RaaS

Resilience as a Service

Work Package 2:
Front-End Engineering Design (FEED) report

Handed over by: E.ON Business Solutions GmbH

Status: Final

Confidentiality: For Publication

Version: V2.0

Date: 17/02/2021

Scottish & Southern Electricity Networks

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Version Control

Version	Date	Owner	Status
1.0	02/02/2021	E.ON	Issued for External Peer Review
2.0	17/05/2021	E.ON	Final for publication

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1. Contents

2. Project Abstract

This abstract summarises the aims and structure of the project to provide context for the Front End Engineering Design work.

The RaaS - Resilience as a Service - project is funded by the Network Innovation Competition (NIC) of the UK's Office of Gas and Electricity Markets (Ofgem). It is being delivered by three partners; Scottish and Southern Electricity Networks (SSEN), E.ON and Costain. SSEN are the distribution network operator (DNO) for the project evaluating the technical feasibility and financial viability from a DNO perspective; E.ON are an energy solutions provider who are leading the technical delivery of the battery system and developing the investor business case; Costain are a management consultancy acting as programme managers and providing input to the market design assessment. The project has a budget of £10.9m.

The aim of the project is to investigate the technical application and commercial opportunities associated with the provision of a new market based flexibility service that could be used by DNOs to improve network resilience in remote or rural areas. This service would use a Battery Energy Storage System (BESS) together with local Distributed Energy Resources (DER) to supply customers in the event of a fault on the network.

This project will determine how network resilience can be improved in a cost-effective manner for customers in areas susceptible to power outages, where traditional reinforcement or use of DNO owned standby generation to improve security of supply would be prohibitively costly. This can be achieved by a DNO procuring RaaS from a third-party service provider, who can stack revenues through participation in other flexibility markets. In addition to developing the technical solution, the project seeks to evaluate the financial case from a DNO perspective while giving insight to RaaS service providers on the investment case necessary, and optimal flexibility markets to operate in.

In the first phase, the project focuses on site selection, system design for the chosen demonstration site, and refinement of the business case. This phase will validate whether the concept is technically feasible and financially viable and will inform a decision to be made in 2021 on whether to proceed with the deployment and operation of a RaaS system at the chosen site for a trial period of up to two years.

Phase two of the project comprises the delivery, commissioning, and operation of the system in a test phase which is due to start in 2022. This will involve monitoring and evaluation of the system's performance as well as examining different combinations of flexibility services.

The Resilience as a Service concept offers a market-based solution to improve operational reliability and provide customers with a low carbon, cost effective and secure electricity supply.

The project is structured with the eight working packages described below.

WP1 – Project Management

WP1 contains all core project management activities carried out by each partner, with Costain leading the overall coordination.

WP2 – Front End Engineering Design

Initial design phase for the BESS and associated EMS to form the foundations for creating the detailed design for the demonstration site.

WP2 includes the following high-level tasks:

- Demonstration site selection and proposal development
- Front End Engineering Design (FEED) for the RaaS BESS and associated EMS

WP3 – Detailed Design

The Detailed Design concentrates on the technical design of the RaaS scheme and establishing the parameters in which the trial will operate.

WP3 will include the following high-level tasks:

- Identification and qualification of potential equipment suppliers
- Detailed design of controls, electrical integration, available Distributed Generation (DG) and the BESS
- Supplier selection and Energy Management System (EMS) development
- Construction, integration, commissioning and testing plans for the demonstration
- Development of the Trial Programme
- Health and Safety assessment

WP4 – Operational Optimisation

The conversion of market interactions analysis into a practical control system to be demonstrated in the operational phase of the project.

WP4 will include the following high-level tasks:

- Market analysis and techno-economic modelling
- Market integration
- Demonstration platform development

WP5 – Business Model

The detailed Design and Operational Optimisation outputs are brought together and expanded to form the Business Model for potential RaaS suppliers.

WP5 will include the following high-level tasks:

- Construct investment business case for RaaS supplier
- Draft Heads of Terms for RaaS method
- Develop the revenue stacking methodology

WP6 – Supply Chain Engagement

Accelerating the pace of RaaS market development by ensuring all DNOs and other potential market participants have the skills, tools and confidence to procure or provide RaaS solutions.

WP6 will include the following high-level tasks:

- Deep dive investigation into the full applications of the RaaS across Great Britain and lessons-learned activities from WP2-WP5
- Create system model and enterprise design of the RaaS system
- Use RaaS requirements to define value structure and produce proposed commercial strategy for the project
- Market consultation and engagement with potential RaaS service providers and supply chains
- Optimisation of commercial, delivery and operational models for RaaS

WP7 – Demonstration Delivery and Operation

Construction of the RaaS demonstration scheme and implementation based on the Detailed Design and Trial Programme. The project will install and operate RaaS at the selected trial site, and following successful demonstration will develop plans for a second site to be implemented beyond the conclusion of the project.

WP7 will include the following high-level tasks:

- Procurement of assets, products and services
- Permitting and construction of RaaS and network assets
- System integration
- Commissioning and testing
- Training
- Operation, Monitoring and optimisation
- Conclusion of the trial via decommissioning of assets or transfer to business as usual and ongoing operation

WP8 – Dissemination

WP8 contains all dissemination and documentation for the project as a whole and all work package specific activities.

- Dissemination will occur throughout the project by way of presentations, publications, and events tailored to the relevant project stakeholders

Dissemination will be carried out in line with key stages of RaaS, and in conjunction with other relevant innovation projects and the ENA's Open Networks project.

3. Executive Summary

The Front End Engineering Design (FEED) Report marks the conclusion of Work Package 2 and together with the Site Selection Report forms Project Deliverable 1 of the Resilience as a Service (RaaS) project.

This document gives a detailed overview of the technical requirements for the Resilience as a Service (RaaS) solution, including detailed analysis on key aspects of how the third party owned system will integrate with the existing network. The report contains the following key sections:

- Data Sources and Assumptions
- Grid Studies
- Calculation of Required Usable Energy Capacity for RaaS
- BESS Design for Drynoch Primary Substation
- RaaS Operational Considerations
- Stakeholder Engagement
- Impact of Results on Further Project Activities
- Report Summary and Key Learning for Future Applications

The content identifies and discusses the key challenges of implementing a RaaS solution into an 11kV network and proposes potential solutions that might be applicable for a range of different sites. It also provides further details on the proposed design of the Battery Energy Storage System (BESS) for the RaaS demonstration scheme at the selected site of Drynoch primary substation on the Isle of Skye. Furthermore, it outlines the proposed operational processes for successful operation of the RaaS solution.

Extensive Grid Studies have been undertaken based on detailed information of the existing Drynoch 11kV network, literature sources and discussions with experts from Scottish and Southern Electricity Networks' (SSEN) business. Modelling, primarily using a DigSilent PowerFactory model, has been undertaken in order to determine implications for protection systems and earthing design for the 11kV network to be supplied in island mode by a BESS. Furthermore, the capability to black start the network using a BESS and the influence of downstream Distributed Generation (DG) has been analysed. Simulations have been done based on the existing network arrangement; for two different islanding scenarios with BESS inverter ratings of 3 MVA and 5 MVA; and for grid mode with BESS connected in parallel. The results show that it is possible to retain the current primary protection scheme at Drynoch to operate safely in islanded mode with proper selectivity when oversizing the rating of the BESS inverter to 5MVA in order to provide the required short circuit currents, but that new protection measures must be introduced to provide two means of backup protection when supplying the network in islanded mode, as required by ENA standards for grid operation. The results also demonstrate that a BESS with an inverter rated to the minimum acceptable power rating for the site of 3MVA, could not integrate with the existing network protection settings adequately. Potential solutions have been identified and analysed however require further analysis by SSEN in the next phase of the project.

The RaaS project aims at being able to seamlessly transition from grid connected mode to BESS islanding in the event of a fault on the upstream 33kV network. It also aims to black start the 11kV network from the BESS in the event of a black out downstream of the primary substation. For this, the Grid Studies have been used to analyse the conditions required to enable a successful black start for a 5MVA rated BESS inverter. A successful black start process can be provided using the BESS by implementing Point on Wave (PoW) switching at the Circuit Breakers (CB) of the two main feeders.

This limits inrush currents to 1pu or less of cumulated transformer nominal currents. Additionally, a switching process using the existing pole-mounted CBs (PMCBs) via telecontrol should be established to sectionalise the 11kV feeders, with the expectation that inrush currents on these feeders does not exceed 3pu. These assumptions will be evaluated during the Detailed Design phase of the project.

The FEED has also applied the minimum required BESS capacity for the RaaS service defined within the Site Selection Report. The conclusions from the battery sizing analysis were that the BESS should have sufficient capacity to cover 90% of all potential 4-hour outages in a year.

Based on the requirements identified through the Grid Studies and the required minimum usable BESS capacity a 4.2 MWh battery combined with a 5 MVA grid-forming inverter and a 3MVA transformer, which can be overloaded during faults, is considered as the right solution for the application of RaaS at Drynoch primary substation. For the controls of the BESS the requirements are defined that the BESS will require a three second zero voltage fault ride through capability in order to supply the faults in island mode. This requires a deviation from the standard G99[1] requirements. Furthermore, it needs to be ensured that the islanding of the 11kV system can be done before disconnecting the BESS due to G99 protection in order to perform a seamless transition to island mode.

With the basic sizing parameters of the BESS defined, a Layout of the BESS in Drynoch substation together with a single line diagram are presented as a first draft for the implementation. An initial check of the feasibility of these specifications has been made with equipment manufacturers, with more detailed studies being undertaken in the Detailed Design phase of the project.

To achieve seamless transition from grid connected mode to island mode in the event of a fault on the 33kV supply, a grid-forming inverter working always as a voltage source is expected to be the more reliable method compared to an inverter that operates in grid-following mode working as a current source whilst connected to the 33kV grid. An initial description of the synchronisation switch settings for Loss of Mains (LoM) detection and reconnection to the grid system is presented. Further simulations of possible fault conditions will be done within the detailed design work to define the final settings and functionality of the synchronisation switch.

Initial operational processes have been developed that define the interfaces between the RaaS Provider and the DNO. An automatic response triggered by the DNO RaaS Controller and implemented via the BESS EMS is planned for all processes regarding seamless transition into island mode, including initiating a black start procedure or reconnecting to the 33kV grid from islanded operation. In addition, the DNO control room will have a supervision function with the right to make decisions regarding enabling the RaaS system, and to maintain safe conditions to black start the 11kV network.

The FEED has been issued for peer review to invite questions, challenge and insight from a range of external stakeholders. All feedback received will be used to inform development of the detailed design for the proposed scheme and help ensure that what's developed through the project is as broadly applicable as possible across different network locations.

[1] ENA ER (Engineering Recommendation) G99 provides guidance on the technical requirements for the connection of generating plant (any source of electrical energy, irrespective of the type or prime mover) to the distribution systems of licensed DNOs

4. Introduction

This section sets out the scope of the Front End Engineering Design (FEED) Report and summarises the process used to identify the trial site selected for the RaaS project. These aspects of WP2 'Front End Engineering Design' form part of Project Deliverable 1 as defined within the Project Direction[2] for RaaS.

4.1. Scope and Structure of the FEED Report

This report gives a detailed overview of the technical challenges and potential resolutions identified through the project work, with consideration to how a RaaS scheme will integrate with the existing 11kV network. The document provides details on the specifications developed for the RaaS solution, and the initial design of the RaaS scheme for potential demonstration at Drynoch primary substation. In addition, the operational processes needed to switch into island mode, to initiate black start of the network, and to reconnect to the grid, are discussed.

The report is structured with the following key sections:

- Data Sources and Assumptions
- Grid Studies
- Calculation of Required Usable Energy Capacity for RaaS
- BESS Design for Drynoch Primary Substation
- RaaS Operational Considerations
- Stakeholder Engagement
- Impact of Results on Further Project Activities
- Report Summary and Key Learning for Future Applications

The FEED builds on previous work within WP2 which provided an evaluation of battery sizing requirements and supported selection of the potential trial site for RaaS. Extensive grid studies have been used to determine the effects of the Battery Energy Storage System (BESS) on network protection and earthing, analysis on the integration with existing equipment, and the requirements for the BESS unit to manage different fault conditions on the network.

The report also presents a calculation of the required minimum usable energy capacity of the BESS needed to meet the RaaS resilience requirements for Drynoch, as set out in the Site Selection process.

Combining the conclusions and requirements from these aspects of work, the initial BESS design has been developed for the demonstration site, and operational processes required to switch into island mode and reconnect to the grid as well as black start the network have been proposed. This report is presented for peer review to invite questions, challenge and insight from a range of external stakeholders. The design and all feedback received will be used to inform development of the detailed design for the proposed scheme and functional specifications for procurement of the BESS within Work Package 3 'Detailed Design'.

The roles and responsibilities of all teams and individuals required for the operation of the RaaS concept from the DNO side will also be defined in detail during WP3 and development of the detailed design concept.

[2] www.ofgem.gov.uk/system/files/docs/2020/01/project_direction_-_raas_-_signed.pdf

4.2. Site Selection Report

A key WP2 activity required prior to development of the FEED was the site selection process undertaken to identify the preferred potential demonstration site for RaaS, subject to a positive stage gate decision to proceed to the trial phase. This work was undertaken in 2020 and the process and conclusions are presented in the RaaS Site Selection Report. To inform the selection process a conceptual engineering design was developed, which provided an understanding of equipment that may be required, factors that should be considered, and an understanding of the required system size and the corresponding space requirements to install a BESS.

During the site selection process, the project team determined the site best suited for the trial phase of the RaaS project based on four key categories:

- Potential benefits of the solution for the customers connected to the network
- Suitability for meeting project objectives (including potential incorporation of local Distributed Generation (DG))
- Practicality of delivery and operation within project timeframes and budget
- Technical design and integration

Using these criteria, Scottish & Southern Electricity Networks (SSEN) derived a shortlist of five sites, which were the further assessed collaboratively by SSEN and E.ON via desktop analysis and completion of site surveys. Based on the decision matrix shown in Appendix 1 Table 28, the primary substation at Drynoch, Isle of Skye, was selected as the potential demonstration site. This site will allow the project to trial a range of factors relevant to the RaaS concept; would demonstrate the benefits of applying a RaaS solution through improved service to customers, increased electricity export for local generation resources, and a reduction in Customer Interruptions (CIs)/ Customer Minutes Lost (CMLs) for the DNO; and supports the trial nature of project with regard to capability to deliver within time and budget.

4.3. Description of Drynoch Primary Substation

4.3.1. Location of the Site

Drynoch is located near the south-east tip of Loch Harport on the west coast of Skye in the Highlands of Scotland (see Figure 1), and supplies power to around 1000 customers connected to the electrical grid. It is a 33kV to 11kV primary substation 33kVwith a single 12.15 km radial line. The peak demand over the last five years was 1.78MVA, and 0.63 MVA of embedded generation connected to the 11kV network, with another 0.1MVA of planned capacity to be installed in 2021. Over the last five years, a total of 17 supply interruption incidents have been recorded, of which 6 were classified high CIs (>500 customers). The average time off supply across these incidents was 34.8 minutes.

The substation is located in a fenced compound beside the B8009 and alongside the River Drynoch, south of Drynoch village (Figure 2).

Figure 1 - Location of Drynoch on the West Coast of Skye

Figure 2 - Location of Drynoch Primary Substation

4.3.2. Existing Primary Substation Arrangement

Drynoch primary substation is connected on a single radial feeder at 33kV from Broadford Grid, with the main equipment within the substation compound being:

- A single 2.5MVA Yyn0 33/11kV (outdoor) oil filled transformer connected to the incoming overhead line
- A neutral/earthing connection that connects the 11kV winding of the above transformer to earth.
- A secondary 11kV switchboard that has an incoming circuit breaker from the transformer and two outgoing circuit breakers which feed to Braemeadle and Carbost/teed Crossal.

4.3.3. Distributed Generation Connected to the 11kV Network

The DG associated with Drynoch (connected to the 11kV distribution network downstream of the substation) comprises the following existing and planned installations:

- Two wind turbines – existing installations, one with a maximum export capacity (MEC) of 0.33MW and one with a MEC of 0.30MW
- One hydroelectric scheme – expected installation in 2021, with an MEC anticipated to be 0.10MW

5. Data Sources and Assumptions

To complete the Front End Engineering Design (FEED) report, different sources of data on the existing Drynoch 11kV network have been used. The main data required was:

1) Site specific load data to complete the BESS sizing for Drynoch, and
2) Information required as input to the grid studies on the Drynoch network, such as: topology, existing protection equipment and settings, earthing arrangements and transformer ratings.

To the greatest extent possible, real values have been used, based on equipment documentation and existing measurements. In cases where precise information was not available or could not be collected on site due to ongoing Covid-19 travel restrictions, reasonable assumptions have been made. The selection and validation of data and assumptions has been done in close collaboration with Scottish and Southern Electricity Network (SSEN) experts.

The following chapters describe all data sources used (Table 1) with references to how each source was used for different parts of the system (Table 2). Appendix 1 provides additional details on the parameters that have been taken from the sources or which have been assumed for this work.

5.1. Data Sources

Table 1 - Data Sources Summary Table

Data source	Description	Provided by
Load data	Load data for Drynoch primary substation, years 2015 to 2019 in half-hourly format. Load data was measured at the primary substation from both downstream feeders.	SSEN
Sincal® Model	Siemens' PSS®Sincal is a simulation software for the analysis and planning of power networks. A specific PSS®Sincal model for the Drynoch 11kV network was used which provides data and information on the existing network infrastructure.	SSEN
Scottish Hydro Electric Power Distribution (SHEPD) Long Term Development Statement (LTDS)	Long Term Development Statement for Scottish Hydro Electric Power Distribution's Electricity Distribution System. The main purpose of the LTDS is to assist existing and prospective users of the electricity distribution network in assessing opportunities available for making new connections, or for additional use of the SHEPD distribution system.	SSEN
Drynoch Primary SLD	Single Line Diagram for Drynoch Primary Substation.	SSEN
Drynoch 33/11kV Substation Protection Settings	Substation protection settings. Substation: Drynoch 33/11kV, rev 3, 07 December 2020	SSEN
PMCB Settings	Current settings for Pole-Mounted Circuit Breakers on feeders 011 and 012 Date: 03.12.2020	SSEN

TG-PS-813	Technical Guide for Power System Protection On SSEPD Networks, rev 1.01, May 2020	SSEN
TG-NET-OHL-005	Fuses and Automatic Sectionalising Links for High Voltage (HV) Pole Mounted Plant- Design, Installation and Maintenance Standard, rev 1.00, June 2018	SSEN
TG-NET-SST-005	Secondary Distribution Substations; Common Clauses - Design and Installation Standard , rev 1.01, February 2020	SSEN
SP-NET-SST-010	Specification for 11kV and 33kV Pole Mounted Transformers, rev 2.00, March 2019	SSEN
SSEN GIS Tool	The SSEN GIS Tool provides information to eligible parties with an account (e.g. ICPs (independent connection providers) – who can perform HV connections) on certain standard information, e.g. transformer ratings and configuration	SSEN
Lecture documentation "Overhead Lines"	Documentation of university lecture on Overhead Lines, given by Prof B. R. Oswald, Institute for Energy Supply and High Voltage Technic, University of Hannover, 2005	E.ON
D. Oeding, B. R. Oswald: "Electrical Power Plants and Grids"	Dietrich Oeding, Bernd R. Oswald „Elektrische Kraftwerke und Netze", 7. Auflage, Springer-Verlag Berlin Heidelberg, 2011 (German engineering standard literature for electrical energy supply)	E.ON
DRIESCHER Documentation	Manufacturer documentation from DRIESCHER High Voltage – High Power fuses according to EN 60282-1, see Appendix 1 Figure 92.	Elektrotechnische Werke Fritz Driescher & Söhne GmbH, www.driescher.de
SIBA Documentation	Manufacturer documentation from SIBA Low Voltage Fuses as provided in https://siba.de/upload/Downloads/kataloge/NH-Sicherungen.pdf, December 2020	SIBA GmbH, www.siba.de
Engineering Standards	Energy Networks Association Engineering Recommendation G99 Issue 1 - Requirements for the connection of generation equipment in parallel with public distribution networks on or after 27 April 2019 Energy Networks Association Engineering Recommendation G5 Issue 5 - Harmonic voltage distortion and the connection of harmonic sources and/or resonant plant to transmission systems and distribution networks in the United Kingdom Energy Networks Association Engineering Recommendation P2 Issue 7 - Security of Supply Energy Networks Association Engineering Report 130 Issue 3 - Guidance on the application of Engineering Recommendation P2, Security of Supply Energy Networks Association Engineering Recommendation P28 Issue 2 - Voltage fluctuations and the connection of disturbing equipment to transmission systems and distribution networks in the United Kingdom	Energy Networks Association National Grid ESO SSEN British Standards Institution

	Energy Networks Association Engineering Recommendation P29 Issue 1 - Planning limits for voltage unbalance in the UK for 132 kV and below Energy Networks Association Engineering Recommendation S34 Issue 2 - A guide for assessing the rise of earth potential at electrical installations Energy Networks Association Technical Specification 41-24 Issue 2 - Guidelines for the Design, Installation, Testing and Maintenance of Main Earthing Systems in Substations Energy Networks Association Technical Specification 41-36 Issue 3 - Switchgear for Service up to 36kV (Cable and Overhead Conductor Connected) The Electricity Safety, Quality and Continuity Regulations 2002. National Grid ESO - Security and Quality of Supply Standard (SQSS) National Grid ESO - The Grid Code The Distribution Code of Licenced Distribution Network Operators of Great Britain British Standards Institution BS EN 60282-1 ESCQR regulations	
SSEN Project Team	Inputs provided by the SSEN Project Team based on feedback from internal operational staff and on-site knowledge.	SSEN
Assumptions	Assumptions have been made for parameters that could not be validated based on existing information. Assumptions have been discussed and aligned between E.ON and SSEN's Project Team and individual operational staff such as the Protection Standards Team. The assumptions are based on industry standards, experience, and input from experts involved in the RaaS project.	SSEN Project Team, E.ON Project Team, SSEN operational staff & protection standards team, Staff from E.ON's grid operator Westnetz, UK-based engineering consultancy CPW (E.ON consultant for FEED work)

5.2. System References

The table below (Table 2 - System References Summary) gives a description of how the sources described were used and information corroborated.

Table 2 - System References Summary

Aspect	Sources	Comments
BESS Sizing	Load Data	The load data is net of downstream Distributed Generation (DG), thus showing lower values than actual consumption. This is in line with the goals of the RaaS project to enable operation of downstream DG also in island mode by using a BESS, showing the benefit compared to using diesel gensets. It is assumed that during stable operation of the 11kV network as an island the DG will operate as normal. Therefore, the data used reflects the expected load on the BESS during island operation. The BESS sizing is described in detail in Section 8.1.
33kV grid	Drynoch Primary SLD SHEPD LTDS Drynoch 33/11kV Substation Protection Settings SSEN Project Team	For further details see Appendix 1 Table 14.
11kV primary substation – primary transformer	SSEN Project Team D. Oeding, B. R. Oswald: "Electrical Power Plants and Grids" Drynoch Substation SLD Drynoch 33/11kV Substation Protection Settings	Some values assumed based on literature and industry standards. For details see Appendix 1 Table 15
11kV primary substation – Earthing and star point treatment	SSEN Project Team	For further details see Appendix 1 Table 17
11kV grid topology	Drynoch 33/11kV Substation Protection Settings PMCB Settings Sincal® Model Lecture documentation "Overhead Lines" D. Oeding, B. R. Oswald: "Electrical Power Plants and Grids" Assumptions	Data on 11kV feeder protection, delayed auto-reclosing (DAR), PMCB telecontrols, positions, line data and connection of downstream DG. Details provided in Appendix 1 Table 18.
Secondary substations – secondary transformers	Sincal® Model D. Oeding, B. R. Oswald: "Electrical Power Plants and Grids"	Data on secondary transformers, where three phase as well as split phase transformers have been used. For details on three phase transformers see Appendix 1 Table 21.

	SP-NET-SST-010 SSEN Project Team Assumptions	For data on split phase transformers see Appendix 1 Table 22.
Grid interconnection LV to HV	Sincal® Model Source? TG-NET-SST-005 TG-NET-OHL-005 DRIESCHER Documentation SIBA Documentation Assumptions	For details on grid interconnection data see Appendix 1 Table 23 with further references to HV and Low Voltage (LV) fuse data as well as exemplary HV fuse tripping times.

6. Grid Studies

The previous work in the Resilience as a Service (RaaS) project identified two main topics to be investigated with grid studies to ensure safe and reliable operation when integrating the BESS system with the existing 11kV network:

1. Adequate performance of protection system, and
2. feasibility of a 11kV local black start

Quantitative studies are performed to investigate the above topics.

In Section 6.1 the performance of existing protection equipment under different scenarios of BESS configuration is analysed, with suggestions on alterations to the existing settings that may be required. In Section 6.2 the black start performance of the BESS is analysed to highlight additional requirements that are not used in typical distribution grid operation, such as the utilisation of Point-on-Wave switching[3].

Finally, suggestions are made in Section 6.3 and 6.4 on alterations to the existing protection and the BESS design.

Aspects to be investigated further in the Detailed Design phase are pointed out throughout the whole section and highlights are summarised again in Section 11.1.1.

6.1. Protection and Earthing Analysis

In the first part of the grid studies an analysis on the performance of the protection system under different scenarios is undertaken. Section 6.1.1 sets out the performance requirements defined for protection of the 11kV network at Drynoch. Section 6.1.2 describes the methodology and modelling approach applied. Section 6.1.3 explores the resulting system model behaviour in terms of influences and plausibility. Sections 6.1.4 to 6.1.6 contains the analysis of the behaviour of the existing protection system. Section 6.1.7 summarizes all findings from Sections 6.1.3 to 6.1.6, concluding with suggestions for measures to enable an operation of the RaaS system that meets all protection requirements.

6.1.1. Protection Performance Requirements for Analysis

Target performance requirements for grid protection are defined in order to enable the performance assessment. The requirements are determined using multiple sources, with workshops between E.ON and Scottish and Southern Electricity Networks (SSEN) being utilised to gain a common understanding on the most relevant aspects of the requirements applying to the real system. The main sources of information that define the requirements are:

1) General standards for DNOs in the UK such as the Distribution Code
2) ER G99 - Requirements for the connection of generation equipment in parallel with public distribution networks
3) SSEN specific standards

[3] this builds on PoW switching experience from SSEN's LEAN - Low Energy Automated Networks - innovation project, as documented in the SDRC 9.5 'Monitoring & Analysis' report - www.ssen.co.uk/WorkArea/DownloadAsset.aspx?id=16848

4) Operational requirements of SSEN
5) Initial discussions with SSEN protection standards team

At this stage in the project the defined requirements list is non-exhaustive. The Detailed Design phase will define additional requirements based on further regulations such as ENA TS 41-24, which has been omitted for this study due to complexity.

Table 3 summarizes the key requirements that were agreed within the project team to be used in the grid studies in the different modes of operation.

Table 3 – Grid Study Requirements

Topic	Level of requirement	Requirement
Grid Only Mode	Shall	Faults in 11kV Grid shall be cleared within a maximum of 3s for short circuit faults and 10s for earth faults.
	Should	Faults in 11kV Grid should be cleared within a maximum of 1s for short circuit faults and 3s for earth faults.
	Shall	On the 11kV side of the secondary substations protected by fuses shall be cleared within the upper bounds defined in the two points above.
	Will	Only bolted faults will need to be considered in the assessment.
	Shall	Fault in the 11kV grid shall be cleared fast enough not to damage any assets beyond the point of fault.
	Will	The tolerable fault clearing times will typically be assessed based on the involved components' short circuit ratings.
	Shall	Faults in the 11kV grid shall be cleared selectively.
	Shall	Main 11kV feeder circuit breakers and PMCB shall be selective.
	Shall	Up to three serial PMCB of a single feeder shall be selective.
	Should	Feeders with more than 3 serial PMCB should selectively clear a fault.
	May	Selectivity within a feeder may be achieved by grading of reclosing schemes.
	Shall	Fault clearing by 11kV side fuses of secondary substations shall be selective to upstream protections.
	Shall	At least one level of effective backup protection shall be implemented remotely.
	Should Not	In accordance with G99 the DG installed with point of common coupling (PCC) at MV-level should not need to disconnect for fault clearing within 1s.
BESS Only Mode	Should	The requirements of scenario "Grid" should be equally fulfilled.
	Shall	Faults in the 11kV grid shall be cleared within the maximum time defined for the scenario "Grid".
	May	The fault clearing may be done by switching of the Island.
	May	Selectivity of fault clearing may be compromised.
	Shall	Backup protection shall be implemented by at least two means of fault clearing.
	May	Backup protection may be implemented without grading.

	Shall	The BESS shall be disconnected as the last asset exporting to grid.
	May	DG may need to disconnect.
Grid + BESS mode	Shall	The requirements of scenario "Grid only" shall be equally fulfilled.
	Shall	The BESS shall disconnect according to G99.
	May	Backup protection by primary substation transformer 11kV devices may be compromised while the BESS remains as a fault current source.[4]
	Should	The Grid should be disconnected as the last feeding instance in case of 11kV feeder faults.
	Shall Not	When a fault occurs on 11kV network the BESS SHALL NOT attempt to transition to island mode.

6.1.2. Methodology of Protection and Earthing Analysis

The following section describes the methodology used and the models applied for the quantitative grid protection studies for the application of RaaS in the Drynoch 11kV network.

6.1.2.1. Goals and Design of Grid Studies

The goals of the grid protection studies are:

1. To give evidence on the degree of fulfilment of performance requirements of the grid protection system, depending on its design and the settings applied.
2. To derive applicable measures to satisfy these requirements, including:
    a. a redesign or reparameterization of the protection system, and
    b. design requirements for the BESS system and its grid integration.
3. To create transparency on the required efforts to fulfil those requirements.

System level studies are performed to determine approximate values for the fault currents and voltages on the Drynoch network in case of faults for different operational scenarios, BESS design variants, as well as fault points and types.

The studies focus on fault entry and the conditions during the faulty state, but not on the clearing of the fault. This offers flexibility through an easy to implement, iterative process where protection concepts and settings can be adapted or investigated as required. Ex-post analyses of the system fault behaviour with respective protection models do provide understanding on protection device reaction (tripping of relays, blowing of fuses), protection system performance (clearing times, selectivity) and BESS requirements (voltages, powers and currents).

There are some limitations to the approach, however, as only the first trip is modelled, and no cascading sequences of events can be investigated. Furthermore, transient stability of the system after selective fault clearing is not investigated. Despite the limitation, the approach is deemed sufficient for the FEED.

[4] When a fault occurs in the 11kV grid, both sources will inject fault current. The BESS may be the dominant source. Assuming a fault on a 11kV feeder and a failure to operate of the main feeder circuit breaker, the current fed by the primary transformer may be too low to trip its protection. The BESS may need to trip first and thereby enable a following trip of the primary transformer. This situation should be investigated in the Detailed Design phase in terms of the tripping time requirements for backup protection.

6.1.2.2. Definition of Investigated Scenarios

Several variants on the key input parameters and settings have been used to analyse a wide range of possible scenarios when operating a RaaS system.

Modes of operation

A successful RaaS operation requires stable and safe operation of the network in three distinct modes of operation, which were considered in the grid studies:

- **Grid only mode (Grid mode)** without BESS
- **Grid and BESS mode** with BESS operating grid-parallel
- **BESS only mode** with 11kV network islanded

The transition between these modes are not part of the quantitative FEED grid studies and is discussed in Section 9.

BESS inverter ratings

Different BESS grid side inverter ratings are considered for the grid studies of Drynoch primary substation. As the 33/11kV transformer at Drynoch primary substation has a rating of 2.5 MVA, a first BESS inverter rating of 3 MVA is modelled to account for potential oversizing for provision of flexibility services. Since initial tests showed 3 MVA likely to be insufficient to fulfil the posed protection requirements, a larger sized BESS inverter with 5 MVA is investigated in accordance with further sizing aspects:

- **BESS scenario 1** = 3 MVA
- **BESS scenario 2** = 5 MVA

Earthing

Different possibilities for the star point treatment of the BESS transformer were considered, depending on the operational scenarios as described in Table 4.

*Table 4 – Earthing scenarios for different operational scenarios. X: considered, n.a.: not applicable, *: only for investigation*

BESS HV Starpoint	Grid only mode	Grid and BESS mode	BESS only mode
Solidly earthed (NC)	n.a.	X*	X
Isolated (NO)	n.a.	X	n.a.

Investigated faults

Faults are investigated in the following areas:

- 11kV grid faults (primary substation busbar, feeders and secondary substation High Voltage (HV) busbar)
- LV grid faults (secondary substation LV busbar, feeder faults)

Faults downstream the LV customer cut-out fuse are addressed qualitatively.

Faults in the 33kV grid, inside transformers and faults inside the BESS system are considered out of scope.

The resulting investigated fault locations for HV faults and faults related to secondary substations are depicted in the topological map of the Drynoch site shown in Figure 3. LV faults are investigated at the marked chosen substation locations.

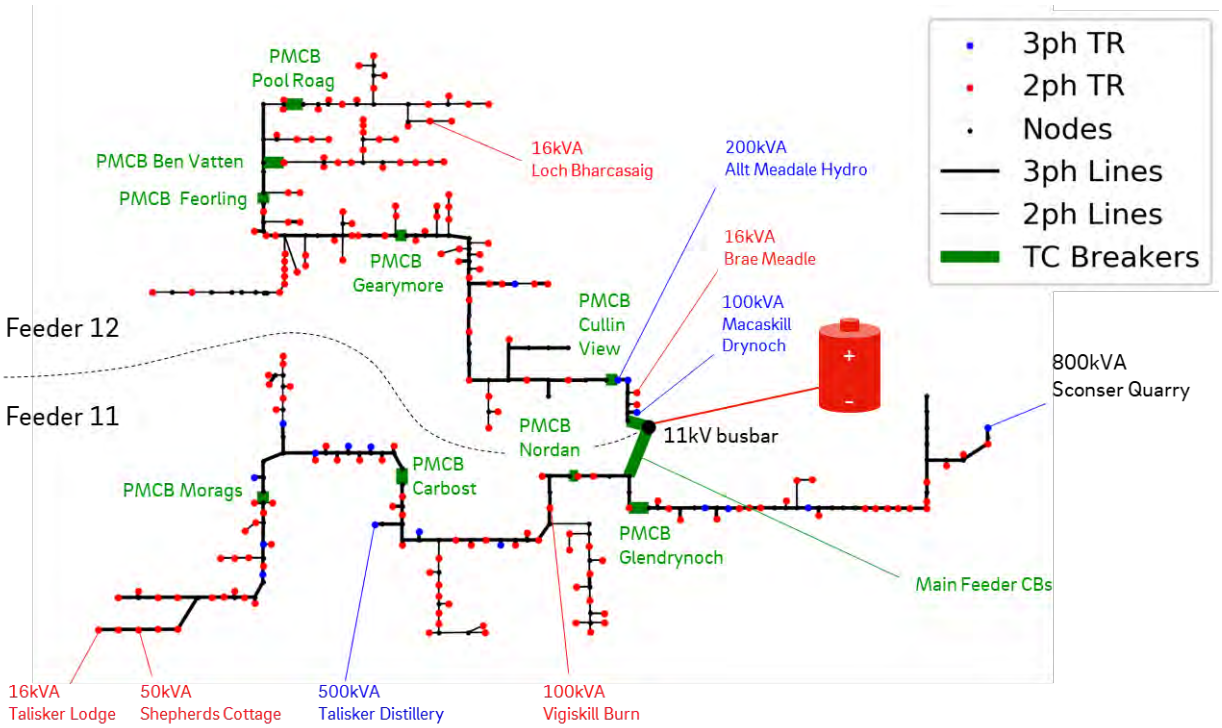


Figure 3 - Topological map of Drynoch 11kV network

HV grid faults are applied at each node depicted (nodes and secondary substations). Nodes are defined at branching points and at points on lines where a change of line type occurs. The high granularity of fault locations is deemed necessary due to the following reasons:

- Realistic assessment of distributed protection system and the existing reserves
- Unknown and non-standardised worst and best-case situations
- Different protection criteria assessed (current, voltage)

All HV faults are considered bolted or metallic, whereby the fault itself is modelled with no internal resistance. The types of faults considered are:

- 1ph-gr
- 2ph
- 2ph-gr
- 3ph (only 3-phase sections)

Longitudinal faults (relating to faults on lines or cables) are considered out of scope for the quantitative FEED studies but are generally relevant for Loss of Mains (LoM) protection.

Secondary substation LV busbar faults are applied at every distribution transformer shown in Figure 3. To be differentiated are the following major transformer types.

- three phase (3ph) transformers
- split phase (2ph) transformers

The following fault types are analysed:

- three phase transformers: 3ph, 2ph, 1ph-gr, 2ph-gr
- split phase transformers: 2ph, 1ph-gr

LV distribution feeder faults are applied to artificial single LV feeders of varying length at the marked locations. The latter are chosen to consider different:

- short circuit level situations
  - locations of low HV grid fault level (in Grid and islanded mode) in periphery of feeders
  - locations of high HV grid short circuit capacity near busbar
- relevant transformer types
  - split-phase: smallest (16kVA) to biggest (100kVA)
  - three-phase: smallest (100kVA) to biggest (800kV)

Fault types in LV feeders considered are:

- 3ph, 2ph, 1ph, 2ph-gr for 3-phase transformers
- 1ph for split-phase transformers

LV customer installation faults are not explicitly modelled. The expected fault currents are extrapolated by the previous analysis of the LV distribution feeder faults.

6.1.2.3. Modelling Requirements and Resulting Approach

Requirements on the modelling are defined by the project team based on experience from previous work and research done in this field, and are presented in Table 5. The following nomenclature applies for the requirements defined in this table:

- 'Shall' and its negative 'Shall Not' is used for a mandatory requirement.
- 'Will' and its negative 'Will Not' is used for a declaration of purpose or expression of simple futurity.
- 'Should' and its negative 'Should Not' is used for a non-mandatory desire, preference or recommendation.
- 'May' and its negative 'May Not' is used to indicate a non-mandatory suggestion or permission.

Table 5 – Summary of modelling requirements

Topic	Level	Requirement
Method	Shall	enable the calculation of short circuit and earth faults
	Shall	provide valid currents and voltages at different locations of the grid
	Shall	enable performing calculations across multiple voltage levels (e.g. 33kV, 11kV, 0,4kV)
	Shall	include both three-phase grid sections and split-phase grid sections, including transformers, loads and other key network components.
	Shall	be able to consider multiple sources of fault-current
	May	focus on the fundamental frequency component
Situations of Interest	Shall	calculate the steady state before fault entry
	Shall	calculate the results during the fault duration
	May	calculate the clearance and after fault recovery
	Should	use component models as simple as possible

Model Complexity and Parameter-ization	Shall	use component models as detailed as necessary to achieve accuracy
	Should	apply models with a level of detail that can be parameterized by available data
	May	utilise a reasonable amount of documented assumptions
Line Models	Shall	include a zero-sequence model
	Should	reflect the influences of neutral conductors, shields, earth return via earth etc
	May	cover those by according line data parameterization
	May	neglect modelling neutral voltage potential rise explicitly
Fault Models	Shall	enable the calculation of symmetrical and asymmetrical faults (phase-phase, phase-earth)
	Shall	enable calculating metallic faults with 0 Ω impedance
	Should	consider impedance faults
	May	neglect nonlinear behaviour of arcing faults
Source Models	Shall	Control of BESS etc. included sufficiently to reflect grid side fault behaviour
	Should	Include typical fault behaviour of grid side inverter (e.g. current limitation)
	Should	be capable of reflecting and dealing with non-linearities
	Should	consider steady state operation of the BESS, not its transient/dynamic operation
	Should	include control loops: achieve steady state, but not necessarily reflect fault transients accurately
	Should	enable studying the interaction of different sources of fault-current
	Should	allow for flexibility of BESS control approaches
Efficiency	Should	enable easy implementation of adaptions and extensions for efficient variations to studies
	Should	enable to easily incorporate information increments over duration of the project
	Should	be designed to easily perform further types of analysis in the next design phase: e.g. stability analysis

As set out in Table 5, steady-state fault-current calculations would be sufficient, but no adequate inverter models, especially for grid-forming inverters are readily available. Additionally, the focus is not only on point-of-fault currents, but also on far off relays making a more detailed model necessary. Furthermore, there are only small differences between normal and fault conditions, meaning some simplifications required for reliable steady state analysis with existing standardised approaches are not applicable.

An approach utilising Root Mean Square (RMS) simulations / phasor modelling has been utilised instead. Benefits and drawbacks of this modelling approach are given in Table 6.

Table 6 - Benefits and drawbacks of the RMS / phasor model selected

Pros	Cons
Well established and tested in commercial programs	Not standardised like IEC 60909
Fundamental frequency deviations can be modelled	Only fundamental frequency is considered, not direct current (DC), not harmonics
Can be used for sequential steady-state investigations	Not useable for phenomena like inrush, DC-transients, in detail frequency behaviour, etc.
Can use a range of component models from simplified to complex	Danger of false accuracy, resulting in incorrect conclusions based on overly specific models
Can be extended to "real" dynamic simulations for stability assessment	Models and data must be available, and control loop tuning needs to become more sophisticated with increasing level of detail
Incorporation of manufacturer models possible	

Considering the modelling requirements defined, RMS simulations are deemed to be acceptable for FEED investigations while also offering potential to be further utilised in the Detailed Design phase with more detailed BESS models made available by potential suppliers.

6.1.2.4. Modelling Assumptions

The modelling assumptions on the existing grid topology, grid components, protection etc. are described in Section 5.2 and Appendix 1 – Figures and Tables. In addition to this, Table 7 summarises the major assumptions on the model for the new BESS equipment to be installed as part of the RaaS demonstration scheme.

Table 7 - Summary of model specific assumptions

Unit	Category	Assumption
Batteries and BESS transformer	Ideal components	An ideal, DC voltage source of unlimited capacity and sufficiently high voltage for all cases is assumed in order to enable ex-post analysis. Transformer limbs are assumed to be identical, with linear characteristics, and not considering saturation.
	Aggregation	All BESS modules are assumed to have an equal and coordinated contribution to system power flows. The battery modules and the transformer are aggregated to be a single unit and are assumed to appear as a single source to the grid.
	LV Side Star Point Treatment	An earthing transformer is applied on the LV side in order to provide a reference potential and assist in modelling calculations.

		No zero-sequence current is ever observed during the simulations, justifying the assumption.
	Internal loads	Internal loads of 100kW are assumed and modelled at the internal busbar.
Grid side inverter	General	General model shown in Figure 4 with model parameters given in Appendix 1 Table 27 . Assumed to be a 3ph grid-forming inverter (GFI) focusing on the base frequency. DC components, harmonics, sub-harmonics etc. are neglected. The inverter is assumed to be able to control and provide positive and negative sequence components of voltage and current, and not deliver zero-sequence current. It's assumed to be capable of four-quadrant operation under both symmetrical and asymmetrical conditions. Assumed to be a positive and negative current source controlled by the described hierarchical control approach.
	Primary control	The control's voltage reference assumptions are as follows: • symmetrical positive sequence voltage system • settable amplitudes of the voltage (e.g. 1.0 p.u. of 11kV) • fixed frequency equal to the grid frequency (here: 50Hz) • settable fixed angular difference to the 33kV grid's Thévenin model's ideal voltage source A droop control influencing voltage reference amplitude and phase angle has been modelled but is not activated for the studies so far.
	Current limitation	A maximum current of 1.2 p.u. of nominal current per phase is assumed, with an equal lowering of positive- and negative-sequence reference currents by a current limitation unit is assumed to occur between the voltage and current control circuits. Current limitation block is depicted in Figure 5. Prior to current limitation by the control system, current limitation to within tolerable limits from the system hardware is assumed to occur without interruption of current supply. Non-switching anti-windup is assumed present, to avoid windup of superior control circuits.

	Fault current characteristics	It is assumed that fault currents are sinusoidal and that upon fault entry, no interruption of the current supply takes place.
	Fault ride through	Fault ride through capabilities are assumed to be unlimited and are analysed ex-post in terms of a requirement definition (voltage dip depth and duration, frequency excursions, overvoltage). For the parallel operation of grid and BESS, the latter is assumed to maintain synchronism. A steady-state fault situation is assumed to be reached if fault clearing is delayed.

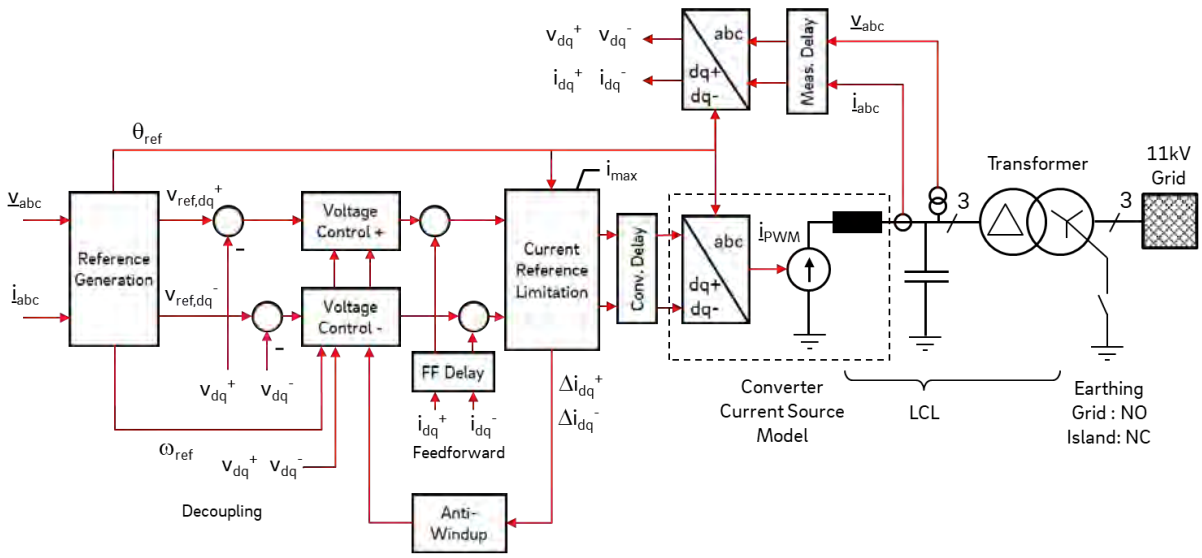


Figure 4 – Grid side inverter model used for grid protection studies

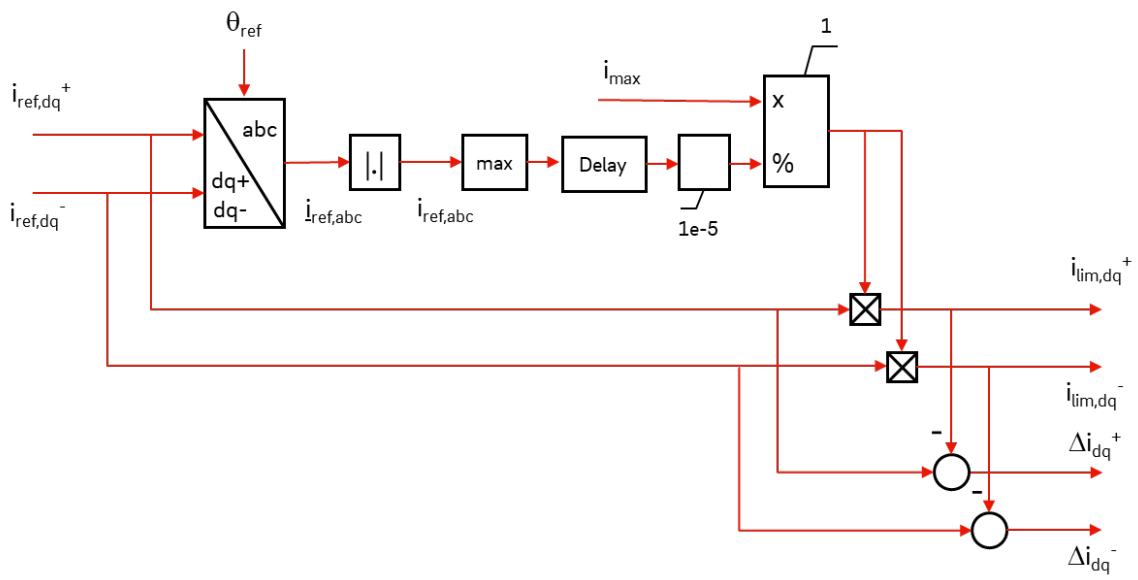


Figure 5 - Current Reference Limitation module of grid side inverter model

6.1.2.5. Modelling Process and Tools

The iterative process in Figure 6 shows the creation of the computable grid model for the FEED study.

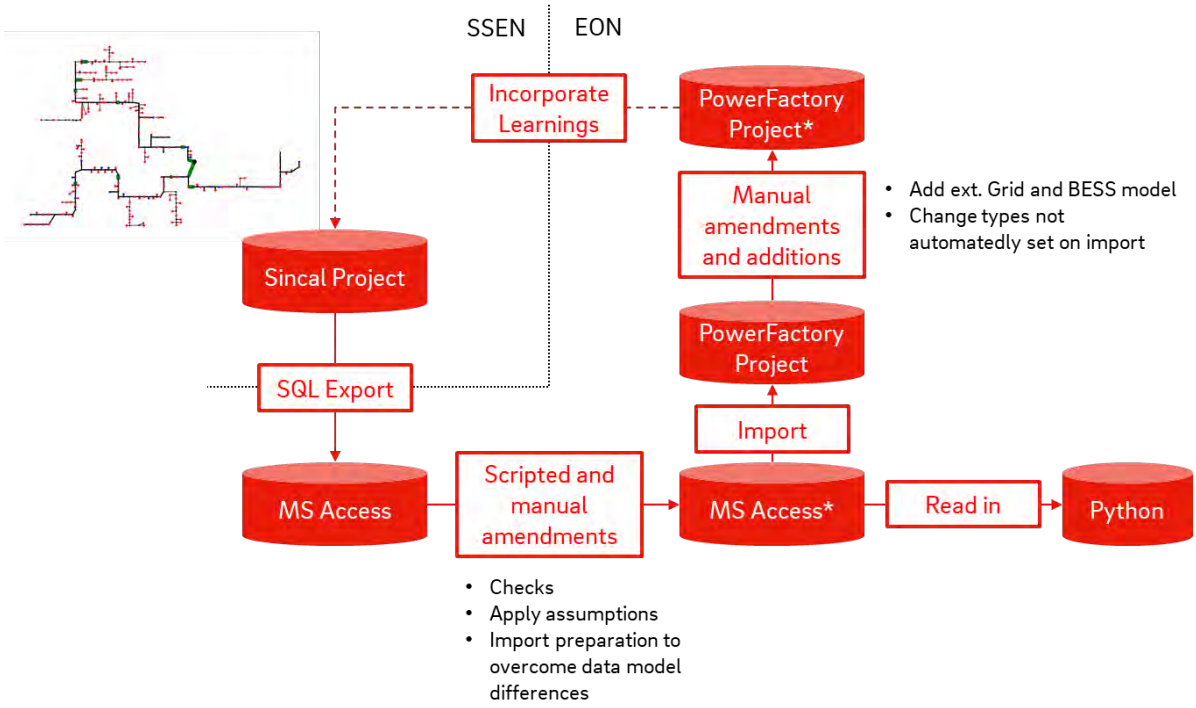


Figure 6 - Iterative modelling process

Based on this model a partially automated process shown in Figure 7 is used to perform the parameter variations in the different operational scenarios with several thousand computations.

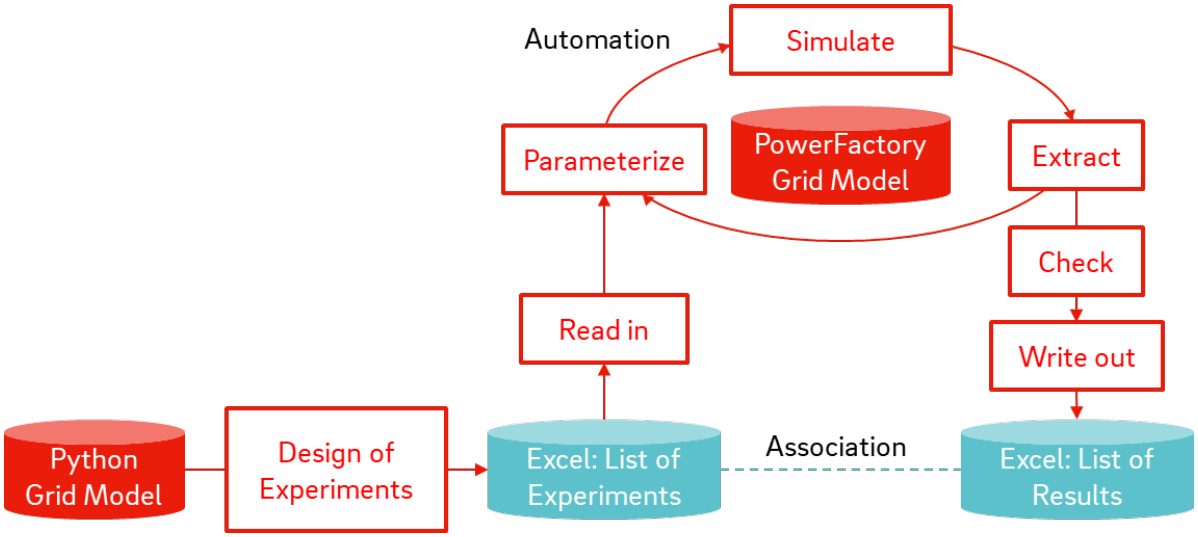


Figure 7 - Partially automated process for scenario calculations

Figure 8 shows the iterative process of the ex-post protection system performance analysis.

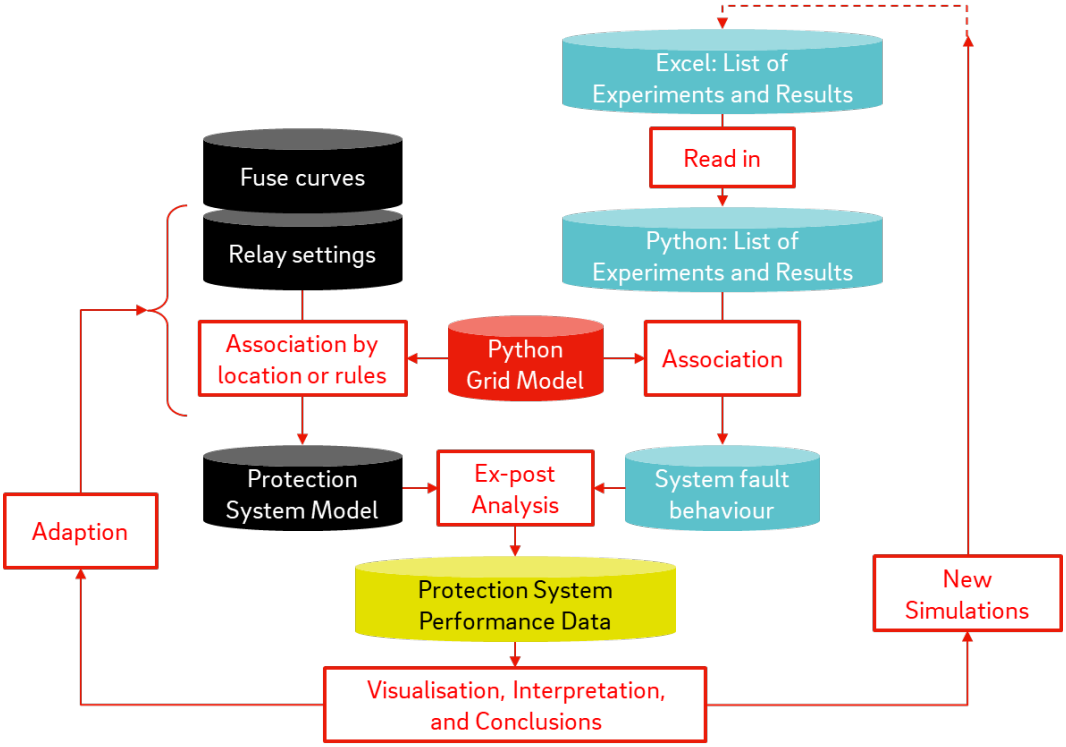


Figure 8 - Iterative process for ex-post protection system performance analysis

The processes shown are implemented in different tools and make use of automation facilities per tool and a toolchain specifically developed in Python.

6.1.2.6. Simulated sequence of events

The sequence of events simulated with the system model is always according to the following steps:

1. t=-0.5s: energisation of 11kV busbar from sources required depending on operational mode
2. t=-0.4s: switch on of first feeder
3. t=-0.2s: switch on of second feeder
4. t= 0.0s: fault entry

Figure 9 shows an exemplary simulation result for a 11kV busbar line-line fault in BESS only mode. The following observations have been made to provide proof that the modelling according to the requirements defined above was successful and to show the limitations as expected:

- The transients produced during switching of the feeders are caused by modelling assumptions but do not affect the steady pre-fault states achieved.
- A dynamic behaviour on fault entry is observable. After fault entry, a steady state fault situation is reached within approximately 20ms. Comparable dynamics result in most cases investigated.
- Exceptions are the no-load grid investigations, where instability occurs in a larger region of Feeder 12 faults (see Section 6.1.3 Influence of Loads). Such results are automatically detected and carefully removed before any interpretation.
- The existence of a steady state fault behaviour is achieved predominantly due to the assumptions on BESS control and the neglection of Distributed Generation (DG) infeed.
- The Detailed Design phase investigations will reveal cases where no steady state will exist.

Feature extraction occurs by saving the steady state value of all variables investigated.

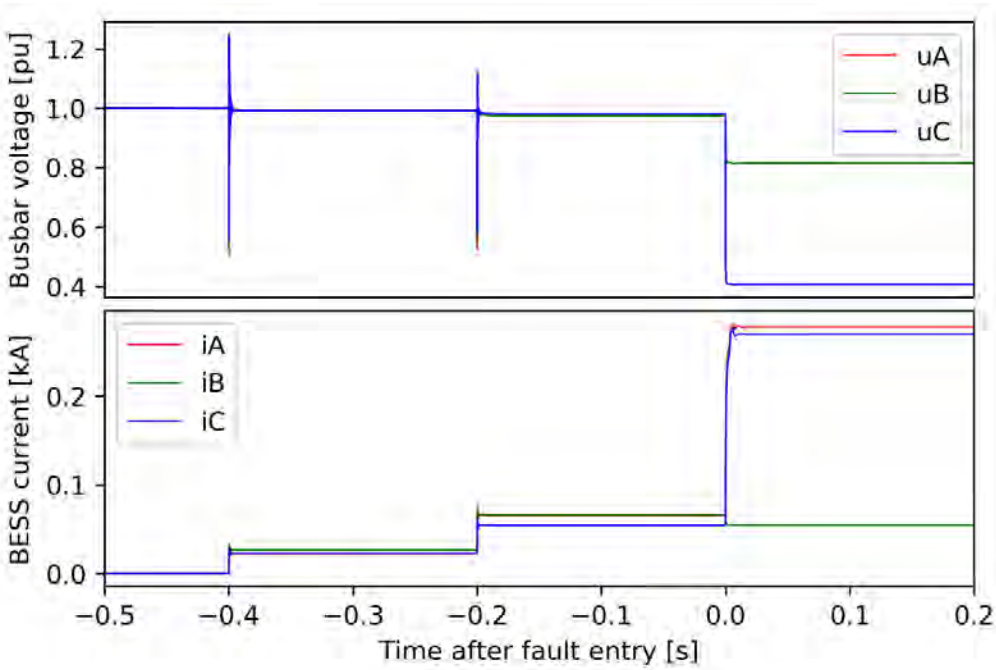


Figure 9 - Exemplary simulation result for a 11kV busbar line-line fault in BESS only mode

6.1.2.7. Calculation Methodology for Thermal Loads

It is necessary to confirm that the thermal limits of the electrical lines will not be exceeded during a potential fault event.

The thermal capability of each line is shown in Figure 10, where it is shown that Feeder 12 has a higher thermal fault current capability than Feeder 11.

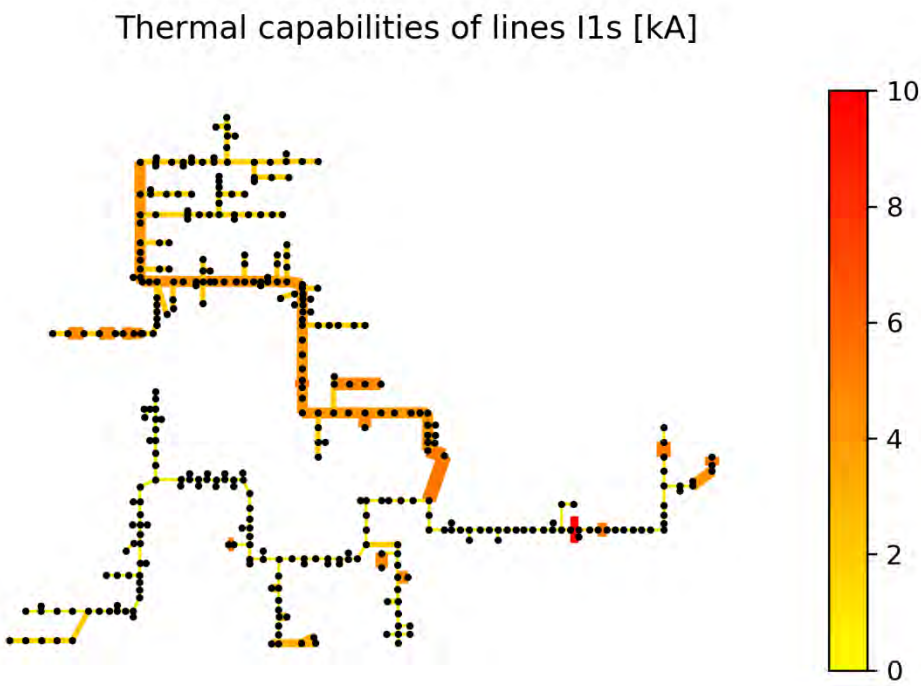


Figure 10 - Thermal capabilities of Drynoch 11kV network

Due to the varying fault durations and locations, to make a fair comparison and to simplify the modelling process, a typical method used for symmetrical faults is utilised, whereby it is assumed that fault current will flow in every phase, independent of fault type. The process used follows the steps described below.

Step 1: For every fault modelled, along the short circuit path from the BESS to the fault point, and across each line, the tolerable thermal current, $I_{th,tol}$ of each component is calculated.

This is done using the equations below where the parameters used are clearing time Tc, the rated 1s short circuit current I_{1s} which is given and determined by the overhead lines and cables used, and the rated clearing time T_{cr} which is set as 1 second accordingly.

If $T_c > T_{cr}$, then:

$$I_{th,tol} = I_{1s} * \sqrt{Tcr/_{Tc}}$$

Else:

$$I_{th,tol} = I_{1s}$$

Step 2: Determine the equivalent thermal fault current I_{th} experienced by each component using the equation:

$$I_{th} = I_{fault} * \sqrt{(m+n)}$$

where n is reflecting the influence of a decaying AC short-circuit amplitude and is chosen as n = 1 to represent a fault occurring far from a synchronous generator, and m is reflecting the influence of a decaying DC short-circuit amplitude and is set to m = 2 as a worst case.

Step 3: Determine the maximum thermal loading for each line for every fault, using the following equation, and plot the results considering the thermal capability of each line:

$$i_{th,max} = \max\{I_{th,i} \ / \ I_{th,tol}\}$$

6.1.2.8. Introduction of Results Diagrams

Various types of graphs are used to visualise the results. Examples of the graphs in this report are shown below to explain their interpretation.

An example of a *topological map* used is shown in Figure 11 below. This type of figure gives information on nodes or edges of the grid, where the arrangement of the nodes is not geographical but reflective of the SCADA system layout. Areas that are coloured are used to show points of interest depending on the criteria being considered

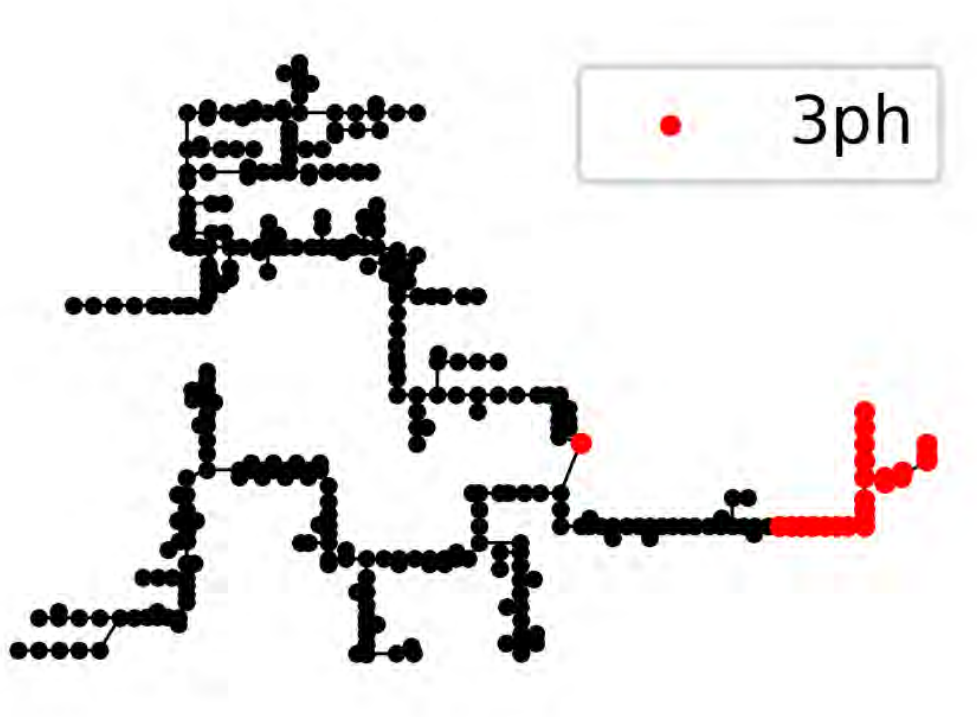


Figure 11 – Example topological map showing nodes where faults were applied

An example of a *3D topology-value map* is shown in Figure 12 below. This graph shows the same network topology illustrated in Figure 11, but with the y-axis representing a numerical value, typically the tripping time of protection devices in seconds. This allows a comparison of protection settings to different fault types, where a slower trip response is shown by a taller peak.

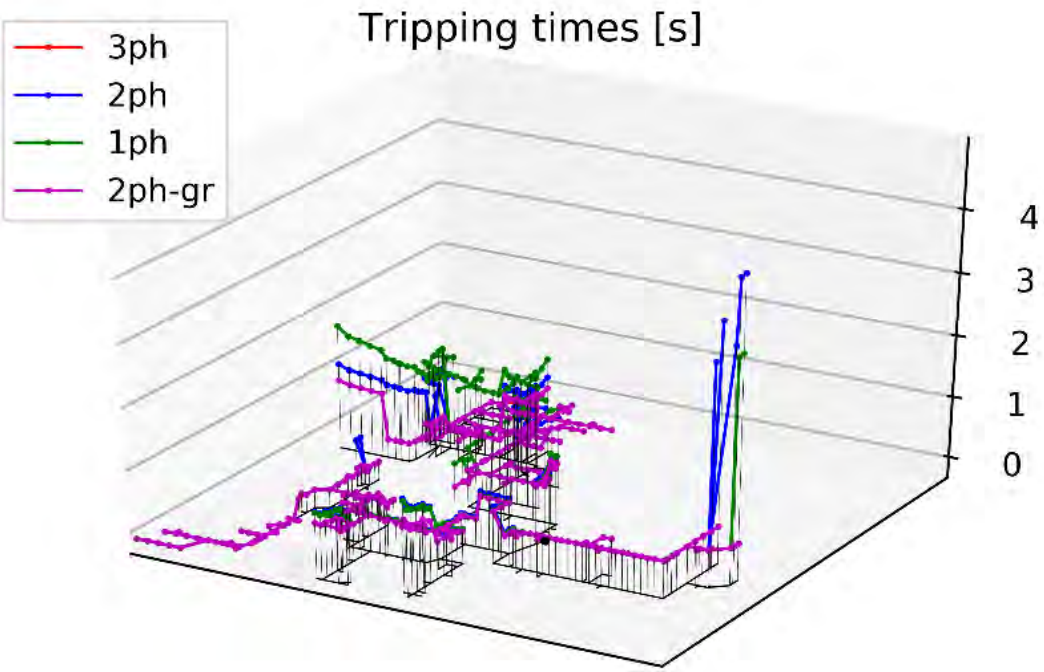


Figure 12 – Example 3D topology-value maps

Nodal distance graphs

Nodal distance graphs show a similar profile to that of the 3D topology value map of Figure 13 but are displayed in a 2D format. They allow an easier comparison of values from different responses and can also illustrate differences in response shape across the network from different fault types.

