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POWER CONSULTING

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Workstream B.2 Report

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EXECUTIVE SUMMARY

Aurora Power Consulting has been commissioned by Northern Powergrid (NPg) to help them shape their overall policy and strategy for assessing and managing the increased roll out of Battery Energy Storage Systems (BESS) on the NPg network in relation to ENA EREC P28/2 and current NPg policy.

This report covers workstream B.2, which details the short-term policy developments or 'quick wins' related to current NPg assessment methodology for new BESS connections, and to confirm if the existing NPg policy is suitable or can be improved to give a more equitable approach.

The key output of the B.2 workstream recommends that NPg should consider requiring BESS power generating facilities to operate at unity power factor or fixed MVAr output, particularly when providing dynamic services to NESO, as this would generally be more beneficial to the NPg network.

Where a BESS operates at unity power factor, assessment of BESS power generating facilities from an operation state of full export at 0.95pf lagging to an operational state of full import at 0.95pf lagging is not required, and an assessment of only the active power change is sufficient. Some further general recommendations are also highlighted for consideration and are discussed in Section 4 of the report.

One of the key issues identified in the report is the risk of coincident swings of BESS units connected to the same part of the distribution network. Currently EREC P28/2 does not have a formal mechanism for considering this behaviour and in the absence of national guidance and in co-ordination with NESO's contracting process, it seems reasonable for DNOs to assume that co-incident BESS operation will occur. The magnitude and coincidence factor therefore need further discussion to agree a reasonable approach for assessing potentially co-incident behaviour. Lastly, it should be noted that there are competing requirements for power factor setpoints when a BESS is providing dynamic services, and when a BESS is trading in the wholesale market or the Balancing Mechanism (BM), as these place very different constraints on the host NPg network, in the former low MVAr exchange with the NPg network is desirable to limit voltage disturbance, whilst in the latter, the use of a unity power factor may not be beneficial to the NPg network, as this could result in the import / export of reactive power to / from the local NPg network which may cause other constraints e.g. sub-optimal system losses. Further complications also arise as it is possible for a BESS to revenue stack and provide a mixture of both dynamic services and wholesale / BM services.

This issue goes beyond the scope of the NIA project, and needs wider discussion by the DNOs and NESO. However, one obvious solution would be for EREC G99 to be expanded to allow DNOs to specify power factor values as required for different ‘modes’ of operation. Typically a BESS would have three main ‘modes’ of operation: 1) Steady state power export, 2) Steady state power import and 3) Dynamic service provision. Each of these modes place very different constrains on the host DNO network, and an ability of the host DNO to specify different power factor depending on the operating mode would be advantageous to the DNO.

It is important to note, as in accordance with the defined scope of work, this report and its recommendations are focussed on situations where the BESS owner/operator has contracted to provide dynamic services to NESO. Where the BESS owner/operator deploys their plant in the energy trading market, or is embedded within a customer’s installation different operating conditions and power factors can be appropriate.

GLOSSARY OF TERMS & ABBREVIATIONS

The following Terms and Abbreviations have been used throughout the document:

ACRONYM	DESCRIPTION
AVC	Automatic Voltage Control
BESS	Battery Energy Storage System
DC	Dynamic Containment
DCRP	Distribution Code Review Panel
DM	Dynamic Moderation
DNO	Distribution Network Operator
DR	Dynamic Regulation
EHV	Extra High Voltage
ELS	Export Limitation Scheme
EMT	Electromagnetic Transients
ENA	Energy Networks Association
FSM	Frequency Sensitive Mode
FRCR	Frequency Risk and Control Report
HV	High Voltage
IEC	International Electrotechnical Committee
LDC	Line Drop Compensation
LFSM	Limited Frequency Sensitive Mode
LV	Low Voltage
NESO	National Energy System Operator
NGET	National Grid Electricity Transmission
NIA	Network Innovation Allowance
NPg	Northern Powergrid
PI	Proportional & Integral
PID	Proportional, Integral & Differential
PPC	Power Park Controller
pu	per unit

RDR	Run Down Rate
RMS	Root Mean Square
RoCoF	Rate of Change of Frequency
RUR	Run Up Rate
RVC	Rapid Voltage Change
WECC	Western Electricity Coordinating Council

SECTION 1 - Introduction

1.1 Introduction

Aurora Power Consulting has been commissioned by Northern Powergrid to help them shape their overall policy and strategy for assessing and managing the increased roll out of Battery Energy Storage Systems (BESS) on the NPg network in relation to EREC P28/2 [1] and current NPg policy.

The scope of this NIA project [2] is to identify the operational effects on system voltage, when a BESS is providing frequency response services such as Dynamic Moderation (DM), Dynamic Regulation (DR) and Dynamic Containment (DC), as well as the effect when a BESS is operating in the balancing mechanism and wholesale market. The project is undertaken in relation to EREC P28 together with DNO policies, and the associated method for assessing EREC P28 compliance.

The BESSs considered in this report are systems that are connected to the DNO network and compliant with recent versions of the EREC G99 standard [3]. However, it should be recognised that larger scale BESS units >50MW, must also comply with parts of the GB Grid Code [4], which imposes additional requirements above those of EREC G99 in terms of performance.

This report provides a summary of the work undertaken so far as part of Workstream B.2.

1.2 Overview

Within the last 5 years, National Energy System Operator (NESO) has released a series of market products intended to provide frequency responses services on the network, known as Dynamic Response (DR), Dynamic Moderation (DM), and Dynamic Containment (DC). These services are primarily provided by BESS power generating facilities. These power generating facilities, whilst highly effective at providing frequency responses services, have raised concerns within DNOs regarding their effect on DNO networks in relation to voltage fluctuations, i.e. voltage step change, rapid voltage change and flicker due to the rapid power changes associated with operation of BESSs.

NPg is seeking to determine the best method of assessing BESSs, when they are operating in accordance with a contact with the NESO to provide dynamic services, in relation to the application of their existing policy documents and compliance with the EREC P28/2 standard.

It is important to note that there are competing requirements for BESS behaviour when the BESS is providing dynamic services, and when a BESS is trading in wholesale market or the balancing mechanism. These different modes of operation place very different constraints on the host DNO network; when a BESS is providing dynamic services its active power is adjusted in response system frequency disturbances, and it is generally beneficial to minimise reactive power flows. However, when a BESS is operating in the wholesale market or balancing mechanism, the active power flow will be continuous within a trading period and use of a specific power factor may be advantageous to the DNO e.g. to optimise network losses. Further complications also arise as it is possible for a BESS to revenue stack and provide a mixture of both dynamic services and operate in the wholesale market or balancing mechanism at the same time. This issue goes beyond the scope of this NIA project, and needs wider discussion by the DNOs and NESO.

It is generally acknowledged that the existing EREC P28/2 standard does not adequately explain how to assess BESSs when they are operating to provide dynamic services / operating in the wholesale market / balancing mechanism, nor how to assess how multiple BESSs could potentially interact. Specific concerns that have been raised relate to:

- How BESSs operating to provide dynamic services to NESO influence system voltage;
- The rage of credible operation scenarios and the associated real and reactive power swings;
- The need to set ramp rates limits for BESS import and / or export;
- The potential interaction with transformer tap controls;
- The potential interaction with Static MVAr compensation equipment;
- The assessment of multiple BESSs on electrically adjacent parts of the network when they are providing similar services; and
- The implications associated with stacking multiple dynamic services and operating in the wholesale market or balancing mechanism..

The project's primary objectives are to:

- Develop simplified and advanced methodologies for assessing the effects of BESS connection and operation on voltage fluctuations on distribution networks operating at EHV or HV where the BESS is connected at the HV busbars of an EHV/HV substation;

- Examine optimal BESS real and reactive power control modes and setpoints to minimise voltage fluctuations associated with BESS operation and the operation of the distribution network;
- Provide material that can be disseminated to NPg staff and included in updates to NPg policies, as required, to facilitate the assessment of voltage fluctuations from BESS connections taking into account real and reactive power flows that are expected to be seen from commercial service operation; and
- Provide feedback to the DCRP EREC P28 workgroup on the project findings.

1.3 Aurora Workstreams

The following workstream have been agreed with NPg to assess the effect of BESSs in relation to assessing compliance with EREC P28/2. The workstreams below, are direct extracts from the project brief [2].

1.3.1 B.1 – Data gathering and consultation

An initial data gathering and consultation stage. NPg will gather and provide key input data to Aurora including the outputs from Workstream A, information from developers about BESS operation and BESS control schemes, and the model of the Ferrybridge network which could potentially be used as a test case. During this stage Aurora will look at historical system frequency data published by NESO and hold discussions with NESO on the specification, service requirements and implementation of frequency response services (including Dynamic Regulation, Dynamic Containment, and Dynamic Moderation).

