Distributed ReStart

Power Engineering and Trials

Demonstration of Black Start from DERs (Live Trials Report) Part 1 December 2021

In partnership with:

tnei

SP ENERGY NETWORKS

nationalgridESO

Contents

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 Dissemination workstreams cover the effective management of the project and sharing of learning. The other three workstreams cover the wide range of issues to enable Black Start services from DERs:

- The Power Engineering & Trials (PET) workstream is concerned with assessing the capability of GB distribution networks and installed DERs 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 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 & Telecoms (OST) workstream is considering the DER-based restoration process in terms of the different roles, responsibilities and relationships needed across the industry to implement at scale. It will specify the requirements for information systems and telecommunications, recognising the need for resilience and the challenges of coordinating Black Start across a large number of parties. Proposed processes and working methods will be tested later in the project in desktop exercises involving a range of stakeholders.
- The Procurement & Compliance (P&C) workstream will address the best way to deliver the concept for customers. It will explore the options and trade-offs between competitive procurement solutions and mandated elements. It will make recommendations on the procurement strategy aiming to be as open and transparent as possible while reflecting wider industry discussions on related topics like Whole System Planning and the development of Distribution System Operator (DSO) functions. It will feed into business-as-usual activities to make changes as necessary in Codes and regulations.

Keep up to date and find all other project reports here: **nationalgrideso.com/innovation/projects/distributed-restart**

Executive Summary

This report is the first of two entitled 'Demonstration of Black Start from DERs' detailing the outcomes and learning from the live network testing which has been planned, and already undertaken, as part of the Distributed ReStart project. The second report will be issued on completion of all the live testing. These reports are the final live trial deliverables from the PET workstream and will conclude the demonstration phase of the project.

The primary focus of this report is to provide an overview of the three live trial sites (Galloway, Chapelcross and Redhouse), the technical issues which have been faced and the learning which has been obtained particularly from the Galloway site, where several days of live testing has been undertaken. In addition, project work relating to grid-forming converter (GFC) connected DER is also given, along with a report on live testing of GFC technology at Dersalloch wind farm, undertaken outwith the Distributed ReStart project, but supported and facilitated by SP Energy Networks (SPEN) and located adjacent to the Galloway live trial area.

Live trial sites

Key features

Galloway trial site
Two distribution connected hydro generators, Glenlee (15 MVA) and Kendoon (13 MVA), have been used separately in live testing as the 'anchor' generator (to initially energise the network and control the voltage and frequency). They generate at 11 kV and are connected to the local 132 kV transmission network which extends to the New Cumnock 275/132 kV wind farm collector substation, and to the distribution network at Glenluce 132/33 kV grid supply point (GSP), which incorporates ~100 MW of wind generation.

Key testing goals:

- Develop strategies to energise the 132 kV transmission network (including grid transformers).
- Energise the 33 kV distribution network, and primary (33/11 kV) transformers, and establish a power island with wind generation connected.
- Test the viability of energising to the 275 kV network (via 275/132 kV 240 MVA super grid transformers).

Chapelcross trial site
This live trial utilises Steven's Croft Biomass generator (60 MVA) as the anchor. This is connected at 33 kV to Chapelcross 132/33 kV GSP distribution network, with the test network also including associated 132 kV overhead line circuits, a 46 MW wind farm, and a 400/132 kV 240 MVA super grid transformer (SGT) at Gretna.

Key testing goals:

- Identify the ability of a steam generator to energise the distribution and transmission networks (including all relevant transformers) up to 400 kV.
- Establish a power island with wind generation and demand (via a load bank) connected.

Redhouse trial site
This live trial focuses on testing the grid following and grid-forming ability of the Redhouse Battery Energy Storage System (BESS) 11.6 MVA. This is located adjacent to, and connected at 33 kV to, Redhouse 132/33 kV GSP, with the local distribution and 132 kV transmission network forming part of the test network.

Key testing goals:

- In grid-following mode, test the ability of the BESS to connect to a weak (low fault level) network, and assist with transformer energisations and load pick-ups.
- In grid-forming mode, prove the ability of the BESS to independently energise the distribution transmission networks (including relevant transformers). This will be a GB first.

Key testing/achievements

Galloway trial site

A total of five days' live testing has been completed, culminating in the Kendoon 11 kV hydro successfully:

- Energising the Kendoon to Glenluce 132/33 kV GSP transmission network in a single step.
- – The single step comprised of energising a Kendoon 11/132 kV 30 MVA transformer, ~60 km 132 kV overhead tower line and a Glenluce GSP 132/33 kV 60 MVA transformer simultaneously.
- Energising two 240 MVA 275/132 kV super grid transformers (SGTs) at New Cumnock simultaneously.

Chapelcross trial site

- Hardware in the Loop (HiL) testing

The National HVDC centre (HVDC centre) has built a model of the Chapelcross distribution and transmission test network on their Real Time Digital Simulator (RTDS) and carried out HiL energisation tests with replicas of the Steven's Coft generator protection relays. Results have shown all energisation steps to be successful with no overvoltage tripping of the generator.

- Live network testing

It is planned to have one test phase, of five consecutive days, in May 2022. At present, preparatory works are in progress to facilitate the testing including DER feasibility studies and switchgear installations.

Redhouse trial site

It is proposed to have two phases of testing with the Redhouse BESS, each up to five days in duration.

- Phase 1 – this will involve establishing a 'private' 33 kV test network at the Redhouse BESS site with the addition of temporary diesel generators, load banks and a 33 kV earthing transformer.
- Phase 2 – this will involve testing from the BESS site to the local distribution and transmission network.

System studies have highlighted the potential for re-ignitions to occur within the test network 33 kV vacuum switchgear (across the circuit breaker contacts when clearing faults), due to high Rate of Rise of Recovery Voltages (RRRVs). This may lead to high transient voltages and introduce the risk of asset failure. The live tests have been rescheduled to summer 2022 to allow time for mitigation options to be considered (for example, the installation of surge arrestors and/or a RC snubber device at suitable locations on the test network).

Key findings – live trials

The key findings from the development and implementation of the live trials to date are:

- Islanded networks – Voltage transient magnitudes and durations, generated by transformer inrush currents, were more severe on the test networks due to the low fault level (high source impedance) than would normally be experienced on an intact network with higher fault levels.
- Transformer energisation – To avoid generator tripping on overvoltage protection, an effective strategy is to reduce the generator terminal voltage, prior to energisation, to provide increased headroom so that the temporary overvoltages (TOVs) produced by transformer inrush currents will not exceed the overvoltage limit.
- Point of Wave (PoW) – In some network energisation scenarios, reducing the generator terminal voltage is insufficient to stop the overvoltage protection operating when energising transformers. 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 testing).
- Switchgear capability – Studies are required to ensure the Transient Recovery Voltages (TRVs), associated with breaking low fault currents or network charging currents, are within the switchgear capability. Moreover, multiple re-ignitions (which can generate harmful voltages) may occur in vacuum switchgear if the RRRV is too high. Surge arrestors may be installed to remove excessive peak TRVs, and RC snubbers installed to reduce the RRRV.
- System modelling – Simulations are carried out using an electro-magnetic transient (EMT) software program. There is often a lack of equipment data for an EMT type of study, particularly 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.
- While extensive system modelling must be used to gain better understanding of the effects of network model sensitivities, 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.

Grid-Forming Converter (GFC) DER Assessments

Protection Assessment – BESS anchor DER

The ability to protect the Chapelcross live trial network was assessed based on the existing synchronous generator (SG) being replaced with an equivalent size (60 MVA) GFC BESS. The key findings were:

Fault levels

- At 415 V, and 11 kV, the fault levels are higher with a GFC compared to an SG.
- At 33 kV, the GFC fault levels are lower than the SG if the converter saturates (the network fault impedance is such the GFC reaches, and maintains, its current limit of 1 pu).
- At 132 kV and 400 kV, the GFC's three-phase fault levels are lower than an SG (due to saturating), but the single-phase-to-ground faults are higher (due to no converter saturation).

It follows that the 11 kV network (and lower voltages) may be adequately protected with reduced settings as per an SG, and more sensitive settings may be required for higher voltages, or alternative protections installed.

GFC network energisation simulations

Using an RTDS model of the Chapelcross test network, Power Hardware in the Loop (PHiL) testing of the ability of a GFC to energise the network has commenced in collaboration with the University of Strathclyde Dynamic Power Systems Laboratory (DPSL), and the Power Networks Demonstration Centre (PNDC).The studies presented in this report, and the future planned studies, are among the first trials to test GFC operation for Black Start with PHiL techniques.

An overview of the simulation test network, the results of 'hard' energisations (switching a transformer directly onto a GFC providing 1 pu voltage), 'soft' energisations (ramping up the GFC voltage with the transformer in service over 10 seconds) and grid synchronisation are presented in this report. Soft energisations were shown to significantly reduce transformer inrush currents and avoid GFC saturation.

Dersalloch Wind Farm – Virtual Synchronous Machine (VSM) Live Test

Using an advanced 'grid-forming' (GF) converter control scheme called Virtual Synchronous Machine (VSM), a world-first Black Start network trial from a wind farm was successfully completed during October 2020 by SP Energy Networks in partnership with ScottishPower Renewables (SPR) and Siemens Gamesa Renewable Energy (SGRE).

While this project was not delivered directly under the Distributed ReStart project, and supported separately through the Scottish Government via the Low Carbon Infrastructure Transition Programme, an agreement has been made by all parties that the learning is highly relevant to this project, and complementary to the findings identified under the Power Engineering & Trials workstream live trials report.

To achieve Black Start capability, four individual turbine converters were equipped with the GF algorithm, and external 125 kVA diesel gensets were connected to provide supply to their auxiliary loads in order to self-start. The Black Start GF procedure implemented a ramped approach to turbine energisation; this 'soft start' ramping process softens inrush effects of network energisation and allows a reduced number of turbines to energise a relatively large network. The technique ramped the turbine terminal voltage from zero to 1 pu over a period of 14.25 seconds.

From the trials completed at Dersalloch, several conclusions can be drawn on technical challenges encountered to enable Black Start from a wind park.

- The successful Dersalloch trials proved that it is possible to energise 132 and 275 kV transmission assets from a limited number of turbines within a grid-forming algorithm using a 'soft start' ramping process to minimise network inrush effects. By including 1 MW of resistive load, the network saw an improved stability and dampening effect. Energisations were attempted with reduced voltage at both turbine terminal voltage and reduced tap settings on transmission grid transformers.
- Using existing transmission protection functions it is not possible to provide any protection coverage on the network during the ramping sequence. By implementing a voltage-controlled overcurrent (VCOC) function within the network, protection coverage could be secured after 3.75 seconds with three WTGs in service.
- It has been demonstrated that using a traditional direct-online energisation (DOL) it is possible to energise transmission networks up to 275 kV involving infrastructure rated at several times the wind park capacity. This learning is perhaps the most significant from all VSM trials completed and in essence proved that a ramping method may not be essential if restoration plans consider the availability of GF strength for large transformer energisation.

1 Introduction

This report focuses primarily on the work that has been undertaken at the three live trial sites (Galloway, Chapelcross and Redhouse) to demonstrate the principle of Black Start from DERs in practice. In addition, project work relating to GFC connected DERs is also given, followed by a report on live testing of VSM technology at Dersalloch wind farm.

Initially, 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 learning.

Chapter 6 gives an overview of the Chapelcross live trial site, the proposed live testing, along with results from the HiL testing which has been carried out on the RTDS at the 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 has been commissioned by the project. In Chapter 8, a report summarising the ability to protect the Chapelcross test network if the anchor generator was a grid-forming BESS, equivalent in size to the existing synchronous generator, is given. Chapter 9 then gives an overview, and initial results, from the PHiL 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), and the Power Networks Demonstration Centre (PNDC).

Chapter 10 gives a report on live testing of VSM technology at Dersalloch wind farm, outwith the Distributed ReStart project, but supported and facilitated by SPEN and located adjacent to the Galloway live trial area.

2 Overview of Live Trials

This chapter describes the general purpose and key technical challenges which are common to the three live trials.

2.1 Introduction

The general purpose of the live trials (within the PET workstream scope) is to prove the principle of the 'Black Start from DERs' concept in practice. While thorough offline investigation and analysis of the case study networks with their DERs can give an indication if a Distribution Restoration Zone (DRZ) would be viable, it is essential for any new operating regime that it be successfully tested on the live network before any credible positive position can be determined with regard to a business-as-usual (BaU) roll-out.

In general, the trials employ an 'incremental' approach in that they are planned to prove the technical building blocks to establish a DRZ one step at a time. For example:

- Step 1 – Establish operation of the anchor generator in island mode (able to operate without a live network supply and control the voltage and frequency).
- Step 2 – Test the ability of the anchor generator to energise the associated distribution and (if applicable) transmission network including all relevant transformers.

The purpose of the testing for each of the trial sites is detailed in the following chapters.

2.2 Objectives of testing

Two key objectives, common to all the live trials, are given below.

2.2.1 Develop viable and optimal network energisation strategies

To evaluate various energisation strategies in practice to inform the development of general strategies appropriate for other DRZs.

The anchor generator within each DRZ will initially be required to energise the distribution and/or transmission network within the DRZ, including equipment such as transformers, cables and overhead lines, necessary to connect to other DERs and restore customer demand.

During Black Start events, network operators will aim to energise networks as quickly as possible under a controlled sequence. Fewer discrete switching sequences will result in faster restoration of the network and allow the load restoration process to commence earlier. There is therefore an incentive to energise several components simultaneously.
A key objective of the trials will be to test various sequences of energisations, such as sequentially or simultaneously energising circuits, to determine the optimal, viable restoration strategies. Different energisation techniques may be used as part of the trials to evaluate the benefits of each. For example:

- reducing the generator and/or network voltages (to minimise transformer inrush currents or the possibility of the anchor generator tripping on overvoltage).
- using a Point-of-Wave relay to control the energising circuit breaker (CB) closing time (to minimise transformer inrush currents).
- soft starting (ramping up the AC voltage to minimise transformer inrush currents).

2.2.2 Evaluate and test the requirements to establish a DRZ

The process of developing the trial sites and implementation of the tests in practice will give valuable learning to what would be required to establish and operate an enduring DRZ as part of a BaU implementation. Key considerations are:

- the system studies required and key technical issues which must be considered.
- works required/practicality of modifying the anchor generator to be able to self-start and control the voltage and frequency (most anchor DERs would not be capable of self-starting and would operate on fixed power output mode).
- evaluation and implementation of the network changes required (e.g. earthing at 33 kV, protection settings changes/ modifications).
- the length of time to make all the required DERs and network changes and to implement the restoration strategy.

2.3 Technical challenges

The distribution network and connected equipment (e.g. DERs) have been planned/designed on the assumption of a strong external grid, and for 'top-down' energisation. They have not been designed for island mode operation. Thus the 'Black Start from DERs' concept is investigating whether the existing network and associated systems can be adapted to operate in a very different power systems environment. An overview of several technical challenges which have been taken into consideration for the live trials are given below.

2.3.1 Network protection

For the trial sites, the system fault level will be significantly reduced (typically ~10% normal levels) as initially only the anchor generator will be connected. An assessment of the existing protections will be required to ascertain:

- if correct operation can still be obtained.
- if correct operation can be obtained with revised settings (e.g. lowering the 'pick-up' values of overcurrents).
- if new protections are required (e.g. voltage dependent relays, which only revert to reduced settings when a collapse in voltages associated with a fault is detected).
- Where revised settings are required, in BaU it is envisaged these would be implemented within the 'group 2' functionality of modern relays. The group 2 settings could be activated remotely via the SCADA system if there was a real Black Start.

Typically, as the voltage levels increase, the number of protections requiring to be modified or being inoperable increases.

Live Trials

For the live trial sites, the networks will be protected by revising the existing settings where required. These setting changes will be done 'manually' for the trials prior to the testing (and returned to normal post testing).
In the live trial sites, revised settings may be used to facilitate the testing but may not be acceptable if it was a BaU DRZ where customer demand was to be restored. The issue is that the revised settings, to protect the network for low fault currents, may be so low that they would also operate for the anticipated load current. In these cases, new protections would be required, i.e. voltage dependent, which would only reduce their settings if a voltage dip associated with a fault is detected.

2.3.2 Converter connected DERs

Wind farms, solar farms and battery energy storage systems (BESS) are typically connected to the power network via a grid-following converter interface (the network voltage is required as reference before they can connect, and for stable operation).

Phase Lock Loop (PLL) Limitations

PLL (the fastest control loop within the converter) has difficulty tracking the grid voltage, which will deviate more erratically in a weak network and can result in the DER tripping. Standard converter control techniques will fail to maintain stability when the short circuit ratio (SCR), the ratio of network fault MVA to DER rating, is typically less than ~3.0 (the required ratio may be lower or higher depending on individual manufacturer requirements). This will result in a limitation to the capacity of converter connected DERs which can be connected in a DRZ for a given network fault level.

PLL Mitigations

Potential alterations to improve performance include modifying the PLL controller for weak grid operation, although any alterations could potentially impact overall performance. Network solutions would include increasing the SCR by adding conventional DERs (rotating machines) to provide increased fault infeed.

Live trials

The Distributed ReStart live trials incorporate wind generation and a BESS, with a key objective to prove the capacity of converter connected DERs which may connect for the given fault levels.

2.3.3 Switchgear capability – breaking reactive load and fault current

Breaking low fault currents associated within an islanded network (typically ~10% normal levels), especially when the fault is close to the anchor generator, can result in higher or faster Transient Recovery Voltages (TRVs) across the circuit breaker contacts when opening. These may exceed the circuit breaker peak TRV rating (potentially causing a disruptive failure of the switchgear), or the type tested Rate of Rise of Recovery Voltage (RRRV). An excessive RRRV is a particular issue for vacuum circuit breakers where multiple re-ignitions may ensue (generating very high transient voltages which may damage surrounding equipment). A fuller understanding of TRV is given in Appendix 1.

Studies for each islanded network are required to ensure the TRVs associated with breaking low fault currents, or network charging currents, are within switchgear ratings. By way of mitigation, surge arrestors may be installed to remove excessive peak TRVs and RC snubbers installed to reduce the RRRV.

2.3.4 Transformer energisation

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

The inrush current profile starts with the highest peak and then decays to a smaller steady state magnetising current. The decay can be rapid or last as long as a few seconds, depending on the damping provided by the network. The inrush current flows through the network impedance to the transformer being energised, causing voltage drops or dips across the network. The voltage dip will be seen from the terminals of generators supplying the busbar where the transformer is being energised. The characteristic of the voltage dip is mainly a function of the inrush current peak value and decay profile, the strength of the system, and the voltage control response of generation resources in the network. Since the flux/current relation for the transformer is nonlinear and is determined by the saturation curve of the transformer, the magnetisation current of a transformer contains harmonics.

The transformer inrush currents, which can be of high magnitude and rich in harmonics, can excite the resonance of the circuit connecting to the anchor generator, resulting in TOV that can last for several seconds (as there is very little resistive damping, such as load, initially on the network). The TOV may operate the overvoltage protection at the generator terminals (typically set at ~1.1 pu to ~1.3 pu with a few seconds' delay or instantaneous operation) resulting in the generator circuit breaker tripping on transformer energisation. See Appendix 2 for the IEC definitions of overvoltages.

Live trials

Overvoltage tripping of the anchor generator, due to TOV associated with transformer energisations, has been a key issue to overcome in the Galloway live trials carried out to date.

2.3.5 Network reactive loading

When distribution or transmission circuits are energised, they will generate Mvars depending on their capacitance. Care has to be taken such that the total Mvar generated by the network does not exceed the reactive power absorption capacity of the anchor generator (or additional DER connected). This may be problematic should a DER trip off (resulting in Mvar loading of the remaining generator[s]), or if a DER is on local voltage control and generates excessive Mvars which cannot be absorbed by the remaining DER (this would result in the generators tripping due to under excitation).

Live trials

For each of the energisation scenarios in the live trials, a calculation of the total network Mvars is produced to ensure that this is within the anchor generator absorption capacity (its leading power factor limit). Where wind farms are incorporated in the live testing, if the number of turbines connected could result in the anchor generator absorption Mvar limit being exceeded, they will be operated in power factor mode to ensure any voltage control instability does not generate excessive Mvars and trip the anchor generator.

2.4 Limitations of testing

The planned scope of the live trials is ambitious; the trials will test the network and DERs in ways that have never been attempted before. There are, however, some limitations associated with the trial which prevent the test environment from being representative of a genuine Black Start event.

2.4.1 Automation

The project has previously determined that an automated monitoring and control solution is required to support the restoration process. The project engaged with industry-leading suppliers of wide area control solutions to develop the functional requirements of a suitable control solution; the solution is referred to as the Distribution Restoration Zone Controller (DRZ-C). The December 2020 report published the functional requirements of a solution based on the engagement with those suppliers. Through 2021, a supplier has developed a proposed DRZ-C solution further by building a prototype, which will be comprehensively tested functionally within a Hardware-in-the-Loop (HiL) environment.

The timeline of the DRZ-C solution development meant that it will not be tested as part of the live trials. The live trials will therefore be done on a manual basis with regard to operations such as varying outputs of DERs, circuit breaker closing and addition of load steps to the DRZ. While this will test the crucial building blocks to establishing a DRZ, a limitation is that the core functionality of the DRZ-C will not be tested, that is:

- slow balancing – coordinating all available DERs to keep the frequency within limits for normal load variations.
- fast balancing – coordinating the sub-second (using a load bank or BESS) response to maintain the frequency within limits during significant events such as when picking up block loads, or when a DER trips causing a sudden frequency disturbance.

2.4.2 Load simulation

During the trials, the networks will be arranged such that customers in the trial areas will continue to be supplied by the grid and will therefore not be included within the test island. The trials therefore will not evaluate the effect of operating a DRZ island on residential/commercial load customers.

Load for the trials will be provided by installing temporary load banks at strategic point(s) on the test networks. Block loading tests will be limited to the rating of the hired load banks. The intention is to configure the load bank with representative profiles to make the testing as realistic as practical.

3 Galloway Live Trial Network

This chapter provides an overview of the objectives and plans for the Galloway live trials and the energisation strategies employed, along with schematic diagrams and maps showing the Galloway test network.

Two hydro generators, Glenlee (15 MVA) and Kendoon (13 MVA), have been used in the Galloway live testing as the 'anchor' generator (to initially energise the network and control the voltage and frequency). They generate at 11 kV and transform directly to 132 kV with this transmission network connecting to the New Cumnock 275/132 kV wind farm collector substation (via ~30 km 132 kV overhead tower line), and to the distribution network at Glenluce 132/33 kV grid supply point (via ~50 km 132 kV overhead tower line), where several wind farms totalling ~100 MW are connected at 33 kV.

3.1 Trial objectives

The high-level objectives of the Galloway trials are as follows:

- Develop strategies to energise from the 11 kV anchor generator to the distribution 132/33 kV GSP (via ~60 km 132 kV overhead tower line network).
- Test the viability of energising from the anchor to the 275 kV network and energising 275/132 kV 240 MVA SGTs.
- Test the ability to establish a power island with wind generation connected.
  – Identify the number of turbines that can connect (given the low fault level).
  – Confirm stable operation of the wind farms when energising primary transformers or performing load steps (temporary load bank will be installed for testing).

3.2 Live testing

3.2.1 Anchor generator selection

In a BaU implementation, Glenlee hydro would be the anchor generator as it always has water available to run by virtue of being supplied from a dammed reservoir (the other local hydros are 'run or river'). However, the configuration of the 132 kV network is such that it is not possible to take an outage to test to the wider transmission network (New Cumnock 275/132 kV), while still keeping the customers at Glenluce and Newton Stewart GSPs supplied from an alternative 132 kV circuit. As a result, subsequent testing utilises Kendoon hydro as the anchor (similar in size and configuration to Glenlee) as, from a network perspective, a test circuit to Glenluce GSP and/or New Cumnock 132 kV substation can be obtained while the customers remain supplied from the Tongland 132 kV circuit.

3.2.2 Energisation strategies

For each live test, a step-by-step test plan was developed to assess the viability of different energisation strategies and increase the chances of success. In particular, the following strategies were employed as part of the live trial energisation scenarios.

Reduced generator voltage

For the Glenlee and Kendoon testing, the generator Automatic Voltage Regulator (AVR) specialist was available to reduce the generator terminal voltage (normally 11 kV) as required for the planned energisation scenarios. A maximum reduction to 0.75 pu (8.25 kV) is available and has two benefits:

- It allows more headroom for transient overvoltages associated with transformer energisation before the generator overvoltage protection may operate.
- It reduces the transformer inrush currents when they are energised at reduced voltage.

Grid transformer tap setting
As well as by reducing the generator voltage, the network voltage may be further reduced by tapping relevant grid transformers (if available). At Kendoon and Glenlee, the scenario of tapping their 132/11 kV transformers to their maximum tap (tap 17) was included. This gives a reduction in 132 kV voltage of 20 per cent (when back energised at 11 kV). If the generator voltage is reduced to 8.25 kV, and the grid transformer on tap 17, the 132 kV voltage is reduced a total of 40 per cent.

This scenario of reducing the network voltage was included as it may help to reduce the inrush currents on the Glenluce 132/33 kV grid transformer, located at the remote end of the 132 kV circuit from the hydro generators.

Point of Wave switching
On the 11 kV circuit breakers at Glenlee and Kendoon (used to energise the test network), a Point of Wave (PoW) relay was installed. This calculates the residual flux in the local 132/11 kV transformers when they are de-energised and calculates the optimum time to close the circuit breaker to minimise the transformer magnetic inrush current (and associated transient overvoltages). This technology operates with a three phase circuit breaker, as used on distribution networks, but is not commonly installed by Distribution Network Operators (DNOs).

Sequential or simultaneous circuit energisation
The test plan included scenarios where networks were energised sequentially (individual circuits one at a time as dictated by circuit breaker locations), and simultaneously, where multiple circuits (including transformers) were energised together to test the limits of what was viable.

3.2.3 Completed live testing
To date, five days of live testing has been completed in the Galloway region, that is:

Phase 1 – October 2020 (1 day) – Glenlee anchor
Tests from Glenlee 11 kV hydro station (15 MVA) to Glenluce 132/33 kV GSP (via ~50 km 132 kV overhead tower line).

Phase 2 – September/October 2021 (4 days) – Kendoon anchor
Tests from Kendoon 11 kV hydro station (13 MVA) to Glenluce 132/33 kV GSP (via ~60 km 132 kV overhead tower line.

- Subsequent tests incorporating a 33 kV half busbar outage of the distribution network at Glenluce GSP (including primary [33/11 kV] transformers).
- Tests from Kendoon 11 kV hydro station to New Cumnock 132 kV substation (via ~30 km 132 kV overhead tower line).
- Subsequent tests incorporating two 275/132 kV 240 MVA super grid transformers (SGTs) at New Cumnock substation.

3.2.4 Results
Chapter 4 of this report details the results of the live testing from Glenlee hydro (Galloway Live Trial Results – Phase 1), and the results from Kendoon hydro are in Chapter 5 (Galloway Live Trial Results – Phase 2).

3.3 Network schematics
The following diagrams are provided to give an understanding of the Galloway test network:
Figure 1: Galloway transmission test network schematic (Kendoon hydro testing)
Figure 2: Galloway distribution test network schematic (Glenluce GSP)
Figure 3: Transmission test network geographic (showing key substations)
Figure 4: Glenluce GSP 33 kV network geographic

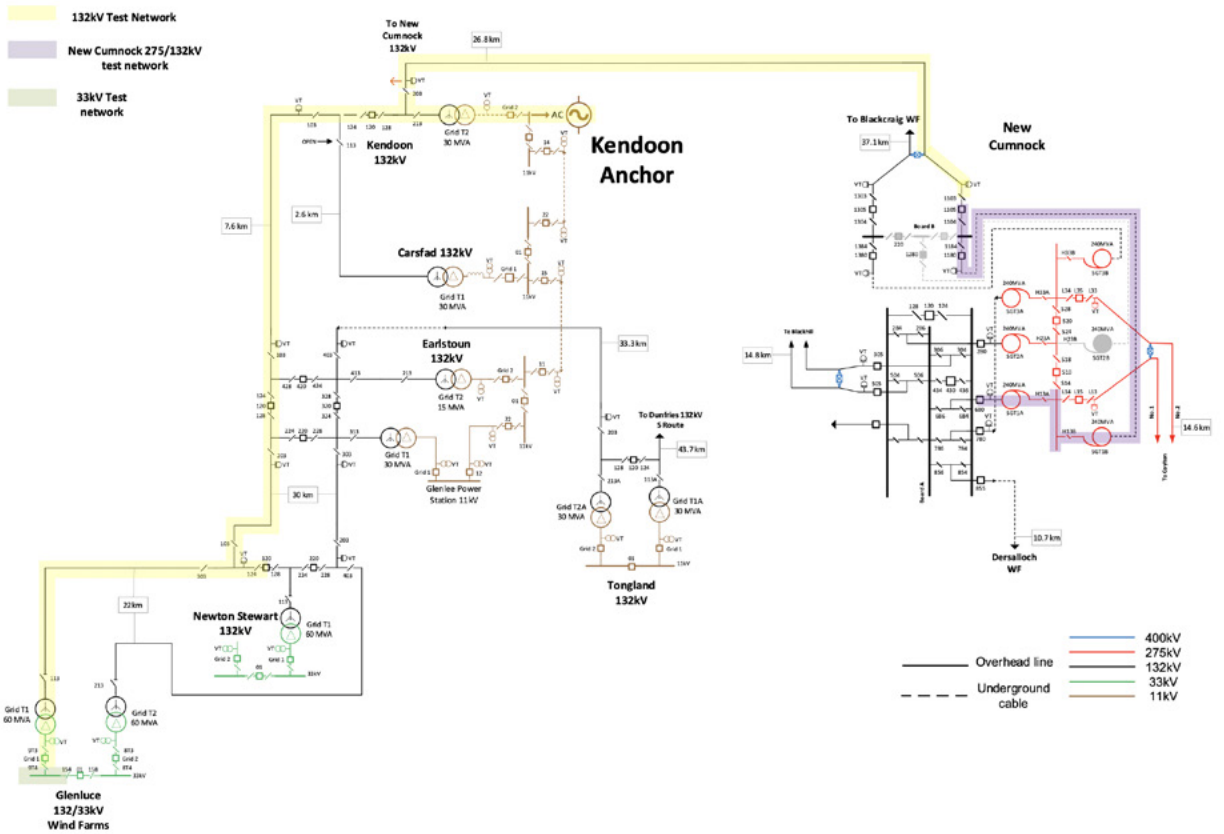


Figure 1: Galloway transmission test network schematic (Kendoon hydro testing)

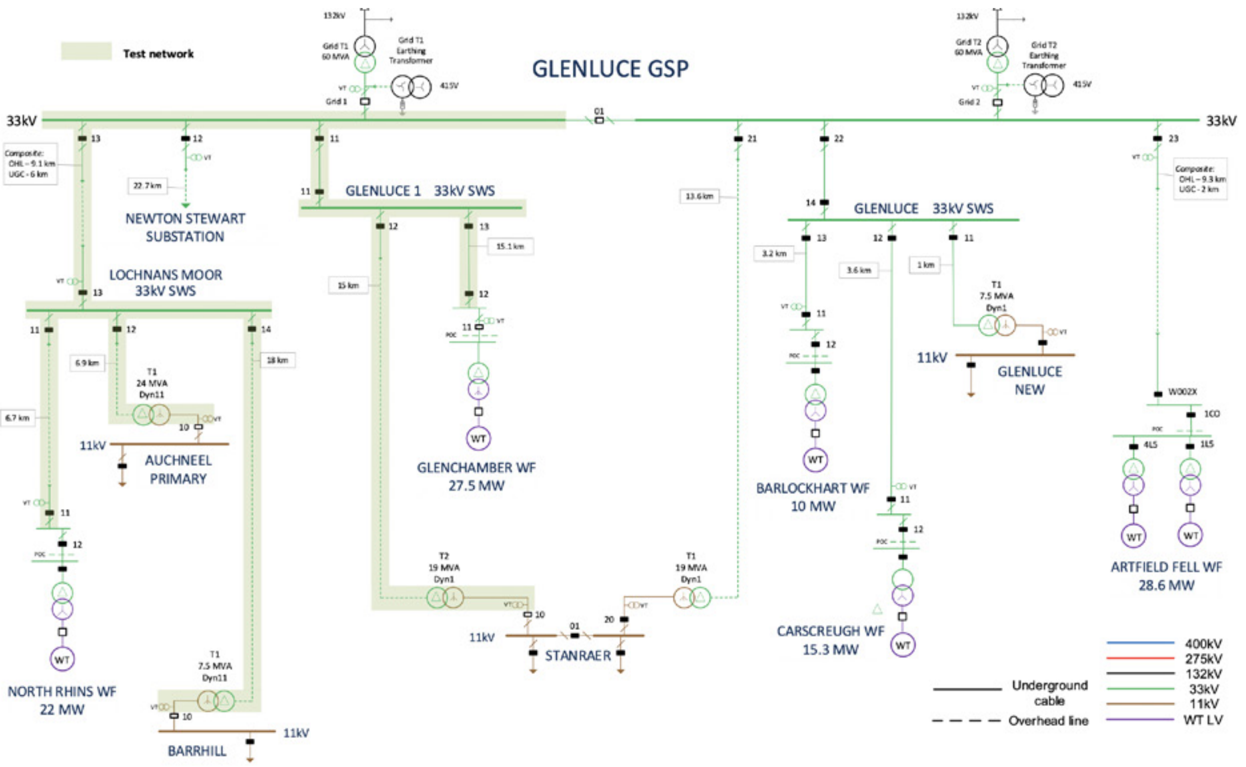


Figure 2: Galloway distribution test network schematic (Glenluce GSP)

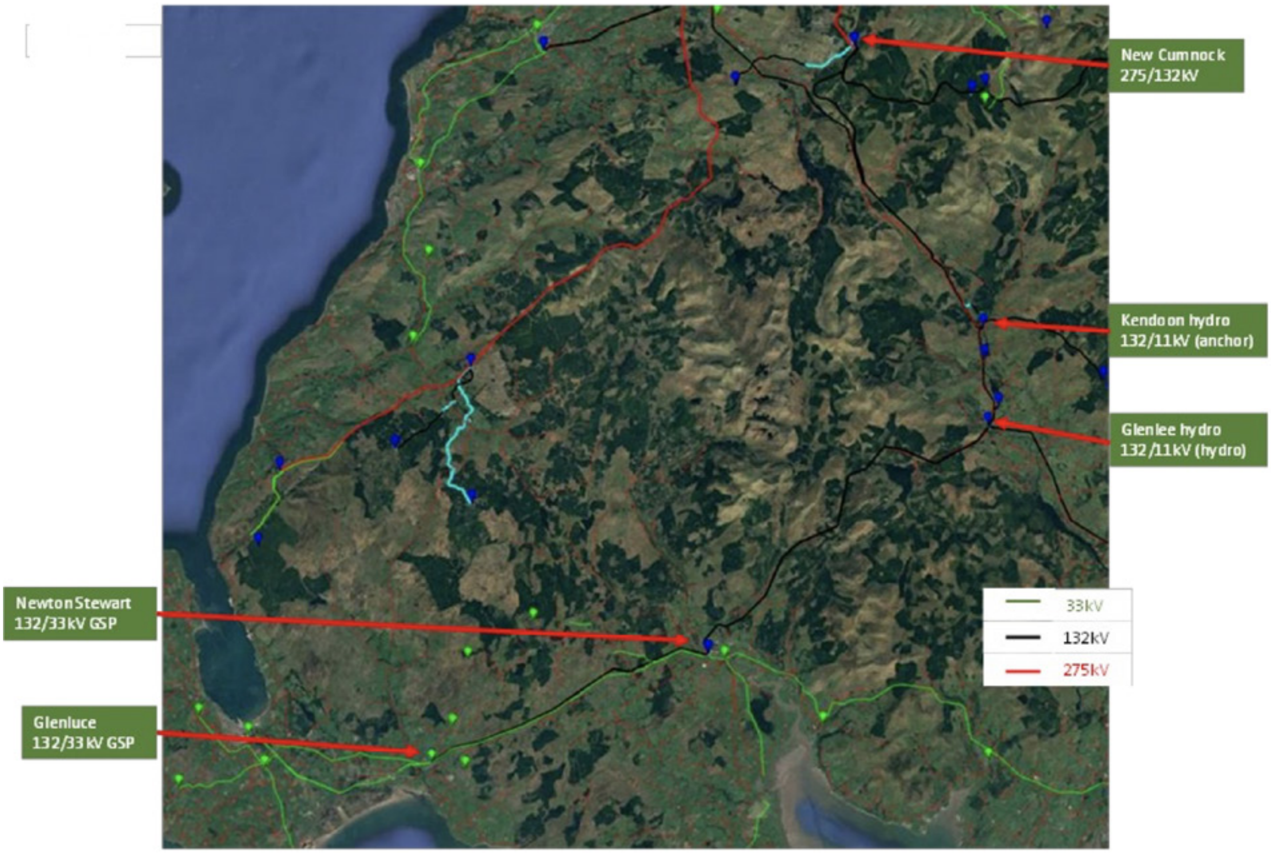


Figure 3: Transmission test network geographic (showing key substations)

Figure 4: Glenluce GSP 33 kV network geographic

4 Galloway Live Trial Results – Phase 1

This chapter provides a summary of the live testing which has been carried out in the Galloway region with Glenlee hydro as the anchor generator.

4.1 Introduction

This first live trial in the Galloway region was performed during one day in October 2020. This was also the first trial undertaken as part of the project, and it provided learning on which to develop the future Galloway trials (from Kendoon). The remainder of this section describes this specific trial.

4.1.1 Trial overview

The test network contains no circuit breakers and could only be subdivided by opening disconnectors which could then not be closed while the network remained live. The layout of the network in this area is shown in Figure 5 (test network highlighted in red). It was therefore decided that an initial test involving a Glenlee generator energising the Glenlee 11/132 kV 30 MVA transformer, the Glenlee/Newton Stewart/Glenluce No 2 132 kV overhead line (OHL) circuit (~50 km) and the Glenluce 132/33 kV 60 MVA transformer should be carried out.

Simulations of the energisation indicated overvoltages were likely, and in view of issues previously experienced with similar tests, it was envisaged that a reduction in generator terminal voltage could be required. The reduced generator voltage would reduce the magnitude of the overvoltage, and would increase the headroom between the generator voltage and the generator overvoltage protection relay settings. The planned generator voltage levels were 100 per cent, 95 per cent, 90 per cent, 85 per cent, 80 per cent and 75 per cent of nominal generator voltage.

The automatic tap changing on the Glenlee transformer would be disabled as it attempts to control the 11 kV voltage. During the tests, this voltage would be controlled by the Glenlee generator, and the effect of automatic tap changing would only affect the 132 kV voltage and would drive the tap changer to one end of its range. The tap position would be set to 19 as this would reduce the 132 kV voltage by 20 per cent. Automatic tap changing on the Glenluce transformer would also be disabled, as the reduced 132 kV voltage would drive it away from its normal position, which would be needed when the system was restored when the tests were complete.

Due to the lack of fault infeed from the rest of the network, fault levels on the test network would be much lower than normal, so protection relays covering the Glenlee transformer LV and HV windings would be reduced for the duration of the test. A further test would involve the use of a Point on Wave (PoW) relay for evaluation during the test. This would be used to control the closure of the Glenlee 11 kV Grid 1 breaker, which would energise the test network. By controlling the point on the generator voltage waveform, it was hoped to reduce the transient caused by the magnetic inrush into the transformer. Two attempts would be made using the PoW relay, the first with the relay set to minimise inrush, with the second set for maximum inrush so that there is a clear indication of the possible improvements that could be achieved.

During the testing, the Glenlee hydro auxiliary transformer was supplied from the local 11 kV network. The generator was thus not made 'self-starting', as the focus of the project is to test its ability to energise the wider network (self-starting would be required for a BaU implementation).

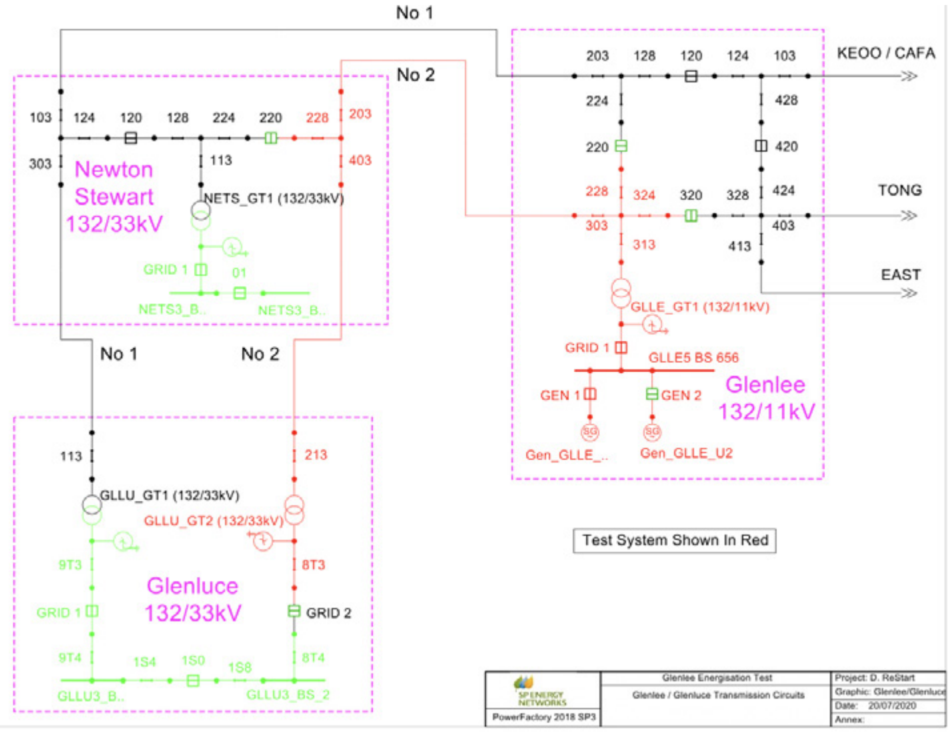


Figure 5: Single line diagram of Glenlee test network

4.1.2 Fault recorders

The results of the energisation tests would be obtained from the fault recorders that are installed throughout the network. There are five fault recorders on the test network located at the following points recording three phase values:

- Glenlee transformer 11 kV voltage and current.
- Glenlee 132 kV voltage and current on GLLE/NETS/GLLU No 2 circuit.
- Newton Stewart 132 kV voltage and current on circuit from Glenlee.
- Newton Stewart 132 kV voltage and current on circuit to Glenluce.
- Glenluce 132/33 kV transformer 33 kV voltage and 132 kV current.

The two Newton Stewart recorders share a common VT, and both currents will be equal and opposite.
The recorders normally record 10 seconds pre-trigger and 20 seconds post-trigger, and have been set to trigger on the appearance of voltage or the loss of voltage.

The fault recorder which has been used for most of the figures in this report is the Glenlee Transformer recorder. This recorded the following parameters:

1. Red–Yellow Voltage on 11 kV side of transformer (Vry).
2. Yellow–Blue Voltage on 11 kV side of transformer (Vyb).
3. Blue–Red Voltage on 11 kV side of transformer (Vbr).
4. Red Phase Current on 11 kV side of transformer (Ir).
5. Yellow Phase Current on 11 kV side of transformer (Iy).
6. Blue Phase Current on 11 kV side of transformer (Ib).

The voltage inputs to the fault recorder have been configured for a 30 per cent overload capability. For an 11 kV RMS waveform, the peak voltage is 15.56 kV, and a 30 per cent overload gives 20.22 kV. In practice, the limit was 20.32 kV. Unfortunately, the overload capability was insufficient, and clipping of the voltage trace occurred during the testing.

4.2 Summary of tests

In total, six energisation tests were undertaken from Glenlee. These are summarised in Table 1.

Table 1: Glenlee energisation tests

Description	Test No	Generator Terminal Voltage	Success /Fail
From Glenlee 11 kV hydro:			
Energise Newton Stewart/Glenluce Circuit and Glenlee 132/11 kV grid transformer T1	1	1.0 pu	Fail
Energise Newton Stewart/Glenluce Circuit and Glenlee 132/11 kV grid transformer T1	2	0.75 pu	Fail
Glenlee 132/11 kV grid T1	3	0.75 pu	Success
Glenlee 132/11 kV grid T1	4	1.0 pu (PoW min transient)	Success
Glenlee 132/11 kV grid T1	5	A1.0 pu (PoW min transient)	Success
Energise Newton Stewart/Glenluce circuit and Glenluce 132/33 kV grid transformer T2	6	1.0 pu (PoW min transient)	Success

4.3 Test results

4.3.1 Test no.1 – FAIL

Circuit energised – Glenlee hydro (1 pu voltage) to Glenluce 132/33 kV GSP
The test network was set up, and the first energisation was attempted with nominal voltage on the Glenlee generator. The generator tripped immediately on overvoltage. The voltage and current data from the fault recorder monitoring at Glenlee Grid 11 kV is presented in Figure 6.

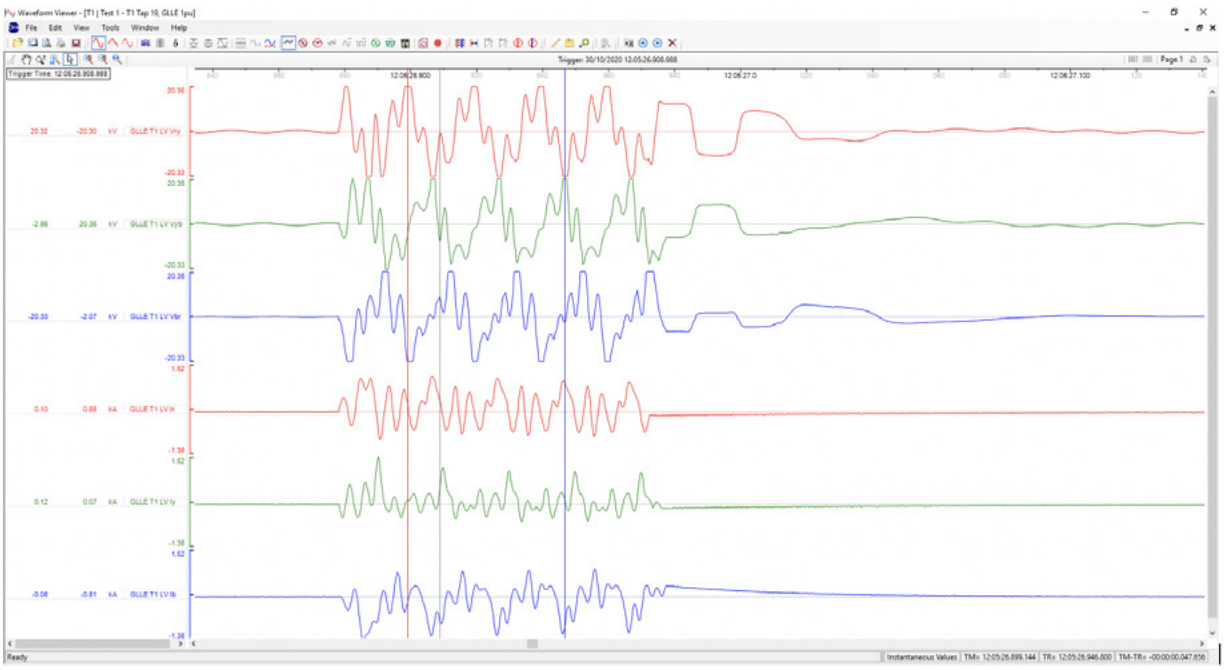


Figure 6: Test No.1, data plot – failed test system energisation at 1 pu

Comments

- Clipping of the 11 kV voltage traces is visible on all three phases. While there is a 50 Hz component of the voltage present, there is also a very large component at about 204 Hz. While this is close to the 4th harmonic, it is likely the result of a resonance between the line capacitance and the transformer inductance.
- The transformer LV winding currents are largely this high frequency component, with little signs of the fundamental component.
- The generator overvoltage protection operated and opened the generator circuit breaker (CB) within 100 ms of the of the CB closing to energise the test network.

4.3.2 Test no.2 – FAIL

Circuit energised – Glenlee hydro (0.75 pu voltage, 8.25 kV) to Glenluce 132/33 kV GSP

In view of the significant overvoltages in test no.1, it was decided that the next test should be carried out at the minimum planned test voltage of 75 per cent, rather than the planned 95 per cent in the next stage of the test document. When the second test at 75 per cent voltage was carried out, the generator again immediately tripped on overvoltage. The data from the fault recorder monitoring the Glenlee Grid 11 kV voltage and current is presented in Figure 7.

Appendix 3: Post Galloway Trials Investigation provides the results of an offline desktop-based analysis of this test which was undertaken to better understand the complex phenomena encountered.

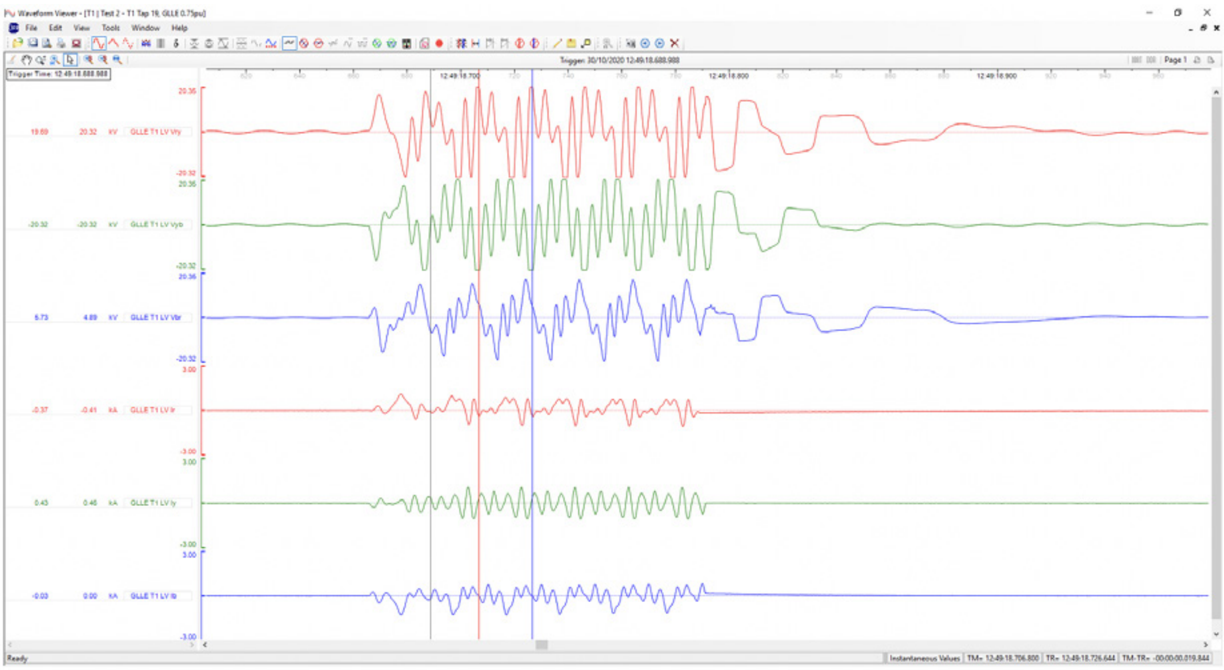


Figure 7: Test no.2, data plot – failed test system energisation at 0.75 pu

Comments

- While the magnitude of the 11 kV voltages has been reduced, clipping of the voltage traces by the fault recorder is still visible on the negative peaks of the Red–Yellow phase voltage, on the positive and negative peaks of the Yellow–Blue phase voltage, but not on the Blue–Red phase voltage.
- A 50 Hz component of voltage is more easily observed on the Blue–Red phase voltage, the other two phases being dominated by the higher frequency.
- The transformer LV currents are largely the higher frequency, with little evidence of the fundamental component (as per test no.1).
- The generator overvoltage protection then operated and opened the generator circuit breaker within 120 ms of the breaker closing to energise the test network.

