A Study of Adaptive Protection Methods for Future Electricity Distribution Systems

Ryan M. Tumilty
MEng

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Institute for Energy & Environment
Department of Electronic & Electrical Engineering
University of Strathclyde
Glasgow G1 1XW
United Kingdom

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Dedicated in memory of my late grandmother,

Isabella Dougherty (1918 – 2010),

for all her love and support.

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Finally, and by no means least, I must acknowledge the seemingly endless support and encouragement of my parents without whom I would not have had the opportunity to continue with my studies.

Abstract

The traditional transmission centric approach to generation connection using large-scale thermal units is evolving as the electricity supply industry and end users both move to play their part in tackling climate change. Government targets and financial incentive mechanisms have created a generation portfolio that is becoming more diverse as both large and small-scale distributed generation projects are commissioned. The net result of these events is that generation now appears across all voltage levels and is a trend that is almost certainly set to continue. Moreover, the manner in which networks are operated is also changing to become more flexible with novel management intended to facilitate the dispersed connection of generation, whilst at the same time improving the quality of supply for end users.

As a consequence of the foregoing changes, new challenges emerge with regard to guaranteeing that the performance of power system protection is not degraded. This thesis documents research that has considered the myriad of issues arising throughout distribution networks. The concept of adaptive protection has been explored as a solution to many of these issues as a means of ensuring that protection better reflects the current state of the primary power system.

Although adaptive protection has been a theoretical possibility for some time it has not generally been applied in practice. The emerging drivers that could change this have been considered along with the challenges of its application. It was concluded from this work that the concept and structure for adapting protection needs to be examined in abstraction from the underlying low level protection algorithms. A layered architecture has been proposed that helps to structure process of adaptation, define key functionality and ultimately clarify how it could be practically realised using currently available substation protection and automation equipment. To demonstrate the application of the architecture two examples have been used that cover both low and high voltage networks. The first considers a low voltage microgrid and the difficulties resulting from inverter interfaced microgeneration. As a second example, the problem of intentionally islanding an area of high voltage network is considered. Taken together, these two examples cover a range of future scenarios that could emerge within so called smart grids.

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Abbreviations

AC	Alternating Current
AI	Artificial Intelligence
ANM	Active Network Management
AVR	Automatic Voltage Regulator
BS	British Standard
BSP	Bulk Supply Point
CB	Circuit Breaker
CI	Customer Interruptions
CML	Customer Minutes Lost
CT	Current Transformer
CVT	Capacitive Voltage Transformer
DC	Direct Current
DER	Distributed Energy Resources
DFIG	Double Fed Induction Generator
DFT	Discrete Fourier Transform
DG	Distributed Generation
DGSEE	*Centre for* Distributed Generation and Sustainable Electrical Energy
DMS	Distribution Management System
DNO	Distribution Network Operator
DSM	Demand Side Management
DT	Definite Time
DTI	Department for Trade and Industry
EF	Earth Fault
EHV	Extra High Voltage (voltage levels in excess of 11 kV)
EI	Extremely Inverse
EMS	Energy Management System
EMTP	Electromagnetic Transients Program
EPSRC	Engineering and Physical Sciences Research Council
EU	European Union
GOOSE	Generic Object Orientated Substation Event

GPS	Global Positioning System
GSP	Grid Supply Point
HV	High Voltage (6.6 & 11kV)
HVDC	High Voltage Direct Current
I/O	Input/Output
ICT	Information and Communication Technology
IDMT	Inverse Definite Minimum Time
IEC	International Electrotechnical Commission
IED	Intelligent Electronic Device
IEEE	Institute of Electronics and Electrical Engineers
IET	Institution of Engineering and Technology
IGBT	Insulated Gate Bipolar Transistor
LAN	Local Area Network
LFDD	Low Frequency Demand Disconnection
LOM	Loss of Mains
LV	Low Voltage (400 V three-phase, 230 V single-phase)
LVRT	Low Voltage Ride-Through
MIPS-INT	Microgrid Integrated Protection System - Interface
MIPS-SUB	Microgrid Integrated Protection System - Substation
MPPT	Maximum Power Point Tracker
MU	Merging Unit
MV	Medium Voltage
NOP	Normally Open Point
NVD	Neutral Voltage Displacement
OC	Overcurrent
PLL	Phase Locked Loop
PME	Protective Multiple Earth
PMU	Phasor Monitoring Unit
PS	Primary Substation
PSL	Programmable Scheme Logic
PWM	Pulse Width Modulation
RMU	Ring Main Unit

ROCOF	Rate of Change of Frequency
SCADA	Supervisory Control and Data Acquisition
SI	Standard Inverse
SPS	Special Protection System
SS	Secondary Substation
TN-C-S	Terre Neutral – Combined – Separate
UK	United Kingdom
VHF	Very High Frequency
VT	Voltage Transformer
VVS	Voltage Vector Shift
WAN	Wide Area Network
WAUP	Wide Area Unit Protection
XML	eXtensible Mark-up Language
XLPE	Cross-Linked Polyethylene

1 Introduction

All electrical power systems require that adequate protection be installed to ensure that equipment with faults can be safely and quickly removed from service with minimal disruption to other healthy circuits [1.1]. Moreover, protection schemes (and their associated switchgear) should perform this task in a time that does not compromise the stability of the wider system. The design and configuration of protection to achieve this is based on a detailed understanding of how the system behaves under an extensive range of fault types and locations. Consequently, protection schemes have been developed with varying degrees of complexity to meet the performance requirements and operational constraints of different voltage levels throughout the system[1]. This knowledge has been gained over the last century as advances in electrical engineering have led to larger, more complex systems serving consumers who demand ever increasing levels of supply quality, reliability and availability. These needs have been satisfied to date through the incremental development of large interconnected power systems using transmission connected thermal power stations [1.2]. More recently, increasing levels of equipment automation and remote telemetry at distribution voltages have also been used to improve the quality and security of supply for end users.

However as the electricity supply industry begins to address its impact towards climate change, the nature of electrical power systems will evolve from the prevailing structure. Large numbers of renewable or sustainable generators will have to be accommodated throughout the transmission system and distribution networks. As a direct consequence of this paradigm shift, new challenges and, indeed, opportunities are expected to emerge within the field of power system protection. The research reported in this thesis addresses a number of aspects concerning emerging future avenues for technological development and innovation in this field of electrical engineering.

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[1] The following UK grid code convention for voltage levels is used throughout this thesis: low voltage (LV) 230 V phase-neutral and 400 V phase-phase; high voltage (HV) 6.6 & 11 kV phase-phase; and extra high voltage (EHV) > 11 kV phase-phase [1.3].

1.1 *Research Context*

The electricity supply industry in the United Kingdom (UK) is under pressure to move away from relying on large transmission connected thermal power stations, and to accommodate a higher proportion of renewable or environmentally sustainable forms of generation connected throughout the system [1.4]. The primary drivers for this change arise from growing concerns surrounding the negative environmental impact of greenhouse gases emitted during the combustion of fossil fuels. Although, to a lesser extent, there is also a general desire to reduce the level of losses incurred during the bulk transfer of power from remote sources to consumers. In addition, opportunities have also arisen for individuals or commercial organisations to take advantage of deregulated energy markets by installing small-scale generating units to export into the system for financial gain.

Strong regulatory incentive mechanisms have been put in place to ensure that the electricity supply industry recognises such opportunities and, moreover, meets the challenging targets set by the UK government. One important example of commitment is that of the UK actively supporting the European Union (EU) target of ensuring that 20 % of the region's electricity is obtained from renewable sources by the year 2020 [1.5]. Furthermore, scenario based projections from government departments [1.6], industry trade associations (e.g. British Wind Energy Association [1.7]) and academia [1.8] have all demonstrated that, allowing for differences in industry externalities such as macroeconomic growth, renewable generation will play an increasingly important role in the nation's generation portfolio.

However, the impact of connecting renewable generation where that energy resource is naturally abundant will result in a markedly different spread of generators across all voltage levels and geographical regions of the system. As this change in the generation portfolio is put into effect, fundamental questions emerge as to how such a highly distributed system can be managed. The complexity of this task is increased given the significant number of entities participating, their geographical locations, the impact of primary energy source intermittency, and other network technical constraints. The role of large-scale renewable generation – such as on and offshore wind farms – has been widely debated and many large research programmes initiated to quantify their impact (e.g. the EU funded collaborative project Trade

Wind [1.9]). In addition to these technologies, many forecasts for the UK generation portfolio over the coming decades have also highlighted the likelihood of a significant level of smaller-scale distributed generation (DG) and microgeneration connected at the lower levels of the distribution network (with ratings of the order of several kW to tens of MW) [1.10].

Although the transmission infrastructure of the UK is being modified to support the bulk transfer of power from remote large-scale renewable sources, its role in supplying the total distribution demand will be partially diminished as the function of distributed and microgeneration is enhanced. This will also be in conjunction with appropriate demand side management (DSM) measures. Even if the total capacity of these small-scale resources is of an order of magnitude such that it can theoretically displace large-scale thermal plant on the basis of energy output, major technical questions still remain regarding network support functions such as participation in system frequency control and local voltage support or regulation.

Given the significance of these changes in the electricity supply system, it is prudent to investigate what the impact on protection will be in the future given its importance for maintaining safety and security of supply.

1.1.1 Smart Grids

To address these system issues, many researchers are working on the smart grid concept in which a local integrated approach is taken to connecting new and emerging technologies (an example being the work supported by the European Smart Grid Technology Forum [1.11]). Figure 1-1 provides a pictorial view of how generation in the future will be connected closer to demand to form active cells as indicated by the meshed network topology at community or municipal levels. Larger-scale generation is connected at the periphery of the system to highlight the continuing role for these forms of generation. The importance of DSM, energy storage and supporting information and communications technology (ICT) infrastructures is also indicated by their inclusion within the figure.

In technical terms the cell within the context of smart grids can be used to define an area of network in which a collection of distributed resources can be controlled to meet a set of objectives (e.g. to maximise microgeneration output or to improve local power quality) [1.12].

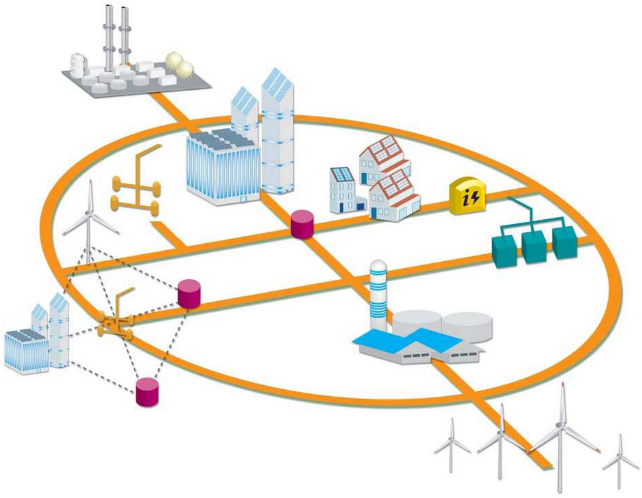

Figure 1-1: An illustration of the smart grid concept [1.11].

Cells can be demarcated based on the underlying structure or topology of the network and are thus expected to include a variety of distributed energy resource (DER) technologies. As a consequence of this definition, cells are likely to be formed at the various levels of network substations and extend down through distribution circuits to either passive consumers or distributed resources (which could in turn be other smaller cells). Furthermore, the demarcation of cells should also be influenced by incorporating existing control zones or network ownership/responsibility boundaries (e.g. independent distribution network operators). The physical size of cells is dependent upon the scale of objectives that are to be allocated or the existence of internal constraints, as well as the degree of acceptable complexity incurred within a hierarchical structure containing many cells. At the lowest voltage levels the term microgrid has been used in many publications to describe the cells that are formed [1.13].

An example of the demarcation of HV cells onto a section of distribution network is shown in Figure 1-2 where 11 kV circuits from primary substations and 33 kV circuits from bulk supply points (BSP) are shown. The BSP and its associated 33 kV distribution have been defined as a cell and include various distributed resources. Three further cells have been allocated based on primary substations with the justification that within these areas there are significant levels of distributed resource that justify sub-grouping within the BSP cell. These three sub-cells are distributed resources falling within the control of the cell defined at the BSP level.

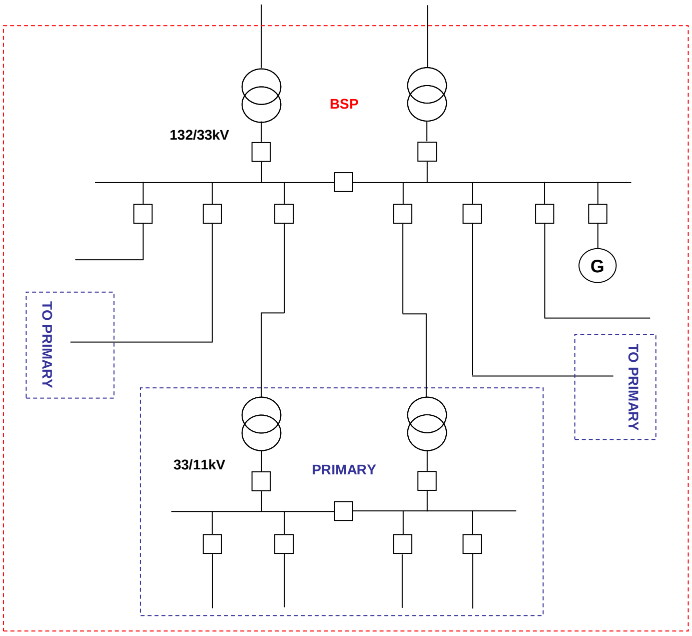

Figure 1-2: The cell concept applied at distribution voltages [1.12].

The research reported in this thesis considers what challenges might emerge for protection if cells are defined (at various voltage levels) and used for operations such as intentional islanding (e.g. microgrids).

1.1.2 Specific Technical Challenges for Protection

The discussion above has illustrated the changes that are currently being experienced within electrical networks. It is reasonable to assume that these will continue in the face of tough regulatory and commercial drivers within the context of addressing climate change and emerging opportunities in evolving electricity markets. It is appropriate, therefore, to now consider what the implications will be for power system protection. Indeed, many of the assumptions made on an *a priori* basis for the design of protection will not be valid as networks evolve to meet the new requirements placed upon them. From the perspective of network protection, the behaviour of the local system to faults will alter and is compounded by changes in the system operational philosophy that are required to facilitate the connection of these new forms of generation. This thesis is primarily concerned with distribution voltages where many of the forecasted changes are to take place; however, reference is made where appropriate to the transmission[2] system such that background information is made available on other forms of established protection principles. Furthermore, it is also noted that system integrity protection such as the low frequency demand disconnection (LFDD) system is based on relays located at distribution. The importance of these relays is likely to greatly increase if capacity projections of less controllable renewable generation come into reality.

Historically distribution networks have generally been constructed to be operated using radial topologies exhibiting passive behavioural characteristics (little or no generation connected). Power within these networks has been unidirectional: flowing from high to low voltage levels down towards consumers. With these technical characteristics in mind, distribution networks have been equipped with relatively simple (but effective) protection, control and more recently automation schemes. In the case of protection, whilst the specific type of schemes applied will depend on the voltage level, it can be nonetheless stated that it is significantly less complex than that expected at transmission. Less onerous constraints are placed on clearance times and a much lower degree of network interconnection[3] assists with designing simpler approaches to ensuring selectivity and sensitivity. For example, within 11 kV distribution networks it is common practice to apply coordinated inverse overcurrent and earth fault elements along the length of radial feeders. Directional elements are not always required and tripping times can extend to around 1.5 s for the clearing of faults under certain backup conditions[4]. This is in stark

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[2] Transmission systems are not the subject of this thesis as the protection that is applied to circuits or other equipment is generally well zoned and is already capable of supporting a high degree of operational flexibility. As would be expected this functionality comes at a high cost, but can be justified based on the importance of the equipment concerned. Although specific challenges may arise at transmission voltages, the immediate area for concern is at distribution where the need for lower cost solutions may in fact drive innovative proposals drawing from prior experience at transmission.

[3] Some notable areas of HV interconnection exist in the UK and are principally to be found within the Manweb distribution licence area. These networks are protected by an extensive arrangement of overlapping unit protection zones with overcurrent as a backup [1.14].

[4] This time is based on the assumption of a standard IDMT overcurrent curve used at an outgoing feeder relay within a primary substation acting in backup for a fault on the low voltage side of a secondary substation located beyond any mid-point protection [1.15].

comparison to transmission clearance times where system transient stability restrictions enforce total clearance times of less than 100 ms[5].

The characteristics outlined above will change as DG is connected to the network and proactive network management techniques are used to both improve the quality of service to customers and facilitate generator connection within technically constrained networks. In many instances generation connections at distribution voltages can be delayed or abandoned due to the high costs of network reinforcement required to remove constraints such as thermal or fault level ratings. Active management of networks and local generation (a key aspect of the smart grid concept) have provided tangible results [1.17], but can add to the complexity of secondary systems such as protection.

Specific illustrations of issues that may arise for protection in the future include the following:

- More complex fault current flows emerging around networks due to multiple sources of contribution from DG. As an example, additional sources of fault current if connected downstream on radial circuits have the potential to reduce the reach of upstream relays [1.18]. A further complication arises when the generating source is intermittent (e.g. renewable) and thus a permanent correction factor applied at the upstream relay may not always be appropriate. Consequently a number of different changes may be required depending on the particular level of DG connected to the primary system.
- Changes in grading paths may occur due to automated reconfiguration and the use of permanent interconnection to form meshed networks (where fault levels permit). In this case, it is the coordination between adjacent protection devices that may be compromised as changes are made in the primary system.
- Increased variation in fault levels can occur due to automated network reconfiguration, use of power electronic interface devices and installation of fault current limiting devices. The pickup value of overcurrent devices may need to be lowered under certain circumstances, but this could be in conflict with the need to cope with cold load pickup. Moreover, the proposed use of

[5] In the UK 400 kV transmission circuits have a target main protection clearance time of 80 ms [1.16].

islanded microgrids where generation is exclusively inverter interfaced presents what is possibly the worst scenario (from a protection discrimination perspective) in which the available fault current may not be very much greater than full load ratings [1.19]. Under these conditions the very application of conventional overcurrent principles is called into question.

- Lastly, the increasing sensitivity of customer loads and certain small generators to even short-term supply interruptions or voltage reductions promotes a general reduction in the desired total clearing time for faults. Furthermore, should advances in power electronics result in the development of cost effective solid-state switchgear, then grading margins or the fault level will have to be reduced to support their application (due to the physical characteristics of the semiconductor devices lacking thermal capacity to allow high through currents to be passed without permanent damage [1.20]).

All of the above statements present a challenge for the prevailing protection practices used on existing networks with many design performance criteria affected. With such new constraints emerging, the trade-offs now made between sensitivity and stability may not be possible in the future without a reconsideration of how protection schemes can better reflect the current status of the primary system.

1.2 Principal Contributions

The research presented in this thesis firstly analyses the nature of the impact upon distribution protection across all voltage levels, arising not only from the connection of local generation, but also due to changes in how the system is operated to improve operational flexibility.

It is generally accepted that as the primary system is subject to far greater changes during operation, it becomes more difficult to design a protection scheme with a single group of settings that will provide satisfactory performance under all foreseeable conditions. Although using more than one group of settings is used within industrial power systems, it has not found widespread application in utility networks with a much larger physical footprint.

Applying adaptive protection as a concept and potential solution to this problem has been a theoretical possibility since the development of numerical relays and, perhaps more significantly, the recent improvements in communication technologies. However, allowing a safety critical system such as protection to change in response to the primary power system represents a major barrier to adoption. The research presented in this thesis addresses this by developing a new formal approach to demonstrate how the benefits of using a clearly defined open (non-proprietary) architecture to design adaptive protection can help address this problem. A layered architecture has been created with elements of functional abstraction included to indicate where specific functions within the scheme best reside or are distributed (e.g. at bay, substation or control centre levels). Attention has also been directed towards how changes can be implemented and validated across a dispersed area of the network making it suitable for application on utility networks. Two example case studies have been provided to apply and demonstrate the merits of the proposed architecture using both LV and HV network scenarios.

At the lowest levels of the distribution network many researchers have proposed the concept of microgrids at LV as a means of integrating large numbers of small-scale generators. Under islanded operating conditions a severely limited fault level contribution from inverter connected generation arises which makes it difficult to apply conventional overcurrent protection. To tackle this issue, the research reported has been concerned with defining what new protection functionality is actually required for the different operating conditions. A new enhanced scheme has been proposed and tested using transient simulation with due consideration being given to the wider protection implications outside the microgrid and application of the proposed adaptive protection architecture.

The use of settings groups is critically evaluated as another means of implementing adaptive protection. In this case, the architecture has been applied and demonstrated for a number of HV islanding scenarios based around a cell defined at the primary substation level. The cell concept has been used in this work as a means of clearly defining the network area to be islanded. It has been used for both short-circuit and system protection functions. The intentional islanding of the network would not be possible without the deployment of this scheme.

In summary, this research has attempted to consider a range of voltage levels within the distribution network. This has been conducted with a view to examining the technical challenges for protection that will be required to maintain and preferably improve its performance in the coming decades. The challenges may be different across the voltage levels, but their common root is derived from the need to support a primary network that is more active, flexible and robust in order to meet the needs of the future.

1.3 Publications

Over the course of the research leading to the writing of this doctoral thesis, the following associated papers have been published:

- Tumilty R.M, Burt G.M. & McDonald J.R., "Protecting Micro-grids – Fault responses of inverter dominated semi-autonomous networks", 40th International Universities Power Engineering Conference, Cork 2005.
- Tumilty R.M., Burt G.M. & McDonald J.R., "Distributed Generation and Network Protection and Control – Improving Power Quality", World Renewable Energy Congress, Aberdeen 2005.
- Kelly, N.J., Galloway, S.J., Elders, I.M., Tumilty, R.M. & Burt, G.M., "Assessment of Highly Distributed Power Systems using an Integrated Simulation Approach", IMechE Journal of Power and Energy (Part A), vol. 222, no. 7, 2008.
- Tumilty, R.M., Brucoli M., Burt, G.M. & Green, T.C., "Approaches to Network Protection for Inverter Dominated Distribution Systems", 3rd International Conference on Power Electronics, Machines and Drives, Dublin 2005.
- Tumilty, R.M., Burt, G.M. & McDonald, J.R., "Coordinated Protection, Control & Automation Schemes for Microgrids", 2nd International Conference on Integration of Renewable & Distributed Energy Resources, Napa, California, USA, December 2006.

- Tumilty, R.M., Elders, I.M., Burt G.M. & McDonald, J.R., "Coordinated Protection, Control and Automation Schemes for Microgrids", *International Journal of Distributed Energy Resources*, Vol. 3, No. 3, July-September 2007.
- Tumilty, R.M., Bright, C.G., Burt, G.M. & McDonald, J.R., "Applying Series Braking Resistors to Improve the Stability of Low Inertia Synchronous Generators", CIRED, Vienna, Austria, May 2007.
- Tumilty, R.M., Roberts, D.A., Kinson, A.S., Burt, G.M. & McDonald, J.R., "A Network Demonstrator for Active Management Devices and Techniques", CIRED, Vienna, Austria, May 2007.
- Tumilty, R.M., Emhemed, A.S., Anaya-Lara, O., Burt, G.M. & McDonald, J.R., "Adaptive Unit Based MV Protection for Actively Managed Distribution Networks", IEEE RVP-AI 2008, Acapulco, Mexico, July 2008.
- Rafa, A.H., Anaya-Lara, O., Tumilty, R.M., Emhemed, A.S., Quinonez-Varela, G., Burt, G.M. & McDonald, "Stability Assessment of Microgeneration Systems", IEEE RVP-AI 2008, Acapulco, Mexico, July 2008.
- Quinonez-Varela, G., Cruden, A., Anaya-Lara, O., Tumilty, R.M. & McDonald, J.R., "Analysis of the Grid Connection Sequence of Stall- and Pitch-Controlled Wind Turbines", Nordic Wind Power Conference, Roskilde, Denmark, November 2007.
- Y. Lei, R.M. Tumilty, G. M. Burt, and J.R. McDonald," Performance of small-scale induction generators protection during distribution system disturbances," The 9th International Conference on Developments in Power System Protection, Glasgow, UK, March 2008.
- Emhemed, A.S., Tumilty, R.M., Burt, G.M. & McDonald, J.R., "Transient Performance Analysis of Single-Phase Induction Generators for Microgeneration Applications", IET 4th International Conference on Power Electronics, Machines and Drives, York, UK, April 2008.
- Emhemed, A.S., Tumilty, R.M., Burt, G.M. & McDonald, J.R., "Transient Performance Analysis of LV Connected Microgeneration", IEEE PES General Meeting, Pittsburgh, USA, July 2008.
- I. Abdulhadi, R.M. Tumilty, G.M. Burt, and J.R. McDonald, "A dynamic modelling environment for the evaluation of wide area protection systems,"

Universities Power Engineering Conference, 2008. UPEC 2008. 43rd International, 2008.

A contribution was made to the following book chapter:

Elders, I.M., Ault, G.W., Burt, G.M., Tumilty, R.M. & McDonald, J.R., Future Electricity Technologies, Chapter 2, “Electricity Network Scenarios for the United Kingdom in 2050”, Cambridge, 2006, pp 24-79.

Two patents related to this work have been filed with the UK Patent Office:

Tumilty, R.M., Elders, I.M., Galloway, S.J. & Burt, G.M., WO/2009/1278, “Self-Organising Unit Protection” – submitted April 2008.
Tumilty, R.M., Dyśko, A. & Burt, G.M., “Phase Angle Drift Detection Method for Loss of Mains/Grid Proection”, PCT/EP2009/062666.

A white paper was also produced as part of the EPSRC Highly Distributed Power Systems project that set out method by which distribution networks with large numbers of distributed generators can be managed using the concept of dividing the network into coordinate cells:

Supergen III: Highly Distributed Power Systems, System Level Concept Definition, EPSRC/HDPS/TR/2008-001, March 2008.

1.4 Outline of Thesis

The structure of this thesis is outlined as follows:

Chapter 2 – **Power System Protection**:
This chapter provides background information on the protection schemes that are commonly to be found within distribution and transmission networks (the latter being included for completeness). Comment is made on specific emerging technologies

(e.g. the substation communications standard IEC 61850) that are relevant to, or are enablers for, adaptive protection.

Chapter 3 – **Development of a Novel Adaptive Protection Architecture**:

The concept of adaptive protection is introduced in Chapter 3 by considering those schemes reported in the academic literature. These are critically assessed and conclusions drawn with regard to shortcomings. To address these, a layered functionally abstracted architecture is then introduced and its components detailed and justified. This model is then used repeatedly in later chapters to support the application of adaptive features in various protection schemes. A basic design methodology for designing adaptive protection has also been proposed and discussion made of commissioning and testing implications.

Chapter 4 – **A Study of Adaptive Protection Failure Modes and Effects:**

This chapter explores the potential failure modes that are associated with adaptive protection. It then assesses them against their implications for performance during the process of transition between different configurations of the primary power system. An assessment methodology for applying failure mode and effects analysis is also discussed along with the discussion of some generic risk mitigation measures.

Chapter 5 – **Enhanced Network Protection to Enable Microgrids:**

The example of LV microgrids supplied by inverter connected generation is examined in this chapter. A scheme is proposed with testing carried out using transient simulations in order to demonstrate its performance. The objective for this chapter is to examine the impacts on protection and potential solutions at the very lowest level of distribution networks. The role of protection at this level is also considered within the context of the adaptive protection architecture.

Chapter 6 – **Facilitating Intentional Islanding of an HV Urban Network**:

The use of multiple settings groups is considered for the case of an area of distribution network that can be islanded from the main grid. In this case further information related to the level of fault current infeed and power flows (system import/export prior to islanding) is included to demonstrate how additional complexity can be managed for the short-circuit and system protection schemes. The overall scheme is designed based on the proposed adaptive protection architecture.

Chapter 7 – **Conclusions & Future Work**:
Conclusions are drawn based on the contributions identified and some proposals for further study are identified.

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2 Power System Protection

Power system protection plays a pivotal role in ensuring the safe, secure and efficient generation, transmission and distribution of electrical energy. All systems have devices of varying complexity installed to remove equipment with faults from service as quickly as possible with minimal disruption to nearby healthy circuits [2.1]. The consequences of protection devices failing to operate when required to do so can, in the worst possible outcome, lead to the loss of human life. Furthermore, the mal-operation of devices can also compromise the security of a power system leading to cascading equipment outages that may result in a complete system collapse or partial blackouts. Serious unnecessary and costly damage to equipment almost always occurs when protection fails to operate as intended. It is therefore apparent that protection devices must be designed, installed and maintained to exacting standards to provide the performance demanded for such critical systems.

Since the application of the basic fuse in the earliest electrical systems around a hundred years ago, protection has evolved into a challenging field in which the advances in microprocessors have been harnessed to implement complex multi-function numerical relays controlling one or more separate circuit breakers. This chapter provides an overview of protection devices and their application at transmission and distribution voltage levels. A review is also provided of the international standard IEC 61850 which deals with communication between intelligent electronic devices (IED) (e.g. protection relays, automation controllers and or other electronic equipment) within substations using a formalised data object model. Further work in this field is expected to extend its coverage between substations across wide area communication networks and will thus play an important role in future developments in power system protection. This is particularly true for wide area (or enhanced system) protection.

2.1 Chapter Outline

The chapter begins in §2.2 with the definition of key protection terminology that will be used throughout this thesis. This is then followed by a review of the main components that are used to make up a protection scheme in §2.3. Details of specific protection schemes are described in terms of the distribution or transmission system application in §2.4. Finally in §2.5 the international standard IEC 61850 is briefly reviewed.

2.2 Protection Terminology

A number of common terms that are used in the description of protection and its performance are as follows [2.1]:

Device: A specific component that forms part of a protection system (a device may integrate the circuit interrupting mechanism and perform one or more specific protection functions). Common examples include fuses, miniature circuit breakers and overcurrent relays.

Relay: An electromechanical, discrete electronic component or microprocessor device which uses one or more power system measurements in determining if a fault exists (using predefined thresholds) and then provides a signal (perhaps after a time delay) to actuate one or more external circuit breakers if required.

IED: An *intelligent electronic device* is the specific term in this context used to describe any modern microprocessor based protection[6] device.

Scheme: A collection of configured devices that are intended to protect a network or item of equipment such as a generator or transformer.

Element: A single instance of a function within an IED (e.g. under voltage).

Stage: Elements may have one or more stages which have different settings that are active at the same time (e.g. a two stage under frequency scheme).

Sensitivity: The ability of a device to be able to distinguish a fault condition from other normal conditions on the network when one or more measured or derived quantities exceeds a user specified threshold. It is particularly important for certain types of faults wherein the

[6] The term IED more generally applies to any microprocessor based device within a substation (e.g. automation controllers).

condition to be detected does not differ significantly from normal operating conditions.

Stability: The ability of a device to avoid tripping in the presence of a fault condition for which it is not intended to operate. An example of this would be for faults that are geographically distant to the relay but may still cause a significant local disturbance. Although this would be observed by the protection device, it should not cause the relay to trip.

Selectivity: The feature of protection that permits only the disconnection of the minimum of plant in response to a fault (also known as discrimination, grading or coordination). In simple terms, the device closest to the fault should operate first thus isolating it from the system and leaving the supply intact to other nearby circuits. Each device in an overall protection scheme may have different measurements taken or settings applied to achieve this.

Trip: The action of the device to either isolate the fault itself or actuate an associated circuit breaker (possibly after a time delay) when an abnormal fault condition has been detected.

Backup: This is the term used for a time delayed mode in which a device acts to counter the failure of other devices and generally leads to a greater degree of unnecessary equipment disconnection than would normally be required.

Mal-operation: A device trip that should not have occurred given the specific network condition.

Non-operation: Describes the failure of a device to trip when it is required to do so.

Zone: A zone refers to the coverage of a device in relation to a defined circuit, specific item of equipment (e.g. transformer) or a combination of these.

2.3 Components of a Protection Scheme

Protection schemes are made up from many different combinations of individual devices and associated measurement transducers. The complexity of schemes depends on the requirements of the specific application (e.g. transmission or distribution voltages) and is highly dependent on the justifiable capital expenditure (typically up to around 5 % of the primary equipment value [2.2]). The following sections briefly outline the main types and characteristics of the devices to be found within protection schemes.

2.3.1 Fuses

Fuses are perhaps the most common form of protection that is applied in any electrical power system [2.3]. They are cheap, simple to apply and have many variations suitable for diverse applications ranging from protecting sensitive semiconductor devices to industrial motors. The limiting factors for fuses in terms of their application are that of fault level and system voltage, with their use being restricted to LV and HV.

A fuse is constructed from a sacrificial metal link surrounded by an insulating medium. The shape of the fuse time-current characteristic is defined by the construction of the link which may include geometrical restrictions, the addition of low melting point metals (M-effect) and the heat dissipation properties of the surrounding insulating medium. Different insulation media include air within semi-enclosed rewireable fuses or high purity granular quartz for enclosed types. The operation of a fuse can be split into two distinct periods of time: (i) pre-arcing, which is that between the occurrence of a current large enough to melt the fuse and the actual instant of an arc developing and, (ii) arcing, which relates to the remaining time required for the arc to extinguish and finally isolate the fault.

The specific time current characteristic for a given fuse changes with its application, but can generally be described as being comparable to the extremely inverse curve used within some overcurrent relays. Examples of time-current characteristics for several LV fuses are provided in Figure 2-1 and are taken from BS 88-1:2007 [2.4]. However, this characteristic is not reflective of all the factors that will impact on fuse operating time. In particular, such curves do not address the current limiting behaviour of fuses as they are presented based on prospective values of fault current. Coordination between fuses is better accomplished by comparing the Joule integral (I^2t) that will be passed by the fuse. This quantity is generally accepted to be a measure of energy let-through with a threshold being known for a fuse to operate. By knowing the pre-arcing I^2t for an upstream (major) fuse and the total I^2t for a downstream (minor) fuse it is possible to coordinate these devices. An accepted practical rule of coordination at LV is that two fuses in series should have the larger I^2t rating 40 % greater than the smaller rating. Time-current characteristics, however, are still useful for coordinating with other device such as relays.

At low values of fault current, the operating times of fuses can be very long and thus their application is not generally recommended unless there is an available fault current of at least three times their specified rating. This can be explained by considering their time-current characteristic and noting that very long time delays are associated with operation just above their rating on the asymptotic part of the curve. The long operating time arises due to the significance of heat transfer from the elements to the casing and surrounding environment. Manufacturers can specify a wider tolerance band at these low values of current due to varying environmental conditions. Thus the application of fuses within a network with a low fault level must be carefully studied.

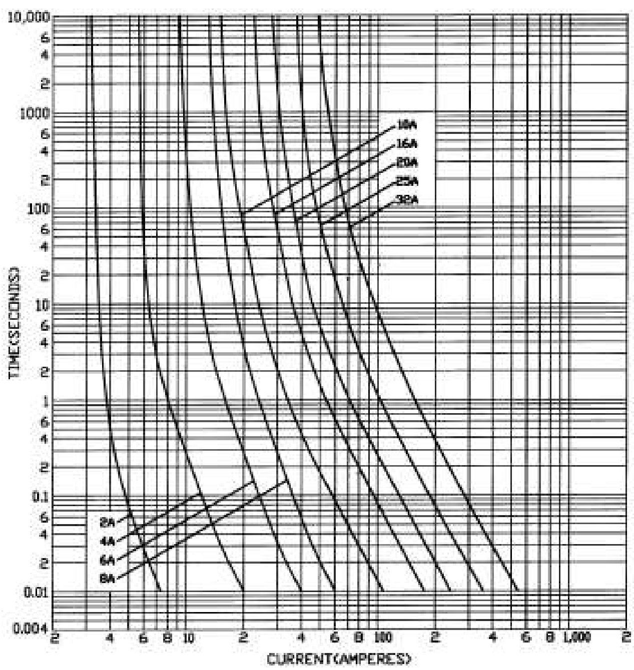

Figure 2-1: Typical fuse time current characterisitc (meets BS 88-1:2007 [2.4])

2.3.2 Measurement Transducers

Measurement transducers form a vital part of protection installations where they provide an accurate scaled replica of the actual primary system voltage or current suitable for application to a relay [2.5]. Conventional instrument transformers are constructed using specifically designed electromagnetic transformers. These are subject to standardised accuracy classes in which maximum permitted errors have been defined for given circuit conditions [2.6]. Physical electrical connections are usually made directly to the relays for the secondary voltages and currents to be applied. More recently, other technologies have been used to build measurement transformers (e.g. magneto-optical effects) and are classified as being of a non-conventional design [2.7]. The change in technology has also led to moves to alter how measurement transducers are connected to relays, with use being made of Ethernet local area networks (LAN) to transmit sampled digital values [2.34] instead of dedicated hardwiring.

2.3.2.1 Current Transformers

Conventional current transformers (CT) are constructed on a per-phase basis using electromagnetic transformers with the primary conductor acting as a single turn winding surrounded by a ring shaped ferromagnetic core [2.1]. A secondary winding is wound around this and is connected to an electrical burden such as a relay or other measuring device. The output rating of a CT is standardised at either 1 or 5 A [2.6], with the former now being more commonly used to supply numerical (microprocessor) relays.

An important factor in the selection of a CT is the ability of the ferromagnetic core to reproduce a secondary current free from the effects of saturation when large currents flow in the primary circuit. The distortion in wave shape due to core saturation can have a detrimental impact on relay performance and thus the dimensioning of a conventional CT core is a vital part of the design of the overall protection scheme.

Depending on the purpose of the current measurement, a number of connection arrangements are available to support the derivation of secondary currents suitable for the range of different fault types (e.g. the use of the residual connection to derive the zero sequence current to be applied to an earth fault relay).

Non-conventional current transformers may use different magneto-optical effects or Rogowski coils. These have the advantage of being inherently linear and in the case of the former provide excellent galvanic isolation from the primary system [2.8].

2.3.2.2 Voltage Transformers

The construction of conventional types of voltage transformer (VT) depends on the voltage level. At HV and below, a standard power (shunt) connection of an electromagnetic transformer to the primary system is used. Whereas at EHV due to greater insulation requirements, a combination of capacitive voltage divider and electromagnetic transformer known as a capacitive VT (CVT) is frequently used. Care must be taken in the design of these devices as a resonant circuit is formed between the divider capacitors and their associated compensating inductance connected at the transformer tapping point.

The output of a VT is standardised as being 110 V three-phase [2.6]. Accuracy classes are also specified for VT in terms of permitted ratio and phase errors under given practical conditions [2.1].

The physical construction of VTs can either be single- or three-phase depending on the application. If a residual voltage is required (e.g. for neutral voltage displacement protection), then a path needs to exist for zero sequence flux to be established and thus either a five limb three-phase transformer or three single-phase transformers must be used.

Non-conventional units can use different technologies such as electro-optical effects and have the advantage of possessing larger measurement bandwidths [2.9].

2.3.2.3 Merging Units

Merging units (MU) are used to send digitally sampled secondary signals over a substation LAN to one or more IEDs. The digital representations of secondary signals may be obtained directly from non-conventional instrument transformers or via analogue to digital converters (ADC) acting on suitable burdens connected to conventional devices. The sampling rate used to produce the digital signals will depend on the final application (e.g. signals to be analysed for power quality studies will require a high rate to ensure that all harmonics of interest can be reproduced). In all cases it is important that the sampled value signals are sent with suitable time stamping to enable any necessary phasor alignment to be carried out in the IED. An example of a suitable standard would be IEEE 1588 [2.10] and the reference for the time stamping could be derived from the Global Positioning System's (GPS) clock. A typical architecture of a MU is given in Figure 2-2 where the instrument transformers and synchronisation source are shown.

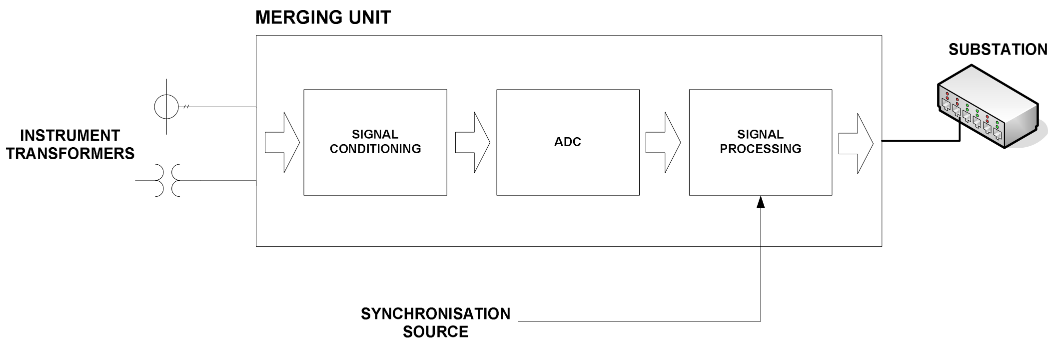

Figure 2-2: A typical merging unit architecture.

The use of a MU offers a number of advantages including a significant reduction in secondary wiring complexity and the ability to remove relays from service without concern for the impact on other relays connected to the same instrument transformers. This could potentially reduce the need for primary circuit outages for certain maintenance or testing tasks on secondary equipment.

2.3.3 Relays

There are three types of relay reflecting the different stages of development within the field of protection, namely: electromechanical, discrete electronic components and numerical (software programmed on a microprocessor). Each of these will be considered in turn using an inverse overcurrent function as an example. Curves as defined in IEC 60255-3 [2.11] (shown in Figure 2-3) are commonly implemented within overcurrent relays.

2.3.3.1 Electromechanical

This is the oldest classification of protection relay in which devices are constructed from electrical, magnetic and mechanical components arranged such that an operating coil acts upon some form of moving mechanism to close trip contacts. The robustness and reliability of these devices results in a service life that can be far in excess of 30 years.

As an example, consider the implementation of a standard inverse (SI) overcurrent characteristic that is based on a shaded-pole induction disk design (Figure 2-4). The principle of this relay is that two fluxes (one due directly to the current flowing in the coil, and a second that is lagging due to the presence of the shading ring) are induced that interact to produce a driving torque acting on the disk. This is able to rotate and close a set of trip contacts.

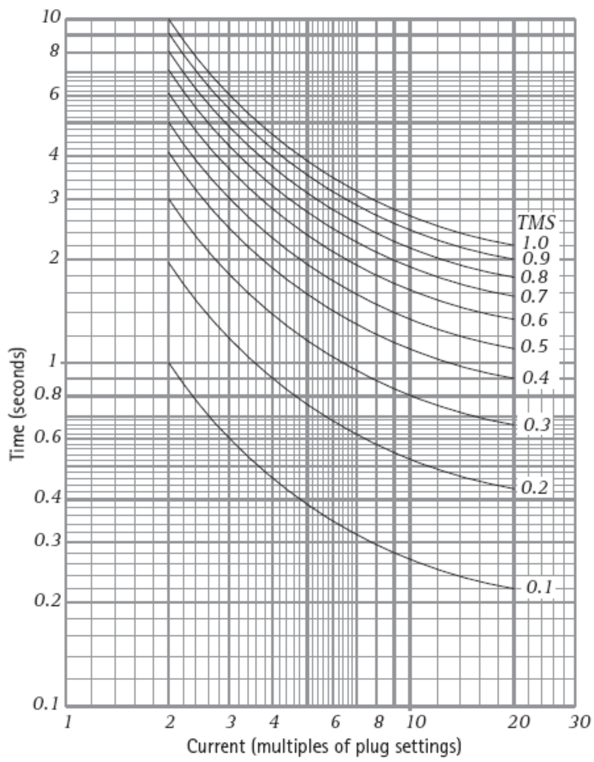

Figure 2-3: IEC 60255-3 SI time-current characteristics [2.11].

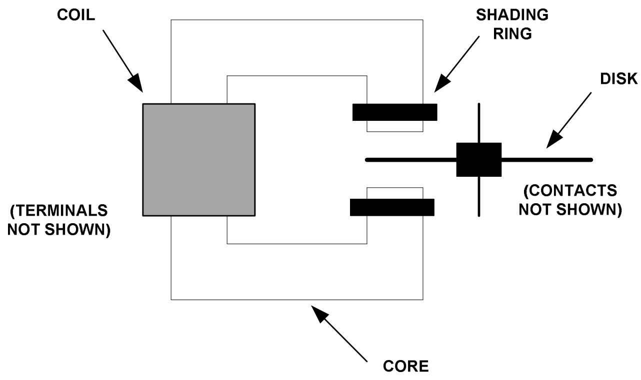

Figure 2-4: Shaded-pole induction disk overcurrent relay design cross section.

A restraining spring is used for control (giving a torque to hold the disk at rest under normal conditions) and to provide a reset action. The electromagnetic torque produced is proportional to the current flowing in the coil and the disk speed is controlled by the damping action which is in turn proportional to the electromagnetic torque. It can be shown that the disk system can be described using Newton's law as in equation (2-1) [2.12]. The solution of this neglecting the disk's inertia and assuming that the spring torque is a constant is given by equation (2-2) (the constant relating to input current has also been modified to enable the input parameter to be the multiple of the pickup setting). By suitable design, the curves shown in Figure 2-3 can be created. The reset behaviour of the disk can be similarly modelled.

$$K_I I^2 - K_d \frac{d\theta}{dt} - \frac{\tau_F - \tau_s}{\theta_{\max}}\theta - \tau_s = m\frac{d^2\theta}{dt^2} \qquad \textbf{(2-1)}$$

$$\theta = \int_0^T \frac{\tau_s}{K_d}(M^2 - 1)dt \qquad \textbf{(2-2)}$$

Where:

I	input current;	K_I	constant;
K_d	drag magnet damping factor;	θ	disk travel;
$\theta_{\max}$	disk travel at contact closure;	τ_s	initial spring torque;
τ_F	spring torque at closure;	m	disk inertia;
M	multiple of pickup setting;	T	time.

It follows from the above discussion that the relay has an inverse relationship between operating time and current. The relay has two settings: current threshold (plug setting or pickup) which acts to alter the number of turns in the coil; and a time setting (or time dial) which is used to alter the starting position of the disk and thus modifies the time characteristic for a given current setting.

2.3.3.2 Discrete Electronic Components

In this stage of relay development, discrete analogue and digital components were used to replicate the characteristics possessed by electromechanical devices [2.13]. The behaviour displayed by the equations governing the induction disk above may be implemented using operational amplifiers and external RC networks to form comparators and integrator circuits. The plug setting and time multiplier are adjustable using switches to vary the resistance at different locations in the circuit. Complex scheme logic can be implemented using digital components. Although good performance can be obtained after initial commissioning, longer-term issues such as component value drift and lifespan have emerged to cause concern.

2.3.3.3 Numerical

The final stage in the evolution of the relay to date is the use of microprocessors to numerically implement protection characteristics [2.14][2.17]. These devices are multi-functional providing a wide range of different characteristics and, indeed, types of protection. This move was questioned at first over concerns surrounding reliability, but self-monitoring has in fact in many ways made relays more reliable [2.15]. This can be explained by noting that relay problems can be automatically reported using built in self-diagnostic tools. This was not the case for other technologies where relays with hardware failures would not have been observed until a mal- or non-operation was investigated after an event occurred. These problems are sometimes referred to as hidden failures of protection schemes [2.16].

The inverse characteristics can be implemented using coded numerical integrators with the settings now being stored in the memory of the relay. However, the flexibility of the numerical relay now allows for complex user defined curves to be used that may be combinations of standard definitions or, perhaps, tailored to meet the needs of specific equipment time/current withstand curves. Numerical relays also allow for multiple groups of settings to be stored and selected either manually or by an external input acting on programmable scheme logic (PSL) executed on the device (an alternative to hardwired auxiliary logic relays).

Numerical relays sample the secondary quantities at a rate that is dependant on the application. A typical modern sampling rate for an overcurrent relay would be 24 samples per cycle of the fundamental waveform and would be higher for more demanding functions such as a numerical distance protection algorithm. Frequency tracking to adjust the sampling rate to ensure that one cycle of the fundamental matches with a set number of samples is a common feature for relays in systems where the frequency can change significantly (e.g. generator protection). A range of numerical methods are used to calculate amplitudes and phases, with a common example being the Discrete Fourier Transform (DFT) calculated for the fundamental terms.

More recently, numerical relays have been offering a range of control and monitoring functions leading to their designation as IEDs. It could be said that manufacturers and, to a greater extent, utilities have not yet fully taken advantage of all possibilities that microprocessor based relays can offer. This statement particularly applies to access to remote measurements or to initiate changes in settings via modern communication networks, which then in turn leads to suggestions of how protection can be adapted to reflect the current configuration or state of the system. Coordination with other secondary systems involved in automating primary system reconfiguration will become a significant challenge as utilities seek to apply these techniques more widely as part of the smart grid vision for future networks.

2.3.4 Circuit breakers

With the obvious exception of fuses, all other protection devices require some form of switch that is capable of making and breaking fault current on command. [2.18]. This is clearly an onerous task given the very high fault currents and the resultant stresses to which equipment are subjected. Many different designs of circuit breakers have evolved using a variety of interruption mechanisms making use of a number of insulating materials (e.g. air, bulk or small-volume oil and sulphur hexafluoride). Differences in typical operating times are evident between technologies, with designs for application at transmission voltages providing interruption in as little as 1.5 – 2 cycles [2.19].

Research has also been ongoing regarding the development of solid-state circuit breakers [2.20] which have the potential to offer sub-cycle interruption times. However, the need to apply time delays for grading purposes could negate this advantage as semiconductor switches are not able to conduct high levels of current for comparatively long periods of time. Consequently, very fast acting and well zoned protection would be required for their widespread application to be successful.

2.4 Transmission Systems

The transmission system is the backbone of the electricity supply system and as such places strict requirements on protection schemes [2.21]. Reliability and speed of response are vital criteria for their design and comparatively high expenditure on transmission protection schemes is justifiable. A section of representative transmission infrastructure is shown in Figure 2-5 in which key elements such as lines, bus-bars and transformers are illustrated (note that switchgear has been omitted).

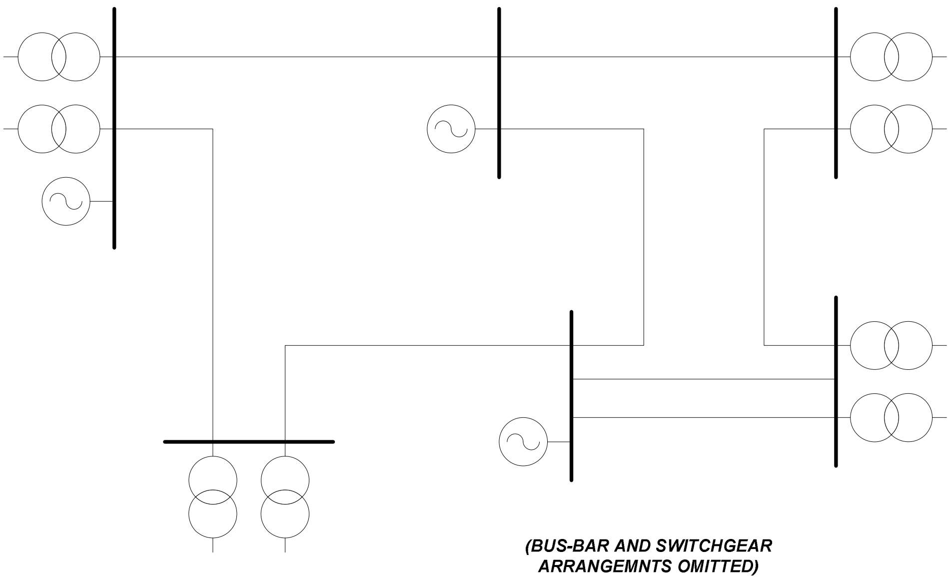

Figure 2-5: A section of transmission network.

2.4.1 Line Protection

Transmission lines are often provided with two main protection schemes as well as a separate backup. Equipment such as trip coils for circuit breakers are also replicated (and supervised) for reliability reasons. The main schemes on important circuits often use unit principles, although communication supported distance may also be used (e.g. acceleration and blocking signalling). Backup protection is generally in the form of overcurrent and earth fault elements.

Auto-reclosers are also used and may be of three- or single-phase types. Schemes may be high speed or time delayed depending on the requirements of the particular system. In the UK, a delayed approach is taken to minimise the likelihood of closing back onto a transient fault due to the additional disturbance this would cause within such a comparatively small system. A key requirement for transmission line protection is that it must be immune to power swings on the network that can occur in large topologically ‘narrow’ systems as key circuits or key generating units are lost from the system.

2.4.2 Bus-bar protection

Bus-bar arrangements can be very complex at transmission with mesh corner arrangements being perhaps the most significant. Complex differential schemes are applied and must cover main and reserve bus-bars as well as a number of bus sections. High impedance schemes find application, but so do circulating current relays depending on the policy of the utility. Although the latter type is now becoming more common in new installations using IEDs. Fast fault clearance is very important and is particularly so where generation is connected or several critical transmission circuits converge.

2.4.3 Transformer protection

Transformers are vital components at any voltage level, but at transmission their position at strategic points makes their protection especially important. Transformers are protected using differential principles with overcurrent and earth fault backup. Buchholtz relays for detecting gas formation in their tanks due to discharges in the insulation and thermal replicas for overloads are also provided.

2.4.4 Special Protection Systems

Special protection systems (SPS) are installed to counter specific events that could precipitate loss of synchronism or other such major disturbances [2.1]. Many of these systems make use of extensive communications to bring together information regarding the current status of the system. Examples of special systems include: complex inter-tripping arrangements, load shedding in response to frequency transients, detection of dangerous cascading overloads and the monitoring of phase angles to check for the onset of synchronous instability. The latter example is finding increasing application as phasor measurement units (PMU) are installed across the network.

A key trend in this area is making sense of the abundance of information that could be available and is akin to previous issues that arose in operator support when the number of alarms and indications increased significantly in the late 1980s/early 1990s [2.22]. The filtering or processing of data streams at different levels and minimising undue complexity are seen as being important aspects of these wide area systems.

2.5 Distribution Networks

The complexity of protection applied to distribution networks varies tremendously down through the voltage levels as individual circuit ratings decrease, whilst at the same time the size of the asset base increases significantly [2.22]. The net impact of this is a desire for cost effective solutions at the lowest levels of the network.

The main elements of a typical distribution network are shown schematically in Figure 2-6. Distribution networks are connected to the transmission infrastructure at grid supply points (GSP) where a typical voltage transmission ratio would be 275 or 400 kV to 132 kV. Overhead line distribution is commonly used at 132 kV to link with bulk supply points (BSP) where larger demand groups are connected.

At a BSP, a voltage transformation of 132/33 kV would typically be used. The circuit construction at 33kV is a mixture of underground cable and overhead line depending on geography. Primary and secondary substations use the voltage transformations 33/11 kV and 11/0.4 kV respectively. At these lowest voltage levels cable circuit predominate where the vast majority of consumers are connected to the network. A radial structure is used where possible with many circuits operated in an open loop configuration (using a normally open point or NOP) to improve resilience to network faults. Note that the ring main units have been omitted from Figure 2-6 and the NOP is represented by a simple switch to simplify the diagram.

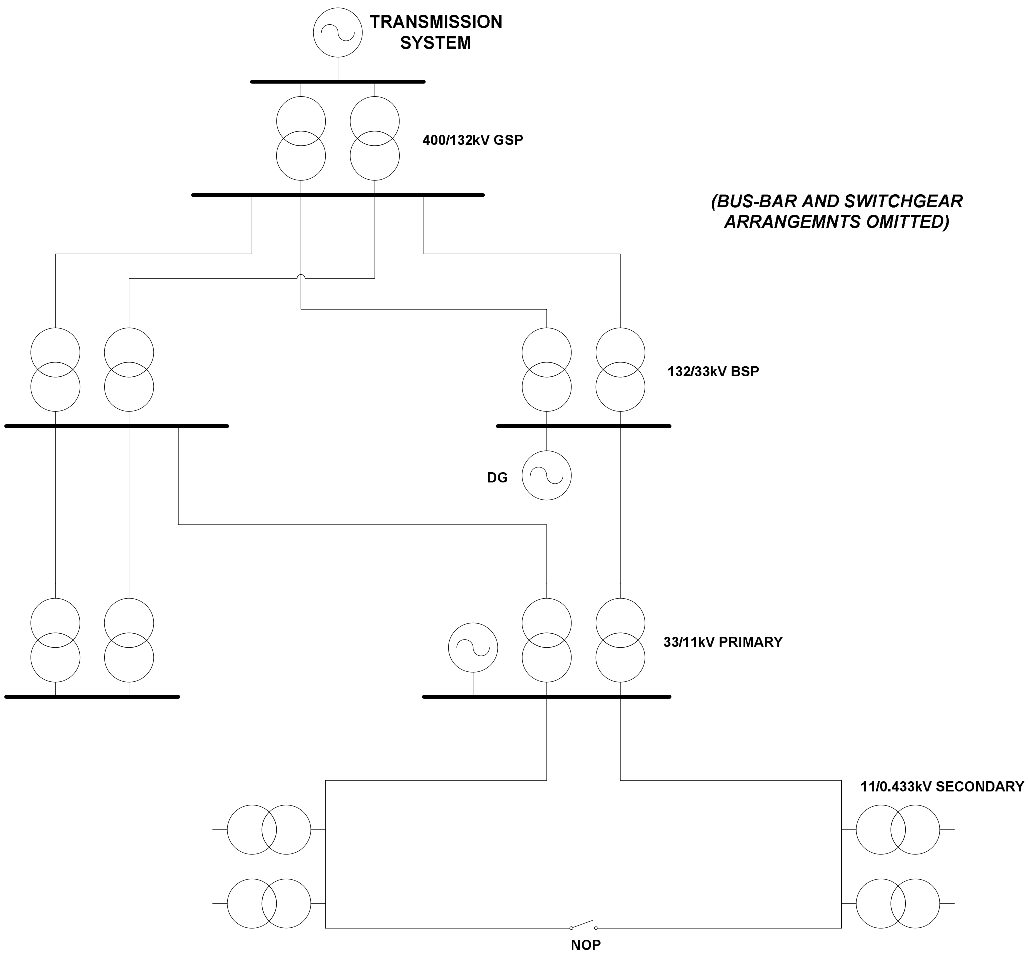

Figure 2-6: A typical distribution network in the UK.

2.5.1 HV Distribution

These networks are protected using a variety of different protective schemes depending on the design philosophy used and the geographical area that they cover. Although fault levels vary depending on factors such as circuit length, typical values for 11 kV and 33 kV substations are 200 MVA and 700 MVA respectively [2.2].

Coordinated inverse overcurrent and earth fault elements along the length of radial circuits are used on 11 kV circuits. High-set instantaneous or definite time overcurrent and earth fault elements can also be used to accelerate tripping times under certain circumstances where appreciable impedances separate parts of grading paths (e.g. transformers). More complex interconnected network configurations or circuits at 33 kV may make use of unit (current differential) schemes for reduced relaying times. Chapter 6 provides further details of typical protection that would be installed on an HV network supplied from a primary substation.

Distance protection is also used at the higher voltage levels of the network between GSP and BSP (132 kV) where the costs of an additional voltage measurement can be justified. Separate back-up relays for the distance protection are also to be found at the higher voltages and would typically use overcurrent elements.

Directionally sensitive elements are provided where necessary depending on network topology. Schemes may also make use of multiple settings groups on numerical relays if a single group proves to be insufficient; however, this is not common on most networks and would be restricted to specific problems (e.g. the switching of parallel circuits). Additionally, given the highly transitory nature of faults within rural overhead line circuits, extensive use is made of delayed auto-reclosers and downstream sectionalisers. Typical maximum clearing times for 33 kV and 11 kV protection schemes and their associated circuit breakers are 300 ms and 1.5 s respectively.

Network automation equipment is increasingly being installed onto HV networks to minimise the level of customer minutes lost (CML) which is a performance index that is monitored by the UK industry regulator Ofgem. Schemes are typically based around the closing of NOP to reconnect groups of consumers using an alternative point of supply after the operation of upstream protective devices on the normal route of supply. VHF radio communications is often used in rural areas as the costs of fixed copper signalling would be prohibitive. With this trend towards automated network reconfiguration, the challenge emerges to ensure that all possible configurations are adequately protected and that their actions are coordinated to ensure optimum post-disturbance switching sequences.

2.5.2 LV Distribution

The prevailing practice for protecting LV (400 V three-phase) distribution networks from overloads, short circuits between phases/neutral and earth faults is to apply coordinated non-unit overcurrent principles. This approach is achievable as within distribution networks the fault levels are generally high enough such that a significant disparity exists between normal load currents (and starting inrush) and those that occur when the system is in a faulted condition. The impedance between the secondary substation transformer neutral point and earth and within the cable earthing arrangement is kept as low as possible to ensure that separate earth fault protection is not required. Within the UK fault levels of around 20 MVA are commonly experienced at LV (three-phase) points of supply at secondary substations.

Fuses are used to protect LV circuits and exhibit what is akin to an extremely inverse characteristic. These devices operate to clear faults quickly in the relatively high fault level environment and would be installed on the circuits leaving the LV boards in secondary substations. The current limiting property of many fuses is a very useful feature and restricts the electromagnetic stress imposed on equipment in the fault path. Fuses are an ideal protective device owing to their simplicity and low costs which are important given the extremely large number of installations.

2.5.3 Low Frequency Demand Disconnection

When the frequency of the power system falls dangerously low due to the unexpected loss of a large amount of generation, under frequency relays are provided to disconnect groups of demand at distribution. The settings of these relays are staggered such that defined amounts of demand are disconnected at carefully selected thresholds with the intention of arresting the fall in frequency. In the UK this system is called low frequency demand disconnection (LFDD) and has its first frequency threshold at 48.8 Hz [2.24].

Under frequency load shedding is also used extensively within industrial power systems that may have to operate in isolation from the grid with limited local generation reserves. In these cases, demand is shed to ensure that vital services can still be supplied immediately after disconnection from the grid (if the net import was high) or if generation trips once the system is islanded. Settings are calculated based on the inertia present within the network and the likely loss of generation.

2.6 Generator Protection

A list of typical functions that would be applied to three-phase generators in the MVA range connected at distribution voltages is listed below [2.25]:

- Voltage controlled/restrained overcurrent and earth fault
- Stator earth fault
- Stator overload
- Reverse power
- Under and over frequency
- Under and over voltage
- Loss of mains (LOM)
- Neutral voltage displacement (NVD)
- Current differential

The issue of detecting if a generator is islanded from the grid (so called loss of mains) is an area that has received much attention in recent years and the requirement for its use in the UK rests in engineering recommendation G59/2 [2.26] (and G83/1 [2.27] for smaller kVA range machines). The following section reviews this function in more detail.

2.6.1 Loss of Mains Detection

The term loss of mains (or islanding) is used to describe the condition wherein a generator is inadvertently isolated from the grid and continues to supply local demand [2.28]. Such an undesirable eventuality could potentially occur due to circuit tripping by protection activity or, perhaps more rarely, accidentally due to network reconfiguration. Figure 2-7 illustrates these two possibilities: both a fault as shown on the substation bus-bar (circuit breaker opening) and the erroneous operation of the indicated switch (that could form part of an RMU as part of an automation scheme) would isolate the generator and local demand from the system.

It is informative to note that as levels of automated network reconfiguration increase alongside DG connections, a similarly increased likelihood exists for the formation of unplanned islands in the future.

