Distributed ReStart

Power Engineering and Trials

Assessment of Power Engineering – Aspects of Black Start from DER

Part 2 – December 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 and Trials (PET)** workstream is concerned with assessing the capability of 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 and 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 and 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.

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Executive Summary

This report is the second part of an *Assessment of Power Engineering Aspects of Black Start from DER* (the first part having been issued in July 2020). Overall, it is the third deliverable of the PET workstream. The content of this report covers three main areas, automation, business as usual (BAU) implementation and system studies.

The primary focus of this report is the initial development of a truly innovative, world-first, automation system (Distribution Restoration Zone Controller (DRZ-C)) to overcome the technical and human resource limitations associated with Black Start from DER. In addition, the functional requirements for an anchor generator have been developed, an assessment undertaken on the potential for GB rollout of a Black Start from DER service, and the proposed testing requirements of this service are presented. System study work covering the areas of network protection and system energisation is also considered.

DRZ-C

- This report presents the generic functional requirements for a DRZ-C System. The requirements have been derived from DRZ-C functional designs proposed by several companies who are each technology providers and industry experts in the development of wide area control systems within the power systems domain. The functional requirements of the DRZ-C System, distribution and transmission systems and DER are each included.
- Chapter 3 provides functional designs associated with key DRZ-C capability (for example the sub second response required to enhance an anchor generator block load capability). The content provided covers a wide range of functionality required of a DRZ-C. Where applicable, different examples of how the capability could be implemented in practice are given. The project does not intend to dictate how a DRZ-C should be designed, but to show viable alternatives of how the industry experts have proposed to approach the use case. Discussion provides insight/analysis relevant to the presented content.
- It is believed that the DRZ-C designs provided show that the required control and coordination functionality is credible. Stage 2 of the DRZ-C works will test one or more of the DRZ-C Systems within a lab-based environment to demonstrate feasibility in advance of any potential live network trials. The provided requirements may be adapted following learning from lab testing.

Functional Requirements – Anchor Generator

The functional requirements of an anchor generator (the DER used to initially energise the network), have been developed with reference to:

- the technical requirements for the existing Black Start service
- the capability of existing synchronous DER
- the emerging technology of Grid-Forming Converters (GFC)
- the specific requirements of an anchor generator within a Distribution Restoration Zone (DRZ).

Key requirements include the time to connect being increased from 2hrs at present (for large power stations) to 8hrs allowing for DER specifics such as staff to travel to unmanned sites. To be as inclusive as practical, some categories have been based on generic capabilities (e.g. G99 voltage and frequency control requirements). Other categories state a minimum requirement, but request that any enhanced capability is notified. The proposed functional requirements will be amended as required based on stakeholder engagement, and as the technical requirements of a DRZ are further developed.

Potential across GB

An estimation of the potential for concept rollout of Black Start from DER across the DNOs in GB has been undertaken using information published within the November 2019 Long Term Development Statement (LTDS) from each DNO. A summary of the synchronous and non-synchronous generation currently connected to the distribution networks is given in the following table. The 11kV and 33kV synchronous generators may be used as an anchor DER (initiate the energisation of the network), with the 132kV DER and non-synchronous DER used to stabilise and expand the DRZ as required.

	Synchronous Generators			Non-Synchronous DER (wind, solar...)		
	Anchor DER 11kV (>10MW)	Anchor DER 33kV	132kV synchronous	11kV (>10MW)	33kV	132kV
Capacity (GW)	1.2	4.8	3.7	0.8	12.0	2.3
No. of individual generators	65	283	26	46	876	31

The total required Black Start capacity for GB is around 18GW which has traditionally been provided by transmission connected resources. The analysis of the 2019 LTDS data shows that there is a total of ~6GW of potential synchronous generation connected at 33kV and 11kV in 339 out of 1045 distribution grid areas. In other words, 32% of all distribution grid areas in GB are potential DRZs that have anchor generation. In addition, there is 12.8GW of non-synchronous 33kV and 11kV connected DER that could support Black Start system restoration. In 2018 there was only ~5GW of synchronous generation and ~12GW of non-synchronous generation connected at 33kV and 11kV, and so it's clear that the potential for Black Start from DER continues to grow.

DRZ Testing Requirements

We present our current proposals for the testing regime that might be implemented with Black Start from DER services. We identify the multiple objectives that testing must satisfy, noting the peculiarities of Black Start compared with other services and highlighting that the purpose is to achieve good outcomes for all parties. We propose approaches and specific physical tests that are similar to what is currently used but reflect the differences in Distributed ReStart, including the much larger number of parties involved, the greater role of DNOs, and the use of a DRZ-C System.

The different stages of DRZ development and the implications for testing are discussed, from conceptual design and feasibility assessment through to ongoing change management. Issues discussed include the challenges of outage planning, new requirements in distribution network modelling and simulation, and methods that may not be appropriate in the early years of rollout but may be adopted as the DRZ concept matures and becomes more widespread. As with other aspects of our solutions, our proposals for testing will be refined based on the live trials and desktop exercises in 2021.

System Studies – Protection (11kV and LV Fuses)

In a DRZ the fault level will be dependent upon the fault infeed from the DER and will be significantly lower than under normal intact network conditions. A key requirement is to identify the minimum network fault levels required for satisfactory protection operation, to ensure there is enough infeed from the DER. The purpose of this study is to identify the minimum source 33kV fault level required (at the HV terminals of a primary 33/11kV transformer), to ensure that secondary substation (11kVV/415V) 11kV fuse protections, and 415V network fuse protections, will operate satisfactorily. There is no practical method to alter the operating value of these protections.

Key findings were that the minimum source 33kV fault levels required vary significantly depending on the 11kV feeder types (e.g. overhead line or underground cable) and lengths. Typically, an 11kV overhead line feeder would be a maximum of 30km. The studies showed that this would require a source fault level of 30MVA (for 20km it would be 16MVA). The 33kV source fault level required increases significantly (between 140–150MVA) if the 11kV circuit length is increased to 40km.

System Studies – Energisations

Transformer energisation voltage dips are not expected to pose a problem to the anchor generators unless they have a particularly conservative under voltage protection setting. Typical worst case voltage dips observed were ~80% retained voltage with a 160ms duration which is unlikely to be an issue for generator protections.

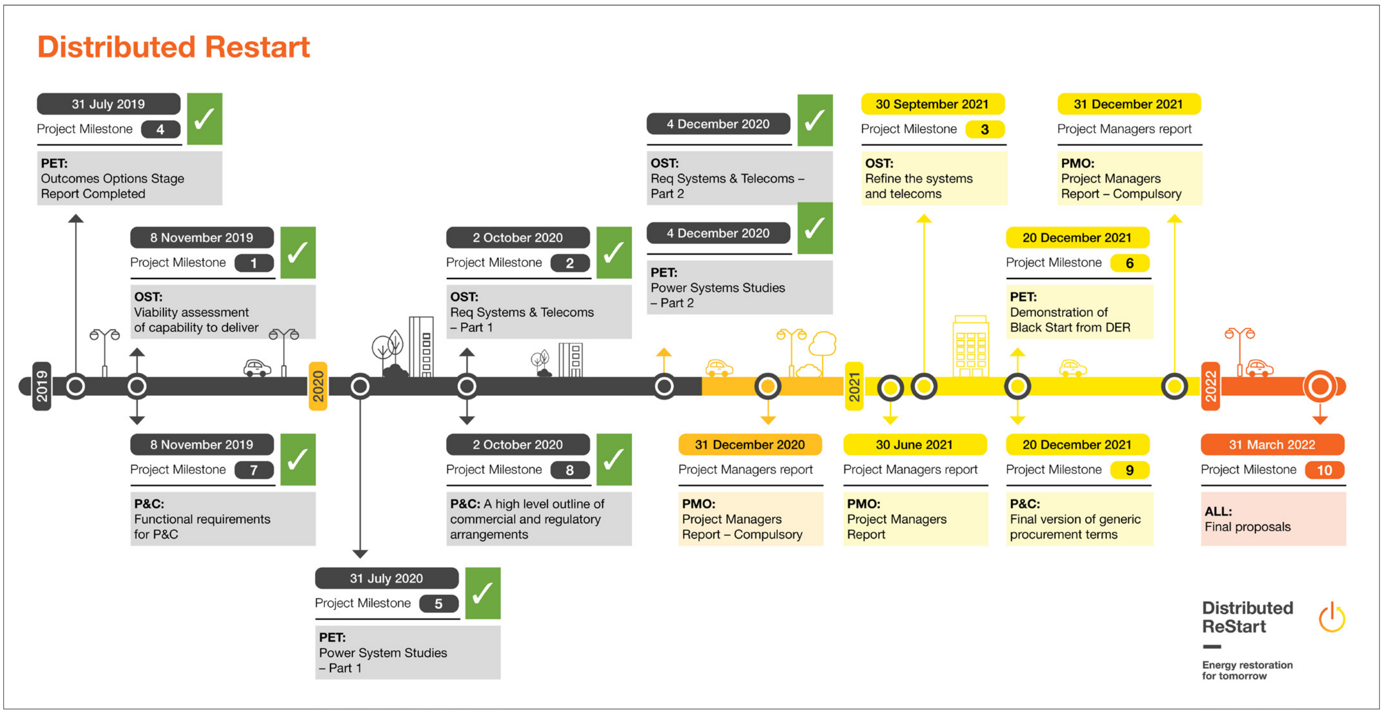
Simultaneous energisation of a grid 33kV network, including all primary (33/11kV) substations (without demand connected) and wind farm array cables, can lead to high switching transients. This was simulated for the Chapelcross case study network and the observed voltage transients across the network were found to all be within the IEC 60071 insulation coordination limits.

Unbalanced circuit energisation can lead to significant voltage unbalance (higher than the ER P29 limit) at the generator terminal but for a short duration. This should not cause a problem unless the unbalance lasts longer than the negative phase sequence protection setting of the generator.

An induction motor starting study (3MW connected at 132kV) showed that as long as the anchor generator and other DER have a combined reactive power capability of at least five to six times the motor rating, and the voltage at the motor terminal does not go below 80%, it should not be a challenge for a generator of any active power size to start the motor.

Energising transmission circuits is dependent on the capability of the anchor generator to absorb the reactive power generated by the circuit. However, the steady state voltage rise at the far end of the circuit might be the limiting factor in energising 275kV and 400kV transmission circuits. For example, for a 400kV line, the maximum length that can be energised before reaching the voltage limit is around 20km and requires roughly 16MVAr of reactive absorption capability. If available, reactive compensation equipment can be used to absorb the MVArs generated by the circuits to reduce the voltage rise.

Project Milestone Timeline



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. Introduction

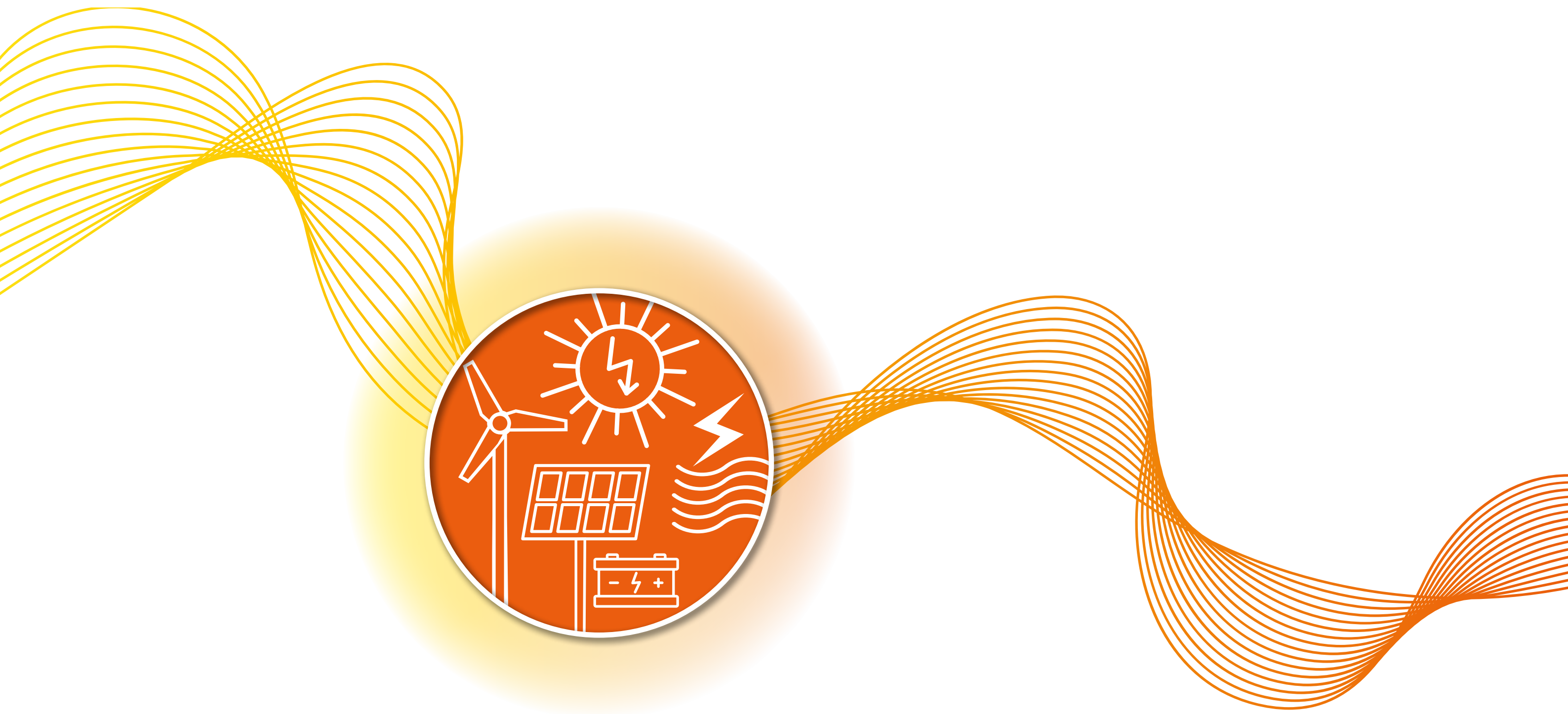
This report focuses primarily on the initial stage of development of an automation system in the form of a DRZ-C, followed by considerations relating to the GB wide rollout of Black Start from DER, and then the most recent system study work.

In Chapters 2 and 3 the system requirements for a DRZ-C are presented, followed by a description of the generic functional design, including examples from different technology providers of how the functionality may be implemented in practice.

The next section of the report (chapters 4 to 6) relate to the BAU rollout of Black Start from DER. The proposed functional requirements for an anchor generator are given, followed by proposals for testing the Black Start from DER service. An update is then given on the capacities of DER currently connected and contracted to connect to DNO networks across GB, and an assessment made of the potential for GB rollout in terms of GW capacity, numbers of DER and potential DRZ sites.

The ongoing work in the area of system studies is then presented (chapters 7 and 8) looking at the minimum fault levels required to operate fuse protections both on the 11kV and LV network, followed by a selection of system energisation studies to cover specific network restoration scenarios (e.g. motor starting).

In the Next Steps section (chapters 10 and 11), the ongoing work relating to DER operability and stability challenges is discussed, along with an overview of the work being undertaken by The National HVDC Centre which includes Real Time Digital Simulation (RTDS) network energisation studies, and Hardware in the Loop (HiL) testing of the DRZ-C.



2. DRZ-C System Requirements

2.1 Introduction

This chapter presents generic functional requirements of a monitoring and control system required to automate the processes of establishing, maintaining and growing a Distribution Restoration Zone (DRZ). The requirements are focused on the DRZ Control (DRZ-C) System, but also include requirements associated with other systems on which the DRZ-C System is dependent, such as National Grid ESO/Distribution Network Operator (DNO), Distribution Management Systems (DMS)/Energy Management Systems (EMS) and supporting DER.

The functional requirements and example designs provided in this chapter are primarily based on the outputs from the Feasibility and Design stage of the DRZ-C work package, this work package is introduced in section 2.1.2.

The aim of this chapter is to provide industry with the functional requirements for a DRZ-C System and provide DRZ-C designers with examples of how key functions of a DRZ-C System could be designed.

The remainder of section 2.1 provides context to the requirements and example designs that follow in later sections.

2.1.1 DRZ-C Terminology

This chapter introduces the terminology of a DRZ-C System, rather than simply a DRZ-C. This change is intended to clarify that the automated control scheme required for the Black Start from DER use case is a wide area distributed control system rather than a standalone single logical or physical unit.

Throughout this document the DRZ-C term is occasionally used as a shorthand to describe capability of the overall system.

Design Focus

Since the Distributed ReStart use case and the associated control system is a new initiative for the industry some aspects of the functional design are novel, such as the frequency management functions described in section 2.1.4. As a result, the focus of the design efforts has been spent examining those novel areas. This document presents a comprehensive set of requirements (functional and non-functional) which would be required for a 'Business as Usual' (BAU) DRZ-C solution.

Requirements Identification

This section describes the methodology adopted to identify the requirements and provides other relevant context to the generic requirements provided in section 2.2.

Four technology companies[1] were engaged to propose the functional design of a DRZ-C. Broadly, the proposed solutions comprised primarily of their own technology products enhanced with new functionality as required. To determine general functional requirements, each proposed DRZ-C design was reviewed to determine functionality essential for a viable DRZ-C solution that might be applicable in the wide range of conditions found across GB. The functional requirements are generic and therefore suitable for all DRZs. The requirements define the required functional capability of a DRZ-C but do not dictate or recommend any aspect of how a DRZ-C should be implemented.

Each of the four DRZ-C companies approached the design task differently; some companies attempted to match existing product capability to the Distributed ReStart use case, whereas others developed a bespoke design from the ground up. Ultimately the essential generic functional requirements are common between the designs and the variety in design/approach is more relevant when considering a specific design and implementation of a DRZ-C. In some cases the DRZ-C companies proposed a unique design with a specific function however the associated functional requirement is common to all designs, and it is that requirement that is presented in this chapter. The requirements presented in this chapter may be adapted and re-published in a later project deliverable based on learning from the Implementation and test stage of the DRZ-C works, where one or more solutions will be implemented and tested in

[1] GE Grid, ZIV Automation, Schweitzer Engineering Laboratories (SEL) and Smarter Grid Solutions (SGS) all participated.

hardware form within a lab based HiL environment.

The requirements are focused on the functional capability of the DRZ-C System and supporting systems. To deploy any DRZ-C solution non-functional requirements specified by National Grid ESO or the host DNO must also be satisfied. In an attempt to provide a holistic requirement set for a DRZ-C System, a non-exhaustive set of the non-functional requirements are provided in section 2.2.10.

The OST workstream is considering implications of telecoms and cyber security aspects on DRZ-C design/rollout therefore those topics are discussed in more detail within the OST Design Stage II report[2].

The functionality capability of DER (and associated indicative data schedule) required by the DRZ-C is provided separately in section 2.3.

2.1.2 DRZ-C Development Stages

In the Distributed ReStart project, the development and demonstration of the DRZ-C System is currently planned in two stages (this report contains the output of stage 1).

Development Stage 1: Feasibility and Design

The first stage explores the feasibility of automating the restoration process.

The project engaged with several external companies to support Development Stage 1. The companies involved are recognised industry experts in the domain of power system automation and wide area control systems. They were contracted to propose a functional design for a DRZ-C System that automates the restoration of a distribution power island. The restoration stages (provided in section 2.1.3) were issued to the companies as a guide to identify the control scheme functionality which could be required. The Development Stage 1 process produced several proposed DRZ-C designs, which were used to identify the essential generic functional requirements and the design examples presented in this chapter. Development Stage 1 was completed in October 2020.

Development Stage 2: Implementation and Testing

Following completion of Development Stage 1, one or more DRZ-C solutions will be implemented and tested within a HiL test environment. Development stage 2 will demonstrate how a DRZ-C would operate in real time, interacting with a simulated network and DER to show how it would maintain the power island within acceptable limits of under/over frequency, Rate of Change of Frequency (RoCoF) rates, voltage limits and other identified performance criteria during normal and abnormal operating conditions. Development stage 2 is expected to begin in early 2021.

2.1.3 DRZ-C Scope

The high-level objective of the DRZ-C is to support energisation and growth of the DRZ to provide a working Black Start capability that can restore customer load as quickly as possible and support restoration of the wider system while operating the network and DER assets within acceptable limits.

To support the initial DRZ-C design process, we identified six main stages of restoration, and key actions associated with each, as listed below. This should not be considered as a firm specification, but merely a starting point to support development of the DRZ-C concept and workable designs.

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

- Provide generator start signal to the anchor DER.
- Supervise ramp up and stabilisation of the anchor generator power (using load/battery resources as necessary).
- Energise a prearranged skeleton network, protecting the anchor generator from disturbances as appropriate (this may be done through a series of energisation steps or it may be appropriate to implement a soft energisation of the anchor generator together with an area of network).

[2] *Organisational, Systems and Telecommunications – Design Stage II* (December 2020).

Stage 3: Power Island Expansion

- Step-by-step energisation of more of the network to restore auxiliary supplies to substations, restore supplies to customers 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: Transmission 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.

2.1.4 DRZ-C Role

This section provides further context to the anticipated role of the DRZ-C System and the functional requirements in section 2.2.

Organisational Context

Figure 1 illustrates the systems that will or could participate in the DRZ-C System and the data interfaces that define the relationships between these systems. Where there is human operator interaction this is also represented, e.g. the DSO control room operator. The context may alter to some degree when considering specific DRZs, i.e. there may or may not be existing distribution control systems (e.g. Active Network Management (ANM)). Interfaces are presented in a simplified manner, highlighting source and destination of information exchange; note that the practical means of transfer may be through another Black Start compliant system, i.e. via the DSO DMS, by phone, text, email etc and in general information transfer will be two-way. The context diagram is not intended to show the communication routes or relate directly to system architectures.

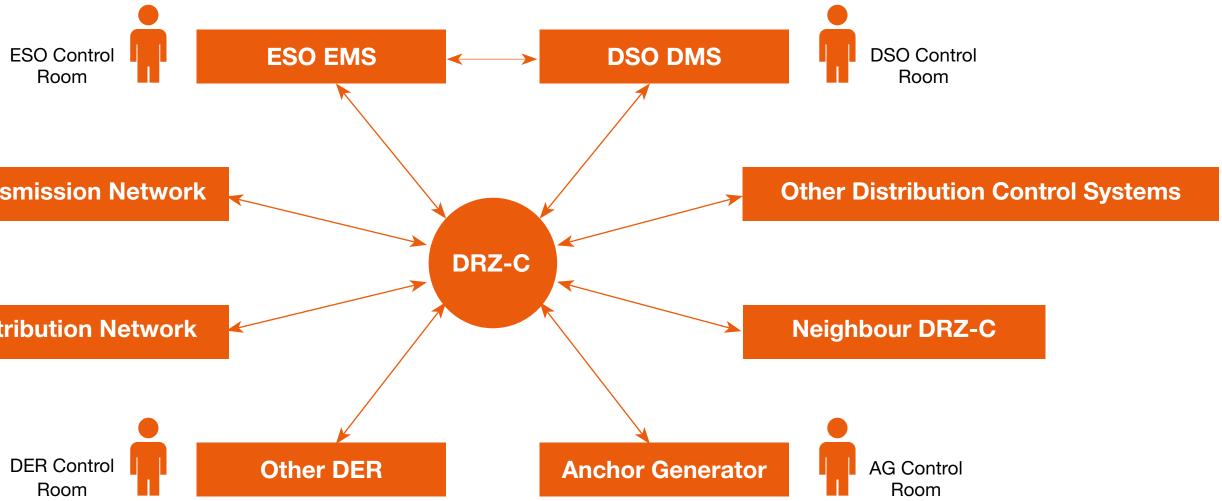


Figure 1: Context of DRZ-C System within existing OT/IT infrastructure

Functional Role

There are four key processes performed and supervised by the DRZ-C.

Fast Balancing: Detects significant disturbances within the island (due to planned or planned events), estimates the island power imbalance and triggers a balancing action using the flexible MW demand (e.g. load bank/ Battery Energy Storage System (BESS).

Slow Balancing: Monitors the loading of all DER and initiates rebalancing such that anchor generator and load bank/battery return within the desired margins, which ensures there is always resource to perform fast balancing.

Wider Network Synchronisation: Supervises and supports the anchor generator synchronise the DRZ with a wider network. Once synchronised the DRZ-C provides real and reactive power services to the control room.

Wider Network Energisation: Co-ordinate the control modes of the anchor generator and all DER to prepare for energisation of the wider network. The DRZ-C reports to the control room the real and reactive power resources before, during and after the energisation process.

Frequency Control

The DRZ-C must manage the frequency of the DRZ as it is energised, loaded, run as an island, resynchronised and restored to normal operation. The power island is likely to have very low inertia and frequency will be very sensitive to changes in load and generation. There is inherent uncertainty in the volume of load picked up and the variations of load and renewable generation, and combined with low inertia, this leads to the risk of highly variable frequency. This is mitigated by the DRZ-C System which applies a supervisory control to apply fast actions to rebalance the system in response to load pickup and unplanned trips of load or generation, as well as slower balancing actions that keep the frequency close to 50Hz and frequency regulation within the control band. The DRZ-C manages the island operation up to and including the resynchronisation process.

Voltage Control

The voltage within the DRZ will fluctuate significantly during the restoration process, particularly when energising long sections of network and primary/grid transformers. Based on system studies performed on the case study network areas it is anticipated that the transient voltages will not be problematic or would be more suited to be mitigated by modifying the restoration process (e.g. energising with reduced voltage to avoid any transient over voltages, or point of wave circuit breaker closing to minimise inrush currents).

Steady state voltage deviations within the 33kV network can typically be maintained within acceptable limits by the voltage regulation capability of the anchor generator and can be supplemented by supporting DER (most likely operating in voltage control mode with a droop) if required. The voltage profile on the 33kV network is not a primary concern as the primary transformer (33/11kV) tap changers will operate to ensure the 11kV voltage is within customer limits. It follows that the DRZ-C will not be typically required to intervene to manage voltage. However, there may be some specific DRZ network scenarios where the DRZ-C is required to play an active role to manage voltage.

Operational Limits

A key input to the DRZ-C design process and operational deployment is a definition of acceptable limits of frequency and voltage during the restoration process. Ultimately the operational limits assumed by the DRZ-C solution must be configurable, however as a reference, and a basis on which to design the DRZ-C solution, the DRZ-C companies were requested, to design a system to operate within the frequency and voltage limits as specified within ENA Engineering Recommendation G99.

Operational limits are critical to define the volume and speed of response of frequency balancing and regulation capability, and the amount of load that can be picked up. It is also important for security against unplanned events. The limits are derived from G99 with further margins for stable operation.

ENA Engineering Recommendation G99 lists the protection requirements in Table 1 for distributed generation types A/B/C/D, covering power generation modules up to 50MW. Since all DER should withstand the G99 conditions, the values in the recommendation are a generalised requirement. There may be islands where maintaining these levels is impractical and protection can be set to wider limits during the islanded state (though there must be frequency protection), but in these cases it is necessary to consider the wider effects on distributed generation stability of operating outside the G99 limits. For example, the capability of Phase Locked Loops (PLL) of smaller renewable generation may be limited to certain frequency and RoCoF limits, and thermal generation may have physical turbine limits.

Protection Function	Trip Setting	Time Delay Setting
Undervoltage (U/V) Stage 1	0.85pu	3.0s
Undervoltage Stage 2	0.6pu	2.0s
Overvoltage (O/V)	1.1pu	0.5s
Underfrequency (U/F)	48Hz	0.5s
Overfrequency (O/F)	52Hz	1.0s
Loss of Mains (LoM) (RoCoF)	1.0Hz/s	0.5s

Table 1: G99 settings for DER long-term parallel operation (reproduced from ENA G99)

RoCoF

It would be possible to disable loss of mains protection during island operation, however this is not advised. Disabling LoM protection would leave the DER generators exposed to isolated operation and over/underspeed. It would add to the complexity of the transition between island and grid-connected operation. Furthermore, operating within the G99 requirements ensures that equipment runs within boundaries for which it has been tested. The DER response to wider frequency and RoCoF excursions outside the connection requirements with protection disabled may be untested in live environments with uncertain outcomes.

Frequency Limits

It is assumed that Under Frequency Load Shedding (UFLS), commonly installed at a 33kV grid substation to disconnect primary substations, and Over Frequency Generation Shedding (OFGS) can be disabled or set to wide limits for the island operation period, so the relevant limits are also related to DER G99 recommendations. As listed in Table 1, under- and over-frequency are 48Hz (0.5s delay) and 52Hz (1s delay) respectively.

Chapter 3 provides examples of functional designs associated with key DRZ-C functional requirements presented in this chapter.

2.2 DRZ-C System Generic Requirements

Provided below are a list of generic functional and non-functional requirements for the DRZ-C System. The requirements are grouped into several sections.

2.2.1 Island Control

General

- The DRZ-C System should be able to balance demand and generation to maintain stability of the DRZ.
- The DRZ-C System should maintain voltage stability within defined limits which should be configurable.
- The DRZ-C System should maintain frequency stability within defined limits which should be configurable.
- The DRZ-C System should be capable of simultaneously managing multiple DER that may comprise of different technologies.
- The DRZ-C System should be able to manage DER in a variety of different operating modes according to the capability of each DER (e.g. PV, PQ, Frequency sensitive control).
- The DRZ-C System should be able to issue a range of set points and other control parameters directly to participating DER.
- The DRZ-C System must support simultaneous control of active and reactive power.
- The DRZ-C System must be capable of supporting manual intervention in combination with automatic control of available resources.
- The DRZ-C System should be configurable for different network configurations.

Fast Balancing

- The DRZ-C must be capable of taking an active role to co-ordinate the anchor generator and other DER resources to ensure that there is sufficient fast balancing response (both pickup and drop-off) available to maintain the generation/load balance of the island when subject to credible disturbances.
- The DRZ-C must continually monitor the stability of the island to detect any disturbances which cannot be managed with the anchor generator/DER and therefore require the DRZ-C to execute a fast-acting mitigating control action.
- If the DRZ-C is unable to restore frequency within the island (e.g. either a fast frequency resource didn't deliver the service as expected, or there wasn't sufficient fast frequency resource at the time of the event) the DRZ-C should take all action necessary to ensure that the anchor generator remains energised and connected to the network.
- The DRZ-C must determine there is insufficient fast response resource to respond to credible disturbances (e.g. block load, energisation steps, DER/feeder trip). This alarm should be raised immediately when the deficit is identified and not post-event after the disturbance has occurred.
- The DRZ-C must capable of restoring frequency of the DRZ within agreed limits under credible conditions of demand variability. The credible conditions will be determined by DSO/National Grid ESO for each DRZ and therefore dictate the required frequency response resource reserves.

Slow Balancing

- The DRZ-C System should be capable of distributing active power changes among the various DER based on a priority e.g. pre-determined feeder priority, pro-rata, speed of response, technical best, proximity etc.
- The DRZ-C System should be capable of pre-positioning different DER to indirectly move the anchor operating position up or down to create more headroom/footroom.

Block Loading

- The DRZ-C System should be capable of calculating the block load capability (pickup/acceptance and drop-off/ rejection capability) of the DRZ.
- The DRZ-C System should be capable of indicating whether each block load is within the DRZs block load capability.The DRZ-C System should inhibit automatic block loading action that exceeds the DRZs capacity.
- The DRZ-C System should only allow a block loading action that exceeds the DRZs capacity under manual over-ride instruction.
- The system must use DER resources to complement the block load capability of the anchor generator and therefore increase the effective block load pickup and drop-off capability of the island.

Distribution Network Energisation

- Once the anchor generator has started up against its own load the DRZ-C must determine when the start-up has been completed successfully (using measurements and any other relevant signals from the anchor generator) and the network is stable to begin energising the wider network.
- The DRZ-C must determine when to energise DER and when to request the DER to begin exporting power.
- The DRZ-C System should be capable of directly (e.g. direct communication with an Remote Terminal Unit (RTU) or circuit breaker (CB) trip circuitry) or indirectly (e.g. via SCADA/DMS) controlling circuit breakers associated with DER and network components, including those that will impose block loads.

2.2.2 Virtual Power Plant (VPP)

When energising the wider network, or operating while synchronised to the wider network outside the bounds of the DRZ, the DRZ-C is required to report the aggregated real and reactive power resources available for control within the DRZ. This capability is often referred to as a Virtual Power Plant (VPP). This section specifies requirements of the VPP capability.

- While maintaining stability and observing all operational limits with the DRZ, the DRZ-C System should act as an aggregator of P and Q services from the DER resources within its controlled area to the interface point with the wider network.
- The DRZ-C System should calculate an available real power (P) and available reactive power (Q) volume in realtime.
- The DRZ-C System must be capable of providing both services (P and Q) simultaneously and independently. Therefore, separate service requests can be sent for each service.
- The DRZ-C System should dispatch set points to control DER active and reactive power output in realtime.
- The DRZ-C System should be capable of executing a pre-determined set of actions to prepare for energisation of the transmission network (or other wider section of the distribution network), such as instructing that all DER enter voltage control mode or instructing the anchor generator to operate with a leading power factor to begin consuming reactive power (to lessen the voltage step change on energisation).

2.2.3 Communications Monitoring and Fail-Safes

The following requirements are typical of an autonomous control system deployed to GB distribution networks (e.g. Active Network Management (ANM) system). As a basis it can be assumed that these requirements also apply to a DRZ-C.

- The DRZ-C shall monitor health of the system (e.g. communication channels, measurements) at all times, and not only when activated as part of a Black Start event. The DRZ-C should raise an alert to the control room when errors are detected.
- The DRZ-C shall have the functionality to monitor the health of the communication channels between the centralised and any decentralised hardware components of the DRZ-C solution and take appropriate fail-safe actions upon a failure or loss of the communications between the components. The agreed actions will range from tripping the DER through to a holding position of the output of the DER.
- The DRZ-C shall be required to monitor the health of the communication channel between the each DER control system and the interfaced DRZ-C device (e.g. a DER controller). In the event of a loss of communication channel, implement a solution that undertakes an agreed fail-safe action.
- The DRZ-C shall be required to monitor the health of the communication channel to all measurements devices and validate the health/quality of all critical measurements. If appropriate the DRZ-C should implement an appropriate mitigating action, such as using a different measurement source, or implementing a fail-safe action.
- The DRZ-C must have the functionality to detect and respond by taking a mitigating action against a connected DER, by disconnecting them from the relevant distribution network for a failure to respond to or non-compliance with, an instruction issued by the DRZ-C System.
- The DRZ-C shall have the functionality to re-connect DER to the distribution network of the relevant DNO following a tripping instruction issued by the DRZ-C only (e.g. tripped due to non-compliance or as an emergency balancing measure) and have the ability to differentiate when a tripping instruction has not been initiated by the DRZ-C (e.g. tripped by a protection system) in the course of its normal and agreed on operation, and thereafter execute a corresponding action to not re-energise the relevant DER until further instruction is received from the relevant DNO operational control centre that the DER can be reconnected to the network.

2.2.4 System Maintenance/Engineering

- The DRZ-C System should be capable of performing the energisation fully manually or completely automated or a combination of both.
- It should be possible to put the DRZ-C System in manual mode and let the control room decide how an energisation sequence should be completed.
- The DRZ-C must allow for the most significant operating margins to be visible to a supervising operator.
- The DRZ-C must allow for all configurable parameters of the DRZ-C to be modified without a DER suffering any outage.
    - The DRZ-C must allow for the maximum and minimum rated controllable power from a DER to be configurable
    - The DRZ-C System must have the functionality to add or remove additional DER from the system without any requirement for full shutdown of the DRZ-C System or adverse interruption to the normal day-to-day operation of existing DER connected and managed by the DRZ-C System.
    - The system must allow the useable block load pickup capability of the anchor generator to be user defined.
- The DRZ-C must provide warning to the supervising operator when the remaining block load pickup capability of the island is insufficient to energise any further demand blocks.
- The DRZ-C component co-located with each controlled DER (DER Controller) should support local and remote access to diagnostic information. It should be possible to see the operational state of all elements. This should include (based on access rights):
    - Current status of all I/O signals
    - Communications status
    - Sequence of event logs
    - Syslog
    - Software modules and versions
    - Battery status
    - Hardware module status
    - Real-time event log.

2.2.5 Wider Network Synchronisation

Before, during and after the process of synchronising to the wider network the DRZ-C is required to maintain stability of the island as per normal operation. It is expected that the anchor generator site will be provided with a remote measurement at the point of interface, and the operators of the anchor generator will manually ramp the generator up/down (and any other actions necessary as determined by the anchor generator operator) to align the island with the wider network. Once frequency and voltage are aligned a synchro check relay operating on the interface will operate to close the associated circuit breaker.

The following requirements are relevant to the DRZ-C during synchronisation:

- The DRZ-C is required to dispatch pre-determined set points (e.g. voltage or frequency set point) or control modes (e.g. request enter voltage control mode if not already) to DER to prepare the DRZ for synchronisation with the wider network.
- Once synchronised to the wider network the DRZ-C is required to report dispatchable real and reactive power to the supervising control room, i.e. operate the island as a virtual power plant (associated requirements are listed in section 2.2.2).

2.2.6 Wider Network Energisation

When the DRZ is requested to energise the wider network there are expected to be significant voltage fluctuations associated with energising various assets on the distribution (e.g. GSP transformers) and transmission network. The wider network to be energised could consist of an adjoining interconnected distribution network however in most cases the DRZ will energise sections of the transmission network (132kV in Scotland, 275kV in England and Wales).

The following requirements are relevant to the DRZ-C during energisation of a wider network:

- The DRZ-C is required to dispatch pre-determined set points (e.g. voltage or reactive power set point) or control modes (e.g. request enter voltage control mode if not already) to DER to prepare the DRZ for the wider network energisation
- The DRZ-C is required to report to the control room available resources of the island as a real power range (generation and load) and reactive power range (absorbing and exporting) in advance of any switching actions taken to energise the wider network, i.e. operate the island as a virtual power plant before, during and after the energisation process (associated requirements are listed in section 2.2.2).

2.2.7 Visualisation

The requirements listed below should not be considered firm or essential; they are provided as an initial proposal of example requirements that may be appropriate. Individual DSOs will have their own preference on how they wish the DRZ-C application to be made visible to the control room and other users.

- A graphical user interface shall be provided for the system and designed in agreement with DSO and EEMUA 191. EEMUA 191 is the basis of Health and Safety Executive Guidance for Operator Displays. The interface will provide users access to important functions and provide visibility of the whole system performance. Real time system status information shall be displayed for each DRZ along with a list of alarms and points requiring a user action. In normal operation, it shall be possible to see the latest data received and access trends for a relevant time period. The following information should be visible on the main user interface available to the control room operator:
    - real-time block load capability of island
    - estimated magnitude of block loads
    - generation/load in reserve for fast balancing
    - setpoints of all dispatched DER.
- Access to the DRZ-C System shall be limited to personnel with dedicated usernames and passwords. Each user shall be assigned an access level and administration rights for the DRZ-C System depending on the role. Examples of authorisation levels are provided below:
    - admin – full control, allowed to initiate changes to configurations etc
    - controller – manage/operate system, unable to change settings/configurations
    - viewer – read only, see current system status and historical operation.
- The centralised component of the DRZ-C should provide a secure Web Server HMI that can be accessed locally or remotely. The displays should include DER monitoring data including voltage, MW and MVAr measurements at the Point of Connection and current set points and connection breaker status.
- The DER Controller should support a local operator panel for local operation. This should be either a graphical touch panel display or a pushbutton/lamps display and should support the following indications for Black start operation:
    - Measurement – Voltage at DER
    - Measurement – Real power (MW) at DER
    - Measurement – Reactive power (MVAr) at DER
    - Measurement – Frequency at DER
    - Control/Indication – Trip and close of any associated metering breaker
    - Control/Indication – MW set point to DER
    - Control/Indication – MVAr set point to DER
    - Control/Indication – Voltage set point to DER
    - Control/Indication – Frequency set point to DER
    - Indication – DER Black Start availability status
    - Indication – Communications status.

2.2.8 General Requirements

- The DRZ-C should co-ordinate with other DSO automation functions to not interfere with the energisation or stability of a DRZ.
- The DRZ-C should integrate with the DNO DMS and be capable of utilising available network SCADA data.
- The DRZ-C should support role based access control to determine functionality available to each user, e.g. viewing, administration and control.
- The DRZ-C should provide a data historian capability to record significant events such as:
  - all control actions issued by the DRZ-C
  - DER compliance to DRZ-C control instructions
  - critical warnings regarding stability of the DRZ
  - monitor DER resource availability.

2.2.9 EMS/DMS Requirements

The DRZ-C design outputs vary in the proposed role of EMS/DMS systems within the restoration process. The requirements listed below are recommendations which represent the majority opinion from the DRZ-C companies' design outputs. These recommendations are subject to change following the lab environment testing of the solution.

- The EMS/DMS system is required to dispatch alternative protection settings to DSO/ESO protection relays as required and appropriate for each stage of restoration.
- The EMS/DMS system is required to perform a network switching schedule to energise the skeleton network of the DRZ. The execution of the energisation should be co-ordinated with the DRZ-C.
- The EMS/DMS system should confirm that the network configuration is suitable to begin Black Start before informing the DRZ-C.
- The EMS/DMS system is required to provide the DRZ-C with live network measurements associated with each block load.

2.2.10 Non-Functional Requirements

The requirements listed below should not be considered firm or essential, they are provided as an initial proposal of example requirements that may be appropriate. Individual DSOs will have their own policy relevant to most non-functional requirements.

The requirements listed below are typical of a mission-critical control system, which the DRZ-C is, but given the unlikely probability that the DRZ-C will ever be used, the cost implications of designing a solution to such standards may dictate that some of the non-functional requirements may be relaxed following a more detailed analysis of the anticipated rollout costs. The Cost Benefit Analysis (CBA) of the DRZ-C rollout should consider whether the infrastructure upgrades are also required for other applications (e.g. ANM, Intertrip and any other automated systems) and therefore reduce the costs directly attributable to the DRZ-C rollout.

Resilience

- The control centre level DRZ-C System should be capable of hot standby in a dual redundant configuration with automatic swap-over in the event of any failure.
- The GSP level DRZ-C should be dual redundant and operate in hot-standby mode with automatic swap-over in the event of any failure.
- The DER Controller should support reliable and resilient communications to the appropriate control centre(s) for managing and overseeing the restoration sequence.
- All field equipment should have a proven track record of reliability in substation environments and should be deployed in BAU for similar applications.

Cybersecurity

- The DRZ-C System should be penetration tested by an independent third-party company and a report made available with the system.
- The DRZ-C System software should be scanned on a regular basis for vulnerabilities using a vulnerability scanning software tool.

- The DRZ-C System should be protected against unauthorised access by means of user authentication which should include two factor authentication.
- The DRZ-C System should support centralised authentication using secure Lightweight Directory Access Protocol (LDAP).
- The DRZ-C System should support a configurable password policy which covers length, complexity, expiry, no use list, and no repeating of passwords.
- The DRZ-C System should support authentication which is based on a role-based mechanism with each role offering a different level of access.
- The DRZ-C System should support account lockout with a configurable timeout.
- The DRZ-C System should record all authorised and unauthorised logins in the logs.
- The DRZ-C System should retain logs and restrict them from unauthorised access.
- The DRZ-C System should transfer all data in a secure and encrypted manner, including the transmittal of password, i.e. they are not transmitted in plain text.
- The DRZ-C System should support system hardening by removing unused applications and closing unused ports.

Availability

- The DRZ-C System shall be a real time operating system and require to function 24/7, 365 days per annum and have a minimum in-service availability of 99.99% per annum. The architecture of the DRZ-C System shall be such that a failure of a single server does not cause the DRZ-C System to fail or detrimentally affect the performance of connected DER had the failure not occurred.

Timestamp

- The DRZ-C System shall conform to an agreed source of timestamp mechanism which will be agreed once the overall clocking arrangement has been designed that will synchronise with relevant network field devices and/or DER interface equipment that forms part of the system that in turn will be sourced from the existing DMS relevant to the distribution network area.
- The purpose of the timestamp will be to assign a sequence order for any action or instruction undertaken or issued by the DRZ-C System and which can be used for post-event auditing and/or settlement of ancillary services.
- Measured values used by the DRZ-C System must have a consistent timestamp that should be synchronised across all critical DRZ-C System components including DER controller equipment and where a timestamp is distributed to the control system of the managed DER.

Maintainability

- It is a requirement that all DER controllers shall require no routine or planned maintenance. The DER controllers shall have no fans or moving parts. The DER controller shall have no memory backup batteries.
- The DER controllers must be able to restart unaided from power on, communication failure and a hard or soft restart.
- All DER controllers will be supported by module or unit repair only for a minimum period of 10 years. All DER controllers supplied will be supported by module replacement for a minimum period of 20 years.

2.3 DER Capability to Support DRZ-C

This section presents the functional capability of each DER type required to support the DRZ-C System. Key data signals expected to be exchanged with each DER type are also provided.

The functionality listed is focused to that which the DRZ-C System directly interacts with. section 4 provides a detailed examination of the feasibility of existing DER becoming Black Start compliant (e.g. self-start, block load etc) and defines performance requirements within the same terminology/context as the existing National Grid ESO requirements for existing large transmission connected Black Start service providers.

The key data signals provided are not exhaustive to all signals which would be exchanged in practice. Additional signals would be transferred based on the specific implementation of the DRZ-C and the DER control system. The OST workstream is separately considering the data protocols appropriate for the interface between the DRZ-C and the DER.

Relevant findings from the OST workstream are published in their Design Stage II report (December 2020).

A section discussing measurement performance is included in section 2.3.3. All measurements are required as 3 phase quantities.

It can be assumed that unless stated otherwise that the data signals are required at an update rate of 1s.

2.3.1 Anchor Generator

The anchor generator is assumed to be a synchronous generator for the purposes of this description however the requirements below are generic and do not dictate that the anchor generator must be a synchronous generator. If a different technology can deliver the required capability it can be considered as an anchor generator.

Functional Capability

- Anchor generator is equipped with an isochronous frequency control mode and voltage control mode.
- Anchor generator must be capable of independently starting and maintaining a stable voltage and frequency output.
- Anchor generator block load acceptance capability is known[3].
- Anchor generator block load rejection capability is known[3].
- Anchor generator power ramp up and ramp down rate limits are known[3].
- Anchor generator protection limits are predefined for under/over frequency, RoCoF, and under/over voltage.
- Anchor generator can accept a voltage and frequency set point.
- Anchor generator can initiate start-up and shut-down processes on instruction from the DRZ-C.
- Anchor generator can alter control mode for Black Start running on instruction from the DRZ-C.
- Anchor generator can adjust (indirectly via the control room) the voltage set point of the Automatic Voltage Control (AVC) relay associated with the generator transformer on the interface to the distribution network.

Key Data Signals

Measurements: Active Power, Reactive Power, Frequency, Voltage

Controls: Island Mode Command (Transition to Island Mode), Grid Connected Mode Command (Revert to Grid Connected Operation)

Digital Status: Island Mode status, Grid Mode status, Warning Alarm

Analog Status: Nameplate Block Load Pickup Capability, Maximum Real Power Limit, Minimum Real Power Limit, Maximum Reactive Power Limit, Minimum Reactive Power Limit, Communications Watchdog

The measurement performance required from each DER site will vary depending on the physical architecture of the solution. It is anticipated that sub second (likely <100ms) measurements will be required from the anchor generator site.

2.3.2 Non-Anchor DER

This section details the expected functional and interface capability of all non-anchor generation, storage and load DER required to support a DRZ-C System.

Functional Capability

- DER power export ramp up and ramp down rate limits are pre-defined and known[2].
- DER protection limits are predefined for under/over frequency, rate of change of frequency, and under/over voltage.
- DER can initiate start-up and shut-down processes on instruction from the DRZ-C.
- DER can modify control modes (e.g. PV, PQ, frequency etc) on instruction from the DRZ-C.

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[3] If the capability is dynamic the control system of the anchor generator must provide a real time signal indicating the real time capability.

- DER can provide the minimum and maximum unconstrained instantaneous real power export capability.
- DER can follow a real power set point inside of the minimum and maximum available limits.
- DER can follow a reactive power set point inside of the minimum and maximum available limits.
- DER can be disconnected via a CB trip initiated by the DRZ-C.

Key Data Signals

Measurements: Active Power, Reactive Power, Frequency, Voltage

Controls: Island Mode Command (Transition to Island Mode), Grid Connected Mode Command (Revert to Grid Connected Operation), Real Power set point (1s update for all DER except fast-dispatch devices such as load bank or BESS), Reactive Power set point (1s update for all DER except fast-dispatch devices such as load bank or BESS)

Digital Status: Island Mode status, Grid Mode status, Warning Alarm

Analog Status: Block Load Pickup Capability, Applied Real Power set point Readback, Maximum Real Power Limit, Minimum Real Power Limit, Maximum Reactive Power Limit, Minimum Reactive Power Limit, State of Charge (BESS only), Communications Watchdog

If a DER is used for fast acting frequency balancing, the DER must be capable of applying an updated set point within 200ms[4] of received set point signal.

