Distributed ReStart

Power Engineering and Trials

Demonstration of Black Start from DERs (Live Trials Report)

Part 2 – October 2022

In partnership with:

tnei

SP ENERGY NETWORKS

nationalgridESO

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Abstract

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

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

The project will tackle these challenges in a three-year programme (Jan 2019–June 2022). Case studies on the SP Distribution (SPD) and SP Manweb (SPM) networks will be used to explore options then design and test solutions through a combination of detailed off-line analysis, stakeholder engagement and industry consultation, desktop exercises and real-life trials of the re-energisation process.

Project Description

The project is made up of five workstreams. The Project Direction, and Knowledge and Dissemination (K&D) workstreams cover the effective management of the project and sharing of learning. The other three workstreams cover the wide range of issues to enable black start services from DERs:

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

Visit Distributed ReStart's *key documents* webpage to view all our other project reports.

Executive Summary

This is the second Power Engineering and Trials (PET) report entitled *Demonstration of Black Start from DERs* (part 1 issued in December 2021). It contains the outcomes and learning from the Galloway Phase 3 and Chapelcross network live trials which have been undertaken in 2022 as part of the Distributed ReStart project.

The primary focus of this report is to detail the results from the third phase of testing at the Galloway live trial site, and several consecutive days of testing at the Chapelcross site. In addition, part two of the study related to the use of grid-forming converter (GFC) connected distributed energy resources (DERs) for black start applications is also included.

Galloway Live Trials – Phase 3

Scope

The trial involved utilising the Kendoon hydro generator as the anchor (used to initially energise the network), along with Glenchamber and North Rhins wind farms which are connected to the Glenluce 33 kV Grid Supply Point (GSP). In addition, a 33 kV connected load bank was utilised to simulate customer demand and allow the wind farms to generate (a turbine typically needs to be running at a minimum of 10% of its rating).

During the live testing, the distribution and transmission networks were configured to facilitate a “test network” while maintaining supply to all existing customers.

Goals

In 2021, the previous two phases of testing at Galloway (four days in total), had successfully proven energisation of the network (from 11 kV to 275 kV) from a single, 11 kV connected, 13 MVA hydro generator at Kendoon.

The goal of the Galloway phase three tests was to build upon the network energisation by establishing a “power island” incorporating multiple DERs (including intermittent resources such as wind farms), and to thus prove the concept of a distribution restoration zone (DRZ) in practice.

Key Achievements

At the end of the testing, we managed to successfully:

- energise primary (33/11 kV) transformers (up to 24 MVA) from the Kendoon hydro generator operating at normal voltage levels (~11 kV)
- prove the block load pickup (BLPU) capability of the anchor generator (the amount of instantaneous demand which can be applied while maintaining the frequency above 47.5 Hz)
- energise the Glenchamber and North Rhins wind farm 33 kV cable arrays, and associated turbine transformers, from the anchor generator (initially all turbines were shut down)
- at Glenchamber and North Rhins wind farms, connect several wind turbines to the “weak” islanded network (supplied only from Kendoon hydro) and prove stable turbine operation both in power factor and voltage control modes
- establish a stable power island with Kendoon hydro and several turbines connected across Glenchamber and North Rhins wind farms simultaneously.

Chapelcross Live Trials

Scope

- The trial used Steven's Croft biomass 11 kV generator as the anchor.
- A 15 MW load bank was installed (connected at 33 kV) to facilitate load testing and provide a minimum stable demand for the generator island mode operation.
- Temporary diesel generators were installed to supply the generator auxiliary demand (at 6.6 kV), isolating it from the main generator output. This was to avoid potential tripping of the auxiliaries, and potentially the main generator tripping, due to test network disturbances.
- During the live testing, the distribution and transmission networks were configured to create a test network (from 11 kV to 400 kV including associated transformers), while maintaining supply to all existing customers.

Goals

The goal of the trial was to:

- prove operation of the Steven's Croft generator in "island mode" (energising and controlling the frequency and voltage on an isolated network)
- prove the BLPU capability of the Steven's Croft generator
- prove the ability of the Steven's Croft generator to energise the local distribution and transmission network (including associated transformers).

Key Achievements

At the end of the testing, we managed to successfully:

- start the Steven's Croft 11 kV generator in island mode, energise the generator 11/33 kV (53 MVA) step-up transformer, and maintain stable MW output with a load bank
- energise the local distribution network, including a 25 km 33 kV underground cable section and a 24 MVA primary (33/11 kV) transformer (where customer demand is normally connected)
- prove the BLPU capability of the anchor generator to be sufficient to pick up the typical demand of a primary substation in a single step
- synchronise the Steven's Croft generator at 33 kV with the main distribution network supply
- energise the transmission network up to 400 kV (via a 400/132 kV 240 MVA super grid transformer).

Conclusions – Live Trials

From the Galloway live trial:

- Initial tests developed and proved the ability of a "small" hydro generator to energise the 11 kV to 275 kV network (including 480 MVA capacity of super grid transformers simultaneously).
- Final Galloway live trials have culminated in successfully establishing a power island with an anchor generator (hydro) and intermittent DERs (wind farms).

From the Chapelcross live trial:

- The viability of a distribution connected biomass generator to operate in island mode, energise the associated distribution and transmission networks (from 11 kV to 400 kV), synchronise at 33 kV, and restore the demand at a primary substation in a single step has been proven.

Overall:

- The fundamental principle of establishing a DRZ, with multiple DERs and energising up to the highest voltage on the transmission network (400 kV) in Great Britain, has now been proven in practice.
- The concept of providing restoration services from DERs is closer to becoming a reality based on the learnings from the live testing at Galloway and Chapelcross.

Key Technical Findings – Live Trials

The key technical findings from the development and implementation of the Galloway (Phase 1,2 and 3) and Chapelcross live trials are:

Islanded Networks

Energising a network from a weak source (low fault level) is likely to result in significant harmonic resonant frequency voltages and currents that are higher in magnitude and longer in duration than would occur on the same network when the fault level is much higher.

Transformer Energisation

The transformer inrush currents, which are of high magnitude and rich in harmonics, can excite the resonance of the circuit connecting to the anchor generator, resulting in temporary overvoltages (TOV) that can last for several seconds. The TOV may operate the overvoltage protection at the generator terminals (typically set at ~1.1 pu to ~1.3 pu) resulting in the generator circuit breaker tripping on transformer energisation. A harmonic impedance study of the network to be energised can be undertaken to identify if there are resonances around typical inrush current frequencies, and therefore the potential for TOV.

To avoid generator tripping on overvoltage protection, several strategies were identified and tested:

- **Generator terminal voltage reduction** – Reducing the generator terminal voltage prior to energisation (on synchronous generators by adjusting the automatic voltage regulator), increases the headroom so that the TOV produced by transformer inrush currents will be less likely to exceed the generator overvoltage limit.
- **Point of Wave (PoW)** – In some network/transformer energisation scenarios, reducing the generator terminal voltage is insufficient to stop the overvoltage protection operating. In these cases, a PoW relay can be installed to control the closing time of the energising circuit breaker to reduce transformer inrush currents, and the corresponding overvoltages (a reduction to ~10% of worst-case inrush currents was observed in the live trials).
- **Resistive damping** – The live network trials showed that by introducing load onto an islanded network (using a temporary load bank), provided 'resistive damping' such that TOV which had previously tripped the anchor generator was eliminated. (On an intact network damping is normally inherently provided by customer load.)
- **Soft energisation** – A 'skeleton' network may be connected to the anchor DER and the generator voltage ramped up from zero (over a matter of seconds) to full voltage. This will eliminate any transformer inrush currents, although the network will be unprotected until the voltage is at a sufficient magnitude for protection operation (this was not tested in the live trials as the previous options were successful).

Network Reactive Loading

When distribution or transmission circuits are energised, they will generate Mvar depending on their capacitance. Care must be taken such that the total Mvar generated by the network, for intact and fault outage scenarios, does not exceed the reactive power absorption capacity of the anchor generator (or additional DER connected).

Switchgear Capability

- **Reactive loading** – The relevant switchgear must be capable of breaking the maximum possible network charging current when opened for non-network fault scenarios (e.g. by generator protection or planned switching). The circuit breaker rated capacitive switching currents may normally be assumed as the capability for this duty.
- **Transient recovery voltage (TRV)** – TRV studies may be required to ensure that, for breaking line charging and/or fault currents, the TRV remains within the relevant circuit breaker design capability. TRV are typically more onerous when there is a lower fault level (as in an islanded network) and may be mitigated by surge arrestors (to limit the peak voltages), and RC snubbers (to limit the rate of rise of recovery voltage [RRRV]).

System Modelling

Simulations are carried out using an electro-magnetic transient (EMT) software program. There is often a lack of specific equipment data required for an EMT type of study, e.g. data required to model transformer core saturation, so assumptions have to be made. This may result in poor correlation between simulation and test results. In addition, it is not always possible to predict protection relay operation based on simulated waveforms, particularly when the waveforms are rich in harmonic contents.

Live Testing

While extensive system modelling may be used to gain a better understanding of the viability of establishing a DRZ in a particular area, without an actual demonstration via live testing there is a risk that restoration efforts in practice will be subject to unknown factors which will emerge to be overcome during an emergency, potentially blocking the restoration progress. As such, as much testing as practical of unconventional network energisation sequences should be carried out to increase the confidence that they will proceed as expected should the need arise to be used in practice.

Grid-Forming Converters (GFC) Network Energisation Simulations – Part 2

This report is the second part of an innovative study commissioned by the PET workstream to investigate to what extent a GFC could provide the function of an anchor generator in a DRZ. A particular area of interest is the ability of the GFC to energise the electricity network (including associated transformers).

Using a Real Time Digital Simulator (RTDS) model of the Chapelcross live trial network, and power hardware-in-the-loop (PHiL) techniques for GFC representation, testing of the ability of a GFC to energise the network was undertaken. This work was done in collaboration with the University of Strathclyde Dynamic Power Systems Laboratory (DPSL) and is among the first trials to test GFC operation for black start with PHiL techniques.

The simulation results demonstrated a successful PHiL utilisation, allowing an external hardware converter to interact with and energise a simulated blacked-out network. The test network included transformers energisation (using soft energisation), load pickups and grid-synchronisation. This preliminary testing success paves the way to more extensive testing that can utilise industrial-scale converters in similar environments under appropriate software/hardware scaling ratios. These converters can then be tested under different network configurations, without being restricted to a particular network topology, while also being exposed to communication delays and limiting conditions that would exist in real networks.

1. Introduction

This report focuses on the outcomes of the Galloway Phase 3 and Chapelcross live network trials to demonstrate the principle of black start from DERs in practice. In addition, part two of the study related to the use of grid-forming converter (GFC) connected DER for black start applications is also included.

Section 2 summarises the contents of the *Demonstration of Black Start from DERs (Live Trials Report) Part 1* report. This was published in December 2021 and provides the context for the work detailed in this report. Section 3 provides the background to the Galloway Phase 3 live trials including the goals of the testing. Section 4 details the Galloway Phase 3 live trial results including the testing sequence, individual test results, and a discussion of technical issues.. Moreover, the key achievements and overall conclusions are also given.

In Section 5, the background is given to the Chapelcross live trials, focusing on the reconfiguration works required for Steven's Croft biomass to operate in "island mode". Section6 then details the results of the Chapelcross live testing following the same format as Section 4 for Galloway.

In Section 7, the second part of a report on GFC network energisation simulations using innovative PHiL techniques is given.

2. Report Context

This report follows on from the Power Engineering and Trials *Demonstration of Black Start from DERs (Live Trials Report) Part 1* report published in December 2021.

2.1 Previous Report Summary

The live trials report part 1 report focused on the work which had been undertaken, both planning and live testing, at the three live trial sites (Galloway, Chapelcross and Redhouse) up to December 2021. In addition, part 1 of the grid-forming converter (GFC) study is included along with a report on live testing of virtual synchronous machine (VSM) technology (an application of GFC technology) at Dersalloch wind farm. The chapters of the report relate to the following subjects:

- Chapter 2 gives an overview of the live trials in terms of the objectives and technical challenges common to all three test sites.
- Chapter 3 gives further details of the Galloway trial site, including introducing the energisation strategies which have been employed, describing the live testing which has been completed and showing the relevant network diagrams.
- Chapter 4 details the results from the Galloway phase 1 live trials in October 2020, utilising Glenlee 11 kV hydro as the anchor generator, with the conclusions detailing the learning which went on to inform the planning of future tests.
- Chapter 5 then details the results of the Galloway phase 2 live trials, in September/October 2021, utilising Kendoon 11 kV hydro as the anchor generator. The key achievements from these live trials are listed along with the key learnings.
- Chapter 6 gives an overview of the Chapelcross live trial site, the proposed live testing, along with results from the hardware-in-the-loop (HiL) testing which had been carried out on the Real Time Digital Simulator (RTDS) at the National HVDC Centre.
- Chapter 7 then gives an overview of the Redhouse live trial site, the proposed testing and the results of TRV studies carried out to date. The next section of the report is related to grid-forming converter connected DER work which had been commissioned by the project.
- Chapter 8 provides a report summarising the ability to protect the Chapelcross test network if the anchor generator was a grid-forming battery energy storage system (BESS), equivalent in size to the existing synchronous generator.
- Chapter 9 then gives an overview, and initial results, from the power HiL testing of a GFC incorporated into an RTDS model of the Chapelcross test network. This work is undertaken in collaboration with the University of Strathclyde Dynamic Power Systems Laboratory (DPSL).
- Chapter 10 gives a report on live testing of VSM technology at Dersalloch wind farm, without the Distributed ReStart project, but supported and facilitated by SP Energy Networks (SPEN) and located adjacent to the Galloway live trial area.

2.2 Live Trials Part 2 Report

This report compliments the live trials part 1 report in the following aspects:

- Details the results of the Galloway Phase 3 live testing
  → follows on from Phase 1 and 2 testing results detailed in Chapters 4 and 5 respectively of the part 1 report.
- Details the results of the Chapelcross live network testing
  → follows on from the trial preparation works detailed in Chapter 6 of the part 1 report.
- Provides part 2 of the study report into PHiL testing of GFC network energisations
  → follows on from the part 1 study report detailed in Chapter 9 of the live trials part 1 report.

The Redhouse network live trial, anticipated to be undertaken in 2023 will be the subject of a separate report. This will follow on from the background given in Chapter 7 of the part 1 live trials report.

3. Galloway Phase 3 – Live Trial Background

This section provides an overview of the objectives and plans for the Galloway Phase 3 live trials along with schematic diagrams and maps showing the Galloway test network.

3.1 Background

In 2021, the previous two phases of testing at Galloway (four days in total), had successfully proven energisation of the distribution and transmission networks (from 11 kV to 275 kV including associated transformers) from a single, 11 kV connected, 13 MVA hydro generator at Kendoon.

3.2 Phase 3 Test Goals

The goal of the Galloway phase three tests was to establish a "power island" incorporating multiple DERs (Kendoon hydro plus two wind farms) and thus to prove the concept of a distribution restoration zone (DRZ) in practice. This goal was split into the following tests:

- The 132/33 kV Glenluce Grid Transformer T1 will be energised from a Kendoon generator over the Kendoon/New Cumnock, Kendoon/Glenlee and Glenlee/Newton Stewart/Glenluce 132 kV circuits based on the learnings from the phase 2 live trial results (carried out in September 2021).
- Once the Glenluce 33 kV No 1 busbar is energised, the 33 kV circuits to Glenchamber and North Rhins Wind Farms will be energised to restore auxiliary supplies to the wind farms. It will also make the load bank available which is connected to a spare 33 kV breaker on the Glenchamber wind farm 33 kV switchboard.
- Energise a primary (33/11 kV) transformer on the Glenluce test network
  - → these tests will be carried out with the Kendoon generator operating at nominal and reduced terminal voltages).
- Test the block load pickup (BLPU) capability of Kendoon Generator
  - → Apply (and remove) incremental demand blocks instantaneously at the load bank until the network frequency dips to a minimum of 47.5 Hz
  - → confirm that the frequency recovers to above 47.5 Hz within 20 seconds (Grid Code – Grid Code Frequency Variations, CC.6.1.3).
- Prove that the Glenchamber and North Rhins wind farm 33 kV networks can be energised (including turbine transformers).
- Prove stable operation of a selected number of turbines at Glenchamber and North Rhins wind farms (the wind farms operating separately first then simultaneously).

3.3 Load Bank Installation

For the phase 3 testing, a 6 MVA load bank was connected to the 33 kV switchboard at Glenchamber wind farm to:

- provide reactive loading to absorb the Mvar generated by the test network and thus ensure the Mvar absorbed by the anchor DER (Kendoon hydro) were kept within limits
- provide a minimum stable MW demand to allow the wind farms to generate
- provide MW demand to test the block loading capability of the anchor DER.

3.4 Test Network Diagrams

The trial involved utilising the Kendoon hydro generator as the anchor (used to initially energise the network), along with multiple turbines at Glenchamber and North Rhins wind farms connected to the Glenluce 33 kV grid supply point (GSP). In addition, a 33 kV connected load bank was utilised (5 MW connected to the Glenchamber wind farm 33 kV network) to simulate customer demand and allow the wind farms to generate (a turbine can typically generate a minimum of 10% of its rating).

During the live testing, the distribution and transmission networks were configured to facilitate a “test network” while maintaining supply to all existing customers. The phase 3 test network is shown in Figure 1 and Figure 2.

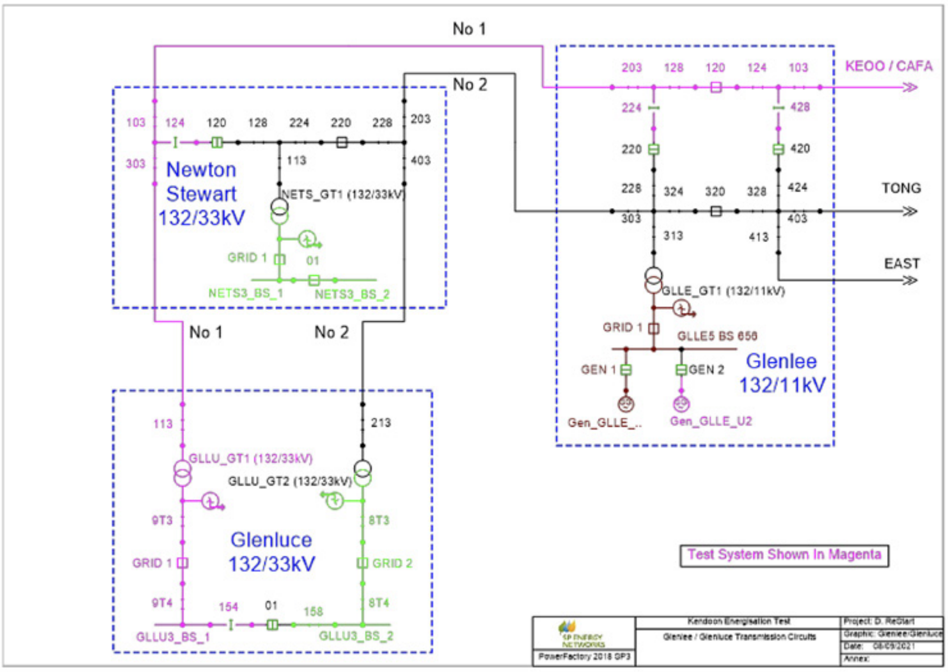

Figure 1:Glenlee/Glenluce 132 kV test network

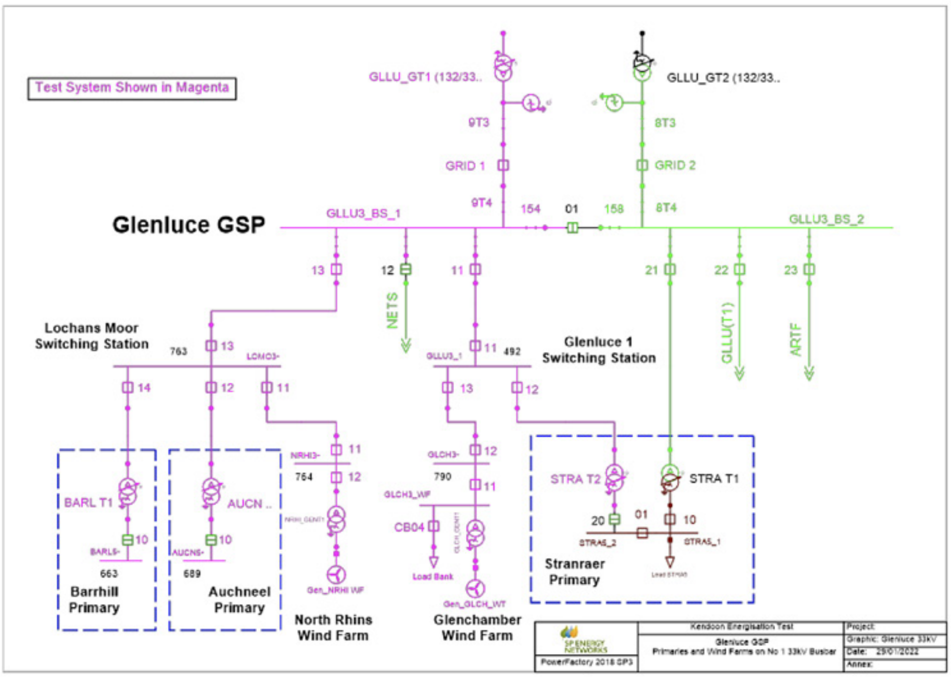

Figure 2: Galloway distribution test network schematic (Glenluce GSP)

4. Galloway Phase 3 – Live Trial Results

This section provides a summary of the Galloway phase 3 live testing and the associated results.

4.1 Trial Overview

4.1.1 Test Dates

The Galloway phase 3 live tests were carried out on 19 and 21 April 2022. Testing was originally planned for 20 April but was not carried out due to a forecast of very light wind conditions.

4.1.2 Fault Recorders

The voltage waveforms have been obtained from fault recorders routinely installed on the network. These recorders can produce continuous root mean square (RMS) data, and waveform data if triggered by one of several set trigger conditions.

Several of the records were triggered by a circuit breaker opening or closing, monitored on a digital input, so other recorders would not trigger. However, other triggers were the result of voltage transients that could be observed elsewhere on the test network.

One of the critical waveforms to examine is the voltage on the Kendoon generator, as the generator had tripped on overvoltage during previous testing. A few events did trigger both the Kendoon fault recorder and one on the Glenluce 33 kV network, so comparisons are possible at the two locations. In most cases, a trigger only occurred on a recorder within the Glenluce 33 kV network, so direct observation of the Kendoon generator voltage was not possible.

4.2 Day 1 (19 April 2022) Testing Sequence

The day 1 tests consisted of:

- energising the transmission network (132 kV) between Kendoon hydro and Glenluce 132/33 kV GSP
- energising Barrhill (7.5 MVA) and Auchneel (24 MVA) primary (33/11 kV) transformers
- energising the Glenchamber and North Rhins 33 kV cable arrays (and turbine transformers)
- carrying out block load testing on the Kendoon hydro generator.