An islanded condition is unacceptable for a number of reasons [2.25], including: the risk to utility operational staff whilst reconfiguring a network that would formerly have not been energized; exposure to the stresses caused by out of synchronism re-closure; and the provision of a poor quality supply to local demand. In all cases the burden of commercial responsibility will rest with the utility and, consequently, their connection agreements will require that generator operators install suitable protection with which to detect this condition.

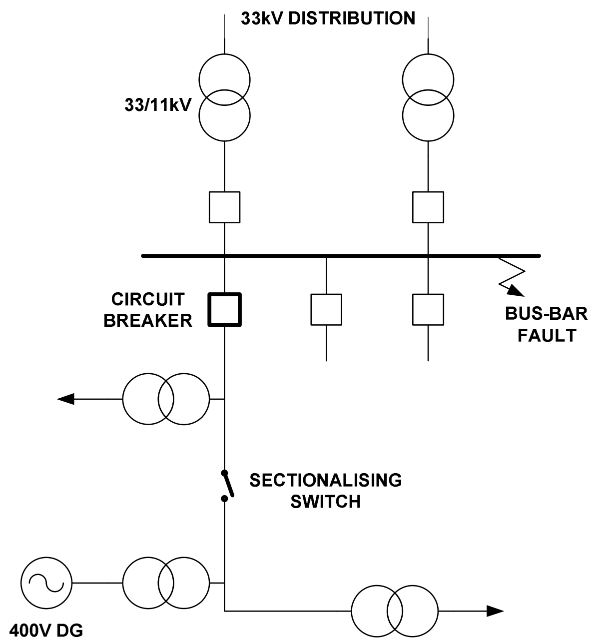

Figure 2-7: An illustration of the loss of mains problem.

The comments made above are reflective of current practices with regard to islanded operation and the viability (and indeed usefulness) of this condition has received much attention in the research literature. Many authors have proposed that, under controlled circumstances, islanded operation should be permitted as a means of improving the quality of supply for consumers. If islanding is permitted, then an important aspect of LOM protection will be to detect when an area should be electrically isolated at a specified boundary (e.g. a circuit breaker at a commercial boundary), and then to initiate the changes in control system mode necessary to ensure stable frequency and voltage (e.g. moving from real power/power factor to voltage/frequency control). This concept is returned to later as a means of initiating the adaptation of protection settings within an islanded network.

2.6.1.1 LOM Detection Methods

The performance of LOM protection can be assessed in terms of sensitivity and stability. For the former criterion, this relates to the smallest possible detectable mismatch between local generation and demand at the instant of islanding. Some authors use the term non-detection zone [2.29] to quantify this as a percentage imbalance based on the generator rating. For stability, the criterion can be defined in terms of fault types, duration and retained voltage at the point of measurement. Thus the objective for designing a LOM method is to provide a small non-detection zone whilst ensuring that stability is maintained for as many fault characteristics as is practically possible. As would be expected, designs and their settings are inevitably a difficult compromise between these two criteria.

Passive methods of detecting LOM rely on direct measurements and some derived quantities. The most basic example being the application of simple under/over frequency and voltage elements set with parameters at the boundary of normal statutory limits. Although these will perform satisfactorily in cases where the mismatch between local generation and demand is always known to be large, they suffer from a comparatively large non-detection zone leading to possible delays in tripping.

Alternatively, derived quantities such as the rate-of-change-of-frequency (ROCOF) [2.30] or voltage vector shift (VVS) [2.31] can be used. These offer superior sensitivity as their settings allow detection to take place within statutory limits, but their settings must be carefully selected to avoid mal-operation during network faults. The trade-off between the two performance criteria is especially difficult for these methods.

A further method is the use of direct inter-trips from possible points of isolation. Some utilities will specify this as part of their connection arrangements should they assess the likelihood of near balance conditions to be unacceptably high. This method evidently suffers from a high capital cost and a single inter-trip would only provide protection from islanding at a single location. Extending a scheme's scope is costly and will lead to complex signalling and marshalling arrangements.

The basis for many of the proposed active LOM methods is the use of a modified generator control scheme that, when islanded, will make the changes in frequency or voltage more easily detectible. A positive feedback loop that inherently destabilizes the output (when islanded) of the generator is proposed added to achieve this and the actual protection is based on simple over/under frequency and voltage elements. Examples of methods include active frequency drift [2.32] and current injection [2.33].

Although the results presented to date have shown the potential for possessing very small non-detection zones, their acceptability from a utility viewpoint remains limited since generator controllers are not subject to the same levels of rigorous testing as would be expected of protection. There is also some evidence that several of the proposed methods may have a detrimental impact on power quality for surrounding loads. With these in mind, passive methods are almost exclusively used in practice.

2.7 IEC 61850 Standard for Substation Communication

IEC 61850 is the international communication standard relating to substation automation systems and, more generally, all IEDs such as protection relays [2.34]. The standard has an aim of providing true interoperability between different vendor's equipment. Furthermore, it should be noted that work is underway to extend the use of the standard to encompass substation to substation communications and other utility applications. A brief overview is provided below on the main principles behind the standard.

2.7.1 Basic Principles

The standard is based on the principle of abstracting the definition of data items and services from the underlying low level communication protocols [2.35]. These abstract definitions may then be mapped to any protocol that can provide the desired level of service. This abstraction is created by the use of models to represent key data items (e.g. circuit breaker status) and services (e.g. open or close circuit breaker).

The modelling begins with the concept of the logical node which is a grouping of data and services that are associated with some power system function (e.g. a circuit breaker). A strict naming convention is used for logical nodes using prefixes (e.g. P for protection and X for switchgear). Furthermore, the type and structure of data associated with a logical node is specified according to the common data class as defined in Part 7-3 of the standard. One or more logical nodes can be associated together to form a logical device and is the basis of representing complex multi-function IEDs and any associated primary or secondary equipment. The substation configuration language which is based on the eXtensible Markup Language (XML) can be used to construct the overall model of the substation to define the levels of logical nodes and devices. Figure 2-8 provides an illustration of the hierarchical structure that is used by the standard including all components ranging from the physical device to data attributes.

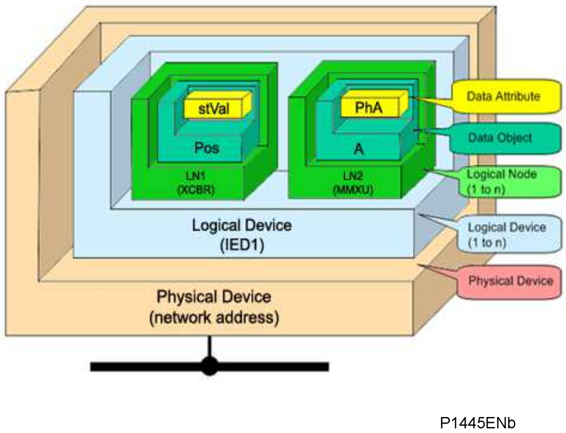

Figure 2-8: IEC 61850 data hierarchy [2.34].

2.7.2 Communication Methods

This standard defines the structure of the data and the methods by which it can be transferred without defining the low level protocols. Communication between logical devices is on a publisher and subscriber. The communication is functionally defined at two levels: the process and station. For the first, a standardised structure has been defined for the sending of sampled values that represent measured power system quantities that replaces conventional secondary wiring. Time synchronisation is required to ensure that corrective measures can be put in place by protection IEDs.

Merging units as discussed in a previous section are used to generate and broadcast the sampled values. At the station bus level, GOOSE (Generic Object Orientated Substation Event) messages are used to transfer either binary status information or analogue values. The publisher writes these to the local buffer where they are obtained by the subscriber.

2.7.3 Application Examples

The power of the standard is best seen by considering several application examples. Figure 2-9 below provides an illustration of a process bus application to send current and voltage sampled values to a circuit protection relay (in this example only the Ethernet controller is shown). A GPS clock source is indicated and the communications is based on a 100 Mbps Ethernet LAN. The communications topology has been omitted, but its reliability is vital for ensuring that the required level of performance is obtained for protection applications.

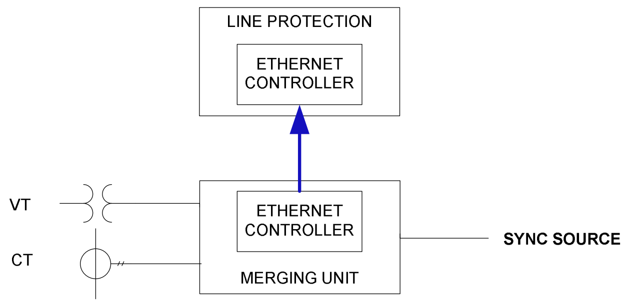

Figure 2-9: IEC 61850 process bus application example.

The higher level of communication is called the station bus and here GOOSE messages are exchanged on the basis that there has been a change in status of a data item in the publishing IED. As an example consider the use of GOOSE messages as part on an adaptive transformer protection scheme. The sensitivity of differential protection applied to transformers can be improved if ratio corrections applied to current vectors are adapted to reflect the current tap position (i.e. the ratio variable within algorithm adapted). It is suggested that GOOSE messages are used to pass information relating to changes in tap position from the tap changer IED to the differential protection IED.

To implement such a scheme, the current tap position needs to be sent to the differential relay when it is changed by the tap changer relay using an analogue GOOSE message. Upon receipt of this information, the protection IED can make the necessary ratio correction based on a lookup table of tap positions. A simple scheme is outlined in Figure 2-10 (current measurements and circuit breaker trips have been omitted and a simple communications topology used). In this case, the transformer differential IED subscribes to the tap position GOOSE message published by the Tap Changer IED.

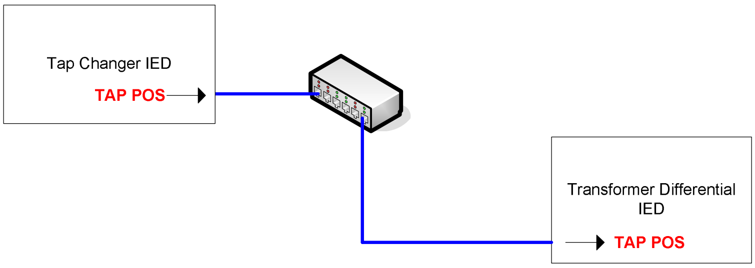

Figure 2-10: IEC 61850 station bus example.

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3 Development of a Novel Adaptive Protection Architecture

The underlying electrical characteristics of a power system are constantly changing during the course of normal operation due to a variety of different reasons. For example, changes in generation capacity as well as circuit outages for routine maintenance all frequently occur as operators manage the needs of the system. Furthermore, the result of one or more protection trips to remove a faulted circuit can also have a significant impact on the network structure, thus altering the impedance between the equivalent system source and a subsequent fault location.

Given that the selection of a particular scheme and the calculation of settings are based on a detailed understanding of such characteristics, the process is invariably a compromise. This is based on the need to provide a workable solution that will correctly identify and coordinate for faults within likely system configurations [3.1]. However with the developments experienced over the previous decades in numerical relays and communications technologies in mind, it would now seem reasonable to consider how relays can be adapted whilst in service to more accurately reflect conditions within the primary power system. Indeed it is widely acknowledged that the performance of protection can be enhanced if such a technique is reliably applied [3.2].

This chapter outlines the basic principles behind adaptive protection and presents an abstracted functional architecture that helps support its practical implementation. In so doing commonly expressed concerns covering safety and practicality can be satisfactorily overcome.

3.1 Chapter Outline

The work presented in this chapter firstly introduces the general concept of adaptive protection in §3.2. The principal drivers for this technology are then set out in §3.3 and are an elaboration of those given in the introduction. A review then follows in §3.4 of the developments in adaptive protection as published in academic literature that is used to identify the different approaches that have been explored to date. These are analysed to identify the main unresolved philosophical design issues and barriers to the adoption of the technology. §3.5 details the key functions that are required within any implementation of adaptive protection and then structures these according to their role in the process. A basic methodology is also outlined for designing adaptive protection in §3.6. Based on this, a new approach is described in §3.7 to realise adaptive protection in which a layered architecture is used to functionally abstract the key elements of its implementation. The tasks at each layer are described and their relative functional and physical locations discussed. A system level view is taken as a means to defining a strategy towards successful adoption of this technology.

3.2 The Concept of Adaptive Protection

Adaptive protection as a concept has been theoretically possible since the development of numerical relays using powerful microprocessors with access to reliable and extensive communication infrastructures [3.2]-[3.4]. The practice, however, has not seen widespread application despite a reasonable level of academic research having been conducted in the field (recent published examples include [3.5]-[3.16]). Some major reasons often cited by utilities include a lack of confidence in the validity of automated changes applied to a safety critical system and, moreover, that current operational practices have not necessitated such advances in order to maintain scheme performance. Consequently the risk of injury and impact of costly system interruptions should incorrect operation occur have understandably dampened industry interest in this concept. An initial objective of this chapter is to consider the ongoing validity of these views (e.g. if the smart grid vision is realised) and, by subsequent careful understanding of the salient issues and risks, propose how these can be overcome.

3.2.1 A Working Definition

With the above comments in mind, it is now appropriate to formulate a working definition of adaptive protection. Conventionally for non-unit schemes, the protection engineer will calculate a group of settings that best minimises the operating times and ensures coordination between adjacent protection devices in major grading paths. In the majority of prevailing circumstances this proves to be satisfactory and no further analytical work is required. However, specific primary equipment changes – principally concerned with the frequent switching of a considerable network impedance or modification of generation capacity – can necessitate the use of an additional group of settings to ensure satisfactory performance. Switching between these groups that are stored in memory within numerical relays might be accomplished by means of hardwired signalling from equipment that is indicative of the primary system change (e.g. circuit breaker auxiliary contacts) [3.17].

Thus the term 'adaptive' when applied to protection refers to the automated real-time modification of settings triggered by changes in the primary power system or, perhaps, the failure of secondary devices such as measurement transducers. Fundamentally, therefore, the challenge of adaptive protection firstly rests in identifying suitable sources of information and then, secondly, in managing validated changes without compromising coverage or performance.

At this stage it would also be useful to define two further terms that will be used throughout this chapter in relation to the process of adapting protection. The term *validation* will be used to describe the process of checking the correctness of the particular settings change selected, whereas v*erification* will be used for checking that it has in fact been implemented.

3.2.2 An Existing Example

Although it has been noted that adaptive protection in its strictest sense has not experienced widespread application, there are some existing relaying functions that can fall into this category. As an example, consider the case of voltage controlled or restrained overcurrent that is frequently installed as part of protection schemes for generators connected at distribution voltages (an example IED providing these functions can be found in [3.18]). In these functions, the effective pickup setting[7] is adjusted in accordance with the magnitude of the measured voltage such that comparatively low currents due to close-up faults near the generator terminals are still cleared (and, importantly, in a timely manner). Due to the extensive application of this feature over many years it is not commonly regarded by many engineers as

[7] The term 'effective' has been used here as the main setting for the current pickup as applied by the user remains unaffected. It is modified dynamically within the relay to reflect the information obtained by measurement from the primary system.

being within the area of adaptive protection. Nonetheless it serves as an example in which relays can undergo changes in effective settings depending on other power system measurements or status indications. Perhaps a key factor in the acceptance of voltage controlled or restrained overcurrent is that the function is only reliant on a local measurement. Its performance can therefore be easily checked using a straightforward testing procedure using basic secondary injection equipment.

However, the wider definition of adaptive protection naturally takes advantage of many different remote sources of information. Consequently it would seem initially difficult to establish sufficiently robust test procedures that are not impractical to apply if many distributed sources of information are used. Verification and validation of changes made during adaptive protection operations are important related issues and will be discussed in more depth later in this chapter.

3.3 Drivers for Adaptive Protection

Like any area of engineering, technological advances in protection must demonstrably address emerging industrial problems by offering substantial performance improvements or cost reductions over existing methods. Although it is widely agreed in the research community that adaptive protection as a concept has some merit (as judged by the publication activity), it is worth considering why the drivers for its use are only just beginning to take meaningful form. Indeed it has been commented previously that distribution networks did not present challenges of sufficient complexity that would warrant a parallel increase in that of protection. This argument may prove difficult to justify in light of how distribution networks are to be operated in the future (i.e. smart grid developments).

The feasibility of an increase in protection complexity may in fact serve as an enabler for network operating practices that offer lower cost solutions for generator connection and improvements in security of supply for consumers. Both of these have the real potential to provide the necessary justification for additional capital equipment expenditure. Figure 3-1 provides an illustration of the drivers and enabling technologies behind adaptive protection and relates these to their implications for several important performance criteria used during scheme design.

The relationships between the drivers and the performance criteria are varied with different weightings depending on the particular application being considered.

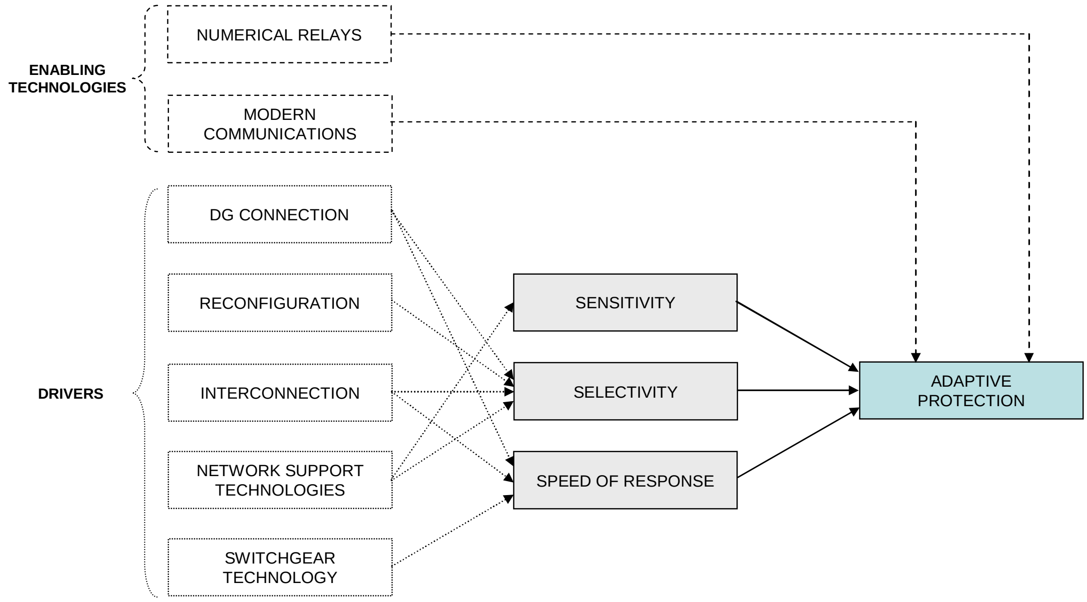

Figure 3-1: Drivers and enabling technologies for adaptive protection.

The following two sections describe these drivers in more detail from the perspective of distribution networks and transmission system in terms of their relative impact on the performance criteria.

3.3.1 Distribution Networks

As noted in the introduction, a number of issues arise at distribution voltages that are worthy of discussion in relation to emerging challenges for protection and are key to understanding the drivers for deploying adaptive techniques. Although many of these will appear in isolation in the near-term as DG is accommodated on an *ad-hoc* basis, the combined strength of these drivers will only reach a critical level for adaptive protection once DG becomes an integral part of the power system. This is in terms of both high local penetration levels of DG (e.g. where a primary fuel resources is available) and when the total national installed capacity becomes a significant portion of the generation mix.

Firstly, the connection of DG at various network locations will cause more complex fault current flows and is a problem for all but single-phase-earth faults.

This is the case because the majority of DG are interfaced without a connection to earth at HV (e.g. due to their interface transformer vector group such as delta-star). As a result they will contribute very little zero sequence current and thus fault current flows under this condition will not be affected[8]. With regard to other fault types at HV, many overcurrent relays are not provided with a voltage measurement with which to apply directional settings and, depending on the particular network topology, coordination issues could consequently emerge [3.19]. Furthermore, additional sources of fault current if connected downstream on existing radial circuits have the potential to reduce the reach of upstream relays. Addressing this complication when the generating source is intermittent (e.g. renewable) by using a permanent correction factor applied at the upstream relay may not always be possible. The emerging driver in this case is the requirement to design for highly intermit generation which is at a level that manual initiation of settings changes may not be feasible in the longer term in order to facilitate connections.

Secondly, changes in grading paths may occur due to automated network reconfiguration and the use of permanent interconnection to minimise utility exposure to regulatory penalties surrounding customer disconnection. In these cases it is the coordination or selectivity between adjacent protection devices that may be compromised as changes are made in the primary system (e.g. the dominant source of fault current may now flow from a different direction within the reconfigured network topology).

Moreover, circuit interconnection could be a way of overcoming thermal constraints or maximising asset utilisation and is therefore a possible driver for protection to be enhanced. It could be argued here that there are existing examples of applying unit protection as a main scheme to cater for such a practice. Although this is indeed true, the schemes are based on older relay technologies and dedicated point-to-point copper pilot wire communication channels. The driver with that problem in mind is to take advantage of more modern technologies and in so doing provide the same, but preferably better levels of performance. Significantly, the need

[8] This is based on the assumption that the network supply transformer neutrals are used as a single point of earthing. These will provide a single-phase fault current contribution that will be much larger than any originating from unearthed 11kV DG or LV DG generation connected using a delta-star transformer via their parasitic capacitance to earth (on the HV winding side).

to make use of more modern communications is given impetus by the fact that the leased pilot wire circuits currently in use may not be available in the future as telecommunications providers upgrade their networks[9]. Some caution however must be exercised when considering the use of further communication as the capital expenditure is still likely to be high for many applications. Any performance enhancements must therefore be readily quantifiable for the network operator.

Increased variation in fault levels can result due to automated reconfiguration (including intentional islanding), use of power electronic devices [3.20] and installation of fault current limiting devices all intended to enhance network performance. The pickup setting of overcurrent devices may need to be reduced during times of low fault level; but this could be in conflict with the need to remain stable when presented with cold load pickup[10]. But perhaps more significant is the suggested islanding of LV microgrids supplied exclusively by inverter interfaced sources. These present what is possibly the worst scenario (with respect to fault detection) in which the available fault current from the inverters may not be very much greater than their nominal load ratings. Under these conditions, the very application of conventional overcurrent principles is called into question as the inverters used to interface generators can only typically provide around 110% of their rating [3.21] for a period of time without being deliberately over specified.

Two approaches are possible for resolving this issue for microgrids: firstly, the existing protection settings can be adapted; or, secondly, an attempt can be made to find a completely new way of detecting faults. The latter suggestion suffers from the fact that although there are many ways of detecting a fault (e.g. the interpretation of fault generated noise using various artificial intelligence techniques), the problem of fault location which is required to establish a coordination methodology invariably still remains. This issue is discussed further in chapter 4 which examines microgrid

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[9] Telecommunications providers are moving towards using packet switched principles as opposed to more traditional connection orientated services. Although this offers many advantages for certain services, concerns have been raised regarding a lower level of performance (e.g. latency) for protection applications such as inter-tripping.

[10] The level of cold load pickup could increase as demand growth could be hidden by the connection of DG (demand being reconnected before generation) and so the use of lower pickup settings, although superficially possible, may not be feasible.

protection. It is shown that the simplicity of LV networks allows for the solution of limited fault level to be achieved without undue scheme complexity.

Lastly, the increasing sensitivity of customer loads and certain small generators to even short-term supply interruptions or voltage reductions promotes a general reduction in the acceptable total clearing time for faults [3.22]. Although methods exist for improving stability of generators, their application to those of every small ratings may not be cost effective. Advances in power electronics may also result in the development of cost effective solid-state switchgear [3.23] which in turn would require that grading margins or the fault level be reduced in support of their application[11]. It is clear from the above that a strong argument emerges for reducing fault clearance times at distribution voltages. Unfortunately automation and many methods for actively managing networks can be in conflict with this aim. If fault level is reduced due to their actions then the operating times of relays that have settings not accurately matching the changed primary systems will be increased. As a specific example, consider the use of fault current limiters to actively manage the fault levels with a part of the network [3.24] to ensure that the ratings of switchgear are not exceeded as more DG is connected. Although the severity of the voltage sag for consumers not directly within the fault path (and so electrically distant) will be reduced due to the increase in impedance [3.25], the duration of the fault may be lengthened if protection settings are not adapted to reflect the lower fault current flowing. Thus sensitive loads or generation electrically close to the fault path would have to be tripped to avoid damage or instability. It is apparent that a changing network gives rise to a challenging environment for protection in which settings may have to be adapted during the course of normal system operation to ensure that the desired levels of performance are maintained.

The potential interaction between of all the factors behind the drivers outlined above is a good illustration of the complexity that will emerge as distribution networks become active: both in terms of their primary behaviour and supporting

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[11] The semiconductor material used within these devices do not posses the thermal properties required to carry high fault currents for the sustained periods of time that would be required for conventional coordination delays [3.23]. Thus although fast switching is advantageous for reducing the impact of fault disturbances on sensitive equipment, they are in fact necessary to support the application of the devices otherwise semiconductor based circuit breakers would be damaged whilst waiting to operate when their associated protection is acting as a backup.

secondary systems. This complexity underlines the need for careful coordination between protection, automation and network management systems at all stages of their development such that information is made readily transferable between devices or systems. It is clear that protection settings must respond to the changes in the network, but it is also suggested that protection could to a lesser extent dictate what changes are possible in the network. Protection is currently reactive when faults actually occur but by being proactive the risks of disturbances under a new operating configuration can be minimised by changing their settings in advance. For example intentional islanding could be blocked if insufficient fault current is available for protection to operate reliably.

A key research question that emerges is in relation to how this concept can be put into practice without the complexity in itself becoming a barrier to the adoption of the technology. Indeed the full realisation of the smart grid concept at distribution will be heavily dependent upon the answer to this question.

3.3.2 Transmission Systems

The discussion of drivers in the preceding paragraphs has been centred on distribution voltages. At first this could appear to be inappropriate since historically advances in protection have been driven by transmission applications where the development costs can be justified by the importance of the primary equipment. However, the wider drivers for protection that are based on changes in the primary system are now becoming immediately apparent at distribution voltages with the moves towards creating what has been termed a smart grid within these networks. Although it should be noted that this thesis will also include those devices installed at distribution to serve a system level function (e.g. LFDD relays [3.26]).

Furthermore, although not the subject of this thesis, it is suggested that some degree of adaptive principles may also be required within transmission systems. Problems for protection could emerge due to a reduction in available fault level (due to the different characteristics of the generators used for renewable energy and the use of HVDC links to control power flows[12]), line protection on circuits with FACTS

[12] Lower fault levels within the transmission system are possible due to the closure of large conventional thermal units and the use of HVDC to upgrade key transmission corridors [3.27]. As

devices installed (e.g. controllable series compensation) or protection related equipment such as auto-recloser relays. In the last example, metrological or system state information could be used to ensure that the dead times applied are better reflective of the needs of the system at particular times of stress.

3.4 Research Reported to Date

Existing work within the field of adaptive protection has principally concentrated on how adaptive features can improve the performance of specific schemes using relatively locally sourced data. For example, the adaptation of impedance characteristics within distance relays to improve their immunity to high fault resistances [3.9] has received attention. Another clear observation already alluded to is that studies have been focussed on transmission systems: the complexity of these systems and the costs associated with mal- or non-operation of protective devices at this level providing the necessary justification. The recent series of system blackouts has also stimulated fresh interest in the application of adaptive protection; although in these cases it is proposals for wide area or special systems that have been most prominent [3.6]. The next section reviews some specific recent examples published in the academic literature[13]. Following from this, some unresolved issues and barriers to the use of the technologies are presented that are apparent from the work published to date.

3.4.1 Review of Recent Literature

The literature review in the following sections is organised under three headings that are related to how adaptive protection research has advanced since its first proposal: modification of individual relay characteristics; automated online settings calculations; and finally wide area schemes. By considering each of these in turn it is possible to identify key philosophical design issues that emerge in putting adaptive protection into practice.

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noted in the text the main protection will be mainly immune to reasonable drops in the available fault levels. However the same might not be true for overcurrent elements which are used as a backup.

[13] Other somewhat simpler examples that find practical application include the use of settings groups to deal with occasions when equipment outage significantly reduces fault levels (such as the removal from service of one of several grid supply transformers within an industrial network).

3.4.1.1 Characteristic Modification

Many publications have considered how specific characteristics can be modified to improve relay performance. This has included, as examples, some numerical methods (e.g. phasor calculation windows [3.7]), impedance plane characteristics [3.9]-[3.12] and ratio correction in transformer differential protection [3.13]. Many of these offer tangible improvements in performance over conventional alternatives and require, in the main, only local measurements or status information. This has arguably been the most successful aspect of the adaptive protection concept to date as manufacturers have implemented some of these features to differentiate their products from competitors. However, it can also be argued that many such proposals for adaptive features have remained unused in practice as the increase in commissioning complexity and computational burden was not justifiable given the performance returns. In some instances simply including more conventional elements within a multi-function IED is more marketable and a better use of microprocessor capacity.

3.4.1.2 Online Centralised Settings Calculation

The development of automated techniques for relay grading received much attention as access to affordable and sufficiently powerful computing systems started to become widespread in the 1980s and early 1990s (e.g. the tools developed in [3.28] and [3.29]). These techniques offered the potential for improving performance through the calculation of optimal settings for a given system configuration. Many straightforward algorithmic as well as artificial intelligence (AI) based techniques have been proposed for what have historically been complex coordination problems (e.g. overcurrent relay coordination in loops with multiple sources of fault current contribution) [3.30]-[3.32].

This work was naturally taken a step further when it was proposed that this could be done online in response to changes in the primary system [3.33]-[3.35]. If necessary, new settings would be calculated centrally and then sent out to relays within substations for application to specific elements. Although it was entirely reasonable to consider this proposal, a number of concerns emerge that have resulted in no serious attempts at practical implementation.

The time taken to perform the re-grading and transmission of settings could lead to the system being in a poor or unprotected state if the process is simply reacting to primary system changes. This approach would only be feasible in a proactive sense if details of a proposed change were known in advance. The optimal or best compromise settings would then be available for synchronised application as the change is made. This could be based on GPS time coordination of both the primary and resulting secondary system changes across the system.

For the short-circuit protection that was used for illustration within the publications it should be noted that, putting aside a theoretical desire for mathematically optimal settings, the centralised architecture may not be entirely appropriate. Many short-circuit protection (e.g. overcurrent or distance) problems are quite localised in nature as they depend on the switching of electrically close circuits or other components. Thus both the cause and solution are confined within limited areas of the system and there is no need for global re-grading of protection devices. This implies that the differentiator between a centralised and decentralised approach is based, at least partially, on the scope of the primary system change.

Returning to the efforts towards applying optimal settings, the lack of practical applications would suggest that the potential returns are not sufficient when weighted against implementation difficulties. The true strength of the automated techniques has been for assisting with specific complex grading problems that really concern backup functions within complex transmission systems (e.g. overcurrent relays in a meshed network). At distribution voltages, the localised nature of problems and, more specifically, simpler network topologies possess protection challenges that can be better solved by the use of multiple settings groups providing satisfactory performance appropriate for the level of engineering that can be justified for implementing their schemes.

3.4.1.3 Alternative Wide Area Schemes

In contrast to the technique discussed above, the wide area approach to date has tended to centralise not only the process of settings calculation, but also the signal processing required for detecting faults. The main reason that emerged for doing this is to take advantage of a larger pool of knowledge concerning the condition of the primary system. In so doing it is assumed that better sensitivity and selectivity can be obtained leading to performance enhancements that offset the higher capital expenditure required for scheme implementation. However a legitimate concern to be countered concerns the reliability of both locating a complex protection function on a single device and the supporting communications system.

The techniques used for detecting faults have included both location based on transient information [3.36] and the use of enhanced multi-layered unit protection principles [3.37]. By centralising the protection function the problem of adapting schemes is reduced as the necessary system information is readily available and the widespread synchronisation of changes on many IEDs is avoided. Unfortunately the serious implications of failure modes such as the centralised protection hardware and communications equipment do raise questions in relation to scheme reliability and the potential levels of redundancy that would have to be included within any design to make the system practical.

More recently, further work has also been reported on taking advantage of PMU data to enhance system or special protection schemes aimed at detecting conditions that may have an impact on the overall system [3.38]. Schemes to avoid cascading trips due to circuit overloading when a system is stressed have also been reported [3.39][3.40]. The common factor in such wide area schemes has been access to more contextual or system level information and, to a certain extent, the longer timescales over which the protection is to make a decision regarding an undesirable condition (i.e. not a main protection for detecting and clearing short-circuits). The research reported to date would therefore suggest that this form of protection is best suited towards system level problems.

3.4.2 Barriers to Adaptive Protection

Adaptive protection as a technology has been constrained by many barriers since its first serious proposal around twenty years ago. Figure 3-2 provides a summary of the main barriers that have been recognised during this period of time. The emerging drivers for protection have been discussed in the preceding section and will not be explored further other than noting the observation that a clear method for assessing the cost/benefit of addressing these issues must be found.

Given the critical nature of the protection performance, legitimate concern may be voiced regarding the implications of an erroneous or incomplete change in relay settings. It is essential that at no time must any part of the system be in an unprotected condition and those responsible for authorising designs must be confident that this is indeed the case. It would also appear sensible that an adaptive protection scheme should in some way be fail-safe, but the method for proving this is challenging. A degree of risk therefore emerges with regard to transitions between settings and careful attention is required to fully understand all potential failure modes. Intuitively these modes are dependent upon a range of factors, including: communication channels, the mechanism with which changes are triggered and the methods that are used to implement and synchronise any settings changes. Fundamental to addressing these is the clear definition of the functional architecture of the scheme in which measures can be taken to mitigate the range of potential failure modes. It is also important that the interactions with non-protection devices or systems are managed. The fact that these may not be subject to the same level of certification must be borne in mind.

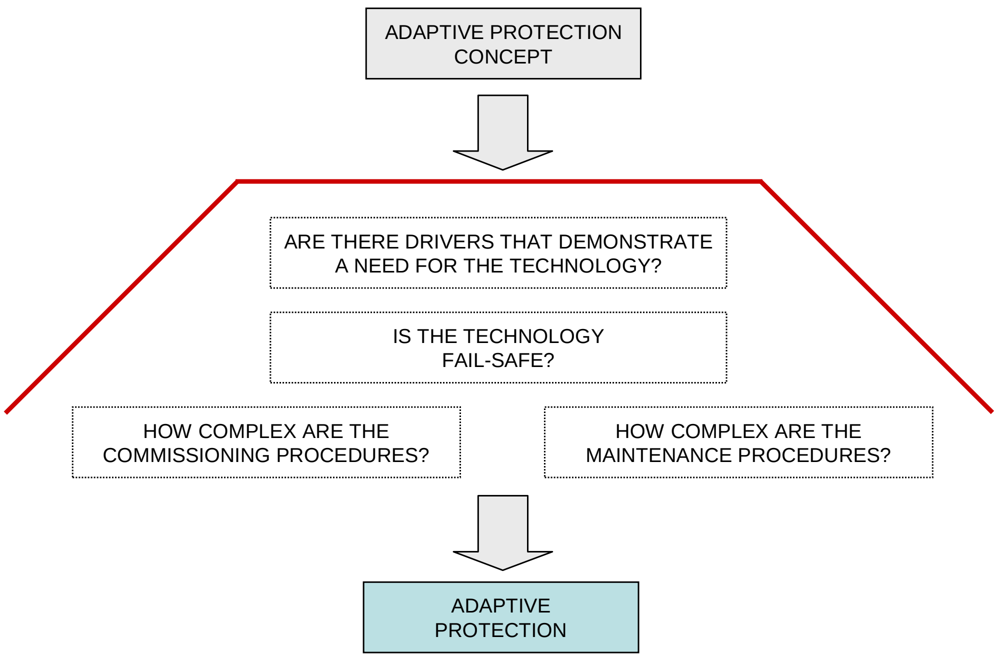

Figure 3-2: Barriers to the adoption of adaptive protection.

Two related barriers are that of complexity within commissioning and maintenance procedures. The number of inputs and possible cause and effect relationships suggests that formulating robust testing strategies may prove to be difficult. This is particularly true where the adaptive scheme is spread over a wide geographical area and thus it may be difficult to coordinate suitable test inputs (which may be numerous and interdependent).

To overcome the commissioning barrier, the design of the scheme must include suitable testing tools which can aid commissioning engineers in this process. These must be transparent and readily understandable as black-box solutions would not be accepted given the nature of protection. An advantageous aspect of any proposal must incorporate coordination with settings and other asset databases to ensure that up-to-date information is maintained on the extent to which a scheme may adapt.

Finally with regard to maintenance, the availability and quality of diagnostic information and its interpretation is of importance to work around this barrier. Provision of this data would be useful for some of today's more complex schemes, but it becomes even more important when the number of potential IEDs participating in a scheme could be higher and with different groups of settings. In this area the importance of suitable engineering tools should is be emphasised.

3.5 A Generalised Structure

To enable the widespread acceptance of the adaptive protection concept, the same rigour must be applied to the design of these schemes as has been the case for their conventional predecessors. However it is apparent from the literature reviewed that there has been little attempt made to assess adaptive protection as a concept in abstraction from the particular disturbance or numerical algorithm being analysed. This process is in fact essential for addressing the key concerns surrounding its adoption. Indeed the barriers discussed previously are independent of whether it is short-circuit or system protection. What is important is the manner in which a robust approach is applied to understanding how an adaptive safety or system critical component can be permitted to adapt in real-time.

A useful starting point is to consider the main functional stages for adaptive protection (applicable to all of the types described in §3.4) as is shown diagrammatically in Figure 3-3. The individual components are then considered in the following sections. Throughout the following sections it is assumed that the actual protection element (the signal processing for detection and any time delays or scheme logic) is functionally separate from the process of adapting settings.

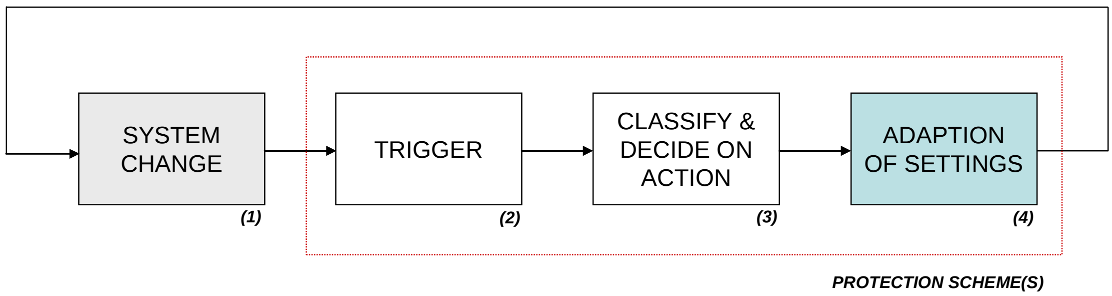

Figure 3-3: Adaptive protection functional stages.

3.5.1 System Changes (1) & Triggering (2)

The methods for identifying network configuration and state[14] transitions within the primary system are vital for the successful implementation of adaptive protection. Changes within the primary system configuration typically include: modifications to network topology, connected generation capacity and demand composition. Similarly, changes in the operational state of the power system may also require the modification of settings. For example, the temporary relaxation of overload settings for systems in an emergency state (or, alternatively, if environmental conditions permit in the case of dynamic circuit/equipment ratings).

The identification of changes can be based solely on local system measurements and equipment status indications or can be greatly assisted through the use of remote data. By using a wide range of remotely available measurements a better interpretation of the configuration and state of the primary system can be obtained by the protection system. Indeed when access to communications equipment is provided, the organisation and validation of remotely sourced data becomes crucial. Issues surrounding corrupted and missing data or the overall status of the communications infrastructure or other secondary components must all be

[14] The state of a power system refers to a classification such as normal, restorative, outage, action and abnormal [3.1]. Information on the state could be useful for system level protection functions such as the LFDD and anti-cascading wide-area protection schemes.

considered. Examples of potential local and remote data sources include plant status indicators (e.g. for switchgear), SCADA systems and Energy/Distribution Management Systems (E/DMS). The work at this level is an example of where good coordination of protection and control could provide significant improvements for both systems wherein data is more effectively exchanged.

At the most basic level, the triggering of adaptive protection can be based on the monitoring of binary status information from equipment such as switchgear. Indeed for simple schemes this will almost certainly be sufficient if the changes being reacted to are limited to simple switching functions and local in scope[15]. However, if the need to adapt the protection arises from more contextual system level information (as would be the case for state transitions relevant for system protection), then a more complex level of interpretation will be required. In such cases the criteria for monitoring could be numerous and highly interdependent upon a range of factors. For example: the state of the system from an EMS, connected generation capacity and metrological data from remote monitoring stations.

It is also important to consider how this information is delivered to the adaptive protection. Some sources may be suited to a hierarchical form of SCADA architecture with information being concentrated at different levels and then delivered to a central location. This would certainly be the case for system level contextual information. Alternatively, many primary equipment data sources will only be used locally to trigger adaptive protection and thus do not require such a large and elaborate architecture for real-time information exchange. Moreover providing protection IEDs with an extensive range of local signals will become easier as substation LANs remove the need for complex hardwiring of circuits for each signal (e.g. IEC 61850 being used for process and station bus applications).

3.5.2 Classification & Action Determination (3)

Once a change in the primary system has been identified, its implications for the current configuration of the protection scheme must be assessed and the appropriate action initiated. The nature of these functions will depend on the type of

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[15] Scope in this sense refers to the impact of the particular change. For example the removal from service of a single transformer will only have an impact on downstream fault levels whereas low generation capacity will be of relevance across the whole system.

protection that is being considered, its physical implementation and the supporting communications.

Firstly consider forms of non-unit protection such as overcurrent or distance in which the basic elements are located throughout the network adjacent to switchgear. For these schemes the changes in the system that are of importance specifically refer to how the short-circuit characteristics are modified, which in turn impacts upon the measured or derived quantity that they monitor. This could relate to how either network reconfiguration or changes in connected generation capacity alter the fault level or calculated impedance towards a potential fault location. The reconfiguration would tend to be localised, whereas any capacity change has a more global impact across the network affecting a large number of relays.

Theoretically, a system change could initiate a complete recalculation of settings for all relays. However as discussed previously, the prevailing practice is for settings to be calculated for a given worst-case system condition and then checked for others to ensure that grading and clearing times are still satisfactory. Unfortunately the anticipated future flexibility of the system means the likelihood of single group settings being sufficient will be reduced. It is important to bear in mind that the range of changes is not infinite and that since a group of settings can cover a range of fault levels or fault path impedances, it would imply that multiple groups of settings are more appropriate than some form of complex regrading exercise. Restricting the changes to predefined groups of settings also has the advantage that the safety of the system can be verified in advance (i.e. that it has sufficient coverage). What is thus required in terms of classification of a system change is at a design stage to identify what changes are likely and then determine the number of discrete groups of settings that will be required. The next problem to be addressed is how to determine what observable events are suitable and readily accessible to allow the change to be classified and mapped to an appropriate group of settings. The scheme designer must then establish some set of rules or logic with which to implement this mapping. A further enhancement could be to add redundancy to this by seeking multiple ways of identifying a system change so as to minimise the risk of unobserved changes, for example, due to temporary communication failures.

In some instances this will be straightforward. For example the islanding of a section of HV network at a primary substation will result in a much reduced fault level being available to operate short-circuit protection within the isolated system (this is examined in detail in chapter 5 as an example of applying the architecture discussed later in this chapter). The data source to be monitored to initiate a change would be the circuit breakers at which the isolation from the main grid has taken place. A more complex case is that once in an islanded mode the protection settings may require modification to use different characteristics depending on, for example, the capacity or type of generation in operation. Changing characteristics could be required to ensure that clearance times are small enough to avoid generator tripping prior to the onset of angular instability if the island is quite electrically weak (e.g. highly loaded synchronous machines at different locations in the network). In technical terms this may be achieved by switching to instantaneous tripping on feeder circuits as opposed to the more conventional use of IDMT. Clearly this could potentially sacrifice the supply security of some consumers, but in the stressed and unusual (i.e. not frequently occurring) condition of islanding this would presumably be acceptable. The data sources for this would be the different generators, loads (pre-disturbance loading would be an important consideration for a small system) and a network management system. The logic in this case would be more detailed and executed at a potentially slower rate than that for the previous example relating to short-circuit protection. The system would still be in an acceptable condition prior to characteristic changes from a safety point of view (i.e. faults would be cleared), albeit at a greater risk of generation tripping and complete loss of local supply. These two examples highlight differences that could occur in terms of time frames for decisions and logic complexity depending on the particular issue being resolved.

It is also important to consider what should happen if the change cannot be immediately classified. Primary system switching operations are limited in number and location and so these are likely to have been satisfactorily identified at the design phase. On the other hand failures in secondary equipment may not. For example the failure of a CT during operation could be identified by the monitoring function that is commonly available on numerical feeder relays. Rather than remain a hidden failure until the relay is called upon to act in the presence of a fault, this information should be interpreted and passed upwards for further consideration and action. Although there may be no adaptive action for the scheme to take, a key feature of future systems will be to make this information readily available to systems overseeing the operation of schemes and is a key architectural design requirement. The consequences of the failure could be assessed in terms of a fault being cleared by one or more other relays acting as a backup. For example a supervisory control system for a small area of a power system may, should this event occur, determine that too many unnecessary customer disconnections would take place. As a result it could initiate a network reconfiguration (which in turn could necessitate the adaptation of protection settings). This additional value of this enhanced performance will be important when adding to the business case for the increased capital investment required for adaptive protection.

Although centralised schemes for short-circuit protection over a wide area of network[16] have been proposed, they have not been developed into practical solutions. Hence for the remainder of this thesis the term centralised will relate to architectures that could be used only to adapt the settings of relays spread throughout the system. A good example being the under-frequency relays belonging to the LFDD system in the UK. Consider that the overall system has experienced a major event and that it has been split for operational reasons into several smaller islands. It is possible under these circumstances that the requirement to disconnect demand in response to a severe fall in frequency may change radically depending on location thus necessitating changes to the settings of the LFDD relays within the distribution networks. A resultant island, for example in the case of Scotland within the UK, could possess a relatively low inertia depending on the characteristics of the generation connected at the time of separation. This could be plausible during a time of high wind speeds where generation in Scotland would be dominated in the future by wind turbines taking advantage of this resource. Thus for a centralised scheme, details of the system provided by the EMS could be used to alter the thresholds for the different stages and zones in the LFDD scheme. It would not just be a simple matter of sending a single "system inertia" value to relays for them to switch between

[16] This qualification being necessary to differentiate what is being proposed from bus-bar protection which is centralised on a single relay but only relates to a single location on the network.

settings groups as the system may be best served by targeting resulting disconnections according to defined areas. It could be that a certain area may have a significant level of DG connected that is supporting the system and so disconnection of this by actions of the LFDD relays during a severe frequency disturbance would be counterproductive.

3.5.3 Adaptation of Settings (4)

The transition between settings or scheme logic arrangements must be strictly controlled in a synchronised timely manner and suitable verification procedures established. In many instances the change could involve the use of existing selectable settings groups on IEDs with additional checks introduced to confirm that the changes have been applied when requested. Commands could be sent over a substation LAN in the case of newer IEDs or via hardwired auxiliary inputs for older legacy devices.

The extent of the synchronisation problem again depends on the nature of the scheme. For the case of short-circuit protection, the schemes must be put in place in such a way as to ensure that the safety is not compromised at any time and thus the time taken for all changes to be made must be as small as is feasible. For other system level functions this time can be permitted to be slightly longer to account for the greater distances (e.g. at remote generator sites) over which the changes must be made and the slower nature of the phenomena being monitored or protected against. A contrast could be made between milliseconds for the former whereas seconds may be acceptable for the latter case.

A key part of the verification of the schemes changes will be in the collation of responses or acknowledgements. Failures to adapt can be interpreted and passed upwards to inform devices managing the network of a potential reduction in protection performance.

3.6 A Methodology for Scheme Design

The discussions in the preceding sections have been used to identify a methodology for designing an adaptive protection scheme as shown in Figure 3-4. The scheme designer must first begin with the set of operational scenarios for which the system must be protected. These are likely to have been defined by those responsible for planning how the network will be operated in the future in response to such factors as demand growth, DG connection and increasing the supply quality or security for consumers. An assessment must then be made of how the existing protection would perform given these scenarios based on the design philosophy currently used by the utility. If performance is not satisfactory, then the designer must then decide if the types of protection functions are still appropriate and, if so, then it is the specific settings that must be changed. In principle it could also be the case that the types of protection function may need to be changed (e.g. different characteristic curves) or added given the new fault behaviour. Moreover the performance criteria may change for reasons such as if the dynamics of the network are more challenging or if selectivity can be acceptably reduced if the system condition is regarded as being temporary and infrequent.

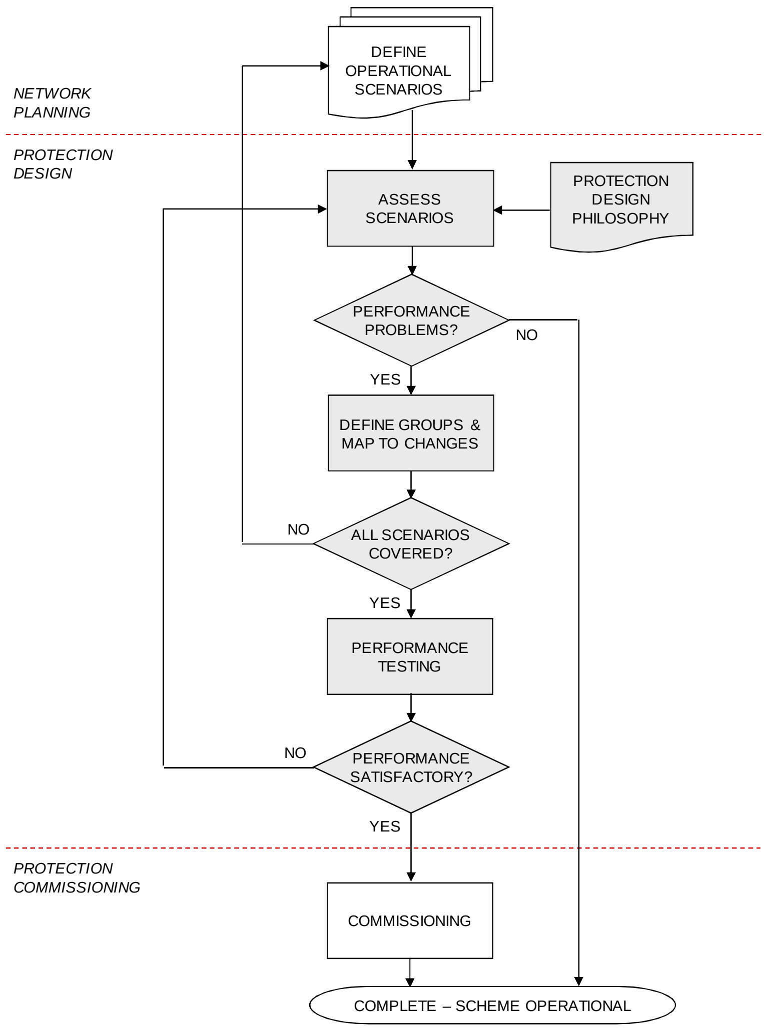

Figure 3-4: A methodology for designing adaptive protection schemes.

A design must be made for each scenario to give satisfactory performance and then the mapping of these to observable network changes must be made. Different sources of data must be identified and perhaps some consideration given to redundancy if the same network change can be identified from multiple sources.

The designer would also have the opportunity to consider the impacts of secondary component failures at this stage and define what information can be passed back to the DMS/EMS systems managing the network in addition to possibly making further settings changes on other protection devices. At this stage the designer now has different protection "schemes" for each scenario (which could relate to groups of settings on different relays) and a mapping of these to signals that are indicative of the changes that would take place as the primary system is modified.

A performance testing phase in the design methodology has been included as a means of checking that the groups have sufficient coverage for all foreseeable primary or secondary system conditions. This process could be highly automated within software design tools such that the original scenarios from the network planners can again be used as an input. Furthermore additional unforeseen conditions may also be identified here given that additional factors such as secondary equipment failures can also be factored into the process. These failures relate to those that could stop the protection adapting as intended and lead to either poor performance or even an unsafe condition. The commissioning phase has been included within the figure for completeness.

The whole process of adapting settings groups can also be thought of as the protection moving between different states and the transitions can be shown graphically. Figure 3-5 shows a simplified example in which the transitions between groups for a section of network that can be islanded are given. As an example, if the system moves from a normal operation state to being islanded, the three distinct groups (short-circuit, islanding detection and LFDD) are all changed. The trigger in this case being the opening of the circuit breakers at which isolation takes place. This could be particularly useful and informative for the designer in visualising how the overall adaptive scheme will function. In so doing the scheme operation will become more transparent and hopefully mitigate dangers inherent within the increase in design and implementation complexity.

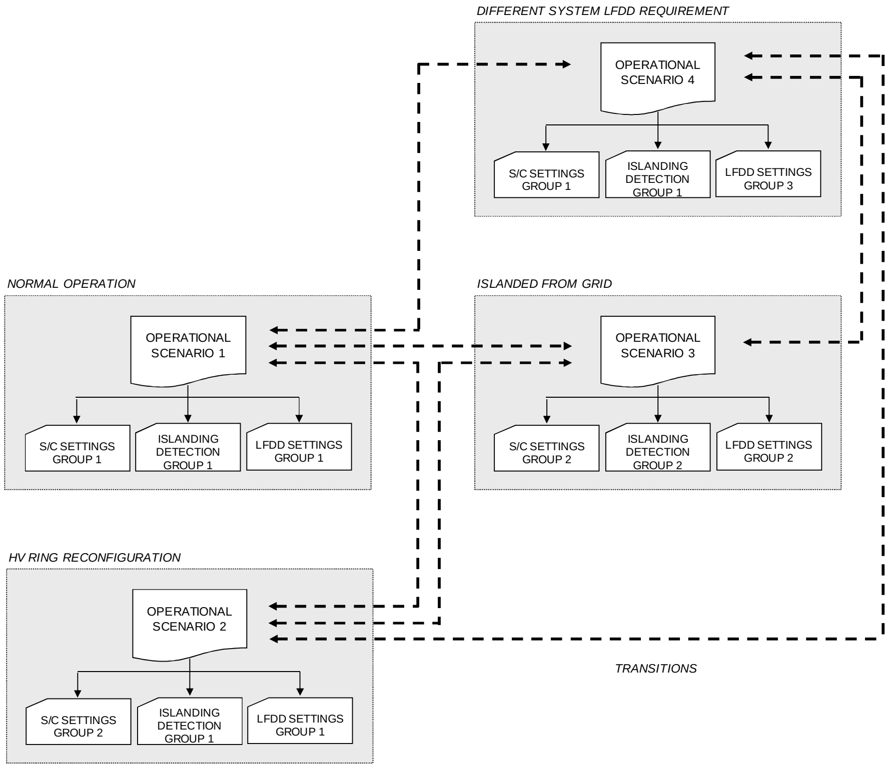

Figure 3-5: State transitions for an adaptive protection scheme.

3.7 An Implementation Architecture for Adaptive Protection

Previous sections in this chapter have discussed the key functional elements of adapting protection to better reflect the current status of the primary system. In that discussion other secondary or supervisory systems were identified as potential data sources and an attempt was made to outline the general process of adaptation. A methodology was also outlined for the scheme designer to move from a range of operational scenarios towards discrete groups of settings and the corresponding mappings required for the transitions between them. Such a treatment, however, does not necessarily move closer to answering questions regarding how complex schemes can be implemented and then finally commissioned.

A suggested solution to these issues is now presented in the form of a functionally abstracted hierarchy that permits straightforward mapping with external devices or systems. Such a structure is in keeping with the approach taken in communications to abstract the methods and data items from the underlying lower level protocols. The following introductory paragraphs define the functional layers and provide an indication of their physical locations and numbers. To begin, the process of adaptation can be broken down into three clear layers of abstracted functionality. Figure 3-6 provides an illustration of this architecture showing these three layers and the data transferred between them.

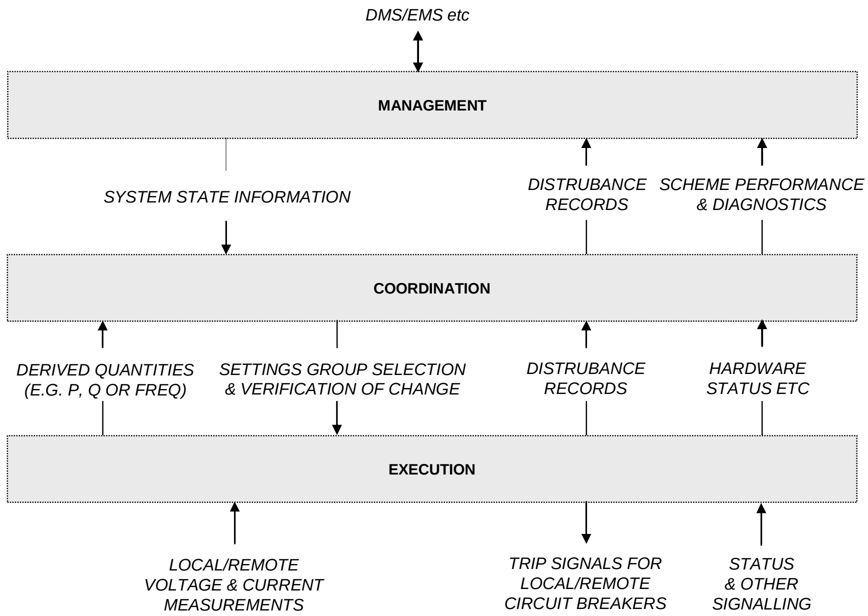

Figure 3-6: An architecture for realising adaptive protection.

At the most basic level, the signal processing that forms the basis of protection must be executed regardless of any desire to change settings or scheme logic. It is intuitive, therefore, to suggest that an *execution* layer is required that merely implements protection functions (e.g. overcurrent or distance) and is not concerned with why or when it should be adapted. This layer may in practice consist of one or more physically separate protection devices. An external command from a higher layer is required to initiate any changes in settings. Note that this does not refer to signals that might be required as part of a particular function such as acceleration or phasors from a remote location that are independent of the settings applied.

Adaptive protection must also possess a way of identifying when the changes in the primary system occur that necessitate modifications to settings. This is independent from the execution of the low level numerical protection algorithms. Consequently it is proposed to separate or devolve this from the underlying execution of the signal processing algorithms in the form of a *coordination* layer. Within this layer some method of mapping settings groups or other user defined parameters to changes in the primary system must be provided. This layer must firstly establish the necessary changes, coordinate their implementation on one or more physical devices, and then finally verify that they have been successfully carried out.

Lastly, some higher level of oversight of the process is required to validate any adaptation at a system level and, furthermore, to facilitate the interaction with specific external network management systems. This topmost management layer is in an ideal location with which to interpret the response of protection (both in terms of adaptations and actual protection operations) such that external systems can be provided with contextualised information regarding past and expected performance.

Alongside the individual layers the communication between them must also be defined and structured. Details of the bidirectional data flows are expanded in the following sections. It is also informative to note that since adaptive protection will inherently be more complex, it is vital that self-diagnostics or methods for validation or testing be built into the scheme at it conception. This will ensure that true value can be obtained that is not outweighed by increase in engineering required.

The following sections discuss the individual layers in more detail. The approach taken is that of defining what functions are performed and the data that is stored or used at each level. This is then followed by a discussion of what interactions take place between the different levels.

3.7.1 Execution Layer

The lowest level in the structure encapsulates the functionality required to execute the basic protection functions that are acting on measured power system quantities. Disturbance recorders and low level IED hardware and software diagnostic monitoring functions (e.g. for the I/O boards and internal memory buffers) are also to be found here. Figure 3-7 provides details of the main functions of this layer.

These functions are not contained within one component and are likely to be distributed amongst a number of IEDs (each storing groups of settings). Thus this layer could contain IEDs from a number of different vendors (including a mix of old and new devices) and be located at various physical locations. For example in a primary substation the execution layer could consist of all the feeder protection IEDs in which the protection functions are the individual overcurrent and earth fault elements. The protection function could also be split between two or more relays as would be the case for unit protection.

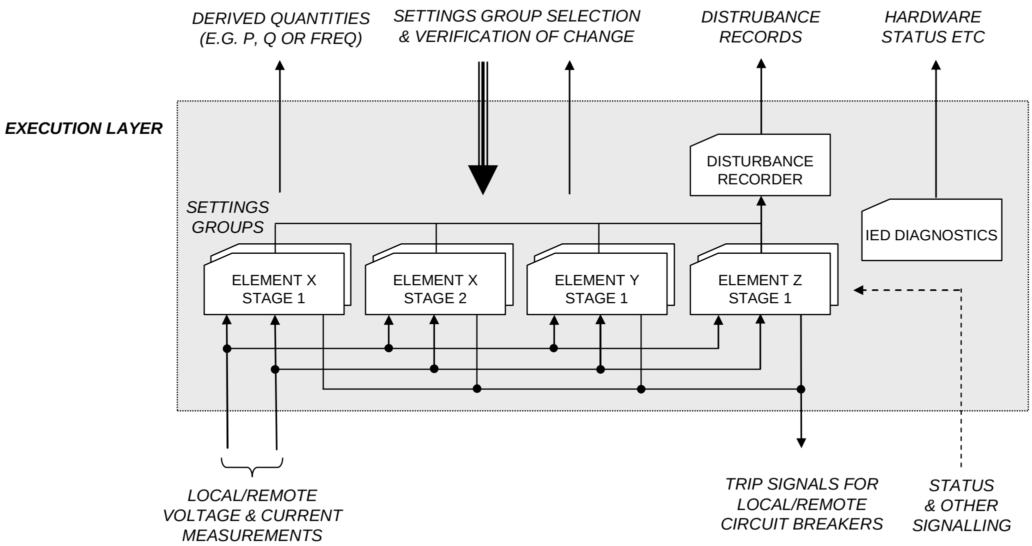

Figure 3-7: The functional components of the execution layer.

Figure 3-8 provides an illustration of the physical realisation of the execution layer between a number of separate relays (connections with measurement transducers have been omitted). In this example three IEDs are shown with both internal commands to switch between groups of settings within a relay that has PSL used to provide coordination layer functionality and the use of an external signal from another device. This could be from either hardwiring or using signals sent over a substation LAN. Disturbance recorder and diagnostics information is passed up to the coordination layer when it is available as triggered by actual system faults or hardware/software watchdog systems within the relays.