2.3.3 Measurement Performance

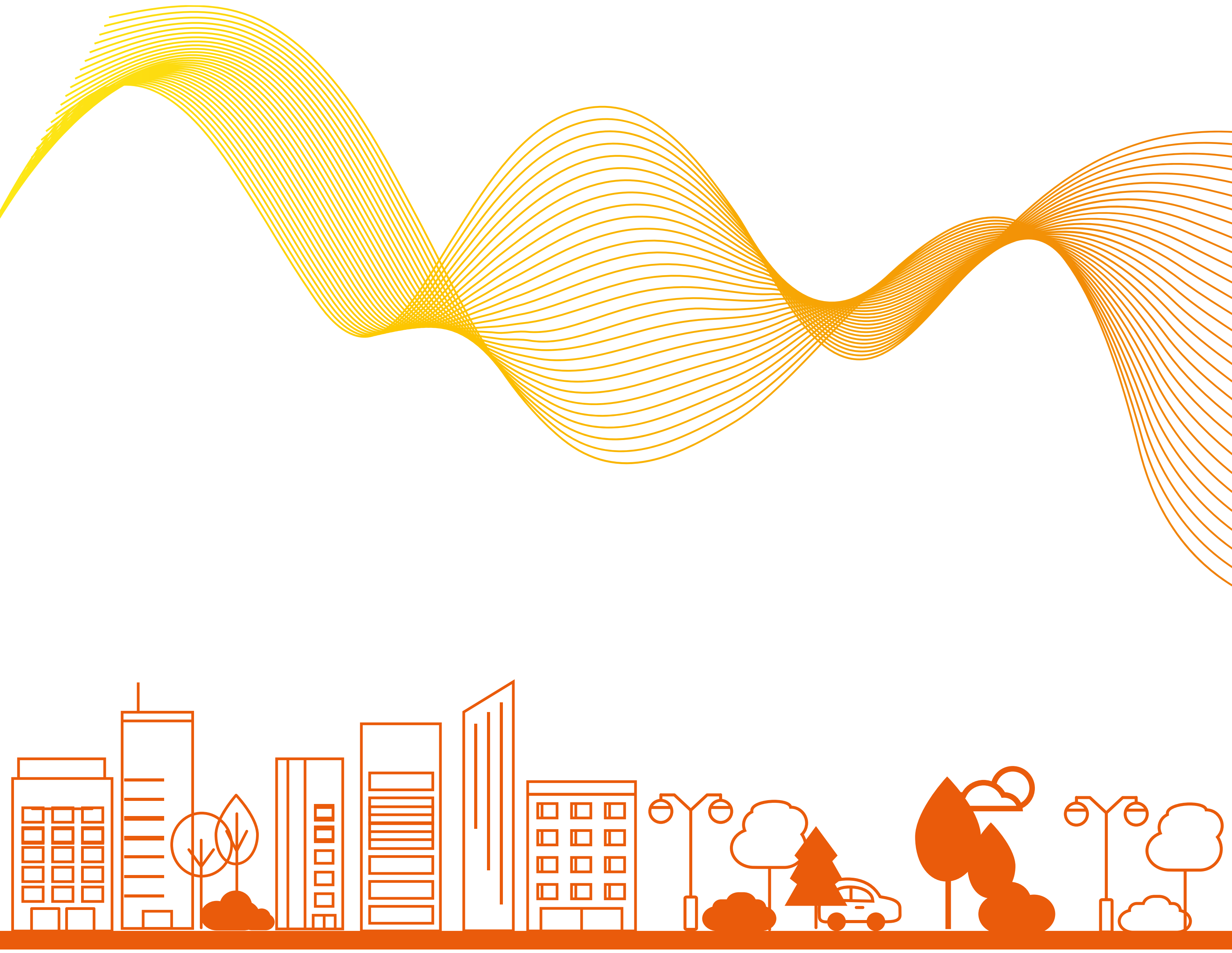
The required update rate and accuracy of the specified measurements at each DER will vary significantly depending on the physical architecture of the proposed solution. Potential physical architectures are presented in section 3.9. As a baseline reference all measurements are expected to be updated within the RTU or transducer providing the source measurement every 1s and is therefore available for the DRZ-C System to poll/subscribe to. A 1s update rate will be suitable for slower control functions such as slow balancing but would be too slow to deliver the fast balancing functionality. The DRZ-C will require to receive and consume a frequency measurement within a timescale no greater than 100ms (indicative estimate, time budget is architecture dependent). To achieve this performance the obvious approach would be to supply the DRZ-C device generating the control signal to be directly fed with CT/VT inputs, and be capable of dispatching the control to the target device. If the target device is a load bank which is co-located with the anchor generator, which is also the centre of inertia, it makes sense to take the fast update frequency measurement from the anchor generator site. One of the architectures (Architecture 1 presented in section 3.9) proposes to install Phasor Measurement Units (PMUs) across the network, at all DER/Anchor sites and on all 33kV feeders. This solution requires that the telecoms infrastructure carry the synchro-phasor measurements across the network to the main GSP/control centre controllers (which generate the fast balancing controls and dispatch to the target DER). Other solutions propose to install dedicated controllers at each DER site and self-dispatch fast balancing controls.

2.4 Conclusions

- This chapter presents the essential generic requirements for a DRZ-C System. The requirements have been derived from DRZ-C functional designs proposed by several companies who are each technology providers and industry experts in the development of wide area control systems within the power systems domain. The functional requirements of the DRZ-C System, DSO/ESO DMS/EMS systems and DER are included.
- Typical non-functional requirements appropriate for a business-critical application such as a DRZ-C have also been provided to present a complete requirement set for the overall DRZ-C System.
- The requirements are generic and therefore define functional capability essential to any DRZ-C implementation. It is anticipated that the generic (i.e. standard) functionality of a DRZ-C can be configured to operate the DRZ-C against any DRZ specific requirements. In some cases configuration may not be a feasible approach and therefore DRZ specific development would be required.
- The requirements may be adapted based on learning from the implementation and test stage of the DRZ-C works (Stage 2), which will test one or more DRZ-C solutions in hardware form within a lab-based Hardware-in-the-Loop (HiL) environment.

[4] The 200ms value is indicative based on power systems simulations which found that this response was required to resolve a power imbalance during a block load. An industry leading supplier of load banks has confirmed that a load bank can deliver a load adjustment from an external control source within 200ms. The operation time is primarily attributable to the delay in the movement of contactors within the load bank control system.

- The functional capability and key data exchange required of each DER type to support the DRZ-C is presented. Each DER is required to provide, in real time, a signal representing the instantaneous real power it can generate/consume. This is critical for intermittent generation to inform the DRZ-C how much generation could be delivered to the island if dispatched. The DRZ-C is likely to dispatch intermittent generation at lower level (and therefore constrain output) to achieve a more predictable service from the DER. DER generators must ensure that the equipment and processes associated with calculating and exposing this signal are designed for high accuracy and availability. This signal is typically provided by controllers of modern PV/wind farms however DER developers/suppliers should ensure that the availability and quality standard is compliant.
- It is believed that the control systems of existing non-anchor DER can provide the functionality required by a DRZ-C System without significant development. The control system of the anchor generators however may require significant development to provide DRZ-C pre-requisite capability, such as being able to self-start, block load, and deliver isochronous frequency control mode.
- The measurement performance required from each DER site will vary depending on the physical architecture of the solution. It is expected that sub second (likely <100ms) measurements will be required from the anchor generator and load bank/BESS site.



3. DRZ-C System Functional Design

This section presents example functional designs associated with key functional requirements of the DRZ-C System.

Each section is introduced with context followed by functional designs as provided by the DRZ-C companies. Multiple design examples are provided for functions where there is significantly variety in designs proposed by the DRZ-C companies. Please note that although some sections have multiple design examples the designs are not entirely unique from one another, there are some unique aspects to each design (which justifies providing different examples) however there is also commonality in the provided examples.

Some of the design content could be described as a conceptual design, while some designs contain detail typically found in a detailed design, so there is significant variety in how the designs are presented. The reader is advised to consider that the design content provided is simply relevant to the section heading (further described by the introduction) rather than being a comprehensive proposition of how the associated capability could be designed.

Each section concludes with a discussion which aims to present a rationalised summary of the most significant observations from the provided designs and include relevant analysis.

3.1 Fast Balancing

The DRZ-C System is required to intervene to restore frequency stability of the island if any disturbances (e.g. DER trip, block load greater than expected) lead to a power imbalance greater than the block load capability of the anchor generator.

If a disturbance within the island leads to an instantaneous generation deficit the DRZ-C System can either reduce demand or increase generation within the island. Given the time critical nature of the mitigating balancing action it is not considered appropriate that a DRZ-C System should be designed such that an intermittent DER generator is relied upon to dispatch and deliver the required increase in generation within the necessary sub-second time budget. While intermittent DER may be able to provide fast frequency support (feasibility of this approach is under evaluation as described in the Next Steps – DER Operability and Stability section of this report) the DRZ-C design process has focussed on how demand could be reduced to mitigate under-frequency events, either by tripping block loads (e.g. 11 or 33kV load serving feeders) or instructing an adjusted set point of a fast-acting dispatchable load, such as a load bank (and potentially a BESS if available). Underfrequency events which require DRZ-C intervention could occur when energising block loads (planned event) (e.g. block load greater than anticipated) or if a DER generator trips (unplanned event).

If a disturbance within the island leads to a generation surplus feasible mitigating measures are either tripping a DER generator or increasing the load of a fast acting dispatchable load (e.g. load bank). It is not considered viable that a DER generator could be curtailed quickly enough to support frequency during significant disturbances. Overfrequency events which require DRZ-C intervention could occur if a block load, or any other DER load trips.

Given the importance of block loading to restore customer load, and the importance of block loading to the overall viability of the Black Start from DER concept, the fast balancing functionality has focussed mainly on mitigating underfrequency disturbances (prioritised over over-frequency mitigation) however the descriptions that follow are largely also applicable to over-frequency events.

Section 3.3 focuses on DRZ-C functionality directly related to block load pickup, which overlaps in some areas with this fast-balancing functionality described in this section.

This section presents two examples of how the DRZ-C companies have approached the design of the fast balancing capability.

Example 1: RoCoF based detection

Example 2: Contingency based detection with load/generation shed scheme and threshold based underfrequency trigger as backup

3.1.1 Example 1: RoCoF Based Detection

Note that this section makes reference to the slow-balancing functionality as described in Example 1 of section 3.2.

Introduction

The fast balancing action must be taken within a defined timeframe depending on the island inertia and the allowable RoCoF in order to stabilise frequency. The balancing action must bring the island power balance sufficiently close such that frequency regulation (mainly from the anchor generator) should keep the frequency nadir or zenith within pre-defined boundaries. Balancing action is done by switching the load bank or BESS.

By default, the anchor generator and the load bank will operate within a pre-defined band with sufficient margin to accommodate an unplanned loss of generation or load. Fast and slow balancing and frequency regulation will normally operate in parallel as follows:

- fast balancing ensures that RoCoF is maintained within limits
- slow balancing manages the margins available for control
- local anchor generator frequency control (governor droop/isochronous) ensures that frequency level does not exceed limits.

Defining Operational Envelope

To ensure that operation remains within the protection limits and withstand capability of the DER, a 20% margin is proposed, relative to the 1Hz/s RoCoF G99 frequency limits as presented in Table 1, in terms of level and time delay. The boundary of acceptable operation is therefore within the protection boundaries. The recommended operational RoCoF limit is therefore +/– 0.8Hz/s.

It is assumed that any existing DSO Under Frequency Load Shedding (UFLS) and Over Frequency Generation Shedding (OFGS) can be disabled or set to wide limits for the island operation period, so the relevant limits are also related to DER G99 recommendations. As listed in Table 2, under- and over-frequency are 48Hz (0.5s delay) and 52Hz (1s delay) respectively.

A 20% margin applied to the frequency level would allow 50Hz +/– 1.6Hz. Applying a 20% limit to the time delay requires that violations are resolved within 0.4s for low frequency and 0.8s for high frequency.

However, the starting point of frequency is variable and not necessarily at 50Hz, and is assumed to be within a band of +/– 0.2Hz for normal operation of the island. This means that an excursion of frequency should be less than 1.4Hz (i.e. 1.6Hz less 0.2Hz normal frequency variability). In the physical system, the frequency during a disturbance should be kept within 48.4–51.6Hz, but in simulations where pre-event frequency is exactly 50Hz, a further 0.2Hz margin should be applied, thus arriving at the limits of 48.6–51.4Hz in Table 2.

	Physical Limit	Simulation Limit	Time delay
Under frequency	48.4Hz	48.6Hz	0.4s
Over frequency	51.6Hz	51.4Hz	0.8s
RoCoF	+/– 0.8Hz/s	+/– 0.8Hz/s	0.4s

Table 2: Frequency and RoCoF limits for physical operation and for simulation-based testing

Functionality

The high-level fast balancing process is shown in figure 2. The process consists of:

- **Event Detection:** RoCoF-based threshold to detect a fast frequency excursion that requires fast balancing action.
- **Imbalance Calculation:** Compute anchor generator Inertia (MVAs) x RoCoF (Hz/s), to determine amount of power imbalance in the island.
- **Trigger and Dispatch:** Digital trigger and MW set point sent to load bank (or BESS if available).
- **Growing Balancing Value:** The power imbalance calculation will increase up to the maximum RoCoF value. The load bank MW set point is continuously updated with this value to ensure the power loss is adequately balanced and frequency stability maintained.
- **Frequency and RoCoF Within Limits:** The operator will have access to a centrally hosted user interface to monitor the frequency and RoCoF performance.

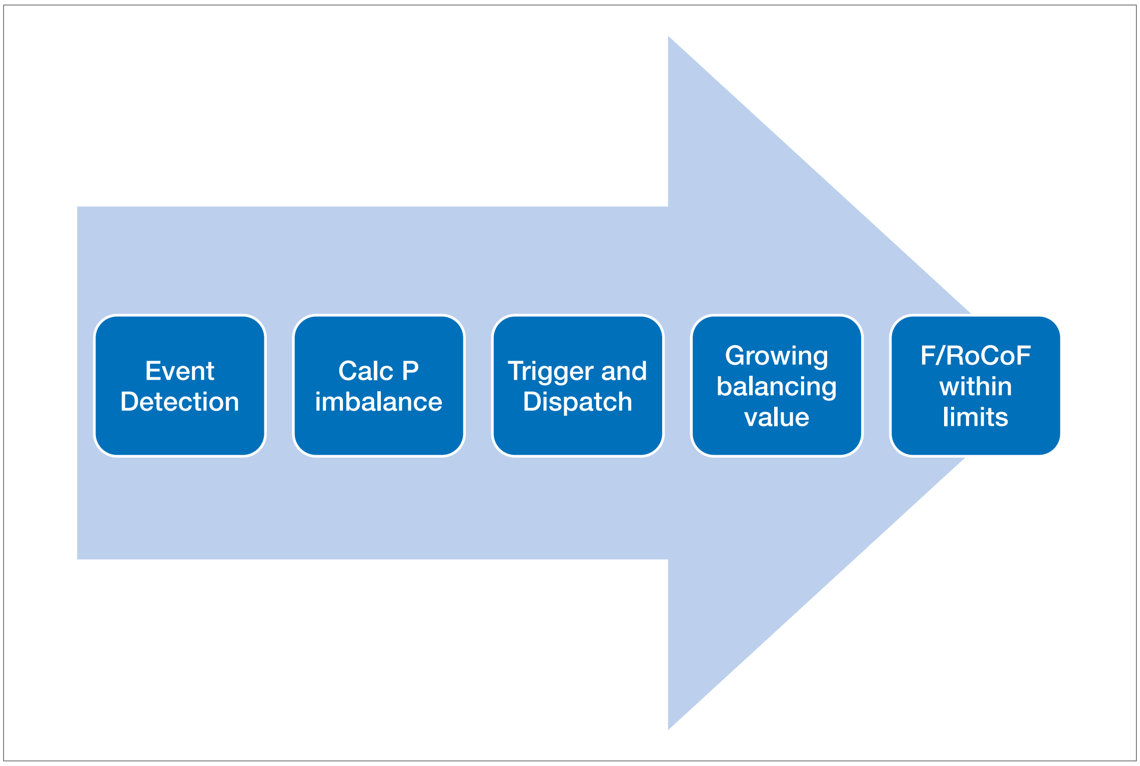


Figure 2: Fast balancing process

Inputs, Outputs and Parameters

Inputs	Algorithm(s)
Frequency from Steven's Croft anchor generator and Chapelcross. Power from load bank. Power from any other loads as measured via the primary circuits. Power from other resource that could conceivably be used for fast balancing i.e. BESS.	Event detection to trigger action at earliest reliable time. RoCoF either using event detection (with growing window) or separate process over given window length using valid samples available. Inertia (use anchor generator H parameter). Power imbalance MW calculated by Inertia (H) x RoCoF.
Pre-requisites	**Parameters**
Inertia H parameter. Islanding vs grid connected mode detection. Acceptable frequency and RoCoF envelope must be defined. Regulation speed of the anchor generator and any other frequency regulators should be known. Maximum sustainable load or generation loss should be defined. Details of how load bank is deployed e.g. set point change, load block trigger, etc.	Acceptable RoCoF limits. Acceptable frequency limits. Event detection configuration parameters. Inertia of anchor generator. RoCoF configuration parameters (e.g. window length, % valid samples). Max/min limits of renewable generation.

Outputs
Trigger to signal an event has been detected. Target balancing power MW (updated based on measured RoCoF).

Example Operation of Fast Balancing

When the island experiences an imbalance of power, the imbalance is proportional to RoCoF, and related by the inertia of the island. At the point of a load pickup, RoCoF immediately drops rapidly to a negative value. The fast balancing scheme detects the disturbance and initiates a response from the Primary Balancing Control resources, which in the case of Chapelcross is the load bank.

If there is sufficient resource available, the fast balancing scheme will target zero RoCoF by compensating the estimated loss of power with a controlled reduction of load at the load bank. In many cases, there will not be enough resource available to fully balance the load pickup, so the fast balancing approach would deploy the available resource with the effect of reducing RoCoF so that it returns within +/– 0.8Hz/s. This avoids DER tripping on loss of mains and also increases the time available for proportional regulation of frequency to act.

The example in figure 3 illustrates qualitatively how frequency is influenced by fast balancing. Without fast balancing, the event produces an initial frequency excursion that violates the RoCoF limit and the lower frequency threshold.

An event occurs at T_0 resulting in a negative power imbalance – this could be a load pickup or an unplanned DER trip. The fast balancing algorithm detects a distinct change in frequency and calculates RoCoF using a growing window starting from T_0. A trigger is raised between T_0 and T_1 and takes effect at T_1 illustrated by the red line diverging from blue in figure 3. This increases RoCoF above -0.8Hz/s within the 0.75s required to avoid loss of mains protection triggers.

Proportional regulation of frequency starts once frequency has increased outside the deadband. Since it is proportional to frequency, it does not immediately respond in proportion to the scale of the event. However, it will increase in value as time passes, and reaches the maximum value around T_2. As long as frequency is outside the target range for no more than 0.4s, the control has achieved its goal.

When the fast balancing control is released, the load bank control should remain at the load level that was last deployed. The load bank level is only changed again once slow balancing is re-enabled and secondary balancing control is deployed in order to restore a frequency balancing margin.

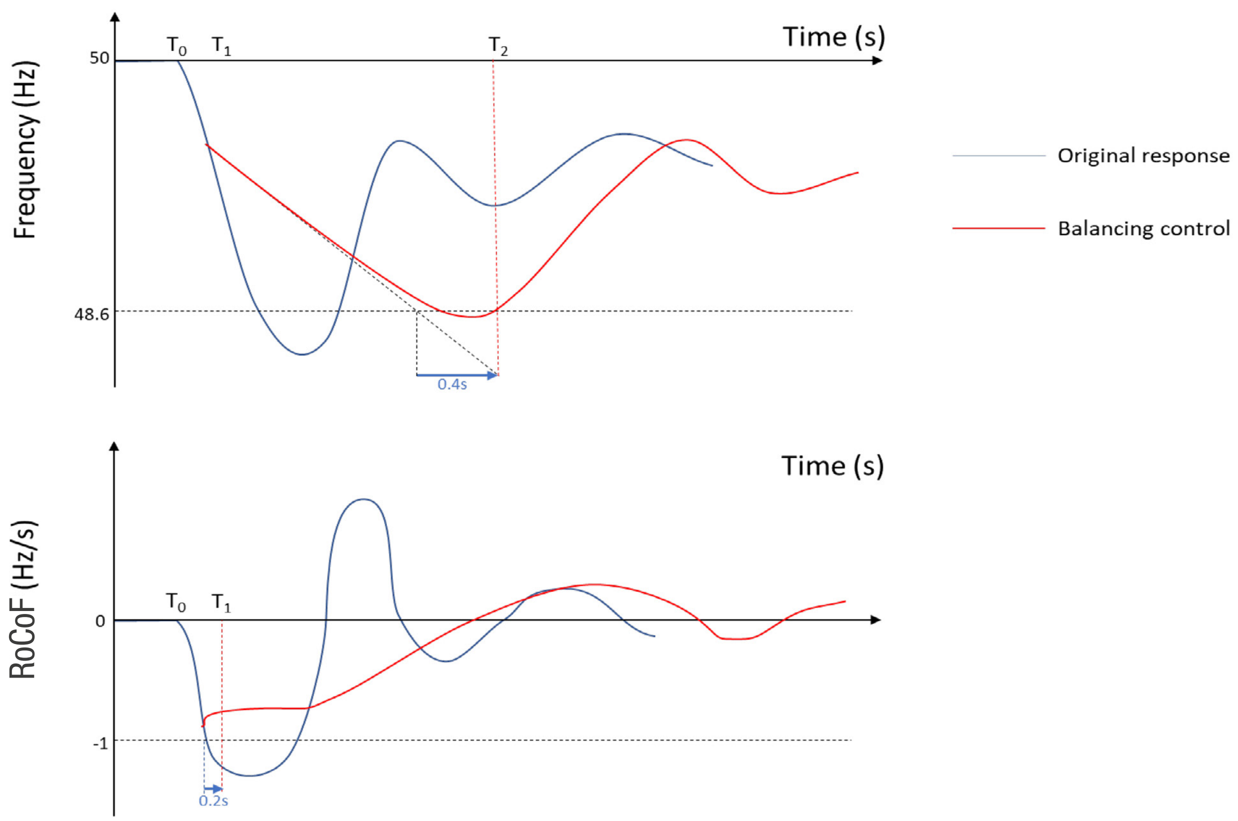


Figure 3: Qualitative illustration of the effect of fast balancing on frequency and RoCoF

Calculating the Balancing Power

The balancing power is calculated using the anchor generator inertia and the event RoCoF. In the tests described here the generator inertia is 200MVAs. Balancing power is calculated as follows:

$$BalancingPower = \frac{2H * ROCOF}{NominalFrequency}$$

It is expected that RoCoF will increase as the event enters the analysis window. It is also expected that RoCoF will reduce during the event due to the fast balancing and anchor generator responses. The calculated balancing power is only allowed to increase with RoCoF (with the same sign) and will stay at that level so that the response is not reduced as soon as RoCoF starts reducing. The load bank/battery will remain at the output corresponding to the largest RoCoF recorded during the event, until the slow balancing function changes the load bank set point to prepare it for the next event.

This is illustrated in figure 4 where the actual imbalance is compared against the balancing power of the load bank. There is a delay in changing the load bank set point based on the event detection trigger and communications latency etc. The MW response will increase based on the measured RoCoF and will stabilise at the maximum RoCoF. The load bank response should deliver a MW response close to the actual loss. Statistics can be produced showing how closely the response met the imbalance. The example on figure 4 shows a ±20% requirement within 1sec of the event.

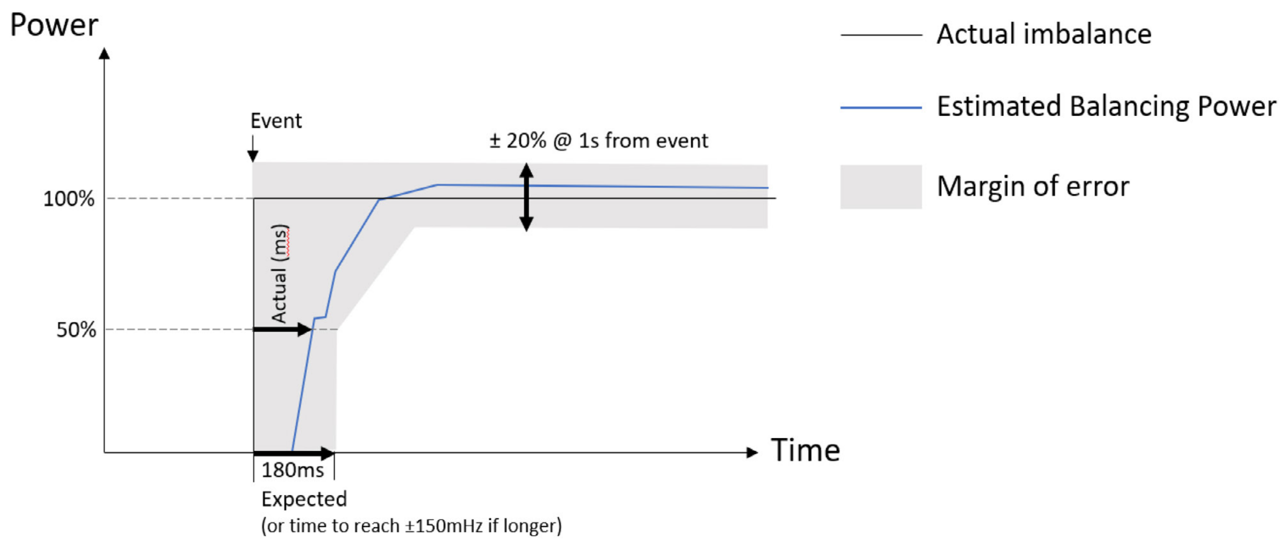


Figure 4: Load bank power response based on measured RoCoF during an event (continuous response provided up to maximum RoCoF). Response should settle within some defined margin of actual imbalance

3.1.2 Example 2: Contingency Based Detection with Load/Generation Shed Scheme and Threshold Based Underfrequency Trigger as Backup

Contingency Based Load Shedding Scheme

The Contingency Based Load Shedding Scheme (CLS) sheds load based on a predicted power deficit in any given island when a contingency occurs. A contingency is defined as the opening of a breaker that interrupts system power flow and causes a power unbalance. This scheme reduces the total plant load to less than the calculated available capacity based on measured capacity and creates a load generation balance. The calculation to balance plant load and available capacity is completed before a contingency occurs and includes the sum of the block load capability of the remaining power sources (generation). This scheme only operates on an opening of a defined contingency breaker under load. By shedding load in accordance with the available capacity, the system can restore the power balance and hence minimise the negative effects of frequency in the system; thereby, preventing blackouts and maintaining stability.

The system runs these calculations every task cycle (2–4ms) prior to the event trigger taking place; therefore, the power deficit can be seen by the operators before an actual event occurs. If there is insufficient plant load to balance the loss of power from a contingency source, an alarm will convey this to the operator. This allows operators to take corrective action and prevent continued operation in a state that could cause a blackout.

This load-shedding scheme involves reducing load on load bank, tripping feeders or individual loads based on the user-defined priorities. Currently, there are multiple circuit breakers that have been identified as contingencies and will initiate primary load-shedding (e.g. DER generator CBs). All circuit breakers that can cause power deficit when opened under load can also be considered as contingency circuit breakers.

Pre-Event Calculations

This system collects the following data and processes them at high speed to dynamically select the loads that will be shed for each possible contingency.

- Status of sources: This includes the online status of each generator and utility tie, as well as the source bus connection. Additionally, this includes the present power output of each source.
- Topology of the power system: This involves determining how each source and load is connected to a bus by use of the status of breakers and disconnect switches located throughout the distribution network.
- Operator inputs: This includes operator-settable parameters such as control enable signals, Block Load Pickup (BLPU), set points, load priorities, and override load consumption values.

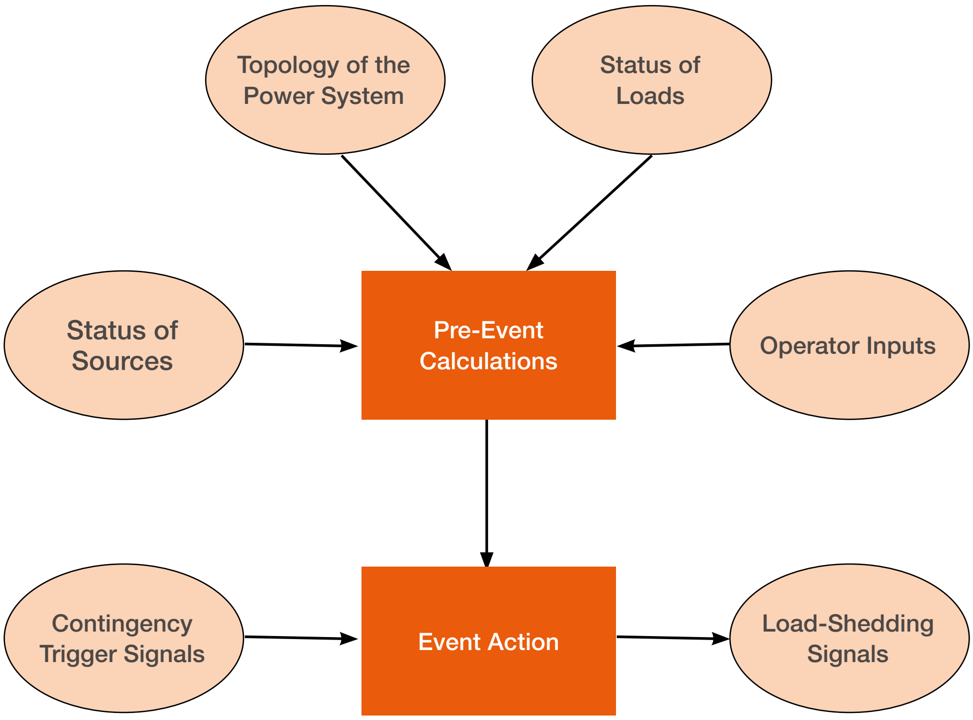


Figure 5: Contingency based load shedding pre-event calculations

Controller Calculations

As previously outlined, the load-shedding controllers perform pre-event calculations to arm the controller with load-shedding decisions based on a real time power system state. The following subsections further describe different power system states that contribute to the pre-event calculations.

Block Load Pick Up Capability

The block load pick up capability (BLPU), can be defined as the amount of step increase in load that a generation asset can provide within the tuning time response of the governor to keep the frequency within specific limits (typically ±1–2Hz). The BLPU is different from spinning reserve, which is the capacity of the generator minus the current operating point of the generator.

For closely timed events occurring within 10s of one another, the system will consider the BLPU only for the first contingencies. As subsequent contingencies occur, the BLPU for the island will be reduced to zero. If a second contingency occurs more than 10s after the first one, the system will again use the BLPU values for the generators. If, however, the events are closely timed (within 10s), the CLS will not use the BLPU for the second contingency because it was already used for the first one. The recommended BLPU values of every generator will be set based on manufacturer provided BLPU capability and Real Time Digital Simulator (RTDS) testing.

Load to Shed Equation

The theory expressed in the Contingency-Based Load-Shedding Scheme Overview section and the BLPU section of this document leads to the fundamental equation of the load-shedding algorithm. The amount of load to be shed is the difference between the amount of source power lost and the sum of the instantaneous power that can be supplied by the remaining sources. This is described in Equation 1, which is performed for each island on the system; meaning that the terms of load, power disparity, and BLPU are all specific to the individual islands.

$$L_n = P_n - \sum_{g=1}^{m} BLPU_g$$

Equation 1: Contingency based load shed equation

Where:

n is the contingency event number

m is the number of sources in the system after n event

g is the generator number, 1 through m

Ln is the amount of load selected for n event (MW)

Pn is the power disparity caused by n event (MW)

BLPUg is the BLPU of all sources after n event (MW).

The system monitors all these connections and arms the analog quantities into the event calculation algorithms. With these armed values, the system can predict the power deficit that would result if that source should trip offline (contingency) and displaying the resulting loads that would be shed. The power deficit calculated is equal to the amount of generation lost on an island minus the BLPU of the remaining sources. This load-to-shed calculation is run continuously in the CLS; however, the system will not initiate a load-shedding event without a trigger. When a trigger is detected, such as a sudden loss of generation on the system, the CLS will shed load according to Equation 1. The controller is also able to pre-calculate the amount of load required to shed if any event occurs. This information is important because it is compared to the available load for shedding to determine if the system will be able to shed enough load to stabilise it. These pre-calculations are then sent to the user interface for display, alerting the operators about the loads selected by the CLS to shed for each defined contingency.

It is possible that one or more of the contingencies cannot be satisfied. In this situation, the operator will receive a critical system alarm indicating that the CLS cannot shed enough load to compensate for the predicted power deficit that would occur if a particular contingency were to occur. It is the responsibility of the operator to adjust to allow the LSS to fully protect the system. In most situations during restart loss of the anchor generator will result in a blackout scenario, however load shedding may be able to save the system from loss of wind farms or other generation assets.

Contingency Triggers

For the CLS scheme, there are two standard methods used to detect contingencies. The first is based on monitoring breakers at high speed. If a source breaker is opened under load, the system will shed load according to the calculations in Equation 1. The second method that results in a contingency trigger is a protection-based breaker trip signal. This would be from some sort of protection operation that results in opening a contingency breaker, as in the first method. The difference in these methods is that instead of the system waiting to receive the breaker open signal, the CLS directly receives the protection trip signal.

This is sent to the DRZ-C at high speed and will reach the controller before the breaker status signal. This allows for even faster load shedding and less system disturbance. By the time the CLS receives a trigger from the contingency breaker status in response to the protection trip, it will already be processing the contingency and may already have sent out load-shedding signals.

If a bus tie is feeding a load bus with no additional generation from the DRZ-C perspective opening the bus-section can result in shedding all load on the bus, or not shedding any load. The bus will be dead either way. However, in some situations having load breakers open on a dead bus can simplify operation. The decision to shed load in a dead bus scenario will be left up to the DNO.

Contingency Breaker Opening

When the DRZ-C detects the opening of a contingency breaker, several conditions must first be met for the CLS to declare it as a contingency event and enable it to shed load. First, the breaker must be without alarm for at least five seconds prior to opening for the status to be valid. If invalid, CB status event provided from protection relay are observed, they must remain healthy for five seconds before the system will consider the breaker for load shedding again. The trigger also cannot occur during an alarmed state and must first be healthy for at least ten seconds. These safety measures help prevent unnecessary triggering of contingencies, ensuring the breaker and monitoring equipment are functioning properly and can be used by the system. Once a valid breaker operation is detected, calculations for load required to shed begin.

Contingency Based Load Shedding Automatic Inhibit

The CLS scheme allows up to five closely timed contingencies to occur and then inhibits itself from tripping more loads for ten seconds so that the system can stabilise. The specific number of closely timed contingencies and the time interval of ten seconds is typical for power systems of this size and will be verified by the RTDS testing to ensure maximum system power balance based on the electrical model. In this way, the system does not act on too many closely timed contingencies based on data from transient conditions. Once load is shed by the CLS scheme, further load will only be shed after the ten second time-out; during that time, the UFLS scheme will protect the system. The number of closely timed contingencies will be based on typical system operating conditions and the RTDS studies performed for the DRZ.

Traditionally, the CLS scheme will also be inhibited if an underfrequency event occurs. Underfrequency events signify a system condition in which the CLS scheme was unable to prevent frequency decay. Frequency fluctuations can cause many cascading events and can be made worse by shedding additional load.

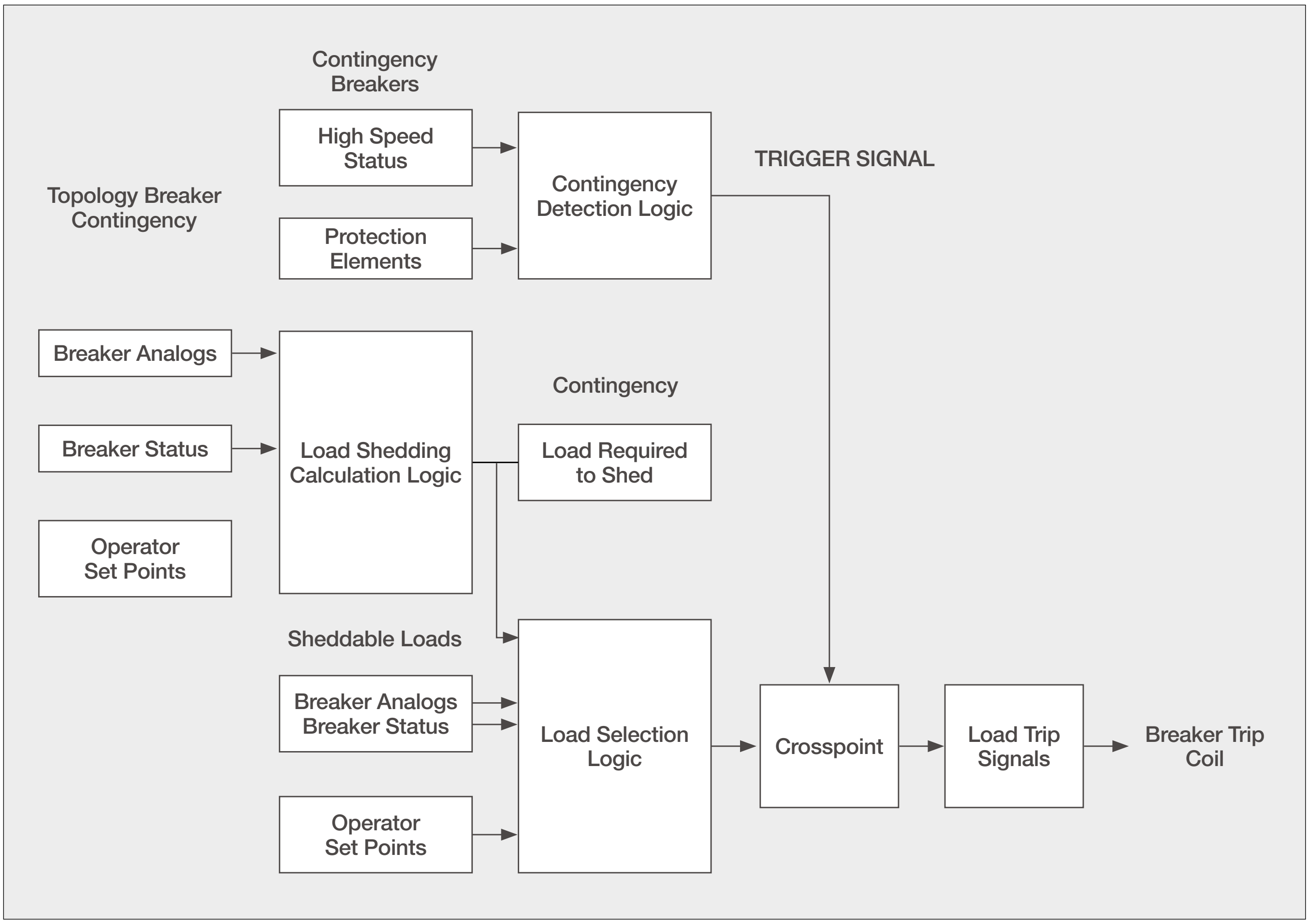


Figure 6: Overall contingency based load shedding flow diagram

Underfrequency Based Load Shedding Scheme Overview

The backup UFLS scheme shed loads based on underfrequency thresholds, which are set in the protection relays located where the generators connect to the busbar. This scheme sheds load corresponding to the frequency response characteristic (FRC) of the system and the predicted power deficit for varying levels of frequency excursion. This scheme backs up the primary load-shedding scheme by detecting frequency decay that was not prevented by the CLS scheme because of an alarmed breaker opening, overestimated BLPU, load-shedding failure because of wiring/trip coil issues, or overestimated MW values for loads.

Relays on the generation buses and other defined locations, as listed in Table 3, send triggers to the CLS when an underfrequency threshold has been crossed. In addition to frequency triggers, relays also provide RoCoF measurements to indicate how quickly the frequency of the system is decaying. These df/dt values further dictate the amount of load to shed with higher values corresponding to more load being shed. This is to be determined based on the RTDS underfrequency study. When the UFLS declares an underfrequency event, it will select an amount of load to shed based on the frequency threshold and the df/dt of the island. Each underfrequency level sheds progressively more load. If the system fails to recover and the next level is triggered via threshold detection, additional load is shed based on the set point.

As with the CLS, the UFLS selects load for shedding based on the high-speed algorithms that determine loads to shed based on required amount, operator-defined priorities, and electrical system topology. An added benefit of this centralised UFLS is the ability to isolate events on an island-by-island basis. This ensures that only relevant loads are shed for frequency excursions throughout the system and that other islands remain unaffected.

The underfrequency (UF) required-to-shed (MW) calculation is a percentage-based value based on the system generation capacity at the given instance. This algorithm is dynamic and will consider system capacity to select the loads required to shed. The DRZ-C supplier and network operators will finalise the required-to-shed values after detailed system studies, simulation, and testing. The proposed UF and df/dt trigger locations for Chapelcross are listed as follows:

Substation	Relays	Type
Chapelcross Bus A 33kV	Protection, Automation, and Bay Control System	UF and RoCoF trigger
Chapelcross Bus B 33kV	Protection, Automation, and Bay Control System	UF and RoCoF trigger

Table 3: Underfrequency and RoCoF trigger locations

Underfrequency-Based Load-Shedding Automatic Inhibit

The UFLS allows for tripping of loads for an underfrequency level trigger one time for any bus. When a frequency-level trigger has been processed, the system will wait until the frequency recovers above that level before allowing that same trigger to shed load again. This prevents the system from acting on transient characteristics and allows the electrical system to stabilise prior to initiating further load shedding. Underfrequency conditions are tracked for each bus. If an underfrequency trigger is detected for any bus on an island, all other buses on that island are inhibited from triggering that particular level because of their electrical connection. This prevents additional tripping in case of the system topology changing during closely timed events.

The UFLS frequency thresholds are coordinated with the generator protection frequency set point to minimise excess load shedding. When the CLS operates, the UFLS will be disabled for 300ms (this will be confirmed during RTDS testing). The temporary disable condition will only occur if the CLS is active and load shedding is enabled. Inhibiting the UFLS for a short period of time when the CLS is active allows for the system frequency to recover after load shedding.

Overfrequency-Based-Generation-Shedding Scheme Overview

The Generation-Shedding Scheme (GSS) scheme sheds generation or adds loads to the load bank based on overfrequency thresholds, which are set in the protection relays located where the generators connect to the busbar. This scheme performs load generation balance corresponding to the frequency response characteristics of the system and the predicted excess power for varying levels of frequency excursion. Relays on the generation buses and other defined locations, as listed in Table 3, send triggers to the DRZ-C when an overfrequency threshold has been crossed. In addition to frequency triggers, relays also provide RoCoF measurements to indicate how quickly the frequency of the system is rising. These RoCoF values further dictate the amount of load bank charging or generation to runback or shed, with higher values corresponding to more generation being reduced. The exact values will be determined based on a dynamic simulation study.

When the GSS declares an over frequency event, it will select an amount of load to be added on the load bank or generation to shed or runback based on the frequency and RoCoF trigger on the island. Each overfrequency level progressively reduces more generation. If the system fails to recover and the next level is triggered via threshold detection, additional action is taken.

As with the UFLS, the GSS selects amount of load to be added via load bank or generation shedding based on the high-speed algorithms that determine load rebalancing, required amount, operator-defined priorities, and electrical system topology. An added benefit of this centralised GSS is the ability to isolate events on an island-by-island basis. This ensures that only relevant generation is shed for frequency excursions throughout the system and that other islands remain unaffected.

3.1.3 Discussion

The design of the DRZ-C fast balancing functionality must consider how to:

- detect the disturbance
- calculate a mitigating action appropriate to the severity of the disturbance
- execute the control action.

The most significant difference in the described designs is how the DRZ-C detects a disturbance. The primary control approach for the first provided example is contingency based load shedding (CLS). The CLS monitors the CB status associated with assets which if tripped could lead to a disturbance which requires an intervening action from the DRZ-C. Such assets would be DER generators and block loads. Since the position change of a CB can be detected quickly (relative to other means of detection such as measuring the frequency directly) a control system is afforded more time to calculate and execute the mitigating action in the required time frame.

To calculate the mitigating control action the contingency based load shedding function monitors the generation associated with a monitored CB and if that CB were to trip the DRZ-C sheds the corresponding amount of load (the process is followed in inverse for overfrequency events). The function is preloaded with other parameters to simplify the calculation and reduce computation time when the contingency is identified. Shedding load in the context of the DRZ-C could be either to reduce the loading on the load-bank (or BESS if available) or trip block loads if necessary to protect the anchor generator.

Some disturbances within the island cannot be detected by monitoring CB changes only (e.g. block load greater than estimated, overestimated block load capability of anchor generator, high-wind speed cut-out) therefore contingency based generation/load shedding is not considered alone to be a viable approach to provide fast balancing capability, therefore some form of frequency based measurement detection will always be required, whether it's the primary means or as a backup as in the case of the first example.

The second example proposes to directly measure the frequency and detects disturbances based on RoCoF deviation and absolute UF/OF thresholds. The mitigating action is calculated based on the RoCoF deviation and the inertia of the island (which is assumed to be the inertia of the anchor generator only).

Both approaches describe the use of RoCoF measurements to determine the severity of the disturbance and inform the magnitude of the mitigating response. The second approach provides detail on how the imbalance would be calculated.

The execution of the mitigating control action is common to both designs, instruct a CB trip signal to DER generator or load, or dispatch fast acting set point control to a dispatchable load.

If the measurement-based approach described in the first example can detect and execute a mitigating control within the necessary timeframe it represents a simpler approach to that of the multi-layered load/generation shedding schemes with frequency measurement based backup.

When developing a DRZ-C solution, a designer should consider the merits and cons of a contingency based shedding and frequency measurement approaches.

3.2 Slow Balancing (Optimal Dispatch of DER)

Slow balancing refers to the steady state adjustment of DER to operate the island with optimal resources to support block loading and enable maximum demand to be restored while retaining sufficient resources in reserve to respond to generation/balance mismatches.

This form of balancing control is distinct from the fast-acting fast balancing control described in section 3.1.

One example design relevant to this function is provided.

3.2.1 Operate to Pre-Determined Operating Margins

Note that this section refers to the fast-balancing functionality as described in Example 1 of section 3.1.

The goal of slow balancing of the island is to maintain the Proportional Regulation (anchor generation) and Primary Balancing Control (load bank) within the operating regions in which they maintain reserve for changes in the island power balance, including slow drift of operating state and following actions of the fast balancing function.

The slow balancing task performed by DRZ-C will dispatch controls direct to the participating DER and breakers. Slow balancing runs in parallel with fast balancing that is also controlled directly from the DRZ-C. Interaction between DRZ-C slow balancing and the DER includes:

- DER operating points and Power Available signal sent from wind farms to the DRZ-C
- DRZ-C will send dispatch changes and trip signals to DER plant and load breakers.

Description

Slow balancing applies generation constraints in order to keep a regulating margin available at the anchor generator and to ensure that there is capacity for positive and negative load steps at the load bank.

There may also be a requirement for load relief if the anchor generator is running close to the maximum output.

The anchor generator should normally operate within a given band, with a margin to its maximum and minimum regulating points. If the generator exceeds these limits, action should be taken to constrain generation or disconnect load in order to move the generator closer to the middle of the regulating range.

If this can be done by changing the load bank operation and moving it closer to the midpoint (or the preferred operating point), then this is given priority. Otherwise, resources such as wind farms shall be sent revised set points (< available power) or loads rejected (as a last resort).

The action is not time-critical since frequency is continuously regulated provided sufficient regulating margin is allowed.

Inputs	Algorithm(s)
Anchor generator power Load bank power Wind farm power Selected loading (power) in Chapelcross primaries	Thresholding with deadband and hysteresis Ordered action list Response validation Iteration of control process
Pre-requisites	**Parameters**
Pre-requisites Available power signal for wind farms Wind farm response time	Anchor generator target operating zone Load bank target operating zone Max/min limits of renewable generation
Outputs	
Load bank power Wind farm power set point Selected load trips	

Table 4: Slow balancing function inputs

Slow Balancing Procedure

Slow island balancing is achieved with the following co-ordinated methods:

1. **Proportional Regulation (PR):** governor droop or speed control carried out by the anchor generator. This is continuous control, active as long as the generator is within its normal operating power zone. PR has no direct input from the DRZ-C.
2. **Primary Balancing Control (PBC):** load bank and/or battery control that is achieved by set point control with rapid response. Primary balancing does not affect customer supply.
3. **Secondary Balancing Control (SBC):** set point or tripping control applied when proportional regulation and primary regulation have insufficient reserve margin to accommodate a possible change in the island power balance. A subset of resources (SBC1) acts on DER generation and does not affect customer supply, while SBC2 resources involve load tripping. SBC1 is used in preference to SBC2 wherever possible.

Slow island balancing is used to dispatch primary and secondary balancing. It has no direct control on the proportional regulation, but primary and secondary changes will affect frequency and therefore will influence the power of the anchor generator.

The goal of slow balancing of the island is to maintain the PR and PBC within the operating regions in which they maintain reserve for changes in the island power balance, including slow drift of operating state and following actions of the fast balancing method.