4.3.3 Test no.3, 4 and 5 – all SUCCESSFUL

Circuit energised – Glenlee 132/11 kV 30 MVA GT1

There was concern over further reduction of the generator voltage in case the fault level on the 132 kV line was insufficient for protection relays to operate. It was therefore decided that the energisation of the Glenlee 132/11 kV transformer only would be attempted (at Glenlee 132 kV substation isolator 303 was opened). Three different strategies were attempted:

Test no.3 – Glenlee hydro 0.75 pu voltage (8.25 kV)

- This energisation was successful.
- Distortion of the voltage waveform was evident, even 20 cycles after transformer energisation.
- As would be expected, the magnetic inrush current tends to reduce the generator terminal voltage; hence, overvoltage tripping was not an issue in this test.

Test no.4 – Glenlee hydro 1.0 pu voltage (11 kV)

PoW relay set to give maximum transient (highest possible inrush current). The data from the fault recorder monitoring the Glenlee Grid 11 kV voltage and current is presented in Figure 8.

- This energisation was successful.
- The PoW relay had successfully monitored the previous successful energisation of the Glenlee 132/11 kV transformer and was now capable of controlling the timing of the closing of the Grid 1 breaker to minimise transients.
- It was used during this test to control the closing of the Grid 1 circuit breaker.
- To determine the improvement that could be obtained by using the PoW relay, the difference between the worst and best time for breaker closure was required. The previous tests did not use a controlled PoW circuit breaker close and were totally random in nature.
- The PoW relay was configured for the maximum transient in this test and would be changed to minimise the transient in the following test.
- A very significant harmonic content was visible on the voltage waveforms.

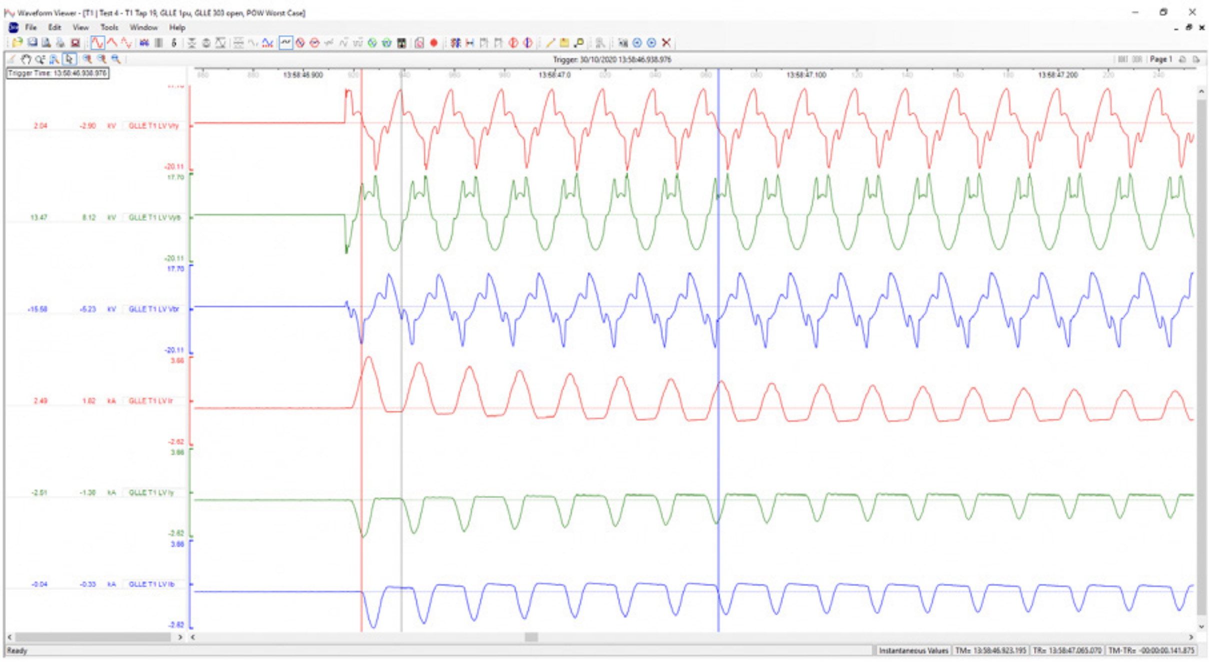


Figure 8: Test no.4, data plot – successful GT1 energisation at 1.0 pu, PoW maximum transient

Test no.5 – Glenlee hydro 1.0 pu (11 kV)
PoW relay set to give minimum transient. The data from the fault recorder monitoring the Glenlee Grid 11 kV voltage and current is presented in Figure 9.

- The energisation was successful.
- The PoW relay was used to control the closing of the Grid 1 circuit breaker and was configured to minimise the transient.
- A small amount of distortion was visible on the voltage traces.
- Inrush currents were reduced to ~15% of those when the PoW was set to maximum transient.

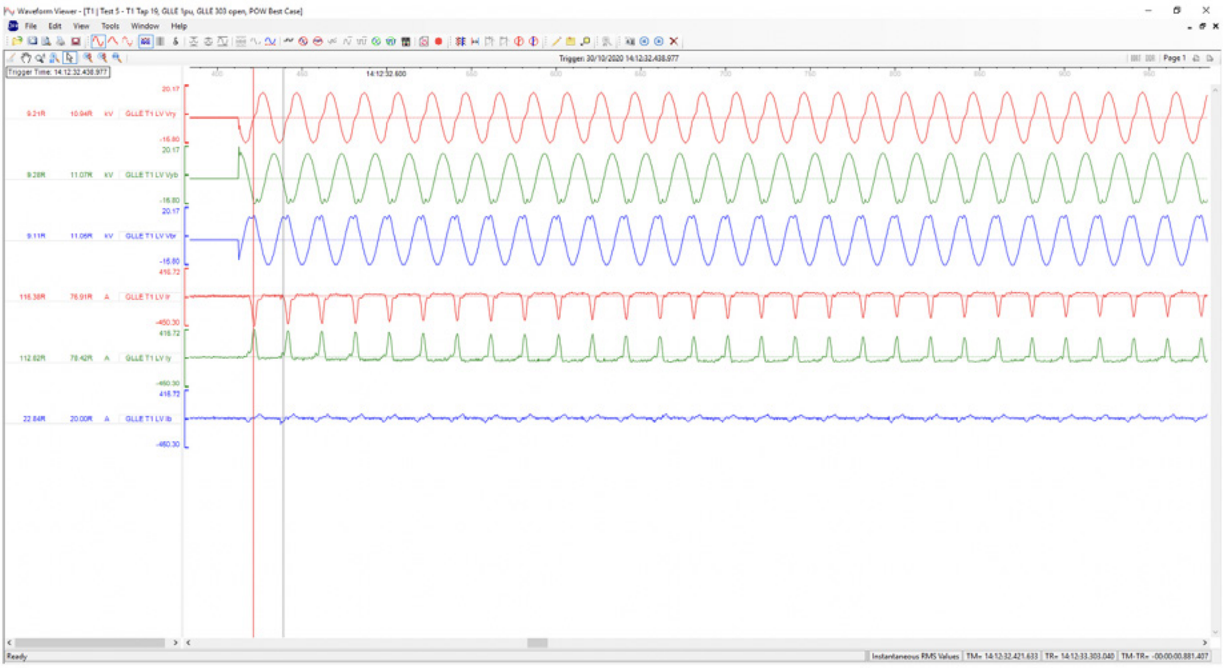


Figure 9: Test no.5, data plot – successful GT1 energisation at 1.0 pu, PoW minimum transient

4.3.4 Test no.6 – SUCCESSFUL

Circuit energised – Glenlee hydro (0.75 pu voltage, 8.25 kV) to Glenluce 132/33 kV GSP.
PoW used to give minimum transient.

In view of the very significant reduction in harmonic content when using the PoW relay to energise Glenlee GT1, it was decided that a further attempt should be made to energise the full test network at 75 per cent voltage with the PoW relay closing the circuit breaker to minimise transients. Figure 10 presents the data captured from this attempt.

- The energisation test was successful.
- Test 6 was a repeat of Test 2 in which the entire test network was energised with the generator terminal voltage reduced to 75 per cent of nominal voltage (8.25 kV). However, the PoW relay was used to close the Grid 1 circuit breaker to minimise the transient.
- Some distortion of the voltage waveform is visible on the first couple of cycles but then disappears. The remainder of the voltage traces shows no visible signs of distortion; hence, the latter section of the waveform is cleaner than that observed during the energisation of the transformer alone.
- This test shows a remarkable improvement over Test 2, when PoW switching was not used.

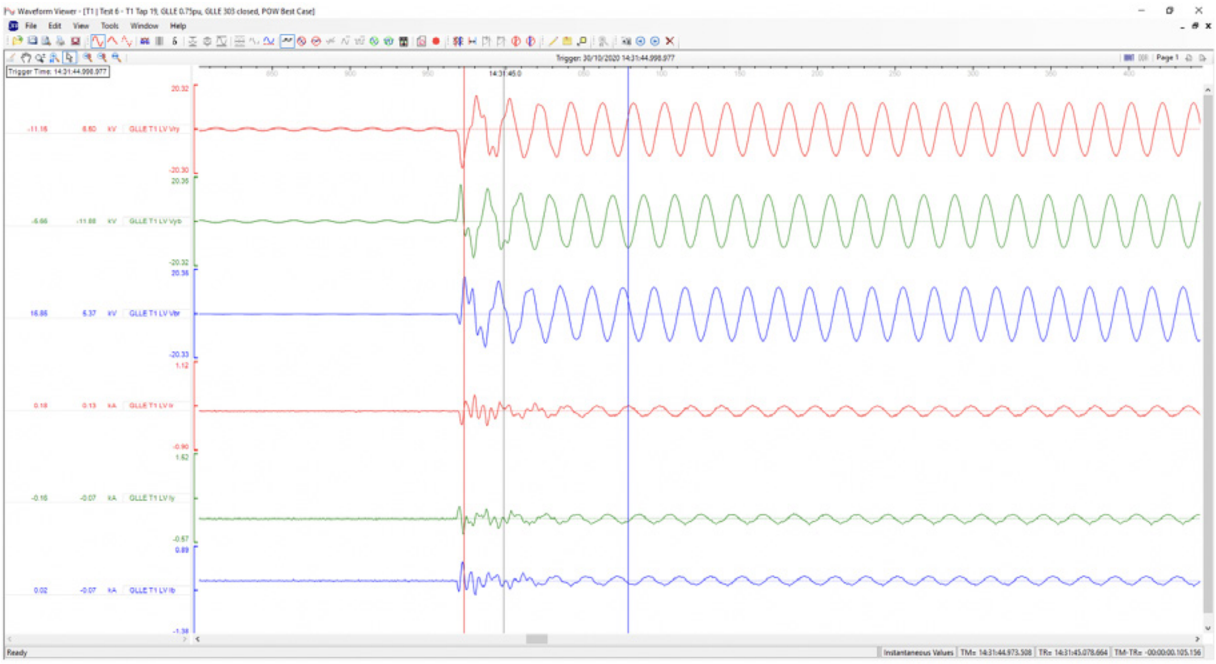


Figure 10: Test no.6, data plot – successful test system energisation with best case PoW

4.3.5 Test system de-energisation

The test system (Glenlee hydro to Glenluce 132/33 kV GSP) was de-energised by opening Grid 1 11 kV CB at Glenlee. Examination of the fault recorder record obtained when the Grid 1 CB opened raised a concern over a very slow interruption of the current by the circuit breaker.

Information from the PoW relay indicated that the circuit breaker contacts parted close to the position of the red cursor line (see Figure 11), but the red phase current was not interrupted for a further 172 ms, followed by the blue phase then the yellow phase.

Due to the extended time taken by the Grid 1 circuit breaker to interrupt the current, testing was terminated at this time until the circuit breaker could be checked the next morning. (No damage was observed, and the breaker was returned to service.)

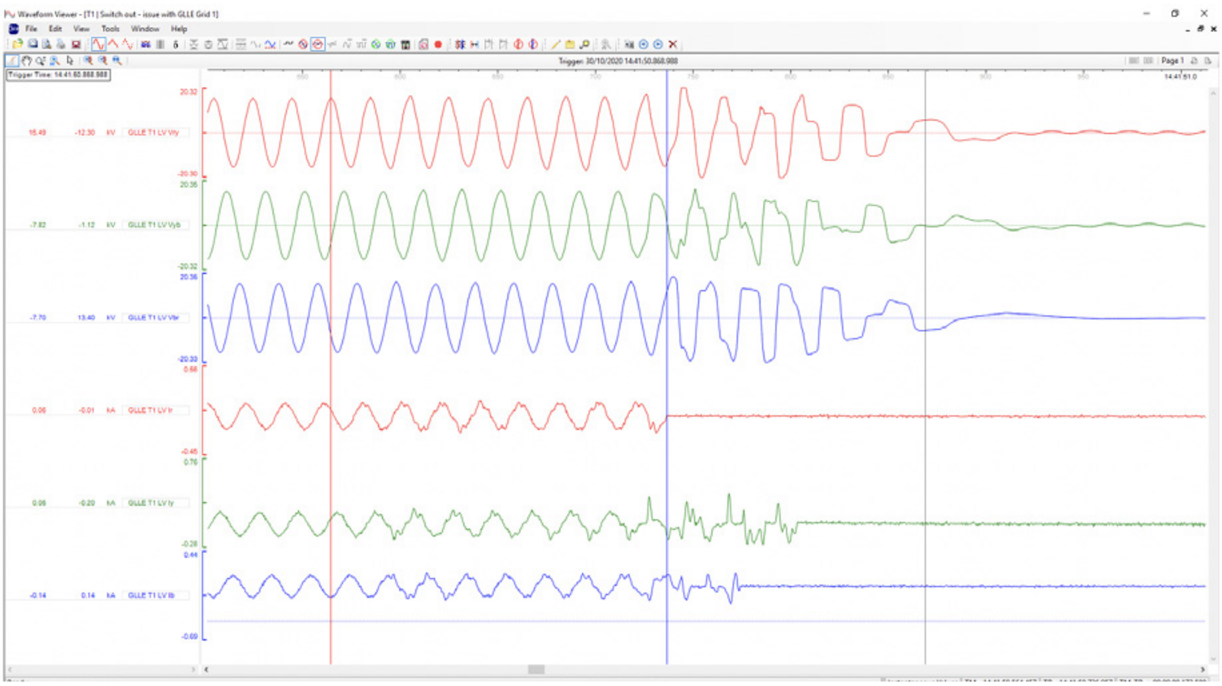


Figure 11: System de-energisation Glenlee 11 kV

4.3.6 Discussion

Circuit Breaker Issues

Following the possible issues related to the Glenlee Grid1 11 kV circuit breaker breaking the network charging current, the scenario was further examined by SPEN.

The Glenlee Grid 1 circuit breaker is an air break type. Under fault conditions, this type of breaker relies on magnetic forces on the arc to drive it from the arcing contacts along the arcing horns and into the arc chute. This leads to a considerable lengthening of the arc which helps to extinguish the arc at a current zero. Under fault conditions, current is limited by the system reactance; hence, there is a 90o difference between the current and voltage. This leads to a high Rate of Rise of Recovery Voltage (RRRV) as the voltage is close to a peak when current zero occurs.

When breaking load current, the current is very much less, and hence the magnetic forces may not be sufficient to drive the arc into the arc chute. However, the voltage and current have only a small phase angle between them. As a result, the RRRV is very much lower allowing current interruption at a current zero.

During the de-energisation of the test network, the breaker was required to interrupt the overhead line charging current, which has a low value similar to load current; however, the reactive nature results in approximately 90o between the voltage and current giving similarly large values of RRRV to a fault but without the lengthening of the arc as it is forced towards the arc chute. As a result, the breaker fails to interrupt the current at a current zero, leading to an extended arcing time before the current is eventually interrupted.

The breaker is normally never required to interrupt the 132 kV line charging current; hence, it experienced unique conditions during this energisation test.

Modelling

The pre-trial overvoltage studies performed for the trial were found to underestimate the overvoltages at Glenlee 11 kV. The generator tripped repeatedly, and ultimately a Point on Wave (PoW) relay was required to successfully proceed with the test. The underestimation was subsequently identified as being due to a modelling error. When performing an energisation study, it is necessary to model the inrush characteristic (due to the non-linearity of the transformer core saturation) of a transformer. Typically, transformers are energised from the HV side; therefore, a default modelling assumption is to use the inrush characteristic suitable for energising from the HV side of the transformer. Manufacturers also provide data for energisation from the HV side, which re-enforces the default decision to model with the HV side characteristic. Subsequent analysis found that when the transformer is energised from the LV side, the inrush current is significantly higher when the inrush characteristic is selected with the LV side (as opposed to the HV side, which was selected for the pre-trial power system studies) as reference for the model.

Given that the bottom-up energisation is not typically studied, default modelling assumptions for energisation and other power system studies should be reviewed to determine suitability for each study.

4.3.7 Conclusions

From the issues encountered during the attempt to use a Glenlee hydro unit to energise the local 132/11 kV transformer, the Glenlee/Newton Stewart/Glenluce No 2 132 kV circuit and the Glenluce 132/33 kV transformer, several conclusions can be drawn.

- Reducing the generator terminal voltage (on synchronous generators by adjusting the Automatic Voltage Regulator [AVR] set point) is an effective strategy to avoid the generator tripping on overvoltage protection. This provides additional headroom for transient and temporary overvoltages, produced by the transformer inrush currents, before the overvoltage protection operates.
- Transformer inrush currents may be significantly reduced using Point of Wave switching on CBs, minimising waveform distortion and the possibility of overvoltage protection operations.
- Plant items including circuit breakers may be required to carry out duties which may be outside their designed capability. Transient Recovery Voltage (TRV) studies may be required to ascertain this.
- Energising a network from a weak source (very low fault level) is likely to result in significant harmonic and 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.
- As much testing as possible of unconventional network energisation sequences should be carried out to increase the confidence that the proposed energisation sequence will proceed as expected should the need arise for it to be used in practice.
- Modelling assumptions related to energisation studies should be validated to ensure suitability for the ‘Black Start from DERs’ bottom-up study scenario.

5 Galloway Live Trial Results – Phase 2

This chapter provides a summary of the live testing which has been carried out in the Galloway region with Kendoon hydro as the anchor generator.

5.1 Introduction

The second phase of live testing trial in the Galloway region was performed during four days in September and October 2021. The remainder of this section describes this specific trial and the results obtained. In addition, section 5.6 gives an overview of live 'set point' testing which was also undertaken with two of the wind farms connected to Glenluce GSP.

5.1.1 Trial overview

Figure 12, Figure 13 and Figure 14 show schematically the test network from Kendoon 11 kV hydro (shown in magenta). The Galloway phase 2 series of tests follows from the phase 1 test, carried out on 30 October 2020, in which a hydro generator at Glenlee Power Station was used to energise the Glenlee 132/11 kV grid transformer, the Glenlee–Newton Stewart–Glenluce No 1 132 kV circuit and the Glenluce 132/33 kV grid transformer T1.

The test involved the simultaneous energisation of the entire circuit as no 132 kV circuit breakers are fitted in the test circuit; hence, energisation took place by closing the Glenlee 11 kV Grid 1 circuit breaker which energised the circuit up to the Glenluce 33 kV Grid 2 circuit breaker.

The energisation attempts last year failed until a Point on Wave (PoW) relay was used to close the Glenlee Grid 1 breaker, as well as reducing the Glenlee generator voltage to 75 per cent of nominal (8.25 kV) during the attempt. This relay calculated the residual flux in the Glenlee 132/11 kV transformer when it was de-energised and calculated the optimum time to close the circuit breaker to minimise the transformer magnetic inrush current. This, together with the reduced generator voltage, allowed the test circuit to be energised without causing an overvoltage protection trip of the generator.

The phase 2 series of tests were planned to energise from Kendoon hydro to Glenluce GSP, and to include a half bar outage at Glenluce grid supply point (GSP) to test energising the 33 kV distribution network and primary (33/11 kV) transformers. It was also planned to energise the 132 kV circuit to New Cumnock and SGTs at New Cumnock as a potential route to other loads and wind farms within West Central Scotland.

The layout of the Glenlee 132 kV substation prevents energising the circuit from Glenlee Power Station to New Cumnock while retaining supplies from Glenluce and Newton Stewart GSPs. As a result, the Kendoon Power Station was chosen as the anchor generator as this can energise the New Cumnock circuit as well as the Kendoon/Glenlee/Newton Stewart/Glenluce circuit while maintaining supplies to Newton Stewart and Glenluce from Dumfries and Tongland.

During the testing, a temporary diesel generator provided the low voltage supplies for the Kendoon generator to start as it was not possible to backfeed the station auxiliary transformer.

Phase 3 of the testing will be carried out in spring 2022 where two 33 kV connected wind farms at Glenluce GSP will be included, to test the ability to include wind farms in a DRZ with the very low fault levels resulting from the single small synchronous generator within the zone.

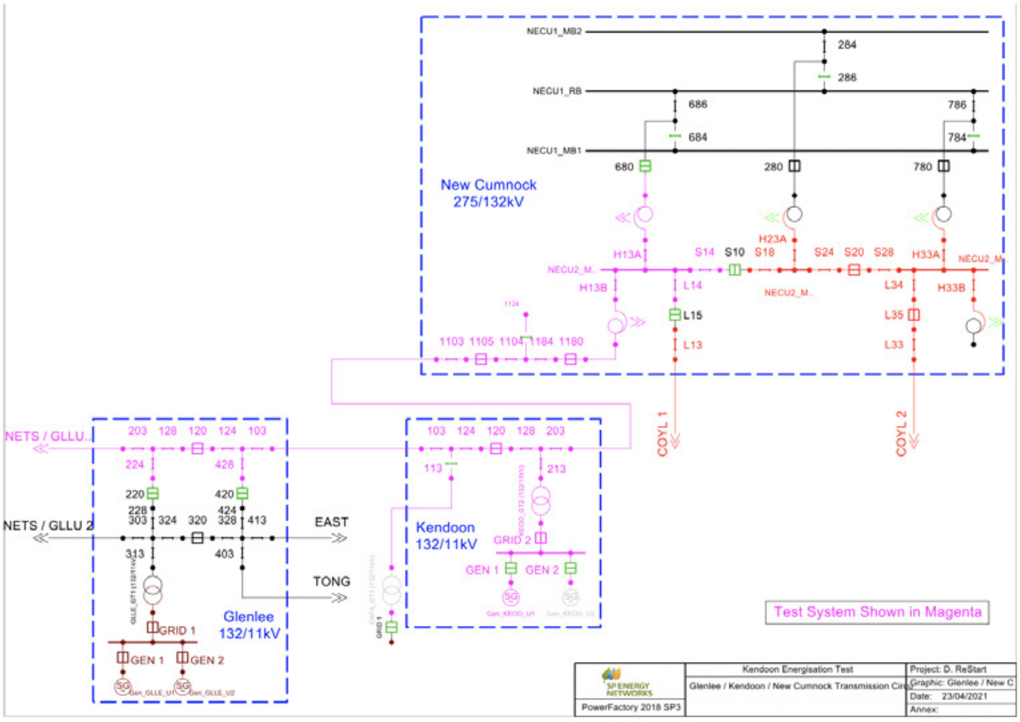


Figure 12: Kendoon 11 kV to New Cumnock 275/132 kV and Kendoon 11 kV to Glenlee 132 kV section of test circuit

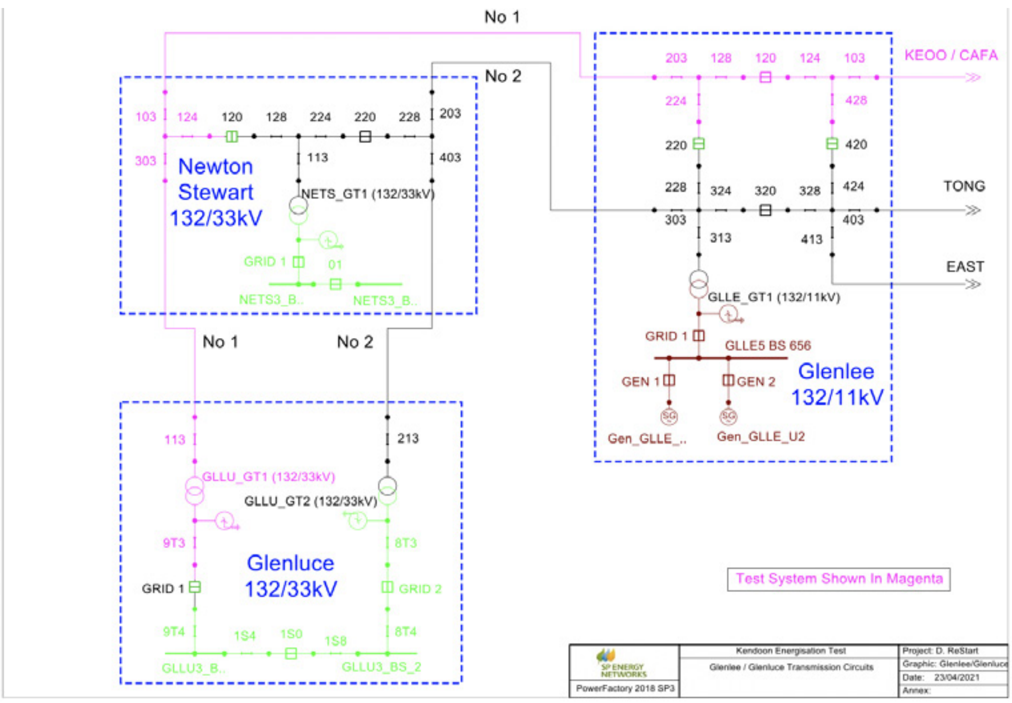


Figure 13: Glenlee 132 kV to Glenluce 132/33 kV GSP section of test circuit

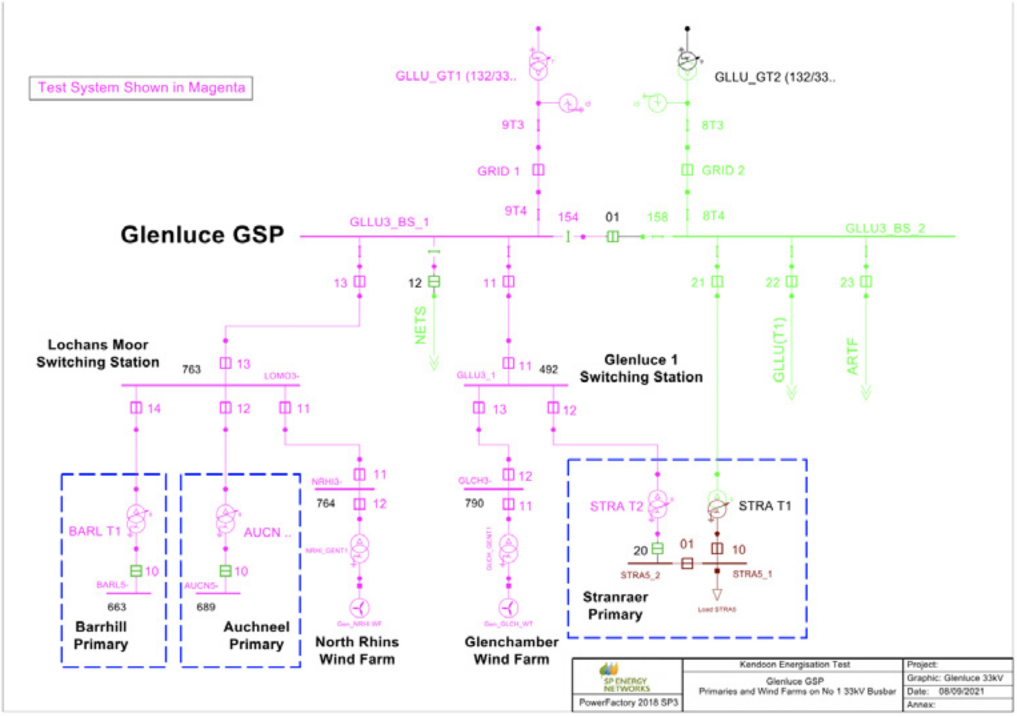


Figure 14: Glenluce 33 kV test network (including primary [33/11 kV] transformers)

5.1.2 Fault recorders

Fault recorders are located at various locations on the test network. These were used to record voltage and current waveforms during the energisation tests.
The most important recorder is connected to the 11 kV side of the Kendoon grid transformer T2. This recorded the 11 kV voltage on the Kendoon generator terminals when the 11 kV Grid 2 circuit breaker was closed. The recorder was triggered by the appearance of voltage when Grid 2 is closed, or by voltage transients.

A second fault recorder at Kendoon monitors the Kendoon/Glenlee 132 kV circuit. As this fault recorder is on the same site as the recorder on the transformer 11 kV side, they can be configured to trip each other. This is not possible for recorders on remote sites. Hence, during the sequential energisation to Glenluce, when the Kendoon 132 kV circuit breaker 120 is closed to energise to Glenlee, the circuit fault recorder triggers on appearance of voltage and triggers the transformer recorder. However, when Glenlee 132 kV circuit breaker 120 is closed to energise the Glenlee/Newton Stewart/Glenluce circuit, the recorder at Glenlee cannot trigger the Kendoon transformer recorder; hence, generator voltage waveforms are only captured if a significant 11 kV voltage transient directly triggers the recorder on the Kendoon transformer. The same situation applies when energising the New Cumnock SGTs by closing a 132 kV circuit breaker at New Cumnock.

As well as capturing triggered waveform data, the fault recorders also capture continuous RMS values of voltage, current, and active and reactive power.

The result is that generator voltage waveforms were not captured for all energisation tests. In total, twenty energisation tests were carried out, of which seven did not record generator voltage waveforms.

5.1.3 Protection modifications

An assessment was carried out of the protections within the test network to ascertain if the network could be protected given the significantly reduced fault levels when only supplied by a 13 MVA synchronous generator. The Kendoon 132 kV fault level was reduced to ~23 MVA and Glenluce GSP 33 kV ~20 MVA. Figure 15 shows that the islanded network could be protected provided the settings changes highlighted by the amber traffic signal were implemented.

It can be seen that the protection philosophy employed was to primarily set the overcurrents down to pick up at ~13 MVA (1600A@11 kV, 60A@132 kV and 240A@33 kV) with a definite time operating setting (when the pick-up is exceeded by any margin, the relay will operate in this 'definite time'). Grading was maintained by setting different definite time settings; for example, Kendoon 11 kV would trip after 0.75 s and the back-up protections on the 132 kV circuits from Kendoon in 0.5 s.

It should be noted that protection operation for loading greater than ~13 MVA may not be feasible in a true Black Start situation as the load current may exceed this value and cause unwanted protection operations (this was not an issue for the tests as no load was connected). A potential solution may be to install voltage-dependent overcurrents (the relays only change to the revised settings if the voltage drops below a certain threshold indicating there has been a genuine fault.)

Substation	Circuit Name	Protection Function	Scheme Type	Device Type	Second Group Available	NEW RELAY REQUIRED	Rating	TRIAL SETTINGS
Kendoon Power Station 11 kV	Grid T2	11kV Transformer Incomer Protection	OC	MCGG31	NO	NO		1600/1, 720A, DT, 0.75s
			SBEF1	MCGG11	NO	NO		no change
			SBEF2	MCGG11	NO	NO		no change
			INTERLOCKED OC	MCGG41	NO	NO		no change
			REF	7SR242 Duobias M	YES	NO		no change
			DIFFERENTIAL		YES	NO		no change
Kendoon GSP 132 kV	Glenlee	132 kV Feeder Main Protection	132 kV Unit (overhead circuits)	MBCI	NO	YES		Ks=0.5
		132 kV Feeder Backup Protection	OC (IDMT)	MCGG62	NO	YES		800/1, 40A, D2, 0.25s
	New Cumnock	132 kV Feeder Main Protection	132 kV Unit (overhead circuits)	P545	YES	NO		no change (minimum setting of relay not sensitive enough for one turbine generator black start fault levels)
		132 kV Feeder Backup Protection	OC (IDMT)	P143	YES	NO		600/1, 60A, DT, 0.5s
			EF (IDMT)	P143	YES	NO		600/1, 60A, DT, 0.5s
	Grid T2	Transformer Feeder Protection	OC	P122	YES	NO		300/1, 60A, DT, 0.75s
			DIFFERENTIAL	7SR242 Duobias M 200	YES	NO		no change
			REF					no change
		Mesh Corner	132 kV Unit	MFAC34	NO	YES		1000/1, setting 25V, 335 ohm
Glenluce 33 kV	Grid T1 Incomer, Newton Stewart T1	33 kV Transformer - OCEF Protection	OC	P14N	YES	NO		800/1, I>240A, 0.75s DT
			Dir. OC Backfeed	P141	YES	NO		no change
			DIFFERENTIAL	Duobias 7SR2423	YES	NO		no change
			REF					
			Standby EF	P14N	YES	NO		no change
				P14N	YES	NO		no change

KEY	
	NO Change
	Setting Change Required
	New Rela or Solution Not Confirmed

Figure 15: Kendoon trial revised protection settings

5.1.4 Reactive loading

Generator Capability
A consideration when energising the test network is to ensure that the reactive power (Mvar) generated by the capacitance of the network does not exceed Mvar absorption capability of the anchor generator (its capacity to operate in a leading power factor). For Kendoon hydro, the 'testing limit' was to ensure that no more than 5 Mvar was absorbed by the generator. As such, Table 2 and Table 3 were produced to ensure the limit was not breached.

Switchgear Capability
The magnitude of reactive loading should not exceed the current breaking capability of the relevant switchgear. In the proposed testing, the Kendoon 11 kV switchgear would see the most onerous scenario, potentially having to discharge the full test network (e.g. the generator may trip at any time opening its 11 kV CB). The capacitor bank switching duty of the switchgear is taken as the most applicable limit (in this case 400 A, 7.5 Mvar), and care must be taken that this limit is not exceeded before load is connected.

Table 2: Test energisation to Glenluce GSP

	Generator Voltage 11 kV Kendoon Transformer Tap 7 Transmission Line Voltage = 132 kV Glenluce Transformer Tap 3 Glenluce No 1 Busbar = 33 kV		Generator Voltage 8.25 kV Kendoon Transformer Tap 7 Transmission Line Voltage = 100 kV	
Line Section	**Section Reactive Power Mvar**	**Total Reactive Power at Kendoon Generator Mvar**	**Section Reactive Power Mvar**	**Total Reactive Power At Kendoon Generator Mvar**
Kendoon–Glenlee	-0.38	-0.29	-0.21	-0.16
Glenlee–Glenluce	-2.53	-2.76	-1.44	-1.58
Glenluce–Glenchamber 33kV circuit	-0.98	-3.76		
Glenluce 33 kV circuits to Auchneel, Barrhill, North Rhins and Stranraer	-0.71	-4.46		

Table 3: Test energisation to New Cumnock

	Generator Voltage 11 kV Kendoon Transformer Tap 7 Transmission Line Voltage = 132 kV		Generator Voltage 8.25 kV Kendoon Transformer Tap 7 Transmission Line Voltage = 100 kV	
Line Section	**Section Reactive Power Mvar**	**Total Reactive Power at Kendoon Generator Mvar**	**Section Reactive Power Mvar**	**Total Reactive Power At Kendoon Generator Mvar**
Kendoon–New Cumnock	-1.88	-1.76	-1.06	-0.99
New Cumnock SGT1A and SGT1B and 132 kV cablee	-0.76	-2.52	-0.43	-1.42

5.1.5 Circuit breaker capability

Transient Recovery Voltages (TRVs)
Given the low fault level of the test network, an issue which must be considered is if the TRV, which appears across CB contacts when opening to break load or fault current, is within the switchgear tested limits. Before the Galloway phase 2 testing was carried out, TRV studies were undertaken to assess the capability of the Kendoon 11 kV Grid 2 CB (for all credible fault and load breaking scenarios), and for the 33 kV switchgear at Glenluce.

An example is given below in Figure 16 of the TRV simulated across the Kendoon Grid 2 CB 11 kV contacts when the Kendoon to Glenluce GSP 132 kV circuit, plus the 33 kV cable circuit to Glenchamber wind farm, is de-energised. It can be seen that the initial peak TRV is 11.093 kV (the first peak is considered the worst as the contacts will have moved further apart by subsequent peaks), with a RRRV of 0.15 (results given in Table 4). Table 5 shows the tested TRV limits for the Kendoon Grid 2 11 kV CB (YSF6 type). From this table the TD1 values are applicable, and both the peak and RRRV values need to be within the tested limits. A peak TRV of 31.2 kV is permissible, along with a RRRV of 2.08; thus, there are no issues with this switching operation. TRV limits may be found in International Standard IEC-62271-100 for high-voltage switchgear.

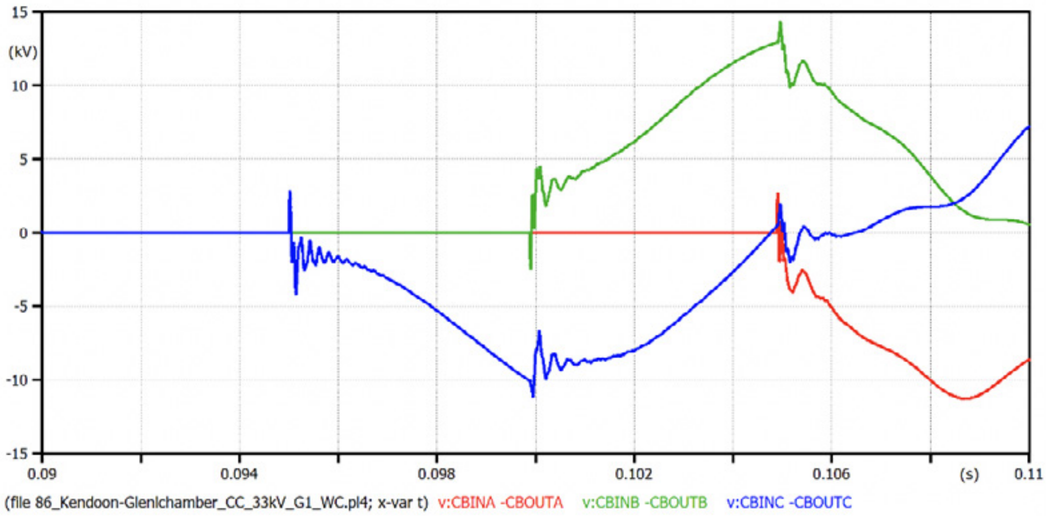


Figure 16: Kendoon 11 kV Grid 2 TRV – load breaking of Kendoon to Glenluce GSP 132 kV circuit, plus Glenchamber wind farm 33 kV cable circuit

Table 4: Kendoon Grid 2 TRV results

Uc	11.093	kV
U1	2.713	kV
t1	18	μs
t2	4924	μs
RRRV	0.150722	kV/μs

Table 5: Kendoon Grid 2 11 kV CB (YSF6) tested TRV parameters

Test Duty	Ur	Isc/kA	Uc	t3	RRRV kV/us	Reference Report
TD1	12	2.5	31.2	15	2.08	Kema 808-82
TD2	12	7.5	29.4	15	1.96	Kema 808-82
TD3	12	15	27.9	29	0.96	Kema 808-82
TD4	12	25	25.7	66	0.38	Kema 808-82
OOPS	13.8	5.1	39.1	125	0.28	Kema 478-88

5.2 Summary of tests

5.2.1 Test programme

Table 6 shows the 20 live energisation tests which were undertaken as part of the Galloway phase 2 testing in September/October 2021.

Table 6: Kendoon Phase 2 live testing completed

Description	Test No	Circuit Breaker Closed to Energise
September 2021 Tests		
Kendoon 132/11 kV grid transformer		
Energise Kendoon grid transformer T2 (Tap 19) to train PoW relay	1.1	Kendoon grid 2 11 kV
Energise Kendoon grid transformer T2 using PoW relay	1.2	Kendoon grid 2 11 kV
Kendoon to New Cumnock 132 kV and Kendoon to Glenluce GSP testing		
Energise Kendoon grid transformer T2 and Kendoon/New Cumnock circuit	2.1	Kendoon grid 2 11 kV
Energise Kendoon/Glenlee circuit	2.2	Kendoon 132 kV No.120
Energise Glenlee/Newton Stewart/Glenluce circuit and Glenluce 132/33 kV grid transformer T1	2.3	Kendoon 132 kV No.120
Energise Kendoon/Glenlee/Newton Stewart/Glenluce circuit and Glenluce 132/33 kV grid transformer T1	2.4	Kendoon 132 kV No.120
Energise Kendoon grid transformer T2, Kendoon/New Cumnock circuit and Kendoon/Glenlee/Newton Stewart/Glenluce circuit and Glenluce 132/33 kV grid transformer T1	2.5	Kendoon grid 2 11 kV
Energise Kendoon grid transformer T2 and Kendoon/Glenlee/Newton Stewart/Glenluce circuit and Glenluce 132/33 kV grid transformer T1	2.6	Kendoon grid 2 11 kV
October 2021 Tests		
Kendoon to Glenluce GSP + No.1 33kV busbar outage		
Energise Kendoon grid transformer T2 and Kendoon/Glenlee/Newton Stewart/Glenluce circuit and Glenluce 132/33 kV grid transformer T1	3.1	Kendoon grid 2 11 kV
Energise Glenluce 33 kV No.1 busbar	3.2	Glenluce grid 1 33 kV
Energise Glenluce/Glenchamber 33 kV cable circuit	3.3	Glenluce 33 kV No.11
Energise Glenluce/Lochans Moor switching station 33 kV circuit	3.4	Glenluce 33 kV No.13
Energise Lochans Moor/Barrhill 33 kV circuit and Barrhill primary transformer	3.5	Lochan Moor switching station 33 kV No.14
Energise Kendoon grid transformer T2 and Kendoon/Glenlee/Newton Stewart/Glenluce circuit and Glenluce 132/33 kV grid transformer T1	3.6	Kendoon grid 2 11 kV

Table 6: Kendoon Phase 2 live testing completed

Description	Test No	Circuit Breaker Closed to Energise
Kendoon to New Cumnock 132 kV including 275/132 kV SGTs		
Energise Kendoon grid transformer T2 and Kendoon/New Cumnock 132 kV circuit using PoW Relay	4.1	Kendoon grid 2 11 kV
Energise New Cumnock SGT1A and SGT1B	4.2	New Cumnock 132 kV No.1180
Energise New Cumnock SGT1B	4.3	New Cumnock 132 kV No.1180
Energise New Cumnock SGT1B	4.4	New Cumnock 132 kV No.1180
Energise New Cumnock SGT1A and SGT1B	4.5	New Cumnock 132 kV No.1180
Energise Kendoon grid transformer T2 and Kendoon/New Cumnock 132 kV circuit without using PoW relay	4.6	Kendoon grid 2 11 kV

5.2.2 Summary of results

For each of the energisation tests, Table 7 shows the recorded maximum peak phase to phase voltages (the maximum of the negative and positive cycles), and the Total Harmonic Distortion (THD).

A 'fail' was when the generator circuit breaker tripped on energisation (normally on overvoltage protection). Typically, a generator will have overvoltage protection set to operate around in the region of 115 per cent to 130 per cent normal voltage and can be set to operate instantaneously (~20 ms in practice) or after a few seconds.
The tests with no voltage/harmonic measurements are where no triggering of the fault recorders occurred.

Table 7: Kendoon Phase 2 tests – summary of results

Test	Success / Fail	Generator Terminal Voltage (11 kV)	Kendoon 132/11 kV GT2 Tap Changer No.	Max Peak Voltage Red/ Yellow kV	THD Red/ Yellow	Max Peak Voltage Yellow/ Blue kV	THD Yellow/ Blue	Max Peak Voltage Blue/ Red kV	THD Blue/ Red
1.1	Success	10.75 pu (8.25 kV)	19	-16.86	30.5%	16.70	23.6%	-13.34	9.9%
1.1	Success	0.75 pu (8.25 kV)	19	13.10	2.9%	-14.43	0.7%	17.63	2.8%
2.1	Success	0.75 pu (8.25 kV)	19	-19.34	18.6%	-16.04	24.8%	-20.41	17.8%
2.2	Success	0.75 pu (8.25 kV)	19						
2.3	Success	0.75 pu (8.25 kV)	19						
2.4	Success	0.75 pu (8.25 kV)	19	15.44	20.0%	-14.65	41.0%	-17.96	35.7%
2.5	Success	0.75 pu (8.25 kV)	19	17.85	27.6%	22.87	46.8%	-14.83	38.1%
2.6	Success	0.75 pu (8.25 kV)	7	-23.63	22.1%	-20.28	35.4%	-18.57	38.6%
3.1	Success	0.75 pu (8.25 kV)	7	-22.53	68.1%	-21.63	55.7%	-18.15	58.4%
3.2	Success	0.75 pu (8.25 kV)	7						
3.3	Success	0.75 pu (8.25 kV)	7						
3.4	Success	0.75 pu (8.25 kV)	7						
3.5	Fail	1.0 pu (11.0 kV)	7	-19.03	42.7%	-21.35	37.0%	17.90	13.4%
3.6	Success	0.75 pu (8.25 kV)	7	22.55	65.8%	22.48	61.1%	-19.27	58.0%
4.1	Success	0.75 pu (8.25 kV)	7	17.03	39.0%	20.21	33.7%	18.25	37.6%
4.2	Success	0.75 pu (8.25 kV)	7	-25.41	67.7%	-25.89	78.0%	26.54	70.7%
4.3	Success	0.75 pu (8.25 kV)	7						
4.4	Success	0.75 pu (8.25 kV)	7						
4.5	Success	0.75 pu (8.25 kV)	7	-24.18	53.6%	-27.75	72.8%	27.45	71.8%
4.6	Success	0.75 pu (8.25 kV)	7	-21.04	59.0%	17.66	48.3%	-17.37	38.9%

Kendoon GT2 Tap Change Position
Initial tests were carried out with the Kendoon GT2 tap changer on tap 19 (its highest position). With 1 pu (11 kV) volts supplied to its LV side, this results in the HV side being 105.5 kV (0.8 pu). The reduced HV voltage was used to see if providing a lower voltage at the Glenluce GT1 HV terminals helped reduce its inrush current significantly. When the generator terminal voltage was reduced to 0.75 pu, this results in the 132 kV voltage being 0.6 pu.

Tests 2.6 onwards were carried out with the Kendoon GT2 on its nominal tap position No.7. This meant the 132 kV voltage was reduced to 0.75 pu when the generator terminal voltage was at 0.75 pu voltage also. From the test results, the tap position of Kendoon GT2 does not seem to have any significant impact.

Test 3.5 Failure
Only one test energisation failed, energising the Barrhill 33/11 kV 7.5 MVA transformer at Glenluce GSP (carried out with the generator voltage at 1 pu). Although a very small transformer compared to the 480 MVA of SGTs which were successfully energised (tests 4.2 and 4.5), transformer inrush currents are still present. Although lower in magnitude, they are full of harmonics and can still excite the resonant frequency of the circuit resulting in overvoltages and protection tripping. Appendix 3: Post Galloway Trials Investigation provides the results of an offline desktop-based analysis of this test which was undertaken to better understand the complex phenomena encountered.

5.3 Test results

This section provides some comments on the results for selected individual tests, including the voltage and current waveform traces for selected energisations. A complete description of all tests is included in Appendix 4: Galloway Live Trials Phase 2 Complete Test Results.

5.3.1 Test 1.2 – SUCCESSFUL

Test 1.2 was an initial energisation of the Kendoon grid transformer T2 (tap 19) using the PoW relay to close the 11 kV circuit breaker grid 2.
After the initial half cycle following energisation there was no significant distortion of the voltage waveforms except for minor disturbance between the 5th and 10th cycles. The data from the fault recorder monitoring the Kendoon 11 kV voltages can be seen in Figure 17.

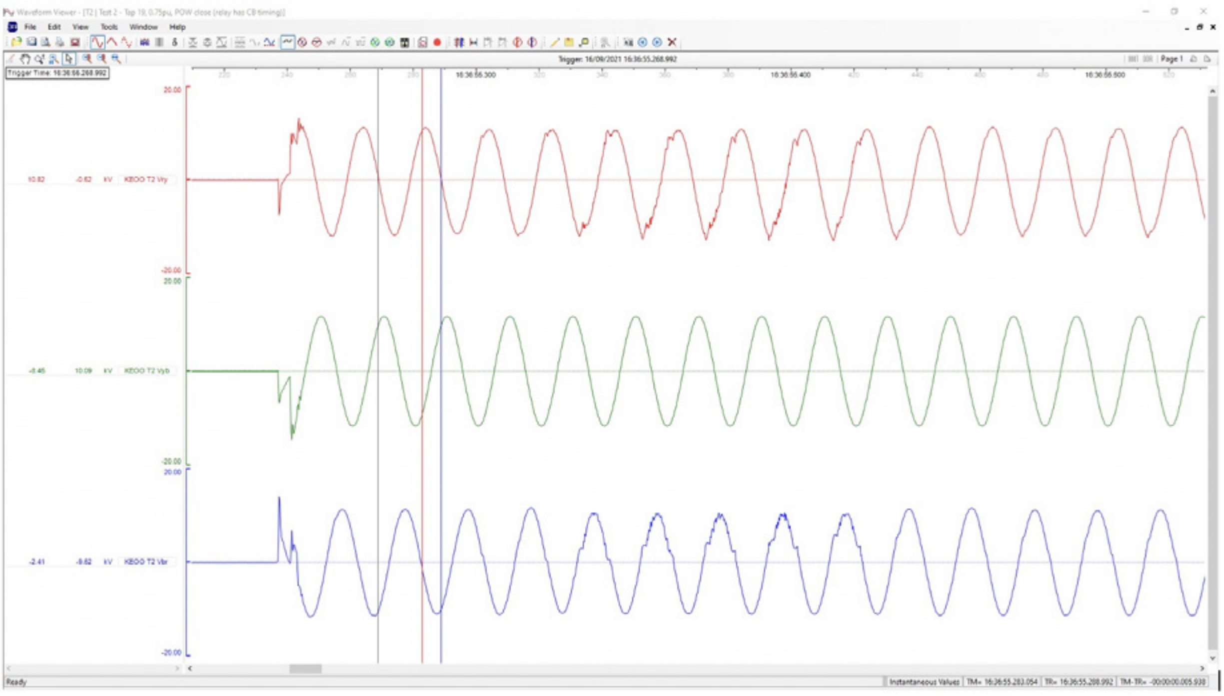


Figure 17: Test 1.2 data plot Kendoon 11 kV voltages

5.3.2 Test 2.1 - SUCCESSFUL

Test 2.1 was the initial energisation of the Kendoon grid transformer T2 and the Kendoon/New Cumnock 132 kV circuit (~30 km).

The energisation was successful. Significant harmonics are visible in the first few cycles, followed by similar distortion to that noticed in Tests 1.1 and 1.2, but of a longer duration particularly on the Red–Yellow voltage (see Figure 18).

