Integration of Active Network Management into the Distribution Control Room Environment

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Abbreviations

A	Ampere
AI	Artificial Intelligence
ANM	Active Network Management
AuRA-NMS	Autonomous Regional Active Network Management System
BERR	Department for Enterprise, Business and Regulatory Reform
BIS	UK Department for Business, Innovation and Skills
CB	Circuit Breaker
CBR	Case Based Reasoning
CHP	Combined Heat and Power
CIGRE	International Council on Large Electric Systems
CIM	Common Information Model
CP	Constraint Programming
CSP	Constraint Satisfaction Problem
CSV	Comma Separated Value
CT	Current Transformer
CoRDS	Control Room Demonstration Suite
DA	Distribution Automation
DFR	Digital Fault Recorder
DG	Distributed Generation
DMS	Distribution Management System
DNO	Distribution Network Operator
DPCR	Distribution Price Control Review

DTI	Department of Trade and Industry
EEE	Electronic and Electrical Engineering
EMS	Energy Management System
EPRI	Electric Power Research Institute
EPSRC	Engineering and Physical Sciences Research Council
EU	European Union
GPS	Global Positioning Satellite
GSP	Grid Supply Point
GW	Gigawatt
HMI	Human Machine Interface
IEC	International Electrotechnical Commission
IED	Intelligent Electronic Device
IEEE	Institute of Electrical and Electronic Engineers
IFI	Innovation Funding Incentive
IPSA	Interactive Power System Analysis
kV	Kilovolt
LCNF	Low Carbon Network Fund
LIFO	Last In First Out
LV	Low Voltage
MVA	Mega Volt Ampere
MVAr	Mega Volt Ampere Reactive
MW	Megawatt
NGC	National Grid Company
NGET	National Grid Electricity Transmission

NMS	Network Management System
OFGEM	Office of Gas and Electricity Markets
OMS	Outage Management System
OPF	Optimal Power Flow
PC	Personal Computer
PFM	Power Flow Management
PLC	Programmable Logic Controller
PMU	Phasor Measurement Unit
PSS/E	Power System Simulator for Engineers
RIIO	Revenue = Incentives + Innovation + Outputs
RPZ	Registered Power Zone
RTU	Remote Terminal Unit
SCADA	Supervisory Control and Data Acquisition
SGS	Smarter Grid Solutions
SSE	Scottish & Southern Energy
TPCR	Transmission Price Control Review
UK	United Kingdom
V	Volt
VPP	Virtual Power Plant
VT	Voltage Transformer
XML	Extensible Mark Up Language

Abstract

The way in which distribution networks are operated and managed from the control room is changing as a result of a number of external factors, most prominently the mounting interest in renewable generation technologies and growing trends of connecting small scale generation plants at distribution level voltages in decentralised locations.

Growing interest in distributed generation (DG) presents a challenge to the validity of existing distribution control room procedures and supporting tools. To accommodate large penetrations of DG, a more active approach to control is necessary and extensive research and development is currently underway in this area.

Active network management (ANM) is one of the enabling strategies that will allow DG to connect, whilst potentially postponing the need for costly and time consuming network reinforcements and upgrades, by operating the network closer to its limits through real-time monitoring and control of system parameters. Parameters such as power flow and voltage, and embedded resources such as responsive demand and DG can all be controlled in a more active manner such that network resources can be used more efficiently.

The management of future active distribution networks is a concern as such changes will impact the control room in various ways. This thesis describes the changes that will occur on networks and how they will affect the control room in different ways, as well as the uncertainties associated with DG and ANM deployment. A Control Room Demonstration Suite (CoRDS) provides a comprehensive view of future networks and their operational issues, allowing preparatory measures to be taken by Distribution Network Operators (DNO). The CoRDS is also used to study the required behavioural changes of distribution control engineers in the way they will interact with ANM schemes.

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Special thanks must go to Robert. After listening to me for four years, he deserves more than just his PhD. I must also thank Euan Davidson for all of his help, support and advice, especially in the experimental stages of my work.

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Chapter 1

Introduction

1.1 Motivation and Justification for Research

This chapter outlines the main motivations and justifications for the research presented in this thesis, and provides a comprehensive introduction to the subject of integration of active network management control philosophies into the control room environment. The main motivations, filtered down from global interests to the research at hand are discussed primarily, followed by an outline of the contributions of the research and an overview of the thesis as a whole.

1.1.1 The Drivers for Changing Electricity Networks

Electricity networks are going through a period of significant change in the UK and around the world with global interests sparking substantial changes in the power industry, particularly the way in which power is generated (thus impacting how it is transmitted and distributed). The drivers for this encompass a range of political, environmental, technical, regulatory, and economic and market issues at national and international levels; and the transitions are causing widespread and cascading ramifications for generators, network operators and consumers alike.

1.1.1.1 Environmental Concerns

Environmental issues have been instrumental in this process of change. The term ‘climate change’ has become a common idiom in the developed world and its threat has prompted major international collaboration on energy policy changes.

There has been global recognition of the detrimental effects that the electricity industry has had on the environment over the years through the burning of fossil fuels. This practice has contributed to both climate change and pollution, and a number of counter measures are now in motion to alleviate further damage. One such step has been the ratification of the Kyoto Protocol, which was created and adopted in 1997 by some 180 countries as well as the European Union (EU) as a separate entity [1]. The primary focus of the Kyoto Protocol is to limit and reduce the emission of greenhouse gases (assumed to be the primary cause of the accelerated climate change we are now facing) in industrialised countries between 2008 and 2012. Each of the signatories has volunteered individual emission reduction targets at a national level. The EU is a key contributor to the Kyoto Protocol and has taken its responsibilities seriously. It has committed to reducing the emissions from 15 EU countries (who were members in 1990) by 8% [2] with each individual country given its own national obligation to meet in order that the EU target can be met by 2012. This has clear implications for the electricity generating portfolios in EU countries.

The EU is proving this commitment to the sustainable development of its electricity networks and it aims to incorporate its environmental obligations with technical and regulatory changes to support this [3]. One of the major strategies developed is the

European Technology Platform for Electricity Networks of the Future (Smartgrids), which takes account of environmental, technical and regulatory concerns, amongst others. The main concerns are highlighted clearly in Figure 1.

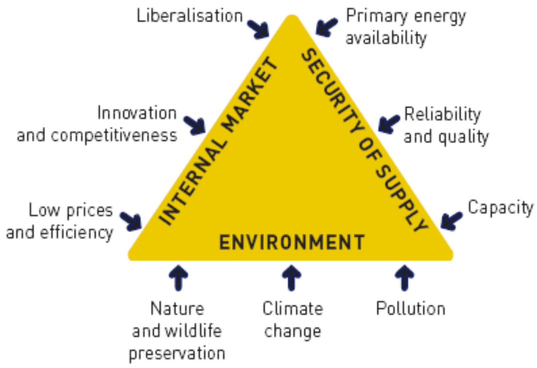

Figure 1: Smartgrids Drivers of Changing Electricity Industry [3]

The Smartgrids technology platform was formulated with the aim to assist continent-wide collaboration on the development of its electricity grids [3]. This technology platform encompasses all of the motivating factors highlighted in Figure 1, working on the principle that change must be brought to all aspects of the electricity industry in order that it is prepared for current and future requirements. The industry has recognised the need for significant development of network infrastructures in order that it will be sustainable throughout the coming years, and the term Smartgrids is indicative of the type of networks envisioned for the future; ‘smart’ electrical grids capable of self-management and -control.

In the UK, a carbon emission reduction target of 80% (on 1990 levels) has been set out. In line with this, the UK government has also set a target of 20% of electricity to be supplied from renewable sources by 2010, and 40% by 2020. The Climate Change Act 2008 [4] outlines the targets for carbon emission reduction, and related issues, up to 2050 and is legally binding.

A number of strategies are in place in the UK in order that these environmental targets can be met, including incentive schemes put in place by the industry regulator Ofgem (Office of Gas and Electricity Markets). Innovation Funding Incentives (IFI) and Registered Power Zones (RPZ) are two of these incentive schemes which have proven successful.

As defined by the Department of Trade and Industry (DTI, now known as the Department of Business, Innovation and Skills (BIS) and formerly the Department of Business, Enterprise and Regulatory Reform (BERR)) and Ofgem, an RPZ is "a defined electrical area that is selected and proposed to form an RPZ by the distribution network operator (DNO) and is then treated as a bounded network zone". There are several criteria that a site must adhere to in order to be eligible for an RPZ, such as; an RPZ must involve the connection of DG or the connection of an incremental increase in MW at an existing generation site, an RPZ must demonstrate innovation, it must be registered with Ofgem and a contingency measure must be available if quality of supply to customers may be affected. The RPZ scheme has further criteria along with a list of its benefits and risks. These are all detailed in [5]. There are currently three defined RPZs operating in the UK at present; the Orkney RPZ in the Scottish & Southern Energy area [6], the Skegness RPZ in the Central Networks area [7] and the Martham Primary RPZ in the EDF Energy area [8].

There is a distinct difference between IFIs and RPZs. Where an RPZ requires the physical connection of distributed generation (DG) (or MW), IFIs are intended to provide funding for any projects focused on the technical development of distribution networks [9]. IFI projects encompass all aspects of the distribution network, including design, construction, and operation. Each of the UK DNOs produce an annual IFI/RPZ progress report.

The Low Carbon Networks Fund (LCNF) is another large-scale platform based in the UK formed as part of the distribution price control review (DPCR5), in place from 2010 to 2015, and is worth up to £500m. The LCNF supports projects sponsored by DNOs which involve the innovation and development of new low carbon technologies and commercial arrangements [10]. The projects undertaken as part of the LCNF encompass smartgrid development, network visibility issues, renewable generation impact assessments and communications and Supervisory Control and Data Acquisition (SCADA) systems. The LCNF has a two-tier system in place, with small projects being offered first-tier funding [11]. The more substantial second-tier funding is awarded to large scale projects on an annual basis, whereby DNOs must compete for the funding. The second-tier projects for 2011 have been selected and more details are available at [12]. The second-tier projects for 2012 are under screening.

Ofgem have introduced a new framework for their transmission price control review (TPCR), the RIIO (Revenue = Incentives + Innovation + Outputs) model. The RIIO model aims to promote innovation on transmission networks [13].

The political response to environmental concerns regarding the electricity industry has brought about these technology platforms and incentive programs. However, many considerations must be taken into account for real-life feasibility of solutions. Technical and regulatory, and economic and market reform and adaption are necessary if any targets are to be met in future.

1.1.1.2 Technical and Regulatory Support

Technical and regulatory issues are very much intertwined. New technical practices require regulatory support and vice versa. The research in this area is concentrating on the integration of distributed and renewable energy sources, the technologies that will facilitate it and the regulatory changes that must be made to allow it. Although current research and development in the UK is part of the larger Smartgrids agenda, it is concerned primarily with DG access to distribution networks, and ensuring this is done economically and safely without compromising security or quality of supply.

Security of supply (in this context, Security of Supply is taken to assume the loss of a certain level of major circuitry and plant does not or has minimal effect on customer supply of electricity) is paramount for network operators, and traditional conservative planning of distribution networks that incorporate the N-1 contingency, whereby the loss of any one major circuit does not affect supply to customers, must be reviewed such that technical and regulatory reform does not affect this principal objective [14], [15]. There is significant existing capacity in distribution networks which can be exploited given suitable regulatory agreement. And, with large amounts of DG connecting to networks, it is important to consider more efficient use of existing assets as an alternative to incrementally adding plant. Regulatory revision on this point can greatly accelerate DG connection, and go a long way towards achieving renewable energy targets by relaxing the N-1 contingency constraint and reducing the substantial costs and time involved in the reinforcement of network assets.

Network operators are also concerned over security and quality of supply as demand continues to grow. Greater demand requires greater supply; yet the operating philosophies of networks are evolving and there is ever growing uncertainty regarding foreign import of fossil fuels. This exerts additional pressure to connect renewable and sustainable generation.

1.1.1.3 Electricity Markets

There has been recognition of the need to reform electricity markets and policies to accommodate large penetrations of renewable generation. The UK regulator, Ofgem, is charged with protecting electricity (and gas) customers by promoting competition in wholesale markets. It is also dedicated to the transition to a low carbon economy, and their duty to contribute to the achievement of sustainable development was introduced in 2004 [16]. They are also instrumental in the process of the UK joining a European liberalised electricity market [17], which will see electricity being traded across the European continent.

Markets are not yet susceptible to the changes in levels of consumer participation brought about by greater awareness of energy usage and waste. In the UK, investigation into the inclusion of demand-side participation in the market framework was carried out as early as 1996 [18], and the pace of implementing smartgrid enabling technologies is accelerating, resulting in various studies into their impact on markets and market structure. [19] investigates the effect of demand response on electricity markets and [20] proposes it as a resource in the future of smartgrids, where [21] assesses effective marketing strategies for wind generation. Several incentives and discount schemes, including smart metering [22], have been offered to promote homes and businesses implementing energy saving measures. It has also become simpler to change energy supplier, thus promoting market competition.

Furthermore, promotion of microgeneration at the domestic level is adding an additional layer of complexity to electricity markets [23].

1.1.2 The Impacts on Electricity Networks

The drivers for change, and the mechanisms and strategies described in Section 1.1.1, are in place to ensure environmental targets are achieved. Yet these will have serious impacts on the electricity networks themselves, and the ways in which they are operated and managed. Conventional power plants, around which today's electricity grid was built, are large centralised entities that produce large amounts of power as and when required. Renewable generation plants are situated in a more decentralised, distributed fashion to optimally harness the energy required, whether that be wind, wave or solar energy. The nature of renewable generation also dictates a factor of intermittency as they rely on the elements to generate power. The push to achieve carbon emission reduction targets will result in networks inundated with renewable generation in a distributed fashion.

And not only do these issues create obstacles for generators, the impacts are felt by network operators. Network connections for distributed generation are often required on low voltage, electrically weak networks in remote locations. There have been a number of studies and investigations into the impacts that DG will have on distribution networks (33kV and 11kV in Scotland, 132kV, 33kV and 11kV in England and Wales) [24], [25]. Distribution networks were originally constructed to transport electricity from bulk supply points down to end-users, and as this purpose is now evolving, the networks must change their operating philosophy in accordance [26].

As distribution networks continue to be populated with generation, the issues cited will arise more frequently and worsen. In order that the connection of DG can be encouraged and enabled, the long-established method of the reinforcement of networks through the addition of new overhead lines and cables and the up rating of transformers and other plant must be revised, with technical and regulatory reform. Small-scale renewable generators are not always financially equipped to meet the cost of such reinforcements, and this has led to research into other enabling solutions which do not involve costly and time consuming upgrades.

A number of solutions are available to allow DG access to networks and in the UK, the focus is on the research and development of active network management (ANM) schemes in the drive towards active distribution networks. ANM is identified as a feasible way of allowing large amounts of DG safe and secure access to networks whilst negating or deferring the need for expensive reinforcements and upgrades [27]. ANM schemes and devices manage specific network parameters in real-time which allow existing network capacity to be used but will ensure this capacity is made available if required during contingencies or outages. Investigations have been carried out on actively managed distribution networks to assess their feasibility [28], [29] and how they can provide the network services required by DG [30 – 33].

Several schemes have already been deployed in trial and are functioning on distribution networks, including the Orkney RPZ in North Scotland [6], the Central Networks RPZ in the East Midlands [7], and EDF Energy's Martham Primary RPZ, a voltage control scheme to manage voltage rise on LV circuits with high penetrations of DG [8]. An Active Networks Deployment Register [34] has been created as an online resource for the active networks research community. It lists all of the known ANM projects completed or in progress throughout the UK, and internationally, and is updated annually.

Although the deployment of ANM schemes is still in its early stages, some impacts of ANM scheme deployment have been studied. Their impact on distribution network planning and design procedures are highlighted in [35]. The paper makes reference to the Active Networks Deployment Register, and the maturity of the projects contained in it emphasises the need for regulatory and technical revisions to accommodate DG and ANM deployment. Some technical and economic impacts of ANM are discussed in [36] using an algorithm to determine impacts on DG output, power losses and voltage efficiency. A study on the impact of an ANM scheme on the volume of SCADA alarms generated was carried out and presented in [37]. The findings suggest that the implementation of an active power flow management scheme to enable increased DG connection reduced the amount of voltage and tap changer alarms generated than if the DG was to run unconstrained.

A significant penetration of DG with a varied portfolio of generation, coupled with active control devices will contribute to a shift in the distribution network operational philosophy. This will have a wider impact on various current practices, including power system planning, control room operations, network maintenance, asset management and investment. Distribution networks will be operated and managed more like transmission networks and many parameters will require real-time monitoring and control, which isn't presently always available at lower voltage levels.

1.1.3 Research Objectives

The principal focus of this research, with reference to the motivations outlined in the previous section, is within the distribution control room. It is concerned primarily with how the described transition to active networks will impact the distribution control room and control engineers in their efforts to operate and manage these networks effectively. The main objectives are as follows

- To investigate the effects of DG from a control room perspective, and how the role of the control engineer will evolve to include the management of DG during both normal operation and outage and fault conditions.
- To establish the impacts that will be felt within the distribution control room as distribution networks adopt an increasingly active, decentralised approach to operation and management through the deployment of ANM schemes.
- To explore the control room and control engineer interactions with ANM schemes, including information exchange, human machine interface (HMI) design, control hierarchies and the role of the control engineer with regards to an actively managed network.
- To provide control engineers and the control room with a higher level of visibility concerning the expected issues to arise from DG and ANM implementation, and suggest ways in which preparations can be made, such that the transition to active networks progresses as smoothly as possible.

1.2 Principal Contributions

The novelty of the research presented in this thesis has allowed a number of contributions to be offered. These contributions are outlined here

- The provision of clarity regarding the issues, technical and otherwise, facing distribution control rooms and control engineers which will result from the trend towards actively managed distribution networks.

- The provision of clarity regarding interfacing issues between control rooms and active network management schemes, encompassing the technical and human elements of interface design.

- The development of a control room integration methodology adaptable to all types of active network management scheme at the deployment stage. This methodology aims to facilitate ANM scheme vendors and DNOs with the integration of a scheme into the DNO control room.

- The proof-of-concept of a Control Room Demonstration Suite (CoRDS), built from widely used control room software. The CoRDS is a demonstration platform upon which DG and ANM scheme impacts on distribution networks can be assessed from a control room and control engineer perspective. The CoRDS facility is aimed not only to compliment the control room integration methodology (mentioned as the previous contribution), but also to provide a means of testing ANM scheme functionality, as well as wider impacts, during development through to the deployment stage.

- The proposal of solutions and modifications, both technical and otherwise, to ensure preparedness for control rooms and control engineers embracing the transition to active distribution networks.

1.3 Published Work

The author has published the following conference and journal papers on this subject over the period 2008 to 2012.

2008

Hay, S. L., Ault, G. W., Bell. K R. W., McDonald, J. R., *System Operator Interfaces to Active Network Management Schemes in Future Distribution Networks*, 43rd International Universities Power Engineering Conference, 1-4 September 2008

2009

Hay, S. L., Ault, G. W., McDonald, J. R., *Process of Simulating Novel Control Room Scenarios for Future Active Networks*, 20th International Conference and Exhibition on Electricity Distribution, 8-11 June 2009

Hay, S. L., Ault, G. W., McDonald, J. R., *Problems and Solutions for Control Rooms in Future Active Distribution Networks*, IEEE Power Energy Society General Meeting, 26-30 July 2009

Hay, S. L., Ault, G. W., Bell. K R. W., *Control Room Scenarios on Active Distribution Networks: Early Results and Next Steps*, 44th International Universities Power Engineering Conference, 1-4 September 2009

2013

Hay, S. L., Ault, G. W., Currie, R. A. F., Foote, C. E. T., Telford, D., *A Control Room Integration Methodology For Active Network Management Scheme Deployment*, IET Gener. Transm. Distrib. Under Review.

1.4 Thesis Outline

A solid background to the operation of distribution networks is provided in Chapter 2 including detailed descriptions of the networks themselves and the ancillary systems, e.g. protection, and components in place which are instrumental to their successful management. This includes descriptions of typical Supervisory Control and Data Acquisition (SCADA) and communications infrastructures implemented at distribution voltage levels, control room tools and techniques used in the daily management of the networks, and the roles and responsibilities of control engineers themselves.

Chapter 3 proceeds to examine the impacts that DG connections and ANM schemes have been shown to exhibit, and are predicted to cause, on distribution networks as penetrations continue to rise. The management of active distribution networks from a control room perspective is of particular interest to this thesis and several important issues are highlighted and discussed.

A number of limitations and uncertainties involving the deployment of ANM schemes are discussed in Chapter 4, followed by the implications each poses with regards to the control room integration, management and control of ANM schemes. In order to highlight the difficulties of developing widely applicable solutions to ANM integration problems, a compare and contrast exercise is carried out using two UK deployed ANM schemes [6], [7], as case studies. Evaluations are made on the integration process, management issues and control philosophies of each scheme, and these are presented and discussed. The control room integration process of [6] was partially undertaken as part of the work presented in this thesis, and resulted in the development of a methodology for the integration of ANM schemes into the control room. This is presented at this stage. The methodology has been developed to facilitate ANM scheme developers and DNOs who wish to deploy ANM schemes onto a distribution network. The scope of the methodology includes the processes of determining ANM scheme alarms, control actions, communications and interface requirements, as well as training methods, such that the integration of a scheme into a control room can be carried out efficiently at the deployment stage.

Chapter 5 presents work carried out in the development of a Control Room Demonstration Suite (CoRDS) aimed at investigating ANM scheme integration issues further. Common control room software and tools are used to simulate future distribution networks with high penetrations of DG and deployment of ANM schemes, and assess the management issues examined in the previous chapters. Results and findings are presented and analysed to determine the ways in which control rooms can prepare for future challenges.

Chapter 6 concludes the work presented in this thesis and reiterates the contributions it makes in the area of control room management of active distribution networks. Routes of further work in the area are then indicated, highlighting the benefits these will bring.

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Chapter 2

Operation and Control of Distribution Networks

2.1 Introduction to Distribution Networks

This chapter describes the various aspects of distribution network operation and how the different elements and systems interface with each other. It takes a particular view of how processes and technologies have evolved over the years and focuses on each ones contribution to the way networks are managed. To begin, distribution networks are described in detail, including typical topologies, voltage levels and planning procedures. The SCADA system and the communications infrastructure of distribution networks are then described including details of the range of technologies and protocols commonly used. Protection of distribution networks is also discussed briefly.

Following this, the evolution of power system operation and control from within the control room is examined, specifically the development of management tools from traditional wall connectivity diagrams to the fully integrated distribution management systems (DMS) used today. The tools and techniques available to control engineers at their workstation that have been implemented over the years to help with the problem of interpreting large volumes of SCADA alarms are also examined, and finally, the role of the distribution control engineer is described, detailing their daily tasks and responsibilities. Figure 2 highlights the different elements and systems involved in distribution network operation and their end-to end interaction.

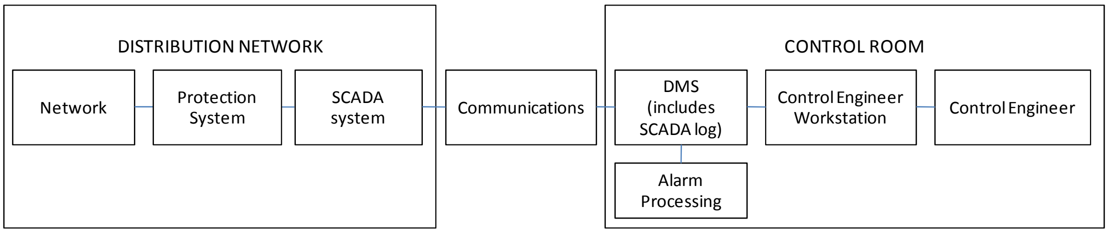

Figure 2: End-to-end Interaction of the Various Elements and Systems of a Distribution Network

This chapter provides the basis upon which the remainder of this thesis is built, dealing with how the networks will evolve from their present operational state into active networks.

2.2 The Distribution Network

In the UK, networks that operate at 11, 33 and up to 132kV are considered distribution networks (132kV is a distribution level voltage in the UK except in Scotland where it is considered to be a transmission voltage) [1]. There are also a small number of 6.6kV distribution networks that remain operational, though this is no longer considered to be a standard voltage and no new infrastructure is built at this level. The backbone of the present electricity network was constructed throughout the 1950's and 1960's, as large centralised generating plants became the favoured method of generation in post-war Great Britain [2], and there is now over 770,000km of distribution network cabling across the 14 UK DNO areas [3-8] and thousands of kilometres of overhead lines and cables in Northern Ireland [9]. Their original purpose was to transport electricity from grid supply points, where transmission voltages are stepped down to distribution level, down to the Low Voltage (LV) network where the voltage is further reduced to 400V 3-phase or 230V, single phase for end-users [10]. Large commercial and industrial consumers may be supplied directly from a 33 or 11kV supply. Over the past 60 years, the role of distribution networks has remained largely unchanged and their primary objective remains the bulk transfer of electricity from transmission to LV consumers.

The unidirectional power flows observed in distribution networks (from transmission level down to consumers) means they are considered passive in operation and, as a result of this, there are minimal control measures in place and network constraints are solved at the planning stage through network studies and analysis. All plant and equipment is sized to appropriately manage the N-1 constraint, where the loss of any one major circuit does not affect the supply to consumers [11]. A result of this conservative design method is that a large proportion of network capacity is unused in all but fault and outage conditions, which can be considered infrequent. Figure 3 illustrates how the N-1 constraint results in large amounts of unused capacity for a large proportion of the time. Each of these circuits must be designed to cope with the flow should the other be in outage and as such, do not operate at their full capacity.

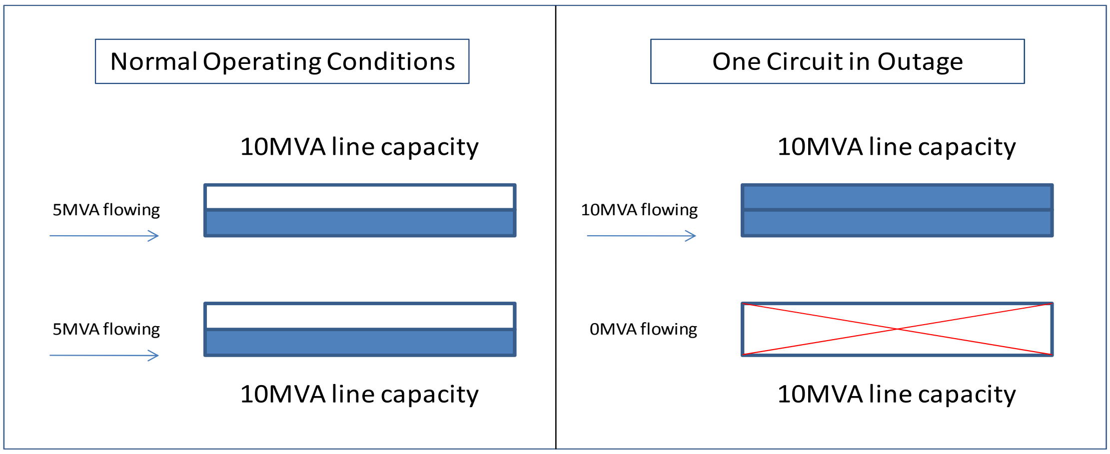

Figure 3: Illustration of the N-1 Contingency

2.2.1 Distribution Network Topology

The network topology in any given area is dependent on the load density of the circuits and the system voltage, as well as the geographical topography of the area. Urban distribution networks consist largely of underground cabling as overhead structures are unsuitable in built up areas. Rural networks, on the other hand, have a high proportion of overhead structures (wood poles in most instances) from 33kV down to LV. The open-loop network configuration, illustrated in Figure 4, is common in networks of 33kV and below.

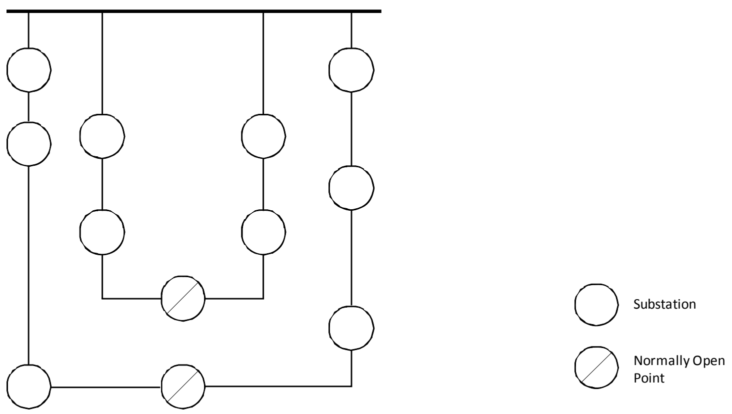

Figure 4: Open-loop Network Configuration (adapted from [12])

Open-loop networks are usually operated as several radial feeders under normal operating conditions with the ability to close the open points during outage or fault conditions to minimise loss of supply to customers. Purely radial networks, as shown in Figure 5, are also common in LV networks especially in rural areas.

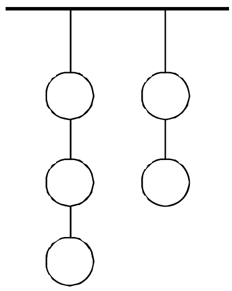

Figure 5: Radial Network Configuration (adapted from [12])

A common distribution network topology in urban areas is the meshed configuration, illustrated in Figure 6. Mesh arrangements provide better security of supply, they are easily extensible, and they have higher utilisation of circuit capacity. As such, they are suitable for busy urban networks which are susceptible to population growth. They can also be operated with open points.

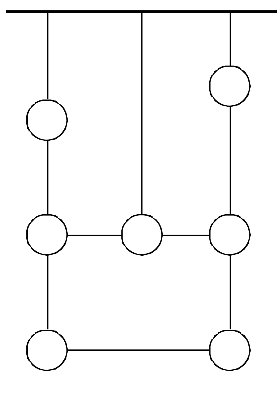

Figure 6: Mesh Network Configuration (adapted from [12])

2.3 Protection of Distribution Networks

Electricity networks are provided with protection systems that protect network assets, people and property. The protection system is vital to the successful operation of networks and various types of protection e.g. overcurrent, distance, differential, provide both main and back-up protection to each element of plant on the network. Protection devices include current transformers (CT) and voltage transformers (VT) and various types of circuit breaker (CB). All operations performed by the protection system are reported to the control room through the SCADA system.

2.4 The SCADA System

Information from the distribution network is collected via the SCADA system to allow the real-time monitoring, management and control of the network from within the control room. Remote terminal units (RTU) are located in substations, and additional monitoring devices are located at various points around the network. These RTUs and monitoring devices collect network information, such as parameter measurements and equipment status. This information is then passed on to the control room DMS and presented in the form of alarms, analogues and indications. As mentioned in Section 2.3, information from protection devices is also relayed to the control room via the SCADA system.

Operation of the SCADA system is reliant on the communications infrastructure, which is described in more detail in Section 2.5. A SCADA network is linked through multiple communications channels using a variety of technologies according to the importance of the connection, suitability of technology, and indeed what generation of technology is available at the time of installation. An example SCADA network is shown in Figure 7.

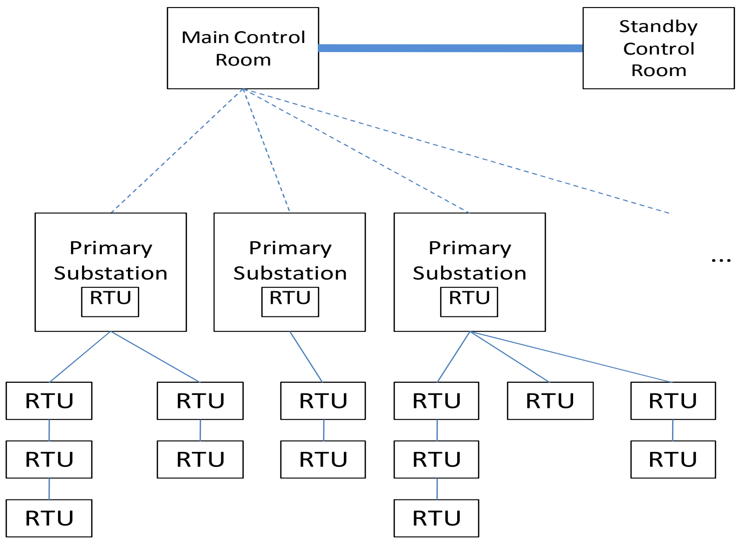

Figure 7: Typical SCADA Network [13]

Information is collected and forwarded through the SCADA system according to SCADA protocols, usually depending on the available technology and the value of the information being transmitted. Priority information is collected or received more frequently than that considered less critical. There are a number of SCADA protocols commonly used in distribution networks, for example polling and DNP3. Polling is one of the simplest protocols to employ, and it involves a master/slave philosophy [14]. The master station (for example, a primary substation RTU) has control over the communications, and it requests information from its slaves (for example, a secondary substation RTU or a monitoring device) at pre-set intervals, usually in a cycle. The master initiates all communication and the slave responds to the master only when requested.

The DNP3 protocol adopts the master/slave polling philosophy, yet is more complicated as it was developed with the view of interoperability between products supplied from different vendors to promote fair competition. The DNP3 protocol is open standard, and is built upon IEC and IEEE standards. A full description of the protocol can be found at [15].

Network analogues such as power, voltage and current are measured using transducers, while indications and alarms such as CB status or threshold warnings are represented as digital binary values. An indication pertains to devices where there are two contact points e.g. a switch, and these produce double digitals i.e. 00, 01, 10, 11. Alarms are produced when the measurement device has a single contact point, and a threshold has been breached causing the contacts to separate. This produces single digital values, 0 or 1. The electrical signal information gathered from mechanical devices on the network is sent to its assigned RTU where it is converted to digital values. Newer devices such as programmable logic controllers (PLC) and microprocessor relays do not require conversion as the signals are intrinsically digital. Analogues directly update the network connectivity diagram in the DMS, while alarms and indications appear in the SCADA alarm log. Alarms and indications are time-stamped.

The SCADA system serves not only to bring information to the control room, it is also used to exercise control actions by control engineers e.g. open/close a circuit breaker. This functionality is very useful for post-fault restoration and many faults can be managed remotely from the control room. It also facilitates switching and outage plans, with control engineers switching remotely whenever possible thus saving time and field engineer man power.

2.5 Communications Infrastructures

As mentioned in Section 2.4, the SCADA system, and indeed the whole power system, is reliant on its communications infrastructure to operate and be operated successfully. Monitoring and measurement devices are each connected to an RTU, either directly or through another device, and in turn, all RTUs are connected to the DMS in the control room either directly or indirectly.

There are many different types of communications media existing on distribution networks in the UK today. The type of media chosen for a certain communication link is dependent on a number of factors including cost, security requirements and geographical topology.

The communications infrastructure on distribution networks was built at the same time as the network itself. Over the years, a large proportion of this infrastructure has been replaced or upgraded. Additionally, new devices and links have been installed with new electrical network. As such, there are multiple generations of technology operating simultaneously, for example, original radio signals and pilot wire links are interoperating with the newer Ethernet and GPS links commonly installed nowadays. It is here that the DNP protocol, discussed in Section 2.4, is proven functional, by allowing the interoperation of a multitude of different communication technologies.

2.6 The Evolution of Power System Control

This section explores the evolution of power system control from paper based management to the fully integrated energy management systems (EMS) and DMS in use today. It details the range of different architectures and functions of EMS and how they are used to provide a streamlined service to the electrical utility from both technical and business viewpoints. Evidence is presented for the problem control rooms have with alarm management and numerous papers and articles are cited which have focused on the issue of high volumes of SCADA alarms. Research into resolving this problem, by various means, including alarm processing and decision support is addressed later in Section 2.7.6.

The roots of power control date back to the 1920s [16]. What is considered 'state-of-the-art' has evolved over the years while the objective has remained much the same; to provide control operators with the most up-to-date and relevant information to allow them to operate and control the power network and deliver a safe and secure power supply to end users.

Since the introduction of computer-based SCADA systems to control rooms in the 1960s, the information provided to control engineers has grown significantly. The 1979 paper by Russell et al. [17] provides a detailed overview of the evolution of control centre capabilities from the early 1960s through to the late 1970s noting the introduction of many basic control centre functions including SCADA, scheduling, state estimation, power flow analysis and interactive planning and the trend towards computer-based systems. Also described are the motivations behind the move from single processor design to a distributed processing architecture, as well as the improvement of database management as functionality in control centres increased and more data was being used for more tasks.

Following on from [17], the history of the EMS is continued through to 1989 in Evans [18]. This article then goes on to describe, in a conceptual context, the three major EMS architectures used at that time; centralised, clustered and distributed, citing the strengths and limitations of each in the areas of responsiveness, expandability and maintainability.

With improving technology came increasing amounts of data and information and Amelink et al. [19] report that by 1986, control centres had to manage anywhere from 20,000 to 50,000 monitoring points. The massive volume of alarms received each day prompted research into tools and techniques that could help operators manage the networks more efficiently.

A survey by a Joint Working Group on Power System Control Centres on excessive alarms received by control centres was carried out by Prince et al. [20] in 1989. The paper reports results of the survey of 87 control centres on the volume of SCADA alarms they receive. The survey included questions on the causes of alarms, alarm processing tools in operation, alarm filtering, how alarms are displayed and operator opinion on the issue. The majority of those surveyed agreed that control centres receive too many alarms and require better processing tools.

Much of the advancements to control room design and technologies were concentrated at transmission level, while distribution control centres continued to rely on paper based management and large wall diagrams. In 1991, Gallagher [21] identified distribution control as the least automated area where the use of manual management systems was still in effect. The implementation of SCADA networks at distribution level improved visibility and monitoring but a lack of processing power hindered information flow. The use of network management systems (NMS) at distribution voltages was recommended to streamline data and control centre functions.

In the early days of DMS integration, a number of papers were published highlighting the functionalities of the systems and the benefits they provide [22], [23]. [22] explains the concept of a DMS and the characteristic layered architecture in detail, and the functionality of each layer. The potential benefits of each layer are then discussed. [23] also discusses the functionality and benefits of DMS applications, and then focuses on how an integrated DMS environment can prove beneficial to business, as opposed to the previous isolation of corporate information systems. Later, in 2000, the Vanderbilt Institute for Software Integrated Systems (ISIS) developed the IDMS, an integrated DMS, for electric utilities [24]. The IDMS provides a configurable integration framework to allow the easy implementation of management systems and decision support tools into a control room. It promotes the idea of fully integrated management systems within the control room to facilitate data management and processing, specifically fault diagnostics and has been integrated into several off-the-shelf management systems.

In 2001, a CIRED paper by Schneider Electric Ltd UK was published describing the features of a modern DMS [25]. Like many of the previous papers cited, this gives both technical and business perspectives when detailing the potential benefits of employing a DMS in the control room. The timeline of this paper suggests the uptake of DMS in the UK remained slow despite the recommendations in the 90's.

An article published in the IEEE Power & Energy Magazine by Maghsoodlou [26] in 2004 supports this assumption. It states that many utilities have not upgraded their technology since it was implemented in the 1990's and the full potential of these systems is not being utilised or exploited. It also emphasises the importance of these systems and makes suggestions of simple changes that can improve the reliability of electricity supply.

In line with the government targets, incentives and policies, outlined in Chapter 1, research and development in the area of active distribution networks and smartgrids gained momentum in the latter part of the last decade and continues to grow, and there are now international conferences dedicated solely to the integration challenges presented by renewable and distributed generators and smartgrid technologies. And although the research is mainly focused on network challenges of DG integration, some attention has been afforded to the control room issues brought about by this. A number of the ideas proposed for control room management of active distribution networks and smartgrids are reviewed here.

A situational awareness tool developed from a distribution state estimator was suggested by Sebastian et al from EDF Energy R&D [27]. The viewpoint that improved real-time visibility and awareness of the network is essential to managing active networks is assumed, and the situational awareness tool presented has the ability to provide this.

An article published in the IEEE Power & Energy magazine in 2009 by Fan et al [28] expresses the requirement for advanced DMS to ensure the successful control room management of smartgrids. Increased monitoring and control at lower voltages, utilisation of open standards, such as the Common Information Model (CIM), and enhancement of existing DMS functions are among the improvements suggested in this article.

DMS vendors have also recognised the challenges ahead for the management and control of active networks and smartgrids, and are becoming increasingly involved in the research and development of control room technologies, specifically fully-integrated DMS architectures [29], [30] capable of managing a smartgrid.

Some insist the key to managing smartgrids lies in increased data availability and network visibility and have taken steps towards this by researching the advantages of phasor measurement units (PMU) in achieving greater visibility [31]. A number of utilities have deployed PMUs on certain parts of their networks with this same objective [32 - 33].

Implementing control rooms specifically for managing renewable generation may also prove to be an attractive option for those utilities with large penetration potential. Red Eléctrica de España, a large Spanish utility currently manages over 20 GW of renewable generation from a dedicated control room [34].

2.7 Distribution Management Systems

As described in Section 2.6, power system control has evolved with improving communication and computer technologies. Historically, distribution networks were monitored and controlled using large wall diagrams and paper based management, with disturbances being handled manually [21]. Tracking advances in technology over the years, distribution network management procedures have also advanced. Although manual analysis of power systems has remained part of the process in many distribution control rooms the majority of the 14 UK DNOs now make use of a DMS to manage their networks. The most widely used DMS in the UK is the GE Enmac™ system [35]. The ENMAC DMS assists in streamlining data, processes and information throughout the variety of interested parties within the utility i.e. the control room, the planning department, the emergency call centre etc. This integrated approach ensures that each has access to the most up to date information through the dissemination of network information. The core functions of a modern DMS are described in this section.

2.7.1 Data and Alarms

The DMS is the repository for all distribution SCADA alarms, indications and measurements, from where they are routed to their relevant destinations. Alarms and indications are time-stamped and presented in the SCADA alarm log. Depending on their nature and priority, many alarms must be acknowledged by the control engineer. The SCADA alarm log has a number of filtering options that allow control engineers to filter alarms by category, type, priority and timing. Analogue measurements of voltage (V), real power (MW), reactive power (MVAr), current (A) and frequency (f) are all updated on the network connectivity diagram (described further in Section 2.7.2) when the information is made available by the SCADA system.

2.7.2 Network Connectivity Diagram

The main interface to the DMS that the control engineers use is the connectivity diagram. It contains all available information and properties about each network component, such as overhead line MVA rating, transformer impedance and busbar voltage etc. This information is a user friendly and more accessible visualisation of a database that contains all of the available network data.

A useful function in times of outage or fault is the DMS facility to perform (current) traces that show which circuit a specific part of the network is being supplied from at any point in time. This allows control engineers to see where customers, primarily affected by an outage or fault, are being supplied from.

2.7.3 Telecontrol Switching

Telecontrol switching is performed via the network connectivity diagram. Where available, the control engineer can operate circuit breakers remotely using the SCADA system telecontrols. This allows for timely restoration of supply following faults, and the control engineer can also perform any accessible switching on outage schedules.

2.7.4 Control Engineer Work Scheduling

Planned outage schedules, such as those created to carry out maintenance works, are created in the DMS using an outage management program. Outage schedules are compiled by maintenance personnel in line with maintenance records, and 'jobs' are created for each outage. Each job consists of a sequential list of steps that must be undertaken and the control engineer is responsible for checking and verifying the integrity of these job lists to ensure no customer supplies are interrupted unnecessarily, and that the work is carried out safely. The control engineer is also responsible for the real-time supervision of each job and is in regular contact with field engineers for the duration of the work. The network connectivity diagram and SCADA alarm log are used by the control engineer to monitor the progress of work, as network plant and circuits change colour to represent their current operating state on the diagram, and SCADA alarms for changes of state of plant are sent to the control room.

2.7.5 Emergency Call Centre

The emergency call centre utilise another system within the DMS, known within ENMAC as the trouble call management system. Customer notifications of loss of supply, as well as other concerns, are logged and passed along to the fault dispatchers where field engineers are contacted and assigned to investigate each problem. The control engineer has access to all of this information such that he can analyse and investigate the occurrence and location of faults, and coordinate the clearing of faults through field engineers and using telecontrols where possible.

A DMS should support each of these core functions described in Sections 2.7.1 to 2.7.5, however, the level of DMS functionality is dependent on the requirements of the utility and many additional features are available such as power flow analysis, SCADA alarm processing and decision support.

2.7.6 Alarm Processing and Decision Support

As expressed in Section 2.6, the size of distribution networks and the amount of SCADA equipment required to provide adequate measurement and control functionality give rise to very large volumes of SCADA data arriving in the control room on a daily basis. The issue of interpreting such large volumes of SCADA alarms has been a focus of control room development for many years. Numerous solutions to this problem have been developed, including alarm processors, decision support tools and expert systems. Each of these solutions works on the premise of collecting the incoming stream of SCADA data and employing various techniques to interpret the data. They each aim to display succinct, meaningful messages to control engineers regarding network events, rather than the common list of raw alarm data, from which they must then infer what event has occurred.

There have been many such tools developed throughout the years, and some examples of the most common types of approach (e.g. expert system, neural network, machine learning) are summarised here.

The principal of neural networks is based on the construction of the human brain and its ability to think, interpret, remember and solve problems. The neural networks are simplified computer models of it [36].

An expert system is a computer program intended to possess the same knowledge as a human expert, such that it is able to make the same judgments and decisions based on data received [37].

Machine learning involves the use of algorithms which allow computer programs to evolve their behaviour based on experience. In essence, the algorithms are considered to be ‘learning’ over time [38].

Amelink et al [19] published a paper in 1986 discussing the issue of alarm processing, and suggested two techniques that could be applied to assist in the processing of large volumes of alarms; statically adaptive and dynamically adaptive message processing. Statically adaptive message processing determines message routing, priority and segmentation by the utility. This allows the utility to ensure that messages are only seen by the people to whom they are relevant. Once these conditions are set, they can only be altered through human intervention. Dynamically adaptive message processing on the other hand, takes into account that message priorities will change with changing system conditions and shifts message priorities accordingly.

This approach to message processing routes messages to the appropriate person and ensures individual control engineers are not burdened with messages that are not pertinent to them, yet they still receive raw data. Many other approaches take the raw alarm data and interpret their meaning in relation to other alarms received to determine if and what event has occurred, and this more meaningful message is displayed to control engineers. A number of examples of this approach to alarm processing are discussed here, each employing a different technique to achieve this objective.

The use of neural networks to interpret SCADA alarms was researched in 1990 by Chan [39]. The application of neural networks in the interpretation of power system data was attempted here by training the neural network to learn and recognise alarm patterns and scenarios. Proof-of-concept testing was carried out on a single substation with the intention to build on this to produce generic intelligent alarm processors.

Also in 1990, a knowledge-based alarm processor was developed by Wisconsin Electric Power Company and the University of Wisconsin [40]. A knowledge-based approach was taken in this instance, whereby knowledge and experience is extracted from human operators and is implanted into a computer program. During power system disturbances, the alarm processor draws on this knowledge and works towards solving the problem at hand in much the same way a human expert would.

A machine learning technique was applied in 1991 by Ypsilantis et al [41] which complements an existing alarm processor through updating its knowledge base following an emergency with information gathered during the incident. It achieves this by implementing a learning algorithm.

Work on the development of alarm processors continued into 1992, when Young et al [42] developed a practical expert system for alarm processing. This particular expert system uses a hypothesis-based approach with the intention of integration into a distribution control room.

In 1993, Burt et al [43] developed a real-time decision support system for a 132kV network through the integration of two well established expert systems; APEX and RESPONDD. APEX was developed as an alarm processor and RESPONDD was a tool used in fault diagnostics. Each of the two expert systems uses a hypothesising approach to their reasoning which allows for inference in the absence of SCADA data. The two were integrated and given a decision support interface.

Several years later in 1998, a model-based approach to intelligent alarm processing was researched by Dahlgren et al [44]. Model-based reasoning was justified here as the best approach, as the overall aim was to suppress power system alarms and only present the most useful information. The 'models' are in fact representations of cause-effect relationships between generated alarms.

There have been some more recent developments in this area in line with technological advances. One of these new developments uses multi-agent systems technology and it has been operating online at a UK utility since late 2004. The Protection Engineering Diagnostic Agents (PEDA) system developed by Hossack et al [45], [46] integrates a number of expert systems to automate the analysis of SCADA and digital fault recorder (DFR) data. These expert systems are a selection of rule-based and model-based systems incorporated with multi-agent system technology.

Kyriakides et al [47] proposed a 'next generation' alarm processing technique in their paper. The proposal states that the algorithm will provide extra features for the alarm processor. In addition to the prioritisation of alarms, it would provide recommendations and decisions to the operator. The algorithm is to be developed with wide area controls.

Such tools, however useful they can be, are not without problems. Maintainability is one of the main issues associated with employing a tool such as those described above, and this issue was also highlighted on a visit to the Scottish Power control room (see

Appendix A). These systems must be updated and likely reconfigured each time the network is changed or updated, and this work requires a certain amount of manual input on each occasion. Although maintenance is an essential feature of any such tool, it can prove to be a significant burden on resources. Further to this, it is often the case that such systems are not developed within the utility for which they are intended and so this results in the designer/developer having to be contracted to upgrade the system. An arrangement of this type can quickly become unsustainable and economically unjustifiable, thus the system falls into disrepair.

2.8 The Control Engineer Workstation

A control engineer must have quick and easy access to all the necessary computer systems at their disposal. For this reason, control engineers will, in general, have upward of 4 PC monitors at their workstation, each displaying a different program or interface necessary to the daily operation of the network. A typical distribution control engineer will have at least the following programs displayed at all times, each on a dedicated PC monitor: email, the SCADA alarm log, the DMS network connectivity diagram and their ongoing work schedule. This is represented diagrammatically in Figure 8.

It is necessary to dedicate a screen to each of these programs to aid interpretation of network events. While a control engineer is working through a work schedule, the SCADA alarm log and the DMS connectivity diagram allows them to monitor a situation as (in the absence of fault conditions) events are usually in correlation with the planned outage. The control engineer refers back to the schedule whilst interpreting information from the connectivity diagram and the SCADA alarm log.

In cases of fault or emergency, the DMS network connectivity diagram and the SCADA alarm log display the same information in different ways and it is part of the control engineer's job is to interpret and correlate information from the various available sources to determine the cause of the problem.

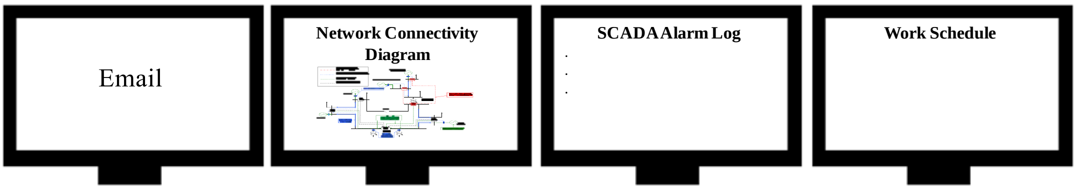

Figure 8: Typical Control Engineer Workstation

Other displays can include the emergency call centre customer call management system interface, which enables the control engineer to access information on faults in their area of network, modelling and simulation software to run contingency analyses for outage planning, meteorological maps showing the occurrence and real-time threat of lightning and the transmission network EMS.

2.9 The Control Engineer

The primary concerns of a control engineer are network and equipment safety and supply integrity. They achieve this through vigilant management of the networks which is made possible by the tools described in the previous sections, and by drawing on years of both operational and control room experience. The control engineer is in charge of outage management for both planned and unplanned outages.

2.9.1 Planned Outages

Planned outages, such as those to allow for maintenance to be performed are scheduled in advance according to planning schedules. The work is scheduled and carried out in very clear stages, each of which must be checked and reviewed by the control engineer to ensure that no customer supplies are affected unnecessarily, that all plant and personnel remain safe at all times and all risks have been assessed. The control engineer manages the outage from the control room by coordinating work steps carried out by the field engineer(s) with steps that can be carried out by the control engineer using telecontrols available from within the DMS. The control engineer will issue a Permit to Safety to the field engineer(s) in order that they can carry out the work. Each completed step must be confirmed with the control engineer and time stamped on the work schedule. The control engineer monitors the progress of the outage using the network connectivity diagram in the DMS and SCADA alarms, ensuring that any actions taken are reflected in the diagram and the alarm log.

2.9.2 Unplanned Outages

Unplanned outages such as those caused by faults are managed on an individual basis depending on the nature of the fault itself. The control engineer can be alerted to the incidence of a fault through the DMS and SCADA alarm log, or through the Emergency Call Centre trouble call management system if a customer has reported a loss of supply. Once the fault has been located, it will be assessed to determine the best way of removing the fault and restoring supply to the customer, using telecontrols where possible. The control engineer will draw on years of operational experience both out with and inside the control room to manage the situations presented to them.

2.10 Chapter 2 Review

This chapter has described distribution networks in some detail, and explained each of the supporting systems in place to ensure their safe and secure operation and management. The common distribution network topologies for urban and rural networks have been discussed, with the reasoning behind these designs. The SCADA system and communications infrastructure that accompany the electrical networks, and the roles they play in network management, are also described.

Moving into the control room itself, the management tools available to control engineers were examined, and a history of the evolution of these tools was presented, which highlights how control room procedures have changed in line with technological advances and increasing system security requirements. The principal features of a DMS, such as those used widely in the UK today, were also described as were the ways in which control engineers can interface and interact with the DMS. Section 2.7.6 looked at the development of alarm processing, and other related tools, which have been introduced over the years to improve the interpretation of SCADA alarms. The role of a control engineer and details of their typical daily tasks and procedures were then given.

This chapter has highlighted the main systems and entities involved in the operation and control of distribution networks, and emphasis is placed on the fact that these electrical networks have changed very little since their construction several decades ago, and the management and control systems are perhaps not as advanced as technology would allow as a result of this. This provides a basis upon which this thesis builds to investigate the impacts of DG and ANM schemes on networks, the control room and control engineers.

2.11 Chapter 2 References

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Chapter 3

Impacts of Distributed Generation and Active Network Management

3.1 Introduction

As Chapter 1 explains, the electricity industry is under increasing pressure to revise its portfolio of generation to include significant amounts of renewable generation in order to combat global climate concerns. As a result, the traditionally passive distribution networks, described in Chapter 2, are undergoing a period of transition which will see their evolution to actively managed networks. Combining high penetrations of DG with a multitude of decentralised ANM schemes will cause this fundamental shift in distribution network operating philosophy. This type of distribution network must be operated more like a transmission network, with more real-time generation and load balancing, and this presents a number of challenges for networks and their management. This chapter offers a review of identified impacts of DG, which focus on network related issues such as power quality and fault levels. The known effects of ANM scheme deployment are then presented. The results of a study of the impacts of active distribution networks on SCADA alarms is also presented, which provides some insight into how the control room and control engineers may be affected by the shift from passive to active operation.