Table 1: Day 1 (19 April) – testing sequence

Test No.	Description
1	Energise Kendoon(KEOO)/Glenluce(GLLU) 132 kV circuit and transformers
2	Energise Barrhill primary transformer (7.5 MVA) – KEOO volts = 75%, GLLU volts = 75%
3	Energise Auchneel primary transformer (24 MVA) – KEOO volts = 75%, GLLU volts = 75%
4	Energise Barrhill primary transformer (7.5 MVA) – KEOO volts = 85%, GLLU volts = 100%
5	Energise Auchneel primary transformer (24 MVA) – KEOO volts = 85%, GLLU volts = 100%
6	Energise Glenchamber load bank transformer (then set to 3 Mvar)

7	Energise Glenchamber wind farm cables and turbine transformers
8	Energise North Rhins wind farm turbine transformer
	(Wind farm automatic restoration scheme energises a turbine transformer approximately every 13 s once the 33 kV cable array is energised. Ten transformers were energised)
17	Energise North Rhins wind farm turbine transformer
18	Kendoon generator block load steps
19	Energise Barrhill primary transformer from intact network
20	Energise Auchneel primary transformer from intact network

4.3 Day 1 – Test Results

Comments are provided on the results of each step in the testing sequence, with data plots also included for the key tests (numbers 1, 4, 5, 8, 18, 20).

The Kendoon generator did not trip during any of the tests on day 1.

4.3.1 Test Number 1

Event – Energise Kendoon/Glenluce 132 kV circuit and transformers

Comments:

- Initial energisation of Kendoon grid transformer T2 (132/11 kV), Kendoon/Glenluce 132 kV circuit and Glenluce grid transformer T1 (123/33 kV).
- The Kendoon generator voltage was set to 75% of nominal voltage.
- The Kendoon grid 2 11 kV circuit breaker was closed by a point on wave (PoW) relay (to minimise inrush currents).
- Significant voltage distortion can be observed even after 30 cycles (600 ms).
- There was no load on the test network during this energisation.
- Significant overvoltages occurred during the first few cycles.

The data plot from the fault recorder monitoring the Kendoon grid 11 kV voltage and current is shown in Figure 3.

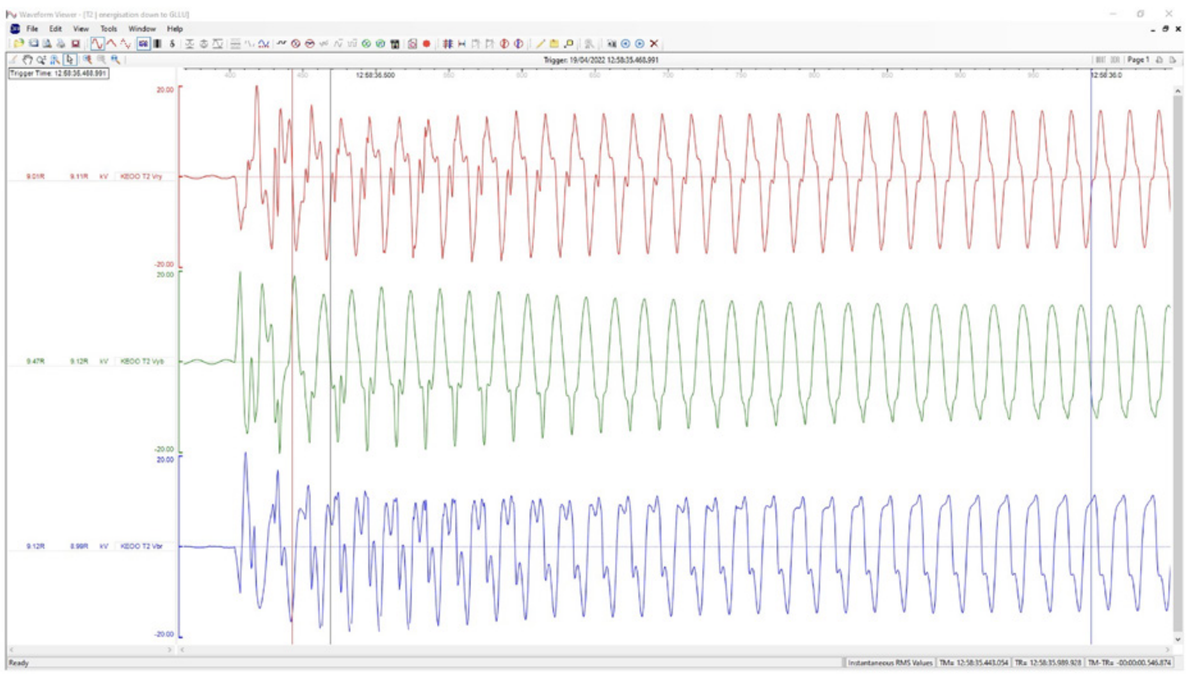

Figure 3: Day 1, test number1, data plot

4.3.2 Test Number 2

Event – Barrhill primary transformer energised from test network.

Kendoon generator voltage = 75%.

Glenluce 33 kV voltage = 75%.

Comments:

- Voltage distortion lasted about eight cycles (160 ms).
- The Kendoon hydro generator **did not trip**.

4.3.3 Test Number 3

Event – Auchneel primary transformer energised from test network.

Kendoon generator voltage = 75%.

Glenluce 33 kV voltage = 75%.

Comments:

- Distortion lasted more than 25 cycles (500 ms).
- Overvoltages were more significant than for the smaller Barrhill primary transformer energisation.

4.3.4 Test Number 4

Event – Barrhill Primary transformer (7.5 MVA) energised from test network.

Kendoon generator voltage = **85%**.

Glenluce 33 kV voltage = **100%**.

Comments:

- The Barrhill primary transformer was energised for a second time from the weak test network and the Kendoon number 1 generator. Generator terminal voltage was set at 85%, and Glenluce 33 kV voltage was 100%.
- Voltage distortion lasted about 16 cycles (320 ms).
- Overvoltages and waveform distortion were significantly worse than when energised previously at 75% voltage.

The data plot from the fault recorder monitoring the Lochans Moor 33 kV voltage is shown in Figure 4.

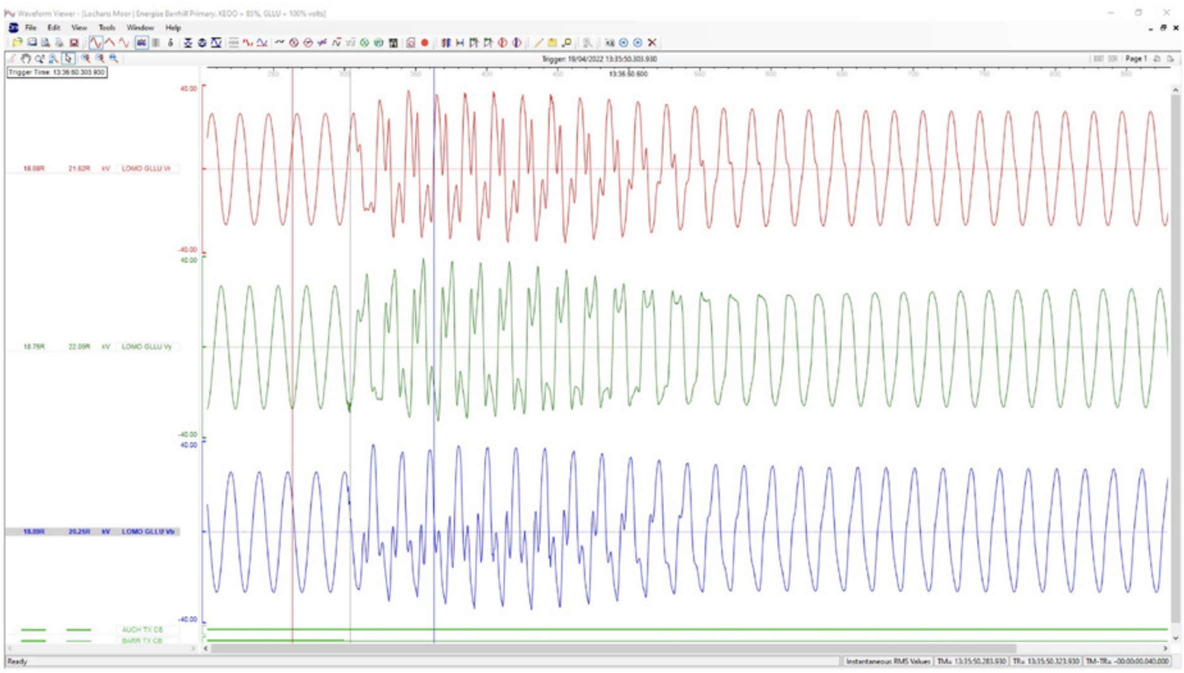

Figure 4: Day 1, test number, data plot

4.3.5 Test Number 5

Event – Auchneel primary transformer energised from test network.

Kendoon generator voltage = 85%.

Glenluce 33 kV voltage = 100%.

Comments:

- The Auchneel primary transformer was energised for a second time from the weak test network and the Kendoon number 1 generator. Generator terminal voltage was set at 85%, and Glenluce 33 kV voltage was 100%.
- Voltage distortion was still very noticeable after 30 cycles (600 ms).

The data plot from the fault recorder monitoring the Lochans Moor 33 kV voltage is shown in Figure 5.

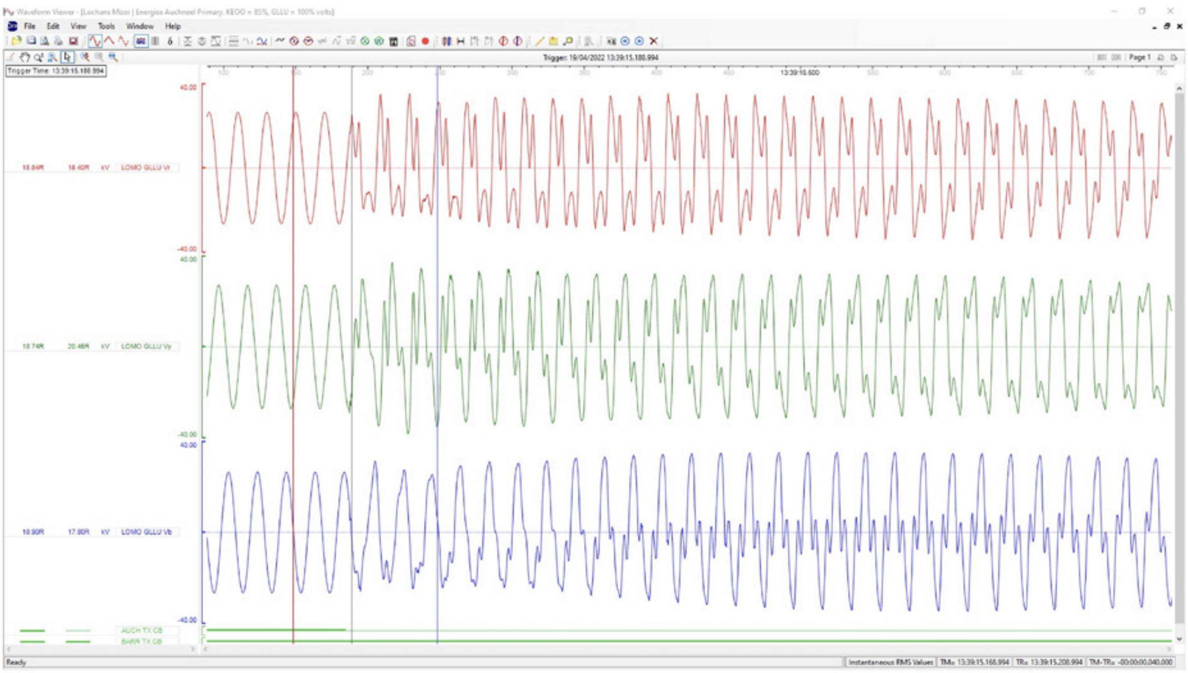

Figure 5: Day 1, test number 5, data plot

4.3.6 Test Number 6

Event – Glenchamber load bank transformer energised from test network.

Kendoon generator voltage = 85%.

Glenluce 33 kV voltage = 100%.

Comments:

- Distortion of the voltage waveforms can be observed for up to 500 ms after the transformer energisation. Overvoltages were also noticeable.

4.3.7 Test Number 7

Event – Energise Glenchamber wind farm cables and turbine transformers.

Comments:

- No fault recorder traces available.
- Minimal disturbances. All wind farm turbine transformers energised simultaneously but a pre-insertion resistor is used to minimise transformer inrush currents.

4.3.8 Test Number 8 to Test Number 17

Event – North Rhins turbine transformer energised from test network.

Sequential energisation of turbine transformers about every 13 seconds.

Kendoon generator voltage = 85%.

Glenluce 33 kV voltage = 100%.

Comments:

- Voltage distortion was observed for up to 400 ms.
- This was one of multiple turbine transformer energisations as the wind farm transformers were sequentially energised about 13 seconds apart.

The data plot from the fault recorder monitoring the Lochans Moor 33 kV voltage is shown in Figure 6 (shown for a single turbine transformer energisation).

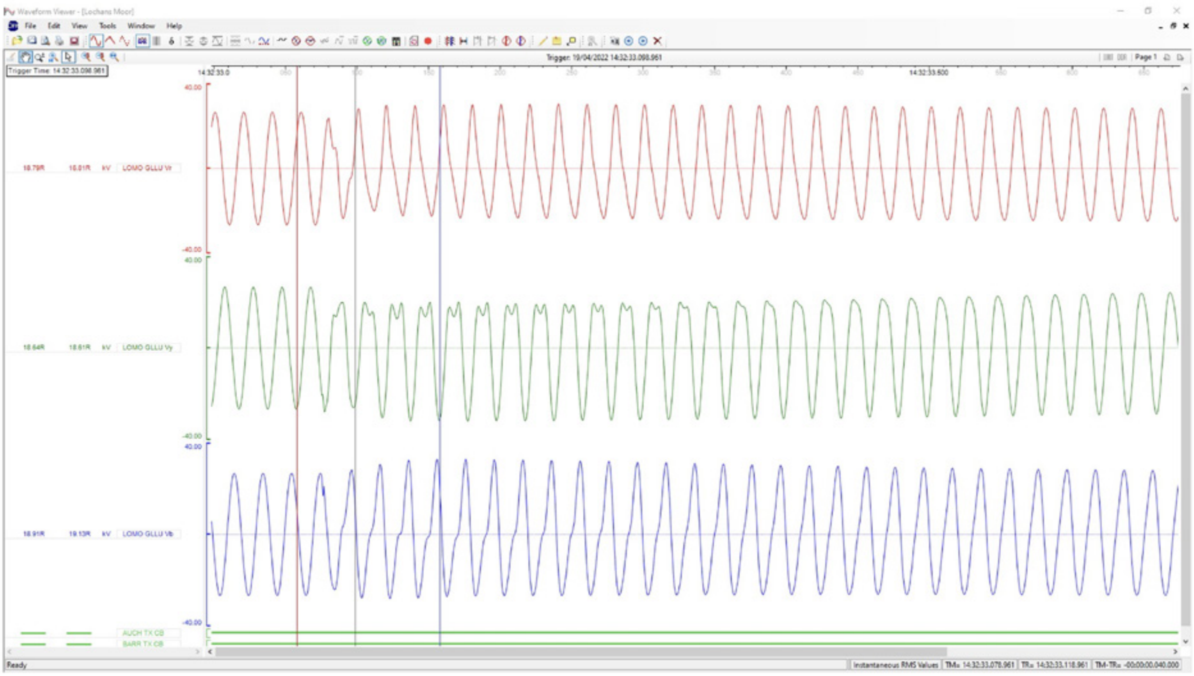

Figure 6: Day 1, test number 17, data plot

4.3.9 Test Number 18

Event – Block load tests on Kendoon generator.

Kendoon generator voltage = 100%.

Glenluce 33 kV voltage = 100%.

Comments:

- It was found that the load bank controller would not permit a step change of active power. However, a step change of power factor was possible, and this was used to test the block load capability of the Kendoon generator.
- A load step of 0.5 MW was found to produce a frequency change of 1 Hz when applied, and 1.3 Hz when removed (reaching 51.18 Hz). For this reason, when the 1.0 MW step was applied, it was removed slowly to avoid a possible frequency transient exceeding 52 Hz which could potentially trip the generator.
- When a load step of 0.5 MW was applied, the rate of change of frequency (RoCoF) was 0.263 Hz/s, rising to 0.502 Hz/s for a 1.0 MW load step.
- Hydro governors tend to be slower than steam governors due to the inertia of the water column. As a result, the governor took between 8 and 10.7 seconds to halt the frequency deviation.
- Further frequency deviations can be observed during the testing of wind turbines at Glenchamber wind farm. As each turbine was started to its minimum level of 0.3 MW, frequency transients of up to 51 Hz were observed.

Results:

The results from applying load steps to the Kendoon hydro number1 generator are given in Table 2. It can be seen that the block load pickup (BLPU) capability of the generator is ~1.0 MW, which results in the frequency dropping to 47.45 Hz. In the Grid Code the BLPU capability is defined as, “active power step (MW) a generator can instantaneously supply without causing it to trip or go outside 47.5Hz–52Hz”.

Table 2: Kendoon hydro load step results

Load Step	Actual Load Step	Peak Frequency	Time to Peak	Rate of Change of Frequency	Initial Frequency	Frequency Change
0.5 MW Increase	0.55 MW	48.69 Hz	8.02 s	-0.263 Hz/s	49.68 Hz	-0.99 Hz
0.5 MW Decrease	0.52 MW	51.18 Hz	10.66 s	+0.224 Hz/s	49.89 Hz	+1.29 Hz
1.0 MW Increase	1.04 MW	47.45 Hz	8.96 s	-0.502 Hz/s	49.77 Hz	-2.32 Hz

The data plot from the fault recorder monitoring the frequency at Kendoon is shown in Figure 7 for a 1 MW load step being applied to the test network (via the load bank at Glenchamber 33 kV wind farm).

It can be seen that the Kendoon hydro BLPU is ~1.0MW (~10% of the generator rating).

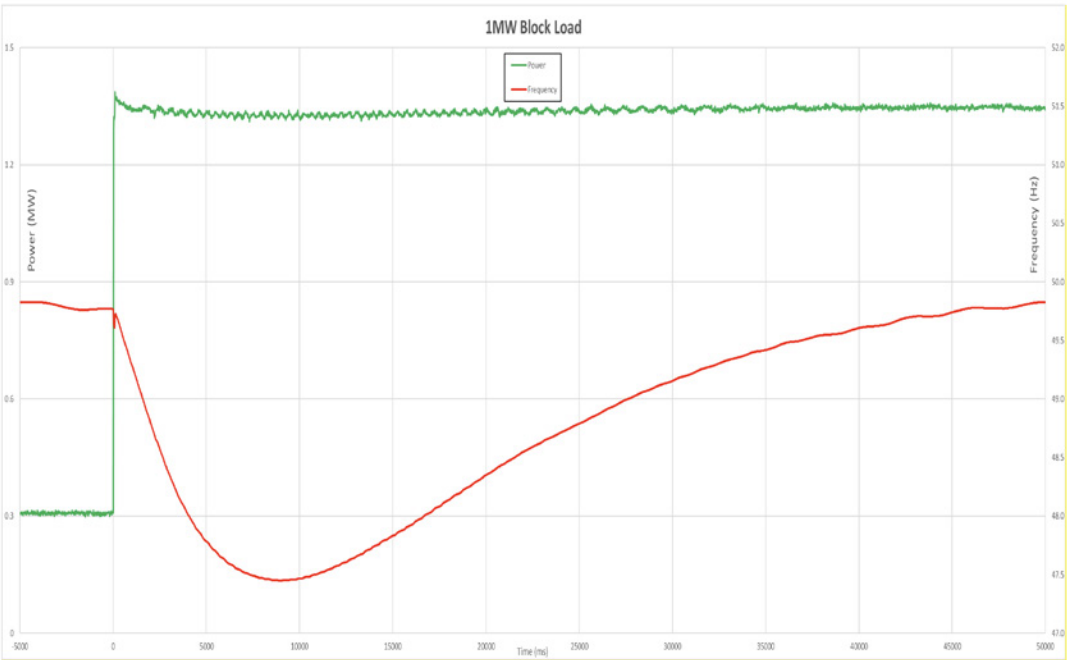

Figure 7: Day 1, test number 18, data plot – frequency response of Kendoon hydro for 1 MW load step

4.3.10 Test Number 19

Event – Barrhill primary transformer (7.5 MVA) energised from intact network.

Comments:

- This energisation took place at the end of the day 1 testing with the transmission network restored. With the fault level from the 132 kV network, together with network loads, there was very little change in voltage or signs of resonance voltages affecting the 33 kV network voltage at Glenluce grid supply point.

4.3.11 Test Number 20

Event – Auchneel primary transformer (24 MVA) energised from intact network.

Comments:

- This energisation took place at the end of testing with the transmission network restored. With the fault level from the 132 kV network, together with network loads, there was very little change in voltage or signs of resonance voltages affecting the 33 kV network voltage at Glenluce grid supply point.
- The data plot from the fault recorder monitoring the Lochans Moor 33 kV voltage is shown in Figure 6. The digital trace at the bottom of the chart shows the time when the Auchneel 33 kV circuit breaker was closed at the Lochans Moor switching station. This can be compared to the data plot for the energisation of the Auchneel transformer in the islanded test network shown in 4.3.5 Test Number 5.

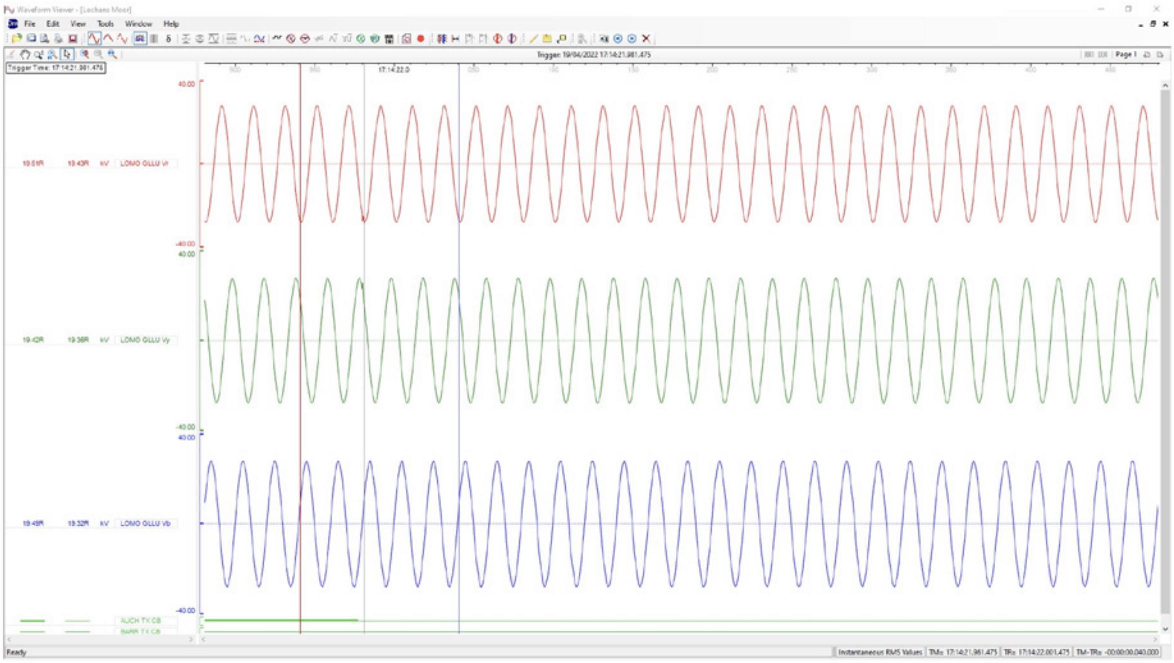

Figure 8: Day 1, test number 20, data plot

4.4 Day 2 (Thursday 21 April 2022) Testing Sequence

The day 2 tests consisted of energising the transmission network (132 kV) between Kendoon hydro and Glenluce 132/33 kV GSP, energising the Glenchamber and North Rhins 33 kV cable arrays (and turbine transformers), and running wind turbines at both wind farms individually and simultaneously.