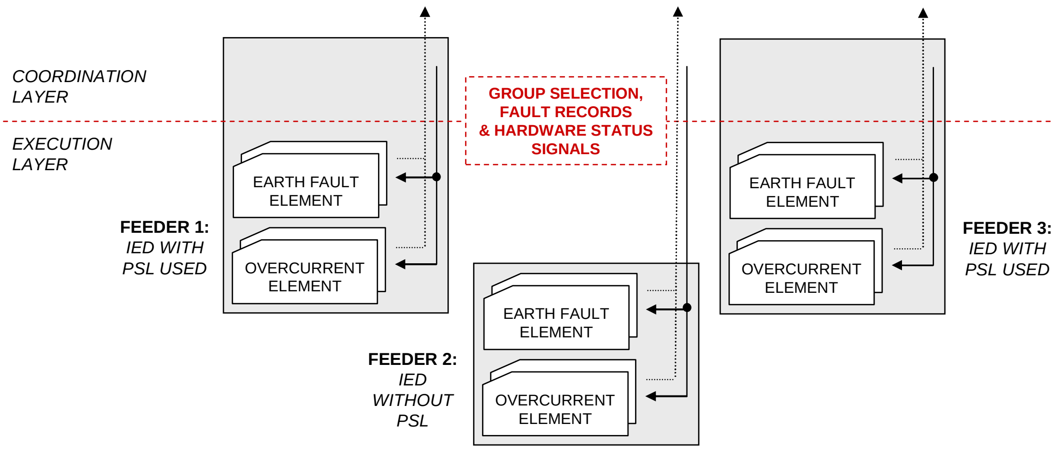

Figure 3-8: Example physical implementation of the execution layer.

3.7.2 Coordination Layer

The primary role of the coordination layer is to map the changes in the primary power system to the different groups of settings that are available for the different elements and stages within the execution layer. Inputs to the layer will be either hardwired (e.g. the switching of a 110 V dc field voltage indicating the status of equipment) or be provided over a substation LAN (e.g. IEC 61850 GOOSE messages [3.41]). Derived quantities from the protection functions such as frequency or active power may also be used which could be provided by the numerical functions within the execution layer. Information on the overall system can be supplied down from the management layer (e.g. a signal to inhibit islanding under certain circumstances). The successful implementation of the required changes at the execution layer will be accomplished by the verification logic checking the returned confirmation signals. Figure 3-9 shows these functional components graphically.

Verification logic is used to confirm that requested changes have been performed by the execution layer. This involves monitoring that the confirmation signals passed back by the lower layer are received within a suitable time window and the passing of details of any missing or erroneous changes to the scheme diagnostics function. This logic is particularly important if the coordination and execution layers are located on physically separate devices separated by an external communications link.

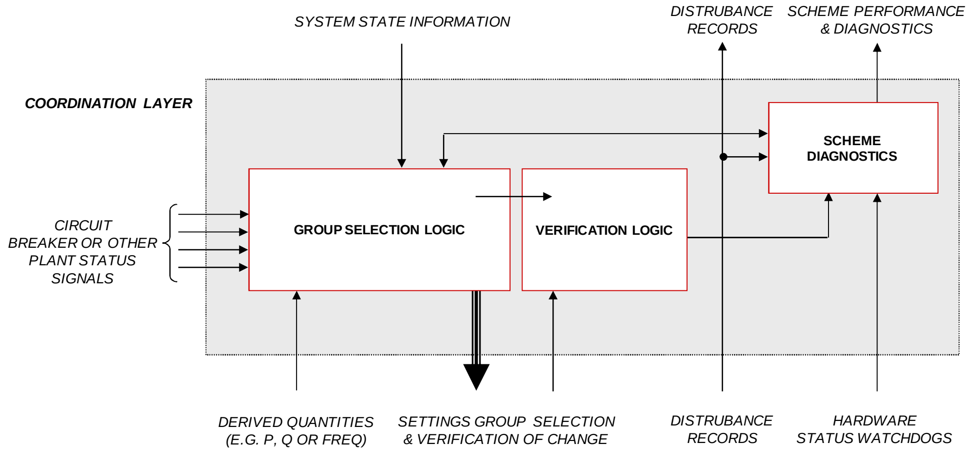

Figure 3-9: The functional components of the coordination layer.

The scheme diagnostics function is included to interpret the performance of the execution layer. An example of this interpretation functionality could include the assessment of the impact on a settings group of a hardware failure (e.g. measurement transducer) which would result in a fault being cleared by another device acting as a backup. The time taken for this may be unacceptable and the scheme diagnostics logic could report the increase in risk to the management layer and possibly initiate a change of group. A further example would be to cross-check an event record produced by disturbance recorders when a fault is unexpectedly cleared on backup to identify the IED or switchgear that failed to operate as intended. This information can then be passed to the management layer to assist with operator investigations.

As was the case with the execution layer, this layer can also be distributed between different devices that may also extend between layers. An example of the physical implementation of the coordination layer is shown in Figure 3-10. In this example the two feeder IEDs have the coordination layer implemented using their own PSL and the commands to change settings groups are therefore internal. These IEDs receive equipment status signals from various locations and system status information is provided via a substation computer. This substation computer provides functions at both this layer and the higher management layer. For the coordination layer, it provides the functions required for an IED that does not have a suitable internal PSL capability (e.g. an older numerical relay).

Alternatively, the coordination layer could have been centralised on a single device such as a substation computer and the commands then sent out to individual IEDs to change their settings groups. Although this is possible, the reliability of the scheme is increased by using the PSL capability as far as possible on individual IEDs.

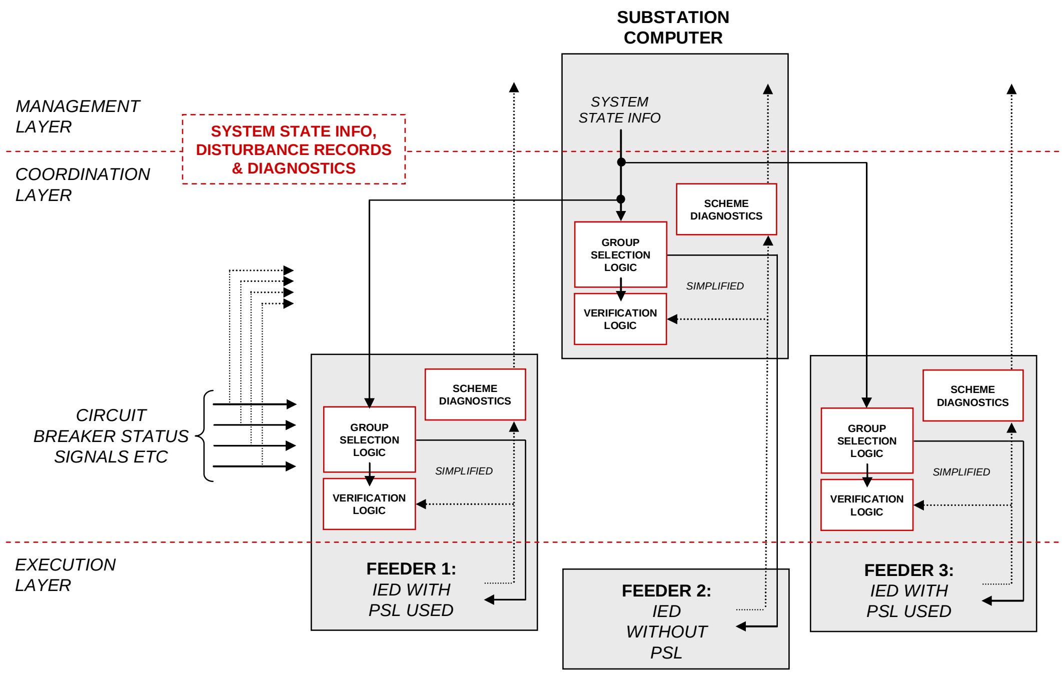

Figure 3-10: Example physical implementation of the coordination layer.

The group selection logic is based on straightforward rules used to map the changes observed in the primary system to the available groups of settings. An example on some group selection logic is provided in Figure 3-11. This is a simplified example (the full logic for intentional islanding is provided in Chapter 5) and shows that basic information from various source locations can be combined to enable different groups of settings.

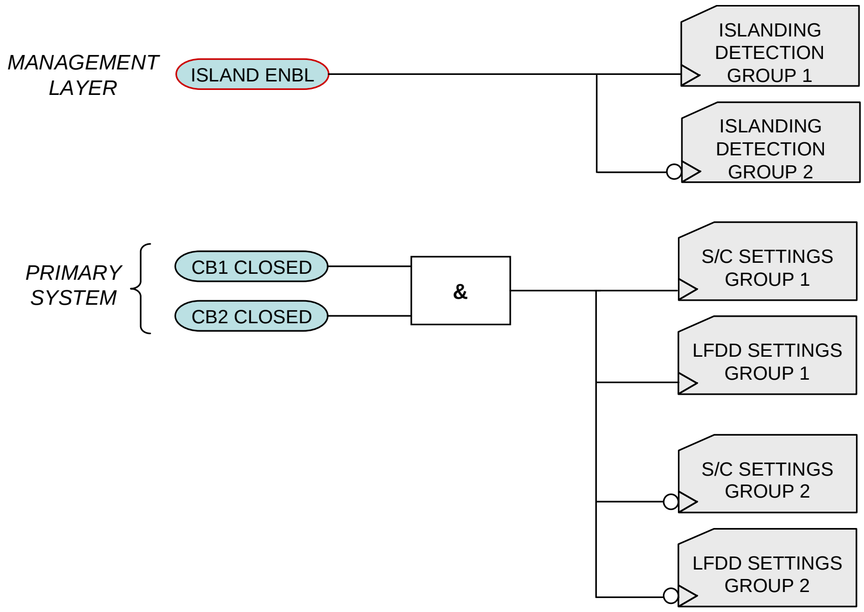

Figure 3-11: Example of logic for switching between settings.

3.7.3 Management Layer

The management layer in the functional architecture is the highest and interacts with systems such as DMS or EMS. Its main functions are to infer information relevant to protection from the system state and to assess the overall performance of scheme. Figure 3-12 shows the management layer functions graphically. This layer is suited to a degree of centralisation within one physical device in so far as it is related to scope of the protection problem being addressed. For example the management layer associated with the LFDD scheme would be centralised at a physical location such as grid control where it has access to all the necessary system data from generation and network assets. It could also be argued that for system level problems such as this that the management layer would in fact form part of DMS or EMS systems. Alternatively, for a local reduction in fault level due to supply circuit switching the management layer functions would be best located on a single device such as a substation computer located close to the relays that will need to have their settings group changed (i.e. within the substation with the highest voltage level associated with the network affected).

For the system state interpretation function as shown in the figure, the management layer would collate information regarding how the system may be operated. For example it could be supplied with information on the generation capacity and types in service within an islanded network. Based on this it could estimate the available fault level and map it to bands such as low, medium or high. This would then be suitable for the coordination layer to use it as input to its mapping onto discrete groups of settings. A further example could be to quantify the stability margin of a small system supplied by a number of relatively low inertia rotating AC generators. The loading of these machines will have a significant impact on their stability margin and thus a similar banding could be used and passed to the coordination layer.

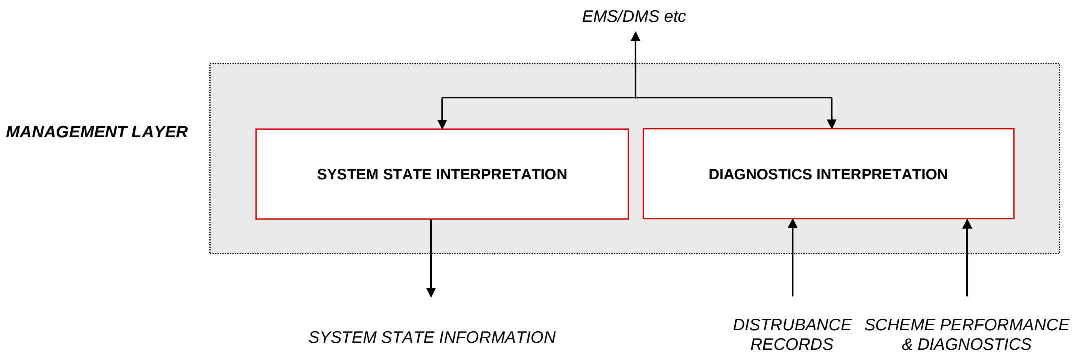

Figure 3-12: The functional components of the management layer.

The selection of a particular group of settings would also be validated by the management layer based on its interpretation of the system state. Rules, for example, can be formed to validate the selection of a group. The information passed from the DMS or EMS could allow for the conclusion to be drawn that the system is in a state with a high degree of risk. The load could be being met by a small number of highly loaded generators as opposed to being spread over a larger number of partly loaded units. The coordination layer may not be able to identify this based on its available data sources and thus the management layer can verify that the group selected (which at design-time would be classified as "low fault level", "low stability margin" etc) is appropriate.

The other main function of this layer is to assess the overall performance of the protection scheme. This would be carried out using the event and disturbance records, IED diagnostics and system state to contextualise this information. By doing this operators or system management systems can receive reports of the expected and actual performance (e.g. total clearance times) of the protection system that are reflective of the environment in which the system is being operated. This may lead to changes in how the system is operated.

It is also important to stress that not all layers of the architecture may be implemented in every application. For example the management layer may not always be necessary if the changes in settings can be determined only by monitoring simple switching operations. This would be relevant for occasions when, for example, only a basic topological change is made that lowers the fault level in an area of the network but not the overall structure (e.g. removing one half of a double circuit from service). In this case no system level changes are made that would require more in-depth interpretation that would ideally require the implementation of the management layer functionality.

3.8 Design Phase Performance Testing & Commissioning

The successful performance of protection is vital for safety and economic reasons. It is therefore a requirement that design phase performance testing and then commissioning procedures are adequately updated to reflect the challenges caused by the use of adaptive protection techniques. This section sets out the concepts that will be necessary and will be elaborated on in later chapters using example systems.

3.8.1 Performance Testing during the Design Phase

The performance testing of an adaptive protection scheme must include both the adequacy of the groups of settings produced and also the ability of the scheme to perform should the adaption process fail to be completed as intended. The following sections discuss the first aspect and the second is explored separately in Chapter 4 where the application of failure mode and effects analysis is considered.

3.8.1.1 Scheme Adequacy Testing

Using the methodology described in §3.6 will provide the protection designer with a potentially complex set of settings groups and supporting logic for system transitions. It is important at this stage for a check to be made that all credible contingencies have in fact been adequately covered and no errors have occurred. In basic terms this would correspond to the checking of each settings group and would confirm the validity of each design. However it is equally important to examine the transitions by methodically transitioning the primary system through the different scenarios. This will ensure that no operating condition has been omitted from the design. A basic functional diagram of a testing environment is shown in Figure 3-13 and consists of a system representation, adaptive protection, an event engine to initiate changes and finally a tool to assess performance.

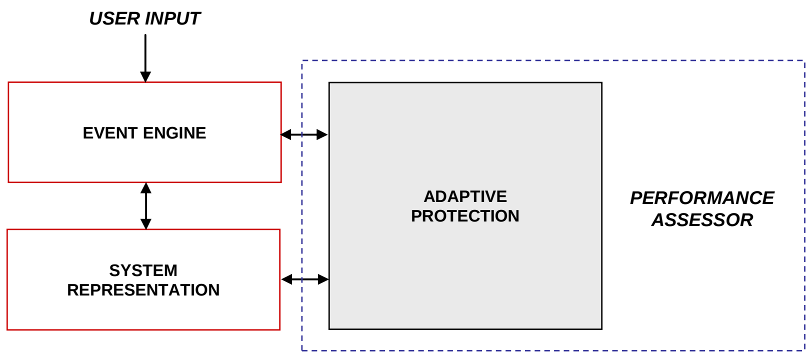

Figure 3-13: A simulated test environment for adaptive protection.

This testing will require a representation of the system that will provide both topological information and its electrical characteristics during a fault. It is interesting to consider the scope of the testing for the adaptive protection scheme in relation to both manufacturers and utility or other end users. The detail of the system representation will vary significantly between these two different parties.

A relay manufacturer will wish to test the complete scheme extending across all three layers of the architecture where their hardware products reside. Consequently they will require a full transient representation of the system with which to synthesise the waveforms for application to the relays (implemented using a typical combination of a real-time digital simulator running EMTP software and external power amplifiers for connection to relays or MU).

End users on the other hand will not require confirmation of the execution layer functioning at the design phase. They require a representation of the system that will allow the transitions to be checked (e.g. opening of the circuit breaker) and the fault current or impedance seen by the relay to be determined. This information will allow grading to be checked. In this case only the top two layers of the adaptive protection would be required. In fact only the design for the settings and logic have to be used and need not be downloaded onto the final hardware platforms. At this stage the procedure could be vendor independent with the outcome leading to a specification to be used as part of tendering process for the actual equipment supply and implementation. The representation in this case would be a network model based on the correct sequence impedances and network topology.

In both cases an event engine will be required to initiate changes in the system representation as dictated by the user. This tool would include such information as switching to be carried out by an automation system and details of local generator status for given operational conditions. Finally, the tool for assessing performance would offer the user a way of comparing the results against defined performance standards (e.g. grading margins) and indicate the nature of any shortcomings.

A further task for this environment during this phase will be to define test scenarios for use during commissioning. These are to be formed such that the final system can be tested appropriately will all necessary data to be used clearly identified.

3.8.2 Testing during Commissioning

The major difficulty for adaptive protection during commissioning is to setup the inputs that may be distributed over a large area. This would be more difficult in a hardwired system but for a LAN or WAN the necessary signals can be put onto the network at a suitable point with appropriate time synchronisation provided.

Time synchronised sampled value signals for the measured waveforms could be transmitted by MUs as part of defined scenarios. Plant status signals would likewise be created and put onto the network addressed to the necessary IEDs. In doing this relays will no longer only be tested against basic input waveforms (by secondary injection methods), but also using more complex testing scenarios that have been created using the design phase testing described above.

3.9 Chapter Summary

This chapter has reviewed the background and drivers for developing adaptive protection. In particular, the moves towards a smart grid concept within distribution networks will create many challenges for protection by increasing the variation in the primary system behaviour that relays must monitor and act on in order to provide satisfactory performance.

Adapting protection settings to more closely match the primary power system is a technique that shows much promise for addressing the challenges within smart grids. However despite much research attention it has not been widely put into practice. This chapter reviewed the material published to date and from this key barriers and problems have been identified.

A design methodology has been presented for adaptive protection and this was then taken forward as a starting point for analysing the concept in some detail. The process and stages inherent within adaptive protection were considered. The necessary conceptual functions were identified at each stage and discussed in detail. From this work a functionally abstracted architecture has been proposed that would permit these functions to be implemented. It is based on three layers that can have their functions distributed, if required, across multiple physical devices thus ensuring that both new and legacy devices can be used. The key functions that are required for the architecture to operate have been described and the interactions and data flow between the different layers defined. The importance was stressed of verifying correct implementation of changes and, importantly, the validation of changes within the context of the current state or configuration of the system. It was commented that in some basic applications not all layers may be required. For example the management layer would be omitted if settings changes only depend on a simple set of logic inputs based on several switching operations with no system data being required. Observations were also made on the requirements for a simulation and test environment that could be used for all or part of the functional layers of the proposed architecture.

Later chapters in this thesis will demonstrate the application of this architecture and discuss how it can be used to overcome many of the barriers identified at the beginning of this chapter. A number of practical examples will be used for illustration and to test the validity of the approach.

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4 A Study of Adaptive Protection Failure Modes and Effects

Protection schemes are critical systems whose failure to operate as intended can have potentially serious safety implications, cause unnecessarily widespread damage to equipment and lead to prolonged system outages. The design of such systems must therefore ensure that all practicable measures are taken to minimise the risk of protection equipment failures and the possibility that the settings applied are not appropriate for the state of the primary system. Although adaptive functionality can clearly be of assistance with this latter concern, the process by which this additional functionality is implemented must not lead to additional critical failure modes which would negate the benefits of improved performance. This chapter briefly considers the potential failure modes that could be introduced if adaptive protection is implemented. A method for applying a failure mode and effects analysis is described along with the discussion of some generic risk mitigation measures.

4.1 Chapter Outline

This chapter firstly explores the potential failure modes that are associated with adaptive protection in §4.2 by grouping them into four classes. Based on this analysis, the failure modes are then assessed against their implications for performance during the process of transition between system states within a generic adaptive protection scheme in §4.3. An assessment method for applying failure mode and effects analysis [4.1] is described in §4.4 along with the discussion of some generic risk mitigation measures and two example applications. Finally in §4.5, a summary is provided of the key points discussed in this chapter.

4.2 Failure Modes

The following analysis excludes failures of instrument transformers (including dedicated wiring and/or merging units), the relay hardware/software performing the execution layer protection functions, trip circuits and circuit breakers. These failures will be dealt with in the usual way by the principles of protection backup using the coordinated application of physically separate devices as described in §2.2. The purpose of this section is to consider how the protection can fail to adapt in response to primary system changes and thus relates to input or status signals, communication between devices, adaptive logic failure (coordination layer functionality) and inadequate scheme design[17].

A generic fault[18] tree [4.2] for adaptive protection is shown in Figure 4-1 which highlights four potential classes of failure mode which are described in more detail in the sections that follow. A qualitative assessment is made in each description of the probability that a failure within a class could occur and also the severity of the consequences (low, medium and high descriptors are used). For reference a summary of these assessments is provided in Table 4-1. This table represents a subjective assessment of the probability and severity of failure classes based on the experience of the author and data available in the public domain such as [4.3] or [4.4].

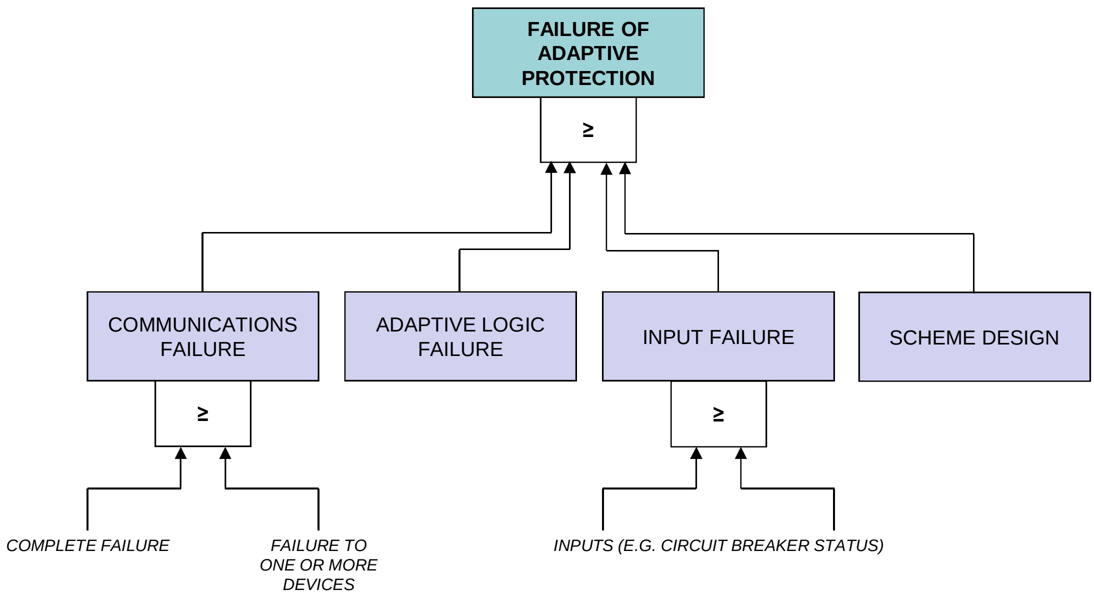

Figure 4-1: Generic fault tree for adaptive protection.

[17] This is not strictly a failure mode but is included for discussion since the inadequate design of an adaptive scheme could lead to unprotected primary system states which can have severe consequences.
[18] The term fault in this case does not refer to primary system faults but rather to failures in the protection hardware/software, communications or the design process.

Table 4-1: Failure mode class qualatitive probability and severity summary.

Class	*Probability*	*Severity*
Communication system	Medium – High	Medium – High
Adaptive logic	Low	Medium
Input or status data	Low – Medium	High
Scheme design	Low	High

4.2.1 Communication Infrastructure Failures

A failure in the communications infrastructure could affect all devices within a scheme or a limited number depending on the topology of the system and the type of equipment or channel failure (e.g. router hardware/software or VHF band interference). The consequences for the performance of the protection will also depend on the number of relays that do not adapt, the role of the affected protection functions and the nature of the change in the primary system. For example, the risk associated with overcurrent relays failing to adapt correctly are higher in safety terms than that of an under-frequency load shedding scheme where the risk is related to the unnecessary shut-down of the whole or part of a system rather than direct personal safety.

The mitigation of this class of failure is clearly dependent on the robustness of the design of the communications infrastructure. Thus the protection engineer must ensure that the specification issued for the communications infrastructure is sufficient (e.g. link redundancy) to meet the demands of the particular protection functions. Furthermore, attention must also be given to how local relays should react if they lose communication with remote devices. This action may differ between protection functions involving potential courses of action such as the disabling of a function (removing a point in a grading path) or the selection of a default group of settings providing some known minimal performance level. This latter action is more related to system protection where the overall scheme performance is not necessarily safety critical.

The probability that a communications failure could occur is conservatively judged to be medium – high with clear dependencies on technology, geography and weather conditions. Without reference to the particular details of an actual communications system it is difficult to be more precise and this assessment is for guidance only[19]. If available reliability data should be used were possible. The severity of a failure occurring is also judged to be medium – high corresponding to either local or global failures respectively.

4.2.2 Adaptive Logic Failures (Coordination Layer)

This class relates to the failure of the coordination layer logic as implemented on the physical device (for example the programmable scheme logic on a numerical relay). Assuming that the inputs to the adaptive scheme logic are correct, the probability of a failure occurring within a device or during programming which would result in an erroneous instruction to the execution layer is considered to be very low. This is due to the high reliably of modern numerical relay technology and software. The scope of this failure will be limited to the device (assuming it is not a type fault) and thus the severity is judged to be no greater than medium.

4.2.3 Input and Status Signal Failures

The ability of the protection to adapt to changes in the primary power system depends entirely on accurate status information that reflects its current state. Sources of such information include local/remote plant status indications as well as information passed down from the management layer which is derived from other control processes or even real-time calculations. Where possible redundancy should be built into the system to provide alternative sources of status information. It is recognised that is not always possible or even necessary for simple parameters or changes.

Since the communication of these signals to the coordination layer is dealt with separately, then the probability of these failing is judged to be low – medium. For example the auxiliary contacts providing the status of a circuit breaker are very

[19] Note that this comment does not relate to communication technologies applied to existing protection schemes such as circulating current unit protection or accelerated distance protection which use dedicated point to point communication channels.

reliable whereas there is a higher probability of a failure occurring where the input relates to the output from another non-protection system (e.g. automation) which may not have been developed or configured to the same standards. The severity of a failure occurring is judged to be high as it could impact upon a large number of relays depending on the nature of the scheme. If a move to an islanded condition, for example, was not detected then all overcurrent relays within a scheme would be operating on a settings group which would not guarantee satisfactory performance.

4.2.4 Inadequate Scheme Design

The inadequate design of the adaptive scheme is not strictly speaking a failure mode, but rather the method by which the mode classes above are either introduced or overlooked. It is therefore considered appropriate for a short discussion on this to be included here. The use of adaptive protection permits a more flexible approach to the operation of the primary system and thus the range of actions the system operators or the EMS can put into effect are greatly increased. This increase in complexity has the potential to lead to a significant number of system states, all of which must always be protected at a minimum level of performance (e.g. coordination and maximum clearance times). If an insufficiently robust design process is used then potential primary system states may not be analysed and thus there is no guarantee that they will be, in the worst case, safe should a primary fault occur. In other words the range of settings available may not be sufficient or the logic incompletely configured to react to a particular primary system change.

A robust design process must include a set of primary system scenarios that fully encompass all potential system states. The scenarios should also be severe enough to cover occasions where the poor performance of the EMS (or manual operator intervention) has led to operating conditions outside normal bounds. This could take the form of operational scenarios that are then stressed to mimic the impact of poor control or generator dispatch. For the latter a problem could arise if the spinning reserve available is too low to cover the sudden loss of a generator meeting a significant proportion of the demand. In addition to the states, the design must also clearly identify the possible transitions between states (e.g. the logic within a network automation scheme controlling network reconfiguration such as the moving of a normally open point) and what sources of input data are available to detect these changes. Furthermore, a robust design must ensure that where possible all groups of settings are able to provide protection at some adequate level even if a number of the relays within the scheme fail to adapt as intended (i.e. a study should be made on the impact on elements of the design such as grading paths).

Assuming that a robust process is followed during design, the probability of this factor resulting in a failure is considered to be low. However it is clear that the severity in terms of scheme performance would be high should the groups of settings created not offer sufficient performance across all potential primary power system states.

4.3 Transition Failures

Power systems are subject to numerous small changes in demand levels, generation dispatch and circuit configuration during the course of normal operation that do not require protection settings to be adjusted to maintain performance. However when one or more primary system changes occur that force the system into a state for which the prevailing protection settings or functions are inappropriate, then it is vital that these changes are quickly reflected by the actions of the adaptive protection scheme. It becomes critical for the protection engineer to carefully consider the failure of a scheme to adapt as intended, whether completely or only in a fraction of the applicable relays after a primary system change. This could relate to either the selection of the wrong settings through bad interpretation of the inputs or, perhaps more likely, no action being taken due to failures in the communication infrastructure. In other words it is important to consider the implications (most notably safety) of the protection settings becoming out of sync with the state of the primary system. This could mean loss of coordination with other correctly adapted relays or poor sensitivity (or some other performance criterion if applicable).

As an illustration consider that power system has three primary states that correspond to three unique groups of protection settings as shown in Figure 4-2. Each group of settings relates to functions that will be physically distributed over a number of relays located across the system. If the system moves from state A to B in this example the protection should adapt from group 1 to 2 in the shortest possible time. However this may not be the case because of, possibly, a communications failure of some kind (either signals not received or subject to delays). This failure could result in none of the relays adjusting their settings groups or only a limited number. Clearly the complete failure to adapt represents a serious problem and the implications on performance are likely to be significant if the system states are radically different. However if only a single or a small number of relays fail to adapt then the system is not necessarily unprotected but, potentially, being protected at a lower level of performance. This could be permanently or for a limited window until remedial action is taken or communications are re-established. For example in a radial circuit being protected by overcurrent devices the failure of a device mid-circuit would not lead to an unsafe condition as other upstream devices would act in backup and a fault would always be cleared from the system. But in this case the number of consumers disconnected will be unnecessarily high due to a breakdown in the coordination between the grading points. Thus when the scheme designer considers the transition diagram for the adaptive scheme, they should examine what level of failure to adapt can be tolerated for a minimum level of performance to be maintained. These criteria will be different for the various protection functions with short-circuit protection being the most onerous. Critical relays or protection functions must be identified and measures taken to lower the risk associated with their failure to adapt when instructed or intended. This is a key feature of a robust design for an adaptive protection scheme.

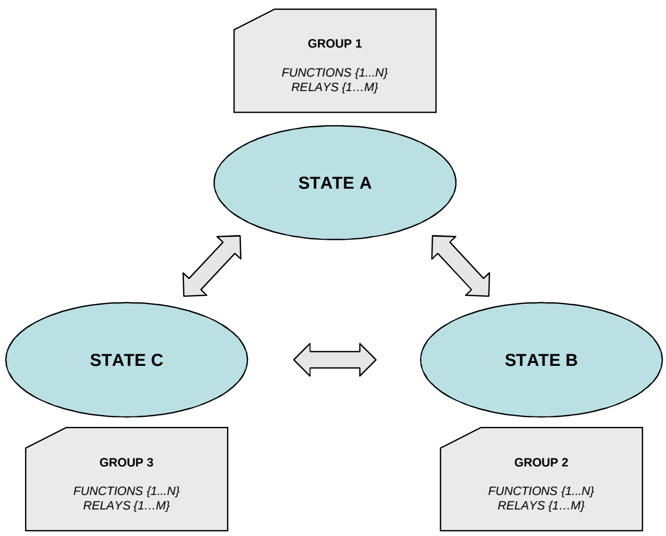

Figure 4-2: Primary power system states and corrresponding settings groups.

4.3.1 Effects & Mitigation

As mentioned above the effect of relays failing to adapt as intended must be carefully studied. For a given primary system change the protection engineer must determine the impact of an incomplete transition between the respective groups of settings. The failure modes described previously serve as a starting point for the analysis. From these the scheme designer can identify the relevant permutations of incomplete or incorrect adaptations and then check the resultant overall performance of the scheme. The probability and severity for each of these can be combined to evaluate the resultant risk. All of the permutations can be ranked using this risk index and mitigation measures explored for all those above a given threshold. This will be set based on factors such as the safety, equipment and operational guidelines.

The mitigation measures could include adjustments to the hardware of the scheme involving greater communication infrastructure redundancy, multiple sources of status information or the action to be taken upon the detection of a scheme failure. If, however, mitigation is not possible then it may be necessary to modify the underlying protection philosophy or, more significantly, to restrict certain operational actions since no reliable method is available for ensuring that the protection can satisfactorily adapt as required.

4.4 Risk and Mitigation Assessment Methodology

Figure 4-3 shows a risk and mitigation assessment methodology that could be applied when developing an adaptive protection scheme [4.5] [4.6]. The methodology incorporates a form of the failure mode and effects analysis using the principles commented on above. It begins with the adaptive scheme design that includes settings groups, details of the primary system transitions and the potential failure modes based on the hardware/software used for the physical implementation. The scheme design data is then used to identify the adaptation failures that could occur and will need to be assessed in terms of their effect on scheme performance. These could be extensive but judgement can be used to eliminate repetition where a scheme contains very similar grading paths (e.g. 11 kV cable feeders supplied from the same primary substation where the number of grading points and settings can be the same or very similar) or other such repeated structures within their design.

Each adaptation failure will be assessed to determine its impact on the overall scheme performance using the criteria mentioned previously (e.g. grading or demand disconnected in the event of a primary system fault). A particular adaptation failure may have minimal or widespread impact and can thus be considered in terms of its severity. These can be used along with an assessment of the likelihood or probability of the failure occurring (taken from a general assessment of failure modes) to qualitatively evaluate risk which can be used to determine if mitigation measures need to be applied. For example this could include changes in the underlying scheme design or operational restrictions to avoid the issue occurring.

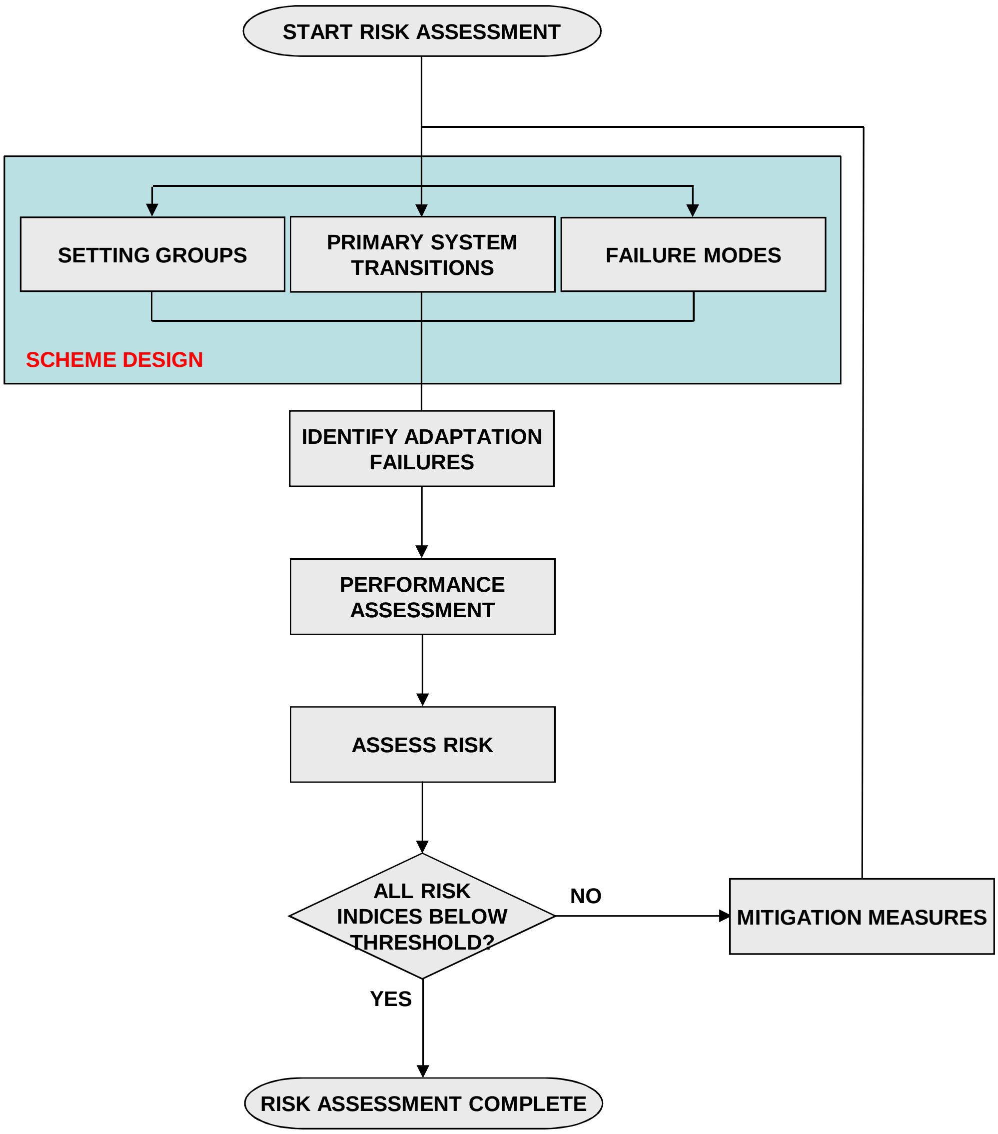

Figure 4-3: Risk assessement methodology.

The qualitative assessment of probability and severity can be combined to derive an assessment of risk as shown in Table 4-2. This shows how low, medium and high assessments for these two criteria can be mapped to corresponding low, medium or high risk indexes. The occurrence of a medium/high risk index can then be used to trigger action to put in place mitigation measures.

Table 4-2: Derivation of a risk index.

Probability	***Severity***	***Risk***
Low	Low	Low
Low	Medium	Low
Low	High	Low
Medium	Low	Low
Medium	Medium	Medium
Medium	High	Medium
High	Low	Low
High	Medium	Medium
High	High	High

4.4.1 Performance Assessment

The following section discuss the generic implications for scheme performance based on typical criteria such as sensitivity, selectivity, speed of response and stability for a simple example. As an illustration, consider the overcurrent protection scheme that could be applied within industrial facility involving coordinated inverse elements at the circuit breaker locations as shown in Figure 4-4 [4.7].

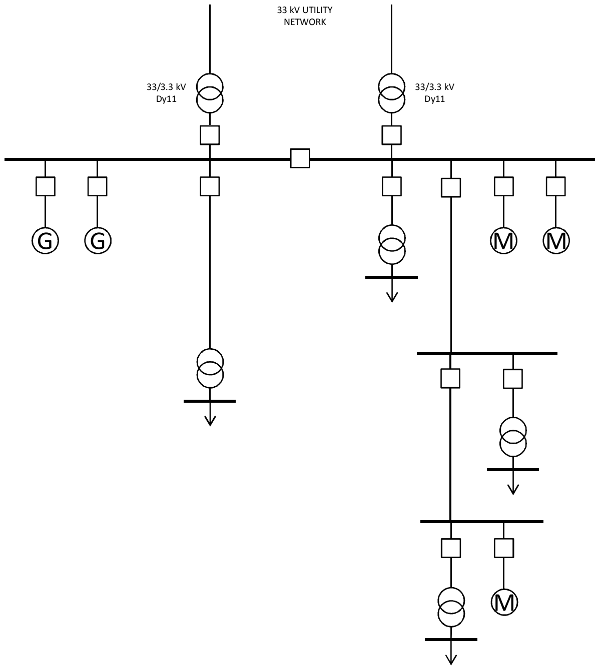

Figure 4-4: Industrial facility schematic.

The main distribution is at 3.3 kV and is supplied by two incoming transformer feeders from the utility system. Local standby generation is also present to supply demand in the event of the grid supply being lost. The load consists of direct-on-line (DOL) motors connected at 3.3 kV, LV distribution and supplies to some remote demand that is spread out over an extensive site such that it requires 3.3 kV distribution. It is assumed for this discussion that overcurrent setting groups are changed should the system be supplied via one incoming transformer feeder or it is supplied only from standby generation. There are therefore two groups of overcurrent settings and the trigger for the transition is either the loss of one of the incoming transformer feeders. For this simple example the potential failure modes are restricted to communication malfunctions: (i) failing to detect the change of system moving between a high to low fault level condition and (ii) the failure of the communications system resulting in not all relays adapting as intended.

The potential for a detrimental impact on system performance is discussed below for each of the four criteria. It is noted that the following discussion is at a high level since no attempt is made to go into the details of the design or mitigation measures.

- *Sensitivity:* The failure to adapt correctly could have an impact both on plant operation and operator safety if the pickup settings of the relays are too high to reliable detect faults. The exact severity of the problem will depend on whether only a few relays are affected resulting in faults being cleared in backup mode by remote relays resulting in unnecessary equipment disconnection, or in the more extreme case fault not being cleared if many relays within a grading path fail to adapt as intended.
- *Selectivity:* A reduction is selectivity leading to unnecessary equipment disconnection would typically be the result of a small number of relays failing to adapt as intended. The severity of the problem will depend on the number of points in a grading path and, if the failure is temporary, on the time until the correct adaptation is put into effect (e.g. communication delays).
- *Speed of response:* If a scheme remains on the settings intended for high fault level whilst operating on low fault level, fault clearance times (assuming that the pickups are low enough to detect the faults) could be significantly increased. This could have a safety concern depending on just how long the increase becomes but, more generally, power quality issues or motor deceleration could be of greater concern.
- *Stability:* The settings group that has been designed to be in use during low periods of low fault level may not offer sufficient stability during the starting of DOL motors when large currents are drawn as the machines accelerate. This could again lead to unnecessary equipment disconnection.

The discussion above has highlighted the range of impacts that failures to adapt as intended can have on the performance of the protection scheme. Although all criteria are important, it can be seen that the sensitivity and speed of response criteria have particular relevance for operator safety and thus have the most severe impact overall on performance. Figure 4-5 shows an illustration how the severity of a failure can be assessed to be low, medium or high depending on its impact on scheme performance. An extension of this would be to quantify this by defining performance benchmarks which can be used within the protection analysis.

LOW	MEDIUM	HIGH
Minimal impact on fault clearance times and no impact on grading.	Reduction in the effectiveness of grading between relays, potential for loss of selectivity at one or more relays.	Serious risk to safety as a fault may not be cleared.

Figure 4-5: Example of overcurrent performance impact severity.

4.5 Chapter Summary

This chapter has considered the potential generic failure modes that could be introduced by adopting adaptive protection. The link between primary power system state transitions and the incomplete or incorrect change in settings groups was discussed. Based on these, a basic methodology was suggested for carrying out a failure mode and effect analysis to assess the impact of adaptation failures during the course of scheme operation. A simple application example was used to discuss how the impact on scheme performance of transition failures can be analysed.

4.6 Chapter References

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5 Enhanced Network Protection to Enable Microgrids

The microgrid concept has been widely investigated as a means of integrating large numbers of microgenerators, energy storage devices and DSM schemes into LV distribution networks [5.1]. Many researchers have indeed noted that this could form an integral part of the smart grid vision at the lowest levels of distribution networks [5.2]. However if the microgrid concept is extensively deployed at LV, serious problems could emerge for the protection currently used at this level of the network. Owing to the nature of the fault response behaviour of LV generators and, significantly, the actions of network management systems in permitting such events as intentional islanding, existing network protection cannot continue to be used as devices may respond slowly or not at all to faults. This is due to the potential for available fault current to be significantly reduced in the circumstances noted above.

This chapter presents the main elements of research concentrating on the development of network protection that will safely enable the deployment of microgrids despite the challenge highlighted above. It will demonstrate how safety related issues can be overcome to avoid constraining the network and consumer benefits that may be obtained from this concept. In particular, it will be shown that two distinct types of short-circuit protection will be required to cater for the two main modes of operation (grid connected and islanded). Moreover, recommendations will be made concerning the minimum level of low-voltage (fault) ride-through and fault current contribution of LV generators. Throughout this chapter reference will be made to the layered architecture for adaptive protection presented in Chapter 3. This will be used to integrate the two types of short-circuit protection with system protection (such as under/over-frequency elements) that are required to ensure stable operation in the event of large disturbances in the local generation and demand balance. Although the role of these will be mentioned, the discussion is limited to placing the microgrid as a concept within the context of the proposed adaptive protection architecture. As a consequence settings will not be considered as the system dynamics concerned are outside the scope of this chapter. However, such protection functions are given a more detailed treatment in the following chapter where HV islanding is examined in some detail.

5.1 *Chapter Outline*

The microgrid concept is firstly examined by outlining the features of their deployment pertinent to the development of network protection in §5.2. This is followed in §5.3 by an illustration of the transient behaviour of a microgrid during faults that leads to the identification of key characteristics (especially the output current limitations of generators). These are important for initially assessing the performance limitations of the existing protection philosophy, and then subsequently for formulating the requirements for a new approach. §5.4 discusses the development and testing of a Microgrid Integrated Protection System (MIPS), a solution that will be developed from the requirements mentioned above. The application of the MIPS within the adaptive protection architecture introduced in Chapter 3 is explored in §5.5 as a means of integrating this with system protection (albeit as a simple example), as is the impact of microgrid protection on external schemes within the upstream HV network. Finally in §5.6, a number of conclusions are drawn with regard to research contribution and suggestions are made for further study in this area.

5.2 *The Microgrid Concept*

The capacity of LV generation connected to the network has been widely forecasted to significantly increase by both government agencies and academic researchers alike [5.3][5.4]. However distributed generation (DG) and microgeneration at present are regarded by some utilities as negative loads with specific local measures put in place to resolve any network constraints or protection issues that may occur. But as the capacity of this resource increases, so too do the opportunities to make use of its functionality to improve the security and quality of supply for consumers. Local voltage support, fault (i.e. low voltage) ride-through and energy storage are some of the equipment capabilities that could offer future tangible network benefits if appropriate technical solutions and financial incentives are put in place to support their application [5.5].

The term *microgrid* refers to the coordinated grid integration of small-scale generation and other related resources within the lowest voltage levels of the distribution network to form defined semi-autonomous zones [5.6][5.7]. A striking feature of a microgrid is that it can be intentionally operated as a temporary island – this may be in response to disturbances within the upstream network to improve continuity of supply (hence it can be thought of as semi-autonomous). An example of this event would be to mitigate the effects of an unplanned circuit outage due to a fault by maintaining the supply to local demand. This is achieved by ensuring that generation can continue to operate whilst upstream repairs or network reconfiguration take place. Such operational functionality will be of particular interest to utilities that are subject to high financial penalties imposed by regulatory bodies as part of drives to minimise the number and duration of supply interruptions for consumers (e.g. CI/CML indices). Moreover as the number of consumers who own generation increases, there will be a growing expectation of receiving an uninterrupted supply as not doing so, in their view, detracts from the perceived benefits of ownership. The functionality being proposed above would also clearly be attractive to utilities servicing consumers in very remote rural areas with correspondingly weak or developing grid infrastructures.

The creation of microgrids effectively forms a cellular structure within the lowest levels of the distribution network and will compromise the conventional hierarchical approach to protection and control that is based on an assumption of unidirectional power flow towards consumers. Generators will now be connected even at the level of individual consumer services. Moreover, the operation of a microgrid as an islanded network greatly reduces the fault current available to operate protection and is especially complicated by the very limited contributions delivered by generation interfaced using power electronic converters [5.8]. Consequently, the safe and efficient operation of microgrids requires the development of new network protection and control schemes if widespread application is to become a reality.

The research reported in this chapter addresses this particular challenge and seeks to prevent protection acting as a barrier to the adoption of this operating strategy. Furthermore, it is important to understand the impact of a number of clustered LV microgrids on the upstream HV protection and network automation schemes. A central element of this research has been to ensure that this impact is minimal or, preferably, that whatever protection is proposed for microgrids assists with the improving of HV protection performance by presenting a standardised and scalable response.

5.2.1 Microgrid Characteristics

For the purposes of this research it has been assumed that the term microgrid applies to the demarcation of a zone using the LV network supplied from a secondary substation (using a HV/LV transformer with the ratio 11/0.4 kV in the United Kingdom). As a result, the peak demand associated with microgrids therefore extends to a maximum of several MVA over a number of typically radial underground cable circuits. Based on the desire to minimize any requirement for expensive energy storage technologies, this size represents the smallest practical scale for a microgrid such that effective use can be made of diversity in both load and generation [5.9]. The following sections highlight the salient features of microgrids that are important with regard to the development of suitable network protection schemes.

5.2.1.1 Typical Network Layout & Neutral Earthing Policy

A single line diagram for an urban LV microgrid is given in Figure 5-1 and illustrates the electrical boundaries where isolation and reconnection with the grid can occur. Only two LV consumer services have been shown for clarity (in reality they would be numerous and distributed over the phases) and the HV supply would typically be obtained from the primary substation using an open ring arrangement.

This research has considered the technical feasibility of providing adequate network protection for LV microgrids and, consequently, the electrical boundary may or may not correspond to commercial boundaries as currently defined by asset ownership or operational responsibilities. It should be noted that some of the protection equipment shown in this figure has been modified from existing industry practice to accommodate the microgrid. In particular, fuses in the LV distribution cabinet have been replaced with circuit breakers as shown in the figure (probably of the light industrial/commercial moulded case type). The isolation link between the transformer LV terminal and the distribution cabinet has been omitted.

The main electrical boundary is located at the circuit breaker installed on the HV side of the secondary substation transformer and forms part of the ring main unit

(RMU). By isolating from the grid at this location, the continuity of the neutral earth for the LV network is maintained as the solidly earthed star connected secondary winding of the transformer remains in circuit. The possibility of over-voltages occurring due to faults on the energised unearthed HV winding when islanded can be addressed by the installation of neutral voltage displacement (NVD) protection and will be commented upon in a later section.

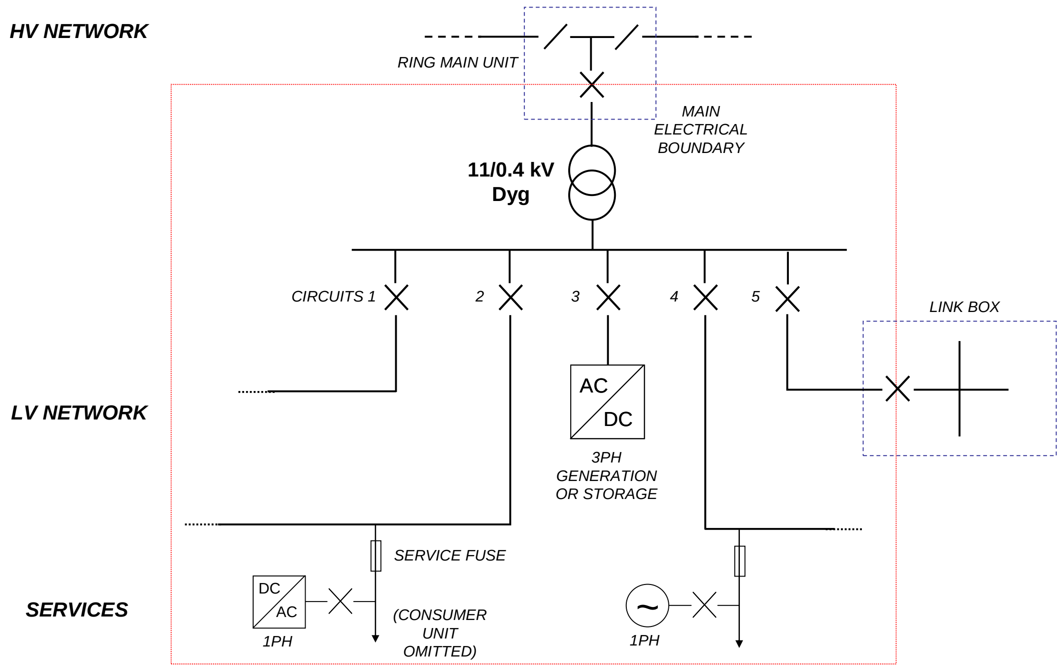


Figure 5-1: LV urban microgrid single line diagram.

Within dense urban networks such as that illustrated in Figure 5-1, alternative points of supply can be obtained from the reconfiguration of the HV cable network, or from adjacent LV circuits fed from a neighbouring secondary substation by reconfiguring the connections within link boxes or street pillars as necessary. Reconnection to the mains (grid) supply using whatever means offers several advantages to the operation of a microgrid. Firstly, although the total demand of the microgrid may not be supportable by a connection (e.g. due to circuit tapering), local generation would be operating and the connection serves as a means of increasing the security of supply. Secondly, the grid connection significantly improves the dynamic behaviour of the microgrid by providing an electrically stiff source to support network voltage and set the microgrid frequency. Thus even if the microgrid is capable of sustained islanded operation, this is likely to be a transitory condition and reconnection of the microgrid at the earliest opportunity to another network operating within set voltage and frequency tolerances would normally be deemed to be advantageous. In fact, the supply to which a microgrid reconnects could be an adjacent microgrid operating as an islanded network as this may still constitute an improvement in security of supply for local demand. This can also be seen as a means of black starting a grid that has collapsed by connecting sections of network that are still live at the lowest level of the system.

5.2.1.2 Typical Generator Connections

Generation connected to the LV cable network can be of single- or three-phase construction using either conventional rotating AC machines or power electronic converter interfaced DC sources or high speed AC machines. Single-phase generators will be mainly installed by individual residential consumers; whereas three-phase units are likely to be located within a commercial property or operated at a community level (e.g. as a district combined heat and power scheme).

5.2.1.3 Additional Network & Generation Control

Generation and demand within the microgrid will be actively controlled when both grid connected and operating as an islanded network. For the case of the former condition, the control objectives will be to supply the needs of consumers as efficiently as possible (from both environmental and economic standpoints), ensure good local power quality, and make surplus generation available for export to the grid. When isolated from the grid, the overriding control objective is to maintain the stability of the microgrid by regulating voltage and frequency, thus ensuring an appropriate quality of supply (typically by using a droop strategy for multiple generators) [5.10] [5.11] [5.12]. The control applied to generators will differ between single- and three-phase units. For single-phase units, control is likely be active power based when both grid connected and islanded. This arises from the fact that most primary energy sources for these types are small and generally not controllable (although a binary on/off control will be possible). For example, photovoltaic arrays and heat-lead micro-CHP fall into this category. The burden of balancing supply and demand will thus inevitably fall to three-phase units that will be fitted with droop control. These could either be generators or energy storage devices. Advanced control of three-phase power inverters may be used to provide per-phase control to counter any significant levels of unbalance should they occur at certain points in time. However, the converters will be required to be rated appropriately to supply the degree of unbalance correction required.

In any case, a need will arise for control schemes to switch between grid connected and islanded modes to ensure satisfactory performance. This is a potential area in which the need for coordination between protection and control becomes evident. Protection functions such as loss of mains (grid) could be useful as a source of information on the network state (grid connected/islanded in this case) as a means of triggering changes in control strategy. Moreover the coordination of controls on converter based generators, as discussed later, must be made with protection to ensure that sufficient fault current is available to operate devices at the lower end of grading paths.

Suitable control will also have to be provided to resynchronize with the grid or an adjacent microgrid if conditions are appropriate (i.e. if voltage and frequency are within prescribed limits).

5.3 Fault Behaviour

A thorough appreciation of microgrid transient behaviour is vital for investigating the scope of the new protection functions that will be necessary. The following sections present both the model used and the results of selected transient simulations. These results are used as the basis for assessing the performance of the existing protection philosophy and formulating requirements for the fault behaviour of LV generation within the microgrid.

5.3.1 Microgrid Transient Model

The single line diagram for an LV microgrid model created as part of this research is provided in Figure 5-2 and shows that the microgrid is supplied from an 11 kV HV cable circuit using an RMU as described previously. This model is intended to accurately represent the electrical characteristics of UK distribution networks and was built using Matlab/Simulink using the Power System Blockset. It is noted that, although not explicitly shown, the model incorporates the PME system and individual service connections distributed along the feeders. The network three-phase fault level at the HV boundary is 120 MVA (an equivalent Thevenin source represents the primary substation and HV cable network) and the secondary substation transformer is rated at 0.5 MVA with an impedance of 4.75 % and is solidly earthed.

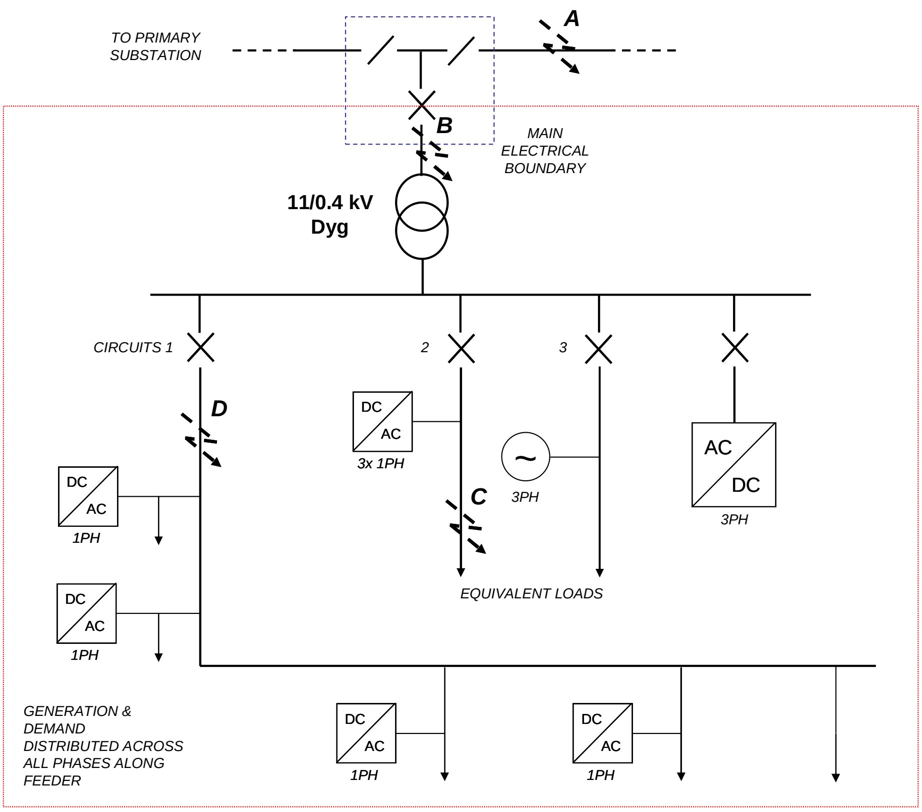


Figure 5-2: LV microgrid single line diagram (fault locations as indicated A-D).

The circuit (1) is modelled in detail including unbalance with consumer demand and generators as installed in individual services (using circuit length 250 m, 95 mm^2 XLPE cable). Table 5-1 provides a summary of the generation and load values (all have a power factor of 0.9 lagging). Generation connected to the microgrid includes both single- and three-phase using power electronic converter interfaces and an induction machine as detailed in the following sections. The structures for these models are provided in Appendix A.

Two LV cable circuits (2 & 3) have been modelled using lumped balanced demand and generation equivalents as indicated using a 1:0.7 ratio between demand and generation.

Table 5-1: Network model and generation data.

Generator	*Rating (kVA)*	*Circuit*	*Load (kVA)*
1ph Inverter	1.5	1	Ph A: 44, B:52, C:44
3ph Inverter	250	2	100
3ph Induction machine	50	3	100

5.3.1.1 Single-Phase Power Electronic Inverter

To represent these devices a full switched model was initially developed which was then reduced to an equivalent functional model. For the purposes of the transient studies the DC source, maximum power point tracker (MPPT) and link capacitor of a photovoltaic (PV) system can be represented as an ideal voltage source. In practice the MPPT is a DC/DC boost converter that acts to regulate the DC voltage of the PV system (a current source) to ensure that it operates at an optimal power level [5.13]. It has been assumed that for the duration of faults that the solar irradiation is constant and thus the DC/DC converter (typically using a PWM switching strategy) will act to maintain the DC link voltage in response to any disturbances originating on the AC side. For the initial stage of the model creation the overall system includes the controller, IGBT bridge, output filter (2nd order LC) and isolation transformer (the resultant filter corner frequency f_c was set at 400 Hz). The control strategy is shown in Figure 5-3 and is intended to operate at a unity power factor [5.14].

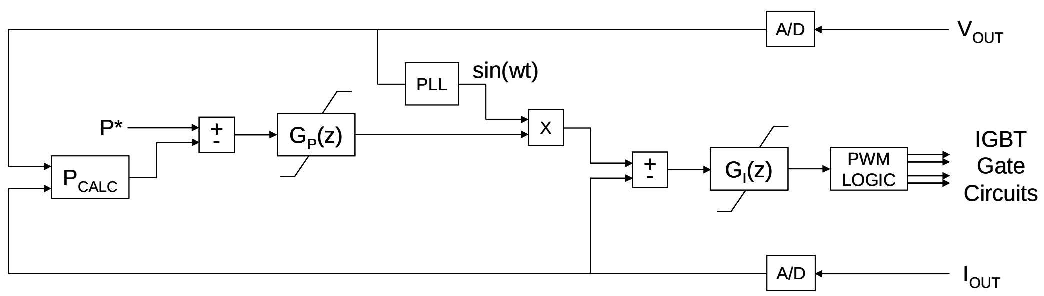


Figure 5-3: Single-phase power electronic inverter control scheme.

The control is based on an inner current regulating loop supplying the input to the PWM bridge controller and is supplemented by an outer real power loop. A phase locked loop (PLL) is used to ensure unity power factor operation by supplying a unity magnitude sinusoidal component in phase with the terminal voltage for the formation of the current reference for the inner loop. The real power reference is set as a constant value based on the aforementioned DC side simplification (in practice this would be derived from the maximum power point tracking unit). A switching frequency of 20 kHz has been used and current limits (1 per unit based on the inverter rating) have been included as shown. An anti-windup strategy has been applied to all integral elements within the loop PI controllers and these have been tuned to give acceptable regulation performance[20].

The initial switched model was used as the basis of a functional model using a controlled voltage source to allow for the connection of a large number of modules whilst ensuring that simulations are completed in a reasonable time. A comparison of the switched and functional models was made for a real power reference change and phase-earth network fault and these were found to be in close agreement. Further details of this comparison can be found in Appendix B.

It is also worth noting that the simplification to use ideal source equivalents must be used with some caution as during the fault the power delivered by the device to the network will be reduced and thus the energy still being extracted from the primary energy source must still be considered. In the case of a micro-turbine this could lead to an over-speed of the machine during the faults (and an excessive increase in DC bus voltage) and will need to be analysed for each generator/turbine design. Some form of DC chopper could be used before the final AC conversion to dissipate some of the power being delivered by the prime mover. During network faults the PV inverter used in the studies will deliver fault current no greater than its continuous rating. Thus it is assumed that the DC/DC boost converter is sized appropriately to maintain the link voltage within an acceptable band to avoid damage (e.g. to the link capacitor) and in so doing provides low-voltage (or fault) ride-through capability. Figure 5-4 below shows the active voltage, current and active power output of a converter (as an example) with its set point at rated value (1.5 kW) for voltage drops of 25 % and 75 %. It can be seen that although the power output from the converter is reduced due to the fall in terminal voltage, it is still able to

[20] It is noted that a proportional plus resonant controller would offer superior control performance when provided with sinusoidal references. However the controller designed performs satisfactorily for the studies being performed.

deliver current to the network during the disturbance. This current is limited by the control loop to ensure than the switching devices are not damaged. The time that it is able to deliver this current into the fault will depend on the design of the DC link components and a recommendation is made later in this chapter for a minimum value.