Finally, the combined effects of DG connection and ANM scheme deployment on the control room are explored, highlighting the barriers which must be overcome in order to accomplish successful operation of active distribution networks.

3.2 Distributed Generation

The connection of generation at distribution voltages has grown considerably in the past few years. The portfolio of DG connecting to networks is varied, more so than traditional centralised generating stations in the UK, which have been fossil fuel based (coal, oil and gas plants), nuclear and some large scale hydro and pumped storage. Generation of electricity is now being achieved through a number of renewable sources such as wind, solar, tidal and wave. Combined heat and power (CHP) generation has also become popular. The introduction of DG has impacted various aspects of network operation, and the renewable generation has also introduced the element of intermittency to generation. These impacts on network operation have been studied to establish what measures must be taken to ensure security and quality of supply is not compromised and the following section describes a selection of those that have been recognised and researched, encompassing power quality, voltage stability, fault level and protection, voltage profile and intermittency.

3.2.1 Impacts of Distributed Generation on Network Operation

The power quality issues, caused by the connection of DG, were discussed in the 1995 paper by Jenkins et al [1]. These issues include steady state voltage excursions, phase voltage imbalance, transient voltage variations (flicker) and voltage waveform variations (harmonics). The impacts are dependent on the size of the generator relative to the network local fault level, the X/R ratio, and the type of generator installed, whether that is a synchronous machine or induction generator, each presenting different problems. Some of these issues are also discussed in a paper by Surender et al [2] who used MATLAB simulations to study them.

Voltage stability has also been identified as an area of concern with increasing levels of DG. The paper by Chen et al [3] studied this issue and used the technique of power flow analysis to establish voltage stability at different parts of a network. The authors also introduced a novel power flow analysis method, using a sensitivity matrix designed specifically for analysis of distribution networks with DG, and based on a voltage stability index.

Fault level and protection are both directly affected by the connection of DG. The addition of DG raises the local voltage, and in turn changes the fault current and this can cause issues with protection schemes in the area. Shafiu et al [4] report on these issues in their paper and suggest some solutions, for example, using distance protection on 11kV feeders as a change from the traditional overcurrent protection, to the problems presented by DG on the protection system.

The impact of small-scale DG on voltage profile was studied, and is presented in the paper by Conti et al [5]. It evaluated the amount of power that can be injected into a distribution feeder without causing overvoltage in the presence of DG, and identified potential bi-directional power flows and performs analysis on distributed and lumped loads. It proves a rise in voltage profile is always apparent when DG is connected, as the current flowing in the feeder is reduced. The paper recommends that the upper limit of current injection of any feeder is assessed to ensure the maximum amount of DG can be connected without causing overvoltage.

Further research in this area of the effects of microgeneration on LV voltage profile was carried out by Richardson et al [6] in 2009. The quantity and location of DG along LV feeders were assessed to determine how they would alter the voltage, highlighting that the location of the microgeneration along a line is a significant factor in determining the maximum penetration capacity.

The issue of intermittency of renewable generation is widely acknowledged. The key concern being the ability of intermittent generation sources to meet peak demand. This subject is discussed in the 2008 paper by Skea et al [7], where the issue is presented as an economic challenge. A methodology for assessing the cost of maintaining system stability, and sufficient capacity to meet demand with renewable generation deployment in comparison to conventional generation plants is presented.

The impacts described here are examples of those which directly affect the electrical operation of the network as a consequence of connection of DG. There are a number of other implications which affect various different aspects of power system operation, and these are investigated later in Section 3.4.

3.3 Active Network Management

There exists numerous definitions for ANM, including the definition given in [8], and for the purposes of this thesis, ANM is understood to involve the pre-emptive control of network parameters such as voltage, real power flow and current by means of real-time monitoring. The philosophy of ANM is to accommodate a greater capacity of generation to connect to networks and utilise the ‘latent capacity’. This is possible as it works on the premis is that action is taken at times when regulatory or statutory limits are under threat of a breach to ensure this does not occur. As explained in Chapter 1, ANM of distribution networks is considered a cost effective enabling solution to increased DG access onto UK networks by permitting generation to connect whilst deferring potentially expensive network reinforcements and upgrades [9].

The notable benefits of ANM have prompted research and development of schemes and techniques in the UK, and an Active Networks Deployment Register has been created at the University of Strathclyde, in conjunction with BIS [10]. The Register lists and summarises all relevant projects from the UK and internationally. Its purpose as an online resource is to disseminate active networks research and development throughout the field and promote collaboration. Similar repositories are available around the world including the EPRI Smart Grid Resource Center [11] in the USA where vast amounts of research is being carried out on ANM and distribution automation projects. The Smart Grid Resource Centre contains information on a variety of demonstration projects relating to distributed energy resources, most notably the Intelligrid Program which facilitates these demonstration projects and also provides key support to utilities on smartgrid related projects.

A number of schemes have been deployed onto UK networks for trial purposes, three of which were under the Ofgem Registered Power Zone (RPZ) initiative, which was explained in Chapter 1. The Skegness RPZ, which is a Dynamic Thermal Ratings ANM scheme developed by Central Networks (now Western Power Distribution), allows increased power flow through overhead lines at times when it is safe to do so [12] and the Orkney RPZ, on the Scottish & Southern Energy distribution network in Orkney, is an ANM scheme which manages the thermal constraints of the network and takes escalating action when a threat appears [13]. The third UK RPZ is that at Martham Primary Substation in Norfolk where GenAVC, a voltage management tool, has been installed by EDF Energy area to solve voltage rise problems caused by local wind generation connected at 11kV [14]. EDF Energy also deployed an active generation constraint system in the Great Yarmouth area, to allow the connection of an offshore windfarm [15].

Chapter 4 explores the operation of the Skegness RPZ and the Orkney RPZ in more detail, and this is accompanied by a description of the processes involved in the integration of the ANM schemes into their respective control rooms with a view to highlighting the differences and similarities of the two.

ANM schemes deployed to support DG connection add further to the changing operational philosophy of distribution networks, and introduce additional issues for network operation.

3.3.1 Impacts of ANM on Network Operation

The impacts of ANM schemes on the direct electrical operation of networks are not widely known as there are very few deployed on networks to date. Further to this, many have not yet been subjected to the full operational stress of their capabilities. As described in Section 3.3, there are four deployed on UK distribution networks, and to date, there have been no reports of their affecting electrical network operation adversely.

A consultation with SSE [Appendix D] where the Orkney RPZ ANM scheme is deployed has reported no impacts on daily network operations to date, however the control room have noted that extra care must be taken when planning outages in the Orkney network where the scheme is operational. Power system analysis must now be carried out to assess which DG sites connected under the scheme are able to generate during the outage, and which ones must be switched off. This is done on a case by case basis resulting in more work for control engineers charged with planning outages on that network.

Further impacts may become apparent as more ANM schemes are deployed in the coming years.

As is true for DG, the introduction of ANM schemes, although they have not yet proven to impact the electrical operation of the network, are expected have an effect on other areas of network operation in the more immediate future. These effects are examined in the following Section 3.4.

3.4 Further Effects of DG and ANM

Having detailed the numerous impacts of DG and ANM schemes which affect the electrical operation of networks in Sections 3.2.1 and 3.3.1 respectively, the following sections highlight a variety of the other areas of network operation which will be affected by the evolution of distribution networks to actively managed systems.

3.4.1 Changes to SCADA Information

Distribution control rooms receive a large volume of SCADA alarms on a daily basis. This volume is dependent on a number of factors including the size of network area being monitored, and the number of controllable devices, and it is usually in the thousands. An increase in the volume, and a variation on what is considered the 'normal' distribution of SCADA alarms received daily may present management problems for control engineers. There are a number of ways in which SCADA alarms could be affected.

Primarily, alarms from DG connection sites themselves will add to the volume of alarms currently received. Additionally, alarms originating from ANM schemes deployed on networks informing the control room of any activity will also contribute. Furthermore, distribution networks with large penetrations of DG will be subject to higher levels of congestion, where systems are operating closer to their limits which in turn will increase the frequency of alarms warning of threats to system limits. Conversely, the introduction of ANM schemes may alleviate some of these alarms by taking pre-emptive control to prevent the aforementioned threats.

A certain level of uncertainty regarding DG connection patterns and ANM scheme deployment is apparent, and this is described fully in Chapter 4. There is also currently little regulation regarding what information generators must provide the control room with. The Distribution Code states that it is at the discretion of the DNO to decide what information it requires from the site:

"*The User shall provide such voltage, current, frequency, Active Power and Reactive Power pulses and outputs and status points from his System as are considered reasonable by the DNO to ensure adequate System monitoring.*" [16]

The scale, in MW, of a DG connection has influence, to a certain extent, over how many alarms it is required to provide, with the Distribution Code stating that for LV and small generating units:

"It is unlikely that more information than that specified in DPC7.3.1 will be required for Embedded Generators who are to be connected at Low Voltage and have less than 50kVA in capacity, or connected at other than Low Voltage and have less than 300kVA in capacity." [17]

With DPC7.3.1 making no reference to telemetry or monitoring, only stating that a 'means of connection and disconnection' must be provided. However, at much larger capacities the regulations increase and, as such, so does the SCADA information required. Medium Power Stations (defined in the Distribution Code as a power station connected to the NGC transmission network with a capacity between 50MW and 100MW) and Large Power Stations (defined in the Distribution Code as 100MW in

England and Wales, 30MW in the Scottish Power area and 10MW in the Scottish Hydro Electric area) are subject to more stringent requirements by the National Grid Transmission Grid Code,

"*NGET shall provide system control and data acquisition (SCADA) outstation interface equipment. The User shall provide such voltage, current, Frequency, Active Power and Reactive Power measurement outputs and plant status indications and alarms to the Transmission SCADA outstation interface equipment as required by NGET in accordance with the terms of the Bilateral Agreement.*" [18]

Where the Bilateral Agreement is a legally binding agreement, used by National Grid for customers who wish to connect to the UK transmission system [19].

In addition to the uncertainty regarding SCADA requirements of DG connections, each ANM scheme that is deployed will produce a different number of alarms depending on its design and functionality and there are no regulations in the various grid codes referencing ANM scheme reporting requirements.

In order to gain more insight into the issue of DG and ANM scheme impact on SCADA alarm volume, a study was conducted as part of this research. The investigation is explained and the results are presented in Section 3.4.1.1.

3.4.1.1 SCADA Alarm Volume: Preliminary Study

Using a sample of SCADA alarms over a 5 day period from a UK DNO, a SCADA alarm study was carried out (The full profile is not provided in the Appendices, however an anonymised sample is provided as Appendix E as part of an analysis of nuisance alarms). The principal aim of this study is to determine the effects of DG and ANM scheme alarms on the overall SCADA volume, and how this may contribute to the distribution control room receiving more information than control engineers can realistically manage.

The nature of a control engineer's job fosters the adoption of routine and familiarity with their work, and this includes a certain familiarity with the SCADA alarms they receive on daily basis. Largely, control rooms receive a 'standard' volume of data under normal operating conditions, they are therefore adept at recognising certain patterns and scenarios with the help of the various tools described in Chapter 2, and as the volume of SCADA alarms only deviates significantly during emergency conditions, this type of situation is easily distinguishable. Figure 9 below shows a 5 day profile of alarm volume data received by a UK control room.

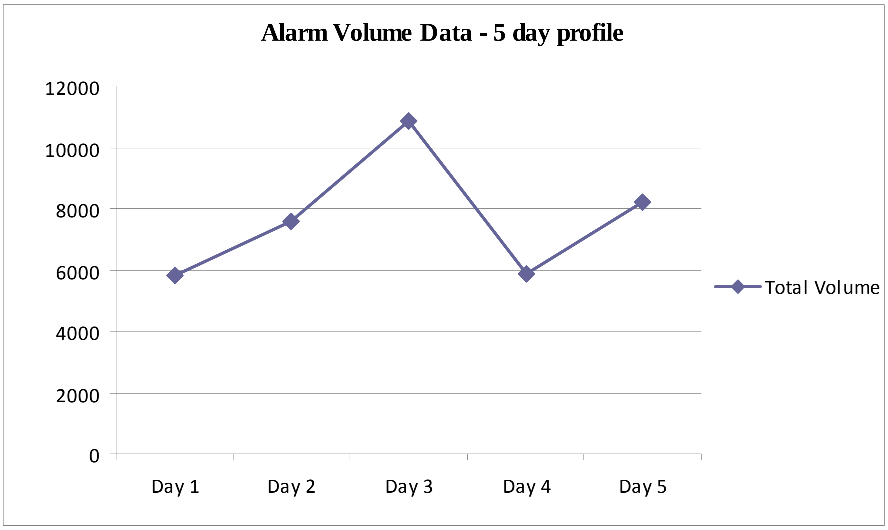

Figure 9: Alarm Data Volume Over a 5 Day Period

Figure 9 highlights that in this particular 5 day sample, the control room received between 5,500 and 8,500 SCADA alarms per day. The occurrence of an incident on Day 3, however, resulted in the volume of SCADA alarms received climbing to over 10,000.

The SCADA alarm volume statistics given in Figure 9 represent the total number of SCADA alarms received by control room operators each day in that particular sample period. This total comprises SCADA alarms from the transmission and distribution networks as well as communications alarms, the problems with which are discussed further in Section 3.4.3, and others. The data sample comprises SCADA alarms received by a transmission control room EMS, and in the absence of correlating data from the distribution control room DMS, a figure of 2,500 alarms is assumed as a daily average of distribution SCADA alarms (this figure was obtained from the DNO who provided the original data and has been added to the distribution number from the original sample to give the total).

Figure 10 is a pie chart representation of the SCADA alarms received on Day 2, according to their classification (e.g. transmission, distribution).

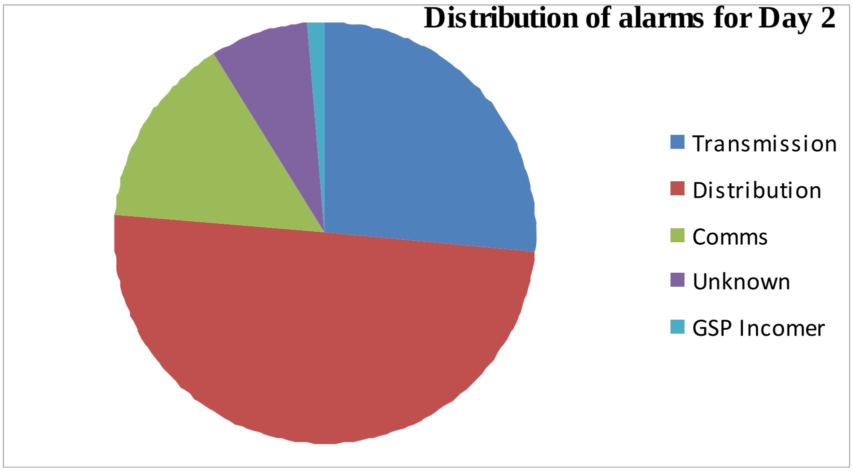

Figure 10: Distribution of SCADA Alarms Received on Day 2

As seen in Figure 10, the distribution network produced the most SCADA alarms on Day 2. Distribution networks cover vast areas and have significantly more items of plant to monitor, in comparison to transmission assets, so the difference in alarm volume received from each can vary greatly in comparison to the other. Conversely, there is much more extensive monitoring and control provisions provided at transmission voltages which is one contributing factor in the large volume of SCADA alarms they receive.

Another contributing factor to the volume of transmission SCADA alarms received daily is their active operating philosophy, the real-time balancing of generation and load and the real-time control of power flows. Currently, as explained in Chapter 2, distribution networks operate in a passive manner, however, as they evolve into more active systems, they will be operated much like transmission networks are and so should expect an increase in the volume of SCADA alarms reaching the control room. Combining this with improved distribution network metering and visibility, which is discussed and recommended in Section 3.4.2, and the vast expanses of network, the issue of too much information is raised and this is discussed further in Section 3.4.2.2.

An increase in data volume such as is evident on Day 3 can be prompted by any number of scenarios; an event such as a storm spanning several hours, or it could be triggered by an event lasting no longer than a few seconds i.e. a transient event. A push in system conditions from normal to emergency can cause thousands of additional alarms, and these can all occur within a short period of time.

Figure 11 shows the distribution of SCADA alarms received by the control room on Day 3.

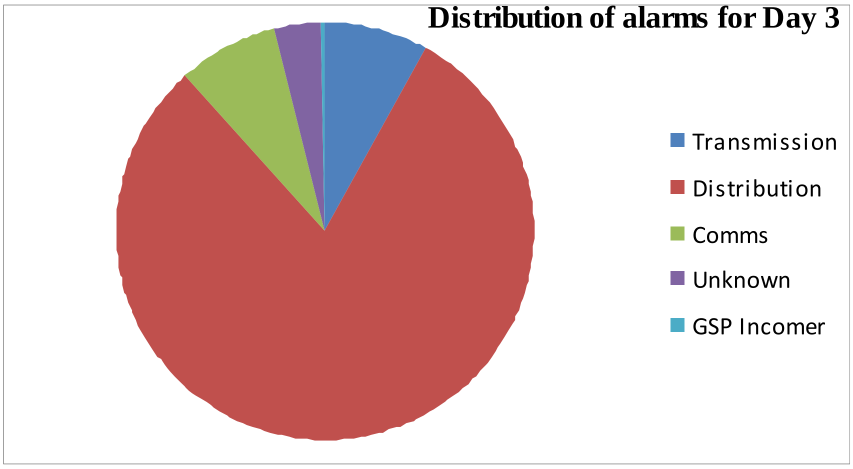

Figure 11: Distribution of Alarms for Day 3 Demonstrating an Incident on the Distribution Network

It is evident from Figure 11 that the incident on Day 3 affected mainly the distribution network, although information regarding neither the cause of the incident nor whether it was considered an emergency is not known. The distribution control room received in excess of 8,500 SCADA alarms on Day 3.

In spite of the large volumes of SCADA alarms that the control room receives on a daily basis, only a small percentage of these alarms require operator attention or intervention, and this is not dependent on the amount received. Control engineer intervention can range from executing a telecontrol action, to alerting field operators to attend to a situation. Figure 12 demonstrates that a larger total volume of SCADA alarms does not necessarily signal that more control engineer intervention is required.

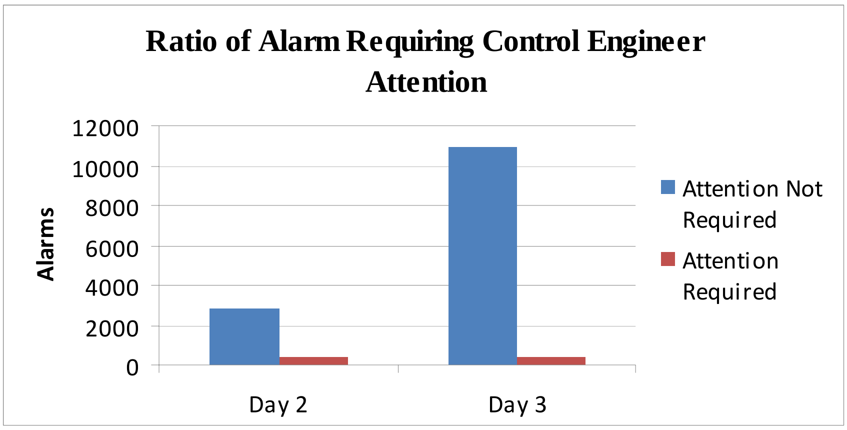

Figure 12: Ratio of Alarms Requiring Control Engineer Intervention on Days 2 and 3

The graph provided in Figure 12 shows that there was proportionally much less control engineer intervention required by operators on Day 3, 4% of the total alarm volume, with the occurrence of an incident, than on Day 2, where 15% of the alarms received required intervention, which is considered as a normal day.

On Day 2, of the 433 SCADA alarms requiring control engineer intervention, most of these were transmission related. Figure 13 illustrates the SCADA alarms requiring intervention for Day 2 by type.

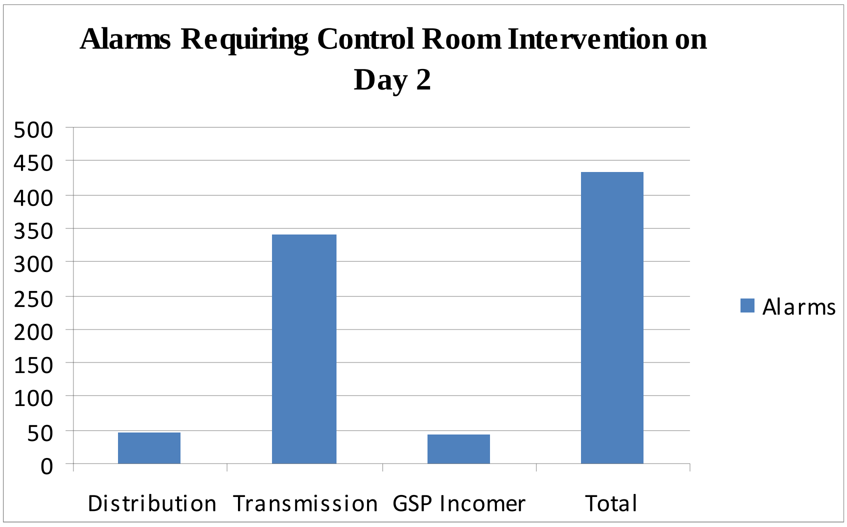

Figure 13: Distribution of SCADA Alarms Requiring Control Engineer Intervention on Day 2

The distribution of SCADA alarms for Day 3 is illustrated in Figure 14.

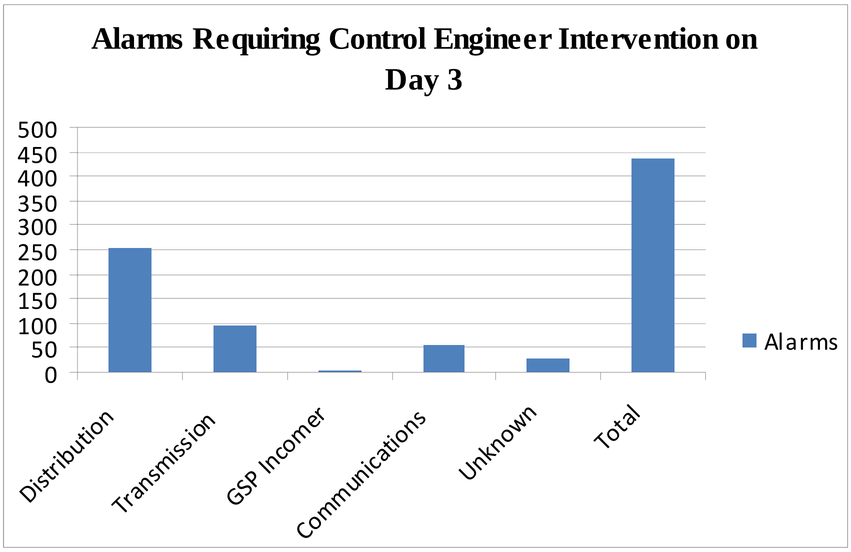

Figure 14 : Distribution of SCADA Alarms Requiring Control Engineer Intervention on Day 3

On Day 3, of the 435 alarms requiring control engineer intervention, most of these were distribution related, which supports the conclusion that the incident on that day was concentrated on the distribution network.

The very small percentage of SCADA alarms requiring control engineer intervention, as demonstrated in Figure 12, supports the idea that control engineers receive a large number of non-critical alarms on a daily basis, and a number of these will be nuisance alarms (described further in Section 3.4.2.1). This is backed up further by the information displayed in Figures 13 and 14 in that no alarms requiring attention were from the communications network despite there being in excess of 1,000 received on Day 2. Similarly on Day 3, of the 800 communications alarms received, only 57 merited attention from a control engineer.

A principal concern of this research is the ability of control engineers to react to new alarms and scenarios brought about by the introduction of DG and ANM schemes to the networks. The following section, Section 3.4.1.2, presents a study that has been conducted to assess the potential impacts of DG connection and ANM scheme deployment on SCADA alarm volume and distribution.

3.4.1.2 SCADA Alarm Volume Study: Further Study

The connection of a generator to a distribution network (or any other network) will give rise to an additional catalogue of data that the control room will receive. Ideally, analogue measurements including voltage, current, real power and reactive power must all be provided to the control room which requires monitoring equipment, telemetry and communication bandwidth. Other alarms associated with the DG such as circuit breaker status, communications failures and equipment faults would also usually be required to be relayed back to the control room, and it is these alarms that will be received in the SCADA alarm log at the control engineer workstation. The requirements regarding what information should be provided to control rooms from generation sites was highlighted in Section 3.4.1, however, these are generally reviewed with every iteration of the Distribution Code.

In order to explore the impacts of new DG connections on the SCADA alarm volume received by the control room, the following assumptions were made to carry out a worst case scenario study; an arbitrary number of 10 additional alarms per DG connection are assigned, each of which is received once daily, over a period of 5 days, in order that it is comparable with the data sample provided. The figure of 10 additional alarms was chosen in this instance to account for the provision of information likely to be required by the control room i.e. circuit breaker status, communication alarms, and also for the eventuality of a DG connection having to provide a greater volume of information for visibility purposes. There remains a great deal of uncertainty on exactly what information DG connections will be required to provide in future, so a figure of 10 alarms was decided as a worst case for use in this study. Chapter 4 addresses these concerns in more detail.

Figure 15 highlights the comparison between the 5-day profile data originally studied and the addition of three volumes of additional generation; 100 DG connections; 250 DG connections and 500 DG connections (data sample encompasses complete DNO area).

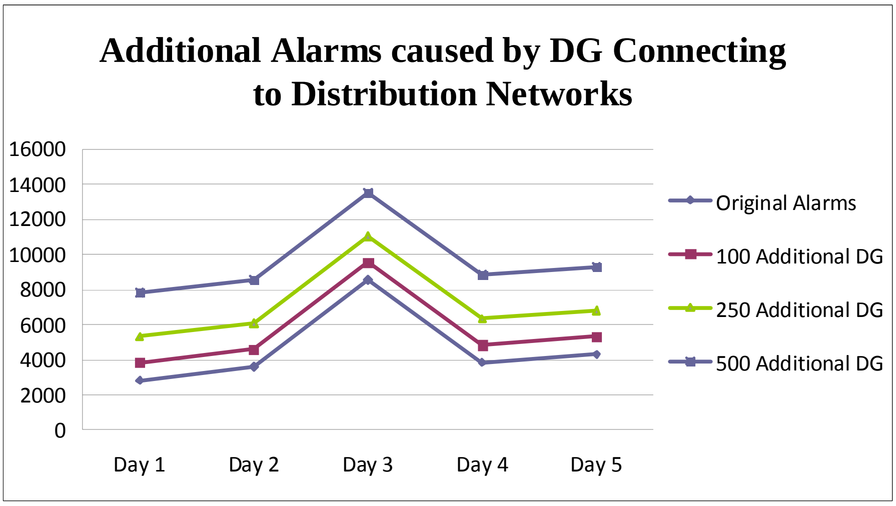

Figure 15: Alarm Data Volume Showing How it Increases with the Addition of 100, 250 and 500 DG Connections

The graph shows how the daily volume changes for these worst case scenarios. As expected, the volume of data has augmented in a linear manner by 1000, 2500 and 5000 additional alarms daily respectively. The increase is unavoidable, and the addition of any further DG will cause further increments in the data volume. While assumptions have been made here about the additional alarms resulting from DG connections, it is unlikely that the worst case scenario will present itself at any point, with the possible exception of an emergency situation. It is also highly unlikely that the increase in alarm volume will be linear, and this is a result of the arbitrary number of alarms assigned to each DG connection, the justification for which is given above. A worst case scenario should be planned for in terms of communications provisions and bandwidth however, care must be taken such that these are not over-designed as there would be significant cost implications.

In addition to this, a contribution of alarms will be provided by any ANM schemes that are installed on networks in conjunction with the DG connections. Pinpointing the effect of ANM schemes on SCADA alarm volume is less straightforward. As so few are currently fully deployed on networks, it is not possible to gauge precisely their contribution to the volume of data received in control rooms, and the number of alarms generated by an ANM scheme is dependent on the scheme function and complexity. It is also highly possible that, while all will generate alarms, some may have a negative net effect on the total alarm volume by reducing the generation of other alarms through preemptive control actions before any alarm is generated.

For the purpose of this analysis, a negative net effect on alarm volume is not considered and a worst case scenario was assessed. It is assumed that one ANM scheme is deployed for every 10 DG connections, and each ANM scheme has a catalogue of 20 alarms, each of which is received once daily over a 5-day period in order that it is comparable with the data sample provided. Figure 16 shows these worst case data volumes for 100, 250 and 500 DG connections.

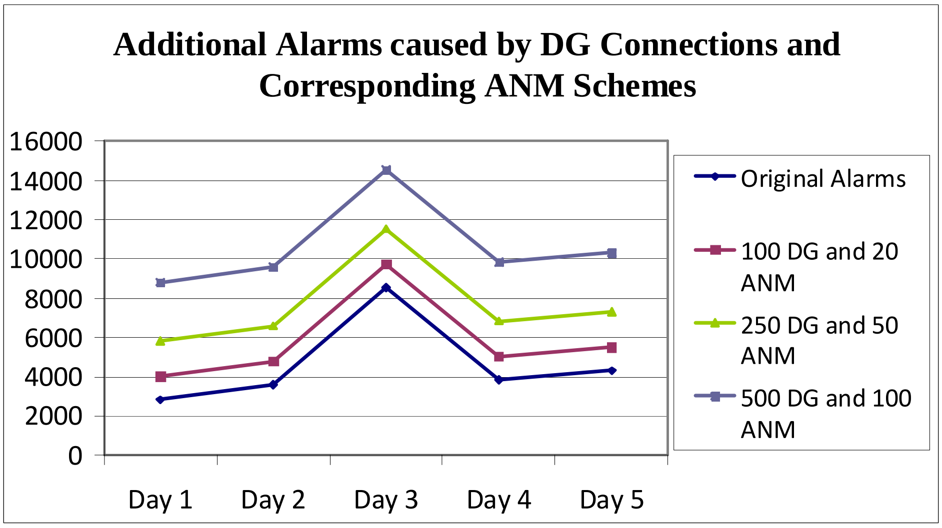

Figure 16: Alarm Data Volume Showing How it Increases with the Addition of 100, 250 and 500 DG Connections and a Respective 20, 50 and 100 ANM Schemes

Again, in this analysis the increase in data volume is linear due to the assignment of an additional arbitrary number of alarms each day, yet the overall impact is not as severe as with the DG connections themselves. The overall increase in alarm volume, encompassing DG and ANM schemes for each scenario equates to 1200, 3000 and 6000 alarms respectively. And although such a great volume is largely unrealistic and a worst case scenario has been adopted, it is useful to demonstrate the likelihood of alarm volume increasing due to ANM scheme deployment. This suggests that perhaps the issue of integrating ANM schemes into the control room may be more related to operator understanding of schemes, and interpretation of how they manage events, rather than simply the processing of high volumes of data and alarms. Control engineer management of changing SCADA alarm volumes is discussed further in Section 3.4.1.3. A more comprehensive view of this alarm study, and a more detailed breakdown of the alarm distribution is given in [20]. The paper also includes a more realistic view of the contribution of alarms from ANM schemes.

3.4.1.3 Control Engineer Management of Changing SCADA Alarms

Habit and experience play a large part in how control engineers carry out their duties, and how they address situations when they occur. As mentioned in Section 3.4.1, a variation from the ‘normal’ SCADA pattern will present problems on a technical level, however, it will also impact the fundamental management techniques that control engineers have developed over their career in the control room. This is especially true for distribution control engineers as distribution networks have changed relatively little since their inception.

The implementation of distributed, active controls will alter both the role and level of involvement that the control engineer will have in managing certain situations, and it will, in all likelihood, take time for control engineers to adapt to and also to learn to recognise new SCADA alarm patterns. The alarm volume analysis conducted in the previous section (Section 3.4.1.2) suggests that an increase in alarm volume could be problematic, as with 500 DG connections and the accompanying 100 ANM schemes, an additional 6,000 daily alarms could be in circulation. However, this is unlikely to be the most significant issue for control engineers. This remains true until the point in which the control room receive too much information, however, it is difficult to determine at which point this occurs and this is discussed briefly in Section 3.4.2.2.

The following sections (Sections 3.4.2 to 3.4.5) describe what are likely to be more immediate issues for control rooms. Fortunately, the gradual shift towards active networks, and the incremental addition of generation that is happening in the UK at present is perhaps in the best interests of control rooms and control engineers alike, as both human and technology are afforded the time to adapt, learn and develop new management processes.

3.4.2 Network Metering and Visibility

At present there is a general shortfall in metering capabilities and visibility available on distribution networks for analogue measurements (as verified by three control rooms, see Appendices A-C). There are no standard regulations for the installation of metering facilities for specific plant at specific voltage levels, and this results in highly variable levels of visibility at each substation. In general, primary substations (which house 33/11kV transformers) are more heavily metered than those at lower voltages. The metering available on overhead lines and cables is considered insufficient [Appendices A, B, C] and there is little or no information reporting on power flows around the network or at some transformers.

The cost of communication equipment and infrastructure is one of the most significant barriers to complete network visibility for control engineers, and this is also true for distribution connected generation, where there is little uniformity in the information required to be provided to the control room, as explained in Section 3.4.1. This is a difficulty faced by control engineers on a daily basis, and a congested network with large amounts of DG will only exacerbate this problem and decrease overall system security by increasing the potential for loss of supply to customers. Management of bi-directional power flows, characteristic of active networks, will require much more extensive and robust metering facilities, even at lower voltages, such that power flow directionality can be efficiently determined by control engineers. It is likely that as more DG connects, a clearer set of requirements for a minimum level of metering and measurement must be gained, which is dependent on the type, capacity (MW), etc of the site (as described in Section 3.4.1, the existing requirements of the grid and distribution codes is already somewhat dependent on the capacity of the generation, and its connection voltage).

In a discussion with a UK DNO control room [Appendix A], it was suggested that existing communication link bandwidth could be utilised more efficiently to enable analogues from DG connections to be sent to the control room. This method would save on infrastructure expansion costs.

Similarly, one Low Carbon Networks Fund (LCNF) project run by EDF Energy Networks is addressing the issue of distribution network visibility at low voltages by utilising existing communications and SCADA facilities to collect more network information [21]. In order that distribution networks are prepared to accommodate low carbon technologies and ANM schemes, it is agreed that the visibility of distribution and LV networks must improve considerably.

The need for better visibility of distribution networks is also identified in another EDF Energy Networks project, in a paper by Sebastian et al [22], where a situation awareness tool fed from a state estimator is described as a necessity for control engineers managing a smart grid or active network. The state estimation tool is built upon alarm processing functionality and provides a detailed interface at the control engineer workstation which allows for greater visibility of the network and effective hour-ahead forecasting.

3.4.2.1 Nuisance Alarms

Nuisance alarms can be described as alarms which arise from phantom failures, which is especially common with the communications network where alarms signalling a fault or failure are often cancelled promptly after reception by a mitigating alarm. Control engineers have to deal with a significant number of nuisance alarms on a daily basis; most notably from the communications network. The issue is also considered further in Section 3.4.3 which discusses power system reliability. As the amount of plant and communication equipment on distribution networks increases, the number of nuisance alarms will also increase, adding to the problems already mentioned in this chapter.

3.4.2.2 Excessive Information

Collating the evidence and information from Sections 3.4.1 through 3.4.2, it is clear that control rooms can expect increases to alarm volume and frequency, and changes to their type and distribution. There is concern however, that the requirement for better visibility and metering will have an adverse effect on the control room by simply providing more information than is manageable. The development and implementation of processing tools is a consideration here, however such tools bring a further set of concerns regarding their maintenance and use of data as was discussed in Chapter 2.

3.4.3 Power System Equipment Reliability

Power system communications can prove unreliable, and failure rates of communication equipment are high in comparison to other pieces of power system equipment. A significant proportion of alarms received by the control room on a daily basis can be communications alarms, the majority of which are nuisance alarms as described in Section 3.4.2.1. During one day of the 5 day SCADA alarm sample provided by a UK DNO (the same sample that was used in the Alarm Study in Section 3.4.1.1) [Appendix E], the amount of received communication alarms was 1827, and the majority of these alarms were unsubstantiated and corrected themselves within a certain time period.

An examination of 112 consecutive communications alarms from this sample running from 00:00am to 03:42am the same day (other types of alarm were not included in the sample), determined that 26 alarms declaring a fault or failure within the communications network were cancelled within this time period resulting in 52 nuisance alarms in total out of a possible 112 (46%). The alarms can be defined as nuisance as there was no operator action taken at any stage. The longest time period that a communications failure alarm remained active was 9 minutes, with the shortest lasting less than a minute. One particular alarm reporting a Time Source Fail on an RTU was received and cancelled 11 times within this time period, accounting for 22 of the 52 nuisance alarms. The 112 alarm sample can be found in Appendix E.1 (DNO specific data has been anonymised).

The issue of communication network reliability is relevant in this case because active networks are heavily reliant on the communications infrastructure to function and the failure of communications could render and ANM scheme inoperable, and control rooms depend on it to manage the network effectively.

It is necessary to invest in the communications infrastructure if active networks are to be successfully introduced, so any economic issues will have to be addressed and agreed upon with DNOs and ANM scheme developers such that suitable equipment is made available.

The matter of unreliability is also true for protection alarms. A protection device alarm is generally given up to a period of time to send a maloperation alarm to counter the initial protection alarm before it is considered a genuine fault and a field engineer is dispatched to investigate.

A sample of alarms encompassing the transmission and distribution networks was taken over the same time period as the communication alarm sample (00:00am to 03:42am). Over this time period, 87 network alarms were received, which is 25% less than the number of communications alarms received. Of these 87 alarms, 21 reported a protection fault which was then cancelled, resulting in 42 nuisance alarms (48% of the total) (as before, no operator action was taken). All protection fault alarms in this sample were cancelled within a minute, and one particular Intertrip alarm occurred 7 times within the sample period, accounting for 14 of the 42 nuisance alarms. The 87 alarm sample can be found in Appendix E.2 (DNO specific data has been anonymised).

Other notable elements of the power system that are prone to failure are sensors e.g. transformer temperature sensors (evidence of this can be viewed in the SCADA sample mentioned here).

3.4.4 Controllability of DG

Much of the DG currently connected to the UK network is self-controlled according to the contractual agreements adopted at the time of connection. The existing regulations regarding the controllability of DG makes it difficult for control rooms to manage the generation on the networks as each connection is different and based on the individual requirements of the connection. This problem will be exacerbated if no progress is made regulating this as penetrations of DG continue to rise. In order to prevent confusion in the future with large amounts of DG with varied control philosophies, it is pertinent to address the issue and provide standard requirements for DG connection visibility. At present, connection agreements based on the Distribution Code (and/or Grid Code) afford the control room the capability to trip DG connected to their network

"*Every installation or network which includes Generating Plant operating in parallel with the DNO's Distribution System must include an Isolating Device capable of disconnecting the whole of the Generating Plant infeed from the DNO's Distribution System. This Isolating Device will normally be owned by the Generator, but may by agreement be owned by the DNO*." [23]

"*The Generator must grant the DNO rights of access to the Isolating Device without undue delay and the DNO must have the right to isolate the Generator's infeed at any time should such disconnection become necessary for safety reasons and in order to comply with statutory obligations. The Isolating Device should normally be installed at the Connection Point, but may be positioned elsewhere with the DNO's agreement.*" [24]

The issue with this type of control is that the control room is left with no ability to control the MW output to better serve real-time network needs. This has now been recognised as a barrier to the successful control room management of active distribution networks and is an issue that should be considered carefully.

The current penetrations of DG have already shown to improve voltage problems on long lines and decrease line loading [Appendix B]. The ability to control DG during outage and fault conditions could prove very useful for management purposes as local loads could be met with local generation during fault and outage conditions, particularly as networks become busier. Metering and communications (discussed in Sections 3.4.2 and 3.4.3 respectively) would also support the successful implementation of more controllable DG.

3.4.5 Control Engineer Unfamiliarity of ANM

Decentralised control schemes which manage network parameters in real-time are relatively novel on distribution networks and for control engineers, with the exception of automation schemes that have been deployed. Distribution network automation is similar in many ways to ANM, yet the two differ in their core operational and control philosophies and it must not be assumed that the existing presence of automation on a distribution network is adequate preparation for control engineers to manage ANM. Both distribution automation and ANM serve their purpose for the benefit of the distribution network however, they are fundamentally different. Table 1 illustrates the differences between distribution automation (DA) and ANM in terms of their operational and control philosophies [8], [25].

Table 1: A Comparison of the Operational and Control Philosophies of Distribution Automation and ANM

	Distribution Automation	**Active Network Management**
Operational Philosophy	Passive	Active
Control Philosophy	Reactive Control following a fault.	Pre-emptive Control to prevent breaches and faults.
Network Restoration	Post-Fault Restoration.	Can prevent fault (and so, need for restoration) through pre-emptive control. In cases of fault, ANM scheme **may** have restorative ability.
Control Room Interface	Identical DA icons on each circuit on the network that is controlled by the DA scheme, on the DMS network topology diagram. [Appendices B, C]	ANM scheme-specific interface, on the DMS network topology diagram.
Operational Requirements	Reliable communications and telemetry.	Reliable communications and telemetry.

As highlighted in Table 1, DA and ANM are similar in their reliance on the SCADA system and the communications network, and each are displayed uniquely in the DMS network topology diagram to facilitate management. Their differences however, are significant, and lie in their operational and control strategies; DA is considered passive with reactive control, as it operates following an incident, where ANM schemes constantly monitor parameters and react in anticipation of an incident. It is therefore essential that the deployment of ANM schemes is not treated in the same way as automation would be. The control engineer has no interaction with automation, however, as this thesis examines, they will have varying levels of responsibility with regards to ANM scheme management.

The unfamiliar operational characteristics of ANM demonstrated in Table 1 gives rise to operation and management issues of ANM schemes for control engineers. Where existing practice sees distribution control engineers reacting to incidents, the implementation of ANM schemes throughout the network will see these control schemes taking pre-emptive action to prevent incidents from occurring. This theoretically removes a level of control from the control engineer, allowing them to take a step back from direct control of certain situations. However, control engineers must remain capable of managing the network should an ANM scheme fail or maloperate for any reason. Thus, they must gain and maintain working knowledge of ANM schemes operating on the network, be familiar with their behaviour patterns in all situations and be able to decipher when one fails to operate correctly and react accordingly. The importance of this issue will magnify as networks become busier and are operating closer to their limits.

This introduces a new aspect to the daily tasks of distribution control engineers. They will have to continue their daily tasks as normal, but will have the added responsibility of being aware of and monitoring the operation of any ANM schemes in their management area. They must also continue to manage outages and faults as normal, however, they must also now consider the contribution of any ANM schemes in the affected area and whether they can continue to operate or should be switched off for the duration of the outage or fault.

These issues have called into question the role of the control engineer. A discussion with the NMS System Manager at Central Networks (East) [Appendix C], raised the suggestion that some control engineers would have to retain the existing, traditional role of managing the real-time network, with others evolving to manage solely the automation and ANM schemes from within the DMS. This suggestion is similar to that from [Appendix B] of a separate control desk dedicated to the management of DG and ANM schemes on the network as deployment continues to rise. With similar motivation, a Spanish network operator, Red Eléctrica de Espaňa (REE), have a dedicated control centre, CECRE, which manages solely all wind generation under its control in Spain [26]. Such a restructure of the control room and its operations would require proactive planning, clear specifications of the role of each control engineer, coordinated interfacing and liaison between control engineers, and possibly new facilitating management tools.

3.4.5.1 Control Engineer Interaction with the Network

Regardless of the path that control rooms take to manage active networks, there will undoubtedly be a change in how a control engineer interacts with the network and with ANM schemes. Busier networks which are operating closer to their limits suggest that control engineers will be interacting with the network more frequently. And yet, as discussed in Section 3.4.5, the removal of direct control of certain situations owing to the operation of ANM schemes suggests that control engineers may have less interaction with networks. In any case, the pattern of control engineer interaction with the network will change, even if the frequency does not. It is one aim of this research to determine how the interactions of a control engineer with the network change. Chapter 5 examines this issue in further detail through experimental research, and with further justification for its necessity given in Chapter 4.

3.4.6 Current Initiatives on Control Room Integration of ANM and DG

There is evidence of industrial interest from DMS developers and vendors taking steps to prepare for active network management and smartgrid requirements, with many taking steps to upgrade and improve their existing technologies to ensure they are able to efficiently manage active networks in the control room. The efforts to prepare control rooms for the management of smart grids and active networks are international, with the major efforts coming from the USA, the UK and Europe, and China, and some of these are described here

- ABB are currently involved in innovating control room technologies, including DMS and SCADA systems, to manage smart grids [27]. Improvements to existing functions and applications are taking place alongside development of more advanced applications required for the management of smart grids through highly integrated control room technologies.
- EFACEC Advanced Control Systems are also involved in development of effective technologies that will support smart distribution networks [28]. They provide tools for SCADA, OMS, DMS, EMS, Automation and Optimisation, and they are all designed with flexibility and extensibility in mind to ensure the effective adoption of emerging smart grid techniques and technologies. The PRISM™ platform is at the core of these technologies, and is in use, in some form, in over 200 electric utilities worldwide.
- Siemens have developed a Decentralised Energy Management System (DEMS) which combines distributed power generating units and intelligent loads to form large scale virtual power plants (VPP) [29]. It is able to optimise network operation in real-time, as well as plan and forecast generation and demand.
- The Smart Grid Electric Power Research Institute (SGEPRI), of State Grid, in China, has produced a range of automation technologies, including grid automation, substation automation and dispatching automation [30]. The Smart Grid Dispatching Support System is in place to aid control engineers with the control and dispatch of generation as grids become smarter and a more advanced level of control is required by operators.

Although this is evidence to confirm that preparations are ongoing in control rooms for the transition to active distribution networks, the work is largely fixed on control room tools as a whole system, i.e. incorporating entire networks and their ancillary systems, rather than the provision of support to the integration of individual smart controls onto networks and into the control room, which is what the tools provided in Chapters 4 and 5 of this thesis are intended for.

3.5 Chapter 3 Conclusions

This chapter has discussed the various impacts that connected DG and deployed ANM schemes will have on distribution networks, both in terms of their effect on the electrical operation, and their impact on other areas of network operation including SCADA alarm volume and patterns. A preliminary investigation into expected changes in SCADA alarm volumes and distributions was presented and this highlighted the significant increase in SCADA alarm volume that can be expected from DG connections. DNOs are becoming increasingly aware of the importance of the provision of information from DG connections and this is reflected in the Distribution Code. As such, each new DG site will contribute alarms to the overall volume and this is mirrored in the study results. The contribution of ANM schemes to the alarm volume is less clear at this stage, however, based on some reasonable assumptions, it is shown that the ANM schemes will also add to the overall alarm volume received by control engineers, although the effect is not as severe as that of the DG contribution.

Reliable communications and SCADA are essential to ANM scheme operation and it is clear that improvements must be made to the communications infrastructure, both in terms of reliability and use, if active distribution networks are to be successfully operated. Similarly, improvements in network metering and visibility are imperative to the operation and management of active networks. Standard regulations on the visibility of DG connections for the control room must also be agreed upon to achieve a balance by preventing either; networks becoming inundated with generation that control engineers are unable to ‘see’ or control; or control engineers being overwhelmed by excesses of information provided by each DG connection with limited means of interpretation and processing.

The impact of active distribution network management on the role of the control engineer has also been examined. It is likely that there will be a shift in control engineer involvement with the network as more automation and ANM schemes are deployed, however the question of whether they will have more, less, or simply different interaction with the network remains unanswered as yet due to the relative novelty of ANM schemes and the lack of a fully active distribution network to assess.

3.6 Chapter 3 References

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Chapter 4

Integration of ANM Schemes into the Control Room

4.1 Introduction

One of the critical steps to achieving highly active distribution networks i.e. those with large volumes of DG penetration and significant levels of accompanying active and automated controls in operation, is ensuring that the control room is capable of managing them; both in terms of equipment and personnel. And one of the principal objectives of this thesis is to facilitate the integration of ANM schemes into control rooms as part of this larger ambition. This chapter begins by highlighting various factors of uncertainty concerning the future of ANM schemes, active distribution networks and the control room, all of which are major concerns for DNOs.

The diversity of ANM schemes in their operational philosophies and management requirements is one of these concerns. To highlight the problems, a comparison of two fully deployed ANM schemes and an account of the process that was undertaken in their integration into the control room is given. A compare and contrast exercise is carried out to illustrate the differences and similarities of the schemes, and the subsequent difficulties encountered in developing an integration solution applicable to multiple schemes and networks. This leads on to the motivation behind the development of a control room integration methodology, comprising a set of rules, for use when integrating an ANM scheme into the control room as it is deployed, which was conducted as part of this research.

The methodology presented here was developed to fulfill the need for a formal integration process to facilitate the widespread deployment of decentralised ANM control schemes. The methodology is an outcome of the control room integration of the Orkney RPZ onto the SSE 33kV distribution network, where the author participated in this work in conjunction with Smarter Grid Solutions (SGS), the ANM developer. Each stage of the methodology is described and justified in detail, and the case study involving the Orkney RPZ is then presented.

Through the development of the methodology, numerous considerations were identified which must be addressed at the time of deployment to ensure successful integration of an ANM scheme into a control room. Each of these considerations is outlined in this chapter and discussed.

4.2 Uncertainties Affecting the Transition to Active Distribution Networks

The factors that contribute to the uncertainty surrounding the transition of distribution networks from passive to active systems are in direct correlation with the uncertainty of DG penetration trends which in turn affects the deployment of ANM schemes. The main factors which dictate the deployment of DG are geographical topology relating to population load centres, geographical topology relating to availability of resource, and the availability of networks to accommodate the connections. These dictate the location, pattern and scale of deployment of DG, although this is notable more so for renewable generation technologies. The following sections, Sections 4.2.1 to 4.2.3 detail the uncertainties of DG connection, ANM deployment and the control room management of active networks.

4.2.1 Uncertainties of DG Connections and Penetrations

The diverse geographical topology of the UK has dictated the population distribution, which in turn has influenced the electricity network infrastructure. This has resulted in a large variation in network topology across the UK systems, with each network having its own requirements and issues. For instance, long, radial lines found in rural areas, common in the North of Scotland, are susceptible to low voltage problems at the end of these lines, whereas, highly dense urban networks, such as those found in Central London, can suffer from different issues entirely; such as thermal overloading and high voltages due to a high density of underground cables producing large amounts of reactive power.

The topological differences are also an important factor in determining the location of DG, particularly renewable generation. Often, large renewable resource is optimal in remote areas, thus there is likely to be higher penetrations of renewable DG connected to sparsely loaded rural networks, whereas highly loaded urban areas have limited renewable resource, or at least limited space to accommodate it. Additionally, the implementation of non-renewable DG sites is perhaps just as difficult to predict as it will have a different set of criteria to meet.

Microgeneration, located in homes and businesses will also be very difficult to forecast and monitor. Social studies conducted in recent years have researched the pattern of household microgeneration installations and concluded that affluent areas are likely to have much higher penetrations due to the high initial costs [1]. It should be noted however, that this can be subject to change if incentives and schemes were to be introduced to help steer the connection of microgeneration.

In addition to this, the scale of DG deployment is ambiguous and somewhat dependent on the factors mentioned here. Urban networks may be restricted in the amount of available capacity they have for DG connections, while rural networks with significant DG potential may have excess capacity but are often considered to be electrically weak and would require reinforcement. The latter is a major barrier to small-scale generators as they are less likely to be able to afford to contribute to the cost of such reinforcements.

Regardless of trends and patterns, all evidence points to a steady increase in the penetration of DG, especially renewable, onto distribution networks. Hence, further down the line as these networks become busier and are operating closer to their limits, a fresh portfolio of challenges will appear for DG wishing to connect to them. With one suggested enabling solution to the issue of crowded networks being the deployment of ANM schemes; there is also some degree of uncertainty when considering this as a solution.

4.2.2 Uncertainties of ANM Scheme Deployment

The unpredictability of future DG penetration trends described in the previous section has a direct impact on the uncertainty surrounding AMM scheme deployment trends. Each type of network, as stated previously, will have distinctive operating characteristics associated with it, and for this reason, each will have different requirements and limitations for DG penetration. Different networks with different DG penetrations comprising various types and sizes will affect the type and scale of ANM scheme necessary e.g. a voltage control scheme to manage a lightly loaded line with a number of DG connections, or a generation curtailment scheme to manage thermal constraints.

Networks may have need for multiple ANM schemes of different types. Further dependency is also placed on the willingness and ability of the DNO to implement these types of decentralised control schemes, although there are incentives in place to encourage these activities (see Chapter 1 regarding IFIs and RPZs) and indeed other forms of innovation.

4.2.3 Uncertainties of Control Room Manageability of ANM Schemes

A further layer of uncertainty is present with the integration of ANM schemes into control rooms with reference to the way control engineers interact with them (this issue was briefly discussed in Chapter 3, Sections 3.4.1.3 and 3.4.5). It is apparent that as the transition to active networks is still in an embryonic stage and only a handful of ANM schemes are deployed on UK networks, which were referenced in Section 3.3 of Chapter 3. Each of the four ANM schemes which are described are fully operational but, as much of the DG in their operating zones (that is associated with the ANM schemes) has not yet been connected, they are not yet working within close range of their design limits up to their full intended potential. The philosophy of ANM schemes, discussed in Section 3.4.5 of Chapter 3, suggests minimal control engineer involvement during normal operation, and to date, the ANM schemes have had minimal interaction with the control room, and control engineers having had little involvement in their operation or management.

The lack of quantifiable information available on the subject leaves control rooms somewhat under-prepared for both the increase in activity of the existing ANM schemes and the introduction of any new ANM schemes. It is one of the principal aims of this thesis to provide other means in which to test future operations and activity levels in the control room. This is achieved through the CoRDS tool, presented in Chapter 5, which is geared towards gaining clearer insight into how ANM schemes will operate under the duress expected of them by design.

4.3 Comparison of two UK-deployed ANM schemes

The previous sections have served to illustrate the difficulties faced in predicting and planning for the transition towards active distribution networks as a result of various levels of uncertainty. This comparison exercise further emphasises these difficulties by highlighting the diversity of the ANM schemes that are available, and are being developed for active networks, and the challenges these pose from a control room integration perspective. The comparison is undertaken with two ANM schemes that are presently operating on UK networks; the Orkney RPZ in the Scottish & Southern Energy (North) DNO area, and the Skegness RPZ in the Western Power Distribution DNO area (formerly Central Networks). It involves a high-level description of the operating principles and requirements, and also the control room interfacing styles of each.

4.3.1 The Orkney RPZ

The Orkney RPZ ANM scheme, introduced briefly in Chapter 3, is a multi-generator, multi-constraint scheme which allows additional generation to be connected to the Orkney 33kV network and use the existing network capacity that is available in all but contingency conditions, where this capacity has not previously been available under regulatory conditions.