1.3.2 B.2 – Short-term policy development

Development of material to explain changes to NPg policy that could be applied in an interim period to allow some “quick wins” to be delivered. Specific possibilities that should be considered include changes to the nominal operating power factor (unity, vs lag / lead) and ramp rates in relation to historical NETS frequency data and aggregated responses of adjacent BESSs.

1.3.3 B.3 – Modelling and analysis

Development of representative power system models at EHV (including EHV/HV substations) that incorporate multiple BESSs, as well as other sources of generation and demand. These may be based on the Ferrybridge network model.

A study of the effect of existing BESS operational practices and a range of credible future practices on voltage fluctuations with due consideration being given to co-incident behaviour of multiple BESS connected to the same distribution system.

Consideration of existing BESS operational practices and a range of credible future practices when operating in fixed power factor, fixed reactive power output and voltage control modes; and any other control modes that emerge as being viable.

Consideration of the effect that BESSs operating in a range of credible control modes have on existing generation and demand customers e.g. stability issues.

Consideration of the effect of BESS operation where it provides NESO frequency response services e.g. Dynamic Containment, Dynamic Modulation and Dynamic Regulation, or where it provides arbitrage serviced in the wholesale market and operation in the balancing mechanism. This will include examining BESS ramp rates associated with each mode of operation and the consequential voltage fluctuations.

Consideration of the effect of BESSs operating in a range of credible control modes on NPg systems, in particular on transformer AVC schemes (both legacy and new) and the effect on NGET transformers AVC schemes at Grid Supply Points, including examining the effects on circulating currents.

Consideration of the effects of future fault level reductions and changes to X/R ratios.

Development of a methodology for detailed EREC P28 assessments of BESSs to be carried out post offer-acceptance (an EREC P28 BESS application guide). These should be capable of being carried out by the DNO or the developer (or their consultants), and the results should be able to be critically reviewed by the other party. The methodology should be suitable for presenting to the DCRP EREC P28 workgroup for consideration in future revisions of EREC P28. The methodology will be at a similar level of detail to that provided in EREC P28 section 6.4.2, Transformer energisation.

Recommendations for sharing generating unit and/or BESS technical details between parties where co-incident effects between different systems need to be assessed. Ways of sharing this information without compromising confidentiality need to be examined and recommendations proposed.

1.3.4 B.4 – Simplified methodology development

Development of a methodology for NPg to carry out realistic simplified assessments of voltage fluctuations associated with BESS connection and operation at the connection design stage. This may be provided in a form such as an Excel based tool that can be used on NPg IT systems.

1.3.5 B.5 – NPg policy update recommendations

Provision of material that can be used to update relevant NPg policy documents with respect to the connection of BESSs to the distribution system.

SECTION 2 - Existing NPg policy

2.1 Existing NPg policy documents

NPg policy approach for assessing connection of BESS units, is based on a series of related codes of practice. The key standards are:

- IMP/001/007 – Code of Practice for the Economic Development of Distribution Systems with Distributed Generation [5].
- IMP/001/007/001 – Battery Energy Storage System Guidance Document [6]; and IMP/001/007/002 - Application guide for modelling generator reactive power control modes [7]. It is important to note that this document was withdrawn in 2022 and is no longer NPg policy and it is referenced here for information only.
- IMP/001/915 - Code of Practice for Managing Voltages on the Distribution System [8].

These codes of practice and guidance documents have developed over several years in relation the connection generation technologies generally and not specifically (with the exception of IMP/001/007/001) updated in relation to the relatively recent the rapid increase in the number of BESS applications. They have therefore not been critically assessed in any detail in terms of their application to BESSs, and some developers have complained that they unfairly penalise BESS installations and delay connections. It is also important to note that one of the purposes of this innovation project is to review, and potentially revise these codes of practice and guidance documents.

2.1.1 Distributed Generation Connection Code of Practice (IMP/001/007)

This code of practice provides high level guidance on the implementation and acceptance criteria for connecting distributed generation to the distribution system. As a form of distributed generation, BESS fall within the scope of this document. Extracts of key requirements are shown below.

- Section 3.3.8: When a system containing distributed generation is being designed, the presence of other generation connected to, or which will be connected to, that part of the system shall be considered. Where there are quotations for any connections which have been issued to a demand Customer or a Generator which are still within their validity period it shall be assumed that these connections will be made. The connection designs should take into account all connection interactivity.

Interactivity can be associated with issues including thermal, voltage and fault level. The connection requirements for second and subsequent distributed generation connections to a given part of the distribution system may be more onerous than for the first and may involve modification to earlier connections. Issues associated with power flow, voltage, fault level and stability are likely to be more serious when there is more than one distributed generation installation connected to part of a distribution system.

- Section 3.4.3: The connection of non-synchronous distributed generation (e.g. inverter connected, asynchronous, DFIG) to the system can affect reactive power flow on the system under fault conditions which can affect the stability of synchronous Power Generating Modules. Where there are existing synchronous Power Generating Modules connected to the EHV or HV system, or the connection of new synchronous or non-synchronous Power Generating Modules is being studied, transient stability studies should be carried out. Where there is only distributed generation connected at HV, rather than undertake stability studies, the Generator should fit pole slip protection.
- Section 3.5.3: The systems employed by Northern Powergrid for maintaining the voltage provided to connected customers within statutory limits were developed in an environment when there was very little distributed generation connected to the system. Consequently, when the export from distributed generation exceeds the local load requirements, careful consideration must be given to the effect of 'reverse' power flow through the system as this will influence the voltage control systems.
- Section 3.5.3.2: When a transformer is equipped with an on-load tapchanger there may be limits to its reverse power capability and the voltage control scheme may not function correctly if the power factor as seen by the transformer is lower than approximately 0.7. Such a situation could occur where the real power output from a generation plant, operating at unity power factor, matches the real power requirements of the network and the reactive power requirements of the network is provided by the transformer. Where the reverse power capability is limited by the capability of the voltage control scheme, it may be possible to increase this capability by installing a modern voltage control scheme. There is currently a programme to install modern voltage control schemes in most substations; where required to support a customer connection it may be possible to advance the replacement of the voltage control scheme at a particular substation.

- Section 3.5.3.3: It may be possible to reduce the set point voltage of an AVC control scheme to ensure that system voltage remains within the required limits. When considering this option system studies are required to ensure that voltages remain within the required limits under credible scenarios of demand and generation on the entire downstream system. It may be possible to mitigate the effects of lower voltages (e.g. when the generator is not operating) through the use of a number of means.
- Section 3.5.4: Voltages at the Point of Supply to customers' premises shall remain within statutory limits at all times. Under normal operation of distributed generation plant any voltage fluctuations shall be within the limits stated in Engineering Recommendation P28. Normal operation includes synchronising, increasing output to the maximum and taking the generation plant offline. Limits on the generation plant ramp up and ramp down rates may need to be imposed to ensure that system transformer tap-changers have time to operate if required. For unplanned outages such as faults it will generally be acceptable to design to a step voltage change of 10% of the nominal voltage.
- Section 3.5.6.2:
  - Where a Power Generating Module cannot achieve compliance with Northern Powergrid's Economic Development Codes of Practice across the power factor range capability range set out in EREC G99, for example where there is excessive voltage rise when operating at a power factor of 0.95 lagging, or where the Power Generating Module would become unstable when operating at a leading power factor, Northern Powergrid will be flexible on requiring compliance throughout the operating range provided that the Generator acknowledges the right for Northern Powergrid to require operation within the full power factor operating range set out in EREC G99 in the future and that this may require the Generator to change their operational behaviour e.g. constrain their output to a level at which issues on the distribution system cease, or potentially install additional equipment to ensure system stability.
  - In order to retain this future flexibility, the Connection Agreement shall state the requirement for the Power Generating Module to operate across the full power factor operating range set out in EREC G99. It is important to note that Northern Powergrid will not require a Power Generating Module to operate at a power factor that could result in Power Generating Module or system instability.