To achieve this without direct control of PR, the slow island balancing will act as follows, with reference to figure 7:

1. Define preset Trim levels for PR and PBC, defining the margin that should be maintained (Trim Level) and the target range to be achieved to complete a trimming action (Trim Margin).
2. Raise Trimming in progress when either PR or PBC reaches the preset Trim Level (+ or –).
3. Determine if the combined PR and PBC levels are within the total PR and PBC Trim Margins, i.e. $B1 + B2 < PR + PBC < C1 + C2$:
   a. If YES define and adjust value of adjust PBC by the larger of:
      i. the value that moves PR within its Trim Margins
      ii. the value that moves PBC within its Trim Margins.
   b. If NO use SBC as described in step 4 below to achieve total PR and PBC levels within the Trim Margins.
4. If SBC response needed (step 3.b.):
   a. Determine maximum and minimum response value of SBC to move PR + PBC within $\{B1 + B2 < PR + PBC < C1 + C2\}$. May be positive or negative.
   b. Select an SBC resource, or a stacked set of resources that achieves $\{B1 + B2 < PR + PBC < C1 + C2\}$ with minimal dispatch, subject to the size of blocks of available SBC reserve and margin of error for confidence to achieve the result.
   c. Dispatch SBC resources according to:
      i. SBC1 Resources prioritised e.g. DER Raise/Lower with no customer loss of supply
      ii. SBC2 Resources e.g. customer load shed used if SBC1 insufficient
      iii. where possible using step sizes smaller than steps that may trigger a fast balancing response (may not always be possible).
   d. Repeat step 3.
5. If no further SBC response needed (case 3.a), confirm that PR and PBC are both within their respective trim margin levels:
   a. If YES lower Trimming in progress
   b. If NO repeat from 3.
6. Trimming in Progress should not remain raised continuously. Although it does not create a problem for other actions (PR and fast balancing are not interrupted), the state would indicate that there is a problem with controlling the devices or that there is insufficient resource available as SBC. If Trimming in Progress remains raised for more than a pre-defined time period or number of slow balancing cycles, a warning is raised with the operators for manual resolution.

Timing is important. Slow balancing is carried out on a regular cycle with sufficient time for the anchor generator governor to settle to a new steady-state level. This would typically be 10–15s, but would be a settable parameter. After a fast balancing action, the slow balancing is disabled for at least two cycle periods of slow balancing.

Power signals are filtered with a lowpass filter before driving the slow balancing process. This removes electromechanical dynamics, avoiding spurious responses to power swings and oscillations. The filter is intended to attenuate components above 0.5Hz; typical local mode oscillations of generators of this size will tend to be above 1Hz.

A fast balancing response may be triggered by a step change of power balance caused by SBC2 load shedding action. A load trip will affect the PR + PBC level and may require a rebalancing between the load bank and generator. The sequence below is possible in the case of an SBC2 load disconnection.

1. SBC initiated as anchor generation (PR) rises above D1 (Trim Level +) and/or negative power of load bank (PBC) rises above D2 (Trim Level +) such that PR + PBC is above C1 + C2 Trim Margin+.
2. Large step change applied as SBC action (e.g. SBC2 load trip).
3. Frequency rises and large positive RoCoF detected.
4. Fast balancing is triggered to increase load at load bank. Frequency gradient is reduced (to target zero–RoCoF if possible) as in a normal fast balancing operation.
5. Anchor generator responds to high frequency by reducing generation (PR) bringing frequency into the normal operating zone within Trim Margin limits.

6. Slow balancing will instruct a load bank change if necessary so that PR and PBC both achieve the appropriate margins.

Similarly, if there is a large load pickup, there is a large negative RoCoF that triggers fast balancing to decrease the load at the load bank. In unusual circumstances, this may result in a slow balancing SBC2 load trip response, however the operational procedure (as described in section 3.3.1) is intended to avoid this. Load pickup is not blocked during a trimming in progress, however the load pickup procedure is described in more detail below.

Slow balancing is not time critical. Therefore, DRZ-C slow balancing actions are relayed through the Resource manager and onto the DMS. The DMS will be responsible for instructing set points and trip commands to the available resource.

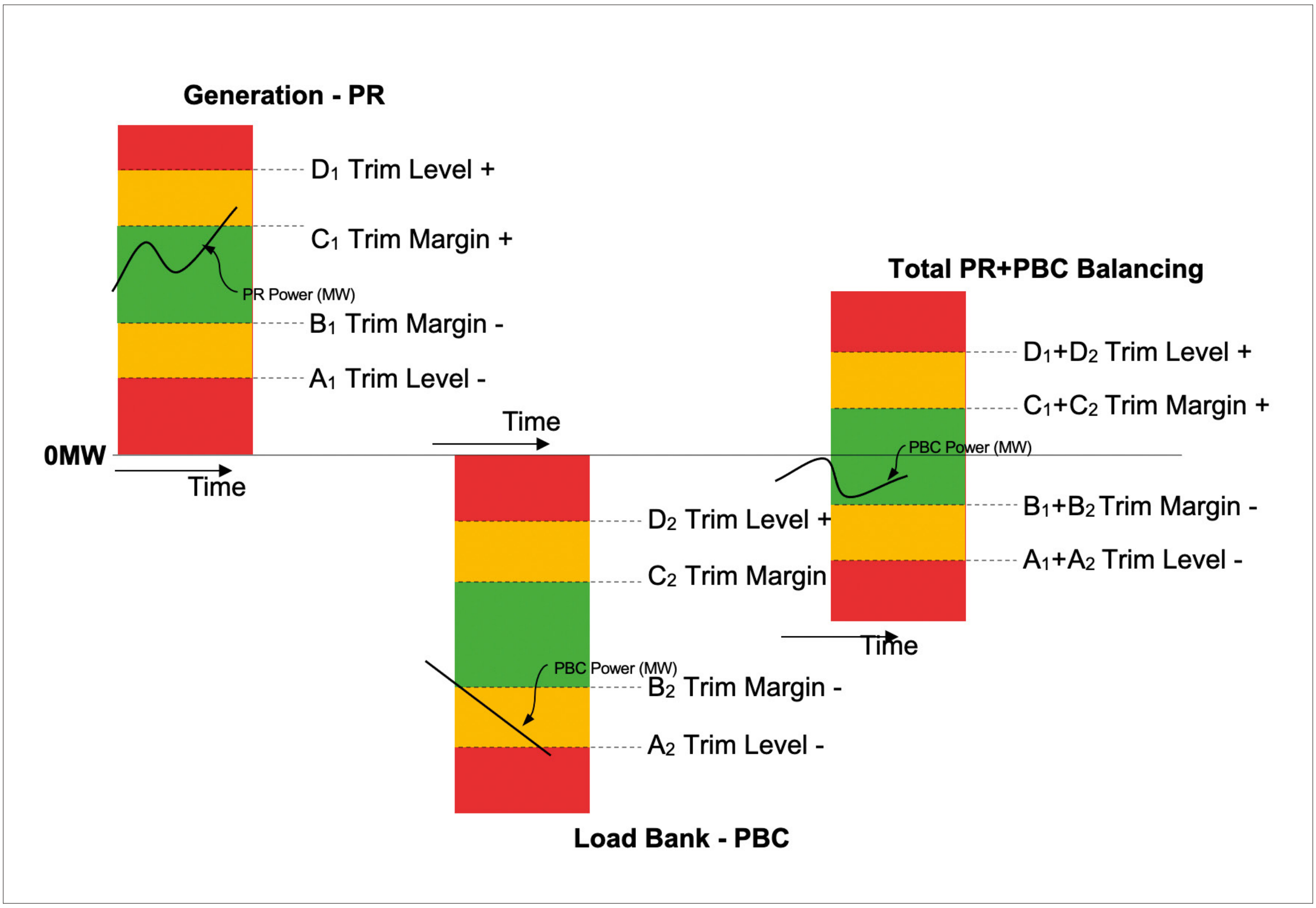


Figure 7: Trim levels and margins for slow island balancing process

Enabling, Disabling, Pausing and Resuming

The slow island balancing function is disabled on startup, as the no-load condition is outside both the anchor generators trim levels and regulation zone, and also outside the load banks trim levels. The function can be enabled once the anchor generator and the load bank are within their respective trim margins (green zones in figure 7). If there is a signal available via the DMS to indicate that the anchor startup is complete, the DMS and Trim Zone level checks can be used to cross-check the readiness to enable Slow and fast balancing.

Slow and fast balancing processes can both be enabled in parallel after the anchor generator has completed the startup procedure and is available. Both slow and fast balancing remain operational for the entire duration of island running from block loading process through to resynchronisation. Fast balancing is always armed, however there are some instances in which slow balancing will be temporarily paused:

1. Following a fast balancing trigger, the slow balancing action will be paused for two cycles, ensuring that at least one full cycle period passes between the fast balancing trigger and the next slow balancing action.
2. An operator dispatch intervention may be required for larger load pickups, where the operator manually rebalances DER secondary resources (SBC1) and maximises load bank demand, prior to load pickup. In this case, the operator should manually suspend slow balancing prior to the load pickup. The load pickup will initiate a fast

balancing action, which will indicate to the DRZ-C that slow balancing can be re-enabled on the second cycle after the fast balancing action (as per point 1 above). A timeout will be configured so that if the load pickup is not carried out or is smaller than expected, the slow balancing process is not blocked indefinitely.

Operational Examples

The following examples qualitatively illustrate the action of slow balancing in various scenarios.

Figure 8 Generator PR at D_1 Trim Limit+ → PBC response

Describes a redispatch of load bank to return the anchor generator within the trim margin levels. This scenario does not involve any secondary balancing control as adjustment of primary balancing control within the load banks margins is sufficient to restore the generator proportional regulation within the margins.

Figure 9 Generator PR at D_1 Trim Limit+ → SBC response

In this case there is insufficient PBC resource to restore the generator PR within margins, so slow balancing calls on SBC resources to rebalance such that PR and PBC can return within margins.

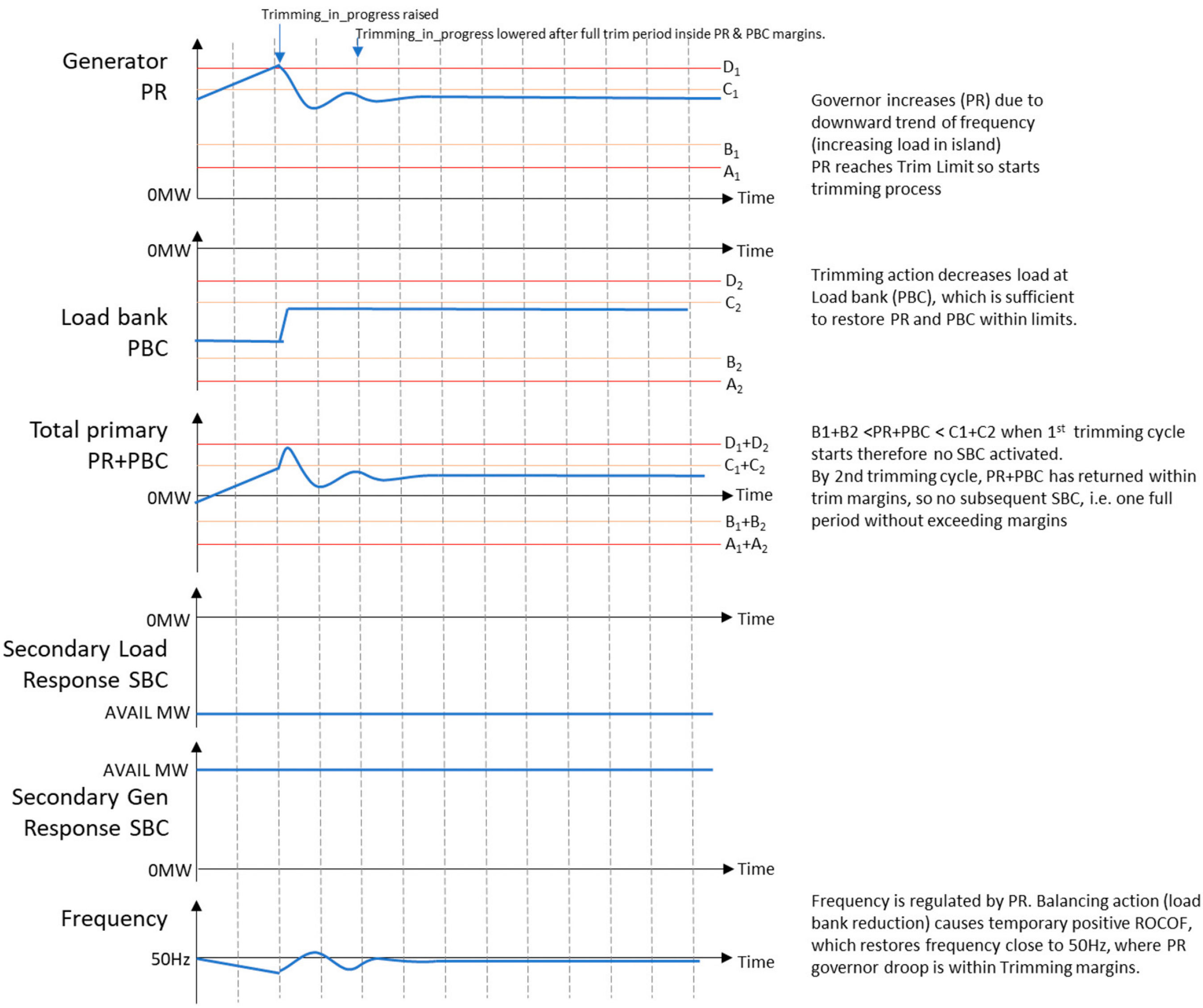


Figure 8: Generator PR at D_1 trim limit+ →PBC response

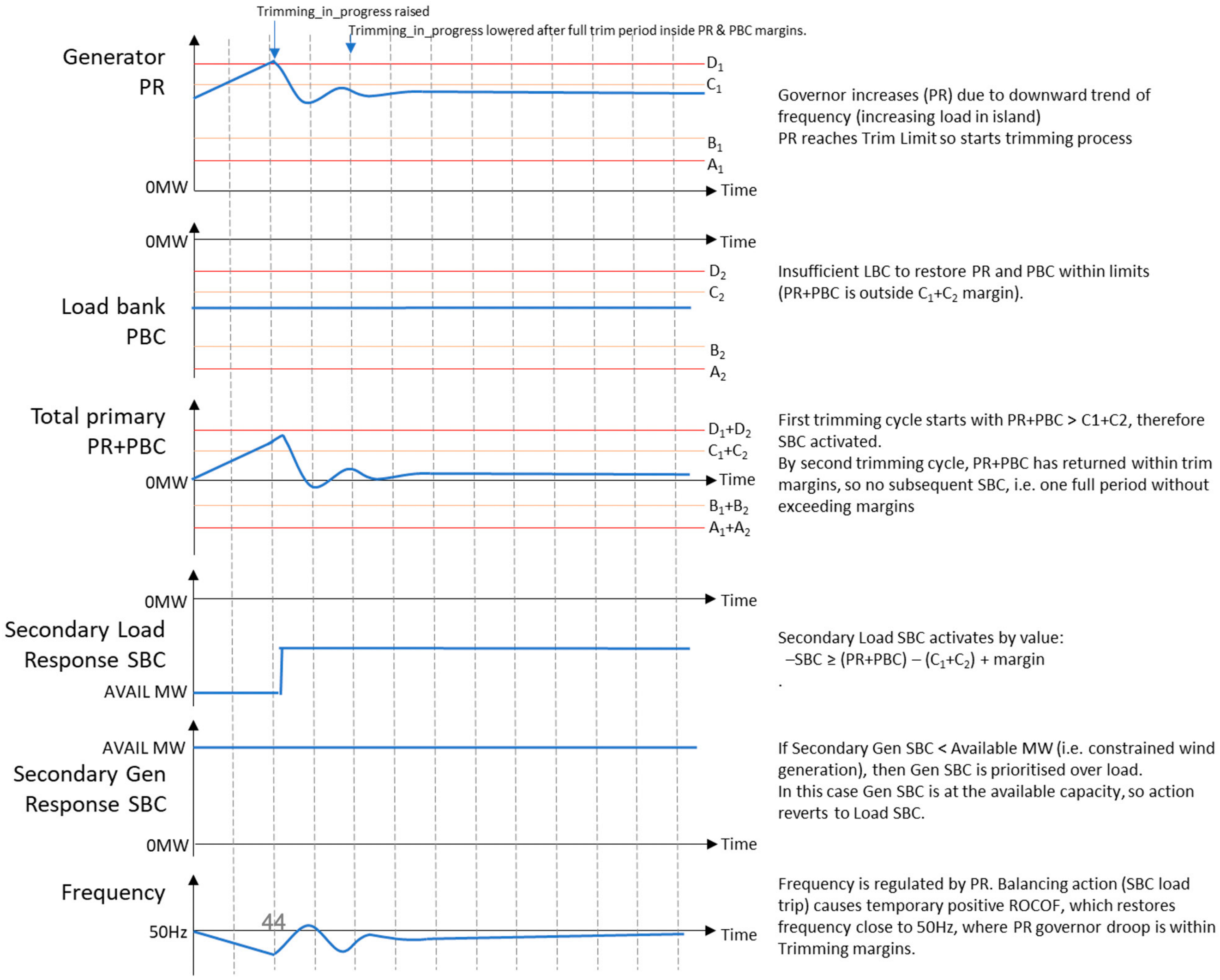


Figure 9: Generator PR at D1 trim limit+ ➞ SBC response

3.2.2 Discussion

All DRZ-C designs have the same common objective to operate the anchor generator toward a preferred operating zone to maintain headroom and footroom appropriate to respond to disturbances. All designs propose to indirectly control the anchor generators operating point by dispatching DER.

The example provides a detailed design on how the thresholds and mitigating actions would be designed.

The slow balancing functionality will be of particular interest to test during HiL testing.

3.3 Prepare for Planned Block Load Pickup

Since energising load is a planned event the DRZ-C can dispatch DER resources in advance to be prepared for the instantaneous load increase when the load is energised. This section describes functionality related to how the DRZ-C can operate resources to increase the block load capability (increase the capability of the anchor generator) of the island and therefore be prepared for the load restoration.

This section is closely related to the fast balancing functionality introduced in section 3.1. The fast balancing section primarily describes how the DRZ-C would detect and respond to disturbances. This section describes how the DRZ-C can prepare in advance of planned block load events.

Two example designs relevant to this function are provided:

Example 1: Define pickup limits based on RoCoF constraints.

Example 2: Online network analysis to simulate pickup events and produce an optimal control.

Supporting Function: Time synchronised control of block load and dispatchable DER.

3.3.1 Example 1: Define Pickup Limits Based on RoCoF Constraints

Note that this section refers to terminology/concepts as described in Example 1 of section 3.1 (fast balancing) and Example 1 of section 3.2 (slow balancing).

The DRZ-C will continuously report to the operator the value of load pickup that can be achieved in the current operating condition using the anchor generator and primary balancing control.

The value of load that can be picked up has two components; both are reported to the operator via the distribution management system (DMS) but the smaller value takes precedence:

RoCoF Constraint {RoCoF_limit (-1Hz/s) * inertia} + {fast balancing load relief = load bank MW}
Balancing Constraint Distance between PR + PBC and {D_1 + D_2 trim limit}

If a load pickup operation is expected to add a smaller load than the pickup capability, then the slow balancing process carries on operating through the procedure. Fast balancing may occur, followed by slow balancing to re-adjust the levels of PR and PBC.

If there is an unexpectedly large load pickup, this is also managed by slow balancing by using some SBC capability, however there is a possibility that if there is insufficient DER resource available, there may be a load trip response.

However, if the operator is attempting to pickup a large load, which is greater than the current pickup capability that is determined by the monitoring process (as described below), the following procedure is followed:

1. Disable slow balancing
2. Maximise Load bank capability to balance load pickup. Prior to load pickup, the island is balanced by increasing DER while anchor generator in maintained in green regulating zone
3. Operator initiates load pickup switching sequence
4. Fast balancing action is triggered by negative RoCoF
5. Resume slow balancing.

Calculation of Pickup Envelope

A control room monitoring function is planned to determine the level of positive or negative power balance step-change disturbance that can be sustained without violating frequency and RoCoF limits. This is presented to the operator as a table that can be compared with the load pickup expected in the next operation. The table can also be used to compare with the maximum N-1 contingency that may be experienced in the system.

The table includes the requirements for respecting RoCoF and frequency limits given the inertia available in the system and the volume of frequency regulation and balancing reserve available.

A power imbalance in the island results in RoCoF, which is sustained until the load and generation return to a balance point, at which RoCoF=0 at the frequency nadir/zenith. The first criterion is that RoCoF will stay within +/– 0.8Hz/s as described in section 3.1.1.

Net power imbalance (ΔP_{imbal}) in the island can be extracted from RoCoF and inertia:

$$\Delta P_{imbal} = \frac{2H}{f_o} ROCOF$$

To ensure that the RoCoF remains within limits, it is necessary to contain the power imbalance such that:

$$-0.8 * \frac{2H}{f_o} \leq \Delta P_{imbal} \leq +0.8 * \frac{2H}{f_o}$$

The largest sustained value of ΔP_{imbal} during a disturbance comprises the system event less the fast-acting response that is deployed within the 0.75s window before loss of mains triggering. In effect, the power imbalance ΔP_{imbal} is the difference between the size of the system event causing an excess of power (P_{excess}) and the fast balancing response capability. P_{excess} is positive for a load loss, and negative for a deficit due to load pickup or generation trip.

In general form, the convention used is that an excess of power in the island is positive, leading to positive RoCoF.

$$\Delta P_{imbal} = P_{excess} - P_{fast\_bal}$$

Thus:

$$-0.8 * \frac{2H}{f_o} \leq P_{excess} - P_{fast\_bal} \leq +0.8 * \frac{2H}{f_o}$$

For clarity in the presentation to the operator, values will be presented for negative RoCoF and positive RoCoF. The negative RoCoF value is a limit for load pickup and generation trip, while the positive RoCoF value is the limit for load tripping leading to high frequency response. For island operation, N–1 security is achieved if the maximum credible load or generation loss are within these values.

As well as respecting RoCoF limits, the island must be operated with sufficient reserve that a frequency deviation must be balanced by proportional regulation (PR) at the anchor generator and fast Primary Balancing Control (PBC) at the load bank. The frequency capability is shown in Table 5. The table can be presented in both the Wide Area Monitoring System (WAMS) and ADMS systems.

Negative ROCOF Load pickup/ Gen trip limit ($P_{deficit\_max}$)	MW	$\left[0.8 * \frac{2H}{f_o} + P_{load\_bank}\right]$ (A)
Positive ROCOF Load trip limit (P_{exess_max})	MW	$\left[0.8 * \frac{2H}{f_o} + (P_{lb\_max} - P_{load\_bank})\right]$ (B)
Negative Frequency Balancing	MW	$\{Anchor_{HighRegLimit} – AnchorPower\}+P_{load\_bank}$ (C)
Positive Frequency Balancing	MW	$\{ AnchorPower – Anchor_{LowRegLimit} \} + \{P_{lb\_max} – P_{load\_bank}\}$ (D)
Low frequency capability	MW	Min { (A), (C) }
High frequency capability	MW	Min { (B), (D) }

Table 5: Frequency capability table presented to operator to confirm security of frequency in load pickup and unplanned disturbances

Other resources can easily be included, for example if two Distribution Restoration Zones are combined and two PR anchor generators provide droop response, or if two or more PBC resources such as batteries and load banks operating together.

Assumption for Frequency Balancing

It is assumed that there is time for PBC resources and F – frequency regulation to deploy before the frequency violates the G99 limits. The time available includes the time for frequency to move from near 50Hz to the f±1.4Hz limit, plus the delay in UF/OF relays (0.5s, see Table 1). Thus, the limits on load pickup are defined only by RoCoF considerations and available resource to balance an event.

If there is a risk that proportional regulation cannot respond in time, then a more conservative RoCoF limit can be applied, accompanied by:

- reduced load pickup through DMS switching or unplanned outage size limit
- some fast-response SBC resources incorporated in PBC e.g. non-critical load tripping and generation tripping.

3.3.2 Example 2: Online Network Analysis to Simulate Pickup Events and Produce an Optimal Control

This approach is founded on an online power network analysis capability. It also refers to a forecast capability which this particular design has recommended.

Based on the current network state, availability of DER and their generation capacity, the DRZ-C System calculates the realtime blockload capability of the DRZ which includes the anchor and any supporting DER that are available and energised at that time.

The system includes all available DER in its transient analysis to determine the current blockloading capability. The result determines whether there are enough DER online before attempting a specific step. The algorithm prioritises

DER that have a low energisation risk and high effectiveness in terms of contribution to the overall blockloading capability. The network analysis engine can also analyse the fault levels within the DRZ to determine the timing and sequence of the DER energisation.

To create an energisation path from the anchor generator to any available supporting DER, sections of the network must first be energised. DRZ-C System treats the network energisation (without adding demand) and block loading in the same way where the demand or network sections are energised incrementally. Both are considered as block loading for the purposes of the DRZ-C System. Creating an energisation path is a sequence of 1 or more block loading phases. The expected energisation blockload is calculated using the load flow analysis of the network analysis engine.

Firstly, before the block load is switched, the size of the block load must be estimated. This is done using a prediction from the Predictor Module (a forecast) to determine the expected magnitude of the demand under normal conditions which is then modified using an algorithm to incorporate the effect of cold-loading (transformer energisation) and load diversification (based on time since disconnection). The resulting calculated block load is then analysed using the steady state and transient analysis engines to determine if the operation will breach acceptable limits. If so, the operation is prevented.

The transient analysis engine models any available synchro-switch dispatchable loads within the model. If synchro-switch loads are not available, then they are not included in the model. If the analysis determines that the system blockload capability is too low, it can re-evaluate the process including any available synchro-switching. If the synchro-switching is required, then the synchro-switch task is armed and used in the blockload phase.

If the analysis determines that the block load is possible without breaching acceptable limits it will identify any necessary voltage adjustments to the DER/Busbars to be implemented prior to block loading.

Finally, once the voltages are correctly set, the block load is switched in.

An example of block loading is shown below.

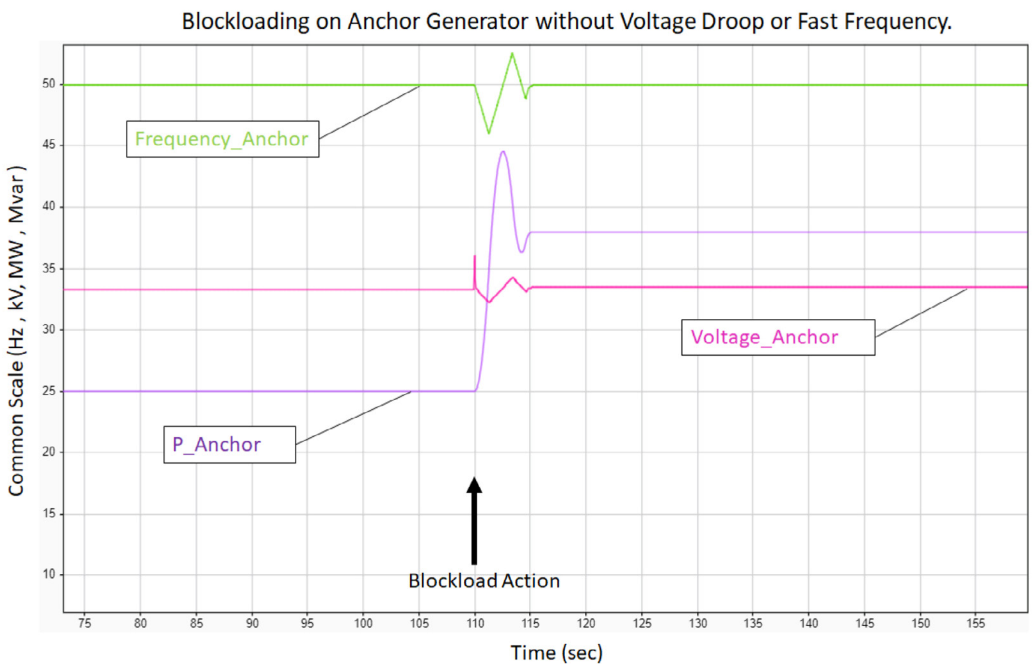


Figure 10: Example of block loading

The demand in the DRZ is energised in blocks. This results in a step response to the power output at the generator and a transient response in voltage and frequency that must remain within pre-defined limits.

Block Load Risk Factor

Based on the expected blockload associated with each circuit/transformer, and the calculated blockload of the DRZ, the controller determines whether it is safe or not to energise each individual circuit.

Each block load action presents a risk which can be described objectively as a Block Load Risk Factor (BLRF).

When the block load of an individual circuit exceeds the DRZs capability the BLRF is greater than 1. Lower BLRF values represent safer energisation steps and can be used to inform either manual or automated energisation processes.

As conditions change the blockload capability of the DRZ will change and therefore the individual BLRF figures for each circuit will change.

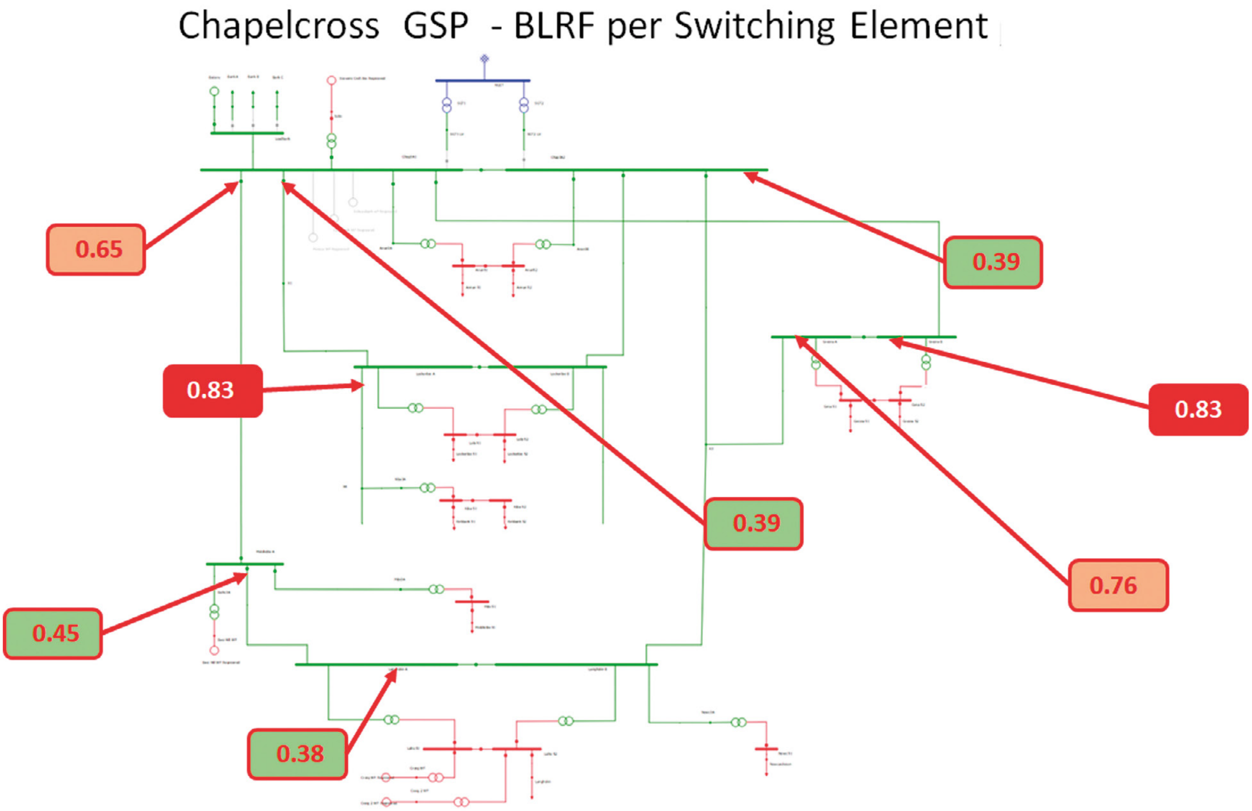


Figure 11: Determine risk of block load

The controller strategy may then select a different course of action based on these updated figures. The controller will seek to energise the DER which can contribute most to the overall blockloading capability. It will do this by energising the DER with energisation patch with the most favourable BLRF ratings.

3.3.3 Supporting Function: Time Synchronised Control of Block Load and DER

The purpose of Synchro-control function is to provide synchronised switching operations at different locations at the same time. This is a valuable function in a Black Start application where load and generation can be switched at the same time to minimise the disturbance on the network from switching large block loads without the corresponding generation to counter-act it. This function allows simultaneous switching at different locations on the network.

Function Objective

In its basic form, the Synchro-control function will support the synchronised control of two breakers at different locations on the network at the same time. This function relies on accurate time synchronisation between both locations and relies on the DER controller having an integrated GPS clock or highly accurate time synchronisation. A DER controller with synchro-control capability needs to be deployed at each control locations. Each controller will be instructed to operate a specified control action at some synchronised time in the future. For safety reasons this time must be far enough into the future to ensure that both sites can be fully armed and notified in advance but not too far into the future that controls may be automatically activated while un-supervised at some future time. The equipment operating times must be defined, and the algorithm must compensate for this to ensure that the plant actions occur simultaneously.

It should be possible to synchronise control functions across any number of locations where Synchronised Control capabilities are available and not just restricted to two locations. In addition, the control action could be a set point control action as well as a switching action.

The operating sequence involves a secure Select-Check-Arm sequence. Firstly, the selection of operating instruction along with the selected operating time is sent to the DER Controller. The DER Controller verifies the control selection and verifies the operating time is within the allowed operating window (typically between 2 and 10 minutes in the future). If it is a valid selection, the DER Controller responds with a positive response and sets a timer while waiting for an arming confirmation. If the arming confirmation is received within the timer window and the arming instruction matches the Select instruction, then the DER will arm the control for execution at the specified time. The DER Controller will then operate the required control action at the specified time (minus the equipment operating time) to ensure the plant operation at both locations occurs at the same time.

The DER Controller is continually monitoring the status of the GPS Clock or time synchronisation source and will reject a Synchro-control if the controller has lost its time synchronisation. If the time specified in the Select instruction is outside the allowed activation window or there is a problem with the selected control action, then the Select will return with a negative confirmation. If the arm instruction is not received before the selection timer expires then the selection expires and is automatically de-selected. Finally, if the arm instruction does not match the select instruction then the selection will be automatically de-selected, and a negative confirmation returned to the arming instruction.

Once armed and the unit is waiting to automatically issue the control action at the specified time, it can be unarmed at any point on receipt of an unarm instruction. The unarm instruction is regarded as an over-riding safety instruction and all armed or selected instructions are immediately cancelled on receipt of this instruction.

Function Inputs

The following general inputs are required by this function:

- specified time in the future for the control event (to 1ms)
- GPS Time synchronisation
- configurable list of control actions to initiate at the specified time
- activation time for each control action
- function Enable/Disable.

Function Outputs

The following general output(s) are produced by this function:

- timed Control Action
- time Sync Status
- function Enabled/Disabled Status.

3.3.4 Discussion

The first example calculates the maximum generation or load loss that the system could sustain based on the RoCoF operational limits (with some margins), the inertia of the island, and the amount of fast acting load available.

The second example proposes to host a power systems model of the DRZ network on the DRZ-C System (including a model of the anchor generator frequency/voltage controllers) and perform load flow and transient simulations to estimate the voltage and frequency deviations within the network. The impact of additional DER resource on the block load pickup capability of the island is also modelled within the simulation before executing a control action.

The time synchronised load dispatch control function is a novel approach to support the anchor generator pickup large loads when there is a risk that that the block load may exceed the capability of the anchor generator. A load bank or other dispatchable load can be co-ordinated to operate at the same moment as the block load is energised, reducing the load subjected to the anchor generator. This approach requires the volume of the mitigating load to be pre-determined since the actual imbalance can't be determined before the block load is energised. Care must be taken when determining the magnitude of the time synchronised load to dispatch. The approach also requires that the DRZ-C have direct control over each block load (or potentially a subset of loads associated with the largest load) and the dispatchable load. If the block loads were energised via SCADA and the DRZ-C simply reacts to disturbances based on frequency measurements, direct control over each block load is not strictly required, although direct control over some block loads may be required to perform emergency load shedding.

A general philosophy to consider when determining the magnitude of the mitigating load (whether time synchronised or reacting to disturbances) could be to overestimate the expected block load and therefore dispatch load to ensure that the anchor generator maintains some additional block load capability to regulate any remaining imbalance, rather than rely on the DRZ-C to detect any remaining imbalance and further dispatch a load-adjustment. The anchor generator frequency control is more granular and better suited to regulating remaining imbalances.

The combination of a time-synchronised load dispatch function and a frequency measurement-based capability would limit the instantaneous load subjected to the anchor generator at time of energisation, with the reactive frequency measurement capability to observe any remaining imbalance and execute a further mitigating action if required.

3.4 Virtual Power Plant

3.4.1 Introduction

The DRZ-C is required to report the aggregated real and reactive power resources within the island to the relevant control engineer to inform capability available for energising the associated higher voltage network, or when synchronised to an adjacent distribution or transmission network. When declaring the available real and reactive power the DRZ-C is required to calculate a range that if dispatched would not compromise the stability of the island.

3.4.2 Functional Overview

This section provides a functional overview of potential VPP capability as provided by a DRZ-C company. Some aspects rely on an online network analysis engine which is not considered essential but is one approach to determine the Island aggregated resource while maintaining the island within limits.

After subsequent Growth Phases the DRZ is energised to a Point of Connection at a transmission Grid Supply Point (GSP) or another DRZ. At this point, the distribution island can begin to provide support services beyond the Point of Connection.

Instructions issued to increase or decrease DRZ output through demand and generation management are provided to facilitate this wider network growth. Demand for Active Power and Reactive Power services are provided by the VPP Module.

Once the power island has re-connected to the main grid it can operate as a virtual power plant providing Active and Reactive Power Services to the main grid at the Point of Connection to support the expansion of the main grid. The DRZ-C calculates in realtime the available capacity of the DRZ zone to provide dispatchable active and reactive power without compromising is own stability. Only this available capacity is offered in real time as dispatchable. It may be that although the VPP is enabled the available capacity is zero for 1 or both services.

The VPP manages the output of the individual DER within the DRZ to deliver the required service levels at the Point of Connection. The VPP Module will calculate the sensitivity of each DER to deliver the service at the Point of Connection and provide and aggregated service to the ESO.

The DRZ network is modelled as a Virtual Power Plant which can provide Active Power dispatch and/or Reactive Power which can be provided as a direct dispatch or as a self-dispatching voltage support service.

The overall algorithm consists of two separate submodules for the different service provisions at the Point of Connection GSP:

- P_Mode – Provides Real time Active Power Service.
- V_Mode – Provides Real time Reactive Power Service.

The VPP Module can provide both services (Active Power and Reactive Power) simultaneously. Therefore, separate service requests can be sent for each service.

When the DRZ has merged with the wider Grid the anchor generator is synchronised with the Grid and transferred to Droop Mode operation. It can then be used as one of the synchronous DER contributing to the active and reactive power services.

Note: The DRZ-C calculates in real time the capability of the DRZ zone to provide active and reactive power services to the wider network at the point of connection. This is done by the VPP function. This function calculates what excess service capacity can be made available without compromising the stability of the DRZ.

Using the real time demand, generation and network running arrangement and network analysis engine, the Active Power Controller calculates the available dispatchable Real Power (P) at the Point of Connection. This is a maximum Real Power available to be dispatched and is calculated in real time. As the DER outputs may change in real time (wind and PV generation), this value is constantly being re-calculated.

As well as providing the maximum instantaneous dispatchable Real Power (P) available at the Point of Connection the Controller also calculates the delivery time for dispatching it by aggregating the ramp rates of the DER that would be used for that specific amount of Real Power.

In general, the Active Power Controller monitors the aggregated active power output of the participating DER at the Point of Connection and compares this to the desired set point. To ensure that the Point of Connection (POC) active power output is maintained at the desired operating point; adjustments are made to the following control plant:

- DER Generator Active Power set point.
- Demand Response Active Power set point.

3.4.3 Discussion

When declaring the real and reactive power resources of the island available to the transmission network the DRZ-C must consider the stage of restoration stage at which the service is declared. If the DRZ-C is energising the transmission network the DRZ-C is still relied upon to maintain stability of the island, and must therefore ensure that it retains resources within its own control to respond to any unexpected disturbances (without significantly disrupting the transmission energisation process). The declaration of controllable resources is simpler if the DRZ is synchronised with a strong transmission network, in which case the DRZ-C can transition to a grid-connected form of operation and can relax operating margins and therefore provide, with fewer restrictions, real and reactive power resources to the transmission network.

The process of determining the available real and reactive resources of the island is likely not to be a simple calculation. The reactive power capability of the island is critical to operators when determining if the DRZ could be used to energise the transmission network. The reactive power capability of each DER resource would be based on its P/Q capability, since the Q capability of synchronous based anchor generators is dependent on the P export the calculation of available P and Q resources must take this relationship into account. A simplification of the DER P/Q capability could be modelled with a conservative estimate of the available reactive power. The design approach which hosts a power system simulation engine would in theory be capable of a more accurately determining the P/Q capability since it would contain a model of the AVR and P/Q capability curve of the generator. If the model contained a representation of the transmission network a simulation could be run to validate if the DRZ could sustain the transients associated with the transmission of switching actions.

The VPP declared real power resource is expected to be simpler to estimate relative to reactive power. The DRZ-C would aggregate the real power capability from all DER and provide an overall real power resource value. Determining the ramp rate associated with the aggregated real power resource could also be of value to an operator.

Role of ANM DER in VPP

Some DRZs will have DER which are managed by intertrip/ANM or other automation schemes to manage distribution (or wider transmission constraints). Before the island is connected to the transmission network it is likely that many distribution constraints would not be applicable due to the modified power flows during islanded operation. When operated islanded the island must consume all generation it produces. However when the DRZ is connected to the transmission network the power flows would change and any distribution or transmission constraints may become active again. A simpler approach regarding the flexible DER could be to not energise any DER which are actively managed (or at least inhibited from exporting). When the DRZ-C is no longer required it can enable any intertrip/ANM schemes which would resume control over those DER.

If flexible DER could participate in the restoration process they would increase the overall quantity of MW available to the DRZ-C. When considering intermittent generation there would be an advantage to energise several generators and operate them at a constrained predictable level, rather than a single intermittent generator. There are some added complexities with this approach such as the DRZ-C coordinating with the ANM or other system when the DRZ is transmission connected (since the constraints must be managed again), and the potential for distribution constraints to exist when islanded (considered low probability). If the penetration of actively managed DER is particularly high within a DRZ, and that resource is considered critical to the restoration of the transmission network, then there would be a strong case to design a DRZ-C System which integrates such DER resource and can include their resources when declaring VPP capability. The decision to use or inhibit DER associated with automation trip/curtail systems would be considered when evaluating each specific DRZ and would depend mostly on whether there was enough DER with a traditional (export to contracted level at any time without control) grid connection to restore island load.

3.5 Automated Restoration Strategy

3.5.1 Introduction

This section describes how the energisation plan adopted to grow the island could be automated.

3.5.2 Functional Overview

This section provides a functional overview of how the energisation plan could be adopted. It is provided by a DRZ-C company, therefore some of the terminology used is supplier specific, however it is hoped that the general concepts presented can be understood.

The order in which DER are energised could be based on several different strategies optimising speed, reliability, number of customers restored etc.

The DRZ-C System interrogates the network model to establish what resources are available and their technical capabilities. The DRZ-C System loads the local network conditions such as the running arrangement, forecast demands, forecast generation and so on.

Based on the optimisation criteria, the DRZ-C System establishes a sequence of tasks combined into phases to energise the DRZ.

The DRZ-C System validates the energisation plan by simulating (load flow/transient simulation) the execution for the current network and validating that it can be executed successfully without introducing any network instabilities.

Initially all workflow models would be defined manually but once operational experience is developed sufficiently to define the principles and rules for the automatic generation of the sequences, the scheduler could be configured to generate them automatically.

To automatically generate a DRZ sequence the algorithm first examines the Block Load Risk Factor associated with each demand on the network as shown in figure 12.

The energisation path to each DER is identified by an algorithm in the DRZ system and combined with the calculated BLRF factors. Only feasible energisations paths where the BLRF figure for each circuit energisation is below the acceptable threshold are considered.

Based on the real time transient analysis capability of the Controller, the system will prioritise DER such as BESS Systems, SVCs or Synchro-switched circuits that have sufficiently fast active or reactive power performance to improve the transient response to a blockload and improve the BLRF of all circuits. These paths will be energised based on this prioritisation.

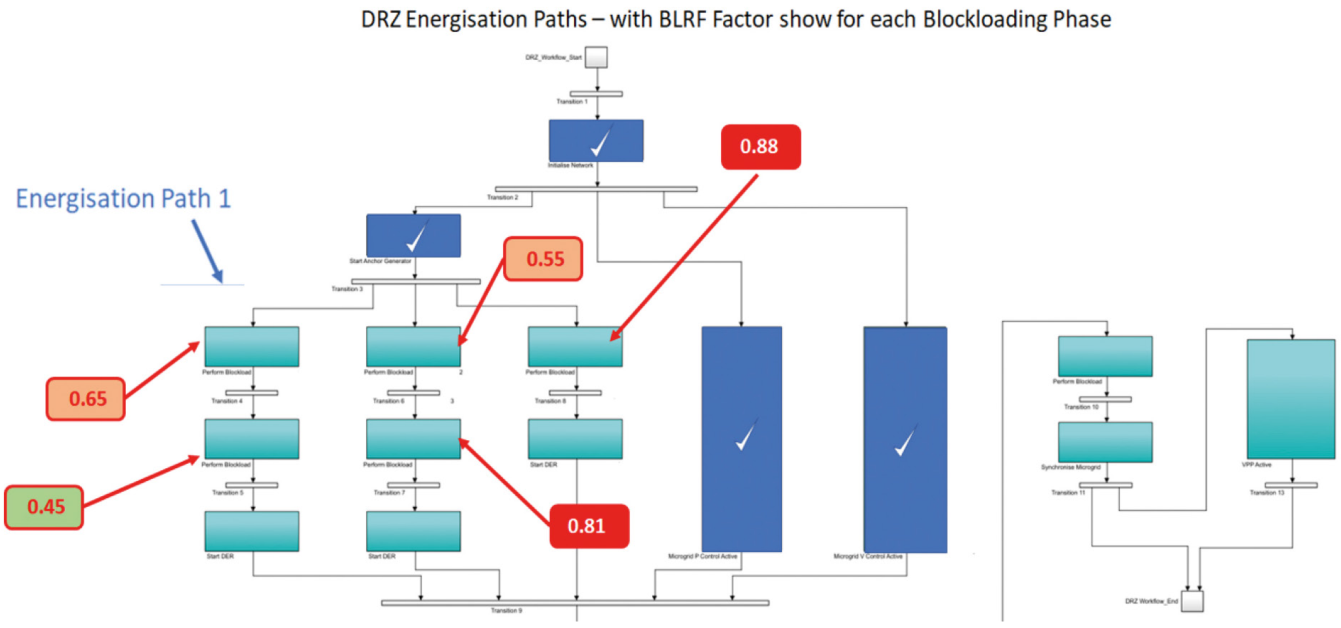


Figure 12: Assessing optimal energisation path

In the example shown above, since Energisation Path 1 has acceptable BLRF Factors, DER 1 can be energised first. Once energised, this results in a revised blockloading capability analysis for the DRZ and hence revised BLRF factors for the remaining blockload Phases in the Workflow.

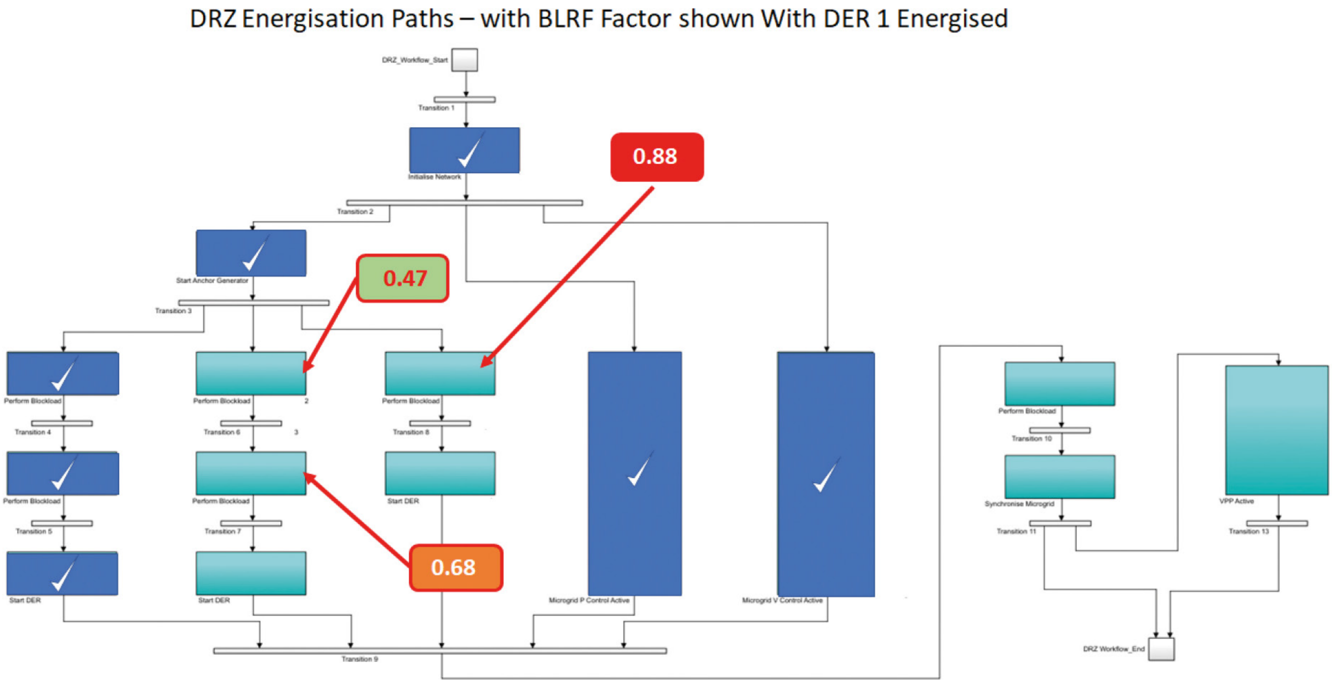


Figure 13: Path to DER1 deemed lowest risk and is energised first

The solution will automatically energise the next most advantageous path – in this case Path 2. Once DER 2 is energised the blockloading capability may increase depending on the DER technology and the BLRF factors will be recalculated.

