Distributed ReStart

Power Engineering and Trials

Demonstration of Black Start from DERs (Live Trials Report)

Part 3 – October 2023

In partnership with:

tnei

SP Energy Networks

nationalgridESO

Table of Contents

List of Figures and Tables

Figures

List of Figures and Tables contd.

List of Figures and Tables contd.

List of Figures and Tables contd.

Tables

Executive Summary

This report details the methodology, results and findings from the Distributed Restart Redhouse live trial, undertaken in June 2023. This trial was the third and final trial undertaken as part of a series of world-first trials. The trials were designed to provide detailed understanding on how distributed energy resources (DERs) can build, maintain and optimise power islands isolated from the main grid – with a view to driving down the time it would take to restore the network following the extremely unlikely event of total shutdown of Great Britain's electricity grid. The traditional top-down approach would be complimented by the DER enabled bottom-up approach to help ensure the target of 60% of demand would be restored within a 24-hour period from 2026 onwards, as detailed in the Electricity System Restoration Standard (ESRS).

The trial at Redhouse was fundamentally different to the two previously completed trials at Galloway and Chapelcross in that the anchor generator for this test was a non-synchronous inverter-based asset, this being a battery energy storage system (BESS), as opposed to a synchronous generator. Details of how the test network was enabled, what tests were undertaken and the result of the tests are included in this report, alongside supplementary supporting material.

The tests took place at SP Energy Networks' Redhouse substation near Glenrothes in central Scotland. The test networks' main elements comprised of:

- the 11.6 MVA (8 MW, 8 MWh) grid-forming capable BESS
- a 24 MVA 11/33 kV primary distribution transformer connected via an underground cable
- a 10 MVA 11/33 kV primary distribution transformer connected via an overhead line (OHL)
- a 5 MVA load bank used to simulate customer demand
- a 3 MVA solar farm utilised as the top-up generator for the island
- a 90 MVA 33/132 kV grid transmission transformer located at Redhouse
- a 10.6 km 132 kV OHL to the neighbouring Glenniston substation
- a 33 kV earthing transformer (ET) for use during the tests when another earth point was not connected
- a supporting 5 MVA diesel genset and auxiliary supplies.

The tests overall were hugely successful and the BESS' performance was tested and observed to be excellent when acting as the anchor generator for the power island. Furthermore, the tests proved that:

- battery energy storage systems (BESS) can be utilised as anchor generators to start, maintain and control power islands very effectively, with the aid of diesel gensets or without
- they can energise both distribution and transmission transformers and lines and are much more effective at doing so when point on wave (PoW) switching is active
- the block load pickup (BLPU) capability of the BESS when compared to synchronous generators of the same capacity is far superior and, in this case, needed to be derived as opposed to measured due to its ability to outperform the biggest load step the equipment could implement (4 MW)
- the Distribution Restoration Zone Controller (DRZC) can automate the start up and operation of the BESS system, optimise the power island's performance and can utilise its functionality to resync with the intact grid
- the island assets can be used together as a dynamic virtual power plant (DVPP) and dispatch load or generation as needed when connected to the grid
- comparatively small diesel gensets in isolation can energise both distribution and transmission transformers and lines and are much more effective at doing so when point on wave (PoW) switching is active.

Ultimately, these world-first tests set a precedent for the use of BESS assets to be used, not just in the UK but around the world, as viable network restoration service providers.

1. Introduction

This report focuses on the outcomes of the Redhouse live network trials to demonstrate the principle of black start from DERs in practice. In addition to energising a network power island via a grid-forming battery energy storage system (BESS), the Redhouse live trials also demonstrated the functionality of a Distribution Restoration Zone Controller (DRZC).

Section 2 provides context to this report and gives a review of the work completed prior to the Redhouse live trial. Section 3 provides information on the work leading up to the Redhouse live trial and its structure. Section 4 summarises the results of the trial and outlines the conclusions.

1.1 Report Context

This report follows on from the *Power Engineering and Trials Demonstration of Black Start from DERs (Live Trials Report) Part 2*.

The *Live Trials Report Part 2* focused on the preparation and work undertaken to deliver the Galloway Phase 3 and Chapelcross trials and the outcomes of these trials. In addition to this, the part 2 report provided details on grid-forming converter (GFC) network energisation simulations which had been completed as part of Distributed ReStart.

Prior to the Redhouse live trial, trials were completed in Galloway and Chapelcross as part of the Distributed Restart project.

The Galloway trial involved utilising two hydro generators (Glenlee and Kendoon, 15 MVA and 13 MVA respectively) to act as anchor generators. The Galloway trial was split into three phases:

- Phase 1 – network energisation via Glenlee Hydro
- Phase 2 – network energisation via Kendoon Hydro
- Phase 3 – network and wind farm energisation via Kendoon Hydro.

The key achievements of the Galloway trial included:

- energising a 11/132 kV 30 MVA transformer, a ~60 km 132 kV overhead line and a 132/33 kV 60 MVA transformer simultaneously
- energising two 240 MVA 275/132 kV super grid transformers (SGTs) simultaneously
- proving the block load pick up (BLPU) capability of Kendoon hydro generator
- energising Glenchamber and North Rhins 33 kV connected wind farms and associated turbine transformers via Kendoon hydro generator
- establishing a stable power island with Kendoon hydro and several turbines connected across Glenchamber and North Rhins wind farms simultaneously.

After the completion of the Galloway trials, tests were completed at Chapelcross using Steven's Croft biomass 11 kV generator as an anchor generator. A 15 MW load bank was installed to facilitate load testing and provide a minimum stable demand for the generator to operate in island mode. The key achievements of the Chapelcross trial included:

- energising the generator's 11/33 kV 53 MVA transformer and prove the stable operation of the Steven's Croft generator in island mode
- energising the local distribution network, which included a 25 km 33 kV underground cable section and a 24 MVA primary transformer
- proving the BLPU capability of the Steven's Croft generator
- synchronising the Steven's Croft generator at 33 kV with the intact distribution network
- energising the transmission network up to 400 kV via a 400/132 kV 240 MVA SGT.

Having successfully tested and operated power islands energised using synchronous generators as anchor generators, the Redhouse trial focused on using an inverter-driven BESS generator to act as the anchor generator.

2. Redhouse Live Trial Background and Structure

2.1 Trial Background and Technical Challenges

2.1.1 Trial Network Equipment and Contributing Parties

The main focus of the trial was the Greenspan Energy BESS generator, which is connected to Redhouse grid supply point (GSP) at 33 kV. The BESS has a capacity of 11.6 MVA and is split up into four 2.9 MVA units. As part of the Distributed Restart project, the BESS was retrofitted with grid-forming technology, giving it the ability to set its own frequency and voltage reference points and therefore act as an anchor generator for a power island. Grid-forming technology is still relatively rare for inverter-based resources (IBRs). Most IBRs use grid-following control, which requires an existing grid voltage for these generators to synchronise with, to allow them to generate power.

The test network also included a 5 MVA diesel generator which was provided by Aggreko. This was connected via a spare circuit breaker at the BESS developer's site. Tests during the trial would be performed with and without the diesel generator. This would provide additional results to compare the BESS performance with, and also provide inertia and fault level to the system when being used in conjunction with the BESS.

Additional equipment provided by Aggreko included a 5 MVA load bank to simulate primary customer demand and implement desired load steps, another diesel generator to provide a power supply for the BESS site's auxiliaries and an earthing transformer to provide a connection to earth for the test network. A connection to earth would normally be provided via the grid transformer at Redhouse GSP, but this was only connected to the test network for a small portion of the trials.

During later stages of the tests, Middle Balbeggie Solar Farm (MBS) would be involved. Middle Balbeggie is connected at 11 kV via the Redhouse primary substation and has a capacity of 3.8 MW. Middle Balbeggie uses grid-following control, meaning there must be a pre-energised power island or grid available for the solar farm to synchronise to, in order to generate power safely to the network.

During the later stages of the trial, the prototype Distribution Restoration Zone Controller (DRZC) was used to control the power island via the BESS' output. The DRZC was developed by GE and has various functionalities that are crucial for a power island's initialisation and stability when operating in this mode. The DRZC exercises these functionalities by controlling the generation or demand of various assets within the power island.

The list below details the parties directly involved operationally in the trials at Redhouse:

- SP Energy Networks – Power Engineering and Trials Lead
- Greenspan Energy– BESS owner and operator
- SMA Altenso GmbH/SMA Solar Technology AG – BESS inverter operator and manufacturer
- Aggreko – Load bank and Diesel Genset provider
- Enspec – Point-on-Wave Relay and Snubber manufacturer
- GE – DRZC developer, manufacturer and trial assistant operator
- Lightsource BP – Middle Balbeggie solar farm operator
- IDEC – Installation delivery partner.

2.1.2 Transient Recovery Voltage and Rate of Rise of Recovery Voltage

Transient recovery voltage (TRV) and rate of rise of recovery voltage (RRRV) are issues that must be considered for networks with low fault level, such as power islands. TRV occurs across the contacts of a circuit breaker when breaking load or fault current and can be problematic with vacuum switchgear. High TRV can cause reignitions and restrikes across the circuit breaker contacts which are not desirable and can lead to overvoltages which may exceed the rating of the equipment.

During initial preparations for the Redhouse trial, a study by Schneider Electric and Enspec showed that circuit breaker operation on the test network during line charging and fault scenarios could lead to reignitions and, in the worst cases, overvoltages which exceeded the ratings of the breakers. Due to these findings, the trials were postponed from early 2022 until June 2023 such that a sufficiently mitigating solution could be implemented.

A TRV mitigating solution was procured from Enspec in the form of RC snubbers. After undertaking relevant power system EMT studies, Enspec specified that the installation of three RC snubbers (0.3 μF + 10 Ω), each fitted with 22 kV surge arrestors would sufficiently mitigate unacceptable TRV levels. Two of the RC snubbers were specified at 33 kV breakers in the BESS developer's site and one was specified at a 33 kV breaker at Redhouse GSP on the SPD network. The surge arrestors would limit the peak TRV, while the resistor-capacitor combination would slow the RRRV during a fault scenario, sufficiently protecting the network.

2.1.3 Transformer Energisation

Transformer energisation is a significant challenge when building a power island. When a transformer is energised, high magnitude inrush currents with many harmonics are generated. This can lead to both undervoltage and temporary overvoltage (TOV) in certain circumstances. If an overhead line and transformer are being energised simultaneously, the resonant frequency of this circuit can be excited by the harmonics of the inrush current, which will result in TOV and could cause network protection to operate.

There are a number of inrush current mitigation methods which can be implemented during transformer energisation:

- point on wave (PoW) switching
- resistive damping
- generator terminal voltage reduction
- soft energisation/ramping up from 0 V.

Within this report there will be multiple references to a "hard" energisation. This is the term used for energisations that were attempted in the absence of any of the above mitigating techniques.

Inrush current mitigation methods have been well covered in the *Live Trials Report Part 2*. For the Redhouse trial, a point on wave relay was procured for the test network. The PoW relay was commissioned such that it would mitigate inrush current for the energisations of the Redhouse primary T1 and Redhouse GT1 transformers. The PoW relay was supplied with connections to the voltage transformer (VT) of each transformer and had a physical switch which was used to select which transformer was being energised. The PoW relay could also be used to mitigate inrush current when energising Chapel primary T1, although there was no load side voltage measurement in this case.

2.1.4 Protection Setting Amendments

While the test network was in operation, the fault level of the network would be largely reduced from normal values. To ensure the network remained protected during the trials, protection settings were amended as per the results from a detailed production study, at relevant points on the SPD and SPT network, as well as at the BESS site and Middle Balbeggie Solar Farm.

Overcurrent protection settings were modified with a lower pick up current at a number of locations. On the transmission system, the 132 kV unit protection a Glenniston was not sensitive enough to pick up the calculated lower fault currents of the test network, so the relay was put into loopback mode to increase its sensitivity. Undervoltage protection settings on the two circuit breakers at the BESS site were amended and an intertrip signal was established to ensure the system did not operate without a connection to earth.

The amended protection settings were established via group 2 settings on the relevant relays. This meant the settings could be loaded in advance of the trials and easily be switched over when required. Such an implementation would be useful if system restoration was required for a genuine black start event. A summary of the amended protection settings has been included in the Appendix.

2.1.5 Network Backfeeding

During the Redhouse trial, no customers were affected by the ongoing tests. All customers were disconnected from the test network and were backfed via other supply routes. The outages required for the project included:

- Redhouse GSP half busbar outage
- Chapel primary half busbar outage
- Redhouse primary full busbar outage
- Transmission outages on the Redhouse to Glenniston line.

The most substantial outage was the Redhouse primary full busbar outage, as all the customers who were normally supplied by Redhouse primary had to be backfed by other means. The network configuration required for this was implemented by Scottish Power Distribution (SPD) engineers prior to the start of testing.

2.1.6 Trial Network Reactive Power Studies

When distribution or transmission circuits are energised, reactive power is generated due to the capacitance of the circuits being energised. This is important to consider for two reasons:

- to ensure that the total MVAr generated by the trial network does not exceed the reactive power absorption capacity of the connected generation.
- to ensure that the total MVAr generated by the trial network does not exceed the reactive breaking capability of relevant switchgear.

To confirm that there would be no issues with the reactive power generated by the trial network, studies were undertaken in DigSILENT PowerFactory. A number of scenarios were tested which replicated the different states of the trial network during testing.

The maximum reactive power which would require to be absorbed by the diesel generator was calculated to be 680 kVAr. This was comfortably under the limit of ~1.3 MVAr. With regards to the reactive current experienced by circuit breakers on the trial network, the power system studies showed a maximum possible reactive current of 11A. This was again comfortably under the capacitive breaking capability of the 33 kV circuit breakers at Redhouse GSP, which had a limit of 110A. In both cases, the scenario which posed the greatest reactive power generation from the trial network was the energisation of the 132 kV circuit to Glenniston.

2.2 Trial Schedule

The following tables show an overview of the testing schedule of the trial:

Table 1: Phase 1 – Tests at BESS site

ID	Description	Day
T1.1	Diesel generator tests	Day 1
T1.2	Diesel generator and grid-following BESS tests (BESS in f and V droop mode)	Day 1
T1.3	Diesel generator and grid-following BESS tests (BESS in set point control mode)	Day 1
T1.4	Diesel generator and grid-forming BESS tests	Day 2
T1.5	Grid-forming BESS tests	Day 2

Table 2: Phase 2 – Tests on Distribution and transmission network

ID	Description	Day
T2.1	Primary transformer energisation via diesel generator	Day 3
T2.2	Primary transformer and MBS energisation via diesel generator and grid-forming BESS	Day 3
T2.3	Primary transformer and MBS energisation via grid-forming BESS	Day 4
T2.4	SPT network energisation via diesel generator	Day 5
T2.5	SPT network energisation via diesel generator and grid-forming BESS	Day 5
T2.6	SPT network energisation via grid-forming BESS only	Day 6

Table 3: Phase 3 – Tests including the DRZC

ID	Description	Day
T3.1	Distribution Restoration Zone Controller (DRZC) tests	Day 7
T3.2	Resynchronisation of power island with intact system via DRZC	Day 8
T3.3	Virtual power plan testing	Day 8

2.3 Test Network Diagrams (SPEN System Extracts)

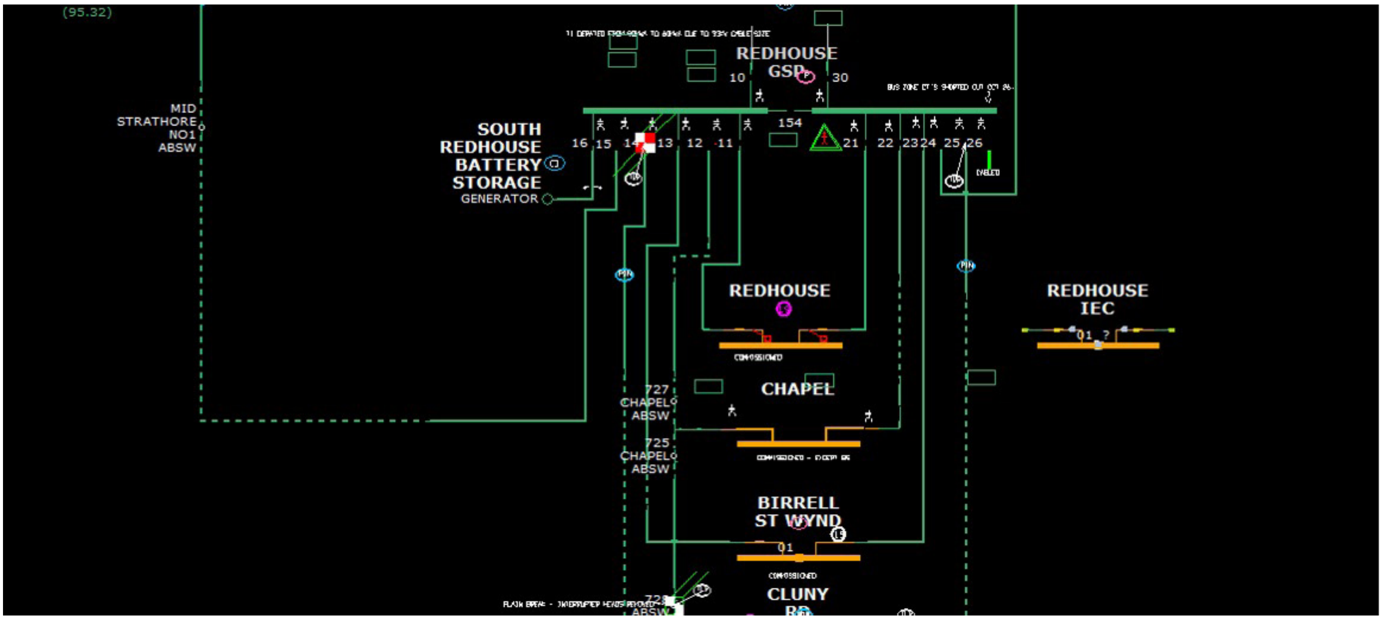


Figure 1: Redhouse GSP network diagram (33 kV)

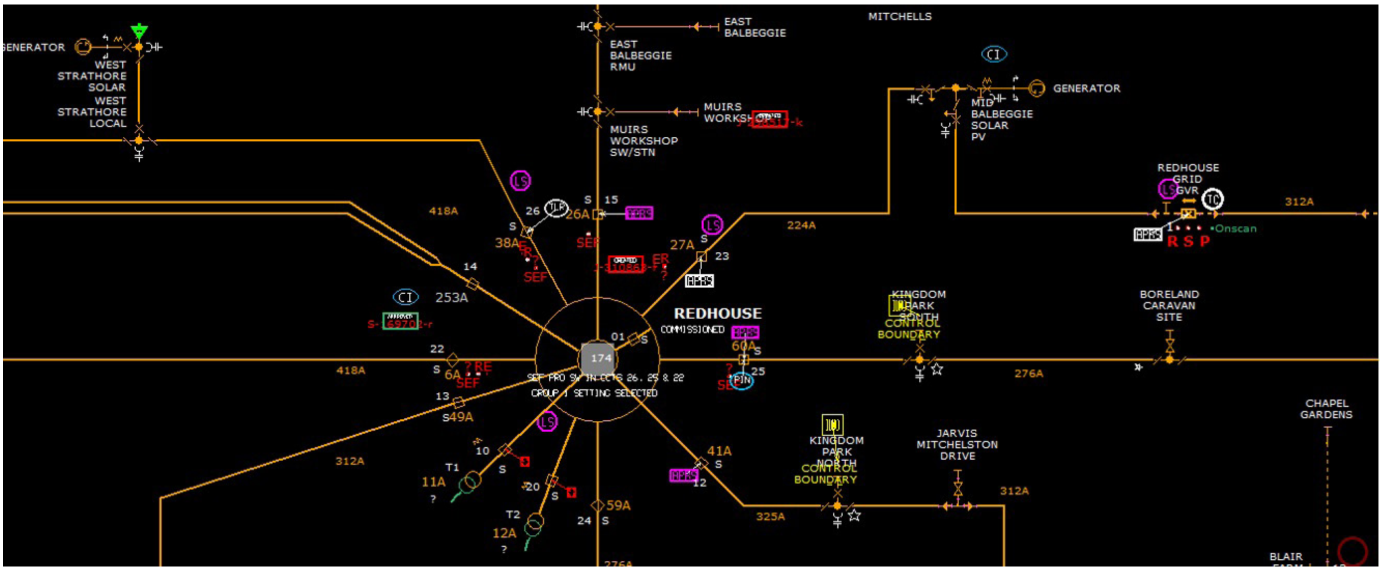


Figure 2: Redhouse primary network diagram (11 kV)

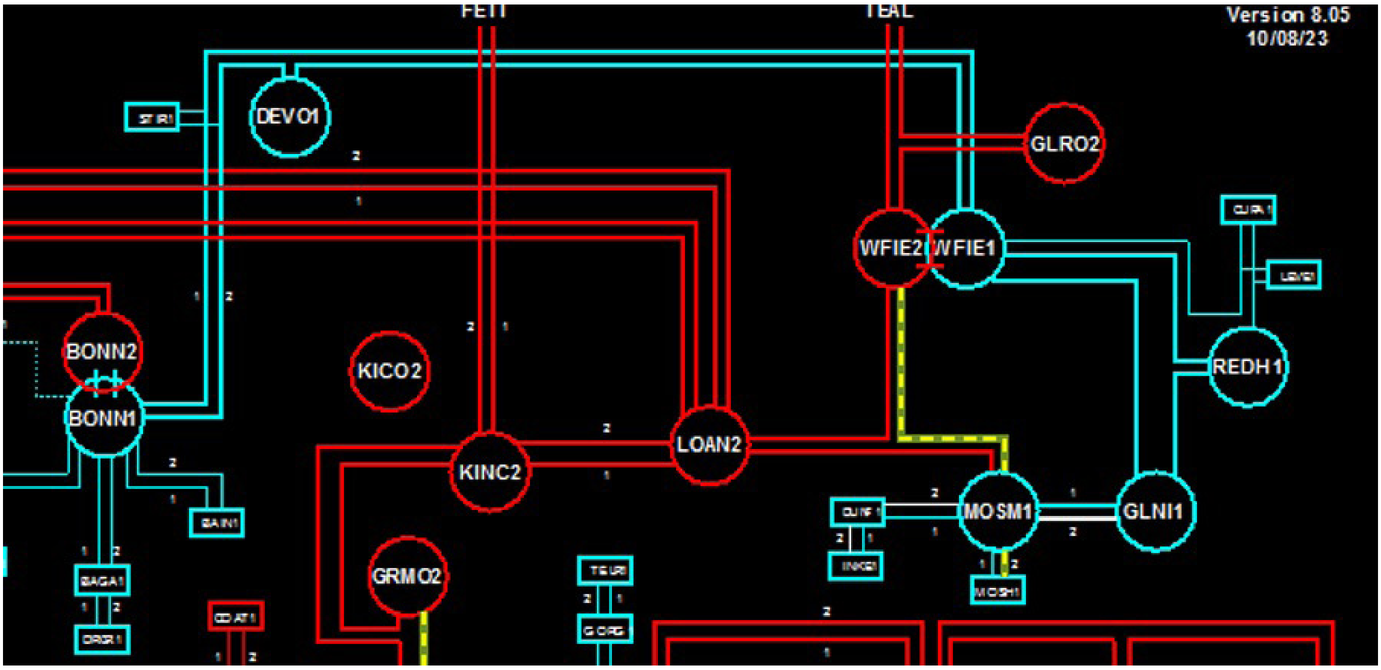


Figure 3: SPT trial network diagram

3. Redhouse Live Trial Results and Findings

The three major phases of the live trial took place on the following dates:

- Phase 1: 19–20 June 2023
- Phase 2: 21–26 June 2023
- Phase 3: 27–28 June 2023.

