at node a, $y1$=0 while $y2$ and $y3$ have not yet been assigned values. The goal of the branch and bound technique is to only grow branches that display potential, in terms of leading to a feasible solution. The solver does this by estimating a limit on the best value that can be achieved if a node were to be extended into a branch. Nodes (or descendants of the node) that are found to be infeasible or non-optimal are discarded. Branch-and-bound solvers differ in how they decide which nodes to extend into branches, how they decide on the next variable in a branch, and on which nodes they choose to discard and when they choose to stop trying to improve on the existing “best” solution. BARON’s branch-and-reduce technique employs range reduction tests at each node of the tree to reduce the search space of the optimisation. The branch-and-reduce technique also applies a heuristic method to reduce the limits on problem variables and applies compound branching techniques to increase the efficiency of the branching method. As the BARON optimisation technique focuses on reducing the search space of the problem (i.e. limiting unnecessary branching of the tree) it is referred to as ‘branch-and-reduce’ rather than ‘branch-and-bound.’ A more thorough explanation of how BARON solves using the branch-and-reduce method is available in [155]. The next section presents the simulation results for both of the systems under study.

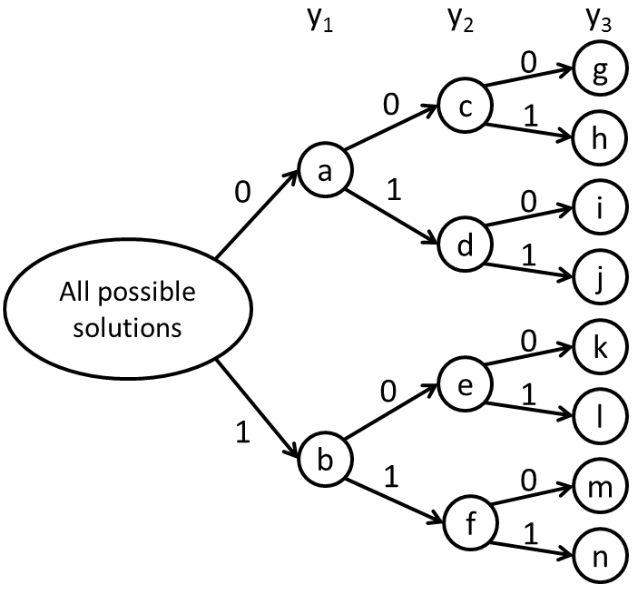


Figure 81: Branch and bound optimisation technique

6.2.3 DG model

When the fault current is calculated with DG connected to the network, the DGs are modelled as ideal voltage sources with a series reactance. This series reactance represents the DG’s source reactance and the DG transformer’s positive sequence leakage reactance. In this study, the values of source reactance and transformer reactance are set to 5 % and 9.67 % respectively. These values give rise to a fault level of 34.08 MVA and are typical for a synchronous generator of 5 MVA output capacity connected at 33 kV [157].

In this study a synchronous generator model of a DG was chosen over an inverter-based model. While inverter-interfaced DG will be more common than synchronous machine based DG in the future, synchronous generators provide a relatively higher fault contribution and therefore have a larger potential impact on network protection performance than inverter-interfaced DGs. Accordingly, to provide a more exacting test of the network protection performance and consequently of the performance of the optimiser, synchronous DG have been employed.

6.3 Simulation results

Five scenarios have been investigated as summarised in Table 25 below, the results of the five cases are summarised in Table 26 at the end of this chapter. The base case, against which the first and second case studies are compared, uses protection settings (pickup current (I_p) and *TMS*) that have been calculated by the optimiser, but all relays are constrained to use the same protection characteristic curve shape of the four available choices. Comparing case studies 1 and 2 to the base case demonstrates how including the choice of protection relay characteristic as an option within the optimiser can result in a significant improvement in protection scheme operation time. The first case study considers the improvement in protection operating times if each relay is permitted to have a different operating characteristic (e.g. SI, VI, etc.) with no DG connected to the network. In this case study both protection settings and the relay characteristic curve shapes are optimised. The second case study optimises relay characteristics and settings (as in case study 1) but also considers the impact on protection operating time when DG is added to the power system with a fixed connection/capacity. Finally, case study 3 reflects the situation where protection settings and characteristics are optimised to accommodate multiple alternative DG configurations, which is representative of emerging and future actual situations that are being, and will be, encountered.

