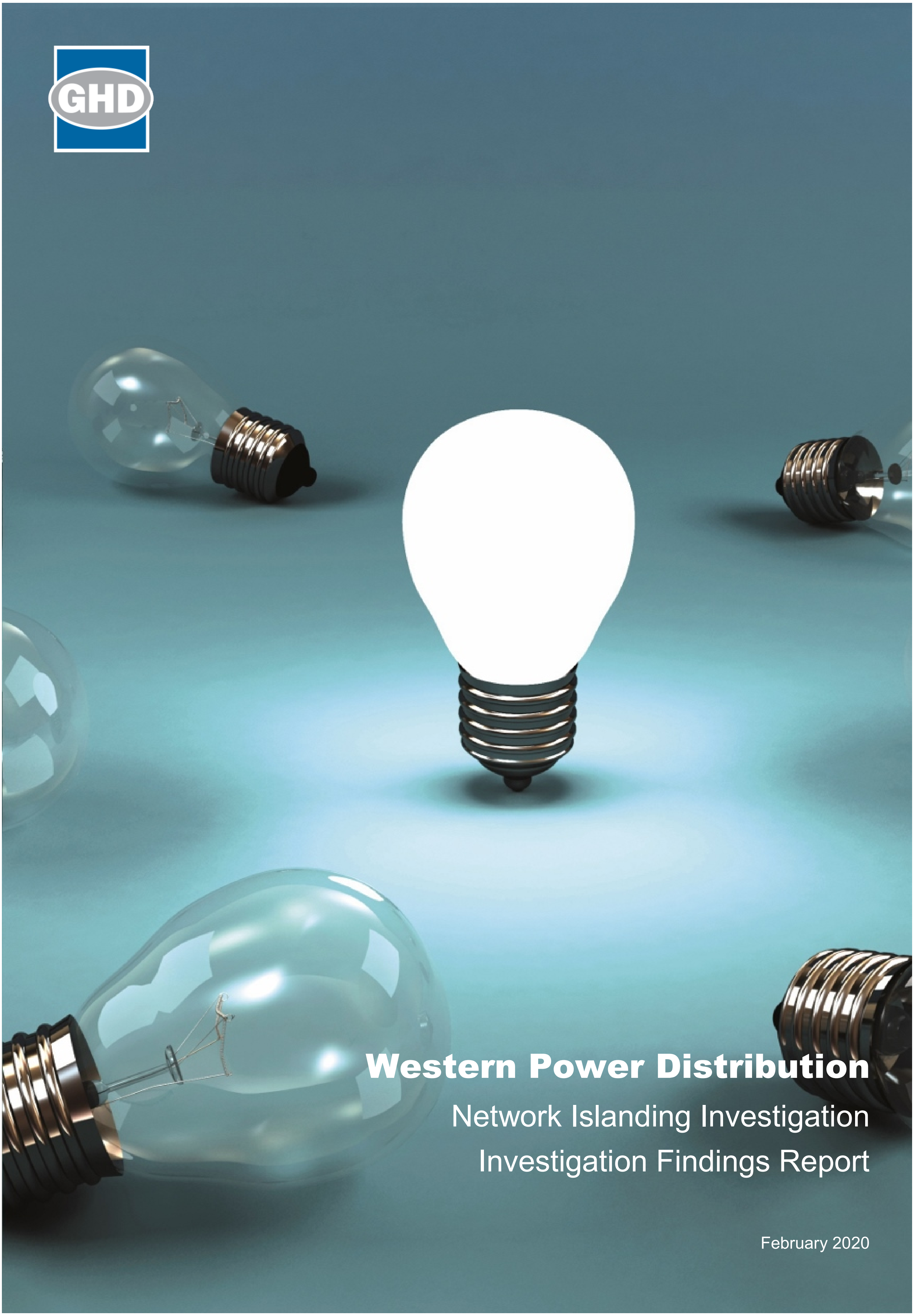

Western Power Distribution

Network Islanding Investigation

Investigation Findings Report

February 2020

Glossary

Acronym	Definition
AC	Alternating Current
ADMS	Advanced Distribution Management System
ANM	Active Network Management
ASC	Available Supply Capacity
AVR	Automatic Voltage Regulator
BEIS	UK Government Department for Business, Energy and Industrial Strategy
BM	Balancing Mechanism
BSC	Balancing and Settlement Code
BSP	Bulk Supply Point
CB	Circuit Breaker
CBA	Cost Benefit Analysis
CDCM	Common Distribution Charging Methodology
CFCT	Critical Fault Clearance Time
CHP	Combined Heat and Power
CMZ	Constraint Management Zones
CNA	Customer Notification Agent
COP2	Code of Practice 2 (Elexon publication)
CT	Current Transformer
CUSC	Connection and Use of System Code
DC	Direct Current
DCUSA	Distribution Connection and Use of System Agreement
DER	Distributed Energy Resources
DFES	Distribution Future Energy Scenarios
DG	Distributed Generator
DMS	Distribution Management System
DNO	Distribution Network Operator
DPC	Distribution Planning and Connection Code
DSO	Distribution System Operator
DSOF	Distribution System Operability Framework
DSR	Demand Side Response
DUOS	Distribution Use of System
DWG	Design Working Group
ECVNA	Energy Contract Volume Notification Agent
EDCM	EHV Distribution Charging Methodology
EHV	Extra high voltage
EMID	East Midlands
EMS	Energy Management System
ENA	Energy Networks Association
EREC	Engineering Recommendation
ESO	Electricity System Operator
ESQCR	Electricity Safety Quality and Continuity Regulations 2002
FCP	Forward Cost Pricing
FES	Future Energy Scenarios
GB	Great Britain
GE	General Electric
GIS	Geographical Information System
HH	Half Hourly
HHS	Half Hourly Settlement
HLRAR	High Level Research and Analysis Report
HMI	Human Machine Interface
HV	High Voltage

Acronym	Definition
LCT	Low Carbon Technology
LRIC	Long Run Incremental Cost
LV	Low Voltage
MADE	Multi Asset Demand Executive
MD	Maximum Demand
MPAN	Meter Point Administration Number
MVA	Mega Volt Ampere
MW	Mega Watt
NER	Neutral Earthing Resistor
NG	National Grid
NHH	Non-Half Hourly
NMS	Network Management System
NPV	Net Present Value
OFGEM	Office of Gas and Electricity Market
OHL	Overhead Line
PC	Profile Class
PCC	Point of Common Coupling
PID	Project Initiation Document
PV	Photovoltaic
RES	Renewable Energy Sources
RIIO	Revenue = Incentives + Innovation + Outputs
RoCoF	Rate of Change of Frequency
RTU	Remote Terminal Unit
SCADA	Supervisory Control And Data Acquisition
SLC	Standard Licence Condition
STOR	Short Term Operating Reserve
SVA	Supplier Volume Allocation
TCR	Targeted Charging Review
TDCV	Typical Domestic Consumption Values
TUOS	Transmission Use of System
UOS	Use of System
VT	Voltage Transformer
WPD	Western Power Distribution

Executive Summary

This report represents the final deliverable in the Network Islanding Investigation Project and concludes the work to establish the technical, commercial, legal and regulatory feasibility of operating parts of the distribution network as an island.

A significant amount of data gathering, research, investigation and studies have been completed since the start of the project in January 2019 and the conclusions in this report supplement and build upon the findings detailed in previous project reports, namely, the High Level Research and Analysis Report and the Feasibility Study Report.

A summary of the key findings is shown below:

INVESTIGATION OF NETWORK ISLANDING			
Key aspects		**Output**	**Comment**
	**Technical**		Our research into case studies and network modelling confirms that network islanding is technically feasible.
	**Legal & Regulatory**		Current legislation and regulations would allow network islanding to be developed for trial purposes. However, in the future network islands are possible.
	**Commercial**		Commercial assessment of financial benefits resulted in negative Net Present Value (NPV) analysis.

The **technical feasibility** of forming network islands was one of the first areas to be investigated as part of the project. The technical element of the investigation was divided into separate stages including: a literature review of existing network island case studies across the globe; the different configurations available for network islands; identification of trial areas for islands on the WPD distribution network; and preliminary designs for implementing network islanding and power system studies. The staging of the technical assessment was deliberate with each one being completed consecutively so that the learning from previous stages informs the development of each subsequent stage. It became apparent during the initial data gathering and high level review stages that both temporary and permanent operation of parts of a public distribution network as an islanded system was already standard practice in some parts of the world, particularly North America, where a number of different case studies were investigated by the project team. These case studies provided useful background material and highlighted not only the technical challenges, but also some of the legal and commercial implications of operating islanded networks.

The technical information gathered during the initial stages helped inform the subsequent analysis and research into the equipment and control systems that would need to be adopted to allow existing parts of the distribution network to be islanded. This stage focussed on understanding the switchgear, operating modes, protection systems, control methods and earthing systems. The results of the research and analysis showed that the equipment and control systems for islanding are available commercially from leading manufacturers. In recent years, manufacturers have also been developing bespoke control systems for microgrids which would also be compatible for network islands. The project team engaged with a number of leading equipment manufacturers regarding these control and protection systems and the information from these discussions have been used to develop cost estimates that have been subsequently applied in the cost-benefit analysis for network islanding.

The identification of preliminary trial areas in WPD's East Midlands licence area also formed part of the technical feasibility work. The project team obtained data from various WPD sources to locate and assess areas of the network that could be configured to operate in island mode. A wide ranging selection of trial areas were identified across the licence area that possessed the basic requirements for islanding such as, controllable generation with multiple units, correct balance of load and generation capacity, no sensitive customers etc. However, research found gaps in network, load and/or generation data in some of the trial areas. The missing data prohibited detailed analysis and resulted in some areas being excluded from further assessments. Notwithstanding this, there was sufficient data available to develop detailed network models for two of the trial areas. Power system studies were performed on these network models to understand the impact that islanding the network had on load flows, fault levels and transient stability. The results from the power system studies were positive and demonstrated that operating the trial areas as islanded networks was feasible in both steady state and transient conditions. The studies also provided the necessary information to allow the settings of protection systems to be changed which is a prerequisite for any network that would move from grid connected to islanded mode.

The findings from all the technical investigations and studies carried out for the project, summarised above, show that it is completely feasible to disconnect parts of the distribution network and operate these as network islands that can seamlessly re-connect back to the main grid. Before the network can be islanded studies need to be performed to understand the exact modifications that are required to the network to ensure that it operates with statutory limits and react correctly to system faults.

In addition to understanding the technical feasibility of network islands, the project also considered the main factors for selection of potential network islands. The studies and analysis throughout the project have highlighted specific factors that have an impact on the suitability of a network to be operated as an island.

Using this information it is now possible to identify the areas of the network that would be most suitable for network islanding, quantify the technical requirements, assess the performance of the network and calculate equipment costs to implement the island.

The **legal and regulatory** requirements for adopting network islanding were identified as a key aspect that should be investigated during the inception of the project. The following documents have been reviewed as part of this activity: Energy Networks Association (ENA) (Open Networks Project and Common Distribution Charging Methodology (CDCM) user guide); Ofgem (Licence Conditions and documents relating to Significant Code Reviews); industry codes (Distribution Code and Distribution Connection and Use of System Agreement (DCUSA)); Elexon (white paper); and WPD (Distribution System operator (DSO) strategy and operability framework documents).

The review did not indicate any issues that would prevent a trial of network islanding. Technical requirements for the implementation of islands, including control system, monitoring and earthing, have been identified to ensure compliance with the Distribution Code. It is recommended that the regulatory sandbox for commercial arrangements under DCUSA, established by Ofgem, would represent a prudent way to implement a trial of the network island solution. In addition, integration of new modules to Distribution Network Operator (DNO)systems is likely to occur as part of the transition to the DSO role. It is anticipated that additional system functionality, as well as new contractual agreements, would enable DSOs to operate islands.

A relatively minor modification to the existing Elexon balancing and settlement system has been identified, which could be used as a mechanism to support network islands. This includes implementation of a new Customer Notification Agent to ensure that correct energy volume data is transferred between parties.

There is no indication that network islanding necessitates changes to the regulatory framework relating to technical operation of the network, and anticipated changes as part of the DSO transition are likely to complement islanding. However, whilst network islanding is a source of flexibility for DSOs, it is not appropriate for DSOs to treat islanding as a flexibility service in competition with, and potentially substituting for, services obtained through competitive procurement.

Based on the review of the charging arrangements, it is not deemed appropriate to reduce Use of System (UOS) charges for particular customers as a result of network islanding. Thus, it is concluded that any financial benefits should be shared between all customers through the calculation of CDCM charges. In addition, ongoing external activities relating to charging arrangements are anticipated to complement network islanding.

In summary, network islanding can be implemented within the existing legal and regulatory framework. However, updates to statutory documentation would be required to remove ambiguity and make explicit provision for network islanding for it to be rolled out across GB. In addition, it is anticipated that changes to the regulatory framework as part of the DSO transition are likely to complement islanding.

A key aspect of the Network Islanding Investigation was to understand and quantify the **commercial benefits** that could be achieved through islanding networks. The WPD charging statement and Common Distribution Charging Methodology (CDCM) model for 2020/2021 charges has been reviewed as part of this work, along with deliverables from other WPD innovation projects.

The investigation into the existing commercial frameworks and possible revenue streams for the trial areas has shown that it is difficult to achieve sufficient financial benefits. The cumulative NPV in 2039 is negative in all cases, with the highest NPV observed for the cases where islands are operated for a shorter duration in the year. This means that, on the basis of the current analysis, the costs to implement the network islands are not recovered from the derived benefits.

For network islands EM1 and EM2 the cumulative NPV in 2039 is limited to between -£357,000 and -£457,900 for an annual islanded duration of 10%. The change from the positive NPV results that were indicated in the Feasibility Study is a result of the switch from the top-down to the bottom-up approach to assessment of financial benefits. The change in approach is principally borne out of the need to ensure fair sharing of benefits between customers inside and outside of any island. Where network islands are implemented by DNOs there would be no change to the basis of the calculation of Distribution Use of System (DUOS) and Transmission Use of System (TUOS) charges, resulting in common charges for all customers of the same category across the relevant licence areas. As such, any potential benefits from network islanding would be shared across all customers and not restricted to the customers islanded at the behest of the DNO. Unfortunately the benefits determined through the bottom-up assessment are lower than those estimated using assumptions as part of the top-down assessment.

It should be noted that the nature of specific reinforcement projects that may be avoided, local generation constraints and associated benefits are specific to the location of prospective network islands. Also, additional DSO service revenues may be achieved through network islanding (or displacement of the need for services provided by others). However, there is potential impact on the competitive market for DSO services and this is deemed to be inappropriate based on the findings about regulatory considerations.

In summary, the investigation into the existing commercial frameworks and possible revenue streams has shown that it is difficult to achieve sufficient financial benefits. This means that the costs to implement network islands are not recovered from the derived benefits, but location-specific benefits and potential additional revenue streams should be reviewed again in 2-3 years.

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Appendices

Appendix A – Network Modelling Report

Appendix B - Correspondence with equipment manufacturers

1. Introduction

1.1 Context of project

Around the world, low carbon technologies (LCTs) have led to a trend of generating power locally to customers from Distributed Generation (DG) connected to the distribution system, including renewable energy resources. Due to rapid demand growth, the system requires an increasing amount of generation. Enhanced use of renewable generators within distribution networks calls for a growing level of network flexibility, whilst maintaining the existing standard for safety. It is expected that the utilisation of Distributed Energy Resources (DER) will support the transition to generate low carbon power with much lesser environmental impact and lower costs for customers.

Islanding of DG under current practice should be avoided. Typical safety schemes for DG include under/over voltage and under/over frequency protection, which prevent continued supply to customers in an islanded section of the network. In addition, Loss of Grid protection ensures that disconnected circuits remain de-energised and thus enabling a safe and secure network.

The Network Islanding Investigation project aims to understand whether intentional islanding of certain sections of network would allow them to be operated in a safe and secure manner, and whether this represents a new tool for Distribution Network Operators (DNOs) to increase network flexibility. The theory is that network islanding could provide significant benefits for customers and support DNOs with the transition to Distribution System Operator (DSO).

1.2 The aim of this report

The Investigation Findings Report presents the work of the Further Investigation and Network Modelling activities in the project. These activities follow on from previous work comprising literature reviews, data gathering, high level review, research and analysis, and the Feasibility Study. Further research has been carried out on aspects identified in those earlier reports and updates have been made to the quantitative modelling of financial costs and benefits.

The work done previously as part of the high level review, research and analysis activities explored the considerations for network islanding relating to: technical; legal; regulatory; and commercial aspects. Following this wide reaching research, the work on the Feasibility Study focused on assessing the feasibility of network islanding in specific trial areas through development of the Cost Benefit Analysis (CBA) and further review of the considerations.

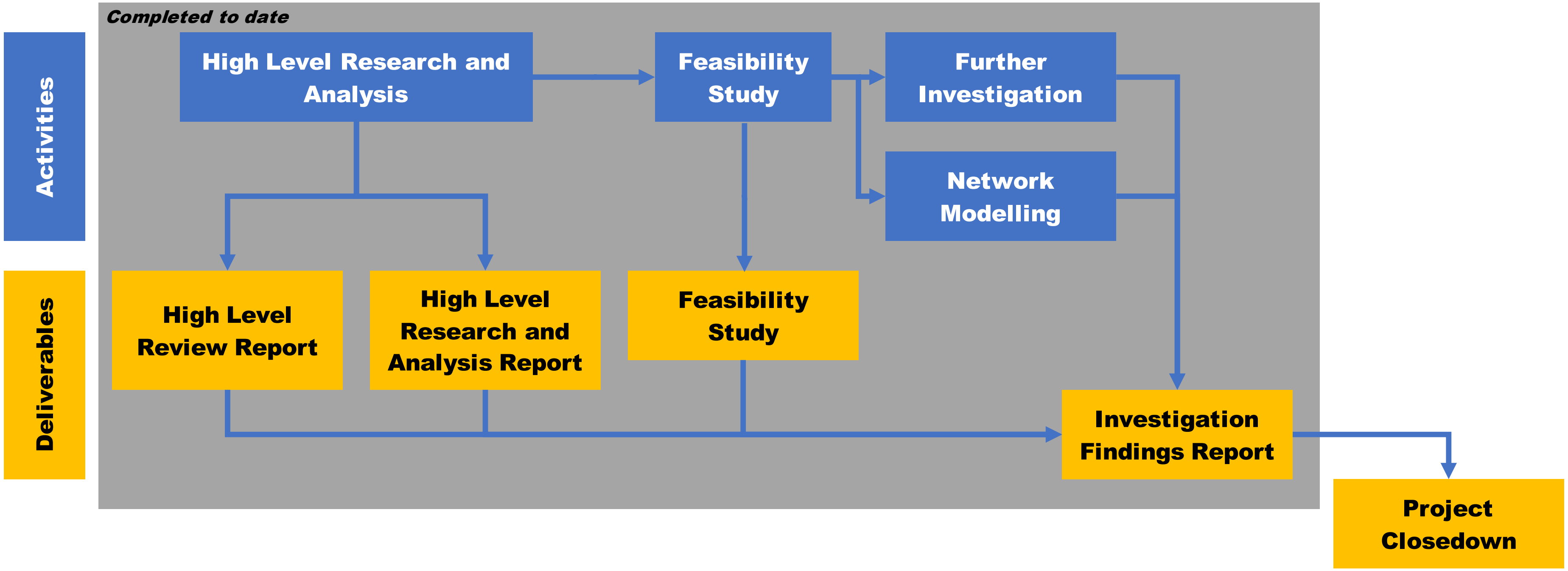
The high level review, research and analysis found that network islanding was both technically and commercially feasible and could provide opportunities for financial and carbon savings compared with the non-islanded case. Further quantitative analysis was summarised in the Feasibility Study Report where a process for identifying network islands was presented along with a more detailed evaluation of the potential financial benefits.

1.3 Tasks and deliverables

Table 1.1 highlights tasks 5 and 6 of the Network Islanding Investigation project, which are the subject of this report.

Table 1.1 Network Islanding Investigation tasks

Task 1: Data Gathering
Task 2: High-Level Review
Task 3: High-Level Research and Analysis
Task 4: Feasibility Study
Task 5: Further Investigation
Task 6: Network Modelling


Completed to date
Activities
Deliverables
High Level Research and Analysis
Feasibility Study
Further Investigation
Network Modelling
High Level Review Report
High Level Research and Analysis Report
Feasibility Study
Investigation Findings Report
Project Closedown

2. Technical requirements

2.1 Overview

This section provides further detail on the technical requirements that are needed to facilitate network islanding on the GB distribution network. The information presented has sought to further build upon and refine the research carried out in the High Level Research and Analysis Report (HLRAR) and Feasibility Study Report completed as part of this investigation. In addition, the following sections have considered specific findings from the detailed network modelling exercise carried out as part of this report. Finally, the findings of an engagement exercise with equipment manufacturers that are able to offer network island solutions to network operators is summarised in detail.

2.2 Technical requirements

2.2.1 Protection requirements

The network modelling results presented in Appendix A show that there is a considerable reduction in fault levels when the network is islanded compared to the grid-connected case. In the islanded case the fault level infeed from the grid is no longer present and this accounts for the observed reduction in fault level.

Overcurrent protection

The islands in this study require to be able to operate both grid-connected and islanded from the interconnected network. Therefore, the overcurrent protection relays located in the island will need to change their protection settings based on the status of the Point of Common Coupling (PCC) circuit breaker to account for the different fault levels in each operational mode. This is described in the diagram presented in Figure 2.1. To implement this scheme the overcurrent relays within the island need to be able to change their settings based on a digital input signal from the network island control system. This functionality is widely available in modern numerical relays that allow a range of group settings to be programmed into the relay's internal software.

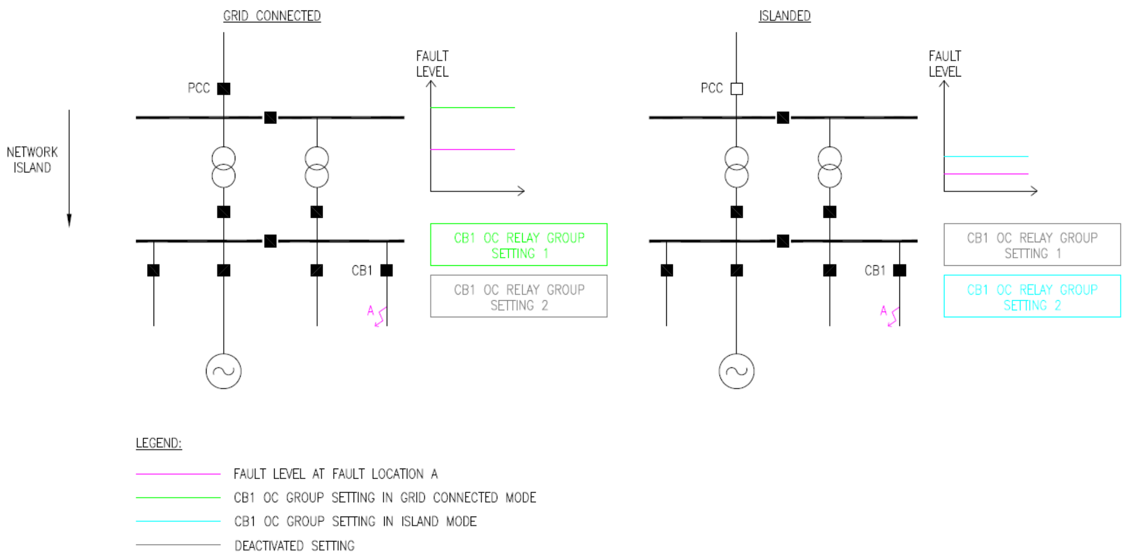


Figure 2.1 Overcurrent group settings in grid-connected and island modes

An important requirement for network islanding is the need for a sufficient margin of fault current above the normal load current to allow the overcurrent schemes to be graded correctly i.e. to ensure that there is proper discrimination of faults in the island. It is proposed that the fault current is a minimum of twice the load current at all points within the island to ensure there is adequate discrimination. This is described and studied in detail within the network modelling report in Appendix A.

Unit protection

There are limited instances of unit protection schemes on the 11kV networks (with the exception of busbar protection schemes at the primary substation and dedicated 11kV feeders); however, these types of schemes become more common on the 33kV network, in particular for the protection of underground cable circuits.

It is not anticipated that islanding networks will have an effect on existing unit protection scheme settings as they rely on the balance of current flowing within the protected zone, unlike overcurrent protection that relies on absolute current magnitude and duration. Since fault levels are generally lower in islands compared to the grid connected case, it is important that a protection study is implemented to check that the circulating current under fault conditions is above the minimum relay setting to ensure sufficient sensitivity of the scheme. Furthermore, unit protection schemes normally employ an overcurrent backup function and this would be subject to change if an island is implemented.

Distance protection

Distance protection is common on overhead 33kV distribution networks. This type of protection scheme monitors both current and voltage at the relaying point to calculate the impedance of the protected line. The relay detects a reduction in the impedance of the line if a fault occurs in the protected zone.

It is unlikely that distance protection schemes will be affected by network islanding as they utilise calculated impedance as the method for fault detection. However, the correct operation of any distance scheme will have to be carefully considered through a detailed protection study as part of the preliminary design phase of any future island installation.

Protection study

A key technical requirement to enable a technically feasible, reliable and safe island will be the implementation of a detailed protection study in the design phase of the project. This study will firstly identify the existing schemes, relay types and settings in the proposed network island. Secondly, the network will be modelled and a range of fault scenarios will be applied to understand the various fault levels (both grid connected and island modes). After this information has been acquired, the design of new or modified schemes can commence, using the network model as a tool to validate the new designs.

2.2.2 Supply metering

An important requirement will be to ensure that the island has suitable metering equipment installed at the PCC. The main purpose of the metering will be to provide accurate measurements of the power flows at the boundary of the island, which will be important for monitoring the stability of the island. In addition, the metering data will feed into the settlement systems and form the basis of any subsequent financial benefits and/or flexibility services, if these are employed.

In this case, it is proposed that half hourly (HH) metering is required at the network island PCC. A dedicated metering Current Transformer (CT) and Voltage Transformer (VT) housed within a metering panel at the PCC site will be required given that this study is concerned with Extra

High Voltage (EHV) and High Voltage (HV) network islands. The metering panel and associated transducers are to be Code of Practice 2 (COP2) compliant as the islanded demand will not exceed 100MVA.

2.2.3 Generator control

The network island control system will need to interact with the generator Automatic Voltage Regulator (AVR) and governor parameters and set-points to provide the basic network island functionality such as synchronisation/disconnection from the grid, load following, load sharing and droop control. This interface is typically provided by a third party local controller installed at the generator customer's site that is able to communicate with the generator control system via the incumbent compatible protocol. A schematic diagram showing a high-level island control system is given in Figure 2.2.

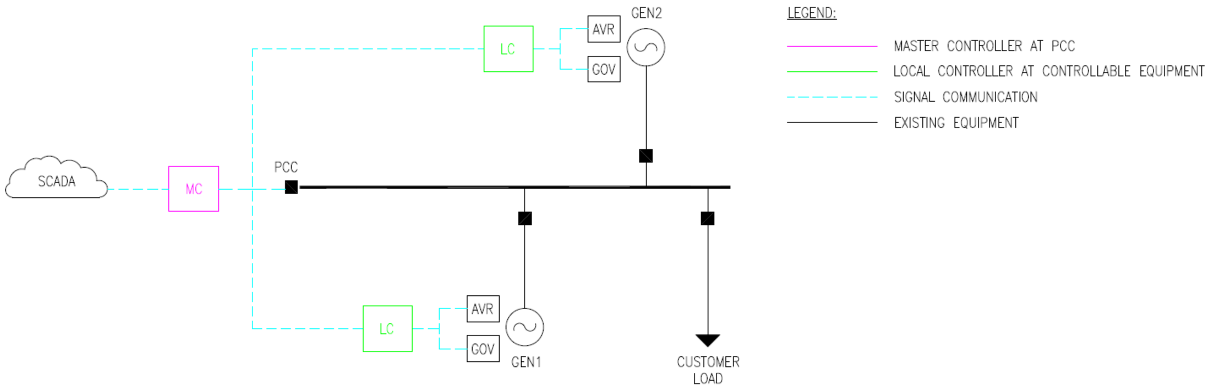


Figure 2.2 High-level island control system

An important requirement will be to study existing generator control systems at an early stage of any project looking to trial a network island, preferably at the site identification stage. There will be significant cost attributed to upgrading the AVR and governor of the generator as well as significant disruption to the customer due to outages to allow for the equipment installation. Therefore generators considered for a prospective island shall have the capability to interface to a third party controller. The majority of controllers are manufactured with the flexibility to communicate over a wide range of different industry standard protocols and therefore cater for generators of different ages.

2.2.4 Seamless transition between island and grid connected modes

A number of conditions must be achieved before a HV circuit breaker is closed to parallel two asynchronous distribution networks. Firstly, the line voltage must be the same between the two networks. Secondly, the frequency slip (frequency difference) and the phase angle of the voltage should be the same at either side of the circuit breaker. Paralleling asynchronous networks without meetings these conditions can cause large current and voltage transients (similar to electrical faults) that can damage electrical infrastructure and present a severe health and safety risk.

In the case of network islanding, control systems are required to ensure that the island can be disconnected from the main interconnected network and resynchronised back to the grid in a stable and seamless manner to ensure that no disruption is experienced by customer supplies.

The synchronisation of the network island to the interconnected grid is normally implemented via a synchronising relay located at the PCC. A synchronising relay includes a 'synchrocheck' element that measures the voltage difference "ΔU" (amplitude), the frequency slip "s" and phase-angle difference "α" between two measurement signals U1 and U2 as shown Figure 2.3.

The synchrocheck function requires the voltage amplitude, slip and phase-angle to be within pre-set margins before the relay releases the breaker to close and parallel the two networks. In the case of a synchronising relay with only the synchrocheck element, manual commands have to be sent to the generator AVR and governor to adjust the measured parameters so that they are synchronised. It also requires a manual command to close the paralleling circuit breaker when synchronising conditions have been fulfilled.

The more advanced synchronising relays include both synchrocheck and independent fully automatic synchronizing elements. The automatic elements include a matching function that can automatically adjust the AVR and governor controls to regulate voltage and frequency parameters to the required set-points. Once these set-points have been achieved the relay is able to generate a command to automatically close the breaker at the PCC. The closing command can be timed to take into account the time delay for circuit breaker contact closing so the parallel is made with minimal transient disturbances.

The transition from grid-connected mode to island mode is simpler than the synchronisation process. The real and reactive power flow at the PCC circuit breaker needs to be monitored and reduced to zero before opening the PCC breaker. This is done by increasing or reducing the generator(s) output so that it matches the demand in the island. The PCC breaker can then be opened and the two networks disconnected with minimal transient voltage and frequency disturbances. The process of disconnection, much like island synchronisation, can be implemented manually by network operatives, or automatically by an island control system dependent on the operational requirements.

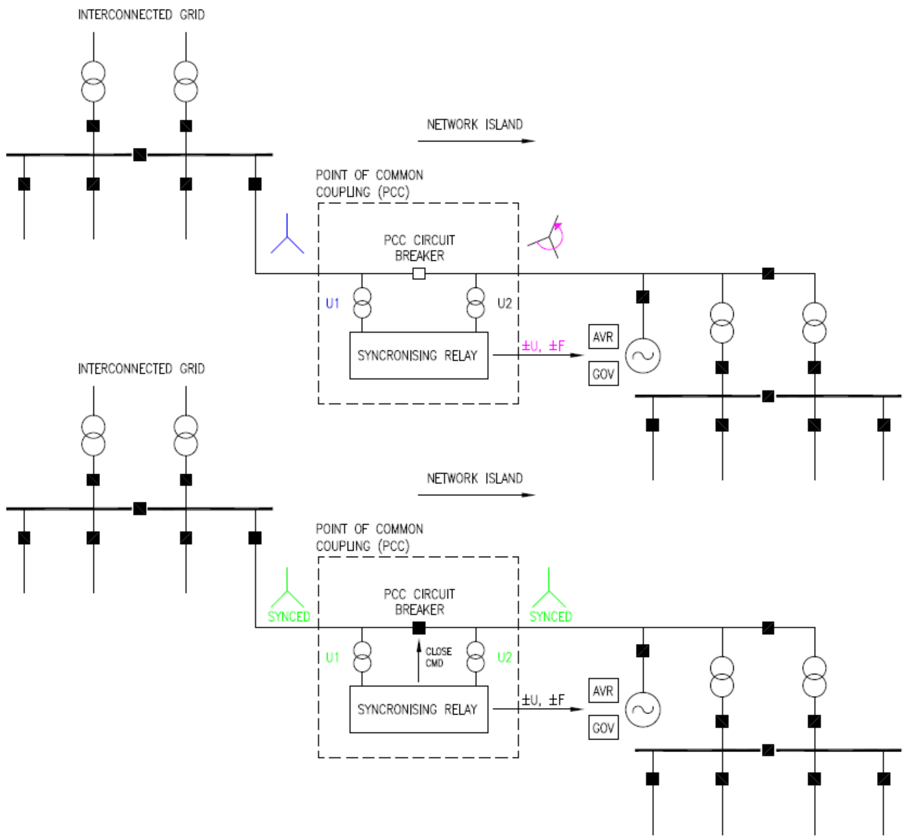


Figure 2.3 Seamless reconnection of island to the main interconnected grid

Available Supply Capacity (ASC) is an agreed maximum demand that the DNO is required to make available to a customer's supply. It is measured in kVA and is only charged on half hourly metered supplies. This quantity is a contract between the customer/end user and the DNO. The charge itself is published and levied by the DNO through the Electricity Supplier to pay for the infrastructure and ensure delivery of the contracted capacity.

The ASC is not applicable in the case of DNO owned and operated islands that are the subject of this investigation. This is because the island is a DNO asset. ASC will have to be considered more carefully for third party owned and operated islands (both new developments and existing networks) that will require a connection agreement between the third party owner and the DNO. This connection agreement will likely include the ASC that is required by the third party in the event that the island is not available i.e. the peak demand is supplied by the grid due to a planned or unplanned outage of the island.

There is an argument that the nominal ASC charges could be reduced for this type of island on the basis that the island operates disconnected from the grid for the majority of the time. However, the ASC charging regime for third party owned and operated islands is beyond the scope of this report and has therefore not been carried out in detail. If these types of ownership model were to be investigated in the future, ASC charges would have to be considered in detail as part of this further investigation.

2.2.5 Security of supply

The security of supply requirements for UK distribution networks is provided in Engineering Recommendation (EREC) P2/7. This document is published by the Energy Networks Association (ENA) and came into effect on 10 August 2019. This revision of the standard has superseded the previous revision of the document (P2/6).

Table 1 in P2/7 classifies Group Demand (MW) into different ranges and specifies the restoration requirements for the each of the classifications under first and second circuit outages. The maximum demand in a network island on the distribution network is most likely to fall into either Class B (over 1MW and up to 12MW) or Class C (over 12MW and up to 60MW). It is unlikely that the Group Demand of a prospective island will be in Class D (Over 60MW and up to 300MW) or above as this would necessitate the presence of a large amount of controllable generation. In the case of Class D, the controllable generation would have to sum to a minimum of 90MW based on the assumption that the controllable generation in the island is to be at least 150% of island peak demand. There is a low probability that this level of controllable generation will be co-located on the 33kV or 11kV distribution network to form a feasible network island.

The extract of Table 1 from the P2/7 is shown in Figure 2.4 and shows the Group Demand restoration requirements for Class B and Class C supplies.

		Minimum demand to be met after*	
Class of supply	**Range of Group Demand**	**First Circuit Outage**	**Second Circuit Outage**
A	Up to 1MW	In repair time: **Group Demand**	Nil
B	Over 1MW and up to 12MW	(a) Within 3 hours: **Group Demand** minus 1MW (b) In repair time: **Group Demand**	Nil
C	Over 12MW and up to 60MW	(a) Within 15 minutes: Smaller of (**Group Demand** minus 12MW); and 2/3 of **Group Demand** (b) Within 3 hours: **Group Demand**	Nil

Figure 2.4 Extract from P2/7 Table 1

If the island is formed from existing distribution network, it can be assumed that the island will be compliant to P2/7 requirements when interconnected to the main network. When the island is disconnected from the main interconnected network, the worst case N-1 condition (i.e. the first circuit outage) will be the loss of the island generation. This corresponds to a loss of the total island Group Demand. The total Group Demand can be restored via the PCC circuit breaker by connecting the island to back to the interconnected network. However, the restoration of supplies will need to be preceded by a significant amount of network configuration so that supplies are restored in a step-by-step fashion to avoid sudden overloading the upstream interconnected network. This could be achieved manually by a control engineer or automatically via a sequence switching scheme. Irrespective of the method, it is clear that the total Group Demand would be able to be restored within the 3 hour requirement for Class C network islands (and therefore also satisfying Class B requirements).

An island could be configured such that the generation shares a common connection to the PCC. In this instance, a network fault causing the first circuit outage would disconnect the generation and also isolate the PCC so that it cannot be used for supply restoration (i.e. the line is faulted). In this case, supplies will have to be restored by 11kV backfeeding from adjacent networks or via an alternative PCC (if this exists).This scenario is apparent for the existing network without the application of network islanding and therefore a suitable restoration procedure should already be available and compliant to P2/7 requirements.

For larger islands falling into the Class C bracket it is probable that a sequence switching scheme will be used to reconfigure the network following the occurrence of the first circuit outage. The restoration of supplies is likely to be completed within the 15 minute requirement as stated in P2/7 Table 1 if a sequence switching scheme is employed.

2.2.6 Impact of potential uncertainties on islanding

National Grid, in its role as Electricity System Operator (ESO), publishes Future Energy Scenarios annually [1]. The key points from the 2019 Future Energy Scenarios (FES) document are summarised as follows:

- It was recognised that the volume of microgeneration (below 1MW) and generators connected to the distributed network has increased in recent years. National Grid (NG) has considered the decentralisation trend in its future scenarios. Particularly, the “Community Renewable” and “Consumer Evolution” have assumed constant growth in distribution connected generation. Therefore, the generation sector would be relying more on distributed resources. Network islanding could be implemented where the constraints on generation export would occur to allow the connection. Also, it could enable customers to use on-site located generation and benefit from a reduction of the energy prices.
- The “Community Renewable” scenario envisages local energy communities to act as coordinating utilities for power and/or district heating. It is assumed that in the more decentralised system, the consumer would be more engaged with their energy production and usage. Therefore, under this scenario the appeal for adopting network islands could be fairly high, allowing consumers to control and manage resources locally.
- Support for generation and storage technology development as well as introducing new commercial schemes is a key requirement for providing a platform for other innovation solutions for local communities.

Western Power Distribution (WPD) has developed the Distribution Future Energy Scenarios (DFES) [2] which has been updated for East Midlands in August 2019. These scenarios are used as inputs to the WPD Strategic investment options: Shaping Subtransmission analysis [3]. The DFES and Shaping Subtransmission documents are summarised as follows:

- The growth in connection applications for distributed generators and batteries has been recorded within the scenarios and they could impact future demand on the network.
- In response to network progress towards decentralisation, changes are likely to be implemented in the calculation of costs for new connections to the grid and use of system charges. The changes to network charging could lead to significant uncertainty for future projects.
- The analysis of the Subtransmission network for WPD is carried out to identify constrained areas of the network. The studies are used to assess options for reinforcement of network and provide recommendation for alternative solutions and investment.

2.3 Engagement with equipment manufacturers

As part of the Further Investigation we have engaged with eight different equipment manufacturers to understand the different equipment and system elements that are required to create stable and reliable network islands. In addition, more detailed and accurate equipment costs have been obtained to better inform our financial model and therefore provide more accurate quantification of the financial benefits of network islanding. The following sections detail and summarise this. A detailed record of the all correspondence with the manufacturers is given in Appendix B

2.3.1 Primary equipment

Network island control systems

Throughout the engagement process with manufacturers, and also through our independent research into network islands, it has become apparent that a dedicated control system is required to manage the technical processes of the island to ensure it operates in a safe and stable manner. The network islands that are the focus of this study are relatively simple in terms of structure i.e. they only have a single controllable generating source and do not contain any intermittent generation or battery storage facilities. It has therefore been found that a relatively basic control system can be deployed on this basis. The main functionality of the control system would be:

1. Synchronisation for reconnecting to the island to the grid – The control system will interface with the synchronising relay to control the generator AVR and governor output to enable synchronisation of the island and grid voltage prior to paralleling the networks;
2. Disconnection of the island from the grid – The control system will have the functionality to automatically prepare the island for disconnection from the grid (i.e. a seamless transition) by modulating the generator power output; and
3. Island stability – The control system controls the dispatchable generation inside the island to maintain the voltage and frequency of the network island.

There are a wide range of manufacturers that are able to supply complete island control systems that satisfy the basic requirements outlined above. They typically have numerous case studies highlighting practical application of the technology across the globe and also demonstrate that the technology is relatively mature. There are typically two different control philosophies dependent on the manufacturer. These are summarised as follows:

1. A centralised control system that is a combination of hardware and software installed at a strategic location within the network island. This system typically requires local controllers to be installed at each dispatchable asset (i.e. generators, batteries etc.) within the island to enable the control system to communicate with the distributed assets. In this way the

local controllers act as an Remote Terminal Unit (RTU) to send and receive signals from the central controller; and

2. A decentralised control system that incorporates a microgrid controller at each point of control within the island i.e. there is a controller at each grid synchronisation circuit breaker and at each controllable generator etc. Each of the microgrid controllers can operate as the “master” unit and provide the intelligence to coordinate the remaining slave units. This philosophy is adopted for improved resilience i.e. if the master unit fails, a slave unit is automatically promoted to take over the master duties at another location in the island.

The philosophies described lend themselves to being modular and scalable. For example, if an additional generator connects to the island, the island is expanded with an additional local control unit and the control parameters adjusted accordingly. The control systems are all able to interface with the network operator’s Supervisory Control and Data Acquisition (SCADA) system and provide both local and remote Human Machine Interface (HMI) facilities to enable site or control room operatives to configure and monitor the network island systems.

The control system will need to become more complex if there are multiple synchronisation points to the main grid and if there are multiple generators connected within the island. This is further exacerbated if a contingent of the generation is renewable (i.e. intermittent) and battery storage is connected. This is due to there being more points of control within the island, which translates into the need for greater coordination between the island assets for the correct implementation of grid disconnection/synchronisation and system balancing. In addition, the complexity is dependent on the requirements of the control system to achieve other overall system objectives, other than those described above. For example, most of the manufacturers implement sophisticated cloud based hardware and software systems, akin to a downscaled Network Management System (NMS), which carry out advanced island management tasks, for example:

- Autonomous management of dispatchable island assets i.e. generation, battery storage, intelligent load etc;
- Optimisation of power flows within the island for customer benefit e.g. to maximise the use of renewable power or to reduce fuel costs; and
- Utilising pricing and weather forecasts to inform the management of the island based on pre-defined rules.

The cost of these sophisticated systems has not been factored into our analysis as the islands investigated in this study are relatively simple and do not contain the levels of intermittent generation, controllable load or battery storage that would be required to justify the additional expenditure. Furthermore, this study is limited in scope to investigating the financial benefits to customers within a network island due to reduced Use of System (UOS) charges, or the socialised benefit through release of network capacity and associated avoidance of traditional reinforcement. The analysis of benefits generated by advanced resource management within the island is not within the scope of this project.

Generator control systems

The existing control systems of controllable DG connected to WPD’s 33kV distribution network will have a range of different equipment and communications protocols dependent on the age and size of the generator. It is assumed as part of this study that the generator in question has a controllable AVR and governor that is able to interface to a third party control system. From our discussions with the various manufacturers, generator control is typically provided by a controller situated locally at the generator. The local controller is essentially a specialised RTU device that allows the main centralised network island control system to interface with the local generator control system for island management tasks. The local controller can either be a wall mounted panel, or a rack mounted solution and would likely be installed at the generator's control room facility. A high-level cost estimate for a local generator controller is approximately £50,000.00 per generator.

Protection systems

It was clear during the discussions with the manufacturers that the protection equipment requirements are highly specific to each individual network island and therefore it is difficult to propose a high-level cost without an in-depth survey and study of the protection scheme requirements.