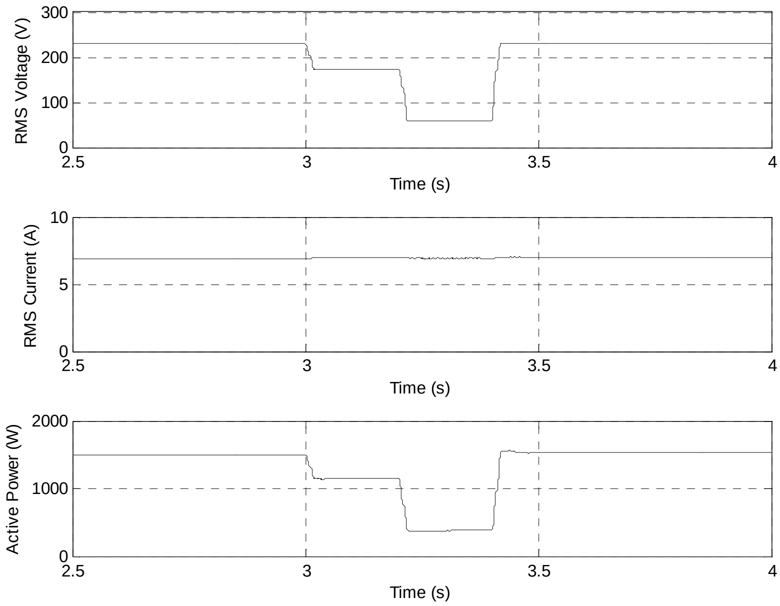


Figure 5-4: Output of single-phase inverter system for different voltage drops.

5.3.1.2 Three-Phase Power Electronic Inverter

A similar ideal voltage source representation has also been used for the three-phase power electronic inverter. The overall system includes the controller, IGBT bridge, output filter (2nd order LC) and delta-star isolation transformer (f_c = 400 Hz, combined for the LC filter and transformer leakage inductance). The control strategy is shown in Figure 5-5 and can operate in a number of modes for both grid connected and islanded conditions [5.16]. For grid connected operation the inverter can deliver power to the network at a specified power factor. Alternatively, for islanded operation the inverter can act to regulate voltage or frequency in a master mode or can participate with other units using a drooped strategy. Only one comparatively large single three-phase inverter is present in the following case study and it thus acts to regulate voltage and frequency without droop constants applied when islanded. The justification for this rests with the fact that it is the performance of the inner high bandwidth control loop that is of interest. This is the ability of the controller to effectively current limit the output of the inverter and thus provide fault ride-through capability. It is again noted that the behaviour of the DC system is important in determining the length of time that the inverter system can feed a fault current contribution into the network.

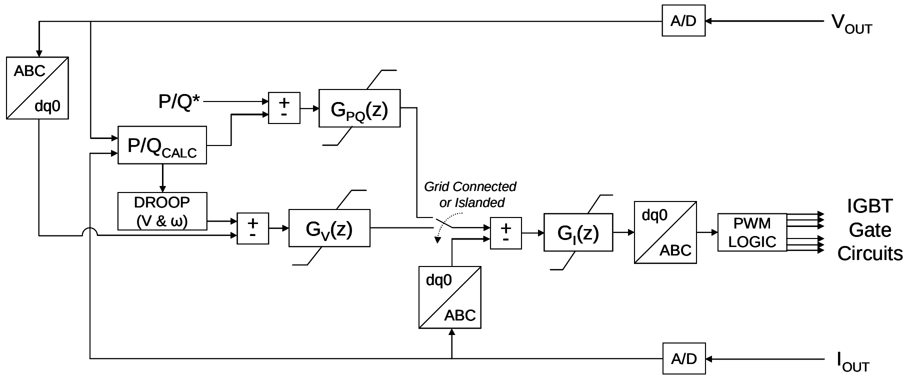


Figure 5-5: Three-phase power electronic inverter basic control scheme.

The control is based on inner inductor current and outer capacitor voltage regulating loops using PI controllers acting on variables transformed onto a synchronously rotating reference frame [5.15]. An output current limit (100 % based on the three-phase inverter rating) and integrator anti-windup strategies have been included. PWM switching is used with a frequency of 4.15 kHz, although the initial switched model was again used as the basis of a functional model using controlled voltage sources. It has been assumed that a system is in place to provide a fault ride-through capability should the source be an AC machine connected to the inverter via a rectifier and internal DC bus.

In general the output from larger three-phase converters is likely to vary from low to high output depending on the energy source availability or the state of charge if it is a storage device. As a consequence of this, it is possible that a device could be delivering a low power output to the microgrid prior to a fault that could be still possible to deliver once the voltage has fallen during such a disturbance. Moreover in the case of an energy storage device being charged, the direction of power flow is opposite to that desired (i.e. into the converter, although the ability to charge would be highly dependent on the retained network voltage). Consequently this device, although potentially able, may not provide fault current of any meaningful level despite perhaps being a significant contributor to the installed generation capacity within the microgrid. The implications for this are discussed later within the context of protection performance. However at this stage it is proposed that an additional control function (which would not necessarily be present in an existing commercial system) is added to increase the reference to the inner control loop to maximise the fault current available from a power electronic device (or to switch from charging to discharging if required). Figure 5-6 shows an example of a potential system.

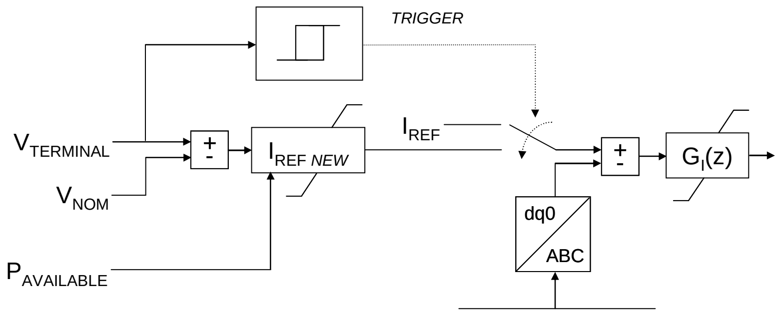


Figure 5-6: Additional three-phase inverter current reference increase logic.

In this simple example the increase in current reference is triggered when the voltage falls below 50 % and may be blocked if the energy source cannot deliver the additional power. The actual value of the increased reference is calculated based on the drop in voltage and the available power from the energy source. The scheme is disabled once the voltage rises above 60 %.

Figure 5-7 below shows how the suggested system functions in response to the low voltage at its terminals during a fault for the 250 kVA three-phase converter. The converter is initially delivering around 98 kW at nominal voltage resulting in a peak current of around 200 A. During the fault the voltage falls to below 25 % at the terminals of the converter. The current response with (60 % of rated, assumed maximum current available from the DC source as an illustration) and without (27 % of rated) the additional control system is shown for comparison in the figure.

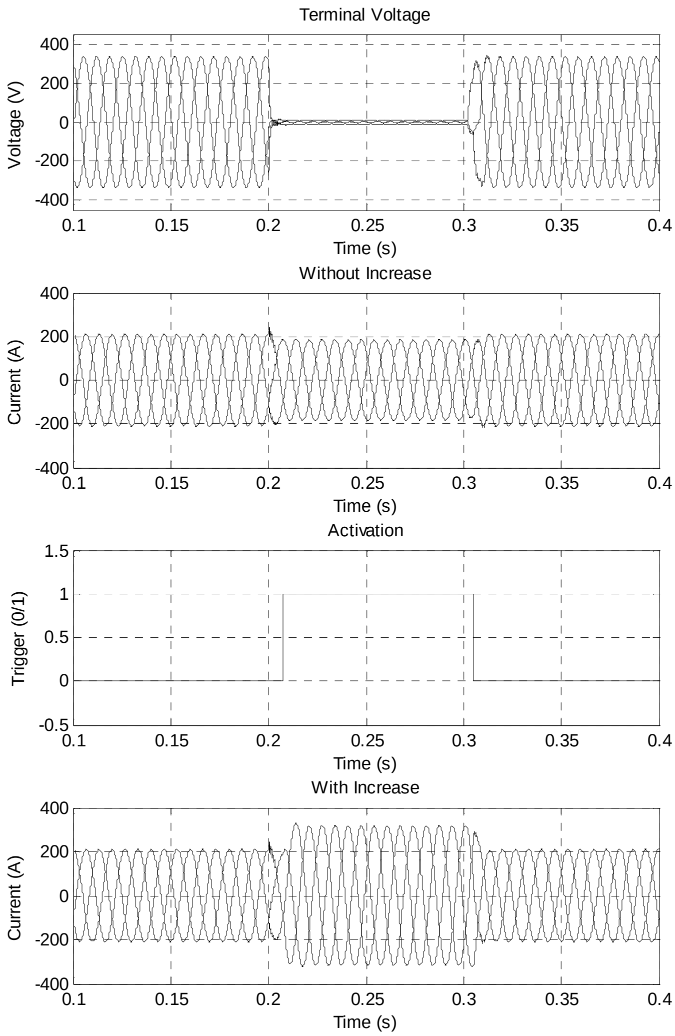


Figure 5-7: Response of current increase logic to low voltage fault disturbance.

For the studies reported in the following sections these converters are operating at or near their rated output and so the impact of this additional control scheme is not apparent. However its inclusion is important due to the reasons highlighted earlier to ensure maximum fault current is available to provide satisfactory margin for operating overcurrent based protection devices at the end of the grading paths (e.g. within consumer units).

5.3.1.3 Fixed Speed Wind Turbine

A basic fixed speed wind turbine has been included in the microgrid using an induction machine. The three-phase 50 kVA asynchronous generator is represented with a 4^{th} order model using a single squirrel cage rotor and is coupled to a small wind turbine [5.16][5.17]. Constant mechanical input torque has been assumed during these studies and appropriate power factor correction capacitors used to ensure close to unity operation.

5.3.2 Fault Studies

The following sections illustrate the transient behaviour of the microgrid described in Section 5.3.1 when subjected to a number of internal and external faults (refer to Figure 5-2 for the locations A – D). Although the selection of the faults to be considered is not exhaustive, they nonetheless characterise the behaviour of the microgrid under a broad range of fault conditions. The rationale for choosing each fault location and type is summarised as follows:

- External, 3ph, location A: This fault represents a typical three-phase fault that could occur on an HV underground cable circuit.
- Internal, 1ph-E, location B (Islanded): Although this fault type would be unusual at this location it is studied as it occurs on what would be an unearthed section of network under islanded conditions.
- Internal, 3ph, location C (Islanded): This fault represents a typical three-phase fault that could occur on an LV underground cable.
- Internal, 1ph-E, location D (Islanded): This fault represents a typical single-phase fault that could occur on a single-phase LV service cable that could occur at any point along a feeder.

The studies all assume a fault duration of 100 ms (after which it is removed) with an inception at 0.1 s. A distinction is made between grid connected and islanded operating modes.

5.3.2.1 External Faults (HV) – Three-Phase at Location A

The fault current contribution from the microgrid as measured through the HV interface circuit breaker and HV voltages are shown in Figure 5-8 (a) and (b) respectively. The pre and post-fault current magnitudes can be observed to be relatively small due to the local generation meeting a significant proportion of the demand leading to a net 0.12 MW import.

During the time within which the fault has been applied, the current magnitude can be observed to have a small increase and a phase change occurs as the direction of flow switches to being out of the microgrid towards the HV network fault. The decaying nature of the microgrid contribution is attributable to the induction generator response. During the fault, the HV interface voltage falls to zero as its location is electrically close to the microgrid terminals and could be seen to serve as an indicator of an external fault.

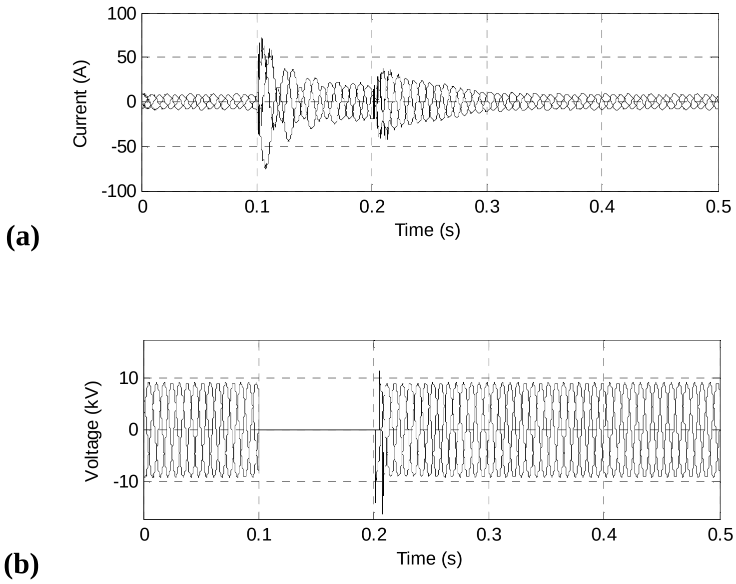


Figure 5-8: External three-phase fault at location A (a) HV phase currents and (b) HV voltages.

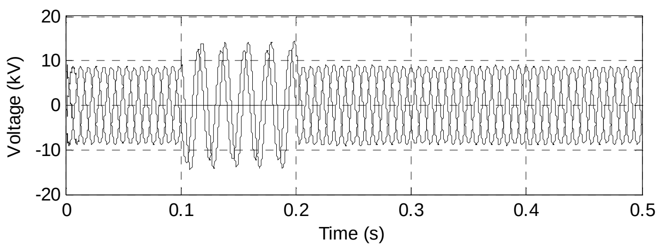
The critical clearance time for the induction machine connected to the microgrid for a three-phase external fault at location A was found to be 306 ms for the worst case of a zero impedance fault. This value was obtained from repeated simulations in which the fault duration was increased until instability occurred.

5.3.2.2 Internal (HV) – Phase A-Earth at Location B (Islanded)

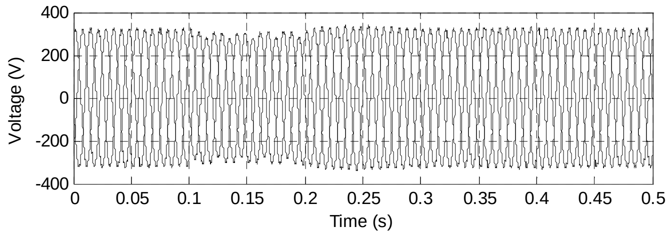
Figure 5-9 (a) shows the phase voltages at the HV terminals of the secondary substation transformer when a phase-ground fault is applied at location B whilst islanded. The rise in the non-faulted phase voltages to phase-phase levels is clearly evident due to the unearthed delta secondary winding of the transformer.

The internal LV microgrid voltages are shown in Figure 5-9 (b) and highlighting that there is limited impact owing to the delta-star vector group of the secondary transformer windings.

Although it could be argued that the likelihood of this fault is low, it does nonetheless represent a condition wherein the microgrid would be unable to reconnect to the grid at this point and thus its identification can be regarded as being important.



(a)



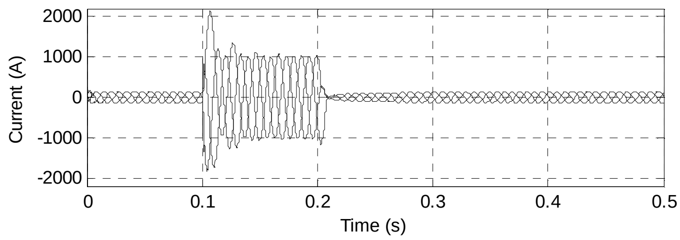
(b)

Figure 5-9: Internal phase-ground fault at location B (islanded) (a) HV voltages and (b) LV voltages.

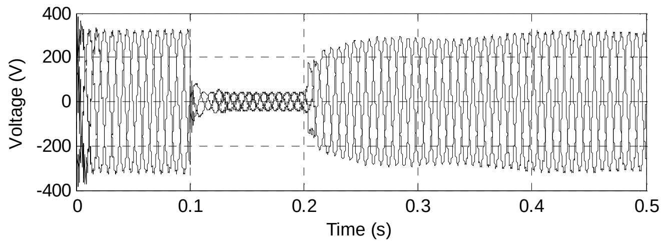
5.3.2.3 Internal (LV) – Three-Phase at Location C (Islanded)

Location C is at the end of the cable circuit 250 m from the distribution cabinet. The fault current contributions into circuit (2) and LV distribution board voltages are shown in Figure 5-10 (a) and (b) respectively. This current contribution is equivalent to a fault level of approximately 0.5 MVA and is evidently far lower than which would conventionally be expected. The reduction in voltage is also clear from Figure 5-10 (b) and is lower than expected from an overload condition within an islanded microgrid (this condition is considered in §4.3.2.5).

The average critical clearance time for the induction machine connected to the microgrid for a three-phase internal fault at location C was found from repeated simulations as being approximately 213 ms for the worst case of a zero impedance fault. This is lower than for the external case but is explained by a lower voltage being present at the machine terminals during the fault when the microgrid is islanded.



(a)



(b)

Figure 5-10: Internal three-phase fault at location C (islanded)
(a) microgrid fault current contribution into circuit 2 & (b) LV phase voltages.

5.3.2.4 Internal (LV) – Phase-Ground at Location D (Islanded)

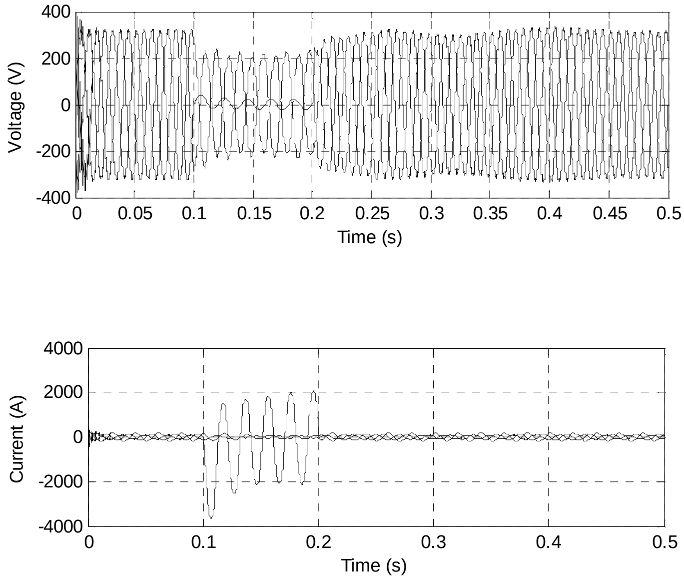
A phase-earth fault was applied at location D and the LV distribution network voltages and total microgrid fault current contribution from all sources outside circuit 1 are shown in Figure 5-11 (a) and (b) respectively. The voltage can be seen to be suppressed on the faulted phase with the others undergoing a small reduction due to the network and generation interconnections. A relatively small fault current (in comparison to a grid contribution) is also observable, although in this case corresponds to approximately twice the RMS level of the previous location. This increase is attributable to the lower fault circuit impedance for location D at the start of the feeder in comparison to location C at the end.

5.3.2.5 Microgrid Overload Condition

To illustrate the case of a microgrid overload, two additional LV circuits are connected to the microgrid, each with the same load as the existing circuit (1) but without generation. This event could be the result of growing the network during a black start condition. The resulting LV voltages are shown in Figure 5-12 at the distribution cabinet and can be seen to be higher than those shown previously for an internal fault. In this case the limits of available generation did not permit the voltage to be returned to the nominal value. Clearly, depending on the specific nature of the control strategy used, this overload condition would be detected using protection such as under-frequency relaying or dedicated overload (overcurrent with a low pickup and long time delay). Detection of overloads is important as power electronic generation does not possess the inherent short-term overload capability that is exhibited by rotating machines unless it has been specifically included within the design by increasing the rating of the switching devices.

5.4 Microgrid Protection

The results presented above indicate that the existing application of only fuse based protection is unlikely to be satisfactory in an islanded microgrid given the limited availability of fault current (only 0.5 MVA in the example above would clearly be unable to operate a 400 A fuse within the LV distribution cabinet). In terms of the methodology for designing adaptive protection described in Chapter 3, it is not just a matter of changing settings as the basic protection element (i.e. the fuse) needs to be reconsidered. It will be shown that a revised form of short-circuit protection is required with changes in settings only necessary should two islanded microgrids be interconnected via an LV link (a practice that may be useful for growing networks during back-starts).



(a)

(b)

Figure 5-11: Internal phase-ground fault at location D (islanded)
(a) LV phase voltages and (b) microgrid fault current contribution.

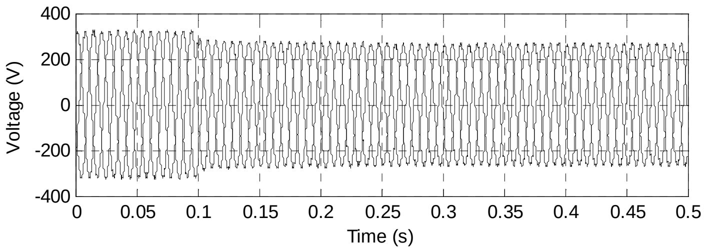


Figure 5-12: Microgrid overload condition LV voltages

However for other system protection such as under-frequency or load shedding required for islanding it will be suggested that changes in settings will suffice for moving between modes of operation[21]. These changes and the integration of the proposed short-circuit protection into the adaptive protection architecture are discussed in §5.5

It is firstly assumed that some form of grading is required within a microgrid to avoid the complete loss of supply for a single internal fault when islanded (i.e. that the generation does not trip instantaneously and has a certain level of low voltage

[21] These of course would not be found on an existing distribution network at this voltage level. However they may in the future be required to function not only with islanded microgrid operation, but also for HV islanding if this is permitted by the utility.

ride-through capability). Designing protection schemes for microgrids represents a challenge owing to the generally low and somewhat variable fault current contribution from different types of LV generators. The sections that follow describe the development of a protection system that is based on a philosophy largely independent of fault current magnitude when islanded from the grid. By considering conventional grading paths starting within the consumer installation and ending at the HV interface for a single microgrid, the key elements of the proposed approach are illustrated. A number of test examples based on transient simulation are also provided. Further discussion is then provided on the implications arising from interconnecting two microgrids.

5.4.1 Generator Protection

Before proceeding with a study of network protection it is worthwhile to firstly comment on the protection installed at generators. The protection installed at a generator is designed to disconnect the generator from the system in the case of either an internal or external fault or other severe network disturbance. In the case of the latter this should be after a time that permits network protection to attempt to clear the fault from the system or for a control system to mitigate the impact of the disturbance. For the case of faults, this functionality remains the same with the time delay coordinated with the fault ride-through capabilities of the specific generator types. In terms of system protection (such as the under and over-voltage/frequency as specified in engineering recommendation G83/1 [5.18]), the overall concept also remains the same as these are set to ensure that generators are only disconnected from the system once the deviation in measured quantity becomes so large that a collapse is inevitable and so they must be tripped to avoid damage.

A further function of protection is to disconnect generation in the event that the connection with the main network is lost in order to prevent islanding (the so called loss of mains protection). Since islanding is now permitted, it is suggested that this protection function at microgrid generation is now coordinated with additional loss of mains protection which will be installed at the boundary with the grid. The latter can be used to initiate islanding and the former set as a backup to trip the generation if the island is not correctly established.

5.4.2 Protection within Consumer Installations

Protection within consumer installations after the utility service connection is presently provided using fuses or miniature circuit breakers (MCB) (Figure 5-13). This need not necessarily change since the current contribution for faults within the installation when islanded from the grid will be, in general, sufficient to operate these devices.

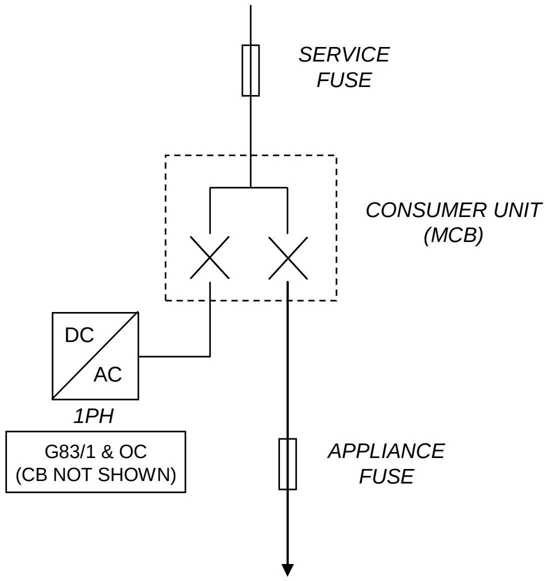


Figure 5-13: Protection within consumer installation.

As a simple example, consider that 0.5 MVA of three-phase LV inverter generation is installed within the microgrid and that it can contribute only a full load RMS phase current magnitude of 722 A. It is assumed that this phase current is available for both three-phase and single-phase faults through appropriate control of the converters. To begin to assess the impact of this magnitude of fault current, Table 5-2 lists the fault current required to ensure 100 ms operation for various common devices as defined within the relevant British Standard (BS) ([5.19] - [5.21]).

Table 5-2: Consumer LV Protection 100 ms Operation Summary

Type	*Rating (A)*	*Required Current (A)*	*BS*
Enclosed Fuse	10	60	88
Semi-Enclosed Fuse	5	45	3036
Miniature Circuit Breaker (Type B)	6	30	60898

It can be observed that the fault current available will ensure operating times are far lower than 100 ms. However this must also be confirmed for the largest protection device that is likely to be found within a consumer installation such as a 40 A MCB (type B) used to protect a cooker or shower circuit. The standard for these devices (IEC 60898 [5.22]) states that a current of at least 5 times a device's rating is required to ensure 100 ms operation (the band for MCB time current characteristics is shown in Figure 5-14, domestic devices are of type B suitable for conditions of little or no inrush). Which in this case would be 200 A and equates to a three-phase installed converter capacity of 0.139 MVA and is within the capabilities of the units available assuming that they are all in operation.

However it is obvious that over the course of operation this level of capacity might not actually be available depending on the demand and availability of primary energy sources. Furthermore, the use of type C MCB devices for lighting or small motor loads (e.g. air conditioning units or within commercial installations such as a small shop were fluorescent lighting is installed) with their larger current required for operation increases the level of installed capacity required for safe operation.

If it is assumed that 722 A is available and type C MCBs have been used within the network, this places a limit that ratings no larger than the standard 63 A value can be used. Clearly any possibility for a reduction in the available fault current will reduce this yet further. Thus if a utility is going to permit intentional islanding it must ensure that careful attention is paid to the likely designs within consumer or commercial installations and the minimum level of generation that would ever be available to contribute to the fault current. A conservative estimate of a minimum generation availability of 50 % of installed capacity (of 0.5 MVA) would imply that MCBs with maximum ratings[22] of 63 A and 32 A can be used safely for types B and C respectively. Moreover this of level capacity is in line with that mentioned previously with regard to microgrid scale. These could be increased but would be at the expense of requiring additional converter capacity.

However if very low generation levels were to be accepted, these MCB devices within the consumer protection could be replaced (at additional cost) with a reduced version of the functionality to be described in a letter section if deemed desirable.

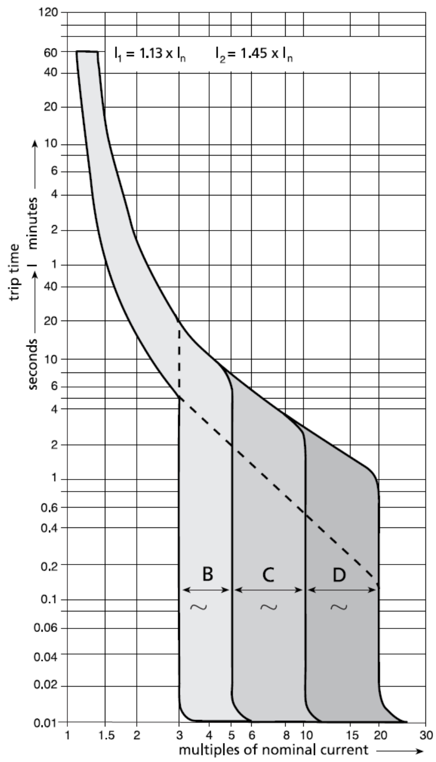


Figure 5-14: MCB time-current characteristics (reproduced from [5.22]).

5.4.3 Service and Network Protection

LV networks are conventionally protected by the graded application of fuses at utility services, secondary substation distribution cabinets and within fused switches on the HV RMU [5.23]. It is noted, however, that in RMUs circuit breakers are replacing fused switches in newer designs. Fast fault clearance is ensured by the adequate fault level contribution from the grid, typically of the order of 15-20 MVA at the LV terminals of the supply transformer [5.24]. However, when both operated

[22] The standard MCB ratings [5.22] are: 6, 10, 13, 16, 20, 25, 32, 40, 50, 63, 80 and 100 A.

as an island and for the case of external faults when grid connected (i.e. on the upstream HV supply circuit), a significantly lower fault level contribution is present (as was observed in §5.3) within or from a microgrid that may not be sufficient to ensure that existing fused based protection would operate satisfactorily.

As a consequence of this restriction in fault current contribution, a number of fuses within LV networks must be replaced should microgrid islanded operation be desired. This has led to the proposed introduction of additional circuit breakers as shown in Figure 5-1 at the interface and LV distribution cabinet to be actuated by relays with suitable characteristics that will be described in a later section. The circuit breaker installed at the main electrical boundary and the switches within link boxes are intended for three-pole tripping or actuation only. However, the circuit breakers at the LV distribution cabinet have single-pole tripping to permit the continued supply of single-phase loads to provide the same level of isolation as afforded by the existing fuses applied to individual circuit phases.

For the case of the utility service fuse, fast operation cannot be guaranteed when the microgrid is islanded and its replacement is required if the same number of isolation points in the grading path is to be maintained (e.g. an 80 A BS 3871 fuse requires 1100 A to ensure 100 ms operation). However, replacement of all service fuses with a more complex protection device would be both expensive and time consuming. Instead, it is proposed that existing service fuses remain in use and will operate as intended when grid connected. Under islanded operation this point in the grading path will be effectively removed and, since faults on the service above the consumer unit are unusual, can be justified during the temporary period of islanding given that protection upstream at the LV secondary distribution cabinets will provide backup. If islanded operation is a transitory condition then this serves as the basis for justifying the removal of one point of graded isolation. If this is not the case, however, a simplified version of the functionality detailed in the following sections could be installed if deemed necessary.

5.4.4 Fault Detection and Grading

The fall in system voltage during a fault offers an effective way of discriminating between load and fault current and is particularly useful in systems with low fault levels. Although it should be noted that grading between protective devices using voltage cannot be reliably achieved as the voltage reduction within a faulted islanded microgrid will be almost uniform across the network. Figure 5-15 illustrates this by showing the RMS voltages at several locations for a fault located at the end of circuit 1 (100 ms duration stating at 0.1 s).

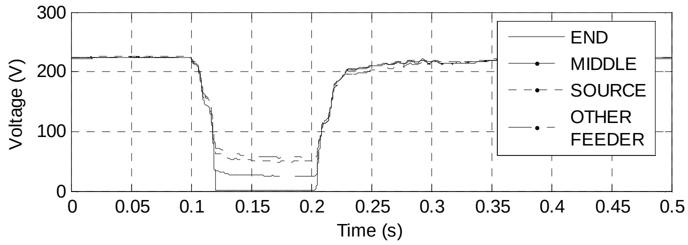


Figure 5-15: Microgrid RMS voltages (phase A) - 3PH fault at end of circuit 1.

The use of measured system voltage as a means of detecting faults within microgrids has been discussed by several authors (e.g. [5.8], [5.25] and [5.26]), with use being made of transformations to a d-q reference frame or a decomposition into sequence components. This published work and the results presented above demonstrate that although such a measurement can be used to reliably detect a fault, further attention must be given to how coordination can be achieved between protection devices if a practically useful scheme is to be developed (since the lack of sufficient impedance between relaying locations will not be sufficient to give a voltage gradient suitable for coordination).

If an under-voltage element is used as a starter for a directional element set with a definite time delay, an acceptable grading method may be created. Within a low fault level environment no damagingly high fault currents exist and thus the longer clearing times towards the source end of a grading path do not necessitate the application of an inverse-time characteristic. The upper boundary for the definite time delay at the source end of a grading path will be limited by such considerations as generator stability (for rotating AC machines), the time that a generator can feed into a fault (power electronic converters), and the sensitivity of loads to voltage disturbances.

Conventional inverse overcurrent characteristics are also required to be provided to cater for internal faults when operating with a grid connection to ensure fast fault clearances. These should use an extremely inverse characteristic to provide good grading with the fuses further down the grading path. Both the conventional overcurrent and under-voltage based scheme can be active at the same time as the high fault level when grid connected will ensure that the former operates more quickly. The delays of the under-voltage based scheme are discussed in a later section and will confirm this assertion.

5.4.5 System Protection Functions

A number of other protection functions that fall within the area of system protection are also required to support islanded operation. Under- and over-voltage and frequency elements are necessary to avoid damaging equipment during longer-term disturbances due to imbalance between demand and generation that cannot be corrected. The settings of these may need to be either enabled/disabled or changed between different groups as the microgrid moves between different modes of operation. For example the under frequency settings will be different should the microgrid be a part of a larger HV islanded power system than would be the case for an islanded microgrid (for example due to different overall generator characteristics). Moreover, the settings may be adapted to trip demand faster when the available generation capacity is low within the microgrid due to the very small size of these systems amplifying the impact of any disturbance. Both of these will require some form of logic to initiate the changes and are will be structured in accordance with the architecture developed in Chapter 3 (refer to §5.5 for further details).

Although not strictly a system protection, NVD is also included in this set of functions to protect against HV earth faults when operated as an island because the delta winding of the supply transformer will create an unearthed system. Either separate phase voltage transformers (VT) or a three-phase three-limb device will be required to establish the zero sequence flux to enable the correct application of this technique. The likelihood of this fault occurring is low but in any case voltage measurement will be required for synchronisation with the grid. Thus a check synchronism element will be required as part of the grid reconnection functionality within the microgrid.

The actual settings for these system elements is not considered further as the dynamics of the microgrid was not the focus of this work. However, system protection for an islanded HV network is considered in the following chapter and similar principles will be applicable.

5.4.6 Microgrid Integrated Protection System

Using the discussion above as a foundation, the concept of a Microgrid Integrated Protection System (MIPS) is now introduced [5.27]. It is based on two basic multi-function IEDs to ensure that the proposed design can be readily scaled to be applied at a large number of secondary substations. The first will be installed within the secondary substation and will provide all the functionality required for a stand-alone microgrid. A further type may be installed at any link box/street pillar that will be used to interconnect two LV microgrids should this functionality be desired using the circuit breaker installed in the link box/pillar as shown in Figure 5-1. If this latter functionality is not required then this second IED can be omitted from the scheme. The two IEDs are called MIPS-SUB (substation) and MIPS-INT (interconnection) respectively and if both are installed then a communication channel must be provided between them. This link will only be used for status and enable signals necessary for scheme operation and not for the transfer of any measured parameters. Therefore a low bandwidth communication channel will be satisfactory. The loss of the channel will disable the MIPS-INT relay preventing interconnection between microgrids and further discussion on this is provided later. Their suggested physical locations and associated measurements within an LV microgrid are shown in Figure 5-16. Note that the trip circuits have been omitted for clarity in the figure. Table 5-3 summarises the individual protection locations/role and functions within the MIPS concept.

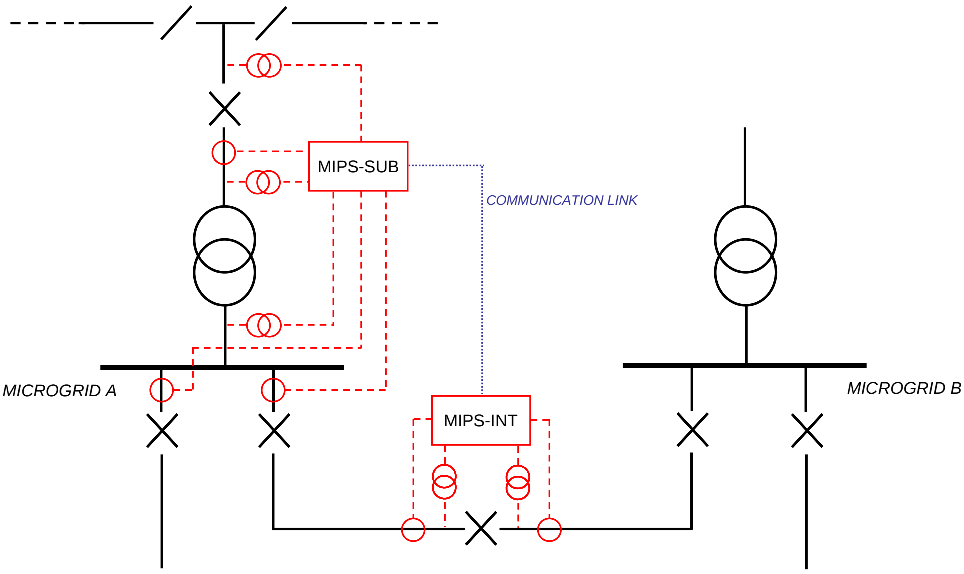


Figure 5-16: Locations of MIPS relays.

The design of the MIPS relay is outlined in the following text by firstly detailing the key functional elements, and is then supplemented by a brief discussion of their numerical implementation. The application of both relays within suggested schemes then follows in a subsequent section.

Table 5-3: Summary of MIPS protection locations/role and functions.

Location/Role	***Functions***
HV CB	Overcurrent, Definite Time Directional Under-Voltage, Check Synchronism.
Distribution Cabinet LV CBs	Overcurrent, Definite Time Directional Under-Voltage
Link Box/Pillar LB CB	Overcurrent, Definite Time Directional Under-Voltage, Check Synchronism.
System	NVD, Under/over-voltage/frequency, Loss of Mains

5.4.6.1 MIPS-SUB Functional Elements

Figure 5-17 provides a diagram of the MIPS-SUB outlining the key protection functions and the low level interconnections within the design. This functionality corresponds to the execution layer within the adaptive protection architecture. These functions are always executed by the relay when active with a given group of settings. Protection functions sets are associated with the HV circuit breaker as well as each of the LV circuit breakers within the distribution cabinet. Each set provides overcurrent as well as the islanded short-circuit protection described earlier.

The relay is based on three individual phase units corresponding to each circuit breaker location and an additional system functions unit. Single-pole tripping is permitted at LV but three-pole tripping is required at HV. Furthermore although not shown, a suitable analogue front end has been incorporated to provide acquisition and isolation functions. Each phase unit has instantaneous and extremely inverse (EI) overcurrent elements in addition to an under-voltage starter used to initiate a directional element with a definite time delay for both the forward and reverse directions. These elements are replicated to protect different number of outgoing LV circuits that could be within the area responsibility of a MIPS-SUB relay. The system function unit includes NVD, loss of mains (LOM), check-synchronism and under/over frequency/voltage elements. The first three of which act on the HV breaker whereas the remainder act to trip all circuit breakers such that the whole microgrid is shut down (after the eventual tripping of generation via their protection).

The MIPS relay requires external connections to current and voltage transformers, the technology of which could change between voltage levels (i.e. LV or HV). It is also proposed that the relay would derive a power supply from one of the instrument transformers that would be used to charge a small internal energy storage device (e.g. battery or capacitor).

The overall functional architecture is shown in Figure 5-18 where execution and coordination layers are indicated. Since the protection system must be scalable and modular, a simplistic approach has been taken and so only the lower two layers of the architecture have been implemented. This can be justified as the microgrid is in either islanded or grid connected mode and the criteria for transition must be simple to ensure that a bespoke complex system does not have to be implemented at the numerous secondary substations in the network. Given the relatively small level of installed generation capacity, it will be invariably matched to demand such that islanding will only be possible should all of it be in service (whereas at HV a larger pool of generation may be available thus providing a larger number of conditions in which islanding would be possible from a capacity perspective).

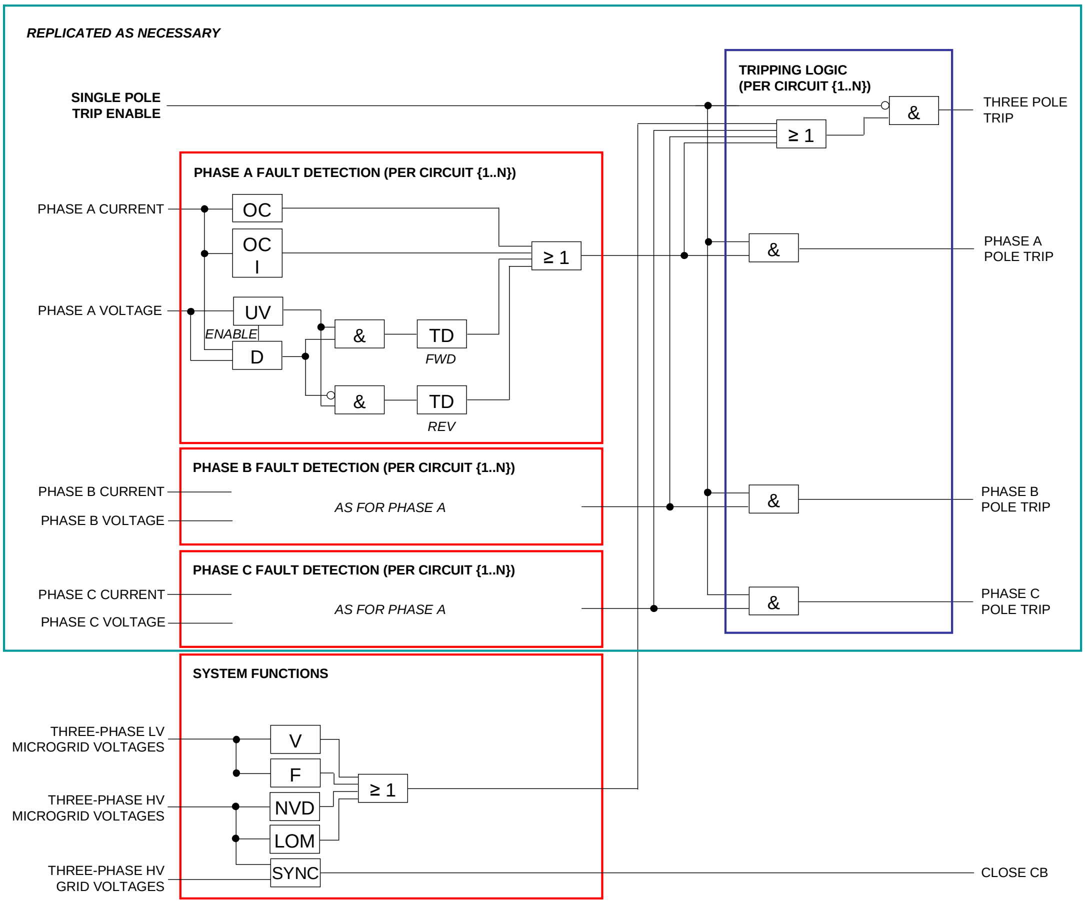


Figure 5-17: MIPS-SUB IED protection elements (execution layer).

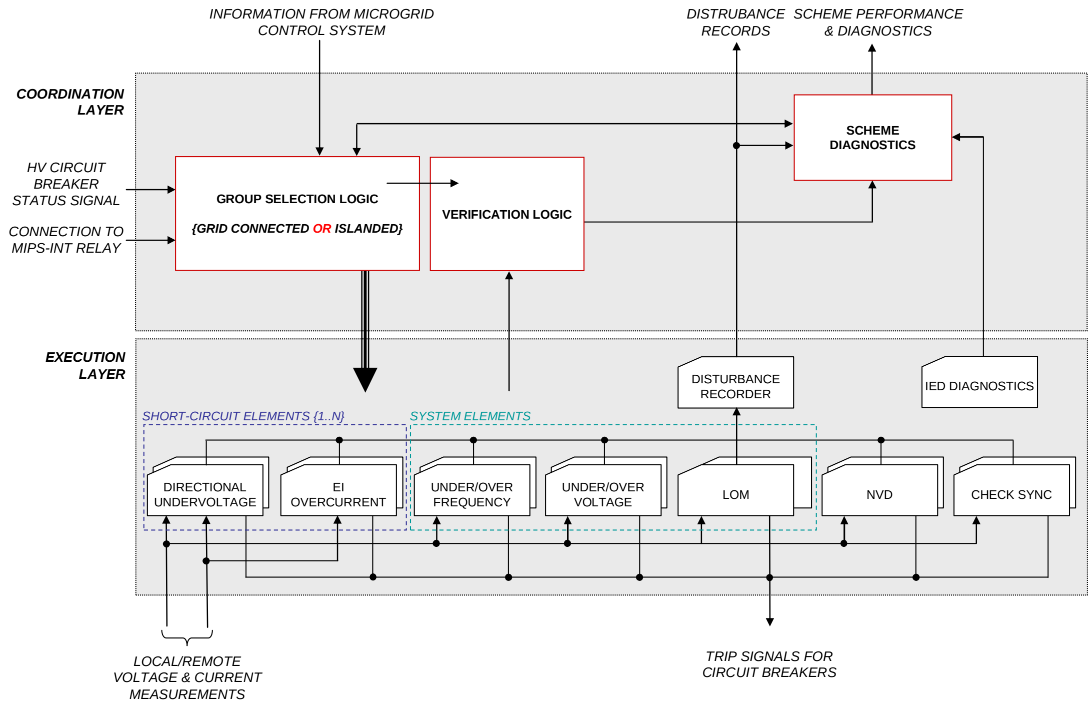


Figure 5-18: MIPS-SUB IED functional architecture.

As noted previously, only the system protection settings need to be modified when moving between operating modes should only an isolated microgrid be considered (however if an MIPS-INT relay is used to interconnect two microgrids then some short-circuit settings will need to be changed). Thus the input to the coordination layer logic is the HV circuit breaker status and that of any potential LV points of interconnection at link boxes or street pillars (communicated from a MIPS-INT relay if installed since a grid connection could be derived via an adjacent microgrid). The management layer in this case is conceptually part of the microgrid control system and would provide a signal to enable the check-sync element (different settings could be applied such as for frequency or voltage differences should they be necessary). The logic for the settings changes that forms part of the coordination layer is discussed later in this chapter. Scheme diagnostics in the case of MIPS-SUB are limited to the failure of onboard relay hardware components and the communications channel to a MIPS-INT relay if installed.

5.4.6.2 MIPS-INT Functional Elements

Figure 5-19 provides a functional diagram of the MIPS-INT outlining the key elements and interconnections within the design. It is to be installed at the link box/street pillar and provides all protection functionality required at this location. This relay will again be line powered using a supply derived from an instrument transformer (a dual supply will be available from both sides of the circuit breaker). Since it is installed at the boundary it will in effect form part of the protection for two adjacent microgrids.

This relay includes the basic instantaneous short-circuit protection functions as was the case for the MIPS-SUB relay, but also includes a dedicated overload function to guard against the overloading of a tapered circuit that is being used for interconnection. A check-synchronism element is of course provided. A further type of protection is included to disconnect the microgrid from the adjacent system should voltage or frequency fall outside of set tolerances. A reverse power flow element is used to trip the circuit breaker should the power exchange from one microgrid to another be high. Scheme diagnostics are again limited to hardware failures.

5.4.6.3 Numerical Implementation

The following paragraphs provide an example numerical algorithm that has been used to implement the voltage based short-circuit protection. Others may of course be used and the design presented does not include the signal processing required for frequency based protection functions. This could, for example, be based on a PLL approach [5.28].

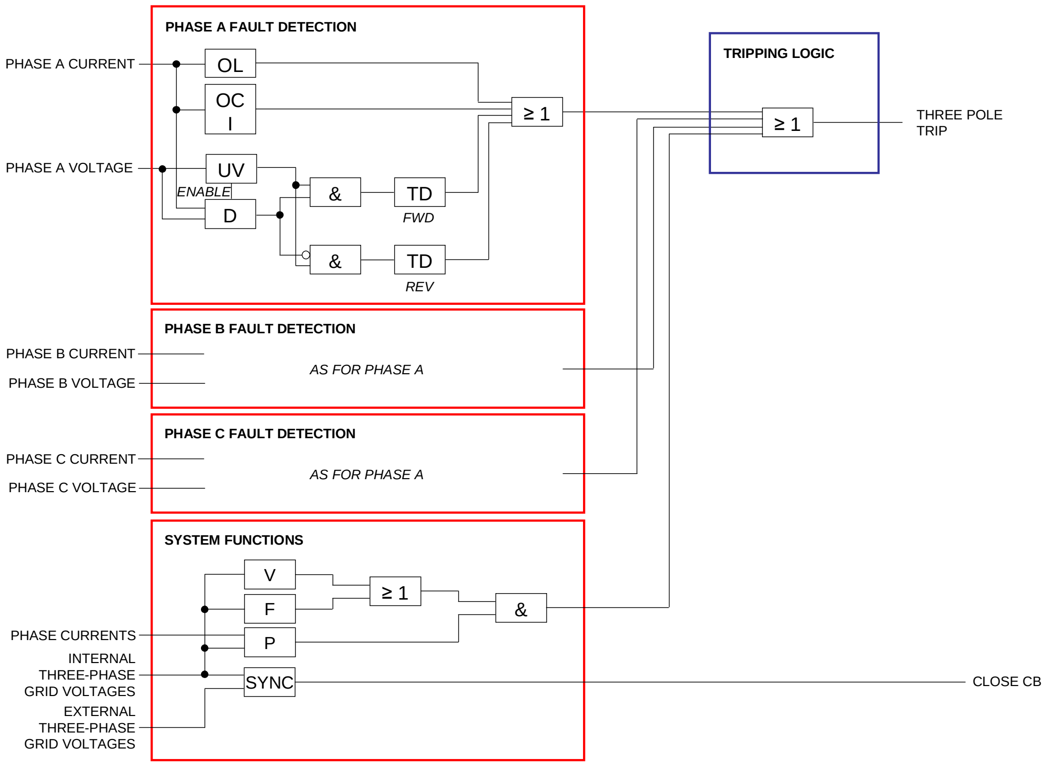


Figure 5-19: MIPS-INT IED protection elements (execution layer).

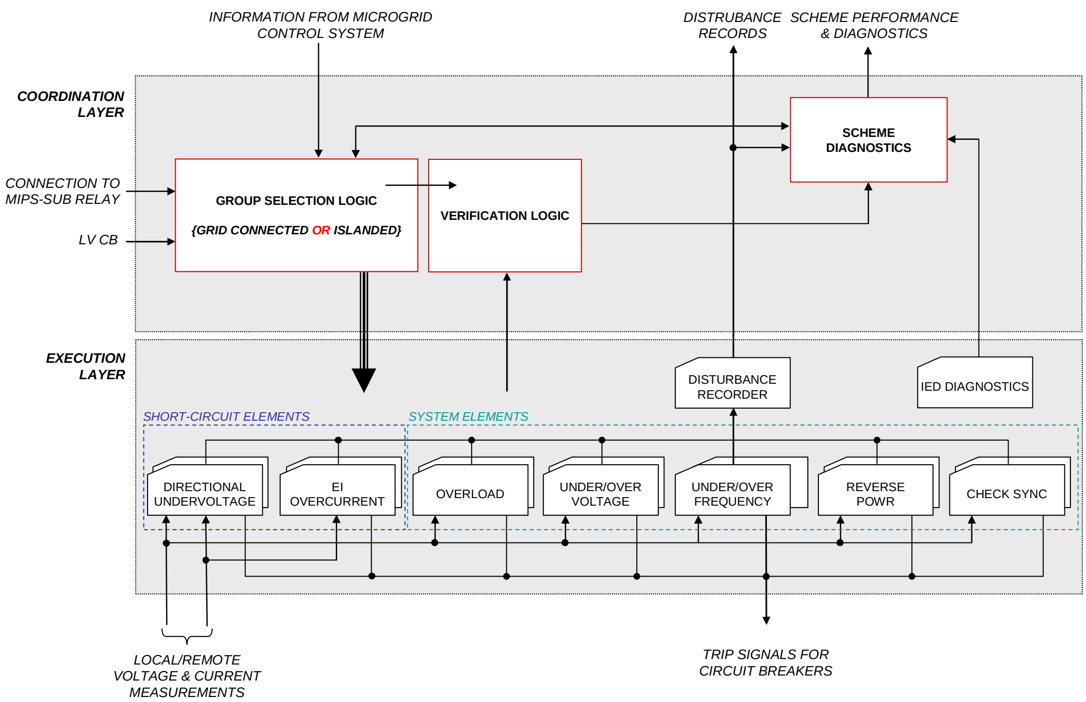


Figure 5-20: MIPS-INT functional architecture.

The numerical algorithms are implemented based on the assumption that a basic hardware platform is desirable and appropriate analogue filtering is used. Accordingly, the relay has been developed using 16 samples per cycle of the fundamental (f_s = 800 Hz, fixed rate) and includes digital pre-filtering using a 2nd order Walsh function with the specific discrete implementation that has been used given in equation (4.1) [5.28].

$$y[n] = -\sum_{k=0}^{3} x[n-k] + \sum_{k=4}^{11} x[n-k] - \sum_{k=12}^{15} x[n-k] \tag{4.1}$$

The phasor peak magnitudes and angles have been calculated using the two-sample method as defined in equations (4.2), (4.3) and (4.4) [5.29] where Δt represents the sampling interval.

$$V^2[n] = \frac{v^2[n-1] + v^2[n] - 2v[n-1]v[n]\cos\omega_0\Delta t}{(\sin\omega_0\Delta t)^2} \tag{4.2}$$

$$I^2[n] = \frac{i^2[n-1] + i^2[n] - 2i[n-1]i[n]\cos\omega_0\Delta t}{(\sin\omega_0\Delta t)^2} \tag{4.3}$$

$$\theta[n] = \frac{\begin{bmatrix} i[n-1]v[n-1] + i[n]v[n] - \\ (i[n-1]v[n] + i[n]v[n-1])\cos\omega_0\Delta t \end{bmatrix}}{IV(\sin\omega_0\Delta t)^2} \tag{4.4}$$

The two-sample method assumes that the measured signals are sinusoids of a fixed fundamental frequency with minimal harmonic distortion if accurate results are to be obtained. However, microgrid frequency regulation can vary depending on the generation and control approach used. The percentage error in peak magnitude calculations for fundamental frequency deviations between 49 Hz and 51 Hz corresponds to a ± 2 % range. For grid connected operation, the fundamental frequency will be relatively stiff (50 Hz ± 1 %) and will only result in very small errors. For illustration the response to a -0.5 Hz/s frequency ramp starting at 0.1 s from a 50 Hz constant voltage input is given in Figure 5-21. The response shows that an oscillation appears in the magnitude calculation with increasing amplitude but this is still very small (less than 1%) and is not regarded as being significant.

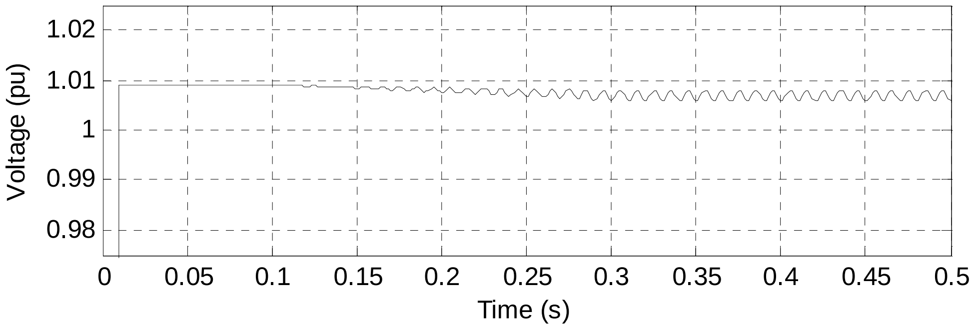


Figure 5-21: Two-sample method response to fundamental frequency ramps.

A further example is given in Figure 5-22 where the response is shown with harmonic distortion. In this case 5^{th} and 7^{th} harmonics at 8 and 5 % respectively of the fundamental have been added as an example of severe distortion.

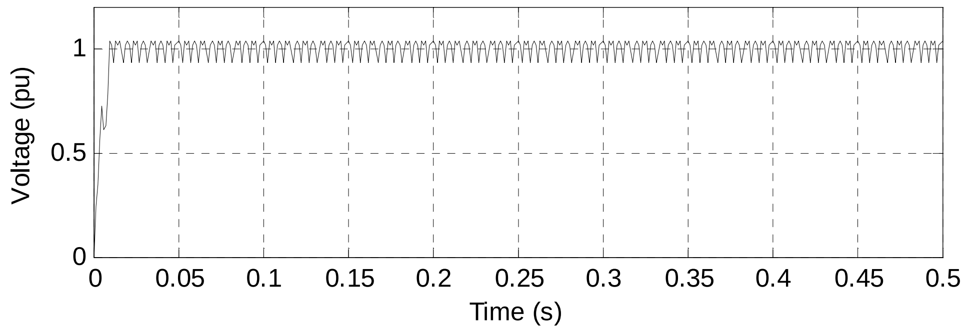


Figure 5-22: Two-sample method response to harmonic distortion.

The transient performance is also good due to the selected digital pre-filter giving minimal overshoot (refer to Figure 5-23 for a 75 % step reduction and increase in voltage).

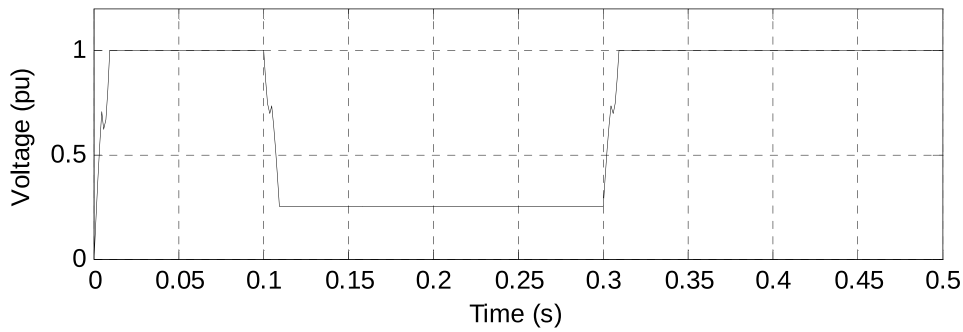


Figure 5-23: Two-sample method response to a step in voltage (100 to 25 %).

5.4.7 Single Microgrid Scheme Application

To demonstrate the operation of the MIPS-SUB relay, its application to the microgrid shown in Figure 5-2 will be described. The relay will be installed at the secondary substation with appropriate voltage and current measurements being taken and circuit breaker trip circuits connected. The selection of overcurrent, NVD, LOM and check-synchronism settings for grid connected operation will not be described in the sections immediately following as these are based on established calculation principles. In the case of the conventional overcurrent protection this refers to the calculation of settings for the inverse elements replacing the original network fuses as commented previously. Definite time grading paths will be described for both internal and external faults to show how forward and reverse settings are used.

5.4.7.1 External MV Fault Grading Path

For a fault located outside the microgrid as shown in Figure 5-24, the current flowing through the grid circuit breaker from the LV generation will be relatively small (hence setting conventional overcurrent in this reverse direction would be difficult) and the HV voltage will be greatly reduced. A definite time grading path in the reverse direction is formed starting at the grid interface and ending, ultimately, at the LV generators. Thus in this case three instances of the protection function are required as indicated in the Figure 5-24.

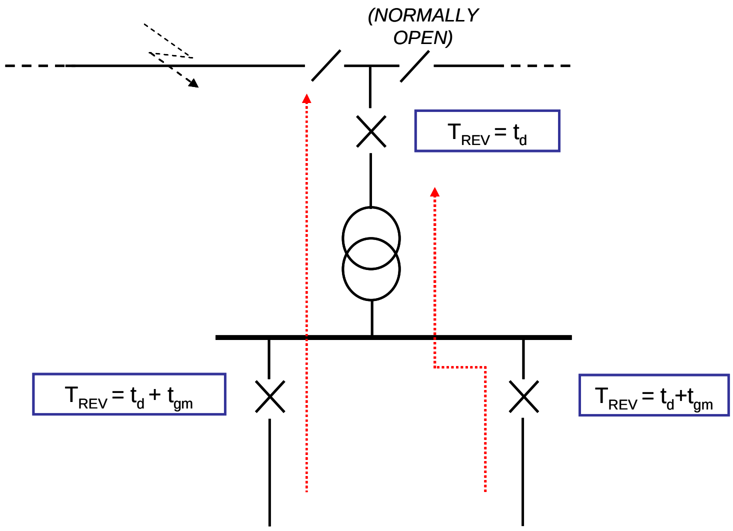


Figure 5-24: External fault grading path.

If the reverse time delay at the interface is t_d, those at the LV circuits will be set as being t_d+t_{gm}, where the additional time t_{gm} represents a suitable grading margin. LV generation protection should be set to operate no faster than t_d+2t_{gm}. This will inevitably result in fast disconnection of the microgrid since the operation of 11 kV network protection, even if the relaying time is negligible for a close-up fault near a circuit breaker, would be in the order of 4-5 cycles because of circuit breaker clearing times. This is not necessarily a disadvantage as one of the objectives of a microgrid is to ensure good power quality for local consumers and so fast disconnection will limit their exposure to the drop in voltage - assuming of course that the microgrid can successfully make the transition to islanded mode of operation.

5.4.7.2 Internal LV Islanded Fault Grading Path

For a fault located downstream of the LV circuit breaker, the definite time grading path is as shown in Figure 5-25. The forward definite time in the outgoing LV circuit is set as being t_d and t_d+t_{gm} is then used for the grid interface forward and LV circuit reverse settings.

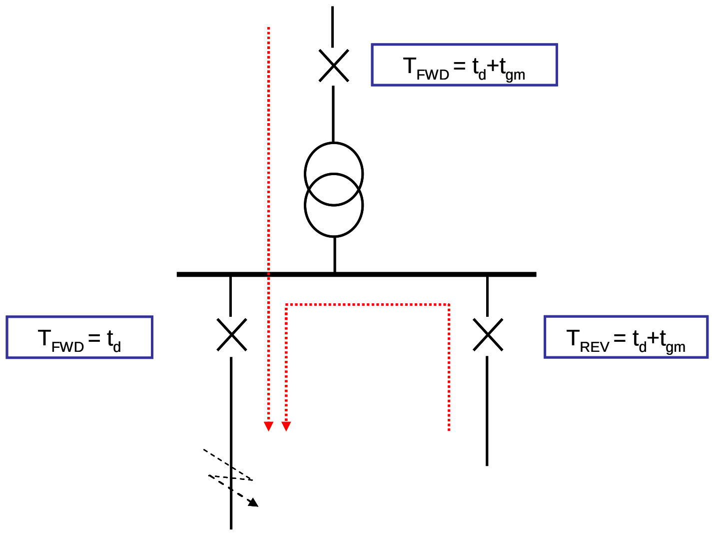


Figure 5-25: Internal islanded fault grading path.

5.4.7.3 MIPS Settings

The value of t_d is set to grade with the operating time of downstream LV fuses and other overcurrent devices within consumer installations. Based on the operating times of typical devices derived from the characteristics given in the BS and the results presented in §5.4, t_d and t_{gm} have been set at 100 ms and 50 ms respectively (assuming that greater than 5 times the rating of any overcurrent device is available to ensure fast operation). At LV a vital aspect of any protection philosophy must be that complex grading calculations must be avoided and general application rules developed. Given the nature of the fall in voltage during a fault, it is proposed that the selection of an under-voltage setting should be straightforward. The under-voltage starter and directional elements have been set at 50 % and 90 °.