In these graphs, the nodal distance used on the x-axis is the number of nodes passed while traversing the grid from the 11kV busbar to the node of interest. It does not consider line length or impedance. The range of values represents different sections of the grid, where:

- 0 = busbar
- Left (values < 0) : Feeder 12,
- Right(values > 0): Feeder 11,

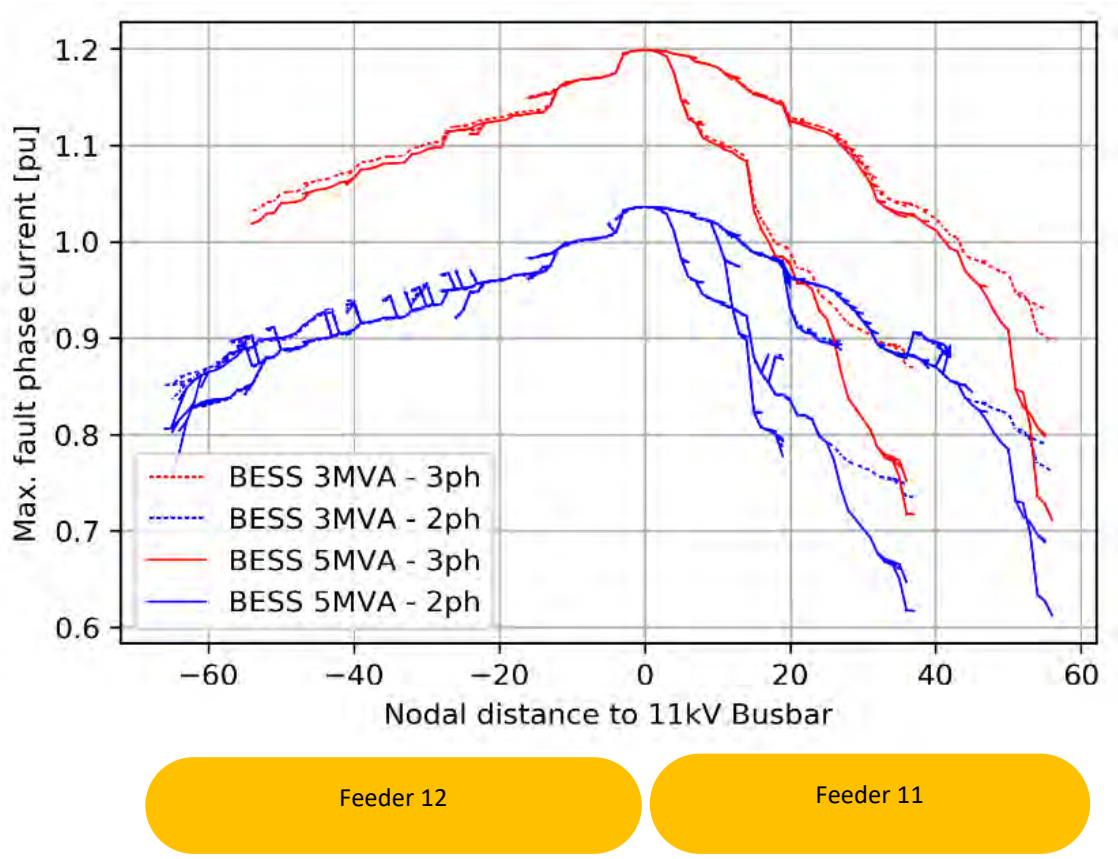


Figure 13 – Example of nodal distance graph

6.1.3. Analysis of Main Influences on System Fault Behaviour

Before investigating the protection system reaction on the system fault behaviour, the general influences on system fault behaviours are analysed. The system behaviour on HV faults is compared across the defined scenarios with regards to fault currents and residual voltages to gain an understanding on major differences and influences before the protection system behaviour is analysed. Special attention is given to the influence of the star point treatment arrangement. The influence of pre-fault load on fault currents flowing at different observations points is investigated to prepare worst-case assessments. Further influences are discussed.

6.1.3.1. Influence of Operational Modes on Fault Types

The following sections analyse and describe the influence of the operational modes 'Grid only', 'Grid+BESS', and 'BESS only' on different fault types. The scenario names are extended in some cases by the BESS inverter rating (e.g. 5MVA) and the BESS 11kV grid side star point configuration (e.g. STP NO = star point normally open, STP NC = star point normally closed).

A strong influence of operational modes is observed in case of *three and two phase-to-phase faults*. Figure 14 shows the fault levels observed across the different scenarios considered for 3ph faults while Figure 15 illustrates the fault levels for 2ph faults.

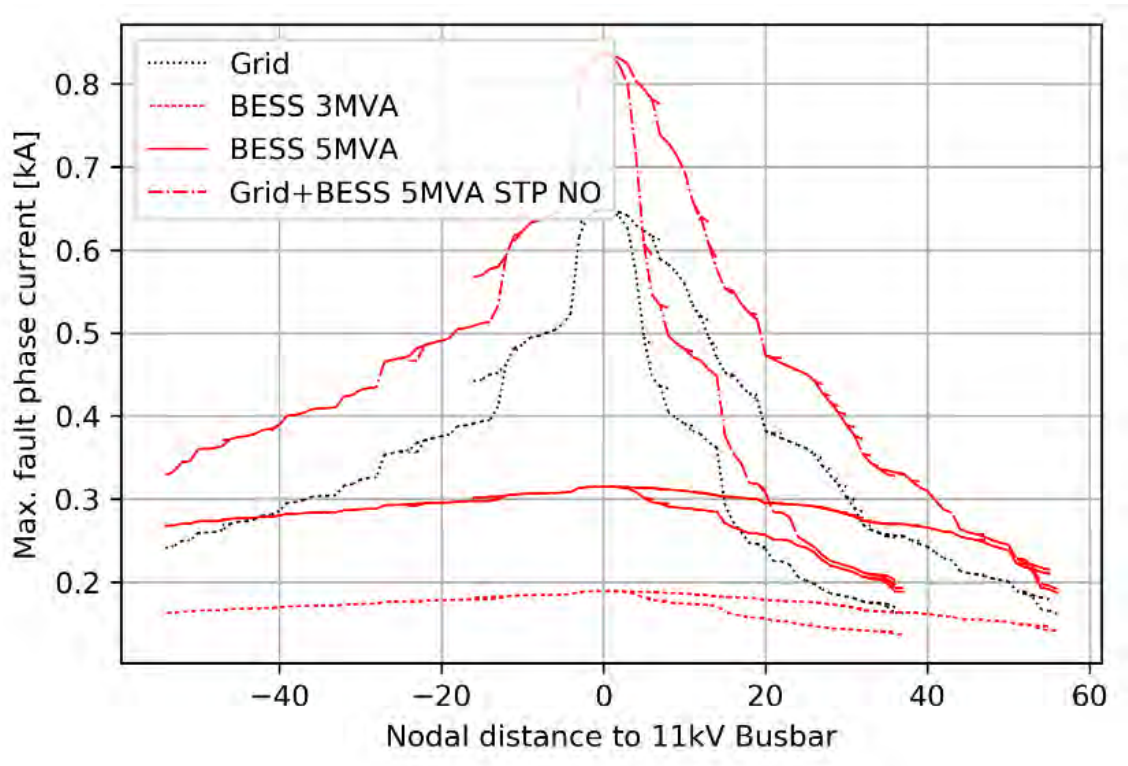


Figure 14 – Fault levels observed across different scenarios on Drynoch network from 3ph faults

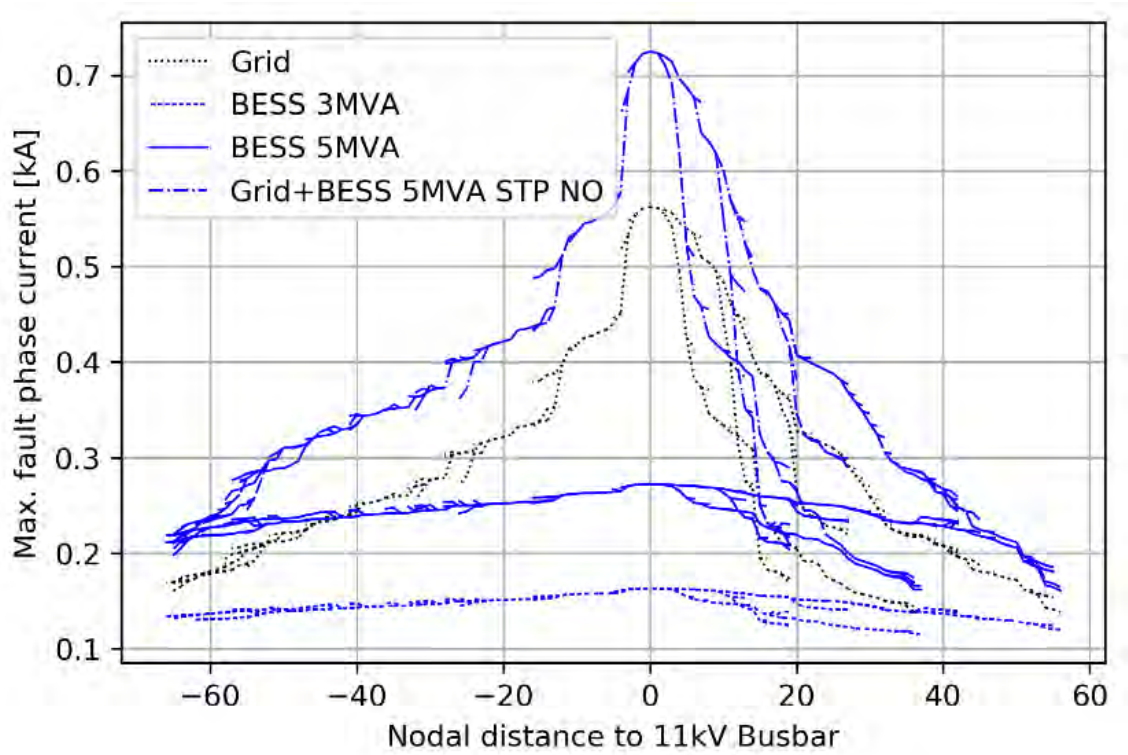


Figure 15 - Fault levels observed across different scenarios on Drynoch network from 2ph faults

These graphs show that short circuit fault currents peak when located close to the busbar for both 3ph and 2ph faults, with a maximum fault current of approximately 0.85kA. This occurs when the system is in Grid + BESS mode. These graphs also demonstrate that in islanded mode of operation, there is a

comparably flat short circuit current profile for 3ph and 2ph faults compared to Grid only mode or Grid + BESS mode, with significantly reduced peaks.

These results are compared with the rated current of the BESS inverter in Figure 16 below. This graph shows that a maximum RMS current of 1.2pu of the rated inverter current is drawn from the inverter for faults close to the busbar, which is acceptable according to suppliers.

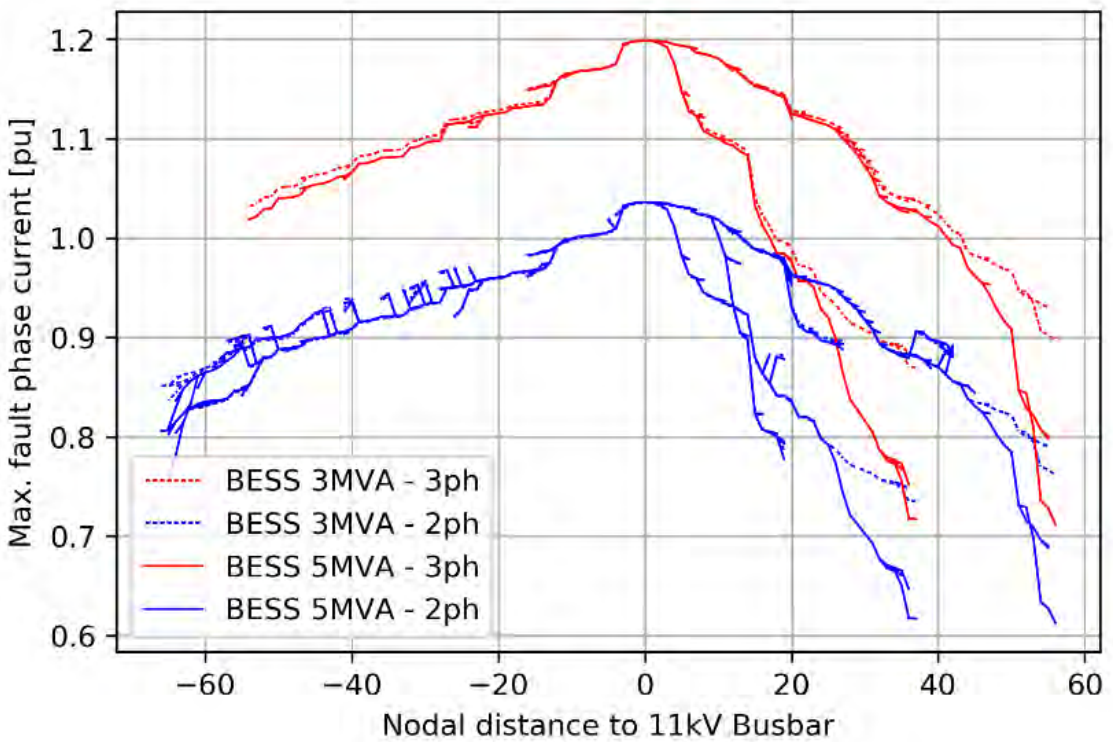


Figure 16 – Short circuit fault currents from inverter for 2ph and 3ph faults

Figure 16 also shows that fault levels are decreasing as the fault location moves away from the busbar. For the 5MVA BESS inverter case (solid lines), this happens to a greater extend in comparison to the 3MVA BESS case (dotted lines) because of the transition to voltage source behaviour without necessary current limitation of the inverter.

The increasing 2ph fault levels in tees of the feeders are related to higher residual voltages at the BESS interconnection point due to high tee impedances resulting in a lower degree of necessary current limitation.

For three phase faults the maximum achievable fault currents are limited by the current limitation setting of 1.2pu of the BESS inverter nominal RMS current. The absolute value is therefore directly proportional to the inverter nominal power rating. The lower current levels in the periphery are due to:

- the loads that draw an increasing share of the inverter maximum current with increasing residual voltage or
- the transition from current limited to pure voltage source behaviour of the BESS inverter.

The fault current level for close to busbar faults is considerably lower than in Grid mode. In the case of the 3MVA BESS, the 3ph fault current is less than the Grid scenario 3ph fault current at all locations. With a 5MVA BESS, the peripheral fault locations exceed the Grid scenario fault level slightly.

The same qualitative observations occur for two phase faults. Fault currents are reduced compared to the 3ph case to a maximum of 1.04pu due to the necessary current limitation in the asymmetrical fault case. Because of the Dy vector group of the BESS transformer, the 2ph fault is transformed into an asymmetrical 3ph fault on the LV side fed by the inverter with one phase experiencing high currents for unlimited voltage source behaviour. The absolute level for fault currents relies on the assumption of current limitation for asymmetrical conditions which needs to be verified in the Detailed Design phase, utilising more detailed information on BESS behaviour during faults.

In Grid+BESS mode, fault current for 3ph and 2ph faults is increased compared to Grid only operation due to the joint infeed. This behaviour relies on the assumption that there is a constant relative angular difference between voltage sources, however, this also needs to be verified in the Detailed Design phase which requires more detailed information on BESS behaviour during faults.

Figure 17 below shows the fault current profiles for *single phase to earth faults* across the operational scenarios.

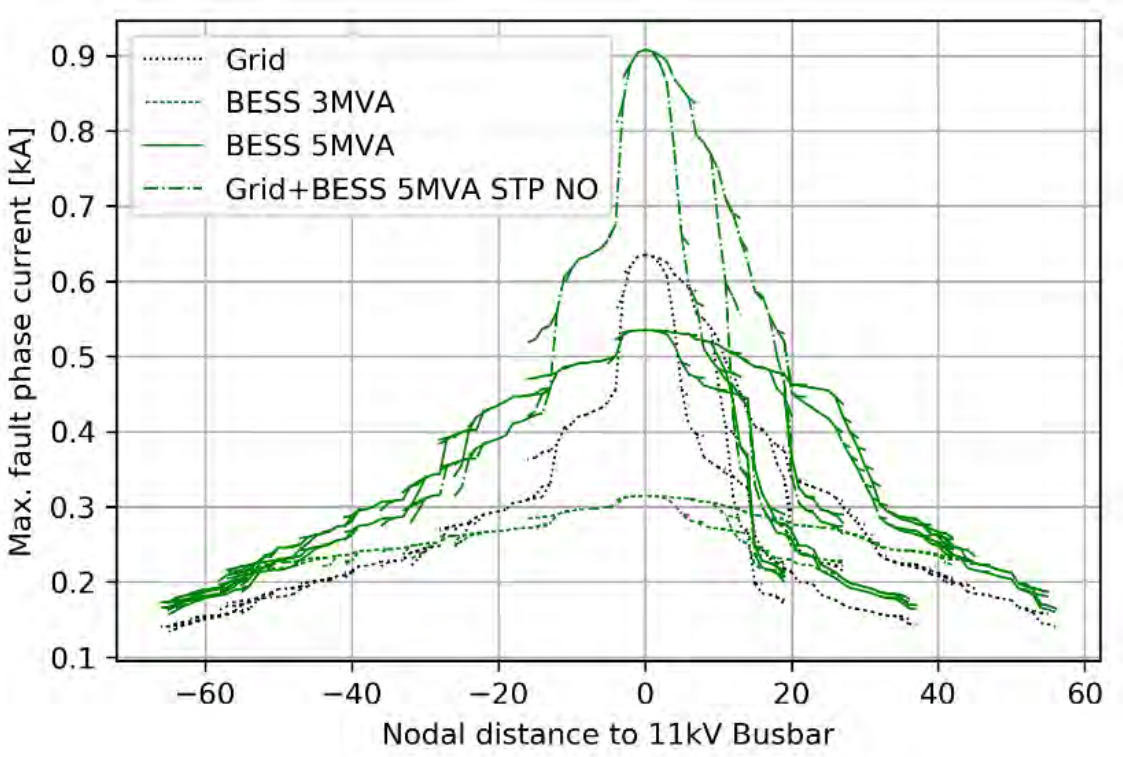


Figure 17 - Fault levels observed across different scenarios on Drynoch network from 1ph-gr faults

The profiles for islanded operation are more similar to impedance graded fault currents compared to 2ph or 3ph faults. These fault currents are influenced by the zero-sequence impedances of the grid and the BESS transformer. Due to the higher fault path impedances the resulting currents are more graded. For peripheral faults a pure voltage source behaviour is experienced, especially for the 5MVA sizing case. In this scenario, grading similar to the grid is taking place. The lower source impedance leads to comparably higher fault levels.

In Grid and BESS mode, the joint fault feeding allows the profiles to exceed the Grid only case. Further analysis on the influence of the BESS transformer star point is analysed in the Section below.

In case of *two phase to earth faults* an influence of the operational mode is expectedly existing. Figure 18 shows the fault current profiles for two phase to earth faults across the operational scenarios.

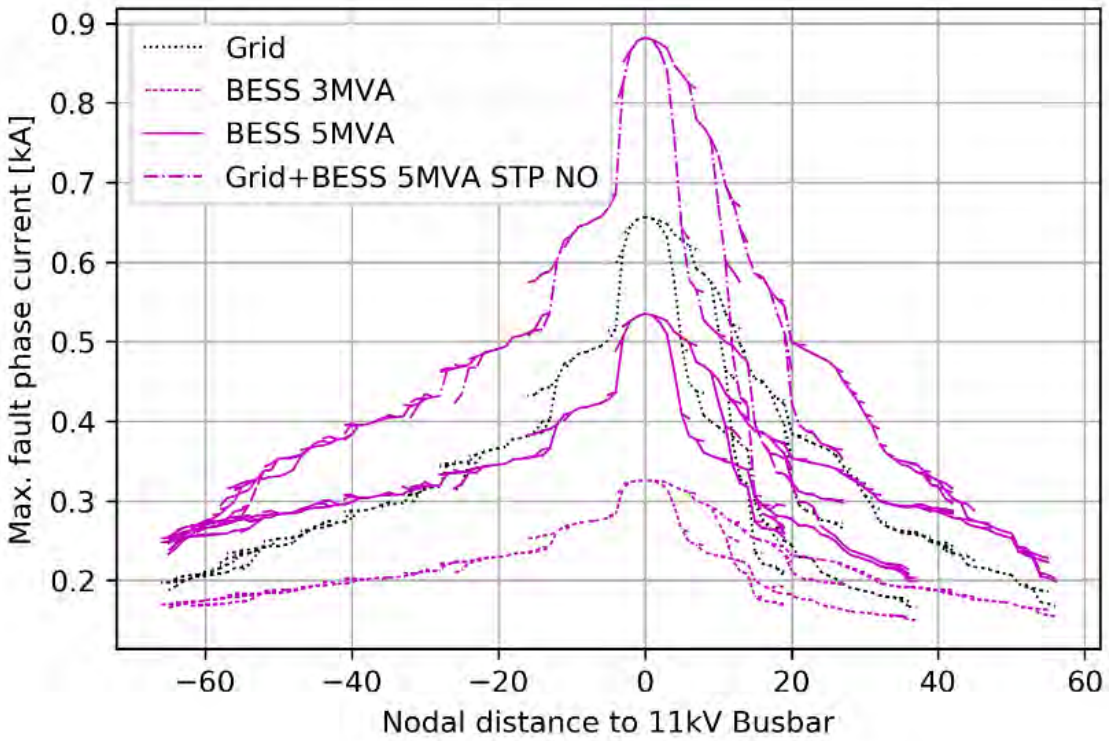


Figure 18 - Fault levels observed across different scenarios on Drynoch network from 2ph-gr faults

With 2ph-gr faults a mixture of the previous cases applies. Restrictions due to the two-phase nature of the fault and the current limitations apply but are superimposed by the zero-sequence fault current path effects, especially for close to busbar faults.

Figure 19 below shows a comparative view on the fault currents in different scenarios, with the purpose of identifying areas of the grid that experience extreme or unexpected fault behaviour.

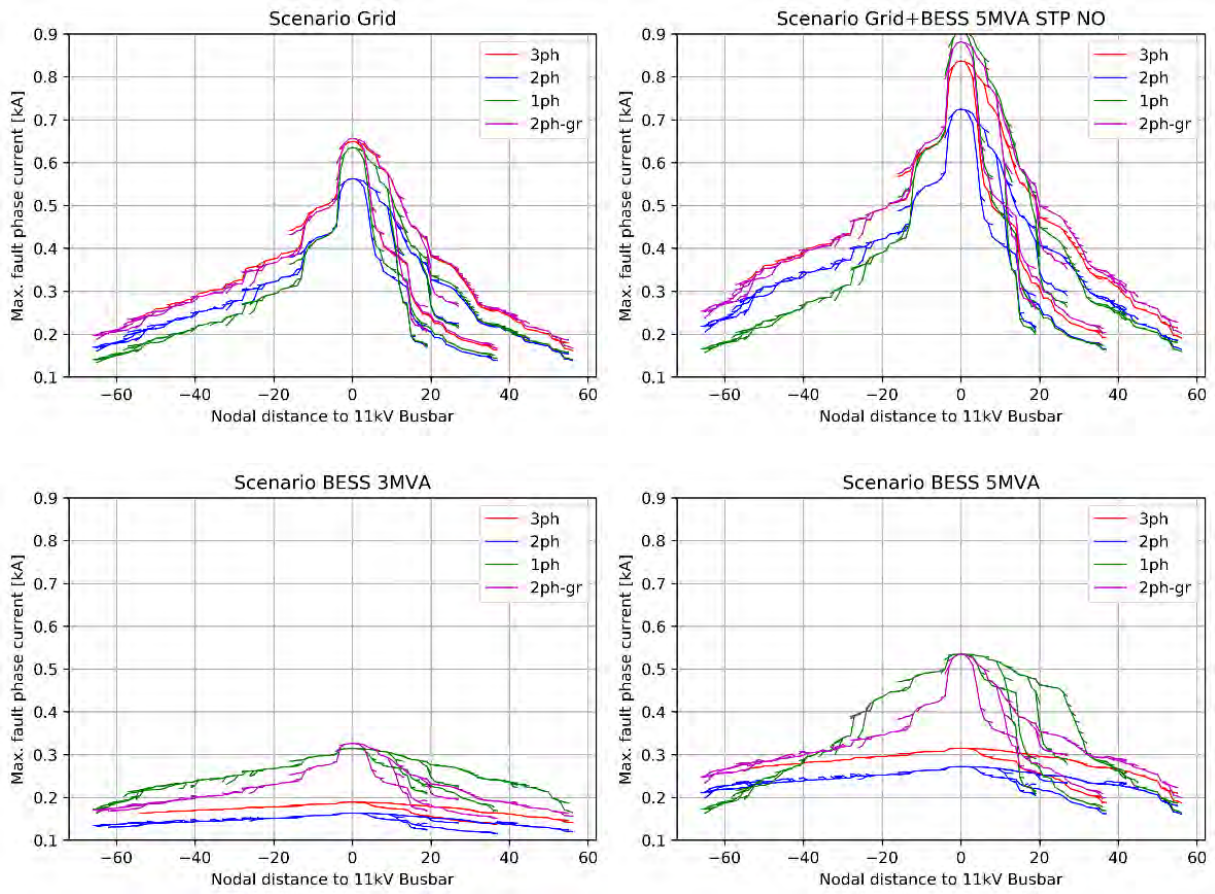


Figure 19 – Comparison of fault currents occurring from different fault types under different operating scenarios

In the scenarios Grid and Grid+BESS, the 1ph-to-earth faults have the lowest fault currents at the end of feeder. When operating in parallel, 1ph-to-earth faults have the largest maximum fault current rating close to the 11kV busbar.

During islanded operation, two phase faults result in the smallest fault currents, followed by three phase faults due to the current limitation imposed by the BESS. Again, the highest observable fault currents occur for 1ph and 2ph-gr faults close to the busbar instead of the 3ph fault. Additionally, for the 5MVA system, single phase-to-earth faults in peripheral locations become the minimum fault type as the system regains its voltage source behaviour, however, this effect does not occur for 3MVA faults.

In conclusion, the previous investigations reveal a systematic difference in the fault levels observed and their profile on the network depending on the existence of a connection to the 33kV grid.

When the BESS is in islanded operation, there are comparably flat profiles with reduced peak fault currents. The lowest fault levels are generally experienced for 2ph and 3ph faults, meaning these are the most relevant for the protection sensitivity analysis.

For the smaller 3MVA BESS inverter, fault currents are dictated by current limitation and they remain at lower levels compared to the Grid scenario for both 3ph and 2ph faults. 1ph faults, however, exceed the Grid case for peripheral faults, but not for close to busbar faults. This is due to the chosen vector group and associated lower zero-sequence impedance of the BESS transformer compared to the primary substation transformer.

For the 5MVA BESS, the fault current profile is increased compared to the 3MVA BESS inverter case. Peripheral faults of all types exceed the current level in Grid mode, however the closer to busbar faults remain generally lower. The 1ph fault level exceeds the Grid case in most fault locations except for very near to busbar faults.

In parallel operation of Grid and BESS for both BESS sizes, all fault types at all locations have higher fault currents compared to the Grid operation due to the additional infeed current from the BESS. These results are based on the assumption that perfect synchronism is maintained during faults. This assumption needs to be further analysed in the Detailed Design phase.

6.1.3.2. Influence of BESS Transformer Star Point Configuration

The step-up transformer connecting the BESS to the grid can have different star point configurations. If the secondary side of the transformer has a Wye connection, it is possible to have the star-point (STP) either earthed (normally closed – NC) or unearthed (normally open – NO) . This section compares these configurations.

Firstly, the influence of the BESS transformer star point configuration on the fault currents at the fault location is analysed. Figure 20 depicts the achieved single phase-to-earth fault currents at the fault location for different operational scenarios of the Drynoch site. This graph is equivalent to Figure 17 with the addition of results from having the star point earthed.

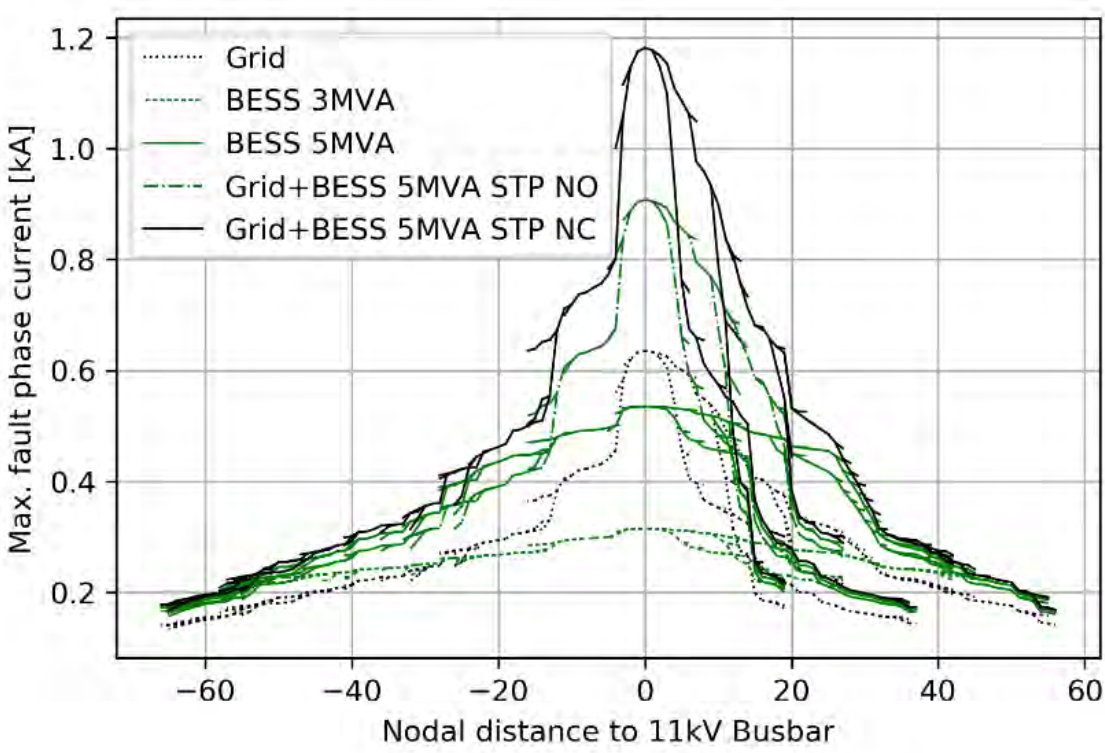


Figure 20 – Fault levels observed from 1ph-gr faults for different scenarios including with different star-point configuration. STP NO = Star Point Normally Open; STP NC = Star Point Normally Closed

In all islanded and parallel scenarios, the single phase-to-earth fault currents achieved in the periphery of the grid are larger than the minimum short circuit levels of the Grid only scenario.

In all islanded modes the BESS provides lower fault levels for faults occurring close to the busbar. In parallel scenarios, larger fault current levels occur for close to busbar faults as the sources jointly feed the fault.

These results allow the following conclusions to be made:

- In islanded operation, the current limitation imposed by the system leads to a lowering of fault currents for close to busbar faults, but an increase of fault currents is observed for peripheral faults compared to Grid operation due to the lower source impedance of the BESS.
- Considering fault currents, with an open star point, during parallel operation grid components may be rated for lower short circuits than with closed star point but still exceed the typical Grid only mode ratings.

Figure 21 shows the influence of the BESS transformer star point configuration on the neutral fault currents provided by the primary substation transformer during different operational scenarios.

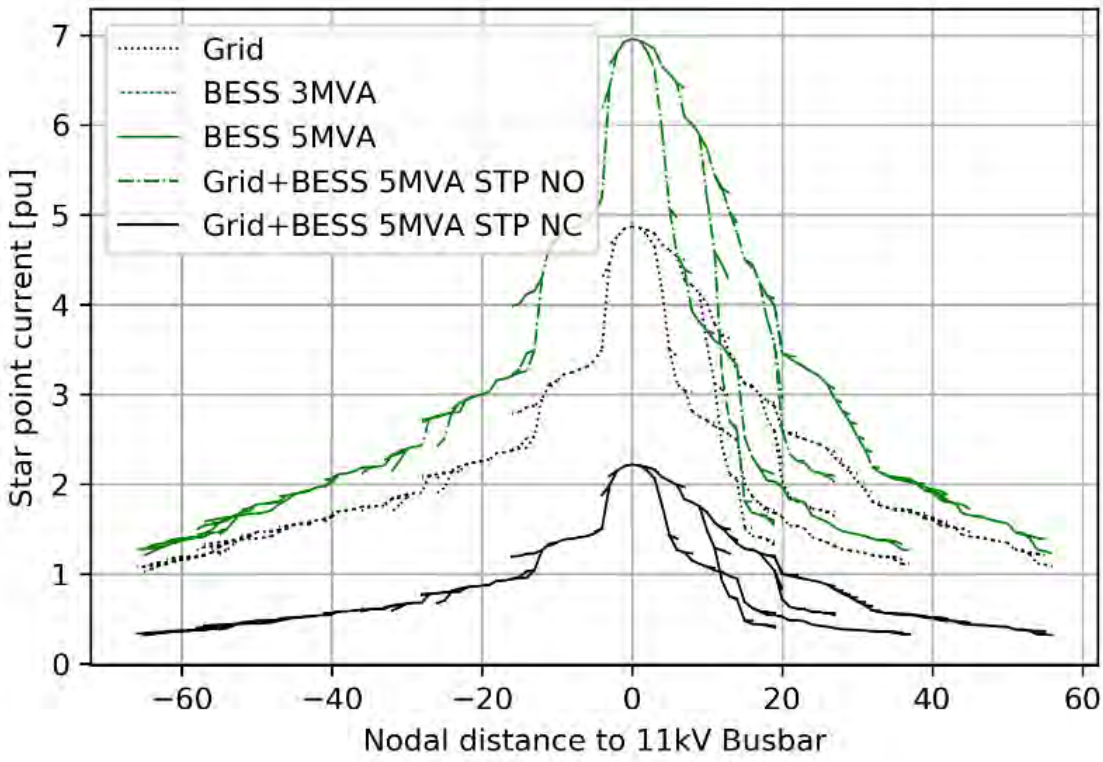


Figure 21 – Comparison of neutral fault currents provided by primary substation transformer. STP NO = Star Point Normally Open; STP NC = Star Point Normally Closed

These results show that when the BESS transformer has an NC star point, the neutral fault current provided by the primary substation transformer is severely reduced. This means that the BESS becomes the major contributor to the earth fault current in this scenario. Relatedly, with a NO star point connection, during parallel operation a larger neutral fault current is enforced on the primary substation transformer.

As expected, the healthy phase voltages rise during asymmetrical earth faults. Figure 22 shows the maximum voltage rise on the healthy phases at the fault location during single phase-to-earth faults for all HV fault locations across the different operational scenarios as well as star point treatment variants considered.

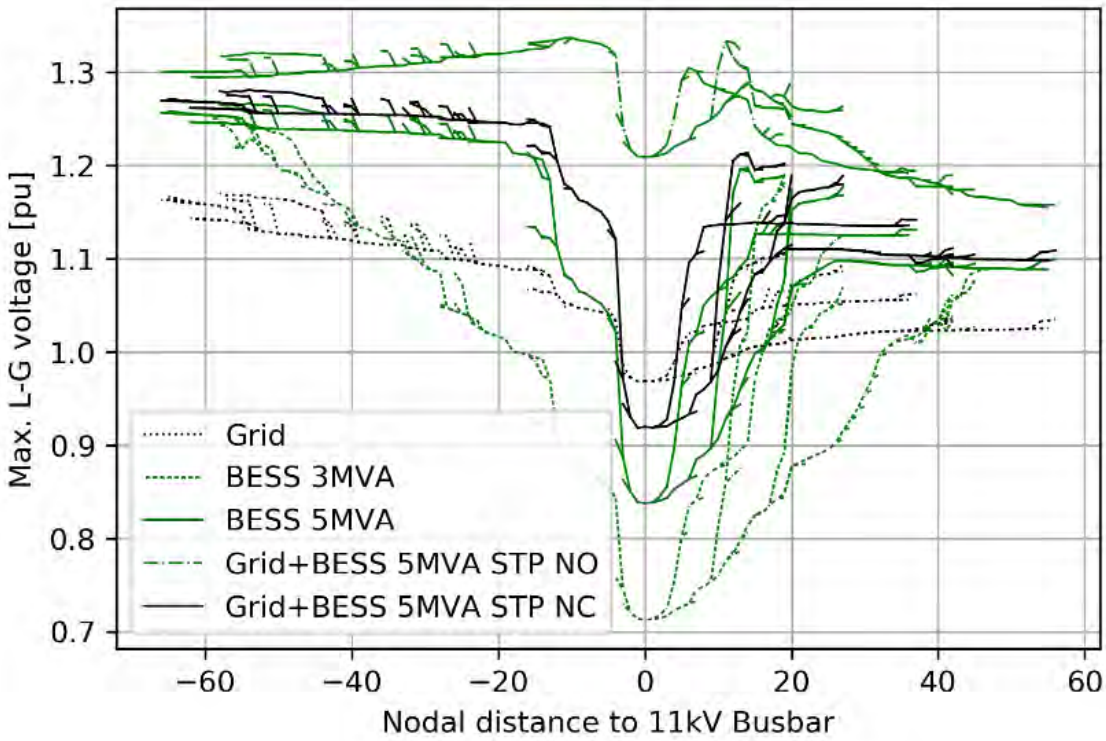


Figure 22 - Healthy phase voltage rise during single phase-to-earth faults. STP NO = Star Point Normally Open; STP NC = Star Point Normally Closed

These results show that the healthy-phase voltage rise is expected to stay below 1.4pu for this grid when solidly earthed, with the maximum voltage rise expected to occur at the fault location. This latter assumption has been successfully verified but is not shown here.

In the Grid mode scenario, the voltage sags for close to busbar faults with the voltage rising to a maximum of <1.2pu for faults located at the end of the feeders.

In the two islanded scenarios, lower residual voltages are experienced for close to busbar faults, with the maximum values rising to approximately 1.27pu for faults located at the end of the feeder.

During parallel operation, the maximum voltage rise increases further. A maximum transformer value of 1.28pu is achieved for end of line faults, while the voltage sag for close to busbar faults is more severe than in Grid only mode. A peak voltage rise on the healthy-phase at all points on the network is observed if the BESS transformer star point is open while the system is in parallel mode. Close to busbar faults experience a rise of a minimum of 1.2pu, with maximum values of 1.34pu occurring along the feeder, while the end of feeder locations achieves only 1.3pu.

These results allow the following conclusions to be made for the influence of BESS transformer earthing on the fault point healthy phase voltage rise:

- All investigated modes of operation remain within the expected maximum healthy phase voltage rise of 1.4pu for single phase to earth faults.
- Islanded and parallel modes of operation experience higher voltage rise than during normal Grid operation.
- Utilising an open star point configuration for the BESS transformer during parallel operation leads to the highest voltage rises on the healthy phase at all points on the network.

To summarize, based on these investigations, all variants of BESS star point treatment are deemed feasible with specific benefits and drawbacks.

While a long-term parallel operation of the 11/33kV and BESS transformer star points is not favoured by SSEN, short term parallel operation is shown to be feasible, e.g. during planned operational mode switching of the site. This is a deviation from the standard G99 requirements, which, however, is in the DNO's discretion to decide for such a scenario.

Influences on component and system stress and ratings are shown and discussed and need to be assessed by SSEN system engineers during the Detailed Design phase.

6.1.3.3. Influence of Loads

Pre-fault load conditions are known to influence fault currents, however, for large short circuit currents, they can be assumed to have a minor effect and can be ignored or simply considered a security factors (as described in standards such as IEC 60909). However, no systematic approach has been proven for islanded systems created by grid forming inverters with relatively small fault currents due to current limitation.

An analysis is therefore performed to determine its significance and to determine an appropriate approach for overcurrent protection assessment. This is undertaken for the scenario of islanded operation with a 5MVA rated BESS inverter.

The analysis firstly compares the 3ph fault currents observed at different locations on the network, namely:

- Feeder Circuit Breakers (CB)
- Fault location
- Closest-to-fault CB (Feeder CB and tele-control PMCB reclosers)

The results also include the no-load scenario for comparison. In a simulation run separately and not included here, it has been shown that during a no-load scenario, the fault currents observed at the Feeder CB are expectedly only marginally higher than those at the fault point and can be used for a worst-case comparison.

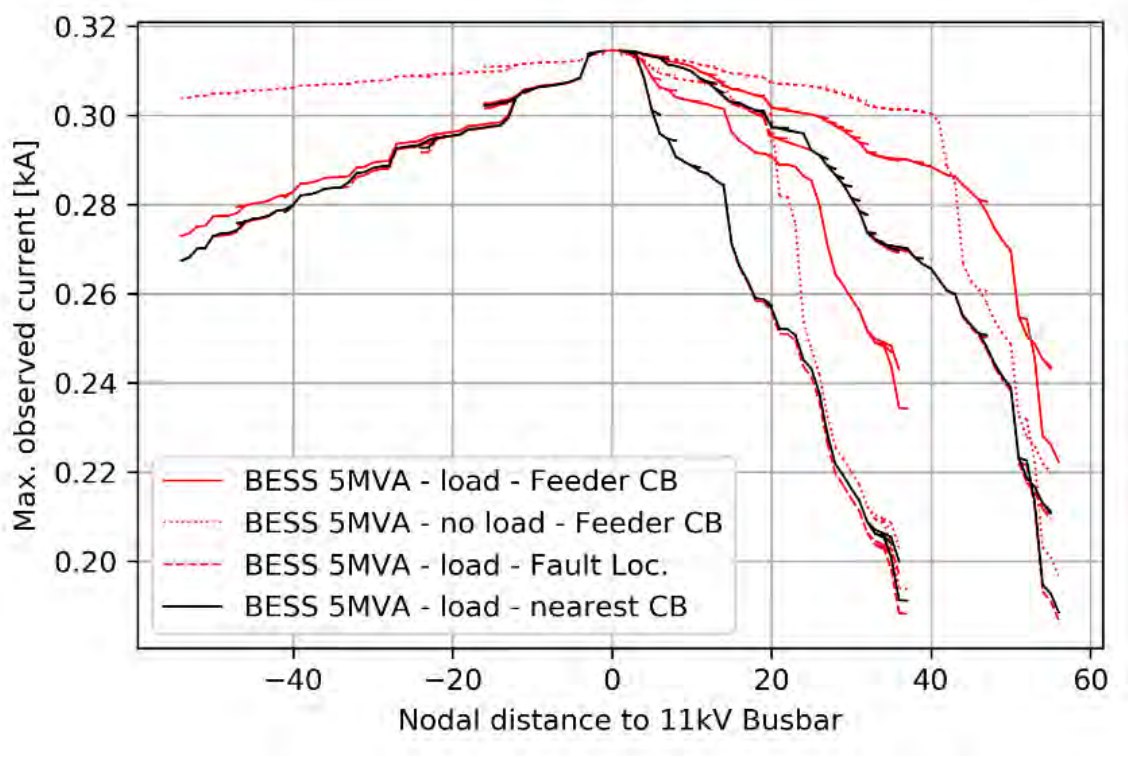


Figure 23 – Fault currents observed at specific locations with and without load due to 3ph faults along the network

The results shown in Figure 23 show that during a no-load scenario, higher fault currents occur for faults on Feeder 12 (left-hand side) and the first sections of Feeder 11 than for any scenario with load. The load scenario therefore represents a worst case in those sections.

When comparing the observation points for the scenario with load, the Feeder CB point expectedly exceeds the currents at the fault location and at the closest to fault CB. The fault location currents are the lowest observed, especially for the end of tee or end of feeder locations. The closest-to-fault CB currents approximate the fault location currents sufficiently well.

In the periphery of Feeder 11, in the no-load case the fault currents drop below the Feeder CB observations in the load case but remain above the fault location currents and the closest-to-fault CB observations. The closest-to-fault CB observation (black line) is therefore a worst-case in terms of sensitivity of overcurrent protection for the two load scenarios.

For 2ph faults, the same results are found in most of the analysed cases, as shown in Figure 24. The worst case for sensitivity is reflected correctly by the nearest CB observations in the full-load scenario. One significant exception is observed for one of the Feeder 11 branches relatively close to the busbar, which will be investigated in further in the Detailed Design phase.

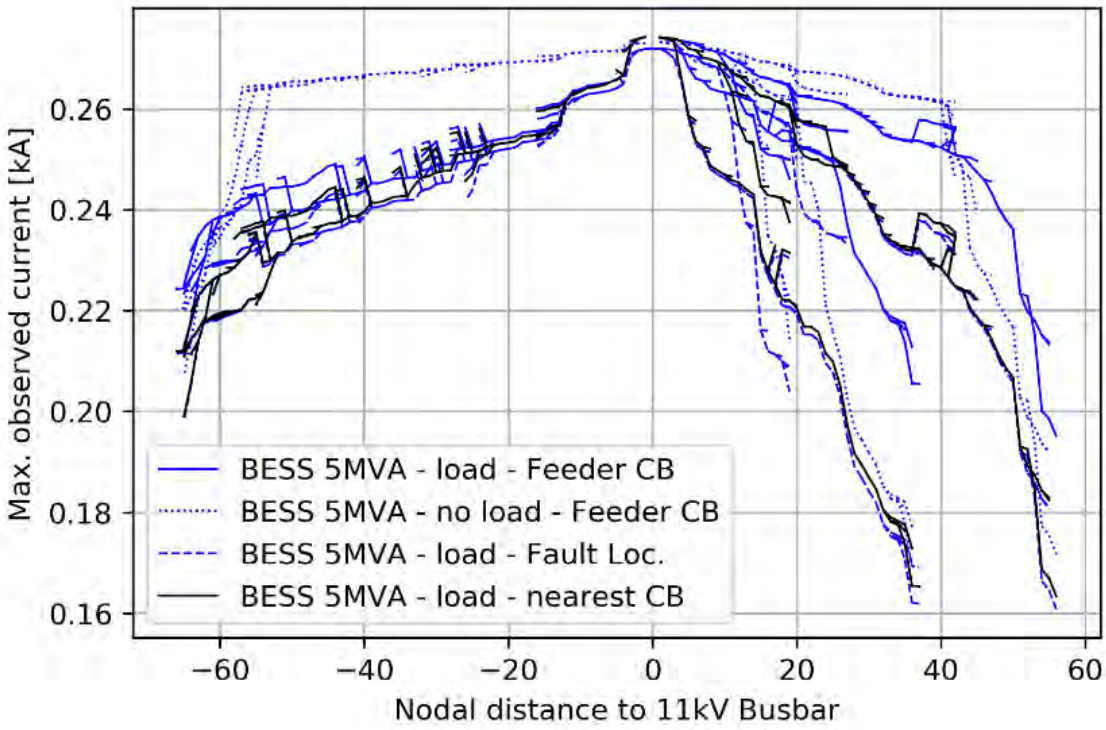


Figure 24 - Fault currents observed at specific locations and with and without load due to 2ph faults along the network

For 1ph faults, a region of Feeder 12 shows no convergence of the simulations in the no-load case. Close-to-busbar faults and faults in the periphery remain assessable as does the complete Feeder 11. Figure 25 shows that the same considerations and exceptions hold as in the 3ph and 2ph case.

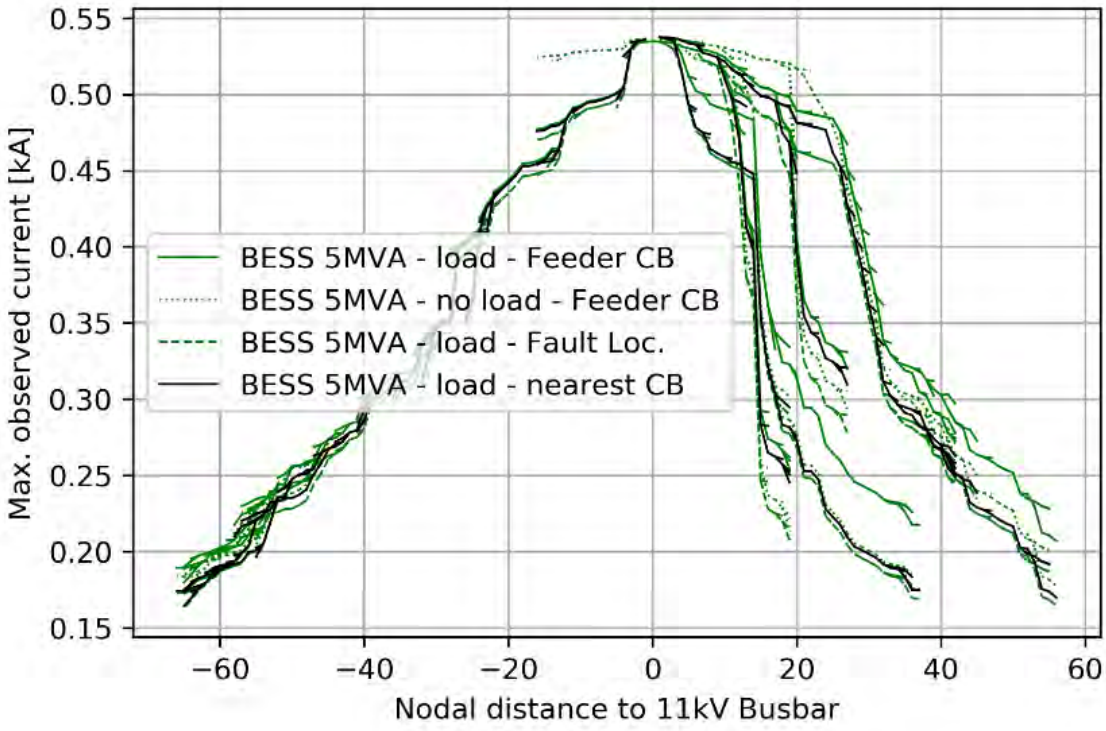


Figure 25 - Fault currents observed at specific locations and with and without load due to 1ph faults along the network

For 2ph-gr faults, Figure 26 shows that the same considerations and exceptions hold as in the 3ph and 2ph case.

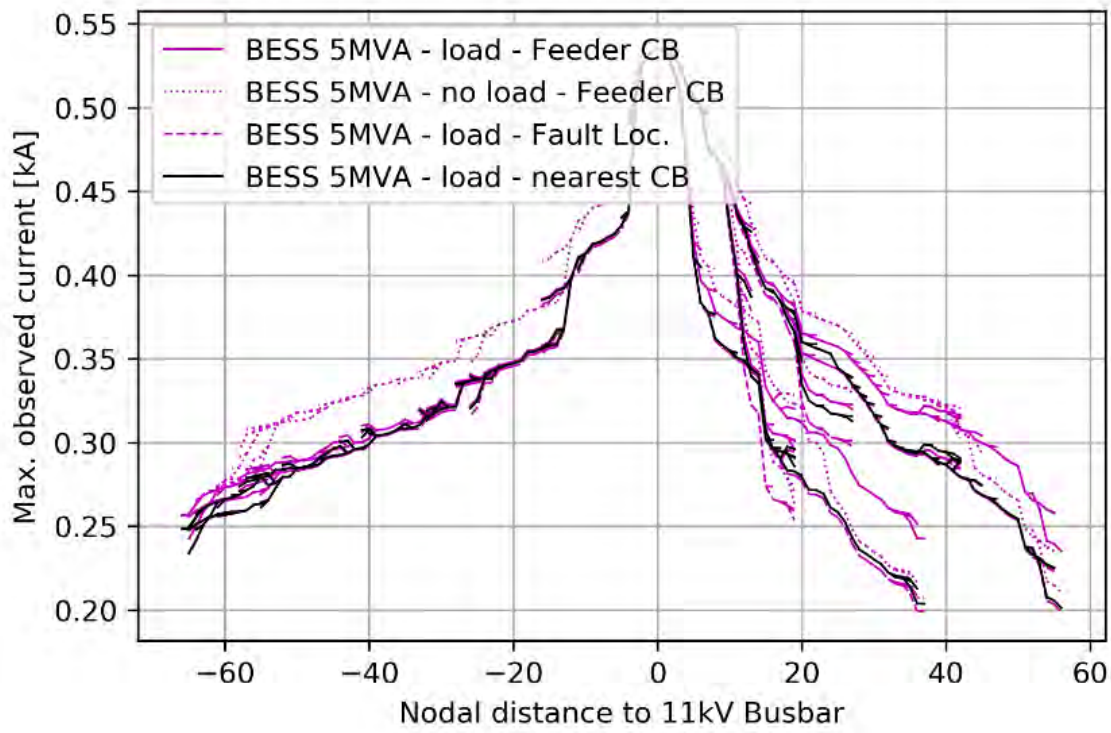


Figure 26 - Fault currents observed at specific locations with and without load due to 2ph-gr faults along the network

These results allow the following conclusion to be made on the influence of load on system behaviour:

- Pre-fault load is shown to influence the system fault behaviour during islanded operation.
- The currents observed at the closest-to-fault CBs are shown to represent a worst-case for sensitivity and will be used for the performance analysis of the distributed HV overcurrent protection system by relays.
- Performance of overcurrent protections elements in secondary substations should be assessed based on the fault location currents in order to perform a worst-case analysis.

6.1.3.4. Influence of Zero-Sequence Impedances of Network Lines and Components

The zero-sequence impedances of components have been assumed as the given values for HV lines and as the worst-case values for additional components of the system, which results in a conservative assessment of the overcurrent protection system. If the actual zero-sequence impedances are higher, then modelling might overestimate the resulting currents and assess the overcurrent protection system performance better than the actual performance. This is especially critical for reliable islanded operation. To mitigate this risk during islanded mode, an additional backup protection measure based on criteria different from overcurrent should be applied as analysed later.

6.1.3.5. Influence of Inverter Operation

In islanded mode the grid forming inverter fault behaviour might deviate from the assumptions taken, especially in asymmetrical fault cases as degrees of freedom exist in designing current limitation.

The effects of primary and secondary control of the grid forming inverter may result in further lowering of fault currents. This, however, has not been considered in these studies as too many possibilities exist at this stage of design. The risk of an even lower sensitivity of overcurrent protection will be addressed in the Detailed Design phase.

6.1.4. Analysis of Existing HV Relay and Fuse Protection

Grid studies have been undertaken on the Drynoch 11kV network to understand whether the existing protection devices' settings or ratings are sufficient for safe and stable operation of an islanded network and to determine which adjustments may be required for the RaaS system or how the BESS design may be utilized to avoid such.

For this purpose, extensive fault analysis has been completed on the HV network downstream of the primary substation to determine the level of fault currents that could be expected on the network, the tripping times achieved by the existing protection system, and the thermal loading on the lines. This helps to identify any areas that are at risk of having an unsatisfactory protection response.

Section 6.1.4.1 first analyses the existing 11kV relay protection including ANSI 50, 50G, 51, and 51G protection functions. In Section 6.1.4.2 backup protection performance by those relays is investigated. Additionally, this section assesses backup protection functions that are foreseeably introduced by the interconnection of the BESS. HV fuse blowing performance for faults in secondary substations is dealt with in Section 6.1.4.3. Overall conclusions are summarized in Section 6.1.4.4.

6.1.4.1. Performance Analysis of HV Relay based Primary Protection

This section introduces the analysis of the existing primary relay protection system on the 11kV grid for the different modes of operation and different BESS scenarios.

Performance of primary relay protection in Grid only mode

The first scenario considered is the 'Grid only' mode, which helps to define the base case for protection system performance. As described above, a nodal model of the network was considered with different types of faults simulated at nodes along both feeders from the busbar (BB) to the furthest point in the network. By completing this, the steady state fault currents can be calculated.

Using this method, the tripping times of the system to all fault types considered at all points along the network can be considered. By plotting their performance in a cumulative fashion versus an increasing tripping time, a view of the entire network can be produced. These results are shown below in Figure 27.

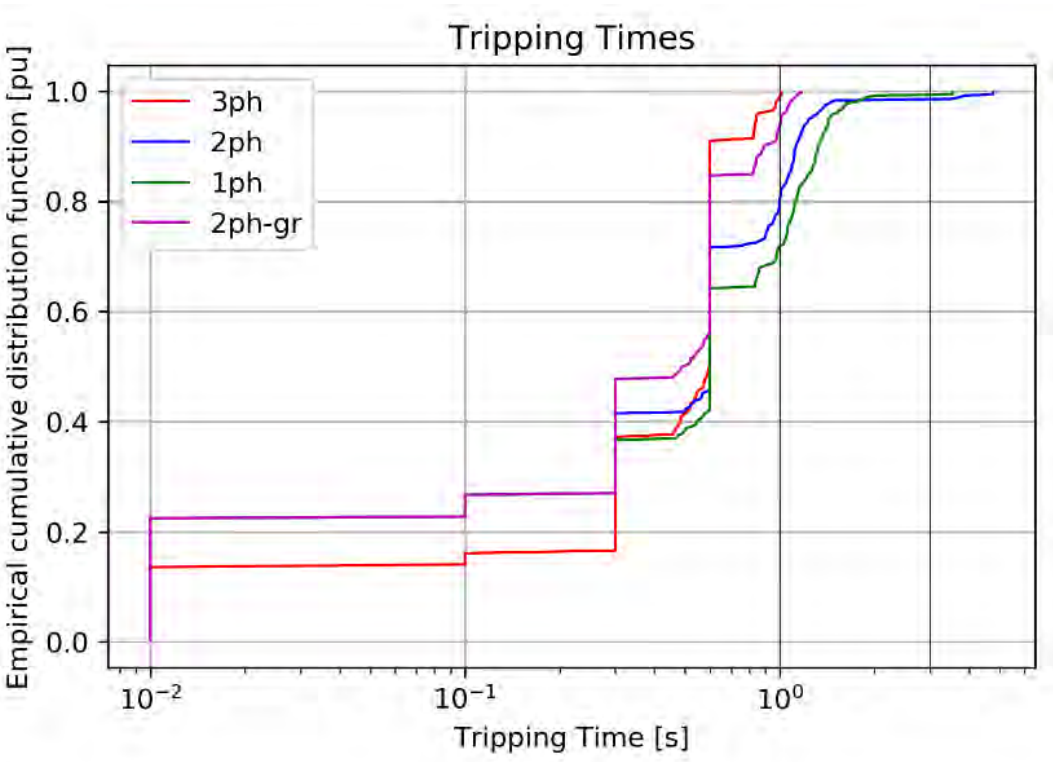


Figure 27 – Empirical cumulative distribution of protection devices connected to Grid only

These results show that most trips occur within 2 seconds, with the longest durations occurring for 1ph faults, followed by 2ph faults especially on the peripheries of Feeder 11 and Feeder 12 due to the mpedance decrease of fault currents. An alternative view of these results is shown below in Figure 28.

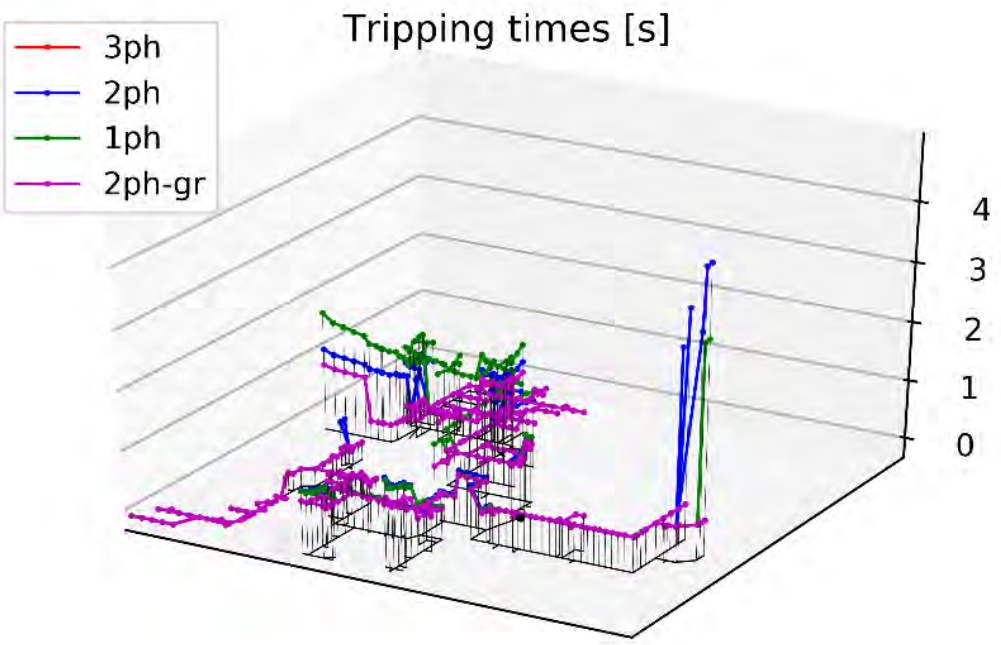


Figure 28 - Drynoch network map with tripping time responses to different fault types when in Grid only mode

It is observed that the performance outliers occur in one zone of Feeder 11 which is protected by Glendrynoch PMCB. Based on the modelling assumptions used and the assumed protection settings, this zone observes a response up to 5 seconds for 2ph faults, exceeding the defined requirements in this worst case scenario analysis by 2 seconds. Up to 4 seconds are needed for 1ph faults which fulfils the requirements.

Due to the low short circuit currents occuring in these end of line sections the influences of modelling assumptions and line data quality may be dominant factors. A closer investigation shows that the instantanous definite time tripping current value of the Glendrynoch PMCB is not hit in these cases, leading to a step-like inrease of calculated tripping times. A decrease of the assumed definite time current thresholds by 20% gains a performance as depicted in Figure 29 fullfilling all posed requirements.

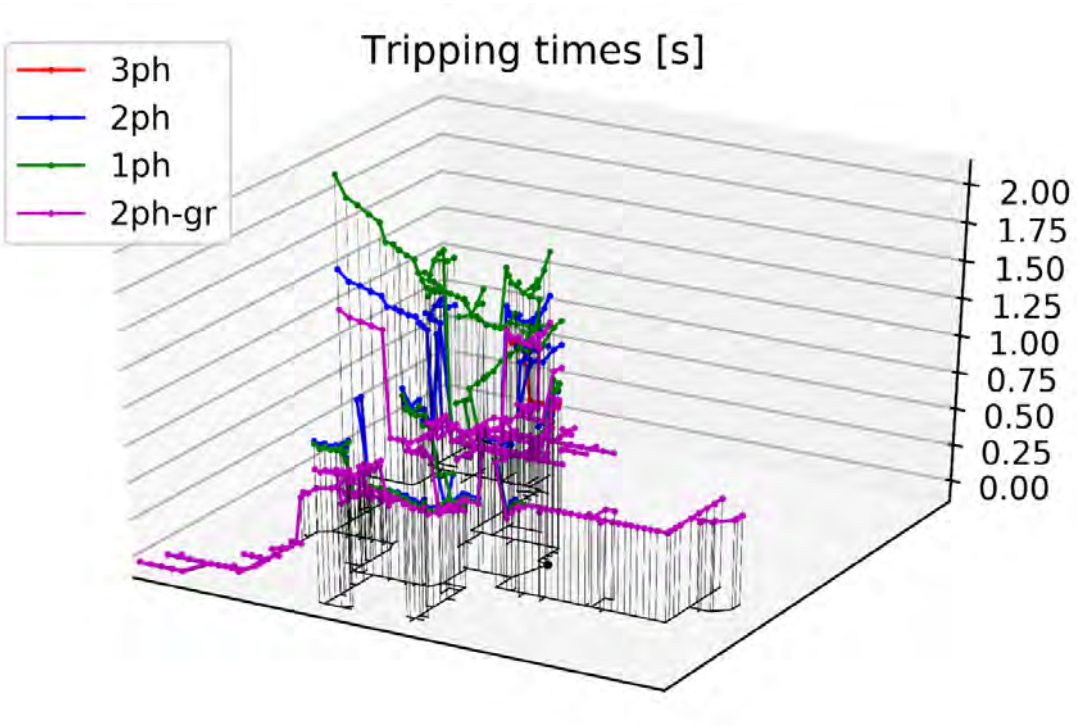


Figure 29 - Drynoch network map with instantaneous definite time tripping current

In conclusion, small deviations on either the model, the data or the protections side have a significant effect on the performance assessment. Further consideration will be given to this in the Detailed Design phase of the project to decrease sensitivity. In order to perform a worst-case investigation the assumed given settings are applied throughout the further analyses.Full selectivity is achieved in Grid only mode of the network, as shown below in Figure 30.

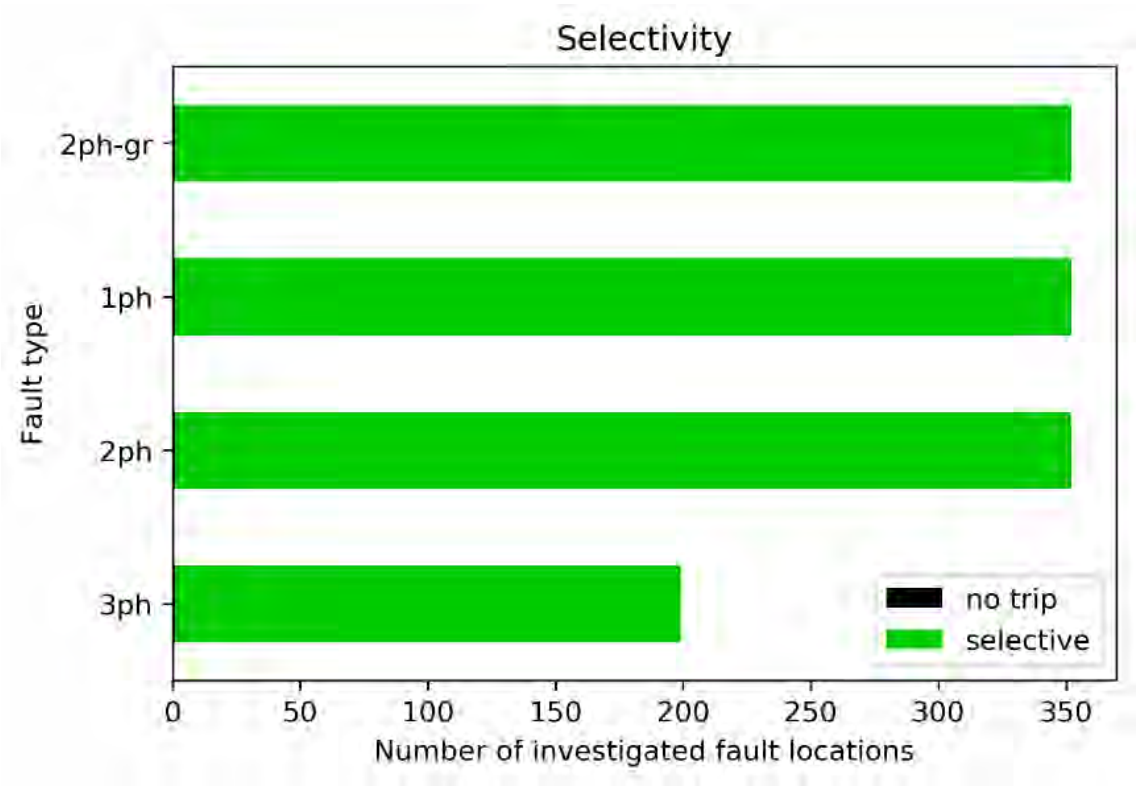


Figure 30 - Level of selectivity achieved considering different fault types when connected in Grid Only mode

The maximum thermal loading of the lines determined by the methodology and with the worst case assumptions described in section 6.1.2.7 is shown in Figure 31.

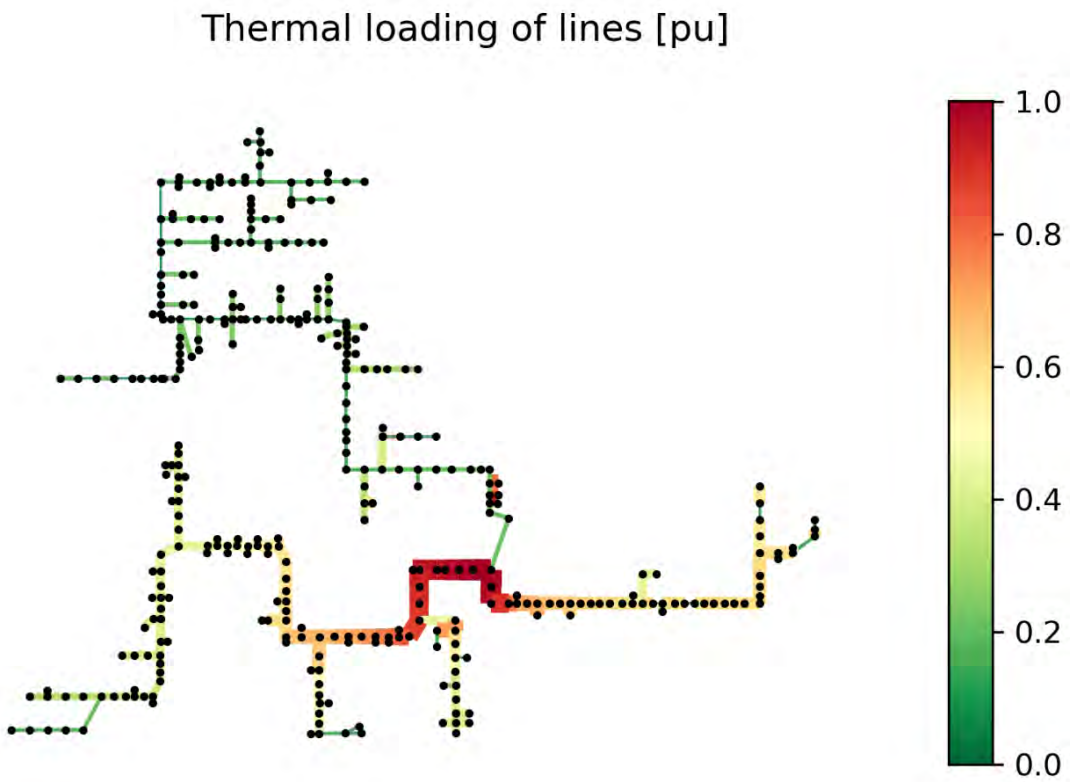


Figure 31 - Thermal loading of lines considering all fault types in Grid only mode

Close to busbar faults fully utilize the thermal capacity of Feeder 11 lines close to the busbar with values of 1.002pu in the worst-case assessment undertaken. Reasons are the resulting high fault current levels in grid only operation and the necessary grading of tripping times to ensure selective operation. Feeder 11 experiences a higher maximum thermal loading due to the lower thermal capacity of the installed lines (compare Figure 10).The results show that the requirements defined for clearing times and selectivity are completely met by the existing protection settings, with the only deviation occurring for clearing times of end-of-line 2ph short circuit faults in one protection zone on Feeder 11 where small amendments in grid data, calculation assumptions or protections settings alleviate the situation. This zone is assumed to be a critical location in islanded operation.