In addition, energisation of the Auchneel (24 MVA) primary transformer was carried out with the Kendoon generator voltage raised in steps from 85% (as tested in day 1) to 100% (nominal 11 kV terminal voltage).

Table 3: Day 2 (21 April) – testing sequence

Test No.	Description
21	Energise Kendoon/Glenluce 132 kV circuit and transformers
22	Energise Aggreko load bank transformer
23	Energise Glenchamber wind farm site cables and transformers (pre-insertion resistor)
24	Energise Lochans Moor/North Rhins wind farm 33 kV circuit
25	Energise North Rhins wind farm site cables

26	Sequential energisation of North Rhins wind farm turbine transformers
27	Test run of Glenchamber wind turbines (1, 2 and 3)
28	Test run of North Rhins wind turbines (1,2 and 3)
29	Test run of Glenchamber and North Rhins turbines (4 in total)
30	Energise Auchneel primary transformer – KEOO volts = 85%, GLLU volts = 100%, test network load = 2 MW
31	Energise Auchneel primary transformer – KEOO volts = 90%, GLLU volts = 100%, test network load = 2 MW
32	Energise Auchneel primary transformer – KEOO volts = 95%, GLLU volts = 100%, test network load = 2 MW
33	Energise Auchneel primary transformer – KEOO volts = 100%, GLLU volts = 100%, test network load = 2 MW

4.5 Day 2 – Test Results

Comments are provided on the results of each step in the testing sequence, with data plots also included for the key tests (numbers 27 and 33).

The Kendoon generator did not trip during any of the tests on day 2.

4.5.1 Test Number 21

Event – Energise Kendoon/Glenluce 132 kV circuit and transformers.

Comments:

- Initial energisation of Kendoon grid transformer T2 (132/11 kV), Kendoon/Glenluce 132 kV circuit and Glenluce grid transformer T1 (123/33 kV).
- Kendoon generator voltage set to 75% of nominal voltage.
- The grid 2 11 kV circuit breaker was closed by a PoW relay.
- Significant voltage distortion can be observed even after 30 cycles (600 ms).
- There was no load on the test network during this energisation.
- Significant overvoltages occurred during the first few cycles.

4.5.2 Test Number 22

Event – Energise Aggreko load bank transformer.

4.5.3 Test Number 23

Event – Energised Glenchamber wind farm site cabling and transformers (pre-insertion resistor).

Comments:

- Initial reactive power of 3.19 MVAr due to load bank was reduced to 2.94 MVAr due to site cabling capacitance.
- No sign of voltage dip at energisation due to the use of a pre-insertion resistor.
- No fault recorders were triggered during this energisation.

4.5.4 Test Number 24

Event – Energised the North Rhins wind farm 33 kV circuit from Lochans Moor SW STN.

Comments:

- Very minor voltage transient on 33 kV voltage waveforms when the North Rhins circuit breaker was closed. The circuit is overhead line (OHL) with short cable sections at each end.

4.5.5 Test Number 25

Event – Energise North Rhins wind farm site cables.

Comments:

- Results as per day 1 testing.

4.5.6 Test Number 26

Event – Sequential Energisation of North Rhins wind farm turbine transformers.

Comments:

- Results as per day 1 testing.

4.5.7 Test Number 27

Event – Wind turbines at Glenchamber wind farm were started sequentially and observed for about 10 minutes before the next turbine was started.

Comments:

- The first wind turbine at Glenchamber wind farm was started at an output of about 300 kW. A frequency transient reached almost 51 Hz occurring when the wind turbine was started and was returned to nearer 50 Hz by the governor on the Kendoon generator.
- The turbines were started initially in power factor control (to minimise the risk of instability with a reduced fault level). Voltage control was later utilised. No instability was observed for either mode.
- After about 18 minutes of stable operation, the second wind turbine was started. The output of the second turbine was also about 300 kW, and again the frequency transiently reached about 51 Hz.
- As each turbine was started, a frequency transient up to about 51 Hz was observed.

The data plot from the fault recorder monitoring the Glenchamber wind farm 33 kV substation is shown in Figure 9.

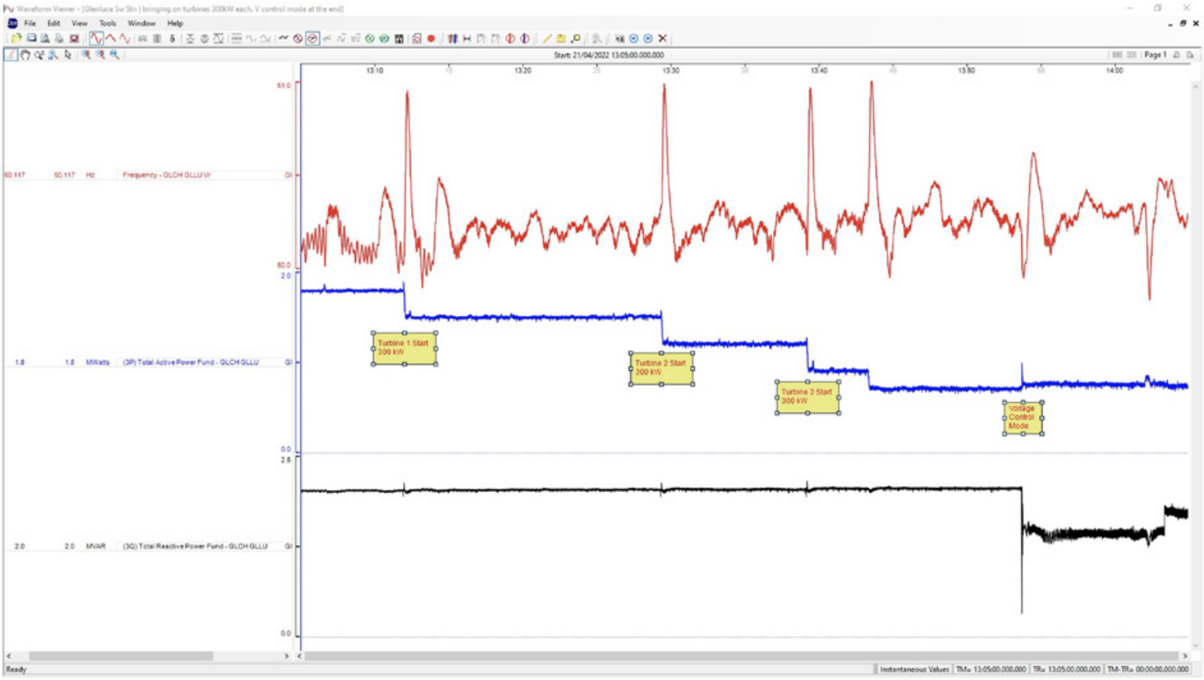

Figure 9: Day 2, test number 27, data plot

4.5.8 Test Number 28

Event – Test run of North Rhins wind turbines (1,2 and 3)

Comments:

- Three turbines successfully connected. Initially in power factor control then voltage control.

4.5.9 Test Number 29

Event – Test run of Glenchamber and North Rhins turbines (4 in total)

Comments:

- A stable power island was established with Kendoon hydro and two wind farms with multiple turbines running.

4.5.10 Test Number 30

Event – Auchneel primary transformer energised from test network.

Kendoon generator voltage = 85%.

Glenluce 33 kV voltage = 100%.

Test network load = 2 MW.

Comments:

- Voltage distortion can be observed for about 500 ms after energisation. A voltage dip after energisation was also observed as would be expected because of the magnetising inrush current. Overvoltages were not observed, probably because of the 2 MW load on the test network at the time of energisation (providing resistive “damping” for any transients).

4.5.11 Test Number 31

Event – Auchneel primary transformer energised from test network.

Kendoon generator voltage = 90%.

Glenluce 33 kV voltage = 100%.

Test network load = 2 MW.

Comments:

- Voltage distortion can be observed for about 500 ms after energisation. A voltage dip after energisation was also observed as would be expected because of the magnetising inrush current. Overvoltages were not observed, probably because of the 2 MW load on the test network at the time of energisation.

4.5.12 Test Number 32

Event – Auchneel primary transformer energised from test network.

Kendoon generator voltage = 95%.

Glenluce 33 kV voltage = 100%.

Test network load = 2 MW.

Comments:

- Voltage distortion can be observed for about 500 ms after energisation. A voltage dip after energisation was also observed as would be expected because of the magnetising inrush current. Overvoltages were not observed, probably because of the 2 MW load on the test network at the time of energisation.

4.5.13 Test Number 33

Event – Auchneel primary transformer energised from test network.

Kendoon generator voltage = 100%.

Glenluce 33 kV voltage = 100%.

Test network load = 2 MW.

Comments:

- Very small transient as circuit breaker closes. Possibly near optimal point on wave switching as well as the effect of the load bank resistive damping of transient voltages.

The data plot of the Lochans Moor 33 kV voltage (from where the Auchneel transformer is energised) is shown in Figure 10.

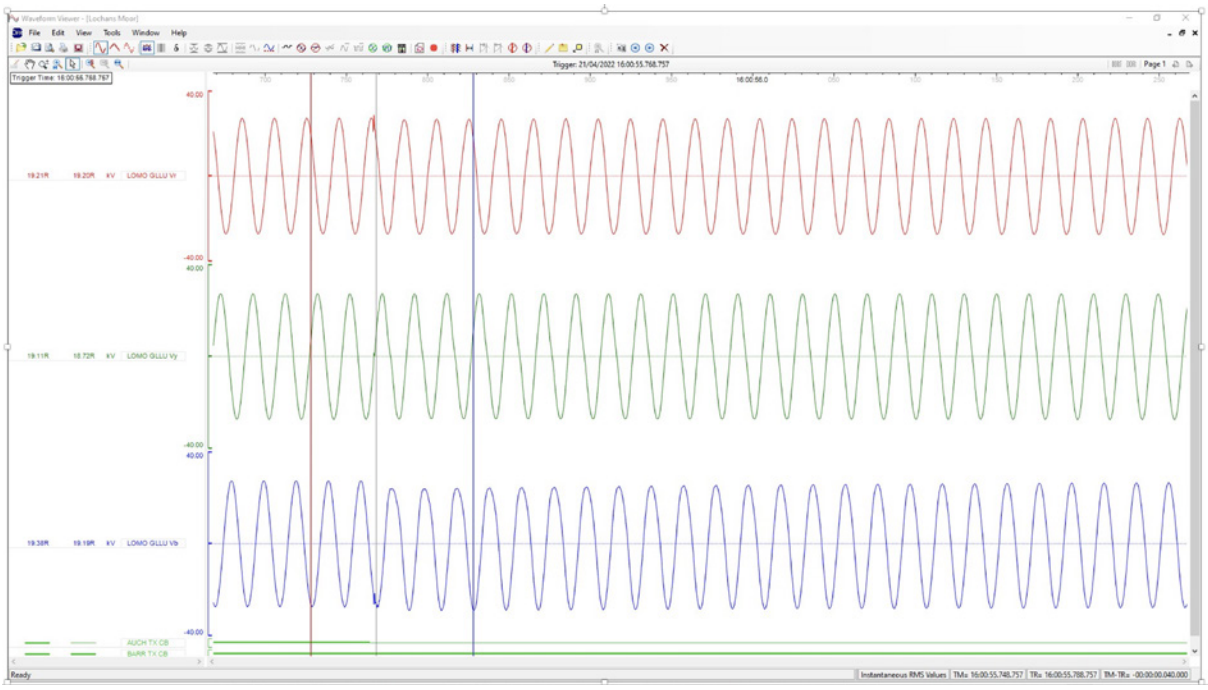

Figure 10: Day 2, test number 33, data plot

4.6 Discussion/Key Achievements/Conclusions

Based on the Galloway phase 3 live trial results, several technical issues have been noted for discussion and the key achievements highlighted.

4.6.1 Discussion

Network Energisation – Resistive Damping

Test number 33 showed that it was possible to energise the Auchneel primary (33/11 kV) transformer (24 MVA) from the Kendoon 11 kV hydro at nominal terminal voltage (11 kV), with a 2 MW load bank connected to the test network. In the Galloway phase 2 tests this scenario had resulted in tripping the Kendoon generator due to transient overvoltages (there was no load bank connected).

Subsequent transient simulation studies were undertaken and Figure 11 shows the overvoltages recorded at Kendoon hydro 11 kV terminals when energising the Barrhill primary (33/111 kV) 7.5 MVA transformer. Figure 12 shows the dramatic reduction in voltages, for the same scenario, when a load bank is connected to the test network.

Figure 13 shows a frequency scan looking into Glenluce 33 kV before energisation of the Barhill primary transformer with and without load bank connected at Glenchamber 33 kV wind farm. It shows that, in the case of temporary overvoltages (TOV), when the load bank is switched in, it causes a decrease in the magnitude of impedance at the resonant condition and therefore reduced the amplification of the injected harmonic currents.

Where practical, using a load bank to minimise TOV has proven (by simulations and live testing) to be an effective strategy and may eliminate the need to reduce generator terminal voltage (to give a greater margin before overvoltage protections operate), or use PoW switching (to minimise inrush currents and corresponding TOV) to avoid generator tripping.

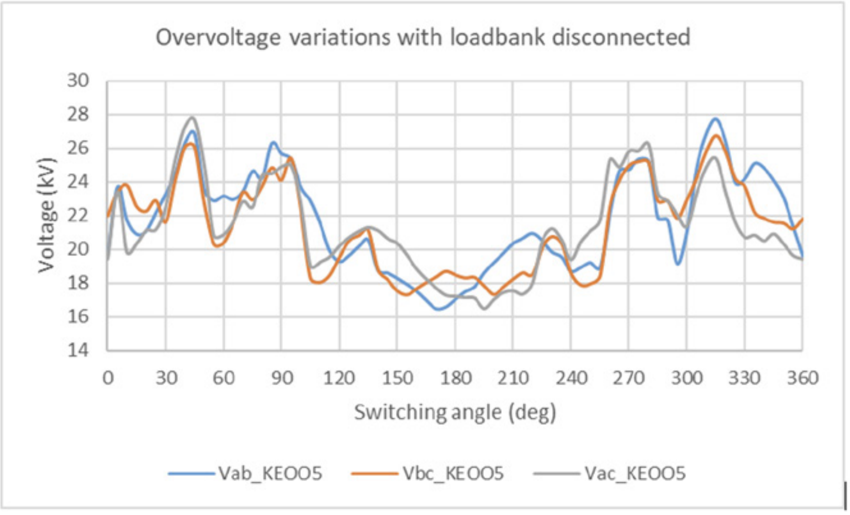

Figure 11:Kendoon 11 kV overvoltage variations – no load bank

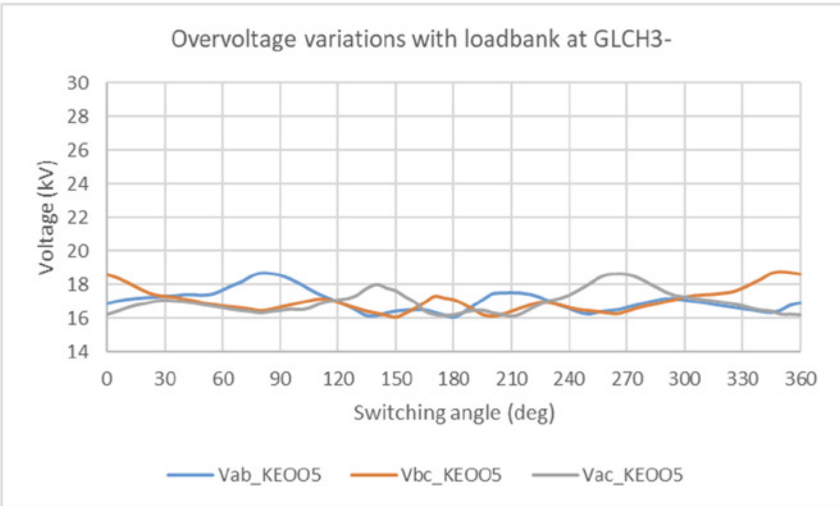

Figure 12: Kendoon 11 kV voltage variations – Glenchamber 33 kV load bank

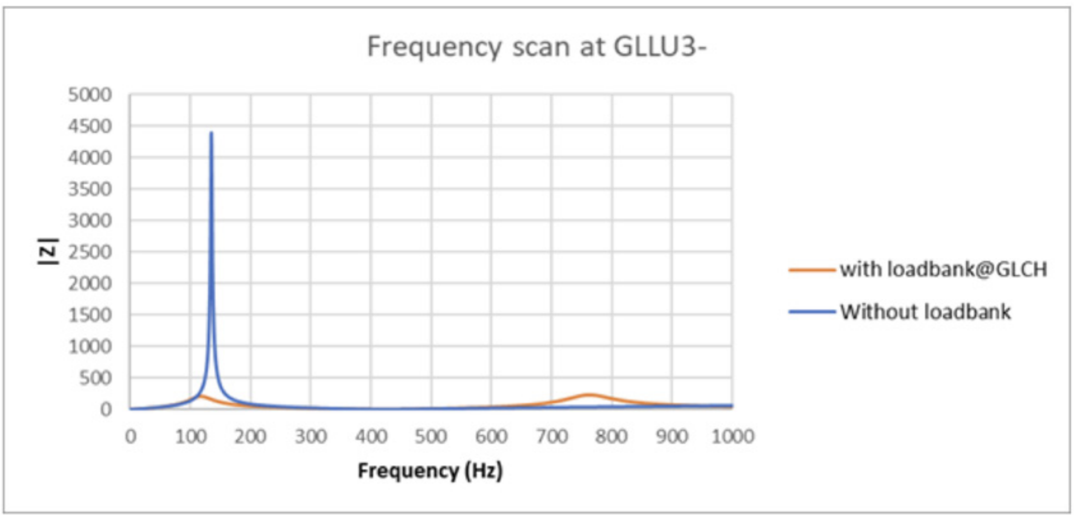

Figure 13: Glenluce frequency scan with and without load bank

Block Load Pickup (BLPU)

Test number18 shows that the BLPU capability of a single hydro generator is only ~1 MW (~10% of the generator rating). The large inertia of the water column to respond to speed up the turbine when required is likely to be a factor. A distribution network 11 kV feeder circuit (at a primary [33/11 kV] substation), has a load of typically several MWs. Thus, the hydro BLPU capability would not be suitable for restoration even on a 11 kV circuit by circuit basis.

It follows that a distribution restoration zone control (DRZC) system would be required to enhance the BLPU of the anchor DER using the fast-balancing functionality which has been designed as part of this project for this scenario. This has sub-second control of a load bank or battery energy storage system (BESS) to support the frequency while the anchor DER responds. However, there will be a balance between the amount of block load that can be applied (which increases the rate at which the frequency falls, the RoCoF), and the time which the DRZC (and associated resources) will need to respond.

Theory

Figure 14 gives two equations showing the “maths behind inertia”. During the block load we have two effects. The first is the machine inertia which determines the RoCoF before the generator starts to act, and the second is the governor behaviour (which is slow in the case of a hydro set).

For Kendoon, the RoCoF for a 1 MW load step is -0.502 Hz/s. Without governor action, 47.5 Hz would be reached in 4.98 s. However, this number is optimistic as Figure 14 shows that the inertia varies as the square of the speed of the generator. At 47.5 Hz the speed has fallen by 5% and H is reduced by 9.75%. Hence the RoCoF at 47.5 Hz (with no governor action) will increase to 0.551 Hz.

Ignoring the inertia change, applying a 10 MW load step, the RoCoF would be -5.02 Hz/s giving a time to 47.5 Hz of 0.498 s. In view of the short time, the governor response would be small, hence, to take a pessimistic view, the governor action should be ignored.

$$H = \frac{\frac{1}{2}J\omega^2}{MVA}$$

H = Inertia constant in MWs / MVA
J = Moment of inertia in kgm^2 of the rotating mass
ω = nominal speed of rotation in rad/s
MVA = MVA rating of the machine

Typical H for a synchronous generator can range from 2 to 9 seconds (MWs/MVA)

$$\frac{\partial f}{\partial t} = \frac{\Delta P}{2H}$$

∂f/∂t = Rate of change of frequency
ΔP = MW of load or generation lost
2H = Two times the system inertia in MWs / MVA

Figure 14:The maths behind inertia

Implementation

To increase the BLPU capability of a DRZ in the Galloway region, it may be desirable to have several Galloway hydro sets running to get the system inertia up to a more manageable level. It should be noted that a hydro generator has a lower inertia than an equivalent sized turbo generator (typically ~ 5 times more).

Wind Turbine Stability Issues

The live testing highlighted two issues when connecting wind turbines to a weak island.

Minimum short circuit ratio (SCR) required

During the testing the total number of turbines connected was limited to four. This ensured that a SCR of greater than three (the ratio of fault level divided by turbine MVA capacity connected) was maintained (this is the minimum typically required by turbine manufacturers for stable operation.

In a business as usual (BAU) implementation this could be a significant limitation on the capacity of converter connected DER which can be connected. Further investigation would be beneficial to see if this ratio can be reduced, or the merits of mitigations to overcome (e.g. retuning converters to work with a reduced SCR, using grid-forming converters, using additional DERs to increase the network fault level).

Turbine reactive power capability

During the live testing a concern was that, with the low fault level, the turbine voltage control may go unstable resulting in excessive Mvars being generated into the test network. This could lead to tripping the anchor DER if it's leading power factor capability (ability to absorb Mvars) is exceeded. For the testing, the turbine Mvar range (normally 0.95 leading to lagging power factor) was reduced so that if instability occurred, there would be no associated network issues.

For a BAU implementation, there may be a compromise between the Mvar range required to support the network and ensuring any voltage instability does not ensue wider network issues.

4.6.2 Key Achievements

At the end of the Galloway phase 3 testing, we managed to successfully:

- energise primary (33/11 kV) transformers (up to 24 MVA) from the Kendoon hydro generator operating at normal voltage levels (~11 kV)
- prove the block load pickup (BLPU) capability of the anchor generator (the amount of instantaneous demand which can be applied while maintaining the frequency above 47.5 Hz)
- energise the Glenchamber and North Rhins wind farm 33 kV cable arrays, and associated turbine transformers, from the anchor generator (initially all turbines were shut down)
- at Glenchamber and North Rhins wind farms, connect several wind turbines to the "weak" islanded network (supplied only from Kendoon hydro) and prove stable turbine operation both in power factor and voltage control modes
- establish a stable power island with Kendoon hydro and several turbines connected across Glenchamber and North Rhins wind farms simultaneously.

4.6.3 Conclusions

- The concept of providing restoration services from DERs is closer to becoming a reality based on the learnings from the live testing at Galloway.
- Initial tests developed and proved the ability of a "small" hydro generator to energise the 11 kV to 275 kV network (including 480 MVA capacity of super grid transformers simultaneously).
- Final Galloway live trials have culminated in successfully establishing a power island with an anchor generator (hydro) and intermittent DER (wind farms).
- The fundamental principle of establishing a DRZ, with multiple DERs, has now been proven in practice.