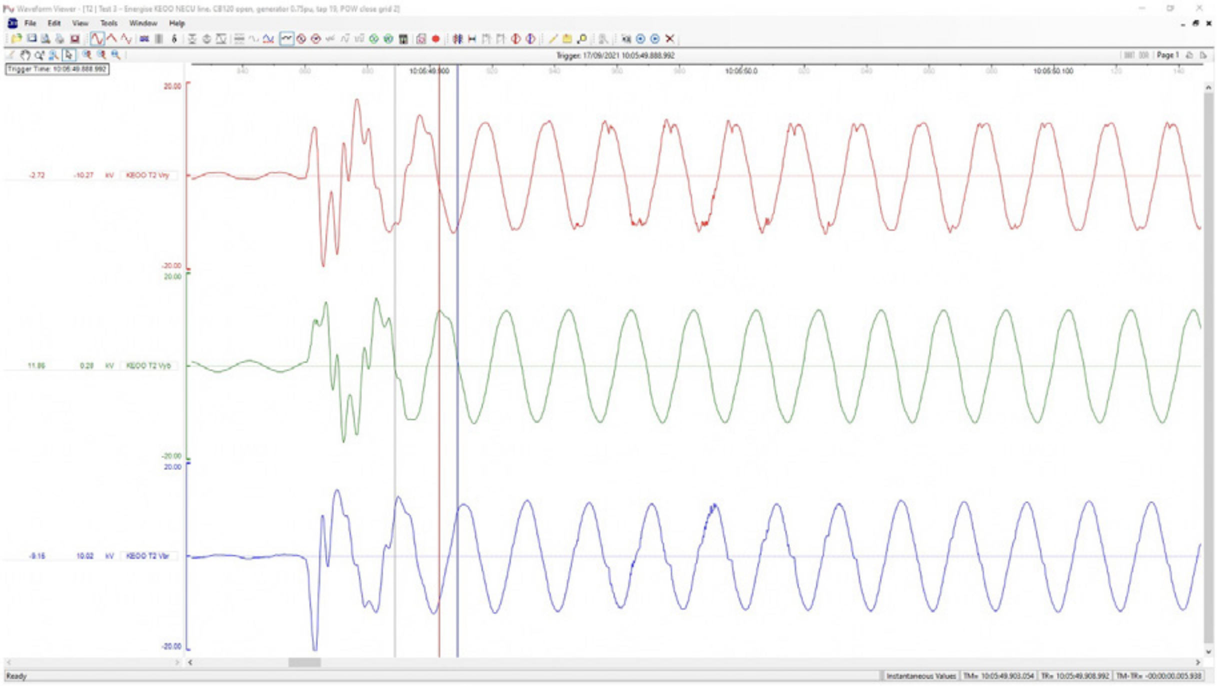


Figure 18: Test 2.1 data plot Kendoon 11 kV voltages

5.3.3 Test 2.5 – SUCCESSFUL

Test 2.5 was the simultaneous energisation of the Kendoon grid transformer T2, Kendoon/New Cumnock 132 kV circuit, Kendoon/Glenlee/Newton Stewart/Glenluce 132 kV circuit and Glenluce 132/33 kV transformer T1 by closing the Kendoon grid 2 11 kV CB.

The energisation was successful.

The Kendoon transformer 11kV fault recorder was triggered during this test (see Figure 19).

The Glenluce transformer 33 kV fault recorder was triggered during this test. No high frequency component is observed at Glenluce during this energisation.

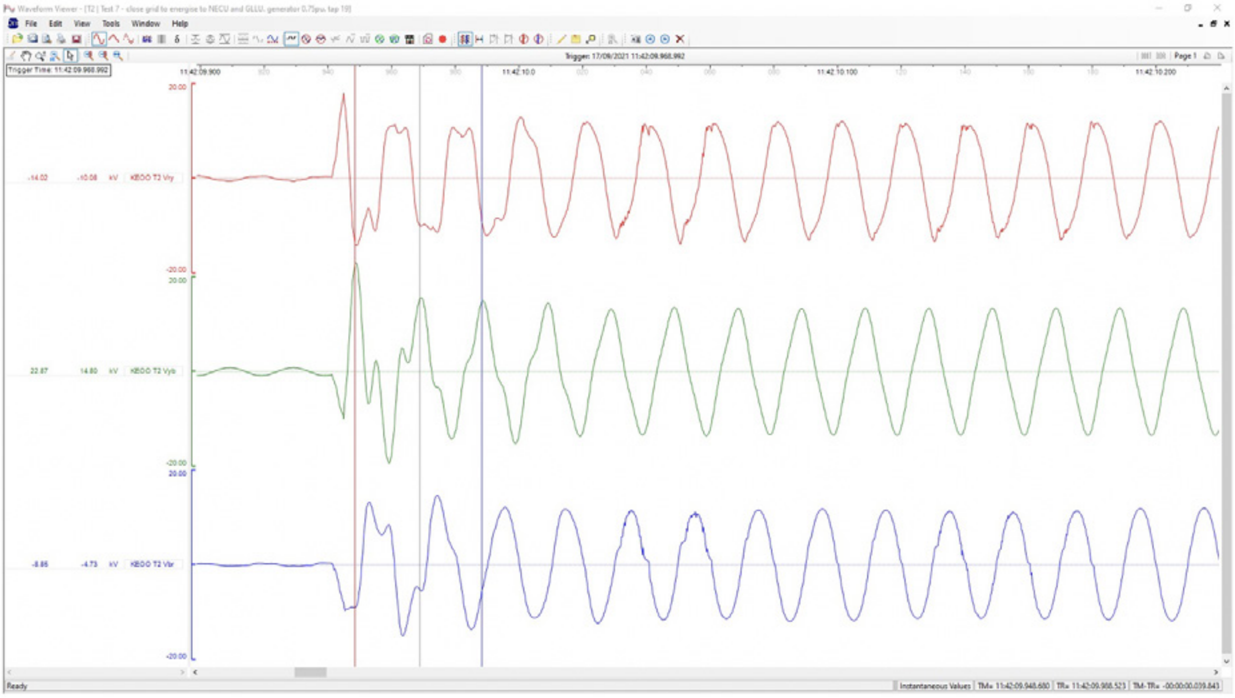


Figure 19: Test 2.5, data plot Kendoon 11 kV voltages

5.3.4 Test 3.5 – FAIL

Test 3.5 was an energisation from the Lochans Moor switching station of the Barrhill 33 kV circuit and Barrhill primary transformer (7.5 MVA).

The Kendoon hydro terminal voltage was raised to 1 pu prior to the energisation.

This energisation was unsuccessful.

The Kendoon transformer 11 kV fault recorder was triggered during this test (see Figure 20).

The Glenluce transformer 33 kV fault recorder was triggered during this test (Figure 21).

There was a 36.3 per cent overvoltage on the Glenluce 33 kV red phase to neutral voltage when the Barrhill primary was energised. The peak overvoltage at Kendoon was 37.5 per cent on the negative peak of the Yellow/Blue phase. While this voltage exceeds the overvoltage protection setting on the relay, it is less than the 45.5 per cent overvoltage observed on the Red/Yellow phase of the following energisation (Test 3.6) which was successful. (See comments in section 5.2.2).

While the peak voltages recorded for this test exceed the generator overvoltage protection setting, there are many other tests where this is also the case (some with higher recorded voltages), yet the generator did not trip. This anomaly may be due to the time delay in the protection operating time, which requires the voltage to stay above a pre-set threshold before operating, or due to the degree of voltage waveform distortion and any internal signal filtering method employed in the relays. These will influence the actual overvoltage 'detected' by the relay during the energisation events and affect the operation and the performance of the relays. As the distribution network is not normally designed to operate continuously under this condition, it is likely that the overvoltage relays are not set up/tested to operate under highly distorted voltage waveforms.

Appendix 3: Post Galloway Trials Investigation provides the results of an offline desktop-based analysis of this test which was undertaken to better understand the complex phenomena encountered.

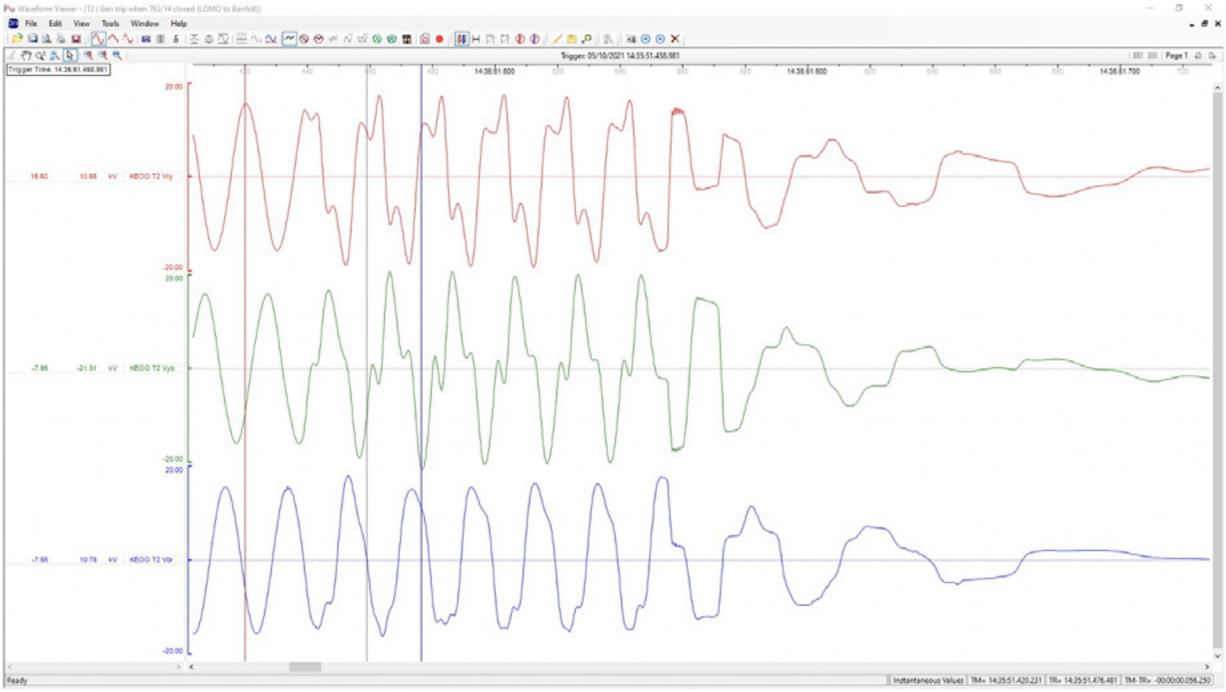


Figure 20: Test 3.5, data plot Kendoon 11 kV voltages

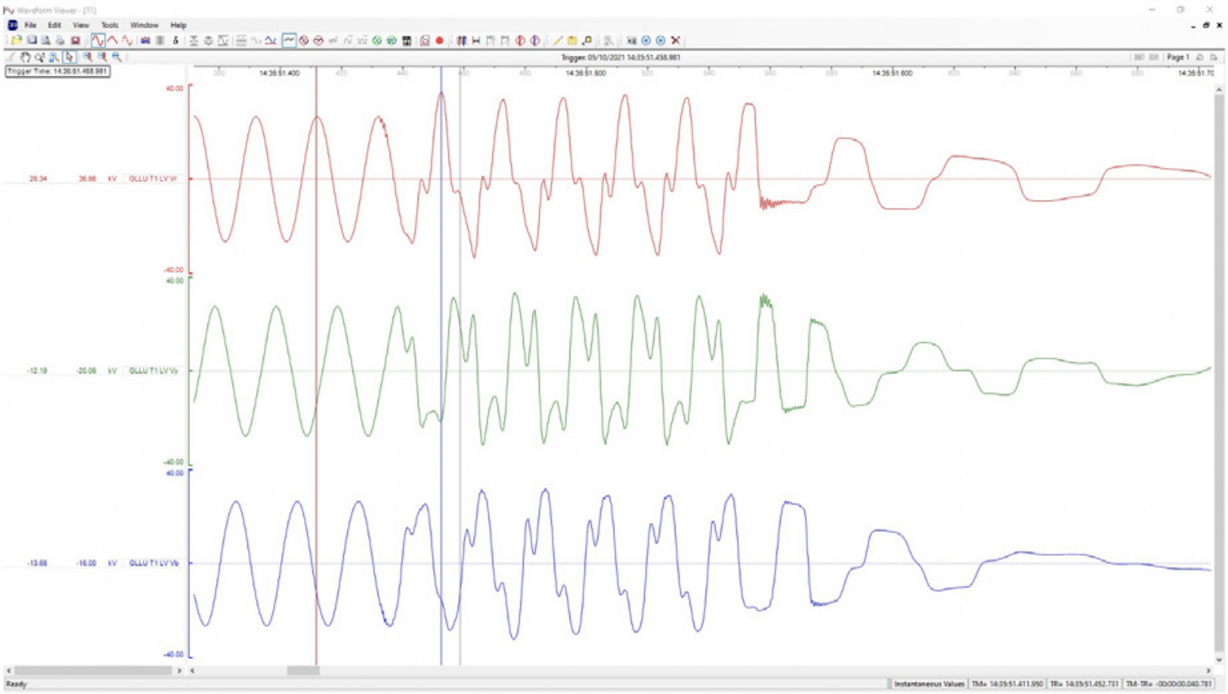


Figure 21: Test 3.5, data plot Glenluce 33 kV voltages

5.3.5 Test 4.2 – SUCCESSFUL

Test 4.2 was an energisation of the New Cumnock SGT1A and SGT1B by closing a 132 kV CB at New Cumnock. The energisation was successful.

The peak transient voltage at Kendoon 11 kV was 26.54 kV on the Blue/Red phase. The normal peak voltage of an 11 kV waveform is 15.56 kV, hence about a 71 per cent overvoltage. The very short duration may be the reason it did not result in an overvoltage trip of the generator (see Figure 22).

Analysis of the Kendoon voltage waveform indicated a Total Harmonic Distortion (THD) of about 70 per cent about one cycle after energising the transformers.

The New Cumnock 132 kV voltage Yellow Phase to Earth (10 seconds record) is shown in Figure 23.
Appendix 3: Post Galloway Trials Investigation provides the results of an offline desktop-based analysis of this test which was undertaken to better understand the complex phenomena encountered.

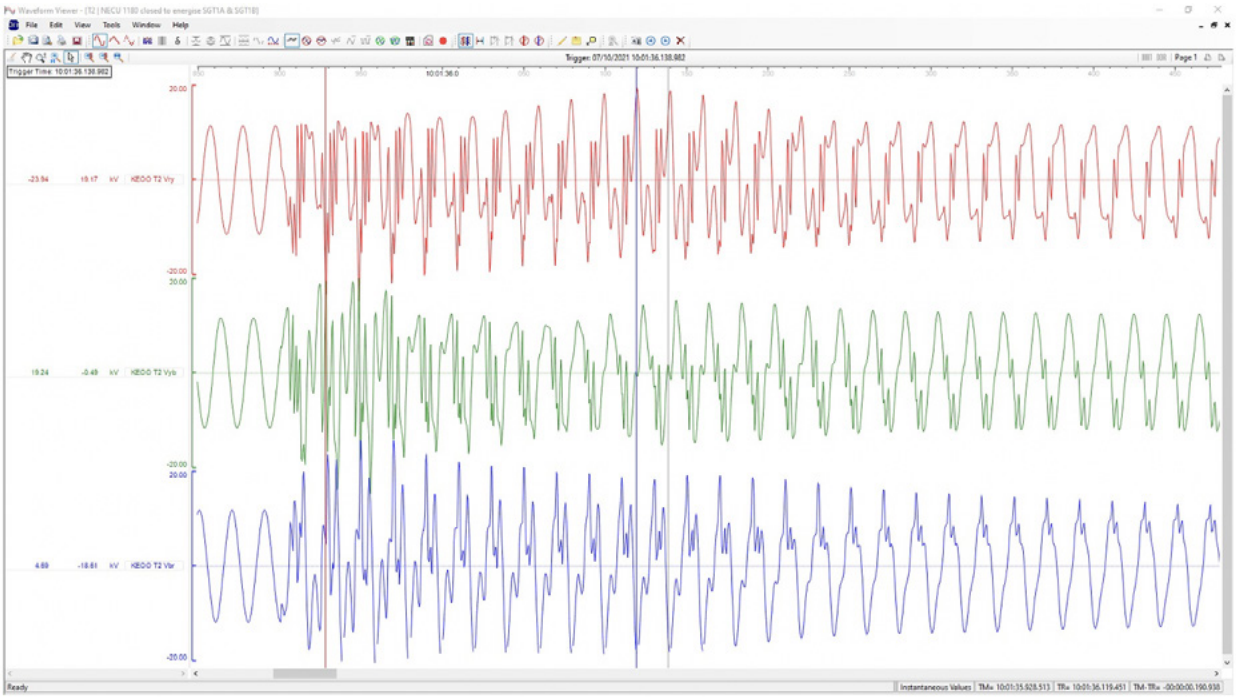


Figure 22: Test 4.2 data plot Kendoon 11 kV voltages

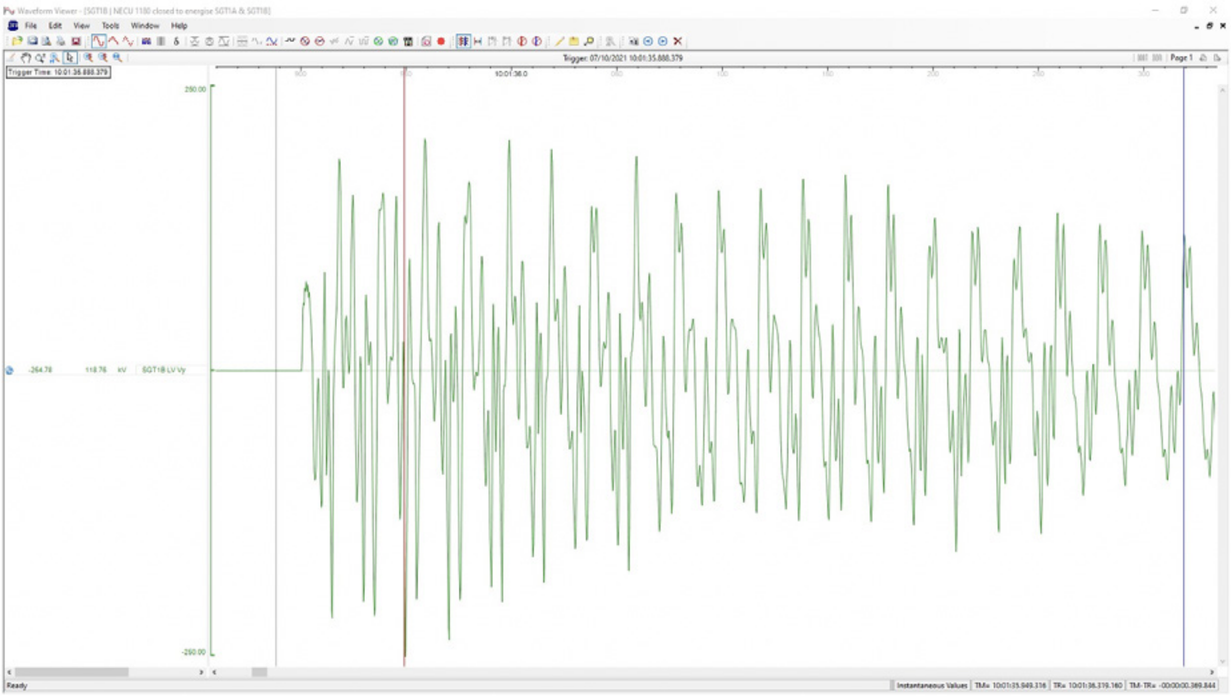


Figure 23: Test 4.2 data plot New Cumnock 132 kV voltage Yellow Phase to Earth (10 seconds record)

5.3.5 Test 4.2 – SUCCESSFUL

Test 4.3 was an energisation of the single New Cumnock SGT1B by closing a 132 kV CB at New Cumnock. The energisation was successful.

Voltage distortion was considerably less than the previous test when two SGTs were energised.

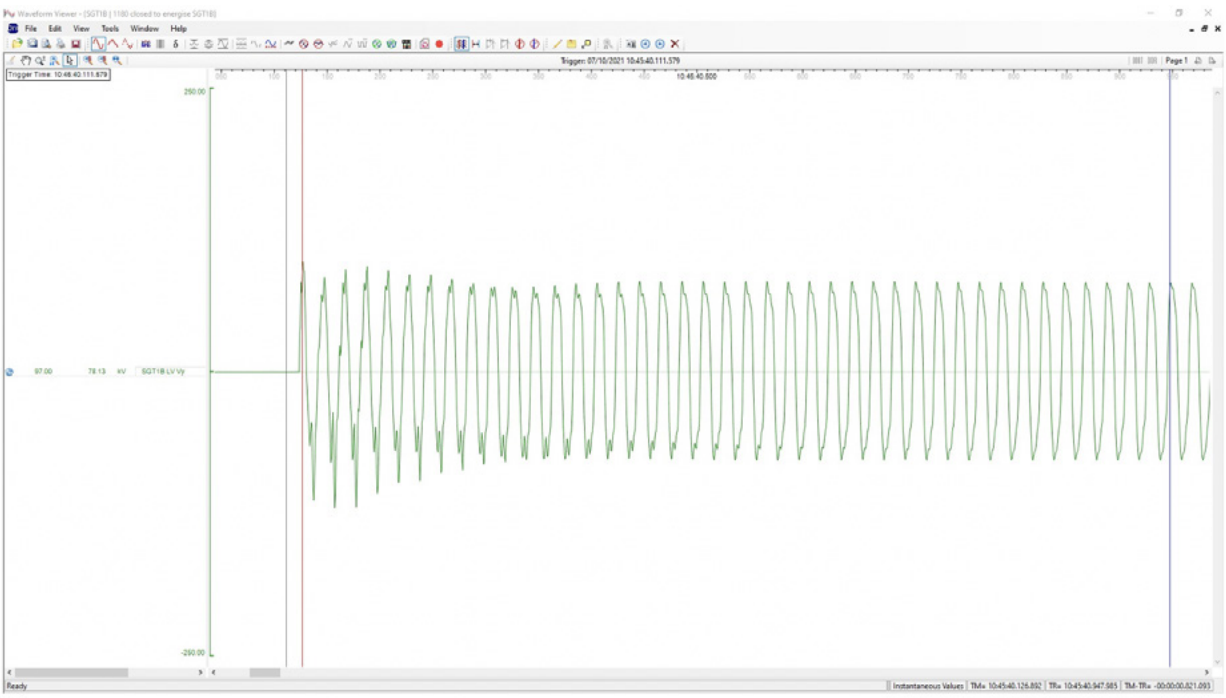


Figure 24: Test 4.3, data plot New Cumnock 132 kV voltage Yellow Phase to Earth

5.4 Key achievements

At the end of the Galloway phase 2 testing, the 13 MVA (11 kV connected) Kendoon hydro generator had been successfully proven to:

1 energise the Glenluce 33kV GSP network in a single step

- simultaneous energisation of the Kendoon 11/132 kV 30 MVA transformer, ~60 km 132 kV overhead tower line and a Glenluce GSP 132/33 kV 60 MVA transformer by closing a 11 kV circuit breaker at Kendoon.

2 energise the Kendoon 11 kV hydro to New Cumnock 132 kV network in a single step.

- simultaneous energisation of the Kendoon 11/132 kV transformer and ~30 km of 132 kV overhead line) (New Cumnock substation transforms up to 275 kV and is a collector substation for wind generation and an exit point to the wider transmission network.)

3 simultaneously energise two 240 MVA super grid 275/132 kV transformers at New Cumnock.

- by closing a 132 kV circuit breaker at the initially energised New Cumnock 132 kV substation. Successful tests were also carried out energising individual 275/132 kV 240 MVA super grid transformers at New.

5.5 Conclusions

- All energisations were successful with the exception of energising the Barrhill primary transformer. This test was performed after the Kendoon generator voltage had been restored to 100 per cent (11 kV). While this reduced the headroom between the generator voltage and the overvoltage protection trip level, the peak transient overvoltage was less than in some other tests.
- The anomaly of the Barrhill primary transformer trip (tripping for peak voltages less than in other tests) may be due to the time delay in the protection operating time, which requires the voltage to stay above a pre-set threshold before operating, or due to the degree of voltage waveform distortion and any internal signal filtering method employed in the relays. These will influence the actual overvoltage 'detected' by the relay during the energisation events and affect the operation and the performance of the relays.
- Tests at Glenlee in 2020 were only successful when the Point on Wave (PoW) relay was used to close the 11 kV breaker to energise the test network. It was assumed that similar issues would arise at Kendoon, so the PoW relay was used to control the closing of the Kendoon 11 kV breaker for most of the tests. A final test (Test 4.6) was carried out with the PoW relay closing at the worst time. This energisation was also successful. Further work will be required to determine under what conditions a PoW relay may be required to ensure a successful energisation.
- The Glenlee energisation required the entire test circuit between the Glenlee 11 kV breaker and the Glenluce 33 kV breaker to be energised as there were no intervening 132 kV breakers. Kendoon still required the simultaneous energisation of the Kendoon transformer T2 and the Kendoon/New Cumnock 132 kV circuit but offered sequential energisation on the route to Glenluce using 132 kV breakers at Kendoon and Glenlee. The 132 kV circuit breaker closing was at a random time as the PoW relay controlled only the 11 kV breaker. However, sequential and simultaneous energisations of the test network were both successful.
- Residual flux in the Glenluce transformer could not be measured by the PoW relay due to its remote location. The PoW relay only took account of the Kendoon transformer residual flux to minimise inrush currents.
- Two SGTs (275/132 kV) were successfully energised at New Cumnock; however, voltage transients were much more severe than when a single SGT was energised. The arrangement at New Cumnock substation is such that there are only 275 kV isolators (no circuit breakers) between the transformers. During a Black Start, both transformers would have to be energised simultaneously or the network de-energised post blackout to close any 275 kV isolators that had been opened.
- The overvoltages resulting from energising two SGTs may be reduced by using a PoW relay to close the 132 kV breaker that energised the transformers. However, an additional relay was not available during the present test programme.
- Voltage transient magnitudes and durations were more severe on the test network due to the low fault level than would normally be experienced on an intact network with higher fault levels.
- Primary transformers are much smaller that the SGTs energised during this study (7.5 MVA compared to 480 MVA). However, overvoltages sufficient to trip the generator are still present when the generator is operating at 100 per cent terminal voltage.

- Reducing the generator terminal voltage would ease the situation in item 7, but when energising a primary (33/11 kV) transformer under Black Start conditions, the local load would also be energised. Energising load at less than nominal load is considered unacceptable. One solution would be to run the generator at 75 per cent of nominal voltage and run the Glenluce 33 kV busbar at nominal voltage by tapping the Kendoon grid transformer to raise the 132 kV voltage by 10 per cent, and achieving the final increase by tapping the Glenluce grid transformer.
- The facility to run the generator at 75 per cent of nominal voltage has required the attendance of the station's AVR specialist to enable such a low voltage as the AVRs normally offer a range of about ±5 per cent of nominal voltage. This reduction has allowed numerous successful energisations. This functionality would have to be 'built in' to the AVR for station staff to readily utilise during a Black Start.

5.6 Wind farm 'set point' tests

It is envisaged that wind farms will be constrained to maintain a fixed MW output within a DRZ, set by the DRZ controller, and will receive signals to ramp up and down their output as required to new set points. In October 2021, tests were undertaken with Glenchamber and North Rhins wind farms (connected at 33 kV to the Glenluce GSP network) to ascertain:

- the ability to maintain a fixed MW constrained output
  – it is not desirable for the output to suddenly increase if there is, for example, a gust of wind. This could cause the frequency to go too high or the anchor generator to motor.
- the ability to set the ramp rate at which it moves between MW set points
  – it is not desirable for the output to move too quickly such that the anchor generator cannot compensate quickly enough and the frequency then goes too high or low.
- the ability to alter the voltage control set point (if in that mode)
  – this would facilitate altering the Mvar output of the wind farm.
- the ability to change the wind farm control mode to power factor control (if normally in voltage control)
  – this may reduce stability issues with turbines connecting in voltage control, with low fault levels, and allow more turbines to connect within a DRZ.

The above tests were undertaken with the wind farms still connected to the network and outputs and controls altered accordingly. Figure 25 shows the output of one of the wind farms being:

i) constrained from normal operating (at ~21 MW) to 5 MW for 15 minutes
ii) ramping up to 10 MW constraint for 10 minutes
iii) returning to normal (unconstrained) output of ~21 MW.

It can be concluded that despite there being plenty of wind to operate at higher outputs, the MW output of the wind farm is held steady by the control system. This is ideal for operation within a weak islanded network.

It should be noted that the wind farm was on voltage control, and hence the Mvar output changed as the voltage at the wind farm 33 kV connection point changed due to the change in MW altering the connecting circuit voltage profile, and the natural voltage changes at the Glenluce GSP 33 kV busbar caused by varying demand.

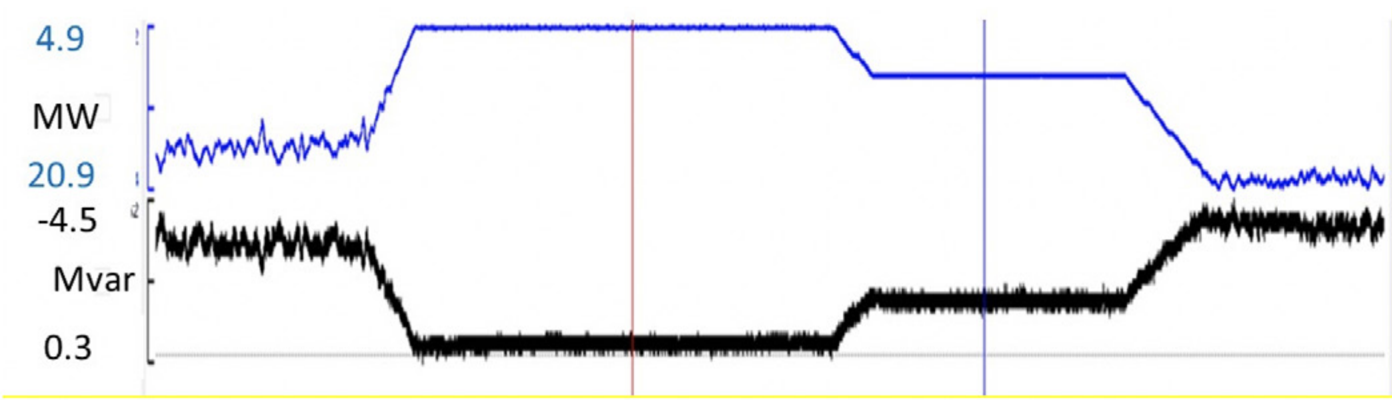


Figure 25: Wind farm MW set point tests

5.7 Next steps

Galloway Live Trials – Phase 3
A final set of live testing is planned for the Galloway region (phase 3). This will involve energising from Kendoon hydro to Glenluce GSP with an outage on the No.1 33 kV busbar to incorporate Glenchamber and North Rhins 33 kV connected wind farms. Learning from this testing would include:

- Can the wind farm 33 kV network (and turbine transformers) be energised from the anchor (Kendoon hydro) generator?
- Can turbines connect to the weak islanded network and remain stable for load steps and/or primary transformer energisations?
- How many wind turbines can be connected with the given fault level?
- How do the two wind farms interact when connected at the same time, do they remain stable, is the total number of turbines which can be connected reduced?

Programme
It is envisaged that the test incorporating Glenchamber and North Rhins wind farms will be carried out around May 2022 when the weather is such that a half busbar distribution outage at Glenluce GSP is feasible.

6 Chapelcross Live Trials

This chapter provides an overview of the objective and plans for the Chapelcross live trials, diagrams showing the test networks, and a summary of the learning from the HiL simulations undertaken.

6.1 Trial overview

This live trial utilises Steven's Croft biomass (60 MVA) as the anchor generator (used to initially energise the network and control the voltage and frequency). This is located near Lockerbie, in the Dumfries and Galloway region of South West Scotland. It is connected at 33 kV (by ~26 km of underground cable) to Chapelcross 132/33 kV GSP substation.

The test network incorporates a section of the Chapelcross GSP 33 kV network, and the associated 132 kV network, with the potential to back energise a SGT to 400 kV. A wind farm connected to the 132 kV network will also be included in the planned tests.

The relevant network test diagrams are presented in Section 6.4.

6.2 Trial objectives

The overall objectives of the Chapelcross trial are as listed below:

- to test the feasibility of utilising a large steam generator in island mode as the anchor generator.
- to test the anchor generator's block loading capability by introducing load steps on a load bank.
- to test the anchor generator's ability to energise the associated distribution and transmission network including overhead lines, underground cables, primary transformers (33 kV/11 kV), grid (132/33 kV) and SGTs (400/132 kV).
- to test the ability to connect a transmission connected wind farm to the weak test network, and to remain stable during network energisations/load pickups.

6.3 Proposed live testing

It is proposed to have one test phase, comprising of up to five consecutive days in duration.
A high-level overview of the proposed testing is presented below:

6.3.1 Day 1 – initial energisation tests

- Operation of Steven's Croft biomass in island mode.
- Energisation of 33kV cable circuit to Chapelcross GSP.

6.3.2 Days 2 & 3 – distribution network tests

- Energise the distribution network on the Chapelcross No.1 33 kV busbars (busbar outage required).
  – This includes 33 kV overhead line circuits of up to ~40 km, and primary (33/11 kV) transformers of varying sizes up to 24 MVA.
- Test different energisation strategies such as reducing the generator and/or network voltages and utilising Point of Wave switching (to minimise transformer inrush currents).
- Energise the Chapelcross grid T1 132/33 kV 90 MVA transformer.

6.3.3 Days 4 & 5 – transmission network tests

- Energise Steven's Croft to Chapelcross 33 kV circuit and grid T1 (No.1 33 kV busbar outage required).
- Energise Chapelcross 132 kV to Gretna 132 kV overhead tower line circuit (13 km).
- Energise Gretna to Ewe Hill wind farm 132 kV circuit (16 km) and 132/33 kV 90 MVA transformer.
- Test establishing a stable island with Steven's Croft biomass and Ewe Hill wind farm (carry out load steps and transformer energisation with both connected).
- Energise Gretna 400/132 kV 240 MVA SGT (1 or 2).

6.3.4 Additional plant requirements

Additional equipment will be required at the Steven's Croft site to facilitate the testing. This includes:

- A load bank to provide the minimum stable demand for the generator to operate and to simulate load steps – approximately 10 MW will be connected at 33 kV.
- A means of earthing the 33 kV network (when the grid 132/33 kV transformers are not in the test circuit then the network earthing transformers are also disconnected.)
  – Various options are being considered including installing a 33kV temporary earthing transformer at the Steven's Croft site.
- Diesel generation to supply the Steven's Croft auxiliary load during testing
  – the auxiliaries will be disconnected from the normal generator auxiliary transformer to avoid voltage and frequency variations during the testing affecting the auxiliaries and possible causing the generator to trip.

6.4 Network schematics

The following diagrams referenced in this chapter are contained with this section.
Figure 26: Chapelcross distribution network test
Figure 27: Chapelcross transmission network test

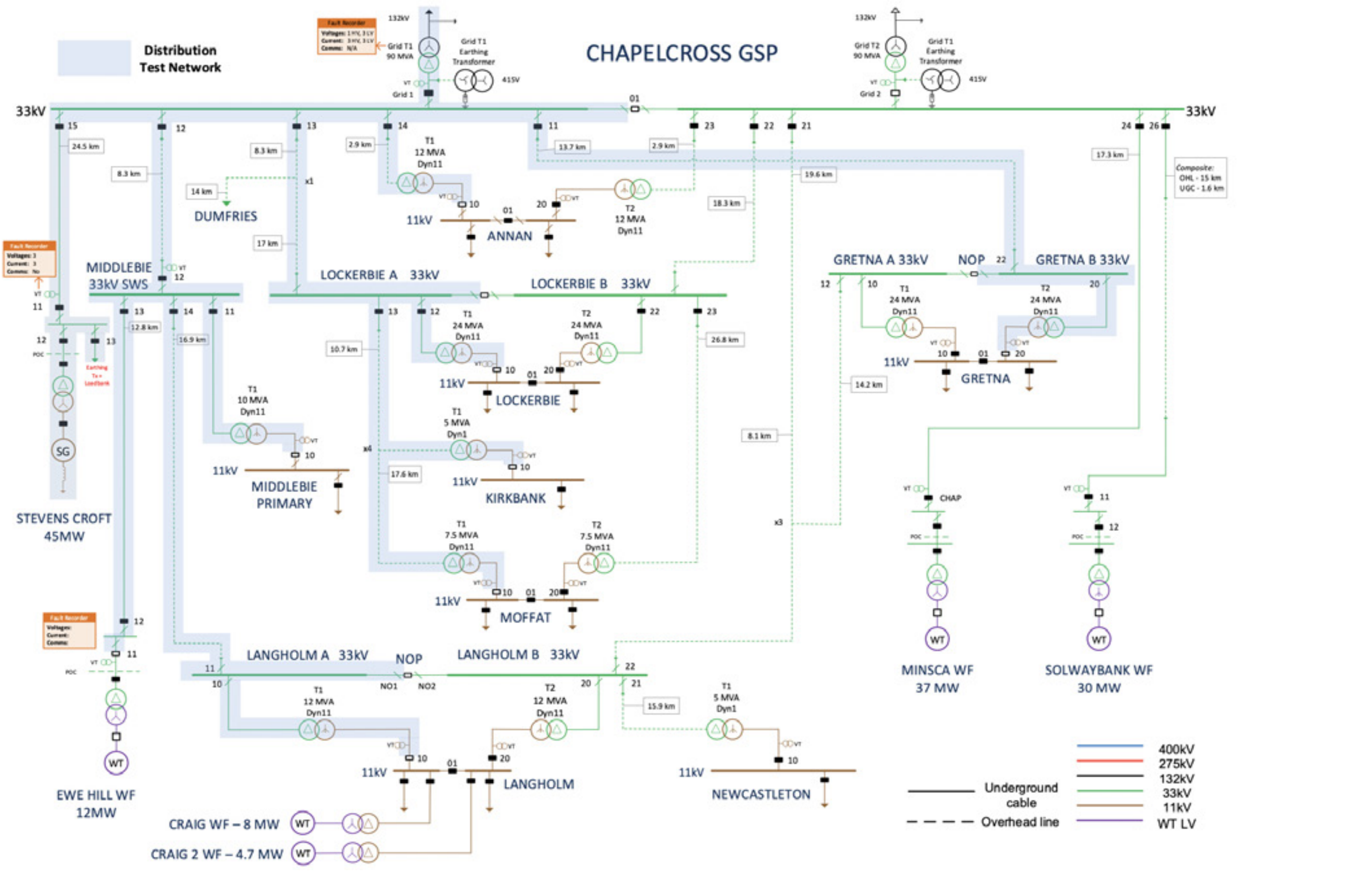


Figure 26: Chapelcross distribution network test schematic

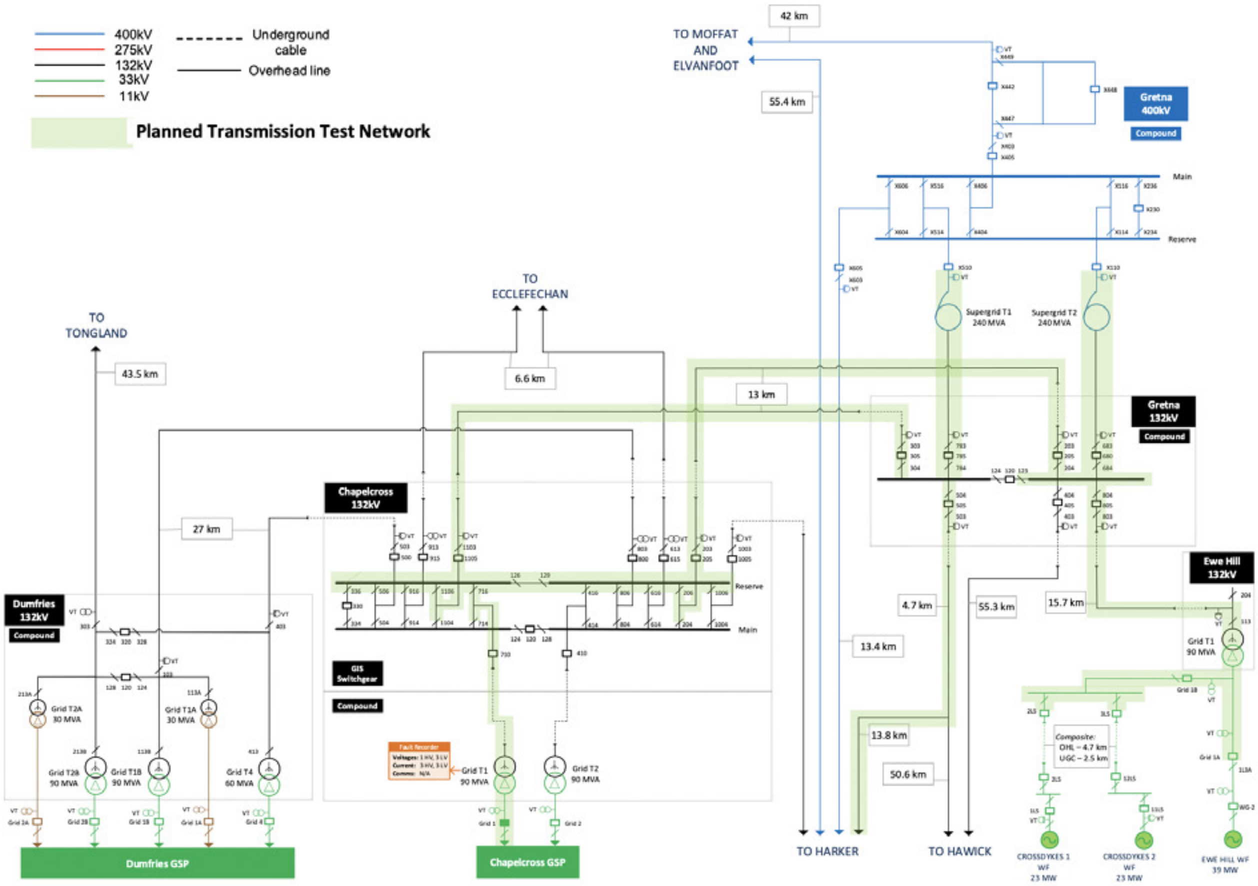


Figure 27: Chapelcross transmission network test schematic

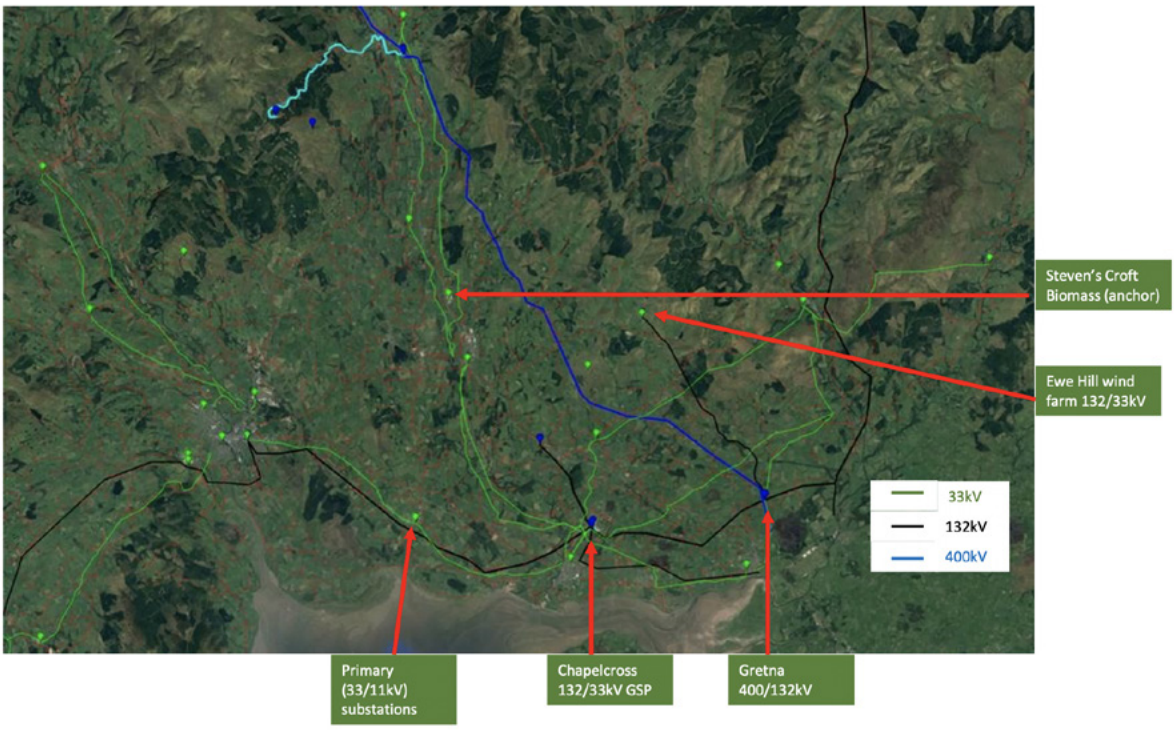


Figure 28: Chapelcross test network geographic

6.5 Pre-trial studies – RTDS simulations

6.5.1 Scope

The National HVDC Centre developed a model of the Chapelcross test network area on their Real Time Digital Simulator (RTDS) platform and carried out simulations[1] of energising the distribution and transmission network from the Steven's Croft generator, based on probable live trial tests which will be undertaken. The results of those simulations will highlight any potential issues before the live testing is undertaken.

Detailed models of the distribution transformers, distribution connected wind farm array cables and busbar arrangements were modelled in the RSCAD platform to study them using a real-time RTDS simulator. The details of the network can be seen in Figure 26 and Figure 27. The simulations undertaken are listed in the case description column of Table 8.

In addition, Hardware in the Loop (HiL) simulations were performed with replicas of the Steven's Croft generator protection relays with the actual settings downloaded from the generator site. This was primarily to determine if the generator was going to trip on overvoltage protection during transformer energisations. A key finding from the Galloway live trials was that the voltage transients during transformer energisation were sometimes sufficient to trigger the generator overvoltage protection. Figure 29 presents an overview of the hardware used as part of the HiL testing.

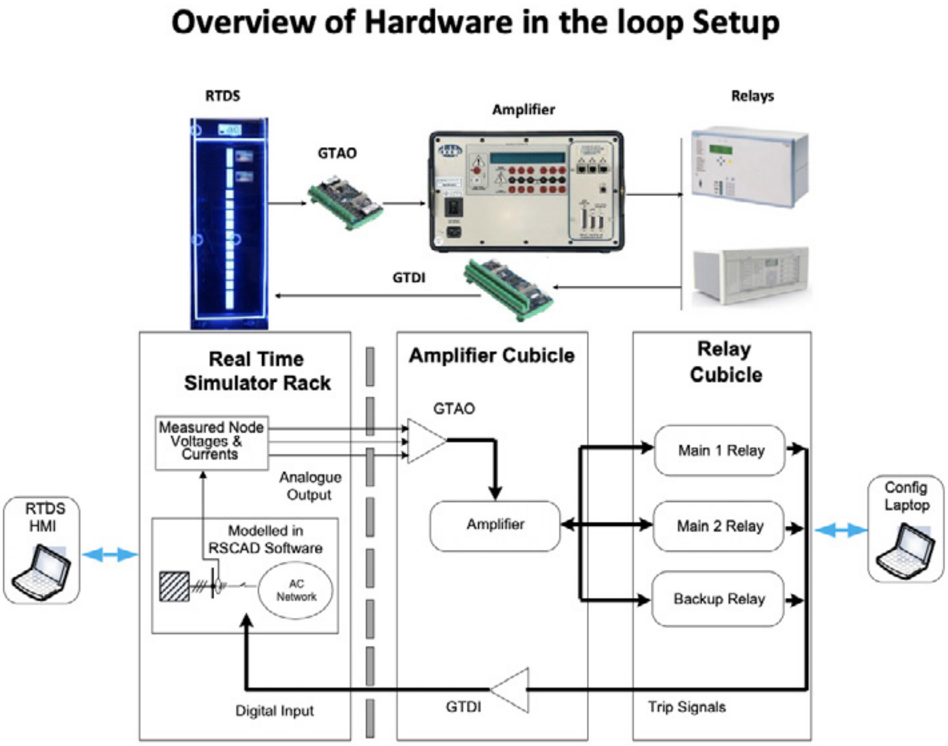


Figure 29: Physical architecture of generic HiL test environment using the RTDS simulator

The simulations focused primarily on energisation operations and the resulting overvoltages. To determine the least and worst-case impact of energisation of transformers, all test scenarios were simulated at 5o intervals based on the Point on Wave when the 33 kV circuit breaker at the Steven's Croft generator site was closed (the angle affects the level of transformer inrush current based on its remnant flux level). A precondition of the remanent flux in the transformers were set at phase A 80 per cent, phase B 0 per cent and phase C 80 per cent to simulate a worst-case scenario. The terminal voltage of Steven's Croft generator was set to 1 pu. All the cases were performed with a load bank operating at 3 MW to provide the minimum load required for stable operation of the Steven's Croft generator (this level was a minimum assumption).

6.5.2 Results

Table 8 provides a summary of the results of the simulations. The steady state reactive power having to be absorbed by the generator is given, along with the maximum line-line RMS voltage recorded at the generator 11 kV terminals and expressed as a percentage of the nominal 11 kV. The voltage presented in Table 8 is the maximum line-line RMS voltage over the 0–180o range of circuit breaker closing.

[1] Distributed ReStart RTDS HIL Study Results Summary', The National HVDC Centre, September 2021, ref: HVDC-DS-003

Table 8: RTDS simulation results: Stevens Croft steady state reactive power and max RMS phase (L-L) Voltages

Case ID	Pre-Energised Circuits	Energised Circuit	Steven's Croft Steady State Q Mvar	Steven's Croft 11 kV L-L RMS	Steven's Croft 11 kV	Generator Overvoltage Protection Trip (HiL)
1	Steven's Croft 33 kV	33 kV cable to Chapelcross GSP	-4.7	14.0	127%	No
2	Steven's Croft 33 kV to Chapelcross 33 kV	Ewe Hill 33 kV feeder from Chapelcross 33 kV	-5.6	12.0	109%	No
3	Steven's Croft 33 kV	33 kV Cable to Chapelcross 33 kV and 33 kV feeder to Ewe Hill 33 kV	-5.8	13.9	126%	No
4	Steven's Croft 33 kV to Chapelcross 33 kV	Annan primary from Chapelcross 33 kV	-4.5	11.3	103%	No
5	Steven's Croft 33 kV to Chapelcross 33 kV	Energise Moffat and Kirkbank T1 primary from Chapelcross 33 kV	-4.5	11.5	105%	No
6	Steven's Croft 33 kV to Chapelcross 33 kV	Energise Lockerbie from Chapelcross 33 kV	-4.5	11.4	104%	No
7	Steven's Croft 33 kV	All primary S/S and cable to Steven's Croft	-5.8	14	127%	No
8	Steven's Croft 33 kV to Chapelcross 33 kV	Energise Chapelcross T1 grid transformer from Chapelcross 33 kV	-4.5	12.2	111%	No
9	Steven's Croft 33 kV	Energise Chapelcross T1 grid transformer and 33 kV cable to Steven's Croft	-3.7	14.0	127%	No
10	Steven's Croft to Chapelcross 132 kV	Energise Chapelcross 132 kV–Gretna 132 kV OHL circuit	-4.4	11.7	106%	No
11	Steven's Croft to Gretna 132 kV	Energise Gretna 132 kV–Ewe Hill (T) 132 kV OHL circuit	-4.4	11.8	107%	No
12	From Steven's Croft to Gretna 132 kV	Gretna 132 kV/400 kV SGT	-4.4	12	109%	No
		Max Values	**-5.8 Mvar**	**14kV**	**127%**	

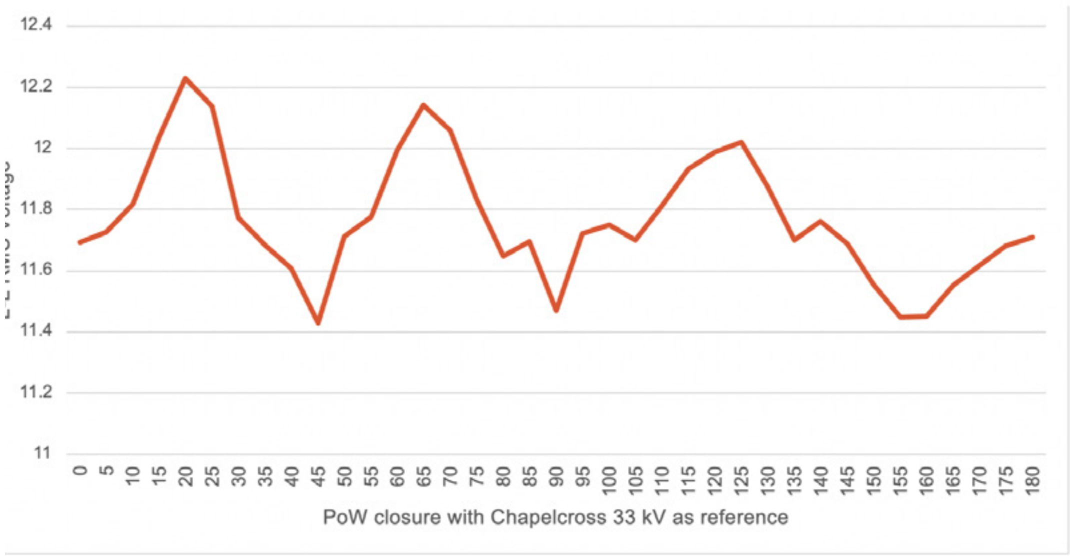


Figure 30: Steven's Croft 11 kV L-L RMS voltage – Chapelcross T1 grid transformer energisation (Case 8)

Figure 30 presents the maximum L-L RMS voltage at all simulated closures on the Point of Wave associated with the energisation of the grid transformer (Case 8). It can be observed from Figure 30 that in some energisation operations (energising a transformer), the maximum voltage can be minimised if the closure is optimally timed, such as can be implemented by a PoW relay.