It has been observed that the fault level at the 33kV and 11kV busbars in the islands reduces significantly in island mode when compared to the existing grid-connected configuration. This has been demonstrated in our network modelling results. Therefore, it is likely that the majority of the overcurrent protection relays would need to be replaced with modern relays that are able to accept multiple group settings and automatically switch between these settings dependent on mode of operation of the island i.e. Circuit Breaker (CB) indications from the PCCs.

For the purposes of this study it is prudent to assume that all existing overcurrent relays within the island would need to be replaced with modern equivalents that are capable of group setting functionality. This allows for a conservative cost estimate with the overall cost of the protection system found by multiplying the cost of a standard modern overcurrent relay with the total number of relays in the existing network island. There will be additional labour costs associated with installation of the systems, they are as follows:

- Survey of the existing protection schemes and equipment within the proposed island;
- Power system studies to determine the appropriate group settings for the new island protection schemes; and
- Testing, installation and commissioning activities associated with rolling out the new schemes within the proposed island.

2.3.2 Other equipment

There are other costs that have to be taken into consideration when implementing network islands. These are described as follows:

Neutral earthing

The networks forming the islands investigated in this study have existing neutral earthing points at the secondary windings of the 132/33kV Bulk Supply Point (BSP) and 33/11kV primary transformers thus ensuring that there is a suitable path for earth fault current on the 33kV and 11kV networks under grid connected mode. The 33kV system becomes un-earthed when the island disconnects from the grid and therefore an additional path for earth fault current is required. A switched Neutral Earthing Resistor (NER) and earthing transformer combination should be employed. The NER is to be rated so that the earth fault levels of the island match the earth fault levels when grid connected so that the earth fault protection settings shall remain valid. It is anticipated that the additional earthing equipment would be installed on the HV side of the generator step-up transformer. The estimated cost is approximately £30,000.00 for an earthing transformer and approximately £10,000.00 for a switchable NER based on generic unit cost information.

Interlocking

We have assumed that there will only be one synchronising circuit breaker for each the islands investigated in this study. However, these island networks have other circuit breakers that are able to parallel the island and the grid networks. An interlocking scheme is therefore required to ensure that these circuit breakers are not able to parallel the two networks when they are out of synchronisation. Only the synchronising circuit breaker can perform this function to reconnect the island to the grid. In practice the interlocking scheme would likely be designed by the manufacturer responsible for the overall network island installation and an estimated cost would be £20,000.00 per island.

Supply and metering

The detailed metering requirements for network islanding are described in Section 2.2.2. It has been proposed to install a COP2 compliant metering panel at the PCC to ensure that there is sufficient metering accuracy for settlement purposes. The cost associated with a panel of this kind is approximately £5,000.00 from previous WPD installations.

2.3.3 Updated equipment cost summary

The following sections summarise the equipment costs for the islands considered in this study based on the manufacturer engagement exercise and further research carried out for this report. The costs are more detailed and build on those provided in the Feasibility Study Report. These revised costs have been included in the revised cost benefit analysis described in Section 5.5.

To be consistent with the Feasibility Study Report, the costs have been split into two categories:

1. Fixed costs – These costs are common to each of the islands (EM1-EM4); and
2. Variable costs – These costs are different for each of the islands and are attributable to the cost of new switchgear and the replacement of protection relays that are not suitable for islanded operation.

Fixed costs

The fixed costs are presented in Table 2.1.

Table 2.1 Fixed capex costs

Technical solution	Comment	£/day	Man-days	Unit cost (£k)	Units per island	Subtotal per island (£k)
Network island master controller	-	-	-	100	1	**100**
Network island local controller	-	-	-	50	1	**50**
Network island control software	-	-	-	25	1	**25**
Synchronising panel (inc.sync relay)	-	-	-	25	1	**25**
HMI and workstation	-	-	-	10	1	**10**
Neutral Earthing Resistor (NER)	-	-	-	10	1	**10**
Earthing/auxiliary transformer	-	-	-	30	1	**30**
Interlocking	-	-	-	20	1	**20**
Supply and metering	-	-	-	5	1	**5**

Technical solution	Comment	£/day	Man-days	Unit cost (£k)	Units per island	Subtotal per island (£k)
Telecommunication systems	No change from Feasibility Study Report**	-	-	100	1	**100**
Power System and Protection System Studies	No change from Feasibility Study Report**	400	30	-	-	**12**
					Total	**387**

**Note 1: The telecommunication and protection design elements of the cost have remained the same as those presented in the Feasibility Study Report. These cost elements are highly dependent on the findings of the upfront engineering work required to design a network island and therefore a more detailed cost estimate is unavailable at this stage.

Variable costs

The variable costs associated with the network islands have not changed since the Feasibility Study Report. The costs have been repeated in Table 2.2 below for completeness.

Table 2.2 Variable capex costs

Variable Expenditure Items						
Island	Technical Solution	Sub task	No. new units	Unit Cost (£k)	Cost (£k)	Subtotal (£k)
EM1	New 33kV circuit breakers	N/A	1	50	50	**-**
	Protection System Updates	Replacement of relays	32	4	128	**178**
EM2	New 33kV circuit breakers	N/A	1	50	50	**-**
	Protection System Updates	Replacement of relays	28	4	112	**162**
EM3	New 33kV circuit breakers	N/A	0	50	0	**-**
	Protection System Updates	Replacement of relays	24	4	96	**96**
EM4	New 33kV circuit breakers	N/A	0	50	0	**-**
	Protection System Updates	Replacement of relays	16	4	64	**64**
					Total	**500**

2.4 Summary of findings

This section has successfully identified and described the technical requirements needed to create manageable, sustainable and safe network islands on the Great Britain (GB) distribution network.

The engagement with various manufacturers has provided more detailed information on the equipment and system requirements for network islands. The engagement also provided a more accurate estimate of the costs attributed to the design, development and installation of islanded networks on the distribution system. The majority of the manufacturers have tried and tested equipment and systems that are able to create and manage utility scale islands. The larger manufacturers can implement turnkey solutions i.e. produce the specification, detailed design, testing, installation and commissioning.

All manufacturers that responded to our enquiries considered that the trial networks investigated in this study could be implemented as technically feasible and stable islands. A key outcome of this engagement is the learning that there is no ‘cut-and-paste’ solution for the specification and design of network islands: each island will have different requirements based on the existing equipment in the island; the number and type(s) of generation in the island; the number of synchronisation points; and the geography/architecture of the network. Each island requires detailed modelling, studies and analysis prior to committing resources for a real-world trial.

3. Network modelling

3.1 Introduction

The need for power system studies was identified at an early stage of the Network Islanding Investigation Project to understand the technical feasibility of operating network islands.

Previous work carried out during the Feasibility Study identified a number of potential network islands on the 33kV network in the East Midlands as shown in Table 3.1.

Table 3.1 Selected network islands

Island Code	Licence Area	Area	Generator Name	Generation type	Capacity / scale	Load Supplied (Primary / MW)
EM1	East Midlands	Wellingborough	Wykes Generation	Biomass Combined Heat and Power (CHP)	25.00 MW @ 33 kV	Sharnbrook / 5.6 Harrold / 1.5
EM2	East Midlands	Wellingborough	Wykes Generation	Biomass CHP	25.00 MW @ 33 kV	Little Irchester / 14.8
EM3	East Midlands	Nottingham	Redfield Road 1 STOR	Dedicated Biomass	20.88 MW @ 33 kV	Wollaton Road / 22.5
EM4	East Midlands	Halfway, Sheffield	Holbrook	Biomass CHP	5.85 MW @ 33 kV	Halfway TA / 3.3

Obtaining detailed network data for the purposes of building a representative network model was critical for the power system studies. Further investigation revealed that EM1 and EM2 had the most accurate and comprehensive set of network data, therefore, these network islands were chosen for the network modelling exercise.

Network models for EM1 (Figure 3.1) and EM2 (Figure 3.2) were built in DIgSILENT Powerfactory power system analysis software using data from WPD's existing databases, Geographical Information System (GIS) and power system software packages.

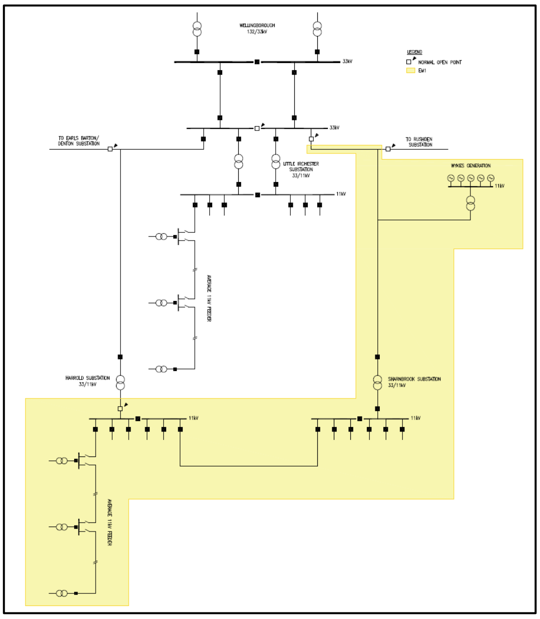


Figure 3.1 EM1 Network Island

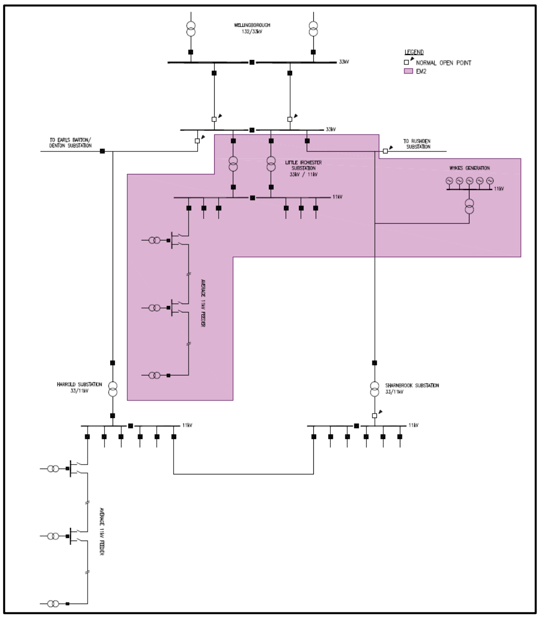


Figure 3.2 EM2 Network Island

DIgSILENT was chosen as the preferred software tool as it has the capability to conduct both steady state and transient studies identified for the islands as listed below:

- **Load flow studies including:**
  - Network loading;
  - Voltage limits;
  - Tap changer positions;
  - Generator dispatch; and
  - System losses.
- **Fault level studies including:**
  - Maximum fault level (to check required changes in settings); and
  - Minimum fault level (to ensure adequate discrimination).
- **Transient studies including:**
  - Transient line fault;
  - Generation trip;
  - Load rejection;
  - Switched in load; and
  - Generator Critical Fault Clearance Time (CFCT).

Following the completion of the studies above, further sensitivity analysis was performed to understand the effects of changing the network length and loading on EM1 and EM2.

Further details of the network data and the methodology used for building the models can be found in Appendix A.

3.2 Summary of modelling results

Appendix A provides a full description of each of the studies that were performed on EM1 and EM2.

Figure 3.3 and Figure 3.4 provide some examples of the outputs of the studies that have been performed for EM1 and EM2

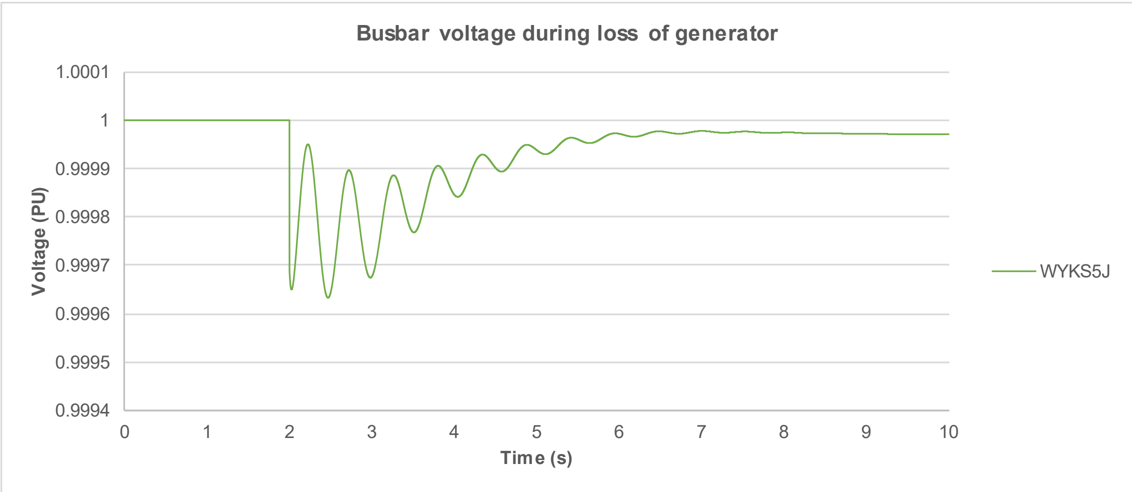


Figure 3.3 Voltage response after loss of a generator on EM1

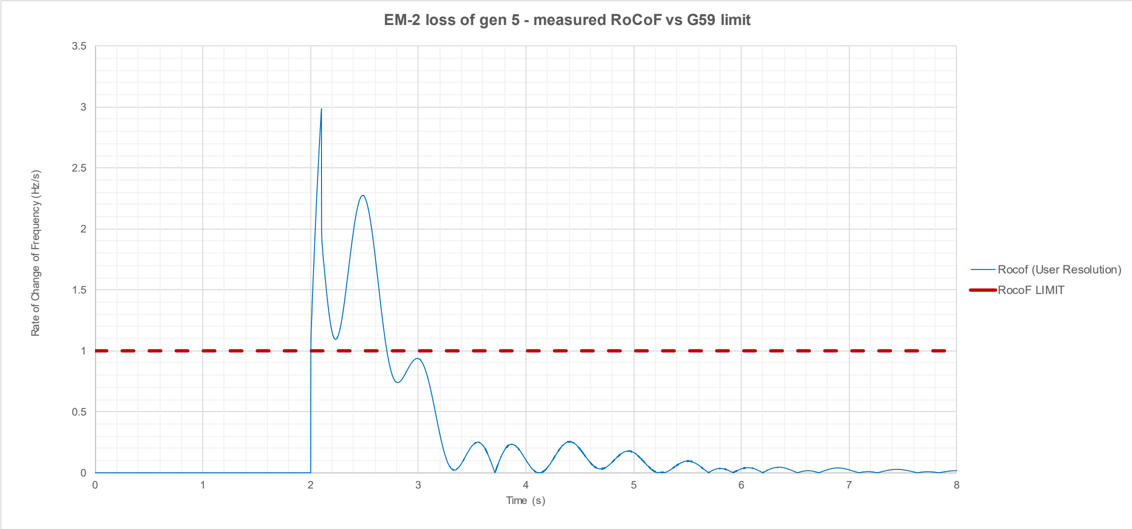


Figure 3.4 Rate of Change of Frequency (RoCoF) simulation for EM2

Table 3.2 shows the summary of the results from the network modelling exercise.

Table 3.2 Network modelling results summary

Study	EM1	EM2
Load flow	✓	✓
Fault level	✓	✓
Transient line fault	✓	✓
Generation trip	✓	✓
Load rejection	✓	✓
Switched in load	✓	✓
CFCT	✓	!
RoCoF	✓	!

✓ Study results show compliance with necessary standards/recommendations

! Study results indicate minor non-compliance with necessary standards/ recommendations

✗ Study results indicate major non-compliance with necessary standards/ recommendations

It can be seen that the majority of the studies that were completed revealed that the network islands would operate within the necessary standards and recommendations during steady state and fault conditions. However, there were two instances where a minor non-compliances were observed on EM2.

The first minor non-compliance related to the CFCT which was calculated to be 1.05s. As the existing back-up protection time is set to around 1.25s this could mean that in the event that main protection does not operate, the generator could become unstable. However, it could be possible to adjust the timing of the back-up protection to be lower than the CFCT when in island mode. This would prevent the generator from becoming unstable when operating for faults on back-up protection.

The second minor non-compliance relates to the RoCoF setting derived from G59/G99. Studies revealed that the RoCoF during the loss of the largest generator would exceed the limit of 1Hz/s for greater than 500ms (as shown in Figure 3.4). However, this setting could be relaxed for EM2 as the normal function of G59/G99 protection is to remove generation that could potentially be islanded and therefore isn’t applicable for networks operating in islanding mode.

3.3 Summary of findings

The detailed power system studies carried out have shown that is possible to operate EM1 and EM2 as network islands within statutory limits and ensure that the islands stay connected during transient events.

The studies also highlighted that the fault level in island mode is significantly less compared with grid connected system. This was identified as a potential issue in work carried out during earlier stages of the project. However, the system studies provided the necessary information to understand if protection discrimination was achievable and the indicative fault level values for the calculation of new protection settings.

Therefore, in summary it is essential that a full network modelling exercise is carried out for any potential network islands. It is expected that the majority of the distribution network where controllable generation exists could operate in island mode. However, the topology, configuration, load and generation size will have an impact on the ability of the network island to ride through faults, remain stable and provide adequate discrimination for internal faults.

4. Legal and regulatory considerations for network islanding

4.1 Introduction

This section provides details of the further investigation that has been carried out to develop and update the earlier research of the considerations for network islanding relating to the legal and regulatory frameworks. The HLRAR [4] presented the findings from the preliminary review and investigation with an overview of the concepts and requirements, and discussion of potential barriers and solutions in each of these areas. The initial broad research was followed by work on the Feasibility Study (which focused on assessing the feasibility of network islanding in specific trial areas) and, finally, this further investigation activity.

The following sections present the findings from the further investigation in each of the principle areas, including a summary of findings highlighted in a table at the beginning of each section. The principle areas for further research, as identified in the HLRAR [4], comprise:

- Compatibility of network islanding with the existing legal and regulatory frameworks, addressed in section 4.2;
- Ownership structures and operational responsibilities, including developments relating to DSO, addressed in section 4.3; and
- Charging arrangements, addressed in section 4.4.

Figure 4.1 presents an overview of relevant aspects of the existing regulatory framework, ongoing developments and anticipated future outcomes discussed in this section of the report.

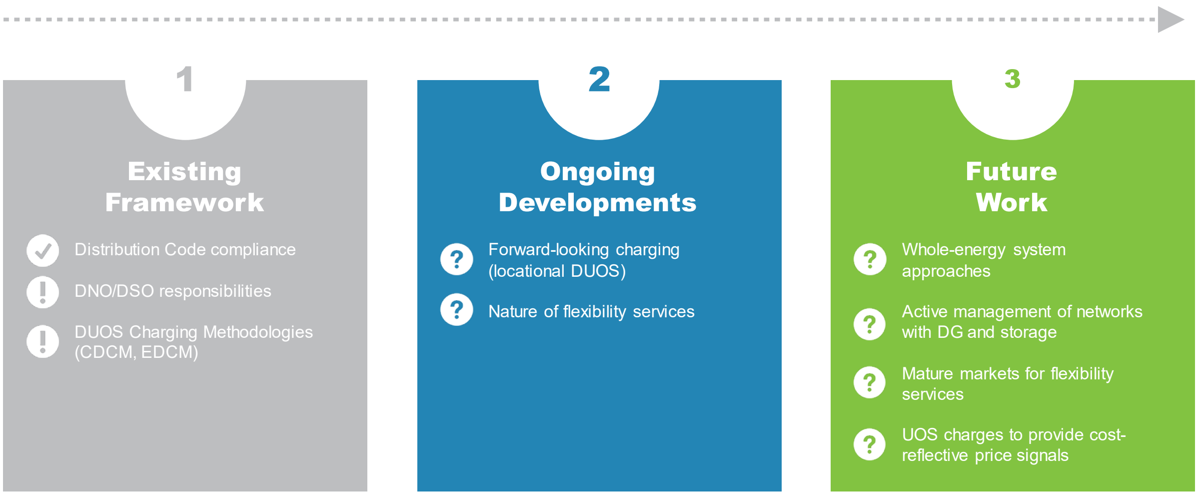


Figure 4.1 Evolution of regulatory framework

The initial research presented in the HLRAR is summarised in Table 4.1.

Table 4.1 Summary of material presented in HLRAR (legal and regulatory considerations)

Description	Legal	Regulatory
Concepts and requirements	Summary of: • Primary legislation. • Secondary legislation.	Summary of: • Electricity sector licences.

Description	Legal	Regulatory
		• Industry codes and subsidiary documents. • Evolution of the regulatory framework. • Charging methodologies. • Summary of regulatory implications for network islanding.
Potential barriers and solutions	Discussion of: • Limitations in legal definitions and explicit provision for network islanding. • Potential incompatibility of network islanding with meeting statutory duties.	Discussion of: • Rules relating to ownership and responsibilities. • Interconnection rules. • Potential incompatibility of network islanding with requirements stated in engineering recommendations. • Use of system charges methodology.

4.2 Compatibility of network islanding with the existing legal and regulatory frameworks

Sections 4.2.1 to 4.2.3 provide the findings from the further investigation relating to considerations under the first area of research, compatibility with the legal and regulatory frameworks. Table 4.2 presents a summary of these findings.

Table 4.2 Summary of findings relating to compatibility of network islanding with the legal and regulatory frameworks

- **Legal definition and provision for network islanding** - under the Government 'Smarter Systems and Flexibility Plan' the objective remains to find broad solutions, which may well support network islanding. As part of its longer term view about the Open Networks Project, the ENA envisages work to achieve 'regulatory enactment and implementation', which may ultimately result in changes to legislation. There are currently no indications that developments would prevent network islanding.
- **Areas of possible ambiguity in the Distribution Code** – this investigation shows how network islanding can be achieved whilst ensuring that the existing standards of reliability and safety are maintained (i.e. adhering to the same obligations and requirements as a normally connected network). As such, technical requirements have been identified elsewhere in this report to mitigate any potential issues and ensure that islands can be operated in compliance with the Distribution Code.
- **Distribution Licence Conditions** – the Electricity Distribution Standard Licence Conditions (SLCs) are the set of fundamental obligations imposed on licensees. There are no indications that modifications are planned that would have any impact on network islanding.

- **Regulatory sandbox** – It is recommended that the regulatory sandbox for commercial arrangements under Distribution Connection and Use of System Arrangement (DCUSA) would represent a prudent way to implement a trial of the network island solution.

There are currently no indications of future developments that would prevent network islanding, and technical requirements have been identified as part of this project to ensure compliance with the Distribution Code. It is recommended that the regulatory sandbox for commercial arrangements under DCUSA would represent a prudent way to implement a trial of the network island solution.

4.2.1 Legal definition and provision for network islanding

There have been no changes to the primary legislation relating to the electricity sector since the Energy Act 2016 (c. 20) [5]. As such, there have been no substantial changes to the legal definitions of the following terms:

- Network islands or microgrids with intentional islanding mode, which is provided for in the Distribution Code as described in section 4.2.2;
- Distribution System Operator (DSO), which is a term that is being used more and more frequently with a range of different meanings, albeit with some emerging consensus from the work of the Open Networks Project [6].
- Energy storage, which is still considered to be a subset of generation. A decision is awaited about changes to the standard generation licence conditions to take explicit account of storage [7];

As stated in the HLRAR, ‘modification of legislation naturally lags behind technological developments’. It remains to be the case that ‘ongoing activities led by the Office of Gas and Electricity Markets (Ofgem) (consultations), and work under the Smarter Systems and Flexibility Plan’ indicate that solutions are being sought with ‘potential to mitigate the barriers sufficiently such that network islanding remains feasible within the legal framework’.

Work to find solutions through the Open Networks Project, managed by the ENA, has continued throughout 2019. An annual review of the 2019 activity is anticipated in the early part of 2020, with a requirement for a subsequent Project Initiation Document (PID) to sanction further work. As part of the PID for the 2019 work (phase 3) [8], the ENA stated that it would continue to support a ‘collaborative development project along the journey to transition to DSO’ as the work evolves beyond 2019. In particular, the document envisaged ‘regulatory enactment and implementation’ in its longer term view beyond 2019. Whilst there are currently no indications that developments to the legal framework would prevent network islanding, the progress of this work should be followed with regard to potential impacts.

4.2.2 Areas of possible ambiguity in the Distribution Code

Appendix A provides a record of the dialogue between the project team and WPD’s appointed representative to address this matter, which is summarised in this section. The request for clarification was originally submitted to the ENA, but this was passed back to WPD to be addressed.

The WPD representative confirmed the project team’s view that the title of section Distribution Planning and Connection Code DPC7.4.7 (‘Frequency Sensitive Relays’) does not appear to align with the content of that section, which relates to connection/disconnection of embedded generators on islanded sections of network.

DPC7.4.7 Frequency Sensitive Relays

It is conceivable that a part of the **DNO's Distribution System**, to which **Embedded Generators** are connected can, during emergency conditions, become detached from the rest of the **System**. It will be necessary for the **DNO** to decide, dependent on local network conditions, if it is desirable for the **Embedded Generators** to continue to generate onto the islanded **DNO's Distribution System**.

If no facilities exist for the subsequent resynchronisation with the rest of the **DNO's Distribution System** then the **Embedded Generator** will under **DNO** instruction, ensure that the **Power Generating Module** and/or **Embedded Transmission System** is disconnected for re-synchronisation.

It was confirmed that no practical application is planned as part of the current project, which is a desktop study with the aim to identify (and resolve, as far as possible) issues relating to network islanding. This report is the output of the project, and seeks to identify the practical considerations/requirements, issues and mitigations to inform possible future trials.

Regarding the possible ambiguity of the Distribution Code, section DPC7.4.7 indicates that network islanding is allowable in certain conditions. Our approach to the project is to investigate how network islanding can be achieved whilst ensuring that the existing standards of reliability and safety are maintained (i.e. adhering to the same obligations and requirements as a normally connected network), as defined in the Electricity Safety Quality and Continuity Regulations 2002 (ESQCR) [9] referenced in the HLRAR. As such, any potential barrier arising from the protection requirements for embedded generators (DPC7.4.3.2) is mitigated since there should be no loss of phase(s) in advance of intentional islanding.

DPC7.4.3.2 Specific Protection Required for Embedded Power Generating Modules

In addition to any **Protection** installed by the **Generator** to meet his own requirements and statutory obligations on him, the **Generator** must install **Protection** to achieve the following objectives:

i. For all **Power Generating Modules**:

- a. To disconnect the **Power Generating Module** from the **System** when a **System** abnormality occurs that results in an unacceptable deviation of the **Frequency** or voltage at the **Connection Point**;
- b. To ensure the automatic disconnection of the **Power Generating Module**, or where there is constant supervision of an installation, the operation of an alarm with an audio and visual indication, in the event of any failure of supplies to the protective equipment that would inhibit its correct operation.

ii. For polyphase **Power Generating Modules**

- a. To inhibit connection of **Power Generating Modules** to the **System** unless all phases of the **DNO's Distribution System** are present and within the agreed ranges of **Protection** settings;
- b. To disconnect the **Power Generating Module** from the **System** in the event of the loss of one or more phases of the **DNO's Distribution System**;

iii. For single phase **Power Generating Modules**

- a. To inhibit connection of **Power Generating Modules** to the **System** unless that phase of the **DNO's Distribution System** is present and within the agreed ranges of **Protection** settings;

b. To disconnect the **Power Generating Module** from the **System** in the event of the loss of that phase of the **DNO's Distribution System**;

The network modelling activity described in section 3, sought to investigate the impact of network islanding on voltage, frequency and power quality (to ensure that these can be controlled to stay within statutory limits). In addition, the technical study presented in section 2, identifies the requirements that would need to be considered as part of the design of an island, including:

- A new generator control system to provide synchronisation (an active system allowing the generator to automatically synchronise to the grid when required);
- Check sync / voltage check facilities that you mention (at all necessary locations);
- Protection and SCADA to allow the island to be created and monitored; and
- Suitable earthing.

In addition, it was noted that network islanding at 33kV would prevent paralleling of systems at 11kV and below, as discussed in section 2.2.4.

4.2.3 Distribution Licence Conditions

An earlier version of the consolidated SLCs for Electricity Distribution, dated 25 August 2017 [10], was summarised in the HLRAR. These conditions have been superseded, with the latest available version dated 10 August 2019. The sections relevant to network islanding are listed below:

- Section A: Standard Conditions for all Electricity Distributors:
  - Chapter 1: Interpretation and application;
  - Chapter 2: General obligations and arrangements;
  - Chapter 3: Public service requirements;
  - Chapter 4: Arrangements for the provision of services
  - Chapter 5: Industry codes and agreements;
  - Chapter 6: Integrity and development of the network;
  - Chapter 7: Financial and ring-fencing arrangements;
- Section B: Additional Standard Conditions for Electricity Distributors who are Distribution Services Providers:
  - Chapter 8: Application and interpretation of Section B;
  - Chapter 9: Requirements within the Distribution Services Area;
  - Chapter 10: Credit rating and Restriction of Indebtedness;
  - Chapter 11: Independence of the Distribution Business;
  - Chapter 12: Provision of regulatory information.

The SLCs do not make explicit provision for network islanding. They are a set of high level obligations imposed on licensees to govern the principles for operation and administration of the sector. For example, they ensure that licensees have fundamental obligations to:

- Provide services to customers who request them;
- Publish statements relating to their charges;
- Comply with industry codes, which include more detailed technical rules (and/or references to subsidiary documents where these are defined) and the common DCUSA.

The SLCs are modified from time to time for different purposes. For example, there is ongoing work that may result in changes to licence conditions to better accommodate energy storage [11]. However, there are no indications that modifications are planned that would have any impact on network islanding.

4.2.4 Regulatory sandbox

In addition, Ofgem has published a decision in November 2019 [12] to implement a regulatory sandbox ‘for innovation projects which fall under the jurisdiction of the DCUSA’. This provides an opportunity for innovators to run trials of new products, services and business models in a real-world environment without some of the usual rules and regulation applying. Ofgem has a role to ensure that consumers will remain protected during the duration of the trial, and consider the results and implications of the test for future policy and regulation development.

The term “innovator” can be used to describe an applicant who has a well-developed plan with a clear objective and with the capability to complete a trial within 24 months of a sandbox being granted. The sandbox allows trialling an innovative idea where some rules have been temporarily removed to enable technology, product, services or business model to be tested.

The main requirements for projects to be eligible to be carried out using the sandbox are:

- The idea is truly innovative and it will deliver customer benefits,
- The regulatory barrier constrains this innovation; and
- The project can be trialled.

From the “insights from running first sandboxes” [13], local energy featured particularly strongly. Local retail supply is a key focus area and innovators are developing business models to allow sharing benefits of small-scale, community-owned generation. It could be explained by the electricity regime from the Electricity Act 1989, which mentioned: “a distinct framework allowing for small-scale unlicensed generation, distribution and supply”. Exploring the industry and regulatory regimes has been an important line of enquiry through the sandbox process and Ofgem is keen to ensure that customers are protected during the trial with a clear understanding of incoming information about billing, local tariffs and charges. Ofgem has already granted regulatory sandboxed to the trial of local energy production to maximize benefits for customer locally.

However, it is important to note that the scope of the regulatory sandbox is limited to rules and regulations covered by Ofgem and it does not extend to industry codes. The regulator has invited all the industry code chairs to join discussions about the wider adaption of the sandbox approach. As a result of the discussion, it was highlighted that the current Balancing Settlement Code (BSC) arrangements could pose a barrier to innovative projects and business ideas. Following a recommendation from Elexon, the regulator approved a modification to allow all industry participants (except for Elexon and NG) to seek a derogation from relevant BSC obligation to allow the innovative services to be developed and tested over a fixed period of time.

It is recommended that the regulatory sandbox for commercial arrangements under DCUSA would represent a prudent way to implement a trial of the network island solution.

4.3 Ownership structures and operational responsibilities, including developments relating to DSO

This section on ownership structures and operational responsibilities presents an overview of the:

- Rules relating to ownership of assets and allocation of responsibilities for operation of them;
- Market arrangements and the settlement mechanism; and
- Nature of operational responsibilities of DNO/DSOs.

It should be noted that the structures described here, which reflect the organisation of the sector in GB, are closely aligned with the charging arrangements discussed in section 4.4. The charging arrangements allow charges to be calculated for all types of customers such that all entities can recover their allowed revenues.

The findings for each area are summarised in Table 4.3.

Table 4.3 Summary of findings relating ownership structures and operational responsibilities

- **Rules relating to ownership of assets and allocation of responsibilities for operation of them** – this report focuses on islands implemented at the behest of the DNO/DSO, i.e. applied to sections of network owned by the DNO. It remains that DG must be owned by a third party, and necessary contractual agreements and refinements to systems would need to be made to support operation of islands. However, the changes to systems are likely to be implemented to support the transition to the DSO role independently of network islanding.
- **Market arrangements and the settlement mechanism** – it is anticipated that the existing settlement systems may be modified to support islanding for certain periods. An Elexon White Paper considers the introduction of a new Customer Notification Agent (CNA) to ensure that correct energy volume data is recorded to account for changes in the relationships between customers and suppliers. The CNA would allow customers to purchase power from multiple suppliers and it is conceivable that this mechanism could be used to account for implementation of network islands (where it may be required to understand when a customer is being supplied from the network or the island). Whilst it would need to be tested thoroughly, this represents a relatively small modification to a system that is already in place and effective.
- **Nature of operational responsibilities of DNO/DSOs** - the current regulatory framework is considered to be unarguable since there is not much room for manoeuvre outside of the strict rules to which DNOs must abide. Therefore, a technical solution would be selected to provide control and monitoring capabilities to ensure that WPD would continue to comply with its obligations. There are no indications that any parts of the regulatory framework relating to technical operation of the network would need to be changed (or derogations sought from Ofgem). Changes are anticipated to support flexibility solutions as part of the DSO transition, which are likely to complement work on network islanding that is considered to be a way to provide flexibility. However, it is likely to be inappropriate for DSOs to derive revenue from network islanding through substitution of flexibility services provided by others in the market.

Refinements to DNO systems are likely to be made as part of the transition to the DSO role. It is anticipated that additional system functionality, as well as new contractual agreements, would enable DSOs to operate islands. A relatively minor modification to the existing settlement system has been identified, which could be used as a mechanism to support network islands. The current regulatory framework is considered to be unarguable and the technical solution can be implemented such that WPD would continue to comply with its obligations. There is no indication that network islanding necessitates changes to the regulatory framework relating to technical

operation of the network, and anticipated changes as part of the DSO transition are likely to complement islanding. However, it is likely to be inappropriate for DSOs to derive revenue from network islanding through substitution of flexibility services provided by others in the market.

4.3.1 Ownership and operational structures

As part of their current roles, DNOs typically operate their networks using SCADA monitoring and communication links back to a control centre that operates a Distribution Management System (DMS). A common example is the General Electric (GE) PowerON product [14], which is adopted by numerous DNOs in GB including WPD. Available DMS or "Advanced" DMS [15] products have been developed to fulfil the current role of DNOs, which is relatively passive. They generally include a range of functionality, as follows:

- **Monitoring and operation** – to 'enable safe monitoring and control of the electrical distribution network for operations personnel' in a control centre through 'monitoring, alarming, measuring, calculating, or controlling power systems' [16];
- **Optimisation** – going beyond SCADA monitoring and control, optimisation modules enable 'utilities to make greater use of automation as a solution for solving growing grid complexity' [15]. These can enable system operators to 'reduce network loading at peak times and increase network efficiency and reliability' through 'assessing the state of the entire network' in real time [16].
- **Outage Response** – to guide maintenance teams 'for outage management and proven to perform through the worst of storms' [15], including through the use of predictive methods.
- **DER Orchestration** – more advanced tools can provide 'an opportunity to unlock DER flexibility through better forecasting and orchestration' [15].

DNO systems do not generally include the final area of functionality for managing dispatch of plant, which is carried out by the Energy Management System (EMS) adopted by the Energy System Operator who has responsibility for dispatch.

Figure 4.2, taken from the Feasibility Study Report, identifies the present and future models that are envisaged for the allocation of responsibilities for ownership and operation of assets, and balancing of distributed generation.

		Present/ Distribution network	**Future/ Network islands**
Network	Operation	DNO	DSO
	Ownership	DNO	DNO/DSO
Distributed Generators	Operation	Third Party	DSO
	Ownership	Third Party	Third Party
	Balancing	Passive	DSO

Figure 4.2 Ownership models

The continuing development of the DSO concept means that no changes to these models have been identified at this stage. It should be noted that network islands fall under the 'network' category in Figure 4.2 since they are implemented at the behest of the DNO/DSO who retains the same obligations. The DG within any network island must be owned by a third party. In order to operate the network island in real time, the DNO/DSO must implement an island control system and necessary contractual arrangements such that it is able to balance the generation output with the island demand.

This shift of the DNO to take on a role that includes dispatch of generating plant is likely to mean that additional functionality is required above that already implemented in its systems. As stated above, solutions are available on the market to undertake the Advanced Distribution Management System (ADMS) and EMS functions. However, additional modules may need to be procured by DSOs and a system integration process completed. It is anticipated that the trend towards DSO will drive the requirement for this additional software functionality, rather than network islanding in isolation.

4.3.2 Market arrangements and settlement

Figure 4.3 and Figure 4.4, taken from the Feasibility Study, illustrate the arrangements of the existing centralised energy market and modified to allow for network islanding. In each case, the yellow lines correspond to power flows and the green lines correspond to the associated financial payments.

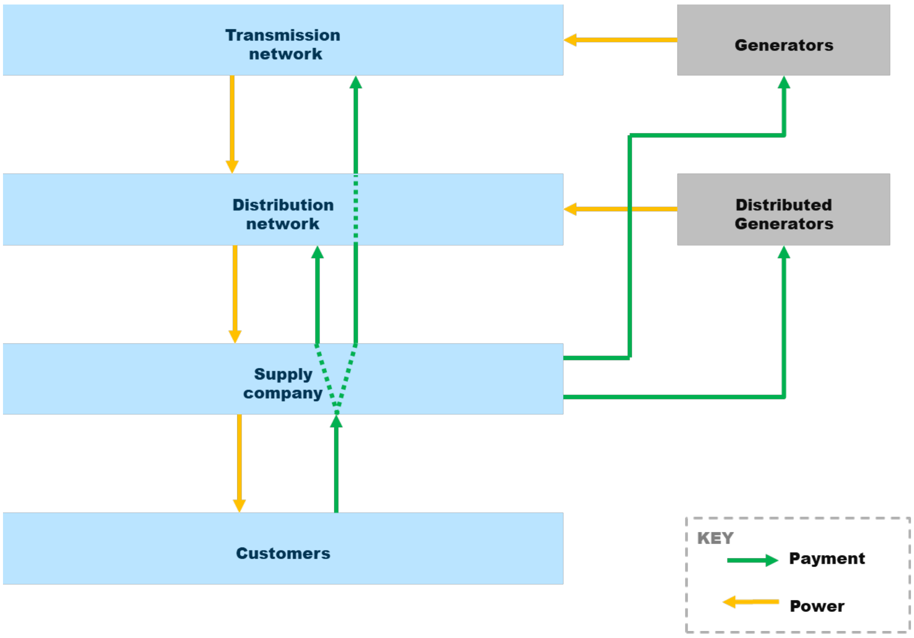


Figure 4.3 Centralised energy market with key parties and activities in electricity industry

In general terms, island customers are supplied by an island supplier, as indicated in Figure 4.4. The settlement systems may be modified to enable existing suppliers, who have contractual agreements in place with customers, to support islanding of those customers for certain periods. Alternatively, a new, dedicated supply/service company may be established. At present, given that it is not envisaged that islands will be implemented on a permanent basis, it is anticipated that systems may be modified to support network islanding. This is in line with the Elexon White Paper 'enabling customers to buy power from multiple providers' [17], which envisages changes to the Supplier Volume Allocation (SVA) arrangements through the introduction of a new CNA as discussed in the following sub-section.

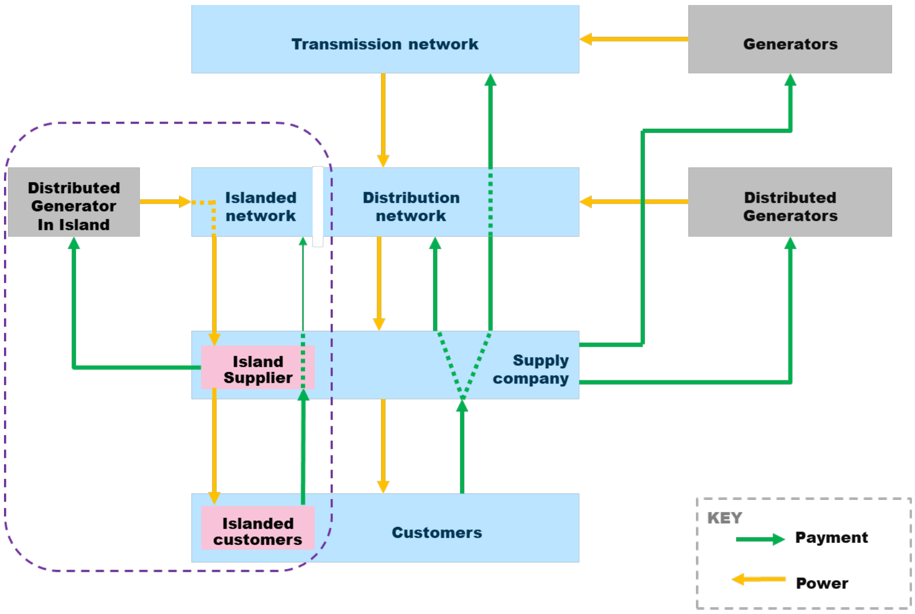


Figure 4.4 Market structure to allow for network islanding

Electricity trading and settlement systems

Figure 4.5 presents an annotated diagram of the trading and settlement systems under the BSC. This is an abbreviated version of the diagram published by Elexon in its knowledge base article about trading and settlement [18], that was described in detail in the Feasibility Study.

The modules that make up the Elexon systems are divided into groups for: central volume allocation; supplier volume allocation; and funds administration. In addition, there are system operator systems and participant systems that interface with the BSC systems. Figure 4.5 includes the potential new CNA participant system, coloured in red.

In summary, the modules in the central volume allocation group provide the following functionality:

- Registration of each individual party that participates in the trading and settlement systems;
- Collection of data related to these parties, including half hourly meter readings for the outstations (grid supply points and generator terminals); and aggregate energy volumes agreed under contracts between parties;
- Settlement administration to calculate the differences between the energy volumes agreed under contracts and those that result from actions to balance the system, and resulting payments.

The modules in the supplier volume allocation group provide the following functionality:

- Allocation of the energy volumes from the half-hourly meter readings for the GSPs to each supplier (using assumptions to account for customers with non-half hourly (NHH)meter readings).

The modules in the participant systems

- Provision of information to the BSC systems about the energy volumes agreed under the forwards market. This represents most of the electricity that is traded for each half hour (from one hour ahead up to years in advance), and corresponds to the bilateral contracts between generators and suppliers;

- Provision of information to the BSC systems about the energy volumes agreed under the power exchange markets, which are used as an alternative to bilateral contracts.

The system operator modules provide the following functionality:

- Provision of information to the BSC systems about energy volumes associated with bids and offers accepted by the ESO under the Balancing Mechanism (BM). These are bids and offers from generators to increase or decrease their outputs, respectively, to allow the ESO to balance the system in real-time.

Should the new CNA be implemented as an external ‘participant system’ then it ‘*would notify BSC central services of the Metering Systems for the customers, generators and Suppliers involved in energy trades under the relevant scheme. It would then notify the associated energy volumes, along the same lines as an Energy Contract Volume Notification Agent (ECVNA)’* [17]. The CNA would ensure that correct energy volume data is recorded to account for changes in the relationships between customers and suppliers (allocation of metered volumes). It is conceivable that this mechanism could be used to account for implementation of network islands.