The trial used the 60 MVA Steven's Croft biomass 11 kV generator as the anchor (to initially energise the network and control the voltage and frequency). The generator has a 53 MVA 11/33 kV step-up transformer and is connected to a SP Distribution (SPD) 33 kV metering switchboard at its site. During the live testing, the distribution and transmission networks were configured to create a test network (from 11 kV to 400 kV including associated transformers), while maintaining supply to all existing customers.

5. Chapelcross – Live Trial Background

This section provides an overview of the Steven's Croft island mode preparation works and procedures, goals of the trials, along with schematic diagrams and maps showing the Chapelcross test network.

5.1 Anchor Distributed Energy Resource (DER)

The trial used the 60 MVA Steven's Croft biomass 11 kV generator as the anchor (to initially energise the network and control the voltage and frequency). The generator has a 53 MVA 11/33 kV step-up transformer and is connected to a SP Distribution (SPD) 33 kV metering switchboard at its site. During the live testing, the distribution and transmission networks were configured to create a test network (from 11 kV to 400 kV including associated transformers), while maintaining supply to all existing customers.

5.1.1 Steven's Croft Normal Configuration/Operation

A high-level schematic of the electrical configuration of Steven's Croft biomass is given in Figure 15. The generator transformer (1BAT10) is normally energised from the SPD network, supplies its auxiliaries (~5 MW base load) from a 11/6.6 kV auxiliary transformer, and the generator is synchronised at its 11 kV circuit breaker (1BAC01). It normally operates on voltage control (an automatic voltage regulator (AVR) controlling its 11 kV terminal voltage), and on "power mode" where the MW output of the generator would be adjusted with no reference to the system frequency (this is determined by the network supply). The installation has been designed such that Steven's Croft can also synchronise at 33 kV across CB 1AHA01 (ensuring the generator 33 kV network is earthed initially through circuit breaker (CB) 1BAT10), but this is not normally used in practice.

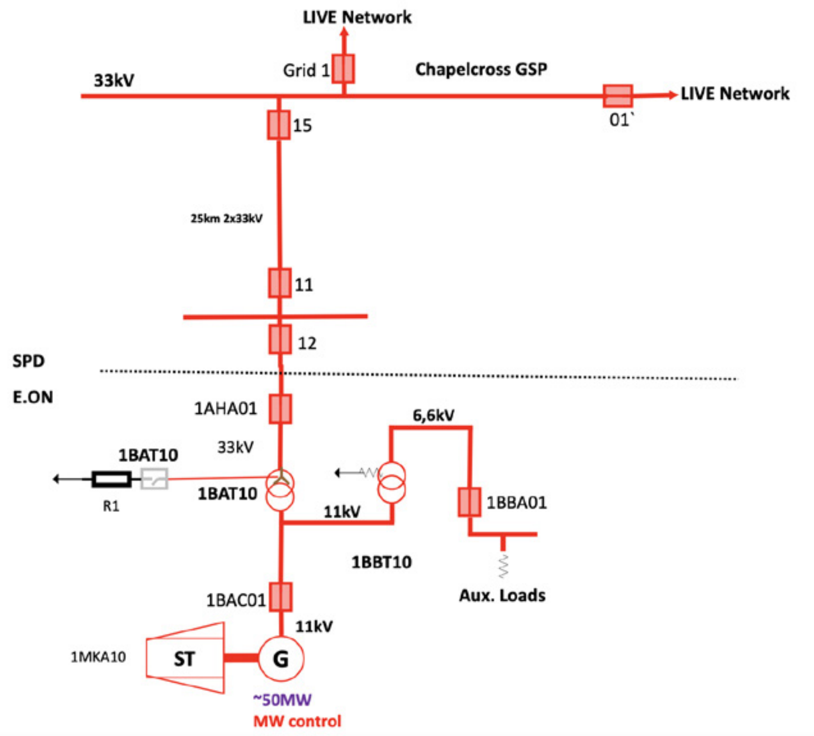

Figure 15: Steven's Croft biomass – normal configuration

5.1.2 Steven's Croft Island Mode Reconfiguration Works

Plant Works

To prepare for island mode operation and testing using the Steven's Croft generator plant, installation works (permanent and temporary) were carried out. These included:

- connecting an additional 33 kV CB (number13) to the SPD Steven's Croft 33 kV substation (shown in Figure 16)
- connecting a temporary 15 MW load bank (the installation included 33,000/400 v transformers) to CB13
- this provided load to test the BLPU capability of the generator, and also a minimum stable demand for generator island mode operation
- connecting an additional 6.6 kV CB (1BBA11) to the E.ON 6.6 kV auxiliary switchboard (shown in Figure 16)
- connecting temporary diesel generators to 6.6 kV CB 1BBA11 to supply the generator auxiliary demand (at 6.6 kV), and to isolate the normal supply which comes through a 11/6.6 kV transformer connected to the main generator 11 kV output
  - → this would ensure that any voltage or frequency transients during testing would not affect the generator auxiliaries, and potentially trip the generator.

Feasibility Study

In addition, Siemens (the original installers of the generator turbine) were commissioned to carry out a feasibility study for the Steven's Croft generator to determine the suitability, and modifications required, to carry out the proposed island mode operation and testing. Their feasibility study covered areas such as:

- preparation of generator electrical systems (protection, synchronisation and excitation systems)
- load steps and speed control stability
- grid energisation and voltage control stability.

Specialists from the Siemens "black start team" attended site during the week allocated for the live testing (week commencing Monday 20 June 2022). During the first day of the week no testing was undertaken (this commenced on Tuesday 21 June) while Siemen's personnel made the necessary control changes to the Steven's Croft plant. This was able to be done while the power station was generating as normal.

An example of the required control changes was making changes to the power station control system to allow circuit breakers to be closed onto a dead busbar (e.g. 11 kV CB 1BAC01). This CB would normally only be allowed to close when there was voltage either side and in synchronism. "Dead bar closing", required for black start, would normally be inhibited.

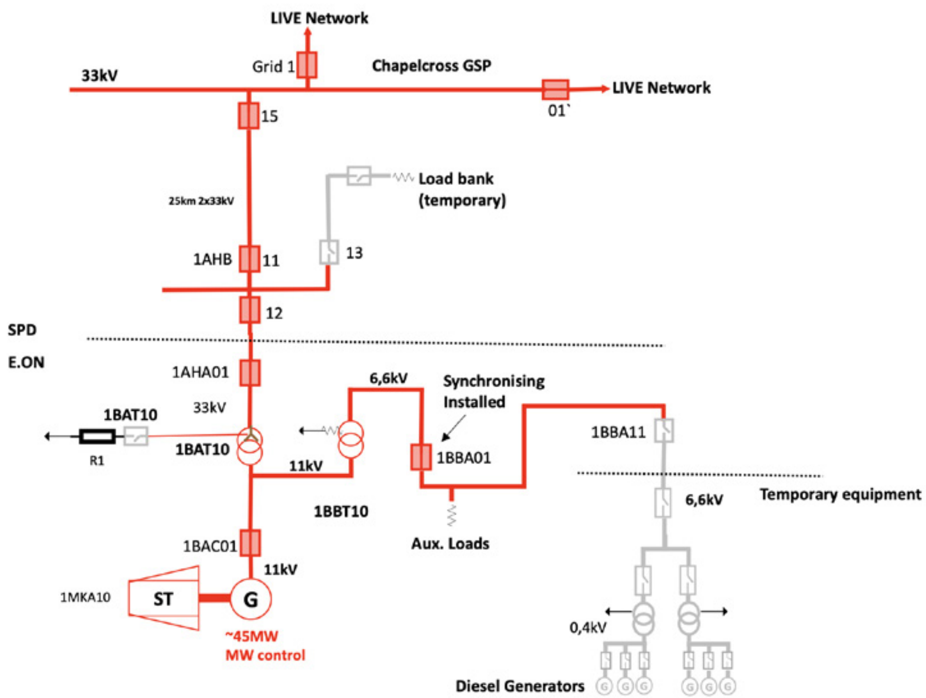

Figure 16: Steven's Croft installation works

5.1.3 Steven's Croft Island Mode Set Up

Island Mode Configuration

Figure 17 shows the planned configuration of the Steven's Croft site for island mode operation, prior to carrying out any network tests. The main features are:

- Steven's croft generator is on frequency control (as well as normal voltage control) mode.
- The 33 kV network is earthed via the generator transformer earth start point (CB 1BAT10).
- The auxiliary load of the generator (~5MW) is supplied by the temporary diesel generators, with the generator auxiliary transformer disconnected.
  - → Space on site was limited, and to minimise the hire cost for diesel generators, the diesel generator capacity was enough to run the station auxiliary loads, but not enough to start some of the larger drives. As a result, transferring to the island mode configuration needs to ensure the auxiliaries always stay on.
- The generator is running against the load bank (~8 MW applied as a minimum stable demand).

Island Mode Set Up Procedure

Testing was not aimed at proving the black start capability of the Steven's Croft site, but purely to assess the feasibility of using Stevens Croft as the anchor generator for a distributed island. It follows that the following procedures were developed to enable Steven's Croft to operate in island mode, without having to install diesel generation capable of restarting all auxiliary drives (this would have required around double the capacity installed).

Transfer of auxiliaries to the diesel generators

The first stage was to reduce output to about 28 MW to avoid the possibility of a trip from full load. The station 6.6 kV auxiliary supply was connected through circuit breaker 1BBA11 to the 6,600/400 v transformers for the diesel generators down to the 400 V busbar. The diesel generators were then synchronised sequentially across their 400 V breakers, and load increased to match the station auxiliary load.

Once zero power transfer through the 11/6.6 kV transformer 1BBT10 was achieved, the 6.6 kV circuit breaker 1BBA01 was opened to island the diesel generators and the Steven's Croft auxiliary loads. At the same time, the diesel generators 6.6 kV transformer winding star point was earthed as the station 6.6 kV earth point was lost when circuit breaker 1BBA01 was opened.

A temporary synchronising scheme was installed on circuit breaker 1BBA01 to allow the station auxiliary loads and diesel generators to be resynchronised to the main Steven's Croft network. This system was successfully tested before circuit breaker 1BBA01 was reopened for the remainder of the testing.

The above procedure avoided the need for the diesels to be able to restart the large auxiliary drives.

Main generator islanding procedure

The next stage involved reducing the generator to minimum load of about 9.5 MW. The load bank, which was connected at 33 kV at the SPD through CB13, was increased to match the generator output.

Once a generation and load balance had been achieved, by confirming zero power flow on SPD CB11 at the Steven's Croft site, this CB would be opened. This would leave the Steven's Croft generator and the load bank islanded from the network. This operation would not be required during a black start as the generator would be started and used to energise a dead network rather than islanding from an active network.

Steven's Croft was believed to have an islanding capability, but investigation showed that this had never been tested. However, this was not relevant as the scheme would have gone into island mode when the station's 33 kV circuit breaker 1AHA01 opened. During testing, this breaker would remain closed, and CB11 beyond the load bank opened.

As a result, the station control system had to be manually told when islanding occurred. When in island mode, the governor control is changed, and the transformer 33 kV star point is earthed through a resistor. It was decided to match the generator output and load bank, then select island mode to ensure the test network is earthed before opening the 33 kV breaker to island the system.

The first day of live testing (Tuesday 21 June) was mainly associated with the steps to achieve the configuration shown in Figure 17. The results are given in Section 6 *Chapelcross – Live Trial Results*.

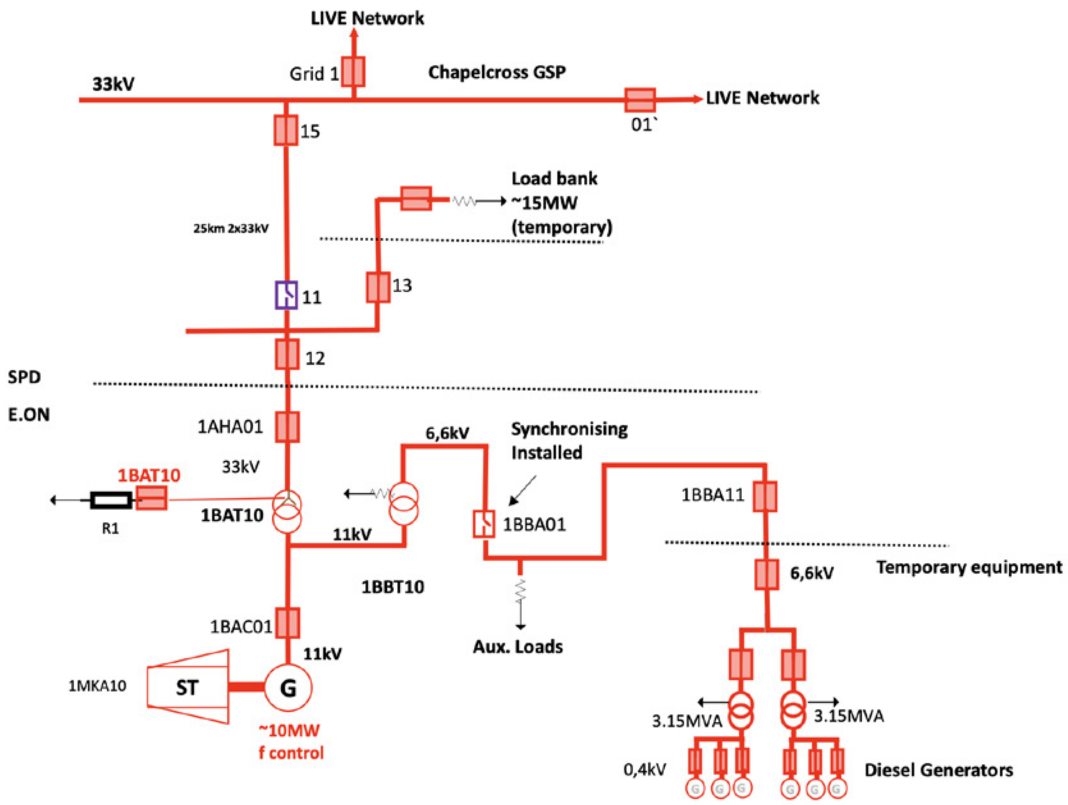

Figure 17: Steven's Croft island mode configuration

5.2 Chapelcross Test Goals

The goal of the Chapelcross live trials was to:

- prove operation of the Steven's Croft generator in "island mode'" (energising and controlling the frequency and voltage on an isolated network)
- test the block load pick up (BLPU) capability of the Steven's Croft generator (the amount of instantaneous demand which can be applied while maintaining the frequency above 47.5 Hz)
- prove the ability of the Steven's Croft generator to energise the local distribution and transmission network (including associated transformers).

5.3 Test Network Diagrams

The Chapelcross test network diagrams, which formed part of the test plan which was executed on the live trial days, are shown below in Figures 18–20.

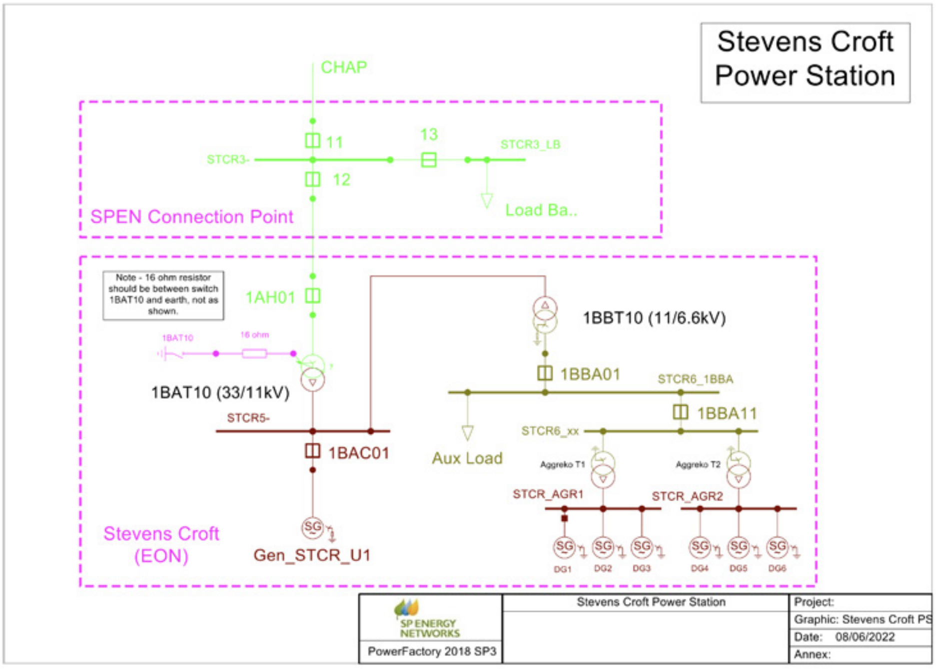

Figure 18: Steven's Croft power station and connection point

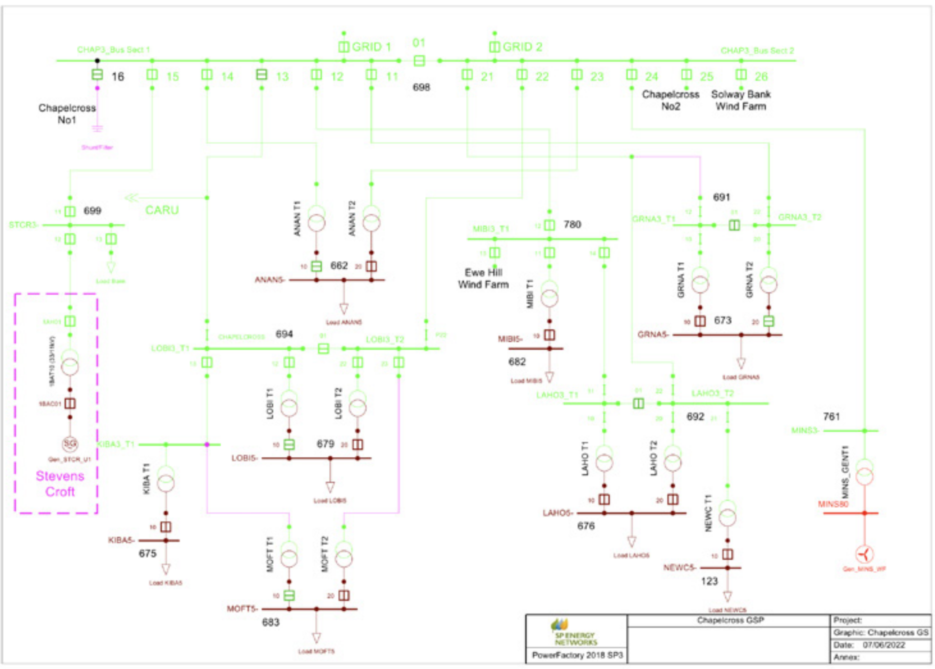

Figure 19: Chapelcross 33 kV grid supply point

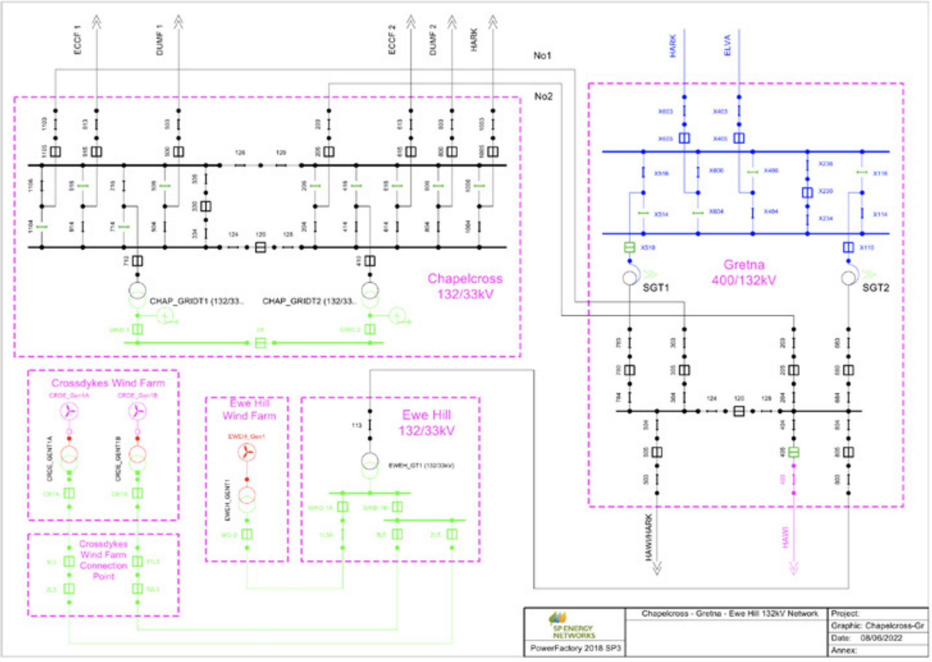

Figure 20: Chapelcross/Gretna 132 kV network

6. Chapelcross Live Trial Results

This section provides a summary of the Chapelcross live testing and the associated results.

6.1 Background

The Chapelcross live testing was planned to take place for up to five consecutive days (as required to complete the testing) starting on Monday 20 June 2022. Live testing commenced on Tuesday 21 June (the Monday was required for preparation works at the Steven's Croft site), and all tests were completed on the second day's testing on Wednesday 22 June.

In this section, the testing sequence which was implemented during the two live trial days is given (see Table 4), followed by comments and results for the key events (key steps in the testing sequence) during the testing. A discussion is given of technical issues highlighted by the trials along with a summary of the key achievements.

6.2 Testing Sequence

The Chapelcross live trial testing sequence is shown in Table 4.

For the events in Table 4 which are numbered, comments and data traces (if applicable) are provided in section 6.3 Results.

Table 4: Chapelcross live trial testing sequence

Time	Event	Description	Comments
Tuesday 21 June 2022			
10:38	–	Island Steven's Croft auxiliary loads on temporary diesels	
10:49	–	Resynchronise facility on 6.6 kV CB 1BBA01 tested	Successful test
10:58		Island Steven's Croft auxiliary loads on temporary diesels	
14:34	1	Prepare to island Stevens Croft Steven's Croft island mode engaged (changes from power to frequency control) and closes 33 kV CB 1BAT10 to provide 33 kV earth. This was done prior to SPD 33 kV CB11 being opened to disconnect network supply	Governor ramped up generator power leading to generator trip
		Prepare to restart generator and auxiliary loads	
		Generator 11 kV CB 1BAC01 closed to back energise 11/33 kV generator Tx (1BAT10). Generator then synchronised to main network at 33 kV across CB 1AHA01. Auxiliaries returned to generator supply and normal generator output (~45 MW resumed).	This reenergisation, following the generator trip, allowed this realistic black start scenario of the generator energising its own network to be proven

Wednesday 22 June 2022			
		Island Steven's Croft auxiliary loads on temporary diesels	
11:21	2	Open SPD 33 kV CB11 at Steven's Croft to island the generator	Successful island operation established with Steven's Croft output of ~8 MW against the load bank
	3	Block load testing of Steven's Croft generator	Using additional available capacity on the load bank
16:35	4	Energise Stevens Croft/Chapelcross 33 kV circuit	~25 km underground cable
16:45	5	Energise Gretna primary transformer	33/11 kV 24 MVA
16:51		De-energise Gretna primary transformer	
16:56:48	6	Energise Chapelcross grid transformer T1	132/33 kV 90 MVA
17:08		Energise Chapelcross 132 kV reserve busbar	
17:09:19	7	Energise Chapelcross/Gretna 132 kV circuit	13 km of 132 kV overhead tower line
17:47		Energise Gretna 132 kV number 1 busbar	
17:48:11	8	Energise Gretna super grid transformer SGT1 (400/132 kV 240 MVA)	**CHAP T1 and CHAP/GRNA No1 Circuit Tripped**
18:22:10	9	Energise Chapelcross grid transformer T1	132/33 kV 90 MVA
18:23:19		Energise Chapelcross 132 kV reserve busbar	
18:24	10	Energise Chapelcross/Gretna 132 kV circuit	13 km of 132 kV overhead tower line
18:25:03		Energise Gretna 132 kV number 1 busbar	
18:29:04	11	Energise Gretna super grid transformer SGT1	400/132 kV 240 MVA

6.3 Results

Further analysis is given for the eleven numbered events signifying the key stages in the testing sequence listed in Table 4.