Table 25: Simulated scenarios

Case Study	Constrained/optimised relay characteristic (curve "shape")	DG connected to network
Base case 1	Constrained	None
Base case 2	Constrained	Fixed amount
1	Optimised	None
2	Optimised	Fixed amount
3	Optimised	Variable amount

6.3.1 Case study 0: Relay characteristics constrained and fixed DG connected to the network

In case study 0, the impact of adding DG to the network (while optimising relays that are constrained to have the same characteristic) is investigated. Figure 82 shows a comparison between main protection operation times on the 30 bus network. In base case 1 the relay characteristic is constrained to one type and no DG is connected to the network. In base case 2 the relay characteristic is constrained to one type and DG is connected at buses 5, 6 and 7. In both cases the optimiser selects the SI characteristic to be applied to all relays. The cumulative main protection operation time of base case 1 is 14.76 s and base case 2 is 14.04 s. The cumulative backup protection operation time of base case 1 is 49.94 s and for base case 2 is 51.48 s. The additional complexity added to the optimisation by the introduction of the DG units has increased the total protection operation time (main and backup) by 0.8192 s.

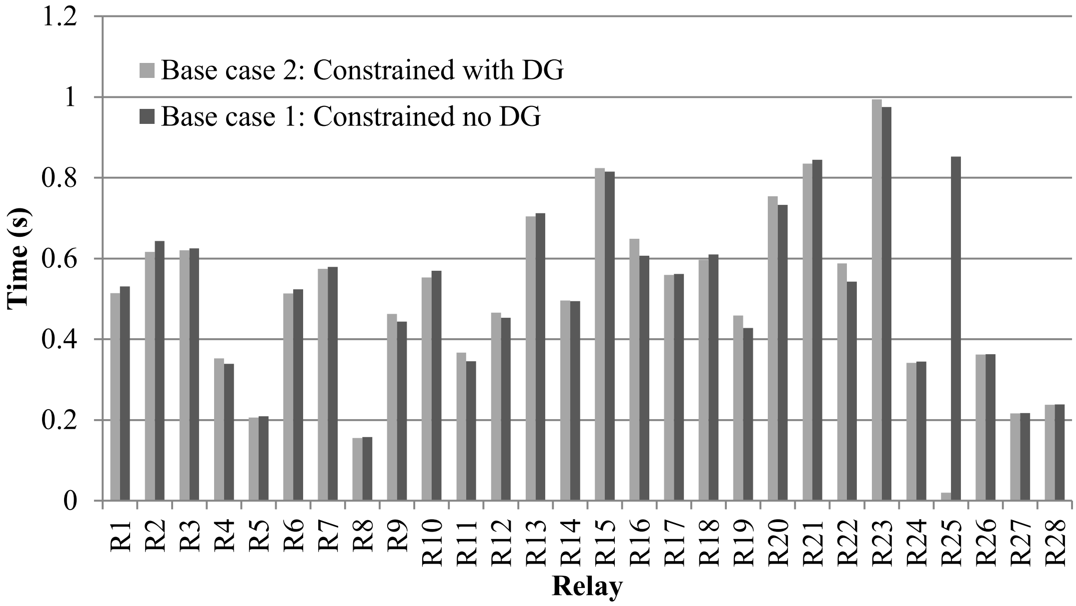


Figure 82: Main relay operation times, constrained relay characteristic, fixed DG, modelled on 30 bus network

6.3.2 Case study 1: Relay characteristic optimised and no DG connected to the network

In case study 1, the impact of allowing relays to have different protection characteristics is investigated. Figure 83 shows the improvement in individual relay operating times for the IEEE-30 bus system when compared to relays that are constrained to all possess the same protection characteristic (i.e. base case 1). The times in Figure 83 are the main relay operations times, the total protection operation time would include the breaker operation time. Breaker operation times vary based on the breaker technology, modern vacuum circuit breakers can open in less than 0.1 s while oil immersed circuit breakers can take up to 0.55s [15]. In the base cases the optimiser selects the SI characteristic for all protection relays. In case study 1 the relay characteristic selection varies between relays. In this case study the optimiser assigns thirteen relays the SI characteristic, four relays the VI characteristic, eleven relays the EI characteristic and no relays the LTEF characteristic to achieve the lowest total time.

