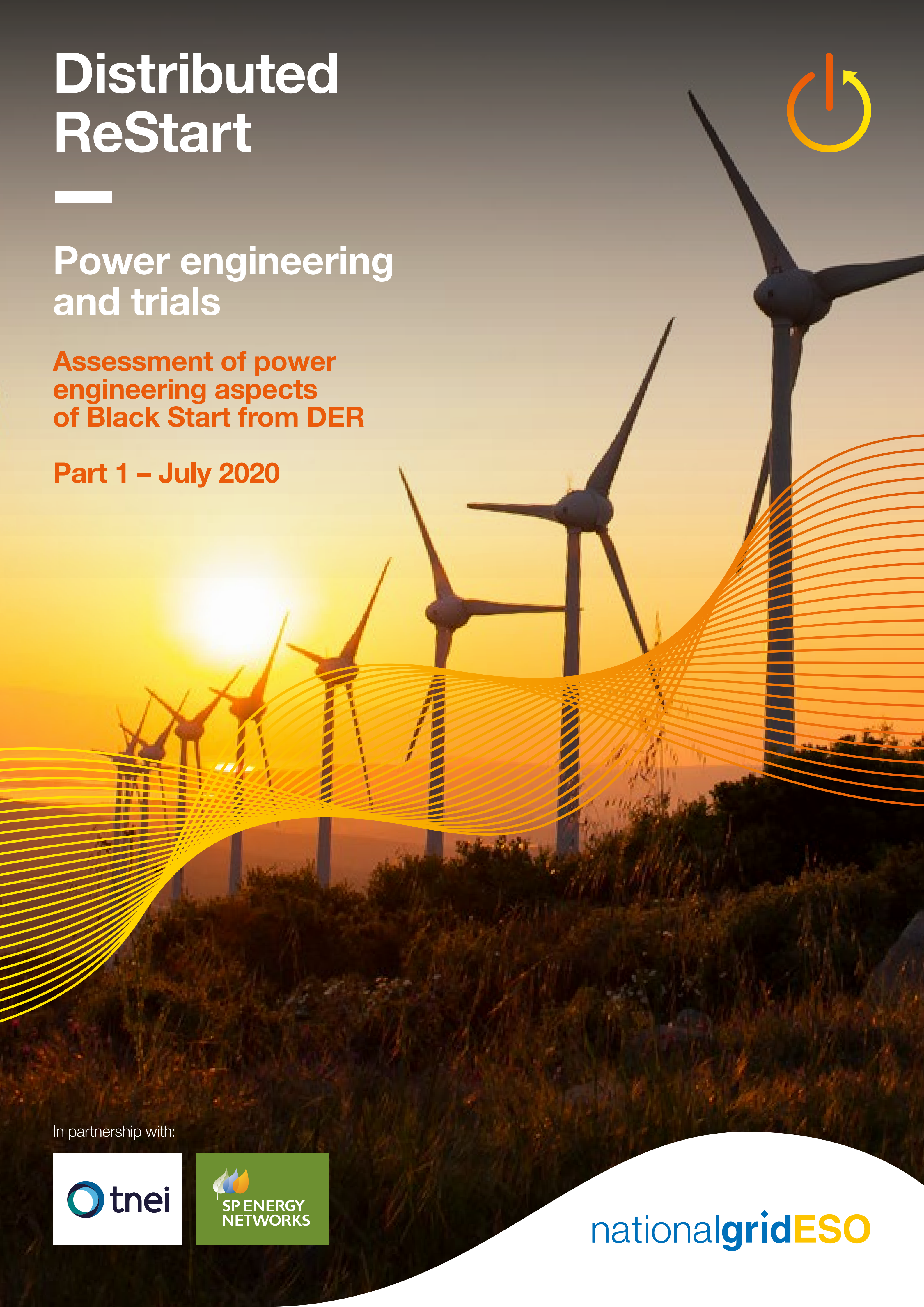

Distributed ReStart

Power engineering and trials

Assessment of power engineering aspects of Black Start from DER

Part 1 – July 2020

In partnership with:

tnei

SP ENERGY NETWORKS

nationalgridESO

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Abstract

The Distributed ReStart project is a partnership between National Grid Electricity System Operator (ESO), SP Energy Networks (SPEN) and TNEI (a specialist energy consultancy) that has been awarded £10.3 million of Network Innovation Competition (NIC) funding.

The project is exploring how distributed energy resources (DER) can be used to restore power in the highly unlikely event of a total or partial shutdown of the National Electricity Transmission System. Past and current approaches rely on large power stations but as the UK moves to cleaner, greener and more decentralised energy, new options must be developed. The enormous growth in DER presents an opportunity to develop a radically different approach to system restoration. Greater diversity in Black Start provision will improve resilience and increase competition leading to reductions in both cost and carbon emissions. However, there are significant technical, organisational and commercial challenges to address.

The project will tackle these challenges in a three-year programme (Jan 2019 – Mar 2022) that aims to develop and demonstrate new approaches, with initial implementations of Black Start service from DER from mid-2022 if deemed feasible and cost effective. Case studies on the SP Distribution (SPD) and SP Manweb (SPM) networks will be used to explore options then design and test solutions through a combination of detailed off-line analysis, stakeholder engagement and industry consultation, desktop exercises, and real-life trials of the re-energisation process.

Project description

The project is made up of five workstreams. The project direction and knowledge dissemination workstreams cover the effective management of the project and sharing of learning. The other three workstreams cover the wide range of issues to enable Black Start services from DER:

- The **power engineering & trials (PET)** workstream is concerned with assessing the capability of Great Britain's (GB) distribution networks and installed DER to deliver an effective restoration service. It will identify the technical requirements that should apply on an enduring basis. This will be done through detailed analysis of the case studies and progression through multiple stages of review and testing to achieve demonstration of the Black Start from DER concept in 'live trials' on SPEN networks. Initial activities have focused on reviewing technical aspects of DER-based restoration in a number of case study locations that will support detailed analysis and testing within the project. Each case study is built around an 'anchor' resource with 'grid-forming' capability, i.e. the ability to establish an independent voltage source and then energise parts of the network and other resources. Then it is intended that other types of DER, including batteries if available, join and help grow the power island, contributing to voltage and frequency control. The ultimate goal is to establish a power island with sufficient capability to re-energise parts of the transmission network and thereby accelerate wider system restoration.
- The **organisational systems & telecoms (OST)** workstream is considering the DER-based restoration process in terms of the different roles, responsibilities and relationships needed across the industry to implement at scale. It will specify the requirements for information systems and telecommunications, recognising the need for resilience and the challenges of coordinating Black Start across a large number of parties. Proposed processes and working methods will be tested later in the project in desktop exercises involving a range of stakeholders.
- The **procurement & compliance (P&C)** workstream will address the best way to deliver the concept for customers. It will explore the options and trade-offs between competitive procurement solutions and mandated elements. It will make recommendations on the procurement strategy, aiming to be as open and transparent as possible while reflecting wider industry discussions on related topics like Whole System Planning and the development of distribution system operator (DSO) functions. It will feed into business as usual activities to make changes as necessary in codes and regulations.

For an overview of the project and current progress click on the link:
Distributed ReStart Progress Report – June 2019

Executive summary

This report is the second deliverable of the PET workstream, following on from a report at the end of the Options stage, in July 2019, on the 'viability of restoration from DER'. The project is now at the end of the Design stage, with the output being this report providing an 'assessment of the power engineering aspects of Black Start from DER'. Given the volume of work identified to provide a comprehensive technical assessment, a supplementary report is scheduled to be issued in December 2020 (Part 2).

The primary focus of this report is the development of restoration plans and the output of steady state, dynamic and transient power system studies, undertaken on three of the case study networks. In addition, a detailed assessment of the ability of the distribution and transmission networks to be protected, with the reduced fault levels when supplied by DER, is given. Moreover, the issues when connecting grid-following converters to a weak network are considered (the interface for most existing wind farms, solar farms and batteries which requires the network voltage as reference to connect). The emerging technology of grid-forming converters is also considered (able to create their own independent voltage source). An overview is given of the project's development of automation to enable and enhance the restoration process, along with an update on the proposed live trials and Issues Register.

Power system studies

In order to ascertain the viability of restoring the distribution and transmission networks from DER, and develop feasible restoration strategies, a range of power system simulation studies were performed to assess the principle technical challenges. The key findings are:

Anchor DER block load pick-up (BLPU) limitation

- The BLPU capability of a DER is the maximum demand which can be instantaneously supplied while ensuring the frequency remains within an acceptable range. It is typically between 10–25 per cent of the generator's active power (MW) rating and depends on factors such as the turbine technology. A 33kV connected anchor DER (used initially to energise the network and impose the system voltage and frequency) will typically have an active power range between 20 MW and 50 MW and thus a BLPU capability of between 2 MW and 12.5 MW. The smallest load which can be practically connected during system restoration is an individual 11kV feeder at a primary (33/11kV) substation. These typically have a maximum demand between 0.5 MW to 6 MW and, for Black Start purposes, up to 200 per cent of these values should be assumed, allowing for a lack of diversity when the load is switched on after a sustained outage (known as cold load pick-up [CLPU]).
- As a result of the BLPU limitations, an anchor generator may only be able to pick up individual lightly loaded 11kV feeders, or at most several 11kV feeders simultaneously. Thus, in order to facilitate the restoration of all demand blocks at a primary substation, or larger blocks of demand to minimise restoration times, it is likely that additional resources will require to be coordinated (e.g. a battery energy storage system) to enhance the BLPU capability within a Distributed ReStart Zone (DRZ). This is a primary focus of the DRZ controller work described in chapter 11 of this report: 'Automation'.

Additional DER (non-anchor generators)

- Based on the detailed analysis of the three case study networks, it is likely that the anchor generator may not have sufficient active power (MW) capacity to restore all the demand in a DRZ. Non-anchor DERs in the same restoration zone can play an important role in providing additional MW support so that more demand can be supplied. In addition to the active power support, additional synchronous DERs such as hydroelectric plants or gas generators will inherently contribute to the system inertia of the DRZ thereby assisting the anchor generator in frequency regulation of the DRZ.
- The additional DERs can also provide reactive power (Mvar) support to the anchor generator to maintain an acceptable voltage profile during energisation of the network and CLPU at the primary substations. The effectiveness of this support, however, depends on the location of the DER relative to the circuits being energised or the primary substation, i.e. the further away the DER, the less effective its reactive power support will be to support the voltage profile.

Transformer energisation

- One of the major challenges with growing a distribution power island is the energisation of grid transformers (e.g. 132/33kV) or super grid transformers (e.g. 275/132kV). The transformers draw high magnetic inrush currents (typically 4 to 7 times of rated current) which may result in the anchor generator seeing a voltage dip at its terminals. The magnitude of this voltage dip depends on the configuration of the network so, for example, as the electrical distance between the anchor generator and the transformer being energised increases, the voltage drop will tend to reduce. In some cases, the voltage dip will be within the G99 protection setting of 20 per cent and would not pose any problem to the anchor generator. However, in other instances, as was observed in two out of the three case study networks, the voltage dip could be significant enough (e.g. more than 20 per cent) to cause under-voltage tripping of the generator. A solution to this problem could be a 'soft start' approach to demagnetise the transformer and reduce the inrush current. Another solution to reduce the voltage dips could be to implement additional hardware for controlled switching of the circuit breakers at a specific point on the voltage waveform to reduce the inrush current (known as point on wave switching).

Circuit energisation

- The energisation of distribution and transmission circuits produce reactive charging power that needs to be absorbed. The case study analysis showed that a 33kV network can typically be energised by the anchor generator and that it is acceptable to simultaneously energise multiple 33kV circuits to speed up the restoration process. However, the charging power produced by circuits at 132kV and higher voltages will most likely exceed the anchor generator's reactive power capability. Other DERs can provide the additional reactive power required during circuit energisation. This is not necessarily dependent on a prime energy source such as wind being available, as modern wind farms can provide reactive power even under no wind conditions.
- Circuit energisation can also result in high switching over-voltages and depending on the network configuration, as seen with the case studies, it could be more than 50 per cent of the nominal voltage rating. This could potentially lead to a rise in voltage at the anchor generator terminal that could result in the anchor generator tripping. A solution to this problem could be to energise the circuits at a reduced voltage to limit the transient spike.

Wider network energisation

- The power system studies showed that a typical 132/33kV grid supply point substation with a 60MVA anchor generator can export around 30 MW and absorb 14Mvar at the transmission-distribution interface point without any support from other DERs. This capability can be increased with contribution from additional DERs in the DRZ to provide support for wider network energisation.
- Energising a typical 132kV overhead line of 20km, for example, can produce around 1.5Mvar (0.075Mvar/km). For the same length of line, the charging power is calculated as 6Mvar for a 275kV line (0.3Mvar/km) and 12Mvar for a 400kV line (0.6Mvar/km). To put it in context, a small anchor generator of 25MVA will have enough capability (9.6Mvar) to absorb the charging power of a 128km 132kV overhead line, but only 32km of a 275kV line and 16km of a 400kV line. Energising longer circuits or multiple circuits of the above length will not be possible unless additional reactive power support is provided by other DERs in the DRZ.

Restoration strategies

- An assessment of different distribution network topologies found that radial distribution networks are relatively easy to restore using DERs because the demand can be easily split into smaller blocks to meet the BPLU capability of the anchor generator, while restoration of meshed networks are harder due to interconnections at 11kV and LV level. Densely interconnected meshed networks are very difficult to restore because they are difficult to split up to limit the extent of energisation in the early stages.
- Analysis of the case studies showed that the best strategy for energising a DRZ is to first restore supply to the additional DERs so that their auxiliary supplies are restored and can remain on standby ready to provide any active and/or reactive power support as and when required by the anchor generator. The second and third steps, before connecting any customers, are to energise the grid/super grid transformers and associated higher voltage circuits, so that any voltage dips and/or switching over-voltages wouldn't be seen by customers.
- Thereafter, primary substations can be energised to pick up customer demand. The primary substation demand can be restored in blocks ranging from individual 11kV feeders, to the whole substation demand simultaneously (by closing a transformer 33kV feeder circuit breaker). The transformer should ideally be initially energised with as large a demand block as possible to minimise any potential increase in the 11kV voltage magnitude (depending on the pre-blackout tap change position of the transformer), and to minimise the switching and associated restoration time. However, the demand blocks must be lower than the BLPU capability of the DRZ, and the CLPU value should not exceed the thermal rating of the primary substation transformer and switchgear.
- This report details the primary transformer restoration options available, with the optimum solution varying for different DRZs based on the factors above. Restoration of a two-transformer radial primary substation, which only had one transformer in service pre-blackout, may have to be inhibited until the tap changer can be altered manually, to avoid excessively high 11kV voltage.

Additional assessments

Protection assessment

A key technical challenge is the ability of the existing distribution and transmission network protection systems to detect and isolate a fault condition, given the significantly reduced fault currents which flow when the networks are energised from DER only. To investigate this, an assessment of the operation of existing protections on the Chapelcross case study network was undertaken when energised only by an anchor DER connected at 33kV. The key findings were:

- With reduced fault levels under a Black Start, some existing protections may continue to operate as normal, revised settings may facilitate correct operation of others, and others may not be able to be modified to operate correctly. In these cases, other solutions may have to be considered. As the voltage levels increase, the number of protections requiring to be modified, or being inoperable, increases.
- Modern protection relays have the facility to be programmed with a second group of settings which can be changed remotely (via SCADA). Where this is required, older relays may have to be replaced.
- As an approximate guide, the following minimum fault levels were identified as being required for satisfactory protection operation (assuming revised settings are applied as required):

  – 33kV – 50MVA*

  – 132kV – 50MVA

  – 275kV – 100MVA

  – 400kV – 250MVA.

  *At the primary (33/11kV) transformer HV terminals. This would ensure the associated 11kV and LV network protections would also operate correctly.
- If there is sufficient fault level for the 33kV network to be protected, then the associated 132kV network will likely be able to be protected. If the fault infeed from the DRZ is of sufficient magnitude, the associated 275kV network can be protected. Based on our detailed analysis of the case studies and considering more general conditions across all of GB, it is likely that a 33kV DRZ on its own will not be able to provide enough fault infeed for existing 400kV protections to operate correctly. It follows that additional fault infeed at higher voltage levels would be required. This may be provided by restoring supplies and restarting generators or from resources like synchronous condensers.

Grid-following converter-connected DER

Wind farms, solar farms and battery energy storage systems (BESS) are typically connected to the power network via a grid-following converter interface (the network voltage is required as reference before connecting, and for stable operation). Following a literature review, the following considerations were identified relating to connecting to a weak network (low inertia and fault level) such as during restoration from DER.

- **Phase lock loop (PLL) limitations**
  PLL (the fastest control loop within the converter) has difficulty tracking the grid voltage which will deviate more erratically in a weak network and can result in the DER tripping. Standard converter control techniques will fail to maintain stability when the short circuit ratio (SCR), the ratio of network fault MVA to DER rating, is typically less than 1.3-1.5 (the required ratio may be higher depending on individual manufacturer requirements). This will result in a limitation to the capacity of converter-connected DER which can be connected in a DRZ for a given network fault level.
- **PLL mitigations**
  Potential alterations to improve performance include modifying the PLL controller for weak grid operation, although any alterations could potentially impact overall performance. Network solutions would include increasing the SCR by adding DER to provide increased fault infeed.
- **Inertial considerations**
  Concerns over the lower system inertia with a high penetration of converter-connected DER have been highlighted, and the corresponding need for such generation to contribute to frequency support. For example, wind turbines, despite having large rotational masses, do not provide any 'real' inertia to the network since they are electrically decoupled. Converter control schemes can provide 'synthetic' inertial response by modifying the converter power reference according to the grid frequency measured through the PLL.

Grid-forming converter considerations

This section investigates the emerging technology of grid-forming converters which, while not widely used at present to connect DER to the electricity network, have technological differences from grid-following converters which may prove beneficial when considering Black Start from DER in the future.

A key difference between grid-forming and grid-following converters is that the former is able to create its own independent voltage source. As such, the project is investigating this technology with the aim of identifying to what extent an equivalent scale grid-forming converter could deliver the same benefit as a synchronous generator and be the anchor generator for a DRZ. In this report, the project provides an overview of the grid-forming converter technology, and has commissioned some initial studies to investigate how this may be applied to Black Start from DER. The benefits of grid-forming converters (GFCs) highlighted include:

- Voltage source – A grid-forming converter can provide the same benefit as a synchronous generator in that it can generate its own independent voltage source.
- Frequency support – A grid-forming converter can also emulate the performance of a synchronous generator in that it can provide 'true' inertia (an instantaneous power response to frequency disturbances). Grid-following converters can provide 'synthetic' inertia which has a delay associated with the frequency having to be measured before a response is initiated.
- Increased stability – Due to its increased stable operation, a grid-forming converter is less susceptible to adverse interactions among multiple power plants under reduced system strength conditions and, unlike a grid-following converter, does not need a minimum network SCR to operate.

Live trial update

The project is currently working with DER owners, distribution network operators (DNOs) and transmission owners (TOs) to develop suitable live trial programmes, and ascertain any DER and network modifications required to be implemented. The scope of testing will be informed by the findings of the power system studies, which have highlighted issues such as generator under voltages, circuit transient over voltages and excessive frequency deviations associated with different restoration stages. To reduce the overall project risk, live trials will be split into at least two phases. Short-term testing refers to the preliminary testing to be carried out ideally in 2020 or Q1 2021. Long-term testing refers to tests to be carried out towards the end of the project (2021/22).

The short-term testing is planned to prove that the generation plant can be islanded from the main network, energise a dead section of network, and control the frequency and voltage independently (transformer energisation may also be included where appropriate). Long-term testing will concentrate on proving the ability to establish and maintain a stable power island within an isolated 33kV network (ideally with multiple DER types), simulating demand block loading and energising up to higher voltage networks.

Automation

In the initial PET workstream viability report[1], it was highlighted that the Black Start from DER restoration process would likely require a level of automation to overcome technical issues and resource constraints. The concept of a Distributed ReStart Zone Controller (DRZ Controller or DRZ-C) has subsequently been developed to describe the system(s) that will enable monitoring, control and coordination of a range of DER and network resources to provide Black Start services. The following update is provided.

- Based on project learning to date, implementation of some form of a DRZ controller (DRZ-C) is critical to providing the functionality of sub-second control, and coordinating multiple DER in order to establish and maintain a DRZ.
- Based on work commissioned by the project, work is currently being undertaken by several technology companies to produce a consolidated set of requirements for overall DRZ-C solutions, including requirements for the DRZ controller itself, DER, and any other associated supporting systems. These requirements, and associated learning, will be presented in the next PET report.[2]
- The project will consider progressing with the next phase of implementing and testing one or more DRZ-C solutions within a lab environment, and will consider the feasibility of installing on the DNO network and integrating into the live testing.

Issues Register

In the initial PET report (July 2019)[1], technical issues identified requiring further investigation were captured in an Issues Register. Of the thirty four issues originally identified, twenty were categorised as ‘amber’ (requiring works to overcome) and fourteen ‘green’ (anticipated to have a relatively simple solution). Since the initial report, all the issues have been/are being addressed with the number of amber issues now reduced to nine and works ongoing to address those outstanding. To date there have been no issues categorised as ‘red’ (no identified solution).

Assurance Statement

The project committed to providing power systems studies to support decisions and overcome challenges associated with live trials. This report fully meets this objective but also reviews optimal restoration strategies, detailed Electromagnetic transient and dynamic studies and detailed protection assessments at each case study site. Furthermore, at each point applicability across GB is considered enabling post project service rollout. The conclusions from this report enable progression to the live trial stage and further development of functional requirements for an enduring service.

Peter Chandler

Peter Chandler
Distributed ReStart Project Lead

1 'Viability of Restoration from DERs' (July 2019)

2 'Assessment of power engineering aspects of Black Start from DER – Part 2' (Dec 2020).

Please go to page 157 for explanation of acronyms.

Project Milestone (10) – Timeline

Distributed ReStart

2019

31st July 2019
Project Milestone **4**

PET: Outcomes Options Stage Report Completed

8th Nov 2019
Project Milestone **1**

OST: Viability assessment of capability to deliver

8th Nov 2019
Project Milestone **7**

P&C: Functional requirements for P&C

31st Dec 2019
Project Milestone **4**

Project Manager **Report PMO YR 1**

30th June 2020

Project Manager **Report**

31st July 2020
Project Milestone **5**

PET: Power System Studies – Part 1

2020

2nd Oct 2020
Project Milestone **2**

OST: Req Systems & Telecoms – Part 1

2nd Oct 2020
Project Milestone **8**

P&C: Compile Contract Requirements

4th Dec 2020

PET: Power Systems Studies – Part 2

4th Dec 2020

OST: Req Systems & Telecoms – Part 2

31st Dec 2020
Project Managers report

PMO: Project Managers Report

30th Sept 2021
Project Milestone **3**

OST: Refine the systems and telecoms

2021

20th Dec 2021
Project Milestone **6**

PET: Demonstration of Black Start from DER

20th Dec 2021
Project Milestone **9**

P&C: Final version of generic procurement terms

31st Dec 2021
Project Managers report

Final YR PMO

2022

31st Mar 2022
Project Milestone **10**

Final proposals **ALL**

1. Introduction

This report focuses primarily on the outputs of the system studies which have been undertaken to carry out a technical assessment of Black Start from DER, but also includes other relevant technical studies, along with an update in relevant project areas.

Initially, an understanding is given of the networks and restoration plans upon which the system studies are based, along with an overview of the specific studies which have been undertaken. The study results are then given for the three case study networks used in the assessment (Chapelcross, Galloway and Legacy), with a final section detailing the overall conclusions from the study results.

A summary is then given of protection assessments which have been undertaken for the Chapelcross and Galloway case studies, highlighting the issues on existing network protection systems with significantly reduced fault infeed when supplied from DER only.

The next section of the report examines the issues associated with converter based DER (typically wind farms, solar farms and batteries) being connected to a weak network (with low inertia) during a Black Start. Two reports are summarised, one focuses primarily on grid-following converters (the technology on DER connected at present) and considers their limitations, including the level of penetration which may be acceptable on a distribution power island. The second report considers grid-forming converters (able to create their own independent voltage source), and examines to what extent they may replace a synchronous generator as the anchor for a power island, and the particular technical challenges with initiating and maintaining a power island.

An update is given on the application of automation to help initiate, maintain and expand a power island with a description given of the functional requirements for a DRZ-C (A full functional specification will be given in the PET December 2020 report.). The latest proposals for live trials on the network are also discussed, along with the next steps for the PET workstream.

2. Networks and restoration plans

This chapter introduces the main distribution network topologies in Great Britain, gives an overview of the three specific case study networks selected for detailed analysis, and discusses the different network restoration strategies which may be utilised for Distributed ReStart.

2.1 SP Energy Networks

SP Energy Networks (SPEN) owns three regulated electricity network businesses in the UK. These are SP Distribution (SPD), SP Manweb (SPM) and SP Transmission (SPT).

SPD supplies electricity to 2 million customers in central and southern Scotland at voltages up to and including 33kV. In the SPD area, SPT owns the 132kV, 275kV and 400kV transmission network. SPM supplies electricity to approximately 1.5 million customers in Merseyside, Cheshire and North Shropshire in England as well as North Wales at voltages up to and including 132kV. In England and Wales, the transmission network is owned by National Grid Electricity Transmission (NGET).

The interface between the SPD and SPT networks is at 275/33kV, 132/33kV or 132/11kV transformer substations called grid supply points (GSPs). These typically have two transformers with SPT owning the transformers, and the associated transformer 33kV circuit breaker(s), and SPD owning the 33kV feeder switchboard.

The interface between the SPM and NGET network is typically at 400/132kV or 275/132kV substations also called GSPs. The 132/33kV substations are fully owned by SPM and are referred to as grid substations or bulk supply points (BSPs).

Figure 2.1
SPEN distribution networks

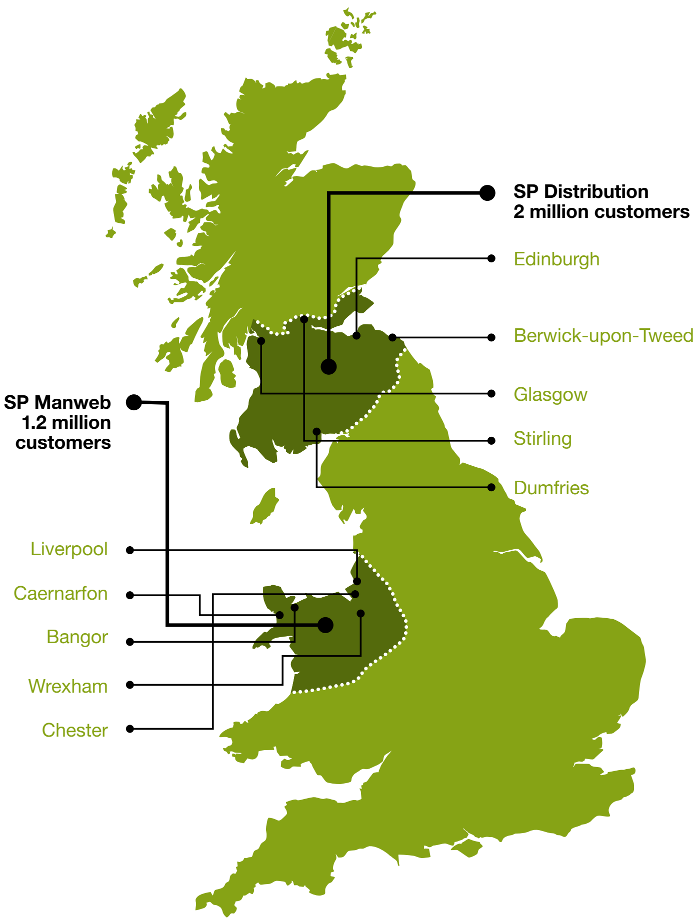
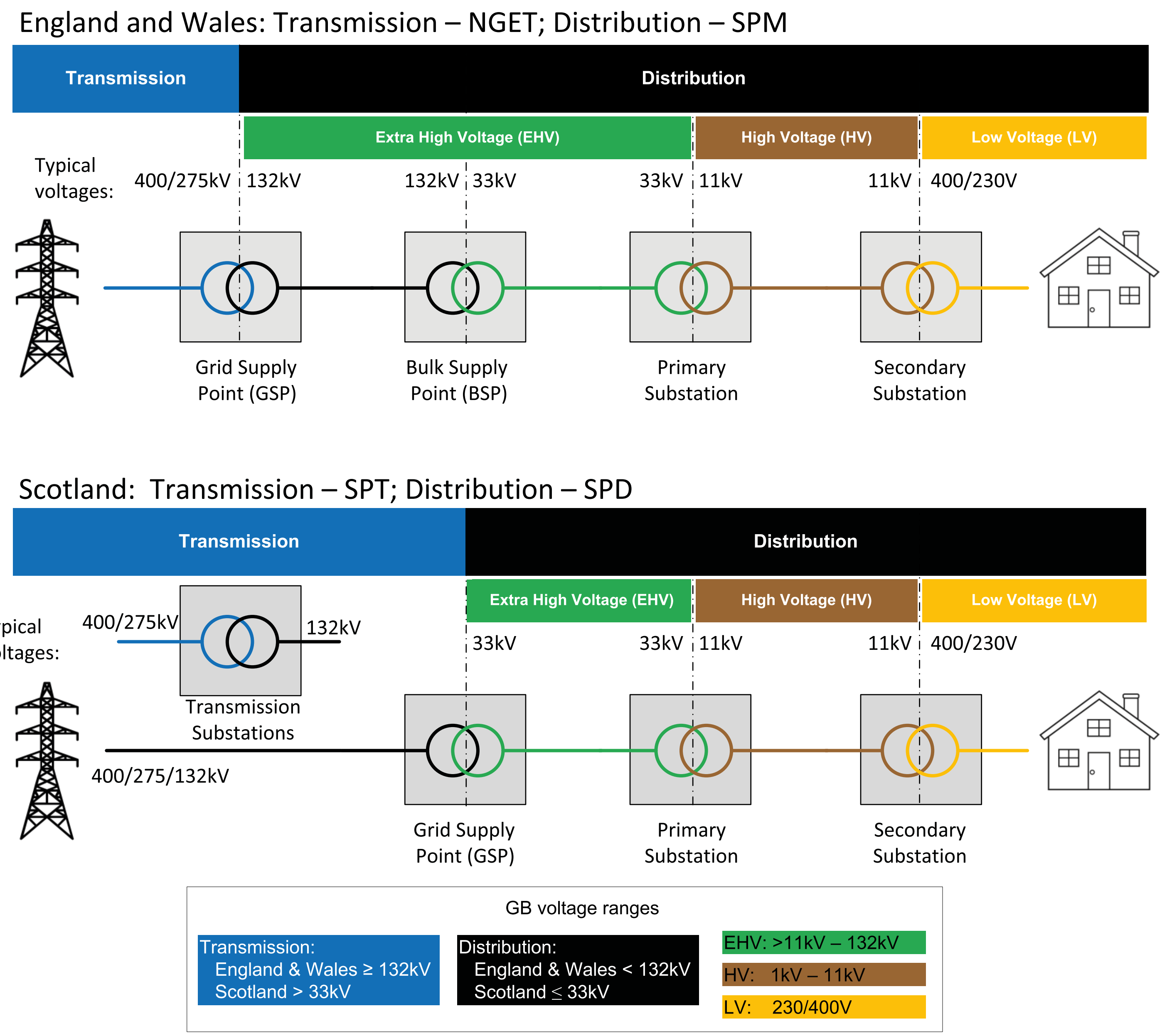


Figure 2.2
Topology of the Great Britain (GB) electricity network and differences between SPD and SPM



2.1.1 SPD networks

The grid supply transformers at a 132/33kV GSP connect to the SPD distribution system via 33kV circuit breakers. Each grid supply transformer is equipped with an on-load tap changer (OLTC) and automatic voltage control (AVC) scheme that maintains the transformer secondary voltage within ±2 per cent of the nominal secondary voltage 33kV.

Extra High Voltage (EHV) network

The SPD EHV distribution system consists of 33kV circuits, originating from the GSPs, which supply primary (33/11kV) substations or customers with an Extra High Voltage (EHV) point of supply. The circuits are typically radial in nature (go directly from the GSP to a primary transformer) and may consist of underground cable or overhead line (supported by steel towers or wood poles), or a combination of both. Tele-control facilities allow real-time monitoring and control across the EHV networks. Interconnection is usually provided between GSPs by one or more 33kV circuits for increased reliability. They are operated normally open and are only used if the transmission infeeds to a GSP are not available.

A primary substation typically has two 33/11kV transformers (although some may have one or three). Standard transformer sizes of 10MVA and 24MVA are most commonly used and are normally Dyn11 vector group. A two-transformer primary substation would supply a two section 11kV busbar with two transformer incoming 11kV circuit breakers, and a 11kV bus section circuit breaker (normally closed).

The primary transformers have on-load tap changers that are normally of the standard random control type, meaning that the two parallel transformers are not out of step by more than one tap step. The tap changing equipment is controlled by an AVC relay, which maintains the secondary voltage within ±2 per cent of the set point voltage under all load conditions. The voltage set point is usually 11.2kV at the HV busbar. The tap change motor is supplied at 400V from the local low voltage (LV) network which is supplied by the secondary substation closest to the primary substation.

High voltage (HV) network

The SPD system also operates at HV (primarily 11kV) and consists of circuits that provide supplies to secondary (11kV/400V) substations and customers with an HV point of supply. These circuits are typically operated radially with a normally open point, but may be operated as closed 11kV 'rings' where unit protection is employed. There is usually also the provision of interconnection, operated normally open, between primary substations. HV circuits comprise sections of underground cable or overhead line or a combination of both. The bulk of the HV distribution system operates at 11kV, with only a few small Legacy areas operating at 6.6kV.

The Chapelcross GSP case study network discussed in chapter 4 is a good example of a radial SPD network (with a mixture of one and two transformer primary substations).

2.1.2 SPM networks

The SPM network is significantly different from the SPD network in that approximately 80 per cent of the network is designed, operated and extended as a meshed network with interconnection at all voltage levels. The design and operating philosophies are based on high transformer utilisation (70 – 85 per cent), where smaller single transformer substations supply power into an interconnected mesh throughout. Each voltage level provides support to the one immediately above, offering a fully integrated and interconnected network.

The primary 33kV network is supplied from the 132kV network at substations referred to as BSPs or grid substations. Standard transformer sizes of 45MVA and 60MVA are most commonly used and are normally Dyn11 vector group. Each transformer has an OLTC with AVC that ensures that the tap changers on each transformer remain synchronised, and that the transformer secondary voltage is maintained within ±1.75 per cent of the nominal secondary voltage (33kV). To achieve high utilisation of the transformers, they are operated in parallel with those at other BSP substations through the interconnected 33kV network.

EHV network

EHV urban networks mainly consist of 33kV underground cables that interconnect different BSP substations. The primary substations are connected to the 33kV interconnector circuits by means of ring-main units, multi-panel switchboards, or radial circuits from BSP substations. The network is generally operated in interconnected groups of two to four BSP transformers. The exact number of transformers that can be operated in parallel is determined by the fault level of the network.

EHV rural networks predominantly consist of 33kV overhead lines between BSP substations. The interconnectors are operated without any open points, so the BSP transformers are operated in parallel. Primary substations either connect to the 33kV interconnectors or by means of radial lines to the BSP substation. The number of primary substations supplied by an interconnector circuit is limited by the maximum loading capacity of the circuit, which is roughly 17 MW for an 33kV overhead line and 20 MW for a 33kV underground cable.

All 33kV circuit breakers are telecontrolled and can therefore be used in remote switching for network reconfiguration and restoration. The Legacy network (selected as a case study for the Distributed ReStart project, and analysed in chapter 6) is a prime example of a meshed rural primary network that is interconnected between a number of BSPs).

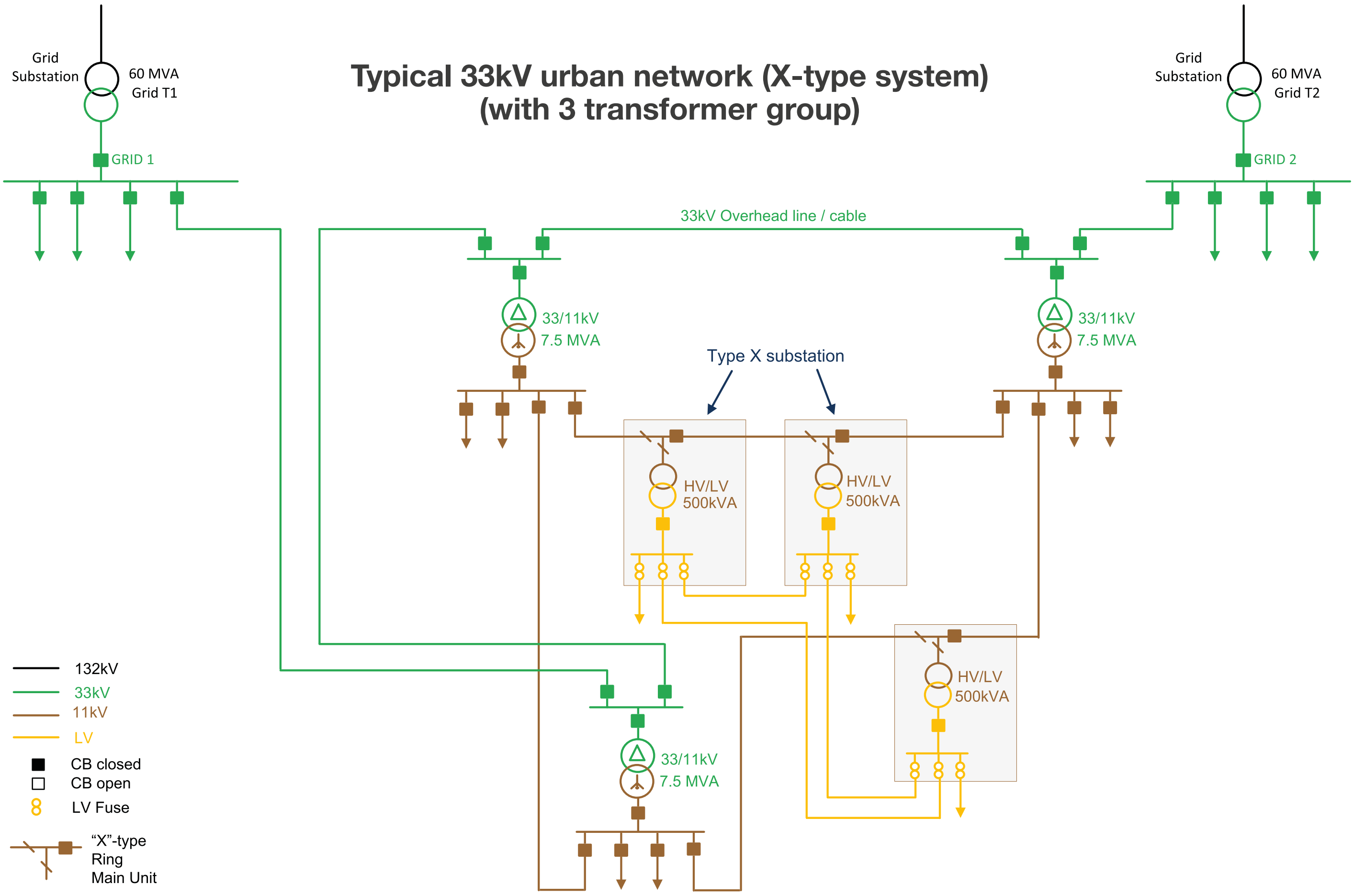
HV network

The bulk of the HV distribution system operates at 11kV and provides supply to the secondary (11kV/400V) substations and customers, but also provides interconnection between primary substations. It is supplied from the primary substations using 33/11kV standard size transformers between 4–10MVA in size, with 7.5 MVA being the most common size. The transformers have a standard Dyn11 vector group. Each transformer has an OLTC with an AVC scheme that ensures that the tap changers on all transformers operating in parallel remain in step. This ensures efficient load sharing and minimises circulating current. The AVC is normally set to maintain the transformer secondary voltage within limits of ±1 per cent of the target voltage set point of 11kV at the primary HV busbar. The tap change motor is supplied from the local LV network which is supplied by the secondary substation closest to the primary substation.

Urban networks

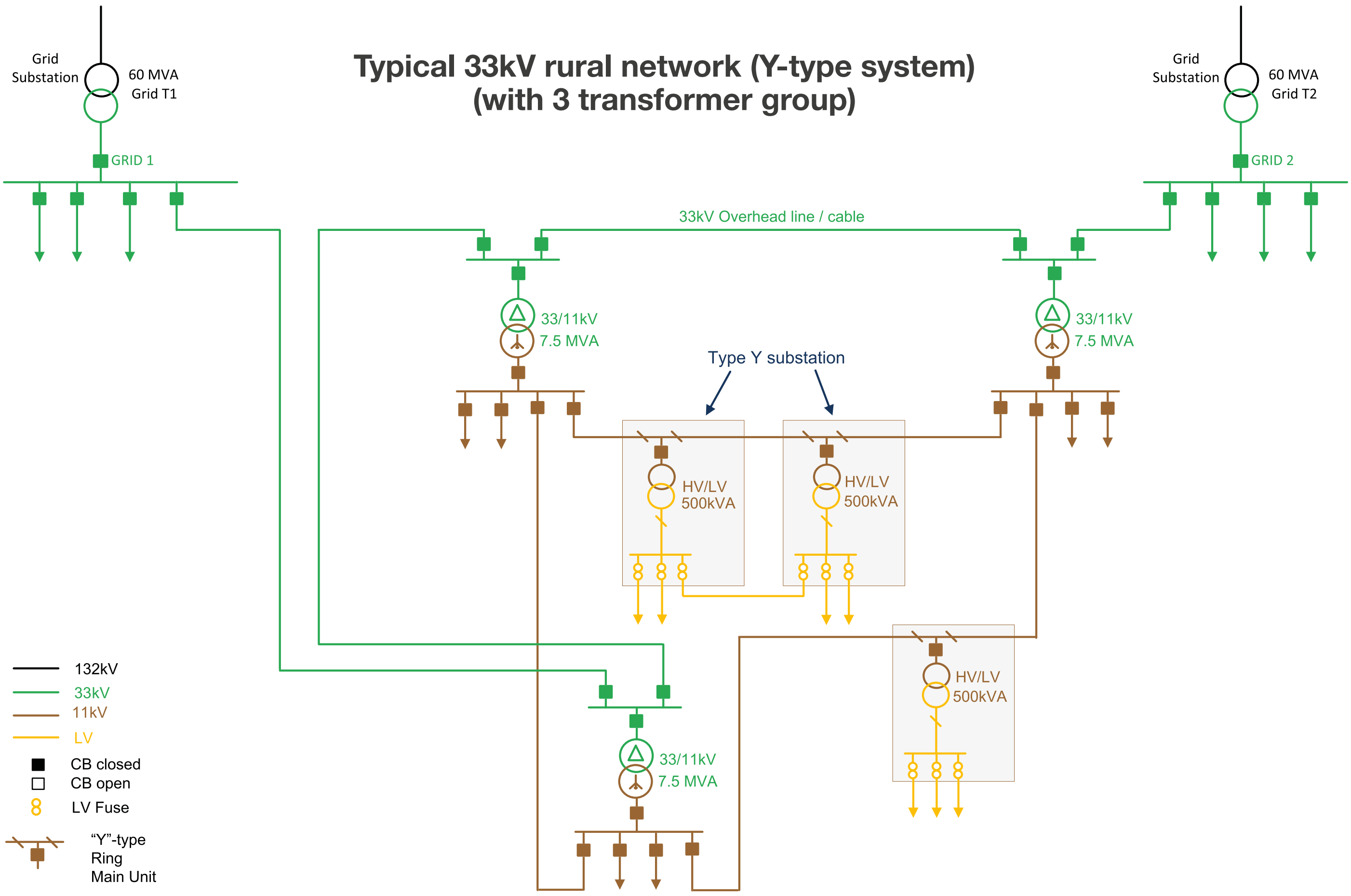
In urban areas the meshed HV network is almost entirely underground and each one can supply up to twelve secondary HV/LV substations. Secondary substations are designated either as X-type or Y-type depending on the switchgear configuration. X-type substations are indoor substations equipped with an X-type ring-main unit, 500kVA HV/LV transformer, LV distribution fuse board, protection relays, battery and charger. These are used in dense urban areas with extensive LV interconnections between secondary substations supplied from different feeders within the same group of primary substations to facilitate high utilisation of transformers and circuits. The interconnections and transformers are protected by unit (differential) type protection schemes. The topology of a typical urban X-type network is shown below.

Figure 2.3
Topology of an X-type urban HV network



Y-type substations are used in sub-urban areas where the amount of LV interconnection is not as extensive. LV interconnectors only occur between secondary substations supplied by the same HV feeder. The substations can be indoor or outdoor with a Y-type ring main unit, HV/LV transformer and LV distribution fuse board. The transformers are protected by time-limit fuses and the interconnectors are protected by over-current protection schemes. An example of a meshed Y-network with three transformer groups is shown below.

Figure 2.4
Topology of a Y-type semi-urban HV network



Rural networks

In rural areas the HV network consists of predominantly overhead lines with radial spur lines branching off. Although rural HV lines run between primary substations, they are operated radially by utilising a normally open point along the circuit route. In the HV network only some, mainly the newer, circuit breakers are telecontrolled.

2.2 Selected case study networks

In the first Power and Engineering Trials Report (published in July 2019) ten SPEN case study networks were identified as potentially viable for Black Start live trials, as well as being representative of the distribution networks and distributed generation mixes across GB. These case study networks all met the essential requirements for Distributed ReStart, namely a synchronous generator to act as the anchor generator for the power island to be established, and also have several converter-connected resources such as wind and solar PV to grow the island, or DRZ.

The case studies were evaluated further and the three case study networks, shown in table 2.1, were selected for in-depth power system analysis.

Table 2.1
Selected case study networks for detailed power system studies

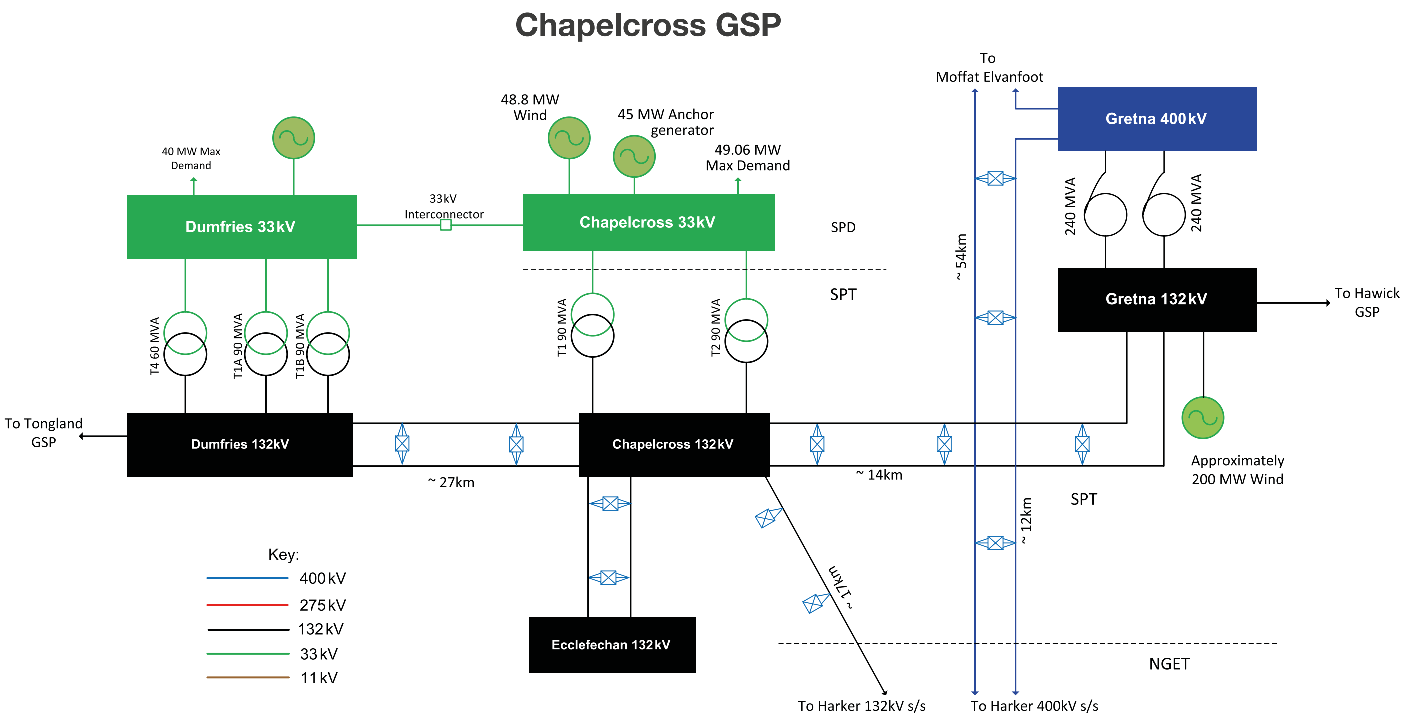
Case study network	Type of 33kV network	Anchor generator (MW)	Additional DER (used in analysis)	Case study summary
Chapelcross GSP (SPD – Dumfries)	Rural, radial	Biomass steam turbine (45 MW)	Wind (50 MW)	• Establish a DRZ using the biomass generator and wind farms and pick up primary substation load. • Back-energise Ecclefechan 132kV line and grid transformer. • Back-energise Chapelcross 132kV grid transformer followed by Dumfries 132kV grid transformer and 33kV busbar. • Back-energise Gretna 400kV grid transformer and connect Ewe Hill 132kV wind farm.
Galloway area (SPD – Dumfries)	Rural, radial	Hydroelectric generators (103.5 MW)	Wind (369 MW)	• Use the hydroelectric generator to energise 3 GSPs (Gleelee, Glenluce and Newton Stewart), energise wind farms and pick up primary substation load. • Energise Tongland and Earlstoun GSPs and connect additional hydroelectric generators at 11kV. • Energise Kendoon GSP and New Cumnock 275/132kV substation, and energise several 33kV wind farms and pick up primary load. • Energise Blackhill substation followed by energising more 33kV wind farms.
Legacy GSP (SPM Wales)	Rural, meshed	Gas turbines (MW)	Wind (68.4 MW) Solar PV (10 MW)	• Use a gas turbine as anchor generator to establish the DRZ, energise primary substations, and pick up demand. • Continue to energisation additional primaries followed by back-energisation of Legacy, Oswestry and Carno BSPs. • Energise wind farms and pick up more primary substation demand.

The above three case study networks were selected because they contain different anchor generator technologies (i.e. a steam turbine, hydroelectric generator, and gas turbine) and represent different network topologies (radial vs meshed). Their diverse nature and specific characteristics represent varying degrees of technical challenges from a power system restoration and stability perspective. Detailed power system analysis of the restoration process of these networks will result in a greater understanding of the typical capability and limitations of GB distribution networks in the provision of Black Start services.

2.2.1 Chapelcross case study network

Chapelcross 132/33kV GSP is located within the Dumfries and Galloway area of the SPT network. The 132kV busbar has interconnections with Dumfries 132/33kV GSP, Gretna 132kV substation and NGET's Harker 132kV substation. The Chapelcross 132kV busbar also supplies the Ecclefechan 132/25kV National Rail substation via two single phase 132kV overhead lines. The Chapelcross 33kV GSP switchboard is fed from two 132kV/33kV 90MVA rated transformers. An overview of the substations in the Chapelcross region is shown in figure 2.5.

Figure 2.5
Substations and transmission connections in the Chapelcross region



The Chapelcross GSP network presented in figure 2.5 has a total generation capacity of 93.8 MW connected at 33kV. The group contains Steven's Croft anchor generator with a net export capacity of 45 MW, two connected wind farms with a combined export capacity of 48.8 MW (Minsca wind farm – 36.8 MW and Ewe Hill wind farm – 12 MW). An additional wind farm with a contracted export capacity of 30 MW will be energised in the future. (Craig I and Craig II wind farms are connected via the 11kV Langholm primary substation, but weren't considered for network restoration due to their 11kV connection). From the Week 24 demand data provided to NGET in 2019, Chapelcross GSP has a maximum load demand of 49.06 MW and a minimum load demand of 12.11 MW.

The Chapelcross 33kV switchboard has thirteen installed circuit breakers supplying eight 33/11kV primary substations. Annan primary substation is connected directly to the Chapelcross 33kV busbar, with the remaining primaries connected via multiple 33kV switching stations. The 33kV Chapelcross busbar provides a point of connection for both the Steven's Croft biomass site and the Minsca wind farm. The Ewe Hill wind farm is connected via the Middlebie 33kV switching station.

The Chapelcross network can be categorised as a long rural radial network with some circuits up to approximately 40km in length. The DERs are connected by long 33kV underground cable circuits to the Chapelcross 33kV busbar: Minsca wind farm by means of a 17km 33kV cable, Ewe Hill wind farm by means of 21km 33kV cable, via Middlebie switching station, and Steven's Croft anchor generator by a 26km double cable.

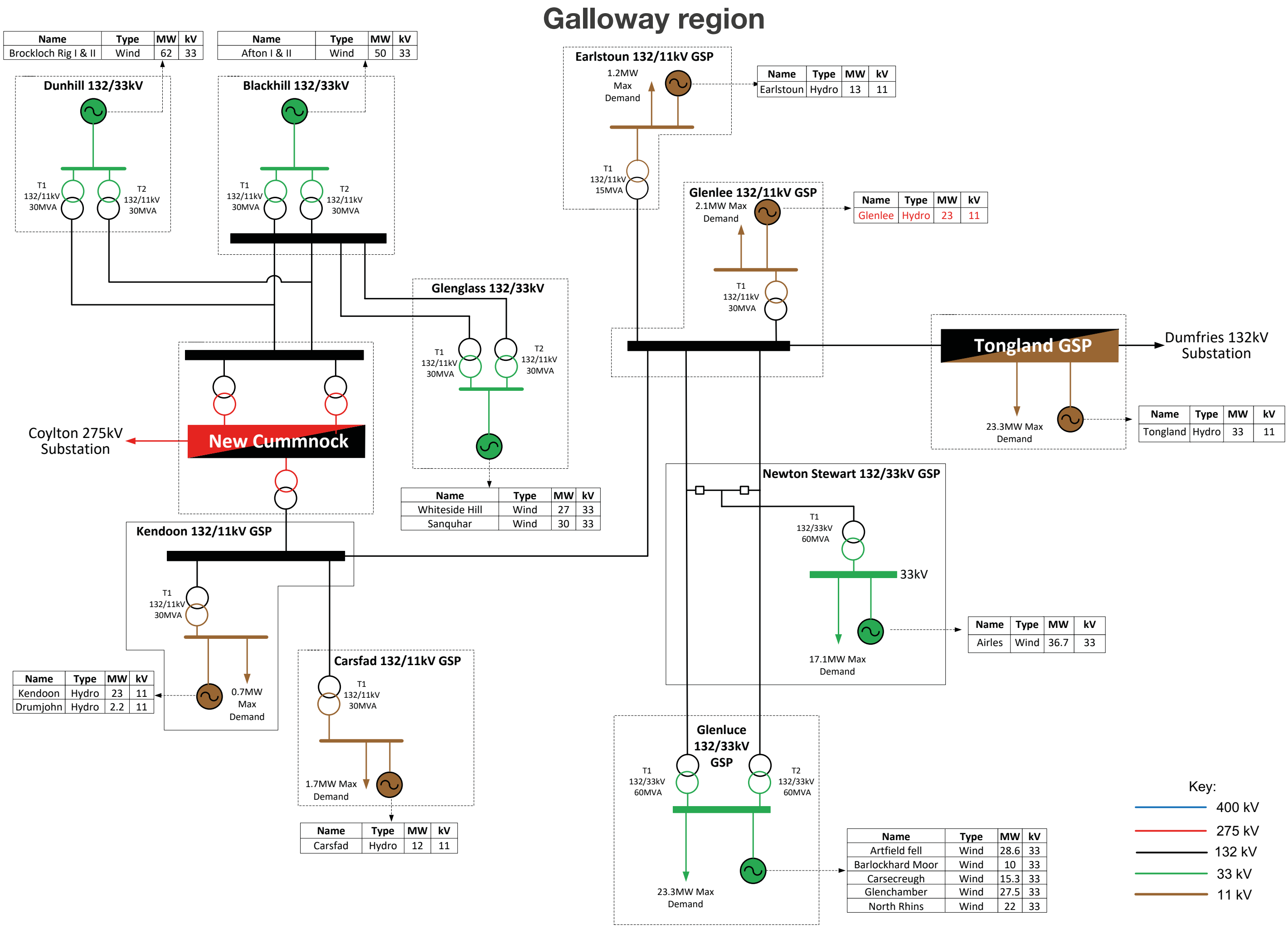
2.2.2 Galloway region case study network

The Galloway region in South West Scotland is made up of several 132/33kV and 132/11kV GSPs that are interconnected via 132kV overhead lines as shown in figure 2.6. Glenlee, Earlstoun, Tongland, Carsfad and Kendoon are 132/11kV GSPs, each containing hydro generation connected at 11kV. Glenlee is the anchor generator for this case study as it has the necessary water reserves available to provide Black Start services. Newton Stewart and Glenluce are 132/33kV GSPs which supply SPD customers and have multiple wind farms connected at 33kV.

Glenluce GSP has two 132/33kV 60MVA transformers and supplies four primary substations. The GSP has a maximum demand of 19 MW and has five wind farms connected at 33kV totalling 97 MW. Newton Stewart 132/33kV GSP has a single 60MVA transformer supplying three primary substations. The GSP has a maximum demand of 17 MW and one wind farm connected at 33kV (35 MW).

The maximum demand for the Galloway region network, shown in figure 2.6 is 68 MW and the minimum demand is 23 MW. The total hydro generation in the region is 103.46 MW, and generation available from the 33kV wind farms is ~130 MW. Almost 238 MW of additional wind generation is available from the wind farms connected to New Cumnock at 132kV, which includes Dersalloch wind farm, as well as the wind farms connected via Blackhill, Glenglass and Dunhill SPT collector stations.

Figure 2.6
Transmission substations and DERs connected in the Galloway region

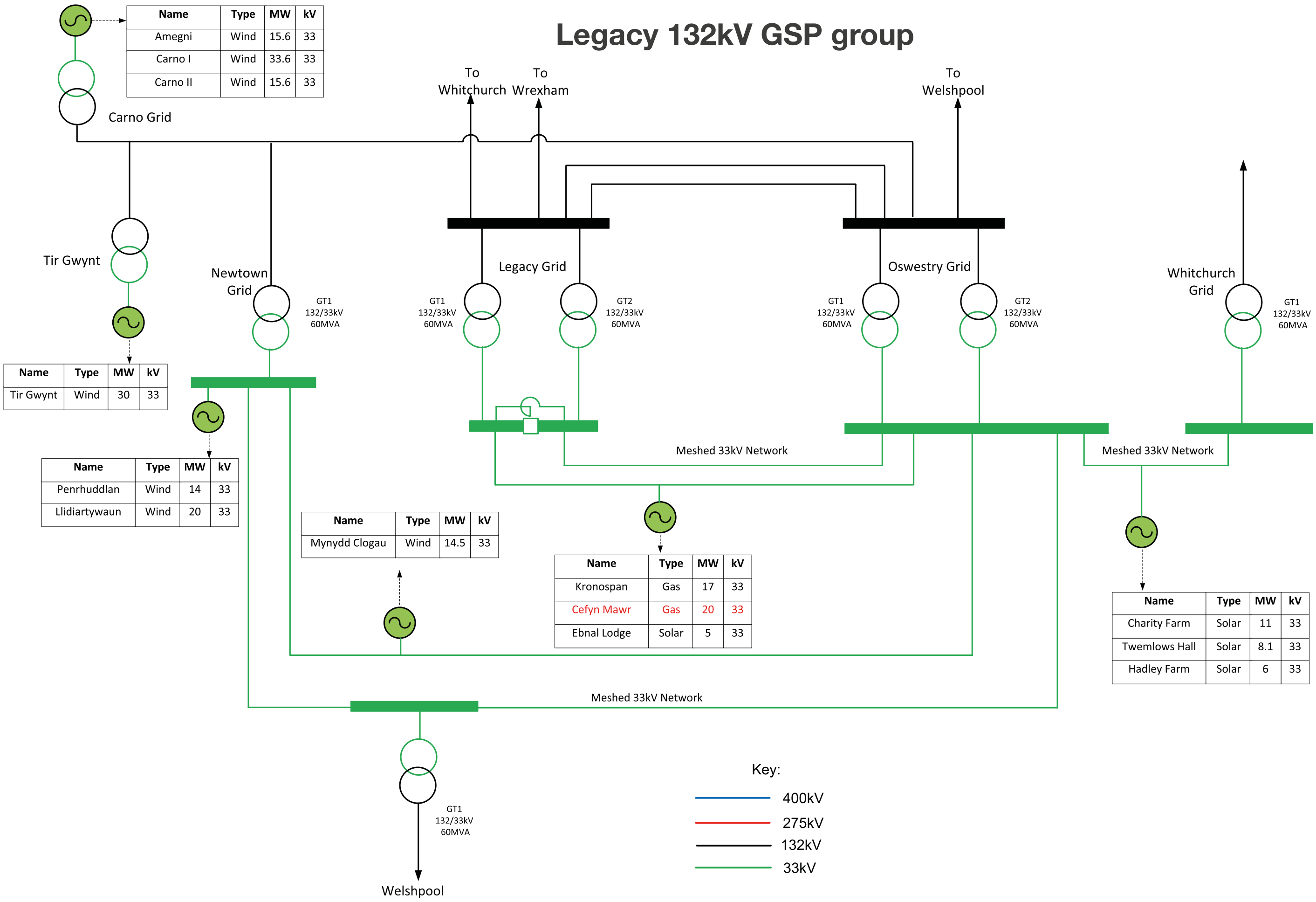


2.2.3 Legacy GSP case study network

Legacy GSP is located in Wales and consists of a number of BSP or grid substations including Newtown, Legacy, Oswestry and Whitchurch. The Legacy local 33kV network is categorised as a rural meshed network. It consists of several primary substations that are interconnected at a 33kV level. Because it is a rural network, only a small number of 11kV networks are interconnected.

The Legacy anchor generator was chosen to be Cefn Mawr which consists of 10 x 2 MW gas generators, connected at 33kV, adjacent to Ruabon primary substation. The total wind and solar DER generation capacity on the Legacy 132kV and 33kV networks is 126 MW and the total demand of the Legacy GSP group is 190 MW.

Figure 2.7
Legacy GSP network showing the grid substations and interconnected 33kV network



2.3 Strategies for network restoration

A number of different restoration strategies can be followed to establish a power island or DRZ with DERs connected to 33kV distribution network. These were discussed in detail in the first Project Engineering and Trials report, and for easy reference are mentioned below. After the anchor generator has been self-started the restoration options are:

- **Option 1 –** Establish the DRZ by energising the GSP/BSP 33kV busbar, followed by restoring supply to the various DERs to ensure that they are available and ready to provide active and reactive power support when required.
- **Option 2 –** Maintain the 33kV DRZ with the maximum stable load connected and do nothing else. Wait until the 132/33kV or 275/33kV grid transformers have been energised from the transmission system and synchronise the DRZ to the transmission network at the 33kV circuit breaker.
- **Option 3 –** Expand the 33kV DRZ to an adjacent 33kV network via interconnecting 33kV circuits, and connect additional DERs and pick up demand. The transfer capacity of 33kV circuits are typically 20MVA, and this could be a limiting factor.
- **Option 4 –** Synchronise the 33kV DRZ with an adjacent 33kV DRZ through 33kV interconnecting circuits to create a single larger power island. The transfer capacity of the interconnecting circuits may also be constraining factor.
- **Option 5 –** Expand the 33kV DRZ by energising one of the 132/33kV grid transformers and then energising a 132kV circuit and an adjacent 132/33kV substation. Energise the adjacent GSP/BSP from the 132kV down to 33kV and pick up more demand and DERs.
- **Option 6 –** Expand the 33kV DRZ by energising one of the 132/33kV grid transformers and then energising a 132kV circuit to connect additional generation connected at 132kV level.
- **Option 7 –** Expand the 33kV DRZ by energising one of the 132/33kV grid transformers and then energising a 132kV circuit and an adjacent transmission substation. Energise the 400/132kV or 275/132kV super grid transformer and energise the 400kV or 275kV busbar.

The restoration of the primary substations in a DRZ is key to the establishment of a stable 33kV power island. Several strategies that can be followed to energise primary substations are discussed in the next section.

2.4 Network restoration strategies – primary substations

When using DER for Black Start, one of the key areas is the energisation of primary (33/11kV) substations to restore customer demand. The potential options for doing this are discussed, both for the SPD (radial) and SPM (meshed) networks.

2.4.1 Strategies for restoring radially connected primary substations

A typical radially connected primary substation will have two 33/11kV transformers supplying a two-section 11kV busbar on which the bus section breaker is normally closed. The 11kV busbar supplies a number of 11kV radial circuits.

Seven different ways of restoring supply to a two-transformer radial primary substation were identified. The first four options (A-D) illustrate the simultaneous energisation of the primary transformer, 11kV busbar and load supplied from the primary substation, and are referred to as 'load' options. The last three options (E–G), known as 'No-load' options consider initial energisation of the primary transformer, followed by the 11kV busbar and lastly the load supplied from the primary substation. The options are discussed, and shown schematically, based on Annan primary which is part of the SPD Chapelcross GSP case study.

Load options – simultaneous energisation of transformer and load

Option A – Single primary transformer energised on full load

With option A, at the primary substation all the 11kV circuit breakers are initially closed, except the Grid 2 primary transformer 11kV circuit breaker (CB) no. 20. At Chapelcross GSP when the 33kV CB 13 is closed, a single primary transformer is energised and simultaneously takes on the full load fed from the primary substation. This is shown schematically in figure 2.8.

Figure 2.8
Primary substation restoration option A

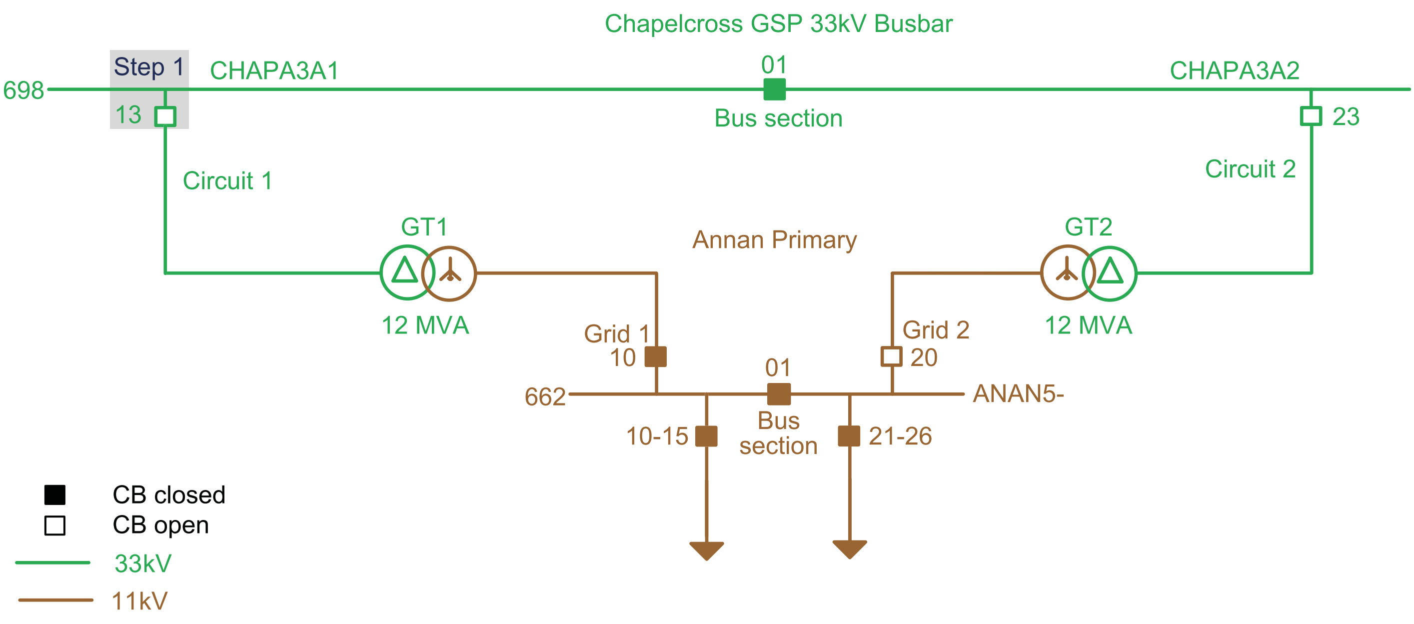


Table 2.2
Option A advantages and disadvantages

Option A – Single primary transformer energised on full load	
Advantages	**Disadvantages**
Only one 33kV switching operation – minimal switching reduces restoration time.	Large block load pick-up – Full primary substation load which may be greater than the historical maximum demand due to cold load pick-up (CLPU).
Power supply to the transformer tap change motor is provided via the 11kV network when the initial load is energised.	Potential for high voltage (few per cent) to customers until the tap changer has operated (up to 30s for the initial tap). This may occur if the 'Black Start demand' is less than the demand on the transformer just prior to the blackout. The latter will have determined the tap position the transformer has been left on, and any reduction in load will result in the voltage rising.

Option B – Single primary transformer energised on full load, second primary transformer back-energised
In restoration option B, all the 11kV CBs are closed including both Grid 1 and Grid 2 11kV CBs. Transformer GT1 will take on the full load supplied from the primary substation when 33kV CB 13 is closed in step 1 as shown in figure 2.9, while transformer GT2 will be simultaneously back-energised.