3.1 Phase 1

The Phase 1 tests took place purely on the Greenspan Energy network side, isolated from the SPEN network as seen in Figure 4 below.

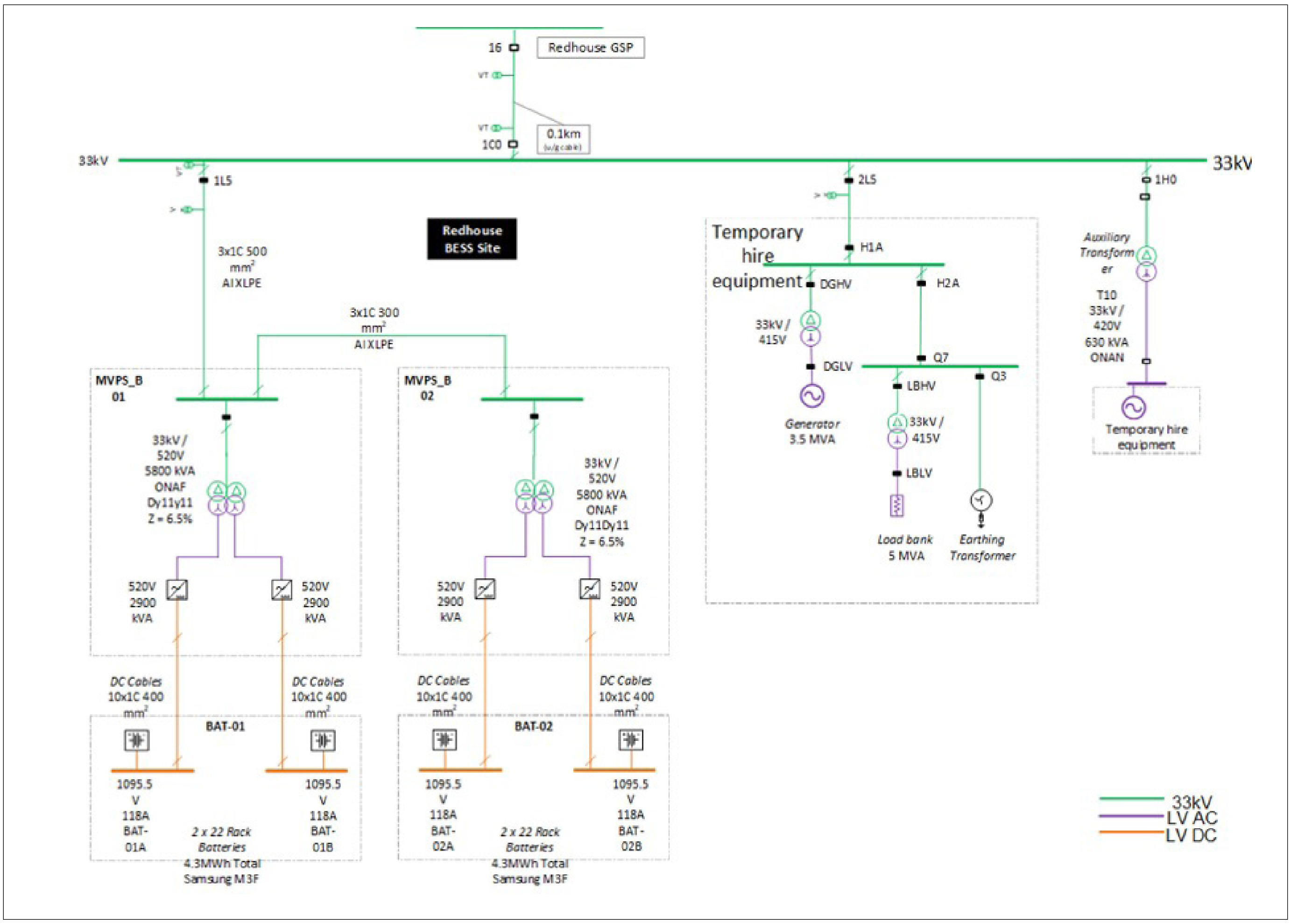


Figure 4: Phase 1 trial network diagram

The primary deliverables for Phase 1 were to prove:

- what the diesel generator block load pickup (BLPU) capability is
- the BESS grid-following ability in droop control
- the BESS grid-following ability in setpoint control
- what the BESS block load pickup (BLPU) capability is.

3.1.1 T1.1: Diesel Generator Tests (BLPU)

Having set up the test network appropriately with a voltage droop setting of 5% and a frequency droop setting of 4% (these settings are maintained for the duration of the tests unless otherwise specified), the BLPU capability of the diesel generator was then tested. This involved using the load bank to apply load steps to the diesel generator, until the frequency dropped to 47.5 Hz. This limit is known as the BLPU.

An initial 1 MW load was applied as a start point and a frequency drop of around 1.5 Hz was observed. A second step of 1.5 MW was then applied and the frequency dropped by 2.5 Hz to almost exactly 47.5 Hz. Thus, as the BLPU limit of 47.5 Hz had been met, no further load steps were attempted and the BLPU of the 5 MVA (4 MW) diesel genset was found to be 1.5 MW. This is roughly equivalent to 1000–1500 homes and is a valuable figure for those generators looking to supplement restoration services with diesel gensets.

3.1.2 T1.2: Grid-Following BESS Tests (BESS in f and V Droop Mode)

This test involved synchronising the diesel generator and BESS together, while they were both in droop control modes. Due to the required fault level ratio of synchronous machine capacity to BESS capacity only one "leg" (2.9 MVA) of the BESS was available during the grid-following mode tests. There was a desire to see how the island would act when two droop control systems were working simultaneously, the BESS droop and the diesel genset droop (the latter cannot be removed during the grid-following remit).

Having established the islanded test network, formed from the diesel genset in droop control mode the BESS was then connected with a frequency droop control setting of 4%. Immediately following this, unstable growing oscillations between the two control systems were observed.

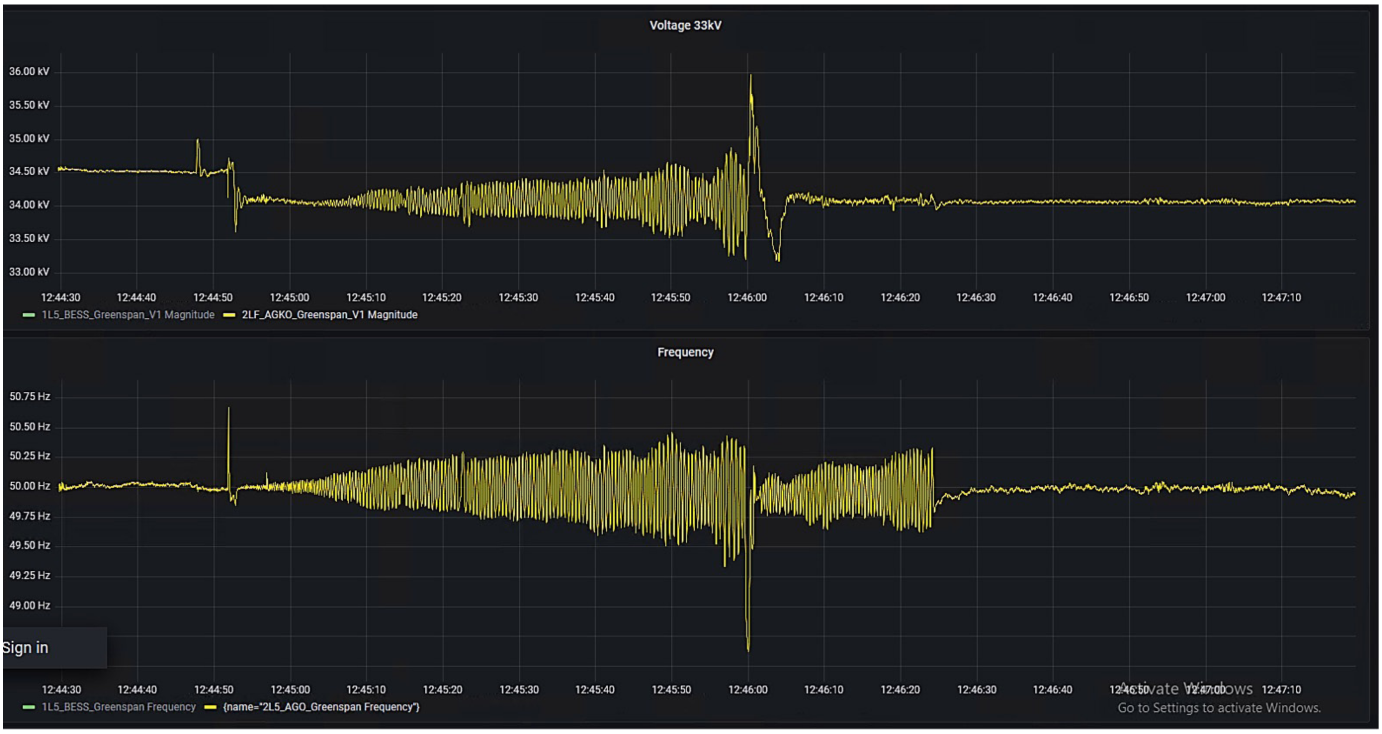


Figure 5: Grid-following BESS synchronised with diesel generator

To prevent any trips or potential damage, the BESS was disconnected. In an attempt to remove the oscillations a number of configurations were trialled. These included the amendment of either the BESS frequency droop setting, dampening load size and/or an inverter filter setting implemented by SMA to change the inverter to react to a moving average as opposed to instantaneous values. Table 4 below summarises the configurations trialled.

Table 4: BESS settings trialled to prevent oscillations

Configuration	Droop control setting (%)	Dampening Load (kW)	Filter (ms)
1	8	500	0
2	8	500	0
3	6	500	0
4	4	500	40
5	3	500	400
6	2	500	200
7	3	500	200
8	4	500	200
9	4	500	400
10	4	500	1000

Whilst a number of the configurations reduced/removed the oscillations the most effective configuration was: 4% frequency droop, 500 kW dampening load, 1 second filter.

Figure 6: Grid-following BESS synchronised with diesel generator, new settings applied

Whilst stability was reached when two droop control systems were operating simultaneously, it is not recommended to be the standard setting in grid-following mode due to the volatility of the behaviour and the subsequent oscillations experienced. The next section details the outcomes of the BESS in setpoint control which has more resilient and repeatable behaviour.

3.1.3 T1.3: Grid-Following BESS Tests (BESS in Setpoint Control Mode)

The purpose of this test was to prove in practice the ability of the islanded BESS to react to setpoints determined by the diesel generator and load bank to then compensate its output accordingly to ensure the island remains stable, through all four MW/MVAr quadrants when in grid-following mode.

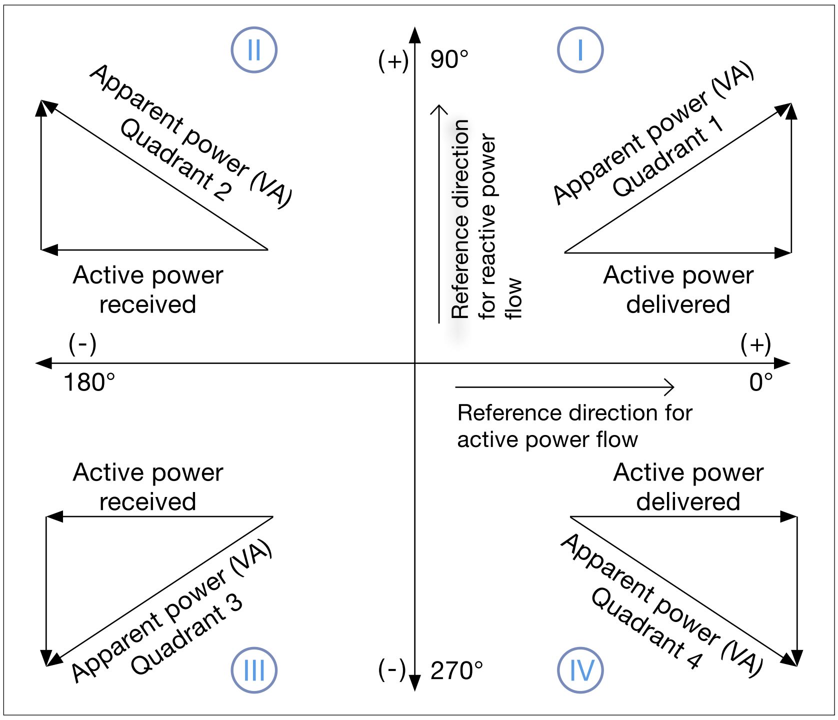


Figure 7: Four quadrants of active and reactive power

To achieve this, the following setpoints were implemented (from the BESS perspective) and the results monitored and analysed.

Setpoints:

- 1 MW generating // 0.5 MVAr generating (I)
- 1 MW charging // 0.5 MVAr generating (II)
- 1 MW charging // 0.5 MVAr charging (III)
- 1 MW generating // 0.5 MVAr charging (IV).

Figure 8 below shows an example of the real and reactive power outputs, measured from the perspective of the BESS and also the perspective of the Aggreko equipment (diesel genset and load bank) whilst being transitioned through quadrants. It shows the BESS reacting to the setpoints as expected and "mirroring" the output of the Aggreko equipment.

Figure 8: Active and reactive power of grid-following BESS under setpoint control

It is clear when comparing the performance of setpoint control vs frequency control, the former is far more reliable and prevents there being unwanted interactions/oscillations between the control systems of the BESS and the diesel genset.

3.1.4 T1.4: BESS Block Load Pickup Capability – Grid-Forming

The BESS was placed into grid-forming mode for these tests and the full 11.6 MVA was available for use. This test involved measuring the BLPU capability of the BESS in a number of different configurations to ensure the BESS' ability to react to instantaneous load steps was as fully understood as far as was reasonably practical. Load steps were applied to the BESS with the following configurations:

- a 4% BESS frequency droop control setting with the diesel genset synchronised
- a 4% BESS frequency droop control setting without the diesel genset synchronised
- a 1% BESS frequency droop control setting with the diesel genset synchronised
- a 1% BESS frequency droop control setting without the diesel genset synchronised.

The reason for repeating the tests with and without the diesel genset synchronised was to understand if it made any tangible difference to the BESS BLPU performance.

Furthermore, tightening the frequency droop control settings to 1% (±0.5 Hz) was to provide analysis on how far the BESS performance could be stressed whilst still maintaining island stability. Providing understanding on how much load could be applied with the BESS ensuring the islands' frequency stayed not just within BLPU limits (47.5 Hz) but also normal grid operation statutory limits (49.5 Hz).

The graphs and analysis below detail the learning of these tests. Measurement of BLPU capability with diesel genset synchronised with 4% frequency droop control.

Figure 9: Grid-forming BESS and diesel generator voltage and frequency – 2.5 MW load step – on and off

Having stepped the load bank up in progressively larger steps from 0.5 MW to 2 MW, it was clear at this stage that the BESS BLPU performance was excellent. With the control system ensuring the instantaneous load steps being applied were catered for in matter of 1-3 cycles (20-60ms) with the frequency and voltage settling at the expected values thereafter. Figure 9 shows a 2.5 MW load Step being applied to the BESS at approx. 11:11:25 and removed at approx. 11:12:03. It can be observed that the frequency drop is arrested almost instantaneously with no instability or oscillations following this.

Figure 10: Grid-forming BESS and diesel generator voltage and frequency – 2.5 MW load step

Figure 10 above shows a 4 MW load step being applied to the BESS at approx. 11:17:27 and removed at approx. 11:18:14. A 4 MW load step is the largest real power load step that the load bank available to the test setup could implement in one step. It can be observed again that the frequency drop is arrested almost instantaneously with no instability or oscillations following this. As the load bank's output had been maximised it was not possible to implement a greater load step. This proved that the BESS has a BLPU capability of at the very least 50% of its full capacity (4 MW load step/8 MW BESS capacity. Furthermore, given the behaviour observed it is expected that the true BLPU capability of the BESS is likely closer to its full rating. This is far superior to synchronous machines of the same capacity.

Figure 11: Grid-forming BESS and diesel generator voltage and frequency – 3.5 MW and 2.6 MVAr load step (1/2)

Figure 12: Grid-forming BESS and diesel generator voltage and frequency – 3.5 MW and 2.6 MVAr load step (2/2)

Figure 11 and Figure 12 above show a 4.36 MVA (3.5 MW/2.6 MVAr) load step being applied to provide understanding on the effect (if any) of having substantial reactive demand as part of the load step. It can again be seen that the BESS reacts to the demand and modulates its output within a few cycles to settle the voltage and frequency at the expected levels on the V and f droop curves of 5% and 4% respectively.

The tests were then repeated but this time without the diesel genset connected/synchronised to the BESS source. Figure 13 and Figure 14 show the iterative load steps being applied and it can be observed that there is negligible behaviour change when comparing to the tests with the diesel genset connected.

Figure 13: Grid-forming BESS voltage and frequency – 0.5 MW, 1 MW and 2 MW load steps (4% droop)

Figure 14: Grid-forming BESS voltage and frequency – 4 MW load step (4% droop)

The frequency droop control settings were then tightened from 4% to 1% to see if the BESS could cope with instantaneous demand within even more strenuous thresholds. Figure 15 and Figure 16 show the behaviour of the BESS driven island when implementing the load steps without the diesel genset synchronised.

Figure 15: Grid-forming BESS voltage and frequency – 2.5 MW load step (1% droop)

Figure 16: Grid-forming BESS voltage and frequency – 4 MW load step (1% droop)

Figure 17: Grid-forming BESS voltage and frequency – 3.3 MW and 2.7 MVAr load step (1/2)

Figure 18: Grid-forming BESS voltage and frequency – 3.3 MW and 2.7 MVAr load step (2/2)

It can be observed that when implementing these larger load steps there is some overshoot in both the voltage and frequency however these are not substantial and again the BESS is able to cope with the load steps of this nature. The frequency and voltage is again returned to a stable state even with such tight frequency bounds. The overshoots observed when implementing both the 2.5 MW and 4 MW load steps and are approximately the same with the frequency momentarily dropping to approximately 49.65 Hz before settling at the expected values as per the droop control curves. This again demonstrates the BESS has excellent performance at responding to frequency events and can be used to drive the island voltage and frequency to as close to nominal V and f as is reasonably practical. Furthermore, when compared to a synchronous machine of the same capacity the results are far superior as the average synchronous machine would be expected to have a BLPU capability of around 10–20% of its capacity. Here the BESS has demonstrated a BLPU of at the very least 50% with the true BLPU capability of the BESS being likely closer to its full rating of 8 MW.

3.2 Phase 2

The focus of Phase 2 was to energise sections of the distribution and transmission network, including two primary transformers, a grid transformer and a 132 kV overhead line. This phase also involved energising Middle Balbeggie Solar Farm, which contributed generation to the power island and acted as the top-up generator. The PoW relay was installed to provide full PoW functionality/switching when energising either the Redhouse primary 24 MVA transformer or the Redhouse grid 90 MVA transformer via a direct monitoring point. Partial PoW functionality was available for Chapel energisation, in the absence of there being a direct monitoring point form the PoW relay to Chapel. Figure 19 shows a diagram of the Phase 2 test network.

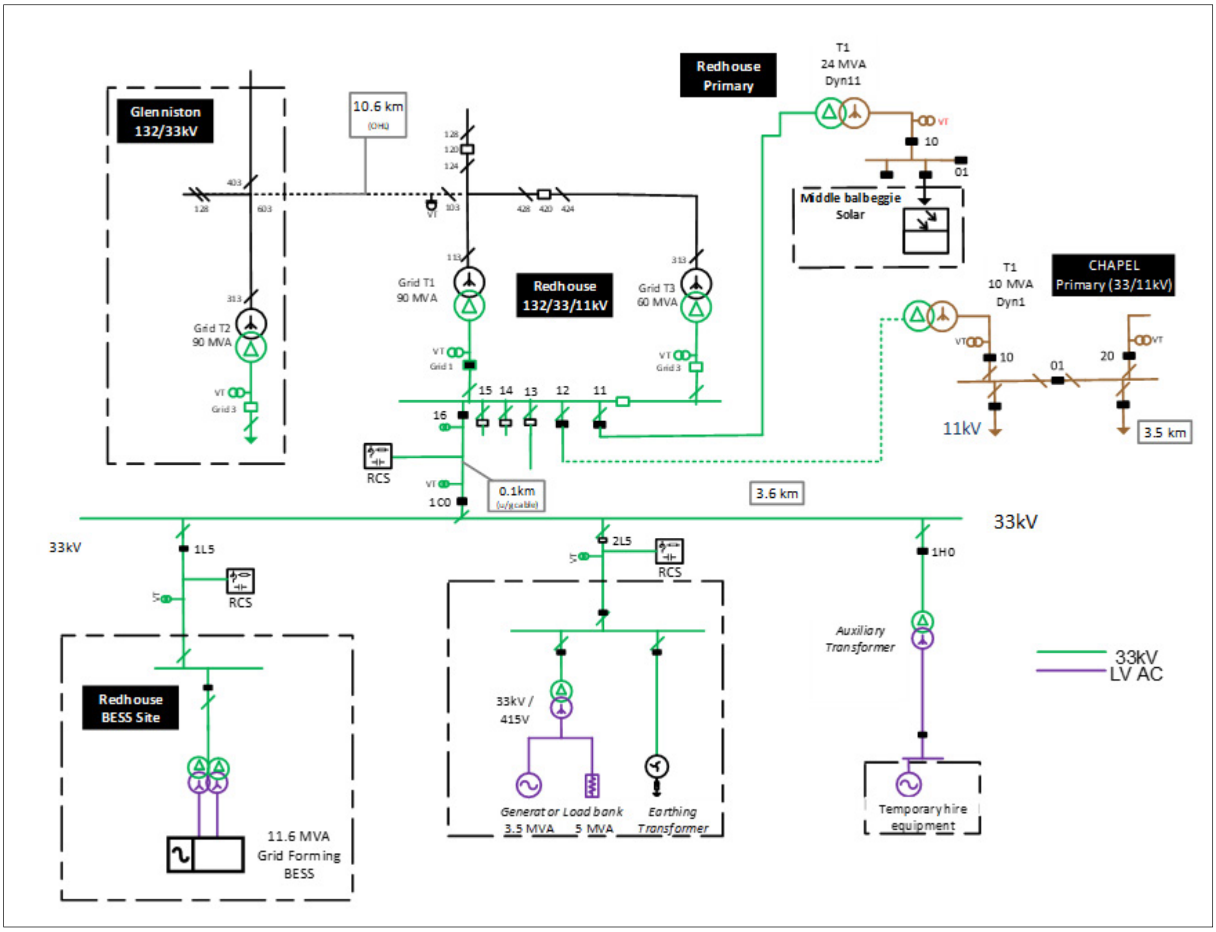


Figure 19: Phase 2 trial network diagram snapshot – SPEN network tests (CB positions may vary test by test)

The primary deliverables of Phase 2 were as follows:

- prove the diesel generator's ability to energise primary transformers
- prove the combined ability of the diesel generator and the grid-forming BESS to energise primary transformers and a solar farm
- prove the grid-forming BESS' ability to energise primary transformers and a solar farm
- prove the diesel generator's ability to energise a grid transformer and a 132 kV overhead line
- prove the combined ability of the diesel generator and the grid-forming BESS to energise a grid transformer and a 132 kV overhead line
- prove the grid-forming BESS' ability to energise a grid transformer and a 132 kV overhead line.