- Section 3.5.6.3
    - For Power Generating Modules connected to the Northern Powergrid distribution system at EHV or at HV via a dedicated HV circuit to an EHV to HV substation, Northern Powergrid will establish the operating power factor that the Power Generating Module should operate at during the connection design study in accordance with IMP/001/007/002 – Application guide for modelling generator reactive power control modes. The exception to this is where the Power Generating Module is connected to a part of the system where new Power Generating Facilities above 1MW fall within the scope of the CUSC Statement of Works process. In this case, it is likely that the Power Generating Module will need to be set in Power Factor Control mode with a set point power factor of unity, or in Reactive Power Control mode with a setting to offset any significant cable susceptance associated with the new connection.
    - Generators with connections at EHV and HV may be required to change the power factor set point of their Power Generating Modules periodically to a value within the range set out in the Connection Agreement, for example where the power factor of the system changes, as required by Northern Powergrid.
    - The agreed fixed power factor should normally refer to the Generator's Point of Supply to the distribution system. Where a Power Generating Facility is supplied via a long circuit, consideration should be given to the reactive characteristics of the circuit when establishing the power factor set point of the Power Generating Module. This may result in the Power Generating Module operating at a leading power factor at the Point of Supply
    - The aim of IMP/001/007/002 is to establish the optimum power factor that reduces reactive power flow on the system and hence reduce system losses. Typically, the power factor set point would be the power factor at the part of the system where the Power Generating Module is connected. If a Power Generating Module is connected to a part of the system where the power factor is low, for example in a ring system, the power factor set point would normally be a minimum of 0.95 lagging.
    - For Power Generating Modules connected at HV (other than via a dedicated HV circuit to an EHV to HV substation) or at LV, Northern Powergrid will normally agree with the operating power factor proposed by the Generator, provided that it is in the range 0.95 lagging to Unity.

  - For Power Generating Modules connected at EHV or at HV, operation at a leading power factor may also be acceptable where there is reasonable justification.

2.1.2 Battery Energy Storage System Guidance (IMP/001/007/001)

This code of practice provides high level guidance on the implementation and acceptance criteria for connecting a BESS to the NPg network. It is worth noting that the focus of the document is on multiple kW BESS installation rather than on the multiple tens of MW BESS installations that tend to provide the majority of the present-day concerns. It is also worth noting that this document was written in 2018 and was not revised or updated when republished in 2024; it is therefore may not reflect current industry or NPg approaches. Extracts of key requirements are shown below.

- Section 3.1.6: Cross reference to IMP/001/007, noting that generators should normally be set to operate in PQ mode where generator controllers fix the power factor of the exported power.
- Section 3.1.6: Regardless of the BESS's operational power factor network assessments should be performed based on a 0.95 lagging power factor. This provides future flexibility for Northern Powergrid to require the BESS to operate at any point in the range 0.95 lagging to unity and be confident that the distribution network would operate efficiently and within the statutory requirements..
- Section 3.1.6: Where a BESS cannot achieve compliance across the full operating range, either because it would require additional equipment on site to do so (e.g. capacitors) or because the customer prefers to be assessed against a specific power factor (if that is different to 0.95 lagging), operation at a specific power factor may be permitted. However, the customer must accept that should Northern Powergrid ask them to operate at a lower power factor in the future, they will have to do so even if this results in a reduction of the maximum active power that can be exported to the Northern Powergrid system. Such an arrangement shall be recorded in the Connection Agreement.
- Section 3.1.8.2: A BESS can cause both RVCs and flicker and should therefore be assessed for both in accordance with EREC P28. The maximum allowed RVC (a voltage change between two steady state voltage conditions) should not exceed 3%. In addition to not exceeding this value, voltage changes should also meet the flicker limits measured or calculated at the Point of Common Coupling, PCC.

However, if voltage change is ramped up/down instead of being an instantaneous step change, a RVC may be allowed to occur more frequently.

- Section 3.2: The application procedure for a BESS depends on:
  - its power rating, measured (Watts) not its energy rating (Watthour);
  - the presence of any other generation within the same premises; and
  - the presence of an ELS.
- Section 3.3.2.2: When calculating the magnitude of voltage fluctuations, maximum system impedance values should be used as these values generally represent the worst case normal operating conditions.
- Section 3.3.2.2.1: Step voltage changes occur before an-load tap changer has time to detect a voltage variation and operate to restore it. The rate at which a BESS varies its power output has a direct impact on the step voltage change and therefore on the overall voltage variation experienced by customers connected to the network. Unless the BESS customer states a lower limit for power swing, the voltage step change should be assessed based on an instantaneous power swing from full export at 0.95 lagging power factor to full import at 0.95 lagging power factor.

2.1.3 Application guide for modelling generator reactive power control modes (IMP/001/007/002)

This withdrawn guidance document provided high level guidance on the connection and modelling of generator reactive power capability on the NPg network. The aim of IMP/001/007/002 was to establish the optimum power factor that reduces reactive power flow on the system and hence reduce system losses. Typically the power factor set point would be the power factor set point would be the power factor at the part of the system where the Power Generating Module is connected. It is worth noting that this document was written in 2018; it is therefore may not reflect current industry approaches. This is one reason why it was withdrawn in 2022, however it may still provide some useful background material..

Relevant extracts are shown below.

- Section 3.2: Generators have traditionally been connected to Northern Powergrid's distribution system operating at unity power factor, or in more recent years at fixed lagging power factors that match the power factor of the network they are connected to. As voltage limits are increasingly constraining the quantity of generation that can be connected requiring more expensive connections to alternative points on the distribution system, different approaches to connecting generators can now be considered. Consideration of overall system losses may also drive a change in the control mode of generator operation.

- Section 3.3: The distribution system shall be designed to operate at the nominal voltages set out in the Code of Practice for Distribution System Parameters, IMP/001/909 and the Code of Practice for Managing Voltages on the Distribution System, IMP/001/915. Voltages shall also be maintained within the limits stated in the following codes of practice:
  - Code of Practice for the Economic Development of the HV System, IMP/001/912;
  - Code of Practice for the Economic Development of the EHV System, IMP/001/913; and
  - Code of Practice for the Economic Development of the 132kV System, IMP/001/914.
- Section 3.4: There are two main methods of generator control, terminal voltage control mode (PV mode), which aims to control the generator terminal voltage by allowing the reactive power output to vary and reactive power control mode (PQ mode), which controls the reactive power output and allows the voltage to vary as dictated by the system voltage.
- Section 3.4: Generally, Northern Powergrid's approach requires PQ (power factor) control mode of operation for generators unless dictated otherwise by National Grid (NGET) via the Grid Code
- Section 3.4.2: Operating a generator in PQ mode controls the reactive power output and allows the voltage to vary as dictated by the system voltage. There are two methods by which this is achieved:
  - Fixed reactive power control - fixes the reactive power output of the generator, which allows the power factor to change with changing active power output allowing the voltage to be controlled by the distribution system.
  - Fixed power factor control - fixes the pf of the generator output allowing the reactive power to change with a change in active power output again allowing the voltage to be controlled by the distribution system.
- Section 3.6: The preferred mode of operation for generators connected to the Northern Powergrid distribution system is fixed power factor control (PQ) mode as this provides us with losses benefits by providing reactive power more locally to where it is required, thereby reducing the losses associated with providing reactive power from the transmission system. This is also the simplest solution that is easily

modelled by our current network modelling tools. However, this may not be the most efficient method of operation for a generation dominant network.

- Section 3.7: Provides a flow chart to assess the target power factor of a generator.
- Section 3.7: A voltage issue in the context of the above studies will normally occur when a Northern Powergrid network transformer runs out of taps and/or the system voltage exceeds statutory limits. It is worth remembering that these issues can occur at different points on the distribution system.

2.1.4 Code of Practice for Managing Voltages on the Distribution System (IMP/001/915)

This document provides high level guidance on managing voltages on the distribution system. This document is more general in nature, and details performance requirements for system voltage control and transformer tap control settings. It is also worth noting that this document was written in 2017 and was not revised or updated when republished in 2024; it is therefore may not reflect current industry or NPg approaches. Extracts of key requirements are shown below.

- Section 3.1.5: As a distribution licence holder, Northern Powergrid is required to comply with the Grid Code. The Grid Code places specific requirements on National Grid Electricity Transmission, Generators and on Northern Powergrid in relation to voltage management including:
    - the requirement for NGET to maintain voltages within defined limits except in abnormal situations; and
    - the requirement for NGET to maintain voltage fluctuations within defined limits.
- Section 3.1.5: Grid Code OC6.5.3 requires DNOs to make arrangements to reduce demand on their network by implementing Demand Control by either:
    - Two voltage reduction stages each of between 2 and 4 per cent (nominal 3 per cent each), each of which can be expected to deliver around 1.5 per cent demand reduction, and up to three Demand Disconnection stages, each of which can reasonably be expected to deliver between four and six per cent demand reduction; or
    - Four Demand Disconnection stages each of which can reasonably be expected to deliver between four and six per cent demand reduction
- Section 3.4.1: The voltage at the source substation 132kV, 66kV, 33kV, 20kV and 11kV busbars shall be held reasonably constant by means of automatic voltage

control (AVC) relays (or an automatic voltage regulator system provided by NGET) controlling the tap changers of the transformers feeding that busbar.