Figure 2.9
Primary substation restoration option B

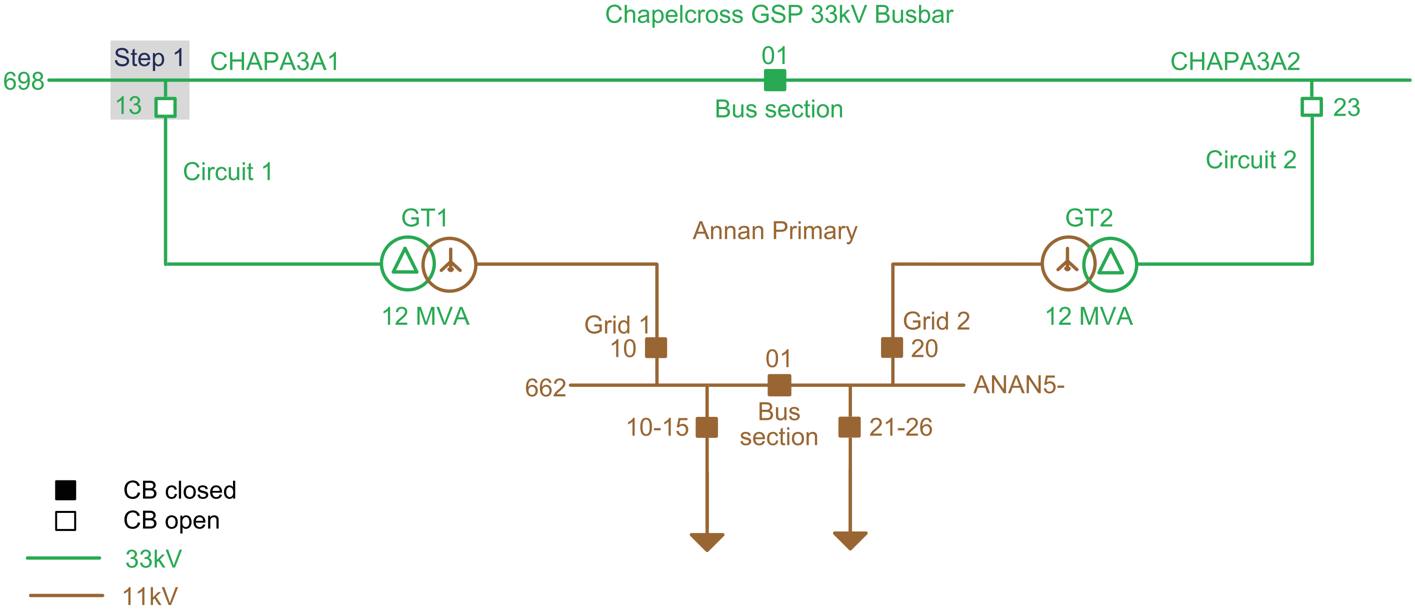


Table 2.3
Option B advantages and disadvantages

Option B – Single primary transformer energised on full load, second primary transformer back-energised	
Advantages	**Disadvantages**
Only one 33kV switching operation – minimal switching reduces restoration time.	Large block load pick-up – Full primary substation load which may be greater than the historical maximum demand due to CLPU.
Power supply to the transformer tap change motors is provided via the 11kV network when the initial load is energised.	Increased magnetic inrush compared to option A due to back-energisation of the second transformer, which could increase the total harmonic distortion seen by customers or potentially damage GT2.
	Potential for high voltage (few per cent) to customers until the tap changer has operated (up to 30s for the initial tap). This may occur if the 'Black Start demand' is less than the demand on the transformer just prior to the blackout. The latter will have determined the tap position the transformer has been left on, and any reduction in load will result in the voltage rising.
	There will be no earth on the 33kV circuit back-energised from the primary transformer. If an earth fault occurred, no protection would operate, which is a major plant and safety risk. This makes this strategy not viable.

Option C – Two primary transformers energised sequentially on half-load
In option C all 11kV circuit breakers are closed, except for the 11kV bus-section circuit breaker which is open as shown in figure 2.10. When CB 13 is closed, the 33/11kV transformer GT1 is energised and takes on half the load fed from the primary substation (assuming that the two sections of 11kV busbar equally share the load). When CB 23 is closed in step 2, the second 33kV primary feeder energises the 33/11kV transformer GT2, and it takes on the second half of the load fed from the primary substation.

Finally, in step 3, the 11kV bus-section CB is closed to improve security of supply.

It's important to note that:

- this option should only be considered if there are no 'closed ring' 11kV circuits between the No.1 and No.2 11kV busbar sections
- the 11kV busbar which supplies the secondary substation providing the LV supply for the primary substation should be energised first (this will provide a supply to the transformer tap change motor).

Figure 2.10
Primary substation restoration option C

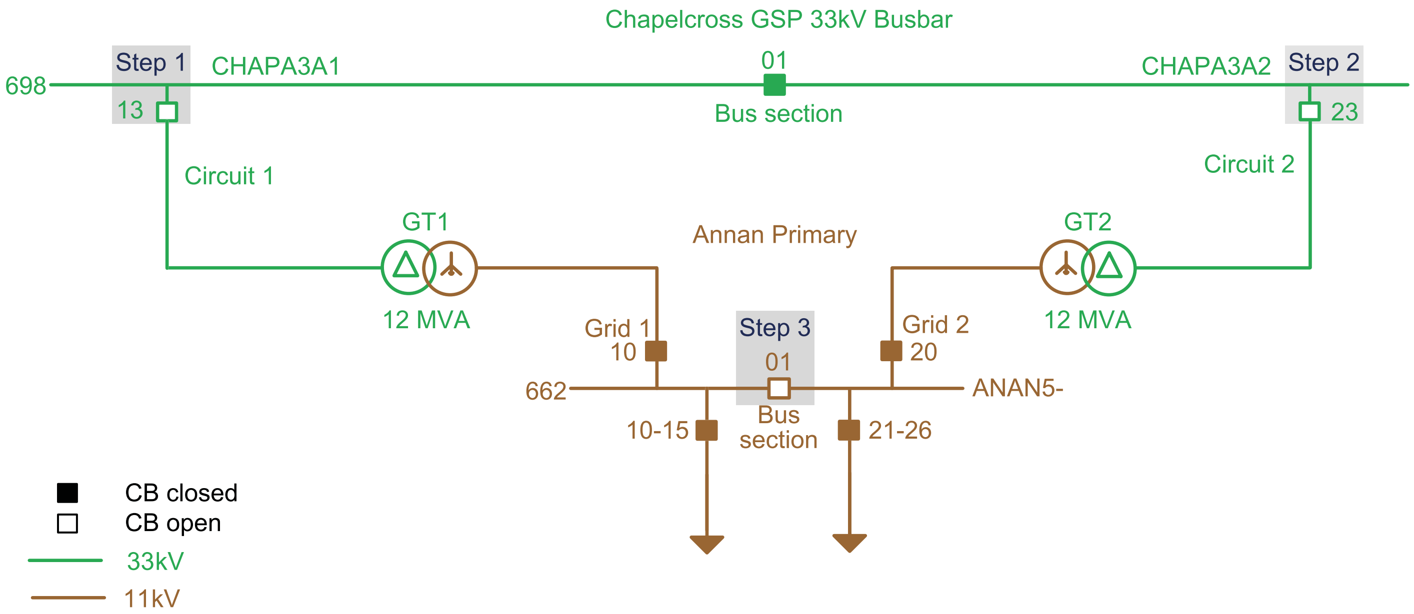


Table 2.4
Option C advantages and disadvantages

Option C – Two primary transformers sequentially energised on half-load	
Advantages	**Disadvantages**
Block load pick-up smaller than with options A and B.	Three switching operations increases the restoration time compared to less switching options.
Two primary feeder circuits energised, resulting in increased security of supply to customers compared to options D-G.	Delay before the bus-section can be switched. To save switching time the bus section could be left open, in which case this strategy would not provide increased security as an advantage.
Power supply to the transformer tap change motors is provided via the 11kV network when the initial load is energised.	Potential for high voltage (few per cent) to customers until the tap changer has operated (up to 30s for the initial tap). This may occur if the 'Black Start demand' is less than the demand on the transformer just prior to the blackout. The latter will have determined the tap position the transformer has been left on, and any reduction in load will result in the voltage rising.

Option D – Single primary transformer energised on half-load

This option is similar to option A, but only half the substation load is energised to reduce the load pick-up. This is achieved by ensuring that the 11kV bus-section CB is open, the GT1 primary transformer CB is closed and GT2 transformer 11kV CB is open. When CB 13 is closed, GT1 is energised and it takes on half the load fed from the primary substation. The bus-section breaker can be closed (step 2) when appropriate to supply the remainder of the full load via GT1.

Figure 2.11
Primary substation restoration option D

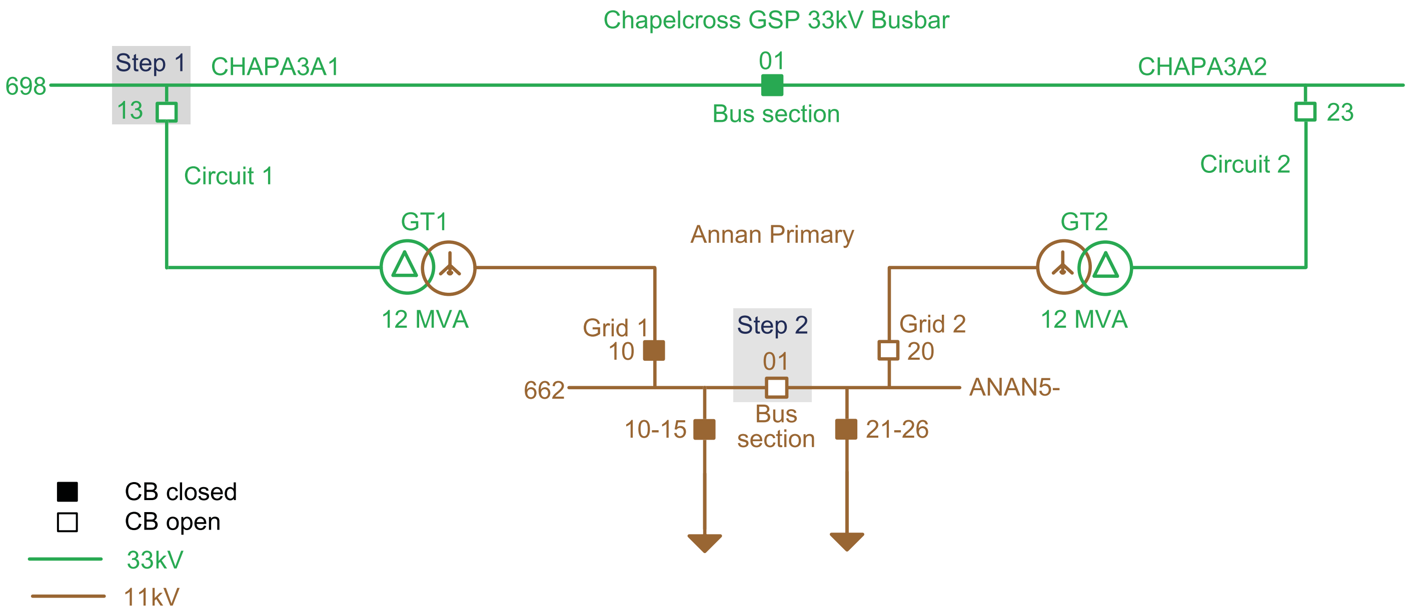


Table 2.5
Option D advantages and disadvantages

Option D – Primary transformer energised on half-load	
Advantages	**Disadvantages**
Load pick-up (including CLPU) is effectively halved compared to option A, allowing one transformer to supply the whole substation's load.	One more switching option compared to option A.
Power supply to the transformer tap change motors is provided via the 11kV network when the initial load is energised.	Delay before the bus-section can be switched.
	Potential for high voltage (few per cent) to customers until the tap changer has operated (up to 30s for the initial tap). This may occur if the 'Black Start demand' is less than the demand on the transformer just prior to the blackout. The latter will have determined the tap position the transformer has been left on, and any reduction in load will result in the voltage rising.

No-load – Sequential energisation of transformer followed by load

Option E – Primary transformer energised, followed by switching full-load

With primary substation restoration option E, the 11kV feeder breakers and the bus-section CB are closed as shown in figure 2.12. When 33kV CB 13 is closed, the GT1 33/11kV transformer is energised open circuit. Once the transformer is energised, the Grid 1 11kV CB is closed in step 2, so the transformer GT1 supplies the full load fed from the primary substation.

Figure 2.12
Primary substation restoration option E

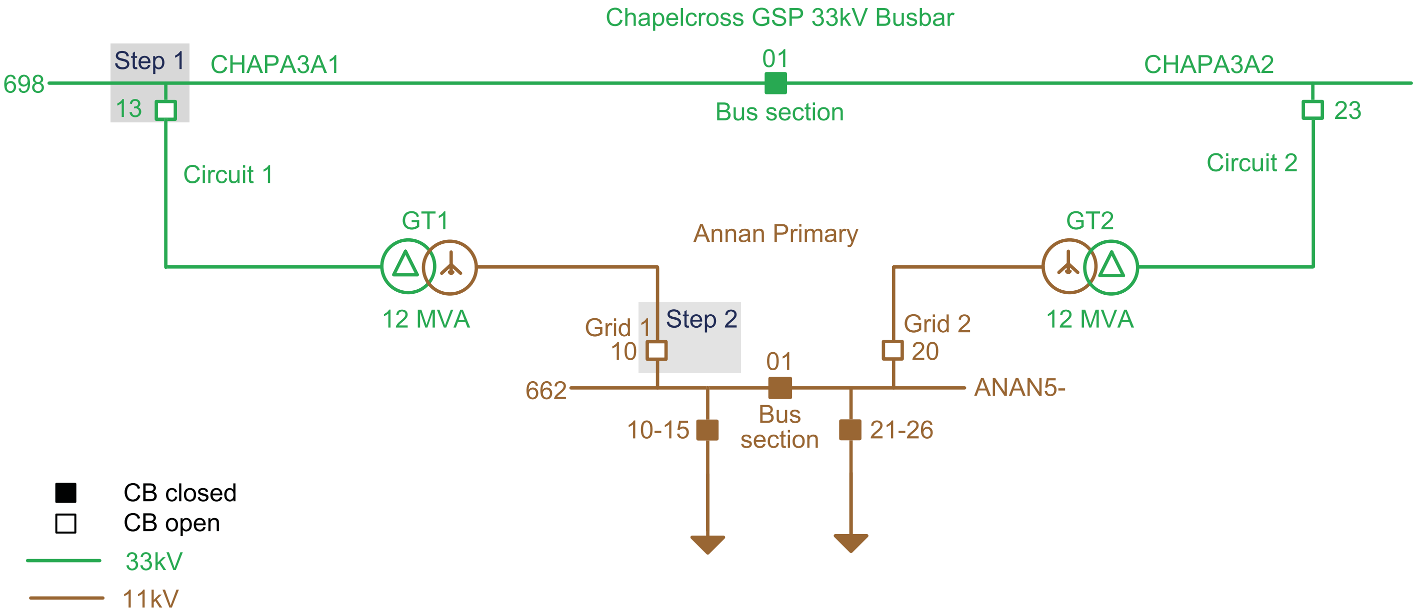


Table 2.6
Option E advantages and disadvantages

Option E – Primary transformer energised, followed by switching full-load	
Advantages	**Disadvantages**
Energisation of a single transformer without load – minimises magnetic inrush.	Large block load pick-up – Full primary substation load.
No customers are subjected to any voltage variations on the 33kV network.	Potential high voltage at the 11kV side of 33/11kV primary transformer following step 1 due to being on the same tap as when previously loaded prior to the blackout. There will be no supply to the tap change motor to correct the voltage (the motor is supplied from the local LV network which has not yet been energised).

Option F – Primary transformer energised, followed by switching half-load

In option F compared to option E, the 11kV bus-section is initially open. When CB 13 is closed, the 33/11kV transformer GT1 is energised. In step 2, the Grid 1 11kV CB is closed, taking on half the load fed from the primary substation (assuming the load is equally split by the bus-section). Lastly, in step 3, the bus-section CB is closed, and the transformer GT1 takes on the second half of the load fed from the primary substation.

Figure 2.13
Primary substation restoration option F

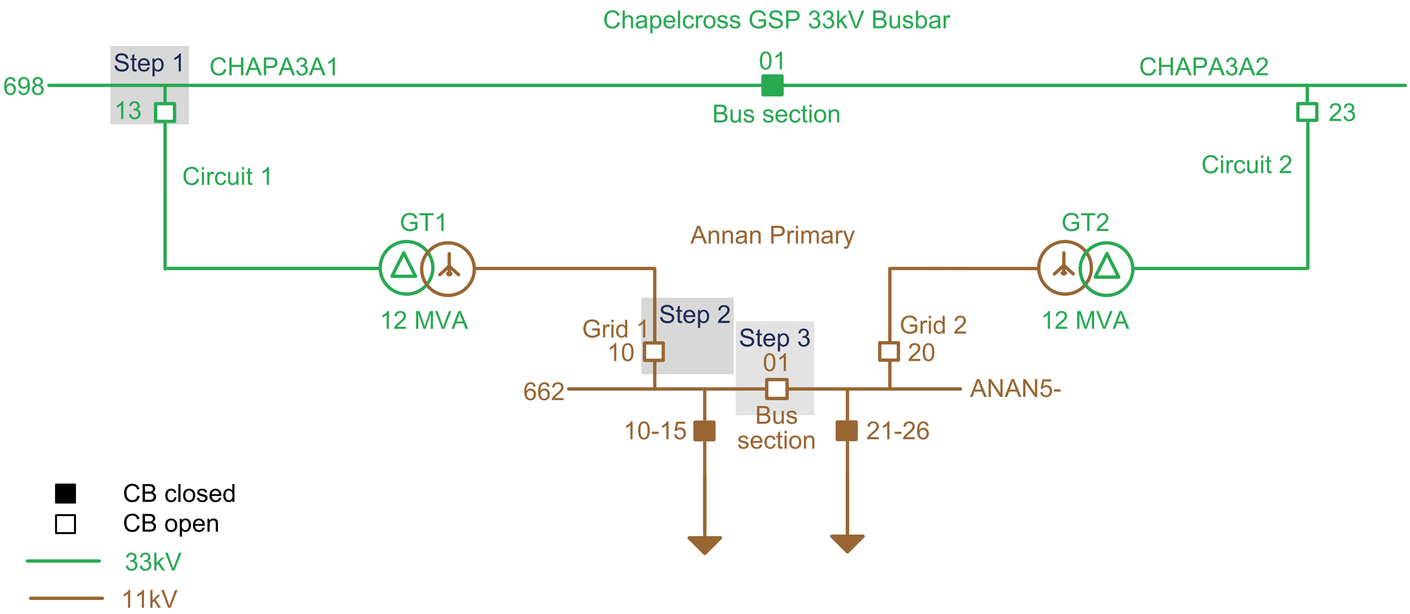


Table 2.7
Option F advantages and disadvantages

Option F – Primary transformer energised, followed by switching half-load	
Advantages	**Disadvantages**
Block load pick-up smaller than option E.	Three switching operations – more switching increases restoration time.
Energisation of a single transformer without load which minimises magnetic inrush.	Potential high voltage at the 11kV side of the 33/11kV primary transformer following step 1 due to being on the same tap as when previously loaded prior to the blackout. There will be no supply to the tap change motor to correct the voltage (the motor is supplied from the local LV network which has not yet been energised) until after step 2.
	Delay before the bus-section can be switched and the rest of the load can be supplied.

Option G – Primary transformer energised, followed by switching individual feeder load
In option G only the 11kV bus-section breaker is initially closed – all other 11kV CBs are open. When CB 13 is closed, the 33/11kV GT1 transformer is energised.

In step 2, the Grid 1 11kV CB is closed and the 11kV busbar is energised. This is followed by the sequential closing of the 11kV feeder CBs and energisation of the individual 11kV feeder circuits as illustrated in steps 3–14 below.

Figure 2.14
Primary substation restoration option G

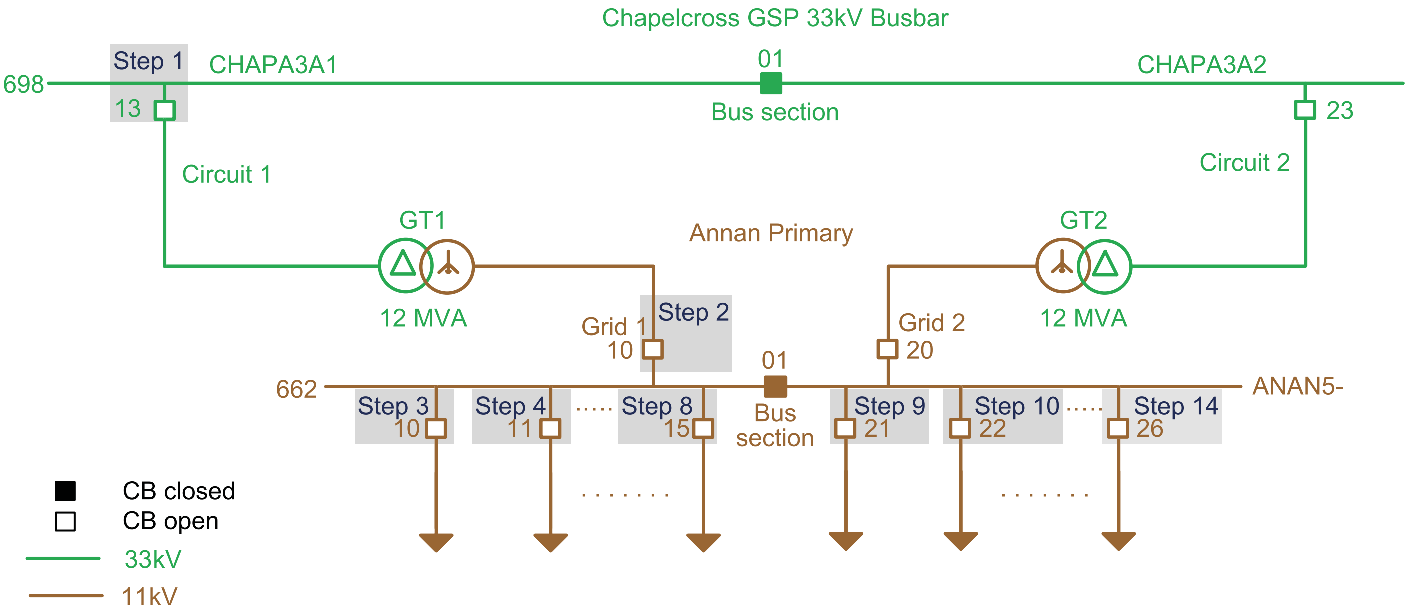


Table 2.8
Option G advantages and disadvantages

Option G – Primary transformer energised, followed by switching individual feeders	
Advantages	**Disadvantages**
Block load pick-up is smaller than option D (reduced to 11kV feeders).	Multiple switching operations (depending on the number of 11kV feeders). More switching increases the complexity of the restoration process and the restoration time.
Energisation of a single transformer without load which minimises magnetic inrush.	Potential high voltage at the 11kV side of 33/11kV primary transformer following step 1 due to being on the same tap as when previously loaded prior to the blackout. There will be no supply to the tap change motor to correct the voltage (the motor is supplied from the local LV network which has not yet been energised) until after step 3.
	The Control Room prefers not to switch 11kV feeder breakers after an outage due to increased number of switching steps and longer restoration time.

Summary findings

A summary of the different options is presented in table 2.9. It has been assumed that the maximum cold load pick up is twice the maximum demand (A detailed explanation of this assumption is covered in chapter 3.2).

Table 2.9
Summary of the primary substation restoration options

Option	No of transformers energised simultaneously	Max block load pick-up (Estimated)	Max cold load pick-up (2 x max load)	Supply to tap change motor from step 1	Number of switching operations
A	1	Full load	2 x Full load	Yes	1
B	2	Full load	2 x Full load	Yes	1
C	1	Half load	Full load	Yes	3
D	1	Half load	Full load	Yes	2
E	1	Full load	2 x Full load	No	2
F	1	Half load	Full load	No	3
G	1	Per feeder	2 x single feeder	No	4 to 18+

Some points worth noting:

- Although option A is the most efficient from a switching perspective with the least amount of switching operations, it may not be feasible in the case of primary substations where the cold block load exceeds the block load capability of the anchor generation or the thermal rating of the primary transformer or switchgear. In such cases, options C or D would be the preferred restoration strategies.
- However, in cases where the anchor generator has a small block load pick-up capability, it may be necessary to switch demand in very small steps, such as in option G, where individual 11kV feeders are switched. However, a restoration strategy that involves switching multiple 11kV CBs could be time-consuming with the risk of switching errors.
- A potential for high voltage exists when the primary transformer is energised and until the tap changer has operated (up to 30s for the initial tap). This may occur if the 'Black Start demand' is less than the demand on the transformer just prior to the blackout. The latter will have determined the tap position the transformer has been left in, and any reduction in load will result in the voltage rising. In most scenarios the voltage would only be high by a few per cent and within acceptable limits.
- Where a primary substation has two transformers, but only one was in service before the blackout, the transformer will mostly likely be in a high tap position. This could result in high 11kV voltage when the demand is energised, until such time that supply to the tap change motor can be restored and it can tap to the correct position. In such scenarios the restoration of the primary substation should be inhibited.
- The restoration strategies have not considered any switching over voltages that may occur at LV level during the demand restoration. Detailed modelling and analysis of the HV/LV network and customer demand may be necessary to determine the risk to customer equipment during system restoration.

2.4.2 Strategies for restoring meshed connected primary substations

The SPM network contains examples of networks which are meshed at some (or all) voltage levels (400V, 11kV, 33kV and 132kV). On the 11kV network, there are two main types of meshed networks (X and Y) as discussed in section 2.1.2.

Restoring X-type substations

Due to the dense LV interconnection between X-type secondary substations, and potentially across different HV interconnector circuits in the same HV group, partial restoration of an HV group with X-type interconnections is highly impractical, because opening circuit breakers at the primary substation and restoring one circuit at a time would result in overloading of the LV cables as load is normally shared between multiple cables and transformers. If an entire group is off, as in the case of Black Start, then consideration needs to be given to the group's maximum demand and the transformer capacity to be restored.

For example, if the secondary transformer group demand is considerably more than a single primary transformer's capacity, more than one primary transformer will need to be restored. Typically, the minimum number of transformers that would be required to supply the maximum demand would be one less than the number of primary transformers in the group.

Restoring Y-type substations

Restoration of networks with Y-type interconnector circuits are more straightforward than with X-type circuits, as the LV interconnector circuits are only within the same HV interconnector circuit. The main points to be considered for the restoration are the generator's block load capability, the 33kV and 11kV network topology, availability of telecontrol on each primary substation and availability of telecontrol on various points along the Y-type circuits.

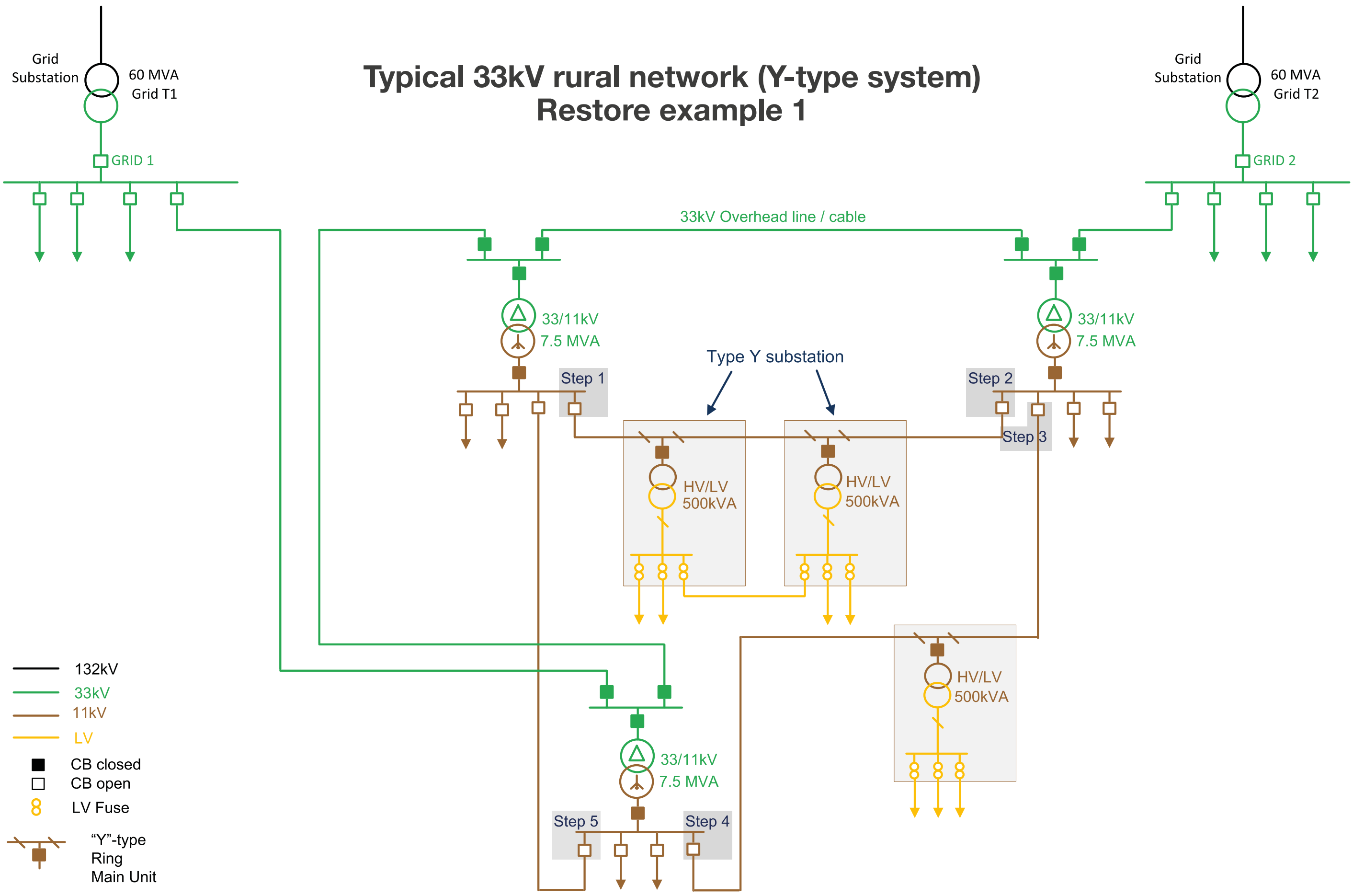
The following restoration options exist:

- **Option 1:** Closing a 33kV circuit breaker at the grid substation which due to network topology will restore enough primary transformers at once with enough capacity to restore the group demand. The minimum number of transformers that would be required to supply the maximum demand would be one less than the number of primary transformers in the group.
- **Option 2:** Simultaneous closing of 11kV or 33kV primary transformer breakers (which is only practical using automated remote switching) within the transformer group.
- **Option 3:** Splitting the HV group at certain points within a Y-type interconnector, or opening the circuit breakers at both ends of the primary substations to enable restoration in stages and smaller block loads. This is feasible with Y-type substations, but not with X-type substations.
- **Option 4:** By a combination of the methods above.

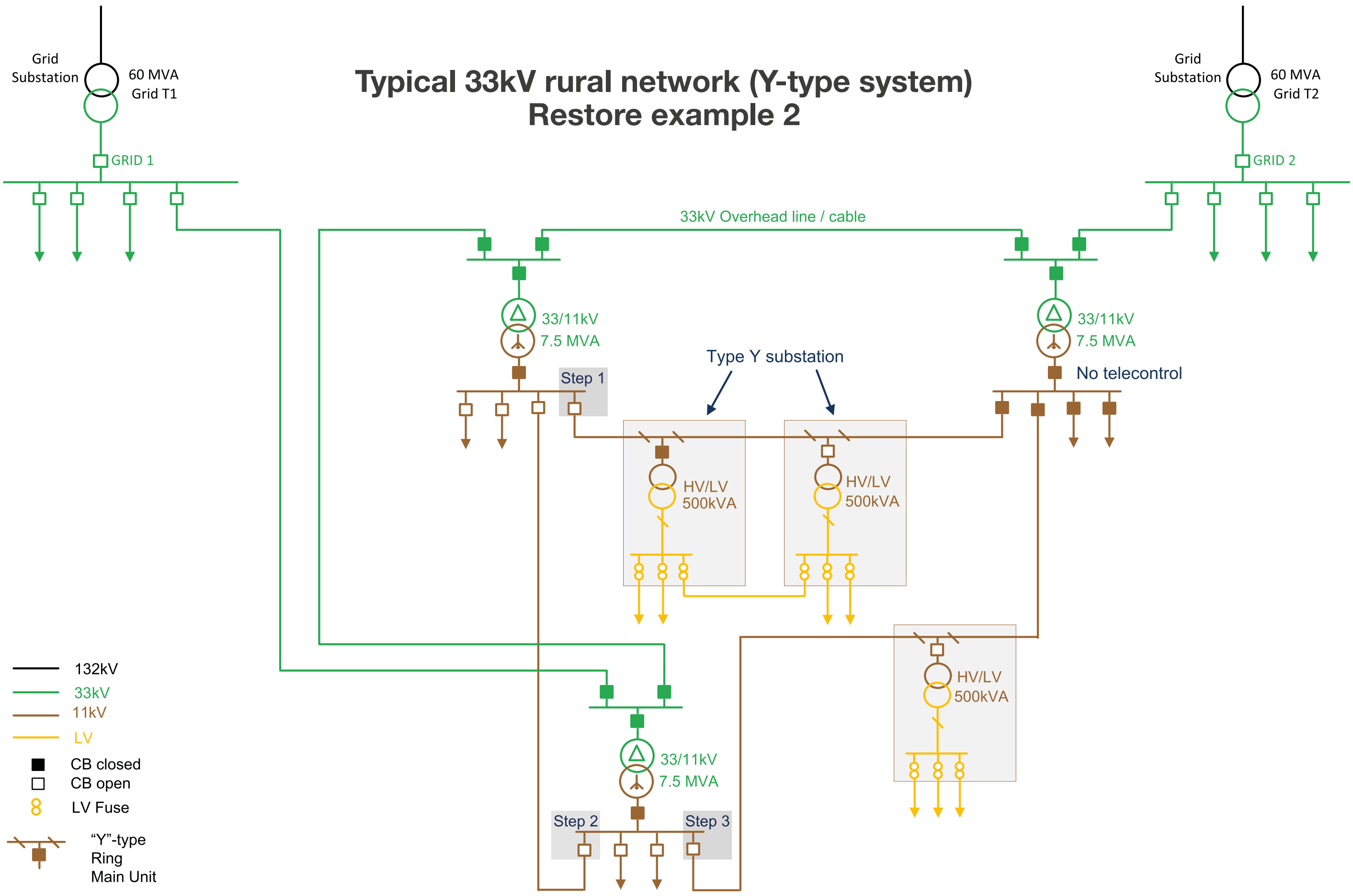
The following two examples illustrate how a Y-type meshed network could be restored using option 3 described above.

Figure 2.15
Two examples of restoring a Y-type system

Example 1:
If telecontrol is available at all the primary substations in a group, then all the HV CBs can be opened and once a primary transformer is energised, CBs can be closed in turn to restore the group's demand in stages.



Example 2:
If telecontrol is unavailable at one of the primary substations, but available at enough other primary substations in the group and/or at other points on the circuits, then there may still be an option to split the group in sufficiently small load blocks to enable restoration.



Summary findings

- Restoring X-type meshed networks is considered to be difficult due to the large number of interconnections at LV level that could result in overloading of LV cables during restoration.
- Y-type meshed networks are more viable to restore than X-type networks, as they have far fewer LV interconnectors and only within the same HV interconnecting circuits. Rural Y-type networks typically have fewer LV interconnections compared to urban Y-type networks and are therefore the easiest kind of meshed network to restore. The following factors need to be considered during restoration:
  - A sufficient number of primary transformers need to be simultaneously energised to supply the maximum demand from the HV network. This would usually be one less than the number of primary transformers in the group.
  - The restoration strategy needs to ensure that the thermal rating of the transformers, as well as the block load capability of the anchor generator is not exceeded during restoration as a result of the cold block load.
  - The number of switching operations should be minimised and be limited to 33kV circuit breakers as far as practically possible. If not automated, the switching of multiple HV circuits could place an operational burden on Control Room staff, which should be avoided.
  - Although all 33kV circuit breakers at primary substations are telecontrolled, HV switchgear have mixed capability, and some circuit breakers in especially old urban substations may not be remotely controllable. The restoration strategy should only consider circuit breakers that have telecontrol capability, as the manual switching of switchgear at multiple substations is not considered practical for Black Start.

2.5 Development of the restoration strategies for the case studies

During the Design stage, several restoration strategies were identified and evaluated for each of the case studies as a prerequisite for the power system studies to be performed. The process for developing these strategies is outlined below:

1) Identification of the anchor generator and its governor and AVR characteristics.
2) Identification of the DERs to support the anchor generation in creating and maintaining the power island. Only DERs connected at 33kV were considered and not those at 11kV.
3) Development of different high-level restoration options and sub-options based on the main aspects to be evaluated during the restoration process e.g. restoring a large rural 33kV network, back-energisation of the 132/275/400kV network etc. The development of these restoration options considered amongst others:
   - Sequence of restoring supply to the primary substations and wind farms. For example, supply restoration to wind farms were prioritised to ensure auxiliary supply for the heating of gear box oil and prevention of condensation, so that wind farms were available when called upon to provide active and reactive power support.
   - The maximum demand of each of the primary substations, and resulting cold load pick-up.
   - The restoration strategy for energising each of the primary substations.
4) Development of a simplified single diagram indicating all the primary and secondary substation busbars, lines and cables, circuit breakers, transformers and loads to be involved in the restoration process, including interconnectors to other GSPs.
5) Determining the network's post-blackout state by considering the state of all the circuit breakers following the blackout, including the normal operating state of the network prior to the blackout, the tripping of circuit breakers due to underfrequency tripping, and the tripping of connected generation as per Engineering Recommendation G59/G99 conditions.
6) Determining the optimal pre-restoration status of all the circuit breakers in the network to minimise switching during the restoration process. The objective is to perform all preparatory switching while the network has no supply, so that the restoration process itself requires minimal switching.
7) Development of the different restoration stages and circuit breaker switching steps required in each stage. This was done in a table format as well as through annotations on a simplified single line diagram so it was easier to follow.

The development of a Distributed ReStart restoration strategy is a compromise between the requirement to restore the network as quickly and with as few switching operations as possible, and the need to restore it in a way that doesn't result in any transformer, circuit or switchgear overloading, ensuring that voltage and frequency remain within limits, and giving due consideration for the impact of cold load pick-up, and the block load pick-up capability of the anchor generation.

3. Overview of power system studies

Energising a DRZ presents unique technical challenges. This chapter provides an overview of the power system simulation studies that were performed to assess the viability of different energisation, block-loading and restoration options for each of the selected case study networks.

Power system simulation studies were performed for the proposed system energisation and load restoration plans to determine if they were technically viable from an anchor generator and DER capability perspective, but also to ensure that equipment thermal loading, network voltage and frequency limits weren't exceeded.

3.1 Power system simulation studies undertaken

3.1.1 Steady state load flow studies

The purpose of the steady state load flow simulation studies was to:

- assess the voltage profile across the case study network and determine the loading condition of each of the main network components during each step of the restoration process
- confirm acceptable anchor generator voltage set points and primary transformer tap positions to be used in each of the different restoration options
- establish the limits of real and reactive power at the transmission interface point, i.e. the range of P and Q that the distribution power island can provide to/absorb from the transmission system (to enable direct comparison with the existing Black Start technical requirements)
- establish the initial conditions for the dynamic simulations and transient analysis.

The load flow studies were performed using DIgSILENT PowerFactory™ software and were used as the first-pass test to verify the viability of each of the restoration options for the case study networks. In cases where over/under voltages or equipment overloading occurred, the restoration process was adjusted until an acceptable steady state response was achieved, before moving on to the dynamic studies.

3.1.2 Dynamic studies

Dynamic studies look at the power system voltage and frequency response over several seconds when a restoration event occurs until the system has reached a new steady state. Dynamic simulations studies were performed for each step in the restoration process using DIgSILENT PowerFactory™ software to:

- assess the voltage and frequency response after energising each of the main network components and picking up cold block loads in accordance with the restoration plan
- assess the voltage and frequency response subsequent to disconnecting a block load, or tripping a connected renewable generation resource in the power island
- confirm voltage control capability and strategy of the anchor generator and other available reactive power sources in the island power system
- confirm frequency control capability and strategy of the anchor generator and other available renewable generation in the island power system.

The voltage and frequency responses were used to determine the viability of each restoration step. Restoration steps were amended and the studies rerun in instances where the voltage and frequency limits were exceeded to establish a viable restoration process.

3.1.3 Electromagnetic transient (EMT) studies

In this project, the EMT studies were used to evaluate the overall power system response during an energisation event over a very short period of time, in the order of microseconds, and monitor whether voltage transients remain within acceptable voltage dip and rise limits. EMT studies were performed using PSCAD™ simulation software to:

- assess transformer inrush and voltage dip for each energisation event in the DRZ, including the grid and super grid transformers and to confirm viability of the energisation event
- assess transient and temporary over-voltages for specific network switching operations
- determine the minimum requirements before each energisation step, i.e. the resources online, their operating points and settings necessary to have high confidence of successful energisation.

3.1.4 Harmonic studies

Harmonic impedance scans were performed using DIgSILENT PowerFactory™ software to identify any possible harmonic resonances occurring during the restoration process.

3.2 Key assumptions

3.2.1 Load flow analysis assumptions

A number of assumptions were made in setting up the network model and in performing the steady state studies for the case study networks.

General assumptions

- All network data in the model, i.e. 33kV and 132kV circuit data, transformer data, load information, generation information, fault level information and HV network information were based on the 2019 Long-Term Development Statement (LTDS).
- The restoration switching sequences were based on the initial restoration strategies developed for each case study network.
- Switching sequences within each stage (marked as steps in the restoration diagrams e.g. figure 4.3) were modelled as single sequences in the load flow studies.
- Voltages in excess of ±6 per cent are permitted on the 33kV network where customers are not directly connected (as per the Security and Quality of Supply Standard (SQSS)[3].

Load demand related assumptions

The following assumptions are made in regard to how load demand is treated in the studies:

- Operating procedure during system restoration is to limit switching to 33kV circuit breakers and avoid switching individual 11kV feeder breakers. Primary substation loads are therefore picked up per 11kV busbar, which effectively amounts to picking up the load in blocks, also known as block-loading.
- Loads are considered to have a constant power characteristic i.e. when the voltage goes down the current goes up to compensate and the effective MW and Mvar remains constant.
- Cold load pick-up (CLPU) is the phenomenon of excessive inrush current drawn by loads when distribution circuits are energised after an extended outage, and is a key consideration during Black Start given that large blocks of load are picked up when primary substations are energised on load. The multiplying factors used to model the cold load decay are based on review of literature on this topic.
- Under normal CLPU, load is picked up in 3 stages:
  - Stage 1: MAX – load values are multiplied by 2, representing the maximum cold load pick-up
  - Stage 2: MED – load values are multiplied by 1.5, representing the decayed cold load value after 15 minutes
  - Stage 3: MIN – load values are multiplied by 1, and reaches its normal value after 30 minutes.
- During system restoration it is assumed that the load in the next stage is energised when the current load is at stage 2, i.e. there is a 15-minute delay between successive energisation stages to enable the cold load to decay by 50 per cent before the next load is switched on.
- In some stages of the restoration, the cold block load pick-up triggers voltage violations. To avoid such a condition, a delayed cold load pick-up is considered in those stages.
- Under delayed CLPU, load is picked up in only 2 stages – MAX & MIN (as above). In this case, after the initial MAX cold load is picked up, it is assumed that the next load (next stage) is switched on only after the current load is back to its normal value (after 30 minutes). This is to avoid potential overloading or voltage issues in the network when large consecutive CLPUs occur.

Generation related assumptions

The following assumptions were made in respect of generators in the power system models:

- All generators are set to voltage control mode by default.
- Studies with wind farms in power factor control mode were performed to compare the differences in the reactive demand on the anchor generator, and worst-case busbar voltage violations with no wind farm voltage support.
- Voltage control of wind farms was considered to be set at 1.02pu at their 33kV point of connection (PoC). The droop setting was kept at 3 per cent.
- Voltage control of synchronous DERs, including the anchor generator, was considered to be set at 1pu at the generator terminal. No droop setting was considered for the anchor generator.
- All generators were set to operate within their respective active and reactive power limits.
- Hydroelectric generators were assumed to have a minimum active power output of 5 per cent.
- The variability of wind during a specific restoration process was not considered. However, the restoration process was modelled for discrete levels of wind generation, namely generation at 10 per cent, 20 per cent, 30 per cent, 40 per cent and 50 per cent of rated capacity. It was assumed that wind farms can only generate up to a maximum of 45 per cent of their rating to ensure that the network is not overdependent on one source. In a few studies this limit was pushed to observe the effects of different energy mixes on the voltages and asset capacities in the network.
- No auxiliary load was considered for the anchor generator as it is expected to be powered by a separate diesel generator throughout the restoration process. However, a load bank of 10 per cent of the anchor generator MVA rating was considered as the minimum demand required for stable operation of the anchor generator. The load bank is disconnected in the simulations as soon as the first substation demand is picked up.
- It was assumed that the anchor generator only operates up to 80 per cent of its rating under normal conditions once the load bank has been disconnected.
- Wind farm auxiliary loads were assumed to be 500kVA.
- Wind farm array cables were not modelled in detail in the load flow studies. However, the Mvar generated from the energisation of the cables was accounted for by considering a rule of thumb of 0.06Mvar/MW, where MW is the nameplate rating of the respective wind farm.
- Multiple units at a generation site such as individual wind turbines in a wind farm, or individual hydro turbines in a hydro plant, were modelled as a single source generator.
- Synchronous generators other than the anchor generator are considered to be operating at their stable minimum active power limit.

[3] Security and Quality of Supply Standard (SQSS), Version 2.4, April 2019.

Transformer related assumptions

The following assumptions were made in respect of transformers and tap changers:

- Some of the primary transformer energisation options considered in section 2.4.1 were found not to be suitable for certain primary substations (e.g. option A and B for Annan substation in Chapelcross) due to short-term transformer overloading. For each primary transformer, the load flow studies utilised the most suitable restoration option, e.g. one that picks up the maximum possible demand with the fewest number of switch steps.
- Primary transformers were considered to be 150 per cent rated for a short duration when only Oil Natural Air Natural (ONAN) cooling is available, based on the protection settings.
- All transformer taps were considered to be on-load auto change i.e. the tap change motor operates automatically via the automatic voltage control (AVC) relay, except the anchor generator station transformers where the on-load tap changer (OLTC) is controlled by the generator control room.
- The anchor generator station transformer tap is locked at the value for which the voltage at the PoC is maintained at 1pu during no load condition.

Transmission-distribution interface assumptions

- The anchor generator active power is limited to 80 per cent of its MW rating.
- The Mvar capability of the DERs including the anchor generator is limited to ±0.95 power factor.
- No tap action is considered for the grid and super grid transformers.

3.2.2 Dynamic studies assumptions

General assumptions

- The time interval between the simulated switching sequences was kept in the order of seconds to maintain a reasonable simulation time for the whole restoration process and limit the size of the exported data. No scaling was done between the simulation time and actual restoration time. The assumed switching intervals were:
  - 40 seconds between successive stages (≈20 minutes in reality)
  - 10 seconds for the picked up cold load to decay from 200 per cent to 150 per cent (≈5 minutes in reality)
  - 50 seconds for the picked up cold load to decay from 150 per cent to 100 per cent (≈25 minutes in reality)
  - 20 seconds between staggered load pick up at some substations (e.g. Annan and Lockerbie in the case of the Chapelcross case study). Therefore, when the second half of the demand is picked up, the first half is at 150 per cent (≈10 minutes in reality).

Demand and generation related assumptions

- Primary substation demand was modelled as lumped loads at 11kV.
- The lumped loads were modelled to have a constant power characteristic i.e. the active and reactive power demand remains constant and does not vary with the substation voltage and the system frequency. So, when the voltage goes down the current goes up to maintain the product of voltage and current constant. This is the most onerous condition for the network as the demand does not contribute to voltage and frequency regulations under stressed conditions.
- To assess the impact of the load model on the response of the anchor generator, an additional study modelling the load with a constant impedance characteristic was carried out only for Chapelcross restoration option 1 to compare the active and reactive power response of the anchor generator with the two wind farms. It wasn't repeated for the other options as the relative impact is considered to be the same. A constant impedance characteristic means that customer demand follows a quadratic relationship with the substation voltage i.e. power goes down as a square of the voltage, with no frequency dependence.
- The turbine governor model of the anchor generator was based on recommended IEEE models with detailed representation of the boiler characteristics.
- AVR models were developed based on the datasheet provided by the generator, or the recommended IEEE models, where actual data wasn't available. The models used appear in Appendix 2: DER ratings and simulation models.
- The anchor generator was assumed to be working in isochronous mode i.e. the governor droop is deactivated, and the generator aims to bring the system frequency back to the nominal value of 50Hz after every disturbance.
- The wind turbine control system and the wind power park control are based on IEC 61400-27-1 Ed. 1.
- All the wind farms are considered to be in voltage control mode with fixed active power output as requested by the Control Room during the restoration process.
- The voltage control set point for all wind farms is 1.02pu at the PoC with a 3 per cent droop.
- The total active power support provided by the wind farms is capped at 45 per cent of rated capacity and is spread across the restoration process in certain steps in keeping with the frequency regulation requirements.
- The active power ramp rate is considered to be 5 per cent of the wind farm rating per second and the following protection thresholds are considered for type A, B & C power generating modules as per G99 guidelines. The setting for Rate of Change of Frequency (RoCoF) is purposely relaxed from 1Hz/s to monitor the maximum extent during the restoration process.
  - Over-voltage threshold – 1.13pu
  - Under-voltage threshold – 0.8pu
  - Over-frequency threshold – 52Hz
  - Under-frequency threshold – 47.5Hz
  - Maximum RoCoF of 2Hz/s.
- The block load pick-up (BLPU) capability of a generator is defined by the Grid Code as the incremental active power steps, from no load to rated MW, which a generator can instantaneously supply without causing it to trip or go outside the frequency range of 47.5Hz – 52Hz.

3.2.3 EMT study assumptions

General assumptions

- The time interval between the simulated switching sequences is in the order of seconds for the energisation study to maintain a reasonable simulation time for the whole restoration process and limit the size of the exported data. The switching intervals are:
  - 1.5 seconds for energisation of cables
  - 2 seconds for energisation of primary transformers
  - 5 seconds for energisation of grid and super grid transformers.
- Point on wave (PoW) energisation studies were used to determine the worst-case and best-case impact on the network voltage when closing a circuit breaker. A PoW study involves performing a 'multi run' simulation i.e. by closing the breaker at different times on the voltage waveform to find out the most onerous (i.e. maximum) and the least onerous (i.e. minimum) voltage transients (dip or rise). In terms of an actual network, this means that if the concerned breaker does not have the PoW feature, then the voltage transient would lie anywhere between the minimum and maximum limits determined from the simulation study.
- The impact of the energisation events on the system voltage were assessed against the recommended planning limits in ER P28[4] and SQSS. The voltage step change limits in planning and operational timescales for user systems supplied at 132kV and below are -12 per cent (voltage fall) and +6 per cent (voltage rise).

Transformer related assumptions

The following assumptions were based on past experience and expert judgement:

- All the transformers were modelled using the parameters present in the Electricity Ten Year Statement (ETYS) and LTDS network model.
- The saturation characteristic of the transformers was modelled using an in-house DC injection method and the air core reactance of the transformers were tuned to match the following inrush current magnitude and decay time:
  - 5 times with a decay time constant of 1 second for 50MVA transformers and above
  - 6 times with a decay time constant of 1 second for the 53MVA Steven's Croft station transformer
  - 7 times with a decay time constant of 0.3 second for transformers smaller than 50MVA.
- The remnant flux at the time of the energisation was considered to be 80 per cent.
- The knee voltage of the transformer core saturation curve was considered to be 1.25pu.

Demand, generation and cable related assumptions

- The energisation study was carried out for no load conditions i.e. only transformers and lines are considered in the network and all customers (both demand and generation, except the anchor generator) are neglected.
- No governor model was considered for the anchor generator as the focus was on studying the impact of energisation on the busbar voltages and not on the cold load pick-up capability of the generator.
- The AVR was modelled based on the parameters from the generator's datasheet.
- Cables and overhead lines were modelled based on their lengths. A simple PI model was used for all circuits less than 2km in length, while longer lines were modelled in detail using a frequency dependent or Bergeron model.
- For wind farm sites, detail array cable layout and individual turbine transformers were modelled according to available data.

3.2.4 Harmonic assessment assumptions

- Only harmonic impedance scan analysis was initially performed to assess the risk of low order resonance. Future studies could consider harmonic voltage penetration and voltage harmonic distortion.
- Cables and overhead lines were considered to have a distributed parameter model. However, in the absence of any public or other information on the frequency characteristic of the resistance, inductance and capacitance of the lines, no frequency dependency of these parameters was considered.
- Wind farm array cables are represented by an equivalent lumped Mvar demand.
- No harmonic voltage contribution was considered from the anchor generator. The machine was represented by an impedance model with stator resistance and sub-transient reactance and without any frequency characteristics of these parameters.
- In the absence of information about the harmonic impedance contribution of wind turbine converters, all wind turbines were considered to have infinite impedance, i.e. they are considered as an open circuit during an impedance scan.
- The primary substation loads were represented by static load models.
- No non-linear loads were considered and harmonic current contribution from the customers was considered to be nil.

[4] Engineering Recommendation (EREC) P28 (Issue 2, 2018)

3.3 DER parameters and model considerations

The dynamic response of a power system is very much dependent on the specific models and parameters used for the different generator control systems such as the governor, AVR, wind turbine control system, wind power park control system etc. These parameters are usually tuned for generator operation in a strong grid with provision for some contingency scenarios. However, Black Start system restoration is an extreme scenario during which the system operates outside its normal operating ranges and statutory limits.

To ensure stable operation of the system during the restoration process, it is imperative to model the control systems as accurately as possible and come up with a set of dynamic parameters which is appropriate for an isolated weak grid operation. Availability of detailed dynamic model and site-specific parameters proved challenging due to two reasons:

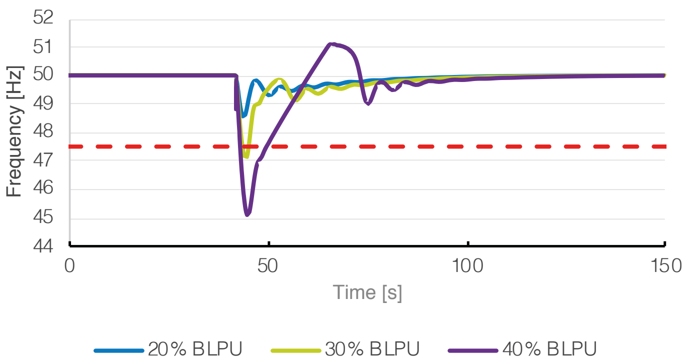
- Complexities around Non-Disclosure Agreements (NDA) and delays in getting the right set of data before the commercial arrangements are in place.
- Historically there was no need for small distribution connected generators to maintain and submit detailed dynamic models as there were no mandatory regulations.

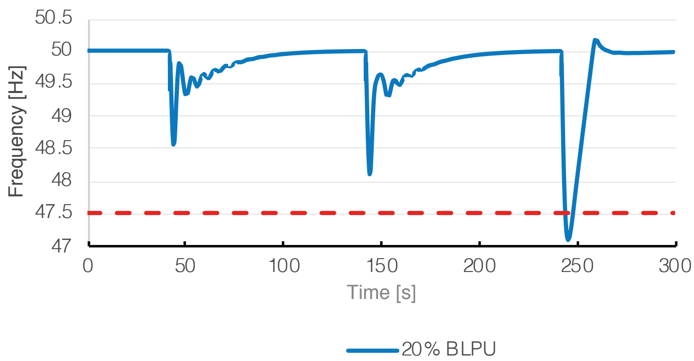
In the absence of site-specific models, standard models were used and populated with available parameters supplemented with expert assumptions as discussed below. A list of all the DER ratings and simulation models used in the power system studies can be found in Appendix 2: DER ratings and simulation models.

Generator block load pick-up (BLPU) capability

This BLPU capability of a generator depends on several factors such as the size of the machine, inertia, turbine technology, governor characteristic and the available spinning reserve. This capability of a generator usually tends to reduce with successive loading due to the non-linear characteristic of the turbine governor system such as the non-linear relationship between the steam flow and the valve opening in case of a steam turbine machine. This means at later stages in the restoration process the same amount of BLPU will result in a higher drop in frequency of the system. This is neglecting any relief offered by the demand due to its voltage and frequency dependency characteristic. Figure 3.1(a) shows the frequency response of a generator having steam turbine technology with detailed boiler model. Three different block load sizes are picked up with the same initial condition. As the size of the block load increases, the frequency nadir goes down and beyond a certain size it will violate the acceptable frequency threshold. Figure 3.1(b) shows the response of the same generator with a block load size of 20 per cent, only this time the same size of load is picked up three times consecutively. As evident, the BLPU capability reduces as the loading on the machine increases.

Figure 3.1
Frequency response of a steam turbine generator for:
(a) different block load per centages and, (b) a specific block load picked up several times
Note: 47.5Hz is the underfrequency threshold as per the G99 engineering recommendations in GB.





4. Chapelcross GSP restoration and power system study results

The restoration strategies for the Chapelcross case study network are discussed in more detail and the results from the power system simulations presented.

4.1 Restoration strategies

4.1.1 Overview

Based on the generic restoration strategies discussed in section 2.3, five main restoration strategies were developed for the Chapelcross case study.

All five strategies begin with the self-starting of the synchronous generating unit at Steven's Croft biomass power plant, followed by energisation of the Chapelcross 33kV busbar and the Minsca and Ewe Hill wind farms. The wind farms are energised as early as possible in the restoration process due to limited resilience against a loss of power. For instance, during a blackout, in the case of turbines with gearboxes, gear box oil can cool down after several hours requiring reheating before the turbines can operate again, and in the case of gearbox-less turbines, machines need to go into 'dry-out' mode for several hours to remove possible condensation that may occur after being without power for a certain period.

The wind farms are energised but are not required to provide any active power until later in the restoration process. It's worth mentioning that in Scotland wind farm turbines operate in voltage control mode by default, whereas in England and Wales power factor control mode is the default. Usually wind farms would auto restart when grid supply is healthy for around 15 minutes. For Distributed ReStart this would need to be disabled.

An overview of the restoration strategies is provided in table 4.1 and figure 4.1.

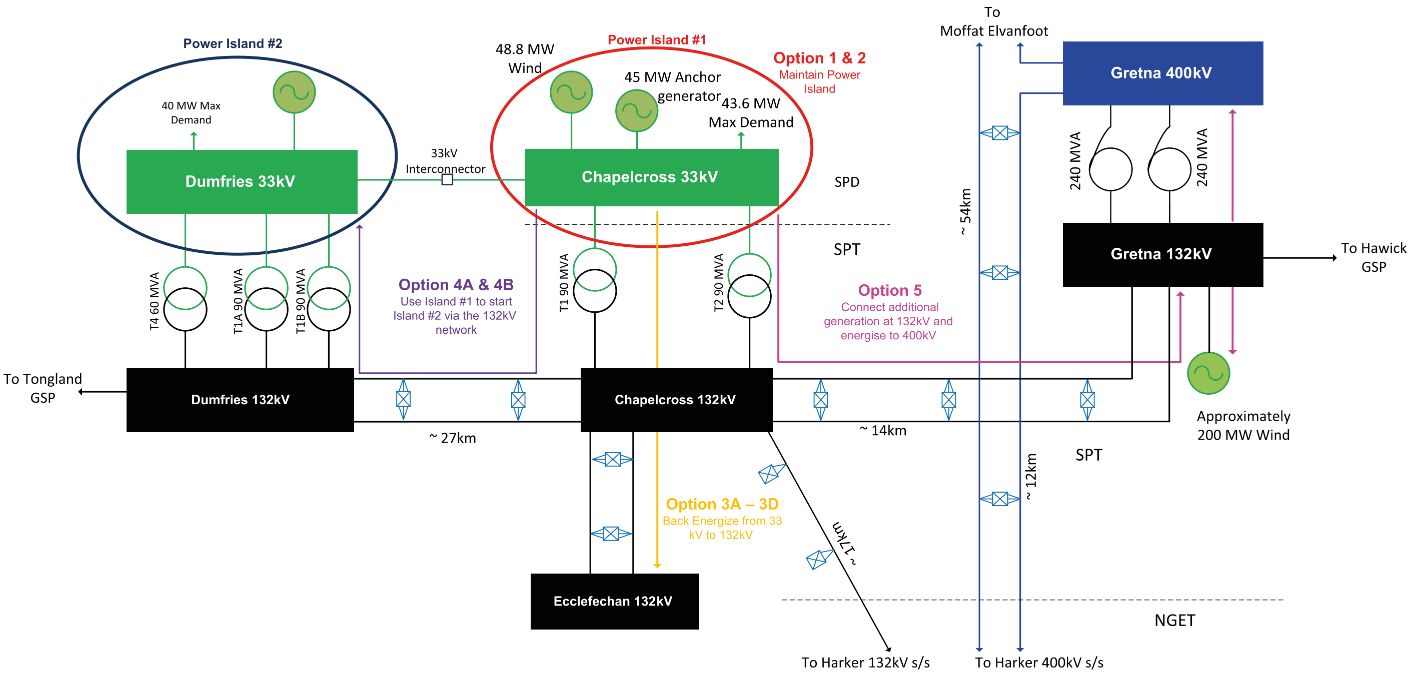
Table 4.1
Overview of the restoration strategies developed for Chapelcross GSP

Main option	Sub-option	Objective/description
1		Establishment of the Chapelcross 33kV power island or DRZ and restoration of load. Start up Steven's Croft generator. Sequential energisation of circuits to the Chapelcross GSP 33kV busbar, 33kV connected wind farms, and primary substations. The simultaneous energisation of primary substation transformers together with load (i.e. primary substation restoration options A-C & G), or sequential energisation of the transformers followed by load (options D-F) is considered.
2		Establishment of the Chapelcross 33kV DRZ and restoration of load. Start up Steven's Croft generator. Simultaneous restoration of the 33kV network to the Chapelcross GSP 33kV busbar and 33kV connected wind farms, followed by sequential restoration of demand as per option 1.
3		Establishment of the Chapelcross 33kV DRZ (network only), followed by energisation of the Chapelcross Grid T1 132/33kV transformer (with and without associated 132kV circuit), after which all the Chapelcross GSP primary substation demand is restored.
	3A	Sequential restoration of Chapelcross 33kV busbar plus Chapelcross 132kV Grid 1 Transformer including Ecclefechan 132kV line and transformer T1.
	3B	Sequential restoration of Chapelcross 33kV busbar plus Chapelcross 132kV Grid 1 Transformer excluding Ecclefechan 132kV line and transformer T1.
	3C	Simultaneous restoration of the Chapelcross 33kV busbar and Chapelcross 132/33kV Grid T1 including the banked Ecclefechan 132kV line (single phase) and associated 132/25kV National Rail transformer.
	3D	Simultaneous restoration of Chapelcross 132kV Grid T1 transformer excluding Ecclefechan 132kV line (isolator opened to unbank).

Table 4.1 continued
Overview of the restoration strategies developed for Chapelcross GSP

Main option	Sub-option	Objective/description
4		Establishment of the Chapelcross 33kV DRZ, followed by energisation of the Chapelcross 132kV substation and a 132kV circuit to Dumfries 132/33kV GSP (26.9km), and picking up some demand and DERs, before restoring demand at Chapelcross GSP.
	4A	Sequential restoration of Chapelcross 33kV busbar plus Chapelcross 132kV Grid 1 transformer including Dumfries 132/33kV Grid T4 transformer and Dumfries 33kV busbar.
	4B	Sequential restoration of Chapelcross 33kV busbar plus Chapelcross 132kV Grid 1 transformer including Dumfries 132/33kV Grid T1A and Grid T1B transformers and Dumfries 33kV busbar.
5		Establishment of the Chapelcross 33kV DRZ, followed by energisation of a 132kV line, 132/400kV transformer and 132kV wind farm, after which the Chapelcross demand is restored. Sequential restoration of Chapelcross 33kV busbar plus Chapelcross 132kV Grid T1 transformer an 132kV circuit to Gretna 132kV substation (13.5km), followed by Gretna 400/132kV SGT and a 132kV circuit to Ewe Hill 132kV wind farm.

Figure 4.1
Overview of the Chapelcross GSP restoration options



The restoration strategies listed above were the result of an iterative design process to ensure the strategies are practically executable and technically feasible from a power systems perspective. Within two of the five main restoration strategies, some sub-options were developed and evaluated to determine the optimal energisation approach in terms of simultaneous or sequential energisation of lines and transformers. Option 1 was also used to evaluate the different approaches of restoring primary substation discussed in section 2.3.

Table 4.2
Comparison between the different restoration options in terms of restoration objectives

Restoration objective	Option 1	Option 2	Option 3a	Option 3b	Option 3c	Option 3d	Option 4a	Option 4b	Option 5
Energise Chapelcross GSP 33kV busbar	✔	✔	✔	✔	✔	✔	✔	✔	✔
Energise 33kV WFs before grid transformer (GT) (132/33kV)	✔	✔	✘	✘	✘	✘	✔	✔	✔
Energise 132kV circuit (from Chapelcross)	✘	✘	✔	✔	✔	✔	✔	✔	✔
Energise Gretna super grid transformer (SGT) (400/132kV)	✘	✘	✘	✘	✘	✘	✘	✘	✔
Energise neighbouring GSP (Dumfries)	✘	✘	✔	✘	✔	✘	✔	✔	✔
Simultaneous energisation of two GTs (from HV to LV)	✘	✘	✘	✘	✔	✘	✘	✘	✘
Active power support from wind farms (WFs) (to increase demand pick up above anchor generator capability)	✔	✔	✔	✔	✔	✔	✔	✔	✔

✔ Included in option ✘ Not included in option

From the above table it can be seen that option 5 is one of the more complex restoration strategies and it is discussed in more detail in the section below as an example of one of the restoration strategies. The restoration stages for options 1, 2, 3c and 4a appear in Appendix 1: Selected Chapelcross restoration options.

4.1.2 Restoration option 5 – detailed discussion

Restoration option overview

Restoration option 5 involves the establishment of the Chapelcross 33kV DRZ, energisation to the 33kV PoC for Minsca and Ewe Hill 33kV wind farms, energisation of the Chapelcross – Gretna 132kV circuit, energisation of the Gretna 132/400kV super grid transformer (SGT), energisation of Ewe Hill 132kV wind farm (supplied from Gretna 132kV substation), and restoration of the primary substations and demand at Chapelcross GSP with the MW support of the wind farms. It's important to note that the restoration stages and steps assume that the network was switched into the agreed pre-restoration state for restoration option 5 as indicated by the breaker statuses in figure 4.2 and figure 4.3. This would be the initial network preparation and initialising stage and would involve actions such as:

- sending out Black Start initiation signals to DER
- opening/closing circuit breakers to reconfigure the network
- changing protection and control settings as required
- confirming the status of the island for Black Start (e.g. are there any critical outages that would affect the planned restoration process, abnormal system conditions etc?).

It is anticipated that the majority of the above would be carried out automatically by the distribution management system (DMS).

Restoration process

The restoration process was broken down into a number of discrete stages, each involving between one and five breaker switching operations or steps. Table 4.3 summarises the different stages of the restoration process. Each stage consists of one or more breaker switching operations or steps, and are numbered as follows <stage no>.<step no.>. So, for example stage 4, step 1, would be step 4.1. The switching steps for all 15 restoration stages are shown on the single line diagrams in figure 4.2 and figure 4.3.