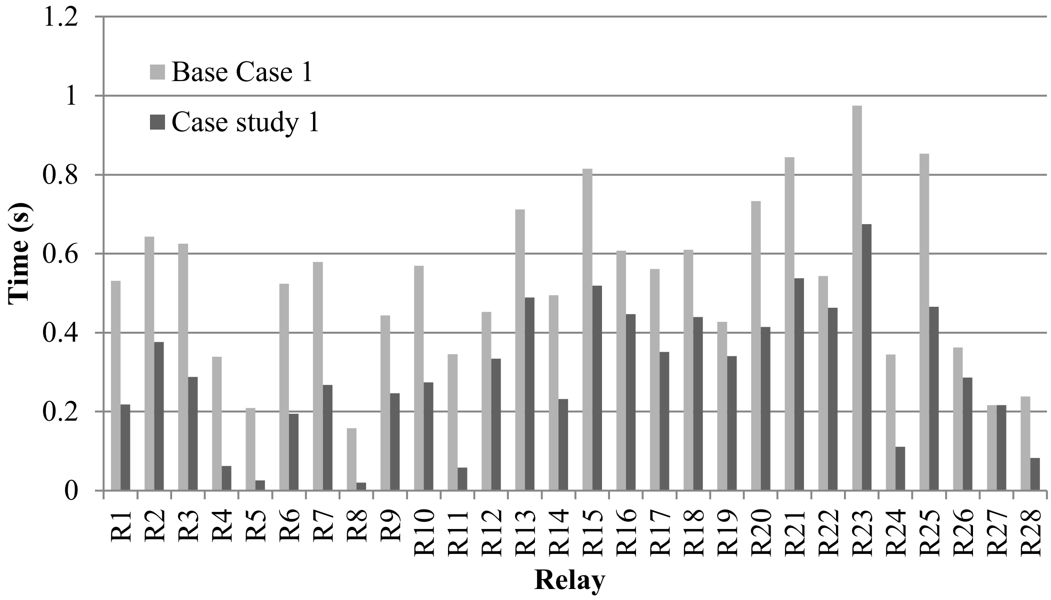


Figure 83: Main relay operation times, optimised relay characteristic, no DG, modelled on 30 bus network

In Figure 83 it can be observed that for every relay (with the exception of R27), allowing variable protection characteristics improves the individual protection operation times (with no constraint violations). The cumulative main protection operation time when optimised using variable characteristics is 8.44 s (improving on 14.76 s for base case 1). The cumulative backup protection operation time is 35.05 s for the optimised case (improving on 49.94 s for base case 1).

6.3.3 Case study 2: Relay characteristic optimised and DG connected to the network at buses 5, 6 and 7

In this case study, the impact of DG on the protection operating time is investigated and the settings and characteristics are optimised to take this into account. Figure 84 shows the improvements in relay operating times compared to base case 2.

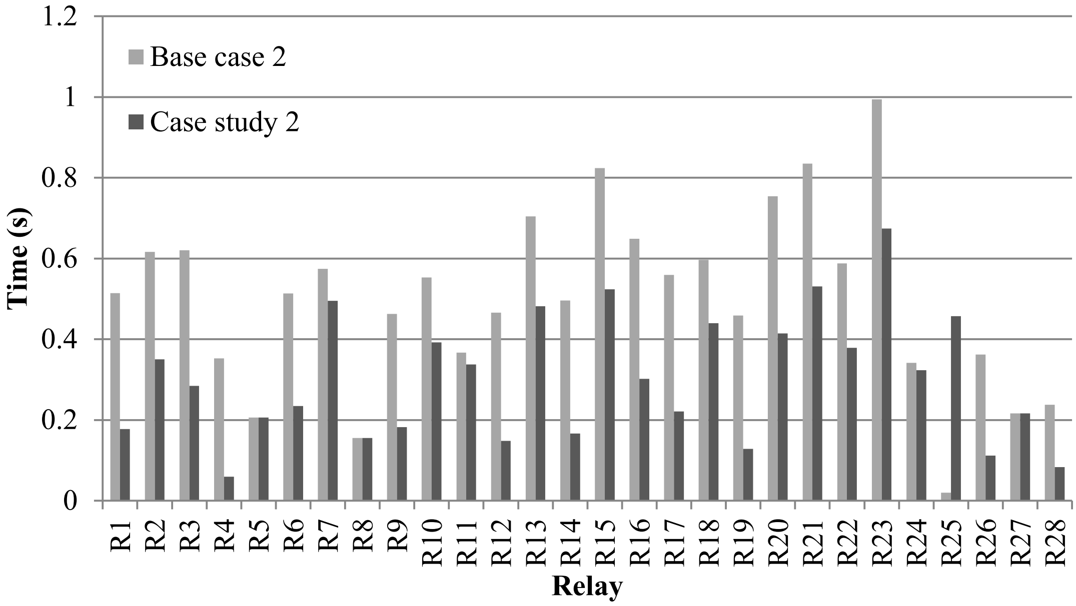


Figure 84: Main relay operation times, optimised relay characteristic, DG at buses 5, 6 and 7, modelled on 30 bus network

In this study adding DG and allowing a variable characteristic for relays results in a cumulative main operating time of 8.47 s (base case 2: 14.04 s) and a cumulative backup relay operating time of 35.67 s (base case 2: 51.48 s). When compared to case study 1 (no DG), the addition of DG has resulted in an increase in the cumulative protection time of only 0.03 s, so the optimiser has preserved excellent protection performance.