- Section 3.4.1: Voltage control shall be provided via tap changers and associated automatic voltage control relay in accordance with the general principles of Engineering Recommendation P1, 275/33kV, 132/33kV and 132/11kV Supply Point Transformers, and Engineering Recommendation P10, Voltage Control at Bulk Supply Points.
- Section 3.5.1: Target voltages, dead band and delay timer settings shall be established for each 132kV, EHV and HV busbar by discussion between Asset Management, Network Management, NGET and individual customers as appropriate and recorded in a controlled document managed by Network Management. The standard target voltages set out below shall be applied unless there is a justifiable reason to apply an alternative target voltage.
- Section 3.5.3.2: The target voltage and dead band at the 132kV, 66kV, 33kV and 20kV low voltage busbars at NGET interface substations are maintained by NGET at a voltage requested by Northern Powergrid and agreed with NGET. The target voltage should be agreed between Northern Powergrid and National Grid and recorded in a controlled document. Target voltages at each substation shall be established following the process set out in section 3.5.3.1. The standard target voltages are set out in the table below. *(Aurora Note - +/-2% in most cases)*
- Section 3.5.3.3: The standard target voltages, dead band and delay timer settings at the EHV busbars at 132kV to EHV substations are set out in the tables below. Settings at each substation shall be established following the process set out in section 3.5.3.1. The standard target voltages are set out in the table below. *(Aurora Note - +/-1.5% in most cases, with a 90s or 60s delay and 10s intertap delay)*
- Section 3.5.3.4: The target voltages at 132 to HV and EHV to HV substations have historically been set at slightly different values in different regions across Northern Powergrid and there is an on-going programme to harmonise and in most cases reduce the HV target voltage. The legacy and harmonised target voltages are set out in the table below. *(Aurora Note - +/-1.5% in most cases, with a 120s or 90s delay and 10s intertap delay)*
- Section 3.5.4 This section describes the HV and LV design principles and key assumptions. Voltages at the HV busbar of a 132kV to HV or EHV to HV substation are controlled to the target voltage as described in the above section. There is generally no voltage control equipment on the HV or LV systems, and the voltage on the HV and LV system is managed by the application of a set of design practices.

These practices recognise that downstream of the last automatic voltage controlled point system voltage is influenced by the current flows on the HV and LV system and the tap position of the HV to LV transformer. A key principle is that HV and LV systems are designed based on allocating the overall permitted voltage drop across the HV and LV system between the HV and LV system in such a way that design work on the HV and LV system can be carried out in isolation from each other. It is recognised that this approach, whilst applicable in the majority of cases, may result in unjustified reinforcement or excessive customer connection costs, and in these cases a more bespoke analysis should be carried out that jointly considers the voltage drop on the HV and associated LV systems.

- Section 3.6.1: Where the design study carried out as part of a new demand connection, a new generation plant connection or an internally driven reinforcement (e.g. initiated as part of an Asset Serviceability Review) indicates that system voltage and / or the supply to customers cannot be maintained within the defined limits when applying the current design rules, alternative means of maintaining voltages within prescribed limits as set out in this section shall be considered as an alternative to traditional system reinforcement.
- Section 3.6.9.1: Where there is significant generation connected to a system it may have an effect on the voltage management on that system. Voltage control and power factor control systems used by generators are linked. Generator controllers are usually set to fix the power factor, and let the terminal voltage fluctuate, or fix the voltage and let the power factor fluctuate. These two control options are generally referred to as PQ and PV respectively. Generators should normally be set to operate in PQ mode where normal operation the generator would not lead to voltage constraints. Further details are provided in the Code of Practice for the Economic Development of Distribution Systems with Distributed Generation, IMP/001/007.
- Section 3.6.9.1: Where the application of standard voltage control techniques, or bespoke AVC settings, or LDC are insufficient to manage the system voltage in generation rich parts of the system it may be possible for the generator to operate in PV mode to limit the potential for excessive voltage rise on feeders by importing reactive power to reduce the voltage at their Point of Supply.
- Section 3.6.9.1: Where generator control is being considered guidance should be sought from the System Planning Manager.

2.1.5 Summary

At present, NPg policy for assessing BESS connections is relatively well developed and considers all of the main technical requirements, in conjunction to voltage disturbances. The basic requirement for generation connections including BESS connections is given in IMP/001/007. Further guidance is provided in IMP/001/007/001. This guidance document, in section 3.3.2.2.1, effectively requires two steady state loadflow studies to be carried out on their network model. The studies are used to assess the step voltage change that occurs between the two states and to identify if the network is within the required 3% limit of EREC P28/2. The study cases used are:

- Steady state loadflow with BESS at maximum power import and maximum reactive power import (0.95pf lagging).
- Steady state loadflow with BESS at maximum power export and maximum reactive power export (0.95pf lagging).

Several key observations are made in the NPg documentation, that allow for some flexibility in assessment:

- IMP/001/007 – section 3.3.8 gives NPg allowance for considering multiple generators connected to the same point, and providing additional constrains on later connections. This will be useful for BESS units, which potentially provide similar services.
- IMP/001/007 – section 3.4.3 gives NPg allowance for requiring more detailed studies for MVAr flow during fault conditions, when adding non-synchronous generation, which may affect synchronous generation stability. This is a useful general clause, but the specific concern is not apparent.
- IMP/001/007 – section 3.5.3.3 gives NPg the flexibility to adjust voltage setpoints on AVC schemes. This may be useful where a BESS exceeds a positive voltage rise limit but is satisfactory on a lower voltage rise limit.
- IMP/001/007 – section 3.5.4 gives NPg the flexibility to limit ramp rates of generators, in order to ensure that interaction with tap changers does not occur.
- IMP/001/007 – section 3.5.6.3 notes that where a new power generating module falls within the scope of a CUSC statements of works assessment, operation at unity power factor or fixed MVAr may be desirable. This section also gives NPg the right to request customers to change their power factor.
- IMP/001/007/002 (withdrawn) – section 3.4.2. Notes that PQ control modes can be either fixed power factor or fixed reactive power.

- IMP/001/007/002 (withdrawn) – section 3.6. Notes that fixed power factor is preferred.
- IMP/001/915 - Section 3.6.9.1 – allows the possibility of generators to operate in voltage control mode

2.2 Connection Agreements

Connection agreements between NPg and Generators include an agreed Maximum Export Capacity (MEC) given in MW and an agreed Main Import Capacity (MIC) also given in MVA.

Generation units have a declared Registered Capacity in MW, which is defined in EREC G99. In accordance with EREC G99, generators are obliged to ensure that non-synchronous Power Generation Modules have the capability to operate at their full Registered Capacity across a range of power factors from 0.95 lag to 0.95 lead when exporting. The connection agreement typically indicates the required operational power factor for the Power Generating Facility at the time of connection.

Changes to the operating power factor, can be required by NPg, but historically this has only happened infrequently and are currently instructed via writing.

At present EREC G99 does not include provision of operating power factor for import conditions, and therefore the DNOs use the general import provisions in DCUSA Schedule 2B Clause 39.14 and in the Connection Agreement in relation to import power factors. DCUSA requires that:

> The User shall at all times and at its own expense take reasonable steps to maintain the power factor of any supply of electricity through each Connection Point is between unity and 0.95 lagging unless otherwise agreed with the Company in the relevant Bilateral Connection Agreement.

The implications of current practice, therefore, give rise to a number of considerations:

- If an export operating power factor is specified to a generator, they will operate in this manner. As the exported active power from the generator's installation changes in response to dynamic setpoints, the exported reactive power from the generator's installation will adjust accordingly if in power factor control mode;
- If an import operating power factor is specified to a generator, they will operate in this manner. As the imported active power from the generator's installation changes

in response to dynamic setpoints, the imported reactive power from the generator's installation will adjust accordingly if in power factor control mode;

- Some confusion may exist about sign convention for power factor when a Power Generating Module changes between export and import (as discussed in section 3.2).

Connection agreements do not currently specify the services that the BESS are limited to, and it is noted that there are some significant differences between a BESS that trades in the wholesale or the Balancing Mechanism and a BESS that provides Dynamic Services. NESO currently contracts for three dynamic frequency-based services, known as DR, DM and DC. The DR and DM services are continuously operating services designed to help regulate the system frequency during normal operation, whilst the DC service is intended as a post-fault recovery service. Details of the performance requirements can be found on the NESO website [9] but are summarised in Figure 2-1 below.

In all cases, it is important to note that the services track the system frequency and respond to frequency excursions by altering their output power. The DR / DM services are designed to respond to frequency changes within the range of ±0.2 Hz and the DC service is designed to respond to frequency changes within the range of ±0.5 Hz. Details of the Dynamic Services can be found on the relevant NESO webpage [9].