Given these delay times, it is possible to comment on the duration of fault ride-through capability requirements for generators. Since the total set delay within a MIPS-SUB relay for a single isolated microgrid would be 150 ms and allowing a conservative time for circuit breaker clearing, a proposal for a capability of at least 200 ms is suggested. This is less than the 213 ms and 306 ms observed for the induction machine within the network studied (see §5.3.2).

5.4.7.4 Summary of Settings

The settings for the three locations used in the examples grading baths in the previous two sections are shown in Table 5-4.

Table 5-4: Summary of MIPS-SUB settings.

Location	*Forward*	*Reverse*
HV Circuit Breaker	t_d+t_{gm}	t_d
LV Circuit Breaker(s)	t_d	t_d+t_{gm}

5.4.8 Single Microgrid Testing

The testing of a MIPS-SUB relay as applied to the microgrid shown in Figure 5-2 is demonstrated for the case of an external three-phase and internal phase-earth faults at locations A and D respectively with an inception at 0.1 s.

5.4.8.1 Three-Phase External Fault (Location A)

The internal relay trip signals for both HV and LV circuit elements and, as an example, LV circuit 2 element internal signals are shown in Figure 5-26.

Trip signals are provided for under-voltage (UV), reverse phase angle (REV-ANG), fault detection (DETECTION) and the delayed trip (TRIP). The fault is applied at 0.1 s and it can be observed that the fault is detected in the reverse direction by both types of elements; however, the HV grid interface element trips all phases at 0.215 s to isolate the microgrid before the LV distribution cabinet elements.

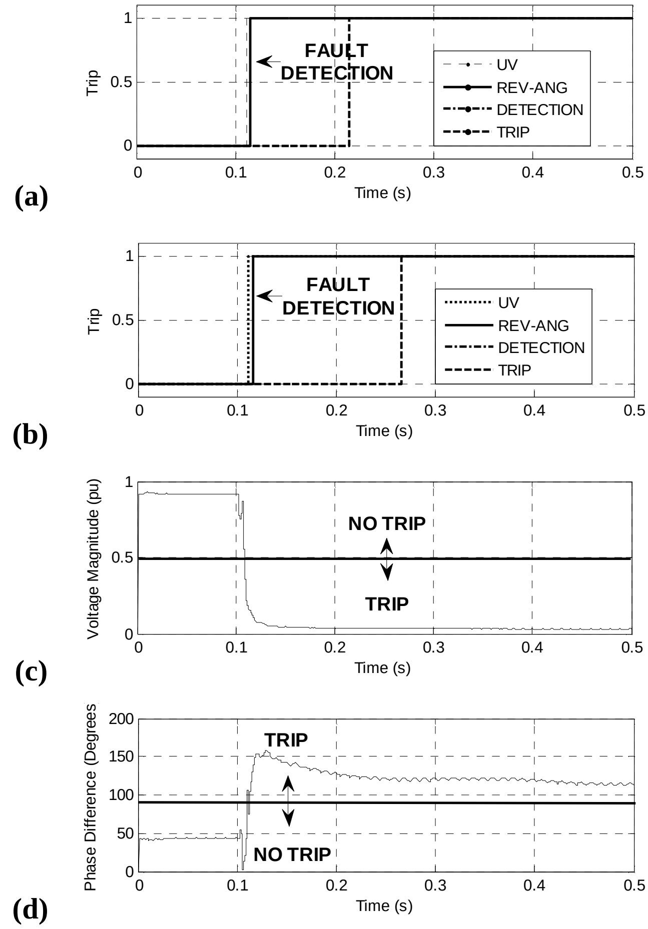


Figure 5-26: 3Ph fault – MIPS-SUB relay signals

(a) HV interface trips; (b) LV circuit 2 trips; (c) LV circuit 2 calculated phase A voltage magnitude; and (d) LV circuit 2 calculated phase angle difference.

5.4.8.2 Phase-Ground Internal Fault (Location D)

The responses of the MIPS relays for this fault type and location are similarly given in Figure 5-27. For this case the forward phase angle signal (FWD-ANG) has been plotted and specific LV calculated voltage magnitudes for each phase are also shown. The LV distribution cabinet element can be observed to operate first and trips phase A correctly at 0.211s.

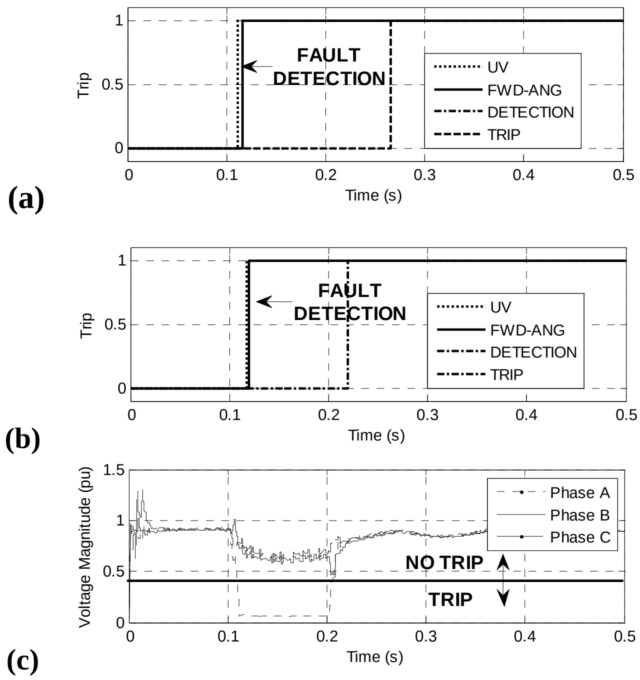


Figure 5-27: Ph-G fault – MIPS-SUB relay signals
(a) HV interface trips; (b) LV circuit 2 trips;
and (c) LV distribution cabinet calculated voltages.

5.4.9 Multiple Microgrid Scheme Application

To consider the short-circuit protection implications for interconnecting multiple islanded microgrids the case of two adjacent networks is considered.

5.4.9.1 Two Islanded Microgrids

Figure 5-28 shows the interconnection between two adjacent microgrids with the settings for MIPS-SUB considered previously (no MIPS-INT relays shown). For part (a) the fault is shown on the shared circuit between the two microgrids and it can be seen that the fault is cleared by the operation of the two distribution cabinet circuit breakers leading to the loss of all demand on this circuit. Furthermore, an internal fault within one microgrid as shown in part (b) will lead to the potential loss of the interconnecting circuit due to the same time delays being applicable both to the internal faulted circuit and the remote end of the interconnected circuit. In both cases the action of protection causes unnecessary loss of demand at a time when no device should be operating as a backup.

To overcome these shortcomings it is proposed that an additional group of settings be used that are activated should the interconnection of two islanded microgrids be carried out. This second group would be activated upon closure of the circuit breaker at the interface by the MIPS-INT relay which has now been installed. The MIPS-INT relay has the same time delay of t_d in both the forward and reverse directions. The time delays for the other MIPS-SUB elements has been modified as shown by increasing their delays for those in the interconnection circuit in both directions and for the reverse direction only for internal circuits.

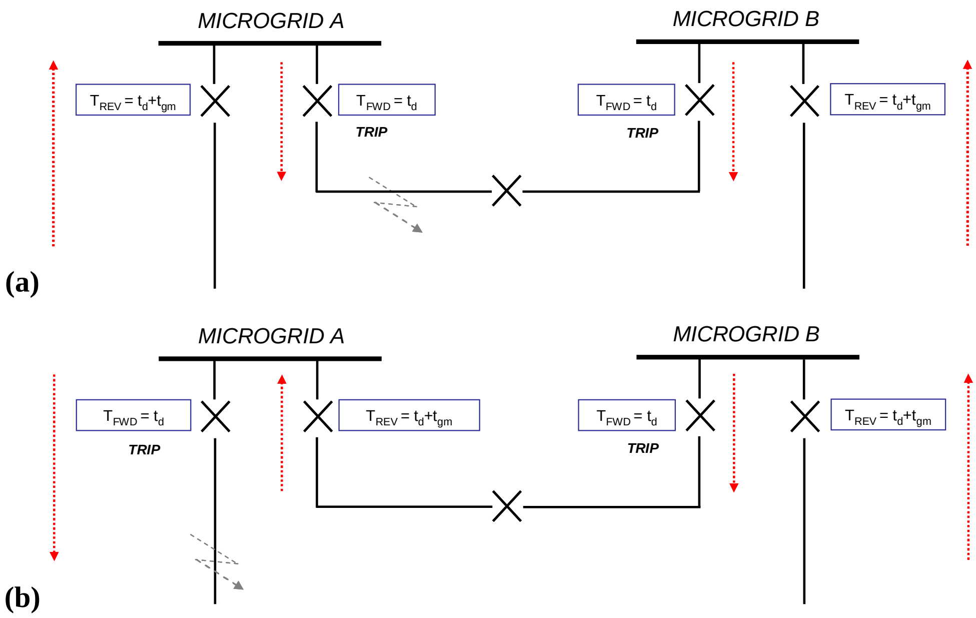


Figure 5-28: Problem with a single group of settings (a) shared feeder fault and (b) internal feeder fault.

With the use of the additional relay and the second group of settings no unnecessary demand is lost for a fault on the interconnecting circuit for faults cleared by their primary protection device as shown in part (a) and (b). A further point to note is that for the case of an internal fault, the two microgrids will become isolated due to the settings on the MIPS-INT relay. Although at first this may appear to be inappropriate, the internal fault may cause a loss of generation capacity within the faulted microgrid leading to a period of lower voltage and/or frequency that would have an impact on power quality within the unfaulted microgrid. For this reason this tripping is tolerated. Additionally, this set of responses is at the expense of an increase in the total time taken to clear faults on the interconnection circuit and for all other faults under backup conditions. This is a trade-off that is inevitable to permit this particular scheme to be extended to provide grading within two interconnected microgrids.

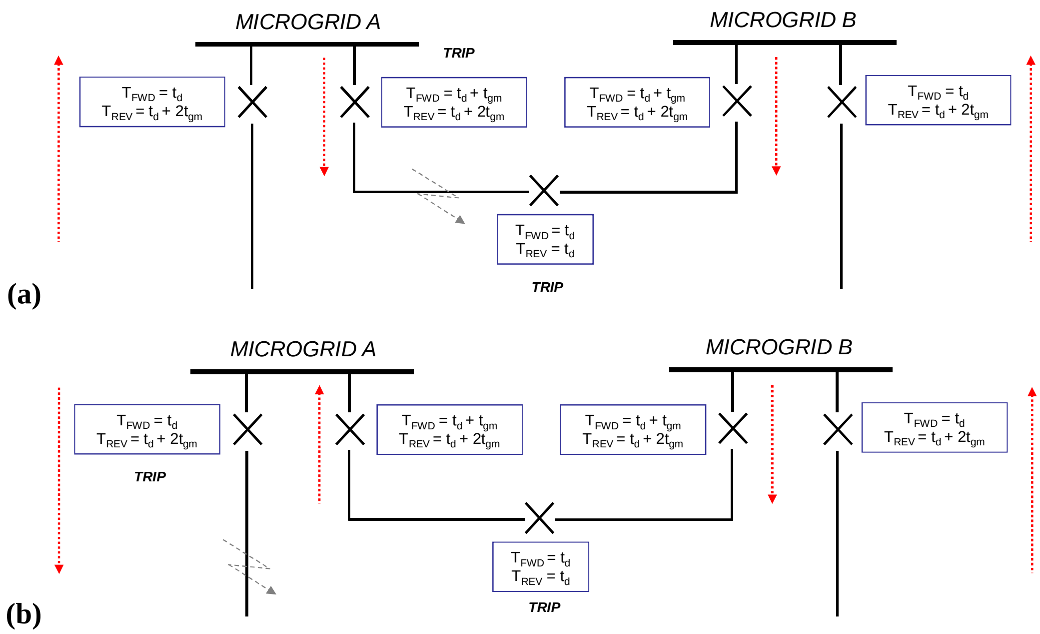


Figure 5-29: Application of a second group of settings (a) internal feeder fault and (b) shared feeder fault.

Although in principle the scheme could be extended to cover say three microgrids, the tripping times in the aforementioned cases could become too long in comparison to the CCT of any small rotating machines connected to the microgrids. Furthermore, should it become necessary to interconnect more than two microgrids together the total demand and generation is likely exceed 1 MVA and thus use of the upstream HV network may be more appropriate. It is also important to note that the loss of the communication channel will result in the MIPS-INT relay tripping its circuit breaker and the MIPS-SUB relay returning to its original settings for a single islanded microgrid.

Since the modifications to the scheme are only increases in time delays no transient simulations are presented.

5.5 *Application of the Adaptive Protection Architecture*

The previous section highlighted how a second group of settings could be used to enhance the performance of the islanded short-circuit protection scheme such that two microgrids could be interconnected at LV when islanded or grid connected at a single point. The coordination layer logic required to implement this is rather basic and simply requires that the status of the interconnecting LV circuit breaker and HV circuit breakers be known. This simple logic would be programmed within the MIPS-SUB relay located at the secondary substation and would require communication with the remote MIPS-INT relay at the LV boundary. In addition to this a third group could be theoretically added as a safety measure to deal with the possibility of a very low fault current during times of low demand or generation capacity that could mean that overcurrent devices down at the ends of the system could not be guaranteed to operate satisfactorily. In this case the forward time delay on circuits leaving the distribution cabinet could be set to zero such that the faulted circuit is immediately removed from the microgrid. The information to activate this change in settings could be the status of a comparatively large source that is connected close to the distribution cabinet (as was the case in the example microgrid used in this chapter) or from a microgrid supervisory control system that is monitoring the generation/demand levels.

A further need for changing between groups of settings is that of system protection when the microgrid transitions between islanded and grid connected operation. Circuit disconnection could be required due to low frequency or voltage (e.g. perhaps if it is known that a large air conditioning unit is connected). The settings for these elements could change from being deactivated to one or more different sets of values depending on the environment within which the microgrid is being operated. For example if the upstream HV network from the primary is operating as an island, then a particular group of under-frequency settings may be required that is different (perhaps in time delays) from those required when the microgrid is itself islanded. To illustrate the discussion above, some example logic for the coordination layer for the MIPS-SUB relay is shown in Figure 5-30.

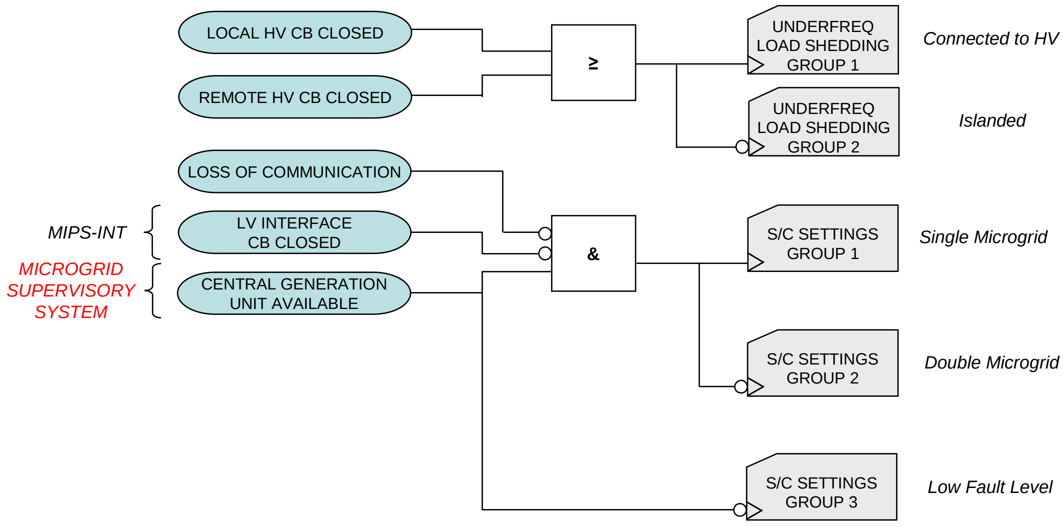


Figure 5-30: MIPS-SUB coordination layer logic.

5.5.1 Impact on HV Protection

The rapid disconnection of a microgrid in the event of an HV fault greatly simplifies the potential impact on the protection and indeed automation at this level. Since the microgrid is removed and does not in any case contribute any significant fault current, the impact on HV protection is negligible and moreover automation is easier to implement since the microgrid does not present an active source in the areas to be reconfigured. Some caution is however required should HV islanding be permitted since the disconnection of microgrid generation/demand in an area of the network electrically distant from the fault (but obviously still within the island) could have a detrimental impact on stability if there are a significant number.

5.6 Chapter Summary

This chapter has presented research associated with the development of a protection scheme to enable the safe and reliable deployment of the microgrid concept at LV. In particular, it permits a microgrid to be operated as an islanded power system in isolation from the grid. This was shown to be a particularly onerous condition from a protection perspective requiring the use of alternative protection methods at LV.

The work documented in this chapter started by considering the key salient features of the microgrid generation with regard to how it might impact protection design and performance. A detailed model of British LV distribution network and a number of microgenerators were created and a set of transient simulations were then used to illustrate the behaviour of the microgrid when subjected to fault disturbances when both grid connected and islanded. These have illustrated the nature of the fault responses of specific microgenerators and shown the limited availability of fault current to operate conventional overcurrent based protection devices. Based on these responses, the implications for network protection were established and then used to identify the protection functions required at the various locations in grading paths originating at the consumer and ending at the secondary substation RMU. This thorough process enabled the deficiencies in existing protection to the identified and then served as the basis for investigating what other techniques could be applied as an alternative. The work also highlighted the importance of the two different operating modes (i.e. grid connected and islanded) with regard to defining the functional requirements of the proposed scheme and if it needs to be adapted when the transition is made.

A protection scheme has been proposed based on an under-voltage starter used to initiate a directional element with forward and reverse definite time delays. Two relays (MIPS-SUB and MIPS-INT) have been described that cover both single and adjacent microgrid scenarios. As an example, the performance of the MIPS-SUB relay has been demonstrated as being satisfactory using transient simulations incorporating the numerical relay implementation described. The application of the adaptive protection architecture was also demonstrated to permit the overall protection scheme (i.e. including system functions such as under frequency elements) for a microgrid to cope with the transition from grid connected to islanded operation as well as for the interconnection of two adjacent islanded microgrids. The application of the adaptive protection architecture provided a simple example to explore how the functions described in Chapter 3 can be defined in practice.

Furthermore, the scheme proposed has been considered within the context of future distribution network protection with attention directed towards how it might impact upon upstream HV schemes.

It is suggested that further work in this area includes a hardware implementation of the MIPS relays and subsequent testing on a realistic demonstrator system. It is only through realistic demonstration that the technology described in this chapter will be accepted and the coordination between different systems such as automation controllers confirmed.

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6 Facilitating Intentional Islanding of an HV Urban Network

As the capacity of generation connected onto distribution networks increases, localised clustering of units could create instances where their combined output is capable of meeting nearby demand for significant periods of time. Under such circumstances the prevailing practice of requiring generation to trip should the grid supply fail can now be legitimately reviewed [6.1]. As a consequence of this, researchers have explored the possibility of intentionally islanding parts of the HV network in response to the complete loss of supply or severe disturbances in order to improve the security of supply for consumers [6.2]. The ambition has been to investigate the feasibility of providing consumers with extremely high levels of supply availability, whilst at the same time continuing to ensure that the statutory levels of power quality are maintained. Meeting this ambition is not straightforward as not only must generation meet active power demand at peak periods if this coincides with islanding, it must also provide a reactive capacity sufficient to regulate local voltages. Both of these problems, and others to be mentioned later, are made onerous because in many instances the availability of the primary energy source may be intermittent or dependent upon some other process (e.g. heat demand in the case of CHP). Moreover, the change from grid connected to islanded operation represents a major change in the local dynamic behaviour exhibited in response to disturbances such as large load changes (e.g. cold load pick-up after switching) or faults.

Although an islanded HV utility network will intuitively have many similarities to industrial power systems that possess their own generation and can operate in isolation from the grid [6.3], several distinct challenges unique to this application emerge. These include: an installed asset base that was not intended for such operation (e.g. voltage control via tap-changers with limited range); generation being widely dispersed in location, rating and primary source type; and a wide range of asset owners and operators. The combination of these factors and the uncertainty regarding future demands on the system such as electric vehicles creates a difficult environment for utility planning staff and, ultimately, for those tasked with operating and maintaining networks. In technical terms the challenges cover a wide range of fields from network design and primary equipment specification, to the calculation and coordination of settings for protection relays and other control equipment such as tap-changers. However although the degree of challenge is high, the potential benefits could likewise be high if this functionality is considered within the context of the security of supply levels expected by end-users if the smart grid vision is mandated by governments and industry regulatory bodies.

The research presented in this chapter concentrates on the development of a protection system that can deal with the widely varying conditions whilst moving from being grid connected to isolated operation as an island. The scale of the changes in the primary system between these two operating modes will be shown to be sufficient to require that protection must be adapted and functionally extended to continue to meet performance requirements. These drivers are used to demonstrate the application of the adaptive protection architecture that was presented in Chapter 3 and the value it can bring for those implementing protection schemes for HV distribution networks with the potential to support islanding. The methodology for designing an adaptive scheme is demonstrated, moving initially from assessing the impact of difference operational scenarios, then to the development of revised settings, and finally to the logic required to make the scheme function correctly.

6.1 Chapter Overview

The chapter begins in §6.2 with a review of the background associated with protection challenges for islanded networks and then moves on to discuss the study scope and how the adaptive scheme design methodology will be applied. §6.3 - §6.5 provide details of how the islanded system is developed. These sections include a description of the existing network configuration and protection, as well as the set of new operational scenarios that will have to be studied (this being the first part of the design methodology). §6.6 explores the characteristics of the study system under grid connected and islanded conditions. Following from this, §6.7 outlines the designs for the adaptive short-circuit and system protection schemes. The diagnostics for the scheme are outlined in §6.8 and finally in §6.9 the material within the chapter is summarised and suggestions made for further study in this area.

6.2 Background, Study Scope & Outline of Design Methodology

Before starting the design of a solution to the islanding protection problem, it is first useful to summarise the background, study scope and how the design methodology presented in Chapter 3 will be applied.

6.2.1 Background

The unintentional islanding of a generator may be caused by the opening of switchgear at a large number of different locations within a network. These points could include those within a circuit to which the generator connection has been looped-in or, in the extreme case, a complete loss of the HV supply to a primary substation (refer to §2.6.1.1 in Chapter 2 for illustrative examples). In these circumstances the act of isolation is essentially random and the captured demand (i.e. that still being supplied) could be either small or large depending on location and the time of switching. At present this mismatch between captured demand and generation is typically substantial (thus aiding detection of the islanding condition) due to the locations at which the relatively small number of generators connected to the network are located. Larger generators are generally connected directly to the primary substation board due to their ratings and to avoid power quality problems for consumers that would otherwise share the same circuits, and smaller units are either looped-in with HV circuits or via an LV point of connection. As isolation can only practically occur either at discrete circuit breakers within the primary substation or at RMU switches within the HV network, the relatively low existing penetration of generation makes the probability of closely matching of supply and captured demand small [6.4]. However as the level of generation increases, the potential for a substantial mismatch that makes islanding detection using conventional methods possible is intuitively diminished. There is thus a correlation between the islanded condition being more difficult to detect and the better chance of islanding being sustainable, and thus attractive from an operational perspective. This of course assumes that other issues that have at previously prevented islanding from being accepted have been resolved (e.g. enhanced training of field staff to reflect the possibility of live downstream networks after isolation from the grid and adequate control to regulate the local island frequency and voltages).

For intentional islanding, the first task is to identify areas (which could be thought of as a cell with appropriate demand and generation levels) where a sustainable island can be formed and then identify all the possible locations where separation could take place. For the first problem this is quite a complex task as it will depend on a wide range of factors such as those highlighted before. The utility nature of the problem also makes it more difficult than that of an industrial network since the footprint will be larger and the asset base more diverse. Consequently quite a margin for error must also be included in assessing the adequacy of generation resource for a given area of demand. The second part of the problem is related to the first and must also consider the different operating configurations for the network. For example a network can be supplied using an alternative configuration during an outage. Indeed having local generation may make this more complex as a greater number of back-feed possibilities may in fact be feasible as restrictions due to tapered circuit ratings may become less onerous.

Dynamic islanding in which a distributed network control architecture acts in response to any isolation to attempt the establishment of a sustained power island could in principle be considered. Although in theory this sounds attractive, in practice this is not really feasible due to the constraints of acting to ensure safety, power quality and avoid asset damage through criteria such as generation adequacy. In particular, the earthing of the network must be borne in mind since single-point earthing is the practice applied in the UK [6.5] and so dynamic islanding could easily lead of unearthed sections of live network. This undesirable outcome is one of the reasons behind the current practice of requiring generation to trip. To ensure that earthing is satisfactory, other points of earthing would have to be established throughout the HV network such that one was always available within a dynamically established island (perhaps switched in once islanding has been detected). The additional costs, complexity and space constraints for additional equipment within substations could make this unfeasible and so this chapter assumes that intentional islanding will only be permitted to occur within predefined boundaries. Although the actual initial isolation may occur beyond a defined boundary, formal isolation would always then take place at designated switchgear once the establishment of the islanded has been initiated (detected by the loss of mains protection function of whatever type). Furthermore, restricting these points of isolation will also ensure that appropriate equipment is present to permit re-synchronisation to the grid if and when this is necessary. Indeed as observed in the previous chapter on microgrids, islanding is only a transitory condition and reconnecting to the grid is highly desirable once it becomes feasible at whatever location that can support the connection.

6.2.2 Scope

The introductory chapter of this thesis provided some indication of the protection challenges that might emerge if intentional islanding within distribution networks is permitted. To consider these, the scope of the study within this chapter covers both short-circuit (overcurrent and earth fault) and system protection functions that will be required within an islanded power system. The focus for study is a representative UK 11 kV HV network.

Firstly, in moving between grid connected to islanded mode of operation the fault level will be reduced. The degree of reduction will depend on the generation technologies present within the island and the capacity actually in service at any given time. In the previous chapter an extreme case of a predominately inverter supplied network was considered for microgrids at LV. At the HV level, a similar situation could potentially arise as full-converter interfaces are commercially available for MW scale wind turbines and energy storage systems. Although the capital costs of these at present are higher than say a DFIG design for wind turbines, they do possess excellent low voltage ride-through (LVRT) and other control characteristics and it is likely that these will see increasing application as the technology matures. This study uses a range of generation types covering synchronous, asynchronous and converter interfaced. The use of only converter interfaced sources, however, is not considered in this study. This is justified on the grounds that the objective of this chapter is to demonstrate the application of the adaptive protection architecture: to achieve this, the study seeks to consider an example that could be put into practice relatively quickly that still includes some of the severe dynamic consequences that an available generation mix could create. In particular, if the fault level is too low then problems such as voltage step changes and harmonics become challenges that will need to be carefully considered. Although worthy of further study, these are not in themselves the main focus of this chapter and so the generation mix has been selected to give workable solutions with conventional control solutions (although as will be observed the dynamics can still be seen to be onerous under certain circumstances).

Secondly, system protection is not generally connected at the HV level of a primary substation with the exception perhaps of an under-voltage function [6.6]. If islanding is going to be permitted then additional frequency and further voltage based functions will have to be added. The calculation of these settings is complicated by the potential for the system dynamics to change as different generation is connected or their relative proportions within the in-service capacity varies. For the case of load shedding in the event of a large mismatch between load and available generation, the rate that frequency will change may vary widely leading to different sizes of load blocks to be tripped. A distinction is made here between demand response (e.g. frequency sensitive devices) intended to support balancing and the protection functions intended to protect equipment in an emergency situation. The former will be an integral part of system balancing whereas the latter will continue to be a separate consideration.

Furthermore, since significant enhancements are being planned to the protection functionality at HV, some assumptions have to be made regarding the relay, automation and communications technology available. It is assumed that modern relays are available of at least an early multi-function numerical type (i.e. IED) that can have multiple groups of settings. It is further assumed that a substation LAN and WAN are available out to any other protection devices outside of the substation within the HV network. For example Ethernet based communication for IEDs using IEC 61850 standard [6.7] would be an ideal method for realising the proposed system. This would permit transducers, relays and automation hardware all to be integrated using both process and station bus communication philosophies.

6.2.3 Application of Design Methodology

The design methodology set out in §3.6 starts with the identification of the different scenarios that will be covered by the adaptive protection (Figure 6-1).

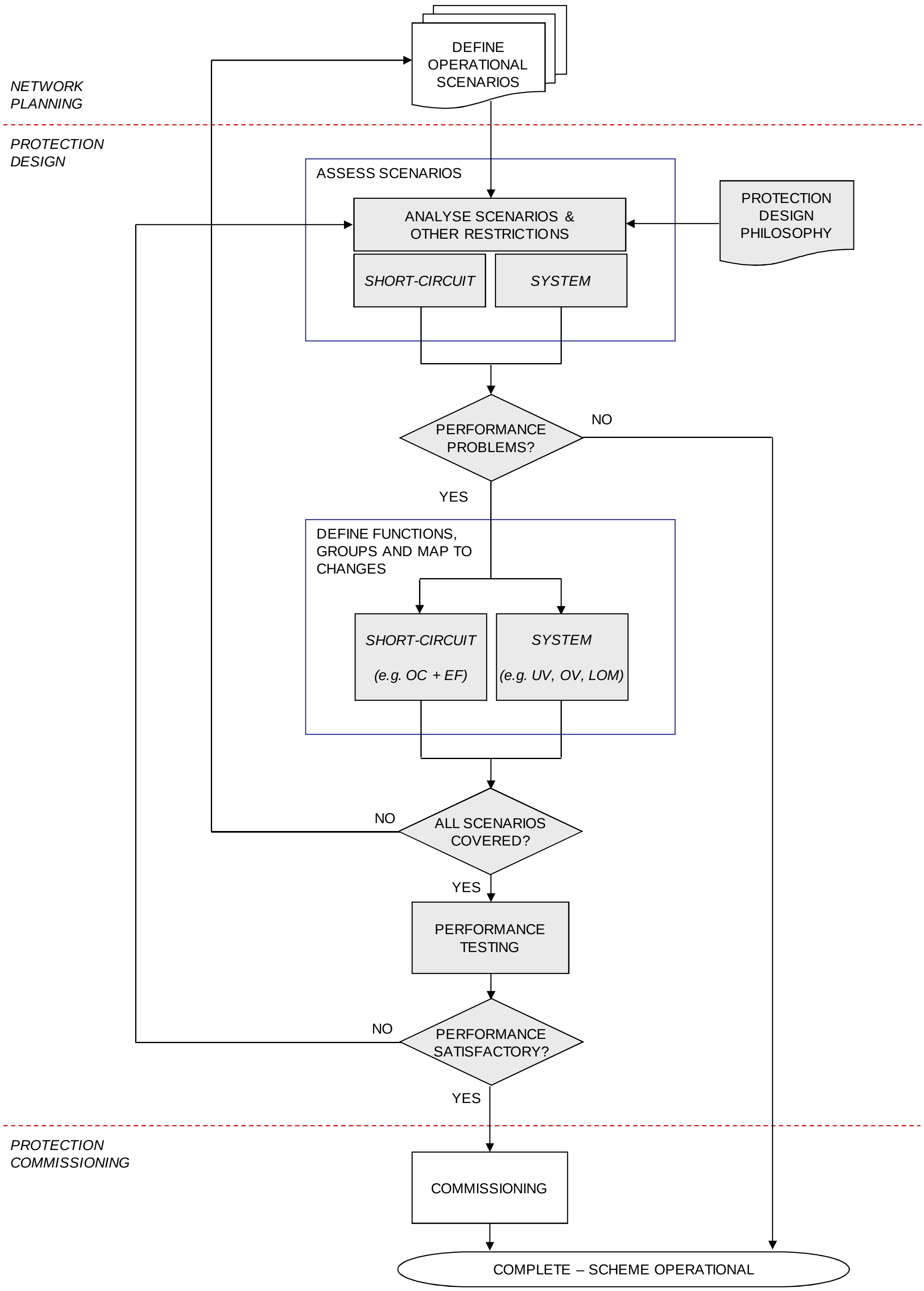

Figure 6-1: Design methodology applied to an HV islandable power system.

These will, in practice, be defined by those network planners who decide that an area of the network has the potential to be operated as an island. This process could be initiated by monitoring net flows from an area along with records of generation and demand connections. As an output from their analysis, they will have demarcated the island (with a suitable supervisory level control scheme, e.g. EMS) such that it can be sustained given the local generation (and, perhaps, responsive demand) available. As with any engineering design, there will be restrictions on when and how this island can be sustained, which in turn lead to undesirable conditions that must be detected and appropriate action taken to disconnect equipment in order to avoid damage. Thus the protection engineer will be provided with the electrical characteristics of the system and the boundaries within which the different operational scenarios are to be permitted (e.g. islanding may be blocked should the pre-isolation transfer across the boundary be too great so as to avoid subjecting consumers to major voltage and frequency transients after islanding). Based on these the protection system must be designed and verified for each scenario and operation restricted within the boundaries specified. The range of the electrical characteristic variation between the scenarios will determine the extent to which the protection needs to be adapted and, in some cases, which additional functions must be added.

In this chapter the creation of these scenarios is also considered since in so doing a greater understanding of the islanded power system challenges can be shown. It is also of interest to observe that since intentional islanded within distribution network is in practical terms a new approach, the burden of analysis required by the utility staff will initially be high. However as time progresses more experience will be gained of different generation capabilities and so these studies should become more straightforward to complete. The extent to which it can become a standard procedure will depend on how generation technologies mature and are deployed, as well as additions to local grid codes to specify how equipment should respond to particular disturbances (e.g. the German grid code specifies the level of reactive current support that must be provided during a fault in proportion to the retained voltage [6.8]). Ideally once defined these can generally be reused and written into design handbooks within the utility to speed-up and standardise the process.

The actual scenarios are created for the study network in §6.3.3.2, but to begin the design process the key areas that must be considered by protection engineers are summarised in Table 6-1. These cover the usual concerns such as the range of available fault level, but now also encompass additional information that is concerned with the frequency and voltage behaviour of the network, as well as when islanding and resynchronisation is permitted. Many of these are interrelated and will have a significant impact on the final design. These areas will, along with the protection philosophy policies of the utility, be used to assess the impact of the scenarios on how protection should be enhanced or developed for the network under consideration.

A graphical summary of the design methodology is shown in Figure 6-1 which has been updated from that in Chapter 3 to reflect the specific protection functions in this example. The scenarios and restrictions are analysed using the protection design philosophy of the utility and equipment capabilities in terms of both short-circuit and system protection. Typical UK practice has been used as documented in [6.6].

For the first type of protection, studies are to be carried out to confirm if either existing settings or functions available are adequate based on the different fault levels available. These studies will be based on previous study work done by planners and will calculate the appropriate parameters required for protection purposes (in this case the fault currents flowing for balanced and unbalanced faults at various locations in the network). The operation times for the functions will be checked to see if they meet requirements and any shortcomings noted.

On the other hand, the second type will require new functions to be added unless this is a modification of an older island zone due to changes in local generation or its footprint (i.e. the physical extent to which the intentional islanding will be put into effect). More detailed dynamic studies will be required here to characterise voltage and frequency responses to the scenarios created by the planners or the disturbances that must be survived as defined in the distribution code and company standard design handbooks.

Table 6-1: Parameters impacting on scenario development.

Parameter	*Issues*
Scale & Footprint of Network	• Where are the boundaries where intentional isolation from the grid is to take place once the decision has been taken? • What are the types and capabilities of the switchgear available at these locations? • Are there other potential smaller islands to be permitted within the larger island? This could, for example, include LV microgrids where sufficient generation is available as discussed in Chapter 5.
Generation Types	• What are the generation technologies connected within the island? • This includes such factors as: fault current contribution, low-voltage ride through, inertia (actual or synthetic), excitation system response, sensitivity to imbalance, overload capability, prime mover dynamics and so on.
Load Types	• What types of load are within the area considered? (e.g. residential, commercial or industrial demand classifications) • Based on these classifications, are there any challenging characteristics to be considered such as air conditioner dynamics or equipment sensitivity to power quality issues? • Are there any loads which have special contractual arrangements that either require a certain security of supply or are available for short-term disconnection under given circumstances?
Profiles	• What are the anticipated generation and demand profiles within the area considered? • This is particularly relevant for generation that is not inherently flexible such as CHP. • What are the extremes of demand and the ramp rates to be expected at different times?
Islanding Initiation & Resynchronisation	• Under what conditions is islanding permitted or perhaps blocked? This could be based, for example, on pre-isolation net power exchanges or unavailability of generation that can increase or decrease its output as required after isolation. • What are the criteria and permitted locations for resynchronisation and reconnection to the grid?

In general the studies described above will identify and then provide new additional settings for the different functions that will find application at some point (when selected) within the execution layer of the adaptive protection architecture. These groups of settings as a whole will form the basis of the coordination layer in the architecture.

These performance assessments will then be followed, if necessary, with the addition of functions, further settings groups and the logic need to map these onto the changes in the primary power system. This last point relates to the creation of the functionality within the coordination layer of the architecture. At this stage a transition diagram will be made to show graphically how the system can move between different groups and what the initiating changes are in the primary or secondary systems. It should be noted that a particular group will correspond to a particular operational scenario that could be defined by a range of parameters. For example, the overcurrent settings could be valid for a base level of generation and be satisfactory with minor changes, either up or down, in the capacity actually operating. Consequently, the mapping and sensitivity to system variations of the scenarios becomes a vital part of the group documentation process. It is also important that these groups are intuitively labelled such that operators are aware of their significance (e.g. a group of settings design to be used when the stability margin of the system is low should be given special attention). The outcome from this work will be clearly defined settings tables for the protection groups and the logic required for their initiation when a change occurs.

Once the basic functional elements and settings of the adaptive protection scheme have been designed, diagnostics can then be added to permit any hardware or software failures to be analysed. This will include at the execution layer the definition of triggers for disturbance recorders and ensuring that the protection settings group in use can be tagged to these recordings. Moving up to the coordination layer, logic needs to be defined to analyse the impact of failures and either take immediate action to change a settings group and/or pass this information to the management layer. Thus diagnostics at the coordination layer could require additional mappings for the settings groups and links within the transition diagram.

The management layer is the highest and which for the purposes of this chapter is closely linked to the EMS. It is here at this level that the performance of operations can be assessed in the context of the overall system. For example, the activation of an instantaneous overcurrent group and then a subsequent fault can be assessed to see if it avoided the instability of a particular generator if it were known that this unit had a particularly low and thus problematic critical clearance time (CCT).

The design process also includes the overall integration and the mapping between actual hardware and the functional architecture. It is at this stage that the settings files for the target vendor's system are created along with the documentation necessary for commissioning. It would be preferable that the scheme can be made ready for implementation using a tool such as the substation configuration language which is part of the IEC 61850 standard. These files would need to include not only the settings but also all other supporting information such as the programmable scheme logic.

Event based testing is then used to check that all scenarios have indeed been adequately assessed and designed against. In practical terms this is the automated use of scenarios within an analysis software tool to check issues such as grading and stability. A set of scripts would ideally be written to allow such a task to be carried out and the results reported to the user. Additional events not originating within the planning process could also be considered at this stage if thought desirable.

The test plans are also created at this stage that will be used by the commissioning engineers. These will include the definition of test inputs with which to verify that the scheme will adapt as required. Given the adaptive nature of the scheme, this will be more involved than would be the case for existing conventional secondary injection testing. Signals mimicking status indications or other data sources will be placed on the LAN or WAN that should cause the coordination layer functionality to take appropriate action. IEDs can then be checked to ensure that the correct action has in fact taken place. Once a certain group of settings has been applied, injection testing can take place if necessary either directly to the relay via power amplifiers or by using simulated sample value signals over the LAN or WAN. The potential for complexity in this test procedure will necessitate good engineering tools with automation and remote access capabilities.

6.3 Study System

The following sections detail the study system that is used for analysis in this chapter. It is based on a representative section of 11 kV HV cable distribution supplied from a primary substation in the UK and includes, as examples, open ring circuits supplying equivalent LV networks. The main characteristics are described in the next section and are then followed by specific details of the existing protection that would be applied. A range of LV and HV generators are then connected across the network with installed capacities and outputs that are dispatched to meet a set of demand scenarios for islanded operation. All modelling was carried out using PSS/E version 32.1. A summary of the data used for the power system modelling is provided in Appendix C.

6.3.1 System Overview

A single line diagram of the example system is shown in Figure 6-2 without any generation connected. The network is supplied at the primary substation via two identical 15/30 MVA Dy11 15 % (on rating) transformers connecting it to incoming 33 kV circuits (15 km, 3x1x400 mm^2 Al XLPE cables), which are in turn connected to an equivalent of the 33 kV network. During the studies this equivalent is set to provide minimum and maximum fault levels as follows:

Three-phase: maximum 1100 MVA and minimum 400 MVA
Single-phase: maximum 700 MVA and minimum 250 MVA

Both transformers have on-load tap changers (OLTC) and their secondary star winding neutral point earthed via resistor (5.3 Ω) to ensure that the single-phase earth fault current is limited to approximately 1 kA per transformer. The OLTC is used to control the voltage at the primary substation and has a dead-band of 1.00 pu – 1.02 pu.

To facilitate islanding and synchronisation, two additional circuit breakers have been installed on the 33 kV side of the substation transformers. These would not normally be installed within an existing primary substation but are now required to support the enhanced islanding functionality by permitting isolation (potentially under external fault conditions) and resynchronisation.

The 11 kV network is comprised of two lumped demand equivalents at the primary substation bus-bar and three underground cable feeders each used to connect secondary substations containing 11/0.4 kV Dy11 4.75 % (on rating) transformers with a mixture of 0.5 MVA or 1 MVA ratings. These three cable circuits have the possibility for interconnection at the normally open points (NOP) as shown on the diagram. All 11 kV circuits use a mixture of 1x185 mm^2 or 3x1x300 mm^2 Al XLPE underground cable.

The LV networks have been modelled as equivalent loads at the distribution boards. A list of all network loads and their power factors are given in Table 6-11. The loads on the network can be characterised as being residential, commercial and (light) industrial with consequential differences in power factor. Two lumped loads are used at the primary substation bus sections as described above to represent a number of HV circuits and their associated secondary substations that have not been modelled in detail.

Most secondary substations use modern RMUs (with T-off position circuit breaker and relay instead of fuses) with the exception of those at the middle of the circuit which have switchboards to permit the installation of a circuit breaker with mid-point protection. All RMUs at the end of the circuits have been assumed to be fitted with automation actuators to permit reconfiguration.

The dynamics of the demand connected to the network are represented using the CLODBL complex load model [6.9]. This enables a mixture of motor, transformer excitation, discharge lighting and other types to be represented in the studies. Note that the HV/LV transformer has been modelled explicitly and so the parameters for this part of the model are set to zero (i.e. the equivalent resistance and reactance terms). Table 6-3 provides a breakdown of the parameters used for residential, commercial and industrial demand within the network.

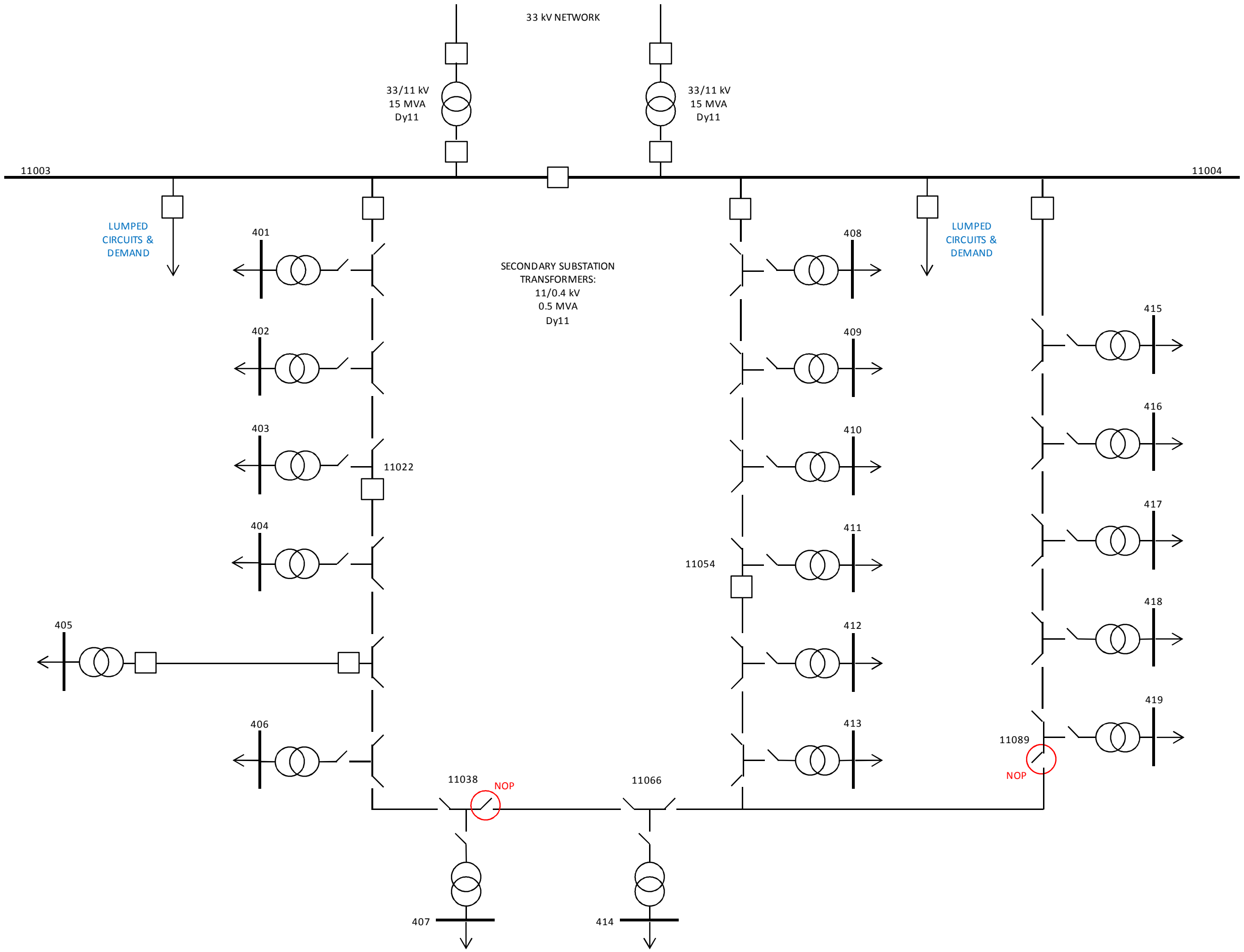

Figure 6-2: Single-line diagram of the study system.

Table 6-2: Network load breakdown (equivalent at LV and HV locations).

Bus Number	***Type***	***Max/Min Active Power [MW]***	**Power Factor**
401	Secondary Sub	0.350	0.98
402	Secondary Sub	0.350	0.98
403	Secondary Sub	0.350	0.98
404	Secondary Sub	0.350	0.98
405	Secondary Sub (industrial)	0.350	0.92
406	Secondary Sub	0.350	0.90
407	Secondary Sub	0.350	0.98
408	Secondary Sub	0.350	0.98
409	Secondary Sub	0.350	0.98
410	Secondary Sub (commercial)	0.500	0.95
411	Secondary Sub	0.350	0.98
412	Secondary Sub	0.350	0.98
413	Secondary Sub	0.350	0.98
414	Secondary Sub	0.350	0.98
415	Secondary Sub (commercial)	0.500	0.95
416	Secondary Sub	0.350	0.98
417	Secondary Sub	0.350	0.98
418	Secondary Sub	0.350	0.98
419	Secondary Sub	0.350	0.98
11003	Lumped at Primary Sub[23]	2.450	0.98
11004	Lumped at Primary Sub[20]	2.450	0.98
Totals:	-	*11.850*	-

[23] These represent a lumped equivalent of several HV feeders containing a mixture of demand and generation connected via secondary substations.

Table 6-3: PSS/E dynamic complex load model (CLODBL) [6.9] parameters.

Parameter	*Units*	*Residential*	*Commercial*	*Industrial*
Large motors	%	0	5	60
Small motors	%	30	40	20
Transformer excitation current	%	2	2	2
Discharge lighting	%	10	20	5
Constant Power	%	30	20	5
K_p remaining	-	2	2	2
Transformer[24]	-	-	-	-

6.3.2 Existing HV Protection Scheme

The protection installed on the HV network consists of numerical relays with multiple elements (overcurrent and earth fault) located at the primary substation feeder circuit breakers, the mid-point of the two circuits and at the T-off position circuit breakers within the secondary substation RMUs. The specific protection elements and their role at each circuit breaker is summarised in Table 6-4. The table also includes the functions installed to protect the transformers and the directional overcurrent intended to isolate a fault on one of the incoming 33 kV feeders. Settings have been calculated for these elements based on typical performance requirements for a system that would only be operated with a connection to the grid.

For the purposes of grading, the first device in the grading path is at the T-off position circuit breaker in the most remote secondary substation. This device has been set to provide back-up for any downstream LV faults should they not be cleared by the fuses. The grading path then moves back via the mid-point circuit breaker, feeder circuit breaker and then finally the 33/11 kV transformer low voltage circuit breakers in the primary substation. A grading margin of 300 ms has been used for both inverse overcurrent and earth fault protection. The settings were calculated under maximum fault level conditions and then checked under minimum conditions. Note that protection was not applied at the bus section circuit breaker since the use of

[24] Parameters not used as the transformers have been modelled explicitly.

mid-point protection (i.e. an additional level in the grading path) made achieving a maximum fault clearance time of 1.5 s impractical at the 33/11 kV transformer LV circuit breakers given the network conditions studied. All overcurrent and earth fault functions use IEC standard inverse curves.

Table 6-4: Summary of HV protection elements.

Location	***Element***	***Comments***
Transformer LV CB	• Directional Inverse Overcurrent • 2 Stage Inverse Overcurrent • 2 Stage Inverse Earth Fault • *Restricted Earth Fault* • Neutral Voltage Displacement • *Winding and Oil Temperature*	• All OC/EF use IEC standard inverse curves. • Directional OC set to 20 % of transformer winding with a TM of 0.1. • NVD set to 5 kV with 5 s delay.
Bus-Section CB	• Inverse Overcurrent	• Not installed in this example.
Feeder CB	• Inverse + DT Overcurrent • Inverse + DT Earth Fault	• All OC/EF use IEC standard inverse curves.
Mid-Point CB	• Inverse + DT Overcurrent • Inverse + DT Earth Fault	• All OC/EF use IEC standard inverse curves.
RMU T-off CB	• Inverse + DT Overcurrent • Inverse + DT Earth Fault	• Provides LV back-up. • All OC/EF use IEC standard inverse curves.

Before giving the detail of the protection settings, the results of symmetrical rms ($I_{k''}$) fault calculations are shown in Table 6-5 and Table 6-6 for minimum and maximum conditions (i.e. lowest grid infeed combined with a single 33/11 kV transformer; and highest grid infeed combined with two 33/11 kV transformers respectively). The fault level at the 11 kV bus-bar varies between approximately 85 MVA and 161 MVA.

Table 6-5: Three-phase short-circuit calculation results in kA and MVA.

Bus Number	*Voltage [kV]*	*Maximum[25] Conditions*		*Minimum[26] Conditions*	
		$I_{k''}$ [kA]	*Equivalent Fault Level [MVA]*	*$I_{k''}$ [kA]*	*Equivalent Fault Level [MVA]*
11003	11	8.44	160.79	4.44	84.53
11004	11	8.44	160.79	4.44	84.52
11022	11	4.88	92.95	3.20	60.90
403	0.4	13.98	9.69	13.13	9.09
11038	11	3.89	74.12	2.74	52.14
407	0.4	13.67	9.47	12.84	8.90
11054	11	5.95	113.33	3.62	69.06
411	0.4	14.23	9.86	13.35	9.25
11066	11	4.84	92.23	3.18	60.50
414	0.4	13.99	9.69	13.13	9.10
11089	11	4.57	87.00	3.05	58.15
419	0.4	13.95	9.67	13.09	9.07

Table 6-6: Phase-earth short-circuit calculation results in kA and MVA.

Bus Number	*Voltage [kV]*	*Maximum[25] Conditions*		*Minimum[26] Conditions*	
		$I_{k''}$ [kA]	*Equivalent Fault Level [MVA]*	*$I_{k''}$ [kA]*	*Equivalent Fault Level [MVA]*
11003	11	2.20	41.95	1.08	20.58
11004	11	2.20	41.95	1.08	20.58
11022	11	1.85	35.23	0.98	18.74
403	0.4	14.38	9.96	13.69	9.49
11038	11	1.70	32.33	0.94	17.88
407	0.4	20.51	14.21	19.26	13.35
11054	11	1.99	37.98	1.02	19.53
411	0.4	21.34	14.79	20.02	13.87
11066	11	1.86	35.46	0.99	18.84
414	0.4	20.94	14.51	19.66	13.62
11089	11	1.82	34.68	0.98	18.63
419	0.4	20.93	14.50	19.64	13.61

[25] Maximum grid infeed and two 33/11 kV transformers in service.
[26] Minimum grid infeed and a single 33/11 kV transformer in service.

The ratios for the CTs installed in the system are as follows:

- Primary Substation: Transformer CB 1200/1 & Feeder CB 600/1
- Mid-Point: 450/1
- RMU T-off: 250/1

The time-current characteristics derived for the overcurrent and earth fault functions are shown in Figure 6-3 and Figure 6-4. A summary of the settings is provided in Table 6-7 and Table 6-8 for reference (only for feeders with mid-point protection). Note that definite time elements have also been included to reduce clearance times for close-up faults and the pickup settings are based on 150 % overloads of primary equipment. For benchmarking purposes Table 6-9 gives the total clearance times (relay plus circuit breaker opening) at the different circuit breaker locations for a zero impedance HV fault in the most remote secondary substation in the grading path under minimum fault level conditions.

Table 6-7: Inverse overcurrent and earth fault protection settings summary.

Location	*Inverse Overcurrent*		*Inverse Earth Fault*	
	Pickup [$A_{primary}$]	*Time Multiplier*	*Pickup [$A_{primary}$]*	*Time Multiplier*
Transformer LV CB	600	0.30	180	0.30
Feeder CB	320	0.30	120	0.30
Mid-Point CB	160	0.25	100	0.20
RMU T-off CB	40	0.15	20	0.10

Table 6-8: DT overcurrent and earth fault protection settings summary.

Location	*DT Overcurrent*		*DT Earth Fault*	
	Pickup [$A_{primary}$]	*Time Delay [s]*	*Pickup [$A_{primary}$]*	*Time Delay [s]*
Feeder CB	2800	0.45	1600	0.45
Mid-Point CB	2300	0.30	1300	0.30
RMU T-off CB	1900	0.15	1000	0.15

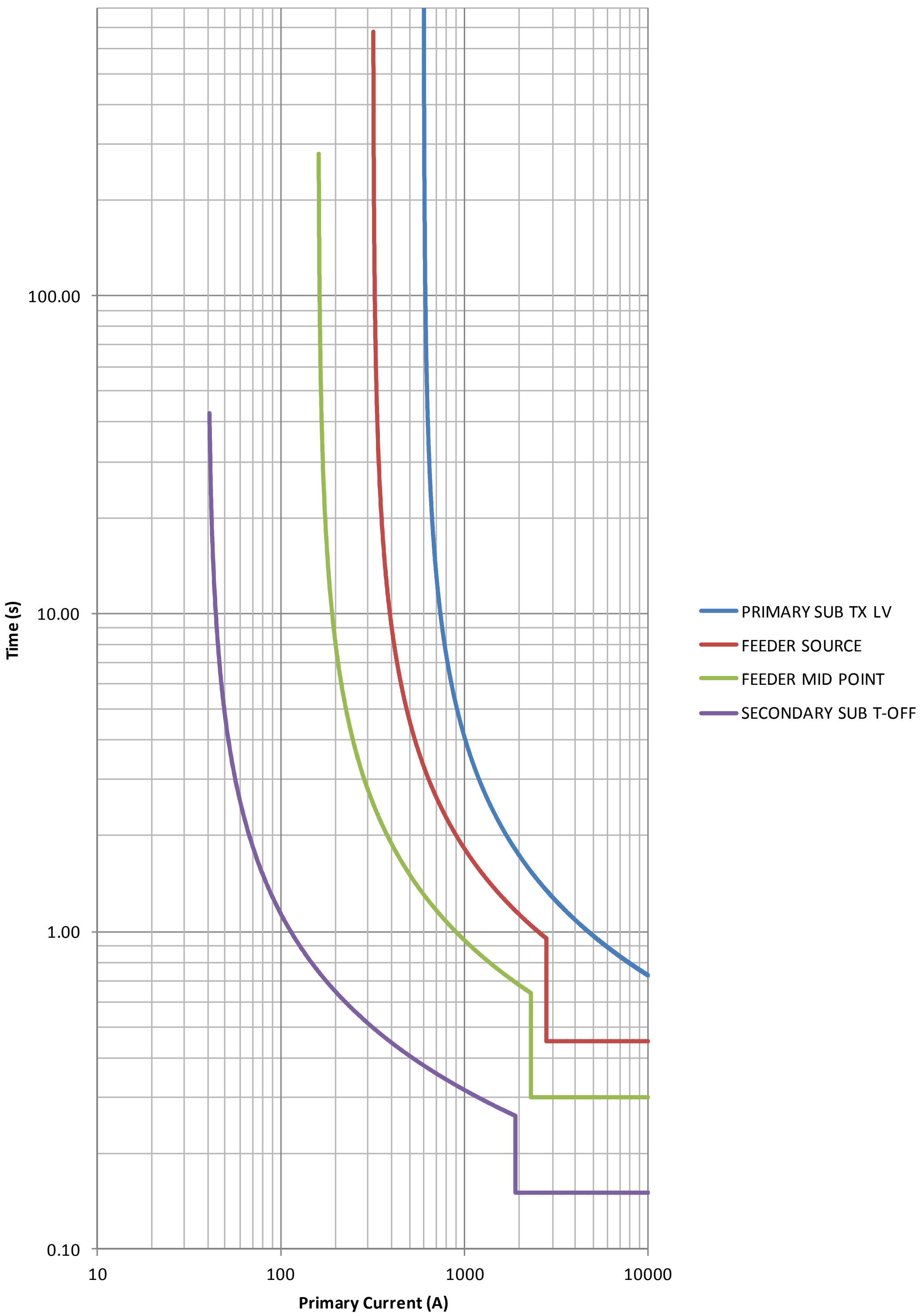

Figure 6-3: Grading diagrams for HV overcurrent protection.

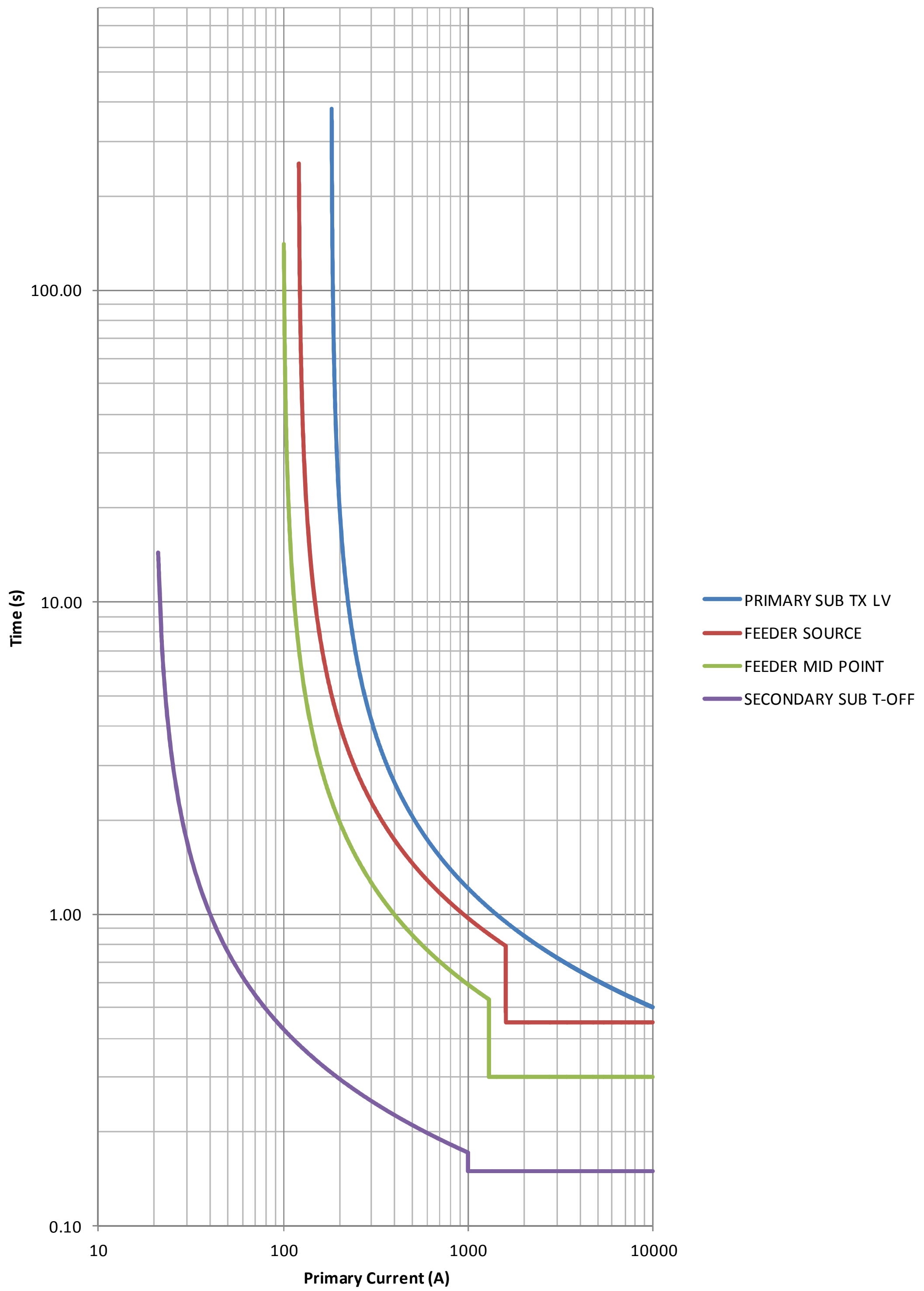

Figure 6-4: Grading diagrams for HV earth fault protection.

Table 6-9: Benchmark clearance times for a remote 11 kV fault.

Location	*Overcurrent [s]*	*Earth Fault [s]*
Transformer LV CB	1.281	1.181
Feeder CB	0.916	0.955
Mid-Point CB	0.579	0.586
RMU T-off CB	0.150	0.150

6.3.3 Generation and Demand Scenario Development

It is assumed that the total generation connected to the feeders originating at this primary substation has been identified as being at a level that will permit successful intentional islanding. Such a conclusion will only be possible after planning staff monitor net flows calculate the maximum plant margin (the percentage by which installed generation capacity exceeds peak demand) and analyse the intermittency characteristics of the various generators.