Table 4.3
Restoration stages for restoration option 5

Stage	Action	Description
0	Self-start	Self-start Steven's Croft anchor generator and energise up to Steven's Croft 33kV PoC
1	Energise 33kV line	Energise the 33kV circuit from Steven's Croft generator to Chapelcross GSP
2	Energise 33kV busbar	Energise Chapelcross GSP 33kV busbars
3	WF online	Energise to Minsca wind farm 33kV PoC
4	WF online	Energise to Ewe Hill wind farm 33kV PoC
5	Energise grid transformer	Energise Chapelcross 132kV T1 grid transformer and 132kV busbar
6	Energise 132kV line, SGT, WF online	Energise Chapelcross to Gretna 132kV circuit, Gretna 132kV busbar, 400/132kV SGT1, and Gretna to Ewe Hill (132kV) wind farm 132kV circuit.
		Restoration of primary substations supplied from Chapelcross GSP as per restoration option 1 from stage 5 onwards
7	Cold load pick-up	Restoration of Annan primary substation (Using option C as in section 2.4.2)
	Energise	Energise
8	Cold load pick-up	Restoration of Middlebie primary substation (Using option A)
9	WFs produce power	First request to Minsca, Ewe Hill and Ewe Hill (132kV) WFs to provide 20% of their nominal rating active power
	Cold load pick-up	Restoration of Langholm primary substation (option A)
10	Cold load pick-up	Restoration of Gretna primary substation (option A)
11	Cold load pick-up	Restoration of Newcastleton primary substation (option A)
12	WFs produce power	Second request Minsca, Ewe Hill and Ewe Hill (132kV) WFs to ramp up to 25% active power
	Cold load pick-up	Restoration of power at Lockerbie primary substation – all feeders connected to bus section 1 (i.e. load 1) (option C)
	WFs produce power	Third request to Minsca and Ewe Hill WFs to ramp up to 45% active power
	Cold load pick-up	Restoration of Lockerbie primary substation – all feeders connected to bus section 2 (i.e. load 2) (option C)
13	Cold load pick-up	Restoration of Kirkbank/Moffat primary substation load 1 (option A)
14	Cold load pick-up	Restoration of Moffat primary substation load 2 (option C)
15	Complete restoration of the DRZ	Network could be restored to normal operating mode to improve security by closing all 11kV bus section breakers that are still open

Figure 4.2
Chapelcross restoration option 5 – restoration steps on the transmission network

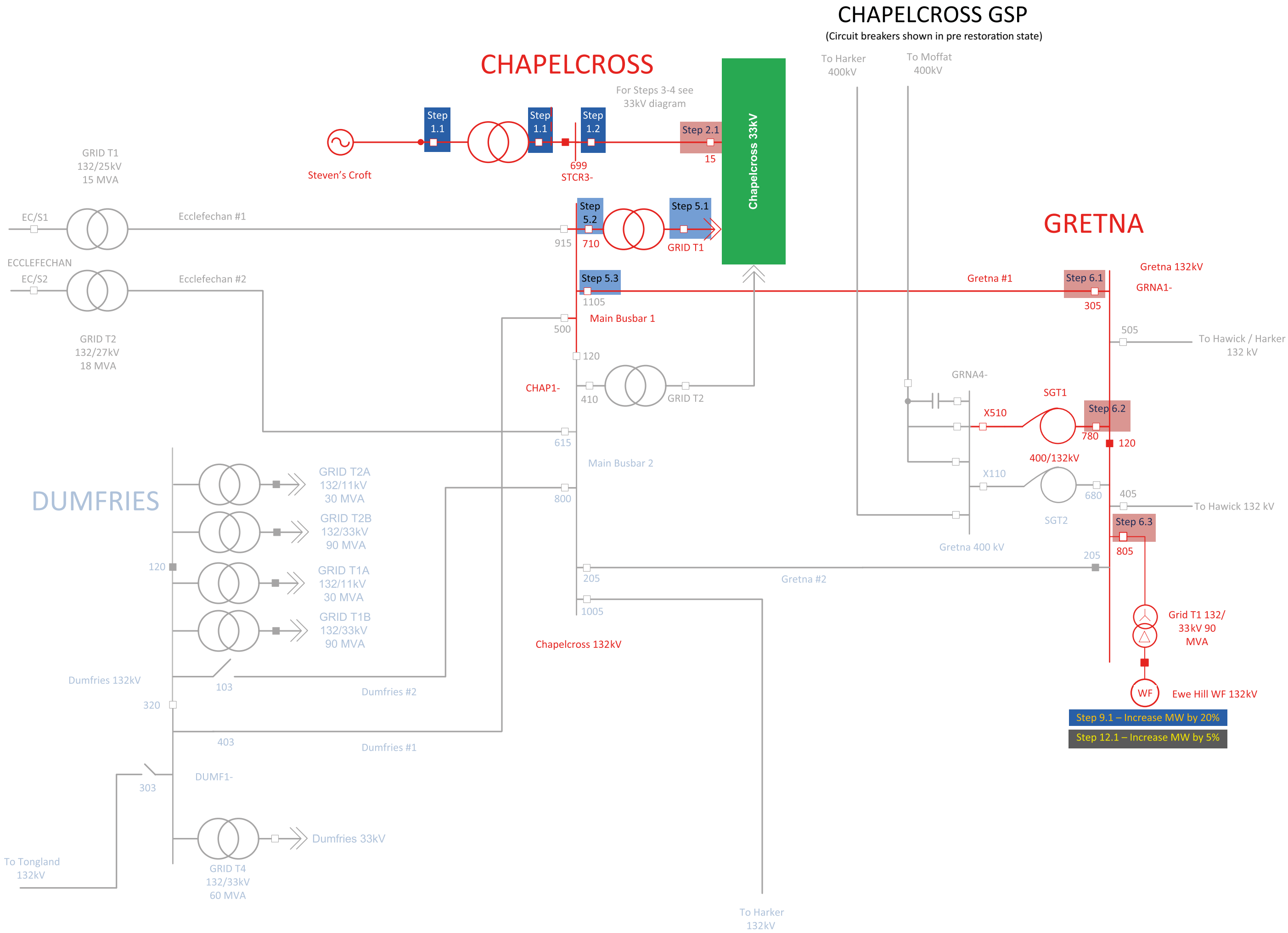
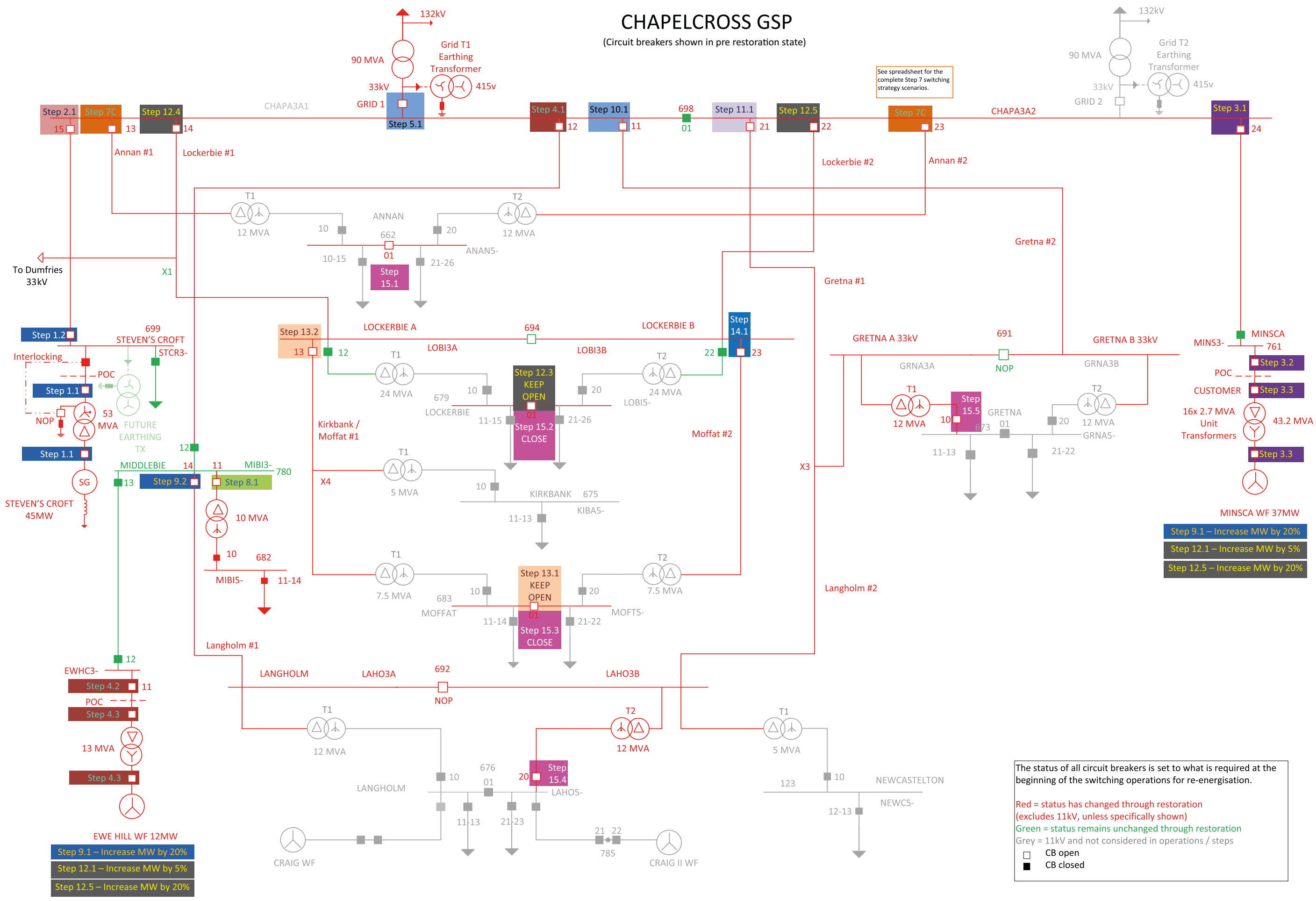


Figure 4.3
Chapelcross restoration option 5 – restoration steps on the 33kV network



4.2 Power system study results

The power system studies described in section 3.1 were performed for all five Chapelcross restoration strategies, and for each stage in each strategy using the assumptions and models covered in section 3.2 and 3.3. The studies were also performed for discrete levels of wind penetration to evaluate the viability of the different restoration strategies, and to determine the minimum level of wind generation that is needed to support the anchor generation in establishing and maintaining the DRZ. In the sections below, the results for all five restoration strategies are summarised (and not just option 5).

4.2.1 Load flow simulation results

section 3.2.1 contains a full list of the assumptions used in the load flow study, and the important ones are repeated in table 4.4 for convenience.

Table 4.4
Important assumptions for the load flow study

Component	Model	Assumptions
Anchor generator	Voltage setpoint	1pu maintained at the generator 11kV terminal. 11/33kV generator transformer fixed tap
	Load bank	10% of the MVA rating of the machine, 0.99 power factor
Wind farms	Operating mode	Voltage control, set point 1.02pu at the 33kV PoC, 3% droop
	Max active power support	50% of the installed capacity
Load	Characteristic	Constant active and reactive power type
	Demand	Maximum LTDS demand at individual primary substations
	Cold load demand (CLPU)	200% at pick up, 150% after 15 minutes, nominal value after 30 minutes
Transformer	Overload rating	150% rated for a short duration on ONAN cooling
	Tap action	OLTC for all transformers except anchor generator station transformer

A load bank is considered in the studies to take into account the minimum demand required by the anchor generator for a stable operation. This demand is 10 per cent of the anchor generator MVA rating and, therefore, the effective capability of the machine is reduced by this amount. The load bank has no role as such in the load flow studies, but it is included to keep parity with the dynamic studies where it is useful for frequency regulation purposes.

Anchor generator active and reactive power capability

Restoration option 1 consists of 13 stages as shown in Appendix 1: Selected Chapelcross restoration options. The simulation results found that the anchor generator on its own is only able to energise up to stage 6 in option 1 (Middlebie substation, please refer to Appendix 1: Selected Chapelcross restoration options) before it reaches its maximum active power operational limit. To reach stage 13 of the restoration plan and energise the whole Chapelcross 33kV GSP, at least 30 per cent of the total Chapelcross demand should be picked up by the wind farms as shown in figure 4.4. The horizontal axis gives the contribution of the wind as a per centage of the total GSP demand energised and the vertical axis on the right gives the anchor generator dispatch as a per centage of its rated MW.

So, with the wind farms supplying 30 per cent of the total demand, the GSP can be fully restored as per option 1, but the anchor generator will be operating at 91 per cent of its MW rating. To maintain a higher headroom for frequency regulation during block load pick-up, it is advisable to consider 40 per cent of wind generation support, so that the anchor generator operates at 81 per cent of its rating.

The availability of wind farm support depends on a lot of factors such as availability of wind resource, ability of the wind farm to synchronise to the network and remain connected to a weak grid etc. If the wind farms fail to provide any support during the restoration process, alternative options are:

- Delay successive substation pick up by more than 30 minutes to allow the cold load demand to settle down to the pre-blackout value, i.e. follow the delayed CLPU, rather than the normal CLPU decay profile discussed in section 3.2.1. The anchor generator would be able to pick up a couple more substations after Annan (stage 5 – option 1) and Middlebie (stage 6 – option 1) but it would still not be able to energise the whole GSP.
- Use a grid-scale battery to support the anchor generator and energise a skeleton network (not all the primary substations) up to the nearest transmission substation and wait for the restoration of the national transmission network. In this case, the battery will provide the additional MW required as the cold load decays over 30 minutes.

Figure 4.4
Required generation mix to restore the whole Chapelcross GSP (restoration stages as per option 1)

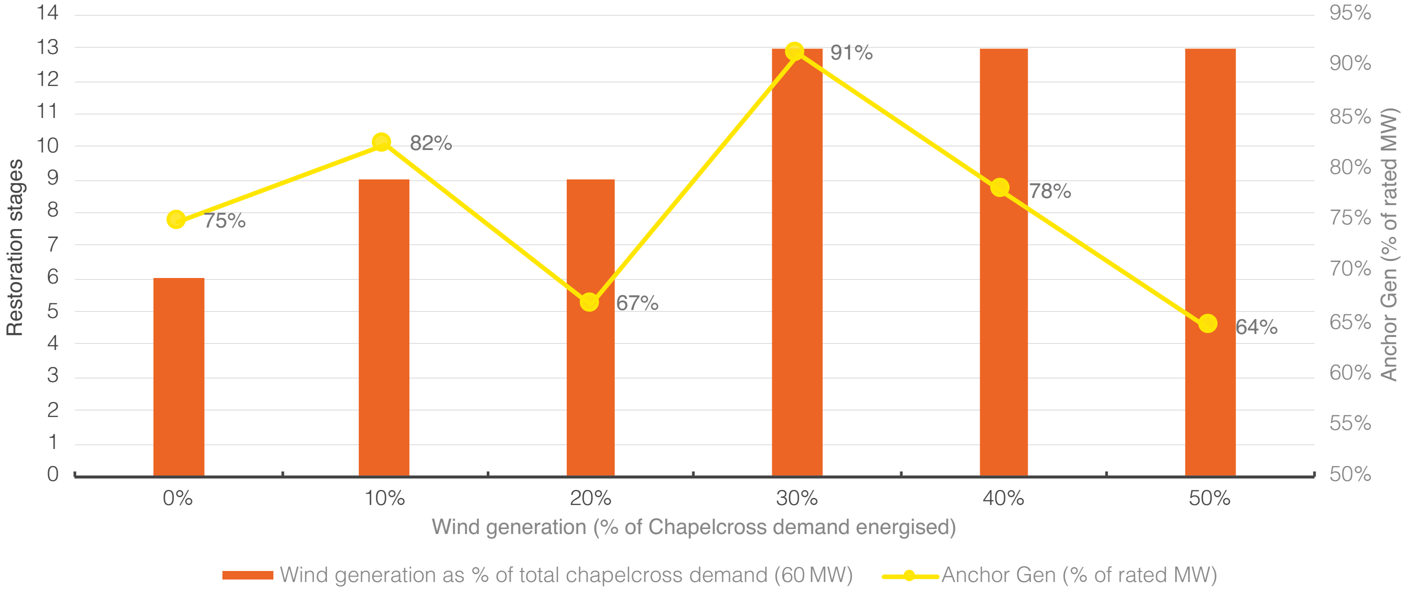
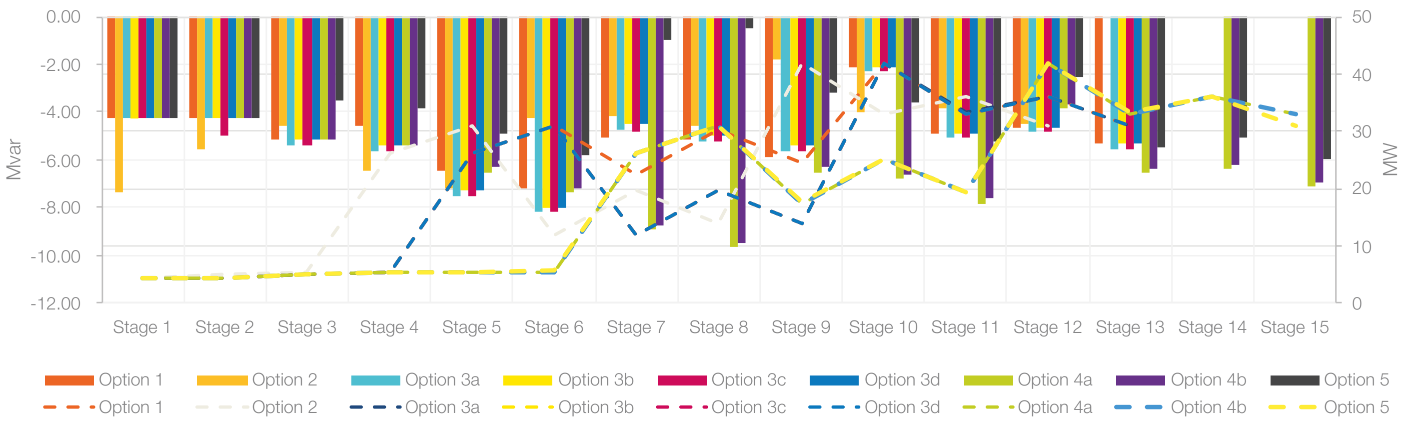


Figure 4.5 compares the active (MW) and reactive power (Mvar) output of the anchor generator across all the options. The solid bars indicate the Mvar output and the dotted lines show the MW output. Options 4a and 4b require the anchor generator to absorb the maximum reactive power of around -10Mvar. This is, however, well within the capability of the generator. The first increase in MW output of the anchor generator differs across all the options as the stage in which the first substation is picked up. So, for example in option 2 the first substation, Annan, is picked up in stage 3, whereas in option 3a, Annan is picked up in stage 4.

Figure 4.5
Anchor generator active and reactive power output at every stage across all restoration options



Transmission interface point MW and Mvar capability

The interface capability study is repeated for two locations in the network, one at the 33kV breaker of the Chapelcross GT and the other at the Gretna SGT 132kV circuit breaker, to make the case study more relevant to the situation in England where 132kV is part of the distribution network. To quantify the amount of MW the anchor generator can provide and Mvar it can absorb at the transmission-distribution (T-D) interface point (IP), a voltage versus active and reactive power sensitivity study was done at the two interface points. Figure 4.6 and figure 4.7 are for the IP at Gretna 132kV breaker. The results for the 33kV IP are summarised in table 4.5.

Figure 4.6 shows the P-V curve for two scenarios, namely when there is (a) no Mvar support from the wind farms, and (b) when both Minsca and Ewe Hill provides Mvar support. The wind farms provide no MW support at any stage. Also, no primary substations have been energised so this study is under no load condition.

The MW demand at the T-D IP is increased gradually until the anchor generator reaches its MW or Mvar capability limit and the corresponding voltages are recorded at the generator LV terminal and the IPs. Steven's Croft generator maintains its terminal voltage tightly at 1pu. As the active power export increases, the voltage drops at the IP; it is assumed there is no voltage control action from the SGT or any other transmission connected sources. Figure 4.6 therefore indicates the amount of MW support the anchor generator can provide to the transmission network. As shown, a 33 MW export would cause the voltage at Gretna 132kV to drop down to 0.92pu. However, if the wind farms provide Mvar support, then the same 33 MW export can be achieved at a voltage closer to the nominal value (0.97pu).

Figure 4.7 presents similar results but for Mvar import at the T-D IP. Two scenarios have been studied, with and without wind farm reactive power support. No primary substations are energised i.e. the anchor generator is under no load condition (except a load bank to maintain minimum stable response). As the Mvar exchanged at the IP increases, the voltage goes up assuming there is no tap action from the Gretna SGT or Mvar support from any other transmission connected sources. A 22Mvar imported at the IP would increase the voltage to 1.14pu. However, with support from the wind farms, this same import can be achieved at 1.1pu. Even though the anchor generator has available capacity, it cannot be used fully because the voltage at Gretna 132kV will increase beyond 1.1pu. So, the voltage profile will most likely be the binding constraint for the IP capability. Figure 4.7 also shows that the total Mvar that can be imported at the T-D IP increases from 26Mvar to 48Mvar with contribution from the wind farms, neglecting the rise in voltage. These limits are based on the assumptions mentioned in section 3.2.1.

Figure 4.6
Available MW at the transmission-distribution interface point – no load

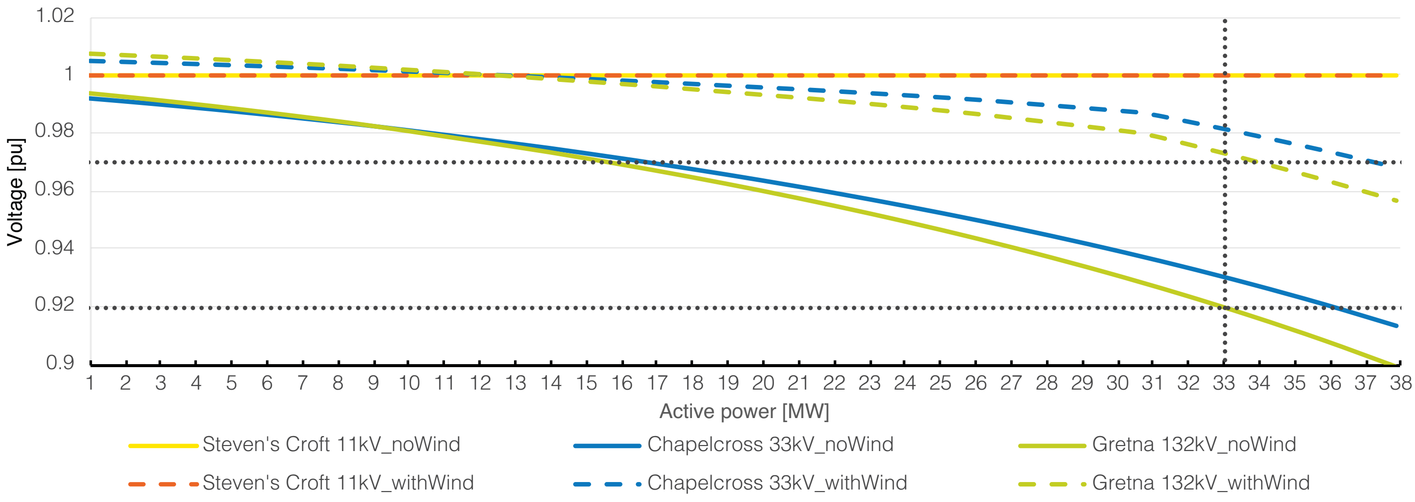
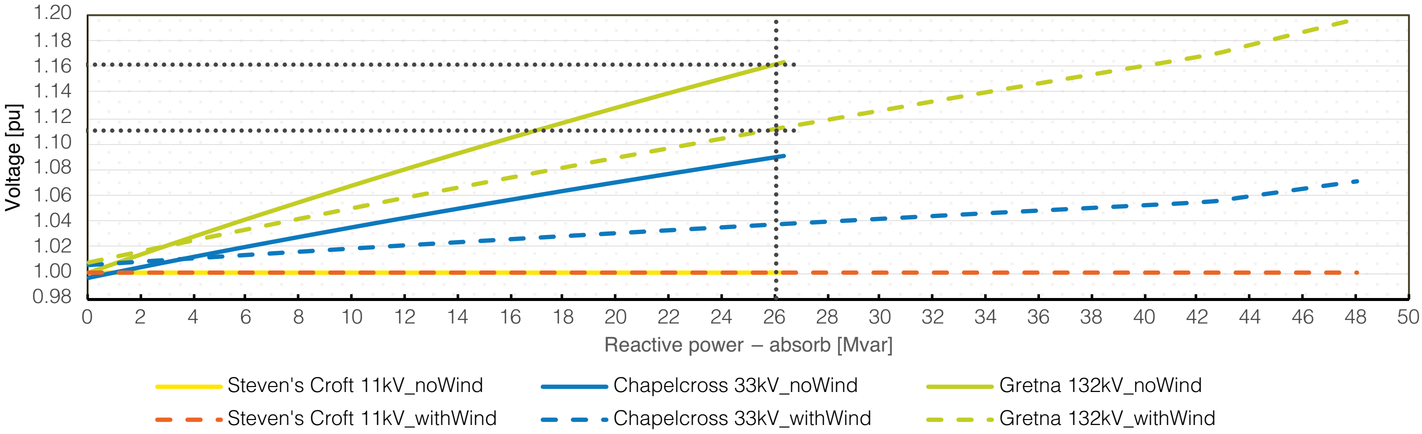


Figure 4.7
Available Mvar at the transmission-distribution interface point – no load



A similar study as above is repeated at the Chapelcross GSP 33kV breaker for a few different scenarios. Table 4.5 and table 4.6 summarise the maximum MW and Mvar exchange possible at the Chapelcross GT 33kV breaker for a few different scenarios depending on the type of support from other DERs.

The MW and Mvar capabilities at the IP are calculated independent of each other i.e. in table 4.5 when 30.5 MW export is calculated, no Mvar import has been considered. This is because in reality either of the two support will be required during restoration. If both MW and Mvar are exchanged at the same time, then the capability will be slightly different. As an example, for Scenario 1 in table 4.5 and table 4.6, the values will be 29.8 MW and 18.8Mvar when both are exchanged at the same time.

Table 4.5
Maximum active power export capability at the Chapelcross 33kV T-D interface point

No	Scenario	GSP demand	Minsca WF	Ewe Hill WF	Transmission entry point
		MW	MW	MW	MW (export)
1	No load connected, no DERs, only anchor generator	NA	NA	NA	30.5
2	No load connected; anchor generator supported by DER – only Mvar support from Minsca WF	NA	NA	NA	30.5
3	No load connected, anchor generator supported by DER – only Mvar support from Minsca and Ewe Hill WF	NA	NA	NA	30.5
4	Anchor generator supplying Annan and Middlebie demand (max it can without support), no MW and Mvar support from DERs	30	NA	NA	5.4
5	Anchor generator supplying demand of all the substations with MW and Mvar support from Minsca and Ewe Hill (40% MW support)	53	20	5	4.85

Table 4.6
Maximum reactive power import capability at the Chapelcross 33kV T-D interface point

No	Scenario	GSP demand	Minsca WF	Ewe Hill WF	Transmission entry point
		MW	Mvar	Mvar	Mvar (import)
1	No load connected, no DERs, only anchor gen	NA	NA	NA	14.5
2	No load connected; anchor gen supported by DER – only Mvar support from Minsca	NA	-10.49	NA	26
3	No load connected, anchor gen supported by DER – only Mvar support from Minsca and Ewe Hill	NA	-10.49	-3.94	30.7
4	Anchor gen meeting Annan and Middlebie demand (max it can without support), no MW and Mvar support from DERs	30	NA	NA	19
5	Anchor gen meeting Annan and Middlebie demand (max it can without support), only Mvar support from DERs – both Minsca and Ewe Hill	30	-2.20	0.81	21.5
6	Anchor gen meeting demand of all the substations with MW and Mvar support from Minsca and Ewe Hill (40% MW support)	53	-10.49	-3.94	36

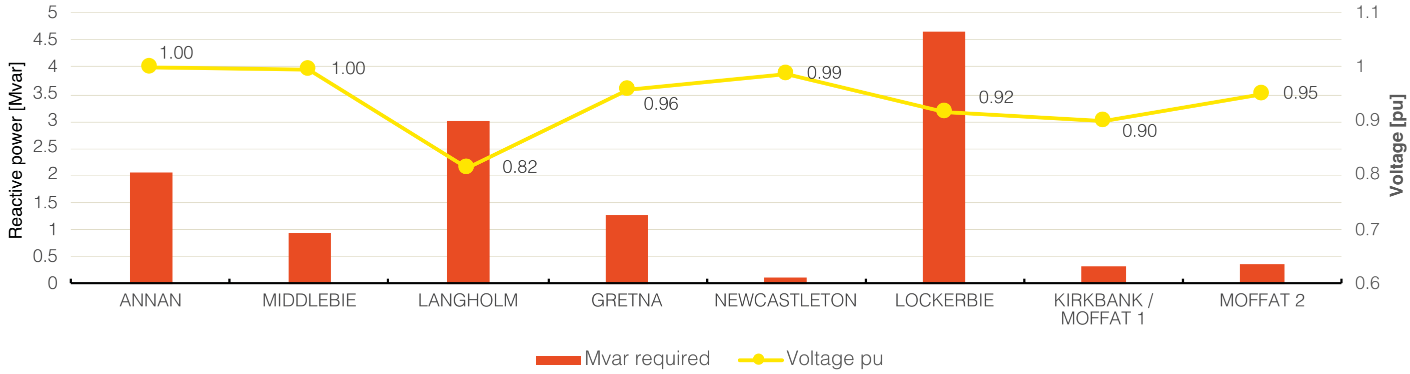
Network loading

Across all the restoration options, no thermal violations occur except for the Chapelcross – Middlebie and Middlebie – Langholm 33kV circuits. The Chapelcross – Middlebie circuit rating is around 20MVA which is less than the combined Middlebie and Langholm firm transformer capacity. So, the circuit rating is the limiting factor and the utilisation exceeds the 33kV cable rating by around 15 per cent for Chapelcross – Middlebie and 45 per cent for Middlebie – Langholm when picking up the 12.66 MW cold load at Langholm primary substation.

Network voltage

For a constant voltage control by the anchor generator and the wind farms as mentioned in table 4.7, the 33kV voltage at Langholm A goes below 0.90pu when picking up the cold load at the substation. This occurs during all five of the restoration options. Figure 4.8 shows the reactive requirement just for option 1 at every primary substation when the respective cold load is picked up, as well as the corresponding 33kV voltage. Both Annan and Lockerbie primaries are electrically close to the Chapelcross 33kV substation and therefore no steady state voltage issues are observed. Langholm primary, on the other hand, is connected by a 16.9km overhead line to the Middlebie primary with a limited reactive support from Ewe Hill wind farm due to its small rating. Ewe Hill is found to hit its maximum reactive limit of 3.94MVAr for majority of the options and hence no further voltage support is available at Middlebie 33kV. Therefore, this part of the network is found to be the weakest in the Chapelcross GSP.

Figure 4.8
Reactive power requirement at primary substations when they are picked up at respective restoration stages in option 1



In options 1 to 4 the 33kV low voltage issue doesn't cause the Middlbie and Langholm substation voltages at the 11kV side to go below 0.9pu. However, in option 5, an 11kV low voltage violation is also observed which can be addressed either by providing local reactive power support, or by energising the transformer on no load, and then restoring the 11kV feeders individually (restoration option G in section 2.4.1).

Key findings

They key findings are:

- Steven's Croft anchor generator on its own, i.e. without any wind farm support (both MW and Mvar), can only restore the demand of the DRZ partially up to stage 9 (Middlebie substation, refer to figure 4.3) before it reaches its maximum active power operational limit.
- However, Steven's Croft anchor generator, supported by Minsca and Ewe Hill wind farms generating at least 30 per cent of the GSP demand, can restore the whole GSP and meet the maximum cold load demand.
- The Chapelcross – Middlebie and Middlebie – Langholm 33kV circuits experience thermal overloads when picking up cold loads at the Langholm primary substation (Middlebie is already picked up in a prior stage). The overloads dissipate when the block loads decay from cold state to normal state. This can be avoided by splitting the total substation demand into blocks of two and picking them up with a delay of 15 minutes (e.g. changing the primary substation energisation strategy from option A to option D or C). (An alternative option could have been to energise Langholm primary via Gretna primary, but this option was not studied further).
- Restoration options 1 to 4 don't result in any 11kV voltage violations greater than 10 per cent, but option 5 does cause a low voltage more than 10 per cent at Langholm primary, which could be mitigated by changing the primary substation energisation strategy from option A to D.

Although the nine different restoration strategies explore slightly different parts of the network, they can be compared using certain success criteria shown in table 4.7. Options 1 and 2 only energise the Chapelcross GSP 33kV network and option 2 meets most of the success criteria. Options 3 to 5 energise the transmission network and, of these, option 3 (all the sub-options) stands out to be the most favourable as it meets the most criteria.

Table 4.7
Chapelcross load flow restoration success criteria during all options

Restoration success criteria – load flow	Option 1	Option 2	Option 3a	Option 3b	Option 3c	Option 3d	Option 4a	Option 4b	Option 5
Restore using anchor generator only*	✔ (partial)	✔ (partial)	✔ (partial)	✔ (partial)	✔ (partial)	✔ (partial)	✔ (partial)	✔ (partial)	✔ (partial)
Restore using anchor generator and WFs	✔	✔	✔	✔	✔	✔	✔	✔	✔
Minsca WF operating within reactive limits (both leading & lagging)	✔	✔	✔	✔	✔	✔	✔	✔	✔
Ewe Hill WF operating within reactive limit (both leading & lagging)	✘	✔	✘	✘	✘	✘	✘	✘	✘
Q burden on anchor gen below 15% of the machine MVA rating	✔	✔	✔	✔	✔	✔	✘	✘	✔
No thermal violations** over the whole restoration process	✘	✘	✘	✘	✘	✘	✘	✘	✘
No voltage violations (±10%) at 33kV ** over the whole restoration process	✘	✘	✘	✘	✘	✘	✘	✘	✘
No voltage violations (±10%) at 11kV ** over the whole restoration process	✔	✔	✔	✔	✔	✔	✔	✔	✘

✔ Fully achieved ✔ Partially achieved ✘ Not achieved

* restoration possible only up to stage 8 i.e. Annan and Middlebie substations
** including same circuits/busbars at different stages

4.2.2 Dynamic simulation results

Dynamic simulations were carried out for all the system restoration options and cover the voltage and frequency response of the system for events such as energisation of the cables, overhead lines, transformers and block load pick-up at primary substations. The energisation of the transformers does not consider the detailed saturation model and remnant flux which is studied separately as part of the EMT studies. The focus was on the following:

- Voltage and frequency response at key substation busbars including the time of energisation.
- Block load pick-up (BLPU) at every primary substation, including the decay of the cold block load from a maximum of two times to a pre-blackout demand level in three stages (section 3.2).
- Anchor generator response including terminal voltage and frequency, Rate of Change of Frequency (RoCoF), MW and Mvar outputs, mechanical torque output, generator field voltage, and generator speed.
- Minsca and Ewe Hill wind farm response including equivalent wind turbine generator (WTG) terminal voltage, MW and Mvar output, active power reference setpoints, and the times at which the active power reference settings are changed.
- Boiler response of the Steven's Croft biomass generator, including the designed set point for the steam turbine, turbine load reference, and throttle steam pressure to the turbine.

Please refer to section 3.2 for a full list of assumptions used in the dynamic studies. The assumptions are consistent across all the options, the important ones are repeated in table 4.8 for the reader's reference.

Table 4.8
Important assumptions for the dynamic studies

Component	Model	Assumptions
Anchor generator	AVR setpoint	1pu maintained at the generator terminal
	Min boiler setpoint	10% of the machine MVA rating
	Governor mode	Isochronous mode i.e. frequency always comes back to 50Hz
	Turbine, Boiler	Four stage turbine, drum type boiler
	Load bank	10% of the MVA rating of the machine
Wind farms	Operating mode	Voltage control, 1.02pu at the PoC (3% droop)
	Max active power support	45% of the installed capacity
	Active power ramp rate	5% of the installed capacity
	Protection settings	Under/over voltage, under/over frequency and RoCoF
Load	Characteristic	Constant active and reactive power type
	Demand	Maximum LTDS demand at individual primary substations
	Cold load demand	200% at pick-up, 150% after 15 minutes, nominal value after 30 minutes
Transformer	Overload rating	150% rated for a short duration on ONAN cooling

Anchor generator BLPU capability

For all the restoration options, Steven's Croft anchor generator is able to maintain a stable voltage and frequency response of the system up to the point when Annan and Middlebie substation load is picked up. The anchor generator is not able to pick up any further substations after Middlebie due to insufficient primary reserve for frequency regulation. This means the BLPU capability of the anchor generator is not sufficient enough to pick up the cold loads. For further energisation of the network it needs support from Minsca and Ewe Hill wind farms to ensure that the voltage and frequency excursions remain within acceptable limits. Table 4.9 summarises which substations can be restored by the anchor generator with and without wind farm support.

Table 4.9
List of substations/lines that can be energised with/without wind farm support

Action	Substations restored
Restore using anchor generator only – all options	• Block load pick-up at Annan, Middlebie (All options) • Energise Chapelcross 132/33kV GT1 (options 3,4,5) • Ecclefechan 132kV overhead line (option 3) • Chapelcross to Dumfries 132kV circuit, Dumfries 132/33kV GT1 (option 4) • Gretna 400/132kV SGT (option 5)
Restore using anchor generator + WFs – all options	• Block load pick-up at Annan, Middlebie, Langholm, Gretna, Newcastleton, Lockerbie, Kirkbank, Moffat (All options) • Energise Chapelcross 132/33kV GT1 (options 3,4,5) • Ecclefechan 132kV overhead line (option 3) • Chapelcross to Dumfries 132kV circuit, Dumfries 132/33kV GT1 (option 4) • Gretna 400/132kV SGT (option 5)
Type of support from wind farms used	• Active power support to offset cold load value of demand and improve block load pick-up capability of the anchor generator • Dynamic voltage support, steady state reactive power support

Figure 4.9 shows the active power output of the anchor generator for all the options for the full restoration of the island. The restoration stages (table 4.3) are marked on the figure for ease of interpreting the results. The highest dispatch for the anchor generator is achieved in stage 11 when picking up Kirkbank and part of Moffat substation cold load demands. The dispatch remains within 45 MW in all the options; however, the operational reserve is different across the options as shown.

After the full restoration of the island, the anchor generator operates at around 35 MW which gives a comfortable 10 MW operational reserve for load variations and any disturbances. In option 3C, however, the anchor generator operates at the active power limit of 45 MW for a few seconds before the drop in the cold load and finally settles down to around 40 MW at the end of the restoration process.

In option 5 additional active power support is received from the transmission connected (132kV) Ewe Hill wind farm which supplements the support from the two 33kV wind farms (Minsca and Ewe Hill). The increased MW wind contribution reduces the burden on the anchor generator as shown.

The AVR of the anchor generator responds fairly quickly to any changes at its terminal voltage and modifies the field excitation accordingly to maintain it at 1.0 per unit. The terminal voltage transient excursions are within a band of 1.025pu and 0.95pu during the whole restoration process as shown in figure 4.10. The occasional spikes are due to the stiffness of the system because of the constant power characteristic of the cold load. This simulates an extreme condition and in reality, the customer demand at the primaries will exhibit a certain voltage dependency. Additional voltage support provided by Ewe Hill wind farm (transmission) improves the voltage excursions in option 5.

Figure 4.9
Anchor generator active power response

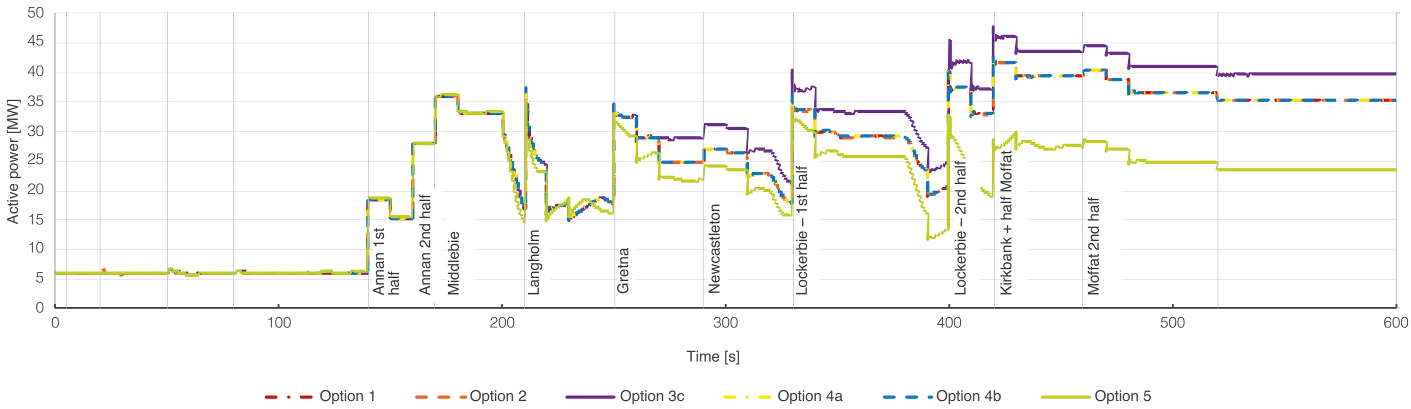
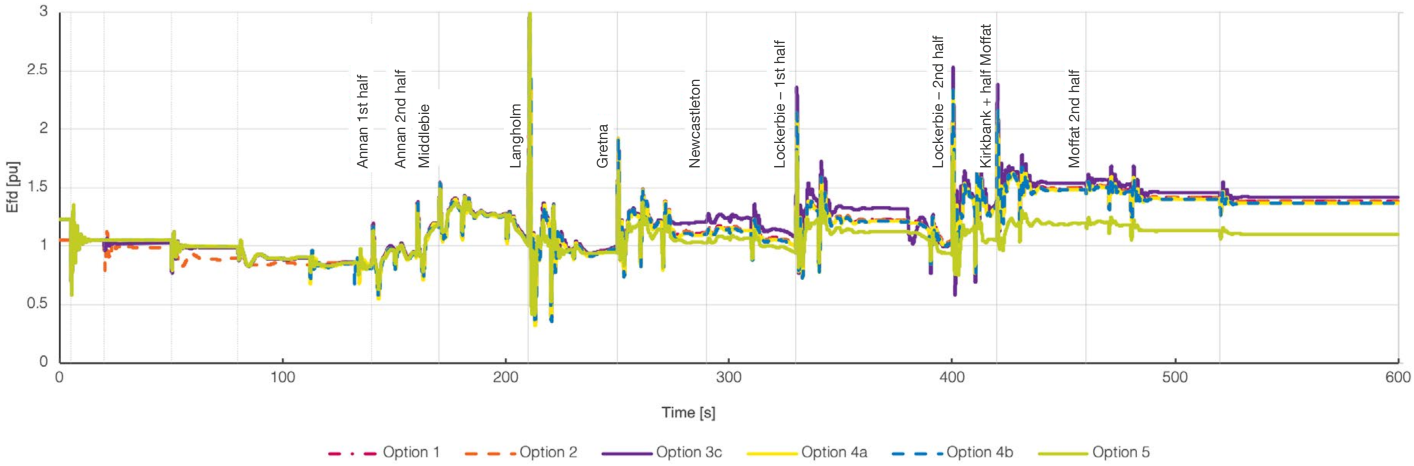


Figure 4.10
Anchor generator AVR response



Wind farm response

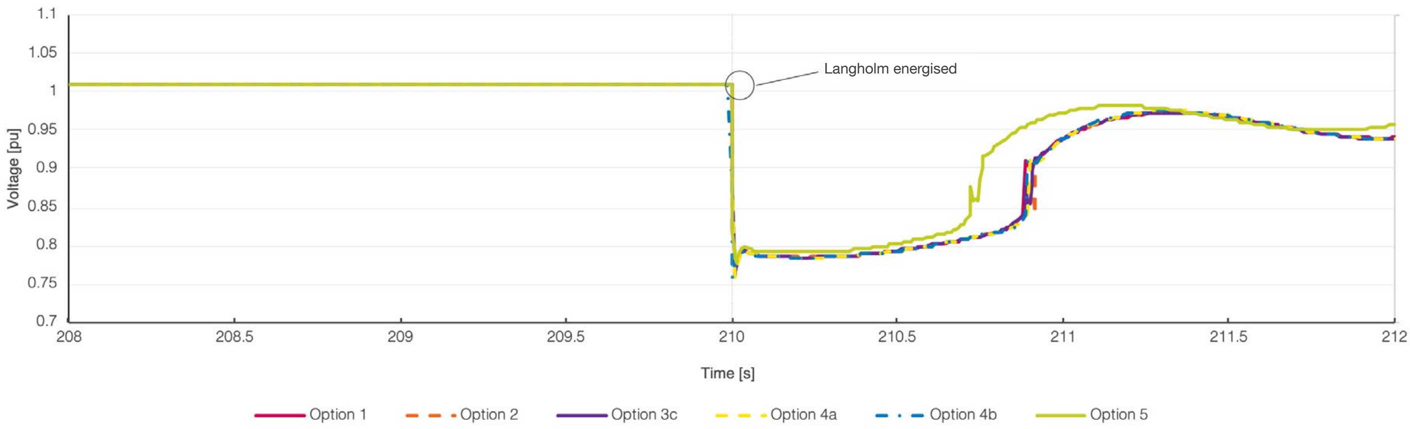
Minsca and Ewe Hill wind farms play an important role in the restoration of the network as mentioned in table 4.9. Minsca wind farm is able to maintain the voltage at the reference value in all the options and provides satisfactory dynamic support in every stage of the restoration process. Ewe Hill wind farm, being the smaller of the two, and located at a weaker part of the network (Middlebie substation), is limited by its maximum reactive power export limit during all of the restoration options.

In order to reduce any power mismatch during the restoration process and to free up more generation capacity from the anchor generator to pick up block loads (and hence increase the spinning reserve), the two wind farms need to increase their MW output in stages with a maximum export limited to 45 per cent of the installed capacity. An active power ramp rate of 5 per cent is considered for both the wind farms i.e. the moment they receive an active power dispatch signal from the network operator, the wind farms start ramping up their power output at the PoC at a rate of 0.05pu/second until the required dispatch is achieved. With this ramp rate, no power oscillations or any other disturbance were observed and the wind farms performed satisfactorily in all the options.

Network voltage response

Voltage response during the restoration process and after the whole DRZ has been restored is acceptable at all primary substation busbars, except at Middlebie and Langholm 11kV busbars. Immediately after picking up the maximum cold block load at Langholm substation at stage 7 (table 4.3), Langholm 11kV busbar experiences a low voltage excursion. The impact of this is also observed at the neighbouring Middlebie substation 200 seconds into the simulation as shown in figure 4.11. Continuous voltage below 0.80pu lasts for 0.5 second and below 0.85pu for another 0.5 second. Transformer tap action at the primaries will not be able to assist here as the fastest tap action will have a 15 seconds delay from the tap change relay and the mechanism to operate. The low voltage excursion is likely to prevent a successful restoration of supply to full block loads at Langholm. A solution is to deviate from one of the standard primary substation restoration strategies discussed in section 2.4.1 and split the Langholm 11kV busbars into two sections and pick up only half of the total cold load at stage 7, and pick up the remaining half in stage 9, together with the full BLPU up at Newcastleton substation.

Figure 4.11
Voltage excursion at Middlebie substation (11kV busbar) when picking up cold load at Langholm

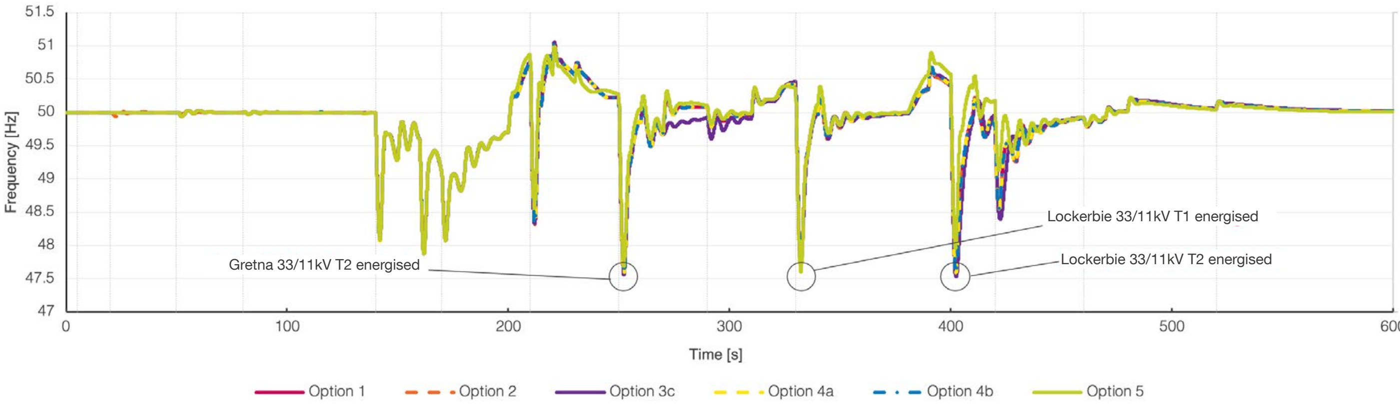


Network frequency response

Frequency excursions are due to power mismatches between generation and demand in the system. To keep the frequency within acceptable limits, the substation demands has been divided into smaller chunks and DERs are requested to provide MW support in addition to the anchor generator.

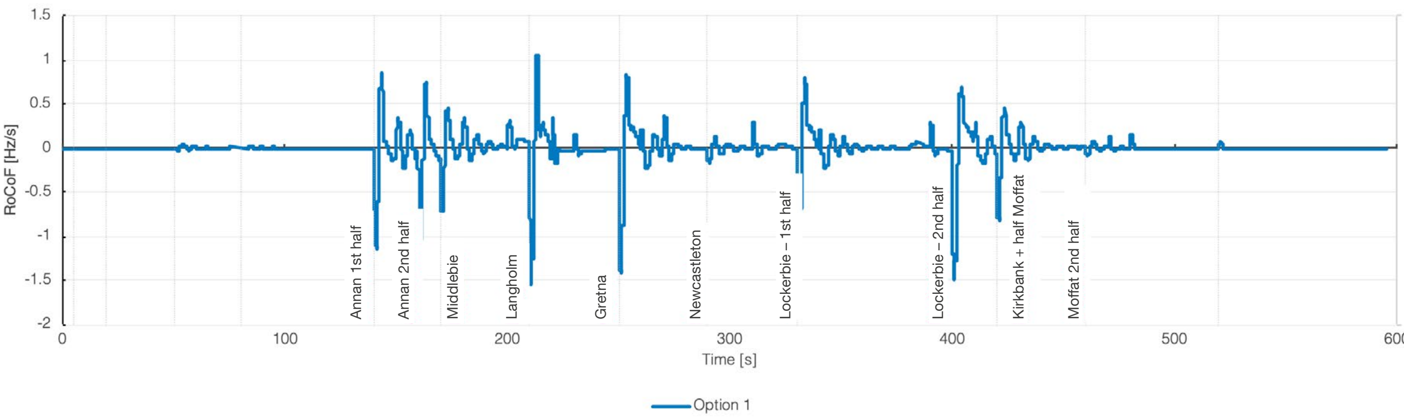
The frequency response of the system is within the acceptable threshold of 47.5 – 51Hz for all stages across all options, provided Minsca and Ewe Hill wind farms provide MW support from stage 8 onwards. A minimum frequency of 47.57 Hz is observed on three occasions; when picking up the demand on transformer T2 in Gretna, and when picking up the split loads on transformer T1 and T2 in Lockerbie (refer to table 4.3 for the restoration stages). Figure 4.12 shows that the frequency nadir is almost identical for these three cold load pick-ups across all the options, except option 5 where the response is slightly better as the share of demand picked up by the anchor generator is less (figure 4.9) due to the additional contribution from the transmission connected wind farm.

Figure 4.12
Frequency response of the system for all restoration options



The RoCoF during the restoration process is fairly high compared to the RoCoF value usually observed in a large system and is close to the present relay settings of 1Hz/s. This is expected as the inertia in the network is only provided by the anchor generator. There is no inertial contribution from the wind farms as they are considered to be type 4 (full converter interfaced turbines), and it is assumed they don't provide fast frequency response (FFR) service in the inertial timeframe. There is no contribution to the effective inertia from the demand as it's considered to have a constant power characteristic. A 500ms moving average window is used to calculate the RoCoF in figure 4.13. Across all the restoration options, the maximum and minimum RoCoF values observed were around 1 Hz/s and -1.55 Hz/s respectively which should not be a concern for the anchor generator and the other DERs, as the RoCoF based protection will be disabled during the restoration process.

Figure 4.13
Rate of Change of Frequency (RoCoF) of the system for restoration option 1



Key findings

- There are no network loading, voltage (steady state and dynamic) and frequency issues associated with energising parts of the transmission network such as Chapelcross 132/33kV GT1, Ecclefechan 132kV overhead line, Chapelcross to Dumfries 132kV circuit, Dumfries 132/33kV GT1, or Gretna 400/132kV SGT across the different restoration options. Steven's Croft anchor generator is capable of absorbing the charging power from the energised 132kV network without any additional DER support.
- Voltage response is acceptable for all events in the system restoration except when cold block load is picked up at Langholm substation. In all options, Langholm 11kV and Middlebie 11kV busbars experience a voltage excursion below 0.8pu for 0.5sec which is below the statutory limit of 0.9pu. Both the wind farms provide reactive power support especially Ewe Hill which is connected at the Middlebie substation and is found to operate at its maximum reactive limit. Three potential solutions could be adopted in addition to the reactive power support provided by the wind farms and the anchor generator.
  - Split the total cold load demand at Langholm by opening the bus section and energising the substation in two stages (i.e. option D).
  - Changing the tap position of the Langholm primary transformer in advance of energising the substation. If arrangements cannot be made for backup power supply to move the tap changer then it has to be changed manually.
  - Install a BESS at Langholm or Middlebie substation to provide dynamic voltage support.
- The frequency response of the system is acceptable for all events across all the restoration options. A minimum frequency nadir of 47.57 Hz is observed with a RoCoF boundary of 1 Hz/s and -1.55 Hz/s. The RoCoF value is higher than the present RoCoF relay setting of 1Hz/s. To avoid any unwanted tripping, all the 33kV connected DERs should have their RoCoF protection disabled during the restoration process. For 11kV connected DERs the RoCoF setting should be modified to ride-through higher values. If this is not achievable then measures should be taken to increase the effective inertia of the network and restrict system RoCoF within 1Hz/s. Potential measures could be to use a FFR service provider like a battery to emulate inertia or use an emerging technology like a carbon fibre flywheel.
- The anchor generator on its own can energise the 132kV networks which are part of the five options (table 4.1) and pick up the cold block load at Annan and Middlebie substations, but it is unable to restore all the demand in the DRZ. To enhance the anchor generator's BLPU capability and energise the whole island, DERs such as wind farms, solar PV, BESS etc. can be used. Minsca and Ewe Hill wind farms can be used for this purpose by providing both MW and Mvar support to the anchor generator in maintaining an acceptable voltage and frequency response throughout the restoration process. To increase the BLPU capability, the active power reference change to the wind farms should be provided a few minutes before the actual cold load pick-up. This is essential to momentarily increase the speed of the anchor generator to achieve a higher effective inertia and also to reduce the active power burden on the machine so that it improves the block load pick-up capability. A DRZ controller will need to coordinate this to maintain an acceptable dynamic response of the system during the restoration process.
- The dynamic studies affirm that the restoration of the Chapelcross GSP using Steven's Croft as the anchor generator is a viable option and it can be achieved through five different strategies with slightly different objectives. However, an important precondition for the success of all the five options is the minimum 45 per cent wind energy contribution from the two wind farms – table 4.10. Their contribution is necessary to meet the maximum demand of the GSP, which is more than the MW limit of the anchor generator, and also to increase the BLPU capability to meet the cold load demand characteristic and keep the frequency nadir within 47.5Hz. Without any support from wind farms or any other sources, the only other option is to delay successive primary substation pick up by more than 30 minutes to allow the cold load demand to decay completely before the next substation is energised. Using this approach, the anchor generator will be able to pick up a few more substations after Middlebie, however, it will still not be able to energise the whole island.
- Table 4.10 compares the dynamic study outcomes for the five different restoration options.

Table 4.10
Restoration success criteria based on dynamic studies

Restoration success criteria – dynamic studies	Option 1	Option 2	Option 3a	Option 3c	Option 4a	Option 4b	Option 5
Restore using anchor generator only	✔	✔	✔	✔	✔	✔	✔
Restore using anchor generator + WFs (active power support in stages – total of 45%, WFs in voltage control mode)	✔	✔	✔	✔	✔	✔	✔
Anchor generator maximum active power dispatch (with WF support) – less than 90% of operational limit	✔	✔	✔	✘	✔	✔	✔
Anchor generator operating reserve at the end of the restoration (with WF support) – more than 40%	✘	✘	✘	✘	✘	✘	✔
Anchor generator reactive power burden at the end of the restoration (with WF support) – less than 20%	✔	✔	✔	✘	✔	✔	✔
Frequency excursion within acceptable limits of 51Hz and 47.5Hz (with WF support)	✔	✔	✔	✔	✔	✔	✔
RoCoF within acceptable limits	✔	✔	✔	✔	✔	✔	✔
Voltage excursion within acceptable limits of 1.1pu and 0.9pu (with WF support)	✔	✔	✔	✔	✔	✔	✔

✔ Fully achieved ✔ Conditionally achieved
✘ Not achieved

4.2.3 EMT simulation results

The EMT simulation studies considered all the restoration events which are part of options 1 to 5, such as the energisation of all the wind turbine transformers, primary substation 33/11kV transformers, 132/33kV GTs, 400/132kV SGT and circuits (both overhead lines and cables). The EMT studies were done without customer demand to determine if there are any transient issues due to energisation. Any issues identified would still persist even if customers are connected. The studies did not specifically evaluate potential transients at HV and LV level.

Around 20 energisation and switching events were modelled in each option to study the inrush effect on the substation voltages. The RMS voltage step changes observed at Steven’s Croft 11kV busbar and Chapelcross 33kV busbar for key energisation and switching events are shown in table 4.11.

Table 4.11
Voltage dip (%) from energisation studies

Restoration energisation events	Trfr rating	Steven's Croft kV (%ΔV)					Chapelcross 33kV (%ΔV)				
	MVA	Option 1&2	Option 3c	Option 4a	Option 4b	Option 5	Option 1&2	Option 3c	Option 4a	Option 4b	Option 5
Steven's Croft step-up transformer	53	-23%	-23%	-23%	-23%	-23%	N/A	N/A	N/A	N/A	N/A
STCR3 – CHAPA3A1		8.58%	8.47%	8.69%	6.97%	7.50%	N/A	N/A	N/A	N/A	N/A
Chapelcross GT1	90	N/A	-8.97%	-8.83%	-8.88%	-8.79%	N/A	-17.25%	-17.35%	-17.25%	-17.16%
Ecclefechan 132kV circuit		N/A	0.50%	N/A	N/A	N/A	N/A	1.18%	N/A	N/A	N/A
Ecclefechan Tx (132kV)	15	N/A	-3.10%	N/A	N/A	N/A	N/A	-5.79%	N/A	N/A	N/A
Dumfries 132kV #1 (Chap end)		N/A	N/A	0.30%	1.00%	N/A	N/A	N/A	0.39%	1.97%	N/A
Dumfries GT4	90	N/A	N/A	-8.19%	N/A	N/A	N/A	N/A	-17.53%	N/A	N/A
Dumfries GT1A and GT1B	90+30	N/A	N/A	N/A	-10.00%	N/A	N/A	N/A	N/A	-20.10%	N/A
Gretna #1 132kV (Chap end)		N/A	N/A	N/A	N/A	0.50%	N/A	N/A	N/A	N/A	1.43%
Gretna SGT1	240	N/A	N/A	N/A	N/A	-1.00%	N/A	N/A	N/A	N/A	-1.96%
EWE Hill 132kV WF GT	90	N/A	N/A	N/A	N/A	-6.60%	N/A	N/A	N/A	N/A	-13.63%
Minsca WF transformer	43.2	-5.39%	-7.68%	-3.53%	-6.67%	-5.08%	-10.98%	-16.15%	-6.54%	-14.73%	-11.24%
EWE Hill WF transformer	13	-3.79%	-3.29%	-2.54%	-3.39%	-0.30%	-9.08%	-8.03%	-5.83%	-7.68%	-0.88%
Annan PS T1	12	-3.29%	-1.20%	-1.34%	-2.29%	-3.59%	-7.42%	-2.70%	-2.91%	-5.05%	-8.43%
Annan PS T2	12	-1.39%	-1.25%	-5.23%	-1.39%	-0.85%	-1.45%	-3.09%	-11.75%	-3.01%	-1.67%
Middlebie PS T1	10	-4.18%	-0.20%	-3.53%	-2.99%	-3.19%	-9.54%	-0.19%	-8.35%	-6.80%	-7.16%
Langholm PS T1	12	-4.58%	-2.29%	-3.53%	-2.59%	-3.39%	-10.50%	-5.31%	-7.96%	-5.73%	-7.94%
Gretna PS T2	12	-3.98%	-3.34%	-3.58%	-3.88%	-3.99%	-8.96%	-7.93%	-8.50%	-9.53%	-9.43%
Newcastleton PS T1	10	-4.78%	-4.09%	-2.34%	-3.59%	-5.48%	-11.75%	-8.80%	-5.25%	-7.68%	-12.77%
Lockerbie PS T1	24	-3.39%	-0.50%	-0.85%	-2.89%	-0.90%	-7.23%	-0.97%	-1.85%	-6.76%	-1.77%
Lockerbie PS T2	24	-3.49%	-1.30%	-10.60%	-6.97%	-5.08%	-7.37%	-2.62%	-23.71%	-14.01%	-11.89%
Kirkbank PS T1 & Moffat PS T1	5.0+7.5	-2.89%	-3.32%	-1.49%	-8.94%	-3.24%	-7.23%	-10.37%	-3.01%	-15.89%	-6.40%
Moffat PS T2	7.5	-1.59%	-1.70%	-2.08%	N/A	-1.44%	-3.85%	-3.43%	-5.88%	N/A	-2.86%

Voltage dips (negative values): Green – within SQSS -12% voltage limits Red – exceeds SQSS -12% voltage limits
Voltage rise (positive values): Green – within SQSS +6% voltage limit Red – exceeds SQSS +6% voltage limits

Anchor generator voltage transients and inrush effect

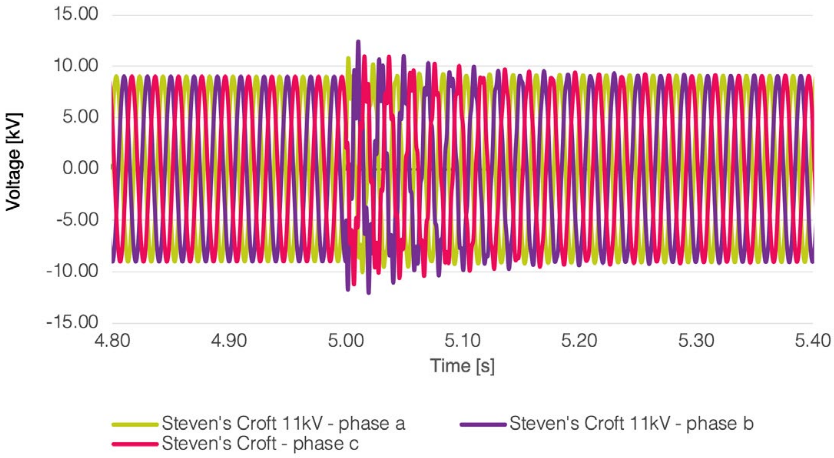
Table 4.11 shows that the inrush current from energising the Steven's Croft step-up transformer causes the 11kV busbar voltage to dip by 23 per cent. It takes around 3 to 4 seconds for the voltage to recover back to the nominal setting of 1.00pu as the inrush decays and the generator AVR takes action to regulate the voltage. This dip in voltage may cause the generator to trip on under voltage. If Steven's Croft decides to provide Black Start services then the developer will need to come up with a solution to self-start the generator and energise up to the PoC at 33kV. Energising the transformer using a 'Soft Start' technique could help to alleviate the problem. With this technique, terminal voltage is gradually increased from zero to a small value and then brought back to zero again. This action is repeated several times with incremental increase in the maximum voltage imposed. By doing this, the remnant flux in the transformer slowly decays which in turn reduces the inrush current magnitude.

The large voltage step change could also negatively impact the auxiliary loads, such as motors connected to the 11kV busbar via auxiliary transformers on site. Therefore, a separate power supply, such as a standby diesel generator or other sources, should be used to power the auxiliary Steven's Croft loads until the full restoration of the DRZ. This is, however, expected to be a standard procedure to avoid auxiliary load trips or stalling during block load pick-up.

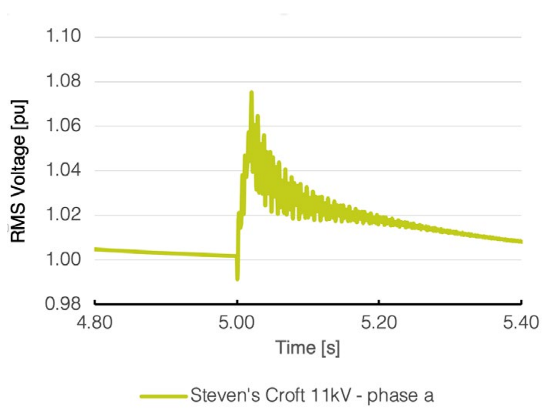
Switching the 33kV cable circuit from Steven's Croft to Chapelcross 33kV busbar in option 5 results in a 7.5 per cent voltage rise at Steven's Croft's 11kV busbar. Figure 4.14(a) shows the instantaneous phase voltages and figure 4.14(b) gives the corresponding root mean square (RMS) value for phase a. The voltage rise is outside the +6 per cent acceptable limits of SQSS. No other transient over-voltage is observed at Steven's Croft's 11kV busbar during primary substation energisation or switching events across all the restoration options.

Figure 4.14
Energisation of Steven's Croft – Chapelcross 33kV circuit; (a) instantaneous phase voltages and (b) RMS voltage (option 5)

(a) Instantaneous phase voltages



(b) RMS voltage value for phase a



Energisation of grid and super grid transformers

Energisation of the 90MVA GT at Chapelcross (options 3,4 and 5) and Dumfries (option 3), and the 240MVA SGT at Gretna (option 5) results in acceptable voltage dips (within SQSS limits) at the terminal of the anchor generator (table 4.13). However, this is based on random switching of the circuit breakers in the simulation and does not indicate the worst-case scenario.

To determine the worst-case voltage dips during energisation, point on wave (PoW) studies (as per the assumptions in section 3.2.3) were carried out for selected energisation events. Events showing violations with random circuit breaker switching does not require further PoW study, however other events with large grid transformers or long circuits that shows an acceptable response in table 4.13, but which are likely to cause transient violations, require further PoW study to assess the extent of the impact on the substation voltage.

Table 4.14 presents the corresponding PoW results which show that the maximum voltage dip (≈17 per cent) at the anchor generator terminal can exceed the SQSS limit. The under-voltage protection setting of generators is usually around 20 per cent, so even if the voltage dip exceeds the SQSS limit, it should not cause the generator to trip. The corresponding voltage dips at the Chapelcross 33kV and 132kV busbars are also much larger. However, this is not a concern as primary substation customers are only picked up after the GT and SGTs are energised. Therefore, even under worst case switching events, the anchor generator is capable of energising the 132kV network without any issue.

Table 4.12
Voltage transient (% rise/dip) based on PoW transformer energisation studies

Restoration energisation events	Transformer rating	Steven's Croft 11kV (ΔV)		Chapelcross 33kV (%ΔV)		Chapelcross 132kV (%ΔV)		Lockerbie 33kV (ΔV)	
	MVA	Max	Min	Max	Min	Max	Min	Max	Min
Lockerbie 33/11kV PS T1	24	-7.30%	-0.12%	-18.97%	-0.21%	NA	NA	-29.9%	-0.3%
Chapelcross GT1	90	-16.96%	-0.37%	-39.81%	-0.72%	-32.66%	6.00%	NA	NA
Dumfries GT1A	90	-16.09%	-1.20%	-36.89%	-2.37%	-50.44%	-2.7%	NA	NA
+									
Dumfries GT1B	30								
Gretna SGT1	240	-17.12%	-0.87%	-44.92%	-1.68%	-54.62%	-2.2%	NA	NA

Voltage dips (negative values): Green – within SQSS -12% voltage limits   Red – exceeds SQSS -12% voltage limits
Voltage rise (positive values): Green – within SQSS +6% voltage limits   Red – exceeds SQSS +6% voltage limits

Energisation of primary substations

Single transformer energisation at all the primary substations as well as energisation of the Kirkbank T1 and Moffat T1 transformers simultaneously does not exceed the SQSS limit at the Steven's Croft 11kV busbar. Table 4.12 gives the PoW energisation result for Lockerbie primary transformer which has the highest rating among all the primaries in the Chapelcross GSP. As evident, the worst-case voltage dip is within the 12 per cent limit. Therefore, energisation of any of the primary transformers in the GSP should not pose any issues to the anchor generator. However, from the customer voltage point of view and SQSS limit, there could be a potential problem. The voltage at Chapelcross 33kV and Lockerbie 33kV goes well below the SQSS limit of 12 per cent (substations supplying user systems below 132kV), causing any customers connected at substations already energised before Lockerbie to experience low voltages. Voltage transients due to inrush current usually lasts for around one second which is enough to cause potential damage to the connected loads before any transformer tap change action can take place to lower the voltage.

Key findings

The findings of the EMT analysis can be summarised as:

- Energisation of the anchor generator step-up transformer causes the Steven's Croft terminal voltage to dip by 23 per cent. This can cause the anchor generator to trip on under-voltage. A potential solution is to use a 'soft start' technique as discussed.
- Based on the PoW studies, the worst-case voltage dip at the anchor generator terminal during energisation of the 90MVA grid transformers (Chapelcross and Dumfries GTs) and super grid transformers (at Gretna) is around 17 per cent which should not cause the generator to trip. Therefore, energisation of the 132kV network using the 33kV connected DER is feasible in the Chapelcross DRZ. The total charging power absorbed by the anchor generator is within its capability limit.
- A PoW study for Lockerbie primary transformer shows that the worst-case voltage dip at the anchor generator terminal of 7.3 per cent is well within the SQSS limits. Since Lockerbie is the largest primary transformer in Chapelcross GSP, all other primary substation energisations are expected to result a smaller voltage dip. From the anchor generator's perspective, energising the primary substations is therefore, not a problem. However, the voltage dip at Chapelcross and Lockerbie 33kV busbars is more than the SQSS limit of 12 per cent with potential problems for all customers already energised before Lockerbie is energised. Suggested solutions to avoid the risk of under-voltage is to:
  a. utilise a PoW capable circuit breaker to control the instance when the breaker is closed. This, however, means changing the existing breakers as they do not have PoW capability, with associated cost implications.
  b. modify the restoration options to energise the primary transformers at no load and then connect customers by sequential 11kV feeder switching.
- The voltage dip at the Chapelcross 33kV busbar can go as low as 44.9 per cent (table 4.12) during some energisation events such as the SGT at Gretna. Since no primary substations are energised at this stage and no customers are connected to the 33kV network, apart from the Minsca and Ewe Hill wind farms which can ride-through the low voltage, this is not a problem.
- Switching the 33kV cable circuit from Steven's Croft PoC to Chapelcross 33kV busbar results in a voltage rise at Steven's Croft 11kV busbar outside the SQSS limit of +6 per cent. The only other transient over-voltage observed is on the 132kV side of the Chapelcross GT during its energisation. This rise is around 6 per cent (table 4.12) which is within the acceptable limit.
- Table 4.13 provides the above summary findings in a tabular form across all five restoration options.

Table 4.13
Restoration success criteria based on EMT energisation studies

Restoration success criteria – EMT energisation studies	Option 1	Option 2	Option 3c	Option 4a	Option 4b	Option 5
Energisation of the anchor generator step-up transformer – ΔV at Steven's Croft 11kV below 12%*	✔	✔	✔	✔	✔	✔
Energisation of the grid transformers – ΔV less than 20% ** at Steven's Croft 11kV	–	–	✔	✔	✔	✔
Energisation of the super grid transformer – ΔV less than 20% ** at Steven's Croft 11kV and Chapelcross 33kV	–	–	–	–	–	✔
Single primary transformer energisation – ΔV below 12% at Steven's Croft 11kV	✔	✔	✔	✔	✔	✔
Single primary transformer (24MVA) energisation – ΔV below 12% at Chapelcross 33kV	✘	✘	✘	✘	✘	✘
Over voltages due to 33kV and 132kV cable energisations – below 12%*	✔	✔	✔	✔	✔	✔

✔ Fully achieved ✔ Conditionally achieved
✘ Not achieved – Not applicable

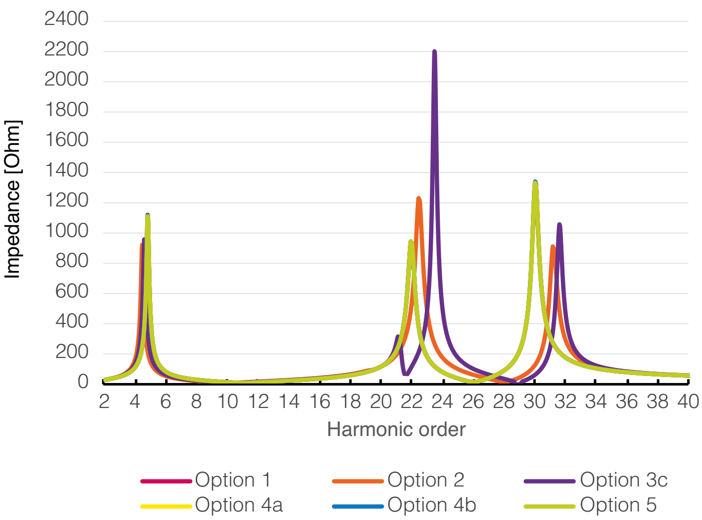
4.2.4 Harmonic simulation results

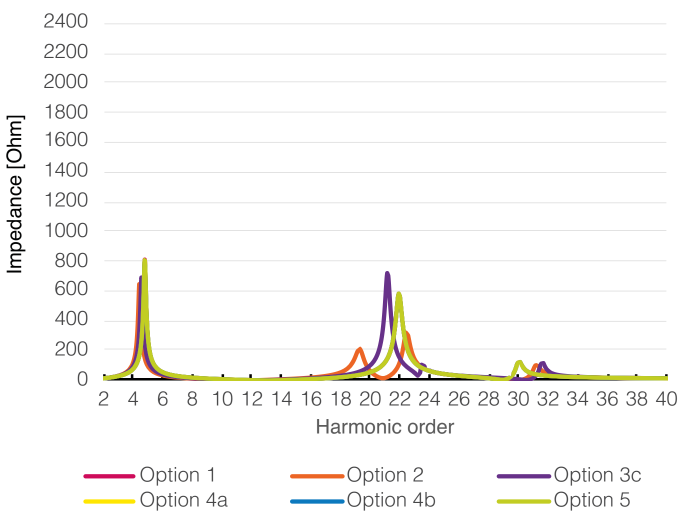
The harmonic impedance of the network changes in every restoration stage, and across different options, as more network components are energised.