Performance of primary relay protection in islanded operation with 3MVA BESS

By using the method described above for the 3 MVA BESS only case, the response from the existing protection devices can be determined to different types of faults occurring on the network.

A cumulative distribution of the clearing times of the protection devices is shown in Figure 32. This graph shows the percentage of protection devices which have particular clearing times. The graph shows how there is a reasonably large percentage of faults that are cleared in a time <3s.

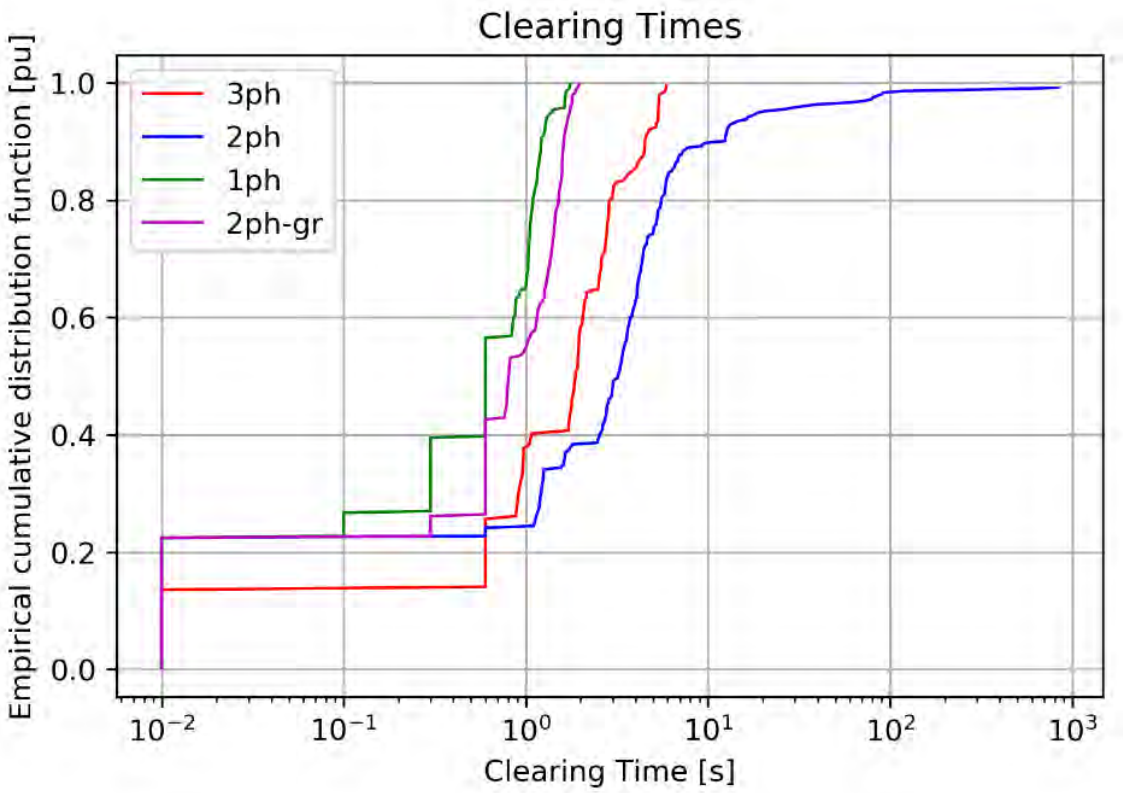


Figure 32 - Empirical cumulative distribution of protection devices with a 3MVA BESS

There are however some violations of the defined performance requirements:

- For 2ph faults, only 45% are within requirements
- For 3ph faults, only 80% are within requirements

Many locations where these issues arise in the 3MVA BESS case are close to the busbar protection zones which is due to the tripping delays and grading. While this is not creating issues in normal Grid only mode, it becomes critical for the islanding scenario. It is also observed that the periphery of Feeder

11 which is protected by the Glendrynoch PMCB is particularly problematic, as can be seen in Figure 33. This is due to this PMCB's sensitivity resulting in extremely long tripping times. Occasionally, the end of this line has no trips for 2ph fault which represents a risk to equipment from overcurrent in the event of a fault.

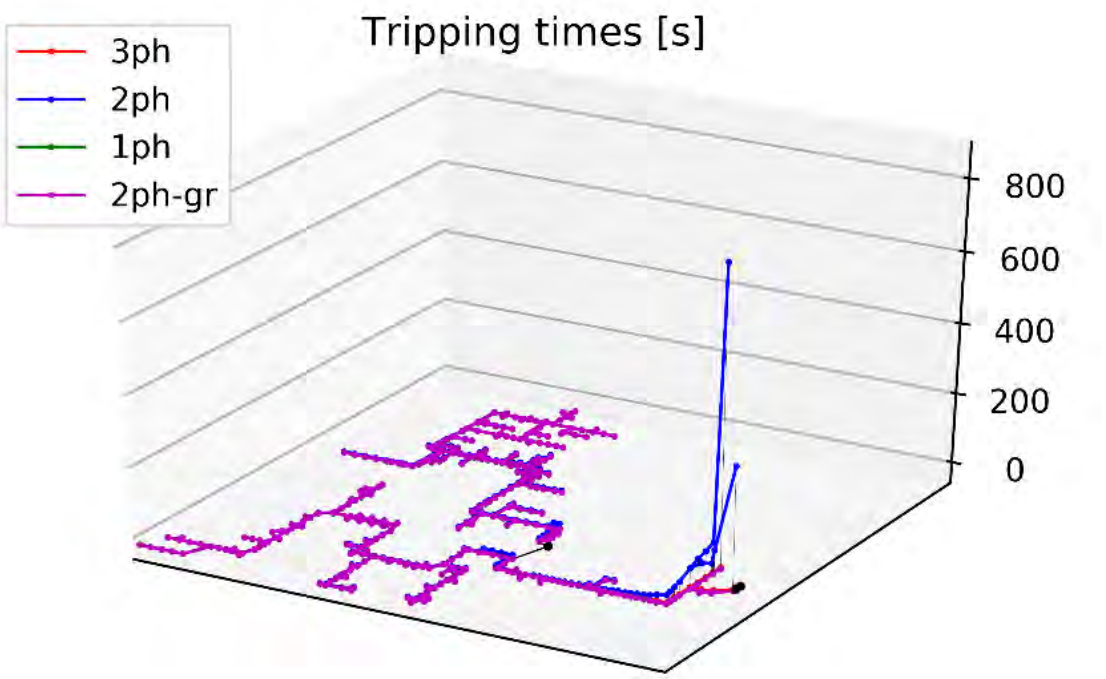


Figure 33 – Drynoch network map with tripping time responses to different fault types with a 3MVA BESS

When the tripping times are compared to the requirements defined as a maximum clearing time of 3s, a larger area of the grid is affected. Figure 34shows that large sections of Feeder 12 experience 2ph fault clearing times larger than 3s. Further locations in Feeder 11 are affected, especially in the Glendrynoch PMCB section. The 3s criterion also fails for close to busbar 3ph faults protected by the main feeder CBs.

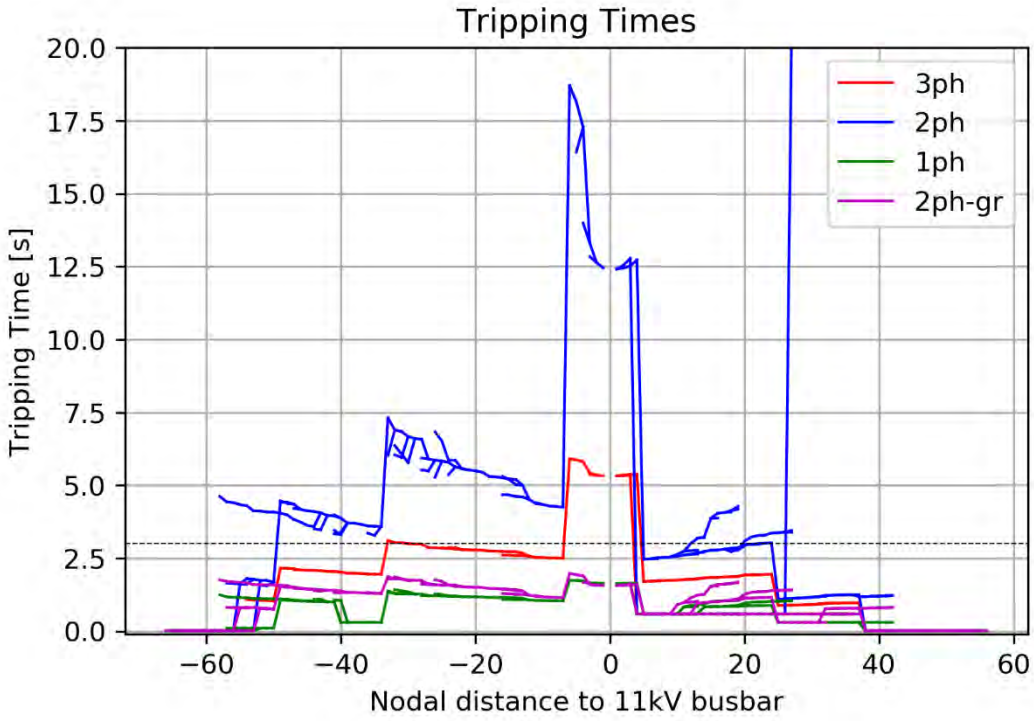


Figure 34 - Nodal distance map for tripping times in islanded mode with 3MVA BESS

The areas not covering the posed requirements can be observed in Figure 35 below, where the response of all fault types was considered, with a requirement that an area of network can be considered satisfactorily protected if all faults are cleared within the requirements.

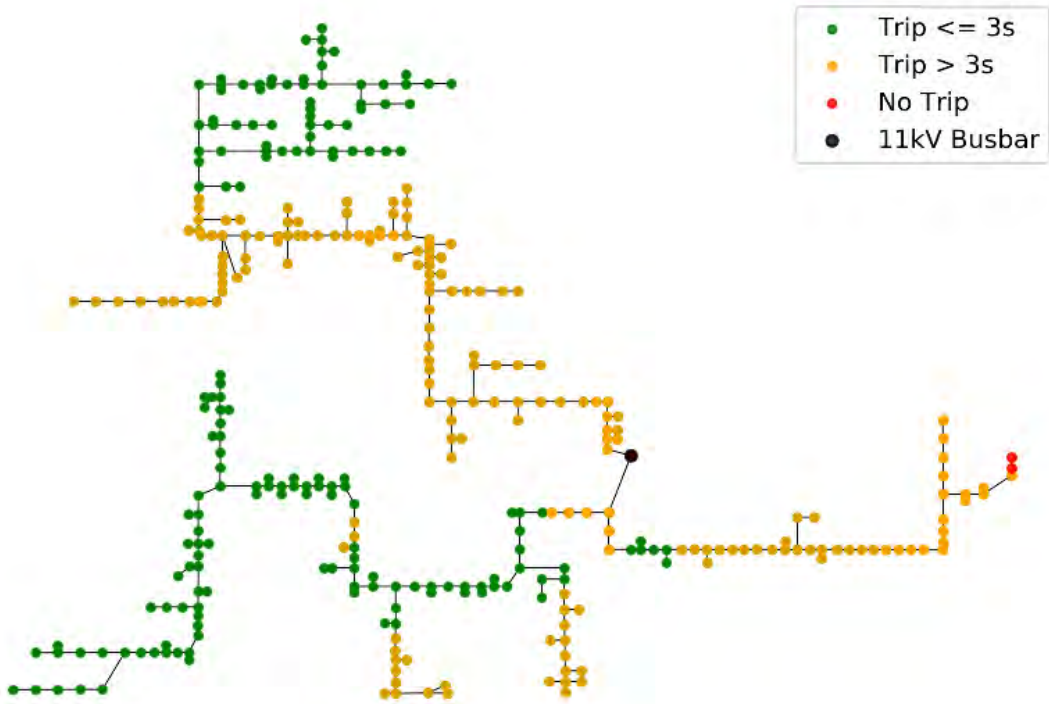


Figure 35 - Network tripping times considering all fault types with a 3MVA BESS

Despite the large area of the network that is non-compliant with the defined requirements in the 3MVA BESS case due to >3s tripping times or no trips of the overcurrent protection system that was originally designed for the Grid only case and it's specific conditions, a high selectivity is still achieved, as can be seen in Figure 36.

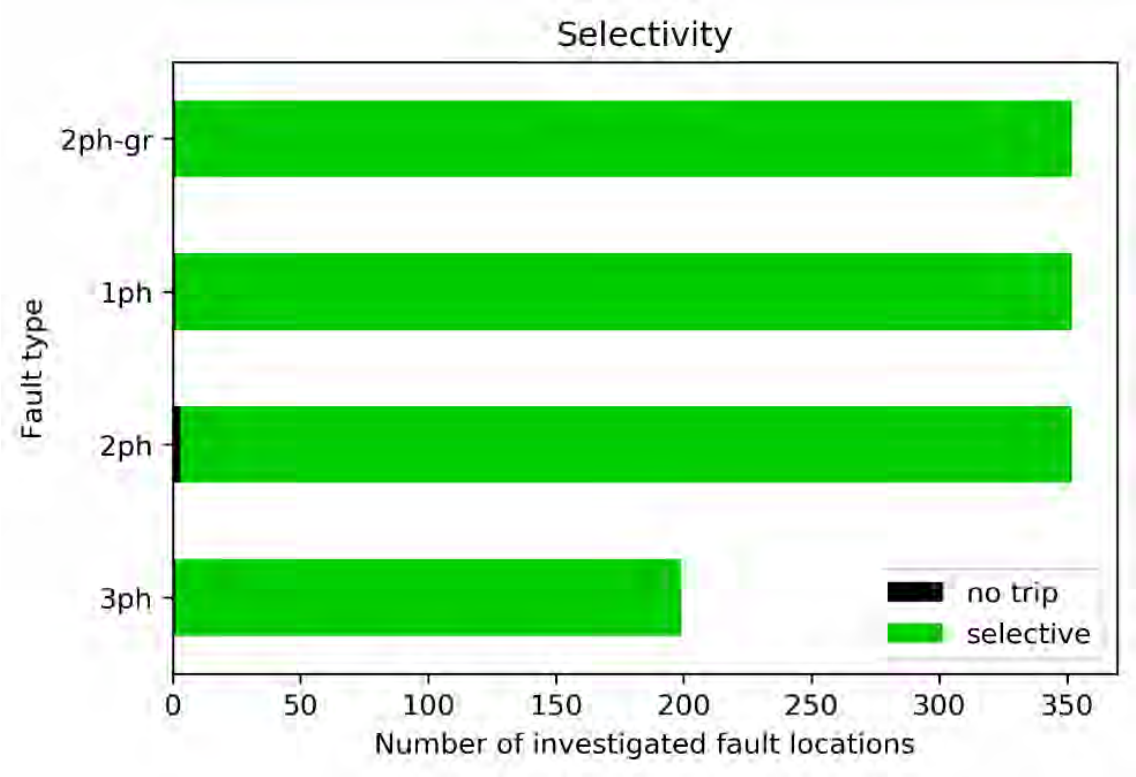


Figure 36 – Selectivity achieved of existing overcurrent protection with a 3MVA BESS

For a RaaS solution with a BESS of a 3MVA rating to be acceptable, all fault types must be cleared within the requirements.

Based on these results, a 3MVA BESS would not be an acceptable solution with the existing primary overcurrent protection settings on the network as the protection system performance would not meet the requirements. For a 3 MVA BESS to be acceptable at this site with regards to tripping times and selectivity, some adaptations would be required, which are described in Section 6.1.7.

Performance of primary relay protection in islanded operation with 5MVA BESS

To compare with the results of the 3MVA case, the larger rated BESS system is analysed in relation to the existing protection system.

As with the 3MVA case, the tripping times of the existing protection devices is considered for a variety of faults along the network. The cumulative distribution function is shown in Figure 37 below.

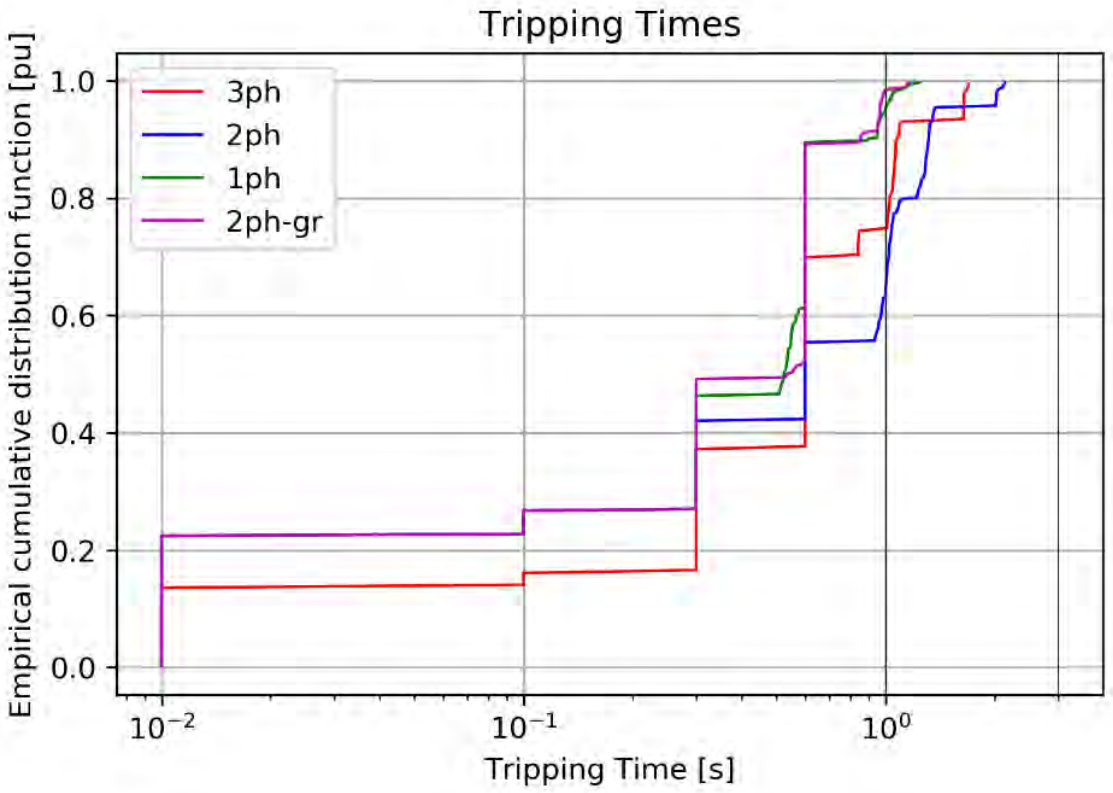


Figure 37 - Empirical cumulative distribution of protection devices with a 5MVA BESS

These results show that for all types of faults, at all points along the network, the protection settings would trip after a maximum of approximately 2 seconds. Another view of these results is shown in Figure 38. This graph shows that the longest clearing times are observed to occur for 3ph and 2ph faults at locations close to the busbar protection zones. This is due to the grading of the protection devices which is set to achieve selectivity. The limited fault current that can be delivered causes an almost constant short circuit current, which is insufficient for faster tripping in contrast to the Grid only mode.

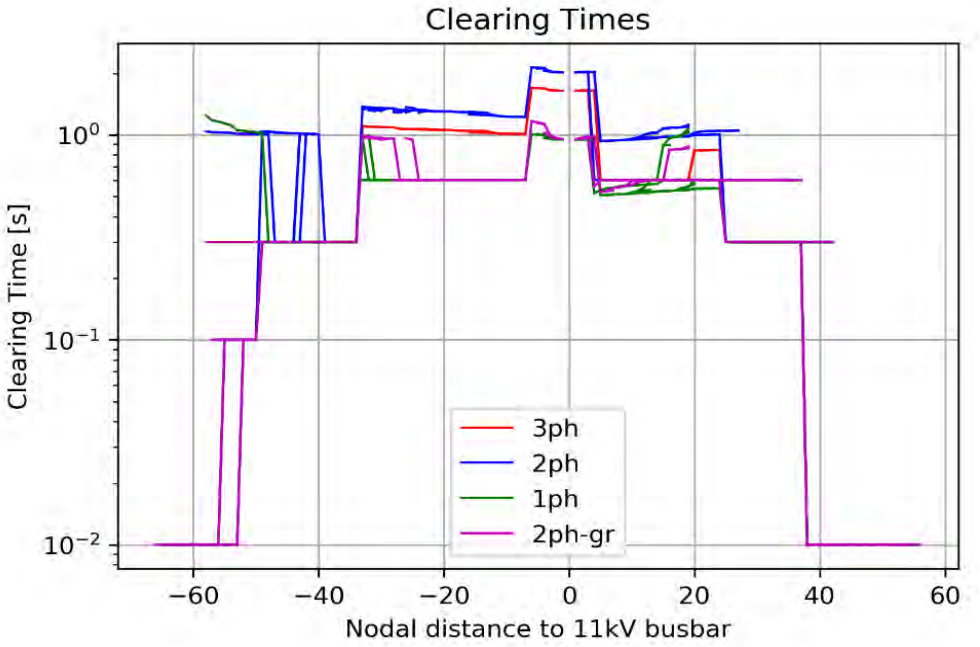


Figure 38 – Tripping times at nodal distances from the 11kV busbar

These results confirm that a 5MVA BESS combined with the existing protection devices satisfies the requirements for tripping times. Subsequently, it is necessary to determine the level of selectivity that can be achieved. This is done by analysing which CB trips in the event of a fault. As the graph below in Figure 39 shows, this configuration produces full selectivity, satisfying this non-mandatory requirement.

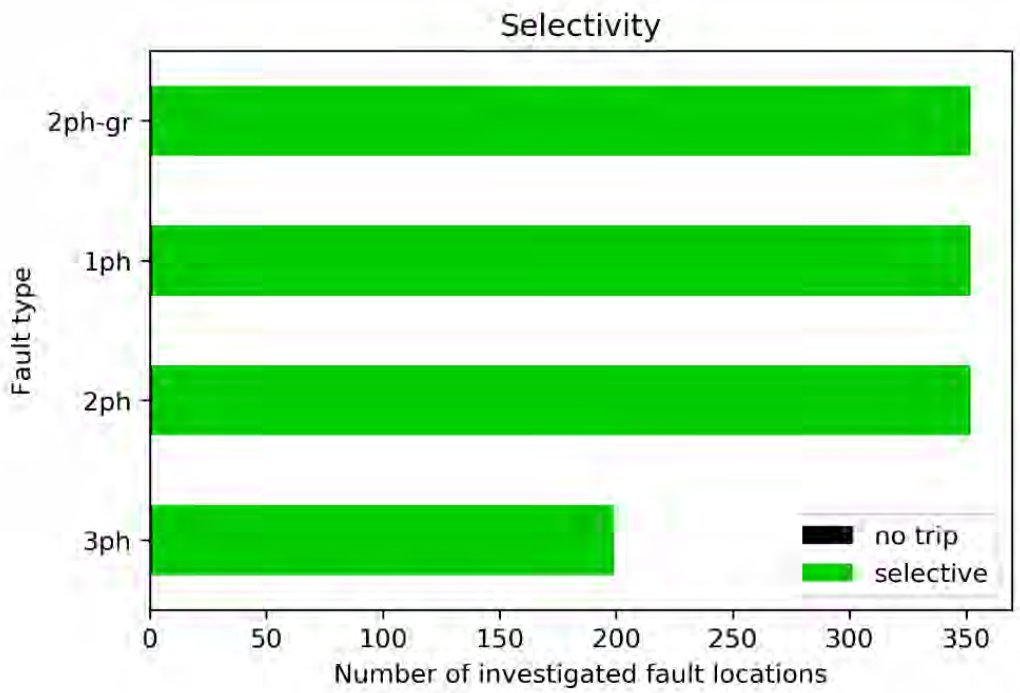


Figure 39 - Selectivity of faults using existing protection settings and a 5MVA BESS

With knowledge that a system of this size satisfies the requirements for tripping times and selectivity, the thermal stress on the system is analysed using the method described in Section 6.1.2 to confirm that limits of the electrical lines will not be exceeded during a potential fault event.

These results are plotted on the network map, shown in Figure 40. While a comparably high fault current is observed on each feeder, a higher per unit thermal loading is observed on Feeder 11 due to its lower thermal capability.

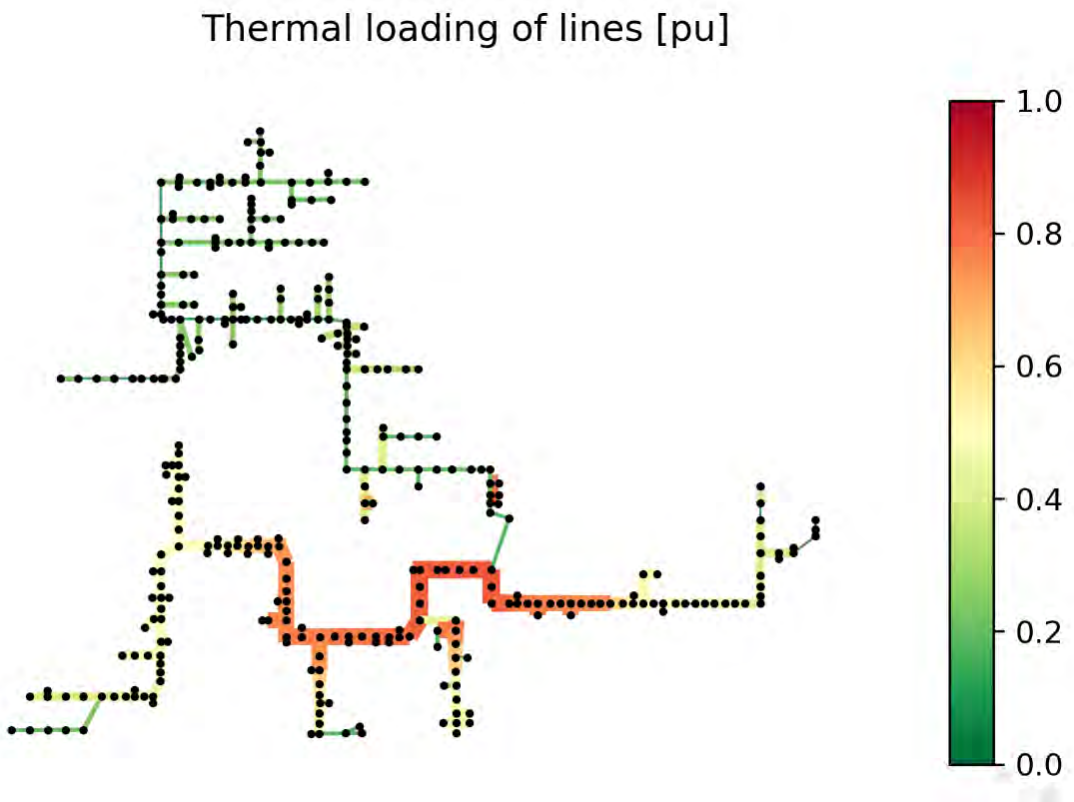


Figure 40 – Thermal loading of lines considering all fault types with a 5MVA BESS

Using this method, utilising the worst case settings taken, the thermal loading is deemed acceptable for the shifted fault clearing situation in islanded mode. In comparison to the Grid only scenario less thermal stress for close to busbar faults is achieved due to the limited current provided by the BESS.

These results confirm that the existing primary protection settings are satisfactory with a 5MVA BESS. It can also be concluded that there is a comparable overall distribution of tripping times when comparing to grid mode, with differences being:

- The fault with the longest tripping time changes to 2ph and 3ph faults instead of 1ph and 2ph
- The location of the fault with the longest tripping time moves from the periphery to near the busbar protection zones

Performance of primary protection in Grid parallel operation with 5MVA BESS

With knowledge that the 5MVA BESS operating in islanded mode satisfies the defined requirements, it is necessary to consider the system in its other mode of operation, namely in parallel operation with the grid. The same analysis is undertaken as above considering this scenario.

The tripping times of the existing protection devices reacting to different types of faults occurring at every node along the network is shown in Figure 41 below. This graph shows that under all fault

conditions, at all points along the network, the existing protection devices have a tripping response that satisfies the defined requirements.

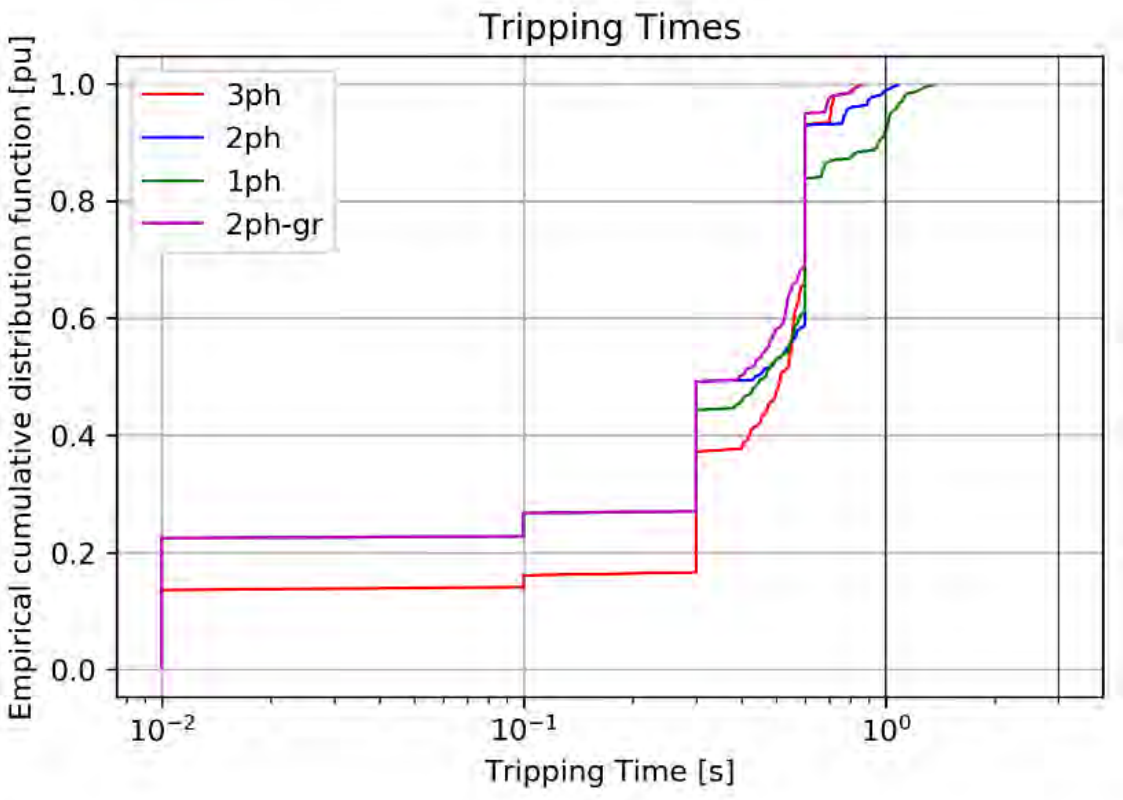


Figure 41 - Empirical cumulative distribution of existing protection devices with a 5MVA BESS in parallel operation with the grid

Another view of the tripping time response is shown below in Figure 42 as a nodal map, which confirms that the tripping time response at all nodes satisfies the requirements.

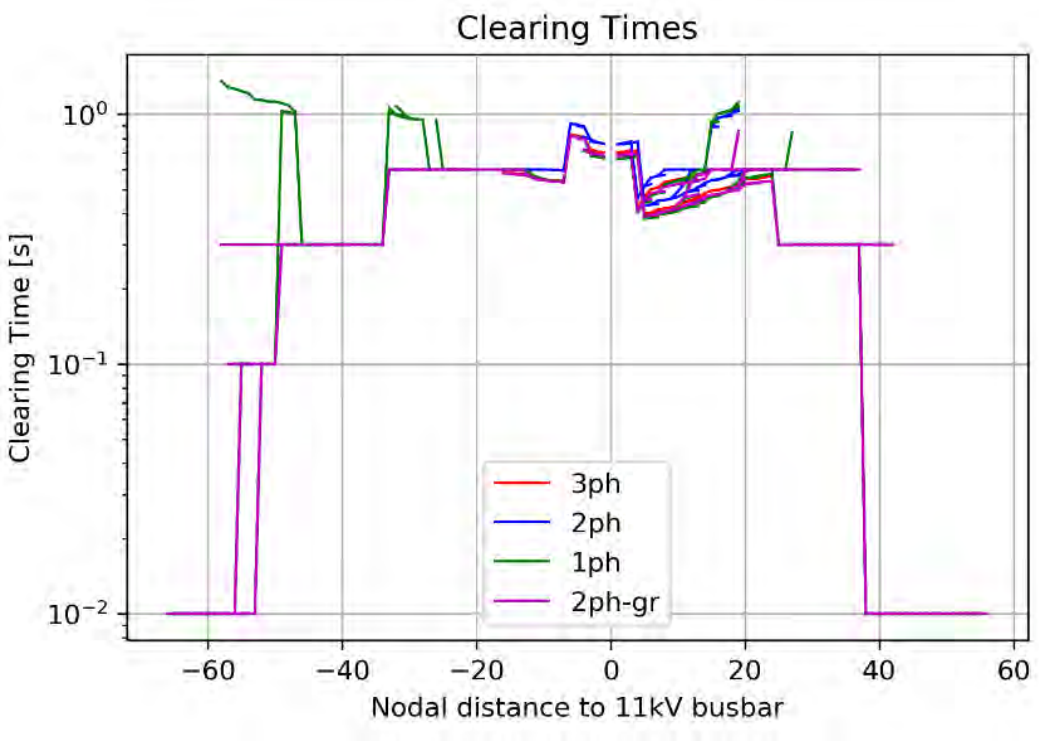


Figure 42 - Clearing times at nodal distances from the 11kV busbar

When considering the selectivity of the existing protection devices when the system is operating in parallel with the grid, it is shown in Figure 43 that full selectivity is achieved, satisfying the requirements.

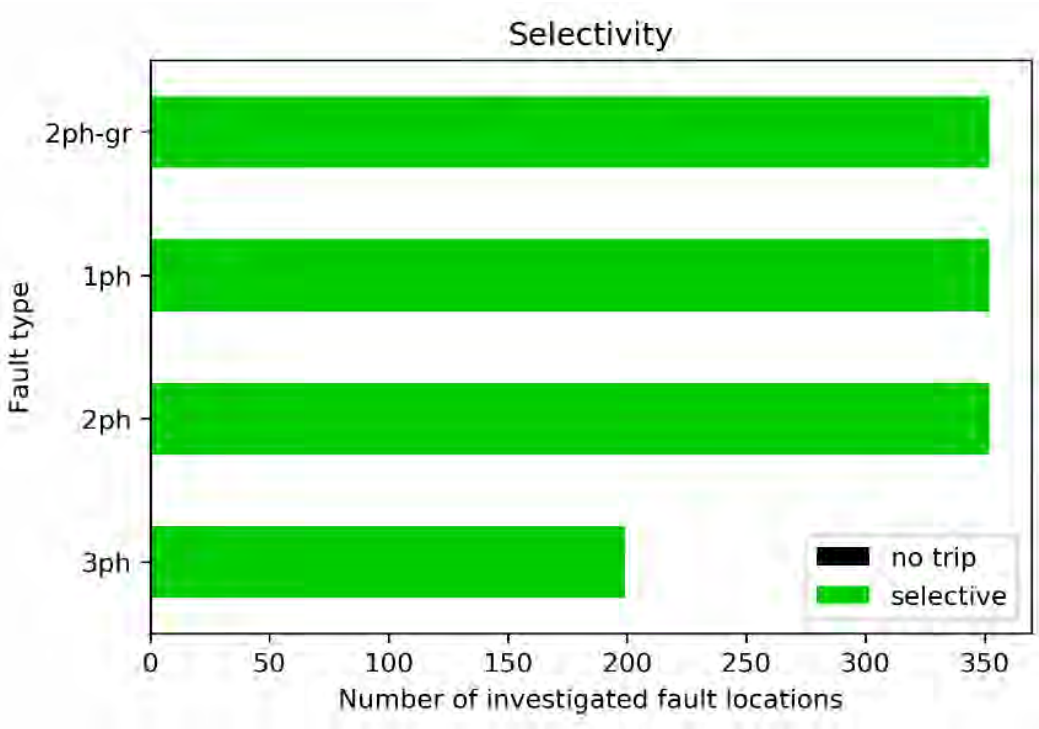


Figure 43 - Selectivity achieved of existing overcurrent protection with a 5MVA BESS in parallel with grid

As in islanded mode, it is necessary to consider whether thermal loading of the lines causes risk to the existing network equipment. As shown in Figure 44, there may be a critically high thermal loading of lines for parts of Feeder 11 close to the busbar during parallel operation of grid and BESS. Since this level of thermal loading may represent an unacceptable level of risk, further consideration must be given to this topic in the Detailed Design phase.

This modelling uses worst-case assumptions which need to be scrutinised together with an investigation into the probability of such an occurrence. If determined necessary, the settings of the protection devices may need to be amended to shorten the tripping times of certain CBs to reduce the potential thermal loading on the lines. Furthermore an adequate maximum fault current interuption capacitiy of the CB should be verified or ensured by the design (e.g. on renewal of the 11kV switch board).

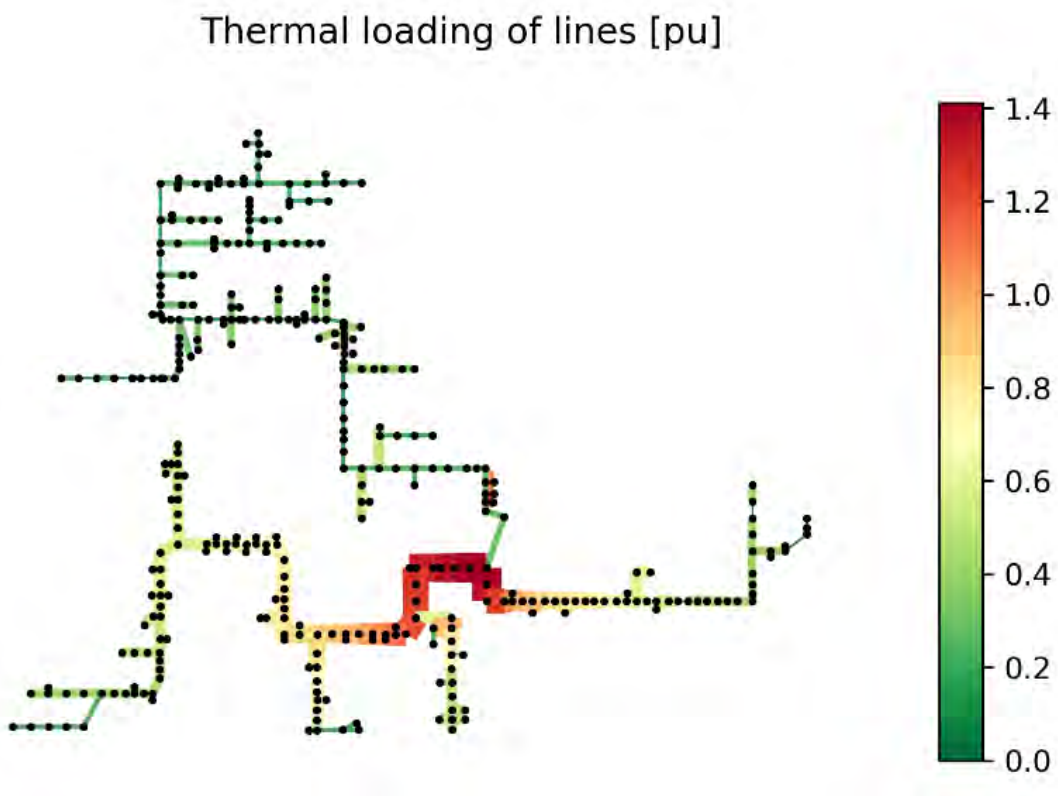


Figure 44 - Thermal loading of lines considering all fault types with a 5MVA BESS in parallel with the grid

6.1.4.2. Performance Analysis of HV Backup Protection

To provide backup protection the Drynoch 11kV network has remote overcurrent protection (via relays out on the network) available that can be utilised, while the BESS itself is expected to utilize undervoltage protection (located at the primary) and trip in case of overloads, which can be utilised. The performance of these different types of backup protection are considered below for both the 3MVA and the 5MVA BESS inverter nominal rating cases.

Performance of backup protection in islanded operation with 3MVA BESS inverter

Backup protection provided by remote overcurrent relays necessarily results in a delayed tripping response compared to primary protection devices, as the backup system must only react after the primary relay fails to trip. Figure 45 below gives a statistical summary of the prolonged tripping times expected at Drynoch.

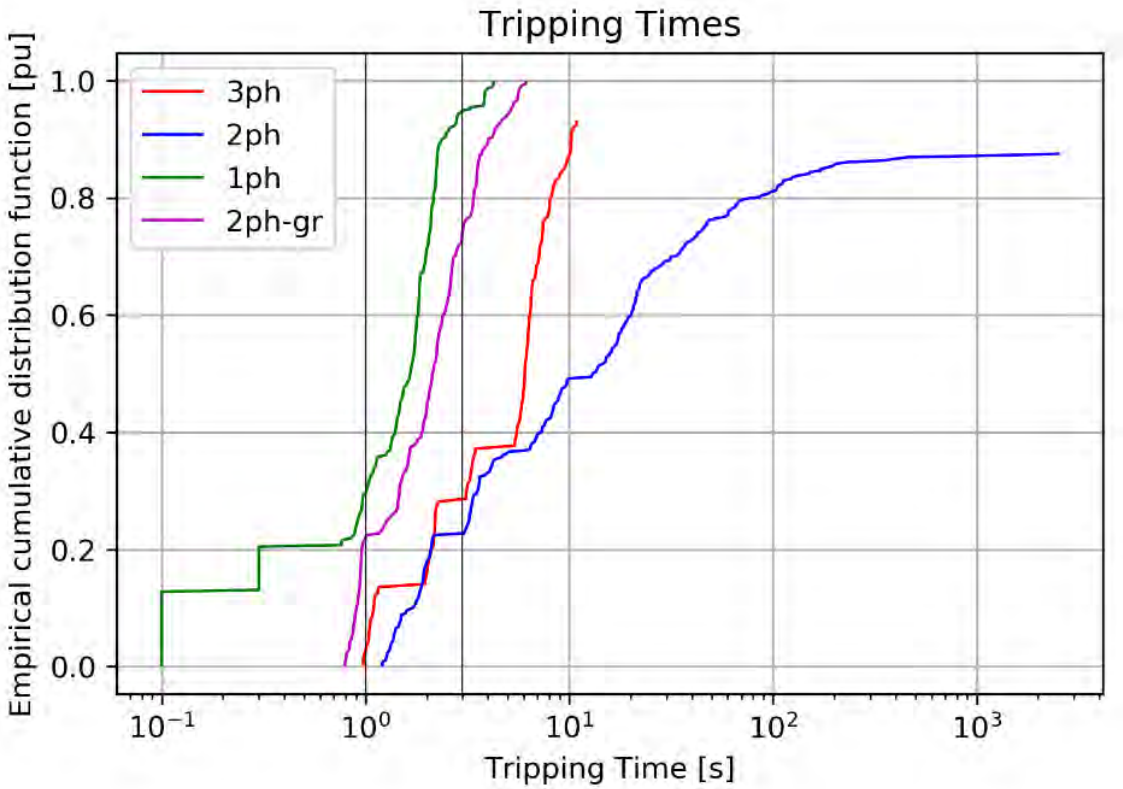


Figure 45 - Tripping time response of existing backup protection systems with a 3MVA BESS in island mode

When compared to the primary protection response, the tripping time response of the backup protection is extended severely for all fault types. 2ph faults are particularly affected, whereby up to 12% of fault events result in no trips from the backup protection. About 8% of the 3ph faults are not cleared by backup protection, however, full selectivity is maintained on relays that do trip.

These results show that only partial backup protection capability can be achieved using the existing remote overcurrent relays, especially for two and three phase faults, and that additional measures would be required to make the system compliant.

Undervoltage protection operating on the 11kV busbar is also considered as backup protection. As shown in Figure 46, backup protection can be provided for 3ph, 2ph and 2ph-gr faults for thresholds above 0.7pu. This means, backup protection can be provided to peripheral fault locations not covered by remote relay overcurrent backup protection.

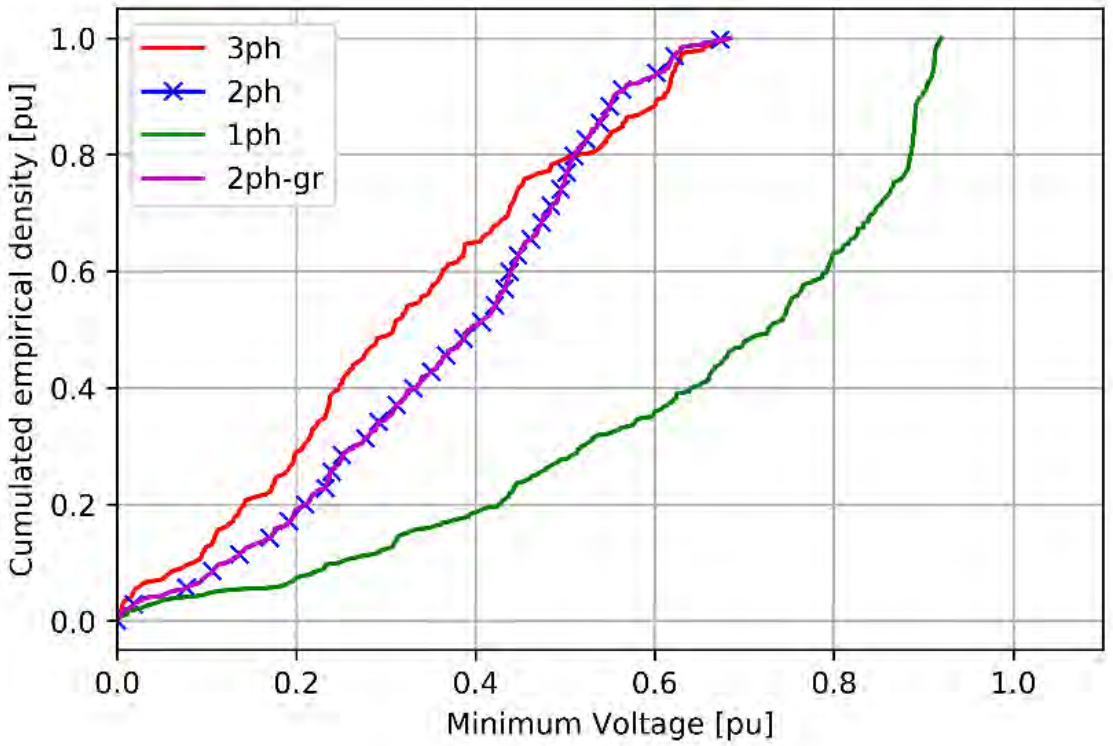


Figure 46 – Cumulative distribution of undervoltage protection backup devices tripping from faults with a 3MVA BESS

Limited sensitivity of backup protection by undervoltage protection is achieved for 1ph faults however, as full network backup protection is only offered for undervoltage threshold settings of >0.92pu. The regions that are not offered backup protection from the undervoltage protection with a typical setting of 0.8pu are shown in the third network maps in Figure 47 below. The other network maps represent the other fault types considered and are uncoloured as full backup protection is offered in these circumstances.

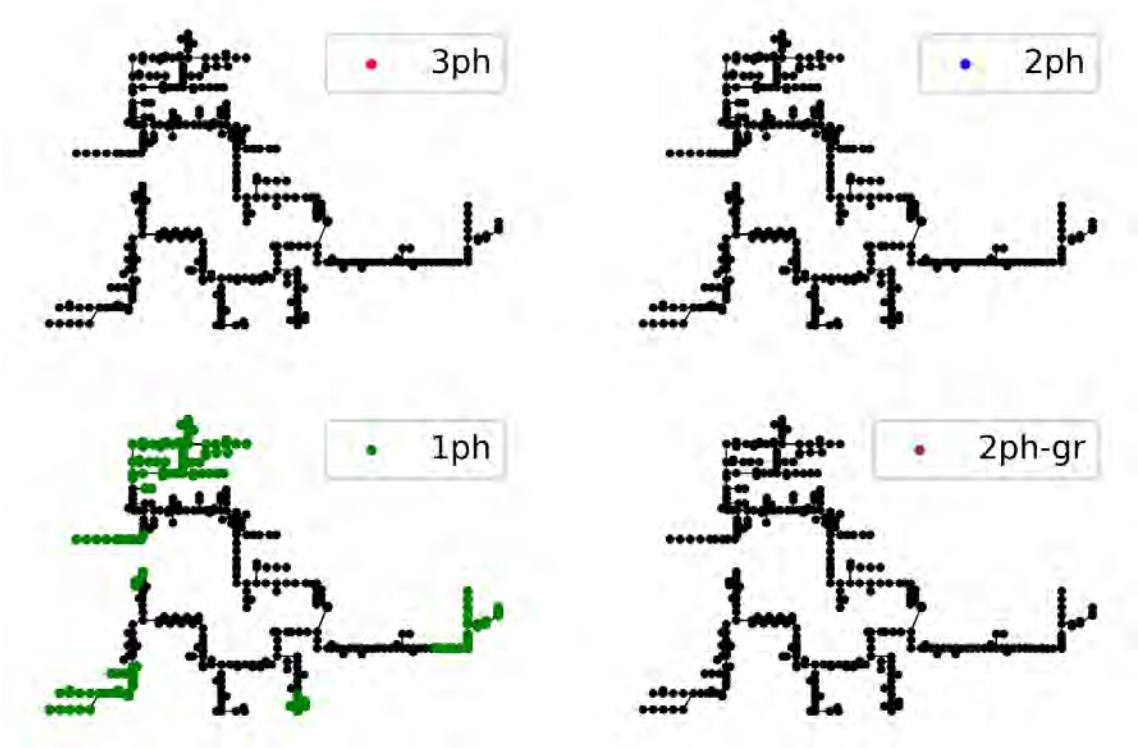


Figure 47 - Regions of no tripping of BESS undervoltage protection for different fault types

Overload tripping of the BESS during faults may also act as a backup protection for grid faults. During fault current injection by the BESS, a highly oscillating active power output is observed during 1ph faults on the network periphery. This results in a peak active power overload to occur on the BESS, assuming the assumptions on BESS behaviour during asymmetrical faults is correct.

The regions which experience BESS overload switching from these 1ph faults are shown in below. If compared to Figure 48, it can be seen that this form of protection only partially offers backup protection to the regions that suffer from no trips from undervoltage protection.

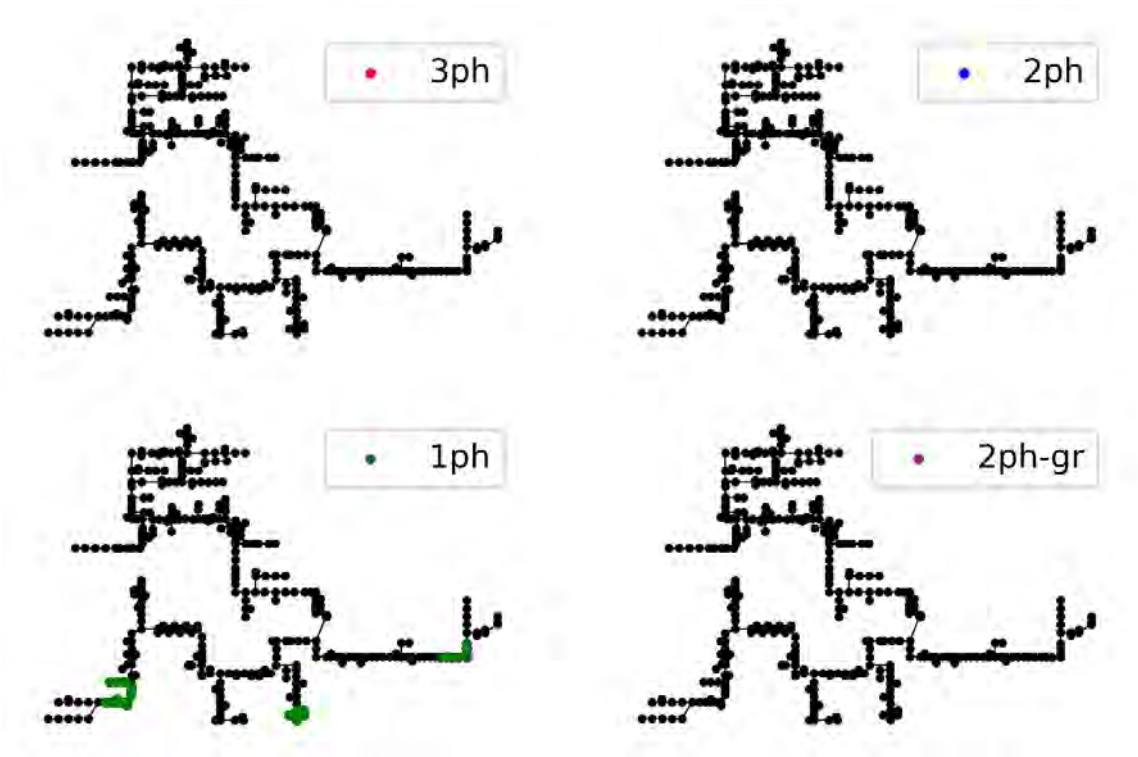


Figure 48 - Regions of BESS peak active power overload for different fault types with a 3MVA BESS

If BESS active power limitation by the controls implemented is in operation to enable fault ride through, the resulting injected currents will be lowered, limiting the applicability of BESS overload tripping as a form of backup protection. However, a lower power output also results in lowered voltages during fault cases, making undervoltage protection more effective.

In conclusion, two levels of remote backup protection are difficult to achieve utilizing the investigated criteria when operating a BESS system with an inverter of 3MVA nominal rating. Further options are investigated in section 6.3.

Performance of backup protection in islanded operation with 5MVA BESS inverter

The backup protection response by remote overcurrent relays when operating with a 5MVA BESS in islanded mode is shown in Figure 49 below.

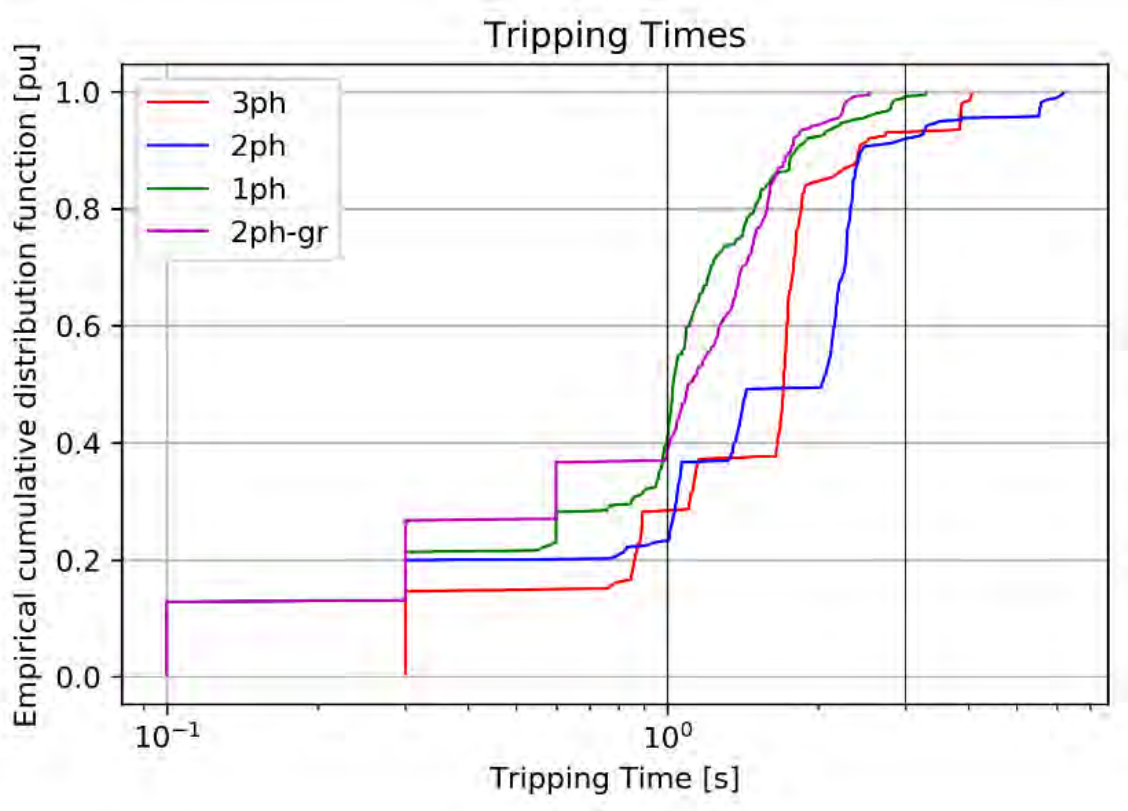


Figure 49 – Tripping times of backup protection with existing protection settings and 5MVA system in BESS only mode

In this case, the grading leads to prolonged tripping times, especially for close to busbar faults being backup protected by transformer protection, and results in some faults not being cleared within the 3 second requirement defined for primary protection. The results confirm that there is no loss of sensitivity for backup protection (not shown).

When applying backup protection by BESS undervoltage tripping the scenario of islanding with a 5MVA BESS inverter offers less sensitivity. A reduced voltage sag is observed at the 11kV busbar due to faults on the feeder periphery when a 5MVA BESS is used instead of a 3MVA BESS due to its higher fault current injection capabilities. Accordingly, no backup protection may be offered by the BESS undervoltage protection in these regions when applying a setting of 0.8pu oriented at default tripping levels of G99. The regions that are not offered backup protection from the undervoltage protection are shown in the network maps in Figure 50 below.

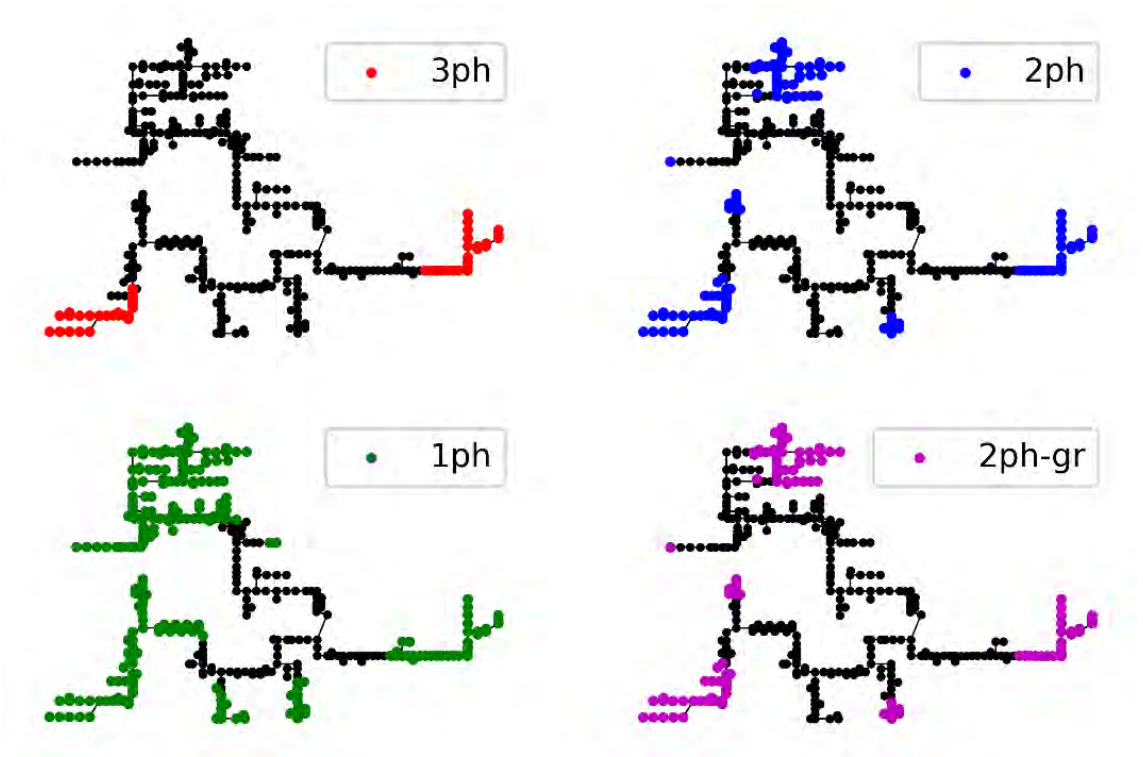


Figure 50 - Regions of no tripping of BESS undervoltage protection for different fault types

Since undervoltage protection is not fully suitable in this scenario, backup protection would have to be provided in those regions by the other methods considered, namely: remote overcurrent protection relays or Fault Ride Through (FRT) failure of the BESS system due to inverter or battery overload.

In dependency of the BESS design overload tripping may act as a backup protection for grid faults. As in the 3MVA case, during active power injection by the BESS, a highly oscillating output is observed during 1ph faults on the network periphery, however, unlike the 3MVA case this also occurs for the other fault types considered. This results in a peak active power overload to occur on the BESS, assuming the assumptions on BESS behaviour during asymmetrical faults is correct.

The regions which experience BESS overload tripping from these faults are shown in Figure 51 below. If compared to Figure 50, portions of the sections that are covered by the BESS overload tripping are not covered by the undervoltage protection. This form of protection therefore offers partial backup protection to the regions that suffer from no trips from undervoltage protection.

If the batteries are significantly oversized however then this type of backup protection would not be suitable as the overload switching limit would not be reached.

The affected locations assuming a permissible 1.2pu overload of the battery itself on the DC side with 3MVA rating to be tolerable are shown in Figure 51.

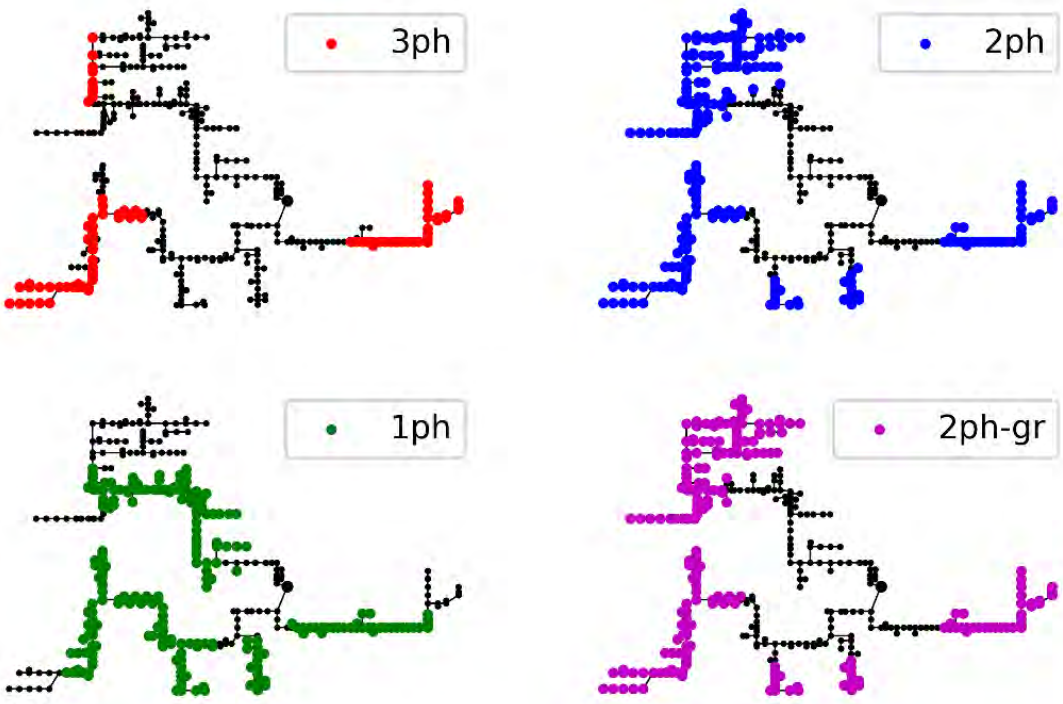


Figure 51 - Regions of BESS peak active power overload for different fault types with a 5MVA BESS

Similar to the 3MVA case, if active power limitation is in operation to enable FRT then BESS overload switching will be limited as a backup protection. However, as the resulting injected currents will be lowered, the voltage will be reduced in those fault cases, improving the ability for undervoltage protection to act as backup protection.

Coordination of Backup and Primary Protection Systems

For the network protection systems to be effective, the primary and backup protection systems must be coordinated to ensure the relays trip in their desired order.

For the *3MVA BESS* inverter rating case, when assuming the BESS undervoltage protection relay operates at 2.5 seconds or 3 seconds for a 0.8pu voltage drop, unselective tripping will result when the primary protection devices have long clearing times, especially for 2ph and 3ph faults. Undervoltage tripping remains selective for fast primary protection operation, especially for 1ph and 2ph-gr faults.

There can be interference between battery overload protection and primary or backup undervoltage protection during 1ph faults occurring at the peripheries depending on the overload duration capabilities of the battery. This would be assessed further in the Detailed Design phase.

For the *5MVA BESS* inverter rating case, when assuming the BESS undervoltage protection relay operates at 2.5 seconds or 3 seconds for a 0.8pu voltage drop, no unselective tripping should happen compared to primary protection.

In the event of a failure of the primary overcurrent protection, undervoltage tripping may be unselective due to the prolonged fault times.

As with faults in the *3MVA BESS* inverter case, there can be interference between battery overload protection and primary or backup undervoltage protection during 1ph faults occurring at the

peripheries depending on the overload duration capabilities of the battery. This would be assessed further in the Detailed Design phase.

6.1.4.3. Performance Analysis of Secondary Substation HV Fuse Protection

This section analyses whether the current HV fuse protection scheme of the secondary substations (11kV/LV) is also valid in island mode.

The majority of secondary transformers at Drynoch have up to 200kVA nominal capacity, with two larger transformers being TALISKER DISTILLERY with 500kVA and SCONSER QUARRY with 800kVA. Analysis has been done for all secondary substations downstream of Drynoch and reveal quite different results for most of the transformers up to 200kVA and the two large units, particularly SCONSER QUARRY 800kVA.

The secondary substation transformers are protected by a HV fuse, as seen in Figure 52. Assigning the maximum permissible fuse ratings according to SSEN's fusing policies in Grid only mode leads to the conclusion that a lower rating will be applied at least in the periphery. The individual actual ratings of those fuses per transformer could not been assessed in the course of this analysis. The fuse sizing is therefore assumed to be done as low as possible but not lower than 1.5 times the nominal current of the transformer, which is used as an assumption in this study (compare Section 5.2). The HV pre-arcing time curves are considered according to the assumption in Table 24.

The HV fuse should protect from faults in the HV and LV busbars of the transformer for all types of existing transformers.