3.2.1 Network Configuration – Distribution

Similarly, to Phase 1, initial network configuration took place at the Greenspan site for Phase 2 and was set up as follows:

- ensure BESS has 50% state of charge prior to disconnection
- shutdown BESS and configure in grid-forming mode for tests with 4% frequency droop, 5% voltage droop
- connect auxiliary transformer to the Greenspan 33 kV busbar
- disconnect BESS site from Redhouse GSP by opening CB16 and 1C0
- change protection settings on circuit breakers at Greenspan's site
- connect earthing transformer to ensure persistent 33 kV earth
- configure diesel generator for tests: 4% frequency droop, 5% voltage droop.

Furthermore, the configuration of the distribution network also took place which involved implementing:

- a Redhouse GSP half busbar outage
- a Chapel primary half busbar outage
- a Redhouse primary full busbar outage.

3.2.2 T2.1: Primary Transformer Energisation via Diesel Generator

Once the network configuration was complete, the diesel generator was started and connected to 500kW of load from the load bank, which would provide resistive damping during transformer energisation. The diesel generator energised up to the open CB16. On the other side of this breaker, CB12 was closed on the not-live 33 kV busbar. The configuration was such that the closure of CB16 would energise the Chapel primary 10MVA T1 transformer.

Chapel primary T1 energisation

As there was no direct feedback from the primary transformer at Chapel to the PoW relay , the PoW function relied on the optimisation of closing angle only when energising Chapel primary, this is what is described above as 'partial' functionality. CB16 was closed three times (via telecontrol) in conjunction with the PoW relay. All closures were successful. Figure 20 shows the voltage dip experienced due to one instance of energising Chapel with PoW switching.

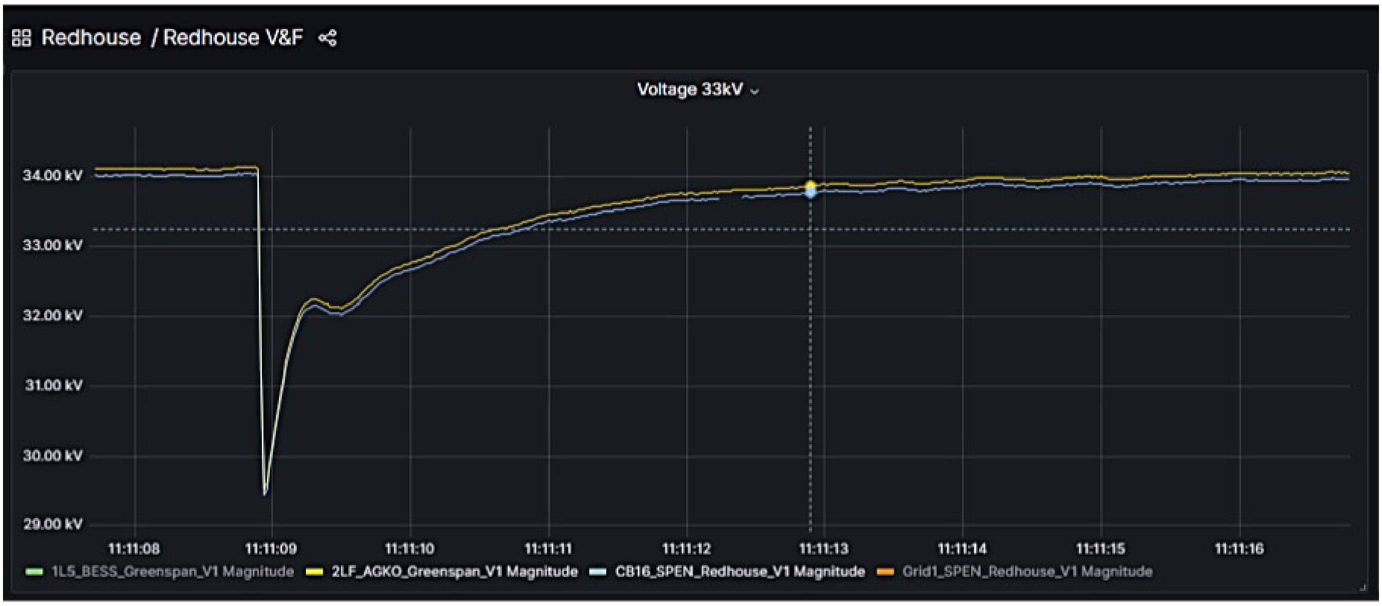


Figure 20: Chapel primary T1 energised via the diesel generator with PoW

The voltage is seen to drop by ~4.5 kV due to the 10 MVA transformer energisation. Three "hard" energisations were then tested, again via the closure of CB16. Figure 21 shows the voltage dip of experienced due to one instance of energising Chapel without PoW switching.

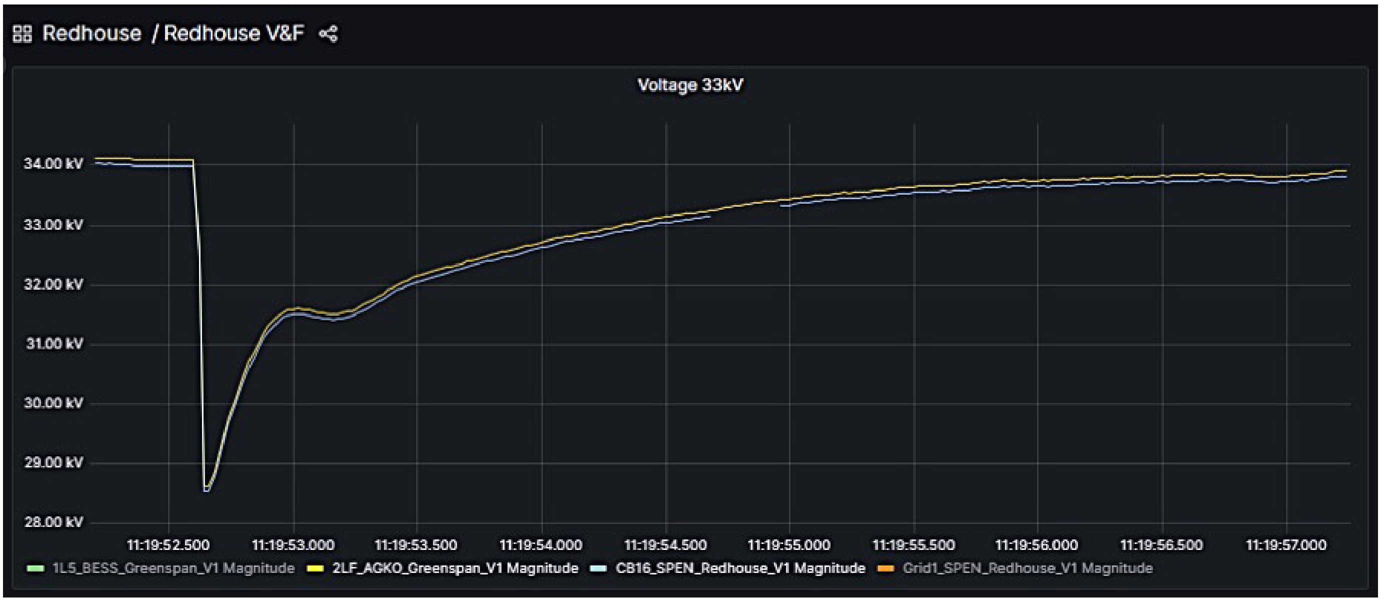


Figure 21: Chapel primary T1 energised via the diesel generator without PoW

Without PoW switching, the voltage dip is larger, measuring ~5.5 kV. All non-PoW closures were completed successfully.

Redhouse primary T1 energisation

The network was re-configured so that CB12 was opened and CB11 was closed, allowing Redhouse primary 24 MVA T1 to be energised by the closure of CB16. Three "hard" closures were successfully completed. Figure 22 shows the resultant voltage and frequency signals during one of the hard closures.

Figure 22: Redhouse primary T1 energised via the diesel generator without PoW

The voltage can be seen to dip to ~26.4 kV before recovering to a steady state voltage after 5 seconds. The other "hard" energisations of Redhouse primary resulted in similar voltage dips to ~25 kV and 25.5 kV.

One PoW assisted energisation of Redhouse primary T1 was then attempted, which was successful. Voltage and frequency traces are shown in Figure 23.

Figure 23: Redhouse primary T1 energised via the diesel generator with PoW

This example of PoW switching results in a much less severe voltage dip to ~31.8 kV due to the mitigation of inrush current, demonstrating the advantages of having full PoW functionality available.

3.2.3 T2.2: Primary Transformer and Middle Balbeggie Solar (MBS) Energisation via Grid-Forming BESS with Diesel Generator Support

The BESS units were started in grid-forming mode and energised up to the Greenspan 33 kV busbar. The isochronous control mode was used for the initial BESS start up before transitioning to frequency droop control in order to synchronise with the diesel generator. The diesel generator was started and set up in base load mode with an output of 50 kW. The BESS and diesel generator were synchronised together via the closure of the DGLV breaker. The BESS was given a reactive power setpoint of 500 kVAr to avoid over excitation of the diesel generator. No resistive damping was used for these tests. The SPD network was configured such that Chapel primary T1 would be energised via the closure of CB16.

Chapel primary T1 energisation

Three "hard" energisations of Chapel primary T1 were completed successfully with the diesel generator and BESS operating together.

Figure 24: Chapel primary T1 energised via the diesel generator and grid-forming BESS without PoW

The voltage dip hits ~31.7 kV – this is a smaller dip than witnessed before. The additional two "hard" closures resulted in similar voltage dips. "Hard" closures do not always result in high levels of inrush current or large voltage dips – it depends on the residual flux in the transformer and the closing angle of the energising breaker – as such "hard" closures performance is random in nature. Figure 25 below shows the active and reactive power traces during two of the "hard" energisations of Chapel primary T1.

Figure 25: Chapel primary T1 energised via the diesel generator and grid-forming BESS without PoW

The transformer energisations resulted in a moderate reactive current draw from the BESS, reaching around 2.25 MVAr. The current/reactive power recovers to steady state after ~5 seconds. Figure 26 shows a subsequent energisation of Chapel T1 using PoW controlled switching.

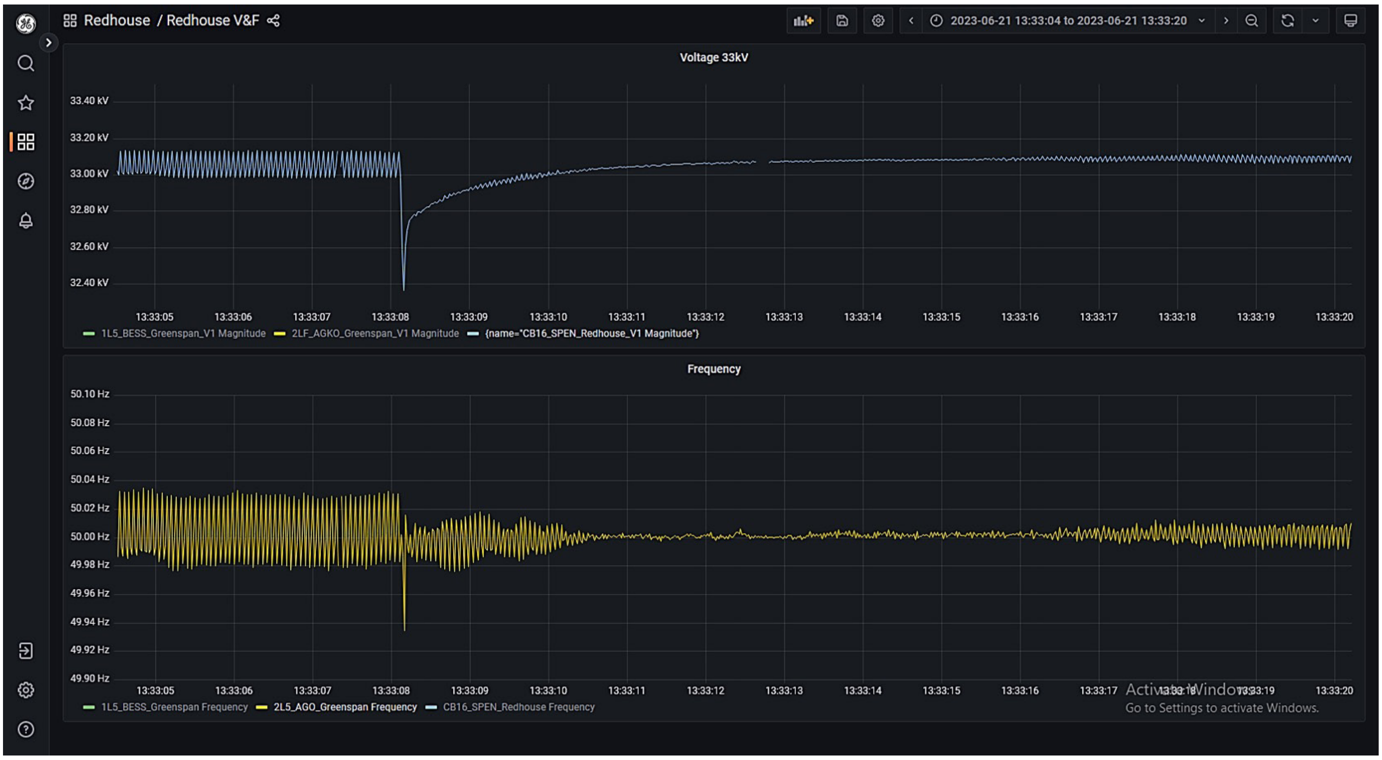


Figure 26: Chapel primary T1 energised via the diesel generator and grid-forming BESS with PoW

The voltage dips to ~32.4 kV, a marked improvement on the attempts made without PoW switching. For this energisation, the BESS contributed ~1 MVAr of reactive power. PoW controlled switching proved to be effective in mitigating inrush current (and voltage dip) in this case.

Redhouse primary T1 Energisation

Similarly, to Chapel, three "hard" energisations of Redhouse primary T1 were completed successfully with the diesel generator and BESS operating together.

Figure 27: Redhouse primary T1 energised via the diesel generator and grid-forming BESS without PoW

The energisation attempt in Figure 27 shows a more severe voltage dip to ~30.2 kV. Figure 28 shows the active and reactive power of the BESS during this energisation.

Figure 28: Redhouse primary T1 energised via the diesel generator and grid-forming BESS without PoW

During the energisation at 13.43, a large reactive power draw of close to 5 MVAr was recorded at the BESS. The BESS reactive power returned to normal levels around 4 seconds after the energisation and the system remained stable. There are several different factors that influence transformer inrush current and one such factor is transformer capacity. Chapel primary T1 has a capacity of 10 MVA, whereas Redhouse primary T1 is 24 MVA. This could have been a factor in the larger reactive current draw observed when energising Redhouse primary T1.

Energisation was then attempted twice using PoW controlled switching, resulting in voltage dips to ~31.5 kV and ~32.2 kV. The respective reactive currents drawn from the BESS were ~2.25 MVAr and ~1.1 MVAr. Figure 29 and Figure 30 show the results of the first PoW controlled energisation of Redhouse primary T1.

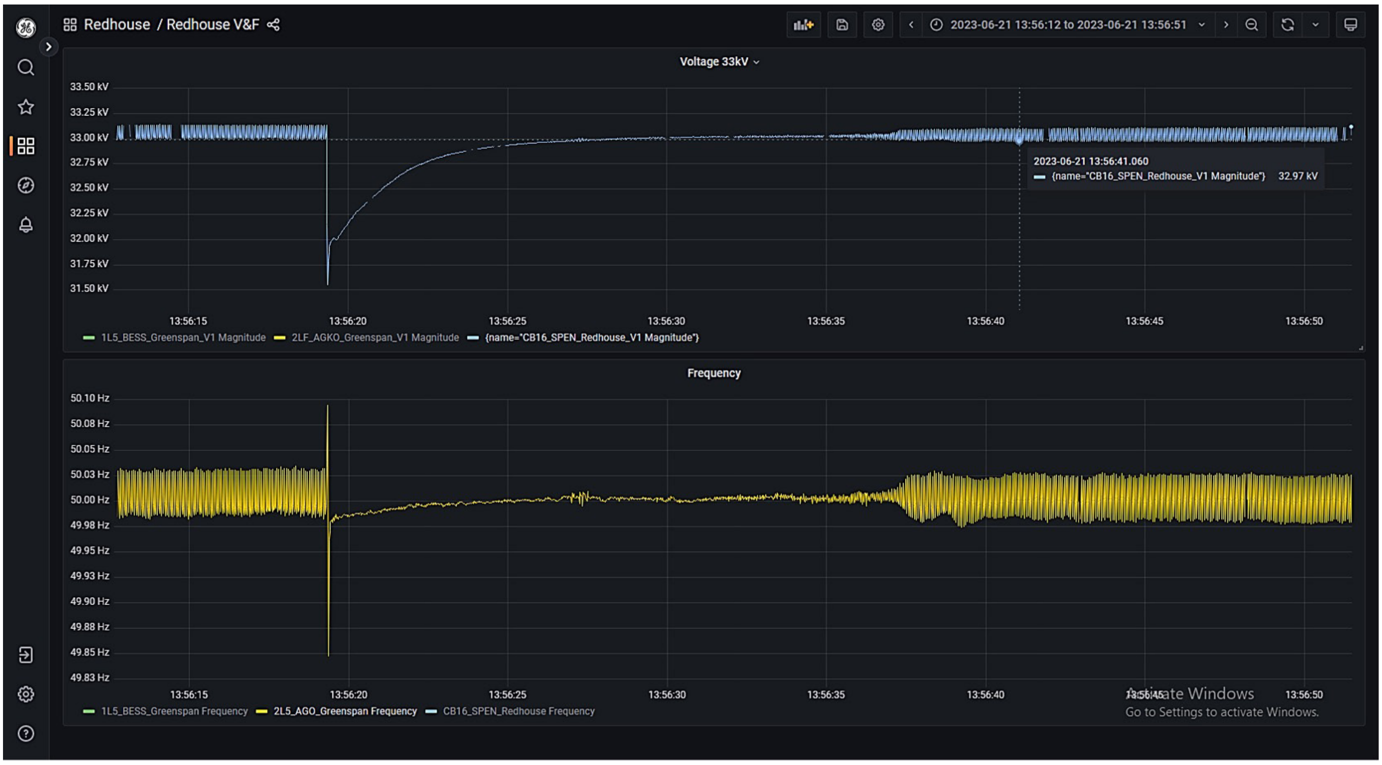


Figure 29: Redhouse primary T1 energised via the diesel generator and grid-forming BESS with PoW

Figure 30: Redhouse primary T1 energised via the diesel generator and grid-forming BESS with PoW

The difference in the inrush current was due to the different levels of residual flux in the transformer in the case of each energisation. As the circuit breaker being switched is a 3-pole gang operated breaker, the closing angle of the breaker cannot be optimised for each phase individually and so optimum point between the three phases is chosen. Depending on the residual flux in the transformer core, the closure of all three phases at once can have varying levels of success.

Chapel primary T1 and Redhouse primary T1 simultaneous energisation

The SPD network was then configured so that CB11 and CB12 at the Redhouse 33 kV busbar were closed, meaning that the closure of CB16 would energise both the Chapel and Redhouse primary transformers simultaneously. Results of one example of this energisation without PoW switching is shown in Figure 31 and Figure 32.

Figure 31: Chapel primary T1 and Redhouse primary T1 energised via the diesel generator and grid-forming BESS without PoW

Figure 32: Chapel primary T1 and Redhouse primary T1 energised via the diesel generator and grid-forming BESS without PoW

In this case, the voltage dips to ~30.75 kV and the reactive power draw from the BESS reached ~3.50 MVAr before returning to its normal value around 5 seconds later. All three energisations of both transformers without PoW switching were successful.

The energisation of both transformers was then repeated with PoW switching enabled.

Figure 33: Chapel primary T1 and Redhouse primary T1 energised via the diesel generator and grid-forming BESS with PoW

Figure 34: Chapel primary T1 and Redhouse primary T1 energised via the diesel generator and grid-forming BESS with PoW

Figure 33 and Figure 34 show that the results of energising both primary transformers via PoW switching were similar to the results shown for the non-PoW switching of the same case. After discussions with the PoW solution provider, it was found that the operating time of CB16 was becoming slightly quicker and so the set operating time programmed into the PoW relay was no longer fully accurate. This resulted in the PoW switching of CB16 being less effective for the energisations of both primaries simultaneously. The operation time setting was updated in the PoW relay and another energisation with PoW switching was tested.

Figure 35: Chapel primary T1 and Redhouse primary T1 energised via the diesel generator and grid-forming BESS with PoW (updated operation time setting applied)

Figure 36: Chapel primary T1 and Redhouse primary T1 energised via the diesel generator and grid-forming BESS with PoW (updated operation time setting applied)

Figure 35 and Figure 36 show the results of the energisation with the updated operation time setting applied to the PoW relay. The results have improved, with the voltage dip only reaching ~31.5 kV versus ~31 kV. The reactive current draw decreased to ~2.75 MVA versus ~3.6 MVA. Updating the operation time setting was successful in improving inrush mitigation in this case. The uncontrolled residual flux in the transformer core was low in this case, meaning that although the operation time setting was accurate, there are more successful examples of PoW switching (in which the residual flux was high).

Middle Balbeggie Solar Farm energisation

Following on from the energisation of the Chapel and Redhouse primary transformers, Middle Balbeggie Solar Farm (MBS) was connected to the trial network via the closure of CB10 at Redhouse primary. Once the connection of MBS had been confirmed with the SPD control centre, MBS was instructed to increase their output from 0 MW to 3 MW (or as close as possible).

Figure 37: MBS output ramping up to ~3 MW

Figure 38: MBS output ramping up to ~3 MW

Figure 37 and Figure 38 above show the voltage, frequency, active and reactive power of the system as MBS increases its output to ~2.75 MW. As the output from MBS increases, the system frequency (dictated by the BESS) increases to 50.6 Hz. This is the result of the 4% frequency droop control which the BESS is acting in accordance with. The BESS reactive power output also reduces from its initial setpoint of 500 kVAr in accordance with the voltage droop setting. Once the power output from MBS had reached a steady state, load steps were applied to the system via the load bank. Figure 39 and Figure 40 show the results for a 1 MW load step.

Figure 39: 1 MW load step applied to trial network with diesel generator, BESS and MBS connected

Figure 40: 1 MW load step applied to trial network with diesel generator, BESS and MBS connected

When the 1 MW load step is applied, the frequency of the system drops from ~50.6 Hz to ~50.4 Hz. In the active power trace, the BESS charging power is seen to drop from ~2.7 MW to 1.7 MW.

Following the 1 MW load step, a 2.5 MW load step was tested. The results for this are shown in Figure 41 and Figure 42.