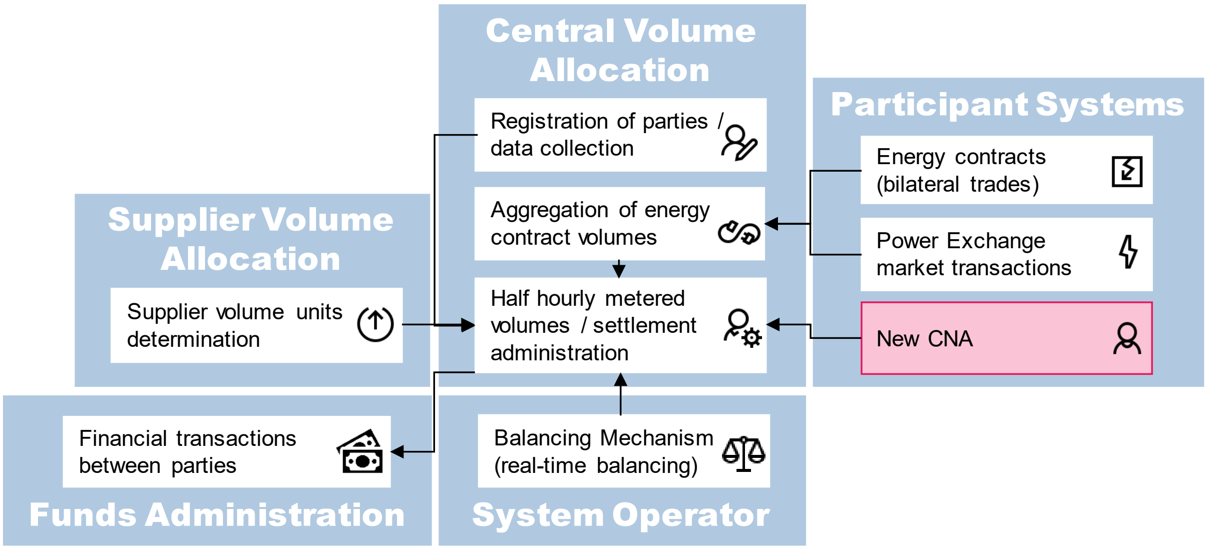


Figure 4.5 Abbreviated trading and settlement systems diagram

The system illustrated in Figure 4.5, with the addition of the new CNA agent, represents a relatively small modification to a system that is already in place and effective. It is clear that such a modification would need to be tested thoroughly by Elexon, but it provides a potential solution that would support network islanding.

4.3.3 DNO/DSO operational responsibilities

The increasing penetration of variable (non-controllable) renewable energy generators connected throughout distribution networks means that there is a new emphasis on active control of distribution networks through the introduction of the role of DSOs. This section describes findings about the:

- Operational responsibilities; and
- Markets for flexibility services.

Responsibilities

As stated in section 4.2.2, the purpose of this desktop research is to investigate how network islanding can be achieved whilst ensuring that the existing standards of reliability and safety are maintained. This means that, in operating a section of its network as an island, a DNO would retain responsibilities to adhere to the same obligations and requirements as if it were a normally connected network. The fundamental obligations are defined in ESQCR [9]. In addition, the guaranteed standards published by WPD [19, 20] under distribution licence conditions 8, 9, and 10 (relating to emergency response and priority services) would be unchanged.

Under the existing regulatory framework there is not much room for manoeuvre outside of the strict rules to which DNOs must abide. As such, the established regulations, industry codes and standards must be respected.

This means that DNOs must develop their networks and implement necessary systems to operate them to provide customers with power in line with prescribed standards of service (safety, reliability and quality). As a result, DNOs can recover allowed revenues, as discussed in section 4.4, which account for the investments made (plus an allowed return) and operating costs incurred. These revenues are represented by the green payment arrows from the customers to the network operators (via the suppliers) in Figure 4.4 and Figure 4.5.

It should be noted that for the purpose of this exercise, the current regulatory framework is considered to be unarguable. Therefore, the technical assessment has identified a solution that includes adequate provision for control and monitoring capabilities to ensure that WPD would continue to comply with its obligations. There are no indications that any parts of the regulatory framework relating to technical operation of the network would need to be changed (or derogations sought from Ofgem). However, derogations may be considered prudent during trial activities.

It is important to note that the regulatory framework is an area that is currently the focus of a lot of attention in relation to the transition to DSO, and this is likely to persist over the next decade as the role solidifies. Significant changes are anticipated to be implemented relating to the way in which networks are built, designed, operated and supplied, including to account for storage solutions and "whole energy" system approaches. The rationale for such changes is to develop flexibility solutions so it is deemed likely that they will complement work on network islanding.

WPD has undertaken a range of activities to prepare for the DSO transition. The activities undertaken by WPD include:

- Participation in the ENA Open Networks Project since January 2017 [21];
- Publication of the WPD DSO Strategy document in December 2017 [22];
- Update of the WPD Distribution System Operability Framework (DSOF) [23] document in 2018;
- Publication of the WPD DSO Forward Plan document in June 2019 [24];

The common theme of these activities is the requirement for flexibility solutions for system operation. Flexibility covers a range of solutions, but network islanding is deemed to be one way to provide flexibility that is likely to form part of the DSO toolkit. Descriptions of the nature of flexibility solutions, described in the outputs from the activities, are summarised below.

The WPD Distribution System Operability Framework (DSOF) Flexibility Services document [25] states that 'smart grid' solutions can be used to allow:

- '*New and existing assets owned by the network operator to be controlled through advanced techniques to provide flexibility*' – generally applicable in operational timescales, including through new products that may be provided by customers with controllable generation or demand; and
- '*The distribution network operator to control the network access rights for those connections and provide flexibility through controlling power flows*', i.e. to provide

connections on an alternative basis, and provide flexibility in '*investment decision timescales to reduce, defer or negate conventional build*'.

According to the ENA Open Networks Project DSO definition document [6, 26], prepared as part of work on workstream 3 - DSO transition, the DSO roles and responsibilities should include:

- '*Support whole system optimisation'*
- *'Provide and maintain systems, processes and data to facilitate markets and services*'.

In addition, the principles of operation for the DSO should include:

- '*Uses market mechanisms that are fair, transparent and competitive, providing a level playing-field for providers of network services and providers of energy products / services in order to deploy the most efficient and effective solutions*'.

Work under workstream 3 of the Open Networks Project included the 'Future Worlds consultation' [27]. This was a '*substantial stakeholder engagement process to map and describe a number of potential future electricity networks ("Future Worlds") capable of supporting the smart decentralised energy industry that the UK is transitioning towards*'. It included future world B, which is '*where DNO and ESO are both involved in the co-ordination of flexibility services and exchange data to facilitate this*'. The aim of the project team was not to '*seek to recommend any particular Future World,* but instead to understand them, creating a common view of how each works allowing informed debate and decisions to follow'. However, future world B appears to be taken as a reasonable expectation for the future since this would seem to allow for gradual development of the DSO model alongside the existing ESO.

Markets for flexibility services

Procurement of system services (known variously as ancillary services, balancing services and flexibility services) is a tool for system operators (transmission and distribution) to aid them in operating the networks effectively. The Ofgem and Government Smart Systems and Flexibility Plan [28] looks for competitive markets to be established to provide this flexibility.

Work under the ENA Open Networks Project - workstream 1a (flexibility services) has included stakeholder engagement and service definition documents to support the early stages of establishing these new markets on a consistent basis.

In addition, WPD has undertaken work on the WPD Multi Asset Demand Execution (MADE) since March 2019 [29].

The WPD DSOF – Flexible Power document is based on the expectation that DSOs will operate in conjunction with the transmission ESO. The DSOF Flexibility Services document states that WPD, as a DSO, intended to develop products to procure '*reserve services for real power or voltage control (rather than fast acting products such as frequency response – which remains the responsibility of the Transmission System Operator)*'.

The work carried out by WPD to date has included consideration of network data and impact of system operation on dispatch of plant. This is similar to what would be required for evaluation of the network to determine whether islands should be created.

The assessment of financial revenues associated with DSO flexibility services as part of the MADE project identifies a potential source of revenue for network islanding. These revenues have been discussed in section 5.4, along with the potential issue relating to the impact on competition in the flexibility services market. In summary, from a regulatory perspective it is likely to be inappropriate for DSOs to derive revenue from network islanding through substitution of flexibility services provided by others in the market.

4.4 Charging arrangements

Charging arrangements are in place to allow regulated network companies in GB to recover their allowed revenues from customers. Annual revenue allowances are determined in advance (ex ante) through the periodic regulatory price control process, as follows:

- RIIO-ED1 – this was the first price control for distribution companies under the new RIIO[1] framework. It applies for the eight-year period from April 2015 to March 2023;
- RIIO-ED2 – this is the next price control period for distribution companies, which will apply for the five-year period of April 2023 to March 2028 following a decision to shorten the length of the period [30].

The Ofgem RIIO-2 Sector Specific Methodology Decision [31], published in May 2019, has identified some mechanisms for after-the-fact (ex post) adjustments through 'Return Adjustment Mechanisms' (RAMs). These work separately from, but in conjunction with 'Output Delivery Incentives' (ODIs) to encourage efficient expenditure in the interest of consumers.

As discussed in the HLRAR, network operators principally recover their allowed revenues through a combination of two types of charges. Strict rules govern how these charges may be set, with common methodologies defined in DCUSA and applied to all GB DNOs for each:

- UOS charges; and
- Connection charges.

Sections 4.4.1 and 4.4.2 focus on the existing arrangements for determining use of system charges and ongoing activities and likely outcomes, respectively. Table 4.4 presents a summary of the findings relating to charging arrangements.

Table 4.4 Summary of findings relating to charging arrangements

- **Existing arrangements** - the mandated Common Distribution Charging Methodology (CDCM) does not prevent network islanding, but presents challenges for it to be implemented successfully. As a result, it is not deemed appropriate to reduce UoS for particular customers as a result of network islanding. This means that should there be sufficient financial benefits from network islanding then these should be shared between all customers.
- **Developments from ongoing activities** - ongoing activities are anticipated to complement work on network islanding since they cover:
  - Support for the development of markets for flexibility, which network islands may be able to participate in;
  - Increased data availability through half hourly metering, which will improve understanding about operation of the network and potential advantages of network islanding to provide flexibility; and
  - Adaptation of the charge calculation methodologies/models to provide cost-reflective charges with improved forward price signals. This is expected to include locational charges, which account for the particular costs of using the network in different locations. This has potential to support network islanding as a means to reduce the cost of operating specific sections of network that are subject to generation constraints.

[1] RIIO stands for "Revenue using Incentives to deliver Innovation and Outputs", which can be shortened to 'Revenue = Incentives + Innovation + Outputs'.

It is not deemed appropriate to reduce UoS for particular customers as a result of network islanding, but financial benefits should be shared between all customers. In addition, ongoing external activities relating to charging arrangements are anticipated to complement network islanding.

4.4.1 Existing charging arrangements

The principles of the existing charging arrangements are described in the 'introduction to electricity distribution charging' slides published by the Charging Futures Forum [32]. The charging arrangements fall under the common methodologies that are defined in the DCUSA [33] and have been described in the Ofgem Access and Forward-Looking Charges – Summer Working Paper document on existing arrangements [34]:

- DCUSA, schedule 16 – CDCM, which applies to the majority of customers connected at voltages below 22kV;
- DCUSA, schedule 17[2] - EHV Distribution Charging (EDCM) Methodology A (Forward Cost Pricing, FCP Model). This defines the methodology for calculating site-specific charges for EHV connected customers (at or above 22kV) using the FCP model. This approach uses a network model separated into network groups. Load flow studies are run with contingency analysis to identify costs for network reinforcements required to accommodate a demand increase of up to 15% over a ten year period. The revenues associated with such reinforcements are used to determine the applicable charges (for each group on an average basis) to allow them to be recovered.
- DCUSA, schedule 18 - EHV Distribution Charging (EDCM) Methodology B (Long Run Incremental Cost, LRIC Model). This defines the methodology for calculating site-specific charges for EHV connected customers (at or above 22kV) using the LRIC model. This approach uses a network model with small incremental demand or generation increases applied to each node. Load flow studies are again used to identify costs for required network reinforcement. The revenues associated with such reinforcements are used to determine the applicable charges to allow them to be recovered.

WPD is mandated to publish a charging statement, schedule of charges and supporting CDCM model annually for each of its licence areas [35]. These provide details of the calculated charges applicable to Low Voltage (LV) and HV customers (calculated under the CDCM) and EHV customers (calculated under the EDCM). WPD adopts the Forward Cost Pricing (FCP) Model EDCM methodology (DCUSA, schedule 17) for its East and West Midlands licence areas. The LRIC methodology (DCUSA, schedule 18) is adopted for the EHV charges in the South Wales and South West licence areas.

The network boundaries for the application of the CDCM and EDCM methodologies are identified in Figure 4.6, taken from the CDCM Model User Guide [36] published by the body that administers the DCUSA document.

[2] DNOs have the option of whether to use EDCM methodology A or B in DCUSA schedule 17 or 18, respectively.

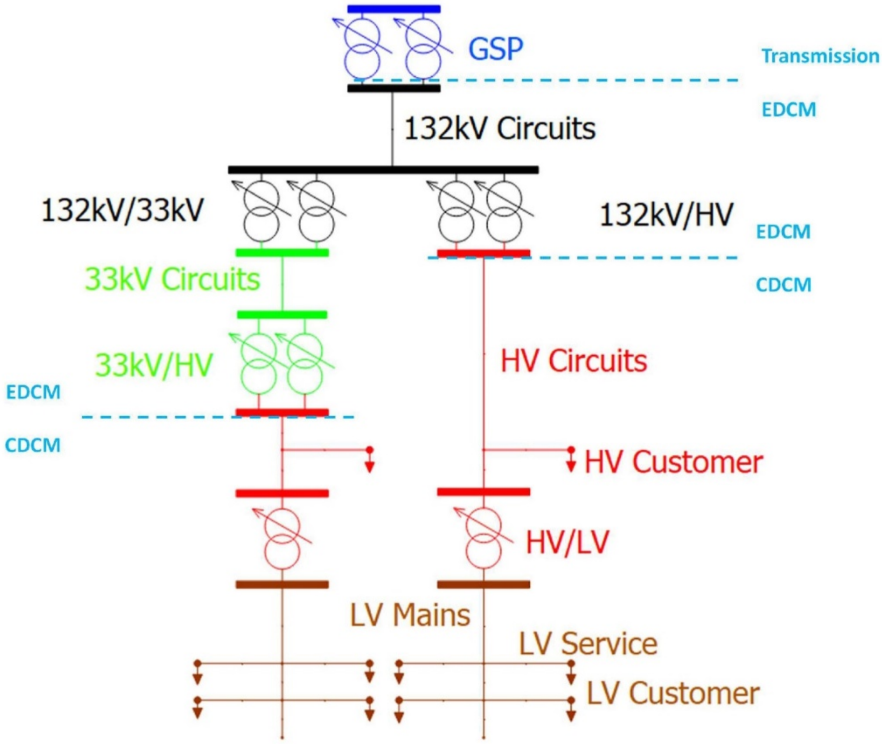


Figure 4.6 Single line diagram showing charging methodology boundaries [36]

The number of customers connected at LV and HV (falling under the CDCM) is far greater than those connected at EHV. In addition, the revenue recovered through use of system charges applied to LV and HV customers is 97.8% of the total, as shown in section 5.1.1. As such, the remainder of this section focuses on providing a summary of the CDCM methodology.

Figure 4.7 is an illustration of the CDCM calculation method, adapted from the Ofgem Access and Forward-Looking Charges – summer 2019 working paper document on existing arrangements [34]. It shows inputs that go into the initial calculation of annual charges for each tariff category. In summary, these comprise operating costs of the business (regular costs) and costs associated with investments in new assets (identified from a generic 500MW network reinforcement model). The fixed, capacity and reactive power charge components of these initial charges remain unchanged. However, the unit charges are increased to recover residual costs such that the target revenue is recovered in full.

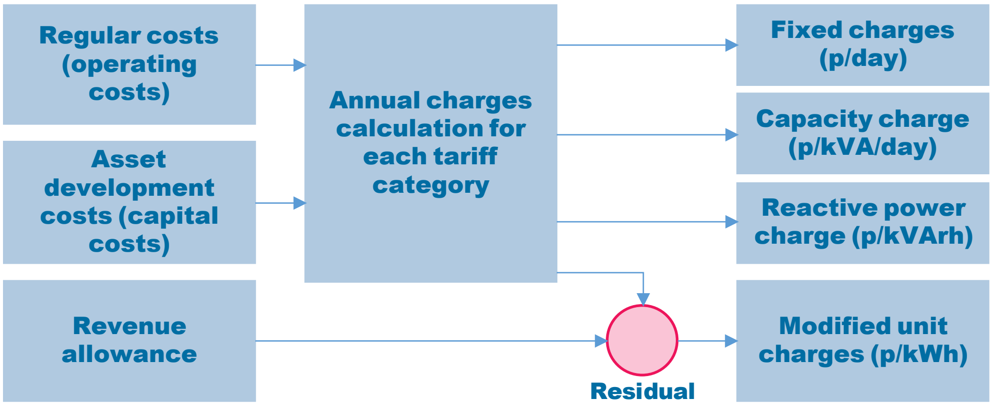


Figure 4.7 Diagrammatic representation of CDCM charge calculation [34]

Figure 4.8 is a comparable illustration that is taken from the CDCM methodology itself (DCUSA [33], schedule 16).

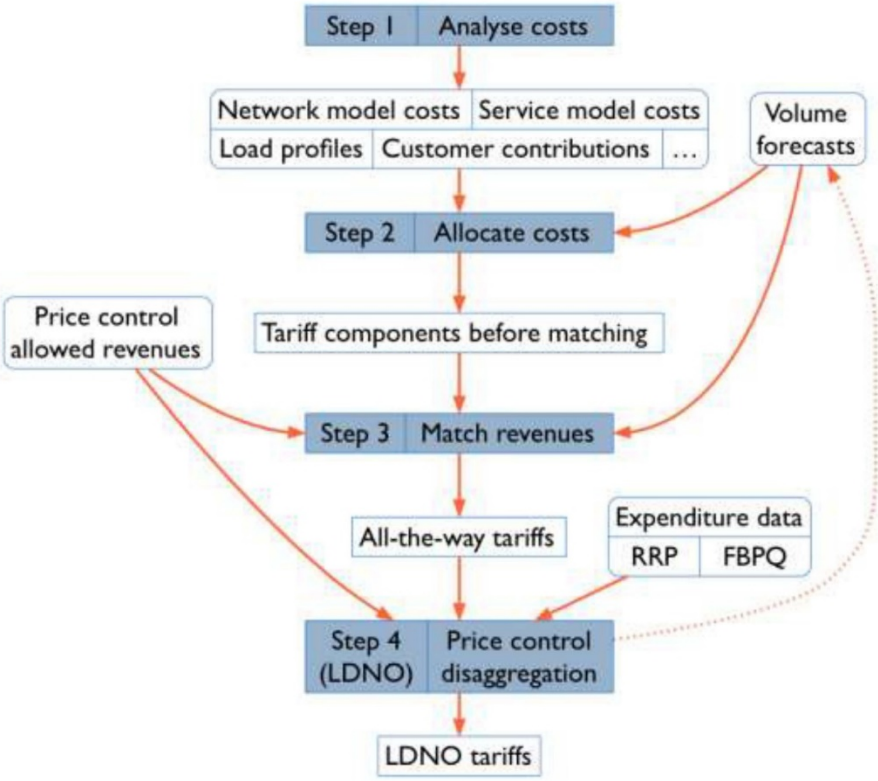


Figure 4.8 Overview of the main steps in the methodology [33]

The key principles of the CDCM methodology described above are to enable licensed DNOs to:

- Comply with the requirements imposed by licence conditions to calculate charges according to the common methodologies prescribed in DCUSA;
- Apply a common methodology to determine charges for different customer types on a consistent basis, such that the approach is perceived to be fair;
- Fully recover their allowed revenues (deemed to be fair by Ofgem through the price control process).

From the point of view of network islanding, the above methodology remains a requirement to be complied with. The methodology does not prevent network islanding, but challenges are presented regarding:

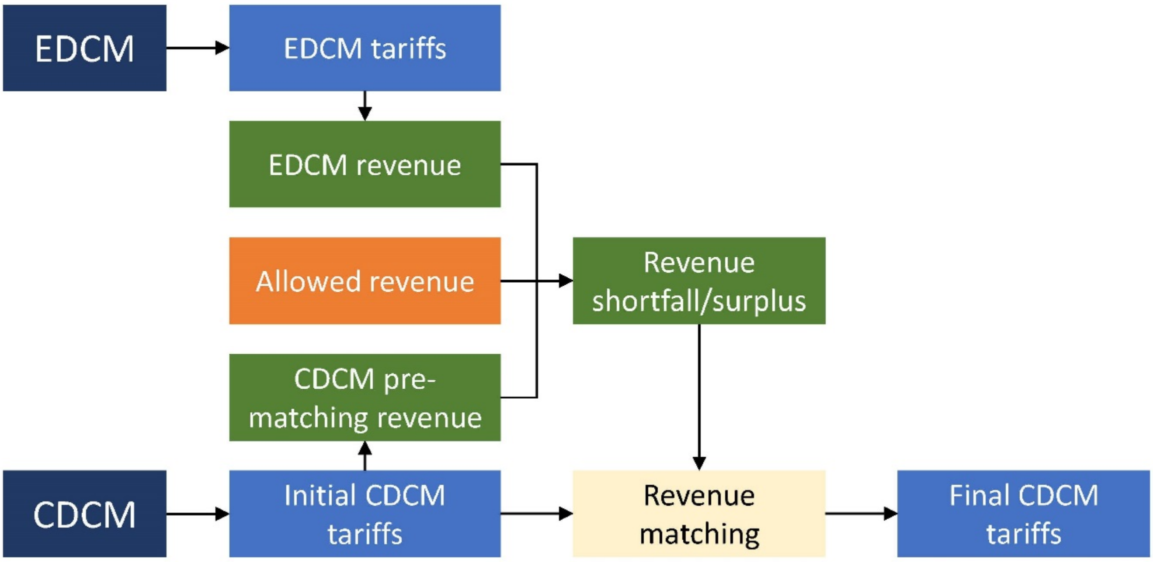
- Full revenue recovery – an intuitive argument for network islanding is that it means that customers rely less heavily on the upstream network and should, therefore, receive a discount in their use of system charges. However, in order to recover the same overall revenue, if Distribution Use of System (DUOS) charges are reduced for particular customers then it must increase for others, which could be perceived to be unfair.
- Computation – given that the characteristics of the system change when an island is established, some of the parameters within the CDCM would need to be modified to account for this. As a result, separate CDCM models (or additional separate modules) would need to be implemented to calculate the charges. It should be noted that the duration of islanding is variable, which would result in a further challenge to ensure that the charges calculated from the models would fully recover the allowed revenues.

These challenges formed part of the discussion with the WPD Finance Team representatives, as described in section 4.4.2. As a result of the challenges identified above, it is not deemed appropriate to reduce DUOS for particular customers as a result of network islanding. This means that should there be sufficient financial benefits from network islanding then these should be shared between all customers.

Residual charging issues

Concerns relating to the recovery of residual charges through adjustments to unit charges have been the subject of much discussion over the last few years. This is due to the perceived unfairness of recovering such charges from customers on the basis of their consumption; since some customers are less able to control their level of consumption than others through investment in particular technologies (e.g. on-site generation, energy efficiency measures, etc). Ongoing activities to address this perceived unfairness are described in section 4.4.2.

In addition to the residual charges illustrated in Figure 4.7, there is effectively an additional level of revenue matching as illustrated in Figure 4.9. This figure shows that any shortfall in revenues recovered through EDCM tariffs would also be fed into the adjustment applied to unit charges in the CDCM tariffs.



Note: (revenue scaling in the EDCM has been excluded from the diagram for simplicity)

Figure 4.9 Recovery of residual revenue (taken from the CDCM Model User Guide, Figure 2.3 [36])

4.4.2 Ongoing activities, and likely outcomes

Discussion with WPD Finance Team representatives

On 14 October 2019, the project team held a meeting with the WPD Income Manager and Business Analyst to discuss the processes adopted by WPD to calculate DUOS charges. During this meeting, the WPD Finance Team representatives were careful to explain that the model currently adopted follows strict rules, in line with the requirements of the common methodology and does not make provision for network islanding. However, it was discussed that should the commercial arrangements be altered to accommodate network islands then different CDCM models and/or different line loss factors would need to be applied for each potential island (based on studies).

In conclusion, as discussed with the WPD Finance Team, in the event that the commercial arrangements be altered to accommodate network islanding then it is likely that either entirely separate models or separate modules within the existing charge calculation models will need to be developed.

External activities

The HLRAR identified '*a lot of developments occurring relating to the electricity sector regulatory framework*'. In particular, the recent and ongoing developments are strongly linked to the evolution of the sector towards supporting the requirement for greater flexibility and active control of the system in order to balance supply from generators with demand in an increasingly decarbonised and decentralised system.

The report stated that Ofgem is undertaking a range of activities to '*to develop specific requirements to address the issues that arise in the sector. Ofgem generally undertakes this role through consultation with industry stakeholders on proposals that it makes*'. Some of the key consultation areas identified in that document include:

- The Upgrading our Energy System – Smart Systems and Flexibility Plan [28] developed by Ofgem and UK Government Department for Business, Energy and Industrial Stratergy (BEIS) – this plan was developed following a consultation and is a '*core component of Ofgem's future facing work to enable the energy system transition, and it forms part of the Government's Industrial Strategy*'. The document includes sections about actions to: remove barriers to smart technologies; enable smart homes and businesses; and make markets work for flexibility. The latter element includes the DSO concept, highlighted as a means '*…to ensure that the system as whole is managed efficiently*'. The plan indicates that opportunities exist to improve efficiency '*…through active use of new technologies, providers and solutions and through greater coordination across the transmission and distribution boundary*', which could be provided in part through network islanding. The document refers to the ENA Open Networks Project as the '*key initiative to drive progress in these areas*'.
- Targeted Charging Review (TCR): Significant Code Review - a review of specific elements of the charging arrangements established in the Connection and Use of System Code (CUSC) and DCUSA was launched in August 2017 [37]. A minded-to decision regarding residual charging arrangements and 'embedded benefits' was published on 28 November 2018 [38]. This follows modelling and completion of a consultation process about industry proposals (CMP264 and CMP265) to change electricity transmission charging arrangements for Embedded Generators [39]. The final decision for the TCR consultation was subsequently published on 21 November 2019 [40]. The outcome is summarised as follows by Current News: '*fixed charges are to be applied to all final demand network users irrespective of their ability to reduce their impact on the grid through generation or flexibility*' [41].
- Electricity Settlement Reform Significant Code Review – this initiative was launched in July 2017 [42] following on from earlier consultations about elective and mandatory half-hourly settlement (HHS) for domestic and smaller non-domestic customers. There is a desire to implement HHS to derive benefit from widespread smart meter deployment, including a more accurate and effective settlement process and tariff innovation (time of use tariffs). The initiative is due to complete its work in Q3 2020 [43], and includes an 'ELEXON-chaired Design Working Group (DWG) [that] has already delivered its recommendation to Ofgem for the Target Operating Model'.
- 'Clarifying the regulatory framework for electricity storage: Licensing' [7] – consulting on changes to the electricity generation licence;
- 'Enabling the competitive deployment of storage in a flexible energy system: Changes to to the electricity distribution licence' [11].

In addition, the HLRAR described the electricity trading and settlement systems operated by Elexon, and identified aspects of the BSC that would potentially require modification for network islanding. The nature of these modifications, which would need to be considered in light of developments in relation to HHS, are described further in section 4.3.2.

Since the HLRAR was issued documents relating to another Significant Code Review, which was launched in December 2018 to address Access and Forward-Looking Charges, have been published:

- Update on timing and next steps on Future Charging and Access reforms, published 21 May 2019 [44]
- Summer 2019 working paper, published 6 September 2019 [34];
- Winter 2019 working paper, published 16 December 2019 [45].

The work on Access and Forward-Looking Charges is looking at a range of options to provide different access rights to networks in future, as well as price signals that '*signal to users how their actions can either increase or decrease future network costs in different locations*'. This is in contrast to the work on the Targeted Charging Review, which strives to resolve the immediate issues of residual charges and embedded benefits for generators not allowing revenues to be recovered on a cost reflective basis.

In addition, the first deliverable has been published from workstream 4 of the ENA Open Networks project, covering charging issues [46]. This workstream covers:

- '*The requirement for a common charging methodology for the costs associated with Active Network Management (ANM).*'
- '*The development of future compensation arrangements for distributed energy resources.*'
- '*The development of cost-reflective charging arrangements for 'behind the meter' connections.*'
- '*The development of cost-reflective charging arrangements for reactive power across transmission and distribution.*'
- '*The development of cost reflective charging arrangements for electricity storage providers.*'

The ongoing activities identified above are anticipated to complement work on network islanding since they cover:

- Support for the development of markets for flexibility, which network islands may be able to participate in;
- Retention of principles of full revenue recovery through common charging methodology, and established charge calculation models (with modifications to account for changes to portions recovered through fixed and variable charge components);
- Increased data availability through half hourly metering, which will improve understanding about operation of the network and potential advantages of network islanding to provide flexibility;
- Clarity about licence conditions relating to energy storage, which may be operated in conjunction with network islands in the future to derive greater benefit;
- Adaptation of the charge calculation methodologies/models to provide cost-reflective charges with improved forward price signals. This is expected to include locational charges, which account for the particular costs of using the network in different locations. This has potential to support network islanding as a means to reduce the cost of operating specific sections of network that are subject to generation constraints.

Whilst it is not possible to provide definitive statements about the outcomes of the ongoing activities identified above, it is anticipated that they will complement network islanding. As such, these developments are similar to the anticipated developments in the regulatory framework for the DSO transition, described in section 4.3.3.

4.5 Summary of findings

Compatibility of network islanding with the existing legal and regulatory frameworks

- **Legal definition and provision for network islanding** - under the Government 'Smarter Systems and Flexibility Plan' the objective remains to find broad solutions, which may well support network islanding. As part of its longer term view about the Open Networks Project, the ENA envisages work to achieve 'regulatory enactment and implementation', which may ultimately result in changes to legislation. There are currently no indications that developments would prevent network islanding.
- **Areas of possible ambiguity in the Distribution Code** – this investigation shows how network islanding can be achieved whilst ensuring that the existing standards of reliability and safety are maintained (i.e. adhering to the same obligations and requirements as a normally connected network). As such, technical requirements have been identified elsewhere in this report to mitigate any potential issues and ensure that islands can be operated in compliance with the Distribution Code.
- **Distribution Licence Conditions** – the Electricity Distribution Standard Licence Conditions (SLCs) are the set of fundamental obligations imposed on licensees. There are no indications that modifications are planned that would have any impact on network islanding.
- **Regulatory sandbox** – It is recommended that the regulatory sandbox for commercial arrangements under DCUSA would represent a prudent way to implement a trial of the network island solution.

There are currently no indications of future developments that would prevent network islanding, and technical requirements have been identified as part of this project to ensure compliance with the Distribution Code. It is recommended that the regulatory sandbox for commercial arrangements under DCUSA would represent a prudent way to implement a trial of the network island solution.

Ownership structures and operational responsibilities, including developments relating to DSO

- **Rules relating to ownership of assets and allocation of responsibilities for operation of them** – this report focuses on islands implemented at the behest of the DNO/DSO, i.e. applied to sections of network owned by the DNO. It remains that DG must be owned by a third party, and necessary contractual agreements and refinements to systems would need to be made to support operation of islands. However, the changes to systems are likely to be implemented to support the transition to the DSO role independently of network islanding.
- **Market arrangements and the settlement mechanism** – it is anticipated that the existing settlement systems may be modified to support islanding for certain periods. An Elexon White Paper considers the introduction of a new Customer Notification Agent (CNA) to interface with its systems. It is conceivable that this mechanism (to ensure that correct energy volume data is transferred between parties) could be used to account for implementation of network islands. Whilst it would need to be tested thoroughly, this

represents a relatively small modification to a system that is already in place and effective.

- **Nature of operational responsibilities of DNO/DSOs** - the current regulatory framework is considered to be unarguable since there is not much room for manoeuvre outside of the strict rules to which DNOs must abide. Therefore, a technical solution would be selected to provide control and monitoring capabilities to ensure that WPD would continue to comply with its obligations. There are no indications that any parts of the regulatory framework relating to technical operation of the network would need to be changed (or derogations sought from Ofgem). Changes are anticipated to support flexibility solutions as part of the DSO transition, which are likely to complement work on network islanding that is considered to be a way to provide flexibility. However, it is likely to be inappropriate for DSOs to derive revenue from network islanding through substitution of flexibility services provided by others in the market.

Refinements to DNO systems are likely to be made as part of the transition to the DSO role. It is anticipated that additional system functionality, as well as new contractual agreements, would enable DSOs to operate islands. A relatively minor modification to the existing settlement system has been identified, which could be used as a mechanism to support network islands. The current regulatory framework is considered to be unarguable and the technical solution can be implemented such that WPD would continue to comply with its obligations. There is no indication that network islanding necessitates changes to the regulatory framework relating to technical operation of the network, and anticipated changes as part of the DSO transition are likely to complement islanding. However, it is likely to be inappropriate for DSOs to derive revenue from network islanding through substitution of flexibility services provided by others in the market.

Charging arrangements

- **Existing arrangements** - the mandated common distribution charging methodology (CDCM) does not prevent network islanding, but presents challenges for it to be implemented successfully. As a result, it is not deemed appropriate to reduce UoS for particular customers as a result of network islanding. This means that should there be sufficient financial benefits from network islanding then these should be shared between all customers.
- **Developments from ongoing activities** - ongoing activities are anticipated to complement work on network islanding since they cover:
  - Support for the development of markets for flexibility, which network islands may be able to participate in;
  - Increased data availability through half hourly metering, which will improve understanding about operation of the network and potential advantages of network islanding to provide flexibility; and
  - Adaptation of the charge calculation methodologies/models to provide cost-reflective charges with improved forward price signals. This is expected to include locational charges, which account for the particular costs of using the network in different locations. This has potential to support network islanding as a means to reduce the cost of operating specific sections of network that are subject to generation constraints.

It is not deemed appropriate to reduce UoS for particular customers as a result of network islanding, but financial benefits should be shared between all customers. In

addition, ongoing external activities relating to charging arrangements are anticipated to complement network islanding.

5. Commercial considerations for network islanding

In addition to the issues relating to charging arrangements, discussed in section 4.4, further investigations have been undertaken to build on the findings of the Feasibility Study with regard to commercial considerations. These include the following:

- Assessment of types of customers per feeder, discussed in section 5.1;
- Bottom-up assessment of potential benefits of network islanding, as follows:
  - Benefit corresponding to network capacity released by implementation of network islands, discussed in section 5.2;
  - Benefit of avoided constraint payments to generators, discussed in section 5.3;
  - Impact of network islanding on services contracted by network operators, and potential benefits from DSO services, discussed in sections 5.4 and 5.5.3.
- Shift in the quantitative modelling approach to incorporate the improved bottom-up assessments of benefits, as described in section 5.5. This new approach moves away from the use of assumptions to represent speculative reductions in Transmission Use of System (TUOS) and DUOS charges in the earlier top-down assessment.

The change to the bottom-up approach to assessment of benefits is principally borne out of the need to ensure fair sharing of benefits between customers inside and outside of any island. As discussed in the Feasibility Study, it may be possible to make an argument for reduction of DUOS for particular customers, so long as this does not result in an increase for other customers. However, this would require further demonstration to support a compelling argument to be made to Ofgem.

Figure 5.1 presents an illustration of the difference between the existing calculation of network charges, and the top-down and bottom-up approaches to the assessment of financial benefits from network islanding. The top-down approach was adopted in the Feasibility Study based on limited information at that time. On the basis of published material indicating significant financial benefits from network islanding, the top-down approach used assumptions to apply percentage reductions for the TUoS and DUoS charges that would result for customers within the island. However, these assumed reductions were only applied to the islanded customers and benefits would not be shared with customers outside, as indicated in Figure 5.1. These reductions are represented by the light blue and light purple elements in the diagram, respectively.

The bottom-up assessment adopted as part of the Further Investigation, presented in this report, looks to identify specific financial benefits. The discussion of the charging arrangements in section 4.4 describes the recalculation of charges within the existing common methodology (and potential developments that are likely to complement network islanding). As such, the charges could be recalculated for all customers to share any potential benefits in a fair way.

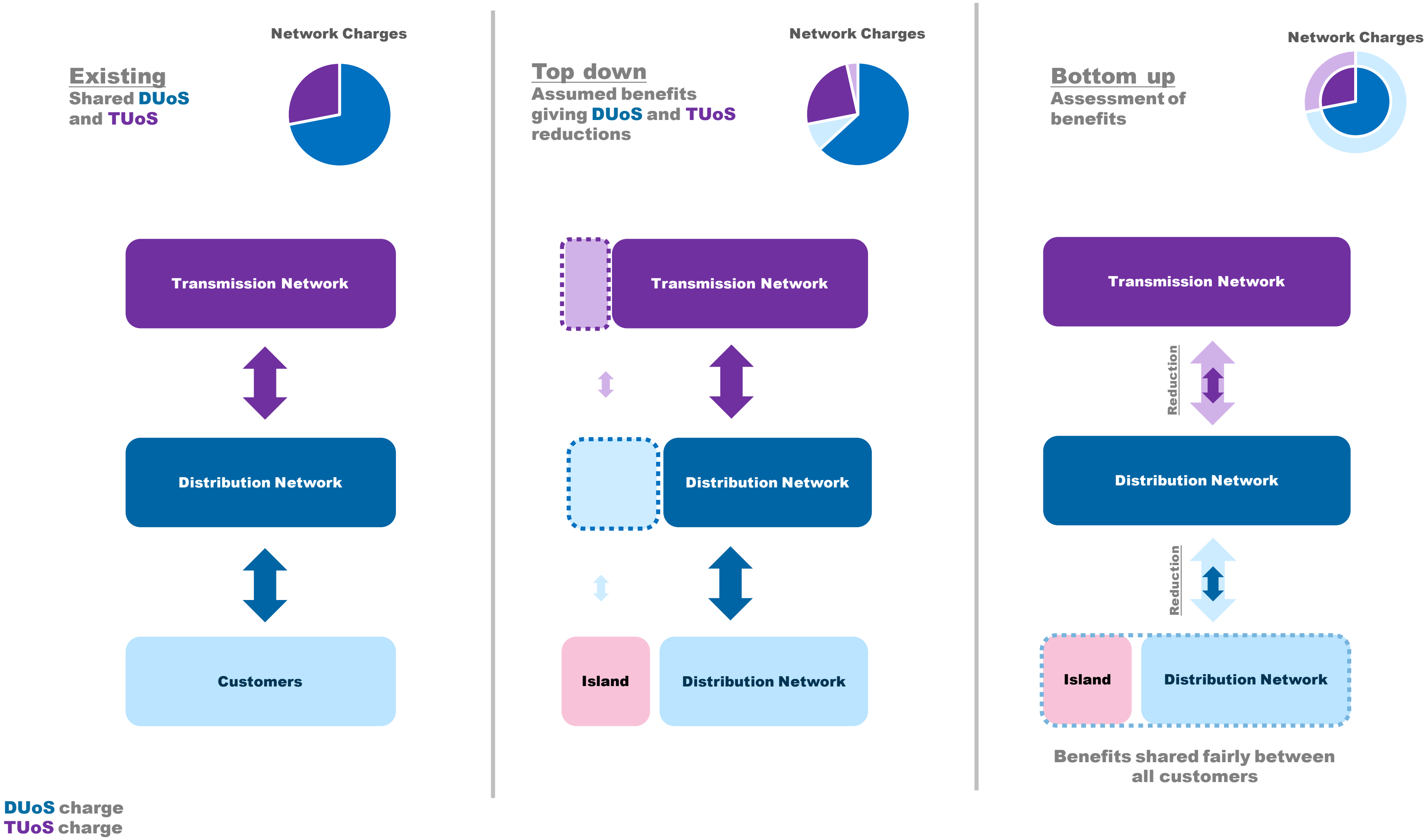


Figure 5.1 Illustration of top-down and bottom-up assessment of benefits

As such, the new approach described in section 5.5 seeks to establish whether sufficient benefits are available for inclusion in the CBA using a bottom-up assessment. In practice such benefits would be shared between all customers through reduction of capital and operating costs, which would be assessed as part of the review of outturn costs and setting of future revenue allowances in the next iteration of the price control process.

5.1 Assessment of revenue recovery and types of customers

5.1.1 Revenue recovery

The figures provided in Table 5.1 show the breakdown of revenue recovered through the CDCM and EDCM charges, taken from the WPD East Midlands (EMID) CDCM model for 2020/21 [35].

Table 5.1 Revenue recovery in EMID, CDCM and EDCM

	Revenue £	% of total
Latest forecast of CDCM Revenue	495,608,958	97.8%
Revenue raised outside CDCM - EDCM and Certain Interconnector Revenue	10,997,124	2.2%
Total Revenue for Use of System Charges	**506,606,082**	

Figure 5.2 provides an illustration of the revenue to be recovered through fixed and variable components that make up the use of system charges that will be effective during the period 1 April 2020 to 31 March 2021. These charges were determined using the CDCM model prior to publication of the final decision relating to the TCR. As such, these do not reflect the breakdown of fixed and variable charges that will be applicable following implementation of the TCR decision.

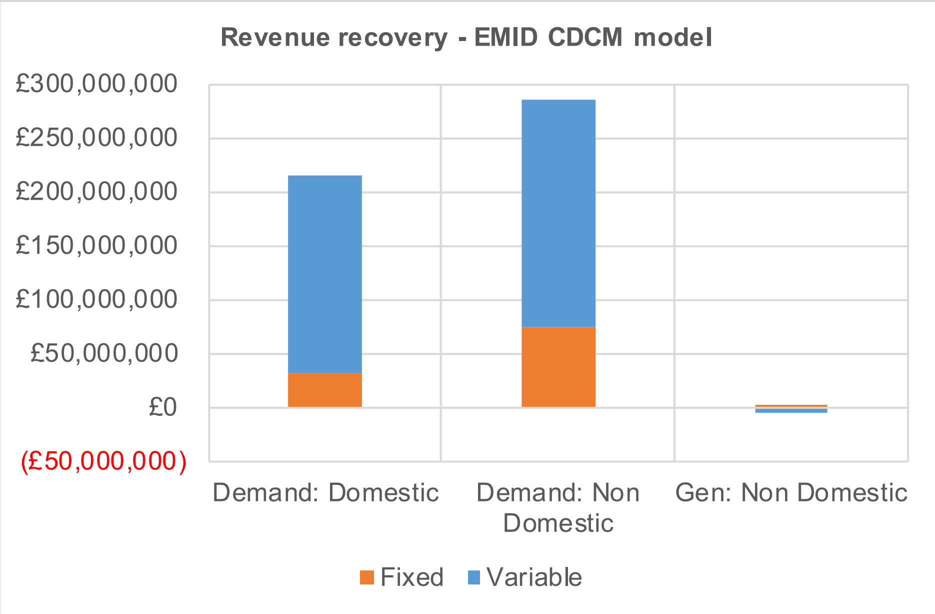


Figure 5.2 Illustration of breakdown of revenue recovery components for whole of EMID through charges

5.1.2 Breakdown of customer types

The profile of different types of customers in each prospective network island is relevant to the consideration of revenue recovery, i.e. fixed and variable DUOS charge components recovered from those particular customers. The shift in approach described in the introduction to this section means that the impact of network islanding on the DUOS and TUOS charges is no longer included directly. However, it is in the interest of WPD to confirm that a prospective network island has a typical breakdown of numbers of customers of each type, in case of any operational issues that may result.

Table 5.2 presents the summary Meter Point Administration Number (MPAN) data that were extracted from the WPD internal systems, showing the number of demand customers of each type. The number of customers is taken to be the number of discrete connections to the network, each represented by a unique MPAN. The data have been extracted to show the customers attributed to each primary substation in the islands that are under consideration.