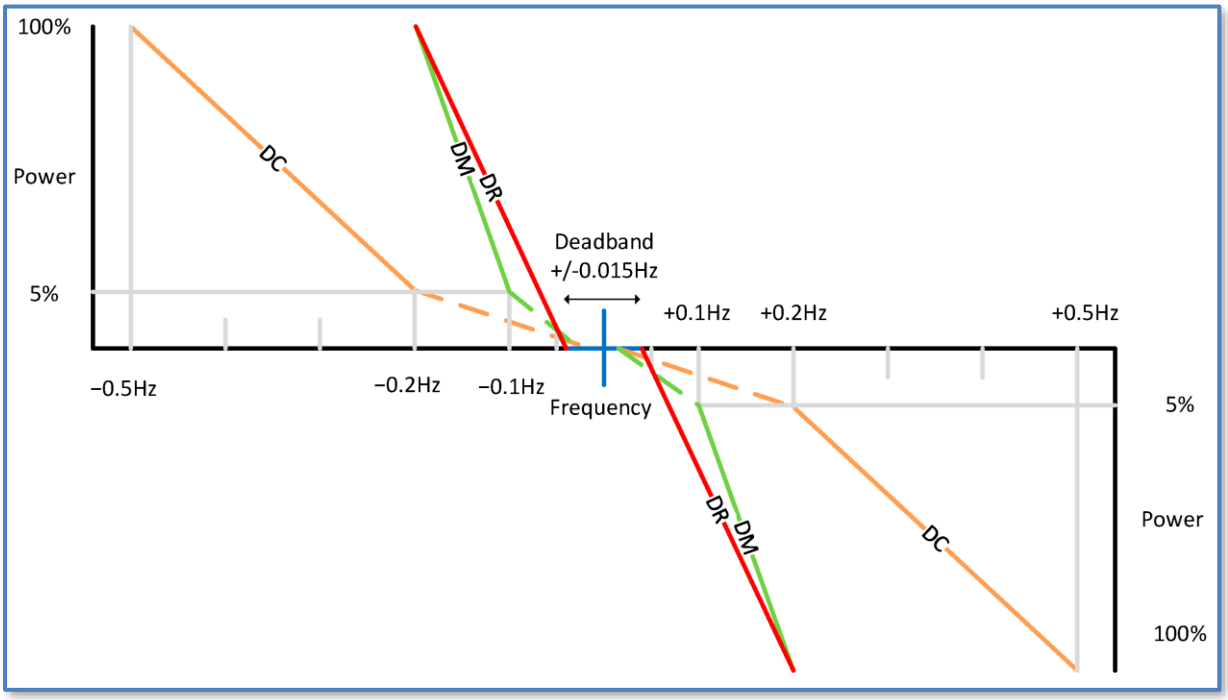

Figure 2-1: NGESO Dynamic Services

2.3 Existing Policy Questions

To assess if the existing NPg policy is suitable, the most robust method is to question the assumptions implicit in the policy to see if they are credible and supported by theoretical and practical knowledge. The following general questions are posed in relation to the policy:

1. Is a BESS unit swinging from full import to full export in a short time scale credible?
2. Is a BESS unit swinging from full export to full import in a short time scale credible?
3. How often do frequency disturbances occur, will they trigger dynamic services and what time scale of a large power change is credible?
4. Will there be potential interaction with transformer tap changer settings?
5. What target power factors are BESS units operated on and why is this selected?
6. Is assuming a reactive power swing from maximum VAr import to maximum VAr export (or vice versa) at the same time as the MW power change reasonable?
7. Are there any shortfalls with carrying out the assessment using two steady state loadflow studies?
8. How do PPCs consider power factor during BESS ramps from import to export?
9. What practice should be used for assessing the impact BESS connected in adjacent parts of the network?

The following responses are suggested to these questions:

1. **Question**: Is a BESS unit swinging from full import to full export in a short time scale credible?

   Response: Yes, this is a credible scenario in a number of different cases.

   a. For DR and DM operation modes, it is credible but should be uncommon. NESO policy on system frequency is defined in the FRCR [10] which sets out the normal operational limits of 50.2 Hz, to 49.8 Hz, along with a maximum RoCoF limit of 0.5 Hz/s. The speed of system frequency change depends on the overall system inertia, but based on the above parameters a frequency change could occur from 50.2 Hz to 49.8 Hz within 1s, and hence fall within normal NESO operational limits.

   b. It is not credible in the DC service. Full response of a BESS providing a DC service requires a system frequency change from 50.5 Hz to 49.5 Hz (or 49.5Hz to 50.5Hz), and would take the system from one extreme limit to another as defined in the FRCR [10].

   c. When operating in the balancing mechanism, the BESS will receive instructions from NESO to alter its import or export. The speed of the change are defined as either the Run Up Rate (RUR) or Run Down Rate (RDR) and are currently set at 60s [11]. If a BESS was previously importing at full power and received an instruction to export at full power it would therefore swing from full import to full export within 60s. As balancing mechanism and wholesale trades occur half hourly, this is considered a likely scenario.

2. **Question**: Is a BESS unit swinging from full export to full import in a short time scale credible?

   Response: In principle, the response to question 2 is the same as response to question 1. However, in practice, rapid frequency rises are less common than frequency dips, as these only occur if a HVDC link trips during export i.e. there is a loss of a large load on the system, or during a major islanding condition. Historical information on grid disturbances is available online [12].

   Whilst a system frequency disturbance event initiating DC service response resulting in a BESS transitioning from full export to import (or vice versa) is unlikely, a more probable scenario could occur in a BESS unit revenue stacking multiple services or transitioning from import to export mode (or vice versa) during different trading periods.

3. **Question**: How often do frequency disturbances occur, will they trigger dynamic services and what time scale of a large power change is credible?
   Response: The number of frequency disturbances on the system is addressed “Workstream B1: Data Gathering”, which indicates that all nominal frequency disturbances greater than ±0.015Hz trigger a DR response, and frequency disturbances greater than ±0.1Hz would trigger a DM service response. Disturbances great than ±0.1Hz occur approximately 15% of the year. The response is split into sub-points below to clarify the issue, as it is complex.

   a. The speed with which power changes, from a BESS providing dynamic services associated with system events, can occur is inherently unpredictable, as the magnitude of system frequency disturbance is proportional to the magnitude of load / generation change that occurs on the system as a consequence of the underlying system event.

   b. Large events (e.g. loss of HVDC link) are uncommon, but major HVDC links trip sometimes on a monthly basis. The power change as a consequence of such events will follow a predictable behaviour and usually trigger a full response of a BESS providing any DR or DM services.

c. Smaller events resulting in smaller system disturbances occur far more frequently and vary considerably in magnitude; they will consequently produce smaller system frequency disturbances, however. based on the work, in “Workstream B: Data Gathering and Consulting”, it was identified that frequency disturbances greater than ±0.1 Hz occurred for circa 15% of the year and that such frequency disturbances typically result in a BESS only importing or exporting up to 50% of its full export capacity if providing DR or DM services. This is however dependent upon the volume of BESS operators with DR or DM contracts with NESO; which is outside DNOs control.
d. Whilst not a system frequency event, it should be noted that transitions between electricity trading blocks, could trigger a power ramp if a BESS changes it import / export in consecutive trading blocks, although this would be over a slightly longer time frame, as the BESS controller would be responding to setpoint, which is inherently slower than automatic control (refer to question 2).

4. **Question**: Will there be potential interaction with transformer tap changer settings?

   Response: Based on the information from the “Workstream A: BESS – EREC P28 Voltage Fluctuations Assessment” report and the NPg policy [8], it was identified that normal tap operation is slow and operates in 60, 90 or 120s. BESS power changes will generally occur much faster than this. Where BESS power changes occur over a longer period than this, operation of the tap changer will generally be beneficial as it will reduce the magnitude of the voltage change seen by customers.
5. **Question**: What target power factors are BESS units operated on and why is this selected?

   Response: NPg practice is based on selecting target power factor using conventional assessment methods for non-BESS generation (refer to the withdrawn document IMP/001/007/002 section 3.7 [7]) where NPg engineers carry out steady state loadflow studies to identify what appears to be a suitable power factor value. However, this approach is based on an underlying false assumption that a BESS power output will always behave in a similar manner to conventional generation. If the output from a BESS is intermittent, variable and unlikely to be operating at its registered capacity for much of the time, it is probably unreasonable to apply the same approach as for a merchant generator where the output is likely to be more consistent and closer to its registered capacity. However, this approach may be reasonable where a BESS is operating in the wholesale market or balancing mechanism.

6. **Question**: Is assuming a reactive power swing from maximum VAr import to maximum VAr export (or vice versa) at the same time as the MW power change reasonable?

   Response: This assumption is partially reasonable. When set in power factor control mode, the reactive power import/export of a BESS will be in proportion to the MW import/export. Thus, if a BESS active power import/export changes, then the reactive power import/export will change accordingly. One area of concern identified, is that sign convention of power factor and generation vs load does not appear to have been considered (refer to section 3.2).