Figure 31 presents a time series plot of the 11 kV RMS peak voltage at Steven's Croft terminals, for an energisation scenario, showing the typical timescale of decay.

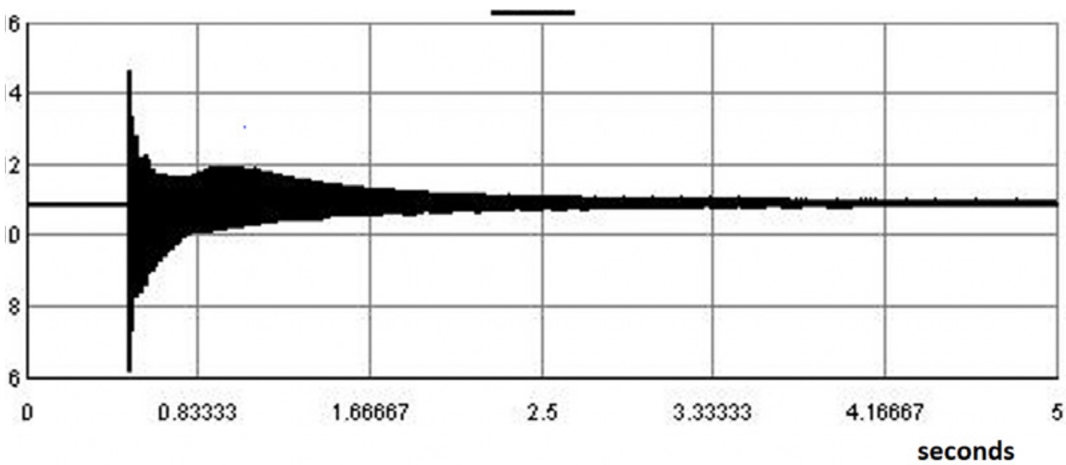


Figure 31: L-L RMS voltage at 11 kV terminals of Steven's Croft generator on energisation of 33 kV circuit to Chapelcross 33 kV (Case 1)

6.6 Conclusions

Despite some RTDS simulations showing transient voltages which exceed the generator overvoltage protection setting, HiL testing with the generator protection relays (and associated settings) did not identify any overvoltage protection trip events (this is likely due to the voltage transients not lasting long enough to operate the relays). In addition, during the energisation scenarios, the reactive power generated was within the limits of the Steven's Croft generator.

Many potential anchor generators across GB are thermal synchronous generators. The Steven's Croft biomass generator is a large (60 MVA) thermal synchronous generator. This trial will provide key learning regarding the feasibility of other thermal synchronous plant to provide Black Start services.

6.7 Next Steps

The Chapelcross trials are planned to be performed during one week in May2022. At present, a feasibility study is being undertaken on the capability of the anchor generator (Steven's Croft biomass). The results of that assessment will shape the scope of the trial plan.

7 Redhouse Live Trials

This chapter provides an overview of the objective and plans for the Redhouse live trials, diagrams showing the test networks and a summary of the learning from the studies undertaken to date.

7.1 Trial overview

This live trial site focuses on testing the grid-following and grid-forming ability of the Redhouse Battery Energy Storage System (BESS) 11.6 MVA. This is located adjacent to Redhouse GSP, in Fife, Central Scotland, and is connected to this substation at 33 kV. Utilising the BESS grid-forming technology, test energisations of the local distribution and transmission network from the BESS on its own will be a GB first.

7.2 Testing objectives

- BESS In grid-following mode.
  – test the ability of the BESS to connect to a weak (low fault level) network, energised by a diesel generator for testing.
  – test the ability to assist with transformer energisations (on the BESS network and primary (33/11kV) and grid (132/33kV) network transformers.
  – test the ability to assist with load pickups (a temporary load bank will be installed on the test network).
- BESS In grid-forming mode.
- Test the ability of the BESS to initiate energisation of the distribution network (including 33/11 kV primary transformers) and the transmission network (including a 132/33 kV 60 MVA grid transformer).

This testing has been rescheduled to summer 2022 due to system studies highlighting the potential for re-ignitions to occur within the test network 33 kV vacuum switchgear if a fault occurs and it is required to break the associated current. Mitigation measures are required, for example surge arrestors to be installed, before testing may proceed.

7.2.1 Technical considerations

The following technical considerations are relevant to the Redhouse trials:

Earthing
A temporary 33 kV earthing transformer will be required on the test network as all phase 1 tests (and most phase 2 tests) do not have the existing network 33 kV earthing transformers (located on the busbars of the Redhouse GSP 132/33 kV transformers) in service. This is required to ensure that there is a 'path' for earth fault currents to flow and thus be detected by the protection systems.

BESS Grid-Following Mode
Temporary diesel generators will provide the voltage source to test the operation of the BESS in grid-following mode (the normal mode of operation for converter connected DERs). For stable operation, the BESS converters require a fault infeed of ~3 times the nominal rating to ensure stable operation. The BESS consists of four 2.9 MVA converters (11.6 MVA total capacity). To minimise the capacity of diesel generation required (approximately the same as the BESS being tested), a single 2.9 MVA converter and associated BESS power source will be used while testing grid-following operation.
The converters are not restricted by a minimum fault level when operating in grid-forming mode; therefore, the rated 11.6 MVA capacity of the BESS will be used for those tests.

Fault recorder
A temporary fault recorder will be installed on the developer's BESS 33 kV network to capture the required voltage and current transient data and allow subsequent analysis.
Protection

Protection modifications will be made to the BESS, distribution network owner (DNO) and transmission owner (TO) networks as required, to ensure correct operation for the reduced island network fault levels. Typically, this will involve reducing the settings on existing protections.

Point on Wave (PoW)
A PoW relay will be installed at Redhouse GSP to control the 33 kV CB connected to the BESS site. When the BESS is used to energise network transformers (in grid-forming mode), this will allow the impact of PoW switching (the CB is timed to close to minimise transformer inrush currents) to be assessed.

Switchgear Capability
Based on the learning from the Galloway live testing, pre-trial TRV studies are required to ascertain that the load and fault breaking duty imposed on all the test 33 kV switchgear will be within its tested capability.

7.3 Proposed live testing

The trial will test a grid-forming battery on a GB distribution or transmission network for the first time. A key objective of the trials is therefore to prove that such an operation is feasible and use the results of the trials to showcase the potential of how a distribution (or transmission) connected battery can support the Black Start process. To enable this, the proposed testing has been split into two phases.
It is proposed to have two phases of testing with the Redhouse BESS, each up to five days in duration.

Phase 1 – Testing within BESS 33 kV network
Phase 1 will involve establishing a 'private' 33 kV test network at the Redhouse BESS site with the addition of temporary diesel generators, load banks and a 33 kV earthing transformer. The phase 1 test plan will include:

- Execute multiple test scenarios (e.g. transformer energisations, load pick-ups, synchronising) between the BESS, diesel gens, load banks and transformers, to identify optimal energisation and control strategies.
- Investigate the performance of the BESS and diesel generator when operating in parallel and energising an unloaded network (with house load only).

The key goal of this testing is to gain an understanding of the operation and capabilities of the BESS in grid-following/forming modes and to have established 'stable modes of operation', before testing on SPD/SPT network.

Phase 2 – Testing on Redhouse SPD/SPT network
Phase 2 will involve testing from the BESS site (with the BESS in grid-following and grid-forming modes) to the local distribution and transmission 132 kV network. The phase 2 test plan will include:

- Prove ability of BESS to assist (grid-following mode) and initiate (grid-forming mode) energisation of distribution network (including primary 33/11 kV transformers) and transmission network (including grid 132/33 kV transformer).
- Energisation options to include 'hard' energisation (energise at 1 pu voltage), reduced voltage, PoW switching, and soft starting (ramping up the voltage from zero to eliminate transformer inrush currents).
- Prove the ability of the distribution power island to synchronise to the wider network (if 132 kV synchronising point is technically viable).

A key goal of this testing is to establish if a grid-forming BESS can initiate the energisation of the distribution and transmission networks, including associated transformers.

Table 9 gives an overview of the network energisation test strategies which are proposed.

Table 9: Redhouse phase 2 energisation plan overview

Energisation Tests		DER Combination and Energisation Strategy											
		5MVA Diesel Generator				5 MVA Diesel Generator + 11.6 MVA Grid Forming Battery				5MVA Diesel Generator			
		1 pu	0.9 pu	PoW	Ramp	1 pu	0.9 pu	PoW	Ramp	1 pu	0.9 pu	PoW	Soft Start
Distribution Network Tests	Chapel T1–10 MVA + 33 kV OHL	√	√	√		√	√	√		√		√	
	Redhouse primary T1 24 MVA	√		√	√	√		√		√		√	√
	Chapel T1 and Redhouse primary T1 transformers simultaneously (Time permitting)	√		√		√		√		√		√	
Transmission Network Tests	Redhouse Grid T1 90 MVA	√				√				√		√	√
	Redhouse Grid T1 + 132 kV OHL to Glenniston	√				√				√		√	√

7.4 Network diagrams

The following diagrams are provided.
Figure 32: Redhouse trials – phase 1 test network
Figure 33: Redhouse trials – phase 2 test network
Figure 34: Redhouse phase 2 tests geographic substation locations

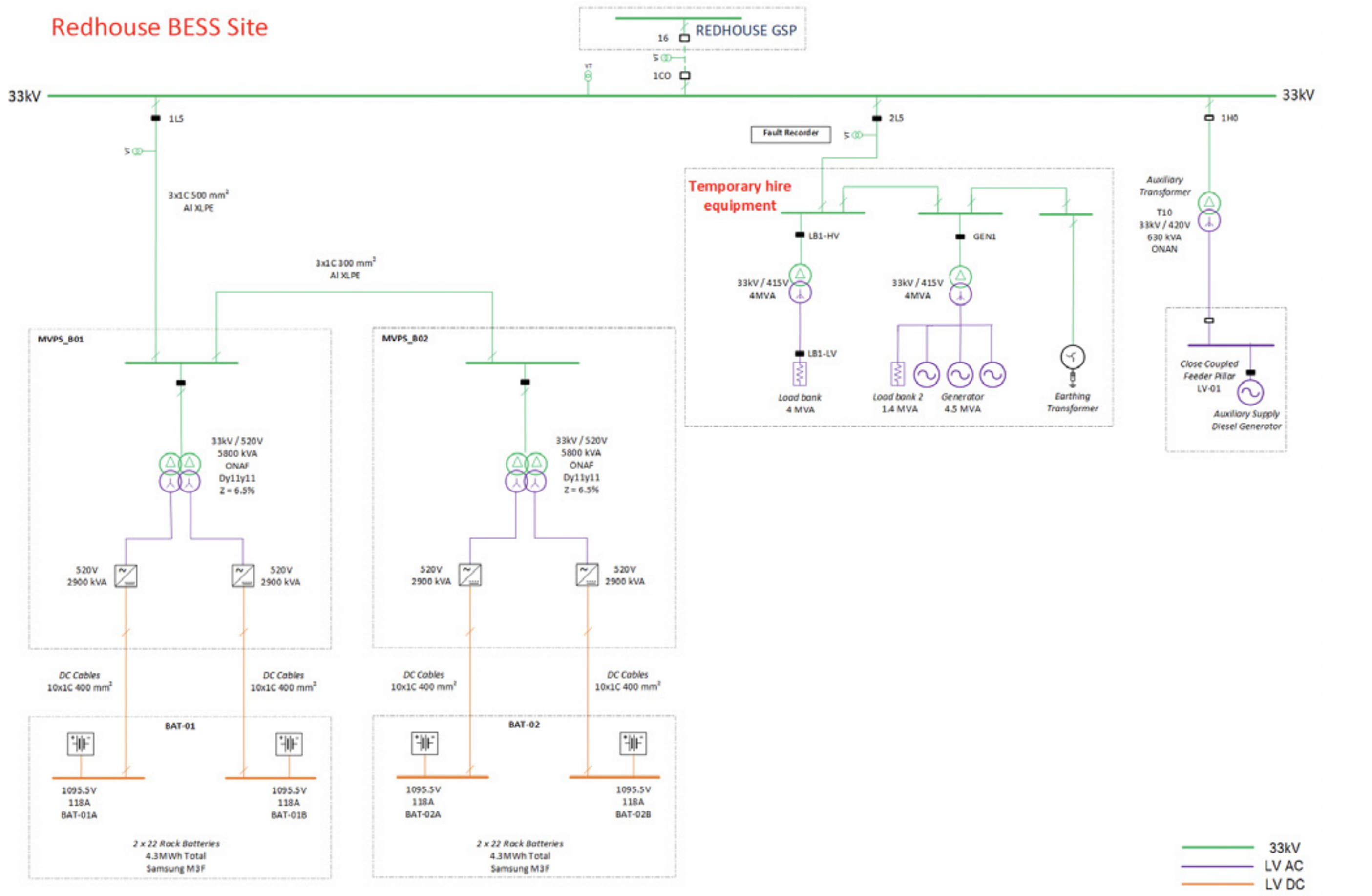


Figure 32: Redhouse trials – phase 1 test network

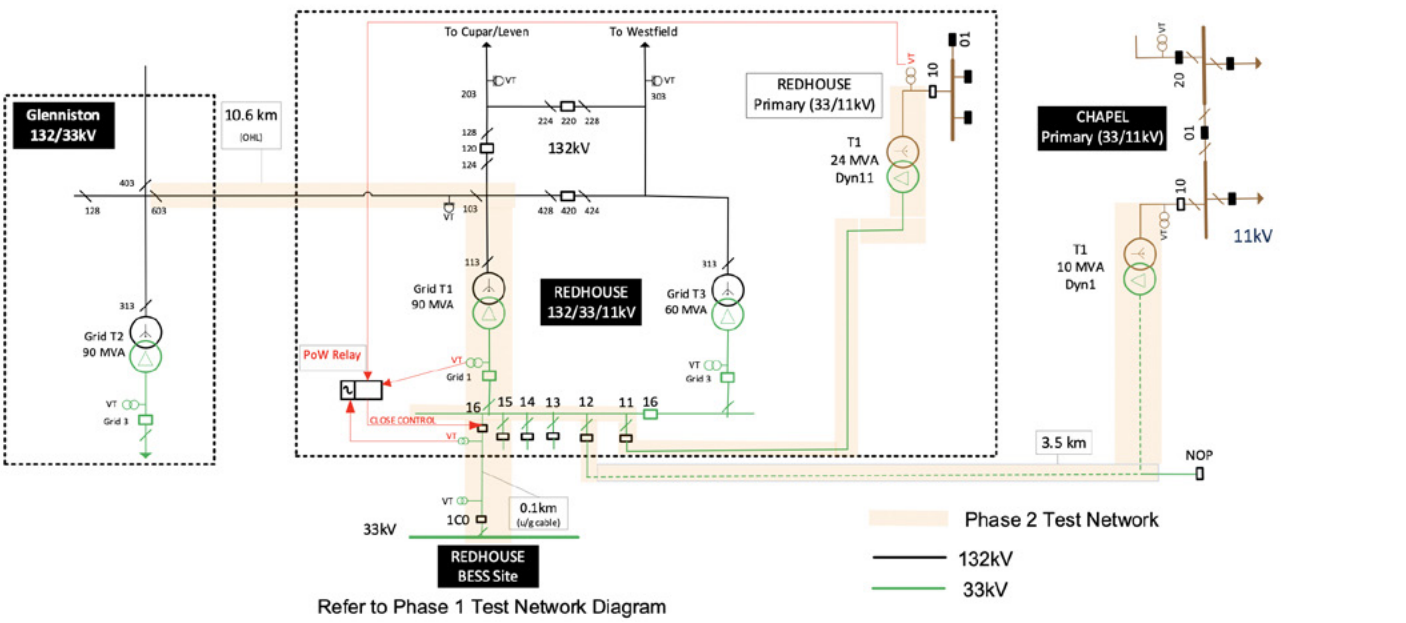


Figure 33: Redhouse trials – phase 2 test network

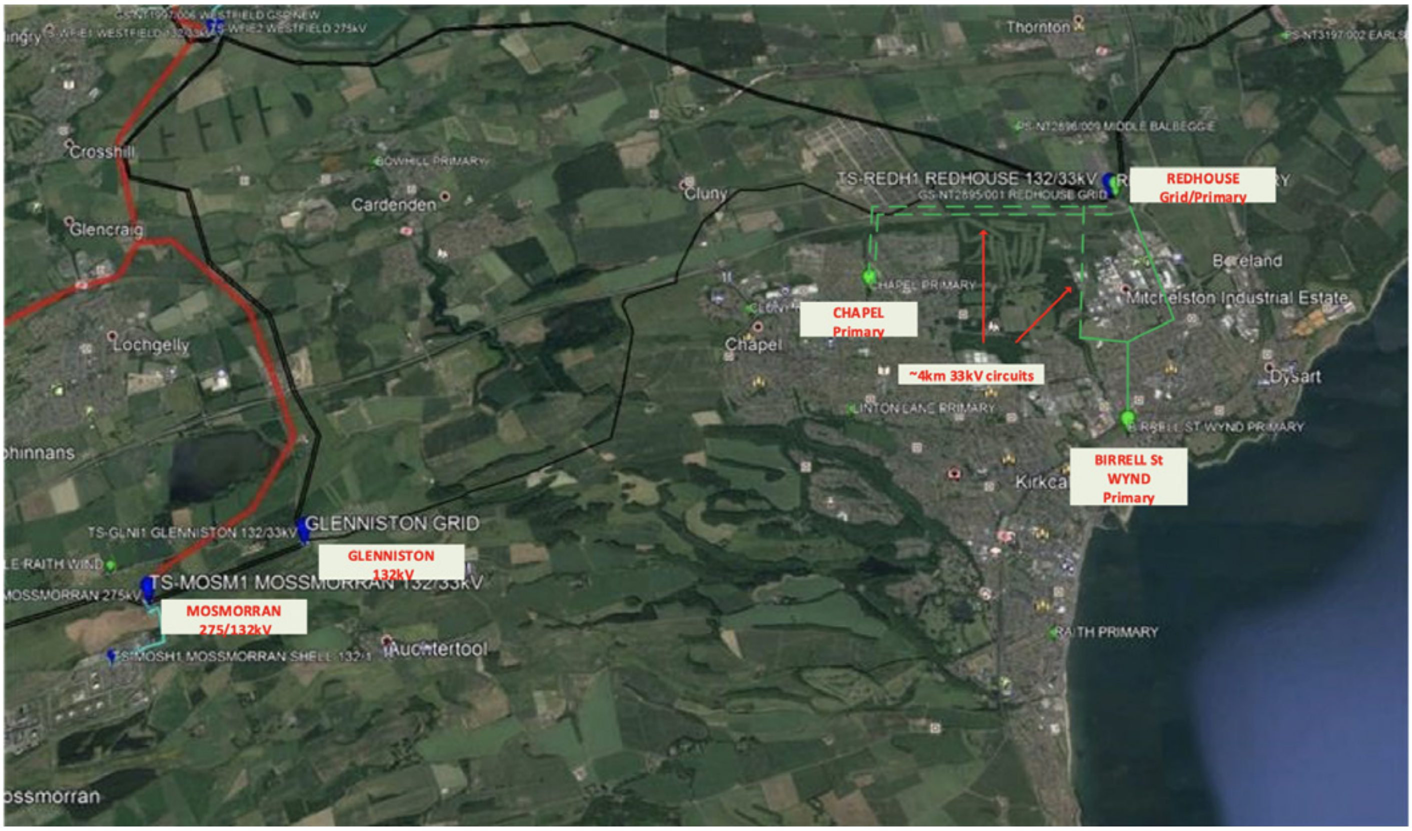


Figure 34: Redhouse phase 2 tests geographic substation locations

7.5 Pre-trial studies

TRV studies were initially carried out to ascertain if the 33 kV switchgear within the test network (all using vacuum interrupter technology) would be capable of interrupting low fault currents. Figure 35 shows the initial study network where a three-phase fault is applied to the Redhouse BESS busbars, which are supplied by only the diesel generators (50 m of 33 kV cable assumed in between). The TRV across 33 kV CB 2L5 is simulated as it opens to clear the fault. This is shown in Figure 35.

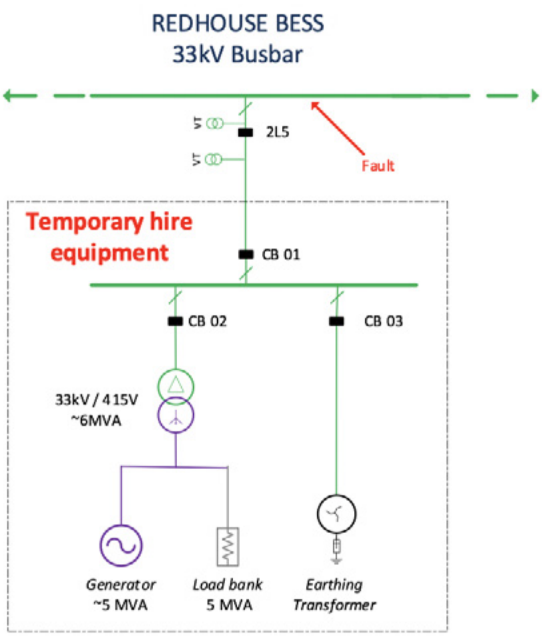


Figure 35: Redhouse TRV study schematic

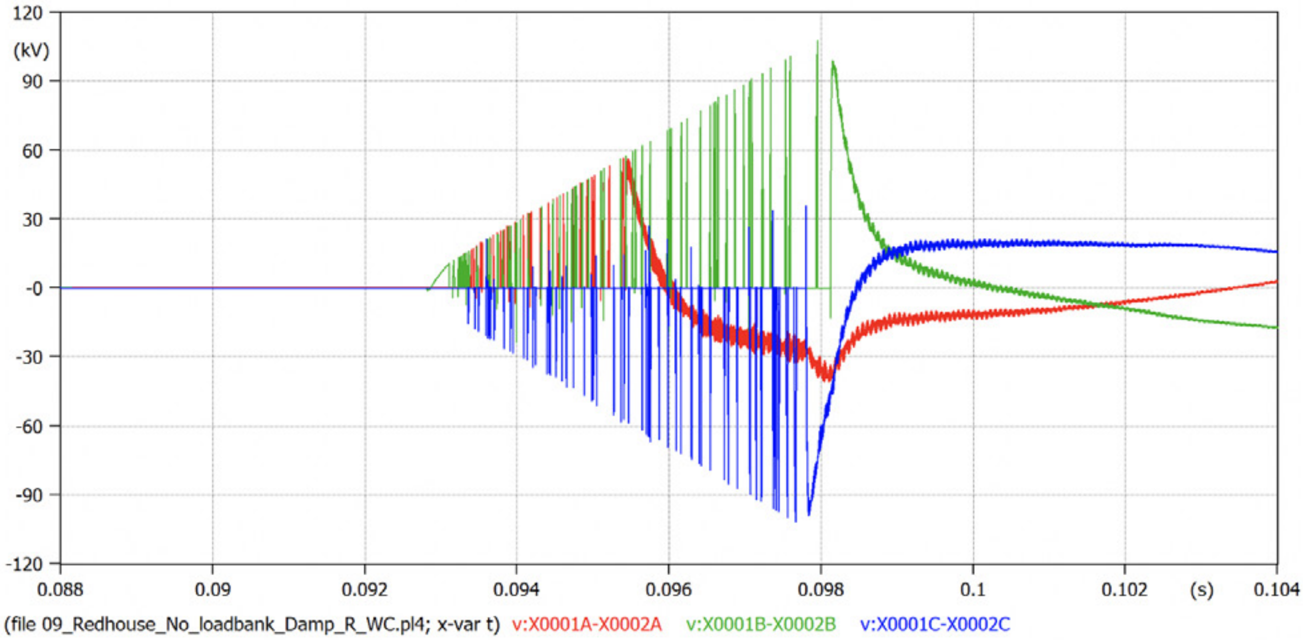


Figure 36: WORST case PoW Peak Phase Voltages measured cross CB 2L5 when opened in response to three-phase busbar fault

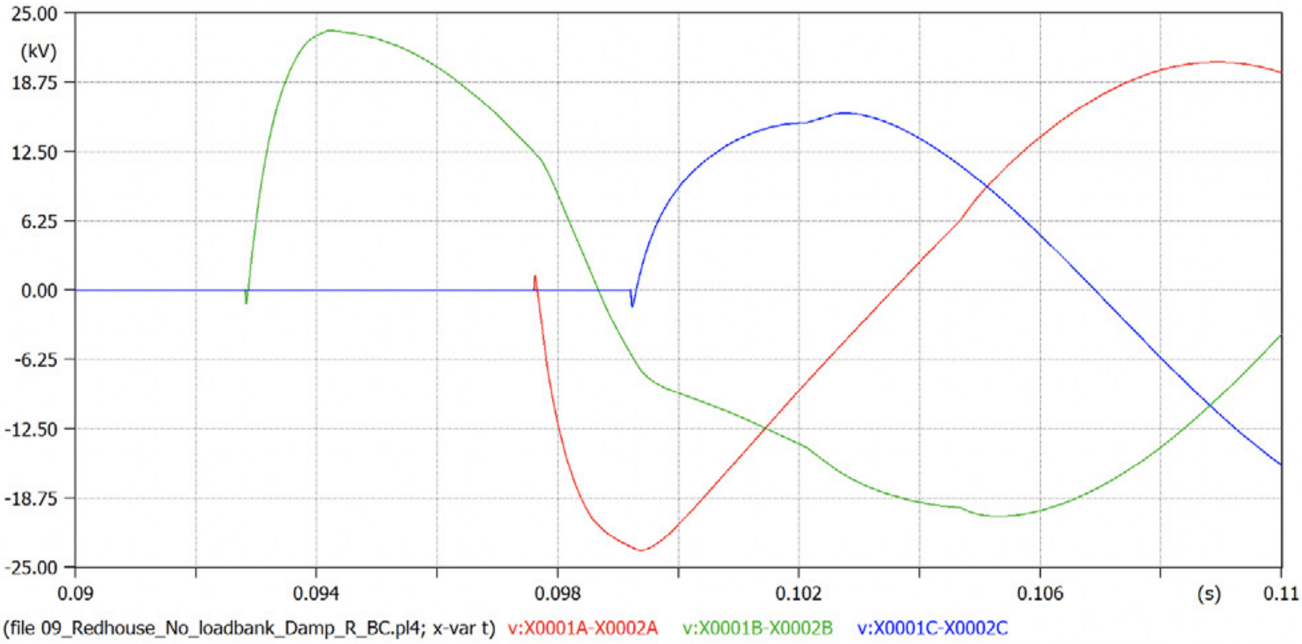


Figure 37: BEST case PoW Peak Phase Voltages measured cross CB 2L5 when opened in response to three-phase busbar fault

In Figure 36 it can be seen that multiple re-ignitions may occur across the CB contacts. This trace is based on the CB opening at the worst-case point on wave. It should be noted that the occurrence of re-ignitions is dependent upon the Point on Wave on which the CB starts to open. When there are no re-ignitions, the peak TRV recorded is independent of the Point on Wave opening. In Figure 37 it can be seen that for a 'best-case' Point on Wave opening, there are no re-ignitions and the peak TRV is ~23.4 kV (33 kV switchgear limits are typically ~70 kV).

The re-ignitions in Figure 36 reach a peak voltage of ~107 kV. This exceeds the peak TRV limit of the switchgear (~70 kV) but is within the lightning impulse withstand capability of the switchgear. Moreover, such high frequency transient voltages have the potential to damage other network equipment, for example voltage transformers. TRV switchgear limits are given as a peak value, and associated RRRV. These may be found in International Standard IEC-62271-100 for high voltage switchgear.

Discussion
Vacuum circuit breakers are known for their excellent interruption capability and dielectric recovery characteristics and are efficient in interrupting high frequency currents. Re-ignitions are prompt to happen when the contacts open near the power frequency current zero (thus this phenomenon is dependent upon the Point on Wave opening of the circuit breaker).

If the high RRRV exceeds the dielectric strength of the vacuum gap, re-ignition will occur, and high frequency currents will flow depending on the characteristics of the circuit. Due to the excellent clearing ability of the vacuum circuit breaker, the high frequency current can be interrupted at the next current zero, causing potentially higher rate of rise of recovery voltage across the vacuum gap. The repeated interruption of these high frequency currents can result in multiple re-ignitions and voltage escalations which may lead to overvoltages exceeding the basic insulation level (BIL) of the electrical system components. These high frequency transients may also excite the internal resonance of nearby transformer and generator winding, creating voltages several times larger than the original transients, leading to insulation breakdown and damage to the internal windings.

7.6 Conclusions

- With weak islanded networks (low fault level) it is important to carry out studies to ensure that the TRV capability of the switchgear is not exceeded (peak TRV value and the associated RRRV).
  – It should be noted that the measured TRV values are not dependent on the Point on Wave when the circuit breaker opens.
- Vacuum circuit breakers have a particular issue in that re-striking may occur if the RRRV exceeds the dielectric strength of the vacuum gap between the opening contacts.
  – While the measured peak value of the re-ignitions may be within switchgear limits, the high frequency transients may still damage nearby transformer and generator windings with voltages several times the magnitude of the initial TRV being generated in the windings.
  – Occurrence of re-ignitions is dependent upon the PoW opening of the circuit breaker.
  – Re-ignitions are only an issue for vacuum interrupters.
- Surge arrestors may be installed to limit the peak TRV values to within switchgear limits.
- RC snubbers may be installed to slow down the RRRV to within switchgear limits and/or avoid re-ignitions.

Live Testing Programme
The phase 1 and phase 2 Redhouse testing was originally scheduled for two weeks in Q3 2021. Following the initial TRV studies, testing has been rescheduled to summer 2022 to allow for the study results to be validated, and the appropriate mitigation measures to be installed if required.

8 Protection Assessment – BESS Anchor DER

8.1 Introduction

The University of Strathclyde (UoS) were commissioned[2] to assess the performance of the existing distribution and transmission network protections, within the Chapelcross live trial network, if the Steven's Croft biomass synchronous generator was replaced with an equivalent size (60 MVA) grid-forming converter (GFC) connected BESS.

The project aimed to identify potential protection limitations, required modification of settings and/or alternative protective solutions, to facilitate the adoption of the GFC as the only generating unit in a Black Start scenario. By considering the replacement of the synchronous generator (SG) based anchor unit by a similarly sized GFC unit, driven by an energy storage battery, a systematic fault level analysis alongside the protection assessment studies was performed. The project utilises data from a previous report by ARCADIS[3] (protection consultants) which identified the Chapelcross protection modifications required when the network is supplied by the Steven's Croft biomass SG only.

Based on the obtained results it was determined whether it is feasible to adopt a GFC unit as anchor in a Black Start scenario from the protection operation perspective. Even though the outcome applies primarily to a specific case study, some of the more generic learnings can be utilised as a foundation for the designing of future Black Start schemes within the distribution systems.

8.2 Methodology

The methodology deployed for the purposes of this work is illustrated graphically in Figure 38 and the main steps can be summarised as follows:

- Initially, the model of Chapelcross 132/33 kV GSP network (developed in DigSILENT PowerFactory) was provided by SPEN along with the protection assessment report3 created by ARCADIS UK. The existing Chapelcross network was validated accounting for the electrical parameters, the model of the Stevens's Croft SG, the resulting fault levels at different voltage levels (i.e. 415 V, 11 kV, 33 kV, 132 kV and 400 kV), and the revised protection settings proposed3 for the Black Start with the SG as anchor generator.
- A representative model of GFC unit driven by a battery energy storage system was developed in DIgSILENT PowerFactory and integrated within the Chapelcross network, by replacing the main Steven's Croft SG.
- A systematic fault levels calculation process was performed (including three-phase and single-phase-to-ground faults) across all the investigated voltage levels (i.e. 415 V, 11 kV, 33 kV, 132 kV and 400 kV), utilising static short-circuit calculations and dynamic RMS simulations, considering the GFC unit as anchor generator. The resulting fault levels were compared with those provided3 where the SG was used as an anchor generator.
- The revised protection settings proposed3 were evaluated in terms of their sensitivity under the influence of the fault current infeed contributed by the GFC unit as an anchor. The protection assessment studies considered overcurrent relays under three-phase and single-phase-to-ground faults.
- The main protection limitations were identified for each voltage level, and possible mitigating solutions such as the utilisation of voltage-dependent overcurrent protection were proposed to enable the adoption of the GFC unit.

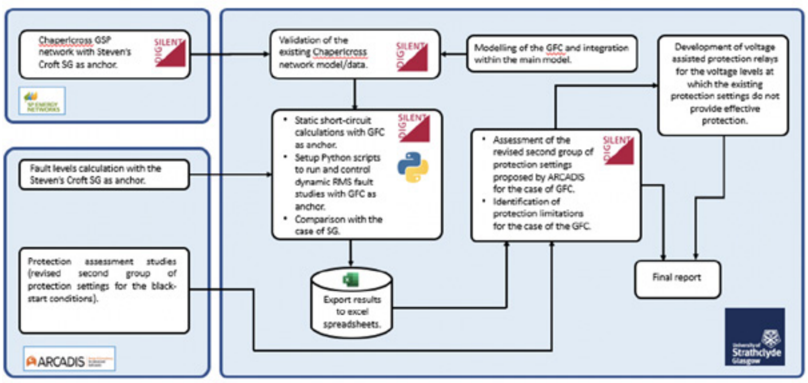


Figure 38: High-level diagram of developed methodology

[2]'Protection performance assessment with Grid Forming converter as the anchor', University of Strathclyde, Nov 2021, Reference: SPEN/PROT/TR/2021-01
[3] 'Steven's Croft Protection Settings', ARCADIS, May 2020, Reference: 10036400/R/PW/01

8.3 Modelling of grid-forming converter and fault level calculation

The dynamic model of the GFC unit contained three main components: a lithium-ion battery, a 60 MVA converter and a step-up transformer. The GFC unit operates as an independent voltage source, providing active and reactive power support by regulating its output voltage angle and magnitude, respectively. In the islanded system, during the balanced and unbalanced faults the GFC unit injects reactive current to maintain the nominal voltage. The fast-acting voltage support provided by the GFC can be considered as a very useful feature for maintaining a relatively high level of fault current so long as it does not exceed the rated value. Initially, the magnitude of the injected current increases rapidly with the fall of the retained voltage. However, for close-up faults with a significant reduction in the retained voltage, the injected reactive current reaches its maximum value and leads the GFC to saturation. When the GFC unit is saturated, it operates as a constant current source. In all calculation studies the maximum current has been set to 1 pu (i.e. the nominal current). Therefore, once the GFC is saturated its output fault current is locked to the GFC rated value.

It has been observed that conventional (static) fault level calculations in simulation tools do not adequately represent this specific characteristic of the converter dynamic behaviour which distinguishes it from the fault response of a synchronous generator, where constant internal reactance can be assumed and voltage controller response is neglected in fault calculations.

For this reason, in case of GFC, two methods of fault level calculation were utilised:

i) Static short-circuit analysis
The 'complete' fault level calculation method in DIgSILENT PowerFactory was utilised.

ii) Dynamic RMS simulation
Time domain simulation was performed at each busbar of the network, using a converter model equipped with a fast voltage regulator as described in the previous section.

The comparative analysis was performed using the I_k current magnitude as an indicator, which corresponds to the current flowing 1 second after the fault occurrence.

The results are shown in Figure 39 and in Figure 40, for three-phase faults and single-phase-to-ground faults respectively, including the following three sets of results:

- static short-circuit analysis using SG as an anchor – benchmark values (blue bars).
- static short-circuit analysis using GFC as an anchor (orange bars).
- RMS dynamic time domain short-circuit analysis using GFC as an anchor (grey bars).

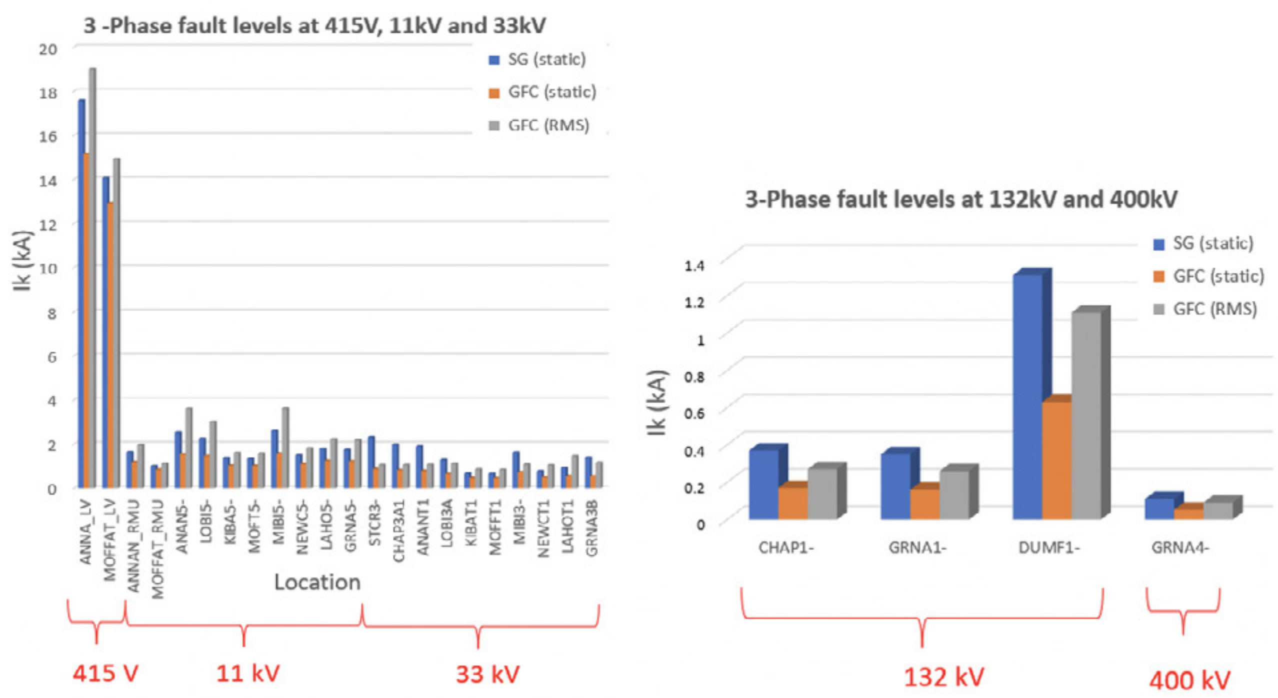


Figure 39: Three-phase fault levels

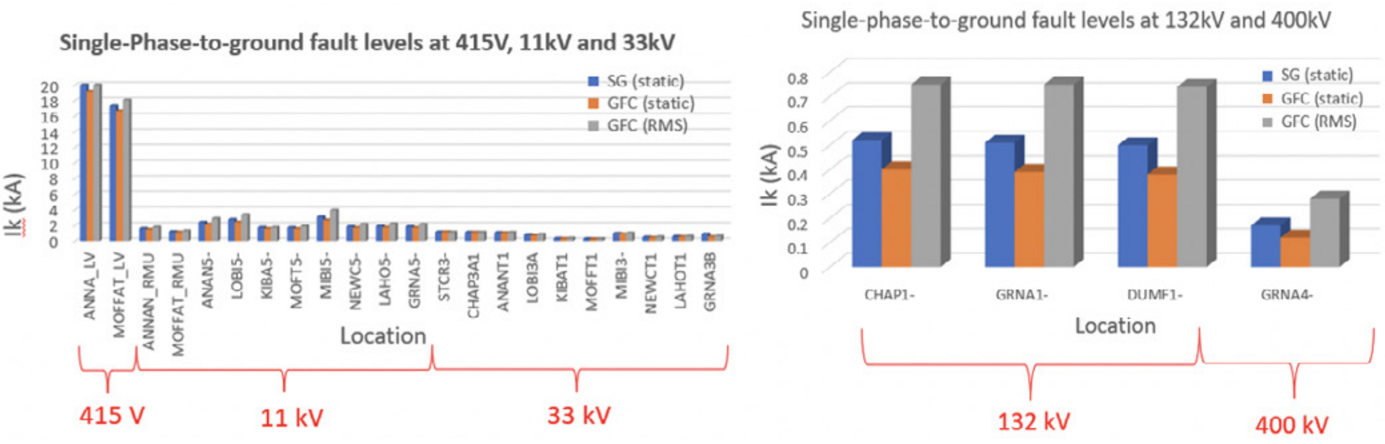


Figure 40: Single-phase-to-ground fault levels for 415 V, 11 kV and 33 kV

8.4 Protection performance analysis

In all protection assessment studies the three fault levels (as indicated in the previous section) were applied for comparison purposes. The time/current characteristic of the appropriate overcurrent relays was modelled in DIgSILENT PowerFactory, utilising the revised protection settings provided. Two example protection studies are outlined in the following subsections.

8.4.1 Example 1 – Insufficient protection sensitivity at 33 kV

Figure 41 presents the overcurrent time grading curves for a three-phase fault applied at 33 kV transformer incomer to Lockerbie switchboard. The three considered fault levels are marked as follows: SG fault level in black, GFC fault level from static calculation in red and GFC fault level from RMS simulation in green.

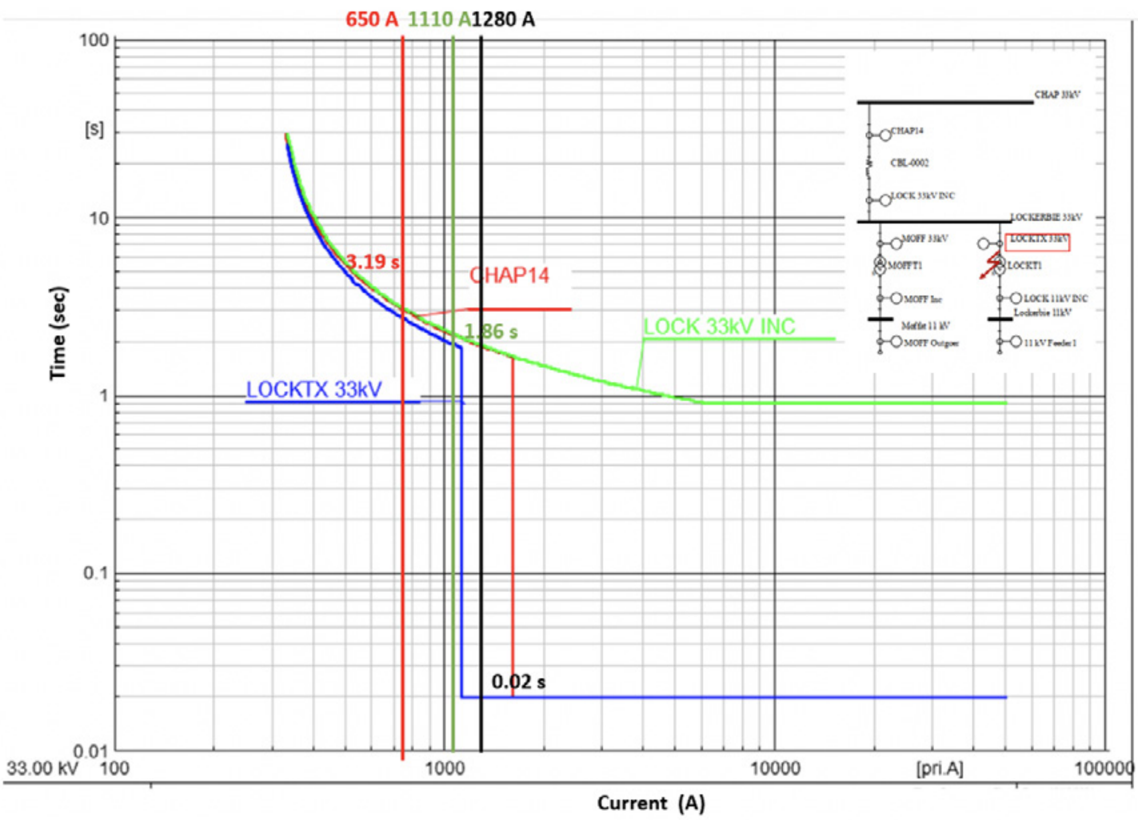


Figure 41: Overcurrent grading curves for three-phase solid fault at 33 kV transformer incomer to Lockerbie switchboard

During this fault, the GFC unit is saturated, providing lower fault level compared to the SG. Therefore, the 'LOCKTX 33 kV' relay at the 33 kV transformer incomer operates faster for the case of the SG as anchor at 0.02 second, while for the GFC unit as an anchor, the fault clearance time is longer. For this fault the assessment of the revised overcurrent settings highlights that when the GFC is saturated during three-phase faults at 33 kV, more sensitive protection settings are required.

To tackle the protection sensitivity issues, the setting of the high set instantaneous element can be reduced, or else, if this was not feasible, the voltage-dependent overcurrent relay could be utilised to provide more sensitive settings when the GFC unit operates in current control mode. The key feature of the voltage-dependent overcurrent relay is that its overcurrent plug setting is automatically reduced when the measured voltage at the switchboard drops below a pre-set threshold, allowing for more sensitive and thus faster overcurrent protection operation.

In this work, the undervoltage threshold has been set to 85 per cent of the nominal voltage, and the pick-up current setting of the sensitive overcurrent element at 50 per cent of the standard pick-up setting.

Figure 42 shows the voltage dip at 33 kV transformer incomer to Lockerbie switchboard during the fault at the 'LOCKTX 33 kV'. As it is a close-up fault, the observed voltage is reduced to zero.

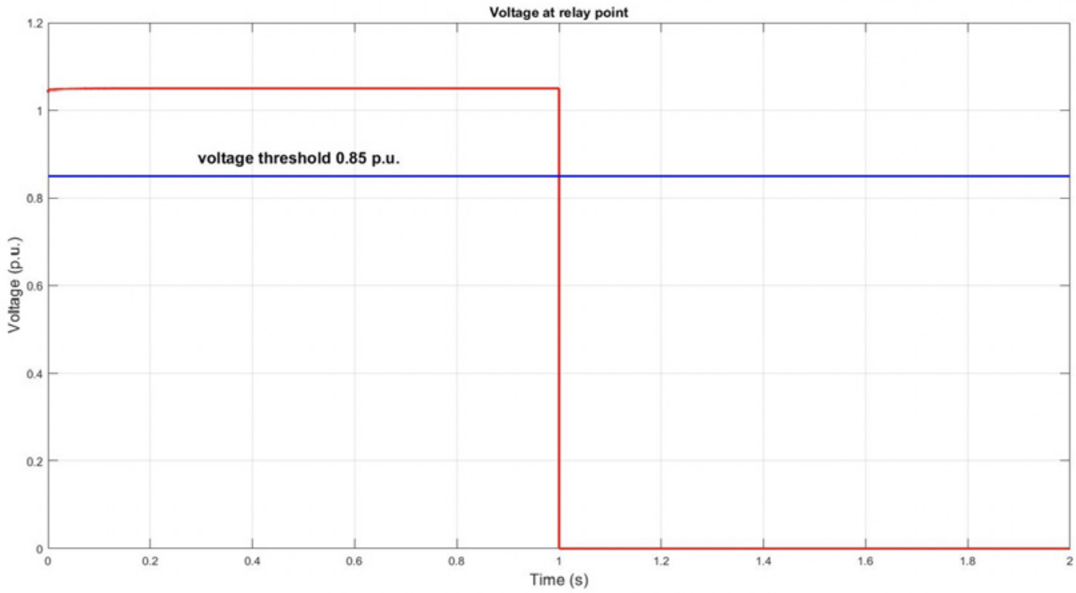


Figure 42: Voltage drop at relay point for a three-phase fault at 33 kV transformer incomer to Lockerbie switchboard

Figure 43 presents the time-current characteristic of the overcurrent relay 'LOCKTX 33 kV', considering the settings proposed (curve indicated with red colour) and the corresponding voltage-dependent sensitive characteristic (curve indicated in green). Under the low retained voltage, the overcurrent relay operating time is reduced from 1.86 seconds to 1.20 seconds.

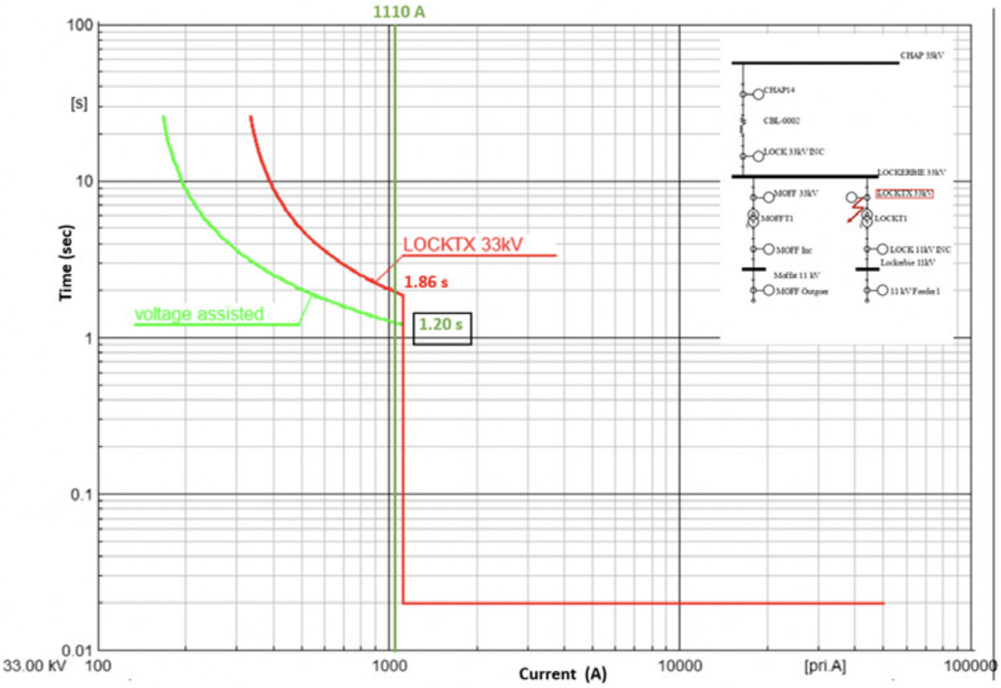


Figure 43: Time-current characteristic of the earth-fault relay and the voltage-dependent relay for a three-phase fault at the 33 kV transformer incomer to Lockerbie switchboard

8.4.2 Example 2 – Protection time grading issues at 11 kV

Figure 44 presents the time grading curves for a three-phase fault at Annan 11 kV busbar. As can be seen, according to RMS simulation the GFC provides a fault level of 3590 A, which is higher compared to the SG. Even though it may seem counterintuitive, this relatively high fault current is a result of the converter operating below its current saturation limit and maintains high voltage at its terminals for an 11 kV remote fault. Due to the increased fault level, the 'Annan INC1' relay at 11 kV transformer incomer operates faster. It is clear that for remote faults at 11 kV, the GFC unit provides sufficient protection sensitivity. However, the IDMT characteristics of '11 kV Feeder' and 'Annan INC1' relay cross each other, jeopardising the protection time grading. Consequently, in this case protection adjustment of the time-setting multiplier is required.