The customer types are categorised according to eight profile classes (PCs), defined as follows:

- PC1 – Domestic Unrestricted Customers;
- PC2 – Domestic Economy 7 Customers;
- PC3 – Non-Domestic Unrestricted Customers;
- PC4 – Non-Domestic Economy 7 Customers;
- PC5 – Non-Domestic Maximum Demand (MD) Customers with a Peak Load Factor (LF) of less than 20%;
- PC6 – Non-Domestic Maximum Demand Customers with a Peak Load Factor between 20% and 30%;
- PC7 – Non-Domestic Maximum Demand Customers with a Peak Load Factor between 30% and 40%; and
- PC8 – Non-Domestic Maximum Demand Customers with a Peak Load Factor over 40%.

Table 5.2 Numbers of each customer type per primary substation

	PRIMARY SUBSTATION NAME	PRIMARY SUB-STATION	PC1	PC2	PC3	PC4	Other (PC5-8 and <blank>)	Total
EM1	HARROLD 33 11kV S STN	920061	563	488	44	52	14	**3,886**
EM1	SHARNBROOK 33 11kV S STN	920057	2,190	1,152	108	130	47	**1,161**
EM2	LITTLE IRCHESTER 33 11kV S STN	920060	2,703	1,511	222	149	101	**4,686**
EM3	WOLLATON ROAD 33 11kV S STN	880020	10,200	4,511	920	659	162	**3,627**
EM4	HALFWAY 33 11kV S STN	890089	2,912	706	134	58	76	**16,452**
	Total		**18,568**	**8,368**	**1,428**	**1,048**	**400**	**29,812**

The breakdown above demonstrates the expected characteristic that there are a large number of PC1 and PC2 customers, namely domestic customers whose individual consumption is relatively modest. The size of the customers gradually increases as the profile class increases through to PC8, meaning that the consumption of each customer increases, but the volume of customers is lower.

Figure 5.3 and Figure 5.4 show the breakdown of the number of customers by type across islands EM1-EM4 (from the system data) and across the East Midlands licence area (based on data from the WPD EMID CDCM model for 2020/21 [35]), respectively. It can be seen that the number of customers by type across the identified islands appears to be consistent with the overall breakdown for the whole of the East Midlands area.

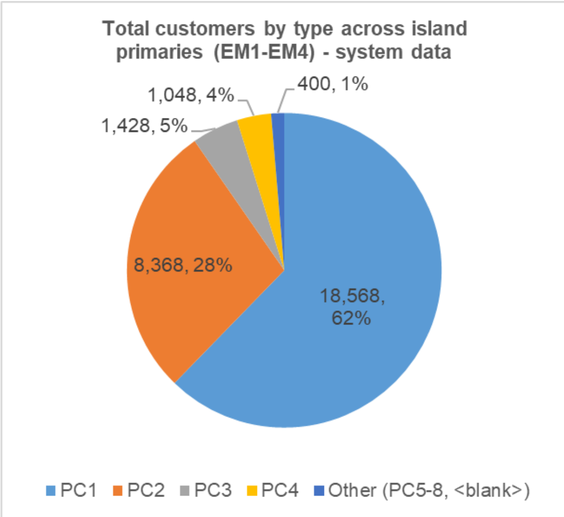


Figure 5.3 Total customers by type across island primaries (system data)

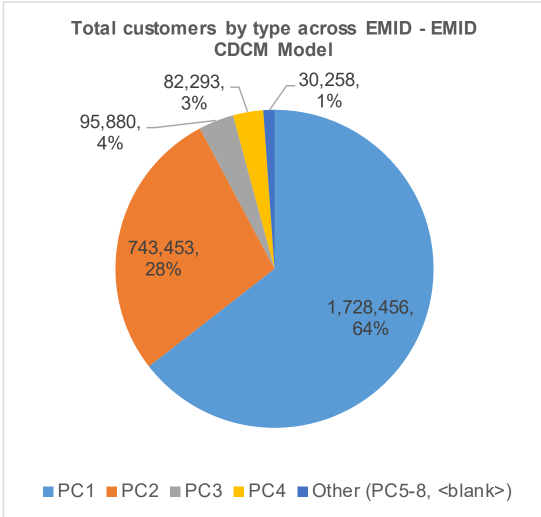


Figure 5.4 Total customers by type across EMID (EMID CDCM model)

Figure 5.5 shows a comparison between the total number of customers in each island as estimated in the Feasibility Study (based on an assumption of 2.5kW per MPAN) and from the extracted system data.

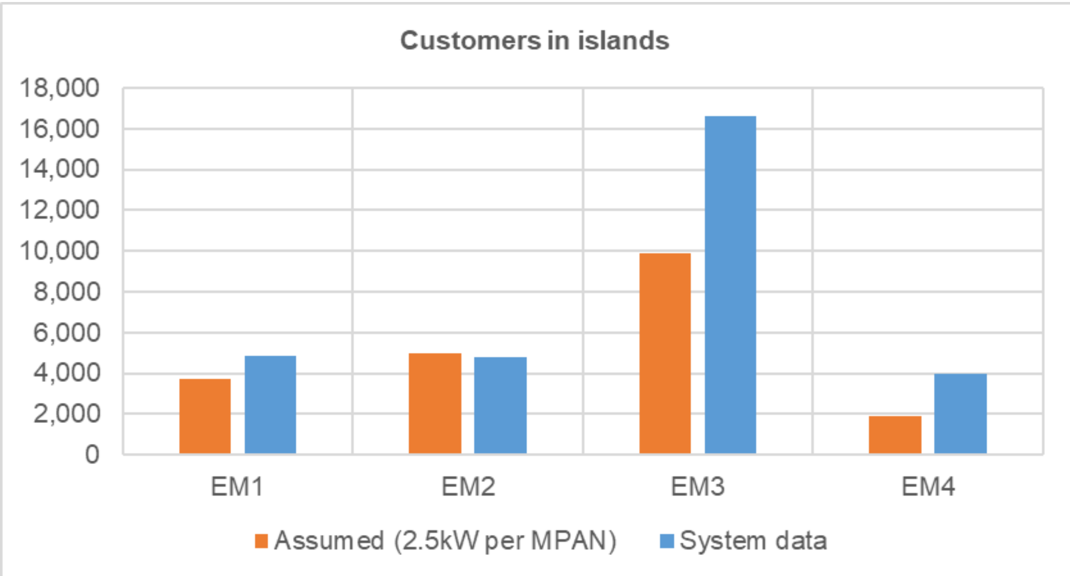


Figure 5.5 Numbers of customers in each island (assumed estimate and system data comparison)

Figure 5.5 shows that the actual number of customers may vary quite a lot from the number calculated based on the average peak demand figure. The estimate based on the average peak demand appears to correspond to quite a realistic number of customers for the EM1 and EM2 islands, but there is greater deviation in the cases of EM3 and EM4. Local characteristics of specific prospective network islands, i.e. the precise breakdown of customers of each type and the aggregate demand of those customers at the time that coincides with the system peak demand, will dictate how they will operate in practice.

Apart from the peak demand corresponding to a single point in time, the annual energy demand that reflects the variation in demand through the year is also of interest. Again, this reflects the make up of the customers in the network who consume power for different purposes and to varying degrees. In January 2020, Ofgem has published an update to its Typical Domestic Consumption Values (TDCV) that were previously updated in August 2017, as shown in Table

5.3. These typical consumption figures only apply to domestic consumers, and are averaged across a large number of households.

Table 5.3 Ofgem Typical Domestic Consumption Values [47]

kWh		Current TDCVs	TDCVs from 1st April 2020
Electricity: Profile Class 1	Low	1,900	1,800
	Medium	3,100	2,900
	High	4,600	4,300
Electricity: Profile Class 2	Low	2,500	2,400
	Medium	4,200	4,200
	High	7,100	7,100

Figure 5.6 presents the total demand units consumed by customers in each category in WPD's East Midlands licence area, as presented in the CDCM model for 2020/21 [35]. Figure 5.7 presents the derived total demand units per customer for each customer type, again calculated for customers across EMID.

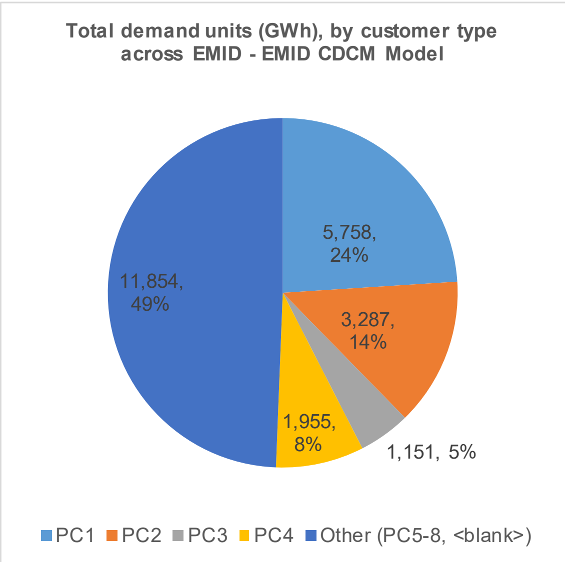


Figure 5.6 Total demand units by customer type across EMID

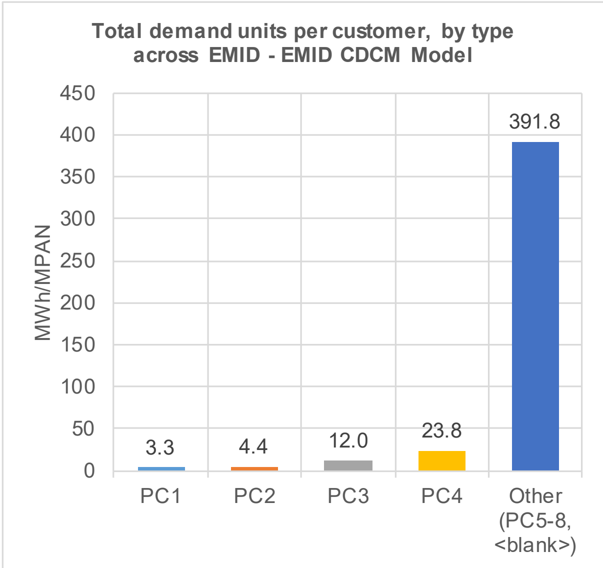


Figure 5.7 Total demand units by customer type across EMID

Figure 5.8 has also been prepared from data in the EMID CDCM model for 2020/21 to show the average annual consumption of customers of each type, along with the corresponding value of the fixed and variable components of the annual DUOS charge.

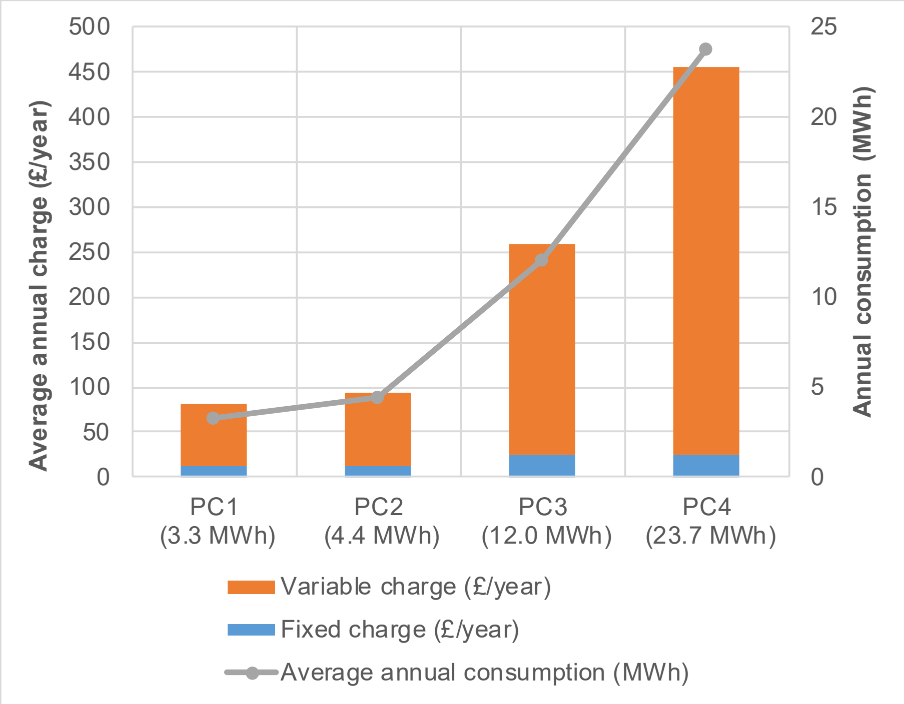


Figure 5.8 Average charges by profile class category

The above assessment is of interest with regard to the revenue recovery considerations that are discussed in section 5.1.1. However, the shift to the bottom-up approach to estimation of potential financial benefits means that refinements to improve the calculation of DUOS (to apply speculative reductions) have not been necessary.

5.2 Assessment of capacity release benefits

5.2.1 Capacity release methodology and calculation

This section describes the methodology used to estimate the potential generation and load capacity that could be released by islanding sections of the distribution network.

The methodology that was used to estimate the capacity release is described in the following steps:

- **Step 1** – The WPD Network Capacity Map was used to identify a list of 25 BSPs that are subject to reverse power flow constraints in the East Midlands licence area i.e. BSPs that have restrictions on the connection of additional DG on their downstream network.
- **Step 2** – The second step was to use WPD DG records to identify all the controllable generation connected to the downstream 33kV network of each of the BSPs found in Step 1. The fuel type of a minority of the generators in the DG records list is ambiguous as they are labelled as “Other Generation”. This generation was assumed to be of the controllable type.
- **Step 3** – The generation capacity release has been calculated as the sum total of the installed capacity (or the export capacity, whichever is lower) of the controllable DG identified in Step 2.
- **Step 4** – The demand capacity release has been calculated as the total generation capacity divided by 1.5 (i.e. the generation to peak demand factor that has been used previously to determine suitable network islands).
- **Step 5** – The final generation and demand capacity released was taken as the average release over the sites identified in the list above. Some of the sites had no generation

connected on their respective 33kV network and therefore these sites were excluded from the averaging calculation.

The results of the capacity release calculations are shown in Table 5.4.

Table 5.4 Average capacity release figures

Substation Name	Substation Number	Total Controllable Generation Capacity (MVA)	Calculated Peak Demand Capacity Released (MVA)
Alfreton	890014	15.7	10.5
Boston	900004	11.7	7.8
Checkerhouse	890010	6.0	4.0
Hawton	900003	20.0	13.3
Lincoln	900002	13.1	8.7
Mansfield	890008	20.0	13.3
Stony Stratford	940005	15.0	10.0
Uttoxeter	870009	5.0	3.3
Wellingborough	940011	25.0	16.7
Willoughby	880006	7.0	4.7
	No. Sites	**10**	**10**
	Total (MVA)	**138.5**	**92.3**
	Average generation capacity release (MVA)	**13.9**	**-**
	Average demand capacity release (MVA)	**-**	**9.2**

It has been shown that the implementation of network islanding on the 33kV network can release significant generation capacity. It is important to note that these figures are the result of averages made over a large network area. A more detailed analysis would have to be undertaken to understand the capacity release and associated benefit from a specific network island that is being considered for implementation. It is also to be noted that generators connected on the condition that a network island has released capacity for them to connect will have to be connected with an alternative connection offer. This would be similar to an ANM schemes that are already being used by most DNOs. It may be the case that the generation will need to be disconnected or curtailed should the network island have to reconnect to the main grid i.e. for generator maintenance or to reinstatement of supply following a fault.

5.2.2 Capacity benefit methodology and calculation

This section describes the methodology used to translate the capacity release figures into a representative financial benefit for network customers. The quantification of the islanding capacity release is found by calculating the equivalent cost attributed to the traditional reinforcement solution, i.e. the base case. In this study, the traditional reinforcement is defined as the installation of an average section of new 33kV circuit and associated 33kV switchgear. The methodology used to calculate the equivalent traditional reinforcement cost is as follows:

- **Step 1** – The first step was to calculate the cost per km of a generic 33kV circuit using historic cost information and average lengths of Overhead Line (OHL) and cable conductors. The generic circuit includes a single unit of 33kV switchgear. The unit costs of the circuit and switchgear were taken from WPD's Statement of Methodology and Charges.
- **Step 2** – The next step was the calculation of the average length of 33kV circuit over all four WPD licence areas by analysing internal network data provided by WPD.
- **Step 3** – The average total cost of traditional reinforcement was found by multiplying the generic 33kV circuit cost by the average length of 33kV circuit.
- **Step 4** – The circuit rating for the 33kV circuit was obtained from WPD policy documents. The winter cyclic rating was used for the purpose of this study with a reduction factor applied to account for thermal losses. The rating of the generic circuit was calculated to be 38.6 MVA with the reduction factor applied.
- **Step 5** – The financial benefit of the capacity release can be found by using the following formula:

$$capacity\ benefit\ (£) = \frac{average\ load\ or\ gen\ capacity\ release}{average\ 33kV\ circuit\ capacity\ release}\ x\ average\ 33kV\ circuit\ cost$$

The results of the financial benefit calculations are shown in Table 5.5.

Table 5.5 Average capacity benefit figures

Item ID	Calculation	Description	Unit	Value
A	-	Typical 33kV circuit cost	£/km	212,333
B	-	Typical 33kV switchgear circuit cost	£	62,900
C	-	Average circuit length	km	3.48
D	(A*C) + B	Average 33kV circuit cost	£	800,818
E	-	Winter cyclic rating	MVA	38.6
F	See Section 5.2.1	Average generation capacity release	MVA	13.9
G	See Section 5.2.1	Average demand capacity release	MVA	9.2
H	**F/E * D**	**Generation capacity benefit per island**	**£**	**288,730**
I	**G/E * D**	**Demand capacity benefit per island**	**£**	**191,102**

5.3 Assessment of benefits from mitigation of generation constraints

This section of the report presents the assessment of the potential benefits of network islanding from the alleviation of generation constraints on the network. In such cases, it may be beneficial for one (or more) generators to meet the demand on the local network, which is disconnected from the main grid. In so doing, this would enable other generators in the vicinity (but outside of the island) to export more power to the grid.

The WPD 'Generation Outage Report' document covering 2018 [48], published under the Energy Data Hub - System and Network Data part of the WPD website [49], presents the breakdown of constrained generation volumes and associated payments per month for each of WPD's licence areas. The following figures have been prepared using data from the report to illustrate the impact of constraints on generators across WPD's network. The charts in Figure 5.9 and Figure 5.10 illustrate the nature of constraint volumes and payments across the East Midlands licence area.

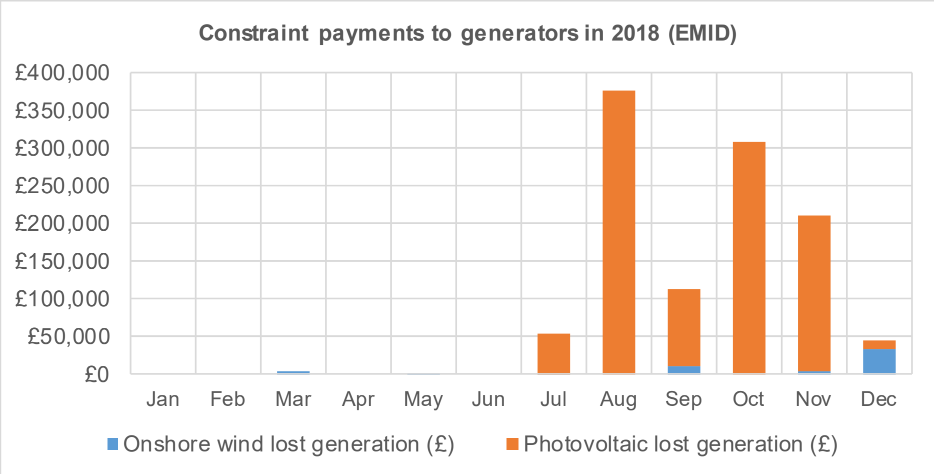


Figure 5.9 Constraint payments to EMID generators in 2018

Figure 5.9 shows that the constraint payments in the East Midlands are dominated by payments to curtailed solar photovoltaic (PV) generators during the July-November period.

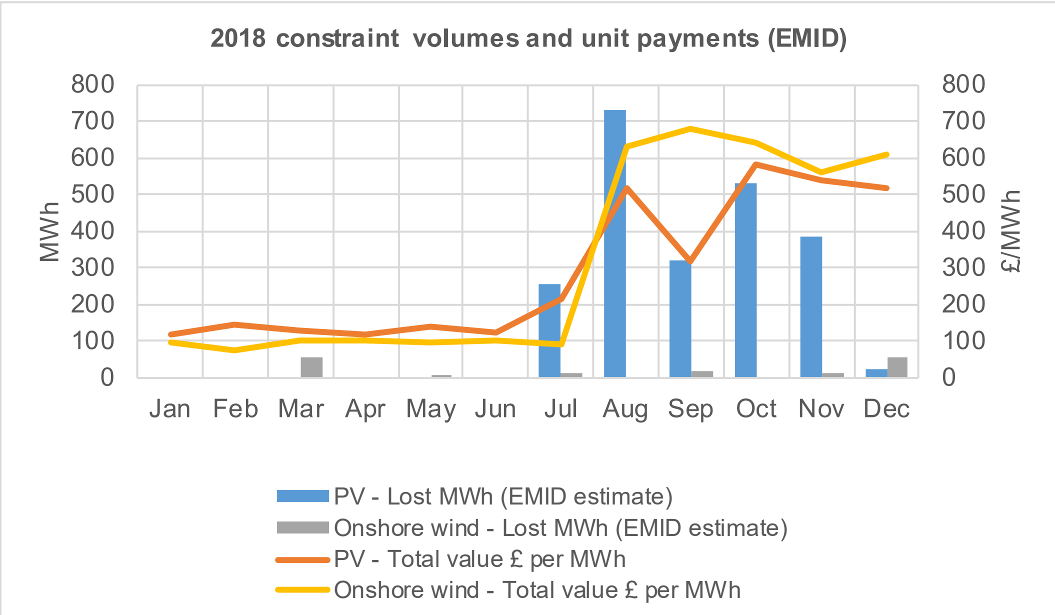


Figure 5.10 EMID 2018 constraint volumes and unit payments

Figure 5.11 provides a comparable chart showing the total volumes and unit payments across all four licence areas operated by WPD.

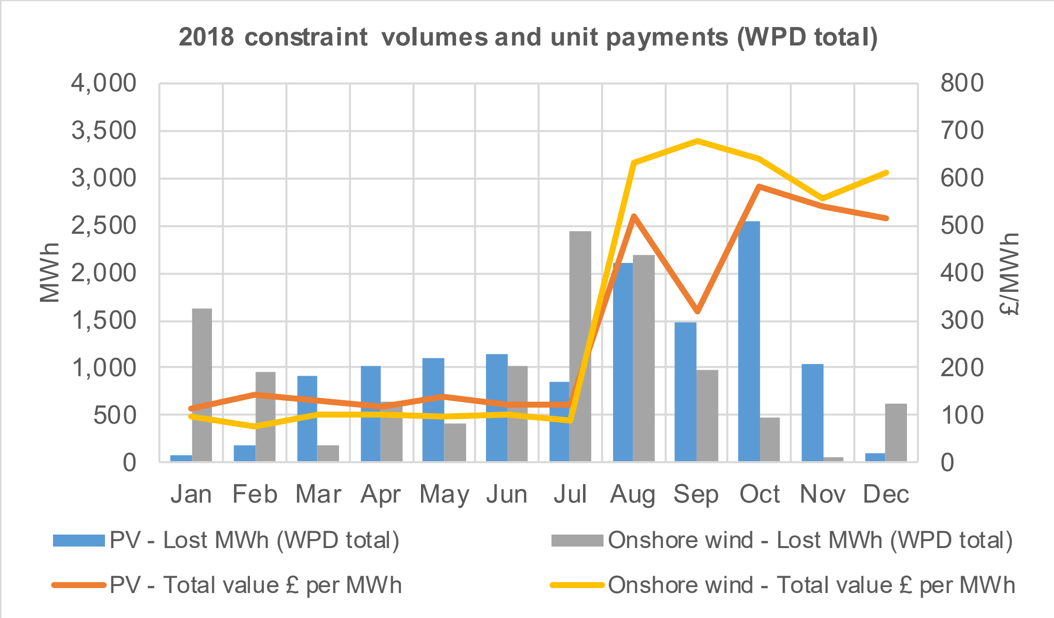


Figure 5.11 WPD total 2018 constraint volumes and unit payments

Figure 5.10 and Figure 5.11 indicate that generation constraints existed in the autumn of 2018 when the demand and solar PV output would have been at moderate levels during a period of change (demand gradually increasing and solar PV output gradually decreasing). It is interesting to note that there was no corresponding trend of increased constraints during the similarly changeable spring time period.

The figures also indicate that there were sharp increases in the payments per unit of constrained generation between July and August. This increase broadly matches the increase in the overall volume of constrained generation during this period.

It should be noted that the 'Generation Outage Report' presents the aggregate constraint volume and payment across each licence area, and does not identify the specific nature or position of local constraints. It is also unclear whether this data for 2018 is representative of a typical year.

Notwithstanding the above comments, it is deemed reasonable to include a financial benefit for the reduction of generator constraint payments that would be mitigated by network islanding. Should network islanding be carried forward, it is recommended that prospective sections of network be reviewed on a case-by-case basis to confirm the nature of generation constraints and associated benefits.

Conservative assumptions have been adopted to underpin an operating expenditure (Opex) line in the non-islanded base case that does not appear in the island case, corresponding to the effect of mitigating these constraints. These assumptions are defined in Table 5.6:

Table 5.6 Generation constraint benefit assumptions

Parameter	Unit	Value	Notes
Compensation payment value	£/MWh	324.4	Average across all WPD licence areas [48]
Total avoided 'other generation' curtailment	% of islanded generator curtailment	0.5%	Defined as a percentage of the generation from the islanded generator that is curtailed. This is no longer exported from the island, and can thus be replaced with generation from other sources.

Parameter	Unit	Value	Notes
			The figure of 0.5% corresponds to between 0.0%-1.0% of total EMID ‘other generation’ curtailment, for the particular islands considered.

5.4 Impact of network islanding on services contracted by network operators

As discussed in section 4.3.2, the role of DSO is emerging in the UK industry and the precise nature of it is expected to gradually crystallise through the recommendations of ongoing projects and, ultimately, decisions of the regulator (Ofgem).

As part of its work to date, WPD has established a platform called ‘Flexible Power’ [50] to enable it to procure demand response services from customers who are able to reduce their electricity demand or increase their supply to the grid during peak demand periods.

In addition, in December 2018 WPD signed up to the Piclo Flexibility Marketplace [51, 52] to support its Flexible Power programme and ‘*improve its visibility of unmet flexibility needs*’.

The latest procurement cycle has been announced in January 2020 [53], in which WPD is looking to procure the largest amount of flexibility services of any UK DNO to date across locations within it licence areas. This follows two procurement cycles in 2019, one in 2018 and a trial in 2017/18.

The amount paid for flexibility services has been fixed to a certain level as part of the Flexible Power scheme, available to customers within the particular identified Constraint Management Zones (CMZs) who meet published conditions. Table 5.7 presents the fixed prices that are applied.

Table 5.7 Flexible Power fixed prices for flexibility services

Type	Arming (£/MW per h)	Availability (£/MW per h)	Utilisation (£/MWh)
Secure	125	N/A	175
Dynamic	N/A	5	300
Restore	N/A	N/A	600

The WPD Multi Asset Demand Execution (MADE) project is working to provide ‘*micro-economic and system-level analysis to extrapolate previous trial findings*’. Its focus is on whole-energy system benefits that may be derived from combinations of multiple energy assets that are available to households. Figure 5.12 presents a chart taken from the ‘Domestic FLEX Opportunity Assessment - Modelling Results’ analysis prepared by Everoze [54] as part of that project.

The analysis undertaken by Everoze uses the fixed prices for flexibility services, established in the Flexible Power scheme, along with assumptions about arming and utilisation of the services to determine expected revenues. The figure shows an average of £165 per year average revenue to customers attributed to provision of the DSO service, which corresponds to the secure service for winter weekdays.

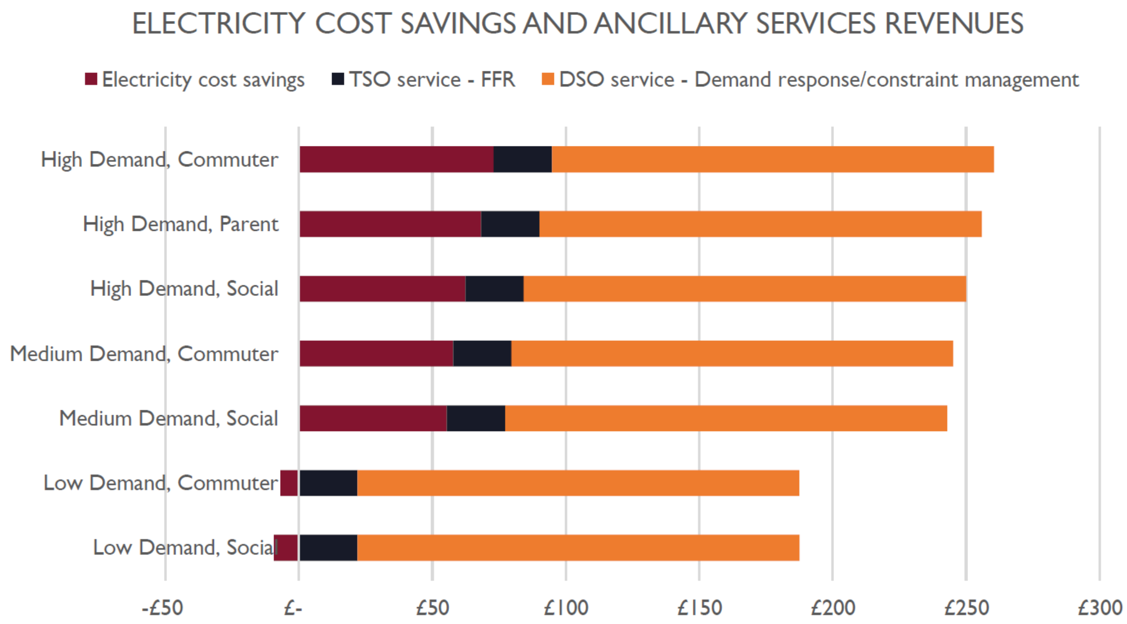


Figure 5.12 WPD project MADE - electricity cost savings and ancillary services revenues

The basis of the assumptions derived from the Everoze analysis for the MADE project is provided in Table 5.8:

Table 5.8 Derived basis of assumptions used in WPD MADE project DSO services revenue modelling

MADE project		
Assumed service volume	3.0	kW
Assumed contracted period	Winter WD	(5 days per week over a period of 6 months, assumed)
Assumed service type	Secure	
Tender success rate	75%	
Utilisation probability rate	50%	
Armed duration	3.5	hours per day
Utilised duration	2.0	hours per day
Average value of annual revenue for services, per customer	165	£ pa

The requirement for DSO services in the specific locations of the prospective network islands has not been assessed in detail. It is recommended that the ability of particular network islands to earn DSO service revenues (or displace the need for services provided by others) should be considered on a case-by-case basis prior to implementation. In addition, the potential impact of network islands (implemented by DNOs) on the competitive market for DSO services should be reviewed.

Given that the procurement cycles are time bound and the prospective network islands considered in this desktop research exercise could not be implemented for some time, the current procurement scheme is not directly applicable. In addition, whilst network islanding is a source of flexibility for DSOs, it is deemed to be inappropriate for DSOs to treat islanding as a flexibility service in competition with and potentially substituting for services obtained through competitive procurement. As such, the potential financial revenues from DSO services have not been included in the quantitative cost benefit analysis. However, the impact of such revenues has been discussed in section 5.5.3.

5.5 Revised cost-benefit analysis

5.5.1 Revisions implemented

Several revisions have been implemented in the cost benefit analysis spreadsheet that was developed as part of work on the Feasibility Study, following the recommendations from that work and other information that has come to light.

In particular, the following updates have been implemented:

- Updated capital costs for the implementation of network islanding, as described in section 2.3;
- Consideration of the annual duration of islanded mode operation, i.e. 0-100% of the time in the year;
- Review of data showing numbers of customers of each type per feeder;
- Addition of bottom-up benefits estimates
  - Capacity release – as discussed in section 5.2; and
  - Mitigation of generation constraint payments – as discussed in section 5.3.
- Removal of top-down benefits estimates (TUOS and DUOS charge reductions) to reflect the recalculation of common charges for all customers to share potential benefits fairly.

5.5.2 Revised cost-benefit analysis results

Table 5.9 presents the characteristics of each prospective network island that has been considered, including:

- Generator installed capacity and substation maximum demand (MW) – as discussed in the HLRAR, the comparison shows that the generation capacity is sufficient to supply the maximum demand of the customers within the island;
- Annual demand (island customers) and annual non-islanded generator output (MWh) – as discussed in the HLRAR, this comparison shows the level of matching between the generator output prior to being islanded and constrained to meet the demand of the island customers (necessary curtailment);
- Capital expenditure (capex), i.e. cost components that are fixed for each island - the capex for implementation of the island (and new islanded generator in the case of the new development island, ND1) is offset by the reinforcement cost in year 2 in the base case, equivalent to the capacity release that the islanding solution provides.

Table 5.9 Island/generator characteristics and capex comparison

Island name:		EM1	EM2	EM3	EM4	ND1
Generator capacity	MW	25.0	25.0	20.9	5.9	11.3
Substation maximum demand	MW	9.1	12.4	24.7	4.6	7.5
Annual demand (island customers)	MWh	24,199	40,003	109,883	14,635	24,278
Annual non-islanded generator output	MWh	65,595	65,595	11,424	20,503	31,792
Year 1 Capex (island/generator)	£k	565.0	549.0	483.0	451.0	9,660.7
Year 2 Base case capex (reinforcement, equiv. capacity release)	£k	435.5	435.5	433.6	130.3	211.1

Table 5.10 presents a summary of the difference (delta) between the base case and islanded case annual opex. This is defined as the base case opex minus the island case opex, i.e. positive values correspond to opex savings derived from islanding.

Table 5.10 Annual opex delta (£k)

	Annual islanded duration		
Island	10%	50%	90%
EM1	-21.3	-106.7	-181.6
EM2	-18.1	-90.3	-130.9
EM3	0	0	0
EM4	-2.2	-10.8	-20.5
ND1	181.4	-28.4	-243.4

Table 5.11 presents the cumulative Net Present Value (NPV) in 2039 for each of the prospective islands. This corresponds to the NPV of the difference in cashflows between the islanded case and base case (including initial capex and annual opex).

Table 5.11 Cumulative NPV 2039

Cumulative NPV 2039 (£k)	Annual islanded duration					
	10%	30%	50%	70%	90%	100%
EM1	-£457.9	-£1,085.1	-£1,712.3	-£2,339.5	-£2,814.1	-£2,953.7
EM2	-£393.7	-£924.5	-£1,455.4	-£1,986.2	-£2,052.8	-£1,865.2
EM3	-£64.1	-£64.1	-£64.1	-£64.1	-£64.1	-£64.1
EM4	-£357.0	-£420.6	-£484.3	-£548.0	-£627.1	-£723.4
ND1	-£6,790.0	-£8,331.8	-£9,873.6	-£11,415.4	-£13,034.4	-£12,731.0

Figure 5.13 presents the cumulative NPV in 2039 figures from Table 5.11 graphically for comparison.

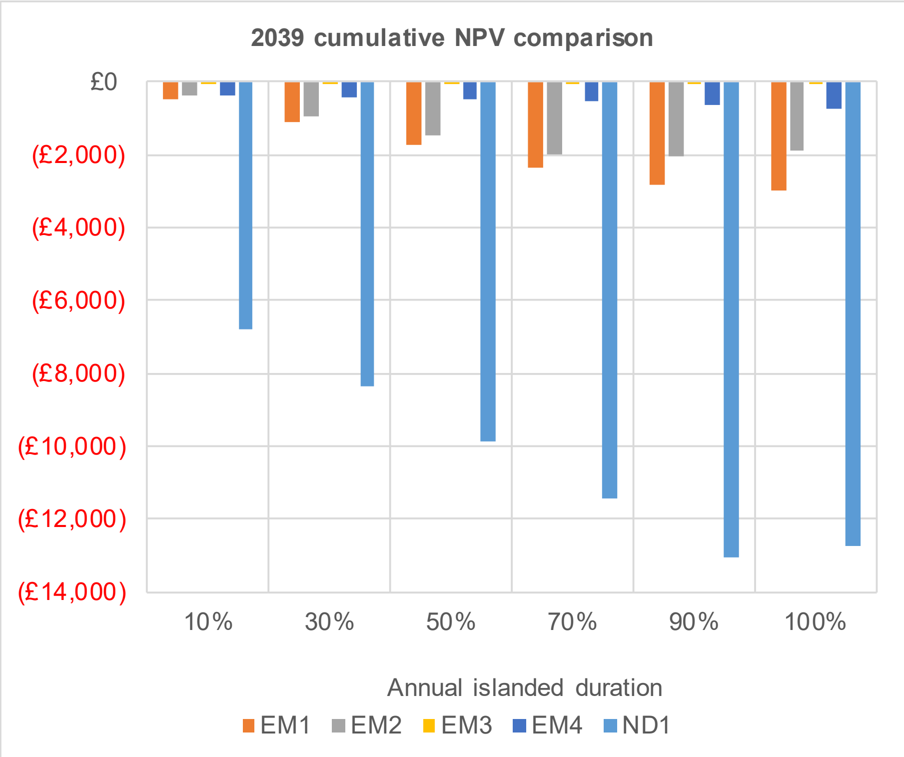


Figure 5.13 2039 cumulative NPV comparison

Figure 5.13 shows a cumulative NPV in 2039 that is negative in all cases. This means that, on the basis of the current analysis, the costs to implement the network islands are not recovered from the derived benefits.

The change from the positive NPV results that were indicated in the Feasibility Study is a result of the switch from the top-down to the bottom-up approach to assessment of financial benefits. The change in approach is principally borne out of the need to ensure fair sharing of benefits between customers inside and outside of any island. As such, it was not deemed reasonable to include speculative reductions in TUOS and DUOS in the analysis. Unfortunately the benefits determined through the bottom-up assessment are lower than those from the previous assumptions.

It can be seen that the cumulative NPV in 2039 reduces for the cases where the islands are operated in islanded mode for a greater portion of the year. This is a result of the repayment to the island DG operator of revenue for generation curtailed whilst operating in island mode increases with the amount of time spent in island mode.

It should be noted that EM3 is an unusual case in that the generator in this prospective island was historically operated to provide the Short Term Operating Reserve (STOR) service to National Grid. The analysis is based on historic data for this generator, which was only operational for very short periods. As a result, the amount of generation that could be curtailed from this generator is very small, and so the repayment to the DG operator is also small.

In addition, as discussed in the Feasibility Study, the ND1 case includes the capital cost for the new generator that would need to be developed as part of the implementation of an island for such a new development. The impact of this additional capex is a strong negative effect on the NPV.

5.5.3 Potential additional benefits

Although the results of the cost benefit analysis in 5.5.2 paint a somewhat negative picture, it should be noted that potential DSO service revenues described in section 5.4 have not been included in this analysis. These could be added as an additional revenue line for the islanded case in the CBA spreadsheet. However, it was a deliberate decision to exclude them given that:

- The procurement cycles are time bound;
- The current procurement scheme is not directly applicable to the prospective network islands; and
- Islands implemented by DNOs are unlikely to be allowed to substitute for flexibility services that are procured through a competitive process from third parties.

Table 5.12 presents the required annual revenues from DSO services for islands to breakeven, should the above challenges be overcome. In such cases, they would provide additional revenues to the DNO, which would act to offset the required investment to implement the islands. The figures highlighted in yellow indicate that additional revenues from provision of DSO services in the range from £24,300 to £73,800 per year would make islands EM1, EM2 and EM4 attractive for time-limited applications (i.e. mitigation of constraints for up to 30% of the year).

Table 5.12 Required annual revenues from DSO services for islands to breakeven

Annual payment to achieve breakeven 2039 cumulative NPV (£k pa)	Annual islanded duration %					
	10%	30%	50%	70%	90%	100%
EM1	£31.2	£73.8	£116.5	£159.2	£191.5	£201.0
EM2	£26.8	£62.9	£99.0	£135.1	£139.7	£126.9
EM3	£4.4	£4.4	£4.4	£4.4	£4.4	£4.4
EM4	£24.3	£28.6	£32.9	£37.3	£42.7	£49.2
ND1	£462.0	£566.9	£671.8	£776.7	£886.8	£866.2

Table 5.13 is the corollary of Table 5.12. It shows the number of customers receiving the average revenue of £165 pa for DSO services that would need to be displaced in order to provide the revenue required to make the network island solution attractive in these cases (between 147 and 447 customers for islands EM1, EM2 and EM4 for up to 30% annual islanded duration).

Table 5.13 Equivalent number of customers with average DSO service revenues

Number of customers with DSO service revenues of £165 pa (taken from MADE)	Annual islanded duration					
	10%	30%	50%	70%	90%	100%
EM1	189	447	706	965	1,160	1,218
EM2	162	381	600	819	846	769
EM3	26	26	26	26	26	26
EM4	147	173	200	226	259	298
ND1	2,800	3,436	4,071	4,707	5,375	5,250

In conclusion, it may be possible to obtain additional revenues to make network islanding attractive for time-limited applications. However, it is not possible to definitively claim that these can be achieved. As such, it is recommended that the cost benefit analysis for network islanding should be reviewed again in 2-3 years to determine whether the relatively modest additional revenues can be achieved.

System losses

The ability of network islanding to reduce system losses was identified as a potential additional benefit at an early stage of the network islanding investigation. The network modelling that was carried out as part of the Investigation Findings Report included a calculation of the electrical system losses on EM1 and EM2 networks in order to quantify this additional benefit. The detailed technical parameters of the losses calculations and the results of the calculations are described in Appendix A.

The initial hypothesis was that network losses would always decrease in islanded operation as the islanded demand would be supplied by local generation instead of being supplied from the local BSP. This was confirmed to be the case for the EM1 calculation, where the losses were observed to decrease by 1.86% in island mode compared to the grid connected mode.

However, the same calculation applied to the EM2 network showed that the losses increased by 0.36% in island mode compared to the grid connected mode. Whilst this was initially thought to be an error in the analysis, it was found that the increase in losses is technically correct. The reason is due to the island generation being physically separated from the demand over a long 33kV feeder and therefore there are relatively high losses from this feeder in islanded mode. In grid connected mode, the demand is connected in very close proximity to the BSP resulting in relatively low losses. The EM1 network has the generation and demand located in close proximity to each other, while both are a relatively long distance from the local BSP. This explains the counter-intuitive losses result that was observed for the EM2 island network.

The analysis shows that it cannot be assumed that a prospective island will improve electrical losses. The island has to be modelled and a calculation has to be carried out to confirm if there is a reduction in losses. In either case, the magnitude of loss reduction/increase is small (lower than 3%) due to the relatively small size of the islands in terms of peak demand. It is therefore apparent that reduced system losses can be an additional benefit of intentionally islanding networks, but it exists, it is not of sufficient magnitude to factor into the commercial feasibility analysis of network islands.

Carbon benefit calculation

The carbon benefit calculation is based on the system losses reduction for EM1 and described in the section above. The total system losses are reduced by 1.86% by EM1, which translates to a saving of 0.138MW. The methodology for calculating the carbon saving from the reduction of system losses due to EM1 is as follows:

- **Step 1** – Obtain the average CO2 intensity for generation across the UK for the purposes of calculating the carbon emission saving from the reduced losses;
- **Step 2** – The second step is to calculate the percentage of the year that the network island is operating in island mode. This will provide the MWh energy saving from the reduction in losses; and
- **Step 3** – The second step is to multiply the average CO2 intensity by the calculated reduction in energy expended due to the reduced losses.

The carbon benefit calculation and associated results are shown in Table 5.14. The results show a modest carbon saving of 22,533 kgCO2 when operated in island mode for 10% of the year. The percentage of year in island mode aligns with the 10% figure that we have used in our benefits calculation spreadsheet. The carbon benefit is improved if the island is operated for longer durations.