As part of this research, the author was involved directly in the integration of this ANM scheme into the SSE control room and this work is described in fuller detail, in Section

4.6, as a case study of the control room ANM scheme integration methodology, which is presented in Section 4.5.

4.3.1.1 Main Operating Principles

The main purpose of the scheme is to utilise existing network capacity that is considered 'spare' under normal operating conditions but is used in contingency conditions, whilst ensuring statutory limits are adhered to. The method employed is power flow management through generation curtailment. This is accomplished by monitoring the current and power flows at several vulnerable points around the network, and taking action when threat of a thermal overload appears. In the instances where an overload is predicted or has occurred, generation is curtailed in order of priority (Last In First Out (LIFO) principle of access is agreed with generators prior to connection into the scheme) until the threat is removed. If the threat persists and curtailment does not remove the breach, the scheme takes escalating action and trips the generation, again in LIFO order. In any case where generation is restricted or removed by the scheme, it is released back in order of priority once it is confirmed as safe to do so.

4.3.1.2 Operational Requirements

As stated, the scheme is a multi-constraint interdependent system and as such, needs several component parts to function and communicate as required. It encompasses a large area of network and operates in real-time. In order to monitor points on the network, measurement equipment at pre-arranged vulnerable locations is required, as is measurement equipment at each DG site, which is programmed to send and receive signals. All measurement data from the network points and the DG sites is retrieved by the scheme central controller where power flow calculations are carried out. This information is also passed on to the DMS in the control room where an interface is built as an add-on into the existing connectivity diagram.

On occasions where generation curtailment or tripping is necessary, the central controller sends instructive control signals to the DG sites. A robust communications infrastructure is needed to enable the scheme components to communicate and function overall. The specific requirements of the scheme with regards to communication links is as follows:

- Central Controller to Network Measurement Point(s)
- Central Controller to DG Site(s)
- Central Controller to the Control Room
- Control Room to DG Site(s)

Figure 17 below illustrates the components of the Orkney ANM scheme and the required communications infrastructure as detailed above. There are also contingency measures in place should a component become unresponsive or fail (these are not detailed in the diagram).

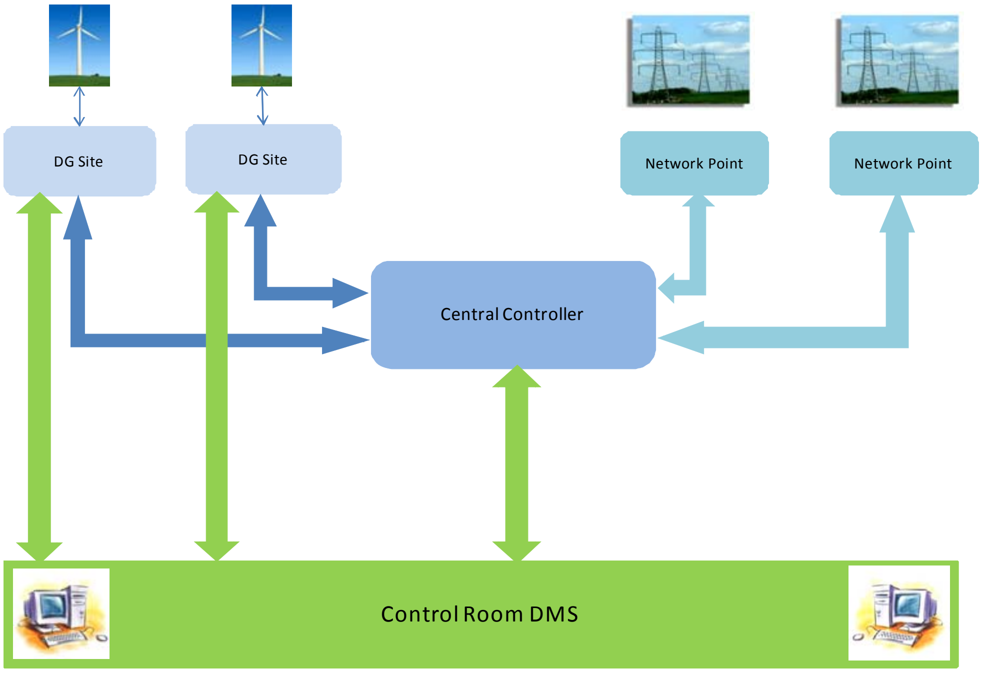

Figure 17: The Components and Communications Infrastructure Required for the Orkney RPZ ANM Scheme

4.3.1.3 Alarms and Control Actions

The Orkney scheme has a portfolio of over 20 alarms and indications associated with it (see Section 4.7.3 for a more complete list). There are alarms associated with each component within the scheme i.e. each DG site, each network measurement point, the central controller, and the communications which link these components. There are also indications and alarms which serve to give an overview of the real-time system operating conditions.

In terms of control actions, the control engineer retains decisive control over the scheme and is able to turn it on and off. The control engineer has also the capability to trip individual DG sites if and when necessary.

4.3.1.4 Control Engineer Responsibility and Interfacing

The decentralised and active nature of the scheme predicates that the control engineer should seldom need to be involved with its operation. However, the size (in terms of network area covered and number of load customers affected) and relative complexity of the scheme requires that sufficient visibility is readily available to control engineers, and for this reason, an HMI is provided in the control room DMS. A secondary HMI is also provided at the site of the central controller as mentioned in the previous section. The interface gives an overview of the scheme and shows the real-time operating conditions including the MW output of each DG site, the current measurements at each network point, and the status of other scheme components.

As stated in Section 4.3.1.3, the scheme has a catalogue of over 20 alarms, and active alarms are highlighted in the DMS interface. The alarms will also appear in the SCADA alarm log when active. Each of the scheme control actions is accessed through the DMS.

The control actions can be initiated from either the control room or from the secondary control point at the central controller where another interface is available. An interlocking mechanism is in place to ensure that only one interface is active at any one time.

4.3.2 The Skegness RPZ

As mentioned briefly in Chapter 2, the Skegness RPZ is a dynamic thermal ratings ANM scheme and it works by exploiting the real-time thermal ratings of a section of 132kV double circuit overhead lines in order to allow larger volumes of power to flow along than would normally be available when adhering to the standard P27 rating [2].

As part of this research, the author visited the Central Networks (East) (now Western Power Distribution) control room to gather insight into how and why the scheme was developed and deployed, and what have been the experiences of its operation. Refer to Appendix C for full details of the visit.

4.3.2.1 Main Operating Principle

The purpose of this particular ANM scheme is to allow existing offshore wind generation in the area to be used efficiently by providing sufficient capacity to transport that level of power, and also to accommodate a further 50-70MW of onshore generation scheduled to connect in the area in the coming years. The provision of additional capacity is achieved here by collecting real-time power flow measurements and weather information to calculate the real-time thermal rating of the overhead lines, as standard P27 ratings are generally conservative and lines can be cooled significantly by the wind. The CIGRE 207 Dynamic Ratings algorithm [3], which takes account of ambient temperature, air pressure, wind speed and wind direction, is used in this scheme (there exists also an IEEE algorithm to calculate dynamic ratings [4]) to calculate the real-time rating of the lines.

Favourably, during times of high wind, an increase in wind generation directly correlates with a greater cooling effect on conductors allowing this additional power to be exported. In the event where there is a capacity deficit, the local onshore wind farms which are connected under the scheme management are (will be) curtailed. Escalating actions result in a final action of one local offshore wind farm being tripped from the system to remove the threat of a thermal breach.

4.3.2.2 Operational Requirements

The scheme takes only the double circuit 132kV overhead lines into account. The overhead line information necessary to carry out the thermal rating algorithm calculation is collected using SCADA telemetry. There are weather stations located at Skegness and Boston substations and these measure the local weather conditions and the telemetry is used to report the information from the weather stations to the DMS in the control room and the thermal rating of the lines are calculated. In future, a device called a power donut [5], which is fixed to the line, will be affixed to various points along the line for more accurate atmospheric readings

The output from the algorithm updates the thermal rating of the overhead lines periodically and information is polled accordingly through the existing SCADA system. The components of the scheme and the communication requirements are illustrated in Figure 18. There are also contingency measures in place should a component become unresponsive or fail (these are not detailed in the diagram).

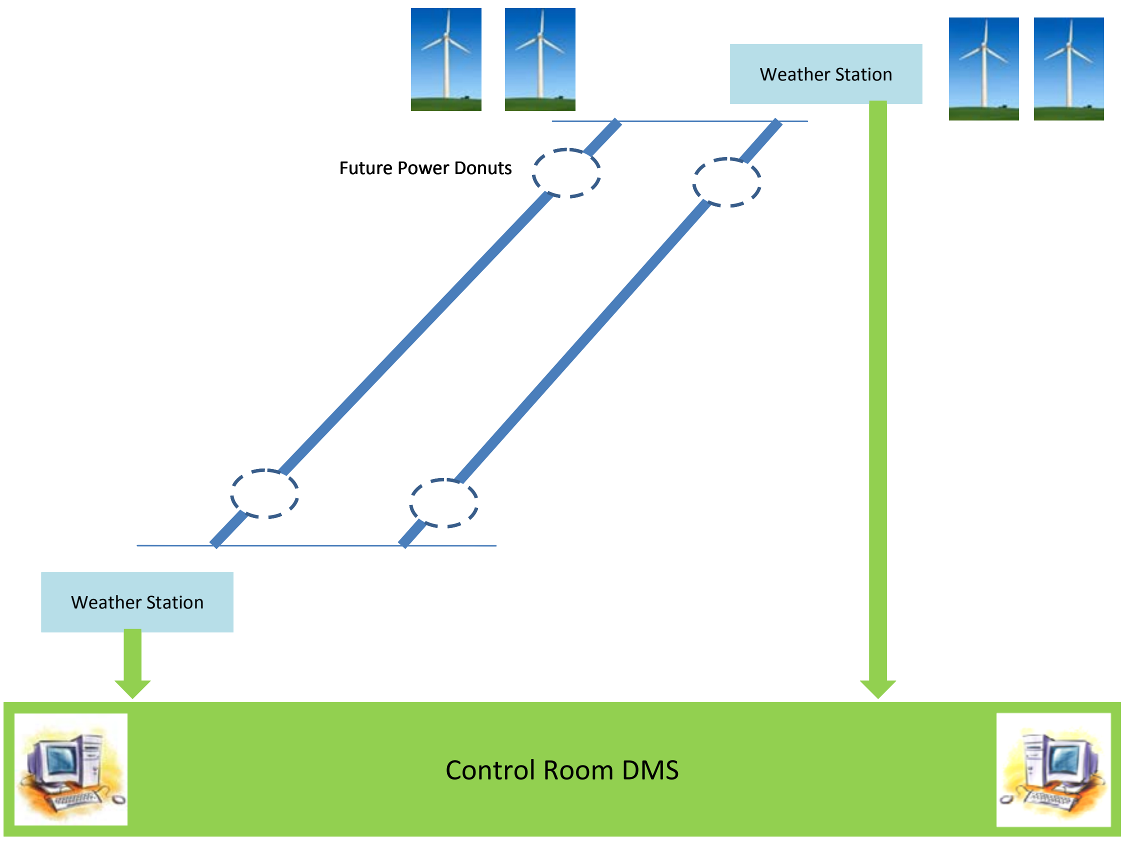

Figure 18: The Components and Communications Infrastructure Required for the Skegness RPZ ANM Scheme

4.3.2.3 Alarms and Control Actions

This scheme has a straightforward function, to recalculate the thermal rating of overhead lines at set intervals, and update these values in the DMS. As such, there are few alarms that are required of the scheme; an alarm is sent to the control room when the line loading exceeds the calculated rating (which the control room would receive in any case of overloading), and another when there is generation curtailment or tripping in progress.

The control engineer retains decisive control over the scheme and is able to turn it on and off, in which case, the thermal rating of the overhead line returns to its P27 rating. This control action is initiated from within the DMS.

4.3.2.4 Control Engineer Responsibility and Interfacing

A dynamic rating ANM scheme does not change any network property, its function is to inform the control engineer and the system if there is extra thermal capacity available which can be exploited. As such, a control engineer will have very little interaction with the scheme and there is no need for a detailed scheme interface. Rather, a small box with the real-time measurements of ambient temperature, wind speed and calculated thermal rating is presented alongside the lines representing the double circuit in the DMS connectivity diagram.

The dynamic ratings algorithm calculation is carried out in the DMS, and the thermal rating is updated on the system diagram while the alarm thresholds for the line are recalibrated. The control engineer is not made aware of a rating change via an alarm, rather, the diagram is updated accordingly.

4.3.3 Compare and Contrast of the ANM Schemes

Each of the ANM schemes described in Sections 4.3.1 and 4.3.2 share a common aim; to allow increased levels of generation to connect to the distribution network by exploiting existing network capacity that has been previously under used due to regulatory restrictions.

The Orkney ANM scheme is rather more complex than the Skegness ANM scheme and as such, requires more hardware i.e. network measurement devices and communication infrastructure. These devices and much of the communications were installed at the time of implementation. The Skegness scheme, however, required only the installation of two weather stations, and exploits the existing SCADA system for its communication needs.

The Orkney scheme has a larger catalogue of alarms and an elaborate DMS interface to allow it to function effectively and provide the control room with a satisfactory level of visibility and awareness of its operation, whereas the Skegness scheme has minimal alarms and a comparatively simple control room interface.

The control room has decisive control over each ANM scheme with the power to switch them on and off if and when necessary.

To date, neither is operating at its intended capacity, with much of the DG yet to connect to the networks under management of the scheme.

It is evident from this compare and contrast exercise that the ANM schemes share a common aim, yet they both achieve this aim through very different means. This highlights the difficulty faced in developing a widely applicable solution to the integration of ANM schemes into the control room. The subject of a universal ANM scheme integration tool is addressed in the following sections with the development of a control room integration methodology for ANM schemes.

4.4 Justification for the Development of an Integration Methodology

As noted in Sections 4.2 and 4.3, there is ambiguity on a number of levels surrounding the transition to active distribution networks, which is, and will continue to impact the roll-out of ANM schemes. Population centres impact the topology of the electricity network, which in turn impacts how DG can be connected. A combination of these then further affects the choice and deployment of ANM, and as proven in the previous sections, these can vary greatly in their operational philosophies and requirements thus it is vital to provide information and uniformity where possible to aid the control room and control engineers throughout the transitional period to active distribution networks. It is with this justification that a control room integration methodology for ANM schemes has been developed as part of this research.

There is little that can be done to mitigate the uncertainties detailed in Section 4.2, hence the main objective of the methodology presented in this chapter is to improve the preparedness of control rooms and control engineers by not only accelerating the process of ANM scheme integration when it reaches the deployment stage, but also to ensure the control room have an opportunity to contribute their opinion regarding the communications and interface design aspects, by which they will be directly affected. The latter will give control engineers confidence that they are receiving the appropriate information from the scheme and that they have a full understanding of the interface.

4.5 Control Engineer Opinions of ANM and the Future

Control engineer opinion regarding ANM schemes, and the general transformation of distribution network operational philosophy varies from person to person. Some agree that change within the control room is inevitable and both the man and the machine must adapt.

> *"The uncertainty of what will happen on the networks in future means that the distribution control room should be prepared for a variety of scenarios that could present themselves"* (see Appendix B)

Opinions differ greatly at this stage, as it remains somewhat unclear in what direction networks are headed, and as such, there is much debate over what measures should be taken to prepare both control rooms and control engineers for the future.

4.6 The Control Room Integration Methodology

The following sections describe the Control Room Integration Methodology that has been developed as part of this research to aid ANM scheme deployment into the control room. It is designed to provide a standard integration process and a degree of uniformity to prevent large volumes of ANM scheme interfaces populating the DMS topology diagram arbitrarily, thus making it, and the schemes themselves, eventually very difficult to interpret.

There are a number of fundamental requirements to consider when integrating an ANM scheme (or any other device) into the control room, each of which is addressed and included as part of the methodology. Figure 19 shows the methodology in a diagrammatical format and each step is explained in further detail in Sections 4.6.1 to 4.6.8. The steps within the main body of the methodology, Steps 2 to 6, are carried out at the integration phase, with Step 1 ordinarily already complete prior to this. Steps 7 and 8 follow the integration phase and are conducted at the deployment phase.

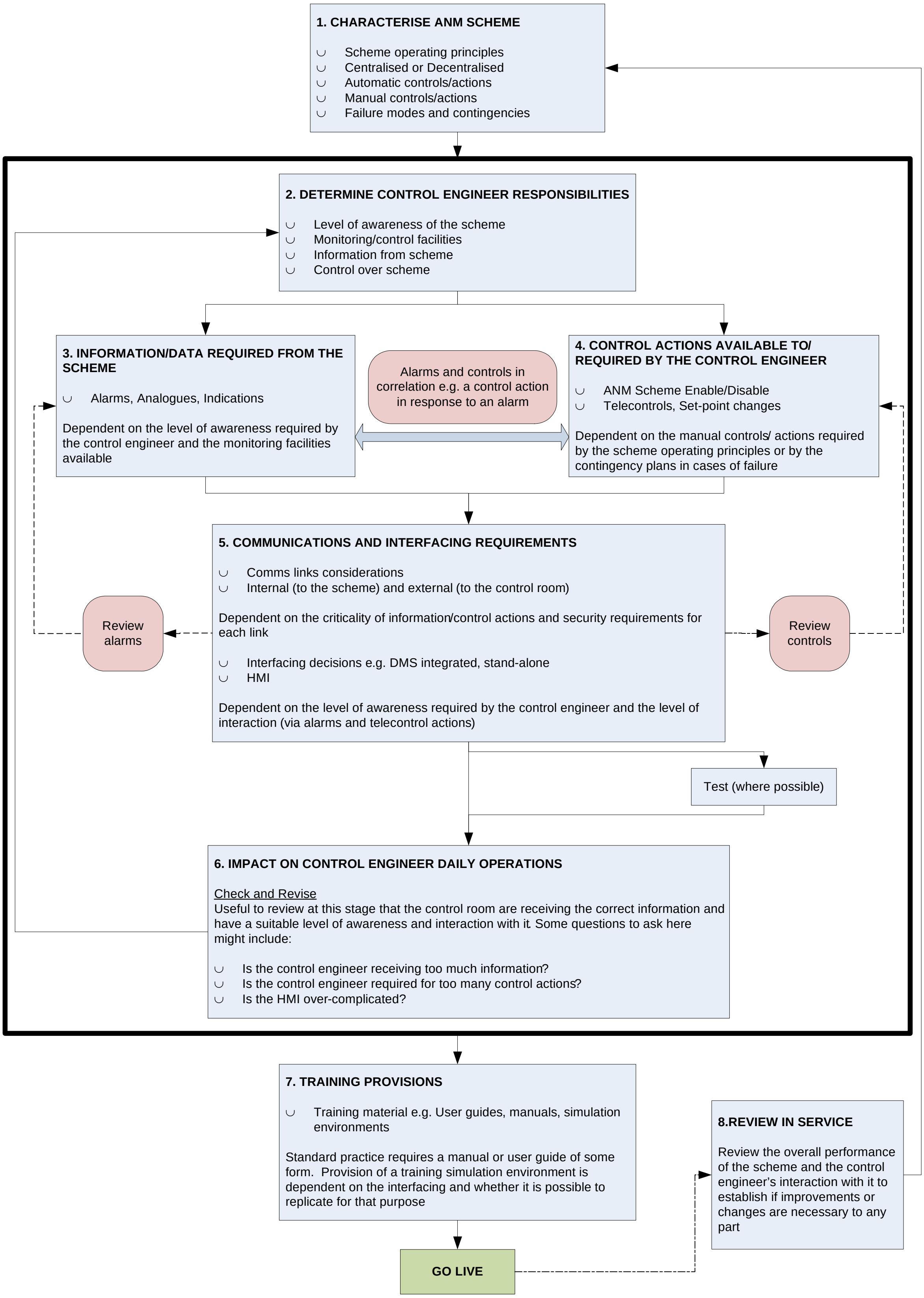

Figure 19: ANM scheme Control Room Integration Methodology

4.6.1 Step 1: Characterisation of the ANM Scheme

As stated in the previous section, the characterisation of an ANM scheme is ordinarily complete at the project inception stage, where thorough Requirements Specification and Functional Design Specification documents would be produced. This initial stage of the methodology builds upon these; ANM scheme operating principles and limitations, the control philosophy (centralised or decentralised) and contingency modes are defined here. Clarification of manual and automatic controls that allow the ANM scheme to perform to specification is required here, and these are expanded upon in the 'Establish Control Actions Available to the Control Engineer' step later in the methodology (Section 4.6.4).

Each of the characteristics described here will impact the requirements and decisions made in the following stages of integration.

4.6.2 Step 2: Determine Control Engineer Responsibilities

The responsibilities that the control engineer has concerning the operation and management of the ANM scheme are contingent on the ANM scheme itself and its characteristics, as finalised in Section 4.6.1. An important consideration is the level of awareness that the control engineer requires regarding the ANM scheme, and this is largely dependent on how autonomous it is. In order that the control engineer can perform the tasks required of them, determination of the amount, type and frequency of information the ANM scheme should provide in the form of alarms, analogues etc, and the type and frequency of control actions the control engineer can exercise is made at this stage.

Also dictated, is the level of detail in the control room interface to the ANM scheme. Establishing this at an early stage allows the monitoring, communications and visibility requirements to be outlined, and whether this will involve exploiting existing monitoring capabilities on the network, or the installation of new monitoring equipment specifically for ANM purposes.

4.6.3 Step 3: Establish Information Required from the ANM Scheme

The information that the control engineer will receive from the scheme, decided in the previous step, will be delivered in the form of SCADA feeds. Each segment of information from the ANM scheme devices and equipment must be categorised in two ways. The first is to assign it a *type*; alarm, analogue or indication. Alarms and indications both serve to warn the control engineer of a change in the system and the severity is noted by assigning a *priority* flag. The priority flags escalate in severity from low priority through non-urgent, operational, and urgent to emergency (specific tag names will vary with DNO however the urgency of each will be similar). There are also alarms specific to highlighting issues with the communications and SCADA network.

As analogues provide measurement values, these do not appear in the SCADA alarm log, rather they are updated directly in the DMS connectivity diagram and/or logged in a data historian for further analysis.

These considerations are valid irrespective of how the ANM scheme is deployed, i.e. whether it is centralised or decentralised.

Upon completion of this stage, the ANM scheme is equipped with a full list of analogues, and alarms and indications with assigned types and priorities.

4.6.4 Step 4: Establish Control Actions Available to the Control Engineer

ANM schemes typically operate autonomously and manual control capabilities afforded to the control engineer are provided primarily for contingency purposes. On such occasions where autonomous operation is not achievable (e.g. under abnormal network conditions or a fault), the control engineer must be able to manage the situation. As such, the manual control actions (e.g. change set-point, open/close circuit breaker) should be easily executable through the use of telecontrols, and will be exercised through the ANM scheme interface.

The control engineer also retains ultimate control over ANM schemes and the option to enable and disable a scheme must also be made available.

Automatic control actions are not considered here as they will be internal to the scheme and the control room will usually be informed of these taking place via and alarm or indication, defined in the previous step.

Upon completion of this stage, the control room has defined a full list of exercisable control actions available through telecontrols and the SCADA system. This stage may have implications for ANM scheme design itself such that the necessary controls are adequately accommodated.

4.6.5 Step 5: Determine Communications and Interfacing Requirements

Following on from the previous steps involving the allocation of the two-way interactions between the control room and the ANM scheme, communication link requirements are considered such that these interactions are achievable. Internal communications of the scheme itself are considered during the ANM implementation phase as they are tailored for the ANM scheme function.

Communications between the ANM scheme and the control room will utilise the SCADA network where possible, including existing links, RTUs and measuring points at the agreement of the DNO and the ANM developer. Should any new communication links be required; the physical, technical and economic requirements are assessed based on the criticality of the information carried along a link thus allowing a cost/benefit calculation to be done to determine suitable specifications for communications to the deployed ANM scheme. As there is not yet any standard deployment practice for ANM schemes, meeting the cost of new communications equipment is agreed upon between the two parties.

Interfacing an ANM scheme with the control room can be reasonably done in one of two ways; a human-machine interface (HMI) can be developed within the existing control room DMS or a stand-alone interface can be built. It is important to opt for the most suitable interfacing technique for the ANM scheme in question such that it can be managed effectively and the control engineers are at ease with how information and control options are presented to them. However as ANM grows, standard approaches to interfacing are likely to be required.

In the instances where an ANM scheme HMI is integrated into the existing control room DMS connectivity diagram, the HMI will be designed to adhere to existing DNO-specific use of symbols and colours in the diagram thereby aligning the HMI with the environment that control engineers are familiar with.

Simpler ANM schemes may not necessitate a detailed HMI, but rather they are interfaced via symbol and colour manipulation of the existing DMS connectivity diagram and screens. Different symbol and colour combinations can be programmed to denote particular ANM scheme modes of operation if desired.

Development of a stand-alone HMI allows an amount of freedom regarding layout and presentation; however operators must then contend with an unfamiliar interface screen in addition to an unfamiliar control scheme. It can also be costly to provide new hardware and software, as well as training for control engineers in its use and maintenance. This is not regarded as the most appropriate option since it tends towards a greater number of stand-alone systems in the control room, which adds complexity.

Section 4.7.8 provides some insight into this issue as the Orkney ANM scheme interface in the SSE DMS connectivity diagram, although necessary, does not provide sufficient visibility and as such, a separate stand-alone interface has been built in addition to this.

At this point, the information (analogues, alarms and indications) decided upon in Section 4.6.3 and the control actions from Section 4.6.4 should be reviewed to ensure the communications and interfacing provisions can accommodate the data traffic (see the feedback loop in Figure 19 regarding review of alarms and control actions).

Upon completion of this stage, the communication requirements including existing and/or new links, RTUs and measuring points are established for the scheme, as is the design and placement of the ANM scheme HMI.

4.6.6 Step 6: Impact on Control Engineer Daily Operations: Check and Revise

It is recommended at this stage to review what has been decided upon in the previous stages, prior to proceeding with integrating the ANM scheme. It might be the case that certain aspects can be removed, modified or simplified. Questions to pose include

- Is the control room receiving too much information?
    - SCADA alarms and indications which are succinct and conform to standard notation

  - Redundant or duplicate alarms and indications should be removed so as not to overburden the SCADA system or the control engineer

- Is the control engineer required to make too many control decisions/actions?
  - Unnecessary or unjustified control actions should be removed to avoid complication

- Is the HMI overly complex?
  - The HMI must display information and alarms clearly, and provide easily accessible controls such that control engineers can assimilate and respond to ANM scheme requirements when necessary

The interim 'Test' step in the methodology, shown in Figure 19, proposes that the ANM scheme be tested at this stage where possible. The CoRDS platform, presented in Chapter 5 is ideally suited for this kind of testing and supports the steps in this methodology.

Any changes noted in the review should be fed back in to the methodology at the 'Determine Control Engineer Responsibilities' stage (see Figure 19) and the necessary amendments should filter down through the remaining steps. This can be repeated as many times as is necessary to ensure the final integrated product is calibrated to an accepted standard.

At this point the integration process can begin on the network and within the control room, and the ANM scheme is physically deployed.

4.6.7 Step 7: Training Provisions

In preparation for the ANM scheme going live, the control engineers require a satisfactory level of training on the ANM scheme and its manifestation in the control room environment. There are several ways in which training can be administered, and it is at the discretion of the ANM developer and DNO control engineers to agree upon the methods of training to be provided. Some proposed ideas are noted here

- It is prudent to produce a manual for the scheme containing all of the information discussed thus far in Sections 4.6.1 through 4.6.6, as well as its general technical scope and operational states. The main benefit of a training manual is that it provides and initial reference point for control engineers which can be accessed at any time
- Oral presentations and discussion forums, between the ANM developers and the DNO control engineers, to facilitate dissemination of information regarding the ANM scheme are also effective methods of training
- Where possible, an ANM scheme training demonstration or simulator can be a useful tool as it can allow operators to interact and become familiar with the working environment of the ANM scheme and the intended HMI. Such a training tool would also facilitate further deployments, developments and awareness of ANM schemes.

4.6.8 Step 8: Review in Service

Following the successful deployment and integration of the ANM scheme onto the network and into the control room, it is important to review the ANM scheme in service to ensure that control engineers are experiencing effective interaction in the manner anticipated during the design of the integration. In cases where the control engineer is seen to be interacting with the ANM scheme more or less often than anticipated, the cause of this should be investigated at this stage to determine if it is an ANM scheme design issue, or a system integration problem.

Frequent communication failures should also be checked although the implications for ANM operation may differ from the effect of such communication failures on other SCADA/DMS functionality.

It is also advised to establish if improvements to any part of the ANM scheme control room interface can be made. A periodic review by the ANM scheme developer would allow for updates and improvements to the scheme and any future ANM integration projects.

4.6.9 The Feedback Loop

The feedback loop, shown in Figure 19 as coming from Step 8 and entering back into Step 1, is an essential part of the overall methodology and it necessitates the need for revision when circumstances with the ANM scheme change e.g. the addition of a new DG connection, the addition of a new measurement device or a change to the network. In the instance of changes such as this, the steps should be taken again to establish whether any consequent changes are needed in terms of new alarms or control actions for DG, new communications infrastructure and updates to the DMS interface.

4.7 Application of the Control Room Integration Methodology in the Deployment of the Orkney RPZ ANM Scheme

The Orkney ANM scheme was deployed in November 2009 on to the Orkney Isles 33kV distribution network by DNO Scottish and Southern Energy plc and ANM Developer Smarter Grid Solutions Ltd (SGS). The ANM scheme has facilitated increased connection of DG to the existing Orkney network by managing power flows and curtailing generation when thermal limits are being approached. The new DG connections to the Orkney network that have been facilitated by ANM would otherwise not be able to connect without significant capital expenditure on network reinforcement. The ANM scheme operating principles are well documented in [6 - 9] and have been described in this chapter and Chapter 3 previously. The methodology described in Section 4.6 of this chapter was an outcome of the deployment of the scheme.

The SSE control room is located several hundred miles from the Orkney Isles, in Perth, Scotland. The ANM scheme on Orkney is deployed at the substation level on an automation controller platform and uses Programmable Logic Controller (PLC) technology. The main hub of the ANM scheme is the central PLC controller which receives information from various network and DG locations, and runs ANM power flow algorithms to determine preventive and corrective control actions. The PLCs deployed at each DG site interface with the DG (owner) control systems and also exhibits failsafe functionality in the event that communications to the DG site are lost. The central controller provides a subset of the data available on the operation of the ANM scheme to the SSE SCADA system via a DNP 3.0 link.

The following sections (Sections 4.7.1 to 4.7.8) describe each stage of the integration process methodology, in detail and Section 4.8 offers some feedback from the control engineers at SSE involved in the scheme management.

4.7.1 Step 1: Characterisation of the ANM Scheme

As described in Section 4.3.1, the Orkney ANM scheme is a multi-generator, multi-constraint scheme which allows additional generation to be connected to the Orkney 33kV network and utilise existing network capacity that is available in all but contingency conditions.

The ANM scheme allows the connected DG to generate unconstrained except in cases where congestion poses a threat to the thermal limits of the circuits, at which point, the scheme takes necessary action i.e. trims and/or trips generation depending on the severity of the situation. The scheme carries out these control actions autonomously and is considered to be decentralised, yet monitoring is performed centrally from the control room.

The autonomous nature of the scheme permits it to carry out the majority of the control actions in this way and there is no call for manual intervention during normal operation. Manual controls are afforded to the control engineer however, for use in times of contingency or emergency. The manual controls allow the control engineer to operate the main circuit breakers at the DG sites should they be required to be disconnected at any point. The ability to enable and disable the scheme should also be available from within the control room.

4.7.2 Step 2: Determine Control Engineer Responsibility

The multi-generator, multi-constraint complexity of the Orkney ANM scheme (and its relative novelty) dictates a higher level of awareness for control engineers.

During consultation between the DNO (SSE) and the ANM vendor (SGS), the parties discussed the role of control engineers and, based on the characteristics of the scheme and its expected operational mode, the control engineers advised on their preferable type and level of control. The scheme is fully active and requires no routine external intervention to function normally. As such, the following remote control actions were considered adequate by the control room:

- Enable/Disable ANM Scheme
- Enable/Disable DG Site

The overall responsibility of the control room over the ANM scheme therefore consists of monitoring; the exception being in cases of contingency and/or emergency at which time, the control room has the capability to disable either individual DG sites, or the entire scheme remotely depending on the requirements of the situation in hand. The receipt of alarms and analogues from the scheme will allow successful monitoring of the scheme.

Following the completion of this stage, the decision on the two way interactions between the scheme and the control room has been finalised.

4.7.3 Step 3: Establish Information Required from the ANM Scheme

In reviewing the potential subset of ANM data that could be provided to the control room, it was decided that the control engineers should be notified of the following:

- The status of the ANM scheme (ENABLED/DISABLED)
- The status of a DG site (ENABLED/DISABLED)
- The Current (A) and Power (MW) at each network measuring point
- The Power Production (MW) of each DG site participating in the ANM scheme

- The status of any DG site(s) being regulated by the ANM scheme (including specific DG site and level of curtailment)
- The status of any DG site(s) tripped by the ANM scheme (including specific DG unit)
- Notification of the reconnection of a DG site by the ANM scheme following a self initiated trip
- Any instance where a DG site is not responding to an ANM control signal or instruction
- The real-time operating mode of the ANM Scheme
- Instances of communication failure
- Instances of equipment failure

As stated in the methodology (Section 4.6.3), the next step involves segregating the information and assigning each segment a type (analogue, alarm, indication) and a priority. Table 2 shows the final list of alarms, and also gives an explanation for the selection.

Table 2: Orkney ANM Scheme Alarm Types and Priorities

Information	**Data Type**	**Priority**	**Justification**
ANM scheme ENABLED	Indication	Non-Urgent	Indication generated when the scheme is enabled (ENABLE from DISABLE). It is classed as Non-Urgent as no action is required from the control room.
ANM scheme DISABLED	Alarm + Indication	Non-Urgent	Indication generated when the scheme is disabled (DISABLE from ENABLE). An alarm is also generated such that it is acknowledged. It is classed as Non-Urgent as only acknowledgement of the alarm is required.
DG site ENABLED	Indication	Non-Urgent	Indication generated when the DG unit is enabled (ENABLE from DISABLE). It is

Information	Data Type	Priority	Justification
			classed as Non-Urgent as no action is required from the control room.
DG Site DISABLED	Alarm + Indication	Non-Urgent	Indication generated when the DG unit switches to DISABLE (from ENABLE). An alarm is also generated such that it is acknowledged. It is classed as Non-Urgent as only acknowledgement of the alarm is required.
Current (A) at Network Measuring Point	Analogue	N/A	All measurement values are analogues.
Output (MW) at DG Site	Analogue	N/A	All measurement values are analogues.
DG Trip	Alarm	Urgent	Alarm is generated here as the control room must acknowledge this action. It is classed as Urgent as an item of plant has been disconnected from the system.
DG Reconnected	Alarm + Indication	Operational	Indication generated when DG is reconnected following a trip. It is classed as Operational as an item of plant has been reconnected to the system and to the scheme.
DG Not Responding	Alarm	Non-Urgent	Alarm generated here as control room must acknowledge non-response and take action. It is classed as Non-Urgent as this is an initial warning.
ANM Mode (Normal, Trim)	Indication	Non-Urgent	Indication generated when scheme enters this mode of operation (from another). It is classed as Non-Urgent as the scheme is

Information	Data Type	Priority	Justification
			operating as normal.
ANM Mode (Sequential Trip)	Alarm + Indication	Operational	Indication generated when scheme enters this mode of operation (from another). Alarm is generated here as the control room must acknowledge this action. It is classed as operational as the scheme is working as expected but the control room should monitor the situation for escalating actions.
ANM Mode (Global Trip)	Alarm + Indication	Urgent	Indication generated when scheme enters this mode of operation (from another). Alarm is generated here as the control room must acknowledge this action. It is classed as Urgent as all DG units in a zone have been tripped and the control room should monitor the situation to monitor network operation.
Communication Failure	Alarm	Communications & SCADA	Alarm is generated here as the control room must acknowledge this action. It is classed as Communications & SCADA as standard and normal protocol for managing SCADA alarms is followed.
Equipment Failure	Alarm	Operational	Alarm is generated here as the control room must acknowledge this action. It is classed as Operational as it may affect scheme operation. The control room should verify this and ensure the scheme equipment back-up is in operation.

Unique identifiers will be assigned to alarms pertaining to specific DG sites and monitoring points.

This full catalogue of alarms and indications will be formatted to conform to the standard alarm notation employed by SSE.

Upon completion of this step, a full list of analogues, alarms and indications attributable to the ANM scheme is available.

4.7.4 Step 4: Determine Control Actions Available to the Control Engineer

The level of responsibility that control engineers have over the ANM scheme was decided in Section 4.7.2. The following four manual control actions were agreed upon and deemed sufficient by control engineers at SSE for the safe operation of the ANM scheme

- ENABLE scheme
- DISABLE scheme
- ENABLE DG site (ramp up from zero)
- DISABLE DG site (ramp down to zero)

The control engineer will only utilise these controls in cases of contingency or fault conditions, otherwise the scheme should function autonomously without issue.

For practicality reasons, the control engineer can access all of the controls remotely within the control room using telecontrols via the HMI.

4.7.5 Step 5: Determine Communications and Interfacing Requirements

Much of the two-way interaction between the ANM scheme and the control room described in the previous sections is achieved by exploiting existing SSE SCADA and communications infrastructure, and the DNP 3.0 protocol is used for these links. To align with the physical, technical and economic requirements, constraints and existing link availability a number of new radio and pilot wire links were implemented as part of the internal ANM scheme communication infrastructure. The main route for data provision to the control room originates with the central controller, which is represented as a virtual RTU in the SCADA system. Supplementary to this is the provision of some alarm information via RTUs at the participating DG sites. Figure 17 in Section 4.3.1.2 gives a clear illustration of the communication links of the ANM scheme.

After consultation with control engineers, it was decided to integrate the HMI for the ANM scheme into the DMS network diagram. The Orkney ANM scheme interface was added adjacent to the Orkney network diagram and it is readily accessible to control engineers managing this particular system. The interface was designed using the standard SSE layout, format and colour scheme.

The interface provides an overview screen, which highlights whether the scheme is ENABLED or DISABLED at any given time. It also informs the control engineer the mode of operation in which the scheme is currently operating (normal, trim etc), and contains a list of scheme alarms, which are highlighted when active. The DG sites are displayed as blocks showing their real-time MW output and curtailment set point. Each block also contains a corresponding list of DG alarms, also highlighted when active. The network measuring points are also displayed as blocks and their monitored current (A) and power (MW) values are given. An illustration of a DG block within the ANM scheme DMS interface is given in Figure 20.

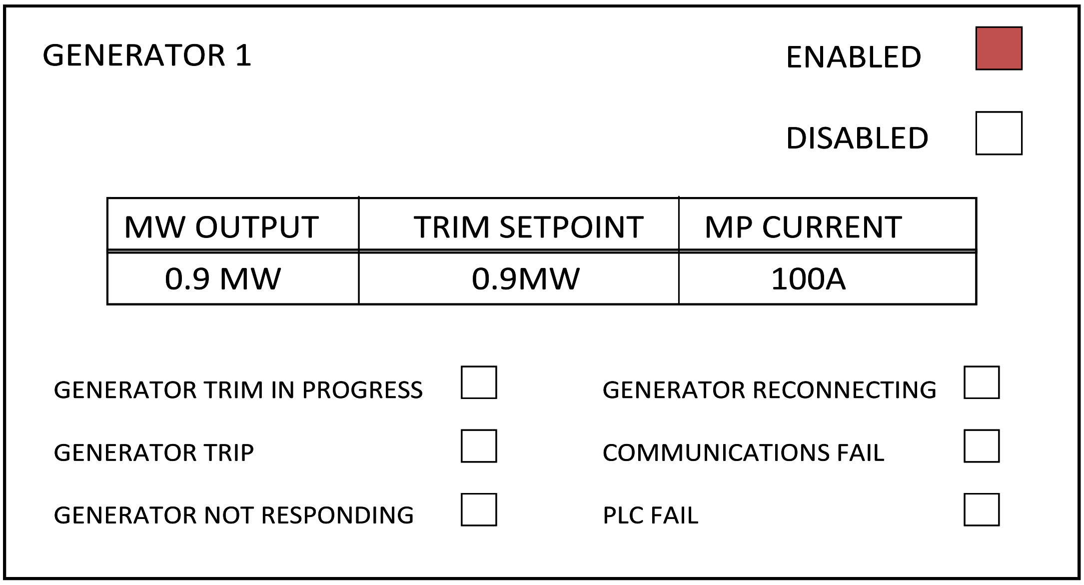

Figure 20: Illustration of the ANM Scheme HMI in the Control Room DMS

An HMI, identical to that in the central control room, has also been deployed at the site of the central controller on Orkney. It permits all the same functions that are available in the central control room to local engineers, on the condition of implementation of suitable interlocking, security and controlled access arrangements.

4.7.6 Step 6: Impact on Control Engineer Daily Operations: Check and Revise

The integration of the Orkney ANM scheme into the SSE distribution control room went through several iterations of the methodology steps described here prior to full deployment. The information regarding alarms in Section 4.7.3, control actions in Section 4.7.4 and the communications and interfacing requirements in Section 4.7.5 all represent the final iteration of the methodology thus far where the alarm catalogue was reviewed and changed, as was the design of the ANM scheme interface in the DMS.

4.7.7 Step 7: Training Provisions

In order to prepare the SSE distribution control engineers for the full deployment of the Orkney ANM scheme, a number of training provisions were made. First and foremost, a user manual was produced, and the document includes all information relevant and essential to scheme operation and management by the control engineers; explaining the ANM scheme, its operating philosophy and modes of operation; and how and when the control room is expected to be involved in its operation.

Given also in the user manual is the list of alarms (Table 2) and control actions decided upon, and these are accompanied by a series of process diagrams detailing the steps the control engineer must take upon receipt of each alarm, and what steps precede the use of each of the available control actions. The user guide was made available in .pdf format, and also in hard copy.

In addition to the user manual, a training session was provided for the SSE distribution control engineers (several were provided to small groups to ensure all control engineers were able to attend one). Each training session involved a presentation by a representative of SGS, and it encompassed all of the material contained in the user manual. Each session was usually followed by lengthy discussions and Q&A where the control engineers were given a podium to ask questions, and air opinions and concerns regarding the ANM scheme and their role in its operation.

A supplementary part of the training session involved an offline demonstration of the HMI that would eventually be implemented in the online DMS connectivity diagram. The demonstration involved running some likely scenarios and highlighting their different stages as they progressed. This facilitated the understanding of how the ANM scheme interfaces with the control room and allowed control engineers to visualise and interact with it prior to its deployment.

4.7.8 Step 8: Review in Service

As part of the methodology process, a follow up consultation interview with the control room at SSE was conducted by the author to establish the successes and lessons learned from the deployment of this trial ANM scheme. A full account of the discussions is given in Appendix D and some highlighted information is given here.

Through the method outlined in this chapter, the Orkney RPZ ANM scheme was deployed on the Orkney 33kV distribution network in the North of Scotland. The SSE control room engineers have been fully exposed to the workings and operation of the Orkney ANM scheme as it has been in service for almost three years.

During this time, a further 6 DG sites have been connected under management of the ANM scheme, now totaling 9 sites and 13MW, and each has been successfully integrated into the scheme algorithm, and to the HMI in the DMS.

The ANM scheme has successfully trimmed generation on several occasions due to thermal congestion to avoid overloading, and it has functioned exactly to specification. Generation has also had to be trimmed on a more frequent basis as a result of communication failures as a failsafe. The most common alarms from the scheme received by the control room are those from the communications infrastructure; even so, the additional volume of alarms has been unremarkable to date.

Outage planning on the network has become more complex, with power systems analysis required to ascertain which ANM-regulated DG sites can remain connected during each outage, and which have to be switched off.

The SSE control room has built an additional HMI to the ANM scheme in a software program called PI Process Book as it is felt to be more user-friendly and illustrative of real-time scheme operation. A better front end within the DMS connectivity diagram would ideally be built however there is confidence with the ANM scheme operation and how information is communicated and presented to the control room at the present time and as such; it is not a current priority.

The most beneficial aspect of the Orkney ANM scheme integration process was the provision of the training and demonstration sessions which provided control engineers the opportunity to become familiar with the ANM scheme operation and its interface.

There is overall confidence and satisfaction with the Orkney ANM scheme and its ability to operate autonomously, notifying control engineers only of events when they occur, rather than bombarding them with unnecessary periodic updates. Other than some improvements to the DMS HMI, the SSE control room is pleased with how the ANM scheme has been integrated into the network and the control room, and the information that is available to them.

4.8 Chapter 4 Conclusions

This chapter has addressed some of the issues facing distribution control rooms and control engineers, specific to ANM deployment, in the coming years, with the evolution of distribution networks towards an active operating paradigm. Layers of uncertainty are challenging the ability to predict and plan for active distribution networks with any measure of confidence, and as ANM schemes are still at an early stage of deployment, further work will be required in this area to gain clearer insight over time.

The comparison of two UK deployed ANM schemes emphasises the difficulties faced, by highlighting the vast differences between scheme operation, requirements and management despite their common goal of accommodating more DG on networks.

In order to combat some of these difficulties and remove some of the disparity of ANM schemes, a methodology for integrating ANM schemes into the control room was presented. The methodology advises the user (ANM developer, DNO) on what essential steps to take and when, when implementing an ANM scheme onto a network. The steps, each of which are dependent on the previous step and will impact the following step, include

- Determination of control room responsibility with regards to ANM scheme operation
- Establishment of alarms and control actions to and from the scheme
- Design of appropriate communications and interfacing facilities
- Provision of adequate training

The inception of the methodology through the Orkney RPZ deployment case study was then presented to demonstrate a working case, and feedback from the control room regarding the integration process that was adopted, and its operation since it has been deployed is provided.

4.9 Chapter 4 References

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Chapter 5

Simulating Active Networks in the Control Room

5.1 Introduction

In order to better understand the future with respect to managing active networks from the control room, a Control Room Demonstration Suite (CoRDS) has been developed as part of this research. The CoRDS facility provides a realistic representation of the power system, encompassing its electrical, communications and SCADA capabilities. This chapter describes the CoRDS in detail, explaining the principal aims of this part of work and the methods used to meet these objectives. The experimental set-up of the tool is provided and each component part of the CoRDS, and its purpose and function, is then described. This is followed by an explanation of how each component interfaces to the others to establish a complete end-to-end system. This operational end-to-end demonstration facility is validated through proof-of-concept testing.

The testing and simulations are carried out on the SSE Orkney 33/11kV distribution network model (consisting of 34 33kV buses and 30 11kV buses) which has some existing DG connections at both voltage levels.

An ANM scheme is then integrated into the system and the CoRDS is validated as a control room demonstration platform through a series of experiments which also serve the purposes of this thesis; the testing of the ANM scheme operation to meet the objectives set out in Section 5.2. The results from the CoRDS experiments are presented and discussed to confirm the success of meeting these initial objectives.

Further attention is given to the value of the results in terms of the future of active distribution networks.

5.2 Principal Aims

The CoRDS simulation environment described in this chapter was assembled with the purpose of investigating several aspects of control room management of active distribution networks. As described in previous chapters, a range of issues are expected to present themselves in the control room as distribution networks become more active, and the capabilities of the CoRDS will allow for more detailed interrogation of some of these issues. A longer term objective of the CoRDS is the provision of a platform upon which the operation of ANM schemes from a control room perspective can be tested prior to their deployment on distribution networks. Table 3 below lists the principal objectives of this part of work involving the CoRDS, noting the desired outcomes from each objective.

Table 3: Objectives of the CoRDS Simulations and Desired Outcomes

	Objective	**Desired Outcome**
A	To assess the behaviour of ANM schemes as networks provide access to higher penetrations of DG	This will allow ANM scheme performance to be tested against their intended design specifications
B	To assess the behaviour of ANM schemes in response to changes in network configuration	This will give a clearer view of how ANM schemes will adapt and react to different situations
C	To understand and quantify the level and nature of control engineer interactions with ANM schemes through changing network events and DG penetrations	This information will shed light on future control engineer management practices, staffing, training and work load requirements

5.3 CoRDS Experimental Set-Up

The CoRDS comprises several component parts, which connect and interface with each other to provide an end-to-end demonstration facility. The three principal components of the tool are the IPSA+ power flow analysis tool, the SCADA simulation package, simSCADA, and a near real-time simulator. Figure 21 below illustrates the CoRDS experimental set-up.

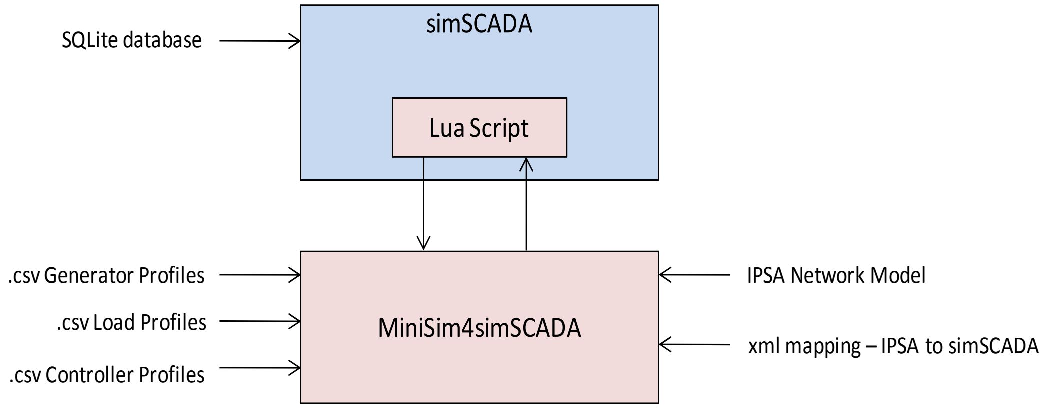

Figure 21: Diagrammatical Illustration of the CoRDS Experimental Set-Up

Figure 21 shows the main structure of the CoRDS and also illustrates the interfacing and connection measures in place to allow each of the programs to communicate and share information effectively. Each component is described in detail in the following Sections 5.3.1 – 5.3.3, which includes an explanation of how they fit into the structure shown in Figure 21 and the part it plays in the overall system.

5.3.1 simSCADA

simSCADA is a software package that was developed by Opal Software. It offers a cost-effective means of simulating large SCADA networks to test and commission new equipment, protocols and functionalities thoroughly prior to their deployment on networks. The benefits of the package include the significant reduction of time spent commissioning new sites, and its use as an operator training tool where operator performance can be tested against any type of network event.

The simSCADA package supports a large number of SCADA protocols including DNP3 and Modbus, and it has a scripting facility which is used to implement actions and scenarios. It is also used as a gateway to interface with other programs and programming languages to enhance functionality. The scripting language used in the current version of simSCADA (Version 3.2) is Lua, although previous versions use C/C++.

Opal Software is a worldwide systems integration partner of GE Energy who provides the ENMAC DMS solution to many utilities across the world, including the majority of UK DNOs who use the DMS to manage their distribution networks. As a result, simSCADA has been developed with the aim to integrate easily with ENMAC.

5.3.1.1 Lua Scripting

As mentioned in Section 5.3.1, simSCADA has a scripting facility which provides the ability to simulate different scenarios, it also enhances the ability to interface with other programs and languages. The scripting language used in simSCADA Version 3.2 is Lua. simSCADA provides a number of simSCADA-specific script functions which Lua can call on for use in the scripting facility. These simSCADA script functions include utility functions, status functions and analogue functions, and are detailed in the Lua Scripting Manual provided by Opal Software [1].

5.3.1.2 SQLite Database

SCADA network infrastructures, consisting of RTUs and communications, are created in the form of a database for use in simSCADA. The simSCADA package can support multiple database types, however, in the case of the CoRDS, the database is a .sqlite file.

The simSCADA package provides a facility, the simSCADA Maintenance Utility, where the user is able to build up a SCADA database consisting of the RTUs monitoring the network in question. The user is able to implement multiple SCADA protocols within the database and assign the RTUs to their corresponding protocol.

Once the basic SCADA infrastructure is built, each RTU is populated with the digital, analogue and control points which are associated with it.

5.3.1.3 simSCADA in the CoRDS

Within the CoRDS system, simSCADA acts as the SCADA system, and it is the focal interfacing point of the system due to the unavailability of the front-end ENMAC DMS for use in this research.

As mentioned in the Introduction (Section 5.1), the network used to perform the CoRDS case study presented in this chapter is the Orkney 33/11kV distribution network. The network, modelled in IPSA+, is described in more detail in Section 5.3.2.1.

As the Orkney distribution network is operated and managed by SSE, the DNO provided the .sqlite database for the Orkney SCADA infrastructure for use in the development of the CoRDS. The .sqlite database provided by SSE is the one that they use in their offline simSCADA/ENMAC test facility, which is identical to their online SCADA/ENMAC facilities, and so it provides an authenticity to the data and information that the CoRDS manages in its case study. Figure 22 shows the .sqlite database loaded into simSCADA, where the list of RTUs is displayed.