6.3.4 Case study 3: Variable amounts of DG connected to network

In the previous section the objective of the optimisation was to achieve the fastest relay operation times with DG connected and assumed to be always in service at buses 5, 6 and 7. In actual situations, DG will not be fixed in terms of its availability, and protection systems must be able to cope with intermittent generation at different locations. If protection settings are optimised for only one DG configuration, then they may not remain optimal when the amount of DG in service changes. This is demonstrated in Figure 85, which depicts the grading margin between relays. The grading margin should ideally be 0.3 s (or greater within acceptable limits but never less). The black line in Figure 85 shows the grading margin between main and backup relays when the protection settings are optimised for DG connected at buses 5, 6 and 7. In Figure 85, constraint 1 represents the grading margin between relay 1 and one of its back-up relays – in this case relay 19; constraint 2 is the grading margin between relay 1 and another of its back-up relays – relay 20; this continues for all relays on the 30 bus system (there are 28 relays in total, numbered from 1 to 28, and several of them have more than one associated back up relay, hence the fact that there are 48 constraints). The shaded area above and below the black line represents the maximum and minimum change in grading margin when the protection settings are retained, but DG availability is varied (i.e. case study 3). For example, at constraint 14, as shown in the zoomed element of Figure 85, the grading margin between the main and backup relay for a particular DG configuration is only 0.1837 s, which is much lower than the 0.3 s required for protection relay discrimination and would present an unacceptable risk of protection maloperation.

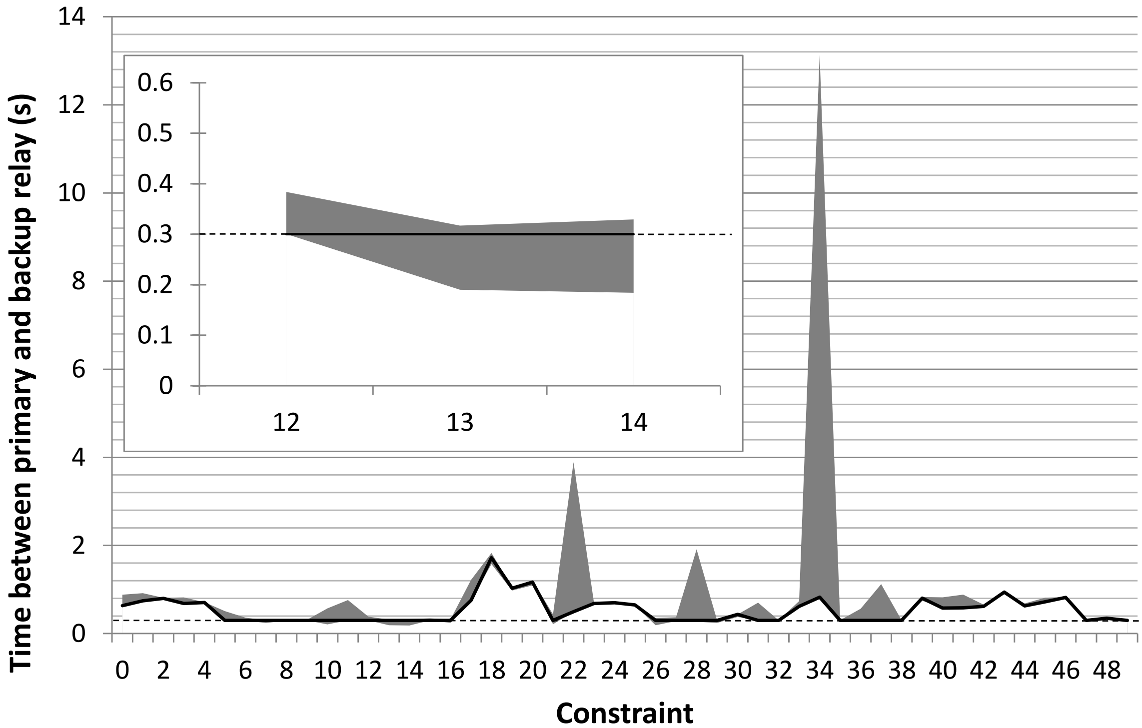


Figure 85: Varying DG availability – constraint violation

Figure 85 demonstrates the need for protection settings that are valid for all possible DG configurations and shows that, with fixed settings and variable DG availabilities, grading margins will vary, in some cases across a very wide range (e.g. from less than one second to more than 12) and in some cases, the minimum grading time (in this case 0.3 s) is violated. To address this, the optimisation was re-executed with DG at buses 5, 6 and 7. In this case the optimiser was configured to find the best group of settings for all possible variants of DG configuration/availability when DG are connected at buses 5, 6 and 7. The resulting protection operation times, when optimising with the objective of establishing a single group of settings best suited for all of the aforementioned variants, are shown in Figure 86.

Each column in Figure 86 and Figure 87 represents a different DG configuration e.g. 000 denotes that DGs are not connected to any buses, 007 means DG is only connected at bus 7, while 567 indicates that DG units are connected at buses 5, 6 and 7, etc. The furthest right column refers to the average protection operation time when the protection settings are optimised for all possible DG configurations. The relay settings are optimised for each particular DG configuration in the first eight columns of Figure 86 and Figure 87.