Table 5.14 Average carbon benefit calculation and results

Item ID	Calculation	Description	Unit	Value
A		EM1 loss reduction	MW	0.138
B	A * 1000	EM1 loss reduction	kW	138
C	-	Average UK gen carbon intensity	gCO2/kWh	186.4
D	-	Percentage of year in island mode**	%	10
E	365 * D * 24	No. hours in island mode	Hours/yr	876
F	B * E	Energy losses reduction	kWh	120,888
G	**(C * F)/1,000**	**Carbon benefit**	**kgCO2/yr**	**22,533**

** The percentage of year in island mode aligns with the 10% figure that we have used in our benefits calculation spreadsheet.

5.6 Summary of findings

During the course of the commercial investigation, the following findings have been obtained:

- It is in the interest of the DNO to undertake an assessment of the numbers of customers and breakdown of types of customers within prospective islands. No particular issues have been identified in this regard, but this is recommended to confirm that no operational issues would be expected to arise, or potential impacts on cost recovery;
- Prospective sections of network for islanding should be reviewed on a case-by-case basis to confirm the nature of specific reinforcement projects that may be avoided, local generation constraints and associated benefits. This project has identified estimates for the anticipated benefits associated with capacity release and mitigation of local generation constraints;
- It is recommended that the ability of particular network islands to earn additional DSO service revenues (or displace the need for services provided by others) should be considered on a case-by-case basis prior to implementation, including the potential impact on the competitive market for DSO services. No such revenues have been included in the quantitative analysis presented in this report;
- On the basis of the current analysis the costs to implement network islands are not recovered from the derived benefits, resulting in a negative cumulative NPV in 2039 in all cases;
- The cumulative NPV in 2039 reduces for the cases where the islands are operated in islanded mode for longer periods, i.e. network islanding is a more attractive solution for limited duration applications;
- It may be possible to obtain additional revenues to make network islanding attractive for time-limited applications (from £24,300 per year). However, it is not possible to definitively claim that these can be achieved. As such, it is recommended that the cost benefit analysis for network islanding should be reviewed again in 2-3 years to determine whether the relatively modest additional revenues can be achieved.

Table 5.15 presents a summary of the link between drivers for network islanding, corresponding benefits and estimated financial benefits.

Table 5.15 Relationships between drivers and benefits

Driver	Corresponding benefit associated with network islanding	Potential means of monetisation of benefit	Estimated financial value of benefit (£)
Supply expansion	Reduced need for traditional reinforcements	Avoided capital costs of traditional reinforcements	Capacity release = £288,730 / 13.9 MVA * generator peak output = £20,845/MVA * generator peak output

Driver	Corresponding benefit associated with network islanding	Potential means of monetisation of benefit	Estimated financial value of benefit (£)
Clean energy	Increased use of renewable generation sources	Mitigation of generation constraint payments	Average EMID constraint payments = £324.4/MWh, assumed to apply to 0.5% of islanded generator curtailment
		Avoided costs of alternative climate change mitigation measures	-
		Avoided costs of penalties associated with GHG emissions	-
Flexibility (local control; clean energy; new products; innovation; reliability; low energy costs)	Additional flexibility tool	Potentially from redirection of revenues from DSO flexibility services markets, i.e. Flexible Power platform.	Average DSO service revenues of £165 pa per customer

6. Conclusions

6.1 Findings

The engagement with various manufacturers has provided more detailed information on the equipment and system requirements for network islands. The engagement also provided a more accurate estimate of the costs attributed to the design, development and installation of islanded networks on the distribution system. The majority of the manufacturers have tried and tested equipment and systems that are able to create and manage utility scale islands. The larger manufacturers can implement turnkey solutions i.e. produce the specification, detailed design, testing, installation and commissioning.

All manufacturers that responded to our enquiries considered that the trial networks investigated in this study could be implemented as technically feasible and stable islands. A key outcome of this engagement is the learning that there is no ‘cut-and-paste’ solution for the specification and design of network islands: each island will have different requirements based on the existing equipment in the island; the number and type(s) of generation in the island; the number of synchronisation points; and the geography/architecture of the network. Each island requires detailed modelling, studies and analysis prior to committing resources for a real-world trial.

Work completed in previous stages of the Network Islanding Investigation project has been supplemented and finalised within the findings detailed in this report. In summary, the results from all the research, studies and investigations indicate that it would be technically possible to implement network islanding as trial on the GB Distribution Network. Network islanding can be implemented within the existing legal and regulatory framework. However, updates to statutory documentation would be required to remove ambiguity and make explicit provision for network islanding for it to be rolled out across GB.

In addition, it is anticipated that changes to the regulatory framework as part of the DSO transition are likely to complement islanding. The investigation into the existing commercial frameworks and possible revenue streams has shown that it is difficult to achieve sufficient financial benefits. This means that the costs to implement network islands are not recovered from the derived benefits. For network islands EM1 and EM2 the NPV in 2039 is -£457,900 and -£393,700 assuming that the network operates in island mode for 10% of the time. The NPV also decreases as the time in islanding mode increases due to the additional curtailment costs that occur. Location-specific benefits and potential additional revenue streams should be reviewed again in 2-3 years.

6.2 Summary of requirements for future trials

The procedures and processes for determining the feasibility of network islands have been captured throughout the delivery of the project. These have been summarised in three separate flow charts; Technical Requirements (Figure 6.1), Regulatory and Legal Checklist (Figure 6.2) and Commercial Assessment (Figure 6.3). These flow charts can be used for future assessments of network islands.

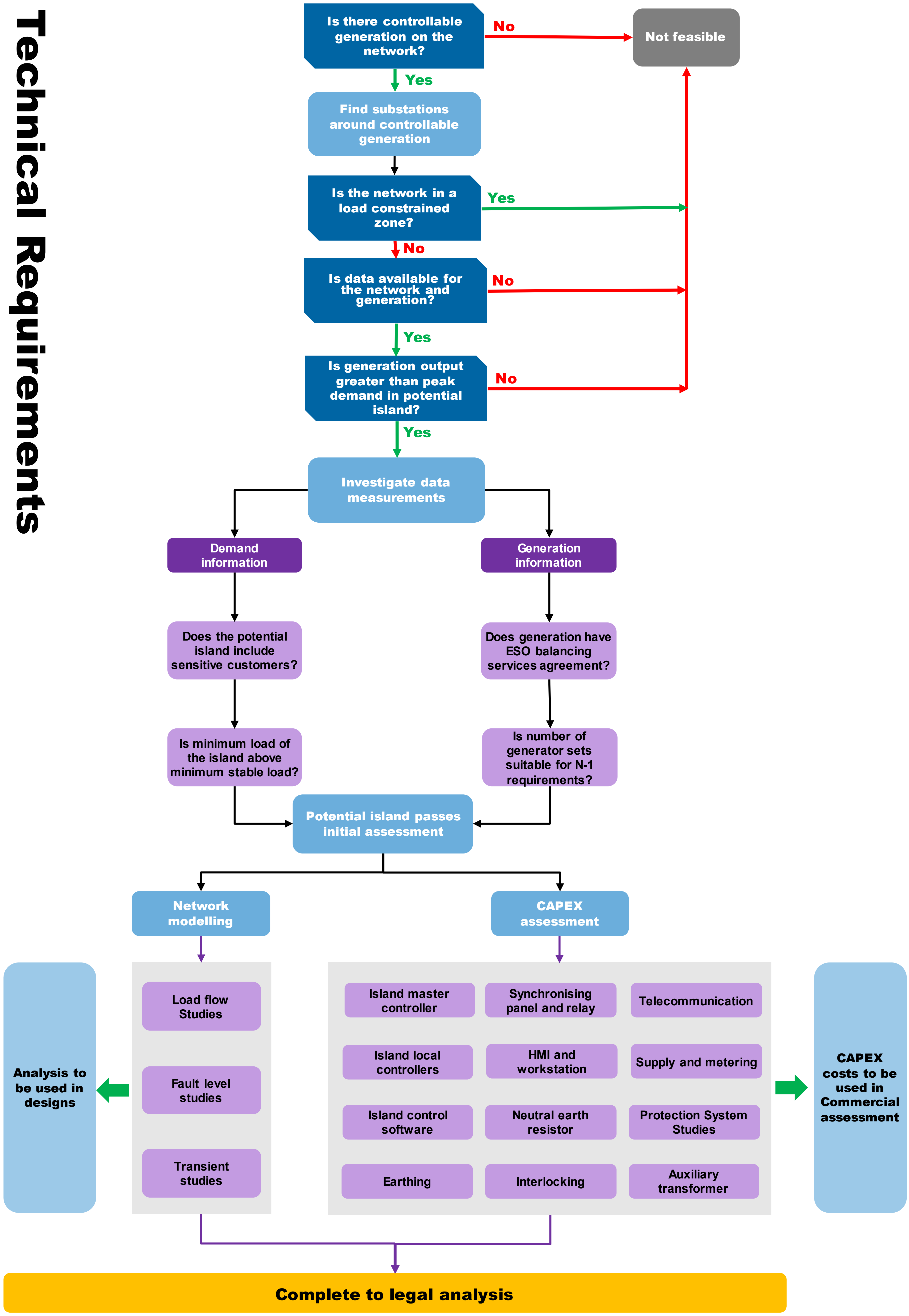


Figure 6.1 Technical requirements flow chart

Regulatory & Legal Checklist

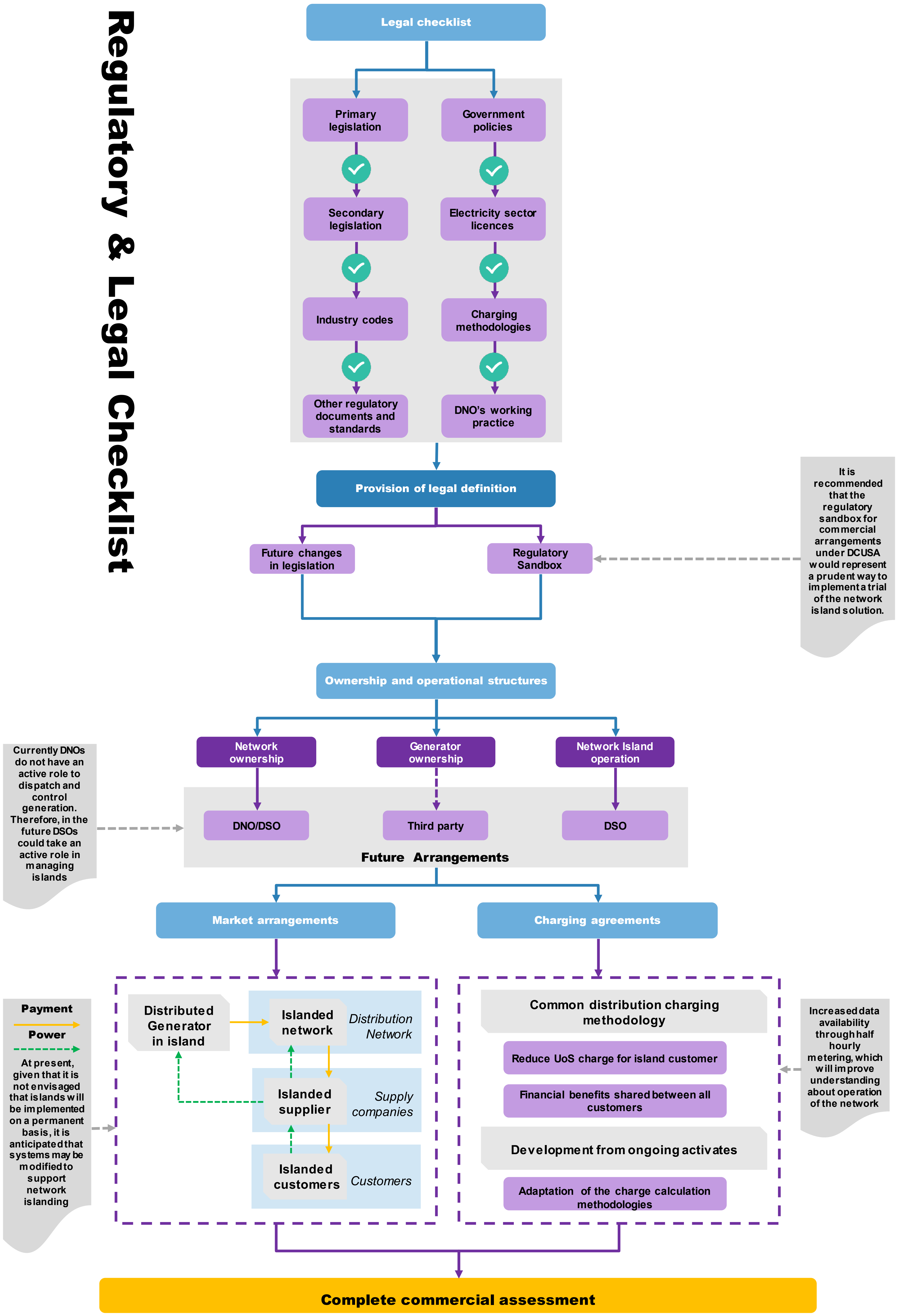


Figure 6.2 Regulatory and legal checklist flow chart

Commercial Assessment

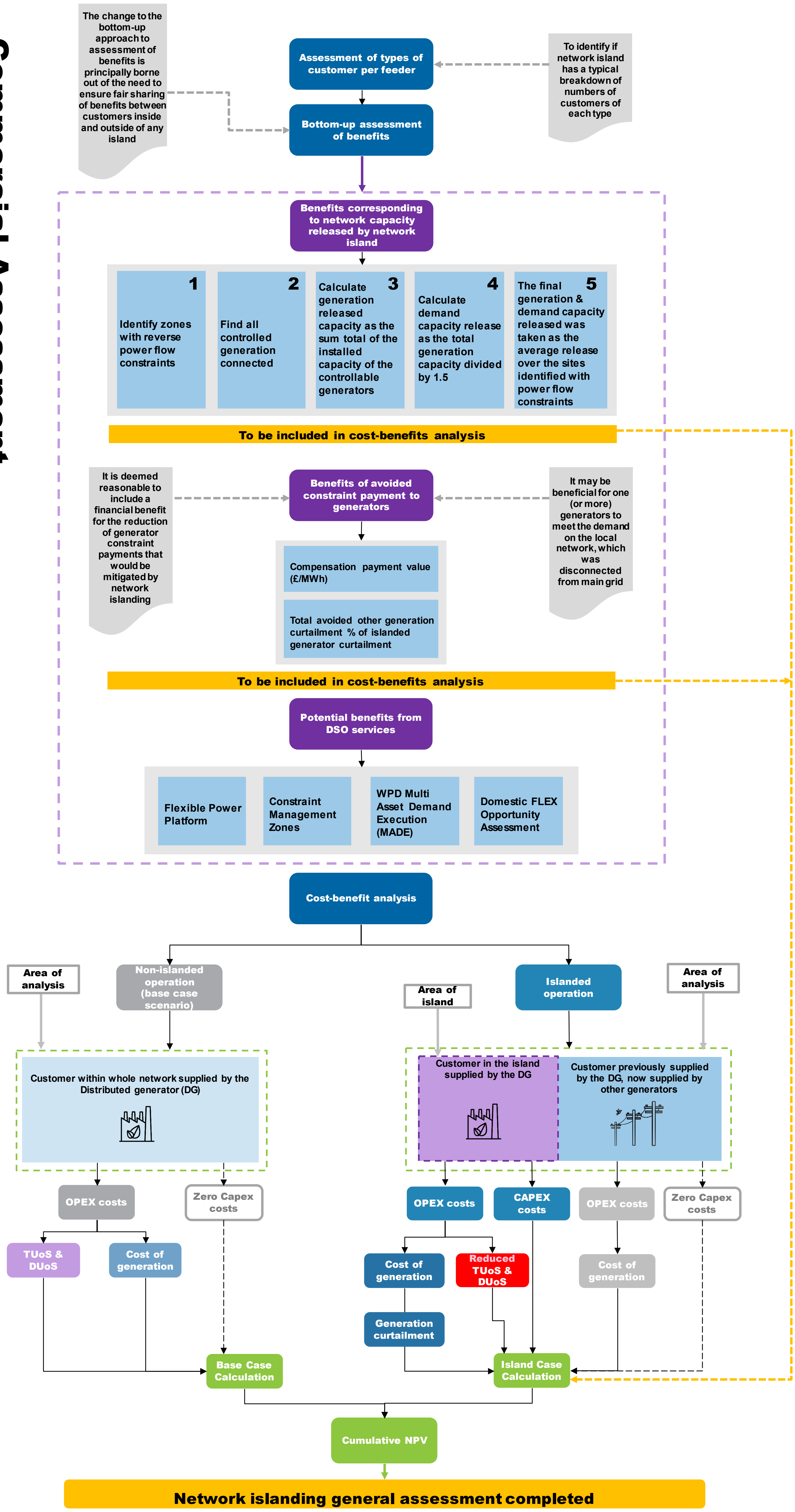


Figure 6.3 Commercial assessment flow chart

In addition to the flow charts produced, two tools have been prepared to assist in the evaluation of network islands. The first tool relates to the assessment and ranking of potential network islands. Figure 6.4 shows the technical factors that need to be considered for islanding and the draft tool has also been produced which allows an initial assessment for EM1 to EM4 in Figure 6.5.

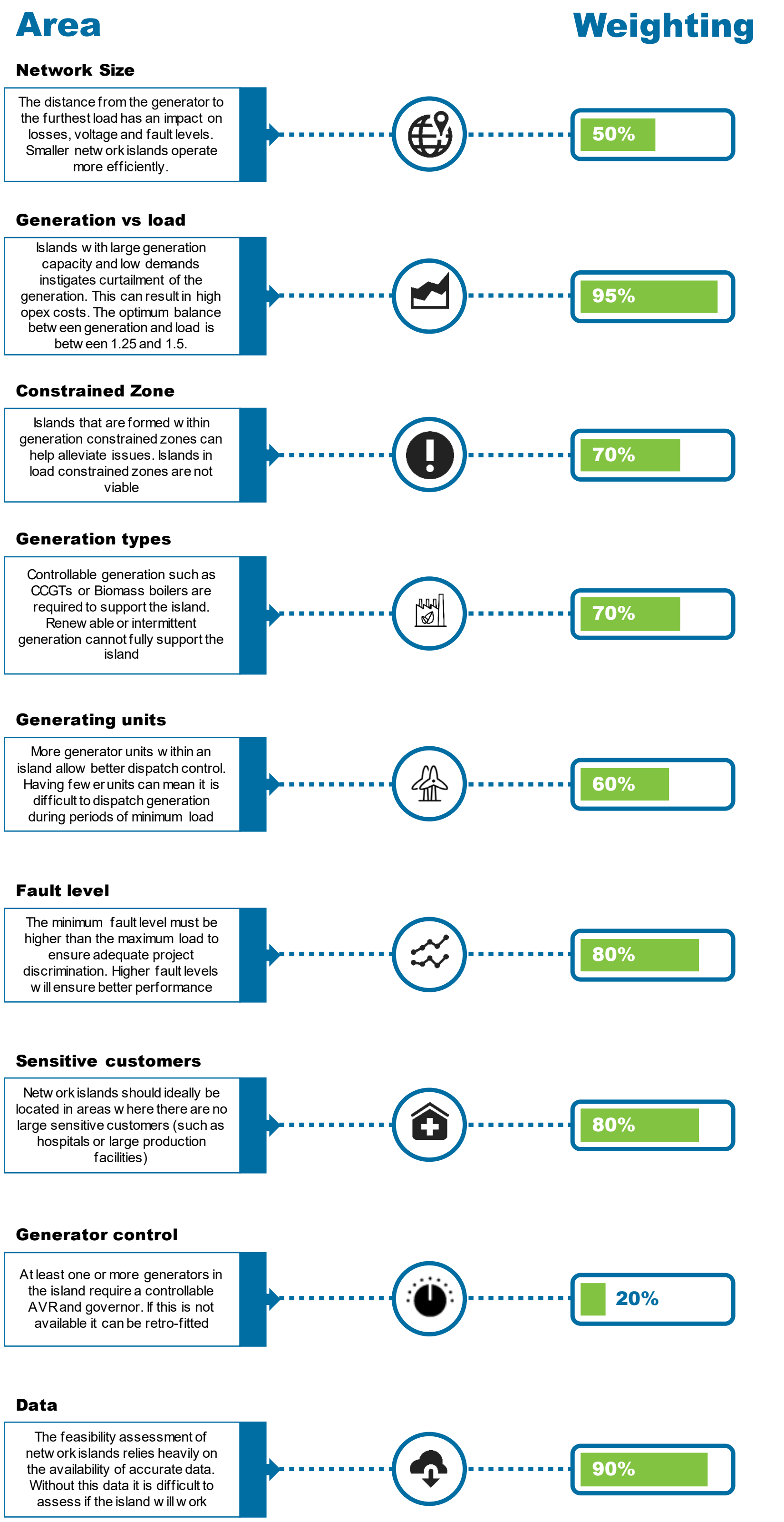


Figure 6.4 Factors to be considered for network islands

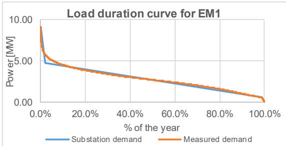
Network Island	Network size Distance from furthest load to generator		Generation vs load Generation Cap versus Max Load		Constrained zone Is the island in a constrained zone		Generation types Is the island has controllable low-carbon emission generator		Generating units Number of generating units in the island		Fault level Minimum fault level versus maximum loading		Sensitive customers Are there any sensitive customers in the island?		Generator control Do the generators in the island have a controllable AVR and governor		Data What data is available for the network island		Total (max. score 100)
	Value	Result (max. score 3)	Value	Result (max. score 3)	Value	Result (max. score 3)	Value	Result (max. score 3)	Value	Result (max. score 3)	Value	Result (max. score 3)	Value	Result (max. score 3)	Value	Result (max. score 3)	Value	Result (max. score 3)	
EM1	9	3	3.5	1	Generation constrained zone	3	Biomass CHP	3	5	3	Greater than 2.5 times minimum load	3	No	3	Yes, 2	2	Yes	3	**89**
EM2	17	2	1.6	1	Generation constrained zone	3	Biomass CHP	3	5	3	Greater than 2.5 times minimum load	3	No	3	Yes, 3	2	Yes	3	**86**
EM3	21	1	0.928	1	No constrained zone	2	Dedicated biomass	3	2	1	Greater than 2.5 times minimum load	3	No	3	Yes, 1	2	No	1	**63**
EM4	12	2	2.2	1	No constrained zone	2	Biomass CHP	3	2	1	Greater than 2.5 times minimum load	3	No	3	Yes, 1	2	No	1	**65**

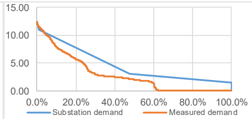
Figure 6.5 Scoring tool for EM1 to EM4

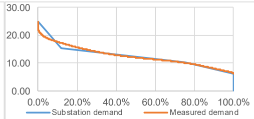
In addition, a detailed commercial analysis tool has been produced which allows potential islands to be assessed from a commercial perspective. The tool uses capital expenditure values (gathered from an assessment of the technical requirements for the island) and operational expenditure values to allow the user to calculate the NPV at different points in time. A screenshot from the tool is shown in Figure 6.6.

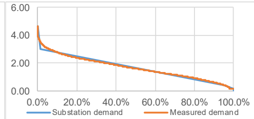
Demand Information

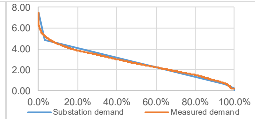
Description	Unit	Value	Source/comments	Value	Source/comments	Value	Source/comments	Value	Source/comments	Value	Source/comments
Substation Peak time	%	0.0%		0.0%		0.0%		0.0%		0.0%	
Substation Shoulder time	%	2.2%		1.0%		12.0%		1.6%		3.5%	
Substation Knee time	%	99.0%		47.5%		75.0%		95.0%		95.0%	
Substation Minimum time	%	100.0%		100.0%		100.0%		100.0%		100.0%	
Substation Minimum time	%	100.0%		100.0%		100.0%		100.0%		100.0%	
100% time	%	100.0%		100.0%		100.0%		100.0%		100.0%	
Substation Demand at System Peak 2017/18	MW		Not used		Not used		Not used		Not used		Not used
Substation Peak Demand	MW	9.14	Based on historic data	12.44	Based on historic data	24.74	Based on historic data	4.63	Based on historic data	7.50	Approximation based on historic data
Substation Shoulder Demand	MW	4.78		11.00		15.42		3.02		4.89	
Substation Knee Demand	MW	0.60		3.03		10.20		0.40		0.65	
Substation Minimum Demand	MW	0.03		1.50		6.33		0.14		0.22	
Zero demand - substation minimum time	MW	0.00		0.00		0.00		0.00		0.00	
Zero demand - 100% time	MW	0.00		0.00		0.00		0.00		0.00	
Annual demand	MWh	24,199		40,003		109,883		14,635		24,278	
Load factor	%	30%		37%		51%		36%		37%	
Assumed load per customer (MPAN)	kW	2.5	Estimate	2.5	Estimate	2.5	Estimate	2.5	Estimate	2.5	Estimate
Number of customers	No.	3,700	Calculated estimate	5,000	Calculated estimate	9,900	Calculated estimate	1,900	Calculated estimate	3,000	Calculated estimate
Annual islanded duration	%	10.0%		10.0%		10.0%		10.0%		10.0%	
Daily islanded duration	%	100%	Estimate - not used	100%	Estimate - not used	100%	Estimate - not used	100%	Estimate - not used	100%	Estimate - not used











3-blocks (demand)	Peak-shoulder demand	MWh	1,341		1,027		21,104		536		1,899	
	Shoulder-knee demand	MWh	22,831		28,567		70,683		13,982		22,189	
	Knee-minimum demand	MWh	27		10,408		18,096		117		190	
	Annual demand	MWh	**24,199**		**40,003**		**109,883**		**14,635**		**24,278**	
3-blocks (demand), adjusted for % annual islanded duration	Peak-shoulder duration	%	2.2%		1.0%		12.0%		1.6%		3.5%	
	Shoulder-knee duration	%	96.8%		46.5%		63.0%		93.4%		91.5%	
	Knee-minimum duration	%	1.0%		52.5%		25.0%		5.0%		5.0%	
	Annual duration	%	**100.0%**		**100.0%**		**100.0%**		**100.0%**		**100.0%**	
	Annual islanded duration	%	**10.0%**		**10.0%**		**10.0%**		**10.0%**		**10.0%**	
	Peak-shoulder islanded duration	%	0.0%		0.0%		0.0%		0.0%		0.0%	
	Shoulder-knee islanded duration	%	10.3%		21.5%		15.9%		10.7%		10.9%	
	Knee-minimum islanded duration	%	0.0%		0.0%		0.0%		0.0%		0.0%	
	Annual islanded duration	%	**10.0%**		**10.0%**		**10.0%**		**10.0%**		**10.0%**	
	Peak-shoulder islanded demand (island mode)	MWh	0		0		0		0		0	
	Shoulder-knee islanded demand (island mode)	MWh	2,359		6,144		11,220		1,497		2,425	
	Knee-minimum islanded demand (island mode)	MWh	0		0		0		0		0	
	Annual islanded demand (island mode)	MWh	**2,359**		**6,144**		**11,220**		**1,497**		**2,425**	
	Peak-shoulder islanded demand (grid connected)	MWh	1,341		1,027		21,104		536		1,899	
	Shoulder-knee islanded demand (grid connected)	MWh	20,472		22,424		59,464		12,485		19,764	
	Knee-minimum islanded demand (grid connected)	MWh	27		10,408		18,096		117		190	
	Annual islanded demand (grid connected)	MWh	**21,841**		**33,859**		**98,664**		**13,138**		**21,853**	
DUOS red-amber-green	Red demand	MWh	3,486		6,921		14,240		2,038		3,555	
	Amber demand	MWh	13,635		23,356		52,222		8,460		13,939	
	Green demand	MWh	7,079		9,725		42,381		4,137		6,784	
	Annual demand	MWh	**24,199**		**40,003**		**108,842**		**14,635**		**24,278**	
DUOS UC1-UC2	UC1 demand	MWh	21,189		31,691		88,001		12,954		21,531	
	UC2 demand	MWh	3,010		8,312		21,882		1,681		2,747	
	Annual demand	MWh	**24,199**		**40,003**		**109,883**		**14,635**		**24,278**	

Figure 6.6 Commercial assessment tool

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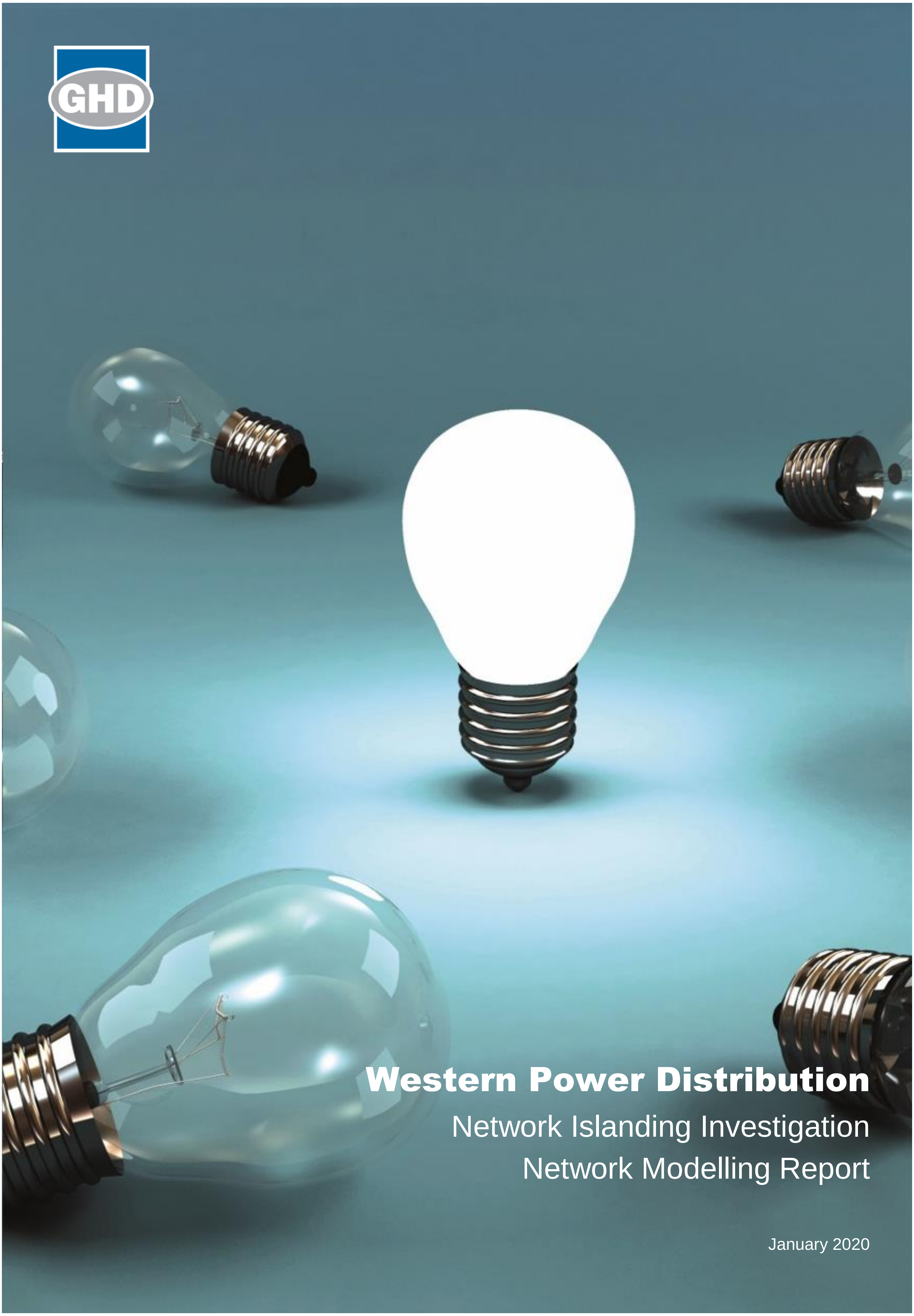
Appendix A
Network Modelling Report



Western Power Distribution

Network Islanding Investigation
Network Modelling Report

January 2020

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Appendices

Appendix A – G59/G99 Requirements

1. Introduction

1.1 Overview

This report details the data and method used to perform power studies as part of the Network Islanding Investigation project and the results obtained from these studies. The scope of the power system studies take information gained by the data gathering, review, research and analysis tasks that have already been completed on the Network Islanding Investigation project as shown in Table 1-1.

Table 1-1 Network Islanding Investigation tasks

Task 1: Data Gathering
Task 2: High-Level Review
Task 3: High-Level Research and Analysis
Task 4: Feasibility Study
Task 5: Further Investigation
Task 6: Network Modelling
Final project deliverable: Network Islanding Investigation Findings Report

Following these tasks, four areas of the Western Power Distribution (WPD) East Midlands distribution network have been identified with the potential to form small island grids within the existing network. The potential islands are designated EM1 to EM4 and are described in detail in the Feasibility Study Report. In general, they consist of one or more primary substation(s), a controllable generating source and associated interconnected 33kV and 11kV network.

The network islands EM1 and EM2 are the subject of this modelling study.

1.2 Network model

This section provides an overview of the method used to construct the network models in DIgSILENT Powerfactory suite of power system analysis software and the assumptions made in the absence of data available to GHD at the time of the study.

1.2.1 Islands studied

Wellingborough Bulk Supply Point (BSP) supplies both the network islands EM1 and EM2 within the Grendon Grid Supply Point (GSP) group. EM1 is supplied by Wykes Engineering Generation Plant (WEGP) and includes Harrold and Sharnbrook primary substations (connected via an 11kV interconnector). EM2 is also supplied by WEGP and includes the Little Irchester primary substation. Simplified schematic drawings for EM1 and EM2 are shown in the highlighted areas in Figure 1-1 and Figure 1-2 respectively.

The DIgSILENT PowerFactory suite of power systems analysis software has been used to create electrical models of both islands. The models have been used to perform fault level, load flow and a series of transient stability studies to assess the technical feasibility of managing and operating each islanded system. Fault level and load flow studies include an analysis of the 11kV system. Further details on the studies are provided in the following sections.

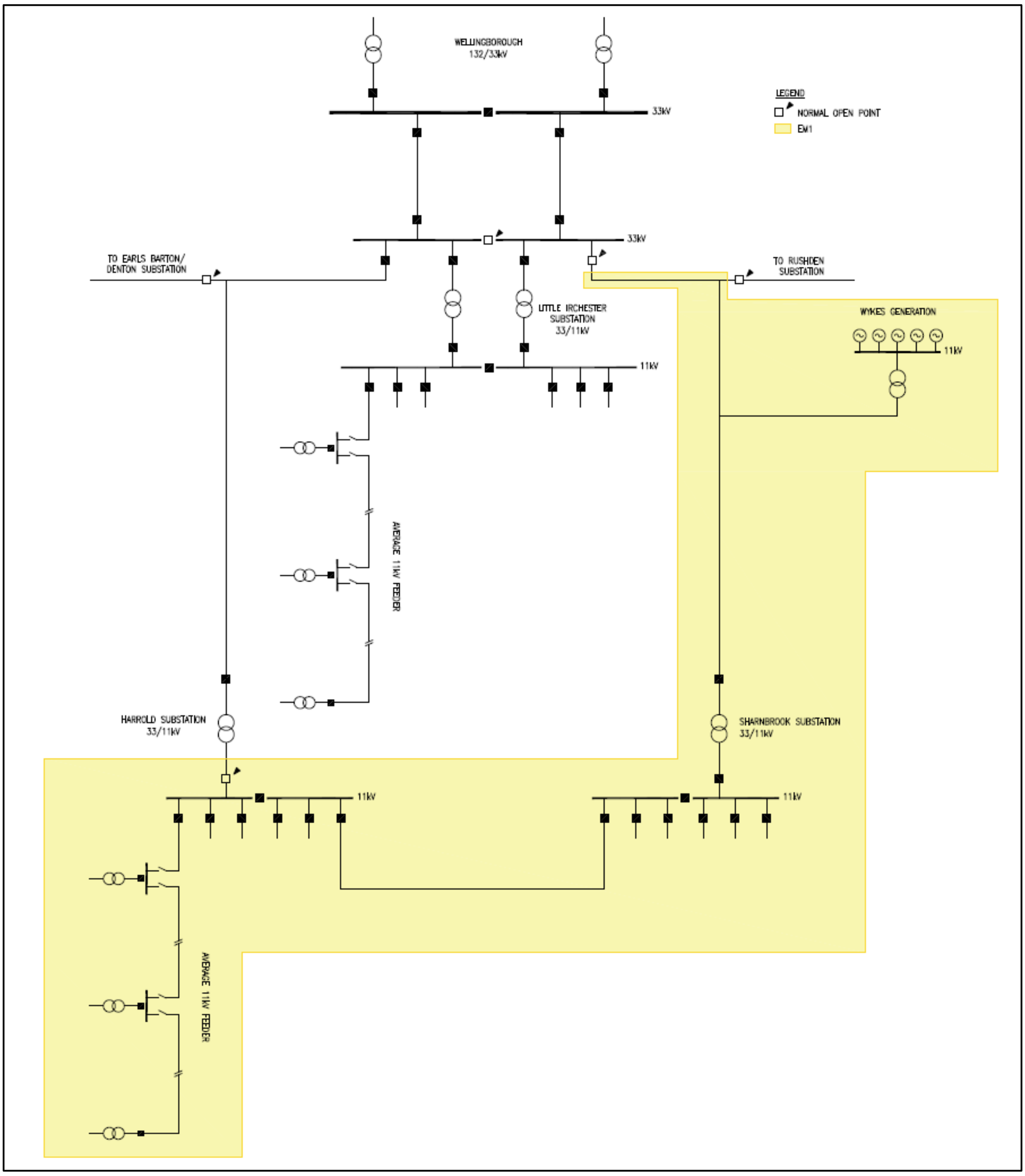


Figure 1-1 EM1 schematic drawing

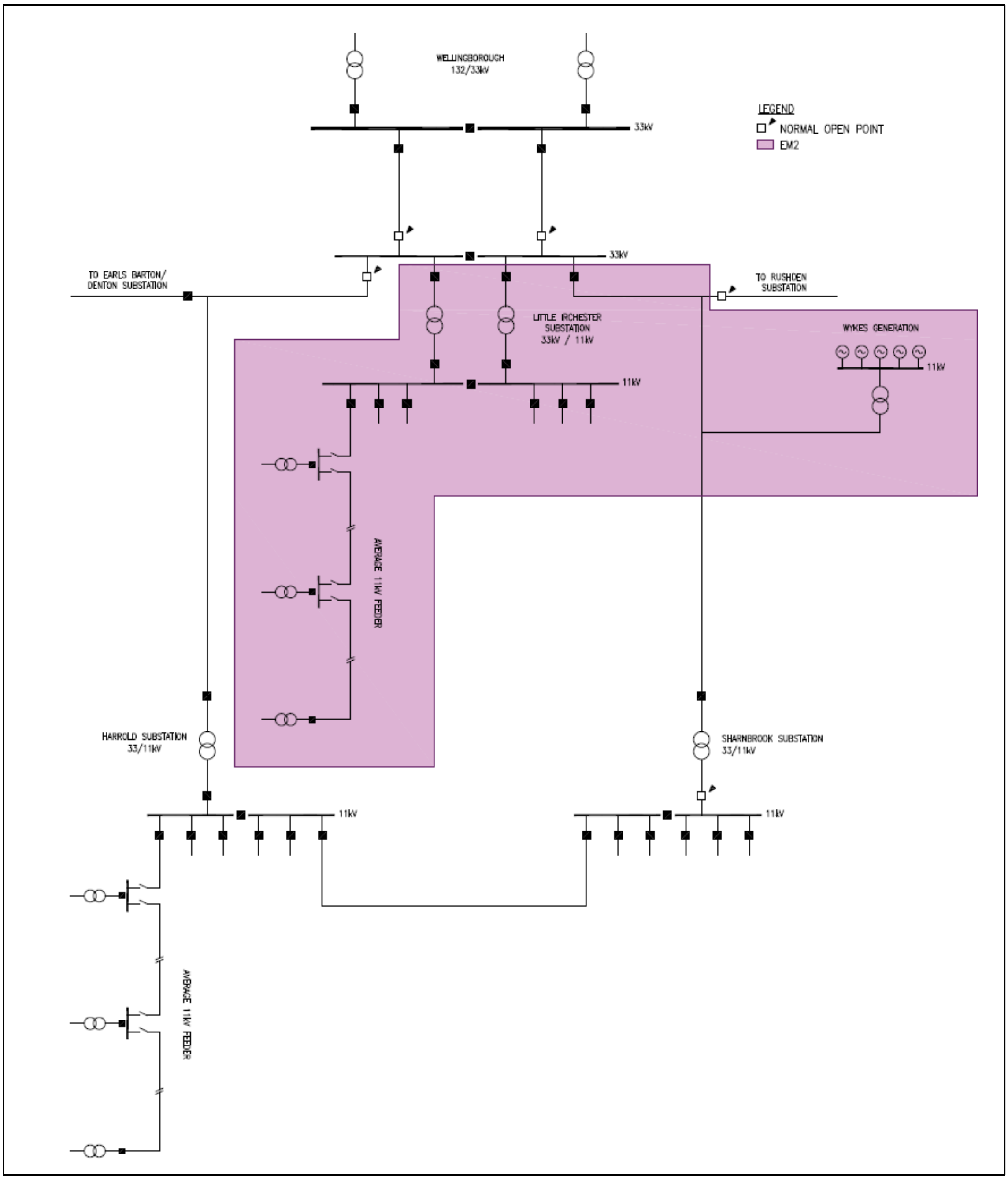


Figure 1-2 EM2 schematic drawing

1.2.2 Generic system data

Various elements of network data were required to create the network models to represent the network islands. The majority of data was available through existing WPD databases and network models; however, in some instances there was a need to make engineering assumptions where data was missing or invalid.

A list of the data that was available from existing sources is shown in Table 1-2.

Table 1-2 Data requirements and sources

Data Requirement	Source
Network configuration	• EMU Mapping System • East Midlands IPSA Model
Equivalent source network (NG infeed)	• East Midlands IPSA Model • 2018 LTDS
Load data	• East Midlands IPSA Model • 2018 LTDS • PI Historian
Line and branch data	• East Midlands IPSA Model • 2018 LTDS
Primary transformer data	• East Midlands IPSA Model • 2018 LTDS
Distribution transformer data	• WPD EE Spec 5
Generator data	• East Midlands IPSA Model • Connection Agreements • G59/G99 Commissioning Records

The following assumptions were made in order to ensure the network model accurately replicates the voltage control elements of the system:

- For 33/11kV primary substation transformers, the 11kV voltage set point has been set at 1.03PU;
- The generation plant 33/11kV transformer tap changer has been setup to control the 33kV voltage at the local 33kV busbar to a set point of 1.01PU; and
- The reference generator was set to control the Wykes 11kV voltage to 1.0PU.

1.2.3 Generator data

At the time of analysis, detailed information was not available for the generation plant units within the network island such as the dynamic characteristics of the machines. Therefore, engineering assumptions were made to account for missing information and to allow the model to be built. Dynamic data from GHD's existing generator database was used to provide typical generator models for the below plant.

- Gen 1 – ALSTOM P140843-10: 5MW;
- Gen 2 – AVK DIG 163n/4: 14.0MW;
- Gen 3 – ABB AMG 1120MP12: 6.6MW;
- Gen 4 – ABB B194CM102-B: 10.4MW; and
- Gen 5 – P-OB-10179-GB: 14.0MW.

IEEE standard AVR and governor models readily available in the Powerfactory standard library were also used within the model to allow the transient analysis to be completed.

The total installed generation at Wykes sums to 50MW, however, the customer only has an agreed export capacity of 25MW. It has been assumed that the balance in generated power is consumed locally, behind the meter, for their own industrial processes. Therefore, we have modelled a 20MW (@ 0.95 PF) shunt load at the Wykes 11kV busbar in order to represent the behind the meter load. The shunt load is required to stabilise the generators, acting as a minimum load top up so that all the generators can be energised without running below their minimum loading. This operational assumption has not been confirmed with Wykes as part of this study, however, it was communicated and agreed with WPD before commencing the studies.