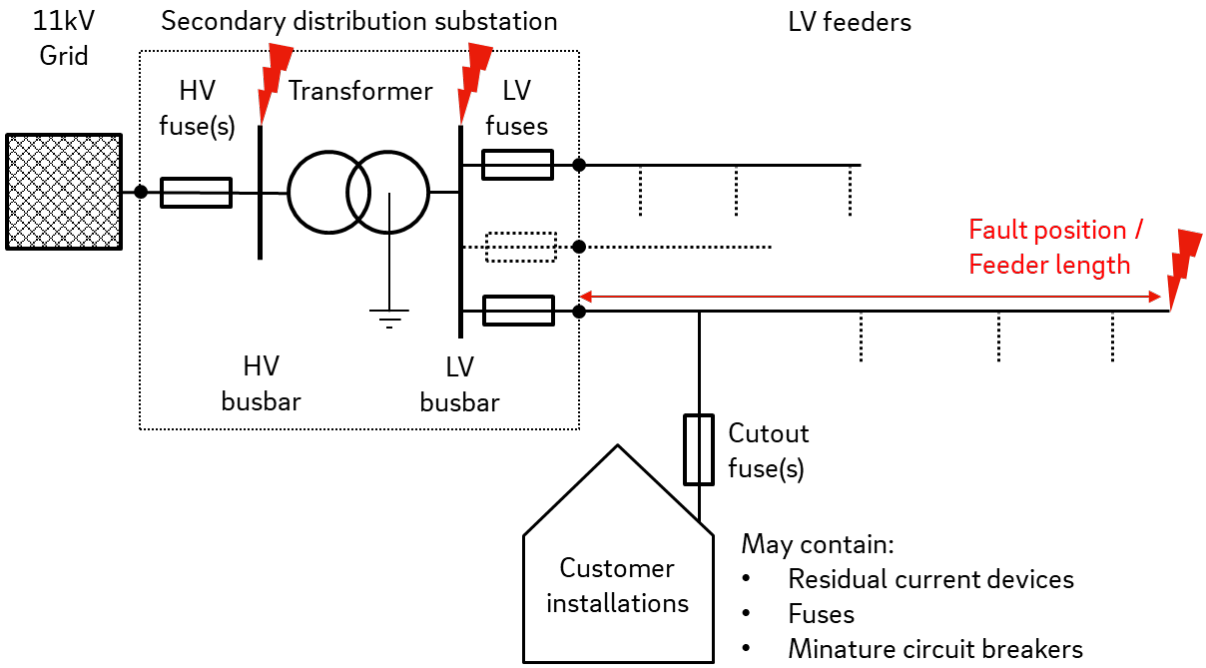


Figure 52 - Principle scheme of the different fuse / protection device locations in Drynoch Secondary substations and LV system

HV fuse blowing for secondary substation HV busbar faults

The secondary substations in Drynoch are equipped with different transformer types depending on its nominal capacity:

- split-phase: 16kVA to 100kVA
- three-phase: 100kVA to 800kV

At all the distribution transformers the following types of faults are applied at the HV busbar:

- three phase transformers: 3ph, 2ph, 1ph-gr, 2ph-gr
- split phase transformers: 2ph, 1ph-gr, 2ph-gr

The analysis reveals in Figure 53 that a 3MVA BESS would trip all the HV secondary substation fuses in less than 1 second with some exceptions:

1. The fusing times of the 500kVA transformer approach 10seconds for 3ph faults and exceed 10s for 2ph faults.
2. In case of the 800kVA transformer no tripping of fuses will occur.

A 5MVA BESS inverter would be able to trip the HV fuse also in case of 500kVA transformer, but still would not be able to trip the 800kVA transformer HV fuse. This situation also happens in grid connected mode, so the tripping time in island mode with a 5MVA BESS is considered equivalent to the grid connected condition.

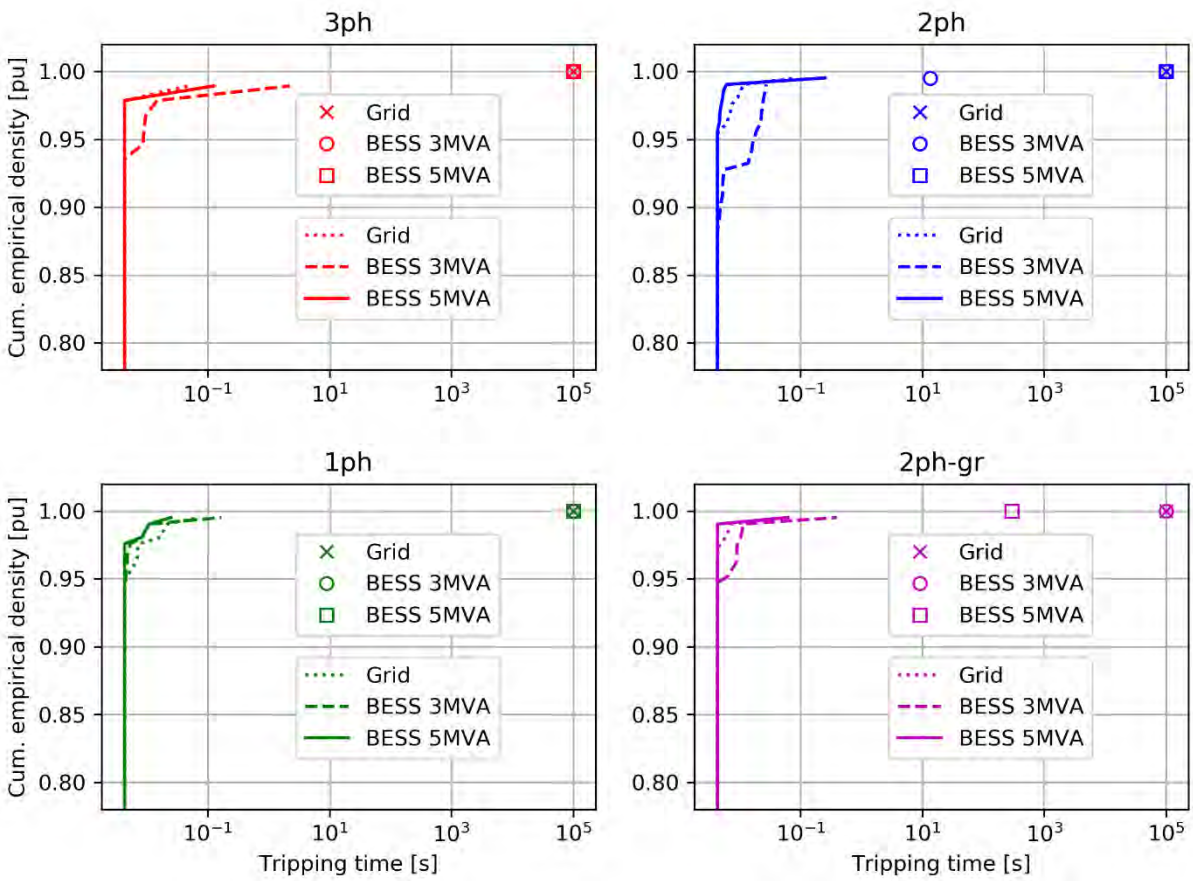


Figure 53 - Cumulative density of transformer tripping time in Drynoch with HV busbar faults and 100% calculated fault current. Tripping times larger 10s drawn by markers only

A simple sensitivity analysis is made reducing the fault current to 80% of the calculated value with results shown in Figure 54. The same results apply with the 5MVA BESS having a performance equal to grid connected mode, with problems only in the HV fuse of the 800kVA transformer. It is concluded that in case of overestimation of fault currents in the study, the results are still valid.

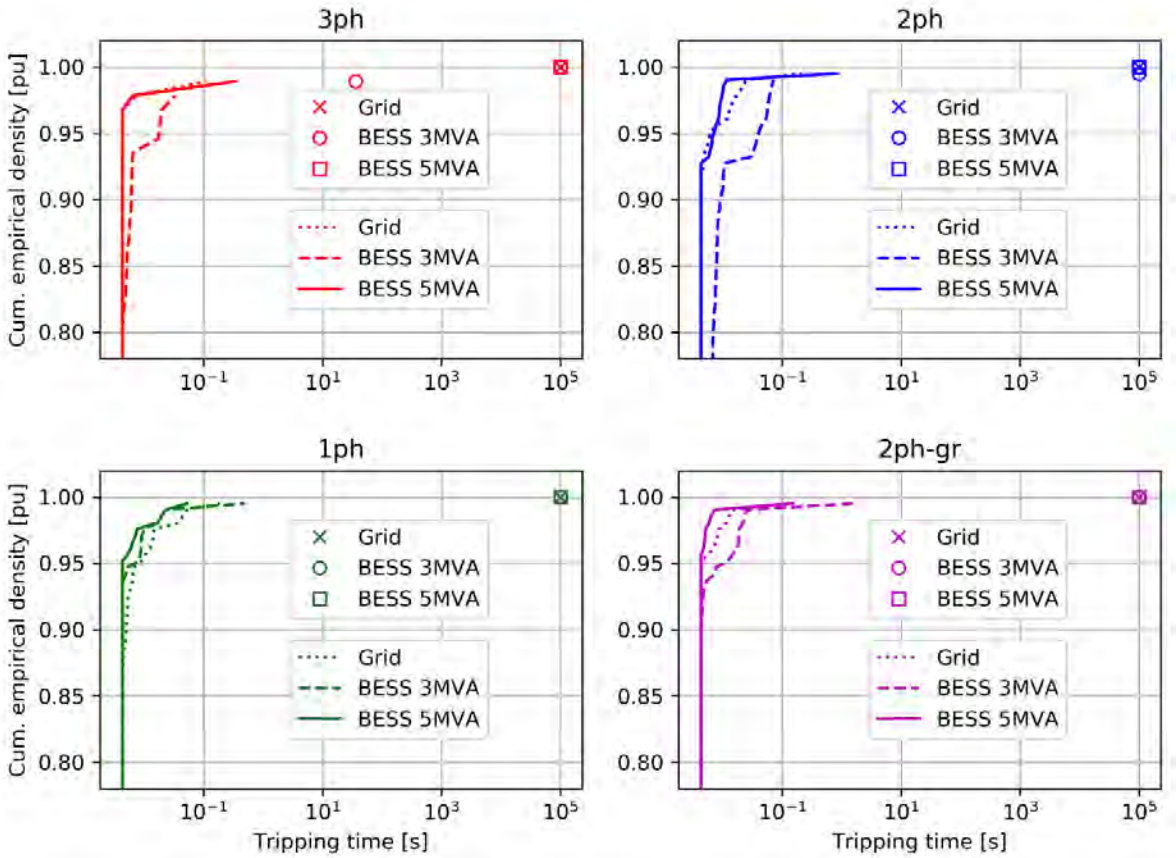


Figure 54 - Cumulative density of transformer tripping time in Drynoch with HV busbar faults and 80% calculated fault current. *Tripping times larger 10s drawn by markers only*

HV fuse blowing for secondary substation LV busbar faults

Faults happening directly at the LV busbar of the secondary substation should be protected by the HV fuse of the transformer as they may appear before the feeder fuses. All these faults are considered bolted/metallic, and the following types are analysed:

- three phase transformers: 3ph, 2ph, 1ph-gr, 2ph-gr
- split phase transformers: 2ph, 1ph-gr

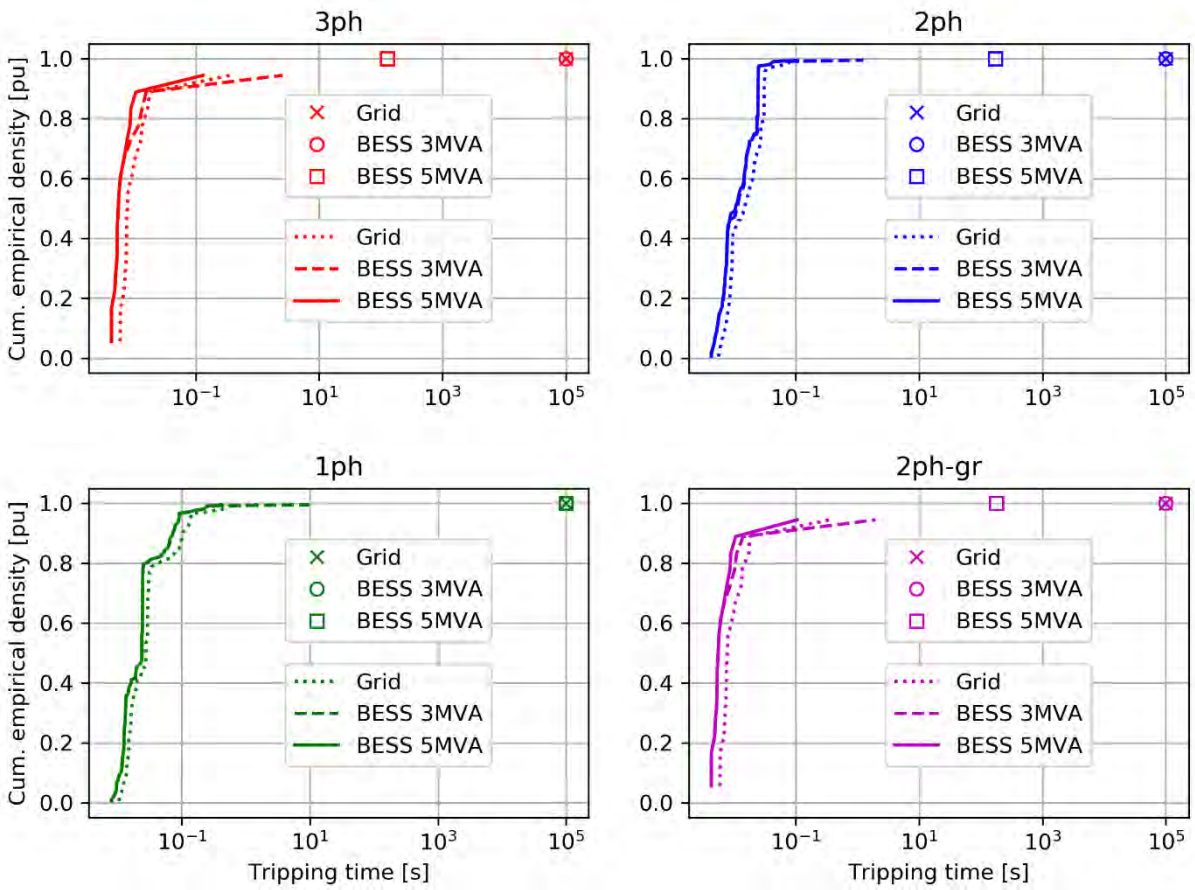


Figure 55 – Cumulative density of transformer tripping time in Drynoch with LV busbar faults and 100% calculated fault current. *Tripping times larger 10s drawn by markers only*

Figure 55 presents the results of the simulations for all transformers in Drynoch showing that tripping time in all transformers is below 1 second, except for the two larger secondary transformers:

- SCONSER QUARRY 800kVA is located in the periphery of feeder number 11. No fuse tripping is achieved in any mode of grid operation, potentially only the 5MVA BESS would be able to blow the LV fuse after 100 seconds in case of 2-phase faults.
- TALISKER DISTILLERY 500kVA is located relatively close to busbar in feeder number 12. It is possible to trip the LV fuses in less than 1s in Grid only or BESS 5MVA only scenarios, but it would take up to 10s in BESS 3MVA only scenario

Again, a sensitivity analysis is made by reducing the calculated fault current by 20% as shown in Figure 56. The artificial lowering of the observed fault current by 20% in all operation modes (Grid, BESS 3MVA only, BESS 5MVA only) shows a delayed tripping in all cases but does not change the overall conclusions.

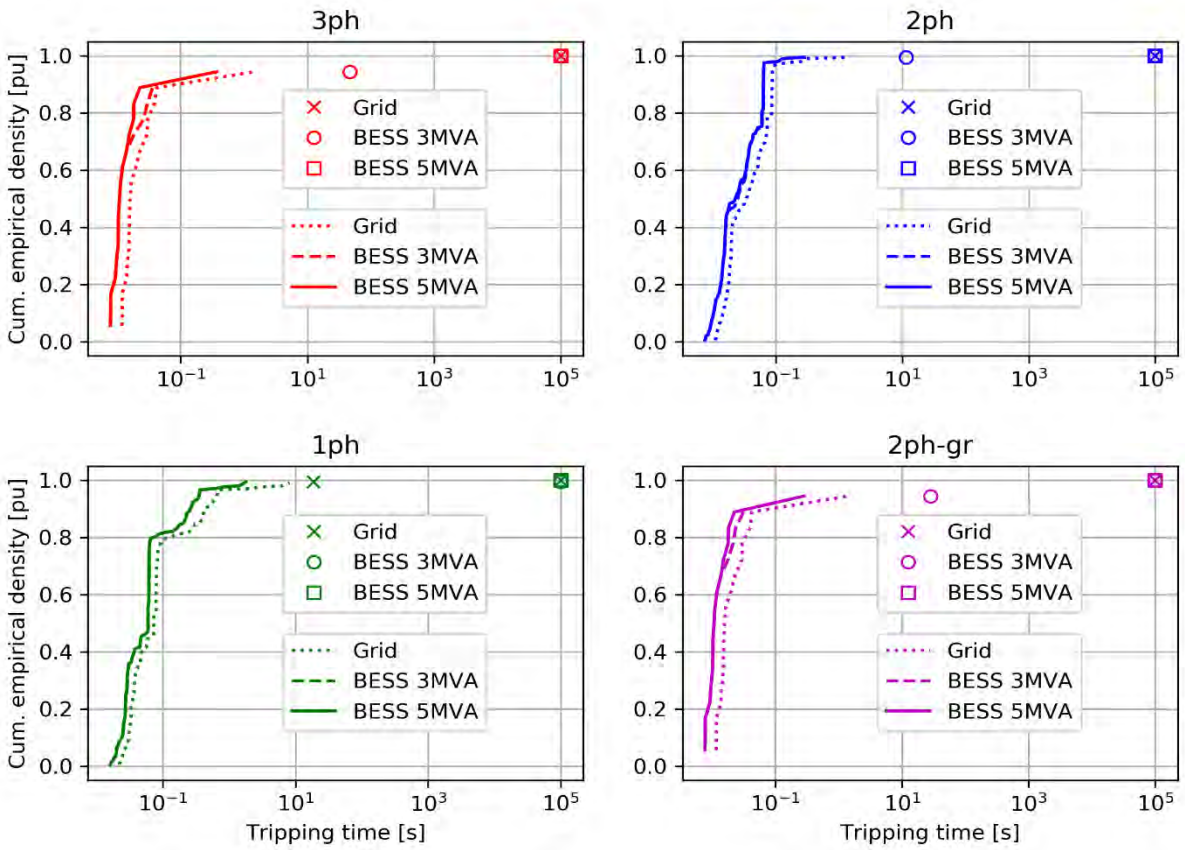


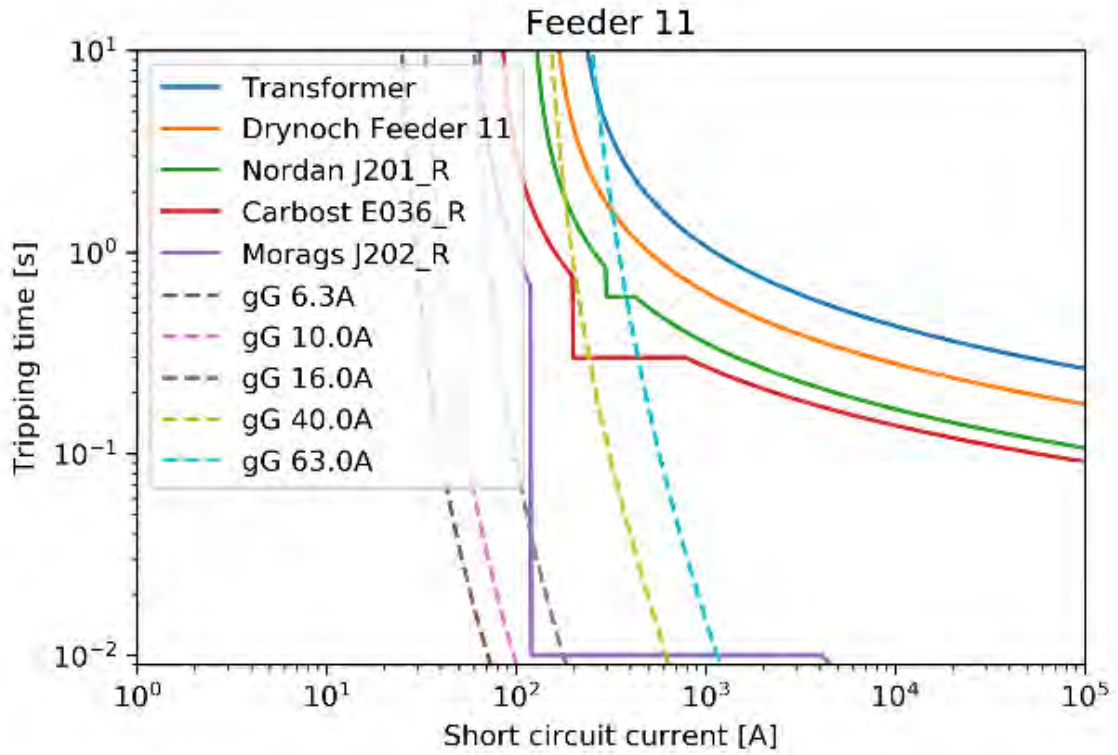
Figure 56 - Cumulative density of transformer tripping time in Drynoch with LV busbar faults and 80% calculated fault current. *Tripping times larger 10s drawn by markers only*

Therefore, the same conclusion can be drawn as for the HV busbar faults. The fault currents fed in islanded mode are as high as in grid only mode or slightly higher, with fusing times as low as in grid only mode or slightly lower. Close to 11kV busbar faults on big secondary substation transformers from 500kVA, show longer tripping times in case of a 3MVA BESS scenario.

It can thus be concluded that the protection system performance requirements can be readily fulfilled in investigated islanded modes with at least equal performance as compared to grid only mode.

Coordination of Fuses and Relays

Figure 57 compares the phase overcurrent tripping curves of the feeder CB and PMCB in Drynoch Feeders 11 and 12 with the typical HV fuse tripping curves.



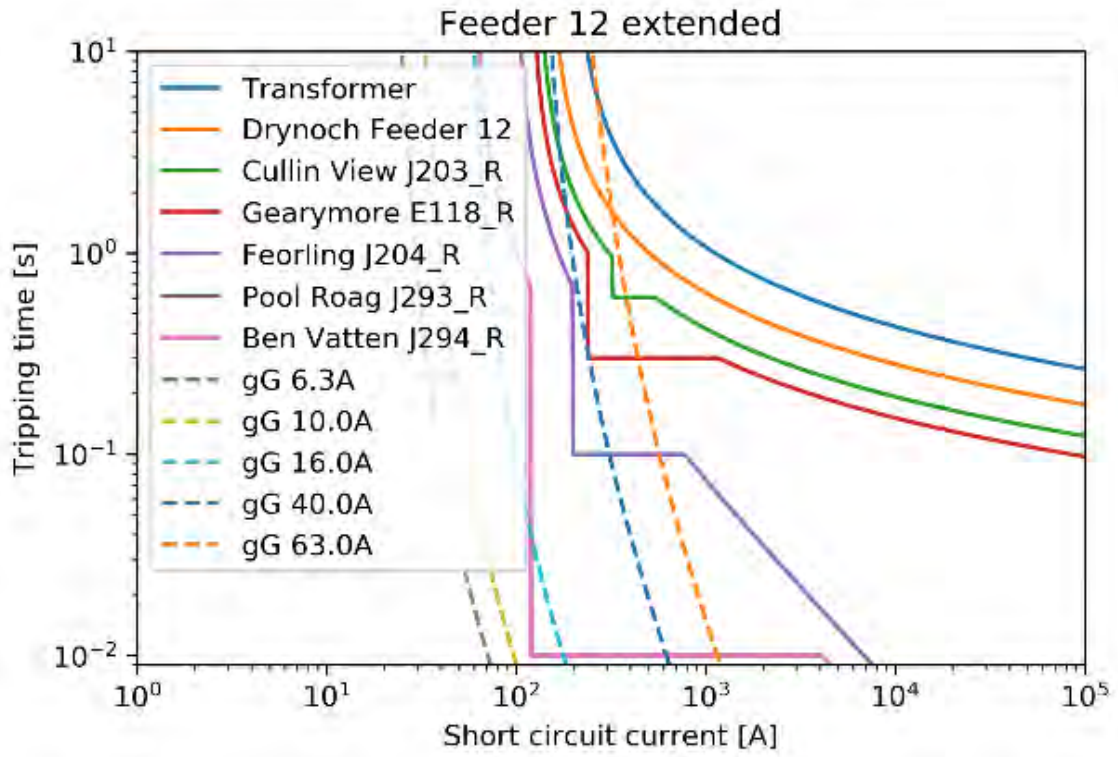


Figure 57 - Tripping curves of installed Relays of selected Drynoch grid sections in comparison to exemplary HV-Fuses typically installed in secondary substations

Most of the presumably installed secondary transformer HV fuses are sized up to 16A and therefore will trip before the HV line relays. But for the larger transformers (500kVA = 40A or 800kVA = 63A, both 3phase), the selectivity of relays and fuses may not be granted.

In general, for zones near to the 11kV busbar, the selectivity of smaller fused substations typically can be assumed. Only in peripheral protection zones, selectivity may be lost, but needs deeper investigation as in this analysis only pre-arcing times are compared and not clearing times of fuses. Currents through relays may be bigger than currents seen by fuse for same event (due to loads) and vice versa (due to intermediate DG infeed).

These results are independent of grid or islanded mode and subject to constraints of protection setting in a weak grid.

6.1.4.4. Conclusions on Performance of Existing HV Grid Protection and Earthing

Based on the HV grid protection studies completed on the Drynoch network, a number of conclusions can be drawn.

It is technically feasible to utilise the existing overcurrent relay-based HV protection systems with existing settings as primary protection in islanded mode of operation. This requires that under the modelling assumptions taken:

1. the assumptions taken on the inverter fault behaviour hold true
2. the inverter rated power is 5MVA or above
3. the overall BESS system design allows for a successful FRT, including:
    a. zero voltage ride through at HV side of transformer of 2 seconds or more
    b. provision of highly oscillating active powers
    c. provision of peak active powers up to 1.2 pu of the inverter rating and the battery for up to 2 seconds
    d. provision of high currents by BESS HV side star point

Remote backup protection by overcurrent relays will be effective in the system defined above. BESS undervoltage protection may react prior to the delayed overcurrent trips especially for faults close to the busbar.

FRT remains challenging for the BESS to achieve at almost all possible fault locations. In case the BESS cannot perform a successful FRT, selectivity and possibly sensitivity of the relay protection system will be lost, and the BESS may unselectively shut down

With the assumptions defined above, thermal stress of lines in the system will remain within acceptable limits for the BESS only case, but potentially not for the BESS+Grid mode. This requires further investigation in the Detailed Design phase.

HV fuse blowing for faults in secondary substations is achievable across all operational scenarios with comparable performance for HV and LV busbar faults with a few exceptions. The performance requirements are met even for a sensitivity analysis with a reduction of the calculated fusing current by 20%. Exceptions exist for the installed large transformers of 500kVA and especially 800kVA. The required performance for smaller transformers is achieved in every operational mode based on the assumption that the fusing policy has not been exploited fully, but rather the smallest possible fuse is used. Selectivity may be threatened for larger transformers in all operational modes.

6.1.5. Analysis of Existing LV Protection

Following the analysis of the existing HV protection, the LV protection schemes has been analysed on their performance as well.

The LV grid is protected by fuses in the feeders connected to the LV side of the secondary transformers as well as 60 to 100A cut-out fuses at every consumer, as seen in Figure 52. Exemplary LV grids are analysed as depicted in Figure 3. An artificial single 3-phase or single-phase line with data given in Table 20 is attached according to the transformer type and is varied in length or fault distance to busbar respectively.

A comparative analysis among the different scenarios (grid connected and islanded with 3MVA or 5MVA BESS sizing) is done to understand the risk of failing to trip protection devices and fuses reliably in islanded mode as well as a potential critical lengthening of tripping times. Modelling assumptions, line parameters or transformer data not fitting the reality will result in similar errors across all scenarios and the comparative analysis will therefore remain correct.

The following methodology has been used based on experience from previous work:

- Comparison of fault current levels achieved in the different scenarios 'grid connected', '3MVA BESS only' and '5MVA BESS only'.
- Investigation of secondary substation examples at selected locations, the locations to be considered are:
    - locations of low HV grid short circuit capacity (in Grid and islanded mode) in periphery of feeders
    - locations of high HV grid short circuit capacity near busbar
- Secondary substations with relevant transformer types to be considered / varied
    - split-phase: 16kVA to 100kVA
    - three-phase: 100kVA to 800kV
- Fault types in LV
    - 1ph for split-phase transformers
    - 3ph, 2ph, 1ph, 2ph-gr for 3-phase transformers

The results of these simulations are then used to understand the expected behaviour of LV feeder fuses, LV customer interconnection fuses and internal LV customer protections.

6.1.5.1. Protection of LV Feeders fed by Split Phase Transformers

Split phase transformers located at the weakest grid points are investigated by means of three examples. The resulting single phase line-neutral fault currents are shown in Figure 58 to Figure 60. All of them considering a variation in the LV line length up to 200m and a bolted fault:

1. TALISKER LODGE 16kVA

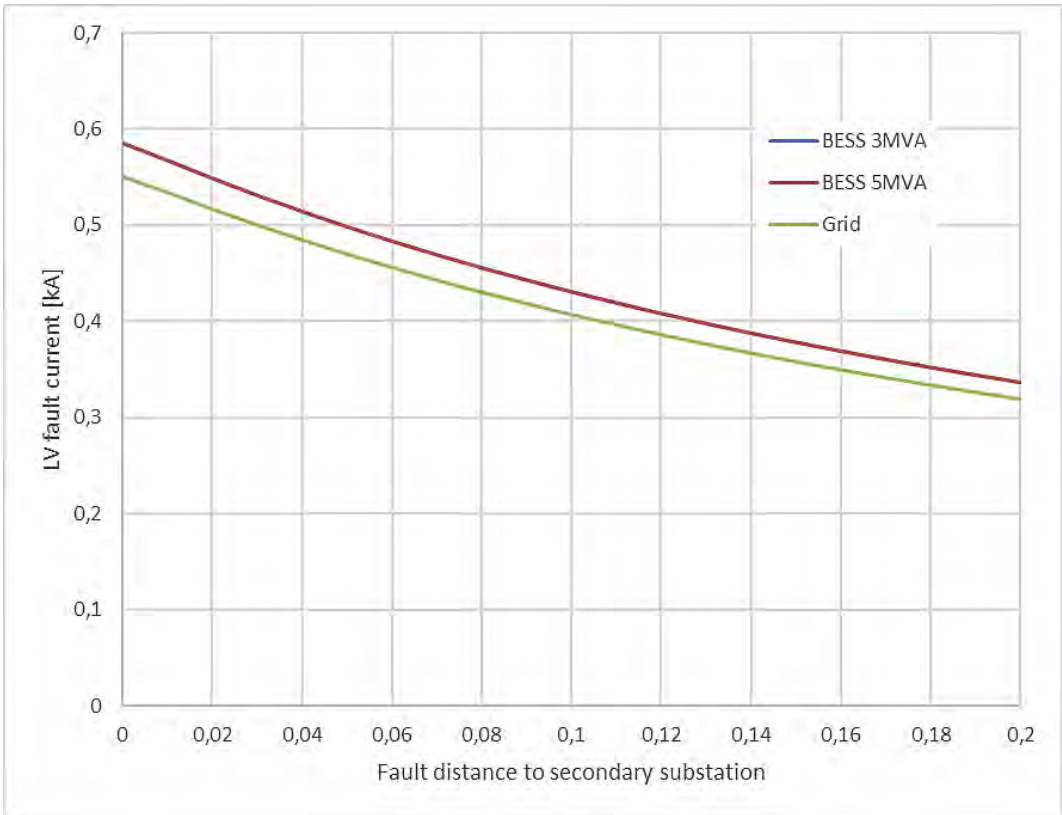


Figure 58 - Single phase line to neutral fault current at TALISKER LODGE 16kVA in grid connected mode, islanded mode with 3MVA BESS and islanded mode with 5MVA BESS. (red line overlaps blue line)

SHEPHERDS COTTAGE 50kVA

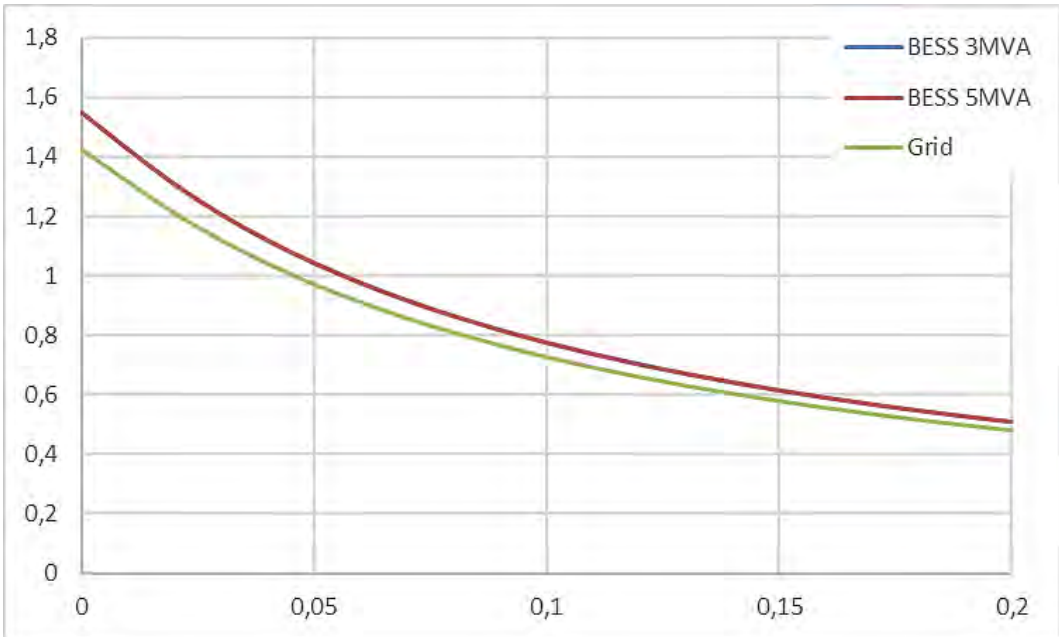


Figure 59 - Single phase line to neutral fault current at SHEPHERDS COTTAGE 50kVA in grid connected mode, islanded mode with 3MVA BESS and islanded mode with 5MVA BESS. (red line overlaps blue line)

2. LOCH BHARCASAIG 16kVA

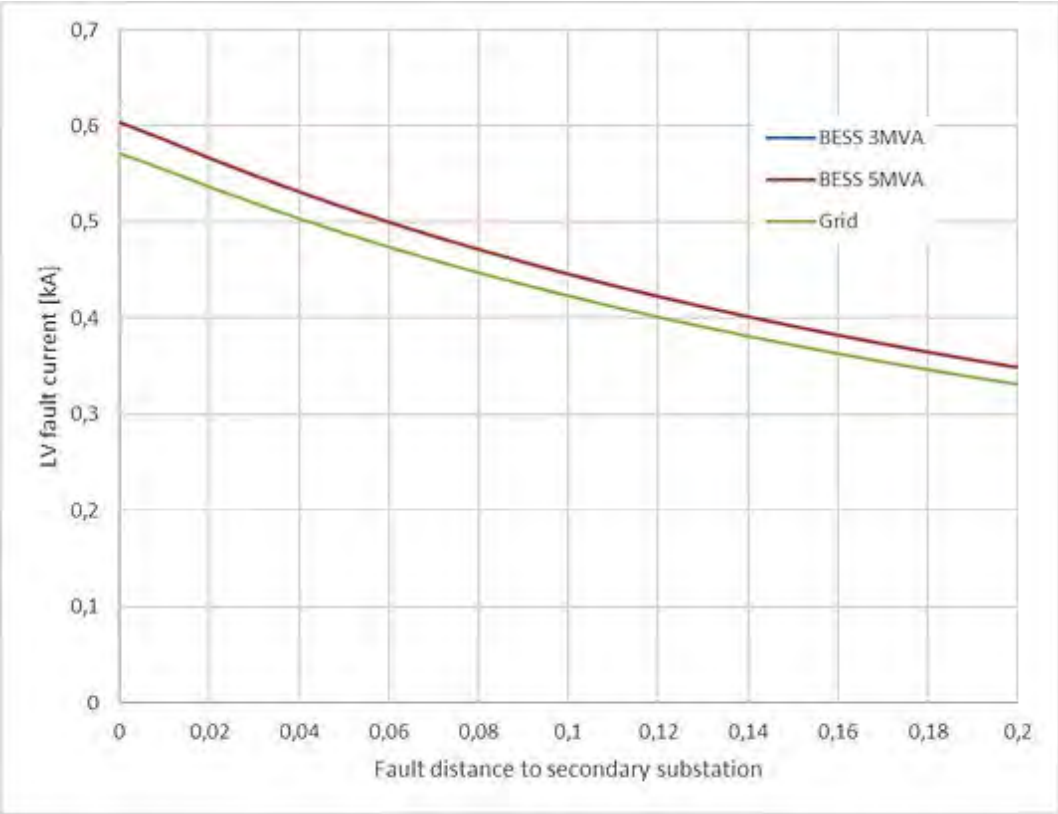


Figure 60 - Single phase line to neutral fault current at LOCH BHARCASAIG 16kVA in grid connected mode, islanded mode with 3MVA BESS and islanded mode with 5MVA BESS. (red line overlaps blue line)

These results are determined by the dominant impedances of the LV transformer and the LV feeder, while the low output impedance of inverter and identical transformer in both islanded BESS scenarios create no difference between the curves of 3MVA and 5MVA BESS. The low 33kV short circuit level scenario that was used for grid mode leads to slightly lower currents. Only short circuit levels differ between secondary transformers sizes, as was expected.

Almost identical current levels are seen in all scenarios, with no detrimental impact of islanded operation on LV protection. The protection elements (e.g. fuses, miniature circuit breakers etc.) dimensioned for the grid connected scenario will show at least equal behaviour in islanded mode.

Two example secondary substation located in a *strong grid point* close to the 11kV busbar are selected to cover the full range of nominal powers:

1. BRAE MEADLE 16kVA
2. VIGISKILL BURN 100kVA

Both examples show comparable results with no detrimental impact of islanded operation on LV protection. The lowest fault currents are found in smaller transformers (16kVA), but still comparable in grid connected mode or islanded mode.

6.1.5.2. Protection of LV Feeders fed by Three Phase Transformers

The extreme case of 800kVA transformer located at one of the *weakest grid points* (SCONSER QUARRY 800kVA) is investigated. The LV feeder line length is 3,8m. The LV feeder line type is a cable CONSAC_AL_LV with 185mm² Al-conductor.

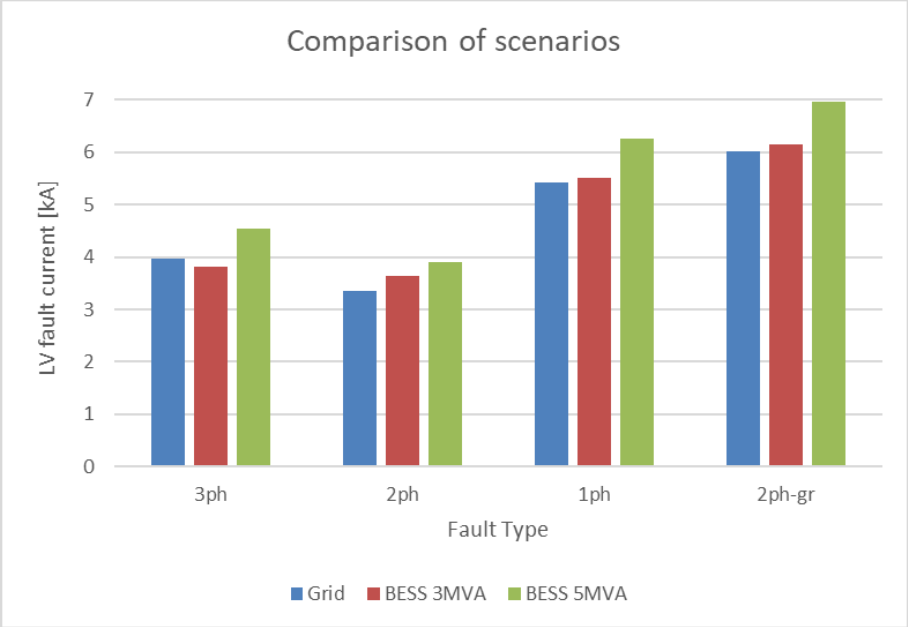


Figure 61 - Fault current in *SCONSER QUARRY 800kVAin case of different feeder faults (3ph, 2ph, 1ph, 2ph-gr)* in grid connected mode, islanded mode with 3MVA BESS and islanded mode with 5MVA BESS

The results in Figure 61 show that the 5MVA BESS can always provide fault currents larger than in Grid connected mode. Only in case of a 3-phase fault, a slight lowering of the expectable fault current can be observed for the 3MVA BESS only in comparison to the grid connected scenario.

A comparable fusing performance is therefore expected for the different scenarios even in this extreme case investigated. Additionally, active power drawn from the BESS during faults investigated can be seen in Figure 62, with no high fault peak active power for the 5MVA BESS only and 20% larger than nominal fault peak active power for the 3MVA BESS only. This results from the BESS inverter driving a current high enough to avoid current limitation in the 5MVA case.

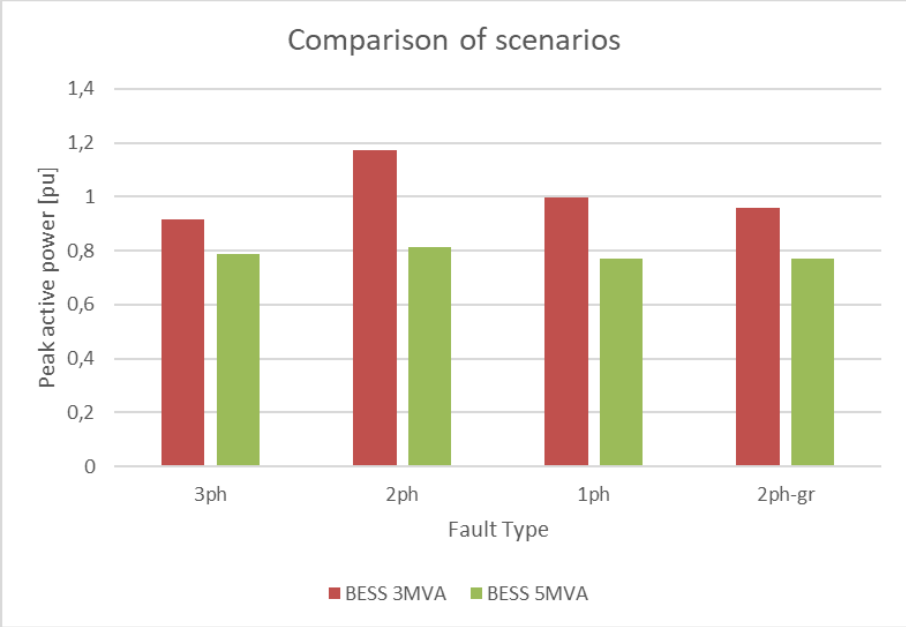


Figure 62 - Peak powers relative to inverter power rating in SCONSER QUARRY 800kVA for different LV feeder fault types

An example of a three phase transformer located at a *medium strong grid point* is the 500kVA transformer located at TALISKER DISTILLERY. The short circuit currents for the different fault types are shown in Figure 63.

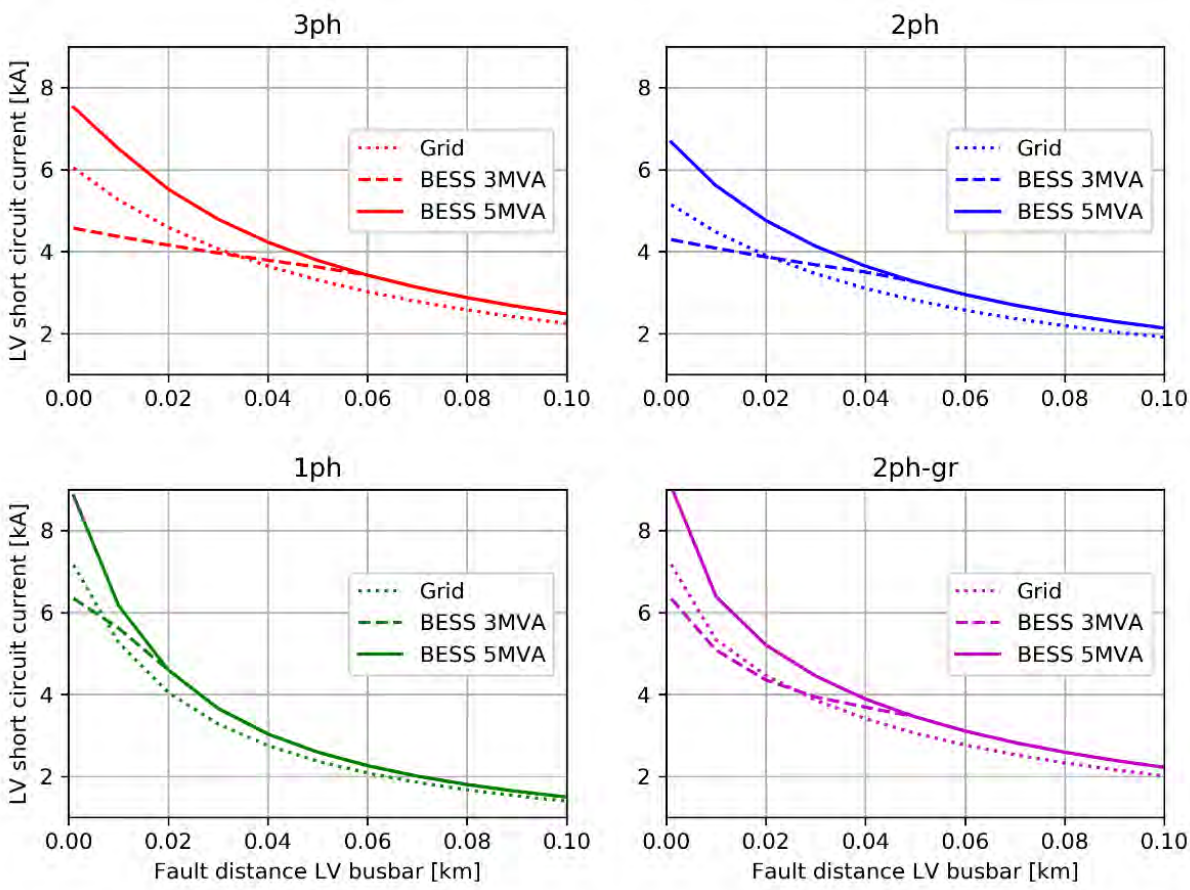


Figure 63 - Short circuit currents at TALISKER DISTILLERY 500kVA for different LV feeder fault type and varying fault distances to LV busbar

When assuming that the maximum tolerable LV fuse rating is applied (400A according to TG-NET-SST-005) the tripping times shown in Figure 64 will result.

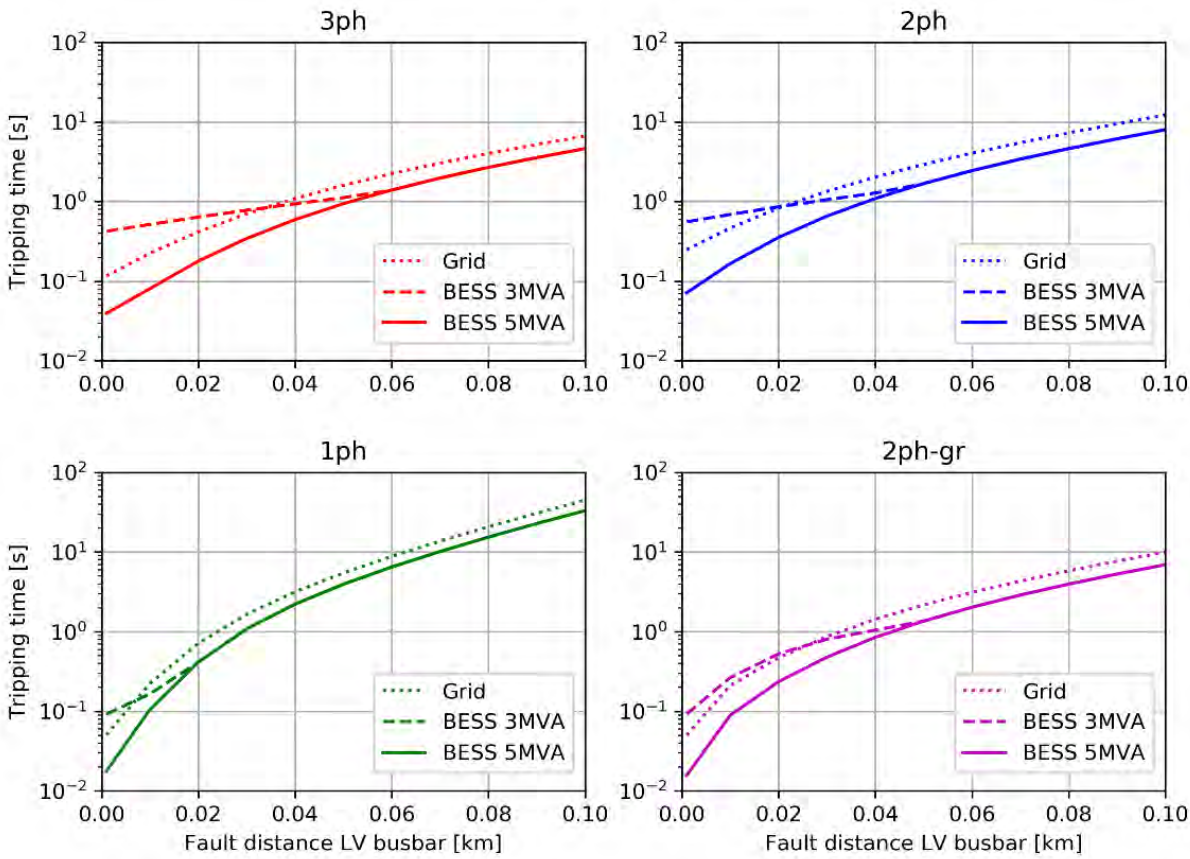


Figure 64 - Short circuit currents at TALISKER DISTILLERY 500kVA for different LV feeder fault type and *varying fault distances to LV busbar*

In all cases the maximum tolerable LV feeder fusing time of 100s (according to PR-NET-NPL-001) is maintained. Only the lower close to busbar fault currents in the 3MVA BESS only case increase tripping times but remain well below critical ranges. For larger fault distances the voltage source behaviour is regained and leads to comparable results as in the Grid connected and 5MVA BESS only scenarios. With the high fault levels of 4kA compared to the permitted maximum LV feeder fuse sizing of 400A (according to TG-NET-SST-005) a moderate slowdown is likely to occur while no trips are not to be expected.

For the selected location the current provided by the 5MVA BESS only remains above that of the grid connected scenario across all fault distances.

Two exemplary three phase transformers located in *strong grid points* locations are analysed:

1. MACASKILL DRYNOCH 100kVA

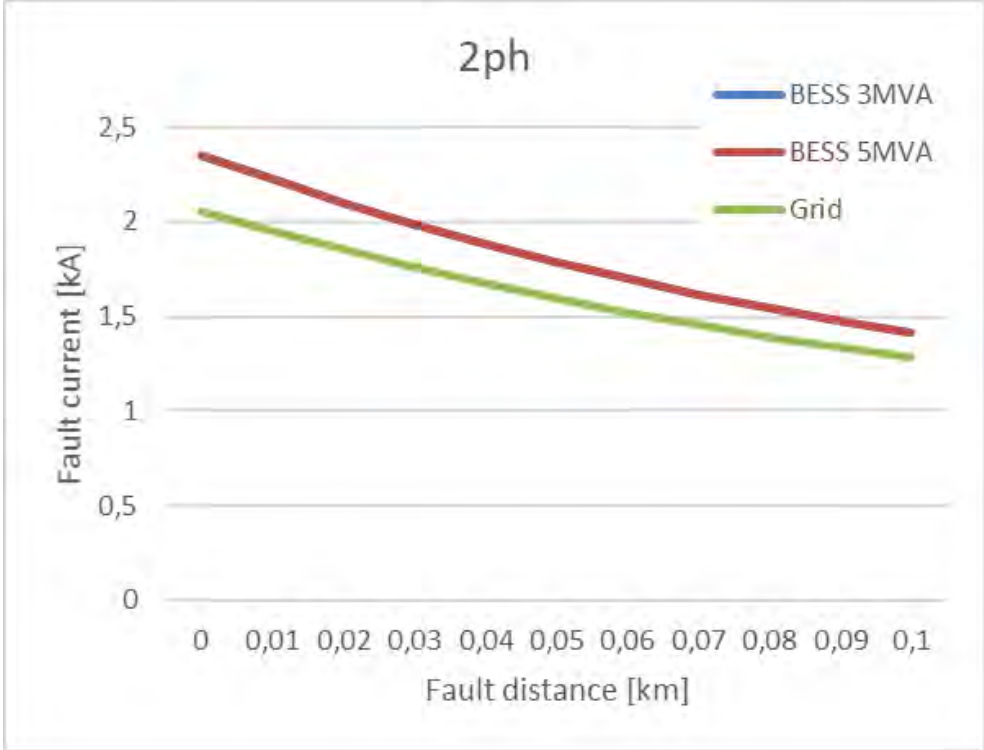


Figure 65 – Two-Phase fault currents at MACASKILL DRYNOCH 100kVA with varying fault distances to LV busbar

2. ALLT MEADALE HYDRO 200kVA

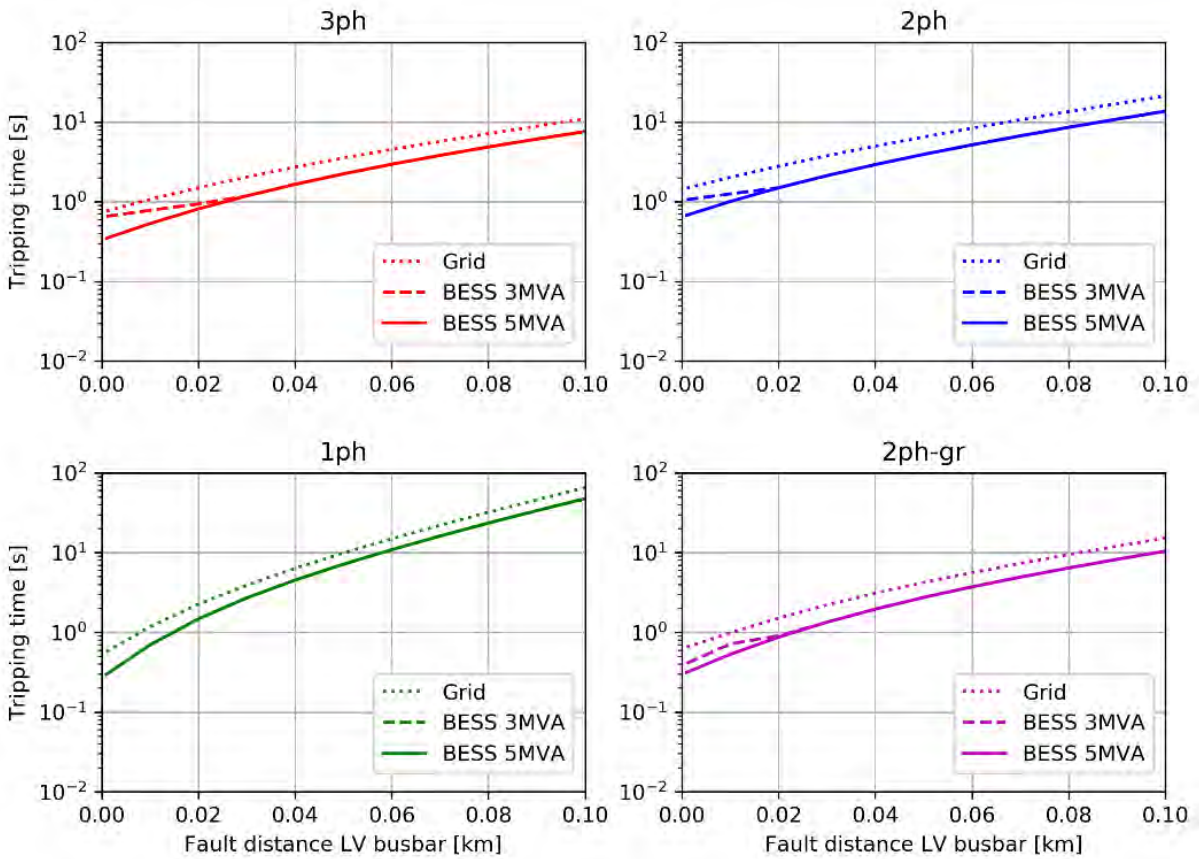


Figure 66 - Tripping LV feeder fuse at ALLT MEADALE HYDRO 200kVA for different LV feeder fault type and *varying fault distances to LV busbar*

In the exemplary analysed 100kVA 3ph transformer, both BESS systems are able to provide higher fault currents than the Grid connected scenario for all fault types. Figure 65shows the case of two-phase fault, but equivalent results are found in other fault types.

In the case of 200kVA transformer, it is found that the 5MVA BESS only scenario still provides higher currents than the Grid connected scenario. In case of 3MVA BESS there is a lowering of fault currents in case of faults close to the LV busbar of the secondary substation. As seen in Figure 66 the tripping times do not go beyond Grid connected scenario.

6.1.5.3. Protection in LV Customer Interconnection Fuses

Every consumer is equipped with a cut-out fuse from the electricity distributor, called here LV customer interconnection fuse. The most critical fuses in terms of sensitivity and tripping will be located on the far end of long LV feeders. Based on the investigations for LV feeders (see previous sections) and due to the voltage source behaviour of the BESS, in these areas no additional limitations or restrictions to fuse operation are expected

Only theoretically, for a fuse of higher rating located near the LV busbar that is dimensioned with little or no reserves for tripping in the grid connected scenario, the shown effect of current limitations may increase tripping times or potentially prohibit it. Assuming a triggering of the feeder fuses according to the specified requirements, this theoretical case would require a fuse of higher rating than the feeder fuse's rating or a very deviating tripping curve. Both cases are not likely to occur. Therefore, no additional limitations or restrictions to fuse operation are expected.

An in-detail analysis for the largest secondary substation transformer ratings should be performed in the Detailed Design phase to verify the argumentation above.

6.1.5.4. Protection in LV Customer Installations

The same considerations for LV customer interconnection fuses apply to overcurrent protection inside customer installations. Fuses and miniature circuit breakers are expected to operate with comparable performance as in the grid connected scenario.

Residual current devices do not rely on the absolute fault current levels and are therefore not expected to be affected in their operation.

An in-detail analysis for the largest secondary substation transformer ratings should be performed in the Detailed Design phase to verify the argumentation above.

6.1.5.5. Conclusions on Protection of LV Feeders

The comparative analysis of the grid for the different scenarios (grid connected and islanded with 3MVA or 5MVA BESS sizing) done for the different types of faults in different transformer types and grid areas, shows that the fault currents achieved with a 5MVA BESS system is at least as high as the fault current when grid connected. Only in the case of using a 3MVA BESS system lower fault currents are found in the rare event of large transformers and faults close to the Secondary Substation LV busbar.

It is therefore concluded that a 5MVA BESS system in island mode should provide in all cases enough fault current to trip all LV protections operational in Grid connected mode in Drynoch.

6.1.6. Assessment of Influences by Distributed Generation (DG)

As the last step to analyse the performance of the existing performance, the influence of DG on protection performance was analysed.

Drynoch has two wind turbines connected to the 11kV distribution network. The wind turbines have a Maximum Export Capacity (MEC) of 0.30MVA and 0.33MVA and are connected in parallel to the grid complying with G59 (previous) or G99 (current) Engineering Recommendation. A new 0.1MVA hydro plant is also expected to come online in 2021.

An initial assessment is made of the potential impact of this DG in the protection scheme during island mode utilising the BESS considered in this study. No specific data on the existing DG could be obtained thus far, therefore, the analysis is based on industry standards and experience gained from similar analysis.

DG is known to affect protection systems in their operation in various ways, for example:

- desensitisation due to blinding[5] of primary and backup protection, or
- nuisance tripping due to sympathetic infeed.

Nuisance tripping is not likely to occur due to the limited installed capacity of DG at the Drynoch site and has thus not been analysed.

The potential effect of the DG on primary and backup protection depends on its location relative to the fault and protection relays. Figure 67 depicts a general situation and names protection zones and subzones.

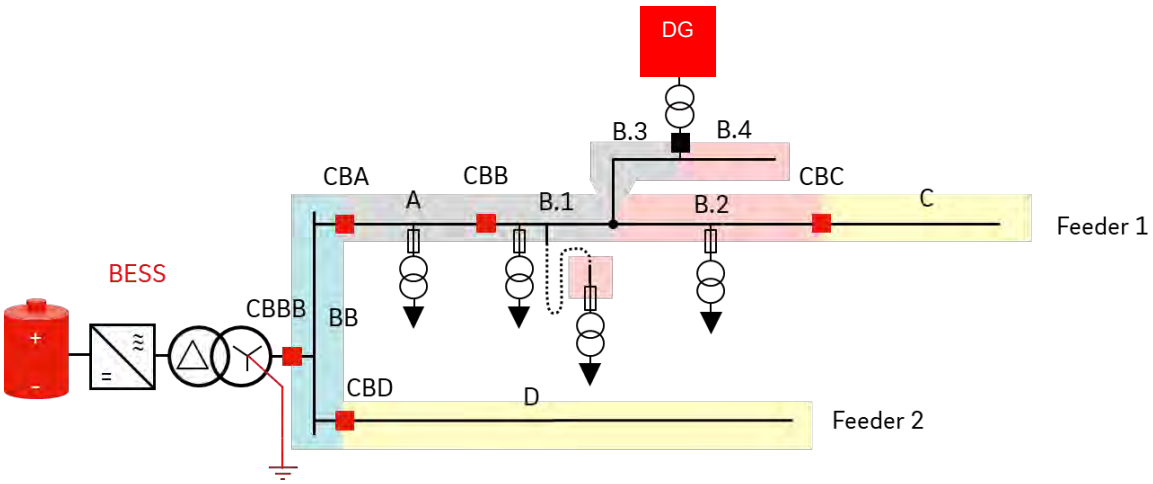


Figure 67 - Naming convention of zones affected by DG intermediate infeed in case of faults

It is assumed based on previous work that the fault current downstream from the interconnection point typically remains at a comparable level to that without DG infeed. Downstream protection zones are therefore only marginally affected. It is further assumed that the upstream primary protection is typically affected negatively for fault locations downstream of the interconnection point inside the same protection zone. Upstream fault locations inside the same primary protection zones will be

[5] the term 'blinding' here refers to situations/assets which can affect the current and voltage identified by grid protection schemes, thereby impacting the operation of the protection systems - this includes inverter interfaced DG, which can contribute to fault currents

affected during a high impedance fault or if high impedance tees are fed uniformly by the fault current sources.

Detrimental effects on overcurrent protection systems exist especially for faults downstream of the interconnection point or the interconnecting tee's basepoint.

As an example, the effect of two wind turbines connected to Feeder 12 with a rated power of 0.33MVA each is investigated for the Drynoch site. As data on the detailed design aspects of the wind turbines has not yet been available, the following simplified estimation is made:

1. The fault currents are simulated without considering the wind turbines.
2. For fault locations downstream of the interconnection point and tee point (compare zones B.2 and B.4), the tripping of the protection relay CBB is assessed by subtracting a current contribution of 1pu of the nominal current from the largest current observed by CBB as given by assumption 1. for all fault types.
3. The tripping of CBB is calculated based on this modified current.

This approach gives qualitative insight into the effect of DG on protection systems and offers valuable insights through sensitivity analysis. It does not consider the DG's specific fault reaction, which will be analysed during the Detailed Design phase of the project, using specific, actual DG data.

In the islanded scenario, with a 3 MVA BESS, severe influences can be observed for all protection settings investigated, as seen in Figure 68, resulting in no-trips and unacceptably long tripping times.

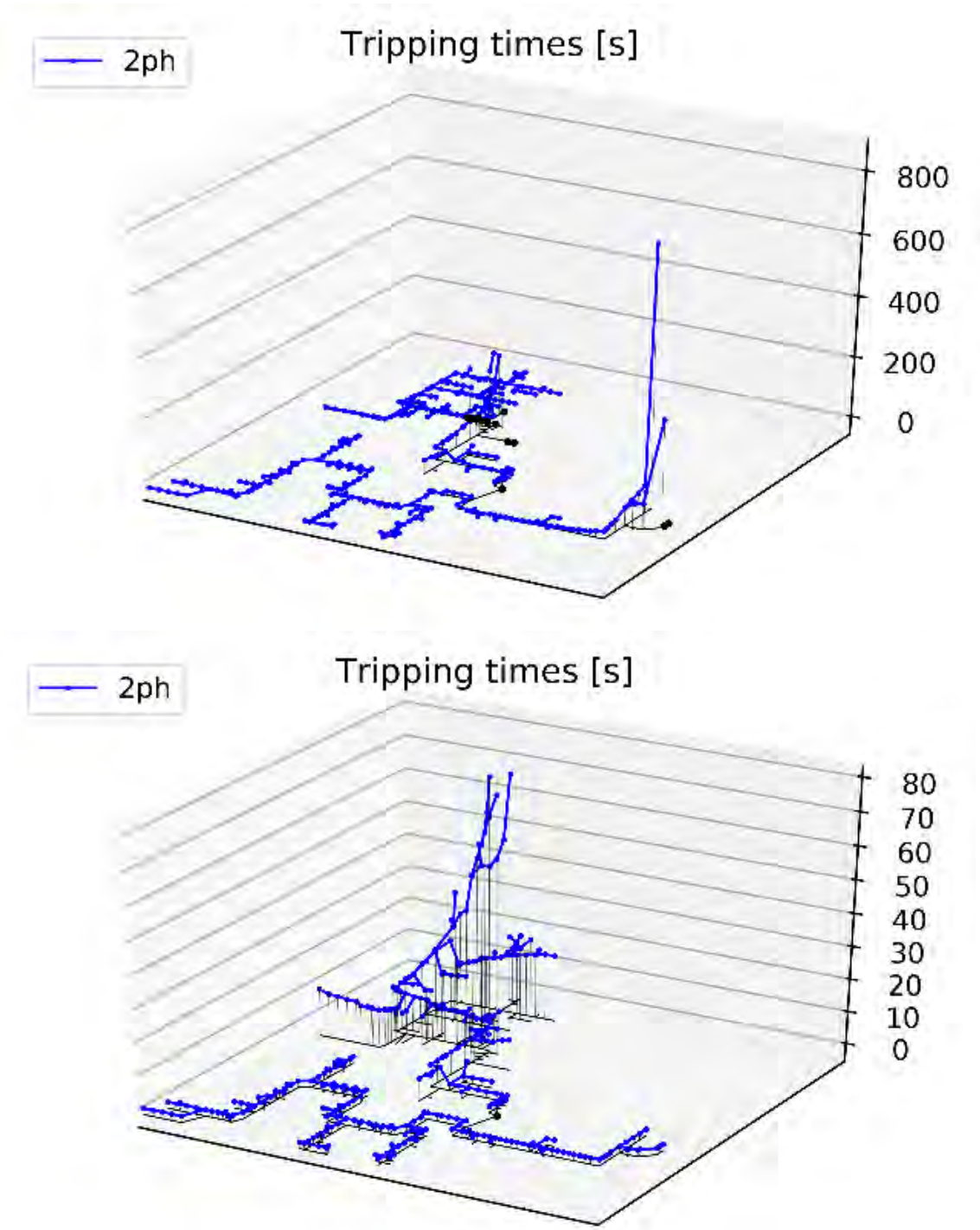


Figure 68 - Tripping times or no-trips(black dots) due to DG infeed: (top) base case with PMCB, (bottom) feeder-based protection

In case of no-trips and unacceptably prolonged tripping times the G59 or G99 protection facilities installed at the DG interconnection point may trigger.

When assessing the G59 or G99 tripping conditions based on the fault voltages at the wind turbines' interconnection points calculated from step 1, an error exists due to the missing infeed of the DG. Nonetheless a general indication may be achieved. Figure 69 shows that for tripping times >2.5s or in

case of no-trips the residual minimum fault voltages at the interconnection points lie below 0.8pu, especially for the case of 2ph faults.

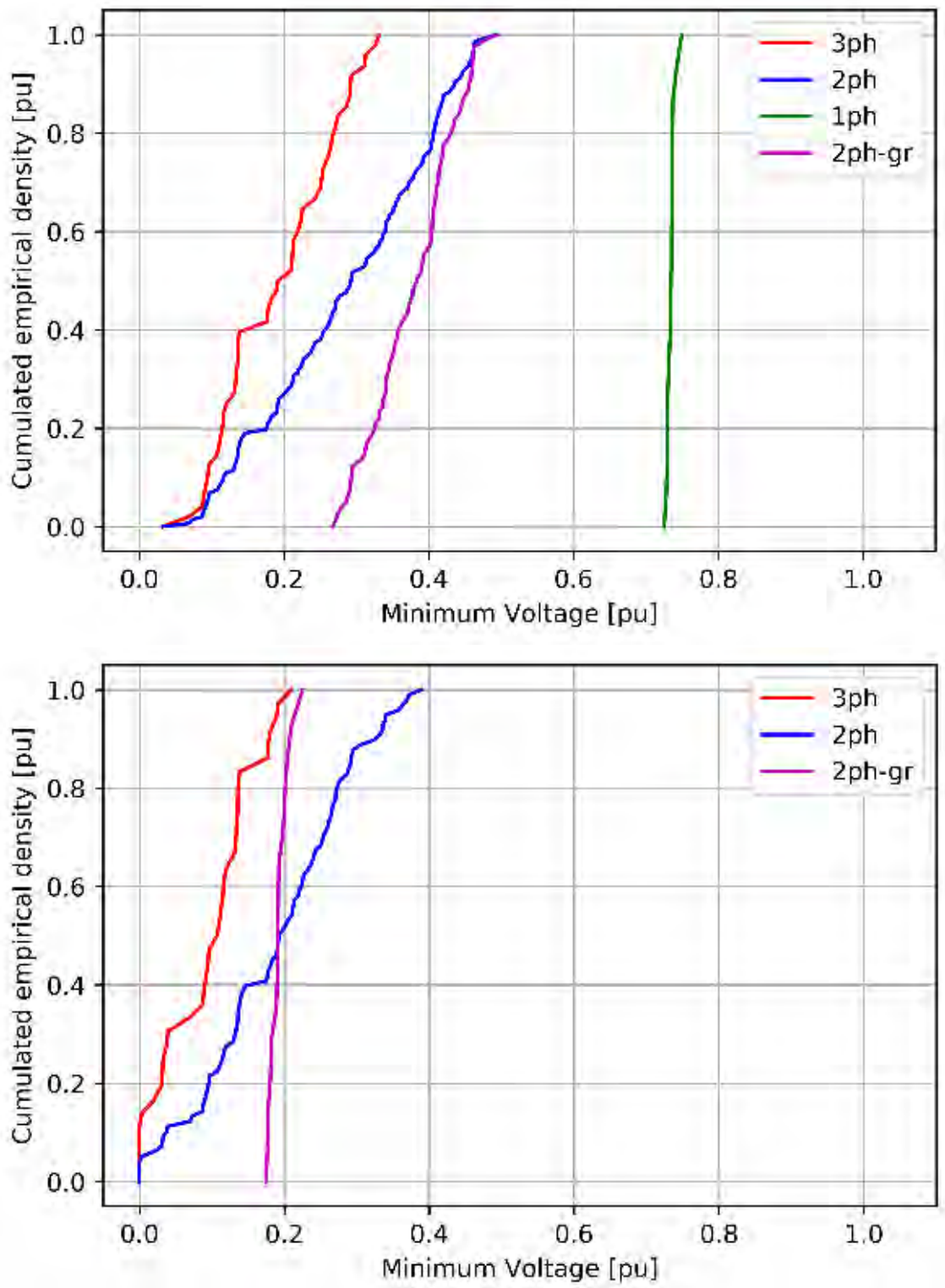


Figure 69 – Minimum residual voltages at wind turbine 1 PCC for faults with no-trips or delayed beyond 2.5s in case of DG infeed: (top) basecase with PMCB, (bottom) feeder based protection

Therefore, a tripping of the wind turbines' G59 or G99 relays is likely to occur in these cases, restoring the situation without intermediate infeed after the assumed setting time of 2.5s. This would result in

a total tripping time prolonged by 2.5s compared to the investigations done without DG infeed approximation beforehand. The same applies to all other operational scenarios.