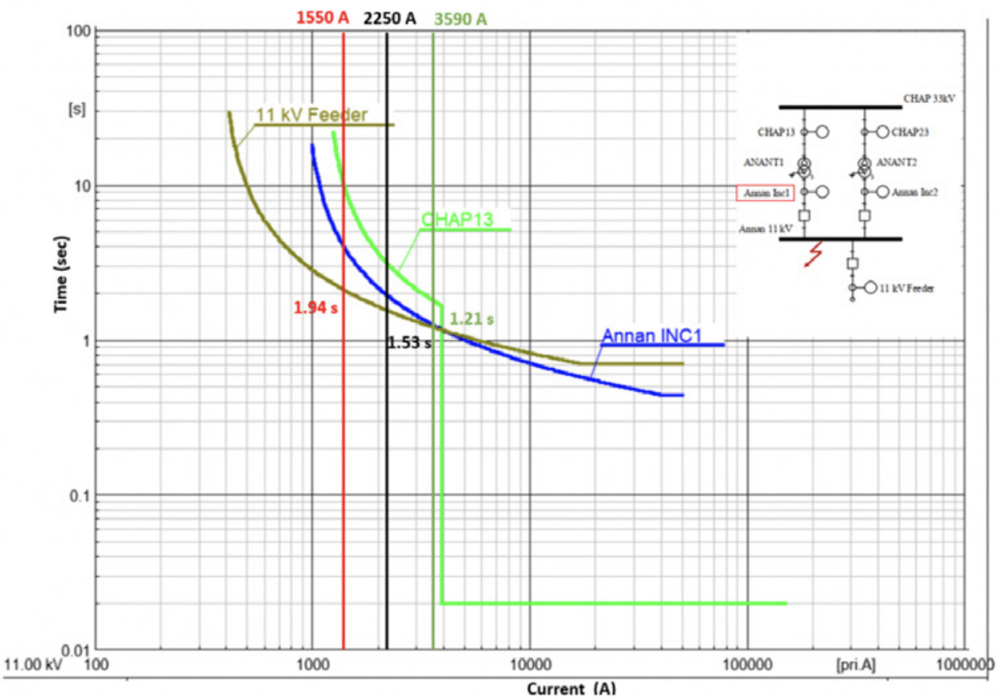


Figure 44: Overcurrent grading curves for three-phase fault at Annan 33 kV busbar

8.5 Key findings and recommendations

8.5.1 GFC fault response

The RMS dynamic simulation-based studies considering the GFC unit as the anchor generator revealed that the GFC unit is likely to be saturated during close-up faults, due to the significant voltage depression. Under these conditions, the injected fault current is equal to the nominal/rated value.

At 33 kV, 50 per cent of the investigated fault scenarios, accounting for three-phase and single-phase-to-ground faults, the GFC unit is saturated (referred to close-up faults at 33 kV). At 132 kV and 400 kV, the GFC unit switches to current control mode only during the three-phase faults, while it operates as voltage source under the influence of the single-phase-to-ground faults.

At lower voltage levels (i.e. 415 V and 11 kV), the GFC unit is never saturated and continues to operate as a voltage source.

8.5.2 Fault levels

The fault level analysis studies for the GFC revealed that the resulting fault levels from the RMS dynamic simulations are higher compared to those derived from the static short-circuit analysis. This can be explained by the inclusion of the fast-acting voltage regulator in the GFC model, which is not adequately represented in the static calculations. The RMS dynamic simulations provide a better insight into the whole-system dynamics and more accurately reflect the fast-acting control of the GFC unit during the fault events.

The comparison between the initial fault levels considering the SG as anchor with those resulting from the RMS calculations for the GFC unit as the anchor indicated that:

- At 415 V and 11 kV, the three-phase and single-phase-to-ground fault levels considering the GFC unit as an anchor are higher compared to those resulting from the SG.
- At 33 kV, when the GFC is saturated and operates in current control mode, the resulting three-phase and single-phase-to-ground fault levels are reduced. However, for some more remote 33 kV faults when the GC is not saturated and still operates as a voltage source providing fast-acting voltage support, the fault levels are higher compared to those of the SG.
- At 132 kV and 400 kV, due to the GFC's saturation during the three-phase faults, the resulting fault levels are lower compared to those of the SG. In contrast, at these voltage levels, the GFC unit is not saturated during the single-phase-to-ground faults, resulting in slightly higher fault levels.

8.5.3 Protection performance

The revised setting of 11 kV protection system previously proposed as suitable for a synchronous generator provides adequate protection in Black Start conditions in terms of protection sensitivity. However, it has been revealed that the protection time grading is not always fulfilled. Adjustments to the time multiplier settings and/or instantaneous element threshold may be required.

At 33 kV, it has been found that the Balanced Earth Fault (BEF) (with settings proposed as suitable for a synchronous generator of same MVA rating) during the single-phase-to-ground fault provides adequate protection for the single-phase-to-ground faults resulting from the GFC unit as anchor. For the three-phase faults, there is sufficient fault levels to operate the 33 kV overcurrent protection in cases when the GFC unit is not saturated. However, for the cases when the GFC is saturated (faults nearer the GFC with less fault impedance), more sensitive settings may be required where feasible (there is a limit to how low settings can be applied to avoid operating for load currents). Alternatively, voltage-dependent protection can perhaps be considered as a viable solution, providing more sensitive protection and faster fault clearance times. This needs to consider the availability of voltage measurement at 33 kV.

At 132 kV, the revised settings proposed (those suitable for a synchronous generator as above) for the earth fault protection provide adequate protection. For the three phase faults, the fault-clearing times are within acceptable limits for the GFC unit as anchor; however, more sensitive settings may be needed for the case of the GFC unit.

9 Grid Forming Converter (GFC) Network Energisation Simulations

9.1 Introduction

This study[4] aims to assess the viability of using a GFC to energise the distribution and transmission networks, and also the associated benefits (relative to software-only RSCAD/PSCAD simulations/testing) of testing grid-forming GFC within a Power Hardware in the Loop (PHiL) environment for Black Start applications.

The assessment starts from a simplified test network, and then considers a segment of the Chapelcross live trial network to simulate the Black-Start energisation from a GFC. The GFC control adopted throughout this report is illustrated in Figure 45. This includes soft energisation (ramping up the voltage), voltage support and grid synchronisation capabilities. The modified grid-synchronisation control requires access to high-precision voltage measurements from the synchronising point.

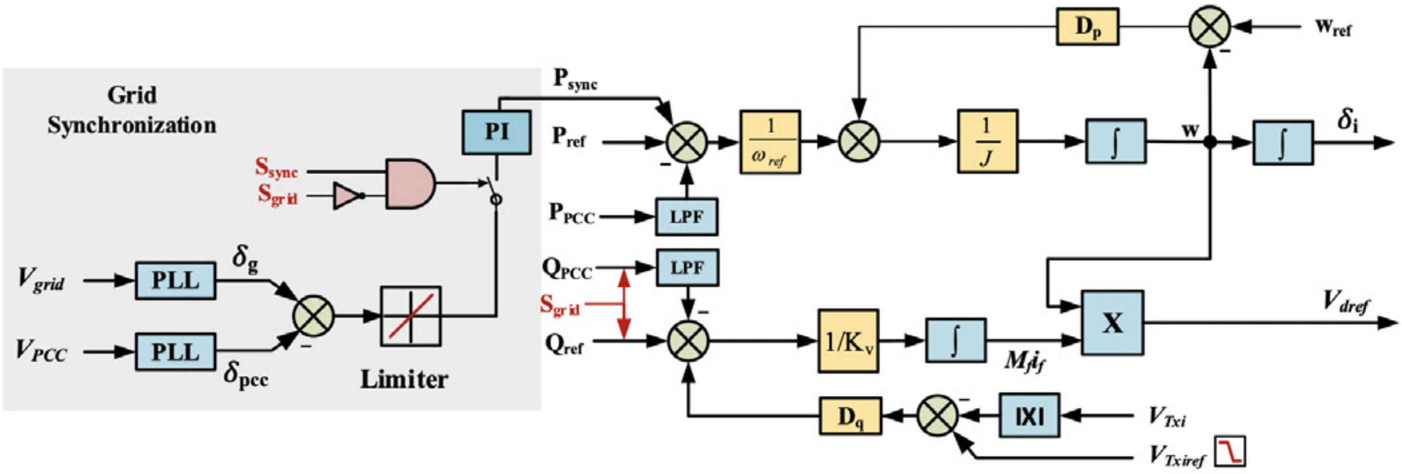


Figure 45: High-level VSM control block diagram for the GFC loop used in this study

Power Hardware in the Loop (PHiL) is investigated to test the integration of the external hardware converter to the simulated RTDS networks in grid-forming mode. This technique aims to test the hardware converter's ability to energise a modelled version of the network, through supplying the simulated RTDS network with a controlled voltage input. The hardware grid-forming converter feeds a scaled power into an interface current source converter receiving its reference from the simulated network, such that the hardware voltage-source/current-source twin mimics the simulated network behaviour.

The prospective advantages of using PHiL for GFC testing is bridging the gap further between simulation and hardware and unlocking the testing ability of hardware GFCs on an expanded network modelled in real time. However, the application of this idea has its limitations and challenges that are highlighted in a dedicated section with relevant recommendations. In this report, the PHiL capability is validated for the simplified Black-Start test network, with the aim of experimenting with a range of test scenarios using a model of the Chapelcross live trial network.

[4] Distributed ReStart: RTDS Based Network Energisation from Grid Forming Converters: Part 1, Iberdrola Middle East and University of Strathclyde

9.2 Simplified network simulation in RTDS

A simplified network is first modelled in RSCAD software to perform preliminary analysis in Real Time Digital Simulation (RTDS) platform in preparation for the PHiL tests. The network block diagram is illustrated in Figure 46.

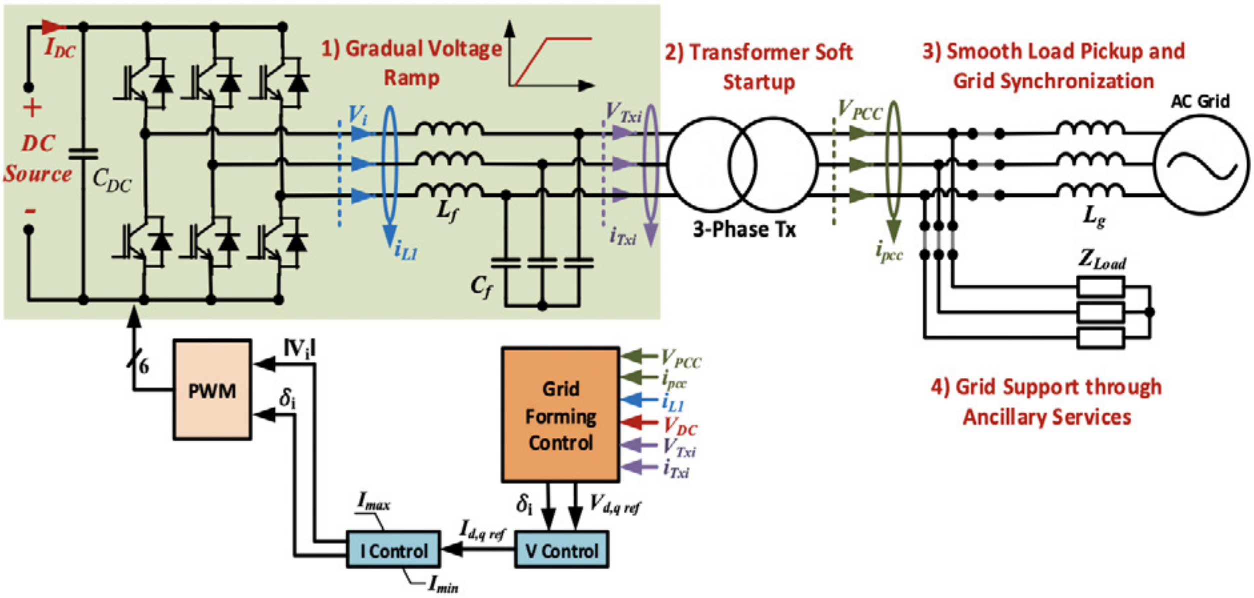


Figure 46: Simplified network used for preliminary grid-forming control validation in RTDS platform

A Chapelcross RSCAD network model has been developed by the HVDC Centre for transient and protection analysis. Since Chapelcross is the area of interest for this study, the transformer model used to interface with the network is modelled with similar saturation characteristics to the generator transformer at the synchronous generator on the existing network. Using the soft Black-Start sequence illustrated in Figure 46 the simulated network Black-Start functionality in RSCAD is confirmed.

A summary of results is illustrated in Figure 47. Soft voltage ramp of 10 seconds is applied, and then a 20 MW load is connected at t=12 seconds, followed by grid synchronisation control activation at t=14 s, and the actual synchronisation taking place just before t = 20 seconds. Transformer residual flux is set to arbitrary values for this test. The resulting energising inrush current is minimal due to the soft energisation, the large load pick-up causes a momentary voltage disturbance that is countered by the GFC voltage control and load synchronisation is achieved smoothly with minimal impact on the frequency trace. The active power setpoint after synchronisation is set to 30 MW to test the controller's ability to follow a setpoint robustly, driving the frequency back to 50 Hz. Figure 47 also illustrates a zoomed view on voltage and current at the synchronisation instant, illustrating the seamless voltage transition, and the smooth current adjustment to follow P and Q setpoints.

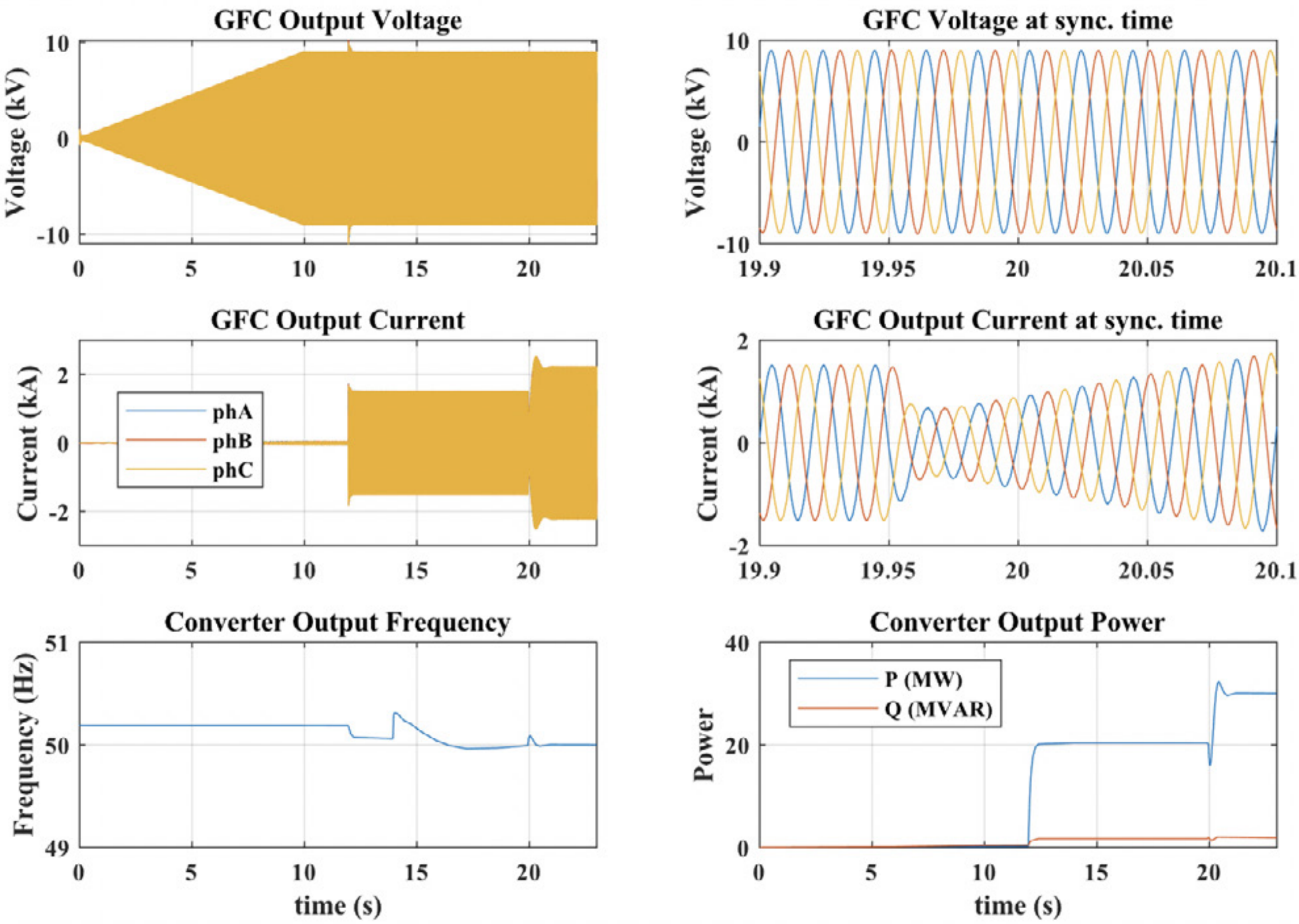


Figure 47: Simplified network RTDS simulation results

9.3 Chapelcross network restoration scenario

The HVDC Centre model for Chapelcross network is adapted in this study to investigate the capability of the GFC for Black Start. The existing synchronous generator (Steven's Croft Power Station) is replaced by a GFC average model at the 11 kV busbar and will be used to energise segments of the network in post-blackout scenarios. One energisation scenario is presented in this report, with the aim of extending to multiple network scenarios in part 2 of this study (to be completed by spring 2022). The selected scenario requires the GFC to energise the area outlined in red in Figure 48, encompassing two large power transformers (53 MVA at 11/33 kV and 90 MVA at 33/132 kV), and two 33 kV earthing transformers (one at the GFC location and the other at the Grid T1 132/33 kV transformer). The HVDC Centre model assumes a 1 per cent rated magnetising current for the transformers, a knee voltage of 1.25 pu, with an air-core inductance of 0.265 pu for the 53 MVA transformer and 0.3 pu for the 90 MVA transformer. Variations to these parameters in reality can alter the studied inrush current behaviour.

Two sub-scenarios are covered here. First, the GFC is required to synchronise at the 132 kV terminals of Grid T1, requiring to energise both the 53 MVA (33/11 kV) and 90 MVA (132/33 kV) transformers and associated earthing transformers. In the second scenario, the synchronisation takes place at the 33 kV side of Grid T1 (across the Grid 1 circuit breaker) with the assumption that this transformer is energised from the 132 kV network.

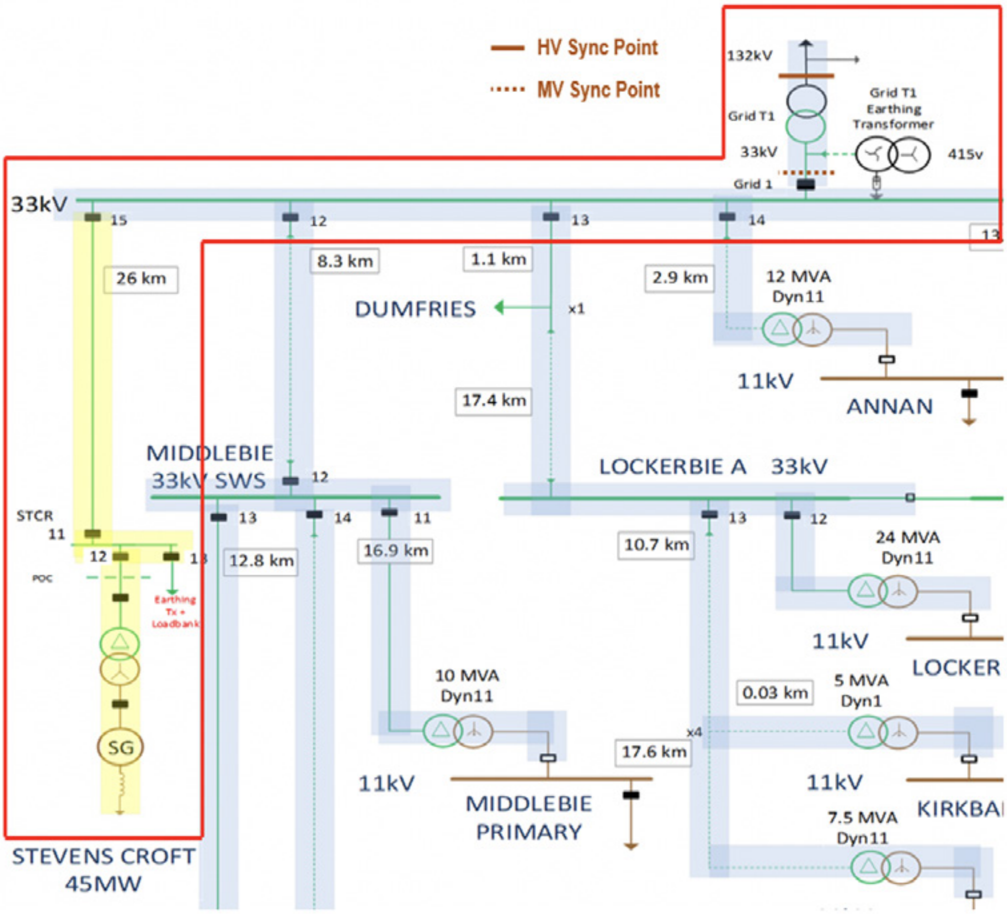


Figure 48: Chapelcross network section considered for energisation in RSCAD model (with HV/MV synchronisation points)

The residual flux is maintained in both the 53 MVA and 90 MVA transformers at phase A: 0.8 pu, phase B: 0 and phase C: -0.8 pu throughout the tests to emulate near worst-case conditions. In steady state island mode, with the full test network connected, it is observed that GFC generates 1.56 MW (transformer losses) and absorbs -3.64 Mvar (primarily 33 kV cable capacitance Mvars). When the 90 MVA transformer is energised by the grid and only the 53 MVA is fed by the converter, the steady state requirements decrease to 0.56 MW and the converter absorbs -4.68 Mvar. These numbers are indicative based on the existing network model and the covered scenario in Figure 48 and can help sizing a converter.

9.3.1 Hard energisation – Chapelcross test network

Hard energisation (connecting the network with the GFC voltage at 1 pu), is first tested only with voltage control applied, and the breaker is closed at -30o to generate the maximum inrush in phase AB of the delta primary of interface transformer at its zero-crossing point. The converter phase currents can exceed 20 kA as observed in some simulations, and peaks around 15 kA for the case presented here as illustrated in Figure 49, demanding around 300 peak Mvar for the full network energisation as in Table 10. For comparison, a 40 MVA converter is rated at 2.97 kA per phase (1 pu). Clearly, classical hard energisation in this case is not advised.

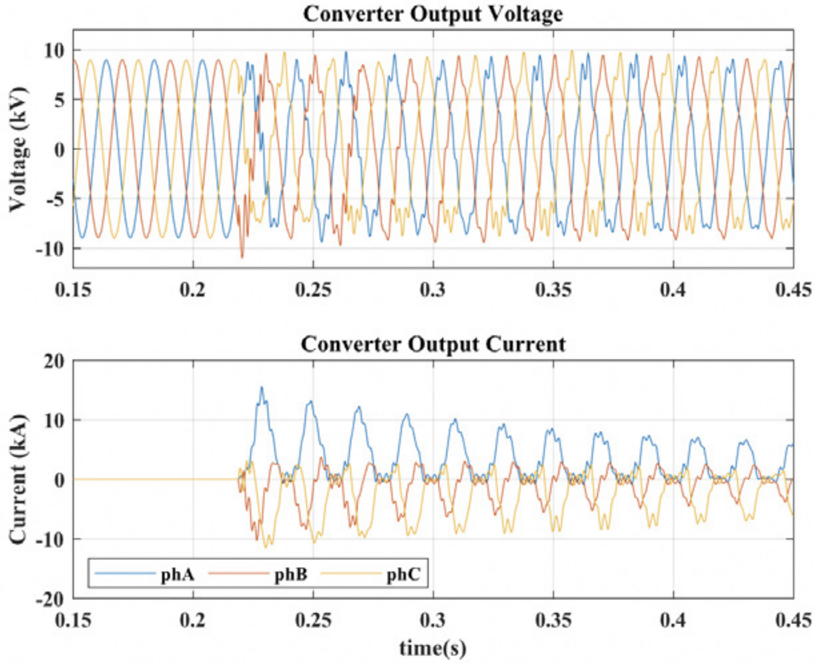


Figure 49: Hard energisation results from Chapelcross scenario (voltage control) with both transformers connected

Next, hard energisation with inner voltage and current control loops is tested. The inner loops are implemented in synchronous dq frame using PI controllers. This implementation is observed to reduce the peak observed current to around 8 kA at 125 Mvar requirement with similar initial energising angle (see Figure 50). The control current reference is restricted here to 5 kA peak. Setting stricter current limits is observed to reduce the peak current further; however, it results in higher voltage spikes at the energisation instant. This could be an interesting point for further studies to balance both acts.

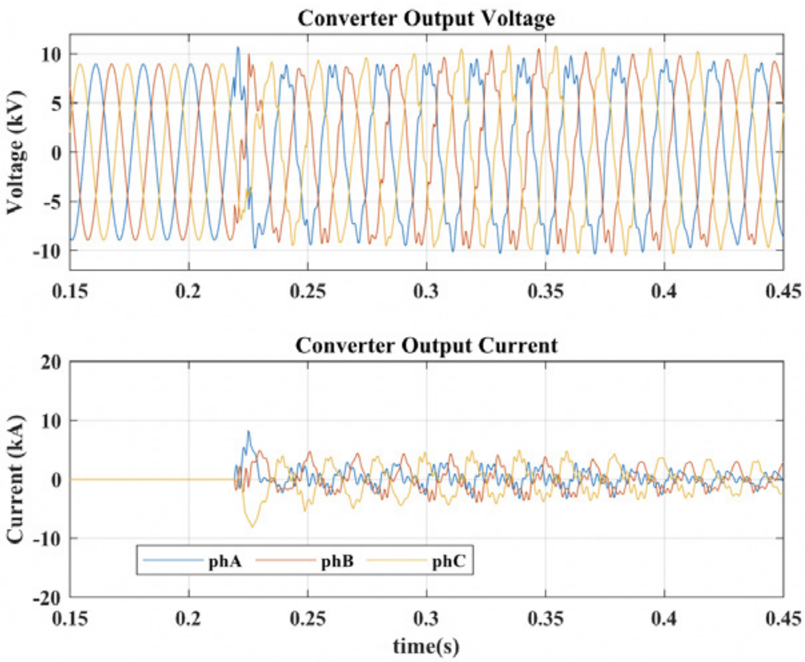


Figure 50: Hard energisation results from Chapelcross scenario (current control) with both transformers connected

In both previous cases (voltage and current controlled energisation), the transients are stabilised in a few seconds and the steady state voltages and currents are as illustrated in Figure 51. The current is non-sinusoid as it is primarily composed of the 53 MVA and 90 MVA transformers magnetising currents with active hysteresis loops.

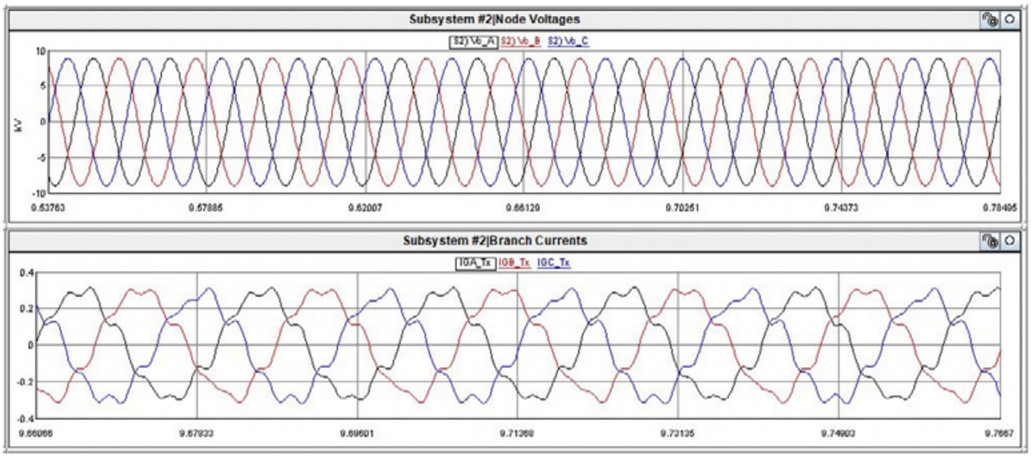


Figure 51: Steady state post-energisation converter voltage and current (kA) waveforms from RSCAD

Conclusion

Setting converter current control limits to lower peak inrush currents may be implemented at the expense of larger voltage disturbances. Live trials would be required to verify if this energisation strategy was viable as protection would have to be set to avoid hardware damage and may result in disconnecting the converter.

9.3.2 Soft energisation – Chapelcross test network

Soft network energisation (ramping up the GFC voltage) aims to minimise inrush current by gradual transformer core flux build-up to avoid saturation and consequent large magnitude inrush currents. Selection of appropriate ramping times is important to avoid too-fast ramps that could still cause inrush, or too slow that could cause protection equipment malfunctions. In this section, the soft energisation of the highlighted network in Figure 49 is carried out for both MV and HV synchronising points, with connected inner voltage and current loops. The ramping time is selected as 10 seconds.

Synchronising at 132 kV (HV) Side

All circuit breakers are initially closed (except for the synchronising point), and the ramping is initiated for a duration of 10 seconds. The results of this scenario are illustrated in Figure 52. The inrush current build-up is significantly minimised compared to hard energisation case with both transformers, peaking around 1 kA with a peak 0.8 Mvar energising demand. Then at t = 12 seconds, the local load is connected (6 MW/1 Mvar). The synchronising control is then activated to gradually match the phase angle between the voltages on both sides of the synchronisation point.

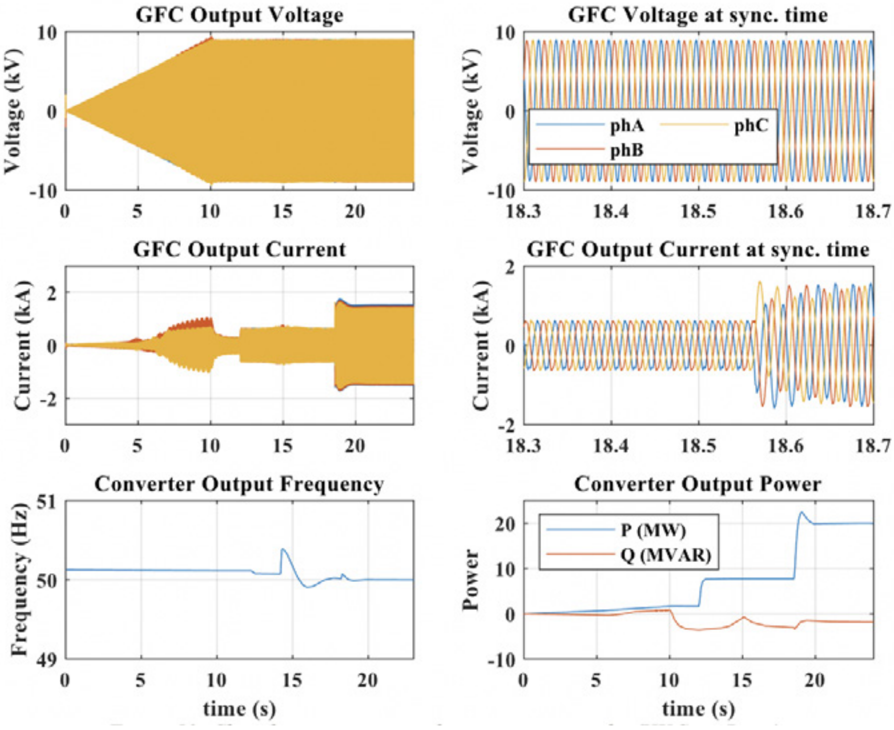


Figure 52: Chapelcross scenario soft energisation results (HV Sync Point).

At t = 18s, the synchronisation is complete, and the HV grid is connected successfully. The VSM shifts at this point to tracking P and Q setpoints, or P and voltage support (design choice, see Figure 45). In this case, voltage tracking is selected as a priority over Q injection, and thus Q varies according to the voltage setpoint. The P setpoint is set to 20 MW. The GFC frequency trace is within acceptable limits throughout the operation, changing mostly during synchronisation because of the fast-synchronising PI control operation (see Figure 45). This can be smoothed for longer durations in reality by choosing slower PI control gains, as these are set here to achieve fast synchronising voltages phase matching for combined results and demonstration purposes.

Summary

A summary of energisation scenarios Mvar energising requirements covered in this report with both 53 MVA and 90 MVA transformers connected is presented in Table 10 for design reference. Most of the power demand during energisation is reactive (resulting from transformers and cables energisation). Soft energisation reduces the reactive power requirements during energisation to a minimum value. Then, the post-energisation steady state requirement depends on the combination of transformers magnetising and cables current. The used source and converter filter should be sized according to the prospective scenario.

Table 10: VAR requirements for network energisation using different starting techniques (for HV sync point).

Both 53 MVA and 90 MVA Tx Connected	Max Network Energising Power
Hard (Voltage Controlled)	300 Mvar*
Hard (Current Controlled – 5 kA current limit)	125 Mvar
Soft Energisation (10 seconds)	0.8 Mvar
Steady State P and Q before synchronisation*	1.5 MW, -3.64 Mvar

Synchronising at 33 kV (Grid 1 CB)
The difference in this case is that the synchronisation takes place at the LV side of the 132/33 kV Grid T1 90 MVA transformer (i.e. when this transformer is energised from the transmission network). Thus, the energising load on GFC is decreased in transient operation, which leads to decreased converter current during the first 10 seconds, peaking around 0.5 kA compared to 1 kA in the previous case. A similar sequence to that followed in synchronising at the 132 kV (HV) side is followed here, and successful energisation is achieved as illustrated in Figure 53. The choice of energising only the 53 MVA transformer and cable segment or both the 53 MVA and 90 MVA transformers depends on the available capacity in the energising source, converter size and the energising method. An adequate selection of soft energisation time as in section 9.3.2 supports the case of simultaneous energisation for both transformers.

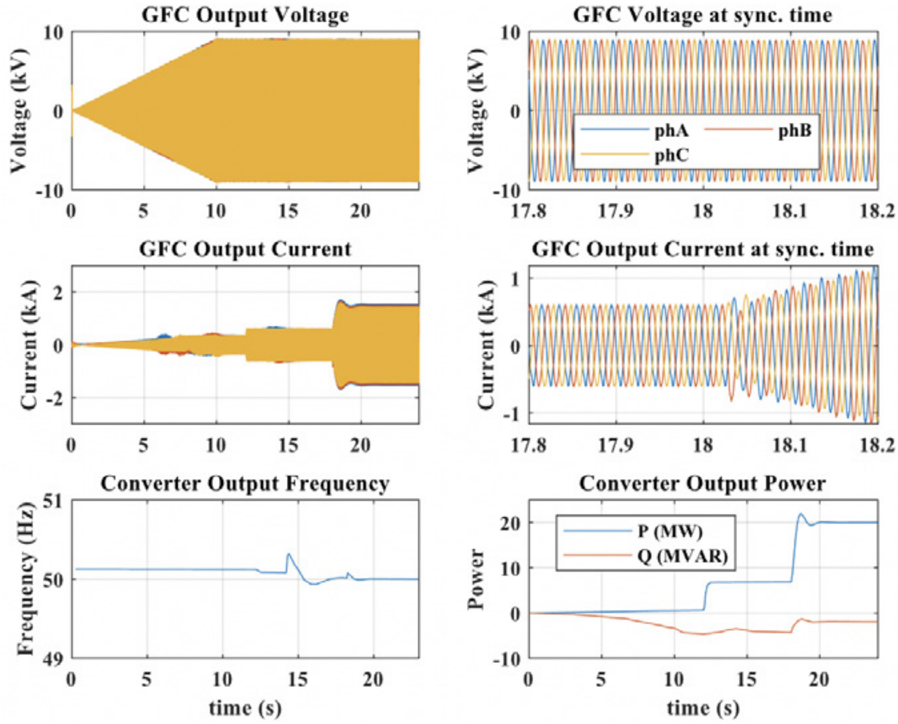


Figure 53: Chapelcross scenario soft energisation results (MV sync point)

9.4 Power Hardware in the Loop (PHiL) for GFC Black-Start application

9.4.1 PHiL overview

PHiL technique is typically utilised in power converters context to carry out investigations of physical grid-following converters that are interfaced with the real-time emulated power grid through a power amplifier, and use the voltage provided by the power amplifier to synchronise and regulate its output for grid-tied application. In this case study, as the grid-forming converter has its internal control loop to regulate voltage and frequency to energise the power network, the PHiL set-up for grid-following converter testing is not applicable as the power amplifier and the grid-forming converter regulate their voltage and frequency separately, and the lack of voltage synchronisation may lead to stability issues. The current-type ideal transformer model (I-ITM) interface is thus employed to tackle the stability issue and incorporate the grid-forming converter in the PHiL setup.

Figure 54 illustrates the block diagram of the PHiL simulation that comprises a Real Time Digital Simulator (RTDS), current-type ideal transformer model (I-ITM) interface, Triphase 15 kVA (TP15 kVA) converter operating in its current-source mode and Triphase 90 kVA (TP90 kVA) converter implemented with grid-forming control schemes. As shown in Figure 55, in the I-ITM interface based PHiL set-up, the output voltage V_abc^* of the GFC (i.e. TP90 kVA converter) is measured and fed back to the RTDS to energise the emulated power network via controllable voltage sources. On the other hand, the current I_abc^* flowing through the point of common coupling (PCC) in the simulated power network is measured and transmitted to the current-source power amplifier (i.e. TP15 kVA) as a command signal to regulate its output current. TP15 kVA is coupled with TP90 kVA by sourcing current, thus enabling the PHiL closed-loop configuration and mimicking the relative power behaviours in the emulated power network.

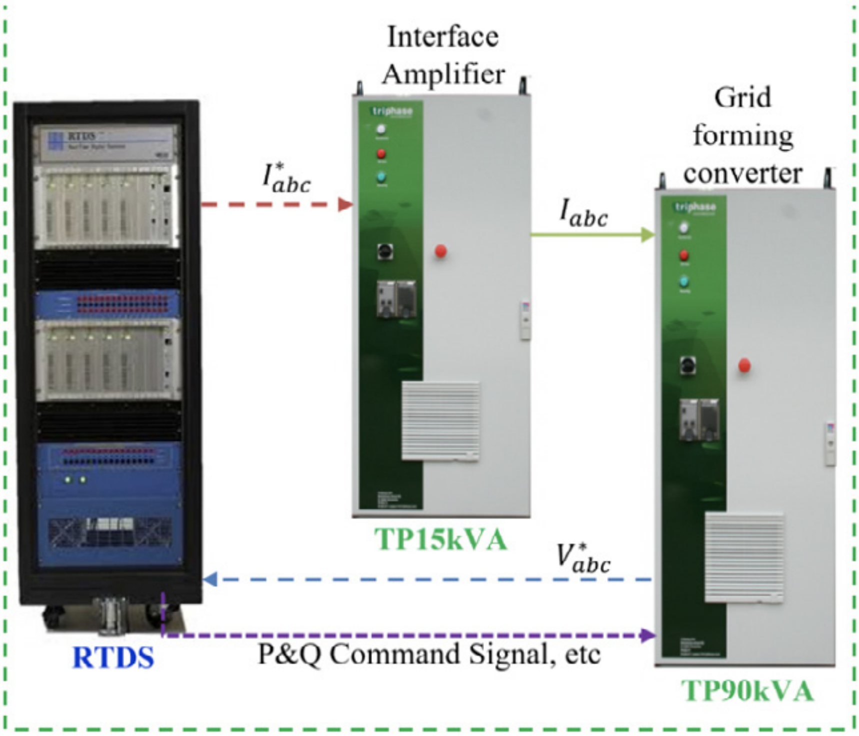


Figure 54: Block diagram of the PHiL configuration

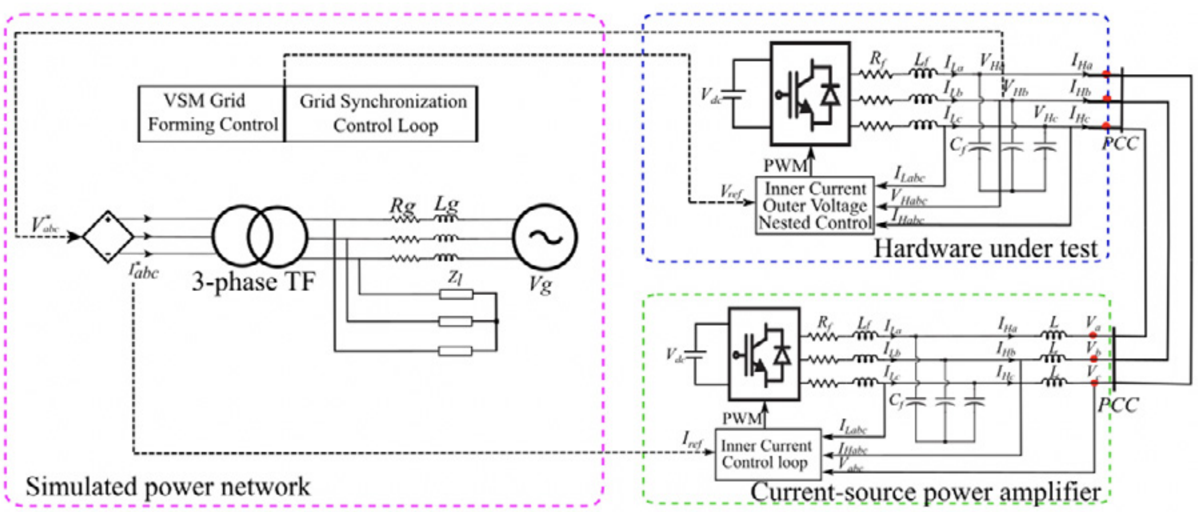


Figure 55: Circuit diagram of the emulated power network and the power converters

Due to the limited voltage levels of the TP90 kVA converter and the current constraint of the TP15 kVA current-source power amplifier, scaling ratios are employed to facilitate the capability of the power converter to be tested and to scale down the command current signal within the current constraint of the TP15 kVA converter. This represents the power converter that is emulated in the RTDS with higher power rating and voltage levels than that of the actual TP90 kVA power converter. Voltage ratio ($r\_v=27.5$) is implemented to scale up the TP90 kVA rated output voltage (0.4 kV) to a higher rated voltage (11 kV) of the controllable voltage sources in the emulated power network in RTDS. Current ratio ($r\_i=1/300$) is designed to scale down the command signal before it is sent to TP15 kVA. By doing so, the power rating of the emulated GFC at the simulation side is 8,250 times that of the actual TP90 kVA converter.

The time delay associated with the signal conversion units (e.g. ADC and DAC cards, low-pass filters designed for noise mitigation), the digital control of the power amplifier and the digital computation of RTDS inevitably degrades the PHiL closed-loop stability margins, and deteriorates the power signal synchronisation and the transparency of the power transfer between the simulation side and hardware side. As the VSM control and grid synchronisation control are dependent on accurate power measurement and voltage signal synchronisation, time delay compensation schemes are developed to facilitate the PHiL simulation and to enable a more stable and accurate closed-loop simulation environment. The dq-frame phase-shift time delay compensation scheme and the DFT based time delay compensation scheme are extensively utilised to compensate for the time delay in the PHiL setup.

9.4.2 PHiL results

The simplified network presented in Figure 46 is used as a basis for the preliminary PHiL tests to validate the hardware GFC integration for Black Start. The tests aim ultimately to achieve stable and accurate PHiL operation throughout the Black-Start process, and to identify potential challenges in the process. Hard energisation is not tested in PHiL to avoid tripping the interface current amplifier. Instead, soft energisation with t = 10 seconds is used here, followed by 40 MW load pick-up in simulation at t = 13 seconds. The used ratio scales down in real-time the 3 kA per phase in simulation when the load is connected to 10 A in hardware.

Voltage delay compensation is implemented in RSCAD to match the measured voltage phase from hardware converter with the reference control sent from RSCAD (see Figure 55), whereas current reference time delay compensation is performed in the hardware side. Figure 56 illustrates the closed-loop PHiL results for soft transformer energisation and load pick-up (from RSCAD). The voltage and current panels on the right represent a zoomed version around ramping end time (t = 10 seconds). The frequency remains close to 50 Hz throughout the test, and the measured power in simulation quickly ramps to 40 MW at load connection instant. Voltage-mode VSM is used in this test for preliminary PHiL functionality validation.

Hardware current measurements are also recorded during the test to validate the observed trends in RSCAD and the hardware current reference tracking behaviour of the interface amplifier. As illustrated in Figure 57, the scaled-down three-phase reference at ($r\_i=1/300$) is received correctly at the hardware side, and the actual measured current attempts to track the ramping trend. However, there is noisy and oscillatory behaviour throughout the voltage ramp. A disturbance is also observed in the dq current amplifier reference prior to load connection with 10 A reference, which suggests a potential impact from the hardware converter phase-locked-loop (PLL) at low and harmonic rich current values. Tackling this tracking issue and implementing stable current control and grid synchronisation as part of the integrated control are the next steps for the project PHiL investigation.

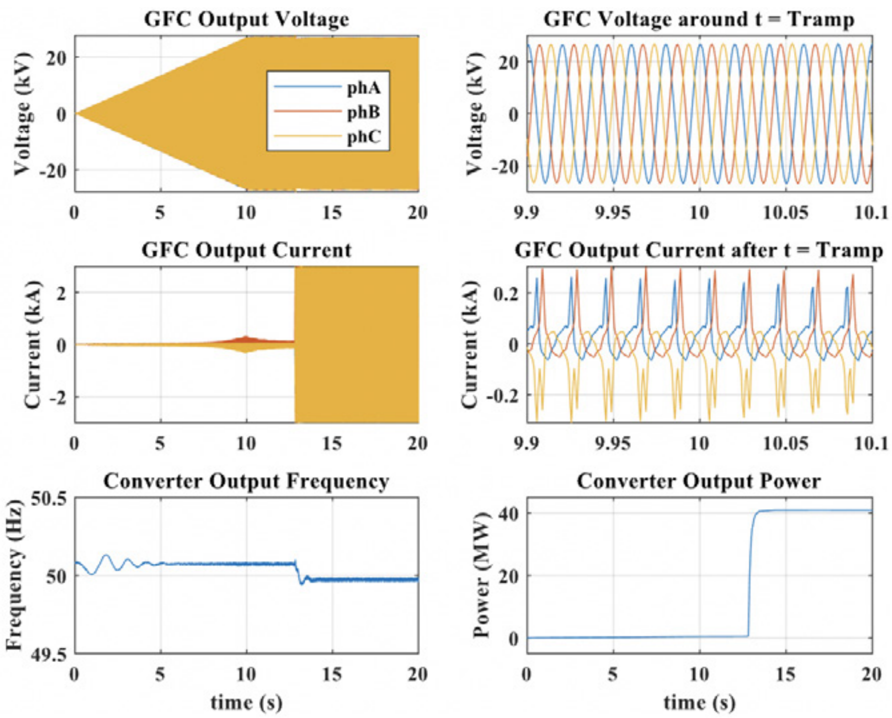


Figure 56: PHiL results (from RSCAD) for the transformer energisation and load pick-up (40 MW) steps

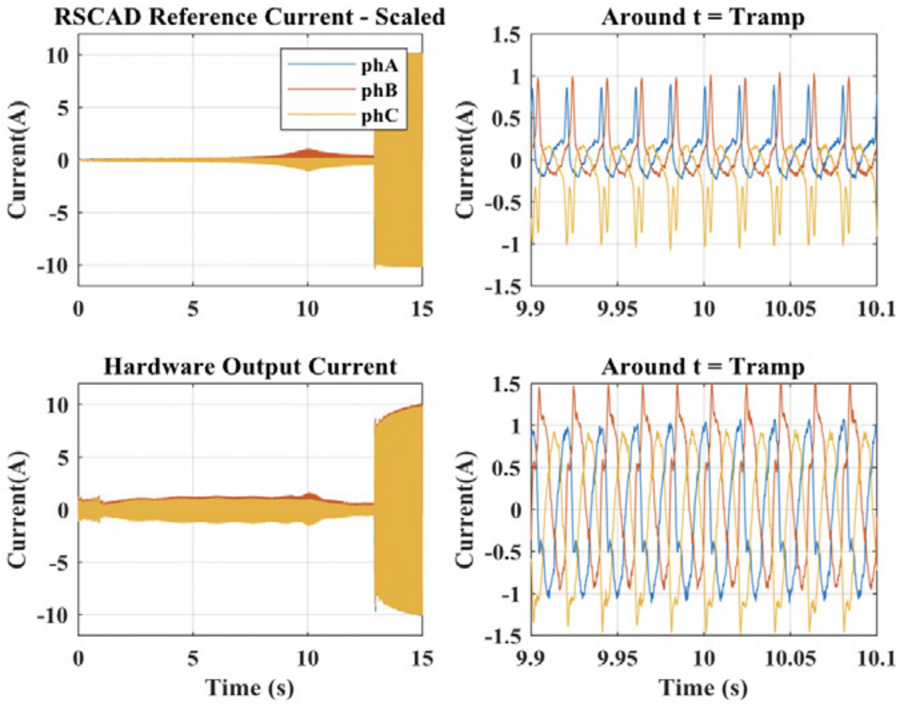


Figure 57: PHiL current reference from RSCAD vs actual hardware output current

9.5 Lessons learned and opportunities identified

9.5.1 RTDS network models exchange

Real-time digital simulator platforms utilise processor- or core-based hardware and licensing configurations. The development of models, particularly for large-scale networks, on such platforms should be paid careful attention to if the model is to be exchanged for use between multiple organisations that have different configurations and number of cores. Real-time simulators offer the capability for users to manually allocate each power system and control components to available processors or cores while reserving one or two processors or cores for network solution. However, this manual allocation makes the model exchange process difficult, as the model may not run seamlessly on the real-time simulator configuration of other organisations and would require manual modifications. It is recommended that auto-allocation of processing power is chosen – a default setting within most real-time simulators.

In this case study, multiple processors or simulator racks could be utilised to run the network simulation at the PNDC. However, this requires the use of travelling wave transmission line or cable models to split the overall model into subsystems. This process can be manually intensive and presents challenges if there are no lines already present in the model in locations that naturally split the model into equal portions from a processing requirement point of view. As an alternative, the Chapelcross network model developed using NovaCor is fragmented into smaller segments for each scenario to run on the allocated PB5 RTDS racks at the PNDC.

9.5.2 PHiL time delay compensation

Time delay is a critical determinant of the stability and accuracy of any PHiL experiment. The exchange of signals between multiple units in a closed loop PHiL configuration presents variability, most often compensated as an average value. This presents an opportunity for more precise time delay compensation methods to be developed that can be utilised to support testing of novel functionalities to support realisation of a net-zero power and energy system.

9.5.3 Internal vs external control implementation of PHiL-control

The grid-forming converter control in PHiL can be implemented either directly in the external hardware (e.g. triphase) based on internal and scaled-down measurements from the network and using the hardware control board, or internally in RTDS side based on the simulated network. In the latter case, the controller output is sent to the hardware converter to drive its components, and the physical output voltage is then sent back to the RTDS network. Table 11 summarises high-level advantages and limitations of both options as observed from this work.