Figure 41: 2.5 MW load step applied to trial network with diesel generator, BESS and MBS connected

Figure 42: 2.5 MW load step applied to trial network with diesel generator, BESS and MBS connected

The 2.5 MW load step results in the frequency dropping from ~50.6 Hz to ~50.05 Hz. This load step reduces the BESS active power to close to 0 MW. This causes the BESS voltage (and therefore reactive power) to oscillate slightly, this small oscillation was present for the duration of the trials when the net power in the island was near 0 MW.

Following the 2.5 MW load step, a 4 MW load step was tested, the maximum value capable by load bank. The results for this are shown in Figure 43 and Figure 44.

Figure 43: 4 MW load step applied to trial network with diesel generator, BESS and MBS connected

Figure 44: 4 MW load step applied to trial network with diesel generator, BESS and MBS connected

The 4 MW load step results in the system frequency dropping from ~50.6 Hz to ~49.7 Hz. In the active power trace, the load step is shown to transition the BESS from charging at ~2.8 MW to discharging at ~1.2 MW. As the load step is applied, the voltage level is seen to drop and settles just under 33 kV. The reactive power output of the BESS responds to this voltage drop and begins to generate just under 200 kVAr.

Following the load steps, MBS powered down and was disconnected from the test system. The primary transformers were de-energised and the diesel generator and BESS were shut down. The distribution network was then re-configured to its normal operating configuration.

3.2.4 T2.3: Primary Transformer and MBS Energisation via Grid-Forming BESS Only

The BESS site was configured similarly as per the description in Section 3.2.1, the only differences being the diesel generator was not configured as it was not required for these tests and the BESS frequency droop was set to 1%.

Chapel primary T1 energisation

Chapel primary T1 was energised from the BESS. Three "hard" energisations were attempted, all three of which were successful. Results from one example of these energisations are shown in Figure 45 and Figure 46.

Figure 45: Chapel primary T1 energised via BESS without PoW

Figure 46: Chapel primary T1 energised via BESS without PoW

In this case, the voltage dips to ~31.25 kV due to the transformer energisation. The reactive current draw from the BESS reaches ~3 MVAr before returning to its steady state value around 4 seconds later.

Following the "hard" energisations, two further energisations were successfully attempted with PoW switching.

Figure 47: Chapel primary T1 energised via BESS with PoW

Figure 48: Chapel primary T1 energised via BESS with PoW

In this example of PoW switching, the inrush current and its effects were slightly worse than the energisation without PoW. The voltage dipped to ~30.7 kV and the reactive power draw from the BESS was slightly higher at ~3.3 MVAr. Although PoW switching is generally more effective than “hard” switching, the residual flux cannot be controlled and so some switching attempts will be more successful than others. Additionally, there is no load side voltage measurement at Chapel, so the PoW switching will be less effective due to its ‘partial’ functionality in this instance.

Redhouse primary T1 energisation

The distribution network was configured to allow Redhouse primary T1 to be energised via the closure of CB16. The first attempt of a "hard" energisation resulted in the BESS internal protection tripping. Figure 49 and Figure 50 show the results of this energisation attempt.

Figure 49: Redhouse primary T1 energisation attempt via BESS with PoW (BESS internal protection tripped)

Figure 50: Redhouse primary T1 energisation attempt via BESS with PoW (BESS internal protection tripped)

The results from this example show that there was an especially high reactive power drawn from the BESS of close to 5 MVAr. This is reflected in the high current signal recorded by the PoW relay.

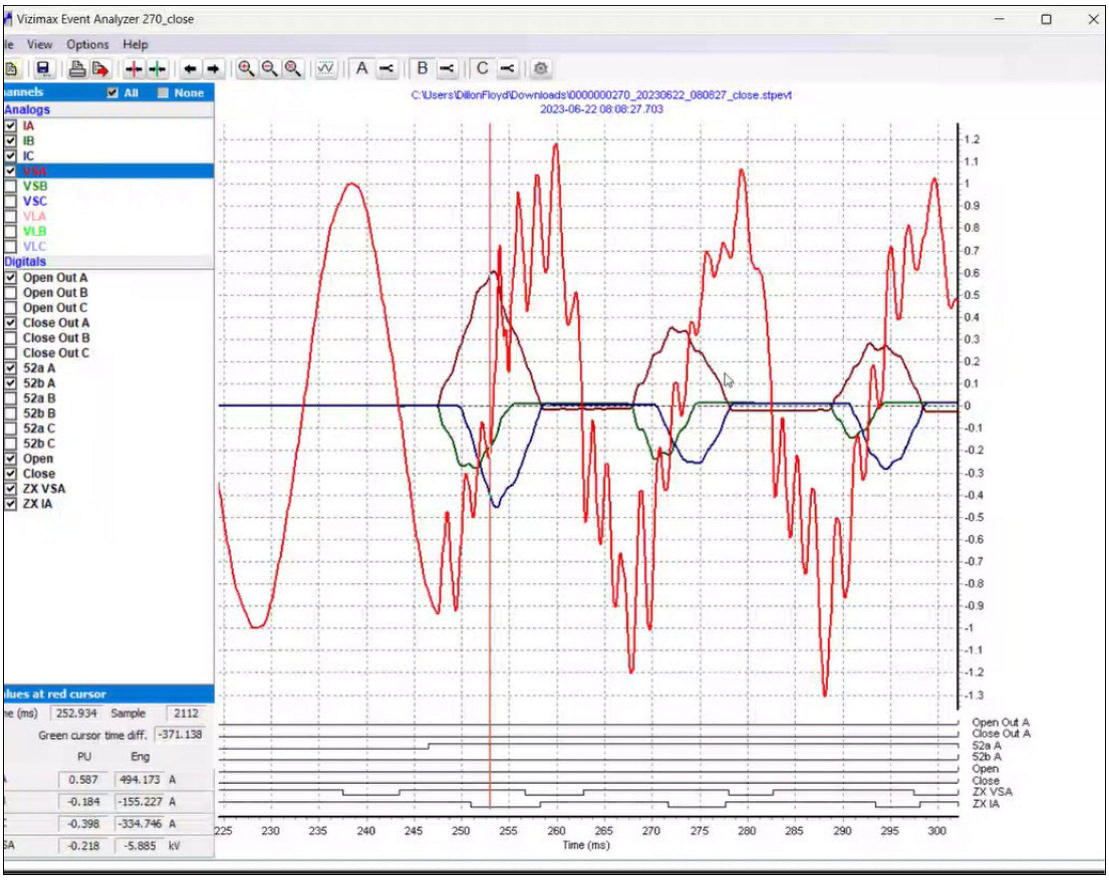


Figure 51: Voltage and current signals from PoW relay, failed Redhouse energisation

Comparing this with a previous successful attempt of the Chapel transformer energisation, the current is a lot smaller.

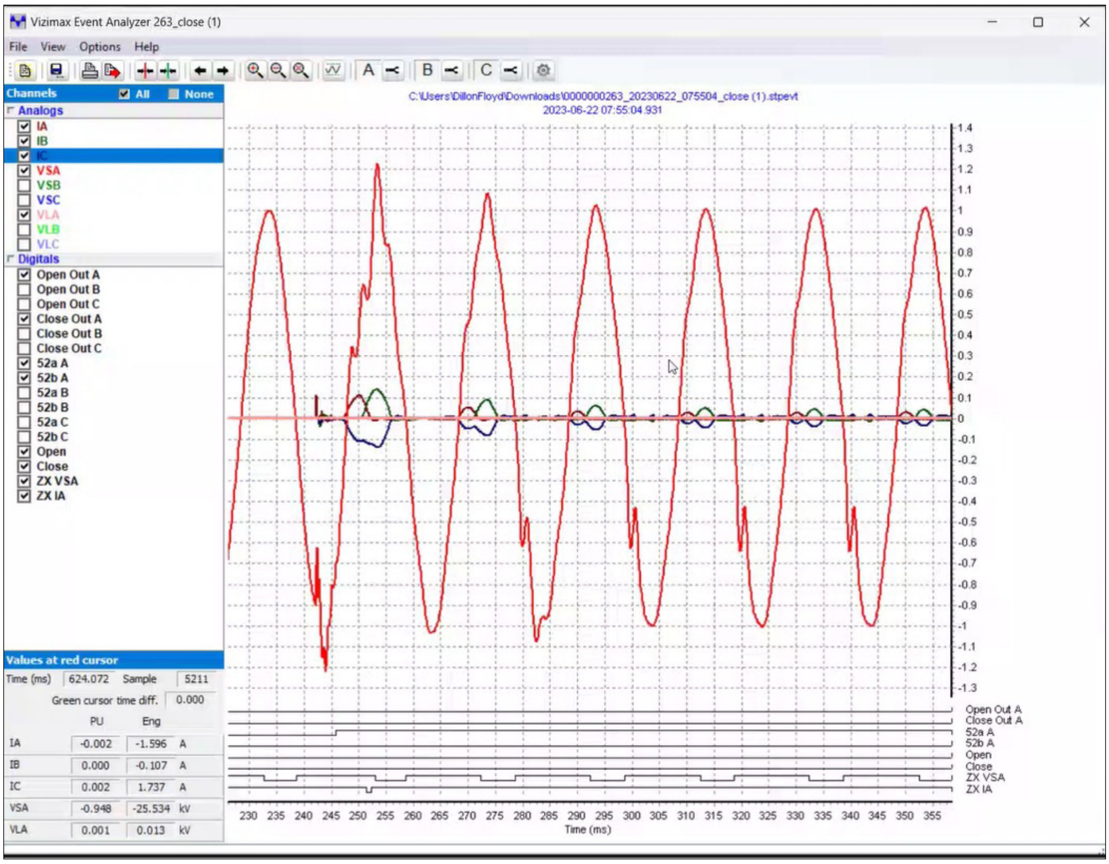


Figure 52: Voltage and current signals from PoW relay, successful Chapel energisation

The inverter operator SMA advised that the inverter software registered overvoltage, undervoltage, over-frequency and under-frequency events during the attempted energisation. Fault ride through mode was activated in all four inverters before the BESS shutdown. The time from CB16 closure to BESS shutdown was measured as 112 ms. To prevent a similar shutdown occurring, the voltage control protection delay of the BESS was increased by SMA.

Once the trial network had been re-started, a "hard" energisation of Redhouse primary was successfully attempted three times. Figure 53 and Figure 54 shows the results of one such energisation.

Figure 53: Redhouse primary T1 energised via BESS without PoW

Figure 54: Redhouse primary T1 energised via BESS without PoW

The voltage dips to ~31.3 kV and the reactive power draw from the BESS reached ~3.7 MVAr. The subsequent attempt of "hard" switching resulted in a voltage dip to ~24.5 kV, but the BESS did not trip.

Three successful attempts of PoW switching were then tested, the results of which are shown in Figure 55 and Figure 56.

Figure 55: Redhouse primary T1 energised via BESS with PoW

Figure 56: Redhouse primary T1 energised via BESS with PoW

In this example, the voltage dipped to ~32.1 kV and the reactive current from the BESS reached close to 1 MVAr. For the energisation of Redhouse primary T1, all PoW energisations were more successful than the "hard" closures.

Chapel primary T1 and Redhouse primary T1 simultaneous energisation

The distribution network was re-configured so that the Chapel and Redhouse primary transformers could be energised simultaneously. The results of the first "hard" switch attempt are shown in Figure 57 and Figure 58.

Figure 57: Chapel primary T1 and Redhouse primary T1 energised via BESS without PoW

Figure 58: Chapel primary T1 and Redhouse primary T1 energised via BESS without PoW

The voltage dipped to ~26.5 kV and the reactive power draw reached over 4 MVAr. This energisation caused the BESS to go into fault ride through mode again, but it did not trip and so the energisation was successful. A second "hard" energisation of both transformers was successful but the third attempt caused the activation of fault ride through mode again and the BESS tripped.

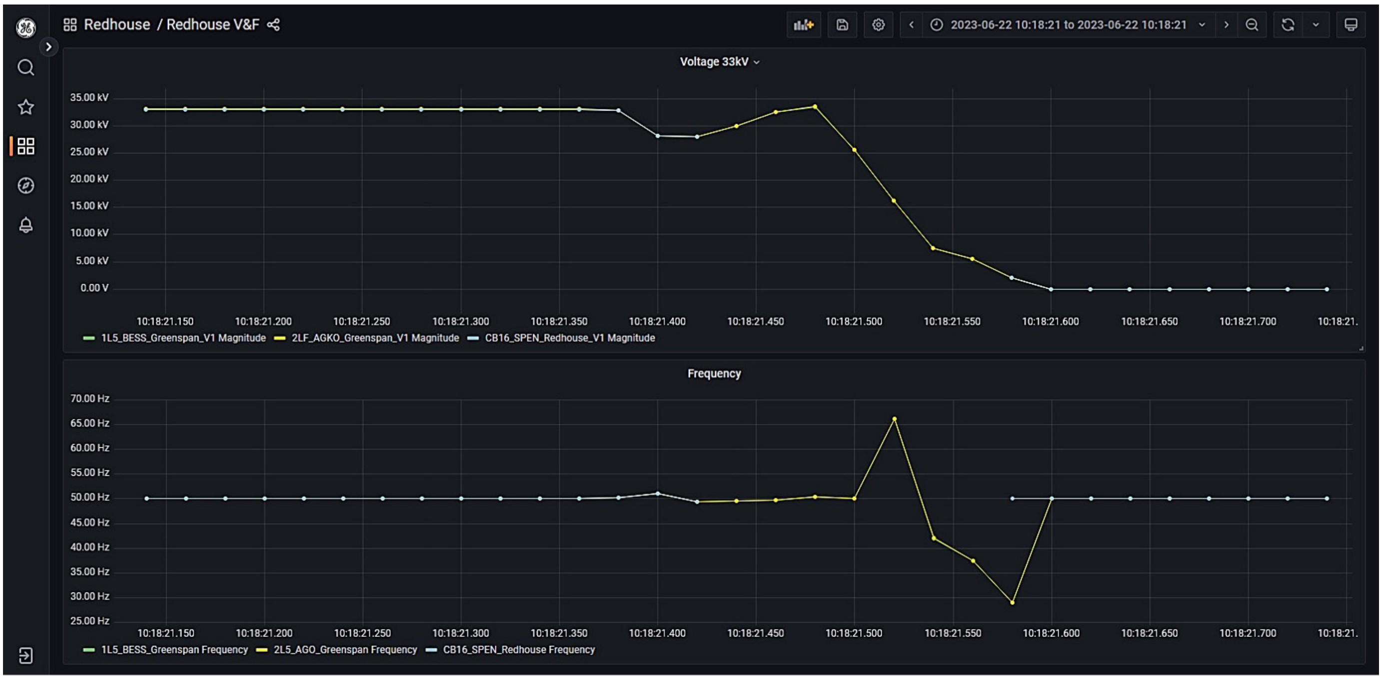


Figure 59: Chapel primary T1 and Redhouse primary T1 energised via BESS without PoW (BESS tripped)

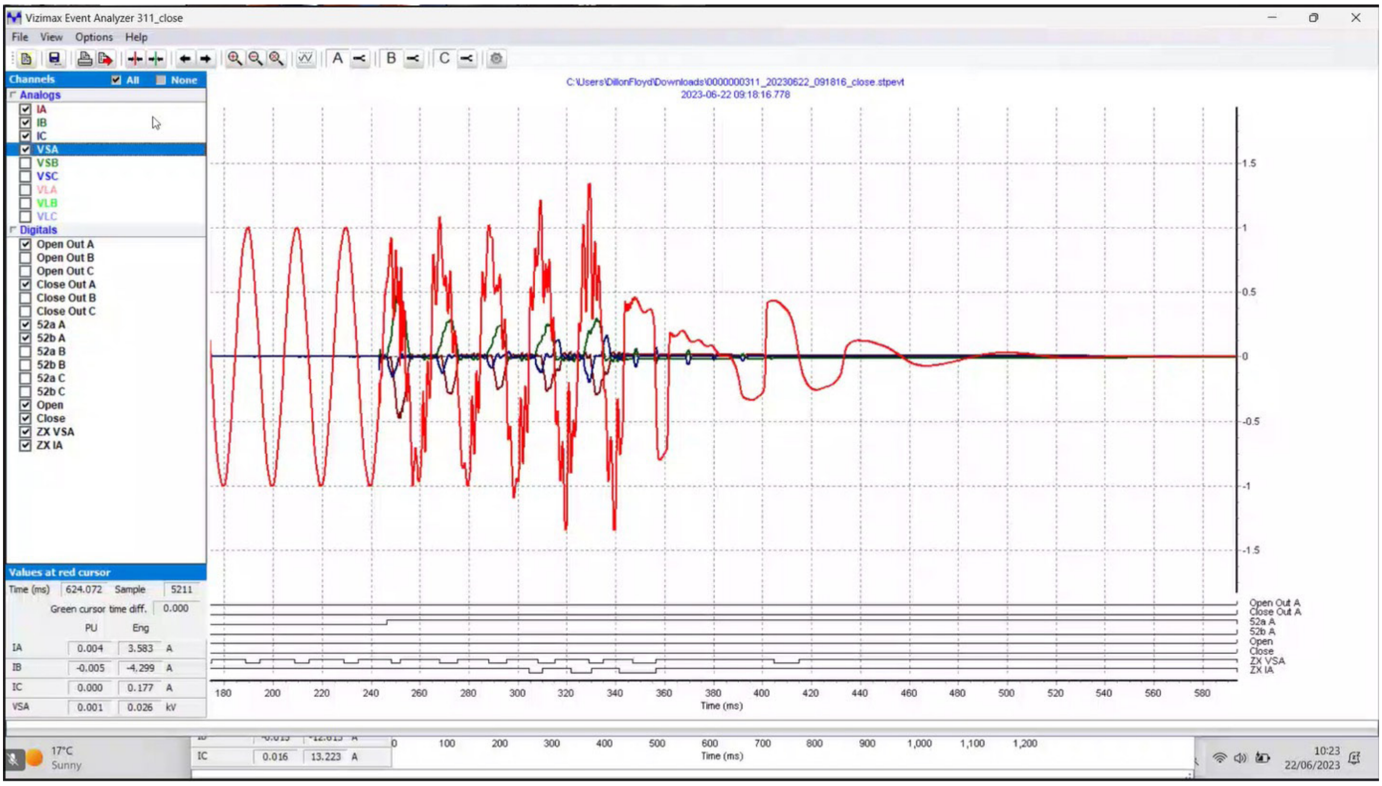


Figure 60: Voltage and current signals from PoW relay, failed Chapel and Redhouse energisation

The reason the fault ride through mode was sustained is thought to be because of the poor voltage waveform quality exhibited in Figure 60. A trip due to the energisation of both primaries was somewhat expected as the BESS had previously tripped while energising Redhouse alone with this configuration.

Following the unsuccessful “hard” energisation, three PoW energisations were attempted.

Figure 61: Chapel primary T1 and Redhouse primary T1 energised via BESS with PoW

Figure 62: Chapel primary T1 and Redhouse primary T1 energised via BESS with PoW

In the example shown in Figure 61 and Figure 62, the voltage dips to ~31.7 kV with an inrush current of close to 2 MVAr. All three PoW switching attempts successfully energised both primary transformers.

Middle Balbeggie Solar Farm energisation

Following the last successful energisation of the Chapel and Redhouse primaries, MBS was energised via CB10 at Redhouse primary. Figure 63 and Figure 64 show the energisation of the transformers within the MBS site.

Figure 63: Energisation of Middle Balbeggie Solar transformers via BESS

Figure 64: Energisation of Middle Balbeggie Solar transformers via BESS

The solar farm contains two 1950 kVA transformers. It was noted that the voltage dip and reactive power draw from the BESS were relatively large given that the transformers being energised have a much lower capacity than the Chapel or Redhouse primaries.

Once again, MBS was instructed to increase their output from 0 MW to 3 MW (or a close as possible).

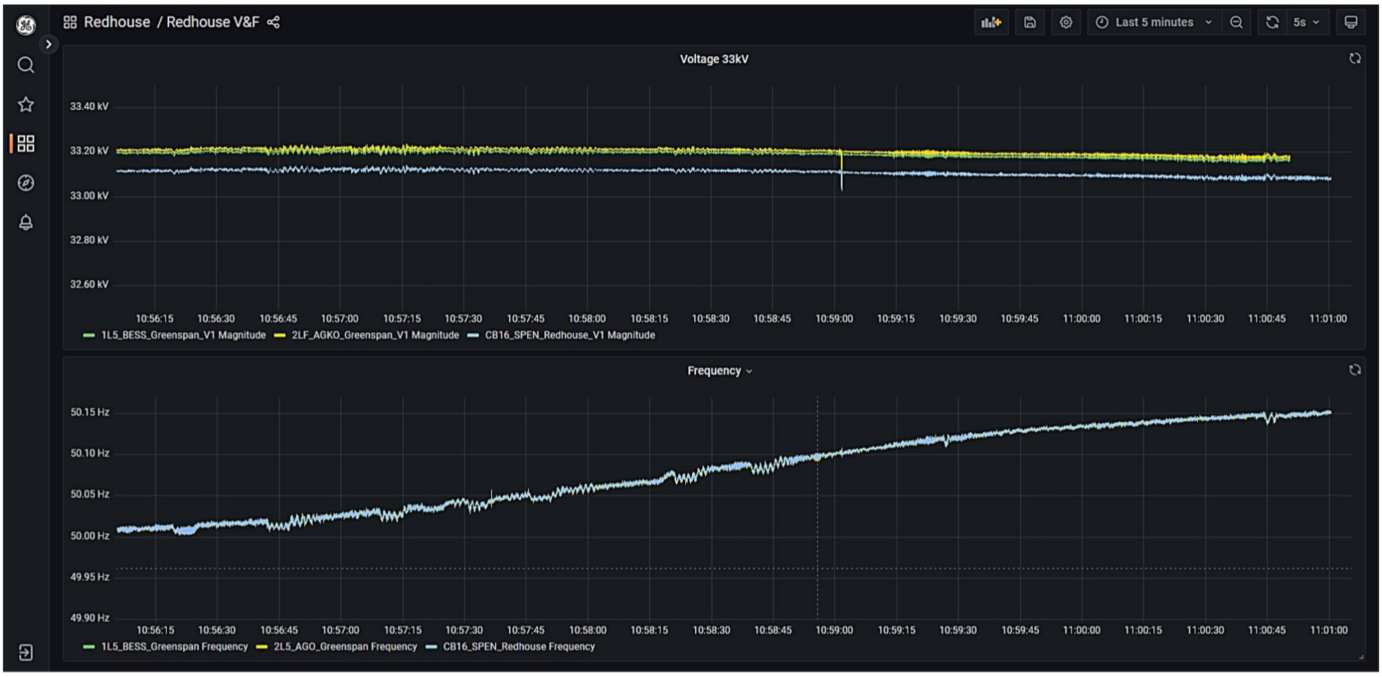


Figure 65: MBS output ramping up to ~3 MW

Figure 66: MBS output ramping up to ~3 MW

In comparison with Figure 37, Figure 65 shows the BESS reached a steady state frequency of ~50.15 Hz, rather than ~50.6 Hz. This is because the BESS was given a tighter frequency droop value of 1%, versus the 4% droop used in previous tests. Load steps were applied to the trial network using the load bank, Figure 67 and Figure 68 show the results of a 1 MW load step.