A schematic of the system with generation connected is shown in Figure 6-5. The generation is connected both within the LV networks and via dedicated generator step-up transformers onto the HV network. The main generators (diesel, gas and wind turbines) for this network are connected either at or via dedicated feeders to the 11 kV bus-bar at the primary substation. LV connected generation at the secondary substations are equivalents with the exception of a larger CHP unit. The sections that follow describe the breakdown of the generation in detail and the scenarios developed to analyse the islanded system. Islanding for this network will only be permitted at the circuit breakers located between the incoming feeders and the 33/11 kV transformers.

6.3.3.1 Islanding Capability

Table 6-10 provides a breakdown of the generation connected to this area of the HV network. A broad mix of generation has been included with the larger synchronous machines in this example being driven by diesel engines. In practice these could be replaced by other fuels or prime moves depending on local conditions. Using the total installed capacity derived from this table and the total peak demand from Table 6-2 the plant margin can be calculated as being approximately 82 %. This may at first appear to be high in comparison to the national system in recent years where a figure closer to 20 % has been the case, but since there are far fewer generators providing diversity, higher values of plant margin are necessary to cover outages, as well as to deal with potentially low load factors associated with intermittent generation. However this plant margin will only give a general indication of the viability of the islanded system. Other issues such as the adequacy of fault level, voltage regulation and indeed operation at varying generation dispatches will all need to be considered. This is done by creating a range of scenarios ranging from minimum to maximum demand levels and these are developed in the following section.

6.3.3.2 Scenarios

The scenarios have been developed based on scaling the demand connected to the network from 20 % to 100 % in 5 equally spaced levels (refer to Table 6-11). It has been assumed that the power factor remains constant across the demand levels. To meet these demand levels, a generation dispatch has been developed using a combination of varying the output from microgeneration and then balancing the system using the controllable plant such as the diesel and gas turbine driven generators. The objective was not to define exactly what the generation/dispatch makeup will be at all times, but rather to represent plausible overall generation dispatches that will probe the range of technical conditions that could occur.

When these dispatches were created, an attempt was made to ensure that in-service diesel generators are loaded in excess of 40 % and that a good level of reserve was available to cover the sudden loss of generation. Table 6-12 shows the generation dispatch created for each scenario, losses and the reserve capacity available from controllable generation. The lowest value occurs in the 80 % scenario where the reserve capacity is 66 % of the generation dispatch total.

During the course of the studies that follow these scenarios are subject to additional scaling (treating the scenario demand as a base) where it is required to stress the system. For example, when considering frequency regulation after the loss of the largest generator. This is to represent the poor performance of supervisory level control such as the EMS in ensuring that sufficient spinning reserve is available. Multipliers from 0.7 to 1.7 in 0.1 increments are used.

Table 6-10: Generation capabilties within the island zone.

Bus Number	***Prime Mover Technology***	***V_{term} [kV]***	***Single or Aggregate [S or A]***	**S_{rating} [MVA]**	**P_{rating} [MW]**
402	Microgeneration	0.4	A	0.150	0.150
403	CHP	0.4	A	1.875	1.500
405	Microgeneration	0.4	S	0.100	0.100
407	Microgeneration	0.4	A	0.100	0.100
410	Microgeneration	0.4	A	0.200	0.200
412	Microgeneration	0.4	A	0.100	0.100
413	Microgeneration	0.4	A	0.100	0.100
417	Microgeneration	0.4	A	0.200	0.200
418	Microgeneration	0.4	A	0.100	0.100
501	Diesel	3.3	S	5.000	4.000
501	Diesel	3.3	S	5.000	4.000
501	Diesel	3.3	S	5.000	4.000
601	Wind	0.69	S	0.533	0.480
602	Wind	0.69	S	0.533	0.480
603	Wind	0.69	S	0.533	0.480
801	GT	11	S	3.125	2.500
801	Fuel Cell	11	S	1.000	1.000
11006	Microgeneration[27]	11	A	0.700	0.700
11010	Microgeneration[27]	11	A	1.400	1.400
Totals:	-	-	-	*25.750*	*21.590*

[27] These values are aggregate representations of the LV connected generation connected to the other HV feeders that have not been represented explicitly in this model.

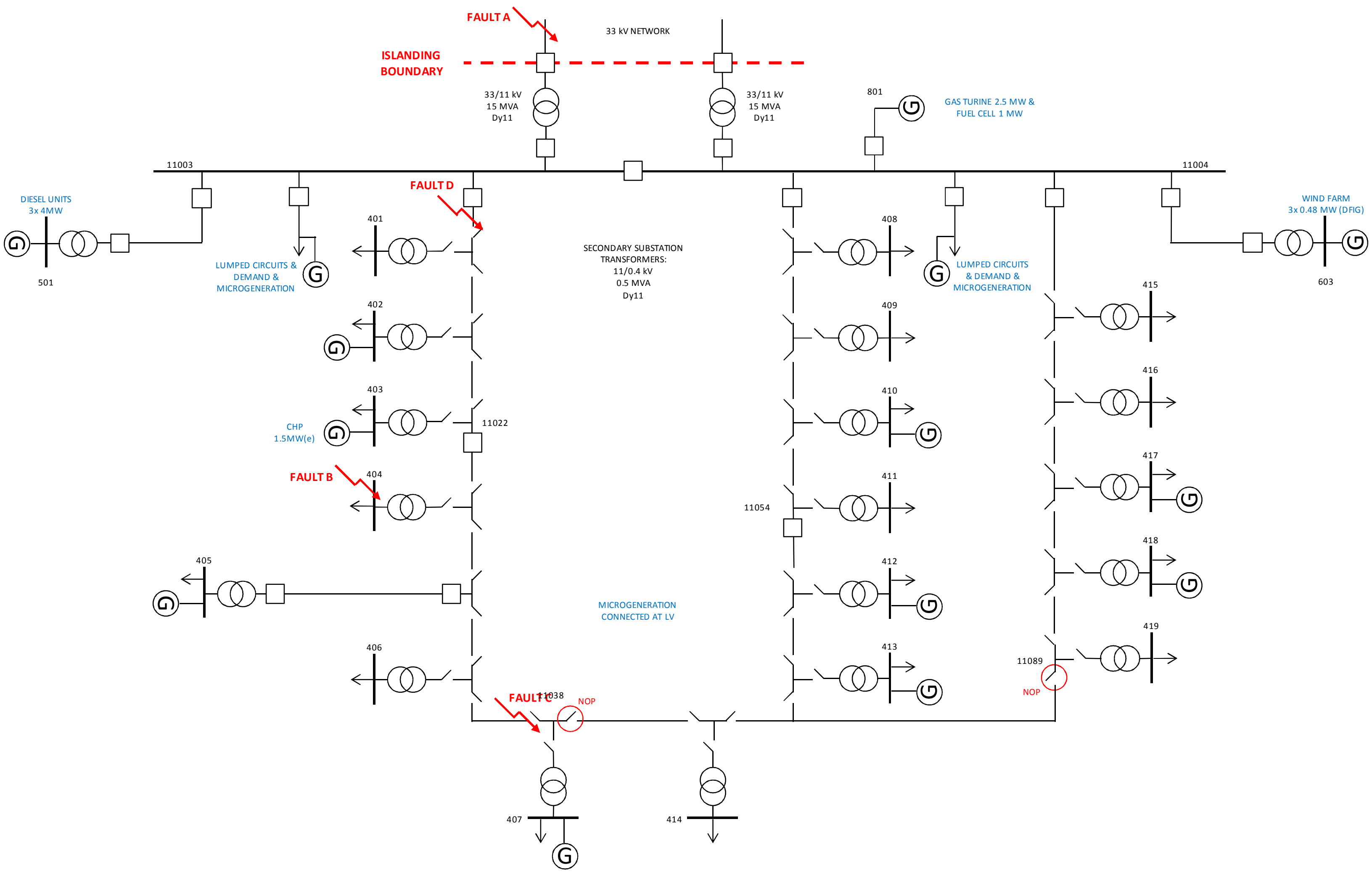

Figure 6-5: Single-line diagram of the study system with generation.

6.3.3.3 Dynamic Models

A summary of the dynamic models used for the generators connected to the study system is provided in Table 6-13 and a set of parameters can be found in Appendix C. All models are of a standard type [6.9] and typical data has been used that is appropriate for the scale of the generators studied.

Table 6-11: Scenario demand levels.

Bus Number	***20 % Demand [MW]***	***40 % Demand [MW]***	***60 % Demand [MW]***	***80 % Demand [MW]***	***100 % Demand [MW]***
401	0.070	0.140	0.210	0.280	0.350
402	0.070	0.140	0.210	0.280	0.350
403	0.070	0.140	0.210	0.280	0.350
404	0.070	0.140	0.210	0.280	0.350
405	0.070	0.140	0.210	0.280	0.350
406	0.070	0.140	0.210	0.280	0.350
407	0.070	0.140	0.210	0.280	0.350
408	0.070	0.140	0.210	0.280	0.350
409	0.070	0.140	0.210	0.280	0.350
410	0.100	0.200	0.300	0.400	0.500
411	0.070	0.140	0.210	0.280	0.350
412	0.070	0.140	0.210	0.280	0.350
413	0.070	0.140	0.210	0.280	0.350
414	0.070	0.140	0.210	0.280	0.350
415	0.100	0.200	0.300	0.400	0.500
416	0.070	0.140	0.210	0.280	0.350
417	0.070	0.140	0.210	0.280	0.350
418	0.070	0.140	0.210	0.280	0.350
419	0.070	0.140	0.210	0.280	0.350
11006	0.490	0.980	1.470	1.960	2.450
11010	0.490	0.980	1.470	1.960	2.450
Totals:	*2.370*	*4.740*	*7.110*	*9.480*	*11.850*

Table 6-12: Scenario generation levels and available reserve.

Generator Bus Number	***20 %***	***40 %***	***60 %***	**80 %**	**100 %**
	P_{GEN} [MW]	***P_{GEN} [MW]***	***P_{GEN} [MW]***	***P_{GEN} [MW]***	***P_{GEN} [MW]***
402	0.075	0.045	0.075	0.075	0.075
403	0.950	-	0.900	1.125	1.350
405	0.010	-	0.050	0.050	0.050
407	0.020	0.030	0.050	0.050	0.050
410	0.020	-	0.100	0.100	0.100
412	0.100	0.030	0.080	0.080	0.080
413	0.010	-	0.050	0.050	0.050
417	0.020	-	0.100	0.100	0.100
418	0.040	0.030	0.050	0.050	0.050
501	-	2.012	2.048	2.066	2.032
501	-	2.012	2.048	2.066	2.032
501	-	-	-	2.066	2.032
601	-	0.096	0.096	0.096	0.096
602	-	0.096	0.096	0.096	0.096
603	-	0.096	0.096	0.096	0.096
801	1.125	1.125	-	-	2.000
801	-	-	0.410	0.500	0.500
11006	-	0.070	0.350	0.350	0.350
11010	-	0.140	0.560	0.560	0.840
Totals [MW]:	*2.370*	*4.758*	*7.143*	*9.498*	*11.883*
Losses [MW]:	*0.1*	*0.138*	*0.146*	*0.193*	*0.225*
Reserve [MW]:	*2.43*	*6.38*	*4.52*	*6.26*	*6.65*

With regard to frequency control, the diesel engine, gas turbine and battery energy storage units all have a droop characteristic applied intended to apportion an increase or decrease in demand across the regulating units in service at a particular time. The DFIG model used incorporates crow-bar protection for the rotor converter and possesses a LVRT characteristic.

Table 6-13: PSS/E Dynamic model descriptions [6.9].

Generator Type	***Component Models***	***Description***
Diesel Engine	GENSAL	Standard salient pole synchronous machine model.
	SEXS	Simplified system that includes lead-lag term for the regulator and first order representation of the exciter.
	DEGOV	System includes isochronous governor, hydro-mechanical actuator and diesel engine representations.
Gas Turbine	GENROU	Standard round rotor synchronous machine model.
	SEXS	Simplified system that includes lead-lag term for the regulator and first order representation of the exciter.
	GAST	Basic gas turbine model that includes regulator, combustion chamber time constant and a load limiting feedback path.
CHP	GENSAL	Standard salient pole synchronous machine model.
	SEXS	Simplified system that includes lead-lag term for the regulator and first order representation of the exciter.
	TGOV	Basic thermal governor model.
Wind Turbines	WT3	Generic model of IEC type 3 wind turbine (DFIG). LVRT modelled (i.e. crow-bar and associated control).
Battery Energy Storage	CBEST	Dynamic model of battery energy storage developed by EPRI. Instantaneous active power response with charge/discharge efficiencies and AVR loop to enable terminal voltage control.
Microgeneration	CIMTR3	Squirrel cage induction machine with saturation. Constant mechanical power input assumed.

6.4 *Overall Control Objectives & Islanding Decision Process*

The decision to permit islanding of an area of network must be based on the aim of improving the security and quality of supply to local demand. There could be times where although it may be possible to island, the best course of action could be to wait and try to ride through a disturbance as this will present the lowest risk to the supply for all customers within the local system. Consider the example of an external transitory network fault in the 33 kV system combined with a relatively large net exchange of power from the grid into the local system. In principle fast islanding could be initiated, but the post-separation power deficit may be large enough to require under-frequency load shedding as insufficient reserve may be available from local controllable generation. Thus given that some customers may be disconnected, it may be a better course of action to delay islanding to check if the disturbance is cleared remotely. However, if the net power exchange is relatively small, fast islanding can proceed without difficulty and the time that the local system is subjected to low supressed voltages minimised.

For the purposes of this study, it is assumed that the overall control for the system will act to maximise the utilisation of available generation resources within the local system, whilst balancing this objective against optimising the net power flows across the boundary to minimise the disturbances that are caused by imbalances should isolation take place. Clearly although this may be technically ideal, minimising net flows could have the unfortunate impact of curtailing generation which may be from a low carbon energy source. Thus the option of minimising islanding transients must be balanced against the environmental and, moreover, financial implications of constraining any local generation. To help with this problem, controllable generation such as diesel units and energy storage can be used as a flexible resource to regulate the spill of energy to the grid (with the preference towards the latter for environmental reasons). This approach has been used for the example system where these types of assets have been built into the local generation mix.

Although the description above represents the control objectives with regard to generation within the system when it is grid connected, the protection must be designed to guard against situation where these cannot be met. Thus there is a link between the hierarchical EMS type control functionality and the role of system protection functions such as and islanding detection/initiation.

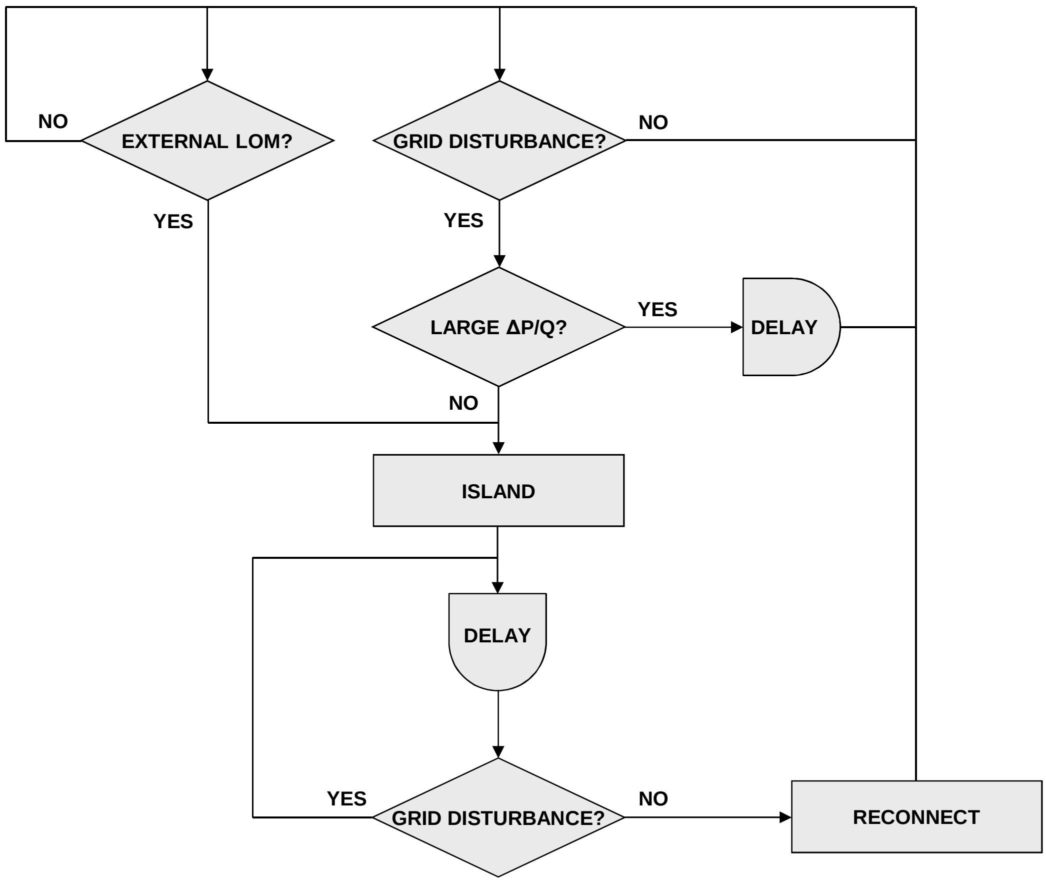

Figure 6-6: Automatic islanding descision making process.

To formalise the philosophy for automatic islanding, a suitable process is shown diagrammatically in Figure 6-6 above. The process starts with the parallel processes of detecting a disturbance such as a fault that has been classified as being appropriate to trigger separation from the grid or detection of loss of mains due to remote switching. Examples could include:

- Isolation from the grid at some remote location due to either manual switching or the action of protection. This would result in the local system either supporting external demand (most likely) or the local system being supported by other demand external to the boundary. In either case the mismatch in power would result in frequency and voltage disturbances that will degrade the power quality for local consumers.

- A fault that is electrically close to the local system that will require isolation to clear the contribution of local generation. For the system under study this could be on the incoming 33 kV circuits from the grid supply point.

For the case of disturbances the next stage in the process is to assess the pre-disturbance net power flows across the boundary. If these are small then isolation at the defined boundary can proceed and power quality levels restored within the islanded system with minimal transients. On the other hand if the net power flows are large, islanding will lead to large frequency and voltage transients as local generation reacts to restore balance. However, the disturbance initiating the potential islanding may be transitory and the best decision could be to delay the decision to island such that the grid supply can be restored without isolation or island only when it is apparent that the disturbance is permanent. For this second approach to be feasible the time delay must be chosen that would allow remote back-up protection to clear a fault that is causing the disturbance but also lower than the critical clearance time of the local generation with respect to external faults.

6.5 Demand Frequency & Under-frequency Load Shedding

At present the demand connected to distribution networks has a frequency response that is attributable only to the underlying technical characteristics of devices (e.g. motors and their associated loads). These characteristics have been incorporated into the studies in the following sections by the use of the CLODBL complex load model as described in section 6.3.1. However, providing dynamic demand response has been the subject of much recent research [6.10] (e.g. resistive elements used for water heating being controlled according to system frequency). As this is an emerging area and not the specific focus of this work, it has not been explicitly modelled in the simulations that follow in order that conservative results are obtained so that the underlying system characteristics can be seen. The application of under-frequency load shedding is studied later and these functions will be installed at the secondary substation level where they will be used to isolate demand at the LV feeder level.

6.6 Study System Characteristics

The following sections describe the characteristics of the study system under a range of operating conditions covering the grid connected and various island scenarios. These are intended to provide the justification for installing enhanced protection using adaptive concepts to address the varying characteristics of the system once islanding is permitted. Moreover, the studies that are described in this section are part of the design methodology where the scenarios for the system are analysed.

6.6.1 Fault Levels

Previous calculations have shown the variation in fault levels when the study system is subject to minimum and maximum grid infeeds. Table 6-14 and Table 6-15 provide the three-phase and phase-earth fault levels respectively for all island operating scenarios as well as when grid connected with all generation as dispatched in the 100 % scenario.

For the case of the three-phase fault levels at the 11 kV primary substation, the values can range from approximately 230 MVA for grid connected with 100 % generation down to 20 MVA for islanded mode with 20 % generation. The islanded mode case with 100 % generation has a fault level at this location of 74 MVA which is approximately 10 MVA lower than for grid connected minimum infeed conditions with no local generation. A further point of note is that the fault level increases slightly from 44 MVA to 47 MVA between the 60 % and 40 % islanded scenarios respectively. This is a consequence of the generation dispatches created for these scenarios in which both have approximately the same level of larger synchronous machine based generation in service (although with slightly different levels of smaller generation).

Table 6-14: Three-phase short-circuit calculation results in kA and MVA.

Bus Number	***Voltage [kV]***	***Grid Connected***		***Islanded***									
		100 % Scenario		***100 % Scenario***		***80 % Scenario***		***60 % Scenario***		***40 % Scenario***		***20 % Scenario***	
		I_k'' ***[kA]***	***Equivalent Fault Level [MVA]***	I_k'' ***[kA]***	***Equivalent Fault Level [MVA]***	I_k'' ***[kA]***	***Equivalent Fault Level [MVA]***	I_k'' ***[kA]***	***Equivalent Fault Level [MVA]***	I_k'' ***[kA]***	***Equivalent Fault Level [MVA]***	I_k'' ***[kA]***	***Equivalent Fault Level [MVA]***
11003	11	12.05	229.64	3.92	74.75	3.24	61.79	2.29	43.57	2.46	46.94	1.04	19.87
11004	11	12.05	229.63	3.92	74.75	3.24	61.79	2.29	43.57	2.46	46.94	1.04	19.87
11022	11	6.20	118.21	3.16	60.11	2.73	51.92	2.05	39.08	2.09	39.80	1.01	19.34
403	0.4	14.44	10.01	13.11	9.08	12.85	8.91	12.22	8.47	12.11	8.39	9.34	6.47
11038	11	4.76	90.74	2.77	52.86	2.45	46.59	1.90	36.21	1.90	36.27	0.98	18.72
407	0.4	14.14	9.79	12.87	8.92	12.63	8.75	12.04	8.34	12.02	8.33	9.25	6.41
11054	11	7.61	145.02	3.33	63.52	2.83	53.98	2.08	39.63	2.23	42.46	1.00	18.96
411	0.4	14.48	10.03	13.04	9.03	12.77	8.85	12.12	8.39	12.27	8.50	9.15	6.34
11066	11	5.90	112.38	2.97	56.68	2.57	49.02	1.94	36.96	2.07	39.48	0.96	18.30
414	0.4	14.23	9.86	12.84	8.89	12.58	8.72	11.95	8.28	12.10	8.38	9.04	6.27
11089	11	5.50	104.76	2.87	54.77	2.50	47.61	1.90	36.18	2.03	38.66	0.95	18.10
419	0.4	14.19	9.83	12.80	8.87	12.54	8.69	11.91	8.25	12.05	8.35	9.01	6.24

Table 6-15: Phase-earth short-circuit calculation results in kA and MVA.

Bus Number	Voltage [kV]	*Grid Connected*		*Islanded*									
		100 % Scenario		*100 % Scenario*		*80 % Scenario*		*60 % Scenario*		*40 % Scenario*		*20 % Scenario*	
		I_k'' [kA]	Equivalent Fault Level [MVA]	I_k'' [kA]	Equivalent Fault Level [MVA]	I_k'' [kA]	Equivalent Fault Level [MVA]	I_k'' [kA]	Equivalent Fault Level [MVA]	I_k'' [kA]	Equivalent Fault Level [MVA]	I_k'' [kA]	Equivalent Fault Level [MVA]
11003	11	2.32	44.24	2.06	39.20	1.98	37.79	1.82	34.74	1.91	36.36	1.30	24.79
11004	11	2.32	44.24	2.06	39.20	1.98	37.79	1.82	34.74	1.91	36.36	1.30	24.79
11022	11	1.95	37.24	1.77	33.74	1.72	32.82	1.61	30.76	1.62	30.85	1.21	23.11
403	0.4	14.80	10.25	13.92	9.64	13.80	9.56	13.44	9.31	13.32	9.23	10.96	7.59
11038	11	1.79	34.13	1.63	31.12	1.59	30.36	1.50	28.64	1.49	28.41	1.15	21.91
407	0.4	21.28	14.75	19.71	13.66	19.42	13.45	18.67	12.94	18.65	12.92	14.72	10.20
11054	11	2.08	39.71	1.85	35.33	1.79	34.19	1.66	31.67	1.73	33.00	1.21	23.03
411	0.4	21.78	15.09	19.97	13.84	19.64	13.61	18.81	13.03	19.05	13.20	14.56	10.09
11066	11	1.94	36.88	1.73	32.93	1.68	31.93	1.56	29.71	1.62	30.88	1.15	21.86
414	0.4	21.37	14.80	19.62	13.59	19.30	13.37	18.50	12.82	18.74	12.98	14.36	9.95
11089	11	1.89	36.02	1.69	32.20	1.64	31.24	1.53	29.11	1.59	30.24	1.13	21.49
419	0.4	21.35	14.79	19.60	13.58	19.28	13.36	18.47	12.80	18.71	12.96	14.33	9.93

Although the phase-earth fault levels vary between scenarios, the magnitudes are not as significant as was the case for three-phase fault levels due to the dominance of the neutral earthing resistors connected to the primary substation transformers. Under islanded conditions the phase-earth fault level varies between 44 MVA and 25 MVA at the primary substation as compared with 21 MVA for minimum grid connected conditions.

It can be appreciated that the variation in fault level has now significantly increased and, as a consequence, will have an appreciable impact on the performance of the overcurrent protection developed in section 6.3.2. Table 6-16 and Table 6-17 show the fault clearance times for the benchmark case of a remote 11 kV fault for each of the scenarios. The grid connected minimum infeed conditions are also shown for reference.

Table 6-16: Three-phase clearance times for a remote 11 kV fault.

Scenario	***Clearance Times [s]***		
	Feeder CB	***Mid-Point CB***	***RMU T-off CB***
Min. Grid	0.916	0.579	0.150
100	0.951	0.596	0.150
80	1.013	0.625	0.150
60	1.232	0.721	0.269
40	1.233	0.722	0.270
20	1.851	0.947	0.318

Table 6-17: Phase-earth clearance times for a remote 11 kV fault.

Scenario	***Clearance Times [s]***		
	Feeder CB	***Mid-Point CB***	***RMU T-off CB***
Min. Grid	0.955	0.586	0.150
100	0.783	0.487	0.150
80	0.791	0.492	0.150
60	0.846	0.524	0.150
40	0.849	0.525	0.150
20	0.908	0.559	0.150

It can be seen that the three-phase clearance times increase as the level of generation connected decreases to match lower levels of demand connected to the network. The largest differences are to be found at the feeder and mid-point circuit breakers where clearance times are delayed by hundreds of milliseconds, with the worst case 20 % scenario being delayed by over 800 ms. Furthermore, the DT elements are no longer effective in the 20 %, 40 % and 60 % scenarios. In contrast, the phase-earth clearance times do not vary as significantly over the range of scenarios due to the impact of the neutral earthing resistors as commented on previously.

6.6.2 Transient Stability

The transient stability of the study system has been examined for a number of fault locations when both connected to the grid and operating in islanding mode under the different scenarios. A worst case zero impedance balanced three-phase fault has been assumed for all simulations and four specific fault locations have been considered (refer to Figure 6-5):

- Fault A: (grid connected only): HV fault placed on the 33 kV network external to the local system.
- Fault B: LV fault placed at the secondary substation located at the mid-point on the first feeder.
- Fault C: HV fault placed at the remote end of the first feeder.
- Fault D: HV fault placed after the source circuit breaker on the first feeder.

6.6.2.1 Grid Connected

A full set of transient studies has been carried out to establish the approximate critical clearance times for generation within the local system for the different scenarios when grid connected. Table 6-18 lists these times and the generators that are at their stability limit. Note that the simulations were carried out with fault durations increasing in 5 ms intervals.

For reference a full set of transient results are provided in Figure 6-7 to Figure 6-10 for the case of fault A occurring at 1 s with a duration of 300 ms for the 100 % scenario. The results show that the system is stable and that all responses are well damped returning to pre-fault levels. Note that the rotor angle plot is shown with all responses referenced to the system average rotor angle.

Table 6-18: Grid connected approximate critical clearance times & generators.

Scenario	*Approximate Critical Clearance Time [ms] & Generators*			
	Location A	*Location B*	*Location C*	*Location D*
100	625 (CHP @ 403)	245 (microgen)	595 (CHP @ 403)	530 (CHP @ 403)
80	620 (CHP @ 403)	245 (microgen)	590 (CHP @ 403)	520 (CHP @ 403)
60	610 (CHP @ 403)	245 (microgen)	585 (CHP @ 403)	505 (CHP @ 403)
40	715 (GT @ 801)	245 (microgen)	645 (GT @ 801)	625 (GT @ 801)
20	595 (CHP @ 403)	245 (microgen)	570 (CHP @ 403)	490 (CHP @ 403)

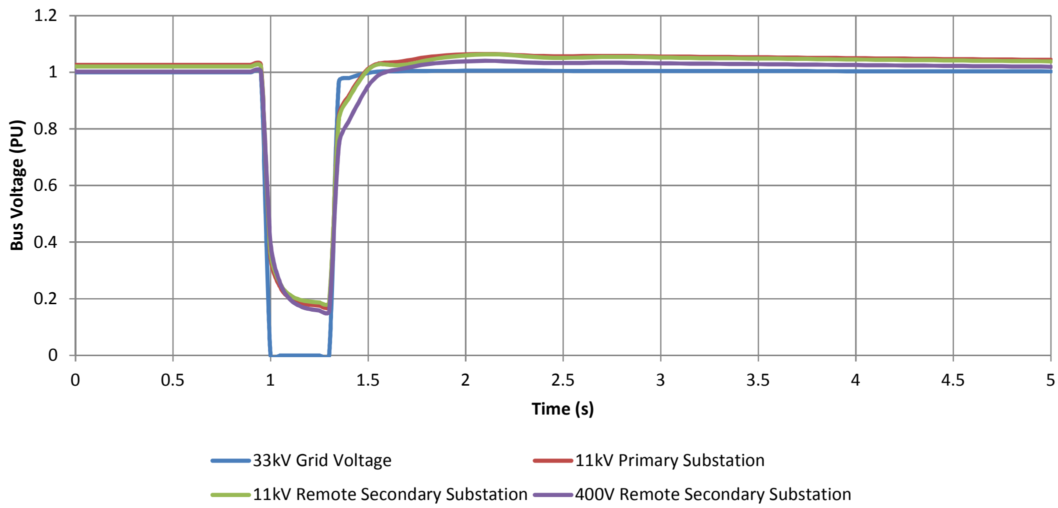

Figure 6-7: 100 %, grid connected, fault A (300ms), network voltages.

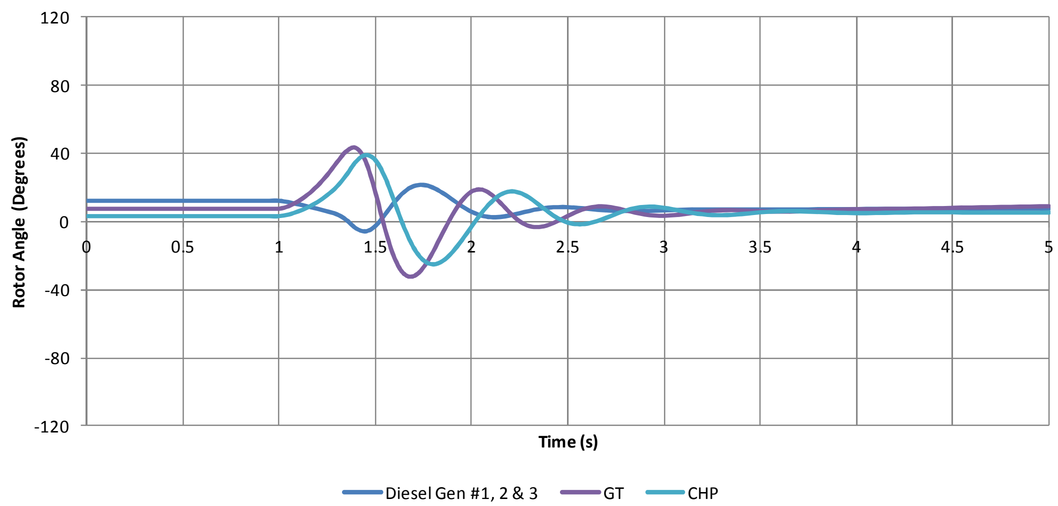

Figure 6-8: 100 %, grid connected, fault A (300ms), sync. m/c rotor angles.

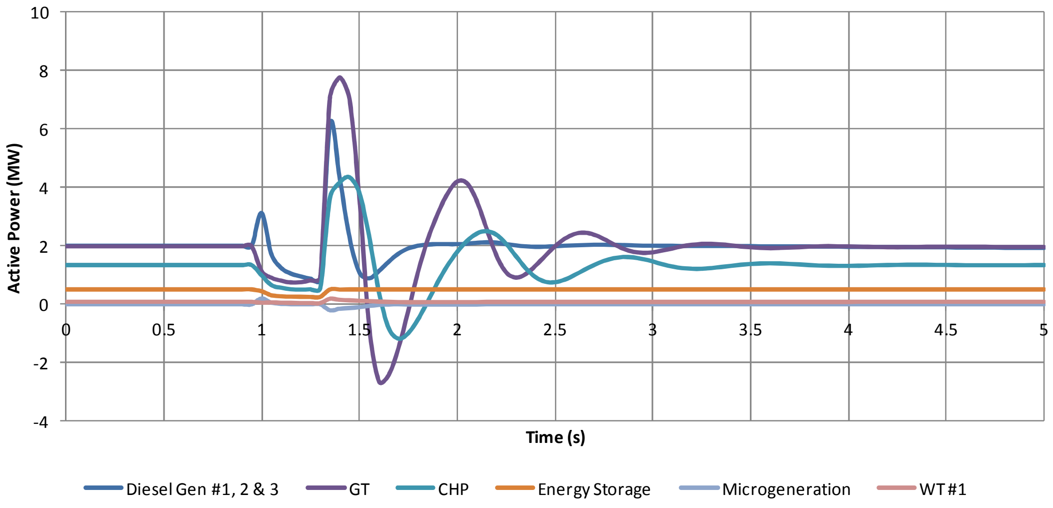

Figure 6-9: 100 %, grid connected, fault A (300ms), generator active powers.

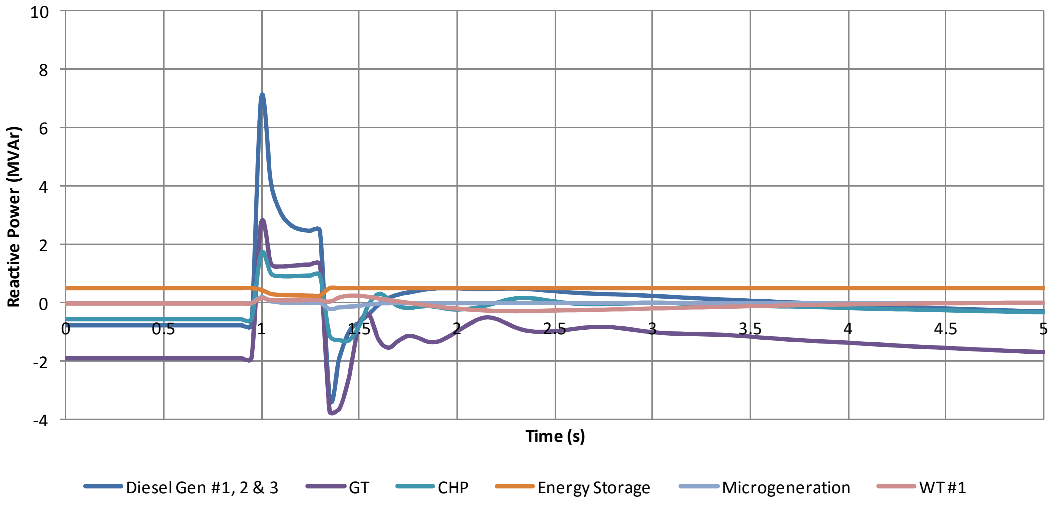

Figure 6-10: 100 %, grid connected, fault A (300ms), generator reactive powers.

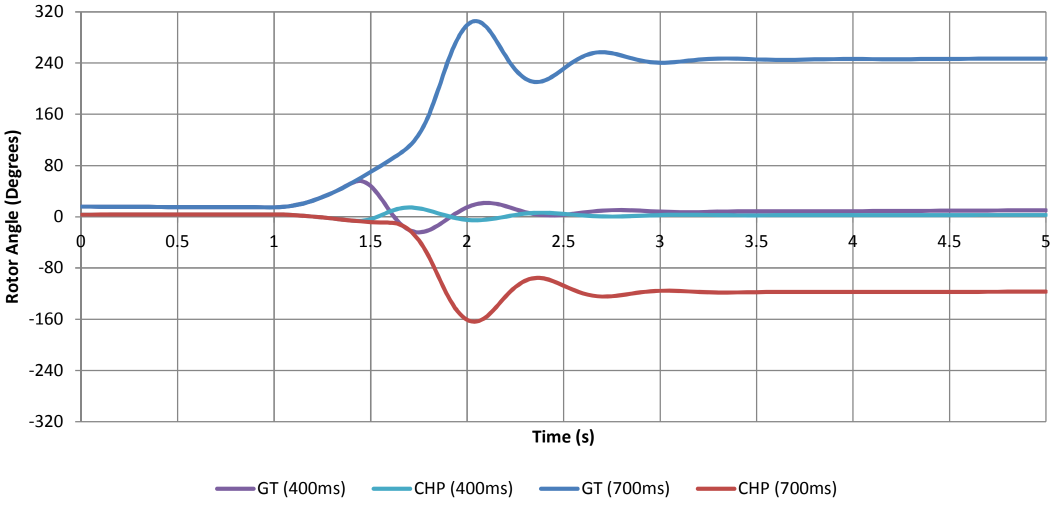

Figure 6-11: 20 %, grid connected, fault A (400/700ms), sync. m/c rotor angles.

Further to these, the onset of transient instability is shown in Figure 6-11 for the case of fault A occurring at 1s. Two faults with durations of 400 ms and 700 ms for the 20 % scenario are used to illustrate stable and unstable cases. In this figure the rotor angles of the two synchronous generators connected to the study system in this scenario are shown and the loss of synchronism can be observed as the rotor angles swing after the disturbance.

The results show that for HV faults the CHP unit is the worst performing generator with a lowest CCT of around 490 ms for a fault close to the primary substation 11 kV bus-bar at location D. If the fault is as shown on the feeder side of the circuit breaker then it would be quickly cleared by the feeder protection as a close-up fault or by the protection associated with the 33/11kV transformer LV circuit breaker as a backup (note that no protection has been assumed for the bus-section breaker). Alternatively, if it occurred on the bus-bar (a particularly rare fault) then the whole local network would be disconnected. In either case there are no stability concerns related to the CHP generator. For location C at the end of feeder 1, the CCT values are higher and, if compared with the times in Table 6-9, it can be seen that they are longer than the time expected for the mid-point protection acting as a backup (the CHP being located at a secondary substation before the feeder mid-point). For LV faults, as would intuitively be expected, the microgeneration has the lowest CCT of around 245 ms and is both comparable to the value derived in Chapter 5 for the microgrid and far longer than LV fuse operating times.

6.6.2.2 Islanded

A full set of transient studies has also been carried out to establish the approximate critical clearance times for generation within the local system for the different scenarios when islanded. Table 6-19 lists these times and the generators that are at their stability limit. For reference a full set of transient results are provided in Figure 6-12 to Figure 6-15 for the case of fault C occurring at 1 s with a duration of 300 ms for the 40 % scenario. The results show that the system is stable and that all responses are well damped returning to pre-fault levels. However the voltage response now shows that it takes longer to restore the voltage to pre-fault levels and is due to the weaker system having to support the reactive power demands of the motors embedded within the LV load.

Table 6-19: Islanded approximate critical clearance times & generators.

Scenario	*Approximate Critical Clearance Time [ms] & Generators*			
	Location A	***Location B***	***Location C***	***Location D***
100	-	215 (microgen)	450 (CHP @ 403)	415 (CHP @ 403)
80	-	215 (microgen)	440 (CHP @ 403)	405 (CHP @ 403)
60	-	215 (microgen)	435 (CHP @ 403)	400 (CHP @ 403)
40	-	215 (microgen)	605 (GT @ 801)	580 (GT @ 801)
20	-	215 (microgen)	335 (CHP @ 403)	285 (CHP @ 403)

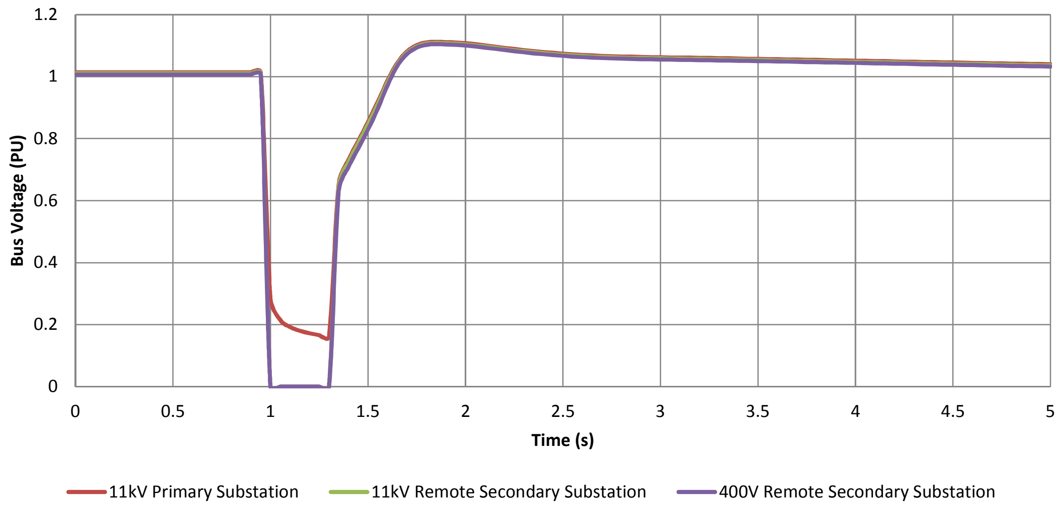

Figure 6-12: 40 %, islanded, fault C (300ms), network voltages.

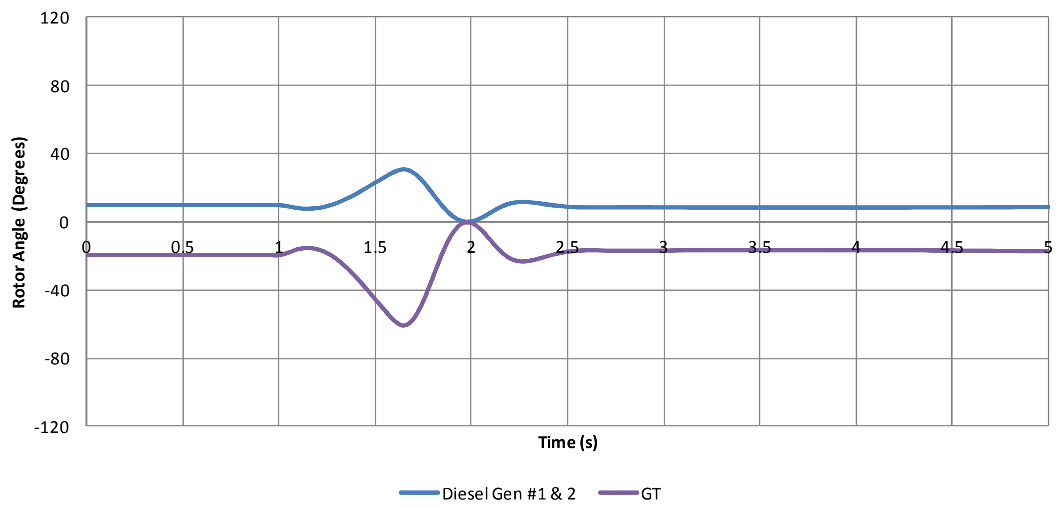

Figure 6-13: 40 %, islanded, fault C (300ms), sync. m/c rotor angles.

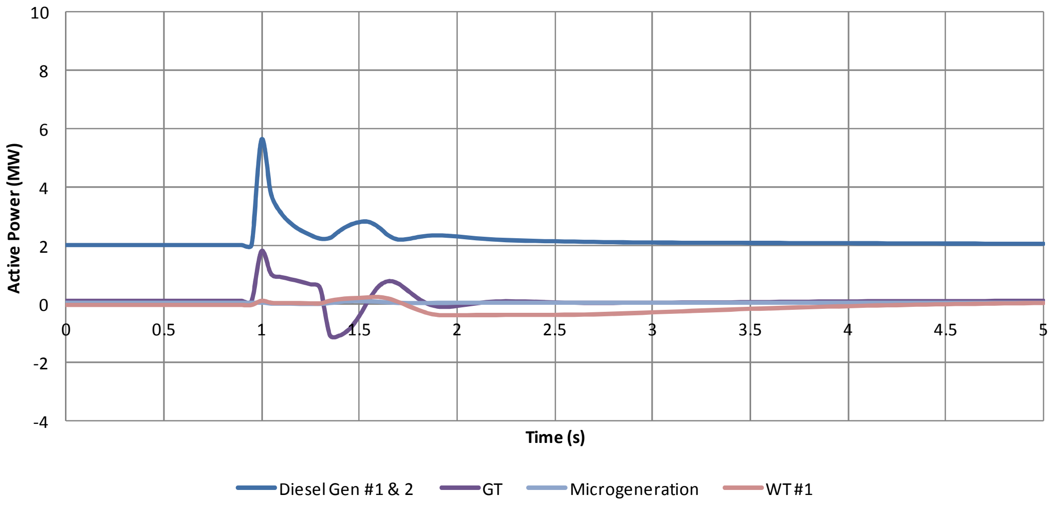

Figure 6-14: 40 %, islanded, fault C (300ms), generator active powers.

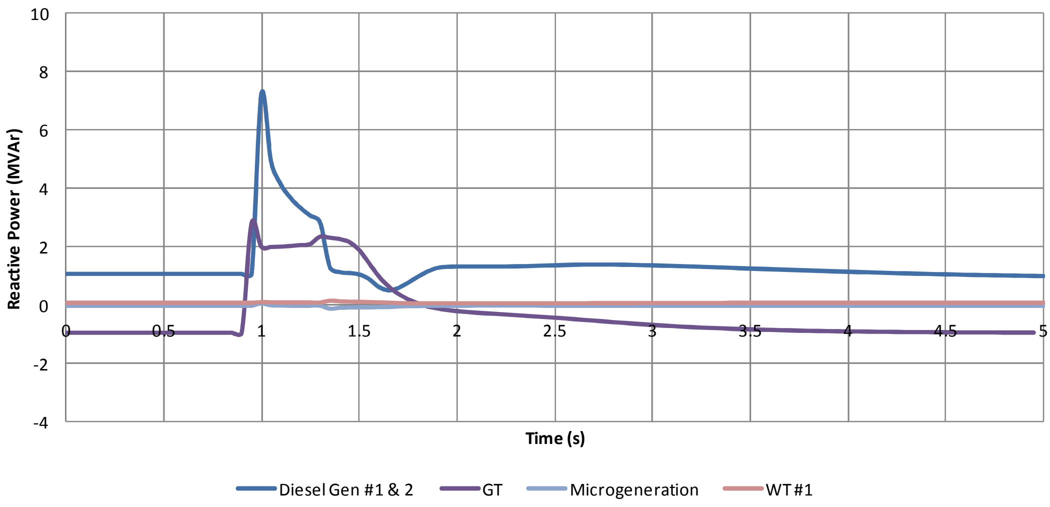

Figure 6-15: 40 %, islanded, fault C (300ms), generator reactive powers.

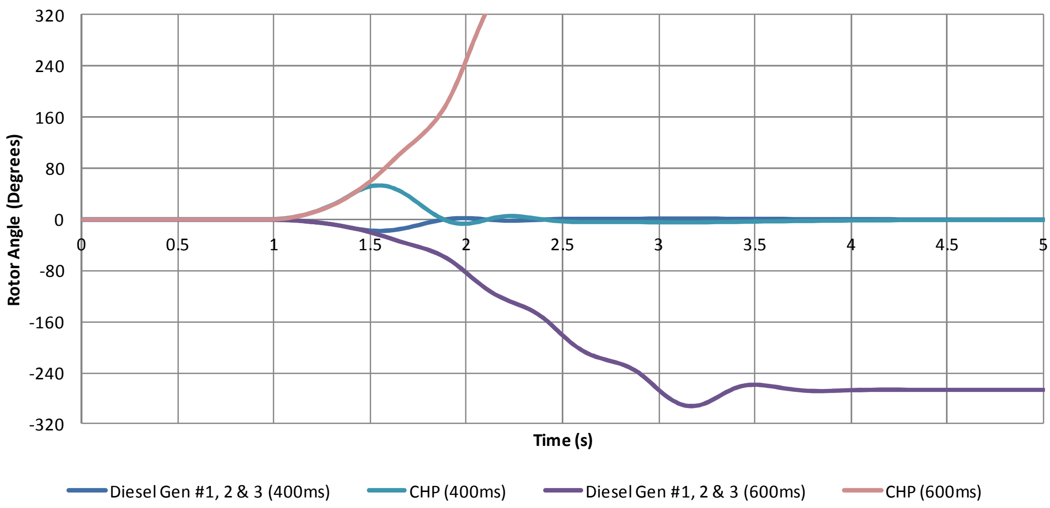

Figure 6-16: 80 %, grid connected, fault D (400/600ms), sync. m/c rotor angles.

Further to these, the onset of transient instability is shown in Figure 6-16 for the case of fault location D occurring at 1s with durations of 400 ms (stable) and 600 ms (unstable) for the 80 % scenario. In this figure the rotor angles of the four synchronous generators connected to the study system are shown and the onset of instability can be observed for the longer fault duration with the diesel generators swinging together against the single CHP unit.

The results in Table 6-19 show that the CCT values fall when the system is isolated from the grid and the CHP unit is again the limiting generator. There is a reduction of over 100 ms for HV fault locations C and D when compared against those in Table 6-18 and consequently clearing faults under-backup mode (or primary clearance for remote cable faults after the mid-point) could lead to generator instability in most cases based on the times given in Table 6-16. Under grid connected conditions this would not be an issue since the generator can be tripped and lost output supplied from the grid once the fault has been cleared from the system. However under islanded conditions if the CHP generator represents an important part of the generation meeting demand then the loss of this unit could present further frequency regulation issues. This would be the case for the 20% scenario developed for this study where the continued operation of the CHP generator should be given priority.

For LV faults, as would intuitively be expected, the microgeneration has the lowest CCT of around 215 ms and is lower than the value found under grid connected conditions. However the earth fault current at the secondary substation transformer LV terminals is still greater than 10 kA in the lowest 20% scenario and this is sufficient to ensure satisfactory LV fuse operation.

6.6.3 Islanding Transients

When the local system is isolated from the grid there will be transients associated with the disturbance initiating the islanding and, potentially, any real and reactive power imbalances between local generation output and demand immediately post-separation. To illustrate these transients, an external 33 kV fault has been simulated that will require the islanding of the system to stop the contribution of the local generation (i.e. it is electrically close to the system). The fault occurs at 1 s and islanding has been assumed to occur at 1.2 s (the grid fault was also removed from the 33kV system at this time such that the grid voltage provides an idealised benchmark for the recovery of the island voltages). Figure 6-17 shows the 33 kV voltage on the grid side of the boundary circuit breakers, 11 kV primary substation voltage and the LV voltage at a remote secondary substation for the 40 % demand scenario. The voltages within the islanded system recover quickly post isolation with minimal overshoot and good damping due to the action of the local voltage controllers.

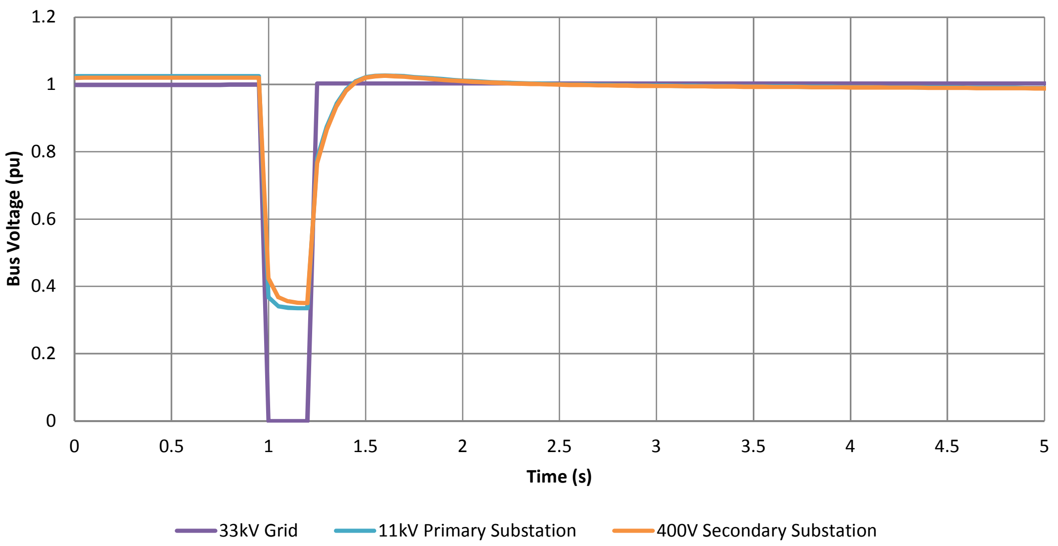

Figure 6-17: System voltages during islanding (40 % demand scenario).

Figure 6-18 shows the corresponding impact of islanding on local frequency for the 40 % demand scenario with additional simulations performed to examine the impact of varying levels of local generation and demand imbalance prior to separation. A set of multipliers were applied to the base scenario demand ranging from 0.7 to 1.7. Note that under-frequency load shedding or frequency responsive demand have not been modelled. The ±1 % (0.5 Hz) statutory steady-state frequency band has also been plotted for reference and it can be seen that the island frequency remains within limits even up to having local demand 70 % greater than the pre-separation generation dispatch. This corresponds to an additional 3.32 MW of demand that requires to be supplied by increased output from local generation. The reserve available from controllable generation within this scenario is 6.38 MW

(Table 6-12) which is more than enough to provide this additional output and the performance of these units is fast enough to maintain the frequency within the ±1 % band. Note that the governors on the controllable generation have been set to return the system frequency back to nominal by means of an adjustment of their load reference set-point.

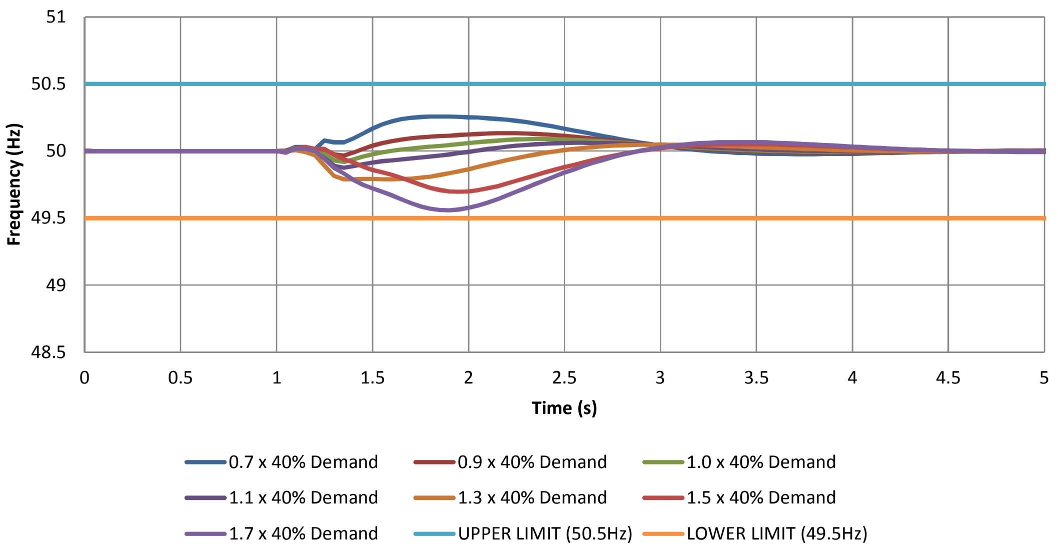

Figure 6-18: Island frequency after separation for 40% demand scenario.

In contrast, Figure 6-19 shows the responses based on the same percentage levels of imbalance for the 80 % scenario. In this case the 70 % positive imbalance causes island frequency to fall below the lower statutory limit and remains there even after 5 s have elapsed from the start of the simulation. This level of imbalance corresponds to 6.64 MW and is greater than the 6.26 MW reserve available from controllable local generation. Thus frequency cannot recover the nominal levels and, although not shown, continuing with the simulation would show that it does not recover sufficiently to move back within the statutory band. The 70 % imbalance in this case is clearly greater than the original 100% scenario level. However, future load growth or the reconfiguration of the local network to incorporate a section of an adjacent feeder could potentially lead to a greater demand being experienced.

These simple studies indicate that the net power exchange between the local system and the grid should be compared with the available reserve to determine if islanding will be successful prior to separation. As an indication, Table 6-20 provides the maximum net boundary power flows to ensure frequency stability based on the available capacity obtainable from the generation in service for a particular scenario. Given the intermittent nature of the generation sources it may not be possible to start additional units and thus the careful consideration of the "spinning reserve" is vital.

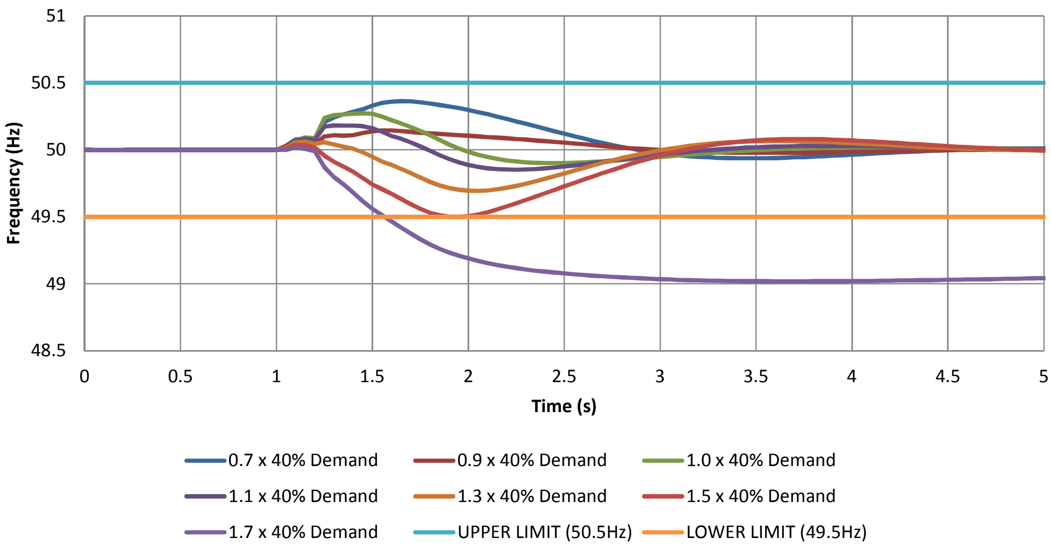

Figure 6-19: Island frequency after separation for 80% demand scenario.

Table 6-20: Pre-separation max. net power flows to ensure frequency stability.

Scenario	***Generation Reserve [MW]***	***Percentage of Scenario Demand [%]***
100	6.65	56.12
80	6.26	66.03
60	4.52	63.57
40	6.38	134.60
20	2.43	102.53

However, this analysis has not, as stated above, considered frequency responsive demand which could have impact on the results. Consequently, this factor must be considered before islanding should be blocked based on net power exchange with the grid.

6.6.4 Frequency Stability

The frequency stability under islanded conditions has been studied by considering the impact of the loss of the largest generator for the different demand scenarios. These have again been scaled using multipliers to reduce the available spinning reserve in order to stress the system.

The results for the 60 % and 100 % scenarios are provided as examples for discussion. In both of these scenarios a single diesel generator is tripped at 1 s and the system frequency and rate of change of frequency (ROCOF) are reported.

Figure 6-20 and Figure 6-21 show the results for the 60 % scenario with the base case and the scaling multipliers 1.2 and 1.4. The results show that for the loss of the diesel generator in the base case there is sufficient spinning reserve available from the remaining controllable generation to ensure that the frequency returns to within the statutory band. For the 1.2 and 1.4 multiplier the system frequency is unable to be restored within the statutory band unless further action is taken to reduce the demand connected to the system. Note that no demand response other than that inherent to the general load was modelled (i.e. that inherent to the CLODBL load model). The results also show that very high rate of change of frequency value in excess of 1 Hz/s are present for longer than 0.5 s. Frequency variations values of this magnitude and duration are in excess of typical values used to set loss of mains functions based on ROCOF principles. These functions typically have settings in the ranges 0.1 - 1 H/z and 0.2 – 0.5 s [6.11].

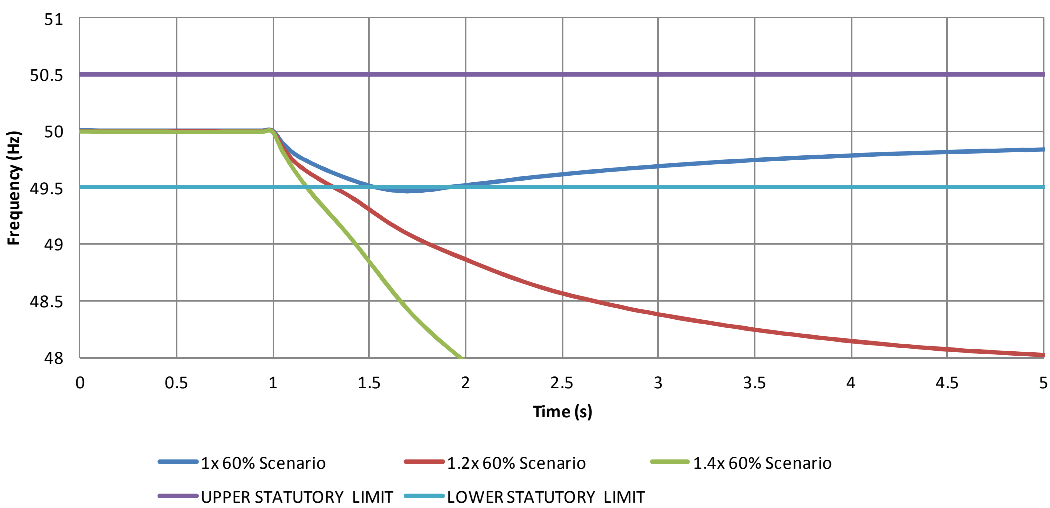

Figure 6-20: 60 % scenario - loss of largest generator (DE #1) – frequency.