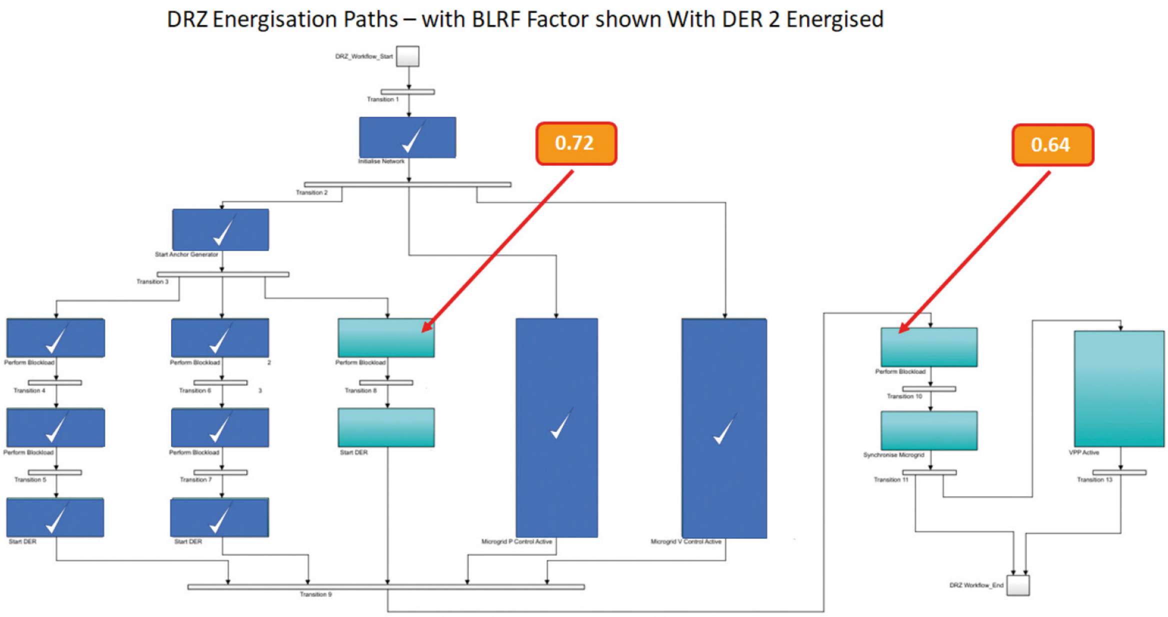


Figure 14: DER2 next lowest risk path and is energised

Once individual DER have been energised and their current headroom and footroom determined, the overall DRZ headroom and footroom can be determined. Then circuits that do not directly lie on any energisation path can be energised in order to optimise the positioning of the Anchor and DER operating points, and to energise out to the point of connection for the VPP service.

3.5.3 Discussion

The majority of designs propose that the restoration strategy (comprised primarily of the switching schedule and protection setting adjustments) is pre-determined in advance by an offline manual process. It is expected that the implementation of the switching schedule and other actions associated with the developed strategy could be automated within the DMS system (this may require development for some DSOs) but the process would be supervised by an operator who could determine whether that schedule is appropriate for the network conditions at the time.

An alternative approach, as described in the provided summary, is that the DRZ-C itself identifies the optimal restoration path, based on an online power system simulation, and proposes to the operator the associated switching schedule. The operator could then decide whether to adopt the schedule or to over-ride it with a different set of actions. The functional design description describes at a high level a design approach for automating the restoration plan. This capability is not considered an essential functional requirement however it is included for information to appreciate that it is possible (in theory without practical demonstration at this stage) with existing technology to automate the restoration switching schedule, which would reduce the burden on an operator to react to the live conditions and therefore facilitate faster restoration times. In practice any switching schedule automatically generated by a control system would likely be closely examined by an operator before it was implemented, which would reduce any time saving.

3.6 Voltage Control

As discussed in section 2.1.3 the case for the DRZ-C to intervene to manage voltage during the restoration process is not yet defined and the project aims to further examine the requirement for DRZ-C voltage control during Stage 2 (Implementation and Testing) and additional power system studies.

The DRZ-C companies have provided the following descriptions of how the DRZ-C could operate to support voltage if active control were required.

Example 1: System strength estimation

Example 2: Undervoltage load shedding system

Example 3: Online network analysis

3.6.1 Example 1: System Strength Estimation

The DRZ-C is capable of voltage management through estimation of system strength during energisation steps from changes in voltage and reactive current.

Estimates of the system strength can be obtained during energisation steps where a change in reactive loading causes a change in voltage magnitude. Low system strength implies a larger change in voltage magnitude for a given change in reactive current (higher system impedance). The system strength measure could be used in the control room to tap voltage higher than normal before energising a transformer for example. Alternatively, the system strength could be used to arm fast voltage control response from BESS or other devices capable of voltage control.

The DRZ-C can provide information to the SCADA system which may automatically (or manually) tap voltage to prepare for a large reactive flow. It is assumed the primary voltage control comes from other local voltage control active in the grid.

3.6.2 Example 2: Undervoltage Load Shedding System

A voltage or reactive power-based load-shedding scheme (LSS) is required due the nature of the DRZ. When energising transformers, transmission lines, or load substations, a significant amount of voltage drop may be observed due to additional demand for the reactive power. If already in the process of restoration, this may cause an outage on the DRZ.

The primary objective of this undervoltage-based LSS to prevent the overall system voltage collapse during system re-energisation. This load-shedding functionality follows similar logic as the load-shedding systems. However, specific undervoltage detection will be programmed into the relays to trigger load shedding and only load at the buses where undervoltage is trigged will be shed.

In summary, the DRZ-C performs the following specific functions:

1. Dynamically calculates the quantity of load to shed for each contingency based on the voltage pick up and reactive power consumption of the load.
2. Dynamically selects individual loads to shed based on user-set priorities, measured reactive power consumption, and the present topology of the power distribution system. Each load will have its own unique priority.

3. Shed load on the location where undervoltage triggers are generated as voltage is a local phenomenon.
4. Responds to a voltage based contingency trigger in less than 50ms, excluding circuit breaker opening time.

3.6.3 Example 3: Online Network Analysis

This example relies on an online network analysis capability.

The reactive power control performs two functions:

- Ensuring that the anchor generator has sufficient headroom to react to any sudden changes in network voltage
- Maintaining all voltage levels throughout the DRZ within their required operating range.

The reactive power control comprises the following sub-components:

- Q set point generator
- reactive power controller
- voltage controller
- Q set point distribution.

The submodules Q setpoint generator and reactive power controller determine the reactive power required from other DER to ensure that the anchor generator maintains sufficient lead and lag reactive power capability to react to any sudden changes in network demand or voltage. The controller can act using a fast-acting Q signal or as self-dispatch voltage control.

The sub-module, voltage controller, is responsible for maintaining all voltage levels throughout the DRZ within the required operating range. The voltage controller inputs include Network Analysis results, anchor generator voltage, Busbar voltages and DER voltages and it has several options for the adjustment of the voltage levels:

1. Anchor Voltage set point: adjusting the AVR set point of the anchor generator allows all voltage levels on the system to be adjusted up or down as required.
2. DER Reactive Power Control: adjusting the total DER reactive power output to control the DRZ voltage level(s). DER normally operate in PV mode in order to respond rapidly to network disturbances.
3. Individual DER Reactive Power Control: adjusting the output of individual DER to control the voltage of specific or individual substation busbars.
4. Operation of ancillary control equipment:
    i. anchor generator Tap-Changer
    ii. MSC/MSR Switching
    iii. Substation On-Load Tap Changers.

Note: DER reactive power can be controlled by direct dispatch in Q Mode or indirectly in Voltage Mode using the self-dispatching droop response of the DER and an associated voltage set point. Using Voltage Mode allows reactive power to be dispatched and also supports a faster acting self-dispatch of reactive power in response to fast network voltage changes.

The fundamental control strategy is to set the voltage level at the anchor generator such that most bus voltages are within regulation, and adjust specific feeders using individual DER or discrete control equipment.

The sub-module Q set point distribution distributes the total reactive power requirement between the individual DER based on their technical capabilities, real time availability, lead/lag capability and their effectiveness/relative contribution to local voltage levels and anchor voltage level.

The module must account for the Q ramp rate characteristics of the DER along with their PQ capabilities as the current P output may influence the reactive power capabilities. In addition, the lead and lag capabilities may not be symmetrical so this needs to be catered for.

3.6.4 Discussion

During the restoration process it is expected that all DER (including the anchor generator) will operate in Voltage Control mode (PV) with a voltage droop characteristic. Power system studies performed by TNEI found that when operated in voltage control mode the AVR capability of the nchor generator and the DER collectively can manage the voltage within the DRZ to within acceptable limits during onerous voltage control events such as block loading (including energisation of dual transformer primary substation) and energising the transmission network.

When operated in PV mode the DER can rapidly self-dispatch reactive power based on a local voltage measurement, which does not require the DRZ-C involvement. The nature of the transient voltage deviations associated with energising transformers, and other equipment with significant reactive power demand/source, require rapid mitigating reactive power support to prevent unacceptable voltage dips.

As Example 3 describes, the DER could potentially be operated in PQ mode. The DRZ-C would then be able to directly control real and reactive power dispatch of the DER. It is not believed viable that the DRZ-C could detect voltage deviation and dispatch an appropriate Q set point to the DER quickly enough to prevent unacceptable voltage dips during onerous, but credible, energisation events. When the DRZ is synchronised to a strong transmission source there may be an advantage that the DRZ-C could directly dispatch reactive power, however the DRZ-C may not be needed at this stage of restoration and the DER would revert to its normal grid connected operation.

The expectation therefore is that DER are operated in PV mode with a droop characteristic.

The three provided examples each provide a unique approach to how voltage control could be integrated into the DRZ-C.

3.7 Forecasting

This section describes three use cases of how forecasting can support the DRZ-C and overall Black Start process.

3.7.1 Use Case 1 – Blockload Estimation

During a DRZ restoration process the network is energised in sequential steps. These blockload steps must be small enough that the DRZ controller, which includes the anchor generator and its supporting DER, can handle the transient after the sudden increase in load on the DRZ voltage and frequency.

Since the block load magnitudes are unknown there is value in forecasting the load in advance of any block load operations.

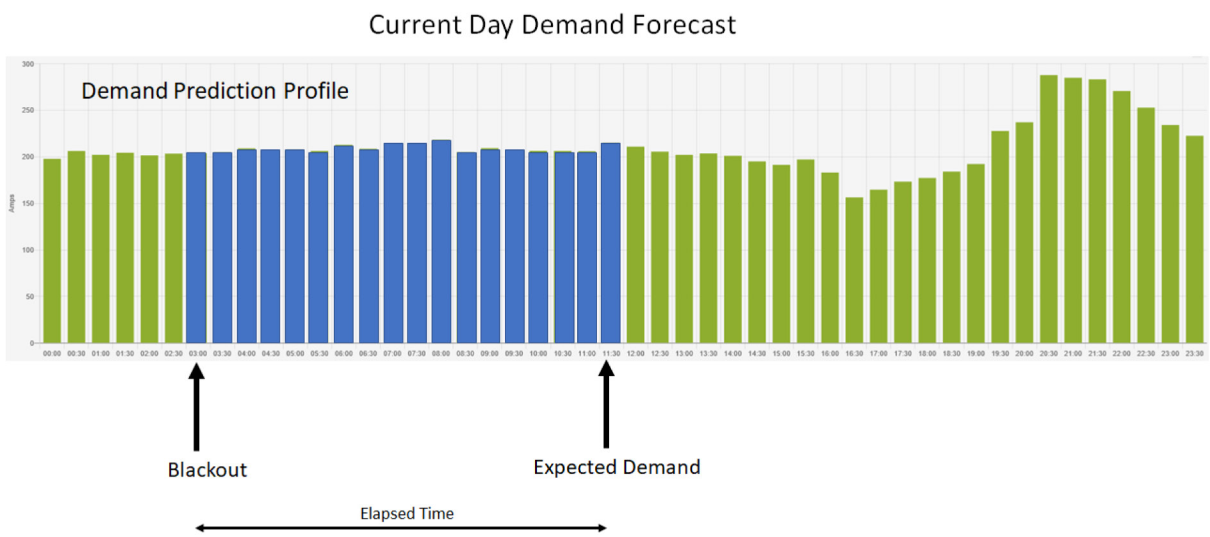


Figure 15: Block load forecast graphic

This is done in a three-step process:

1. Forecast normal blockload size based on the expected demand under normal conditions.
2. Apply an aging function to the blockload based on the time elapsed since blackout occurred, to allow for diversification.
3. Apply an energisation factor to account for transformer energisation.

3.7.2 Use Case 2 – Anchor Generator Load Forecast

During DRZ operation the DRZ-C manages the supporting DER output to maintain the anchor generator within a defined operating range to maintain acceptable headroom and footroom.

The DRZ is expected to operate for up to a week duration. During this time there will be constant variation in the demands and also variability in some of the supporting DER generation capability based on changing weather conditions.

By combining the forecast for generation and demand the DRZ-C can determine the required output of the anchor generator and whether action needs to be scheduled to perform load-shedding or utilise support from Battery Systems etc to protect the anchor generator.

This forecasted requirement can then be used to raise a warning for any expected load loss. Additionally, forward knowledge of the excess generation capacity can be used to plan any windows where a battery or other storage systems can be charged to ensure availability when needed.

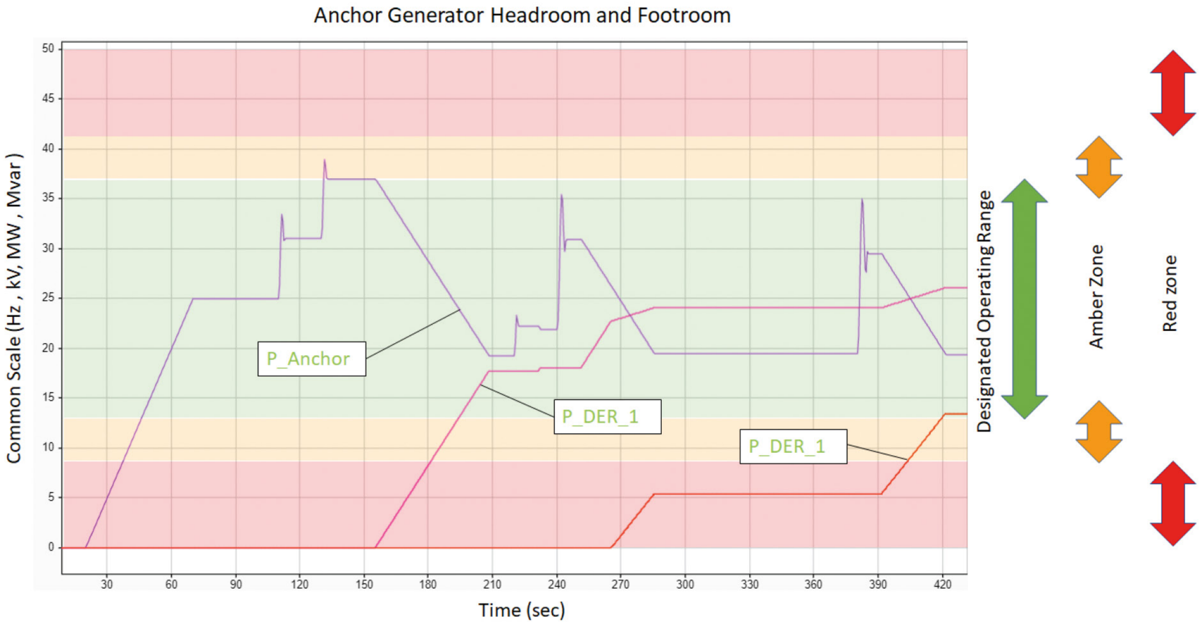


Figure 16: Example of Operating Ranges to manage anchor generator Headroom/Footroom

3.7.3 Use Case 3 – Virtual Power Plant Availability Declaration

When re-connected to the transmission grid the VPP Controller manages the DER in the DRZ area to provide an aggregated P and Q service to the transmission grid while maintaining the anchor generator within a defined operating range to maintain headroom and footroom to react to any network events.

The VPP is expected to operate for up to a week duration. During this period the VPP may be called on to provide active and reactive power support to the transmission grid or a neighbouring DRZ. During this time there will be constant variation in the demands and also variability in some of the supporting DER generation capability based on changing weather conditions. This ultimately affects the available capacity of the VPP to support external grids.

By combining the forecast for Generation and Demands, the VPP Controller can predict the support capacity available to external grids at the point of connection over the forthcoming period, typically 0–24 hrs.

3.7.4 Discussion

At this stage it is not considered essential, and therefore an associated functional requirement is not listed in section 2.2, that the DRZ-C System either calculates itself, or is provided with, forecasts of generation or demand. Forecasts could in principle be used by the DRZ-C to optimise control actions. This section provides three use cases of how forecasting could be integrated into the DRZ-C System. If time allows the project will evaluate the added value of forecasting to the overall restoration process.

3.8 Role of BESS

This section contains excerpts from the DRZ-C designs describing how a BESS could be integrated into the DRZ-C System.

3.8.1 Overview 1

Both the load bank and BESS are termed flexible demand that can be used by the fast balancing function to manage the anchor generation frequency. The resources can be used interchangeably and in parallel for fast balancing where a combined response would increase the BLPU capability.

The anchor generation will manage the DRZ frequency in speed-setting mode and the BESS can be used for fast balancing via DRZ-C set point control. BESS would not be set in a frequency sensitive mode of control.

Slow balancing would manage the anchor and BESS regulating margins to ensure the anchor generation can manage the DRZ frequency and also ensure that BESS response is available in case of unplanned load tripping.

If both BESS and load bank were available in the same DRZ this would increase the BLPU capability. Both BESS and the load bank constraints could be managed to ensure greater MW response is available to fast balancing.

It is understood that BESS has STATCOM like capabilities. Voltage management by the DRZ-C is currently out of scope but use cases related voltage control include:

- Increasing the reactive load pickup capability through BESS voltage control. We propose a Q load probing capability to determine the V/Q response after each energisation step to determine the reactive load pickup capability. It is assumed BESS voltage control acts in <100ms to help stabilise voltage and allow increased reactive loading
- The island will be operating at very low system strength with most of the contribution coming from the anchor generation. BESS can help support system strength at near-nominal voltage and may facilitate more stable connection of DER to the DRZ.

3.8.2 Overview 2

BESS systems can provide reliable on-demand active power either using a self-dispatching frequency response or direct active power dispatch from the DRZ-C depending on the deployment model as discussed earlier.

Self-dispatch will be independent of the communication infrastructure and faster than an instructed value. Self-dispatching is fast enough to support the anchor during blockloading and direct P dispatch can be performed at a slower rate for balancing functions.

If the communication is fast enough then an instructed P set point calculated by the Controller can be equally effective in mitigating the effects of a blockload however this requires very low latency (<10ms), reliable communications.

Many existing ANM schemes include one or more BESS Systems already with fast acting inverters so this capability should be used to its fullest extent to stabilise the DRZ. If the BESS does not support self-dispatching frequency response, then this function can be implemented in a DER controller, allowing self-dispatching to be retrofitted. Some BESS Systems may only be configured for an over-frequency response, so this can be provided through a DER controller.

Existing BESS systems are on standard communications networks which generally are not fast enough for direct P dispatch. However, since BESS devices are effective at improving blockloading capability it is reasonable to consider that its cost effective to install fast low latency communications to a small number of sites.

For certain cases it may make sense to install the battery system directly at the anchor generator site minimising the cost of provisioning high speed communications. This approach minimises the communications investment by focusing on utilising the most effective equipment and retaining the existing DER on the current SCADA infrastructure.

3.8.3 Discussion

It is appreciated that if a DRZ included a BESS it could be operated to support the restoration in many ways, such as it can self-dispatch fast frequency control to complement the anchor generator in times of need. The DRZ-C designs assume that the BESS could at least be used in the same way as the load bank. The BESS could likely be used in other modes to support restoration, such as providing reactive power support to support energisation of the transmission network.

As the penetration of BESS increases in GB it is possible that in some DRZ zones that the DRZ-C role could be significantly simpler than that described in this report. For example, if the BESS were operated in a frequency sensitive mode the DRZ-C may not be required to intervene in the management of frequency (fast balancing as described in this chapter). If the BESS was operated in a frequency mode (e.g. Fast Frequency Response (FFR)) it could not be directly dispatched by the DRZ-C as part of the slow balancing process or any other process. As a compromise it may be viable to enable FFR in advance of significant planned events such as a large block load/transmission energisation, then disable FFR and transition to a PQ mode suitable for dispatch from the DRZ-C.

Since the project is required to develop requirements for a solution viable by the end of the project in 2021 it is considered essential that a DRZ-C design should not rely on a DRZ containing a BESS.

3.9 Physical Architecture

The designs presented in previous sections have not described how the functionality would be hosted on physical hardware. This section provides an overview of possible physical architectures of a DRZ-C System.

Please note that diagrams provided were produced by the DRZ-C companies and include varying level of detail. The main intention of this section is to present potential physical architectures.

3.9.1 Architecture 1

This architecture makes several references to Chapelcross, which is the GSP case study area.

The high-level architecture of the DRZ-C and associated systems are shown in figure 17. The communication paths and protocols are shown with a unique colour key as well as the main measurement locations and monitoring systems. The DRZ-C System relies on fast, synchronised measurements at key resource locations to enable sub-second control actions. Sub-second control is necessary to manage frequency and Rate of Change of Frequency (RoCoF) in the low inertia conditions of the DRZ-C island.

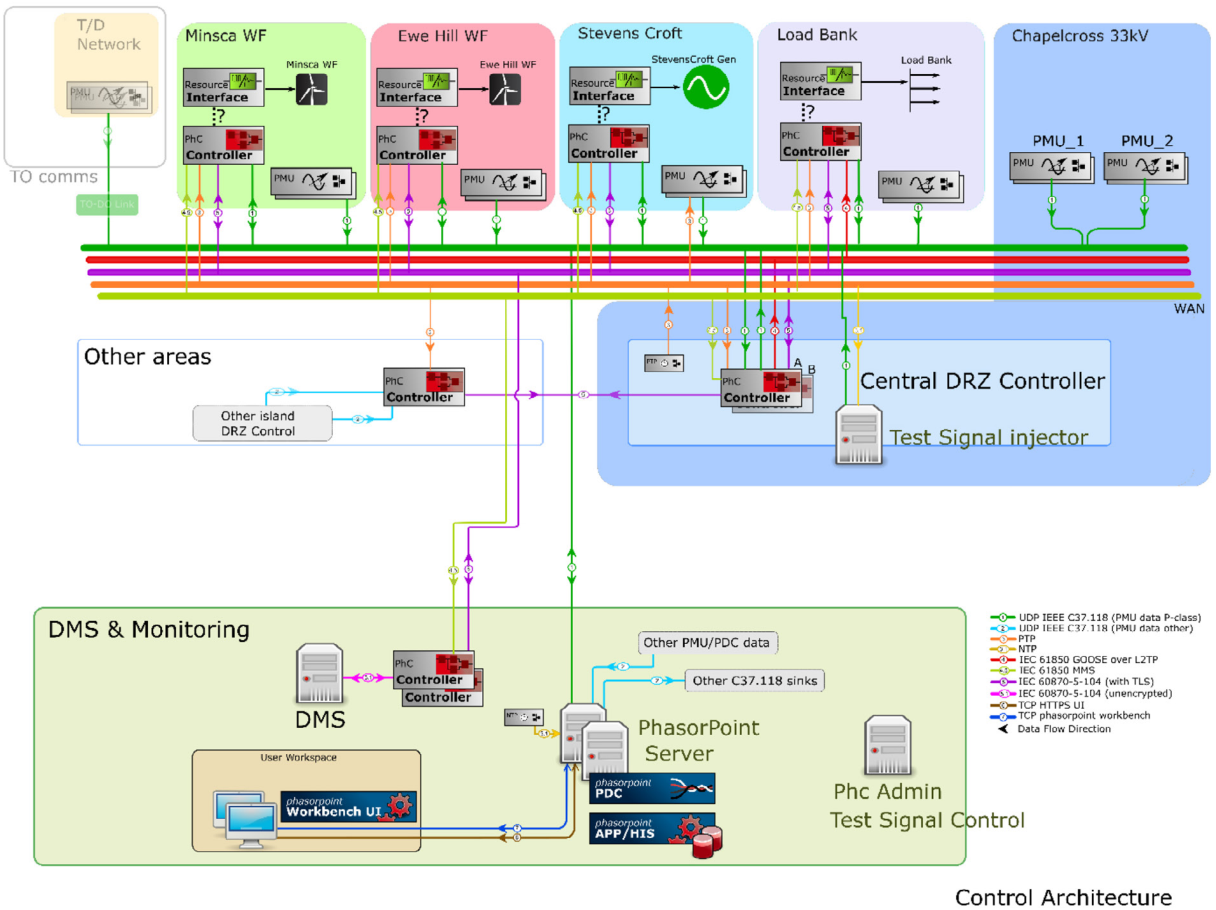


Figure 17: High level DRZ-C solution design including key components, links and communications protocols

The main components of the scheme shown in figure 17 are described further in Table 6, based on Chapelcross 33kV network:

Component	Location	Function
Phasor Measurement Unit (PMU)	Main Interconnected Transmission System (MITS) Steven's Croft Load Bank Minsca WF Ewe Hill WF Chapelcross 33kV SS	Measure V and I phasors + frequency streamed to main DRZ-C controller (Chapelcross 33kV SS) and central Wide Area Monitoring System (WAMS) server. Data is streamed in real time across the network as defined by UDP IEEE.C37.118 protocol. PMUs should be configured as P-class to reduce measurement latency.
Phasor Controller (PhC)	DNO Control Centre Steven's Croft Load Bank Minsca WF Ewe Hill WF Chapelcross 33kV SS	Chapelcross 33kV PhC hosts the main DRZ-C scheme. Control signals are relayed to resource via a range of protocols depending on latency requirements (IEC 61850 GOOSE, IEC 60870-5-104). It can also act as a PDC to forward measurements to other locations e.g. TO/TSO. Other PhC locations handle encryption and protocol conversion etc.
Resource Interface	Resource locations	Interface to resource DRZ-C Systems (within resource DRZ-C System) that defines communications protocol.
TO-DNO Link	SPD to SPT/National Grid ESO communications	Communications channel between DNO and TO/TSO to share PMU and DRZ-C data. GE PhasorPoint supports the SCADA protocol IEC 60870-5-104 for this purpose. Alternatively, the ADMS may support ICCP for data forwarding.
DMS	DNO Control Centre	Primary monitoring tool for overall ReStart process and sequences. Data point sent via PhC and WAMS over IEC 60870-5-104.
Precision Time Protocol (PTP) Source	Chapelcross 33kV SS	Provides PTP signals to synchronise range of DRZ-C devices, based on IEEE-1588 protocol.
EMS	TSO Control Centre	National Grid ESO monitoring. Information exchanged between DMS and EMS to be defined based on organisational model.
Network Time Protocol (NTP)	DNO Control Centre	Provide NTP source for WAMS (PhasorPoint server).
WAMS Server (PDC + Applications)	DNO Control Centre	Store PMU data and DRZ-C control status to enable DRZ-C scheme to be audited. Both TCP IEEE.C37.118 and UDP IEEE.C37.118 streams can be configured with data observed via the workbench UI. Relevant data can be streamed to DMS over IEC 60870-104.
Workbench UI	DNO Control Centre	UI linked to WAMS server over TCP HTTPS.
PhC Admin	DNO Control Centre	DRZ-C controller admin to manage settings and thresholds.
Other DRZ-C	Other DRZ islands	Potential to link multiple DRZ-C under one DNO region for possible distribution resynchronisation before transmission connection.

Table 6: Description of key DRZ-C components (based on Chapelcross 33kV network)

3.9.2 Architecture 2

To facilitate deployment and minimise costs, the DRZ-C System should utilise as much of the existing infrastructure as possible. This includes, existing DER, existing network support equipment and existing communications infrastructure where possible.

However, the system needs to meet certain performance criteria to support Black Start and therefore, different elements of the control system may be deployed at different levels on the network. There are three basic levels for system deployment, Control Centre, Substation GSP and DER levels.

Level 3 is located at the Control Centre and generally runs on IT Server infrastructure.

Level 2 is located at the GSP or substation and runs on substation certified hardware.

Level 1 is in the field, at the DER interface and runs on substation certified hardware.

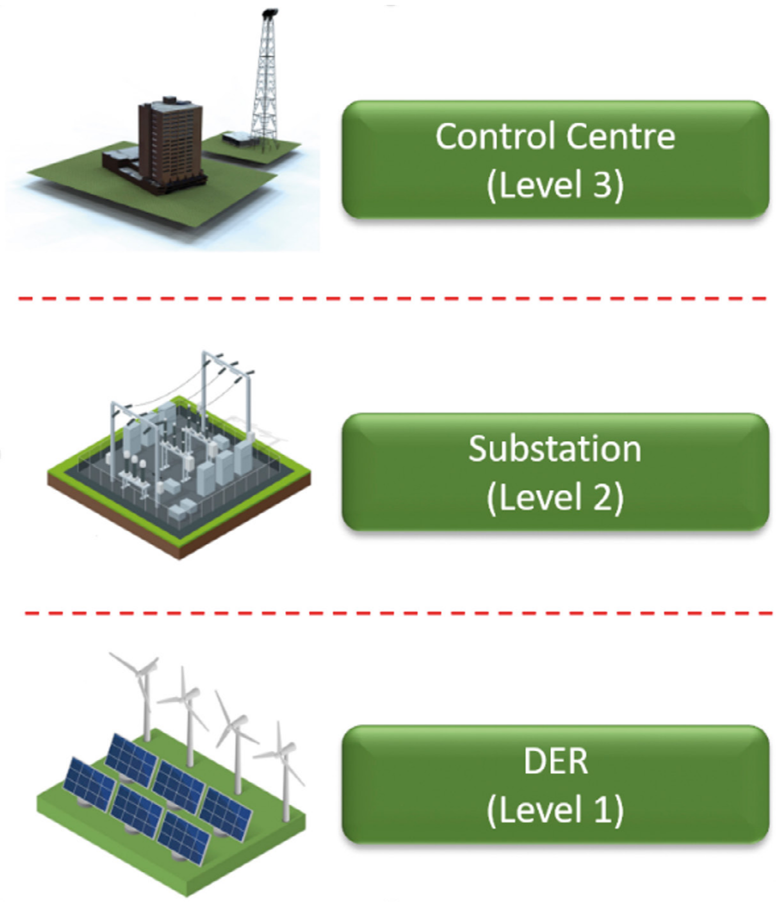


Figure 18: DRZ-C tiered architecture

To utilise as much of the existing infrastructure as possible, the system design should support different performance levels.

From our initial network studies the network transients that may lead to network instabilities happen in the order to 40–60ms and there are two options for responding to these:

1. self-dispatch from fast-acting DER (e.g. BESS, SVC, Solar, Load Shedding etc.) or
   self-dispatch provided by the Level 1 Controller controlling the fast acting DER
2. high-speed control of these fast-acting DER from a Level 2.

While the control system must be able to support all these options, self-dispatch is generally available from most of these DER and if not can be provided by the Level 1 Controller controlling them. Therefore, the use of self-dispatch minimises the overall system cost. Local self-dispatching functions at the DER/Level 1 Controller provide the fastest possible response and can be used for fast corrective response (<50ms) to network events.

The second level response is much less critical (500ms–10sec) as its about balancing load and demand and repositioning the operating point of the anchor generator. This is a typical ANM function which can use standard communications with latencies in the order of 30–60ms. This second level response can be provided at Level 2 (substation level) in the form of a Substation DRZ-C or at Level 3 (enterprise level) in the form of a DRZ-C System running on centralised IT servers. The deployment depends on the available communications infrastructure but both options are possible. The two models will be described in the next sections.

Finally, any coordinating control between systems or system updates will happen at an enterprise level, coordinating between Substation DRZ-C or the centralised DRZ-C Systems. As the response times of these systems is in the order of tens of seconds, communications latencies are not critical so a large latency can be tolerated. A figure of 200ms is used for the purposes of this report but in practice it is expected to be much less than this. This to provide high level operating parameters and coordination between systems.

Dividing the system into the various response times identifies where and when the performance is required to respond to network events while maximising the use of existing infrastructure and minimising overall system costs. Low latency, fast communications is always desirable particularly as data volumes increase over time, but the control system should be able to operate using as much of existing communications infrastructure as possible to simplify the deployment and minimises the costs. That said, the system will always benefit from improved communications, but this should not be an impediment to deployment.

As outlined above, two deployment models are considered depending on the available communications:

1. Model 1 – Centralised deployment
2. Model 2 – Hybrid deployment.

DRZ-C Centralised Deployment

The following diagram shows the deployment plan for Model 1. Apart from the Level 1 DER control functions, all other control functions are deployed centrally (Centralised DRZ) at Level 3.

UK DRZ Scheme Deployment – Model 1

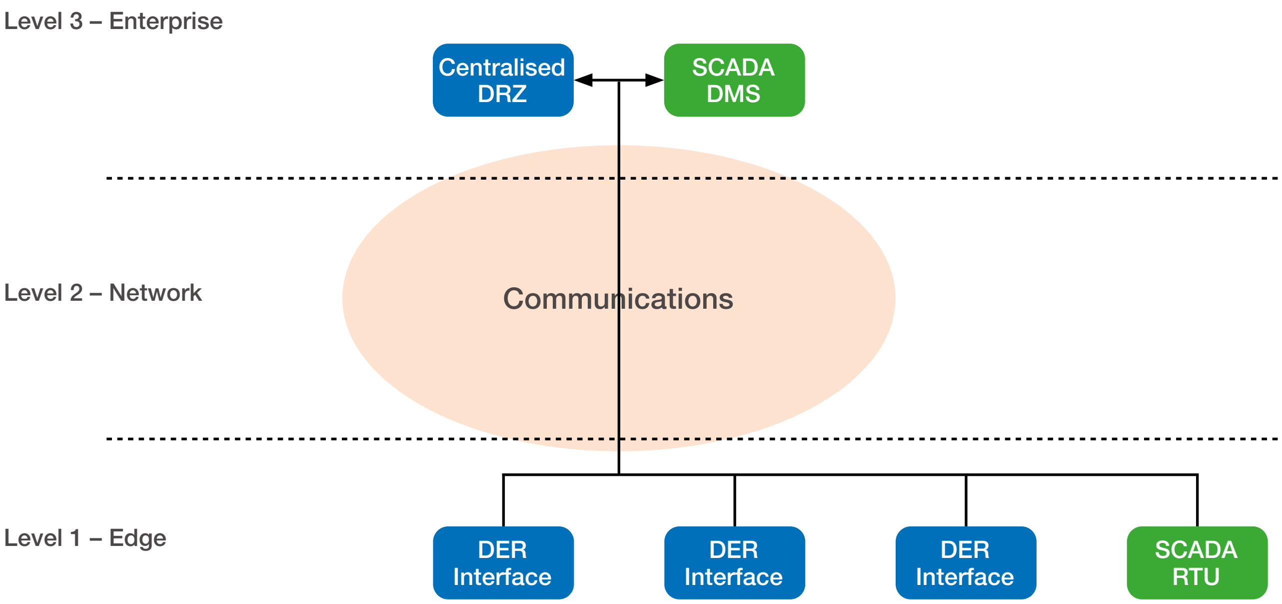


Figure 19: DRZ-C Centralised deployment

This deployment model assumes that self-dispatching is done at Level 1 for fast corrective response to any network event and all other DRZ control is deployed at Level 3 (Enterprise Level) assuming the communications between Level 3 and Level 1 is capable of meeting the < 50ms latency requirement required for standard ANM Control.

DRZ-C Hybrid Deployment

The following diagram shows the deployment plan for Model 2. Apart from the Level 1 DER control functions, any real time control functions are deployed at Level 2 where faster communications are provided, and the remaining management functions can be deployed at Level 3 where response times are less critical but where management functions are easier to apply.

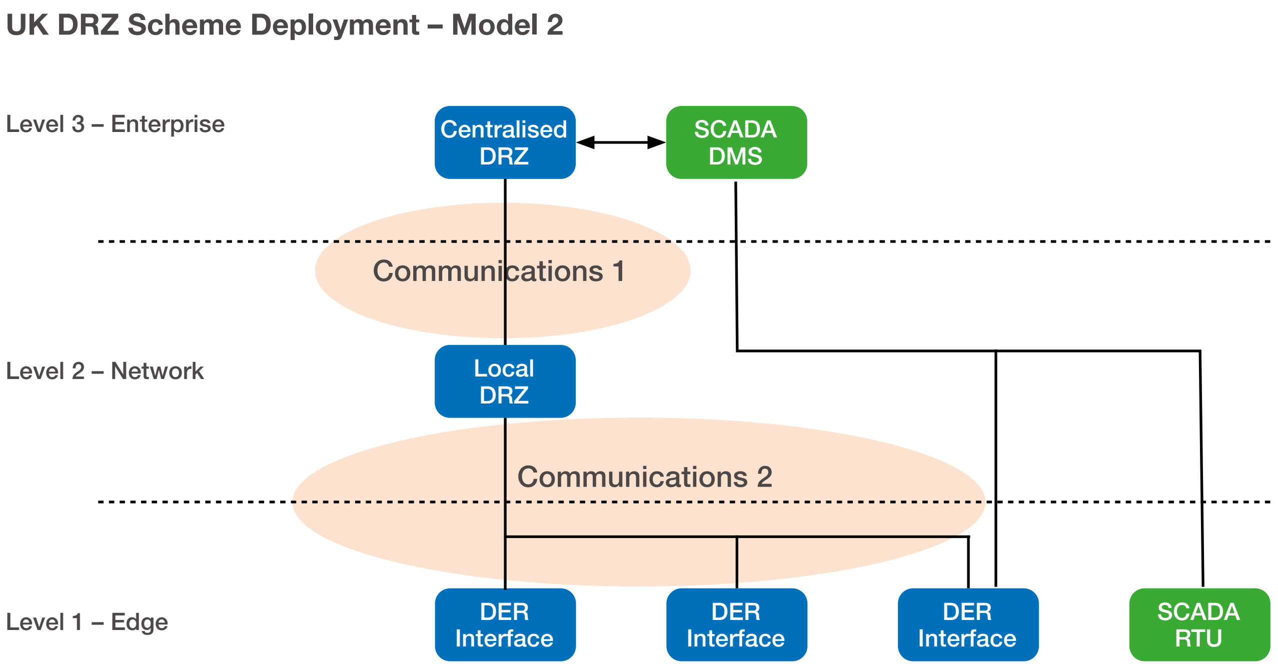


Figure 20: DRZ-C hybrid deployment

Where low latency communications cannot be provided directly between the Level 1 Controllers and the Level 3 system then a hybrid system can be deployed. Here the Level 1 DER Controllers at remote DER locations are connected to a Level 2 Controller via low latency communications. The Level 2 Controller can then communicate with a higher Level 3 Controller for wider system coordination where the speed of response is not as critical and management functions are easier to apply. The architecture assumes self-dispatch locally at the DER/Level 1 Controller for fast corrective response to any network event. Peer-to-peer communications between Level 1 Controllers is not considered necessary if self-dispatch is provided by the DER and/or the Level 1 Controllers.

An alternative to self-dispatch could be closed loop control implemented between the Level 2 Controller and the Level 1 Controllers. This would require highly resilient communications, with latencies in the order of <10ms to react to transients which happen in the order of 40–60ms. This level of communications is not generally available between Level 2 and Level 1 DER and would require additional investment. In this case it may be more appropriate to locate the supporting DER (e.g. BESS) beside the anchor generator.

A further option could employ peer-to-peer communications between the Level 1 Controllers where, for example, the Anchor DER could communicate directly with a support DER (e.g. BESS). This too would require highly resilient communications, with latencies in the order of <10ms to react to transients which is not generally available between Level 1 DER.

3.9.3 Discussion

This section provides examples of how functional capability described in this chapter may be deployed to physical hardware. The physical architecture of the solution is critical to evaluate the capability of the existing Operational Telecoms (OpTel) system to accommodate DRZ-C control capability. The DRZ-C companies provided indicative estimates of telecoms performance (e.g. latency, bandwidth) of their solution. The Design Stage II (December 2020) report produced by the OST workstream presents learning relevant to the functional requirements of a telecoms system required to support a DRZ-C solution.

DER Controller

The two architectures examples provided, and other DRZ-C designs received but not included in this section, all propose new physical DRZ-C equipment installed at each DER site. The role of DER Controllers within the DRZ-C context vary from design to design but could be used to:

- self-dispatch real or reactive power resource based on a local measurement at DER site
- receive set point instructions from a central controller and translate into a form suitable for the control system of each DER

- facilitate secure wide-area communication (i.e. DER controller and Central controller encrypt communication)
- implement non-compliance (curtail/trip if not responding) or fail-safe (take action if comms fail to DER rather than letting the DER running uncontrolled).

Each DER site may also require additional measurement equipment depending on the performance of the measurements required. The first architecture and associated overall solution, relies on synchrophasor measurements provided by Phase Measurement Units (PMU) deployed at each DER site.

Centralised DRZ-C System Functionality

All architectures propose to deploy DRZ-C functionality within a centralised location, deployed alongside other critical DSO/ESO critical applications.

Most designs propose that a standalone supplier provided DRZ-C application is required (i.e. control centre level functionality couldn't be hosted into DMS/EMS). It is expected that application could be deployed on commodity DSO/ESO supported virtualised or physical servers. The functionality hosted on the centralised component of the solution may include:

- calculate and dispatch the optimal DER operating positions (often referred to as slow balancing with this chapter)
- calculate the dispatch fast-acting controls (if performance of the telecoms network allows)
- a supervising function of the DRZ-C to perform co-ordination between multiple DRZ-C/DRZ.

DRZ System Functionality at GSP

It may be advisable that DRZ functionality is deployed at the GSP substation. The functionality hosted at the GSP would be similar to that described in a centralised DRZ-C System. Deploying DRZ-C functionality at the GSP could reduce the performance requirements on the DSO/TSO back-bone telecoms network, since the DRZ-C could measure the frequency/voltage of the network directly and similarly directly issue any fast-acting control actions.

Centralised vs GSP

The DRZ-C design activity has so far focused on a single island and not considered any use cases associated with managing multiple DRZ islands. In such a use case there would likely be some technical/commercial advantages to consider:

- Potential to host the main intelligence of the DRZ-C in a single (with redundant/standby sites) centralised location. The centralised solution would require one main controller whereas the GSP approach would require a physical deployment to each GSP.
- Supervising function of the DRZ-C to perform co-ordination between multiple DRZ-C/DRZ.

The example architectures (and associated technology of the proposing companies) presented in this section could be adapted to either a Centralised or GSP based (or Hybrid as described in the second example) solution.

DRZ Functionality Hosted by DSO/ESO Systems

All designs assume that the DSO/ESO DMS/EMS systems are enhanced with additional capability to support operators supervise the restoration process and take a controlling action if required. The DRZ likely requires the following functionality to be implemented with the DMS/EMS:

- Switching sequences and automation for:
    - configuring the network topology to a known initial state for Black Start
    - switching protection settings groups to island mode
    - restoring grid-connected protection settings groups after resynchronisation.
- Operator initiates load pickup stages via DMS – this may be just individual breaker close, but possibly there may be more complex sequences, e.g. staggering load pickup to manage RoCoF.
- Operator visualisation of the island including Block Load pickup limits/risks and resource availability.

3.10 Online Network Analysis

One of the DRZ-C companies propose that the DRZ-C hosts a network analysis engine capable of performing power static, dynamic and transient simulations. This section provides a general introduction to the network analysis capability as described by that company.

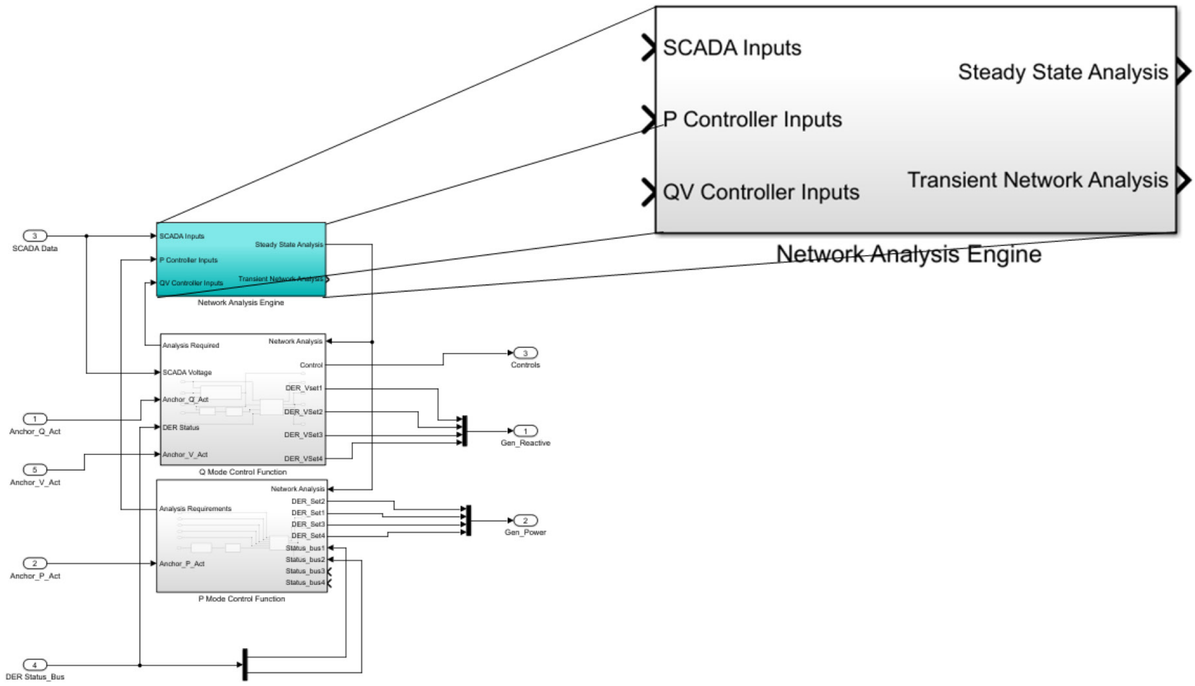


Figure 21: Block diagram showing inputs and outputs to network analysis engine

The network analysis engine performs steady state analysis and transient analysis in real time on the network in question. The results are passed back to the individual service modules in real time for use in controlling the network.

The network analysis engine is used to analyse the network operation in real time to determine if any action needs to be taken to ensure it operates within safe operating limits or to determine if any proposed actions will cause steady state or transient instability on the network and to identify alternative actions to avoid problems.

3.10.1 Steady State Load Flow and Fault Level Analysis Module

The steady state analysis performs a set of steady state power flow analysis calculations on a power system network model incorporating asset data and power flow data. The network model and the power flow analysis may use historical, forecasted, simulated or real time data depending on how the control functions is being used.

Real-time data is used for DRZ and VPP control functions. Simulated data is used for self-test and validation functions. Historical data is used to train the neural models in the predictor (used for forecasting block loads etc) which can then be used to plan for future states of the DRZ.

For continuous analysis of the current network operation it uses current real time data for its analysis. For any switching operations it analyses the network configuration with the proposed switching states and any expected additional generation or demand.

- Steady state module uses:
  - current network model
  - network data, including power flows and switch statuses (including inferred switch status), obtained from the remote devices
  - real time SCADA signals from the control devices.

The network model is the static representation of the physical power system with a sufficient level of detail to allow control of the system.

The static network model must be supplemented with dynamic data to represent different operating conditions such as generation and demand values and alternative running arrangements. The dynamic data required to achieve this will be obtained, or derived from, the real time data from the SCADA system and/or directly from the remote control and monitoring devices. All such data is stored in the DRZ-C so that the analysis can access the appropriate data as required.

The analysis software includes a variety of user configurable settings which can be defined and saved along with the static network model.

The control functions engine runs on demand when new dynamic data is received. It performs a set of calculations based on that dynamic data and produces a set of analysis outputs. When complete the steady state engine is then ready to perform subsequent calculation based on alternative data scenarios.

The analysis engine maintains an internal file of historical data which is used for a variety of purposes including the monitoring of DER responses to set point changes over time.

The static network model and dynamic data updates allow load flow and fault level calculations to be undertaken based on the current operating state of the network. Load flow calculations identify all thermal overloads, reverse power flows and voltage violations.

Thermal overloads are identified based on seasonal ratings for lines and transformers (monthly ratings can be defined). The appropriate rating is selected automatically based on the current date and time. Shared ratings between circuits and transformers and transformer reverse power flows can also be monitored.

Voltage violations are identified from the defined voltage limits for each nominal voltage level. These voltage limits default to the statutory limits but users can add nominal voltage levels and adjust the default voltage limits.

The steady state analysis module includes several functions that may be executed depending on the specific request of the client application.

These may include:

- data validation and data quality checks to determine if the calculated load flow results are within tolerance
- sensitivity calculations to determine the sensitivity of power flows and voltages to changes in DER outputs
- violation checks and generator curtailment to identify and resolve thermal and voltage constraints using real and reactive generator control
- contingency analysis calculations to identify worst case operating conditions (e.g. N–1) and use these as the basis for other control modules
- reactive capability calculations to determine the reactive capability of generators which have voltage or active power dependant characteristics
- fault level calculations are undertaken to:
  - ensure the fault level ratings of equipment are not exceeded
  - ensure that there is adequate short circuit current to operate protection correctly, including correct operation of fault passage indicators (FPIs)
  - ensure that Earth Loop Impedance does not exceed limits, to ensure sufficient fault current to operate protection correctly and to prevent flicker.