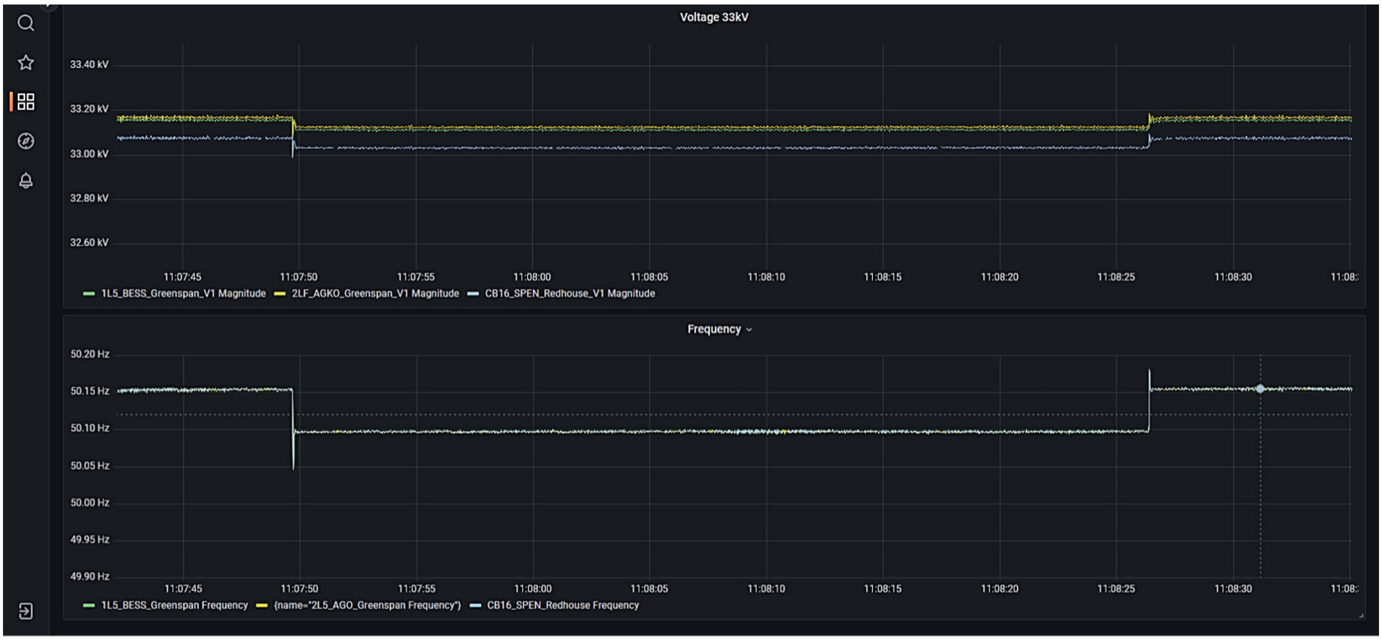


Figure 67: 1 MW load step applied to trial network with BESS and MBS connected

Figure 68: 1 MW load step applied to trial network with BESS and MBS connected

The frequency was observed to drop from 50.15 Hz to 50.1 Hz in accordance with the tighter frequency droop control setting.

Figure 69 and Figure 70 show the effects of a 4 MW load step on the trial network.

Figure 69: 4 MW load step applied to trial network with BESS and MBS connected

Figure 70: 4 MW load step applied to trial network with BESS and MBS connected

The frequency of the network drops to ~49.93 Hz. There is a moment of overshoot before the frequency arrives at this steady state value. The BESS starts to generate reactive power as a result of the voltage dropping.

3.2.5 Network Configuration – Transmission

The test network was configured such that the transmission asset being utilised for energisation within the trial were isolated from the main grid as seen and highlighted in Figure 71.

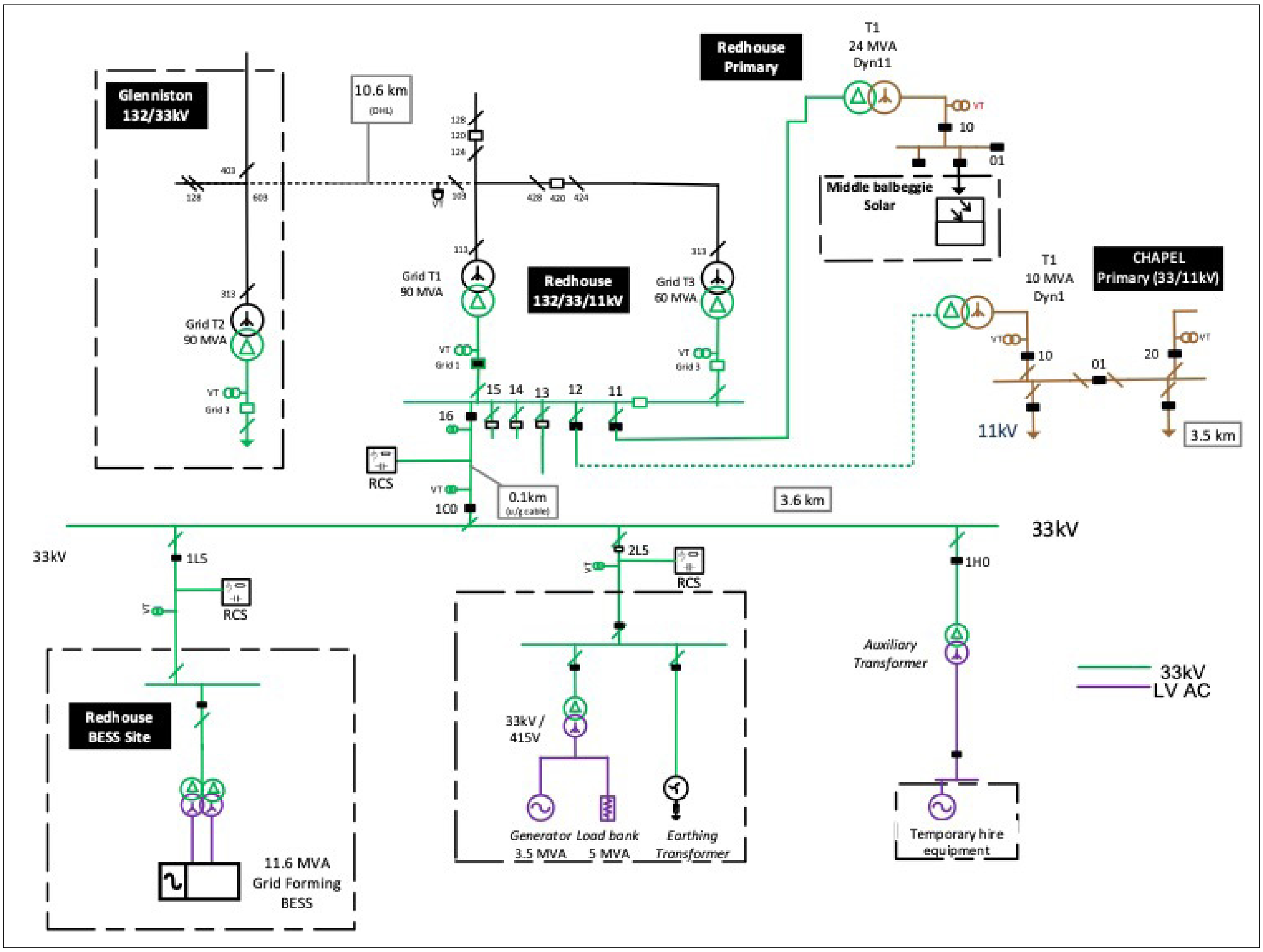


Figure 71: Phase 2 trial network diagram – Scottish Power transmission (SPT) network tests

3.2.6 T2.4: SPT Network Energisation via Diesel Generator

Initial transmission energisation tests were done in a similar manner to the distribution initial tests through use of purely the diesel genset with no contribution from the BESS. This section details the findings from the tests.

The 90 MVA grid T1 transformer at Redhouse GSP was the first transmission asset to be energised. It was the expectation that given the size of the asset, the inrush currents experienced would be greater and thus the transformer would be more difficult to energise from the voltage sources the trial had available (diesel genset and/or BESS).

Figure 72 and Figure 73 show the voltage, frequency, real and reactive power waveform during a successful 90 MVA grid T1 energisation when point on wave was not active.

Figure 72: Redhouse GT1 energised via the diesel generator without PoW

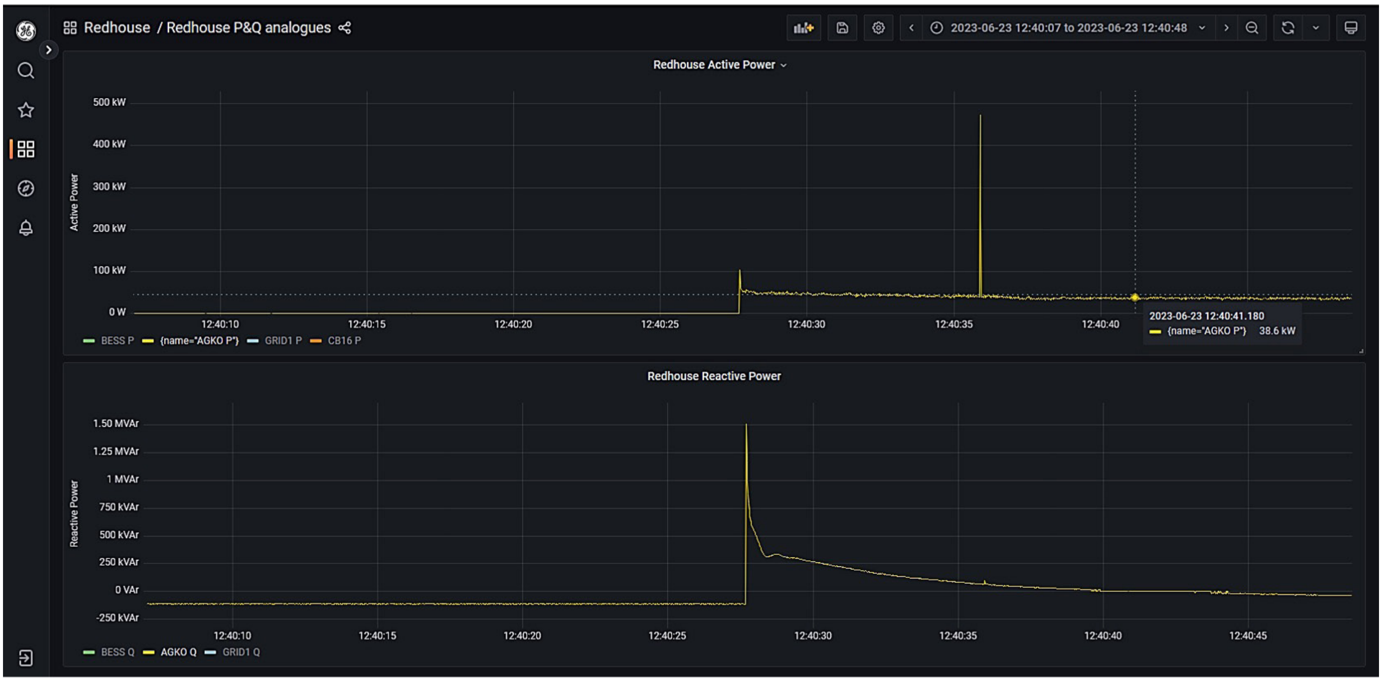


Figure 73: Redhouse GT1 energised via the diesel generator without PoW

Figure 74 and Figure 75 show the voltage, frequency, real and reactive power waveform during a successful 90 MVA grid T1 energisation when point on wave was active.

Figure 74: Redhouse GT1 energised via the diesel generator with PoW

Figure 75: Redhouse GT1 energised via the diesel generator with PoW

Coupled with the above, Figure 76 shows a 15 minute history showing 2 switches without PoW and then 3 with.

Figure 76: PoW and non-PoW energisation of Redhouse GT1

Whilst all the switches provided a successful energisation, it was again apparent that the PoW heavily mitigated the effects of the inrush current during the transformer energisation period. The figures recorded below ratify this as the:

- reactive power peaks without PoW were 1.5 to 2.5 MVAr
- reactive power peaks with PoW were 0.4 to 0.8 MVAr
- voltage troughs without PoW were 23 to 29 kV
- voltage troughs with PoW were 30.5 to 31.8 kV

Following the successful energisations of the 90 MVA grid in isolation, the 10.6 km 132 kV OHL between Redhouse GSP and Glenniston substation was switched into the test network which would form the combination of transmission assets to next be energised.

Figure 77 and Figure 78 show the voltage, frequency, real and reactive power waveform during 1 of the 3 successful 90 MVA Grid T1 and 132 kV OHL energisations when point on wave was not active.

Figure 77: Redhouse GT1 and 132 kV OHL energised via the diesel generator without PoW

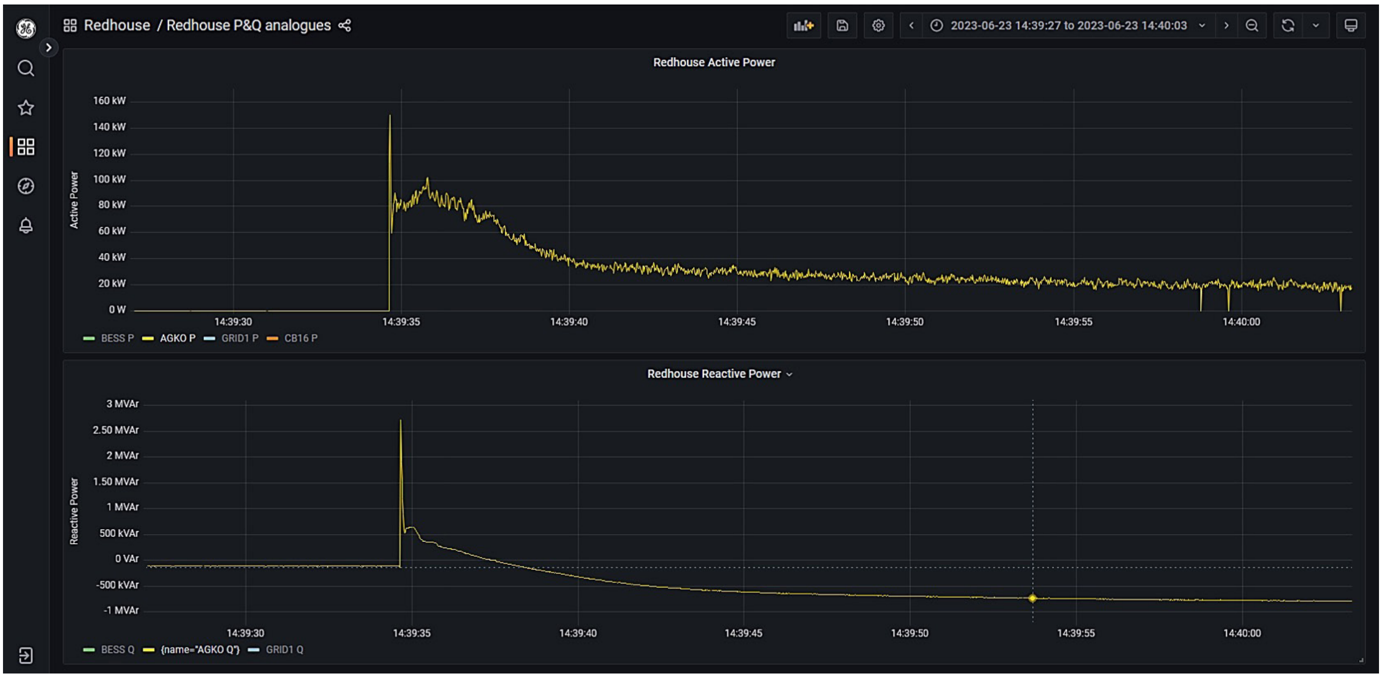


Figure 78: Redhouse GT1 and 132 kV OHL energised via the diesel generator without PoW

Figure 79 and Figure 80 show the voltage, frequency, real and reactive power waveform during 1 of the 3 successful 90MVA grid T1 and 132 kV OHL energisations when point on wave was active.

Figure 79: Redhouse GT1 and 132 kV OHL energised via the diesel generator with PoW

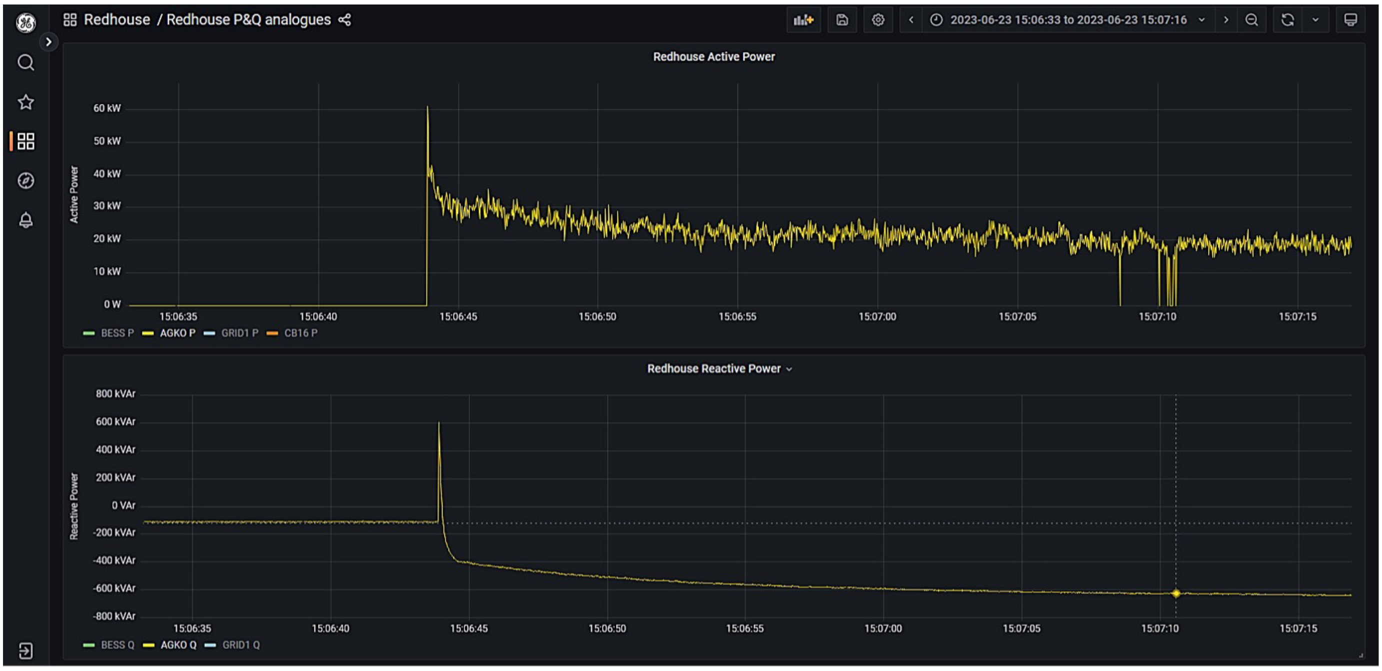


Figure 80: Redhouse GT1 and 132 kV OHL energised via the diesel generator with PoW

Once again, while all the switches provided a successful energisation, it was again apparent that the PoW heavily mitigated the effects of the inrush current during the asset energisation period. The figures recorded below ratify this as:

- without PoW the voltage troughs were: 24.6 kV, 26.2 kV, 25.5 kV
- with PoW the voltage troughs were: 31.2 kV, 32.5 kV, 32.0 kV.

3.2.7 T2.5: SPT Network Energisation via Grid-Forming BESS with Diesel Generator Support

Following the diesel genset in isolation energisations, the test network was again energised from the grid-forming BESS source. The diesel genset was then synchronized to the BESS voltage source and the transmission assets were energised. First the 90 MVA grid transformer in isolation.

Figure 81 and Figure 82 show the voltage, frequency, real and reactive power waveform during 1 of the 3 successful 90 MVA Grid T1 energisations when point on wave was not active.

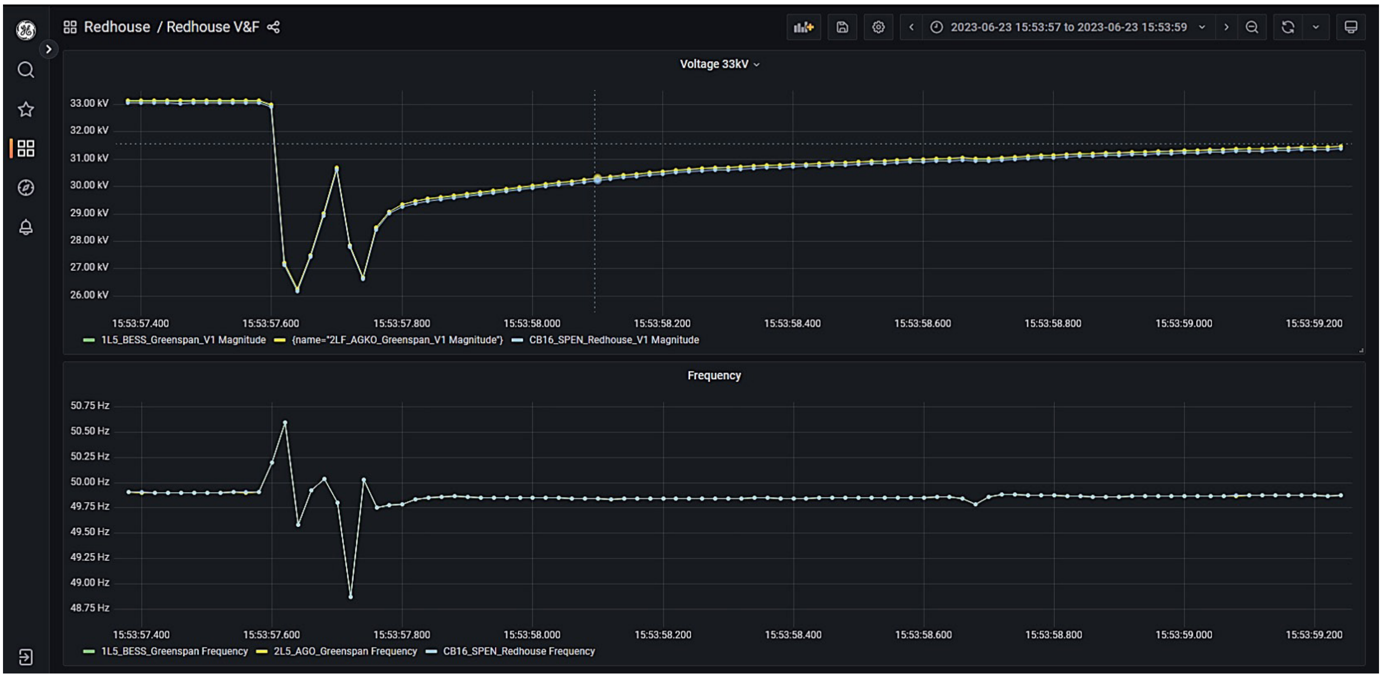


Figure 81: Redhouse GT1 energised via the BESS and diesel generator without PoW

Figure 82: Redhouse GT1 energised via the BESS and diesel generator without PoW

It is evident that during the period of transformer energisation that there is fluctuations in the real and reactive power outputs, particularly the former. With the power swinging between the BESS and the Aggreko equipment before settling to stable operation following the inrush period. There is no cause for concern with these power swings as they are well within the limits of the assets and furthermore produce a stable operation following the more volatile period of energisation.

Figure 83 shows the voltage and frequency waveform during 1 of the 3 successful 90 MVA grid T1 energisations when point on wave was active.