Figure 4.15(a) shows the impedance scan of the network as seen from the Minsca WF's 33kV point of connection (PoC) during the energisation of the wind farm in the different restoration options. Figure 4.15(b) gives the impedance scan at the same stage but seen from the Steven's Croft 33kV PoC. A lower order resonance is observed around the fifth harmonic (250Hz) of magnitude 1100Ω and 800Ω at the PoC of Minsca and Steven's Croft, respectively. This can potentially cause a temporary over-voltage due to the transformer inrush current (rich in lower order harmonics like 2nd, 3rd etc) and lead to over-voltage ripping of the sources. The impedance magnitude at the 5th order remains fairly similar across all the options, so there is no advantage in adopting a particular strategy.

Higher order resonances are observed around 22nd and 32nd harmonics. Both the resonance frequency and the magnitude vary slightly across the options. Since no customers are connected to the network at this point, the only source of harmonic current is from transformer energisations which usually have very low harmonic content beyond 15th order. So, the higher order resonance is not a cause for concern during the wind farm energisation.

Figure 4.15
Harmonic impedance scan when energising Minsca wind farm, measured at
(a) Minsca 33kV PoC and (b) Steven's Croft 33kV PoC

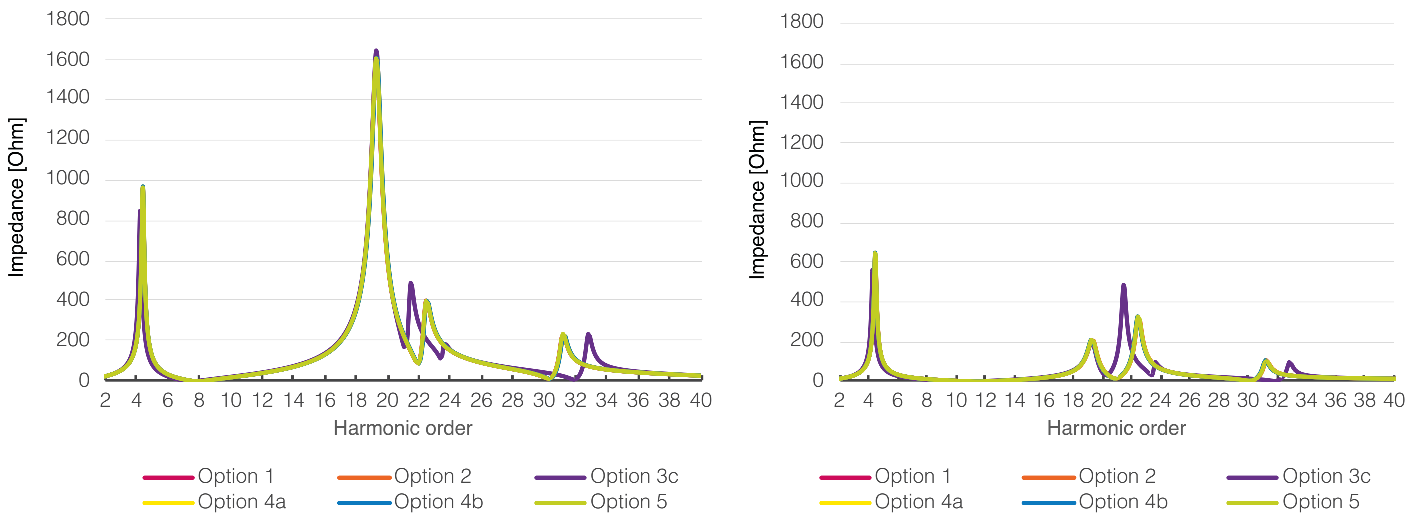




A similar impedance characteristic is observed when energising the Ewe Hill wind farm during the different restoration options. Figure 4.16(a) shows the impedance seen at the Ewe Hill 33kV PoC and Figure 4.16(b) gives the impedance seen from the anchor generator PoC. Similar to Minsca wind farm, the lower order resonance is around the 5th order harmonic but with a slightly reduced magnitude.

The energisation of the Chapelcross – Middlebie circuit to bring online Ewe Hill wind farm after energising Minsca (figure 4.3) has very limited impact on the resonance seen from Minsca and Steven's Croft's PoC. This can potentially cause over-voltage issues from the transformer inrush current harmonics at all the three sites and should be looked into in more detail.

Figure 4.16
Harmonic impedance scan when energising Ewe Hill wind farm, measured at
(a) Ewe Hill 33kV and (b) Steven's Croft 33kV



In the latter part of the restoration process, when the primary substations are energised, no lower order resonance is observed. The first resonance occurs around 19th order with a maximum magnitude of 1600Ω (figure 4.15a) when Annan substation is energised.

Key findings

The key findings from the harmonic assessment are:

- During the energisation of the Minsca and Ewe Hill wind farms in all the options, a resonance around the 5th order harmonic is observed at the three DER sites (anchor generator and two wind farms). The inrush current from the wind farm transformers can potentially cause over-voltage issues that can lead to potential over-voltage tripping of the DERs. Further studies are required with a detailed model of the wind farm array cable layout.
- No lower order resonance is observed once the primary substations are energised. So, inrush current from primary substation energisation is unlikely to cause harmonic over-voltage issues.

4.3 Summary

4.3.1 Restoration options

Five different restoration options with some sub-options were considered for restoring DRZs in Chapelcross GSP. Please refer to table 4.2 for an overview of the key differences between the different options.

In terms of energising the Chapelcross GSP 33kV network, option 2 is better than option 1, as it has fewer thermal violations during the restoration process, and also because it does not result in Ewe Hill wind farm exceeding its reactive power limits.

Option 3 focuses on energising the 132kV Ecclefechan line and the Chapelcross and Ecclefechan grid transformers before restoring the primary substations in the 33kV network. It is further split into four sub-options to explore different ways of energising the 132kV network. Compared to options 4 and 5, which also energise parts of the 132kV network, option 3 is better in terms of circuit utilisation and voltage violations. Option 4 results in several thermal overload violations while also placing a reactive power burden on the anchor generator. Option 5 also results in thermal overload violations as well as voltage violations at 11kV.

Several instances of voltage dips are identified during component energisation, with the more severe instances occurring when the Gretna SGT is energised (option 5) or the Dumfries 132/33kV grid transformers are energised (option 4), as well when the Lockerbie 24 MVA grid transformer is energised (all options). Only in the case of Lockerbie are customers already connected that would experience the voltage dip, and the recommended solution is to change the Lockerbie energisation strategy to option G that involves switching 11kV feeders individually, which is not ideal due to the amount of switching that has to be coordinated by the Control Room.

4.3.2 Power system simulation study results

The following table summarises the power system study results for the different restoration options.

Table 4.14
Summary of the power system simulation study results

Power system study	Restoration option 1	Restoration option 2	Restoration option 3	Restoration option 4	Restoration option 5
Load flow studies	• Anchor generator can only partially restore the DRZ (up to stage 6) • Ewe Hill WF operates at reactive power limit • Several 33kV voltage violations and thermal overload violations	• Anchor generator can only partially restore the DRZ (up to stage 5) • Several 33kV voltage violations and thermal overload violations	• Anchor generator can only partially restore the DRZ (up to stage 4) • Ewe Hill WF operates at reactive power limit • Several 33kV voltage violations and thermal overload violations	• Anchor generator can only partially restore the DRZ (up to stage 8) • Ewe Hill WF operates at reactive power limit • Several 33kV voltage violations and thermal overload violations	• Anchor generator can only partially restore the DRZ (up to stage 8) • Ewe Hill WF operates at reactive power limit • Several 33kV and 11kV voltage violations and thermal violations
Dynamic studies	• Anchor generator can only partially restore the DRZ – due to limited BLPU • Under-voltage issues when Middlebie & Langholm primaries are energised • No frequency or RoCoF violations if DER support available	• Anchor generator can only partially restore the DRZ – due to limited BLPU • Under-voltage issues when Middlebie & Langholm primaries are energised • No frequency or RoCoF violations if DER support available	• Anchor generator can only partially restore the DRZ – due to limited BLPU • Under-voltage issues when Middlebie & Langholm primaries are energised • No frequency or RoCoF violations if DER support available	• Anchor generator can only partially restore the DRZ – due to limited BLPU • Under-voltage issues when Middlebie & Langholm primaries are energised • No frequency or RoCoF violations if DER support available	• Anchor generator can only partially restore the DRZ – due to limited BLPU • Under-voltage issues when Middlebie & Langholm primaries are energised • No frequency or RoCoF violations if DER support available
EMT studies	Voltage dip violation: • At Steven's Croft when energising step-up transformer • Lockerbie primary when grid transformer energised No voltage rise violations	Voltage dip violation: • At Steven's Croft when energising step-up transformer • Lockerbie primary when grid transformer energised No voltage rise violations	Voltage dip violation: • At Steven's Croft when energising step-up transformer • At Chapelcross 33kV when Chapelcross GT1, Minsca WF GT, or Lockerbie primary are energised • Lockerbie primary when grid transformer energised No voltage rise violations	Voltage dip violation: • At Steven's Croft when energising step-up transformer • At Chapelcross 33kV when Chapelcross GT1, Dumfries GT 4 / 1A&B, Minsca WF GT, and Dalswinton WF GT, Lockerbie primary or Kirkbank/Moffat primaries are energised • Lockerbie primary when grid transformer energised No voltage rise violations	Voltage dip violation: • At Steven's Croft when energising step-up transformer • At Chapelcross 33kV when Chapelcross GT1, Ewe Hill WF, Gretna SGT and Newcastleton primary, or Lockerbie primary are energised • Lockerbie primary when grid transformer energised No voltage rise violations
Harmonic impedance scan	• 5th order resonance at anchor generator and 2 WFs when WFs are energised	• 5th order resonance at anchor generator and 2 WFs when WFs are energised	• 5th order resonance at anchor generator and 2 WFs when WFs are energised	• 5th order resonance at anchor generator and 2 WFs when WFs are energised	• 5th order resonance at anchor generator and 2 WFs when WFs are energised

The power system studies confirmed that the anchor generator can only partially restore the DRZ in all five restoration options, and that additional DER active and reactive power support is needed to complete the restoration.

4.3.3 Required DER interventions

DER active and reactive power contribution is required during all the restoration options to support the anchor generator in energising some of the primary substations. Active power support is required to improve the BLPU capability to pick up the cold loads at the primary substations, in particular larger ones such as Lockerbie and Kirkbank/Moffat.

Dynamic voltage support is required from the DERs during the cold load pick-ups to restrict the voltage transients within acceptable limits.

4.3.4 Other required interventions

In all the restoration options, customers are only connected after the DRZ has been expanded to the 132kV or 400kV networks, and so any voltage dips at Chapelcross 33kV busbar during these restoration stages don't have a major impact.

To mitigate the voltage dip at the anchor generator's terminals when the Steven's Croft step-up transformer is energised, a 'soft start' should be adopted. Strategies to reduce the voltage dips at other parts in the network during primary substation energisation include installing PoW circuit breakers, or changing the restoration strategies to energise the primary transformers on no load, and then pick up demands by switching individual 11kV feeders (option G).

4.3.5 Transmission interface point capability

The anchor generator on its own, without any DER support, is capable of exporting around 30.5 MW and importing 14.5Mvar at the Chapelcross 33kV GT breaker interface point under no load conditions. This capability is calculated separately i.e. either active power or reactive power is exchanged at any one time. This capability can be enhanced through support from other DERs such as Minsca and Ewe Hill wind farms which can extend the reactive import limit to 30.7Mvar. Once the DRZ has been fully restored, it can provide 4.85 MW and import 36Mvar at the interface point. In this case, however, the assumption is that DERs will provide up to 40 per cent MW support and full Mvar support to the anchor generator.

4.4 Conclusion

All five Chapelcross restoration options are technically viable, but they do require active and reactive power support from the DERs to assist the anchor generator in full DRZ restoration. The two major constraints are insufficient BLPU capability and dynamic voltage support during the cold load pick-up. One conclusion that can be drawn from the Chapelcross case study is that the capability of an anchor generator, of rating comparable to the total maximum demand of the GSP, will not be sufficient enough to energise the demand of the whole GSP (assuming maximum LTDS demand). The amount of support required from other DERs will vary depending on the mitigation actions taken such as delaying successive substation pick-ups or reducing the block load size by 11kV feeder switching.

In the Chapelcross case study, the only DERs available are wind farms. Probabilistic wind energy availability studies are needed to estimate the amount of support we can expect from the Minsca and Ewe Hill wind farms with a high degree of confidence and if this value is enough to meet the requirement of 45 per cent. If the wind farms are found not to be able to provide 45 per cent with a high confidence throughout the year then additional sources such as a BESS might be required. The alternate option would be to restore supply to as many customers as possible using the anchor generator only and energise the network up to a transmission interface point and wait until further support is available.

5. Galloway region restoration and power system study results

The restoration strategies for the Galloway region case study network is presented in more detail and the results from the power system simulations discussed.

5.1 Restoration strategies

5.1.1 Overview

The Galloway region case study network was introduced in section 2.2.2 and consists of several 132/11kV and 132/33kV GSPs, 132/33kV transmission stations, as well as connections to the New Cumnock 275/132kV transmission substation as was shown in figure 2.6. A list of the Galloway region GSPs and transmission stations and the connected DERs appear in Appendix 2: DER ratings and simulation models.

5.1.2 Restoration options 1–3

For the Galloway region, a total of three main restoration strategies were developed. Unlike the other case studies, the three restoration options are not independent of each other; instead, the options are more like sequential stages of a single large restoration plan that expands the DRZ as far as possible. Since the MW capacity of the anchor generator is more than the total demand of the three primary substations, Glenluce, Barhill and Newton Stewart, it was thought to be sufficient to restore the DRZ as per option 1. There was no specific need identified to energise additional hydroelectric stations until later on in the restoration process.

Glenlee 25.5 MW hydroelectric plant is utilised as the self-starting anchor generator to energise the Glenlee GSP 132kV busbar and from there the surrounding GSPs. A high-level overview of the restoration options is provided in table 5.1.

Table 5.1
Overview of restoration options for the Galloway network

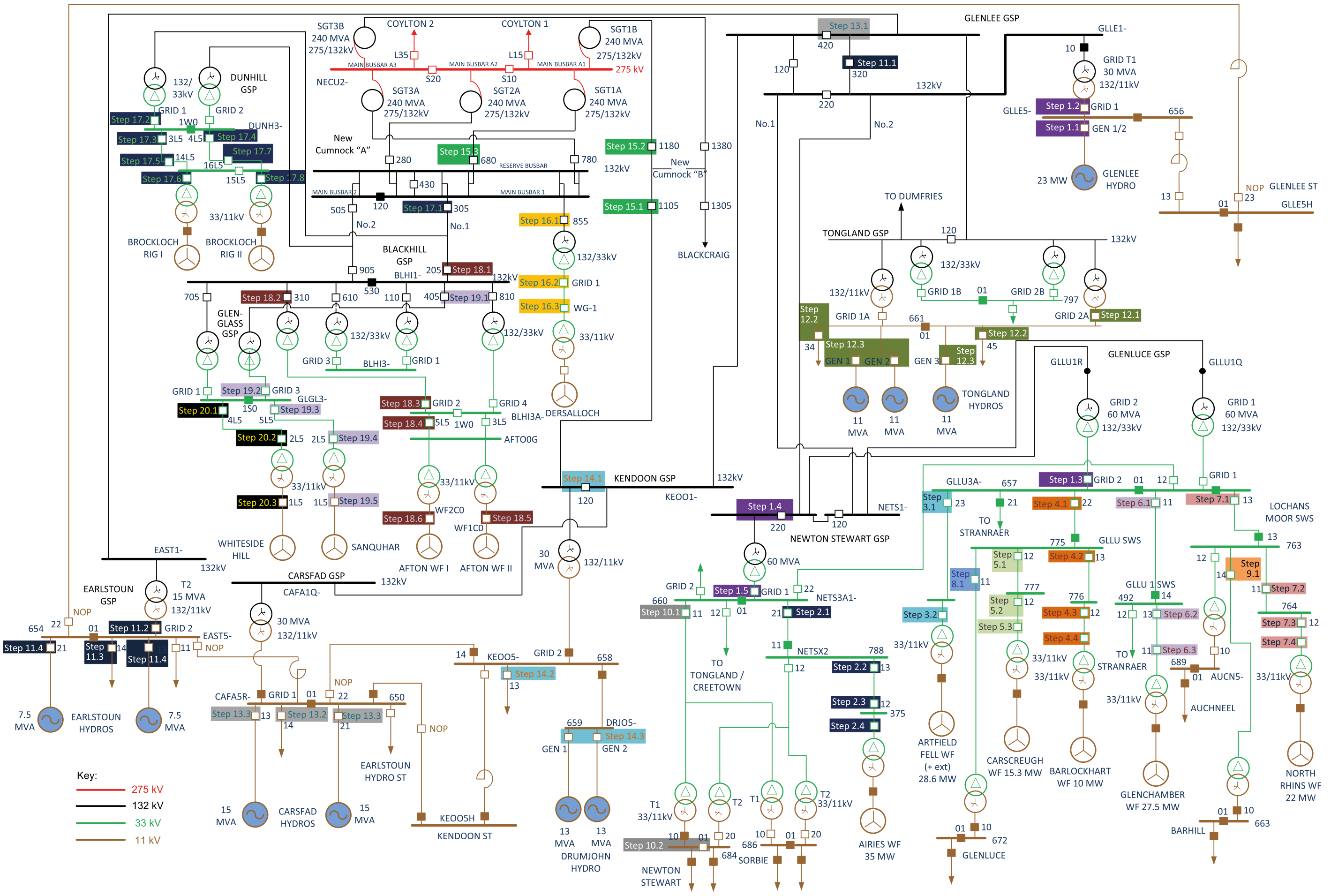
Restoration option	Description
1	Self-starting of Glenlee Hydro followed by energisation of the Glenlee GSP 132kV busbar, Glenluce GSP 132kV and 33kV busbars are energised, as well as Newton Stewart GSP 132kV and 33kV busbars. Energisation of multiple 33kV wind farms connected to Newton Stewart and Glenluce 33kV busbars. Restoration of power supply to primary substations.
2	Expand the DRZ from Glenlee GSP, via the 132kV network, and energise the Earlstoun, Tongland, Carsfad and Kendoon Hydros via their respective 132/11kV grid transformers.
3	Expand the DRZ from Glenlee 132kV busbar to New Cumnock 275/132kV transmission substation and energise the Dersalloch wind farm. Then expand the DRZ and energise several 33kV wind farms connected at Dunhill, Blackhill and Glenglass transmission stations.

An overview of the main stages in each of the three restoration options is presented below in table 5.2. ach stage consists of several circuit breaker operations or steps, which are shown in figure 5.1. Like with the Chapelcross case study the steps are numbered in the diagram.

Table 5.2
Overview of restoration options for the Galloway network

Option	Stage	Action	Description
1	0	Anchor generator self-start	Start Glenlee hydroelectric anchor generator
	1	Energise 132kV transformer, and 2 x GSPs via 132kV	Energise Glenlee 132kV busbar, and then via the transmission network energise Glenluce 132/33kV grid transformer and 33kV busbar, followed by energising Newton Stewart GSP 132kV busbar, 132/33kV grid transformer, and 33kV busbar
	2	1st WF online	Restoration of power supply to Airies wind farm (WF) via Newton Stewart 33kV switching station
	3	2nd WF online	Restoration of power supply to Artfield Fell WF from Glenluce GSP 33kV busbar
	4	3rd WF online	Restoration of power supply to Barlockhart Moor WF from Glenluce 33kV switching station
	5	4th WF online	Restoration of power supply to Carscreugh WF from Glenluce 33kV switching station
	6	5th WF online	Restoration of power supply to Glenchamber WF via Glenluce 33kV switching station
	7	6th WF online	Restoration of power supply to North Rhins WF via Lochans Moor 33kV switching station
	8	Energise 1st primary sub	Energisation of Glenluce 33/11kV primary substation from Glenluce 33kV switching station (using primary substation energisation strategy A)
	9	Energise 2nd primary sub	Energisation of Barhill 33/11kV primary substation from Glenluce 33kV switching station (Energisation strategy A)
	Airies and Carscreugh WFs each ramp up to 10% active power to support BLPU		
	10	Energise 3rd primary sub	Energisation of Newton Stewart primary substation (option D, i.e. load is picked up in two steps, with only one transformer energised)
2	11	Energise GSP, 2nd hydro online	Energisation of Earlstoun 132/11kV GSP via a 132kV line from Glenlee GSP, followed by energisation of the Earlstoun hydroelectric station
	12	3rd hydro online	Energisation of the Tongland 11kV busbar and energisation of the Tongland hydroelectric station
	13	Energise GSP, 4th hydro online	Energisation of Earlstoun 132/11kV GSP via a 132kV line from Glenlee GSP, followed by energisation of the Earlstoun Hydros
	14	Energise GSP, 5th hydro online	Energisation of the Kendoon (Drumjohn) Hydros from Kendoon 132/11kV GSP
3	15	Energise transmission sub and SGTs	Energisation of New Cumnock 132kV and 275kV substations from Kendoon GSP. This involves energisation of two 275/132kV SGTs
	16	7th WF online	Energisation of Dersalloch wind farm from New Cumnock 33kV busbar
	17	Energise GSP, 8th & 9th WF online	Energisation of Dunhill 132/33kV switching station from New Cumnock 132kV busbar, followed by energisation of Brockloch Rig 1 and 2 WFs
	18	Energise GSP, 10th & 11th WF online	Energisation of Blackhill 132/33kV GSP from New Cumnock, followed by energisation of Afton 1 and 2 WFs via Blackhill 33kV switching station
	19	Energise GSP, 12th WF online	Energisation of Glenglass 132/33kV switching station from Blackhill, followed by energisation of Sanquhar WF
	20	13th WF online	Energisation of Whiteside WF from Glenglass switching station
	21		End of the Galloway DRZ restoration process

Figure 5.1
Galloway region restoration steps (options 1–3)



It's worth noting the following:

- Options 1–3 could have been done independently, however, they were done sequentially to represent the worst-case scenario for the Glenlee anchor generator.
- The main purpose of option 2 is to energise the hydroelectric stations in the region to increase the system inertia and fault levels, and to make more MW available before energising the New Cumnock 275/132kV transmission station and the surrounding substations. If the hydroelectric stations have insufficient water to produce active power, they can still be run like synchronous condensers to contribute inertia.
- It needs to be noted that the stages and steps, as well as the specific sequence, were the result of a number of initial load flow studies to avoid thermal overloading of transformers, and minimise the number of voltage violations. One of these studies revealed that it is not possible to pick up the demand at Sorbie primary substation as its demand of 4.7MVA will result in a CLPU of 9.4MVA, which cannot be met by the BLPU capability of the anchor generator. Usually a different primary substation restoration strategy could be tried to reduce the CLPU, but in Sorbie's case the bus section circuit breaker is not telecontrolled, which means splitting the load before the restoration process, and therefore using a different primary substation energisation strategy is not remotely possible.

5.2 Power system study results

The same set of power system studies performed for the Chapelcross GSP case study was repeated for the Galloway restoration strategies, using the same assumptions and models described in section 3.2 and 3.3. A summary of the findings is provided below.

5.2.1 Load flow simulation results

Table 5.3
Important assumptions for the load flow study

Component	Model	Assumptions
Hydroelectric anchor generator	Voltage setpoint	1pu maintained at the generator terminal
	Load bank	10% of the MVA rating of the machine
Wind farms	operating mode	Voltage control, 1.02pu at the PoC with 3% droop
	Max active power support	45% of the installed capacity
Load	Characteristic	Constant active and reactive power type
	Demand	Maximum LTDS demand at individual primary substations
	Cold load demand	200% at pick up, 150% after 15 minutes, nominal value after 30 minutes
	Overload rating	150% rated for a short duration on ONAN cooling
Transformer	Tap action	OLTC on Newton Stewart and Glenluce 132/33kV transformers switched on and Glenlee 132/11kV transformer OLTC switched out (since it will interfere with the Glenlee hydroelectric AVR control at 11kV).

Please refer to section 3.2.1 for a full list of assumptions used in the load flow study. The assumptions are consistent across all the options, with the important ones repeated in table 5.3 for the reader's reference.

The load flow simulations considered the normal CLPU profile discussed in section 3.2.1. The following outputs were monitored during the simulation of each stage of the restoration process:

- The thermal loading conditions of circuits and transformers to ensure no assets are overloaded at any point during the restoration;
- The voltage profiles at key 275kV, 132kV, 33kV and 11kV nodes to confirm that no deviations outside of the allowable limits occur during the restoration;
- The MW and Mvar output and available generation capacity from the anchor generator to understand its performance and responses during the restoration process;
- The MW and Mvar contribution from all the other DERs over the course of the restoration;
- The tap position of the transformers to understand if, and under what conditions, they change during the restoration, and the impact thereof;
- The MW and Mvar capability of the DRZ to support the transmission network as measured at the 132kV breaker of New Cumnock SGT.

Using the above measurements, it was possible to ascertain the suitability of the restoration options and the capability of the assets within the Galloway region to achieve the successful execution of the planned restoration. The key success factors for the steady-state analysis were:

- acceptable voltage profile during system restoration,
- acceptable network loading conditions, especially for cold load pick-up.

Any voltage or thermal violations that occurred during the simulation of the restoration are highlighted and potential mitigating solutions proposed.

Anchor generator active and reactive power capability

The Glenlee hydroelectric plant has two units each of 12.75 MW and 5Mvar maximum capability. The two units are modelled as a single machine in the studies. The anchor generator is self-started with a 3 MW load bank (10 per cent of MVA rating), but because it is a hydroelectric generator it does not require the load bank for stable operation. The load bank is therefore not considered in the load flow studies, however it is included to keep parity with the dynamic studies where it is useful for frequency regulation purposes.

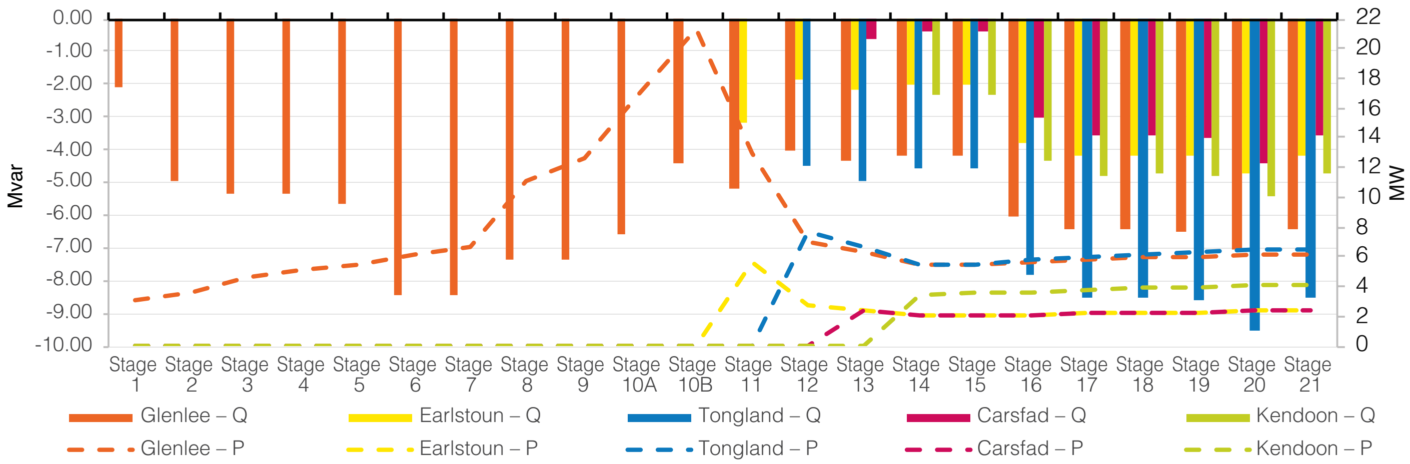
In option 1 (table 5.2), from purely a steady state load flow analysis perspective, Glenlee hydroelectric plant's generation capacity of 25.5 MW is sufficient for picking up the maximum cold loads at the 33kV primary substations (i.e. Glenluce, Barhill and Newton Stewart) without requiring any active power support from the six energised wind farms connected to Glenluce GSP and Newton Stewart GSP. This however does not consider the dynamics of the system and the BLPU capability of the generator which is discussed in the dynamic simulation results section. The wind farm's 10 per cent active power support mentioned in table 5.2 only relates to the dynamic simulation requirements, and isn't necessary for the steady state analysis.

Before energising the first primary substation at stage 8 in option 1, the anchor generator operates at 25 per cent of rated MW output and provides power mainly to auxiliary loads at the wind farm sites and the load bank. After picking up the cold loads at Glenluce, Barnhill and Newton Stewart primaries in stage 10, the loading increases up to 83 per cent of the rated MW output. stage 10 marks the end of the restoration in option 1.

In options 2 and 3, no further primary substations are energised, so the 83 per cent loading of the anchor generator is not a constraint. Four additional hydroelectric plants at Earlstoun, Tongland, Carsfad and Kendoon are brought online in option 2. The primary substation demands (energised in option 1) are now shared across all the hydro plants, thus reducing the MW burden on the anchor generator. In option 3 another seven wind farms are brought online to increase the ability of the DRZ to provide MW and Mvar support to the transmission network. At the end of the restoration process (stage 21), the anchor generator is only around 24 per cent loaded, allowing for the available reserve to be exported at the transmission-distribution (T-D) interface point (IP).

Figure 5.2 gives the active and reactive power dispatch of all hydro plants in the Galloway study case area for all the restoration stages as part of options 1–3.

Figure 5.2
Active and reactive power output of all hydro plants (including anchor gen) at every stage of the whole restoration process



Around 15.3Mvar of charging power is generated in stage 7 from the energised 132kV and 33kV networks, and the array cables of the embedded wind farms. This is beyond the 10Mvar capability of the anchor generator. In order to maintain the voltage within acceptable limits, the six wind farms provide reactive power support by absorbing around 6.9Mvar of charging power. The remaining reactive power of 8.4Mvar is absorbed by the anchor generator as shown in figure 5.2, stage 7. As mentioned in section 3.2.2, the wind farms operate in voltage control mode and maintain 1.02pu at their point of connection (PoC). So, any Mvar generated by the wind farm array cables is absorbed by the wind farms themselves to reduce the burden on the anchor generator. A point to note here is that not all the six wind farms energised in option 1 necessarily need to provide reactive power support. The minimum support required can be provided by the first three energised wind farms, i.e. Airies WF, Artfield Fell WF, and Barlockhart Moor WF.

Transmission interface point MW and Mvar capability

To find out the amount of MW Galloway restoration zone can provide at the transmission-distribution (T-D) interface point (IP), a voltage versus active power sensitivity study was done at the 132kV breaker of New Cumnock SGT. Figure 5.3 shows the P-V curve for two scenarios, when there is no MW and Mvar support from the other DERs (hydroelectric plants Earlstoun, Carsfad, Kendoon and Tongland), and when the DERs provide support. The six wind farms energised in option 1 (table 5.2) provide only Mvar support in the second scenario (option 2). Also, no primary substations have been energised i.e. this study is under no load condition.

The MW demand at the T-D IP is increased gradually until the anchor generator reaches its MW or Mvar capability limit and the corresponding voltages are recorded at the generator LV terminal, and at New Cumnock 132kV breaker. Glenlee generator maintains its terminal voltage tightly at 1pu throughout the simulation study.

As the active power export increases, the voltage drops at the IP considering there is no voltage control action from the SGT or any other transmission connected sources.

This value indicates the amount of MW support the anchor generator can provide to the transmission network while remaining within its operational limits. As an example, in figure 5.3, an export of 21 MW would lower the voltage from around 1.05pu to 1.025pu at the IP when no other DERs provide voltage support. When the DERs provide MW and Mvar support, then around 4.5 times more active power can be exported at the IP for a small drop in the voltage.

Figure 5.4 presents similar results but for Mvar import at the T-D IP. Two scenarios were studied, with and without reactive power support from DERs. No primary substations are energised at this stage i.e. the anchor generator and the DERs are under no load condition except for supplying their respective auxiliary demands.

As the Mvar exchanged at the IP increases, the voltage increases considering there is no tap action from the New Cumnock SGT or Mvar support from any other transmission connected sources. If 3Mvar is imported at the IP, it would increase the voltage to 1.07pu if there's no DER support. With support from the hydroelectric plants, this export can be achieved at a reduced voltage of 1.02pu. Also, the total Mvar that can be absorbed at the T-D IP increases from around 3Mvar to 59Mvar with contribution from the DERs.

Figure 5.3
Available MW at transmission-distribution interface point – no load

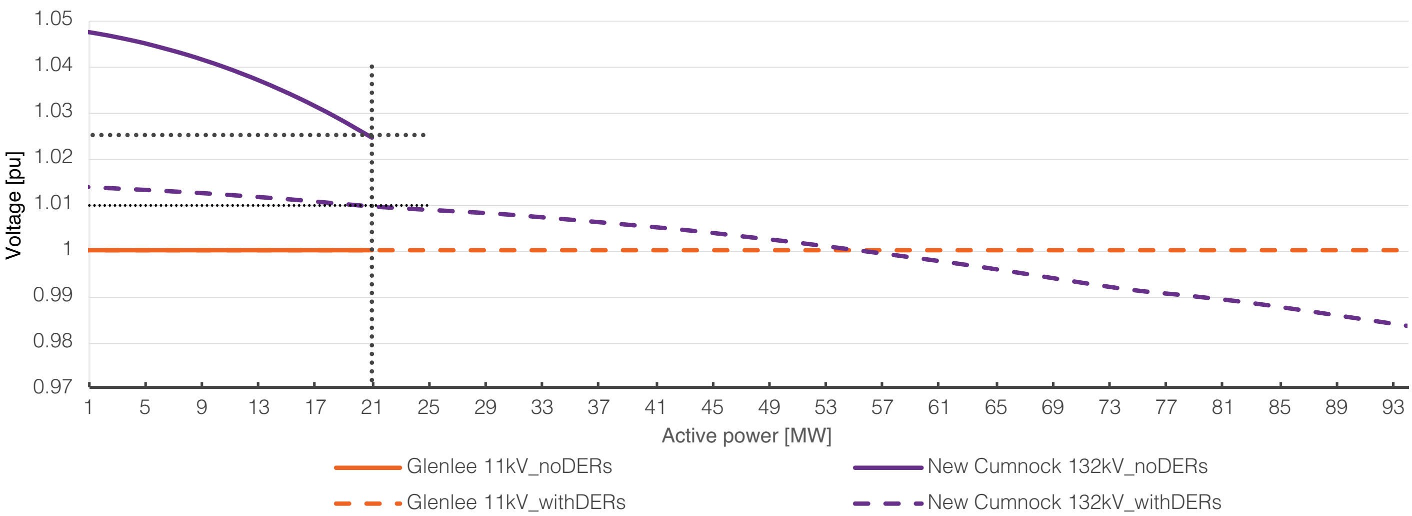
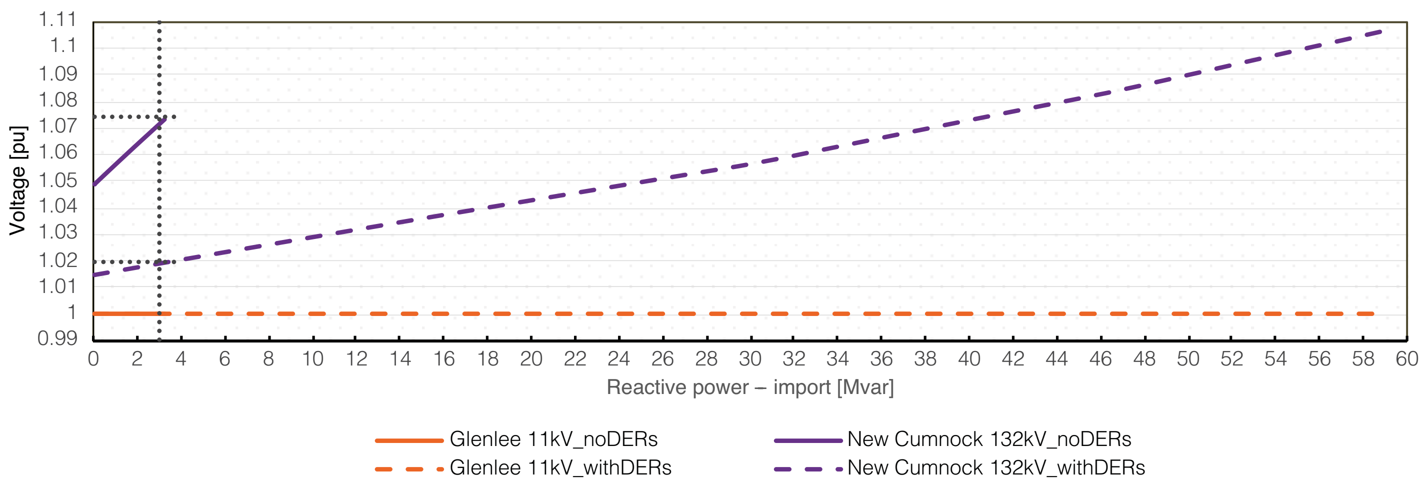


Figure 5.4
Available Mvar at transmission-distribution interface point – no load



A similar study as above is repeated after the primary substations at Glenluce, Barhill and Newton Stewart are fully restored and the cold load demands at the substations have settled down to their pre-blackout values. The maximum possible MW and Mvar exchanges at the New Cumnock 132kV breaker for four different scenarios are summarised in tables 5.4 and table 5.5.

The MW and Mvar capabilities at the IP are calculated independent of each other i.e. in table 5.4 when 20 MW export is calculated, no Mvar import has been considered. This is because, in reality, for either of the two, support will be required during restoration. If both MW and Mvar are exchanged at the same time, then the capability will be slightly different. As an example, for scenario 1 in table 5.4 and table 5.5, the values will be 20 MW and 6.1Mvar when both exchanged at the same time.

Table 5.4
Maximum active power export capability at the New Cumnock 132kV T-D interface point

No	Scenario	GSP demand	Transmission entry point
		MW	MW (export)
1	No load connected, no DERs, only anchor gen	NA	20
2	No load connected, anchor gen supported by DER – MW and Mvar support from Earlstoun	NA	27.9
3	No load connected, anchor gen supported by DERs – MW and Mvar support from Earlstoun, Carsfad, Kendoon, Tongland	NA	90.7
4	Glenluce, Barhill and Newton Stewart primaries energised, anchor gen supported by DERs – MW and Mvar support from Earlstoun, Carsfad, Kendoon, Tongland	9.72	81

Table 5.5
Maximum reactive power import capability at the New Cumnock 132kV T-D interface point

No	Scenario	GSP demand	Transmission entry point
		MW	MW (export)
1	No load connected, no DERs, only anchor gen	NA	3.24
2	No load connected, anchor gen supported by DER – MW and Mvar support from Earlstoun	NA	23.16
3	No load connected, anchor gen supported by DERs – MW and Mvar support from Earlstoun, Carsfad, Kendoon, Tongland	NA	58.82
4	Glenluce, Barhill and Newton Stewart primaries energised, anchor gen supported by DERs – MW and Mvar support from Earlstoun, Carsfad, Kendoon, Tongland	9.72	58.8

Network loading

With the exception of Newton Stewart's primary transformer, which experiences an acceptable temporary overload of 10 per cent, no other network components were found to experience an overload at any stage during the system restoration simulation. The maximum loading is 29 per cent on the 132kV and 33kV circuits and 61.8 per cent on 132kV and 33kV transformers.

Newton Stewart is energised following the primary substation energisation strategy option D (section 2.4.1). In this option, the total demand on the substation is split into two by separating the bus sections and picking up the demand in a staggered manner. The total demand is picked up by a single transformer and because of the cold load characteristic the utilisation of the transformer exceeds its rating by only 10 per cent which is well within the overload rating of 150 per cent (table 5.3).

Network voltage

The network is considered to have maximum LTDS demand before the blackout, as mentioned in the load flow assumptions list in section 3.2.1. Therefore, the primary transformer tap positions are assumed to be unchanged, and correspond to these demand values when energised. Given these tap positions, no under-voltage (<0.90pu) or over-voltage (1.06pu) issues are observed at any part of the network across all voltage levels during the whole restoration process.

Key findings

- Glenlee anchor generator has enough active power to energise the Galloway DRZ including the six wind farms in option 1, however it has insufficient reactive power to absorb the charging power of the wind farm array cables and the energised 132kV circuits, and requires additional DER support for voltage control beyond stage 6. This reactive power required can be provided by the first three energised wind farms.
- No network components experience overloads during the entire restoration process, except Newton Stewart primary transformer which experiences a temporary 10 per cent overload, which is within its 150 per cent overload rating for a short duration (≈15 minutes).

Table 5.6
Galloway restoration load flow success criteria

Restoration success criteria – load flow*	Option 1	Option 2	Option 3
Capability of the anchor generator to restore Galloway DRZ**	✔	✔	✔
Restore using anchor generator and WFs (MW and Mvar support from three WFs)	✔	✔	✔
All WFs operating within reactive limits (leading and lagging)	✔	✔	✔
No thermal violations across all voltage levels	✔	✔	✔
No voltage violations across all voltage levels	✔	✔	✔

✔ Fully achieved ✔ Partially achieved ✘ Not achieved

* Although the three options form part of one large expanding option, the success criteria is evaluated independently for each option.

** The anchor generator needs DER Mvar support to restore the DRZ in option 1.

5.2.2 Dynamic simulation results

Dynamic simulations were carried out for the three system restoration options discussed in section 5.1. The following dynamic simulation results were used to assess the response and dynamic performance of the system:

- Voltage and frequency response at key substation busbars including the time of busbar energisation.
- Maximum cold block loads, decayed cold block loads, and normal block loads, as well as the time of block load pick-up, and changes from the cold state to the half cold state, and eventually to the steady state.
- Generator response at five hydro power stations including generator terminal voltage, electrical frequency, and Rate of Change of Frequency (RoCoF); generator stator MW and Mvar outputs; generator rotor speed, angle, and mechanical torque output; generator excitation voltage and current; relevant hydro governor variables; and times the generators are synchronised to the system.
- Wind farm response at all eleven wind farm sites including WTG terminal voltage, MW and Mvar output, wind farm controller active power reference settings and voltage settings, and the times at which the active power reference settings and voltage settings change.

Section 3.2.2 contains a full list of assumptions used in the dynamic studies; the important ones are repeated in table 5.7.

Table 5.7
Important assumptions for the dynamic studies

Component	Model	Assumptions
Hydroelectric anchor generator	AVR setpoint	1pu maintained at the generator 11kV terminal
	Governor mode	Isochronous mode (i.e. bring frequency back to 50Hz after disturbance)
	Turbine	Inelastic water column with surge tank, penstock and tunnel dynamics
	Governor	Proportional control with transient droop
	Load bank	10% of the MVA rating of the machine
Wind farms	operating mode	Voltage control, 1.02pu at the POC, 3% droop
	Max active power support	45% of the installed capacity
	Active power ramp rate	5% of the installed capacity per second
	Protection settings	Under/over voltage, under/over frequency and RoCoF
Load	Characteristic	Constant active and reactive power type
	Demand	Maximum LTDS demand at individual primary substations
	Cold load demand	200% at pick up, 150% after 15 minutes, nominal value after 30 minutes
Transformer	Overload rating	150% rated for a short duration on ONAN cooling

Anchor generator BLPU capability

Based on the generic generator models used in the study (section 3.3) and simulation results, the BLPU capability of the Glenlee hydroelectric generator is estimated to be around 15 per cent of its MVA rating or 4.5 MW. This is the maximum demand the anchor generator can pick up.

Similar to the load flow results, the anchor generator dynamic response indicates that it's capable of energising the six wind farms, their respective transformers and any 132kV circuits on its own. However, although the load flow studies didn't highlight any CLPU constraints, the dynamic study showed that the lack of sufficient inertia in the network and a slow governor response from the anchor generator makes it impossible to pick up the full Newton Stewart substation cold load demand of 12.4 MW (40 per cent of generator MVA rating) in one go. Even when dividing the demand into two, the reduced block load of 6.2 MW is still too much for the anchor generator to pick up without exceeding the frequency threshold of 47.5Hz. Therefore, without any support from other DERs, the Glenlee anchor generator on its own can only energise up to stage 9.

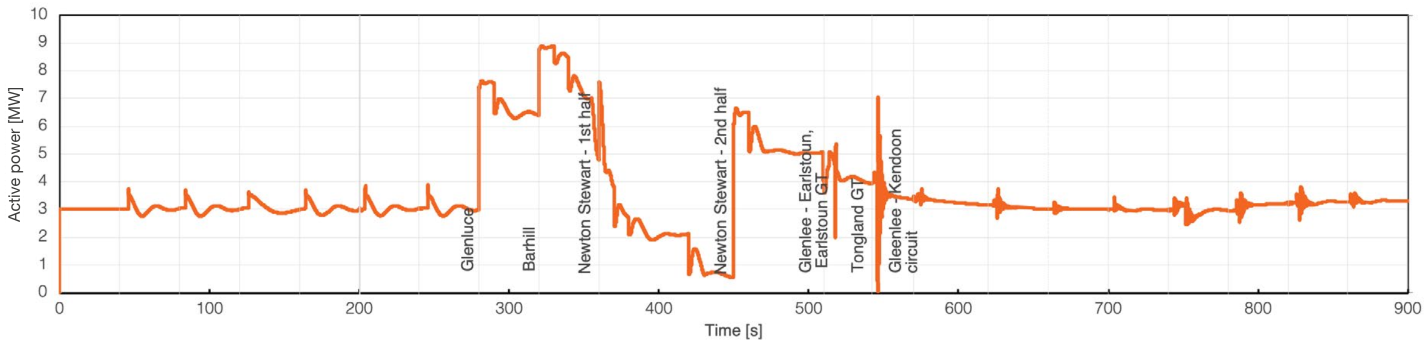
To progress beyond stage 9 and achieve an acceptable frequency response. the probable solutions are:

1) To follow a slightly different restoration plan and bring the four other hydroelectric plants (figure 5.1) online before the wind farms. Assuming that all the other hydroelectric plants have a BLPU capability of 15 per cent, estimations are that bringing on all the synchronous DERs will be more than sufficient to energise the whole Newton Stewart primary substation.
2) Implement a coordinated action of load bank switching and wind farm MW ramp up.
3) Reduce the block load pick-up size by implementing individual 11kV feeder switching.
4) Utilise a BESS to provide fast frequency regulation and therefore increase the BLPU capability of the anchor generator.

Solution 2 was simulated in the power system studies using a combination of a 3 MW load bank action and wind farm active power support. This scheme is slightly different from the one adopted in the Chapelcross study where only wind farm active power support was used, because in Galloway's case, wind farm active power support alone is inadequate due to the low inertia of the system. In the simulation, just before picking up the first half of Newton Stewart demand, the load bank is switched out and the Airies and Carscreugh wind farms are asked to ramp up to 10 per cent of their installed capacity. In practice, some level of automation may be needed to coordinate this action to maintain an acceptable system frequency. The active power output of the anchor generator reduces between 350 seconds and 450 seconds (figure 5.5) in the simulation (between steps 9 and 10) due to the combined action of the load bank and the wind farms to pick up the Newton Stewart substation.

In restoration option 2 (after 500 seconds in figure 5.5), four other hydroelectric plants are energised – Earlstoun, Tongland, Carsfad and Kendoon – and synchronised to the rest of the network. Since the total demand on the system at this point is much less than the combined capacity of all the generations online (hydroelectric plants and wind farms), these four hydro plants only operate at their minimum MW limit of 5 per cent. Also, they do not participate in frequency regulation. Only the anchor generator is responsible for maintaining the system frequency.

Figure 5.5
Anchor generator active power response



At the end of the restoration process, Glenlee generates around 3.3 MW, having more than 20 MW headroom as operating reserve, while its steady state reactive output is around 3Mvar (lagging) which is only 30 per cent of its limit. This means that the anchor generator has plenty of spare capacity to energise the transmission network at the interface point at the New Cumnock 132kV circuit breaker.

Wind farm response

The wind farms can play an important role in the restoration of the network by absorbing the charging reactive power generated by the wind farm array cables, and providing active power to increase the BLPU capability of the anchor generator. When connected to the system, the wind farms operate in voltage control mode i.e. the wind farms will deliver or absorb reactive power as required to maintain their terminal voltages at the required voltage setpoint of 1.02pu. The wind farm power park controller output was found to be acceptable in response to any simulated voltage excursions in the system.

Out of the six wind farms in option 1, only two are required to provide MW and Mvar support. In the simulation studies, Airies and Carscreugh wind farms were used, but any two out of the six will suffice provided their turbine technology permits. It is not necessary for all six wind farms to participate in the restoration process.

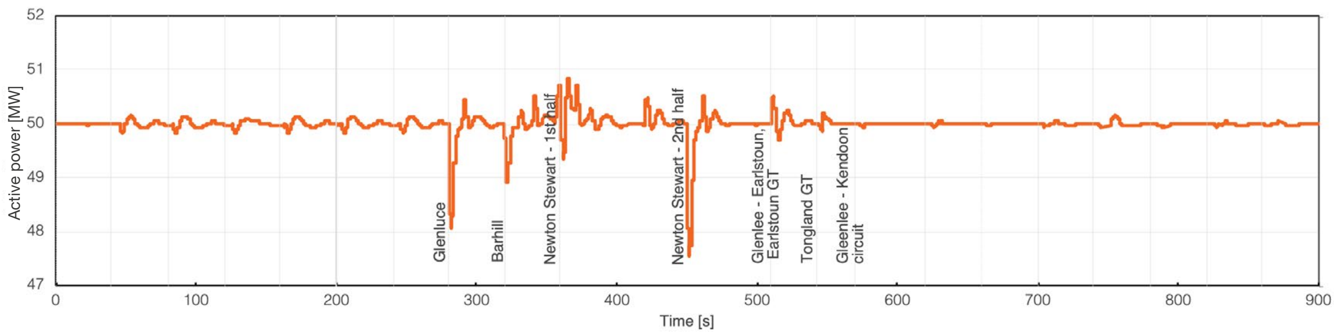
Network voltage response

No significant voltage excursions were observed across the energised 132kV and 33kV network during the simulations. The network voltages at all the substations were within acceptable limits (±10 per cent for 132kV and ±6 per cent for 33kV) throughout the restoration process.

Network frequency response

The frequency response of the system was found to remain acceptable at all stages and for all restoration events. A minimum frequency nadir of 47.65Hz was recorded when picking up half of the cold block load at Newton Stewart (i.e. 6.2 MW) in stage 10.

Figure 5.6
System frequency response at Glenlee 11kV



Key findings

Based on analysis of the dynamic simulation results, the key findings are:

- Glenlee hydroelectric anchor generator, without any support from other DERs including wind farms, can energise several 132kV GSPs, 6 wind farms and restore the power supply to Glenluce and Barhill primary substations (i.e. up to stage 9 in table 5.2). The block loads at both these substations are within the anchor generator's BLPU capability of 15 per cent. However, CLPU value of the demand at Newton Stewart primary, is more than Glenlee's BLPU capability and so it is not possible for the anchor generator alone to energise Newton Stewart in stage 10.
- Several options exist to increase Glenlee's BLPU capability to enable the DRZ restoration process to progress beyond stage 9. This includes:
  1) The restoration options are modified by changing the sequence of the stages in option 1 and 2, so that the hydroelectric plants at Earlstoun, Carsfad, Tongland and Kendoon are energised before Newton Stewart primary is energised. Adding the hydroelectric plants will increase the effective inertia of the network, and provide higher spinning reserve which will assist the anchor generator to better manage the frequency and energise the whole DRZ. This is the preferred solution.
  2) Implementing a coordinated action of load bank switching and wind farm MW ramp up.
  3) Reducing the block load pick-up size by implementing individual 11kV feeder switching.
  4) Utilising a BESS to provide fast frequency regulation and therefore increase the BLPU capability of the anchor generator and arrest the frequency drop.
- No rotor angle and voltage stability issues were observed in the system, and no unacceptable power oscillations were observed among the hydroelectric generators, between the wind farms, or between the hydroelectric generators and the wind farms.
- No particular challenges were observed with synchronisation of the hydroelectric plants to the weak network, apart from electromechanical oscillations of around 1Hz, typical of salient pole machines, which decayed within a few seconds.
- No voltage excursions were observed across the energised network throughout the restoration process simulation when picking up cold block loads at the primary substations.
- Table 5.8 compares the results across the different restoration options.

Table 5.8
Galloway dynamic simulation success criteria

Restoration success criteria – dynamic studies*	Option 1	Option 2	Option 3
Capability of the anchor generator to restore Galloway DRZ **	✔	✔	✔
Restore Galloway DRZ using anchor generator + WFs + load bank	✔	✔	✔
Restore Galloway DRZ using anchor generator + four other hydroelectric plants (if energised in option 1 before picking up Newton Stewart primary)	✔	✔	✔
Anchor generator operating reserve at the end of the restoration – more than 50% (12.75 MW) of the operational limit	✔	✔	✔
Anchor generator reactive power burden at the end of the restoration – less than 40% (4Mvar) of operational limit	✔	✔	✔
Frequency excursion within acceptable limits of 51 Hz and 47.5 Hz	✔	✔	✔
RoCoF within acceptable limits	✔	✔	✔
Voltage excursion within acceptable limits of ±10% at 132kV and ±6% at 33kV	✔	✔	✔

✔ Fully achieved ✔ Partially achieved ✘ Not achieved

* Although the three options form part of one large expanding option, the success criteria are evaluated independently for each option.

** The anchor generator needs MW and Mvar support from other DERs to complete the restoration in option 1.

5.2.3 EMT simulation results

The EMT studies considered events such as the energisation of the GTs, SGTs and circuits (both overhead lines and cables). Selected energisation events were studied as discrete events to assess the maximum and minimum voltage transients based on PoW simulation. No customer demand was considered in these studies.

Table 5.9 lists the energisation events and the corresponding max and min voltage changes at the anchor generator LV terminal (Glenlee 11kV) and the grid side busbar (Glenlee 132kV). Apart from energising the Barhill primary transformer, all the other events lead to a worst-case voltage dip that exceeds the SQSS limit of 12 per cent for very infrequent events. The minimum voltage dip, however, is within the limit.

The Tongland hydroelectric energisation event is found to have the highest impact on the voltage and could potentially lead to under-voltage tripping of the anchor generator. Energising the two SGTs at New Cumnock also has a big impact on the Glenlee 132kV and 11kV voltages. This is expected due to the size of the transformers, but it's important to note here that even with PoW switching, the minimum voltage transient is very close to the SQSS limit of 12 per cent.

During an actual energisation, the voltage transient could be anywhere between the Max and Min limits. Although addition of customer demands is expected to reduce the transients to a certain extent, there is still a risk for the anchor generator to energise these network elements. A couple of solutions are provided in the summary section to mitigate the risk of voltage transients.

Table 5.9
Voltage dips (%) from selected Galloway energisation events

No	Restoration energisation events	Transformer rating	Circuit length	Glenlee 11kV (ΔV)		Glenlee 132kV (ΔV)	
		MVA	Km	Max	Min	Max	Min
1 Stage 1	Glenlee hydro 132/11kV GT	30	NA	-19.82%	-3.61%	NA	NA
	+						
	Glenlee – Newton Stewart – Glenluce 132kV circuit	NA	52				
	+						
	Glenluce 132/33kV GT	60	NA				
2 Stage 9	Barhill 33/11kV primary transformer	5	NA	-9.55%	-0.18%	-14.81%	-0.25%
3 Stage 10	Newton Stewart 33/11kV primary transformer T1	10	NA	-13.72%	-0.74%	-24.06%	-0.86%
	+						
	Sorbie 33/11kV primary transformer T1	7.5	NA				
4 Stage 12	Glenlee – Tongland 132kV circuit	NA	33	-27.53%	-2.46%	-43.65%	-2.63%
	+						
	Tongland hydroelectric 132/11kV GT 2A	30	NA				
	+						
	Tongland – 132/33kV GT 2B	60	NA				

Green – within SQSS -12% voltage dip limits Red – exceeds SQSS -12% voltage dip limits

Table 5.9 (continued)
Voltage dips (%) from selected Galloway energisation events

No	Restoration energisation events	Transformer rating	Circuit length	Glenlee 11kV (ΔV)		Glenlee 132kV (ΔV)	
		MVA	Km	Max	Min	Max	Min
5 Stage 13	Glenlee – Kendoon 132kV circuit	NA	6	-17.45%	-0.48%	-27.03%	-0.69%
	+						
	Kendoon – Carsfad 132kV circuit	NA	2.6				
	+						
	Carsfad hydro 132/11kV GT	30	NA				
6 Stage 15	New Cumnock A – two 275/132kV SGTs	2x240	NA	-24.15%	-8.63%	-37.32%	-12.74%
7 Stage 16	New Cumnock A – Dersalloch 132kV circuit (line + cable)	NA	10.7	-15.15%	-2.16%	-21.42%	-2.45%
	+						
	Dersalloch WF 132/33kV GT	90	NA				

Green – within SQSS -12% voltage dip limits Red – exceeds SQSS -12% voltage dip limits

Table 5.10 presents a couple of events where over-voltage transients are observed. The first event shown in the table also appeared in table 5.9 where a voltage dip was recorded for the same switching event. Due to the combined energisation of the transformers (at Glenlee hydroelectric plant and Glenluce GSP) and the energisation of the Glenlee GSP – Newton Stewart GSP – Glenluce GSP 132kV circuit, the voltage transient has deviations both above and below the nominal value of 1pu.

Figure 5.7(a) shows the instantaneous voltage values at the anchor generator's 11kV terminal and figure 5.7(b) gives the corresponding RMS value. As evident from the figures, the transient has a maximum voltage rise of 1.45pu. Figure 5.7 corresponds to the PoW value for which there is maximum voltage rise. There are similar figures for maximum voltage dip (as mentioned in table 5.9), but these are not discussed further.

Figure 5.7
Energisation event no. 1 from table 5.10;
(a) instantaneous phase voltages and (b) RMS voltage

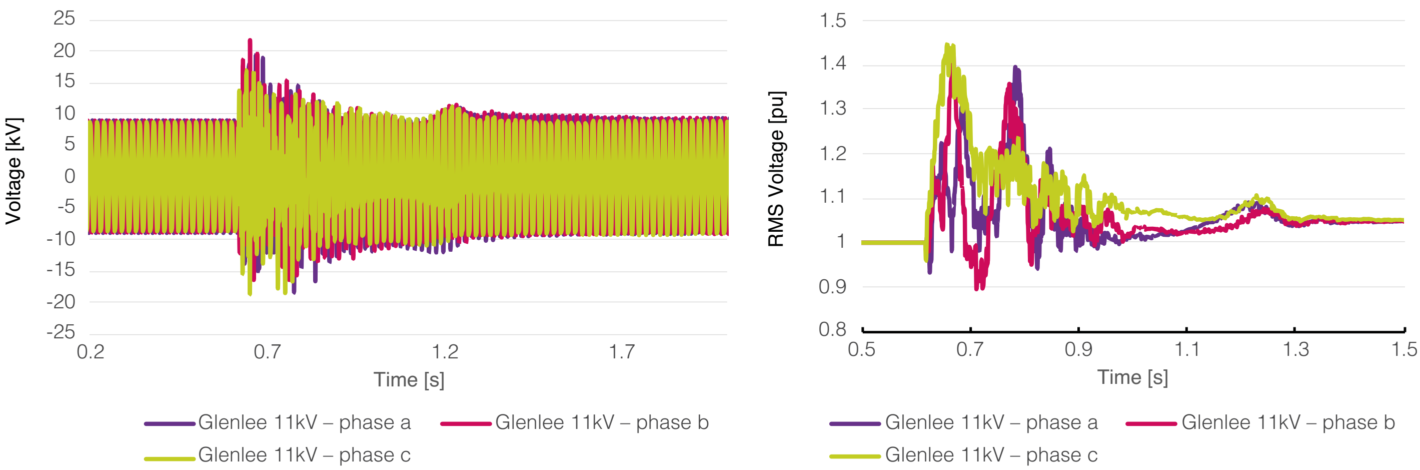


Table 5.10
Voltage dips (%) from selected Galloway energisation events

No	Restoration energisation events	Trfr rating	Circuit length	Glenlee 11kV (ΔV)		Glenlee 132kV (ΔV)		Tongland 132kV (ΔV)	
		MVA	Km	Max	Min	Max	Min	Max	Min
1 Stage 1	Glenlee hydro 132/11kV GT	30	NA	45.00%	14.50%	100.00%	26.70%	NA	NA
	+	NA	52						
	Glenlee – Newton Stewart – Glenluce 132kV circuit								
	+								
	Glenluce 132/33kV GT	60	NA						
2 Stage 12	Glenlee – Tongland 132kV circuit	NA	33	13.90%	0.28%	36.60%	0.20%	35.81%	0.00%
	+								
	Tongland hydroelectric 132/11kV GT 2A	30	NA						
	+								
	Tongland – 132/33kV GT 2B	60	NA						

Green – within SQSS +6% voltage limit Red – exceeds SQSS +6% voltage limits

Key findings

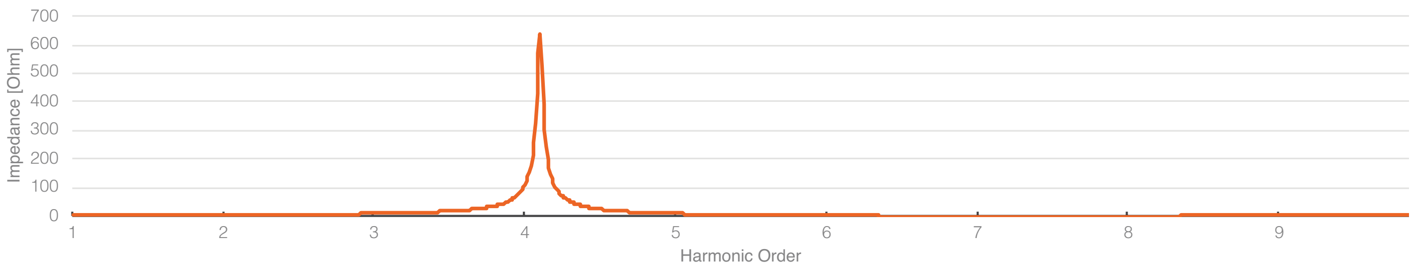
- Transformer energisation based on PoW simulations shows that the most onerous voltage dip for all restoration events, with the exception of Barhill primary substation, will exceed the acceptable limits defined by SQSS. Suggested solutions to mitigate the risk of under-voltage dips include:
  - Implement circuit breakers with PoW switching capability to minimise voltage transients. This, however, means replacing existing breakers, which could very expensive.
  - Use a ‘soft start’ technique for anchor generator as explained in the Chapelcross case study.
- The Glenlee – Newton Stewart – Glenluce 132kV circuit and the Glenlee – Tongland 132kV circuit is expected to cause significant voltage rise (>50 per cent) with the potential to damage equipment such as surge arresters, insulation failures etc. A PoW breaker will have little impact on limiting the voltage rise. A potential solution to this problem could be to energise the 132kV circuits at say 10 per cent reduced voltage (118.8kV) to limit the amount of charging reactive power generated, thereby reducing the voltage transient. Detailed studies would need to be performed to determine the exact energisation voltage.

5.2.4 Harmonic simulation results

The harmonic impedance scans highlighted a few potential resonance issues.

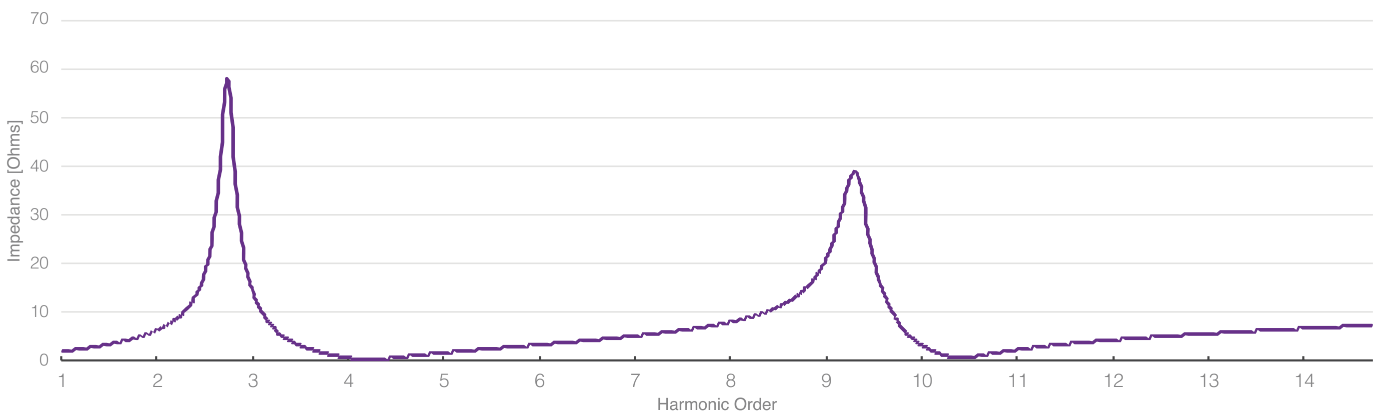
- At stage 1 (table 5.2), the Glenlee Hydro energises the 132/11kV grid transformer, and the transmission network to Newton Stewart GSP and Glenluce GSP. In total, three grid transformers are energised, one of 30MVA and the other two of 60MVA. At the terminal of the anchor generator, a low order resonance is observed at the fourth harmonic (200Hz) of magnitude 635Ω (figure 5.8). This can potentially cause a temporary over-voltage due to the transformer inrush current (rich in lower order harmonics like 2nd, 3rd etc) and lead to over-voltage tripping of the generator. However, a simple calculation based on the transformer rating, inrush current assumption (section 3.2.4) and the resonance magnitude shows that to cause a 10 per cent rise in the terminal voltage, the lower order harmonic currents should be a minimum of around 16 per cent of the fundamental. So as long as the harmonic content of the inrush current remains below this value, the resonance should not be a cause for concern.

Figure 5.8
Harmonic impedance scan at Glenlee anchor generator 11kV busbar – Restoration option 1



- At stage 2, when the Airies windfarm is energised at Newton Stewart GSP, a second resonance point is introduced to the impedance spectrum at Glenlee 11kV bus. The first resonance seen in figure 5.8 now shifts to the third harmonic (150 Hz) with a magnitude of 58 Ω. The second resonance is introduced around the tenth order (500 Hz) with a magnitude of 39 Ω. Since the magnitude of these impedances has reduced by a factor of ten compared to stage 1, this is not expected to cause any over voltage issues.

Figure 5.9
Harmonic impedance scan at Glenlee anchor generator 11kV busbar – Restoration option 2



- In stages 3–21 this trend continues with only smaller resonance points being introduced in the impedance spectrum at Glenlee 11kV busbar. Considering the small magnitude of these resonances, this is of little concern. When further transformers are energised, the inrush current from the previous transformers will have died down already and because more impedance is introduced in the network, the effective magnitude of the harmonic currents (even neglecting phase angle cancellations) will be less than in stage 1.

Key findings

The findings of the harmonic assessment for the Galloway study case can be summarised as:

- Lower order resonances are observed at the anchor generator terminal during some of the restoration stages. However, the magnitude of the impedance at these points is very small and, therefore, it is not expected to cause any over voltage issues.

5.3 Summary

5.3.1 Restoration plans

Galloway restoration options 1 to 3 are three sequential parts of a single large restoration plan. The plan aims to energise 3 primary substations with a total demand of around 12 MW, whereas the total demand in the region is around 68 MW. Furthermore, the region has a very large hydroelectric and wind farm resource totalling more than 470 MW. In the current restoration plan only around 5 MW of additional DERs are utilised for the DRZ restoration.

It is suggested that some additional restoration plans are investigated for the Galloway region to explore the maximum demand that can be energised with the available DER sources.

5.3.2 Power system study results

The table below provides a summary of the power system simulation study results highlighting the main technical findings and challenges that are likely to be experienced and that may require mitigation.