Each of the above modules may be run in sequence or in parallel depending on the application and response time requirements.

3.10.2 Discussion

If the DRZ-C has the capability to perform power system simulations in real time in advance of planned control actions it could lead to the generation of more optimal control actions and therefore a more controlled/efficient restoration process. If the network analysis simulation engine is provided with good quality data across key nodes of the network the DRZ-C will be capable of determining the effectiveness of any potential control action. A range of different control actions could be evaluated (by simulation) based on the conditions at the time before implementing the optimal control action.

To justify the adoption of a network analysis engine within the DRZ-C System (considering the perceived additional complexity) it would be required to demonstrate how the capability to simulate the network provides benefit over the simpler single purpose rule-based logic. In practice any implementation of a DRZ-C with an inbuilt simulation engine may also have the capability to implement rule-based logic for some aspects of fast-acting control as an emergency backup when events are inconsistent with the model.

The online network analysis approach could be particularly valuable if the normal operating conditions of the network change (e.g. network running arrangement). If provided with necessary network data (e.g. CB status) the online network analysis could generate a revised switching schedule (if also capable of determining an optimal restoration plan).

Although the necessity for the DRZ-C to play an active role in managing voltage of the DRZ is not yet defined, if the DRZ-C has the capability to perform load-flow/transient studies it can simulate voltage at any location on the network when subject to any control action. Such a capability could provide the framework on which other DRZ specific voltage control functions could be developed.

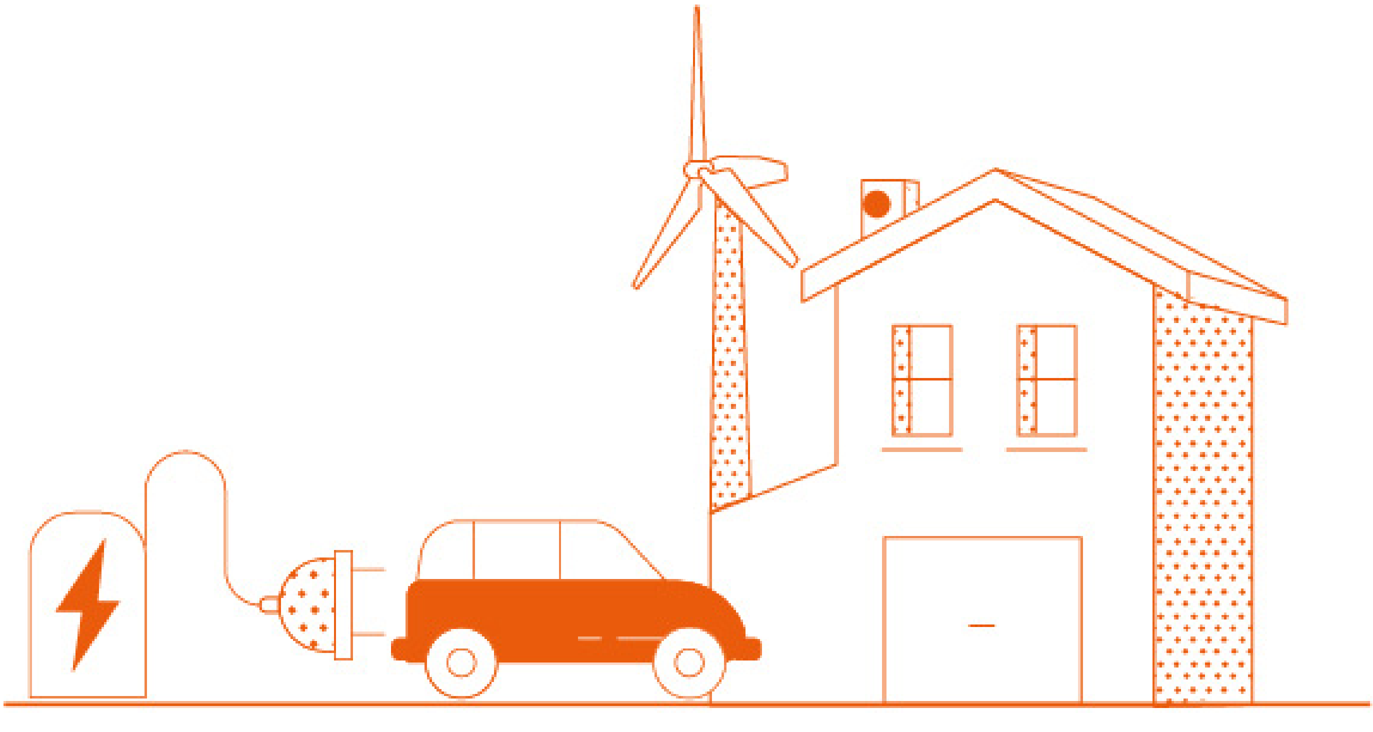
The proposal of an online network analysis engine within a DRZ-C provides a different perspective on how control systems are typically implemented with pre-determined rules/threshold. If a DRZ-C System can simulate the power system environment it would intuitively provide the basis on which to build a range of other control applications rather than be tailored to DRZ-C control only.

3.11 Conclusion

This chapter provides descriptions of functional design associated with key DRZ-C capability. The content provided covers a wide range of capability, it is hoped that the section provides DRZ-C designers with a grasp of the functionality required of a DRZ-C and provides some examples about how the capability could be designed. The designs presented are based on functional design outputs provided by industry leading companies. The section does not intend to dictate how a DRZ-C should be designed but provides examples of how the industry experts have proposed to approach the use case. Discussion provides insight/analysis relevant to the presented content.

It is believed that the DRZ-C designs provided are credible and will be proven feasible during an implementation and test activity. Development stage 2 of the DRZ-C works will test one or more of the DRZ-C Systems with a lab-based environment to demonstrate feasibility in advance of any potential live network trials. The provided requirements may be adapted following learning from lab testing.

The OST workstream's Design Stage II report will present their assessment on the implications on the telecoms infrastructure of supporting the described DRZ-C functionality. The OST work will also include an appreciation of relevant cyber-security standards and interface capability (e.g. data protocols).



4. Functional Requirements – Anchor Generator

4.1 Introduction

An anchor generator is required within each DRZ as the initial source of power able to energise a dead network. The range of individual technical services which may be required to establish, grow and maintain a DRZ are given in Table 7. It can be seen that an anchor generator is essential for each DRZ.

Technical Services	Requirement	Potential Providers	Comments
Anchor generator	Essential	Synchronous generator, or other technologies with required capability. A single point of connection is required with the DNO network.	Only one anchor gen is required per DRZ.
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 (MW)	Potential	May be schedulable or intermittent MW. Demand side management, others…	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.
Inertia	Potential	Synchronous generator, synchronous compensator (or converter-based sources with appropriate control), others…	Increase frequency stability of the DRZ and /or allow greater demand blocks to be picked up.

Table 7: DRZ technical services

In this section of the report the technology agnostic functional requirements of an anchor generator are developed. (The functional requirements for the additional services will be finalised at a later stage in the Distributed ReStart project.) This has been done by first considering the existing technical requirements for a Black Start station (built around large conventional power stations). An anchor generator mainly retains the principles of the existing requirements, however some specific requirements may need to be modified to reflect the capabilities of smaller generators and new requirements may be required.

At present, based on DER connected to the GB network, synchronous generators are the DER technology most likely to be able to meet the requirements of an anchor generator (for example the ability to create its own independent voltage source). As such, the functional requirements for an anchor generator are further developed with reference to the capability of synchronous generators connected to the distribution network (primarily steam, gas and hydro powered). It should be noted that emerging technologies such as GFC (connected to wind farms, solar farms or BESS), may also be able to offer some, or all, of the anchor generator requirements, and have also been considered in the development of the requirements.

The functional requirements for an anchor generator should also take account of the specific technical issues associated with initiating, maintaining and expanding a DRZ.

In conclusion, the functional requirements for an anchor generator have been developed with reference to:

- the existing technical requirements for a Black Start service
- the capability of existing synchronous DER
- the emerging technology of GFC
- the specific requirements of an anchor generator within a DRZ.

For each of the proposed functional requirements the following is given:

- category
- existing definition (for large conventional power stations)
- existing requirement (for large conventional power stations)
- DER considerations
- proposed Black Start from DER functional requirement.

4.1.1 Functional Requirement No.1 – Time to Connect

Existing Definition: Time taken to start up the Black Start plant from shutdown, without the use of external power supplies, and be ready to energise part of the National Electricity Transmission System (NETS) within 2 hours of receiving an instruction from the Electricity System Operator (ESO).

Existing Requirement: ≤ 2 hours

DER Considerations:

Self-start: For Black Start from DER, the anchor generator will be required to self-start and generate its own independent voltage source, being responsible for initially energising a dead network. The majority of synchronous DER are powered by steam (e.g. CHP, energy from waste, biomass), gas and hydro. Some sites are manned 24/7 (typically the steam plants), but others may be manned only during working hours or may be fully automated. It is not envisaged that a fully automated system would be installed for self-starting (unless feasible from an existing automated system), due to the complexities of reconfiguration for anchor generator island operation.

The generator should be capable of energising its own network (including any generator transformers) up to the DNO or transmission point of connection which should be at 33kV or 11kV (transforming directly to a higher voltage). It should be able to operate at rated frequency without the connection of load from the DNO network.

Time to Connect: An appropriate time to connect for synchronous DER will depend on several factors such as:

- amount of works to reconfigure to islanding mode of operation
- if the site is permanently manned or not (if not, the time for personnel to get to site has to be considered)
- the type of plant (e.g. the requirement for a steam boiler be hot enough to start the generator).

Given that multiple DRZs will be established in a staged process, it is not necessary or desirable that all anchor generators are available at the shortest possible time. In addition, the different generator technologies themselves do not lend themselves to a one size fits all requirement. As such, individual generator capability should be declared within the minimum time to connect requirement. It should be noted that it could be up to 72 hours after a black out when a Black Start generator is instructed to restart.

Time to Connect – Proposed Anchor Generator Requirement

The proposed time to connect requirement for an anchor generator is given in Table 8.

Category No.1: Time to connect	Proposed DER Requirement	≤8h
	Proposed DER Definition	• Time taken from instruction (from the relevant system operator) to start up the Black Start plant from shutdown, without the use of external power supplies. • Instruction to start up may be up to 72hrs after a black out. • Energise up to the DNO statutory point of connection. • Ability to operate at rated frequency, no load, for four hours (without connection to the DNO network). • Connected to DNO or transmission network at 33kV or 11kV (transforming directly to a higher voltage).
	Comments	• Exact capability to be declared. • Confirm if loadbank is required to meet the proposed DER definition.

Table 8: Proposed anchor generator time to connect requirement

4.1.2 Functional Requirement No.2 – Service Availability

Existing Definition: The ability to deliver the contracted Black Start service over 90% of a year, or other time period appropriate to the contractual arrangements. Note: it is the responsibility of the provider to demonstrate its service availability.

Existing Requirement: ≥ 90%

DER Considerations: It is anticipated that most anchor generators will be able to meet the current requirement and thus this will remain unchanged for DER.

Service Availability – Proposed Anchor Generator Requirement

The proposed service availability requirement for an anchor generator is given in Table 9.

Category No.2: Service Availability	Proposed DER Requirement	≥90%
	Proposed DER Definition	• The ability to deliver the contracted Black Start service over 90 per cent of each year of providing a Black Start service. • Note: It is the responsibility of the provider to demonstrate its service availability.
	Comments	• A Black Start could happen at any time thus a high service availability is required.

Table 9: Proposed anchor generator service availability requirement

4.1.3 Functional Requirement No.3 – Resilience of Supply, Black Start Service

Existing Definition: When instructed to Black Start, the minimum time the provider will deliver the contracted service.

Existing Requirement: ≥10h

DER Considerations: The current Black Start strategy allows for up to 5 days (120hours) before 100% of the GB demand may be restored (60% to be restored within 24 hours). As such theoretically an anchor generator could be instructed to start at the beginning of a black out, and would need to remain operational, but disconnected from the MITS, for up to 120 hours.

It is anticipated that a more realistic maximum time span for operation would be ~3 days, allowing for a delay after a black out before starting, and/or the MITS being available several days after a black out. Moreover, it may be excessively onerous for a DER to have enough on-site fuel supply for five days, whereas three days may be a more realistic capability. The fuel reserves should also be based on a continuous output of 90% rating, being the maximum load factor anticipated in order to provide the necessary frequency control.

Resilience of Supply, Black Start Service – Proposed DER Requirement

The proposed 'resilience of supply, Black Start service' requirement for an anchor generator is given in Table 10.

Category No.3: Resilience of Supply, Black Start Service	Proposed DER Requirement	≥72h up to 120h
	Proposed DER Definition	• When instructed to Black Start, the minimum time the provider will deliver continuous output at 90% rated capacity.
	Comments	• Exact capability to be declared.

Table 10: Proposed anchor generator 'resilience of supply, Black Start service' requirement

4.1.4 Functional Requirement No.4 – Resilience of Supply, Black Start Auxiliary Units

Existing Definition: Run continuously at rated output for a minimum of three days.

Existing Requirement: ≥ 72 hours

DER Considerations: An anchor generator will need enough auxiliary power supply to maintain the plant availability for up to 72 hours after a black out, and also to enable the power station to operate for the time period declared in 'resilience of supply, Black Start service'. It is anticipated that during generator operation, the essential house loads would still be supplied from the auxiliary generation to prevent them being exposed to under/over voltage or under/over frequency events during the energising and operation of a DRZ network.

Resilience of Supply, Black Start Auxiliary Units – Proposed DER Requirement

The proposed 'resilience of supply, Black Start auxiliary units' requirement for an anchor generator is given in Table 11.

Category No.4: Resilience of Supply, Black Start Auxiliary Units	Proposed DER Requirement	120h
	Proposed DER Definition	• Run continuously for a maximum of 5 days in order to: 1. maintain the generator declared time to connect availability for up to 72 hours after a blackout 2. maintain the generator house loads for the declared time in the 'resilience of supply, Black Start service'.
	Comments	• Provider to determine the fuel supply required.

Table 11: Proposed anchor generator 'resilience of supply, Black Start auxiliary units' requirement

4.1.5 Functional Requirement No.5 – Frequency Control

Existing Definition: Ability to manage frequency level when block loading (47.5Hz–52Hz).

Existing Requirement: Existent on large power stations.

DER Considerations: An anchor DER will require to have its own fast acting frequency control as it will be primarily responsible for controlling the frequency in a DRZ.

For DER connected before 27th April 2019 (not subject to ER G99), the DNO Connection Agreements and the Grid Code determined the required frequency control capability. Under the Grid Code, all large power stations must maintain provision for frequency control through either Limited Frequency Sensitive Mode (LFSM) or Frequency Sensitive Mode (FSM). Most DER which are subject to these regulations are unlikely to be operating with their continuously acting frequency control mode enabled (FSM), and would use LFSM only which responds to reduce output for frequency deviations in excess of 50.4Hz.

Most existing smaller DER are not subject to the Grid Code requirements and are instead subject to the relevant DNO's Connection Agreement. For Scotland, England and Wales there has been no DNO requirement to provide frequency control. A DER still has governor control, but this typically operates in base load (MW) control.

ER G99 requires that Types C and D (>10MW) generators are able to contribute to frequency control by having a fast-acting frequency control device. Type B (1–10MW) should also have the capability to respond to low and high frequencies (LFSM).

It is anticipated that frequency control can be activated or retrofitted to existing DER, and that future DER will have this capability, therefore the requirement can be satisfied.

Frequency Control – Proposed Anchor Generator Requirement

The proposed 'frequency control' requirement for an anchor generator is given in Table 12.

Category No.5: Frequency Control	Proposed DER Requirement	**A fast-acting proportional frequency control device is required.**
	Proposed DER Definition	• Frequency control device as defined in Engineering Recommendation G99 (applicable to Type C and D generators). • The ability to manage frequency level when block loading (47.5Hz-52.0Hz). • Fast acting frequency control device capable of being operated in isochronous mode or with a set point and droop setting if required.
	Comments	

Table 12: Proposed anchor generator 'frequency control' requirement

4.1.6 Functional Requirement No.6 – Voltage Control

Existing Definition: Ability to control voltage level within acceptable limits during energisation/block loading (+/– 10 per cent).

Existing Requirement: Existent on large power stations.

DER Considerations: An anchor generator will require to have its own independent continuously acting voltage control to regulate the voltage on the DRZ during transient events such as load pick up and network energisations, and during steady state conditions when the demand is constantly varying.

In Scotland, the DNO Connection Agreements require that a synchronous generator operates in constant voltage control at its generator terminals (this equates to droop control considering the impedance of the generator transformer). In England and Wales power factor control is usually stipulated in the Connection Agreements (typically a generator is required to operate near unity power factor). Engineering Recommendation (ER) G99 (for DER connected after 27 April 2019) requires all Type C and D generators (10MW and above) to provide continuous steady state control of the voltage at the connection point with a set point and slope (droop) characteristic.

Voltage Control – Proposed Anchor Generator Requirement

The proposed 'Voltage control' requirement for an anchor generator is given in Table 13.

Category No.6: Voltage Control	**Proposed DER Requirement**	**Ability to provide continuous steady state control of the voltage with a set point and slope characteristic.**
	Proposed DER Definition	• Voltage control device as defined in Engineering Recommendation G99 (applicable to Type C and D generators). • Ability to create a voltage source (independent of the DNO network) and control the voltage within acceptable limits during energisation/block loading (+/– 10%).
	Comments	• During a Black Start event the anchor generator will need to maintain voltage (within limits) when creating, maintaining and expanding a DRZ.

Table 13: Proposed anchor generator 'voltage control' requirement

4.1.7 Functional Requirement No.7 – Block Loading Size

Existing Definition: Capacity to accept instantaneous loading of demand blocks.

Existing Requirement: ≥ 35MW

DER Considerations: The block load pickup (BLPU) capability of a synchronous DER is typically between 10–25% of its active power (MW) rating and depends on factors such as the turbine technology. A 33kV connected anchor generator will typically have an active power range between 20MW and 50MW and thus a BLPU between 2MW and 12.5MW. The smallest demand blocks which can practically be connected during system restoration is an individual 11kV feeder at a primary (33/11kV) substation. These typically have a maximum demand between 0.5MW and 6MW and, for Black Start purposes, up to 200 per cent of those 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).

It follows that an anchor generator may only have the BLPU capability 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 demand blocks to minimise restoration times, it is likely that additional resources will require to be coordinated to enhance the BLPU within a DRZ. This is a primary function of a DRZ controller which will also seek to minimise the 'stress' on the anchor generator by reducing the BLPU which it 'sees' to a minimum. It follows that within each DRZ the anchor generator will have to provide a minimum BLPU capability, the value of which will depend on the DRZ control scheme, and other available resources.

Block Loading Size – Proposed DER Requirement

The proposed 'block loading size' requirement for an anchor generator is given in Table 14.

Category No.7: Block Loading Size	**Proposed DER Requirement**	**Estimated ≥ 2MW (site specific depending on DRZ)**
	Proposed DER Definition	• Capacity to accept instantaneous loading of demand blocks and maintain the frequency within the 47.5Hz to 52Hz range.
	Comments	• Exact capability to be declared.

Table 14: Proposed anchor generator 'block loading size' requirement

4.1.8 Functional Requirement No.8 – Reactive Capability

Existing Definition: Ability to energise part of the network (MVAr>0, MW=0)

Existing Requirement: ≥ 100MVAr Leading

DER Considerations: The Grid Code states that 'all onshore synchronous generating units must be capable of continuous operation at any point between the limits 0.85 power factor lagging and 0.95 power factor leading[5]' at the generator terminals. ER G99 requires that Type C and D synchronous generators (10MW and above) are able to do 0.92 leading power factor at the connection point.

Given the varying MVA capacity of DER (and corresponding MVAr absorption capability) it is proposed that the required leading capability of the anchor generator is based on the available power factor and not on a fixed capacity of MVAr. If additional MVAr absorption is required, to energise the distribution/transmission network, then this would be contracted as a separate service via additional DER.

Reactive Capability – Proposed DER Requirement

The proposed 'reactive capability' requirement for an anchor generator is given in Table 15.

Category No.8: Reactive Capability	Proposed DER Requirement	**Minimum of 0.95 leading and 0.95 lagging power factor at the point of connection.**
	Proposed DER Definition	• Ability to absorb MVArs (leading power factor) to energise the DNO network whilst active power is zero. • Ability to generate MVArs (lagging power factor) to supply network demand.
	Comments	• Numerical (MVAr) leading and lagging values to be declared.

Table 15: Proposed anchor generator 'reactive capability' requirement

4.1.9 Functional Requirement No.9 – Sequential Start-Ups

Existing Definition: Ability to perform at least three sequential start-ups

Existing Requirement: ≥ 3

DER Considerations: It is anticipated that this requirement would be similar to the large power stations.

Sequential Start-Ups – Proposed DER Requirement

The proposed 'reactive capability' requirement for an anchor generator is given in Table 16.

Category No.9: Sequential Start-Ups	Proposed DER Requirement	≥ 3
	Proposed DER Definition	• Ability to perform at least three sequential start-ups.
	Comments	• Time required between sequential start-ups to be declared.

Table 16: Proposed anchor generator 'reactive capability' requirement

[5] The Grid Code (CC.6.3.2).

4.1.10 Functional Requirement No.10 – Fault Current Injection

Existing Definition: Short-circuit level (SCL), following the start of a system disturbance. Injection of reactive current during a disturbance.

Existing Requirement: 100MVA (t>80ms)

DER Considerations: A minimum SCL will be required at each voltage level within a DRZ to ensure that existing protection systems (with reduced Black Start settings where appropriate) will be able to detect and isolate fault conditions on the network. The anchor generator will be required to provide sufficient SCL in order that the network it energises can be protected (additional DER may be subsequently connected to increase the SCL to allow more network/different voltage levels to be energised if required).

Given the SCL available from DER is typically proportional to the MVA rating of the generator, and the varying capacities of anchor generator available, it is proposed that the required SCL capability is based on a ratio of the anchor generator MVA rating and not on a fixed capacity. It should be noted that the feasibility study for a DRZ will determine the minimum SCL required to protect the network (a fixed capacity) and, while an anchor generator may meet the generic ratio requirement for fault infeed, this may not be sufficient for the DRZ requirements. It follows that the DER would require to install additional resources to increase its SCL to be considered as an anchor generator.

Sequential Start-Ups – Proposed DER Requirement

The proposed 'SCL' requirement for an anchor generator is given in Table 17.

Category No.10: Short Circuit Level (SCL)	Proposed DER Requirement	**≥ 1 x DER MVA rating**
	Proposed DER Definition	• Injection of reactive current during a disturbance. • SCL measured at generator terminals.
	Comments	• DRZ feasibility study to determine if DER SCL is sufficient to be the anchor DER.

Table 17: Proposed anchor generator 'SCL' requirement

4.1.11 Functional Requirement No.11 – DRZ technical

Existing Definition: N/A

Existing Requirement: N/A

DER Considerations: Depending on the restoration plan for a DRZ, and the network characteristics, there may be specific technical requirements placed upon an anchor generator within a specific DRZ. Moreover, a DRZ-C System may be installed to automate parts of the restoration process and may require the anchor generator to provide specific functionality. For example, an anchor generator may be required to be able to change its automatic voltage regulator (AVR) set point (manually or automatically) to alter the network voltage. It may be required to have an on-load tap changer on the generator transformer (manual or automatic operation) or be able to ramp up the AVR voltage (soft starting to minimise transformer inrush currents) if requested.

Any specific anchor generator requirements will be detailed in this section on a DRZ specific basis.

DRZ Specific Technical Requirements

The proposed 'DRZ technical' requirement for an anchor generator is given in Table 18.

Category No.11: DRZ Specific Technical	Proposed DER Requirement	**To be confirmed based on specific DRZ requirements.**
	Proposed DER Definition	• Technical requirements on an anchor DER specific to a DRZ in order to facilitate the restoration process.
	Comments	• DRZ feasibility study to confirm.

Table 18:Proposed anchor generator 'DRZ technical' requirements

4.2 Conclusion

The eleven proposed functional requirements for an anchor generator to provide a Black Start service are given in Table 19. These requirements will be subject to revision as further technical requirements for establishing a DRZ are finalised, and the compatibility with existing DER capability is further assessed.

Category No.1: Time to Connect	**Proposed DER Requirement**	**≤8h**
	Proposed DER Definition	• Time taken from instruction (from the relevant system operator) to start up the Black Start plant from shutdown, without the use of external power supplies. • Instruction to start up may be up to 72hrs after a blackout. • Energise up to the DNO statutory point of connection. • Ability to operate at rated frequency, no load, for four hours (without connection to the DNO network). • Connected to DNO or transmission network at 33kV or 11kV (transforming directly to a higher voltage).
	Comments	• Exact capability to be declared. • Confirm if loadbank is required to meet the proposed DER definition.
Category No.2: Service Availability	**Proposed DER Requirement**	**≥90%**
	Proposed DER Definition	• The ability to deliver the contracted Black Start service over 90 per cent of each year of providing a Black Start service. • Note: It is the responsibility of the provider to demonstrate its service availability.
	Comments	• A Black Start could happen at any time thus a high service availability is required.
Category No.3: Resilience of Supply, Black Start Service	**Proposed DER Requirement**	**≥72h up to 120h**
	Proposed DER Definition	• When instructed to Black Start, the minimum time the provider will deliver continuous output at 90% rated capacity.
	Comments	• Exact capability to be declared.
Category No.4: Resilience of Supply, Black Start Auxiliary Units	**Proposed DER Requirement**	**120h**
	Proposed DER Definition	• Run continuously for a maximum of 5 days in order to: 1. maintain the generator declared time to connect availability for up to 72 hours after a blackout 2. maintain the generator house loads for the declared time in the 'resilience of supply, Black Start service'.
	Comments	• Provider to determine the fuel supply required.
Category No.5: Frequency Control	**Proposed DER Requirement**	**A fast-acting proportional frequency control device is required.**
	Proposed DER Definition	• Frequency control device as defined in Engineering Recommendation G99 (applicable to Type C and D generators). • The ability to manage frequency level when block loading (47.5Hz-52.0Hz). • Fast acting frequency control device capable of being operated in isochronous mode or with a set point and droop setting if required.
	Comments	• Provider to determine the fuel supply required.

Category No.6: Voltage Control	Proposed DER Requirement	**Ability to provide continuous steady state control of the voltage with a set point and slope characteristic.**
	Proposed DER Definition	• Voltage control device as defined in Engineering Recommendation G99 (applicable to Type C and D generators). • Ability to create a voltage source (independent of the DNO network) and control the voltage within acceptable limits during energisation/block loading (+/– 10%).
	Comments	• During a Black Start event the anchor generator will need to maintain voltage (within limits) when creating, maintaining and expanding a DRZ.
Category No.7: Block Loading Size	Proposed DER Requirement	**Estimated ≥ 2MW (site specific depending on DRZ).**
	Proposed DER Definition	• Capacity to accept instantaneous loading of demand blocks and maintain the frequency within the 47.5Hz to 52Hz range.
	Comments	• Exact capability to be declared.
Category No.8: Reactive Capability	Proposed DER Requirement	**Minimum of 0.95 leading and 0.95 lagging power factor at the point of connection.**
	Proposed DER Definition	• Ability to absorb MVArs (leading power factor) to energise the DNO network whilst active power is zero. • Ability to generate MVArs (lagging power factor) to supply network demand.
	Comments	• Numerical (MVAr) leading and lagging values to be declared.
Category No.9: Sequential Start-Ups	Proposed DER Requirement	**≥ 3**
	Proposed DER Definition	• Ability to perform at least three sequential start-ups.
	Comments	• Time required between sequential start-ups to be declared.
Category No.10: Short Circuit Level (SCL)	Proposed DER Requirement	**≥ 1 x DER MVA rating**
	Proposed DER Definition	• Injection of reactive current during a disturbance. • SCL measured at generator terminals.
	Comments	• DRZ feasibility study to determine if DER SCL is sufficient to be the anchor DER.
Category No.11: DRZ Specific Technical	Proposed DER Requirement	**To be confirmed based on specific DRZ requirements.**
	Proposed DER Definition	• Technical requirements on an anchor DER specific to a DRZ in order to facilitate the restoration process.
	Comments	• DRZ feasibility study to confirm.

Table 19: Anchor generator – proposed functional requirements

5. Black Start from DER – Proposals for Testing

Our July 2019 report on the viability of restoration from DER[6] presented our initial thinking on testing. This chapter presents our current proposals, which will be further refined in the final year of the project with experience from the live trials and desktop exercises. Based on project learning so far, it is proposed that the overall approach to testing will retain many features from the current approach with an assurance framework that includes a range of physical tests supplemented by simulation-based testing and training, assurance audits and desktop exercises. However, there will be many differences with a DER-based approach.

5.1 Introduction

Given the nature of Black Start, where the service is expected to be very rarely used – possibly never – functionality will mainly be demonstrated only in testing. Clearly this is important to give confidence that the service will work as intended if ever needed for an actual Black Start. However, given that the service may never actually be delivered, it is testing that will provide the justification for payments to be made. Testing also provides the best opportunity to refine the approach, across all technical, organisational and other aspects of performance. Black Start testing, therefore, is somewhat different from other compliance testing, such as that done during normal connection and commissioning processes, as these are generally a means to the end of generating power and providing ancillary services. It is hoped that the Black Start service is never actually needed so the testing process itself may be considered the end, not just the means.

5.2 Purpose of Testing

The testing regime should be designed to satisfy the following objectives:

1. Prove technical capability of the plant and associated systems to deliver the required Black Start service
2. Demonstrate the ability of operational staff to undertake a Black Start
3. Confirm that appropriate procedures and resources are in place to support service delivery
4. Identify opportunities for improvement
5. Inform the review and update of the wider plans for Black Start.
6. Justify payment for provision of services.

Project learning has highlighted how, compared with the conventional approach, delivering Black Start from DER will rely much more on the coordinated use of multiple resources across different organisations. This means testing any DRZ-C System as well as the individual DER and putting more emphasis on multi-party testing than is currently done.

When introducing new methods, such as those proposed for Distributed ReStart, testing also provides an important means of training and establishing a common understanding of how things will work. Thus, it is likely that in the early years of this new concept being implemented, every testing activity will result in action plans including changes to equipment, revisions to procedures, additional training, and transfer of learning to other instances. The early years of rollout should, in some ways, be viewed as a continuation of the testing done within this project.

This raises questions around openness and confidentiality. It is of value to end customers and the industry collectively if the testing regime is sufficiently open to allow shared learning. It is also necessary to protect the confidentiality of individual parties, who are competing with others to provide services. These competing interests are already being managed in the testing being done within this project, and in other innovative initiatives across the industry, so it is not an insurmountable problem. However, the special nature of Black Start – in that there is likely to be only testing and no actual delivery – puts extra value on the sharing of learning from testing.

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[6] *Assessment of Power Engineering – Aspects of Black Start from DER, Part 1*, July 2020.

We expect the Distributed ReStart concept to be implemented gradually across the country, where it offers the most cost-effective option for system restoration. The overall restoration strategy for the system as a whole will involve a mixture of different resources, likely to include large power stations and HVDC links, as well as DER-based solutions. The strategy will continue to shift and adapt to circumstances and testing plays an important role in informing that. One aspect of this is to provide information on expected restoration timescales. It is only through testing that firm evidence can be collected that the requirements for speed and scope of restoration are being satisfied.

By 'testing' we primarily mean the review of capabilities from time to time to demonstrate capability. However, it is closely related to 'monitoring' of service availability and readiness. The current approach applies rigorous testing but then relies on Black Start service providers to declare themselves available. This informs the strategic positioning of the system by the ESO, driving operational decisions on what other resources might be needed, and feeds through into commercial settlement with service providers. With many more parties involved, Distributed ReStart makes monitoring of availability and readiness potentially much more difficult. This is another area where the communications and control systems put in place to facilitate Black Start from DER can assist. By providing reliable and up to date information on the condition of each service provider, and the service capability overall, this can inform the ESO's assessment of the strategic position at GB level as well as supplying the data needed for commercial settlement.

Ultimately, it must be possible to decide whether a service provider has 'passed' a test or not, not least because commercial reward will be directly dependent on it. Requirements must be clear and unambiguous and there must be practical means of assessing compliance in an objective way. However, it is better to view testing as a collaborative effort to arrive at the best outcome and improve quality of services, not as an assessment of one side by the other. The goal is to ensure that all parts of the country have adequate and resilient Black Start capabilities delivered in the most cost-effective way.

5.3 Parties Involved

Most existing Black Start testing involves a single service provider and National Grid ESO with tests focused on the technical capabilities of a specific generating unit or power station and the organisational readiness of the provider. Tests do sometimes involve energisation of the network and these will involve the relevant TO. Separately, the TOs and National Grid ESO conduct training exercises using the simulator at the Electricity National Control Centre (ENCC). From time to time tests will be performed with all parties that are signatories to a Local Joint Restoration Plan (LJRP), which will involve one or more generators, the local TO and DNO, and National Grid ESO. There may also be tests that straddle TO or DNO boundaries and so involve more parties, but these are much rarer. Demand customers are not involved in Black Start testing in GB. Our 2019 report described the existing approach in more detail.

A fundamental difference with Distributed ReStart is that the Black Start service will almost certainly involve multiple DER. This applies whether restoration is limited to an area of distribution network, or if using DER to achieve a capability equivalent to a single large service provider for transmission network energisation, as per existing LJRPs. As described in the July 2020 PET report[7], to support transmission network energisation it may be necessary to re-energise and add larger resources connected at higher voltages, e.g. a synchronous compensator to boost fault levels. The combination of DER across an area of network will be achieved by establishing a DRZ, most likely using a DRZ-C System, which requires involvement by the local DNO. Thus, as described in reports from our OST workstream, the parties involved in Distributed ReStart could include:

- multiple DER
- other larger generators or service providers
- the local DNO (possibly multiple)
- the local TO (possibly multiple)
- National Grid ESO
- any additional service providers required to support the above parties.

The current approach has National Grid ESO as the sole procurer of Black Start services and responsible for managing testing, although it is worth noting that the Grid Code does put obligations on all parties to jointly share the task of planning, preparing, participating in and facilitating testing. A testing regime for Distributed ReStart that was entirely coordinated and led by National Grid ESO would require significant resources in that one organisation. As with other forms of audit and quality assurance, there is an expectation of those overseeing tests have some independence from the providers themselves. The testing process must allow for sufficient independent review while not imposing too great a burden or reliance on any one party.

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[7] *Assessment of Power Engineering – Aspects of Black Start from DER,* Part 1, July 2020 nationalgrideso.com/document/174411/download

Our proposed approach to the restoration process, as described in the OST Central Model, has the DNO playing a much greater role, going beyond existing involvement in assurance activities and desktop exercises. With a DER-based approach the DNO will be involved in hosting and participating in tests. This has various implications for DNO resources and the approach to testing.

With the implementation of Engineering Recommendation G99[8], the DNOs are already taking on new responsibilities in reviewing performance and compliance of generators connecting to the distribution networks. The assignment of greater responsibilities to DNOs for Black Start testing is aligned with this and with the wider transition to their role as a so-called Distribution System Operator (DSO). However, this has potentially significant implications for DNO resources and capabilities, which must be recognised in regulated funding.

We propose that the current testing regime will continue as is for larger Black Start providers, possibly with some small adjustments in the National Grid ESO approach to reflect any changes in the overall strategy to accommodate Distributed ReStart.

5.4 Stages of Testing

Establishing a new DRZ will require significant testing in the initial feasibility assessment, design and commissioning stages. Testing will then continue throughout the lifetime of a DRZ to ensure capability is maintained, but particularly when changes are made to the network, DER, or DRZ-C. The main stages of testing are shown in figure 22.

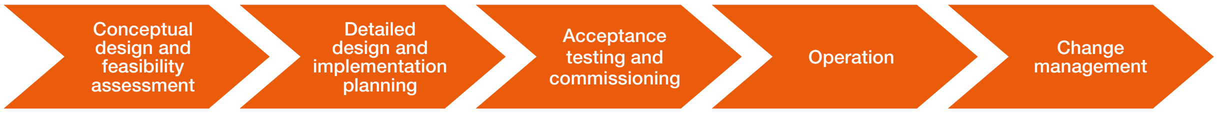


Figure 22: Stages of DRZ development and testing

During conceptual design and feasibility assessment testing is likely to be entirely in off-line simulation and desktop appraisal of capabilities. This may be driven by National Grid ESO or the host DNO wanting to explore the possibility of a DRZ in a particular area, or by DER expressing an interest in providing a Black Start service. The initial analysis will be relatively shallow, so that it can be done at minimal cost, but must deliver a conclusion on whether it is worthwhile progressing to more detailed design. There may be scope for some physical testing at this stage, particularly if it involves a new technology that has not been proven elsewhere. While National Grid ESO and the DNO may offer technical support to testing at this stage, it is likely that the cost will be borne by the DER testing their own capability.

Detailed design will require significantly more analysis, likely to include power system studies like those reported elsewhere in this report. The organisational aspects of service delivery will also have to be worked out. This should follow a common model that is applied in a similar way to every DRZ but as with any complex engineering challenge there will always be specific issues that need resolving that may be unique to each DRZ. This will have to be coordinated across the multiple parties involved in a DRZ with the specific requirements for the DRZ-C being collected and used to inform its design. Physical testing may be deemed necessary to de-risk or confirm some aspects of the design. This stage will also confirm the details of the commercial framework for implementation.

The commissioning process for a new DRZ is likely to involve a full set of physical and organisational tests, as described further below. The DRZ-C and its telecoms infrastructure will also require thorough testing, as is appropriate to a new operational monitoring and control system. The testing requirements of the DRZ-C will depend on the approach taken in implementing it, as discussed further elsewhere in this report, and this chapter will not cover this in detail.

As with current Black Start services, a DRZ and the individual DER within it will be subject to ongoing assurance testing throughout the lifetime of the service. The sections below describe further the tests we propose as being appropriate at commissioning and through operation.

It is highly likely that the operational design of a DRZ will change during its lifetime. With multiple DER parties involved, a change on any one of them will prompt some reassessment of capability for the DRZ. Distribution networks tend to be modified more quickly and more often than the transmission network, plus there are constant changes in the connected demand and smaller DER. The DRZ design will have to be reviewed when changes are made, and a decision made on what testing is required. This will continue throughout the operational life of a DRZ and may mean additional testing if it is not feasible to wait for the next round of regular testing.

[8] ENA Engineering Recommendation G99.

5.5 Proposed Tests

5.5.1 Physical Testing

The current approach with conventional, large Black Start providers involves physical testing at the start and on a regular basis throughout the lifetime of the service. Existing testing focuses on a service provider's ability to selfstart and energise parts of the network. As described in more detail in our July 2019 report, current physical tests include:

- **Unit Test:** The power station remains connected to the grid and tests are performed on individual units while the others remain in normal operation. The purpose is to demonstrate that the independent auxiliary supplies for a generating unit can be started and used to restart the generator.
- **Station Test:** The whole power station is disconnected from the grid and shut down. The facility must then restart and synchronise with the network without any external supplies.
- **Dead Line Charge Test:** Energise part of the network and control parameters, e.g. voltage, at the remote end.
- **Remote Synchronisation Test:** Energise a section of the network, as in a Dead Line Charge Test, then synchronise to the rest of the system at the remote end.
- **Secondary Generation Test:** Energise a network route to another generator and provide the power required to restart and synchronise that second generator. This is a more complex test as it involves additional parties and requires more onerous outages on the transmission network.

These physical tests are supplemented by simulation-based testing and training, assurance audits and desktop exercises, which will be used to varying degrees according to specific needs before commencement of a new Black Start service and throughout its lifetime.

A Distributed ReStart approach will require a similar range of tests plus others. Table 20 presents our current thinking on physical tests that may be required, noting the parties that need to be involved in delivering each test – note that this is separate from the party that may be overseeing the test and reviewing performance.

Test	Description	Anchor DER	Other DER or larger providers	DNO	TO	National Grid ESO
Anchor Self-Start	Like the existing **Station Test** and encompassing the **Unit Test**, demonstrates an ability to restart the generator without external supplies and provide a stable voltage at its connection point to the network.	Y				
Network Energisation	Like the existing **Dead Line Charge Test**, energise part of the distribution network and demonstrate an ability to control parameters like voltage and frequency. The extent of network to be energised will be specific to each test but may include transformers and circuits at a voltage level higher than the DER is connected to.	Y		Y		
Energise Other DER	Like the **Secondary Generation Test**, demonstrate an ability to re-energise a network route that reaches other DER and then provide them with the external supplies they need to get started, resulting in a stable power island with two or more DER.	Y	Y	Y		
Other DER Services	Once energised from the anchor generator, the other DER that get added to the DRZ will be contracted to provide specific services. Tests will be performed to demonstrate different capabilities as appropriate. It may be acceptable for some of these tests to be conducted on the DER in isolation rather than as part of a DRZ. For example, reactive power control tests might be performed when connected to the network as normal.	?	Y	?		

Test	Description	Anchor DER	Other DER or larger providers	DNO	TO	National Grid ESO
Stable Operation	While operating in a DRZ power island with two or more DER, demonstrate an ability to maintain stability when subject to disturbances. This is necessary to prove that the DER will be able to cope with the variability of demand and other disturbances that may be faced during a real restoration process.	Y	Y	Y		
Energise Transmission	Where the DRZ is expected to energise upwards from distribution to transmission then this deserves a test to demonstrate this capability. This will involve the local TO and possibly also National Grid ESO.	Y	Y	Y	Y	?
Remote Synchronisation Test	As with the existing **Remote Synchronisation Test**, energise an area of network, then synchronise to the rest of the system at the remote end. This may be at distribution level or may follow an Energise Transmission test. If involving the Anchor and Other DER then this test poses the particular challenge of managing multiple resources to achieve the necessary control over voltage magnitude, frequency and angle at the synchronisation point, and therefore would encompass other tests listed above.	Y	Y	Y	?	?
DRZ-C System (Island Only)	If the stable operation of the power island, or its expansion beyond a certain point, relies upon the actions of a DRZ-C System then tests must be performed to demonstrate its capabilities. This would be an extension of the Stable Operation test but would be focused on the performance of the DRZ-C. This might include 'hybrid' tests that combine physical actions with emulation, e.g. injection of 'dummy' signals to the DRZ-C representing a change in demand to prompt control action with a test resource like a load bank.	Y	Y	Y		
DRZ-C System (External Services)	If the DRZ is going to be operated in such a way that it performs like a VPP that provides external services, such as energisation of network beyond its boundaries, then tests must be performed to demonstrate its capabilities. This is likely to involve the local TO and possibly also National Grid ESO.	Y	Y	Y	Y	?
DRZ-C System (Without DER)	The DRZ-C System is expected to be integrated with various other systems, particularly at the DNO (e.g. PowerON) but perhaps also at the TO and National Grid ESO. Systems integration testing and Black Start exercises could be performed without any involvement from DER, which would be emulated or otherwise represented in the test. Or these tests may be incorporated into one of the DRZ-C tests listed above.			Y	?	?
Telecoms Resilience	Given the reliance on telecoms for the effective operation of a DRZ-C, it may be appropriate to perform specific tests focused on the resilience of the telecoms infrastructure. This may be done separately from tests on the electrical network. Depending on the telecoms design, it may be possible for the DNO to conduct these tests on its own, or it may require participation of others.	?	?	Y	?	?

Table 20: Proposed DRZ physical tests and participants

The tests will be designed to reflect the specific technologies being tested. For example, the Self-Start test for converter-connected DER will require demonstration of grid forming capability, which is still a new technology that has not been widely demonstrated. If any of the DER uses an intermittent energy source, like wind, then its ability to control power output may be one aspect of testing – although the ability to control power output may also be an important test for other sources that are not intermittent but may lack flexibility.

The Network Energisation test and others that involve the DNO, or TO networks must consider the specific challenges of operating a DRZ. This includes the provision of adequate earthing and protection. Specific tests might be included to test protection systems if there is any doubt about their operation in the very low fault level conditions that will exist in an early stage distribution power island. If energising the network at reduced voltage, or Point on Wave (PoW) switching is being implemented to de-risk some of the energisation steps then this will require appropriate testing.

Our proposals for testing maintain the current GB approach of not interrupting supplies to customers not directly involved in the tests. This means any demand used in the tests must come from test resources like load banks, which could be prohibitively expensive, or from contracted participants like energy storage or demand side response providers. An alternative may be to use hybrid approaches that mix emulation with physical testing, e.g. injection of secondary signals to prompt a real response from DER. The exclusion of 'real' demand customers from testing may be reviewed in future if it proves inadequate.

5.5.2 Other Testing and Training

We propose that the rollout of Distributed ReStart include the implementation of non-physical testing and training similar to what is already done for Black Start. This is particularly important in the early years of rollout as the industry becomes familiar with this new approach.

Modelling, simulation, training and various other assurance activities will play an important role in the initial assessment of feasibility and setting up of a new DRZ. Then throughout its lifetime there will be assurance visits, e.g. the DNO to DER, and National Grid ESO to the DNO, together with submission and review of documentation. Desktop exercises will be run that allow all parties involved in a DRZ to test and review their processes and organisational readiness. The design of such exercises will be informed significantly by our own organisational, systems and telecoms desktop exercises to be run in 2021.

We see significant value in training using an environment like the existing ENCC simulator but configured for the particular circumstances of a DRZ. This does impose a burden in terms of modelling and simulation and will need new tools to be created and maintained, most likely by the DNOs. However, this is an area in which we expect the needs of Distributed ReStart to align with other industry developments and resources like distribution network training simulators will be introduced for other reasons and therefore also be available to support Black Start. We will report further on this in later project reports, once we have gathered more learning from our own live trials and supporting work on modelling and simulation.

5.6 Test Practicalities and Alternatives

5.6.1 Timing and Frequency of Testing

We are not, currently, making any firm recommendations on the frequency of testing. This will be considered later in the project taking account of findings from the live trials and desktop exercises. As discussed above, testing will be necessary when a new DRZ is established or new DER are added, as well as throughout the life of the DRZ. A sensible approach may be to test some aspects more frequently than others. There might be a split between 'major' testing done every five years, say, and 'minor' testing that is done annually. Some aspects of the DRZ-C, like telecoms links, may be 'tested' every few minutes as part of its routine operation.

The requirement for repeat testing of the main Black Start capability is likely to be driven by the requirements of the Codes, particularly the Emergency and Restoration (E and R) European Network Code[9]. This specifies mandatory tests that apply to all 'Restoration Service Providers' with defined frequency of testing. However, there may be different ways to satisfy the Code requirements and the onus is not solely on the National Grid ESO or the DNO to force tests to be done, it is ultimately the service provider's responsibility to demonstrate compliance.

5.6.2 Outage Planning

Establishing a DER power island then progressing to energise a transmission line will require coordination of outages on the distribution network and the target transmission circuit. This will require careful outage coordination between National Grid ESO and potentially multiple DNOs/TOs. Securing outages is becoming increasingly difficult as the networks become more heavily utilised with greater use of constraint management and related methods. Nevertheless, network outages for Black Start testing will continue to be essential.

It therefore makes sense to exploit opportunities when they arise. For example, the commissioning of new DER or maintenance outages may be an appropriate time to demonstrate Black Start capabilities. Similarly, if outages on the network are going to leave DER disconnected and out of service, then this provides an opportunity for Self-Start or other tests. The philosophy would be that whenever a suitable outage is planned for business as usual activities, the opportunity be taken, within agreed bounds, to demonstrate Black Start functionality.

[9] Commissioning Regulation (EU) 2017/2196.

5.6.3 Modelling and Simulation

Modelling, simulation and analysis of power system behaviour will play an important role in assessing the feasibility of Black Start from DER in a given area and then in the design of any new DRZ and the configuration of any DRZ-C System. Given the challenges of real-life testing and the potentially unacceptable impact on customers, we expect modelling and simulation to also play a role in ongoing testing of a DRZ, in combination with physical testing methods. Whether performed entirely in simulation software or with elements of hardware-in-the loop testing, suitably configured models would provide the means of conducting comprehensive testing on a routine basis. There are significant challenges in this approach given the complexity of the system conditions of interest and there would be costs in developing and maintaining the analysis tools and associated models. There would also be risks that the models do not fully capture all effects and therefore miss a critical aspect. This could be mitigated by using whatever real-life testing is performed to validate and extend the modelling approach.

As well as providing assurance of technical aspects of service delivery, a suitably configured modelling environment could also be used in training and to support assurance of organisational aspects in desktop exercises.

5.6.4 Offline Testing of DRZ-C Updates

As noted above, some form of testing will be required each time something changes in the DRZ, the DER or network within, or in the DRZ-C. As a critical monitoring and control system relying on a combination of distributed hardware and software, the DRZ-C may be supported by an offline testing environment. Sometimes referred to as a pre-production or sandbox environment, this would be a duplicate of the DRZ-C hardware and software together with appropriate models of the network and DER that allows for testing of software upgrades and other changes before they are deployed on the real, or production, environment. The exact approach will depend on the design of the DRZ-C, but it is another reason why it will be important to maintain accurate models of the DRZ.

5.6.5 Self-Certification

In previous reports we suggested that some aspects of testing might involve third party or self-certification. Based on our findings over the last year we would not recommend this approach for the initial rollout of the concept; the first implementation of a DRZ will inevitably involve a high degree of scrutiny and assessment by all involved parties. However, these types of approaches may become acceptable very quickly as the concept becomes more widely established. For example, self-certification tests may be the most cost-effective approach for some of the suggested top-up services, such as frequency response or fast MW, which can be demonstrated in normal network conditions. These tests would be to prove capability of individual DER rather than for testing the restoration process, which will still involve other parties like the host DNO.