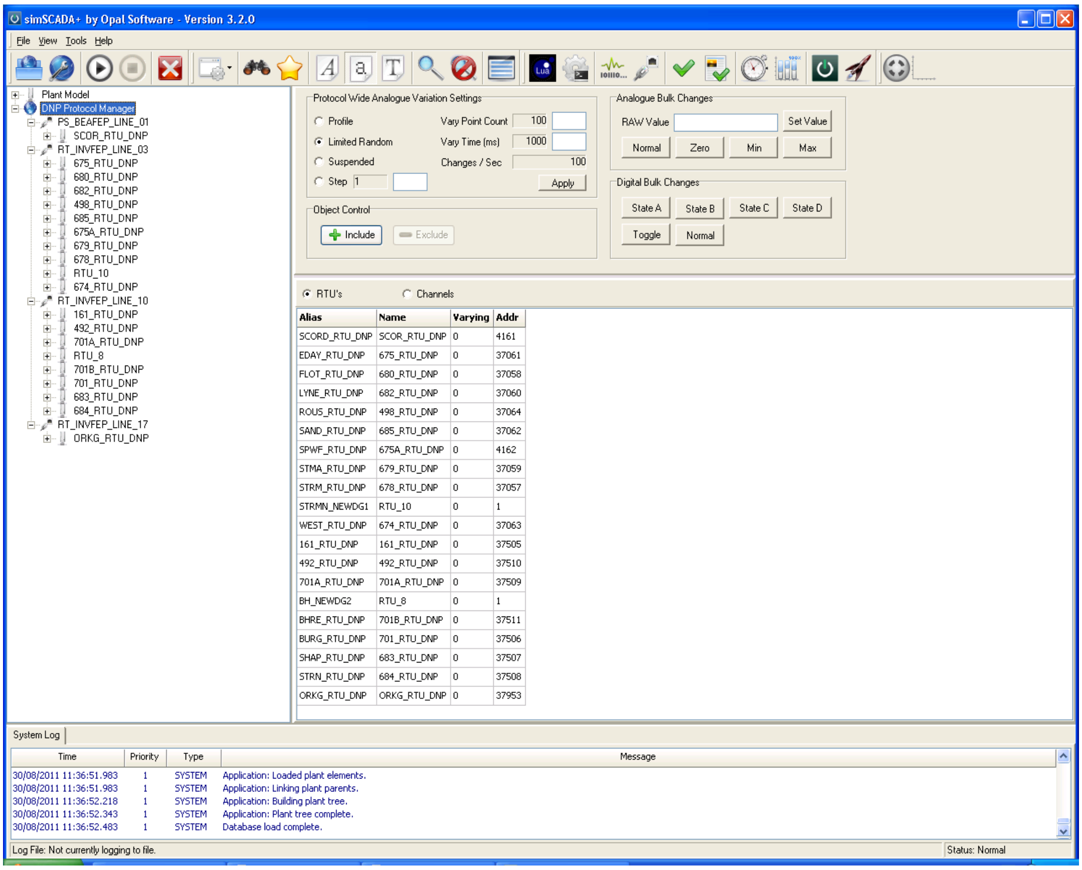

Figure 22: Orkney .sqlite SCADA Database Loaded into simSCADA

As is common in the UK, and the issue has been discussed at length in Chapter 3, there is limited metering and visibility on distribution and LV networks, and Orkney is no exception, where very limited metering is available at 11kV and only 16 RTUs monitor the 33kV network in specific areas. Each of the RTUs has a catalogue of digital, analogue and control points associated with it which represent a status, measurement or controllable device or switch on the network. Figure 23 highlights the simSCADA tree view of one of the RTUs in the database and its associated digital, analogue and control points.

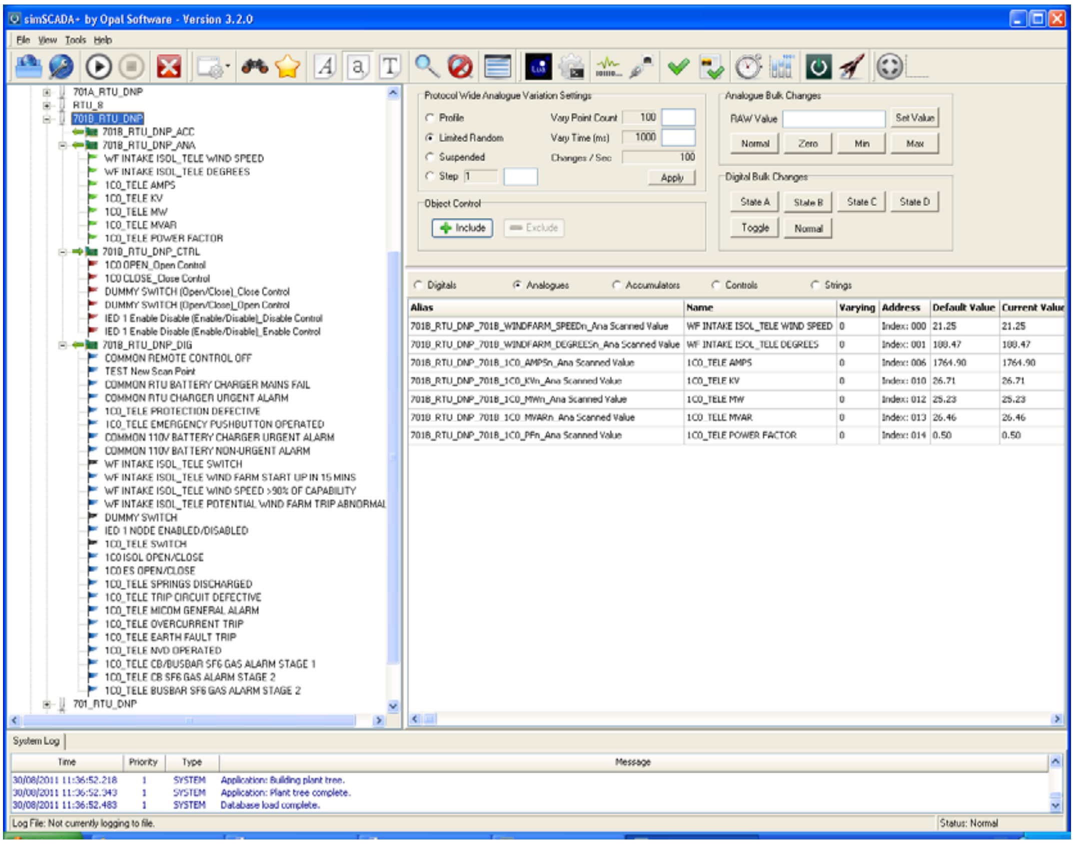

Figure 23: Tree View of the Digital, Analogue and Control Points Monitored by the RTU

The link between the network model in IPSA+ and the SCADA points in simSCADA is achieved through the creation of an .xml mapping file, which is described later in Section 5.3.2.2.

The Lua scripting function in simSCADA is used in the CoRDS to call each of the other programs, files and software packages together and it is from here that the operation of the entire system is streamlined and coordinated. The order in which the different components are called and brought back to simSCADA via Lua is illustrated in Figure 24.

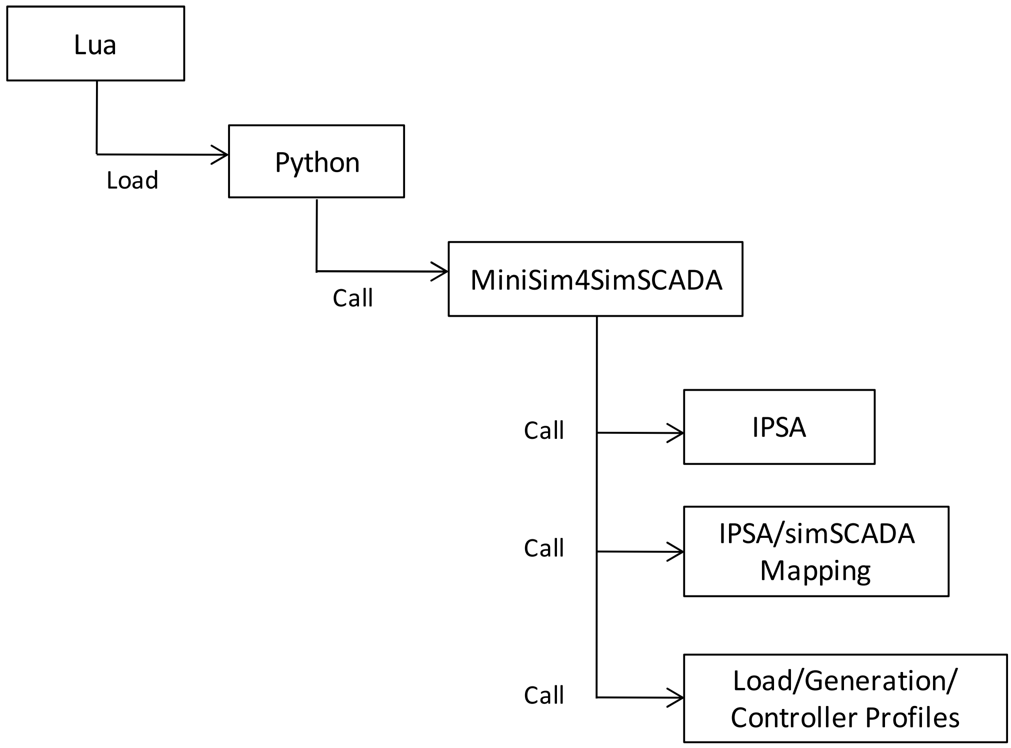

Figure 24: Flow Chart View of the Lua Script Calling External Programs and Files

The initial step taken by the Lua script is to load Python, as this is the language in which MiniSim4SimSCADA is written. MiniSim4SimSCADA is the time simulator and is responsible for the running of CoRDS. As shown in Figure 24, it is MiniSim4SimSCADA that calls each of the other programs and files used in the running of CoRDS. The simulator is described in more detail in Section 5.3.2, and each of the other programs and files are described in subsequent sections.

The Lua script is provided in its entirety in Appendix F.

5.3.2 MiniSim4simSCADA

MiniSim4SimSCADA is a Python script developed specifically for use within CoRDS and simSCADA for the purposes of emulating a power system close to real-time. It is specifically designed to run a load flow calculation in a power systems analysis tool (IPSA+ in this case) once per second to give an accurate and feasible view of the steady state behaviour of a power system simulated over a period of time, which can be specified by the user. It is a sequential steady state time-step simulator, and is accessed by simSCADA via the Lua scripting interface, as described in Section 5.3.1.1.

The python script configures the network inputs, outputs and controllers. It is also used at a further stage of the experiment, to configure the OPC clients and server. The use of the OPC server is essential to the CoRDS when it must communicate with the AuRA-NMS ANM scheme algorithm, which is also coded in python, and which is integrated into the CoRDS as the ANM scheme to be tested. All of this is discussed further in Section 5.3.5.2.

5.3.2.1 IPSA+ Power System Analysis Software

The power system analysis tool used in the CoRDS is IPSA+. IPSA+ was chosen in this case as it is user friendly and it interfaces well with Python, the language in which MiniSim4SimSCADA is written. Equally, another load flow engine, such as PSS/E, could be used and only minor adjustments would be required in the simulator Lua code. This flexibility is a major benefit of the CoRDS should it be used in future projects.

An Orkney distribution network model was built in IPSA+ using data provided by SSE. Information regarding generators, loads, busbars, transformers and lines was used to construct an accurate model of the Orkney distribution network at 33kV. So as not to over complicate the model, loads were aggregated at the 11kV side of transformers. Figure 25 provides a view of the Orkney network model in IPSA+.

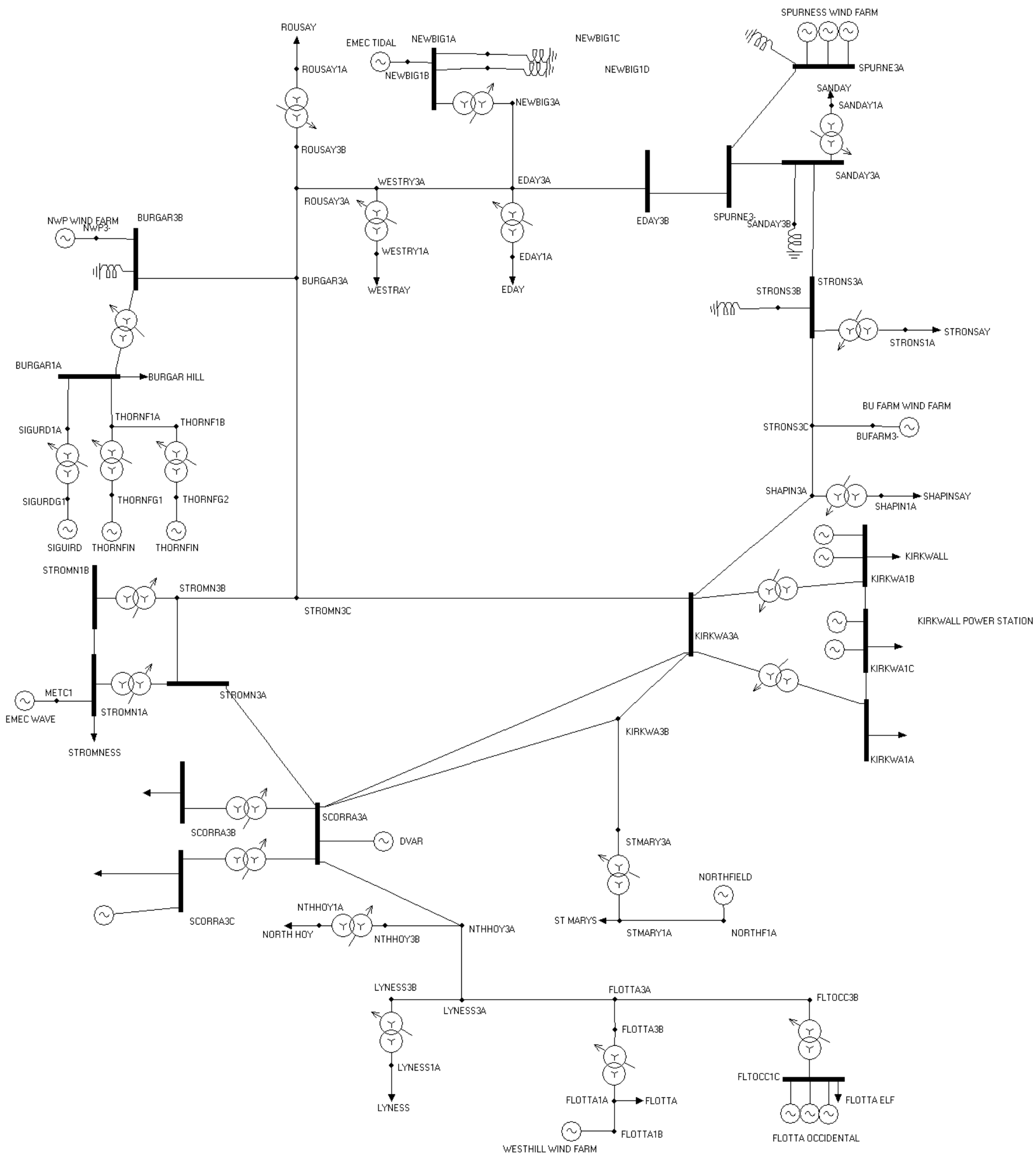

Figure 25: Orkney Distribution Network Model in IPSA+

The IPSA+ load flow engine is called from MiniSim4SimSCADA, as described in Section 5.3.2, and a load flow calculation is performed on the Orkney network model once per second. Load and generator profiles, in .csv format, for each aggregated load and generator are also fed into the network model via MiniSim4SimSCADA. These profiles are described in further detail in Section 5.3.2.3.

Following the execution of each load flow calculation, analogue values of voltage, current and power (MW and MVAr) are then extracted according to the RTU protocol, and are sent back to simSCADA. As mentioned in Section 5.3.1.3, the Orkney distribution network is monitored by 16 RTUs and 14 of these of these RTUs employs the DNP3 SCADA protocol (which was explained in Chapter 2) and this is reflected in the simSCADA database and the information on these 14 RTUs from IPSA+ load flow calculations is brought back to simSCADA according to the DNP3 protocol. The remaining two RTUs on the Orkney network employ the WISP protocol as these are older substations. These are not modelled for the experimental work carried out in this thesis, but can be easily added for future simulations.

The analogue values are assigned to the appropriate point in the simSCADA .sqlite database by means of the IPSA+ to simSCADA .xml mapping file, which is described in Section 5.3.2.2.

5.3.2.2 IPSA+ to simSCADA Mapping

The interfacing tool employed in CoRDS to map analogue values obtained from the IPSA+ load flow calculations to the correct RTU point in simSCADA is an .xml (Extensible Markup Language) mapping file. Firstly, the Orkney .sqlite database file was examined to determine what analogues are physically monitored, as not all available data from the IPSA+ network model is normally monitored by the SSE control room. Following this, the corresponding values were located on the IPSA+ network model and mapped using the .xml file. An example of one of the IPSA+ analogues being mapped to its corresponding simSCADA point is given here.

```
<ipsa2simSCADAmapping alias="SUB6_11KVn_Ana Scanned Value"
ignore_vary="True" type = "FLOAT"
maptoclasstype="IscBusbar" name ="FLOTTA1A"
equivalent_field_address = "IscBusbar.Volts"/>
```

The mapping file can be found in its entirety in Appendix G.1.

5.3.2.3 .csv Profiles

Load and generation profiles are fed into the IPSA+ Orkney model, based on data provided by SSE. The data provided by SSE consisted of static load and generation outputs for the two profile sets (high generation/low load and low generation/high load) and, given the intended short duration of 180s for the CoRDS experiments, these values were kept static i.e. the profiles for load and generation provide 180 seconds worth of data (which equates to 180 1 second iterations of the static value provided) to the network and they are read in through MiniSim4SimSCADA and fed from there into the IPSA+ model.

In order to test the network in different situations and scenarios, a number of test case profiles were created to simulate these. Of particular interest is network operation at times of high load and low generation, and vice versa. Table 4 highlights the two load/generation profile sets provided by SSE for use in the CoRDS. The full profiles are provided in Appendix H.

Table 4: Load and Generation Profile Sets Provided by SSE

Profile Set	Generation characteristic	Load characteristic	Network Characteristic
1	High	Low	Overloads expected, Export to the Scottish mainland
2	Low	High	Import from the Scottish mainland

5.3.3 End-to-End System Operation of the CoRDS

Sections 5.3.1 and 5.3.2 explained the CoRDS tool at its component level, describing each component and the interfacing methods employed to enable their interaction. The end-to-end operation of the CoRDS is achieved through the successful operation of each of these components in order, which is predefined in the Lua script, and the steps are described here.

As stated in Section 5.3.1.3, the Lua script, written within simSCADA, is where each of the programs and scripts is called to and enables the end-to-end operation of the system. Figure 24 illustrates diagrammatically the order in which these programs are called. The initial step in operating the CoRDS is to run the Lua script from within the simSCADA interface. The script then steps through the commands in order, beginning with loading Python, which enables MiniSim4SimSCADA to run. MiniSim4SimSCADA, from within the Lua script, then calls IPSA+ and loads the network model the user wishes to use in the simulations. The next step calls the .xml mapping file is called which allows the selected outputs from the IPSA+ load flow calculations to be mapped correctly to the corresponding monitored points in simSCADA. The final step is the selection of the load and generation profile files, in .csv format, which are input into the IPSA+ network model whilst load flow calculations are executed, from within MiniSim4SimSCADA. The load flow calculations are executed once per second, and figures from the load and generation profiles iterate at the same rate. The analogues brought back from the IPSA+ load flow calculations are updated in simSCADA following each iteration, via the .xml mapping file, and these can be viewed in the user interface.

It should also be noted that the CoRDS tool is set up for experiments involving only steady state analysis within IPSA+. No tests are carried out to assess the dynamic behaviour of the networks at this stage. Recommendations to examine the dynamic behaviour of active distribution networks is suggested as a future research avenue in Chapter 6 and the CoRDS has the scope to extend its capabilities for this purpose.

5.3.4 CoRDS Proof of Concept Testing

Initial testing was carried out on the CoRDS tool in order to verify the functionality of the tool as an end-to-end system. The testing involved running a basic load flow operation on an IPSA+ network model and ensuring the correct outputs reach simSCADA as expected. Table 5 shows the input values of generation from the .csv file. And Figure 26 shows the analogue values brought back to simSCADA after the load flow calculation, returned after one load flow iteration.

Table 5: Generation Profile Input into Orkney IPSA+ Network Model

Generator	**simSCADA Monitoring Point Alias**	**MW Input (Profile Set 1)**
BUFARM3-.BU FARM WIND FARM	Not monitored	1.32
FLTOCC1C.FLOTTA OCCIDENTAL	Not monitored	0
FLOTTA1B.WESTHILL WIND FARM	SUB6_MWn_Ana Scanned Value	1.13
FLTOCC1C.Generator2	Not monitored	1.13
FLTOCC1C.Generator3	Not monitored	1.13
KIRKWA1B.Generator2	Not monitored	0
KIRKWA1B.KIRKWALL POWER STATION	Not monitored	0
KIRKWA1C.Generator1	Not monitored	0
KIRKWA1C.Generator2	Not monitored	0
METC1.EMEC WAVE	SUB4_096MWn_Ana Scanned Value	0
NEWBIG1B.EMEC TIDAL	Not monitored	0
NORTHF1A.NORTHFIELD	Not monitored	0
NWP3-.NWP WIND FARM	SUB11B_1C0_MWn_Ana Scanned Value	5.00
SIGURDG1.SIGUIRD	SUB11_013_MWn_Ana Scanned Value	1.22
SPURNE3A.Generator2	SUB3A_1C0_MWn_Ana Scanned Value	2.43
SPURNE3A.Generator3	Not monitored	2.43

Generator	simSCADA Monitoring Point Alias	MW Input (Profile Set 1)
SPURNE3A.SPURNESS WIND FARM	SUB3A_1K0_MWn_Ana Scanned Value	2.43
THORNFG1.THORNFIN	SUB11_014_MWn_Ana Scanned Value	2.00
THORNFG2.THORNFIN	Not monitored	2.00

The field marked 'Time' in Figure 26 below (and all similar figures to follow) is representative of the date and time at which the experiment was carried out. In the experiments to follow, the time resolution is very accurate, which is not necessarily important here, however this level of accuracy is important when managing SCADA alarms and issues such as latency (cited as avenues of future research in Chapter 6). The CoRDS can be configured to the desired level of time resolution as required by the user.

Time	Priority	Type	Message
13/06/2012 19:00:08.564	1	EVENT	Loading Python
13/06/2012 19:00:08.580	1	EVENT	Importing MiniSim
13/06/2012 19:00:08.580	1	EVENT	Configuring MiniSim
13/06/2012 19:00:09.173	1	EVENT	Setting up callbacks
13/06/2012 19:00:12.189	1	EVENT	Making a step...
13/06/2012 19:00:12.798	1	EVENT	Made a step...
13/06/2012 19:00:12.798	1	EVENT	Getting ouputs...
13/06/2012 19:00:12.798	1	EVENT	49

13/06/2012 19:00:12.798 1 EVENT SUB12_3S0_AMPSn_Ana Scanned Value: 21.449170152432

13/06/2012 19:00:12.798 1 EVENT SUB11_011_012_AMPSn_Ana Scanned Value: 62.070720455472

13/06/2012 19:00:12.798 1 EVENT SUB11C_AMPS: 237.37521634202

13/06/2012 19:00:12.798 1 EVENT SUB3_11KV_AMPSn_Ana Scanned Value: 4.4614309939429

13/06/2012 19:00:12.798 1 EVENT SUB10_11_AMPSn_Ana Scanned Value: 15.755434740773

13/06/2012 19:00:12.798 1 EVENT SUB11B_1C0_AMPSn_Ana Scanned Value: 89.794264491774

13/06/2012 19:00:12.798 1 EVENT SUB12_3S0_MWn_Ana Scanned Value: -1.1303470514548

13/06/2012 19:00:12.798 1 EVENT SUB4B_AMPS: 113.0288556573

13/06/2012 19:00:12.798 1 EVENT SUB6_MWn_Ana Scanned Value: 1.13

13/06/2012 19:00:12.798 1 EVENT SUB3A_1C0_MVARSn_Ana Scanned Value: -2.29178

13/06/2012 19:00:12.798 1 EVENT SUB6_1C0_AMPSn_Ana Scanned Value: 59.578548017941

13/06/2012 19:00:12.798 1 EVENT SUB5_11_AMPSn_Ana Scanned Value: 6.6418083739972e-07

13/06/2012 19:00:12.798 1 EVENT SUB4B_VOLTS: 32.891532361507

13/06/2012 19:00:12.798 1 EVENT SUB9_011_AMPSn_Ana Scanned Value: 7.8622728009734

13/06/2012 19:00:12.798 1 EVENT SUB11C_VOLTS: 33.574885368347

13/06/2012 19:00:12.798 1 EVENT SUB4_T1_T2_AMPSn_Ana Scanned Value: 120.59455476884

13/06/2012 19:00:12.798 1 EVENT SUB11B_1C0_KVn_Ana Scanned Value: 34.056958079338

13/06/2012 19:00:12.798 1 EVENT SUB6_33_KVn_Ana Scanned Value: 33.056734800339

13/06/2012 19:00:12.798 1 EVENT SUB4_096MWn_Ana Scanned Value: 0

13/06/2012 19:00:12.798 1 EVENT SUB12_3S0_MVARn_Ana Scanned Value: 0.47175799250518

13/06/2012 19:00:12.798 1 EVENT SUB11_014_MWn_Ana Scanned Value: 2.00

13/06/2012 19:00:12.798 1 EVENT SUB4_096VOLTSn_Ana Scanned Value: 10.857626020908

13/06/2012 19:00:12.798 1 EVENT SUB11_013_AMPSn_Ana Scanned Value: 62.11288059665

13/06/2012 19:00:12.798 1 EVENT SUB3A_1K0_MVARSn_Ana Scanned Value: -3.3816599845886

13/06/2012 19:00:12.798 1 EVENT SUB3A_1C0_MWn_Ana Scanned Value: 2.43

13/06/2012 19:00:12.798 1 EVENT SUB3A_1K0_AMPSn_Ana Scanned Value: 217.01308717811

13/06/2012 19:00:12.798 1 EVENT SUB6_11KVn_Ana Scanned Value: 10.998631000519

13/06/2012 19:00:12.798 1 EVENT SUB7_11_AMPSn_Ana Scanned Value: 9.7540682593773

13/06/2012 19:00:12.798 1 EVENT SUB11_013_MWn_Ana Scanned Value: 1.22

13/06/2012 19:00:12.798 1 EVENT SUB3A_1C0_AMPSn_Ana Scanned Value: 217.01308717811

13/06/2012 19:00:12.798 1 EVENT SUB1_AMPSn_Ana Scanned Value: 11.05661547184

13/06/2012 19:00:12.798 1 EVENT SUB12_3S0_VOLTSn_Ana Scanned Value: 32.927448928356

13/06/2012 19:00:12.798 1 EVENT SUB11_014_AMPSn_Ana Scanned Value: 177.06374863614

13/06/2012 19:00:12.798 1 EVENT SUB3A_1K0_MWn_Ana Scanned Value: 2.43

13/06/2012 19:00:12.798 1 EVENT SUB4_096MVArn_Ana Scanned Value: 0

13/06/2012 19:00:12.798 1 EVENT SUB4_096AMPSn_Ana Scanned Value: 51.84614103067

13/06/2012 19:00:12.798 1 EVENT SUB6_TR1_AMPSn_Ana Scanned Value: 35.692992540321

13/06/2012 19:00:12.798 1 EVENT SUB11_014_MVARn_Ana Scanned Value: 0

13/06/2012 19:00:12.798 1 EVENT SUB11_TR1_AMPSn_Ana Scanned Value: 218.28998582776

13/06/2012 19:00:12.798 1 EVENT SUB11B_1C0_MWn_Ana Scanned Value: 5.0

13/06/2012 19:00:12.798	1	EVENT	SUB11B_1C0_MVARn_Ana Scanned Value: 0
13/06/2012 19:00:12.798	1	EVENT	SUB8_11_AMPSn_Ana Scanned Value: 11.007382101785
13/06/2012 19:00:12.798	1	EVENT	SUB3A_1C0_VOLTSn_Ana Scanned Value: 33
13/06/2012 19:00:12.798	1	EVENT	SUB2_AMPSn_Ana Scanned Value: 41.33136429136
13/06/2012 19:00:12.798	1	EVENT	SUB11_013_MVARn_Ana Scanned Value: 0
13/06/2012 19:00:12.798	1	EVENT	Step done...

Figure 26: Corresponding Analogue Values Received by simSCADA

As is evident from the figures above, the CoRDS now functions as an end-to-end control room simulator, and successfully reports measurements calculated from load flow calculations to simSCADA, according to the designated SCADA protocol. The MW output of all the monitored generation is highlighted in Table 5 and Figure 26, and can be traced from the .csv profile inputs, through IPSA+ and on to the output in simSCADA (via the Lua interface).

5.4 Integration of the AuRA-NMS ANM Scheme into the CoRDS

Following the successful proof of concept testing of the end-to-end operation of the CoRDS tool, which comprised of the execution of load flows on a network model using variable load and generation profiles, and mapping the analogues back to simSCADA at pre-set intervals of once per second. The next stage of the experimental process in CoRDS involves the integration of a previously developed ANM scheme algorithm.

The Autonomous Regional Active Network Management Scheme, AuRA-NMS, was chosen to be integrated into the CoRDS tool to facilitate meeting the objectives of this part of work, which were outlined in Section 5.2.

The AuRA-NMS algorithm used is described further in Section 5.4.1, and the various additional programs and interfacing tools required to enable its operation within the CoRDS are described in Sections 5.4.2 to 5.4.5. Figure 27 illustrates the experimental set-up of the CoRDS following the integration of the AuRA-NMS ANM scheme.

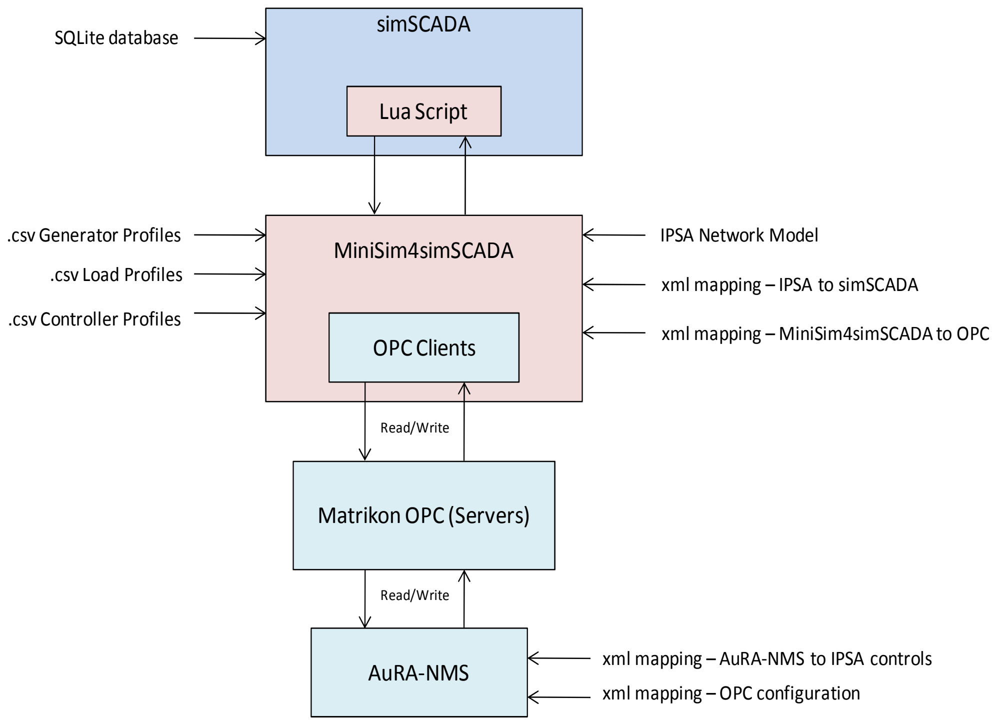

Figure 27: Diagrammatical Illustration of the CoRDS Experimental Set-Up Including the AuRA-NMS ANM Scheme

5.4.1 AuRA-NMS Active Network Management Scheme

The Autonomous Regional Active Network Management Scheme, AuRA-NMS, is a multi-objective ANM scheme developed by seven universities in the UK, two DNOs (EDF Energy and Scottish Power Energy Networks) and a major manufacturer (ABB). [2]. The AuRA-NMS concept was derived to address problems facing DNOs in the UK in the near future, and as such, it tackles the issues of power flow management (PFM), steady state voltage control, automatic restoration and network optimisation. It was designed with flexibility and extensibility in mind such that it can operate successfully on various different network topologies and voltage levels, and it is also reconfigurable when changes to a network occur. For this reason, a multi-agent systems approach was chosen. This allows each of the separate objectives, mentioned above, to be integrated together on a single platform. The use of multi-agent systems as an approach in the development of AuRA-NMS is discussed in [3] and [4].

The several control functions involved in the AuRA-NMS scheme, mentioned above, are PFM, steady state voltage control, restoration and optimisation (minimization of losses). Further to this, there are different approaches to achieving each control function as is explained in [3]. Of the various approaches to PFM, AuRA-NMS implemented a Constraint Programming (CP) approach and an Optimal Power Flow (OPF) approach. In terms of voltage control, two approaches were also developed as part of the project; a Constraint Programming approach and a Case-Based Reasoning (CBR) approach. A method of network restoration was developed to minimise the number of disconnected customers.

The AuRA-NMS algorithm chosen in for use in the CoRDS experiments is the PFM algorithm using constraint programming. This approach uses the artificial intelligence (AI) technique of constraint programming to manage the real-time power flows on distribution networks with DG in an autonomous manner [5]. To facilitate the connection of DG to achieve the renewable energy targets set by the UK Government, explained in Chapter 1, and to overcome the regulatory barriers also outlined in Chapter 1, DG connected on UK distribution networks in recent years has been done so in a 'non-firm' manner, meaning the generator can connect, yet they are contractually obliged to constrain output at times of thermal overload to keep the network within its limits.

AuRA-NMS manages these thermal constraints and DG connections autonomously and keeps the network within its thermal limits by issuing control signals to generators at times where the thermal limits of overhead lines and cables are at risk of being breached. A full description of the constraint programming AI technique is given in [5]. The paper also details how the generation curtailment by constraint programming is achieved using the constraint satisfaction problem (CSP) method. Full justification for the choice and use of the AuRA-NMS constraint programming PFM algorithm in this research is given in Section 5.5.

5.4.2 Matrikon OPC Server

OPC is a collection of standards originally developed by a collection of automation suppliers and Microsoft. The original standard was borne out of the growing need for interoperation and communication of devices from different manufacturers through a defined set of objects, interfaces and methods [6].

The hardware platform upon which the AuRA-NMS was built consists of substation computing equipment, on which the control software is installed. It is here that external measurement devices, for example intelligent electronic devices (IED), for gathering information, and the communications infrastructure [7] are also installed. The substation computer is the COM6XX, a product of ABB [8]. The use of the COM6XX allows the use of multiple features and protocols, including IEC61850 using OPC clients and servers, to communicate with any external devices.

As the AuRA-NMS algorithms were built on the COM6XX distributed computing platform, they require the use of OPC to communicate with external programs. In the absence of a COM6XX substation computer for use in this research, a suitable OPC server replacement was found in the Matrikon OPC server software, a free online resource [9]. Matrikon OPC provides equipment data connectivity software based on the OPC standard mentioned above.

5.4.3 MiniSim4SimSCADA to OPC Server Mapping

OPC clients are embedded in the MiniSim4SimSCADA code to enable it to communicate and exchange data with the AuRA-NMS ANM scheme. The AuRA-NMS constraint programming algorithm is also coded in Python, as described in Section 5.4.1. The OPC clients within MiniSim4SimSCADA communicate with an OPC server, in this case the Matrikon OPC server, described in Section 5.4.2, which in turn communicates with the AuRA-NMS ANM scheme. The analogues obtained from the IPSA+ load flow calculations must be input into the AuRA-NMS algorithm such that it can firstly perform its calculations to determine what action, if any, is required to be taken. The algorithm will then execute these actions according to its specifications. This is done through the OPC clients and servers and using communications standard IEC61850. The IEC 61850 details layered substation communications architecture [10]. As such, the OPC clients within MiniSim4SimSCADA must be mapped to the Matrikon OPC server and this is done using an .xml mapping file. An example of one of the IPSA+ analogues being mapped to AuRA-NMS through the OPC clients within MiniSim4SimSCADA and the Matrikon OPC server is given here in Figure 28.

```
<input_opc_mapping classid=""
equivalent_field_address="IscLoad.RealMW"
logicalnodepath="IEC61850 Subnetwork.FLOTTA1A
FLOTTA.MEAS.MMXU1.TotW.mag" maptoclasstype="IscLoad"
name="FLOTTA1A.FLOTTA" opchost="localhost"
opcserver="Matrikon.OPC.Simulation.1" type="FLOAT"/>
```

Figure 28: Example of OPC Client Mapping to OPC Server

The mapping file can be found in its entirety in Appendix J.

5.4.4 AuRA-NMS to IPSA+ Controls

In order that the AuRA-NMS ANM scheme can control generation output of DG under its management, the controls must be configured correctly. In this case, the controller profile is an .xml file which stipulates what generation the PFM algorithm has control over, and to what degree. The example below, Figure 29, shows a new DG connection (NEWDG1) being mapped into the control of the AuRA-NMS PFM algorithm, noting that the scheme has only the ability to trim this generation. The rating is dependent on each separate generation connection.

```
<P_trim_controllable_generator name="STROMN3C.NEWDG1"
type="syn" rating="10"/>
```

Figure 29: Example DG Control Mapping from AuRA-NMS

The mapping file can be found in its entirety in Appendix K.

5.5 Justification for Use of Orkney and AuRA-NMS PFM Algorithm

The flexibility of the AuRA-NMS algorithms was a major contributor to the decision to use this particular ANM scheme in this section of research. As stated in Section 5.4.1, the AuRA-NMS algorithms are designed with flexibility and extensibility at the core, as well as being easily configurable to different network topologies. As such, it was easily configurable with the Orkney 33/11kV network used in the experiments.

The use of a PFM algorithm was favourable here with the following justifications:

- There is evidence that the Orkney network has a considerable renewable resource which is being exploited through the connection of wind farms, and the thermal issues that this is causing to require the implementation of a PFM ANM scheme have made it an ideal candidate for study.

- There exists already an ANM scheme in operation on Orkney, the Orkney RPZ, explained in detail in Chapter 4, which manages generation output through PFM.

- The AuRA-NMS constraint programming algorithm is written in Python and it is therefore able to communicate directly with MiniSim4SimSCADA, which is also written in Python.

- The AuRA-NMS algorithm and MiniSim4SimSCADA, as they are coded in Python, can interface easily with IPSA+, and also with simSCADA itself through the Lua scripting facility.

5.6 Operational Limitations of the CoRDS

The most prominent operational limitation of the CoRDS as it is presented in this thesis, is the unavailability of a DMS front-end, mentioned briefly in Section 5.3.1.3. The absence of a front-end DMS interface, from where the control engineers operate and manage networks, prevents certain processes from being fully assessed, including Objective C outlined in Table 3. As a consequence, the CoRDS tool is capable of assessing some impacts of ANM schemes on the control room, however, the complete feedback loop with regards to interface design and information presentation is unavailable as the CoRDS is currently configured. Chapter 6 details the future work avenues for this research and the implementation of a DMS front-end for the CoRDS environment features heavily.

Other limitations include the circulation of alarms and digital signals. It was decided that, in the absence of a DMS front-end and accompanying SCADA alarm log, it would be very difficult to collate and decipher this type of information. The functionality is available within the CoRDS such that it will be easily implementable when a front-end is obtained.

That said, although not configured such that Objective C in Table 3 can be fully assessed, the CoRDS as it is presented in this thesis is fully able to tackle the other two objectives (Objectives A and B) set out for the experiments.

5.7 CoRDS Experimental Procedure

Following the successful proof-of-concept testing described in Section 5.3.4, Section 5.8 presents further testing. The purpose of the experiments is three-fold; firstly to validate the integration and operation of the AuRA-NMS algorithm; to achieve the objectives set out in Table 3 in Section 5.1; and finally to gain insight into the control room impacts of ANM integration. The following sections, Sections 5.7.1 – 5.7.4 describe the experimental process undertaken for each of the experiments. The sections explain how and what information is presented at each stage of the experimental process.

Description of Experiment

A description of the experiment is provided initially, and the justification for undertaking the experiment is included at this point. The value of the results, and how they relate to previous and following experiments, is also emphasised in the description. Speculative discussion on the expected results is considered.

Fixed Experimental Settings

Each experiment works to a set of pre-defined experimental settings. A summary of the fixed settings for the experiment is provided in this section. Included in each summary is

- The topology of the Orkney 33/11kV network for the duration of the experiment.
- Information regarding the load and generation profile sets that are used.
- The status of the AuRA-NMS ANM scheme (in/out of service).
- Details of any DG which is under the management of the ANM scheme for the duration of the experiment.
- Details of fault or outage conditions.

Experimental Results

This section describes the results of the experiment that has been carried out. The results are presented and supporting graphs and figures, extracted at various points during the experiment. The result set is then analysed, correlated and discussed.

Conclusion and Discussion

This section concludes the experiment and the value of the results, highlighted in the initial description, are verified. Also noted in the conclusion is the progress towards meeting the principal objectives (Table 3 in Section 5.2).

5.8 CoRDS Experiment Descriptions and Results

The following sections contain the experimental results of all simulations carried out in the CoRDS and, in accordance with Section 5.7, each of the experimental reports have a similar structure. Table 6 highlights the experiments that were carried out and are presented in this thesis.

Table 6: List of Experiments Performed within the CoRDS

	Experiment Title	To Meet Principal Objective (from Table 3)
1	Operation of the Orkney distribution network in its current state	None
2	Operation of the Orkney distribution network with additional DG connected	A
3	Operation of the Orkney distribution network with additional DG connected and the AuRA-NMS ANM scheme deployed	A, B, (C)
4	Operation of the Orkney distribution network under outage condition, with additional DG connected and the AuRA-NMS ANM scheme deployed	A, B, (C)

5.8.1 Experiment 1: Operation of the Orkney Distribution Network in its Current State

The following sections describe the experiment involving the simulation of the Orkney distribution network operating in its current state.

5.8.1.1 Description of Experiment 1

The initial simulations carried out in the CoRDS involve the operation of the Orkney distribution network as it is currently configured. The purpose of this initial experiment is to provide a baseline in terms of network operation, and also in terms of the information the control room receives from the network. No notable issues are expected to be reported as this is the current network configuration and no outages or faults are being simulated during this experiment.

The experiments following this one will add DG incrementally and then an ANM scheme will be introduced, and the impacts will be assessed with reference to this initial experiment.

5.8.1.2 Experiment 1 Fixed Settings

The network used in these simulations is the Orkney 33/11kV distribution network which is in operation at this time. The network diagram is shown in Figure 25 in Section 5.3.2.1.

Load and generation profile set 1, given in Table 4 in Section 5.3.2.3, is used in this experiment.

5.8.1.3 Experimental Results

As expected, no notable issues were apparent on the Orkney network during this experiment. As seen from Figure 30, the IPSA+ Orkney network model, no thermal or voltage limits were breached where, a thermal breach would appear on the IPSA+ network diagram as red arrows along the overloaded plant in question in the direction of the power flow, and voltage issues are displayed by highlighting any busbars outwith their set limits. CoRDS is not set up to transmit alarms due to the limitations highlighted previously in Section 5.6, which is ordinarily how a control engineer is alerted to a breach of this sort, however, the list of outputs from Table 26 in Section 5.3.4 is received at the CoRDS user interface (this experiment processed the same inputs as those in the proof-of-concept test). All demand was met with adequate levels of generation, with the remainder exported to the Scottish mainland (represented as being absorbed at the swing bus at SCORRA3C in this network model).

In Figure 30 below, and in Figure 34 further on, the following key should be followed to decipher the power flow results on the diagram. The value adjacent to the:

- Generator represents the MVA output of the generator
- Load represents the lumped MVA load
- Transformer represents the MVA flow through the transformer
- Branch represents the MVA flow through the branch
- Busbar represents the per unit voltage of the busbar

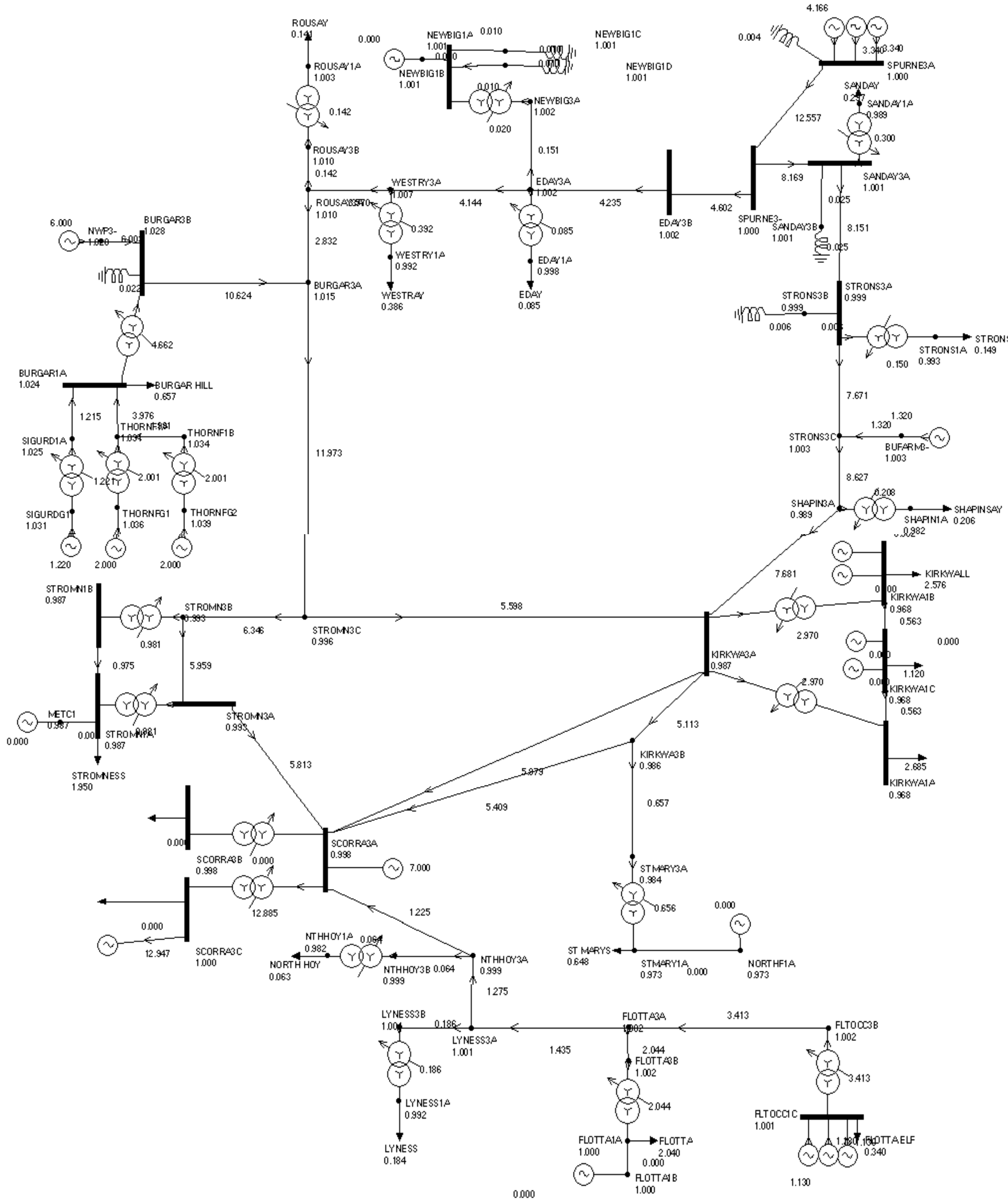

Figure 30: Orkney Network Load Flow Results during Current Operating Conditions

5.8.1.4 Conclusions of Experiment

The main conclusion to draw from this experiment is that the Orkney 33/11kV distribution network operates normally and can meet local demand when the network is not under outage or fault conditions. In times of high generation, the excess is exported to the mainland, while in times of low generation, the deficit is imported from the mainland through two 33kV subsea circuits at Scorradale.

5.8.2 Experiment 2: Operation of the Orkney Distribution Network with Additional DG Connected

The following sections describe the experiment involving the simulation of the Orkney distribution network operating with additional DG connected at 33kV.

5.8.2.1 Description of Experiment

In this experiment, additional DG is connected to the Orkney distribution network which was tested in the previous experiment, the results of which were presented in Section 5.8.1. Distributed generation connections were added to the network at two 33kV busbars and the effects of this extra generation capacity on the Orkney system were tested.

The information from the DG units that is received by the control room is also of interest.

5.8.2.2 Experiment 2 Fixed Settings

The network used in these simulations is the Orkney 33/11kV distribution network as it is in its current state, with two additional DG connections. The DG units are connected to STROMN3C 33kV busbar, and BURGAR3A 33kV busbar. The network diagram is shown in Figure 31.

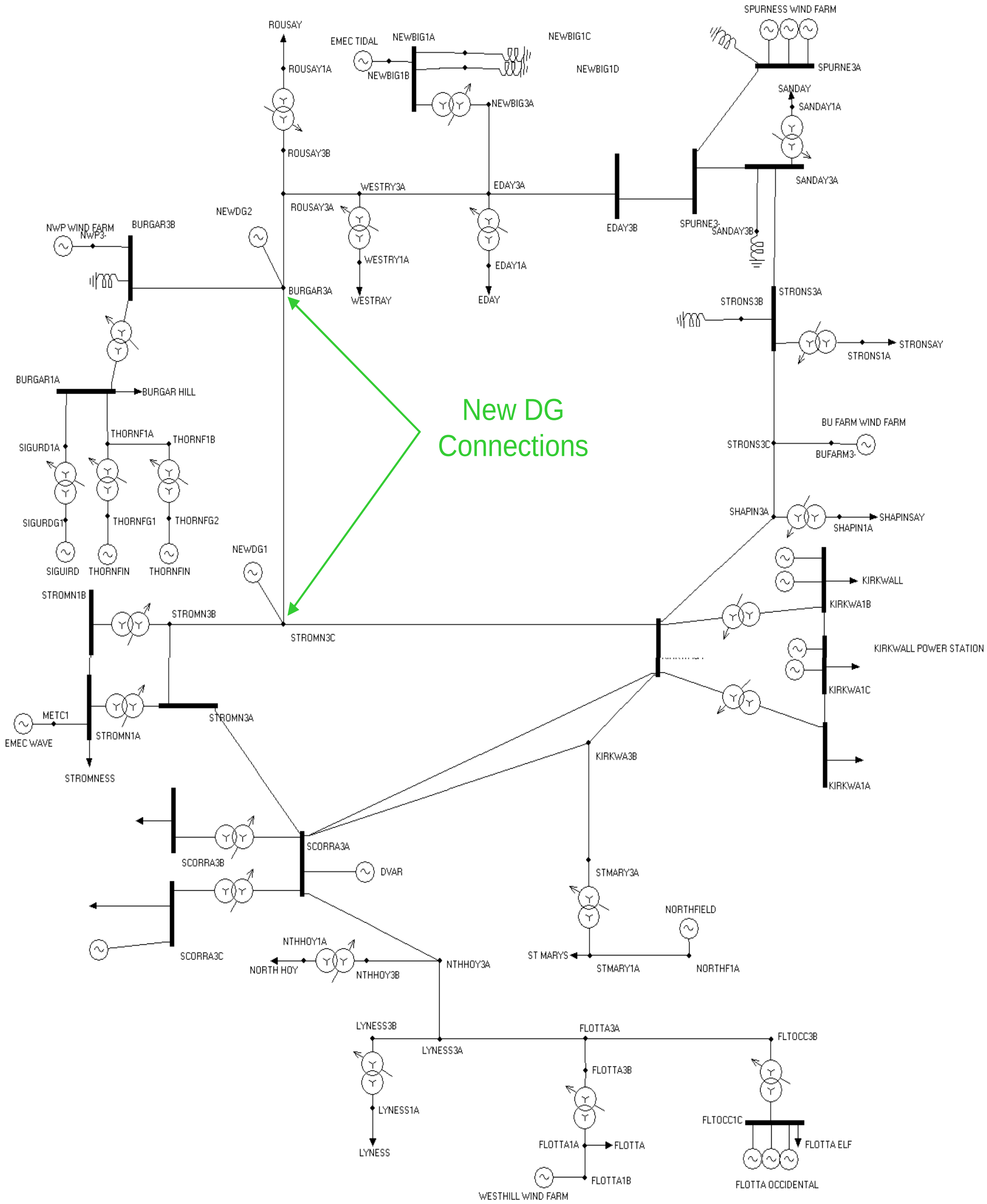

Figure 31: Orkney Distribution Network Model in IPSA+ with Additional DG

The capacity of NEWDG1 is set to 9MW and the capacity of NEWDG2 is set to 11MW for this experiment to provoke thermal overloads around the 33kV network. The process undertaken to add these generators to the network involved initially adding them to the IPSA+ Orkney network model, as shown in Figure 31. Following this, the generators were included in the IPSA+ to simSCADA mapping file, described in Section 5.3.2.2. Figure 32 shows the two additional generators' mapping code which was added to the file, provided in Appendix G.1. The full .xml mapping file with the additional generation is given in Appendix G.2.

```
NEWDG1 (MW, MVAR)

<ipsa2simSCADAmapping alias="SUB4B_NEWDG1_MW" ignore_vary="True" type = "FLOAT" maptoclasstype="IscSynMachine" name ="STROMN3C.NEWDG1" equivalent_field_address = "IscSynMachine.GenMW"/>

<ipsa2simSCADAmapping alias="SUB4B_NEWDG1_MVAR" ignore_vary="True" type = "FLOAT" maptoclasstype="IscSynMachine" name ="STROMN3C.NEWDG1" equivalent_field_address = "IscSynMachine.GenMVAr"/>

NEWDG2 (MW, MVAR)

<ipsa2simSCADAmapping alias="SUB11C_NEWDG2_MW" ignore_vary="True" type = "FLOAT" maptoclasstype="IscSynMachine" name ="BURGAR3A.NEWDG2" equivalent_field_address = "IscSynMachine.GenMW"/>

<ipsa2simSCADAmapping alias="SUB11C_NEWDG2_MVAR" ignore_vary="True" type = "FLOAT" maptoclasstype="IscSynMachine" name ="BURGAR3A.NEWDG2" equivalent_field_address = "IscSynMachine.GenMVAr"/>
```

Figure 32: IPSA+ to simSCADA Mapping of New Generation

Load and generation profile set 1 (with additional sections for the new DG), described in Table 4 in Section 5.3.2.3, is used in this experiment to allow examination of the DG impacts on the thermal constraints of the Orkney network under the most susceptible state of operation for thermal problems; high generation and low load.

5.8.2.3 Experimental Results

As expected, simulation of the Orkney network with 20MW total of additional generation connected resulted in some thermal overloading around the network. In this instance one 33kV circuit was affected initially, the circuit from BURGAR3A to STROMN3C (the circuit which connects the two new DG sites). The MVA flow along the branch is now 20.586 MVA which is 8.613 MVA more than in Experiment 1 where no DG was connected, and 2.486 MVA more than the 18.1 MVA rating of the branch, giving a loading of 113%.

The analogue values of the DG collected from simSCADA via the Lua interface is shown in Figure 33.

Time	Priority	Type	Message
18/06/2012 18:43:53.500	1	EVENT	SUB11C_NEWDG2_MW: 11
18/06/2012 18:43:53.500	1	EVENT	SUB11C_NEWDG2_MVAR: 0
18/06/2012 18:43:53.500	1	EVENT	SUB4B_NEWDG1_MW: 9
18/06/2012 18:43:53.500	1	EVENT	SUB4B_NEWDG1_MVAR: 0

Figure 33: Corresponding Analogue Values received by simSCADA

The addition of two DG connections has resulted in an additional four analogue notifications; MW and MVAr output from each generator (not including associated alarms which are not considered in the CoRDS as it is presented here due to the absence of a DMS front-end).