Table 5.11
Summary of the Galloway power system simulation study results

Power system study	Restoration option 1	Restoration option 2	Restoration option 3
Load flow studies	• Anchor generator cannot restore DRZ alone; it can energise the DRZ up to stage 6, then needs DERs to provide reactive power support due to charging power of 132kV, 33kV networks and WF cables • No overloading or voltage violations	• Anchor generator can restore DRZ option 2 • No overloading or voltage violations	• Anchor generator can restore DRZ option 3 • No overloading or voltage violations
Dynamic studies	• Anchor generator can energise 6 wind farms and 2 primary substations (stage 9), thereafter DER active power support is necessary to increase the BLPU capability to pick up the cold load at Newton Stewart • No voltage violations • No frequency or RoCoF violations	• Additional hydroelectric plants only operate at minimum 5% MW level of and make no contribution to frequency regulation • Frequency regulation is done only by the anchor generator • No voltage violations • No frequency or RoCoF violations	• Anchor generator has 20MW, and 70% Mvar in reserve • No voltage violations • No frequency or RoCoF violations
EMT studies	Possible voltage dip violations: • Stage 1 when Glenlee 132/11kV grid transformer and 132kV circuits to Newton Stewart and Glenluce GSPs are energised • Stage 9 when Glenluce primaries are energised • Stage 10 when Newton Stewart GSP primaries are energised Voltage rise violations: • Stage 1 when Glenlee hydro 132/11kV grid transformer, 132kV circuits to Newton Stewart, Glenluce GSPs and Glenluce 132/33kV transformer are energised (extreme)	Possible voltage dip violations: • Stage 12 when Glenlee – Tongland 132kV circuit and Tongland Hydros are energised (extreme) • Stage 13 when Glenlee – Kendoon 132kV line and Carsfad hydro is energised Voltage rise violations: • Stage 12 when Glenlee – Tongland 132kV circuit and Tongland Hydros are energised	Possible voltage dip violations: • Stage 15 when New Cumnock A SGTs are energised • Stage 16 when New Cumnock A – Dersalloch 132kV line and Dersalloch WF is energised
Harmonic impedance scan	• Fourth order harmonic in Stage 1 – very small risk of over-voltage tripping of anchor generator	• No significant harmonics	• No significant harmonics

5.3.3 Capability of the anchor generator to restore the DRZ

Although the anchor generator has enough active power to supply the demand of the primary substations in the restoration plan, it does not have enough reactive power capability beyond stage 6 in option 1 to absorb the charging power of the 132kV and 33kV circuits, and the wind farm cable arrays. It also has insufficient BLPU capability to pick up the New Stewart primary substation cold block load in stage 9.

The conclusion is therefore that the anchor generator on its own can only energise the Glenlee GSP 132/11kV grid transformer, the Glenlee GSP – Glenluce GSP and Glenlee GSP – Newton Stewart GSP 132kV circuits, the Glenluce 132/33kV grid transformer and 33kV busbar, and the Newton Stewart GSP 132/33kV grid transformer and 33kV busbar, as well as the first 5 wind farms in the Glenluce GSP.

5.3.4 Required DER interventions

In option 1, six wind farms are brought online from stage 2 to stage 7 (table 5.2). The charging power produced by the 132kV and 33kV networks, as well as the cable arrays of the wind farms, is more than what can be provided by the anchor generator, and additional DERs are required to progress the restoration beyond stage 7. The required Mvar can be provided by the first 3 wind farms energised, namely Airies WF, Artfield Fell WF and Barlockhart Moor WF.

In option 1, stage 10, the CLPU of Newton Stewart primary is more than the BLPU of the anchor generator, which at that stage is already reduced because of load previously energised. Picking up Newton Stewart primary in two steps is not sufficient, and a shortfall of around 5 MW needs to be provided by other DERs in order for the DRZ restoration process to continue.

No additional DER interventions are required during options 2 and 3, as more hydroelectric stations are brought online, which increases the system inertia, as well as the active and reactive power capability to absorb charging power from the transmission network and export MWs.

5.3.5 Other required interventions

The power system simulation studies show that significant over- and under-voltage dips could occur during the energisation of the grid transformers. Under-voltage dips could be mitigated by replacing the existing circuit breakers with PoW capable breakers to minimise the voltage transients, but this could be an expensive solution. Alternatively, the anchor generator could utilise a ‘soft start’ technique of gradually increasing and decreasing the generator terminal voltage a number of times to reduce the transformer inrush current magnitude and therefore the voltage transients.

The energisation of the Glenlee – Newton Stewart – Glenluce 132kV circuit and the Glenlee – Tongland 132kV circuit is expected to cause significant voltage rise (>50 per cent) with the risk of damaging equipment. A potential solution could be to energise the 132kV circuits at say a 10 per cent reduced voltage to reduce the charging power generated, and therefore also the voltage transient.

5.3.6 Transmission interface point capability

The transmission-distribution interface point capability study indicates that without any DER support and under no load conditions the DRZ can export 20 MW and import 3.24Mvar at the New Cumnock A 132kV circuit breaker. With DER support, and after restoring the whole DRZ, around 81 MW can be exported and 58.8Mvar can be imported from the transmission grid.

5.4 Conclusion

The Glenlee hydroelectric anchor generator has insufficient MW and Mvar capability to restore option 1 on its own and other DERs are required to provide both reactive power and active power at different stages in the restoration process to enable the DRZ and primary demand to be energised. At the same time, there are several significant voltage transients (voltage dip and voltage rise) resulting from component energisation .g. Glenlee – Glenluce 132kV circuit and the Glenluce grid transformer. These could be mitigated by implementing solutions presented in the EMT analysis section.

6. Legacy GSP restoration options and power system study results

Simulation studies for the Legacy GSP restoration options provide insight into some of the technical challenges associated with meshed networks and the requirements for viable DRZ restoration.

6.1 Restoration strategies

6.1.1 Overview

As mentioned in section 2.2.3, Legacy GSP is a rural network consisting of several interconnected 132/33kV BSP or grid substations and a large number of primary substations that are meshed at 33kV level.

The two restoration options listed in table 6.1 were identified for detailed systems studies to verify the Black Start potential of a meshed network. Although there are solar PV farms connected to the Legacy GSP network, these are not utilised during the restoration process, as the restoration options did not extend to the transformer groups these PV farms are connected to.

Table 6.1
Overview of the two main restoration options for Legacy GSP

Restoration option	Description
1	Self-starting of Cefn Mawr anchor generator, followed by sequential energisation and picking up the load at a number of primary substations (Ruabon, Monsanto, Llangollen, and Llansilin) interconnected between Legacy and Oswestry 132/33kV grid substations.
2	Self-starting of Cefn Mawr anchor generator, followed by energisation of Legacy 132kV busbar via the 132/33kV grid transformers. The DRZ is expanded to Oswestry 132/33kV grid substation from where a number of wind farms are energised via the 132kV network, before the load from Newton grid substation is picked up. Finally, the load is picked up at Ruabon, Monsanto, Llangollen, and Llansilin primaries, similar to option 1.

6.1.1 Restoration option 1

Restoration option 1 is a fairly basic restoration scenario in which only four 33kV primary substations are sequentially energised. No 132/33kV transformers are back-energised and no additional DERs are energised in this option, as the focus is solely on determining the ability of the anchor generator to pick up cold block load in a sequential manner. Due to the typical limited BLPU capability of a gas generator, the load at large primaries such as Ruabon, Llangollen and Llansilin can only be picked up in small sequential steps.

For example, with the BLPU of a gas generator typically being around 20 per cent of its capacity, the BLPU capability of Cefn Mawr works out to around 4 MW. This means that the maximum block load that can be energised is 2 MW for a CLPU of 200 per cent nominal load. In other words, only 11kV feeders, or groups of feeders, with less than 2 MW load can be picked up. This is explained in more detail in section 6.2.2. The stages of the restoration process are outlined in table 6.2 and table 6.3.

Table 6.2
System restoration stages for Legacy option 1

Stage	Action	Description
0	Self-start anchor generator	Self-starting of Cefn Mawr anchor generator
1	Energise PoC	Energisation of the Cefn Mawr 33kV PoC
2	Cold load pick-up	Energisation of Ruabon primary 33kV busbar and sequential pick up of the load by sequentially switching 4 groups of 11kV feeders < 2 MW each (primary substation restoration option G discussed in section 2.3). 2a – Energise Ruabon 11kV feeder 1 2b – Energise Ruabon 11kV feeder 2 & 3 2c – Energise Ruabon 11kV feeder 4 & 5 2d – Energise Ruabon 11kV feeder 6 & 7
3	Cold load pick-up	Energisation of Monsanto primary substation and picking up load
4	Cold load pick-up	Picking up load at Llangollen primary by sequentially energising 4 groups of 11kV feeders (primary substation restoration strategy G). 4a – Energise Llangollen 11kV feeder 1 4b – Energise Llangollen 11kV feeder 2 4c – Energise Llangollen 11kV feeder 3 4d – Energise Llangollen 11kV feeder 4 & 5
5	Cold load pick-up	Energisation of Llansilin primary and picking up half the load
6	Energise 33kV	Energisation of Legacy BSP 33kV busbar
7	Restoration complete	End of the restoration process

6.1.2 Restoration option 2

Restoration option 2 is more complex than option 1 and includes expanding the DRZ to the 132kV distribution network and energising wind farms connected to the 132kV network to support the restoration process in the early stages. The last stages of option 2 are similar to option 1, except that by this time in the restoration process the anchor generator is significantly more loaded compared to option 1, although it has the support of the connected wind farms.

Table 6.3
System restoration stages for Legacy option 2

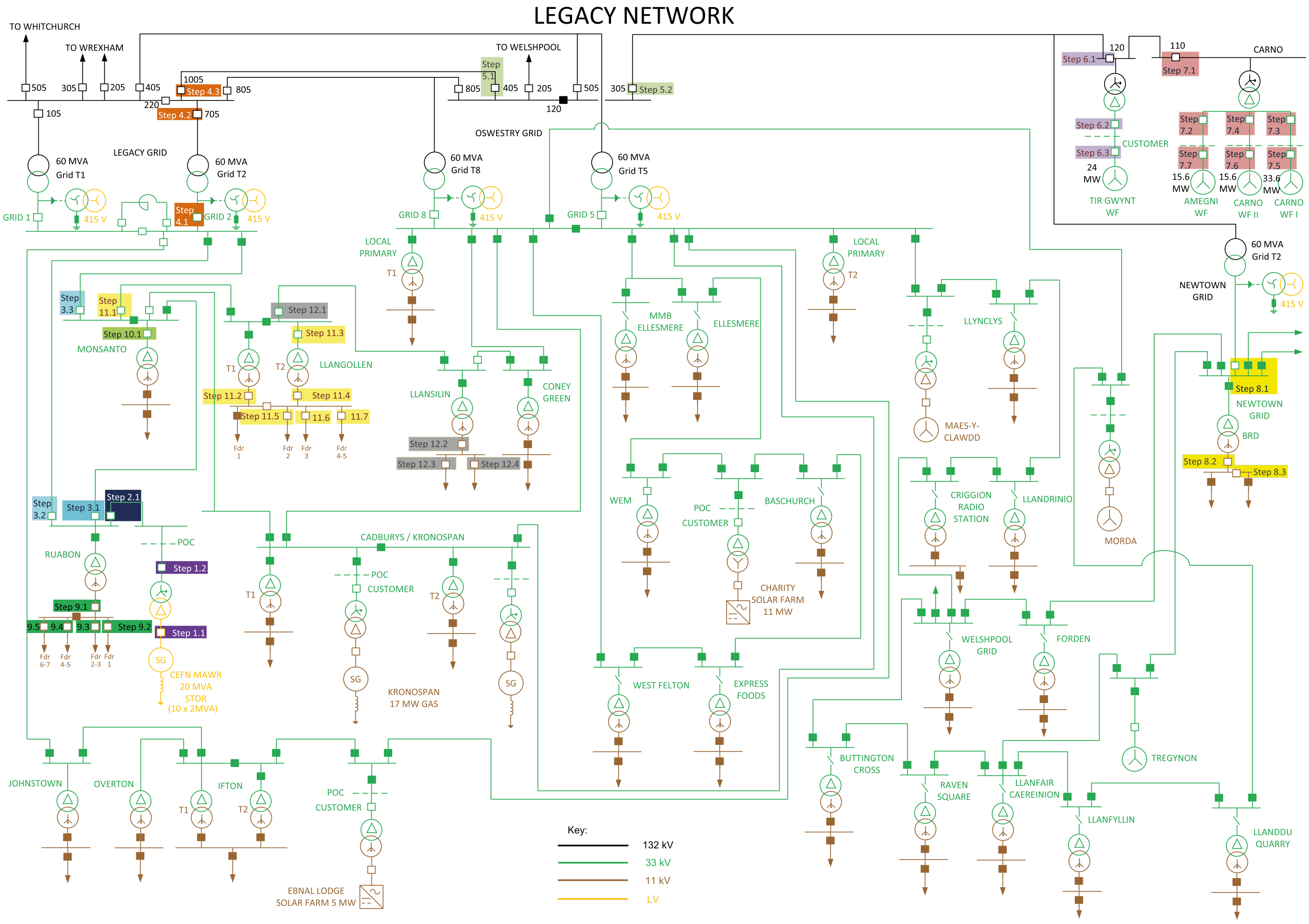
Stage	Action	Description
0	Self-start anchor generator	Self-starting Cefn Mawr anchor generator
1	Energised PoC	Energisation of the Cefn Mawr 33kV PoC
2	Energise primary, no load	Energisation of Ruabon 33kV busbar, without picking up load
3	Energise primary, no load	Energisation of Monsanto primary 33kV busbar, without picking up load, and energisation of the Legacy BSP 33kV busbar
4	Energise grid transformer and 132kV circuit	Back-energisation of Legacy 132/33kV grid transformer 2, energise 132kV Legacy busbars and circuit to 132kV Oswestry busbar
5	Energise 132kV circuit to WF, energise grid transformer	Energisation of Oswestry BSP 132kV busbar, followed by the 132kV circuit to Tir Gwynt busbar and Carno 132kV busbar, as well as the energisation of Newtown grid substation 132/33kV transformer
6	WF online	Energisation of Tir Gwynt 132kV busbar followed by the restoration of supply to Tir Gwynt wind farm

Table 6.3 (Continued)
System restoration stages for Legacy option 2

Stage	Action	Description
7	WF online	Energisation of Carno 132kV busbar followed by the restoration of supply to Amegni and Carno I & II wind farms (Collectively referred to as Carno WFs)
8(a)	Cold load pick-up (CLPU)	Energisation of Newtown Grid 33kV busbar, and picking up half the load (load 1) at BRD primary substation (Using primary substation energisation strategy C)
Tir Gwynt and Carno WFs each ramp up their active power to 2% of their installed capacity		
8(b)	Cold load pick-up (CLPU)	Pick up of the second half of the load at BRD primary (load 2)
Similar restoration process to option 1 stages 2 – 5		
9	CLPU	Picking up Ruabon primary 11kV load by sequentially energising 4 groups of 11kV feeders (primary substation restoration option G discussed in section 2.3)
9(a)	CLPU	Energise Ruabon 11kV feeder 1
9(b)	CLPU	Energise Ruabon 11kV feeder 2 & 3
9(c)	CLPU	Energise Ruabon 11kV feeder 4 & 5
Tir Gwynt and Carno WFs each ramp up their active power to 10% of their installed capacity		
9(d)	CLPU	Energise Ruabon 11kV feeder 6 & 7
10	CLPU	Energisation of Monsanto primary 33/11kV transformer and picking up load
11	CLPU	Picking up Llangollen primary 11kV by sequentially energising 4 groups of 11kV feeders (primary substation restoration strategy G)
11(a)	CLPU	Energise Llangollen 11kV feeder 1
11(b)	CLPU	Energise Llangollen 11kV feeder 2
11(c)	CLPU	Energise Llangollen 11kV feeder 3
11(d)	CLPU	Energise Llangollen 11kV feeder 4 & 5
12	CLPU	Energisation of Llansilin primary 33kV busbar and picking up the load in two steps
13	Demand normalises	Cold load demand picked up in stages 11 and 12 settles down
14	Restoration complete	End of the restoration process

Figure 6.1 shows the restoration steps for each of the above stages in option 2. Steps are numbered for easy reference.

Figure 6.1
Switching steps for Legacy restoration option 2



6.2 Power system study results

Simulation studies for the Legacy GSP restoration options provide insight into some of the technical challenges associated with meshed networks and the requirements for viable DRZ restoration.

6.2.1 Load flow simulation results

The important load flow simulation assumptions are repeated in table 6.4 for the reader's reference.

Table 6.4
Important assumptions for the load flow study

Component	Model	Assumptions
Anchor generator	Voltage setpoint	1pu maintained at the generator terminal
	Load bank	10% of the MVA rating of the machine, 0.99 power factor
Wind farms	Operating mode	Voltage control, 1.02pu at the PoC
	Max active power support	10% of the installed capacity
Load	Characteristic	Constant active and reactive power type
	Demand	Maximum LTDS demand at individual primary substations
	Cold load demand	200% at pick up, 150% after 15 minutes, nominal value after 30 minutes
Transformer	Overload rating	150% rated for a short duration on ONAN cooling
	Tap action	OLTC for all transformers except anchor generator station transformer

As in the case of the Galloway case study, a load bank is considered in the studies to take into account the assumed minimum demand of 10 per cent rating required by the anchor generator for stable operation. The load bank effectively reduces the capability of the machine by this amount. It has no role as such in the load flow studies, but it is included to keep parity with the dynamic studies where it is useful for a stable response of the turbine governor system.

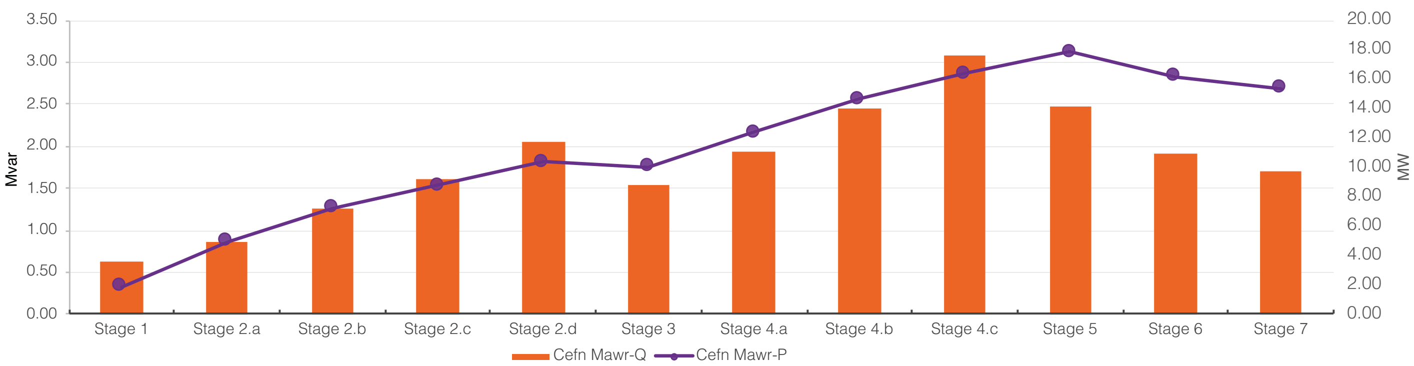
Anchor generator active and reactive power capability

The Cefn Mawr gas plant has ten units in parallel, each of 2 MW and +1.49Mvar/ -0.961Mvar maximum operational limit. The units are modelled as an equivalent source in the load flow and dynamic studies.

Legacy restoration option 1 focuses on energising only the 33kV part of the network. The total demand at each primary substation is divided into two to three blocks by switching 11kV circuit breakers and energising individual feeders or two feeders as a group (refer to the restoration stages in table 6.4). This is not necessary from a steady state analysis point of view but during dynamic studies this is essential to keep the total demand below the BLPU capability of the anchor generator. Further explanations are provided in section 6.2.2.

Figure 6.2 shows the active (MW) and reactive (Mvar) power output of Cefn Mawr at different stages of the restoration. The maximum active power dispatch of 18 MW is reached when picking up half of the Llansilin substation demand in stage 5 (table 6.3) whereas the reactive demand peaks in stage 4.c when picking up the last part of the Llangollen substation demand. As the cold load characteristic settles down, the MW and Mvar demand on the anchor generator reduces as well as seen in stages 5,6 and 7. The Cefn Mawr anchor generator, therefore, is capable of restoring the demand of the four primary substations (Ruabon, Monsanto, Llangollen and Llansilin) without any additional support.

Figure 6.2
Anchor generator active and reaction power output – option 1

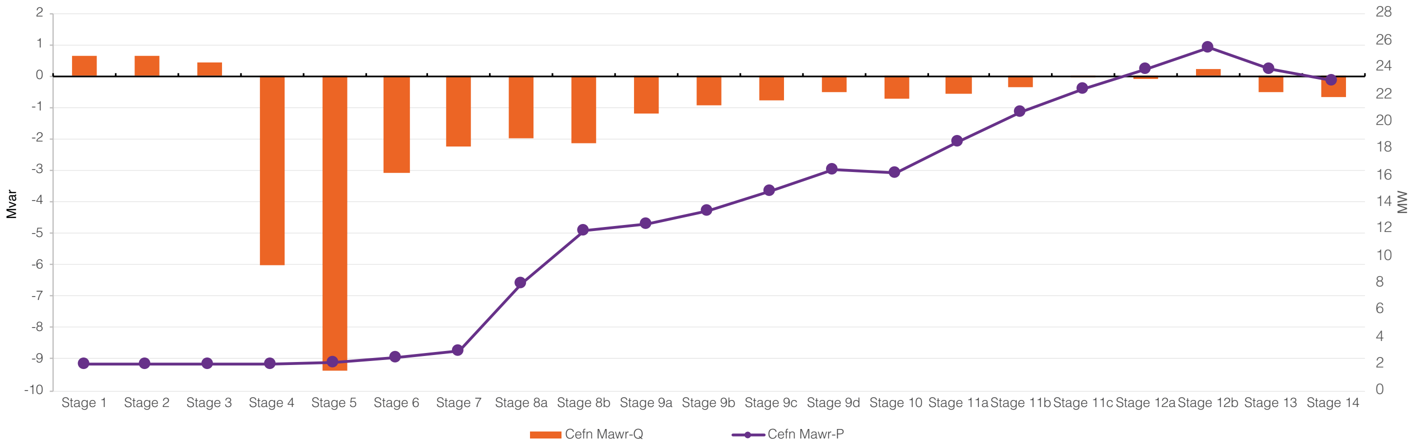


In option 2, primary substation demand is only picked up after energising the Legacy 132kV circuits (table 6.3). All the charging power from the 132kV network is absorbed by the anchor generator before Tir Gwynt wind farm is brought online in stage 6 to provide voltage control support. Around 11Mvar flows back to the 33kV network which exceeds the leading reactive power limit of the anchor generator (10 x 0.961Mvar). In other words, the anchor generator is operating at its reactive capability limit and is unable to absorb the extra charging power. Since there are no other sources to absorb this extra Mvar, the anchor generator will trip on under-excitation limiter.

A workaround to this problem is to energise the 132kV circuits at a reduced voltage. Since the amount of charging power generated in a circuit depends directly on the square of the line voltage, maintaining a reduced voltage will bring down the Mvar feeding back to the anchor generator. Operating the anchor generator with a terminal voltage of 0.95pu therefore, maintains the 132kV voltage at 1.05pu and the generated charging power is within the capability of Cefn Mawr. The acceptable voltage limit is ±6 per cent at 132kV as per the SQSS and hence there is no issue as such at stage 5 if the voltage goes up to 1.05pu.

Figure 6.3 gives the active (MW) and reactive (Mvar) power dispatch of the anchor generator at every stage of the restoration process. The active power output increases from stage 8 onwards as the substation cold load demands are picked up. At stage 11b, the MW output exceeds the anchor generator active power operational limit of 20MW. Therefore, without any active power support from other DERs such as wind farms or a BESS, the anchor generator on its own can only energise part of the DRZ. It cannot pick up two thirds of the demand at Llangollen and the full demand at Llansilin. Apart from MW support, the wind farms also provide voltage control support by absorbing the Mvar generated from the 132kV circuit and the wind farm array cables.

Figure 6.3
Anchor generator active and reactive power output – option 2



Transmission interface point MW and Mvar capability

Although not technically part of the transmission network, Legacy BSP 132 kV circuit breaker was selected as the DRZ's interface point between the distribution and the transmission network. To find out the amount of MW the anchor generator can provide at the transmission-distribution (T-D) interface point (IP), a voltage versus active power sensitivity study was done at the 132kV breaker of Legacy SGT. Figure 6.4 shows the P-V curve for two scenarios, when there is no Mvar support from the wind farms, and when both provide Mvar support. The wind farms provide no MW support at any stage. Also, no primary substations have been energised i.e. this study is under no load condition.

The MW demand at the T-D IP is increased gradually until the anchor generator reaches its MW or Mvar capability limit and the corresponding voltages are recorded at the generator LV terminal, Legacy GSP 33kV busbar and at Legacy 132kV breaker. Cefn Mawr generator maintains its terminal voltage tightly at 0.95pu. As discussed in the previous section, the reason for maintaining a voltage lower than 1pu is to avoid too much charging power flowing back to the anchor generator.

As the active power export increases, the voltage drops at the IP considering there is no voltage control action from the SGT or any other transmission connected sources. This value gives us an idea of the amount of MW support the anchor generator DRZ can provide to the transmission network while remaining within its operational limits.
As an example, an export of 15MW would lower the voltage from around 1pu to 0.98pu at the IP when no other DERs provide voltage support. When Tir Gwynt and Carno wind farms provide Mvar support, then hardly any change in the voltage profile is observed.

Figure 6.5 presents similar results but for Mvar import at the T-D IP. However, only one scenario is studied in this case as without wind farm reactive power support the anchor generator is not capable of absorbing any reactive power, as discussed in the anchor generator active and reactive power capability section. In figure 6.5 no primary substations are energised i.e. the anchor generator is under no load condition (except a load bank to maintain minimum stable response).

As the Mvar exchanged at the IP increases, the voltage goes up considering there is no tap action from the Legacy SGT or Mvar support from any other transmission connected sources. A 15Mvar imported at the IP would increase the voltage to around 1.06pu.

Figure 6.4
Available MW at the transmission-distribution interface point – no load

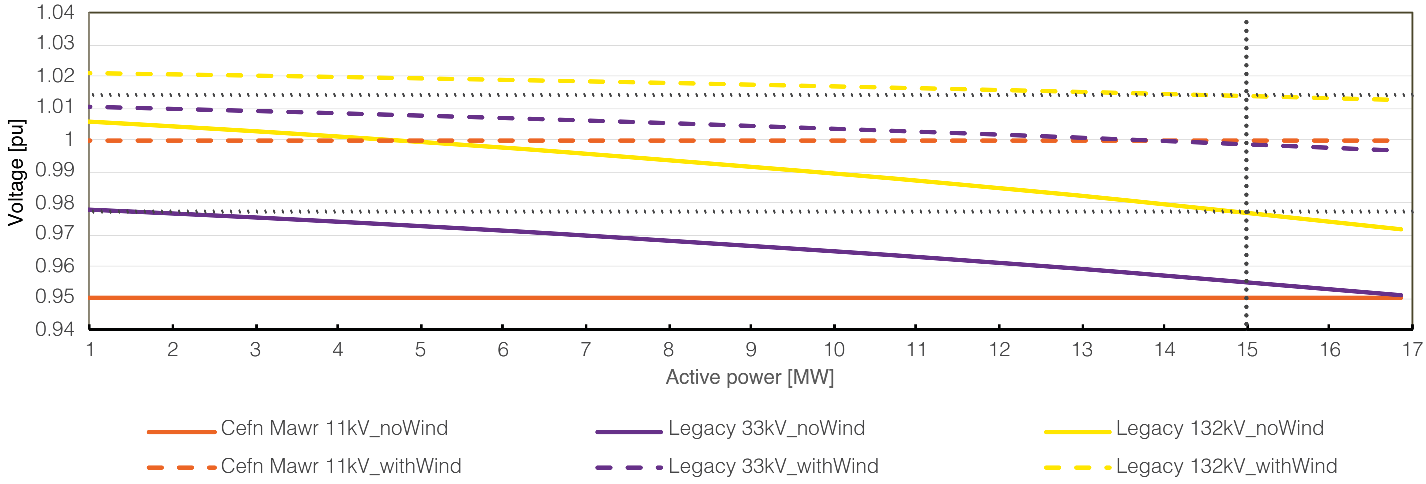
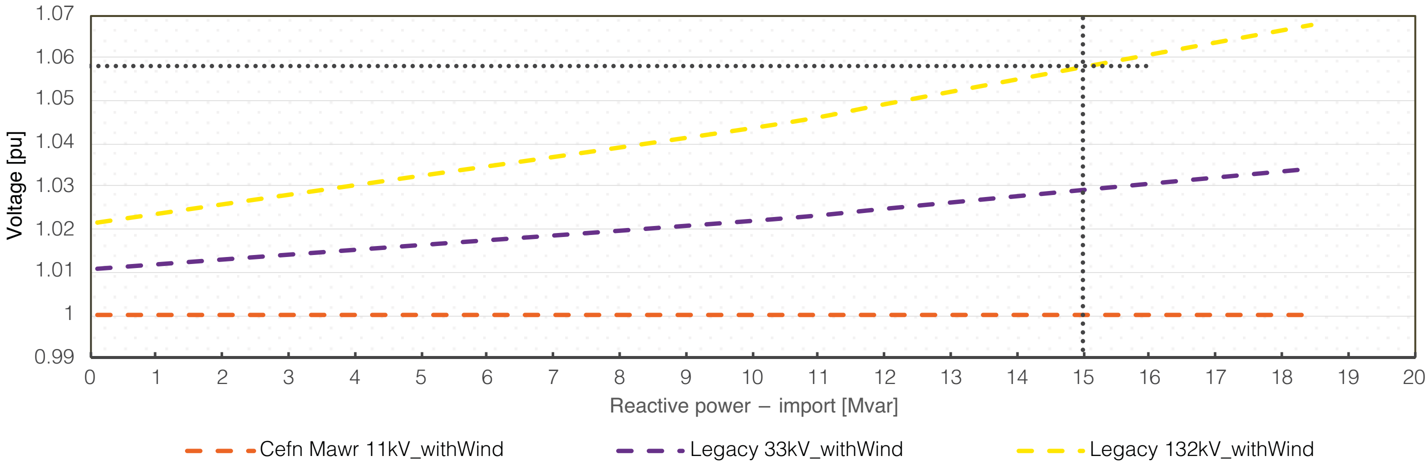


Figure 6.5
Available Mvar at the transmission-distribution interface point – no load



A similar study as above is repeated after the Legacy GSP is fully restored and the cold load demand at the primary substations have settled down to their pre-blackout values. In this case, however, the wind farms provide both active and reactive power support as the restoration of the whole GSP is not possible without additional DER support due to the shortfall of MW capacity. Table 6.5 and table 6.6 list the maximum possible MW and Mvar exchanges at Legacy 132kV breaker for the three different scenarios discussed above.

Table 6.4
Maximum active power export at the Legacy 132kV T-D interface point

No	Scenario	GSP demand	Transmission entry point
		MW	MW (export)
1	No load connected, no DERs, only anchor gen	NA	16.87
2	No load connected, anchor gen supported by DERs – only Mvar support from Tir Gwynt and Carno	NA	16.87
3	All primaries energised, anchor gen supported by DERs – MW and Mvar support from Tir Gwynt and Carno	23.4	6.39

Table 6.5
Maximum reactive power import at the Legacy 132kV T-D interface point

No	Scenario	GSP demand	Transmission entry point
		MW	MW (export)
1	No load connected, no DERs, only anchor gen	NA	not possible
2	No load connected, anchor gen supported by DERs – only Mvar support from Tir Gwynt and Carno	NA	18.45
3	All primaries energised, anchor gen supported by DERs – MW and Mvar support from Tir Gwynt and Carno	23.4	23

Network loading

No network component overloads occur at any stage in the system restoration for both the options. All 33kV circuits are loaded less than 50 per cent of their MVA ratings, and all 33/11 kV transformers are operated below their MVA ratings.

Network voltage

No network voltage violations occur in option 1. In option 2, as discussed in the anchor generator capability section, it is not possible to energise the 132kV network with 1pu maintained at Cefn Mawr terminal, as the amount of Mvar fed back to the 33kV network is more than the leading reactive power capability of the generator. A possible workaround solution is for Cefn Mawr to maintain 0.95pu voltage at its terminals before bringing the two wind farms online. After the wind farms are energised and operate in voltage control mode, the anchor generator voltage can be increased to 1pu. With this approach the voltage violations are mitigated.

Key findings

- Cefn Mawr anchor generator is capable of energising the Legacy 33kV BSP and restoring supply to the four primary substations as per restoration option 1.
- In option 2, the full restoration of the network is not possible without any active power support from other DERs such as wind farms, as the total demand exceeds the maximum active power capability of the anchor generator. This is because in addition to the four primary substations energised in option 1, a 10.06 MW cold load is picked up at BRD substation in option 2.
- Also, in option 2, a significant amount of charging power is fed back to the anchor generator when energising the 132kV network, especially the Legacy – Oswestry and the Oswestry – Carno – Newtown Grid 132kV circuits. The charging power is more than the reactive power capability of the Cefn Mawr generator. This can be mitigated by maintaining a lower voltage (≈0.95pu) at the generator terminal and increasing it after the Tir Gwynt wind farm is energised and ready to provide voltage support.

Table 6.6 lists the load flow success criteria for the Legacy group GSP restoration options.

Table 6.6
Legacy load flow restoration success criteria – all options

Restoration success criteria – load flow	Option 1	Option 2
Capability of the anchor generator to restore Legacy GSP DRZ	✔ (fully)	✔ (partially)
Restore Legacy DRZ using anchor generator + WFs (both MW and Mvar support)	–	✔ (fully)
Anchor generator remain within reactive limits	✔ (fully)	✔ (fully)
No thermal violations across all voltage levels	✔ (fully)	✔ (fully)
No voltage violations at 132kV and 33kV	✔ (fully)	✔ (fully)
No voltage violations at 11kV	✔ (fully)	✔ (fully)

✔ Fully achieved ✔ Partially achieved – Not applicable

6.2.2 Dynamic simulation results

Dynamic simulations were carried out for the two system restoration options. The following simulation results were used to assess the response of the system and to evaluate the viability of each restoration option and identify any actions and measures required to achieve a successful system restoration:

- Voltage and frequency response at key substation busbars including the time of energisation.
- Block load pick-up (BLPU) at every primary substation, with consideration of the CLPU decay profile discussed in section 3.2.1).
- Anchor generator response including terminal voltage and frequency, Rate of Change of Frequency (RoCoF), MW and Mvar outputs, mechanical torque output, generator field voltage, and generator speed.
- Tir Gwynt and Carno wind farm response including equivalent wind turbine generator (WTG) terminal voltage, MW and Mvar output, active power reference setpoints, and the times at which the active power reference settings are changed.

Section 3.2 contain the full list of assumptions; the important ones are repeated in table 6.7 for easy reference.

Table 6.7
Important assumptions for the dynamic studies

Component	Model	Assumptions
Anchor generator	AVR setpoint	1pu maintained at the generator terminal
	Min load setpoint	10% of the machine MVA rating
	Governor mode	Isochronous mode i.e. frequency always comes back to 50Hz
	Turbine	Four stage turbines
	Load bank	10% of the MVA rating of the machine
Wind farms	Operating mode	Voltage control, 1.02pu at the PoC
	Max active power support	10% of the installed capacity
	Active power ramp rate	5% of the installed capacity
	Protection settings	Under/over voltage, under/over frequency and RoCoF
Load	Characteristic	Constant active and reactive power type
	Demand	Maximum LTDS demand at individual primary substations
	Cold load demand	200% at pick up, 150% after 15 minutes, nominal value after 30 minutes
Transformer	Overload rating	150% rated for a short duration on ONAN cooling

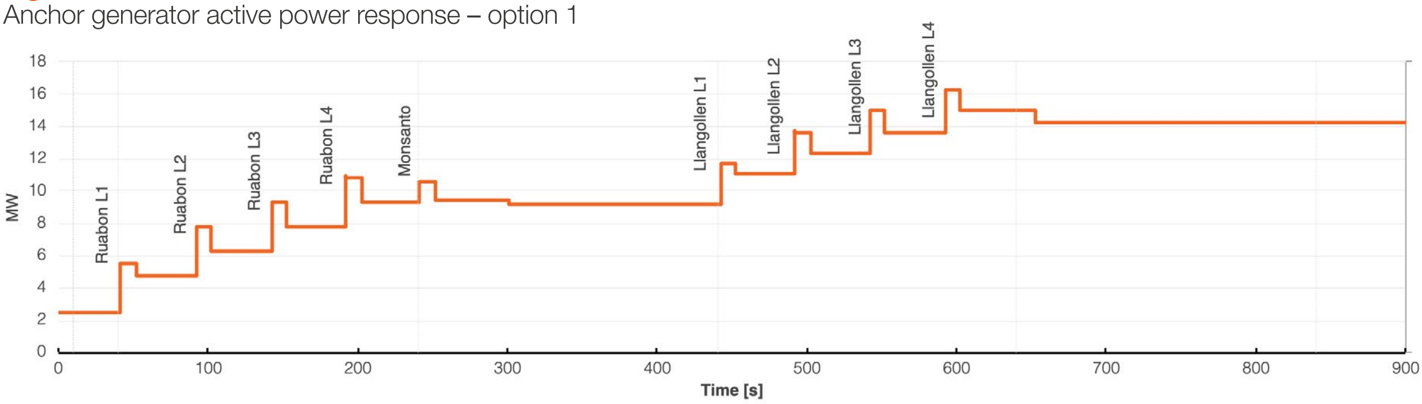
Anchor generator BLPU capability

As mentioned in section 6.1.1, the BLPU of Cefn Mawr anchor generator was estimated to be around 20 per cent of its MW rating, meaning that it's capable of picking up a maximum cold block load of 4 MW. All the primary substations in Legacy restoration options 1 and 2, except Monsanto, have cold load demands more than 4 MW, which means that the demands can only be picked up through switching and energising individual 11kV feeders or groups of feeders that have a nominal maximum demand less than 2 MW. To achieve the restoration, the number of 11kV feeders supplied by each substation were grouped as per table 6.2 and table 6.3.

While the steady state response from the load flow studies showed that Cefn Mawr can energise the whole DRZ as per option 1 without any issues (table 6.6), the dynamic response is found to be unacceptable during the cold BLPU of Llansilin primary substation even though the demand picked up is less than the initial 20 per cent BLPU capability of the machine. This is because by the time Llansilin is energised the BLPU of the generator has reduced as shown in figure 3.1. Therefore, from a dynamic study perspective, Cefn Mawr is not capable of energising all the primary substations in option 1 without the support from other DERs present in the Legacy group or additional sources like BESS.

Figure 6.6 shows the anchor generator active power (MW) response in option 1 including the restoration of Ruabon, Monsanto and Llangollen primaries, but excluding Llansilin. The generator is 70 per cent loaded (14 MW) at the end of the restoration process. No other DERs are considered in the option 1 study.

Figure 6.6
Anchor generator active power response – option 1



In option 2, BRD is the first primary substation energised. Even after splitting the total demand into two blocks, each half is almost equal to the estimated BLPU capability of the anchor generator due to the cold load characteristic. Cefn Mawr can pick up only one half of the BRD block load while the second half requires support from other sources to limit the frequency nadir above 47.5Hz. Any DER can provide this help such as other synchronous generators, wind farms or batteries. In this case, the Tir Gwynt and Carno wind farms are used as these are the only available sources in the energised network (In reality, a wind farm may not be the preferred option due to the uncertainty around wind availability, and a BESS may be used instead).

To increase the BLPU capability of the anchor generator, the two wind farms are asked to ramp up by 2 per cent of their installed capacity a few seconds before picking up the demand at BRD (table 6.3). This increases the speed of the anchor generator momentarily thereby increasing the effective inertia of the system and reducing the drop in frequency. The wind farms are required to ramp up a second time (by another 8 per cent) before picking up the last part of the Ruabon block load. Figure 6.7 shows the active power response of Cefn Mawr in different stages of the restoration process.

Figure 6.7
Anchor generator active power response – option 2

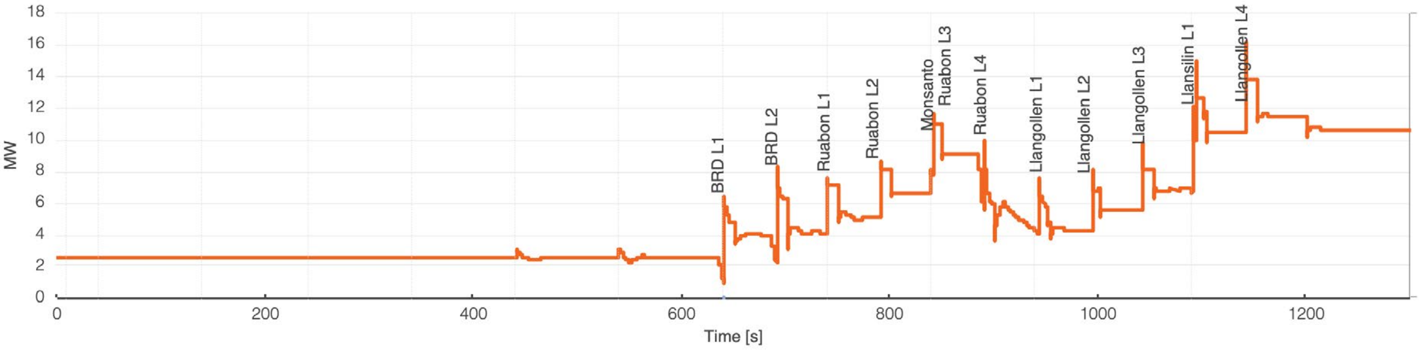


Table 6.8 lists the extent of the Legacy group GSP that can be energised by the anchor generator Cefn Mawr without any further active power support from other DERs.

Table 6.8
Primary substations that can be energised by the anchor generator with/without additional support

Action	Option 1	Option 2
Restore using anchor generator only	• Energise primary substations Ruabon, Monsanto, Llangollen • Llansilin cannot be energised	• Energise Legacy 132/33kV GT, Legacy – Oswestry 132kV circuit and Tir Gwynt and Carno wind farms • Pick up half of the cold block load at BRD
Restore using anchor generator + other sources (e.g. WF, battery)	• No additional DERs available (If DERs were available then all four primary substations could be energised)	• Energise Legacy 132/33kV GT, Legacy – Oswestry 132kV circuit and Tir Gwynt and Carno wind farms • Pick up cold block loads at all five primary substations (BRD, Ruabon, Monsanto, Llangollen, Llansilin)
Type of support used from wind farms or other sources	• Not applicable (no additional DERs)	• Active power support to offset cold load value of demand and improve block load pick-up capability of the anchor generator • Dynamic voltage support, steady state reactive power support

Wind farm response

After reconnecting Tir Gwynt and Carno wind farms to the system (option 2 only), the wind farms are operated in voltage control mode to maintain their terminal voltages at the 1.02pu voltage setpoint. They provide dynamic reactive support during the restoration process and assists the anchor generator in bringing the system voltage back to its nominal value after every disturbance.

A maximum MW support of 10 per cent (of their installed capacity) is requested from Tir Gwynt and Carno in two stages, first when picking up half of the block load at BRD and a second time while picking up the last part of the block load at Ruabon (table 6.3).

Voltage response

During restoration option 1, the voltage response at all 33kV and 11kV busbars remains within the statutory limits defined in SQSS. In option 2, however, some over- and under-voltage issues occur.

When energising the Oswestry – Carno 132kV circuit, a temporary over-voltage of more than 1.15pu is observed due to the charging power of the circuit. The results shown in figure 6.8 correspond to 0.96pu voltage at the terminal of the anchor generator before closing the breaker at Oswestry. The voltage rise remains above the statutory limit of 10 per cent for about 0.5 seconds before the anchor generator AVR responds by absorbing any additional Mvar and tries to maintain the terminal voltage at the setpoint of 0.96pu. The temporary voltage might impose a challenge on the safety of network components and is investigated further in the EMT studies. A possible solution to this problem is to further reduce the terminal voltage of the anchor generator (say from 0.96pu to 0.9pu) before energising this 132kV circuit to keep the voltage rise within the 10 per cent limit.

Figure 6.8
Over-voltage issue observed in option 2

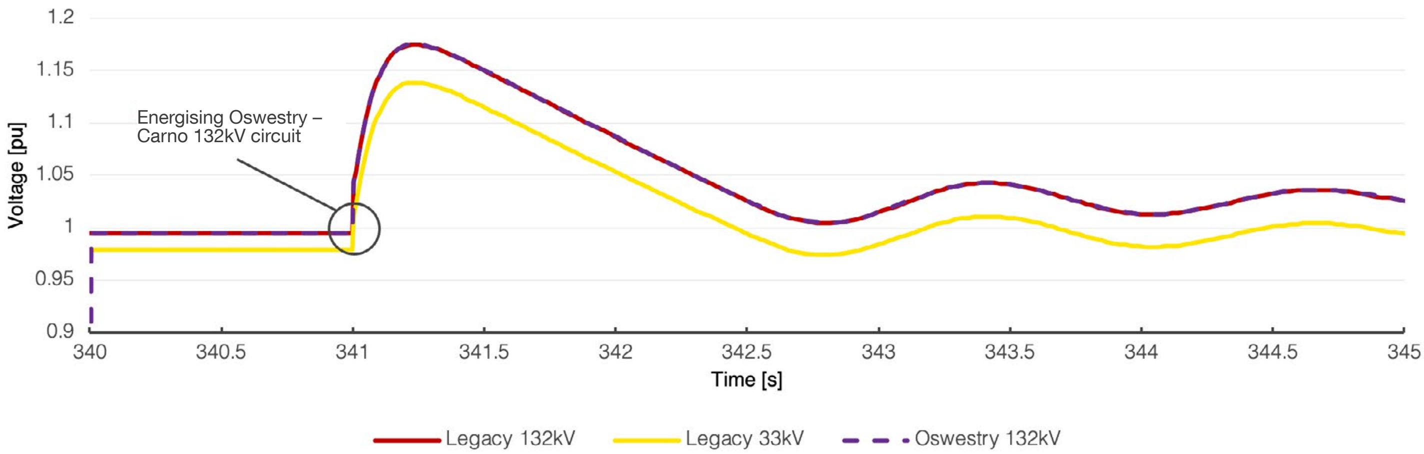


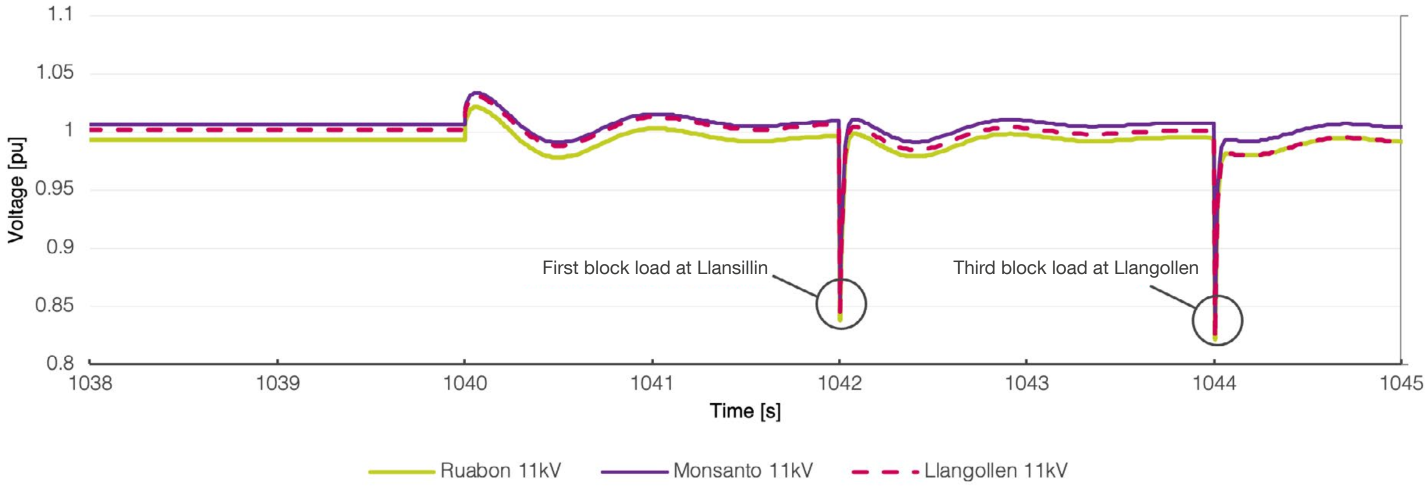
Figure 6.9 shows the simulated under-voltage issues observed in the network during option 2. As shown the 11kV busbars at Ruabon, Monsanto, Llhangollen and Llansilin experience voltages below 0.85pu, when picking up the first block of demand at Llansilin and a second time when picking up the third block of demand at Llangollen. It's important to keep in mind that when the first block load is picked up in Llansilin, the two blocks of demand already picked up in Llangollen (table 6.3) are still recovering from the cold load characteristic. So, even though the BLPU is restricted to 4 MW, the effective demand on the substation is close to the maximum LTDS demand.

The voltage dips are sharp and the voltage recovers within 200ms, a response typical of a stiff system i.e. when demands are insensitive to voltage change.

In reality, a customer demand will decrease somewhat with a dip in the voltage, thus supporting the anchor generator in a way. Some options to get around the problem could be:

- The restoration of successive substations can be delayed from 15 minutes to 30 minutes to the allow the cold load demand to settle down to a steady state value, thereby reducing the BLPU demand.
- Increase the reference set point of the anchor generator by a certain margin before picking up the demands at Llangollen and Llansilin substations.
- In the case of severe voltage regulation issues and to comply to SQSS, dynamic voltage support could be provided from other sources such as a battery or STATCOM.

Figure 6.9
Under-voltage issue observed in option 2



Frequency response

The frequency response of the system remains within acceptable limits so long as the demand at the Llansilin substation is not picked up in option 1, which exceeds the remaining BLPU of the anchor generator. After picking up the demands at Ruabon, Monsanto and Llangollen, the remaining spinning reserve is not enough to energise Llansilin while restricting the frequency nadir above 47.5Hz.

Figure 6.10 shows the frequency response of the system in option 2, as seen at the anchor generator terminal. The lowest drop in the frequency of 48.17Hz occurs when picking up the second part of the block load at BRD substation. Although this is within the limit of 47.5Hz, the RoCoF of the system during this event is slightly more than 1Hz/s which is the current setting of RoCoF relays in DERs.

Figure 6.10
System frequency response at the anchor generator terminal – option 2

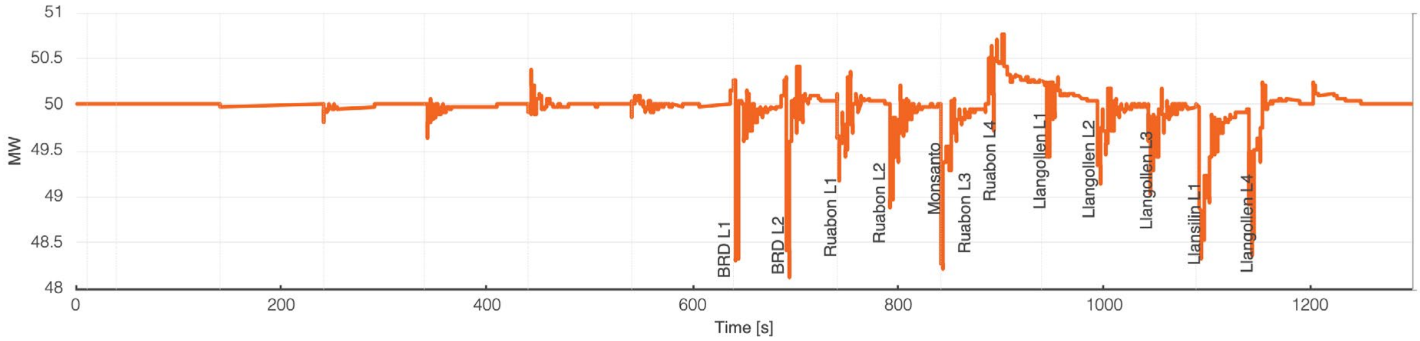
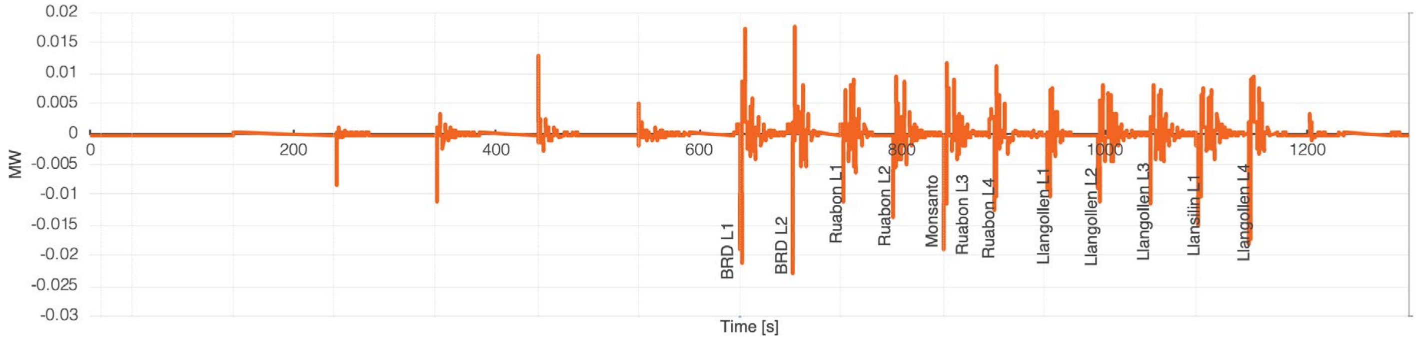


Figure 6.11
Rate of Change of Frequency (RoCoF) of the system – option 2



Key findings

Based on analysis of the simulation results, the key findings can be summarised as:

- Cefn Mawr anchor generator is only capable of restoring the demand of three out of four primary substations in option 1 without any additional DER support. This is based on the estimation that the BLPU capability of the machine is around 20 per cent (4 MW), and demand is restored using 11kV feeder switching to ensure that the BLPU is less than 4 MW. Since there are no additional DERs connected to the network at this stage, it is not possible to energise the fourth substation, Llansilin.
- In option 2, the anchor generator can energise the 132kV network up to Oswestry and Newtown Grid. However, it requires restoration at a reduced voltage to avoid any over-voltage issues from line charging currents. The two sets of wind farms (Tir Gwynt WF and Carno WFs) should operate in voltage control mode to absorb the additional charging power generated by the 132kV circuits.
- In option 2, BRD is the first primary substation energised and its cold load demand is almost three times the BLPU capability of the anchor generator. Therefore, the anchor generator can pick up only half of the demand. For the other half, it needs active power support from other DERs such as wind farms to increase BLPU capability.
- In option 2, potential low voltage issues (figure 6.9) might occur during CLPU at Llangollen and Llansilin substations. This can be avoided by a combination of delayed substation energisation (>30 minutes) and a higher voltage setpoint of the anchor generator AVR.
- Due to the relatively small generator size of Cefn Mawr, the system inertia is quite low, and restricting the RoCoF within 1Hz/sec is a challenge. Breaking down the block loads into smaller chunks helps somewhat, there is one event, when picking up the second half of BRD load, where RoCoF exceeds the limit (figure 6.11).
- Table 6.9 shows how the two restoration options meet the different restoration success criteria.

Table 6.9
Legacy restoration dynamic studies success factors

Restoration success criteria – dynamic studies	Option 1	Option 2
Restore Legacy group DRZ using anchor generator only	✔	✔
Restore Legacy group DRZ using anchor generator + WFs or other DERs (both MW and Mvar support)	–	✔
Frequency excursion within acceptable limits of 51 Hz and 47.5 Hz	✔	✔
RoCoF within acceptable limits of ±1Hz/s	✔	✔
Voltage excursion within acceptable limits of ±10% at 132kV	–	✔
Voltage excursion within acceptable limits of ±10% at 11kV	✔	✔

✔ Fully achieved ✔ Partially achieved – Not applicable

6.2.3 EMT simulation results

The EMT study considered events such as energisation of grid transformers (GT) and circuits (both overhead lines and cables) in the Legacy group GSP. Selected energisation events were studied as discrete events to assess the worst- and best-case voltage transients based on PoW simulations. No customer demand was considered in these studies.

Table 6.10 lists the energisation events and the corresponding maximum and minimum voltage changes at the anchor generator LV terminal (Cefn Mawr 0.4kV), Legacy BSP 33kV busbar and at Oswestry 132kV busbar. Similar to Chapelcross and Galloway case studies, energisation of the anchor generator step-up transformer can lead to more than a 20 per cent voltage drop, however it was assumed that the generator would take its own appropriate measures to avoid any under-voltage tripping of the machine during self-start.

The worst-case voltage dips from energisation of the four primary substations in Legacy are within the SQSS limit of 12 per cent (very infrequent event) at the generator terminal. Although, the per centage drop exceeds the limit at Legacy 33kV busbar, it does not require any further attention, since no customers are directly connected here.

PoW energisation studies of the Legacy 132/33kV grid transformer show a very high potential dip at Legacy 33kV busbar. The 57 per cent dip is, however, not a cause for concern as the grid transformer is only energised in option 2 (table 6.3) where no primary substations are picked up before energising the 132kV network. However, the resulting 27 per cent voltage dip at the anchor generator terminal could cause the anchor generator to trip on under-voltage.

Table 6.10
Voltage transients (% dip or rise) during energisation events – Legacy study case

No	Restoration energisation events	Trfr rating	Circuit length	Cefn Mawr 0.4kV (%ΔV)		Legacy 33kV (%ΔV)		Oswestry 132kV (%ΔV)	
		MVA	Km	Max	Min	Max	Min	Max	Min
1	Cefn Mawr step-up transformer – 33/0.415kV	22	NA	-27.18%	-0.20%	NA	NA	NA	NA
2	Ruabon primary transformer – 33/11kV	7.5	NA	-11.94%	-0.09%	NA	NA	NA	NA
3	Monsanto primary transformer – 33/11kV	7.5	NA	-10.29%	-0.09%	-16%	-0.09%	NA	NA
4	Llangollen primary transformer – 33/11kV	7.5	NA	-9.51%	-0.09%	-15.04%	-0.09%	NA	NA
5	Llansilin primary transformer – 33/11kV	7.5	NA	-8.89%	-0.09%	-13.75%	-0.09%	NA	NA
6	Legacy grid transformer – 132/33kV	45	NA	-27.06%	-0.01%	-57.73%	-0.05%	NA	NA
7	Legacy – Oswestry 132kV overhead circuit	NA	26	11.70%	10.10%	25.20%	21.05%	37.40%	31.30%
8	Oswestry – Carno – Newtown grid 132kV overhead circuit	NA	46	9.98%	2.61%	10.89%	6.89%	41.90%	18.33%
	+								
	Newtown grid transformer – 132/33kV	60	NA	-19.97%	-1.87%	-24.64%	-3.01%	-31.4%	-3.35%

Voltage dips: Green – within SQSS -12% voltage limits Red – exceeds SQSS -12% voltage limits
Voltage rise: Green – within SQSS +6% voltage limit Red – exceeds SQSS +6% voltage limits

Energisation of the Legacy – Oswestry 132kV circuit (No 7 in table 6.10) can cause significant over-voltage both at 132kV and 33kV levels in the network. Unlike transformer energisation, where PoW switching can reduce the amount of inrush current drawn by the transformer, the impact of PoW switching on the charging reactive power generated by long overhead lines or cables is minimal. This can cause significant damage to the switchgear and other connected equipment. A potential solution to this problem is discussed in the summary section.

The last event in table 6.10, when the long overhead circuit from Oswestry – Carno – Newtown grid is energised simultaneously with the Newtown grid 60MVA transformer, causes both a significant rise and dip in the voltage which lasts for around half a second. Figure 6.12 and figure 6.13 show the corresponding time domain responses at the anchor generator terminal and Oswestry 132kV busbar, respectively. These figures correspond to the PoW value for which there is maximum voltage rise i.e. 9.98 per cent at Cefn Mawr LV (figure 6.12) and 41.9 per cent at Oswestry (figure 6.13). The results show that this event can potentially trigger under-voltage tripping of the anchor generator and cause over-voltage damage to equipment.

Figure 6.12
Oswestry – Carno – Newtown grid energisation;
(a) instantaneous phase voltages and (b) RMS voltages at Cefn Mawr

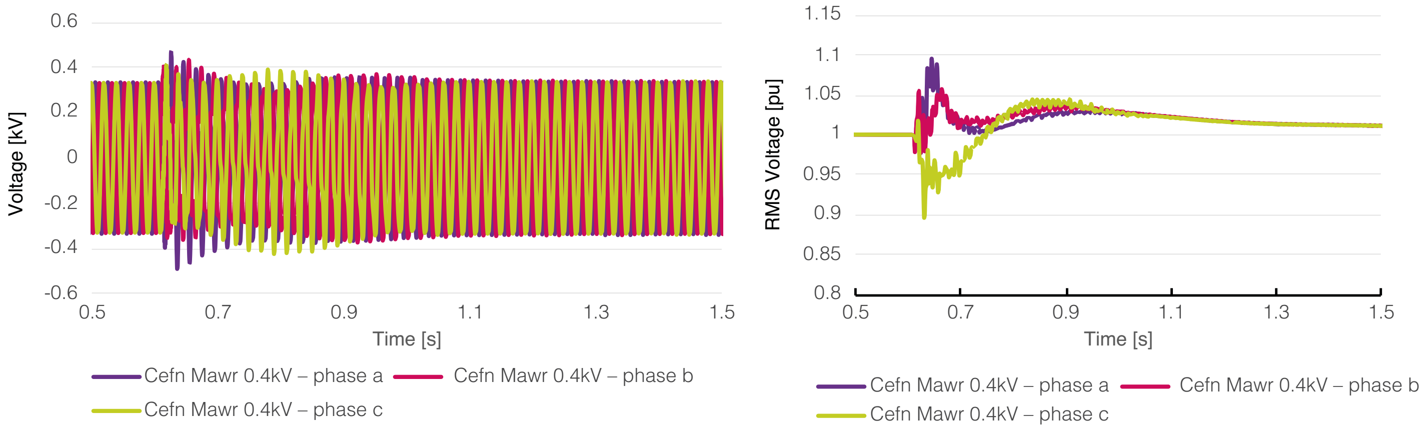
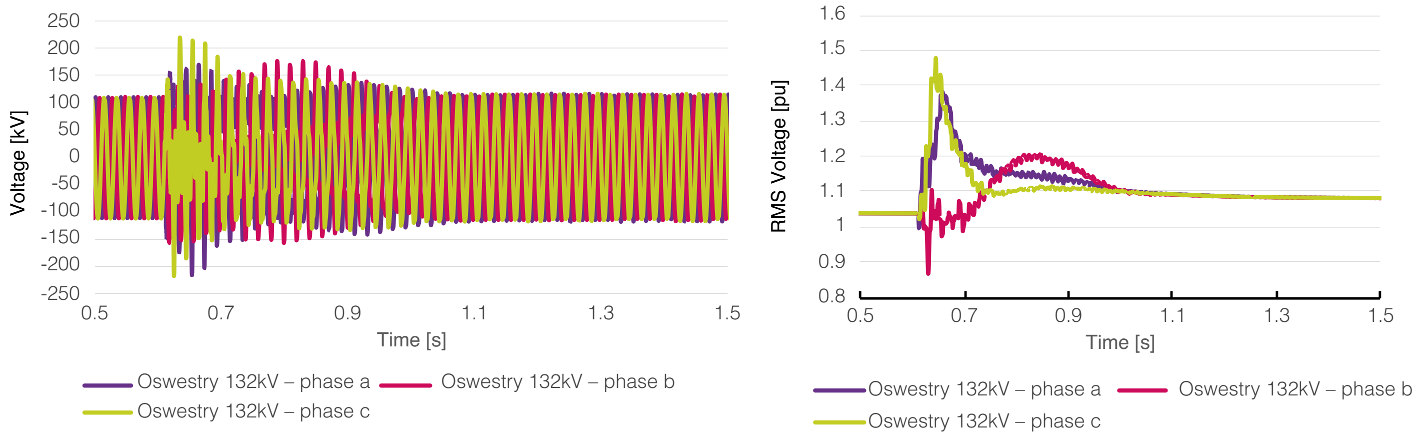


Figure 6.13
Oswestry – Carno – Newtown grid energisation;
(a) instantaneous phase voltages and (b) RMS voltages at Oswestry



Key findings

- The PoW based study results show that energisation of the primary substations as per restoration option 1 is feasible and should not require any further action to mitigate under-voltage issues.
- Energisation of circuits as per option 2 will pose significant challenges in terms of voltage rise. Energisation of the Legacy – Oswestry 132kV circuit and the Oswestry – Carno – Newtown grid 132kV circuits can cause significant voltage rise (≈40 per cent) that can damage equipment. A potential solution to this problem could be to energise the 132kV circuits at 10 per cent reduced voltage (118.8kV) to limit the amount of charging reactive power generated, thereby reducing the voltage transient.
- Energisation of Legacy 132/33kV and Newtown grid 132/33kV transformers could lead to voltage dips more than the acceptable limits in the SQSS. Suggested solutions to mitigate the risk include:
  - implementing a circuit breaker with PoW switching capability, which could be expensive
  - using a generator ‘soft start’ technique to reduce the transformer inrush current magnitude, as discussed in the case of Chapelcross (section 4.2.3).

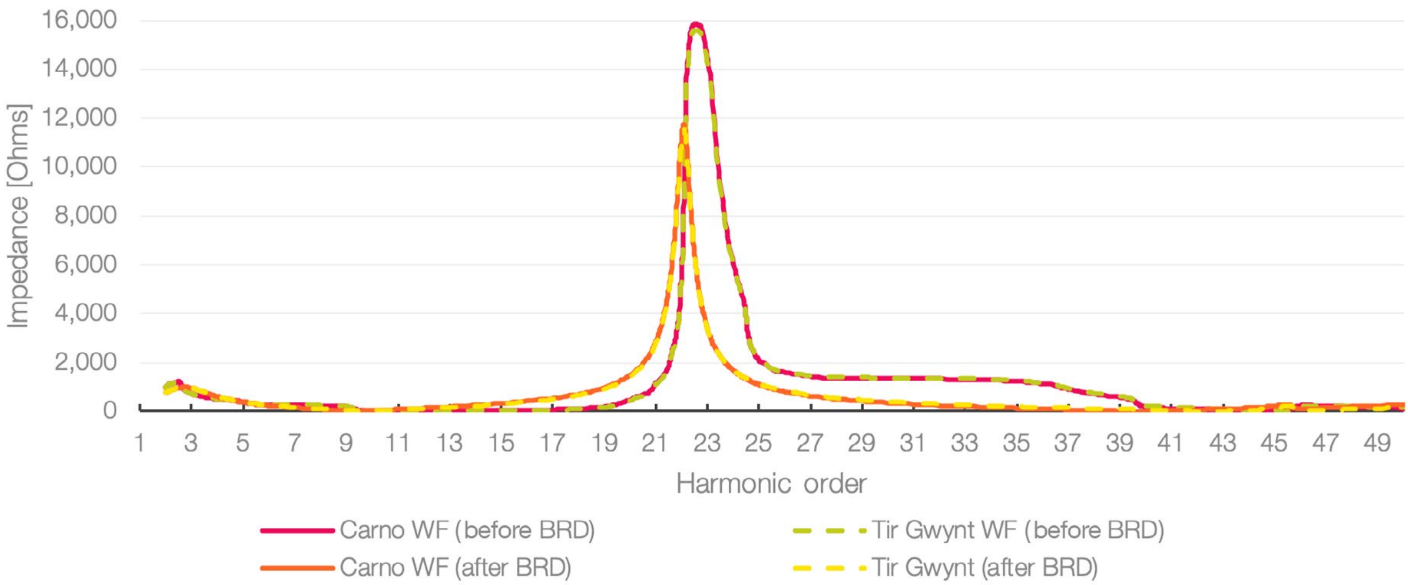
6.2.4 Harmonic simulation results

The harmonic impedance scan revealed that:

- No lower order harmonic resonance is observed at the anchor generator terminal in option 1. The lowest observed resonance is around the 12th order when Llangollen substation is energised and it remains until the end of the restoration. Since the impedance value is quite low (≈130Ohms) the risk of causing over voltage issues to the anchor generator is regarded as very low.
- In option 2, a persistent resonance is observed around the 23rd order at the 132kV connection point of the Tir Gwynt and Carno wind farms (table 6.3). The impedance value reduces from ≈17kOhms to ≈10kOhms with the energisation of the primary substations. However, the value still remains quite high until the end of the restoration process and it could potentially interfere with the wind farm operation. A detailed study is necessary with the wind farm collector grid modelled in and the actual controller data.

Figure 6.14

Harmonic impedance at Tir Gwynt WF and Carno WFs 132kV terminals, before and after BRD is energised



Key findings

- Option 1 has no harmonic resonance issues and it is unlikely that the anchor generator will be impacted in any way.
- Option 2 requires further investigation. The two wind farm sites might have resonance issues around the 23rd order. However, it cannot be confirmed without detailed modelling of the wind farm collector grid.

6.3 Summary

6.3.1 Power system study results

The following table summarises the findings from the power system simulation studies in terms of the viability of the different restoration options, as well as the main technical challenges that are likely to be experienced and require mitigation.

Table 6.11
Summary of the Legacy power system simulation study results

Power system study	Restoration option 1	Restoration option 2
Load flow studies	• Anchor generator can restore almost all of the DRZ alone, except the second half of the Llansilin substation • No voltage or thermal issues observed	• Anchor generator can achieve restoration up to stage 8 of 14 only, and then needs MW support from other DERs to restore the DRZ • Anchor generator has insufficient Mvar capability to absorb charging power when 132kV lines are energised. Can be mitigated by reducing terminal voltage to 0.96pu and then increasing it after WFs are online • No voltage or thermal issues observed
Dynamic studies	• Anchor generator can only energise 3 of 4 primary substations (stage 4 of 7) before needing DER active power support • Demand needs to be picked up at individual feeder level < 2 MW to remain within 4 MW BLPU of generator	• Anchor generator can energise 132kV network to Oswestry and Newtown grid (stage 4 of 14), but needs to operate at reduced voltage to avoid over-voltage from high charging current • Needs DER MW and Mvar support to pick-up the full demand at BRD • Potential low voltage at Llangollen and Llansilin. Can be mitigated by stretching the switching intervals to 30 min, and increasing the generator voltage • RoCoF exceeds 1Hz/second when restoring BRD demand. May not be an issue.
EMT studies	• No issues	• Significant (≈40%) transient over-voltage when energising 132kV circuits. Can be mitigated by reducing generator terminal voltage by 10%. • Significant under-voltage when energising 132/33kV grid transformers. Can be mitigated by PoW switching
Harmonic impedance scan	• No low order harmonics	• 23rd order resonance at 132kV connection point between Tir Gwynt and Carno WFs

6.3.2 Capability of the anchor generator to restore the DRZ

From the analysis it can be seen that the anchor generation cannot restore option 1 or option 2 on its own. In option 1, it can achieve restoration of the DRZ only up to stage 4 of the restoration, i.e. it can restore the load at Ruabon, Monsanto and Llangollen primary substations, but is unable to energise Llansilin substation due to insufficient active power.

In option 2, the anchor generator can only restore the DRZ up to stage 4, which means it can energise the Legacy 132/33kV grid transformer, the Legacy – Oswestry 132kV circuit and the Tir Gwynt and Carno wind farms connected at 132kV, as well as pick up half the load at BRD primary substation. The anchor generator would also need to energise the 132kV circuits at a 10% reduced voltage to sufficiently reduce the charging power to avoid a transient over-voltage.