5.6.6 Methods for Future Consideration

Our July 2019 PET report suggested the possible use of a statistical approach to DER testing. Based on project learning we have concluded that this is unlikely to be appropriate, at least in the near term. The challenges of Black Start from DER are too complex and we think it necessary for all implementations to be tested. This may change in future if the concept is deployed widely and becomes normal practice, then approaches like type testing or random sampling might be used.

The Black Start from DER concept includes the establishment of power islands at distribution level, similar in functionality to the DRZ concept that has been demonstrated in numerous projects around the world. One feature of many DRZs is the ability to transition seamlessly from grid-connected to island mode and back again. Many industrial facilities and some power stations have the capability to 'trip to house load', which means they can continue operating if they lose their grid connection. It was proposed that part of the testing strategy for a DER-based approach could be to deliberately create distribution level power islands to demonstrate Stable Operation before returning to full grid connection. This might be referred to as 'trip to island mode'. This could, in theory, allow testing of Stable Operation, DRZ-C System functionality and possibly also an Energise Transmission test. However, based on our assessment of the technical requirements and changes needed in a distribution network between normal and island operation, we believe this type of approach to be impractical. It would also require adjustments to market mechanisms to ensure energy is balanced in the power island. The concept might be revisited in future years once the industry has become more familiar and comfortable with DRZ operation.

As noted above, we propose that we maintain the current GB approach of not interrupting supplies to demand customers for the sake of Black Start testing. As explained, the range of other tests, including appropriate modelling and simulation and the use of hybrid test methods, should be sufficient to give confidence that restoration can be delivered effectively when needed. However, the deliberate interruption and restoration of supplies is done in other countries and as our Black Start services continue to develop using new technologies then it may be collectively agreed that testing with 'real' demand customers may be of value in future.

5.7 Codes and Commercial Aspects

The impact of testing on Codes and commercial arrangements, and vice versa, will be dealt with more fully in the Procurement and Compliance workstream. Further work is required to understand the required changes to Codes and arrive at a preferred design for commercial arrangements, so this will be reported on later in the project. For example, just as the Grid Code now identifies specific types of test required for Black Start, the Distribution Code may be modified to include the tests listed above, or a subset of them.

Commercial arrangements for testing will be complex, especially where tests require the involvement of multiple DER or extensive network outages. This emphasises the value of standalone tests combined with modelling and simulation to give the required confidence with minimum physical testing.

As noted at the beginning of the chapter, for Black Start it is testing of capability that is likely to form the basis for most payments, rather than delivery of the actual service, which we hope is never needed. Testing and ongoing monitoring of capability availability and readiness is therefore critical to commercial settlement. This interdependency between testing and commercial design, and the role of the DRZ-C in monitoring and feeding data to settlement processes, will be explored further in the final year of the project.

5.8 Conclusions

In proposing an approach to testing, it is noted that Black Start is different from other ancillary services because it is hoped that the service is never actually needed, which makes the testing process very important in terms of assessing delivery against contractual obligations. It is proposed that the overall approach to testing will retain many features from the current approach with an assurance framework that includes a range of physical tests supplemented by simulation-based testing and training, assurance audits and desktop exercises.

Any testing regime must satisfy multiple objectives with the overall purpose being to achieve good outcomes for all parties. As being demonstrated within this project, testing objectives include training and sharing of learning as well as proving technical capability of plant and associated systems.

A fundamental difference with Distributed ReStart is that the Black Start service will involve more parties, including multiple DER. The overall process of establishing a new DRZ will involve various stages, although these are not fundamentally different from what is currently done when introducing new Black Start providers. We have proposed a set of physical tests that are similar to what is currently used but reflect the differences in Distributed ReStart, including the much larger number of parties involved, the greater role of DNOs, and the use of a DRZ-C System.

Issues to be considered in testing include the challenges of outage planning across distribution and transmission, new requirements in modelling and simulation, and the frequent testing that may be required each time something changes in the DRZ or DRZ-C System. As shown elsewhere in this report, modelling, simulation and analysis of power system behaviour will play an important role in assessing the feasibility of Black Start from DER in a given area and then in the design of any new DRZ and the configuration of any DRZ-C System. As well as providing assurance of technical aspects of service delivery, a suitably configured modelling environment could also be used in training and to support assurance of organisational aspects in desktop exercises.

6. Potential Across GB

This chapter provides a view of the high-level potential of distribution networks across GB to facilitate Black Start from DER. It is an update of the study included in the 2019 PET report.

6.1 Introduction

In the Power Engineering and Trials 2019 report on the viability of restoration from DER, the GB rollout section quantified the high-level potential for DRZ across GB based on 2017 Long Term Development Statement data from the DNOs. An update of this assessment is provided in this chapter.

The update has the following changes from the initial assessment:

- updated to the latest LTDS, i.e. November 2019
- 132kV synchronous generators now identified as an individual category and not as an anchor generator
- minor methodology changes to account for missing data in LTDS
- added a DRZ requirement study.

Other than these changes the assessment has remained the same as the previous assessment. The latest understanding of the distribution network and generator criteria are described, followed by a review of the assessment methodology, results are provided, and conclusions drawn.

6.2 Distributed Restart Criteria

With regard to the assessment of Black Start potential across GB, the assessment did not apply strict network criteria in identifying candidate networks for Black Start. Due to the bespoke nature of each network design, it is not appropriate to apply generalisations (which are required for a full GB rollout assessment).

An essential requirement for a potential DRZ is to have at least one anchor generator connected at 33kV or 11kV transforming directly to a higher voltage, with grid forming capability. Synchronous generation at 132kV has been quantified and may be utilised to expand the DRZ.

Across GB a variety of anchor generator technologies are found including hydroelectric, energy from waste, biomass, combined heat and power, diesel peaking plant and gas turbines. Additional DER have been quantified, typically non-synchronous renewables, which will help to maintain the stability of and grow the DRZ.

6.3 GB Rollout Methodology

6.3.1 LTDS Data Processing

An estimation of the potential for concept rollout of Black Start from DER across the different DNOs in GB was made. Potential network areas for distributed restart were identified using the technical information published within the latest available (November 2019) LTDS data for each DNO.

The essential criteria for selecting the potential network areas, or DRZs was:

- at least one anchor (synchronous) generator connected at 33kV or 11kV transforming directly to a higher voltage (assumed as 11kV of 10MW or greater)
- if available, support from additional DER (e.g. wind farms, solar farms and battery energy storage systems) to expand and maintain a stable power island.

The number of potential Black Start networks, or DRZs, (and the associated capacity and types of DER) meeting the above criteria was calculated using the technical information within each DNO's LTDS data and given as a percentage against the total number of grid substations within each DNO.

For each DNO the total MW of anchor generation and additional DER was calculated based on existing connected DER, and also with the contracted generation included.

6.3.2 Input Data Limitations

In assessing the input data used for this analysis, issues were encountered which may have a material effect on the results.

Under the LTDS generation categories, a proportion of DER in each DNO was classified as 'Other' or 'Mixed'. This totalled ~9GW (17% of total generation) across all DNOs including connected and contracted generation (a reduction of ~1GW compared to the previous assessment). It was unclear if these DER would be able to participate in Distributed Restart and, if so, if it could be classified as anchor generation or additional DER. As a result, the 'Other' or 'Mixed' generation were excluded from the original assessment, which probably resulted in a pessimistic view of the capacities and network areas suitable for Black Start from DER, particularly for the DNOs where this classification had a higher percentage of total generation.

In order to make the study less pessimistic and more realistic, a blanket assumption was applied to generation classed as 'Other'. In England and Wales only, where anchor generators were found to be a higher percentage of the generation mix, 15% of generation classed as 'Other' was considered to be anchor generation. The remaining 85% was not considered as part of the assessment. This is considered a reasonable assumption with regards to the amount of anchor generation in GB but is likely to still be a conservative estimate.

Separate from the generator classification issues, in a number of areas, information regarding the 33kV network layout was not included within the respective LTDS generation tables. As a result, DRZs in these areas could only be considered as a 132kV group only.

6.4 Results

6.4.1 Assumptions

Each part of the 33kV distribution network in GB was considered individually as a DRZ. This would be per Bulk Supply Point (BSP) in England, and per Grid Supply Point (GSP) in Scotland. As part of each 33kV DRZ, 11kV generators greater than 10MW were included within the zone assessment. Generators connected at 132kV were considered 'shared' by each 33kV DRZ, as they could potentially be utilised in each DRZ, so these were included within the zone of each downstream DRZ.

Certain places in the GB network have 66kV BSPs; these were considered as individual potential DRZs in the same way as with 33kV BSPs. Similarly, 33kV network 'groups' in meshed networks were considered as a single DRZ for zone assessments.

In addition, in areas of England where LTDS data was not available by BSP, DRZ assessments were made by GSP. As a GSP can contain many BSPs within it, direct comparisons are not appropriate. To avoid introducing distortions in data/graphics, the GSP DRZ results were not mixed in with the results for other network areas.

As a result, DRZ volume assessments do not consider the area in and around London (which would be observed, incorrectly, as inconsequential if included due to the fewer GSPs). However, generators in this area were included in sections analysing generation capacity.

Due to the various conflicting classifications and complications, the term 'network area' is used throughout the assessment as the terminology for each part of the network tested as a potential DRZ.

6.4.2 GB DNO Potential Black Start Network Areas

Across the total 1045 network areas considered as part of the analysis, 365 were found to have at least one synchronous generator. The vast majority (339) being classed as an anchor generator (connected at 33kV or 11kV). This essentially means that ~32% of the network areas considered had at least one anchor generator connected.

Figure 23 shows the number and percentage of DRZs, per DNO, based on the connected generation (132kV synchronous gens are included in this data as a potential anchor for a DRZ). It was found that the DNOs with the highest number of DRZs was WPD East Midlands, and NPG York with 47 potential DRZs each. However, as a percentage of total network areas, the highest percentages were found in WPD South Wales (94%) and WPD South West (75%).

When considering a scenario where all currently contracted generation could connect in the future, the total number of network areas which meet the essential criteria would increases by 55 giving a total of 420 (40%) potential DRZs.

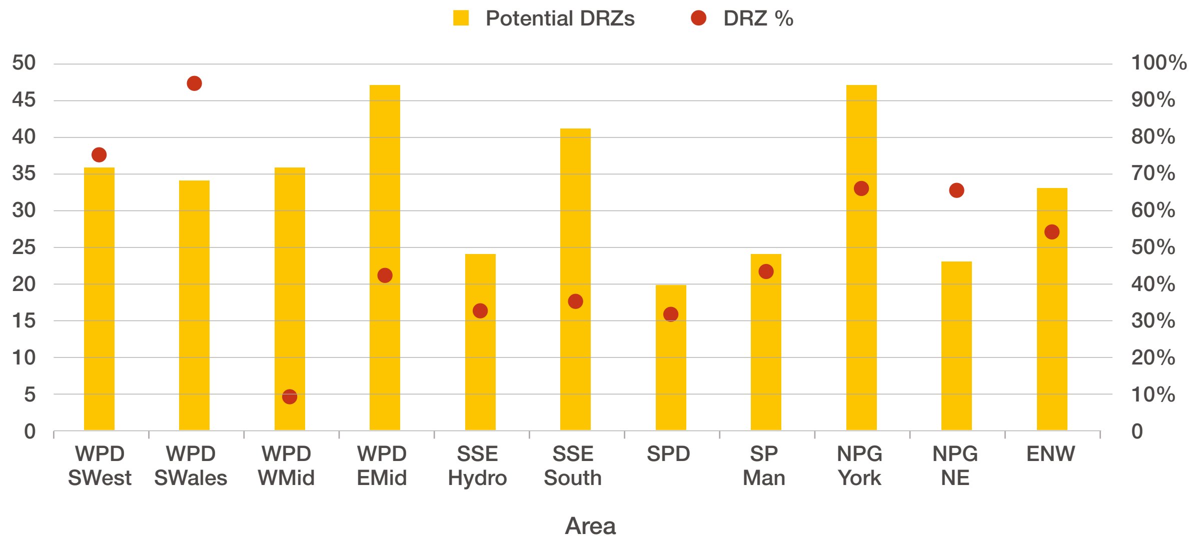


Figure 23: Network areas, for each DNO, that are potential DRZs

6.4.3 GB DNO DER Capacity

The total amount of presently connected synchronous generation and additional DER in each DNO network area is shown in figure 24 and figure 25 . It can be seen that there is a total of 10GW of synchronous generation and 15GW of additional DER across all GB DNOs.

If 50% of the current contracted generation is included, the total synchronous generation rose to 13GW and additional DER to 20GW. If 100% was used the synchronous generation increased to 16GW and additional DER 25GW.

6.4.4 Split of Synchronous and Non-Synchronous DER by Connection Voltage

The following figures and tables show a variety of data related to the capacities and types of generation currently connected to the DNO networks.

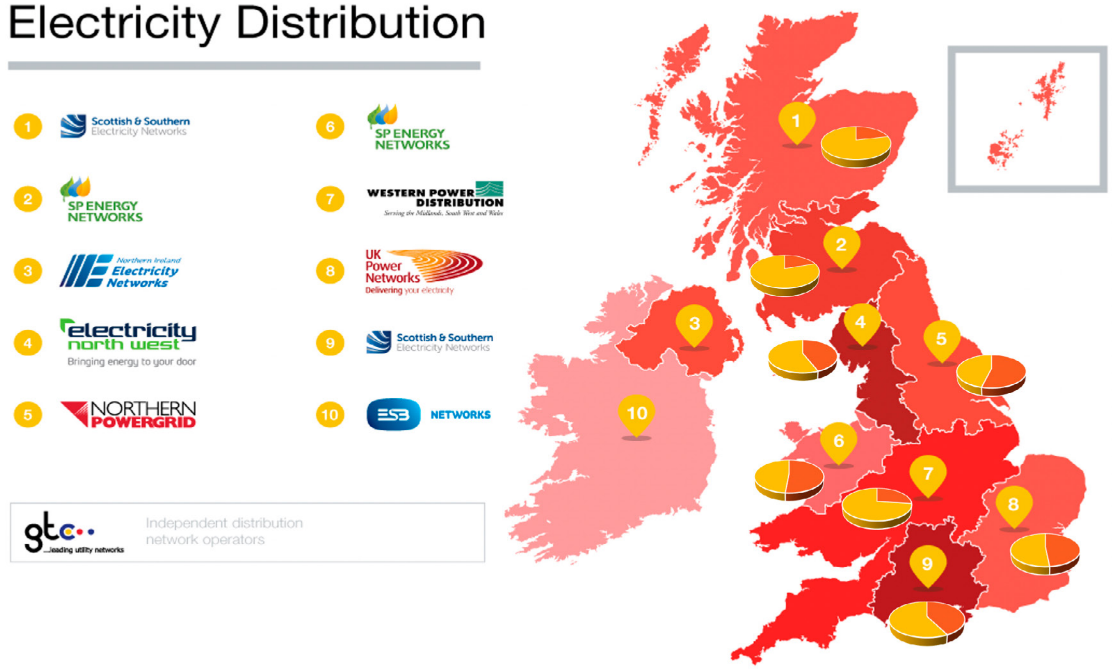


Figure 24: Amount of presently connected synchronous generation (orange), and non-synchronous generation (yellow) per DNO area. [GB Electricity Distribution Map from ENA website]

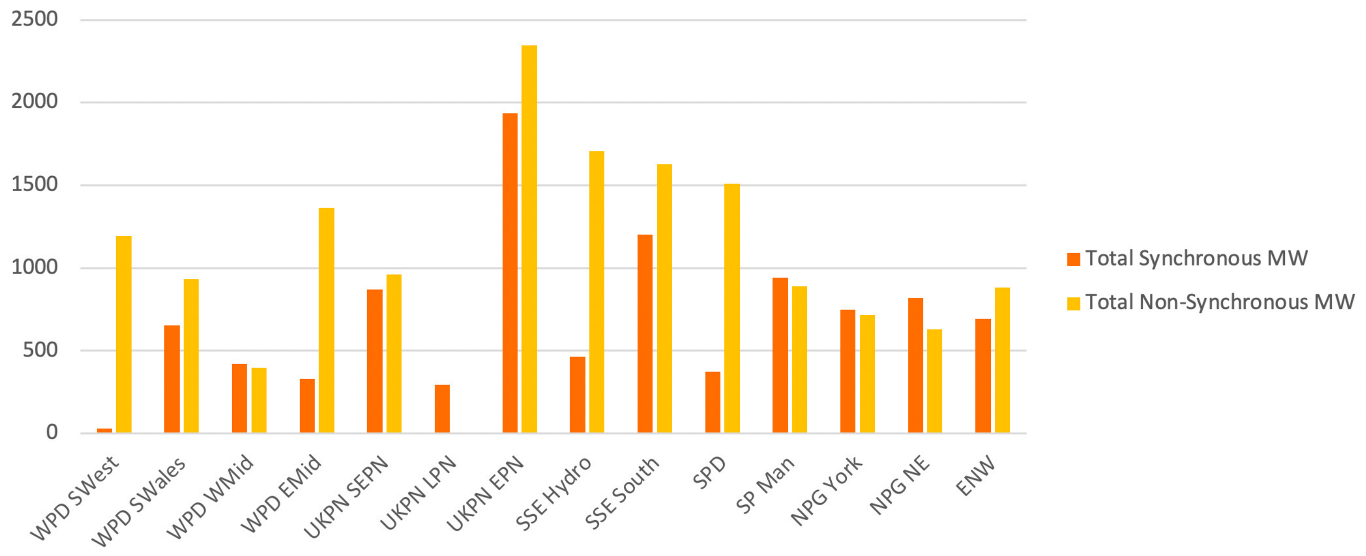
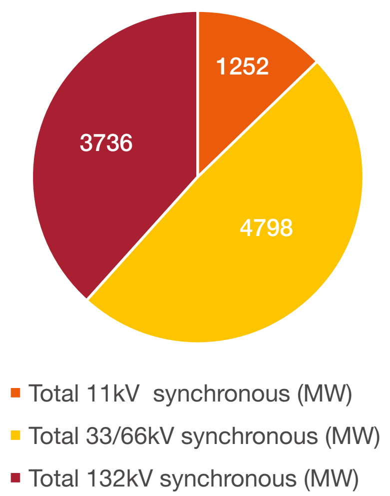


Figure 25: Amount of presently connected synchronous generation (orange), and non-synchronous generation (yellow) per DNO area



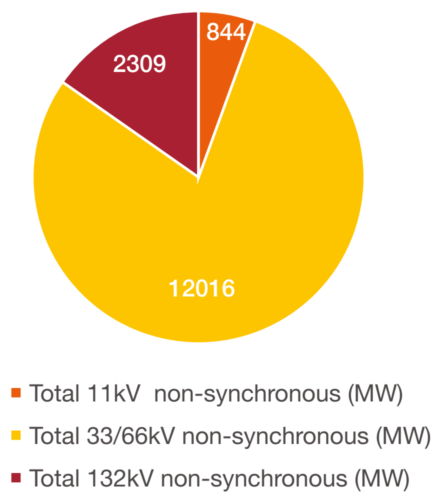
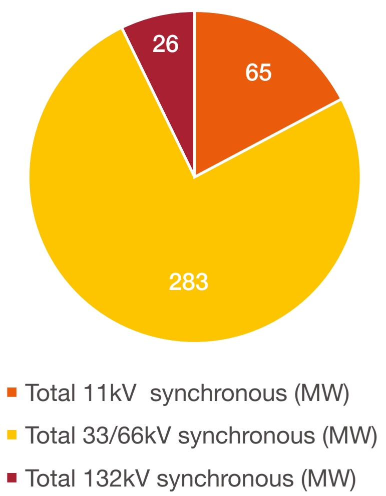


Figure 26: Synchronous DER and non-synchronous DER MW split by connected voltage



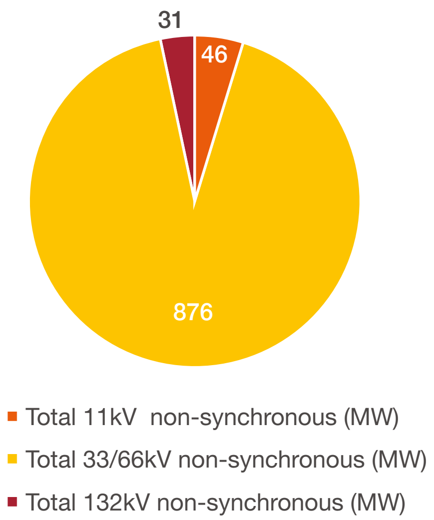


Figure 27: Synchronous DER and non-synchronous DER number of eligible plants in GB split by connected voltage

Figure 26 shows the MW split of the synchronous and non-synchronous DER based on connected voltage, and figure 27 shows the number of individual generation sites. Note that, in accordance with the methodology, only 11kV generators equal to or greater than 10MW were considered eligible.

As this analysis looked at the existing connected generation compared with the previous assessment, the 15% of Other Generators as Anchors assumption does not apply to this section. Only defined generation was considered.

Figure 26 shows that the capacity of synchronous DER connected at 33kV and 132kV is a ~4.8GW, and ~3.7GW respectively. Figure 27 showed this came from 283 generators connected at 33kV, and 26 generators connected at 132kV.

Figure 26 also shows that the vast majority of non-synchronous DER is connected at 33kV, with ~80% of the total MW capacity. Figure 27 shows that, correspondingly, 33kV non-synchronous DER also accounts for ~90% of the total number of sites.

Plant Type	Difference in Sites Numbers	Difference in Total MW
132kV Synchronous DER	-8	~ -150MW
33/66kV Synchronous DER	+34	~ +800MW
132kV non-synchronous DER	-2	~ +300MW
33/66kV non-synchronous DER	+28	~ +600MW

Table 21: Growth/reduction in DER plant numbers and total MW between LTDS 2017 and 2019 (changes at 11kV were negligible)

The differences between the 2019 and 2017 LTDS is shown in Table 21. A clear increase was observed in 33/66kV synchronous, 132kV non-synchronous, and 33/66kV non-synchronous, and a small decrease was observed in 132kV synchronous.

Notably the 132kV non-synchronous DER reduced in number of sites but increased in MW of generation. This is potentially due to site extensions, which are fairly common practice by renewable plant developers (which make up a high proportion of non-synchronous DER).

6.4.5 DRZ Requirement Study

To examine the effect changing the DRZ requirements would have on the number of DRZs across GB, the LTDS data was interrogated across a range of Anchor (including 132kV synchronous generators), and additional DER requirements. The Anchor and additional DER requirements were tested to 100MW in 1MW increments, and the number of DRZs recorded. This resulted in the outcome shown in figure 28.

It can be seen that if the DRZ requirements were 50MW of anchor generation, and 0MW of additional DER generation, there would be between 50–100 DRZs in GB. If there was a requirement for more than 0MW of additional DER the number of DRZs immediately would drop to between 0–50.

A key message of this graphic is that there is a significantly reduced number of DRZs with both anchor and additional DER generation.

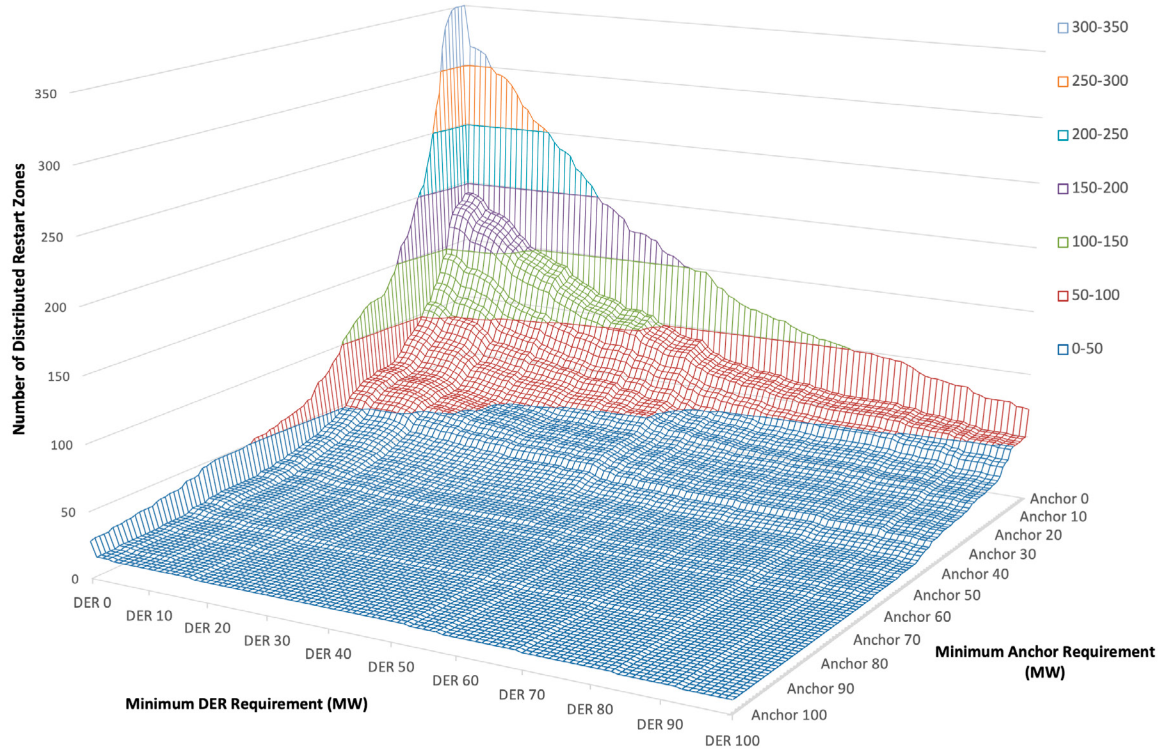


Figure 28: Number of DRZs as related into increasing anchor and DER requirements (does not Include network in and around London)

Figure 29 shows the MW capacity of all DRZs, from largest to smallest. Using this graphic, it can be seen that approximately half of the DRZs have 40MW DER or more. A total of 174 (41%) of the 339 DRZ sites have no additional DER (synchronous generation only).

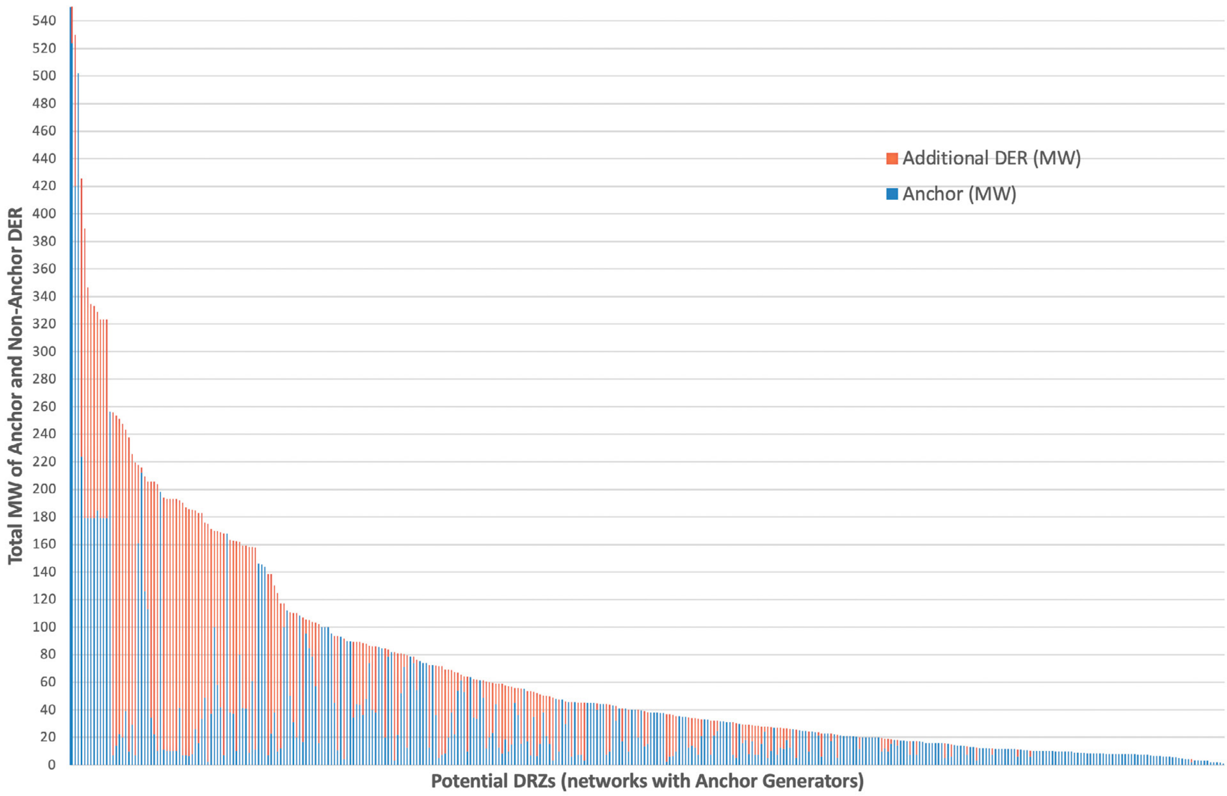
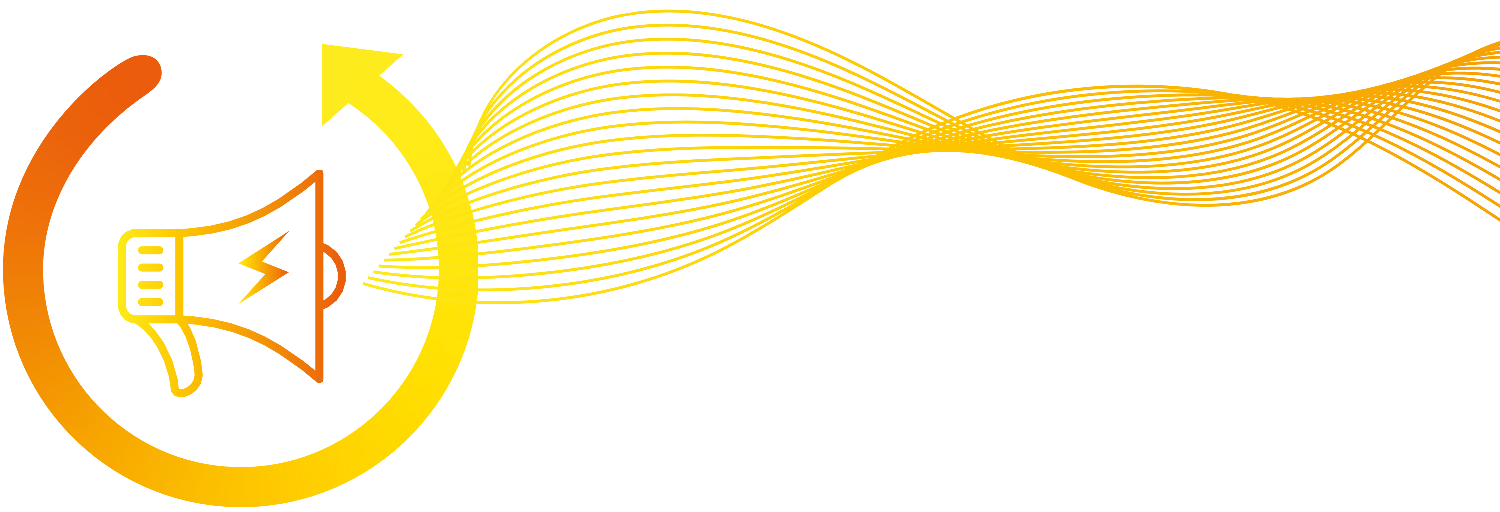


Figure 29: Total size of DRZ assessed – from largest to smallest

6.5 Conclusions

We have drawn the following conclusions:

- An estimation of the potential for concept rollout of Black Start from DER across the DNO's in GB has been made using the information published within the respective DNO LTDS from November 2019.
- Within the GB DNO LTDS data, there is ~9GW of generation (connected and contracted) in England and Wales which is classified as 'other' or 'mixed'. To give a conservative estimate 15% of this generation was considered as anchor generation.
- Analysis of the GB DNO networks indicates that there is almost 10GW of synchronous generation currently connected. This consists of ~1.2GW connected at 11kV, ~4.8GW connected at 33kV and ~3.7GW connected at 132kV. This power is produced from 374 individual generation sites, of which 283 (76%) are connected at 33kV.
- For non-anchor generators there is a total of ~15GW of additional DER currently connected across the GB DNOs. The majority of this (~12GW) is connected at 33kV which equates to 876 individual generation sites out of a total of 953 (92%).
- There are 339 (32%) potential DRZ network areas out of a total of 1045, with 283 of these having a 33kV connected anchor generator.
- A total of 191 (56%) of the 339 potential DRZ sites contain an anchor generator plus additional (non-synchronous) DER.
- If 50% of the DER which is currently contracted (but not connected), is included in the assessment, the total synchronous generation would rise by 3GW to 13GW and additional DER by 5GW to 20GW.
- DRZs should be considered with synchronous generation alone, (not always with additional DER) otherwise the potential number of DRZs will reduce significantly.



7. System Studies – Protection (11kV and LV Network)

7.1 Introduction

In the July PET report approximate minimum fault levels at 33kV, 132kV, 275kV and 400kV were identified for existing protection systems to operate (with revised settings if necessary). This section summarises the output of the report[10] to explore in more detail the relationship between the 33kV fault level (at the HV terminals of a 33/11kV transformer) and the associated 11kV and LV fault levels. This was done for various network topologies, to identify the minimum 33kV fault level required to ensure all lower voltage networks are adequately protected. A primary concern is that there will always be sufficient fault level on the LV network to blow the 11kV and LV fuses at secondary (11kV/415V) substations, or within consumers 415V premises (operating levels on these cannot be altered).

7.2 Network

The proposed network under consideration consists of:

- 33kV source infeed
- primary 33/11kV transformer
- 11kV cable/OHL
- secondary 11kV/415V transformer
- 415V cable.

The simplified single line diagram of the network under consideration is presented in figure 30. The fuse protections under consideration are highlighted in yellow.

The schematic of the network under consideration showing the variation of the values of certain components is presented in figure 31.

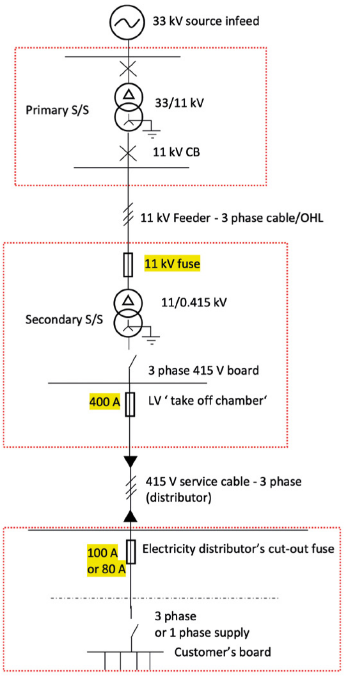


Figure 30: Simplified single line diagram of the network under consideration

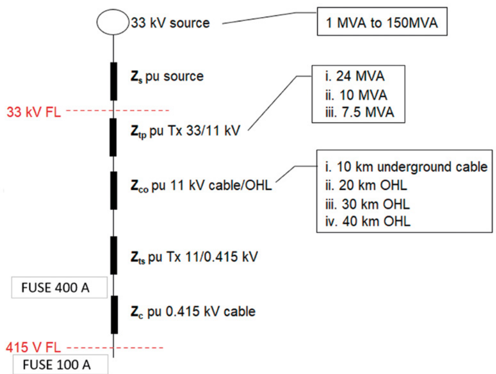


Figure 31: Schematic showing the component variations considered.

[10] ARCADIS *Supplementary Studies Work Package 1.*

7.2.1 33kV Source Infeed

A 33kV source infeed with an assumed value of X/R equal to 10 is modelled. This source infeed represents the available 33kV fault level at the transformer's 33kV terminals. The 33kV fault level range examined is from 1MVA to 150MVA with varied step dictated by the necessity of the accuracy in the results. It is assumed that the positive, negative and zero sequence impedances are equal.

7.2.2 Primary 33/11kV Transformer

A 24MVA, a 10MVA and a 7.5MVA transformer is considered. The impedance values of the transformers are assumed based on typical values found in the LTDS 2019 and are summarised in Table 22. It is assumed that the positive, negative and zero sequence impedances are equal. DYn transformer winding is assumed.

Transformer details	24MVA	10MVA	7.5MVA
Z% on Tx base	24%	10%	9.8%
X/R	20.02	19.97	19.98

Table 22: Transformer parameters

7.2.3 11kV Cable/OHL

The impact of four different options for the feeder circuit to the secondary substation is considered. The feeder options with details of the parameters of each feeder are presented in Table 23. These 11kV feeder 'templates' are only a guide and assessment would be required against the actual maximum feeder lengths, and conductor sizes, found on a particular network. It is estimated that the impedance of the 30km 11kV OHL feeder represents the maximum typically found on DNO networks.

Feeder circuit to secondary substation	Length (km)	Positive/Negative Sequence Impedance (Ohms)	X/R	Zero Sequence Impedance (Ohms)	X0/R0
10km 185mm^2 11kV underground cable feeder	10	1.834	0.485	1.834	0.485
20km 11kV OHL feeder (10km 150mm^2 ACSR + 10km 50mm^2 ACSR)	20	10.155	0.929	33.909	3.168
30km 11kV OHL feeder (20km 150mm^2 ACSR + 10km 50mm^2 ACSR)	30	13.713	1.073	49.997	3.567
40km 11kV OHL feeder (30km 150mm^2 ACSR + 10km 50mm^2 ACSR)	40	17.272	1.169	66.085	3.809

Table 23: 11kV Feeder circuit parameters

7.2.4 Secondary 11/0.415kV Transformer

A 1MVA transformer is considered with a 5% impedance. The X/R value is assumed 20. It is assumed that the positive, negative and zero sequence impedances are equal. DYn transformer winding is assumed.

7.2.5 415V Cable

The 415V service cable details are presented in Table 24. The maximum typical length of a three phase LV feeder cable is considered with a length of 0.4km.

LV Cable	Length (km)	Positive/Negative Sequence Impedance (Ohms)	X/R	Zero Sequence Impedance (Ohms)	X0/R0
0.4km 185mm² 415V underground service cable	0.4	0.073	0.487	0.294	0.487

Table 24: 415V Underground service cable

7.3 Protection Assessment

This assessment is to identify the minimum 33kV fault level (at the primary transformer HV terminals), required to operate the following fuse protections:

1. **Secondary Substation 11kV Fuse (Typically 80A)**

Location – in Ring Main Units (RMUs) typically connected to a secondary (11kV/415V) transformer.

Minimum fault current location – the 11kV fuse should operate to clear a fault on the LV busbars of a secondary transformer (just before the LV feeder cable fuses).

Current/MVA required for operation:

- 1s – 400A@11kV (7.5MVA)
- 10s – 250@11kV (4.7MVA)
  - Based on SIBA HHD-BSSK fuse.

2. **LV Feeder Cable Fuse (Typically 400A)**

Located at the LV take off chamber at a secondary substation.

Minimum fault current location – the LV feeder fuse should operate for a fault at the end of the feeder it is protecting (assumed 400m typical maximum length).

Current/MVA required for operation:

- 1s – 3,000A@415V (2.1MVA)
- 10s – 1,800A@415V (1.3MVA)
  - BS88 fuses.

3. **LV Fuse (Typically 100A)**

Located within individual customer premises.

Minimum fault current location – within customer premises.

Current/MVA required for operation:

- 1s – 660A (0.5MVA)
- 10s – 400A (0.3MVA)
  - BS88 fuses.

Ideally there should always be enough fault current to operate a fuse within 1s, but for Black Start conditions a maximum permissible operating time of 10s has been assumed. Consideration has also given to the overcurrent setting protection which may be applied to the 11kV feeder circuit breakers, at a primary (33/11kV) substation, when the 33kV fault level is reduced.

7.3.1 Methodology

To identify the minimum required 33kV fault levels, for 11kV and LV fuse operation, the 33kV fault level has been varied from 1MVA to 150MVA at the 33kV transformer primary terminals. The total network impedance in pu has been calculated for each network configuration. The analysis has been repeated for each of the three options for the primary transformer (24MVA, 10MVA and 7.5MVA) and also for the varying 11kV circuit lengths and types given in section 7.2.3. The calculation has been performed using Excel.

The results are shown in this report for a 24MVA primary transformer. Studies were also undertaken with 10MVA and 7.5MVA transformers and the results are very similar (any variations result in slight increases to the fault levels), thus the 24MVA results are a worst case and are applicable for all three sizes.

On the relevant graphs the line for the fault current required for fuse operation within 1s is noted. The 400A LV fuse is a general purpose fuse (gG type) that complies with the standard BS EN 60269-2. Small deviations from the presented required fault current are expected depending on the manufacturer's time-current tolerance band.

7.3.2 11kV Feeder Circuit Breaker Overcurrent Protection

The 11kV feeder circuit breakers, at a primary (33/11kV) substation, typically have an overcurrent protection which must be set to 'pickup' greater than the expected load current, but below the minimum fault current. This would occur for a fault at the end of the 11kV feeder circuit (connected to the last secondary transformer). Figure 32 shows the three phase 11kV fault levels at the end of the different 11kV feeder circuits (detailed in section 7.2.3) for variations of the 33kV source fault level.

11kV Overcurrent Setting

Figure 32 shows that for a 30km 11kV feeder (typically the longest on DNO networks), when the 33kV source fault level at a 24MVA transformer is 0.35kA (20MVA), the minimum 11kV fault current is ~300A (5.6MVA). This would mean that the 11kV primary circuit breaker feeder overcurrent protection would have to be set to pick up below 5.6MVA, but above the feeder load current. This would be viable as long as the feeder maximum demand was not greater than ~4.0MVA, and an overcurrent pickup setting could be set ~4.8MVA (this allows for 20% error in the load or fault current measurements).

A definite time overcurrent setting could be applied such that when the pickup setting is exceeded, the protection will operate in a pre-programmed definite time. Modern relays have a 'cold load pick up' facility to inhibit operation for a duration of time when the circuit is first energised and may experience increased loading due to a lack of diversity in the individual loads.

Conclusions

We have drawn the following conclusions:

- A suitable 11kV overcurrent setting, on most primary substation circuit breakers, should be attainable for a minimum 33kV source fault level of ~0.35kA (20MVA). This allows for ~5MVA load current. The loading on 11kV feeder circuits may vary from hundreds of kWs up to ~6MW but is typically in the order of several MW.
- The fault levels on a 11kV cable circuit is several times higher than the equivalent length of overhead line due to its relatively reduced impedance. This would allow for the overcurrent pickup setting to be set higher than for an overhead line which is advantageous as cables tend to be in urban/industrial environments and more heavily loaded.
- For 24MVA and 10MVA primary transformers the relationship between 33kV and 11kV fault currents is identical (they have the same relative impedance). For 7.5MVA transformers the 11kV fault currents are slightly increased giving more flexibility for protection settings.

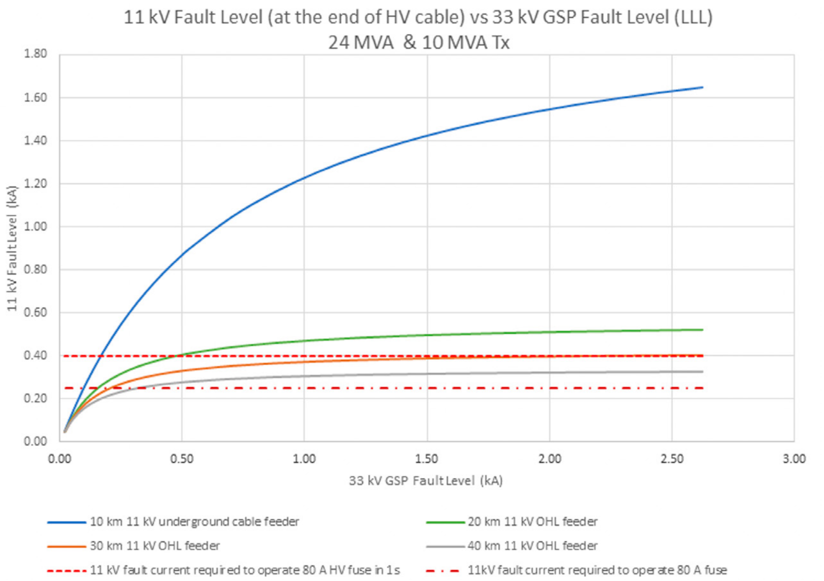


Figure 32: 11kVFault level (at end of feeder circuit) vs 33kV source fault level (LLL) for a 24MVA primary transformer

7.3.3 Secondary Substation 11kV Protection Operation

At each secondary (11kV/415V) substation there is typically a set of 11kV fuses (located in a RMU), or less frequently a circuit breaker and protection relay, which protects for faults on the secondary transformer. These fuses need to operate for:

1. 11kV at remote end of feeder (secondary transformer HV terminals)
2. LV fault on secondary transformers LV busbars (just before the LV feeder cable fuses).

11kV Faults

In figure 32 it can be seen that for 33kV source fault levels greater than 356A (20MVA), for 11kV faults at the remote end of all overhead line feeder lengths, a 80A fuse will operate in ~10s. For a 10km 11kV cable feeder the fault levels are significantly higher and would operate the 80A fuse in 1s.

LV Faults

In figure 33 it can be seen that for a 11kV overhead line (OHL) feeder of 30km, for a fault on the secondary transformer LV busbars, a source 33kV fault level of greater than 500A (28MVA) is required to ensure the 11kV 80A fuse operates in 10s (30MVA is required for a 7.5MVA transformer). For a 20km 11kV OHL, a 33kV source fault level of ~285A (16MVA) is required for the same fuse operation.

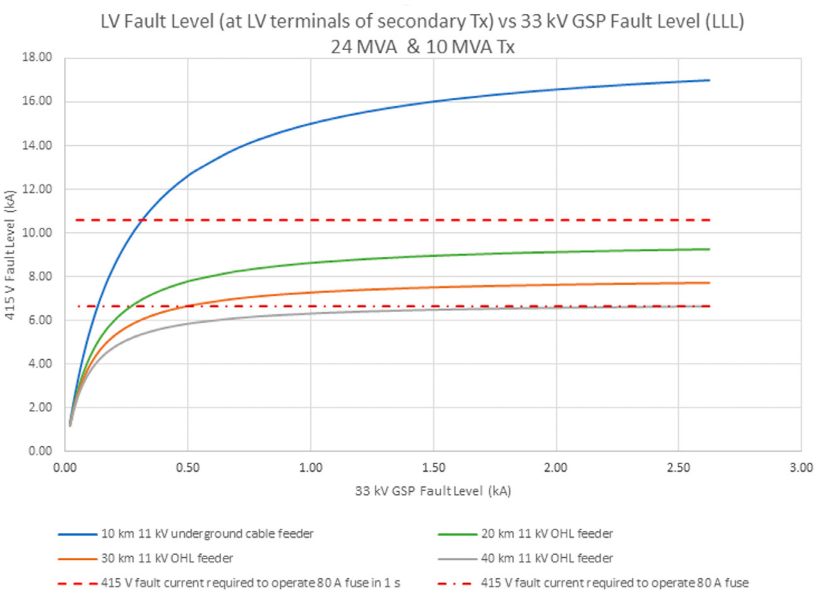


Figure 33: Fault level (at LV terminals of secondary Tx) for four 11kV feeder options vs 33kV GSP fault level (LLL) for a 24MVA primary transformer

Conclusions (11kV secondary transformer fuses)

The following conclusions are drawn:

- 1kV Faults – A minimum 33kV source fault level of 20MVA is required to ensure that 11kV faults at the HV terminals of secondary substations on 11kV OHL feeders up to 40km in length will be able to operate the 11kV fuses (80A) within 10s. Underground cable 11kV feeders result in higher 11kV fault currents and faster fuse operating times.
- LV secondary transformer busbar faults – A minimum 33kV source fault level of 30MVA is required to ensure that a fault on the LV terminals of a secondary transformer, at the end of a 30km OHL feeder, has sufficient fault current to operate the 80A 11kV transformer fuse (in 10s). For a maximum 11kV OHL of 20km 16MVA 33kV source fault level is required. Underground cable 11kV feeders result in higher LV fault currents and a faster fuse operating times.

7.3.4 LV Fuse Operation

A primary concern is that there is enough fault level to operate the LV feeder fuses at a secondary substation take off chamber (typically 400A), and then at the end of the feeders (typically 400m maximum length with a 100A fuse in domestic premises).

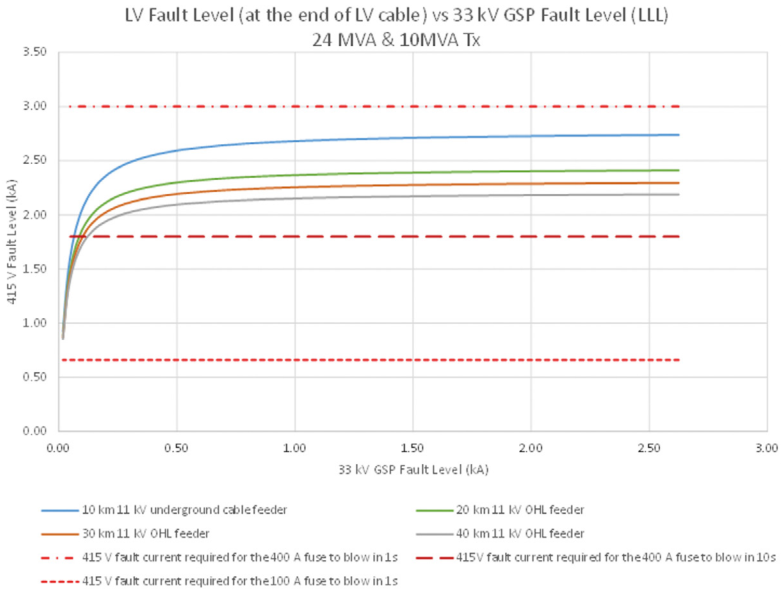


Figure 34: LV Fault level (at end of 400m LV cable) for four feeder options vs 33kV GSP fault level (LLL) for a 24MVA primary transformer; the 415V fault current for a 400A and 100A fuse to blow in 1s are shown

Results

In figure 34 it can be seen that for 33kV source fault levels greater than ~285A (16MVA), the LV fault current at the end of a LV feeder will be between 2kA and 2.5kA, for all 11kV circuit lengths/types. This is sufficient to operate the 100A in domestic premises in less than 1s and the 400A LV feeder cable fuse in 10s (1800A required).