1.2.4 11kV network data

A model for the existing 11kV network was not readily available and therefore an “average” 11kV feeder was created and representative of a typical WPD feeder:

- An average 11kV feeder length of 9km;
- Composition of 11kV feeder – 3km 240 Cu, 6km 185 Cu;
- HV/LV substations interspersed along the 11kV feeder circuit;
- HV/LV transformer specification of:
  - 1,000kVA;
  - 11/0.415kV;
  - 4.75 % impedance on rating; and
  - Tap changer present (-5%, +5% in 2.5% steps), however, off-load only and hence disabled (Set at 0% nominal for the studies).

As part of the study, it was important not only to understand the implications of the network island on the 11kV network, but also the LV network. Therefore, the studies investigated the impact on an HV/LV substation at the start, middle and end of the feeder as shown in Figure 1-3

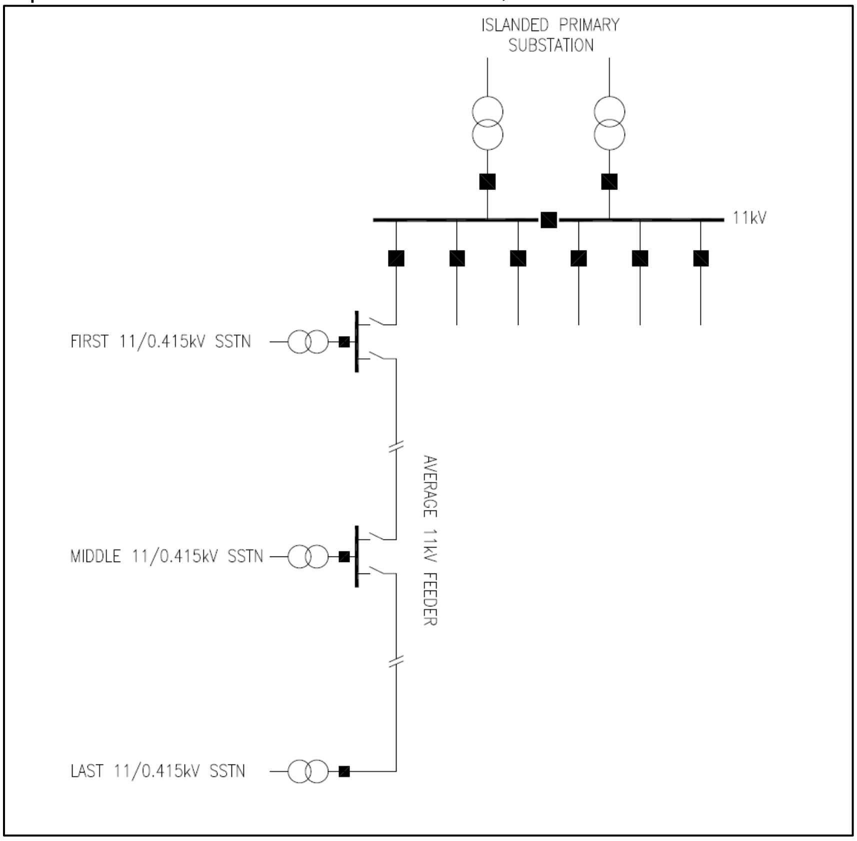


Figure 1-3 Distribution substations on 11kV feeder

The load at the primary substation has been equally distributed between the distribution substations in the network model, as there is no accurate data is available for these substations. This is a worst-case scenario as there will be many more substations on the 11kV network, which would result in a more even distribution of load across the network.

1.3 Power system studies

1.3.1 Overview

The following studies were performed on the network island models to establish the technical feasibility of managing and operating the island networks:

- Load flow;
- Fault level; and
- Transient stability.

Further detail of the studies performed are described in following sections.

1.3.2 Load flow

The steady state load flow studies investigated the impact that islanding had on current flow and voltage within EM1 and EM2. The studies captured the following elements:

- Network loading as a percentage of equipment ratings to ensure there were no thermal overloads;
- Measurement of voltage at various network nodes to ensure that voltages were within statutory limits;
- Monitoring of tap changer positions to ensure that transformers were not operating at the upper or lower limits (i.e. check that there is still tap positions available);
- Examination of generator dispatch – check the loading of each generator (MW, MVAr) and control mode (PQ or V control modes); and
- Measurement of system losses at maximum load for each island (for comparison with grid-connected scenario).

The load flow studies were carried out with four of the five generators with fixed active and reactive power export (i.e. PQ control mode). The remaining generator was designated as the reference machine, set to control generation plant at 11kV to 1.0PU (i.e. V control mode).

1.3.3 Fault level

Short circuit fault level studies were calculated for the network islands using the IEC 60909 standard. The studies were performed on EM1 and EM2 in both grid connected and islanded modes. The following scenarios were studied for each network island:

- Maximum fault level – Intact network and five generators connected; and
- Minimum fault level – Non-intact network:
  - a) Loss of one primary Grid Transformer (GT); or
  - b) Loss of the single largest generator.

For the grid-connected studies, an equivalent of the 400kV and 132kV networks was replicated within the DIgSILENT model using the impedance data from the WPD 2019 LTDS.

A key part of the assessment for the network islands is to compare the minimum fault levels with load current. The available fault current at the end of a protection zone (i.e. remote end of a feeder) should be at least double the maximum load current for that circuit, so that the protection relay can discriminate between load and faults. The results for this assessment are described in Sections 2.1.3 & Section 2.2.3 and indicate a "PASS" or "FAIL" against the above criteria.

No detailed analysis was undertaken for earth fault levels as a switched neutral earthing resistor (and transformer if required) set to match the grid connected earth fault level shall be installed within the proposed island. Hence, the earth fault current shall remain unchanged (within a certain tolerance) and existing settings will remain valid.

1.3.4 Transient stability

Transient stability studies were performed to determine if the islanded network remains stable when subjected to disturbances that commonly occur on the distribution network. A brief description and method of the studies conducted is shown below:

- **Transient line fault –** A transient three phase symmetrical fault is placed on the 33kV OHL feeding out from Wykes Engineering and cleared within 100ms. A three phase fault is simulated as it will show the worst case fault current. The line faults have been applied to midpoint of the 33kV OHL feeding out from Wykes generation;
- **Generation trip –** A generating unit is disconnected in the simulation. The trip of the generator is not related to a generator or network fault. The voltage and frequency on the system are recorded and analysed. Generator loadings before and after the fault are assessed to understand if the remaining generators are functioning within their operational limits;
- **Load rejection –** An outgoing 11kV circuit from the primary substation is disconnected following a non-fault event, and the response of generators assessed by reviewing system voltage and frequency response. The P and Q export from the generators is also assessed after the event to ensure that all generators remain within their capability limits;
- **Switched in load –** This involves the reverse operation of the load rejection study. The 11kV feeder and associated load is reconnected and the effect on system voltage and frequency is analysed. The P and Q export from the generators is also assessed after the event to ensure that all generators remain within their capability limits; and
- **Generator Critical Fault Clearance Time (CFCT) –** A short circuit is placed at the 11kV terminals of the generator, and cleared within a specified time period. If the system is able to recover: i.e. if voltage and frequency stabilise then the system is designated to be stable for the given time period. If the system does not recover this is recorded as a “FAIL” and the maximum clearance time that produces a stable system is recorded as the CFCT.

As there was limited data available for the generator dynamic models at Wykes, the following assumptions were made in order to perform the transient stability studies:

- Each generator was equipped with an Automatic Voltage Regulator (AVR) as part of its control system;
- Generators 3 and 4 (the largest non-steam turbine generators) have a dynamic governor model (capable of controlling the speed of the machine and frequency of the islanded system); and
- On load tap changers were enabled for the study initialisation, however, it has been assumed that the controller time delay is larger than the period of any of the studies; hence, they are not active during the studied transient events (i.e. loss of load, load step increase, or the fault outage studies described).

2. Modelling results

2.1 East Midlands 1 network island

2.1.1 Overview

This section of the report details the results of the study of the EM1 network island; consisting of Harrold and Sharnbrook substations supplied from the Wykes Engineering generation plant as shown in Figure 2-1 below.

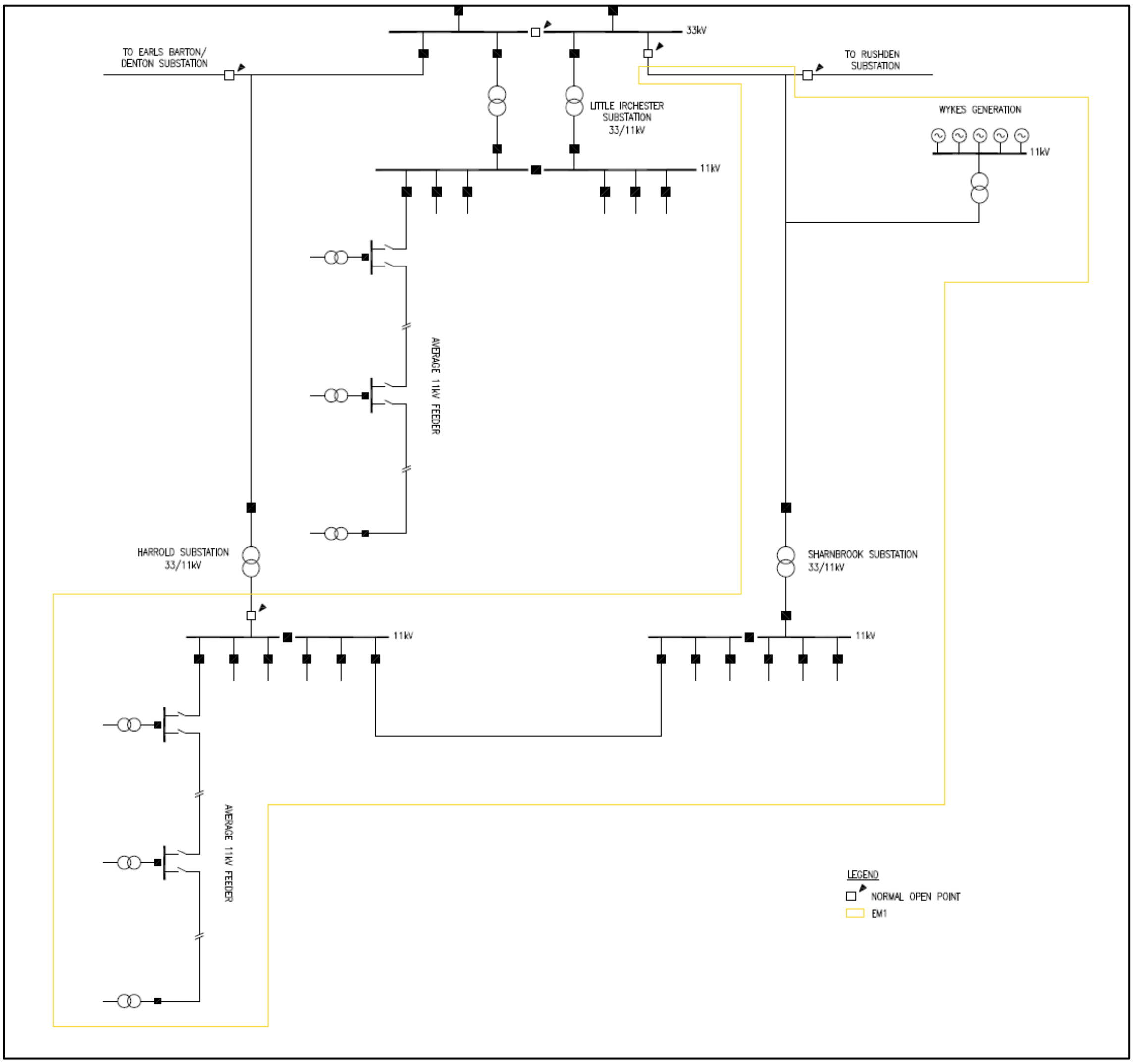


Figure 2-1 EM1 network island

2.1.2 Load flow study

Maximum load for the EM1 grid is 27.94MW, which includes 20MW of behind the meter load at Wykes Generation. The total generation production for the island is 28.07MW, the small discrepancy in these figures is attributed to grid losses. Table 2-1 shows the share of the total generation across the five generators for the maximum loading case.

Table 2-1 EM1 – Load flow – maximum load case – generator dispatch

EM1 - Generator Dispatch - Max Load						
Gen ID	Generator Type / model	Voltage (kV)	Rated Power (MW)	Control Mode	Power (MW)	Reactive Power (MVAr)
Gen 1	ALSTOM P140343-10	11	5.0	PQ	3.00	0.99
Gen 2	AVK DIG16n14	11	14.0	PQ	8.00	1.62
Gen 3	ABB AMG1120MO12DSE	11	6.6	V	3.47	1.31
Gen 4	ABB B194CM102-B	11	10.4	PQ	8.00	2.63
Gen 5	AVK P-OB-10179-B	11	14.0	PQ	5.60	1.84
				Total	28.07	8.39

Minimum load for the EM1 grid is 22.18MW, which includes the 20MW behind the meter load at Wykes generation. The total generation is 22.26MW, again, the small difference is attributed to grid losses. Table 2-2 shows the share of the total generation across the five generators for the minimum loading case.

Table 2-2 EM1 – Load flow – minimum load case – generator dispatch

EM1 - Generator Dispatch - Min Load						
Gen ID	Generator Type / model	Voltage (kV)	Rated Power (MW)	Control Mode	Power (MW)	Reactive Power (MVAr)
Gen 1	ALSTOM P140343-10	11	5.0	PQ	2.00	0.66
Gen 2	AVK DIG16n14	11	14.0	PQ	5.60	1.23
Gen 3	ABB AMG1120MO12DSE	11	6.6	V	4.92	2.18
Gen 4	ABB B194CM102-B	11	10.4	PQ	4.15	1.36
Gen 5	AVK P-OB-10179-B	11	14.0	PQ	5.60	1.23
				Total	22.26	6.66

The voltage assessment study involves running the system at maximum and minimum load and recording the voltage at each busbar on the system. The results are displayed in Table 2-3. As the maximum load within the network island is relatively low at (around 8MW) it can be seen there are no issues with maintaining voltages within the acceptable limits of the ESQCRs.

Table 2-3 EM1 – Load flow - voltage results

EM-1 Load Flow - Voltage Result				
BB Name	BB Name	Voltage (kV)	Max Load - Voltage (PU)	Min Load - Voltage (PU)
WYKS5J	Wykes Generation 11kV	11	1.000	1.000
WYKS3J	Wykes Generation 33kV	33	1.002	1.012
WYKS3T	Wykes Tee 33kV	33	1.002	1.011
SHAR3J	Sharnbrook 33kV	33	0.993	1.010
SHAR5J	Sharnbrook 11kV	11	1.032	1.034
HAR5J	Harrold 11kV	11	1.020	1.031
HAR5A	Harrold Sub - A 11kV	11	1.020	1.032
HAR5B	Harrold Sub - B 11kV	11	1.019	1.032
HAR5C	Harrold Sub - C 11kV	11	1.019	1.032
HAR04A	Harrold Sub - A 415V	0.415	1.019	1.031
HAR04B	Harrold Sub - B 415V	0.415	1.019	1.031
HAR04C	Harrold Sub - C 415V	0.415	1.018	1.031

The transformer tap positions at Wykes Generation and Sharnbrook have also been recorded in Table 2-4 for both the maximum and minimum load cases. It can be seen that all the taps are within limits and are not at the fringes of operation for the maximum or minimum load scenarios.

Table 2-4 EM1 – Load flow – tap position results

EM-1 - Tap changer results								
Tx ID	Transformer Name	Maximum Tap	Minimum Tap	%V / Tap	Tap Position Max Load	Tap % Max Load	Tap Position Min Load	Tap % Min Load
WYK-T1	Wykes Generation T1	8	-8	1.25%	1	1.25%	1	1.25%
SHAR - T1	Sharnbrook T1	4	-11	1.25%	-4	-5.00%	-2	-2.50%

The results of the losses study are shown in Table 2-5. The losses have been calculated using the inbuilt tool in DIgSILENT PowerFactory. The studies were performed at peak island demand and with 20MW of behind the meter load at Wykes Generation.

The results show that the network losses reduce from 3.83% when the island is connected to the grid to 1.97% when running in island mode, representing a reduction of 1.86%.

Table 2-5 EM1 – Load flow – losses results

EM-1 – Losses results @ peak demand 7.4MW		
Operational mode	Losses (MW)	Losses (%)
Grid connected	0.284	3.83
Island	0.146	1.97

2.1.3 Short circuit study

The short circuit studies have been implemented based on three scenarios:

1. Grid connected fault level – maximum;
2. Island only fault level – maximum; and
3. Island only fault level – minimum.

Fault level results have been recorded at each 33kV and 11kV substation busbar in both grid connected and island cases. In addition, the fault level has been recorded at the 11kV and 415V busbars of the notional HV/LV substations modelled along the average 11kV feeder circuit from Harrold substation. Harrold substation was chosen, as it is furthest from the source with the lowest fault levels therefore representing the worst case for minimum fault levels.

Table 2-6 shows the results of the fault level study. It is observed that the fault level at each busbar is much lower in the islanded case compared to the grid connected case. This is to be expected, as the grid contribution to the fault level is no longer present in the island case.

Table 2-6 EM1 – Short circuit results

Fault Level Study - EM1								
BB Name	BB Name	Voltage (kV)	Grid Fault Level		Max Fault Level		Min Fault Level	
			Fault Level (MVA)	Fault Current (kA)	Fault Level (MVA)	Fault Current (kA)	Fault Level (MVA)	Fault Current (kA)
WYKS5J	Wykes Generation 11kV	11.0	114.9	6.0	443.8	23.3	305.7	16.0
WYKS3J	Wykes Generation 33kV	33.0	312.9	5.5	128.6	2.3	105.1	1.8
WYKS3T	Wykes Tee 33kV	33.0	320.6	5.6	127.5	2.2	104.2	1.8
SHAR3J	Sharnbrook 33kV	33.0	218.8	3.8	108.2	1.9	89.6	1.6
SHAR5J	Sharnbrook 11kV	11.0	85.6	4.5	61.0	3.2	51.0	2.7
HAR5J	Harrold 11kV	11.0	82.8	4.3	41.4	2.2	35.0	1.8
HAR5A	Harrold Sub - A 11kV	11.0	66.5	3.5	36.8	1.9	31.1	1.6
HAR5B	Harrold Sub - B 11kV	11.0	54.0	2.8	32.6	1.7	27.5	1.4
HAR5C	Harrold Sub - C 11kV	11.0	45.2	2.4	29.2	1.5	24.6	1.3
HAR04A	Harrold Sub - A 415V	0.415	16.9	23.5	13.9	19.4	12.1	16.8
HAR04B	Harrold Sub - B 415V	0.415	16.0	22.3	13.4	18.6	11.6	16.1
HAR04C	Harrold Sub - C 415V	0.415	15.3	21.2	12.8	17.8	11.1	15.4

Table 2-7 shows the islanded fault levels as a percentage of the grid connected fault level, in order to show a further comparison between the two. It is noted that the islanded fault levels are significantly lower, but the magnitude of difference decreases as measurements are made further down the 11kV feeders. This can be explained by the increasing impedance between the source and the fault location as the fault is applied further downstream in the grid connected case. This increasing impedance reduces the grid connected fault level contribution and therefore the percentage difference between the grid connected and island results is reduced.

Table 2-7 EM1 – Comparison against grid connected fault level

Island vs Grid Fault Level			
BB Code	BB Name	% of grid connected	
		Island Max - Grid	Island Min - Grid
WYKS3J	Wykes Generation 33kV	41.1%	33.6%
WYKS3T	Wykes Tee 33kV	39.8%	32.5%
SHAR3J	Sharnbrook 33kV	49.5%	40.9%
SHAR5J	Sharnbrook 11kV	71.2%	59.6%
HAR5J	Harrold 11kV	49.9%	42.3%
HAR5A	Harrold Sub - A 11kV	55.3%	46.8%
HAR5B	Harrold Sub - B 11kV	60.4%	50.9%
HAR5C	Harrold Sub - C 11kV	64.6%	54.3%
HAR04A	Harrold Sub - A 415V	82.6%	71.6%
HAR04B	Harrold Sub - B 415V	83.2%	72.1%
HAR04C	Harrold Sub - C 415V	83.8%	72.5%

Table 2-8 presents the results of the investigation into the comparison between the maximum load current versus minimum phase-to-phase fault current for each of the busbars in the EM1 model. The results show that the minimum phase-to-phase fault current is more than double the maximum load current at all recorded points. The magnitude of these fault levels is therefore sufficient to allow adequate grading of the overcurrent protection settings when the system is islanded. It should be noted that changes to protection settings would be required to facilitate island mode due to the reduction in fault level from the grid connected scenario. It should be noted that the load current for the HV/LV substations has been based on the maximum rated current of a secondary distribution substation which is normally 1MVA (52A).

Table 2-8 EM1 – Short circuit results – load vs fault level.

Overcurrent settings Limits						
BB Code	BB Name	Max load (MVA)	Load Current (kA)	Min Phase - Phase Fault Current (kA)	Minimum OC Settings	OC Settings > Load
WYKS5J	Wykes Generation 11kV	25.0	1.312	13.7	6.84	PASS
WYKS3J	Wykes Generation 33kV	25.0	0.437	1.3	0.65	PASS
WYKS3T	Wykes Tee 33kV	25.0	0.437	1.3	0.65	PASS
SHAR3J	Sharnbrook 33kV	7.4	0.129	1.4	0.68	PASS
SHAR5J	Sharnbrook 11kV	7.4	0.388	1.6	0.80	PASS
HAR5J	Harrold 11kV	2.0	0.105	1.1	0.56	PASS
HAR5A	Harrold Sub - A 11kV	1.0	0.052	1.1	0.56	PASS
HAR5B	Harrold Sub - B 11kV	1.0	0.052	1.1	0.56	PASS
HAR5C	Harrold Sub - C 11kV	1.0	0.052	1.1	0.56	PASS
HAR04A	Harrold Sub - A 415V	1.0	1.391	14.6	7.28	PASS
HAR04B	Harrold Sub - B 415V	1.0	1.391	13.9	6.96	PASS
HAR04C	Harrold Sub - C 415V	1.0	1.391	13.3	6.66	PASS

2.1.4 Transient study

The following studies were undertaken for EM1:

- Transient line fault;
- Generation trip;
- Load rejection;
- Switched in load; and
- Generator Critical Fault Clearance Time (CFCT).

The results of these studies are described in the following sections.

Transient line fault

A three-phase symmetrical fault was simulated on the 33kV circuit between Sharnbrook and Wykes Generation tee as in Figure 2-2 as “Fault EM1”. The three-phase fault is applied for 100ms, representing a transient fault. A three phase transient fault was studied in order to assess the worst-case scenario for generator stability.

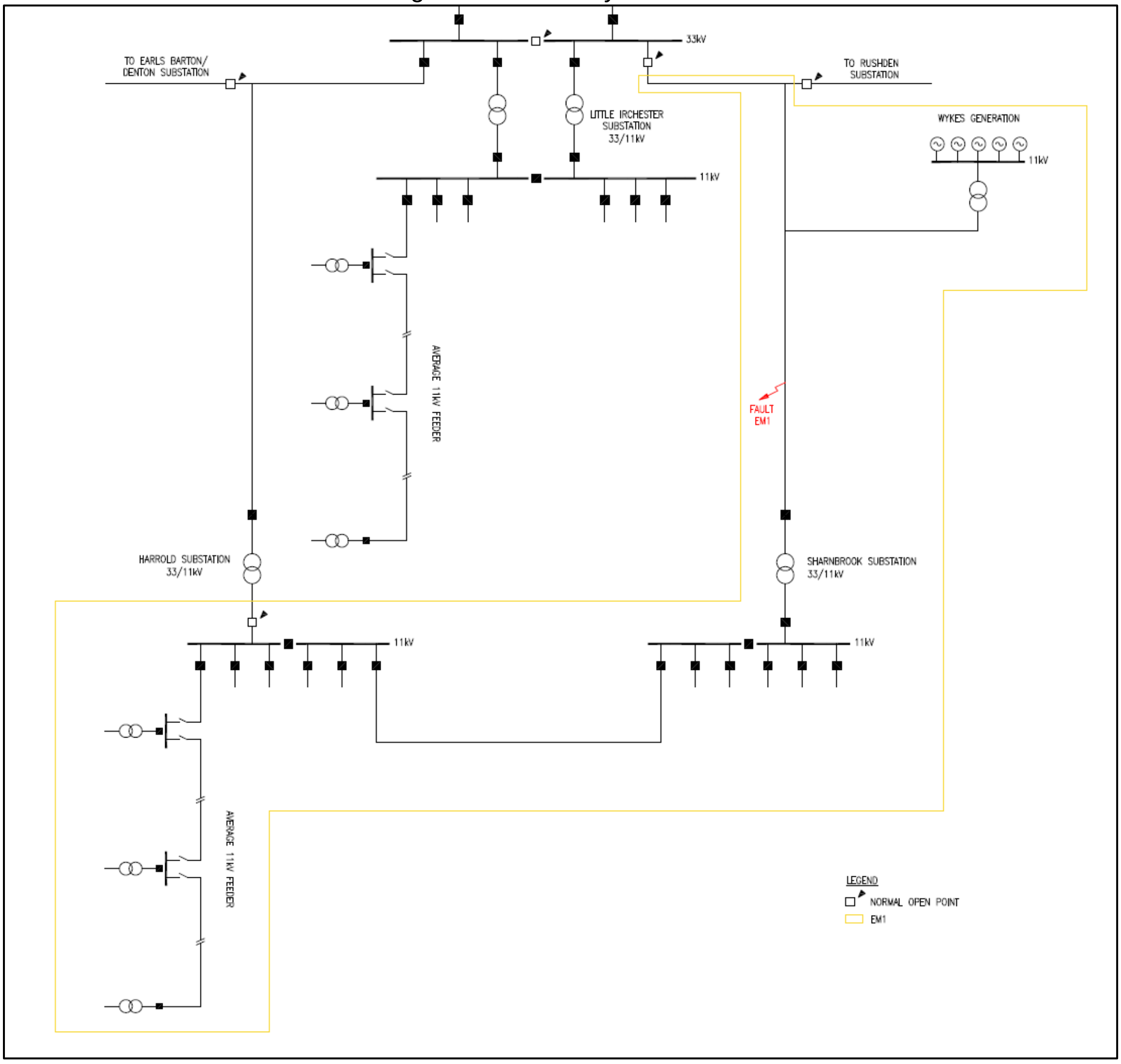
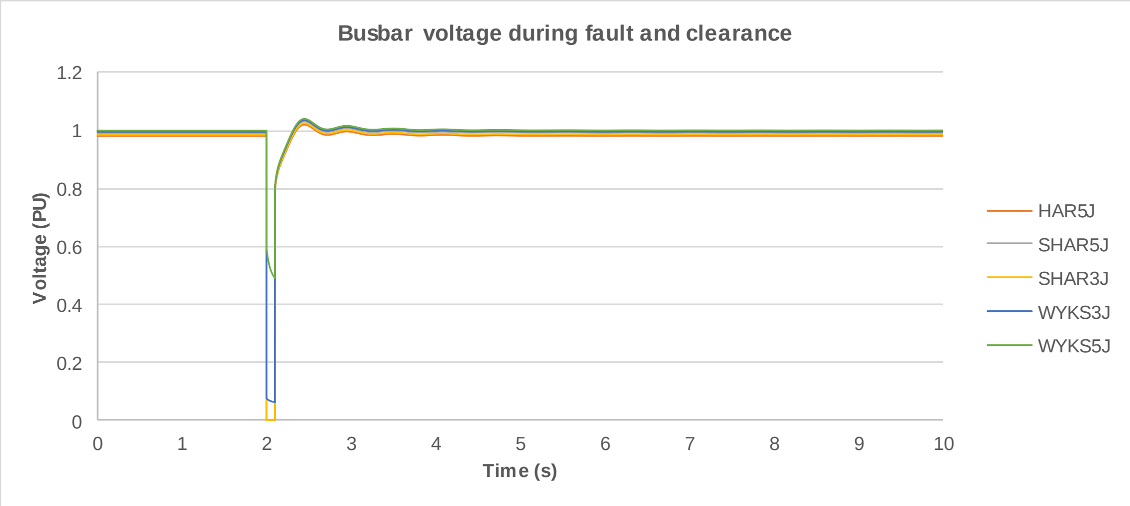


Figure 2-2 Transient fault location on EM1

Maximum load case

The first study observed the transient response of the island at maximum load with 20MW of behind the meter load at Wykes. Figure 2-3 and Figure 2-4 show the voltage and frequency



response of the EM1 island for the duration of the 100ms fault and the subsequent transient period. The fault is applied at 2.0s and the fault is cleared at 2.1s. The results show that the generator AVR has stabilised the voltage within 4s. The frequency takes slightly longer to stabilise, becoming stable after around 9s, following a short transient period. As the voltage and frequency are stable (within the statutory limits of 49.5Hz to 505Hz) in less than 60s after the event, this can be deemed as acceptable (as per National Grid SQSS).

A steep frequency increase that is likely in excess of 1Hz/s is noticed immediately after the fault, but this will not cause a G59/G99 trip on RoCoF as it is not sustained for more than 500ms (the setting time delay). The frequency peaks at 50.9Hz and it therefore within the over frequency settings within the G59/G99 standards (52Hz for 500ms). The voltage is seen to exceed the under voltage limit of 0.8PU, but the voltage collapse is only present for the duration of the fault before returning above the minimum setting before the 500ms under voltage setting time delay and therefore the generator will not trip on G59/G99 under voltage protection.

Figure 2-3 Busbar voltage during fault and clearance - Max load

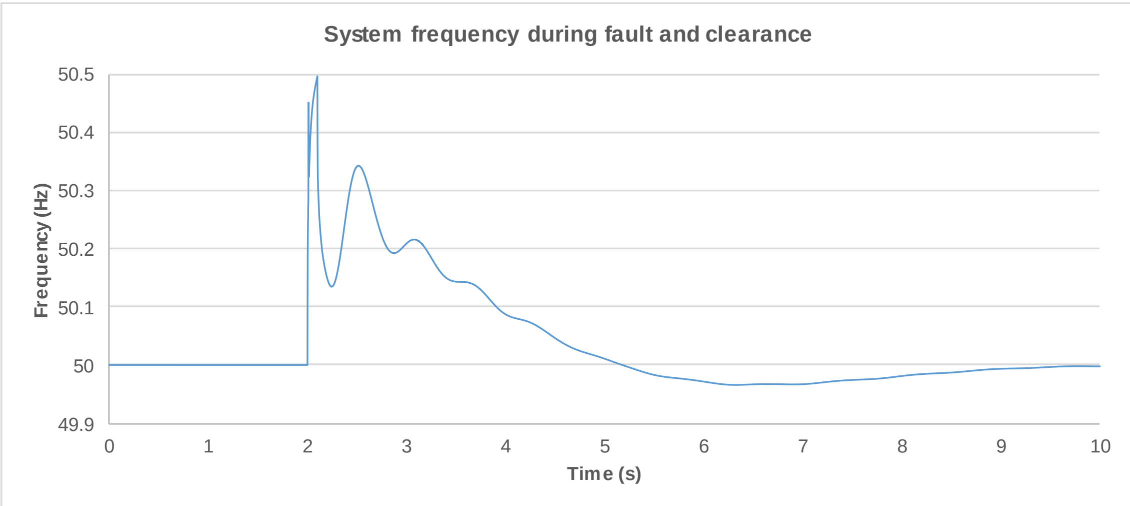


Figure 2-4 Frequency during fault and clearance - Max load

Minimum load case

The second study observed the transient response of the island at minimum load with 20MW of behind the meter load at Wykes. Figure 2-5 and Figure 2-6 show the voltage and frequency response of the EM1 island for the same fault as detailed for the maximum load scenario. Similar to the maximum load scenario, it can be seen that voltage stabilises within 4s with the frequency taking slightly longer, stabilising after around 9s, following a short transient period. As with the maximum load case, this is acceptable.

A steep frequency increase that is likely in excess of 1Hz/s is noticed immediately after the fault, but this will not cause a G59/G99 trip on RoCoF as it is not sustained for more than 500ms (the setting time delay). The frequency peaks just below 50.4 Hz and is therefore within the over frequency settings on G59/G99 standards (52Hz for 500ms). The voltage is seen to exceed the under voltage limit of 0.8PU, but the voltage collapse is only present for the duration of the fault before returning above the minimum setting before the 500ms under voltage setting time delay and therefore the generator will not trip on G59/G99 under voltage protection.

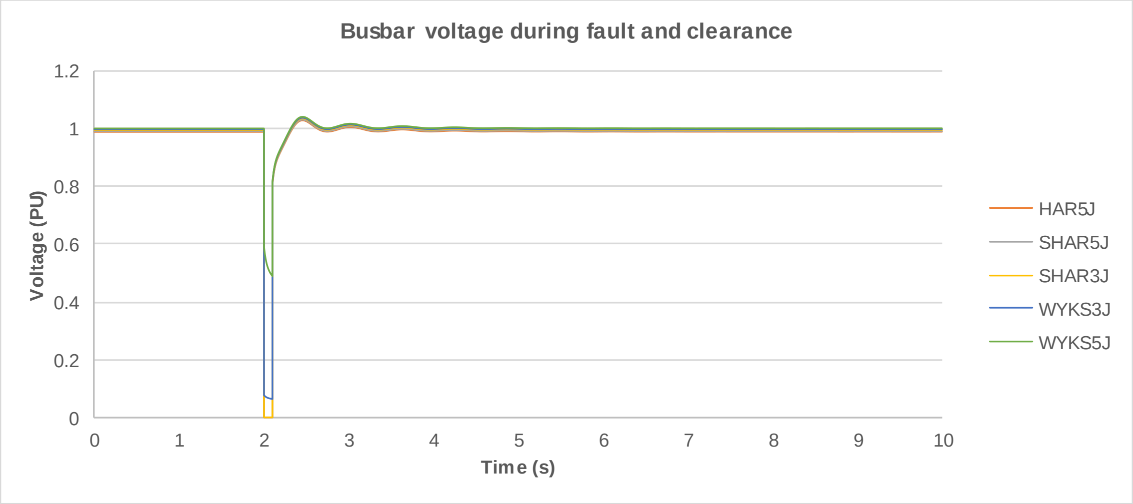


Figure 2-5 Busbar voltage during fault and clearance - Min load

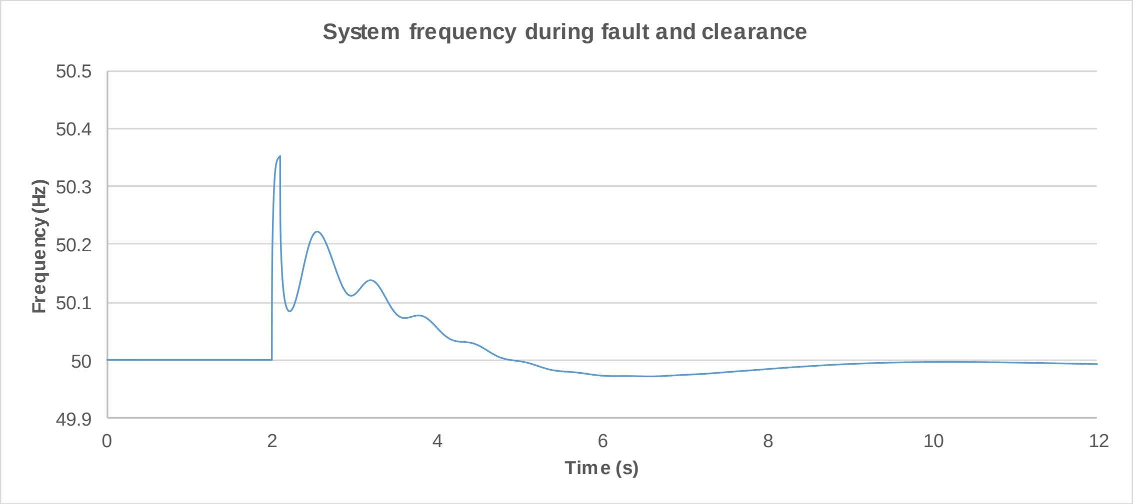


Figure 2-6 Frequency during fault and clearance - Min load

Generation trip

This study analyses the system voltage and frequency response following the tripping of a generator at the Wykes generation plant. The post trip loading of the generators is also verified to ensure that no machine is over or under loaded. The studies are performed at maximum load with the loss of the largest generating unit, which represents the worst case for system stability.

For these studies, it has been assumed that generator units 1, 3 and 4 have frequency and power control systems installed as described in Section 1.3.4.

Table 2-9 shows the generator dispatch before and after the loss event, it is observed that due to the dynamic controller models, the load is shared across the remaining generators and all remain within their active and reactive capability.

Table 2-9 Generator dispatch before and after fault event

Generator dispatch pre/post fault										
Details					Performance pre-fault			Performance post-fault (15s)		
Gen ID	Generator Type / model	Voltage (kV)	Rating (MW)	Rating (MVA)	P	Q	Cosphi	P	Q	Cosphi
Gen 1	ALSTOM P140343-10	11	5	6.25	3.0	1.0	0.949	3.5	1.7	0.900
Gen 2	AVK DIG16n14	11	14	14.34	8.0	1.6	0.981	8.0	3.8	0.903
Gen 3	ABB AMG1120MO12DSE	11	6.6	8.25	3.4	1.6	0.905	6.3	0.3	0.999
Gen 4	ABB B194CM102-B	11	10.37	12.95	8.0	2.6	0.951	10.2	2.9	0.962
Gen 5	AVK P-OB-10179-B	11	14.0	14.34	5.6	1.8	0.952	0.0	0.0	N/A

Figure 2-7 and Figure 2-8 show the voltage and frequency response following the loss of the largest generator. After a short transient period of 5s post event, the generator busbar voltage returns to a stable 1.0 per unit. The frequency stabilises after 8s post event to a lower level of 49.78Hz.

The system does not return to the pre-event 50Hz following the gain of load on the remaining four generators due to the generator droop setting. The frequency will remain at the reduced level of 49.78 Hz until the control systems are reset.

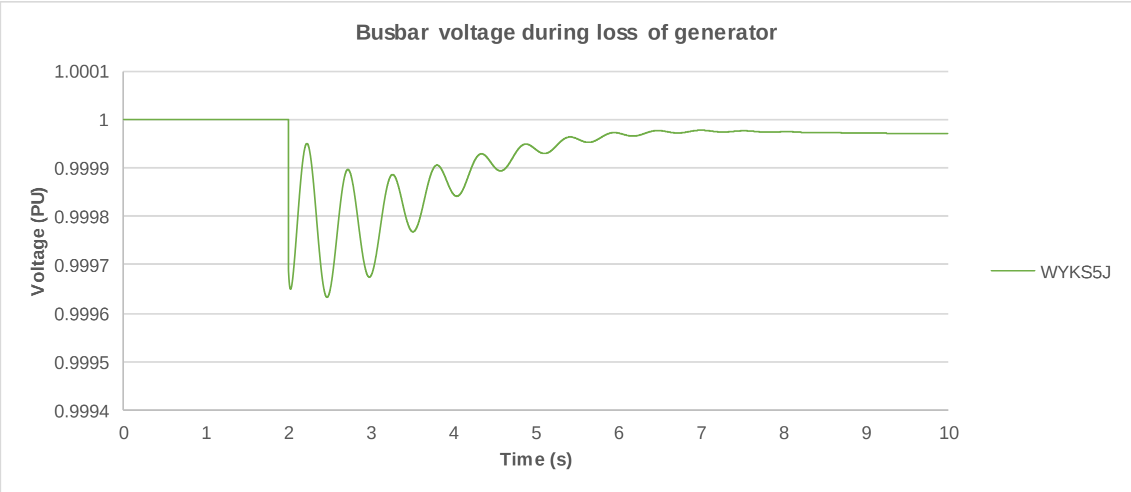


Figure 2-7 Busbar voltage following loss of Generator 5

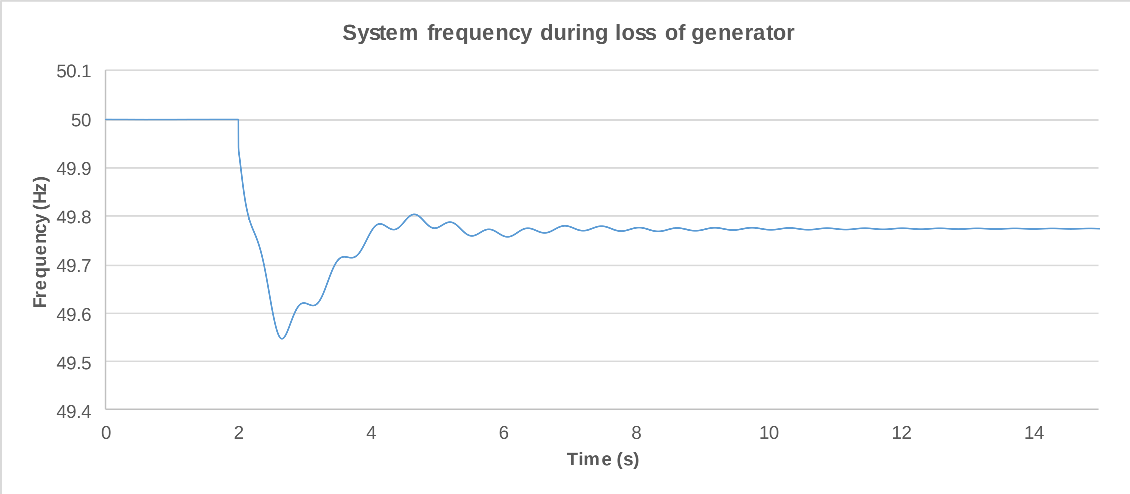


Figure 2-8 Frequency following loss of generator 5

Figure 2-9 shows the generator power response where the increase in active power post event can be seen on generator units 1, 3 and 4 (the machines fitted with the dynamic control systems).

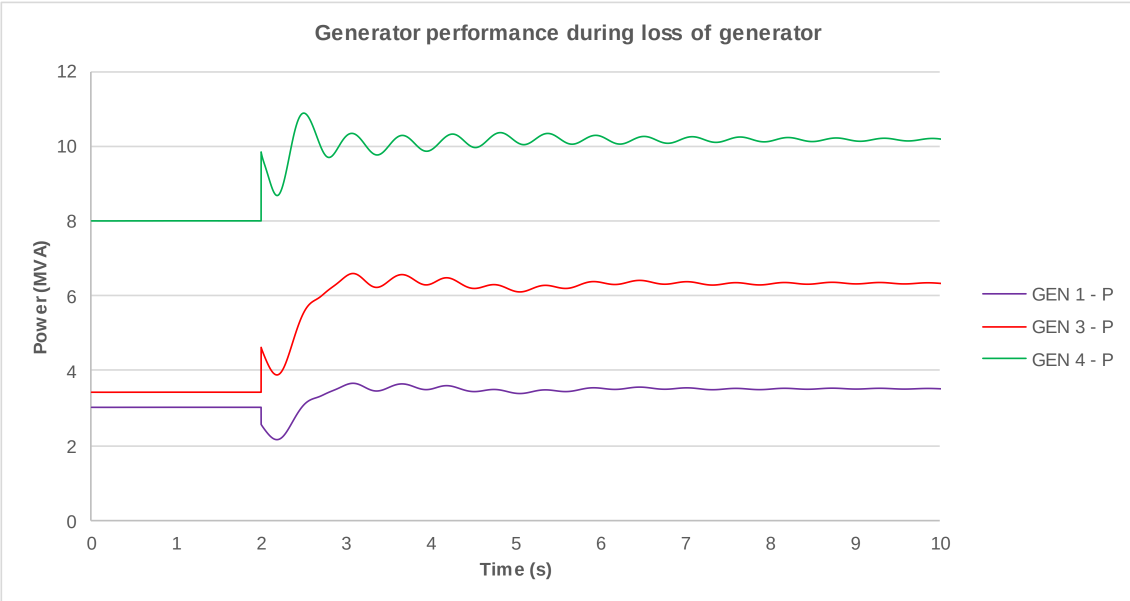


Figure 2-9 Active power response following loss of Generator 5

The RoCoF for the network island was also investigated as part of the stability studies following the loss of Generator 5. Figure 2-10 shows the RoCoF of the network island during the loss of Generator 5 against the 1Hz/s limit detailed in G59/G99.