6.3.3 Required DER interventions

A number of DER interventions were identified that could assist the anchor generator in restoring the DRZ. In option 1, additional active power needs to be provided by DERs in order to pick up the cold load at Llansilin substation.

In option 2, DER support is required in stage 5 in the form of active and reactive power to enable the energisation of BRD primary substation, as well as picking up the cold block loads at Ruabon, Monsanto, Llangollen and Llansilin primary substations.

6.3.4 Other required interventions

In option 2 there are potential over-voltage and under-voltage constraints. To avoid over voltage issues when energising the 132kV circuits to connect the wind farms, the generator terminal can be reduced to 0.95pu, and then increased again after the wind farms are online. To avoid the under-voltage issues the substation energisation needs to be slowed to one every 30min to allow the cold load demand to decay to normal levels. Another alternative would be to use a BESS or static synchronous compensator (STATCOM) to provide the required dynamic voltage support.

To mitigate transient voltage dips occurring when 132/33kV primary transformers are energised, PoW switching can be implemented, but this would require the replacement of existing circuit breakers. Using a ‘soft start’ approach for the anchor generation could also reduce the transformer inrush current to avoid the under-voltage problem.

Although a 23rd harmonic resonance was identified as a potential problem at the 132kV connection point between Tir Gwynt and Carno wind farms, more detailed analysis would be required once the frequency characteristic information of the network is known to assess whether the problem is real, and to recommend a solution.

6.3.5 Transmission-distribution interface point capability

On its own, without any DER support, and under no load conditions the anchor generator has the capability to export 16.87 MW to the transmission network at the transmission-distribution interface point (Legacy SGT 132kV breaker). It cannot, however, import any Mvar as the line charging current from the energised 132kV circuits already utilise the full reactive power absorption capability. After the DRZ is fully restored with support from the DERs (Tir Gwynt and Carno wind farms), around 6.39 MW can be exported and 23Mvar can be imported from the transmission network at the interface point.

6.4 Conclusion

None of the technical challenges with restoring the DRZ using option 1 and option 2 are impossible to overcome.

It’s worth mentioning that the energisation of the primary substations will require switching of individual or small groups of 11kV feeders (< 2 MW) to avoid exceeding the BLPU capability of the anchor generator. More switching will be required compared to the primary substation restoration strategies discussed in section 2.4 where only one or two 33kV breakers are operated, which may result in more system control resources being needed to implement the Distributed ReStart.

However, additional DERs are needed to provide active and reactive power support to the anchor generation to complete the restoration process in both options. The amount of active and reactive power support needed from the DERs is only 10 per cent of their installed capacity which could easily be provided by the Tir Gwynt and Carno wind farms, even when the wind resource is low.

7. Restoration and power system study conclusions

The following conclusions can be drawn from the different restoration strategies and the power system simulation study results.

7.1 Anchor generation capability

The anchor generator's primary role in the DRZ is to start the process of network restoration by imposing and regulating the voltage and frequency in the restoration zone, thereby enabling the connection of additional generation resources and supporting restoration of demand and energisation of the wider network where possible. The studies demonstrated the importance of maintaining adequate headroom on the anchor generator throughout the restoration process. To provide satisfactory frequency regulation, and to factor in the uncertainty in the cold load pick-up characteristics of demand, it is recommended that the anchor generator is not loaded to more than 80 per cent of its operational MW rating.

The power system studies highlighted that the anchor generator's block load pick-up (BLPU) capability i.e. the capacity of demand which can be added instantaneously without the frequency falling below 47.5Hz, is a function of several factors including its MW rating, inertia, turbine and governor characteristics and available spinning reserve. For example, the analysis has shown that the BLPU capability of a hydro anchor generator is around 15 per cent of its MVA rating, while for a gas engine and steam turbine it is typically 20–25 per cent. These values are estimated based on the generic models used in the studies. The actual BLPU capability of an anchor generator will depend on site-specific information.

The anchor generator's BLPU capability will limit the restoration process in terms of the demand blocks which can be energised at any one time. For example, at best a DER may have a BLPU capability of ~10 MW (50 MW DER with 20 per cent capability). This would limit the restoration to individual 11kV primary substation feeders where the demand is typically several MW and may be up to 200 per cent of normal demand initially due to lack of diversity after a sustained outage (known as cold load demand). It follows that the BLPU of the anchor DER will likely require to be enhanced through the coordination of additional resources (e.g. a battery energy storage system) to enable a viable restoration strategy or increase the capability above 11kV feeder level. Automation is being developed in terms of a distributed ReStart zone Controller (DRZ-C) to facilitate this (described further in chapter 11 of this report).

7.2 Circuit energisation

The energisation of cable and overhead line circuits produce reactive charging power that needs to be absorbed by the anchor generator and other DERs to maintain acceptable system voltage. The amount of reactive power produced increases with line length and voltage level.

During the initial stages of DRZ restoration only the anchor generator is available to absorb the charging power, and care needs to be taken to ensure that the charging power is within the absorption (leading reactive power) capability of the anchor generator. The three case studies demonstrated that the anchor generators are capable of energising the whole 33kV GSP without any issue with reactive power absorption. It is only with energising the 132kV network and above, that the anchor generator might need help depending on the length of the circuit energised. As an example, in the Legacy case study, the Legacy – Oswestry – Carno 132kV circuit produces around 11Mvar which is more than the reactive power capability of the 25MVA Cefn Mawr anchor generator (9.6Mvar). A mitigation could be to energise the circuit at a lower voltage, e.g. 10 per cent below the rated voltage to reduce the amount of line charging power generated and wait for additional reactive power support from other DERs in the DRZ added during subsequent restoration stages, before increasing the voltage back to the nominal value. Wind farms in voltage control mode can be good candidates to enhance the reactive power capability of the DRZ so that longer and higher voltage circuits can be energised, as they can do so even under no wind conditions.

The studies also showed that the energisation of circuits can cause temporary over-voltage due to switching transients. This can particularly be a problem with 132kV circuits, as seen in the Galloway and Legacy networks. The switching transient can cause an over-voltage at the terminal of the anchor generator which could be more than the G99 over-voltage protection setting (13 per cent) of the generator. The voltage spike can be reduced to a certain extent by energising the circuits at a reduced voltage, e.g. 10 per cent below the rated voltage.

7.3 Primary transformer energisation

Inrush effect

The EMT simulation results show that energising a primary transformer by the anchor generator would not have any issue in most cases. However, depending on the topology of the network, some primaries like Lockerbie in Chapelcross GSP can experience a transient voltage dip of up to 0.7pu at the transformer terminals and at some nearby primaries. The magnitude of the voltage dip is dependent on the size of the transformer, the magnetic characteristic of the transformer iron core and the point on the voltage waveform when the breaker is closed. Although the voltage dips last less than a second, it could negatively impact customer demand at nearby substations previously restored. Presence of industrial load such as induction motors can further deteriorate the voltage and lead to sustained under-voltage phenomenon. The problem could be mitigated by implementing additional hardware for controlled switching of the circuit breakers at a specific point on the voltage waveform to reduce the inrush current (known as point on wave (PoW) switching).

Demand restoration

Several primary substation restoration strategies were evaluated. The preferred strategies are those where the number of switching operations are minimised and the primary transformers are energised with a load as close as possible to the pre-blackout demand to minimise the risk of high 11kV voltages, but subject to the BLPU capability of the DER. Allowance needs to be made for the cold load characteristic when energising the demand, so that the CLPU does not exceed the thermal rating of the primary transformer and switchgear.

The restoration of demand at a primary substation should commence with the 11kV feeder which restores the substation local LV supply, so that the primary transformer tap change motor is powered up as early as possible to regulate the voltage.

Where a primary substation has two transformers, but only one was in service before the blackout, the transformer may be on a high tap position since it has to supply all the demand. This could result in high 11kV voltage if it was then energised with a significantly reduced demand. To avoid this, the restoration of a two-transformer primary substation with only one transformer in service prior to the blackout may need to be inhibited or the tap position needs to be manually adjusted before energisation.

7.4 Grid transformer energisation

Inrush effect

One of the major challenges with growing a distribution power island is the energisation of grid transformers (e.g. 132/33kV) or super grid transformers (e.g. 275/132kV). The transformers draw high magnetic inrush currents (typically 4 to 7 times of rated current) which may result in the anchor generator seeing a significant voltage dip at its terminals. The magnitude of this voltage dip depends on the configuration of the network, so for example, as the electrical distance between the anchor generator and the transformer being energised increases, the voltage drop will tend to reduce.

Energisation of grid transformers by the anchor generator such as the Glenluce 132/33kV 60MVA GT in Galloway, or the Gretna 400/132kV 240MVA SGT in Chapelcross result in voltage dips in several parts of the network. These voltage dips are significant and greatly exceed the SQSS limit of 12 per cent for infrequent events at some parts of the network. Therefore, it is advisable to energise these transformers before any customers are restored in the network.

Impact on the anchor generator

In some cases, energisation of grid transformers could result in severe (e.g. more than the G99 protection setting of 20 per cent) voltage dips at the anchor generator terminal, which is significant enough to potentially cause under-voltage tripping of the machine. This could be mitigated using a soft start technique to reduce the remnant flux and thereby the inrush current magnitude, or by implementing circuit breakers with PoW switching capability.

7.5 Additional DERs (non-anchor generators)

The case study evaluations showed that it is likely that the anchor generator may not have sufficient active power (MW) capacity to restore all the demand in a DRZ. Non-anchor DERs in the same restoration zone can play an important part in providing additional active power support (if the prime energy source is available) so that more demand can be restored. As an example, in the Chapelcross case study, the Minsca and Ewe Hill wind farms provided MW capacity support to improve the DRZ's BLPU capability. If the DRZ has synchronous DERs, such as hydroelectric plants or gas generators, they will inherently contribute to the system inertia, thereby assisting the anchor generator in frequency regulation of the DRZ.

The additional DERs can also provide reactive power (Mvar) support to the anchor generator to maintain an acceptable voltage profile during energisation of the network and CLPU at the primary substations. Modern wind farms can provide reactive power and voltage support even when there is no wind available. For example, in the Legacy case study, Tir Gwynt and Carno wind farms provided reactive power to absorb the charging power produced by the 132kV circuits to support the voltage. The effectiveness of this support, however, depends on the location of the DER relative to the circuits being energised or the primary substation, i.e. the further away the DER is, the less effective its reactive power support will be to maintain the voltage profile.

It is recommended that additional DERs are energised to the network and provided with auxiliary supply as early as possible in the DRZ restoration process so they can be on standby to provide reactive and/or active power support and voltage control when needed. Active power output of the DERs will need to be controlled in a coordinated approach to ensure stability of the DRZ.

7.6 Network restoration strategy

An assessment of different distribution network topologies found that radial distribution networks are relatively easy to restore using DERs because the demand can be easily split into smaller blocks to meet the BPLU capability of the anchor generator, while restoration of meshed networks is harder due to interconnections at 11kV and LV level. Densely interconnected meshed networks are very difficult to restore because they are difficult to split up to limit the extent of energisation in the early stages.

Analysis of the case studies showed that the best strategy for energising a DRZ is to first restore supply to the additional DERs so that their auxiliary supplies are restored and can remain on standby ready to provide any active and/or reactive power support as and when required by the anchor generator.

The second and third steps, before connecting any customers, are to energise the grid/super grid transformers and associated higher voltage circuits, so that any voltage dips and/or switching over-voltages wouldn't be seen by customers.

Thereafter primary substations can be energised to pick up customer demand. The primary substation demand can be restored in blocks ranging from individual 11kV feeders, to the whole substation demand simultaneously (by closing a transformer 33kV feeder circuit breaker).

Several primary transformer restoration options are available, with the optimum solution varying for different DRZs based on the factors above. In general, network restoration strategies that minimise the number of switching operations and overall restoration time are preferred, provided of course that the restoration process is technically viable, and that the block loads picked up don't exceed the capability of the anchor generator or result in any voltage violations or overloading of network components.

7.7 Wider network energisation capacity

The capability of the DRZ to energise the wider network at 132kV and above depends on its reactive power absorption limit and size of the network to be energised. The power system studies showed that a typical 132/33kV GSP substation with a 60MVA anchor generator can export around 30 MW and absorb 14Mvar at the transmission-distribution interface point without any support from other DERs. This capability can be increased with contribution from additional DERs in the DRZ to provide support for wider network energisation.

Energising a typical 132kV overhead line of 20km, for example, can produce around 1.5Mvar (0.075Mvar/km). For the same length of line, the charging power is calculated as 6Mvar for a 275kV line (0.3Mvar/km) and 12Mvar for a 400kV line (0.6Mvar/km). To put it in context, a small anchor generator of 25MVA will have enough capability (9.6Mvar) to absorb the charging power of a 128km 132kV overhead line, but only 32km of a 275kV line and 16km of a 400kV line. Energising longer circuits or multiple circuits of the above length will not be possible unless additional reactive power support is available from other DERs in the DRZ. If the additional DERs are not available before energising the circuit, then a potential solution would be for the anchor generator to energise the circuit at a reduced voltage (e.g. 0.9pu), and thereafter connect the DERs (assuming that the DERs are capable of synchronising to the network at the reduced voltage) and increase the voltage to the nominal value.

8. Protection assessment

8.1 Introduction

For the PET report on the 'viability of restoration from DERs' (July 2019), a protection assessment[5] was undertaken to assess if existing protections would still operate correctly, given the reduced fault current when the network is only supplied by a single DER (the anchor generator). This was based on the Chapelcross case study, which has network voltages up to and including 132kV, and has a 60MVA synchronous generator as the anchor.

Following on from this report, a further protection assessment[6] on the Chapelcross network was commissioned to identify the protection changes which would be required (including calculating revised settings where appropriate) to protect the network at all voltage levels. The goal is to identify any limitations to the DER restoration process because of protection issues, and to quantify the works required to make the protection systems 'Black Start ready'.

This section summarises the outputs of the protection assessments giving an overview of the impact on fault levels, and existing protections when operating in island mode. The protection changes required are then highlighted, and any associated network limitations detailed. Finally, the potential to protect the 275kV and 400kV networks, when energised from a 33kV island, is discussed.

8.2 Fault levels

Within an electrical system, fault level is defined as the maximum current that would flow during a short circuit fault. It is a measure of the electrical strength of a system and, whilst fault levels must be limited for safety reasons, a minimum threshold is required to ensure protection systems operate correctly. Fault current is primarily produced inherently by synchronous generators connected to the network and is proportional to the size of the generator. A key technical challenge when restoring the distribution and transmission networks from DER, is the ability of the existing protection systems to detect and isolate a fault condition on the network.

The fault level is significantly reduced, from normal intact system conditions, when the network is supplied only from relatively small synchronous generators connected at 33kV and/or 11kV. For example, at Chapelcross GSP, for a fault on the 33kV busbars, approximately 650MVA of fault infeed comes through the 132/33kV grid transformers. The fault level design limit at 33kV is typically 1,000MVA, meaning that the all the distribution connected generation should not exceed ~350MVA of fault infeed. Thus, in Black Start conditions, a maximum of 300MVA of fault infeed would be available form the 33kV network.

In this case study, a single synchronous generator (60MVA) is used to energise the network. It has a 33kV PoC to the DNO network and is connected by a 25km underground cable circuit to the Chapelcross GSP 33kV busbar. At Chapelcross GSP there are two 132/33kV 90MVA transformers (24 per cent impedance on rating), but only one is utilised when back-energising up to 132kV. The generator is modelled with a transient reactance of 0.333pu and gives a three phase fault level of 121MVA (break time 90ms) and 94MVA (break time 1s) at the Chapelcross GSP33kV busbar.

Table 8.1 shows the lowest fault levels, as a per centage of the normal system fault levels, for the Chapelcross case study. The three phase fault levels have been considered (3Ph) along with single phase to earth (1Ph-E).

Table 8.1
Chapelcross island fault levels

Chapelcross 132/33kV GSP		
Voltage level	**Fault**	**Lowest % normal**
LV	3Ph	94%
	1Ph-E	94%
11kV	3Ph	36%
	1Ph-E	68%
33kV	3Ph	14%
	1Ph-E	59%
132kV	3Ph	2.7%
	1Ph-E	3.3%
400kV	3Ph	0.6%
	1Ph-E	1.0%

[5] Black Start from distributed energy resources. Protection and Earthing Study June 2019.
[6] ARCADIS Distributed ReStart – Chapelcross Protection Changes/Limitations Assessment June 2020.

8.2.1 Results

Table 8.1 shows that the network fault levels (when islanded) are at their highest per centage of the normal intact system levels for the lower voltages and decrease as the voltage levels increase. It can be seen that the three-phase fault current at 400kV is only 0.6 per cent of the normal level.

The results highlighted in orange show where the fault levels are similar to the normal intact system levels (these are explained in section 8.2.2 and 8.2.3 respectively). As a result, it can be assumed that the existing protection systems will still operate correctly. At all the other voltage levels, the protections will need to be assessed to establish:

i) if the existing protection will operate correctly with the reduced fault level
ii) if revised settings may be applied to the existing protection to enable correct operation
iii) the fault level is too low for existing protections to operate (even with revised settings).

Where fault level is too low, further assessment would be necessary to determine the options available and their cost effectiveness. Options may include:

- boosting the fault level by adding more generators or other sources of fault current
- replacing the existing protections with alternatives that will operate safely with very low fault levels.

Given the safety critical nature of protection, changes to philosophy and equipment would have to be subject to comprehensive risk assessment. This could take account of the peculiar circumstances of Black Start and may allow for some relaxation of quality, e.g. in discrimination between faults at different locations or the need for backup protection, but it remains essential that the network is operated safely.

8.2.2 LV fault levels

It can be seen that the LV fault levels are only reduced slightly, being 94 per cent of the intact system values. This is because the LV fault level is primarily dominated by the impedance of the LV network which remains unchanged. It follows that there will be sufficient fault current for normal protection operation in customer premises, e.g. to blow a fuse. Studies have shown that a fault level of ~30MVA at the GSP 33kV busbar would be sufficient to ensure that LV fault levels remained above ~75 per cent of their intact system levels (in the Chapelcross case study, the GSP 33kV busbar fault level is ~90MVA).

8.2.3 33kV 1Ph-E

An earth fault on the Chapelcross 33kV network is shown to be 59 per cent of the intact network value. The magnitude of earth fault current is determined by the design (including earthing resistor value) of the earthing transformers which are connected to the 33kV network. For normal system conditions, two earthing transformers are in service with one being connected to each of the two 132/33kV transformers. When operating as a 33kV island, these are both disconnected and a new earthing transformer will need to be connected at the anchor generator location (this is explained in the PET viability report, July 2019). The results show that the earth fault when islanded is just slightly higher than when one grid transformer is in service (50 per cent value). Thus the 33kV network earth fault protections will operate as normal as they are designed for when one grid transformer is in service. If one of the 132/33kV grid transformers is then back-energised, to energise the 132kV network, its earthing transformer will also be brought into service, and the 33kV 1Ph-E fault level will increase further.

8.3 Protection operation assessment

Based on the fault level results in table 8.1, table 8.2 shows an assessment of the individual protections which are installed, at the various voltage levels in the Chapelcross case study network. A green light indicates that existing protections will still operate correctly for Black Start conditions, and an amber light indicates where existing protections will not operate correctly. For these, further investigation will be required to ascertain if a settings change is feasible, and will facilitate correct operation, if other solutions can be considered, or if no viable solution is available.

8.3.1 Results

It can be seen that there are no issues with the LV protection operation (as expected with the fault level being close to intact system values). At 11kV, four of the protection categories will potentially require modifications, including the overcurrent protection on the primary transformer incomer 11kV circuit breaker, and 11kV feeder circuit breakers. This means that potentially all of the 11kV circuit breakers in a primary (33/11kV) substation may need protection modifications.

At 33kV, six protection types have been identified for further assessment, primarily located on the 33kV feeder circuit breakers. At 132kV it is estimated that only 10 per cent of the existing protections will still operate correctly, with the majority potentially requiring settings to be changed. The protections at 275kV and 400kV are not included in this assessment as the Chapelcross case study did not include network at these voltage levels. However, consideration of protection requirements at 275kV and 400kV is given later in section 8.5.4.

Table 8.2
Protection operation assessment

LV (400v)		
Protection function	**Rating**	**% Ok**
Overcurrent		100%
Earth fault		

11kV		
Protection function	**Rating**	**% Ok**
Transformer incomer overcurrent		60%
Transformer incomer directional overcurrent		
Transformer incomer earth fault		
Transformer ref		
11kV feeder main protection		
11kV feeder overcurrent		
11kV feeder earth fault		
Transformer feeder overcurrent		
Transformer feeder earth fault		
Generator protection		

33kV		
Protection function	**Rating**	**% Ok**
Grid transformer incomer transformer differential		54%
Grid transformer incomer LV REF		
Grid transformer incomer LV SBEF		
Grid transformer incomer LV SBEF		
Busbar protection		
33kV feeder main protection		
33kV feeder distance protection		
33kV feeder backup overcurrent		
33kV feeder backup earth fault		
33kV feeder to local generator		
33kV transformer HSOC		
33kV transformer OC		
33kV transformer BEF		

33kV		
Protection function	**Rating**	**% Ok**
Busbar protection		10%
132kV feeder main protection		
132kV feeder distance protection		
Transformer differential		
GT HV REF		
132kV transformer HSOC		
132kV transformer OC		
132kV transformer EF		
132kV feeder overcurrent		
132kV feeder earth fault		
33kV transformer HSOC		
33kV transformer OC		
33kV transformer BEF		

8.4 Protection revision assessment

Given the number of protections shown in table 8.2 which may require revision, an assessment of all protections on the Chapelcross case study network[6] was carried out. This followed four stages:

Stage 1
Calculate the reduced fault levels at the relevant network nodes on the network (where protection systems are installed). Shown in section 8.2.

Stage 2
Identify the existing settings for all protections at these nodes.

Stage 3
Carry out a grading study to verify if existing protections will operate satisfactorily.

Stage 4
Highlight all protections where changes are required, propose changes (e.g. settings and/or new relay) and verify with an updated grading study.

Highlight where a suitable revised setting cannot be achieved or there is a protection limitation.

[6] ARCADIS Distributed ReStart – Chapelcross Protection Changes/Limitations Assessment June 2020.

8.4.1 Stage 2 & 3

Table 8.3 shows an example of stage 2 of the assessment process where the existing protections on a 33kV feeder circuit breaker at Chapelcross have been recorded. It can be seen that there is a main differential (unit), high set overcurrent (HSOC), and back up overcurrent (OC) and earth fault (EF) protections. The existing settings are given, along with a reference in the original report where the grading assessment can be viewed. This assessment was carried out for all protections, at all voltage levels, on the case study network.

8.4.2 Stage 4

Table 8.4 shows an example of the stage 4 assessment (same example as in figure 8.3) where any required revisions to the protections are recorded (under 'Black Start settings').

A green traffic light means no setting change is required, amber signifies revised protection settings are proposed and red no suitable settings are feasible.

Additional information is given such as 'Second Group Available'. Modern protection relays have the facility to be programmed with a second group of settings and the device can be switched locally or remotely (via the SCADA system) between settings groups. Some relays also have the facility to enable 'cold load pick-up'. This can be enabled to inhibit maloperation of the relay due to excessive initial load currents when a demand is connected after being deenergised for a period. This feature is particularly relevant to this project, given that it may be hours, or days, before demands are restored. This assessment was carried out for all protections on the case study network.

Table 8.3
Chapelcross – Middlebie/Langholm 33kV feeder, existing protection example

Substation	Circuit name	Protection function	Scheme type	Device type	Actual settings
Chapelcross 33kV	CHAP12 feeder to Middlebie/Langholm	33kV Feeder Protection	LINE DIFFERENTIAL	7SD522	400/1, I diff > 0.6 A, Idiff >> 1.6 A Idiff > switch on 0.8 A, 1.6 A
			HSOC	7SJ611	400/1, 4 A, 1600 A
			BEF		400/1 , 0.35 A, 140 A
			OC	7SJ632 DAR	400/1, 1.0 A, 400 A 0.45s NI
			EF		400/1, 0.25 A, 100 A 0.3s NI

Table 8.4
Chapelcross – Middlebie/Langholm 33kV feeder, protection revision example

Substation	Circuit name	Protection function	Scheme type	Device type	Second group available	Voltage control available	Cold load pick-up	New relay required	Rating	Black Start settings
Chapelcross 33kV	CHAP12 feeder to Middlebie / Langholm	33kV feeder protection	LINE DIFFERENTIAL	7SD522	YES	NO	NO	NO		400/1, I diff > 0.2 A, Idiff >> 1.6 A Idiff > switch on 0.2 A, 1.6 A
			HSOC	7SJ611	YES	NO	YES	NO		No change
			BEF							No change
			OC	7SJ632 DAR	YES	YES	YES	NO		400/1, 0.69 A, 276 A 0.4s NI
			EF							400/1, 0.25 A, 100 A 0.13s NI

8.5 Protection revision overview

Figure 8.1 shows a high level schematic of the Chapelcross case study network, with a summary of the protection changes/limitations identified. The following annotation is used:

- Settings changes required. Existing relay can facilitate a second settings group.
- Settings changes required. A new relay is required which can facilitate a second settings group.
- This indicates a protection limitation to network operation has been identified.

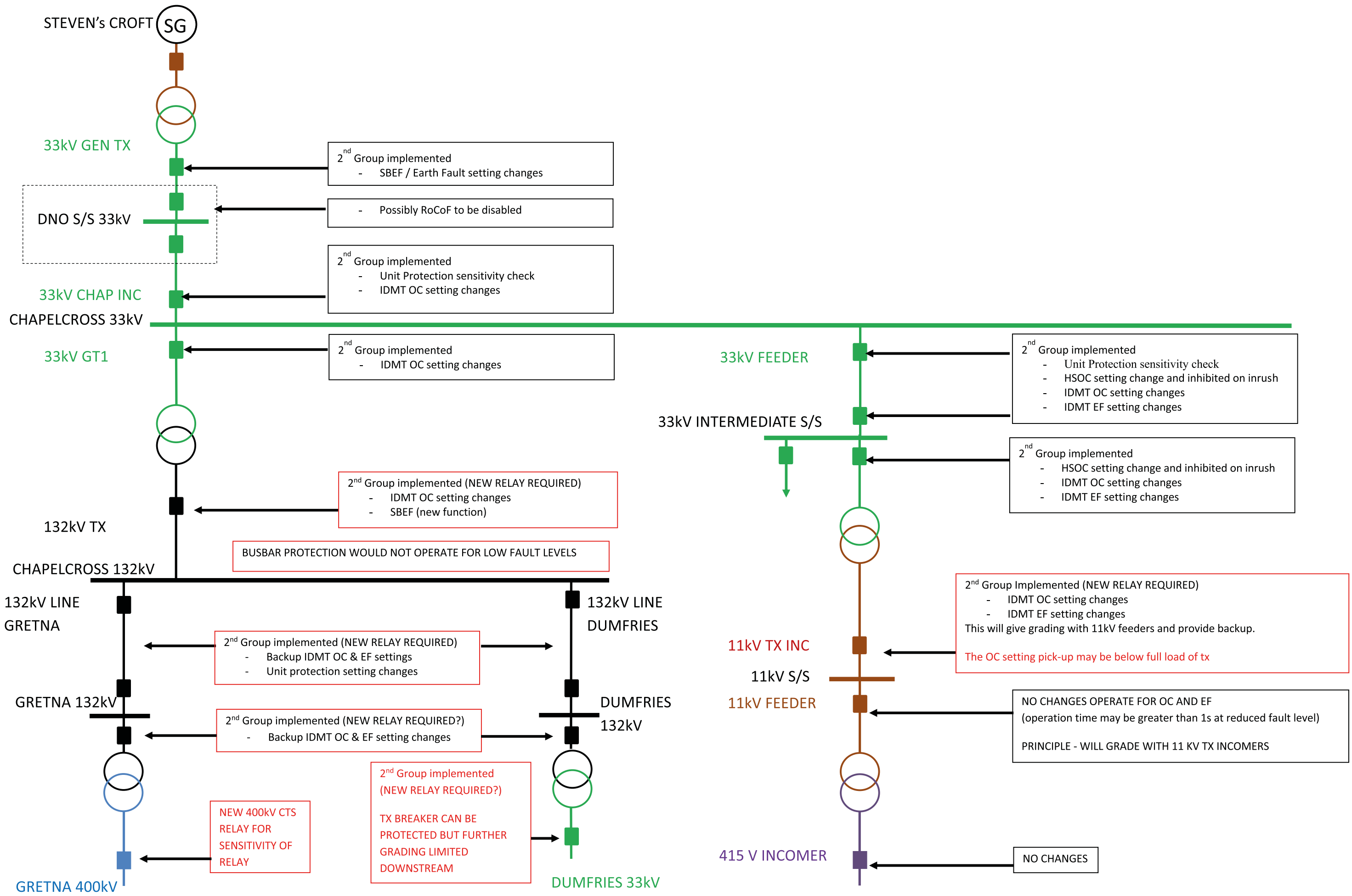
It can be seen that the network can be adequately protected on the LV, 11kV, 33kV and 132kV voltage levels, with the proposed settings and/or relay changes. However, some protection limitations have also been identified.

Further explanation is given in this section of the methodology behind the protection changes, and any limitations identified, for the following protections:

- primary substation – 11kV feeder protection
- primary substation – 11kV transformer incomer
- GSP substation – 33kV feeder.

In addition, a guide is given to assess the suitability of existing protection systems at 132kV, 275kV and 400kV to protect the network, when energised from 33kV DER.

Figure 8.1
Chapelcross case study – protection revisions overview schematic



8.5.1 Primary substation – 11kV feeder protection

Figure 8.2 shows that the protection settings at primary substations, on 11kV feeder circuit breakers, may have to be altered. This will need to be assessed on a case by case basis and will depend on:

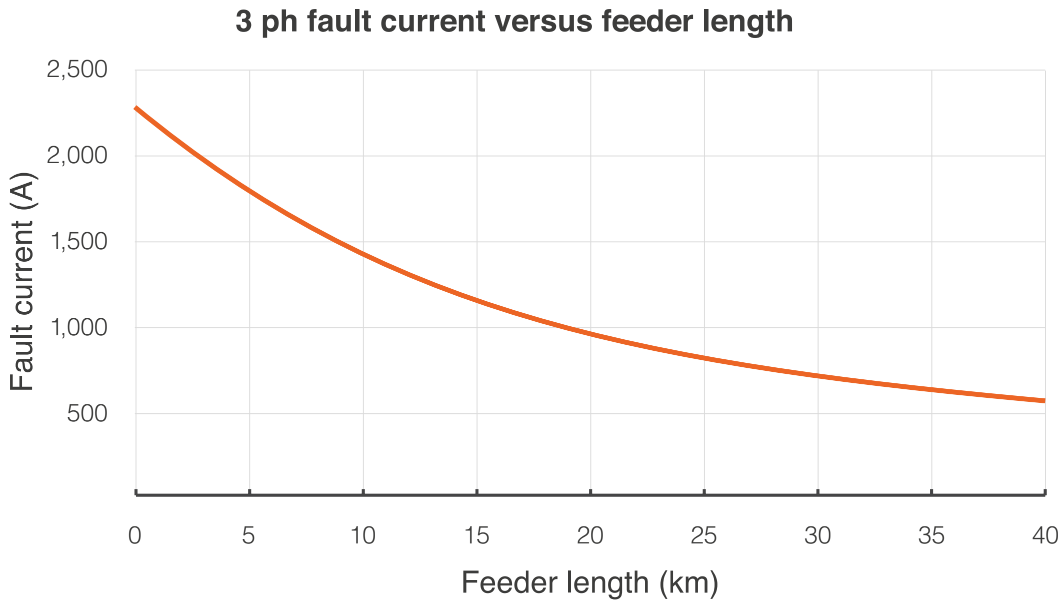
i) the existing settings
ii) the length of the 11kV feeder being protected, and corresponding fault level at the remote end
iii) the operating time required (typically an operating time of <1s would be desired, but up to several seconds may be permitted depending on DNO policy)
iv) ensuring grading with the transformer incoming 11kV circuit breaker (this may be optional depending on the level of discrimination that is deemed acceptable).

For example, the Annan primary substation 11kV feeders have inverse definite minimum time (IDMT) overcurrent settings of:

- 375A pick-up
- 0.4 time multiplier (TM)
- Standard inverse curve (the higher the current, the less time taken for the relay to operate).

The relationship between fault current and feeder length is given in figure 8.2 for a typical 11kV feeder at Annan primary.

Figure 8.2
Annan primary 11kV three phase fault current versus feeder length (based on 185mm^2 11kV cable)



Existing operating times

It can be seen that the fault current at the Annan primary 11kV busbars (0km feeder length) is 2.3kA. The fault current decays as the feeder length increases and is 1kA at 20km and ~500A at 40km. With the existing 11kV feeder settings, the following operating times would be achieved:

- feeder fault (0.1km) – 1.5s
- feeder fault (20km) – 2.8s
- feeder fault (30km) – 4.0s.

Potential revisions

The above results would be acceptable if the requirement is to ensure protection operating times are less than 3s, and the 11kV feeder is not longer than ~20km in length. Alternatively, the TM could be reduced to provide faster clearance times. A disadvantage is that this may sacrifice grading with any other protection devices further down the 11kV feeder. However, under Black Start conditions, it is assumed that ensuring this level of discrimination would not be a priority.

In addition, the overcurrent relay is set to pick up at 375A. Traditionally, a fault current of 2x the pick-up value would be required to guarantee correct relay operation (750A). It can be seen from figure 8.2 this could only be provided for feeders up to ~30km in length. Modern relays guarantee operation for 130 per cent, in this case meaning that a fault current of 1.3x375 = 488A could be detected. This would allow a feeder length up to ~40km to be protected, and would still operate in <3s if a TM of 0.1 was applied.

Conclusion

The 11kV feeder protection will need to be assessed on a case by case basis to ensure the pick-up and TM are such that the full length of the feeder is protected, operating time for a far end fault is acceptable, and grading is achieved with the transformer 11kV incomer.

8.5.2 Primary substation – 11kV transformer incomer

Table 8.5 shows that there may be a protection limitation associated with the primary (33/11kV) transformer 11kV circuit breaker (known as the 11kV transformer incomer). The overcurrent settings on this circuit breaker are typically set such that:

1) The pick-up setting is high enough to allow an acceptable loading on the transformer (typically above the substation maximum demand but below the transformer full rating).
2) The pick-up setting is low enough such that it is <=50 per cent of the fault current at the primary substation 11kV busbar (this is to ensure there will be 2x fault current to operate the relay).
3) The pick-up setting is low enough such that it allows grading with the overcurrent relays on the bus-section and 11kV feeder circuit breakers (to ensure that a fault on an 11kV feeder will open the feeder circuit breaker and not the transformer incomer).

To achieve the above, a change may be required to the existing IDMT overcurrent pick-up setting, with the lower fault levels during a Black Start. Table 8.5 shows that in order to ensure that the 11kV fault current is at least 2x the incomer overcurrent pick-up, the IDMT LV pick-up value may be less than the rating of the transformer. The loading on the transformer would have to be limited to these values (shown in orange) to avoid operation of the protection for load currents. (N.B. it may not be possible to select these exact values of pick up on the relay, and if not the closest lower setting available would be chosen resulting in a slight increase to the limitation.)

Given that the substation demand may be greater than normal when energised after a blackout (due to lack of load diversity) it would be advantageous to ensure that the primary transformer can utilise its full thermal capacity. Table 8.5 also shows that if the ratio of the 11kV fault current to incomer overcurrent pick-up is reduced to 1.5, the loading limitations on three of the primary transformers are removed and reduced in two others (shown in blue). Modern relays have guaranteed operating levels down to detecting currents 110 per cent of the pick-up setting.

It should be noted that, even if the existing IDMT overcurrent pick-up settings do not require revision, changes will most likely be required to the TM (and the earth fault TM) to reduce the operating times. A disadvantage of increasing the pick-up setting is that it will reduce the length of the 11kV feeder circuits, for which it would operate as backup protection, should the 11kV feeder circuit breaker fail to trip.

Conclusion

The transformer 11kV incomer IDMT overcurrent pick-up setting may have to be reduced to ensure operation for 11kV faults. This may result in a loading limitation on the primary transformers. This may be removed if a lower ration of fault current to relay pick-up current is acceptable i.e. the pick-up setting can then be increased. The TM on the IDMT overcurrent and earth fault elements will have to be changed to reduce the operating time regardless.

Table 8.5

Chapelcross primary substation loading & 11kV incomer settings

Transformer ID	Max demand	Max demand x 2	33/11kV transformer MVA	IDMT 11kV O/C pick-up A	IDMT 11kV O/C pick-up MVA	Fault current at Tx 11kV BB A	11kV fault current compared to 11kV IDMT O/C pick-up	IDMT 11kV O/C pick-up A	IDMT LV pick-up current MVA	Fault current at Tx 11kV BB A	11kV fault current compared to 11kV IDMT O/C pick-up
Lockerbie 33/11 kV	15.7	31.4	24	1035	**19.7**	2070	2.0	1380	26	2070	1.5
Moffat 33/11 kV	4	8	10	635	12.1	1270	2.0	847	16	1270	1.5
Annan 33/11 kV	12	24	24	1145	**21.8**	2290	2.0	1527	29	2290	1.5
Langholm 33/11 kV	4.7	9.4	24	830	**15.8**	1660	2.0	1107	**21**	1660	1.5
Gretna 33/11 kV	6.9	13.8	24	815	**15.5**	1630	2.0	1087	**21**	1630	1.5

8.5.3 GSP substation – 33kV feeder protection

At the Chapelcross GSP substation, on a 33kV feeder, the high set overcurrent (HSOC) protections will require reduced pick-up settings to detect faults on the 33kV circuits up to the primary transformer bushings. In addition, the pick-up of the IDMT overcurrent elements will need to be changed to ensure they are not higher than 50 per cent of the fault level on the 11kV busbar of the primary substation being protected. This ensures relay operation to provide backup for an 11kV busbar fault. This pick-up setting will result in the same magnitude of primary transformer loading limitation as described for the 11kV transformer incomer (see 8.5.2).

Reduction of the IDMT overcurrent TM will also be required to provide satisfactory operating times. The IDMT earth fault TM will also be reduced to ensure that it grades with the IDMT earth fault protection on the 33kV circuit from the anchor generator (so the generation is not tripped for a feeder backup protection operation.) If unit protection is installed a sensitivity check will be required as to the minimum operating current (normally 10 per cent of nominal current). This should operate satisfactorily.

Conclusion

Settings changes will be required on HSOC and IDMT 33kV feeder protections. The IDMT pick-up setting may be a limiting factor on the associated primary transformer loading.

8.5.4 Dumfries GSP limitation

In table 8.5 it can be seen that there is a limitation associated with the Dumfries 132/33kV transformer 33kV circuit breaker. The Chapelcross case study network is such that initially the Chapelcross 33kV network is energised. A subsequent restoration option is to energise the 132kV circuit to Dumfries GSP, and energise a 132/33kV grid transformer. The fault level on the Dumfries 33kV busbar is ~1kA (it is 2.1kA at the Chapelcross busbar). It is estimated that this fault level will be sufficient to provide grading with a downstream 33kV connection (e.g. a wind farm), but it may not be possible to achieve grading to protect the network further downstream (e.g. a primary substation).

8.6 Protection operation – minimum fault level guide

8.6.1 Introduction

This section seeks to develop a guide as to the minimum fault level which would be required, at distribution and transmission voltage levels, to ensure correct protection operation. When assessing the suitability of DER to provide Black Start services, and the restoration options which may be achievable, an initial guide would be helpful rather than commissioning a full protection assessment at the early feasibility stages.

8.6.2 Fault level guide for 33kV, 11kV and 415v operation

The minimum fault level required at 33kV to operate the 33kV protection, and all lower voltage protections, is complex having to ensure that all main and backup protections grade, and the primary transformers (33/11kV) do not trip for the required load current. Table 8.6 gives a guide as to the 33kV source fault levels (the fault level required at the 33kV bushings of a primary transformer) which would be required to achieve this.

The guide is given for the three most common primary transformer sizes 24MVA, 10MVA and 7.5MVA. It can be seen that for a 24MVA and 10MVA transformer, a source fault level of 44MVA would be required, and 34MVA for a 7.5MVA unit. The fault level at a grid 33kV busbar, from available DER, could be calculated. From this the fault level at the primary transformer 33kV terminals can be determined (furthest away likely to be the lowest), to see if the minimum fault level criteria can be met.

Conclusions

Allowing for a 15 per cent margin of error, the following conclusions could be draw:

- 24MVA (33/11kV) transformers – Minimum transformer terminals 33kV fault level of 50MVA required.
- 10MVA (33/11kV) transformers – Minimum transformer terminals 33kV fault level of 50MVA required.
- 7.5MVA (33/11kV) transformer – Minimum transformer terminals 33kV fault level of 40MVA required.

It should be noted that:

1) Table 8.6 is just an approximate guide given that there are a lot of variables such as the transformer loading required, the acceptable discrimination between load currents, relay pick-up currents, fault currents, the configuration of the networks, and DNO protection setting policies.
2) For the 24MVA and 10MVA transformers, the source fault level required would reduce to ~40MVA if the ratio of fault currents to relay pick-ups was reduced to 110 per cent (the minimum guaranteed for operating times on modern relays).
3) A 33kV source fault level of ~30MVA will ensure that associated LV fault levels are ~80 per cent of their intact system values and thus protections will operate as normal.

Table 8.6
Minimum 33kV primary transformer source fault level requirements

			Primary (33/11kV) transformer											
Min source fault level to protect Tx and allow full load		Ratio 11kV BB fault current to 33kV & 11kV IDMT pick-ups	Tx rating	Voltage		Impedance	33kV IDMT pick-up (set to full load)	11kV IDMT pick-up (set to full load)	Through fault current 33kV	11kV BB fault current	33kV HSOC pick-up (150% If)	Ratio – 33kV If/ HSOC pick-up (150% If)	33kV HSOC pick-up (120% If)	Ratio – 33kV If/ HSOC pick-up (120% If)
MVA	kA		MVA	HV	LV	% on rating	A	A	A	A	A	A	A	A
44.0	0.77	1.3	24	33	11	24.00%	419.89	1259.67	535	1604	802	0.96	642	1.20
44.0	0.77	3.1	10	33	11	9.99%	174.95	524.86	535	1604	802	0.96	642	1.20
34.0	0.59	3.1	7.5	33	11	9.80%	131.22	393.65	412	1236	618	0.96	494	1.20

8.6.3 Fault level guide for 132kV, 275kV and 400kV protection operation

Typical transmission owner (TO) and DNO feeder protection policies dictate that at 132kV there should be a main and a backup protection, and at 275kV and 400kV two main protections and a backup. A main protection can either be unit protection (sometimes called biased current differential protection). This measures the current going into a zone and the current going out and trips if the two are not within a set tolerance (indicating a fault within the zone). Alternatively, distance protection may be used which measures the impedance of the network to distinguish between load and a fault. IDMT back-up overcurrent and earth fault protection would also be provided.

Feeder unit protection requires a minimum operating current of 10 per cent to 30 per cent of the nominal current. Distance protection has a minimum operating current of 10 per cent of the nominal. The nominal current (In) equals 1A based on the standard current transformer (CT) ratios shown in table 8.7. It follows that 10%In operation of a relay with a 1200/1 CT would require 120A on the primary side to operate.

Protection operating – minimum fault levels required

Table 8.8 gives an indication of the minimum fault level required at 132kV, 275kV and 400kV in order to assess if the existing protections, main and backup, will be capable of detecting a fault (with revised minimum settings).

Table 8.7
Standard CT ratios

	400kV	275kV	132kV	33kV
CT ratio	2000/1	1200/1	1200/1	800/1

Table 8.8
Protection operation min fault levels required

Voltage level	CT ratio (feeder)	Main unit/distance pick up (10%In)		Back-up O/C (E/F) IDMT min plug setting 10% In assume min If = 1.5 x plug setting		Min fault level req (+15%) MVA
		A	MVA	A	MVA	
132kV	1200/1	120	27.4	180	41.2	**47.3**
275kV	1200/1	120	57.2	180	85.7	**98.6**
400kV	2000/1	200	138.6	300	207.8	**239.0**

Methodology

To guarantee operation of the main protection, 10%In current is required. For the back-up protection, minimum pick-up setting of 10 per cent may be applied. In addition, the minimum TM setting which can utilised is 0.05. Allowing for a fault current which is 150 per cent of the pick up, with a TM of 0.05, the protection will operate in ~0.9s (a back up protection time or <1s is typically required). The minimum fault level required to operate protection at each voltage level is the higher of the value required for the main protection or the back-up protection. In table 8.8, 15 per cent has been added to the minimum fault levels identified to provide a margin for error.

Thus, as a 'rule of thumb', for adequate protection operation you need a minimum fault level (three phase and phase to earth) of:

- 132kV – 50MVA
- 275kV – 100MVA
- 400kV – 250MVA.

It should be noted:

1) The fault level should be calculated after 1s. The fault current magnitude decays from the point of fault inception, and 1s is approximately the slowest protection operating time expected at 132kV, 275kV or 400kV.
2) The above guide is based on standard CT ratios. In reality the Chapelcross 132kV network has CTs which are 500/1 and 600/1 which would result in a reduction in the required fault levels.
3) Three phase fault levels should be compared with the 'rule of thumb' values as the phase to earth fault levels are normally higher at 132kV, 275kV and 400kV due to multiple earthing points on the network.
4) A full protection assessment would be required, and protection changes identified, to guarantee viability.

8.7 Chapelcross case study – fault level sensitivities

The Chapelcross case study network protection assessment has been carried out based on the fault infeed from a single 60MVA synchronous generator connected at Chapelcross 33kV GSP. Table 8.9 shows the impact, at the higher voltage levels, of varying the size of this generator.

Table 8.9
Chapelcross case study fault level sensitivities

		Chap 33kV		Chap 132kV		Gretna 275kV[9]		Gretna 400kV	
		3 phase fault (1s)		3 phase fault (1s)		3 phase fault (1s)		3 phase fault (1s)	
Anchor gen 33kV	**MVA**	**kA**	**MVA**	**kA**	**MVA**	**kA**	**MVA**	**kA**	**MVA**
0.5	30	0.9	49[7]	0.2	44	0.09	41	0.06	40
1 x	60	1.6	94	0.3	78	0.15	71	0.09	65
2 x	120	3.15	180	0.6	129	0.24	112	0.16	109
3 x	180	5.1	292	0.7	165	0.29	139	0.20	136
4 x[8]	240	6.9	395	1.1	258	0.42	200	0.28	192

8.7 Chapelcross case study – fault level sensitivities

The Chapelcross case study network protection assessment has been carried out based on the fault infeed from a single 60MVA synchronous generator connected at Chapelcross 33kV GSP. Table 8.9 shows the impact, at the higher voltage levels, of varying the size of this generator.

8.7.1 33kV fault infeed

It should be noted that there is a finite limit of generation which can be connected at 33kV to high fault level limitations under normal intact system conditions. The standard design 33kV fault level limit is 1,000MVA. From the Chapelcross GSP example, the fault infeed from the two grid transformers is ~650MVA. Thus there is ~350MVA fault level headroom for generation and demand. In table 8.9, '3 x Anchor Gen 33kV' is shown to provide 292MVA of fault infeed at Chapelcross 33kV busbar after the fault level has decayed a period of 1s. The maximum 33kV fault level is calculated at 90ms, and this would equate to ~350MVA. It follows that the '3 x Anchor Gen 33kV' results are a good guide as to the maximum fault infeed which could be expected from a grid 33kV network.

8.7.2 Fault level relationship across voltage levels

Once the 132kV network has been energised from the 33kV network, it may be that there is an option to bring on generation connected at 132kV to increase the fault level and allow the 275kV and/or 400kV network to be energised. Appendix 4: fault levels across voltage levels shows the relationship between fault infeed at one voltage level on the fault level at other voltage levels through standard network impedances. For example:

i) A fault level of 350MVA at 132kV would be required to provide a fault level of 250MVA at 400kV (the minimum for protection operation).

ii) A 33kV fault level of 300MVA (the maximum typically available from DER) would provide a fault level of approximately 150MVA at 132kV and 400kV. Thus, an additional 100MVA fault infeed at 132kV would be required before the 400kV network could be energised.

8.7.3 Conclusions

Based on the minimum fault level guide for protection to operate correctly given in section 8.5.4, the following conclusions can be drawn:

- If the 60MVA generator was half the size (30.0MVA) there would not be enough fault infeed to protect the 132kV network.
- A single 60MVA DER would allow the 33kV and 132kV networks to be protected.
- 275kV network – Doubling the 33kV generation capacity to 120MVA, and above, would enable the 275kV network to be protected.
- 400kV network – Even with four of the 60MVA 33kV connected generators (above practical 33kV DER fault infeed limits) there is insufficient fault level at 400kV to protect the network.
- 400kV network – To protect the 400kV network, the additional fault infeed required at 132kV would range from ~100MVA (when the 33kV network has the maximum fault infeed permissible) to ~250MVA (when the 33kV network has the minimum fault infeed to protect the 33kV network).

[7] A protection assessment will be required to verify that the 33kV, 11kV and LV network can be protected.
[8] Chapelcross Grid T1 & Grid T2 132/33kV transformers in service (all other results only Grid T1 in service)
[9] Gretna does not have a 275kV network in reality. This node has been added for study purposes.
NB[1] The generator is modelled with a Xd' of 0.333pu and is connected to Chap 33kV by a 25km underground cable circuit.
NB[2] Fault currents calculated at 1s break time.

8.8 Protection assessment conclusions

From the protection assessments that have been undertaken on the Chapelcross case study network the following conclusions can be drawn:

- Under Black Start conditions, the fault level that will be available on the network (at the different voltage levels) will be a determining factor as to whether the existing protection will operate (with existing or revised settings) and thus if the network can be energised.
- The Chapelcross case study Black Start fault level calculations highlighted that the LV, 60 per cent of 11kV, 54 per cent of 33kV and 10 per cent of 132kV protections would still operate correctly with the reduced fault levels.
- If there is sufficient fault level for protections to operate to allow a 33kV DRZ to be established, it is likely there will be sufficient fault level for the associated 132kV network to be protected (revised settings applied where required).
- Revised settings may be applied to modern relays which have the functionality for a second group of settings. Older relays may require to be changed to provide this functionality.
- The lower network fault levels, and associated revised protection settings, may result in some limitations on how the network can be operated. For example, the loading on primary (33/11kV) transformers may have to be constrained below full load, or the restoration path at 33kV or 132kV may be limited due to decaying fault levels as the network expands. These limitations may be alleviated if the ratio of fault current to relay pick up current is reduced (modern relays guarantee correct time operation for a fault current 110 per cent of pick up, historically 200 per cent was required).
- As a guide, the following minimum fault levels are required for satisfactory protection operation (based on standard CT ratios):

  – 33kV – 50MVA*

  – 132kV – 50MVA

  – 275kV – 100MVA

  – 400kV – 250MVA.

  *At primary (33/11kV) transformer HV terminals. This ensures associated 11kV and LV networks will also be adequately protected.
- In the Chapelcross case study example, it is not possible to energise up to the 275kV or 400kV network due to insufficient fault infeed from the 33kV network (a single 60MVA generator) to operate existing protections.
- The DER at a 33kV grid substation has the potential to provide enough fault infeed to allow 275kV protections to operate and the network to be energised (~180MVA of fault infeed required at the 33kV grid substation).
- Based on our detailed analysis of the case studies and considering the more general conditions across all of GB, it is likely that a 33kV DRZ, on its own, will not be able to provide enough fault infeed for existing 400kV protections to operate correctly. It follows that additional fault infeed at higher voltage levels would be required. For example, at 132kV between 100MVA and 250MVA of additional fault infeed would be required depending on the 33kV DER fault infeed. This might be provided by restoring supplies and restarting generators or resources like synchronous condensers on the 132kV network.

9. Grid-following converter-connected DER – considerations

9.1 Introduction

DER types such as wind farms, solar farms and batteries, are connected to the electricity network via a power electronics converter interface. In general, converter-connected controllers can be categorised into two groupings; grid-following or grid-forming. Grid-following controllers require an existing grid voltage as a reference to track and connect to. Grid-forming controllers can generate their own independent voltage source, similar to a conventional synchronous generator. Chapter 10 will consider grid-forming converter-connected technologies in more detail, with this chapter focusing on grid-following technology and the associated issues.

In the initial PET workstream report 'Viability of Restoration from DERs' (July 2019), it was highlighted that the behaviour of converter-connected generation during any distributed restoration process might be compromised; that is, these devices are susceptible to maloperation when connected or attempting to connect to a weak (low short circuit level) network.

Existing converter-connected sources are primarily grid-following which has been effective to incorporate a high penetration of renewable power into the distribution and transmission network based on the network having the required frequency and voltage stability (high inertia and short circuit level). However, as the network continues to transition from being dominated by synchronous generators to converter interfaced resources, issues with system operability have increasingly been observed. Moreover, in distribution power islands, with relatively low inertia and short circuit level, it is likely that stability issues with grid-following converter-connected resources will be exacerbated.

To investigate grid-following converter performance, a literature review[10] has been undertaken on a number of areas relating to their behaviour in weak grids. Literature relating specifically to performance during a Black Start or system restoration is limited, therefore the findings are predominately based upon 'microgrid' applications; where the network will share similar characteristics. In using the term 'microgrid', we are referring to small multi-user, MV networks.

This section contains a summary of the key findings obtained from the literature review. Adaptations to grid-following converter control to improve operation in a weak grid and enable frequency support are discussed. Implications on the internal dynamics of common wind turbine technologies when attempting to provide frequency support are also explained.

9.2 Grid-following converter – inertial and system strength considerations

Several publications have explored how the penetration of converter-connected DER into the power system faces limitations linked to different aspects of stability such as voltage, frequency and control interactions. However, the specific challenges of Black Start from DER has not been widely studied and presents unique characteristics that evolve depending on the stage of the restoration. For example, as the Black Start continues by energising neighbouring areas the additional generation of different sizes/technologies will change the dynamic behaviour of the power island and appropriate control will be needed to maintain stability.

A general definition for stability could be the ability of an electric power system, for a given initial operating condition, to regain an acceptable operating state after a disturbance. The dynamic characteristics of a power system depends on the dynamic behaviour of the connected resources. Where most of the resources connected to microgrids are converter based renewables, the dynamic behaviour and operational characteristics are quite different from the main intact power network.

Due to the coupling between different system variables, it is not easy to classify the instability as voltage or frequency instability in microgrids. Regarding this difficulty, a more useful classification scheme is to emphasise the type of equipment or controller that is involved in instability triggered by a system disturbance.

Stability issues of microgrids can be divided into two main categories: issues related to control systems and the instability caused by active and reactive power sharing and balance. Disturbances may be caused by component failure, short-circuits, loss of generation or other unexpected phenomena. While some disturbances impose a large change on the system, there can also be a risk from small disturbances where the system is stimulated to respond in a particular way that amplifies the effect of the disturbance, leading to much larger changes. Depending on the root cause, small-perturbation instability can be either a short-term or a long-term phenomenon.

[10] Strathclyde University 'Literature review and initial assessment of converter-connected generation in the context of Distributed ReStart project', June 2020.

For microgrids, control system stability issues will appear because of inadequate control schemes (i.e. control interactions of parallel DERs) and/or poor tuning of one or more equipment controllers. In the case of instability due to poor tuning of an equipment controller, the system cannot be stabilised until the controller is re-tuned or the associated piece of equipment is disconnected. This type of stability is related to electrical machines and inverter control loops, inductance-capacitance-inductance (LCL) filters and phase-locked loops (PLL) and is subcategorised into synchronous machines and converter stability. Converter control issues have been reported as a limiting factor for the integration of renewable power into the network.

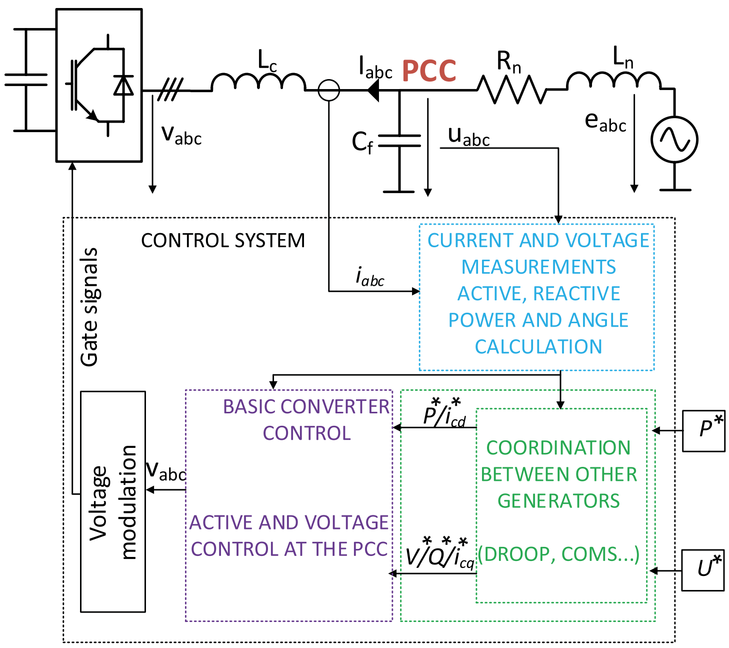
Most converter-connected generation units utilise voltage source converters using a PLL to synchronise with the system voltage. In a microgrid with low inertia and fault level, the voltage behaviour would be more dynamic and can lead to loss of voltage tracking. The main issues in this regard are:

- Converter controller stability – PLL, inner and outer loop
- Control interactions between synchronous generator and converter.

9.2.1 Grid-following converters – system strength considerations

An important consideration for a Black Start restoration process is the potential strength of the network established, which is often assessed in terms of its short circuit ratio (SCR). The SCR is the ratio between the short circuit capacity at the point of connection and the power rating of the converter. The SCR is still the most common definition of grid strength, but new definitions are being developed to consider power electronics and multi-infeed scenarios.

Figure 9.1
Converter controller structure



A Black Start scenario will also cause the short circuit capacity of the network to drop below its usual values due to there being far fewer synchronous generators online and much sparser network interconnection in the early stages. A common interpretation of SCR is to characterise any grid with an SCR between 1 and 3 as ‘weak’; and below 1 as ‘very weak’. One of the main effects of low SCR networks is an increased likelihood of undesirable control response between the power converter and the grid. These can be caused by:

- the increased coupling resonances between the network and the converter filter and/or controller;
- the increased cross-coupling between active and reactive power (which can lead to instabilities within a controller and between controllers).

Grid-following controllers, such as the widely used vector current control (VCC), are well understood by academics and industry, with almost all existing grid-connected converters utilising this technology. Most renewable energy sources, such as wind turbines interfaced with fully rated converters (FRC) and photovoltaic (PV) panels (as well as battery storage units) utilise VCC. Typical VCC structure includes a PLL, an outer loop and an inner current loop. Using the measured voltage values at the point of common coupling (PCC), the PLL has the task of latching on to the PCC voltage to provide the voltage phase, and as a result all measurements can be transformed into their dq-components. The control in the synchronous reference frame (dq-frame) simplifies the control analysis and implementation. The inner loop regulates the active and reactive current components independently and the outer loop calculates the current references to achieve a particular active power or reactive current (or voltage) at the PCC. The outputs of the outer loop are the inputs of the inner loop. The main components of a converter controller are shown in figure 9.1 and described in more detail below.

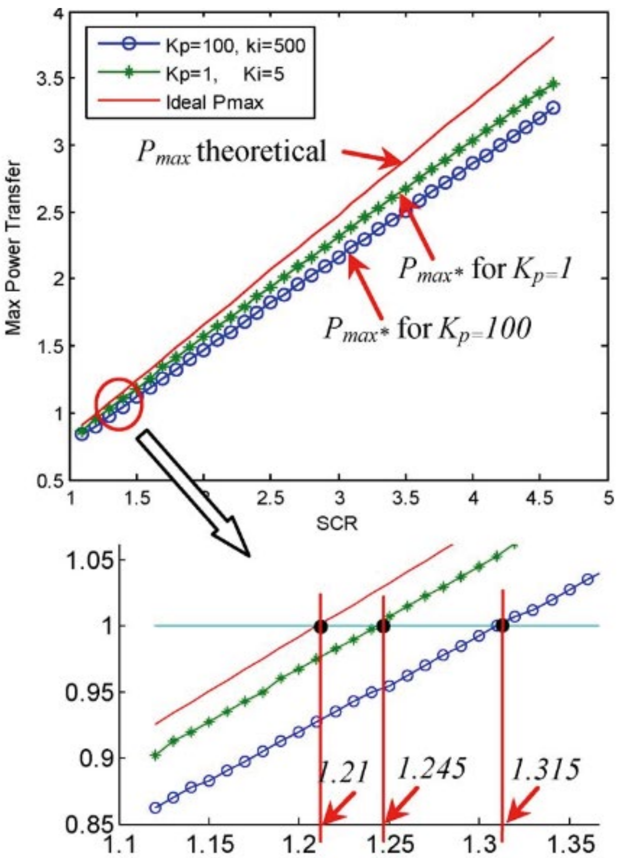
Phase-locked loop (PLL) – measurement and power and angle calculations (blue box): This block samples the currents (iabc) and voltages (uabc) at the PCC and performs the required active, reactive and angle calculations depending on the converter control technology.

Inner loop – basic converter control (purple box): The basic converter control has the mission to achieve the required active power (P*) and voltage (U*) references (or reactive power) at the PCC. The inputs to the basic converter control are the references, the measured and calculated electrical quantities (depending on the configurations) and the outputs are the voltages that the power converter should apply.

Outer loop – coordination between other generators (green box): This block calculates the required active and reactive power references to achieve a certain degree of coordination between converters or synchronous machines. This block can be seen as equivalent to the automatic voltage regulator (AVR) or governor control in traditional synchronous machines, but communications or other control techniques can be used instead.

Voltage modulation: This block calculates the converter switch states that provide the voltage required by the basic converter control.

Figure 9.2
Impact of the PLL parameters



This control structure has been used in most converter-based generation until now. However, with converter-based generation comprising of a significant amount of the electricity generation, the basic form of this control structure must either be improved, in order to support the grid, or supplemented with grid-forming control. While VCCs are seen to perform well in strong and stable networks, their performance suffers in networks with low inertia and low SCR. They cannot inherently provide inertial response and have limited overcurrent capabilities to provide synthetic inertia.

PLL stability

The PLL is the standard method of synchronisation for grid-connected converters. The stability of the PLL is reduced when the power converter is connected to a weak grid. Figure 9.2 shows the impact of the PLL parameters in the maximum stable power that can be extracted from a voltage source converter (VSC) controlled using standard vector control depending on the short circuit ratio (SCR). Lower PLL gains (reduced bandwidth) allow rated power to be delivered at a lower SCR. The limit is due to the onset of voltage instability occurring from increased power flow. When the gains are larger, the oscillations build faster which leads to an earlier onset of instability. This trend continues with differences becoming more observable at higher SCR ratios.

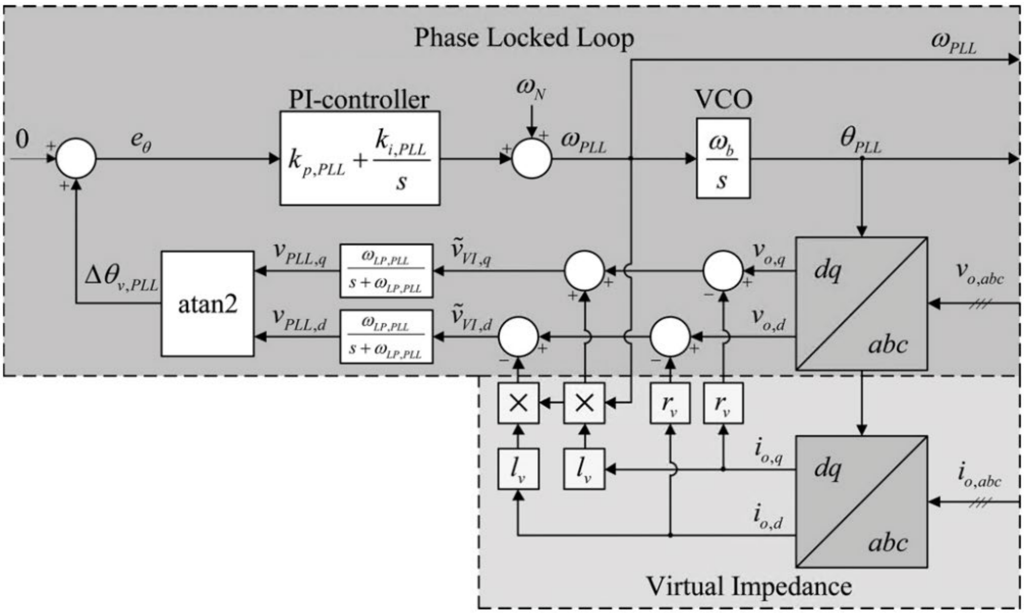
Large-signal issues have been reported when a very severe grid voltage sag (grid voltage near zero) occurs near a converter. In these cases, the PLL might lose stability as the voltage is very small or impossible to track and the frequency (or voltage phase) estimated by the PLL during the voltage sag is unstable. Standard converter control techniques fail to maintain stability when the short circuit ratio is low (SCR<1.3-1.5).

- The PLL voltage tracking ability is reduced and lower power throughput is achieved.
- Reducing the bandwidth of the PLL (using smaller control gains) can improve power transfer across a larger range of SCR.
- This is most important when a very low SCR causes the maximum power transfer to fall below 1pu.
- Reduced PLL bandwidth provides lower system damping, especially at higher SCR ratios, therefore gains used for normal operation and Black Start processes may require to be different.

Solutions to prevent such loss of synchronisation include injecting active and reactive currents that account for the X/R ratio – however this is practically difficult because it requires knowledge of the network equivalent impedance. An alternative is to use a PLL frequency based active current injection algorithm.

The transient behaviour of a fluctuating voltage will affect the PLL's ability to track the voltage phase and therefore the converter's stability. To overcome this problem, research suggests synchronising to a virtual part of the grid, rather than the point of common coupling (PCC), by introducing an impedance-conditioning term in the PLL. This is done by tracking not just the PCC voltage, but also the current, which is then multiplied by a virtual impedance, resulting in a virtual voltage. The PCC voltage and the virtual voltage are added, and then the resultant voltage is fed to the PLL, as per figure 9.3.

Figure 9.3
Schematic of proposed PLL with virtual impedance



Another solution is where the behaviour of the network and PLL are predicted and considered in the combined inner loop and outer-loop controller. As a result, an increased operational range is achieved.

Further corrective action that can be taken is simply to reduce the PLL bandwidth and slow its response. The effect of PLL gain changes is demonstrated to have a significant impact on the performance of the converter. However, any method that causes an overall reduction in PLL bandwidth (which may include virtual impedances) ought to be used with caution. A slower PLL may lead to reduced response capabilities for overcurrent protection, just as PLL-less converters have no overcurrent protection. Research has shown retuning and synchronisation of the PLL to an artificial bus improved stability – and it concludes that the artificial bus method yielded better results overall.

It has been identified that the PLL perturbations in weak grids cause low-order harmonics in the output current. Research suggests introducing a feed-forward branch to compensate for the PLL perturbations. The measured voltage, of which the PLL tracks the phase, is also passed through a transfer function that predicts the PLL dynamics and compensates for them before modulating the converter voltage.

Outer and inner control loop stability

In addition to the PLL dynamics issues, the design of the traditional control loops may influence the performance and stability of converters connected to weak grids. Some investigations indicate standard outer and inner loop controllers may make the converter unstable. The control system might become unstable in weak grids due to the effect of the outer controllers coupling. In general, we assume that the converter should behave linearly but when the converter is connected to a weak grid a different operating point might present very different dynamics. As in the conventional systems, in microgrids, since tuning inner and outer control loop gains is a challenging issue, inverter voltage and current control loops are a major concern for small-signal stability of the system.

The outer loop

Suggested adaptions to the outer loop as a means of stability improvement are advantageous as they do not interfere with the bandwidth or the inner loop. Research considered has focused on two areas:

- The coupling between the active and reactive power, and the inclusion of a feed-forward branch from the power reference to the output of the voltage magnitude control; in effect compensating the voltage branch for changes in power.
- Gain scheduled multi-variable controllers using the H∞ fixed-structure control design methodology is also proposed, allowing for stable operation across the entire VSC range. Gain scheduling is an appropriate method for converter control in nonlinear systems (such as weak grids) and therefore has a lot of benefits. However, it is unclear how this method responds to changes in network impedance.

The inner loop

It has been determined that bandwidth reduction within the inner current loop can also improve weak grid stability. However, caution should be taken not to affect the controller's ability to prevent overcurrent by affecting the response time. Research considered has focused on the following areas:

- Online controller tuning, where a grid impedance estimation method estimates the network Thevenin equivalent impedance, and subsequently determines the optimum Kp and Ki using the Newton-Raphson iterative method such that a pre-determined bandwidth and damping ratio are achieved.
- Introducing a virtual impedance, 'shaping' the converter output impedance, to increase stability and harmonic rejection. This is done by introducing a parallel and series-connected impedance in the current controller.

By using a parallel impedance, that is the negative of the output impedance, the combined converter impedance becomes infinite. In theory, this eliminates all the current harmonics caused by the grid voltage. Unfortunately, it also introduces considerable control delays. As such, the parallel impedance shaping method enhances harmonic rejection ability but weakens the stability robustness.

The virtual series impedance, on the other hand, is used to boost the phase of the equivalent impedance in the high frequency components to counteract the effect of the parallel impedance on those frequencies. This combination of virtual parallel and series impedance makes the converter capable of strong grid voltage harmonic rejection and strong stability robustness against the variations of the typical inductive resistive grid impedance.

Filter resonances

Filter resonances occur when components in the network (such as network inductances or capacitors) and the converter filter start to interact with one another. These problems tend to become worse as the network becomes increasingly weak because filters are normally designed to operate at a particular impedance range. These resonances normally occur in the high-frequency range, around the LCL filter resonance, which is between the fundamental frequency and the switching frequency. Mitigations for filter resonances include:

- the use of real resisters and virtual resistors
- adaptive damping.

9.2.2 Grid-following converter – inertial considerations

Frequency regulation in a microgrid is a major concern due to the lower system inertia and a high share of intermittent DERs. A lower number of power generation units increases the risk of a large disturbance in a microgrid in the event of generator outage. For these disturbances, the system frequency may experience large changes, threatening the system frequency stability. In these cases, conventional frequency control methods are not fast enough to overcome quick changes of system frequency even with enough reserve generation.