In the final example (the rightmost column on Figure 86), the optimiser has the goal of providing a group of settings that will cater for *all* variations in DG connection, not just for one configuration. It is clear that the settings that are valid for all configurations give cumulative main relay operation times that are not significantly different to those produced by the settings optimised for specific amounts of DG (in fact, in some cases, the performance is better than for specifically optimised settings). The reason that the main time is approximately the same in the 'most difficult' rightmost column when compared to the 'easier' scenarios (in the first eight columns) is because the speed of backup protection has been sacrificed. Increases in backup time of between 2-4 s can be seen in Figure 87. The averaged cumulative main relay operation time (averaged across all eight scenarios, each incorporating different DG amounts) is faster than the base case scenario, with an averaged cumulative main relay operation time of 8.64 s (base case: 14.76 s) and an averaged backup relay total time of 39.27 s (base case: 49.94 s).

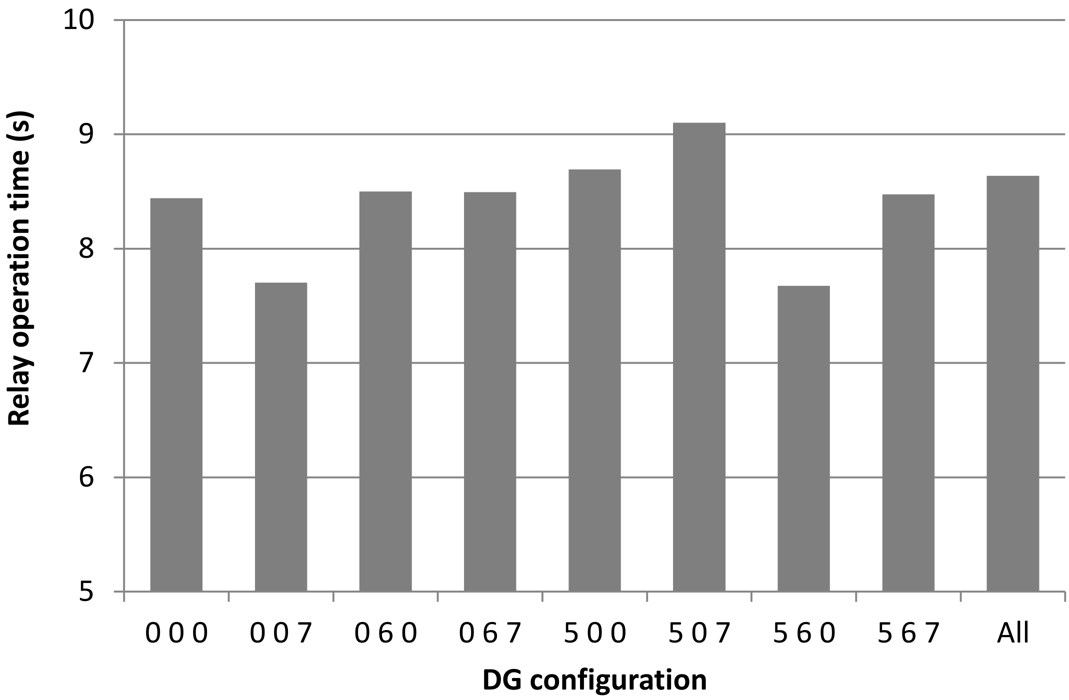


Figure 86: Cumulative main relay operation times, optimised relay characteristic, variable amounts of DG at Buses 5, 6, 7, modelled on 30 bus network