The data traces are obtained from the relevant recorders which were triggered. It should be noted that events 1, 2, 3 and 5 did not trigger any fault recorders. For these events, the slow root mean square (RMS) data was extracted so voltage waveforms are not available for these events.

6.3.1 Event Number1 – Initial Failure to Island and Generator Trip – Tuesday 21 June

Description

This event was the first attempt to island the Steven's Croft generator, along with the load bank, from the network 33 kV supply.

As described in Section 5.1.3, once a generation and load balance had been achieved by confirming zero power flow on the Steven's Croft to Chapelcross circuit, CB11 at Steven's Croft would be opened to disconnect the incoming network supply.

Steven's Croft was believed to have an islanding capability, but investigation showed that this scheme would have gone into island mode when the station's 33 kV circuit breaker 1AHA01 opened. During testing, this breaker would remain closed, and the SPD CB11 beyond the load bank opened.

As a result, the station control system had to be manually told when islanding occurred. When in island mode, the governor control is changed, and the transformer 33 kV star point is earthed through a resistor. It was decided to match the generator output and load bank, then select island mode to ensure the test network is earthed before opening the 33 kV breaker to island the system (CB11).

Results

Figure 21 shows island mode being selected with a power mismatch of about 0.4 MW and a network frequency of 49.91 Hz. The governor then starts to ramp up the generator output to achieve 50 Hz, however as the generator is still connected to the network there was no frequency change. Due to the increasing power mismatch, the 33 kV circuit breaker (CB11) was not opened. About 1 minute 41 seconds later the generator tripped.

The power ramp indicates that in island mode, the governor includes an integral term. This will ensure that in island mode, the frequency is kept very close to 50 Hz. However, it could cause issues if other generators in the island are providing frequency control, especially if they also have an integral term in the governor. While this is unlikely to be a problem initially, later when islands are being merged it could become an issue.

Due to the generator trip, the sequence to recover from a trip was then carried out. There was a delay while the control system was modified to allow the generator 11 kV breaker to be closed on to a dead busbar. Eventually the procedure was completed, but testing was then stopped for the day.

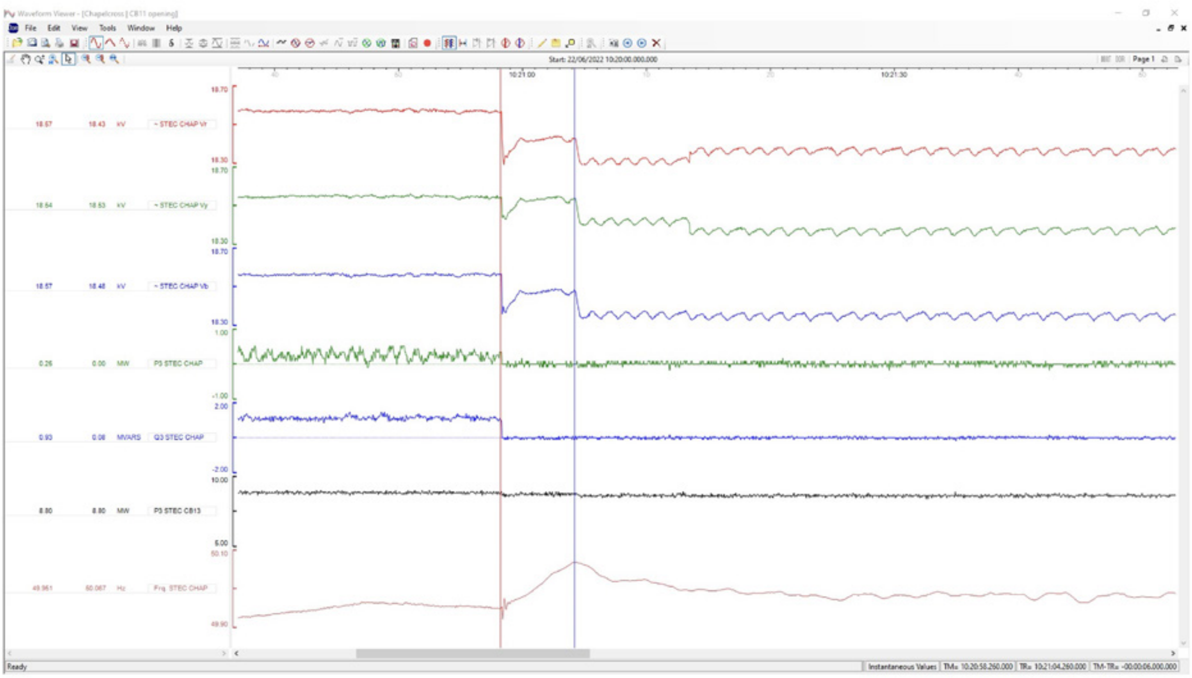

Figure 21: Initial failure to island Steven's Croft leading to generator trip

6.3.2 Event 2 – Island Steven's Croft Generator – Wednesday 22 June

Description

At the start of the second day's testing, another attempt was made to island the Steven's Croft generator, and the distribution and transmission network outages commenced in preparation for energisation tests.

This time, the generator governor integral time constant had been changed to reduce the ramp rate by a factor of 10. Thus, when in island mode in parallel with the network supply, there should be time to disconnect the network 33 kV supply before any significant change in generator output.

However, as the Steven's Croft 33 kV earthing switch had operated correctly (when island mode was enabled), it was decided to open 33 kV CB11 first (to minimise any risk of tripping), and then immediately select island mode to earth the generator 33 kV network and enable frequency control.

Results

The above procedure resulted in successful islanding of the Steven's Croft generator. Figure 22 shows CB11 being opened, and island mode selected about 6 seconds later. During this period, the test network frequency increased from 49.95 Hz to 50.07 Hz. The governor then brought the frequency back to nominal.

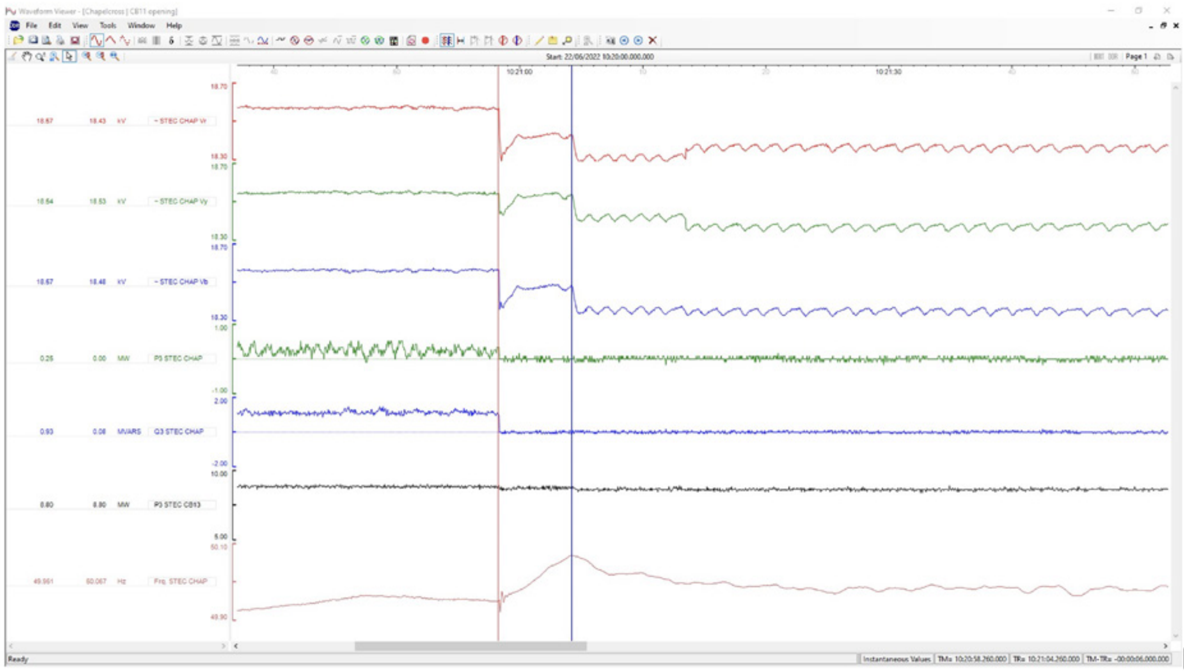

Figure 22: Island Steven's Croft by opening CB11 at connection point (prior to island mode selection)

6.3.3 Event 3 – Block Load Step

Description

Block load steps were carried out to determine the load capability of the generator. The aim was to determine the maximum load step that could be applied without the test network frequency dropping to 47 Hz and recovering above 47.5 Hz within 20 seconds. Removal of the block load must not result in the frequency reaching 52 Hz. These values are based on the Grid Code Connection Condition CC.6.1.3.

Previous testing on a hydro generator at Kendoon Power Station had found a block load capability of about 10% of the generator rated power (see Section 4.3.9). Performance of a steam generator was expected to be better due to the time required to accelerate the water column on a hydro station compared with increasing steam flow to the turbine on a thermal unit.

Due to the size of the load banks and the limited space at the Steven's Croft site, it was decided to install a 15 MW load bank. This would provide about 10 MW to keep the generator above minimum load with 5 MW available to provide the block load step.

The first test was carried out with a 0.5 MW block load. This produced a frequency variation of about 0.06 Hz which tended to be only slightly larger than the random frequency variation on the test system.

Further tests were carried out with 1, 2, 3 and 4.6 MW (the maximum available from the load bank) steps. The results will concentrate on the final test as the 4.6 MW step.

The tests carried out involved applying a load step, followed 20 seconds later by the removal of the step. The tests were aimed at examining the effect of the machine inertia and the behaviour of the governor. The step application was kept short to minimise any need for the boiler to respond. A Siemens Energy report indicates that, based on the boiler response, the unit is capable of a 20 MW step change, but if a 30 MW change is required, the first 20 MW could be a direct jump, but the following 10 MW increase would have to be over a 9 minute period.

Results (4.6MW Block Load Step)

A 4.6 MW block load resulted in a frequency change of about 0.4 Hz, well short of the maximum permissible frequency variation (~3Hz). This indicates a potential block load capability in excess of 25 MW (excluding the boiler limitations mentioned above).

Results

The fault recorder data for the application and removal of the 4.6 MW load step is shown in Figure 23, with the results tabulated in Table 5. An expanded view of the power and frequency is shown in Figure 24 for application of the block load.

The field current of a synchronous generator must be increased to move the generator operating point towards increasing lagging power factor. The field current must also be increased for increasing active power. When energising a primary, the load is very unlikely to be at unity power factor and the 33 kV circuit from the GSP to the primary will also generate reactive power which may partially offset the reactive demand of the load. However, during this test there was no circuit change, and as the load bank was purely resistive hence there was no significant change in reactive power. However, the increased load will result in a voltage drop until the generator AVR can increase the generator field current. This can be clearly seen in Figure 23.

During the load bank step increase (applying the load), the voltage dropped from 33.1 kV to 32.7 kV, a change of -0.4 kV or -1.2%.

During the load bank step decrease (removing the load), the voltage increased from 33.1 kV to 33.5 kV, a change of +0.4 kV or +1.2%.

In both cases, the AVR restored the voltage within 2 seconds.

During the load bank step increase, the frequency dropped from 49.98 Hz to 49.58 Hz, a change of -0.4 Hz or -0.8%.

During the load bank step decrease, the frequency increased from 49.97 Hz to 50.37 Hz, a change of +0.4 Hz or +0.8%.

The governor halted the frequency drop in 1.52 seconds, after which it increased the frequency towards 50 Hz.

A small transient lasting about 200 ms can be observed on the frequency trace on application of the load step. Similar transients can be observed on the voltage traces from which the frequency is calculated. This transient is likely to be a result of the fault recorder calculation of voltage and frequency from the original voltage waveforms. The rate of change of frequency (RoCoF) shown in the table was calculated between 300 and 600 ms to avoid the initial transient. As no recorder trigger occurred, no waveform data was recorded.

If a block load step of 25 MW was used, the RoCoF is likely to be 2.3 Hz/s or greater (generator protections are typically set to operate for a RoCoF greater than 1.0 Hz/s).

Table 5: 4.6 MW load step results

Load Step	Actual Load Step	Peak Frequency	Time to Peak	Rate of Change of Frequency	Initial Frequency	Frequency Change
4.6 MW Increase	4.5 MW	49.58 Hz	1.52 s	-0.414 Hz/s	49.98 Hz	-0.40 Hz
4.6 MW Decrease	4.5 MW	50.37 Hz	1.42 s	+0.413 Hz/s	49.97 Hz	+0.40 Hz

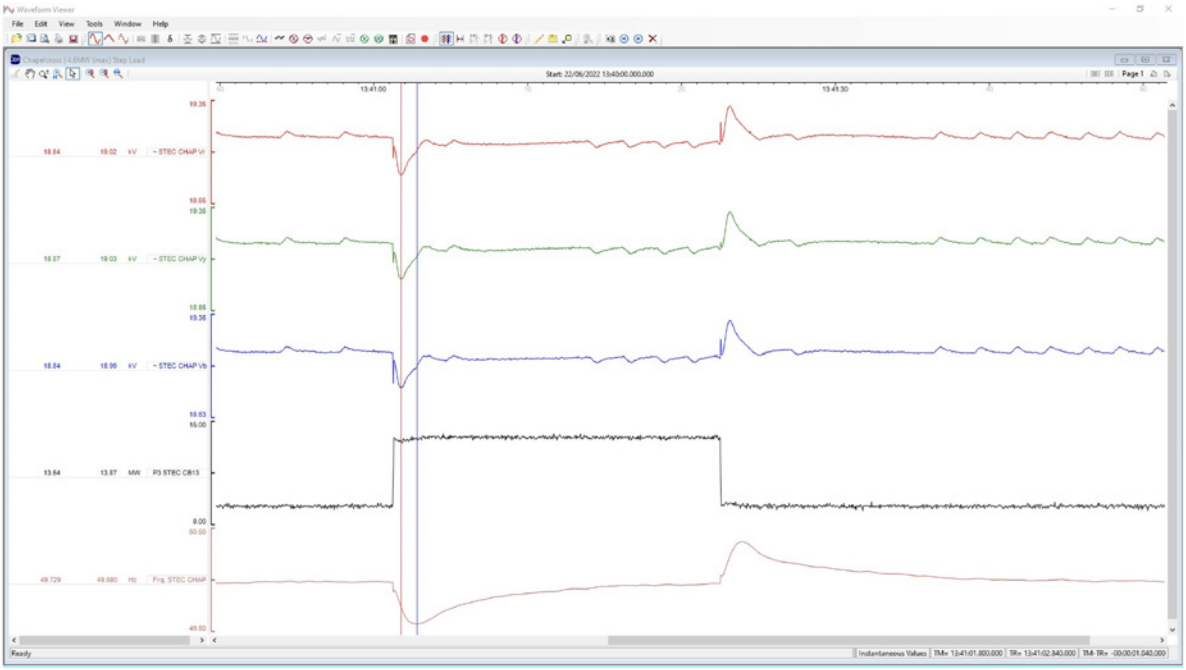

Figure 23: Block load step 4.6 MW (increase and decrease)

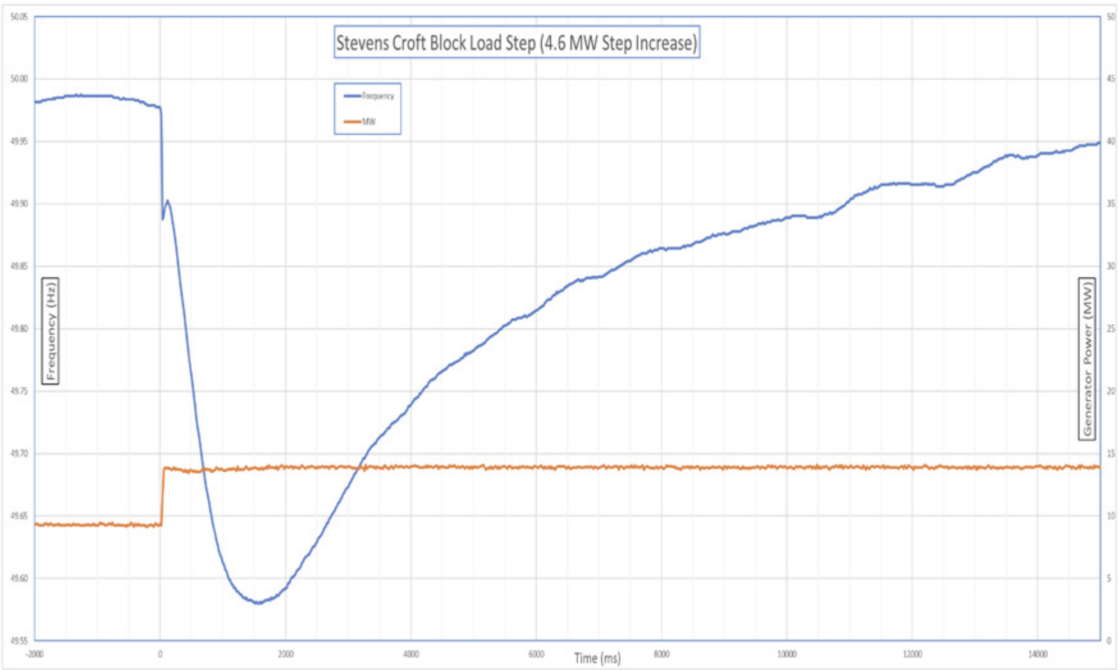

Figure 24: Block load step 4.6 MW increase

6.3.4 Event 4 – Energise Steven’s Croft to Chapelcross 33 kV Circuit

Description

This was energising the 25 km 33 kV underground cable circuit between the Steven’s Croft site and Chapelcross 132/33 kV grid supply point (GSP).

Results

Figure 25 shows that energising the 33 kV cable circuit caused a voltage transient at Steven’s Croft, but the duration was only a few milliseconds. Overvoltages can be observed on the yellow and blue phase voltages.

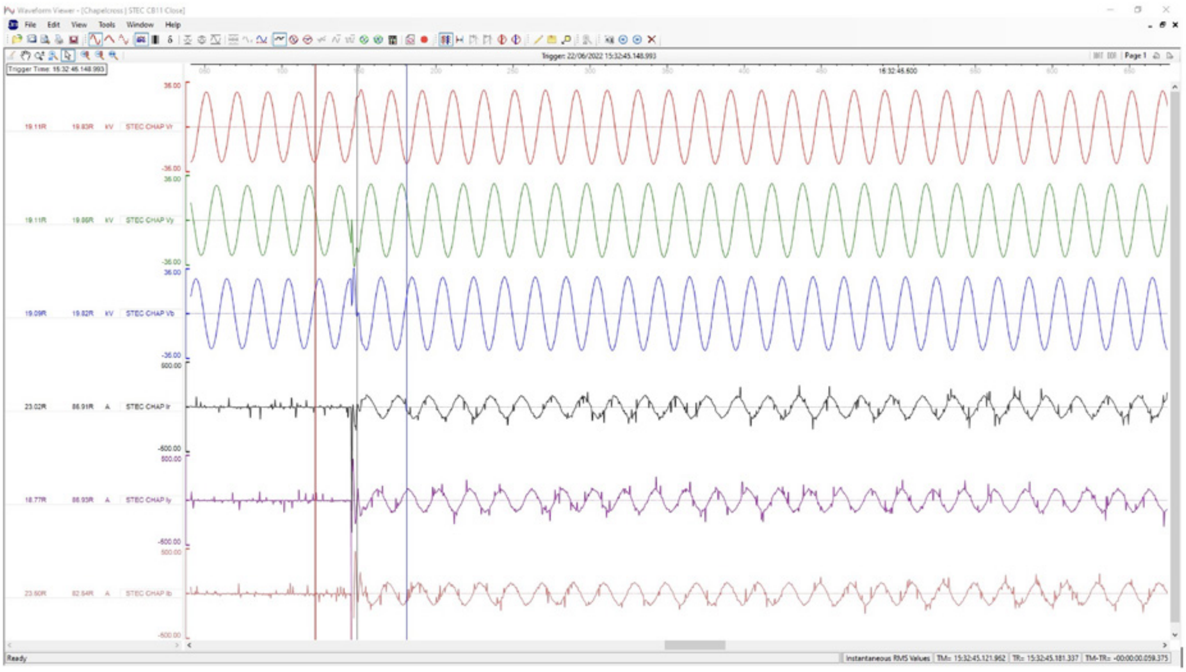

Figure 25: Energising the Steven’s Croft to Chapelcross 33 kV circuit

6.3.5 Event 5 – Energise Gretna Primary

Description

Energising the Gretna primary (33/11 kV) transformer (24 MVA) from the Chapelcross 33 kV busbar did not trigger the Steven’s Croft fault recorder. The slow RMS data was extracted from the fault recorder.

Results

Figure 26 contains the data trace for this energisation. A step reduction in the 33 kV voltage can be observed, presumably because of the magnetising inrush current to the primary transformer. A small overshoot followed as the AVR responded to the voltage dip. The duration of the transient was about 1 second.

Less easy to explain is the significant reduction of the 3 phase currents. Again, the duration of the transient was about 1 second.