Furthermore, frequency regulation in a microgrid can be challenging, owing to the strong coupling between voltage and frequency. Due to the high R/X ratios of microgrid feeders, the decoupling of active power flow and voltage magnitude is not valid. Another cause of instability could be the poor coordination of multiple frequency controllers and power-sharing between DERs, which may trigger small-perturbation stability issues leading to undamped frequency oscillations in the span of a few seconds to a few minutes.

Conventional synchronous-based power stations inherently store energy in the form of inertia due to the mass of their rotational components and their rigid coupling to the electrical network. This allows them to contribute to maintaining frequency stability and reducing the Rate of Change of Frequency (RoCoF). In a network where converter-based generation does not provide any inertial response, the frequency stability is affected.

As a result, low inertia is considered a major problem in the electrical grid, especially when the grid is vulnerable to instability – as it would be in the event of a Black Start. Wind turbines, despite having large rotational masses, do not provide 'real' inertia to the network due to the fact that they are electrically decoupled. As such, there has been much concern that increasing the penetration of wind energy into the GB network would reduce the system inertia.

This section presents the most common control schemes using standard VCC that can provide inertia response. In general, these control schemes modify the converter power reference according to the frequency measured through the PLL. This section analyses the following control structures:

- Doubly-fed induction generator (DFIG) specific solutions due to their prevalence in onshore wind farms.
- Fully rated converters (FRC) due to their relevance to most new/large wind turbines, as well as PV and battery systems.

DFIG wind turbines

DFIG wind turbines are unique in their ability to interact with the grid via both the grid side converter and the rotor side converter due to the rigid electrical coupling between the grid and the stator. DFIG-type wind turbines were designed to allow variable speed operation of wind turbines fitted with induction generators. The stator is directly connected to the grid via a transformer, while the rotor is connected via slip rings to a back-to-back converter. This allows for variable frequency operation of the induction machine with a partially rated converter, a much cheaper option than a fully rated converter. This is done by regulating the torque on the machine side converter, thus regulating the rotational speed, in addition to regulating the reactive power injection separately.

Frequency support provided by the rotor side converter

One concept for DFIG frequency support investigates how the rotor side converter control can take advantage of the rotor mass in order to provide frequency support. The optimal power is calculated based upon the aerodynamic parameters of the turbine. The electrical torque required for optimal power extraction does not provide the network with frequency support. Therefore, if a DFIG controller is to be ‘dual purposed’, and balance both the needs for optimal power extraction of the wind turbine but also support grid frequency, the reference torque value needs to take both objectives into account.

The resulting calculation introduces the term for a virtual inertial constant and the angular velocity now represents a virtual value linking grid frequency with the reference frequency (as there is not actual mechanical coupling).

The main advantage of this method is that it comes with no additional hardware requirements, unlike the use of a battery or super-capacitor for significant inertial response contribution when implementing grid side converter methods only. However, this does come with its own caveat: this method only works well when the turbine rotor is turning at a sufficiently high speed and therefore has enough stored energy in the rotor.

Frequency support provided by the grid side converter

A further concept of frequency support in a DFIG control scheme, provided by the grid side converter, is where the control structure is augmented by introducing frequency and voltage magnitude droop control branches, compatible with both battery and no battery operation. The power reference is produced by both DC link voltage regulation and an additional frequency response regulation. The DC link voltage regulation ensures that safe limits are not breached, whilst the frequency response droop controller is designed to respond to frequency deviations, even allowing for islanded operation.

Similarly, voltage magnitude is controlled via a droop controller in the reactive power management scheme. As such, voltage support is provided in the event of connection to a non-stiff (high impedance) grid, as well as voltage regulation in the event of islanded mode operation. To summarise, this structure allows for slight DC link voltage deviation in order to provide frequency support when no storage is integrated into the DC link; whereas storage would allow improved DC link voltage performance and similar frequency support. Only the grid side converter control is modified in this equation.

Other research suggests combining both rotor inertia contribution and additional energy storage in the DC link as a means of getting the best of both worlds: using rotor energy when it is available; having a battery alternative for low wind days; and providing both primary and secondary response.

Fully rated converter (FRC) wind turbines, PV, battery storage

Most new wind farm turbines utilise a fully rated converter hardware topology; with the grid side control being the same for wind turbines, batteries and PV. The increase in FRC-type wind turbines is further aided by the reducing cost of power electronics and increasingly stringent requirements, making DFIGs less appropriate due to their reactive power consumption and difficulty in fault ride-through.

DC voltage reference modification

Methods proposed to aid frequency support include utilising the energy stored in the DC shunt capacitors to regulate and level the network frequency, specifically in the event of synchronous generators 'swinging' against one another, producing low-frequency oscillations. While the proposed solution addresses a very specific problem, it could be extended to more general frequency support purposes. The link between DC stored energy and frequency is made in the inertia emulation control loop. This control technique is mainly suitable for energy storage systems.

Assessing rotational inertia in fully rated converters (FRC)

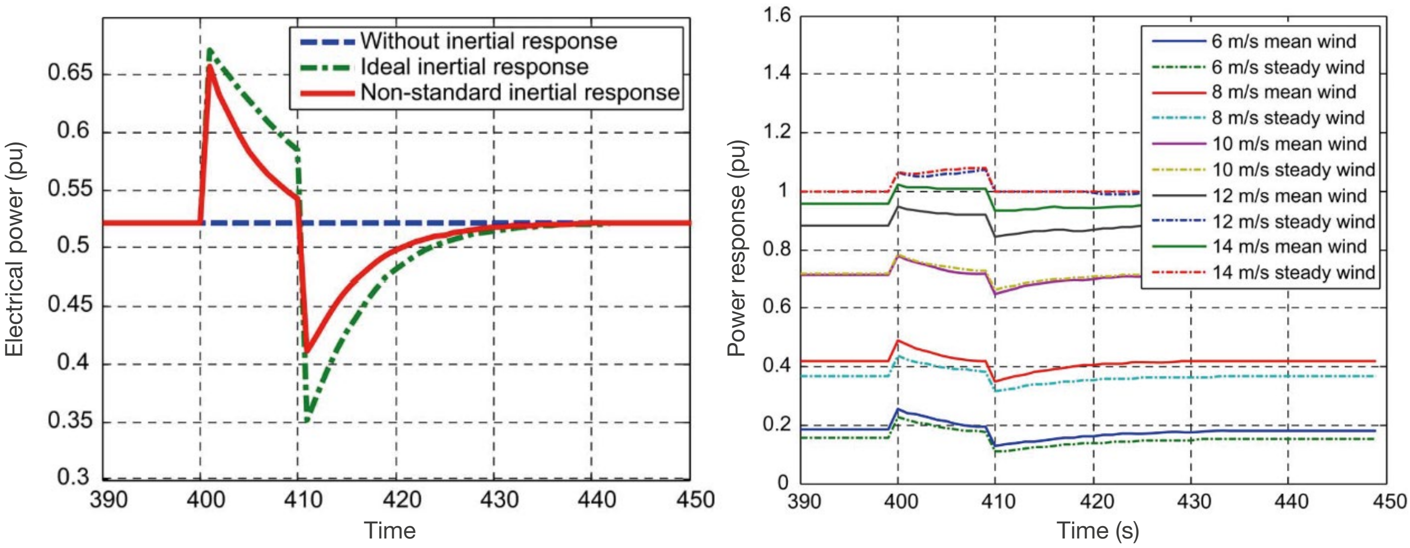
Many FRC type wind turbines utilise the energy stored in the DC link in order to compensate for frequency deviations. The advantage of this is that the wind turbine controller objectives of extracting the maximum power is uncompromised and therefore the rotor speed can stay constant. However, the real inertia stored in a wind turbine rotor is huge and due to the large range of speeds across which a wind turbine can produce electricity (down to 0.7pu as opposed to 0.95pu for conventional power station synchronous generators), a wind turbine with the same inertia constant and power rating as a conventional turbine can produce over 4 times more kinetic energy simply because it is able to access more energy (between the speeds of 0.95pu and 0.7pu) assuming it is operating at almost 1pu.

The downside of extracting kinetic energy from a wind turbine rotor is that, unlike a conventional generator, there is no governor reaction to the reduction in speed. Therefore, the increased power output cannot be sustained for long periods of time. The rotor speed recovery should also be considered when extracting rotor kinetic energy as this will cause a dip in the power output. As a result, this technique is only suitable for the (short term) primary response, as long as power converter limitations are respected, and would require wind turbine owners to agree to the additional stresses exerted on the wind turbines as well as the reduced income due to sub-optimal turbine performance during the grid supporting period. Research has shown this is achieved by determining the power reference as both the required frequency response and the available inertia in the rotor, which is estimated in an internal rotor model.

Such an implementation considers how a permanent system frequency deviation is not possible due to the non-dispatchable nature of wind, but nonetheless short periods of frequency support by releasing fractional amounts of stored kinetic energy is possible by accessing the rotor inertia in FRC-type wind turbines. Research also considers communication between the wind turbines and conventional plants, to notify them of the impending power imbalance caused by the frequency deviation.

One of the biggest limitations of such a method is the uncontrollability of the stored inertia. If frequency support is required on a windy day, turbines will be able to participate using such a method. However, in periods of calm weather, wind turbines will have very limited rotor inertia. The ability for wind turbines to respond adequately in various wind conditions is shown in figure 9.4, this demonstrates the ability of a wind turbine to respond to a frequency event using the rotor inertia in 9 m/s winds, compared to a conventional fuelled generator; and the power response for a range of wind speeds, respectively.

Figure 9.4
(a) Elec. power at constant wind speed of 9 m/s (b) Power response for a range of wind speeds



Summary

In considering the implications for Distributed ReStart, the following thoughts can be drawn from the above research:

- Standard converter control techniques fail to maintain stability when the short circuit ratio is low (SCR<1.3-1.5) for a number of reasons.
  - The PLL voltage tracking ability is reduced and lower power throughput is achieved.
  - Control interactions within inner and outer loops due to weak grids cause instability at higher levels of power throughput.
- It is expected that within a microgrid the frequency and voltage will be more coupled due to the resistive nature of the systems.
  - The inertia issue is translated in the speed of the converter controllers to react to frequency and voltage variations and the availability of the resource.
  - A fast-supervisory control using communications might help to keep the system balance.
- Static voltage stability might be limited in grids with high penetration of power converters and assessing the need for extra reactive power capability by means of the Q-V characteristics is recommended.
- Control related stability issues in microgrids should be taken into consideration for high penetration of converter-based equipment. Some of the aspects to consider are:
  - Proper tuning of the exciters and governors of the synchronous machines.
  - Consideration of small-signal stability and the issues created by extensive usage of PLL based synchronisation strategies.

Table 9.1 and table 9.2 below give overviews of methods to improve converter control stability when connected to weak networks and in order to improve frequency support.

Table 9.1
Improved converter control stability in low SCR networks

Converter control	Improved stability at low SCR
PLL	• Injecting active and reactive currents that account for the X/R ratio – requires knowledge of the network equivalent impedance. An alternative is to use a PLL frequency based active current injection algorithm. • Synchronising to a virtual part of the grid, rather than the point of common coupling (PCC) by introducing an impedance-conditioning term in the PLL. This is done by tracking not just the PCC voltage, but also the current, which is then multiplied by a virtual impedance, resulting in a virtual voltage. • Reduce the PLL bandwidth and slow its response.
Inner loop	• Introduction of gain scheduled multi-variable controllers – doesn't interfere with bandwidth or inner loop.
Outer loop	• It has been determined that bandwidth reduction within the inner current loop can also improve weak grid stability. • Online controller tuning, where a grid impedance estimation method estimates the network Thevenin equivalent impedance. • Introducing a virtual impedance.

Table 9.2
Improved converter controller frequency support in low inertia networks

Wind turbine	Wind turbine	Improved frequency support
Doubly-fed induction generator wind turbine	**Frequency support from rotor side converter**	• Rotor side converter control can take advantage of the rotor mass – introduction of term for a virtual inertial constant. • The angular velocity now represents a virtual value linking grid frequency with the reference frequency. • The main advantage of this method is that it comes with no additional hardware requirements. • Only works well when the turbine rotor is turning at a sufficiently high speed and therefore has enough stored energy in the rotor.
Inner loop	**Frequency support from grid side converter**	• Control structure is improved by introducing frequency and voltage magnitude droop control branches. • Structure allows for slight DC link voltage deviation in order to provide frequency support when no storage is integrated into the DC link.
Fully rated converter wind turbine	**Frequency support**	• Extract kinetic energy from the wind turbine rotor – utilising the energy stored in the DC shunt capacitors to regulate and level the network frequency. • Disadvantage – there is no governor reaction to the reduction in speed. Therefore, the increased power output cannot be sustained for long periods of time.

9.3 Implications on the internal dynamics of DER

This section presents key issues affecting the internal dynamics of DERs when participating in a Black Start restoration process. As research covering this specific topic is limited, the performance of DER has been assessed in weakened power systems and microgrids, as the grid during Black Start will share characteristics of both systems.

9.3.1 Inverter implications

In considering each DER technology connected to the network, and those with potential involvement in a distributed restoration process, all interface with the grid via a power electronic inverter. Therefore, any alterations to the inverter to enhance suitability are applicable to all.

In most cases it is favourable to extract maximum power from the resource for infeed to the grid. The power electronic devices impose a strict current limit of around 1.1pu. Some suggestions are made to run the DER curtailed although this leads to reduced efficiencies in some systems.

Another alteration considered is the overrating of the converter, however this can lead to reduced performance at rated power. Studies have shown that an oversized converter experienced poor performance due to partial load operation of the inverter.

9.3.2 Wind turbine implications

Direct drive permanent magnet synchronous generator (PMSG) wind turbine

The PMSG consists of a three-phase wound stator and a rotor fitted with rare earth permanent magnets. The generator stator is connected to the grid via an FRC allowing for a high degree of output controllability. The FRC also provides electrical decoupling of the generator from the grid. In the case of the FRC used in PMSG systems both sides of converter control can interact to cause vibrations in the wind turbine drivetrain and subsequently the tower.

The generator side converter control usually consists of a current control loop, the references for which are provided from a torque controller attempting to extract maximum power from the turbine; operating independently from the grid. However, algorithms can be added to reduce vibrations in the drivetrain but can cause increased interactions. Research has found that since energy for damping of mechanical components was extracted from the DC link and the DC link voltage was controlled from the network side converter, a link between the electrical and mechanical systems was formed. In attempts to remedy the issue, the DC link voltage control was moved to the generator side converter. While propagation of mechanical vibrations into the network was reduced, mechanical damping of the turbine also lessened leading to increased drivetrain stress. This will be an important point to consider since Black Start will undoubtedly cause increased stress on the system. However, the location can be shifted via control to improve the life span of the worst affected components.

Permanent magnet generator wind turbine response to voltage and frequency deviations

In theory, PMSG WTs should be less susceptible to network voltage and frequency events as the FRC provides electrical decoupling. However, advanced control algorithms can lead to increased interactions with oscillations being propagated in both directions depending on the control architecture. The improved reliability of DD PMSG WTs is a bonus as the mechanical system can cope with greater stresses at a lower failure rate.

Studies have been conducted to research interactions between the mechanical and electrical systems in PMSG WTs. Findings show that steps in generator torque created large oscillations in shaft twist angle when a simple field-oriented control algorithm was used. This could cause problems during Black Start as fast deviations in network frequency and voltage will cause rapid changes in generator torque since the WT is participating in frequency and voltage regulation. Interactions between the turbine pitch control and electrical system have been reported, effectively resulting in further electrical torque steps in the generator and leads to torsional vibrations in the drivetrain which could propagate to the wind turbine tower.

Methods for achieving the required power reserve to provide frequency and voltage support have also been researched. Three different methods were analysed: de-rated where the maximum power output is capped, delta which maintains a fixed amount of power relative to the maximum available power and per centage which maintains a per centage of the maximum available power for reserve.

Table 9.3 displays the fatigue load change for each vibrational mode due to de-loaded operation. Only the blade edgewise vibration causes increased damage, except for shaft torque for the delta control method (this anomaly was said to be due to the study control method and calculation for fatigue load). These values are for the de-loaded operation only and do not account for any response to network events. This analysis shows that the changes in fatigue load due to de-rating are smaller than the differences that occur normally due to different wind speeds. Given that Black Start is extremely unlikely and will not last long, it is concluded that changes in fatigue due to de-rating are of no concern.

Table 9.3
Vibrational mode fatigue load change

Blade edge	+0.0%	+0.0%	+4.1%	+5.2%	+1.9%	+3.3%
Blade flap	-2.5%	-4.6%	-9.2%	-12.6%	-8.4%	-10.9%
Shaft torque	-5.5%	-9.1%	+3.5%	-0.8%	-0.2%	-5.2%
Tower fore-aft	-5.0%	-10.3%	-7.6%	-12.6%	-7.6%	-13.0%
Tower side-side	+0.0%	-15.3%	+0.0%	-2.3%	-10.7%	-16.8%

Doubly-fed induction generator (DFIG) wind turbine

The DFIG wind turbine consists of a three-phase stator winding and a three-phase rotor. The rotor is connected via slip rings to a back-to-back converter supplied via the AC grid and the stator is connected directly to the AC grid; making a DFIG susceptible to grid events due to this direct coupling. A crowbar is normally connected to prevent overcurrent damage. Two controllers are used to regulate current flow in both the rotor and grid converters. The grid side controller has little effect on mechanical interactions in the drivetrain due to the decoupling provided by the DC link. Due to the control algorithm applied, the rotor side converter can increase interactions between the electrical and mechanical systems.

With basic grid-following control, where constant power and voltage references are used, most network voltage and frequency events do not propagate to the mechanical system as there is no feedback path. However, if the network side converter is expected to contribute to frequency regulation and support the power island voltage, this can lead to rapid fluctuations in power demand. Further to this, adding extra control loops such as virtual inertia can cause further stress to the wind turbine drivetrain. It has been shown that the introduction of an inertia emulation loop caused increased risk of torsional vibration in the drivetrain; with the inertia causing greater interactions from mechanical to electrical systems than from electrical to mechanical systems.

DFIG wind turbine response to voltage and frequency deviations

During the initial stages of Black Start, the load connected to the system experiences rapid fluctuations causing deviations in network frequency. Since the stator winding of the DFIG is coupled to the network, the generator electrical torque is also influenced by the voltage at the PCC. If the network voltage falls, the generator electrical torque drops, and torsional vibrations are created in the drivetrain. The overall deviation and rate of change of voltage as well as the control structure all influence the severity of the disturbance and increased stress in the drivetrain. Research has shown that torsional stress in the drivetrain will lead to increased lateral movement of the turbine tower.

In addition to this, it was also shown that the strength of the grid or short circuit ratio (SCR) influenced the mechanical damping of tower vibrations. A lower SCR or weaker grid resulted in increased tower vibrations, this is particularly pertinent when considering Black Start capability. The oscillations in tower acceleration exhibit lower damping as the short circuit level decreases. This indicates that a strong grid aids in the damping of mechanical vibrations. An almost linear relationship is observed in this case between peak tower acceleration and short circuit level.

Further work has found that balanced voltage dips led to a torque sag in the gearbox if current limiting was required and caused increased strain on gearbox components during the dip and the recovery period. Large voltage dips are not necessarily expected to happen during Black Start but since inverters tend to operate near to capacity, current limiting can occur, increasing the risk of torque sags.

9.3.3 Summary

In general, while there may be some impact on performance and some additional risk of equipment fatigue during Black Start conditions, nothing was identified that represents a fundamental problem in the use of DER or prevents their participation in Black Start. A summary of the key technical considerations related to DER internal dynamics is given in table 9.4.

Table 9.4
Technical considerations on DER internal dynamics

Technical consideration	Potential impact on DER internal dynamics
Frequency support	During the formation of, or when joining, a power island as part of the Black Start procedure inverter generation may be expected to contribute to frequency regulation to allow connection of further loads leading to increased power output fluctuation. The system load varies rapidly with connections and potential disconnections which may lead to large power transients exacerbated by the weak grid with the possibility of large torque steps occurring in rotational generators or rapid discharge of battery energy storage systems (BESS).
Voltage support	During the formation of, or when joining, a power island inverter generation would be expected to contribute to voltage regulation to support connection of further elements of the grid leading to increased reactive power output fluctuation. Voltage tends to experience faster network transients than frequency, therefore fast response of the DER is paramount. This leads to faster changes in current from the DER which tends to increase wear on components.
Reduced grid strength	The power island will be weaker than the usual grid connection leading to reduced damping and voltage stability with similar conditions to some microgrids. In cases where DERs have a direct coupling to the network, voltage related issues can be more serious. This is due to almost instantaneous torque changes, as there is no converter buffer to maintain the stator voltage when the network voltage deviates. Fast transients can lead to oscillations and without sufficient damping from a stronger network, vibrations can be propagated to the generator and further system components even if a fully rated converter (FRC) is employed.
Power reserve	Without energy storage, DERs will have to run at a de-loaded operating point to provide required services potentially altering the internal dynamics of the system. If sufficient reserve is unavailable, inverter capacity limits response and further harm can be caused. If energy storage is utilised, this could also alter the internal dynamics of the DER during network events and the effects must be explored.

9.4 Conclusions

This section has provided a summary of the key findings obtained from a literature review relating to grid-following converter considerations. Whilst specific study of converter behaviour during Black Start from DER is not comprehensively covered in existing academic work, a number of related conclusions can be drawn.

- **PLL limitations**

  It has been discussed that standard converter control techniques will fail to maintain stability when the SCR of the network is typically less than 1.3–1.5. This is due to the PLL (the fastest control loop within the converter) struggling to track the voltage which deviates more erratically in a weak network and can result in the DER tripping. It follows that if the network fault level is 100MVA, it may only be feasible to connect between 66MVA to 77MVA of converter-connected DER to ensure stability (the exact value may be lower and would be determined by the converter manufacturer).

- **PLL mitigations**

  Potential alterations to improve performance include retuning the PLL controller for weak network operation, although any alterations could potentially impact overall performance. Network solutions would include increasing the SCR by adding DER to provide increased fault infeed.

- **Inertial considerations**

  Concerns over the lower system inertia with a high penetration of converter-connected DER have been highlighted, and the corresponding need for converter-connected generation to contribute to frequency support. At present, despite wind turbines having large rotational masses, they do not provide any ‘real’ inertia to the network since they are electrically decoupled. Converter control schemes can provide ‘synthetic’ inertial response by modifying the converter power reference according to the frequency measured through the PLL.

- **DER internal dynamic considerations**

  In reviewing the impact on internal dynamics for common wind turbine configurations, it was concluded that while there may be some effect on performance and some additional risk of equipment fatigue during Black Start conditions, nothing was identified that represents a fundamental problem in the use of DER or prevents their participation in a distributed Black Start process.

10. Grid-forming converter technology

10.1 Introduction

Converter interfaces for DER can be classified as either grid-following or grid-forming. The former operates the converter as a current source (and requires the network voltage for reference), while the latter operates as an independent voltage source. The primary aim of investigating the emerging technology of grid-forming converters is to identify to what extent an equivalent scale grid-forming converter could deliver the same benefit as a synchronous generator in terms of being the 'anchor' generator and establishing and maintaining a DRZ. To achieve this, the project has partnered with a research institute with the first deliverable[11] presented in this report.

10.2 Grid-forming converters capability

10.2.1 Overview

A grid-following converter (GFC) can generate its own independent voltage source, similarly to a conventional synchronous generator. As such, it has the potential to act as a future anchor generator within a DRZ. It has been highlighted that, during the early stages of a restoration process, the network will be weak (low SCR) and system inertia will be low. Grid-following converters do not require a minimum SCR to operate (they do not need to track the network voltage) and can provide 'true' inertia (see section 10.4) into the system to help provide additional frequency support. Due to its increased stable operation, a grid-following converter is less susceptible to adverse interactions among multiple power plants under reduced system strength conditions. In addition to its role during a distribution restoration process, grid-following converters have the capability to provide many additional ancillary services to increase overall system resilience, reducing the need for traditional network reinforcement.

10.2.2 Grid-following converters proven capabilities

Different applications of grid-following converters have been recently developed and tested in lab and real environments such as microgrids, offshore wind and Universal Power Supply (UPS) applications. Table 10.1 illustrates the validated characteristics of different GFC, published in December 2019 as part of the MIGRATE EU project. Scaling up these tests to higher power should have no major impact, though network considerations such as inrush currents should be considered.

Table 10.1
Validated characteristics of different GFC

Characteristic	Lab demonstration	Microgrid	Offshore wind	UPS
Voltage source	✔	✔	✔	✔
Distributed control	✔	✔	✘	✘ ✔
Phase jump robustness	✔	✘	✘	✘
Multi MW size	✘	✘	✔	✘
Grid connected	✔	✘	✘	✘

[11] Iberdrola Innovation Middle East 'Grid-forming Converters Technical and Economic Evaluation', May 2020

In addition, table 10.2 shows the main functional GFCs product requirements when compared to conventional grid-following converters (GFLs) in terms of hardware and software changes, which are relevant to technology manufacturers and system operators.

Table 10.2
Examples of functional requirements for grid-forming compared to grid-following converters

Examples of Functional Requirements for GFC	Higher current capability? (Hardware)	Energy Buffer? (Hardware)	Control algorithm change? (Software)
Fast Power variations	Potentially	Yes	Yes
Response to voltage shifts	Yes	Yes	Yes
Inrush currents	Yes	No	Yes
Fault current contributions	Yes	No	Yes

10.3 GFC control techniques

A key objective of this study is to investigate the use of grid-forming converters for Black Start and network stability support applications. Whilst many works in literature have proposed and analysed these converters for different applications such as inertia support, grid-connected and islanded microgrids operation and ancillary services provision to the grid, the number of published studies investigating their use for Black Start applications has been limited and without detailed scope from a control point of view.

Several classifications of GFCs exist in literature, such as classifying grid-forming techniques into inertial and non-inertial, or DC side vs. AC side reliant. For a Black Start scenario, an important classification can also be based on the technique compatibility with a direct voltage reference control in order to be able to use a ramping reference as not all techniques inherently provide such flexibility.

This section investigates four different GFC control techniques, aiming to assess their performance against AC and DC disturbances, and their high-level suitability for Black Start applications. The outcomes of this preliminary study will help to determine suitable controllers for Black Start from the four candidates and to identify performance advantages and shortcomings. The four compared GFC control techniques are: droop, PSC, Virtual Synchronous Machine (VSM) and matching control. The selection for these four techniques in particular is justified as below:

- Droop and PSC were selected due to the wide use of the former, and the similarities between both techniques. Studying their performance simultaneously thus provides a valuable assessment tool.
- VSM control performs best in terms of AC side disturbances study, whereas matching control performs best against DC side source saturation.

The principles of operation for each of these four techniques in addition to their market maturity are summarised in table 10.3.

Table 10.3
Comparison of GFC control and market maturity

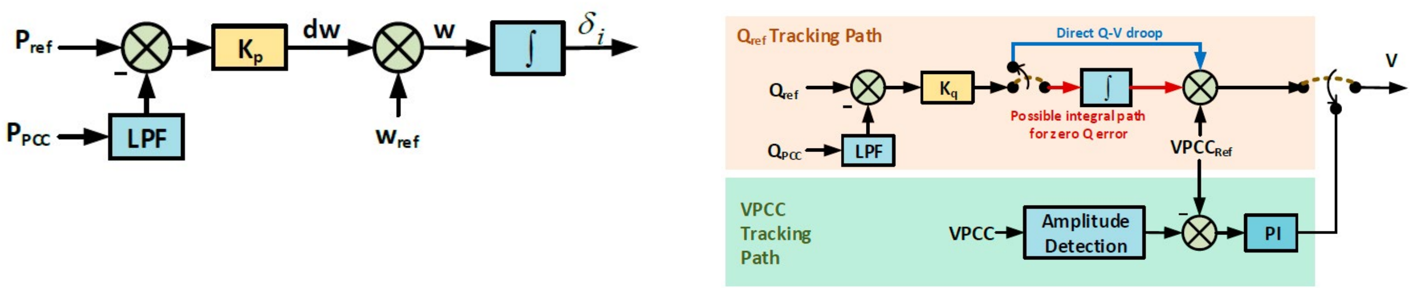
GFC technique	Principle of operation	Market maturity
Droop	Simulating speed droop of synchronous generator	The basic shared structure of both techniques is widely implemented. Moderate research focus is still observed for droop.
PSC	Simulating power synchronizing behaviour between synchronous generators	
VSM	Yes	No
	Simulating the speed droop and inertia of SG swing equation	Strong research focus, prototype implementations and feasibility studies.
Matching	Exploiting the analogy between voltage DC and SGs frequency variations	Early research stage with different possible implementations.

10.3.1 Droop control

VSC droop control is inspired by the droop characteristic of synchronous machines, which aims to balance the power supply between different generators within the grid and to maintain their power sharing and stabilise the network frequency. Droop is a common technique that is used for several converter control applications, especially when power sharing between various VSCs is required in a similar fashion to that of SMs. Droop control does not require communication links between the different converter units connected within an islanded operation and relies on local measurements for active/reactive power sharing. Having said that, this technique has been known for its inherent power sharing mismatch under variable network conditions (e.g. the network X/R ratio and the impedance variation at the PCC of different grid converters). Virtual impedance has been proposed as a remedy to this limitation by several researchers. A fully optimised droop implementation for VSC application is still an active research question.

Conventional droop control under inductive network assumption includes a P-f loop and a Q-V loop, thus inherently achieving grid-forming operation compatibility. The former loop is responsible for frequency deviation and angle reference generation (figure 10.1), while the latter is responsible for voltage and reactive power regulation (figure 9.3). K_P and K_q are the power and reactive power droop coefficients, respectively.

Figure 10.1
Droop control block diagram: (a) Power loop, (b) Voltage loop with various implementations



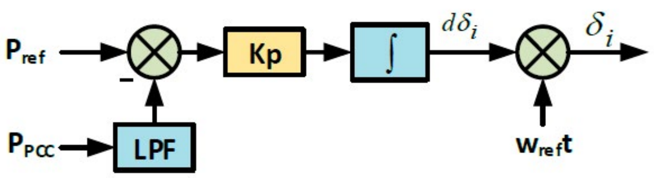
10.3.2 Power synchronising control (PSC)

This VSC control technique was first introduced mainly for HVDC applications connected to weak grids in order to mitigate the stability issues of PLLs when connected to weak grids. The proposed controller includes a power synchronizing loop (PSL), in addition to voltage and reactive power control loops. These loops are connected or disconnected depending on the application needs. A backup PLL is proposed in the original design to provide synchronisation under fault conditions, where a modified current control structure alters the operating mode between PSL and PLL based on the measured current threshold to maintain grid synchronism.

DC voltage control is similarly implemented for the four compared techniques in this report, and the voltage/reactive power loops are similar in nature to those discussed in the droop control section. Thus, the main studied variation is in the PSL loop, which is illustrated in figure 10.2.

The grid-forming and synchronisation capability of PSC is embedded into the PSL. Similarities between the PSL loop in PSC and the P-f loop in droop control are easy to notice. Thus, it is expected that the performance of both droop and PSC techniques is similar under normal operating conditions, assuming the use of a unified voltage loop implementation.

Figure 10.2
PSC controller – power loop

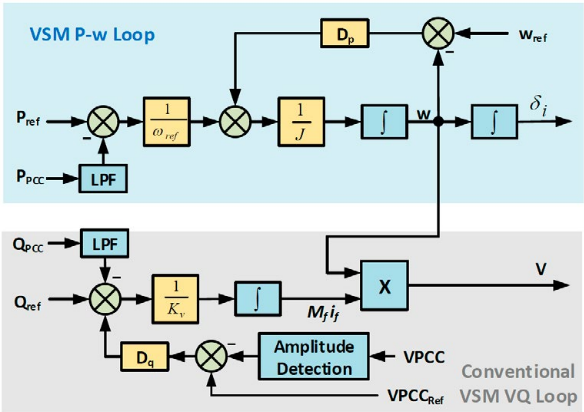


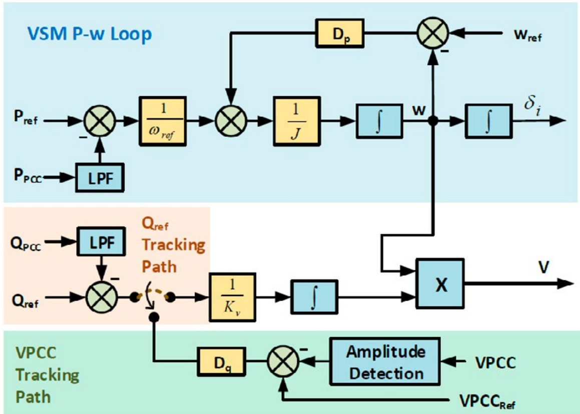
10.3.3 Virtual synchronous machine (VSM)

The concept of virtual inertia provision through VSC control has been receiving significant traction in academia and industry. The used terminology might differ between various papers such as synchronverter or VSM based on the implementation. As the name suggests, the VSM grid-forming control concept also stems from emulation of SG characteristics. A VSM can be designed to emulate a variable subset of SG capabilities based on the application requirements. Most existing implementations focus on emulating the SG inertial response to frequency events. In contrast to the other techniques discussed here, VSM power control loops include additional term(s) that emulate frequency dynamics. The conventional voltage-reactive power control loop in VSM is also inspired by SG excitation and control theory.

Figure 10.3 (a) shows the conventional implementation of both VSM power and voltage loop. The conventional voltage loop illustrates a combined voltage and reactive power tracking terms, which introduces mismatches to both quantities due to their interdependency. If accurate voltage or reactive power tracking is required, then the voltage loop can be separated to achieve a single objective as required by the application, see figure 10.3 (b). A similar distinction is implemented in using a PI voltage controller.

Figure 10.3
VSM control block diagram: (a) with conventional P/V loop, (b) with modified V loop to allow for V and Q tracking modes implementation

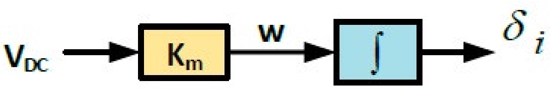




10.3.4 Matching control

The matching control technique also aims to exploit structural similarities between VSCs and SMs. The matching control principle is based on the observation that DC link voltage variations indicate power imbalances in an analogy to SG frequency. The power loop uses this analogy to drive the converter frequency from the dynamic DC link voltage as illustrated in figure 10.4.

Figure 10.4
Matching control power loop, based on DC voltage variations



The matching control power loop is fairly simple, as it mainly transforms the DC link voltage to a converter frequency signal using the transformation factorkm which is then integrated to generate the converter synchronizing angle.

In matching control, the active power regulation is implicitly implemented from the DC link voltage control. The converter tracks the power reference defined by the DC voltage controller. Thus, the use of a stiff, ideal, DC voltage source to simulate matching control behaviour is not possible. Any DC voltage reference V_{DCref} variation during converter operation should also be reflected in real time on K_m to avoid controller setpoint mismatches. The DC voltage controller is designed to consider the unified steady-state slope.

10.4 Converter inertial response

There are two types of inertial response associated with converter-connected DER, synthetic and 'true' (or VSM).

10.4.1 Synthetic inertia

VSC droop control is inspired by the droop characteristic of synchronous machines, which aims to balance the power supply between different generators within the grid and to maintain their power sharing and stabilise the network frequency. Droop is a common technique that is used for several converter control applications, especially when power sharing between various VSCs is required in a similar fashion to that of SMs. Droop control does not require communication links between the different converter units connected within an islanded operation and relies on local measurements for active/reactive power sharing. Having said that, this technique has been known for its inherent power sharing mismatch under variable network conditions (e.g. the network X/R ratio and the impedance variation at the PCC of different grid converters). Virtual impedance has been proposed as a remedy to this limitation by several researchers. A fully optimised droop implementation for VSC application is still an active research question.

Conventional droop control under inductive network assumption includes a P-f loop and a Q-V loop, thus inherently achieving grid-forming operation compatibility. The former loop is responsible for frequency deviation and angle reference generation (figure 10.1), while the latter is responsible for voltage and reactive power regulation (figure 9.3). K_P and K_q are the power and reactive power droop coefficients, respectively.

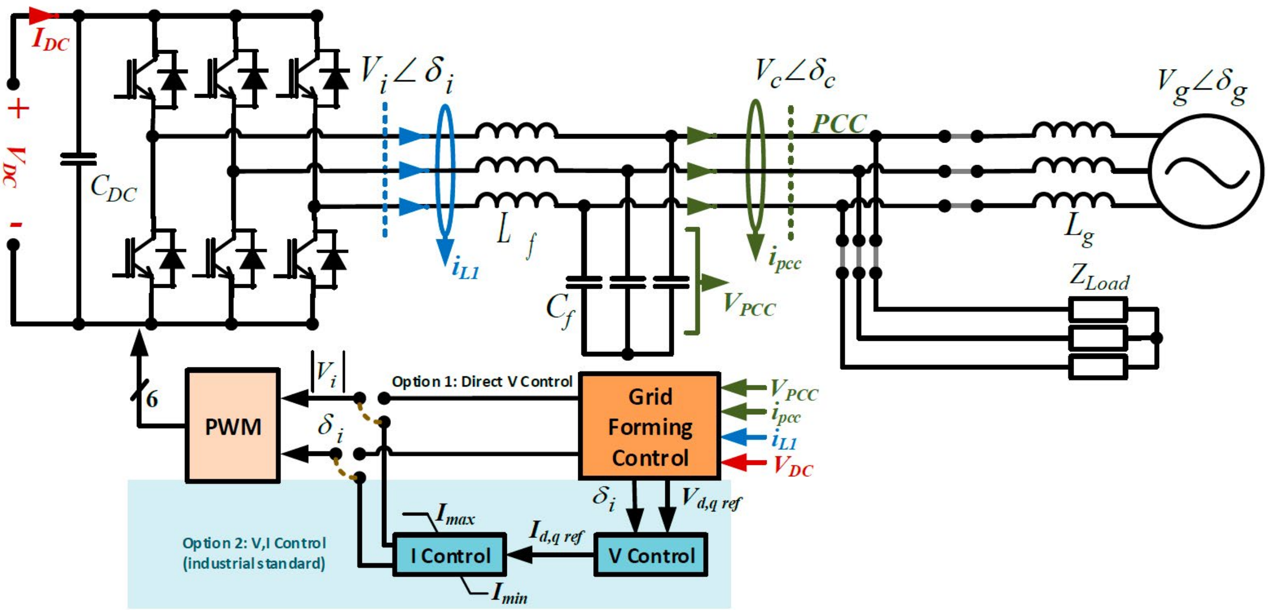
10.4.2 True inertia or VSM inertia

True inertia is a concept used in literature to identify the inherent and fast VSM response in front of a frequency disturbance. Compared to synthetic inertia, true inertia or VSM inertia does not require any additional control loop to be provided and it is instantaneous. This can only be provided by a grid-forming converter.

10.5 GFC controller study simulation and findings

A simulated network resembling the one shown in figure 10.5 was implemented in MATLAB/Simulink environment to study the performance of each considered GFC controller in a single converter,-load,-grid configuration. In addition, standalone (islanded) converter-load scenarios were tested to validate the high-level suitability of the studied techniques for Black Start applications with soft-start using a combination of resistive and reactive loads. Mathematical formulation was simultaneously derived using circuit analysis to predict the converter output voltage and angle difference with the PCC and the grid in order to validate simulation behaviour for each operating point. The soft-starting test records active and reactive power for each scenario, in addition to the PCC voltage ramp and the converter frequency.

Figure 10.5
High-level control block diagram of a 2-level, 3-phase VSC grid-following converter



In the following subsections, the results for each considered disturbance (load connection at the PCC of P = 1pu, 0.2pu DC voltage disturbance and 0.5pu power reference variation) are presented and analysed for each technique under current control configuration, in addition to the soft-starting tests. This is followed by presenting sample results from tests performed without current control (option 1 in figure 10.5) in order to compare the performance of both options, while re-iterating that current control is the industrial standard. This comparison is presented because some research activities are attempting to study ways of implementing GFC techniques without the current control limitations on techniques such as VSM, while preserving the protection functions. The study test parameters are shown in table 10.4.

Table 10.4
Study test parameters

Test parameter	Value
PCC voltage (LL)	33kV
DC link voltage	53.74kV
Nominal active power	35 MW
Nominal frequency	50 Hz
Converter rating	40MVA
Network X/R ratio	10
Short circuit ratio (SCR)	5
Q-tracking mode reference (Mvar)	5 Mvar

10.5.1 Load disturbance response – 100 per cent (35 MW step)

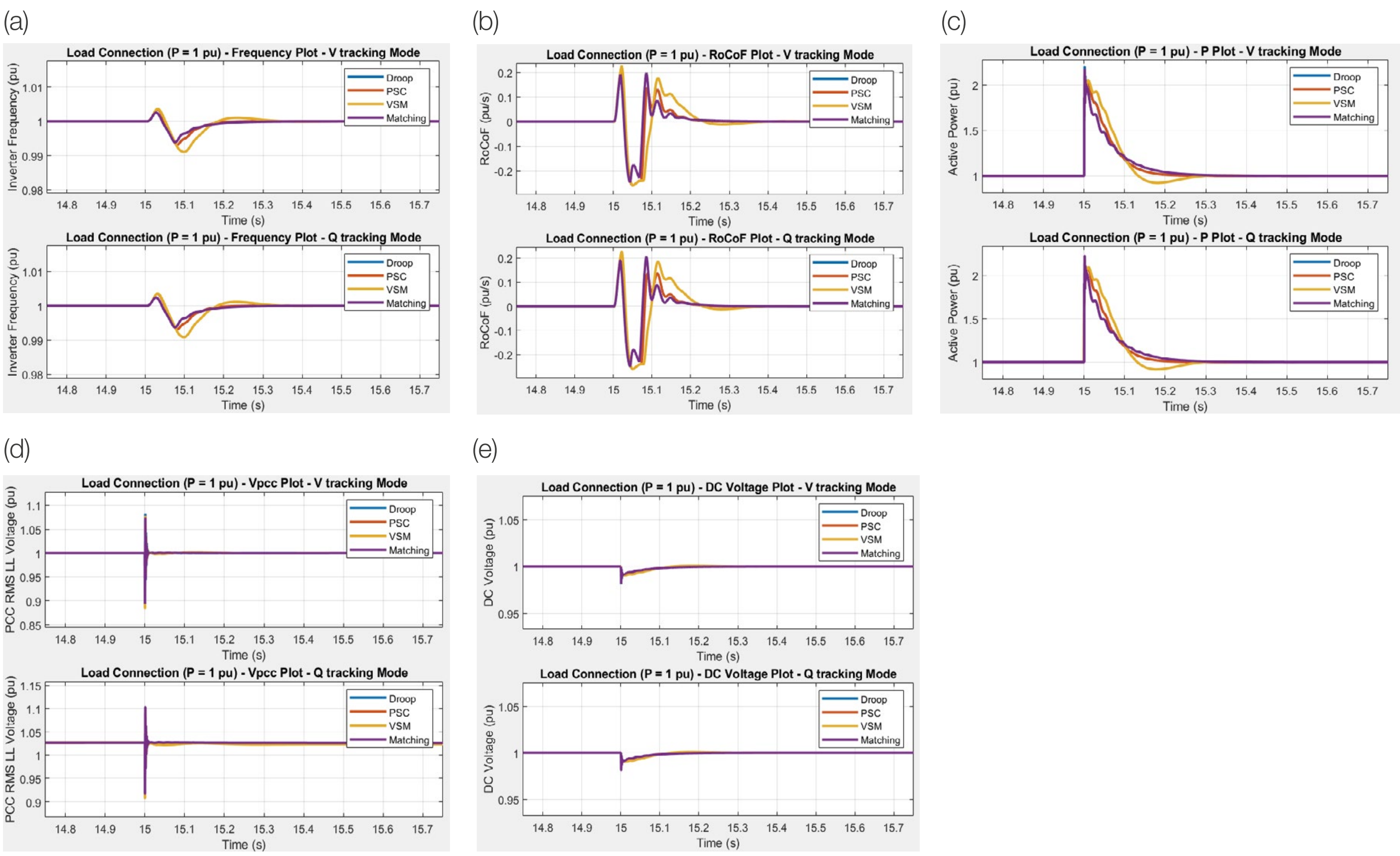
The response of the four controllers to this disturbance was similar in terms of magnitude changes in the tested parameters. The performance of both V tracking and Q tracking modes is also fairly similar as illustrated in figure 10.6, with the main variation being in PCC voltage since the Q tracking mode is concerned with reactive power tracking that ultimately changes the PCC voltage under grid-connected mode. The performance of PSC and droop is also particularly similar under the reported test conditions as predicted.

Since the similar V and Q tracking modes performance is established, the analytical focus hereafter will be on the V mode as it is more relevant to the Black Start applications. The maximum per unit frequency change was less than 1 per cent at 0.991pu for the VSM, whereas the minimum frequency nadir was recorded for the matching control at 0.994pu. RoCoF measurements are also similar with the matching control also having the minimum RoCoF nadir. Though, the other techniques only varied from that value by less than 5 per cent, signalling again the similar performance between the different techniques for this disturbance, with similar ratios for the active power, PCC voltage and DC voltage plots. The maximum active power variation is almost similar in value to the connected load (1pu) for all controllers, which indicates that the converter reacts quickly and supplies power to the connected load based on the droop constants until the grid gradually takes over the additional load requirement and the converter reverts back to its nominal reference operating point.

The main step change among the five measured parameters for this disturbance occurs in the PCC voltage, with a magnitude change approaching 10 per cent of nominal value, though, only for a few milliseconds before being restored to the nominal value. This considerable change is due to the sudden load connection at the PCC.

Based on these results and comparison, it can be concluded that the four controllers perform similarly for this disturbance with acceptable parameter variation that is aligned with grid requirements.

Figure 10.6
GFCs response to the load disturbance scenario. (a) Frequency plot, (b) RoCoF plot, (c) active power plot, (d) PCC voltage plot, (e) DC voltage plot

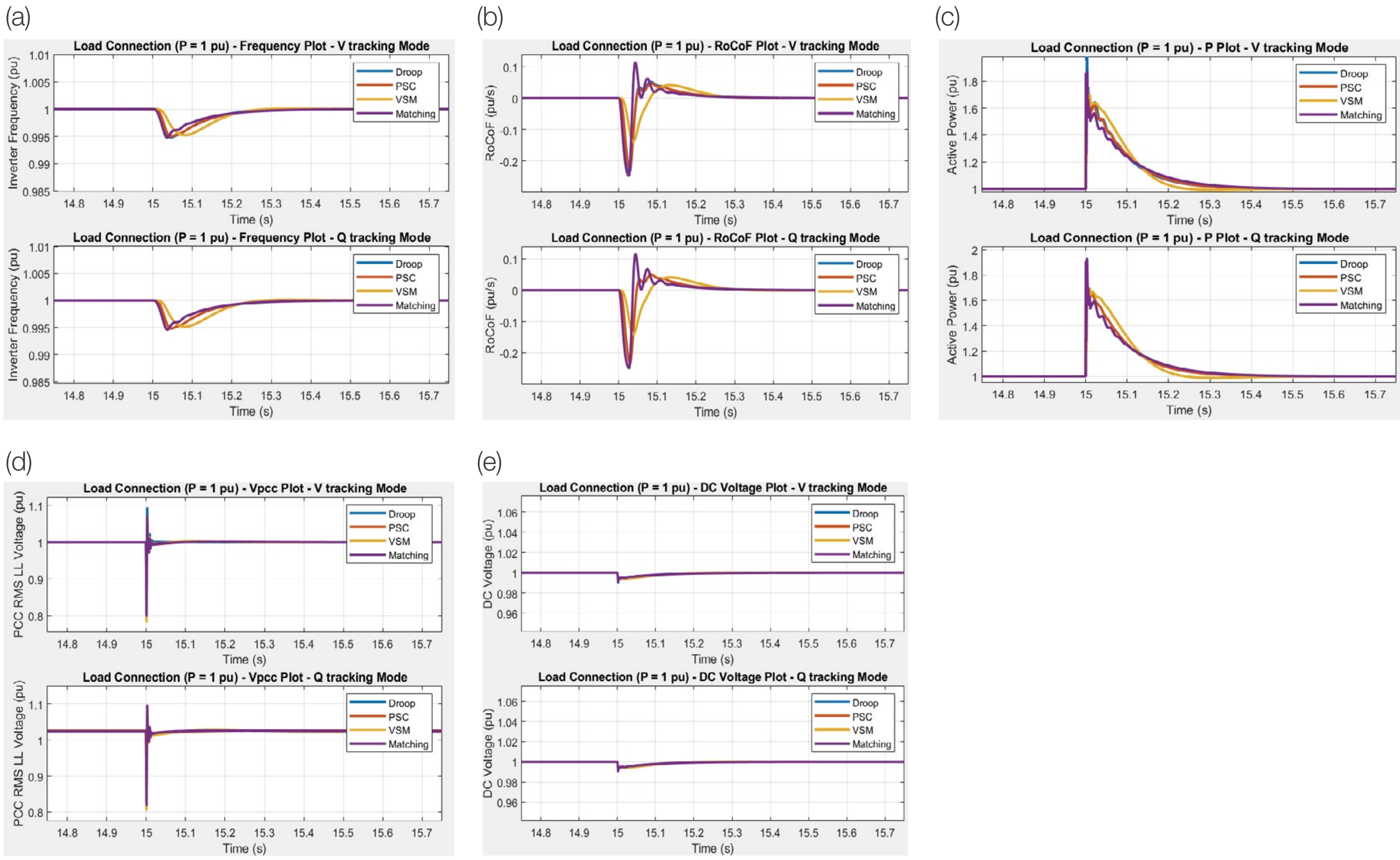


10.5.2 Load disturbance response: 100 per cent (35 MW step) without current control

The same disturbance is tested here but without including the inner current control in order to measure the effect of current control on the overall converter's performance (option a in figure 10.7).

A significant variation between both control modes (with and without inner current loops) is that the high-level objective of the voltage loop of each GFC controller is affected. a) and b) describe effects of with and without current control. In case of current control: The GFC voltage loop generates the PCC voltage reference V_(d_ref), and then passes it to voltage and current loops in order to generate the internal grid converter terminals voltage reference. b) without current control: The outer GFC loop directly generates the converter terminal voltage reference. The latter mode might result in faster frequency response as it mitigates the controller induced delays. This is evident in figure 10.7 when compared to figure 10.6 in terms of the frequency nadir and RoCoF in particular.

Figure 10.7
GFCs response to the active power reference disturbance scenario (without current control). (a) Frequency plot, (b) RoCoF plot, (c) active power plot, (d) PCC voltage plot, (e) DC voltage plot

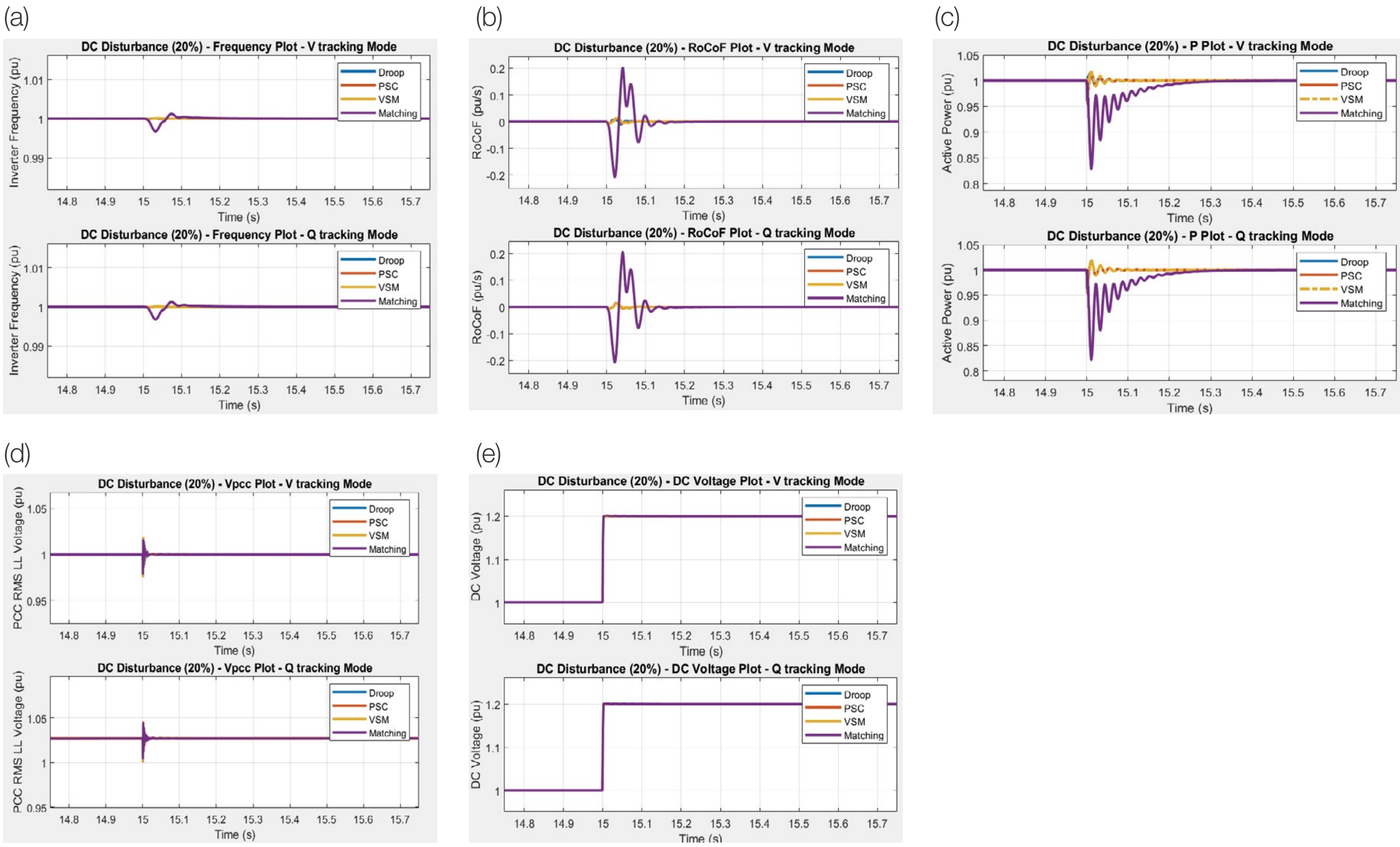


10.5.3 DC voltage disturbance response: 0.2pu

Three of the four techniques had a neutral response to this type of disturbance as shown in figure 10.8, except for matching control as it depends on DC voltage in its control. The outcomes of this test indicate that again V and Q tracking modes respond similarly. Although DC reference variation is a rare event since the DC voltage is typically well regulated by dedicated power converters, it is observed that matching control performs poorly when compared to the other compared techniques under this disturbance.

Figure 10.8

GFCs response to the DC voltage disturbance scenario. (a) Frequency plot, (b) RoCoF plot, (c) active power plot, (d) PCC voltage plot, (e) DC voltage plot



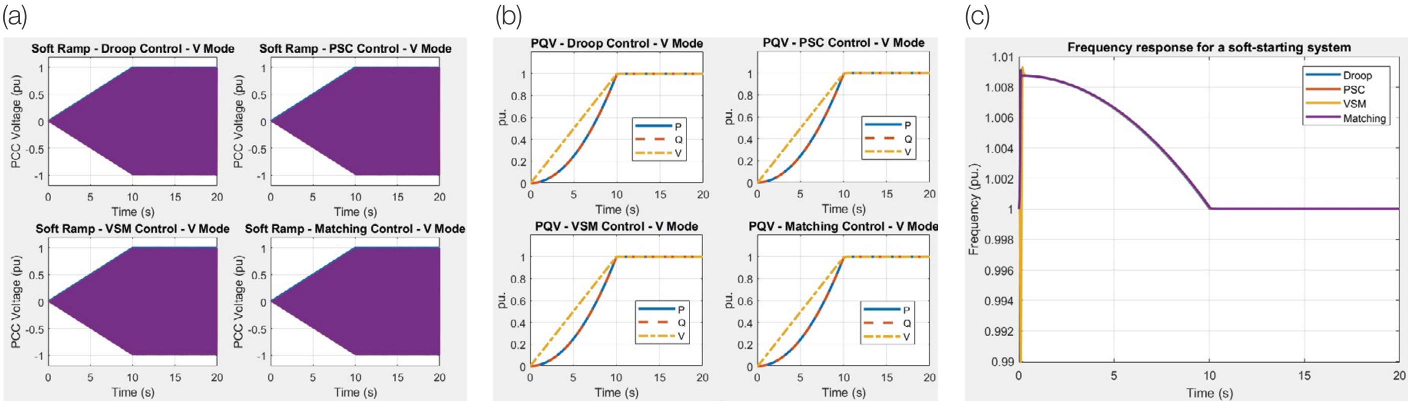
10.5.4 DC voltage disturbance response: 0.2pu

GFCs, in principle, are equipped with this capability given that an adequate controller is implemented, and a DC source is connected with sufficient energy content to support network restoration. Soft Black Start is an important capability that the controller should be compatible with for cases that require transformer or cable energisation to mitigate their inrush currents. It has been established earlier that a reason for selecting these four grid-forming controllers (droop, PSC, VSM and matching) was their compatibility with this requirement.

Depending on the operating mode, some techniques use the PCC voltage reference as a constant and add a deviation to it based on the controller action, which is typical in Q tracking mode, whereas the voltage reference is 'synthesised' in the V tracking mode through P/PI controllers to convert the PCC voltage error into a reference. The speed at which this voltage reference is synthesised depends on the selected controller gains. Smaller gains can lead to slow convergence, whereas excessively higher gains can lead to instability. Soft-start is typically implemented to ramp up the voltage to a reference at a specific slope (e.g., within 10 seconds in this test), and thus the P/PI control design should take into consideration having a minimal effect on slowing this requirement.

As the reactive power requirement during Black Start can be varying with a level of uncertainty, the voltage tracking mode is employed in this test scenario, where P = Pref and Q = Qref loads from table 10.4 are connected in an islanded network configuration and the voltage ramp is observed for all controllers. Figure 10.9 summarises the test results and illustrates successful PCC voltage tracking with no measurable delays from t = 0 to t = 10, as well as for the active and reactive power references for all controllers. The frequency in figure 10.9(c) descends from an initial value to 1pu at t = 10 s as a result of the initial power loop reference mismatch.

Figure 10.9
GFCs response to the islanded soft-start scenario with P = Pref and Q = Qref from table 8.7



This test thus demonstrates, at a high level, that the four controllers are capable of following a reference voltage ramp while simultaneously supplying active and reactive power to loads. This is an important step for a successful soft Black Start implementation where transformer and cable models will replace the static loads in this test.

10.6 Conclusions

The project has provided an overview of the grid-forming converter technology, and commissioned some initial studies to investigate how this may be applied to Black Start from DER. The following conclusions can be drawn in relation to the benefits of GFCs.

- Voltage source – A grid-forming converter can provide the same benefit as a synchronous generator in that it can generate its own independent voltage source.
- Frequency support – A grid-forming converter can also emulate the performance of a synchronous generator in that it can provide 'true' inertia (an instantaneous power response to frequency disturbances). Grid-following converters can provide 'synthetic inertia' which has a delay associated with the frequency having to be measured before a response is initiated.
- Increased stability – Due to its increased stable operation, a grid-forming converter is less susceptible to adverse interactions among multiple power plants under reduced system strength conditions, and unlike a grid-following converter does not need a minimum network SCR to operate.
- Ancillary services – In addition to their role during a distribution restoration process, grid-forming converters have the capability to provide many additional ancillary services (e.g. frequency support) to increase overall system resilience, reducing the need for traditional network reinforcement.
- Combination with energy storage – In combination with a sufficient energy storage buffer, a grid-forming converter can support system inertia with far less capacity when compared to conventional thermal generation. It can also deliver a faster injection rate of active or reactive current without destabilising its performance in weak systems. Previous work within the associated NIA[12] project has attempted to provide related MW quantities of BESS to conventional plant for similar stability characteristics.

[12] NGESO NIA Black Start from Non-Traditional Generation Technologies, June 2019

11. Automation

11.1 Introduction

The project is currently engaged with several companies, recognised industry experts in the domain of power system automation and wide area control systems, to explore how a control system could automate key aspects of the restoration of a distribution power island. The restoration stages given below were given as a guide to the technology companies to assess the control scheme functionality which will be required. This work is stage 1 (Feasibility and Design) of a three-stage process, which the project will consider progressing to develop a DRZ-C. The three stages of the Development and Demonstration process are described below, along with initial project findings on the requirements and criticality of a DRZ-C. In addition, a breakdown of the technical services which may be required to form a DRZ is given, along with conclusions and an overview of the next steps.

11.2 Restoration stages

The main stages of the Black Start from DER restoration process and indicative operations associated with each are provided below. The task of the DRZ-C, supported by DER and other DSO/NGESO systems, is to automate these operations.

Stage 1: Network preparation and initialisation

- Send Black Start initiation signals to DER.
- Open/close circuit breakers to reconfigure the network.
- Change protection and control settings as required.
- Confirm readiness for Black Start.

Stage 2: Anchor generator start-up and initial network energisation

- Confirm anchor generator start and readiness.
- Energise a prearranged ‘skeleton’ network, protecting the anchor generator from disturbances as appropriate (this may be done through a series of energisation steps or a single step which may also incorporate ‘soft energisation’ [gradually ramping up of the network voltage] of the anchor generator together with an area of network).

Stage 3: Power island expansion (including block load pick-up)

- Step-by-step energisation of more of the network to restore auxiliary supplies to substations, restore supplies to customers (block load pick-up) and support the reconnection of other DER.
- Observe status of all controlled resources to ensure all are kept within their operational limits and to maintain headroom for island control and contingencies.
- As conditions change (possibly due to actions instigated by an operator), initiate fast control of available resources to balance the system (frequency and voltage) and minimise the stress on the anchor generator.
- Update protection and control settings as changes are made and the system expands.

Stage 4: Maintaining a stable power island

- With the distribution power island energised as far as possible given the available DER, maintain stable operation for as long as is necessary before the next stage of the restoration process.
- Control resources to keep all within operational limits and maintain island voltages and frequency while responding to events, volatility in demand or generation, or operator actions as necessary.

Stage 5: Wider network energisation (where resources allow)

- On operator instruction, prepare for and manage controlled resources during step-by-step energisation of transmission network assets.
- Control resources to keep all within operational limits and maintain island voltages and frequency while responding to the transient disturbances and enduring change in conditions caused by energising transmission network transformers and circuits.

Stage 6: Power island resynchronisation

- On operator instruction, prepare for and supervise resynchronisation, which could be with another DRZ or with the wider system, possibly synchronising on the transmission grid.
- Adjust voltage and frequency in the power island under operator instruction/control to align angle and frequency to enable resynchronisation.
- Maintain post-synchronisation stability of all resources within the DRZ area of control.

Stage 7: DRZ termination

- On receipt of a ‘termination of Black Start’ signal, restore settings and transition to normal operating conditions.

11.3 Development and Demonstration process

The Development and Demonstration of the automated DRZ-C solution is split into three stages.

Stage 1: Feasibility and design

The first stage explores the feasibility of automating the restoration process. Several contractors have been engaged to each propose a design for a viable DRZ-C system. Key aspects of the design include:

- investigation of the capabilities and requirements of the DER resource and distribution network
- control strategy to co-ordinate frequency response and voltage control capabilities from DER, including short-term fast-acting and long-term slower response.
- producing a design with the flexibility to cater for all possible combinations of DER resources which may exist in a power island.
- definition of the requirements of the communications infrastructure necessary to support the control strategy
- consideration of how the proposed design and overall solution addresses cyber security considerations
- initial cost estimate for implementation of the proposed design in a 'typical' GB distribution network area.

Based on the stage 1 outputs from the contractors, the project will produce a consolidated set of requirements for the overall DRZ-C solution, including requirements for the DRZ controller itself, DER, and any other supporting systems (such as DSO/NGESO SCADA/DMS).

Stage 2: Implementation and testing

Following completion of stage 1, one or more DRZ-C solutions may be implemented and tested within a Hardware-in-the-Loop (HiL) test environment. The DRZ-C solution will be tested against power islands of different compositions of DER. For example, one test case may include an island with a BESS and one large wind farm. A different test case may test operation with several small wind farms and a large PV generator. The test scenarios will contain a definition of the DER composition and events (e.g. wind farm unexpectedly trips) within each scenario. The scenarios will be developed to test the extreme operating conditions of the island.

This stage will test that the DRZ-C can maintain the power island within acceptable limits of under/over frequency, RoCoF rates, voltage limits and other identified performance criteria during the extreme operating conditions specified in the test cases.

The testing will include representative dynamic models of the anchor generator and other supporting DER. Where possible, interfaces to DER and measurement equipment will be based on representative data protocols (e.g. IEEE C37.118 for PMUs, DNP3 for DER interfaces, IEC 61850 GOOSE for time sensitive control actions).

The solution will be tested against SPEN/NGESO required cyber security standards. Demonstration of compliance to the necessary cyber security standards is a pre-condition of deployment to the SPEN network.

Deliverables at this stage include:

- Detailed design specification – A document which describes the detailed functional and non-functional design of the solution to be tested.
- Test specification – A document which describes how the solution will be tested, including an overview of the test environment, the test strategy and test cases.
- Testing – Witness testing of the prototype solution within a HiL environment against the agreed test cases.
- Delivery of a 'black-box' software model to test the DRZ-C in PowerFactory (and support for simulations). The model should be configurable for a range of the Distributed ReStart project case studies, and allow for multiple resource types (e.g. batteries, wind farms) to be defined and parameterised.

Stage 3: Live trial

Following a successful demonstration within a HiL environment, a solution may be selected for integrating into the testing at one of the case study live trial sites. Initially the solution may operate in open-loop as a 'soak test' (i.e. system is provided with input data but does not have control over any equipment) on the SPD network.

The solution may be integrated into the relevant SPEN and NGESO DMS/EMS testing (pre-production) environments to facilitate end-to-end testing. The integration of the tested solution may be primarily a centralised (main control unit hosted in a DNO/NGESO control centre) or de-centralised (main control unit installed at GSP or other location within the DRZ).

The DRZ-C live trial on the SPD or SPM network is expected to include control over an anchor generator, a wind farm, and several controllable load banks (to simulate load at primary substations). This stage will test novel control functions, such as validating the response of the DRZ-C to an event where the generation/demand balance of the island is mismatched such that the anchor generator alone is unable to regulate the frequency within limits (i.e. the anchor generator would be operated outside its block load pick-up/rejection capability without the DRZ-C intervening).

The Distributed ReStart project team will witness the DRZ-C solution in its hardware form (e.g. control cabinets, PSU, terminations) appropriate for installation within the SPD network. Depending on the architecture of the DRZ-C solution under test, the hardware deployment may include installation of a main controller at the DNO GSP substation, with additional decentralised controllers as necessary at the anchor generator, a wind farm, or at the site of a load bank. Deliverables include:

- Design specification – The functional and non-functional specification of the solution to be deployed for the trial network use case. This document will specify the configuration of the solution for trial network DRZ use case.
- Test specification – Describes the test environment and test cases adopted for factory acceptance and site acceptance testing. Test cases will be a subset of those performed as part of stage 2, and as previously stated will be limited to focus on novel functions.
- Factory acceptance testing – Subset of tests to validate the hardware and software solution is ready for deployment.
- Site acceptance testing – Testing on the SPD/SPM network.

11.4 DRZ-C initial findings

From the project works to date, some of the initial requirements of the DRZ-C are highlighted below.

11.4.1 Block load pick-up

Based on feedback from DER owners, and power system analysis carried out to date, the block load pick-up capability of a synchronous DER is estimated to be between 10 per cent and 20 per cent of its rated capacity. The value depends on the specific site installation and the type of prime mover (steam, gas or hydro). It follows that a 20 MW synchronous generator, with a block load pick-up (BLPU) capability of 10 per cent, will only be able to pick up demand in blocks of 2 MW at a time (if greater the frequency will drop below the permissible 47.5Hz limit).

Realistically, the smallest demand blocks that could be restored by DER would be 11kV feeders. These typically have demands of several MW (up to ~6 MW per 11kV circuit) excluding the effects of cold load pick-up. It follows that the minimum block loads available may not be within the anchor generator's capability, and thus restoration of the network from a single synchronous DER is not viable.

In order to mitigate this issue, a critical function of a DRZ-C is to facilitate block load pick-ups which are greater than the generator's inherent capacity. The technology companies have been tasked with developing their own control schemes, but options include synchro switching of a load bank when picking up demand (the generator is incrementally loaded against a load bank which is switched out at the same time as demand is switched in so that the generator sees a minimal net demand change) or coordinating the use of a battery storage system to achieve a similar effect.

11.4.2 Sub-second control

Moreover, preliminary power system simulations of the Chaplecross network identified that the DRZ-C is required to execute sub-second control (potentially < 200ms). This may be required to control DER, or substation plant, to provide a fast response to 'protect' the anchor generator from system disturbances which may cause fast frequency deviations.

The intervening fast frequency control capability of the DRZ-C is of key relevance to the DRZ-C design process since it requires the fastest action (based on initial stage 1 findings) of the system and informs:

- logical/physical architecture of the DRZ-C solution
- requirements of the supporting telecoms infrastructure
- requirements of the computing platform(s) (e.g. PLC/Server) which hosts and executes the time-sensitive control functions.

11.4.3 Steady state control

The DRZ-C will also be required to perform slower longer-term control functions such as managing the load on the anchor generator, load bank and other DER (e.g. wind farm) in order to maintain a continual generation/load balance. The DRZ-C is required to operate the island with a suitable margin such that stability of the island can be maintained. For example it may have to shed demand when the output of a wind farm decreases. It can be understood therefore that maintaining the 'optimal' load on the various DER assets, and maximising their utilisation, is not a simple process particularly where intermittent generation is part of the control scheme.

11.5 DRZ – Technical services

Table 11.1 shows the individual technical services which may be required to establish, grow and maintain a DRZ. Within each DRZ an anchor generator will be required. The remaining services may or may not be required depending on factors such as the capability of the anchor generator, the network topology, the restoration plan and the DRZ-C scheme which has been developed. Effectively, these are the 'building blocks' which the DRZ-C can utilise in order to establish a viable technical restoration process. It may be that in some DRZs the existing DER can already can meet all the required technical services (an individual DER may be able to provide several services), or in others additional services are required to expand the restoration options, or for others additional DER will require to connect first before a viable technical solution can be provided.

The services required will be further developed as the project progresses, including providing functional specifications for the specific services.