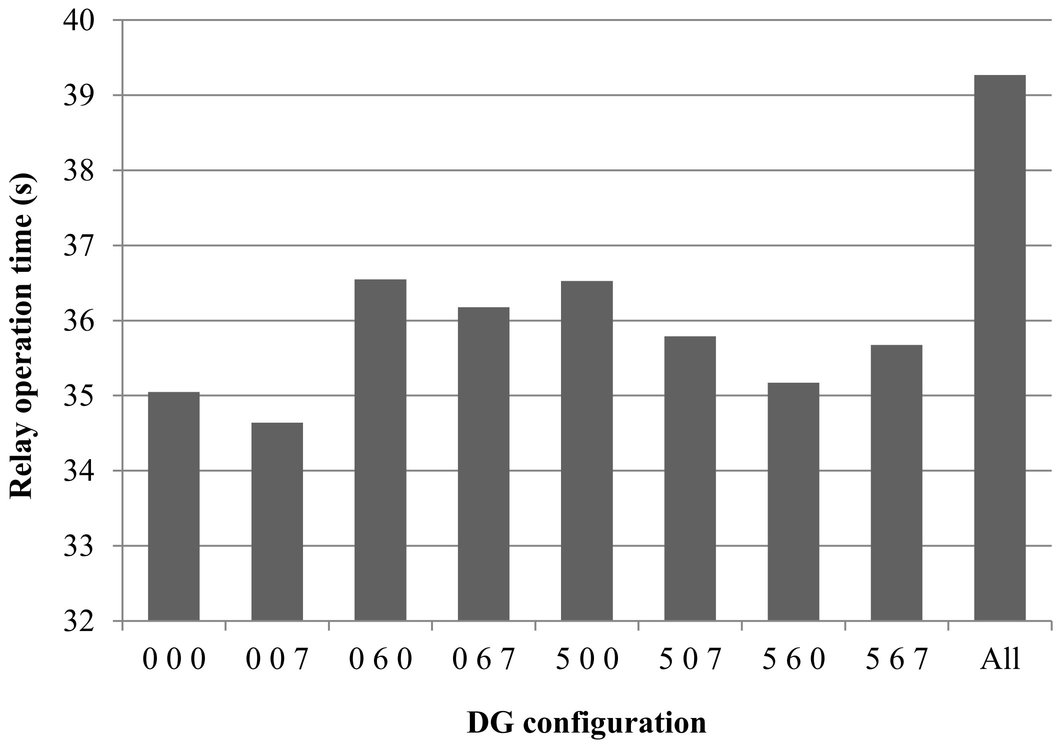


Figure 87: Cumulative backup relay operation times, optimised relay characteristic, variable amounts of DG at Buses 5, 6, 7, modelled on 30 bus network

6.4 Summary of performance improvements

Table 2 presents the performance improvements achieved by the optimiser for each of the three case studies, clearly illustrating the benefits offered, with improvements in protection performance, in terms of cumulative main and backup operation times, of up to 43 % and 30 % respectively. The primary limitation of this solution is its inability to be applied to all scenarios. In many cases, it was found that as additional DG was added to the network the protection scheme became more difficult to coordinate.

Table 26: Summary of protection operation times in each case study

Case study (30 bus system)	Cumulative main time (s)	Cumulative backup time (s)
Base case 1	14.76	49.94
Base case 2	14.04	51.48
Case study 1	8.44	35.05
Case study 2	8.47	35.67
Case study 3 (average)	8.64	39.27

6.5 Chapter summary

Applying optimisation techniques to relay protection setting typically results in a decrease in the total protection operating time. This chapter has demonstrated that: (1) the optimisation technique introduced in [132] can be applied to networks with DG and (2) the optimisation technique can be used to find a single set of protection settings and characteristics that will be applicable for varying amounts of DG connections while still retaining compliance with all operational requirements. By applying the optimisation techniques demonstrated in this chapter to improve the operation speed of the protection scheme means many of the problems associated with DG penetration (and reported earlier in this thesis) such as sympathetic tripping, slow/non operation and possible loss of coordination between relays could be avoided. This improvement thereby avoids or delays the requirement for complex and costly special or adaptive protection schemes and the need for communications. Furthermore, faster protection operation achieved using this method will help to preserve the stability of networks incorporating high amounts of DG and will reduce the duration of disturbances, minimizing risks to sensitive consumer loads.

The protection optimisation solution presented in this chapter optimises the total protection operation combined (main and backup). The results presented in this chapter show that in many cases the optimiser sacrifices improvements in main protection operation time in order to achieve a ‘larger’ achievable reduction in backup operation time. Backup protection settings must of course be optimised so that in the event that main protection fails backup protection will operate within an acceptable delay. Also, the primary protection settings of one relay within the protection scheme presented in this chapter will relate to the backup settings for a different fault location. However, the result presented in this chapter suggest that due to the high reliability of main protection (and typically modern protection relays have a failure rate of only 1 per 10,000 operations [36]), the optimising of primary protection should be given a greater priority than optimising backup setting. This is an area of research that should be investigated more in future studies.

Chapter 7 Conclusions, contributions and future work

This chapter summarises the main conclusions and contributions from relevant chapters in this thesis. This chapter also discusses potential topics for future work based on the findings presented in this thesis.

7.1 Conclusions and contributions

There are many challenges associated with the integration of renewable generation into present day power systems. One of the main challenges is the re-configuration of network protection to accommodate the change from traditional forms of power generation to distributed forms of generation. In the introductory chapters of this thesis, the main problems relating to protection operation as a result of distributed generation being added to the network were reviewed. The later chapters of this thesis focus thoroughly on the analysis of one protection issue, sympathetic tripping, in order to ascertain the severity of this protection problem. An empirical inverter model was developed to evaluate sympathetic tripping of inverter-interfaced DG in simulation. This model was developed by testing an industry supplied inverter in a laboratory under fault conditions. The sympathetic tripping problem has been tested exhaustively using the PSCAD simulation platform. Following on from the investigation of sympathetic tripping, two potential techniques for avoiding sympathetic tripping have been demonstrated and evaluated. The first technique improves the speed of protection operation by optimising protection settings. The second technique uses a communications system to block inverter undervoltage operation for faults on adjacent feeders. Conclusions and contributions from each of the relevant chapters of this thesis are presented in the following section.