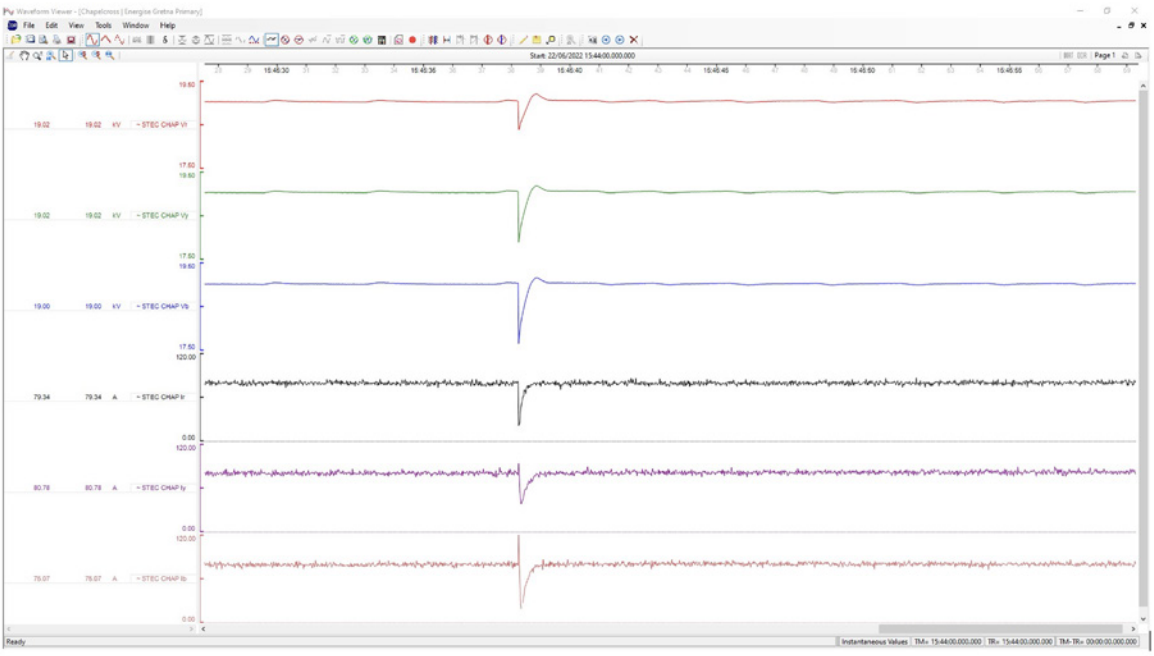

Figure 26: Energise Gretna primary transformer

6.3.6 Event 6 – Energise Chapelcross Grid Transformer T1

Description

Energising the Chapelcross grid transformer T1 (132/33 kV, 90 MVA) triggered the Steven's Croft and grid transformer T1 132 kV fault recorders. The grid transformer T1 33 kV fault recorder did not trigger which was unexpected as the 3 phase voltage channels should have triggered on the appearance of voltage when the grid 1 circuit breaker was closed.

Results

Figure 27 and Figure 28 show the Steven's Croft 33 kV and Chapelcross 132 kV voltage traces respectively. Energising the transformer caused distortion of all 3 phase voltages at Steven's Croft and on the T1 132 kV voltage. Over a period of 20 cycles (400 ms) the amplitude of the distortion decreased by about 50%.

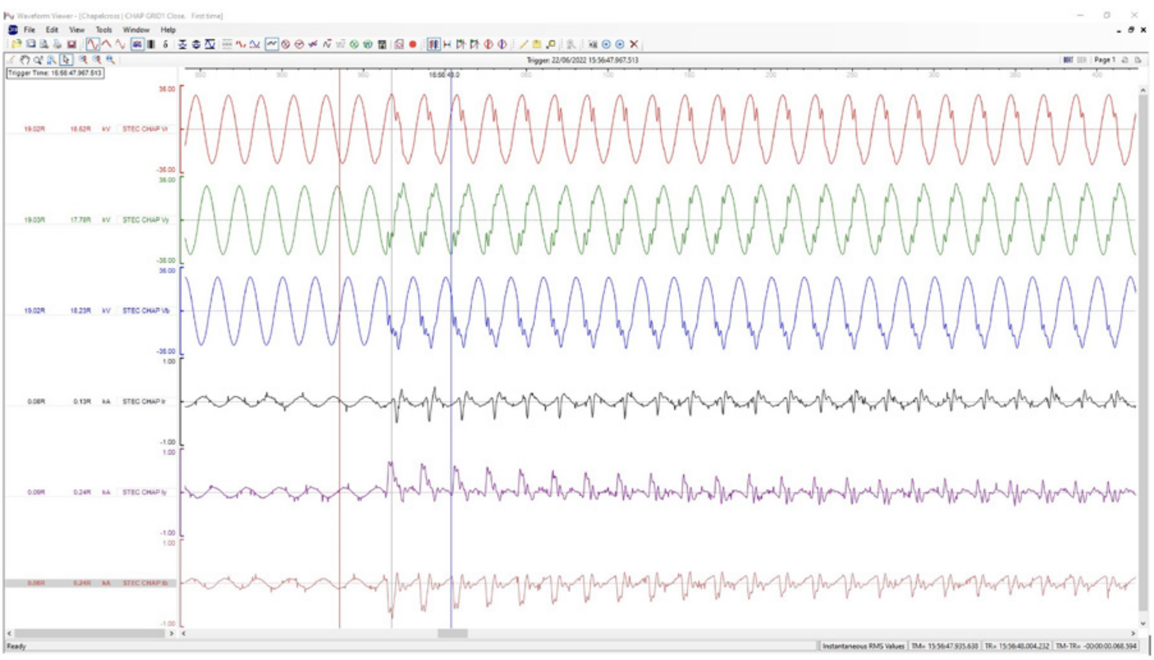

Figure 27: Energise Chapelcross grid transformer T1, Steven's Croft 33 kV voltages

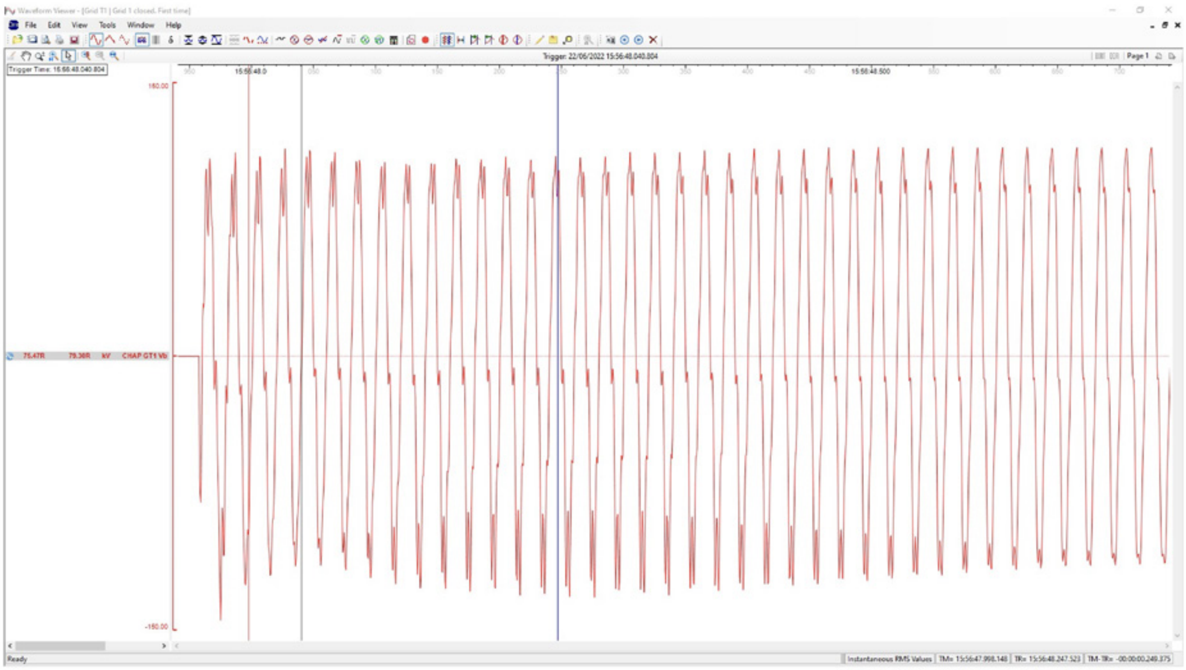

Figure 28: Energise Chapelcross grid transformer T1, Chapelcross T1 132 kV voltage

6.3.7 Event 7 – Energise Chapelcross/Gretna 132 kV Number 1 Circuit

Description

From Chapelcross 132 kV substation, a 13 km 132 kV overhead tower live circuit to Gretna 132 kV substation was energised.

Results

Figure 29 shows that a short duration transient on the voltage traces is visible lasting for about half a cycle (10 ms). There is also a slight offset to the voltages lasting about 5 cycles (100 ms).

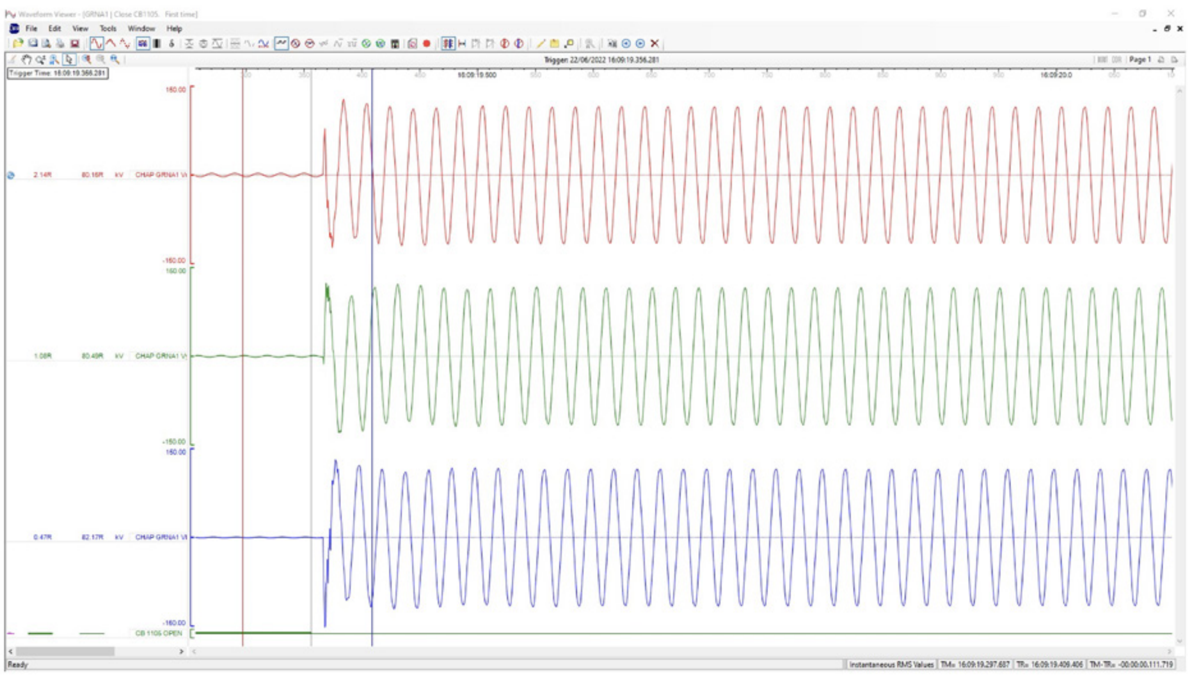

Figure 29: Energise Chapelcross/Gretna 132 kV number 1 circuit, Chapelcross end 132 kV voltage

6.3.8 Event 8 – Energise Gretna Super Grid Transformer SGT1

Description

The first attempt to energise the Gretna super grid transformer SGT1 (400/132 kV, 240M VA) resulted in a trip of the Chapelcross grid transformer T1 and the Chapelcross to Gretna 132 kV number 1 circuit. This is believed to have been due to incorrect protection changes (overcurrent protections operated instantaneously instead of with a planned 250 ms delay to allow for inrush currents to decay).

Results

Figure 30 and Figure 31 show the Steven's Croft 33 kV voltages and currents and the Chapelcross 132 kV voltages respectively.

All fault recorders were triggered by this event. SGT1 was energised for about 3 cycles before the trips occurred.

A high frequency resonance is visible following energisation, particularly in Figure 31 on the blue phase.

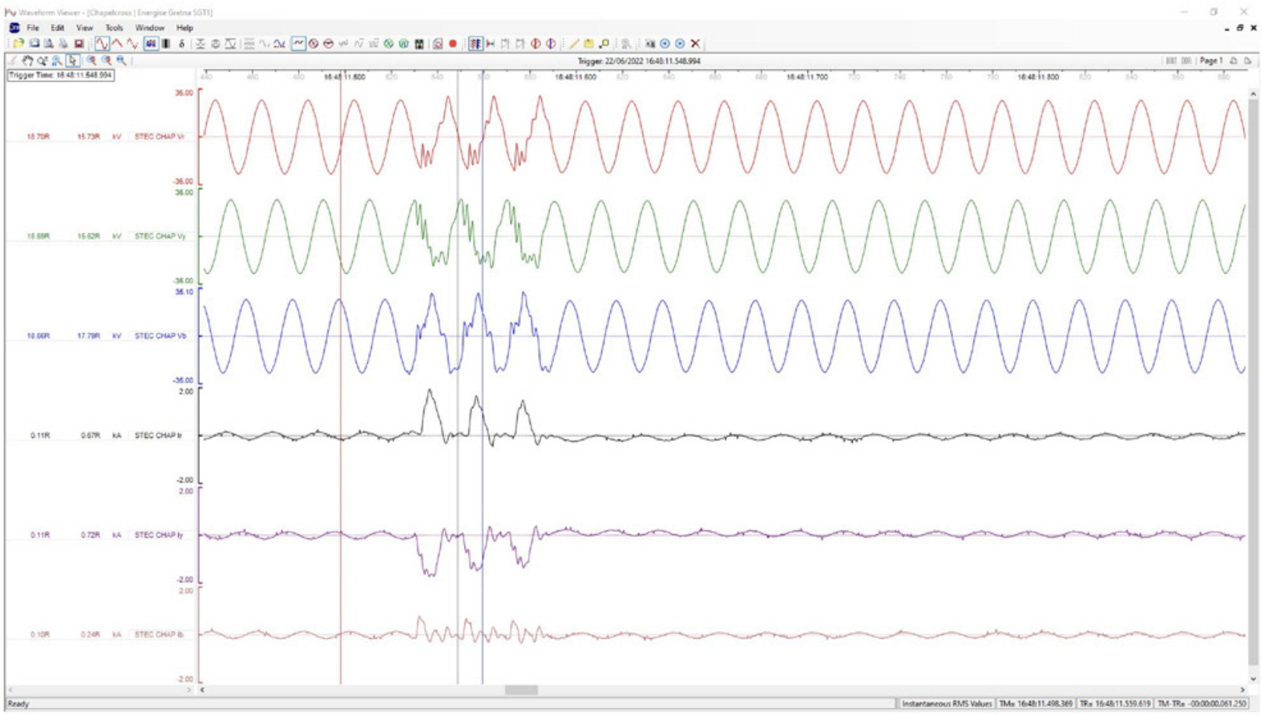

Figure 30: Energise Gretna super grid transformer SGT1 and trip, Steven's Croft 33 kV voltages and current

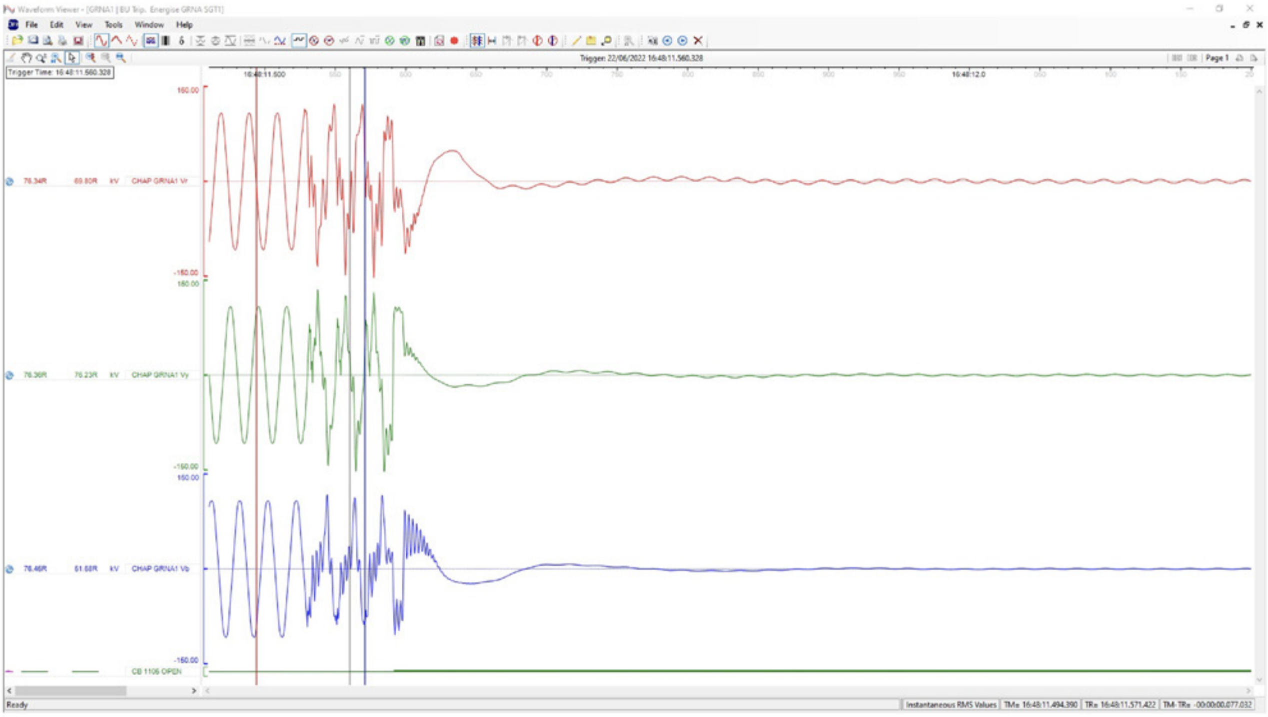

Figure 31: Energise Gretna super grid transformer SGT1 and trip, Chapelcross/Gretna 132 kV circuit voltage (Chapelcross end)

6.3.9 Event 9 – Energise Chapelcross Grid Transformer T1

See comments on Event 6. Very similar behaviour.

6.3.10 Event 10 – Energise Chapelcross/Gretna 132 kV Number 1 Circuit

See comments on Event 7. Very similar behaviour.

6.3.11 Event 11 – Energise Gretna Super Grid Transformer SGT1

Description

This second attempt to energise the Gretna super grid transformer SGT1 was successful (protection settings had been altered to include a 250 ms time delay so as not to operate for inrush currents).

Results

Figure 32, Figure 33 and Figure 34 show the Steven's Croft 33 kV, Chapelcross 33 kV and Gretna 132 kV and 400 kV data traces. It can be seen that energising the transformer caused distortion of all 3 phase voltages at Steven's Croft and on the Chapelcross T1 33 kV voltage. It is also visible on both sides of SGT1. Over a period of 20 cycles (400 ms) the amplitude of the distortion decreased by about 50%.

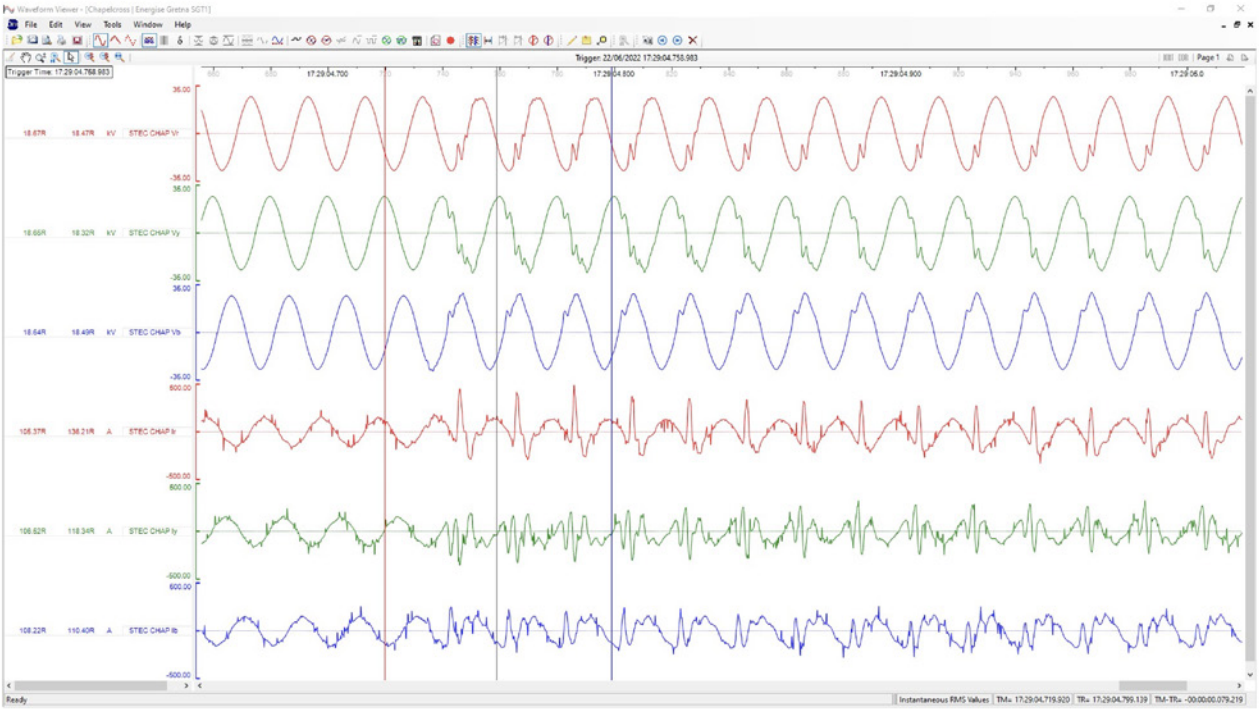

Figure 32: Energise Gretna super grid transformer SGT1, Stevens Croft 33 kV voltages and current

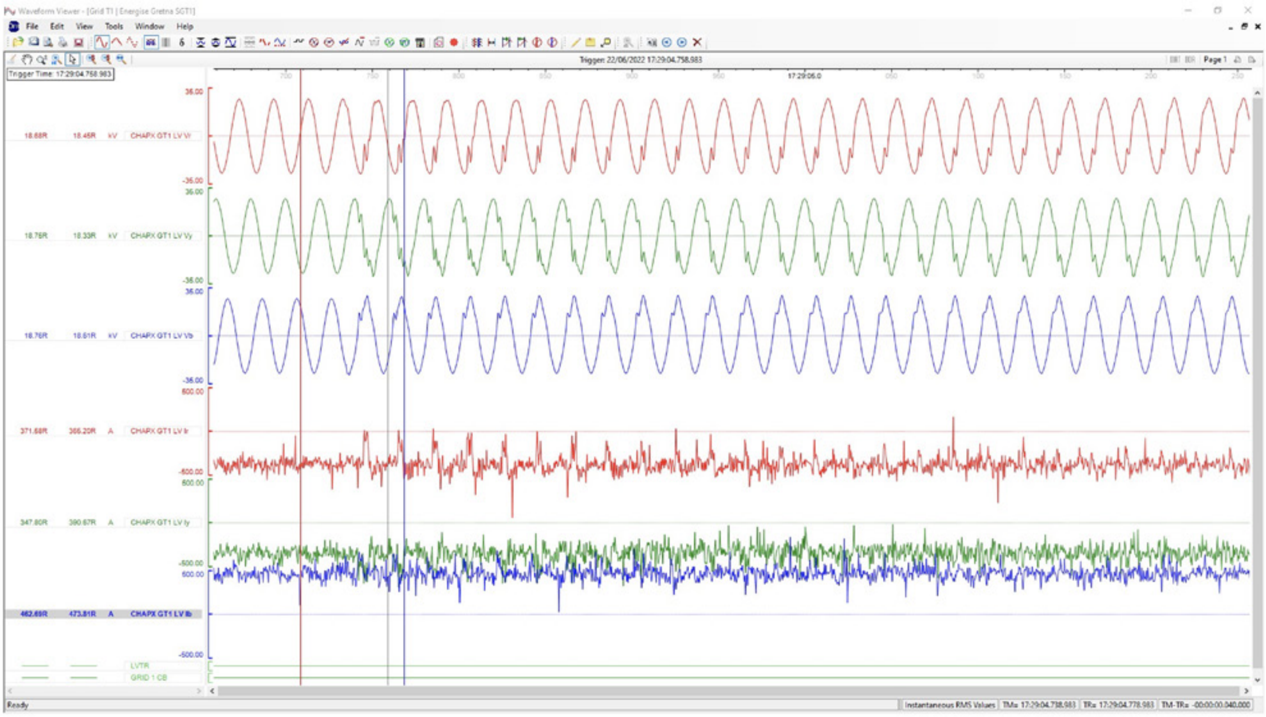

Figure 33: Energise Gretna super grid transformer SGT1 and rrip, Chapelcross grid transformer T1 33 kV voltages and current