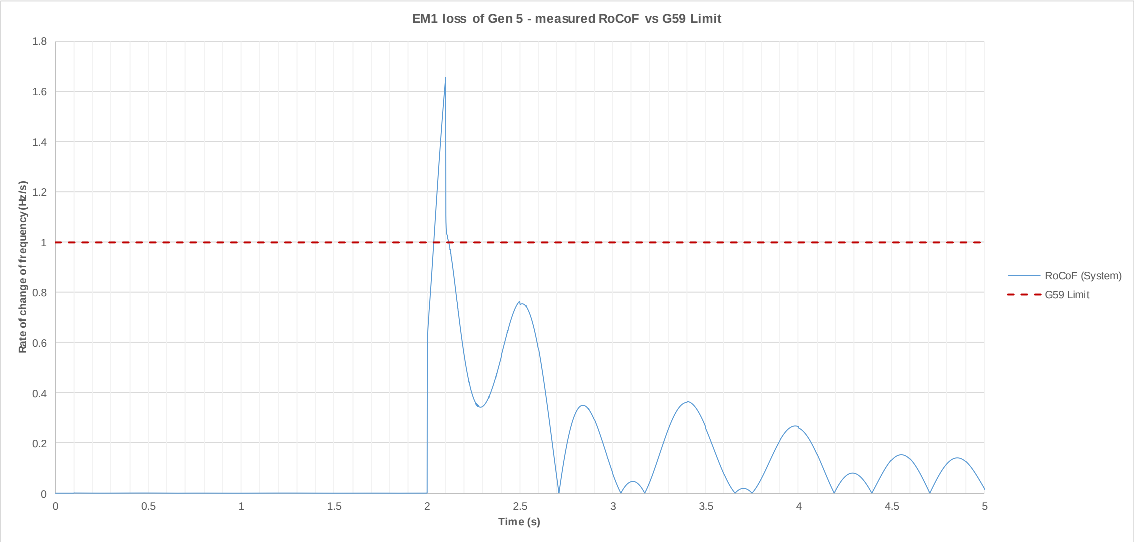


Figure 2-10 Rate of change of system frequency following loss of Generator 5

Although RoCoF does exceed 1Hz/s second post event, it is observed that is only for 81ms, which is less than to 500ms delay prescribed in G59/G99. Therefore, the generation would remain connected to the system and would not result in the network island being completely disconnected.

Load Rejection

Harrold – Maximum load

This study investigates the loss of a single outgoing 11kV circuit at Harrold substation with the island operating at maximum load.

Figure 2-11 shows the voltage of the system and Figure 2-12 frequency response following the load loss at 2s. The voltage can be seen to increase, but is stable after 1.5s post event, with the generator busbar voltage (WYK5J) returning to 1.0PU. The frequency increases post event and is stable at a slightly higher value of 50.05Hz at 9s (7s post event).

The response of the generator during this system is not severe, there is a small step change in voltage and frequency increases and stabilises to a higher value.

The frequency does not return to the original set point of 50Hz, settling at around 50.05Hz, which is within G59/G99 and Grid Code limits. The RoCoF is also within the G59/G99 limits.

The generator does not return to the pre-event frequency of 50Hz as the governor droop setting, as per the IEEE model, does not have an active set-point. However, the droop setting can be adjusted so that the frequency settles within a closer tolerance of 50Hz and we would expect this to be implemented on the network island.

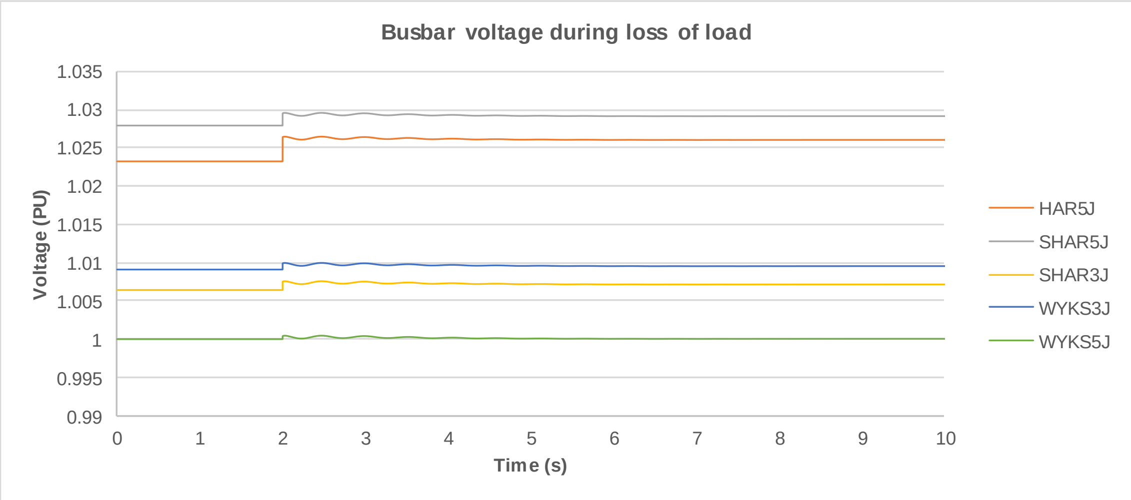


Figure 2-11 Busbar voltage following loss of Harrold 11kV feeder

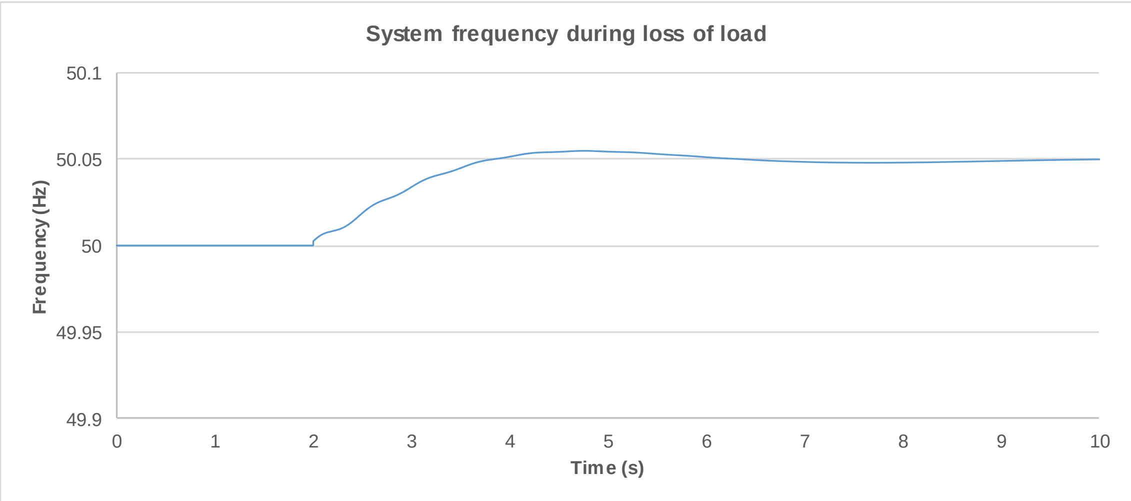


Figure 2-12 Frequency following loss of Harrold 11kV feeder

Sharnbrook – Maximum load

This study investigates the loss of a single outgoing 11kV circuit at Sharnbrook substation with the island operating at maximum load.

Figure 2-13 shows the voltage of the system and Figure 2-14 frequency response following the load loss at 2s. The voltage can be seen to increase, but is stable after 3.5s post event, with the generator busbar voltage (WYK5J) returning to 1.0PU. The frequency increases post event and is stable at a slightly higher value of 50.15 Hz at 9s (7s post event).

The response of the generator during this system is not severe, there is a small step change in voltage and frequency increases and stabilises to a higher value.

The frequency does not return to the original set point of 50Hz, settling at around 50.05Hz, which is within G59/G99 and Grid Code limits. The RoCoF is also within the G59/G99 limits.

The generator does not return to the pre-event frequency of 50Hz as the governor droop setting, as per the IEEE model, does not have an active set-point. However, the droop setting can be adjusted so that the frequency settles within a closer tolerance of 50Hz and we would expect this to be implemented on the network island.

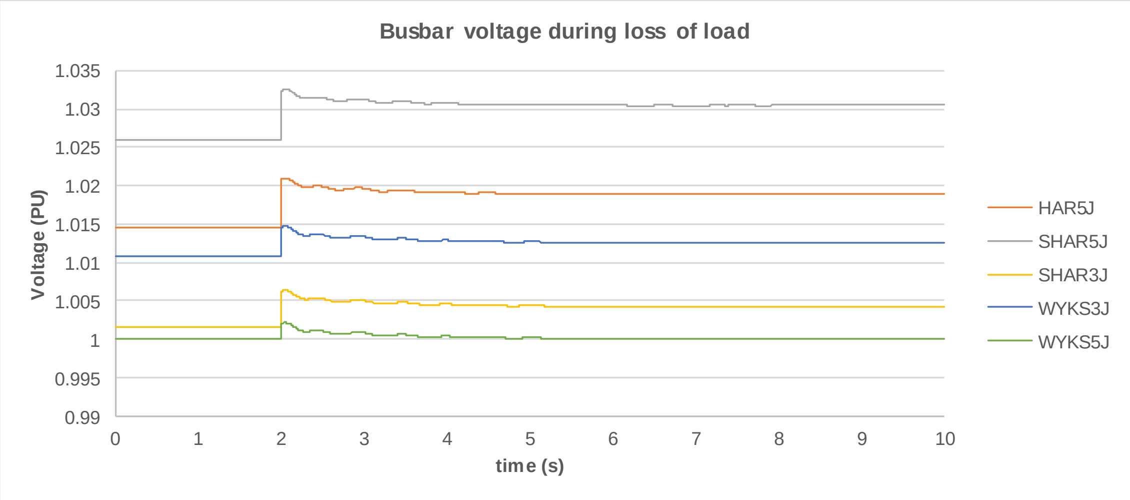


Figure 2-13 Busbar voltage following loss of Sharnbrook 11kV feeder

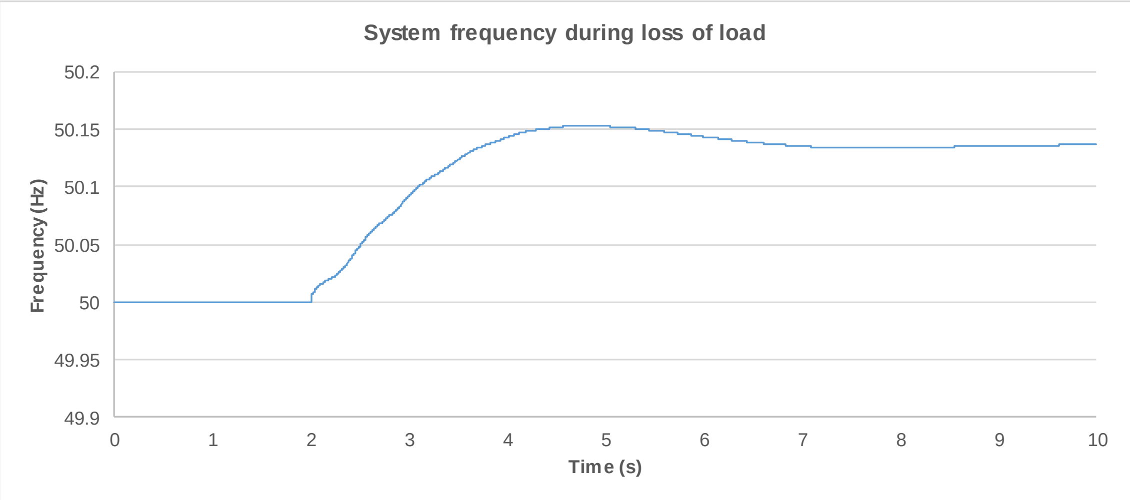


Figure 2-14 Frequency following loss of Sharnbrook 11kV feeder

Switched in load

This study analyses the system voltage and frequency response following the restoration of a single 11kV feeder fed from Harrold and Sharnbrook substations. A study at maximum load has been analysed to assess the worst case.

Harrold – Maximum load

Figure 2-15 shows the voltage of the system and Figure 2-16 frequency response following the connection of load at 2s. The voltage can be seen to decrease, but is stable after 1s post event, with the generator busbar voltage (WYK5J) returning to 1.0 PU. The frequency decreases post event and is stable at a slightly lower value of 49.95 Hz at 10s (8s post event).

The response of the generator during this system is not severe, there is a small step change in voltage and frequency decreases and stabilises to a slightly lower value.

The frequency does not return to the original set point of 50Hz, settling at around 49.95Hz, which is within G59/G99 and Grid Code limits. The RoCoF is also within the G59/G99 limits.

The generator does not return to the pre-event frequency of 50Hz as the governor droop setting, as per the IEEE model, does not have an active set-point. However, the droop setting can be adjusted so that the frequency settles within a closer tolerance of 50Hz and we would expect this to be implemented on the network island.

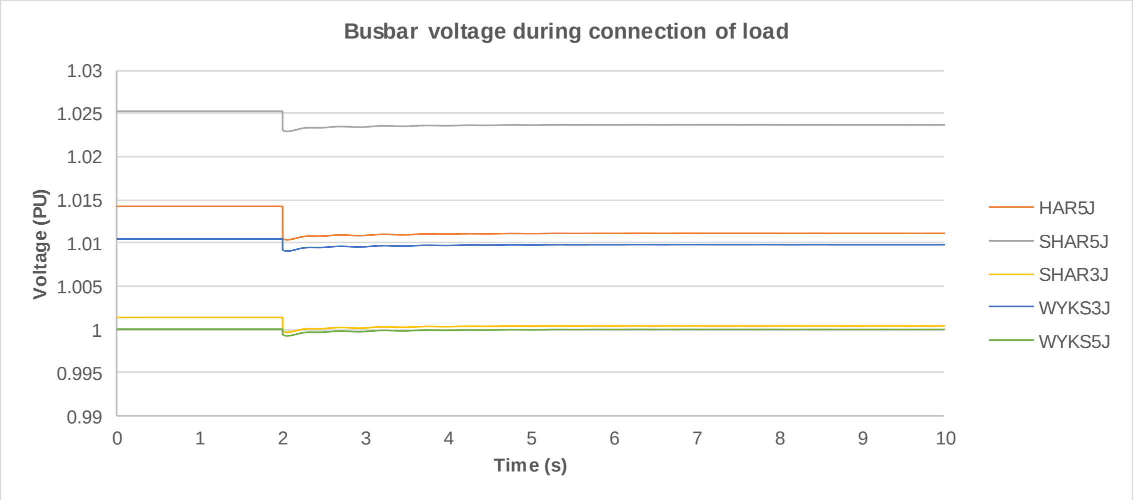


Figure 2-15 Busbar voltage following connection of Harrold 11kV feeder

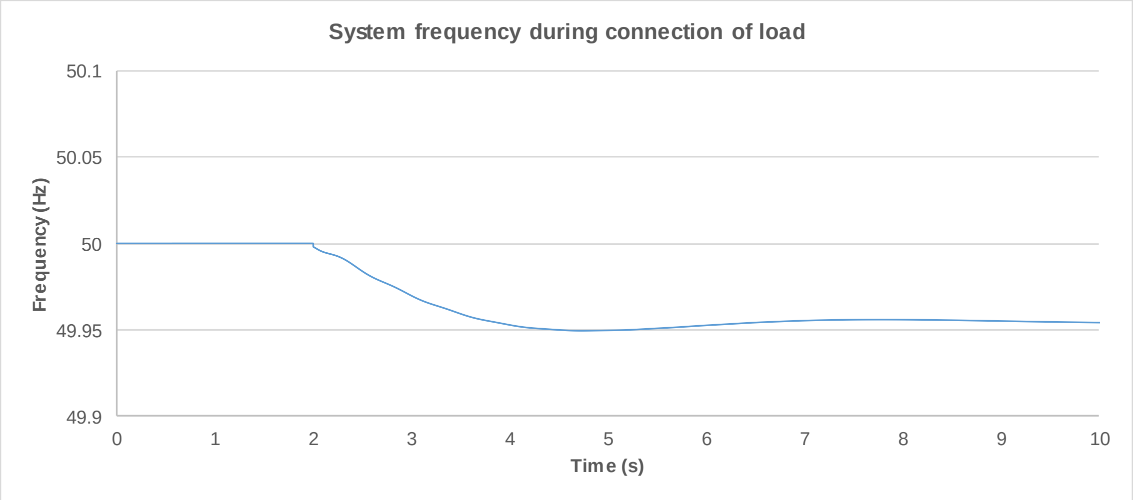


Figure 2-16 Frequency following connection of Harrold 11kV feeder

Sharnbrook – Maximum load

Figure 2-17shows the voltage of the system and Figure 2-18 frequency response following the connection of load at 2s. The voltage can be seen to decrease, but is stable after 3s post event, with the generator busbar voltage (WYK5J) returning to 1.0 PU. The frequency decreases post event and is stable at a slightly lower value of 49.85 Hz at 10s (8s post event).

The response of the generator during this system is not severe, there is a small step change in voltage and frequency decreases and stabilises to a slightly lower value.

The frequency does not return to the original set point of 50Hz, settling at around 49.85Hz, which is within G59/G99 and Grid Code limits. The RoCoF is also within the G59/G99 limits.

The generator does not return to the pre-event frequency of 50Hz as the governor droop setting, as per the IEEE model, does not have an active set-point. However, the droop setting can be adjusted so that the frequency settles within a closer tolerance of 50Hz and we would expect this to be implemented on the network island.

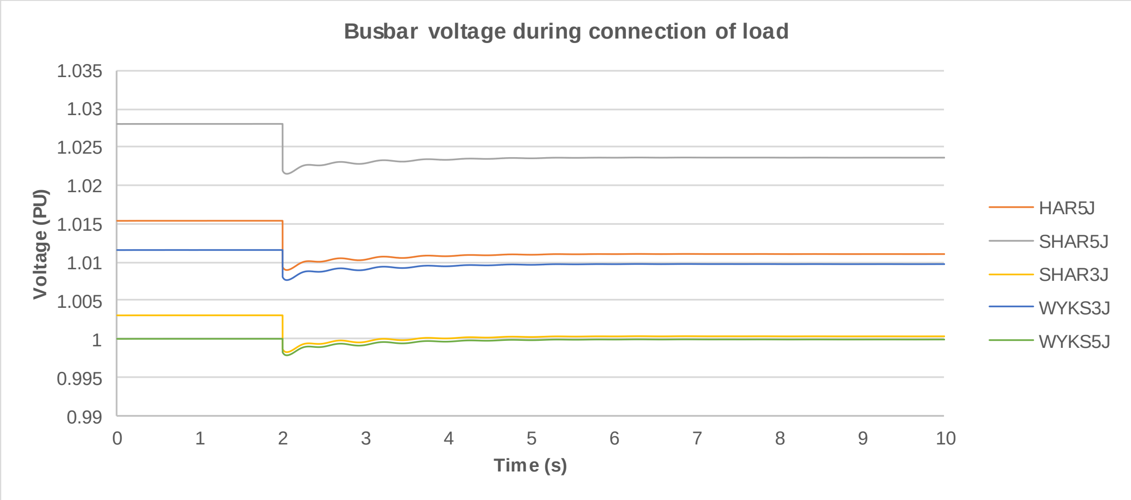


Figure 2-17 Busbar voltage following connection of Sharnbrook 11kV feeder

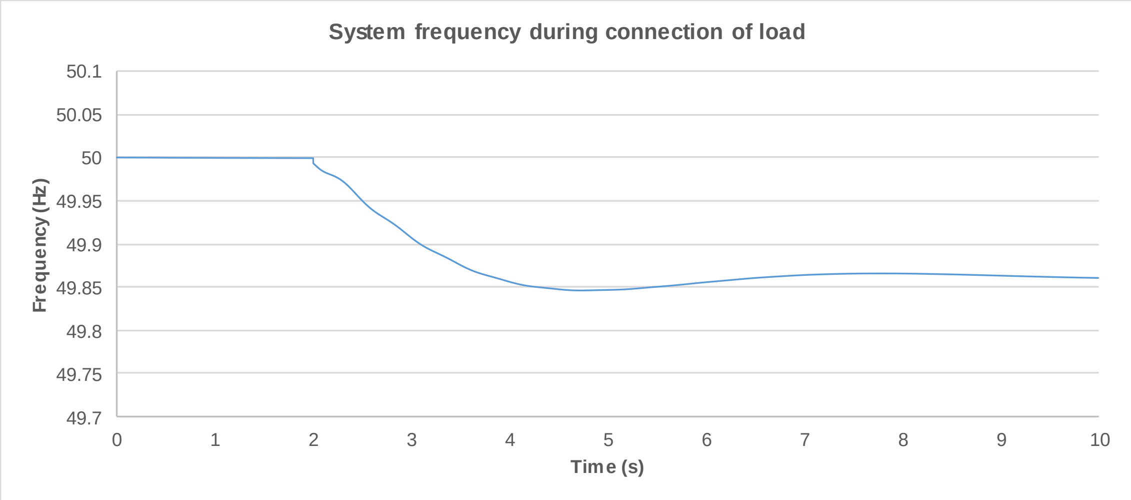


Figure 2-18 Frequency following connection of Sharnbrook 11kV feeder

Critical Fault Clearance Time

This study analyses the reaction of the generators to a fault placed on the generator 11kV busbar and then cleared in increasing time increments until the system fails to return to a stable state.

Table 2-10 details the voltage and frequency response post-fault with respect to increasing fault clearance times. It is observed that when the fault clearance time is greater than 1.35s, the system is unable to return to stability. Therefore, the CFCT is 1.35s.

The generator main protection time is 250ms and back up is 1.25s, so it is observed that any fault on the generator 11kV busbar will be cleared by the backup protection before the system loses stability.

Table 2-10 EM1 - RMS - critical fault clearance time - max load

Generator critical fault clearance time			
Fault clearance time (s)	Voltage stable time (s)	Frequency stable time (s)	System stable (Y/N)
0.1	9.2	11.1	Y
0.2	11.5	12.0	Y
0.3	12.9	13.5	Y
0.4	13.5	14.7	Y
0.5	14.1	15.4	Y
0.6	15.2	16.0	Y
0.7	19.9	16.6	Y
0.8	21.4	21.1	Y
0.9	21.9	22.4	Y
1.0	22.2	22.5	Y
1.1	22.4	22.6	Y
1.2	22.4	22.6	Y
1.3	22.4	22.6	Y
1.35	22.4	22.6	Y
1.4	N/A	N/A	N

2.2 East Midlands 2 network island

2.2.1 Overview

This section of the report details the results of the study of the EM2 network island; consisting of Little Irchester primary substation supplied from the Wykes Engineering generation plant as shown in Figure 2-19 below.

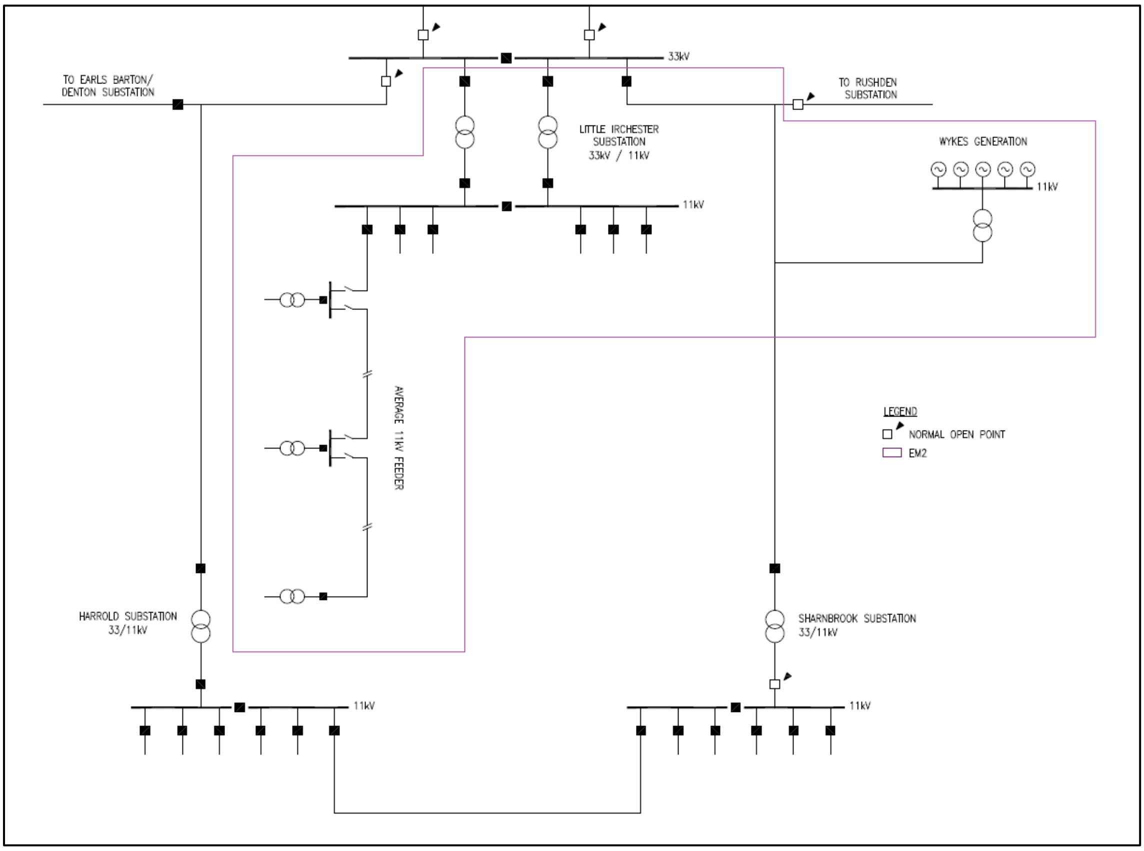


Figure 2-19 EM2 network island

2.2.2 Load flow study

Maximum load for the EM2 grid is 35.63MW, which includes 20MW of behind the meter load at Wykes Generation. The total generation production for the island is 35.98MW; the small difference is attributed to grid losses. Table 2-11 shows the share of the total generation across the five generators for the maximum loading case.

Table 2-11 EM2 – Load flow – maximum load case – generator dispatch

EM2 - Generator dispatch - max load						
Gen ID	Generator Type / model	Voltage (kV)	Rated Power (MW)	Control Mode	Power (MW)	Reactive Power (MVAr)
Gen 1	ALSTOM P140343-10	11	5.0	PQ	4.50	1.48
Gen 2	AVK DIG16n14	11	14.0	PQ	9.00	1.83
Gen 3	ABB AMG1120MO12DSE	11	6.6	V	5.48	4.41
Gen 4	ABB B194CM102-B	11	10.4	PQ	8.00	3.87
Gen 5	AVK P-OB-10179-B	11	14.0	PQ	9.00	1.83
				Total	35.98	13.42

Minimum load for the EM2 grid is 24.36MW, which includes the 20MW behind the meter load at Wykes generation. The total generation is 24.38MW, again, the small difference is attributed to grid losses. Table 2-12 shows the share of the total generation across the five generators for the minimum loading case.

Table 2-12 EM2 – Load flow – minimum load case – generator dispatch

EM2 - Generator Dispatch - Min Load						
Gen ID	Generator Type / model	Voltage (kV)	Rated Power (MW)	Control Mode	Power (MW)	Reactive Power (MVAr)
Gen 1	ALSTOM P140343-10	11	5	PQ	3.00	0.99
Gen 2	AVK DIG16n14	11	14	PQ	7.00	1.42
Gen 3	ABB AMG1120MO12DSE	11	6.6	V	1.38	1.49
Gen 4	ABB B194CM102-B	11	10.365	PQ	6.00	1.97
Gen 5	AVK P-OB-10179-B	11	14	PQ	7.00	1.42
				Total	24.38	7.29

The voltage assessment study involves running the system at maximum and minimum load and recording the voltage at each busbar on the system. The results displayed in Table 2-13 show that there are no issues with maintaining voltages within the acceptable limits of the ESQCRs.

Table 2-13 EM2 – Load flow – voltage results

EM-1 Load Flow - Voltage Result				
BB Name	BB Name	Rated Voltage (kV)	Max Load - Voltage (PU)	Min Load - Voltage (PU)
WYKS5J	Wykes Generation 11kV	11.0	1.000	1.000
WYKS3J	Wykes Generation 33kV	33.0	1.025	1.008
WYKS3T	Wykes Tee 33kV	33.0	1.024	1.008
LITI3J	Little Irchester 33kV J	33.0	1.006	1.004
LITI3K	Little Irchester 33kV K	33.0	1.006	1.004
LITI5J-1	Little Irchester 11kV	11.0	1.029	1.026
LITI5A	Little Irchester Sub - A 11kV	11.0	1.024	1.025
LITI5B	Little Irchester Sub - B 11kV	11.0	1.020	1.024
LITI5C	Little Irchester Sub - C 11kV	11.0	1.018	1.023
LITI04A	Little Irchester Sub - A 415V	0.415	1.018	1.023
LITI04B	Little Irchester Sub - B 415V	0.415	1.014	1.022
LITI04C	Little Irchester Sub - C 415V	0.415	1.012	1.022

The transformer tap positions at Wykes Generation and Little Irchester have also been recorded in Table 2-14 for the maximum and minimum load cases. One transformer has been switched out (LITI-T1) to replicate the worst-case condition for maximum load. It can be seen that all the taps are within limits and are not at the fringes of operation for the maximum or minimum load scenarios.

Table 2-14 EM2 – Load flow – tap position results

EM-1 - Tap changer results								
Transformer	Transformer Name	Maximum Tap	Minimum Tap	%V / Tap	Tap Position Max Load	Tap % Max Load	Tap Position Min Load	Tap % Min Load
WYK-T1	Wykes Generation T1	8	-8	-0.013	5	-0.063	1	-0.013
LITI-T1	Little Irchester T1	4	-11	-0.013	0	0	-2	0.025
LITI-T2	Little Irchester T2	4	-11	-0.013	-5	0.0625	-2	0.025

The results of the losses study are shown in Table 2-15. The losses have been calculated using the inbuilt tool in DIgSILENT PowerFactory. The studies were performed at peak island demand (14.8MW) and with 20MW of behind the meter load at Wykes Generation.

The results show that the network losses increase from 1.57% when the island is connected to the grid to 1.93% when running in island mode, representing an increase of 0.36%. It was initially expected that the network losses would always decrease in islanded operation as the islanded demand would be supplied by local generation instead of from the local BSP; this was confirmed to be the case for the losses results for EM1 presented in Section 2.1.2. It was therefore a surprising outcome from the EM2 results that the losses were increasing. However, on closer inspection it was found that the increase in losses is technically correct for the EM2 island. The reason is that Wykes Generation is connected to Little Irchester via a long 33kV feeder and therefore there are relatively high losses from this feeder in islanded mode. In grid connected mode, Little Irchester is connected in very close proximity to Wellingborough BSP resulting in relatively low losses.

Table 2-15 EM2 – Load flow – losses results

EM-2 – Losses results @ peak demand 14.8MW		
Operational mode	Losses (MW)	Losses (%)
Grid connected	0.233	1.57%
Island	0.285	1.93%

2.2.3 Short circuit study

The short circuit studies have been implemented based on three scenarios:

1. Grid connected fault level – maximum;
2. Island only fault level – maximum; and
3. Island only fault level – minimum.

Fault level results have been recorded at each 33kV and 11kV substation busbar in both grid connected and island cases. In addition, the fault level has been recorded at the 11kV and 415V busbars of the notional HV/LV substations modelled along the average 11kV feeder circuit from Little Irchester substation.

Table 2-16 shows the results of the fault level study. It is observed that the fault level at each busbar is much lower in the islanded case compared to the grid-connected case. This is to be expected, as the grid contribution to the fault level is no longer present in the island case.

Table 2-16 EM2 – Short circuit results

Fault Level Study - EM1								
BB Name	BB Name	Voltage (kV)	Grid Fault Level		Max Fault Level		Min Fault Level	
			Fault Level (MVA)	Fault Current (kA)	Fault Level (MVA)	Fault Current (kA)	Fault Level (MVA)	Fault Current (kA)
WYKS5J	Wykes Generation 11kV	11.0	114.9	6.0	443.8	23.3	305.7	16.0
WYKS3J	Wykes Generation 33kV	33.0	312.9	5.5	128.6	2.3	105.1	1.8
WYKS3T	Wykes Tee 33kV	33.0	320.6	5.6	127.5	2.2	104.2	1.8
LITI3J	Little Irchester 33kV J	33.0	785.0	13.7	103.3	1.8	86.0	1.5
LITI3K	Little Irchester 33kV K	33.0	785.0	13.7	103.3	1.8	86.0	1.5
LITI5J-1	Little Irchester 11kV	11.0	170.6	9.0	70.1	3.7	43.8	2.3
LITI5A	Little Irchester Sub - A 11kV	11.0	115.0	6.0	58.7	3.1	38.5	2.0
LITI5B	Little Irchester Sub - B 11kV	11.0	82.1	4.3	49.2	2.6	33.7	1.8
LITI5C	Little Irchester Sub - C 11kV	11.0	63.1	3.3	42.1	2.2	29.7	1.6
LITI04A	Little Irchester Sub - A 415V	0.415	19.0	26.4	16.2	22.6	13.0	18.0
LITI04B	Little Irchester Sub - B 415V	0.415	17.9	24.9	15.5	21.5	12.4	17.3
LITI04C	Little Irchester Sub - C 415V	0.415	17.0	23.6	14.8	20.5	11.9	16.5

Table 2-17 shows the islanded fault levels as a percentage of the grid connected fault level, in order to show a further comparison between the two. It is noted that the islanded fault levels are significantly lower, but the magnitude of difference decreases as measurements are made further down the 11kV feeders. This can be explained by the increasing impedance between the source and the fault location as the fault is applied further downstream in the grid connected case. This increasing impedance reduces the grid connected fault level contribution and therefore the percentage difference between the grid connected and island results is reduced.

Table 2-17 EM2 – Comparison against grid connected fault level

Island vs Grid Fault Level			
BB Code	BB Name	% of grid connected	
		Island Max - Grid	Island Min - Grid
WYKS3J	Wykes Generation 33kV	41.1%	33.6%
WYKS3T	Wykes Tee 33kV	39.8%	32.5%
LITI3J	Little Irchester 33kV J	13.2%	11.0%
LITI3K	Little Irchester 33kV K	13.2%	11.0%
LITI5J-1	Little Irchester 11kV	41.1%	25.7%
LITI5A	Little Irchester Sub - A 11kV	51.0%	33.5%

LITI5B	Little Irchester Sub - B 11kV	59.9%	41.0%
LITI5C	Little Irchester Sub - C 11kV	66.7%	47.0%
LITI04A	Little Irchester Sub - A 415V	85.7%	68.4%
LITI04B	Little Irchester Sub - B 415V	86.4%	69.2%
LITI04C	Little Irchester Sub - C 415V	87.0%	70.0%

Table 2-18 presents the results of the investigation into the comparison between the maximum load current versus minimum phase-to-phase fault current for each of the busbars in the EM1 model. The results show that the minimum phase-to-phase fault current is more than double the maximum load current at all recorded points. The magnitude of these fault levels is therefore sufficient to allow adequate grading of the overcurrent protection settings when the system is islanded. It should be noted that changes to protection settings would be required to facilitate island mode due to the reduction in fault level from the grid connected scenario. It should be noted that the load current for the HV/LV substations has been based on the maximum rated current of a secondary distribution substation which is normally 1MVA (52A).

Table 2-18 EM2 – Short circuit results – load vs fault level.

Overcurrent settings Limits						
BB Code	BB Name	Max load (MVA)	Load Current (kA)	Min Phase - Phase Fault Current (kA)	Minimum OC Settings	OC Settings > Load
WYKS5J	Wykes Generation 11kV	25.0	1.312	13.7	6.84	PASS
WYKS3J	Wykes Generation 33kV	25.0	0.437	1.3	0.65	PASS
WYKS3T	Wykes Tee 33kV	25.0	0.437	1.3	0.65	PASS
LITI3J	Little Irchester 33kV J	7.4	0.129	1.3	0.65	PASS
LITI3K	Little Irchester 33kV K	7.4	0.129	1.3	0.65	PASS
LITI5J-1	Little Irchester 11kV	2.0	0.105	1.3	0.67	PASS
LITI5A	Little Irchester Sub - A 11kV	1.0	0.052	1.3	0.67	PASS
LITI5B	Little Irchester Sub - B 11kV	1.0	0.052	1.3	0.67	PASS
LITI5C	Little Irchester Sub - C 11kV	1.0	0.052	1.3	0.67	PASS
LITI04A	Little Irchester Sub - A 415V	1.0	1.391	15.6	7.80	PASS
LITI04B	Little Irchester Sub - B 415V	1.0	1.391	14.9	7.47	PASS
LITI04C	Little Irchester Sub - C 415V	1.0	1.391	14.3	7.14	PASS

2.2.4 Transient study

As described in Section 2.1.4 the following studies were undertaken for EM2:

- Transient line fault;
- Generation trip;
- Load rejection;
- Switched in load; and
- Generator Critical Fault Clearance Time (CFCT).

The results of these studies are described in the following sections.

Transient line fault

A three-phase symmetrical fault was simulated on the 33kV circuit between Little Irchester and Wykes Generation tee as seen in Figure 2-20 as "Fault EM2". The three-phase fault is applied for 100ms, representing a transient fault. A three phase transient fault was studied in order to assess the worst-case scenario for generator stability.

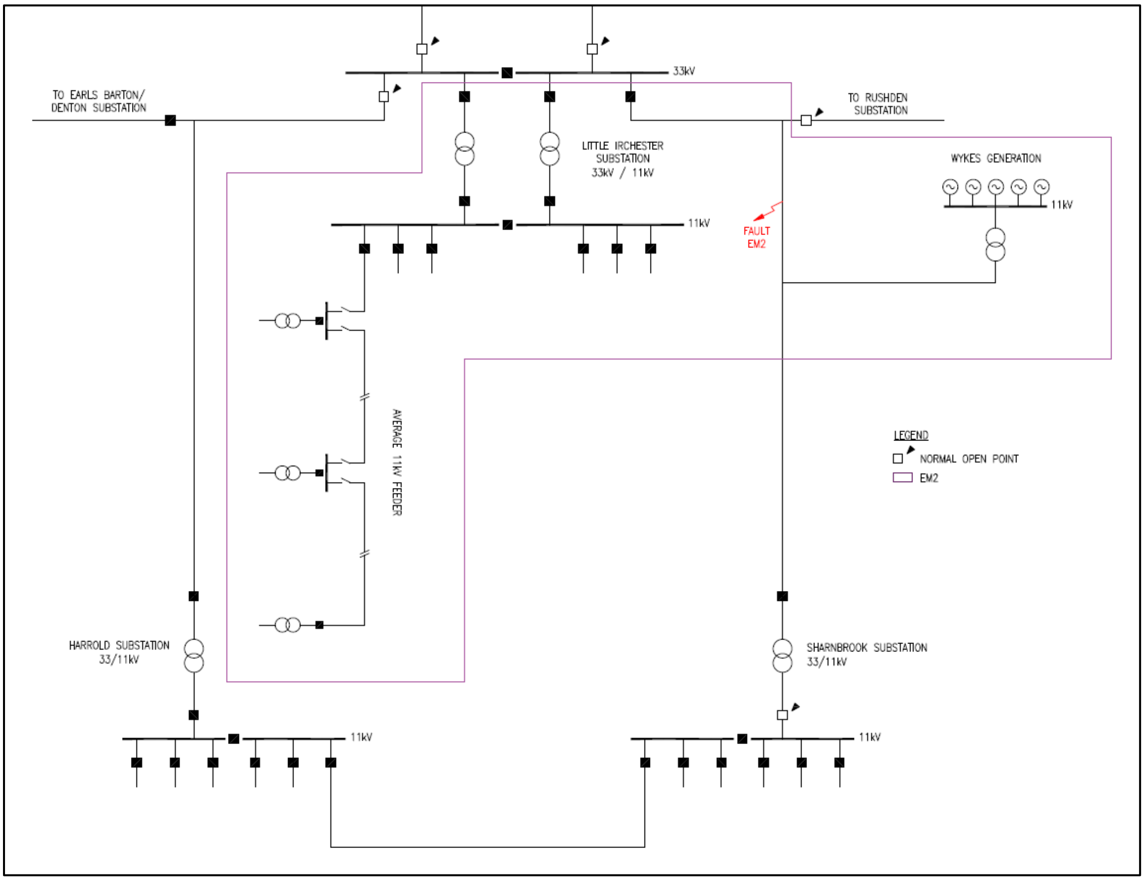


Figure 2-20 Transient fault location on EM2

Maximum load case

The first study observed the transient response of the island at maximum load with 20MW of behind the meter load at Wykes. Figure 2-21 and Figure 2-22 show the voltage and frequency response of the EM2 island for the duration of the 100ms fault and the subsequent transient period. The fault is applied at 2.0s and the fault is cleared at 2.1s. The results show that the generator AVR has stabilised the voltage within 4s. The frequency takes slightly longer to stabilise, becoming stable after around 8s, following a short transient period. As the voltage and frequency are stable (within the statutory limits of 49.5Hz to 50.5Hz) in less than 60s after the event, this can be deemed as acceptable (as per National Grid SQSS).

A steep frequency increase that is likely in excess of 1Hz/s is noticed immediately after the fault, but this will not cause a G59/G99 trip on RoCoF as it is not sustained for more than 500ms (the setting time delay). The frequency peaks at 50.7Hz and it therefore within the over frequency settings within the G59/G99 standards (52Hz for 500ms). The voltage is seen to exceed the under voltage limit of 0.8PU, but the voltage collapse is only present for the duration of the fault before returning above the minimum setting before the 500ms under voltage setting time delay and therefore the generator will not trip on G59/G99 under voltage protection.

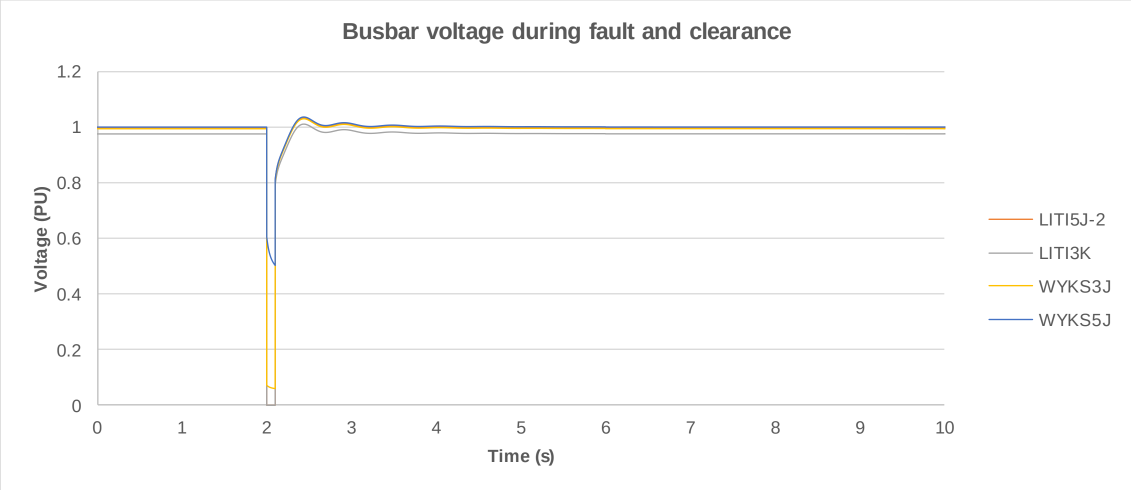


Figure 2-21 Busbar voltage during fault and clearance – Max load

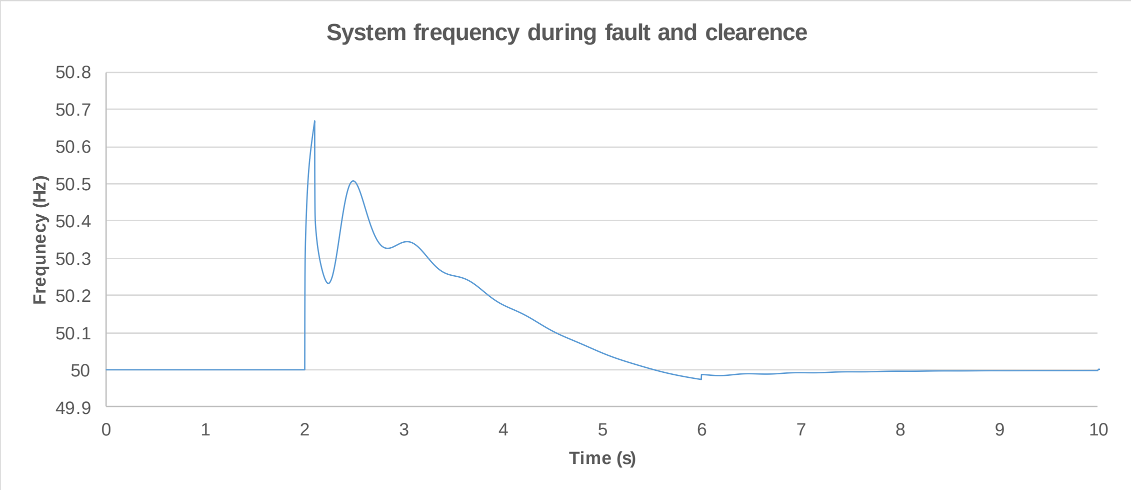


Figure 2-22 Frequency during fault and clearance – Max load

Minimum load case

The second study observed the transient response of the island at minimum load with 20 MW of behind the meter load at Wykes. Figure 2-23 and Figure 2-24 show the voltage and frequency response of the EM2 island for the same fault as detailed for the maximum load scenario. Similar to the maximum load scenario, it can be seen that voltage stabilises within 4s with the frequency taking slightly longer, stabilising after around 7s, following a short transient period. As with the maximum load case, this is acceptable.