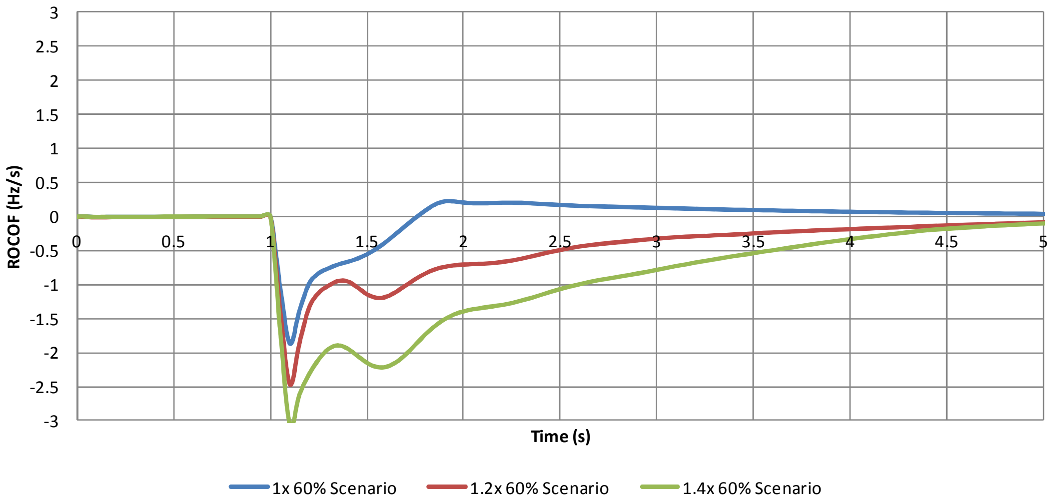

Figure 6-21: 60 % scenario - loss of largest generator (DE #1) – ROCOF.

Figure 6-22 and Figure 6-23 show the results for the 100 % scenario with the base case and the scaling multipliers 1.2 and 1.4. For this scenario the 1.4 multiplier when applied to system demand results in an incontrollable drop in frequency on the loss of one of the diesel generators. The rates of change of frequency are lower than in the 60 % scenario but nonetheless are still in excess of 1 Hz/s. Note that for the 1.4 multiplier, the system generation would eventually trip on under-frequency protection (stage 1 as recommended in ER G59/2 which is set at 47.5 Hz [6.1]).

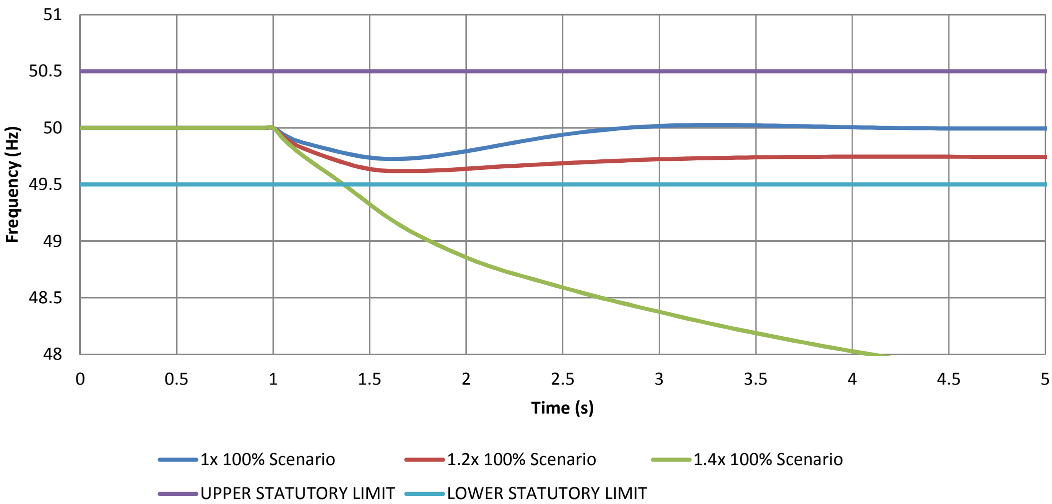

Figure 6-22: 100 % scenario - loss of largest generator (DE #1) – frequency.

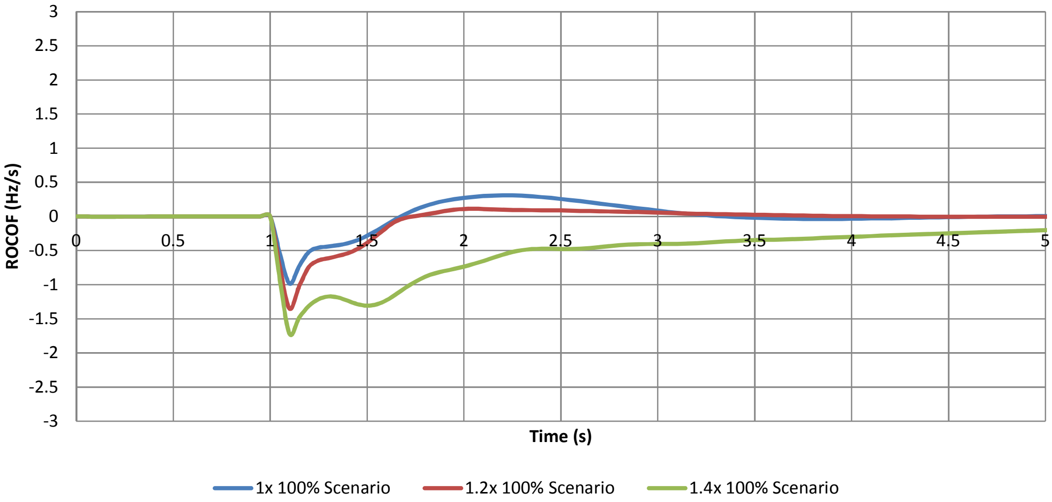

Figure 6-23: 100 % scenario - loss of largest generator (DE #1) – ROCOF.

These results illustrate that the spinning reserve may not always be sufficient to deal with the sudden loss of generation and, since the starting of additional units may not be feasible, some form of load shedding will be necessary. Furthermore, the rates of change of frequency observed are very much greater than what would be experienced on the national system with values in excess of 1.5 Hz/s. As a consequence of this action must be prompt to arrest any fall in system frequency. The design of an under-frequency load shedding scheme is complicated by the fact that faster acting schemes can lead to larger than necessary levels of demand disconnection. Thus there is a tangible performance advantage in being able to adapt the settings to reflect the level of risk that the system is exposed to in the event of a larger generator disconnection. Moreover, if the functions are located at the secondary substation, then these must be blocked if the local generation output is high enough out into the HV system.

6.7 Development of an Adaptive Protection Scheme

The previous sections examined the fault level variation and dynamic characteristics of the test system under grid connected and islanded operating conditions. For the case of overcurrent protection, it was shown that there is a significant degradation in performance with backup fault clearance times increasing significantly and definite time functions not able to operate as intended. The relatively low CCT of the CHP generator was also highlighted with the value for this becoming more onerous under islanded conditions. Furthermore, the frequency transients post-islanding or the loss of the largest generator were shown to the severe enough for problems for loss of mains functions and for corrective measures involving load shedding to be considered under certain circumstances. With such behaviour in mind, this section now considers how the adaptive architecture can be applied to the protection for this example system such that its performance can be at least maintained and where possible improved.

The section that follows briefly describes how the proposed adaptive architecture has been applied to the protection devices across the test system. Each subsequent section then considers a separate protection function and describes how it has been developed in accordance with the proposed methodology. The process starts with assessing the impact of the scenarios, moves onto defining groups of settings and then finishes with testing the robustness of the solution performance based on identifying potential failure modes and any mitigation measures that are required.

6.7.1 Architecture Application

A structure for the complete adaptive protection system is shown in Figure 6-24 which identifies the execution, coordination and management layers of the proposed architecture built up from the elements described in Chapter 3. Modern numerical protection relays have been assumed to be used across the system and a substation computer is used for both the management layer of the architecture and the EMS located in the primary substation. The EMS is responsible for system balancing through controllable generator dispatch (or controllable units) or the use of controllable demand. The protection studied is located at the grid interface, primary/secondary substations and at the generators. No alterations are proposed to the LV protection as the satisfactory operation of fuses has been checked and confirmed for all operating scenarios. No LV microgrids are present in this system and thus no further subdivision of the network is possible.

6.7.1.1 Execution Layer

The execution layer functionality is distributed between all of the numerical relays across the system with the necessary connections made to measurement transducers such as current and voltage transformers. Changes are made to the settings group in use in response to commands from the coordination layer functions. Note that since modern numerical relays are used, the execution and coordination layers are within the same physical device. Fault and event recorders have been setup to record disturbances and relay performance. These functions are discussed later in section 6.8.

6.7.1.2 Coordination Layer

The coordination layer functionality is also distributed between all of the numerical relays with connections made to the auxiliary contacts of the interface circuit breakers and other logic signals made accessible over via communication links with generators and secondary substations. Verification logic for this scheme (i.e. confirmation that adaption has taken place as requested) is simple since the coordination and execution layers are physically located on the same devices. In terms of practical implementation on a relay this is the setting of flags within the firmware at the device level and notifying the management layer of their activation.

6.7.1.3 Management Layer

The management layer is centrally located at the primary substation and is deployed on a substation computer and integrated with the EMS such that data is made available to the coordination layer on assessments such as the level of HV connected conventional generation currently in service. This layer will also check that the correct adaptation verification has been carried out across the scheme as a whole and process any diagnostics or disturbance recorder data.

6.7.1.4 Communication

It is assumed for the purposes of this study that a wide area communication system (e.g. VHF radio based) exists between the primary/secondary substations and generation sites. This system is able to support the transfer of protection signals between relays (e.g. GOOSE messages) that will enable the coordination layer logic to function in response primary system changes. No specific communication system implementation is used and, instead, generic failure modes are used when this area of the design is analysed to maintain the generality of the example.

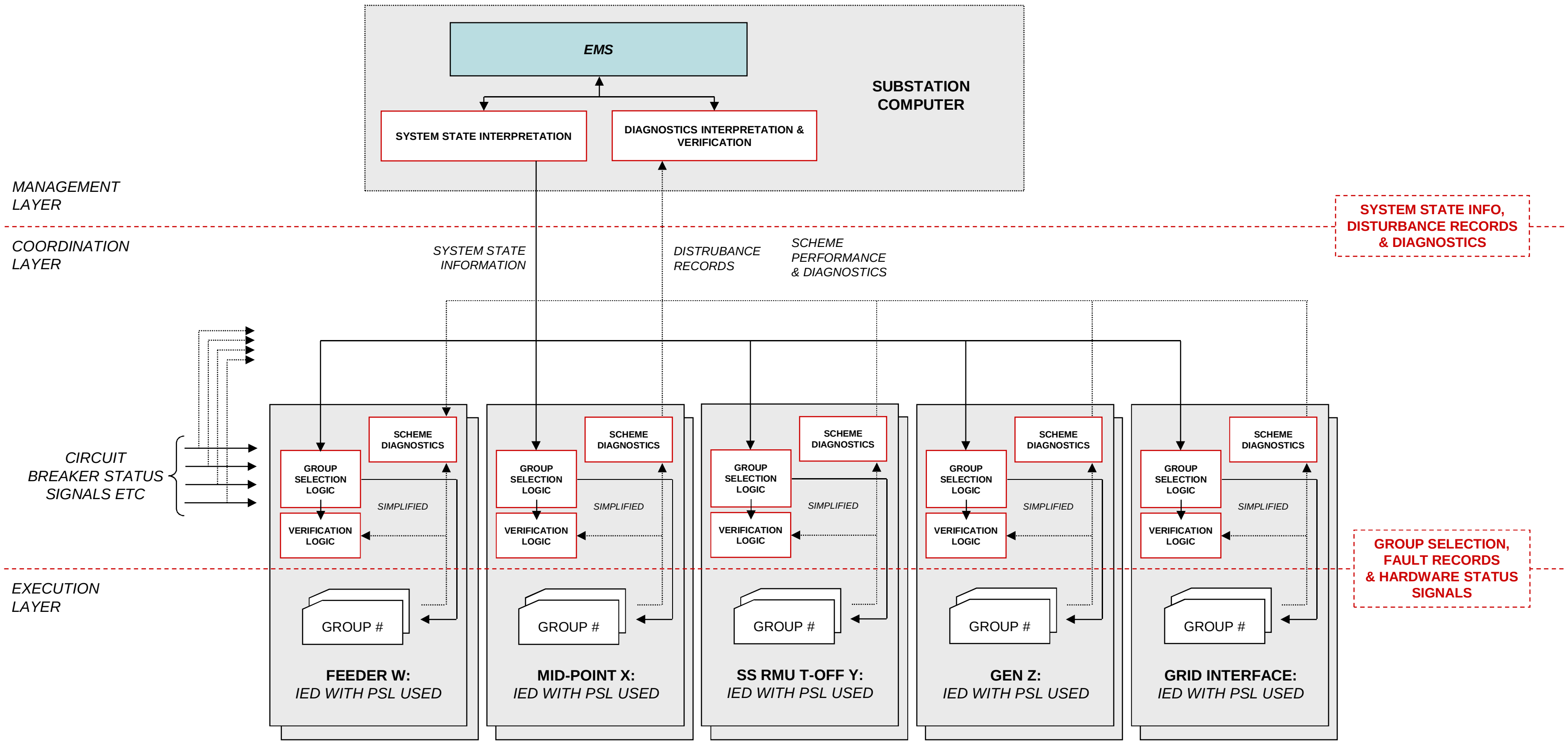

Figure 6-24: Architecture of the proposed adaptive protection scheme.

6.7.2 Adaptive Overcurrent Protection

The analysis presented in section 6.4 demonstrated that the performance of the overcurrent protection designed for a grid connected system is significantly degraded when the lower demand level scenarios are considered when islanded (in this case the clearance times are longer and the operation of definite time functions no longer satisfactory). In order to maintain the same level of performance as benchmarked for the grid connected case with minimum grid infeed, new settings are required to better reflect the lower fault levels present in the islanded system. The following sections describe the development of an adaptive overcurrent scheme according to the design methodology illustrated previously in Figure 6-1.

6.7.2.1 Assess Scenarios

The performance of the original earth fault protection was found to be satisfactory for all scenarios and no adaptive settings are proposed during islanded operation. However this is not the case for the overcurrent protection functions across the various islanded scenarios. Taking the 20 % scenario as an example, the maximum clearance time for a remote HV fault by a feeder circuit breaker is 1.8 s which is in excess of the 1.5 s design target. Furthermore, the definite time elements are ineffective in the 20 %, 40 % and 60 % scenarios. These shortcomings clearly indicate that changes need to be made to settings to improve performance. Note that the protection associated with generators is not considered here are as it is assumed that if the performance of the network protection is maintained then the settings for the generator relays do not need modification in order to maintain coordination.

A review of Table 6-16 which gives the clearance times for the benchmark remote HV fault shows that the performance of the overcurrent protection can be put into three groups where the performances are similar. These groups are in effect three different states of the local system reflecting high, medium and low three-phase fault levels. The groups are as follows:

1. Grid connected under minimum infeed conditions and the 80% / 100% islanded scenarios which have a clearance time of around 0.9 – 1s
2. 40% / 60% islanded scenarios with clearance times of around 1.2s

3. 20% islanded scenario with a clearance time of around 1.8s

Note that the dominant sources of fault current contribution within the islanded network are the diesel generators and gas turbine that are located at the source of the islanded grading paths (i.e. feeding directly via the primary substation bus-bar). Only smaller generators are connected along the grading paths and their contribution relative to the main generation avoids any reach issues for the mid-point protection on the two feeders modelled in detail that include these additional grading points.

6.7.2.2 Define Functions, Settings Groups and Map to Changes

The justification for these groups can be established by comparing the magnitudes of the fault levels as given in Table 6-14 where similarities can been seen within the groups listed above. If group 1 is taken as the reference, then new settings are required in groups 2 and 3 to maintain the same level of performance. A re-grading exercise was carried out and two new groups of settings have been calculated with the results listed in Table 6-21 and Table 6-22. There are therefore now three groups of settings with which the system can now adapt to better meet the prevailing fault levels. The time-current characteristics for the three groups at the three points in the grading paths are given in Figure 6-25 to Figure 6-27.

Table 6-21: Adaptive inverse overcurrent protection setting groups.

CB Location	***Group OC-1-I***		***Group OC-2-I***		***Group OC-3-I***	
	Pickup [$A_{primary}$]	***Time Multiplier***	***Pickup [$A_{primary}$]***	***Time Multiplier***	***Pickup [$A_{primary}$]***	***Time Multiplier***
Feeder	320	0.30	320	0.25	320	0.15
Mid-Point	160	0.25	160	0.2	160	0.1
RMU T-OFF	40	0.15	40	0.1	40	0.05

Table 6-22: Adaptive DT overcurrent protection setting groups.

CB Location	***Group OC-1-D***		***Group OC-2-D***		***Group OC-3-D***	
	Pickup [$A_{primary}$]	T_D	***Pickup [$A_{primary}$]***	T_D	***Pickup [$A_{primary}$]***	T_D
Feeder	2800	0.45	1900	0.45	1000	0.45
Mid-Point	2300	0.30	1600	0.30	750	0.30
RMU T-OFF	1900	0.15	1200	0.15	500	0.13

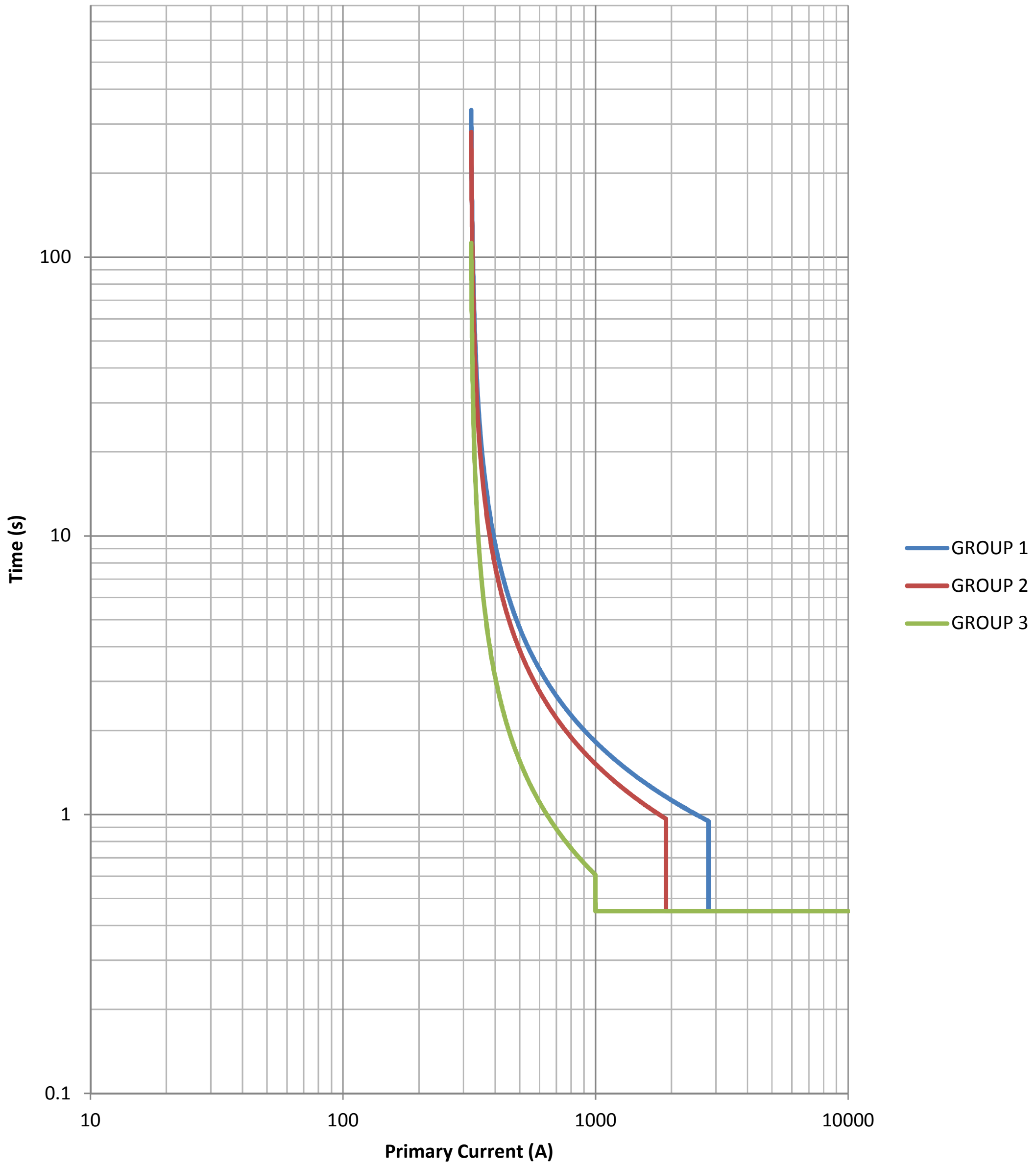

Figure 6-25: Feeder CB inverse overcurrent protection groups.

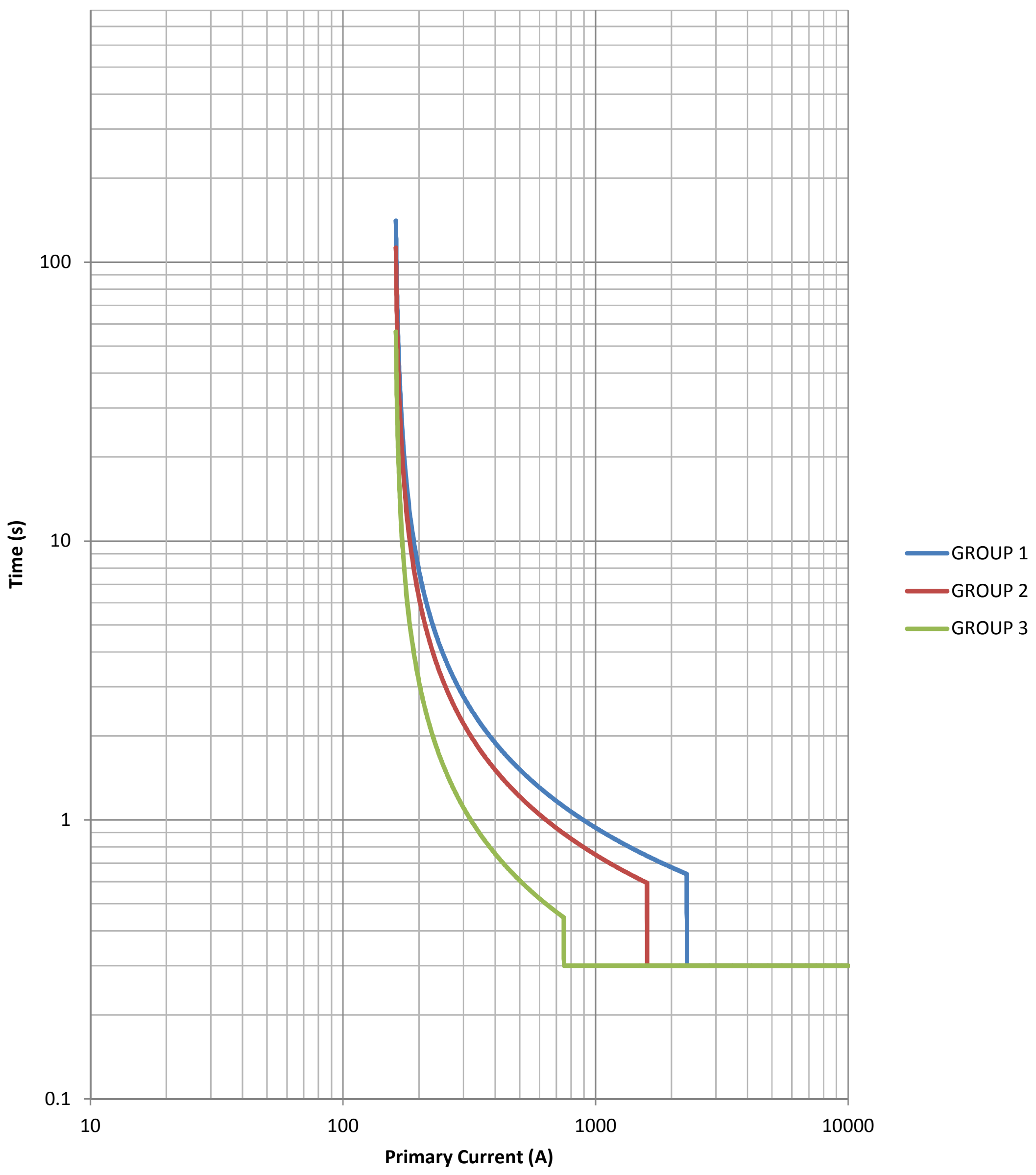

Figure 6-26: Mid-point CB inverse overcurrent protection groups.

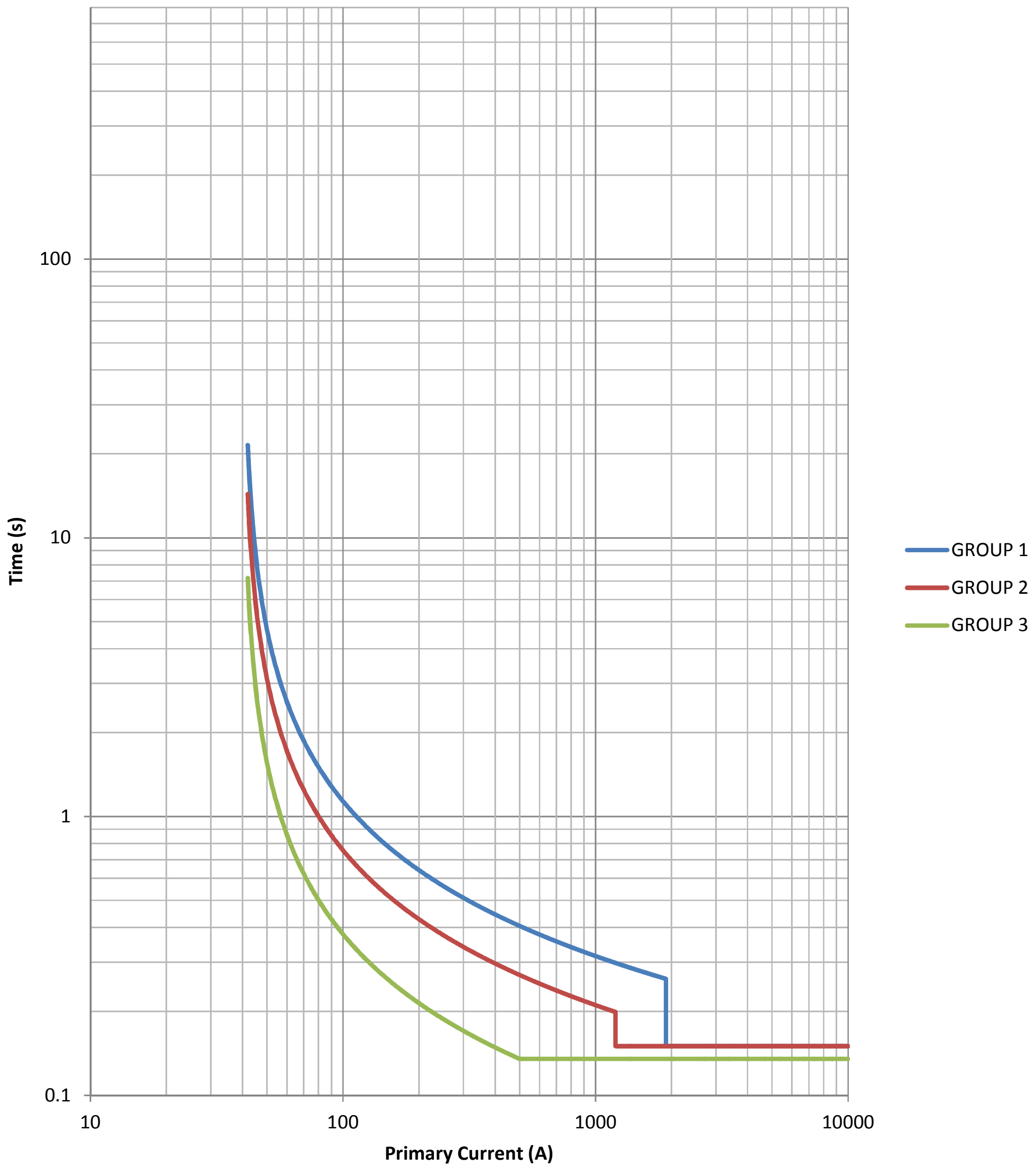

Figure 6-27: Secondary substation RMU T-Off overcurrent protection groups.

The logic for mapping the three settings groups to primary system changes is shown in Figure 6-28. Inputs are taken from the auxiliary contacts of the circuit breakers at the 33 kV interface to indicate islanding and from the management layer which passes a simple assessment of the generation currently active as being low, medium or high. For the scenarios developed this assessment primarily relates to the number of diesel generators in service at a given time: low – 0, medium – 2 and high – 3. Since this represents quite a simple criterion, this logic could in principle be implemented at the coordination layer with status signals coming directly from the diesel power station. However, future generation connections could offer other possibilities and, as a consequence, the functionality is allocated to the management layer. For example, the proportion of small to medium generation embedded across the network could increase to a level that initiates a change in settings group. If this were the case then access to the information contained within the EMS would need to be used to establish the overall fault level within the system and, potentially, could require a simplistic short-circuit calculation to be carried out. This increased level of complexity is functionally best suited to the management layer where it can be coordinated with the EMS and its resources (data and processing capability).

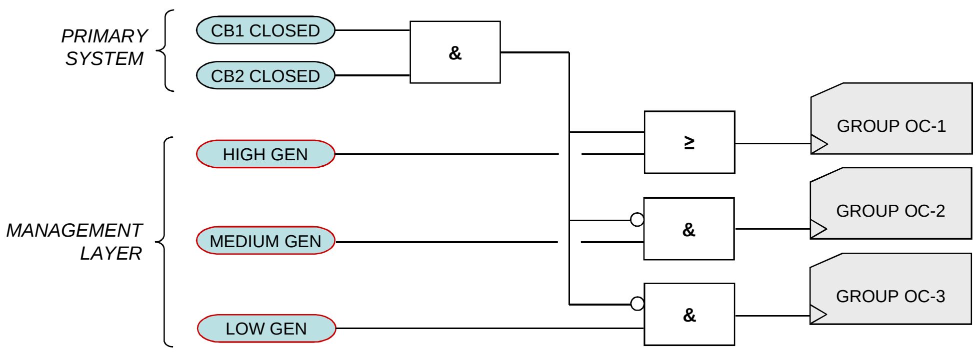

Figure 6-28: Coordination layer logic for adaptive overcurrent settings groups.

A transition diagram for the overcurrent settings groups and the corresponding system state is provided in Figure 6-29 where the triggers for moving between groups are marked. The diagram is at the relay level for all devices except those at generators where the overcurrent protection remains unchanged. As noted previously the execution and coordination layers are located on the same physical devices and thus the verification logic for the coordination layer is straightforward.

A set of flags can be used to record the success of a change in settings group and be communicated upwards to the management layer which is located remotely on the substation computer.

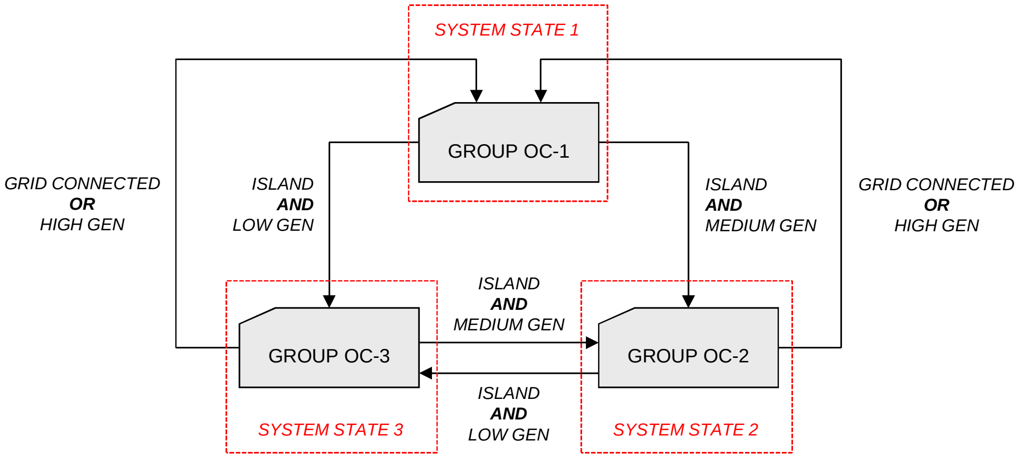

Figure 6-29: Transition diagram for adaptive overcurrent protection.

6.7.2.3 Performance Testing

This section focuses on the performance of the overcurrent protection should it fail to adapt as intended. The failure modes for the scheme have been identified and analysed based on the three transitions shown above in Figure 6-29 and is based on the process developed in Chapter 4. Transitions 1 – 2, 2 – 3 and 3 – 1 are set out separately as examples in Table 6-23 – Table 6-25 which include descriptions of the underlying failure, an assessment of its implications for protection performance and finally any mitigation measures that are recommended. Only two issues with medium risk were identified that require mitigation measures in these three examples (the two remaining transitions that have not been shown for brevity). Although for several failures either definite time functions are unable to trip or grading between two relays may be lost, sufficient backup functionality remains to ensure the overall integrity and safety of the scheme. In particular it is noted that from a safety perspective the most important relay to undergo correct adaptation is that of the feeder since this has the potential for disconnecting the highest level of unnecessary demand. However the failure of these devices is mitigated by the fact that the communication to this relay is within the substation and, in principle, significantly more reliable than those out to remote locations.

Table 6-23: Adaptive overcurrent transition 1 - 2.

Transition Fault	Description	Probability	Performance Assessment	Severity	Risk	Mitigation Measures (If Required)
1a	Failure of interface circuit breaker auxiliary contacts to provide correct islanded/grid connected staus indication.	LOW	No relays will adapt as intended and protection will remain in settings group 1. There is sufficient fault current for inverse function to trip but the clearance times will be increased. Maximum clearance time under backup conditions now approx. 1.2s. DT functions not able to trip.	MEDIUM	LOW	-
1b	Failure of EMS/management layer to correctly classify fault level.	MEDIUM	Relays may either remain in group 1 (refer to 1a assessment) or move to group 3. For this second group the clearance times and grading margins will be reduced due to the higher fault levels. Maximum clearance time under backup conditions now approx. 0.4s and grading margin < 0.2s. DT functions can trip.	MEDIUM	MEDIUM	Include additional source of information on fault level by monitoring export from diesel generation circuit as these contribute significantly to system fault level.
2a	Complete failure of the communications infrastructure covering the network.	LOW	No relays will adapt as intended and protection will remain in settings group 1. There is sufficient fault current for inverse functions to trip but the clearance times will be increased (refer to 1a assessment). DT functions not able to trip.	MEDIUM	LOW	-
2b	Partial failure of the communications infrastructure: feeder protection relay only.	LOW	Only the feeder relay will fail to adapt as intended. Maximum clearance time under backup conditions now approx 1.2s and grading integrity is maintained. DT function not able to trip in feeder relay.	MEDIUM	LOW	-
2c	Partial failure of the communications infrastructure: mid-point protection relay only.	MEDIUM	Only the mid-point relay will fail to adapt as intended. Grading integrity is maintained but more demand will be disconnected if feeder protection relay operates in backup.	LOW	LOW	-
2d	Partial failure of the communications infrastructure: T-off protection relay only.	MEDIUM	Only the T-Off relay will fail to adapt as intended. Grading integrity is maintained but more demand will be disconnected if feeder or mid-point relays operate in backup.	LOW	LOW	-
3	Failure of adaptive logic on physical devices.	LOW	Limited in scope to device unless type fault occurs across the system that affects a large number of relays.	LOW	LOW	-

Table 6-24: Adaptive overcurrent transition 2 - 3.

Transition Fault	Description	Probability	Performance Assessment	Severity	Risk	Mitigation Measures (If Required)
1a	Failure of interface circuit breaker auxiliary contacts to provide correct islanded/grid connected staus indication.	LOW	Circuit breaker status could wrongly indicate grid connected mode which would activate group 1. Maximum fault clearance under backup conditions approx. 1.8s. DT functions not able to trip.	MEDIUM	LOW	-
1b	Failure of EMS/management layer to correctly classify fault level.	MEDIUM	Relays may either switch to group 1 (refer to 1a assessment) or remain in group 2. For this second group no relays will adapt as intended . Maximum clearance time under backup conditions now approx 1.6s and grading integrity is maintained. DT functions not able to trip.	MEDIUM	MEDIUM	Include additional source of information on fault level by monitoring export from diesel generation circuit as these contribute significantly to system fault level.
2a	Complete failure of the communications infrastructure covering the network.	LOW	No relays will adapt as intended and protection will remain in settings group 2. Maximum clearance time under backup conditions now approx 1.6s and grading integrity is maintained. DT functions not able to trip.	MEDIUM	LOW	-
2b	Partial failure of the communications infrastructure: feeder protection relay only.	LOW	Only the feeder relay will fail to adapt as intended. Maximum clearance time under backup conditions now approx 1.6s and grading integrity is maintained. DT function not able to trip in feeder relay.	MEDIUM	LOW	-
2c	Partial failure of the communications infrastructure: mid-point protection relay only.	MEDIUM	Only the mid-point relay will fail to adapt as intended. Grading integrity is maintained but more demand will be disconnected if feeder protection relay operates in backup.	LOW	LOW	-
2d	Partial failure of the communications infrastructure: T-off protection relay only.	MEDIUM	Only the T-Off relay will fail to adapt as intended. Grading integrity is maintained but more demand will be disconnected if feeder or mid-point relays operate in backup.	LOW	LOW	-
3	Failure of adaptive logic on physical devices.	LOW	Limited in scope to device unless type fault occurs across the system that affects a large number of relays.	LOW	LOW	-

Table 6-25: Adaptive overcurrent transition 3 - 1.

Transition Fault	Description	Probability	Performance Assessment	Severity	Risk	Mitigation Measures (If Required)
1a	Failure of interface circuit breaker auxiliary contacts to provide correct islanded/grid connected staus indication.	LOW	No relays will adapt as intended and protection will remain in settings group 3. Grading margins now < 0.1s.	LOW	LOW	-
1b	Failure of EMS/management layer to correctly classify fault level.	MEDIUM	Relays may either remain in group 3 (refer to 1a assessment) or switch to group 2. For this second group no relays will adapt as intended . Grading margins now < 0.15s.	LOW	LOW	-
2a	Complete failure of the communications infrastructure covering the network.	LOW	No relays will adapt as intended and protection will remain in settings group 3. Grading margins now < 0.1s.	LOW	LOW	-
2b	Partial failure of the communications infrastructure: feeder protection relay only.	LOW	Only the feeder relay will fail to adapt as intended. Grading lost between feeder and mid-point/T-Off relays potentially causing loss of whole feeder.	MEDIUM	LOW	-
2c	Partial failure of the communications infrastructure: mid-point protection relay only.	MEDIUM	Only the mid-point relay will fail to adapt as intended. Grading margin between mid-point and T-Off relays <0.1s.	LOW	LOW	-
2d	Partial failure of the communications infrastructure: T-off protection relay only.	MEDIUM	Only the T-Off relay will fail to adapt as intended. Grading integrity is maintained.	LOW	LOW	-
3	Failure of adaptive logic on physical devices.	LOW	Limited in scope to device unless type fault occurs across the system that affects a large number of relays.	LOW	LOW	-

6.7.3 Adaptive Transient Stability Protection

The dynamic analysis reported previously indicated that the CHP generator connected to one of the feeders has a low CCT and may pole-slip for faults cleared in backup timescales. This is an issue for low demand conditions as represented by 20 % demand scenario in which this generator provides an important contribution to balancing the system. Under these circumstances its loss could result in frequency instability as there is a low level of spinning reserve available to regulate its output and make up the loss of generation output. To minimise this risk, this section outlines a further group of overcurrent settings that can be activated when the system moves into a state comparable to the 20 % demand scenario.

6.7.3.1 Assess Scenarios

This issue occurs in the 20 % demand scenario where the CHP generator plays an important role in balancing the system and, possibly, regulating system frequency. Within a scenario of this type there are only a few generators connected that are able to act to provide frequency regulation and, in this particular case, only the gas turbine will remain in service. Although in the base scenario this generator will be able to make up the lost output with this particular demand and dispatch, this will not be the case after only a relatively small increase in demand or reduction in the number of microgenerators connected. Given that an operating state will encompass a band of demand or generation about the base case, it is considered that some form of mitigation is required. It is proposed that a single additional settings group is developed to cover a low demand system state such as this discussed above.

6.7.3.2 Define Functions, Settings Groups and Map to Changes

To mitigate the impact of the low generator CCT, the fault clearance times within the network must be reduced even under backup conditions and it is suggested that this is achieved by modifying the settings of the mid-point relay on the feeder with the CHP generator connected and the overcurrent functions at the other feeder relays. The group 3 (OC-3) definite time overcurrent functions will be adapted at these locations to have time delays of 250 ms by group TR-1. Although this adaptation will increase the level of demand disconnected (effectively removing the mid-point from the other feeders from the grading paths), it is considered permissible since it significantly reduces the risk of a system shutdown due to insufficient reserve should the CHP generator trip to avoid instability. A summary of the additional settings group is provided in Table 6-26 below which indicates at which circuit breaker location changes are required.

Table 6-26: Adaptive transient stability protection setting groups.

CB Location	*Feeder*	*Group TR-1*	
		Pickup [$A_{primary}$]	T_D
Feeder	≠1	1000	0.25
Mid-Point	1	750	0.25

This settings group will triggered either by the management layer classifying the system state as having a particular reliance on the CHP generator based on the EMS functionality or, more directly, by the coordination layer monitoring the status of the diesel generator feeder circuit breaker status or power flow. For this latter method, it is noted that the low demand scenario has no diesels in service and that these, in general, are used to provide the majority of the spinning reserve available to the system in islanded mode.

The coordination layer logic and transition diagram are shown in Figure 6-30 and Figure 6-31 respectively. These have been designed on the basis that since the activation of this transient stability group has the effect of reducing the overcurrent scheme discrimination, it must only be activated when both inputs to the coordination logic are present. Thus the removal of either of the two inputs will initiate a return to the original settings group.

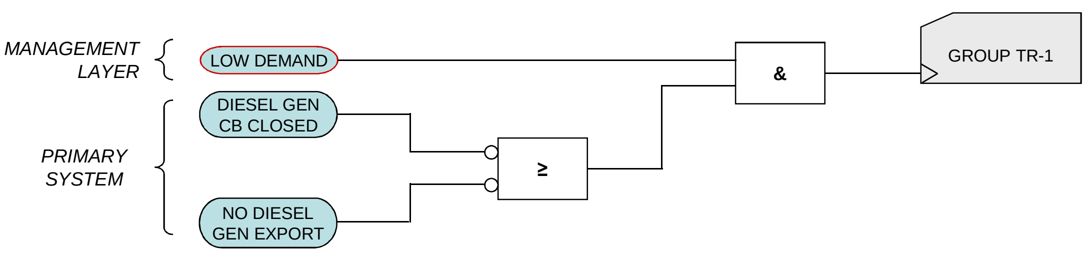

Figure 6-30: Coordination layer logic for adaptive transient stability groups.

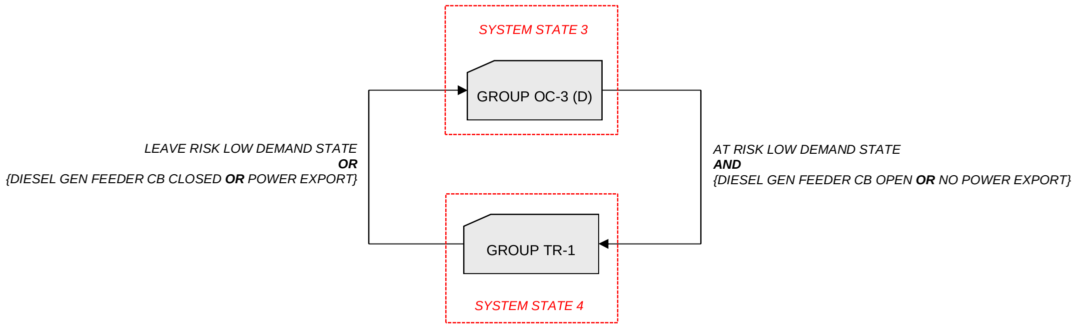

Figure 6-31: Transition diagram for adaptive transient stability protection.

6.7.3.3 Performance Testing

The failure modes and effects for this adaptation of the protection have been reviewed and summarised in Table 6-27 and Table 6-28. This table shows that the risk of transition failures for this adaptive protection is considered to be low. The inputs to the logic are either local within the primary substation or from the DMS in assessing the state of the system. The failure of the protection to adaptive as intended would not leave the system exposed in an unprotected state.

6.7.4 Adaptive Islanding Protection

The detection of an islanded condition (i.e. loss of mains/grid) remains an essential function to be included within the protection applied to this system. In a conventional system where islanding is to be avoided, this function is installed at all generators and set to detect the change in some measured or derived quantity (e.g. voltage vector or ROCOF) post-islanding. The settings must be sensitive enough to detect islanding in a near balance condition, whilst at the same time remain stable during disturbances such as faults. However for a system such as this which can be intentionally islanded, the application of this function becomes more onerous.

The function must still be installed at all generators but, in addition, it must also be applied at the boundary of the system where isolation from the grid can take place. At this location its purpose is to detect when an external islanding event has occurred and act to trip the local circuit breakers in order to permit a local stable system to be established. The islanding detection at the generation must act as a backup should this fail and, furthermore, detect inadvertent local islanding occurring within the system when isolated from the grid. It is proposed that conventional ROCOF principles are used to provide islanding detection for this system.

Table 6-27: Adaptive transient stability protection transition 1 - 2.

Transition Fault	Description	Probability	Performance Assessment	Severity	Risk	Mitigation Measures (If Required)
1	Failure of diesel generator circuit breaker status indication to indicate that the units are not connected.	LOW	No impact unless power measurement input also fails.	LOW	LOW	-
2	Failure of diesel generator power measurement to indicate that only a small power import is present (supply of unit auxiliaries).	LOW	No impact unless status indication input also fails.	LOW	LOW	-
3	(1) AND (2)	LOW	Settings group will not be activiated because of the requirementfor both management layer and local indication inputs to be triggered. Potential for loss of islanded system if fault cleared on backup occurs and CHP generator trips.	MEDIUM	LOW	-
4	Incorrect management layer classification of low demand state.	LOW	Settings group will not be activiated because of the requirementfor both management layer and local indication inputs to be triggered. Potential for loss of islanded system if fault cleared on backup occurs and CHP generator trips.	MEDIUM	LOW	-
5	(1) AND (2) AND (3)	LOW	Settings group will not be activiated. Potential for loss of islanded system if fault cleared on backup occurs and CHP generator trips.	MEDIUM	LOW	-
6	Failure of communication between management and coordination layers located on physically different devices.	LOW	Settings group will not be activiated because of the requirementfor both management layer and local indication inputs to be triggered. Potential for loss of islanded system if fault cleared on backup occurs and CHP generator trips.	MEDIUM	LOW	-
7	Failure of adaptive logic on physical devices.	LOW	Limited in scope to device unless type fault occurs that affects a large number of relays.	MEDIUM	LOW	-

Table 6-28: Adaptive transient stability protection transition 2 - 1.

Transition Fault	Description	Probability	Performance Assessment	Severity	Risk	Mitigation Measures (If Required)
1	Failure of diesel generator circuit breaker status indication to indicate that the units are connected.	LOW	No impact unless power measurement input also fails.	LOW	LOW	-
2	Failure of diesel generator power measurement to indicate that there is power export.	LOW	No impact unless status indication input also fails.	LOW	LOW	-
3	(1) AND (2)	LOW	Settings group will not be activiated because of the requirementfor both management layer and local indication inputs to be triggered. Potential for loss of demand/generation if faultoccurs.	MEDIUM	LOW	-
4	Incorrect management layer classification of medium/high demand state.	LOW	Settings group will not be activiated because of the requirementfor both management layer and local indication inputs to be triggered. Potential for loss of demand/generation if faultoccurs.	MEDIUM	LOW	-
5	(1) AND (2) AND (3)	LOW	Settings group will not be activiated. Potential for loss of demand/generation if faultoccurs.	MEDIUM	LOW	-
6	Failure of communication between management and coordination layers located on physically different devices.	LOW	Settings group will not be activiated. Potential for loss of demand/generation if faultoccurs.	MEDIUM	LOW	-
7	Failure of adaptive logic on physical devices.	LOW	Limited in scope to device unless type fault occurs that affects a large number of relays.	MEDIUM	LOW	-

6.7.4.1 Assess Scenarios

The studies presented in sections 6.6.3 and 6.6.4 demonstrate that the frequency disturbances immediately post-islanding or the loss of generation when in islanded mode have the potential to trip islanding protection that has been deployed with typical settings (for example a setting of 0.2 Hz/s which can be derived from the table provided in G59/2 section 10.5.7.1 [6.1] and set with a time delay of 0.4 s). As mentioned above, these functions are located both at the boundary of the system and at each of the local generators. The function located at the boundary of the system is only used when grid connected and is thus not exposed to these transients. However, those at the generators will experience these challenging conditions in which the settings that are suitable for grid connected operation are not appropriate for use when islanded. It is proposed that these functions have two groups of settings that are adapted when the transition from grid connected to islanded operation (or vice versa) occurs.

Although the ROCOF setting for the islanding detection function at the boundary does not need adaptation, the time delay setting could be reduced if the net power flow across the boundary is low and the generation capability is considered to be sufficient to meet the needs of the system post-islanding. Under these conditions moving to islanded mode will not result in additional transients in relation to the power imbalance and may limit the system's exposure to those caused by external factors. For example, a large captured external demand due to remote islanding could cause a rapid drop in system frequency. If the net power flow was small pre-disturbance then the best course of action would be to initiate local isolation more quickly as a means of protecting the local system. It is noted that although reducing the time delay could be considered undesirable with regard to the conventional application of this protection due to the potential for reduced stability, for this application its adaptation only occurs at a time when the transition to islanded mode would involve minimal imbalance transients.

6.7.4.2 Define Functions, Settings Groups and Map to Changes

The function at the boundary is set with two settings groups (IB-1 and IB-2) that have the same ROCOF value of 0.2 Hz/s. However two different time delays of

0.2 s and 0.4 s are used which correspond to low and high imbalance conditions respectively. A threshold of 1.2 MW is proposed (50 % of the generation reserve for the 20 % demand scenario) for the transition between the two settings groups.

The generator functions are also provided with two groups as follows:

- Grid connected (IG-1): set with the same ROCOF setting but with an additional time delay of 0.2 s to coordinate with the function at the boundary should it fail to act as intended.
- Islanded (IG-2): under this condition a higher ROCOF value of 1 Hz/s with a time delay of 0.75 s is proposed. These values are based on the onerous conditions that are likely to occur using the worst case condition of the loss of a diesel generator with low spinning reserve present in the system. Although these values are significantly higher than typical settings, a range of internal islanding scenarios have been considered to check that they are still suitable for detecting and tripping generation if necessary.

The transition between settings groups at the generators will be initiated by the status of the boundary circuit breakers as communicated by the associated merging unit. The coordination layer logic and transition diagram for the functions are provided in Figure 6-32 and Figure 6-33 respectively.

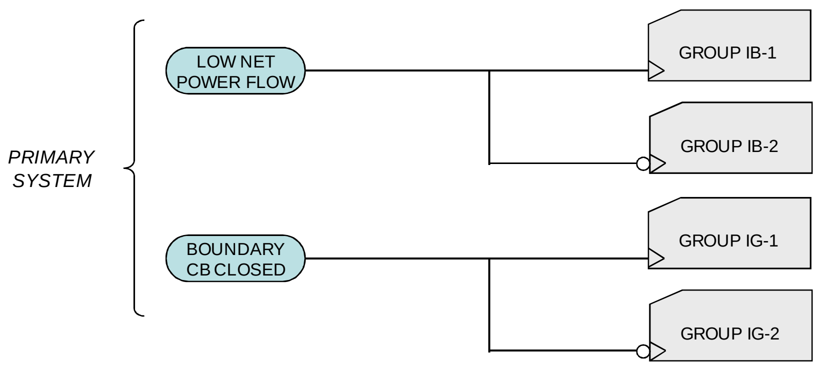

Figure 6-32: Coordination layer logic for islanding detection settings groups.

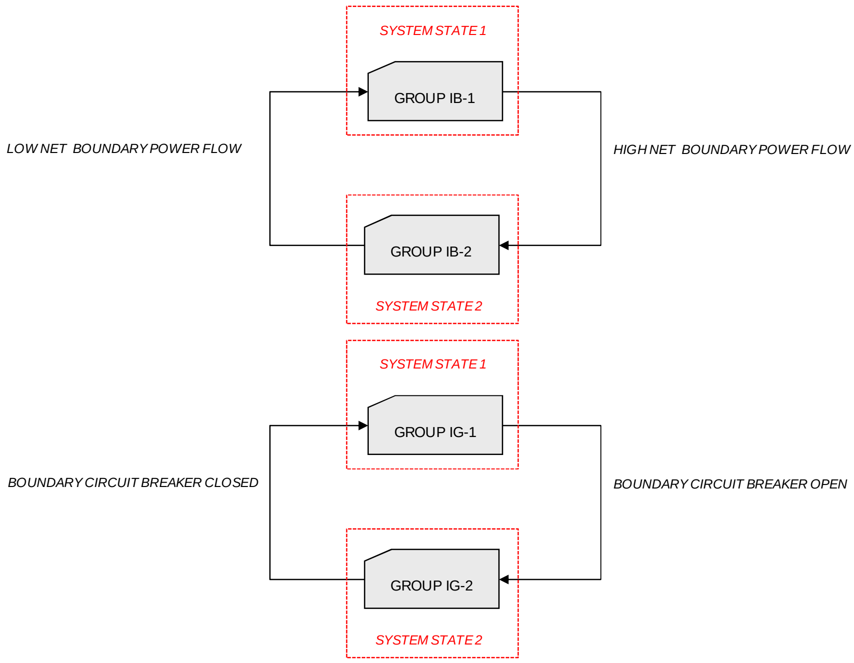

Figure 6-33: Transition diagram for islanding detection protection.

6.7.4.3 Performance Testing

The failure modes and effects for this adaptation of the protection have been reviewed and summarised in Table 6-29 and Table 6-30. These tables show that the risk of transition failures for this adaptive protection is considered to be low for the majority of cases. However the loss of communication of the islanding status has been found to given medium/high risk levels and mitigation measures have therefore been proposed:

- Transition 1 – 2 (Medium): A widespread loss of communication could lead to an elevated risk of generator tripping for severe disturbances when islanded due to the grid connected settings remaining in use. The proposed mitigation for this is to consider using wire based communication for key generators such as the diesel or CHP units to limit the scope of the risk.
- Transition 2 – 1 (High): For this case the loss of communication would result in the less sensitive islanded settings being in use when grid connected. This could result in the non-detection of an island condition. The mitigation measure proposed for this is to always revert to the grid connected settings on loss of communication is detected by the generator relay.

Table 6-29: Adaptive islanding detection protection transition 1 - 2.

Transition Fault	Description	Probability	Performance Assessment	Severity	Risk	Mitigation Measures (If Required)
1	Failure of interface circuit breaker auxiliary contacts to provide correct islanded/grid connected staus indication.	LOW	No relays adapt as intended with the grid connected settings still being in use. Risk of widespread generator tripping for severe frequency transients in islanded mode.	MEDIUM	LOW	-
2	Failure of communications between boundary circuit breaker merging unit and generator protection relays.	MEDIUM	Some relays not adapt as intended with the grid connected settings still being in use. Risk of widespread generator tripping for severe frequency transients in islanded mode.	MEDIUM	MEDIUM	Consider using non-radio based communication for key generators (i.e. diesel and CHP units).
3	Failure to detect high net boundary power flow (i.e. power measurement).	LOW	Fast islanding functionality not available.	LOW	LOW	-
4	Failure of adaptive logic on physical devices.	LOW	Limited in scope to device unless type fault present.	LOW	LOW	-

Table 6-30: Adaptive islanding detection protection transition 2 - 1.

Transition Fault	Description	Probability	Performance Assessment	Severity	Risk	Mitigation Measures (If Required)
1	Failure of interface circuit breaker auxiliary contacts to provide correct islanded/grid connected staus indication.	LOW	No relays adapt as intended with the islanded settings still being in use. Risk of islanded conditon not being detected for local islands within system boundary.	LOW	LOW	-
2	Failure of communications between boundary circuit breaker merging unit and generator protection relays.	MEDIUM	Some relays not adapt as intended with the islanded settings still being in use. Risk of that the external islanded conditon will not be detected.	HIGH	MEDIUM	On loss of communications revert to grid connected settings.
3	Failure to detect low net boundary power flow (i.e. power measurement).	LOW	Fast islanding functionality remains in use when it is not the best option.	LOW	LOW	-
4	Failure of adaptive logic on physical devices.	LOW	Limited in scope to device unless type fault present.	LOW	LOW	-

6.7.5 Adaptive Under Frequency

All power systems require that a suitable under frequency load shedding scheme is installed to support the system when insufficient generation capacity is available to meet demand. These schemes are generally set below the statutory frequency band as load should only be shed from a system under extreme circumstances when frequency stability is under threat. The study results presented previously for the islanded system demonstrated that the loss of a large generator (such as one of the diesel units) when the available spinning reserve is low can make maintaining system frequency problematic. This section presents a proposal for an adaptive under frequency load shedding scheme that offers the potential for superior performance over a more conventional approach.

6.7.5.1 Assess Scenarios

The five scenarios developed for this system represent plausible generation dispatches across the range of system demand which have reasonable levels of spinning reserve available. However when these are stress tested with elevated demand levels low spinning reserve can be shown to occur. Taking the 60 % scenario as an example, Figure 6-34 shows the system frequency in response to the loss of one of the diesel generators for the base case and the stressed conditions of plus 20 % and 40 % demand levels.

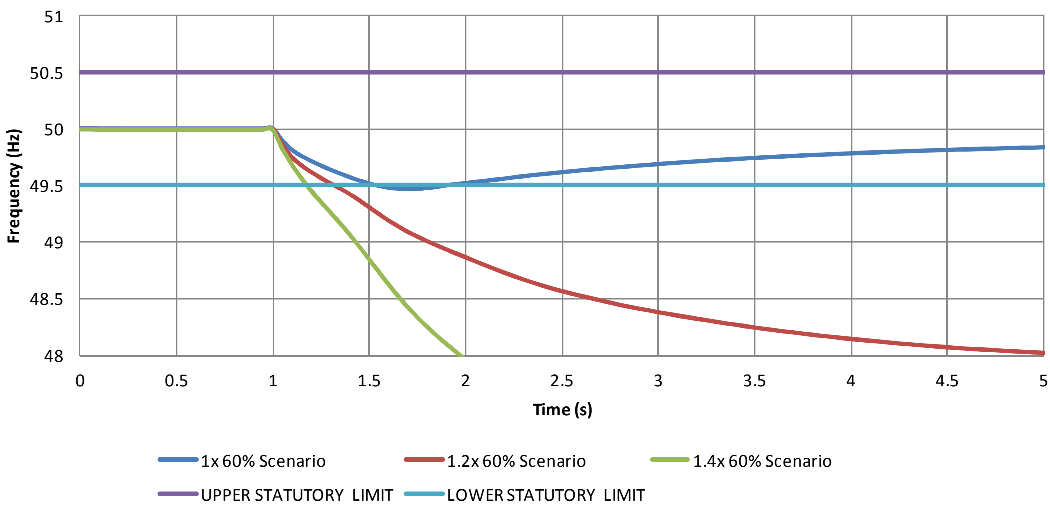

Figure 6-34: 60 % scenario – loss of largest generator (DE #1) – frequency.

Given the rapid and uncontrolled fall in system frequency under stressed conditions, it is proposed that a faster acting load shedding scheme be used to take corrective action to limit the depth of the frequency transient.

6.7.5.2 Define Functions, Settings Groups and Map to Changes

The scheme has been designed on the basis of three load shedding stages with each corresponding to one third of the secondary substations connected to the system. Within each primary substation when the stage is triggered it will act to trip the RMU T-off circuit breaker unless a reverse power flow back into the HV network is detected. Two groups of settings have been derived to be applied under normal and low levels of spinning reserve. For the latter condition, the philosophy of the scheme is that the stages are set with higher frequency triggers such that demand is shed more quickly. However these should only be activated for the low spinning reserve condition as under normal conditions they could cause more demand than is necessary to be disconnected. The two settings groups are listed in Table 6-31 for each of the three stages. It can be seen that the UF-2 group highest frequency trigger has been set at the lower statutory limit.

Table 6-31: Adaptive under frequency protection settings groups.

Stage	*Group UF-1*		*Group UF-2*	
	f [Hz]	*T_D (s)*	*f [Hz]*	*T_D (s)*
A	49.0	0.0	49.5	0.0
B	49.0	0.5	49.5	0.5
C	48.5	0.0	49.0	0.0

To demonstrate the effectiveness of the scheme, the previous study of the loss of one of the diesel generators is repeated for the 60 % scenario (approximately 4.5 MW of spinning reserve as shown in Table 6-12) for each of the two settings groups. The system frequency response is shown in Figure 6-35 and the total connected demand in Figure 6-36. These figures show that for the base case the UF-2 group results in unnecessary demand disconnection after the loss of the diesel generator (for the UF-1 group no action is triggered). In contrast for the two elevated demand cases, the UF-2 group provides a higher frequency nadir than would be the case with the UF-1 group.

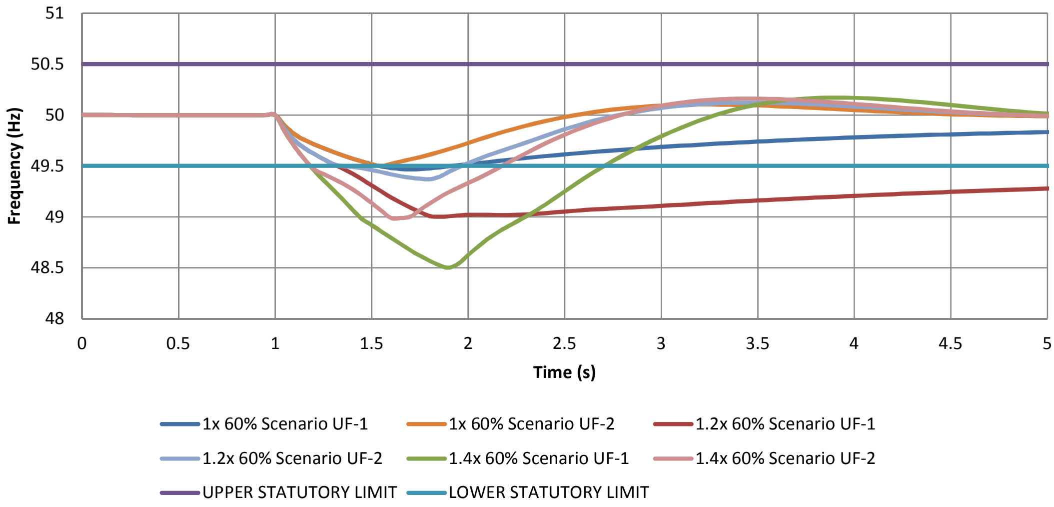

Figure 6-35: 60 % scenario – loss of largest generator (DE #1) with UF – freq.