The IPSA+ network diagram below, Figure 34, shows the overloaded circuit which is highlighted with red arrows.

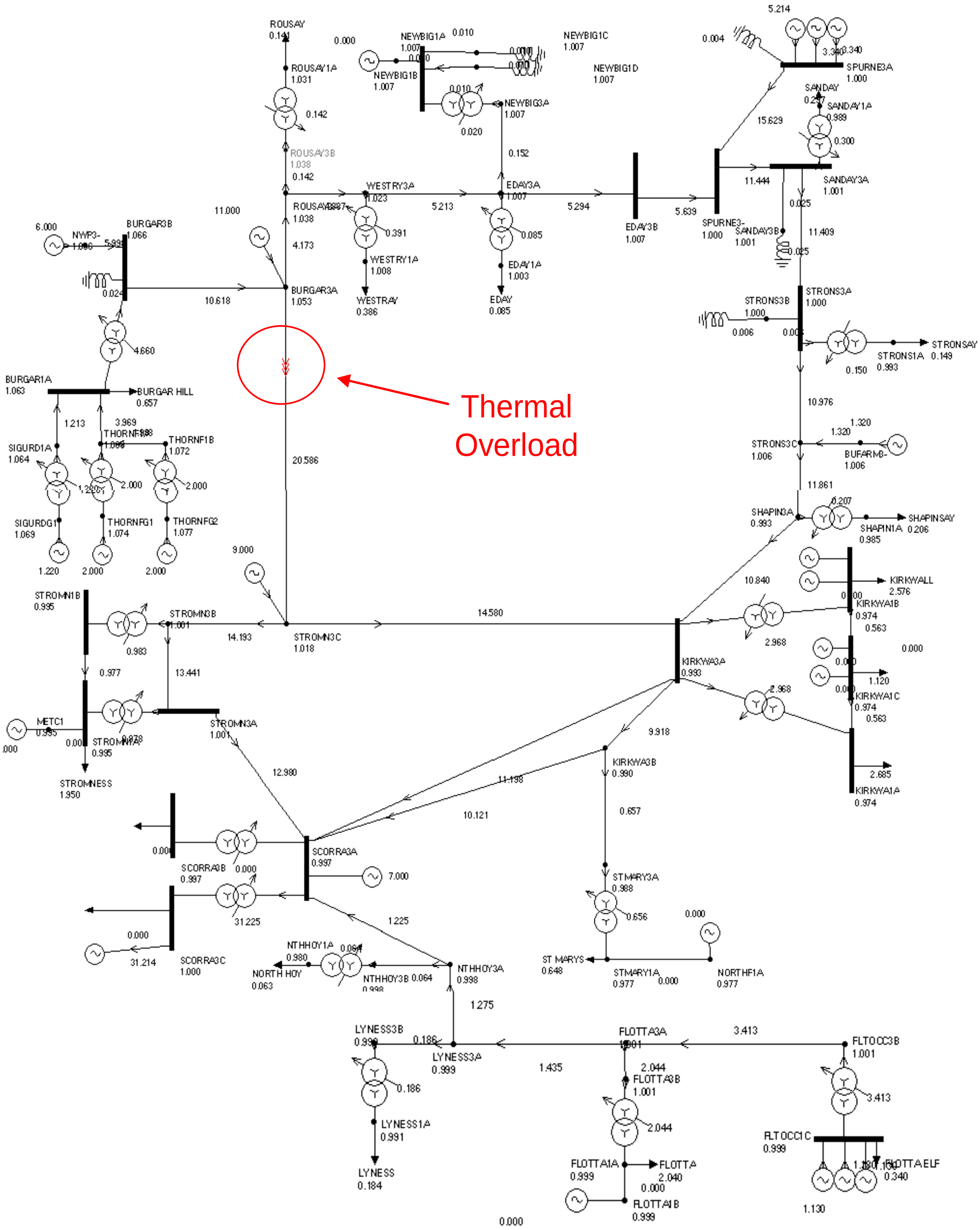

Figure 34: Orkney Network Showing Thermal Overloads as a Result of Additional DG Connections at 33kV

5.8.2.4 Conclusions of Experiment

Based on the results of this experiment, when compared to those of Experiment 1, where the only change has been the addition of DG (i.e. load and generation profiles for existing generation are identical), it can be inferred that the DG is the direct cause of the thermal overloading on the 33kV circuit highlighted in Figure 34.

It is at this stage that a solution, such as active network management, would have to be considered to allow further connections as higher penetrations of DG around the Orkney network will only exacerbate thermal congestion. This option is explored in the following experiment in Section 5.8.3.

5.8.3 Experiment 3: Operation of the Orkney Distribution Network with Additional DG Connected and the AuRA-NMS ANM Scheme Deployed

The following sections describe the experiment involving the simulation of the Orkney distribution network operating with additional DG connections at 33kV, and with an ANM scheme deployed to manage the thermal congestion the DG was proven to cause in Experiment 2.

5.8.3.1 Description of Experiment

The results of Experiment 2, presented in Section 5.8.2, highlighted some thermal congestion issues which arose as a result of two additional DG connections to the 33kV network in Orkney. An ANM scheme to manage the thermal constraints on the Orkney network has been deployed for this experiment to assess this as a viable enabling solution to connecting additional generation to the network and maximising use of existing assets and capacity.

The ANM scheme that is added is the AuRA-NMS power flow management scheme, where the integration process was described in Section 5.4, and the scheme itself described in Section 5.4.1. Use of the AuRA-NMS power flow management tool was justified in Section 5.5.

In addition to the information provided through the simSCADA Lua interface, further information regarding the DG and the ANM scheme is supplied through the ANM scheme interface (created as part of the AuRA-NMS project and not specifically for use in the CoRDS and, as such, not subject to the integration methodology presented in Chapter 4 in the absence of a front-end DMS). The information provided by the AuRA-NMS interface is considered to be that which would be received by the control room regarding the ANM scheme and its control actions i.e. in the DMS interface.

The AuRA-NMS scheme is being tested for two different network operating conditions; high generation and low loading; and low generation with high loading. It is expected that the AuRA-NMS will have to exercise more control actions for the former network condition due to higher volumes of MW present around the network which is not being consumed locally (and so is exported to the mainland).

5.8.3.2 Experiment 3 Fixed Settings

The network used in these simulations is the Orkney 33/11kV distribution network as it was run in Experiment 2, inclusive of the additional DG connections (see Figure 31).

Load and generation profile sets 1 and 2, given in Table 4 in Section 5.3.2.3, are used in this experiment to allow examination of the AuRA-NMS ANM scheme controlling the

DG and managing thermal constraints as they are approached during different load and generation scenario combinations.

These experiments (Experiments 3A and 3B) are designed to address Objective A in Table 3 and the experiment will test the same levels of DG as before in Experiment 2, with NEWDG1 at 9MW and NEWDG2 at 11MW in size.

The AuRA-NMS PFM algorithm will be in operation throughout this experiment and the generation under its management includes the two additional DG connections (NEWDG1 and NEWDG2), as well as an existing wind farm DG connection at Burgar Hill (NWP3- 33kV busbar). The wind farm has a capacity of 6MW and this will remain constant throughout all experiments in this section.

5.8.3.3 Experimental Results

Experiment 3A: NEWDG1=9MW, NEWDG2=11MW, NWP3=6MW, Profile Set 1: High Generation, Low Load

The implementation of a power flow management ANM scheme to the Orkney network to manage thermal limitations was proven successful in this experiment.

As is illustrated in Figure 35, NEWDG1 and NEWDG2 are ramped up towards 9MW and 11MW respectively, with the existing Burgar Hill Windfarm at 6MW. A thermal overload on the 33kV circuit from BURGAR3A to STROMN3C (the circuit connecting the two new DG sites) is then flagged up by the AuRA-NMS interface as shown in Figure 36, when NEWDG1 reaches 9MW and NEWDG2 reaches 9.8MW, and is the same thermal overload that occurred during Experiment 2. At this point the ANM scheme implements control measures, as shown in Figure 36, to remove the thermal overload. NEWDG1 is tripped off, the MW output of NEWDG2 is instructed to trim its generation to 5MW, however the thermal overload is removed and NEWDG2 settles at 7MW output. Burgar Hill Windfarm remains at 6MW throughout.

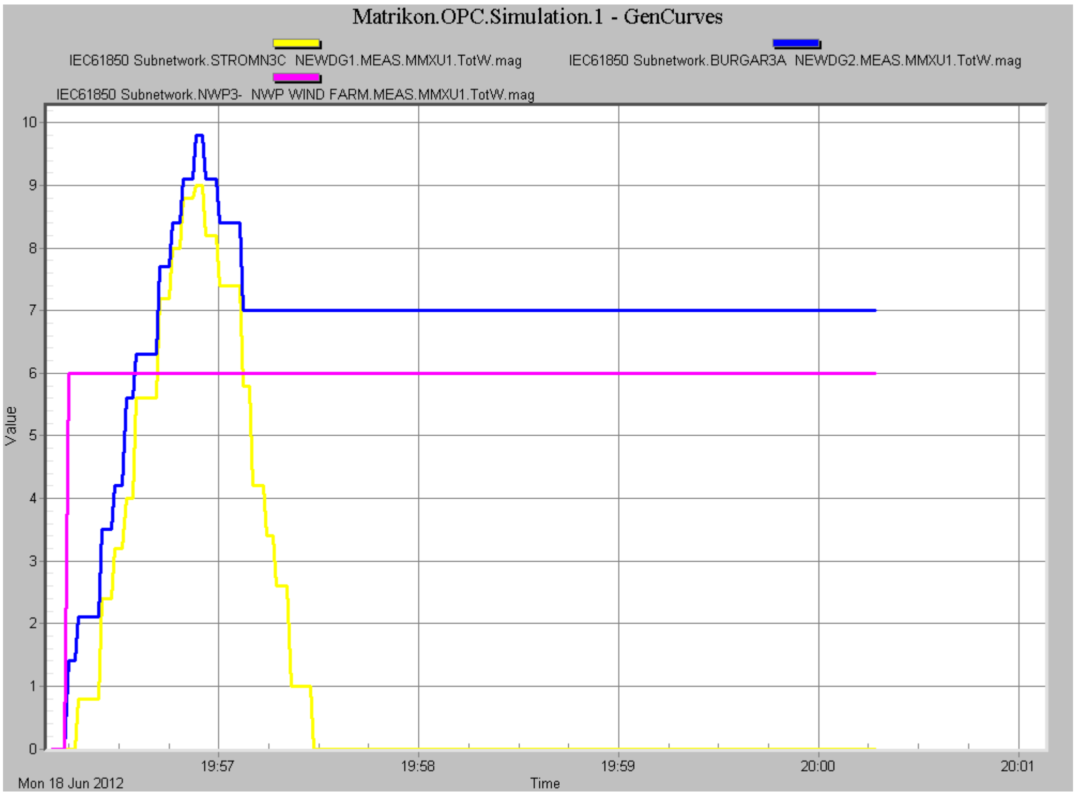

Figure 35: MW Output Curves of the Three DG Connections Under the Management of the AuRA-NMS Scheme during Experiment 3A

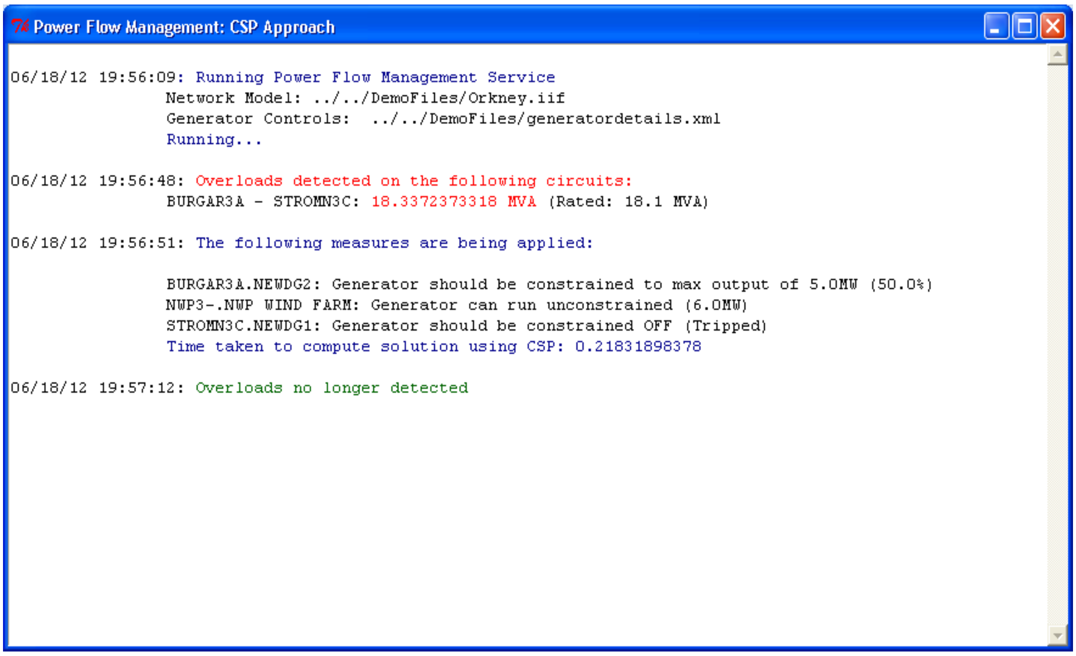

Figure 36: AuRA-NMS Interface Window showing Control Actions Taken During Experiment 3A

The information received by simSCADA during the course of the experiment is shown here in Figure 37. The list has been limited to display only the analogues of interest generated by the ANM scheme (MW output of the ANM-regulated DG). This shows that the CoRDS tool functions as expected; the two new DG connections are shown to ramp up their MW output until the AuRA-NMS issues control actions to reduce this output, and so corresponds to the information provided in Figures 35 and 36.

In terms of information to process, surplus to analogue values from the new DG connections, the control room now also receives information from the ANM scheme. This information comprises detection of overloads, information of control actions the scheme is taking, and notification of the removal of overloads.

This experiment has proven the successful implementation of the AuRA-NMS scheme into the system. As the generation MW output remains constant at NEWDG1 = 0MW, NEWDG2 = 7MW and Burgar Hill Windfarm = 6MW after about 80 seconds, the list of analogues is truncated here.

Time	Priority	Type	Message
18/06/2012 19:56:10.718	1	EVENT	SUB11C_NEWDG2_MW: 0.7
18/06/2012 19:56:10.734	1	EVENT	SUB4B_NEWDG1_MW: 0
18/06/2012 19:56:13.718	1	EVENT	SUB11C_NEWDG2_MW: 1.4
18/06/2012 19:56:13.718	1	EVENT	SUB4B_NEWDG1_MW: 0
18/06/2012 19:56:16.578	1	EVENT	SUB11C_NEWDG2_MW: 2.1
18/06/2012 19:56:16.578	1	EVENT	SUB4B_NEWDG1_MW: 0.8
18/06/2012 19:56:19.671	1	EVENT	SUB11C_NEWDG2_MW: 2.8
18/06/2012 19:56:19.671	1	EVENT	SUB4B_NEWDG1_MW: 1.6
18/06/2012 19:56:22.484	1	EVENT	SUB11C_NEWDG2_MW: 3.5
18/06/2012 19:56:22.484	1	EVENT	SUB4B_NEWDG1_MW: 2.4
18/06/2012 19:56:25.890	1	EVENT	SUB11C_NEWDG2_MW: 4.2
18/06/2012 19:56:25.890	1	EVENT	SUB4B_NEWDG1_MW: 3.2
18/06/2012 19:56:29.812	1	EVENT	SUB11C_NEWDG2_MW: 4.9
18/06/2012 19:56:29.812	1	EVENT	SUB4B_NEWDG1_MW: 4
18/06/2012 19:56:31.687	1	EVENT	SUB11C_NEWDG2_MW: 5.6
18/06/2012 19:56:31.703	1	EVENT	SUB4B_NEWDG1_MW: 4.8
18/06/2012 19:56:35.187	1	EVENT	SUB11C_NEWDG2_MW: 6.3
18/06/2012 19:56:35.187	1	EVENT	SUB4B_NEWDG1_MW: 5.6
18/06/2012 19:56:37.515	1	EVENT	SUB11C_NEWDG2_MW: 7

18/06/2012	19:56:37.531	1	EVENT	SUB4B_NEWDG1_MW: 6.4
18/06/2012	19:56:40.625	1	EVENT	SUB11C_NEWDG2_MW: 7.7
18/06/2012	19:56:40.625	1	EVENT	SUB4B_NEWDG1_MW: 7.2
18/06/2012	19:56:43.656	1	EVENT	SUB11C_NEWDG2_MW: 8.4
18/06/2012	19:56:43.656	1	EVENT	SUB4B_NEWDG1_MW: 8
18/06/2012	19:56:48.375	1	EVENT	SUB11C_NEWDG2_MW: 9.1
18/06/2012	19:56:48.390	1	EVENT	SUB4B_NEWDG1_MW: 8.8
18/06/2012	19:56:51.796	1	EVENT	SUB11C_NEWDG2_MW: 9.8
18/06/2012	19:56:51.812	1	EVENT	SUB4B_NEWDG1_MW: 9
18/06/2012	19:56:52.718	1	EVENT	SUB11C_NEWDG2_MW: 9.1
18/06/2012	19:56:52.734	1	EVENT	SUB4B_NEWDG1_MW: 8.2
18/06/2012	19:56:57.031	1	EVENT	SUB11C_NEWDG2_MW: 8.4
18/06/2012	19:56:57.046	1	EVENT	SUB4B_NEWDG1_MW: 7.4
18/06/2012	19:56:58.156	1	EVENT	SUB11C_NEWDG2_MW: 8.4
18/06/2012	19:56:58.156	1	EVENT	SUB4B_NEWDG1_MW: 7.4
18/06/2012	19:57:04.375	1	EVENT	SUB11C_NEWDG2_MW: 7
18/06/2012	19:57:04.390	1	EVENT	SUB4B_NEWDG1_MW: 5.8
18/06/2012	19:57:06.765	1	EVENT	SUB11C_NEWDG2_MW: 7
18/06/2012	19:57:06.765	1	EVENT	SUB4B_NEWDG1_MW: 5
18/06/2012	19:57:07.625	1	EVENT	SUB11C_NEWDG2_MW: 7
18/06/2012	19:57:07.625	1	EVENT	SUB4B_NEWDG1_MW: 4.2
18/06/2012	19:57:12.859	1	EVENT	SUB11C_NEWDG2_MW: 7

18/06/2012 19:57:12.859	1	EVENT	SUB4B_NEWDG1_MW: 3.4
18/06/2012 19:57:14.734	1	EVENT	SUB11C_NEWDG2_MW: 7
18/06/2012 19:57:14.750	1	EVENT	SUB4B_NEWDG1_MW: 2.6
18/06/2012 19:57:16.656	1	EVENT	SUB11C_NEWDG2_MW: 7
18/06/2012 19:57:16.671	1	EVENT	SUB4B_NEWDG1_MW: 1.8
18/06/2012 19:57:21.625	1	EVENT	SUB11C_NEWDG2_MW: 7
18/06/2012 19:57:21.625	1	EVENT	SUB4B_NEWDG1_MW: 1
18/06/2012 19:57:23.453	1	EVENT	SUB11C_NEWDG2_MW: 7
18/06/2012 19:57:23.468	1	EVENT	SUB4B_NEWDG1_MW: 0.2
18/06/2012 19:57:27.218	1	EVENT	SUB11C_NEWDG2_MW: 7
18/06/2012 19:57:27.281	1	EVENT	SUB4B_NEWDG1_MW: 0
18/06/2012 19:57:30.562	1	EVENT	SUB11C_NEWDG2_MW: 7
18/06/2012 19:57:30.562	1	EVENT	SUB4B_NEWDG1_MW: 0

Figure 37: simSCADA Analogues for NEWDG1 and NEWDG2 Received During Experiment 3A

Experiment 3B: NEWDG1=9MW, NEWDG2=11MW, NWP3=6MW, Profile Set 2: Low Generation, High Load

As is illustrated in Figure 38, NEWDG1 and NEWDG2 are ramped up towards 9MW and 11MW respectively, with the existing Burgar Hill Windfarm at 6MW. Due to the network conditions involved in this experiment i.e. low generation and high load conditions, no thermal overloading of the Orkney circuits occurs in the course of this experiment and this is demonstrated through Figure 39 which indicates that no action was taken by the AuRA-NMS scheme for the duration.

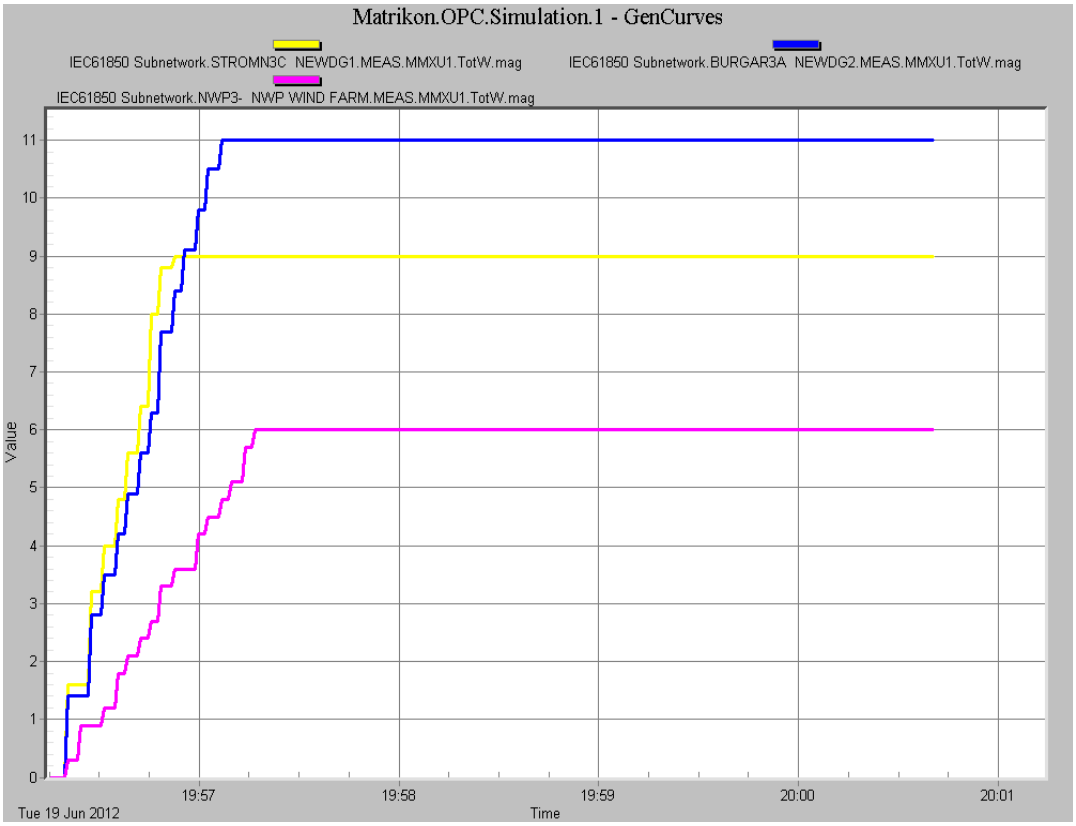

Figure 38: MW Output Curves of the Three DG Connections Under the Management of the AuRA-NMS Scheme during Experiment 3B

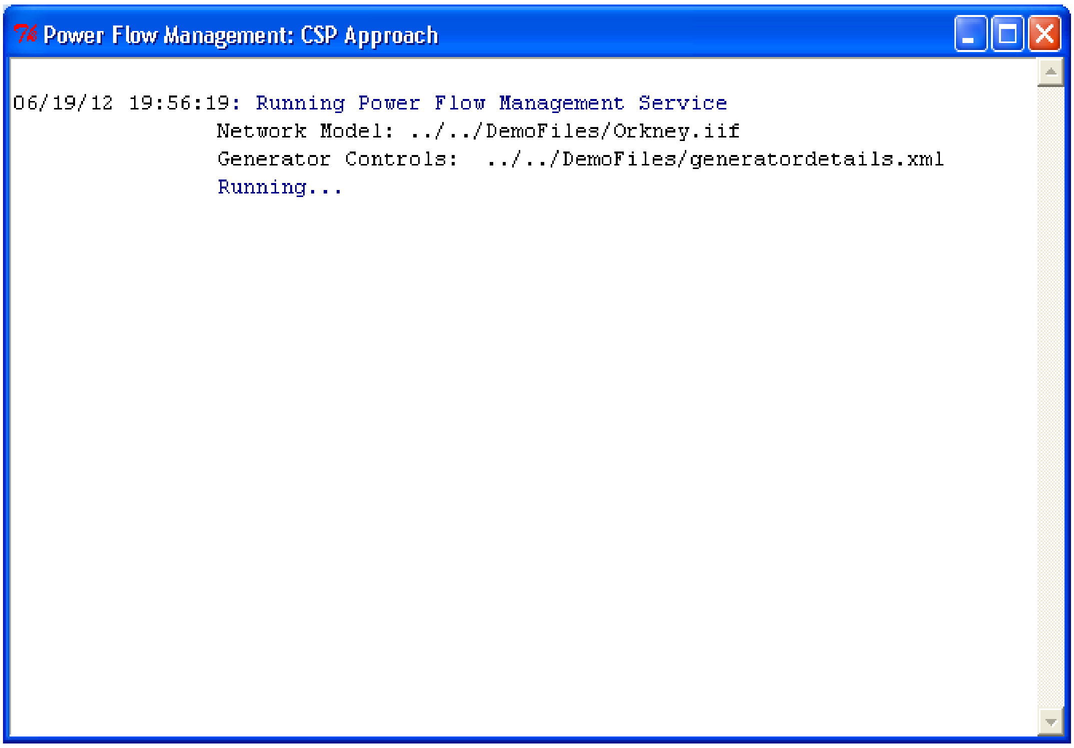

Figure 39: AuRA-NMS Interface Window showing Control Actions Taken During Experiment 3B

The analogues received by simSCADA relating to the MW output of NEWDG1 and NEWDG2 during the course of this experiment are not shown here, but are available in full in Appendix L.1.

5.8.3.4 Conclusions of Experiment

The operation of the AuRA-NMS PFM algorithm has been tested through two experiments on the Orkney 33/11kV network encompassing two very different network operating conditions (high generation with low loading, and low generation with high loading) to determine its use and benefits as an enabling solution for increased levels of generation on distribution networks. Increasing levels of DG were simulated, for these two conditions and the results prove that the AuRA-NMS functions as expected, as noted in Section 5.8.3.1; and having to exercise more control during Experiment 3A where a surplus of generation was present.

Under the condition of Experiment 3A, an additional 7MW of generation was made possible through the use of the ANM scheme, and Experiment 3B conditions allowed a total of 20MW additional generation (with the potential for more) to operate, thus the benefits of ANM can be clearly understood.

The MW output of the three generators remained constant for the duration of the experiments as the load and generation profiles are static and so the network conditions do not change. In order to provoke further action from the AuRA-NMS scheme e.g. releasing capacity back to the DG, the profiles would have to be dynamic.

From a control room perspective, the amount of information that the control engineer must manage and process has increased through the addition of SCADA alarms from DG, and an ANM interface. Each of these aspects of changes to the control room has been discussed in previous chapters. Figure 37 shows the information received by the CoRDS (Experiment 3A only).

5.8.4 Experiment 4: Operation of the Orkney Distribution Network Under Outage Condition, with Additional DG Connected and the AuRA-NMS ANM Scheme Deployed

The results of Experiment 3 showed that the AuRA-NMS ANM scheme is capable of managing network constraints to ensure no thermal overloading occurs on the Orkney network. The following sections describe this experiment which involves the simulation of the Orkney distribution network, where additional DG has been connected and the AuRA-NMS ANM scheme has been deployed to manage the additional generation as with Experiment 3, is operating under outage conditions.

5.8.4.1 Description of Experiment

As stated, this experiment involves testing the Orkney 33/11kV network which has additional DG connected, and an ANM scheme deployed to manage subsequent thermal constraints, in an outage situation. The value of this experiment is in testing how the AuRA-NMS scheme reacts to an outage on the network and whether the algorithms reconfigure successfully to the new network topology, and that it remains capable of controlling the DG connected under its management for the duration of this outage.

5.8.4.2 Experiment 4 Fixed Settings

The network used in these simulations is the Orkney 33/11kV distribution network as it was run in Experiments 2 and 3, inclusive of the additional DG connections. A branch outage was placed on the network as shown in Figure 40 below.

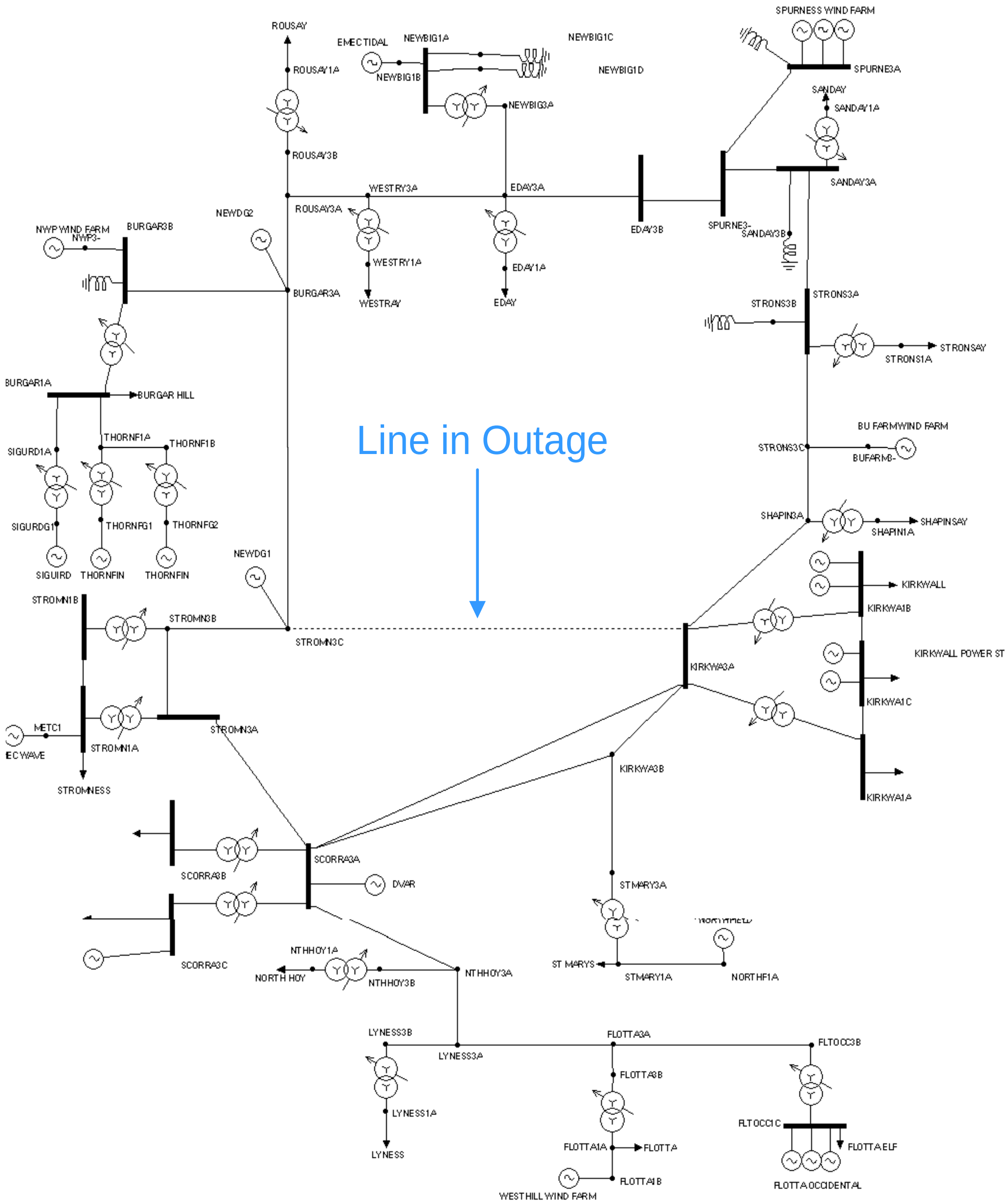

Figure 40: Orkney Distribution Network Model in IPSA+ with Additional DG under Outage Conditions

The outage is a branch outage, on the 33kV circuit connecting KIRKWA3A and STROMN3C, which is in the immediate vicinity of the circuit connecting the busbars to where the new DG, connected in Experiment 2, is connected.

As before, there is DG connected to STROMN3C 33kV busbar (NEWDG1) and it is 9MW in size, and there is DG connected to BURGAR3A 33kV busbar (NEWDG2) which is 11MW in size.

Load and generation profile set 1, given in Table 4 in Section 5.3.2.3, is used in this experiment to allow examination of the AuRA-NMS ANM scheme controlling the DG and managing thermal constraints as they are approached whilst the network topology has reconfigured during an outage.

As in Section 5.8.3.2, the generation under management of the AuRA-NMS scheme throughout this experiment includes NEWDG1 and NEWDG2 and the existing windfarm at Burgar Hill (6MW).

5.8.4.3 Experimental Results

As is illustrated in Figure 41, this outage causes thermal overloading of 33kV circuits on the network when the DG is generating. The overload that is detected by AuRA-NMS in this experiment is the same as that detected in Experiments 2 and 3A; the branch connecting the two new DG sites (BURGAR3A and STROMN3C). Additionally, an overload is detected at the SCORR3A – SCORR3C transformer to the swing bus which is dealt with by AuRA-NMS, as shown in Figure 42 (this overload has been caused by the way in which the network is modelled in IPSA+ and would not expect to be seen in practice, with the exception of an outage situation involving one of the subsea circuits connecting the mainland).

Each of the DG connections reaches their MW output capacity before the ANM scheme detects the first overload at Scorradale and issues a control action to trip (ramp down to 0MW) NEWDG1, while NEWDG2 and Burgar Hill Windfarm are allowed to remain at maximum output. Promptly following this, the overload on the BURGAR3A – STROMN3C circuit is detected and NEWDG2 is instructed to reduce its MW output to 50% however it rests at 7MW as the overload is cleared by this point. As a direct result of the outage of the STROMN3C – KIRKWA3A circuit, the overload experienced on the BURGAR3A – STROMN3C circuit is around 2MW higher than that experienced in Experiment 3A without the outage (18.3MW in Experiment 3A and 20.1MW in this experiment).

The generation pattern deviates from that exhibited in Experiment 3A, despite identical load and generation profiles being used, due to the outage causing a change in the power flows around the network.

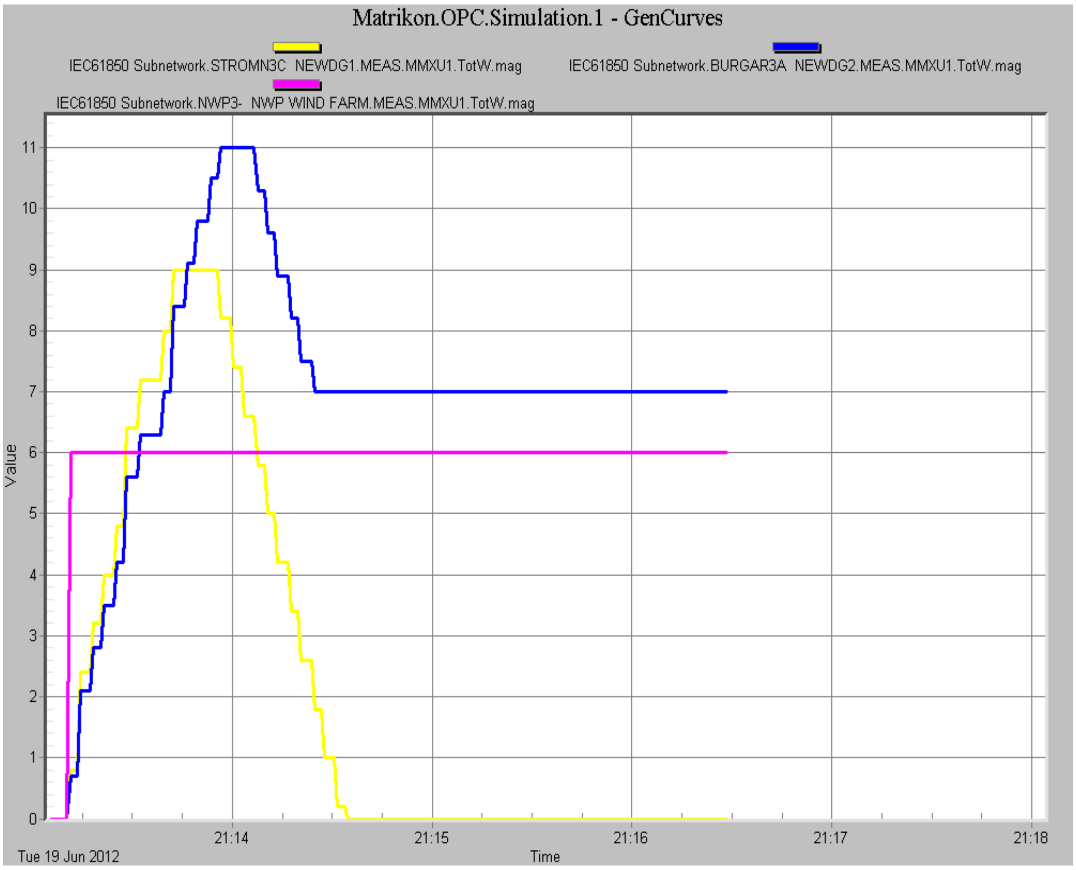

Figure 41: MW Output Curves of the Three DG Connections Under the Management of the AuRA-NMS Scheme during Experiment 4

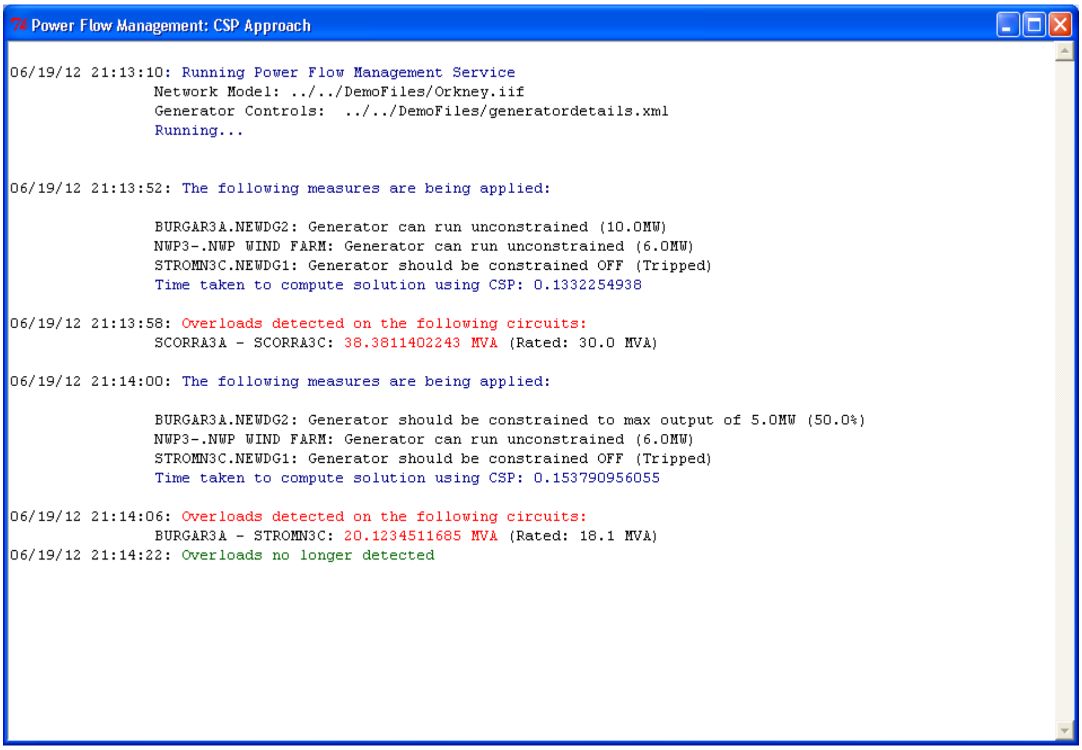

Figure 42: AuRA-NMS Interface Window showing Control Actions Taken During Experiment 4

The analogues received by simSCADA relating to the MW output of NEWDG1 and NEWDG2 during the course of this experiment are not shown here, but are available in full in Appendix L.2.

5.8.4.4 Conclusions of Experiment

This experiment has shown that the AuRA-NMS ANM scheme is, as quoted in the literature referenced in Section 5.4.1, adaptable to changing network conditions and has reconfigured its PFM algorithm successfully, and without any external interference, to accommodate the outage demonstrated in Experiment 4.

Under the condition of Experiment 4, as with Experiment 3A, an additional 7MW of generation was provided access through the use of the ANM scheme, thus the benefits of ANM, which are clearly demonstrated in the preceding experiments, are not necessarily removed during times of outage, as has been proven with this experiment.

5.9 Chapter 5 Conclusions

This chapter has presented the Control Room Demonstration Suite (CoRDS), developed as part of the research involving the operation, control and management of distribution networks as they evolve to active systems. The provision of a platform on which to simulate and test ANM scheme deployment on networks is a necessary step towards the successful wide-spread integration of ANM schemes on UK distribution networks and beyond.

The CoRDS was developed by combining widely used control room software packages and other easily accessible software, such as Python. Following descriptions of each of these component parts, the end-to-end operation of the tool was verified through proof-of-concept testing, which was presented in Section 5.3.4.

The CoRDS viability as a demonstration facility for ANM was then proven with the successful integration of the AuRA-NMS ANM scheme power flow management algorithm. The integration process and requirements were outlined in Section 5.4, and the operation of the scheme is verified and presented through a series of experiments in Section 5.8.

The first objective (A), to assess the behaviour of the ANM scheme as the network provided access to increasing penetrations of DG was achieved through the experiments in Experiments 2 and 3 where two additional generators were added to the network, and an existing generation site, were placed under the management of the AuRA-NMS scheme. Experiment 2 first justified the case for an ANM scheme as the additional generation caused some thermal overloading. The AuRA-NMS scheme was then implemented for Experiments 3A and 3B and the generation outputs were managed by the scheme. The AuRA-NMS scheme managed the thermal limits of the Orkney network successfully in the two experiments which each exhibited different operating conditions (high generation and low demand, and low generation and high demand).

The second objective (B) set in Section 5.2 included the assessment of ANM scheme operation in response to different network events. This objective was met through the testing carried out in Experiment 4, where the behaviour of the ANM scheme was tested with an outage on the 33kV network. The experiment proved that the AuRA-NMS scheme is readily adaptable to changing network conditions and topologies and was able to reconfigure automatically without external interference.

The final objective (C) of this chapter, and of the experiments, was to discover new information regarding the nature of control engineer interactions with the network, DG and ANM schemes. A number of conclusions can be drawn from the CoRDS experiments regarding this, and the principal statement is that SCADA and communications are essential for the successful operation of an ANM scheme (which reiterates the same conclusion made in Chapter 3). These facilities are required both; internally such that the scheme can monitor parameters, issue controls and signals; and externally such that their activities can be reported back to the control room as SCADA alarms, alerts and analogues.

Through the reporting of activities, the control room is made aware of operational activities that affect the network via SCADA alarms, alerts etc. This information is not always easily interpretable and as such, the information presented to the control engineer from ANM schemes must be presented in an accessible format. The AuRA-NMS interface, presented in Section 5.8 illustrates an HMI which relays succinct information to the control engineer, and this is in addition to the SCADA log presented to the control room. Without this interface, control engineers would be reliant on the SCADA feeds to understand an ANM scheme action which is not a suitable option.

Taking this into account, the overall conclusion to draw regarding control room interaction with ANM schemes, is that there must be adequate SCADA and communications facilities to enable ANM operation, and the ANM scheme should have a dedicated interface from where the present operating situation can be interpreted and control actions can be exercised by the control engineer. This supports the work presented in Chapter 4 regarding the Control Room Integration Methodology.

The additional SCADA alarms received from DG, and the ANM interface result in the control engineer processing and managing more information, confirming each of these as symptoms of active networks which have been discussed in previous chapters. The reliance of ANM on the communications and SCADA systems is also emphasised from the CoRDS experiments where these systems are used for AuRA-NMS to send control signals to generation and to provide information to the control room.

It is clear that much more extensive and diverse testing of different ANM schemes and network operating conditions is required, and the CoRDS has proven to be a viable platform to achieve this and facilitate in the improvement and understanding of future potential control room conditions.

The recognised limitations of the CoRDS tool, as it is presented in this thesis, are outlined in Section 5.6. Methods of overcoming these limitations, and improving the functionality of the tool are presented as future work in Chapter 6.

5.10 Chapter 5 References

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Chapter 6

Conclusions and Future Work

6.1 Introduction

This final chapter initially summarises the research presented in this thesis, chapter by chapter, and notes the key conclusions drawn in each. Following this is a review of the individual contributions that have been made, which were set out initially in Chapter 1, and how they have been achieved. A summary and review of the thesis as a whole and its overall significance is then made in Section 6.4. The final contribution is then presented in Section 6.5 where a several recommendations and possible routes of future work are outlined, to build upon and take further the research presented here.

6.2 Review of Main Findings

Chapter 1 of this thesis presented the motivation and justification for this research which encompasses technical, environmental and political factors. The principal objectives of the research and the main thesis contributions were also outlined in this chapter.

Chapter 2 provided a thorough description of distribution networks as they presently operate, taking account of the electrical network and the accompanying systems including communications, SCADA, and protection, and how they interact. The evolution of power system control and control room technology is also set out, examining the changes that have been introduced throughout the years, thus providing a timeline of power system control to present day and from which the control of active distribution networks will evolve.

Chapter 3 presented and discussed notable impacts that DG and ANM are expected to have on distribution networks in the coming years

- A SCADA alarm volume study indicated a likely increase in the amount of SCADA information the control room can expect to receive on a daily basis, with likely changes to the distribution of these alarms resulting from an evolved operating philosophy (passive to active).
- Network metering and visibility, and reliable communications were cited as the main concerns by DNOs, with improvements necessary for the successful operation of active distribution networks.
- Control engineer role and responsibility for the distribution network was also discussed as a concern as decentralised ANM control schemes are deployed, whereby the traditional distribution control engineer role must adapt to changing networks and management requirements.

Further challenges faced in planning for active distribution networks were discussed in Chapter 4, which focused on the ambiguity surrounding how the networks will evolve

- Layers of uncertainty are hindering the ability to predict and plan for active distribution networks with any measure of confidence as DG penetration and ANM deployment are dependent on specific network characteristics and DNO requirements.

- The comparison of two UK deployed ANM schemes highlighted that two control schemes with a similar objective can be vastly different in their method and function, which indentified a need for a standard integration process applicable to all types of ANM.

This need has been met here through the introduction of a Control Room Integration Methodology. It is a step by step guide to ANM scheme integration into the control room at the deployment stage. The key points of the methodology encompass the

- Determination of control room responsibility with regards to ANM scheme operation

- Establishment of alarms and control actions to and from the scheme

- Design of appropriate communications and interfacing facilities

- Provision of adequate training for control engineers

The inception of the methodology through the Orkney RPZ deployment case study was presented to demonstrate a working case. To date the Orkney ANM scheme has been operating successfully on the Orkney 33kV network.

Feedback from the SSE control room regarding its integration into their management systems has been positive, noting that

- It is important for the DNO (control room) to be involved in the development of an ANM scheme at an early stage.

- The most helpful step in the methodology was identified by the SSE control room as the provision of training which incorporated seminars, discussions, demonstration and documented manuals, allowing control engineers to familiarise themselves with the scheme prior to full deployment.
- A dedicated ANM interface has proven key to the successful daily management of the scheme.

In order to investigate the impacts of DG and ANM on the control room further, a Control Room Demonstration Suite was developed and this was presented in Chapter 5. The CoRDS has been proven as a viable demonstration platform upon which ANM testing and integration studies can be carried out, and which has significant scope for assessing the impacts on control rooms and control engineers caused by active networks.

In addition to this, a set of experiments carried out as part of this research reiterated some of the future control room challenges highlighted in previous chapters, including

- The management of increasing volumes of SCADA alarms, alerts and analogues from the connection of DG and ANM.
- The reliance of ANM schemes on the communications and SCADA networks to operate and be operated.
- The importance of interfacing and how and where information is presented to the control engineer. A dedicated ANM scheme interface is highly recommended to provide maximum clarity to control engineers.

6.3 Review of Thesis Contributions

Chapter 1 of this thesis served to present the basis of the work and highlight the context and justification for it. Additionally, a set of intended contributions were outlined for the work.

The first of these contributions was to offer an improved level of clarity regarding the issues, technical and otherwise, facing distribution control rooms and control engineers which will result from the transition towards actively managed distribution networks. This was achieved through the work presented and discussed in Chapter 3, where the trend towards active distribution networks is explained and a review of the work being undertaken in the area is provided. This information allowed a number of well-informed conclusions to be made regarding the impacts that will be felt on various aspects of network operation and the challenges these will create. In terms of SCADA and communications, the concerns include

- Changes to the SCADA information received in the control room, where additional alarms generated by DG and ANM schemes will increase the volume of information received, potentially significantly depending on adoption levels.

- The need for improved metering of distribution networks to increase visibility for control engineers. This can be achieved through more efficient use of existing metering and communications equipment, alongside the installation of new equipment. An addition to this is to find a balance such that visibility of the network is sufficient but the control engineer is not overwhelmed by excessive information.

A review of integration procedures revealed that those currently in place will not necessarily be valid for actively managed networks, and may have to be revised to accommodate control room requirements, for instance

- The current lack of uniformity in the information and controllability afforded to the control room for DG connections up to a certain sizes, where the information provided is unique to each connection, could lead to difficulties in network management. Mitigating the risk of large volumes of DG that the control engineer has varied levels of control over could potentially entail changes to Distribution Codes and regulations. However, it would afford control engineers with more flexibility to operate and manage networks efficiently.

A likelihood of revision has also been assumed for the role of the control engineer and how they manage distribution networks on a daily basis. Autonomous, decentralised ANM control schemes will fundamentally alter the role that the control engineer plays in certain scenarios, and becoming less involved in certain situations where they must, for example, relinquish control of a network overload to an ANM scheme, and trust its actions. The unfamiliarity of control engineers with ANM scheme operation and control philosophies means it will take time to build this trust.

With much of the concern focused on how ANM will potentially reduce the level of responsibility from control engineers, there is a flip side as SSE reported in Chapter 4. There is now more work involved for control engineers when planning an outage on Orkney now that the Orkney ANM scheme has been populated, almost to saturation, with DG. System studies have to be conducted to determine which DG connected under the scheme can stay on and which must be switched off for each individual outage. This may become a widespread consequence.

Through the information presented in Chapter 3, there is now improved focus and clarity regarding the wider impacts of DG connection and ANM scheme deployment on the operation and management of distribution networks from the control room. It has also provided some insight into how some of the challenges that will appear can be met and managed. For instance, improvements to the communications facilities will address the issue of metering and visibility, and it could also accommodate the additional volume of SCADA information anticipated from DG and ANM. This not only meets the challenges mentioned, it will also make any improvements more cost effective if they stand to serve more than one purpose.

In terms of addressing the issue of control engineer unfamiliarity of ANM, the most sensible option is to adapt alongside the ANM schemes as they are introduced, and this is currently happening relatively slowly.

The provision of a higher level of clarity regarding interfacing issues between control rooms and active network management schemes, encompassing the technical and human elements of interface design is another contribution offered in this thesis. Initially, Chapter 4 introduced a variety of uncertainties associated with DG connection patterns, resulting ANM scheme requirements and deployment predictions. It also established the uncertainty regarding how these ANM schemes will be managed by control engineers following their deployment. The chapter then went into depth and addressed this issue by establishing how those ANM schemes which are already deployed on UK networks were integrated into the control room, and how they relay information to the control engineer.

The Skegness RPZ and the Orkney RPZ were both studied and the communications and interfacing techniques used in their deployment were presented and explained in Section 4.3. The operational characteristics, SCADA alarms produced, control facilities, communication link requirements and interface design for each scheme was discussed and compared, which served to highlight the lack of uniformity in how they were integrated and interfaced, and how they are now managed. This comparison exercise lent weight to the earlier uncertainty factors of the deployment trends of DG and ANM schemes.

The outcome of this contribution feeds directly into the following thesis contribution: the development of a Control Room Integration Methodology adaptable to all types of active network management scheme at the deployment stage. The purpose of the methodology is to facilitate ANM scheme vendors and DNOs with the integration of a scheme into the DNO control room, and it is also presented in Chapter 4. The methodology can be considered as a solution to some of the issues with uniformity discussed throughout the thesis as it is aimed to promote standardisation when integrating an ANM scheme in to the DMS interface that the control engineer uses to manage networks.

The methodology was presented and each of the stages was explained and justified, which included the assignment of SCADA alarms an ANM scheme will provide and their priority classification, control actions that will be made available to the control engineers and how these can be accessed via the HMI, and the design of the HMI and communications infrastructure according to these requirements. The methodology also advises on tailoring procedures and training provisions to fit the requirements. A case study of the Orkney RPZ is presented here, as this methodology was developed in conjunction with its deployment onto the SSE Orkney distribution network. Feedback from the SSE control room has validated the process of the Control Room Integration Methodology, and some improvements have been suggested which were highlighted in Chapter 4.

A significant contribution of this thesis is considered to be the development of a demonstration platform that would allow the assessment of control room involvement and participation in the management of DG and ANM schemes. The demonstration facility developed for this purpose, the Control Room Demonstration Suite (CoRDS), was built using widely used control room software. Chapter 5 presents the CoRDS tool experimental set-up, describing each component part of the tool individually, its function and how it is interfaced to other component parts thus combining to emulate the end-to-end operation of a power system.

The core part of the CoRDS tool, illustrated in Figure 21 in Chapter 5, underwent proof-of-concept testing to prove that it could monitor a network model stored in IPSA+ and route pre-defined information back to the control room interface, here provided by simSCADA, via communications links and protocols.

Following the initial proof-of-concept testing, an ANM scheme was added to the CoRDS platform which extended to accommodate it and a number of modifications were made to the tool to ensure its ability to function. Further testing was carried out to assess its capability as an ANM scheme demonstration platform. This was proven through a series of experiments which not only allowed the CoRDS tool to be further validated, but also the functionality of the ANM scheme was tested and analysed from a control room perspective.

The experiments carried out in the CoRDS (itself being a contribution of this thesis), presented in Section 5.8, also provided a platform on which to test some of the impacts of DG and ANM cited in earlier chapters such as changing SCADA information. They also provided some insight into the future requirements for successful DG and ANM operation.

With regards to changing SCADA information, the experiments confirmed this as a valid concern with additional information being provided to the control room from new DG connections as well as the ANM scheme.