7. **Question**: Are there any shortfalls with carrying out the assessment using two steady state load flow studies?

   Response: It has been observed in some transient studies that a transient voltage 'swell' can occur as power swings from import to export and from export to import. This phenomenon occurs as the BESS active power import/export approaches zero, and appears to be limited predominantly to when the BESS is operating at unity power factor and is connected to a network with high X/R ratio. This is examined in section 3.5. Hence, the observed maximum voltage change could exceed that established if two steady state conditions are considered.

8. **Question**: How do PPCs consider power factor during BESS ramps from import to export?

   Response: Power Park Controller behaviour is currently unclear, as whilst there are some standards that are followed such as WECC [13], the majority of PPCs are of a bespoke design and covered by the manufacturer's intellectual property restrictions and are not routinely shared. It is therefore impossible to make definitive statements, it is however a concern that different PPCs may use different sign conventions for power factor during export and import modes - refer to above question 6 and section 3.2.

9. **Question**: What practice should be used for assessing the impact BESS connected in adjacent parts of the network?

   Response: Consideration of multiple BESS units is referenced in EREC P28/2 although no details are provided, and whilst guidance is provided in NPg document IMP/007/001 in section 3.3.2.3, it would be reasonable to review that guidance. There is currently little consensus across industry on the most appropriate approach and at present there are two main views:

a. BESSs connected to adjacent parts of the network may be operating in similar modes, as they will be responding to similar market triggers and/or the same frequency disturbances in a similar way, and therefore be providing similar services and behave in the same way.
b. An auction process is used by NESO to bid for DC, DM and DR services, therefore it is unlikely that adjacent BESSs will be operating in the same mode at the same time.

In the absence of national guidance and co-ordination with NESO's contracting process, it seems reasonable for DNOs to assume that co-incident BESS operation will occur.

As noted in the response to questions 6 and 8, one critical issue that was identified during the initial assessment is the use of power factor sign conventions and their application during the assessment of BESS. This is discussed further in section 3.2.

2.4 Longer Term Policy Questions

Longer term policy developments that will be addressed in the B.3 workstream include deeper questions such as:

- Is the use of voltage control mode for a BESS, and/or other types of generation practical or desirable? If so how should that be modelled?
- How can the impacts of coincident power changes associated with BESSs connected to adjacent parts of the network be mitigated?
- How can coincident power changes associated with BESSs connected to adjacent parts of the network be apportioned?
- Can generic models of PPC and dynamic controllers be considered sufficiently robust to assess their performance, and will their inclusion help to minimise voltage disturbances?
- Is the use of RMS simulation modelling necessary to capture the transients that occur in some BESS power changes?

2.5 Summary of Policy Review

The NPg policy for connection of BESS to the system is, in general, reasonable and suitable for most applications. The NPg policy is both detailed and generic, which gives NPg room to make specific decisions on individual projects based on their local requirements.

However, the specific requirement for all generation plant to operate in a fixed power factor, and for the assessment of the generation plant to be assessed for both full import at 0.95pf lagging to full export at 0.95pf lagging is very onerous and may not represent a credible operational scenario for BESSs and may have undesirable implications for the distribution system.

Conventionally, synchronous generation plants would be operated in a fixed power factor mode, and their active power output would be agreed with the DNO in relation to overall system demands and local constraints; the generator associated power factor would be defined by the DNO to meet any local requirements. However, for a BESS providing dynamic services to NESO, the use of a fixed, non-unity, power factor mode may not be beneficial as the BESS is responding constantly to frequency fluctuations on the overall system, and therefore constantly altering its reactive power output in line with the dynamic services requirements; this would lead to localised reactive power swings in the distribution network which may provide deleterious effects as the DNO typically sets generator reactive power output to optimise local network constraints and reduce losses.

For some connections it may be necessary for a BESS to provide reactive power compensation at its connection point, to account for losses due to cable and transformers in the BESS system. If such requirements are necessary, then an alternative to operating at unity power factor would be for the BESS to operate in fixed reactive power mode. This would provide a more stable system MVAr output into the DNO network, as this would avoid the BESS reactive power import / export altering continually as its active power output changes. It is however noted that the majority of BESS sites are located close to main substations, so the need for reactive power compensation is often minimal.

It is therefore suggested that consideration should be given to either requiring the BESS to operate at unity power factor, or that they operate at a fixed reactive power output. Operation at unity power factor is relatively simple and easy to implement, whilst operating at fixed reactive power import/export is also relatively easy to implement, but the target reactive power value must be clearly defined taking into account network load variations. The implications of these approaches and implications for the NPg network are discussed in detail in the following section.

It is also suggested that policy IMP/001/007, wording in section 3.5.6.3 be expanded to allow NPg the right to request that a BESS be moved from power factor control mode, to fixed reactive power mode, or voltage control mode.

SECTION 3 - BESS Assessment Approaches

3.1 Overview

The previous section of the report reviewed existing NPg policy, and in general found the policy to be suitable for application to BESSs connected to the network. Three notable aspects that could be addressed as short-term policy updates were identified:

1) Clarification of the flexibility for BESSs to export at a defined power factor within the range 0.95 lagging to 0.95 leading.
2) Clarification of the flexibility for BESSs to import at a defined power factor within the range 0.95 lagging to unity.
3) Review the initial assessment of BESS operation based on a power changes from full import at 0.95pf lagging to full export at 0.95pf lagging.

These aspects are reflected in connection offers issued by NPg, which, for active power export mode, give a required operational range between 0.95pf leading and 0.95pf lagging, and an agreed target power factor specified by NPg at the time of the connection offer (and potentially subsequently varied anywhere within that range). But for active power import, only operating limits for power factor are defined, namely, that the power factor must stay within the range 0.95pf lagging to unity, and therefore there is some ambiguity on the customer responsibility for pf operation in import mode. There are, however, provisions in DCUSA permitting the DNO to agree a specific operational power factor with the customer.

The requirements when operating in active power import mode, are also unclear in EREC G99 primarily because EREC G99 is focussed on export rather than import. These issues are related and could potentially have a significant impact on the way BESS are assessed and the maximum permitted power change associated with BESS operation.

It is therefore suggested that when the BESS is providing dynamic services, it should be operated and assessed for operation at unity power factor, provided there are no conditions imposed by NESO in the bilateral connection agreement between NPg and NESO and at a fixed reactive power import when these conditions are imposed by NESO in the bilateral connection agreement.

3.2 Power Factor Sign Convention

As noted in section 2.3, questions 6 and 8, it was noted that one of the potential areas of confusion relates to sign conventions of power factor. This is a common area of confusion amongst engineers, and it is easy for mistakes to occur. For the avoidance of doubt, the convention for all power factors for BESS units are based on generator orientation convention, where a lagging power factor means exporting reactive power.

The following sections of the report highlights the implications these policy proposals for the network and provides specific examples of BESS responses.

3.3 Steady State vs Dynamic Simulations

Currently NPg use a steady state loadflow analysis method to consider the impact of a BESS on their distribution network. This approach is simple and robust and easy to apply, however it does not capture any system dynamics that can occur during the transition from one steady state to another. For these dynamics to be captured it is necessary to carry out a time-based simulation, such as Root Mean Square (RMS) or Electromagnetic Transient (EMT) studies.

Dynamic simulations are significantly more complex than steady state assessments and require the provision of detailed, well defined, data from the BESS developer. Typically control systems of synchronous machines, inverters and transformer tap controllers are fully defined within a dynamic simulation model. The principle advantage of dynamic simulations is that they can identify transient electrical disturbances that may occur and also identify any problems with the stability and response of control systems in response to network disturbances.

Conventionally RMS modelling techniques have been used to undertake dynamic simulations where the individual phases of a system are converted to a simplified positive phase sequence equivalent, using a calculation time step of 10ms (conventionally). This allows most slower transient events associated with motor starting, frequency changes and generator governor / AVR response to be modelled accurately. RMS modelling remains the preferred tool of most network operators and consultants as it is robust, relatively simple to complete and accurate for most routine switching and ramping events.

EMT modelling, is significantly more complex than RMS modelling, and the simulation program solves the differential equations of the system, for each individual phase. The calculation time steps are adjustable depending on the phenomena being assessed (typical values of 10-20 µs are used) and significantly smaller time values can be used for assessing lightning and other fast switching transients. EMT modelling is becoming more popular due to increased computing power, but is significantly more challenging and usually restricted to small systems and fast phenomena. It is not considered appropriate for modelling slow battery ramps and step changes.