A steep frequency increase that is likely in excess of 1 Hz/s is noticed immediately after the fault, but this will not cause a G59/G99 trip on RoCoF as it is not sustained for more than 500ms (the setting time delay). The frequency peaks just below 50.4 Hz and is therefore within the over frequency settings on G59/G99 standards (52Hz for 500ms). The voltage is seen to exceed the under voltage limit of 0.8PU, but the voltage collapse is only present for the duration of the fault before returning above the minimum setting before the 500ms under voltage setting time delay and therefore the generator will not trip on G59/G99 under voltage protection.

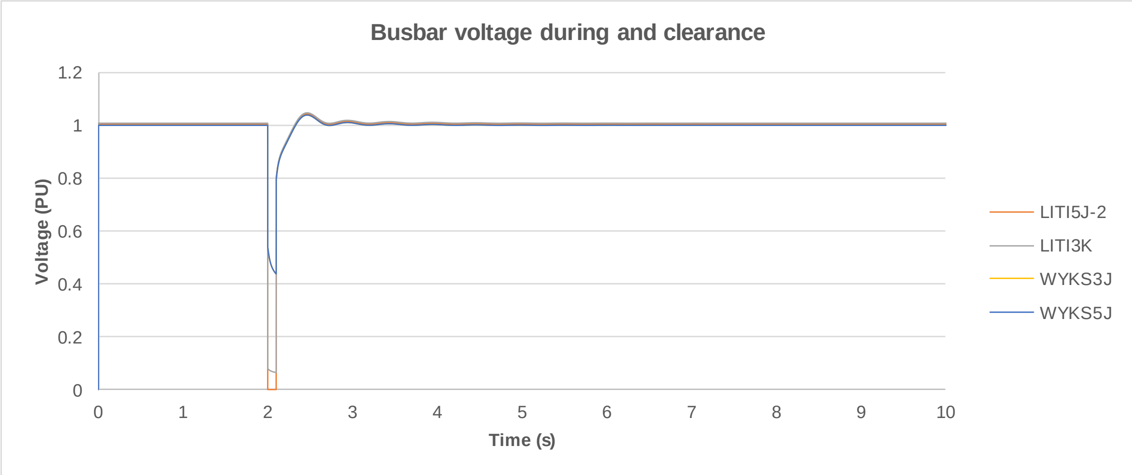


Figure 2-23 Busbar voltage during fault and clearance – Min load

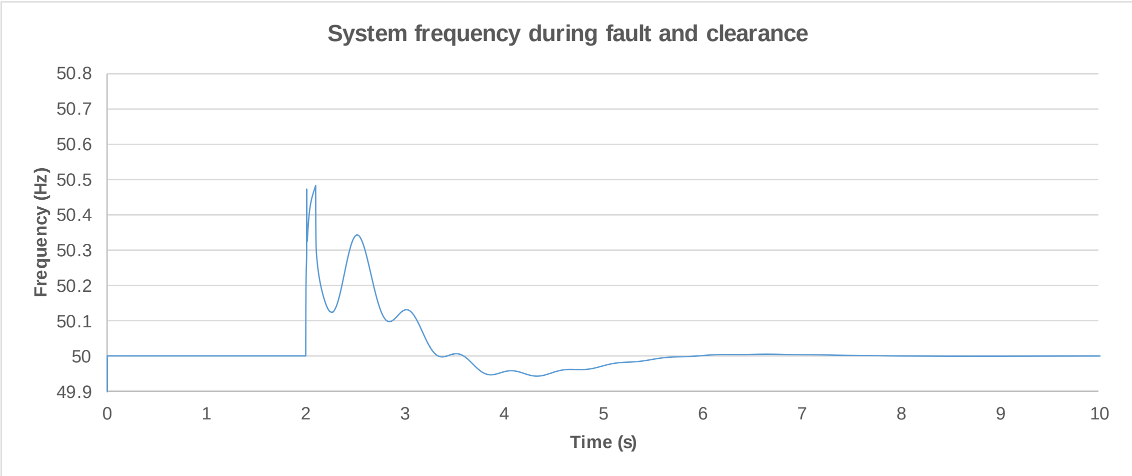


Figure 2-24 Frequency during fault and clearance – Min load

Generation trip

This study analyses the system voltage and frequency response following the tripping of a generator at the Wykes generation plant. The post trip loading of the generators is also verified to ensure that no machine is over or under loaded. The studies are performed at maximum load with the loss of the largest generating unit, which represents the worst case for system stability.

For these studies it has been assumed that generator units 1, 3 and 4 have frequency and power control systems installed as described in Section 1.3.4.

Table 2-19 shows the generator dispatch before and after the loss event, it is observed that due to the dynamic controller models, the load is shared across the remaining generators and all remain within their active and reactive capability.

Table 2-19 Generator dispatch before and after fault event

Generator dispatch pre/post fault										
Details					Performance pre-fault			Performance post-fault (15s)		
Gen ID	Generator Type / model	Voltage (kV)	Rating (MW)	Rating (MVA)	P	Q	Cosphi	P	Q	Cosphi
Gen 1	ALSTOM P140343-10	11	5	6.25	3.0	1.0	0.949	3.5	1.7	0.900
Gen 2	AVK DIG16n14	11	14	14.34	8.0	1.6	0.981	8.0	3.8	0.903
Gen 3	ABB AMG1120MO12DSE	11	6.6	8.25	3.4	1.6	0.905	6.3	0.3	0.999
Gen 4	ABB B194CM102-B	11	10.37	12.95	8.0	2.6	0.951	10.2	2.9	0.962
Gen 5	AVK P-OB-10179-B	11	14.0	14.34	5.6	1.8	0.952	0.0	0.0	N/A

Figure 2-25 and Figure 2-26 show the voltage and frequency response following the loss of the largest generator. After a short transient period of 5s post event, the generator busbar voltage returns to a stable 1.0PU. The frequency stabilises after 7s post event to a lower level of 49.3Hz.

The system does not return to the pre-event 50Hz following the gain of load on the remaining four generators due to the generator droop setting. The frequency will remain at the reduced level of 49.3Hz until the control systems are reset.

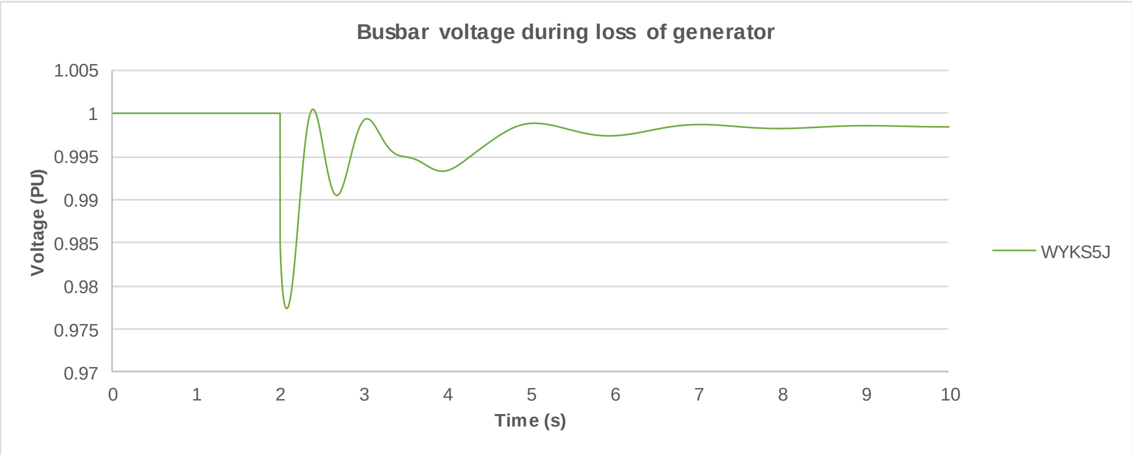


Figure 2-25 Busbar voltage following loss of Generator 5

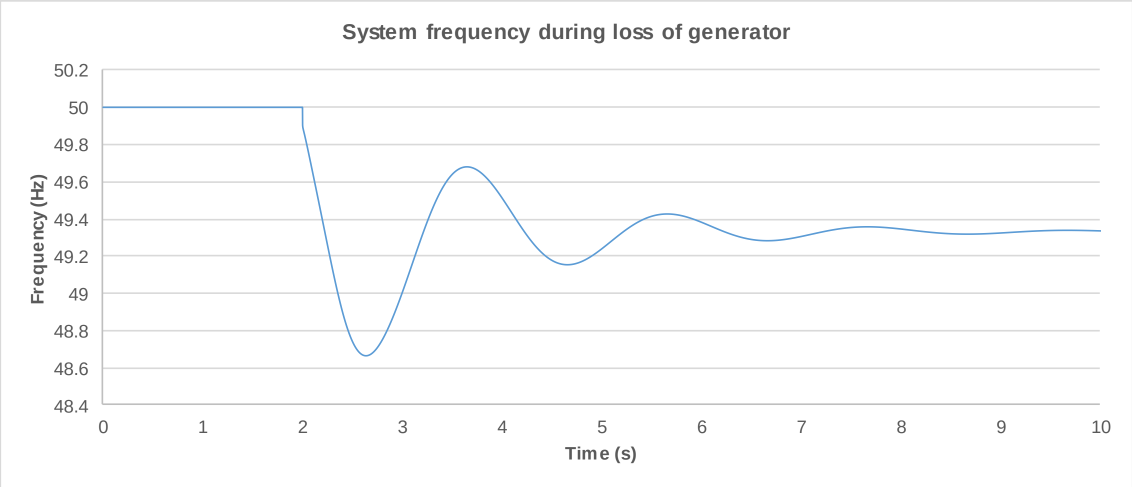


Figure 2-26 Frequency following loss of Generator 5

Figure 2-27 shows the generator power response where the increase in active power post event can be seen on generator units 3 and 4 (the machines fitted with the dynamic control systems).

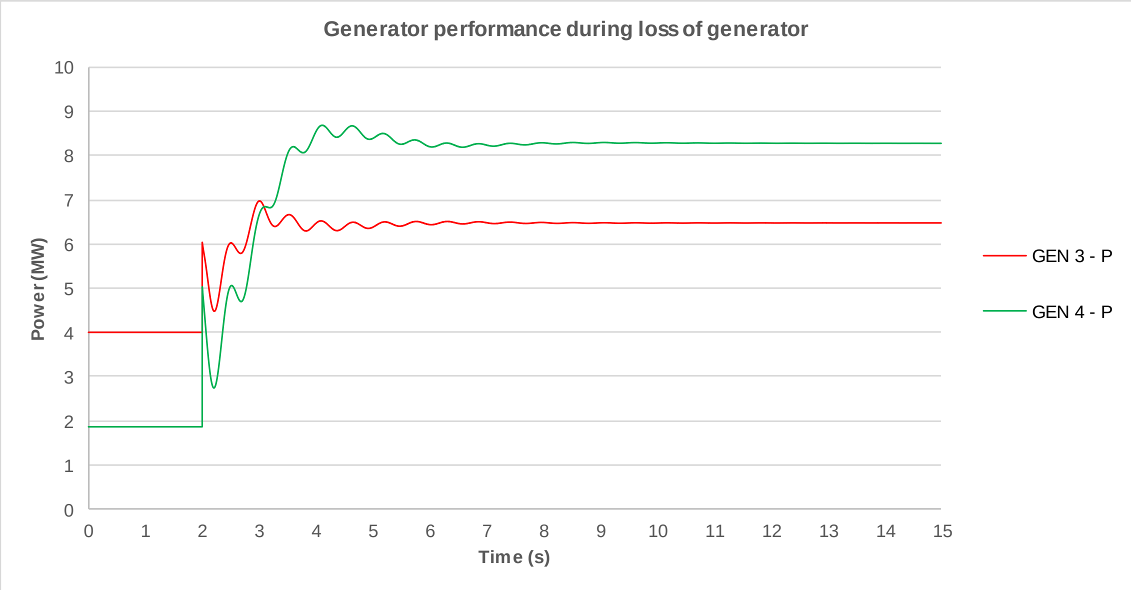


Figure 2-27 Active power response following loss of Generator 5

The RoCoF for the network island was also investigated as part of the stability studies following the loss of Generator 5. Figure 2-28 shows the RoCoF of the network island during the loss of Generator 5 against the 1Hz/s limit detailed in G59/G99.

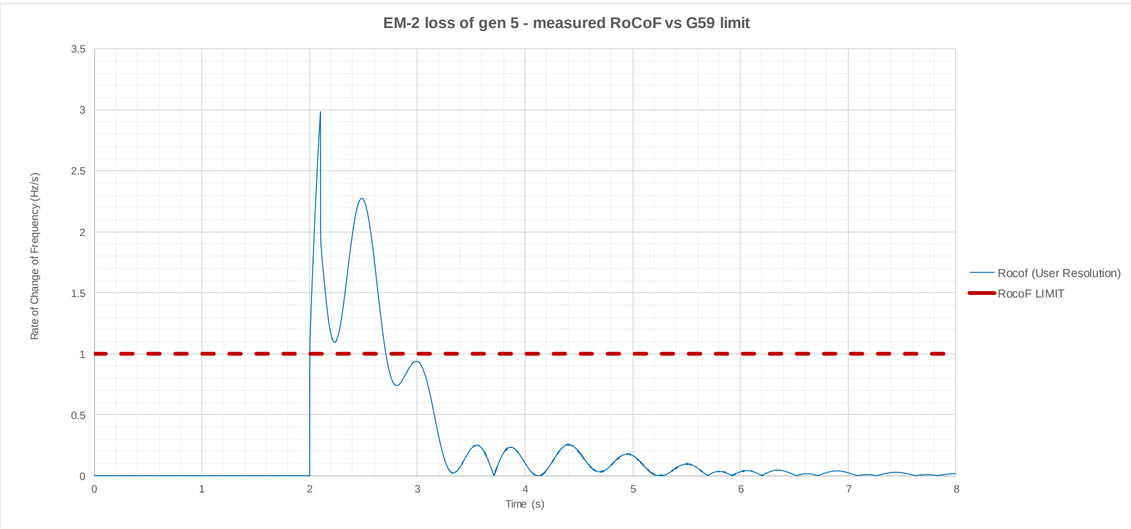


Figure 2-28 Rate of change of system frequency following loss of Generator 5

Figure 2-28, above, shows the rate of change of frequency (blue) against the 1 Hz/s limit (red).

It is visible that the RoCoF is greater than 1 Hz/s for 0.6s, hence The G59/G99 relay would trip the circuit breaker, disconnecting the generator and the load within the island.

Although RoCoF is intended for exactly for this purpose, being a LoM protection scheme, it is not applicable in this situation as it is designed to prevent network islanding when unintended. This will be need to be investigated further if the network island were to be implemented. A potential solution could include a blocking signal for the LoM when the network has been islanded upon command.

Load Rejection

This study investigates the loss of a single outgoing 11kV circuit at Little Irchester substation with the island operating at maximum load.

Figure 2-29 shows the voltage of the system and Figure 2-30 frequency response following the load loss at 2s. The voltage can be seen to increase, but is stable after 2s post event, with the generator busbar voltage (WYK5J) returning to 1.0PU. The frequency increases post event and is stable at a slightly higher value of 50.3 Hz at 7s (5s post event).

The response of the generator during this system is not severe, there is a small step change in voltage and frequency increases and stabilises to a higher value.

The frequency does not return to the original set point of 50Hz, settling at around 50.1Hz, which is within G59/G99 and Grid Code limits. The RoCoF is also within the G59/G99 limits.

The generator does not return to the pre-event frequency of 50Hz as the governor droop setting, as per the IEEE model, does not have an active set-point. However, the droop setting can be adjusted so that the frequency settles within a closer tolerance of 50Hz and we would expect this to be implemented on the network island.

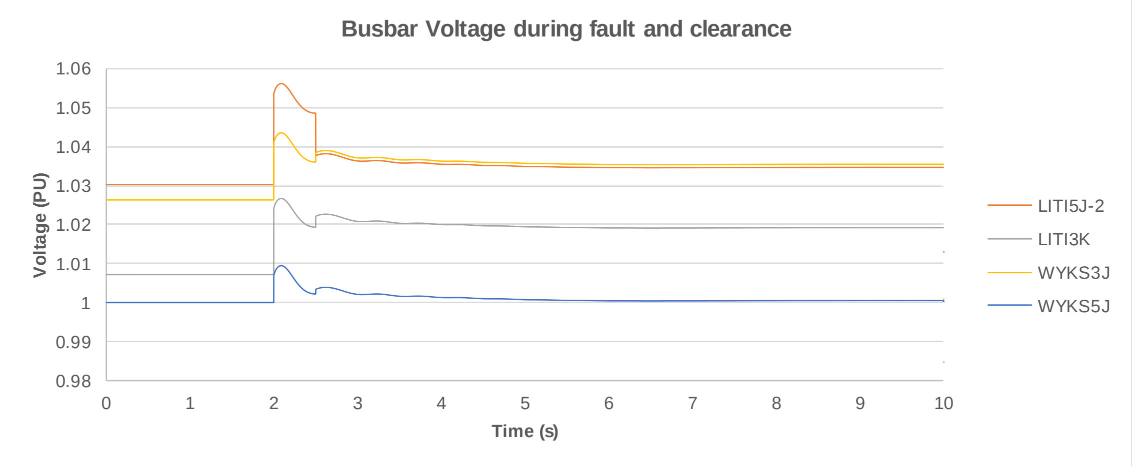


Figure 2-29 Busbar voltage following loss of Little Irchester 11kV feeder

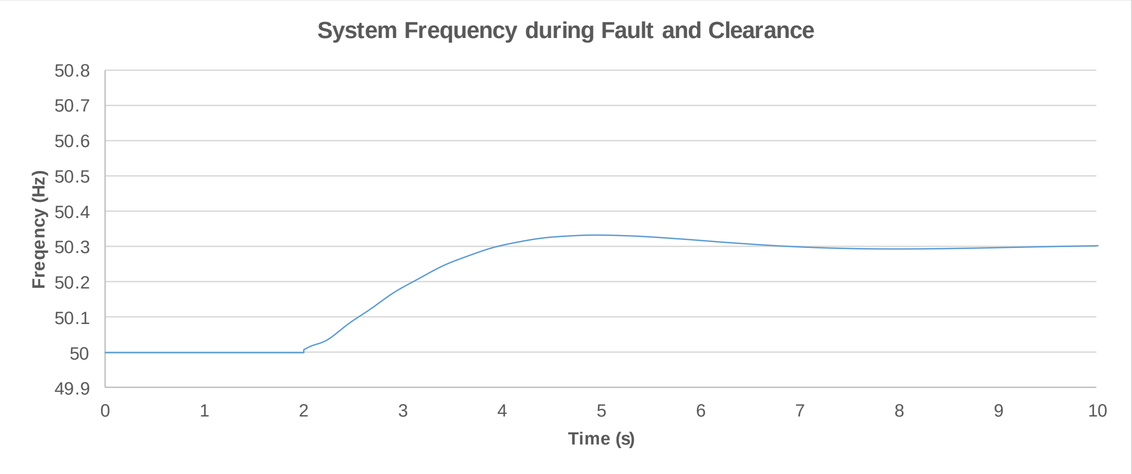


Figure 2-30 Frequency following loss of Little Irchester 11kV feeder

Switched in load

This study analyses the system voltage and frequency response following the restoration of a single 11kV feeder fed from Little Irchester substation. A study at maximum load has been analysed to assess the worst case.

Figure 2-31 shows the voltage of the system and Figure 2-32 frequency response following the connection of load at 2s. The voltage can be seen to decrease, but is stable after 1s post event, with the generator busbar voltage (WYK5J) returning to 1.0PU. The frequency decreases post event and is stable at a slightly lower value of 49.8Hz at 8s (7s post event).

The response of the generator during this system is not severe, there is a small step change in voltage and frequency decreases and stabilises to a slightly lower value.

The frequency does not return to the original set point of 50Hz, settling at around 49.95Hz, which is within G59/G99 and Grid Code limits. The RoCoF is also within the G59/G99 limits.

The generator does not return to the pre-event frequency of 50Hz as the governor droop setting, as per the IEEE model, does not have an active set-point. However, the droop setting can be adjusted so that the frequency settles within a closer tolerance of 50Hz and we would expect this to be implemented on the network island.

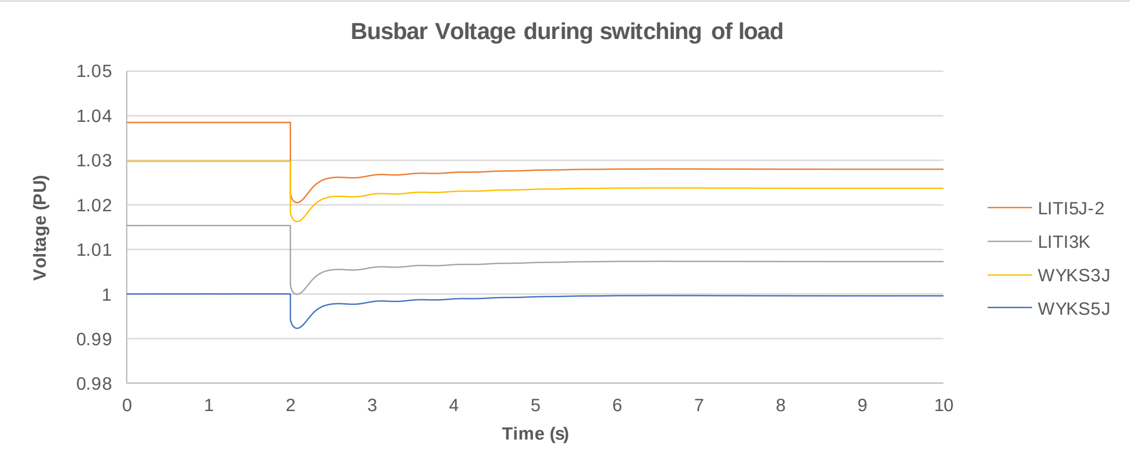


Figure 2-31 Busbar voltage following connection of Little Irchester 11kV feeder

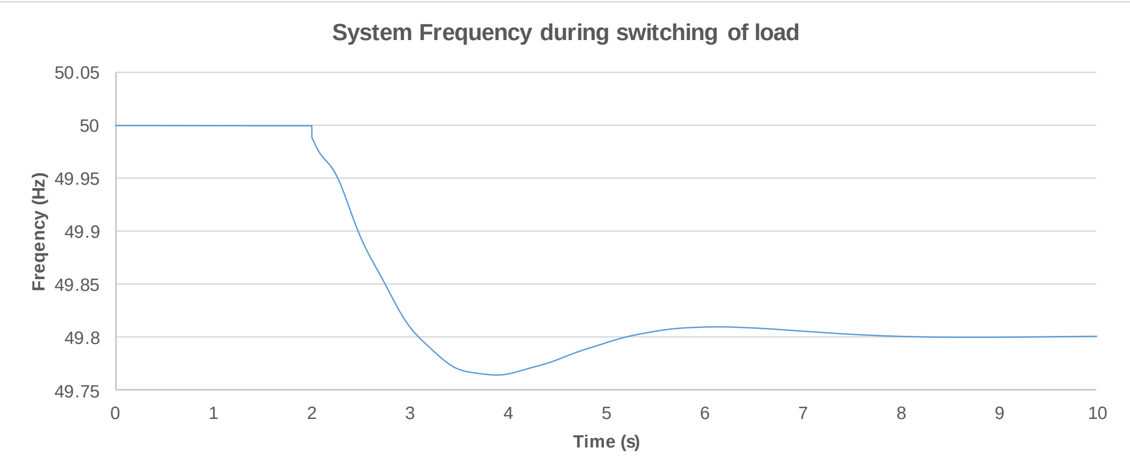


Figure 2-32 Frequency following connection of Little Irchester 11kV feeder

Critical Fault Clearance Time

This study analyses the reaction of the generators to a fault placed on the generator 11kV busbar and then cleared in increasing time increments until the system fails to return to a stable state.

Table 2-20 details the voltage and frequency response post-fault with respect to increasing fault clearance times. It is observed that when the fault clearance time is greater than 1.05s, the system is unable to return to stability. Therefore, the CFCT is 1.05s.

The generator main protection time is 250ms and back up is 1.25s. Therefore, the operation of main protection on the generator will ensure that the generator does not become unstable. However, if the main generator protection fails to operate it is likely that the generator will become unstable before the back-up protection operates to clear the fault. This would require the back-up setting to be adjusted if the network island were to be implemented.

Table 2-20 EM2 - RMS - critical fault clearance time - max load

Generator Critical Fault Clearence Time			
Fault Clearance Time (s)	Voltage Stable time (s)	Frequency Stable time (s)	System Stable (Y/N)
0.1	8.5	12.7	YES
0.2	9.8	13.7	YES
0.3	10.9	14.3	YES
0.4	11.6	18.7	YES
0.5	13.5	18.8	YES
0.6	17.0	22.1	YES
0.7	17.5	22.5	YES
0.8	18.5	23.1	YES
0.9	19.2	23.8	YES
1.0	20.3	24.4	YES
1.05	24.5	25.5	YES
1.1	N/A	N/A	NO

2.3 Sensitivity analysis

2.3.1 Overview

EM1 and EM2 provide representative examples of networks that could be islanded, however, further studies were completed to understand if changing the configuration of these networks would have an impact on the results.

The sensitivity analysis was performed by increasing the 33kV and 11kV feeder length to understand when voltage drop would exceed allowable limit and when fault level would become too low to allow adequate discrimination. Analysis was carried out to establish the effect of increasing substation load to match the firm capacity of stated in the LTDS.

2.3.2 Load flow study

The 11kV studies detailed in Sections 2.2.2 and 2.3.2 were repeated with feeder lengths of 20km representing the maximum feeder length expected at this voltage level. Similarly, the 33kV studies 1 were repeated with feeder lengths of 21km, which is the longest length circuit of this voltage from the WPD East Midlands LTDS.

The results of the sensitivity analysis showed that the voltages were well within ESQCR limits with the minimum voltage of 0.956PU recorded at the most remote EM2 11kV/LV distribution substation.

2.3.3 Short circuit study

The sensitivity studies for the increased 33kV and 11kV network feeders were also completed using the same methodology as detailed in 2.2.3 and 2.3.3.

The fault level studies were conclusive and showed that minimum phase-to-phase fault current at the end of the circuit is greater than double the maximum load current through the primary substation breaker for all scenarios. However, the lowest fault level was experienced on the 11kV feeder in EM2 where the value was only marginally above the maximum load current.

2.3.4 Transient study

Transient sensitivity studies were completed for EM2 as this represented the worst case for stability as shown in the comparison between the results of EM1 (Section 2.1.4) and EM2 (Section 2.2.4).

Transient Line Fault

The transient line fault study investigated the voltage and frequency response during the application and subsequent clearance of a fault on the 33kV line between Little Irchester and Wykes tee with increased loading and feeder lengths as previously described.

As per the results from Section 2.2.4, both the voltage and frequency were able to stabilise after around 4-5s following the line fault and were within acceptable limits.

Generation Trip

This study was performed to show the effect of losing the largest generator. The results showed that the voltage is able to recover back to 1.0PU at the generator terminals after 6s post event. Frequency stabilises to 49.3Hz after 7s post event and does not return to 50Hz. In addition, the power export from generators three and four increases in order to pick up the lost supply from generator 5, which has been lost.

The RoCoF was also studied to establish if the generator would trip on G59/G99 settings. The results of this studies showed that the RoCoF was only above 1Hz/s for 250ms therefore this would not trip the generation.

Load Rejection

The load rejection study showed that the voltage stabilises to the pre-fault value within 7s post event and frequency stabilises to 50.15Hz, 8s post event. As previously discussed the droop control on the generators would need to be adjusted in order for the frequency to return to 50Hz, however, as the frequency is well within acceptable limits this is not an issue.

Switched in load

The switched in load assessment was performed when 1.8MW of load is energised on an 11kV feeder from Little Irchester substation.

The results showed that the generator voltage settles back to 1.0PU within 3s of the event and the frequency is stable at 49.8Hz, 5s after the event. As for the load rejection study, the frequency does not stabilise back to 50Hz, however this is not an issue.

Critical Fault Clearance Time

The CFCT for the sensitivity analysis employed the same method that was used for the studies detailed in Section 2.1.4 and 2.2.4. EM1 or EM2 results. For this study the effect of removing the 20MW "behind the meter load" at Wykes was investigated. The results show that with 0MW "behind the meter load" the CFCT time is greater therefore providing no issues with generator stability.

As per the results from Section 2.2.4, both the voltage and frequency were able to stabilise after around 4-5s following the line fault and were within acceptable limits.

3. Conclusions

3.1 East Midlands 1 network island

3.1.1 Load flow results

The results in Section 2.1.2 show that the EM1 network island was within the required voltage and thermal limits at both maximum and minimum loading. The on-load tap changers for Sharnbrook and Wykes generation also remained within an acceptable tap range (i.e. not at the extents of the operation).

3.1.2 Short circuit results

Section 2.1.3 details the results for the short circuit studies for EM1. The results showed that the fault levels reduced significantly under islanded operation, however, this was expected as the contribution from the grid was no longer available. The minimum phase-to-phase fault current was compared against load current to ensure that sufficient margin was available to discriminate between the two values. The studies showed that there is adequate headroom between the setting and load current for discrimination purposes.

3.1.3 Transient study results

Section 2.1.4 shows the results of the transient studies carried out for EM1. These included transient line fault, generation trip, load rejection, step increase of load and fault clearance time studies to assess the voltage and frequency response of the generation plant to these events. The studies were carried out for the most onerous scenario and the voltage and frequency were compared against G59/G99 limits.

The results show that for each transient study simulation, the generator control system is able to react to the event, and voltage and frequency are stabilises within a maximum period of 10s. The only concern raised is the droop setting included in the IEEE standard governor model that has been used for the studies. This causes the frequency to settle outside of the 50Hz target, but still with acceptable industry limits. This droop setting on the generators can be altered such that the frequency will stabilise back to 50Hz after an event, however, this has not been implemented for the studies.

3.2 East Midlands 2 network island

3.2.1 Load flow results

The results in Section 2.2.2 show that the EM2 network island was within the required voltage and thermal limits at both maximum and minimum loading. The on-load tap changers for Little Irchester and Wykes generation also remained within an acceptable tap range (i.e. not at the extents of the operation).

3.2.2 Short circuit results

Section 2.2.3 details the results for the short circuit studies for EM2. As for EM1, the results showed that the fault levels reduced significantly under islanded operation; however, this was expected, as the contribution from the grid was no longer available. The minimum phase-to-phase fault current was compared against load current to ensure that sufficient margin was available to discriminate between the two values. The studies showed that there is adequate headroom between the setting and load current for discrimination purposes.

3.2.3 Transient study results

Section 2.2.4 shows the results of the five different transient studies carried out for EM2. Again, the studies were carried out for the most onerous scenario and the voltage and frequency were compared against G59/G99 limits.

For the majority of the studies, the generator control system is able to react to the event, and voltage and frequency are stabilises within a maximum period of 10s. However, the studies highlighted that there were two areas that would need to be addressed if EM2 were to be implemented.

The first area relates to the RoCoF in relation to the loss of Generator 5 (the largest generator). In this instance, the RoCoF exceeds the G59/G99 setting of 1Hz/s for a period of 500ms, which would result in all the generation being disconnected. However, as it can be shown that the generation can recover and stabilise, this setting could be relaxed for EM2 if it were to be implemented.

The second area relates to the CFCT for EM2 where the studies showed that faults lasting longer than 1.05s would result in the generation becoming unstable. Although most faults at the generation busbar would be cleared by the main protection in around 250ms, if this were to fail then the standard backup protection could take up to 1.25s to clear. In this instance the generation could again become unstable. If the EM2 network island were to be implemented this backup setting would need to be revised to ensure that it would operate before the generation becomes unstable.

The only other area of concern was the droop setting as discussed for EM1 in Section 2.1, which could be resolved by implementing an active set-point.

3.2.4 Sensitivity study results

The results in Section 2.3 detail three different studies undertaken to determine the sensitivity analysis of both EM1 and EM2 network islands.

The first area, the sensitivity load flow study in Section 2.3.2, determined the voltages to be within the ESQCR limits, with the minimum voltage of 0.956PU recorded at the most remote EM2 11kV/LV distribution substation.The on-load tap changers also remained within an acceptable range.

The second area analysed the short circuit sensitivity (Section 2.3.3). This concluded that the minimum phase-to-phase fault current at the end of the circuit is greater than double the maximum load current through the primary substation breaker for all scenarios, which gives a sufficient headroom margin..

The third area analysed included five separate studies. The transient sensitivity studies were completed for EM2 as this represented the worst case for stability as shown in the comparison between the results of EM1 (Section 2.1.4) and EM2 (Section 2.2.4).

The transient line fault study investigated in Section 2.2.4, showed both the voltage and frequency were able to stabilise after around 4-5s following the line fault and were within acceptable limits.

The generator trip study (Section 2.3.4) showed that in the case of a generator 5 trip, generators 3 and 4 are capable of increasing their power export to compensate for the lost supply.

The RoCoF study determined it would not trip the generation as it was only above 1Hz/s for 250ms.

The load rejection study showed that the voltage and frequency stabilise to the pre-fault value within 7-8s respectively. These are within a sufficient margin to allow the droop control maintain the same.

The results of the switched in load study determined that the generator voltage settles back to 1.0PU within 3s of the event and the frequency is stable at 49.8Hz, 5s after the event.

The CFCT for the sensitivity analysis study showed the effect of removing the “behind the meter load” at Wykes. The results show that with 0MW “behind the meter load” the CFCT time is greater therefore providing no issues with generator stability.

3.3 Summary

Table 3-1 provides a summary of the studies carried out for network islands EM1 and EM2.

Table 3-1 Summary of studies

Study	EM1	EM2
Load flow	✓	✓
Fault level	✓	✓
Transient line fault	✓	✓
Generation trip	✓	✓
Load rejection	✓	✓
Switched in load	✓	✓
CFCT	✓	!
RoCoF	✓	!

✓ Study results show compliance with necessary standards

! Study results indicate minor non-compliance with necessary standards

✗ Study results indicate major non-compliance with necessary standards

Appendix A
G59/G99 Requirements

Appendix A – G59/G99 Requirements

The results from power system studies have been compared against the requirements of ENA ER G99, G59 and the Grid Code.

Table 3-2 and Table 3-3 provide the requirements for G99 and G59 respectively. Wykes generation has been commissioned using the requirements of G59. However, a comparison has been made against G99 (which superseded G59 in April 2019) to ensure the studies are valid for the latest requirements.

Table 3-2 ENA ER – G99 voltage and frequency protection settings

ER G99 Voltage And Frequency Limits				
Element - Voltage	Setting (PU)	Setting (kV)	Time Delay (s)	Comment
O/V 1	1.1	12.1	1	
O/V 2	1.13	12.43	0.5	
U/V 1	0.8	8.8	2.5	
U/V 2	N/A			*No U/V Stage 2 in G99*
Element - Frequency	Setting (PU)	Setting (Hz)	Time Delay (s)	
O/F 1	1.04	52	0.5	Must remain connected for up to 15 minutes at frequencies up to 52Hz
O/F 2	N/A			*No O/F Stage 2 in G99*
U/F 1	0.95	47.5	20	
U/F 2	0.94	47	0.5	
Element - RoCoF	Setting		Time Delay (s)	
RoCoF	1Hz/s		0.5	RoCoF only to trip if 1Hz/s is exceed for longer than 500ms
All data from ENA EREC - G99				

Table 3-3 ENA ER – G59 voltage and frequency protection settings

ER G59 Voltage And Frequency Limits				
Element - Voltage	Setting (PU)	Setting (kV)	Time Delay (s)	Comment
O/V 1	1.1	12.1	1	
O/V 2	1.13	12.43	0.5	
U/V 1	0.87	9.57	2.5	
U/V 2	0.8	8.8	0.5	
Element - Frequency	Setting (PU)	Setting (Hz)	Time Delay (s)	
O/F 1	1.03	51.5	90	
O/F 2	1.04	52	0.5	
U/F 1	0.95	47.5	20	
U/F 2	0.94	47	0.5	
Element - RoCoF	Setting		Time Delay (s)	
RoCoF	1Hz/s		0.5	RoCoF only to trip if 1Hz/s is exceed for longer than 500ms

The latest data provided for Wykes Engineering, shows that the applicable RoCoF setting for this installation is 0.5 Hz/s for 500ms. G99 (and also the current Accelerated Loss of Mains Change Programme) state that the setting shall be 1Hz/s for 500ms, hence all comparisons in this study use the more relaxed setting.

The RoCoF has been calculated for the most onerous case of change of frequency which is the loss of a generator. The RoCoF has been calculated using Excel, by sampling the frequency data over a rate of 0.1s intervals and recording the rate of change across the sampled intervals. The maximum RoCoF has been compared against the G59/G99 Limit. Noting that the time delay for RoCoF is 500ms, we have also studied whether the period of RoCoF above this limit is greater than the time delay.

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Document Status

Revision	Author	Reviewer		Approved for Issue		
		Name	Signature	Name	Signature	Date
V01	K Davis	D Hardman		N Murdoch		14/01/2020

Appendix B
Correspondence with equipment manufacturers

Manufacturers conversation log about network islanding technologies

Date	Company	Communication	Detail
19/09/2019	Manufacturer 1	Request for a quotation by email	The initial request for information regarding microgrid controller technology.
23/09/2019	Manufacturer 1	Teleconference	Follow-up chat about technology capabilities.
19/09/2019	Manufacturer 2	Request for a quotation by website	The initial request for information regarding a specific microgrid controller
23/09/2019	Manufacturer 2	Email	Information about Manufacturer 2s capabilities to work with the client on project design
01/10/2019	Manufacturer 2	Email	After the review of SLDs, Manufacturer 2 provided indicative costs for consultancy services of £200k.
02/10/2019	Manufacturer 2	Email	Manufacturer 2 confirmed that the price provided before had not included costs of any equipment.
19/09/2019	Manufacturer 3	Request for a quotation by website	The initial request for information regarding a specific microgrid controller .
23/09/2019	Manufacturer 3	Phone call	Discussion of the controller requirements, introduction to the project and progress to date.
03/10/2019	Manufacturer 3	Email	Request for additional information regarding network island: source of generation, interface details, storage and operation.
07/10/2019	Manufacturer 3	Phone call	Discussion of the network diagrams and required infrastructure for the islanded operation.
07/10/2019	Manufacturer 3	Email	Follow-up by email regarding the phone call.
11/10/2019	Manufacturer 3	Email	Share the document to help to understand the technology
25/10/2019	Manufacturer 3	Email	Follow-up on the shared documents and provide handouts for generation controller and microgrid advisor.
20/09/2019	Manufacturer 4	Request for a quotation by website	The initial request for information regarding specific microgrid controller.
15/10/2019	Manufacturer 4	Phone call	Chat to discuss project details and progress, and catch up about Manufacturer 4 microgrid experience.
15/10/2019	Manufacturer 4	Email	Follow-up on the phone call and share information about case studies, experience and qualifications.
17/10/2019	Manufacturer 4	Email	Received details from Manufacturer 4 to proposed system at each substation to communicate with existing software.

24/10/2019	Manufacturer 4	Email	Set-up meeting to discuss the technology at Conference
31/10/2019	Manufacturer 4	Meeting	Discussion about the network island requirements to enable operation and costs of the solution
20/09/2019	Manufacturer 5	Request for a quotation by website	The initial request for information regarding microgrid controller "Microgrid Control System".
15/10/2019	Manufacturer 5	Email	The information has been received and passed on to the team.
17/10/2019	Manufacturer 5	Email	Manufacturer 5 requested additional information and SLDs.
25/10/2019	Manufacturer 5	Email	Manufacturer 5 requested the clarification on some information provided.
29/10/2019	Manufacturer 5	Email	Set-up meeting to discuss the technology at Conference
31/10/2019	Manufacturer 5	Meeting	A brief chat about the Manufacturer 5 capabilities and experience in microgrids' technologies and operation.
1/11/2019	Manufacturer 5	Email	Manufacturer 5 requested to NDA document.
07/11/2019	Manufacturer 5	Email	Manufacturer 5 prepared and shared the response document to "Request for Information, which outlines the Manufacturer 5 solution.
19/09/2019	Manufacturer 6	Request for a quotation by website	The initial request for information regarding specific microgrid controller
20/09/2019	Manufacturer 6	Email	Manufacturer 6 requested additional information and SLDs.
24/09/2019	Manufacturer 6	Phone call	Discussion about the project background, progress and requirements for the microgrid technology.
07/10/2019	Manufacturer 6	Email	The quotation for microgrid controller (£43k) was received together with additional information and relevant white papers.
10/10/2019	Manufacturer 6	Email	Set-up meeting to discuss the q at Conference
31/10/2019	Manufacturer 6	Meeting	A short discussion about the understanding of the project concept and requirements of the technology.
07/11/2019	Manufacturer 6	Email	Follow-up after the meeting to discuss the costs of the equipment.
11/11/2019	Manufacturer 6	Teleconference	The detailed discussion of costs for simple/basic (single generator) and advanced (multiple generator and storage) network island configuration.
13/11/2019	Manufacturer 6	Email	Follow-up on the teleconference to clarify the costs of equipment.
19/09/2019	Manufacturer 7	Request for a quotation by website	The initial request for information regarding specific microgrid controller
23/09/2019	Manufacturer 7	Email	Initial conversation to clarify the project scope.
26/09/2019	Manufacturer 7	Email	Follow-up from Manufacturer 7 Microgrid Systems team.

27/09/2019	Manufacturer 7	Email	Update on the quotation preparation.
02/10/2019	Manufacturer 7	Email	The quotation for £94k for controller was received with additional information and functional brochures.
10/10/2019	Manufacturer 7	Email	Further discussion over quotation details.
15/10/2019	Manufacturer 7	Phone call	Follow-up on the quotation.
24/10/2019	Manufacturer 7	Email	The additional information about the Manufacturer 7 microgrid controller capabilities was received.
07/11/2019	Manufacturer 7	Email	GHD sent additional request for information.
08/11/2019	Manufacturer 7	Email	Manufacturer 7 shared the request for clarification.
12/11/2019	Manufacturer 7	Meeting	Meeting with Manufacturer 7 Control and Protection representative to discuss the opportunity.
14/11/2019	Manufacturer 7	Teleconference	Follow-up on the meeting and discussion to understand the controller requirements and details from the received quotation.

GHD

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Revision	Author	Reviewer		Approved for Issue		
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