The recommendation made in Chapter 3 that SCADA and communications will be essential to ANM scheme operation was also verified through the CoRDS experiments. The functionality of the AuRA-NMS ANM scheme, and its reporting back through the system is dependent on reliable communications and SCADA equipment.

The importance of a dedicated ANM scheme HMI was also highlighted; emphasising the value one can provide when interpreting ANM scheme actions and corresponding network events.

A significant point to note is how effective the integration of the AuRA-NMS proved to be in terms of allowing a higher penetration of DG to connect to the network, whilst having little or no impact on normal network operation. If DNOs and control rooms can be convinced of the wealth of benefits that ANM can bring, some of which the CoRDS can demonstrate, it would encourage the confident wide-spread adoption of ANM.

The CoRDS tool was designed with flexibility and extensibility in mind, and some future extensions and improvements to the tool are outlined in the Future Research Avenues section, Section 6.6, of this chapter.

The final contribution of this thesis is the proposal of solutions and modifications, both technical and otherwise, to ensure preparedness for control rooms and control engineers embracing the transition to active distribution networks. This contribution has been achieved through the analysis of the outcomes of each of the preceding contributions and the conclusions that have been drawn from them in their respective chapters. The proposals made as part of this contribution are presented in Section 6.5 to follow.

6.4 Thesis Conclusions

To review the significance and contribution of this thesis and the research it presents, this section offers a summary of the main offerings and conclusions. This research has

- Clarified the need for ANM to manage active distribution networks which are emerging as a result of growth in DG connections, and established the need for this ANM to be suitably integrated into DNO activities, particularly the control room.
- The significant challenges of ANM integration were highlighted through the presentation of results from a study of SCADA alarms, and a comparison of two deployed ANM schemes on UK networks.
- A Control Room Integration Methodology, which was developed from the experience of a real case (the Orkney ANM scheme), was set out to facilitate ANM integration into control rooms.

- A control room environment simulation and test capability for ANM was developed which provides a platform to test ANM schemes, both in terms of operation, and in terms of their integration challenges.
- Simulated operation of ANM in the control room test environment and this showed:
  - The impact on SCADA and communication networks such that they can accommodate DG and ANM.
  - The dependence that ANM has on the SCADA and communications network to function.
  - The importance of an HMI dedicated to the management of an ANM scheme
  - The benefits of deploying ANM onto a network.
- Provided a number of solutions and suggestions to the control room and control engineers to meet the challenges that they can expect to encounter.

The control rooms at three UK DNOs have been involved in this research owing to the fact that all of the contributions, suggestions and future work contained in this thesis serve to prepare the control room and control engineers for the growth of active distribution networks, to streamline the processes of integration of ANM schemes and to limit difficulties in the future.

6.5 Recommendations in Preparing for Active Distribution Networks

Based on the research findings presented in this thesis, a number of recommendations cultivated over the course of this research regarding preparations to manage the growth in DG penetration levels and resulting active distribution networks are provided. These recommendations are applicable to DNO control rooms, ANM developers and the industry as a whole.

6.5.1 Practical Implementation of ANM Schemes

On a number of occasions throughout this research, the observation was made that it is perhaps not ideal, in various ways, for DNOs to implement large amounts of hardware-based ANM schemes around networks. There are several drawbacks to this method of decentralised control including the cost of new hardware, the time, money and resources required to integrate them into the SCADA and control room systems, as well as the lifetime cost of maintenance.

A preferred approach suggested by some interested parties within DNO companies [Appendix B], [Appendix C] is the route of software based schemes integrated into the existing DMS or equivalent system. This method has merit and there are already many distribution automation algorithms and schemes in operation that have been implemented, and function well, in this manner. Some possible cost could be incurred if a monitoring or communication link upgrade is required, and there is the initial cost of developing and implementing the software, however, when compared to the lifetime cost of hardware-based ANM schemes, the cost benefit analysis may favour this option. Timescales to implementation is also likely to be quicker with software-based applications.

A further dimension to this option would be the DMS vendors offering software-based decentralised ANM control schemes as part of their product package. This could potentially save the DNO developing schemes, and would also provide a level of uniformity for ANM scheme deployment, a trait which is recommended in Section 6.3.2. Potential barriers to this would be the cost, whether it would be cheaper to develop in-house, and whether the DMS vendors could adequately capture the user requirements of DNOs in terms of ANM schemes.

6.5.2 Uniformity of Interfacing

The promotion of uniformity when interfacing DG and ANM schemes into the control room is a highly important principal. A standard methodology for integration was presented in Chapter 4 of this thesis, which was developed with a view to streamline the control room integration process at the deployment stage and to efficiently interface ANM schemes into the control room DMS.

The thinking behind this suggestion is that it is believed to be in the best interests of the control room and control engineers to standardise interface design and embed the interfaces to ANM schemes into the existing control room management software. This will mitigate a situation arising where the DMS network topology diagram is clogged with bespoke interface designs which are over complicated, and the diagram becomes very difficult to navigate and understand.

6.5.3 Utilisation of Existing Assets

Utilisation of existing network and communications assets is one of the key messages to come out of this thesis. The efficient use of all existing network assets is one of the fundamentals of ANM schemes and active distribution as it mitigates the need for additional assets, where possible, in favour of utilising the current network.

One DNO in particular highlighted that there is a significant amount of bandwidth in communication links which could be freed up to support increased monitoring and visibility of networks if only information was transmitted more efficiently [Appendix B]. The need to increase monitoring and visibility on distribution networks was highlighted in Chapter 3 as a major issue for active distribution networks.

6.5.4 ANM Scheme Management Training

The training of control engineers in the management of ANM schemes, and indeed active distribution networks as a whole is vital to their successful operation. It is a necessity to ensure that any and all personnel that will be charged with managing an operational ANM scheme must be appropriately trained to manage any situations that may arise. Control engineers should be trained on scheme operation; what the scheme does, what it doesn't do, how it functions to achieve its objective, and what procedures should be employed should the scheme fail. They must also be trained in the use of the interface; how they can access this from within their tool set and what actions they can exercise over the scheme from within the interface.

6.5.5 Redefinition of the Role of the Control Engineer

The role of the distribution control engineer is certain to change and adapt with the changing demands of network management, and this will have implications for control engineers and the control room as a whole. The idea of having different 'types' of control engineer has been suggested by some DNOs [Appendix B], [Appendix C]; the idea being that some control engineers will retain the traditional role they play today and manage the network through faults, outages and maintenance, while some will take on the role of managing the DG, ANM and DA deployed on the distribution network.

The decision on whether to separate the roles of control engineers whereby DG and ANM is managed separately would be at the discretion of the DNO and their control room and it will depend heavily on the level of DG penetration and ANM scheme deployment.

6.5.6 Data Archiving and Analysis

An important recommendation from this thesis is the logging of data for analysis purposes. Active distribution networks and their characteristics are still in their early stages of maturity and there remains much to research and learn in order to make adequate preparations. It is for this reason that data collection is important, as it will allow DG, ANM, DA and active distribution network operations and behaviours to be better understood and enable future tools and technologies to be developed accordingly.

Gathered data can be fed into many of the research tools and simulations being developed, including those presented in this thesis.

6.5.7 Improving Visibility and Metering

Perhaps the most important recommendation of this thesis is the necessity to improve the metering and visibility of distribution and LV networks. The amount of DG, ANM and DA will increase, as will their participation levels in daily network management. It is therefore imperative that there is enough visibility of the network to ensure these devices and schemes are properly monitored. Furthermore, the operational philosophy of active networks is fundamentally different to how they operate currently, and as such, control engineers will require more key information from the network and the DG and ANM deployed on it.

6.6 Future Research Avenues

The following sections review the work presented in this thesis and look towards possible areas and avenues of future work to continue the preparation of distribution control rooms and control engineers for active networks.

6.6.1 Addition of a DMS to CoRDS

One of the most crucial avenues to pursue to follow on from the work presented in this thesis is the addition of a DMS to the CoRDS tool; such that the impact of ANM schemes on the control room front-end can be assessed.

Due to the extensive use of GE's ENMAC DMS tool by DNOs in the UK, this is recommended to be used. Additionally, Opal Software, the developer of simSCADA, is an integrated partner of GE, and as such, the simSCADA platform is fully supported by ENMAC and easily integrated.

The CoRDS tool, as it is presented in Chapter 5, has the capability to simulate analogue value information being transmitted from a network model, with or without DG and ANM schemes deployed, back through the communications network via the SCADA system. It essentially models the power system, SCADA and communications networks, and the control room with the exception of the front-end interface that the control engineers use to operate, manage and control the network. The addition of ENMAC will enable the full end-to-end simulation of the power system; from the electrical network through to the control room. The full functionality of a DMS, and ENMAC in particular, is described in Chapter 3. The implementation of ENMAC will allow for the following additional functionality:

- A network topology diagram can be built and populated which corresponds to the network being run in IPSA+
- Analogues can be updated on the network topology diagram concurrently with the receipt of the information from simSCADA
- Time-stamped alarms can be viewed in a SCADA log window, and be filtered according to user requirements
- Changes in the network topology of the IPSA+ network can be viewed in the ENMAC network topology diagram
- Interfaces to ANM schemes can be built within the DMS environment and reviewed in operation
- Outage scenarios can be easily built and simulated to test ANM scheme functionality under outage in its monitored area
- Offline environment could be set up where control engineers could be trained on the operation of ANM schemes prior to deployment

The CoRDS tool, with the integration of ENMAC will provide a robust investigatory platform for future active distribution networks where the control room impacts of DG and ANM schemes can be thoroughly assessed.

Additionally, the integration of any ANM scheme into the DMS, following its integration into the CoRDS, can be facilitated using the Control Room Integration Methodology presented in Chapter 4 of this thesis. This can be used to stipulate alarms and control requirements, communication links and SCADA protocols, and DMS interface design.

6.6.2 Further Testing of Active Distribution Networks

The CoRDS has vast potential for future tests to be carried out to assess the control room implications resulting from active distribution networks, and a number of these are presented in the following sections.

6.6.2.1 Testing of ANM Schemes

The ANM scheme used in the simulations in Chapter 5 is the AuRA-NMS, specifically the constraint programming power flow management algorithm. This technique manages power flows by constraining generation such that thermal rating limits of the network are adhered to.

The CoRDS provides a platform for an expanse of future simulations and experiments involving other methods of ANM. There are a number of other fully developed AuRA-NMS ANM algorithms that could be run in the CoRDS; optimal power flow, voltage control [2], and these can be easily implemented as they are fully integrated within the overall AuRA-NMS package which is already fully configured to operate within the CoRDS.

There is also the opportunity to run and test other software based ANM algorithms within the CoRDS, and the Lua scripting interface ensures there is scope to interface with a variety of different software packages, including Python, in which the AuRA-NMS algorithms are built.

Furthermore, with the addition of the ENMAC, mentioned previously, the impact of these can be assessed from the front end.

6.6.2.2 Testing of Other Active Components

The CoRDS platform, as mentioned in Section 6.2.2, provides the potential for a great expanse of future simulations and experiments. In addition to testing other ANM schemes, it can also be used to assess other components that are considered to be active, such as demand side management (DSM) and electric vehicle technology amongst others.

6.2.2.3 Testing the Role of State Estimation in Active Networks

The role of state estimation in future active distribution networks is potentially large given the metering and visibility issues cited in this thesis. The CoRDS can be used to test the role of state estimation and the benefits it could provide in the absence of adequate visibility of the network.

6.2.2.4 Testing the Dynamic Behaviour of Active Networks

The dynamic behaviour of networks is very important, as is the dynamic behaviour of any generation connected to it. The CoRDS tool has the capability to assess the dynamic characteristics of a network which would be simulated through IPSA+ (or other power system analysis software). The behaviour of ANM schemes or other active components during a transient or dynamic event, where fault ride through procedures for DG is likely to occur, would be of interest.

6.6.3 Full Use of MiniSim4SimSCADA Functionality

One function of the MiniSim4SimSCADA program that was not utilised fully in the experiments carried out in Chapter 5 of this thesis is the use of controllers. The MiniSim4SimSCADA code provided the functionality to control the DG units when they were under the management of the AuRA-NMS ANM scheme. However, there is also the capability to control generation set points and transformer tap changers. The use of these functions in later experiments would allow the simulation of more flexible and active network operation, and give a more realistic impression to results.

6.6.4 Interoperability of ANM Schemes

One interesting avenue of future research, that is made possible with the CoRDS platform, is the simulation of multiple ANM schemes on a network to investigate their interaction with one another. As ANM schemes become more prolific on distribution networks, it is assumed that multiple schemes will operate on the same networks and as such, their ability to operate alongside one another is essential. Testing in the CoRDS would allow the interoperability of ANM schemes to be assessed prior to their deployment to determine if any number of ANM schemes can operate on the same area of network, where one ANM scheme does not interfere with the operation of any other by counteracting a control signal and inhibiting it operating as expected.

6.6.5 Using CoRDS to Conduct Further SCADA Alarm Investigations

The SCADA alarm study presented in Chapter 3 was conducted based on information provided by a DNO, and a number of assumptions regarding the connection of DG and ANM schemes to distribution networks. Further development of the CoRDS, as suggested in Sections 6.6.1 to 6.6.3, would allow a more accurate investigation to be conducted regarding the SCADA alarm volume received by the distribution control room and give a more realistic idea of the impact of these on the daily operation and management of distribution networks by control engineers as the networks develop more active operational philosophies.

The ability to accurately assess the impact on SCADA alarm volume will also shed some light on future communications requirements, which was also mentioned as a potential problem in Chapter 3. The CoRDS, with ENMAC, will allow additional SCADA alarms from DG and ANM schemes to be quantified, in terms of bandwidth, and measured against the capability of existing communication links to transmit the information as required. This compliments the recommendation to utilise existing communication network assets in Section 6.5.3.

6.6.6 Further Development of Methodology

The methodology for the control room integration of ANM schemes, presented in Chapter 4 of this thesis, was built with the experience of the integration of the Orkney RPZ ANM scheme into the SSE distribution control room. The methodology however, was developed as a generic model to enable the integration of any type of ANM scheme and it can be further developed, added to and polished with feedback and experience such that it can be used in future deployments of ANM schemes as networks evolve.

6.7 Chapter 6 References

[1] Davidson, E. M., Dolan, M. J., Ault, G. W., McArthur, S. D. J., '*AuRA-NMS: An Autonomous Regional Active Network Management System for EDF Energy and SP Energy Networks*', IEEE PES General Meeting, 25-29 July 2010.

Appendix A: Review of Operations at Scottish Power Control Room

A.1 Introduction

The following section details the knowledge acquired from a 3-day visit to the Scottish Power Operations Control Centre in Kirkintilloch, Scotland. This control centre manages both the transmission and distribution networks of Central and Southern Scotland and has transmission interconnections with Scottish & Southern Energy to the North, National Grid to the South and Northern Ireland Electricity to the West.

The main aims of the visit were to gain insight into the daily operation of a control room and tasks of a control engineer. This was achieved through discussions with control engineers regarding the tools and techniques used in the control room, such as the DMS. Both transmission and distribution control engineers were consulted concerning their daily tasks, and through this the differences in their management styles were identified. Meetings with control room support engineers involved in management of the SCADA and Pi systems also proved very useful to understand the technologies used in network management and how they interface.

Additionally, research and development activities involving automation and ANM schemes within Scottish Power were discussed. These discussions were accompanied by general thoughts on active distribution networks and smartgrids, and the main issues facing the industry, and more specifically the control room, as a result.

The information and knowledge gathered from this visit is presented in a high level manner in sections below, with the topics clearly specified and noting who the author spoke with.

A.2 Visit to Scottish Power Energy Networks Operations Control Centre, Kirkintilloch

22 – 24 February 2010

Contact on site: John Kirkwood

Date: Monday 22/2/10 (am)

Scottish Power Contact: John Kirkwood, Operations

John works in the Technology Division of Power System Operations and his job involves the development and deployment of DA and telecontrols on distribution networks. John is heavily involved with interfacing automation technology with the SCADA system and the DMS at the deployment stage.

When discussing the general aspects of the Scottish Power (SP) control room, the following key points were noted:

- The Energy Management System (EMS) used to manage the transmission network (400, 275 and 132kV) is the Areva product *e-Terra.*
- The DMS used to manage the distribution networks (33 and 11kV) is the GE product ENMAC.
- ENMAC uses the DSP4 Ferranti protocol and requires protocol converters.
- The Scottish Power control room is in the process of upgrading their ENMAC from Version 4 to Version 5. One of the significant changes that Version 5 will incorporate is the routing of incoming data from the network. In the existing Version 4, the SCADA data arrives in the control room and no ordering or filtering is carried out, i.e. the control engineers must seek out what data is relevant to their area of network. Version 5, however, will have the capability to

filter and route data to the appropriate control engineer as it is received thus saving time and reducing error.

- Communications Standard IEC 61850 is being integrated into SCADA and communications equipment monitoring the transmission network, as the *e-Terra* product can talk to RTUs using this protocol. The standard will eventually be integrated into distribution network SCADA and communications.
- The SP automation devices installed on their networks are produced according to the standard IEC 61508 Safety Integrity of Automation Devices.
- SP has taken an interest in where the control philosophy of distribution network automation is and should be heading; centralised vs. decentralised. Results show a 50/50 divide among those involved directly with automation. External review reached same conclusion.
- The PS Alerts database was developed in-house in response to a need (this is explained later by Paul Johnson).
- The Pi historian tool only measures load currents on the yellow phase for use in ENMAC at SP. The SCADA protocol in operation here is report by exception; else the current value is measured and stored every 30 minutes.
- Power meters are installed at primary substations to provide phase angles but these are not derived through ENMAC.

When discussing tools and techniques employed by SP to improve their services (focused around DA, ANM and control room technologies):

- PROSPER reporting tool extracts data from ENMAC and uses it to generate reports on faults. This allows tracking to be carried out to determine if fault targets are being met.
- Central Control Unit (CCU) is a DA tool which was developed within SP, and it provides decentralised control during emergencies. The CCU is usually located in an 11kV substation and it can control up to 17 points on the network (these limitations are caused by the need for the use of protocol converters).

- New ‘smarter’ CCUs have been developed and these provide the same functionality as the original DA unit, only they have the capability to control up to 80 points on the network.

When discussing thoughts on how distribution networks can evolve into active networks:

- SP monitors 10^3 substations and locations, and each has a catalogue of 10^3 possible alarms and indications, which in turn each have a number of statuses. This is a very large volume of data to manage.
- There is a need to be smarter with data presently. Some parameter measurements provide analogue data up to 7 decimal points. This is excessive and the bandwidth could be used for other relevant data (possible from presently unmetered plant) to be transmitted back to the control room.
- There is also a need to be smarter with the ENMAC network connectivity diagram. Existing symbols and tags could be modified to represent different scenarios e.g. flashing or colour change of symbol to indicate a problem.
- Any ANM schemes deployed on a SP distribution network will be integrated into the existing control infrastructure and DMS. An interface to the ANM scheme will be placed in the ENMAC network connectivity diagram (a dedicated stand-alone interface will not be an option).
- SP is involved in the Clyde Gateway project and is pioneering an electricity regeneration scheme in the East end of Glasgow. This project is working towards the creation of the UK’s largest smartgrid by revolutionising the electricity network and installing state of the art technology, as well as improving the efficiency of existing assets. (Further information can be found at [http://www.scottishpower.com/PressReleases_1994.htm]).

As noted previously, SP has a DA scheme in operation on their distribution networks (CCU). The automation scheme is a fault restoration scheme and is deployed widely (to date, one third of distribution circuits have the scheme installed) across both the SP and Manweb networks.

The scheme is not dynamic and have been installed in various locations, including some where there is not necessarily a history of faults, however, it is hoped to mitigate future risks.

When discussing some potential issues and limitations of active distribution networks and smartgrids:

- SP use mainly radio communications on 11kV distribution networks but these are limited and not all network is covered. Additionally, where DG is installed, in some cases there is no communications available at the DG site which prevents data e.g. analogues being transmitted through the SCADA system despite there being sufficient bandwidth to accommodate DG analogues. At present this causes visibility and management issues and the control room are unaware of the activity at the DG site and along some network circuits.
- A suggested development is to install a main CB to the DG site which is visible to the SP control room such that when this is tripped, control engineers are aware that they no longer have this generation and can coordinate accordingly.
- The following table, Table 7 was mused as a possible scale for the metering requirements of DG connections.

Table 7: Generation Profile Input into Orkney IPSA+ Network Model

DG Size	**Provisions (For example)**	**Benefit**
<100kW	No communications	N/A
>100kW	Radio communications transmitting MW output hourly	Greater visibility
>1MW	Radio communications transmitting MW output half-hourly. Main CB installed.	Greater visibility

As an overall opinion John suggested a step change approach to active network operation i.e. small changes that will gradually increase control engineer visibility of the network. Provided as an example; start with installing a main CB at DG sites, then move on to installing communications to allow transmission of data at set intervals, and possibly eventually, a real-time view of the generation.

Another suggestion by John was to consider ANM schemes providing a large catalogue of alarms initially until such times as control engineers became familiar with their operation and behaviour, at which point they could reduce the number of alarms.

Date: Monday 22/2/10 (am)

Scottish Power Contact: Milorad Dobrijevic, Control Room Manager

Milorad is the Control Room Manager of the SP Control Centre in Kirkintilloch and is responsible for the overall management of the transmission and distribution control facilities.

When discussing the general aspects of the SP control room, information was provided on generation, transmission and distribution management and the following key points were noted:

Generation:

- The SP control room has a set response sequence when dealing with underfrequency problems. The sequence consists of a Primary response, a Secondary response followed by a 5 minute response to try and alleviate the problem. Following this, if all previous actions have failed to alleviate the issue, automatic load shedding will be carried out.
- Response mechanisms are also in place to manage overfrequency issues. This includes turbine governor control.
- All transmission connected generation is controlled and managed by National Grid (NG), hence there is no generation management carried out within the SP control room.
- DG is self-controlled (i.e. controlled by the DG developer) according to contractual agreements.
- *E-Terra* has an interface where control engineers can view grid connected generation (that which is controlled by NG) in operation and the MW and MVAr outputs in real time. The display screen also shows the MW and MVAr being exported and imported to/from NG in England, SSE to the North and NIE to the West. A tab on this window also shows all DG and the MW and MVAr output from each site.

Transmission:

- Autotransformers are single winding transformers which are tapped off at the secondary voltage. This type of transformer is used where there is a small ratio of voltage change i.e. 275:132 = 2:1
- Double wound transformers have double windings in star and delta formations. This type of transformer is used where there is a large ratio of voltage change i.e. 275:33 = 9:1

When discussing thoughts on how distribution networks can evolve into active networks:

- Impedance mapping which is used to locate faults is commonly used at transmission level, and this technique is being adopted at distribution level. Notably, many transmission techniques are now being adopted at distribution.
- Fault recorders are installed at all transmission substations.
- PMUs are being deployed on the transmission network providing in-depth measurement data for analysis. However, these are too expensive to deploy at distribution voltages.
- Milorad has no issue with increasing amounts of automation being deployed on networks; citing that a plane can fly itself, and there is no reason to assume a power system cannot do the same.

When discussing control engineers and their abilities in successfully managing transmission and distribution networks:

- Alarm processing is not used to facilitate management of the transmission network as it is felt that the control engineers are more adept at assessing a situation.

- The personnel in the control room are all highly experienced engineers with extensive experience in other parts of the company. Each undergoes 9 months of training and shadowing prior to being charged with managing a network alone.

When discussing a hypothetical deployment of an ANM scheme into the SP control room (The ANM scheme suggested by the author is a Dynamic Line Rating (DLR) scheme):

The DLR scheme should have the functionality to change the alarm threshold in line with the real-time rating as determined by the DLR algorithm and input parameters. The control room would not need or want to receive alarms from such a scheme.

Presently, overhead lines (OHL) and cables generate alarms at

- 70%: Warning (This is what the OHL is <u>rated</u> at)
- 100%: Danger
- 120%: Emergency (Can stay at this value for no longer than 10 minutes)

Building upon this, a DLR scheme would recalculate the three percentage values and change them within the EMS in real time and the control engineer would not be sent any alarms or notifications.

Date: Tuesday 23/2/10 (am)

Scottish Power Contact: Robert Davidson, Transmission Control Engineer

Robert is a transmission control engineer and his daily tasks include the management of the transmission network, as well as the planning, approval and supervision of switching and outage schedules.

When discussing fault and outage schedules:

- The control room is involved in fault and scheduled work management. Work schedules (switching etc) are checked and supervised by the control engineers.

- Whilst a job is in progress, each step must be confirmed and time stamped by the control engineer within the work scheduler in the DMS such that the DMS network connectivity diagram is kept up to date.

- Permit for Work form must be completed by field engineers undertaking the work.

- Alarms caused or corresponding to the work being carried out are monitored on a separate screen within the SCADA alarm log.

- The planning department do studies in PSSE, such as contingency analysis. They use historical load data.

When discussing the typical alarm volume received by transmission control engineers:

- In the 45 minute period where the author was present, the transmission *e-Terra* system received roughly 275 alarms.
- Alarms are assigned a category; Category 1 is for primary plant alarms (change of state). Categories 1, 2 and 3 are the main ones the control engineers look for when scanning the SCADA alarm log. *E-Terra* can filter alarms based on category (it can also filter according to various other factors, such as time received, priority). The software also has the functionality where the user can search a keyword e.g. a substation ID and see all active alarms associated with it.
- No alarm processing is used in the management of the SP transmission network. Operator experience, alarms and the DMS network connectivity diagram are all used to decipher situations.
- Robert feels that an alarm processor would be useful in some instances, but it would have to be properly maintained.

- *E-Terra* has an Online Analyzer tool but it hasn't been properly maintained so it is not used anymore.
- *E-terra* does not (need to) talk to ENMAC (which is used to manage the distribution networks), it is essentially a power flow tool.
- The 33kV grid supply points (GSP) are operated in *e-Terra*, but ENMAC is not updated when this happens. As such, distribution control engineers have to work with both ENMAC and *e-Terra* to establish a clear view of networks surrounding GSPs. The control room are looking to streamline this process of updating ENMAC with the real time GSP analogues with the upgrade of ENMAC to Version 5.
- Alarms stay in the SCADA alarm log until they are dealt with; either action is taken, or the alarm is acknowledged by the control engineer. For example, a 'Protection Faulty' alarm may be left in the log for more than 3 hours before someone is dispatched to check it out. Normally, a 'Protection Faulty OFF' alarm is received within this time and this is considered a maloperation. This is a common occurrence which explains the 3 hour time delay.
- When the network is deficient in reactive power, overspeeding synchronous generators can generate extra VARs.

Date: Tuesday 23/2/10 (pm)

Scottish Power Contact: Milorad Dobrijevic, Control Room Manager

Distribution:

- The SP network throughout Scotland consists of between 16,000 and 20,000 secondary substations (11kV/400V).
- The Scottish network also has around 450 primary substations (33/11kV).
- The rail network is supplied by SP through a 25kV supply.
- Some 6.6kV network remains on the network, this will be upgraded to 11kV when necessary.

- At present, the control room has control over the Feeder Protection and the normally open point (NOP), but it does not have unit protection and so these sections, highlighted in Figure 43 below, can only be isolated manually. This is where automation can be a valuable asset.
- Logical Sequence Switching is a type of automation which would prove useful. Telecontrollers would be installed that detect fault currents and operate circuit breakers automatically (possibly unit protection).

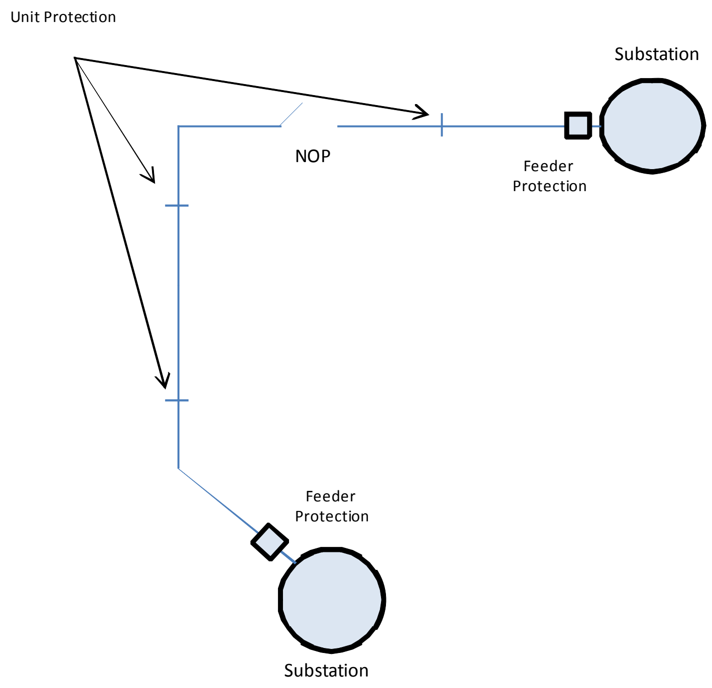

Figure 43: A-1 Illustration of the Scope of Control over Protection Devices on the SP Network

- There are more control engineers managing distribution networks than those managing the transmission network due to the sheer size of the networks. Each distribution operator is responsible for a geographical area.

Date: Tuesday 23/2/10 (pm)

Scottish Power Contact: Ken Condy, Distribution Control Engineer

- The distribution control engineer is responsible for fault and scheduled work management on a daily basis, in the same manner as the transmission network (as explained by Robert Davidson previously).
- The distribution control engineers have access to both ENMAC and *e-Terra* in order that they can control their designated 33/11kV network as well as the 33kV GSPs (controlled by *e-Terra* as explained by Robert Davidson previously).
- Alarms in the ENMAC SCADA alarm log are monitored to ensure they correspond to the tasks being undertaken on the work management schedules.
- The distribution control engineers are generally busier than transmission control engineers due to the size of the networks they are charged with.
- The control engineers have to interpret many sources of information to establish the current network situation. When the author was shadowing Ken, Figure 44 illustrates he had six PC monitors and shows what was on each screen.

Email	Distribution SCADA Alarm Log	ENMAC Network Topology Diagram	Ongoing Work Schedule	Transmission Generation Interface	*E-Terra*

Figure 44: A-2 Distribution Control Engineer PC Monitor Set-up

Date: Wednesday 24/2/10 (am)

Scottish Power Contact: Paul Johnson, I.T.

Paul works in an I.T role and is responsible for the development, upkeep and maintenance of many of the software technologies used in the control room.

When discussing the various control room tools and how they are utilised:

- Pi is a historic archive and it provides the SP control room with analogues collected from the transmission and distribution networks, and digitals from the transmission network only (and these are forwarded to NG). Pi communicates with *e-Terra* and other programmes through an Inter-Control Centre Protocol (ICCP) interface. The alarms are provided in real-time as it is a real-time interface.
- Pi employs the 'report by exception' protocol on the transmission SCADA network.
- PS alerts is a software program (developed by Paul) that provides digitals for the distribution network (and the transmission network which are filtered through to *e-Terra*) in 10 minute batch files. This will change to real-time with the ENMAC upgrade.
- There are three types of network management package used throughout SP and Manweb; SP Transmission use *e-Terra*, SP Distribution use ENMAC and SP Manweb use Thales NMS.
- There are two SP Pi nodes (servers) located in Kirkintilloch and Cathcart, where the back-up (Cathcart) is a disaster contingency node. Manweb only has one Pi node with no contingency.
- Network data is still collected by old meters (BETA). This data is received in the control room and used for analysis. It can also be compared to current SCADA data to flag up problems.

Date: Wednesday 24/2/10 (pm)

Scottish Power Contact: Ian Mitchell, Operations

Ian works in Power System Operations and one of his main tasks is the analysis of the incoming network data from the SCADA network

When discussing SCADA system processes and characteristics specific to SP:

- Some SCADA alarms must be acknowledged upon receipt. An alarm symbol (sound can also be enabled) is attached to those alarms that have to be acknowledged and dealt with. There are two sections on the SCADA alarm log for the alarms which require acknowledgement within *e-Terra*; active alarms and past alarms. Active alarms remain in the active section of the screen until they are acknowledged and then remain in the past section until they are purged.
- An indication is produced in situations where there are 2 contact points e.g. a switch has two contact points and will produce double digitals (00,01,10,11). Whereas alarms generally have only one contact point and produce single digitals (0, 1).
- Two separate lists of alarms are available to control engineers; the System Log which contains all alarms, indications and messages; and the Alarm Summary which contains only alarms with an acknowledgement symbol attached.
- Analogues only generate alarms when they are approaching or have passed their assigned limits.
- DG of size 30MW and above (connected at any voltage) is monitored by SP in *e-Terra* (through the *e-Terra* generation interface described by Milorad

Dobrijevic previously) as an NG requirement. This information is also useful to SP in case of blackstart.

- MVA, MW, MVAR, KV and AMPS are all presented to control engineers in real-time for each node and line where the monitoring is available.
- In the 24 hour period previous to the author's discussion with Ian, the transmission control room received roughly 11,500 alarms through *e-Terra*. Roughly 1/4 to 1/3 (2875 to 3833) of these were distribution related (GSPs). These alarms are additional to the large volume that is received through ENMAC that the distribution control room has to manage.

Appendix B: Review of Operations and Deployed ANM Scheme at Scottish & Southern Energy Control Room

B.1 Introduction

The following section details a visit to the Scottish and Southern Energy (SSE) control room located in Perth, over a period of one week. This SSE control room manages the transmission and distribution networks in the North of Scotland, with another control room managing the SSE network in the South of England. It has a transmission interconnection with SP to the South.

The main aims of this visit were much the same as those of the SP visit, detailed in Appendix A, however more emphasis was placed on the transition to active distribution networks as the SSE Orkney 33kV network has the operational ANM scheme described in Chapter 4 deployed, and work is underway on a number of similar projects. The abundance of ANM-related activity in SSE is due to the wealth of renewable resource in the network area and the subsequent connection of various wind farms, tidal schemes as well as other types of DG.

The programme for the visit afforded a comprehensive view of how the control room operates and manages networks. The SSE control room facilities include an emergency call centre, a field engineer fault dispatch group, short and long term maintenance planning departments as well as the control desks themselves, all of which were visited.

It is evident from the visit that the control engineers at SSE are making preparations for the future and anticipate a number of issues resulting from increased DG penetration and ANM scheme deployment.

B.2 Visit to Scottish and Southern Energy's Scottish Hydro Electric Control Room, Perth

22 – 26 March 2010

Contact on site: Neil Sandison

Date: Monday 22/3/10 (am)

SSE Contact: Bernice, Emergency Call Centre

When discussing the function of the Emergency Call Centre within the SSE control room:

The emergency call centre receives calls from customers who have lost their supply of electricity, or who have witnessed damage or an accident to equipment. Standard practice is for a field engineer to respond to a call within 3 hours.

All calls are logged in SIMS, a computer program that can be accessed by all appropriate personnel, which is a part of the overall network management system. The call centre employee logs relevant details of the outage, fault or damage into SIMS and this is passed to the Fault Dispatch personnel. The information is also updated by relevant personnel to ensure accurate up to date feedback can be given to customers who call enquiring about the issue.

Date: Monday 22/3/10 (pm)

SSE Contact: Euan, Fault Dispatch

When discussing the function of the Fault Dispatch Centre within the SSE control room:

Calls logged in the emergency call centre are passed to the Fault Dispatch personnel. It is then their responsibility to locate the appropriate field engineer and give them a detailed description of the job such that they can work to restore supply or fix damage. The fault dispatcher will liaise with this field engineer (who will then also liaise with the relevant control engineer, who also has access to the SIMS log) throughout the process and then log updates and completion of the job into SIMS.

Both the Emergency Call Centre and Fault Dispatch are located in very close proximity to the control room such that communication between them and the control engineers is readily achieved.

Date: Tuesday 23/3/10 (all day)

SSE Contact: David Howitt, Shift Leader, Distribution

When discussing the management of distribution networks and the shortfalls in metering and visibility at these voltage levels:

- SSE distribution networks have some automation deployed presently, and the area is making progress. There is room for major improvement in this area however this will require significant investment.
- The automation that is installed throughout the SSE distribution networks is non-generic and varies from location to location depending on network topologies and specific issues.
- Presently, not all DG connected to the SSE network provides the necessary analogue measurements to the control room. Ideally, the control room would receive real-time analogues (V, I, MW and MVAR) from all 11 and 33kV

connected wind farms (and other forms of DG) but this is not the case at the moment, with some connections providing all of these analogues, some providing none and other providing a limited selection. The cost of installing communications infrastructure is a identified as the main barrier.

- David's opinion is that there are currently not enough analogue measurements provided on the distribution network itself. There is very little or no visibility of power flows through lines and transformers, or at voltage regulators.
- The National Fault and Interruption Reporting Scheme is a scheme where every fault on the network and interruption to customer supply has to be reported detailing the causes and remedial action taken. This reporting feeds into making improvements, installing automation and upgrading plant.

Date: Wednesday 24/3/10 (am/pm)

SSE Contact: Dave Sanderson, Distribution Control Engineer

When discussing the issues that afflict the distribution control engineers and general opinion on how active networks could change the situation:

- The DMS used to manage the SSE distribution network is ENMAC.
- Inaccurate or lack of visibility and metering at sites proves problematic for the distribution control engineers.
- Dave is of the opinion that the uncertainty of what will happen on the networks in future means that the distribution control room should be prepared for a variety of scenarios that could present themselves.
- Decent quality metering is required, such as MW and MVAR information. This type of information is needed to allow the control engineers to deduce the directionality of power flows as these can no longer be assumed as

unidirectional, and they will be subject to frequent changes with the increasing penetration of DG.

- There is no great deal of trouble with present levels of connected DG. In some cases it is actually proving helpful to some extent by decreasing loading on lines. It could also be used to alleviate low voltage issue at the end of long circuits; however this would be subject to appropriate contractual agreements as DG is currently tripped under abnormal operating conditions. It is foreseen however, that increasing penetrations will eventually cause issues on the network and these must be considered.
- One major concern of distribution control engineers is that they will be unaware of generation status and activity, and of what is happening on the network without appropriate metering.
- It would be useful to network management if DG could also be allowed to provide some reactive control to the network.

Date: Thursday 25/3/10 (am)

SSE Contact: David Wallace, Transmission Control Engineer

When discussing the transmission control room and some practices and procedures that could be adopted at distribution voltages to improve management:

- The management system used to manage the SSE transmission network is ENMAC, which is used as an EMS in this case and although it works in this capacity, it is not ideal for transmission alarm management.
- SSE (North) has only 275 and 132kV transmission network presently; the new 400kV Beauly-Denny circuit will be their only 400kV network when it is built.

- The transmission network is very dynamic and usually always has more generation than demand at any one time, with the surplus being transferred to SP to the South where there is more demand.
- The weather has a significant impact on generation in the SSE network as, with the exception of Peterhead, all SSE generation is renewable, consisting mainly of hydro and wind power. As a result, the transmission of electricity is done through balancing.
- There are much better and more accurate metering facilities available at transmission voltages as there is significantly more real-time control and analysis carried out. This reality can be used as an argument for improving metering on distribution networks as they begin to behave more like transmission networks with increasing penetrations of DG connecting, and ANM schemes being deployed.
- Generation connection agreements stipulate requirements for certain analogues to be provided such that the visibility is available for the control engineers. Adoption of this for distribution connections would ensure visibility improves at the lower voltages.

Date: Thursday 25/3/10 (pm)

SSE Contact: John Robertson, Real-time Systems

The real time systems (RTS) department look after the infrastructures that allow the control room to manage and operate the network in real-time i.e. servers, RTU communications etc. They are currently upgrading the servers and bringing in a windows-based ENMAC system. They have two test networks for testing communications and SCADA equipment, as well as the active power system.

Information regarding the architecture of their systems and servers was required to be kept confidential.

Date: Friday 26/3/10 (am)

SSE Contact: Neil Sandison, Network Performance Manager

The session with Neil involved a review of the week in the SSE control room, and also a discussion involving the future of distribution networks and the research presented in this thesis:

Neil has spent some time developing an 'Active Distribution Network Interface'. The interface was constructed in ENMAC and contains a list of all distribution networks and the generation connected to them. Assigned to each generator is a collection of alarms or notifications that flag up issues to the control engineers that would go unnoticed without this interface e.g. voltage swing across two generators. Such a situation would be very difficult to ascertain using only SCADA alarm data and the DMS connectivity diagram. A GSP with a collection of distribution networks connected to it represents each distribution network as shown in Figure 45.

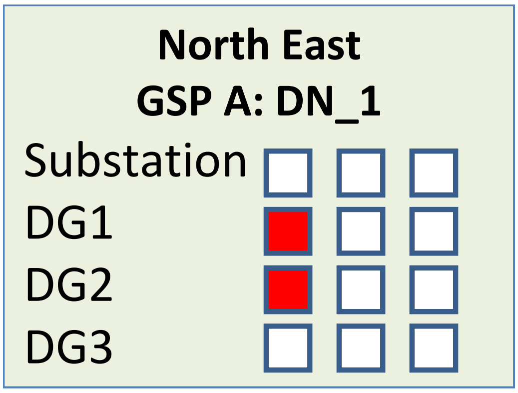

Figure 45: B-1 An Example Outline of the 'Active Distribution Network Interface' Developed in-house by SSE to Manage DG

The boxes each represent a specific event or occurrence at the generator and the screen is intended to provide a useful overview and awareness of all DG to control engineers.

Date: Friday 26/3/10 (am)

SSE Contact: Gordon Ritchie, Transmission Planning

- Transmission network planning is done in various stages; a seven year plan is made according to the Seven Year Statement. Five and three year plans are also done and year-ahead plans are firmed up with SSE and National Grid.
- SSE Transmission does not abide by the Grid Code as they are the system owners; it is only entities that connect to the transmission network i.e. generators and distribution networks that need to comply with the Grid Code.
- Contingency analysis for outages during planned works is done in the power system analysis software PSS/E.

Date: Friday 26/3/10 (pm)

SSE Contact: Paul Swan, Graduate Intern

Paul has been working on modelling the distribution networks of SSE in their entirety in PSS/E to allow real-time (very near real-time) analysis of the system. It can be used to see the effect of turning off generators, making parallel connections prior to outages etc and allow the control engineers to make confident decisions. His work has shown on various accounts that DG need not be tripped during abnormal conditions which could lead to revised connection agreements. The PSS/E model imports data from ENMAC and Pi.

B.3 Collaborative Work

This visit raised the possibility of working with SSE on a Smartgrid Demonstrator, which turned into the Control Room Demonstration Suite (CoRDS) presented in Chapter

5 of this thesis. Data and results relating to the CoRDS were shared between SSE and the author in a mutually beneficial relationship.

Appendix C: Review of Deployed ANM Scheme at Central Networks (East) Control Room

C.1 Introduction

The following section details a one day visit to the Central Networks (East) (new Western Power Distribution) control room in the Midlands, England. The control room operates the distribution networks in the Midlands area from 132kV and below.

The main aim of this visit was to discuss the recently deployed Dynamic Ratings ANM scheme in operation on their network, and to elicit how the scheme was developed and deployed. Any issues the scheme has raised to date, and future expectations of how the scheme will operate were also discussed.

The potential for offshore wind generation in the network area has prompted the internal research and development into active control solutions and automation, and other sites where a dynamic ratings scheme would be beneficial are being investigated.

C.2 Visit to Central Networks (East) Control Centre, Pegasus, Midlands

28 Sept 2010

Contact on site: Bob Ferris

Date: Tuesday 28/9/10 (am)

Central Networks Contact: Bob Ferris, Research and Innovation Manager

Bob is the Research and Innovation Manager and his main role includes coordinating the research and development of network technologies.

When discussing the distribution network area operated by Central Networks:

- Central Networks operate and manage distribution networks from 132kV and below (including some 66kV)

When discussing the recently deployed Dynamic Ratings ANM scheme:

- The dynamic ratings ANM scheme deployed on the Central Networks network is a product of in-house research.
- The dynamic ratings scheme is in operation on a dual circuit 132kV OHL.
- It was developed to allow new wind generation to connect without the need for expensive network reinforcement of 132kV circuits.
- DG in the area includes two existing offshore wind farms; Lynn (90MVA) and Inner Dowsing (90MVA) that were connected in this configuration rather that a larger 180MVA wind farm in order to avoid Grid Code compliance issues.
- There is currently a further 50 – 70 MW of proposed onshore wind farms to be connected at 33kV which are awaiting principles of access agreements for the accompanying dynamic ratings ANM scheme.

- In the network area, there is a surplus of generation and so much of the wind from these connections must be exported.
- Weather stations are located at Skegness (with adequate redundancy) and Boston which measure the ambient temperature, wind speed, air pressure etc.
- The weather station data is sent back to ENMAC (which is the DMS used by Central Networks distribution control room) where the dynamic ratings algorithm calculates the real time thermal rating of the OHLs.
- There is also an Areva protection relay as a back up to ENMAC-controlled protection devices which are fully decentralised such that, in the event that there is a loss of communications with the control room, the ANM scheme can be disabled.
- An Areva protection relay is connected to each weather station and has a data logger and algorithm calculator.
- The WASP (a wind speed prediction tool) was used to measure the wind speed, direction etc at various points on the network and derive assumed values for the algorithm: Wind Direction = 20 deg, Minimum Load = 20MW, Solar Radiation = 890W/m2, Power Factor Pf = 0.95, Conductor Temperature Tc = 50 degC.
- The CIGRE 207 standard was used to develop the dynamic ratings scheme algorithm.
- The scheme operates as follows
  - if the thermal rating of the OHL exceeds 95%, the onshore wind farms (yet to be connected) will be curtailed according to the principles of access,
  - if the thermal rating exceeds 99%, one of the offshore wind farms (Lynn and Inner Dowsing) is tripped off
- The scheme underwent 7 months of commissioning (from March to September 2010).
- Alarms are sent to the control room when
  a) circuit loading exceeds the calculated rating,

b) generation is being curtailed,
c) generation has been tripped

- The scheme is displayed in the ENMAC connectivity diagram by a box sited alongside the circuits upon which it is operating. The box contains the real time measurements of ambient temperature Ta, wind speed Vw and the Calculated Rating (the highest Ta and lowest Vw represent the worst thermal case).
- The scheme can be switched off from within its interface in the DMS connectivity diagram, in which case the colour of the Calculated Rating field in the box is changed and the rating returns to its P27 rating.

Date: Tuesday 28/9/10 (pm)

Central Networks Contact: Bob Ferris, Research and Innovation Manager and Paul Cox, NMS System Manager

Paul manages the network management system, and accompanying systems, in operation within the Central Networks control room.

When discussing automation schemes in operation on the Central Networks distribution network:

- There is an automation algorithm for Fault Restoration implemented on the majority of the 11kV circuits in the East of the control area where it has value, and there are plans to extend this into the Western networks.
- The algorithm is implemented through ENMAC using internal software and as such it does not require any hardware to be installed out on the network which is a huge cost saving.
- The automation scheme looks to restore as many customers as possible following a fault by interrogating all telemetred devices in the area and identifying which ones saw fault current.

- About 20 restorations per month are performed by the various automation schemes on the network.
- There is no automation implemented on Ring configuration circuits as there are no directional Fault Pass Iindicators (FPI), although there is scope to look at this as a possibility as the number of DG connections increases.
- This scheme is more flexible than pre-defined schemes and it works with the real time network configuration.
- Pre-defined automation schemes are more appropriate at 33kV as they have no switched midpoints, which are an integral part of the 11kV restoration process, and are designed to N-1 anyway so it is easier to restore supplies from other interconnected lines.
- Central Networks want GE (the vendor of ENMAC) to implement the scheme into ENMAC as standard to save them having to do the maintenance. It would also be better integrated and faster as a result.
- The automation scheme is annotated in the ENMAC connectivity diagram as a simple box on the circuit on which it is deployed such that control engineers can readily indentify which circuits have the scheme in operation for fault restoration actions.

When discussing future requirements of control rooms and control engineers as active network management becomes increasingly prevalent:

- More training for control engineers is required such that they are familiar with the operation of what are considered active networks.
- More staffing is required, which may include different types of control engineer in the future e.g. control engineers to manage the usual daily work load such as outages and faults, and other control engineers charged solely with the management of automation and ANM schemes that are deployed on distribution networks.

When discussing the issues of metering and visibility at distribution voltages, specifically the information provided by DG connections:

- DG which is less than 23kW in capacity needs only under/over voltage protection and this does not have to even be displayed in ENMAC.
- DG which is between 23kW – 50MW in capacity has G59 protection (including rate of change of frequency (ROCOF) protection) and these are not required to provide export MW information.
- Lack of information and metering will prove problematic for the management of distribution networks as more and more DG connects because, amongst other issues, there is no way to determine directionality of power flows or the power factor.
- As more DG connects along radial circuits, the voltage is likely to breach regulatory limits.
- The ACTIV project aims to displace the voltage at the source end of these circuits through tap change operations to ensure the voltage does not breach limits further along the lines.
- Circuits with no generation are used as a reference for voltage, and as the availability of these diminishes, there will be monitoring required at the end of all circuits.
- Restrictions in communications bandwidth cause an issue with what and amount of information can be brought back to the control room, and how often.

Appendix D: Post Deployment Review of ANM Scheme at Scottish & Southern Energy Control Room

D.1 Introduction

This appendix contains details of an information and feedback gathering meeting with SSE regarding the Orkney ANM scheme (described in Chapter 4). The purpose of this visit to the SSE control room was to obtain feedback on the operation of the Orkney ANM scheme now that it has been operational for around 18 months and several more DG connections have been added under management of the scheme. This information was gathered as part of the methodology presented in Chapter 4, in order that lessons learned can be incorporated and used to continually improve the integration process.

A list of relevant questions was posed and the responses noted, and the format of this appendix is as such.

D.2 Visit to Scottish and Southern Energy Control Room, Perth

5 June 2012

Contact on site: Neil Sandison

Date: Tuesday 05/06/12 (pm)

SSE Contact: Neil Sandison, Network Performance Manager

How much generation is now connected to the Orkney distribution network as part of the Orkney ANM scheme?

There are now 9 DG sites connected under the scheme, both at 33 and 11kV, totalling around 13MW. Many of these connections are small single turbine installations of around 900kW. At present there are four Measuring Points in operation, with a total of seven available for future connections.

What control actions has the ANM scheme had to perform to date?

The ANM scheme has only had to trim generation and no further escalating action has been required thus far. More frequent and acute control actions are expected as the summer weather arrives with minimum demand and higher levels of generation (compared to the previous summer) on the Orkney network.

How frequently does the ANM scheme operate, on average?

In a 30 day period, there occurred a curtailment of three hours when thermal limits on the network were threatened. In this same period, there were three further curtailments initiated due to communications failures within the ANM scheme. There is an inbuilt fail safe that ensures generation is curtailed for the duration of communications faults associated with the ANM scheme.

Communications faults are the most prevalent alarms that the control room receive. In the case of the Orkney network, this is mainly as a consequence of the geography of the area. Otherwise, the volume of alarms associated with the ANM scheme received by the control room has been very small and unintrusive to date.

Have any issues arisen as a result of the implementation of the ANM scheme?

Now that there are a number of generators connected under the ANM scheme (referred to as New Non-Firm Generation (NNFG)), as well as NFG and FG connections, outage planning on the Orkney network can prove complicated. Power systems analysis is carried out in each case to determine what generation can remain connected and what must be switched off for the duration of the outage.

Have any changes or additions been made to the ANM scheme interface in the DMS connectivity diagram?

The interface in the DMS has been expanded to accommodate the additional DG connections of the ANM scheme. SSE have also built a more illustrative interface to the scheme in PI Process Book which highlights (by colour) what communications links are operational and what DG is trimming/tripping etc. This has been found to be much more useful to control engineers as the communications network is the source of the majority of alarms from the scheme. The PI Process Book interface is also much more user friendly and provides control engineers with an instant view of the Orkney ANM scheme. The DMS interface is not ideal for providing a 'load flow' view of the scheme that will highlight the nested constraints of the scheme.

The control room would ideally develop a better front end yet, because the scheme is working so well, the confidence in it is such that they are in no hurry to dedicate resources to this task presently. Very little policing is carried out for the same reason.

The ANM scheme is thought to be performing well because the DNO (SSE) were involved in its development from a very early stage when specifications were being outlined. This meant that many issues were ironed out early on and the scheme was integrated very smoothly. The training sessions provided for the control engineers were also very useful in the integration process, specifically the provision of a demonstration of the ANM scheme interface in an offline version of ENMAC which afforded the control engineers time to familiarise themselves with the ANM scheme operation and its interface.

Are there any plans to implement the ANM scheme, or other types of ANM, in any other areas of the SSE network?

SSE are exploring implementation of the ANM scheme in other areas of their network where congestion is an issue. They are also considering dynamic line ratings, voltage profile optimisation and state estimation on the Orkney network, which is considered a test bed, and success here could lead to implementation elsewhere (although this is also dependent on Ofgem financial incentives to this effect).

As the Orkney ANM scheme is an Ofgem trial, any and all information must be shared with the other UK DNOs to promote adoption.

How has the Orkney ANM scheme interacted with existing distribution automation on the network?

There have been no issues presently, however it is inevitable that ANM and automation will have to interact in the future.

Appendix E.1: DNO Alarm Sample of Communication Alarms

This appendix contains the 112 communication alarm sample which highlights the problems of communication network reliability and associated nuisance alarms.