Table 11.1
DRZ technical services

Technical services	Requirement	Potential providers	Comments
Anchor generator (or power park)	Essential	Synchronous generator (steam, gas, hydro or diesel), or other technology with required capability	Only one anchor gen is required per power island
Fast MW response	Potential	Battery, loadbank, flywheel, generator, others	May be required to supplement technical capability of anchor gen e.g. enhance block loading
Fast Mvar response	Potential	Wind farm, solar, battery, synchronous gen, STATCOM, SVC, others	May be required to enhance Mvar capability of DRZ to expand the island/ energise to a higher voltage
Energy (MWh)	Potential	Schedulable MW – Synchronous generator (additional to the anchor) Intermittent MW – solar farm, wind farm	Enhance capability of DRZ to restore demand above capacity of anchor generator
Fault infeed	Potential	Synchronous generator, synchronous compensator, others	Increase DRZ fault level. Facilitate protection operation at higher voltage levels or converter DER to connect. Converter-connected DER (WFs, battery, solar) are very limited in their ability to provide this service
Inertia	Potential	Synchronous generator, synchronous compensator (or converter based sources with appropriate control), others	Increase frequency stability of the DR and/or allow greater demand blocks to be picked up

11.6 Conclusions/next steps

- Based on project learning to date, development of a DRZ-C is critical to providing the functionality of sub-second control, and coordinating multiple DER, in order to establish and maintain a DRZ.
- Based on the outputs of stage 1 provided by the DRZ-C contractors, the project will produce a consolidated set of requirements for the overall DRZ-C solution, including requirements for the DRZ controller itself, DER, and any other supporting systems (such as DSO/NGESO SCADA/DMS). These requirements and associated learning from stage 1 will be presented in the next PET report[13]. To acknowledge that there will likely be different approaches to design a viable DRZ-C, the requirements may be presented within the context of different control philosophies.
- The project will consider progressing with stage 2 and stage 3 of the Development and Demonstration process. The set of requirements from stage 1 may be further revised based on learnings from stage 2 or stage 3.

[13] Assessment of power engineering aspects of Black Start from DER – Part 2 (Dec 2020).

12. Issues Register

12.1 Introduction

To provide a consistent method for capturing the main technical challenges, the initial PET report 'Viability of Restoration from DERs' (July 2019) utilised an Issues Register. The purpose of this was to record the issue, identify the main technical challenges with respect to Black Start from DER, assign a level of criticality, and to form a basis of future works to ensure that all issues are addressed.

A traffic light symbol is used where a green light indicates an issue which is anticipated to have a relatively simple solution. An amber light represents an issue requiring more works to overcome, but the potential solution(s) are not anticipated to be so onerous that they would act as a project blocker. A red light depicts an issue which does not have an identified solution, or where the solution may be prohibitive from a technical or economic perspective. Red issues will require specific further analysis in later project stages or potentially represent a restriction on where or how Black Start can be facilitated by DERs.

Appendix 1 contains the Issues Register which gives a description of the issues, identifies the challenge for DER restoration, and shows the criticality level which was assigned in July 2019. A column has been added showing the mitigation works which have been undertaken between July 2019 and July 2020, along with a current assessment of criticality given the works and knowledge to date.

12.2 Assessment

It can be seen that out of the thirty four issues, twenty were assessed as amber in July 2019, with none being designated as red. Following the works in the last year, the number of amber issues has now reduced to nine. The remaining amber issues are primarily related to ongoing works. For example, issue T1 is related to identifying the level of converter-connected DER which may be connected to a weak network (low fault level when only supplied by a single synchronous DER). This is an area of current research in the electricity industry, where the project has commissioned several reports to date to determine the learning that may be applied to Distributed ReStart.

Only one issue has increased a level in criticality (S5), where system studies have shown that large voltage dips (~20 per cent) may be observed on the 33kV network when a primary (33/11kV) transformer is energised. This is only an issue where the primary is connected by a long 33kV circuit to the grid substation (~40km) resulting in a larger voltage drop. Further investigation will be required in this area, but mitigation measures include reducing the 33kV voltage prior to energising, or 'soft starting' (ramping up the 33kV voltage) which helps to minimise transformer inrush currents.

12.3 Conclusions

Significant progress has been made since the July 2019 viability report in addressing the issues which were identified. Works are ongoing to try and resolve all the remaining amber issues such that a viable technical solution can be proposed.

13. Conclusions

This report is the first of two to provide an assessment of power engineering aspects of Black Start from DER. This report focuses on power system studies, protection assessments, grid-following and grid-forming converter considerations, and gives an update on the development of automation to enable the restoration process, as well as the work being done to address the issues recorded in the Issues Register.

13.1 Power system studies

The following conclusions can be drawn from the steady state, dynamic and transient power system simulation studies of various network restoration options for the three case study networks.

Anchor DER block load pick-up (BLPU) limitation

- The BLPU capability of a DER is the maximum demand which can be instantaneously supplied while ensuring the frequency remains within an acceptable range. It is typically between 10 – 25 per cent of the generator's active power (MW) rating and depends on factors such as the turbine technology, governor type, inertia of the machine and the spinning reserve. A 33kV connected anchor DER will typically have an active power range between 20 MW and 50 MW and thus a BLPU capability of between 2 MW and 12.5 MW. The smallest load which can be practically connected during system restoration is an individual 11kV feeder at a primary (33/11kV) substation. These typically have a maximum demand between 0.5 MW to 6 MW and, for Black Start purposes, up to 200 per cent of these values should be assumed allowing for a lack of diversity when the load is switched on after a sustained outage (known as cold load pick-up [CLPU]).
- As a result of the BLPU limitations, an anchor generator may only be able to pick up individual lightly loaded 11kV feeders, or at most several 11kV feeders simultaneously. Thus, in order to facilitate the restoration of all demand blocks at a primary substation, or larger blocks of demand to minimise restoration times, it is likely that additional resources will require to be coordinated (e.g. a battery energy storage system) to enhance the BLPU capability within a DRZ. This is a primary focus of the DRZ controller work described in chapter 11 of this report: 'Automation'.

Additional DER (non-anchor generators)

- Based on the detailed analysis of the three case study networks, it is likely that the anchor generator may not have sufficient active power (MW) capacity to restore all the demand in a DRZ. Non-anchor DERs, including synchronous and asynchronous DERs, in the same restoration zone can play an important role in providing additional MW support so that more demand can be supplied. In addition to the active power support, synchronous DERs such as hydroelectric plants or gas generators will inherently contribute to the system inertia thereby assisting the anchor generator in frequency regulation of the DRZ.
- The additional DERs (e.g. wind farms, hydro plants) can also provide reactive power (Mvar) support to the anchor generator to maintain an acceptable voltage profile during energisation of the network and CLPU at the primary substations. The effectiveness of this support, however, depends on the location of the DER relative to the circuits or the primary substation being energised, i.e. the further away the DER is, the less effective its reactive power support will be to maintain the voltage profile.

Transformer energisation

- One of the major challenges with growing a distribution power island is the energisation of grid transformers (e.g. 132/33kV) or super grid transformers (e.g. 275/132kV). The transformers draw high magnetic inrush currents (typically 4 to 7 times of rated current) which may result in the anchor generator seeing a voltage dip at its terminals. The magnitude of this voltage dip depends on the configuration of the network, so for example, as the electrical distance between the anchor generator and the transformer being energised increases, the voltage drop will tend to reduce. In some cases, the voltage dip will be within the G99 protection setting of 20 per cent and would not pose any problem to the anchor generator. However, in other instances, as was observed in two out of the three case study networks, the voltage dip could be significant enough (e.g. more than 20 per cent) to cause under-voltage tripping of the generator. A solution to this problem could be a 'soft start' approach to demagnetise the transformer and reduce the inrush current. Another solution to reduce the voltage dips could be to implement additional hardware for controlled switching of the circuit breakers at a specific point on the voltage waveform to reduce the inrush current (known as point on wave switching).

Circuit energisation

- The energisation of distribution and transmission circuits produces reactive charging power that needs to be absorbed. The case study analysis showed that a 33kV network can typically be energised by the anchor generator and that it is acceptable to simultaneously energise multiple 33kV circuits to speed up the restoration process. However, the charging power produced by circuits at 132kV and higher voltages will most likely exceed the anchor generator's reactive power capability. This, however, depends on the type of circuit. As an example, in one of the case studies, a particular 132kV circuit is a combination of a 20km overhead line and a 3km underground cable. So, the amount of charging power produced by this circuit (≈5Mvar) is significantly more than a typical 132kV line (≈1.5Mvar).
- Other DERs can provide the additional reactive power required during circuit energisation. This is not necessarily dependent on a prime energy source such as wind being available, as modern wind farms can provide reactive power even under no wind conditions.
- Circuit energisation can also result in high switching over-voltages. Depending on the network configuration, as seen with the case studies, it could be more than 50 per cent of the nominal voltage rating. This could potentially lead to more than a 13% rise in voltage at the anchor generator terminal resulting in the risk of the anchor generator tripping. A solution to this problem could be to energise the circuits at a reduced voltage to limit the transient spike.

Wider network energisation

- The power system studies showed that a typical 132/33kV GSP substation with a 60MVA anchor generator can export around 30 MW and absorb 14Mvar at the transmission-distribution interface point without any support from other DERs. This capability can be increased with contribution from additional DERs in the DRZ to provide support for wider network energisation. However, it is important to note that the voltage profile at the interface point could be a limiting factor. So, the DERs can have capacity available, but the effective magnitude of active and reactive power that can be exchanged will depend on the voltage at the interface point. A high value of reactive power absorbed may increase the voltage beyond the acceptable limit of 10 per cent.
- Energising a typical 132kV overhead line of 20km, for example, can produce around 1.5Mvar (0.075Mvar/km). For the same length of line, the charging power is calculated as 6Mvar for a 275kV line (0.3Mvar/km) and 12Mvar for a 400kV line (0.6Mvar/km). To put it in context, a small anchor generator of 25MVA will have enough capability (9.6Mvar) to absorb the charging power of a 128km 132kV overhead line, but only 32km of a 275kV line and 16km of a 400kV line. Energising longer circuits or multiple circuits of the above length will not be possible unless additional reactive power support is provided by other DERs in the DRZ.

Restoration strategies

- An assessment of different distribution network topologies found that radial distribution networks are relatively easy to restore using DERs because the demand can be easily split into smaller blocks to meet the BPLU capability of the anchor generator. Meshed networks are harder to restore due to interconnections at 11kV and LV level, and densely interconnected meshed networks are very difficult to restore because they are hard to split up.
- Analysis of the case studies showed that the best strategy for energising a DRZ is to first restore supply to the additional DERs so that their auxiliary supplies are restored and can remain on standby ready to provide any active and/or reactive power support as and when required by the anchor generator. The second and third step, before connecting any customers, is to energise the grid/super grid transformers and associated higher voltage circuits, so that any voltage dips and/or switching over-voltages wouldn't be seen by customers.
- Thereafter primary substations can be energised to pick up customer demand. The primary substation demand can be restored in blocks ranging from individual 11kV feeders, to the whole substation demand simultaneously (by closing a transformer 33kV feeder circuit breaker). The transformer should ideally be initially energised with a demand as close as possible to the pre-blackout value to minimise any potential increase in the 11kV voltage magnitude (depending on the pre-blackout tap change position of the transformer), and to minimise the switching and associated restoration time. However, the demand blocks must be lower than the BLPU capability of the DRZ, and the CLPU value should not exceed the thermal rating of the primary substation transformer and switchgear. Restoration of a two-transformer radial primary substation, which only had one transformer in service pre-blackout, may have to be inhibited until the tap changer can be altered manually, to avoid excessively high 11kV voltage.

13.2 Protection assessment

An assessment of existing protections on the Chapelcross case study network was undertaken, based on the networks being energised by the 33kV connected 60MVA anchor DER only. Key findings were as follows:

- With reduced fault levels under a Black Start, some existing protections may continue to operate as normal, revised settings may facilitate correct operation of others, and others may not be able to be modified to operate correctly. In these cases other solutions may have to be considered. As the voltage levels increase, the number of protections requiring to be modified, or being inoperable, increases.
- Modern protection relays have the facility to be programmed with a second group of settings which can be changed remotely (via SCADA). Where this is required, older relays may require to be changed.

- As an approximate guide, the following minimum fault levels were identified as being required for satisfactory protection operation (assuming revised settings are applied as required):
  – 33kV – 50MVA*
  – 132kV – 50MVA
  – 275kV – 100MVA
  – 400kV – 250MVA.

  *At the primary (33/11kV) transformer HV terminals. This would ensure the associated 11kV and LV network protections would also operate correctly.
- If there is sufficient fault level for the 33kV network to be protected, then the associated 132kV network will likely be able to be protected. Based on our detailed analysis of the case studies and considering the more general conditions across all of GB, it is likely that a 33kV DRZ, on its own, will not be able to provide enough fault infeed for existing 400kV protections to operate correctly. It follows that additional fault infeed at higher voltage levels would be required. For example, at 132kV between 100MVA and 250MVA of additional fault infeed would be required depending on the 33kV DER fault infeed. This might be provided by restoring supplies and restarting generators or resources like synchronous condensers on the 132kV network.

13.3 Grid-following converter-connected DER considerations

A summary of the key findings obtained from a literature review relating to grid-following converters was provided. Whilst specific study of converter behaviour during Black Start from DER is not comprehensively covered in existing academic work, a number of conclusions can be drawn.

PLL limitations

It has been discussed that standard converter control techniques will fail to maintain stability when the SCR (short circuit ratio) of the network is typically less than 1.3-1.5. This is due to the PLL (the fastest control loop within the converter) struggling to track the voltage which deviates more erratically in a weak network and can result in the DER tripping. It follows that if the network fault level is 100MVA, it may only be feasible to connect between 66MVA to 77MVA of converter-connected DER to ensure stability (the exact value may be lower and would be determined by the converter manufacturer).

PLL mitigations

Potential alterations to improve performance include retuning the PLL controller for weak network operation, although any alterations could potentially impact overall performance. Network solutions would include increasing the SCR by adding DER to provide increased fault infeed.

Inertial considerations

Concerns over the lower system inertia with a high penetration of converter-connected DER have been highlighted, and the corresponding need for converter-connected generation to contribute to frequency support. At present, despite wind turbines having large rotational masses, they do not provide any 'real' inertia to the network since they are electrically decoupled. Converter control schemes can provide 'synthetic' inertial response by modifying the converter power reference according to the frequency measured through the PLL.

DER internal dynamic considerations

In reviewing the impact on internal dynamics for common wind turbine configurations, it was concluded that while there may be some effect on performance and some additional risk of equipment fatigue during Black Start conditions, nothing was identified that represents a fundamental problem in the use of DER or prevents their participation in a distributed Black Start process.

13.4 Grid-forming converter technology

The project has provided an overview of the grid-forming converter technology, and commissioned some initial studies to investigate how this may be applied to Black Start from DER. The following conclusions can be drawn.

Voltage source – A grid-forming converter can provide the same benefit as a synchronous generator in that it can generate its own independent voltage source.

Frequency support – A grid-forming converter can also emulate the performance of a synchronous generator in that it can provide 'true' inertia (an instantaneous power response to frequency disturbances). Grid-following converters can provide 'synthetic inertia' which has a delay associated with the frequency having to be measured before a response is initiated.

Increased stability – Due to its increased stable operation, a grid-forming converter is less susceptible to adverse interactions among multiple power plants under reduced system strength conditions, and unlike a grid-following converter does not need a minimum network SCR to operate.

Ancillary services – In addition to its role during a distribution restoration process, grid-forming converters have the capability to provide many additional ancillary services (e.g. frequency support) to increase overall system resilience, reducing the need for traditional network reinforcement.

Combination with energy storage – In combination with a sufficient energy storage buffer, a grid-forming converter can support system inertia with far less capacity when compared to conventional thermal generation. It can also deliver a faster injection rate of active or reactive current without destabilising its performance in weak systems.

13.5 Automation

- Based on project learning to date, implementation of some sort of DRZ controller (DRZ-C) is critical to providing the functionality of sub-second control, and coordinating multiple DER, in order to establish and maintain a DRZ.
- Based on work commissioned by the project, work is currently being undertaken by several technology companies to produce a consolidated set of requirements for overall DRZ-C solutions, including requirements for the DRZ controller itself, DER, and any other supporting systems (such as DSO/NGESO SCADA/DMS). These requirements, and associated learnings, will be presented in the next PET report[13].
- The project will consider progressing with the next phase of implementing and testing one or more DRZ-C solutions within a lab environment and will consider the feasibility of installing on the DNO network and integrating into the live testing.

13.6 Issues Register

In the initial PET viability report (July 2019), technical issues identified requiring further investigation were captured in an Issues Register. Of the thirty four issues originally identified, twenty were categorised as ‘amber’ (requiring works to overcome) and fourteen ‘green’ (anticipated to have a relatively simple solution). Since the initial report, all the issues have been/are being addressed with the number of amber issues now reduced to nine and works ongoing to address those outstanding. To date there have been no issues categorised as ‘red’ (no identified solution).

[13] Assessment of power engineering aspects of Black Start from DER – Part 2 (Dec 2020).

14. Next steps

This section outlines the next steps for the PET workstream in terms of the works required for the project deliverable reports, and progression of the live trial proposals.

14.1 Deliverable reports

The PET workstream is now at the end of the Design phase of the project, with the output being this report providing an assessment of the power engineering aspects of Black Start from DER. Given the volume of work required to provide a comprehensive technical assessment, a supplementary report is scheduled to be issued in December 2020 ('Assessment of power engineering aspects of Black Start from DER – Part 2'). In the next six months, works are being completed such that this report will include:

- generic functional specification for a DRZ controller
- draft functional requirements for DER to provide Black Start services
- real time simulation (RTDS) analysis of restoration scenarios
- proposals for future testing requirements for a Black Start service
- estimation of costs (network and DER) to implement a Black Start service
- further case study protection assessments
- update on live trial proposals.

The second and final phase of the project, the Demonstration phase, begins in July 2020. The first stage of this phase is known as the Refine stage. The goal of this stage is to take the technical learning to date, and propose initial DER, network and testing requirements to facilitate Black Start from DER. The publishing of the supplementary report in December 2020 will be complementary to this outcome. In addition, during this time period, it is proposed to initiate the implementation and testing phase of the DRZ-C development, where ideally at least one prototype of a control scheme will be built and tested.

The second stage of the Demonstration phase is known as Confirm, where final versions of the technical requirements to provide Black Start from DER will be detailed. There is one deliverable for the PET workstream at the end of the project (~Q1 2022). A report will be produced detailing the outcomes and learning from the live trials. (The final technical requirements will be included in a combined workstream project report also at this time.)

14.2 Live trials update

14.2.1 Background

In the Demonstration phase of the project, work will continue to develop proposals for live network trials. The project is currently working with the DER, DNOs and TOs to develop suitable live trial testing programmes, and ascertain the DER and network modifications required to implement.

To determine the most practical and optimal testing which can be done, the following case studies are under consideration:

- Chapelcross case study – Steven's Croft biomass (53 MW) anchor generator.
- Galloway case study – Glenlee hydro (22 MW) anchor generator.
- Legacy case study – Cefn Mawr gas engine (20 MW) anchor generator.
- Glenrothes case study – Redhouse battery/solar development.

The above represents the three main types of synchronous generators which are connected at present to DNO networks (steam, hydro and gas) and gives the opportunity to test different types of additional DER (e.g. batteries). The most appropriate number, scope and location of the tests to be carried out will be determined from the ongoing development work.

It should be noted that testing will not involve proving Black Start capability of individual generators as this is outside the scope of this project. It will be up to the generators to prove their Black Start capability if a market is established for this type of service.

To reduce the overall project risk, case study live trials will be split into at least two phases. Short-term testing refers to the preliminary testing to be carried out ideally within 2020 or Q1 2021. Long-term testing refers to tests to be carried out towards the end of the project (2021/22).

14.2.2 Short-term testing

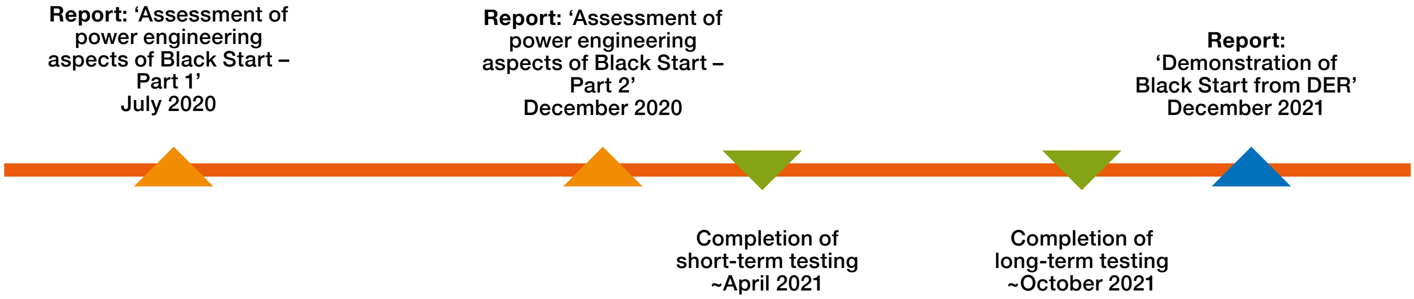
The short-term testing is planned to prove that the generation plant can be islanded from the main network, energise a dead section of network, and control the frequency and voltage independently (transformer energisation may also be included where appropriate). This is required to minimise the risk of unforeseen delays caused by the anchor generator during the long-term testing which will involve more extensive 33kV (and higher voltage) network outages. Block loading tests of the generators may also be carried out during the short-term testing to help validate models used in simulation studies.

14.2.3 Long-term testing

This testing will concentrate on proving the ability to establish and maintain a stable power island within an isolated 33kV network and energise up to the transmission network. The tests may include installation of a DRZ-C to prove any critical functionality which has been identified (e.g. its ability to facilitate syncro-switching of a load bank and demand to enable load pick up). The tests will ideally involve coordinating the output of the anchor generator with a broad range of additional DER types (e.g. wind, solar and batteries). Block loading on the network will be simulated by switching load banks, with the demand programmed to mimic realistic profiles.

The key milestones and deliverables are summarised in figure 13.1.

Figure 13.1
Key milestones and deliverables



Appendix 1: Selected Chapelcross restoration options

Details of Chapelcross restoration options 1, 2, 3c and 4a are provided in this appendix.

Restoration option 1

Once the Steven's Croft generator has started, restoration option 1 focuses on the establishment of a 33kV DRZ through sequential energisation of circuits to the Chapelcross GSP 33kV busbar, 33kV connected wind farms, and primary substations.

Primary substations are energised based on the most viable restoration strategy for the particular substation (options A – G) given its maximum demand and the BLPU capability of the anchor generation. The restoration stages for option 1 are summarised in table A1.1.

Table A1.1
Restoration stages for Chapelcross restoration option 1

Stage	Action	Description
0	Self-start	Energise Steven's Croft anchor generator
1	Transformer energise	Connect Steven's Croft generator to Chapelcross GSP
2	Line energise	Energise Chapelcross 33 kV busbars
3	Line and transformer energise, WF online	Restoration of power supply to Minsca wind farm
4	Line and transformer energise, WF online	Restoration of power supply to Ewe Hill wind farm
5	Cold load pick-up	Restoration of power supply to Annan primary substation (option C is the preferred restoration option, see section 2.4)
6	Cold load pick-up	Restoration of power supply to Middlebie primary substation
First request to Minsca and Ewe Hill WFs for active power support – 30 per cent of their nominal rating		
7	Cold load pick-up	Restoration of power supply to Langholm primary substation
8	Cold load pick-up	Restoration of power supply to Gretna primary substation
9	Cold load pick-up	Restoration of power supply to Newcastleton primary substation
Second request to Minsca and Ewe Hill WFs for active power support – ramp up to 38 per cent		
10 (a)	Cold load pick-up	Restoration of power supply to Lockerbie primary substation (load 1)
Third request to Minsca and Ewe Hill WFs for active power support – ramp up to 45 per cent		
10 (b)	Cold load pick-up	Restoration of power supply to Lockerbie primary substation (load 2)
11	Cold load pick-up	Restoration of power supply to Kirkbank/Moffat primary substation (load 1)
12	Cold load pick-up	Restoration of power supply to Moffat primary substation (load 2)
13	Complete restoration of the island	Restore network to normal operating mode to improve security

Restoration option 2

Restoration option 2 is similar to option 1, with the only difference being that the GSP 33kV and the 33kV circuits to the Minsca and Ewe Hill wind farms are simultaneously energised.

Table A1.2
Restoration stages for Chapelcross restoration option 2

Stage	Action	Description
0	Self-start	Energise Steven's Croft anchor generator
1	Line and transformer energise	Connect Steven's Croft to Chapelcross GSP, energise Chapelcross 33 kV busbar and circuits to Minsca and Ewe Hill wind farms
2	WF online	Restoration of power supply to Minsca wind farm
3	WF online	Restoration of power supply to Ewe Hill wind farm
Restoration of power supply to the primaries fed from Chapelcross GSP as per option 1 stage 2 onwards		
4	Cold load pick-up	Restoration of power supply to Annan primary substation (option C is the preferred option, see section 2.4)
5	Cold load pick-up	Restoration of power supply to Middlebie primary substation
First request to Minsca and Ewe Hill WFs for active power support – 30 per cent of their nominal rating		
6	Cold load pick-up	Restoration of power supply to Langholm primary substation
7	Cold load pick-up	Restoration of power supply to Gretna primary substation
8	Cold load pick-up	Restoration of power supply to Newcastleton primary substation
Second request to Minsca and Ewe Hill WFs for active power support – ramp up to 38 per cent		
9 (a)	Cold load pick-up	Restoration of power supply to Lockerbie primary substation (load 1)
Third request to Minsca and Ewe Hill WFs for active power support – ramp up to 45 per cent		
9 (b)	Cold load pick-up	Restoration of power supply to Lockerbie primary substation (load 2)
10	Cold load pick-up	Restoration of power supply to Kirkbank/Moffat primary substations (load 1)
11	Cold load pick-up	Restoration of power supply to Moffat primary substation (load 2)
12	Complete restoration of the island	Restore network to normal operating mode to improve supply security

Restoration option 3c

Once the 33kV DRZ skeleton network (i.e. without load) has been established, the Chapelcross 132/33kV grid transformer, as well as the banked 132kV Ecclefechan line and associated 132/25kV National Rail transformer are simultaneously energised, following by the sequential restoration of the Chapelcross primary substation demand as in option 1. Options 3a, 3c, and 3d are variations of the restoration strategy. The restoration stages for option 3c are summarised in table A1.3.

Table A1.3
Restoration stages for Chapelcross restoration option 3c

Stage	Action	Description
0	Self-start	Energise Steven's Croft anchor generator
1	Energise 33kV line and transformer energise, Energise grid transformer, 132kV line and grid transformer	Simultaneously: Connect Steven's Croft to Chapelcross GSP and energise 33kV busbar Energise 33kV circuits to Minsca and Ewe Hill wind farms Energise Chapelcross 132/33kV Grid 1 transformer, 132 kV busbar Energise 132 kV circuit to Ecclefechan and Ecclefechan transformer T1
Restoration of power supply to the primaries fed from Chapelcross GSP as per option 2 stage 2 onwards		
2	WF online	Restoration of power supply to Minsca wind farm
3	WF online	Restoration of power supply to Ewe Hill wind farm
3	Cold load pick-up	Restoration of power supply to Annan primary substation (option C is the preferred option, see section 2.4)
4	Cold load pick-up	Restoration of power supply to Middlebie primary substation
First request to Minsca and Ewe Hill WFs for active power support – 30 per cent of their nominal rating		
5	Cold load pick-up	Restoration of power supply to Langholm primary substation
6	Cold load pick-up	Restoration of power supply to Gretna primary substation
7	Cold load pick-up	Restoration of power supply to Newcastleton primary substation
Second request to Minsca and Ewe Hill WFs for active power support – ramp up to 38 per cent		
8 (a)	Cold load pick-up	Restoration of power supply to Lockerbie primary substation (load 1)
Third request to Minsca and Ewe Hill WFs for active power support – ramp up to 45 per cent		
8 (b)	Cold load pick-up	Restoration of power supply to Lockerbie primary substation (load 2)
9	Cold load pick-up	Restoration of power supply to Kirkbank/Moffat primary substations (load 1)
10	Cold load pick-up	Restoration of power supply to Moffat primary substation (load 2)
11	Complete restoration of the DRZ	Restore network to normal operating mode to improve supply security

Restoration option 4

Option 4b entails the establishment of the Chapelcross 33kV DRZ, followed by energisation of the Chapelcross 132kV Grid 1 transformer and a 132kV circuit to Dumfries 132/33kV GSP (26.9km), energisation of the Dumfries 132/33kV Grid T1A and Grid T1B transformers and Dumfries 33kV busbar, followed by picking up some Dumfries demand and DER, before restoring demand at Chapelcross GSP. The restoration stages for option 4b are shown below.

Table A1.4
Restoration stages for Chapelcross restoration option 4b

Stage	Action	Description
0	Self-start	Self-start Steven's Croft anchor generator and energise up to Steven's Croft 33kV PoC.
1	Circuit energise	Energise the 33kV circuit from Steven's Croft generator to Chapelcross GSP
2	Busbar energise	Energise Chapelcross 33 kV busbars
3	Line and transformer energise, WF online	Restoration of power supply to Minsca wind farm from Chapelcross via Minsca PoC
4	Line and transformer energise, WF online	Restoration of power supply to Ewe Hill wind farm from Chapelcross via Ewe Hill PoC
5	Energise grid transformer, 132kV circuit, grid transformer	Sequentially: Energise Chapelcross 132 kV Grid 2 transformer, 132 kV busbar, Dumfries 132 kV circuit, Dumfries 132 kV busbar and Dumfries 132 kV Grid 1A and 1B transformers
6	Energise 33kV busbars, WF online, cold load pick-up	Sequentially: Energise Dumfries 33 kV busbars and restoration of power supply to Dalswinton wind farm and Cargenbridge primary
Restoration of power supply to the primaries fed from Chapelcross GSP as per option 1 from stage 5 onwards		
7	Cold load pick-up	Restoration of power supply to Annan primary substation (option C is the preferred option, see section 2.4.1)
8	Cold load pick-up	Restoration of power supply to Middlebie primary substation
First request to Minsca and Ewe Hill WFs for active power support – 30 per cent of their nominal rating		
9	Cold load pick-up	Restoration of power supply to Langholm primary substation
10	Cold load pick-up	Restoration of power supply to Gretna primary substation
11	Cold load pick-up	Restoration of power supply to Newcastleton primary substation
Second request to Minsca and Ewe Hill WFs for active power support – ramp up to 38 per cent		
12 (a)	Cold load pick-up	Restoration of power supply to Lockerbie primary substation (load 1)
Third request to Minsca and Ewe Hill WFs for active power support – ramp up to 45 per cent		
12 (b)	Cold load pick-up	Restoration of power supply to Lockerbie primary substation (load 2)
13	Cold load pick-up	Restoration of power supply to Kirkbank/Moffat primary substation (load 1)
14	Cold load pick-up	Restoration of power supply to Moffat primary substation (load 2)
15	Complete restoration of the DRZ	Restore network to normal operating mode to improve security

Appendix 2: DER ratings and simulation models

A summary of the DER ratings and simulation models used in the power system studies.

The table below provides a summary of electrical ratings of each of the DERs included in the power system studies as well as the models used for the turbine or governor and voltage control in each case.

Table A2.1
DERs, governor, and AVR models used in the power system studies

Study case	GSP/ substation	Plant name	Generator type	Tech-nology	MW	MVA	Leading Mvar limit	Lagging Mvar limit	Volt-age	Turbine/ Governor model	AVR model/ Voltage control
Chapelcross	Chapelcross	Steven's Croft	Synchronous	Biomass steam	45	59.68	-29.84	42.96	33	Detailed boiler, turbine model based on IEEE recommendation	IEEE AC 2b
		Minsca WF	Wind	Type III	38	43.44	-10.49	14.13	33	Wind turbine model based on IEC 61400-27-1 Ed. 1	Wind Power Park model based on IEC 61400-27-1 Ed. 1
		Ewe Hill WF	Wind	Type III	12	12.63	-3.94	3.94	33	Wind turbine model based on IEC 61400-27-1 Ed. 1	Wind Power Park model based on IEC 61400-27-1 Ed. 1
		Craig I WF	Wind	Type III	8	11.11	-3.46	3.46	11	Wind turbine model based on IEC 61400-27-1 Ed. 1	Wind Power Park model based on IEC 61400-27-1 Ed. 1
		Craig II WF	Wind	Type III	2.2	2.5	-0.78	0.78	11	Wind turbine model based on IEC 61400-27-1 Ed. 1	Wind Power Park model based on IEC 61400-27-1 Ed. 1
Galloway	Carsfad	Carsfad Hydro	Synchronous	Hydro	12	15	-4.98	4.98	11	Modelled based on actual data from Glenlee Hydro	IEEE AC 8b
	Earlstoun	Earlstoun Hydro	Synchronous	Hydro	12	15	-4.98	4.98	11	Modelled based on actual data from Glenlee Hydro	IEEE AC 8b
	Glenlee	Glenlee Hydro	Synchronous	Hydro	25.5	30	-10	10	11	Modelled based on actual data from Glenlee Hydro	IEEE AC 8b
	Kendoon	Drumjohn Hydro	Synchronous	Hydro	21	26.2	-8.72	8.72	11	Modelled based on actual data from Glenlee Hydro	IEEE AC 8b
	Tongland	Tongland Hydro	Synchronous	Hydro	33	41.25	-18	21.72	11	Modelled based on actual data from Glenlee Hydro	IEEE AC 8b
	Newton Stewart	Airies WF	Wind	Type III	35	43.33	-11.36	16.84	33	Wind turbine model based on IEC 61400-27-1 Ed. 1	Wind Power Park model based on IEC 61400-27-1 Ed. 1

Study case	GSP/ substation	Plant name	Generator type	Tech-nology	MW	MVA	Leading Mvar limit	Lagging Mvar limit	Volt-age	Turbine/ Governor model	AVR model/ Voltage control
Galloway	Glenluce	Artfield WF	Wind	Type I	19.5	21.66	-6.76	6.76	33	Wind turbine model based on IEC 61400-27-1 Ed. 1	Wind Power Park model based on IEC 61400-27-1 Ed. 1
	Glenluce	Barlock-hart Moor WF	Wind	Type III	10	10.53	-2.09	2.09	33	Wind turbine model based on IEC 61400-27-1 Ed. 1	Wind Power Park model based on IEC 61400-27-1 Ed. 1
	Glenluce	Carscreu-gh WF	Wind	Type III	15.3	16.1	-5.31	5.31	33	Wind turbine model based on IEC 61400-27-1 Ed. 1	Wind Power Park model based on IEC 61400-27-1 Ed. 1
	Glenluce	Glen-chamber WF	Wind	Type III	30	30.55	-7.4	10.7	33	Wind turbine model based on IEC 61400-27-1 Ed. 1	Wind Power Park model based on IEC 61400-27-1 Ed. 1
	Glenluce	North Rhins WF	Wind	Type III	22	23.16	-7.23	7.23	33	Wind turbine model based on IEC 61400-27-1 Ed. 1	Wind Power Park model based on IEC 61400-27-1 Ed. 1
	Dunhill	Brock-lock Rig I&II WF	Wind	Type III	62	83.33	-19.66	28.74	33	Wind turbine model based on IEC 61400-27-1 Ed. 1	Wind Power Park model based on IEC 61400-27-1 Ed. 1
	Glenglass	Whiteside Hill WF	Wind	Type III	27	30	-7.17	10.27	33	Wind turbine model based on IEC 61400-27-1 Ed. 1	Wind Power Park model based on IEC 61400-27-1 Ed. 1
	Glenglass	Sanquhar WF	Wind	Type III	30	32.22	-10.31	10.31	33	Wind turbine model based on IEC 61400-27-1 Ed. 1	Wind Power Park model based on IEC 61400-27-1 Ed. 1
	Blackhill	Afton I&II WF	Wind	Type III	50	55.55	-17.8	17.8	33	Wind turbine model based on IEC 61400-27-1 Ed. 1	Wind Power Park model based on IEC 61400-27-1 Ed. 1
	New Cum-nock	Dersal-loch WF	Wind	Type III	69	76.66	-18.33	26.24	33	Wind turbine model based on IEC 61400-27-1 Ed. 1	Wind Power Park model based on IEC 61400-27-1 Ed. 1
Legacy	Ruabon	Cefn Mawr	Synchronous	Gas	20	24.83	-9.61	14.9	33	Detailed turbine model based on IEEE recommen-dation	IEEE AC 2b
	Cadkro	Krono-span	Synchronous	Gas						Not modelled	
	Carno	Tir Gwynt	Wind	Type III	22.8	24	-7.5	7.5	33	Wind turbine model based on IEC 61400-27-1 Ed. 1	Wind Power Park model based on IEC 61400-27-1 Ed. 1
		Carno I, II, III	Wind	Type III	45.6	48	-15	15	33	Wind turbine model based on IEC 61400-27-1 Ed. 1	Wind Power Park model based on IEC 61400-27-1 Ed. 1

Appendix 3: Chapelcross protection revision results

Substation	Circuit name	Protection function	Scheme type	Device type	Second group available	Voltage control available	Cold load pick-up	New relay required	Rating	Black Start settings
Gretna 400kV	Gretna 400/ 132kV Tx feeder	400kV SGT protection	HSOC	Depends on existing type if a second group of settings can be utilised to reduce the pick-up						Confirm relay type however normal ranges can start from 0.08 In which is only 160 A which is above fault level of 90 A
Chapelcross 132kV		Busbar protection	High impedance	Depends on existing type if a second group of settings can be utilised to reduce the pick-up						Confirm relay type and existing settings
	Dumfries 1 & 2	132kV feeder main protection	132kV unit (overhead circuits)	Solkor 'M'	No	No	No	This relay is obsolete, new relay with 2nd group of settings		Suggested temp settings 500/1 – 0.25 Diff Mult, 30 per cent slope, O/C check off, EF check 0.1 In
		132kV feeder backup protection	OC	KCGG140	Yes	No	Yes	No		500/1, 140A, SI 0.05TM
			EF							250 A SI 0.05TM
	Gretna 1 & 2	132kV feeder main protection	132kV unit (overhead circuits)	Solkor 'M'	No	No	No	This relay is obsolete, new relay with 2nd group of settings		Suggested temp settings 500/1 – 0.25 Diff Mult, 30 per cent slope, O/C check off, EF check 0.1 In
		132kV feeder backup protection	OC	KCGG142	Yes	No	Yes	No		500/1, 140A, SI 0.05TM
			EF							250 A SI 0.05TM
	Harker	132kV feeder main protection	132kV unit distance	SHPM101	Depends on existing relay being able to detect for mimimum voltage					Confirm existing settings
	Chapelcross 132/33kV Tx feeder	132kV transformer feeder MP	HV REF	Duobias	Settings remain suitable			No		No change
			DIFFERENTIAL							No change
										No change
		132kV transformer feeder BUP	HSOC	MCGG42	No	No	No	Yes		No change
			SBEF	New function required				Yes		500/1, 0.2A, 100A 0.225TM SI
			OC	Reyrolle	TBD	TBD	TBD	Yes		500/1 150A, SI 0.1TM

Key

No change · Setting change required · New relay or solution not confirmed

Substation	Circuit name	Protection function	Scheme type	Device type	Second group available	Voltage control available	Cold load pick-up	New relay required	Rating	Black Start settings
Chapelcross 33kV		Busbar protection	High impedance	DAD-N	Yes	No	Yes	No		No change
	CHAP11 feeder to Gretna	33kV feeder Protection	HSOC	7SJ611	Yes	No	Yes	No		400/1, 3.25 A, 1300 A
			BEF							No change
			OC	7SJ632 DAR	Yes	Yes	Yes	No		400/1, 0.69 A, 276A 0.4s NI
			EF							400/1, 0.25 A, 100 A 0.13s NI
	CHAP12 feeder to Middlebie /Langholm	33kV feeder protection	LINE DIFFERENTIAL	7SD522	Yes	No	No	No		400/1, I diff> 0.2 A, Idiff >> 1.6 A Idiff> switch on 0.2 A, 1.6 A
			HSOC	7SJ611	Yes	No	Yes	No		No change
			BEF							No change
			OC	7SJ632 DAR	Yes	Yes	Yes	No		400/1, 0.69 A, 276 A 0.4s NI
			EF							400/1, 0.25 A, 100 A 0.13s NI
	CHAP13 feeder to Annan	33kV feeder protection	HSOC	7SJ611	Yes	No	Yes	No		400/1, 3.25 A, 1300 A
			BEF							No change
			OC	7SJ612	Yes	No	Yes	No		400/1, 0.94 A, 376 A 0.3s NI
			EF							400/1, 0.25 A, 100 A 0.13s NI
	CHAP14 feeder to Lockerbie	33kV feeder protection	LINE DIFFERENTIAL							**DETERMINE SETTINGS**
			HSOC	7SJ611	Yes	No	Yes	No		400/1, 4.0 A, 1600 A
			BEF							No change
			OC	7SJ632 DAR	Yes	Yes	Yes	No		400/1, 0.75 A, 300 A 0.4s NI
			EF							400/1, 0.25 A, 100 A 0.13s NI
	CHAP15 feeder to Steven's Croft	33kV feeder protection	LINE DIFFERENTIAL	7SD522	Yes	No	No	No		800/1, I diff> 0.2 A, Idiff >> 1.0 A Idiff> switch on 0.2 A, 1.0 A
			OC	7SJ611	Yes	No	Yes	No		800/1, 1.2 A, 960 A 0.15s NI
			EF							No change
	GT1 and GT2	33kV transformer incomer protection	DOC	7SJ632	Yes	Yes	Yes	No		No change
			OC							1600/1 , 0.35 A, 560 A, 0.1TM NI
			SBEF1							No changes
			SBEF2							No changes
			REF	Duobias	Settings remain suitable			No		No changes
			DIFFERENTIAL	Duobias High Impedance				No		No changes
										No changes
Middlebie SWS 33kV	Chapelcross incomer	Middlebie SWS incomer protection	LINE DIFFERENTIAL							Set as the Chapelcross Feeder
			HSOC							Set as the Chapelcross Feeder
			OC							Set as the Chapelcross Feeder
			EF							Set as the Chapelcross Feeder
	Langholm feeder	Transformer feeder protection	HSOC	7SJ611	YES	NO	YES	NO		400/1, 2.35 A, 940 A
			BEF							No changes
			OC	'7SJ632 DAR'	YES	YES	YES	NO		400/1, 0.69 A, 276 A 0.28s NI
			EF							400/1, 0.12 A, 96 A 0.05s NI
Lockerbie SWS 33kV	Chapelcross incomer	Lockerbie primary incomer protection	LINE DIFFERENTIAL	7SD522/23	YES	NO	NO	NO		No change
			OC	Miom P145 Schneider	YES	YES	YES	NO		800/1 0.38 A, 304 A, 0.4TMS SI
			DOC							No change
	Lockerbie local Tx feeder	Transformer feeder protection	HSOC	Micom P122 Schneider	YES	NO	YES	NO		800/1, 1.52 A, 1216 A
			BEF							No changes
			OC	Miom P145 Schneider	YES	YES	YES	NO		800/1, 0.38 A, 304 A 0.35tms SI
			EF							800/1, 0.12 A, 96 A 0.05 NI

Key

No change Setting change required New relay or solution not confirmed

Substation	Circuit name	Protection function	Scheme type	Device type	Second group available	Voltage control available	Cold load pick-up	New relay required	Rating	Black Start settings
Lockerbie SWS 33kV (continued)	Moffat/ Kirkbank TX feeder	Transformer feeder protection	HSOC	Micom P122 Schneider	YES	NO	YES	NO		800/1, 0.88A, 704 A
			BEF							No changes
			OC	Miom P145 Schneider	YES	YES	YES	NO		800/1, 0.2 A, 160 A 0.52tms SI
			EF							800/1, 0.12 A, 96 A 0.05 NI
Steven's Croft		33kV protection utility feeder	OC	7UM621				NO		No changes
			OC i>> DiR							No changes
			U/V							No changes
			O/V							No changes
			NVD							No changes
			U/F							No changes
			O/F							No changes
			Df/dt							No changes
		33kV protection generator transformer	OC	7UT633				NO		No changes
			DIFFERENTIAL							No changes
			REF							No changes
			3xlo							0.35 I/InS, 0.7 s restraint 7.5 I/InS
			EF							Ie = 0.25 A 313 A pri, 0.7s
			11 kV impedance protection	7UM621				NO		No changes
			DIFFERENTIAL							No changes
Langholm 11kV	TX incomer	11kV transformer – OCEF protection	SBEF	MCGG52	NO	NO	NO	NO		No changes
			LVOC	CDG31	NO	NO	NO	MAYBE		TBD depends on the feeder cable length
	Outgoer	11kV feeder protection	WF BACKUP OC	MCGG52	NO	NO	NO	NO		No changes
Lockerbie 11kV	TX Incomer	11kV transformer – OCEF protection	Dir. OC Backfeed into 33kV from 11kV	METI	NO	NO	NO	NO		No changes
			OC	CDG31	NO	NO	NO	MAYBE		Changes required depends on feeders
			REF	MCGG	NO	NO	NO	NO		No changes
			Standby EF	MCGG	NO	NO	NO	NO		20%, 0.15 LTI (1200/5A CT assumed)
	Outgoer	11kV feeder protection	OC, EF					NO		Typical settings assumed TBC
Moffat 11kV	TX Incomer	11kV transformer – OCEF protection	LVOC	CDG31	NO	NO	NO	MAYBE		TBD depends on the feeder cable length
			SBEF					NO		300/5 20% 0.15 LTI
	Outgoer	11kV Feeder Protection	OC	CDG	NO	NO	NO	NO		No changes
Annan 11kV	TX Incomer	11kV transformer – OCEF protection	LVOC	Depends on existing type if a second group of settings can be utilised				MAYBE		Changes required depends on feeders
			LVEF					Confirm type and settings		180A, SI, TM0.65 TBC
			Dir. OC Backfeed into 33kV from 11kV					NO		No change
	Outgoer	11kV feeder protection	OC, EF					NO		Typical settings assumed TBC
Gretna 11kV	TX Incomer	11kV transformer – OCEF protection	LVOC	Depends on existing type if a second group of settings can be utilised				MAYBE		Changes required depends on feeders
			LVEF					Confirm type and settings		180A, SI, TM0.65 TBC
			Dir. OC Backfeed into 33kV from 11kV					NO		No change
	Outgoer	11kV feeder protection	OC					NO		Typical settings assumed TBC

Key
No change Setting change required New relay or solution not confirmed

Appendix 4: Fault levels across voltage levels

Fault levels across different voltages

The fault level at different parts of a network depends on the impedance between the fault location and the original sources of fault current, which mainly comes from generators. While all overhead lines and cables have impedance it is the transformers between voltage levels that have the biggest influence. Some simple calculations can be done to demonstrate the challenges in achieving the necessary fault levels when the sources are small and connected at 33kV.

An approach often applied in power system analysis is to perform simplified calculations by expressing all values as a 'per unit' impedance and neglecting some of the details to give a quick approximation. Fault level and system impedances can be expressed as the inverse of one another. The calculations below apply this method to assess how fault levels transfer across voltage levels. All per unit values (pu) are expressed on a 100 MVA base. So a fault level of 500 MVA is equivalent to a system impedance of 100/500 = 0.2pu.

A typical 132/33kV transformer, as at Chapelcross, has an impedance of approximately 0.27pu.

A typical 400/132kV auto-transformer, as at Gretna, has an impedance of approximately 0.1pu.

If we assume the minimum required fault level at 400kV is 250 MVA, this is equivalent to a total system impedance, as seen at 400kV, of 0.4pu.

If there is one 400/132 transformer with 0.1pu impedance then the equivalent impedance at 132kV must be no higher than 0.3pu. This is equivalent to there being a fault level of 333 MVA at 132kV.

If there is one 132/33 transformer with 0.27pu impedance then the equivalent impedance at 33kV must be no higher than 0.03pu. This is equivalent to a fault level of 3,333 MVA at 33kV. This is not feasible, not just because there would be insufficient generation capacity at 33kV, but also because the switchgear at that voltage level could not accommodate such high fault currents.

If the maximum possible fault level at 33kV is assumed to be 1,000 MVA, which is the design rating of 33kV switchgear in SPEN networks then, assuming a single 132/33 transformer with 0.27pu impedance, the maximum fault level at 132kV will be 270 MVA.

If there is one 400/132 transformer with 0.1pu impedance then the maximum fault level achieved at 400kV will be 213 MVA. However, it is unlikely that a 1,000 MVA fault level at 33kV will be achieved using DER alone.

If the maximum fault level at 33kV achievable with DER alone is assumed to be 300 MVA then, assuming the same transformer impedances as above, this translates into fault levels of 166 MVA at 132kV and 142 MVA at 400kV, which is likely to be too low to operate protection effectively.

In these circumstances, it may be necessary to add other sources of fault infeed at 132kV or 400kV. If another source was added at 132kV with a fault level infeed of 167 MVA then the total fault levels would be boosted to 333 MVA at 132kV and 250 MVA at 400kV.

Alternatively, a source with fault infeed of 108 MVA could be connected directly at 400kV to raise the fault level there to 250 MVA. This would also boost fault levels by 97 MVA at 132kV and by 77 MVA at 33kV.

The impact of fault infeed at different levels is illustrated in the charts below, which again assume impedances of 0.27pu between 33 and 132kV and 0.1pu between 132 and 400kV.

Figure A4.1
33kV fault infeed impact on 132kV and 400kV networks

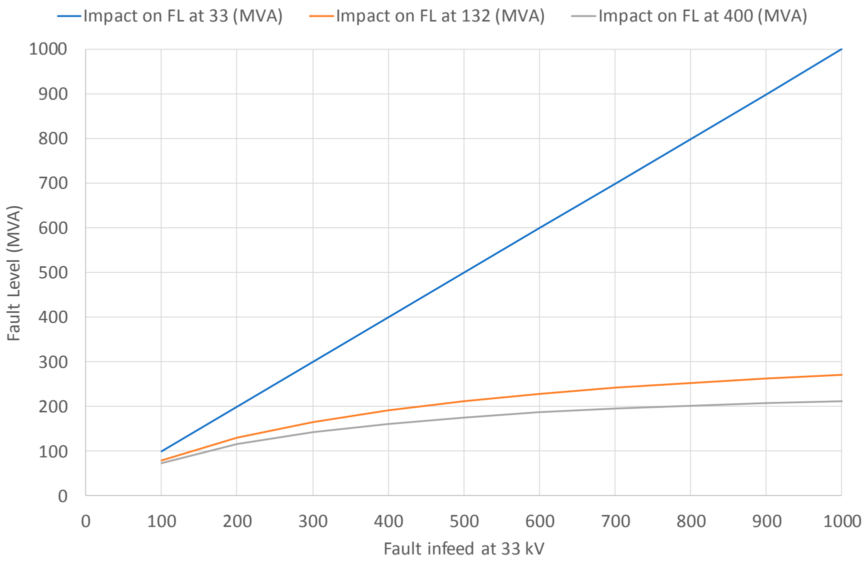
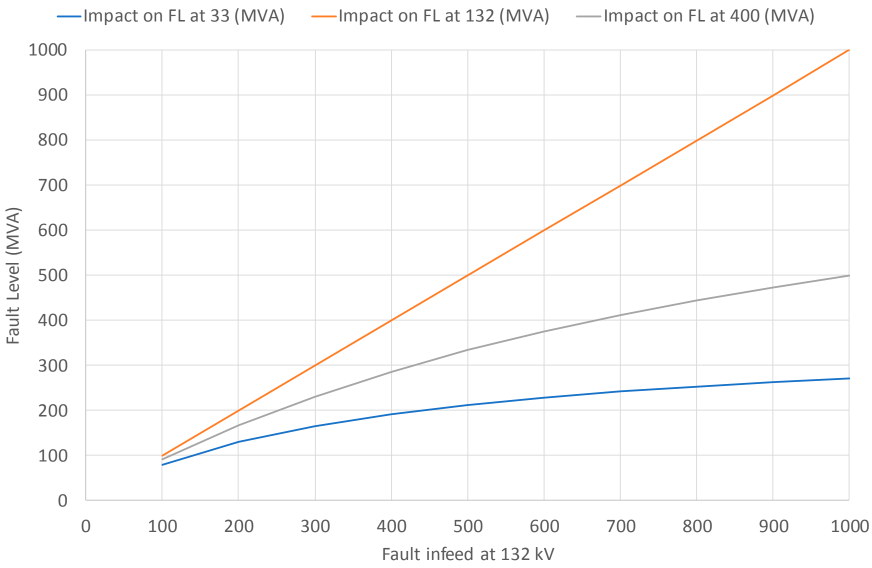


Figure A4.2
132kV fault infeed impact on 33kV and 400kV networks



Appendix 5: Issues Register

Table A5.1
Issues Register – DER Technical

July 2019					July 2020	
Category	**No.**	**Description**	**Black Start DER challenges**	**Status**	**Mitigation**	**Status**
DER Technical	**T1**	Converter-connected generation is sensitive tolow system fault level and resulting voltage instability.	The fault level might not be sufficient to allow converter-connected gen to stably connect. Control settings may need changing for Black Start scenario. The gen may trip for system disturbances.		Strathcyde University have been commissioned to do five reports, and simulation studies, to investigate the issues associated with connecting converters in weak grids. A summary of these reports is provided in this report. The issue is still 'amber' as the issue of what level of penetration of converter-connected DER is acceptable is the subject of current industry research/ debate with no definitive answers available as yet.	
DER Technical	**T2**	Dynamic models not available for DER (unless large as defined in the Grid Code). The dynamic models for DER (if available) or the generic dynamic models may be suitable for normal operation only and not for Black Start related simulations.	Dynamic response required to know key parameters such as the block load capability (for synchronous generators).		Dynamic models, including boiler dynamics where appropriate, of the anchor generators in the three case studies selected for further analysis have been built. Manufacturer data has been used where available, and where not generic models/values have been used. This issue is now 'green' as accurate models have been constructed, and are most relevant for anticipating the outcome of the live trials, (where an initial test stage will be used to validate the models where feasible). In addition, for GB roll-out, site specific capability is not crucial as the generic capability will be more applicable on a wider scale.	
DER Technical	**T6**	Most anchor generator types need a minimum demand to start with (to avoid overheating the boiler or turbine blade cavitation). This ranges from ~20 per cent to 50 per cent of rating.	It is unlikely this demand can be provided from the network due to: i) the uncertainty of demand being connected, ii) the demand exceeding the gen load pick up capability.		Further detailed investigation into the capability of the three predominant types of anchor generators has been undertaken (steam, gas and hydro). Results have concluded that some generators require no auxiliary demand to start and can operate at 'full speed no load' indefinitely or for a number of hours. Where a demand is required a load bank can be provided.	
DER Technical	**T3**	Most existing DER normally operates in base load (MW control), and may not have frequency control installed (unless a Grid Code large power station).	Frequency control is required on at least one anchor gen when operat-ing in an island.		Case study assessments of anchor generators to date has shown that frequency control mode may be commissioned (where installed but not normally utilised), or may be installed, given that there is already a governor to regulate the power output.	
DER Technical	**T4**	DER in England & Wales typically operates in power factor control.	Voltage control is required on at least one anchor gen in an island. Gen control modes may need to be changed for Black Start. The DNO connec-tion may not be suitable for V control.		Case study assessments to date have shown that, where an anchor DER may operate in power factor control, it will have a AVR which can be modified/ commissioned to operate in voltage control. If the thermal rating of the DNO connection is a limiting factor for power factor operating range, the MW output of the anchor DER will only have to be slightly derated (~5 per cent) to mitigate this.	
DER Technical	**T5**	DERs have different control methods. Some manned 24/7, others are fully remote controlled and others a combination.	Resilient control of the DER from Black Start will have to be developed taking into account all current control methods.		This issue will be considered by the Organisational, Systems & Telecoms workstream.	
DER Technical	**T7**	Wind farm, battery and solar sites are typically not permanently manned and are controlled remotely.	Direct control of the DER may be required as part of an islanding control scheme (i.e not via a remote control room).		Four technology companies have been commissioned to provide a functional design specification for a Distributed ReStart Zone Controller (DRZ-C) which will consider how DER should be controlled/coordinated.	
DER Technical	**T8**	Some wind farms require to start at ~10 per cent of rated output.	The network to which it connects must be capable of absorbing the minimum wind farm export power.		Consultants have been commissioned to determine the technical capability/resilience of wind farm insallations (output due in the December 2020 PET report). The minimum operating output of a wind farm can be allowed for in how it is utilised if required.	

Table A5.2
Issues Register – DER resilience

July 2019					July 2020	
Category	**No.**	**Description**	**Black Start DER challenges**	**Status**	**Mitigation**	**Status**
DER Resilience	**DR1**	Varying capacities, and sustainability, of auxiliary backup supplies. Some battery backup only. Others limited standby gen (e.g for essential services and/or to protect the turbine).	Auxiliary power required to maintain availability of gen (e.g protection, comms, keep boiler warm) and to be able to self start (typically 10–15 per cent of MW rating required).		Case studies have identified the self-starting auxiliary power required for anchor generators. This can be provided by gas or diesel generators (and potentially other sources such as batteries in the future). Steam generators have the largest auxiliary power capacity requirements (10–15 per cent of rating) which will include motor starting. Hydro and gas generators typically require 5–10 per cent. There is no issue providing this, it is just a matter of cost and capacity.	
DER Resilience	**DR2**	Generators utilising a combustion process (e.g EfW) must control their operation (e.g ramp rates) to keep within emissions limits.	The operation required for Black Start (or the project live trials) may result in the generator emissions limits being exceeded.		Initial discussions have been held with the appropriate environmental agencies with a view to discussing the derogations which may be required for the live trials, periodic testing if providing a Black Start service (especially starting and low load operation), and during a Black Start itself. Derogations are uncommon and thus this risk has been left at amber at present.	
DER Resilience	**DR3**	Fuel stores are typically in the order of several days. For some, ash disposal may be an issue after several days.	A suitable resilience timeline for DER types will need to be defined.		Case studies are ongoing to determine the existing capacity and what can realistically be achieved in terms of sustaining continuous output with on site supplies. Results to date would suggest that ~3 days, operation is currently achievable and may be increased to 5 days if required with additional resource stockpiling.	
DER Resilience	**DR7**	Wind turbines receive their auxiliary supplies (e.g for heating) from the incoming 33kV supply. After ~6 hours, outage the gear box oil may have cooled too much to allow restarting (depends on ambient temperature).	If the DNO connection is not restored to a wind farm within ~6 hours, it may take days to restart due to the turbines having to be individually pre-heated.		Consultants have been commissioned to determine the technical capability/resilience of wind farm installations (output due in the December 2020 PET report). Mitigation options include seeking to energise a wind farm array as soon as practical in a restoration strategy or installing auxiliary power which can energise the turbine 33kV arrays to keep the turbine heaters supplied.	
DER Resilience	**DR4**	A licence condition of certain generators is that they do not discuss Black Start in public documents (e.g planning applications).	A DER may have to make modifications for Black Start which would normally require public disclosure of the reason.		Issue to be investigated by Procurement and Compliance workstream.	
DER Resilience	**DR5**	A DER receiving Renewable Obligation Certificate (ROC) payments requires Ofgem approval to any changes to their electrical single line diagram (SLD).	Changes to a DER SLD may be required to make them resilient and self-starting.		Issue to be investigated by Procurement and Compliance workstream.	
DER Resilience	**DR8**	A hard trip (not ramping the output down) stresses the wind turbines and they are then more prone to faulting and not reconnecting.	The relative voltage and frequency instability of a power island may result in a wind farm disconnecting more often.		Initial DRZ-C designs propose that a wind farm output is controlled by providing it with MW output setpoints. No planned hard trips are anticipated (unplanned may still occur due to network/equipment faults).	

Table A5.3
Issues Register – Earthing and distribution island operation

July 2019					July 2020	
Category	**No.**	**Description**	**Black Start DER challenges**	**Status**	**Mitigation**	**Status**
Earthing	**E1**	The 33kV network will be unearthed if the grid transformer L.V circuit breakers are open. In addition, the location of the earthing transformers does not comply with the ESQCR when the network is energised from a DER remote to the grid substation.	An alternative means of earthing the 33kV network will be required if a 33kV power island is to be established.		Design works have determined that an earthing transformer will require to be installed at the site of the anchor generator, and have the facility to be switched in and out of service.	
Protection	**P1**	There may be insufficient fault level for existing protections to operate adequately for a distribution power island.	The protection will need to be able to detect and clear faults before the network can be energised from DER.		Detailed protection assessments have been (and are being) carried out on several case studies to determine issues with existing protections and what mitigation is required (e.g. change of protection settings). Viable protection solutions have been proposed for the distribution network when supplied by DER only. Further work is required to determine whether protections on the 275kV and 400kV network can be adapted.	
Earthing	**E2**	The Rise of Earth Potential (RoEP) may increase at the grid substation with an earthing transformer fault infeed from a remote generator site.	Safety is required to be maintained at the grid substation.		Protection consultants have confirmed that this will not be an issue.	
Earthing	**E3**	The 33kV generator earthing transformer should not be operated in parallel with more than one grid earthing transformer.	It is unlikely that expansion of a 33kV power island would involve more than one grid transformer connected to that network.		Restoration plans will ensure only one grid transformer is switched in service at any time when the anchor generator earthing transformer is in service.	
DIO	**DIO 1**	A distribution power island will have a low fault level relative to normal operation.	Existing protection may not be able to detect faults/operate quickly enough. Voltage disturbances will be greater, causing unwanted protection operations. Converter-connected generation may not be able to connect or remain stable.		Protection issues have been studied and viable mitigations proposed. Strathclyde Uni have been commissioned to report on the issues with grid-forming converter stability. This is a current industry issue which is being researched by manufacturers and academia.	
DIO	**DIO 2**	System oscillations.	Oscillations between power, voltage and frequency can occur on a closely coupled distribution power island.		Electromechanical oscillations have been studied in the case studies and some potential issues were identified although not all plant data was available. Electromagnetic oscillations can only be captured through an EMT simulation i.e. any oscillations due to improper tuning of controllers (anchor gen, wind) under weak grid conditions. Ideally EMT studies and Modal analysis, with actual WF controllers or standard models, will be used to carry out sensitivity analysis.	
DIO	**DIO 3**	Lack of human resources (DNO control engineers and DER personnel) to establish and maintain distribution power islands and associated restoration times with only manual intervention.	Design a level of automation into the Black Start from DER process that makes it viable with existing human resources but also results in a safe and manageable system.		This issue will be considered by the Organisational, Systems and Telecoms workstream.	

Table A5.4
Issues Register – Distribution island operation and resilience

July 2019					July 2020	
Category	**No.**	**Description**	**Black Start DER challenges**	**Status**	**Mitigation**	**Status**
DIO	DIO 4	Block load capability of DER in power island.	The block load capability of DER (due to low system inertia) may not be sufficient to pick up the demand of a primary substation. Additional 11 kV switching may be required to reduce the demand block size which may not be viable operationally and completed within exceptable timescales.		System studies have been undertaken to identify the block loading capability of the three main synchronous DER types on the network (steam, hydro and gas). Results have shown that some larger DER may have sufficient capability to restore demand on its own (providing the load can be split into small enough blocks) but others do not have sufficient capability. Works has been commissioned for the design of a Distributed ReStart Zone Controller (DRZ-C) with one of the primary requirements to coordinate other resources (such as loadbanks or batteries), to enhance the block load capability of the anchor DER.	
DIO	DIO 5	Low system inertia.	A generation/load imbalance will cause larger frequency changes due to low inertia.This will result in a more severe test of the generator's governors than with intact system conditions.		The functional design for a DRZ-C has been commissioned with another of its tasks being to maintain the generation/load balance in a low inertia system by coordinating and controlling available resources.	
DIO	DIO 6	High variability of load and generation (particularly solar).	It may be hard to maintain a stable frequency in a power island where the demand and intermittent generation resources are much more variable on a power island.		The DRZ-C will be used to manage the variability of resources on the island to mainatain stable operation. In addition, intermittent resouces may be curtailed to provide a higher degree of stability of output. It is proposed to carry out studies to ascertain the level of curtailment for wind and solar that would be applicable to give an acceptable certain consistency of output.	
DIO	DIO 7	Power island 33kV voltage control	When operating a 33kV power island there will be no direct way of monitoring or controlling the 33kV voltage.		Studies have shown that the 33kV networks are unlikely to require fast acting voltage control. The anchor generator voltage output can be set such that an acceptable voltage profile is obtained throughout the network for all loading scenarios. In addition, the DRZ-C could control the anchor generator or other resources if, for a specific case, dynamic voltage control is required.	
RES	R1	The protection and SCADA at substations is dependent upon batteries which have variable resiliences from ~18 hours to 72 hours.	A substation may not be safe to energise at the required time after a Black Start if the protection and SCADA was not available.		A project assumption has been made to design to 72 hours resilience (i.e. it may be up to three days before DER or network is energised for Black Start services). This level of resilience will likely be installed under current DNO policies (e.g. 72 hour batteries) and where it is not it can be retrofitted for Black Start from DER.	
RES	R2	It may only be possible to close a circuit breaker at a substation once after which there will be no LV supply to recharge the closing springs.	A circuit breaker is closed as part of a power island restoration plan. If the power island collapses, or the circuit breaker has to be opened to shed load, it may not be able to be reclosed.		The restoration strategy will be such that the secondary substation supplying the primary substation LV supply will be energised first.	
RES	R3	If there is no LV supply at a transformer substation the transformer tap change motor will not operate.	When a transformer is energised, its LV voltage may be out with satisfactory limits and if high voltage may cause damage to equipment.		In this report multiple options for energising primary transformers have been discussed with guidance given on selecting the optimum option to reduce the probability of any high voltages, and restore supply to the transformer tap change motor as soon as practical (see section 2.4).	

Table A5.5
Issues Register – Network system studies

July 2019					July 2020	
Category	**No.**	**Description**	**Black Start DER challenges**	**Status**	**Mitigation**	**Status**
Network System Studies	**S1**	Opening circuit breakers to create restoration paths and reduce block loading in SPM.	Most of the SPM network is highly meshed, with interconnection at all voltage levels. This can pose challenges when opening circuit breakers to create restoration paths. Moreover, primary substations (33/11kV) share the same interconnected network at lower voltages (11kV and LV) in normal operation.		Splitting the 11kV and LV meshed network by establishing multiple open points in the primary group prior to the Black Start would ensure that the size of the block loads is reduced to the capacity of primary transformers, reducing the impact on the DER. The SPM network is ~20 per cent radial, 40 per cent meshed (Y type) and 40 per cent meshed (X type). Analysis of the network has shown that the Y type network (not as highly meshed as X type) may be practical to split into sufficiently small block load sizes. If the primary groups cannot be practically split, then solutions to take on larger block loads consistent with the full primary group load need to be identified. One of the proposed functions of the DRZ-C is to coordinate multiple DER and resources to enhance the anchor generator block load capability.	
Network System Studies	**S3**	High voltages on the 11kV side of a primary (33/11kV) transformer of energised open circuit.	Prior to a blackout, the primary transformer may have been heavily loaded and the tap changer will have tapped to a position to keep the 11kV voltage within acceptable limits. If the transformer is then energised without the load, studies have shown that the open circuit 11kV voltage may be up to 10 per cent above nominal. There will also be no local LV supplies available to power the tap change motor and reduce the voltage.		In the system studies multiple options have been identified to energise a primary substation, and these take into account the potential 11kV voltage violations which may ensue. When demand is reconnected to a primary substation, the voltage should not exceed 11.25kV to ensure the LV voltage does not exceed the statutory limit of 253v. If a primary transformer is energised along with the load, initially customers may experience high voltage if the load is less than the load just prior to the blackout (as the transformer tap on a position is set for a higher demand). If a primary transformer is energised with no load, as noted a worst case +10 per cent high 11kV voltage will be recorded. This would not affect customers but is the limit of switchgear insulation. Section 2.4 of this report discusses the primary substation restoration strategies available with guidance given on the optimum strategy to minimise the risk of over voltages, and when automatic restoration may have to be inhibited.	
Network System Studies	**S2**	Insufficient reactive power in the power island which can generate voltage exceedances.	DERs may not have sufficient reactive power capability to sustain the growth of the island and to maintain voltages within the acceptable limits.		System studies have shown there are no voltage issues caused by a lack of reactive power resources in the case study networks. The ability of an island to energise the transmission network may be limited by the capability for the DER network to absorb Mvars and on the voltage profile at the interface point even if we have capability to absorb Q it doesn't mean we can. As part of the system studies the MW/Mvar capability of a distribution island to energise the transmission system has been identified. This can be enhanced as required by methods such as installing reactive loadbanks/compensation, increasing the number or capability of DER and optimising restoration strategies.	
Network System Studies	**S4**	High voltage step changes.	High voltage step changes may occur in weak systems such as power islands.		The power system studies in this report have identified potential transient over-voltages when energising 132kV circuits. Mitigation measures are proposed (e.g. energising the network at a reduced voltage level).	
Network System Studies	**S5**	Voltage dips due to transformer energisation.	Due to low fault levels in the power island, voltage dips may occur during transformer energisation.		Power system studies, on three case studies, have identified some excessive voltage dips associated with energising transformers with voltages greater than 33kV (e.g. 132/33kV, 400/275kV). In addition, energising some primary (33/11kV) transformers, which are connected by very long 33kV circuits (~40km), have recorded voltage dips of ~20 per cent. This will require further investigation. This issue may be mitigated by actions such as reducing the voltage levels (but still within acceptable limits prior to transformer energisation, or ramping up the voltage (soft starting) which can elininate inrush currents).	

Appendix 6: Table of abbreviations

Acronym	Definition
AVC	Automatic voltage control
AVR	Automatic voltage regulator
BESS	Battery energy storage system
BS	Black Start
BSP	Bulk supply point
DER	Distributed Energy Resource
DNO	Distribution Network Operator
DRZ	Distributed ReStart Zone
DRZ-C	distributed restart zone controller
EfW	Energy from Waste
EHV	Extra High Voltage
EMT	Electromagnetic transient
ER	Engineering Recommendations
ESQCR	Electricity Safety, Quality Continuity Regulations
f	Frequency
GSP	Grid supply point
GT	Grid transformer
HV	High voltage
LPS	Large power station
NETS	National Electricity Transmission System
NGESO	National Grid Electricity System Operator
NGET	National Grid Electricity Transmission
OLTC	On-load tap changer
PLL	Phase-locked loop
POW	Point on wave
PET	Power engineering and trials
PV	Photovoltaic
RoCoF	Rate of Change of Frequency
SCADA	Supervisory Control and Data Acquisition
SGT	Super grid transformer
SHET	Scottish Hydroelectric Transmission
SLD	Single line diagram
SPD	Scottish Power Distribution
SPEN	Scottish Power Energy Networks
SPM	Scottish Power Manweb
SPT	Scottish Power Transmission
WF	Wind farm

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