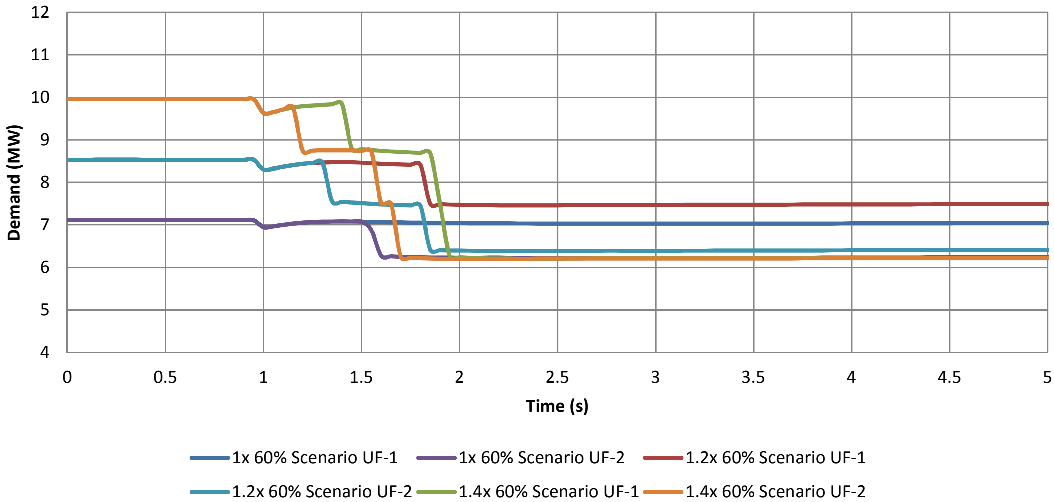

Figure 6-36: 60 % scenario – loss of largest generator (DE #1) with UF – load.

The transition between settings groups at the generators will be initiated by the management layer in response to the EMS classifying the system as having low spinning reserve. The coordination layer logic and transition diagram for the functions are provided in Figure 6-37 and Figure 6-38: Transition diagram for under frequency protection. respectively.

Figure 6-37: Coordination layer logic for under freq. protection settings groups.

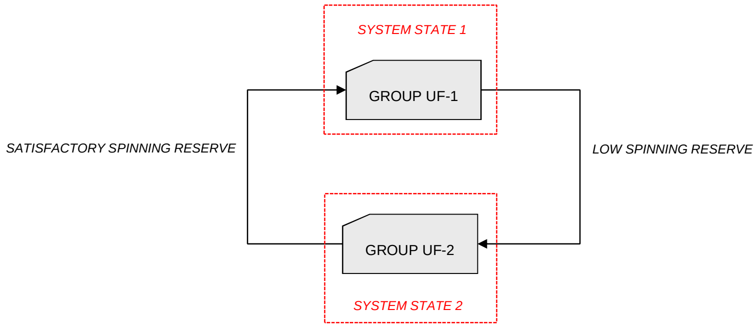

Figure 6-38: Transition diagram for under frequency protection.

6.7.5.3 Performance Testing

The failure modes and effects for this adaptation of the protection have been reviewed and summarised in Table 6-32 and Table 6-33. These tables show that the risk of transition failures for this adaptive protection is considered to be low for the majority of cases. However the loss of communication between the primary and secondary substations has been found to result in a medium risk for fault 2 in transition 2 – 1 in which the scheme would remain with UF-2 in service exposing the system to unnecessary demand shedding. The mitigation measure of reverting back to the conventional settings group of UF-1 proposed when loss of communication is detected.

Table 6-32: Adaptive under frequency protection transition 1 - 2.

Transition Fault	Description	Probability	Performance Assessment	Severity	Risk	Mitigation Measures (If Required)
1	Failure of EMS/management layer to identify low spinning reserve conditon.	LOW	Relays at secondary substations remain in group UF-1 meaning that enahanced performance is unavailable.	LOW	LOW	-
2	Failure of communications between management layer at primary substation and relays at secondary substations.	MEDIUM	Relays at secondary substations remain in group UF-1 meaning that enahanced performance is unavailable.	LOW	LOW	-
3	Failure of adaptive logic on physical devices.	LOW	Limited in scope to device unless type fault present.	LOW	LOW	-

Table 6-33: Adaptive under frequency protection transition 2 - 1.

Transition Fault	Description	Probability	Performance Assessment	Severity	Risk	Mitigation Measures (If Required)
1	Failure of EMS/management layer to identify normal spinning reserve conditon.	LOW	Relays at secondary substations remain in group UF-2 meaning that more demand than is necessary may shed or the first stage accidentally triggered.	MEDIUM	LOW	-
2	Failure of communications between management layer at primary substation and relays at secondary substations.	MEDIUM	Relays at secondary substations remain in group UF-2 meaning that more demand than is necessary may shed or the first stage accidentally triggered.	MEDIUM	MEDIUM	On loss of communications revert to UF-1 settings.
3	Failure of adaptive logic on physical devices.	LOW	Limited in scope to device unless type fault present.	LOW	LOW	-

6.8 *Diagnostics*

The diagnostics functionality proposed for this protection scheme is intended to provide access to conventional disturbance recorder files, as well as information that can be used to assess the performance of the adaptive aspects of its design. Figure 6-39 provides an overview of this functionality with respect to the three layers present in the scheme architecture and brings together the functions described separately for each layer in Chapter 3. Each of the layers is described separately in the sections that follow. The intention is to provide enhanced performance by structuring the collection and interpretation of fault recordings and proactively monitoring relay hardware/software and the adaptive process itself. In so doing the likelihood of so called hidden protection failures occurring will be reduced and improve the robustness of the adaptive functionality by providing suitable checks and enabling remedial action to be taken if required in response to failures.

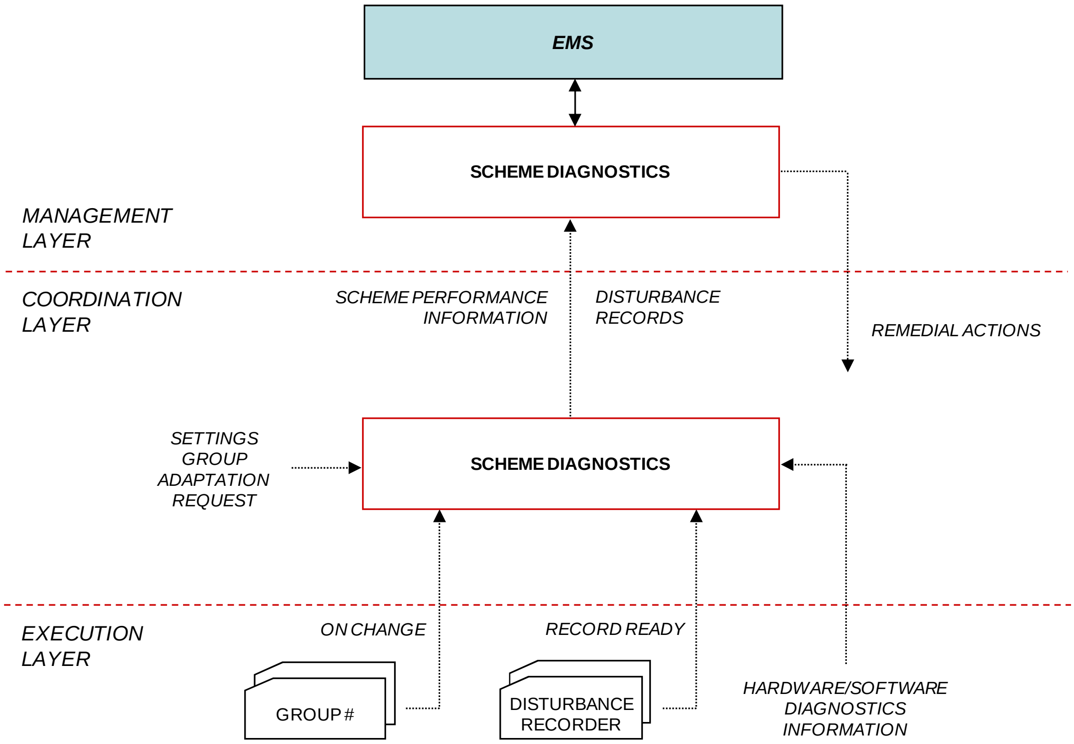

Figure 6-39: Overview of scheme diagnostic functionality.

6.8.1 Execution Layer

The execution layer at the lowest level of the architecture includes disturbance recorder functions with their triggers set according to the particular group of settings that are applied to the various protection functions. When triggered and the data recording is complete, the disturbance recorder will provide the coordination layer with the data files (e.g. in COMTRADE format) and details of the initiating protection function. More routinely, the execution layer will also confirm the successful changing of settings groups in response to commands from the coordination layer. A further diagnostic role for the execution layer is to provide indications of any physical hardware faults or software issues (e.g. instrument transformer supervision or other watchdog functions). For this particular adaptive scheme disturbance recorders should be setup for each overcurrent, loss of mains and under-frequency protection function on the various relays spread across the system.

6.8.2 Coordination Layer

The coordination layer firstly checks that confirmation has been received from the execution layer of any settings group changes that have been requested. If successful these confirmations will be logged and sent to the management layer to provide notification the current protection state. However if no confirmation is received within a defined time window then this is also sent to the management layer along with the last known settings group in use. This information would be supplemented by any available diagnostics information from the relay hardware/software which might be associated with the failure to adapt as intended. Diagnostics information would also be passed separately to the management layer if required should a hardware or software failure occur at any time.

In addition, the coordination layer will pass upwards any disturbance recorder records that are created within the execution layer and ensure that additional contextual information is appended. For example the active settings group, function and relay identifier.

6.8.3 Management Layer

At the management layer the information passed upwards from the lower two layers will be interpreted to assess the performance of the scheme in response to both primary system faults and changes that require the adaptation of settings groups, as well as hardware, software or communication infrastructure faults. The outcome of this could be that no action is required if the impact on performance is small or to initiate some form of remedial action. The management layer may initiate remedial action such as requesting an alternative settings group change on other relays or signal the EMS to take some form of control based action. For example, the following actions could be initiated for the under-frequency load shedding and transient stability adaptive protection:

- For the case of the under-frequency load shedding scheme, consider the scenario that a significant number of relays have functions disabled because of reverse power flows from the LV network up into the HV network. Under these circumstances the effectiveness of the load shedding scheme could be compromised. The management layer would be used to assess the performance of the scheme using the remaining load shedding points and may, if required, instruct the coordination layer to change to an alternative settings group to maximise the capability at other relays locations. In other words an alternative settings group that uses a higher level of load shedding could be used to make up the lost capability.

- If a number of the relays associated with the transient stability adaptive function failed to adapt as intended when the system is heavily reliant upon the CHP generation (i.e. the risk of it having to trip being increased due to potentially longer fault clearance times), the management layer could be set to signal the EMS with a view to connect further generation to increase the reserve. This is an example of the potential for interaction between protection and control systems in order to improve the performance of the local power system.

6.9 *Chapter Summary*

This chapter has presented research associated with the development of an adaptive protection scheme which can permit the intentional islanding of an area of 11 kV distribution network. The design methodology developed in Chapter 3 was applied to illustrate its main stages using an example where its functionality could be of use.

A study system was presented that is representative of a network to be found in the UK and included a range of generation types connected at both LV and HV. To analyse the system, a detailed model and a set of scenarios was developed that covered the range of generation/demand levels that could occur in grid connected and islanded modes of operation. These scenarios allowed the performance of the existing overcurrent protection to be checked and the dynamic behaviour of the islanded system to be investigated in response to faults, isolation from the grid and the sudden loss of generation. The analysis found that the overcurrent protection required adaptation to better reflect the state of the primary power system as it underwent changes and, in addition, other system protection elements also benefited from having adaptive functionality. These additional system functions included under-frequency load shedding and islanding detection (loss of mains/grid).

Based on these findings, an adaptive protection scheme for the network was developed based on the three layers of the architecture. The settings groups were established for the execution layer, logic for the coordination layer and the tasks for the management layer defined. These were made possible by identifying what data sources were available to detect the primary system change and how these should be communicated and interpreted. The settings groups were identified to cover the full range of scenarios based on a rigorous analysis of the system performance.

The impact of the scheme failing to adapt as intended was also studied using the methodology discussed in Chapter 4 with the application of a basic failure mode and effects analysis. It was found that the scheme is robust and can tolerate the failure of some relays or individual elements to adapt as intended and still maintain a satisfactory level of performance. Finally the implementation of diagnostics functionality was discussed.

6.10 Chapter References

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7 Conclusions & Future Work

The research presented in this thesis has addressed what enhancements may be required in the application of power system protection as changes are made to both how networks operate and what types of equipment are connected in the future. The scope of the work included, as example applications, the creation of microgrids within LV networks as well as the islanded operation of a HV 11 kV network to cover the lower levels of distribution systems. It concentrated on how existing protection functions can be combined or adapted to better reflect the status of the primary power system, rather than the creation of entirely new algorithms. The specific conclusions drawn from the research presented in this thesis are given below. They are then followed by a discussion of potential future avenues of investigation that could be taken forward to further research in this field.

7.1 Conclusions

The conclusions from the research are grouped below based on the background and drivers for adaptive protection, followed by the proposal of a design methodology and functional architecture for adaptive protection schemes, and finally the two application examples used.

7.1.1 Background and Drivers for Adaptive Protection

An initial literature review in Chapter 3 demonstrated that although over the years there has been a significant level of research activity within the area of adaptive protection, this has not been followed by widespread implementations. At the root of this observation are two shortcomings in the previously reported work which have been identified and considered.

Firstly, the need for widespread adaptive protection has not presented itself as networks are still only evolving towards such concepts as the smart grid where the primary system will undergo frequent changes during the course of normal operation. Until this becomes a reality[28], the need to adapt protection does not routinely exist

[28] It is recognised that significant progress is now being made as interest in smart grid technologies is being driven by a supportive regulatory environment and associated funding mechanisms (e.g. Ofgem's low carbon network fund in the UK).

except for applications where localised changes to a small number of settings on a few relays are required (e.g. in industrial power systems). Typically only a few local inputs are required and these would normally be obtained using hardwired local inputs to the relay. Moreover, some requirements on protection, particularly at distribution have not been technically demanding since the networks have been relatively passive in nature with low levels of automation. This is rapidly changing as generation and automation equipment are connected, as well as more sensitive loads and increasing customer and indeed regulator expectations in terms of quality and security of supply. These factors will influence how protection is designed as they will have an impact on the performance criteria used as part of this process. For example, automated reconfiguration has the potential to dynamically alter the structure of grading paths, raise or lower fault levels, and alter where in the network topology generation is connected. All three of these could have a serious impact upon coordination, sensitivity, speed of response and stability depending on the particular system conditions. In the majority of instances, where necessary, adapting the settings of particular functions or, combining certain functions as the system changes can overcome these performance issues. This thesis considered this approach rather than the on-line recalculation of settings.

Secondly, the previously reported work tended to concentrate on the detail of a particular function or scheme such as a new approach to on-line settings calculation or a novel signal processing technique. It did not consider how, in principle, a safety critical system should be robustly designed to adapt in response to primary system changes. Moreover, one reason that has been perceived as a barrier to adopting adaptive protection is concern over the protection failing, for whatever reason, to adapt as intended with the result being potentially dangerous or costly non- or mal-operation. Little attention was given to how the scheme is designed to be intrinsically fail safe in response to these failures whilst providing some minimum level of performance. This is particularly important for schemes that are distributed over a wide area where full or partial communication failures need to be carefully considered. Therefore, it is important that the protection designer must fully understand process by which protection will adapt and the failure modes that this introduces into the overall scheme.

7.1.2 A Design Methodology & Functional Architecture for Adaptive Protection

The concept of adaptive protection was considered from first principles as a starting point for analysing it in some detail. The process and stages inherent within adaptive protection were considered in order to identify the key functionality and relationships with other systems or data sources providing primary system status information (e.g. a local EMS or network automation scheme controller). This was necessary in order to separate the concept from any scheme specific issues and serve as the basis for developing a straightforward design methodology.

The design methodology developed as part of this research is intended to ensure that robust designs are realised that take into account the full range of configurations or states that the primary system have and move between during operation. It begins by creating operational scenarios and then assessing the performance of any existing protection against the applicable performance criteria. It is important that the scenarios not only cover normal operating conditions, but also stressed conditions where control systems have either performed poorly or incorrectly. For example this could relate to a local EMS in an islanded system HV system that is unable to maintain a good level of spinning reserve or voltage profile. The creation of scenarios is followed by the creation of new groups of settings or functions as required if the existing protection is not satisfactory and then the performance testing once all groups have been created. The performance testing includes checking that the logic intended to adapt the settings functional correctly given the inputs from the primary system as well as analysing the potential failure modes within the adaptation process. This second aspect is very important as it is here that concerns over reliability are centred given the likelihood of input data coming from remote locations and must be addressed by the designer. In itself the design methodology is simple, but its careful application will assist in overcoming some of the barriers to the adoption of the adaptive protection concept by ensuring the probability of unforeseen primary system configurations or states is minimised.

It was noted that when the concept of adaptive protection is analysed the functions required form a hierarchy with each level becoming more abstracted as it moves away from the basic signal processing for protection functions at the bottom.

A novel functionally abstracted three layer architecture was defined as a key contribution that moves up from the basic signal processing in an execution layer, to the adaptive logic in the coordination layer and finally to the management layer where interactions with other high level systems are implemented. The separation of the execution of the actual protection functions from the higher adaptive functionality provides a clearer structure during the design process and once the scheme is in service. The layers of the architecture need not be located on a physical device but rather distributed as required within a single substation and beyond depending on the role of the protection. This also permits legacy protection devices to be incorporated that may lack the enhanced functionality to implement some of the higher level functionality. For example some early numerical relays may not have an extensive programmable logic capability, but may be able to offer multiple groups of settings selectable via hardwired inputs. The key functions within each layer were set and the data flow between layers defined. These flows include not only instructions to change between groups of settings, but also signals confirming changes as well as diagnostic information on how the scheme is performing. This is a key feature of the architecture as providing enhanced diagnostic information enables the verification of the adaptations and avoiding hidden failures, which permits also aids in overcoming the perceived reliability barrier.

In addition to the architecture, this thesis also analysed the potential generic failure modes that could be introduced by adopting adaptive protection. The link between primary power system state transitions and the incomplete or incorrect change in settings groups was explored. Based on these, a basic methodology was set out for carrying out a failure mode and effect analysis to assess the impact of adaptation failures during the course of scheme operation. This is essential for ensuring that the introduction of an adaptive capability does not lower the reliability of the protection which would in turn compromise the performance gains expected from its implementation. It was also stressed that where possible that each settings group should be considered in terms of how well it could perform if only partially adapted due to whatever failure mode. Ideally settings groups should be designed with some degree of redundancy, where possible, with regard to input data sources initiating adaptation or in terms of the basic protection functions and their zones or reach.

7.1.3 Example Applications for Adaptive Protection

Two example applications were used which highlighted situations where the existing protection approach will no longer be suitable if smart grid type operating practices are adopted. The solutions presented for these emerging challenges differ, but nonetheless indicate that more complex protection schemes will be required in order to facilitate more approaches to network operation.

The first example presented in Chapter 5 considered establishing microgrids at the very lowest level of the system within LV networks. The main technical challenge in this case was the low fault level present in an islanded network supplied by predominately power electronic converter connected generation. It was seen that although the existing overcurrent type protection functions can function as normal during grid connected mode, a different approach is required when islanded. To cover this second mode a scheme based on under-voltage starters used to initiate directional elements with forward and reverse definite time delays was proposed. Under grid connected conditions the overcurrent functions will operate faster than these additional elements. Therefore although there are two distinct protection functions, no logic is required to trigger any adaption between the two main short-circuit protection types. However, adaptive functionality was suggested to be of use with regard to system protection functions such as under-frequency load shedding between grid connected and islanded modes, occasions where two islanded microgrids are interconnected to increase demand security (adaptation require to correct grading issue) and to cover an extremely low generation scenario where fused based protection with consumer premises may not be able to operate. The principles of the proposed microgrid protection were tested using EMT system modelling which incorporated detailed signal processing based models of the MIPS relays.

A second example was given in Chapter 6 that presented research associated with the development of an adaptive protection scheme which can permit the intentional islanding of an area of 11 kV distribution network. A study system was presented that is representative of a network to be found in the UK and included a range of generation types connected at both LV and HV. To analyse the system and begin the application of the proposed design methodology, a set of scenarios was developed that covered the range of generation/demand levels that could occur in grid connected and islanded modes of operation. These scenarios allowed the performance of the existing overcurrent protection to be checked and the dynamic behaviour of the islanded system to be investigated in response to faults, isolation from the grid and the sudden loss of generation. The analysis found that the overcurrent protection required adaptation to better reflect the state of the primary power system as it underwent changes and, in addition, other system protection elements also benefited from having adaptive functionality. These additional system functions included under-frequency load shedding and loss of mains.

Based on these findings, an adaptive protection scheme for the network was developed that was based on the design methodology and defining the content of the three layers of the architecture. The settings groups were calculated for the execution layer, logic for the coordination layer and the tasks for the management layer defined. These were made possible by identifying what data sources were available to detect the primary system change and how these should be communicated and interpreted.

The impact of the scheme failing to adapt as intended was also studied using the methodology discussed in Chapter 4 with the application of a basic failure mode and effects analysis. It was found that the scheme is robust and can tolerate the failure of some relays or individual elements to adapt as intended and still maintain a satisfactory level of performance. Finally the implementation of diagnostics functionality was discussed and comments made on the actual physical implementation of the scheme.

7.2 Future Work

The research on adaptive protection presented in this thesis has developed an architecture, which it is proposed, will serve as the basis for implementing robust and reliable schemes. Both of the application examples used in this thesis are at an early stage of development as further work is required to take the concepts further. The following suggestions are offered as potential areas of future study:

- The analysis of failure modes and reliability during the adaptation process should be studied in more detail. A quantitative assessment of actual communication systems, including their capacity for designed redundancy and component availabilities, would be informative and assist with the acceptance of the concept of adaptive protection. In addition, further work would also be useful in formalising the quantification of the severity of adaptive protection failure. This could be achieved by defining suitable performance benchmarks which can be used during the protection analysis.
- The development of a testing environment as described in §3.8 in which the adequacy of a scheme can be thoroughly assessed. This would involve the development of an event based testing environment which could incorporate real-time EMT testing. By doing this all levels of the architecture can be tested: injection testing of execution level functions with voltage and current signals, coordination layer logic with asset status information, and finally management layer functions with links to other network control or management systems.
- Finally, this work has been limited to two distribution examples and it would be useful apply the concepts to a more complex transmission application. A suitable choice of scheme would the a wide area protection scheme providing a system level protection function would involve a much higher reliance on communications and interactions with operational control of the system.

Appendix A Microgrid Model

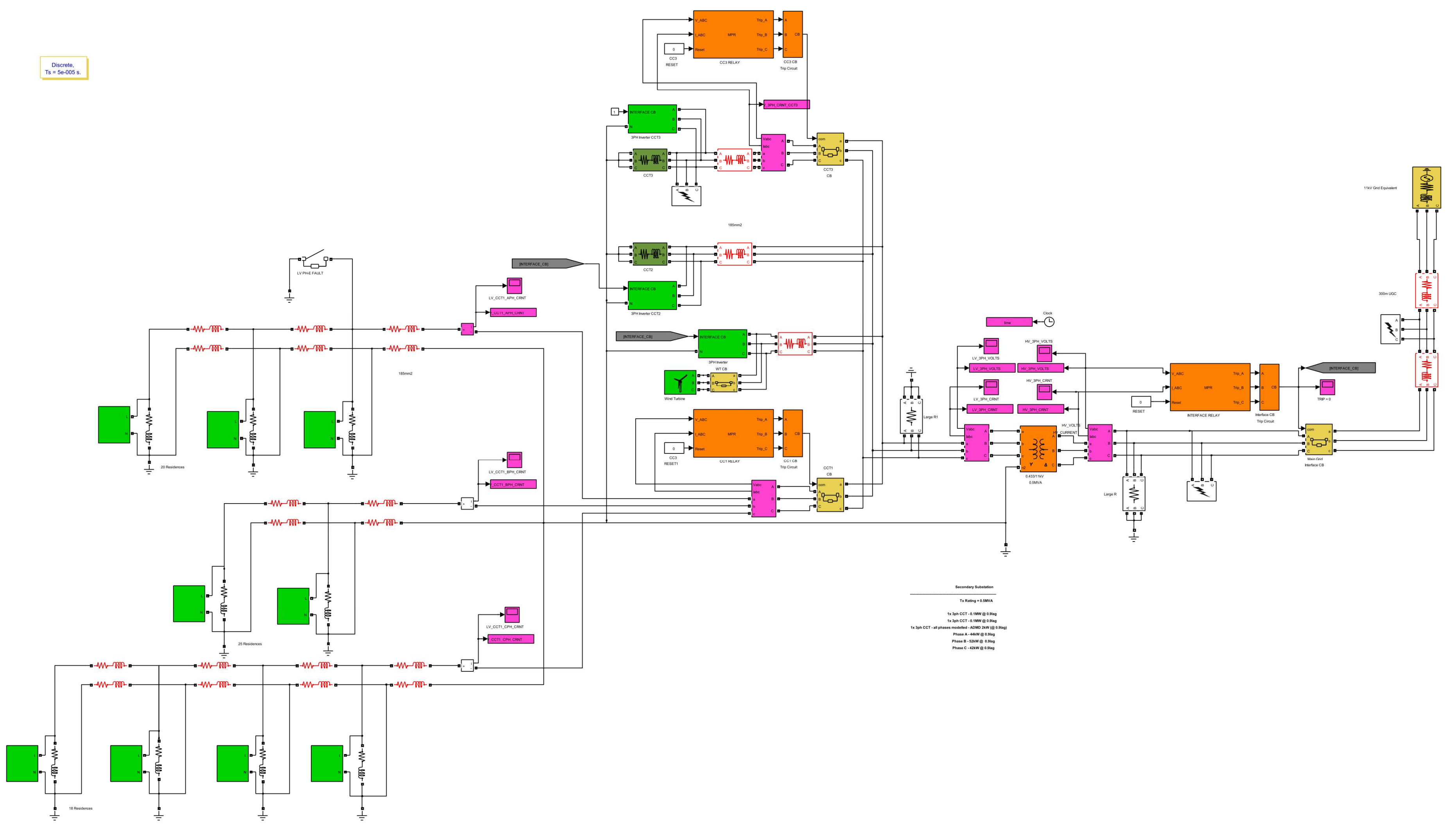

Figure A-1: Overall microgrid schematic.

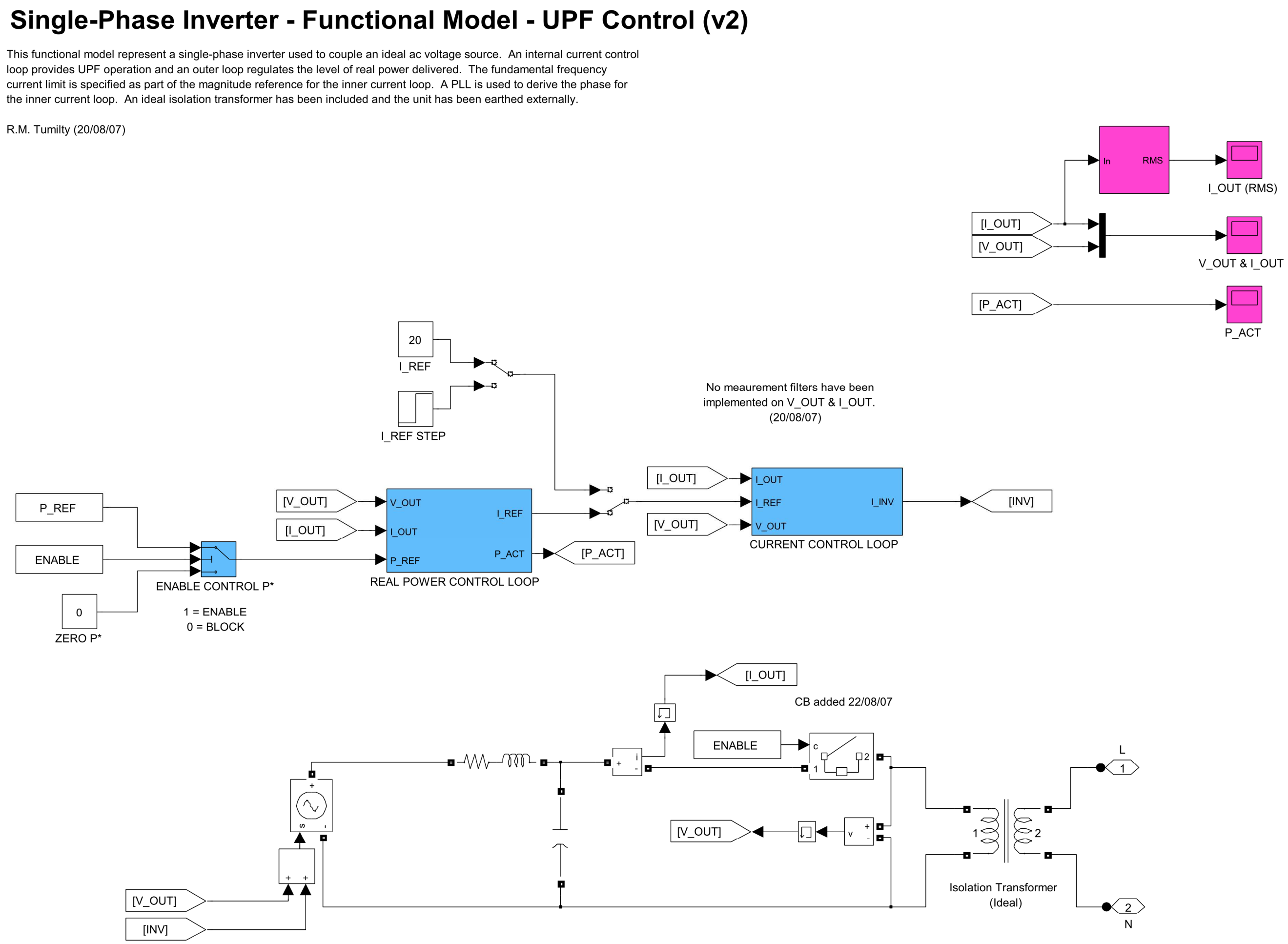

Figure A-2: Single-phase inverter model.

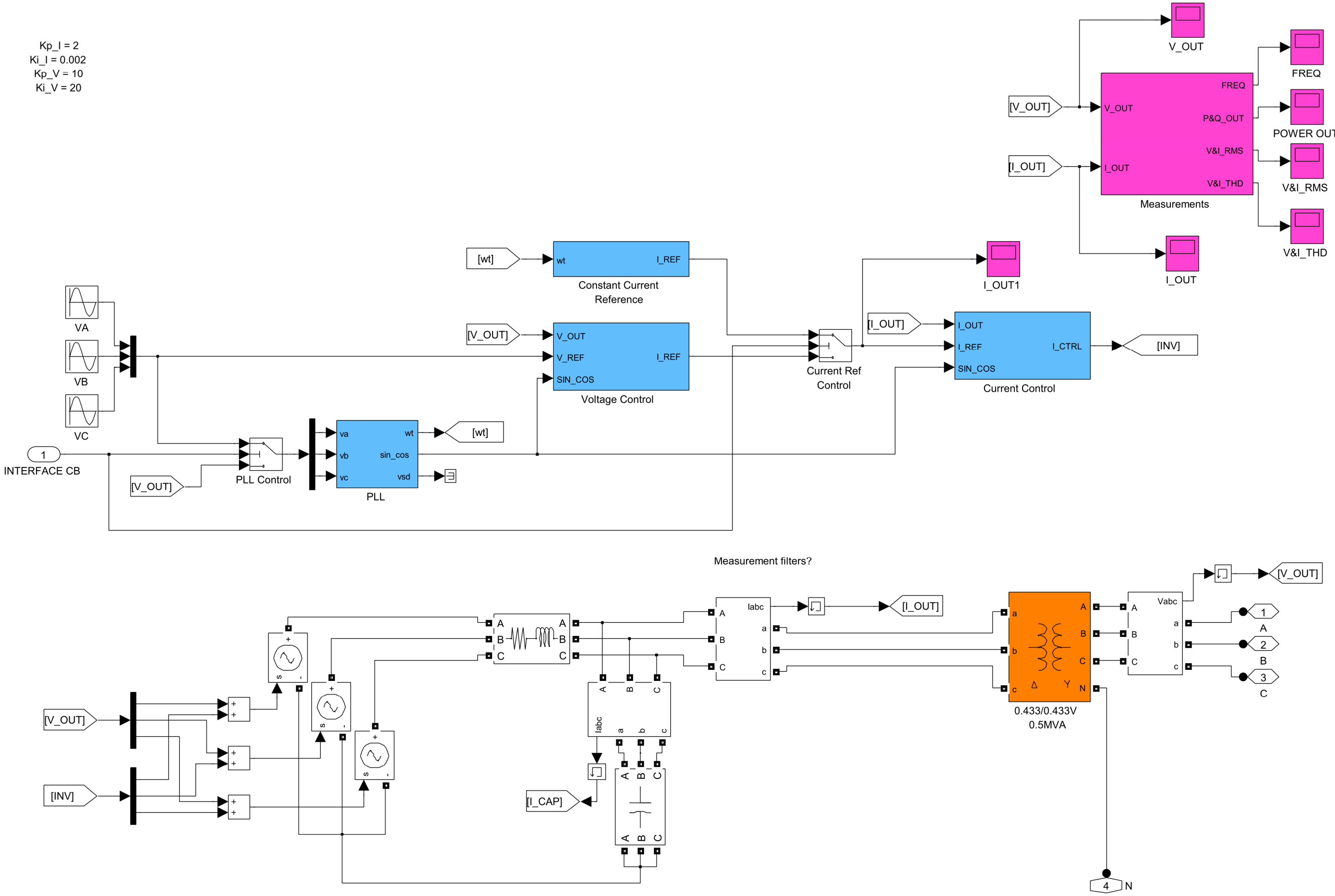

Figure A-3: Three-phase inverter model.

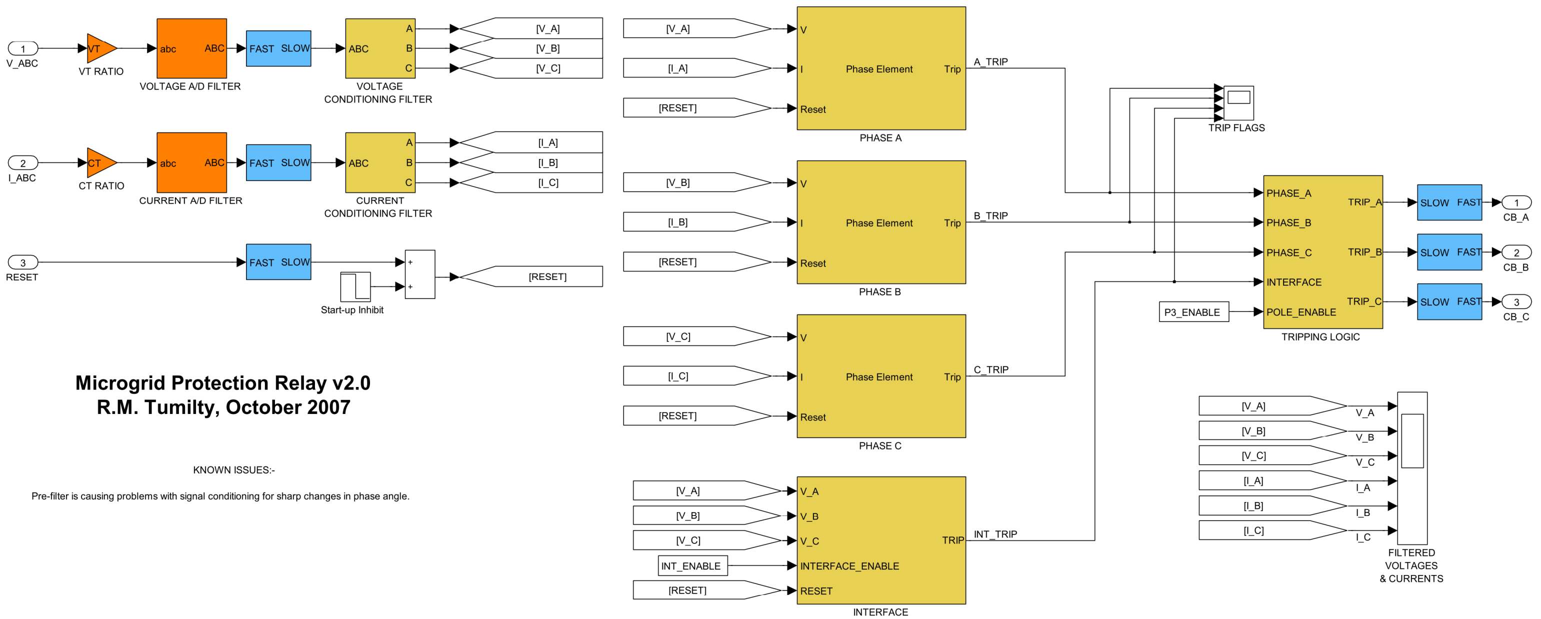

Figure A-4: MIPS relay overall structure.

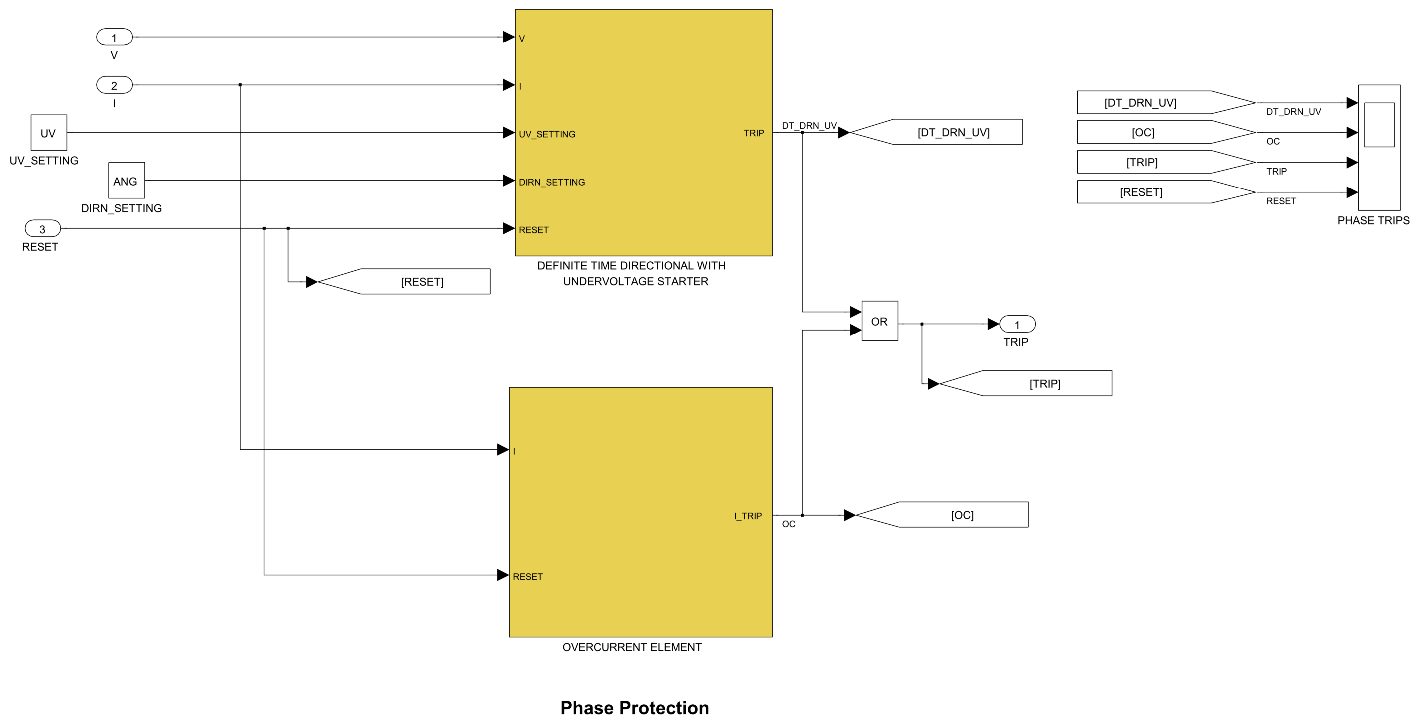

Figure A-5: MIPS relay phase protection.

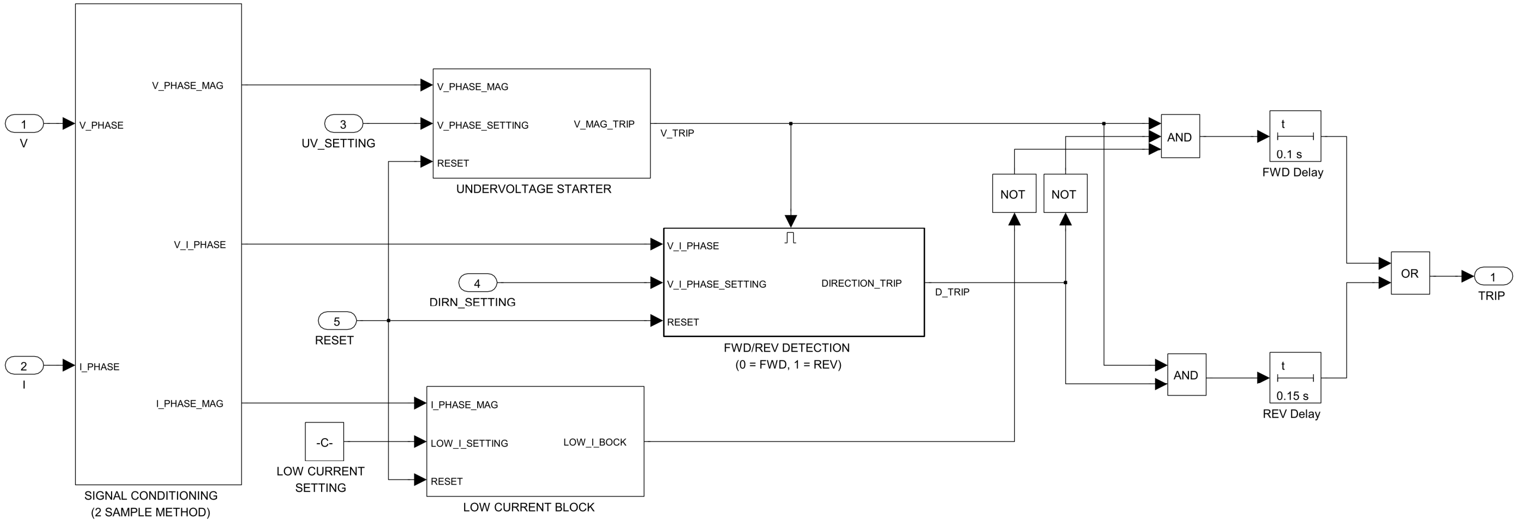

Figure A-6: MIPS relay directional DT element.

Notes:
Reset has been included as being instantaneous.

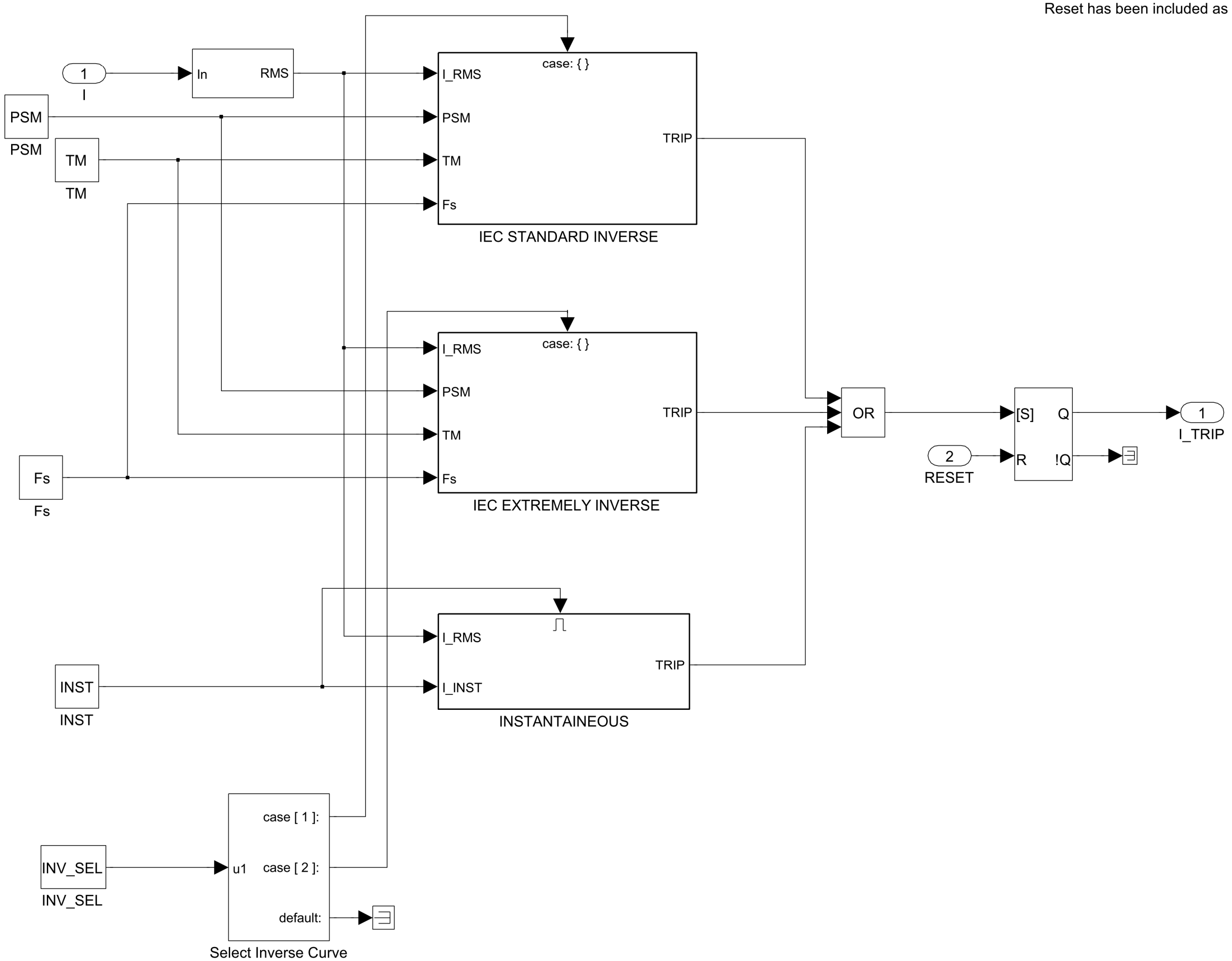

Figure A-7: MIPS relay overcurrent elements.

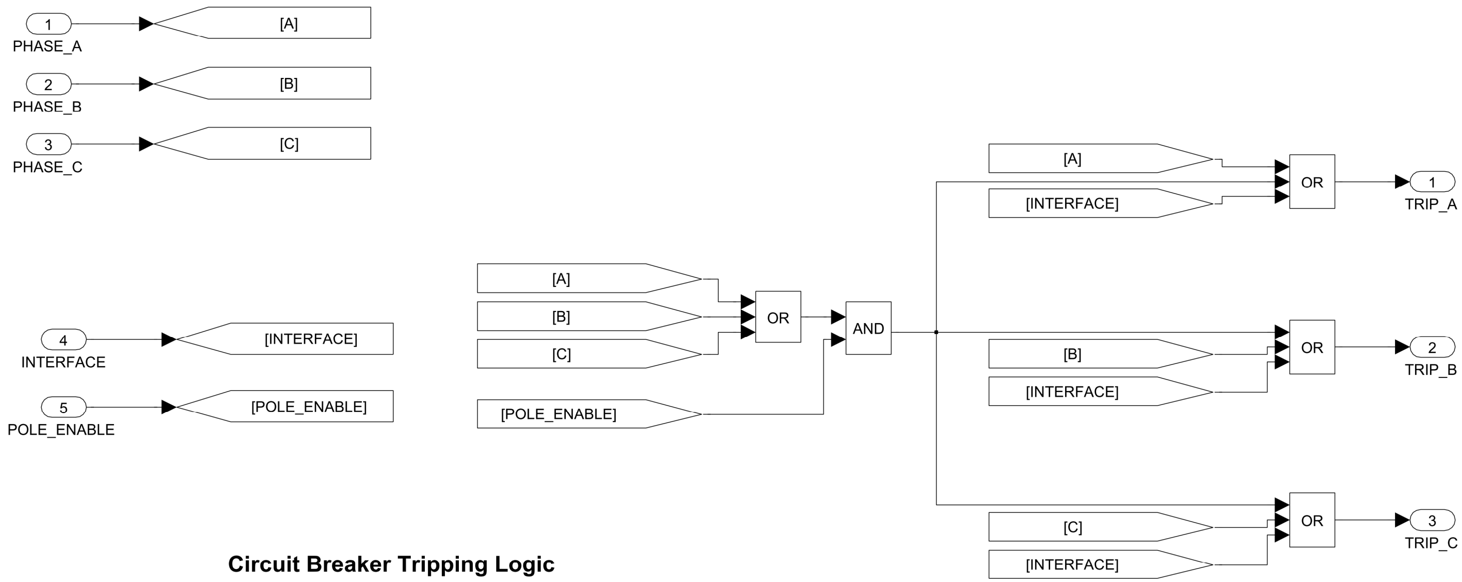

Figure A-8: MIPS relay tripping logic.

Appendix B Ideal Source Inverter Representation

The validity of the single-phase functional inverter model used for the studies in this paper is demonstrated below for the cases of a power reference change and the application of a temporary remote phase-neutral fault in Figures B-1 and B-2 respectively.

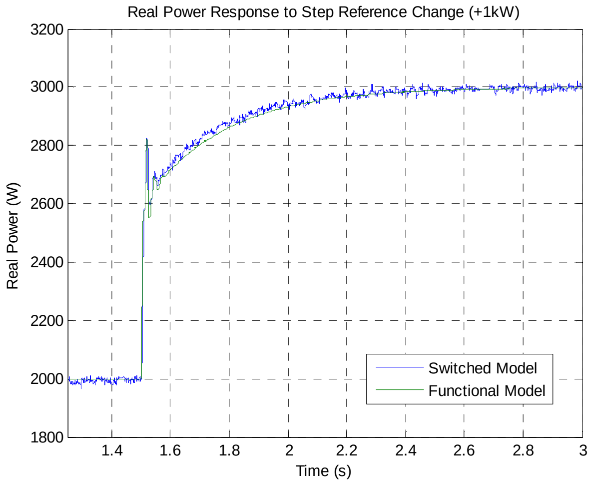

Figure B-1: Real power response to step reference change.

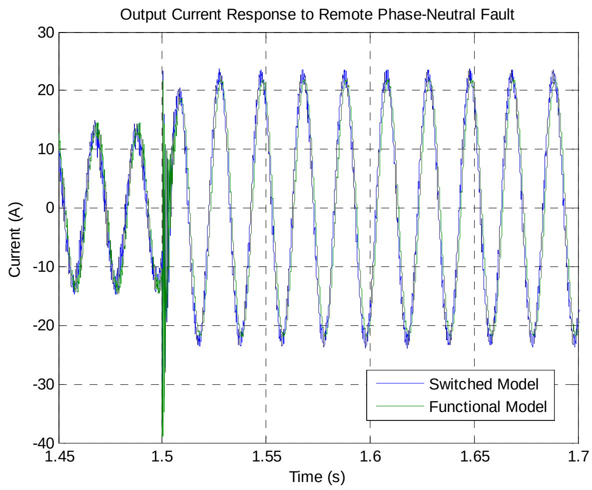

Figure B-2: Real power response to step reference change.

Appendix C HV Model Dynamic Data

Component models:

```
GENSAL        T'do,T''do,T'qo,T''qo,H,D,Xd,Xq,X'd,X'q,X''d,Xl,S(1.0),S(1.2)
GENROU        T'do,T''do,T''qo,H,D,Xd,Xq,X'd,X''d,Xl,S(1.0),S(1.2)
SEXS          TA/TB,TB,K,TE,EMIN,EMAX
TGOV1         R,T1,VMAX,VMIN,T2,T3,Dt
DEGOV         T1,T2,T3,K,T4,T5,T6,TD,TMAX,TMIN
CIMTR3        T',T'',H,X,X',X'',Xl,E1,S(E1),E2,S(E2),switch,syn-pow
CLODBL        % large motor,% small motor, % discharge lighting,% constant power
              Kp remaining, branch R, branch X
WT3G1         Xeq,Kpll,Kipll,Pllmax,Prated
WT3E1         Tfv,Kpv,Kiv,Xc,Tfp,Kpp,Kip,Pmx,Pmn,Qmx,QmnIPmx,Trv,RPmax,RPmn,T_power,
              Kqi,Vmincl,Vmaxcl,Kqv,XIQmin,XIQmax,Tv,Tp,Fn,wPmin,Wp20,wp40,wp60,
              Pmin,wp100,
WT3T1         VW,H,DAMP,Kaero,Theta2,Htfrac,Freq1,Dshaft
WT3P1         Tp,Kpp,Kip,Kpc,Kic,TetaMin,Tetamax,RTetaMax,Pmx
```

```
    402 'CIMTR3' 1     1.0550       0.0000       3.0000       4.0100
         0.16000      0.10000      0.90000E-01   1.0000      0.60000E-01
          1.2000      0.15000       0.0000       0.0000    /
    403 'CIMTR3' 1     1.0550       0.0000       3.0000       4.0100
         0.16000      0.10000      0.90000E-01   1.0000      0.60000E-01
          1.2000      0.15000       0.0000       0.0000    /
    405 'GENROU' 1     3.4100      0.30000E-01  0.33000      0.30000E-01
          2.0000       0.0000       2.7300       2.7300      0.21000
         0.25000      0.16000      0.14000      0.90000E-01  0.38000    /
    405 'SEXS'   1    0.20000       10.000       100.00      0.10000
         0.50000       5.5000    /
    405 'TGOV1'  1    0.50000E-01  0.50000       1.0000      0.20000
          1.5000       5.0000       0.0000    /
    407 'CIMTR3' 1     1.0550       0.0000       3.0000       4.0100
         0.16000      0.10000      0.90000E-01   1.0000      0.60000E-01
          1.2000      0.15000       0.0000       0.0000    /
    410 'CIMTR3' 1     1.0550       0.0000       3.0000       4.0100
         0.16000      0.10000      0.90000E-01   1.0000      0.60000E-01
          1.2000      0.15000       0.0000       0.0000    /
    412 'CIMTR3' 1     1.0550       0.0000       3.0000       4.0100
         0.16000      0.10000      0.90000E-01   1.0000      0.60000E-01
          1.2000      0.15000       0.0000       0.0000    /
    413 'CIMTR3' 1     1.0550       0.0000       3.0000       4.0100
         0.16000      0.10000      0.90000E-01   1.0000      0.60000E-01
          1.2000      0.15000       0.0000       0.0000    /
    417 'CIMTR3' 1     1.0550       0.0000       3.0000       4.0100
         0.16000      0.10000      0.90000E-01   1.0000      0.60000E-01
          1.2000      0.15000       0.0000       0.0000    /
    418 'CIMTR3' 1     1.0550       0.0000       3.0000       4.0100
         0.16000      0.10000      0.90000E-01   1.0000      0.60000E-01
          1.2000      0.15000       0.0000       0.0000    /
    501 'GENSAL' 1     4.0000      0.42000E-01  0.17000       4.0000
         0.0000       1.9200       1.0200      0.29000      0.21000
         0.34000      0.10000      0.40000    /
    501 'SEXS'   1    0.20000       10.000       100.00      0.10000
```

```
     0.50000       5.5000    /
  501 'DEGOV'  1    0.10000E-01  0.20000E-01  0.20000       40.000
     0.25000      0.40000E-01  0.90000E-02  0.30000E-01  0.80000
      0.0000    /
  501 'GENSAL' 2     4.0000      0.42000E-01  0.17000       4.0000
     0.0000       1.9200       1.0200      0.29000      0.21000
     0.34000      0.10000      0.40000    /
  501 'SEXS'   2    0.20000       10.000       100.00      0.10000
     0.50000       5.5000    /
  501 'DEGOV'  2    0.10000E-01  0.20000E-01  0.20000       40.000
     0.25000      0.40000E-01  0.90000E-02  0.30000E-01  0.80000
      0.0000    /
  501 'GENSAL' 3     4.0000      0.42000E-01  0.17000       4.0000
     0.0000       1.9200       1.0200      0.29000      0.21000
     0.34000      0.10000      0.40000    /
  501 'SEXS'   3    0.20000       10.000       100.00      0.10000
     0.50000       5.5000    /
  501 'DEGOV'  3    0.10000E-01  0.20000E-01  0.20000       40.000
     0.25000      0.40000E-01  0.90000E-02  0.30000E-01  0.80000
      0.0000    /
  801 'GENSAL' 1     3.0000      0.35000E-01  0.13000       3.0000
      0.0000       1.7500      0.90000      0.26000      0.19000
     0.30000      0.10000      0.40000    /
  801 'SEXS'   1    0.20000       10.000       100.00      0.10000
     0.50000       5.5000    /
  801 'GAST'   1    0.50000E-01  0.40000      0.10000       3.0000
      1.0000       2.0000       1.0000     -0.50000E-01   0.0000    /
  801  'CBEST'  2
      1.0000       1.0000       1.0000       1.0000       100.00
     0.10000       10.000      0.10000       10.000       2.5000
      0.0000      0.50000E-01/
11006 'CIMTR3' 1     1.0550       0.0000       3.0000       4.0100
     0.16000      0.10000      0.90000E-01   1.0000      0.60000E-01
      1.2000      0.15000       0.0000       0.0000    /
11010 'CIMTR3' 1     1.0550       0.0000       3.0000       4.0100
     0.16000      0.10000      0.90000E-01   1.0000      0.60000E-01
      1.2000      0.15000       0.0000       0.0000    /
33001 'GENCLS' 1     0.0000       0.0000    /
  401 'CLODBL' 1     0.0000       30.000       2.0000       10.000
      30.000       2.0000       0.0000       0.0000    /
  402 'CLODBL' 1     0.0000       30.000       2.0000       10.000
      30.000       2.0000       0.0000       0.0000    /
  403 'CLODBL' 1     0.0000       30.000       2.0000       10.000
      30.000       2.0000       0.0000       0.0000    /
  404 'CLODBL' 1     0.0000       30.000       2.0000       10.000
      30.000       2.0000       0.0000       0.0000    /
  405 'CLODBL' 1     60.000       20.000       2.0000       5.0000
      5.0000       2.0000       0.0000       0.0000    /
  406 'CLODBL' 1     0.0000       30.000       2.0000       10.000
      30.000       2.0000       0.0000       0.0000    /
  407 'CLODBL' 1     0.0000       30.000       2.0000       10.000
      30.000       2.0000       0.0000       0.0000    /
  408 'CLODBL' 1     0.0000       30.000       2.0000       10.000
      30.000       2.0000       0.0000       0.0000    /
  409 'CLODBL' 1     0.0000       30.000       2.0000       10.000
      30.000       2.0000       0.0000       0.0000    /
```

```
  410 'CLODBL' 1     5.0000      40.000      2.0000      20.000
       20.000      2.0000      0.0000      0.0000    /
  411 'CLODBL' 1     0.0000      30.000      2.0000      10.000
       30.000      2.0000      0.0000      0.0000    /
  412 'CLODBL' 1     0.0000      30.000      2.0000      10.000
       30.000      2.0000      0.0000      0.0000    /
  413 'CLODBL' 1     0.0000      30.000      2.0000      10.000
       30.000      2.0000      0.0000      0.0000    /
  414 'CLODBL' 1     0.0000      30.000      2.0000      10.000
       30.000      2.0000      0.0000      0.0000    /
  415 'CLODBL' 1     5.0000      40.000      2.0000      20.000
       20.000      2.0000      0.0000      0.0000    /
  416 'CLODBL' 1     0.0000      30.000      2.0000      10.000
       30.000      2.0000      0.0000      0.0000    /
  417 'CLODBL' 1     0.0000      30.000      2.0000      10.000
       30.000      2.0000      0.0000      0.0000    /
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       30.000      2.0000      0.0000      0.0000    /
  419 'CLODBL' 1     0.0000      30.000      2.0000      10.000
       30.000      2.0000      0.0000      0.0000    /
11006 'CLODBL' 1     15.000      30.000      2.0000      10.000
       30.000      2.0000      0.0000      0.0000    /
11010 'CLODBL' 1     10.000      30.000      2.0000      10.000
       30.000      2.0000      0.0000      0.0000    /
  601 'WT3G1' 1
       1  0.80000      30.000      0.0000      0.10000      0.48000     /
  601 'WT3E1' 1       0      0      1      0      0        '0 '
      0.15000      18.000      5.0000      0.0000      0.50000E-01
       3.0000     0.60000      1.1200     0.10000      0.29600
     -0.43600      1.1000     0.50000E-01  0.45000     -0.45000
       5.0000     0.50000E-01  0.90000      1.2000      40.000
     -0.50000     0.40000     0.50000E-01  0.50000E-01   1.0000
      0.69000     0.78000     0.98000      1.1200      0.74000
       1.2000     /
  601 'WT3T1' 1
        1.2500       4.9500       0.0000       0.70000E-02    21.980
        0.0000       1.8000       1.5000     /
  601 'WT3P1' 1
       0.30000       150.00       25.000       3.0000       30.000
        0.0000       27.000       10.000       1.0000     /
  602 'WT3G1' 1
       1  0.80000      30.000      0.0000      0.10000      0.48000     /
  602 'WT3E1' 1       0      0      1      0      0        '0 '
      0.15000      18.000      5.0000      0.0000      0.50000E-01
       3.0000     0.60000      1.1200     0.10000      0.29600
     -0.43600      1.1000     0.50000E-01  0.45000     -0.45000
       5.0000     0.50000E-01  0.90000      1.2000      40.000
     -0.50000     0.40000     0.50000E-01  0.50000E-01   1.0000
      0.69000     0.78000     0.98000      1.1200      0.74000
       1.2000     /
  602 'WT3T1' 1
        1.2500       4.9500       0.0000       0.70000E-02    21.980
        0.0000       1.8000       1.5000     /
  602 'WT3P1' 1
       0.30000       150.00       25.000       3.0000       30.000
        0.0000       27.000       10.000       1.0000     /
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603 'WT3G1' 1
      1  0.80000       30.000       0.0000      0.10000      0.48000     /
603 'WT3E1' 1       0      0      1      0      0         '0 '
     0.15000       18.000       5.0000       0.0000      0.50000E-01
      3.0000      0.60000       1.1200      0.10000      0.29600
    -0.43600       1.1000      0.50000E-01  0.45000     -0.45000
      5.0000      0.50000E-01  0.90000       1.2000       40.000
    -0.50000      0.40000      0.50000E-01  0.50000E-01   1.0000
     0.69000      0.78000      0.98000       1.1200      0.74000
      1.2000     /
603 'WT3T1' 1
       1.2500        4.9500        0.0000       0.70000E-02    21.980
       0.0000        1.8000        1.5000     /
603 'WT3P1' 1
      0.30000        150.00        25.000        3.0000        30.000
       0.0000        27.000        10.000        1.0000     /
```