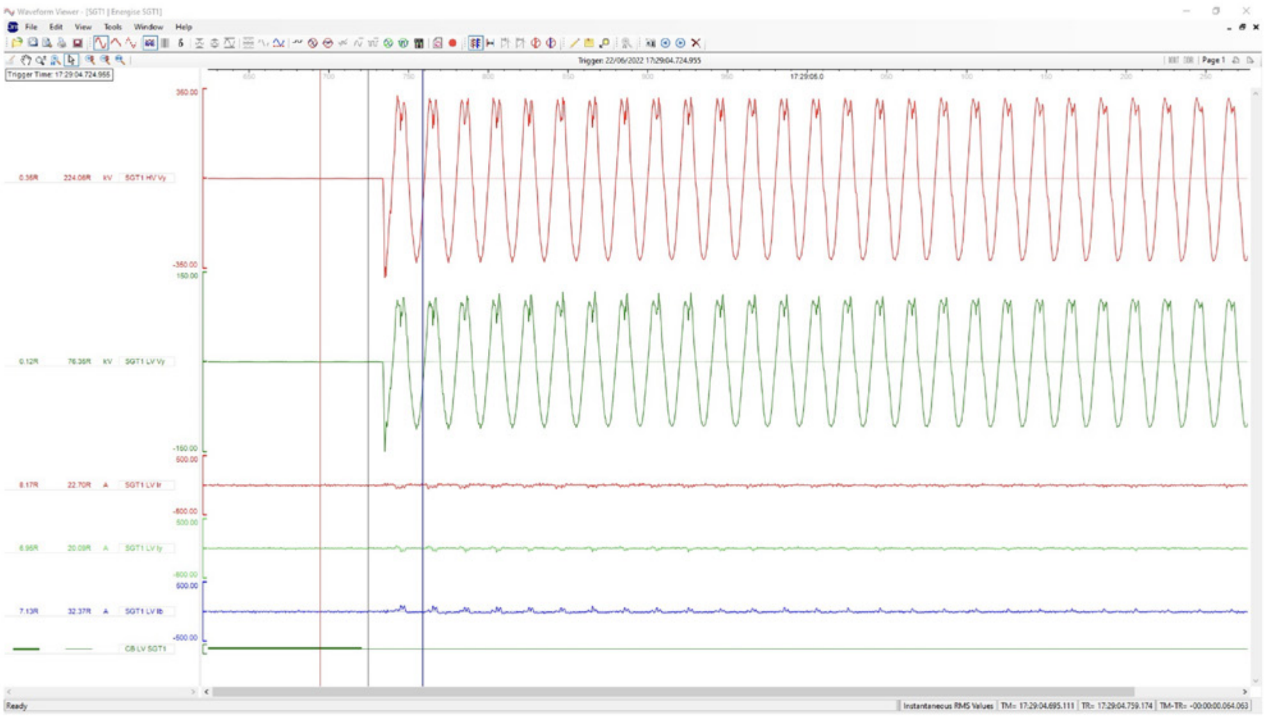

Figure 34: Energise Gretna super grid transformer SGT1 and trip, Gretna SGT1 low voltage and high voltage current

6.4 Discussion/Key Achievements/Conclusions

6.4.1 Discussion

Steven's Croft Block Load Pickup (BLPU)

Results showed that for Steven's Croft biomass a BLPU of ~20 MW is achievable (the limit being the ability of the boiler to sustain this load increase). This would be sufficient to pick up the demand at a typical primary substation in a single step. In addition, it has a continuous export capacity of ~45 MW with the maximum demand at Chapelcross grid supply point (GSP)being ~40 MW.

It follows that Steven's Croft biomass on its own is sufficient to restore the Chapelcross GSP demand following a blackout. That is, it does not need any additional DERs for "top-up" services and automation in the form of the distribution restoration zone control (DRZC) system. The two key functions of a DRZC are "fast-balancing" to enhance the anchor DER BLPU, and "slow-balancing" to manage intermittent resources used to connect demand more than the anchor DER capability. In this case the capability of Steven's Croft is such these are not required.

There are several 33 kV connected wind farms connected to the Chapelcross grid network. These could be allowed to operate as normal on an islanded network (subject to the relevant technical assessments) and would result in Steven's Croft reducing output (and saving fuel) as the wind MW output was available.

Load Bank

The Siemens Energy report shows that a load step from 4 to 23 MW is also possible. Hence starting the generator, then transferring the auxiliary loads from the diesels used to start up the generator to the main generator should provide a load close to 4 MW. The report also shows that the size of a possible load step increases slightly with increasing generator load. Hence, it appears possible that the Steven's Croft generator could act as the anchor generator for an island based at Chapelcross without the need for a load bank. However, there is a risk that the generator auxiliaries' trip from the voltage dips associated with load pickups as they would be supplied from the main generator 11 kV output (via the 11/6.6 kV auxiliary transformer).

33 kV Earthing

Background

The Steven's Croft site was unusual in that they had already installed a switchable means of earthing the 33 kV network. This was designed to protect their own 33 kV network prior to synchronising at 33 kV and is then removed when the connection is made. Distribution network operator (DNO) connection agreements typically require that all DERs connecting at 33 kV have an unearthed high voltage (HV) connection. This is so that the 33 kV network is only earthed at the grid substations to limit the fault current which will flow and avoid circulating currents.

Implementation

A means of earthing the 33 kV network is required, as close as practical to the anchor generator, when in island mode operation in order that earth fault current may flow and be detected by the protection. As such it is likely that a 33 kV earthing transformer (ET) will have to be installed at the anchor DER site as part of a DRZ implementation (with a switchable means of connecting in service). The impedance of the ET should be selected such that the earth fault currents are of a similar magnitude to when a single grid transformer ET is in service (to ensure existing protections will operate).

Peterson coil effect

Steven's Croft is connected to the grid substation by a 25 km 33 kV underground cable circuit. When undertaking fault studies (using the ET impedance of a standard available transformer) it was found that the 33 kV earth fault currents were very low. On investigation, it was found that the earthing transformer zero-sequence inductance was resonating with the zero-sequence capacitance and behaving like a Petersen Coil (these inductive coils designed such that, based on the capacitance of the network, at 50 Hz minimal fault current flows). Figure 35 shows how the 33 kV earth fault levels at Steven's Croft vary depending on the impedance of the ET selected.

It follows that care must be taken when designing an ET installation, particularly where there is a predominantly capacitive network (underground cables), that the Peterson Coil effect does not inadvertently ensue.

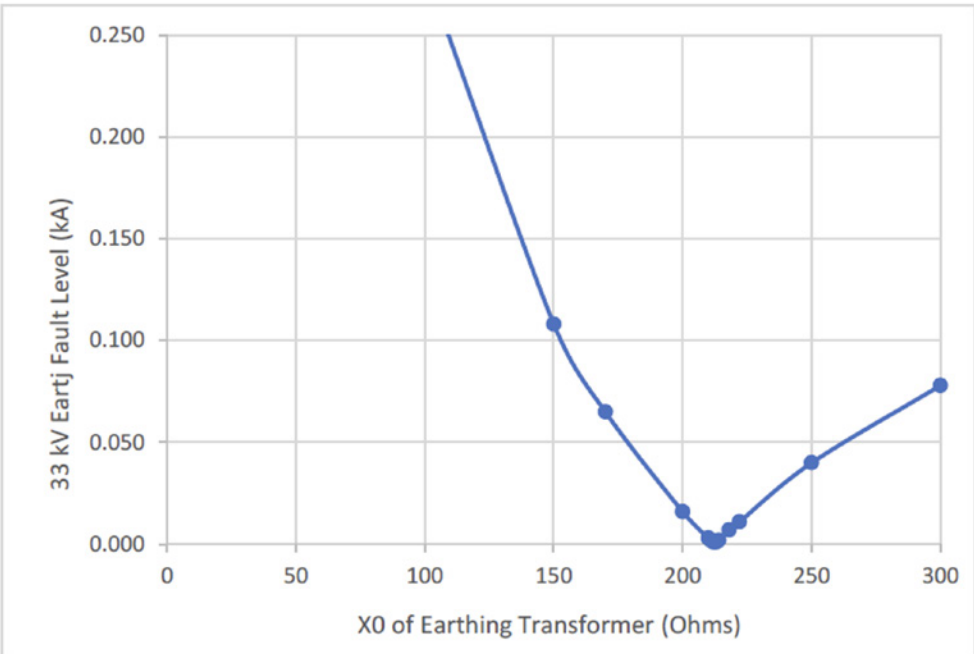

Figure 35: Steven's Croft ET zero sequence impedance versus 33 kV earth fault level

6.4.2 Key Achievements

At the end of the testing, we managed to successfully:

- start the Steven's Croft 11 kV generator in island mode
- energise the generator 11/33 kV (53 MVA) step-up transformer
- maintain stable MW output with a load bank
- energise the local distribution network, including a 25 km 33 kV underground cable section and a 24 MVA primary (33/11 kV) transformer (where customer demand is normally connected)
- prove the BLPU capability of the anchor generator to be sufficient to pick up the typical demand of a primary substation in a single step
- synchronise the Steven's Croft generator at 33 kV with the main distribution network supply and energise the transmission network up to 400 kV (via a 400/132 kV 240 MVA super grid transformer).

6.4.3 Conclusion

- The Chapelcross live trial has shown the viability of a distribution connected biomass generator to operate in island mode, energise the associated distribution and transmission networks (from 11 kV to 400 kV), synchronise at 33 kV, and restore the demand at a primary substation in a single step.
- The fundamental principle of establishing a distribution restoration zone (DRZ), and the potential to energise up to the highest voltage on our transmission network (400 kV), from a single anchor DER, has now been proven in practice.

7. Grid-Forming Converter (GFC) Network Energisation Simulations

7.1 Introduction

This section summarises the results achieved in investigating the use of grid-forming converters (GFC) control for blackstart applications, as part of the Distributed ReStart project collaboration between SPEN and Iberdrola Innovation Middle East. The experiments reported here are carried out in collaboration with the state-of-the-art Dynamic Power Systems Laboratory (DPSL) at the University of Strathclyde.

The previous deliverable, published as Chapter 9 of the report *Demonstration of Black Start from DERs (Live Trials Report) Part 1*, demonstrated the use of a modified virtual synchronous machine (VSM) grid-forming control to energise networks simulated in a real-time digital simulation environment. The energised networks ranged from simplified test networks to segments of the Chapelcross network. Results demonstrated successful energisation using a voltage ramp with significantly mitigated transformers inrush current, as well as block loads pick up and grid synchronisation. Preliminary results were also presented to test power hardware-in-the-loop (PHiL) technique capabilities, where a hardware GFC is used to energize a simulated network in a real-time digital simulation environment such as the real-time digital simulator (RTDS).

This section builds on the results presented earlier and expands them to extended PHiL tests and investigations through a complete black start scenario that successfully demonstrates the hardware GFC use for network energisation. This paves the way for similar experiments in the future that allow for repetitive and non-destructive testing of hardware grid-forming converters through a hybrid environment that takes into account practical aspects such as communication delays and limitations existing in the real network, while allowing for testing black start scenarios in different simulated network configurations and connections. Key limitations of the PHiL technique are also identified in this section for reference. Finally, the GFC control used throughout this section is illustrated in Figure 36, where its main functionalities are soft energisation, voltage support and grid synchronisation capabilities.

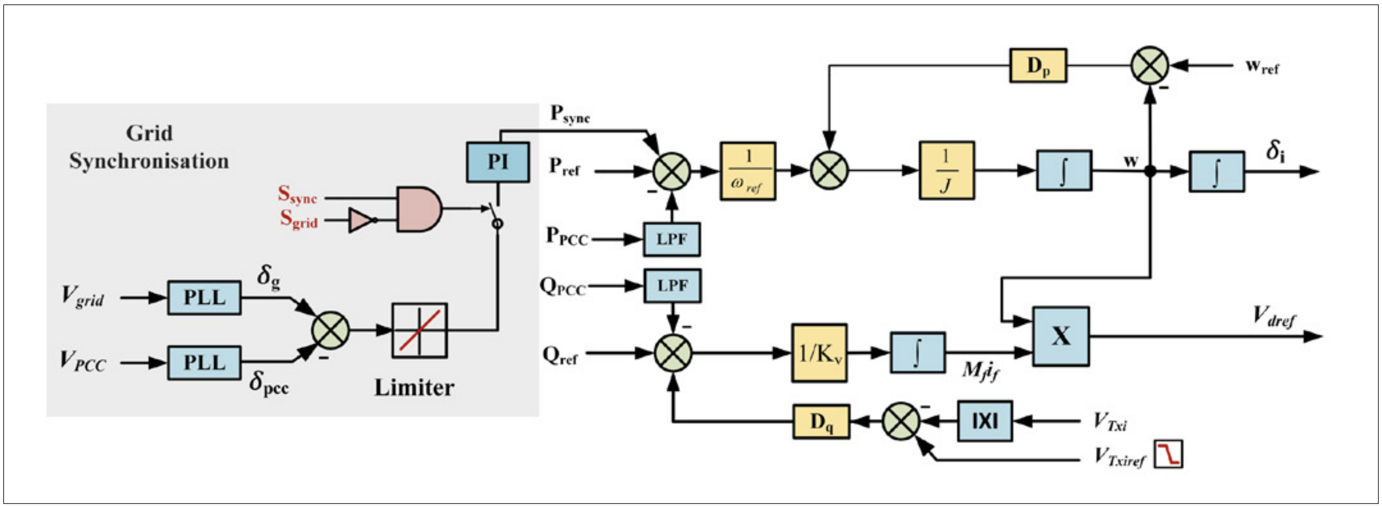

Figure 36: High-level VSM control block diagram for the GFC loop used in this study

7.2 Test Network: Overview and Parameters

Black start service provision through grid-forming converters is validated in this study through a simplified test network that consists of the energising converter, interface transformer, transmission line, loads and a grid connection point for post black start synchronisation. The network block diagram used is illustrated in Figure 37. The components are selected to reflect a common configuration in distribution networks, and to be closely correlated to the Chapelcross network in Scotland. For instance, the used transformer model maintains the same parameters from the Chapelcross RSCAD model developed at The National HVDC Centre [1], with a similar 53 MVA rating and saturation characteristics. A π-section line is also used with default MATLAB/Simulink library RLC parameters. The network loads are divided into a main (initially closed) 20 MW load, and a 10 MW disturbance load. The VSM control utilises inertia and damping factors that maintain minimum frequency variations at rated power disturbances. Inner voltage and current loops are integrated in all the experiments presented in this section. For the PHiL test, the hardware part of the network (converter and LC filter) and the real-time simulated software part (L_2 and rest of the network) are highlighted in Figure 38.

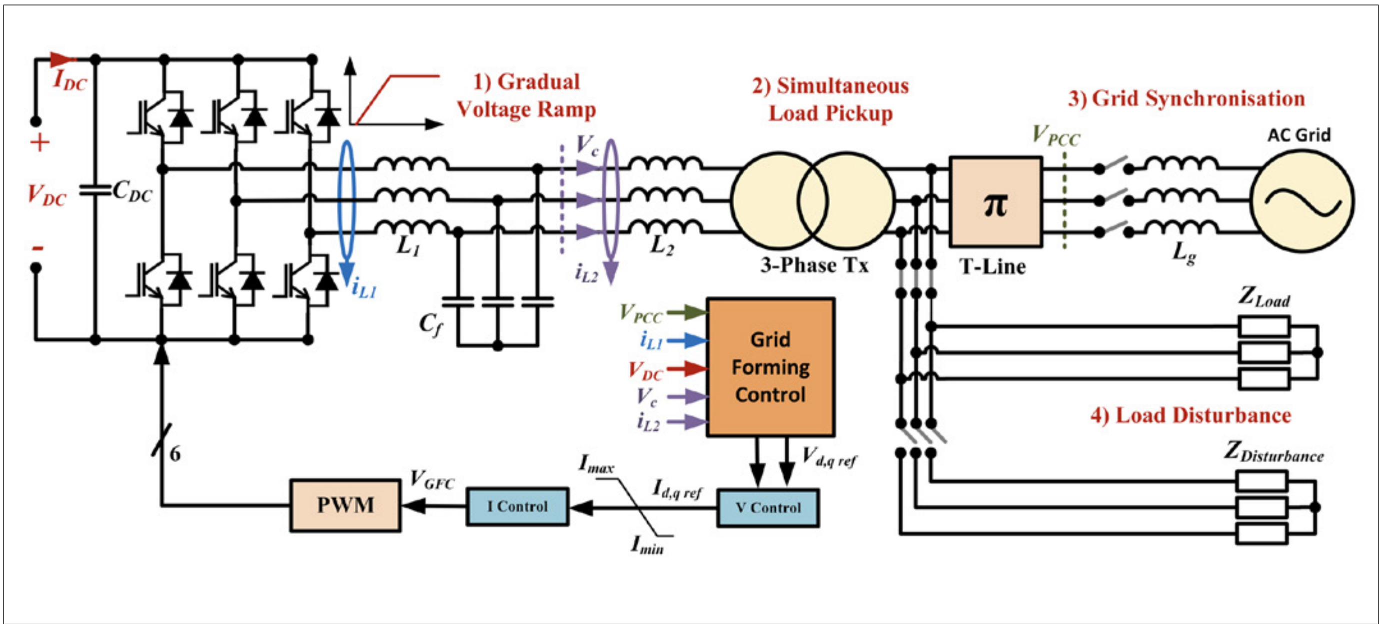

Figure 37: Test network block diagram used for black start experiments

The main test network parameters are summarized in Table 6. It should be noted that the converter MVA rating is selected to resemble a value close to operating steady state conditions. Whereas this rating can be decreased when combined with appropriate energisation techniques if its main purpose is to perform black start.

To mitigate transformer and line energising inrush currents, a soft energisation technique is used with a ramp duration of 10 seconds. This ramp duration can be shortened (or prolonged) depending on the network and transformer conditions. A study on the ramp rate influencing factors by the authors is reported in [2]. Local load pick up (20 MW) is performed simultaneously to the transformer and line energisation. Considering that load energisation through a ramping voltage may not be compatible with all load types, the loads requiring 1 pu voltage supply for connection are integrated at a later stage as a disturbance. Grid synchronisation is performed using the modified controller in Figure 36, where it aims to drive the phase angle difference between point-of-common-coupling (PCC) and grid voltages to zero. Beyond synchronisation, the grid-forming VSM continues to operate in voltage control mode and capable of reactive power injection/absorption as a possible ancillary service. The VSM maintains the voltage required to exchange power with the grid after synchronisation (i.e. power tracking mode) within its rating and capabilities.

Table 6: Key test network parameters

Grid Forming Converter Ratings			
Power Rating	40 MVA	Output Voltage	11 kV_{LL}
Transformer Parameters ($\Delta - Y$)			
Power Rating	53 MVA	Voltage Ratio V_o/V_i	$33/11\ kv$
Knee-Voltage	1.25 pu	Air-core Inductance	0.265 pu
Steady-State i_m	1%	Phases Residual Flux	[0.25, -0.1, -0.15] pu
Transmission Line Parameters ($\pi - model$)			
(R, L, C) per km	12.73 $m\Omega$, 0.93 mH, 12.74 nF	Length	30 km
Network Loads			
Main Load	20 MW	Disturbance Load	10 MW
Grid Parameters (33 kV_{LL})			
Short-Circuit Power	500 MW	X/R Ratio	14.5

The modified VSM capabilities were demonstrated in MATLAB/Simulink and RTDS simulations in previous reports and studies [1, 3, 4]. Whereas here, the control is implemented using a scaled hardware grid-forming converter (typically with kW rating), which is interfaced to the simulated network in Figure 37 through a power amplifier. The network itself is simulated in RTDS (with MW ratings) and is used to receive and supply references to the external converter and power amplifier in a closed-loop configuration. A complete black start scenario including energisation, loads connection and grid synchronisation is executed in this configuration. The following section provides more description of the used PHiL interface technique.

7.3 Power Hardware-in-the-Loop (PHiL)

Power hardware-in-the-loop simulation, as an advanced real-time simulation methodology, has been extensively leveraged for the repeated and non-destructive experimental assessment of emerging power apparatus [5]. Figure 38 presents the equivalent circuit diagram of the PHiL setup that consists of a real-time emulated network to be energised by GFC, and a current-mode power amplifier that is coupled with the GFC power converter. A current-type (I-ITM) interface is utilised to define the PHiL configuration in this study.

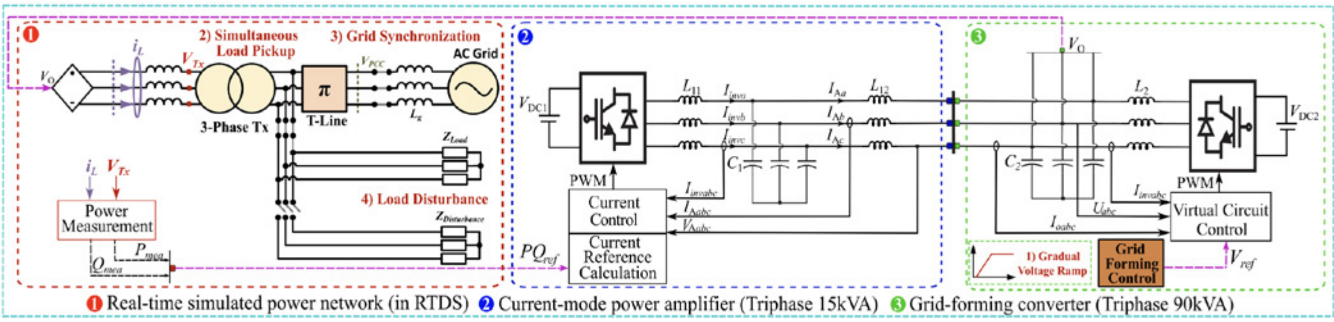

Figure 38: Equivalent circuit diagram of the PHiL setups

The power amplifier source or sink current to the GFC under test and the GFC output voltage is transmitted to the software side as a reference value that energises a controllable voltage source in the real-time simulated network. By doing so, the GFC is incorporated into the closed-loop configuration with its power behaviours replicated in the simulated network while the dynamics at the GFC interfacing point in the simulated network are also replicated to the hardware GFC.

Figure 39 shows the configuration of the experimental setup with its cells corresponding to these as illustrated in Figure 38. Grid forming control schemes are implemented in triphase 90 kVA (TP90 kVA) power converter to regulate its output voltage, which is utilised by triphase 15 kVA (TP15 kVA) for output current regulation through a phase-locked loop (PLL) unit. The voltage and power signals transmission are realised by the Aurora protocol and giga-transceiver analogue output (GTAO) card in RTDS.