ALARM_TIME	ALARM_PRIORITY	ALARM_TYPE	ALARM_TEXT	ALARM_SUBSTATION_NAME	ALARM_NAME
31/07/2008 00:00	PRIORITY 1	DIGITAL POINT CHANGE	ON	SUB1	HMI HEARTBEAT ALARM
31/07/2008 00:00	PRIORITY 1	DIGITAL POINT CHANGE	OFF	SUB1	HMI HEARTBEAT ALARM
31/07/2008 00:00	PRIORITY 1	DIGITAL POINT CHANGE	FAIL	SUB2	TIME SOURCE FAIL
31/07/2008 00:01	PRIORITY 1	DIGITAL POINT CHANGE	NO	SUB3	R ALARM (A)
31/07/2008 00:01	PRIORITY 1	DIGITAL POINT CHANGE	NO	SUB3	R ALARM (A)
31/07/2008 00:03	PRIORITY 1	DIGITAL POINT CHANGE	OK	SUB2	TIME SOURCE
31/07/2008 00:07	PRIORITY 1	DIGITAL POINT CHANGE	FAIL	SUB2	TIME SOURCE FAIL
31/07/2008 00:16	PRIORITY 1	DIGITAL POINT CHANGE	OK	SUB2	TIME SOURCE
31/07/2008 00:34	PRIORITY 1	DIGITAL POINT CHANGE	FAIL	SUB2	TIME SOURCE FAIL
31/07/2008 00:37	PRIORITY 1	DIGITAL POINT CHANGE	OK	SUB2	TIME SOURCE
31/07/2008 00:46	COMFAIL	COMMS	FAILED	SUB4	COMFAIL - FEP3 CFE3 COM4008 SIDE B
31/07/2008 00:46	COMFAIL	COMMS	ONLINE	SUB4	COMFAIL - PORT FEP3 CFE3 COM3008 SIDE A
31/07/2008 00:48	SWITCHING DECISION REQUIRED	DIGITAL POINT CHANGE	OFF	SUB5	2ND MAIN COMMS CHNL FLTY
31/07/2008 00:51	RTUFAIL	RTU	FAILED	RTU	RTUFAIL - RTU SHRUR
31/07/2008 00:51	COMFAIL	COMMS	FAILED	SUB4	COMFAIL - PORT FEP4 CFE4 COM1211 SIDE B
31/07/2008 00:51	COMFAIL	COMMS	ONLINE	SUB4	COMFAIL - FEP4 CFE4 COM2001 SIDE A
31/07/2008 00:51	RTUFAIL	RTU	ONLINE	RTU	RTUFAIL - RTU SHRUR
31/07/2008 00:53	COMFAIL	COMMS	FAILED	SUB4	COMFAIL - FEP2 CFE2 COM4012 SIDE B
31/07/2008 00:53	COMFAIL	COMMS	ONLINE	SUB4	COMFAIL - PORT FEP2 CFE2 COM3012 SIDE A
31/07/2008 00:57	PRIORITY 1	DIGITAL POINT CHANGE	FAIL	SUB2	TIME SOURCE FAIL
31/07/2008 01:00	PRIORITY 1	DIGITAL POINT CHANGE	ON	SUB1	HMI HEARTBEAT ALARM
31/07/2008 01:00	COMFAIL	COMMS	ONLINE	SUB4	COMFAIL - FEP1 CFE1 COM1515 SIDE A
31/07/2008 01:00	PRIORITY 1	DIGITAL POINT CHANGE	OFF	SUB1	HMI HEARTBEAT ALARM
31/07/2008 01:00	RTUFAIL	RTU	FAILED	RTU	RTUFAIL - RTU DRCR
31/07/2008 01:00	RTUFAIL	RTU	FAILED	RTU	RTUFAIL - SCAN GROUP DRCR POOL
31/07/2008 01:00	COMFAIL	COMMS	FAILED	SUB4	COMFAIL - FEP1 CFE1 COM1515 SIDE A
31/07/2008 01:00	COMFAIL	COMMS	ONLINE	SUB4	COMFAIL - FEP1 CFE1 COM1515 SIDE B
31/07/2008 01:00	RTUFAIL	RTU	FAILED	RTU	RTUFAIL - RTU DRCR
31/07/2008 01:00	RTUFAIL	RTU	FAILED	RTU	RTUFAIL - SCAN GROUP DRCR POOL
31/07/2008 01:00	COMFAIL	COMMS	FAILED	SUB4	COMFAIL - FEP1 CFE1 COM1515 SIDE B
31/07/2008 01:00	RTUFAIL	RTU	ONLINE	RTU	RTUFAIL - RTU DRCR
31/07/2008 01:03	PRIORITY 1	DIGITAL POINT CHANGE	OK	SUB2	TIME SOURCE

ALARM_TIME	ALARM_PRIORITY	ALARM_TYPE	ALARM_TEXT	ALARM_SUBSTATION_NAME	ALARM_NAME
31/07/2008 01:05	PRIORITY 1	DIGITAL POINT CHANGE	NO	SUB3	R ALARM (A)
31/07/2008 01:06	PRIORITY 1	DIGITAL POINT CHANGE	NO	SUB3	R ALARM (A)
31/07/2008 01:07	PRIORITY 2	DIGITAL POINT CHANGE	NO	SUB6	MUX RACK MINOR ALARM (B)
31/07/2008 01:08	PRIORITY 2	DIGITAL POINT CHANGE	NO	SUB6	MUX RACK MINOR ALARM (B)
31/07/2008 01:11	PRIORITY 1	DIGITAL POINT CHANGE	ON	SUB5	48V DISTRIBUTION ALARM
31/07/2008 01:11	PRIORITY 1	DIGITAL POINT CHANGE	OFF	SUB5	48V DISTRIBUTION ALARM
31/07/2008 01:12	PRIORITY 1	DIGITAL POINT CHANGE	NO	SUB3	R ALARM (A)
31/07/2008 01:13	PRIORITY 1	DIGITAL POINT CHANGE	NO	SUB3	R ALARM (A)
31/07/2008 01:15	PRIORITY 1	DIGITAL POINT CHANGE	FAIL	SUB2	TIME SOURCE FAIL
31/07/2008 01:18	PRIORITY 1	DIGITAL POINT CHANGE	OK	SUB2	TIME SOURCE
31/07/2008 01:42	COMFAIL	COMMS	ONLINE	SUB4	COMFAIL - FEP2 CFE2 COM2215 SIDE A
31/07/2008 01:43	PRIORITY 1	DIGITAL POINT CHANGE	OK	SUB2	TIME SOURCE
31/07/2008 01:48	SWITCHING DECISION REQUIRED	DIGITAL POINT CHANGE	OFF	SUB7	CRTO/GAHO INTERTRIP SYSTEM > FLTY
31/07/2008 01:49	PRIORITY 1	DIGITAL POINT CHANGE	FAIL	SUB8	TIME SOURCE FAIL
31/07/2008 01:49	PRIORITY 1	DIGITAL POINT CHANGE	NO	SUB3	R ALARM (A)
31/07/2008 01:49	PRIORITY 1	DIGITAL POINT CHANGE	NO	SUB3	R ALARM (A)
31/07/2008 01:52	PRIORITY 1	DIGITAL POINT CHANGE	OK	SUB8	TIME SOURCE
31/07/2008 01:53	PRIORITY 1	DIGITAL POINT CHANGE	ON	SUB9	48V DISTRIBUTION ALARM
31/07/2008 01:53	PRIORITY 1	DIGITAL POINT CHANGE	OFF	SUB9	48V DISTRIBUTION ALARM
31/07/2008 01:56	PRIORITY 1	DIGITAL POINT CHANGE	ON	SUB9	48V DISTRIBUTION ALARM
31/07/2008 01:56	PRIORITY 1	DIGITAL POINT CHANGE	OFF	SUB9	48V DISTRIBUTION ALARM
31/07/2008 01:59	PRIORITY 1	DIGITAL POINT CHANGE	FAIL	SUB10	DLL TIME CONSISTENCY FAIL
31/07/2008 01:59	PRIORITY 1	DIGITAL POINT CHANGE	OK	SUB10	DLL TIME CONSISTENCY
31/07/2008 02:00	PRIORITY 1	DIGITAL POINT CHANGE	ON	SUB1	HMI HEARTBEAT ALARM
31/07/2008 02:00	PRIORITY 1	DIGITAL POINT CHANGE	OFF	SUB1	HMI HEARTBEAT ALARM
31/07/2008 02:02	PRIORITY 1	DIGITAL POINT CHANGE	FAIL	SUB2	TIME SOURCE FAIL
31/07/2008 02:05	PRIORITY 1	DIGITAL POINT CHANGE	OK	SUB2	TIME SOURCE
31/07/2008 02:08	PRIORITY 1	DIGITAL POINT CHANGE	NO	SUB3	R ALARM (A)
31/07/2008 02:08	PRIORITY 1	DIGITAL POINT CHANGE	NO	SUB3	R ALARM (A)
31/07/2008 02:28	PRIORITY 1	DIGITAL POINT CHANGE	FAIL	SUB2	TIME SOURCE FAIL
31/07/2008 02:37	PRIORITY 1	DIGITAL POINT CHANGE	OK	SUB2	TIME SOURCE
31/07/2008 02:41	PRIORITY 1	DIGITAL POINT CHANGE	FAIL	SUB2	TIME SOURCE FAIL

ALARM_TIME	ALARM_PRIORITY	ALARM_TYPE	ALARM_TEXT	ALARM_SUBSTATION_NAME	ALARM_NAME
31/07/2008 02:42	PRIORITY 1	DIGITAL POINT CHANGE	FAIL	SUB11	DLL TIME CONSISTENCY FAIL
31/07/2008 02:42	PRIORITY 1	DIGITAL POINT CHANGE	OK	SUB11	DLL TIME CONSISTENCY
31/07/2008 02:42	PRIORITY 1	DIGITAL POINT CHANGE	FAIL	SUB12	TIME SOURCE FAIL
31/07/2008 02:45	PRIORITY 1	DIGITAL POINT CHANGE	OK	SUB12	TIME SOURCE
31/07/2008 02:46	PRIORITY 1	DIGITAL POINT CHANGE	NO	SUB3	R ALARM (A)
31/07/2008 02:46	PRIORITY 1	DIGITAL POINT CHANGE	NO	SUB3	R ALARM (A)
31/07/2008 02:47	PRIORITY 1	DIGITAL POINT CHANGE	OK	SUB2	TIME SOURCE
31/07/2008 02:51	COMFAIL	COMMS	FAILED	SUB4	COMFAIL - PORT FEP3 CFE3 COM3008 SIDE B
31/07/2008 02:51	COMFAIL	COMMS	ONLINE	SUB4	COMFAIL - FEP3 CFE3 COM4008 SIDE A
31/07/2008 02:57	SWITCHGEAR MOVEMENT RELATED	DIGITAL POINT CHANGE	FAIL	SUB5	TIME SOURCE FAIL
31/07/2008 02:57	PRIORITY 1	DIGITAL POINT CHANGE	FAIL	SUB2	TIME SOURCE FAIL
31/07/2008 03:00	PRIORITY 1	DIGITAL POINT CHANGE	ON	SUB1	HMI HEARTBEAT ALARM
31/07/2008 03:00	COMFAIL	COMMS	ONLINE	SUB4	COMFAIL - PORT FEP1 CFE1 COM911 SIDE A
31/07/2008 03:00	COMFAIL	COMMS	FAILED	SUB4	COMFAIL - PORT FEP2 CFE2 COM3012 SIDE B
31/07/2008 03:00	PRIORITY 1	DIGITAL POINT CHANGE	OFF	SUB1	HMI HEARTBEAT ALARM
31/07/2008 03:00	COMFAIL	COMMS	ONLINE	SUB4	COMFAIL - FEP2 CFE2 COM4012 SIDE A
31/07/2008 03:00	RTUFAIL	RTU	FAILED	RTU	RTUFAIL - RTU ENMAC
31/07/2008 03:00	RTUFAIL	RTU	FAILED	RTU	RTUFAIL - SCAN GROUP ENMAC POOL
31/07/2008 03:00	COMFAIL	COMMS	FAILED	SUB4	COMFAIL - PORT FEP1 CFE1 COM911 SIDE A
31/07/2008 03:00	PRIORITY 1	DIGITAL POINT CHANGE	OK	SUB2	TIME SOURCE
31/07/2008 03:00	COMFAIL	COMMS	ONLINE	SUB4	COMFAIL - PORT FEP1 CFE1 COM911 SIDE B
31/07/2008 03:00	SWITCHGEAR MOVEMENT RELATED	DIGITAL POINT CHANGE	OK	SUB5	TIME SOURCE
31/07/2008 03:00	RTUFAIL	RTU	FAILED	RTU	RTUFAIL - RTU ENMAC
31/07/2008 03:00	RTUFAIL	RTU	FAILED	RTU	RTUFAIL - SCAN GROUP ENMAC POOL
31/07/2008 03:00	COMFAIL	COMMS	FAILED	SUB4	COMFAIL - PORT FEP1 CFE1 COM911 SIDE B
31/07/2008 03:00	RTUFAIL	RTU	ONLINE	RTU	RTUFAIL - RTU ENMAC
31/07/2008 03:06	PRIORITY 1	DIGITAL POINT CHANGE	FAIL	SUB2	TIME SOURCE FAIL
31/07/2008 03:12	PRIORITY 1	DIGITAL POINT CHANGE	FAIL	SUB11	DLL TIME CONSISTENCY FAIL
31/07/2008 03:12	PRIORITY 1	DIGITAL POINT CHANGE	OK	SUB11	DLL TIME CONSISTENCY
31/07/2008 03:15	PRIORITY 1	DIGITAL POINT CHANGE	OK	SUB2	TIME SOURCE
31/07/2008 03:21	PRIORITY 1	DIGITAL POINT CHANGE	FAIL	SUB2	TIME SOURCE FAIL
31/07/2008 03:24	PRIORITY 1	DIGITAL POINT CHANGE	OK	SUB2	TIME SOURCE

ALARM_TIME	ALARM_PRIORITY	ALARM_TYPE	ALARM_TEXT	ALARM_SUBSTATION_NAME	ALARM_NAME
31/07/2008 03:25	PRIORITY 1	DIGITAL POINT CHANGE	NO	SUB3	R ALARM (A)
31/07/2008 03:25	PRIORITY 1	DIGITAL POINT CHANGE	NO	SUB3	R ALARM (A)
31/07/2008 03:29	PRIORITY 1	DIGITAL POINT CHANGE	FAIL	SUB2	TIME SOURCE FAIL
31/07/2008 03:30	RTUFAIL	RTU	FAILED	RTU	RTUFAIL - RTU EXXO
31/07/2008 03:30	COMFAIL	COMMS	FAILED	SUB4	COMFAIL - PORT FEP2 CFE2 COM1009 SIDE B
31/07/2008 03:30	RTUFAIL	RTU	ONLINE	RTU	RTUFAIL - RTU EXXO
31/07/2008 03:31	PRIORITY 2	DIGITAL POINT CHANGE	NO	SUB3	METERING PH 1 VOLTS FAIL
31/07/2008 03:31	PRIORITY 2	DIGITAL POINT CHANGE	NO	SUB3	METERING PH 1 VOLTS FAIL
31/07/2008 03:31	PRIORITY 2	DIGITAL POINT CHANGE	NO	SUB3	METERING PH 3 VOLTS FAIL
31/07/2008 03:31	PRIORITY 2	DIGITAL POINT CHANGE	NO	SUB3	METERING PH 3 VOLTS FAIL
31/07/2008 03:35	PRIORITY 1	DIGITAL POINT CHANGE	OK	SUB2	TIME SOURCE
31/07/2008 03:37	PRIORITY 1	DIGITAL POINT CHANGE	FAIL	SUB2	TIME SOURCE FAIL
31/07/2008 03:39	COMFAIL	COMMS	ONLINE	SUB4	COMFAIL - PORT FEP4 CFE4 COM811 SIDE A
31/07/2008 03:40	PRIORITY 1	DIGITAL POINT CHANGE	OK	SUB2	TIME SOURCE
31/07/2008 03:42	PRIORITY 1	DIGITAL POINT CHANGE	FAIL	SUB11	DLL TIME CONSISTENCY FAIL
31/07/2008 03:42	PRIORITY 1	DIGITAL POINT CHANGE	OK	SUB11	DLL TIME CONSISTENCY

Appendix E.2: DNO Alarm Sample of Network Alarms

This appendix contains the 87 network alarm sample which highlights the problems of protection system reliability and associated nuisance alarms.

ALARM_TIME	ALARM_PRIORITY	ALARM_TYPE	ALARM_TEXT	ALARM_SUBSTATION_NAME	ALARM_NAME
31/07/2008 00:13	SWITCHING DECISION REQUIRED	DIGITAL POINT CHANGE	FAIL	SUB13	1ST MAIN CARRIER FAIL
31/07/2008 00:14	SWITCHING DECISION REQUIRED	DIGITAL POINT CHANGE	FAIL	SUB13	1ST MAIN CARRIER FAIL
31/07/2008 00:15	SWITCHGEAR MOVEMENT RELATED	DIGITAL POINT CHANGE	ON	SUB14	OPEN CIRCUIT DETECTOR OPD
31/07/2008 00:15	LOW PRIORITY EVENT	DIGITAL POINT CHANGE	ON	SUB15	DRYCOL BREATHER SUPPLY FLTY
31/07/2008 00:15	LOW PRIORITY EVENT	DIGITAL POINT CHANGE	OFF	SUB15	DRYCOL BREATHER SUPPLY FLTY
31/07/2008 00:15	SWITCHGEAR MOVEMENT RELATED	DIGITAL POINT CHANGE	OFF	SUB14	OPEN CIRCUIT DETECTOR OPD
31/07/2008 00:16	SWITCHGEAR MOVEMENT RELATED	DIGITAL POINT CHANGE	ON	SUB14	OPEN CIRCUIT DETECTOR OPD
31/07/2008 00:16	SWITCHGEAR MOVEMENT RELATED	DIGITAL POINT CHANGE	OFF	SUB14	OPEN CIRCUIT DETECTOR OPD
31/07/2008 00:43	SWITCHING DECISION REQUIRED	DIGITAL POINT CHANGE	FAIL	SUB13	1ST MAIN CARRIER FAIL
31/07/2008 00:44	SWITCHING DECISION REQUIRED	DIGITAL POINT CHANGE	FAIL	SUB13	1ST MAIN CARRIER FAIL
31/07/2008 00:48	SWITCHING DECISION REQUIRED	DIGITAL POINT CHANGE	ON	SUB16	2ND INTERTRIP SYS FLTY
31/07/2008 00:48	SWITCHING DECISION REQUIRED	DIGITAL POINT CHANGE	ON	SUB16	2ND MAIN PROT FLTY
31/07/2008 00:48	SWITCHING DECISION REQUIRED	DIGITAL POINT CHANGE	ON	SUB5	2ND INTERTRIP SYS FLTY
31/07/2008 00:48	SWITCHING DECISION REQUIRED	DIGITAL POINT CHANGE	ON	SUB5	2ND MAIN COMMS CHNL FLTY
31/07/2008 00:48	SWITCHING DECISION REQUIRED	DIGITAL POINT CHANGE	OFF	SUB16	2ND INTERTRIP SYS FLTY
31/07/2008 00:48	SWITCHING DECISION REQUIRED	DIGITAL POINT CHANGE	OFF	SUB16	2ND MAIN PROT FLTY
31/07/2008 00:48	SWITCHING DECISION REQUIRED	DIGITAL POINT CHANGE	OFF	SUB5	2ND INTERTRIP SYS FLTY
31/07/2008 00:48	SWITCHING DECISION REQUIRED	DIGITAL POINT CHANGE	OFF	SUB5	2ND MAIN COMMS CHNL FLTY
31/07/2008 00:52	SWITCHING DECISION REQUIRED	DIGITAL POINT CHANGE	ON	SUB16	2ND INTERTRIP SYS FLTY
31/07/2008 00:52	SWITCHING DECISION REQUIRED	DIGITAL POINT CHANGE	ON	SUB16	2ND MAIN PROT FLTY
31/07/2008 00:52	SWITCHING DECISION REQUIRED	DIGITAL POINT CHANGE	ON	SUB5	2ND INTERTRIP SYS FLTY
31/07/2008 00:52	SWITCHING DECISION REQUIRED	DIGITAL POINT CHANGE	ON	SUB5	2ND MAIN COMMS CHNL FLTY
31/07/2008 00:52	SWITCHING DECISION REQUIRED	DIGITAL POINT CHANGE	OFF	SUB16	2ND INTERTRIP SYS FLTY
31/07/2008 00:52	SWITCHING DECISION REQUIRED	DIGITAL POINT CHANGE	OFF	SUB16	2ND MAIN PROT FLTY
31/07/2008 00:52	SWITCHING DECISION REQUIRED	DIGITAL POINT CHANGE	OFF	SUB5	2ND INTERTRIP SYS FLTY
31/07/2008 00:52	SWITCHING DECISION REQUIRED	DIGITAL POINT CHANGE	OFF	SUB5	2ND MAIN COMMS CHNL FLTY
31/07/2008 01:13	SWITCHING DECISION REQUIRED	DIGITAL POINT CHANGE	FAIL	SUB13	1ST MAIN CARRIER FAIL
31/07/2008 01:14	SWITCHING DECISION REQUIRED	DIGITAL POINT CHANGE	FAIL	SUB13	1ST MAIN CARRIER FAIL
31/07/2008 01:14	SWITCHING DECISION REQUIRED	DIGITAL POINT CHANGE	ON	SUB7	CRTO/GAHO INTERTRIP SYSTEM > FLTY
31/07/2008 01:14	SWITCHING DECISION REQUIRED	DIGITAL POINT CHANGE	OFF	SUB7	CRTO/GAHO INTERTRIP SYSTEM > FLTY
31/07/2008 01:15	SWITCHING DECISION REQUIRED	DIGITAL POINT CHANGE	ON	SUB7	CRTO/GAHO INTERTRIP SYSTEM > FLTY
31/07/2008 01:15	SWITCHING DECISION REQUIRED	DIGITAL POINT CHANGE	OFF	SUB7	CRTO/GAHO INTERTRIP SYSTEM > FLTY

ALARM_TIME	ALARM_PRIORITY	ALARM_TYPE	ALARM_TEXT	ALARM_SUBSTATION_NAME	ALARM_NAME
31/07/2008 01:16	SWITCHING DECISION REQUIRED	DIGITAL POINT CHANGE	ON	SUB7	CRTO/GAHO INTERTRIP SYSTEM > FLTY
31/07/2008 01:16	SWITCHING DECISION REQUIRED	DIGITAL POINT CHANGE	OFF	SUB7	CRTO/GAHO INTERTRIP SYSTEM > FLTY
31/07/2008 01:17	SWITCHING DECISION REQUIRED	DIGITAL POINT CHANGE	ON	SUB8	1ST INTERTRIP SYS FLTY
31/07/2008 01:17	SWITCHING DECISION REQUIRED	DIGITAL POINT CHANGE	ON	SUB8	1ST MAIN COMMS CHNL FLTY
31/07/2008 01:17	SWITCHING DECISION REQUIRED	DIGITAL POINT CHANGE	ON	SUB8	1ST MAIN PROT FLTY
31/07/2008 01:17	SWITCHING DECISION REQUIRED	DIGITAL POINT CHANGE	ON	SUB12	1ST INTERTRIP SYS FLTY
31/07/2008 01:17	SWITCHING DECISION REQUIRED	DIGITAL POINT CHANGE	ON	SUB12	1ST MAIN COMMS CHNL FLTY
31/07/2008 01:17	SWITCHING DECISION REQUIRED	DIGITAL POINT CHANGE	ON	SUB12	1ST MAIN PROT FLTY
31/07/2008 01:17	SWITCHING DECISION REQUIRED	DIGITAL POINT CHANGE	OFF	SUB8	1ST MAIN COMMS CHNL FLTY
31/07/2008 01:17	SWITCHING DECISION REQUIRED	DIGITAL POINT CHANGE	OFF	SUB8	1ST MAIN PROT FLTY
31/07/2008 01:17	SWITCHING DECISION REQUIRED	DIGITAL POINT CHANGE	OFF	SUB8	1ST INTERTRIP SYS FLTY
31/07/2008 01:17	SWITCHING DECISION REQUIRED	DIGITAL POINT CHANGE	OFF	SUB12	1ST INTERTRIP SYS FLTY
31/07/2008 01:17	SWITCHING DECISION REQUIRED	DIGITAL POINT CHANGE	OFF	SUB12	1ST MAIN COMMS CHNL FLTY
31/07/2008 01:17	SWITCHING DECISION REQUIRED	DIGITAL POINT CHANGE	OFF	SUB12	1ST MAIN PROT FLTY
31/07/2008 01:22	SWITCHING DECISION REQUIRED	DIGITAL POINT CHANGE	ON	SUB17	CRTO/GAHO INTERTRIP SYSTEM > FLTY
31/07/2008 01:22	SWITCHING DECISION REQUIRED	DIGITAL POINT CHANGE	OFF	SUB17	CRTO/GAHO INTERTRIP SYSTEM > FLTY
31/07/2008 01:43	SWITCHING DECISION REQUIRED	DIGITAL POINT CHANGE	FAIL	SUB13	1ST MAIN CARRIER FAIL
31/07/2008 01:44	SWITCHING DECISION REQUIRED	DIGITAL POINT CHANGE	FAIL	SUB13	1ST MAIN CARRIER FAIL
31/07/2008 01:46	WRN-LIM	ANALOG LIMIT	ON	SUB1	HZ LOW WARNING LIMIT 49
31/07/2008 01:46	WRN-LIM	ANALOG LIMIT	ON	SUB22	HZ LOW WARNING LIMIT 49
31/07/2008 01:46	WRN-LIM	ANALOG LIMIT	ON	SUB22	HZ LOW WARNING LIMIT 49
31/07/2008 01:46	WRN-LIM	ANALOG LIMIT	ON	SUB17	HZ LOW WARNING LIMIT 49
31/07/2008 01:46	WRN-LIM	ANALOG LIMIT	ON	SUB18	HZ LOW WARNING LIMIT 49
31/07/2008 01:46	WRN-LIM	ANALOG LIMIT	ON	SUB19	HZ LOW WARNING LIMIT 49
31/07/2008 01:46	WRN-LIM	ANALOG LIMIT	ON	SUB16	HZ LOW WARNING LIMIT 49
31/07/2008 01:46	WRN-LIM	ANALOG LIMIT	ON	SUB20	HZ LOW WARNING LIMIT 49
31/07/2008 01:46	WRN-LIM	ANALOG LIMIT	ON	SUB21	HZ LOW WARNING LIMIT 49
31/07/2008 01:46	WRN-LIM	ANALOG LIMIT	OFF	SUB18	HZ WARNING LIMIT 49
31/07/2008 01:46	WRN-LIM	ANALOG LIMIT	OFF	SUB16	HZ WARNING LIMIT 49
31/07/2008 01:47	WRN-LIM	ANALOG LIMIT	OFF	SUB22	HZ WARNING LIMIT 49
31/07/2008 01:47	WRN-LIM	ANALOG LIMIT	OFF	SUB22	HZ WARNING LIMIT 49
31/07/2008 01:47	WRN-LIM	ANALOG LIMIT	OFF	SUB20	HZ WARNING LIMIT 49

ALARM_TIME	ALARM_PRIORITY	ALARM_TYPE	ALARM_TEXT	ALARM_SUBSTATION_NAME	ALARM_NAME
31/07/2008 01:47	WRN-LIM	ANALOG LIMIT	OFF	SUB19	HZ WARNING LIMIT 49
31/07/2008 01:47	WRN-LIM	ANALOG LIMIT	OFF	SUB21	HZ WARNING LIMIT 49
31/07/2008 01:47	WRN-LIM	ANALOG LIMIT	OFF	SUB1	HZ WARNING LIMIT 49
31/07/2008 01:47	WRN-LIM	ANALOG LIMIT	OFF	SUB17	HZ WARNING LIMIT 49
31/07/2008 01:48	SWITCHING DECISION REQUIRED	DIGITAL POINT CHANGE	ON	SUB7	CRTO/GAHO INTERTRIP SYSTEM > FLTY
31/07/2008 01:48	SWITCHING DECISION REQUIRED	DIGITAL POINT CHANGE	OFF	SUB7	CRTO/GAHO INTERTRIP SYSTEM > FLTY
31/07/2008 02:00	NORMAL	ANALOG LIMIT	NO	SUB23	AMPS HIGH NORM LIMIT 300
31/07/2008 02:00	NORMAL	ANALOG LIMIT	NO	SUB23	AMPS NORMAL LIMIT 300
31/07/2008 02:13	SWITCHING DECISION REQUIRED	DIGITAL POINT CHANGE	FAIL	SUB13	1ST MAIN CARRIER FAIL
31/07/2008 02:14	SWITCHING DECISION REQUIRED	DIGITAL POINT CHANGE	FAIL	SUB13	1ST MAIN CARRIER FAIL
31/07/2008 02:24	SWITCHING DECISION REQUIRED	DIGITAL POINT CHANGE	ON	SUB7	CRTO/GAHO INTERTRIP SYSTEM > FLTY
31/07/2008 02:24	SWITCHING DECISION REQUIRED	DIGITAL POINT CHANGE	OFF	SUB7	CRTO/GAHO INTERTRIP SYSTEM > FLTY
31/07/2008 02:32	SWITCHING DECISION REQUIRED	DIGITAL POINT CHANGE	ON	SUB24	INTERTRIP SYSTEM FLTY
31/07/2008 02:43	SWITCHING DECISION REQUIRED	DIGITAL POINT CHANGE	FAIL	SUB13	1ST MAIN CARRIER FAIL
31/07/2008 02:44	SWITCHING DECISION REQUIRED	DIGITAL POINT CHANGE	FAIL	SUB13	1ST MAIN CARRIER FAIL
31/07/2008 02:46	SWITCHING DECISION REQUIRED	DIGITAL POINT CHANGE	ON	SUB7	CRTO/GAHO INTERTRIP SYSTEM > FLTY
31/07/2008 02:46	SWITCHING DECISION REQUIRED	DIGITAL POINT CHANGE	OFF	SUB7	CRTO/GAHO INTERTRIP SYSTEM > FLTY
31/07/2008 02:54	LOW PRIORITY EVENT	DIGITAL POINT CHANGE	OFF	SUB23	DRYCOL BREATHER SUPPLY FLTY
31/07/2008 02:54	NORMAL	ANALOG LIMIT	NO	SUB23	AMPS HIGH NORM LIMIT 300
31/07/2008 02:54	NORMAL	ANALOG LIMIT	NO	SUB23	AMPS NORMAL LIMIT 300
31/07/2008 03:10	LOW PRIORITY EVENT	DIGITAL POINT CHANGE	ON	SUB23	DRYCOL BREATHER SUPPLY FLTY
31/07/2008 03:13	SWITCHING DECISION REQUIRED	DIGITAL POINT CHANGE	FAIL	SUB13	1ST MAIN CARRIER FAIL
31/07/2008 03:14	SWITCHING DECISION REQUIRED	DIGITAL POINT CHANGE	FAIL	SUB13	1ST MAIN CARRIER FAIL

Appendix F: simSCADA Lua Script

This appendix contains the Lua script, from within simSCADA, which is the principal interface to the CoRDS, described in Section 5.3.1.3 in Chapter 5. It is from here that all other functions, programs and scripts are called. The version of the Lua script shown here is the full version as it is following the integration of the AuRA-NMS.

```
function InitialiseScript()

   ss.LogMessage("Loading Python");

   lib = package.loadlib("C:/python26/lunatic.dll", "luaopen_python")

   lib()

   ss.LogMessage("Importing MiniSim");

   python.execute("from MiniSim4simSCADA import *")

   python.execute("from ipsa import *")

   python.execute("from simSCADAipsaUtils import *")

   ss.LogMessage("Configuring MiniSim")


   python.execute("ipsaFile = \"D:/Documents and Settings/shay/Desktop/Orkney.iif\"")

   python.execute("ipsasys = IscInterface()")

   python.execute("net = ipsasys.ReadFile(ipsaFile)")

   python.execute("configurationMapping = ConfigurationMapping()")

   python.execute("configurationMapping.ipsaModel = net")

   python.execute("configurationMapping.readInConfiguration(\"D:/Documents and
Settings/shay/Desktop/NetworkData/miniSimConfig.xml\")")

   python.execute("simulator = MiniSim4simSCADA(configurationMapping)")

   python.execute("simulator.setUpLogging()")

   python.execute("simulator.setLoadFileP(\"D:/Documents and
Settings/shay/Desktop/NetworkData/ProfileData/A-OrkLoad_High.csv\")")
```

```
   python.execute("simulator.setSynGenFileP(\"D:/Documents and
Settings/shay/Desktop/NetworkData/ProfileData/A-OrkSGen_Low.csv\")")

   ss.LogMessage("Setting up callbacks")



   ss.SetTimerResolution(1000)

end

function Timer()

   ss.LogMessage("Making a step...")

   python.execute("simulator.step()")

   python.execute("outputs = simulator.mapping.inputmappings.values()")

   length = python.eval("len(outputs)")

   outputs = python.asattr(python.eval("outputs"))

   vals = python.asindx(outputs)

   for i=0, length-1, 1 do

      value = python.asattr(vals[i])

      ss.LogMessage(tostring(value.alias)..": "..tostring(value.value))

      ss.SetValue(tostring(value.alias), value.value, false)

   end

   ss.LogMessage("Step done...")

end



InitialiseScript()
```

Appendix G.1: IPSA+ to simSCADA .xml Mapping File

This appendix contains the IPSA+ to simSCADA mapping code, described in Section 5.3.2.2 in Chapter 5, which is used to map points on the IPSA+ network model to their appropriate monitored points in simSCADA.

```
<?xml version="1.0" ?>

<configuration name="Test" network="ORKNEY">

<details>

This file gives the mapping between simSCADA and MiniSim4simSCADA, i.e. IPSA.

</details>

<algorithm_inputs_read>

<ipsa2simSCADAmapping alias="SUB5_11_AMPSn_Ana Scanned Value" ignore_vary="True" type =
"FLOAT" maptoclasstype="IscBranch" name ="STMARY1A.NORTHF1A.Line1"
equivalent_field_address = "IscBusbar.Amps"/>

<ipsa2simSCADAmapping alias="SUB6_11KVn_Ana Scanned Value" ignore_vary="True" type =
"FLOAT" maptoclasstype="IscBusbar" name ="FLOTTA1A" equivalent_field_address =
"IscBusbar.Volts"/>

<ipsa2simSCADAmapping alias="SUB6_1C0_AMPSn_Ana Scanned Value" ignore_vary="True" type =
"FLOAT" maptoclasstype="IscBranch" name ="FLOTTA3A.FLTOCC3B.Line1"
equivalent_field_address = "IscBusbar.Amps"/>

<ipsa2simSCADAmapping alias="SUB6_FLOT_MWn_Ana Scanned Value" ignore_vary="True" type =
"FLOAT" maptoclasstype="IscSynMachine" name ="FLTOCC1C.FLOTTA OCCIDENTAL"
equivalent_field_address = "IscSynMachine.GenMW"/>

<ipsa2simSCADAmapping alias="SUB6_FLOT_33_KVn_Ana Scanned Value" ignore_vary="True" type
= "FLOAT" maptoclasstype="IscBusbar" name ="FLOTTA3B" equivalent_field_address =
"IscBusbar.Volts"/>
```

```
<ipsa2simSCADAmapping alias="SUB6_TR1_AMPSn_Ana Scanned Value" ignore_vary="True" type =
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equivalent_field_address = "IscBusbar.Amps"/>

<ipsa2simSCADAmapping alias="SUB7_11_AMPSn_Ana Scanned Value" ignore_vary="True" type =
"FLOAT" maptoclasstype="IscBranch" name ="LYNESS3B.LYNESS1A.Transformer1"
equivalent_field_address = "IscBusbar.Amps"/>

<ipsa2simSCADAmapping alias="SUB12_3S0_VOLTSn_Ana Scanned Value" ignore_vary="True" type
= "FLOAT" maptoclasstype="IscBusbar" name ="SCORRA3A" equivalent_field_address =
"IscBusbar.Volts"/>

<ipsa2simSCADAmapping alias="SUB12_3S0_AMPSn_Ana Scanned Value" ignore_vary="True" type =
"FLOAT" maptoclasstype="IscBranch" name ="SCORRA3A.NTHHOY3A.Line1"
equivalent_field_address = "IscBusbar.Amps"/>

<ipsa2simSCADAmapping alias="SUB12_3S0_MWn_Ana Scanned Value" ignore_vary="True" type =
"FLOAT" maptoclasstype="IscBranch" name ="SCORRA3A.NTHHOY3A.Line1"
equivalent_field_address = "IscBusbar.RealPowerReceived"/>

<ipsa2simSCADAmapping alias="SUB12_3S0_MVARn_Ana Scanned Value" ignore_vary="True" type =
"FLOAT" maptoclasstype="IscBranch" name ="SCORRA3A.NTHHOY3A.Line1"
equivalent_field_address = "IscBusbar.ReactivePowerReceived"/>

<ipsa2simSCADAmapping alias="SUB4_096VOLTSn_Ana Scanned Value" ignore_vary="True" type =
"FLOAT" maptoclasstype="IscBusbar" name ="STROMN1A" equivalent_field_address =
"IscBusbar.Volts"/>

<ipsa2simSCADAmapping alias="SUB4_096AMPSn_Ana Scanned Value" ignore_vary="True" type =
"FLOAT" maptoclasstype="IscBranch" name ="STROMN1A.STROMN1B.Line1"
equivalent_field_address = "IscBusbar.Amps"/>

<ipsa2simSCADAmapping alias="SUB4_096MWn_Ana Scanned Value" ignore_vary="True" type =
"FLOAT" maptoclasstype="IscSynMachine" name ="METC1.EMEC WAVE" equivalent_field_address =
"IscSynMachine.GenMW"/>

<ipsa2simSCADAmapping alias="SUB4_096MVArn_Ana Scanned Value" ignore_vary="True" type =
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"IscSynMachine.GenMVAr"/>

<ipsa2simSCADAmapping alias="SUB4_T1_T2_AMPSn_Ana Scanned Value" ignore_vary="True" type
= "FLOAT" maptoclasstype="IscBranch" name ="STROMN3B.STROMN3A.Line1"
equivalent_field_address = "IscBusbar.Amps"/>

<ipsa2simSCADAmapping alias="SUB11_011_012_AMPSn_Ana Scanned Value" ignore_vary="True"
type = "FLOAT" maptoclasstype="IscBranch" name ="BURGAR1A.SIGURD1A.Line1"
equivalent_field_address = "IscBusbar.Amps"/>
```

```
<ipsa2simSCADAmapping alias="SUB11_TR1_AMPSn_Ana Scanned Value" ignore_vary="True" type =
"FLOAT" maptoclasstype="IscBranch" name ="BURGAR3A.BURGAR3B.Line1"
equivalent_field_address = "IscBusbar.Amps"/>

<ipsa2simSCADAmapping alias="SUB11_013_MWn_Ana Scanned Value" ignore_vary="True" type =
"FLOAT" maptoclasstype="IscSynMachine" name ="SIGURDG1.SIGUIRD" equivalent_field_address
= "IscSynMachine.GenMW"/>

<ipsa2simSCADAmapping alias="SUB11_013_MVARn_Ana Scanned Value" ignore_vary="True" type =
"FLOAT" maptoclasstype="IscSynMachine" name ="SIGURDG1.SIGUIRD" equivalent_field_address
= "IscSynMachine.GenMVAr"/>

<ipsa2simSCADAmapping alias="SUB11_013_AMPSn_Ana Scanned Value" ignore_vary="True" type =
"FLOAT" maptoclasstype="IscBranch" name ="SIGURD1A.SIGURDG1.Transformer1"
equivalent_field_address = "IscBusbar.Amps"/>

<ipsa2simSCADAmapping alias="SUB11_014_MWn_Ana Scanned Value" ignore_vary="True" type =
"FLOAT" maptoclasstype="IscSynMachine" name ="THORNFG1.THORNFIN" equivalent_field_address
= "IscSynMachine.GenMW"/>

<ipsa2simSCADAmapping alias="SUB11_014_MVARn_Ana Scanned Value" ignore_vary="True" type =
"FLOAT" maptoclasstype="IscSynMachine" name ="THORNFG1.THORNFIN" equivalent_field_address
= "IscSynMachine.GenMVAr"/>

<ipsa2simSCADAmapping alias="SUB11_014_AMPSn_Ana Scanned Value" ignore_vary="True" type =
"FLOAT" maptoclasstype="IscBranch" name ="THORNF1A.THORNFG1.Transformer1"
equivalent_field_address = "IscBusbar.Amps"/>

<ipsa2simSCADAmapping alias="SUB11B_1C0_KVn_Ana Scanned Value" ignore_vary="True" type =
"FLOAT" maptoclasstype="IscBusbar" name ="NWP3-" equivalent_field_address =
"IscBusbar.Volts"/>

<ipsa2simSCADAmapping alias="SUB11B_1C0_AMPSn_Ana Scanned Value" ignore_vary="True" type
= "FLOAT" maptoclasstype="IscBranch" name ="BURGAR3B.NWP3-.Line1"
equivalent_field_address = "IscBusbar.Amps"/>

<ipsa2simSCADAmapping alias="SUB11B_1C0_MWn_Ana Scanned Value" ignore_vary="True" type =
"FLOAT" maptoclasstype="IscSynMachine" name ="NWP3-.NWP WIND FARM"
equivalent_field_address = "IscSynMachine.GenMW"/>

<ipsa2simSCADAmapping alias="SUB11B_1C0_MVARn_Ana Scanned Value" ignore_vary="True" type
= "FLOAT" maptoclasstype="IscSynMachine" name ="NWP3-.NWP WIND FARM"
equivalent_field_address = "IscSynMachine.GenMVAr"/>

<ipsa2simSCADAmapping alias="SUB1_11_AMPSn_Ana Scanned Value" ignore_vary="True" type =
"FLOAT" maptoclasstype="IscBusbar" name ="ROUSAY1A" equivalent_field_address =
"IscBusbar.Volts"/>
```

```
<ipsa2simSCADAmapping alias="SUB2_AMPSn_Ana Scanned Value" ignore_vary="True" type =
"FLOAT" maptoclasstype="IscBranch" name ="WESTRY3A.ROUSAY3A.Line1"
equivalent_field_address = "IscBusbar.Amps"/>

<ipsa2simSCADAmapping alias="SUB3_11KV_AMPSn_Ana Scanned Value" ignore_vary="True" type =
"FLOAT" maptoclasstype="IscBranch" name ="EDAY3A.EDAY1A.Transformer1"
equivalent_field_address = "IscBusbar.Amps"/>

<ipsa2simSCADAmapping alias="SUB3A_1C0_VOLTSn_Ana Scanned Value" ignore_vary="True" type
= "FLOAT" maptoclasstype="IscBusbar" name ="SPURNE3A" equivalent_field_address =
"IscBusbar.Volts"/>

<ipsa2simSCADAmapping alias="SUB3A_1K0_AMPSn_Ana Scanned Value" ignore_vary="True" type =
"FLOAT" maptoclasstype="IscBranch" name ="SPURNE3A.SPURNE3-.Line1"
equivalent_field_address = "IscBusbar.Amps"/>

<ipsa2simSCADAmapping alias="SUB3A_1K0_MWn_Ana Scanned Value" ignore_vary="True" type =
"FLOAT" maptoclasstype="IscSynMachine" name ="SPURNE3A.SPURNESS WIND FARM"
equivalent_field_address = "IscSynMachine.GenMW"/>

<ipsa2simSCADAmapping alias="SUB3A_1K0_MVARSn_Ana Scanned Value" ignore_vary="True" type
= "FLOAT" maptoclasstype="IscSynMachine" name ="SPURNE3A.SPURNESS WIND FARM"
equivalent_field_address = "IscSynMachine.GenMVAr"/>

<ipsa2simSCADAmapping alias="SUB3A_1C0_AMPSn_Ana Scanned Value" ignore_vary="True" type =
"FLOAT" maptoclasstype="IscBranch" name ="SPURNE3A.SPURNE3-.Line1"
equivalent_field_address = "IscBusbar.Amps"/>

<ipsa2simSCADAmapping alias="SUB3A_1C0_MWn_Ana Scanned Value" ignore_vary="True" type =
"FLOAT" maptoclasstype="IscSynMachine" name ="SPURNE3A.Generator2"
equivalent_field_address = "IscSynMachine.GenMW"/>

<ipsa2simSCADAmapping alias="SUB3A_1C0_MVARSn_Ana Scanned Value" ignore_vary="True" type
= "FLOAT" maptoclasstype="IscSynMachine" name ="SPURNE3A.Generator2"
equivalent_field_address = "IscSynMachine.GenMVAr"/>

<ipsa2simSCADAmapping alias="SUB10_11_AMPSn_Ana Scanned Value" ignore_vary="True" type =
"FLOAT" maptoclasstype="IscBranch" name ="SANDAY3A.SANDAY1A.Transformer1"
equivalent_field_address = "IscBusbar.Amps"/>

<ipsa2simSCADAmapping alias="SUB9_011_AMPSn_Ana Scanned Value" ignore_vary="True" type =
"FLOAT" maptoclasstype="IscBranch" name ="STRONS3A.STRONS1A.Transformer1"
equivalent_field_address = "IscBusbar.Amps"/>

<ipsa2simSCADAmapping alias="SUB8_11_AMPSn_Ana Scanned Value" ignore_vary="True" type =
"FLOAT" maptoclasstype="IscBranch" name ="SHAPIN3A.SHAPIN1A.Transformer1"
equivalent_field_address = "IscBusbar.Amps"/>
```

```
<ipsa2simSCADAmapping alias="SUB4B_VOLTS" ignore_vary="True" type = "FLOAT"
maptoclasstype="IscBusbar" name ="STROMN3C" equivalent_field_address =
"IscBusbar.Volts"/>

<ipsa2simSCADAmapping alias="SUB4B_AMPS" ignore_vary="True" type = "FLOAT"
maptoclasstype="IscBranch" name ="STROMN3C.KIRKWA3A.Line1" equivalent_field_address =
"IscBusbar.Amps"/>

<ipsa2simSCADAmapping alias="SUB11C_VOLTS" ignore_vary="True" type = "FLOAT"
maptoclasstype="IscBusbar" name ="BURGAR3A" equivalent_field_address =
"IscBusbar.Volts"/>

<ipsa2simSCADAmapping alias="SUB11C_AMPS" ignore_vary="True" type = "FLOAT"
maptoclasstype="IscBranch" name ="BURGAR3A.STROMN3C.Line1" equivalent_field_address =
"IscBusbar.Amps"/>

</algorithm_inputs_read>

<control_actions_write/>

</configuration>
```