The conclusions are that the sensitivity analysis performed shows a potential impact on the current primary protection system performance by the two wind turbines installed in Feeder 12. This impact becomes critical only in case of islanded operation with the 3MVA BESS inverter sizing variant despite the wind turbines' small size compared to the BESS system. The G59 or G99 tripping conditions will likely turn off the DG in critical cases, prolonging the clearing time by about 2.5s. The effects are expected as follows:

- As the permissible tripping times achieved by the existing overcurrent protections are already out of limits, a worsening by 2.5s may occur.
- In case of the changed setup with increased feeder based overcurrent protection introduced in the Section 'Performance Analysis of HV Backup Protection' the tripping may rise up to a total of 5 seconds, exceeding the required limits by 2s.

The protection system performance requirements for islanded operation with a 3 MVA BESS will not be fulfillable due to the DG intermediate infeed in case the assumption of the applied methodology hold.

With the methodology declared, no critical impact on primary overcurrent protection clearing times is observed in the analysis of the BESS only scenario with 5MVA system due to the higher fault current levels achieved.

The validity of the sensitivity analysis and the assumptions taken will be further analysed in the Detailed Design phase, also extending the analysis to backup protection impacts.

6.1.7. Existing Protection Performance Assessment and Options for Improvement

Sections 6.1.4 to 6.1.6 have so far provided analysis on the impact on the protection scheme of operating Drynoch in island mode with the BESS or in parallel operation of BESS and Grid. The HV relay protection, secondary substations and LV protections have been analysed to assess whether the analysed BESS configurations can be implemented for a RaaS solution at Drynoch primary substation using the existing protection system.

This section collects all the results of the protection and earthing analysis to conclude on a BESS specification and the impact on the existing network protections.

The SSEN specification for Drynoch requires two means of remote backup protection in islanded mode, as required by ENA standards for grid operation. The previous analysis shows that this may be possible to achieve with a 5MVA BESS, although only with a combination of protections that requires further validation of the assumptions in the Detailed Design phase. Therefore, a set of new protection measures for islanded systems is analysed and proposed.

From the analysis presented in the previous sections, the following conclusions can be drawn.

6.1.7.1. Protection Performance Assessment in Grid Only Mode

In grid mode the Drynoch site fulfils the protection performance requirements in grid only mode with the following exceptions when undertaking a worst-case analysis:

- 2ph fault clearing times at the end of the feeder of the Glendrynoch section exceed the 'shall' criterion of 3s by 2s.
- The fuse protection of an 800kVA transformer located at the end of line of the Glendrynoch section will not be effective should typical ratings (defined in SSEN's standard fusing policy) have been applied.

The first exception has been demonstrated to be subject to small changes in calculated currents due to grid data and modelling assumptions as well as protection settings. Those points will be addressed in the Detailed Design phase. Nonetheless, such critical points in protection system performance in grid only mode will remain critical in islanded or parallel operation.

6.1.7.2. Protection Performance Assessment in Islanded Operation with 5MVA BESS

The islanded operation of Drynoch with a 5MVA BESS leads to the results, that primary protection on the HV level is achievable within the required times with grid only mode settings. The exception is the aforementioned 800kVA transformer HV fuse protection. A delaying influence by downstream DG is identified but is estimated not to go beyond the acceptable maximum tripping times. This is to be investigated further in the Detailed Design phase.

In islanded operation with a 5 MVA BESS backup protection on HV level is achieved by remote overcurrent relays. However, two means of remote backup protection in islanded mode can only be achieved by a combination of the following systems:

- undervoltage tripping at the BESS 11kV busbar
- sensitive earth fault protection at the main feeder circuit breakers (see III.c Appendix 2)
- overload tripping of the BESS when applicable

Should overload tripping of the BESS not occur based on the design chosen, some peripheral regions will remain without a second level of backup protection as depicted in Figure 70.

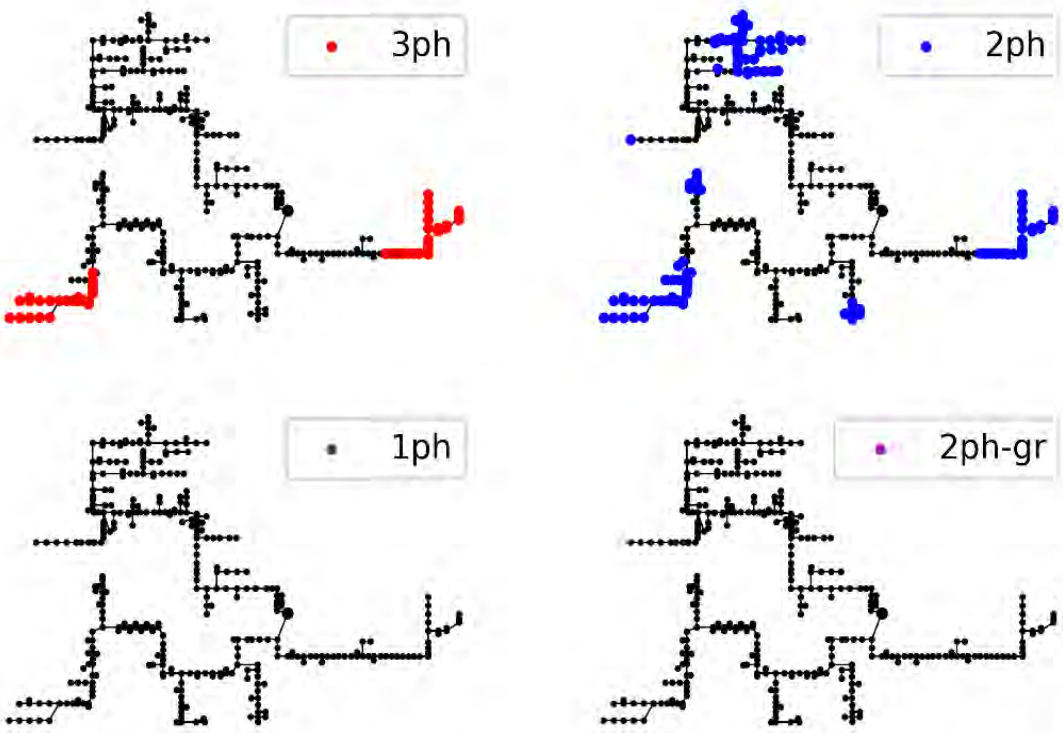


Figure 70 – Areas of network that lose 2nd level backup protection should 5MVA BESS overload tripping fail

Furthermore, the influence of DG on backup protection has not been analysed in this study.

Selectivity during islanded operation with a 5 MVA BESS will be maintained mostly when not considering DG intermediate infeed. The selectivity of HV fuses and relays may be lost due to lower fault current levels especially for larger fuse ratings. Selectivity is generally lost when tripping of backup BESS undervoltage protection or BESS overload occurs.

6.1.7.3. Protection Performance Assessment in Islanded Operation with 3MVA BESS

The investigations on islanded operation of Drynoch with a 3MVA BESS show that no-trips and unacceptable delays of overcurrent protection are observed with grid only mode settings. Additional measures for increasing sensitivity would be required and are proposed in the following section. In addition to the 800kVA transformer fuse protection also the 500kVA transformer fuse protection is expected to go out of limits. A delaying influence by intermediate DG is identified and may violate the acceptable maximum tripping times in a major number of cases.

In islanded operation with a 3MVA BESS, backup protection by overcurrent relays on the HV level is not likely to be achieved with the grid only mode settings nor with adapted protection functions and settings. Backup protection by undervoltage criteria at the BESS busbar is shown not to cover the 1ph case fully. Thus, two means of backup protection when supplying the network in islanded mode will be difficult to achieve for all fault types and locations in the grid. Additional measures for increasing sensitivity would be required and are proposed later in the following section. The influence of DG on backup protection has not been studied for the 3MVA BESS either.

Selectivity during islanded operation with a 3MVA BESS will only be achievable for uniform increase of sensitivity of all relays, which has not been further investigated in this study. The focus on feeder protection suggested in the following section will result in a loss of selectivity when the PMCB regular

functions are not deactivated. The selectivity of backup protection by undervoltage criteria may be gained by certain measures suggested in the following section.

6.1.7.4. Summary of Options to Improve Protection Performance

As previously described, the fulfilment of two means of backup protection in islanded mode is challenging with the analysed BESS configurations. Further oversizing of the BESS inverter rating would also not provide improved performance as the sensitivity of undervoltage protection and overload at the BESS decrease inherently. Therefore, several additional protection measures are evaluated here for Distribution Network Operator (DNO) consideration.

Table 8 - Additional protection measures

Option	Pros	Cons	Detailed description in:
Undervoltage protection at the 11kV busbar	Central implementation	Not sensitive for peripheral 1ph faults highly unselective	Chapter 6.1.4
Directional feeder undervoltage protection	More selective	Additional efforts Not sensitive for peripheral 1ph faults	Appendix 2a, Distributed undervoltage protection
Undervoltage protection including telecontrol PMCB	Highly selective May be designed to be more sensitive due to closer to fault sensing	Needs amendment of PMCB	Appendix 2a, Distributed undervoltage protection
U2 or U0 overvoltage protections at busbar or remote locations	Additional degree of freedom by new criteria	Additional parameterization Risk of nuisance tripping	Appendix 2a, Distributed undervoltage protection
Increased sensitivity of feeder overcurrent protection	Higher sensitivity	Switching of settings risk of nuisance tripping	Appendix 2b, Feeder based sensitive overcurrent protection
Additional current based protection criteria	Additional degree of freedom by new criteria	Additional parameterization Risk of nuisance tripping	Appendix 2d, Current Limitation Duration Threshold
Distance protection	Fault location speedup after clearing	Setting problematic due to high R/X line ratio interfering with load discrimination approaches	Not investigated
Line differential protection	Absolute selectivity	Infeasible or highly expensive	
Traveling waves protection	To be investigated	To be investigated	

Most of these options were analysed and are shown in detail in “Appendix 2 – Adapted and Additional Protection for Islanded Operation”, and others are proposed for further analysis in the Detailed Design phase. A summary of the assessment is given in the following.

Primary protection by overcurrent criteria is shown to be achievable for the 3MVA BESS inverter rating scenario in case more sensitive settings are applied to the feeder circuit breakers and if an additional negative sequence overcurrent tripping criterion can be successfully parameterized without creating nuisance tripping in normal operation. However, the detrimental effect of DG intermediate infeed is estimated to let the tripping performance go out of limits.

Additional sequence current based criteria are shown not to deliver superior performance for faults in the periphery of the grid.

Backup protection by remote overcurrent relays was already shown to be feasible for usual grid protection settings in Section 6.1.4 for the 5MVA BESS case.

Backup protection by undervoltage criteria is shown not to be effective for peripheral regions when applied centrally only, regardless of the criteria applied. When utilised in a distributed manner at selected additional existing PMCB locations, sensitivity may be achieved for most grid regions, except for certain end of line regions. Only in case additional measures for grading are applied, sensitivity will be achievable.

Sequence voltage-based criteria are shown not to offer superior sensitivity in the critical cases.

Backup protection by sensitive earth fault functionality at the feeder circuit breaker level is shown to be effective for the critical 1ph fault end of line regions in the 3MVA BESS inverter scenario when more sensitive settings can be applied for islanded operation. Sensitivity is achievable with the actual settings in the 5MVA BESS inverter case already.

Backup protection by BESS active power overload tripping is shown to be effective for end of line cases in Section 6.1.4. Overload existence is on the one hand based on the modelling assumptions and on the other would require the control system not actively avoiding it. Should the control system actively supress such a BESS state, the backup protection functionality would disappear.

Backup protection by limiting the duration a BESS may remain in current limitation mode is shown not to be effective for end of feeder cases but for relatively close to busbar tees with no sensitivity achievable with undervoltage protection.

The results indicate that no single means of backup protection will cover all fault cases reliably and that simultaneous application of multiple backup protection approaches might have to be considered.

The results also indicate that the installation of one or two additional PMCB for high impedance feeder branches (e.g. one in the Glendrynoch section) could improve the primary protection system performance.

6.2. Black Start Analysis

A BESS for a RaaS application is expected to be able to black start the 11kV network. This will be needed after a fault or outage in the 33kV supply line or further upstream if a seamless transition was not possible to enter island mode or if that was prohibited due to missing permission by the DNO to do so.

The black start process shall be manually triggered by the DNO control room and afterwards be executed by an automated process controlled by the BESS Energy Management System (EMS).

The key challenge in performing a black start from the BESS is to provide sufficient current to supply the in-rush current to magnetise the core of the secondary distribution transformers during switch on and energisation. This current is transient in nature and exists for a few ten milliseconds, but the time length is sufficient to compromise the stable operation of the BESS and the overall system. The inrush current may easily be up to 3 times higher than normal rated current of transformers, so detailed analysis of the black start process is required when sizing the BESS.

6.2.1. Options to Black Start the 11kV Network

Different practices are known of to deal with or mitigate transformer inrush from transmission system black start, distribution system black start[6], distribution system operation, microgrid black start and other scenarios.

While extensive automatization is available at the transmission level or in industrial microgrids that allows them to switch customers on and off, such options do not exist in a typical electrical distribution system for public supply as we find in Drynoch. Adding more automation at the secondary substation level to the current Drynoch network is not seen as a feasible solution at this point due to high cost involved. Thus, the black start process needs to be done with the customers connected. A key requirement is hereby to safely energise the network to avoid any risks to people or damage to equipment.

The black start process therefore will majorly rely on tele-controlled PMCB and feeder CB at the HV level and options in configurating the BESS.

The options given in Table 9 are related to the circumstances of adding an unenergized section of the grid to the black start procedure and to try to establish a viable compromise between the size of the portion of the network to be energised and the accompanying inrush current.

Table 9 - Options for minimising transformer inrush on grid energisation

Switching option	Requires	Customer experience	Relevancy
Direct	Adequate section sizing	Normal	Analysed
Point-on-Wave (PoW)	PoW-Relays Adequate section sizing	Normal	Analysed
Reduced system voltage	BESS EMS option	Lowered voltages	Rejected
Voltage ramp-up			Rejected
Via bypass impedance	Special hardware		Rejected
Via bypass voltage divider			Rejected

[6] for information on related innovation with regard to distributed black start please see National Grid ESO's Distributed ReStart project www.nationalgrideso.com/future-energy/projects/distributed-restart

Energisation by **direct switching** requires adequate sizing of the energised sections to avoid tripping of the BESS as the single source at any stage of the process. The feasibility at Drynoch is investigated in the following sections.

Point-on-Wave switching relies on special relays that reduce the resulting inrush current by adapting the time of energisation to the estimated residual flux of the secondary transformers to be supplied. The resulting gains in section sizing and required levels of inrush limitation will be investigated in the following sections.

The black start process could be done at a **reduced system voltage** from the BESS, around 70-80% of the nominal value. This practice is known to reduce the in-rush current but would repeatedly or constantly make the customers subject to non-standard voltages and is therefore rejected at this design stage.

The black start process can be done by the BESS with a **ramping voltage** up to the nominal value to reduce in-rush. This would present two problems in Drynoch. Firstly, it should be done with all the network connected, otherwise it could only be applied to the first section being energised. Furthermore, as all customers connected in LV need to remain connected while performing the black start process, a voltage ramp may conflict with connected equipment. It is therefore rejected at this design stage.

Switching with **series impedance** that is bypassed later or a two-step energisation with **voltage divider** that is bypassed later are techniques which at this point are evaluated as too complex and too costly to implement in this project. Furthermore, customers would again be subject to non-standard voltages.

Innovative in-rush suppression techniques implemented by inverter manufacturers may be explored in the further development of the project.

6.2.2. Analysis of the Network Topology

The network can be sectionalised using the tele-controllable main feeder Circuit Breakers (CB) and Pole Mounted Circuit Breakers (PMCB) along the two 11kV feeders. Figure 71 shows the topology of the Drynoch network and assigns names to the different sections that can potentially be created on the two Feeders utilising all CB and PMCB.

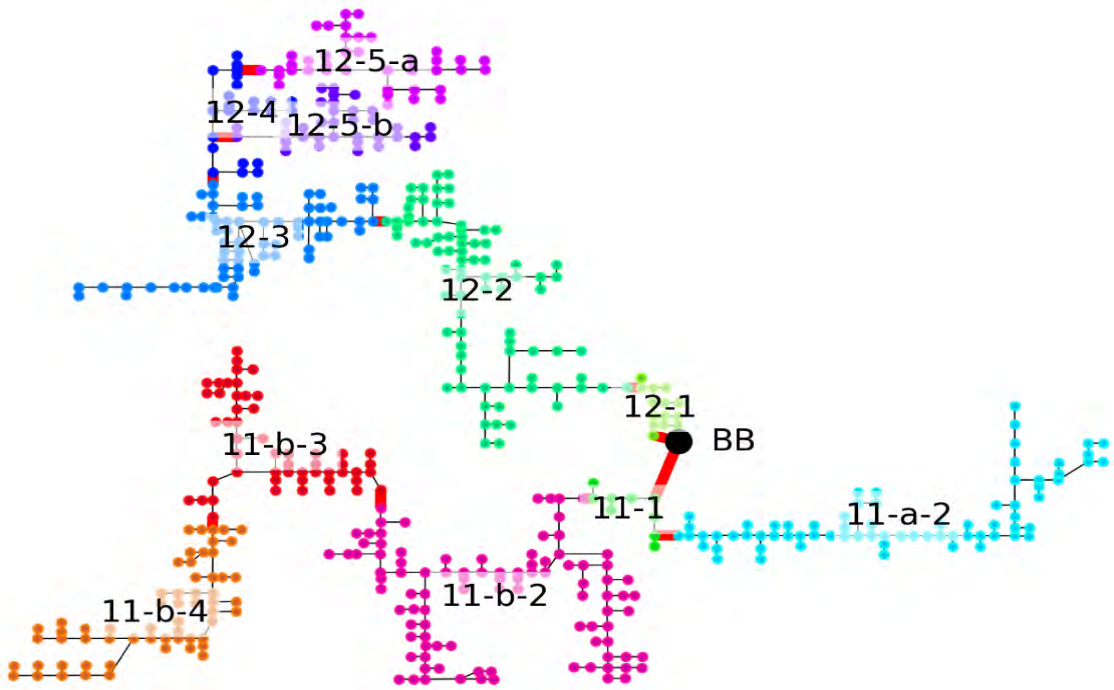


Figure 71 - Topological location of grid sections that can be created with current 11kV switches in Drynoch. BB: 11kV busbar

The possible switching sequence candidates during energisation of the grid are bound by the topological neighbourhood of those sections that is shown in Figure 72 together with the summed transformer nominal currents and maximum loads per section.

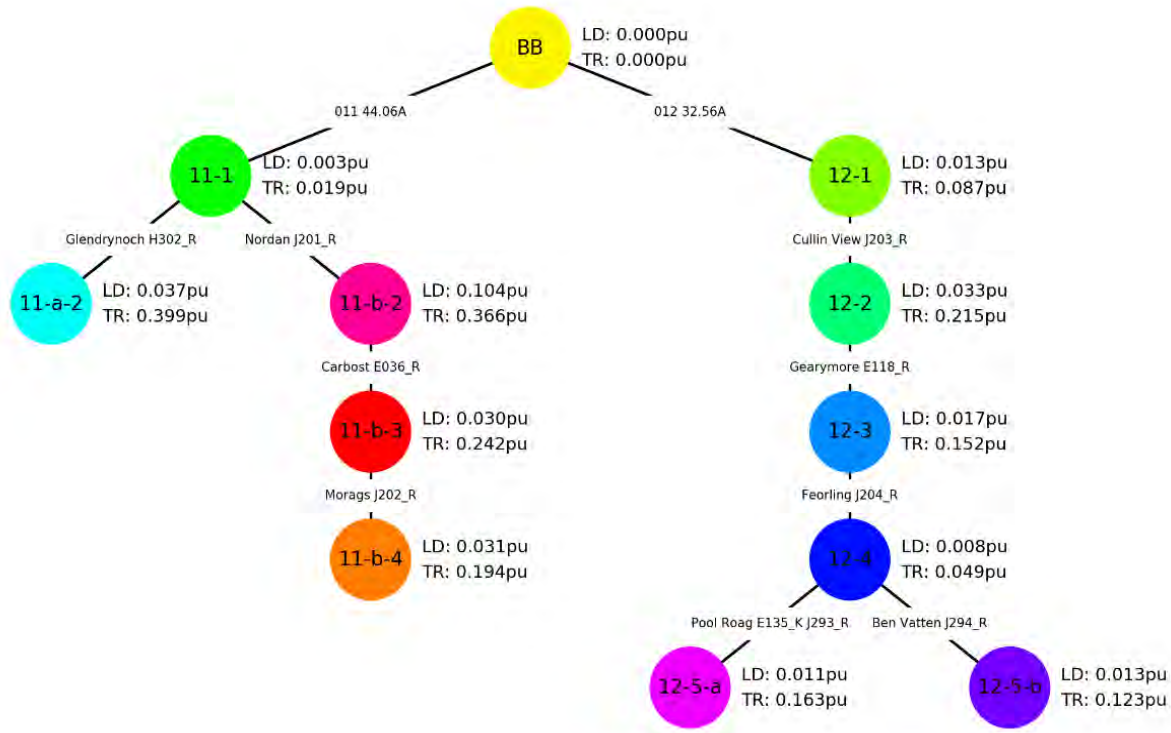


Figure 72 - Possible switching sequences and cumulated load (LD) and cumulated transformer nominal current (TR) in p.u. of BESS rating (5 MVA) per topological location depicted in previous figure

When reducing the applied switches to the main feeder CB of Feeder 11 and 12 the estimated cumulated loads and transformer nominal currents are depicted in Figure 73.

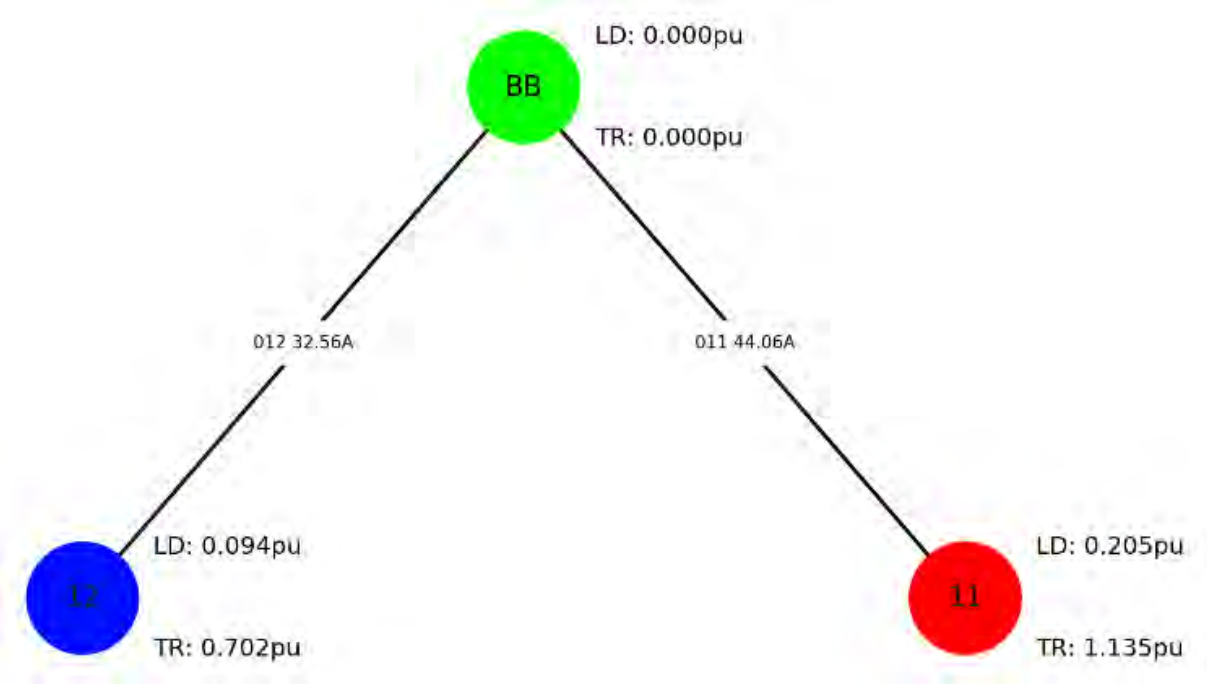


Figure 73 - Possible switching sequences and cumulated load (LD) and cumulated transformer nominal current (TR) in p.u. of BESS rating (5 MVA) when using feeder CBs only

The feasibility of different switching sequences in dependency of the applied switching option is estimated in the following.

6.2.3. Direct switching of grid sections

Direct switching utilises the installed circuit breakers without additional measures.

The first option to analyse is to energise the two feeders sequentially, so that the in-rush of one feeder doesn't add up to the other feeder.

Figure 74 shows the estimated currents flowing in case of feeder level switching assuming an inrush level of 3 pu when compared to the maximum current capacity of a 5MVA BESS inverter.

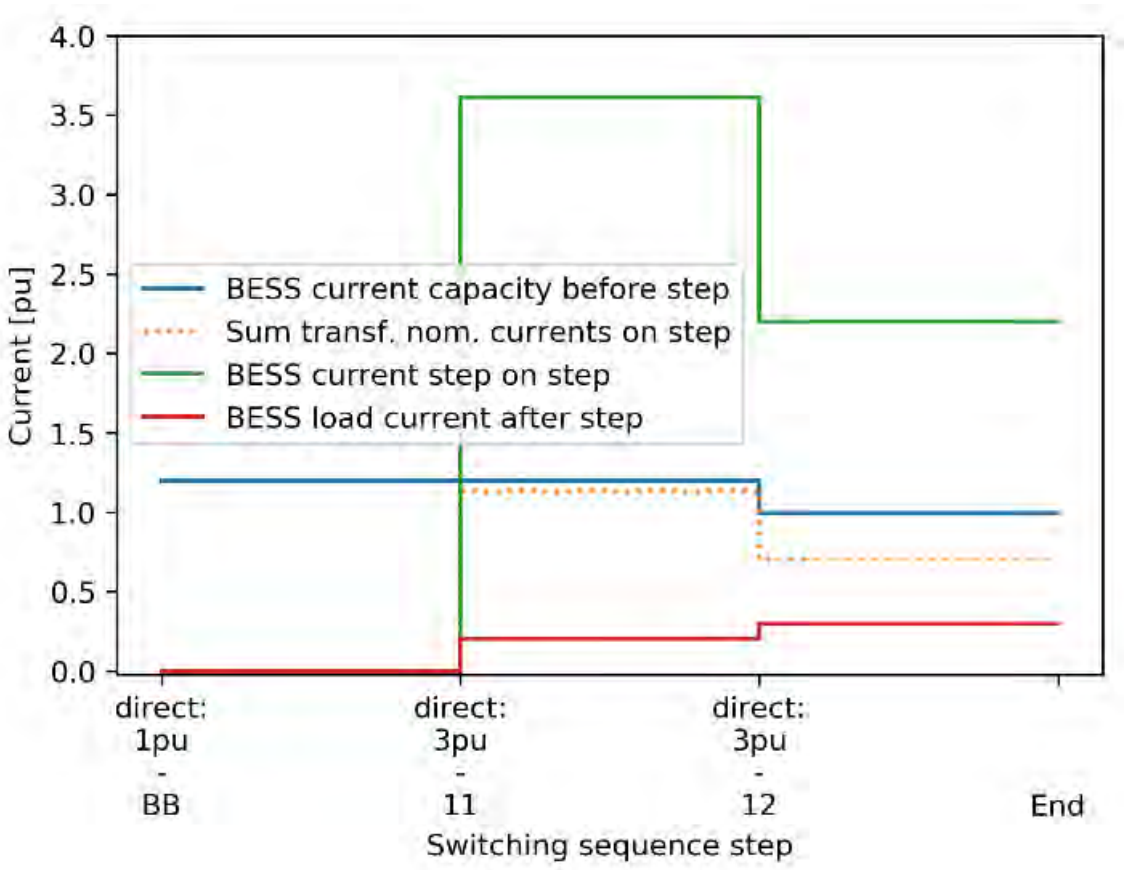


Figure 74 - Feeder level direct switching sequence for 5MVA BESS inverter

Whilst both feeders could be energised from the load point of view, the inrush currents would violate the current capacity by more than 2pu. Only in cases where the inrush would limit itself to 1pu of the cumulated transformer nominal currents a black start may be successful with a 5MVA BESS inverter. Even stronger assumptions would need to be made in case of a 3MVA BESS inverter. The approach is therefore deemed not to be reliable but might be functional on repetitive trials.

The second option considered additionally utilises the existing 11kV PMCBs which are installed on every feeder, so that the energisation of every feeder is done in 4 or 5 stages. The switching would start by closing the feeder CBs with all the other PMCBs open, and then sequentially closing them. The limitation is that the order of the sections can't be chosen arbitrarily but needs to follow the neighbourhood restrictions already discussed. The section which is furthest away from the substation must be the last one to be energised, with the loads of the other sections already connected.

Figure 75 shows an exemplary switching sequence for a 5MVA BESS inverter that energises the larger grid sections in Feeder 11 first. A best case is shown in that the split phase transformers are assumed uniformly distributed about the sections.

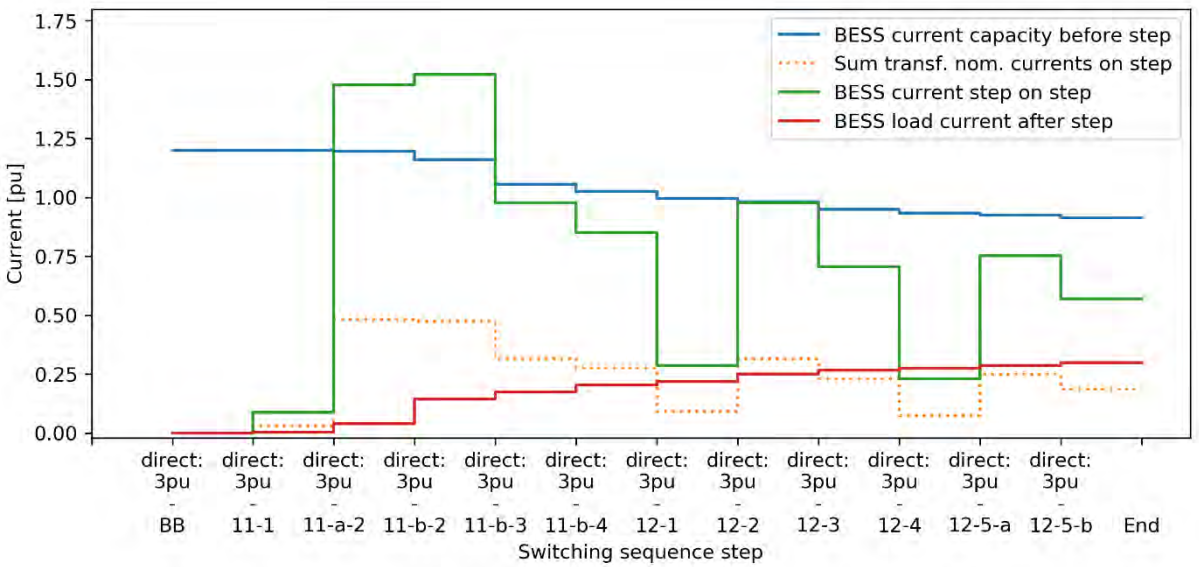


Figure 75 - Exemplary switching sequence for a black start utilising a 5MVA BESS

The direct switching sequence may be feasible to perform when a limitation of the transformer inrush to less than 2 pu may be assumed at least for the largest section in Feeder 11, compromising reliability to some extent. Further alternatives with PoW switching are therefore developed in the next sections.

6.2.4. Point on Wave Switching

PoW controllers are high-speed microprocessor-based relays used to open and close the contacts of Circuit Breakers (CB) at the pre-determined point on wave to minimise the switching transients. PoW switching uses precision timing to control the exact moment of conduction that results in the minimum inrush current possible.

When applied in energising transformers, SSEN made the experience in their previous innovation project LEAN, that PoW switching can reduce in-rush current to energise a primary substation transformer. When energising groups of secondary transformers in the same network section, PoW is expected to reduce the inrush but limited experience exists to quantify the limitation that may be guaranteed in this application. The PoW manufacturer estimates a limitation to values not larger than 50% of the nominal cumulated transformer currents to be feasible. Requirements for PoW performance are identified in the following analysis for different switching sequences in Drynoch. The feasibility of such a PoW performance will need to be investigated further.

Due to the investments and efforts involved, PoW switching is assumed to be used at the main feeder CBs of the substation only.

6.2.4.1. Feasibility of PoW Switching at Feeder Level

Considering the possible connection steps in Figure 76 it can be seen that a BESS able to provide 3MVA would require a limitation of the in-rush current to values below 30% of the nominal transformer currents when assuming a worst case distribution of split-phase transformers (all in same phases per feeder). When assuming a best case equal distribution of split phase transformers, the permittable PoW values increase to 45% of the nominal transformer currents.

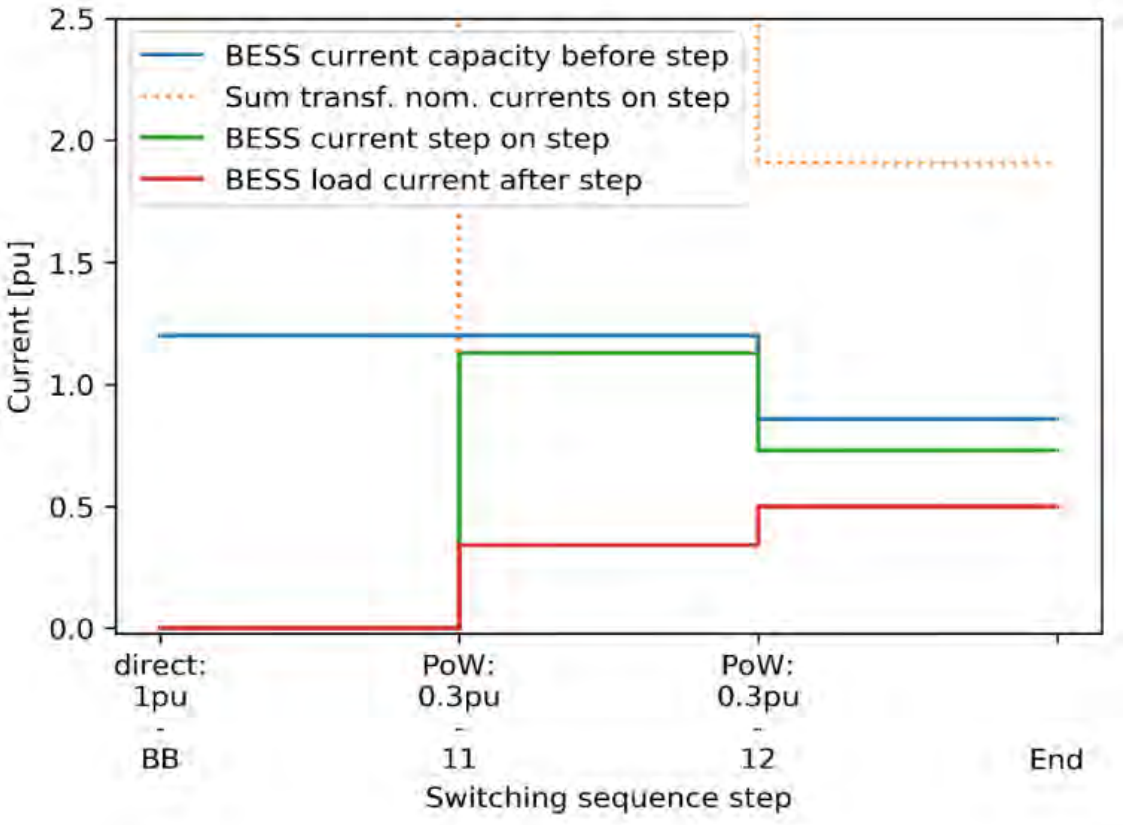


Figure 76 – 3MVA BESS current capacity vs. required in-rush current in case PoW switching can limit the current to 30% of the nominal transformer value

Considering the possible connection steps in Figure 77 it can be seen that a BESS able to provide 5MVA would require a limitation of the in-rush currents to values below 60% of the nominal transformer currents, when assuming a worst case distribution of split-phase transformers (all in same phases per feeder). When assuming a best case equal distribution of split phase transformers, the permittable PoW values increase to 85% of the nominal transformer currents.

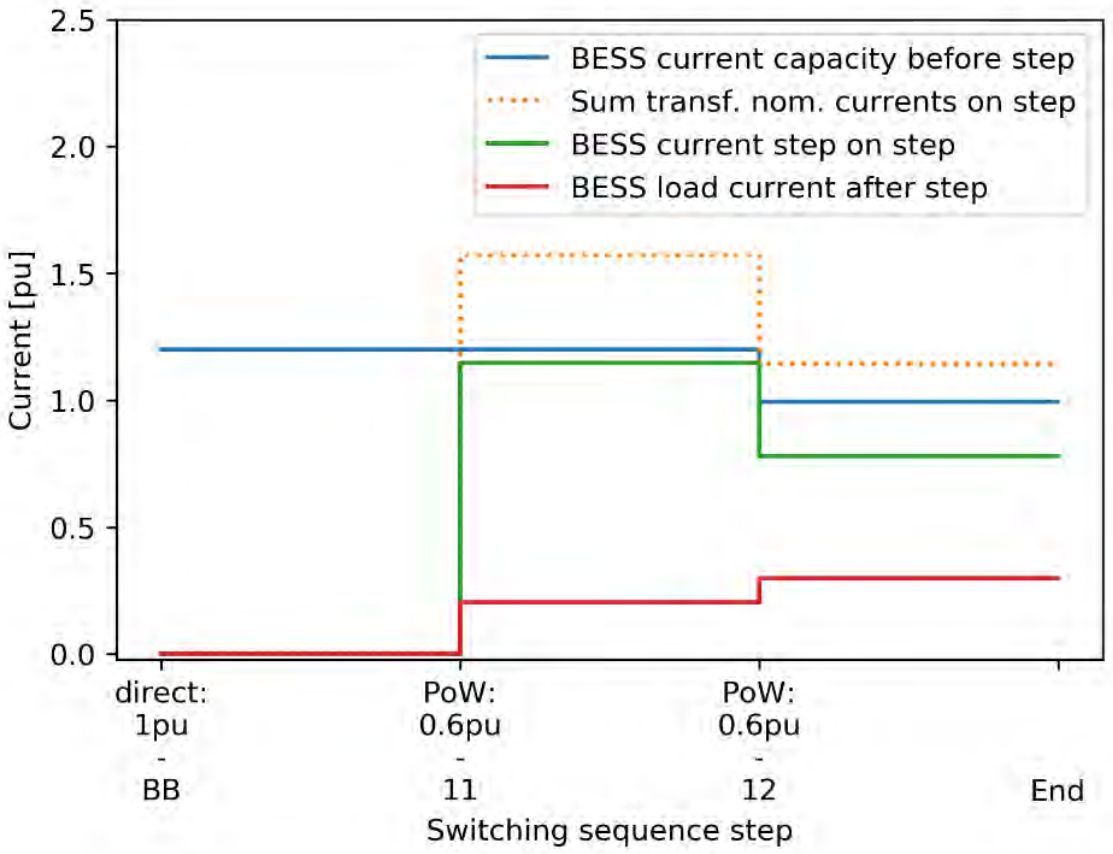


Figure 77 – 5MVA BESS current capacity vs. required in-rush current in case PoW switching can limit the current to 60% and 100% of the nominal transformer value

With these results a BESS with an inverter rated at 5MVA may be able to do a reliable black start in combination with PoW switching in the main feeder CBs. To offer a backup strategy the following switching sequence is investigated.

6.2.4.2. Feasibility of Combined PoW and Direct Switching of Grid Sections

As shown in Figure 78, a more developed black start strategy can be executed by combining PoW switching at the two CBs of the feeders and using direct switching in the lateral 11kV PMCBs of the feeder. The key idea is to switch as large as possible sections close to the busbar by PoW relays at once. For the sequence suggested a worst case 1.0pu value of PoW performance may be successful for a 5MVA inverter, even when assuming a 3pu inrush of the lateral grid sections.

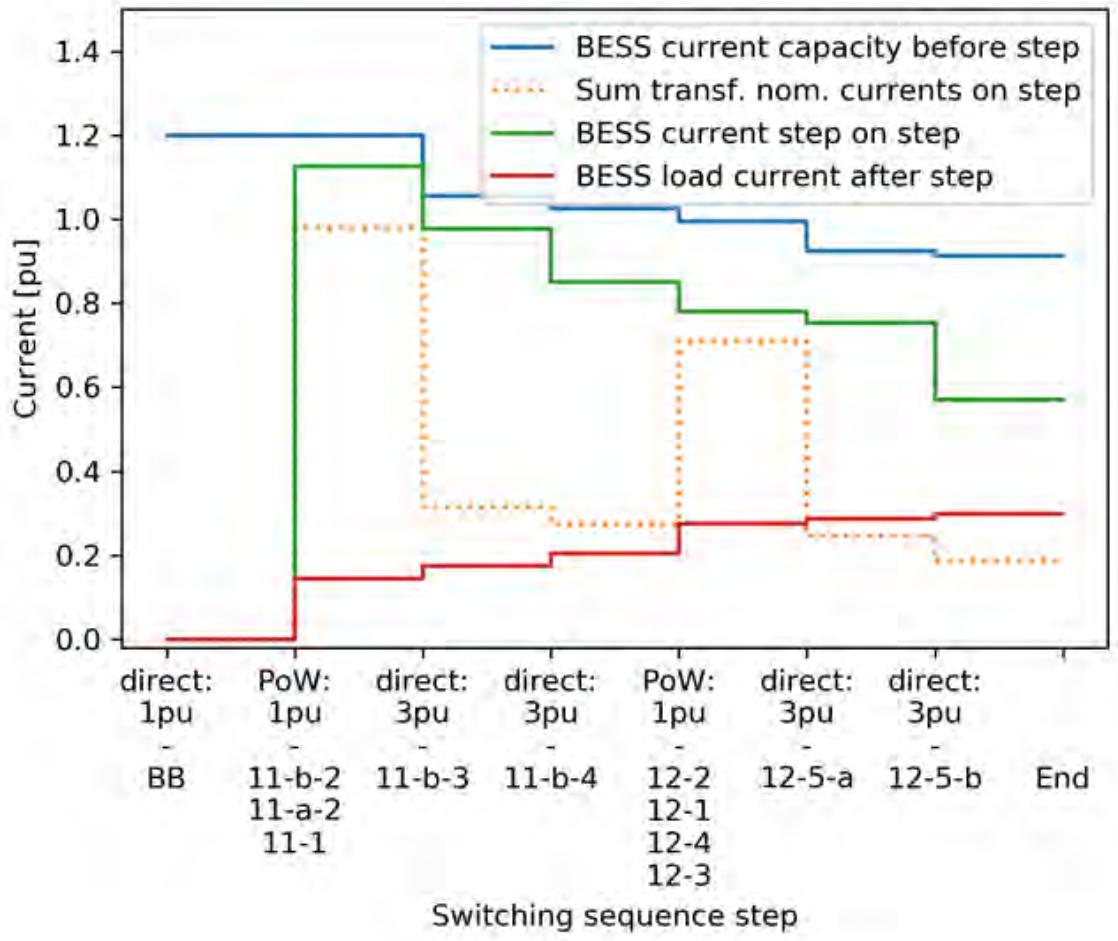


Figure 78 - 5MVA BESS current capacity vs. required in-rush current in case PoW switching can limit the current to 100% and direct switching to 300% of the nominal transformer value

Figure 79 shows that the approach might not be fulfillable with a 3MVA BESS inverter, even for 0.6 pu PoW switching due to the only marginally limited lateral inrush of 3 pu. Only in case the lateral inrush sections may additionally be assumed to stay within 1.5pu, the concept may work for a 3MVA BESS inverter.

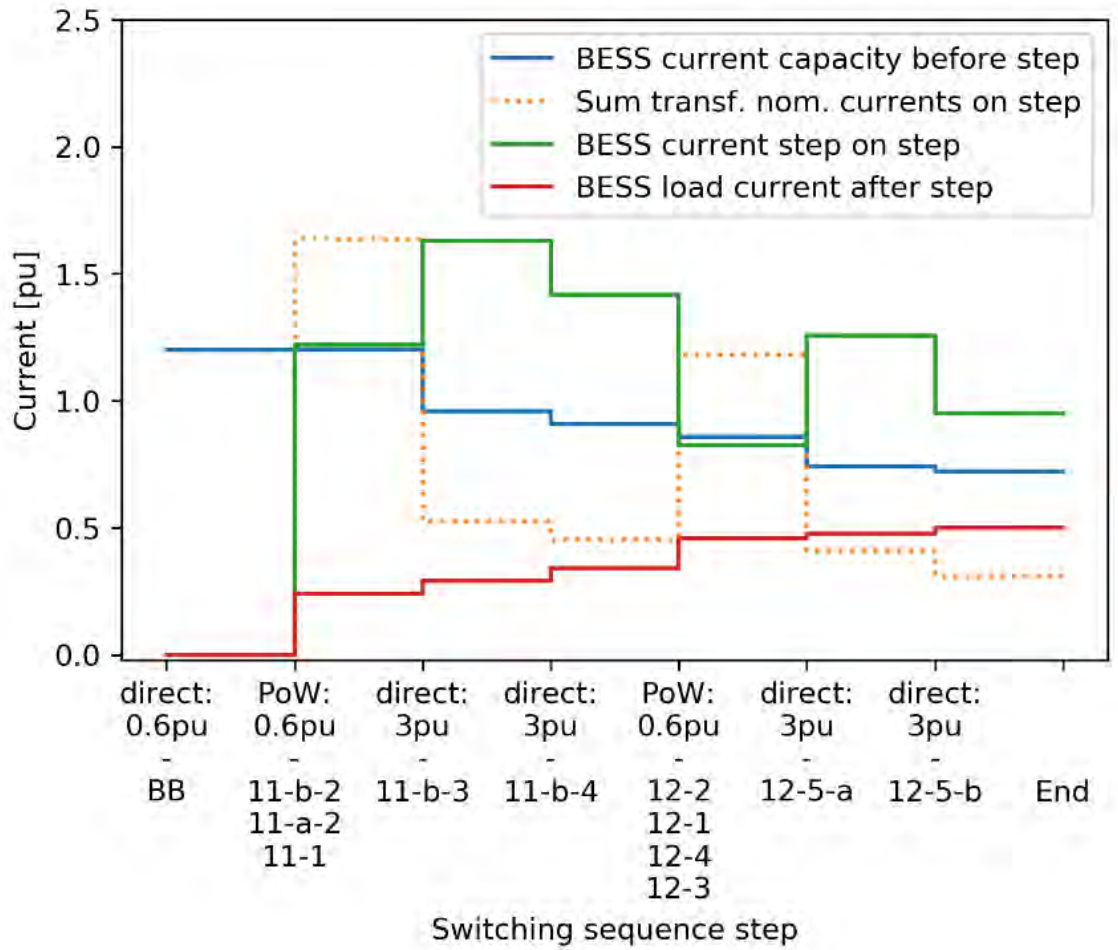


Figure 79 - 3MVA BESS current capacity vs. required in-rush current in case PoW switching can limit the current to 60% and direct switching to 300% of the nominal transformer value

6.2.5. Conclusion from Black Start Analysis

The previous analysis shows that PoW switching will likely enable reliable black start of the 11kV network of Drynoch under the following conditions:

- Availability of a 5MVA BESS inverter rating with 1.2 pu overcurrent capability.
- Application of PoW switching at the two main feeder CBs.
- Inrush limiting performance of PoW to 1pu of cumulated transformer nominal currents.
- Inrush of lateral grid sections not larger than 3pu.
- Utilisation of existing PMCBs via telecontrol to switch on sections 11-b-3, 11-b-4, 12-5a, and 12-5-b

Further variants have been investigated but are not deemed to be reliable.

In the Detailed Design phase, these findings will be further analysed and validated based on simulations and testing.

6.3. Suggestions on Adaptations of Existing Protection System

One key result from the protection and earthing analysis is that the requirement of two means of remote backup protection in islanded mode can only be achieved fully with the concepts investigated in this study if extensive additional measures are implemented. A 5MVA BESS is shown to deliver results that almost meet this requirement, except for certain distinguished worst-case scenarios. Therefore, a risk assessment could be performed by SSEN on the possibility to lower this requirement for these worst-case scenarios in island operation (e.g. 'shall' to 'should').

Should lowering this requirement not be possible, SSEN may choose to implement and investigate additional systems that are discussed here or investigate other alternative protection concepts further in the Detailed Design phase.

Assuming a lowering of the requirement and the implementation of a 5MVA BESS, the following suggestions for the grid protection to safely operate the RaaS system in island mode can be derived from this study:

- Feeder main circuit breaker settings and PMCB settings may be left as is.
- The possibility to add a PMCB in the Glendrynoch feeder section and one other location should be evaluated by SSEN.
- The second level of backup protection will be gained by the following measures:
    - Undervoltage tripping shall be implemented at the BESS. It will provide backup protection for all kinds of faults with limited sensitivity in the periphery.
    - The SEF protection function shall be used at the main feeder circuit breakers. It will provide remote backup protection for end of line 1ph and 2ph-gr faults. The setting of the SEF should set more sensitive if feasible.
    - Overload tripping should be implemented in the BESS when applicable. It will provide remote backup protection especially for peripheral 2ph and 3ph faults.

In case of a significant oversizing of the BESS inverter in comparison to the battery rated power, battery overload situations may result. The BESS therefore shall protect itself against damage, which may be done by BESS tripping after a certain duration. This tripping will act as a kind of unselective backup protection for the grid. Alternatively, self-protection of the BESS may also be achieved by designing control (e.g. inverter control) to lower the output in an adequate fashion. This will likely result in lower output current accompanied with lowered voltages that will increase undervoltage tripping sensitivity.

To enable secure parallel operation of the BESS and the grid the following is suggested:

- The circuit breaker short circuit ratings should be assessed and eventually increased during renewal, at least for the main feeder circuit breakers.
- The busbar short circuit capacity should be assessed and eventually increased during renewal.

Independently of the above the protection of the 800kVA transformer should be reassessed.

For the black start of the 11kV network a rating of the BESS inverter of 5MVA is required in order to successfully manage the transformer inrush when voltage ramping is not tolerable and Point on Wave switching may not guarantee adequately low inrush levels for a lower inverter rating. The following three points should be considered when designing the RaaS solution:

- Reclosing should be deactivated in islanded mode to avoid system collapse
- Point on Wave relays should be applied at the feeder CB level
- An inrush desensitisation should be applied at the designated black start switching CBs/PMCBs

6.4. Resulting BESS Requirements for Drynoch Primary Substation

In the following section, the results from the grid studies are summarised with regards to the design and the rating of the BESS. As these requirements are based on the assumptions on BESS design and behaviour given in section 6.1.2.4 those also need to be considered as valid requirements. The consequences of deviations from those assumptions need to be estimated in the Detailed Design phase.

6.4.1. BESS Inverter

A sizing of the BESS inverter with 5MVA has been identified as the best option for the design of the BESS to enable the use of the existing protection in island mode and to achieve a proper selectivity. In the Detailed Design, the oversizing may be refined based on detailed inverter models.

The BESS inverter will have to be able to provide fault currents of 120% of its nominal rating for a minimum of three seconds. The assumptions on fault current injection and current limitation in case of faults should be fulfilled with comparable behaviour (compare section 6.1.2.4).

In case the BESS system is build up modularly, a minimum rated inverter capacity of 5MVA with according battery capacity needs to remain active during islanded operation to maintain protection system performance. In case of module failures, maintenance etc., resulting in lower aggregated capacity, either protection performance requirements will need to be lowered or islanding needs to be prohibited. The different modules shall behave as one during events and shall not loose synchronism.

A full four-quadrant operation of the BESS inverter is required.

Furthermore, the BESS inverter is assumed to work as a voltage source also when operated in parallel to the grid. In case of fault events the BESS shall not loose synchronism.

The FRT curve during island mode needs to take care of the maximum and minimum line-earth and line-line voltages observed during faults at the 11kV busbar, as shown in Figure 80.

A drop of residual voltages down to 0pu for approximately two seconds is observed during faults, going beyond the standard G99 requirements. Therefore, a zero voltage fault ride through requirement for three seconds is required. During islanding it would also be required to switch off standard G99 relay functionality at the BESS and use discrete relays instead.

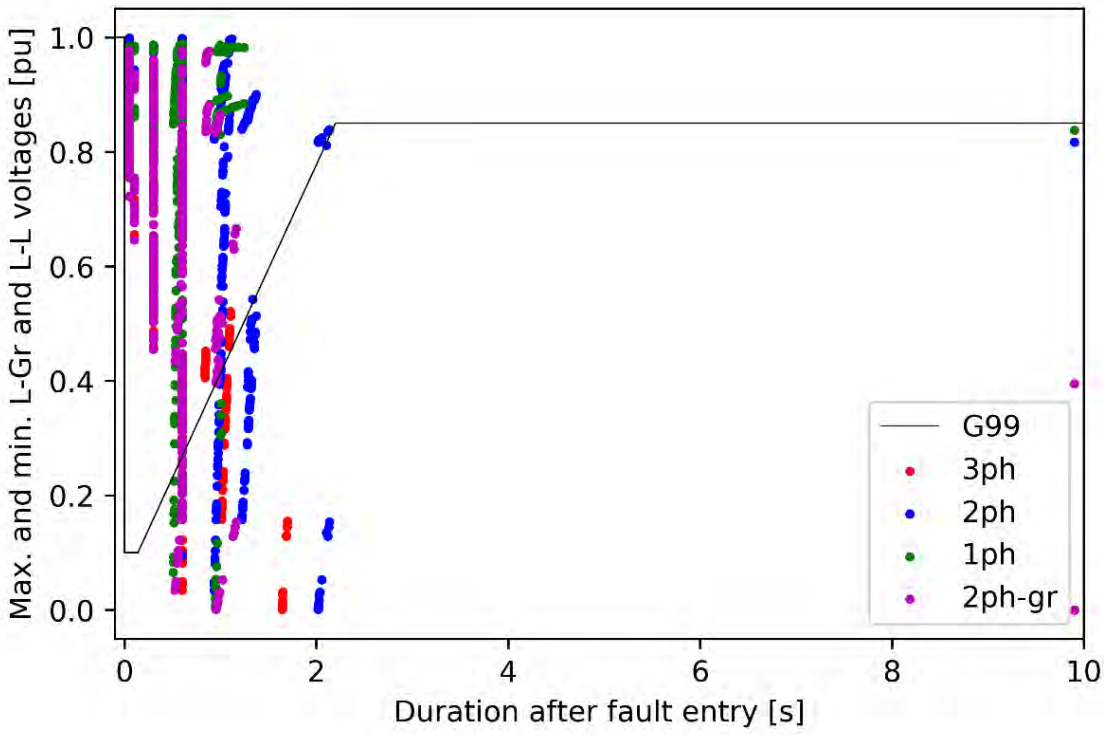


Figure 80 - Maximum and minimum line-earth and line-line voltages observed during faults at the 11kV busbar in Drynoch compared to LVRT G99 standard curve

6.4.2. Battery and Transformer Loading

During faults the entire BESS system needs to provided active and reactive power and the response to symmetrical and asymmetrical grid faults needs to be considered. Asymmetrical faults are expected to have oscillating powers (P_{osc}) with twice the nominal frequency as seen in Figure 81.

Figure 81 - Expected active power delivery in case of symmetrical and asymmetrical grid faults

With the defined nominal BESS inverter of 5MVA, Figure 82 shows the empirical distribution of P_{avg}, P_{osc} tuples for faults in the HV grid. Figure 82shows that peak active powers may in some cases exceed 1pu, up to 1.2pu of the BESS inverter rating with durations of up to two seconds.

Therefore, the BESS transformer, battery and DC-link need to be designed to operate with peak loads of up to 1.2pu of the BESS rated power of 5MVA for up to two seconds.

A rated transformer power of 3MVA is deemed sufficient for the application.

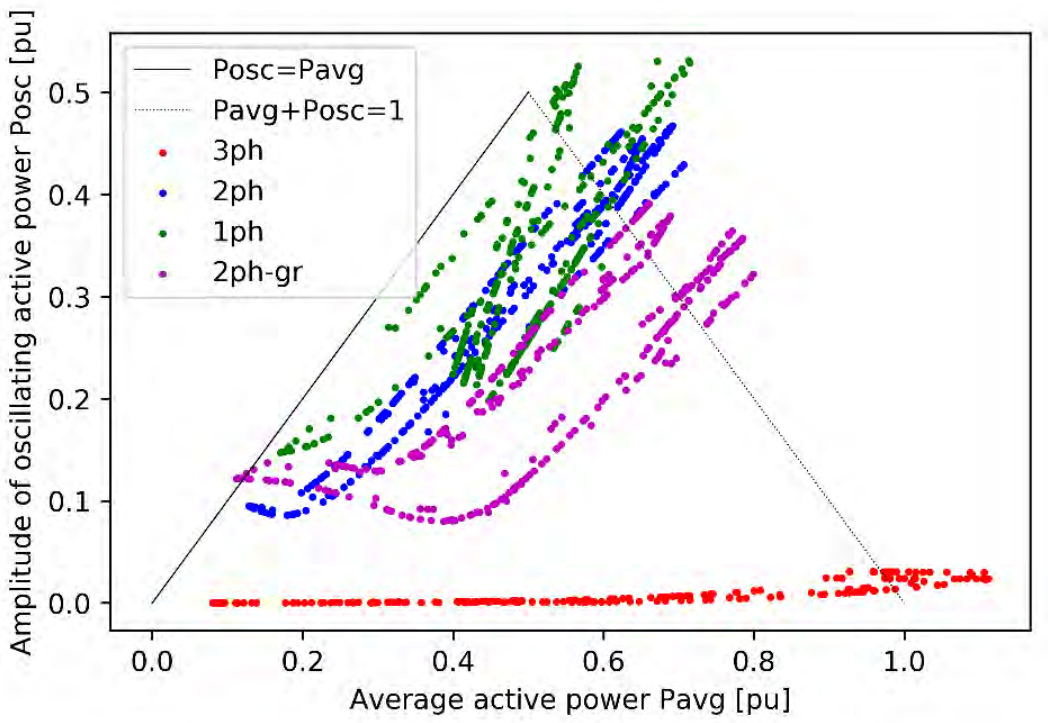


Figure 82 - Empirical distribution of average active powers and the amplitude of the oscillating active power during faults in 11kV network in Drynoch, in p.u of the power converter nominal power of 5MVA

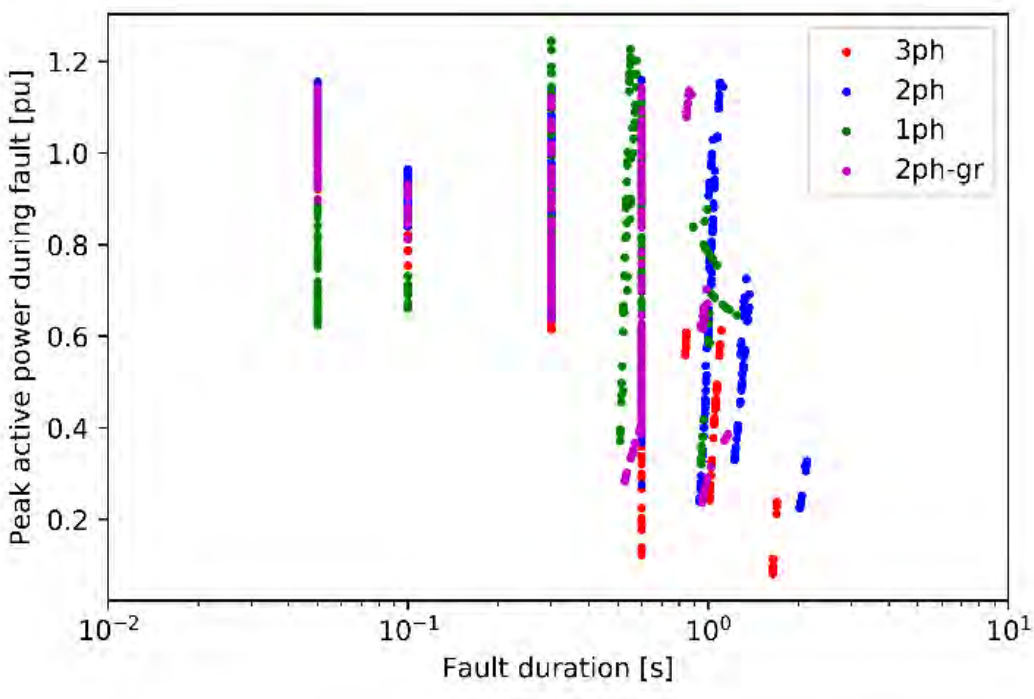


Figure 83 - Tripping time and peak active power delivery (in p.u of the power inverter nominal power of 5MVA) during faults in 11kV network in Drynoch

Battery overload may occur depending on the actual battery sizing in comparison to the inverter rating. During the Detailed Design phase, solutions will be sought in close contact with manufacturers on a proper way to handle this situation. Options may be:

1. Accepting some periodic peak overload
2. Resizing of battery or increase of discharge capacity
3. Tripping of the BESS system based on duration
4. Active power limitation by BESS control

7. Calculation of Required Usable Energy Capacity for RaaS

In the Site Selection Report, it was determined that a suitable definition of the Resilience as a Service (RaaS) service requirements is to achieve a service duration to cover the peak load at each site for 4 hours in 90% of a year[7]. This method will also be applied for the RaaS Service Windows as defined in the report E4.1 'Product Design Scenarios' in WP4: Operational Optimisation. Results and potential impacts on the BESS sizing will be discussed in the reports E4.2 and E4.3 'Operational Optimisation Report' in WP4.

This section applies the methodology developed in the Site Selection process to Drynoch primary substation load data of five years and derive the required usable energy capacity for a RaaS Battery Energy Storage System (BESS).

The five-year load data for Drynoch primary substation is shown in Figure 84 below, with data measured in MVA.

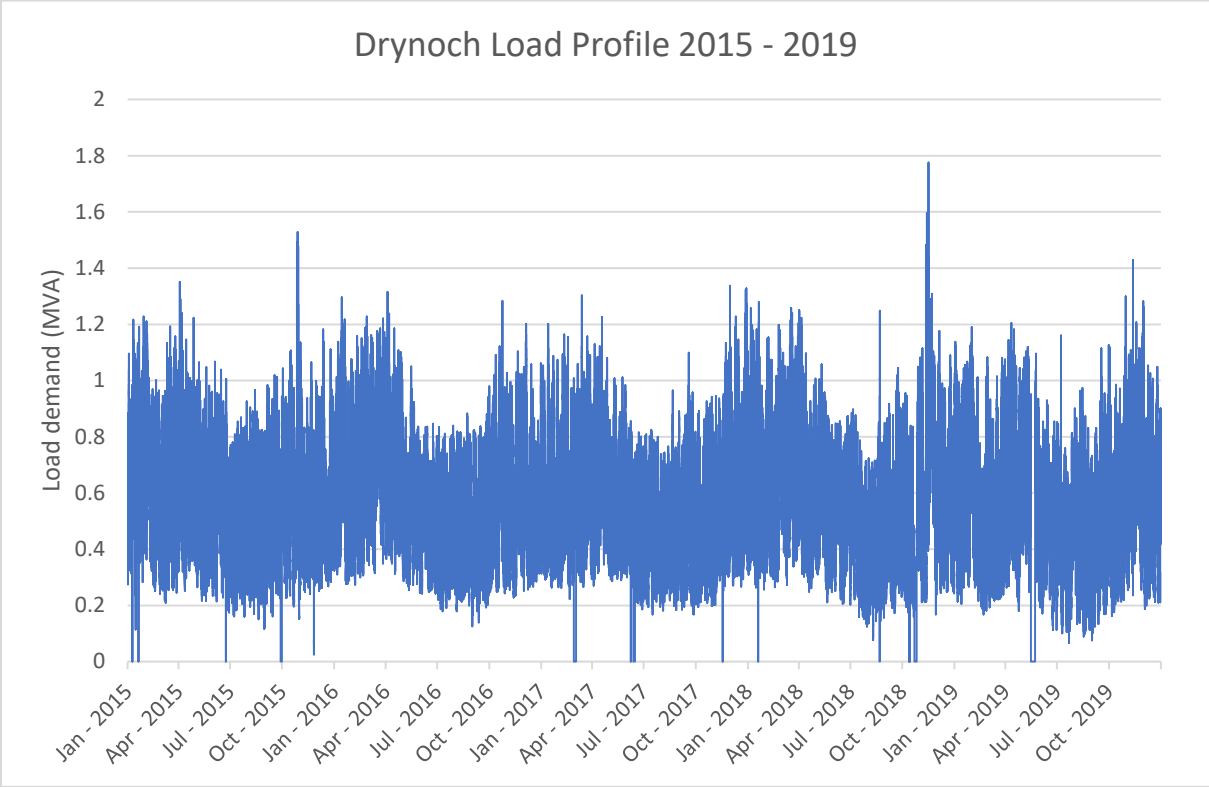


Figure 84 - Drynoch load data 2015 to 2019 (including local DG)

Table 10 shows that little variation in average load or total annual demand is observed over the five years considered. Average load has a maximum of 4.7% variation compared to the five-year average of 0.55 MVA while annual demand has a maximum of 4.8% variation compared to the five-year average for annual demand of 9.7 GVAh. There is greater variation with the peak demand, however, with a maximum variation of 20.2% in the last five years compared to the average peak. This shows, that no

[7] For further details on this calculation methodology, please refer to the Site Selection Report as published on the RaaS Project website (https://project-raas.co.uk) or available upon request from the RaaS project team

significant changes in consumption has been observed in the last five years, which gives confidence that sizing the BESS with the available data is sufficiently future proof.

Table 10 - Annual and peak demand at Drynoch between 2015 and 2019

Year	Average load (MVA)	Annual Demand (MVAh)	Peak load (MVA)
2015	0.55	9,679	1.53
2016	0.57	10,008.	1.32
2017	0.52	9,192	1.34
2018	0.56	9,764	1.78
2019	0.55	9,630	1.43
Average	**0.55**	**9,655**	**1.48**

The required usable BESS energy capacity has been determined using the methodology developed during the site selection process. The available load data has been used to identify the required battery energy to cover 90% of all potential 4-hour outages. Figure 85 shows the results compared to the 90% requirement. A summary of these results is also provided in Table 11 below.