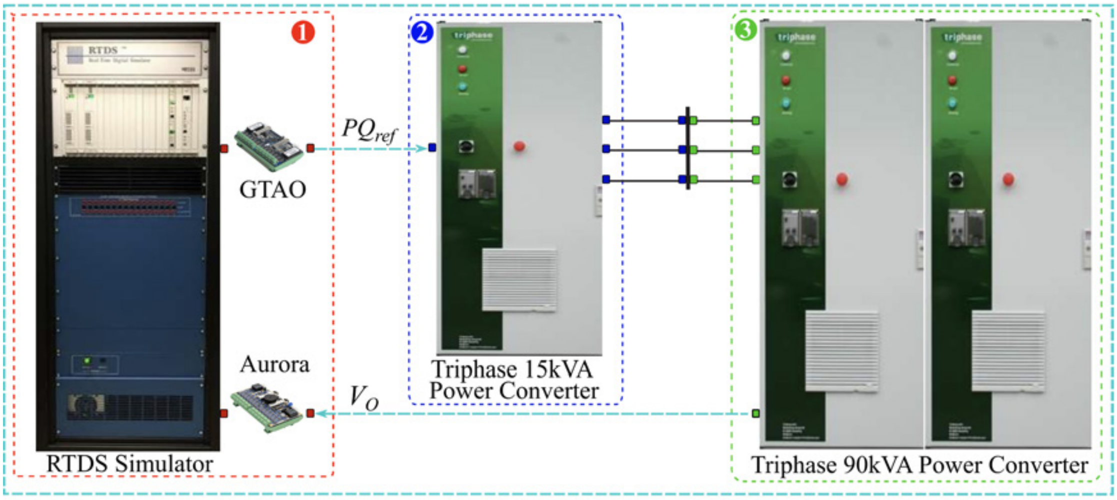

Figure 39: PHiL experimental setup representation

Due to the limited voltage levels of the TP90 kVA converter, a voltage scaling ratio (V_{scale} = 27.5) is employed to scale up the TP90 kVA output voltage to a higher level to enable MW-scale emulation in the real-time simulated network. In terms of the current replication by TP15 kVA, the scaled-down active and reactive power readings from RTDS (P_{scale} = 4125) are transmitted to the power amplifier interface to improve P/Q tracking accuracy and mitigate the impact of small phase drifts. These measurements are then converted to scaled current references when divided by the TP90 kVA voltage that is also applied at TP15 kVA terminals. The active and reactive power scaling ratio scales down the calculated current reference within the constraint of TP15 kVA (i_{scale} = 150). This established interface leads to a closed-loop dual system operation in hardware and software, where the hardware feeds the voltage reference into the software and receives back a current or power reference. The voltage and power signals transmission are realised by the Aurora protocol and the giga-transceiver analogue output (GTAO) card in RTDS, respectively.

7.4 PHiL Results

The results presented in this section show a combination of hardware and software results obtained from the blackstart experiment. Initially, the grid forming VSM implemented in TP90 kVA unit is activated with a 10 second voltage ramp between 0 and 325 V_{peak} (400 V_{LL} equivalent). This voltage is sensed and sent to RTDS and scaled up by 27.5 to represent 8981 V_{peak} (11 kV V_{LL} equivalent). The scaled-up voltage is fed into the RTDS simulation network to energise the 53 MVA transformer, line and 20 MW load. Then the restored island is synchronised to the grid after the angle error is driven to zero, followed by power reference variation and a load disturbance. The synergy in trends between hardware and software sides, starting by GFC output voltage waveforms, is illustrated in Figure 40.

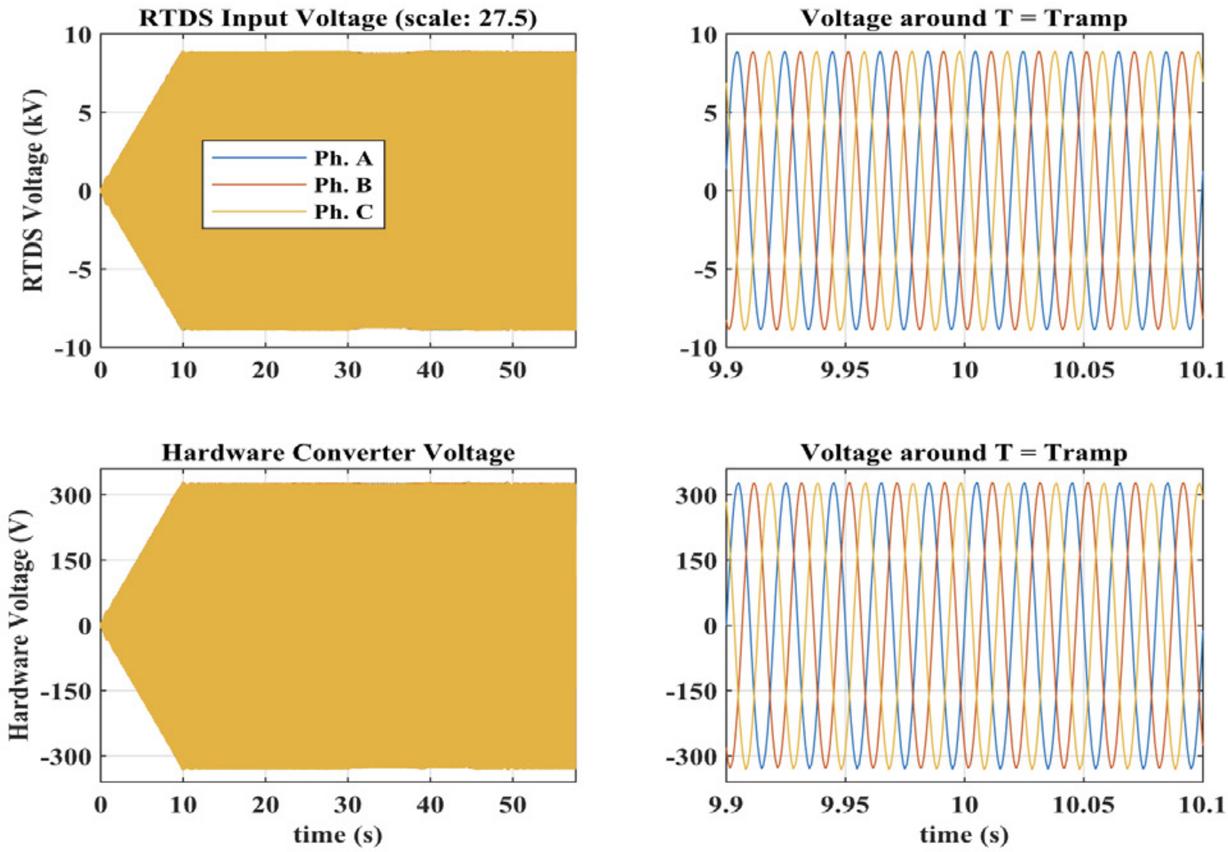

Figure 40: RTDS vs. hardware input voltage measurements

After the voltage ramp is completed at t = 10 s, the synchronising control continues to operate to drive the synchronising voltages phase difference to zero, and the smooth grid-connection takes place around t = 22.75 s. After synchronisation is done, the VSM tracks the power reference which is initially set to 20 MW (equivalent to pre-synchronisation load demand) to avoid sudden jumps. At t = 29.75 s (after 7 seconds), the power reference ramps to 35 MW using a 7.5 MW/s slope. After 7 seconds, the reference is ramped down with a similar slope to 10 MW, before ramping up again to the initial 20 MW point around t = 43.75 s. Finally, a load disturbance is applied at t = 48.75 s where an additional 10 MW load is connected ($Z_{disturbance}$) in Figure 37. The impact of these events on both hardware and RTDS VSM currents is illustrated in Figure 6, where similar trends can be observed between the RTDS input current and the measured hardware converter current, showing successful reference tracking and coordinated operation of both hardware and software using PHiL.

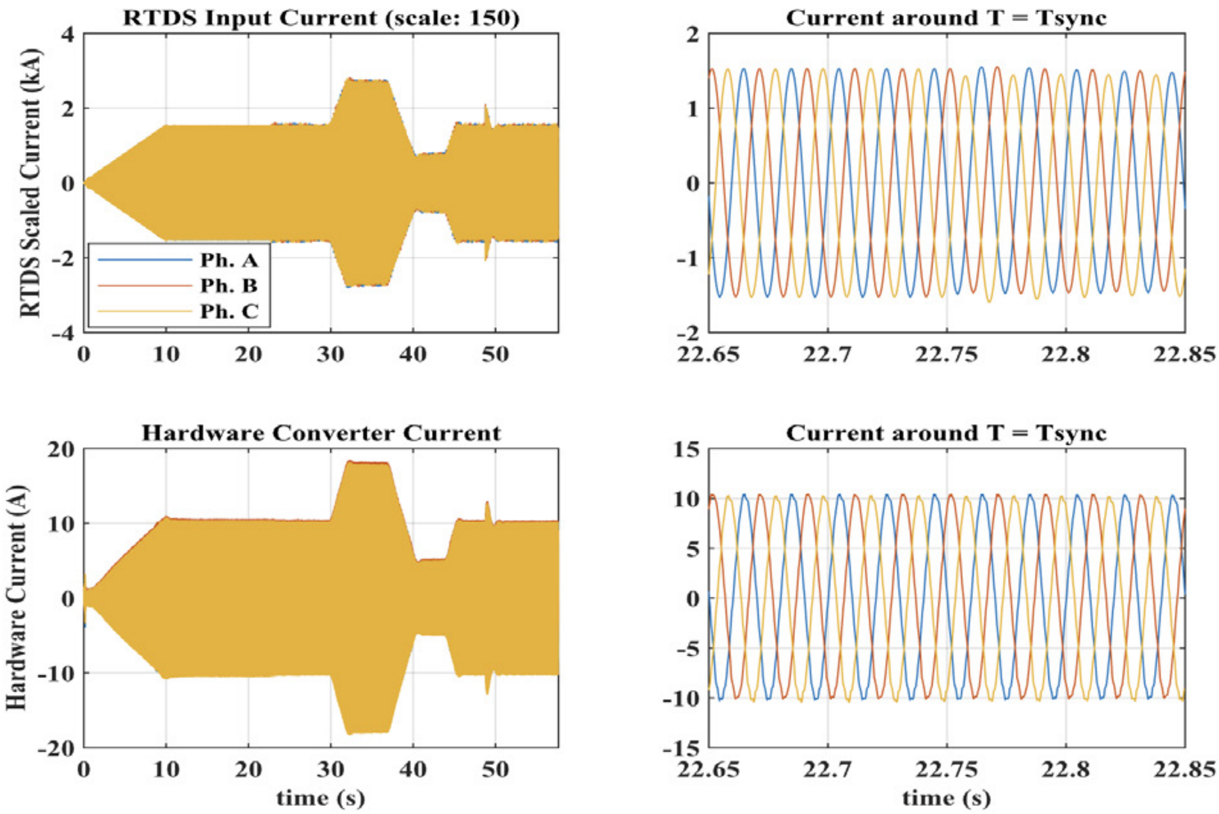

Figure 41: RTDS vs. hardware input current measurements

The software vs. hardware active and reactive power tracking performance is also benchmarked for the PHiL application as illustrated in Figure 42. For this comparison, the hardware power is scaled up by 4125 to match the RTDS network power scale. The illustrated P/Q traces are passed through low-pass filters. The same filtered measurements are used for the VSM control power and voltage loops. The power reference tracking performance is satisfactory between hardware and software, with the applied time TP15 kVA time-delay compensation of around 94 μs.

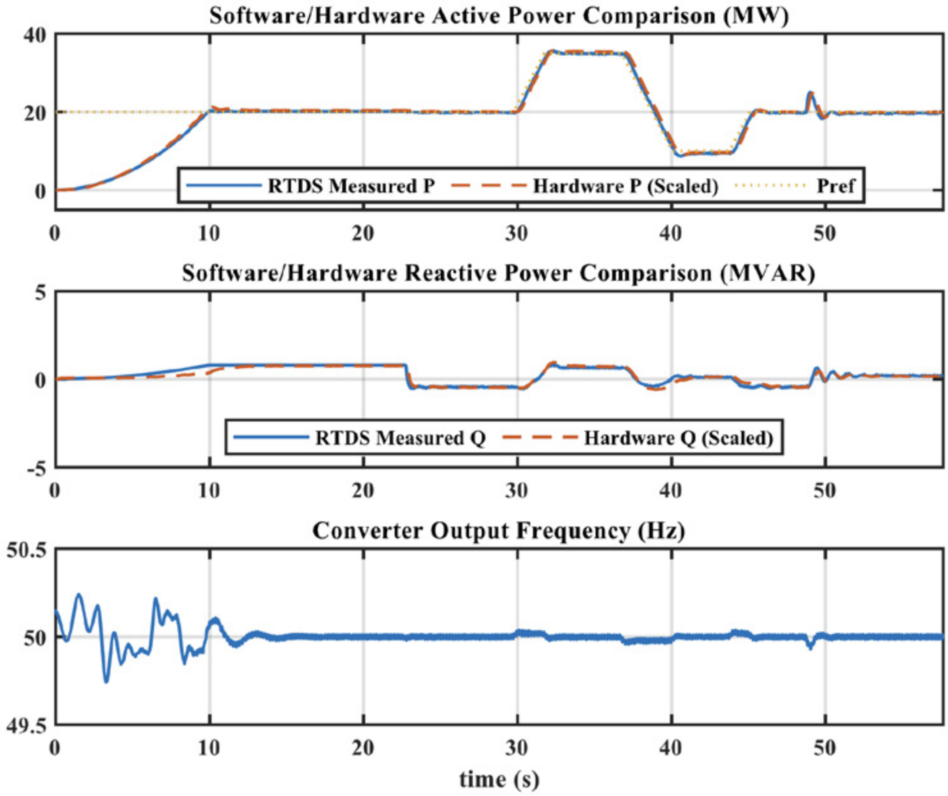

Figure 42: PHiL active and reactive power tracking performance (software vs. hardware), and GFC frequency

Figure 42 also illustrates the VSM voltage frequency trace throughout the simulation, showing slight variations around the steady 50 Hz points during the ramp and synchronising control action, and small changes as a result of the power reference adjustments. The converter output voltage frequency value remains within an acceptable band throughout the experiment.

Finally, the synchronising control action is also illustrated in Figure 43. The control is activated during the ramp to accelerate the phase-matching. Initially, an evident phase-shift is observed. As the synchronising PI control tracks the zero-angle point error, the phase-angle between PCC and grid voltages approaches zero. The second panel shows both voltages around the moment of controlled synchronisation, where the process is done smoothly. From here, the power exchange between the VSM and the grid is initiated following the VSM power reference. It is worth noting that the implemented synchronisation technique requires access to the phase angle error at the PCC, which can be sent using high-speed communication infrastructure to the VSM control. Alternatively, synchronising relays can be used when the system is ready to go into grid-connected mode. Overall, a successful black start demonstration through PHiL has been presented in this section, showing the technique capabilities and potential. The next section identifies some of the lessons learned from these experiments, highlighting some PHiL limitations and points to be considered for testing.

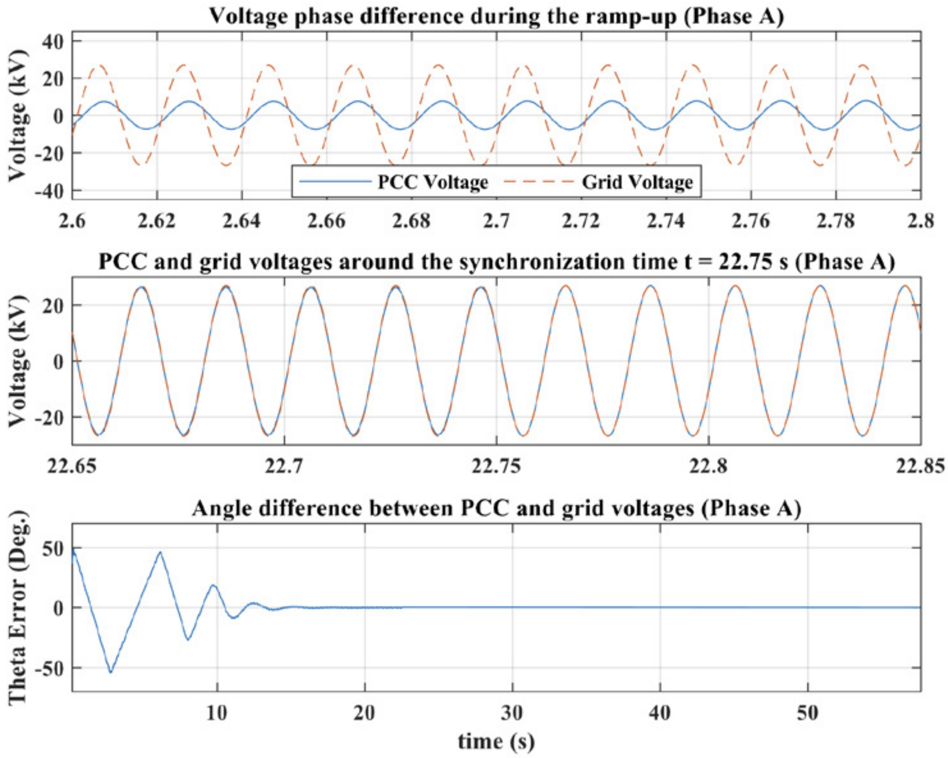

Figure 43: Synchronizing control impact in reducing the phase shift between PCC voltage and grid before synchronisation

7.5 Lessons Learned

This section summarises the lessons learned from PHiL and GFC experiments and aims to provide some helpful tips for readers interested in working on similar experiments.

- **PHiL-GFC control implementation:** Two options can be adopted to implement the GFC control.
  a) in the RTDS itself, where all the control functions are performed there, and the output reference is then sent for the hardware converter to replicate and share back with the RTDS software to drive its scaled voltage source.
  b) directly in the external hardware converter through its dedicated software interface (e.g. MATLAB/Simulink, dSPACE or a vendor specific software).

  Both options were investigated, and it is found that direct control implementation in the external hardware provides improved performance as it directly utilises hardware measurements and mimics the realistic case since vendors typically implement the control software in the converter itself.

- **PHiL time-delay compensation impact:** Appropriate compensation of the communication links time-delay is essential for proper PHiL operation. Different compensation magnitudes were tested as part of this study (e.g. between zero and 180 degrees), and the impact of improper delay compensation is evident in terms of deviation in active and reactive power readings, which can cause more adverse tracking issues when combined with grid synchronisation. Large mismatches in real networks may lead to accuracy deviations, and in some cases, even stability issues especially when the communication signal is used for sensitive parameters control.

- **PHiL network impedance and ratios:** It is observed that the nature of network impedance impacts the PHiL performance under certain conditions (e.g. grid-synchronisation). Selecting an inductive impedance for appropriate power transfer between the GFC and the grid was observed to increase the system power tracking accuracy. Selecting proper voltage and current scaling ratios is also observed to impact stability. Further investigation is recommended on these points to generalise the observed trends.

- **Unbalanced reference replication capability:** In I-ITM interface technique, the power amplifier receives its current reference from RTDS. In black start and network energisation studies, inrush currents are likely to be involved in some scenarios, which means the current reference can be highly unbalanced and rich in harmonics due to the inrush current nature. If the physical power amplifier control is unable to replicate this reference due to its implemented control, then the hardware will not be able to track currents that correspond in shape to the irregularities generated in RTDS, and the hardware VSM will not see similar conditions to that in RTDS. Understanding the control type implemented in the power amplifier interface thus becomes important if accurately studying such phenomenon is of an experimental interest.
- **Impact of VSM tuning on tracking accuracy:** The selection of VSM damping and virtual inertia parameters influence the control performance against disturbances. Proper tuning is required to maintain fast frequency response after any disturbance, while also being able to track the power references in grid-connected mode. The damping and inertia parameters should thus be balanced to take both objectives into consideration.

7.6 Remarks

Being one of the first attempts to investigate the use of PHiL technique for grid-forming converters testing in black start, the results presented in this section serve as a reference to showcase the potential of using power hardware-in-the-loop for network energisation tests. The experiments demonstrated a successful PHiL utilisation, allowing an external hardware converter to interact with and energise a simulated blacked-out network in a complete scenario. The scenario included transformers energisation, loads pickup and grid-synchronisation. This preliminary testing success paves the way to more extensive testing that can utilise industrial-scale converters in similar environments under appropriate software/hardware scaling ratios. These converters can then be tested under different network configurations, without being restricted to a particular network topology, while also being exposed to communication delays and limiting conditions that would exist in real networks.

That said, PHiL technique limitations should also be considered, such as using a power amplifier interface that is able to replicate unbalanced and/or harmonics-rich current references received from RTDS. PHiL stability margins is another important identified point that is impacted by factors such as simulated network impedances and scaling ratios. Understanding such sources of error is important for accurate behavior replication between software and hardware, and for accurate results interpretation in relation to the studied phenomenon.

From an application standpoint, the main study objective was to investigate networks energisation with minimum inrush current during black start from grid-forming converters. The modified VSM control implemented in the hardware converter was able to achieve this aim through applying soft energisation. The soft-ramp voltage duration is an important factor to consider to avoid fast ramps that can still lead to significant inrush. Combining this aspect with PHiL allows for testing the hardware converter capability under different ramp speeds and ancillary services provision requirements. Expanding the presented results into larger network simulations should, in principle, be feasible with similar methodology to the one presented in this section.

Recommended routes for relevant future PHiL research include investigating different disturbances such as various active and reactive load combinations, or the use of multiple converters (e.g. from a wind farm) for black start PHiL testing and synchronising between a larger number of network segments.

7.7 References

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Appendices

Appendix 1: Table of Abbreviations

Abbreviation	Definition
AVC	automatic voltage control
AVR	automatic voltage regulator
BESS	battery energy storage systems
BIL	basic insulation level
BOA	bid offer acceptance
BS	black start
BSP	bulk supply point
CCGT	combined cycle gas turbines
CHP	combined heat and power
DER	distributed energy resource
DNO	distribution network operator
DOL	direct online (energisation strategy)
DRZ	distribution restoration zone
DRZC	distribution restoration zone control system
EfW	energy from waste
EHV	extra high voltage
EMT	electro-magnetic-transient
ER	engineering recommendations
ESQCR	Electricity Safety, Quality and Continuity Regulations
f	frequency
GFC	grid-forming converter
GSP	grid supply point
GT	grid transformer
HiL	hardware-in-the-loop
HV	high voltage
LPS	large power station
MITS	main interconnected transmission network
NETS	national electricity transmission system
NGESO	National Grid Electricity System Operator
NGET	National Grid Electricity Transmission
OLTC	on-load tap changer
PLL	phase locked loop

PoW	point on wave
PET	Power Engineering and Trials workstream
PV	photovoltaic
ROCOF	rate of change of frequency
RRRV	rate of rise of recovery voltage
RTDS	real time digital simulator
SCADA	supervisory control and data acquisition
SHET	Scottish Hydro Electric Transmission
SLD	single line diagram
SPD	Scottish Power Distribution
SPEN	Scottish Power Energy Networks
SPM	Scottish power Manweb
SPT	Scottish Power Transmission
STOR	short term operating reserve
TOV	temporary overvoltages
TRV	transient recovery voltage
WF	wind farm

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