Appendix G.2: IPSA+ to simSCADA .xml Mapping File with Additional DG Mapped

This appendix contains the IPSA+ to simSCADA mapping code inclusive of the additional generation added to the IPSA+ Orkney network model for experiments presented in Sections 5.8.2 to 5.8.4.

```
<?xml version="1.0" ?>

<configuration name="Test" network="ORKNEY">

<details>

This file gives the mapping between simSCADA and MiniSim4simSCADA, i.e. IPSA.

</details>

<algorithm_inputs_read>

<ipsa2simSCADAmapping alias="SUB5_11_AMPSn_Ana Scanned Value" ignore_vary="True" type =
"FLOAT" maptoclasstype="IscBranch" name ="STMARY1A.NORTHF1A.Line1"
equivalent_field_address = "IscBusbar.Amps"/>

<ipsa2simSCADAmapping alias="SUB6_11KVn_Ana Scanned Value" ignore_vary="True" type =
"FLOAT" maptoclasstype="IscBusbar" name ="FLOTTA1A" equivalent_field_address =
"IscBusbar.Volts"/>

<ipsa2simSCADAmapping alias="SUB6_1C0_AMPSn_Ana Scanned Value" ignore_vary="True" type =
"FLOAT" maptoclasstype="IscBranch" name ="FLOTTA3A.FLTOCC3B.Line1"
equivalent_field_address = "IscBusbar.Amps"/>

<ipsa2simSCADAmapping alias="SUB6_FLOT_MWn_Ana Scanned Value" ignore_vary="True" type =
"FLOAT" maptoclasstype="IscSynMachine" name ="FLTOCC1C.FLOTTA OCCIDENTAL"
equivalent_field_address = "IscSynMachine.GenMW"/>

<ipsa2simSCADAmapping alias="SUB6_FLOT_33_KVn_Ana Scanned Value" ignore_vary="True" type
= "FLOAT" maptoclasstype="IscBusbar" name ="FLOTTA3B" equivalent_field_address =
"IscBusbar.Volts"/>
```

```
<ipsa2simSCADAmapping alias="SUB6_TR1_AMPSn_Ana Scanned Value" ignore_vary="True" type =
"FLOAT" maptoclasstype="IscBranch" name ="FLOTTA3A.FLOTTA3B.Line1"
equivalent_field_address = "IscBusbar.Amps"/>

<ipsa2simSCADAmapping alias="SUB7_11_AMPSn_Ana Scanned Value" ignore_vary="True" type =
"FLOAT" maptoclasstype="IscBranch" name ="LYNESS3B.LYNESS1A.Transformer1"
equivalent_field_address = "IscBusbar.Amps"/>

<ipsa2simSCADAmapping alias="SUB12_3S0_VOLTSn_Ana Scanned Value" ignore_vary="True" type
= "FLOAT" maptoclasstype="IscBusbar" name ="SCORRA3A" equivalent_field_address =
"IscBusbar.Volts"/>

<ipsa2simSCADAmapping alias="SUB12_3S0_AMPSn_Ana Scanned Value" ignore_vary="True" type =
"FLOAT" maptoclasstype="IscBranch" name ="SCORRA3A.NTHHOY3A.Line1"
equivalent_field_address = "IscBusbar.Amps"/>

<ipsa2simSCADAmapping alias="SUB12_3S0_MWn_Ana Scanned Value" ignore_vary="True" type =
"FLOAT" maptoclasstype="IscBranch" name ="SCORRA3A.NTHHOY3A.Line1"
equivalent_field_address = "IscBusbar.RealPowerReceived"/>

<ipsa2simSCADAmapping alias="SUB12_3S0_MVARn_Ana Scanned Value" ignore_vary="True" type =
"FLOAT" maptoclasstype="IscBranch" name ="SCORRA3A.NTHHOY3A.Line1"
equivalent_field_address = "IscBusbar.ReactivePowerReceived"/>

<ipsa2simSCADAmapping alias="SUB4_096VOLTSn_Ana Scanned Value" ignore_vary="True" type =
"FLOAT" maptoclasstype="IscBusbar" name ="STROMN1A" equivalent_field_address =
"IscBusbar.Volts"/>

<ipsa2simSCADAmapping alias="SUB4_096AMPSn_Ana Scanned Value" ignore_vary="True" type =
"FLOAT" maptoclasstype="IscBranch" name ="STROMN1A.STROMN1B.Line1"
equivalent_field_address = "IscBusbar.Amps"/>

<ipsa2simSCADAmapping alias="SUB4_096MWn_Ana Scanned Value" ignore_vary="True" type =
"FLOAT" maptoclasstype="IscSynMachine" name ="METC1.EMEC WAVE" equivalent_field_address =
"IscSynMachine.GenMW"/>

<ipsa2simSCADAmapping alias="SUB4_096MVArn_Ana Scanned Value" ignore_vary="True" type =
"FLOAT" maptoclasstype="IscSynMachine" name ="METC1.EMEC WAVE" equivalent_field_address =
"IscSynMachine.GenMVAr"/>

<ipsa2simSCADAmapping alias="SUB4_T1_T2_AMPSn_Ana Scanned Value" ignore_vary="True" type
= "FLOAT" maptoclasstype="IscBranch" name ="STROMN3B.STROMN3A.Line1"
equivalent_field_address = "IscBusbar.Amps"/>

<ipsa2simSCADAmapping alias="SUB11_011_012_AMPSn_Ana Scanned Value" ignore_vary="True"
type = "FLOAT" maptoclasstype="IscBranch" name ="BURGAR1A.SIGURD1A.Line1"
equivalent_field_address = "IscBusbar.Amps"/>
```

```
<ipsa2simSCADAmapping alias="SUB11_TR1_AMPSn_Ana Scanned Value" ignore_vary="True" type =
"FLOAT" maptoclasstype="IscBranch" name ="BURGAR3A.BURGAR3B.Line1"
equivalent_field_address = "IscBusbar.Amps"/>

<ipsa2simSCADAmapping alias="SUB11_013_MWn_Ana Scanned Value" ignore_vary="True" type =
"FLOAT" maptoclasstype="IscSynMachine" name ="SIGURDG1.SIGUIRD" equivalent_field_address
= "IscSynMachine.GenMW"/>

<ipsa2simSCADAmapping alias="SUB11_013_MVARn_Ana Scanned Value" ignore_vary="True" type =
"FLOAT" maptoclasstype="IscSynMachine" name ="SIGURDG1.SIGUIRD" equivalent_field_address
= "IscSynMachine.GenMVAr"/>

<ipsa2simSCADAmapping alias="SUB11_013_AMPSn_Ana Scanned Value" ignore_vary="True" type =
"FLOAT" maptoclasstype="IscBranch" name ="SIGURD1A.SIGURDG1.Transformer1"
equivalent_field_address = "IscBusbar.Amps"/>

<ipsa2simSCADAmapping alias="SUB11_014_MWn_Ana Scanned Value" ignore_vary="True" type =
"FLOAT" maptoclasstype="IscSynMachine" name ="THORNFG1.THORNFIN" equivalent_field_address
= "IscSynMachine.GenMW"/>

<ipsa2simSCADAmapping alias="SUB11_014_MVARn_Ana Scanned Value" ignore_vary="True" type =
"FLOAT" maptoclasstype="IscSynMachine" name ="THORNFG1.THORNFIN" equivalent_field_address
= "IscSynMachine.GenMVAr"/>

<ipsa2simSCADAmapping alias="SUB11_014_AMPSn_Ana Scanned Value" ignore_vary="True" type =
"FLOAT" maptoclasstype="IscBranch" name ="THORNF1A.THORNFG1.Transformer1"
equivalent_field_address = "IscBusbar.Amps"/>

<ipsa2simSCADAmapping alias="SUB11B_1C0_KVn_Ana Scanned Value" ignore_vary="True" type =
"FLOAT" maptoclasstype="IscBusbar" name ="NWP3-" equivalent_field_address =
"IscBusbar.Volts"/>

<ipsa2simSCADAmapping alias="SUB11B_1C0_AMPSn_Ana Scanned Value" ignore_vary="True" type
= "FLOAT" maptoclasstype="IscBranch" name ="BURGAR3B.NWP3-.Line1"
equivalent_field_address = "IscBusbar.Amps"/>

<ipsa2simSCADAmapping alias="SUB11B_1C0_MWn_Ana Scanned Value" ignore_vary="True" type =
"FLOAT" maptoclasstype="IscSynMachine" name ="NWP3-.NWP WIND FARM"
equivalent_field_address = "IscSynMachine.GenMW"/>

<ipsa2simSCADAmapping alias="SUB11B_1C0_MVARn_Ana Scanned Value" ignore_vary="True" type
= "FLOAT" maptoclasstype="IscSynMachine" name ="NWP3-.NWP WIND FARM"
equivalent_field_address = "IscSynMachine.GenMVAr"/>

<ipsa2simSCADAmapping alias="SUB1_11_AMPSn_Ana Scanned Value" ignore_vary="True" type =
"FLOAT" maptoclasstype="IscBusbar" name ="ROUSAY1A" equivalent_field_address =
"IscBusbar.Volts"/>
```

```
<ipsa2simSCADAmapping alias="SUB2_AMPSn_Ana Scanned Value" ignore_vary="True" type =
"FLOAT" maptoclasstype="IscBranch" name ="WESTRY3A.ROUSAY3A.Line1"
equivalent_field_address = "IscBusbar.Amps"/>

<ipsa2simSCADAmapping alias="SUB3_11KV_AMPSn_Ana Scanned Value" ignore_vary="True" type =
"FLOAT" maptoclasstype="IscBranch" name ="EDAY3A.EDAY1A.Transformer1"
equivalent_field_address = "IscBusbar.Amps"/>

<ipsa2simSCADAmapping alias="SUB3A_1C0_VOLTSn_Ana Scanned Value" ignore_vary="True" type
= "FLOAT" maptoclasstype="IscBusbar" name ="SPURNE3A" equivalent_field_address =
"IscBusbar.Volts"/>

<ipsa2simSCADAmapping alias="SUB3A_1K0_AMPSn_Ana Scanned Value" ignore_vary="True" type =
"FLOAT" maptoclasstype="IscBranch" name ="SPURNE3A.SPURNE3-.Line1"
equivalent_field_address = "IscBusbar.Amps"/>

<ipsa2simSCADAmapping alias="SUB3A_1K0_MWn_Ana Scanned Value" ignore_vary="True" type =
"FLOAT" maptoclasstype="IscSynMachine" name ="SPURNE3A.SPURNESS WIND FARM"
equivalent_field_address = "IscSynMachine.GenMW"/>

<ipsa2simSCADAmapping alias="SUB3A_1K0_MVARSn_Ana Scanned Value" ignore_vary="True" type
= "FLOAT" maptoclasstype="IscSynMachine" name ="SPURNE3A.SPURNESS WIND FARM"
equivalent_field_address = "IscSynMachine.GenMVAr"/>

<ipsa2simSCADAmapping alias="SUB3A_1C0_AMPSn_Ana Scanned Value" ignore_vary="True" type =
"FLOAT" maptoclasstype="IscBranch" name ="SPURNE3A.SPURNE3-.Line1"
equivalent_field_address = "IscBusbar.Amps"/>

<ipsa2simSCADAmapping alias="SUB3A_1C0_MWn_Ana Scanned Value" ignore_vary="True" type =
"FLOAT" maptoclasstype="IscSynMachine" name ="SPURNE3A.Generator2"
equivalent_field_address = "IscSynMachine.GenMW"/>

<ipsa2simSCADAmapping alias="SUB3A_1C0_MVARSn_Ana Scanned Value" ignore_vary="True" type
= "FLOAT" maptoclasstype="IscSynMachine" name ="SPURNE3A.Generator2"
equivalent_field_address = "IscSynMachine.GenMVAr"/>

<ipsa2simSCADAmapping alias="SUB10_11_AMPSn_Ana Scanned Value" ignore_vary="True" type =
"FLOAT" maptoclasstype="IscBranch" name ="SANDAY3A.SANDAY1A.Transformer1"
equivalent_field_address = "IscBusbar.Amps"/>

<ipsa2simSCADAmapping alias="SUB9_011_AMPSn_Ana Scanned Value" ignore_vary="True" type =
"FLOAT" maptoclasstype="IscBranch" name ="STRONS3A.STRONS1A.Transformer1"
equivalent_field_address = "IscBusbar.Amps"/>

<ipsa2simSCADAmapping alias="SUB8_11_AMPSn_Ana Scanned Value" ignore_vary="True" type =
"FLOAT" maptoclasstype="IscBranch" name ="SHAPIN3A.SHAPIN1A.Transformer1"
equivalent_field_address = "IscBusbar.Amps"/>
```

```
<ipsa2simSCADAmapping alias="SUB4B_NEWDG1_MW" ignore_vary="True" type = "FLOAT"
maptoclasstype="IscSynMachine" name ="STROMN3C.NEWDG1" equivalent_field_address =
"IscSynMachine.GenMW"/>

<ipsa2simSCADAmapping alias="SUB4B_NEWDG1_MVAR" ignore_vary="True" type = "FLOAT"
maptoclasstype="IscSynMachine" name ="STROMN3C.NEWDG1" equivalent_field_address =
"IscSynMachine.GenMVAr"/>

<ipsa2simSCADAmapping alias="SUB11C_VOLTS" ignore_vary="True" type = "FLOAT"
maptoclasstype="IscBusbar" name ="BURGAR3A" equivalent_field_address =
"IscBusbar.Volts"/>

<ipsa2simSCADAmapping alias="SUB11C_AMPS" ignore_vary="True" type = "FLOAT"
maptoclasstype="IscBranch" name ="BURGAR3A.STROMN3C.Line1" equivalent_field_address =
"IscBusbar.Amps"/>

<ipsa2simSCADAmapping alias="SUB11C_NEWDG2_MW" ignore_vary="True" type = "FLOAT"
maptoclasstype="IscSynMachine" name ="BURGAR3A.NEWDG2" equivalent_field_address =
"IscSynMachine.GenMW"/>

<ipsa2simSCADAmapping alias="SUB11C_NEWDG2_MVAR" ignore_vary="True" type = "FLOAT"
maptoclasstype="IscSynMachine" name ="BURGAR3A.NEWDG2" equivalent_field_address =
"IscSynMachine.GenMVAr"/>

</algorithm_inputs_read>

<control_actions_write/>

</configuration>
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Appendix H: Load and Generation Profile Sets

The following appendices provide the load and generation profiles used in Experiments 1 – 4 in Section 5.8 of Chapter 5. As the profiles are static and do not change over the 180 second duration of the experiments, only an example section is given for each profile.

H.1. Generation Profile Set 1: High Generation (without Additional DG)

BUFARM3-.BU FARM WIND FARM	FLOTTA1B.WESTHILL WIND FARM	FLTOCC1C.FLOTTA OCCIDENTAL	FLTOCC1C.Generator2	FLTOCC1C.Generator3	KIRKWA1B.Generator2	KIRKWA1B.KIRKWALL POWER STATION	KIRKWA1C.Generator1	KIRKWA1C.Generator2	METC1.EMEC WAVE	NEWBIG1B.EMEC TIDAL	NORTHF1A.NORTHFIELD	NWP3-.NWP WIND FARM	SIGURDG1.SIGUIRD	SPURNE3A.Generator2	SPURNE3A.Generator3	SPURNE3A.SPURNESS WIND FARM	THORNFG1.THORNFIN	THORNFG2.THORNFIN
1.32	0	1.13	1.13	1.13	0	0	0	0	0	0	0	6	1.22	2.43	2.43	2.43	2	2
1.32	0	1.13	1.13	1.13	0	0	0	0	0	0	0	6	1.22	2.43	2.43	2.43	2	2
1.32	0	1.13	1.13	1.13	0	0	0	0	0	0	0	6	1.22	2.43	2.43	2.43	2	2
1.32	0	1.13	1.13	1.13	0	0	0	0	0	0	0	6	1.22	2.43	2.43	2.43	2	2
1.32	0	1.13	1.13	1.13	0	0	0	0	0	0	0	6	1.22	2.43	2.43	2.43	2	2
1.32	0	1.13	1.13	1.13	0	0	0	0	0	0	0	6	1.22	2.43	2.43	2.43	2	2
1.32	0	1.13	1.13	1.13	0	0	0	0	0	0	0	6	1.22	2.43	2.43	2.43	2	2
1.32	0	1.13	1.13	1.13	0	0	0	0	0	0	0	6	1.22	2.43	2.43	2.43	2	2
1.32	0	1.13	1.13	1.13	0	0	0	0	0	0	0	6	1.22	2.43	2.43	2.43	2	2
1.32	0	1.13	1.13	1.13	0	0	0	0	0	0	0	6	1.22	2.43	2.43	2.43	2	2

H.2 Generation Profile Set 1: High Generation (with Additional DG)

BUFARM3-.BU FARM WIND FARM	BURGAR3A.NEWDG2	FLOTTA1B.WESTHILL WIND FARM	FLTOCC1C.FLOTTA OCCIDENTAL	FLTOCC1C.Generator2	FLTOCC1C.Generator3	KIRKWA1B.Generator2	KIRKWA1B.KIRKWALL POWER STATION	KIRKWA1C.Generator1	KIRKWA1C.Generator2	METC1.EMEC WAVE	NEWBIG1B.EMEC TIDAL	NORTHF1A.NORTHFIELD	NWP3-.NWP WIND FARM	SIGURDG1.SIGUIRD	SPURNE3A.Generator2	SPURNE3A.Generator3	SPURNE3A.SPURNESS WIND FARM	STROMN3C.NEWDG1	THORNFG1.THORNFIN	THORNFG2.THORNFIN
1.32	11	0	1.13	1.13	1.13	0	0	0	0	0	0	0	6	1.22	2.43	2.43	2.43	9	2	2
1.32	11	0	1.13	1.13	1.13	0	0	0	0	0	0	0	6	1.22	2.43	2.43	2.43	9	2	2
1.32	11	0	1.13	1.13	1.13	0	0	0	0	0	0	0	6	1.22	2.43	2.43	2.43	9	2	2
1.32	11	0	1.13	1.13	1.13	0	0	0	0	0	0	0	6	1.22	2.43	2.43	2.43	9	2	2
1.32	11	0	1.13	1.13	1.13	0	0	0	0	0	0	0	6	1.22	2.43	2.43	2.43	9	2	2
1.32	11	0	1.13	1.13	1.13	0	0	0	0	0	0	0	6	1.22	2.43	2.43	2.43	9	2	2
1.32	11	0	1.13	1.13	1.13	0	0	0	0	0	0	0	6	1.22	2.43	2.43	2.43	9	2	2
1.32	11	0	1.13	1.13	1.13	0	0	0	0	0	0	0	6	1.22	2.43	2.43	2.43	9	2	2
1.32	11	0	1.13	1.13	1.13	0	0	0	0	0	0	0	6	1.22	2.43	2.43	2.43	9	2	2
1.32	11	0	1.13	1.13	1.13	0	0	0	0	0	0	0	6	1.22	2.43	2.43	2.43	9	2	2

H.3 Load Profile Set 1: Low Load

BURGAR1A.BURGAR HILL	EDAY1A.EDAY	FLOTTA1A.FLOTTA	FLTOCC1C.FLOTTA ELF	KIRKWA1A.Load1	KIRKWA1B.KIRKWALL	KIRKWA1C.Load1	LYNESS1A.LYNESS	NTHHOY1A.NORTH HOY	ROUSAY1A.ROUSAY	SANDAY1A.SANDAY	SCORRA3B.Load1	SCORRA3C.Load1	SHAPIN1A.SHAPINSAY	STMARY1A.ST MARYS	STROMN1A.STROMNESS	STRONS1A.STRONSAY	WESTRY1A.WESTRAY
0.55	0.06	2.04	0	2.44	2.32	0	0.14	0.06	0.1	0.25	0	0	0.18	0.22	1.63	0.11	0.33
0.55	0.06	2.04	0	2.44	2.32	0	0.14	0.06	0.1	0.25	0	0	0.18	0.22	1.63	0.11	0.33
0.55	0.06	2.04	0	2.44	2.32	0	0.14	0.06	0.1	0.25	0	0	0.18	0.22	1.63	0.11	0.33
0.55	0.06	2.04	0	2.44	2.32	0	0.14	0.06	0.1	0.25	0	0	0.18	0.22	1.63	0.11	0.33
0.55	0.06	2.04	0	2.44	2.32	0	0.14	0.06	0.1	0.25	0	0	0.18	0.22	1.63	0.11	0.33
0.55	0.06	2.04	0	2.44	2.32	0	0.14	0.06	0.1	0.25	0	0	0.18	0.22	1.63	0.11	0.33
0.55	0.06	2.04	0	2.44	2.32	0	0.14	0.06	0.1	0.25	0	0	0.18	0.22	1.63	0.11	0.33
0.55	0.06	2.04	0	2.44	2.32	0	0.14	0.06	0.1	0.25	0	0	0.18	0.22	1.63	0.11	0.33
0.55	0.06	2.04	0	2.44	2.32	0	0.14	0.06	0.1	0.25	0	0	0.18	0.22	1.63	0.11	0.33
0.55	0.06	2.04	0	2.44	2.32	0	0.14	0.06	0.1	0.25	0	0	0.18	0.22	1.63	0.11	0.33

H.4 Generation Profile Set 2: Low Generation (without Additional DG)

.BU FARM WIND FARM	FLOTTA1B.W ESTHILL WIND FARM	FLTOCC1C.F LOTTA OCCIDENTAL	FLTOCC1C.G enerator2	FLTOCC1C.G enerator3	KIRKWA1B.G enerator2	KIRKWA1B.KI RKWALL POWER STATION	KIRKWA1C.G enerator1	KIRKWA1C.G enerator2	METC1.EME C WAVE	NEWBIG1B.E MEC TIDAL	NORTHF1A.N ORTHFIELD	NWP3-.NWP WIND FARM	SIGURDG1.SI GUIRD	SPURNE3A.G enerator2	SPURNE3A.G enerator3	SPURNE3A.S PURNESS WIND FARM	THORNFG1.T HORNFIN	THORNFG2.T HORNFIN
0	0	0.37	0.37	0.37	0	0	0	0	0	0	0	6	0	0.02	0.02	0.02	0	0
0	0	0.37	0.37	0.37	0	0	0	0	0	0	0	6	0	0.02	0.02	0.02	0	0
0	0	0.37	0.37	0.37	0	0	0	0	0	0	0	6	0	0.02	0.02	0.02	0	0
0	0	0.37	0.37	0.37	0	0	0	0	0	0	0	6	0	0.02	0.02	0.02	0	0
0	0	0.37	0.37	0.37	0	0	0	0	0	0	0	6	0	0.02	0.02	0.02	0	0
0	0	0.37	0.37	0.37	0	0	0	0	0	0	0	6	0	0.02	0.02	0.02	0	0
0	0	0.37	0.37	0.37	0	0	0	0	0	0	0	6	0	0.02	0.02	0.02	0	0
0	0	0.37	0.37	0.37	0	0	0	0	0	0	0	6	0	0.02	0.02	0.02	0	0
0	0	0.37	0.37	0.37	0	0	0	0	0	0	0	6	0	0.02	0.02	0.02	0	0
0	0	0.37	0.37	0.37	0	0	0	0	0	0	0	6	0	0.02	0.02	0.02	0	0

H.5 Generation Profile Set 2: Low Generation (with Additional DG)

.BU FARM WIND FARM	BURGAR3A. NEWDG2	FLOTTA1B.W ESTHILL WIND FARM	FLTOCC1C.F LOTTA OCCIDENTAL	FLTOCC1C.G enerator2	FLTOCC1C.G enerator3	KIRKWA1B.G enerator2	RKWALL POWER STATION	KIRKWA1C.G enerator1	KIRKWA1C.G enerator2	METC1.EME C WAVE	NEWBIG1B.E MEC TIDAL	NORTHF1A.N ORTHFIELD	NWP3-.NWP WIND FARM	SIGURDG1.SI GUIRD	SPURNE3A.G enerator2	SPURNE3A.G enerator3	SPURNE3A.S PURNESS WIND FARM	STROMN3C. NEWDG1	THORNFG1.T HORNFIN	THORNFG2.T HORNFIN
0	11	0	0.37	0.37	0.37	0	0	0	0	0	0	0	6	0	0.02	0.02	0.02	9	0	0
0	11	0	0.37	0.37	0.37	0	0	0	0	0	0	0	6	0	0.02	0.02	0.02	9	0	0
0	11	0	0.37	0.37	0.37	0	0	0	0	0	0	0	6	0	0.02	0.02	0.02	9	0	0
0	11	0	0.37	0.37	0.37	0	0	0	0	0	0	0	6	0	0.02	0.02	0.02	9	0	0
0	11	0	0.37	0.37	0.37	0	0	0	0	0	0	0	6	0	0.02	0.02	0.02	9	0	0
0	11	0	0.37	0.37	0.37	0	0	0	0	0	0	0	6	0	0.02	0.02	0.02	9	0	0
0	11	0	0.37	0.37	0.37	0	0	0	0	0	0	0	6	0	0.02	0.02	0.02	9	0	0
0	11	0	0.37	0.37	0.37	0	0	0	0	0	0	0	6	0	0.02	0.02	0.02	9	0	0
0	11	0	0.37	0.37	0.37	0	0	0	0	0	0	0	6	0	0.02	0.02	0.02	9	0	0
0	11	0	0.37	0.37	0.37	0	0	0	0	0	0	0	6	0	0.02	0.02	0.02	9	0	0

H.6 Load Profile Set 2: High Load

BURGAR1A.B URGAR HILL	EDAY1A.EDA Y	FLOTTA1A.F LOTTA	FLTOCC1C.F LOTTA ELF	KIRKWA1A.L oad1	KIRKWA1B.KI RKWALL	KIRKWA1C.L oad1	LYNESS1A.L YNESS	NTHHOY1A.N ORTH HOY	ROUSAY1A.R OUSAY	SANDAY1A.S ANDAY	SCORRA3B.L oad1	SCORRA3C.L oad1	SHAPIN1A.S HAPINSAY	STMARY1A.S T MARYS	STROMN1A. STROMNESS	STRONS1A.S TRONSAY	WESTRY1A. WESTRAY
1.31	0.2	0.09	0	5.88	5.83	0	0.2	0.1	0.23	0.56	0	0	0.34	0.59	4.31	0.4	0.37
1.31	0.2	0.09	0	5.88	5.83	0	0.2	0.1	0.23	0.56	0	0	0.34	0.59	4.31	0.4	0.37
1.31	0.2	0.09	0	5.88	5.83	0	0.2	0.1	0.23	0.56	0	0	0.34	0.59	4.31	0.4	0.37
1.31	0.2	0.09	0	5.88	5.83	0	0.2	0.1	0.23	0.56	0	0	0.34	0.59	4.31	0.4	0.37
1.31	0.2	0.09	0	5.88	5.83	0	0.2	0.1	0.23	0.56	0	0	0.34	0.59	4.31	0.4	0.37
1.31	0.2	0.09	0	5.88	5.83	0	0.2	0.1	0.23	0.56	0	0	0.34	0.59	4.31	0.4	0.37
1.31	0.2	0.09	0	5.88	5.83	0	0.2	0.1	0.23	0.56	0	0	0.34	0.59	4.31	0.4	0.37
1.31	0.2	0.09	0	5.88	5.83	0	0.2	0.1	0.23	0.56	0	0	0.34	0.59	4.31	0.4	0.37
1.31	0.2	0.09	0	5.88	5.83	0	0.2	0.1	0.23	0.56	0	0	0.34	0.59	4.31	0.4	0.37
1.31	0.2	0.09	0	5.88	5.83	0	0.2	0.1	0.23	0.56	0	0	0.34	0.59	4.31	0.4	0.37

Appendix J: MiniSim4SimSCADA to OPC Server Mapping File

This appendix contains the file used in the CoRDS to map the OPC clients contained within the MiniSim4SimSCADA code to the Matrikon OPC server, described in Section 5.4.3 in Chapter 5, which is required for successful AuRA-NMS integration.


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logicalnodepath="IEC61850 Subnetwork.EDAY1A  EDAY.MEAS.MMXU1.TotW.mag"
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opcserver="Matrikon.OPC.Simulation.1" type="FLOAT"/>

<input_opc_mapping classid="" equivalent_field_address="IscLoad.RealMW"
logicalnodepath="IEC61850 Subnetwork.SHAPIN1A  SHAPINSAY.MEAS.MMXU1.TotW.mag"
maptoclasstype="IscLoad" name="SHAPIN1A.SHAPINSAY" opchost="localhost"
opcserver="Matrikon.OPC.Simulation.1" type="FLOAT"/>

<input_opc_mapping classid="" equivalent_field_address="IscLoad.ReactiveMVAr"
logicalnodepath="IEC61850 Subnetwork.SHAPIN1A  SHAPINSAY.MEAS.MMXU1.TotVar.mag"
maptoclasstype="IscLoad" name="SHAPIN1A.SHAPINSAY" opchost="localhost"
opcserver="Matrikon.OPC.Simulation.1" type="FLOAT"/>

<input_opc_mapping classid="" equivalent_field_address="IscLoad.RealMW"
logicalnodepath="IEC61850 Subnetwork.STMARY1A  ST MARYS.MEAS.MMXU1.TotW.mag"
maptoclasstype="IscLoad" name="STMARY1A.ST MARYS" opchost="localhost"
opcserver="Matrikon.OPC.Simulation.1" type="FLOAT"/>

<input_opc_mapping classid="" equivalent_field_address="IscLoad.ReactiveMVAr"
logicalnodepath="IEC61850 Subnetwork.STMARY1A  ST MARYS.MEAS.MMXU1.TotVar.mag"
maptoclasstype="IscLoad" name="STMARY1A.ST MARYS" opchost="localhost"
opcserver="Matrikon.OPC.Simulation.1" type="FLOAT"/>

<input_opc_mapping classid="" equivalent_field_address="IscLoad.RealMW"
logicalnodepath="IEC61850 Subnetwork.STROMN1A  STROMNESS.MEAS.MMXU1.TotW.mag"
maptoclasstype="IscLoad" name="STROMN1A.STROMNESS" opchost="localhost"
opcserver="Matrikon.OPC.Simulation.1" type="FLOAT"/>

<input_opc_mapping classid="" equivalent_field_address="IscLoad.ReactiveMVAr"
logicalnodepath="IEC61850 Subnetwork.STROMN1A  STROMNESS.MEAS.MMXU1.TotVar.mag"
maptoclasstype="IscLoad" name="STROMN1A.STROMNESS" opchost="localhost"
opcserver="Matrikon.OPC.Simulation.1" type="FLOAT"/>

<input_opc_mapping classid="" equivalent_field_address="IscLoad.RealMW"
logicalnodepath="IEC61850 Subnetwork.STRONS1A  STRONSAY.MEAS.MMXU1.TotW.mag"
maptoclasstype="IscLoad" name="STRONS1A.STRONSAY" opchost="localhost"
opcserver="Matrikon.OPC.Simulation.1" type="FLOAT"/>

<input_opc_mapping classid="" equivalent_field_address="IscLoad.ReactiveMVAr"
logicalnodepath="IEC61850 Subnetwork.STRONS1A  STRONSAY.MEAS.MMXU1.TotVar.mag"
maptoclasstype="IscLoad" name="STRONS1A.STRONSAY" opchost="localhost"
opcserver="Matrikon.OPC.Simulation.1" type="FLOAT"/>

<input_opc_mapping classid="" equivalent_field_address="IscLoad.RealMW"
logicalnodepath="IEC61850 Subnetwork.WESTRY1A  WESTRAY.MEAS.MMXU1.TotW.mag"
```

```
maptoclasstype="IscLoad" name="WESTRY1A.WESTRAY" opchost="localhost"
opcserver="Matrikon.OPC.Simulation.1" type="FLOAT"/>

<input_opc_mapping classid="" equivalent_field_address="IscLoad.ReactiveMVAr"
logicalnodepath="IEC61850 Subnetwork.WESTRY1A  WESTRAY.MEAS.MMXU1.TotVar.mag"
maptoclasstype="IscLoad" name="WESTRY1A.WESTRAY" opchost="localhost"
opcserver="Matrikon.OPC.Simulation.1" type="FLOAT"/>

<input_opc_mapping classid="" equivalent_field_address="IscSynMachine.GenMW"
logicalnodepath="IEC61850 Subnetwork.BUFARM3-  BU FARM WIND FARM.MEAS.MMXU1.TotW.mag"
maptoclasstype="IscSynMachine" name="BUFARM3-.BU FARM WIND FARM" opchost="localhost"
opcserver="Matrikon.OPC.Simulation.1" type="FLOAT"/>

<input_opc_mapping classid="" equivalent_field_address="IscSynMachine.GenMVAr"
logicalnodepath="IEC61850 Subnetwork.BUFARM3-  BU FARM WIND FARM.MEAS.MMXU1.TotVar.mag"
maptoclasstype="IscSynMachine" name="BUFARM3-.BU FARM WIND FARM" opchost="localhost"
opcserver="Matrikon.OPC.Simulation.1" type="FLOAT"/>

<input_opc_mapping classid="" equivalent_field_address="IscSynMachine.GenMW"
logicalnodepath="IEC61850 Subnetwork.BURGAR3A  NEWDG2.MEAS.MMXU1.TotW.mag"
maptoclasstype="IscSynMachine" name="BURGAR3A.NEWDG2" opchost="localhost"
opcserver="Matrikon.OPC.Simulation.1" type="FLOAT"/>

<input_opc_mapping classid="" equivalent_field_address="IscSynMachine.GenMVAr"
logicalnodepath="IEC61850 Subnetwork.BURGAR3A  NEWDG2.MEAS.MMXU1.TotVar.mag"
maptoclasstype="IscSynMachine" name="BURGAR3A.NEWDG2" opchost="localhost"
opcserver="Matrikon.OPC.Simulation.1" type="FLOAT"/>

<input_opc_mapping classid="" equivalent_field_address="IscSynMachine.GenMW"
logicalnodepath="IEC61850 Subnetwork.FLOTTA1B  WESTHILL WIND FARM.MEAS.MMXU1.TotW.mag"
maptoclasstype="IscSynMachine" name="FLOTTA1B.WESTHILL WIND FARM" opchost="localhost"
opcserver="Matrikon.OPC.Simulation.1" type="FLOAT"/>

<input_opc_mapping classid="" equivalent_field_address="IscSynMachine.GenMVAr"
logicalnodepath="IEC61850 Subnetwork.FLOTTA1B  WESTHILL WIND FARM.MEAS.MMXU1.TotVar.mag"
maptoclasstype="IscSynMachine" name="FLOTTA1B.WESTHILL WIND FARM" opchost="localhost"
opcserver="Matrikon.OPC.Simulation.1" type="FLOAT"/>

<input_opc_mapping classid="" equivalent_field_address="IscSynMachine.GenMW"
logicalnodepath="IEC61850 Subnetwork.FLTOCC1C  FLOTTA OCCIDENTAL.MEAS.MMXU1.TotW.mag"
maptoclasstype="IscSynMachine" name="FLTOCC1C.FLOTTA OCCIDENTAL" opchost="localhost"
opcserver="Matrikon.OPC.Simulation.1" type="FLOAT"/>

<input_opc_mapping classid="" equivalent_field_address="IscSynMachine.GenMVAr"
logicalnodepath="IEC61850 Subnetwork.FLTOCC1C  FLOTTA OCCIDENTAL.MEAS.MMXU1.TotVar.mag"
maptoclasstype="IscSynMachine" name="FLTOCC1C.FLOTTA OCCIDENTAL" opchost="localhost"
opcserver="Matrikon.OPC.Simulation.1" type="FLOAT"/>
```

```
<input_opc_mapping classid="" equivalent_field_address="IscSynMachine.GenMW"
logicalnodepath="IEC61850 Subnetwork.FLTOCC1C  Generator2.MEAS.MMXU1.TotW.mag"
maptoclasstype="IscSynMachine" name="FLTOCC1C.Generator2" opchost="localhost"
opcserver="Matrikon.OPC.Simulation.1" type="FLOAT"/>

<input_opc_mapping classid="" equivalent_field_address="IscSynMachine.GenMVAr"
logicalnodepath="IEC61850 Subnetwork.FLTOCC1C  Generator2.MEAS.MMXU1.TotVar.mag"
maptoclasstype="IscSynMachine" name="FLTOCC1C.Generator2" opchost="localhost"
opcserver="Matrikon.OPC.Simulation.1" type="FLOAT"/>

<input_opc_mapping classid="" equivalent_field_address="IscSynMachine.GenMW"
logicalnodepath="IEC61850 Subnetwork.FLTOCC1C  Generator3.MEAS.MMXU1.TotW.mag"
maptoclasstype="IscSynMachine" name="FLTOCC1C.Generator3" opchost="localhost"
opcserver="Matrikon.OPC.Simulation.1" type="FLOAT"/>

<input_opc_mapping classid="" equivalent_field_address="IscSynMachine.GenMVAr"
logicalnodepath="IEC61850 Subnetwork.FLTOCC1C  Generator3.MEAS.MMXU1.TotVar.mag"
maptoclasstype="IscSynMachine" name="FLTOCC1C.Generator3" opchost="localhost"
opcserver="Matrikon.OPC.Simulation.1" type="FLOAT"/>

<input_opc_mapping classid="" equivalent_field_address="IscSynMachine.GenMW"
logicalnodepath="IEC61850 Subnetwork.KIRKWA1B  Generator2.MEAS.MMXU1.TotW.mag"
maptoclasstype="IscSynMachine" name="KIRKWA1B.Generator2" opchost="localhost"
opcserver="Matrikon.OPC.Simulation.1" type="FLOAT"/>

<input_opc_mapping classid="" equivalent_field_address="IscSynMachine.GenMVAr"
logicalnodepath="IEC61850 Subnetwork.KIRKWA1B  Generator2.MEAS.MMXU1.TotVar.mag"
maptoclasstype="IscSynMachine" name="KIRKWA1B.Generator2" opchost="localhost"
opcserver="Matrikon.OPC.Simulation.1" type="FLOAT"/>

<input_opc_mapping classid="" equivalent_field_address="IscSynMachine.GenMW"
logicalnodepath="IEC61850 Subnetwork.KIRKWA1B  KIRKWALL POWER
STATION.MEAS.MMXU1.TotW.mag" maptoclasstype="IscSynMachine" name="KIRKWA1B.KIRKWALL POWER
STATION" opchost="localhost" opcserver="Matrikon.OPC.Simulation.1" type="FLOAT"/>

<input_opc_mapping classid="" equivalent_field_address="IscSynMachine.GenMVAr"
logicalnodepath="IEC61850 Subnetwork.KIRKWA1B  KIRKWALL POWER
STATION.MEAS.MMXU1.TotVar.mag" maptoclasstype="IscSynMachine" name="KIRKWA1B.KIRKWALL
POWER STATION" opchost="localhost" opcserver="Matrikon.OPC.Simulation.1" type="FLOAT"/>

<input_opc_mapping classid="" equivalent_field_address="IscSynMachine.GenMW"
logicalnodepath="IEC61850 Subnetwork.KIRKWA1C  Generator1.MEAS.MMXU1.TotW.mag"
maptoclasstype="IscSynMachine" name="KIRKWA1C.Generator1" opchost="localhost"
opcserver="Matrikon.OPC.Simulation.1" type="FLOAT"/>

<input_opc_mapping classid="" equivalent_field_address="IscSynMachine.GenMVAr"
logicalnodepath="IEC61850 Subnetwork.KIRKWA1C  Generator1.MEAS.MMXU1.TotVar.mag"
```

```
maptoclasstype="IscSynMachine" name="KIRKWA1C.Generator1" opchost="localhost"
opcserver="Matrikon.OPC.Simulation.1" type="FLOAT"/>

<input_opc_mapping classid="" equivalent_field_address="IscSynMachine.GenMW"
logicalnodepath="IEC61850 Subnetwork.KIRKWA1C  Generator2.MEAS.MMXU1.TotW.mag"
maptoclasstype="IscSynMachine" name="KIRKWA1C.Generator2" opchost="localhost"
opcserver="Matrikon.OPC.Simulation.1" type="FLOAT"/>

<input_opc_mapping classid="" equivalent_field_address="IscSynMachine.GenMVAr"
logicalnodepath="IEC61850 Subnetwork.KIRKWA1C  Generator2.MEAS.MMXU1.TotVar.mag"
maptoclasstype="IscSynMachine" name="KIRKWA1C.Generator2" opchost="localhost"
opcserver="Matrikon.OPC.Simulation.1" type="FLOAT"/>

<input_opc_mapping classid="" equivalent_field_address="IscSynMachine.GenMW"
logicalnodepath="IEC61850 Subnetwork.METC1  EMEC WAVE.MEAS.MMXU1.TotW.mag"
maptoclasstype="IscSynMachine" name="METC1.EMEC WAVE" opchost="localhost"
opcserver="Matrikon.OPC.Simulation.1" type="FLOAT"/>

<input_opc_mapping classid="" equivalent_field_address="IscSynMachine.GenMVAr"
logicalnodepath="IEC61850 Subnetwork.METC1  EMEC WAVE.MEAS.MMXU1.TotVar.mag"
maptoclasstype="IscSynMachine" name="METC1.EMEC WAVE" opchost="localhost"
opcserver="Matrikon.OPC.Simulation.1" type="FLOAT"/>

<input_opc_mapping classid="" equivalent_field_address="IscSynMachine.GenMW"
logicalnodepath="IEC61850 Subnetwork.NEWBIG1B  EMEC TIDAL.MEAS.MMXU1.TotW.mag"
maptoclasstype="IscSynMachine" name="NEWBIG1B.EMEC TIDAL" opchost="localhost"
opcserver="Matrikon.OPC.Simulation.1" type="FLOAT"/>

<input_opc_mapping classid="" equivalent_field_address="IscSynMachine.GenMVAr"
logicalnodepath="IEC61850 Subnetwork.NEWBIG1B  EMEC TIDAL.MEAS.MMXU1.TotVar.mag"
maptoclasstype="IscSynMachine" name="NEWBIG1B.EMEC TIDAL" opchost="localhost"
opcserver="Matrikon.OPC.Simulation.1" type="FLOAT"/>

<input_opc_mapping classid="" equivalent_field_address="IscSynMachine.GenMW"
logicalnodepath="IEC61850 Subnetwork.NORTHF1A  NORTHFIELD.MEAS.MMXU1.TotW.mag"
maptoclasstype="IscSynMachine" name="NORTHF1A.NORTHFIELD" opchost="localhost"
opcserver="Matrikon.OPC.Simulation.1" type="FLOAT"/>

<input_opc_mapping classid="" equivalent_field_address="IscSynMachine.GenMVAr"
logicalnodepath="IEC61850 Subnetwork.NORTHF1A  NORTHFIELD.MEAS.MMXU1.TotVar.mag"
maptoclasstype="IscSynMachine" name="NORTHF1A.NORTHFIELD" opchost="localhost"
opcserver="Matrikon.OPC.Simulation.1" type="FLOAT"/>

<input_opc_mapping classid="" equivalent_field_address="IscSynMachine.GenMW"
logicalnodepath="IEC61850 Subnetwork.NWP3-  NWP WIND FARM.MEAS.MMXU1.TotW.mag"
maptoclasstype="IscSynMachine" name="NWP3-.NWP WIND FARM" opchost="localhost"
opcserver="Matrikon.OPC.Simulation.1" type="FLOAT"/>
```

```
<input_opc_mapping classid="" equivalent_field_address="IscSynMachine.GenMVAr"
logicalnodepath="IEC61850 Subnetwork.NWP3-  NWP WIND FARM.MEAS.MMXU1.TotVar.mag"
maptoclasstype="IscSynMachine" name="NWP3-.NWP WIND FARM" opchost="localhost"
opcserver="Matrikon.OPC.Simulation.1" type="FLOAT"/>

<input_opc_mapping classid="" equivalent_field_address="IscSynMachine.GenMW"
logicalnodepath="IEC61850 Subnetwork.SCORRA3A  DVAR.MEAS.MMXU1.TotW.mag"
maptoclasstype="IscSynMachine" name="SCORRA3A.DVAR" opchost="localhost"
opcserver="Matrikon.OPC.Simulation.1" type="FLOAT"/>

<input_opc_mapping classid="" equivalent_field_address="IscSynMachine.GenMVAr"
logicalnodepath="IEC61850 Subnetwork.SCORRA3A  DVAR.MEAS.MMXU1.TotVar.mag"
maptoclasstype="IscSynMachine" name="SCORRA3A.DVAR" opchost="localhost"
opcserver="Matrikon.OPC.Simulation.1" type="FLOAT"/>

<input_opc_mapping classid="" equivalent_field_address="IscSynMachine.GenMW"
logicalnodepath="IEC61850 Subnetwork.SCORRA3C  Generator1.MEAS.MMXU1.TotW.mag"
maptoclasstype="IscSynMachine" name="SCORRA3C.Generator1" opchost="localhost"
opcserver="Matrikon.OPC.Simulation.1" type="FLOAT"/>

<input_opc_mapping classid="" equivalent_field_address="IscSynMachine.GenMVAr"
logicalnodepath="IEC61850 Subnetwork.SCORRA3C  Generator1.MEAS.MMXU1.TotVar.mag"
maptoclasstype="IscSynMachine" name="SCORRA3C.Generator1" opchost="localhost"
opcserver="Matrikon.OPC.Simulation.1" type="FLOAT"/>

<input_opc_mapping classid="" equivalent_field_address="IscSynMachine.GenMW"
logicalnodepath="IEC61850 Subnetwork.SIGURDG1  SIGUIRD.MEAS.MMXU1.TotW.mag"
maptoclasstype="IscSynMachine" name="SIGURDG1.SIGUIRD" opchost="localhost"
opcserver="Matrikon.OPC.Simulation.1" type="FLOAT"/>

<input_opc_mapping classid="" equivalent_field_address="IscSynMachine.GenMVAr"
logicalnodepath="IEC61850 Subnetwork.SIGURDG1  SIGUIRD.MEAS.MMXU1.TotVar.mag"
maptoclasstype="IscSynMachine" name="SIGURDG1.SIGUIRD" opchost="localhost"
opcserver="Matrikon.OPC.Simulation.1" type="FLOAT"/>

<input_opc_mapping classid="" equivalent_field_address="IscSynMachine.GenMW"
logicalnodepath="IEC61850 Subnetwork.SPURNE3A  Generator2.MEAS.MMXU1.TotW.mag"
maptoclasstype="IscSynMachine" name="SPURNE3A.Generator2" opchost="localhost"
opcserver="Matrikon.OPC.Simulation.1" type="FLOAT"/>

<input_opc_mapping classid="" equivalent_field_address="IscSynMachine.GenMVAr"
logicalnodepath="IEC61850 Subnetwork.SPURNE3A  Generator2.MEAS.MMXU1.TotVar.mag"
maptoclasstype="IscSynMachine" name="SPURNE3A.Generator2" opchost="localhost"
opcserver="Matrikon.OPC.Simulation.1" type="FLOAT"/>

<input_opc_mapping classid="" equivalent_field_address="IscSynMachine.GenMW"
logicalnodepath="IEC61850 Subnetwork.SPURNE3A  Generator3.MEAS.MMXU1.TotW.mag"
```

```
maptoclasstype="IscSynMachine" name="SPURNE3A.Generator3" opchost="localhost"
opcserver="Matrikon.OPC.Simulation.1" type="FLOAT"/>

<input_opc_mapping classid="" equivalent_field_address="IscSynMachine.GenMVAr"
logicalnodepath="IEC61850 Subnetwork.SPURNE3A  Generator3.MEAS.MMXU1.TotVar.mag"
maptoclasstype="IscSynMachine" name="SPURNE3A.Generator3" opchost="localhost"
opcserver="Matrikon.OPC.Simulation.1" type="FLOAT"/>

<input_opc_mapping classid="" equivalent_field_address="IscSynMachine.GenMW"
logicalnodepath="IEC61850 Subnetwork.SPURNE3A  SPURNESS WIND FARM.MEAS.MMXU1.TotW.mag"
maptoclasstype="IscSynMachine" name="SPURNE3A.SPURNESS WIND FARM" opchost="localhost"
opcserver="Matrikon.OPC.Simulation.1" type="FLOAT"/>

<input_opc_mapping classid="" equivalent_field_address="IscSynMachine.GenMVAr"
logicalnodepath="IEC61850 Subnetwork.SPURNE3A  SPURNESS WIND FARM.MEAS.MMXU1.TotVar.mag"
maptoclasstype="IscSynMachine" name="SPURNE3A.SPURNESS WIND FARM" opchost="localhost"
opcserver="Matrikon.OPC.Simulation.1" type="FLOAT"/>

<input_opc_mapping classid="" equivalent_field_address="IscSynMachine.GenMW"
logicalnodepath="IEC61850 Subnetwork.STROMN3C  NEWDG1.MEAS.MMXU1.TotW.mag"
maptoclasstype="IscSynMachine" name="STROMN3C.NEWDG1" opchost="localhost"
opcserver="Matrikon.OPC.Simulation.1" type="FLOAT"/>

<input_opc_mapping classid="" equivalent_field_address="IscSynMachine.GenMVAr"
logicalnodepath="IEC61850 Subnetwork.STROMN3C  NEWDG1.MEAS.MMXU1.TotVar.mag"
maptoclasstype="IscSynMachine" name="STROMN3C.NEWDG1" opchost="localhost"
opcserver="Matrikon.OPC.Simulation.1" type="FLOAT"/>

<input_opc_mapping classid="" equivalent_field_address="IscSynMachine.GenMW"
logicalnodepath="IEC61850 Subnetwork.THORNFG1  THORNFIN.MEAS.MMXU1.TotW.mag"
maptoclasstype="IscSynMachine" name="THORNFG1.THORNFIN" opchost="localhost"
opcserver="Matrikon.OPC.Simulation.1" type="FLOAT"/>

<input_opc_mapping classid="" equivalent_field_address="IscSynMachine.GenMVAr"
logicalnodepath="IEC61850 Subnetwork.THORNFG1  THORNFIN.MEAS.MMXU1.TotVar.mag"
maptoclasstype="IscSynMachine" name="THORNFG1.THORNFIN" opchost="localhost"
opcserver="Matrikon.OPC.Simulation.1" type="FLOAT"/>

<input_opc_mapping classid="" equivalent_field_address="IscSynMachine.GenMW"
logicalnodepath="IEC61850 Subnetwork.THORNFG2  THORNFIN.MEAS.MMXU1.TotW.mag"
maptoclasstype="IscSynMachine" name="THORNFG2.THORNFIN" opchost="localhost"
opcserver="Matrikon.OPC.Simulation.1" type="FLOAT"/>

<input_opc_mapping classid="" equivalent_field_address="IscSynMachine.GenMVAr"
logicalnodepath="IEC61850 Subnetwork.THORNFG2  THORNFIN.MEAS.MMXU1.TotVar.mag"
maptoclasstype="IscSynMachine" name="THORNFG2.THORNFIN" opchost="localhost"
opcserver="Matrikon.OPC.Simulation.1" type="FLOAT"/>
```

```
</algorithm_inputs_read>

<control_actions_write>

<output_opc_mapping classid="" equivalent_field_address="input" logicalnodepath="IEC61850
Subnetwork.BURGAR3A  NEWDG2.CTRL.PGGIO2.AnIn.mag" maptoclasstype="GeneratorControl"
name="BURGAR3A.NEWDG2" opchost="localhost" opcserver="Matrikon.OPC.Simulation.1"
type="FLOAT"/>

<output_opc_mapping classid="" equivalent_field_address="input" logicalnodepath="IEC61850
Subnetwork.NWP3-  NWP WIND FARM.CTRL.PGGIO2.AnIn.mag" maptoclasstype="GeneratorControl"
name="NWP3-.NWP WIND FARM" opchost="localhost" opcserver="Matrikon.OPC.Simulation.1"
type="FLOAT"/>

<output_opc_mapping classid="" equivalent_field_address="input" logicalnodepath="IEC61850
Subnetwork.STROMN3C  NEWDG1.CTRL.PGGIO2.AnIn.mag" maptoclasstype="GeneratorControl"
name="STROMN3C.NEWDG1" opchost="localhost" opcserver="Matrikon.OPC.Simulation.1"
type="FLOAT"/>

</control_actions_write>

</configuration>
```

Appendix K: AuRA-NMS to IPSA+ Controls

This appendix contains the code used to commit control of the DG connections to the management of the AuRA-NMS ANM scheme. One existing wind farm DG connection and two additional DG connections are assigned to the PFM algorithm, and it has the ability to trim the generation output from the three generators.

```xml
<?xml version="1.0" encoding="utf-8"?>

<minisim_plant_controllers>

<P_trim_controllable_generators>

<P_trim_controllable_generator name="BURGAR3A.NEWDG2" type="syn" rating="10"/>

<P_trim_controllable_generator name="STROMN3C.NEWDG1" type="syn" rating="10"/>

<P_trim_controllable_generator name="NWP3-.NWP WIND FARM" type="syn" rating="6"/>

</minisim_plant_controllers>
```

Appendix L.1: simSCADA Analogues: Experiment 3B

This appendix contains the analogues received from the network by simSCADA during Experiment 3B. As the generation MW output remains constant at NEWDG1 = 9MW, NEWDG2 = 11MW and Burgar Hill Windfarm = 6MW after about 63 seconds, the list of analogues is truncated here.

19/06/2012 19:56:17.546	1	EVENT	SUB11C_NEWDG2_MW: 0.7
19/06/2012 19:56:17.546	1	EVENT	SUB4B _NEWDG1_MW: 0.8
19/06/2012 19:56:20.421	1	EVENT	SUB11C _NEWDG2_MW: 1.4
19/06/2012 19:56:20.437	1	EVENT	SUB4B _NEWDG1_MW: 1.6
19/06/2012 19:56:23.343	1	EVENT	SUB11C _NEWDG2_MW: 2.1
19/06/2012 19:56:23.343	1	EVENT	SUB4B _NEWDG1_MW: 2.4
19/06/2012 19:56:26.078	1	EVENT	SUB11C _NEWDG2_MW: 2.8
19/06/2012 19:56:26.078	1	EVENT	SUB4B _NEWDG1_MW: 3.2
19/06/2012 19:56:29.312	1	EVENT	SUB11C _NEWDG2_MW: 3.5
19/06/2012 19:56:29.312	1	EVENT	SUB4B _NEWDG1_MW: 4
19/06/2012 19:56:32.187	1	EVENT	SUB11C _NEWDG2_MW: 4.2
19/06/2012 19:56:32.187	1	EVENT	SUB4B _NEWDG1_MW: 4.8
19/06/2012 19:56:35.468	1	EVENT	SUB11C _NEWDG2_MW: 4.9
19/06/2012 19:56:35.484	1	EVENT	SUB4B _NEWDG1_MW: 5.6
19/06/2012 19:56:38.875	1	EVENT	SUB11C _NEWDG2_MW: 5.6
19/06/2012 19:56:38.890	1	EVENT	SUB4B _NEWDG1_MW: 6.4
19/06/2012 19:56:41.187	1	EVENT	SUB11C _NEWDG2_MW: 6.3

19/06/2012 19:56:41.187	1	EVENT	SUB4B _NEWDG1_MW: 7.2
19/06/2012 19:56:44.937	1	EVENT	SUB11C _NEWDG2_MW: 7
19/06/2012 19:56:44.937	1	EVENT	SUB4B _NEWDG1_MW: 8
19/06/2012 19:56:47.328	1	EVENT	SUB11C _NEWDG2_MW: 7.7
19/06/2012 19:56:47.328	1	EVENT	SUB4B _NEWDG1_MW: 8.8
19/06/2012 19:56:50.437	1	EVENT	SUB11C _NEWDG2_MW: 8.4
19/06/2012 19:56:50.437	1	EVENT	SUB4B _NEWDG1_MW: 9
19/06/2012 19:56:53.656	1	EVENT	SUB11C _NEWDG2_MW: 9.1
19/06/2012 19:56:53.656	1	EVENT	SUB4B _NEWDG1_MW: 9
19/06/2012 19:56:56.343	1	EVENT	SUB11C _NEWDG2_MW: 9.8
19/06/2012 19:56:56.343	1	EVENT	SUB4B _NEWDG1_MW: 9
19/06/2012 19:56:59.500	1	EVENT	SUB11C _NEWDG2_MW: 10.5
19/06/2012 19:56:59.515	1	EVENT	SUB4B _NEWDG1_MW: 9
19/06/2012 19:57:04.015	1	EVENT	SUB11C _NEWDG2_MW: 11
19/06/2012 19:57:04.015	1	EVENT	SUB4B _NEWDG1_MW: 9
19/06/2012 19:57:06.906	1	EVENT	SUB11C _NEWDG2_MW: 11
19/06/2012 19:57:06.906	1	EVENT	SUB4B _NEWDG1_MW: 9
19/06/2012 19:57:08.500	1	EVENT	SUB11C _NEWDG2_MW: 11
19/06/2012 19:57:08.500	1	EVENT	SUB4B _NEWDG1_MW: 9
19/06/2012 19:57:11.218	1	EVENT	SUB11C _NEWDG2_MW: 11
19/06/2012 19:57:11.218	1	EVENT	SUB4B _NEWDG1_MW: 9
19/06/2012 19:57:14.328	1	EVENT	SUB11C _NEWDG2_MW: 11
19/06/2012 19:57:14.328	1	EVENT	SUB4B _NEWDG1_MW: 9
19/06/2012 19:57:18.656	1	EVENT	SUB11C _NEWDG2_MW: 11
19/06/2012 19:57:18.671	1	EVENT	SUB4B _NEWDG1_MW: 9
19/06/2012 19:57:20.281	1	EVENT	SUB11C _NEWDG2_MW: 11

19/06/2012 19:57:20.281	1	EVENT	SUB4B _NEWDG1_MW: 9

Appendix L.2: simSCADA Analogues: Experiment 4

This appendix contains the analogues received from the network by simSCADA during Experiment 4. As the generation MW output remains constant at NEWDG1 = 0MW, NEWDG2 = 7MW and Burgar Hill Windfarm = 6MW after about 95 seconds, the list of analogues is truncated here.

19/06/2012 21:13:07.265	1	EVENT	SUB11C _NEWDG2_MW: 0.7
19/06/2012 21:13:07.281	1	EVENT	SUB4B _NEWDG1_MW: 0.8
19/06/2012 21:13:09.859	1	EVENT	SUB11C _NEWDG2_MW: 1.4
19/06/2012 21:13:09.859	1	EVENT	SUB4B _NEWDG1_MW: 1.6
19/06/2012 21:13:13.015	1	EVENT	SUB11C _NEWDG2_MW: 2.1
19/06/2012 21:13:13.031	1	EVENT	SUB4B _NEWDG1_MW: 2.4
19/06/2012 21:13:15.843	1	EVENT	SUB11C _NEWDG2_MW: 2.8
19/06/2012 21:13:15.843	1	EVENT	SUB4B _NEWDG1_MW: 3.2
19/06/2012 21:13:18.937	1	EVENT	SUB11C _NEWDG2_MW: 3.5
19/06/2012 21:13:18.937	1	EVENT	SUB4B _NEWDG1_MW: 4
19/06/2012 21:13:22.375	1	EVENT	SUB11C _NEWDG2_MW: 4.2
19/06/2012 21:13:22.375	1	EVENT	SUB4B _NEWDG1_MW: 4.8
19/06/2012 21:13:24.875	1	EVENT	SUB11C _NEWDG2_MW: 4.9
19/06/2012 21:13:24.875	1	EVENT	SUB4B _NEWDG1_MW: 5.6
19/06/2012 21:13:28.046	1	EVENT	SUB11C _NEWDG2_MW: 5.6
19/06/2012 21:13:28.046	1	EVENT	SUB4B _NEWDG1_MW: 6.4
19/06/2012 21:13:30.859	1	EVENT	SUB11C _NEWDG2_MW: 6.3

19/06/2012 21:13:30.859	1	EVENT	SUB4B _NEWDG1_MW: 7.2
19/06/2012 21:13:34.531	1	EVENT	SUB11C _NEWDG2_MW: 7
19/06/2012 21:13:34.531	1	EVENT	SUB4B _NEWDG1_MW: 8
19/06/2012 21:13:36.968	1	EVENT	SUB11C _NEWDG2_MW: 7.7
19/06/2012 21:13:36.968	1	EVENT	SUB4B _NEWDG1_MW: 8.8
19/06/2012 21:13:39.921	1	EVENT	SUB11C _NEWDG2_MW: 8.4
19/06/2012 21:13:39.921	1	EVENT	SUB4B _NEWDG1_MW: 9
19/06/2012 21:13:43.734	1	EVENT	SUB11C _NEWDG2_MW: 9.1
19/06/2012 21:13:43.734	1	EVENT	SUB4B _NEWDG1_MW: 9
19/06/2012 21:13:47.250	1	EVENT	SUB11C _NEWDG2_MW: 9.8
19/06/2012 21:13:47.250	1	EVENT	SUB4B _NEWDG1_MW: 9
19/06/2012 21:13:48.968	1	EVENT	SUB11C _NEWDG2_MW: 10.5
19/06/2012 21:13:48.968	1	EVENT	SUB4B _NEWDG1_MW: 9
19/06/2012 21:13:52.000	1	EVENT	SUB11C _NEWDG2_MW: 11
19/06/2012 21:13:52.000	1	EVENT	SUB4B _NEWDG1_MW: 9
19/06/2012 21:13:54.843	1	EVENT	SUB11C _NEWDG2_MW: 11
19/06/2012 21:13:54.843	1	EVENT	SUB4B _NEWDG1_MW: 8.2
19/06/2012 21:13:58.093	1	EVENT	SUB11C _NEWDG2_MW: 11
19/06/2012 21:13:58.109	1	EVENT	SUB4B _NEWDG1_MW: 7.4
19/06/2012 21:14:01.062	1	EVENT	SUB11C _NEWDG2_MW: 11
19/06/2012 21:14:01.062	1	EVENT	SUB4B _NEWDG1_MW: 6.6
19/06/2012 21:14:04.015	1	EVENT	SUB11C _NEWDG2_MW: 10.3
19/06/2012 21:14:04.015	1	EVENT	SUB4B _NEWDG1_MW: 5.8
19/06/2012 21:14:08.765	1	EVENT	SUB11C _NEWDG2_MW: 9.6
19/06/2012 21:14:08.781	1	EVENT	SUB4B _NEWDG1_MW: 5
19/06/2012 21:14:10.375	1	EVENT	SUB11C _NEWDG2_MW: 8.9

19/06/2012 21:14:10.390	1	EVENT	SUB4B _NEWDG1_MW: 4.2
19/06/2012 21:14:12.328	1	EVENT	SUB11C _NEWDG2_MW: 8.9
19/06/2012 21:14:12.328	1	EVENT	SUB4B _NEWDG1_MW: 4.2
19/06/2012 21:14:16.187	1	EVENT	SUB11C _NEWDG2_MW: 8.2
19/06/2012 21:14:16.203	1	EVENT	SUB4B _NEWDG1_MW: 3.4
19/06/2012 21:14:21.281	1	EVENT	SUB11C _NEWDG2_MW: 7.5
19/06/2012 21:14:21.296	1	EVENT	SUB4B _NEWDG1_MW: 2.6
19/06/2012 21:14:22.390	1	EVENT	SUB11C _NEWDG2_MW: 7
19/06/2012 21:14:22.390	1	EVENT	SUB4B _NEWDG1_MW: 1.8
19/06/2012 21:14:26.265	1	EVENT	SUB11C _NEWDG2_MW: 7
19/06/2012 21:14:26.265	1	EVENT	SUB4B _NEWDG1_MW: 1
19/06/2012 21:14:28.343	1	EVENT	SUB11C _NEWDG2_MW: 7
19/06/2012 21:14:28.343	1	EVENT	SUB4B _NEWDG1_MW: 0.2
19/06/2012 21:14:31.953	1	EVENT	SUB11C _NEWDG2_MW: 7
19/06/2012 21:14:31.968	1	EVENT	SUB4B _NEWDG1_MW: 0
19/06/2012 21:14:35.578	1	EVENT	SUB11C _NEWDG2_MW: 7
19/06/2012 21:14:35.578	1	EVENT	SUB4B _NEWDG1_MW: 0
19/06/2012 21:14:37.796	1	EVENT	SUB11C _NEWDG2_MW: 7
19/06/2012 21:14:37.796	1	EVENT	SUB4B _NEWDG1_MW: 0
19/06/2012 21:14:42.171	1	EVENT	SUB11C _NEWDG2_MW: 7
19/06/2012 21:14:42.171	1	EVENT	SUB4B_NEWDG1_MW: 0