3.4 Dynamic Simulation

To show the impact of different power factors on the system voltage profile, a simple test network and PPC was developed and dynamic simulations carried out. The configuration of the PPC plays an important role in performance of a BESS, as the PPC controls the inverter output in response to changing MW, MVAr or power factor setpoints. The majority of PPC designs are derived from the WECC standard models [14] of PPCs, but there are usually some vendor specific differences in control loops. The key issue with all PPCs is ensuring that the PID (or PI) controllers have been correctly setup and tuned as part of the commissioning process. This is important for all generators, but most conventional generators operate at fixed active power output, or on defined droop curves in LFSM, FSM. However, BESSs providing dynamic services, will alter their output continually in relation to system frequency, and therefore poorly setup or tuned controllers can lead to oscillations appearing in the active and reactive power output of the BESS.

The test network was based on a 132kV connection point, represented by a grid element with a 10kA fault level, 132kV busbar, 132/33kV, 90MVA, Z=12.5%, Dyn11 step down transformer with an OLTC, 33kV busbar and a 50 MW BESS. This can be seen below in Figure 3-1.

The purpose of the test network is to show the transient system behaviour for power changes of different power factor, and the behaviour during line-drop compensation mode. The following scenarios are shown:

- 1 a) Full Import to Export at Unity power factor
- 1 b) Full Export to Import at Unity power factor
- 2 a) Full Import to Export at 0.95pf lagging
- 2 b) Full Export to Import at 0.95pf lagging
- 3 a) Full Import to Export at 0.95pf leading
- 3 b) Full Export to Import at 0.95pf leading
- 4 a) Full Import to Export at Fixed & +5MVAr
- 4 b) Full Export to Import at Fixed & +5 MVAr

The sign convention in all the study cases is for negative values of active power to indicate a power import from the DNO network to the BESS, and for negative values of reactive power to indicate a reactive power import from the DNO network to the BESS.

Of key note in the responses below is a transient 'swell' that occurs during some of the power ramp events. This is discussed in more detail in section 3.5.

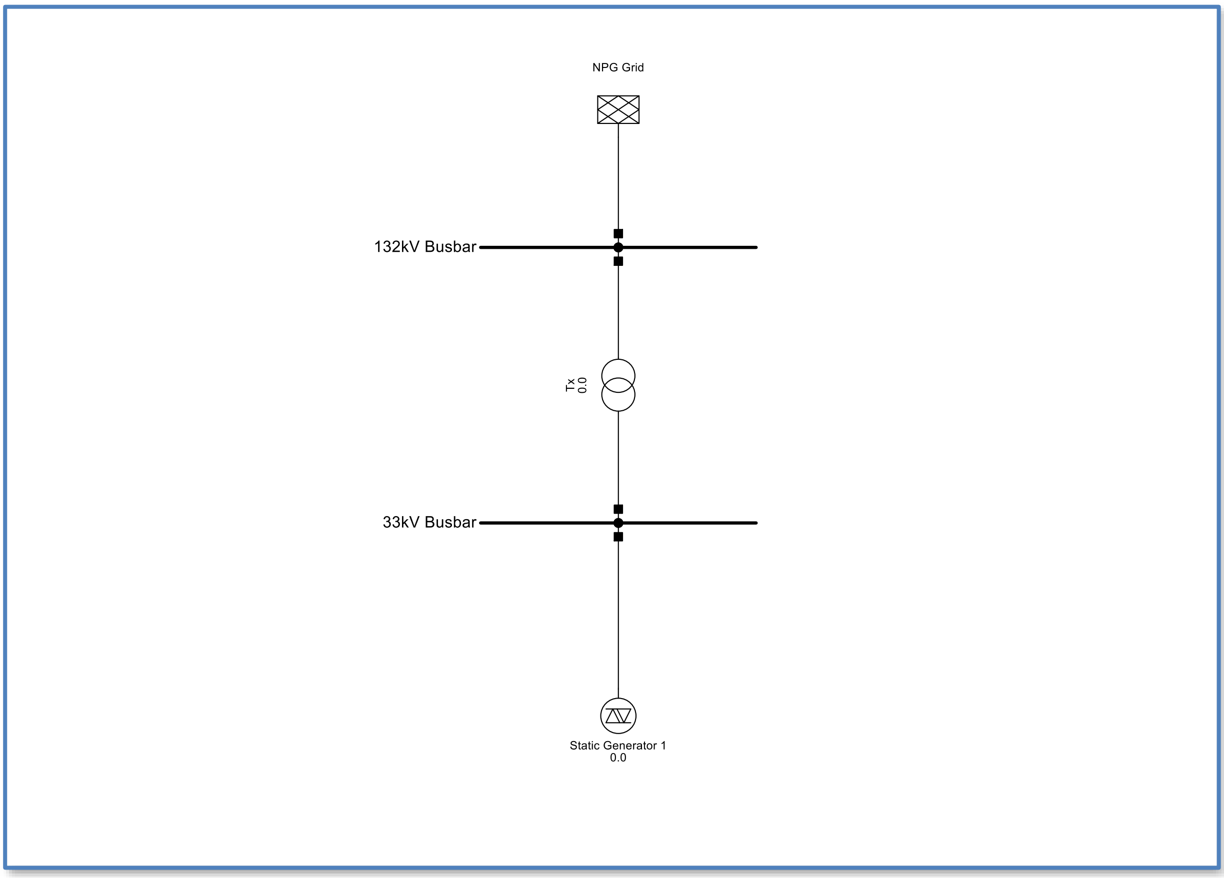

Figure 3-1: Test Network

3.4.1 Case 1a: Import to Export at Unity power factor

This case shows the BESS ramping from full power import (-50MW) to full power export (+50MW), over a period of 1s, with the power factor remaining constant at unity during the operation. The results can be seen below in Figure 3-2.

Of note is the voltage 'swell' that occurs during the transient on the HV (132kV) busbar but is much reduced on the MV (33kV) busbar. The issue of the transient swell is discussed in more detail in section 3.5.

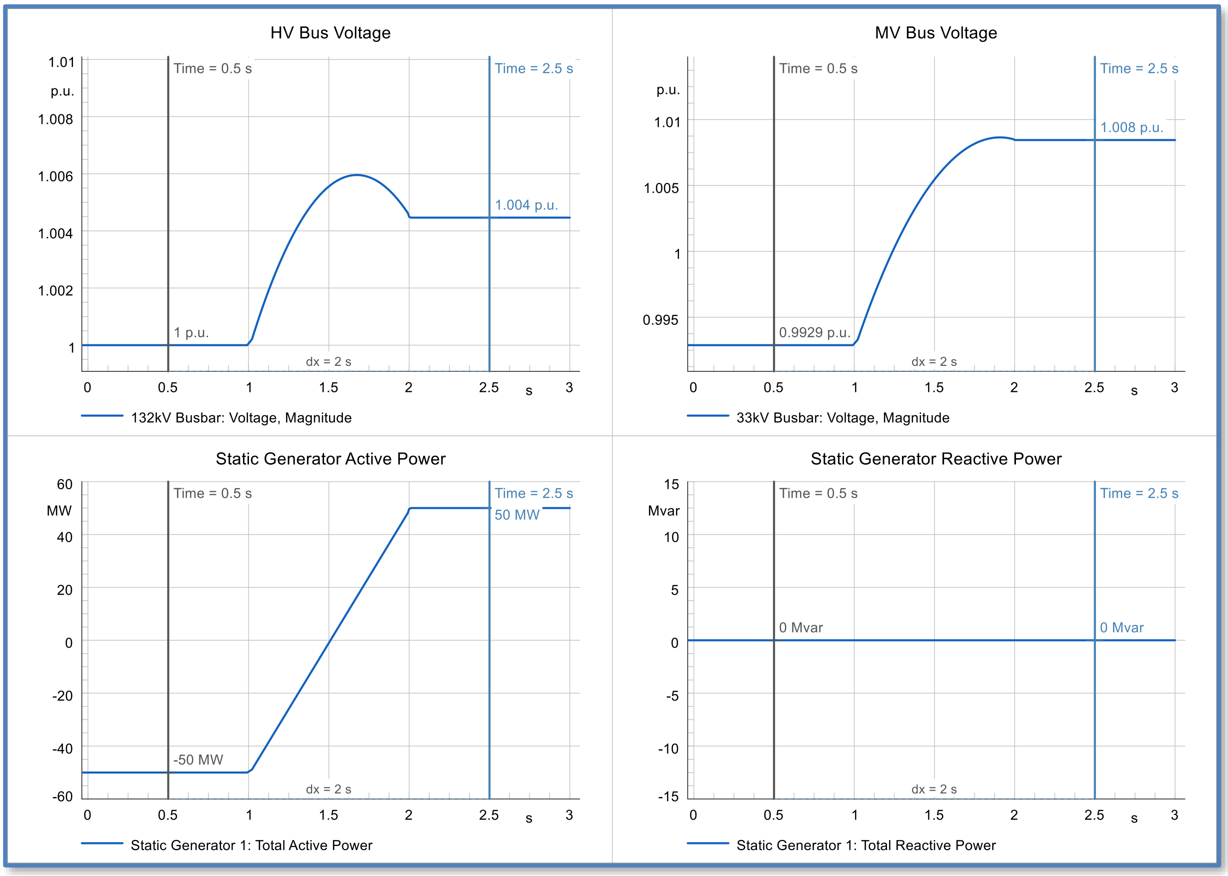

Figure 3-2: Case 1a Import to Export Unity power factor

3.4.2 Case 1b: Export to Import at Unity power factor

This case shows the BESS ramping from full power export (+50MW) to full power import (-50MW), over a period of 1s, with the power factor remaining constant at unity during the operation. The results can be seen below in Figure 3-2.