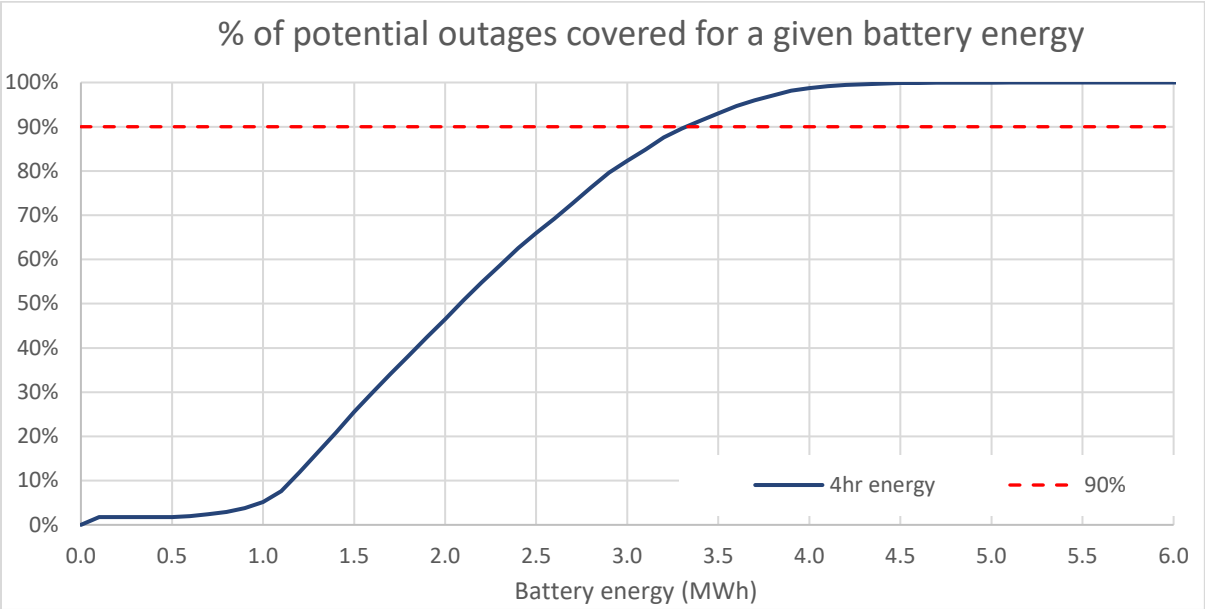


Figure 85 - Percentage of potential 4-hr outages that can be covered for a given battery capacity

Table 11 - Summary of battery capacities required to provide different levels of resilience

Year	Required energy for 90% of potential 4-hr outages [MWh]
2015	3.2
2016	3.3
2017	3.1
2018	3.5
2019	3.4
Max	**3.5**

Following this analysis, 3.5 MWh has been determined as the minimum usable BESS energy capacity to meet the defined requirement to cover 90% of all potential 4-hour outages during a year.

8. BESS Design for Drynoch Primary Substation

This section describes the sizing and design proposal of a Battery Energy Storage System (BESS) implemented at Drynoch primary substation as part of the Resilience as a Service (RaaS) project trial

First, the sizing of the BESS is described based on the requirements derived from the grid studies and the calculation of the required usable energy capacity for RaaS.

Afterwards, a full design proposal is provided before a cost update (redacted) and the split of scope between the RaaS Provider and the DNO are discussed.

8.1. BESS Sizing

To define the specifications of the installed BESS, further considerations are needed to ensure the minimum usable BESS energy capacity requirements are met for the entire contract term. These include adjustments to the installed battery capacity for the range of usable capacity (Depth of Discharge – DoD) as well as aging of the battery cells. Additionally, the BESS requirements resulting from the grid studies are taken into consideration for specifying the BESS inverter and transformer sizes.

8.1.1. BESS Energy Capacity

It is not possible to utilise the entire range of a lithium-ion BESS capacity during normal operation for safety reasons. As an industry standard a maximum DoD of 90% can be assumed.

Additionally, a lithium-ion battery will degrade with use and time, leading to a reduction of usable capacity over the lifetime of the battery. Initial assumptions for a 5-year term of usage[8] is that the battery will degrade by 10% of its usable capacity.

Both factors are dependent on the final technology provider and many other aspects and therefore currently represent assumptions based on industry standards.

To be able to provide the required 3.5 MWh of usable BESS energy capacity over the entire term of a RaaS contract therefore requires an oversizing of the initially installed battery by 20%, leading to an installed BESS energy capacity of 4.2 MWh.

8.1.2. BESS Inverter Sizing

Equally, the power rating of the BESS needs to be defined by sizing the BESS inverter. Two different approaches can influence the required BESS Inverter rating.

Firstly, the c-rate of the battery cells define the maximum active power in relation to the installed BESS energy capacity that can be drawn from the battery cells. As defined in the Site Selection Report, a BESS with a C-rating of 1 MWh/MW provides the best solution for the RaaS application as it can cope with the power and energy demands for RaaS. Therefore, the maximum nominal inverter power is

[8] 5 years have been chosen based on initial considerations in WP5: Business Model of the RaaS project as being a suitable time frame for a RaaS contract.

given with 4.2 MW. This is significantly larger than the maximum observed peak load at Drynoch substation and gives enough capacity to be active on the flexibility markets.

Sizing of the BESS Inverter needs also to consider the power factor range required by the grid connection agreement. For this study a power factor range from cosphi = -0.8 to cosphi = +0.8 is assumed, resulting in a maximum installed inverter rating of 5.25 MVA.

Secondly, as described in Section 6.4.1, the BESS Inverter needs to be sized in accordance with grid protection and black start requirements. The results from the grid studies lead to the conclusion that a BESS inverter with 5 MVA would be sufficient for a safe and stable operation of the 11kV network at Drynoch primary substation in grid parallel mode as well as in island mode.

A reduction of the installed BESS Inverter size from 5.25 MVA to 5 MVA would be acceptable in the context of this project as this still exceeds the maximum peak load observed on the network and leaves sufficient power capacity for activity on the flexibility markets. This is also beneficial as a 5 MVA sized inverter is commercially more readily available.

A BESS Inverter size of 3 MVA would also be sufficient for the resilience and flexibility requirements but would not meet the protection and black start requirements. Intermediate values and the exact configuration of the BESS Inverter will be discussed with manufacturers during the Detailed Design phase, including detailed studies based on inverted models.

Therefore, the BESS specification for the Front End Engineering Design (FEED) is set at 4.2 MWh / 5 MVA.

8.1.3. BESS Transformer Sizing

As shown in Section 6.4.2, a 0.4/11kV transformer rating of 3MVA would be sufficient to meet the protection and black start requirements. With the reasoning provided in the section above on the BESS inverter sizing this has been selected as the BESS transformer rating for the FEED.

Potential requirements to oversize the transformer to enable more import and export for activity at the flexibility markets will be analysed based on the results of WP4's flexibility modelling, which will be published in the reports E4.2 and E4.3 'Operational Optimisation Report'.

8.2. BESS Design

Utilising the sizing described above, the configuration and specifications of the BESS have been further defined.

8.2.1. BESS Setup

A proposed design for the system is shown in Figure 86 below. This is one potential configuration for this system, developed by E.ON in collaboration with its consultancy *Couch Perry and Wilkes LLP* as variations on how components are integrated and housed vary by supplier. The layout will be further defined in the Detailed Design phase based on supplier responses to the Request for Proposal (RfP).

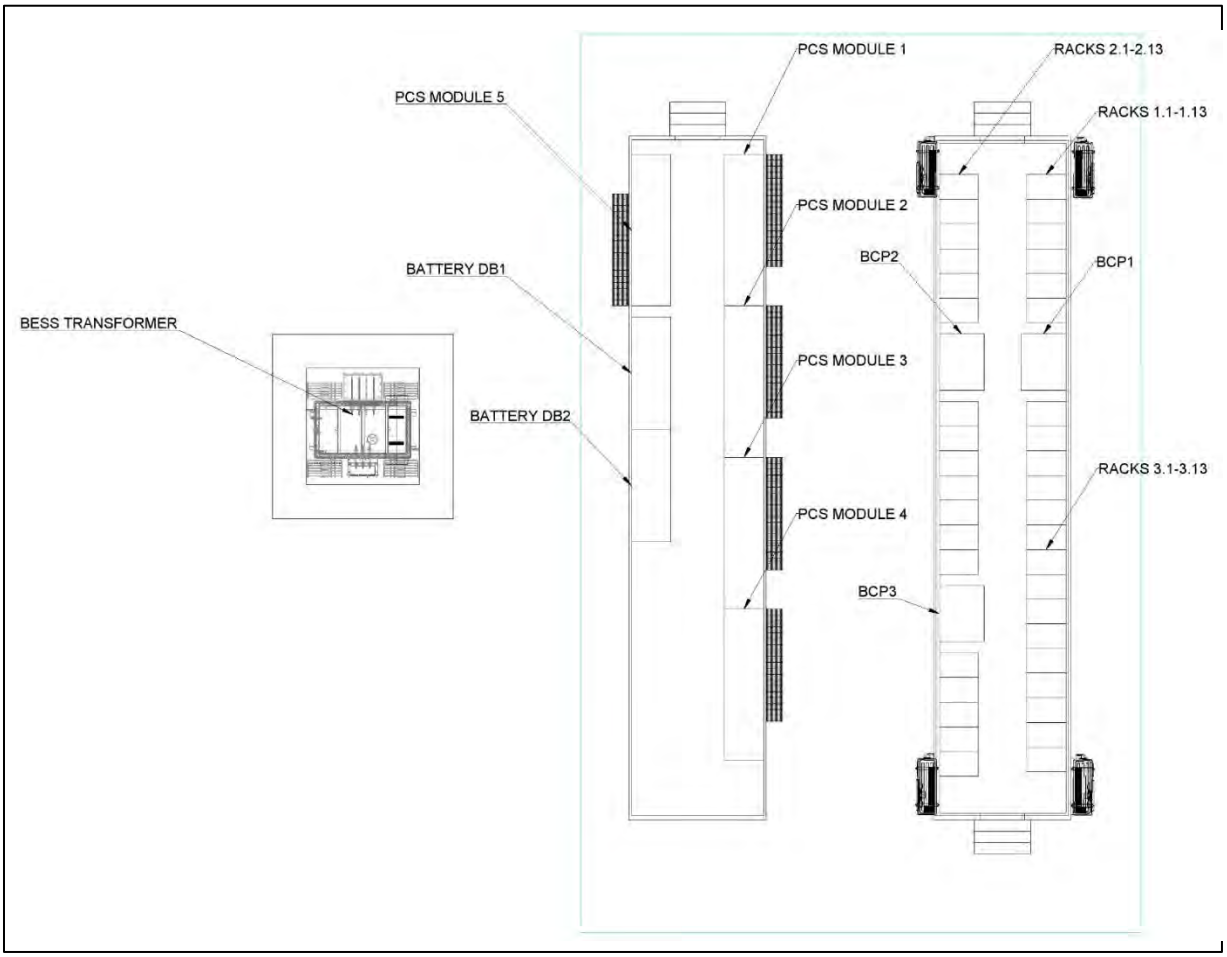


Figure 86 – Typical layout of BESS

The exemplary design includes one containerised unit that will house the BESS components and a second containerised unit housing the BESS Inverter as well as the DC distribution equipment to link the BESS Inverter to the Battery Combiner Panel (BCP).

In this example design, both containers are system-built, prefabricated, weatherproof and secure enclosures designed to protect the equipment contained from the external environmental conditions likely to be experienced at Drynoch.

The following ancillary systems shall be included for both containers: -

- Heating, Ventilation and Air Conditioning (HVAC) systems to ensure optimum operating temperatures for the battery cells
- Full fresh-air ventilation systems for the BESS Inverter .
- An auxiliary AC power distribution point supplied from the Low Voltage (LV) terminals of the BESS transformer
- An Uninterruptable Power Supply (UPS) for the Battery Management System (BMS) and the BESS Inverter control systems to maintain control during loss of the external power supply including performing black start operation.
- Utility power outlets for maintenance.
- Internal lighting and emergency lighting for maintenance and access purposes.
- External lighting in the yard area around the BESS containers and the transformer enclosure for security and access for inspection and maintenance.

- Fire detection and alarm systems configured to standards BS5839, linked to a remote monitoring station.
- Intruder detection systems and CCTV monitoring.
- Access control systems to the doors.

The auxiliary LV supplies derived from the LV side of the BESS transformer is required to provide power to the equipment when the main LV synchronising CB is open, and the BESS is not connected to the primary substation 11kV bus.

The 0.4kV/11kV BESS transformer will be housed in a GRP enclosure and located next to the battery and BESS Inverter container.

The general arrangement of the containers and a 3D representation of the layout is indicated on the images below (Figure 87 and Figure 88):-

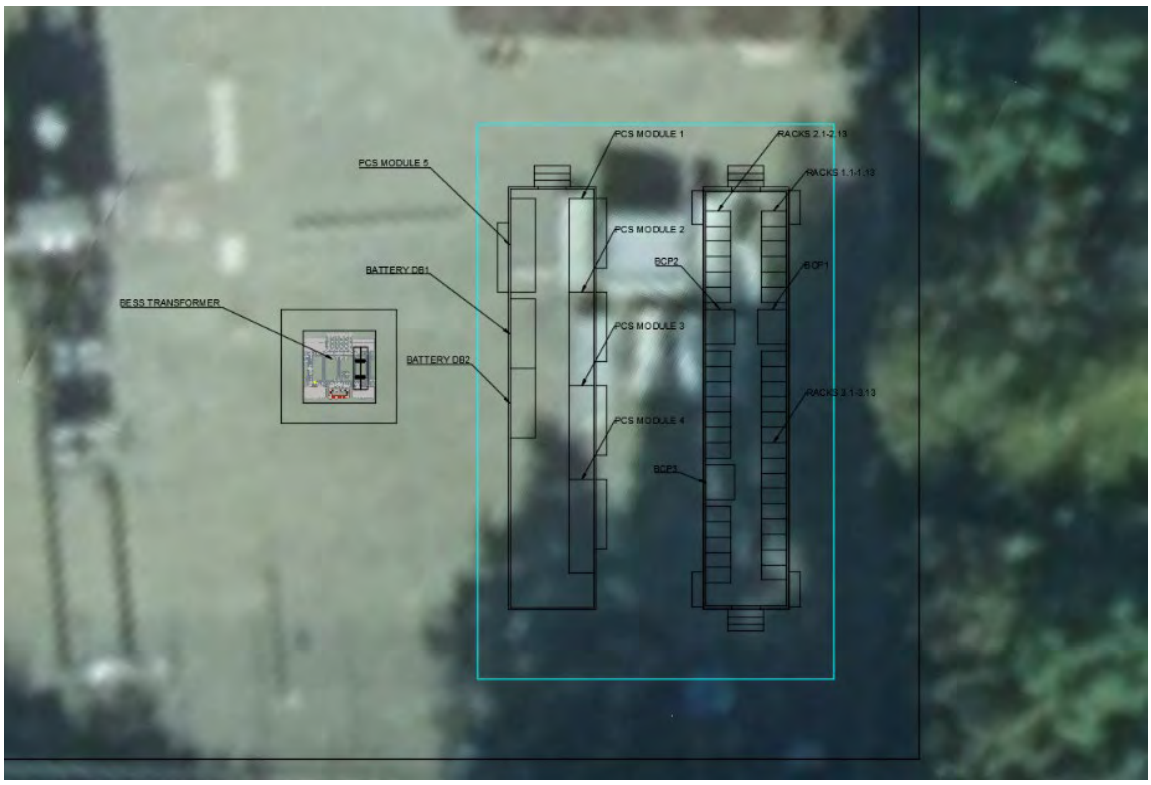


Figure 87 – BESS General Arrangement

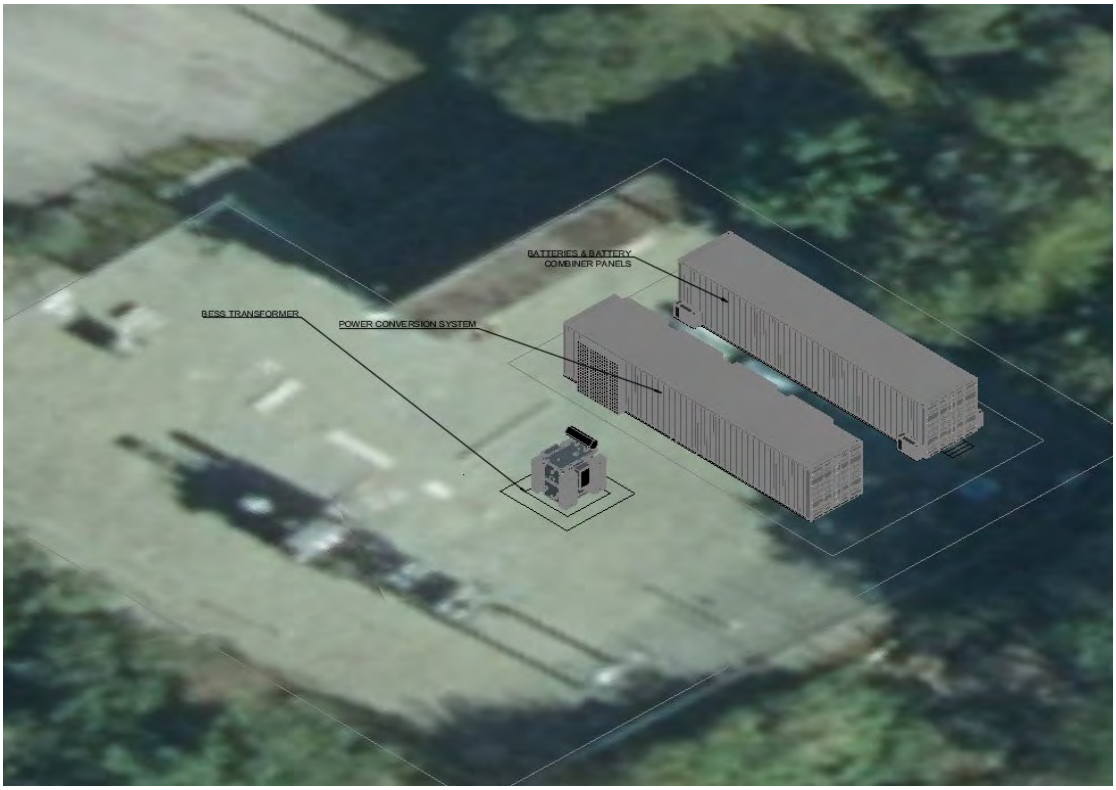


Figure 88 - 3D Representation of the BESS general arrangement at the Drynoch substation

8.2.2. Battery Components

8.2.2.1. Battery Modules

The proposed BESS is based on lithium-ion battery modules. One battery module contains multiple battery cells, cell voltage and temperature measurement sensors, communications interfaces and a ventilation unit.

The size and number of the battery cells and battery modules are dependent on the manufacturer selected, but typically 16 to 24 cells per module.

8.2.2.2. Battery Racks

The individual batteries will be housed in battery racks, which are a (mainly steel) storage rack to accommodate a number of battery modules. For ease of installation and removal of the single battery modules, the racks contain trays in which the battery modules can be inserted and removed. With this arrangement, DC string voltages up to 1000 V can be achieved. Consequently, the number of racks can be considered equivalent to the number of DC strings in parallel.

Circuit isolation and protection for each battery rack will be provided in either top or bottom shelf of the battery rack. The individual battery racks are then connected to the BCP or BESS Inverter .

Protection of the battery modules (e.g. overcurrent, state of charge) will be afforded via an in-rack DC circuit breaker. A communication interface will be provided to the BMS to monitor the battery cell status.

8.2.2.3. Battery Management System (BMS)

A BMS will be provided which monitors the status and health of the batteries and also detects abnormal conditions, such as cell voltage, current and temperatures, ensuring that cells are operating within their limits. the BMS will either give warning to the superior EMS or if second safety level thresholds are exceeded, immediately disconnects the battery system.

8.2.3. BESS Inverter

It is proposed that the BESS Inverter will operate in 'Virtual Synchronous' mode, which is intended to be similar to the characteristic operation of a synchronous generator or synchronous motor operation. In this mode, the BESS Inverter will provide active power in accordance with frequency-based droop curve characteristic, which is a linear curve which determines the active power output or input of the BESS Inverter at a certain frequency level (P- f droop).

The BESS Inverter will be operated in 'grid-forming' mode and be capable of serving as a voltage and frequency source, which will enable the BESS to support the local 11kV network supplied from Drynoch primary substation in 'island' mode.

The EMS will control the synchronisation and connection of the BESS to the grid when the BESS is operating in parallel as this is possible due to the far larger power capacity of the grid compared to the power capacity of the BESS. The capacity of the grid allows the EMS to control the BESS Inverter in synchronous operation with the grid.

When the BESS is intended to move to 'Island Mode' having the BESS Inverter operating as a frequency and voltage source, results in no requirement for any mode change or start-up of the BESS Inverter , which will ensure that the BESS continues to operate without any interruption in the supply of electricity to the 'islanded' 11kV network.

When the grid becomes available following an outage, the 'islanded' 11kV network supported by the BESS will be synchronised to the grid across the grid transformer 11kV circuit breaker by the EMS. The EMS will modify the droop curves within the BESS Inverter to match voltage and frequency, allowing closure of the grid circuit breaker and return to parallel operation with the BESS acting as a distributed generator under the definition of ENA EREC G99.

8.2.4. Cabling Installations

All cabling installations shall be in accordance with the requirements of BS7671.

The cabling and cable support systems will be routed below ground in cable ducts and shall be provided as follows:

- Between the 11kV switchboard and the BESS transformer: three core 6350/11000V cable with copper conductors, XLPE insulation, steel wire armouring and a red PVC over sheath configured to standards BS 6622.
- Between the BESS transformer and the BESS Inverter units: four core 600/1000V cables configured to standards BS 5467.

The LV installations within the containers shall be in accordance with BS 7671.

8.2.5. BESS Transformer

A BESS transformer (referenced as B1) that links the BESS Inverters in the relevant BESS enclosure to the primary substation 11kV bus shall be housed in a GRP enclosure in the yard-area. The GRP enclosure will be designed to cater for over-pressure if the transformer catastrophically fails, and with ventilation louvres to ensure that the transformer operates within its temperature limits.

The transformer shall comply with ENA TS 35-1 and Tier 2 under EU EcoDesign Regulation 548/2014, and shall be manufactured in compliance with BS EN 60076.

The transformer shall be a liquid filled, naturally cooled unit, filled with a synthetic liquid (typically Midel 7131) and thus will be designated as KNAN. The transformer shall include welded steel tanks with gasketed lids and welded steel radiators attached to the tanks. It shall also be mounted on a skid base complete with jacking lugs. The technical parameters of the transformer shall be as follows:

Table 12 - Technical parameters for the proposed transformer design

Parameter	Value
Primary voltage	11kV
Secondary voltage	to suit the operational voltage range of the BESS Inverter (assumed to be 400V)
Vector Group	Ynd11
Maximum continuous rating	3MVA
Impedance on rating	8%
Short circuit withstand rating	25kA for 3 seconds

If the maximum output of fault current from the converter will be 1.2 p.u. on rating (i.e. 6MVA), with a BESS transformer continuous rating of 3MVA, this equates to a current of 2.0 p.u. on rating of the transformer. This will be well within the capability of the transformer to carry such a current for long enough for the protection to operate, as shown in the typical 'damage curve' of the transformer, illustrated in Appendix 1 Figure 95.

8.2.6. Earthing Arrangements

The existing 11kV earthing arrangement at Drynoch is earthed from the star point on the secondary winding of the 33/11kV Grid transformer.

The arrangement only keeps the 11kV system earthed when the transformer 11kV circuit breaker is closed. This is acceptable when the proposed BESS is connected in parallel with the Grid, but in 'island' mode operation, the transformer CB will be 'open', removing the earth reference or potential return earth path to enable satisfactory operation of any earth fault protection on the 11kV network.

It is therefore proposed that an additional earth is provided from the star point on the BESS transformer that is switchable via a contactor, such that the earth is applied only when the transformer CB is 'open' and removed when the BESS is in parallel with the Grid.

Under EREC G99, it is not permissible for distributed power generating modules to operate in parallel with the power distribution system in 'long-term' parallel with the generating module neutral connected to earth, other than for 'short-term' periods, which is limited to five minutes aggregated over any one month period. It is, however, in the discretion of the DNO to release this requirement.

At Drynoch it is therefore proposed that there is an electrical interlock between the Grid transformer 11kV circuit breaker and the BESS transformer earthing contractor to prevent both devices being closed simultaneously, other than for a few milliseconds whilst the changeover occurs, to avoid the BESS system neutral to float. The control for closing the BESS transformer primary winding earthing contactor shall be part of Scottish and Southern Electricity Networks (SSEN) controls infrastructure and interlocked as part of the new replacement switch board enabling control and interlocking with the main transformer circuit breaker T1. The BESS EMS shall require interlocks signalling the closure of the contactor along with the grid transformer circuit breaker in a fault condition to indicate the earth is present in island operation.

It is proposed that the earthing contactor be included within the new replacement 11kV switchboard arrangement as part of this project.

The contactor shall be a suitably rated vacuum unit with connection to the neutral of the BESS transformer via a single core 6350/11000V rated XLPE (Cross-linked polyethylene) insulated copper cable with overall aluminium wire armour.

The earth connection from the BESS transformer neutral/earth contactor shall be connected to the same substation earth as the existing Grid transformer. Additional earth electrodes and grading electrodes will be installed around the BESS containers and the BESS transformer housing to ensure that the site has an earth potential rise below 430V and so is designated as COLD. Also, an earth potential rise of less than double the touch potential limit (<466V), to allow the HV and LV to be combined with no further limitations.

The touch potentials and step potentials in the immediate area surrounding the BESS containers and the transformer housing will be below the limits stated in ENA EREC S34 and ENA TS 41-24, to ensure that the installation does not pose any unacceptable risk for personnel in the vicinity.

All earthing conductors will be sized and selected to handle the maximum earth fault currents generated for the disconnection times achieved by the earth fault protection settings of the relevant protection relays.

It is intended that the BESS LV installation associated with the AC network on the BESS side of the transformer will be an IT system as defined by BS7671. This is a typical arrangement of a BESS Inverter installations which tends to have the AC side not connected to earth. Protection against AC earth faults on the LV side of the BESS transformer and the DC battery network will be afforded by insulation monitoring devices.

The insulation monitoring devices will be in accordance with BS EN 61557-8:2007: “Electrical safety in low voltage distribution systems up to 1000 V AC. and 1500 V DC. Equipment for testing, measuring or monitoring of protective measures. Insulation monitoring devices for IT systems”.

BS EN 61557-8:2007 specifies that insulation monitoring devices must support a prescribed measuring principle which enables them to monitor both symmetrical and asymmetrical deteriorations in insulation.

8.2.7. Protection Design

Several statutory documents apply to the implementation of the Primary RaaS scheme at Drynoch. The primary objective is that the electricity public distribution network (PDN) must be operated in a manner that ensures network security and the safety of customers and the public. The requirements

that apply are listed in the Engineering Standards in Table 1. Of particular relevance are ENA EREC G99 which defines how the protection system of the BESS should co-ordinate with the DNO's existing protection.

A summary of the key criteria relevant for RaaS are outlined in 6.4, as well as the criteria that RaaS is exempt from. Table 29 in Appendix 1 shows the minimum suggested protection and measurement devices to be arranged in the 11kV switchboard at Drynoch for the safe connection and operation of the BESS.

In accordance with clause 10.2.1 of ENA EREC G99, the maximum time for the relay to pick up and operate for a reduction in voltage of >20% is 2.5s, and disconnect the Power Generating Module in a time shorter than any auto reclose dead time on the DNO's network. This will make allowance for circuit breakers fitted with Delayed Auto Reclose (DAR), where the minimum operation time of 0.5 s should be allowed, so that the relay will then coordinate with auto-reclosers set with a dead time of 3s.

The G99 compliant protection will operate in parallel with the EMS, which will detect via the BESS Inverter an out of range deviation of system voltage and frequency and will instigate opening of the Grid transformer 11kV circuit breaker well in advance of the G99 protection operating on under voltage (2.5s dwell time). The G99 relay will therefore only instigate a tripping of the BESS LV circuit breaker if the EMS fails to open the Grid Transformer 11kV circuit breaker within the 2.5s window.

If the BESS LV circuit breaker is opened by the G99 protection and the BESS is disconnected from operating in parallel with the Grid, if the Grid is still healthy, or has recovered from a sustained voltage depression, or has recovered due to an auto recloser restoring the 33kV network, the G99 relay will automatically reset and allow reconnection of the BESS after a minimum time delay of 20s, in accordance with EREC G99 Clauses 10.3.4 and 10.3.5.

8.2.8. Power Quality Analysers

Power quality analysers will be provided on the 11kV side of the Grid Transformer and the BESS Transformer to continuously monitor voltage quality in terms of harmonic content and flicker on the 11kV primary bus when connected to the grid and in Island mode.

Due to the much higher system impedance in Island mode, the presence of significant levels of harmonic voltages can have a significantly detrimental effect on the operation and stability of the BESS. Data from the analysers will be forwarded to the EMS.

For this application it is recommended to utilise power quality analysers with a range of additional functions compared to typical power quality meters. As well as reliably recording harmonics, phase unbalance, transients, voltage dips, voltage swell, flicker, phase shifts and reactive power, the analysers will also continuously monitor the power quality in accordance with BS EN 50160 "Voltage characteristics of electricity supplied by public electricity networks" (when the network is connected to the Grid or in island mode), and BS EN 61000.

8.2.9. Synchronisation Switch Settings

In the following section, the required settings to resynchronise the islanded 11kV network to the upstream 33kV network are discussed. Currently, a conceptual discussion of the settings has been completed, with a detailed definition being required as part of the Detailed Design.

8.2.9.1. General Requirements for Synchronisation

The 11kV system of Drynoch will be disconnected from the primary 33/11kV transformer of the substation to create an electric island in case of a failure in the 33kV supply. The circuit breaker performing this disconnection will be named here Synchronisation Switch as it will be automatically commanded by the BESS EMS to perform islanding in case of fault, and re-synchronisation to the 33kV network when supply is back to normal (and manual permission from SSEN control room is given).

The settings for synchronisation and decoupling control will be completely defined in the next phase of final engineering together with SSEN. The settings needed to cover the disconnection from the 33kV network (islanding) and the resynchronisation to the 33kV network.

Decoupling from Mains:

This will be an automated function of the synchronisation switch as it needs to be fast enough to allow a seamless transition to island mode. Typical parameters are:

i. Frequency High
   1. Threshold
   2. Delay / time the value is exceeded
ii. Frequency Low
   1. Threshold
   2. Delay / time the value is exceeded
iii. Voltage High
   1. Threshold
   2. Delay / time the value is exceeded
iv. Voltage Low
   1. Threshold
   2. Delay / time the value is exceeded

For the RaaS project, loss of mains can arise from various scenarios meaning a more complex definition of the decoupling detection may be required. An initial view on the analysis to be done for the final engineering is done in Section 9.1.

Synchronisation:

In order to reconnect the islanded substation system to the utility, both systems need to be synchronous to each other (with minor deviations). This requires modifying the BESS Power Converter operation parameters in order to match the “external” utility parameters (frequency, voltage, phase angle, etc.).

If the synchronisation controller is not disabled by the EMS (either automatically or manually) or by the DNO (manually), it will provide a close command to the grid connection breaker to complete the synchronisation procedure. Typical parameters are:

1. Max. frequency deviation of external system from the internal (island) system
2. Max. voltage deviation of external system from the internal (island) system
3. Max. phase angle deviation of external system from the internal (island) system
4. Min. duration of all parameters being “synchronous” prior to closing the grid coupling breaker

A typical implementation is via the internal parameters of the circuit breaker controller, which then communicates to the BESS EMS to modify them as seen in Figure 89 and Figure 90.

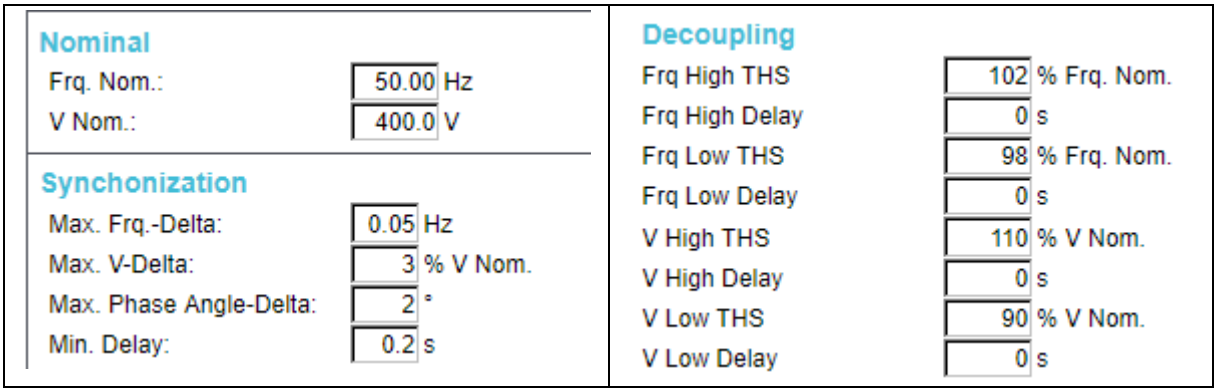


Figure 89 - Exemplary synchronisation and decoupling settings of a real BESS controlled by BESS EMS in LV range (courtesy of DHybrid)

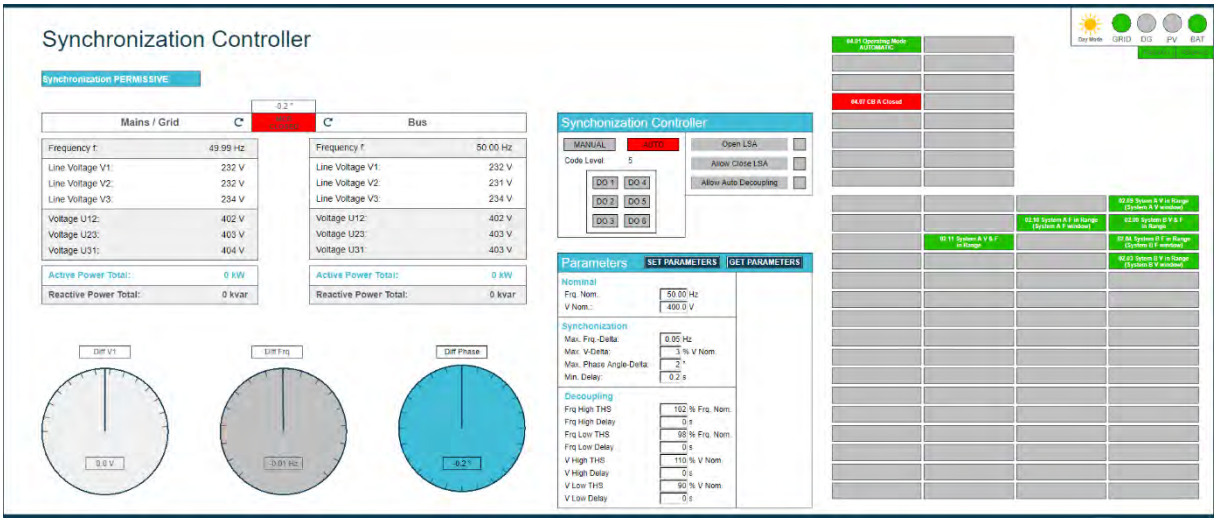


Figure 90 - Exemplary synchronisation and decoupling settings of a real BESS controlled by a BESS EMS in LV range (with measured data, synchroscopes, settings and status, and alarm depiction) (Courtesy of DHybrid)

8.2.9.2. Loss of Mains Detection

The configuration in Drynoch may create problems with the detection of a loss of mains. In case of a loss of mains or grid failure, different scenarios are to be distinguished:

1. Fault with short circuit (either 1-phase, 2-phase or 3-phase): This kind of fault is typically accompanied by a high requirement for (short) circuit currents which must be supplied (by the islanded storage system). Respectively, also the voltage level of the remaining grid drops.
2. Disconnection of the mains via an external breaker (not within the scope of the substation).
3. Depending on the position of disconnection – and the loads which are connected in addition to the regular loads downstream of the substation – there may be no high currents drawn from the islanded storage system (zero export / import scenario). This results in a risk that the seamless feature of the BESS does not allow a dead bus detection which then results in the BESS Inverter powering the entire “dead bus” – including the external part of the transmission line.

Given the different possible scenarios for loss of mains, various methods can be used to detect this status. For certain scenarios some of the methods can already clearly detect this. Depending on the system architecture or type of loss of mains a combination of multiple detection mechanisms gives a clear result. Some typical potential approaches are described below:

Monitoring of exported currents (from substation towards grid) / definition of **overcurrent trip** for the grid coupling breaker.

Rate of change of frequency (RoCoF)

This mechanism appears to work best when there are higher currents – either supply from or to the grid.

Modelling of voltage / frequency bias

The EMS models a voltage or frequency bias to the nominal setpoint voltage of the power converters. As long as the system is connected to the mains, this voltage bias will not have any impact on the system voltage as the mains' capacity is too large to allow any severe change. Once the grid is disconnected, the voltage bias will not be suppressed by the mains anymore – the present voltage bias will be detected by the EMS which concludes the loss/disconnection of mains.

When relying on a dynamic variation of the frequency it should be considered this could result in micro cycling of the battery, whilst a variation of the voltage may only cause an exchange of reactive power between BESS Inverter and grid.

Line Differential Protection (Relays)

In order to detect any interruption of the 33kV power line feeding the substation, it can be equipped with line differential protection equipment. Measurement equipment at the beginning and end of the observed infrastructure measures the currents at both positions and compares them – this results in communication between both units being required. If the current difference is larger than a certain threshold (depending on infrastructure and distance), the line differential protection considers this as a fault and trips respective protective breakers.

Active Signalling

Similar to the comparison of currents between the beginning and the end of a transmission line, it is also possible to inject a signal to the power lines at the beginning of the observed lines. Once a fault happens on the transmission lines, the signal will not be received by the receiving unit – an interruption or fault on the transmission line is then detected.

Remote Monitoring of all breakers / disconnectors of the TN

In order to secure the case of not-fault related disconnection of the mains, one approach can be an automatic or manual transmission of this information to the DNO control room and from there to the substation – which consequently trips the mains coupling breaker. Depending on the information transmission infrastructure in-place this may require seconds to achieve or up to several minutes.

Line Differential Protection and Active Signalling require communication lines alongside the power lines. If this has not been installed during the erection of the transmission lines, those approaches will require additional effort.

For events when scheduled or manual intervention cause a disconnection of the substation, it is recommended to place the system into island mode prior to this measure.

A deeper analysis of the solution to finally use in Drynoch will be done in the Detailed Design phase as it will require the involvement of equipment suppliers.

8.2.10. Single Line Diagram

A simplified version of the single line diagram of the proposed BESS installation is shown in Figure 96 in Appendix 2. A detailed version can be provided by the project team upon request - contact details provided on page 1.

8.3. Split of Scope Between RaaS Provider and DNO

Following the updated BESS design the split of scope between the RaaS Provider and the DNO has been discussed. This is done considering a future business as usually (BAU) roll-out, with specific changes in the RaaS demonstration scheme being highlighted.

For a future BAU roll-out it is expected that in the majority of the cases, a RaaS system would not be located within an existing substation compound. Therefore, there is a natural split of scope, where all equipment and components leading up to the 11kV interconnection between the RaaS system and the 11kV network is in the RaaS Provider's responsibility. This includes the installation and operation of the batteries (incl. all controls and connections), the inverters, the BESS transformer and all auxiliaries as well as the responsibility to secure suitable land and fulfil Principal Designer (PD) and Principal Contractor (PC) roles. The EMS will also be provided and operated by the RaaS Provider with data interfaces being further discussed in Section 9.

For the RaaS demonstration scheme, the batteries and the inverters as well as the EMS will be delivered and operated by E.ON as the RaaS Provider. Due to the RaaS demonstration scheme being located within the primary substation compound it is currently discussed whether it is beneficial for the project to have SSEN supply the BESS transformer to grant the earthing in island mode. This will be decided when further detailing the installation plans.

In order to connect the BESS to the existing 11kV network, a new circuit breaker will be required to connect to the BESS transformer and allow charging of the batteries and correspondingly discharging them to support the network. The integration and design of the circuit breaker into the existing or a new 11kV switchgear is part of the scope of the DNO.

Responsibilities for Principal Designer (PD) and Principal Contractor Roles (PC) during the RaaS demonstration scheme are also under discussion due to the complexity of installing a 3rd party owned and operated system within an existing primary substation. The best solution for a successful implementation of the RaaS project will be selected based on further details on the installation timelines that will be discussed during WP3: Detailed Design.

9. RaaS Operational Considerations

For a successful delivery of the planned Resilience as a Service (RaaS), the following three transitional operational scenarios need to be considered, and are described in more detail in the sections below:

1) Active Islanding: caused by failure of the upstream 33kV feeder, the target is a seamless transition from grid connected to islanded mode, resulting in no discernible interruptions for customers. The islanding would happen automatically through the local BESS energy management system (EMS), after prior activation (or non-deactivation) of the functionality through the Scottish and Southern Electricity Network (SSEN) control room.
2) Resynchronisation: resynchronisation and reconnection of the local 11kV network to the 33kV network through a synchronisation procedure under the control of the local control system, or by intervention from SSEN's control room.
3) Black start: restarting and operating the local 11kV network from the BESS in the event of a total black-out of the 11kV network. The BESS will go through a start-up routine and synchronise to the 'dead' primary bus to restore the 11kV network. The procedure is automatically started by the DNO RaaS Controller.

9.1. Active Islanding Process

The active islanding process is depicted in Appendix 1 Figure 97.

i) The situation is 'normal', Drynoch primary substation is connected to the 33kV network and is supplying the local 11kV network via the primary grid transformer. The BESS is synchronised to the grid at the Drynoch Primary Substation 11kV bus and is supporting some or all of the load on the network.
ii) A failure of the grid occurs (loss of the 33kV feeder)
ii) The EMS within the BESS detects an out of range deviation of the frequency and voltage on the system and trips the grid transformer 11kV circuit breaker (CB), disconnecting the Drynoch primary from the grid, placing the local 11kV network in 'island' mode.
iv) At the same time, the EMS will close the BESS transformer 11kV winding neutral/earth contactor to restore and earth reference to the 11kV network.
v) As the deviation in the system voltage and frequency and opening of the grid transformer CB will occur rapidly and the G99 compliant protection will start to pick up on the deviation in voltage, the BESS Low Voltage (LV) circuit breaker will remain closed, as long as the grid transformer CB has opened within the 2.5s window for the undervoltage setting on the G99 protection relay. At the same time the EMS having detected opening of the grid transformer CB and relays a 'blocking' signal to the G99 protection relay to prevent its further operation with the 11kV network in 'island' mode.
vi) In island mode, the BESS is the single source of voltage and frequency regulation for the 11kV network and supports the full network demand.
vii) The BESS will continue to support the network in island mode until either the grid returns to a healthy state, or the BESS batteries fall below a threshold SOC_{min} value and shuts down.

9.2. Resynchronisation Process

The resynchronisation process is depicted in Appendix 1 Figure 98.

i) When the grid returns, this will be detected by voltage and frequency that are in range appearing on the feeder VT on the grid transformer side of the grid transformer 11kV CB by the EMS.
ii) If the BESS is available for service, the EMS will enable the synchronisation of the BESS Inverter after a dwell time to prove that the grid remains stable.
iii) A signal will be raised to SSEN's RaaS Controller indicating that the grid is available for reinstating and waits for signal from the RaaS Controller to proceed.
iv) Once proceed signal is received, the EMS will match voltage and frequency across the Grid transformer 11kV CB by monitoring across the feeder VT on the 11kV side of the grid transformer and the VT on the primary 11kV bus. When in limits, a 'close' signal will be relayed to close the grid transformer 11kV CB.
v) The BESS will then operate in parallel with the grid, operating as a voltage source with the active and reactive power controlled by the EMS.

9.3. Black Start Process

The black start process is depicted in Appendix 1 Figure 99.

i) If the BESS is off line, and there is a loss of grid due to a failure on the 33kV network feeding Drynoch primary, or the grid transformer 11kV CB trips, then the EMS will instigate a black start procedure under the control of the distribution network operator (DNO), via a DNO operated RaaS Controller.
ii) When the BESS is available, the DNO RaaS Controller will be notified, and a black start initiation procedure will be instigated
iii) The RaaS Controller will trip the two outgoing feeders to the 11kV network supported by Drynoch primary substation
iv) A 'start-up signal' will be relayed from the RaaS Controller to the EMS.
v) The EMS will open the Grid transformer 11kV CB (if it has not already tripped), which in turn will close the BESS transformer 11kV winding neutral/earth contactor to restore and earth reference to the 11kV network.
vi) The EMS will start the first BESS Inverter module and synchronise to the 11kV 'dead bus' in the primary substation via the BESS transformer LV CB (the BESS transformer 11kV remains closed)
vii) The EMS starts up the remaining BESS Inverter modules and signals to SSEN control the BESS is available.
viii) SSEN restores the 11kV network via telecontrol, closing the remote transformers and the two outgoing circuit breakers on the Drynoch primary 11kV bus in a controlled sequence to prevent transient overloading of the BESS as described in Section 6.2.5.
ix) The network is then in 'island' mode.

9.4. Integration of DG into the Operational Scenarios

As described, a total DG Maximum Export Capacity (MEC) of 0.73 MW is expected to be on the Drynoch 11kV network once the RaaS system is commissioned. This section discusses briefly the expected behaviour of the two wind turbines and the planned hydro power plant during the islanding, reconnecting and black start procedures.

For scenarios 1 and 2, the G99 (or G59 if the units have been operating prior to G99 being introduced) compliant protection should not see a disturbance of sufficient magnitude to trip the DG 'off grid'. If this does occur, it is assumed that they will automatically re-connect when the system parameters stabilise and their protection relays re-set. Under black start (scenario 3), the units will stop generation when the 11kV network shuts down. They will synchronise to the network again automatically when power is restored, or under an enable signal from the DNO control room.

Further investigations will have to be made in the Detailed Design phase for the influence of DG on resynchronization and stability during islanded mode, for which more detailed information on the DG is required.

9.5. Additional Protection Associated with Operation

The control system provided by the EMS makes allowance for remote intervention from the SSEN control room, and possibly for manual intervention when there is a need to intervene at site level. Therefore, additional protection has been specified for the points on the network within Drynoch primary substation, where closure of 11kV circuit breakers could result in an unsynchronised close, Resulting in potential damage to equipment or personnel. The additional protection against unsynchronised closure is provided by Check Synchronisation relays (ANSI Code 25C) installed on the Grid Transformer 11kV CB and the BESS Transformer 11kV CB. These relays can be arranged to allow the following scenarios show in Table 13.

Table 13 – Check Synchronisation Logic

Circuit Breaker	Permitted Operation
Grid Transformer 11kV CB	Live Line – Dead Bus Live Line – Live Bus
BESS Transformer 11kV CB	Live Line – Dead Bus Live Bus – Dead Line

The synchronisation 'window' settings will be coordinated with the 'window' settings in the EMS synchronisation controller to ensure that valid synchronisation commands are not blocked by the check synchronisation relays.

9.6. Control Interfaces to the DNO

It has been indicated by SSEN that DN3P or IEC 61850 protocol is to be used for this project. The following section outlines the high level interfaces planned for the integration of the RaaS demonstration scheme, which will be required for the BESS to operate under full compliance with EREC G99. Specific details regarding the integration of control functions will be developed as part of WP3: Detailed Design of the RaaS project.

The required control interfaces are split into interfaces required for compliance with EREC G99 and operational interfaces for the operation of RaaS:

Interfaces for compliance with EREC G99

1. The Active Power output of a Power Generating Module should not be affected by voltage changes within the statutory limits declared by the distribution network operator (DNO) in accordance with the ESQCR.
2. Power Generating Modules shall be equipped with a communication interface (input port) in order to be able to reduce Active Power output following an instruction at the input port.
3. Under abnormal conditions automatic low-frequency load-shedding provides for load reduction down to 47 Hz. In exceptional circumstances, the frequency of the DNO's Distribution Network could rise above 50.5 Hz. Therefore, all Power Generating Modules should be capable of continuing to operate in parallel with the Distribution Network in accordance with the following:
    a. 47 Hz – 47.5 Hz Operation for a period of at least 20 s is required each time the frequency is within this range.
    b. 47.5 Hz – 49.0 Hz Operation for a period of at least 90 minutes is required each time the frequency is within this range.
    c. 49.0 Hz – 51.0 Hz Continuous operation of the Power Generating Module is required.
    d. 51.0 Hz –51.5 Hz Operation for a period of at least 90 minutes is required each time the frequency is within this range.
    e. 51.5 Hz – 52 Hz Operation for a period of at least 15 minutes is required each time the frequency is within this range.

Interfaces for the operation of RaaS:

1. Monitoring of the Grid voltage and frequency from the VT on the incoming (Grid) side of the Grid transformer 11kV CB. (for loss of Grid and synchronisation purposes)
2. Monitoring of the voltage and frequency on the primary substation 11kV bus (via a busbar VT) (for synchronisation purposes)
3. Open and close signals to the Grid transformer 11kV CB (under control of the EMS)
4. Load shedding signal to the DNO control centre for the DNO to open the outgoing 11kV circuit breakers under 'black start' (Scenario 3)
5. Status signal from the DNO control centre that the load shedding is complete
6. Status signal to the DNO control centre that the BESS in synchronised to 'dead' bus on the primary substation main 11kV bus and is ready to accept load.

10. Alignment with Distributed ReStart

The RaaS project engages with other relevant innovation projects and initiatives on an ongoing basis to ensure strong dissemination of findings and knowledge sharing.

One key project in this regard is National Grid ESO's Distributed ReStart project[9]. Distributed ReStart explores how Distributed Energy Resources (DER) in Great Britain can be used to restore power in the highly unlikely event of a total or partial blackout of the national electricity transmission system. It aims to assess the potential and identify the prerequisites for this supply restoration use case.

Within the Power Engineering & Trials (PET) workstream, the grid protection of Distributed Restart Zones (DRZs) is investigated as one of several challenging technical questions. This section provides a summary of the comparative analysis of grid studies undertaken in the Distributed ReStart and RaaS projects.

Background

The RaaS and Distributed ReStart projects explore two approaches to improve security of supply, with distinct use cases at distribution and transmission level. The objectives of the projects clearly align as they work to develop cost effective solutions to network issues which accelerate the UK's transition to Net Zero. Accordingly the project teams are working closely to share knowledge and experience which can inform development of the solutions. By identifying synergies and challenges across network boundaries, this collaboration will support the key principle of open markets which offer opportunities for future flexibility service providers to participate in a range of markets, and allow such solutions to be applied alongside each other.

As part of the FEED Peer Review process, the distinctions between the projects were highlighted as "philosophically different engineering approaches, necessitated by circumstances" to achieve a similar goal. The RaaS project aims to design and size a system to suit the network conditions and enable island operation, whilst the Distributed ReStart project has to engineer an islanding operation around the given capacity of their anchor generators (the DER used to initially energise the network).

Thus, the scope and the methodology of the grid studies undertaken in both projects differ.

As shown in Figure 91, Distributed ReStart considers all voltage levels from LV to 400kV due to the intended extent of the DRZs, while RaaS focusses on 11kV and LV but also includes LV customers. Distributed ReStart uses site specific models of the 33kV voltage level and above and applies generic distribution system models on lower levels. The RaaS project performs site specific investigations on the 11kV network and semi-generic exemplary LV networks. Both protects deliver insights for different scenarios and thereby add value to understand the challenges and potential solutions for black starting and operating islanded sections of the grid.

[9] www.nationalgrideso.com/future-energy/projects/distributed-restart

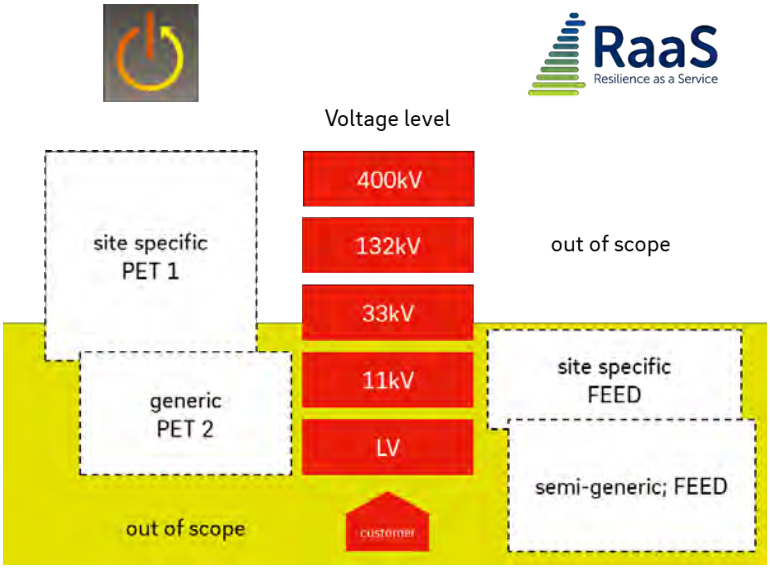


Figure 91 - Comparison of scope for grid studies between the Distributed ReStart Project and the RaaS Project

Similar to grid areas supported by RaaS, DRZs represent intentionally islanded regions of the grid. Both concepts have to ensure adequate grid protection of the HV and LV grids as well as customer installations, while being cost efficient. A use-case specific compromise between acceptable risks, efforts in planning and investments in infrastructure while guaranteeing safety is sought by both projects.

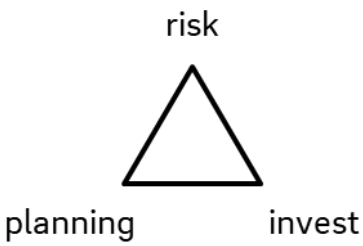


Figure 92 provides an overview of the scope and methodologies of the grid studies undertaken in the Distributed ReStart and RaaS projects. The Distributed ReStart and RaaS protection investigations on the 11kV and LV level also differ in terms of the generator type used for building the grid. Up to the Distributed ReStart PET report - part 2[10], 11kV sites in DRZs are assumed to be powered by synchronous generation as this represents the existing DER technology on GB networks able to create an independent voltage source, as required from an anchor generator. However, emerging Grid Forming Converter (GFC) technology is considered as a possible future option to provide the anchor for a DRZ. Within the RaaS project the 11kV network island is assumed to be solely built and maintained by a GFC as part of a Battery Energy Storage System (BESS). The impacts of GFC controls and their limitations are explicitly considered also in case of asymmetrical grid faults by a specially crafted GFC model in RaaS, which adds further insights to the results generated by Distributed ReStart, applying state of the art standards to investigate far from generator three phase faults.

[10] Distributed ReStart Power Engineering and Trials, 'Assessment of Power Engineering - Aspects of Black Start from DER - Part 2', December 2020, www.nationalgrideso.com/document/182481/download

In terms of methodology, Distributed ReStart aims at identifying fault levels that need to be guaranteed at primary substations inside a DRZ to ensure reliable protection operation for typical and worst case situations. Thereby, detailed site specific 11kV protection investigations may be avoided, which enables efficient planning of the restart process. The methodology of the RaaS project is to define minimal protection performance requirements for the use case and to choose the most cost efficient solution from either designing of the BESS and the GFC to exploit the existing site specific protection or to find the smallest possible amendments of the existing protection to fulfil those requirements.

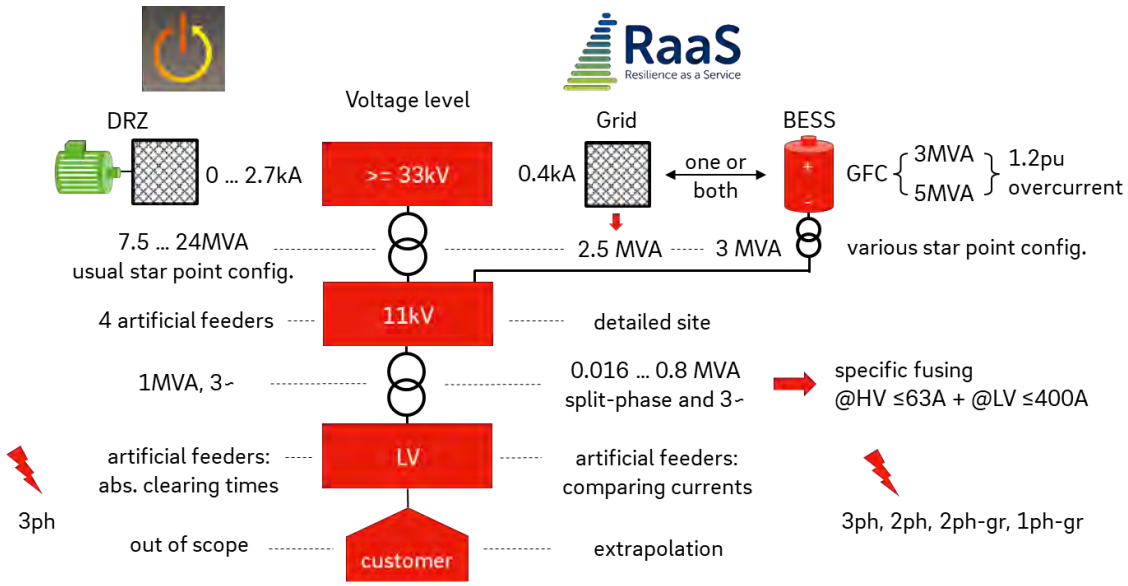


Figure 92 - Scope and methodologies of grid studies undertaken within the RaaS and Distributed Restart Project for 33kV network and below

The RaaS project team has discussed this assessment and the key findings from this FEED report and potential impacts from using GFC with the Distributed ReStart team, and the teams will continue to collaborate on further detailed analysis. Further detailed investigations on the use of GFC will be undertaken in close alignment, as this will be a key topic for RaaS during the Detailed Design stage and also be investigated by Distributed ReStart.

11. Impact of Results on Further Project Activities

The work completed to develop the FEED has highlighted various factors that will require further consideration as part of the further engineering and technical design activities within the project. This ongoing development will also influence and be influenced by activities within WP4 'Operational Optimisation'.

11.1. Impacts on the Detailed Design Phase

As referenced throughout this report both the FEED work and the feedback from external peer review will be used to inform development of the Detailed Design for the proposed scheme. This section summarises the key considerations.

11.1.1. Impacts from Grid Studies

A number of key points of learning have resulted from the grid studies undertaken for the FEED, as summarised below.

Additional, detailed analysis on grid protection and stability using inverter models provided by potential suppliers would be of significant value to better understand the specific BESS behaviour during faults, and the resulting absolute level of fault currents. This has now been considered in E.ON's supplier shortlisting work and incorporated into the Request for Information (RfI) issued to identify a shortlist of potential equipment suppliers. Therefore, the results from this FEED grid study will inform and be the basis for the further analysis conducted in close collaboration with suppliers.

One key assumption during modelling was that perfect synchronism is maintained during faults. This assumption needs to be further analysed in the Detailed Design phase.

The operation of protection systems with DG integration into the RaaS scheme should be further investigated using detailed specifications of the existing and planned DG.

Measures to adapt the existing protection scheme potentially include the incorporation of one or two additional downstream PMCB for high impedance feeder branches. This could offer potential for improved primary protection system performance during RaaS operation.

A more refined understanding of the operation of RaaS on existing assets and grid stress would be of value. This is particularly relevant to thermal loading of the 11kV lines during grid parallel operation of the BESS.

Detailed consideration should also be given to the protection schemes of the largest downstream secondary transformers during island mode, to ensure safe and stable operation of those transformers.

11.1.2. Impacts from BESS Design

The results of this FEED and the requirements for BESS design established through the grid studies will be developed into a functional specification to be used in the Request for Proposal (RfP) process to be run with the shortlisted suppliers identified through the RfI stage. As mentioned above, this will include close collaboration with the suppliers.

One important factor that also will need to be considered with regard to the detailed specification of the BESS is the requirements for and/or design of any new switchgear to be installed by SSEN.

Clear boundaries for the interfaces between systems (inc. DNO & third party assets) and responsibilities during the operation of RaaS are required to ensure safe and stable operation of the grid, and the FEED provides a valuable basis for defining and refining those aspects of system operation. This also applies for the installation and commissioning phase of the RaaS system, requiring clarification of the roles of Principal Designer and Principal Contractor for the on-site works within Drynoch primary substation.

The layout of the demonstration system to be installed at the trial site will be further defined in the Detailed Design work based on supplier responses to E.ON's RfP.

11.2. Impacts on other Work Packages

The findings from this report will also influence (and be influenced) by work undertaken in the other Work Packages, as described below.

11.2.1. Impact on WP4 'Operational Optimisation'

WP4 analyses and models the revenue potential of a third party RaaS asset from participation in additional flexibility markets. Potential outcomes of the work in WP4 may influence the requirements regarding battery sizing in the BESS design. This will also be evaluated in the WP3 'Detailed Design' phase.

Similarly, the Detailed Design and detailed work with suppliers and manufacturers that follows this FEED work will likely influence the ability to provide flexibility services from the RaaS system. Any changes arising from these interdependencies will be highlighted in the future reports in WP3 and WP4.

11.2.2. Impact on WP5 'Business Model'

The results of this FEED report will inform supplier discussions and future procurement of equipment, and the findings from that engagement will inform the cost of installing and operating the RaaS system. This will be reflected in the Investor Business Case, developed as part of WP5.

The risks associated with operating a RaaS system highlighted in this report will also inform the development of the Investor Risk Matrix within WP5, which seeks to understand, categorise and analyse the risks any potential RaaS investor might see in participating in such a scheme.

12. Report Summary and Key Learning for Future Applications

This FEED report has provided a broad overview and extensive insights into the technical challenges and possible solutions associated with the application of RaaS, using the example of the selected potential demonstration site at Drynoch primary substation.

Drawing on the results from the analysis undertaken to develop the FEED, as presented in this report, it can be concluded that the application of RaaS is technically feasible with reasonable adaptations to the existing network. To further detail these requirements and ensure a safe and stable operation of the RaaS system, more work and more detailed analysis will be undertaken in the upcoming WP3 'Detailed Design' stage.

12.1. Summary of the FEED Report

The goal of the FEED report was to identify and discuss the key challenges of implementing a RaaS solution into an 11kV network and to propose potential solutions that may be applicable for a wide range of different sites, and to provide detail on the potential design of a RaaS solution for the selected trial site of Drynoch primary substation.

To do this, a broad range of data was provided by SSEN, information was extracted from applicable codes and standards, and key assumptions were discussed and agreed. This information was used to undertake extensive quantitative grid studies to analyse the existing protection performance under various scenarios, and to analyse a potential black start situation.

This analysis supported the identification of options for the adaptation of the existing protection system on the Drynoch 11kV network, based on analysing various options that will also be applicable in various other network locations. This highlighted that the ENA requirement for grid operation to have two means of remote backup protection in islanded mode cannot be achieved fully with the concepts investigated in this study, therefore this requires further measures to be investigated by the DNO for application to network protection requirements and settings, or potentially may require a change to the definition of the requirements to accommodate a RaaS solution.

To safely black start the network additional measures have been identified, where a sequential switching of individual grid sections would be required together with the use of controlled Point on Wave (PoW) switching of the main Circuit Breakers. This combination is expected to be able to contain the expected in-rush currents from secondary transformers within a level that can be accommodated by the BESS.

Requirements for the design of the BESS for the RaaS demonstration scheme at Drynoch primary substation have been developed based on the grid studies. These highlight the need for a minimum BESS inverter capacity of 5MVA, as well as a short term peak load provision of up to 120% of the nominal rating for all BESS components.

Further, the BESS sizing analysis introduced in the Site Selection Report indicates that the required usable energy capacity to meet an assumed RaaS resilience requirement of covering 90% of all 4-hr outages in a year, has been calculated to be 3.5 MWh for Drynoch.

With the requirements for the BESS design and further necessary adjustment factors to transform the required usable BESS energy capacity to an installed BESS energy capacity, the BESS specification was

subsequently set at 4.2MWh / 5MVA with a 3MVA BESS transformer, and a first design proposal was developed for this configuration. Alongside this, the requirements for the earthing arrangements and for the BESS protection requirements have also been considered.

After developing the initial BESS design, operational considerations for RaaS were discussed amongst the project team, with a focus on a definition of the transition modes between grid connected and islanded operation, and on the black start scenario. The integration of DG was also addressed, as was the need for additional protection associated with RaaS operation and the required control interfaces with the DNO for compliance with G99. This illustrates the need for the BESS EMS to manage the transition into and out of islanding mode to provide the speed of response required to provide a seamless transition for resilience. Adding to this, the DNO Control Room will retain the option to disable the RaaS system and deactivate the transition capability. Similarly, algorithms, embedded within the DNO Control Room would be required to actively manage the black start procedure to control the safe ramping up of the network and maintain the in-rush currents of the secondary transformers on a level that can be provided by the BESS.

In addition to the technical development of the FEED, a review of relevant innovation projects has been undertaken to clearly establish how the RaaS project can interact and share learning with other industry initiatives. The FEED has also been issued for peer review to invite questions, challenge and insight from a range of external stakeholders. All feedback received will be used to inform development of the detailed design for the proposed scheme, and help ensure that what's developed through the project is as broadly applicable as possible across different network locations.

12.2. Key Learning for the Future Application of RaaS

The following points summarise key learning from the work undertaken to develop the FEED. In addition to supporting development of the RaaS concept, these points may have relevance for similar projects in the future.

- Based on the BESS model created for this analysis, the system fault behaviour is likely to deviate from conventional grid operation during islanded mode of operation. This will be relevant in establishing requirements for protection systems and settings, system design, and verification when assessing the use of existing protection systems, or utilising additional or adapted protection concepts other than unit-protection.
- The tools and models necessary to undertake the analysis required for the design of a RaaS solution may need to be created individually for each location where a RaaS solution is being considered. Similarly, little guidance is available for efficient execution of such simulations, resulting in high dependency on the expertise of key individuals. Furthermore, specific and detailed data is required to conduct meaningful studies, and this data and associated assumptions need to be carefully examined and discussed with regard to validity.
- Voltage and current based protection criteria applied for RaaS are highly site specific and should be investigated in detail for individual sites with regard to their efficiency and reliability.
- A well-informed and representative network model of a distribution system could enable the efficient design of a BESS system for resilience and could help to avoid increased cost and risks during operation.
- Deviations from the standard G99 requirements would be required for earthing and Low Voltage Ride Through for the operation of RaaS. These can be granted by the responsible DNO.

I. List of Abbreviations

AC	Alternating Current
AVC	Automatic Voltage Control
BaU	Business as Usual
BCP	Battery Combiner Panels
BESS	Battery Energy Storage System
BMS	Battery Management System
CBA	Cost Benefit Analysis
CDM	Construction Design and Management Regulations 2015
CI	Customer Interruptions
CML	Customer Minutes Lost
DAR	Delayed Auto Reclose
DC	Direct Current
DER	Distributed Energy Resources
DG	Distributed Generation
DNO	Distribution Network Operator
DoD	Depth of Discharge
DSM	Demand Side Management
DSR	Demand Side Response
EHV	Extra High Voltage (>=33kV)
EMS	Energy Management System
FEED	Front End Engineering Design
FFS	Firefighting System
FSP	Full Submission Proposal
FRT	Fault Ride Through
HGV	Heavy Goods Vehicle
HV	High Voltage (>1kV & <33kV)
HVAC	Heating, Ventilation and Air Conditioning
IIS	Interruptions Incentive Scheme
LoM	Loss of Mains
LTDS	Long Term Development Statement
LV	Low Voltage (<1000V)
MEC	Maximum Export Capacity
MVA	Mega Volt-Amps
MW	Mega Watt
MWh	Mega Watt-Hours
NG ESO	National Grid Electricity System Operator
NIC	Network Innovation Competition
OHL	Overhead Lines

P2/7	Engineering Recommendation P2/7 - Security of Supply
PC	Principal Contractor
PD	Principal Designer
PCC	Point of Common Coupling
PCS	Power Conversion System
PoW	Point on Wave
RaaS	Resilience as a Service
RfI	Request for Information
RfP	Request for Proposal
RMS	Root Mean Square
SHEPD	Scottish Hydro Electric Power Distribution
SSEN	Scottish and Southern Electricity Networks
UPS	Uninterruptable Power Supply

II. Appendix 1 – Figures and Tables

a. Grid Studies

i. 33kV Grid

Table 14 - 33kV grid data

Aspect	Symbol	Value	Unit	Basis	Source
33kV connection	-	Single radial feeder from Portree	-	-	Drynoch Primary SLD SHEPD Long Term Development Statement (LTDS)
Protection of incoming 33kV CB	-	Set of 'spare' class PX current transformers upstream of circuit breaker Set of 'spare' class 5P10 current transformers downstream of circuit breaker. No further protection for incoming 33kV circuit breaker assumed within substation	-	-	Drynoch Substation SLD Drynoch 33/11kV Substation Protection Settings
Neutral voltage displacement protection	-	Provided via Yy 19,050/110V transformer	-	-	Drynoch Substation SLD Drynoch 33/11kV Substation Protection Settings
33kV maximum short circuit level	SK'' X/R	20.5 3.02580	MVA -	- -	SSEN Project Team

ii. 11kV primary substation

Table 15 - Primary transformer data

Aspect	Symbol	Value	Unit	Basis	Source
Vector Group	-	Yyn0	-	-	SSEN Project Team
Internal Delta Winding	-	none	-	-	SSEN Project Team
Rated Power	Sr	2.5	MVA	-	SSEN Project Team
Short circuit impedance	uk	6.84	%	-	SSEN Project Team
Short circuit impedance, real part	ukr	2	%	-	D. Oeding, B. R. Oswald: "Electrical Power Plants and Grids"
Zero-sequence impedance	uk0	3	pu	uk	Assumption, worst case for given vector group, agreed with SSEN
Idle current	i0	1.2	%	Ir	D. Oeding, B. R. Oswald: "Electrical Power Plants and Grids"
No load Losses	pFE	5	kW		D. Oeding, B. R. Oswald: "Electrical Power Plants and Grids"
Transformer circuit breaker protection	-	Plain (non-directional) time graded over current and earth fault protection	-	-	Drynoch Substation SLD Drynoch 33/11kV Substation Protection Settings
Transformer protection	-	Restricted earth fault protection connected in neutral/earth line Winding temperature and main Buchholz trip Secondary winding provided with two stage standby earth fault protection (SBEF) No intertripping between 11kV and 33kV CBs	-	-	Drynoch Substation SLD Drynoch 33/11kV Substation Protection Settings
Automatic Voltage Control (AVC)	-	Connected to 11,000/110V feeder VT and CTs on incoming side of transformer 11kV circuit breaker	-	-	Drynoch Substation SLD Drynoch 33/11kV Substation Protection Settings
Protection settings	-	See Table 16	-	-	Drynoch 33/11kV Substation Protection Settings

Table 16 - Primary transformer protection settings taken from SUBSTATION PROTECTION SETTINGS, SUBSTATION: Drynoch 33/11kV, DATE: 20 July 2018, REV: 2

Circuit Name	No	Protection	Abbrev	Relay	CT Ratio	Settings			
						FN	SET	TIME	MVA
11kV VCB	TR1	Overcurrent Earth Fault Trip Relay	20C EF TH	CDG31 VAJY11	400 5		200A 80A	0.25SI 0.35SI	3.8MVA

Table 17 - Earthing and star point treatment data

Aspect	Symbol	Value	Unit	Basis	Source
33kV side transformer star point treatment	-	None	-	-	SSEN Project Team
11kV transformer side NER	-	None	-	-	SSEN Project Team
11kV side star point treatment	-	Solid earth against primary substation earth	-	-	SSEN Project Team
Maximum expectable primary substation earth impedance	-	2	Ohm	-	SSEN Project Team

iii. 11kV grid topology

Table 18 - 11kV grid topology

Aspect	Symbol	Value	Unit	Basis	Source
11kV feeder protection	-	Plain (non-directional) time graded overcurrent and earth fault protection and time graded non-directional standby earth fault protection	-	-	Drynoch 33/11kV Substation Protection Settings
PMCB settings	-	As given in grid mode, incorporating planned telecontrolled PMCB and relay switches Pool Roag and Ben Vatten	-	-	PMCB Settings
Feorling PMCB tripping delay	-	100	ms		Assumption, agreed with SSEN
PMCB telecontrol reclosing in island mode	-	Deactivated, only considering first shot	-	-	Assumption
Positions	-	Various positions of grid components	-	-	Sincal® Model
DG connection to 11kV network	-	Inverter connection under G59/G99 conditions	-	-	Assumption Sincal® Model
Line data	-	See tables below	-	-	Sincal® Model Lecture documentation "Overhead Lines", D. Oeding, B. R. Oswald: "Electrical Power Plants and Grids"

Table 19 – Overhead line values according to the literature and Sincal® Model. Given values from Sincal® Model, new values from Lecture documentation "Overhead Lines".