Table 11: High-level PHiL control approaches

Control Type	Perceived Advantages	Perceived Limitations
Hardware Control	- Direct consideration of hardware filter dynamics with internal measurements. - Direct control implementation on the target hardware board.	- Requires access to higher number of scaled control measurements from the simulated network (e.g. for synchronisation). - More prone to variable delays.
RTDS Control	- Direct access to all control measurements in simulated network. - Direct time delay compensation for the control.	- Indirect consideration to hardware GFC filter measurements (requires additional measurement points).

9.5.4 Optical fibre vs copper wire as communications medium for signal exchange

Most real-time simulators offer two types of I/O interfaces for the exchange of signals with the power amplifier: (i) typical copper wire for analogue signal transmission or (ii) transmission through optical fibre using Aurora protocol, a serial protocol dedicated to high-speed point-to-point communication. The signals transmitted through copper wire analogue transmission present more noise than optical fibre-based communication as shown in Figure 58. The noise in the signal can cause issues with the implementation of control and its performance. Employing a low pass filter with a high cut-off frequency is typically adopted to mitigate the issue. In this PHiL case study, random frequency jumps were observed when using copper wire transmission, which resulted in consequent jumps in measured power. These jumps were eliminated when fibre transmission was used instead. Thus, signal exchange over fibre is preferable when possible.

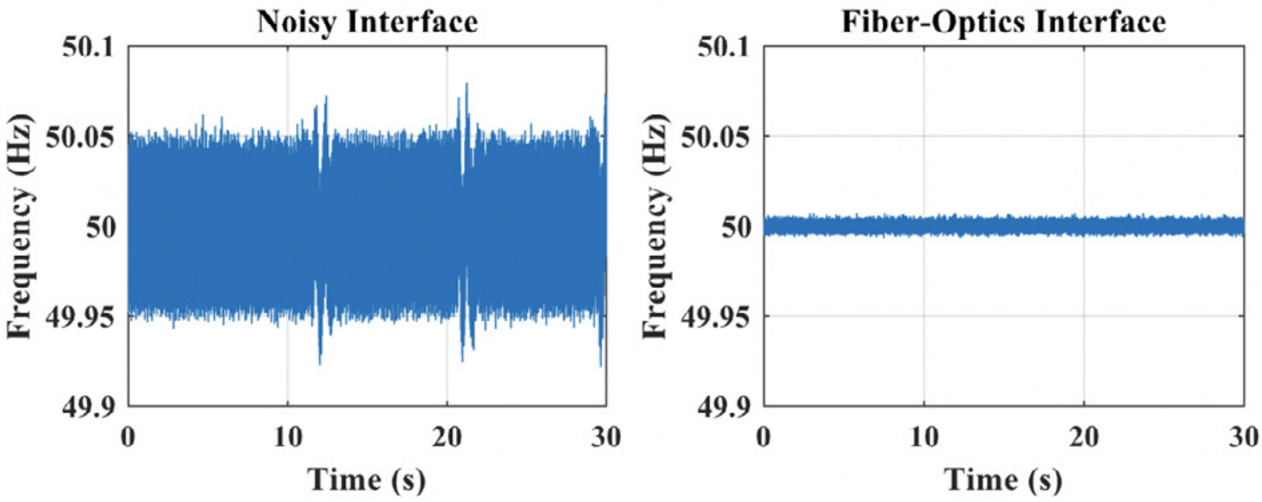


Figure 58: Frequency behaviours of the voltage signals transmitted by (a) copper wires (b) fibre link

9.5.5 Impact of numerical models and their sensitivity to signal variations

PHiL interfaces hardware and software components to form a combined network. The simulated network model in RSCAD is discretised and numerical in nature, meaning that components are represented using a set of mathematical discrete equations and approximations.

Power transformers inrush currents are correlated to core flux values in most power system simulators, and the flux is estimated by integrating the winding voltages. Small mismatches introduced by analogue to digital conversion can thus lead to creating an offset which can influence the flux integrator, thus overestimating the resulting inrush current.

This was observed in the present PHiL study when input transformer voltages had a non-zero variable average creating a less than 0.2 per cent offset, which was sufficient to produce 20 times the steady-state peak converter current (700–800 A instead of 39 A peak). In the shorter term, a solution is devised based on signal processing to compensate the offset by subtracting the moving average from the received voltage, restoring the PHiL magnetising current to its nominal range (see Figure 59). Further investigation is recommended to provide more insights on the sources and remedies of this phenomenon.

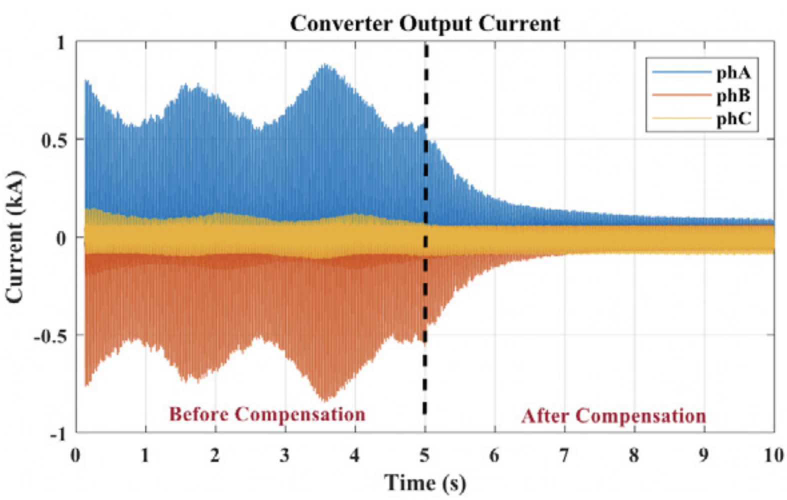


Figure 59: Comparison between magnetising current before and after A/D impact compensation on input voltage

9.6 Conclusions

This report presented simulations and PHiL results of GFCs used for Black-Start applications. Simulation results using RSCAD software were first used to successfully validate the model. Following this, a RSCAD model for the Chapelcross live trial network, developed by the HVDC centre, was used to test Black Start a section of the network segment, replacing the 33 kV synchronous generator (Steven's Croft) with an average model GFC.

Hard energisation – Simulation results show that using hard energisation, with 0.8, 0, -0.8 pu residual flux in the 11/33 kV and 33/132 kV transformers phases resulted in excessive inrush currents beyond these transformer rating undervoltage and current control scenarios. Setting converter current control limits to lower peak inrush currents may be implemented at the expense of larger voltage disturbances. Live trials would be required to verify if this energisation strategy was viable as protection would have to be set to avoid hardware damage and may result in disconnecting the converter.

Soft energisation – A 10-seconds voltage ramp was observed to significantly reduce inrush currents, even when energising both main transformers and the earthing transformers simultaneously. Grid synchronisation using a modified control was also tested, and successful connection to the 132 kV simulated grid was achieved under different scenarios. Notably, varying the network model assumptions could influence the reported quantified results though the observed soft energisation impact remains valid.

PHiL hardware – Software interface technique was also tested with the aim to investigate its capabilities and understand its challenges and limitations. Current-type ideal transformer method (I-ITM) was used for the interface at the DPSL. Stable closed-loop operation was observed when using the simplified RSCAD network model for Black Start in terms of soft energising the simulated transformer and picking up simulated load, however there are tracking mismatches for the hardware current when low current references are applied. Further investigation is planned first to validate stable operation of grid synchronisation in closed-loop PHiL for the simplified network and to investigate different control implementation options, in addition to transformer energisation. Then, it is planned to expand the PHiL technique investigation into Chapelcross network elements at the PNDC, where work is currently ongoing by the PNDC team to validate the hardware converters and RTDS units' readiness at the facility for these tests.

The presented and planned studies are among the first trials to test GFC operation for Black Start with PHiL techniques. The lessons learned so far present interesting opportunities to be explored in terms of improving the GFC-PHiL interface, and the GFC control robustness in response to practical network conditions and variations. Collectively, the outcomes of this project should contribute to answering the question of the added benefits from using PHiL as a complementary tool to pure simulations in validating novel functionalities of power electronic devices.

9.7 Relevant publications

[1] A. Alassi, K. Ahmed, A. Egea-Àlvarez and O. Ellabban, "Innovative Energy Management System for MVDC Networks with Black-Start Capabilities", Energies, vol. 14, no. 8, 2021.

[2] Z. Feng et al., "A Scheme to Improve the Stability and Accuracy of Power Hardware-in-the-Loop Simulation", in IECON 2020 The 46th Annual Conference of the IEEE Industrial Electronics Society, 18–21 Oct. 2020 2020, pp. 5,027–5,032.

[3 A. Alassi, K. Ahmed, A. Egea-Alvarez and C. Foote, "Soft Transformer Energization: Ramping Time Estimation Method for Inrush Current Mitigation", in 2021 56th UPEC Conference, 31 Aug.–3 Sept. 2021 2021, pp. 1–6.

[4] A. Alassi, K. Ahmed, A. Egea-Alvarez and C. Foote, "Modified Grid-forming Converter Control for Black-Start and Grid-Synchronization Applications", in 2021 56th UPEC Conference, 31 Aug.–3 Sept. 2021 2021, pp. 1–5.

[5] M. H. Syed, E. Guillo-Sansano, S. M. Blair, A. Avras and G. M. Burt, "Synchronous reference frame interface for geographically distributed real-time simulations", IET Generation, Transmission & Distribution, https://doi.org/10.1049/iet-gtd.2020.0441 vol. 14, no. 23, pp. 5,428–5,438, 2020/12/01 2020.

10 Dersalloch Wind Farm – VSM Live Tests

This chapter provides a summary of the Dersalloch VSM Black Start trials completed by SP Energy Networks, ScottishPower Renewables and Siemens Gamesa Renewable Energy.

10.1 Introduction

Using an advanced 'grid-forming' (GF) converter control scheme called Virtual Synchronous Machine (VSM), a world-first Black Start network trial from a wind farm was successfully completed during October 2020 by SP Energy Networks, in partnership with ScottishPower Renewables (SPR) and Siemens Gamesa Renewable Energy (SGRE).

The wind farm used for testing was Dersalloch 69 MW site in Ayrshire, Scotland, consisting of twenty-three 3 MW direct-drive full-converter turbines, owned by SPR, supplied by SGRE and connected to the SP Energy Networks transmission network. While this project was not delivered directly under the Distributed ReStart project, and supported separately through the Scottish Government via the Low Carbon Infrastructure Transition Programme, an agreement has been made by all parties that the learning is highly relevant to this project and should be disseminated through the Power Engineering and Trials workstream live trials report.

10.2 Trial overview

Successful trials were completed by SPR and SGRE in 2019 to demonstrate further benefits of the VSM control algorithm in proving an inertial response to frequency events on the transmission network. Within 2020 the trials sought to prove that the wind park could autonomously operate in an islanded mode (IMO), and demonstrate the ability of a smaller number of GF turbines in IMO to support a large number of Wind Turbine Generators (WTGs) operating in conventional grid-following current control mode. The wind park was then able to demonstrate a re-synchronisation from islanded to grid-connected at the park boundary with the transmission network.

Further trials were then scoped to demonstrate Black Start capability, with the GF algorithm having the ability to generate its own independent voltage source. Initially this was demonstrated within Dersalloch network and then to energise sections of the transmission network to 132 kV (90 MVA grid transformer) and 275 kV (240 MVA super-grid transformer) to New Cumnock. Re-synchronisation of the islanded network would be attempted at New Cumnock 132 kV. This section provides an overview of the network Black Start energisation testing.

10.2.1 Black Start turbines

To achieve Black Start capability, four individual turbine converters were equipped with the GF algorithm, and external 125 kVA diesel gensets were connected to provide supply to their auxiliary loads in order to self-start; as shown in Figure 62, turbines A1, A2, B9 and C17 were selected. The remaining turbines within the wind park were run in the conventional 'grid-following' current control algorithm. This number of turbines were selected as in combination there is enough reactive power capacity to cover the requirements for the wind park network, plus the Grid 1 90 MVA 33/132 kV transformer, connecting 10 km overhead line and cable and the 240 MVA 132/275 kV super-grid transformer. Figure 63 displays the connecting network to New Cumnock 275 kV.

The Black Start GF procedure implemented a ramped approach to turbine energisation; this 'soft start' ramping process softens inrush effects of network energisation and allows a reduced number of turbines to energise a relatively large network. The technique ramped the turbine terminal voltage from zero to 1 pu over a period of 14.25 s.

Further test equipment was required in the form of a controllable flexible 7 MVA load bank, 0.95 pf both capacitively and inductively. The load bank was connected at LV via a step-down transformer. A remote-control device was used by the on-site operator to change the load bank value in real time in response to requests from the test team.

10.2.2 Protection

Similarly to the trials described within earlier sections, it is expected that the network protection would have limited coverage due to the reduced fault in-feed during testing. This was further reduced due to the turbine fault in-feed restricted by the converter limits and by implementing a ramped approach to network energisation. Both SPR and SPEN performed a full review of respective network protection prior to the trials.

WF Protection
The following were conclusions drawn on undetected faults from a protection assessment on the SPR network for Black Start testing and mitigations put in place for the limited coverage.

- MV three phase (LLL) faults with 23 WTGs (wind farm network).

Undetected by overcurrent protection due to low WTGs fault current infeed. Risk assessment analysing network design, age of assets and operational history concluded that the probability of an LLL fault occurring is very low and it is acceptable to operate with this risk for short periods of time.

- LV LLL faults with 1 or 23 WTGs (WTG LV network).

Undetected when there is 1 WTG as a local LV LLL fault would be seen as a load and would continue to feed the fault; with 23 WTGS connected again a LV LLL fault would appear as additional load to the WTGs. The protection design implemented at construction is such that the WTG transformer and 690 V cable are protected as one 'unit' with no LV breaking device between the cable to the WTGs and WTG external transformer. The mitigation strategy used was SGRE would monitor the WTG outputs for any commanded change.

- LV LLL faults with 1 WTG (auxiliary systems load).

Undetected due to the lack of fault current. This fault was mitigated by removing the auxiliary transformer from service during testing and using the LV back-up supply from the local distribution network.

SPEN Network Protection
An assessment of the transmission network protection concluded that there is insufficient current to set any of the existing protection during the voltage ramp sequence to provide coverage and limited coverage could be expected with minimum setting selected on existing relay functions with four WTGs in service at 1.0 pu voltage. By implementing an additional voltage controlled overcurrent (VCOC) function within the circuit at Grid 1, this would provide coverage from 4.5 s during the ramp with three WTGs in service. This is shown below in Figure 60.

In order to provide provisions for assurance of safety during the trial with no protection coverage on any transmission asset during the initial 4.5 seconds of ramp, a comprehensive review of risks and suitable mitigations was completed. A review of asset records and inspection reports to identify any defects concluded with the assets relatively new (oldest asset commissioned 2014) none were reported.

It was perceived that the highest risk for a fault to occur would involve live conductors like OHL/busbars; due to the network arrangement and design geometry, it was considered that an SLG fault be most probable. Assuming the risk inside substation compounds could be managed by qualified operations staff, the highest risk of fault and potential impact on this party would be along the 132 kV OHL route to New Cumnock, particularly where crossing public roads (A713), public paths or fields with agricultural activities taking place. The testing would be carried out during fair weather; hence, faults relating to bad weather be considered relatively low.

A subsequent ALARP (as low as reasonably practicable) assessment was completed based on the OHL section with probability of failure from CBRM, with the risk an acceptable level when exposure is less than 5 minutes. In order to further remove third party risk, operations staff were positioned at strategic locations along the route with real-time communication channels established between all participating parties. Further to this, manually operated emergency trip facilities will be provided by SPEN at Dersalloch 132 kV, New Cumnock 275 kV and SPR at Dersalloch wind farm. It was there deemed acceptable all potential risks had been evaluated with suitable mitigation implemented to proceed with the network trials.

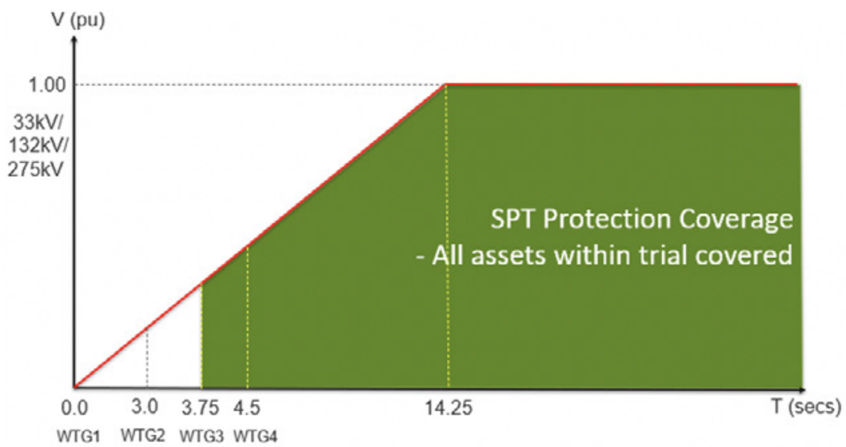


Figure 60: VCOC protection coverage from three WTGs in service during ramp

10.3 Network schematics

The following diagrams are provided to give an understanding of the Dersalloch–New Cumnock test network:
Figure 61: Dersalloch wind farm network and 132 kV connection to New Cumnock.
Figure 62: New Cumnock 132 and 275 kV network.

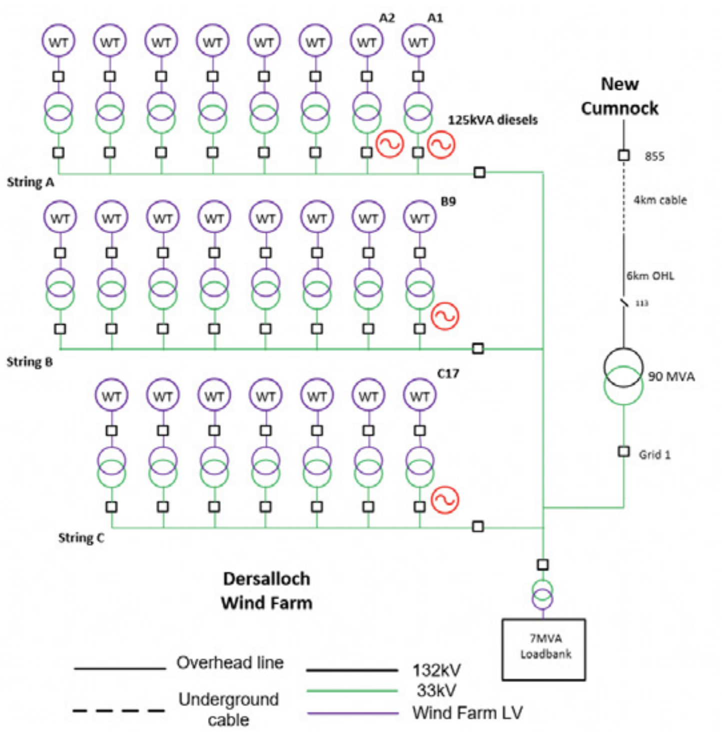


Figure 61: Dersalloch wind farm network and SPEN network to New Cumnock 132 kV

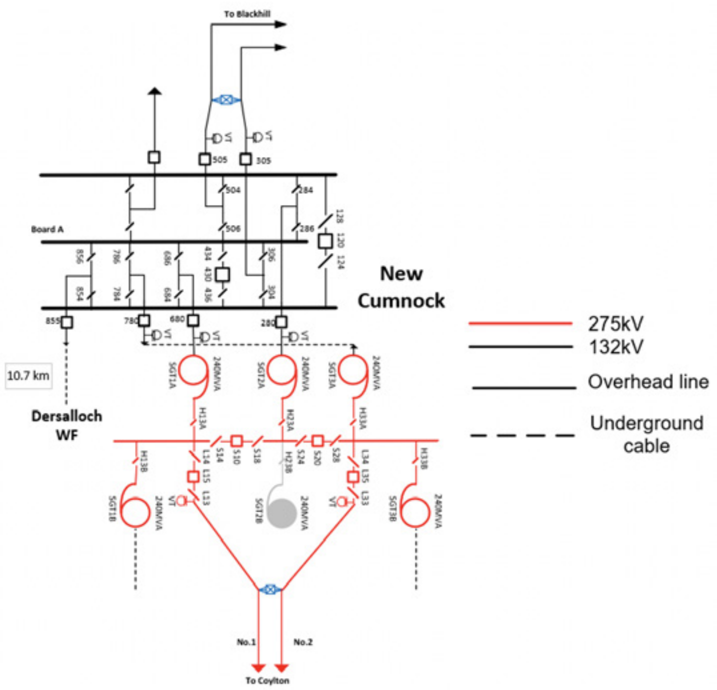


Figure 62: New Cumnock 132 & 275 kV network test results

10.3.1 Black Start ramp to HV 132/33 kV 90 MVA grid transformer

The energised network is displayed in Figure 63, showing the four WTGs and open 132 kV disconnector (113) on the HV side of the Grid 1 90 MVA transformer. In order to reduce the 132 kV voltage level, Grid 1 90 MVA was tapped up to 13 (nominal) from its normal running arrangement. With no 132 kV VT within the energised network, SPT measurements were taken at the LV side of the grid transformer at 33 kV. The network included 500 kW resistive loading for damping.

The ramp was successful with 33.2 kV measured on the SPT network, the island was maintained for 7 minutes for data gathering and the voltage was seen to rise to 33.4 kV by the end of energised testing period.

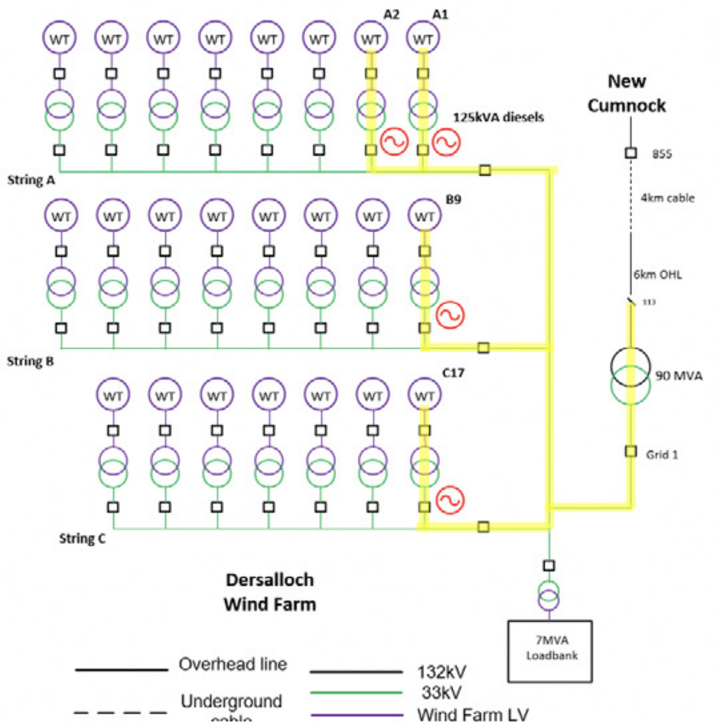


Figure 63: Energised network – WF ramp to disconnector 113

Figure 64 below displays measurement data obtained from the 33 kV side of the Dersalloch Grid 1 90 MVA transformer during the ramping procedure up to nominal voltage.

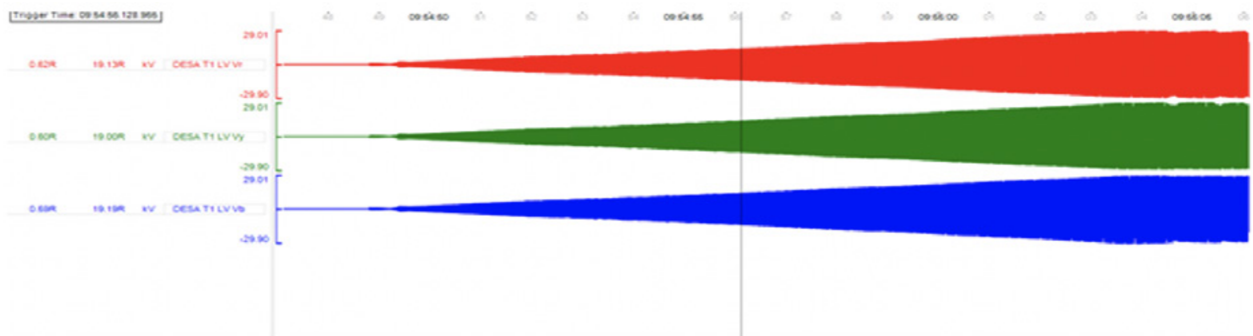


Figure 64: Voltage ramp profile on the 33 kV side of Dersalloch Grid 1 90 MVA transformer

Figure 65 and Figure 66 below display the measured harmonic components during the middle and end of the voltage ramp, with pronounced 6th and 7th harmonic orders.

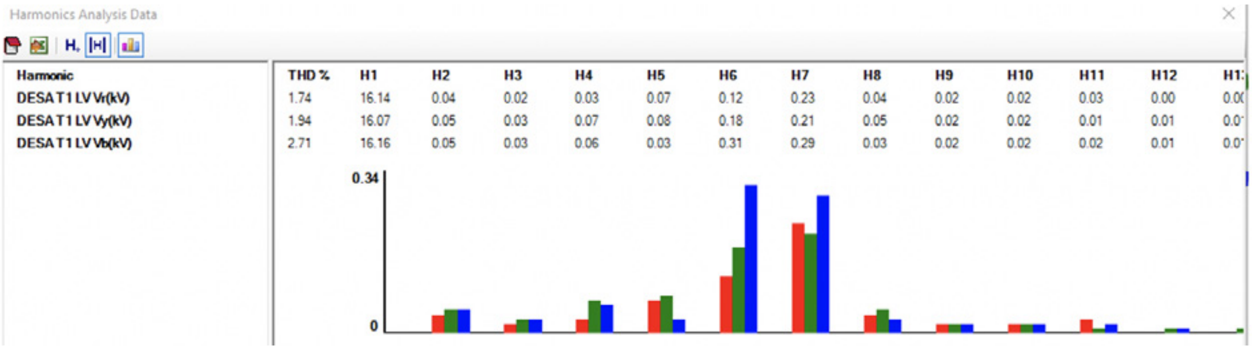


Figure 65: Harmonic components at middle of the voltage ramp

Figure 66: Harmonic components at the end of the voltage ramp

The ramped energisation was completed successfully three times; a comparison of the measured voltage and current profiles for the test are displayed below in Figure 67 and Figure 68.

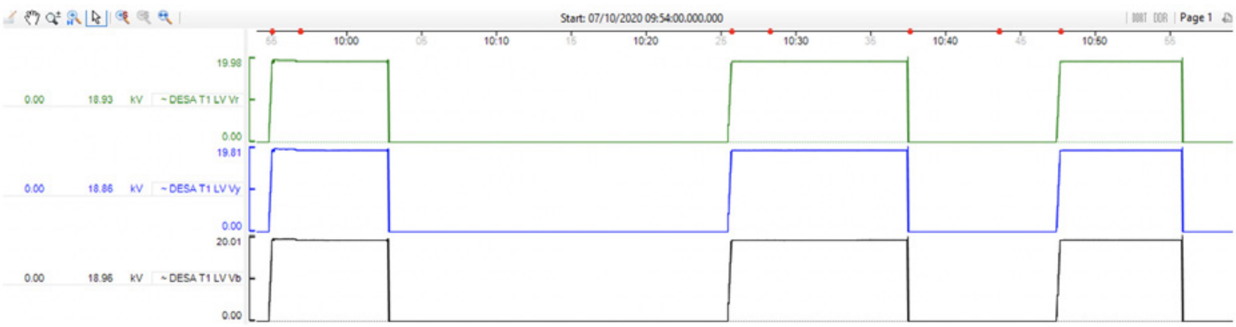


Figure 67: Voltage profiles for three ramp tests

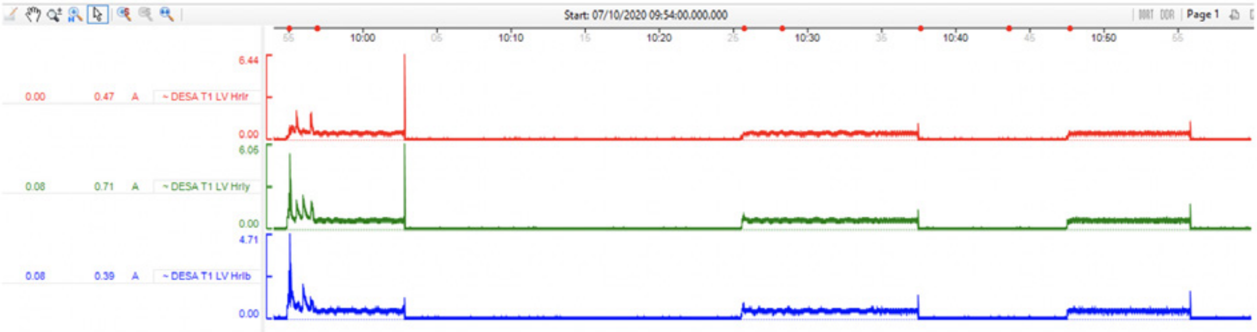


Figure 68: Current profile for three ramp tests

10.3.2 Black Start ramp to 132 kV New Cumnock

The energised network is displayed in Figure 69, showing the four WTGs and connecting overhead line and cable circuit to CB855 at New Cumnock 132 kV substation. This line introduced an additional 6.4 Mvar capacitance from cable energisation, which represents approximately 1.6 Mvar per turbine.

The ramped energisations were attempted several times with alternating Grid 1 tap positions to lower the 132 kV voltage level. The network stability was seen to be significantly improved with the addition of 1 MW resistive load, to provide additional damping at harmonic frequencies, and 6 Mvar reactive loading within the wind park network.

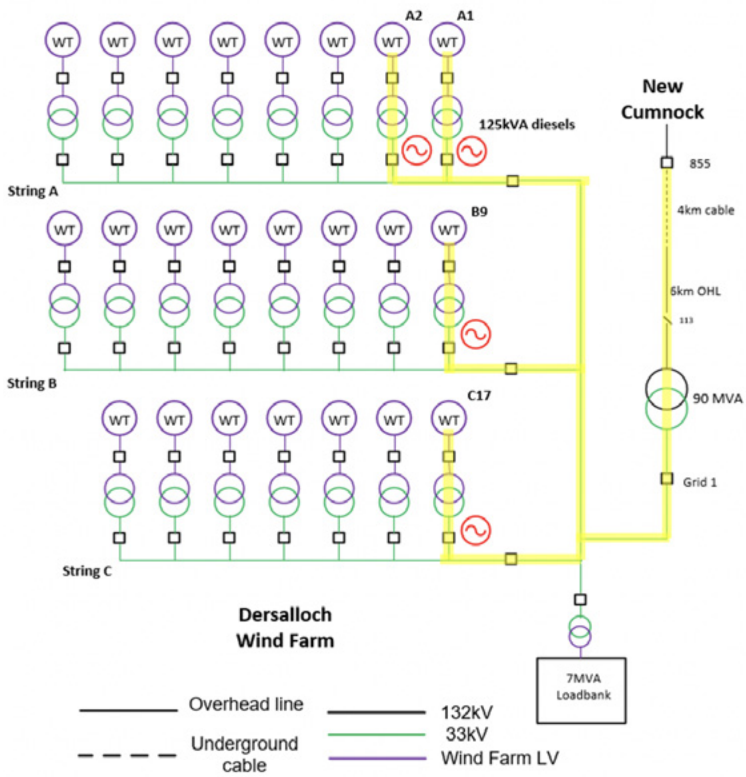


Figure 69: Energised network – WF ramp to CB855 132 kV

Figure 70 displays the 132 kV voltage profile at New Cumnock during the ramp, at 122 kV; Figure 71 and Figure 72 display the 33 kV voltage and current profile taken at the 33 kV side of Grid 1 90 MVA transformer, at 0.96 pu.

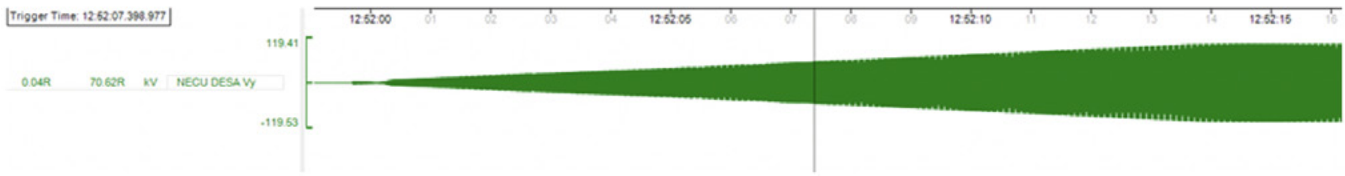


Figure 70: New Cumnock 132 kV voltage profile

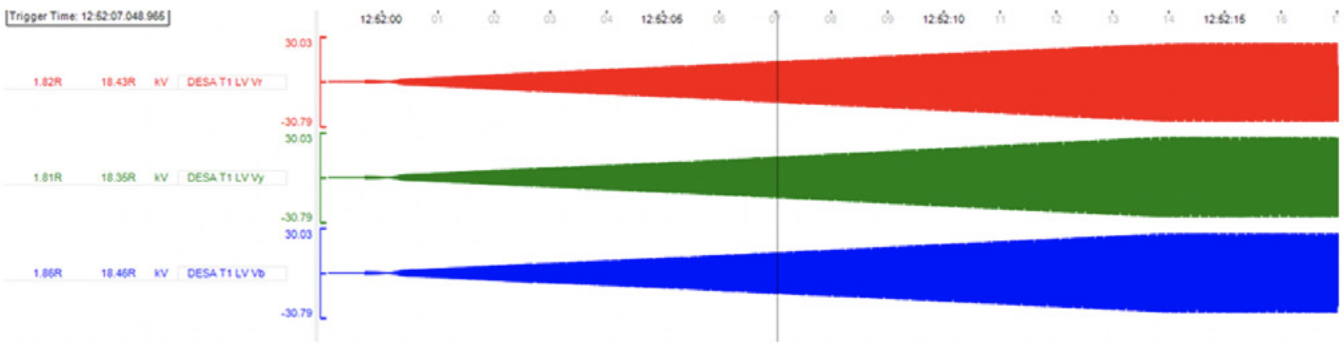


Figure 71: Dersalloch Grid T1 voltage profile

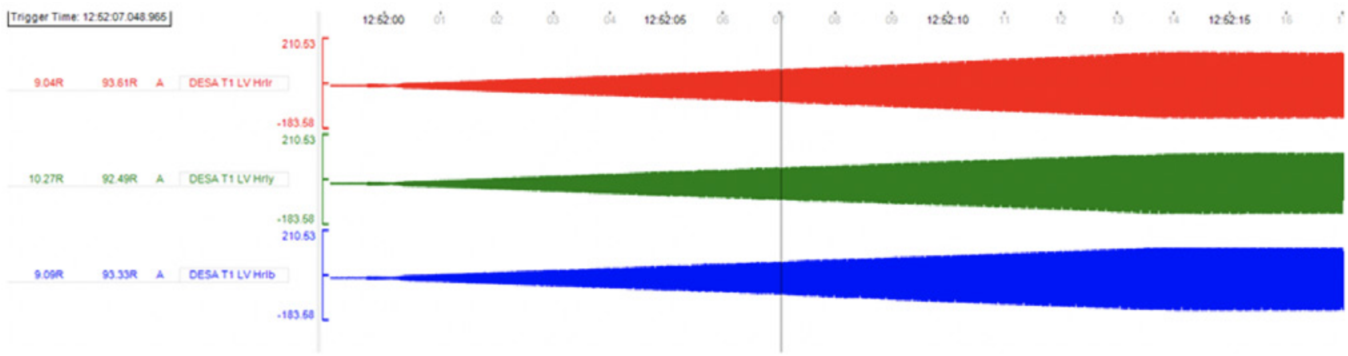


Figure 72: Dersalloch Grid T1 current profile

10.3.3 Re-synchronisation at 132 kV

Upon successful energisation, once the islanded network was stable a re-synchronisation process across CB855 using a sync check relay was completed. Once the system was confirmed to have no overvoltages activating the surge arrestors on the 132 kV system, then the voltage setpoint of the wind park was adjusted to get a close match across CB855 to a difference of less than 0.1 per cent, within both the capability of the WTGs to withstand and the accuracy limits of the measurement transformers.

Similarly, the frequency setpoint on the wind park was adjusted to operate at 50 Hz; however, controlled matching was not possible as the wind park does not have closed loop frequency across CB855. The synchronisation angle was approximately 5.6°, shown in Figure 73, and the brief transient due to the phase step at each WTG approached 1 pu VA.

Figures 73, 74 and 75 display data related to the wind park voltage, frequency and reactive power output during the resynchronisation.

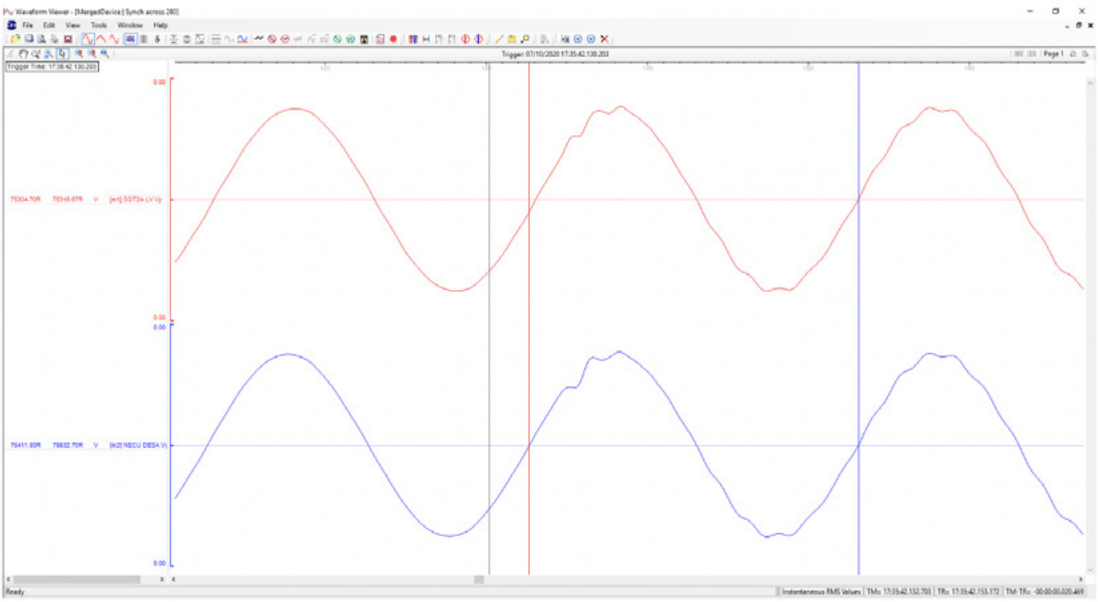


Figure 73: 132 kV resynchronisation @ 5.6°

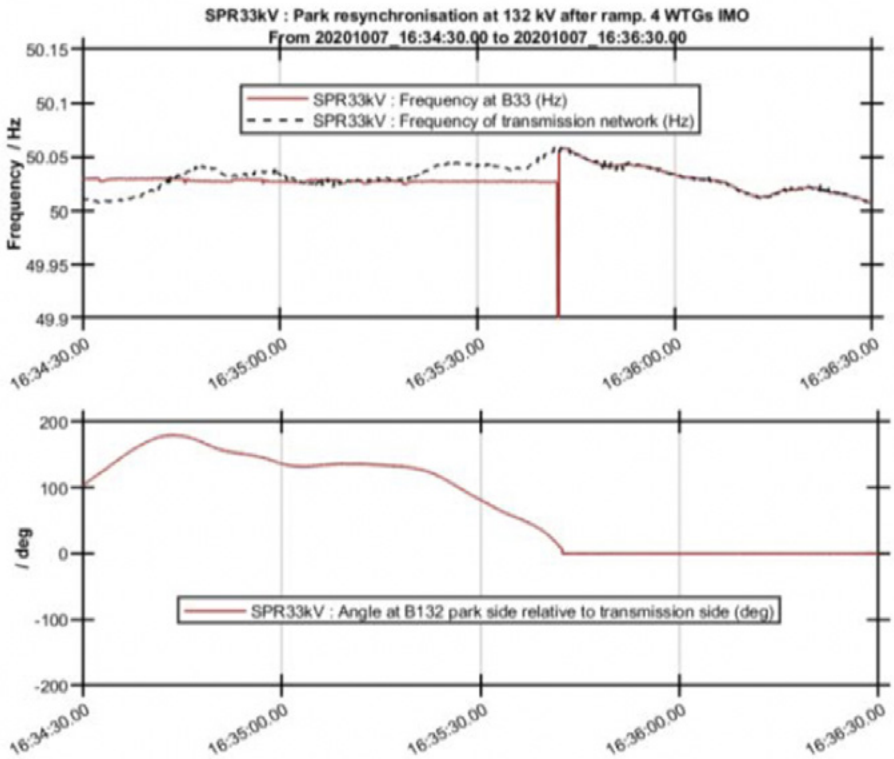


Figure 74: Wind park island network frequency, Bottom: Phase angle difference between grid and island

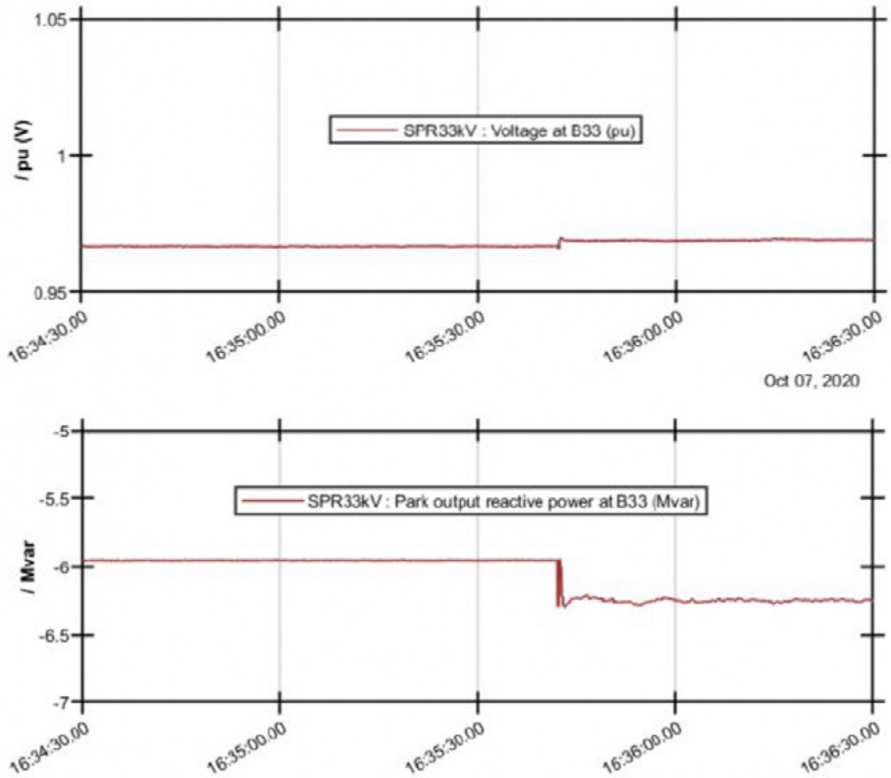


Figure 75: Top: Wind park 33 kV voltage, Bottom: Wind park reactive power output

10.3.4 Black Start ramp to 275 kV New Cumnock

The energised network is displayed in Figure 76, showing the connecting network at New Cumnock 275 kV and SGT2A. 1 MW of resistive loading was added to the wind park network, and in order to reduce the HV voltage, Grid 1 was placed at tap position 18 and SGT2A at tap 1.

Figure 77 to Figure 79 display the data obtained from the SPT network. As can be observed the 33 kV voltage ramped to 0.99 pu, while 132 kV and 275 kV voltages were 0.93 pu due to an applied -8 per cent tap setting at the HV winding of the 90 MVA transformer. Figure 80 displays the wind park data obtained for the voltage magnitude, reactive power and harmonic components during the energisation.

Upon successful energisation and stabilisation of the island, the remaining turbines within the wind park were energised to increase the strength and resilience of the network, increasing fault levels and enabling further protection coverage. The transformer tap positions were then altered to achieve nominal voltage at both 132 kV and 275 kV.

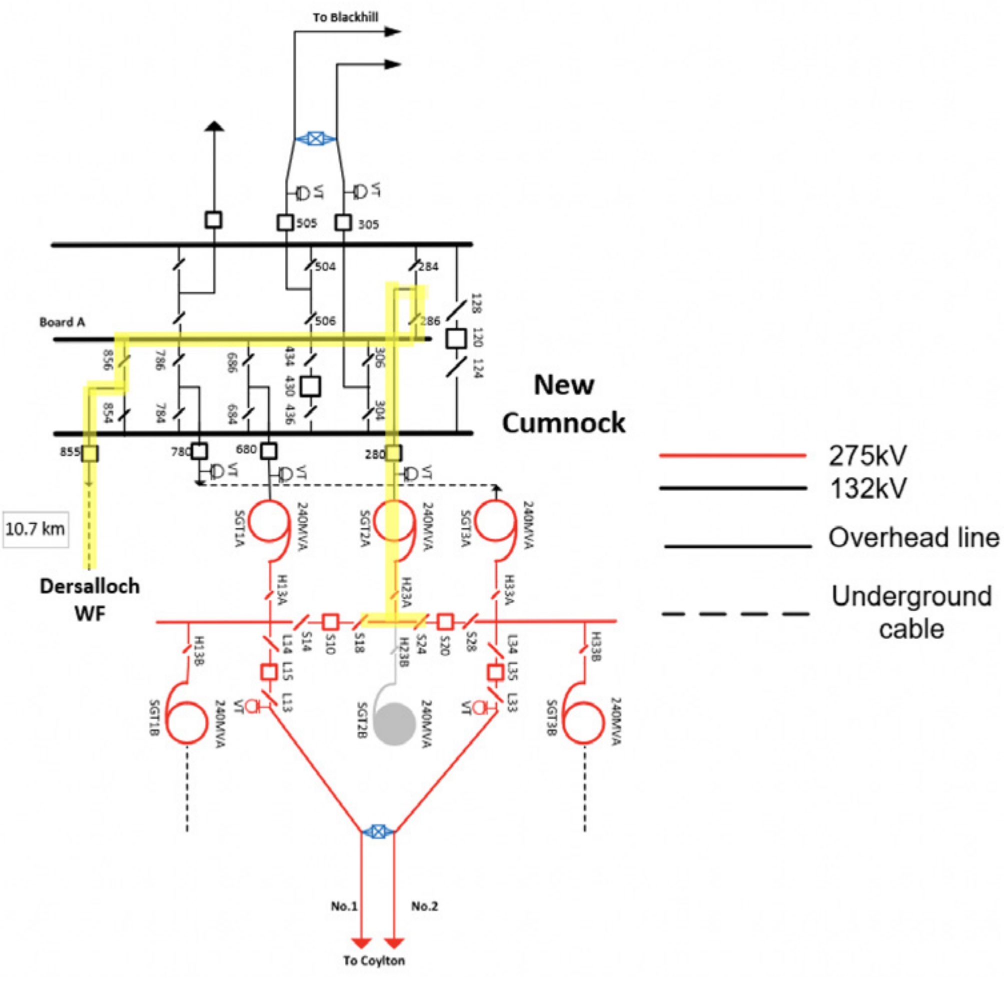


Figure 76: Energised network – WF ramp to New Cumnock 275 kV

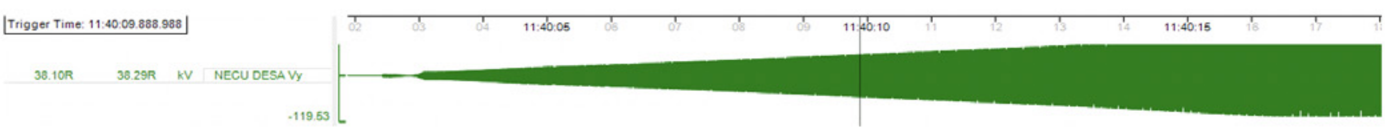


Figure 77: NECU-DESA HV voltage profile

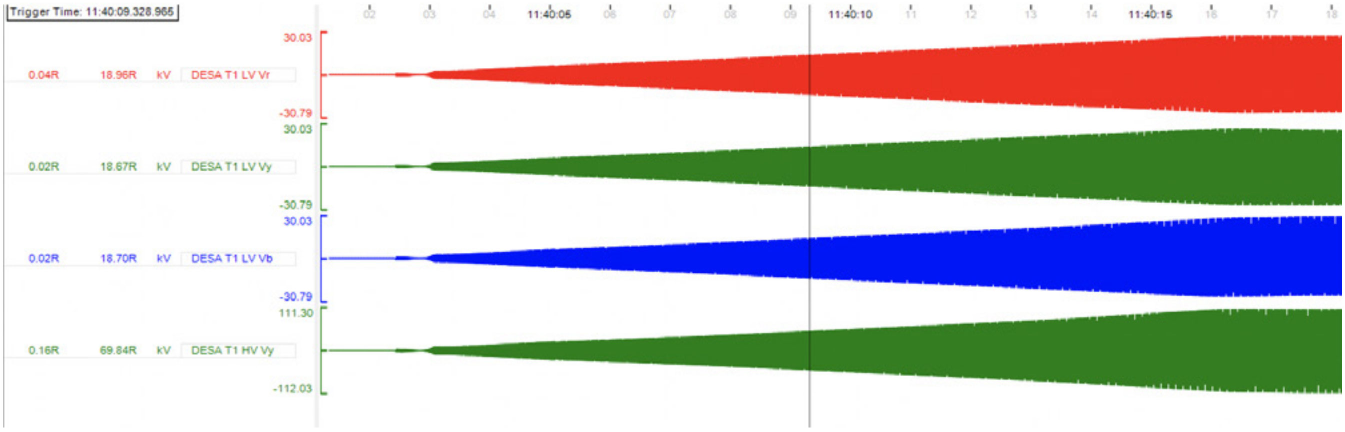


Figure 78: Dersalloch Grid 1 HV and LV voltage profiles

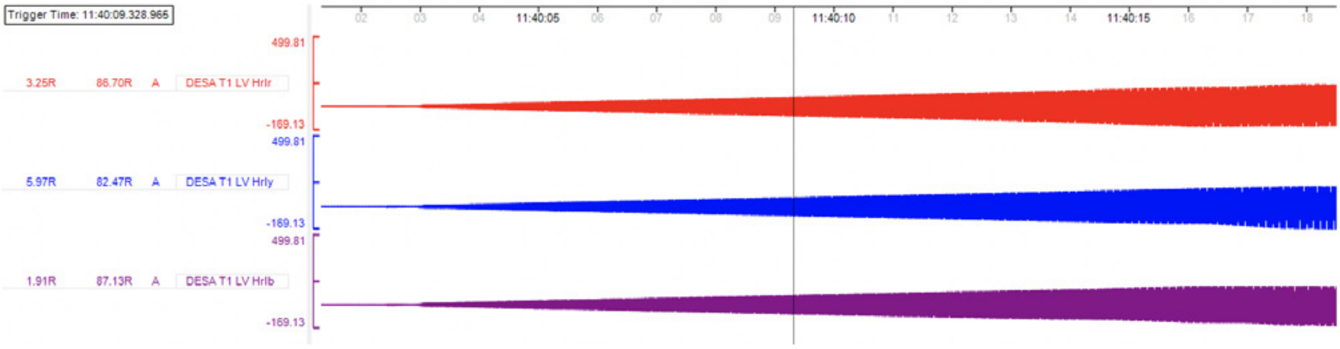


Figure 79: Dersalloch LV current profiles

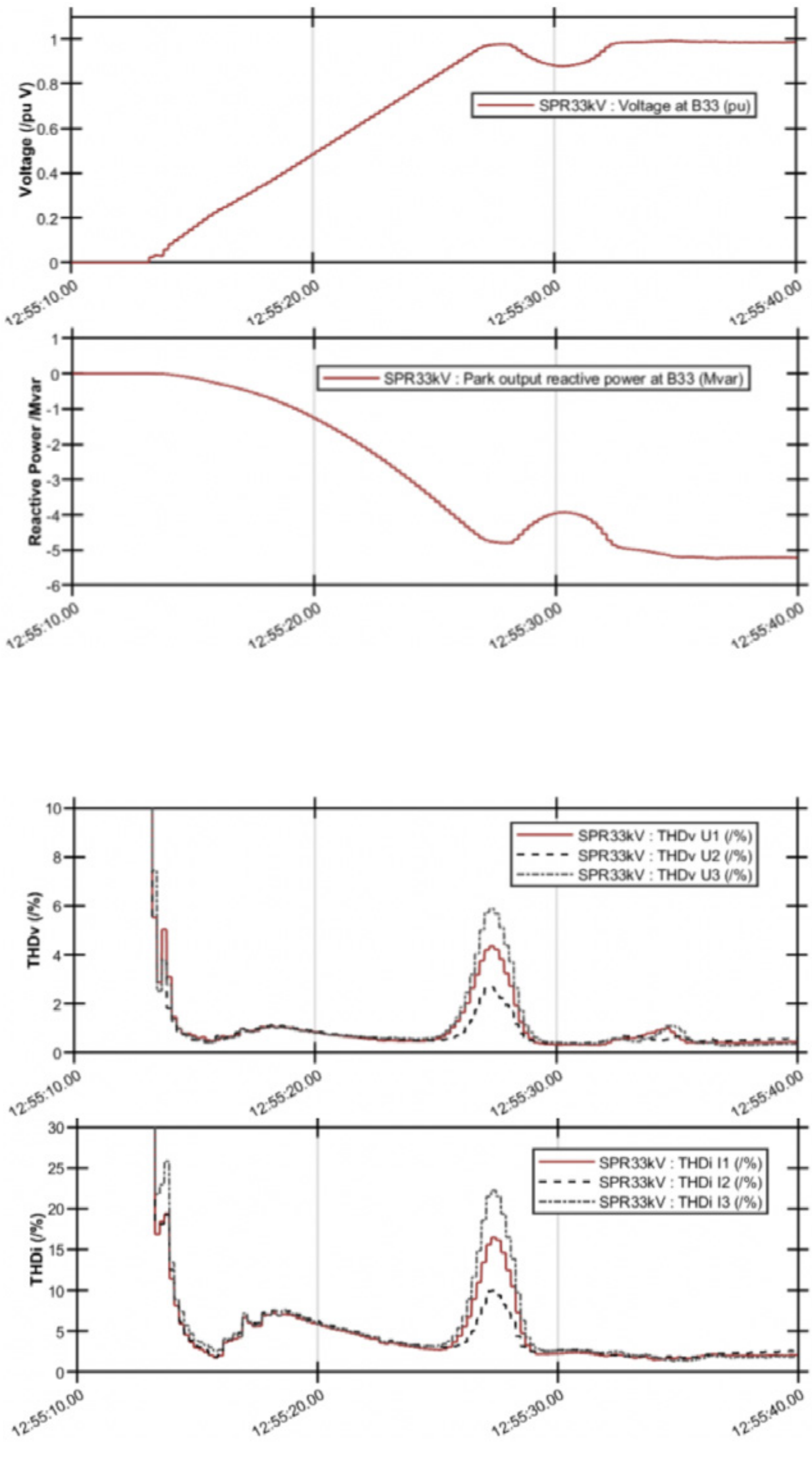


Figure 80: Wind park voltage magnitude, reactive power, THDv and THDi during ramped energisation

10.3.5 Black Start DOL to 275 kV New Cumnock

Due to the successful energisations using the soft ramped approach, similar energisations of the network to 275 kV at New Cumnock were attempted using the traditional direct-on-line (DOL) method to energise grid transformers. Several advantages can be drawn from this approach with more turbines online before upstream energisation, offering improved robustness after the DOL initial transient and increased fault current for protection coverage on the network while also minimising the protection coverage cap during energisation. However the DOL method does require a much larger current to be drawn from the turbines due to the significant inrush current when energising the transformers, and additional turbines required to provide this.