Figure 83: Redhouse GT1 energised via the BESS and diesel generator with PoW

Once again whilst all the switches provided a successful energisation, it was again apparent that the PoW heavily mitigated the effects of the inrush current during the SPT asset energisation period. The figures recorded below ratify this as:

- without PoW the voltage troughs were: 26.0 kV, 26.2 kV, 27.5 kV
- with PoW the voltage troughs were: 31.5 kV, 32.3 kV, 32.1 kV.

The test network was then reconfigured to include the 132 kV OHL again. The transformer and the OHL were then attempted to be energised from the BESS source without the PoW relay active, however a period of instability followed by a trip was recorded as seen in Figure 84 and Figure 85.

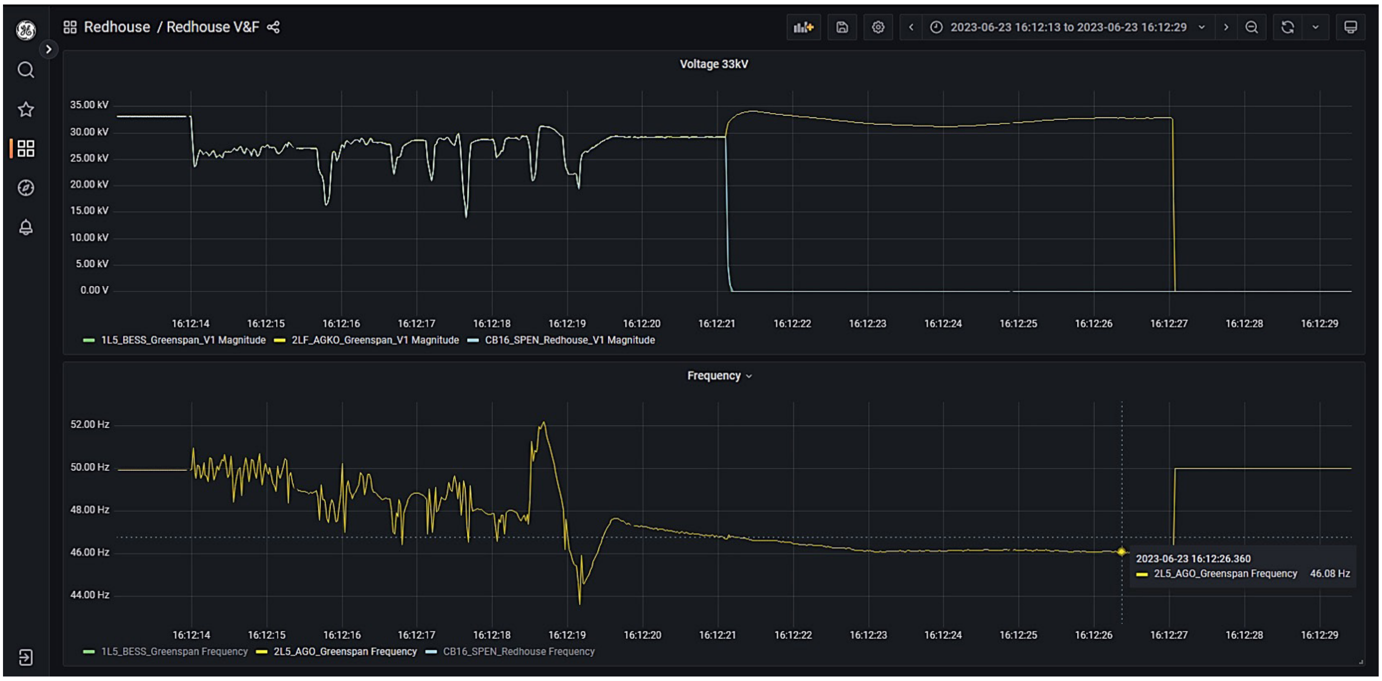


Figure 84: Redhouse GT1 and 132 kV OHL energisation attempt via the BESS and the diesel generator, instability led to trip

Figure 85: Redhouse GT1 and 132 kV OHL energisation attempt via the BESS and the diesel generator, instability led to trip

The test network protection tripped on underfrequency due to a sustained period of low frequency experienced by the island, caused through instability when attempting to energise the transformer and the OHL.

Instability Analysis

This section reviews in detail the instability event caused when energising the grid 1 transformer and the 132 kV line.

Stage 1: CB16 Switching event and voltage settling to 26 kV (14:00–14.50 s on graphs)

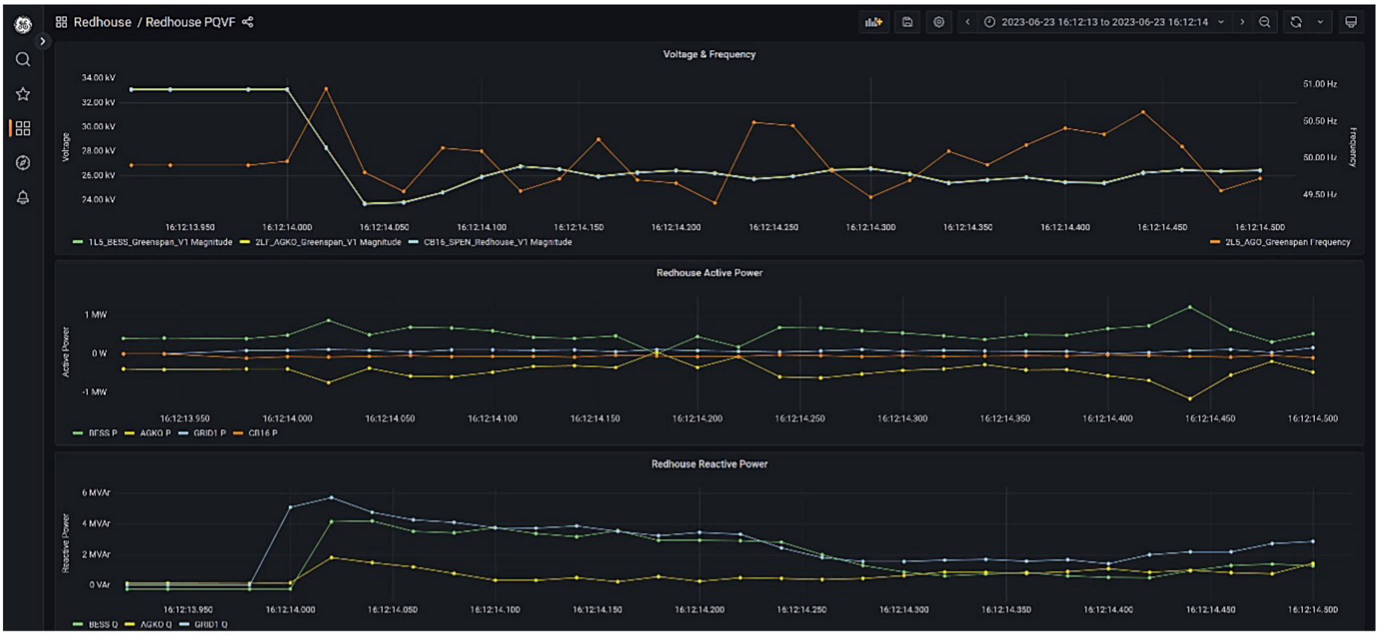


Figure 86: Signals from Stage 1 14.00–14.50 s

1. Pre-event, BESS supplies 402 kW to load bank diesel genset, diesel genset was supplying around 50 kW, voltage stable at 33 kV.
2. CB16 switch produces largest magnetising inrush and lowest voltage of all tests to this point, voltage reduces to 23.64 kV (0.72 pu).
3. Large reactive power supplied from both BESS (4.15 MVAr) and diesel genset (1.81 MVAr) to support island voltage.
4. Voltage settles at very low level (25–26 kV). Reduction of grid 1 reactive power from 5.71 MVAr (14.02 s) to 1.55 MVAr (14.28 s) does not reduce voltage further.
5. The event in Figure 86 may be compared with a previous grid 1 and 132 kV switching test, without PoW active, that showed a deep voltage depression with recovery. The event for comparison is marginally stable (Figure 87), and not an ideal response, but is useful for comparison between collapse and recovery. By 0.5 s after the event, it is clear that the marginally stable case is recovering with voltage at >0.9 pu and rising, while the unstable event continues to show sustained low voltage and no indication of recovery.

Table 5: Comparison of stable vs unstable cases

	Previous Marginally Stable Case		Unstable (this) Case	
	@ 60 ms	@ 0.5 s	@ 60 ms	@ 0.5 s
Voltage	26.18 kV	30.16 kV rising	23.64 kV	26.46 kV not rising
VAr	5.31 MVAr	3.17 MVAr	5.71 MVAr	2.87 MVAr

The low voltage and unusual relationship between VAr and volts may be indicative of the system being in voltage instability, i.e. in the unstable regions of the QV and/or PV curves (Figure 88). In a voltage instability, the system is unlikely to recover without shedding real and/or reactive load (in this case reactive).

The extreme waveform distortion and harmonics at this stage continue through the further seconds of energisation which is probably responsible for the noise and vibration that was reported on site during this period.

Frequency is variable between 48.4 Hz and 50.6 Hz. The frequency deviations are very fast and related more to changes in electrical AC wave shape rather than changes in mechanical speed of the generator. Loss of synchronism (out-of-step) between the BESS and DGEN is a possibility in this case, however, not conclusive.

Figure 87: Comparison with grid 1 and 132 kV line energisation deep voltage depression 23-06-2023 1553 without PoW – successful but close to limit

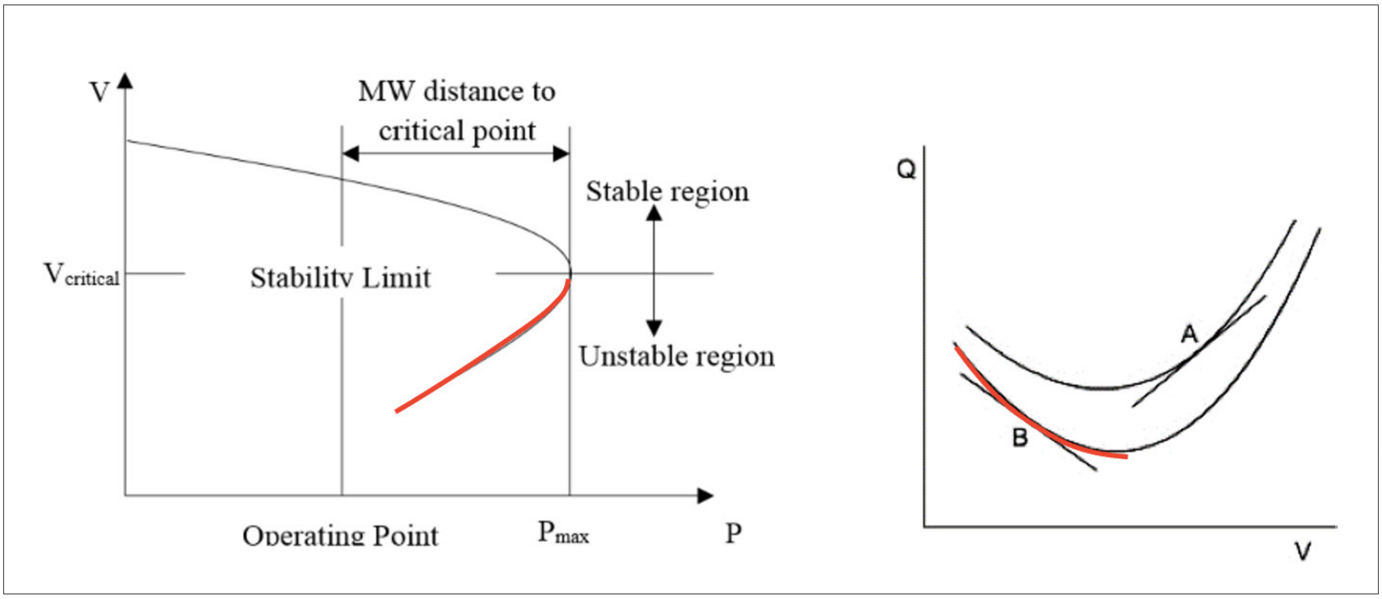


Figure 88: PV and QV stability curves

Stage 2: Variability of V and f until apparent stabilisation at low voltage (14.50 s to 15.64 s)

Voltage and frequency continue to be highly variable for a time but settle to at a depressed voltage (27.08 kV) and low frequency (48.95 Hz). At the time when it stabilises, the reactive load drawn by the transformer and 132 kV system is 736 kVAr. At this time, the BESS is not performing according to voltage droop, and is absorbing VAr when in a normal state it would be supplying VAr.

It is possible that there is some protective functions in the inverters causing the opposite response of VAr compared with normal voltage droop, or a limitation on current supply. Despite the apparent stabilisation at 15.4 s, the BESS is operating outside its expected performance envelope.

The diesel genset is supplying VAr which avoids voltage collapse at this stage.

Note that the load bank is a voltage-dependent resistive load. The original load of around 0.5 MW will be significantly depressed by a factor of (V/Vnom)2, i.e. 0.67*0.5 MW = 0.33 MW by the end of the Stage 2 period.

Figure 89: Stage 2 Highly variable V and f until stabilisation at low voltage

Stage 3: Periodic voltage dips and partial recovery (15.7 s to 19.0 s)

The BESS periodically draws additional reactive power at roughly 0.5 s intervals at 15.7 s, 16.7 s, 17.1 s, 17.6 s, 18.0 s, 18.5 s, 19.0 s. While these periods of reactive power draw occur, the voltage drops further, with low voltages reaching 14 kV.

There are two occurrences of increase in active power from the BESS (16.0 s, 18.5 s), and during these events the frequency recovers briefly, but this is not sustained. At the end of the period, there is a particularly severe frequency drop to 44 Hz.

The active power from the Aggreko load bank and genset should match the BESS power given that there is no power export. However, as the BESS draws power, the power drawn from the genset may be decelerating the machine (i.e. dropping frequency) rather than being matched by mechanical power from the diesel machine.

This period of cyclic operation coincides with the waveform oscillography showing 0.5 s cycling between periods of highly distorted waveforms and cleaner periods of waveforms.

Figure 90: Cyclic deep voltage depressions 15.7–19.0 s

Stage 4: Frequency decline and underfrequency trip (18.9 s to 21.1 s)

During this period, the signals stabilise and the cyclic behaviour stops, however there is an energy deficit and the frequency declines. The BESS is drawing active power rather than supplying active power as would be expected if normal frequency droop was active.

The frequency drops below 47.0 Hz at 20.54 s and 1L5 and 2L5 trip at 21.10 s.

After the trip, the Aggreko voltage (2L5) recovers to 33 kV, but the frequency stays low. The voltage recovery will increase the load bank power back to 0.5 MW, which appears to prevent the diesel genset from recovering to nominal speed.

It is not clear why the balance of power is negative and the frequency shows a steady decline. It is not certain that the low frequency condition would be present in other similar cases. Underfrequency disconnection is not a reliable protection for this situation, both because the frequency may not be as low in other cases, and because underfrequency load shed may not separate at the best point to restore the island.

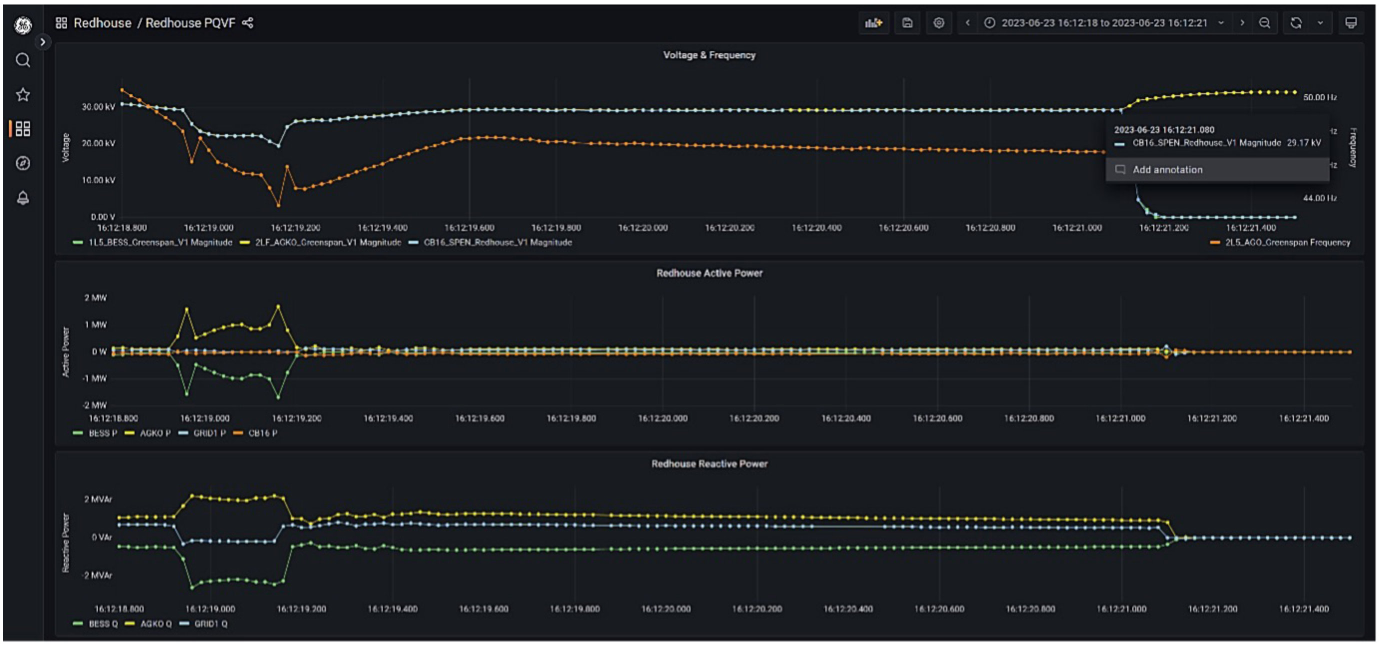


Figure 91: Stabilisation and decline of frequency up to underfrequency tripping

Stage 5: Trip, standby and BESS recovery

After the underfrequency trip, the Aggreko equipment recovers voltage for 6 s, but frequency does not recover and the diesel genset trips.

At 16:13:11 (52 s from the underfrequency trip) the BESS comes out of standby mode and re-energises 2L5. At this stage, there is little to be gained from restoring voltage and it would be preferable for the integrity of the equipment and operationally to be sure of the state of the network that the BESS does not restore voltage.

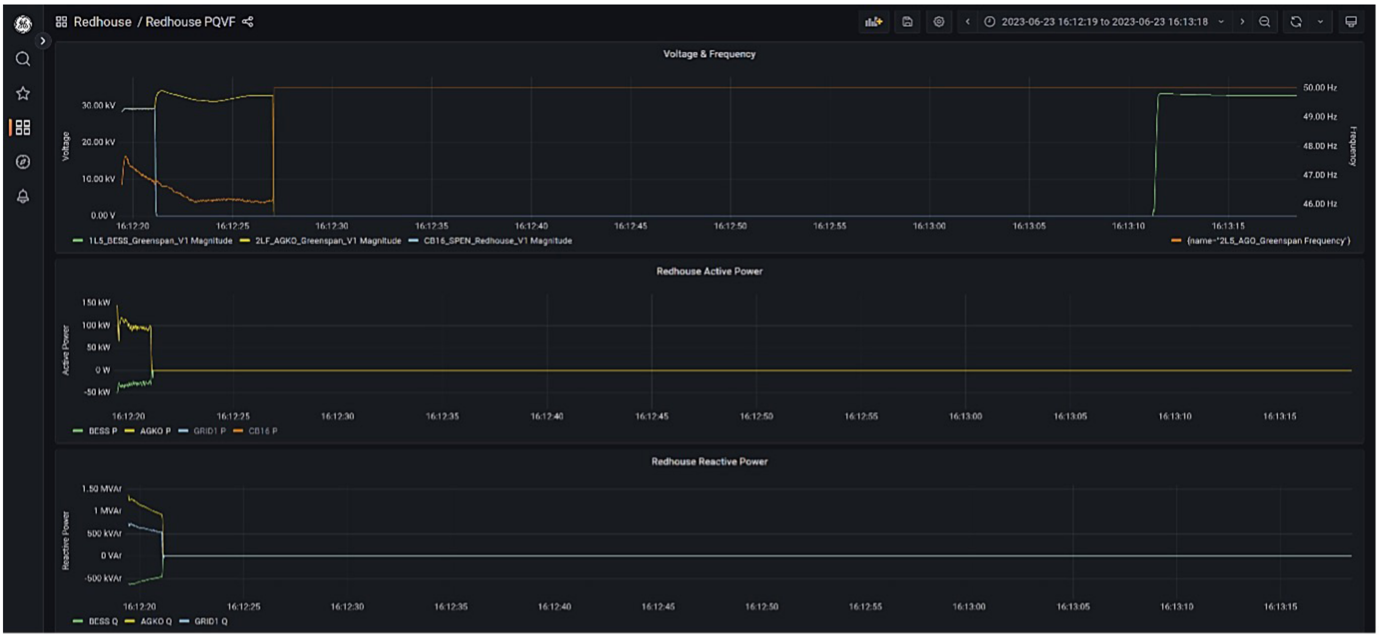


Figure 92: Diesel generator trip up to BESS automatic re-energisation (16:12:21–16:13:12)

Following this the energisation was re-attempted with the PoW relay active. Figure 93 and Figure 94 demonstrate the energisation was successful this time around.

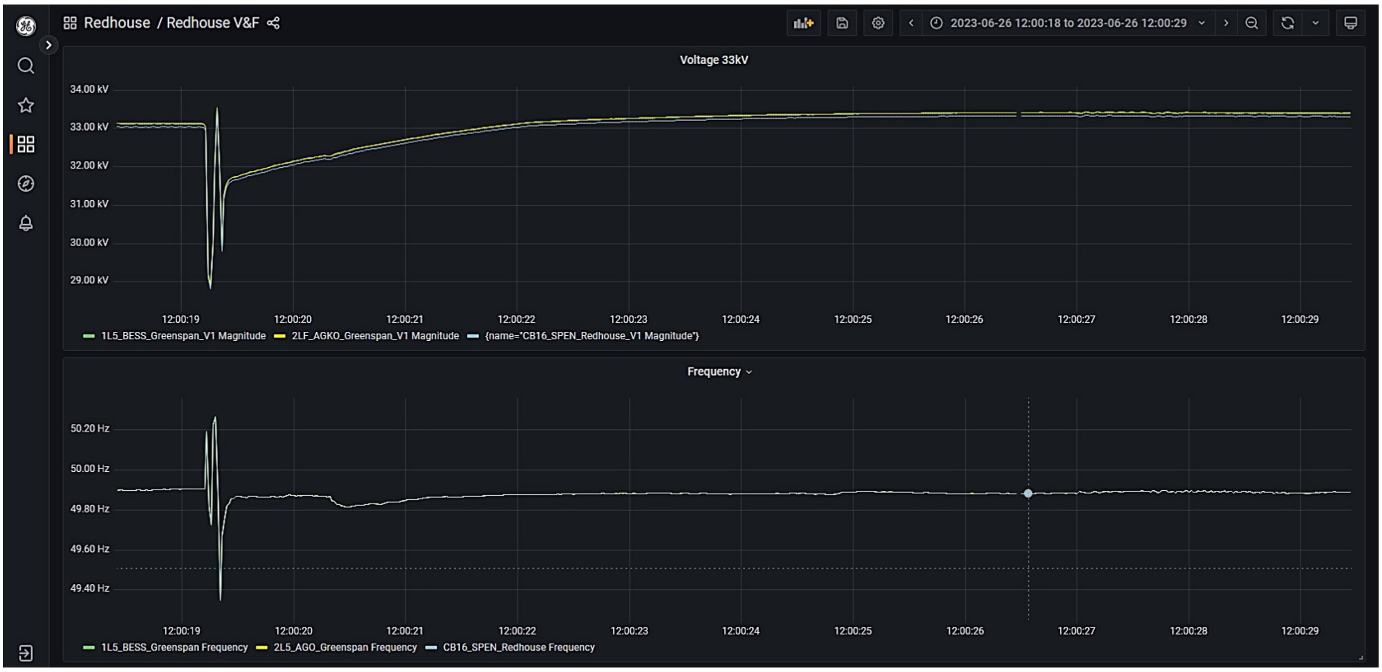


Figure 93: Redhouse GT1 and 132 kV OHL energised via the BESS and the diesel generator with PoW

Figure 94: Redhouse GT1 and 132 kV OHL energised via the BESS and the diesel generator with PoW

3.2.8 T2.6: SPT Network Energisation via Grid-Forming BESS Only

Having completed the tests involving the diesel genset, the final set of tests as part of Phase 2 was the completion of the transmission elements from solely the grid-forming BESS. Following the instability event experienced in the previous set of tests it was decided by the project team to first attempt the energisations with the PoW active to avoid, as far as is reasonably practical, unstable operation.