7.3.5 Conclusions and Recommendations

The purpose of this study work is to identify the minimum source 33kV fault level (at the HV terminals of a primary transformer), to ensure that the 11kV and LV networks are adequately protected.

General Conclusions

The following conclusions are drawn:

- The primary transformer size (24MVA, 10MVA or 7.5MVA) does not make a significant difference to the 415V fault levels.
- The length (impedance) of the 11kV feeder has an impact on the 11kV and LV fault levels at the secondary substations.
- A suitable 11kV overcurrent setting (definite time), on primary substation circuit breakers, should be attainable for a minimum 33kV source fault level of ~0.35kA (20MVA). This allows for ~5MVA load current. The loading on 11kV feeder circuits may vary from hundreds of kWs up to ~6MW but is typically in the order of several MW.
- Protection studies should be undertaken for each network to be protected under Black Start conditions, considering the protection devices, settings and circuit impedances specific to that network.

Minimum 33kV Source Fault Levels Required

Table 25 shows the minimum source 33kV fault levels required (at the primary transformer HV terminals), for various 11kV feeder types and lengths, in order to ensure operation of the downstream 11kV and LV fuse protections. For example, a minimum source 33kV fault level of 30MVA is required if the 11kV circuits are a maximum of 30km in length (7.5MVA transformer). It can be seen that the 33kV source fault level required increases significantly (between 140–150MVA) if the 11kV circuit length is 40km in length.

Transformer Rating MVA	Overall Length (km)	Circuit Description	Operation of an 80A HV fuse in 10s		Operation of a 400A LV fuse in 10s
			0.25 kA at 415V	6.63 kA at 415V	1.8 kA at 415V
			Primary Tx 33kV terminals MVA		
24MVA Transformer	10.00	10km cable 185mm	6	8	4
	20.00	10km 150mm + 10km 50mm OHL	9	16	5
	30.00	20km 150mm + 10km 50mm OHL	12	28	6
	40.00	30km 150mm + 10km 50mm OHL	18	140	7
10MVA Transformer	10.00	10km cable 185mm	8	8	4
	20.00	10km 150mm + 10km 50mm OHL	9	16	5
	30.00	20km 150mm + 10km 50mm OHL	12	28	6
	40.00	30km 150mm + 10km 50mm OHL	18	140	7
7.5MVA Transformer	10.00	10km cable 185mm	8	8	4
	20.00	10km 150mm + 10km 50mm OHL	9	16	6
	30.00	20km 150mm + 10km 50mm OHL	12	30	6
	40.00	30km 150mm + 10km 50mm OHL	20	>150	8

Table 25: 33kV Source fault levels to ensure 11kV and LV fuse operation

8. System Studies – Energisations

The power system studies in the July 2020 PET report[11] revealed that the energisation of grid transformers and 132kV–400kV circuits present technical challenges for Black Start from DER which require further analysis.

8.1 Introduction

The system restoration strategies developed for the three case study networks (Chapelcross GSP, Galloway Area and Legacy GSP), and presented in the previous PET report, focused primarily on ensuring that the thermal rating of equipment and the block load capability of the anchor generator was not exceeded during restoration. This was done through an iterative process that also aimed to minimise the number of switching operations to ensure the restoration could be done as quickly as practically possible.

The electromagnetic transient (EMT) studies that were performed on the three networks evaluated the power system response during different energisation events to determine whether temporary voltage dips and swells would remain within acceptable limits during the restoration process. In some instances, the voltage dips and swells were found to be quite large, which have prompted further studies to understand the impact on the network equipment and what it means for the restoration process.

The chapter firstly provides a theoretical background about transient phenomenon that occur when energising transformers and circuits, followed by a discussion of the following power system study results:

- energisation of a 132/33kV grid transformer
- energisation of 132kV unbalanced lines
- energisation of 33kV networks and primary transformers
- starting of large motors
- energisation of 275kV and 400kV transmission circuits.

The findings from these studies aim to identify energisation strategies that are acceptable, but also where energisation steps could be combined to reduce the number of switching operations.

8.2 Theoretical Background

Energisation of transformers and circuits is an important part of the system restoration process. The energisation events, however, generate transient currents and voltages, which can potentially result in adverse effects and, in extreme cases, degrade insulation, lead to surge arrestor failure or damage network equipment. It is therefore important to assess these phenomena and understand the risk it poses to safe system restoration. The adverse effects that typically result from energisation events include:

- Switching transient overvoltages[12] occurring due to the energisation of overhead lines or cable circuits in the network. Surge arrestors are used in the network to protect equipment from any switching transients such as Slow Front Switching Overvoltage (SFO). Refer to Appendix 1 for the IEC 60071 definitions of the different switching transients that can occur on a network.
- Large power frequency voltage swells across the network. Voltage swells such as temporary overvoltage[13] (TOV) phenomena which occurs due to resonance in the network may exceed the operating limits of surge arrestors in extreme scenarios that could result in surge arrestor failure and subsequent damage in network equipment. IEC 60071 specifies that in order to prevent insulation degradation or damage of equipment, the TOV should be within the standard short duration withstand voltage limits of the equipment (i.e. the insulation coordination limits).

[11] Ibid., p70.

[12] Transient overvoltage typically lasts less than one cycle (IEC 60071).

[13] Temporary overvoltage (TOV) can typically last from one cycle to several minutes (as per IEC 60071).

- Large voltage dips across the network which could be more than the undervoltage protection setting of generators resulting inadvertent generator tripping.
- Maloperation of relays causing tripping of generators and distributed energy resources (DER) which have been reconnected to the network. This could be due to high transformer inrush current being interpreted by the protection relays as fault current and voltage decrease being interpreted as undervoltage following a fault in the network.

8.2.1 Applicable Standards

Voltage dips and swells are defined in ENA Engineering Recommendation (EREC) P28 as the temporary decrease and increase of the RMS voltage at a point in the network below and above a specified start threshold. In addition to EREC P28, the following engineering standards and technical brochures are also relevant and provide a guidance for assessment of voltage dips, voltage swells, and TOV in transmission and distribution networks in GB. These standards are applicable for the planning and operational timescale for both planned and unplanned outages, and don't apply during a system restoration scenario:

- ENA Engineering Recommendation G99
- National Electricity Transmission System Security and Quality of Supply Standard (SQSS) version 2.4
- ENA Engineering Recommendation P2-6 (Security of Supply)
- The Distribution Code (D-code)
- Transformer Energisation in Power Systems: A Study Guide, Cigré TB-568
- Resonance and Ferroresonance in Power Networks, Cigré TB-569.

However, the following standards cover the safe operating limits and conditions of equipment, and therefore their overvoltage limits apply at all times:

- IEC 60071 – Insulation Co-ordination Standard
- Electricity Safety, Quality and Continuity Regulations (ESQCR), 2002.

8.2.2 Transformer Energisation

A transformer transfers electrical energy through the process of electromagnetic induction. When a transformer is energised, it draws a large transient input current known as inrush current. The magnitude of the inrush current can vary and is a function of the residual flux in the transformer core and the point of energisation on the voltage waveform. The peak inrush current can typically be up to 7–11 times higher than the full load current of the transformer, considering an ideal voltage source. In a real network, the inrush current magnitude usually reduces with an increase in the effective impedance between the transformer and the voltage source.

The inrush current profile starts with the highest peak and then decays to a smaller steady state magnetising current. The decay can be rapid or last as long as a few seconds, depending on the damping provided by the network. The inrush current flows through the network impedance to the transformer being energised, causing voltage drops or dips across the network. The voltage dip will be seen from the terminals of generators supplying the busbar where the transformer is being energised.

The characteristic of the voltage dip is mainly a function of the inrush current peak value and decay profile, the strength of the system, and the voltage control response of generation resources in the network. Since the flux/current relation for the transformer is nonlinear and is determined by the saturation curve of the transformer, the magnetisation current of a transformer contains harmonics.

Analysis suggests that the TOV can be due to the presence of a low order parallel resonance in the network formed by the nonlinear inductance of the transformer core and the charging capacitance of overhead lines and cables. As a result, energisation of a transformer during system restoration may trigger a parallel resonance as the harmonic rich inrush current serves as a current source for the lower order harmonics.

8.2.3 Circuit Energisation

A slow front switching transient due to energisation of a long overhead line (OHL) or cable can eventually develop into a TOV depending on the existing network components and the resonance frequency of the network.

The severity of the TOV is associated with:

1. the size of the distributed generator
2. the shunt capacitance of the isolated system mainly from the charging capacitance of the long OHL and cable circuit
3. presence of any shunt reactors
4. a neutral earthing point provided by the grid transformer

5. proximity in terms of harmonic order of the first series resonance point, as seen by the generator
6. the available damping provided by the connected load in the system.

When energising a long OHL or cable circuit, especially at 132kV or above, a series resonant circuit is likely to be formed by the combination of equivalent inductance of the generator, the circuit, and the 132/33kV and/or 400/132kV transformers and the charging capacitance of the 132kV or 400kV circuit. If the resonant frequency approaches the power frequency then the sinusoidal voltage source (generator) can drive the resonant circuit to generate a TOV. The capacitance of the long OHL or cable circuit plays an important role in the formation of the series resonant circuit. The longer the line, the higher are the chances of having lower order resonances.

When comparing the TOV to the rated withstand voltage of equipment, IEC 60071 suggests using a safety factor to 'compensate for differences in equipment assembly, the dispersion in the product quality, the quality of installation, the ageing of the insulation during the expected lifetime, and other unknown influences'. For internal insulation, IEC suggests using a safety factor of 1.15, which means a 15% reduction of the initial insulation strength. This approach does not take into account the TOV duration, leading to a conservative TOV estimation. In other words, more headroom will be available for the TOV towards the required insulation level of the equipment.

Figure 35 below shows the principle of TOV vs withstand voltage of equipment during energisation events in a power system.

Theoretically, as long as the resulting TOV from the energisation event, multiplied by a safety factor, is below the specified standard withstand voltage of equipment as per IEC 60071, the TOV would be acceptable. The designed withstand voltages of 132kV and 33kV equipment in the SPEN distribution network are 275kV (2.083pu) or 388.9kVp and 70kV (2.12pu) or 99kVp, respectively. For voltage levels below 245kV, there is no distinction between phase-to-earth and phase-to-phase TOV limits.

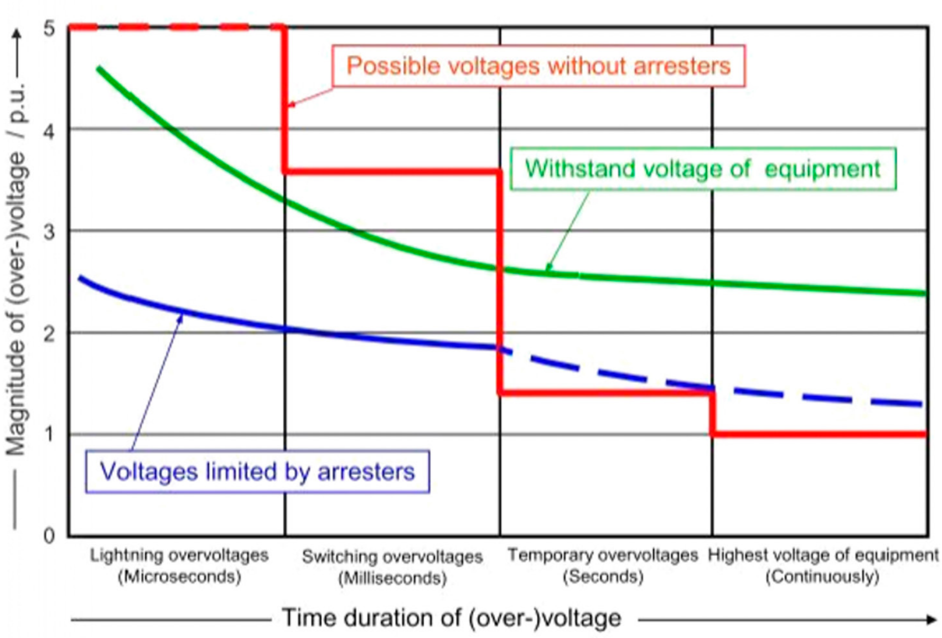


Figure 35: Temporary overvoltage vs withstand voltage of equipment[14]

8.2.4 Combination of Transformer and Circuit Energisation

High TOVs can also occur during a combined energisation of a long OHL or cable circuit and a large transformer. Similar to energisation of a long OHL and cable circuit, the TOV is caused by the capacitance of the long OHL or cable circuit, which forms a series resonant circuit with the equivalent inductance of transformers, circuits and the anchor generator.

The outstanding technical challenges identified in the previous PET report have been addressed through the studies presented below. The above discussion on TOV and voltage dip underpins the analysis of the results. The purpose of the studies has been to assess the complex interaction of various parameters which influence these phenomena and explore the possibility of developing simple rules which can serve as quick screening techniques to apply to the wider GB network.

[14] Volker Hinrichsen, *Metal-Oxide Surge Arrester in High-Voltage Power System, 3rd edition,* Siemens AG, 2011.

8.3 Energising a 132/33kV Grid Transformer

8.3.1 Scope

The objective of this study is to come up with a set of generic conclusions by considering a range of values for all the parameters which can potentially influence the magnitude of the transformer inrush current, and the voltage dip seen at the terminal of the anchor generator when a 33kV connected DER is used to energise a Grid Transformer (132/33kV) along with a 132kV overhead circuit.

8.3.2 Methodology

The Chapelcross GSP from SP Distribution license area is considered for this study. The topology of the network studied includes Steven's Croft biomass generator, which serves as the anchor generator, two parallel 26km cables connecting the generator to the Chapelcross 33kV busbar, the 132/33kV Grid Transformer (GT) and a 12.8km long 132kV overhead line. A schematic is given in figure 36.

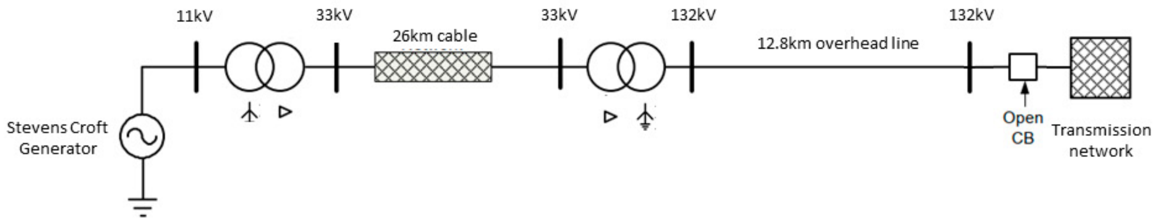


Figure 36: Schematic of the network used for the grid transformer energisation study

The following seven parameters are varied in different combinations to simulate 56 different scenarios.

Parameter	Values
Grid transformer rating	45MVA, 90MVA
Transformer saturation characteristic e.g. decay time constant, inrush magnitude	Inrush – 4 times, 7 times Decay time 0.8sec, 1.2sec
Transformer tap position e.g. high tap, low tap	Max tap, min tap, nominal tap
Size of the anchor generator	25MVA, 60MVA
System strength in terms of the effect of electrical distance between the anchor generator and the transformer	Strong – 1km Weak – 50km
Voltage of the network during energisation	0.9pu, 1pu
Damping of the network in terms of connected load	No load, 6MW load (Annan primary substation)

Table 26: List of parameters varied

The 56 scenarios are studied using Point on Wave (PoW) simulations to find out the relative influence of the seven parameters as a function of the switching instant. So, in total, for each system variable such as voltage dip at the generator terminal, there are (56*21) = 1176 data points which are analysed to construe the relative impact on system variables.

8.3.3 Key Findings

Based on the above studies, the relative influence of the parameters on the dip in the system voltage is ascertained and listed out in Table 27 below in terms of four qualitative categories. PoW switching is found to exhibit a very strong influence on the degree of the voltage dip. Irrespective of any other parameters, the minimum voltage dip can only be achieved through PoW switching.

Anchor generator size, system strength in terms of the effective electrical distance from the generator, system voltage at energisation and saturation characteristic of a transformer are all found to have a strong influence. As an example, energisation at 10% reduced voltage leads to around a 3% reduction in voltage dip on an average. However, this value is largely influenced by other system conditions such as strength of the system and the closing time of the breaker.

Transformer tap position and the loading on the system showed relatively weaker influence compared to the other parameters.

Parameter	Correlation
Point on wave switching	Very strong
Generator size	Strong
System strength	Strong
Network voltage	Strong
Saturation characteristic	Strong
Transformer size	Medium
Transformer tap setting	Weak
System loading	Weak

Table 27: Relative influence of parameters on voltage dip at the generator terminal

Figure 37 presents radar plots for two different network conditions to capture the quantitative influence of the parameters and a quick visual cue to potential options to counter the voltage dip issue due to high inrush currents.

The concentric circles with values from 0 to 0.2 are the delta change in the voltage dip values with respect to a base case. The base case is selected to be a 90MVA grid transformer with an inrush of 7 times and 1.2sec decay, and energised by a 60MVA anchor generator at 1pu system voltage when there is no loading on the system and the distance from the generator to the transformer is 1km.

For a strong network (figure 37(a)), the influence of the four parameters follow a uniform relationship with the PoW switching. The coloured patches correspond to the four switching instants (0ms, 5ms, 9ms and 15ms) shown in the figures. So, irrespective of switching, the network voltage always has the highest influence on the voltage dip compared to the other parameters and energisation at a reduced voltage decreases the amount of voltage dip.

For a weak network (figure 37(b)), however, no such clear relationship is available. The influence of the parameters varies with the instant of the breaker closing. So, while the energisation voltage has a stronger influence on the voltage dip for 5ms PoW, transformer and generator size will have a higher impact for 15ms PoW. But above all, it again shows that PoW switching has the highest impact, given by the green radar plot.

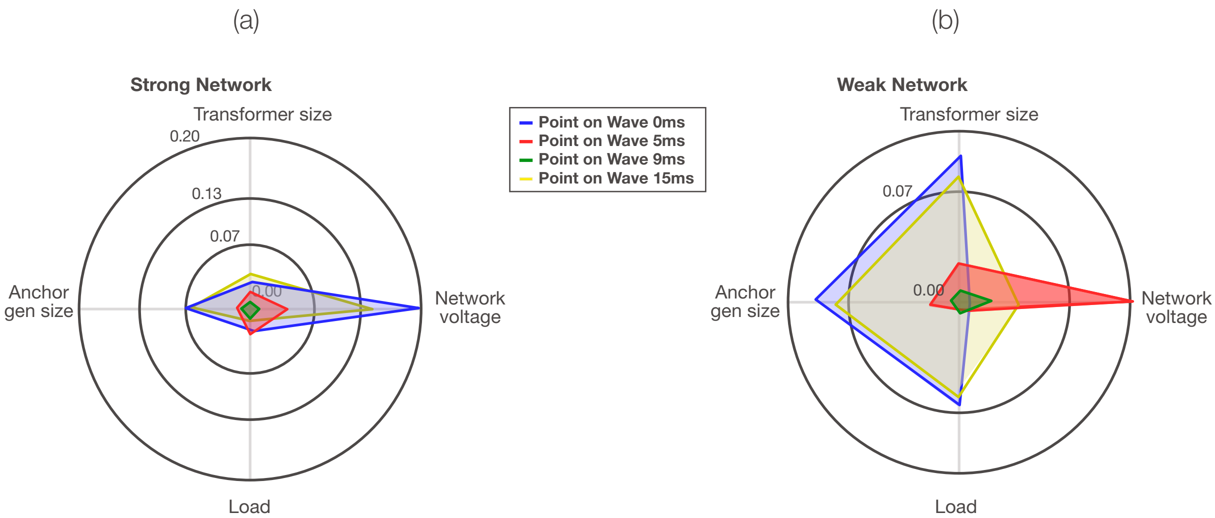


Figure 37: Quantitative influence of parameters on system voltage dip

8.3.4 Application

The findings from the above study shows that electromagnetic transients on distribution networks are a complex phenomenon and coming up with a simple rule of thumb is difficult due to the number influencing factors. This concurs with the findings in the July 2020 PET report where the worst-case voltage dip at the anchor generator terminal in the Galloway case study was 27.5% when energising Tongland GT while in the Chapelcross case study the worst-case was around 17% when energising the Gretna SGT.

What can be concluded is that the voltage dip at the generator terminal depends on the skeleton network energised, and that it reduces as more network is energised. The following broad guidelines can be drawn from the simulation results:

- PoW switching has the highest potential of any mitigation strategy to reduce voltage dips.
- Energisation at a reduced voltage seems promising in terms of reducing any voltage dip, however, the effectiveness might depend on the strength of the system.
- The interaction of the parameters is complex. EMT studies might be required in cases where the anchor generator under-voltage protection setting is conservative such as 80% retained voltage with a 160ms delay.

8.4 Energising 132kV Unbalanced Overhead Lines

8.4.1 Scope

While care is taken to mitigate the sources of unbalance in a network and keep it within the acceptable limit of 2%[15], there could be certain network configurations such as a single phase line which is inherently unbalanced and during network energisation it could introduce a significant negative phase sequence component. Unbalance can cause inadvertent tripping of generators, heating of stator windings of generators, motors and stalling of induction motor loads.

In the Chapelcross case study network, the 132kV Ecclefechan overhead line is a single phase double circuit connection which supplies a traction load by two 132/25kV step down transformers. This study looks into the impact of energising this circuit along with the traction transformer in terms of transients and unbalance introduced at the anchor generator terminal and assesses the possibility of any untoward negative phase sequence tripping of the generator.

8.4.2 Methodology

The topology of the network studied includes Steven's Croft biomass generator, two parallel 26km cables connecting the generator to the Chapelcross 33kV busbar, the 132/33kV GT and a 6.56km long Ecclefechan overhead line (only one circuit considered in the study) with a 132/25kV traction transformer. A schematic is given in figure 38.

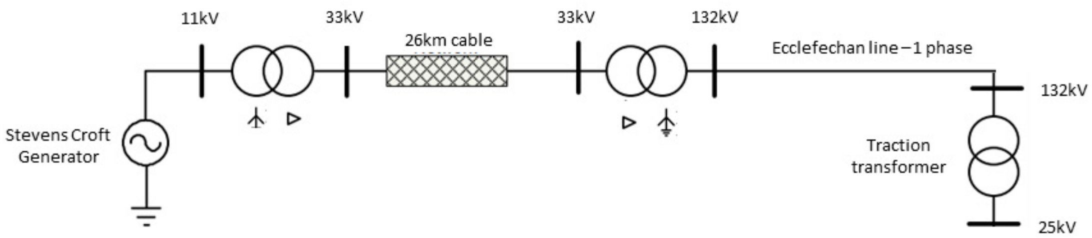


Figure 38: Schematic of the network used for the Ecclefechan energisation study

Eight case studies are considered to assess the impact of energisation voltage, system loading and transformer saturation on the unbalance and temporary overvoltage in the system. The case studies are given in Table 28. In all the case studies, the anchor generator step-up transformer (11/33kV) and the 26km cable is considered to be already energised.

[15] As per Engineering Recommendation P29 – Planning limits for voltage unbalance in the United Kingdom.

Case Study	Description
Case 1	• 132/33kV grid transformer saturation considered • 132/25kV traction transformer saturation considered • No loading on the system • Energisation at 1pu
Case 2	• 132/33kV grid transformer considered to be already energised • 132/25kV traction transformer saturation considered • Annan primary substation load considered • Energisation at 1pu
Case 3	• 132/33kV grid transformer saturation considered • 132/25kV traction transformer saturation considered • Annan primary substation load considered • Energisation at 1pu
Case 4	• 132/33kV grid transformer considered to be already energised • 132/25kV traction transformer saturation considered • No loading on the system • Energisation at 1pu
Case 5	• Same as case study 1 except energisation at 0.7pu
Case 6	• Same as case study 2 except energisation at 0.7pu
Case 7	• Same as case study 3 except energisation at 0.7pu
Case 8	• Same as case study 4 except energisation at 0.7pu

Table 28: Case studies considered for the Ecclefechan energisation study

Figure 39 shows the impact of energisation voltage on the maximum and minimum peak TOV. In case study 5, the energisation voltage is reduced from 1pu to 0.7pu while keeping all other system conditions the same. As is evident, energisation at a reduced voltage helps in restricting both the maximum and minimum peak of the TOV and the reduction is roughly uniform across all the busbars, as calculated in Table 29. Therefore, reduced voltage energisation is a promising technique to avoid excessive voltage stresses on network components.

(a) Case Study 1

(b) Case Study 5

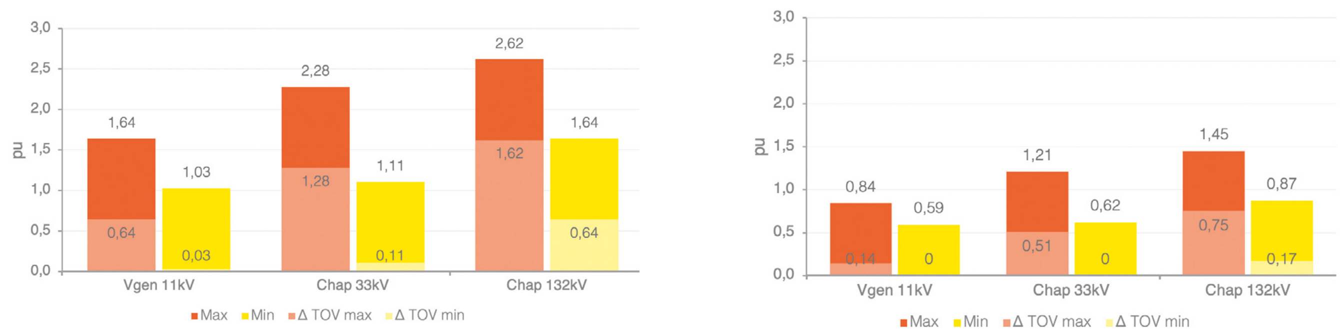


Figure 39: Impact of energisation voltage on the TOV

Busbar	Decrease in Max TOV	Decrease in Min TOV
Chapelcross 132kV busbar (Chap 132kV)	43%	45%
Steven's Croft 11kV busbar (Vgen 11kV)	46%	30%
Chapelcross 33kV busbar (Chap 33kV)	46%	37%

Table 29: Percentage change in TOV due to energisation voltage

The single phase Ecclefechan overhead line introduces unbalance in the system during energisation of the traction transformer. However, the negative phase sequence protection setting of some generators could be very sensitive causing it to trip during the process. So, it is important to check the actual settings on the generator and update it accordingly (by introducing a longer delay time or increasing the unbalance threshold) before the energisation process. The settings can be brought back to the normal value after the restoration process is complete.

8.4.3 Key Findings

Based on the above studies, the key findings relating to energisation of unbalanced lines are:

- The peak TOV observed in all the eight case studies is within the short-term power frequency limits specified in IEC 60071.
- Damping provided by loads helps to reduce both the maximum and minimum peak TOV. The amount by which the TOV reduces is, however, not uniform in all busbars and the maximum effect is observed at the busbar closest to the load.
- The interaction between a circuit and a transformer energisation is complex and it cannot be said with certainty that separate energisation will have a positive effect on TOV at all busbars.
- Energisation at a reduced voltage can reduce the TOV peak and the effect is fairly uniform across all the busbars.
- Voltage unbalance varies with PoW switching and the energisation voltage. Energisation at a reduced voltage can help to reduce the unbalance.
- PoW switching has the highest impact on TOV peak and voltage unbalance.

8.4.4 Application

For Distributed ReStart, energisation at a reduced voltage will be beneficial in terms of minimising voltage stresses on network components, surge arresters and insulations and the voltage unbalance. To reduce the TOV further, PoW switching can be adopted, although it may require a large capital investment.

8.5 Energising a 33kV Network and Primary Transformers

8.5.1 Scope

The Chapelcross case study network includes 13 primary substation transformers (33/11kV) apart from the wind turbine transformers at Minsca and Ewe Hill wind farms. The full network diagram is provided in Appendix 1.

In this study, we explore the possibility of energising the whole 33kV network underneath the Chapelcross GSP at one go i.e. through a single breaker operation and assess the impact on the anchor generator and busbar voltages.

8.5.2 Methodology

The generator is assumed to have already energised the step-up transformer and the system is in steady state before closing the 33kV breaker at the Steven's Croft side of the 26km cable to the Chapelcross substation. The 33kV network including the 13 primary transformers, Minsca and Ewe Hill wind farm array cables and wind turbine transformers are energised simultaneously.

Two cases are considered, one with 1pu energisation voltage and the second one with a reduced voltage of 0.7pu. The peak voltages observed at all the busbars are due to switching transients (EMT plots in Appendix 1) such as Slow Front Overvoltage (SFO). No significant TOV phenomenon both in terms of magnitude and duration were observed across the network.

Figure 40 shows the peak SFO at different busbars. The maximum and minimum peak SFO are calculated from a series of PoW simulations. The changes in the peak values are also shown in the figures as pattern bars.

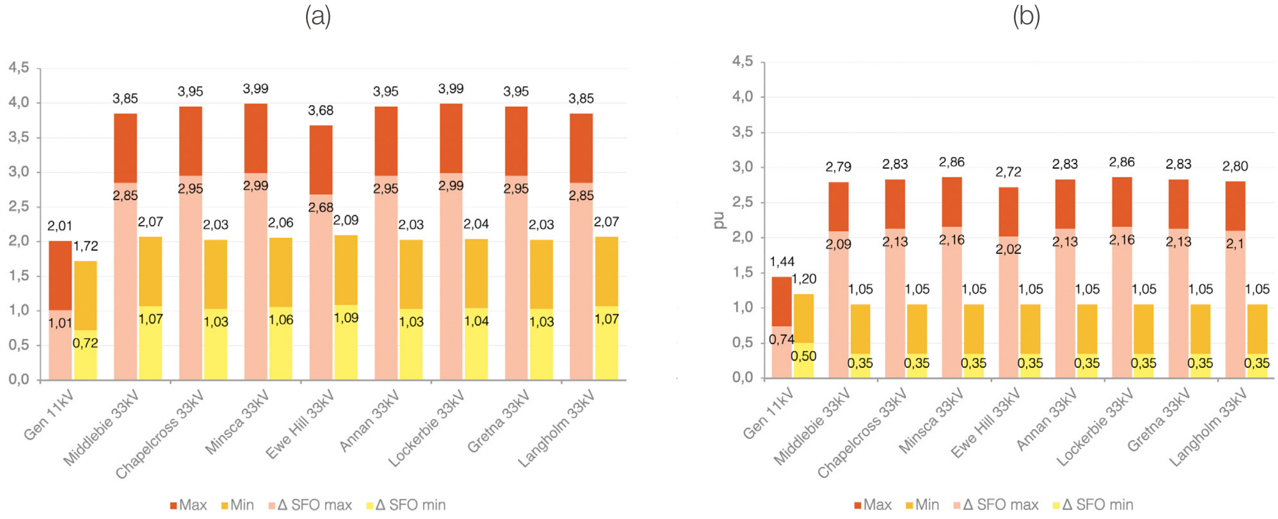


Figure 40: Impact of energisation voltage on the TOV, (a) energisation at 1pu, (b) energisation at 0.7pu

The results show that reducing the energisation voltage reduces not only the absolute peak value, but also on the maximum and minimum rise in SFO at all the busbars. For example, at Middlebie substation the peak energisation voltage reduces from 3.85pu to 2.79pu when the energisation voltage reduces from 1pu to 0.7pu, while the maximum SFO rise decreases from 2.85pu to 2.09pu. Also, the rise in SFO is found to be uniform across the whole 33kV network which shows that there is no resonance related specific issues at any particular busbar.

Similar to SFO, lowering the energisation voltage reduces the maximum and minimum voltage dip. The maximum voltage dip recorded in our studies is 16% which is well above the anchor generator's limit and should not interfere with the undervoltage protection.

8.5.3 Key Findings

Based on the above case studies, the key findings are:

- For the Chapelcross 33kV network the energisation transient voltage is below the equipment safety limits. This means that energisation of all primary substations and the 33kV circuits is possible through a single circuit breaker switching at 1pu energisation voltage.
- A total of 214MVA of transformers (13 primary transformers of different sizes ranging from 5MVA to 24MVA and 22 wind turbine transformers of 2.7MVA) can be energised using a 60MVA anchor generator.
- Energisation at a reduced voltage (0.7pu) lowers both the relative increase in peak SFO and the absolute value of peak SFO at all PoW switching instants.
- Similarly, the dip in the voltage due to transformer inrush current is also reduced when energised at a reduced voltage.

8.5.4 Application

For insulations below 245kV, IEC 60071 defines no voltage limits for switching transients. Therefore, the peak TOV limits of 388.9kVp and 99kVp for 132kV and 33kV equipment can be used for the purpose. The highest peak SFO observed in the studies is 3.99pu or 76kV at the Minsca and Lockerbie 33kV busbars for an energisation voltage of 1pu (Table 33 in Appendix 1). The peak SFO recorded at other busbars are around 3.8pu and are within IEC 60071 limits.

Based on the studies, there are no issues with energising the whole Chapelcross 33kV GSP with a single breaker operation at 1pu energisation voltage. However, to reduce any voltage stress on the component insulations, intervention techniques such as PoW switching or reduced voltage energisation are effective to reduce switching transients.

8.6 Motor Starting Studies

8.6.1 Scope

This study looks to assess the impact of starting large auxiliary motor-type loads (e.g. boiler feed pumps, forced draft fans, induced draft fans etc.) in a 132kV connected power station using a 33kV connected anchor generator. The size of such motor loads is typically around 1% of the power plant rating. So, for a 300MW plant, the auxiliary motors could be 3MW each. Unlike static loads (non-motor loads), induction motors exhibit high reactive power sensitivity depending on the load torque characteristic. During start up, a significant reactive current (5 to 8 times of the nominal current) is drawn to build up the motor torque before the motor slip settles down to the nominal value.

Among other findings, the two important questions answered here are:

- Will the Steven's Croft anchor generator have sufficient reactive capability to start a 132kV connected power station auxiliary motor load without stalling the motor?
- Is there any potential for sustained voltage depression due to this event?

8.6.2 Methodology

A schematic of the studied network is shown in figure 41.

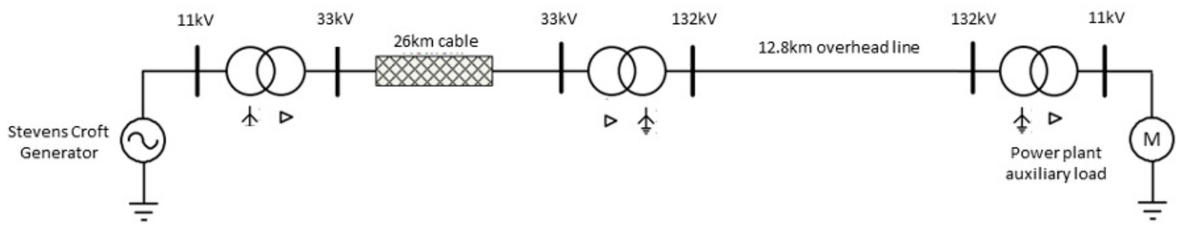


Figure 41: Schematic of the network used for the induction motor starting study

A 3MW induction motor is connected at the end of the 132kV line via a step-down transformer. The motor is assumed to have a load inertia of 100kgm2, in addition to the motor shaft inertia. All other motor parameters correspond to a standard 11kV double cage induction motor available in DIgSILENT library. Table 30 lists the case studies considered. Apart from the anchor generator, no other DER are included in the studies.

Case Study	Description
Case 1	• 3MW induction motor with quadratic torque characteristic • Motor starting at a reduced voltage of 0.95pu (through GT tap action) • 12.8km 132kV overhead line
Case 2	• 3MW induction motor with quadratic torque characteristic • Starting voltage increased to 1.01pu (through GT tap action) • 12.8km 132kV overhead line
Case 3	• 3MW induction motor with quadratic torque characteristic • Motor starting at a reduced voltage of 0.95pu (through GT tap action) • 132kV overhead line length increased to 50km

Table 30: Case studies considered for the induction motor starting study

8.6.3 Key Findings

Based on the simulation results, the key findings are:

- For a 60MVA anchor generator, restoring a 132kV connected power plant auxiliary large induction motor loads is not a problem. The voltage dip at the anchor generator terminal is less than 10% and the maximum MVAr requirement is within the reactive power capability of the anchor generator.
- The lightly loaded transmission lines and distribution cables help with the initial surge in the reactive power demand of the motor.

- Induction motor starting at a reduced voltage helps with the initial peak transient. However, this is a trade-off between peak value and settling time. If the anchor generator has sufficient active and reactive power capability available then energisation at a higher voltage is advisable to speed up the restoration process.

8.6.4 Application

A 3MW motor draws around 15MVAr during starting. Neglecting any offset offered by line capacitances, the anchor generator reactive power capability should be at least 5 times the motor size. This can be used as a rule of thumb for screening possible power plants which can be restored by an anchor generator before doing detailed study for the live trial.

8.7 Energising 275kV and 400kV Circuits

8.7.1 Scope

In the previous PET report published in July 2020, we focused on energising the network up to 132kV. In this study, we investigate the possibility of energising 275kV or 400kV transmission lines using the 33kV connected anchor generator. The objective is to find out if the anchor generator on its own has enough reactive capability to absorb the line charging power and if this capability can be enhanced with support from other DER in the DRZ.

8.7.2 Methodology

A schematic of the studied network is shown in figure 42.

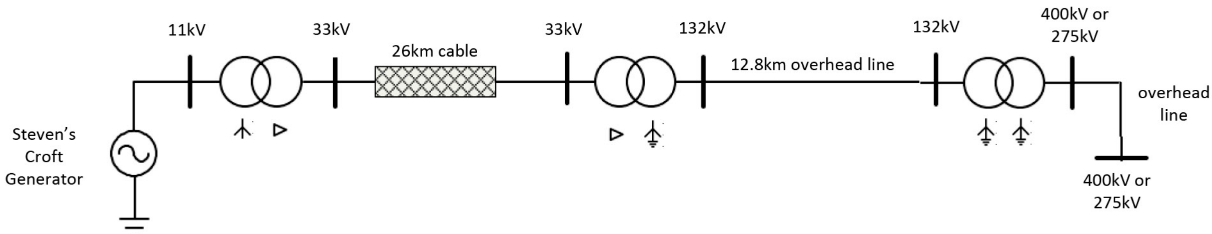


Figure 42: Schematic of the network used for 275kV and 400kV transmission line energisation

As shown in the schematic, the studied network considers a 400kV substation with a single 400kV overhead transmission line. To simulate the 275kV energisation, the 400/132kV Super Grid Transformer (SGT) is replaced by a 275/132kV SGT and a 275kV overhead line. Table 31 describes the four case studies considered and for each case study the line lengths are varied in four discrete steps to determine a rough estimate of the maximum length possible to energise before hitting the reactive power capability limit or the steady state operational voltage limits as per the SQSS standard.

Case Study	Description
Case 1	• Only anchor generator • GT (132/33kV) and SGT (400/132kV or 275/132kV) at nominal tap
Case 2	• Only anchor generator • GT (132/33kV) and SGT (400/132kV or 275/132kV) at minimum tap, GT can provide -20% reduction and SGT can provide -14%
Case 3	• Anchor generator + other DER (Minsca and Ewe Hill WFs) • GT (132/33kV) and SGT (400/132kV or 275/132kV) at nominal tap
Case 4	• Anchor generator + other DER (Minsca and Ewe Hill WFs) • GT (132/33kV) and SGT (400/132kV or 275/132kV) at minimum tap, GT can provide -20% reduction and SGT can provide -14%

Table 31: Case studies considered for the 275kV, 400kV energisation study

8.7.3 Key Findings

Based on the study results, the key findings are:

- Tap action on the grid and super grid transformers can be utilised to keep the voltage within limits and reduce the amount of line charging power generated. As transmission connected generators are brought online, the transformer taps can be moved back to nominal and the additional MVAr will be picked up by the generators.
- DERs other than the anchor generator can support the process by increasing the effective reactive power absorption capability of the DRZ, and combined with tap action, a much longer length of transmission circuit can be energised.
- For a 400kV line, the maximum length that can be energised before hitting the 110% SQSS voltage limit (at 400kV) is around 20km. This requires roughly 16MVAr of reactive absorption capability from the generator. If voltage control is applied, then considering the reactive power capability of the 60MVA Steven's Croft generator, the maximum length of 400kV line that can be energised increases to around 90km.
- Similarly, the maximum length of a 275kV line that can be energised before hitting the 109% SQSS voltage limit (at 275kV) is around 60km. This requires roughly 22MVAr of reactive absorption capability from the generator. If voltage control is applied, then considering the reactive power capability of the 60MVA Steven's Croft generator, the maximum length of 275kV line that can be energised, increases to 220km.

8.7.4 Application

The Steven's Croft 60MVA anchor generator, along with the two wind farms, and using transformer tap switching, can potentially energise up to 90km of 400kV circuit and 220km of 275kV circuit. This includes energising the 26km cable, the 33/132kV GT, 12.8km of 132kV line and the 132/4400kV or 132/275kV SGT. If there is any reactive compensation equipment available in the network then that should be used first, followed by tapping down the SGT. Increasing the length of 275kV or 400kV circuit that is energised will help the DRZ connect to transmission connected Black Start units which can help to restore the power network much faster.

8.8 Conclusion

The key findings from these additional power system studies can be summarised as:

8.8.1 Voltage Dips Resulting From Transformer Energisation

- Voltage dips resulting from transformer energisation could result in undesired undervoltage protection operation and the anchor generator tripping during distributed restart. The three case study networks have shown that the maximum dip in the voltage and the duration of the dip is not significant enough to interfere with G59 or G99 protection settings. However, if an anchor generator has a particularly conservative under-voltage protection setting (such as 80% retained voltage with a 160ms delay) then either it needs to be relaxed or detailed EMT studies are necessary to determine a suitable restoration sequence alternative.
- Voltage dips due to the energisation of a grid transformer depends on the combination of several factors such as strength of the system, size of the generator, saturation characteristic of the transformer etc. Of all the strategies considered in the studies, Point-on-Wave (PoW) switching was found to have the highest impact in terms of reducing the voltage dip.
- Furthermore, transformer energisation at a reduced voltage to mitigate the voltage dip seems promising, however, the effectiveness depends on the strength of the system. The voltage dip at the generator terminal depends on the skeleton network energised and as more network is brought on the voltage dip tends to improve.

8.8.2 Temporary Overvoltage

- Energisation of a full GSP 33kV network instantaneously (without any 11kV demand customer connected), i.e. simultaneous energisation of 13 primary transformers (33/11kV) totalling 155MVA, 22 wind farm transformers totalling 58.8MVA, and all 33kV circuits through a single circuit breaker operation at 1pu energisation voltage results in switching transients such as Slow Front Overvoltage (SFO), however the voltage peaks are below the equipment IEC insulation limits.
- Reducing the energisation voltage and increasing the loading on the system are found to reduce the overvoltage SFO in addition to PoW switching. The effect of reduced voltage energisation on the peak SFO is found to be uniform across the network while the effect of system loading is found to be location dependent, i.e. the influence on the SFO is maximum at the busbar closest to the connected load.

8.8.3 Energising Unbalanced Overhead Lines

- Energisation of an unbalanced 132kV OHL and traction transformer can cause a voltage unbalance at the anchor generator terminals. In the Chapelcross case study the maximum observed voltage unbalance was 8% which is not a problem from machine design perspective. However, if the unbalance lasts longer than the negative phase sequence trip delay of the generator protection, it could trip the generator. It is therefore important to check the generator protection settings and update it accordingly (by introducing a longer delay time or increasing the unbalance threshold) before restoration. Another option could be to delay the energisation of any unbalanced circuits/demands until the system gets stronger.

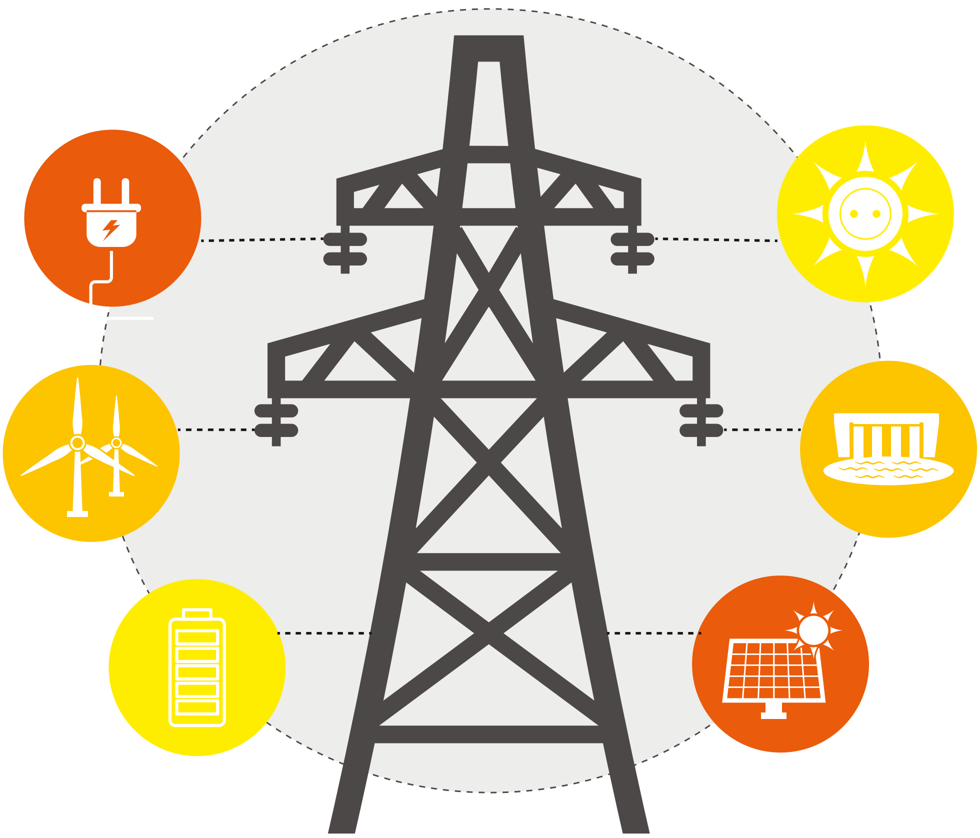
8.8.4 Motor Starting Capability

- For a 60MVA anchor generator, restoring a 132kV connected large induction motor load is not a problem. The voltage dip at the anchor generator terminal is less than 10% and the maximum MVAr requirement is within the reactive power capability of the anchor generator. As long as the anchor generator and other DER have a combined reactive power capability of at least five to six times the motor rating and the voltage at the motor terminal does not go below 80%, starting an induction motor should not be a challenge for an anchor generator of any size.

- Increasing the electrical distance of the motor from the anchor generator has little impact on the MW and MVAr response of the generator, and the voltage and frequency of the system, so long as there are no other loads connected with significant reactive demand.

8.8.5 Energising 275kV and 400kV Transmission Circuits

- For a 400kV line, the maximum length that can be energised before reaching the SQSS voltage limits, is around 20km, and this requires roughly 16MVAr of reactive absorption capability. Similarly, the maximum length of a 275kV line that can be energised before reaching the SQSS voltage limits is around 60km and this requires roughly 22MVAr of reactive absorption capability.



9. Conclusions

This report is the second providing an *Assessment of Power Engineering Aspects of Black Start from DER*. This report focuses on the development of automation in the form of a DRZ-C, works related to the BAU rollout of a Black Start from DER service, followed by the latest system study work related to protection and network energisation.

9.1 DRZ-C

The following conclusions can be made based on the DRZ-C generic requirements and example functional designs provided in Chapter 2 and 3 respectively:

- The generic DRZ-C requirements provided in Chapter 2 (Development Stage 1) may be adapted based on learning from the Implementation and Test stage of the DRZ-C works (Development Stage 2), which will test one or more DRZ-C solutions in hardware form within a lab-based Hardware-in-the-Loop (HiL) environment.
- It is anticipated that the generic (i.e. standard) functionality of a DRZ-C can be configured to operate against any DRZ specific requirements. In some cases configuration alone may not be a feasible approach and therefore DRZ specific development would be required.
- It is believed that the control systems of existing non-anchor DER can provide the functionality required by a DRZ-C System without significant development. The control system of the anchor generators however may require significant development to provide DRZ-C pre-requisite capability, such as being able to self-start, block load, and deliver isochronous frequency control mode.
- Each DER is required to provide, in real time, a signal representing the instantaneous real power it can generate/consume. This is critical for intermittent generation to inform the DRZ-C how much generation could be delivered to the island if dispatched. The DRZ-C is likely to dispatch intermittent generation at lower level (and therefore constrain output) to achieve a more predictable service from the DER. DER generators must ensure that the equipment and processes associated with calculating and exposing this signal are designed for high accuracy and availability. This signal is typically provided by controllers of modern PV/wind farms however DER developers/suppliers should ensure that the availability and quality standard is compliant.
- It is believed that the DRZ-C designs provided are credible and will be proven feasible during an implementation and test activity. Stage 2 of the DRZ-C works will test one or more of the DRZ-C Systems with a lab-based environment to demonstrate feasibility in advance of any potential live network trials. The provided requirements may be adapted following learning from lab testing.
- The Organisational, Systems and Telecoms (OST) workstream's Design Stage II report will present their assessment on the implications on the telecoms infrastructure of supporting the described DRZ-C functionality. The OST work will also include an appreciation of relevant cyber-security standards and interface capability (e.g. data protocols).