Mat.	q	C'		C0'	
		given	new	given	new
-	mm^2	nF/km	nF/km	nF/km	nF/km
Cu	all	0	11	0	4.5

Table 20 - The adaptation of given line parameters for lines marked as cables in the Sincal® Model. Given values from Sincal® Model, new values from D. Oeding, B. R. Oswald: "Electrical Power Plants and Grids".

Mat.	q	R'		X'		C'		R0'/R'		X0'/X'		C0'/C'	
		given	new	given	new	given	new	given	new	given	new	given	new
-	mm^2	⍰/km	⍰/km	⍰/km	⍰/km	nF/km	nF/km	p.u.	p.u.	p.u.	p.u.	p.u.	p.u.
Cu	35	0.62	0.53	0.11	0.143	390	230	3	3	3	3	0	1
Cu	45	0.1	0.45	0.4	0.138	0	245	20	3	4	3	0	1
Cu	50	0.1	0.39	0.4	0.135	0	260	20	3	4	3	0	1
Cu	70	0.57	0.27	0.1	0.128	289	295	3	3	3	3	0	1
Cu	95	0.23..0.34	0.197	0.09	0.122	440	330	3	3	3	3	0	1
Cu	150	0.27	0.13	0.09	0.113	382	390	3	3	3	3	0	1

iv. Secondary Substations and Distribution Transformers

Table 21 - Basic parameters for the three phase distribution transformers

Aspect	Symbol	Value		Unit	Basis	Source
		given	assumed			
Transformer type		Three phase				Sincal® Model
Vector Group	-	Dyn11		-	-	Sincal® Model
Rated Power	Sr	100 … 800		kVA	-	Sincal® Model
Short circuit impedance	uk	4.5…4.75		%	-	Sincal® Model
Short circuit impedance, real part	ukr	0…2.025	2.025	%	-	Given values: Sincal® Model Assumed value: assumption for worst case analysis
Zero-sequence impedance, imaginary part	uk0i	0.8	1	pu	uk	Given values: Sincal® Model Assumed value: assumption for worst case analysis
Zero-sequence impedance, imaginary part	uk0r	0.2	1	pu	ukr	Given values: Sincal® Model Assumed value: assumption for worst case analysis
Idle current	i0	0	3	%	Ir	Given values: Sincal® Model Assumed value: assumption based on D. Oeding, B. R. Oswald: "Electrical Power Plants and Grids"

No load losses / Iron losses	pFE	0…0.29	0.3	%	Sr	Given values: Sincal® Model Assumed value: assumption based on D. Oeding, B. R. Oswald: "Electrical Power Plants and Grids"
Saturation	-	Transformers modelled linear without saturation				Assumption
Earthing and star point treatment	-	Solidly earthed against substation earth on LV side No star point treatment on HV side		-	-	SSEN Project Team

Table 22 - Basic parameters for the split phase distribution transformers

Aspect	Symbol	Value		Unit	Basis	Source
		given	assumed			
Vector Group	-	Ii0i6		-	-	Sincal® Model
Rated Power	Sr	16 .. 100		kVA	-	Sincal® Model
Short circuit impedance	uk	4.5…4.75		%	-	Sincal® Model
Short circuit impedance, real part	ukr	0…2.025	2.025	%	-	Given values: Sincal® Model Assumed value: assumption for worst case analysis
Idle current	i0	0	3	%	Ir	Given values: Sincal® Model Assumed value: assumption based on D. Oeding, B. R. Oswald: "Electrical Power Plants and Grids"
No load losses / Iron losses	pFE	0…0.29	0.3	%	Sr	Given values: Sincal® Model Assumed value: assumption based on D. Oeding, B. R. Oswald: "Electrical Power Plants and Grids"
Saturation	-	Transformers modelled linear without saturation				Assumption
Wiring of primary windings	-	Split phase transformers connected to split		-	-	Sincal® Model

		phase feeders on primary sides in between feeder phases			
Wiring of secondary windings	-	Different options possible according to standard SP-NET-SST-010. Actual winding not available in Sincal® Model. Worst case assumption in terms of short circuit current provision for secondary faults is assumed (see a) or c) in Figure 93 - Wiring of secondary windings below)	-	-	SP-NET-SST-010 Assumption

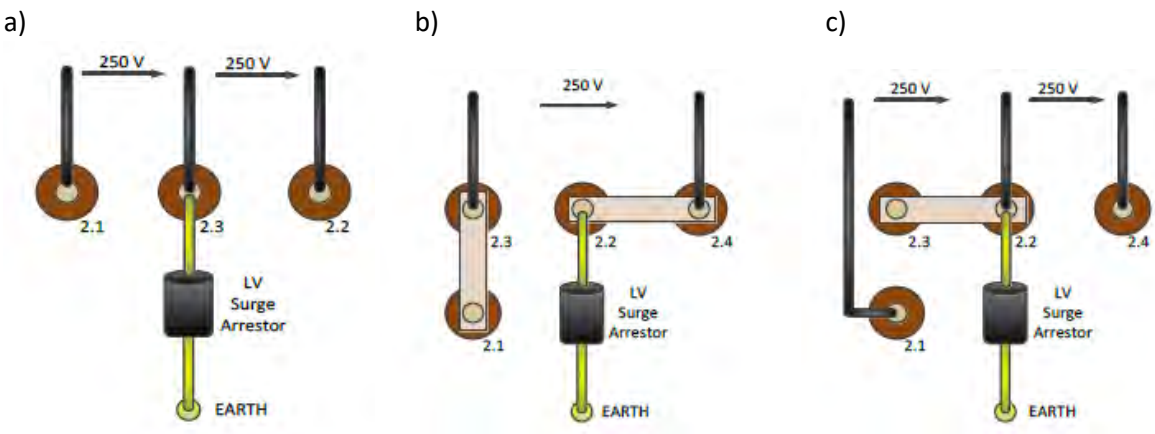


Figure 93 - Wiring of secondary windings

Table 23 – Secondary substation protection system data

Aspect	Symbol	Value	Unit	Basis	Source
HV side Protection	-	HV fuses on primary side with values provided in Appendix 1 Table 24 - Assumed ratings of HV fuses applied at secondary substations Adaptations made to fuses to mirror likely real values.	-	-	TG-NET-SST-005 TG-NET-OHL-005 Assumptions
HV Fuses tripping times	-	Exemplary manufacturer tripping curves (tripping times >10s indicative only) as given in Figure 94	-	-	DRIESCHER Documentation
LV side busbar protection	-	No fuses between secondary winding of transformer and LV busbar	-	-	Assumption
LV feeder protection	-	LV fuses with maximum dimensioning according to Table 25	-	-	TG-NET-SST-005 TG-NET-OHL-005
LV feeder fuse tripping times		According to manufacturer data			SIBA Documentation

Table 24 - Assumed ratings of HV fuses applied at secondary substations

Transformer Type	Sr,Tr	ULL	Ir,TR	Fusing Policy maximum Inom	Fusing_Assumption Inom
	MVA	kV	A	A	A
Split Phase	0,016	11	1,5	20	6,3
	0,025	11	2,3	20	6,3
	0,050	11	4,5	20	10
	0,100	11	9,1	(25) 20	16
Three-Phase	0,100	11	5,2	(10) 20	10
	0,200	11	10,5	(31.5) 20	16
	0,500	11	26,2	(50) 40	40
	0,800	11	42,0	63	63

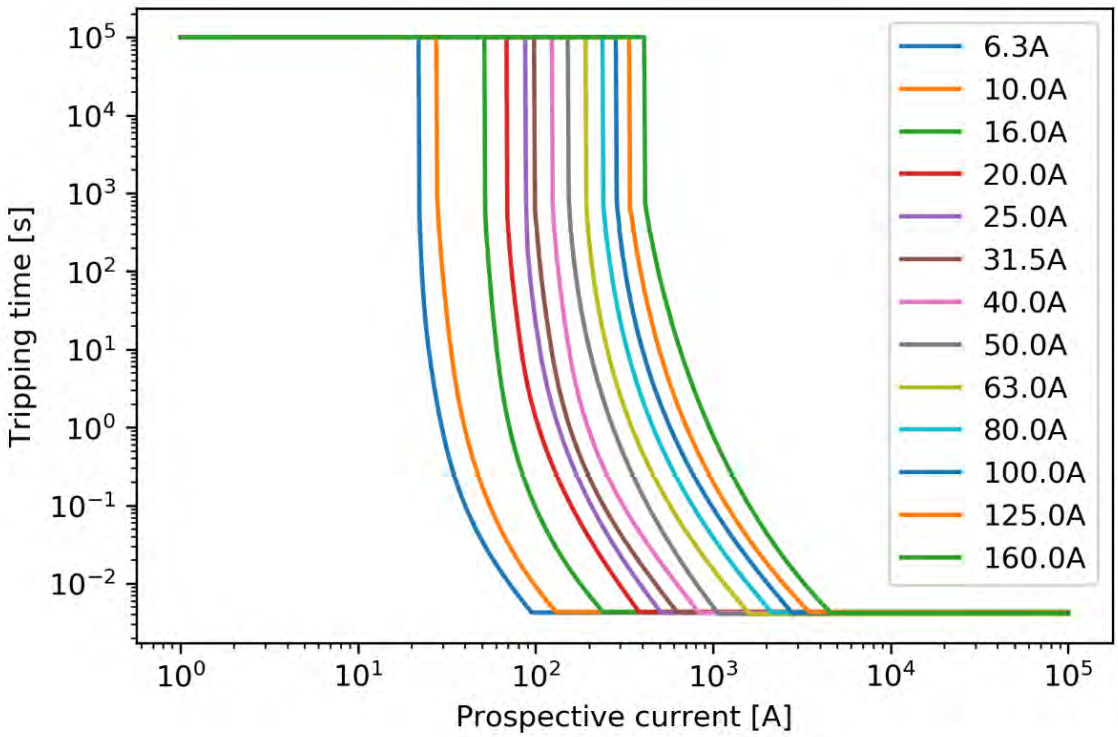


Figure 94 – Exemplary HV fuse tripping curves of the manufacturer assumed in this study

Table 25 - Maximum ratings of LV feeder fuses applied at secondary substations

Transformer Type	**Sr,Tr**	**Fusing Policy maximum Inom**
	MVA	**A**
Split Phase	0,016	100
	0,025	100
	0,050	160
	0,100	315
Three-Phase	0,100	200
	0,200	400
	0,500	400
	0,800	400

v. BESS Transformer

Table 26 - Assumptions for the BESS transformer modelling

Aspect	Symbol	Value	Unit	Basis	Source
Vector Group	-	YNd5	-	-	Assumption
Rated Power	Sr	3.0	MVA	-	Assumption
Short circuit impedance	uk	8.0	%	-	Assumption, typical
Short circuit impedance, real part	ukr	3.33	%	-	Assumption based on literature
Zero-sequence impedance	uk0	1	pu	uk	Assumption, worst case for given vector group, agreed with SSEN
Idle current	i0	0.15	%	Ir	Assumption
No load Losses	pFE	3.8	kW	-	Assumption

vi. Grid Side Inverter

Table 27 - Summary of Grid Side Inverter model parameter values.

Aspect	Symbol	Value	Unit	Basis	Source
Inverter physical output inductance	L	10	%	ZB	Assumption by design
Rated Power	Sr	varied	MVA	-	Assumption by design
Overcurrent capability	imax	1.2	pu	Ir	Assumption by design
Measurements 1st order Low Pass Filter (LPF) time constant	T	0,1	ms	-	Assumption by design
Voltage control, proportional gains per d+q component of positive and negative sequence	kp	5	-	-	Assumption by design
Voltage control, integral gain per d+q component of positive and negative sequence	ki	20	-	-	Assumption by design
Current feed-forward 1st order LPF time constant	T	1	ms	-	Assumption by design
Anti-windup linear gain	kAWU	0.9	-	-	Assumption by design
Anti-windup 1st order LPF time constant	T	1	ms	-	Assumption by design
Current reference limitation 1st order LPF time constant	T	0,1	ms	-	Assumption by design
Converter current control and PWM equivalent model 1st order LPF time constant	T	1	ms	-	Assumption by design

b. BESS Design

Table 28 - Site Selection Summary.

Substation Name	Pros	Cons	Conclusion
Drynoch	- Space for battery within substation compound - Good level of DG (0.93 MVA) - Low risk for delivery and operation - Regular outages to be expected for live testing - E.ON relationship to local businesses	- P2/7 compliant - Low Interruption Incentive Scheme (IIS) - Need to replace existing 11kV switch board and protection	Selected as potential Demonstration Site
Kinloch	- Very High IIS - Long Overhead Lines (OHL) - P2/7 non-compliant - No 11kV back feed - Good space availability - No 11kV switchboard existing - Regular outages to be expected for live testing	- No embedded generation - High risk accessibility on Island for Delivery and Operations	Selected as potential follow-up site for PD8 regarding BAU preparation for a second site
Kishorn Hill	- High IIS - P2/7 non-compliant - Some DG (0.45 MVA) - Proportion of load can be restored via 11kV	- Low number of faults - Short OHL - No space for system - Replacement of complete substation required	Not selected for the project trial
Lochinver	- High IIS - P2/7 non-compliant - Some DG (0.24 MVA) - no 11kV back feed - Good space availability - Regular outages to be expected for live testing	- Possible reinforcement due - Extensive ground and civil works required - Difficult accessibility on site - Difficult connection to 11kV - Housing in close vicinity with potential noise issues	Not selected for the project trial
Mallaig	- High IIS - Long OHL - High number of faults - Good level of DG (0.8 MVA hydro) - Good space availability - Good accessibility - Regular outages to be expected for live testing	- P2/7 compliant - Back-feed possible via Arisaig 11kV circuit - Proportion of load can be restored via 11kV	Not selected for the project trial

i. BESS protection settings

Table 29 - Minimum protection setting for proposed BESS system at Drynoch primary substation

Panel Ref.	Designation	Duty	Current Transformers	Protection and Metering	Control	Voltage Transformers	Comments
TR1	Incomer from 2.5MVA 33/11kV Grid Transformer TR1	630A	400/5 class 5P10	DOC (67), DEF(67N)	Refer to specification for control methodology for operation of the CB in local and remote. Remote control is via the BESS EMS	1. Feeder Connected 2. Busbar Connected	AVC, REF, SBEF and metering in stand-alone panels Check Synch is to prevent out of synch closure under local control. Synch is via the BESS EMS Grid Transformer Main Buchholz (80) and Winding Temperature (26) trip signal to CB
			400/1 class PX	REF (64)			
			150/1 class 5P10	LDC/AVC			
			300/5 class 0.5	Metering and Power Quality Recording			
				Check Sync (25C)			
011	Carbost / Teed Crossall	630A	200/5 class 5P10	OC (50/51), EF (50N/51N), SEF (51NSBY) DAR (79)	CB has Point of Wave (POW) Closing Control is from DNO control		CB is used for load shedding/restoration under Black Start conditions by DNO Control. Refer to EMS specification.
012	Braemeadle	630A	200/5 class 5P10	OC (50/51), EF (50N/51N), SEF (51NSBY) DAR (79)	CB has Point of Wave (POW) Closing Control is from DNO control		CB is used for load shedding/restoration under Black Start conditions by DNO Control. Refer to EMS speciation.
B1	Incomer from 3MVA 0.4/11kV BESS Transformer B1	630A	400/5 class 5P10	DOC (67), DEF(67N)	G99 Compliant Protection (within EMS Container) Refer to specification for control methodology for operation of the CB in local and remote	1.Feeder Connected	Check Synch is to prevent out of synch closure under local control. Synch is via the BESS transformer LV CB BESS Transformer Main Buchholz (80) and Winding Temperature (26) trip signal to CB G99 Protection acts on Transformer LV CB and is blocked in 'Island' Mode
			300/5 class 0.5	Metering and Power Quality Recording			
				Check Sync (25C)			

Key to Protection Relay Codes: OC – Overcurrent (ANSI Code 50/51), EF - Earth Fault (ANSI 50N/51N), REF - Restricted Earth Fault (ANSI Code 64), SBEF - Standby Earth Fault (ANSI Code 51NSBY),

DOC - Directional Over Current (ANSI Code 67), DEF - Directional Earth Fault (ANSI Code 67N), Check Synch (ANSI Code 25C), WTT - Transformer Winding Temperature Trip (ANSI Code 26), Transformer Buchholz Trip (80), AVC – Transformer Automatic Voltage Control

ii. Damage curve of a 3MVA BESS transformer

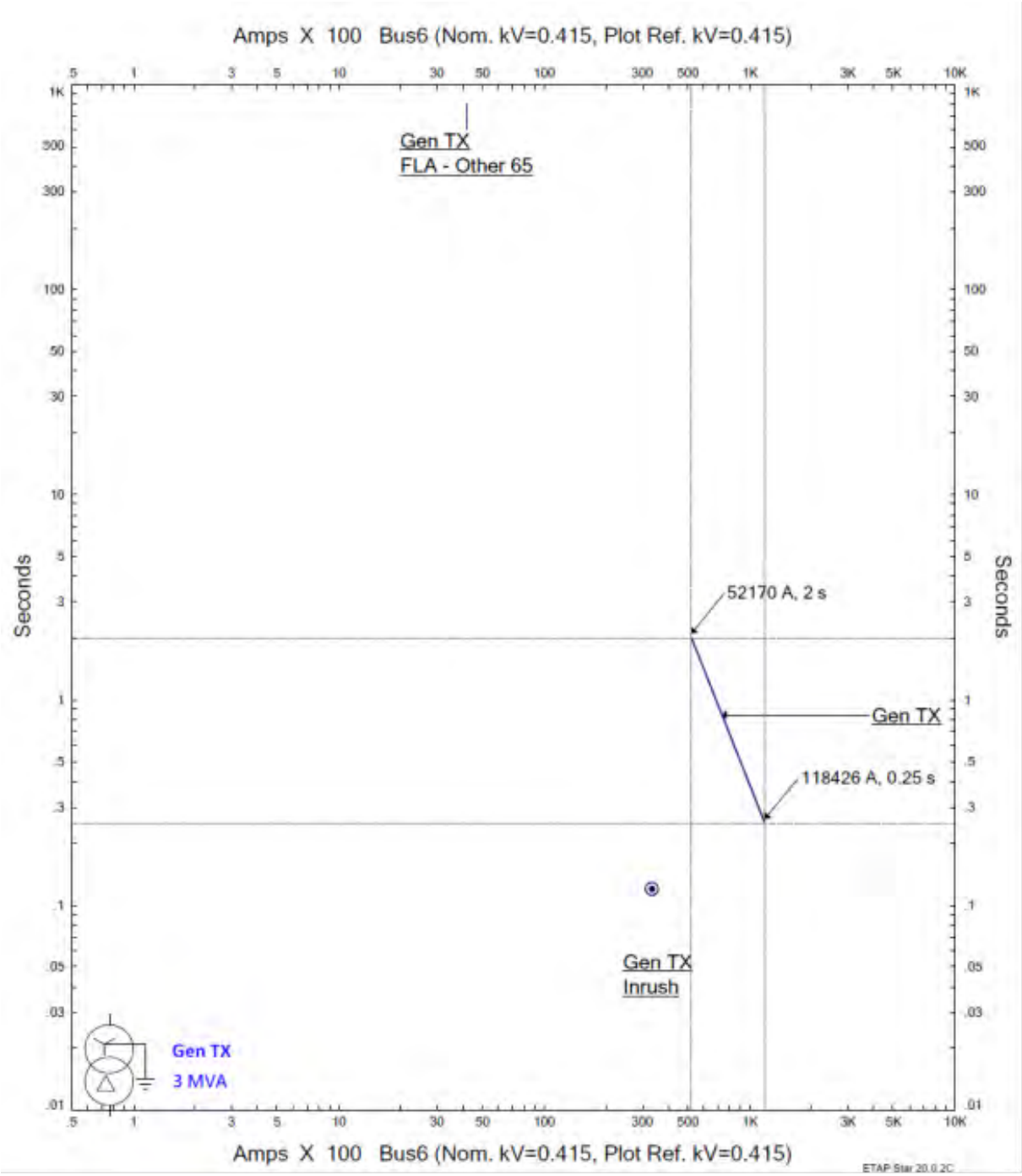


Figure 95 – Damage curve of a 3MVA BESS transformer

iii. BESS Single Line Diagram

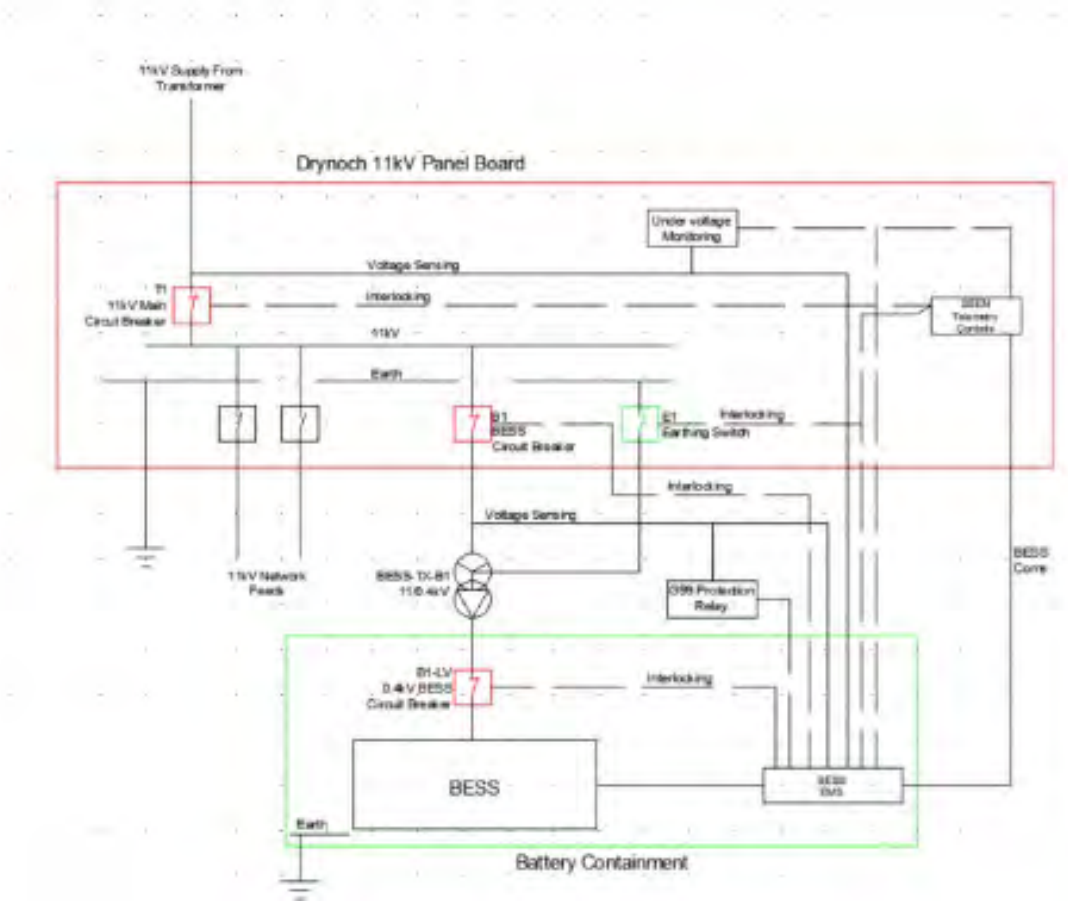


Figure 96 – Simplified Single Line Diagram of Drynoch Primary Substation with BESS

A detailed version of this diagram can be provided by the project team upon request - contact details provided on page 1 of this report.

c. RaaS Operational Considerations

i. Active islanding procedure

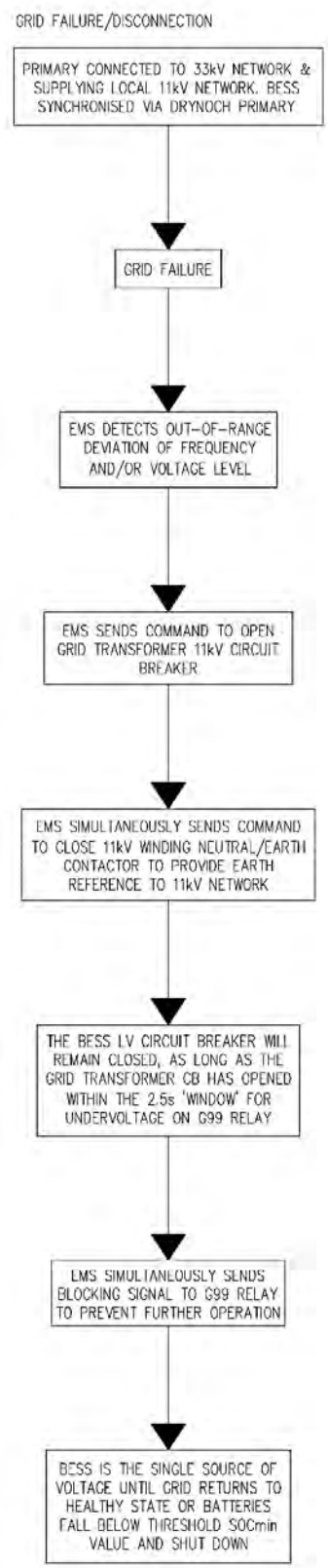


Figure 97 - Active Islanding procedure

ii. Grid return procedure

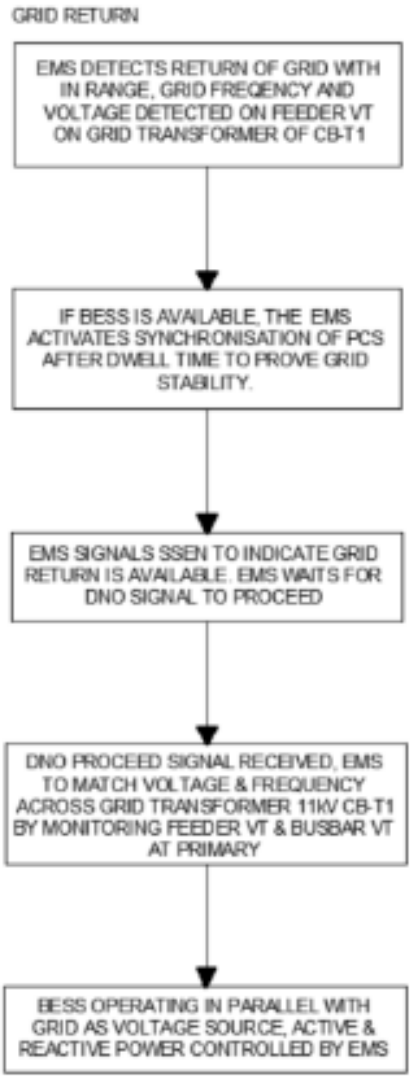


Figure 98 - Resynchronisation process

iii. Black Start procedure

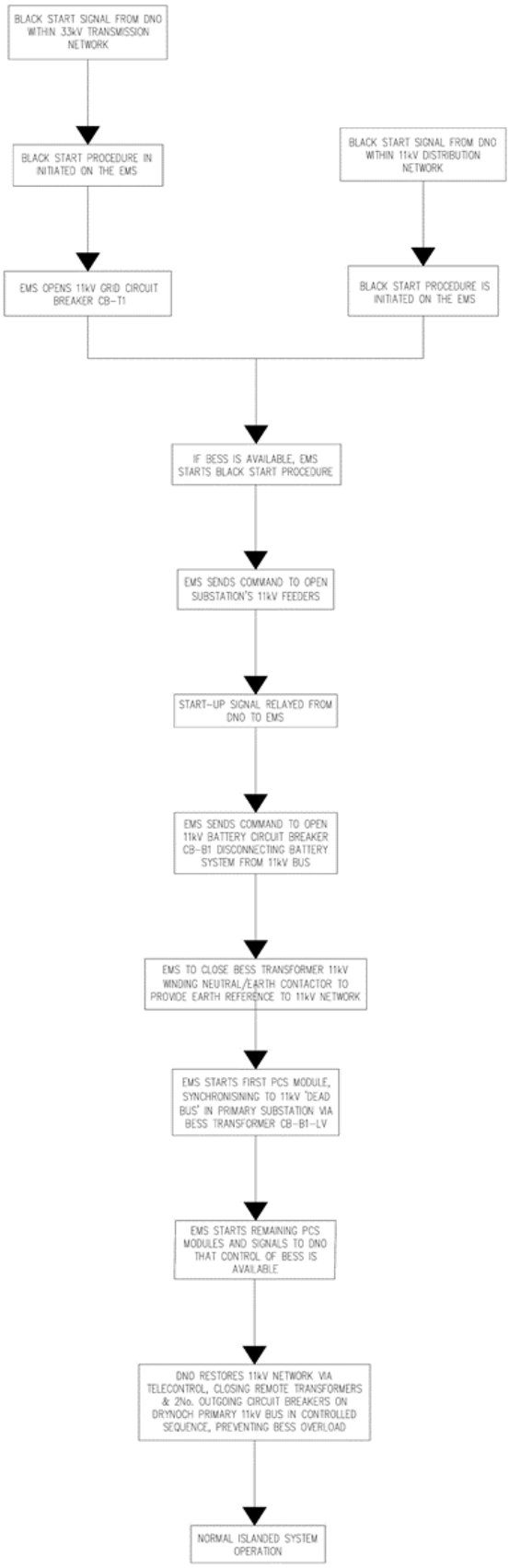


Figure 99 - Black Start procedure

III. Appendix 2 – Adapted and Additional Protection for Islanded Operation

The grid studies have shown that, depending on the BESS inverter rating, different measures may be applied in the protection system in order to achieve the requirements for backup protection during islanded operation. Several alternatives were investigated, and details are shown below.

a. Distributed undervoltage protection

i. 3MVA BESS case

Regarding backup protection by undervoltage, it was previously identified that undervoltage tripping located at the 11kV busbar will not be sensitive to end of line or end of tee for 1ph faults.

Figure 100 and Figure 101 depict the minimum voltages for 1ph faults observed at the busbar and at the more remote locations of the PMCB.

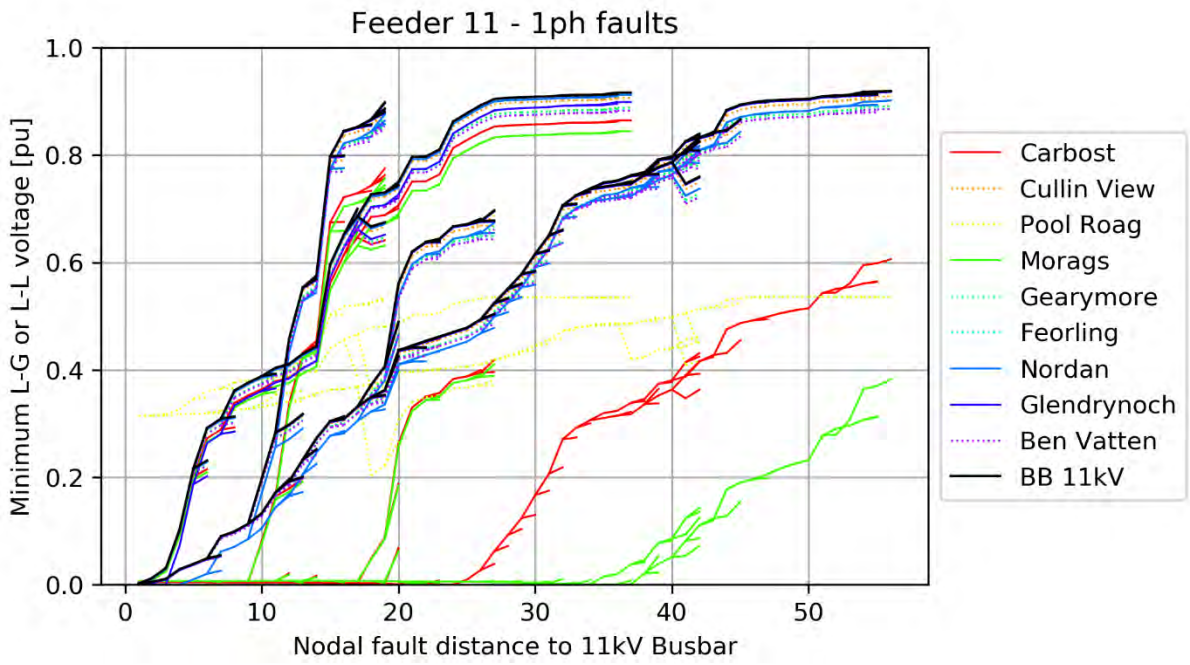


Figure 100 – Minimum voltages for 1ph faults in 11kV Busbar - Feeder 11. 3MVA BESS case

In Feeder 11 significantly lower voltages are observed in the feeder sections hosting the Nordan, Carbost and Morags PMCB, especially for end of line fault in case of the Morags or Carbost PMCB. An undervoltage relay operating the Carbost PMCB is sensitive for all peripheral 1ph faults in its downstream sections for a 0.8 pu setting. The undervoltage insensitive close to busbar tee is not covered by the Carbost PMCB and is neither sensitive when observing the busbar nor the Nordan PMCB due to the latter's close to busbar placement. The same problem applies to the feeder sections protected by the Glendrynoch PMCB. Only an undervoltage sensing located sufficiently further downstream would gain sensitivity for end of line faults.

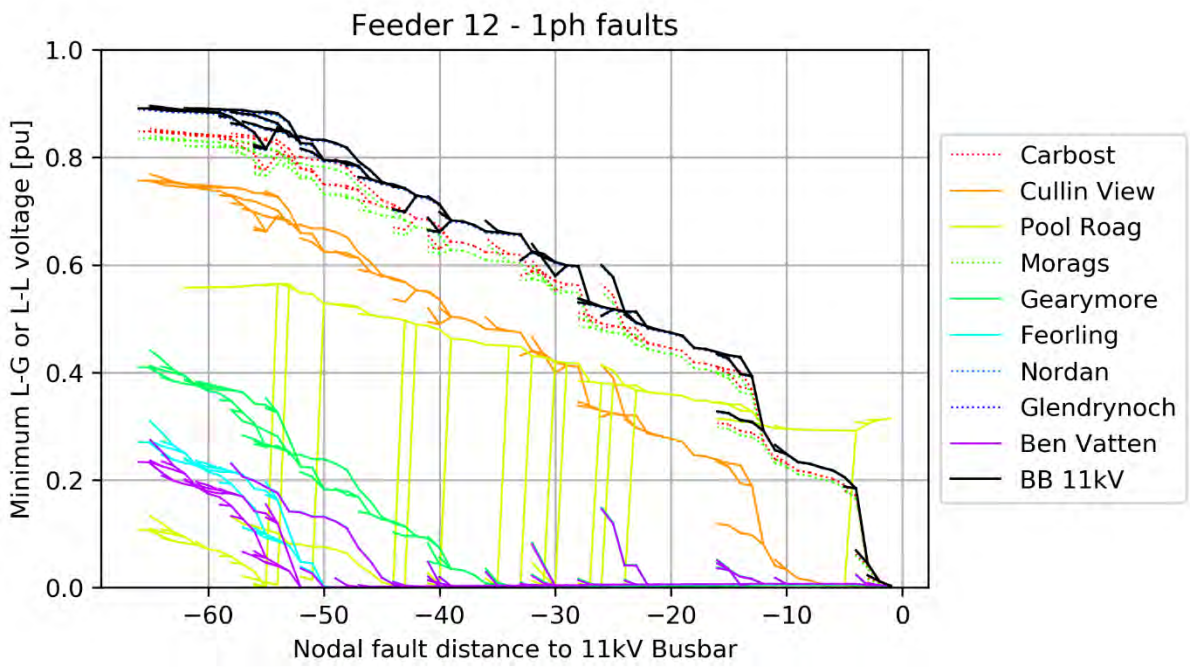


Figure 101 - Minimum voltages for 1ph faults in 11kV Busbar - Feeder 12. 3MVA BESS case

In contrast, all Feeder 12 sections with undervoltage insensitivity at the busbar measurement point may be covered by a sensing at the Gearymore PMCB. The Feorling PMCB could be used to increase selectivity but would not cover one larger insensitivity branch section located further upstream.

Figure 102 shows the lowered remaining insensitivity.

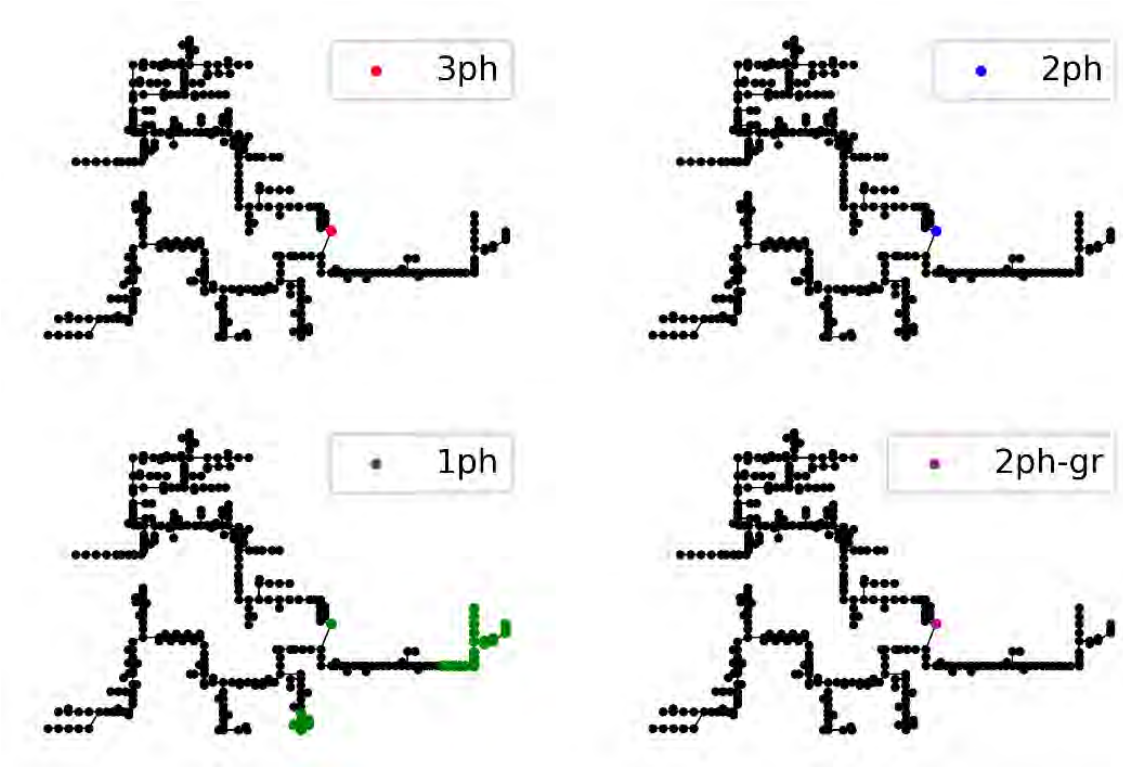


Figure 102 - Regions of no tripping of BESS undervoltage protection for different fault types. 3MVA BESS case

ii. 5MVA BESS case

Figure 103 and Figure 104 reveal that the same qualitative results and performances are obtained at the identified locations in the 5MVA case. The special Feeder 11 cases are again not solvable as discussed before.

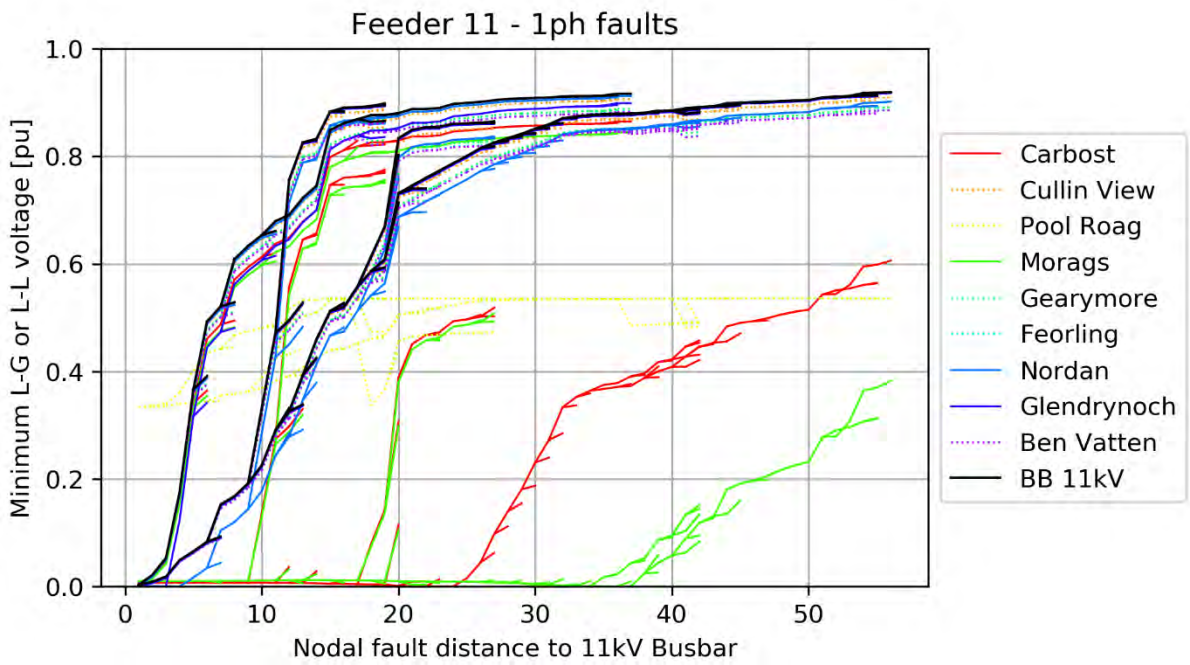


Figure 103 - Minimum voltages for 1ph faults in 11kV Busbar - Feeder 11. 5MVA BESS case

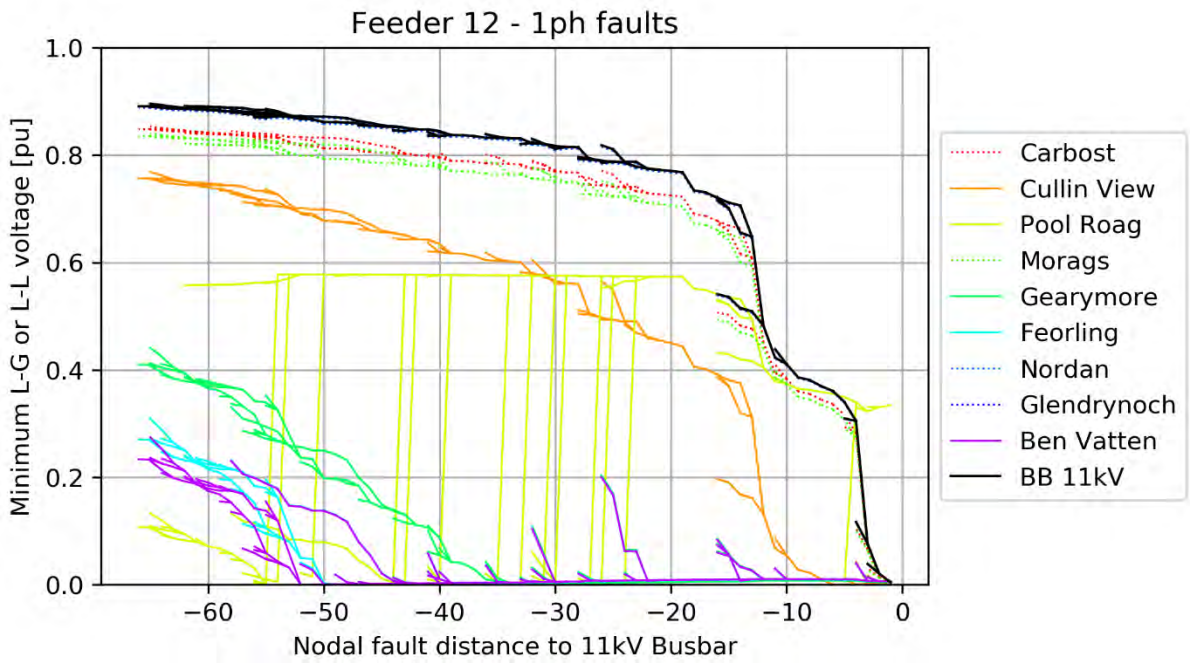


Figure 104 - Minimum voltages for 1ph faults in 11kV Busbar - Feeder 12. 5MVA BESS case

Due to the higher fault currents levels a larger peripheral region of insensitivity of busbar undervoltage protection for Feeder 12 was identified in Section 6.1.3. The distributed voltage sensing achieves an undervoltage tripping coverage as shown in Figure 105.

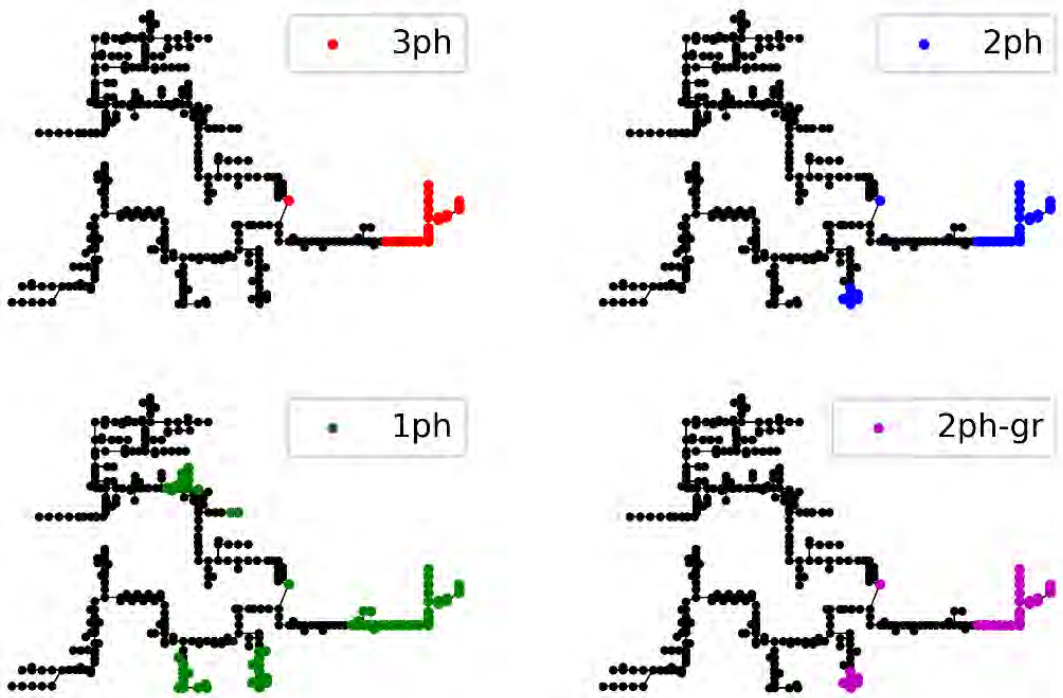


Figure 105 - Regions of no tripping of BESS undervoltage protection for different fault types. 5MVA BESS case

Figure 106 shows the improved sensitivity in the 1ph case for Feeder 12 when applying the option to equip the Culling View PMCB with sensing in order to increase sensitivity.

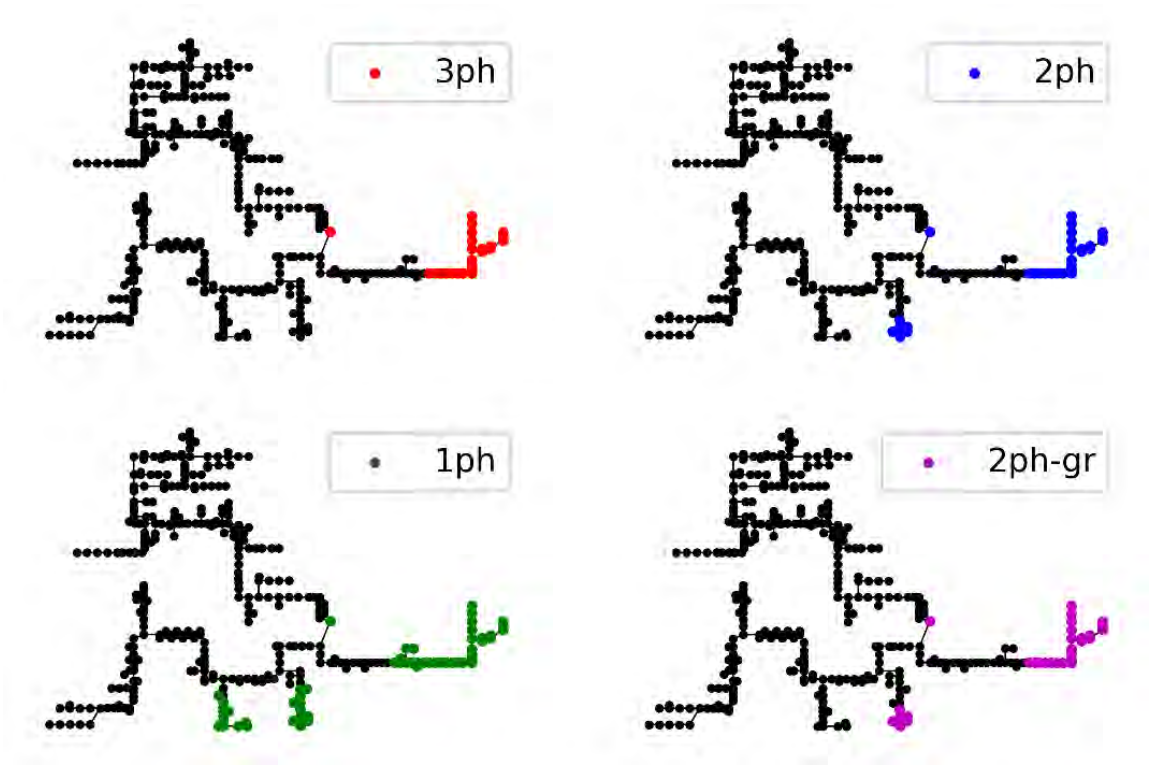


Figure 106 - Regions of no tripping of BESS undervoltage protection, improvement of sensitivity for 1ph faults

Alternative voltage criteria

Further voltage-based criteria were investigated in terms of sensitivity:

- U2 and U2/U1
- U0 and U0/U1

No superior performance was observed in comparison to the undervoltage criterion discussed before. Especially the critical sections are not covered by those criteria, neither when used at the busbar nor at remote locations. Furthermore, nuisance tripping risks would need to be investigated in more detail due to necessary low settings. Figure 107 and Figure 108 show the results obtained by applying voltage-based criteria.

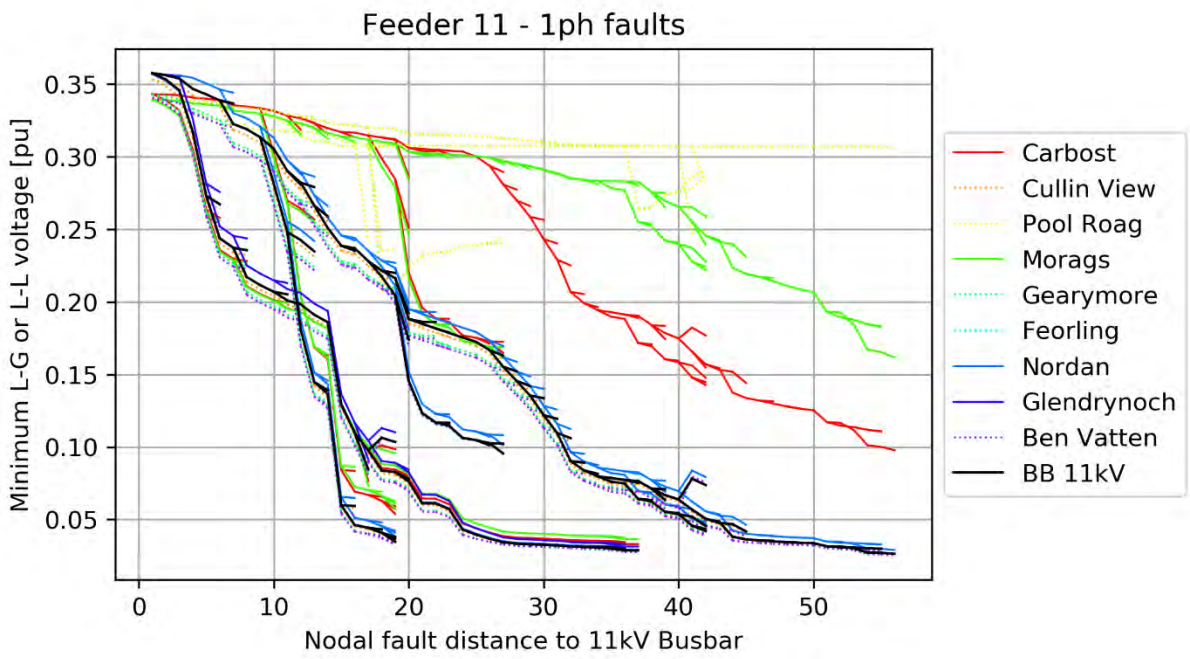


Figure 107 - Minimum voltages for 1ph faults in 11kV Busbar - Feeder 11. 3MVA BESS case, U2 criteria

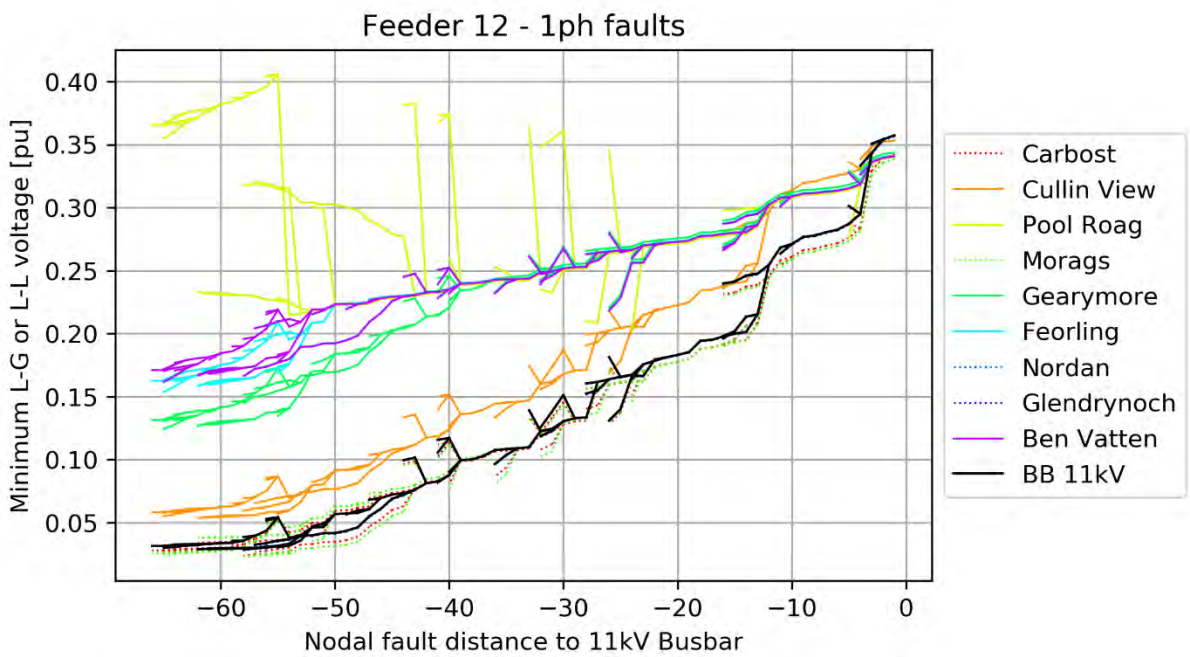


Figure 108 - Minimum voltages for 1ph faults in 11kV Busbar - Feeder 12. 3MVA BESS case, U2 criteria

Figure 109 shows the regions of insensitivity in PMCB Gearymore, Carbost and Culling View with U2>0.1p.u criteria.

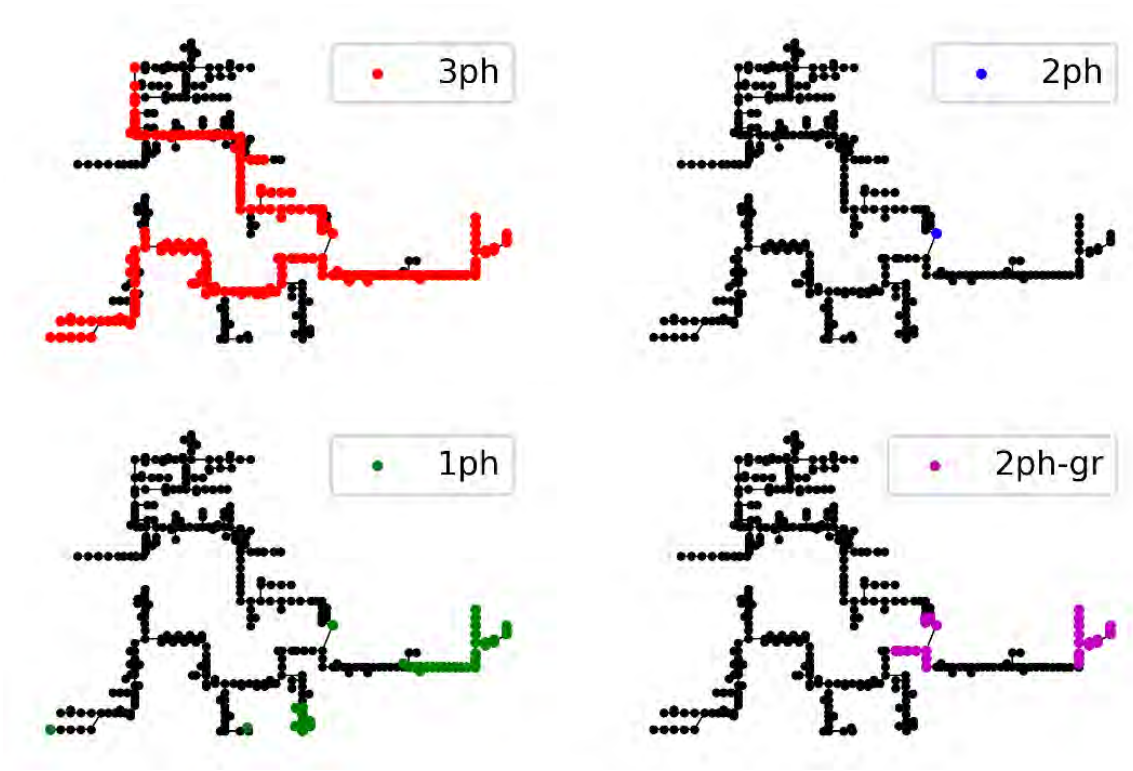


Figure 109 - Regions of no tripping of BESS undervoltage protection with U2>0.1p.u.

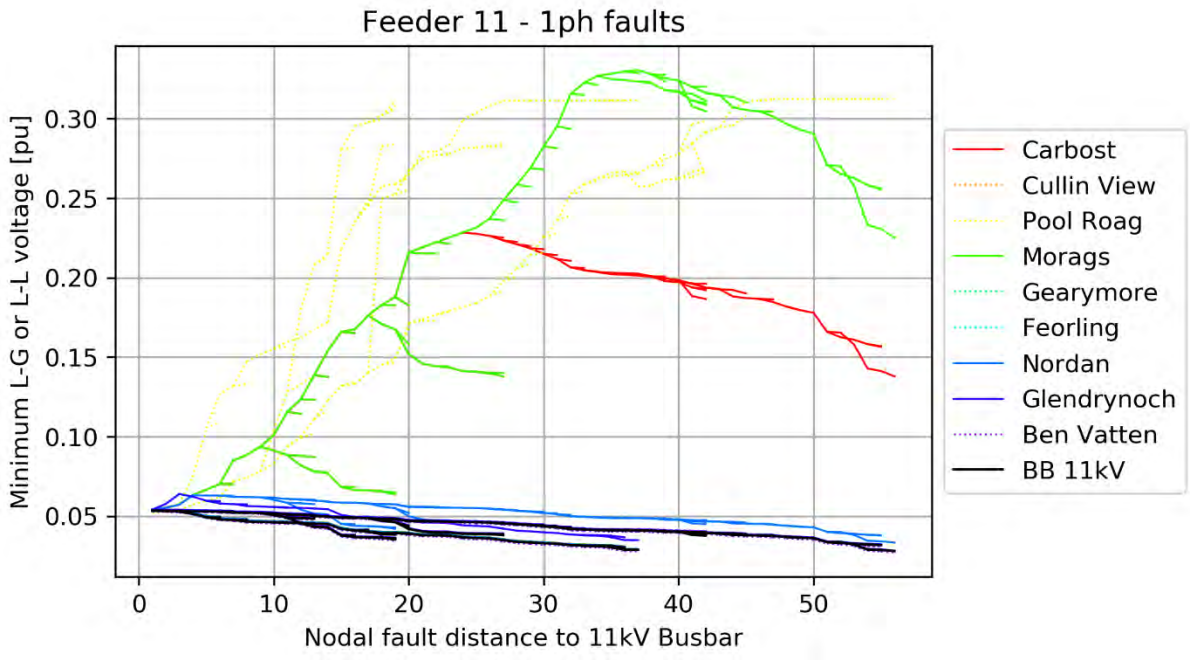


Figure 110 - Minimum voltages for 1ph faults in 11kV Busbar - Feeder 11. 3MVA BESS case, U0 criteria

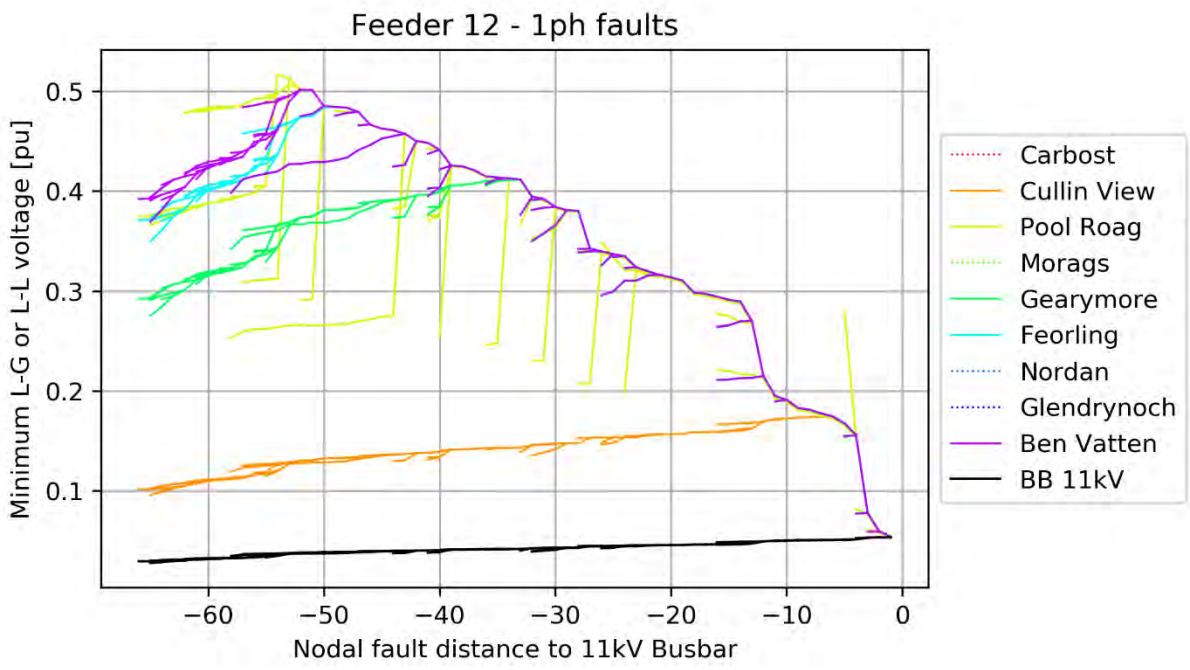


Figure 111 - Minimum voltages for 1ph faults in 11kV Busbar - Feeder 12. 3MVA BESS case, U0 criteria

Figure 112 shows the regions of insensitivity in case only Carbost and Gearymore PMCB with U0>0.1p.u criteria.

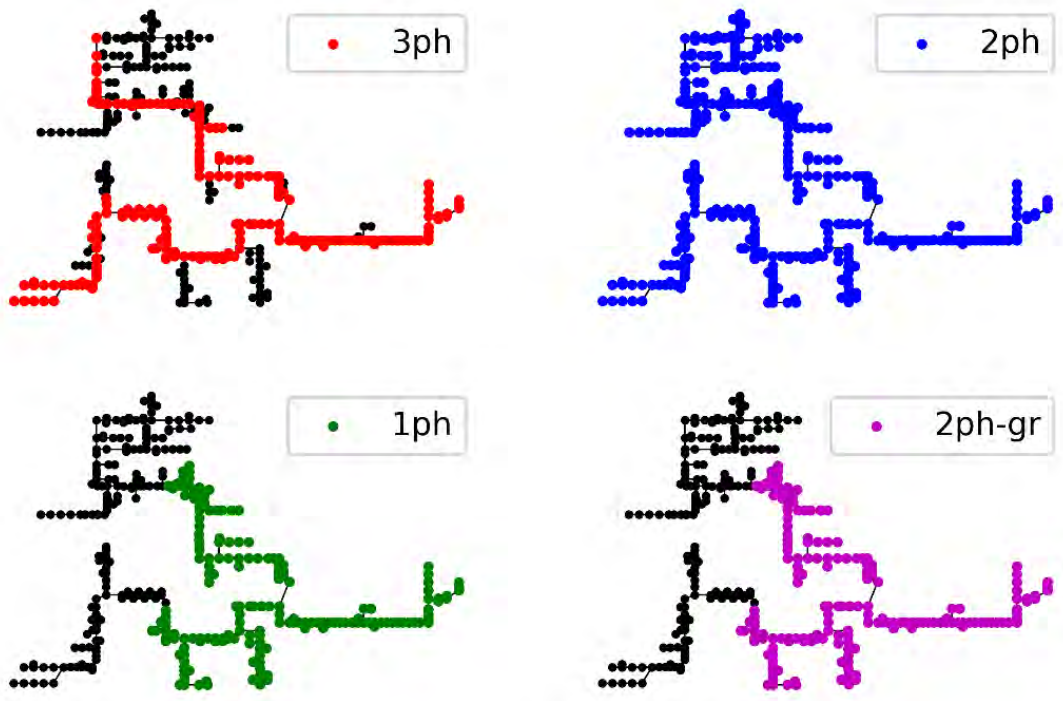


Figure 112 - Regions of no tripping of BESS undervoltage protection with U0>0.1p.u.

Figure 113 shows the regions of insensitivity with additional Cullin View PMCB.