7.1.1 Chapter 3: Development of empirical inverter model

In the first part of this chapter the laboratory fault test procedure of a 3 kW single phase inverter used for photovoltaic applications was outlined. The results recorded in the laboratory tests suggest that inverters of this capacity produce a much lower fault contribution than what is presented and assumed in the majority of the literature.

In the second part of this chapter the laboratory results (voltage response, current response and connection time) were compared to standards relating to DG fault response. It was shown that the inverter's fault response complies with the current standard (G83) but not with the predicted future standard (G59/2) at significant levels of undervoltage.

In the final part of this chapter the empirical inverter fault model developed from the results recorded in the laboratory tests was described. This model is used in the simulations to evaluate blinding of protection and loss of protection coordination in Chapter 4 and sympathetic tripping in Chapter 4 and Chapter 5. The laboratory results were compared to the simulated results and good matching was demonstrated.

7.1.2 Chapter 4: The impact of renewable generation on protection

In this chapter three problems that relate to increasing DG penetration were evaluated: blinding of protection, loss of protection coordination and sympathetic tripping of inverters. Each problem was investigated using PSCAD simulation and parts of the UKGDS large rural network model. The empirical inverter model developed in Chapter 3 was used in the simulation study to model inverter fault behaviour.

The simulation results show that blinding of protection does not occur at typical levels of DG penetration (3 MVA per 11 kV feeder), due to the low fault contribution from the DG relative to the fault contribution from the grid infeed. It has also been established that loss of protection coordination also does not occur at expected levels of DG penetration. However, the results indicate that DG adds greater complexity to protection scheme coordination. Sympathetic tripping is found to occur at existing and expected future levels of DG penetration.

In the second part of this chapter, existing solutions to these problems were reviewed and evaluated. Solutions include adaptive protection, fault current limiters and optimisation of protection settings. Many of the present adaptive protection limitations are discussed. These limitations include communication infrastructure requirements and often a lack of consideration for DG connectivity and/or variability with respect to location, capacity or output. Fault current limiter technology can effectively limit the fault contribution from DG and often stop the occurrence of protection problems relating to increasing DG penetration. However, fault current limiter technology is only beginning to be deployed on power systems and cannot yet be cost effectively implemented for small scale DG. Typically protection optimisation solutions do not require additional infrastructure and they can remove many DG related protection problems by improving the operation speed of existing protection schemes. The application of a novel protection optimisation solution is presented in more detail in Chapter 6.

7.1.3 Chapter 5: Sympathetic tripping study

In this chapter the sympathetic tripping study in Chapter 4 was extended by using a 'real world' UK rural/urban network over a larger range of fault levels, inverter penetrations and fault locations than that considered in Chapter 4. It was demonstrated through simulation that the occurrence of sympathetic tripping is highly dependent on the protection settings, relay characteristics and inverter fault contribution. The network conditions at which sympathetic tripping occurs were determined through extensive simulation based testing.

In the second part of this chapter two solutions to sympathetic tripping were evaluated. The first solution is to modify existing protection settings and/or modify G59/2 protection settings. This was shown to be extremely effective in reducing the occurrence of sympathetic tripping. However, this solution may cause problems for protection coordination and in some cases may cause damage to the inverter. The second solution involves the use of an IP/MPLS communication based blocking scheme. This operation of the communication solution was investigated and then evaluated for teleprotection latency requirements using laboratory test equipment. It is demonstrated that the latency of the IP/MPLS system is well below the limits required by IEC61850 standards and it is also well within the requirements of the proposed blocking scheme in this chapter.

7.1.4 Chapter 6: Optimisation solution

In this chapter, the optimisation solution introduced in Chapter 4 was applied to the directional overcurrent relays within the IEEE 30 bus network. This technique optimises the pickup current, time multiplier setting and relay characteristics of all relays within the protection scheme using GAMS optimisation software. The solution presented in this chapter improves on the solutions reviewed in Chapter 4 by developing an optimisation solution that improves the protection scheme operation time of networks that contain variable levels of DG penetrations. DG penetration may vary due to equipment or variability in energy supply.

This solution is applied to three case studies: no DG connected to the network; a fixed penetration of DG connected to the network and a varying penetration of DG connected to the network. It was demonstrated that the optimisation solution can improve protection operation times by up to 42 %.

7.2 Future work

There are a number areas in the work presented in this thesis that could be expanded in future studies. They are discussed below.

7.2.1 Chapter 3: Development of empirical inverter model

In this chapter the fault response of a single phase 3 kW inverter used for photovoltaic applications is evaluated. Available literature on inverter fault response suggests that inverters of a higher capacity than 3 kW are capable of supplying a greater fault current contribution (relative to their capacity ratings). It would be useful from a protection viewpoint to evaluate how the fault responses of inverters change as the capacity of the inverter is increased. It would also be useful to investigate how the fault response changes between single and three phase inverters and between different manufacturers. Another aspect that would be useful to investigate is how higher capacity inverters comply with relevant standards.