Figure 95 and Figure 96 show the voltage, frequency, real and reactive power waveforms during 1 of the 3 successful 90 MVA grid T1 energisations when point on wave was active.

Figure 95: Redhouse GT1 energised via the BESS with PoW

Figure 96: Redhouse GT1 energised via the BESS with PoW

Figure 97 and Figure 98 show the voltage, frequency, real and reactive power waveforms during all 3 of the successful 90 MVA grid T1 and the 132 kV OHL energisations when point on wave was active.

Figure 97: Redhouse GT1 and 132 kV OHL energised via the BESS with PoW

Figure 98: Redhouse GT1 and 132 kV OHL energised via the BESS with PoW

The results show the three successful energisations and also the characteristics of the line capacitance causing the voltage to rise following the inrush/energisation period. The lowest voltage deviation with the PoW active when energising the transformer and the OHL was observed to be 32.17 kV, well within operational, statutory or protection tripping threshold limits.

Having successfully produced stable energisations with the PoW it was concluded that there would be value in conducting some “hard” switches with the PoW disabled.

Figure 99 and Figure 100 show the voltage, frequency, real and reactive power waveforms during one of the 90 MVA grid T1 and 132 kV OHL energisations when point on wave was not active, which produced a successful switch.

Figure 99: Redhouse GT1 and 132 kV OHL energised via the BESS without PoW

Figure 100: Redhouse GT1 and 132 kV OHL energised via the BESS without PoW

This was then re-attempted a second time, however there was protection trip on the test network. The details of which are below and can be observed in Figure 101 and Figure 102.

Figure 101: Redhouse GT1 and 132 kV OHL energisation attempt via the BESS without PoW – protection tripped

Figure 102: Redhouse GT1 and 132 kV OHL energisation attempt via the BESS without PoW – protection tripped

Details from the trip event:

1. voltage dips to 22.5 kV but does not recover above 29 kV
2. undervoltage protection correctly trips 2L5 at 1.25 s; 1L5 at 1 s
3. BESS produces 3.7 MVAr to 3.9 MVAr
4. BESS voltage recovers once 1L5 trip occurs
5. BESS fault ride through (FRT) activated in all four banks.

Following reconfiguration of the test network to an intact state, this was then re-attempted a third time, however once again there was protection trip on the test network. The details of which are below and can be observed in Figure 103 and Figure 104.

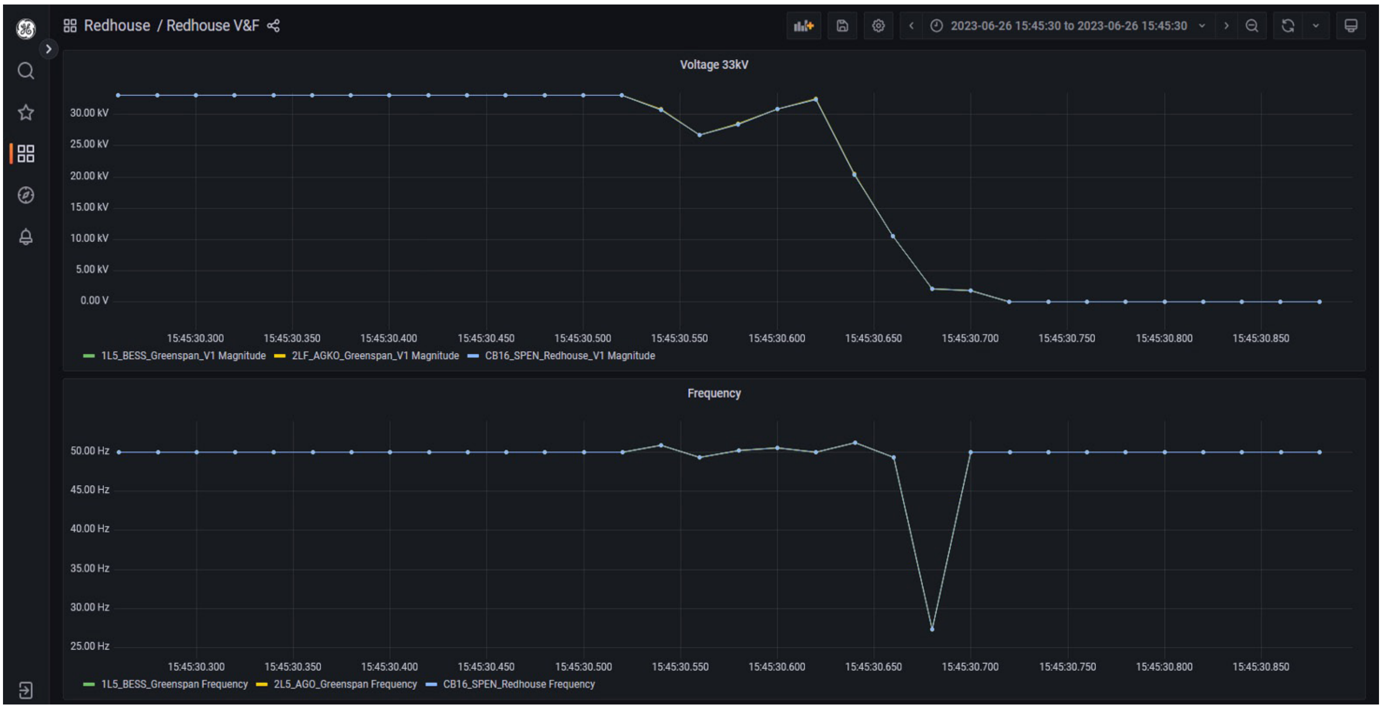


Figure 103: Redhouse GT1 and 132 kV OHL energisation attempt via the BESS without PoW – protection tripped

Figure 104: Redhouse GT1 and 132 kV OHL energisation attempt via the BESS without PoW – protection tripped

Details from the trip event:

1. voltage dips to 25 kV but momentarily recovers before collapsing due to inrush/voltage distortion
2. BESS inverters trip
3. BESS produces up to 3.1 MVAr during the event.

Figure 105 shows details of the 3-ph voltage waveform distortion.

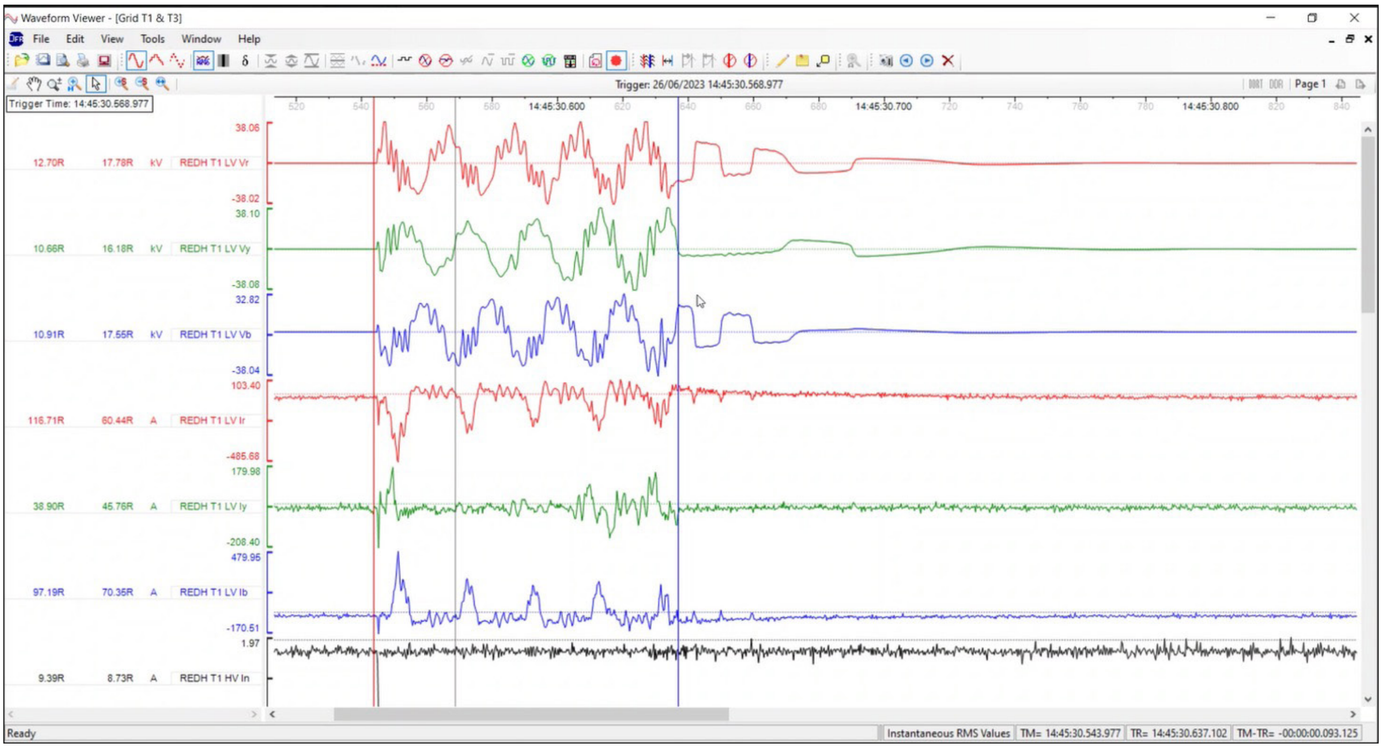


Figure 105: Transmission fault recorder capture during protection trip

It is clear from the results that whilst some “hard” switches can be successful, all PoW switches proved to be successful through the mitigation of transformer inrush current. It is therefore suggested that, to ensure repeatability and a high level of reliability, network operators using DERs to contribute to distribution restoration zones (DRZs), as demonstrated in these trials, have PoW functionality included – ensuring the asset acts as expected when called upon to energise the desired network elements.

3.3 Phase 3

Phase 3 focused on the testing of the prototype Distribution Restoration Zone Controller (DRZC) on real network environment. The first day of the Phase 3 testing involved testing the fast and slow balancing functionalities of the DRZC, ensuring the control functionality remained as expected when energising primary transformers and MBS. The second day of Phase 3 involved testing the resynchronisation ability of the controller and virtual power plant testing. The DRZC had connections to both the BESS and load bank and was able to control both of these assets. The DRZC also has connections to measurement devices at 1L5, 2L5, CB16 and Redhouse grid T1. The test network for Phase 3 was the same in Phase 2 as seen in Figure 106.

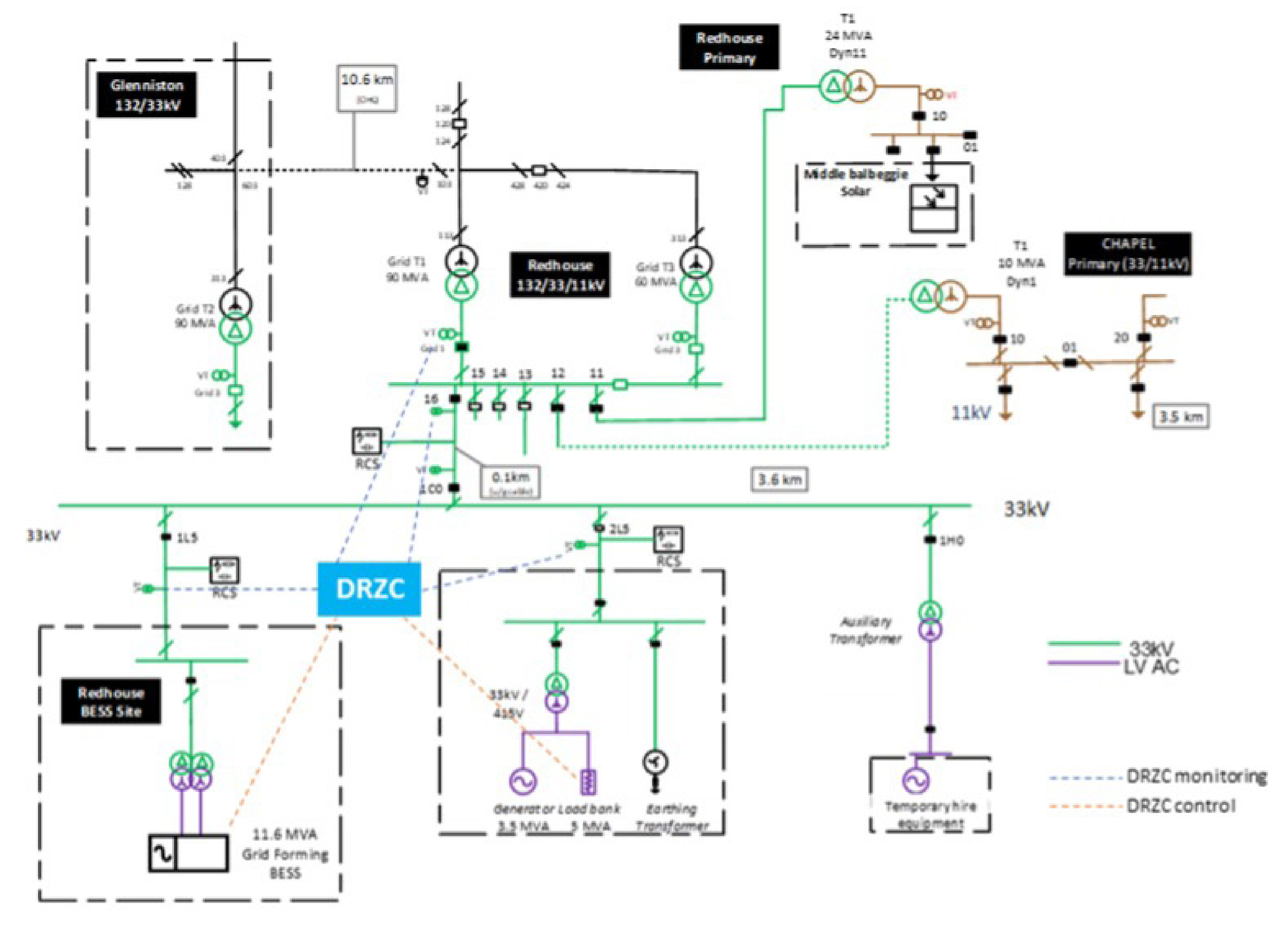


Figure 106: Phase 3 trial network diagram

The primary deliverables of Phase 3 were as follows:

- test the fast and slow balancing functionalities of the DRZC controller, with the BESS, diesel generator and solar farm contributing to the power island
- successfully resynchronise the power island with the intact system
- successfully operate the combination of resources on the test network as a virtual power plant via the DRZC.

3.3.1 Network Configuration

For Phase 3, the test network was configured as follows:

- ensure BESS has 50% state of charge prior to disconnection,
- shutdown BESS and configure in grid-forming mode for tests with 4% frequency droop, 5% voltage droop
- connect auxiliary transformer to the Greenspan 33 kV busbar
- disconnect BESS site from Redhouse GSP by opening CB16 and 1C0
- change protection settings on circuit breakers at Greenspan's site
- configure site layout, including earthing transformer connection
- configure diesel generator for tests: 4% frequency droop, 5% voltage droop.

The configuration of the distribution network also took place at the start of the final two days of testing. This involved implementing:

- a Redhouse GSP half busbar outage
- a Chapel primary half busbar outage
- a Redhouse primary full busbar outage.

Due to an issue with one of the load bank circuit breakers, only 2 MW of load was available from the load bank for the Phase 3 tests, however this did not affect any of the desired outcomes/tests.

3.3.2 DRZC Configuration

One of the primary functions of the DRZC is its ability to control the power output/input of controllable resources on the network to facilitate fast and slow balancing. The definitions of fast and slow balancing are as follows:

- 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 resource (e.g. the load bank/BESS).
- slow balancing: monitors the loading of all DER and initiates rebalancing such that the BESS and load bank return within the desired margins, which ensures there is always resource to perform fast balancing.

Table 6 and Figure 107 show the levels and margins programmed into the DRZC which are required for the slow balancing function.

Table 6: DRZC margins for the BESS and load bank

		BESS PR_1	REDH LB PBC_1
Unit Capacity		8.0 MW	
Operating Limit +	N	8.0 MW	0 MW
Trim Level +	D	2.75 MW	-0.4 MW
Trim Margin +	C	1.5 MW	-0.8 MW
Trim Margin -	B	-1.5 MW	-1.5 MW
Trim Level -	A	-3.0 MW	-1.8 MW
Operating Limit -	M	-8.0 MW	-2.0 MW

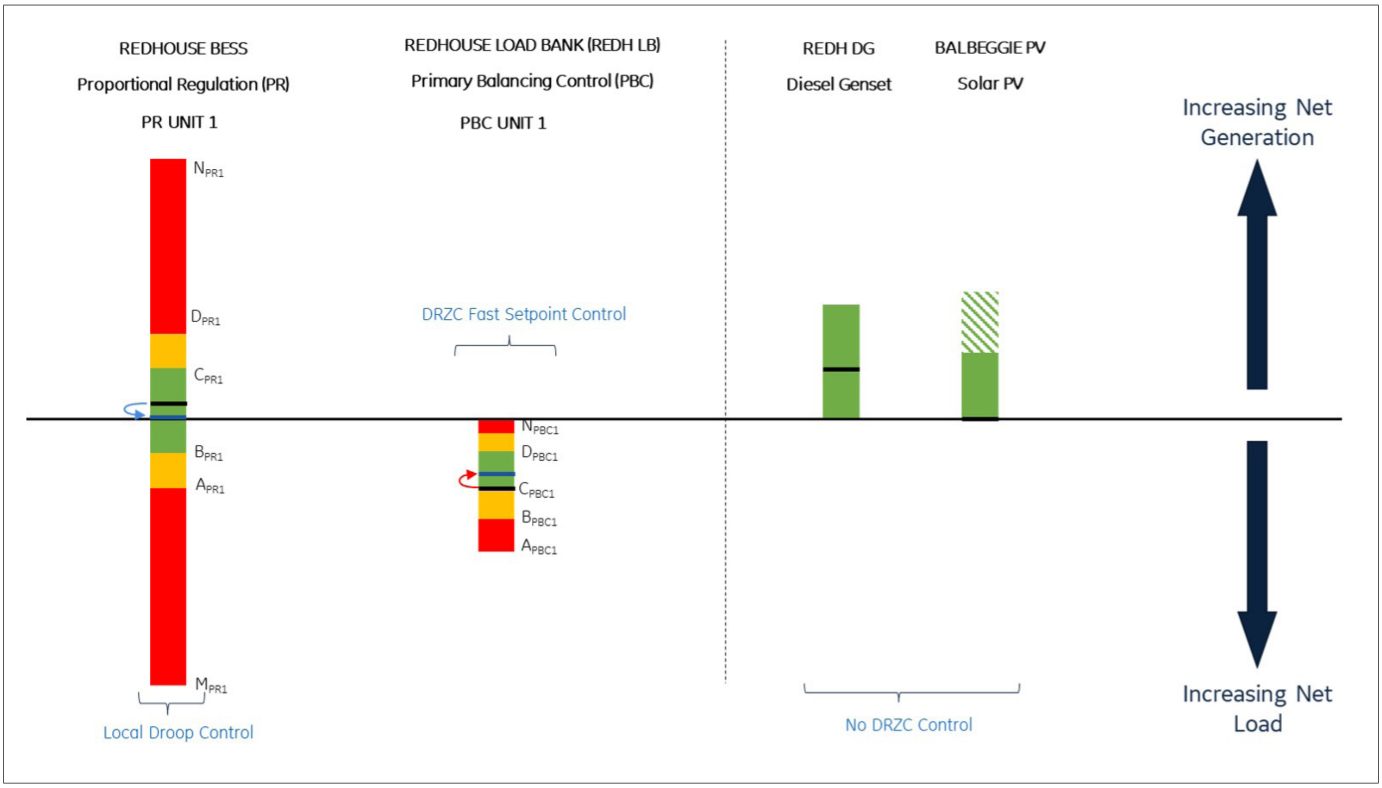


Figure 107: Visual representation of DRZC margin values

3.3.3 T3.1: Distribution Restoration Zone Controller (DRZC) Tests

Once the test network had been configured, the BESS was energised via the DRZC using a "black start" command, which started all 4 of the BESS inverters in isochronous mode with a manual reactive power setpoint of 500 kVAr. The BESS was switched to voltage and frequency droop control before synchronising to the diesel generator, which was configured in base load mode with a set output of 50 kW.

Confirmation of BESS and Load bank Control

To prove the DRZC was able to control the load bank, a 0.5 MW load step was tested, with the command given via the DRZC (balancing actions were disabled).

Figure 108: Testing DRZC control of load bank

Figure 108 shows the active power trace when the load step was successfully implemented via the DRZC. An inductive 0.5 MVAr load step was also successfully tested via the DRZC. A capacitive load step could not be tested as the load bank cannot provide capacitive load and so did not respond to a positive MVAr setpoint.

Control of the BESS active power setpoints of the frequency droop characteristic were also tested. A setpoint of 1 MW was applied, followed by a setpoint of -1 MW. This is shown in Figure 109.

Figure 109: Testing DRZC control of BESS real power setpoints

For the active power setpoint tests, the frequency was observed to move by +/-0.23 Hz, in accordance with the BESS 4% frequency droop control. The actual active power output measured in Figure 109 stays at zero MWs apart from some small deviations as the power setpoint of the frequency droop characteristic was altered.

Control of reactive power setpoints of the BESS was also tested. The first attempt of this was unsuccessful as the manual setpoint of 500 kVAr was still being applied to the BESS. This was removed and various reactive setpoints were implemented via the DRZC.