The energised network is the same as previous, and shown in Figure 69 and Figure 76. Similarly, transformer tap positions were selected to reduce 132 kV (-10 per cent) and 275 kV (-15 per cent) voltages, and the 33 kV wind park voltage at 93 per cent to minimise inrush. Results showed this to be successful, with no noticeable inrush witnessed on DOL energisation of the grid transformers. Upon stabilisation of the network, both grid transformers were returned to nominal, bringing the 175 kV voltage up to 0.97 pu. Figure 81 to Figure 83 display the 132 kV New Cumnock voltage profile and Dersalloch Grid 1 33 kV voltage and current profile.

Subsequent DOL energisation was performed with 0.98 pu 33 kV wind park voltage and -10 per cent Grid 1 transformer voltage initial tapping; once stable the Grid 1 transformer was tapped back to nominal. The 240 MVA SGT2A was then energised at nominal tap, resulting in large inrush currents. Data obtained from the wind park network is shown in Figure 84. This energisation process was repeated several times to demonstrate robustness.

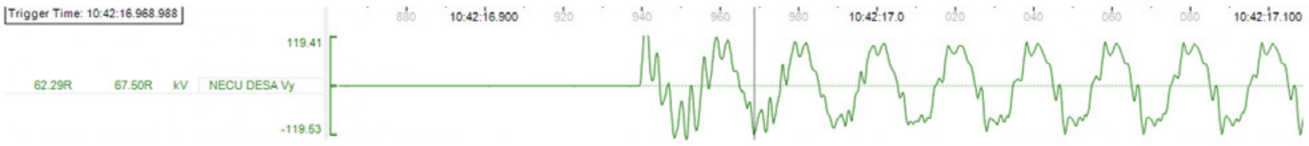


Figure 81: New Cumnock 132 kV voltage profile

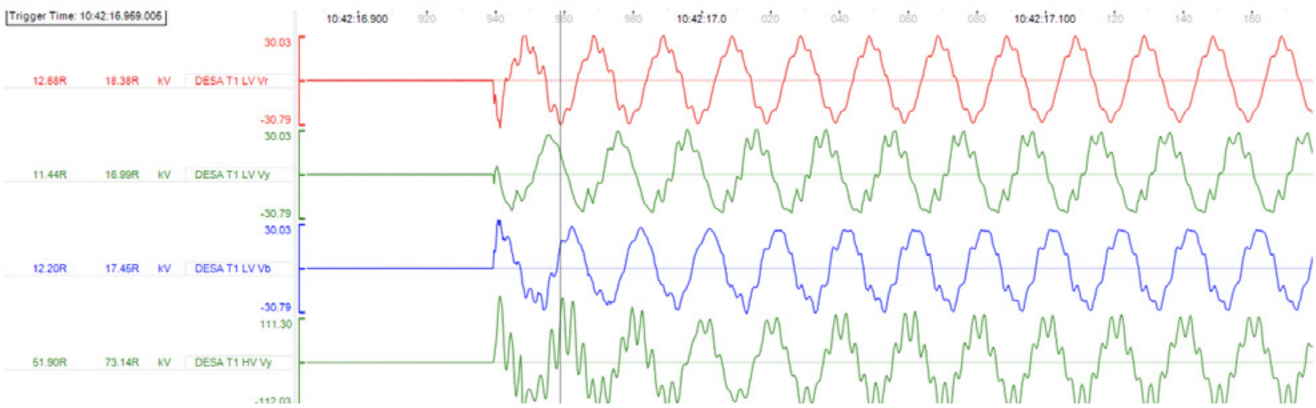


Figure 82: Dersalloch Grid 1 LV voltage profile

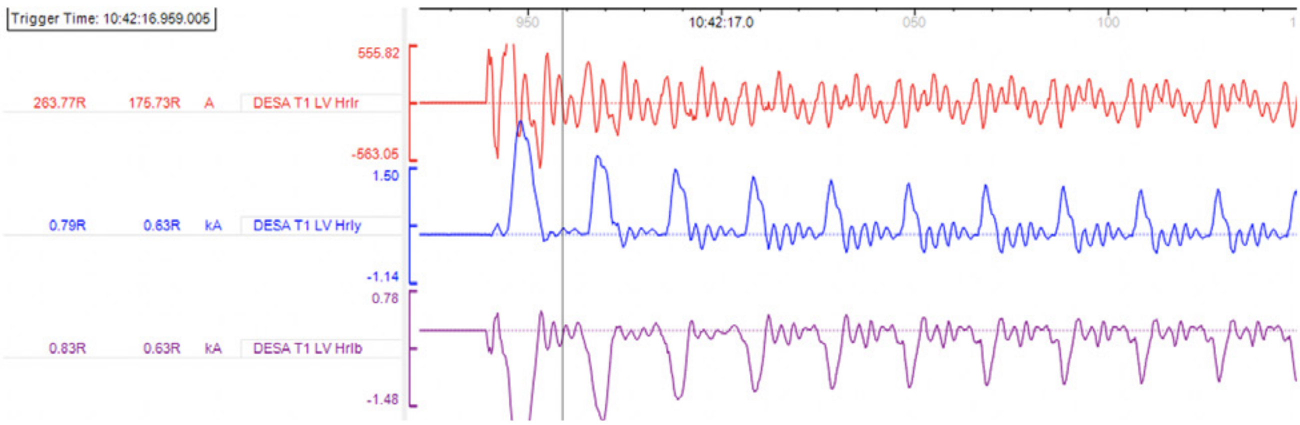


Figure 83: Dersalloch Grid 1 LV current profile

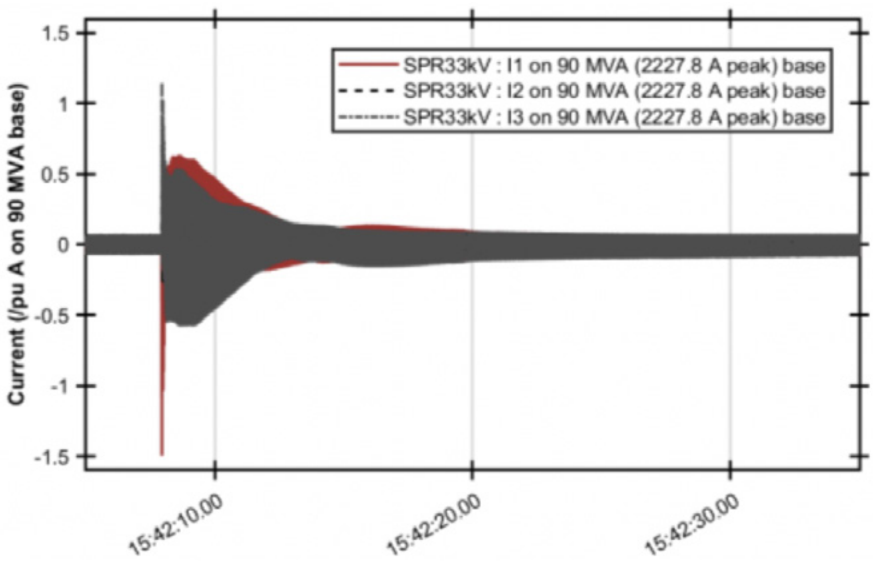


Figure 84: Current profile at wind park 33 kV during DOL energisation of 240 MVA SGT2A at 1.0 pu

10.4 Conclusion

From the trials completed at Dersalloch several conclusions can be drawn on technical challenges encountered to enable Black Start from a wind park.

- The successful Dersalloch trials proved that it is possible to energise 132 and 275 kV transmission assets from a limited number of turbines within a grid-forming algorithm using a ‘soft start’ ramping process to minimise network inrush effects. By including 1 MW of resistive load the network saw an improved stability and dampening effect. Energisations were attempted with reduced voltage at both turbine terminal voltage and reduced tap settings on transmission grid transformers.
- Using existing transmission protection functions it is not possible to provide any protection coverage on the network during the ramping sequence. By implementing a voltage-controlled overcurrent (VCOC) function within the network, protection coverage could be secured after 3.75 seconds with three WTGs in service.
- It has been demonstrated that using a traditional direct-online energisation (DOL) it is possible to energise transmission networks up to 275 kV involving infrastructure rated at several times the wind park capacity. This learning is perhaps the most significant from all VSM trials completed and in essence proved that a ramping method may not be essential if restoration plans consider the availability of GF strength for large transformer energisation.

11 Conclusions

This report is the first of two reports entitled 'Demonstration of Black Start from DERs' to detail the outcomes and learning from the live network testing which has been planned, and already undertaken, as part of the Distributed ReStart project.

The report focuses on the work being undertaken at the three live trial sites (Galloway, Chapelcross and Redhouse). Additional work related to grid-forming converter connected DERs is also given (a case study protection assessment and details of hardware in the loop (HiL) energisation tests which are being undertaken.) In conclusion, a report on live testing of VSM technology at Dersalloch wind farm is given, undertaken outwith the Distributed ReStart project, but supported and facilitated by SP Energy Networks (SPEN) and located adjacent to the Galloway live trial area.

11.1 Galloway live trial results phase 1

From the live testing utilising Glenlee hydro unit to energise the local 132/11 kV transformer, the Glenlee/Newton Stewart/Glenluce No 2 132 kV circuit and the Glenluce GT2 132/33 kV transformer, the following conclusions can be drawn:

- Reducing the generator terminal voltage (on synchronous generators by adjusting the Automatic Voltage Regulator [AVR] set point) is an effective strategy to avoid the generator tripping on overvoltage protection. This provides additional headroom for transient and temporary overvoltages, produced by the transformer inrush currents, before the overvoltage protection operates.
- Transformer inrush currents may be significantly reduced using Point of Wave switching on CBs, minimising waveform distortion and the possibility of overvoltage protection operations.
- Plant items including circuit breakers may be required to carry out duties which may be outside their designed capability. Transient Recovery Voltage (TRV) studies may be required to ascertain this.
- Energising a network from a weak source (very low fault level) is likely to result in significant harmonic and 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.
- As much testing as possible of unconventional network energisation sequences should be carried out to increase the confidence that the proposed energisation sequence will proceed as expected should the need arise for it to be used in practice.

Modelling assumptions related to energisation studies should be validated to ensure suitability for the 'Black Start from DERs' bottom-up study scenario.

11.2 Galloway Live Trial Results Phase 2

From the live testing utilising Kendoon hydro unit to:

- energise the local 132/11 kV transformer, the Glenlee/Newton Stewart/Glenluce No 1 132 kV circuit and the Glenluce GT1 132/33 kV transformer
- energise the Glenluce GSP No.1 33 kV busbar network (including primary transformers [33/11 kV])
- energise the Kendoon to New Cumnock 132 kV circuit, and New Cumnock 275/132 kV SGT1A and SGT1B transformers the following conclusions can be drawn.
- All energisations were successful with the exception of energising the Barrhill primary transformer. This test was performed after the Kendoon generator voltage had been restored to 100 per cent (11 kV). While this reduced the headroom between the generator voltage and the overvoltage protection trip level, the peak transient overvoltage was less than in some other tests.
- The anomaly of the Barrhill primary transformer trip (tripping for peak voltages less than in other tests) may be due to the time delay in the protection operating time which requires the voltage to stay above a pre-set threshold before operating, or due to the degree of voltage waveform distortion and any internal signal filtering method employed in the relays. These will influence the actual overvoltage 'detected' by the relay during the energisation events and affect the operation and the performance of the relays
- Tests at Glenlee in 2020 (Galloway phase 1 live tests) were only successful when the Point on Wave (PoW) relay was used to close the 11 kV breaker to energise the test network. It was assumed that similar issues would arise at Kendoon, so the PoW relay was used to control the closing of the Kendoon 11 kV breaker for most of the tests. A final test (Test 4.6) was carried out with the PoW relay closing at the worst time. This energisation was also successful. Further work will be required to determine under what conditions a PoW relay may be required to ensure a successful energisation.
- The Glenlee energisation required the entire test circuit between the Glenlee 11kV breaker and the Glenluce 33kV breaker to be energised as there were no intervening 132kV breakers. Kendoon still required the simultaneous energisation of the Kendoon Transformer T2 and the Kendoon / New Cumnock 132kV circuit but offered sequential energisation on the route to Glenluce using 132kV breakers at Kendoon and Glenlee. The 132kV circuit breaker closing was at a random time as the PoW Relay controlled only the 11kV breaker. However, sequential and simultaneous energisations of the test network were both successful.
- Residual flux in the Glenluce transformer could not be measured by the PoW Relay due to its remote location. The PoW Relay only took account of the Kendoon transformer residual flux to minimise inrush currents.
- Two SGTs (275/132 kV) were successfully energised at New Cumnock; however, voltage transients were much more severe than when a single SGT was energised. The arrangement at New Cumnock substation is such that there are only 275 kV isolators (no circuit breakers) between the transformers. During a Black Start, both transformers would have to be energised simultaneously or the network de-energised post blackout to close any 275 kV isolators that had been opened.
- The overvoltages resulting from energising two SGTs may be reduced by using a PoW relay to close the 132 kV breaker that energised the transformers.
- Voltage transient magnitudes and durations were more severe on the test network due to the low fault level than would normally be experienced on an intact network with higher fault levels.
- Primary transformers are much smaller that the SGTs energised during this study (7.5 MVA compared to 480 MVA). However, overvoltages sufficient to trip the generator are still present when the generator is operating at 100 per cent terminal voltage.
- Reducing the generator terminal voltage would ease the situation energising the SGTs, but when energising a primary (33/11 kV) transformer under Black Start conditions, the local load would also be energised. Energising load at less than nominal voltage is considered unacceptable. One solution would be to run the generator at 75 per cent of nominal voltage and run the Glenluce 33 kV busbar at nominal voltage by tapping the Kendoon grid transformer to raise the 132 kV voltage by 10 per cent, and achieving the final increase by tapping the Glenluce grid transformer.
- The facility to run the generator at 75 per cent of nominal voltage has required the attendance of the station's AVR specialist to enable such a low voltage as the AVRs normally offer a range of about ±5 per cent. This reduction has allowed numerous successful energisations. This functionality would have to be 'built in' to the AVR for station staff to readily utilise during a Black Start.

11.3 Chapelcross live trials

From the results of the Chapelcross RTDS Black Start testing, it can be concluded that:

- The Steven's Croft generator was not tripped during any of the energisation simulations. The peak voltage at the 11 kV generator terminals reached as high as 160 per cent; however, the voltage was not sustained above the pick-up threshold for long enough to activate a protection trip.
- Reactive power generation/consumption by the anchor generator during the energisation tests are within the ratings of the generator unit.

The Chapelcross trials are planned to be performed during one week in May 2022. At present, a feasibility study is being undertaken on the capability of the anchor generator (Steven's Croft biomass). The results of that assessment will shape the scope of the trial plan.

11.4 Redhouse live trials

- With weak islanded networks (low fault level) it is important to carry out studies to ensure that the TRV capability of the switchgear is not exceeded (peak TRV value and the associated RRRV).
  – It should be noted that the measured TRV values are not dependent on the Point on Wave when the circuit breaker opens.
- Vacuum circuit breakers have a particular issue in that re-striking may occur if the RRRV exceeds the dielectric strength of the vacuum gap.
  – While the measured peak value of the re-ignitions may be within switchgear limits, the high frequency transients may still damage nearby transformer and generator windings with voltages several times the magnitude of the initial TRV being generated in the windings.
  – Occurrence of re-ignitions is dependent upon the POW opening of the circuit breaker.
  – Re-ignitions are only an issue for vacuum interrupters.
- Surge arrestors may be installed to limit the peak TRV values to within switchgear limits.
- RC snubbers may be installed to slow down the RRRV to within switchgear limits and/or avoid re-ignitions.

11.5 Protection assessment – BESS anchor DER

The ability to protect the Chapelcross live trial network was assessed based on the existing synchronous generator (SG) anchor being replaced with an equivalent size (60 MVA) grid-forming converter (GFC) BESS. The key findings were:
Fault Levels

- At 415 V and 11 kV the fault levels considering the GFC unit as an anchor are higher compared to the SG.
- At 33 kV, when the GFC is saturated (the fault impedance is low enough such that it reaches its maximum current output, typically ~1 pu), the resulting fault levels are less than an equivalent SG.
- At 132 kV and 400 kV, due to the GFC's saturation during the three-phase faults the resulting fault levels are lower compared to those of the SG. In contrast, at these voltage levels the GFC unit is not saturated during the single-phase-to-ground faults, resulting in slightly higher fault levels.

Network Protections

- The 11 kV network (and lower voltages) may be adequately protected with reduced settings as required.
- At 33 kV and 132 kV, for three-phase faults when the GFC is saturated, more sensitive settings than an equivalent SG may be required or voltage-dependent protection considered (alternative settings are enabled when the voltage drops below a defined limit as would happen in a fault).

11.6 GFC network energisation simulations

- Hard energisations – RTDS simulations show that setting converter current control limits to lower peak inrush currents may be implemented at the expense of larger voltage disturbances. Live trials would be required to verify if this energisation strategy was viable as protection would have to be set to avoid hardware damage and may result in disconnecting the converter.
- Soft energisation – A 10-second voltage ramp was observed to significantly reduce inrush currents, even when energising both main transformers and the earthing transformers simultaneously.
- Grid synchronisation – Using a modified control was also tested, and successful connection to the 132 kV simulated grid was achieved under different scenarios. Notably, varying the network model assumptions could influence the reported quantified results. However, the observed soft energisation impact remains valid.
- The presented and planned studies are among the first trials to test GFC operation for Black Start with PHiL techniques. The lessons learned so far present opportunities to be explored in terms of improving the GFC-PHiL interface, and the GFC control robustness in response to practical network conditions and variations. Collectively, the outcomes of this project should contribute to answering the question of the added-benefits from using PHiL as a complementary tool to pure simulations in validating novel functionalities of power electronic devices.

11.7 Dersalloch wind farm – VSM live tests

From the trials completed at Dersalloch a number of conclusions can be drawn on technical challenges encountered to enable Black Start from a wind park.

- The successful Dersalloch trials proved that it is possible to energise 132 and 275 kV transmission assets from a limited number of turbines within a grid-forming algorithm using a 'soft start' ramping process to minimise network inrush effects. By including 1 MW of resistive load the network saw an improved stability and dampening effect. Energisations were attempted with reduced voltage at both turbine terminal voltage and reduced tap settings on transmission grid transformers.
- Using existing transmission protection functions it is not possible to provide any protection coverage on the network during the ramping sequence. By implementing a voltage-controlled overcurrent (VCOC) function within the network, protection coverage could be secured after 3.75 seconds with three WTGs in service.
- It has been demonstrated that using a traditional direct-online energisation (DOL) it is possible to energise transmission network up to 275 kV involving infrastructure rated at several times the wind park capacity. This learning is perhaps the most significant from all VSM trials completed, and in essence proved that a ramping method may not be essential if restoration plans consider the availability of GF strength for large transformer energisation.

Appendices

Appendix 1: Transient Recovery Voltage (TRV) Background

When a circuit breaker interrupts the current flow across the contacts of a circuit breaker there exists a voltage difference between the source and load sides of the circuit breaker. The voltage difference is referred to as the Transient Recovery Voltage (TRV). When a current is interrupted an arc will appear across the contacts of the circuit breaker. To break the fault current, the arc must be fully extinguished, or the arc may sustain the flow of current across the contacts of the circuit breaker. There exists a voltage limit specific to each medium (e.g. Vacuum, SF6), that if exceeded across the circuit breaker terminals will result in a breakdown of the medium and the arc reigniting across the contacts of the circuit breaker, leading to flow of fault current across the circuit breaker. This event is referred to as a restrike (or reignition if the breakdown occurs within a quarter cycle of the original fault interruption).

The severity of the TRV and likelihood of a restriking can be studied by a desktop power system study. It is critical that any such study is based upon an accurate model which should include parameters such as breaker class, rated voltage, rated short circuit current, type of fault current and magnitude of fault current under examination. With a model prepared a simulation can be performed to identify the critical parameters of interest, which is the TRV itself, and the Rate of Rise of Recovery Voltage (RRRV). The RRRV characterises how quickly the TRV rises on fault interruption.
The prospective TRVs (obtained by simulation) must lie within the circuit breakers rated TRV capability envelope (obtained in lab by standardised tests).

The findings of TRV studies performed for specific trial areas found that some switchgear may be operated outside of the TRV envelope of the device during specific conditions. Vacuum circuit breakers in particular were found to be likely operated out of range in some considered trial tests. Vacuum circuit breakers can quickly extinguish the fault current however a significant peak TRV and RRRV can occur leading to medium breakdown and restriking.

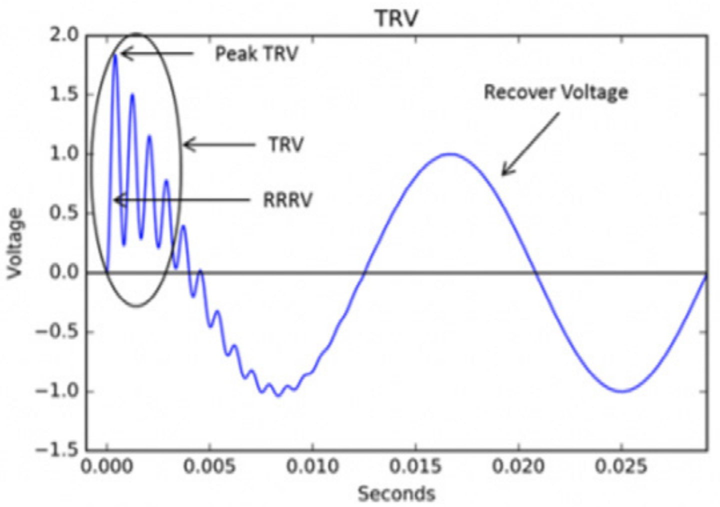
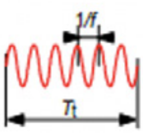
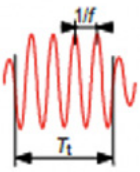
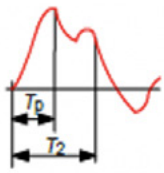
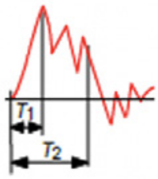
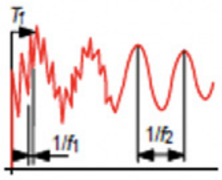
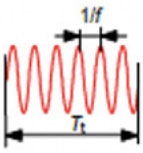
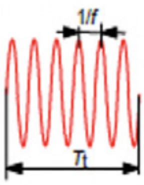
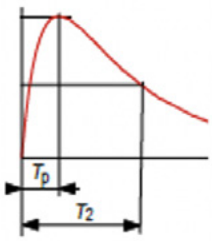
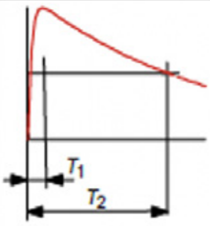


Figure 85: Parameters of interest for TRV analysis

Overvoltages can lead to significant damage to equipment on the power system. The magnitude of overvoltages expected during the live trial tests must be known to understand the associated risk of protection operation or more severe damage to plant.

Appendix 2: IEC 60071 definitions for overvoltage

IEC 60071 definitions for over voltage

Class	Low frequency		Transient		
	Continuous	Temporary	Slow-front	Fast-front	Very-fast-front
Voltage or over-voltage shapes					
Range of voltage or over-voltage shapes	f = 50 Hz or 60 Hz $T_t \geq$3 600s	10 Hz < f < 500 Hz 0,02 s $\leq T_t \leq$ 3 600 s	20 µs < $T_p \leq$ 5 000 µs $T_2 \leq$ 20 ms	0,1 µs < $T_1 \leq$ 20 µs $T_2 \leq$ 300 µs	$T_f \leq$ 100 ns 0,3 MHz < f_1 < 100 MHz 30 kHz < f_2 < 300 kHz
Standard voltage shapes	 f = 50 Hz or 60 Hz T_t [a]	 48 Hz $\leq f \leq$ 62 Hz T_t = 60 s	 T_p = 250 µs T_2 = 2 500 µs	 T_1 = 1,2 µs T_2 = 50 µs	a
Standard withstand voltage test	a	Short-duration power frequency test	Switching impulse test	Lightning impulse test	a

[a] To be specified by the relevant apparatus committees.

Figure 86: IEC 60071 classes and shapes of overvoltages, standard shapes and stand withstand voltage tests

A3.1 Introduction

FromThe main body of this report presents results of the Galloway Trials and associated learning. This appendix contains the results of electromagnetic transient (EMT) power system studies performed after the live trials. The test cases adopted within these studies are modelled to represent specific live tests for which further investigation was required to understand complex phenomena encountered.

The following cases have been performed using the PSCAD EMT software program.

Case 1 – Energise Glenlee transformer GT1 and 132kV line to Glenluce GT2 against 1xGlenlee generator
Prior to the energisation, the Glenlee generator terminal voltage was reduced to 0.75 p.u and the Glenlee Grid T1 transformer at neutral tap position. The energisation was performed without P.O.W relay. The PSCAD simulated results were obtained assuming ±30% residual flux on the Glenlee Grid T1 transformer.

Case 2 – Energise Kendoon Grid T1 up to New Cumnock 132 kV against 1xKendoon generator
Prior to the energisation, the Kendoon generator terminal voltage was reduced to 0.75 p.u and the Kendoon Grid T2 transformer at neutral tap position. The PSCAD simulation was performed with ±20% residual flux on the Kendoon Grid T2 transformer. The simulation was performed assuming without P.O.W relay to demonstrate the worst case overvoltage.

Case 3 – Energise SGT1A and SGT1B at New Cumnock by closing CB 1180 against 1xKendoon generator
Prior to the energisation, the Kendoon generator terminal voltage was reduced to 0.75 p.u and the Kendoon Grid T2 transformer at neutral tap position. The simulation was performed assuming a ±20% residual flux on both of the SGTs and with no P.O.W closing relay.

Case 4 – Energise Barhill primary transformer via Lochans Moor – Glenluce – Glenlee – Kendoon route, against 1xKendoon generator
Prior to the energisation, Kendoon generator was operating at 1 p.u voltage, the Kendoon Grid T2 transformer at its neutral tap position and the Glenluce Grid T1 transformer was tapped to reduce the LV voltages to 1 p.u. The energisation was performed without P.O.W relay, the residual flux on the Barhill primary transformer was assumed to be ±50%.

A3.2 Frequency scans

The positive sequence self-impedance plots at the respective generator 11 kV terminals for the four cases have been obtained and are shown in Figure 86. Note that these impedance plots have been calculated assuming that the switching energisation has been completed. For Cases 1 to 3, the results show strong resonance points between the 4th and the 5th harmonics. It is also observed that at the 5th harmonic impedance magnitude for case 1 is higher compared to Case 2 and Case 3 whereas the 4th harmonic impedance magnitudes for Case 2 and Case 3 are higher compared to Case 1. For case 4, the resonance point is observed around the 3rd harmonic.

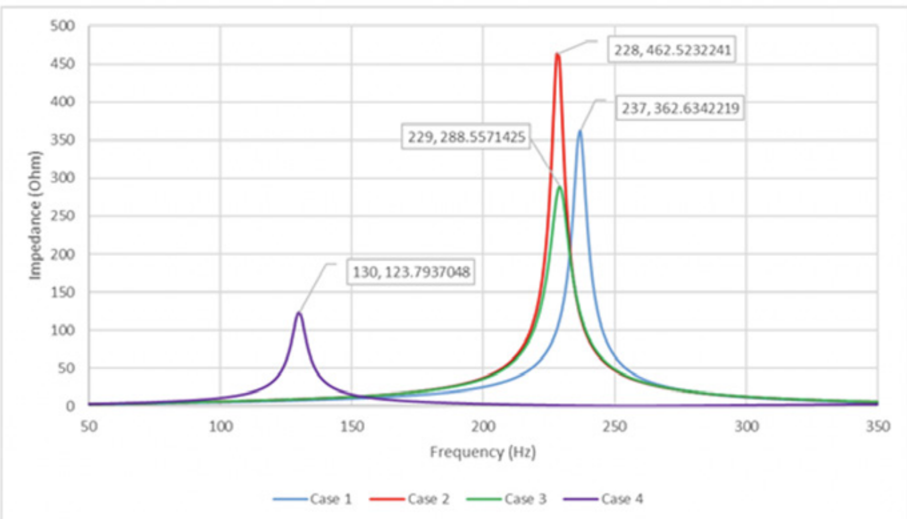


Figure 87: Impedance scans at the generator terminals

A3.3 EMT simulations

The EMT simulation results for the line-line voltages at the Glenlee generator terminal during the switching energisation for Case 1 are shown in Figure 87. It can be observed that the instantaneous peak voltage exceeded 3 p.u based on the line-line voltage peak (15.56 kV). The results show that the voltage waveforms are composed of various low harmonic components. The corresponding RMS voltages (phase R-Y) and current harmonics calculated through an FFT block are shown in Figure 88. The results show that the 4th harmonic component exceeded the 50 Hz RMS voltage and the 5th harmonic component reaches close to the 50 Hz RMS voltage. It is noted that during the live trial, the generator protection tripped around 100 ms after the switching energisation. The simulation shows that if the protection did not trip, the voltage magnitude would potentially last for 600 ms, which is visible in the 4th harmonic component trace in Figure 88.

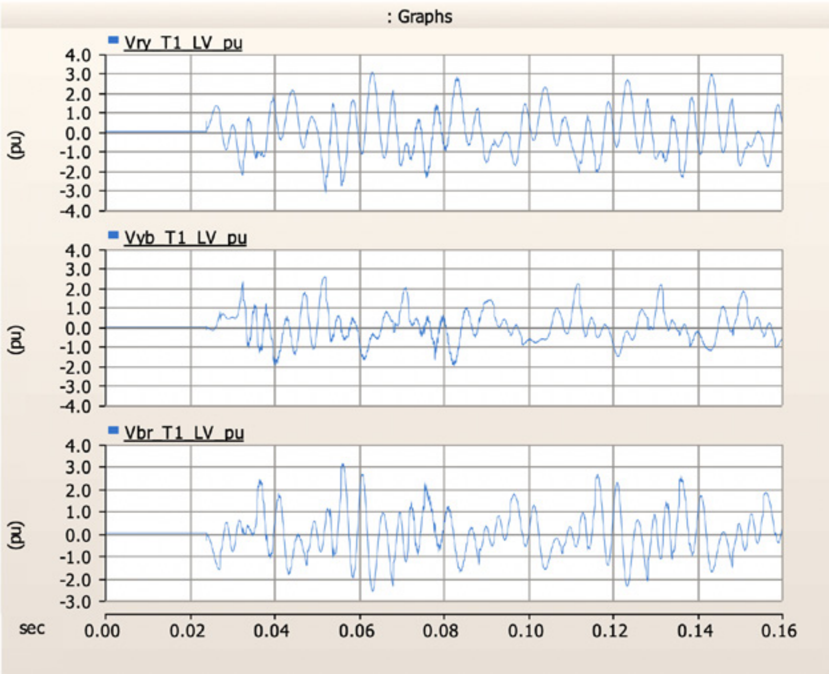


Figure 88: Instantaneous line-line voltages simulated at the Glenlee generator terminals

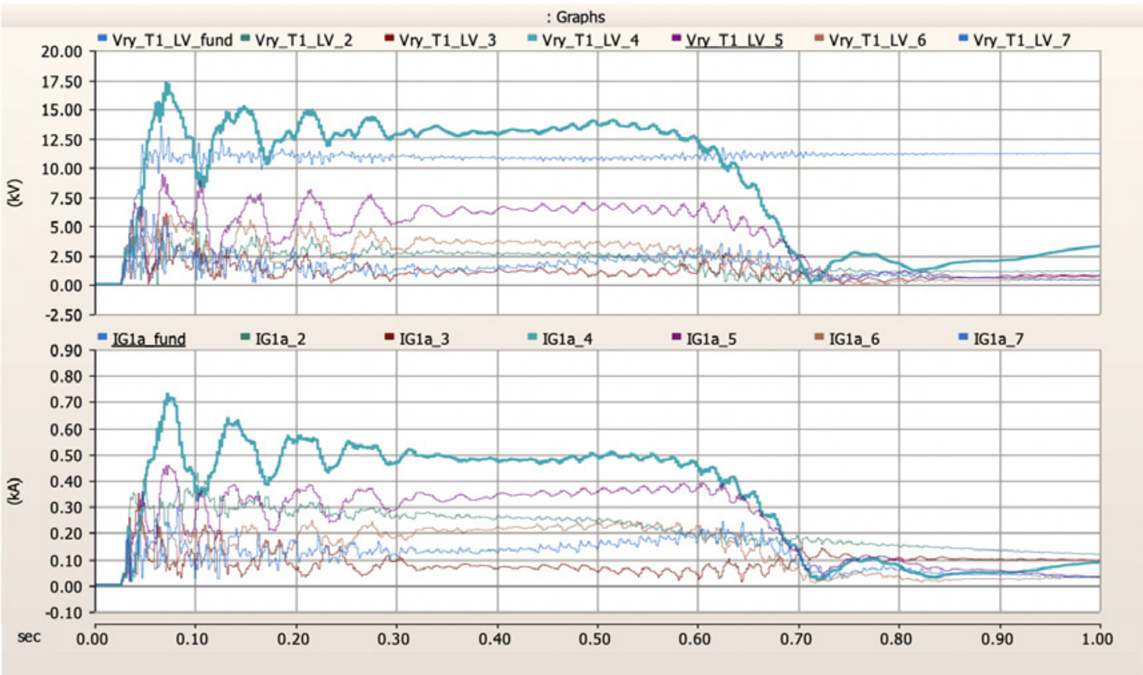


Figure 89: Case 1 – Harmonic contents (up to the 7th harmonic) of the voltages and currents simulated at the generator terminals

The harmonic impedance scans in Figure 86 shows that there is a strong resonance around 229 Hz for both Case 2 and Case 3. The EMT simulation results in Figure 90 show that the 4th harmonic component dominates the harmonic voltage spectrum, and it is almost twice the 50 Hz RMS voltages magnitude at 0.65 seconds. This is also reflected in the line-line voltage plots in Figure 90 where the maximum instantaneous overvoltage reached around 3 p.u based on the line-line voltage peak (15.56 kV) around 0.65 seconds. It is noted that the during the live trial the energisation switching was performed via the P.O.W relay whereas the EMT simulation assumed that the switching energisation was performed at the worst case switching angle. The results show that without the P.O.W relay, the switching energisation would potentially result in the Kendoon generator tripping on overvoltage.

The EMT results for Case 3 in Figure 93 shows that although the 4th harmonic components dominates the harmonic voltage spectrum its magnitude is relatively lower as compared to that in the previous Case 1 and Case 2. This is consistent with the impedance scans in Figure 86 which shows a lower impedance magnitude at the resonance frequency for Case 3 as compared to Case 2. The instantaneous line-line voltage reached 2.6 p.u. The results show that the energisation would potentially cause generator tripping on overvoltage. However, two attempts of the same energisation had been performed during the live trial and were both successful. Further investigations are required to understand the reason for this, particularly on the relay characteristics and its operation under harmonic-rich conditions.

For comparison, the instantaneous line-line voltage through an RMS meter in PSCAD for the two cases are shown in Figure 94.

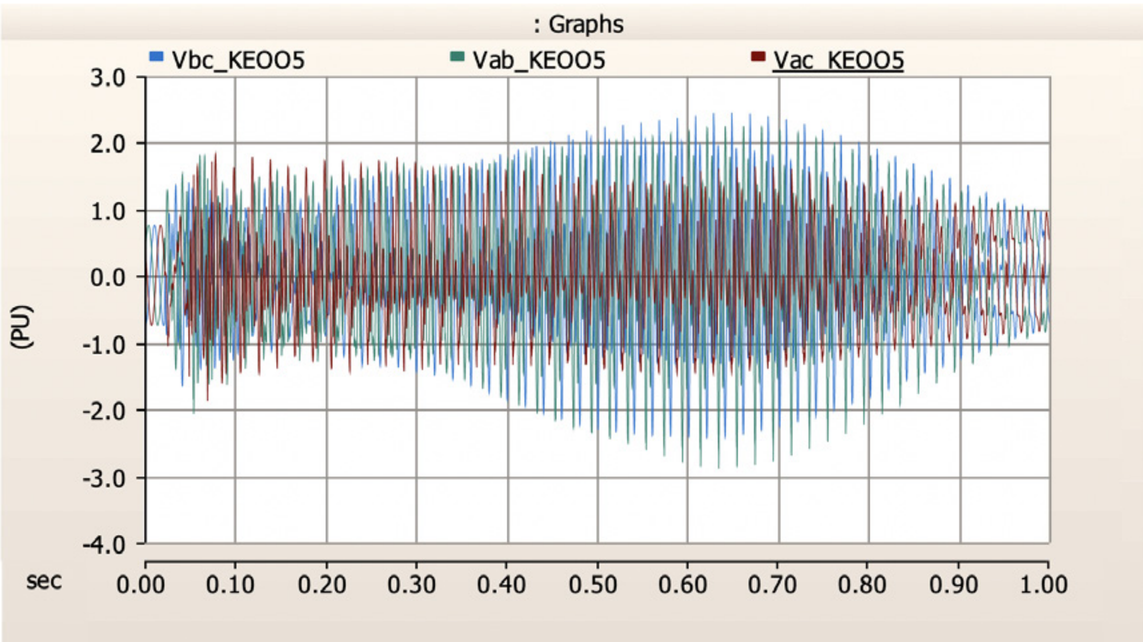


Figure 90: Case 2 - Instantaneous line-line voltages simulated at the Kendoon generator terminals

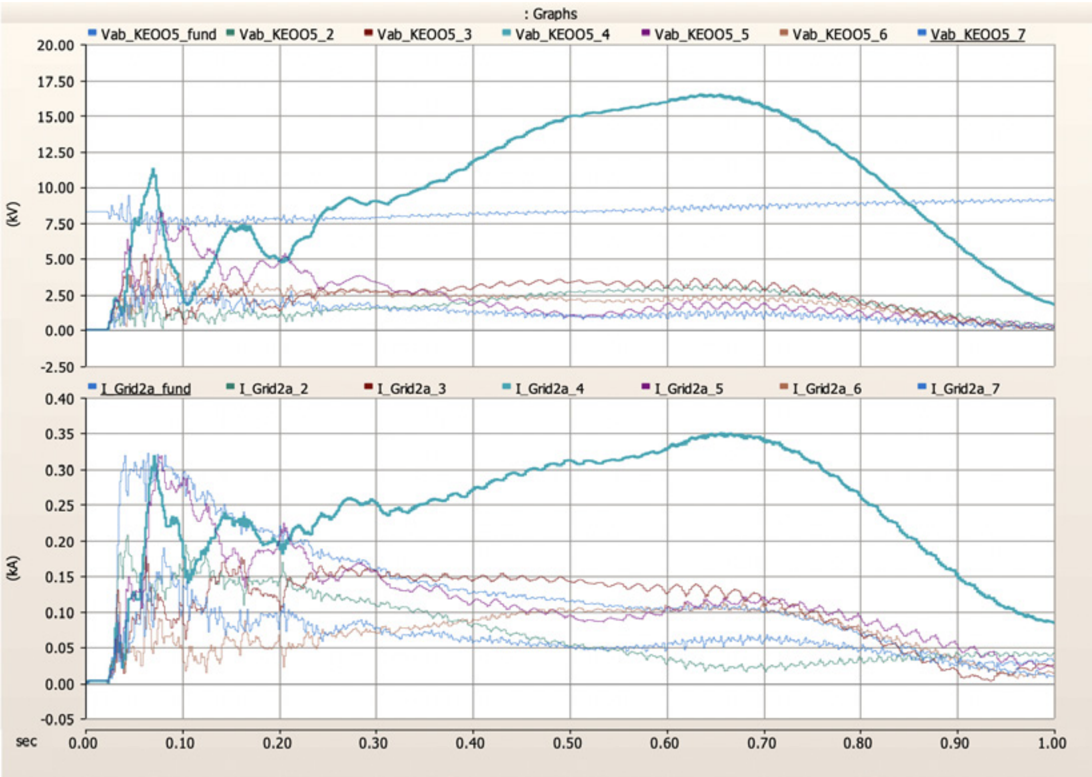


Figure 91: Case 2 - Harmonic contents (up to the 7th harmonic) of the voltages and currents simulated at the generator terminals

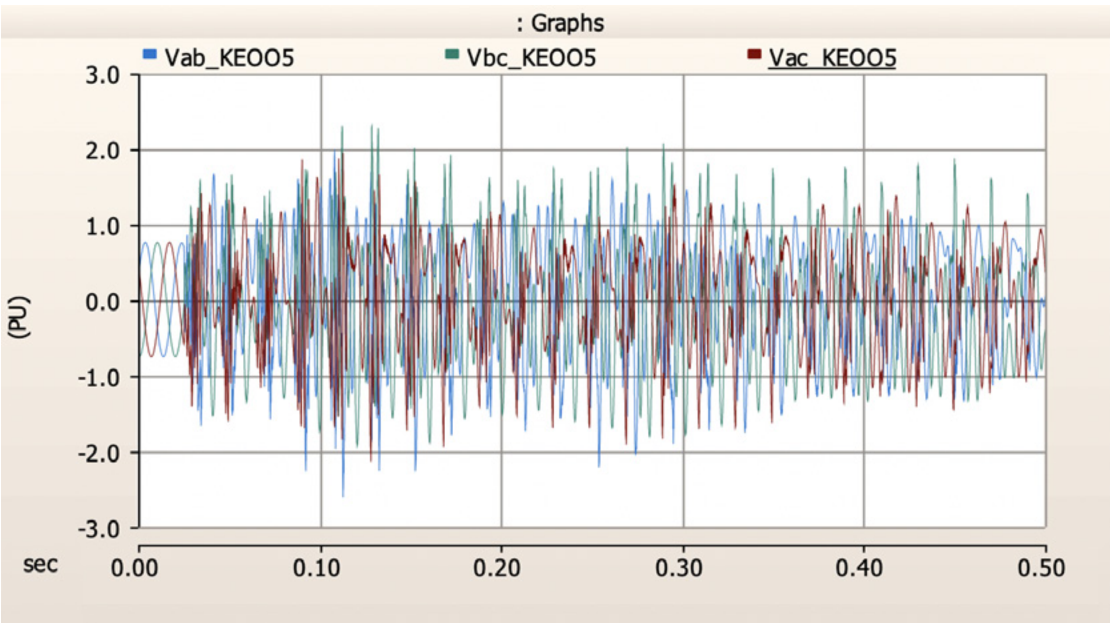


Figure 92: Case 3 - Instantaneous line-line voltages simulated at the Kendoon generator terminals

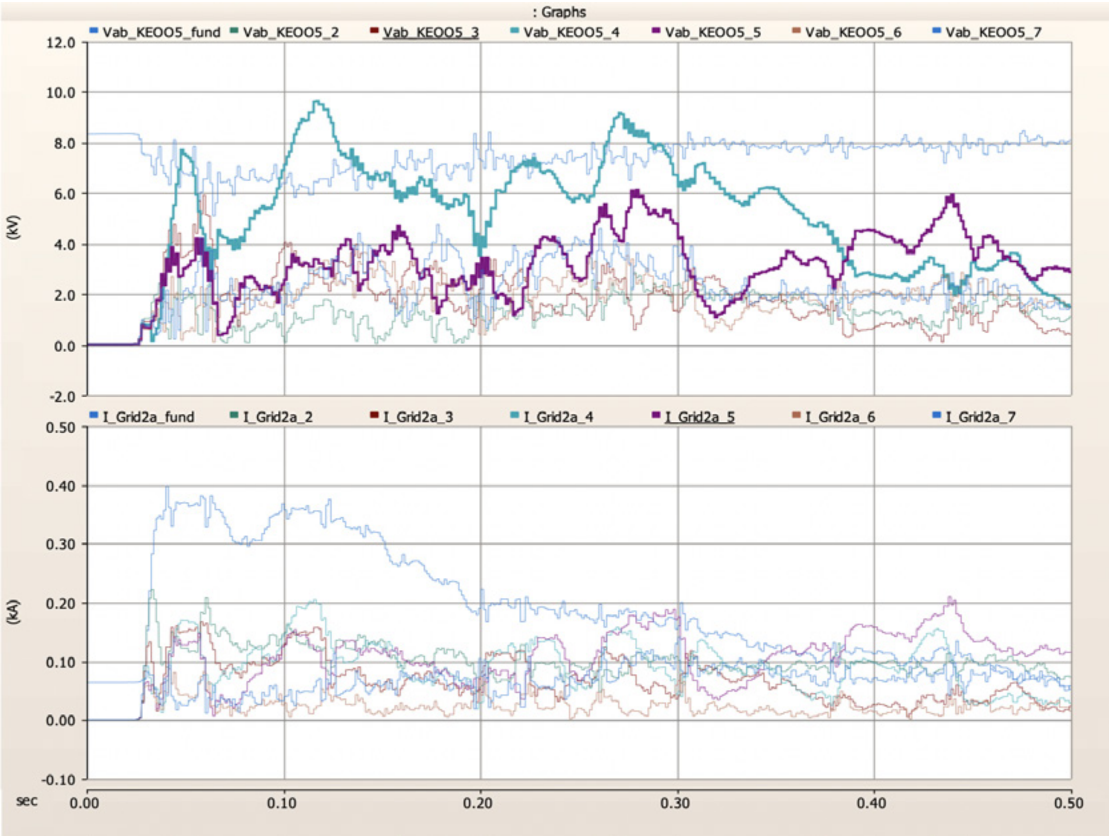


Figure 93: Case 3 - Harmonic contents (up to the 7th harmonic) of the voltages and currents simulated at the generator terminals

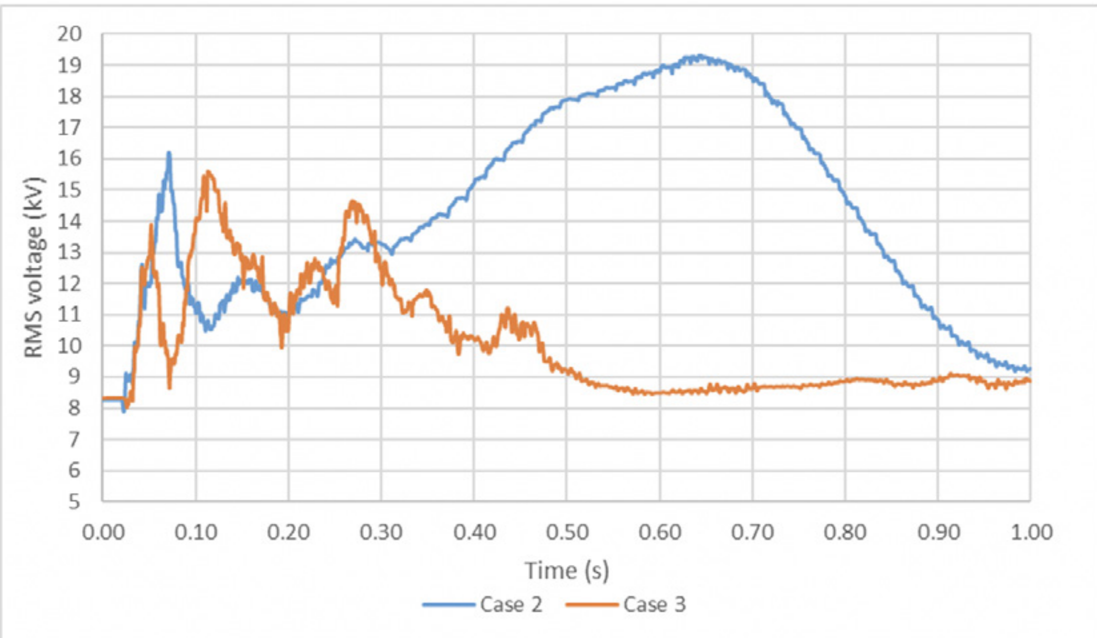


Figure 94: Comparison of instantaneous line-line RMS voltages for Case 2 and Case 3

PSCAD simulations show that energising the Barhill primary transformer (Case 4) resulted in high 2nd and 3rd harmonic components in the 11 kV line-line voltage harmonic spectrum as shown in Figure 96. This is consistent with the harmonic impedance plots shown in Figure 86 where the resonance peak at 130 Hz is visible. The instantaneous line-line voltages at the Kendoon 11 kV generator terminal are shown in Figure 95, where the maximum line-line voltage of 1.77 p.u can be observed. Note that during the live trial, this energisation case resulted in the Kendoon generator tripped on overvoltage protection.