The inverters in the laboratory test employed DC power supplies. This is an idealised scenario, in a 'real world' application the inverters would be connected to PV panels or other sources (including storage, electric vehicles, micro-hydro, etc.). These energy sources are likely to have a much lower capability to supply fault current than the dedicated DC power supplies used in the laboratory fault test. Future studies should investigate how actual energy sources impact inverters fault response and compliance with relevant standards.

7.2.2 Chapter 4: The impact of renewable generation on protection

In this chapter loss of protection coordination is evaluated for one specific protection configuration. However, there are multiple variations of loss of protection coordination that could be investigated using different combinations of protection device. This is a topic that could be developed further to gain an understanding of what combinations of protection devices are most at risk of coordination failure as a result of increasing DG penetration. Other factors that could be evaluated for their impact on coordination include network type, network characteristics, fault type, fault impedance, DG capacity, DG type and DG penetration level. The outcomes of this study could help protection engineers identify which networks are most at risk from coordination failure as more DG is added to the network.

As discussed in this chapter, the phrase "sympathetic tripping" is sometimes also used to describe a delayed voltage recovery sympathetic tripping problem [89]. This occurs when faults cause induction motor loads to lose speed during voltage depressions. This large load is often a result of the aggregated loads of residential air conditioners. When the motors lose speed they draw more current and this overcurrent as they accelerate can cause the protection scheme to operate. This aspect of sympathetic tripping was not considered within this thesis, but should be investigated in future studies.

7.2.3 Chapter 5: Sympathetic tripping study

In the first part of this chapter the impact of three phase faults on sympathetic tripping is investigated, single phase faults are not considered. To simplify the model, multiple single phase inverters were modelled as one large three phase inverter. If a single phase fault was modelled, the three phase inverter's behaviour would not be representative of three single phase inverters. The three phase inverter is configured to output a fault current that is dependent on the voltage at its terminals. In the case of a three phase fault this operation is correct, all phases are equally depressed, an inverter on phase A would output the same fault current as an inverter on phase B. In the case of a phase A to earth fault on the 11 kV network, this would result in a voltage depression on phases A and C on the star side (400 V side) of the 400 V star to 11 kV delta transformer. The three phase inverter is configured to operate in fault mode if any of the phases are faulted, whereas in this scenario only the single phase inverters on phase A and C should operate in fault mode. The impact of single phase to earth faults is an area that will need to be evaluated in future studies as they account for 85 % of all system faults [24].

In the second part of this chapter IP/MPLS is evaluated as a candidate technology for implementing a blocking scheme to prevent the occurrence of sympathetic tripping. IP/MPLS is shown to be capable of meeting the latency requirements for the blocking scheme. However, this solution may not be cost effective unless it is used as part of a larger communication network that can also be used for applications such as substation automation, smart metering, fault and protection management etc. There are a variety of technologies that are being proposed for use in smart metering applications such as GSM (Global System for Mobile Communications), GPRS, 3G, WiMAX (Worldwide Interoperability for Microwave Access), PLC (Power Line Communication) and Zigbee [158]. The next stage in evaluating the viability of the proposed blocking scheme is to perform comparative tests of these candidate technologies to determine the optimum communication solution.

7.2.4 Chapter 6: Optimisation solution

The objective of the optimisation solution presented in this chapter is to minimise the total operation time of both main and backup protection. As modern protection systems typically have a very low failure rate, this study could be repeated, but with main protection operation time being assigned a higher priority than backup operation as, has been attempted in [159]. The study reported in this chapter imposes no restrictions on the type of protection characteristic that each relay is eligible to use. In actual applications, there may be external factors that would limit the acceptable protection characteristics for each relay e.g. if the relay was required to grade with LV fuse protection it may be required to use an EI characteristic. Such additional constraints would not be excessively difficult to incorporate as a constraint in the optimiser and this should be investigated in the future.

One of the advantages of the optimisation technique demonstrated in this chapter is that it does not require a communication system to improve the speed of the protection scheme. In future smart grids, the number of DGs connected to the grid may be greater than the number evaluated in this chapter. It is probable that at some increased level of DG penetration, a single set of protection settings (calculated using optimisation protection setting techniques – as in case study 3) will no longer be valid for all combinations of DG availability. In this scenario, a communication system may be required to change the relay protection settings between different pre-sets based on DG availability. This would ensure protection coordination would be maintained for all possible DG availabilities. This is another topic that could be investigated in future.

To fully evaluate the capability of this technique, future studies will need to consider different DG configurations and capacities, as well as varying fault types and a greater range of fault locations. A problem that applies to many optimisation solutions is that they are not generically applicable, for some DG and network configurations the optimisation solver will be unable to find a feasible solution to the problem. Future studies will need to investigate the limitations in applying optimisation solutions to different network conditions and develop new techniques for making the optimisation method more generic. Future studies will also have to consider how the optimisation can be re-applied if network topology changes or additional DG are connected to the network.

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