9.2 Functional Requirements – Anchor Generator

The eleven proposed functional requirements for an anchor generator to provide a Black Start service are given in Table 32. These requirements will be subject to revision as further technical requirements for establishing a DRZ are finalised, and the compatibility with existing DER capability is further assessed.

Category No.1: Time to Connect	**Proposed DER Requirement**	**≤8h**
	Proposed DER Definition	• Time taken from instruction (from the relevant system operator) to start up the Black Start plant from shutdown, without the use of external power supplies. • Instruction to start up may be up to 72hrs after a blackout. • Energise up to the DNO statutory point of connection. • Ability to operate at rated frequency, no load, for four hours (without connection to the DNO network). • Connected to DNO or transmission network at 33kV or 11kV (transforming directly to a higher voltage).
	Comments	• Exact capability to be declared. • Confirm if loadbank is required to meet the proposed DER definition.
Category No.2: Service Availability	**Proposed DER Requirement**	**≥90%**
	Proposed DER Definition	• The ability to deliver the contracted Black Start service over 90 per cent of each year of providing a Black Start service. **Note:** It is the responsibility of the provider to demonstrate its service availability.
	Comments	• A Black Start could happen at any time thus a high service availability is required.
Category No.3: Resilience of Supply, Black Start Service	**Proposed DER Requirement**	**≥72h up to 120h**
	Proposed DER Definition	• When instructed to Black Start, the minimum time the provider will deliver continuous output at 90% rated capacity.
	Comments	• Exact capability to be declared.
Category No.4: Resilience of Supply, Black Start Auxiliary Units	**Proposed DER Requirement**	**120h**
	Proposed DER Definition	• Run continuously for a maximum of 5 days in order to: 1) maintain the generator declared 'time to connect' availability for up to 72 hours after a blackout 2) maintain the generator house loads for the declared time in the 'resilience of supply, Black Start Service'.
	Comments	• Provider to determine the fuel supply required.
Category No.5: Frequency Control	**Proposed DER Requirement**	**A fast-acting proportional frequency control device is required**
	Proposed DER Definition	• Frequency control device as defined in Engineering Recommendation G99 (applicable to Type C and D generators). • The ability to manage frequency level when block loading (47.5Hz – 52.0Hz). • Fast acting frequency control device capable of being operated in isochronous mode or with a set point and droop setting if required.
	Comments	

Category No.6: Voltage Control	**Proposed DER Requirement**	**Ability to provide continuous steady state control of the voltage with a set point and slope characteristic**
	Proposed DER Definition	• Voltage control device as defined in Engineering Recommendation G99 (applicable to Type C and D generators). • Ability to create a voltage source (independent of the DNO network) and control the voltage within acceptable limits during energisation/block loading (+/– 10%).
	Comments	• During a Black Start event the anchor generator will need to maintain voltage (within limits) when creating, maintaining and expanding a DRZ.
Category No.7: Block Loading Size	**Proposed DER Requirement**	**Estimated ≥ 2MW (site specific depending on DRZ)**
	Proposed DER Definition	• Capacity to accept instantaneous loading of demand blocks and maintain the frequency within the 47.5Hz to 52Hz range.
	Comments	• Exact capability to be declared.
Category No.8: Reactive Capability	**Proposed DER Requirement**	**Minimum of 0.95 leading and 0.95 lagging power factor at the point of connection.**
	Proposed DER Definition	• Ability to absorb MVArs (leading power factor) to energise the DNO network whilst active power is zero. • Ability to generate MVArs (lagging power factor) to supply network demand.
	Comments	• Numerical (MVAr) leading and lagging values to be declared.
Category No.9: Sequential Start-Ups	**Proposed DER Requirement**	**≥ 3**
	Proposed DER Definition	• Ability to perform at least three sequential start-ups.
	Comments	• Time required between sequential start-ups to be declared.
Category No.10: Short Circuit Level (SCL)	**Proposed DER Requirement**	**≥ 1 x DER MVA rating**
	Proposed DER Definition	• Injection of reactive current during a disturbance. SCL measured at generator terminals.
	Comments	• DRZ feasibility study to determine if DER SCL is sufficient to be the anchor DER.
Category No.11: DRZ Specific Technical	**Proposed DER Requirement**	**To be confirmed based on specific DRZ requirements**
	Proposed DER Definition	• Technical requirements on an anchor DER specific to a DRZ in order to facilitate the restoration process.
	Comments	• DRZ feasibility study to confirm.

Table 32: Proposed anchor DER functional requirements

9.3 Potential across GB

The following conclusions were drawn:

- An estimation of the potential for concept rollout of Black Start from DER across the DNOs in GB has been made using the information published within respective DNO LTDS from November 2019.
- Within the GB DNO LTDS data, there is ~9GW of generation (connected and contracted) in England and Wales which is classified as 'other' or 'mixed'. To give a conservative estimate 15% of this generation was considered as anchor generation.
- Analysis of the GB DNO networks indicates that there is almost 10GW of synchronous generation currently connected. This consists of ~1.2GW connected at 11kV, ~4.8GW connected at 33kV and ~3.7GW connected at 132kV. This power is produced from 374 individual generation sites, of which 283 (76%) are connected at 33kV.
- For non-anchor generators there is a total of ~15GW of additional DER currently connected across the GB DNOs. The majority of this (~12GW) is connected at 33kV which equates to 876 individual generation sites out of a total of 953 (92%).
- There are 339 (32%) potential DRZ network areas out of a total of 1045, with 283 of these having a 33kV connected anchor generator.
- A total of 192 (59%) of the 339 potential DRZ sites contain an anchor generator plus additional (non-synchronous) DER.
- If 50% of the DER which is currently contracted (but not connected), is included in the assessment, the total synchronous generation would rise by 3GW to 13GW and additional DER by 5GW to 20GW.
- DRZs should be considered with synchronous generation alone, (not always with additional DER) otherwise the potential number of DRZs will reduce significantly.

9.4 Testing

We present our current proposals for the testing regime that might be implemented with Black Start from DER services. We identify the multiple objectives that testing must satisfy, noting the peculiarities of Black Start compared with other services and highlighting that the purpose is to achieve good outcomes for all parties. We propose approaches and specific physical tests that are similar to what is currently used but reflect the differences in Distributed ReStart, including the much larger number of parties involved, the greater role of DNOs, and the use of a DRZ-C System.

The different stages of DRZ development and the implications for testing are discussed, from conceptual design and feasibility assessment through to ongoing change management. Issues discussed include the challenges of outage planning, new requirements in distribution network modelling and simulation, and methods that may not be appropriate in the early years of rollout but may be adopted as the DRZ concept matures and becomes more widespread. As with other aspects of our solutions, our proposals for testing will be refined based on the live trials and desktop exercises in 2021.

9.5 System Studies – Protection

The purpose of this study work is to identify the minimum source 33kV fault level (at the HV terminals of a primary transformer), to ensure that the 11kV and LV networks are adequately protected.

General Conclusions

- The primary transformer size (24MVA, 10MVA or 7.5MVA) does not make a significant difference to the 415V fault levels.
- The length (impedance) of the 11kV feeder has an impact on the 11kV and LV fault levels at the secondary substations.
- A suitable 11kV overcurrent setting (definite time), on primary substation circuit breakers, should be attainable for a minimum 33kV source fault level of ~0.35kA (20MVA). This allows for ~5MVA load current. The loading on 11kV feeder circuits may vary from hundreds of kWs up to ~6MW but is typically in the order of several MW.
- Protection studies should be undertaken for each network to be protected under Black Start conditions, considering the protection devices, settings and circuit impedances specific to that network.

Minimum 33kV Source Fault Levels Required

Table 33 shows the minimum source 33kV fault levels required (at the primary transformer HV terminals), for various 11kV feeder types and lengths, in order to ensure operation of the downstream 11kV and LV fuse protections. It can be seen that a minimum source 33kV fault level of 30MVA is required if the 11kV circuits are a maximum of 30km in length (7.5MVA transformer). The 33kV source fault level required increases significantly (between 140–150MVA) if the 11kV circuit length is 40km in length.

Transformer Rating MVA	Overall Length (km)	Circuit Description	Operation of an 80A HV Fuse in 10s		Operation of a 400A LV Fuse in 10s
			0.25 kA at 415V	6.63 kA at 415V	1.8 kA at 415V
			Primary Tx 33kV Terminals MVA		
24MVA Transformer	10.00	10km cable 185mm	6	8	4
	20.00	10km 150mm + 10km 50mm OHL	9	16	5
	30.00	20km 150mm + 10km 50mm OHL	12	28	6
	40.00	30km 150mm + 10km 50mm OHL	18	140	7
10MVA Transformer	10.00	10km cable 185mm	8	8	4
	20.00	10km 150mm + 10km 50mm OHL	9	16	5
	30.00	20km 150mm + 10km 50mm OHL	12	28	6
	40.00	30km 150mm + 10km 50mm OHL	18	140	7
7.5MVA Transformer	10.00	10km cable 185mm	8	8	4
	20.00	10km 150mm + 10km 50mm OHL	9	16	6
	30.00	20km 150mm + 10km 50mm OHL	12	30	6
	40.00	30km 150mm + 10km 50mm OHL	20	>150	8

Table 33: 33kV Source fault levels to ensure 11kV and LV fuse operation

9.6 System Studies – Energisations

9.6.1 Voltage Dips Resulting from Transformer Energisation

- Voltage dips resulting from transformer energisation could result in undesired undervoltage protection operation and the anchor generator tripping during restoration. The three case study networks have shown that the maximum dip in the voltage and the duration of the dip is not significant enough to interfere with G59 or G99 protection settings. However, if an anchor generator has a particularly conservative undervoltage setting (such as 80% retained voltage with a 160ms delay) then either it needs to be relaxed or detailed EMT studies are necessary to determine to suitable restoration sequence alternative.

- Voltage dips due to the energisation of a grid transformer depends on the combination of several factors such as strength of the system, size of the generator, saturation characteristic of the transformer etc. Of all the strategies considered in the studies, Point-on-Wave (PoW) switching was found to have the highest impact in terms of reducing the voltage dip.
- Furthermore, transformer energisation at a reduced voltage to mitigate the voltage dip seems promising, however, the effectiveness depends on the strength of the system. The voltage dip at the generator terminal depends on the skeleton network energised and as more network is brought on the voltage dip tends to improve.

9.6.2 Temporary Overvoltage

- Energisation of a full GSP 33kV network instantaneously (without any 11kV demand customer connected), i.e. simultaneous energisation of 13 primary transformers (33/11kV) totalling 155MVA, 22 wind farm transformers totalling 58.8MVA, and all 33kV circuits through a single circuit breaker operation at 1pu energisation voltage results in switching transients such as Slow Front Overvoltage (SFO), however the voltage peaks are below the equipment IEC insulation limits.
- Reducing the energisation voltage and increasing the loading on the system are found to reduce the Overvoltage SFO in addition to PoW switching. The effect of reduced voltage energisation on the peak SFO is found to be uniform across the network while the effect of system loading is found to be location dependent, i.e. the influence on the SFO is maximum at the busbar closest to the connected load.

9.6.3 Energising Unbalanced Overhead Lines

- Energisation of an unbalanced 132kV OHL and traction transformer can cause a voltage unbalance at the anchor generator terminals. In the Chapelcross case study the maximum observed voltage unbalance was 8% which is not a problem from machine design perspective. However, if the unbalance lasts longer than the negative phase sequence trip delay of the generator protection, it could trip the generator. It is therefore important to check the generator protection settings and update it accordingly (by introducing a longer delay time or increasing the unbalance threshold) before restoration. Another option could be to delay the energisation of any unbalanced circuits/demands until the system gets stronger.

9.6.4 Motor Starting Capability

- For a 60MVA anchor generator, restoring a 132kV connected large induction motor load is not a problem. The voltage dip at the anchor generator terminal is less than 10% and the maximum MVAr requirement is within the reactive power capability of the anchor generator. As long as the anchor generator and other DER have a combined reactive power capability of at least five to six times the motor rating and the voltage at the motor terminal does not go below 80%, starting an induction motor should not be a challenge for an anchor generator of any size.
- Increasing the electrical distance of the motor from the anchor generator has little impact on the MW and MVAr response of the generator, and the voltage and frequency of the system, so long as there are no other loads connected with significant reactive demand.

9.6.5 Energising 275kV and 400kV Transmission Circuits

- For a 400kV line, the maximum length that can be energised before reaching the SQSS voltage limits, is around 20km, and this requires roughly 16MVAr of reactive absorption capability. Similarly, the maximum length of a 275kV line that can be energised before reaching the SQSS voltage limits is around 60km and this requires roughly 22MVAr of reactive absorption capability.

10. Next Steps DER Operability and Stability Challenges

10.1 Introduction

In this section the operability and stability challenges associated with integrating converter connected DER into a weak network will be discussed, and an outline given of the further study work proposed to identify the issues and compare the DER control modes which may be integrated with a DRZ-C[16].

Part 1 of this report[17] noted that there is limited literature available relating to the performance of converter connected DER during a Black Start, or system restoration of the distribution network. Most literature relates to DRZ applications which are typically small multi-user, single site MW networks, or is related to the stability of the MITS with the closure of conventional thermal power stations (for example the National Grid System Operability Framework[18]). As such, bespoke study work is required to address the unique challenges associated with operating converter connected and synchronous DER within a DRZ.

10.2 Overview

Low inertia or low system strength are some of the issues that might face a DER network during Black Start. Power Converter (PC) interfaced DER might be required to participate in the active power balancing and voltage control to release the ‘stress’ on the synchronous generators (SGs). PCs might require modifications to their present control structure to be more responsive to the system needs. From one side, the standard converter control structure known as grid-following might need to be upgraded to grid-forming to support Black Start. On the other side, PCs should be equipped with controllers, to share the active power and voltage control with other generation units. Both modifications of the converter controllers might result in undesired interactions between converters and synchronous machines. For this reason, a detailed stability study is required to determine the optimal operation modes and control gains for the different controllers and ensure the small-signal stability.

10.3 Power Converter Control Challenges in the Context of a Distributed Restart Network

From the power converter point of view, grid-following and grid-forming controls are the two main converter control philosophies, with grid forming still under development. Grid following is the most common control technique and can offer active and reactive power/voltage support, for example, droops. During system restoration standard grid-following controlled PCs require a minimum amount of SGs connected to the grid to provide a voltage that converters can synchronise to. Grid forming controlled PCs can build up a voltage without the need of external voltage and energise the network by themselves without an anchor generator. The following are some other points that will be studied during the next phase of the project related to DER network stability:

- With the grid-following control, grid synchronisation is usually achieved by a Phase Locked Loop (PLL) and the power converter directly controls the active and reactive current. It is common practice to use a droop mechanism to control the AC voltage in PC and even the network frequency. Voltage control based on a droop characteristic might be already implemented in some existing PCs, as it is a Grid Code requirement in some parts of the world. However, grid following requires a minimum system strength to synchronise. In standard power networks, it is assumed that SGs will provide the required system strength. This might not be the case during system restoration using DER where PCs ratio increases dramatically and the anchor generator becomes less-dominant. Therefore, the anchor generator might not be sufficient to guarantee system stability and PCs controllers should be modified, either introducing advanced grid-following techniques or using grid-following controllers, to consider the reduction on system strength. Based on the existing literature, further research is required for the DER networks.

[16] Strathclyde University, *Assessment of converter connected generation in the context of the Distributed Restart project.* Part 2

[17] *Assessment of Power Engineering – Aspects of Black Start from DER,* Part 1, July 2020 – Chapter 9

[18] nationalgrideso.com/research-publications/system-operability-framework-sof

- It is important to consider and study other control structures, such as grid-forming control, in the scenario of systems with DER. During Black Start, PCs will confront a grid with very low inertia and reduced system strength, which could be properly handled by a grid-forming control. With grid-forming PCs, all generation units operate similar to synchronous generators, where its terminal voltage is controlled by closed loops, similar to the AVR in SGs, to effectively support the grid, with high control performance.
- There are some examples in existing literature of control interaction between power converters or power converters and synchronous machines. It has been reported that instability could be due to the controllers used to coordinate the different elements (droops) or due to some internal controller of the power converter, such as the PLL. These interactions are usually at low frequency and can be examined and better understood with an EMT simulation or small-signal study of the network.

10.3.1 Local Control and Coordination

In a DER network, it is likely that small synchronous machines coexist with power electronics interfaced devices. Due to the size of the different equipment, it is likely that coordination between elements is required at the secondary level (steady state response) as well as at the primary level (instantaneous response). One option is utilise the DRZ-C, using communications, to coordinate all control (centralised control). An alternative is to have a measure of local control at a DER where a droop control is installed and only relies on local measurements (also referred to as decentralised control).

10.4 Voltage and Reactive Power Control

10.4.1 Voltage Control Requirements

During the restoration process in an electrical network with DER, it is essential to regulate the voltage and the reactive power ensuring coordination between the different generation units. The main requirements to maintain the voltage stability are:

1. The overall reactive power capacity of the DER in steady state should be sufficient for the system reactive power requirements and voltage regulation.
2. AC grid voltage should be maintained within limits.
3. Voltage may need to be be controlled during transients, for example transformer energisation (this may be achieved by mitigation measures such as energising with a reduced voltage and not necessarily by direct DER support). synchronous machines and power converters present very different and, at the same time, complementary characteristics. Table 34 presents a list of capabilities and limitations related to reactive power control.

	Capabilities	Limitations
SG	• SGs present an excellent overcurrent capability that can provide reactive power.	• AVR and voltage controllers of a synchronous machine can be slow to react to changes.
PC	• PCs can provide a very fast (100ms or less) voltage response. Most can provide reactive power support even when the renewable energy source is not connected (STATCOM model).	• Power converters present a very strict current limitation; the current limit is slightly above 1pu. • PC output voltage range is finite and determined by various factors, such as dc-link voltage, control scheme, and semiconductor devices. • Due to the vulnerability of power converters, large current and voltage during grid events might force the power converter to disconnect.

Table 34: Characteristics of generation units for reactive power control

10.4.2 Reactive Power Balancing and Voltage Challenges

The next phase of the study work is related to voltage stability and will consider the following points:

- If a droop control strategy is used, it is likely that adverse control interactions between the converter and the synchronous machine voltage droop might exist and extensive tuning and dynamic studies are required to guarantee the DER network voltage stability. The instability due to the voltage control interaction is largely affected by different parameters such as network topology and grid conditions. This implies that studies covering different operating points are required.
- PC can provide a faster active power response and voltage regulation than synchronous machines if the current limit of the converter is not exceeded (and a primary source of energy is available). Also, it is possible that some DER converters can remain connected without active power transfer in STATCOM mode.
- One significant challenge of Black Start operation is the energisation of transformers, which may introduce large inrush currents due to the residual flux. Transformer energisation might be a challenge in DER networks as power electronic converters present a very strict current limitation and might not be able to provide the required excitation current. The energisation of transformers and lines can be sequential or soft-start. In the sequential approach, the lines/cables and transformers are energised one at a time with the power converter at nominal voltage. In the soft-start approach, lines and transformers of the de-energised network are connected to the converter and the voltage is ramped up using the power converter. The second method avoids large inrush current and overvoltage. This is an area for which each individual network should be studied to determine if the generation units can provide the required reactive current to energise a transformer.

10.5 Frequency and Active Power Control

10.5.1 Frequency Control Requirements

System frequency regulation is always a major concern, which is especially the case during the restoration period. With the various energy sources integrated, an effective frequency management scheme is required to control generation units and loads. Keeping the active power balanced during Black Start is essential to guarantee the network stability. The main points that should be considered are:

1. the overall active power capacity of the generation units should be sufficient to power the connected loads
2. AC grid frequency of the system should be regulated within limits
3. Active power must be balanced within a reasonable time, keeping the RoCoF within limits. Table 35 presents a list of capabilities and limitations of SG and PC in terms of system frequency control.

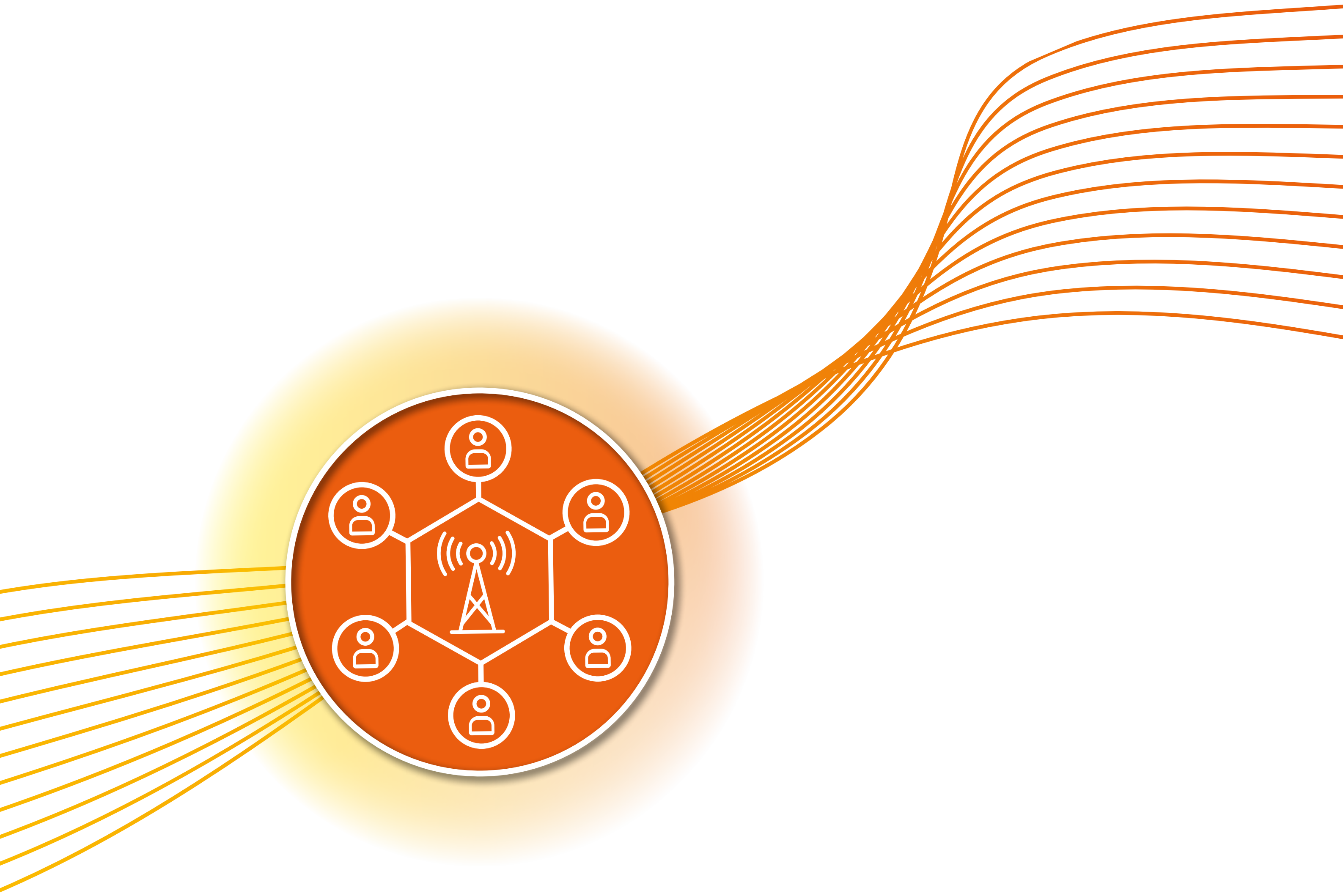
	Capabilities	Limitations
SG	• The inherent inertia can provide effective power support for the grid. However, the reduction in number or capacity of SG leads to an inertia decrease.	• Due to the mechanical characteristics and slow primary mover, SGs usually require longer response time to increase/decrease its output power.
PC	• PCs can provide fast frequency support if the primary resource is available.	• PCs can only provide inertia if the converter controller is programmed to do so. • Their output current is highly limited due to the semiconductor limitations. • DER rich networks have low inertia.

Table 35: Characteristics of generation units for frequency control

10.5.2 Active Power Balancing and Frequency Stability Considerations

The next phase of the study work considers frequency stability and the main points are the following:

- If the power converters and synchronous machines share the control of active power, droop controllers should be tuned to avoid potential interactions and maximise the grid stability. It has been reported in the literature that aggressive P-f droop controllers can increase the penetration of converter-based resources but increase the risk of control system interactions. Careful tuning and study is required. Alternatively, the DRZ-C could be used to provide secondary control.
- A distributed restart network is characterised by low inertia making the speed response of the synchronous generator and the power converters critical to achieving fast-active power balancing. Generally, one of the SG primary movers characteristics is a slowed response that can endanger the frequency stability in case of large load or generation variation. A detailed study of the SG primary mover time constant needs to be considered. If the SG cannot provide active power, the PC should be able to provide it. Alternatively, the DRZ-C could be responsible for utilising the DER resources available for ‘fast balancing’.
- If PCs must provide active power balancing, it is likely that the energy should come from a curtailed energy resource. In this case, the speed that the power can be extracted should be taken into account as some delays might exist (e.g. wind turbine internal controllers’ dynamics). If a converter interfaced energy storage system is used, the converter can react instantaneously within the limitations of the primary source.



11. Next Steps – The National HVDC Centre Analysis and Testing

This section introduces the network and hardware analysis capabilities of The National HVDC Centre (the HVDC Centre), and the scope of works which will be undertaken to support the Distributed ReStart project.

11.1 Introduction

Initially dynamic simulations of restoration scenarios will be performed, with one of the Distributed ReStart case study networks (Chapelcross) modelled using the HVDC Centre's real time digital simulator – RTDS®. This incorporates a 33kV connected biomass synchronous generator (Steven's Croft) as the anchor. If practical, replicas of the generator protection relays will be tested in Hardware-in-the Loop (HiL) environment to ascertain as close to reality as possible the stability of the generator. The case study network also contains several 33kV connected wind farms.

It is proposed that prototypes of the DRZ-C functionality described in the initial chapters of this report are built and factory tested by the relevant technology companies. Following this, HiL testing of prototype DRZ-C(s) will then be undertaken at the HVDC Centre allowing the full functionality of the Black Start process, and the coordination of multiple DER, to be tested. Additional DER types such as BESS, not in the original case study network, will be added to the RTDS model as required.

Within the HVDC Centre, it is possible to replicate certain simulation conditions within a Real Time Digital Simulation (RTDS®) environment. It is not intended that these simulations replace existing analysis, but rather by constructing an appropriate scale model in RTDS, a range of sensitivity cases are performed exploring significant areas of conclusion. Further as the name implies, RTDS can be used to construct re-energisation scenarios in real time, which allow the sequences of switching, block load support, fault ride through and network re-synchronisation to be played out in a realistic manner that can inform training and assurance of re-energisation from new resources.

11.2 Scope of Testing

To streamline and focus the analysis that is being performed, the HVDC Centre has divided its involvement in the Distributed Restart project into four stages.

11.2.1 Stage – 1

In the first stage the HVDC Centre plans to create the RTDS® model of the Chapelcross case study network. Once, the baseline of the model is created, additional analysis of Black Start scenarios related to the Steven's Croft generator would be performed. In addition, the HVDC Centre would perform similar/related Black Start scenarios using grid forming converter-based generation sources to see to what extent these can provide the same benefits as a synchronous generator.

11.2.2 Stage – 2

In this stage the HVDC Centre will provide the specification requirements of the DRZ-C which relate to its practical demonstration within an RTDS environment and/or be modelled in that environment. The HVDC Centre will further identify the associated modelling needs, taking account of prior stage 1 modelling work. Finally, the HVDC Centre will identify the scope and key test conditions associated with the associated RTDS HiL.

11.2.3 Stage – 3

During the Black Start condition the system strength of the distribution network would be very low which in turn could compromise the performance of the existing protection system as they mainly rely on the high fault currents injected from the higher voltage network or strong generation source. So, in this stage the HVDC Centre would study and analyse the performance of the existing anchor generator protection system using the real hardware relays along with power amplifiers. This stage may also test the existing, and any revised network protection settings which have been identified, to ensure the network can be safely energised.

11.2.4 Stage – 4

In this stage the HVDC Centre would test the DRZ-C associated with aggregating DER to support Black Start restoration. Given that Black Start is not a common network occurrence, it will not be possible to demonstrate fully such a systems' performance within the actual network reliably. The HVDC Centre would test the controller in a realistic test condition using the RTDS and the network communication emulator by simulating the expected conditions of Black Start and stress test the control system robustness and function in that context.

11.3 The National HVDC Centre

The National HVDC Centre is part of Scottish Hydro Electric Transmission plc (SHE Transmission), who own and maintain the transmission system in the north of Scotland. As an Ofgem (NIC) funded facility, the HVDC Centre operates together with Scottish Power Energy Networks, National Grid Electricity Transmission, and National Grid Electricity System Operator; who form the Centre's Technical Advisory Board.

The HVDC Centre, founded in the 2013 Ofgem Network Innovation Competition and operational since 2017, has a proven track-record of supporting Transmission Owners and the Electricity System Operator in the de-risking of areas of HVDC specification, design, testing and operation. The Centre houses cutting edge Real time Simulators, the replica control and protection for the Multi-Terminal Caithness-Moray-Shetland scheme and has simulation capabilities across EMT (PSCAD) and RMS (Digsilent and PSS-E) supporting cross platform analysis and model verification activities. The Centre supports all HVDC schemes, both already in operation and in development, that connect to the Great Britain (GB) electricity grid. The HVDC Centre also has several state-of-the-art power amplifiers that could be integrated with the RTDS to test complex protection system using real hardware relays. The Centre also has communication emulator to facilitate the emulation of various telemetry factors across the controllers and protection relays.

A key aspect of the Centre's design is its ability to host and support confidential models and integrate these with equally confidential network information and hardware to support a total picture of the end design and its grid integration.

11.4 Real-Time and HiL Testing

Real-time operation enables the connection of physical devices in a closed-loop with the simulated environment. It shows the dynamic response of the system as test continues after action of the device and allows multiple devices to be tested simultaneously. It gives a more detailed system representation than open-loop tests would provide.

11.4.1 Hardware-in-the-Loop (HIL) Testing

HIL testing is commonly used to verify the correct operation of control and protection equipment within power systems. A simulation model emulates the target network and physical hardware is used to synthesise the measurement output which is fed into the hardware test object. The test object then sends and outputs signals (e.g. trip signals) back to the simulation system, thus closing the hardware/software 'loop'. In this way, as far as the test object is concerned it is connected to a 'real' system. To accomplish this, real time simulation methods and hardware are required.

11.4.2 Real-Time Simulation

Real time simulation in this context means a computer model of the physical system that executes at the same rate as actual time i.e. 1s of simulation is 1s of real-world time. It is this ability to match a real-world clock that allows real devices to be subjected to thorough testing as if connected to the real network but with a controllable virtual environment.

RTDS® system

The National HVDC Centre uses the RTDS Simulator. It is used by all of the world's major protection and control equipment manufacturers, as well as by leading electric utilities, educational institutions, and research facilities around the world[19].

[19] rtds.com/technology/

The RTDS Simulator is a combination of custom hardware and all-in-one software, specifically designed to perform real-time Electro-Magnetic Transient (EMT) type simulations. It operates continuously in real time while providing accurate results over a frequency range from DC to 3kHz. The RTDS Simulator's fully digital parallel processing hardware can simulate complex networks using a typical time step of 50μs. The simulator also allows for small timestep subnetworks that operate with timesteps in the range of 1–4μs for simulation of fast switching power electronic devices (e.g. VSC bridges with PWM switching).

11.4.3 Physical HIL Test Setup

Figure 43 shows a typical simple HIL setup. There are three main components in the hardware of the typical setup which include:

- RTDS and IO Cards
- amplifier
- test device(s) i.e. Relay Cubicles.

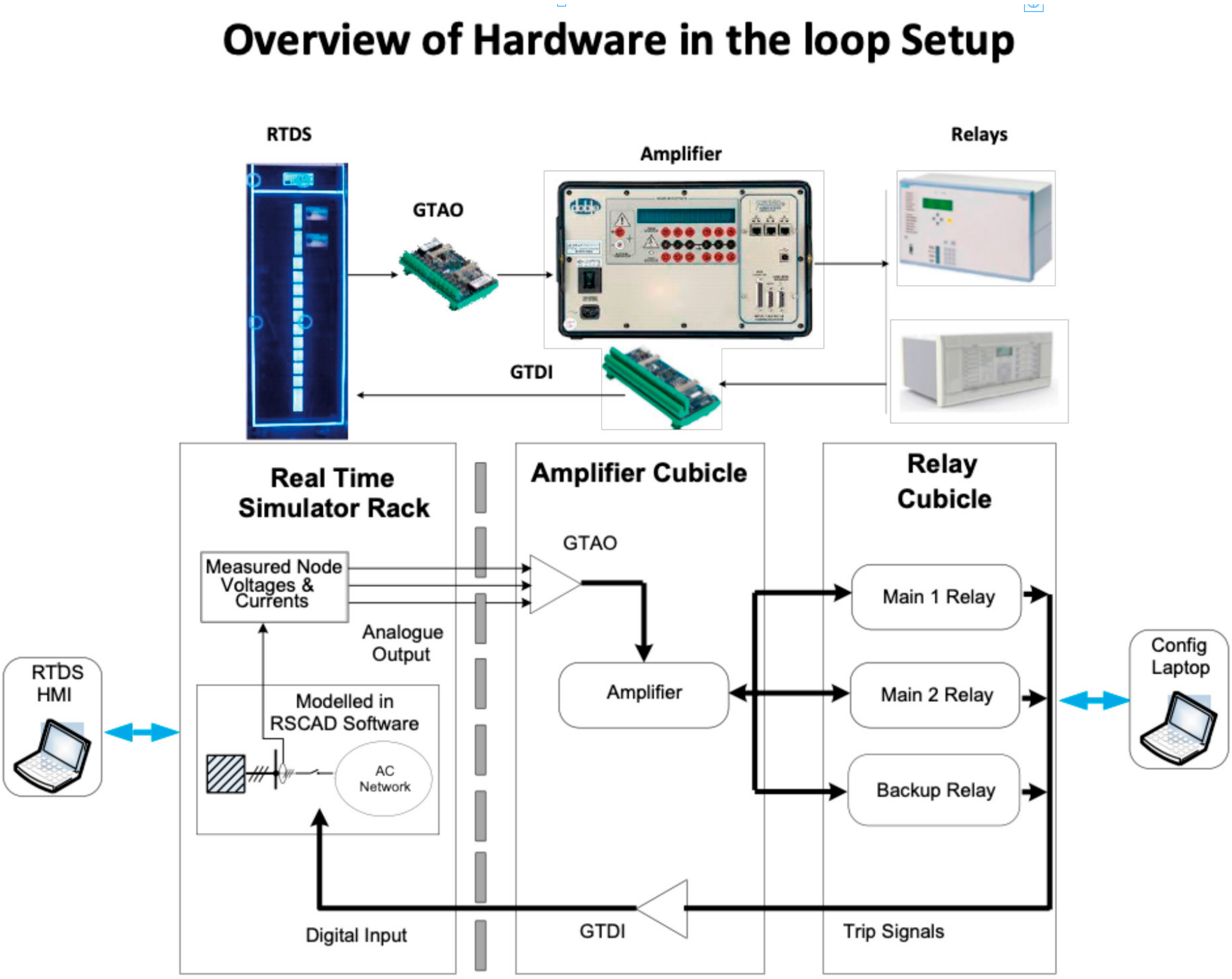


Figure 43: HiL setup

More complicated setups could include analogue signals returning from the test device as inputs to the simulation and digital signals as additional inputs to the test device. An alternative to the use of analogue signals would be making use of industry standard communication protocols, which the RTDS simulator can support. Additional test equipment can also be included to, for instance, emulate the communication channels more accurately.

RTDS

The RTDS (Real Time Digital Simulator) is the cubicle that has the processors for simulating the grid models in real time. To output/input the real time signals to any external hardware the RTDS uses IO Cards[20].

GTIO

Giga-Transceiver Input/Output (GTIO) cards facilitate analogue and digital data exchange between the simulation and physical devices. Details of different cards are as follows[21]:

- GTAO (GIGA-TRANSCEIVER ANALOGUE OUTPUT CARD) is an analogue output card that is used to output analogue signals from RTDS. The signals are in the form of ±10V signals.
- GTAI (GIGA-TRANSCEIVER ANALOGUE INPUT CARD) is an analogue input card that is used to input analogue signals to RTDS. The signals are in the form of ±10V signals.
- GTDI (GIGA-TRANSCEIVER DIGITAL INPUT CARD) is a digital input card which receives digital input from external hardware. This card received a dry contact and is powered by either a 5V or 24V supply.
- GTDO (GIGA-TRANSCEIVER DIGITAL OUTPUT CARD) is a digital output card which sends digital output from the RTDS software to an external hardware. This voltage output range is from +5 to +30Vdc (dependent upon external source).
- GTSYNC (GIGA-TRANSCEIVER SYNCHRONIZATION CARD) is used to synchronise the RTDS simulation timestep to an external time reference (eg. GPS clock) and to synchronise devices under test.

GTNETx2 Card

The GTNETx2 card provides communication link to and from the simulator via Ethernet. Different protocols can be used depending on the application. Available protocols include: MODBUS; IEC 61850 GOOSE; IEC 61850-9-2LE/IEC 61869-9 Sampled Value messaging; PMU (Phasor Measurement Unit) output data streams according to the IEEE C37.118.2-2011[22].

Amplifiers

Amplifiers are used to amplify the analogue signals that are given out by the GTAO signals if required. These signals would be amplified as per the requirement for the test device inputs, taking a relay as an example this would typically be from ±10V to 110V or 1A. Available for use at The National HVDC Centre are two Omicron CMS 356 devices[23] and two Doble F6350e devices[24]. These amplifiers are standard production that has been used for hardware in loop testing worldwide.

Other Equipment

Within HIL setups other devices can be introduced that can be useful and informative during testing. Available for use at The National HVDC Centre is a Netropy 10G2 device, this can be used to emulate a communications path and introduce noise, lag etc.[25].

Connections between the Equipment

1. The RTDS rack and the IO cards are connected using fibre connectors.
2. GTAO and the amplifier are connected using universal low voltage cable.
3. The amplifier and test objects would be connected using test leads.
4. The relays and GTDI are to be connected using low voltage wires.

[20] rtds.com/technology/simulation-hardware/

[21] knowledge.rtds.com/hc/en-us/articles/360034281234-GTIO-Cards

[22] knowledge.rtds.com/hc/en-us/articles/360034788593-GTNETx2

[23] omicronenergy.com/en/products/cms-356/

[24] doble.com/product/external-amplifiers/

[25] apposite-tech.com/wp-content/uploads/2018/12/Netropy_10G2_Hardware-Guide.pdf

11.5 Future Studies

The RSCAD software has a tool to import PSCAD models in to the RSCAD Software. Since the network in the PSCAD model is a detailed model with hundreds of components, the generator model was split from the rest of the network and prepared to be imported in the RSCAD separately. The RSCAD import tool was used to import the PSCAD generator model along with the exciter and the governor controls.

Once the RSCAD model is validated, various study cases will be set up to simulate the energisation, from the anchor generator, of different sections of the case study distribution and/or transmission network. This will help to identify and validate viable restoration strategies. In addition, any live testing planned on the Chapelcross case study will be tested on the RSCAD model prior to any testing.

11.5.1 Energisations

Energisation scenarios will include variations such as:

1. with and without load connected at 33kV
2. varying number of transformers energised simultaneously
3. three-phase fault at the Steven's Croft generator 11kV bus
4. three-phase fault at the Steven's Croft 33kV bus
5. operating voltage lower/higher
6. soft start – slow ramp of AC voltage.

11.5.2 Protection Performance

The performance of the generator protection during the simulation scenarios would be assessed. The possibility of integrating and testing physical generator protection IED is currently being assessed and performance tests would be done as part of later stages. The anticipated assessment of generator protection is as below:

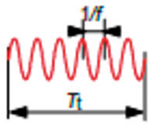
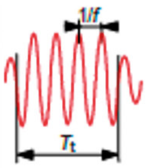
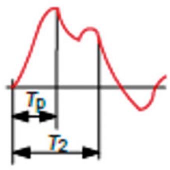
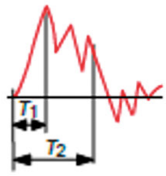
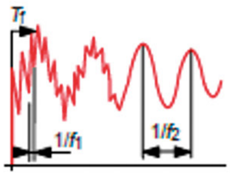
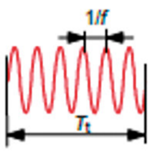
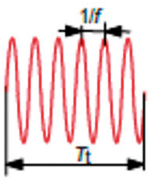
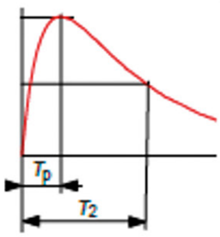
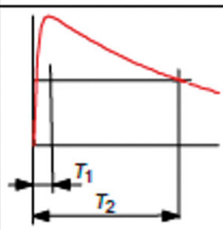
1. Performance of low voltage protection at the generator terminals (G59 under voltage protection is usually set ~-20% for 0.5s, G99 undervoltage protection is now -20%, 2.5s).
2. Performance of high voltage protection at generator terminals (G99 +10% 1s, +13%, 0.5s). Possibility of switching out G99 during Black Start.
3. Performance of generators own instantaneous overvoltage protection.
4. Performance of negative phase sequence (NPS) protection.
5. Performance of under excitation protection.

11.5.3 Miscellaneous Studies

Study scenarios to perform Black Start using converter-based solutions like wind farms will also be tried along with scenarios to connect the wind farm to the Black Started network. The possibility of testing the below scenarios would be explored:

1. Resynchronisation of the Black Started network with AC grid.
2. Performance of loss of mains RoCoF protection.

IEC 60071 Definitions for Overvoltage

Class	Low frequency		Transient		
	Continuous	Temporary	Slow-front	Fast-front	Very-fast-front
Voltage or over-voltage shapes					
Range of voltage or over-voltage shapes	f = 50 Hz or 60 Hz T_t ≥3 600s	10 Hz < f < 500 Hz 0,02 s ≤ T_t ≤ 3 600 s	20 µs < T_p ≤ 5 000 µs T_2 ≤ 20 ms	0,1 µs < T_1 ≤ 20 µs T_2 ≤ 300 µs	T_f ≤ 100 ns 0,3 MHz < f_1 < 100 MHz 30 kHz < f_2 < 300 kHz
Standard voltage shapes	 f = 50 Hz or 60 Hz T_t [a]	 48 Hz ≤ f ≤ 62 Hz T_t = 60 s	 T_p = 250 µs T_2 = 2 500 µs	 T_1 = 1,2 µs T_2 = 50 µs	a
Standard withstand voltage test	a	Short-duration power frequency test	Switching impulse test	Lightning impulse test	a

[a] To be specified by the relevant apparatus committees.

Figure 44: IEC 60071 classes and shapes of overvoltages, standard shapes and stand withstand voltage tests

Chapelcross GSP Case Study Network

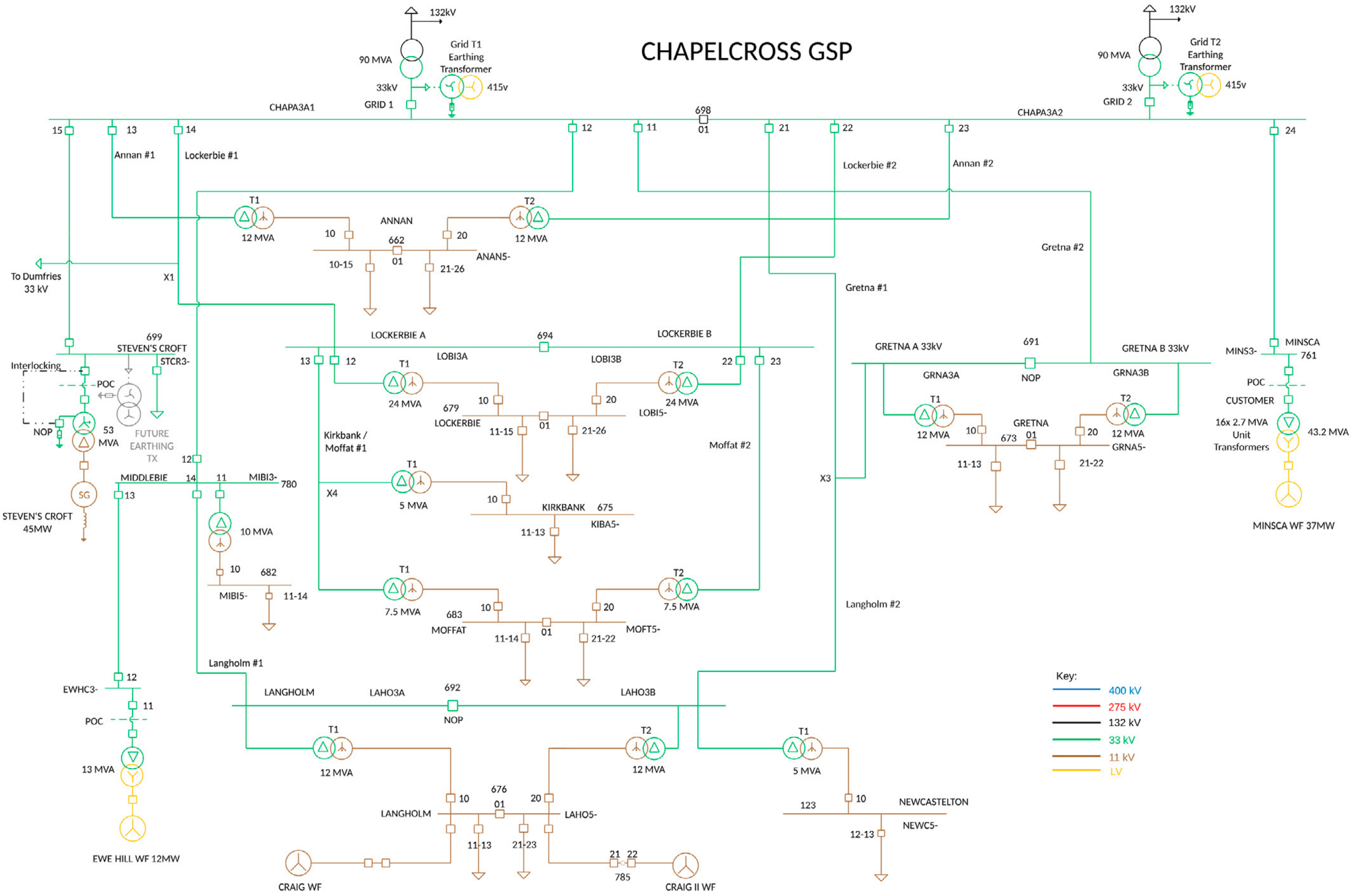


Figure 45: Chapelcross GSP case study network single line diagram

Switching Transients When Energising a 33kV Network and Primary Transformers

The following figures present the instantaneous phase voltage waveforms at the Lockerbie 33kV busbar corresponding to the worst case PoW switching.

(a) (b)

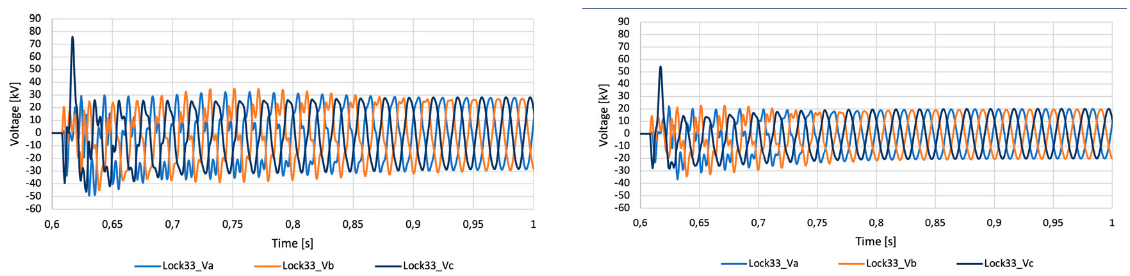


Figure 46: Instantaneous phase voltages at Lockerbie 33kV busbar for (a) 1pu and (b) 0.7pu energisation voltage

Appendix 2: Abbreviations

ABBREVIATION	DEFINITION
ADMS	Advanced Distribution Management System
AVC8	Automatic Voltage Control
AVR	Automatic Voltage Regulator
BES	Battery Energy Systems
BOA	Bid Offer Acceptance
BS	Black Start
BSP	Bulk Supply Point
CCGT	Combined Cycle Gas Turbines
CHP	Combined Heat and Power
DER	Distributed Energy Resources
DMS	Distributed Management System
DNO	Distribution Network Operator
DRZ	Distribution Restoration Zone
DRZ-C	Distribution Restoration Zone Control
EfW	Energy from Waste
EHV	Extra High Voltage
EMS	Energy Management System
EMT	Electro-Magnetic-Transient
ER	Engineering Recommendations
ESQCR	Electricity Safety, Quality Continuity Regulations
f	Frequency
GSP	Grid Supply Point
GT	Grid Transformer
H	Inertia
HV	High Voltage
LPS	Large Power Station
MITS	Main Interconnected Transmission Network
NETS	National Electricity Transmission System
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
SHET	Scottish Hydro Electric Transmission
SLD	Single Line Diagram
SPD	Scottish Power Distribution
SPEN	Scottish Power Energy Networks
SPM	Scottish Power Manweb
SPT	Scottish Power Transmission
STOR	Short Term Operating Reserve
VPP	Virtual Power Plant
WF	Wind farm

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