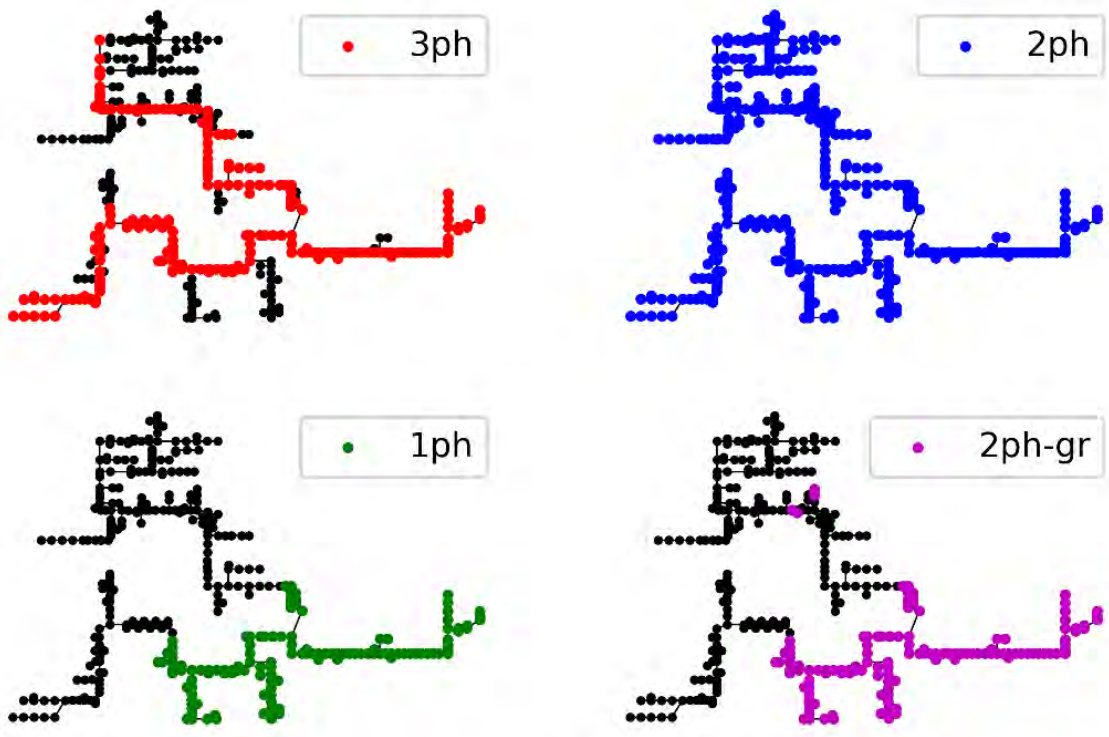


Figure 113 - Regions of no tripping of BESS undervoltage protection with U0>0.1p.u.

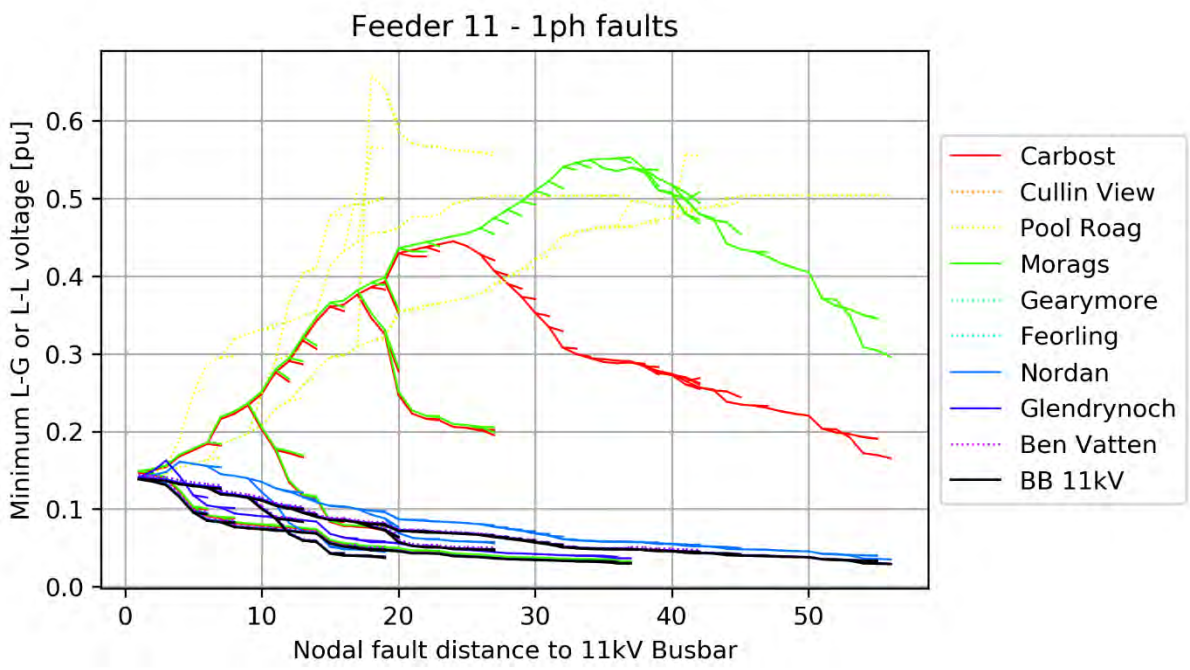


Figure 114 - Minimum voltages for 1ph faults in 11kV Busbar - Feeder 11. 3MVA BESS case, U0/U1 criteria

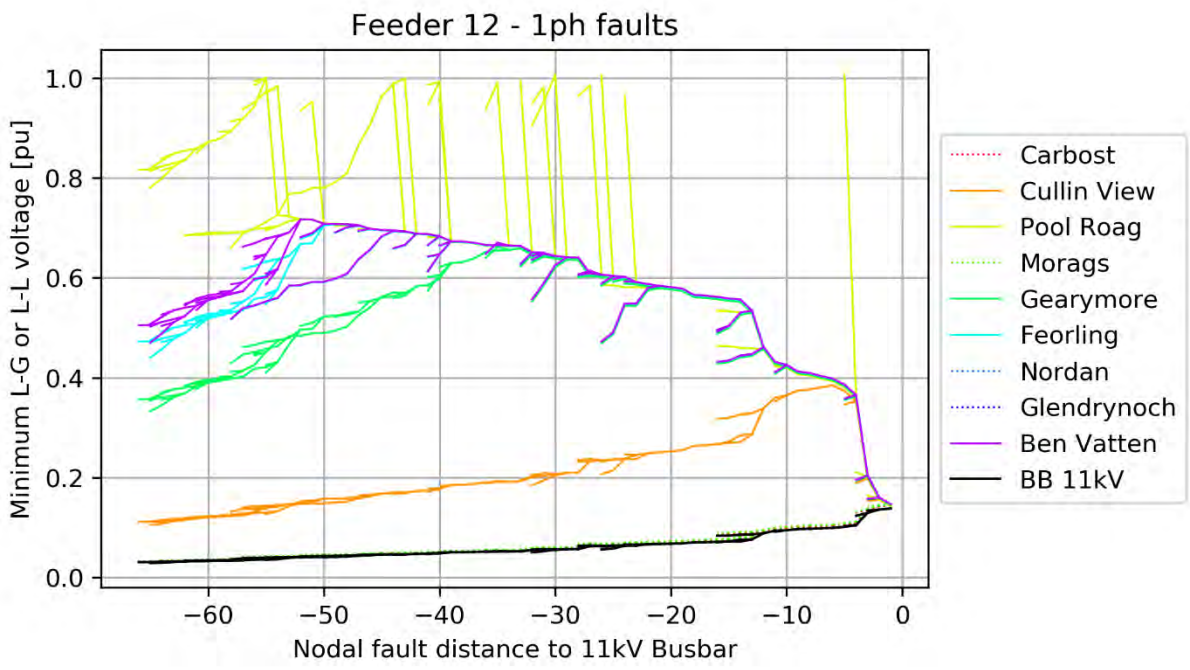


Figure 115 - Minimum voltages for 1ph faults in 11kV Busbar - Feeder 12. 3MVA BESS case, U0/U1 criteria

Additional criteria

Depending on the amount of acceptable nuisance tripping and selectivity additional criteria and grading may need to be added to the triggering conditions.

Goal	Measures
Selectivity at Feeder level U< (main feeder circuit breakers)	minimum current criteria, directional criteria, time grading with BESS U<
Avoid nuisance tripping of feeder CB U< for nearby faults in neighbour feeder	see above
Avoid nuisance tripping of PMCB U< for upstream faults	time grading with feeder + busbar level U<
Avoid nuisance tripping of PMCB U< for nearby faults	minimum current criteria or directional criteria
Avoid nuisance tripping in case of intentional shutdown	minimum current criteria

Conclusions

The sensitivity of undervoltage protection can be increased significantly compared to a BESS level U< only criterion (see Section 6.1.3) by adding according tripping criteria to selected remote PMCB positions.

A full sensitivity of all grid sections is not achievable. Especially one feeder 11 section protected by the PMCB Glendrynoch is not coverable without adding further downstream observations points.

Comparing minimum line-earth and line-line undervoltage tripping to zero-sequence and negative sequence overvoltage criteria does not show a superior performance of the critical regions.

When applying the extended U< concept nuisance tripping may be avoided, and selectivity gained by adding time grading (longer times for the periphery) and minimum current or directional criteria.

b. Feeder based sensitive overcurrent protection

i. 3MVA BESS case

The concept aims at exploiting possible modifications of the main feeder CBs. The active protections functions and settings are assumed to be switched when going to islanded mode and vice versa.

The protection tripping by distributed PMCB is assumed to be deactivated in islanded mode as a starting point and will be discussed later.

A no change of the existing main Feeder CB settings would lead to unacceptable tripping times and 40% of no trips for 2ph faults (at best, ignoring Fault Ride Through (FRT) capabilities of BESS and backup protection) according to Figure 116.

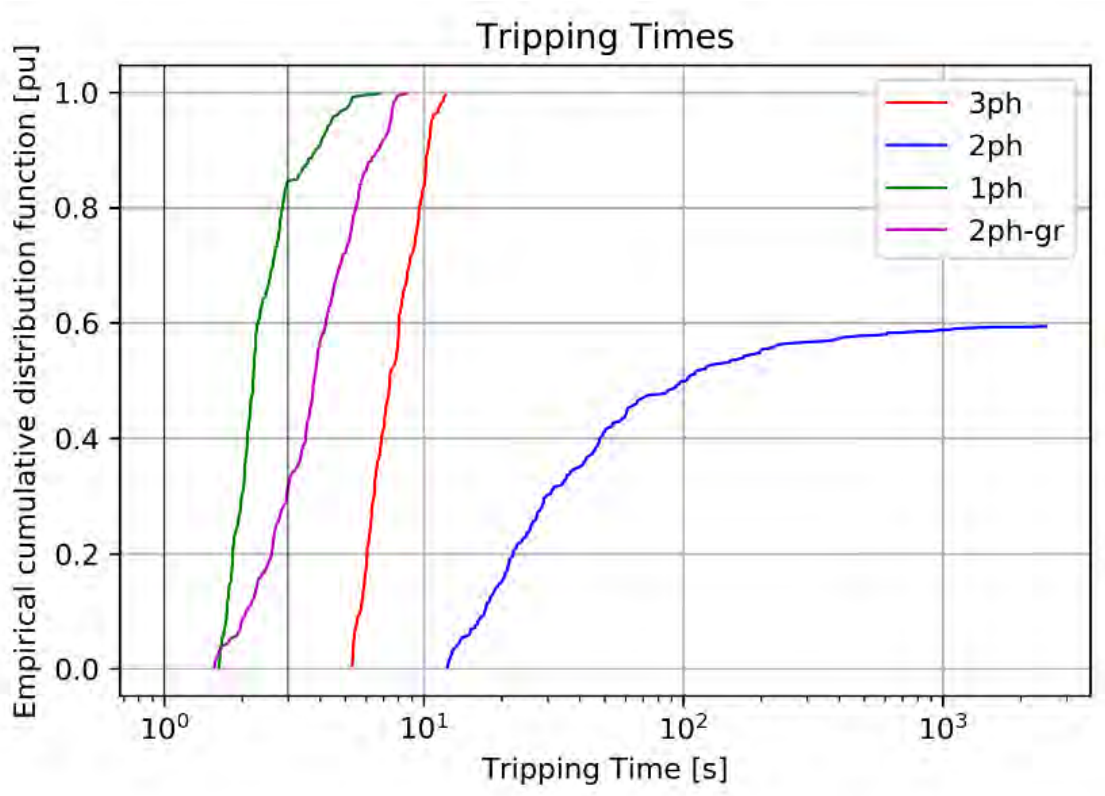


Figure 116 - Tripping time response of overcurrent protection for a 3MVA BESS

Increasing the sensitivity by lowering of 51 function SI threshold current to 120A gains tripping times inside the maximum tolerable range in all cases, as shown in Figure 117.

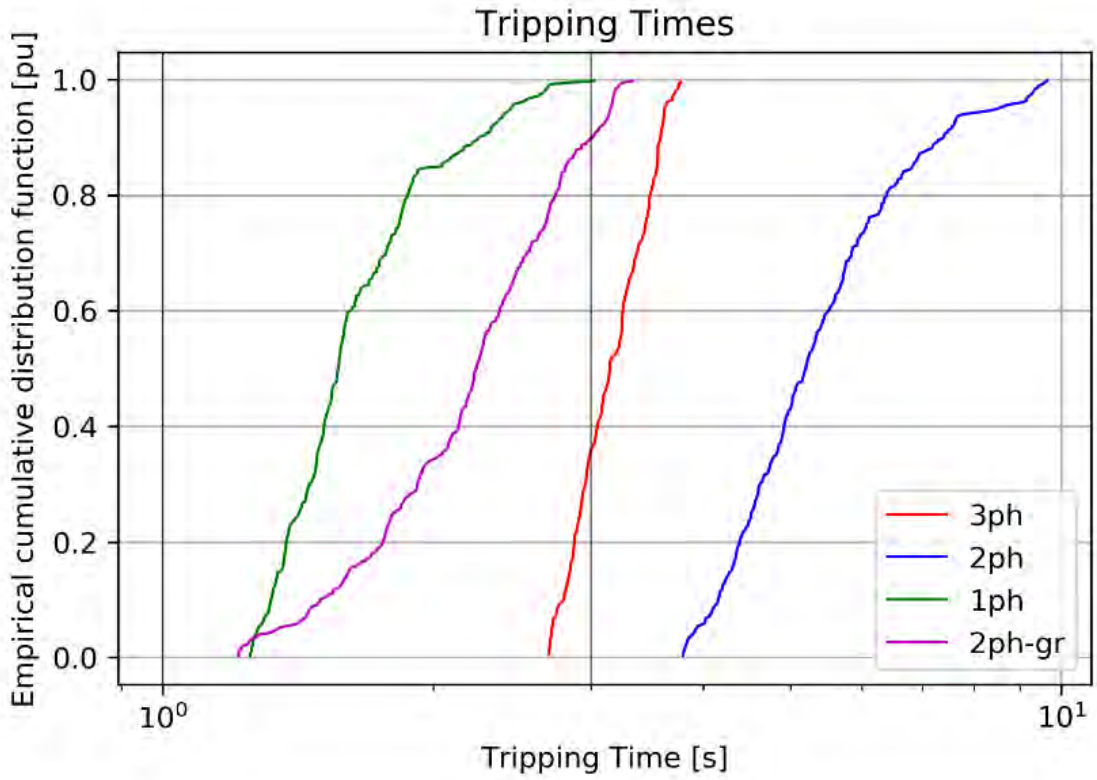


Figure 117 - Tripping time response of overcurrent protection for a 3MVA BESS, SI threshold 120A

Adding a negative sequence current I2 instantaneous tripping function gives an additional degree of freedom in parameterization. Figure 118 shows the I2 current profiles sensed at the feeder CB observation points during different operational scenarios.

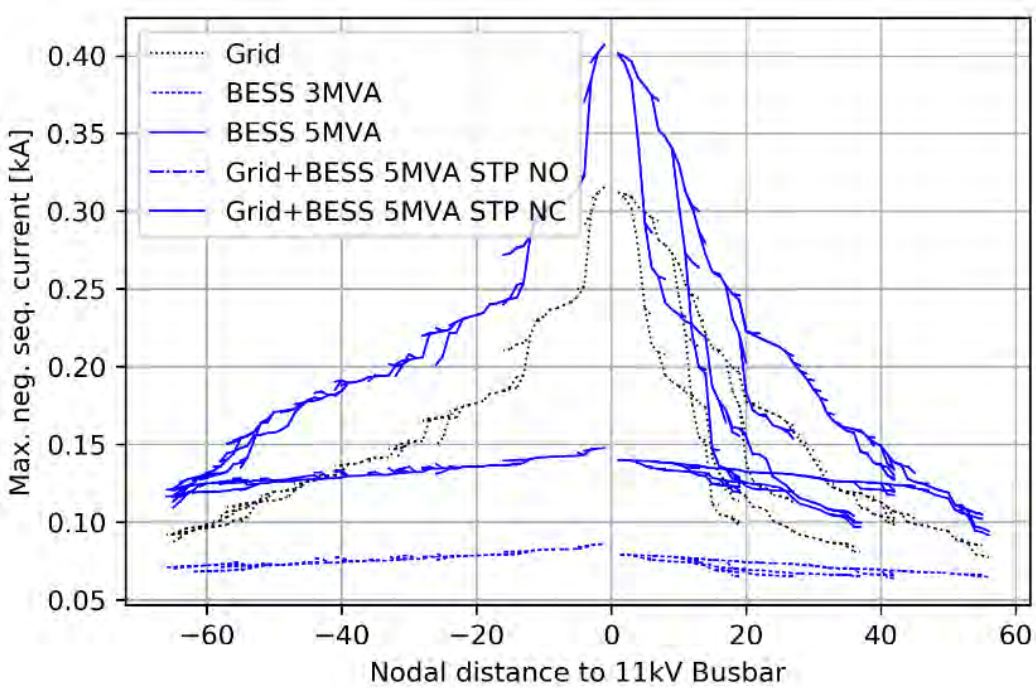


Figure 118 – Maximum negative sequence current for different operational scenarios

The profiles in islanded mode are expectedly flat. In case of the 3MVA inverter rating the profile would not allow for settings higher than 60A.

A further increase in sensitivity of the 51 function to SI threshold currents of 100A and adding an additional instantaneous I2 tripping at 60A with a time delay of 2s results in tripping times according to Figure 119.

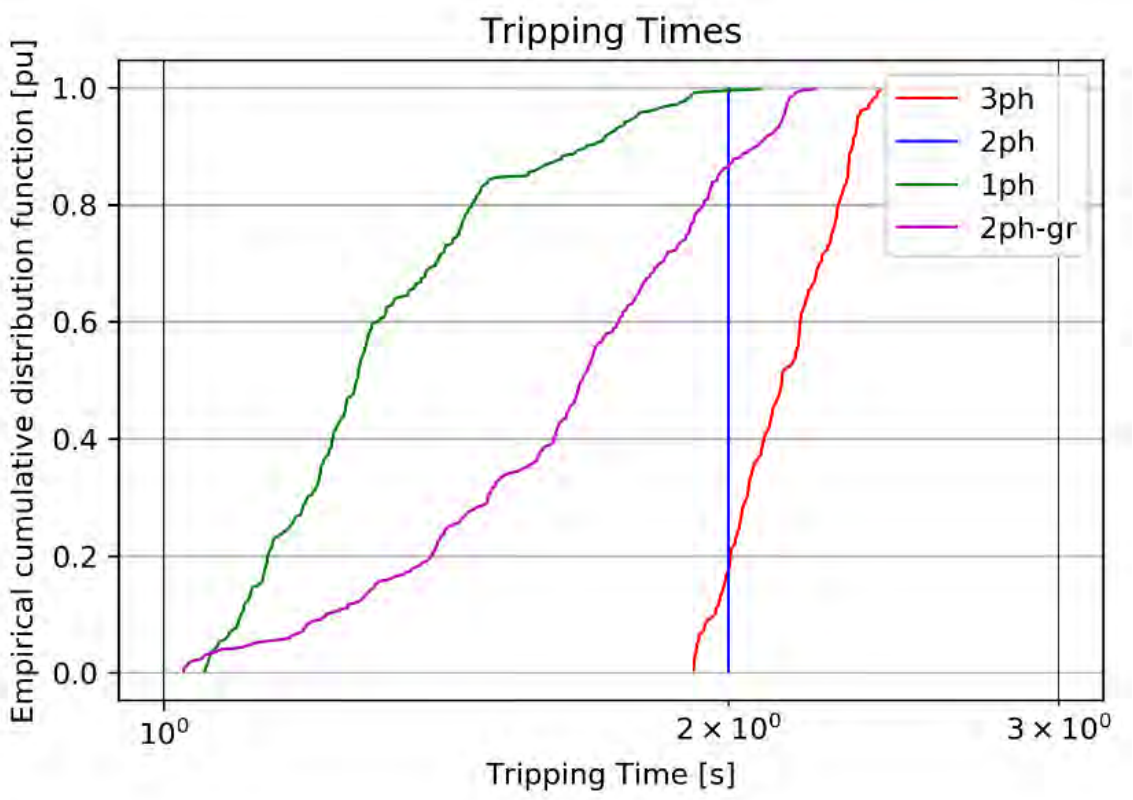


Figure 119 - Tripping time response of overcurrent protection for a 3MVA BESS, SI threshold 100A, I2 tripping 60A and 2s time delay

Assessing these trips thermally according to the given scheme shows a maximum of 0.5 thermal loading per line according to Figure 120 and therefore does not give an indication of unacceptable stress.

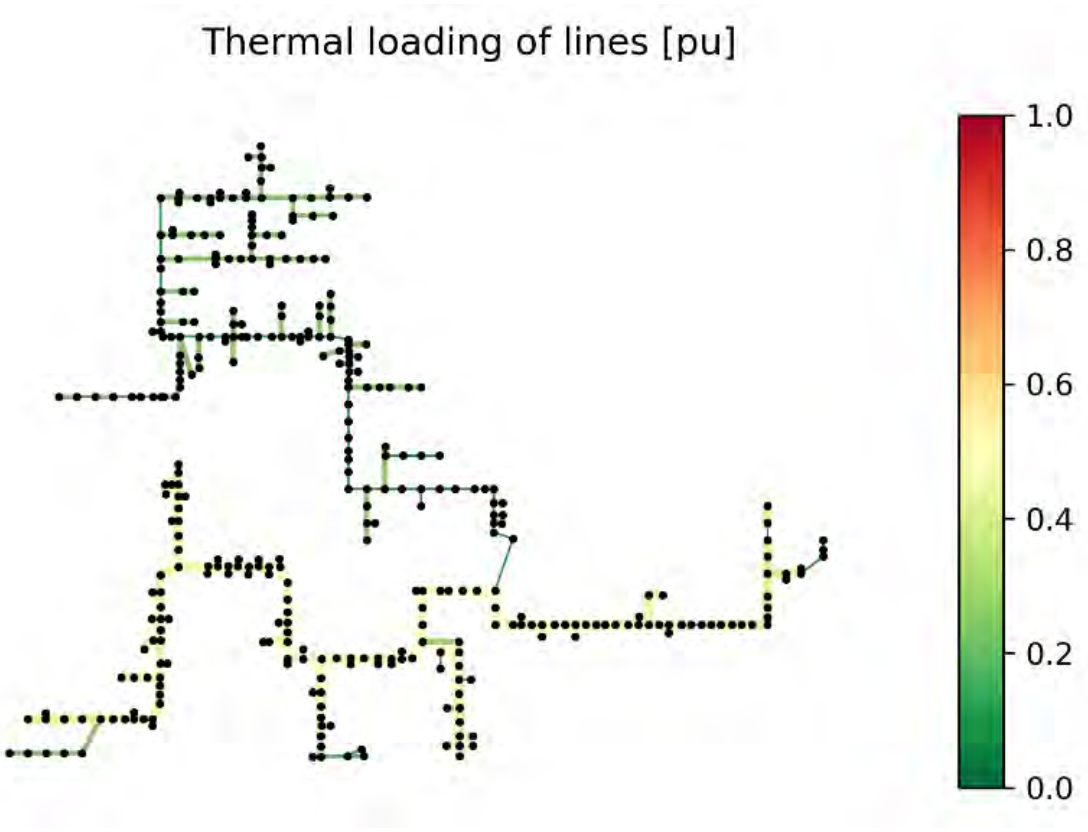


Figure 120 - Thermal loading of lines

The deactivation of the distributed PMCB leaved more chances to blow HV Secondary Substation fuses selectively, as shown in Figure 121.

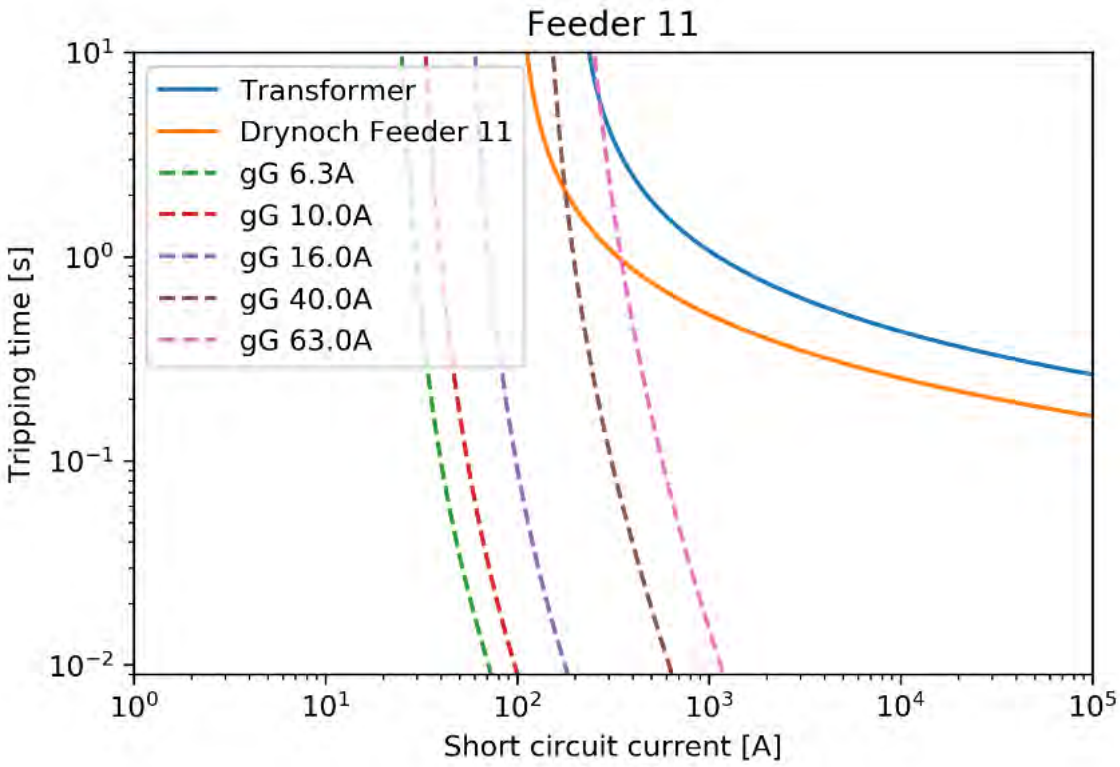


Figure 121 – Tripping curves of relay of Feeder 11 and HV Secondary Substation fuses

Comparing the tripping curves of the more sensitive feeder CB settings with the existing closest to busbar PMCB in Feeder 11 regions of non-selectivity emerge in the range of 100-200A which is intersecting the relevant range of fault currents in the 3MVA case, see Figure 122. The deactivation of PMCB protection tripping with the existing settings may be tolerated at the risk of unselective tripping.

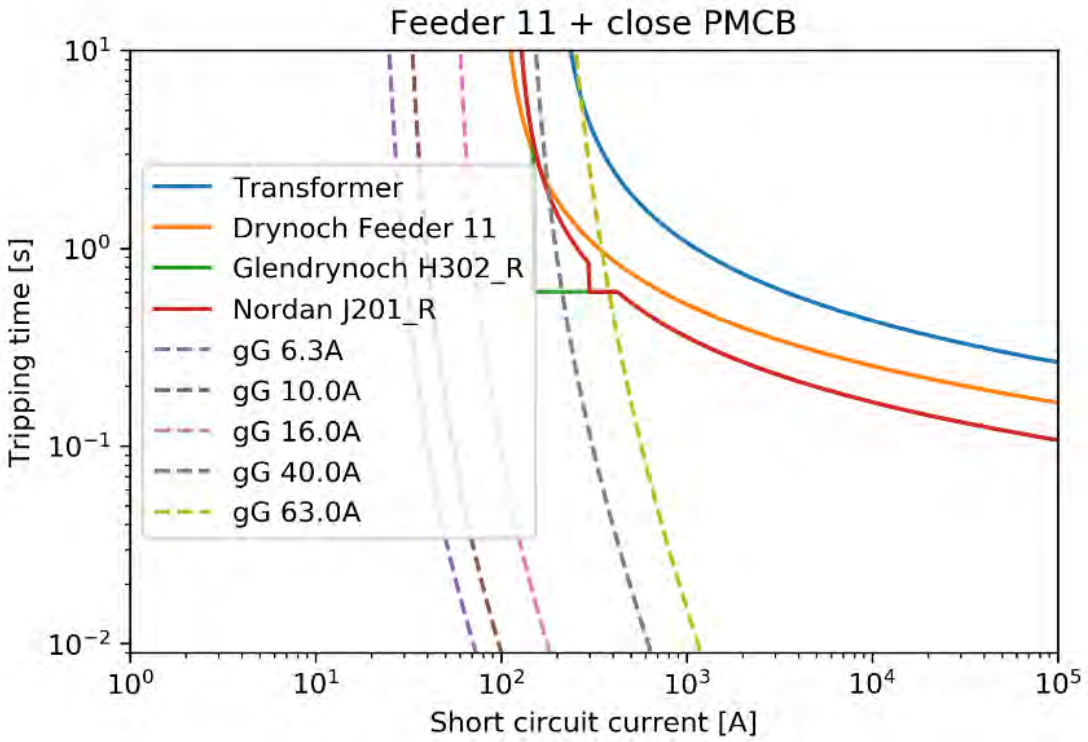


Figure 122 – Tripping curves of relays of selected grid sections of Feeder 11 and HV Secondary Substation fuses

When considering an active power limitation by the BESS for faults in the periphery according to the approach given in Section 6.1.3 a slightly slower 1ph fault tripping results.

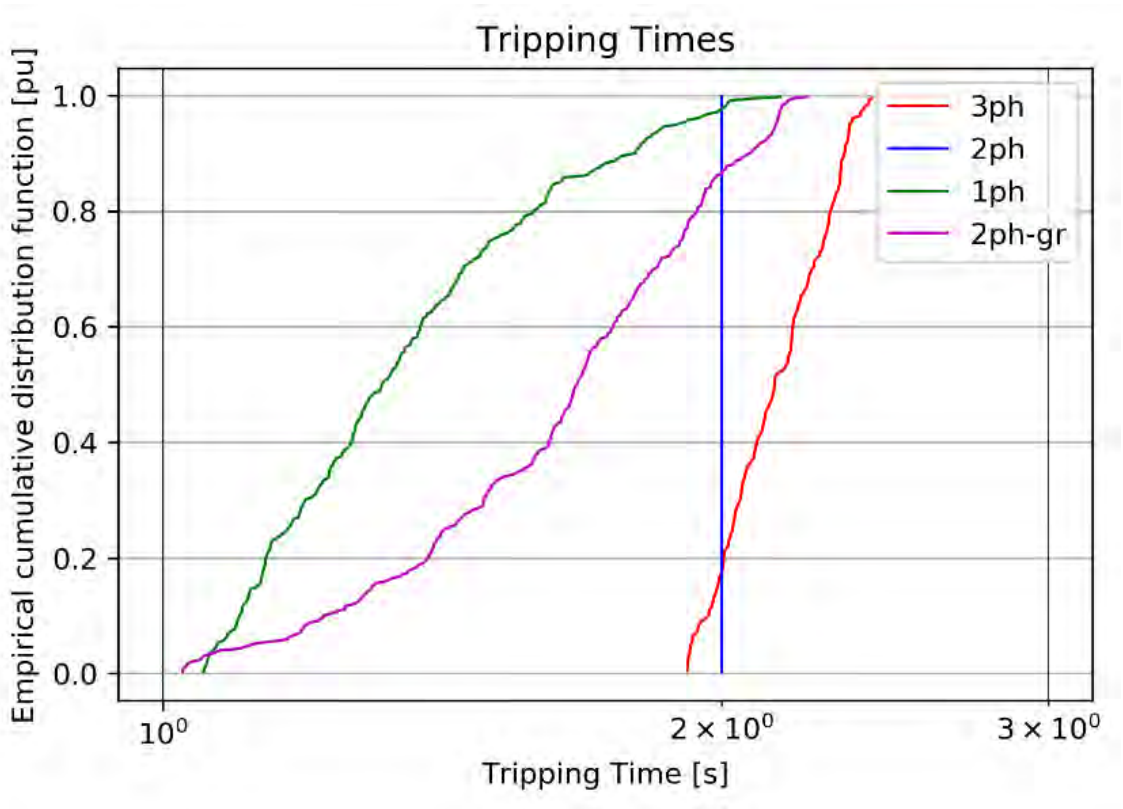


Figure 123 - Tripping time response of overcurrent protection for a 3MVA BESS, considering active power limitation

As a variant to instantaneous I2 tripping the use of an IDMT SI I2 overcurrent tripping with designable speed may be considered. Figure 123 shows the results for a setting I2> and t=0,2.

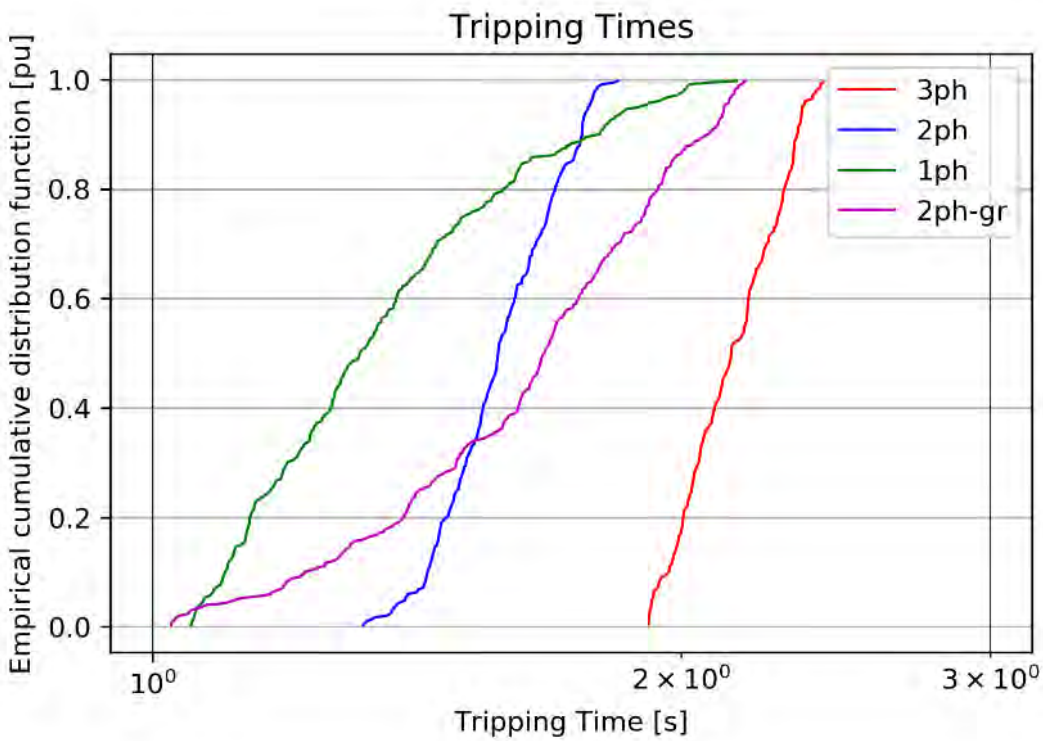


Figure 124 - Tripping time response of overcurrent protection for a 3MVA BESS, using IDMT SI I2> and t=0,2

The tripping of 2ph faults in the low rated 3MVA BESS inverter scenario is covered by the described approach that is intended to be used as primary protection. Due to the necessary low set I2 tripping levels further studies on potential nuisance tripping should be conducted in the Detailed Design phase in normal islanded operation.

c. Feeder based or distributed sensitive earth fault protection

i. 3MVA BESS case

The difficult to detect end of tee or line one phase to earth faults can be detected at the Feeder main circuit breaker observation positions when a lowered tripping value of 4.5% instead of 6% is acceptable. Figure 125 and Figure 126 show the calculated zero-sequence currents for all HV fault locations.

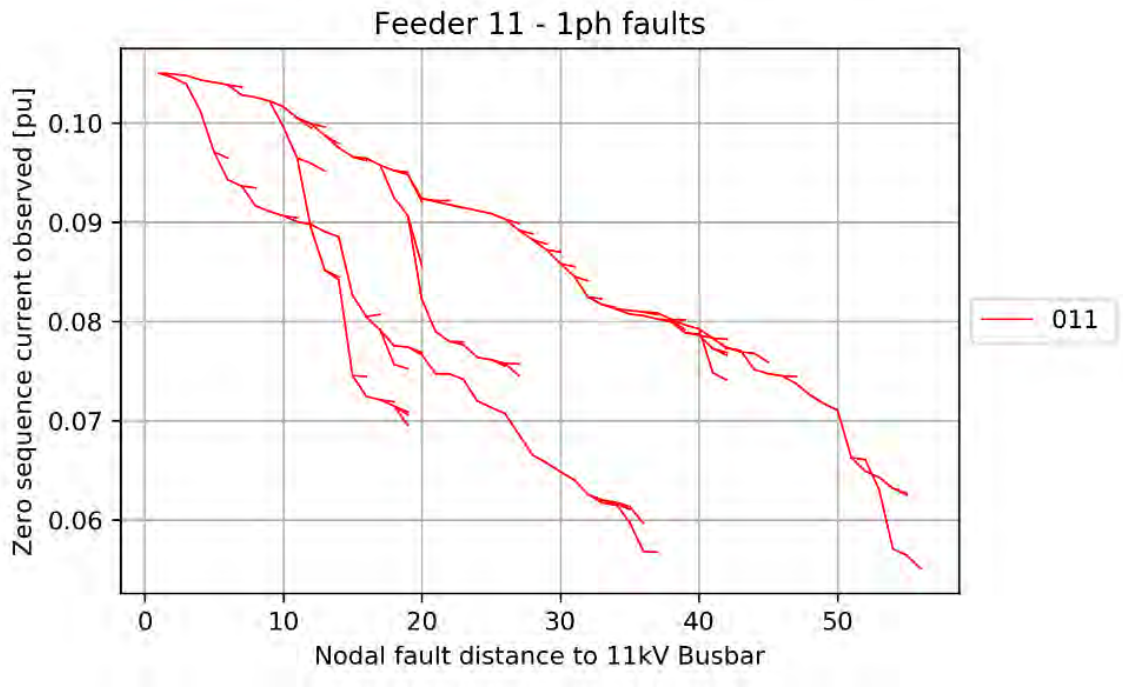


Figure 125 – Calculated zero-sequence currents for HV faults. Feeder 11

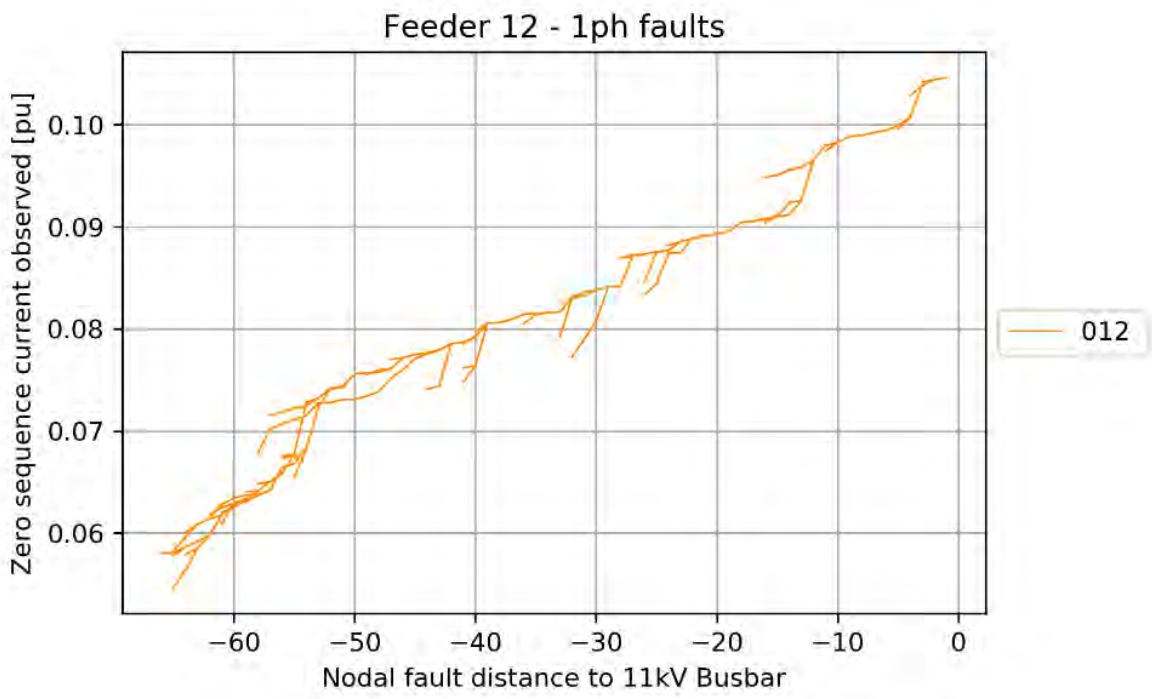


Figure 126 - Calculated zero-sequence currents for HV faults. Feeder 12

Due to the associated typical tripping times this approach may provide backup protection by where undervoltage protection is insensitive.

The possibility to lower the SEF tripping values further than usual in the Grid only operational scenario at the feeder main CB locations will need to be investigated further.

Should the risk of nuisance tripping not be acceptable for the whole feeders, the criteria could be implemented in further downstream PMCB, e.g. at the identical locations as for the distributed undervoltage concept, see Figure 125 and Figure 128.

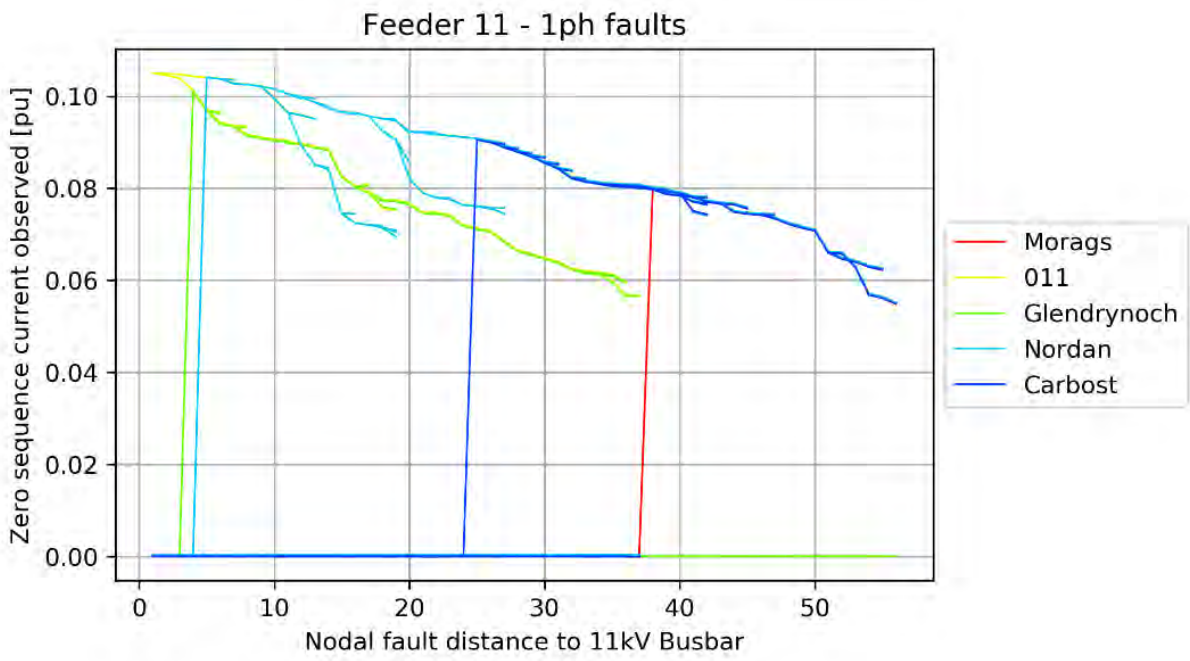


Figure 127 - Calculated zero-sequence currents for HV faults at insensitive locations for U< protection. Feeder 11

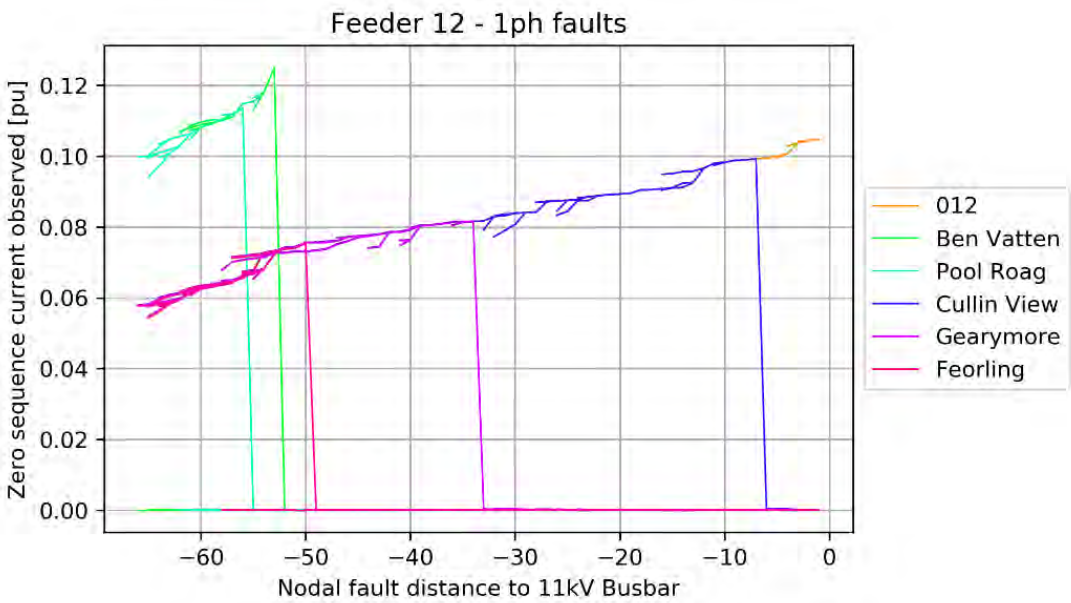


Figure 128 - Calculated zero-sequence currents for HV faults at insensitive locations for U< protection. Feeder 12

The Glendrynoch feeder section will need to be added to the PMCB to be modified should the feeder level not be acceptable.

In case multiple levels are equipped with SEF, time grading will need to be applied in order to gain selectivity.

ii. 5MVA BESS case

In the 5MVA BESS inverter rating case higher zero-sequence currents are observed for close to busbar fault, but peripheral locations remain at comparable levels. Identical considerations therefore apply for this case.

d. Current Limitation Duration Threshold

The approach achieves to provide additional coverage in the close to busbar tees of Feeder 11 that are not covered by undervoltage protection. In the 5MVA case the 1ph fault is still not covered in those regions. Figure 129 and Figure 130 show the regions of insensitivity resulting by current limitation mode for 3MVA and 5MVA BESS respectively.

i. 3MVA BESS case

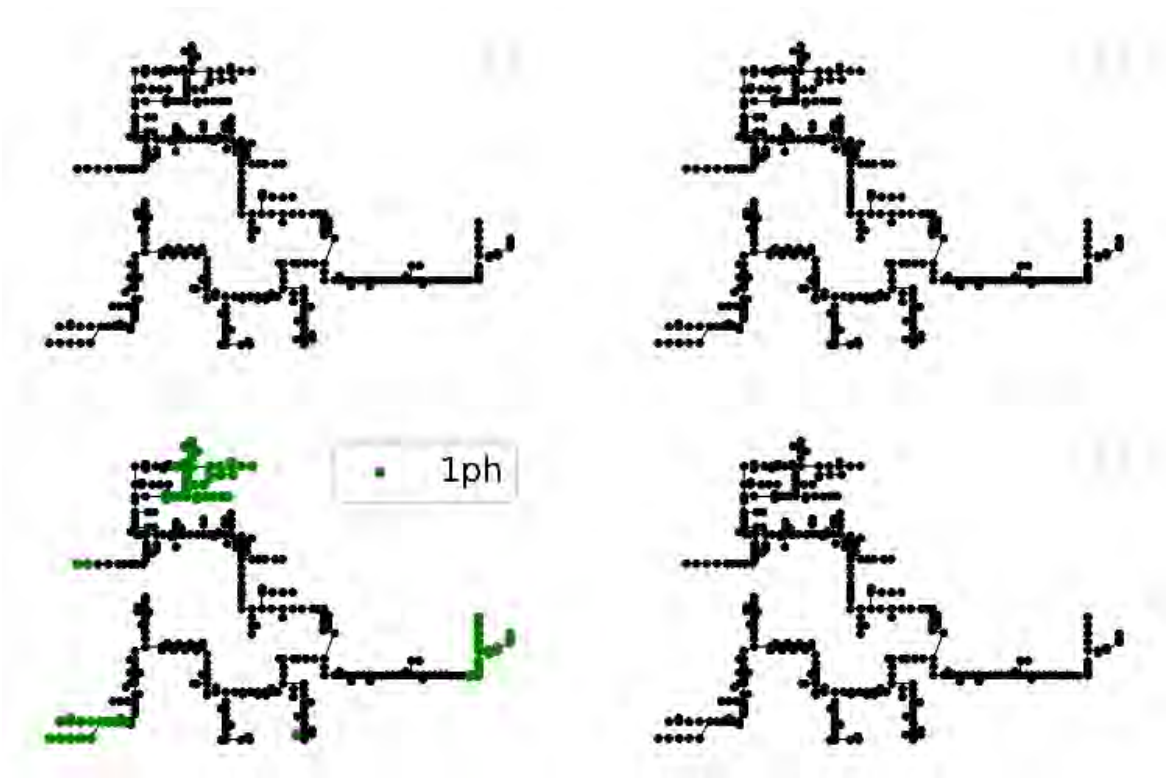


Figure 129 - Regions of no tripping of BESS by current limitation mode. 3MVA BESS case

ii. 5MVA BESS case

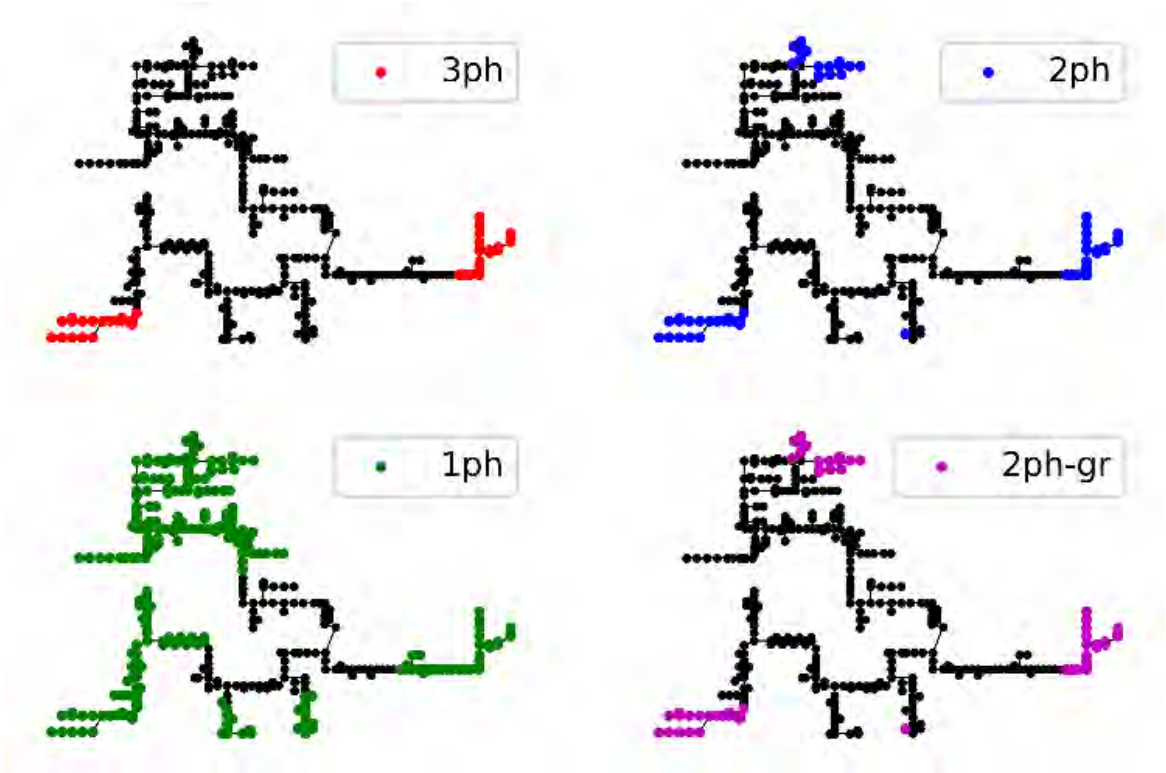


Figure 130 - Regions of no tripping of BESS by current limitation mode. 5MVA BESS case

e. Conclusions

i. General

Several changes on the installed protection system have been identified as potentially required for islanded operation. The following points are highlighted as they are likely to require tele-control:

1. Deactivation of auto-reclosing on feeder main CB and all distributed PMCB
2. In dependency of the solution chosen for islanded operation:
    a. Deactivation of PMCB relays when unselective tripping shall be avoided
    b. Activation of now unused protection functions like U< in PMCB to increase sensitivity of i.e. backup protection

The results indicate that no single means of backup protection will cover all fault cases reliably. The simultaneous application of multiple backup protection approaches should be considered.

The addition of one or two additional further downstream PMCB for high impedance feeder branches, e.g. one in the Glendrynoch section should be investigated in the Detailed Design phase. This could also offer potentials for increased primary protection system performance.

ii. Primary protection

In order to use overcurrent protection as primary protection in the islanded mode of operation with the lower rated 3MVA BESS inverter, the sensitivity of relays needs to be increased in comparison to the Grid only case.

When restricting modifications to the feeder circuit breaker level, the 2ph faults currents as those with especially low fault current levels will require low triggering levels or the introduction of an additional protection criterion as suggest here with the negative sequence current tripping.

The selectivity of the more sensitive feeder settings and the distributed PMCB may be compromised and may require PMCB tripping deactivation by e.g. tele-control as mentioned before.

Nuisance tripping due to the low set current may occur. Also, for a gross lowering of fault currents the overcurrent protection may be rendered ineffective. In case of an overestimation of the achievable fault currents due to false modelling assumptions the residual voltages would decrease and increase sensitivity of undervoltage protection.

The usage of voltage-based criteria as primary protection as often suggested in literature is shown to be of restricted sensitivity when applied on the BESS or the feeder level only. While the region of sensitivity of undervoltage protection is more extended in the 3MVA case than in the 5MVA case, no full coverage is achievable under the assumptions taken in the modelling approach. The relatively high impedances of the feeders investigated create residual minimal voltages greater than 0.8pu even for the lower fault currents driven in the 3MVA case due to the application of worst case zero-sequence impedances for overcurrent tripping.

Adding remote undervoltage sensing to existing PMCB locations is shown to effectively improve sensitivity for feeder branches where the PMCB location is far enough downstream to the end of tee or line in terms of impedances (position in voltage divider). In the 3MVA case, at least two branches do not fulfil this criterion. In the 5MVA case even less sensitivity is achieved. Additional measures are identified as necessary when seeking minimal selectivity of a voltage-based approach.

Sequence voltage-based criteria are shown not to be more effective for the sensitivity critical end of line regions. Only minor degrees of freedom exist in the choice of the undervoltage threshold due to nuisance tripping in normal operation.

The effectiveness of both, overcurrent and voltage-based criteria will depend on the behaviour of the BESS during faults and should be investigated in more detail in the Detailed Design phase.

iii. Backup protection

Backup protection by remote overcurrent relays was shown to be infeasible for usual grid protection settings in chapter 6.2 for the 3MVA case but remain viable for the 5MVA case. While not investigated the effort to enable primary overcurrent protection in the 3MVA case suggests the remote backup capability to be limited.

Backup protection by undervoltage criteria are effective when utilised in a distributed manner except for certain end of line regions in both cases.

Backup protection by sensitive earth fault functionality at the feeder circuit breaker level is shown to be effective for the critical 1ph fault end of line regions in the 3MVA BESS inverter scenario when more sensitive settings can be applied for islanded operation.

Backup protection by BESS active power overload tripping was shown to be effective for end of line cases. Overload existence is on the one hand based on the modelling assumptions and on the other would require the control system not avoiding it. In case the latter is not true the backup protection functionality would disappear.

Backup protection by limiting the duration a BESS may remain in current limitation mode is shown not to be effective for end of feeder cases but for relatively close to busbar tees with no sensitivity achievable with undervoltage protection.

IV. Appendix 3 – EREC G99 Requirements

a. Summary of EREC G99 requirements

The requirements set out in EREC G99 are designed to facilitate the connection of Power Generating Modules whilst maintaining the integrity of the Distribution Network, both in terms of safety and supply quality. It applies to all Power Generating Modules, irrespective of the type of electrical machine and equipment used to convert any primary energy source into electrical energy. It is noted that although Electricity Storage is in the scope of EREC G99, a number of technical requirements do not apply, as Electricity Storage (except for pumped storage) is currently excluded from the Requirements for Generators Network Code. The exclusions for Electricity Storage and other exceptions are noted in Annex A.4 of EREC G99. The rest of the document applies to Electricity Storage in full. It is also noted however that a review of EREC G99 and its relevance for Electricity Storage is currently under review by the Energy Networks Association (ENA).

EREC G99 provides the technical requirements for the connection of different categories of Power Generating Modules, categorised as Type A, Type B, Type C and Type D to the Distribution Networks of licensed DNOs in Great Britain.

The types listed above are defined by the system voltage that the Power Generating Module is connecting to and its registered capacity. For the application at Drynoch the Power Generating Module is categorised at Type B - *A Power Generating Module with a Connection Point below 110 kV and Registered Capacity of 1 MW or greater but less than 10 MW.*

For the application at Drynoch, the Power Generating Module, being a Battery Energy Storage System (BESS), will be categorised as a Power Park Module (PPM) which is defined as - *A Generating Unit or ensemble of Generating Units (including Electricity Storage devices) generating electricity, which is either asynchronously connected to the network or connected through power electronics, and that may be connected through a transformer and that also has a single Connection Point to a Distribution Network.*

Connection of a Power Generating Module must comply with Regulation 26 of the ESQCR 2002, whereby no DNO is compelled to commence or continue a supply if the Customer's Installation may be dangerous or cause undue interference with the Distribution Network or the supply to other Customers. The same regulation empowers the DNO to disconnect any part of the Customer's Installation which does not comply with the requirements of Regulation 26. This dictates that the

power generating module will need to satisfy a number of conditions that are encompassed in various Energy Networks Association documents that are cross-referenced in EREC G99, namely: -

ENA EREC G5 Issue 5: Harmonic voltage distortion and the connection of harmonic sources and/or resonant plant to transmission systems and distribution networks in the United Kingdom

ENA EREC P28 Issue 2: Voltage fluctuations and the connection of disturbing equipment to transmission systems and distribution networks in the United Kingdom

ENA EREC P29 Issue 1: Planning limits for voltage unbalance in the UK for 132 kV and below (this should be easily achieved as the Power Generating Module is a balanced, three-phase device).

There are several other requirements that the BESS being installed at Drynoch will need to meet to achieve full acceptance under EREC G99 by the DNO. Being a Type B Power Generating Module, Table 30 is a full list of compliance requirements.

Table 30 - List of EREC G99 Compliance Requirements for a Type B Power Park Module

Form B2-1 Part 2 - Compliance Requirements for Power Park Module (Part extract from Annex B of ENA EREC G99)			
G99 Clause Reference	**Compliance Requirement of the Power Generating Module**	**Submission Stage**	**Evidence Requested (and / or)**
17.2.1, 17.2.3, 17.4.1	Confirmation that a completed Standard Application Form has been submitted to the DNO	A, IS, FONS	P, MI, D
14.3	Site Responsibility Schedule	E	D
9.4.2	Power Quality – Voltage fluctuations and Flicker: The installation shall be designed in accordance with EREC P28.	IS	MI, D, TV
9.4.3	Power Quality – Harmonics: The installation shall be designed in accordance with EREC G5	IS	MI, D, TV
12.5	Reactive Power capability Confirm compliance with Section 12.5 by carrying out simulation study in accordance with B.4.2 and by submission of a report	IS	S, MI, TV
12.2.4	Limited Frequency Sensitive Mode – Over frequency Confirm the compliance with 12.2.4 by carrying out simulation study in accordance with B.4.5 and by submission of a report	IS	S, MI, TV

12.2	Confirm that the plant and apparatus is able of continue to operate during frequency ranges and to withstand the rate of change of frequency specified in 12.2.1 and 12.2.2	IS	MI, TV
12.1.3	Confirm the Active Power set point can be adjusted in accordance with instructions issued by the DNO	IS	MI, TV
12.3 and 12.6	Fault Ride Through and Fast Fault Current Injection Confirm the compliance with 12.3 and 12.6 by carrying out simulation study in accordance with B.4.4 and by submission of a report. Testing of Fault Ride Through is not required.	IS	MI, TV, S
Section 10 and Form B2-2	Interface Protection: Over and under voltage protection Over and Under Frequency protection Loss of mains protection Other protection: Details of any special protection, e.g. Pole Slipping or islanding As an alternative to demonstrating protection compliance with Section 10 using Manufacturers' Information or type test reports, site tests can be undertaken at the time of commissioning the Power Generating Module	IS, FONS	MI, TV, T
12.2	Frequency Response Test Confirm the Power Park Module meets the requirements of 12.2 by testing in accordance with B.6.2	FONS	T, MI, TV
10.3.3	Automatic reconnection Confirm by testing that the reconnection sequence starts after a minimum delay of 20 s for restoration of voltage and frequency in accordance with paragraph 10.3.3	FONS	T, MI, TV
B.3	Installation and Commissioning Form B3 completed with signed acceptance from the DNO representative	FONS	D

Key to Submission Stages

A – Application: Submission of the Standard Application Form.

E – Energisation: Documentation required prior to Energisation.

IS – Initial Submission: The programme of initial compliance document submission to be agreed between the Generator and the DNO as soon as possible after acceptance of a Connection Offer. The Power Generating Module Document shall be completed as agreed in accordance with paragraph 17.2.2 at least 28 days before the Generator wishes to synchronise its Power Generating Module for the first time.

FONS – Final Operational Notification Submission: The Generator shall submit post energisation verification test documents within 28 days of synchronising in accordance with paragraph 17.4.2 to obtain Final Operational Notification from the DNO.

Key to evidence requested

S - Indicates that DNO would expect to see the results of a simulation study

P - Generating Unit or Power Generating Module design data

MI - Manufacturers' Information, generic data or test results as appropriate

D - Copies of correspondence or other documents confirming that a requirement has been met

T - Indicates that the DNO would expect to see results of, and/or witness, tests or monitoring which demonstrates compliance

TV - Indicates Type Test reports (if Generator pursues this compliance option)

It should be noted that EREC G99 states that DNOs are required by their licences to have in force and comply with the Distribution Code. Generators (operators of Power Generating Modules connected to the PDN) will be bound by their Connection Agreements and licences if applicable, to comply with the Distribution Code.

b. Summary of EREC G99 exemptions

It should be noted that for Electricity Storage devices (i.e. the BESS) the following sections of EREC G99 **do not apply**, as listed in Annex A4 of EREC G99:-

For Type B Generation Modules (1 MW or greater but less than 10 MW):

12.2.3 (constant Active Power output); *continuously maintaining constant Active Power output for system frequency changes within the range 50.5 to 49.5 Hz; and maintaining its Active Power output at a level not lower than the figure determined by the linear relationship shown in Figure 12.1 for system frequency changes within the range 49.5 to 47 Hz for all ambient temperatures up to and including 25°C, such that if the system frequency drops to 47 Hz the Active Power output does not decrease by more than 5%.*

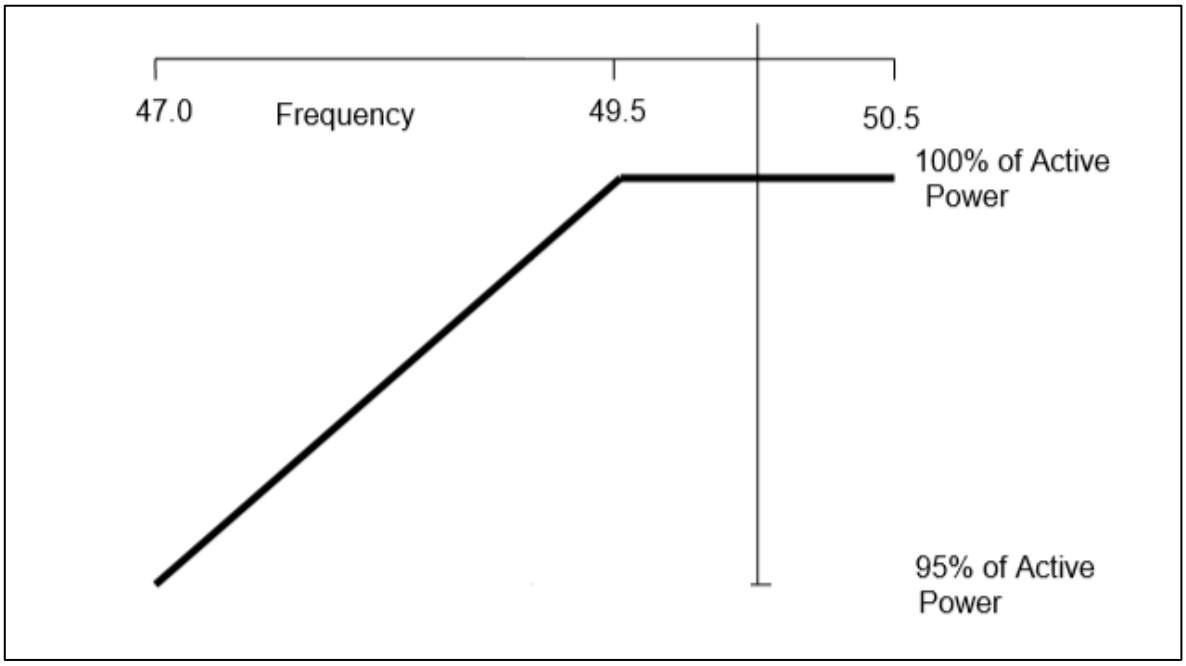


Figure 131 - From EREC G99 - Change in Active Power with falling frequency

12.2.4 (Limited Frequency Sensitive Mode – Over frequency); Each Power Generating Module shall be capable of reducing Active Power output in response to the frequency on the Total System when this rises above 50.4 Hz. The Power Generating Module shall be capable of operating stably during limited frequency sensitive mode – over frequency (LFSM-O) operation. If a Power Generating Module, has been contracted to operate in Frequency Sensitive Mode the requirements of LFSM-O shall apply when the frequency exceeds 50.5 Hz

12.3.1 – 12.3.1.7 inclusive, 12.3.4 and 12.6 (Fault Ride Through, Fast Fault Current injection)

c. Contribution to the Security of the DNO's Network (Compliance with ENA EREC P2/7)

The DNO must meet certain statutory and Distribution Licence obligations when designing and operating their Distribution Network. These obligations may influence the options for connecting Power Generating Modules.

The DNO has confirmed that the 11kV network supported by Drynoch Primary is already compliant with the provisions of EREC P2 Issue 7 – "Security of Supply", which means also that the guidance of EREP 130 Issue 3 – "Guidance on the application of Engineering Recommendation P2, Security of Supply", will apply. It has been confirmed that the existing security of the supply is such that if there is a complete outage of the 33kV network that feeds Drynoch Primary Substation, then there will be a time delay to re-connect the 11kV network to alternate supply sources, in accordance with the requirements of EREC P2.

The Power Generating Module that forms the RaaS scheme will increase the security of supply and should either remain synchronised and in parallel with the Distribution Network under the outage condition being considered or be capable of being resynchronised within the time period specified in EREC P2. There may be commercial issues to consider in addition to the connection cost and this may influence the technical method which is used to achieve a desired security of supply.

As the intention is to use the BESS as a means to increase supply security, EREP 130 provides for two distinct modes; *Contribution to System Security from Contracted DG, DSR Schemes, and ES (Clause 8)* or *Contribution to System Security from Non-Contracted DG, DSR Schemes, and ES (Clause 9).*

It has been assumed that the commercial arrangement at Drynoch is for the BESS to be operated as an ES that is Non-Contracted in terms of system security, and the DNO will rely on the fortuitous security contribution of Non-Contracted ES, in accordance with the requirements laid down in clause 9.