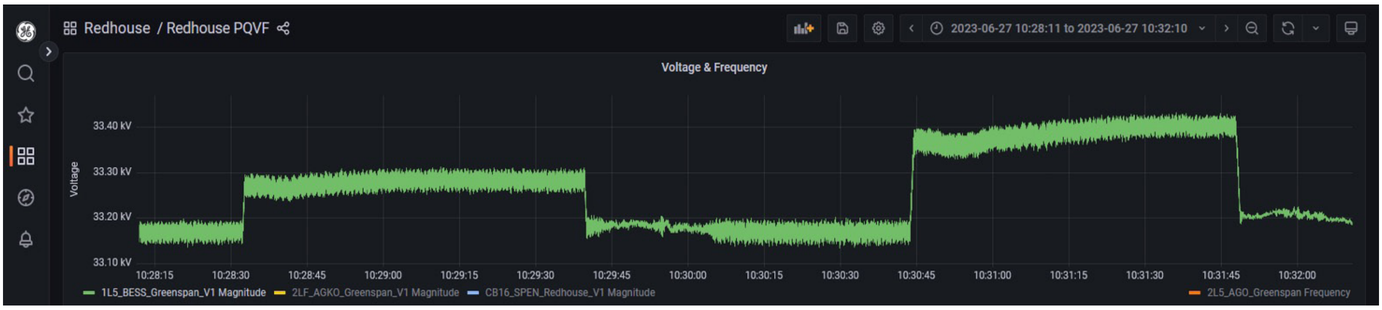


Figure 110: Testing DRZC control of BESS reactive power setpoints

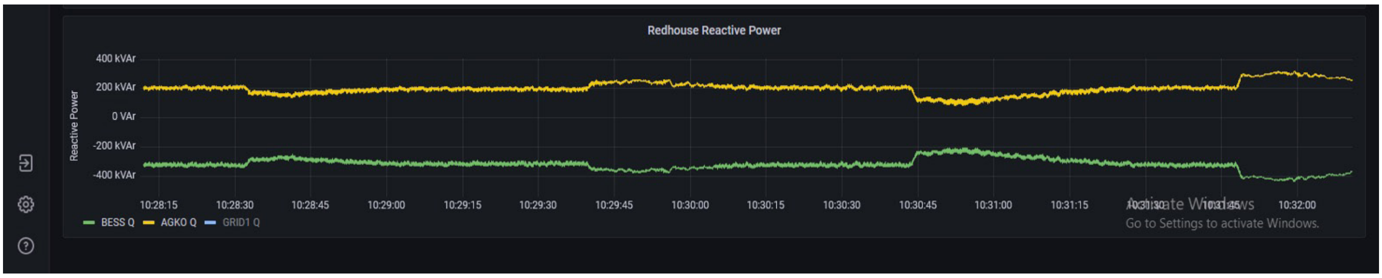


Figure 111: Testing DRZC control of BESS reactive power setpoints

It was found that reducing the reactive power setpoint by 0.5 MVAr on the voltage droop characteristic resulted in a voltage change of -0.1 kV. This is smaller than expected, given that a 5% droop over a 2.65 MVAr range would result in a change of -0.31 kV by calculation. The setpoint was then increased by 1 MVAr and this gave a change in voltage of +0.2 kV, which is consistent with the previous setpoint change. The reactive power output of the BESS rises and falls during these tests due to the setpoint changes and the small variations in voltage between setpoint changes.

The DRZC also has the ability to control the voltage and frequency setpoints of generation assets. Attempts were made to test this control on the BESS, but they were unsuccessful. It was concluded that when the BESS is in droop control mode, it does not respond to voltage and frequency setpoints, only active and reactive power setpoints.

Fast and slow balancing configuration

Following the setpoint tests, the fast-balancing functionality was configured and tested by deliberately tripping the diesel generator with an initial 1 MW output and 0.6 MW of load connected to the load bank.

Figure 112: Initial fast balancing test via diesel generator 1 MW trip

Once the diesel generator trips there is a 1 MW change in the yellow signal (which shows the aggregated active power of the load bank plus diesel generator). A fast balancing action is triggered by this trip which results in the DRZC altering the load bank setpoint from 0.6 MW to 0 MW. The total time for the load bank to respond to the trip was 0.86 s. Frequency changes accordingly during the trip and returns to ~50 Hz when the fast balancing action has been completed.

Fast and slow balancing tests

The initial conditions prior to the fast and slow balancing tests were as follows:

- load bank: -0.65 MW
- diesel generator: 0.5 MW
- BESS: 0.15 MW.

Table 7 shows a summary of the diesel generator setpoint tests completed.

Table 7: Summary of diesel generator setpoint tests

Diesel Generator Step	DRZC Response	Response Details
0.5 MW → 1 MW	None	N/A
1 MW → 0 MW	Fast balancing	LB: -0.65 MW → -0.5 MW
0 MW → 1 MW	None	N/A
1 MW → 2 MW	Fast balancing	LB: -0.5 MW → -1.12 MW
2 MW → 0.5 MW	Fast balancing	LB: -1.12 MW → -0.5 MW
0.5 MW → 2 MW	Fast balancing	LB: -0.5 MW → -0.65 MW
2 MW → 3 MW	None	N/A
3 MW → 0.5 MW	Fast and slow balancing	LB: -0.65 MW → -0.18 MW (fast) LB: -0.18 MW → -0.4 MW (slow)
0.5 MW → 1.5 MW	None	LB: -0.4 MW → -0.9 MW

Figure 113 and Figure 114 show the results of two of the diesel generator power step changes from Table 7.

Figure 113: Diesel generator step from 1 MW to 2 MW

Figure 114: Diesel generator step from 3 MW to 1.5 MW

Figure 113 shows that there were several fast-balancing triggers before a value of -1.12 MW was set. In Figure 114, the major fast balancing action is shown around the 13:24:00 time, with the slow balancing action occurring around 13:26:50.

A further test of fast and slow balancing was completed with different initial setpoints:

- load bank: -1.5 MW
- diesel generator: 3 MW
- BESS: -1.5 MW.

The diesel generator was tripped in two stages of 1.5 MW, the results of this is shown in Figure 115 below.

Figure 115: Diesel generator trip in two stages of 1.5 MW

On the completion of the fast balancing actions, slow balancing occurs to restore the margin on the load bank.

Figure 116: Slow balancing action to restore load bank margin

After the BESS power setpoint was manually restored to zero, slow balancing restored the margin on the load bank to beyond the -0.4 MW trim level. It is not clear what caused the frequency disturbance at 14:51:03.

Inclusion of Middle Balbeggie Solar

The test network was re-configured such that MBS was energised via Redhouse primary T1. A constraint of 1.5 MW was applied to MBS. For this series of tests, the initial conditions applied to the assets on the network were as follows:

- load bank: -0.5 MW
- diesel generator: 0.05 MW
- BESS: -0.2 MW
- MBS: 0.65 MW.

As the output of MBS is weather dependent, the power produced by the solar farm varied throughout the tests between ~0.3 MW and ~0.7 MW.

Table 8: Summary of diesel generator setpoint tests with MBS included

Diesel Generator Step	DRZC Response	Response Details
0 MW → 0.75 MW	Fast balancing	LB: -0.5 MW → -0.9 MW
0.75 MW → 0 MW	None	N/A
0 MW → 1 MW	Fast balancing	LB: -0.75 MW → -0.95 MW
1 MW → 2 MW	Fast and slow balancing	LB: -0.95 MW → -2 MW (fast) LB: -2 MW → -1.6 MW (slow)
2 MW → 0.5 MW	Fast balancing	LB: -1.6 MW → -1.2 MW
0.5 MW → 2 MW	Fast balancing	LB: -1.2 MW → -1.3 MW
2 MW → 0.05 MW	Fast balancing	LB: -1.3 MW → -0.5 MW

Figure 117: Diesel generator step from 1 MW to 2 MW

In this case, fast balancing activates multiple time before settling at 2 MW around 15:12:15. Slow balancing then restores the load bank demand to 1.5 MW. Figure 118 shows the diesel generator step change from 2 MW to 0.05 MW.

Figure 118: Diesel generator step from 2 MW to 0.05 MW

Fast balancing activates twice here, the first time due to ROCOF and the second time due to a sustained lower frequency (< 49.7 Hz).

State of charge management

The DRZC includes a state of charge (SOC) management function which was tested as part of the trials. High and low SOC limits were set as 60.5% and 55% respectively. Figure 119 shows an example of when the SOC management function is active.

Figure 119: DRZC state of charge management

At this time in the trial, the solar farm was producing ~1 MW. After charging at ~0.5 MW, the BESS reaches the high SOC limit. At this point, a slow balancing action takes place to increase the load bank power setpoint and therefore reduces the power consumption of the BESS. As the BESS power crosses 0 MW and the power output begins to increase, the frequency continues to decrease. Once the frequency of the system reaches 49.7 Hz a fast balancing action is triggered which reduces the load bank demand. This pattern repeats to keep the BESS under the high SOC limit, while maintaining a frequency above 49.7 Hz.

3.3.4 T3.2: Resynchronisation of Power Island with Intact System

The goal of this series of tests was to resynchronise the BESS power island with the intact system via the Redhouse grid 1 33 kV circuit breaker. For these tests, the network was set up as per section 3.2.5 with the exception the primary transformers were not connected.

Resynchronisation via load bank control

Once the BESS, diesel generator and load bank were connected to the test network and CB16 had been closed, setpoints were provided via the DRZC (and manually for the diesel generator):

- load bank: -1 MW
- diesel generator: 0.05 MW
- BESS: 0.95 MW/1.5 MVAr.

By changing the active/reactive power setpoints of the assets on the trial network, the frequency and voltage of the power island were deliberately offset from the grid frequency and voltage. This meant that the DRZC had to use its ability to control the load bank to return the power island to a voltage and frequency close to that of the intact grid. Figure 120 shows the process of achieving offset voltage and frequency value and the resynchronisation via the grid 1 breaker.

Figure 120: Voltage and frequency offset and resynchronisation via load bank control

At 11:19 the DRZC's Resync Control mode was initiated from the advanced distribution management system (ADMS) in the SPEN control room. The load bank active power and reactive power were controlled via the DRZC to bring the voltage magnitude and frequency close to that of the intact grid. At 11:20 a Resync Ready indication was received via the ADMS in the control room and the synchrocheck relay was armed. At 11:21 the grid 1 breaker closed successfully. The frequency difference at the time of closure was 0.06 Hz and the voltage angle difference was 7.5°. The point of closure is shown clearly in Figure 120 where the closing angle becomes zero. Note that there was a small difference in the voltage measurements at grid 1 and CB16 of 0.1 kV due to a small calibration error. The active and reactive power traces before and after the closure of grid 1 are shown in Figure 121.

Figure 121: Active and reactive power before and after the closure of grid 1

Resynchronisation via BESS control

Another resynchronisation attempt was made, this time using the DRZC to control the BESS output to match the power island's voltage and frequency to the intact grid. The load bank was given setpoints of 0.5 MW and 0.5 MVAr to offset the power island. The BESS reacted quickly to maintain a close voltage and frequency to the grid.

Figure 122: Voltage and frequency regulation via control of BESS prior to resynchronisation

The load bank value of 0.5 MW was applied at 14:21:45 and 0.5 MVAr was applied at 14:23:15. The BESS responds and brings the frequency and voltage back to match the grid. The grid 1 breaker closed successfully at 14:26:47 as shown in Figure 123.

Figure 123: Resynchronisation via BESS control

At breaker closure, the voltage angle difference was 8.5° and the frequency difference was 0.03 Hz. The frequency of both the grid and the island then become aligned when the angle difference becomes zero. There is still an error in the voltage measurement of 0.1 kV.

Circuit breaker Q3 was opened to remove the earthing transformer from service (the system is now earthed via Redhouse GT1). From 14:26 to 14:39, the BESS is grid connected and continues to operate in grid-forming mode with no issues. The BESS was then switched to grid-following mode prior to the final set of tests with no issues during the transition between operating modes.

3.3.5 T3.3: Dynamic Virtual Power Plant (D-VPP) Testing

D-VPP mode was then activated from the ADMS. This will control the power output behind the grid 1 breaker using the controlled assets of the DRZC – the load bank and the BESS. A tolerance of 0.2 MW was applied for this mode. Figure 124 shows the moment D-VPP mode was activated, bringing the grid 1 output power measurement to 0.16 MW.

Figure 124: D-VPP mode switched on

The diesel generator was used to inject 0.2 MW steps to the system and the D-VPP control responded to this by controlling the BESS active power value. This keeps the grid 1 power output ~0 MW.

Figure 125: Diesel generator power steps while D-VPP mode is active with setpoint of 0 MW

The D-VPP setpoint was then changed to 2 MW. This is shown in Figure 126.

Figure 126: D-VPP setpoint change to 2 MW

The response to this change in setpoint is covered solely by the BESS. The initial response is quick but the second part takes 2 to 3 seconds. Step changes in output were applied to the diesel generator and the D-VPP maintained the 2 MW output.

Figure 127: Diesel generator power steps while D-VPP mode is active with setpoint of 2 MW

This final set of tests successfully demonstrated the D-VPP function of the DRZC. Following this, the D-VPP mode was deactivated and the BESS was switched back to grid-forming mode to enable the disconnection of the BESS site. The BESS and diesel generator were then shut down culminating the Redhouse live trials testing remit.

3.4 Summary of Deliverables

The table below summarises what deliverables were achieved during the respective testing phases/stages.

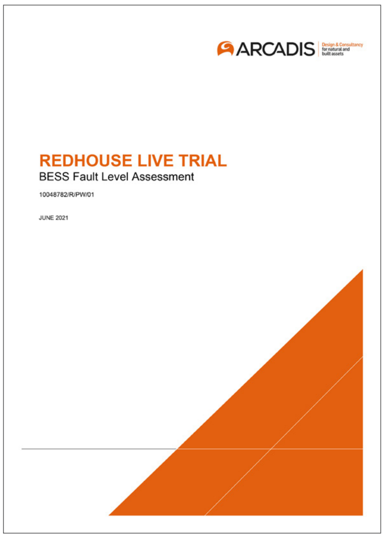
Table 9: Summary of deliverables

Phase	Description	Deliverable	Successful
1	Configure/modify the Redhouse BESS site for testing.	Set up network.	✔
	Diesel generator against load bank steps.	Measure or infer the diesel generator block load pickup (BLPU) capability.	✔
	Grid-following BESS and diesel generator. Various load step/energisation tests with BESS operated in frequency and voltage droop control.	Prove BESS grid-following ability in droop control.	✔
	Grid-following BESS and diesel generator. Various load step/energisation tests with BESS in MW and MVAr setpoint control.	Prove BESS grid-following ability in setpoint control.	✔
	Grid-forming BESS and diesel generator, various energisation and load step changes.	Prove BESS grid-forming ability with diesels running.	✔
	Grid-forming BESS (droop control), no diesel generator. Various energisations/load steps/load profiles.	Measure or infer the BESS block load pick up (BLPU) capability.	✔
2	Redhouse BESS isolation and test readiness.	Set up BESS network.	✔
	SPD distribution network setup – Redhouse 33 kV No.1 busbar outage.	Set up distribution network.	✔
	Diesel generator only. Energise primary transformers.	Prove diesel generator's ability to energise primary transformers.	✔
	Diesel generator and grid-forming BESS, various energisation and load step changes droop control.	Prove the combined ability of the diesel generator and the grid-forming BESS to energise primary transformers and a solar farm.	✔
	Grid-forming BESS only. Various energisations/ load steps/load profiles.	Prove the grid-forming BESS's ability to energise primary transformers and a solar farm.	✔
	Distribution network restoration.	Distribution network restoration.	✔
	Transmission tests setup.	Set up transmission network.	✔
	Diesel generator only. Energise Redhouse grid transformer T1 and 132 kV OHL to Glenniston. Diesel operated in frequency and voltage droop control.	Prove diesel generator's ability to energise grid transformer and 132 kV OHL.	✔
	Diesel generator and grid-forming BESS, energise Redhouse grid transformer T1 and 132 kV OHL to Glenniston.	Prove the combined ability of the diesel generator and the grid-forming BESS to energise grid transformer and 132 kV OHL.	✔
	Grid-forming BESS (droop control), no diesel generator. Energise Redhouse grid transformer T1 and 132 kV OHL to Glenniston.	Prove the grid-forming BESS's ability to energise grid transformer and 132 kV OHL.	✔

Phase	Description	Deliverable	Successful
3	Redhouse BESS isolation and test readiness.	Set up BESS network.	✔
	SPD distribution network setup – Redhouse 33 kV No.1 busbar outage.	Set up distribution network.	✔
	DRZC prototype testing.	Test the fast and slow balancing functionalities of the DRZC controller, with the BESS, diesel generator and solar farm contributing to the power island.	✔
	Resynchronisation with intact grid.	Successful resynchronisation of power island with intact system.	✔
	Dynamic VPP.	Successfully operate the combination of resources on the test network as a VPP via the DRZC.	✔
	Network restoration.	Network restoration.	✔

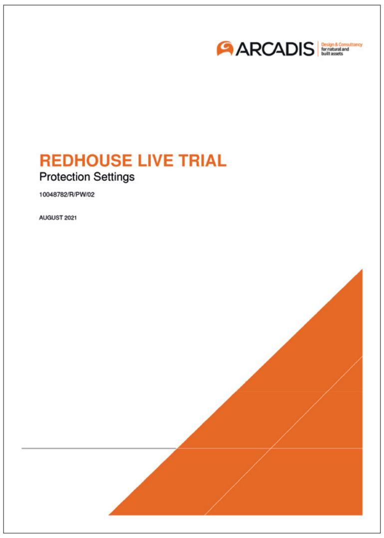
Appendices

Appendix 1: Protection Reports


ARCADIS

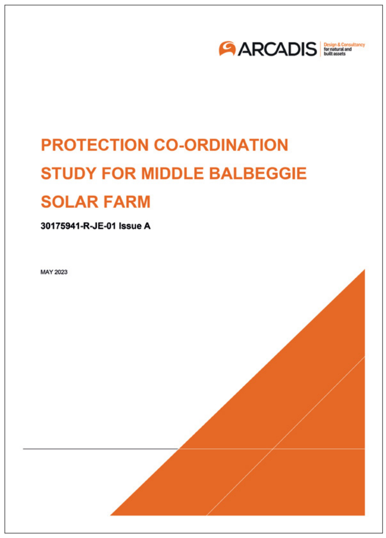
REDHOUSE LIVE TRIAL
BESS Fault Level Assessment
10048782/R/PW/01
JUNE 2021

BESS Fault Level Assessment


ARCADIS

REDHOUSE LIVE TRIAL
Protection Settings
10048782/R/PW/02
AUGUST 2021

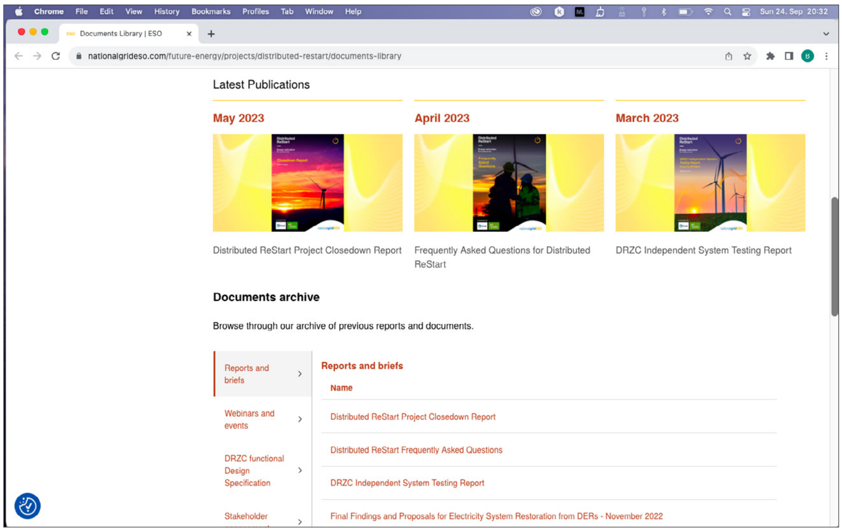
Protection Settings


ARCADIS

PROTECTION CO-ORDINATION STUDY FOR MIDDLE BALBEGGIE SOLAR FARM
30175941-R-JE-01 Issue A
MAY 2023

Protection co-ordination study for Middle Balbeggie solar farm

Appendix 2: Distributed ReStart Documents Library



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Appendix 3: Abbreviations and Acronyms

ADMS	advanced distribution management system
AG	anchor generator
ANM	active network management (system)
BAU	business as usual
BEIS	Department for Business, Energy & Industrial Strategy
BESS	battery energy storage system
BLPU	block load pickup
BSP	bulk supply point
BSUoS	balancing services use of system
CBA	cost-benefit analysis
CCGT	combined cycle gas turbine
CHP	combined heat and power
CIGRE	Conseil International des Grands Réseaux Electriques; this translates as Council on Large Electric Systems
CUSC	Connection and Use of System Code
DER	distributed energy resources
DERMS	distributed energy resources management systems
DMS	distribution management system
DNOs	distribution network operators
DOL	direct online (energisation)
DRZ	distribution restoration zone
DRZC	Distribution Restoration Zone Controller
DRZP	Distribution Restoration Zone Plan
DSO	distribution system operator
DSR	demand side response
EIS	Energy Innovation Summit
EMS	energy management system
ENA	Energy Networks Association
ENIC	Electricity Networks Innovation Conference
ENSTG	Energy Networks Strategic Telecommunications Group
ESO	electricity system operator
ESR	electricity system restoration
ESRS	Electricity System Restoration Standard
EU	European Union
EV	electric vehicle
FAT	factory acceptance testing
FES	Future Energy Scenarios
GFC	grid-forming converter
GSP	grid supply point
HiL	hardware-in the-loop (testing)
ICCP	Inter-Control Centre Communications Protocol
I&C	industrial and commercial
IEEE	Institute of Electrical and Electronics Engineers
IP	Internet Protocol
K&D	Knowledge and Dissemination workstream

kW	kilo watt
MCR	Material Change Request (NIC requirement)
MVA	mega volt ampere
MVAr	mega volt ampere of reactive power
MW	mega watt
NETS	national electricity transmission system
NIA	Network Innovation Allowance
NPV	net present value
NREL	The National Renewable Energy Laboratory (in the United States)
OEM	original equipment manufacturer
OPTEL	operational telephony network
OST	Organisational, Systems and Telecommunications workstream
PAs	participation agreements
P&C	Procurement and Compliance workstream
PET	Power Engineering and Trials workstream
PHiL	power hardware-in-the-loop
PMO	Project Management Office
PNDC	Power Networks Demonstration Centre
PoW	point on wave
PPR	project progress report
PV	(solar) photovoltaic
Q&A	questions and answers
RaaS	Resilience as a Service
RC	resistor-capacitor
RDPs	Regional Development Programmes
RIIO-ED2	Revenue = Incentives + Innovation + Outputs - Electricity Distribution 2. The next price control (known as RIIO-ED2) will cover the five-year period from 1 April 2023 to 31 March 2028.
RTDS	real time digital simulator
RTU	remote terminal unit
SAP	Stakeholder Advisory Panel
SE	South East
SGRE	Siemens Gamesa Renewable Energy
SG	synchronous generator
SGT	super-grid transformer
SPEN	Scottish Power Energy Networks
SPD	Scottish Power Distribution
SPR	Scottish Power Renewables
SPT	Scottish Power Transmission
SSEN	Scottish & Southern Electricity Networks
STATCOM	static synchronous compensator
STC	System Operator Transmission Owner Code
SVC	Static VAR compensator
TAC	Technology Advisory Council
TO	transmission owner
TOV	temporary overvoltages
TRL	technology readiness level
TRV	transient recovery voltage
TUS/TuS	top-up service (provider)
VAr	volt amperes reactive
VCOC	voltage-controlled overcurrent
VSM	virtual synchronous machine
VT	voltage transformer

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