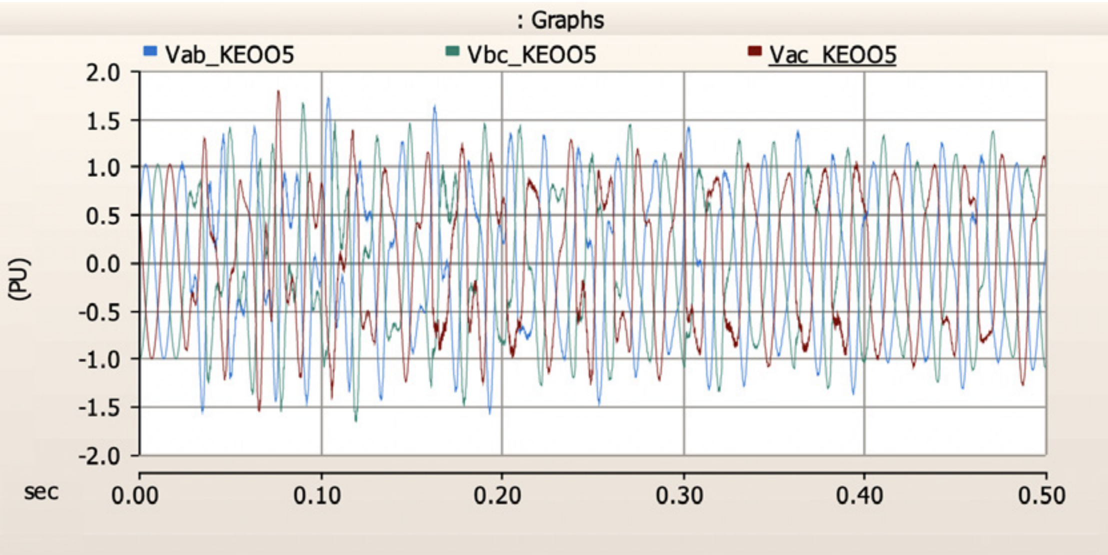


Figure 95: Case 4 – Instantaneous line-line voltages simulated at the Kendoon generator terminals

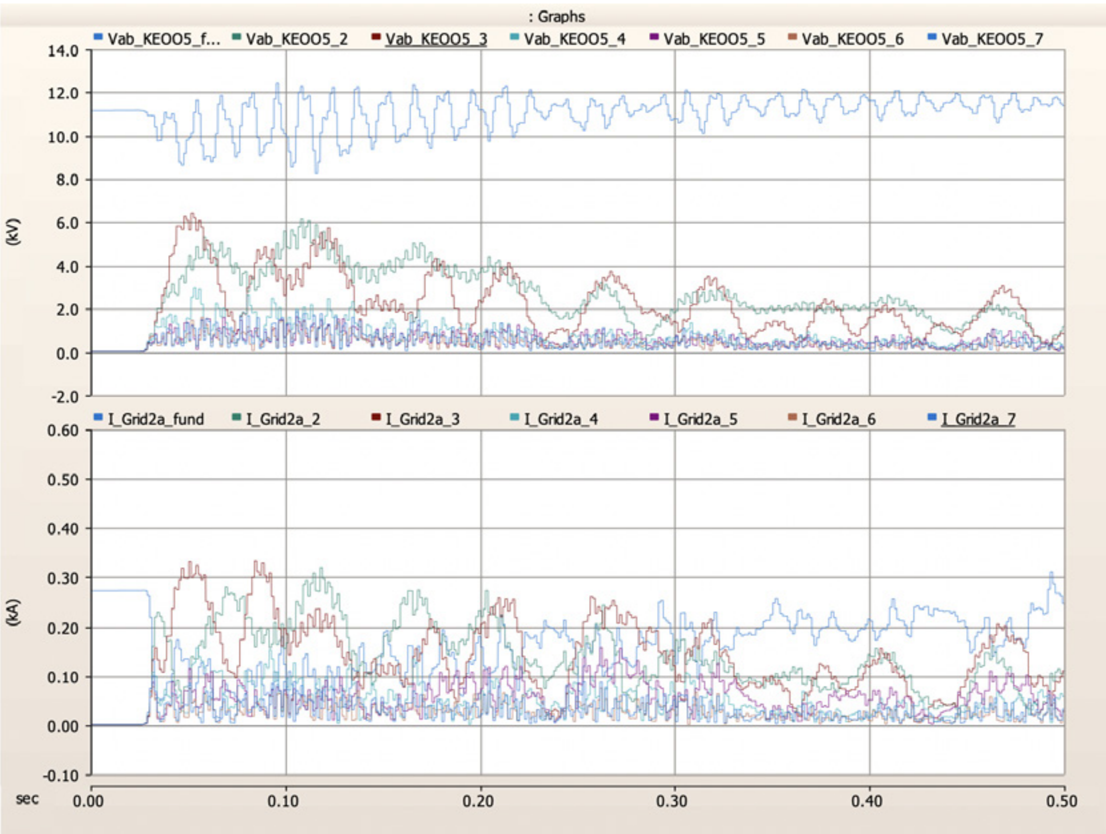


Figure 96: Case 4 - Harmonic contents (up to the 7th harmonic) of the voltages and currents simulated at the generator terminals

Appendix 4: Galloway Live Trials Phase 2 Complete Test Results

This Appendix provides comments on the results of all tests performed as part of the Galloway Phase 2 trials, Section 5.3 of the main body provides the results for a selected sub-set of tests only.

Test 1.1

Test 1.1 was an initial energisation of the Kendoon Grid Transformer T2 to allow the PoW relay to determine the delay between instructing the 11kV Circuit Breaker Grid 2 to close, and the breaker contacts closing.

After the initial half cycle following energisation there was no significant distortion of the voltage waveforms except for minor disturbance between the 5th and 10th cycles.

Test 1.2

Test 1.2 was an initial energisation of the Kendoon Grid Transformer T2 (tap 19) using the PoW relay to close the 11kV Circuit Breaker Grid 2.

After the initial half cycle following energisation there was no significant distortion of the voltage waveforms except for minor disturbance between the 5th and 10th cycles. The data from the fault recorder recording the Kendoon 11kV voltage can be seen in Figure 97.

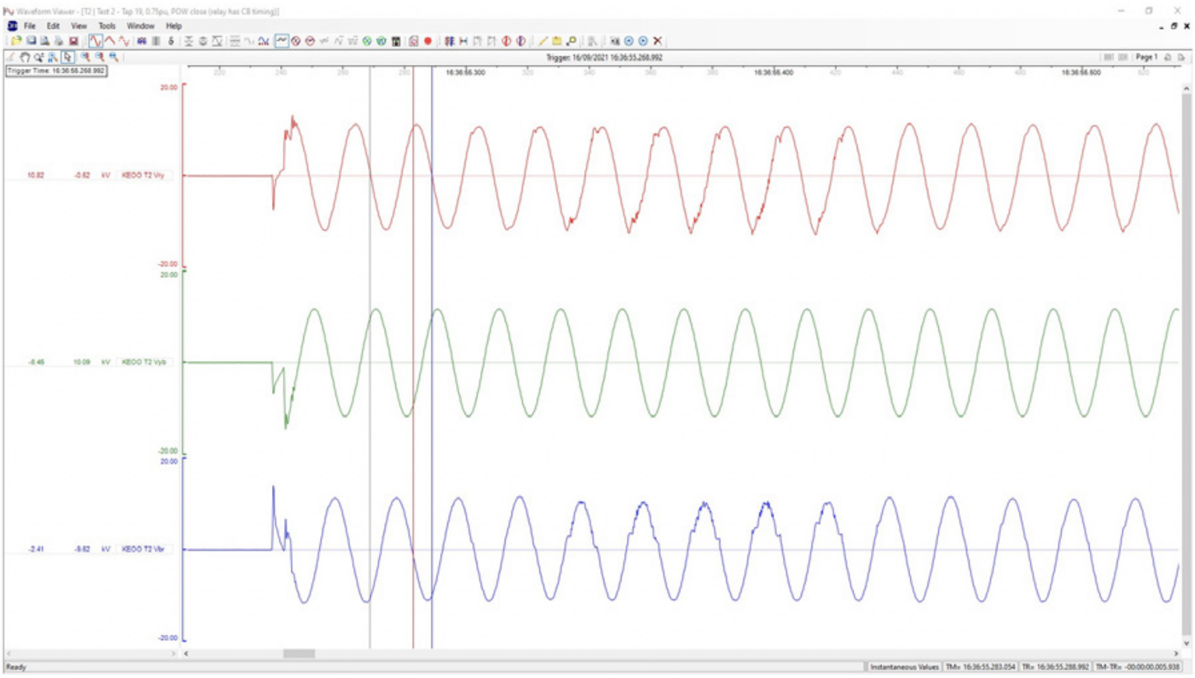


Figure 97: Test 2.1 Data plot Kendoon 11kV Voltages

Test 2.1

Test 2.1 was the initial energisation of the Kendoon Grid Transformer T2 and the Kendoon / New Cumnock 132kV Circuit (~30km).

The energisation was successful.

Significant harmonics are visible in the first few cycles, followed by similar distortion to that noticed in Tests 1.1 & 1.2, but of a longer duration particularly on the Red-Yellow voltage (see Figure 98).

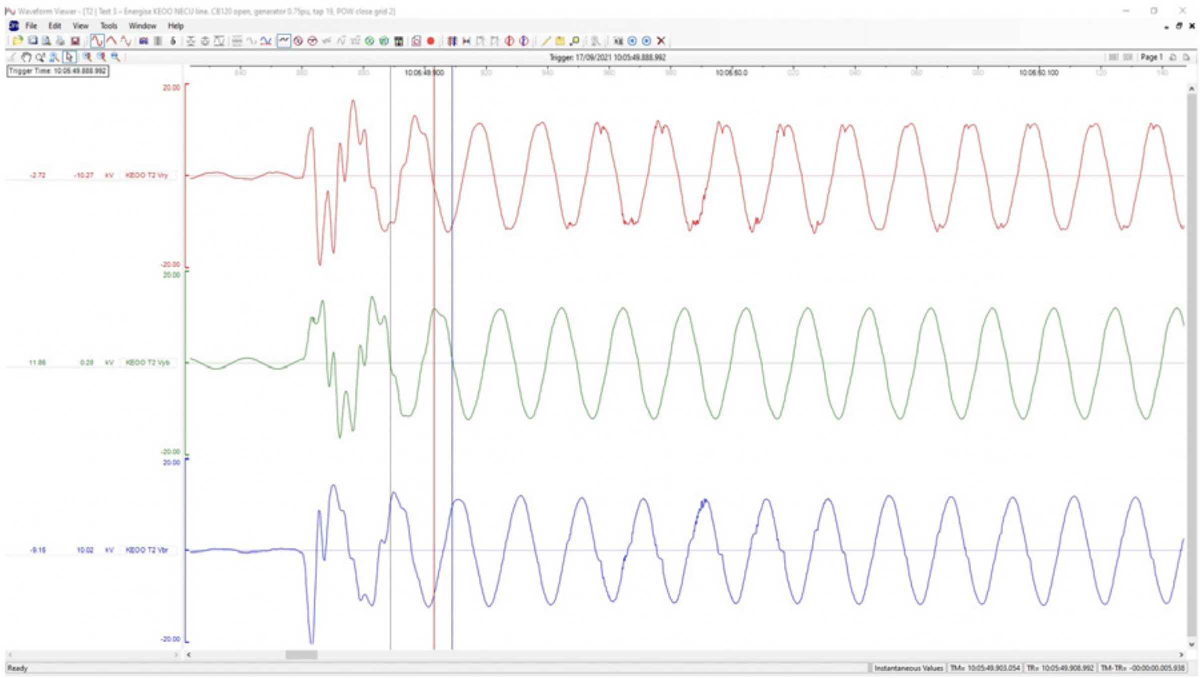


Figure 98: Test 2.1 Data plot Kendoon 11kV Voltages

Test 2.2

Test 2.2 was the energisation of the Kendoon / Glenlee 132kV Circuit by closing Kendoon 132kV Circuit Breaker 120.

The energisation was successful.

Minor waveform distortion is visible for about one cycle following energisation.

The energisation did not trigger the fault recorder, however the recorder on the Kendoon / Glenlee Circuit triggered when voltage appeared when CB 120 was closed. As this recorder is on the same site, it sent a trigger to the transformer LV recorder, hence capturing the voltage waveforms.

Test 2.3

Test 2.3 was an energisation of the Glenlee / Newton Stewart / Glenluce 132kV Circuit and Glenluce 132/33kV Transformer T1 by closing a 132kV CB at Glenlee.

The energisation was successful.

The Kendoon Transformer 11kV fault recorder was not triggered during this test.   Hence only voltage waveforms at Glenluce were recorded (see Figure 99).

A high frequency component is visible over the first cycle.

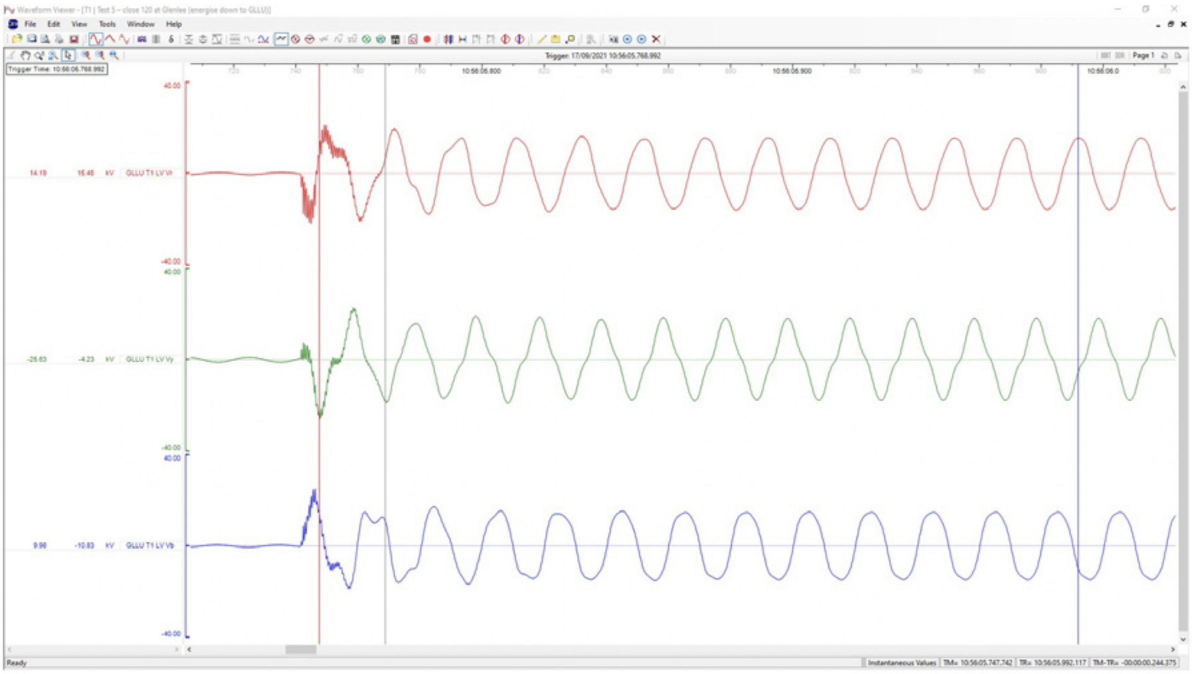


Figure 99: Test 2.3 Data Plot Glenluce 33kV Voltages

Test 2.4

Test 2.4 was the simultaneous energisation of the Kendoon / Glenlee / Newton Stewart / Glenluce 132kV Circuit and Glenluce 132/33kV Transformer T1 by closing the Kendoon Grid 2 11kV CB. The energisation was successful.

The Kendoon Transformer 11kV fault recorder was triggered during this test by the Kendoon / Glenlee 132kV Circuit fault recorder.

A high frequency component is observed during the first cycle at Glenluce (see Figure 100). The high frequency component was not observed at Kendoon.

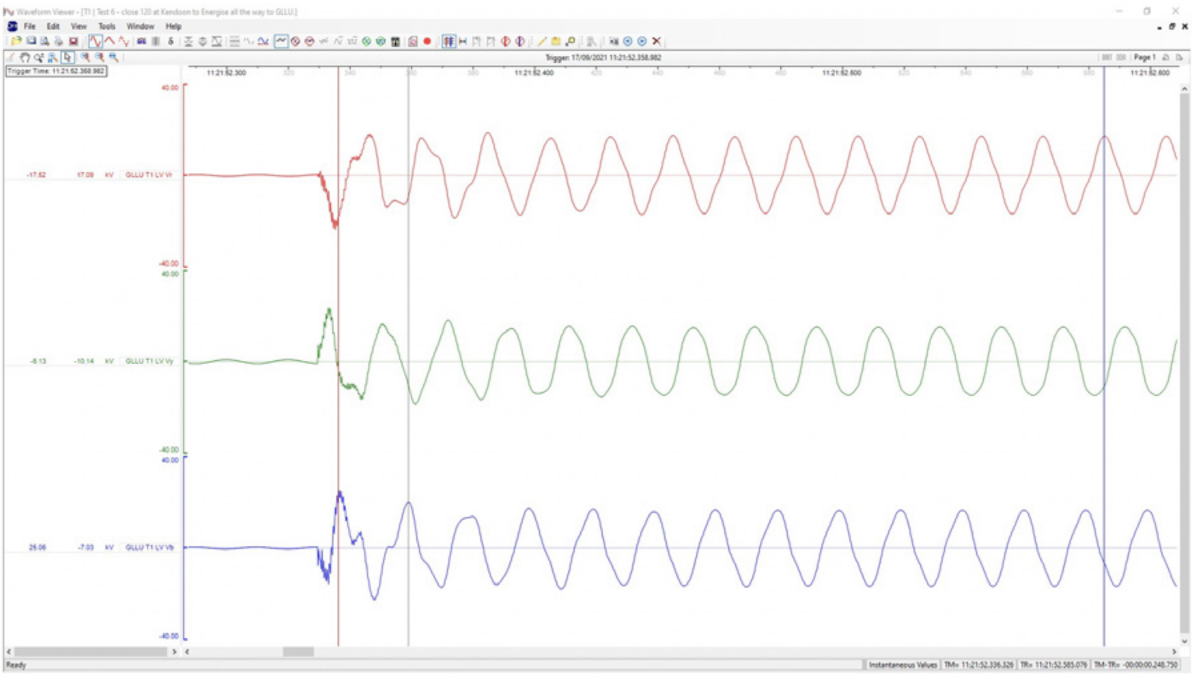


Figure 100: Test 2.4, Data Plot Glenluce 33kV voltages

Test 2.5

Test 2.5 was the simultaneous energisation of the Kendoon Grid Transformer T2, Kendoon / New Cumnock 132kV Circuit, Kendoon / Glenlee / Newton Stewart / Glenluce 132kV Circuit and Glenluce 132/33kV Transformer T1 by closing the Kendoon Grid 2 11kV CB energisation was successful

The energisation was successful.

The Kendoon Transformer 11kV fault recorder was triggered during this test (see Figure 101).

The Glenluce Transformer 33kV fault recorder was triggered during this test. No high frequency component is observed at Glenluce during this energisation.

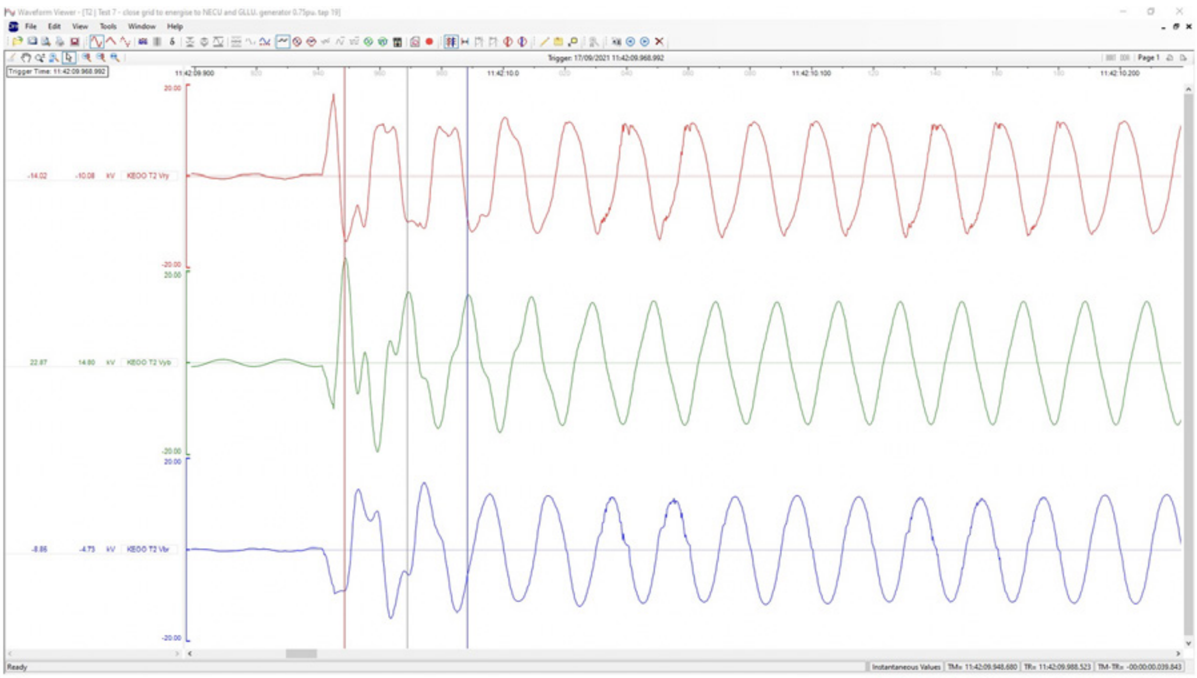


Figure 101: Test 2.5, Data Plot Kendoon 11kV Voltages

Test 2.6

Test 2.6 was a simultaneous energisation of the Kendoon Grid Transformer T2, Kendoon / Glenlee / Newton Stewart / Glenluce 132kV Circuit and Glenluce 132/33kV Transformer T1 by closing the Kendoon Grid 2 11kV CB.

This test is similar to Test 2.5 without energising the Kendoon / New Cumnock 132kV Circuit. This is the test circuit that will be used in Test 3.1. The Kendoon / New Cumnock Circuit will be omitted to minimise the leading reactive load on the Kendoon generator when the Glenluce / Glenchamber Wind Farm 33kV Cable Circuit is energised. In addition, the Kendoon GT2 tap changer was moved to nominal tap no. 7 (was at 19 to reduce the 132kV voltage for all previous tests). This was to ascertain if a successful energisation could be obtained without having to alter the tap change position (i.e. reduce the 132kV voltage as well as the generator terminal voltage).

The energisation was successful.

The Kendoon Transformer 11kV fault recorder was triggered during this test (see Figure 102).

The Glenluce Transformer 33kV fault recorder was triggered during this test.

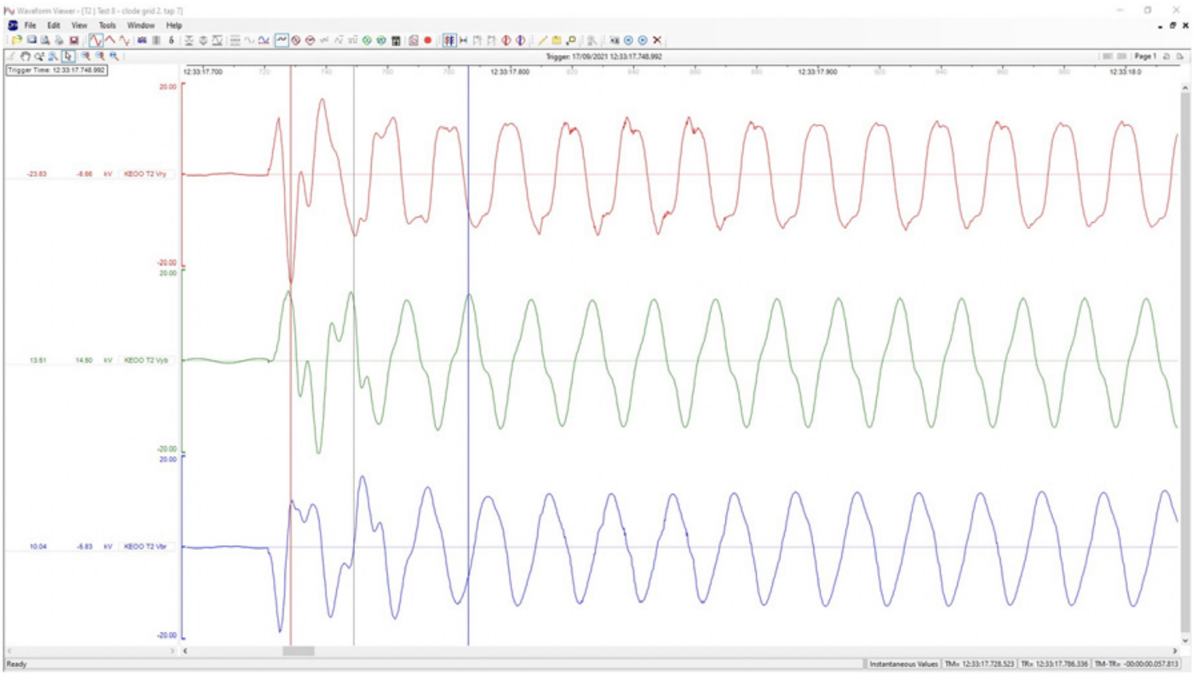


Figure 102: Test 2.6, Data Plot Kendoon 11kV Voltages

Test 3.1

Test 3.1 was an energisation of the Kendoon Grid Transformer T2, Kendoon / Glenlee / Newton Stewart / Glenluce 132kV Circuit and Glenluce 132/33kV Transformer T1 by closing the Kendoon Grid 2 11kV CB.

This was the energisation strategy that had been proved in test 2.6. The energisation was successful.

The Kendoon Transformer 11kV fault recorder was triggered during this test.

The Glenluce Transformer 33kV fault recorder was triggered during this test.

Test 3.2

Test 3.2 was an energisation of the Glenluce 33kV No 1 busbar from the Glenluce Grid 1 33kV CB. The very limited capacitance of the busbar was not expected to produce any transient.

No fault recorder triggered during this test. No voltage transients would be expected, so no triggers were expected.

Test 3.3

Test 3.3 was an energisation of the Glenluce / Glenchamber Wind Farm 33kV Cable Circuit by closing the appropriate 33kV CB at Glenluce GSP. The energisation was successful.

The tests planned for Spring 2022 will include a load bank connected to a spare 33kV CB at the wind farm. As well as providing some load for the wind farms, it will also allow the absorption of some reactive power to keep the leading reactive load on the Kendoon generator below -5 Mvar.

Figure 103 shows the generator voltage and reactive power changes when the Glenluce / Glenchamber 33kV Cable Circuit was energised.

There is a scaling factor error on the reactive power trace as the chart indicates the reactive power increased from -4.24 Mvar to -7.28 Mvar. However, the reactive power on the generator did not exceed -5 Mvar.

The generator voltage before the energisation was 11kV, with a transient increase to about 11.5kV (4.55% overvoltage) as the cable was energised (see Figure 103).

No fault recorder triggered during this test as the transients were small, hence only RMS data is available and no waveforms.

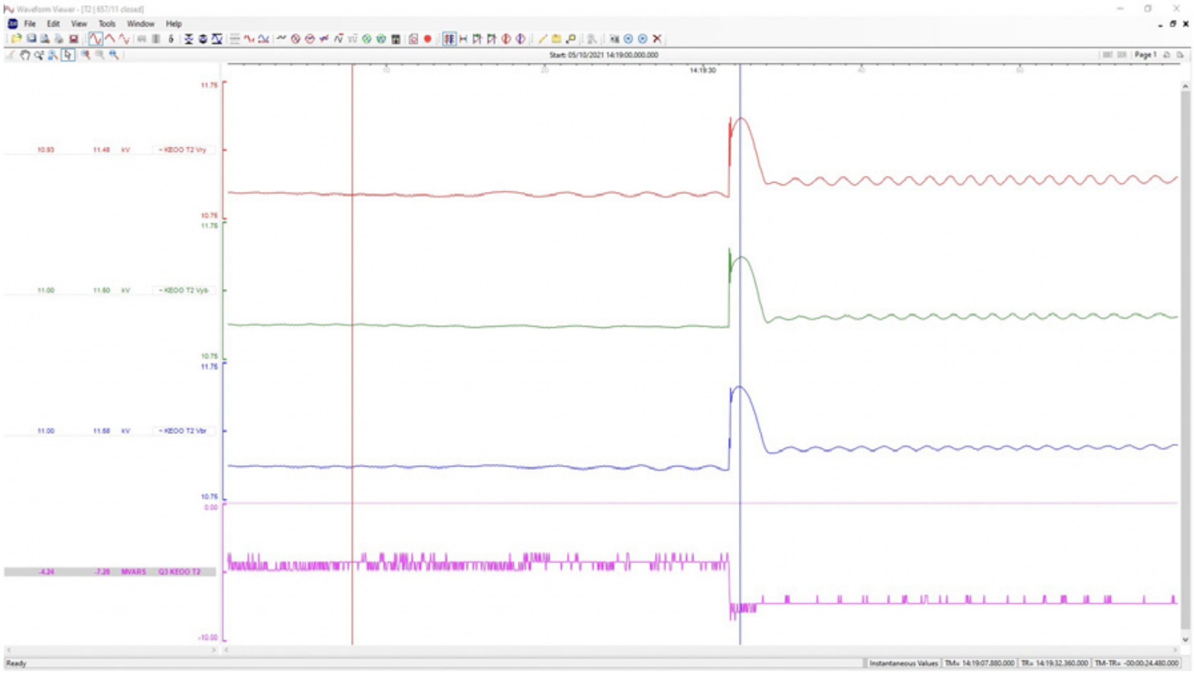


Figure 103: Test 3.3, Data Plot Kendoon 11kV Voltages and Mvars

Test 3.4

Test 3.4 was the energisation of the Glenluce / Lochans Moor Switching Station 33kV OHL Circuit from Glenluce GSP (the Glenchamber 33kB cable circuit, energised in Test 3.3, was switched out to reduce the Mvars generated by the test circuit).

This energisation was successful.
No fault recorder triggered during this test as voltage transients were small.

Test 3.5

Test 3.5 was an energisation from the Lochans Moor Switching Station of the Barrhill 33kV Circuit and Barrhill Primary Transformer (7.5MVA).

The Kendoon hydro terminal voltage was raised to 1pu prior to the energisation.

This energisation was unsuccessful .

The Kendoon Transformer 11kV fault recorder was triggered during this test (see Figure 104).

The Glenluce Transformer 33kV fault recorder was triggered during this test (Figure 105).

There was a 36.3% overvoltage on the Glenluce 33kV red phase to neutral voltage when the Barrhill Primary was energised. The peak overvoltage at Kendoon was 37.5% on the negative peak of the Yellow / Blue phase. While this voltage exceeds to overvoltage protection setting on the relay, it is less than the 45.5% overvoltage observed on the Red / Yellow phase of the following energisation (Test 3.6) which was successful. (see comments in section 5.2.2).

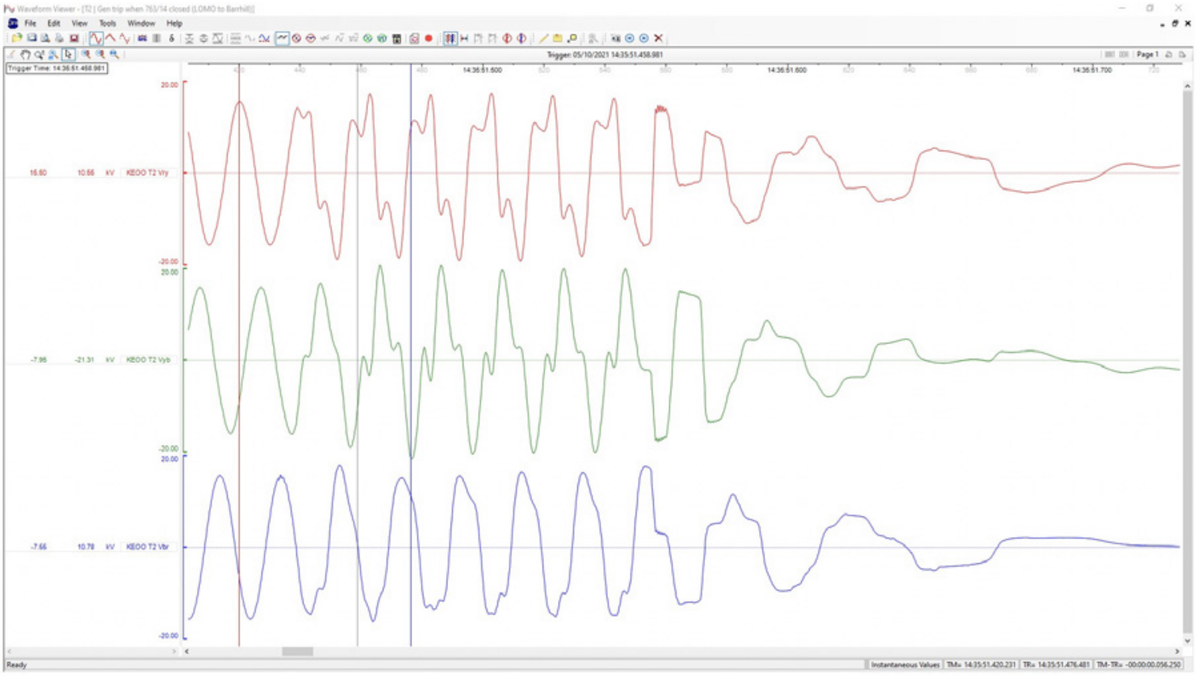


Figure 104: Test 3.5, Data Plot Kendoon 11kV Voltages

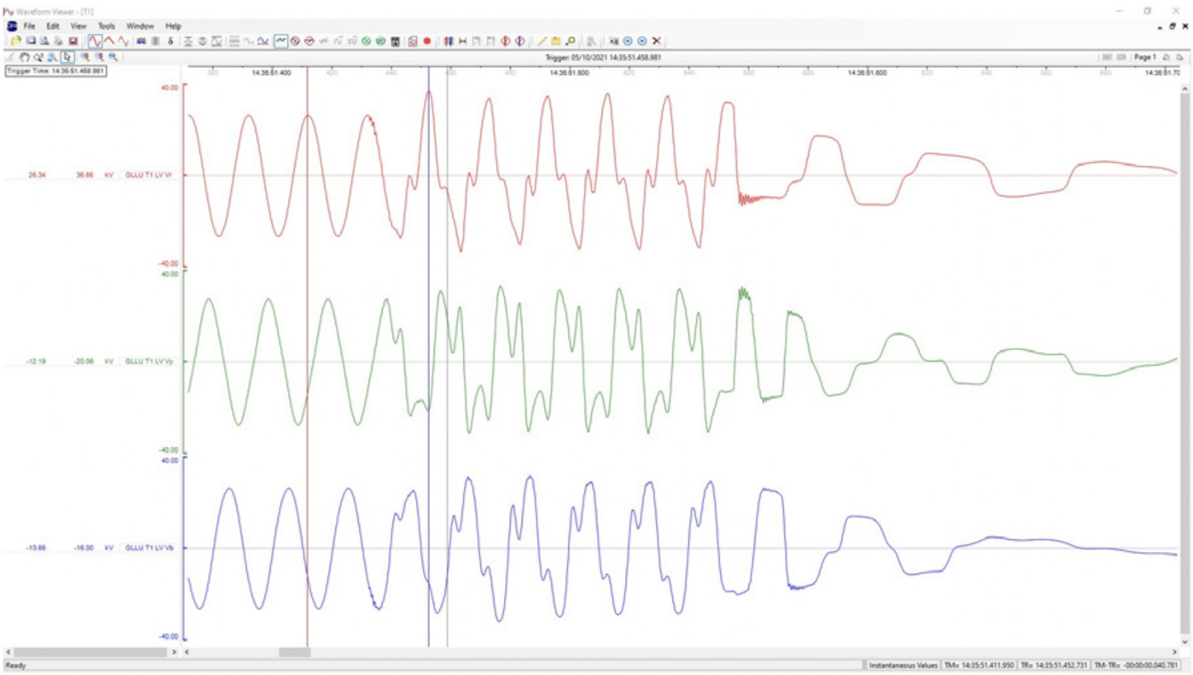


Figure 105: Test 3.5, Data Plot Glenluce 33kV Voltages

Test 3.6

Test 3.6 was an energisation of the Kendoon Grid Transformer T2, Kendoon / Glenlee / Newton Stewart / Glenluce 132kV Circuit and Glenluce 132/33kV Transformer T1, from Kendoon Grid 2 11kV CB.

The Kendoon Transformer 11kV fault recorder was triggered during this test.

The Glenluce Transformer 33kV fault recorder was triggered during this test.

This energisation followed the tripping out of the test circuit due to the failed attempt to energise the Barrhill Primary. It was planned that a further attempt would be undertaken, but with the Kendoon generator voltage retained at 75% (8.25kV).

However, reports of disturbances on customer supplies at Glenluce GSP (being supplied from the No.2 33kV busbar for the duration of the tests) resulted in testing being abandoned to restore network security.

Test 4.1

Test 4.1 was the energisation of the Kendoon Grid Transformer T2 and the Kendoon / New Cumnock 132kV Circuit from Kendoon Grid 2 11kV CB.

The energisation was successful.

The peak transient voltage at Kendoon 11kV was 20.21kV on the Yellow/Blue phase. The normal peak voltage of an 11kV waveform is 15.56kV, hence about a 30% overvoltage.

Analysis of the Kendoon voltage waveform indicated a Total Harmonic Distortion (THD) of about 35% about one cycle after energising the transformers.

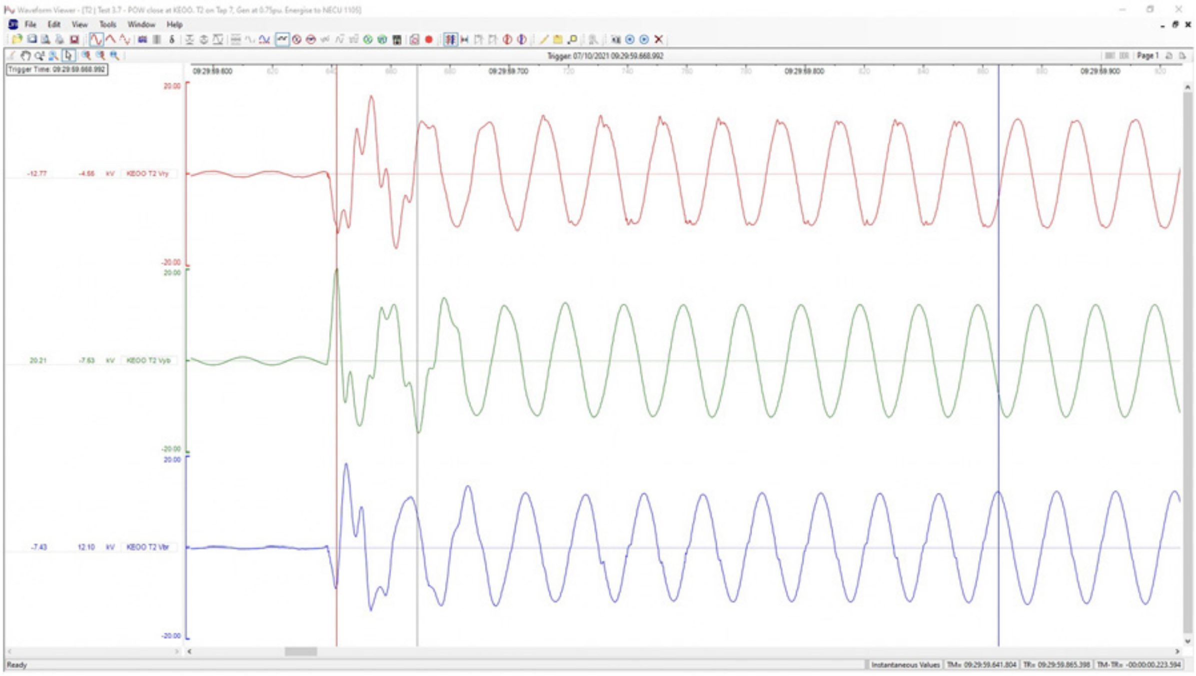


Figure 106: Test 4.1 Data Plot Kendoon 11kV Voltages

Test 4.2

Test 4.2 was an energisation of the New Cumnock SGT1A and SGT1B by closing a 132kV CB at New Cumnock. The energisation was successful.

The peak transient voltage at Kendoon 11kV was 26.54kV on the Blue/Red phase. The normal peak voltage of an 11kV waveform is 15.56kV, hence about a 71% overvoltage. The very short duration may be the reason it did not result in an overvoltage trip of the generator (see Figure 107).

Analysis of the Kendoon voltage waveform indicated a Total Harmonic Distortion (THD) of about 70% about one cycle after energising the transformers.

The New Cumnock 132kV Voltage Yellow Phase to Earth (10 seconds record) is shown in Figure 108.

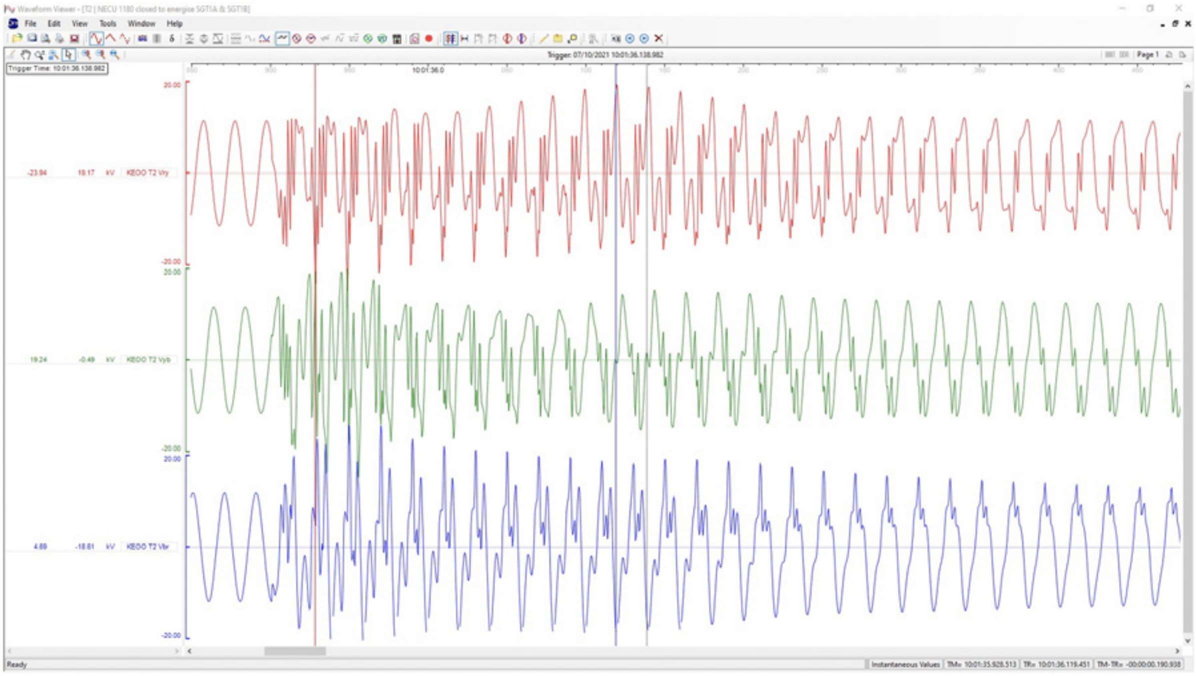


Figure 107: Test 4.2 Data Plot Kendoon 11kV Voltages

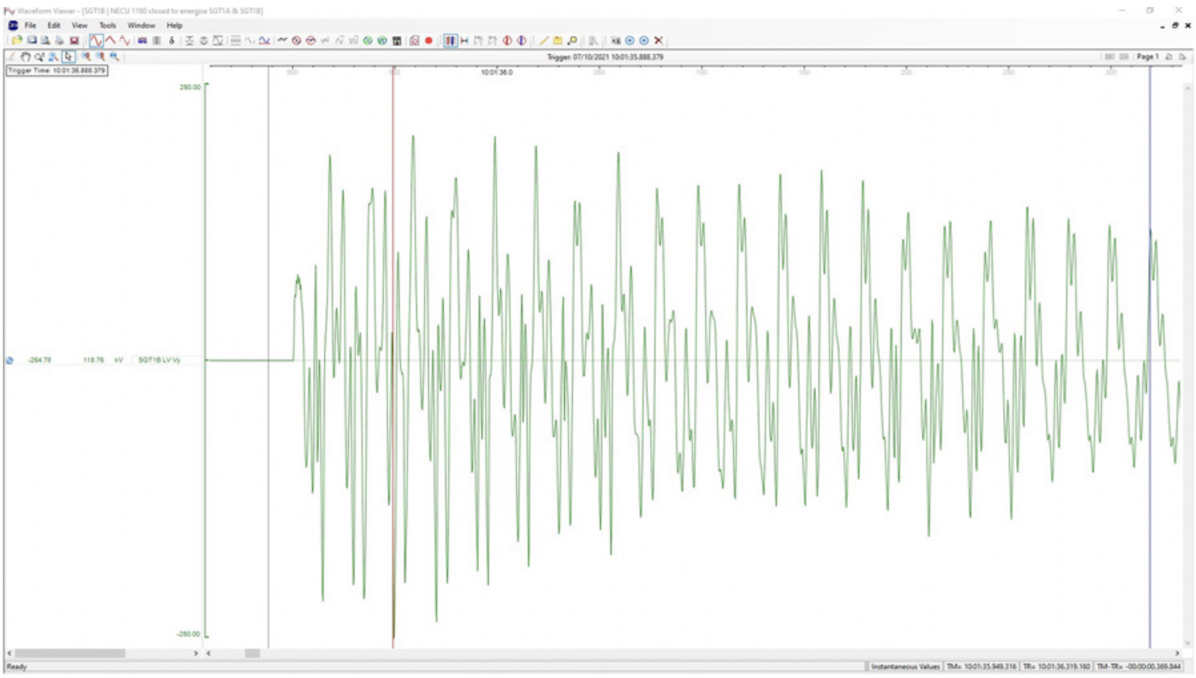


Figure 108: Test 4.2 Data Plot New Cumnock 132kV Voltage Yellow Phase to Earth (10 seconds record)

Test 4.3

Test 4.3 was an energisation of the single New Cumnock SGT1B by closing a 132kV CB at New Cumnock. The energisation was successful.

Voltage distortion was considerably less than the previous test when two SGTs were energised.

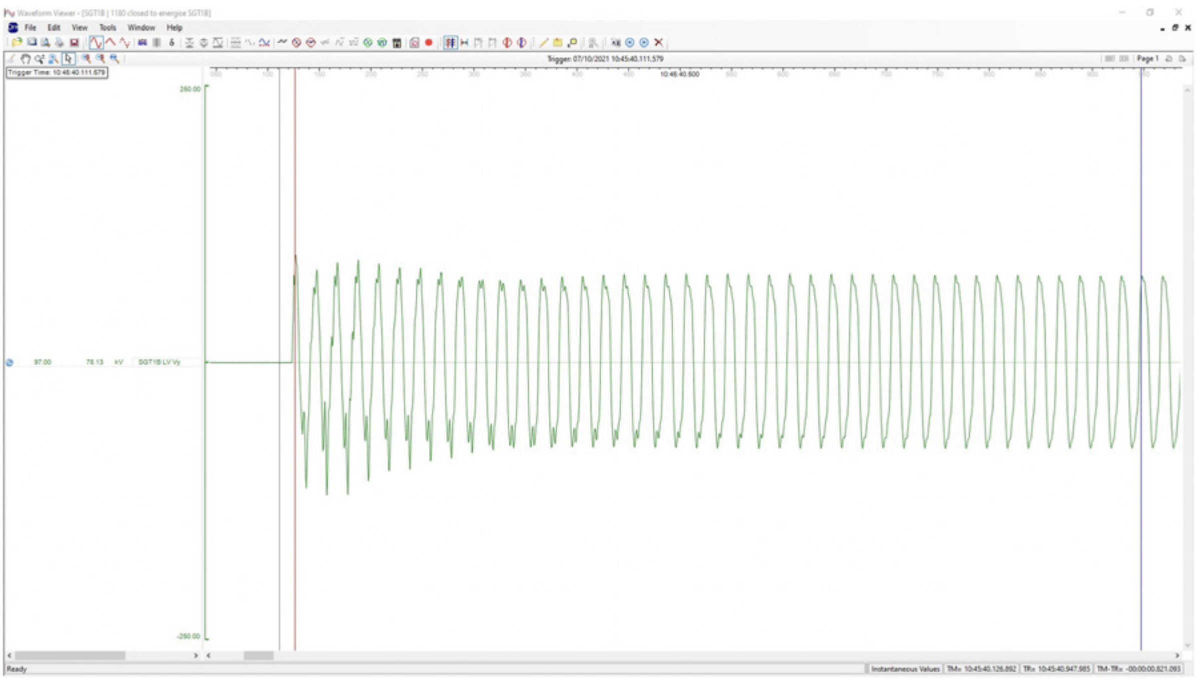


Figure 109: Test 4.3, Data Plot New Cumnock 132kV Voltage Yellow Phase to Earth

Test 4.4

Test 4.4 was a repeat of test 4.3 to provide confidence that consistent energisation could be achieved.

The energisation was successful.

Test 4.5

Test 4.5 was a repeat of test 4.3 (energising New Cumnock SGT1A and SGT1B simultaneously) to provide confidence that consistent energisations could be achieved.

The energisation was successful.

Test 4.6

Test 4.6 was the energisation of the Kendoon Grid Transformer T2 and the Kendoon / New Cumnock 132kV Circuit (the same as test 4.1) but without using the PoW Relay.

The energisation was successful. The successful energisation may be an indication that the PoW Relay may not be required at Kendoon for the successful energisation of the Kendoon transformer and the Kendoon / New Cumnock 132kV Circuit.

Appendix 5: Table of abbreviations

Table 12: Table of abbreviations

Abbreviation	Definition
AVC	Automatic Voltage Control
AVR	Automatic Voltage Regulator
BES	Battery Energy 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 on Line (Energisation Strategy)
DRZ	Distributed ReStart Zone
DRZC	Distributed ReStart Zone Controller
EfW	Energy from Waste
EHV	Extra High Voltage
EMT	Electro-Magnetic-Transient
ER	Engineering Recommendations
ESQCR	Electricity Safety, Quality Continuity Regulations
f	Frequency
GFC	Grid Forming Converter
GSP	Grid Supply Point
GT	Grid Transformer

Table 12: Table of abbreviations

Abbreviation	Definition
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
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 over voltages
TRV	Transient Recovery Voltage
WF	Wind Farm

National Grid Electricity System Operator
Faraday House
Warwick Technology Park
Gallows Hill
Warwick
CV34 6DA
United Kingdom

Registered in England and Wales
No. 11014226

nationalgrideso.com