Of note is the voltage 'swell' that occurs during the transient on the HV (132kV) busbar but is much reduced on the MV (33kV) busbar.

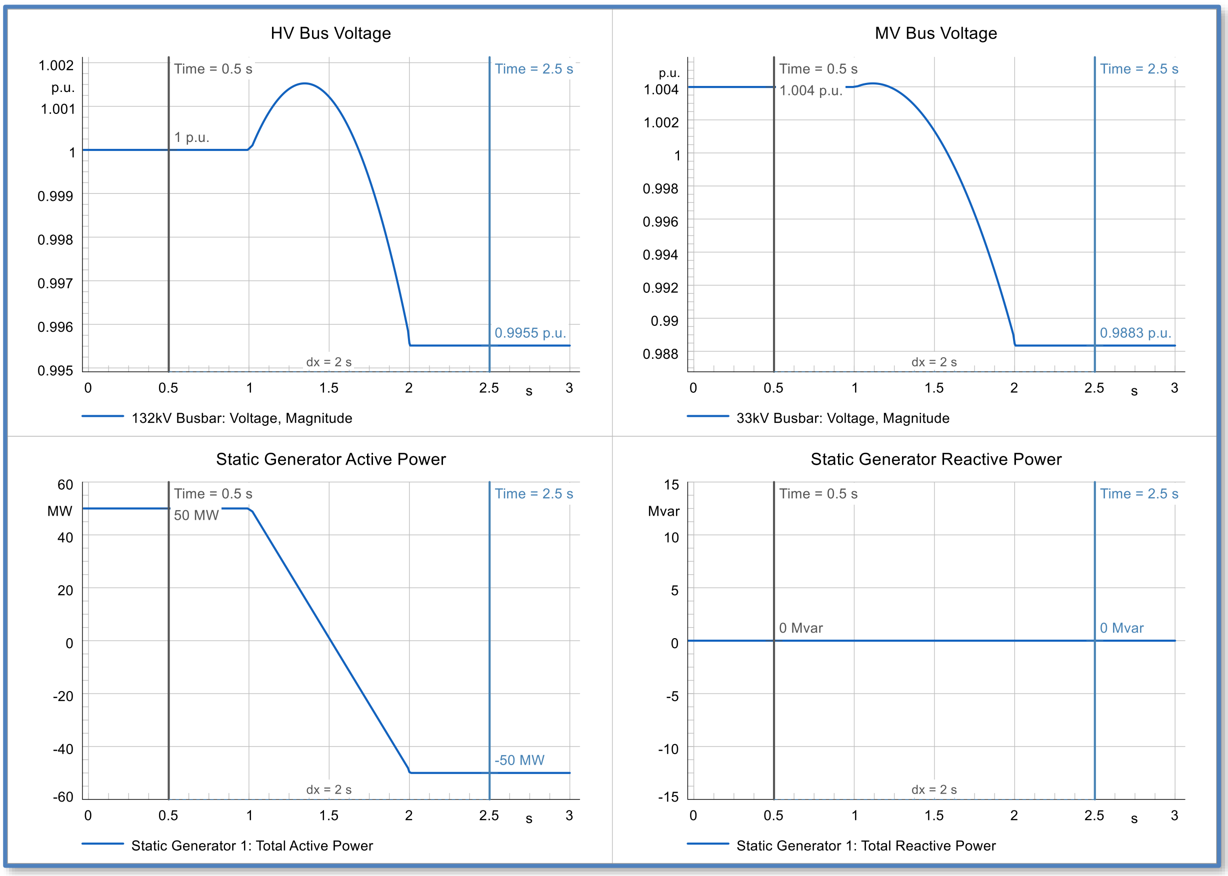

Figure 3-3: Case 1b Export to Import Unity power factor

3.4.3 Case 2a: Import to Export at 0.95pf Lagging

This case shows the BESS ramping from full power import (-50MW) to full power export (+50MW), over a period of 1s, with the power factor remaining constant at 0.95 lagging during the operation. The results can be seen below in Figure 3-4.

Of note is the voltage 'swell' that occurs during the transient is no longer present in this scenario, but the magnitude of the voltage disturbance is much higher (as expected).

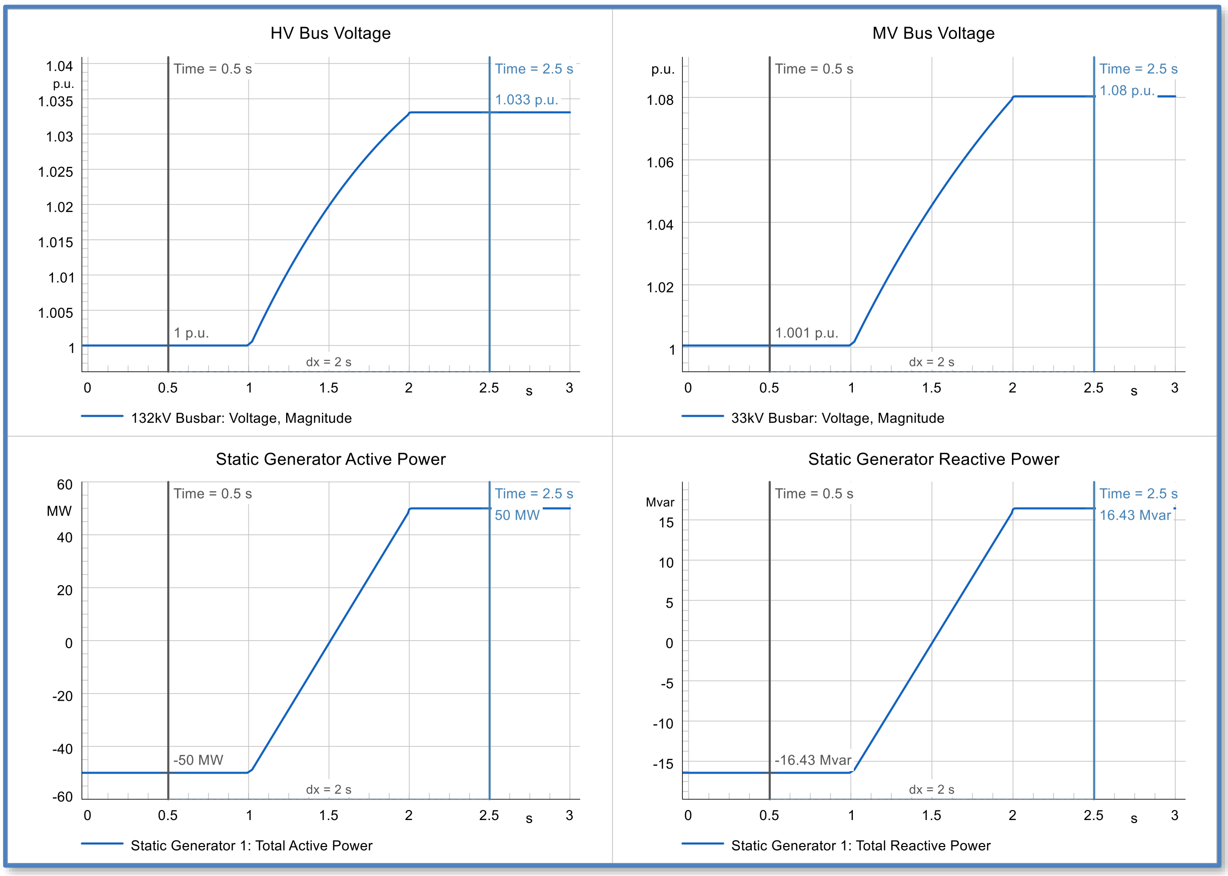

Figure 3-4: Case 2a Import to Export 0.95pf Lagging

3.4.4 Case 2b: Export to Import at 0.95pf Lagging

This case shows the BESS ramping from full power export (+50 MW) to full power import (-50 MW), over a period of 1s, with the power factor remaining constant at 0.95 lagging during the operation. The results can be seen below in Figure 3-5.

Of note is the voltage ‘swell’ that occurs during previous transients is no longer present in this scenario, but the magnitude of the voltage disturbance is much higher (as expected).

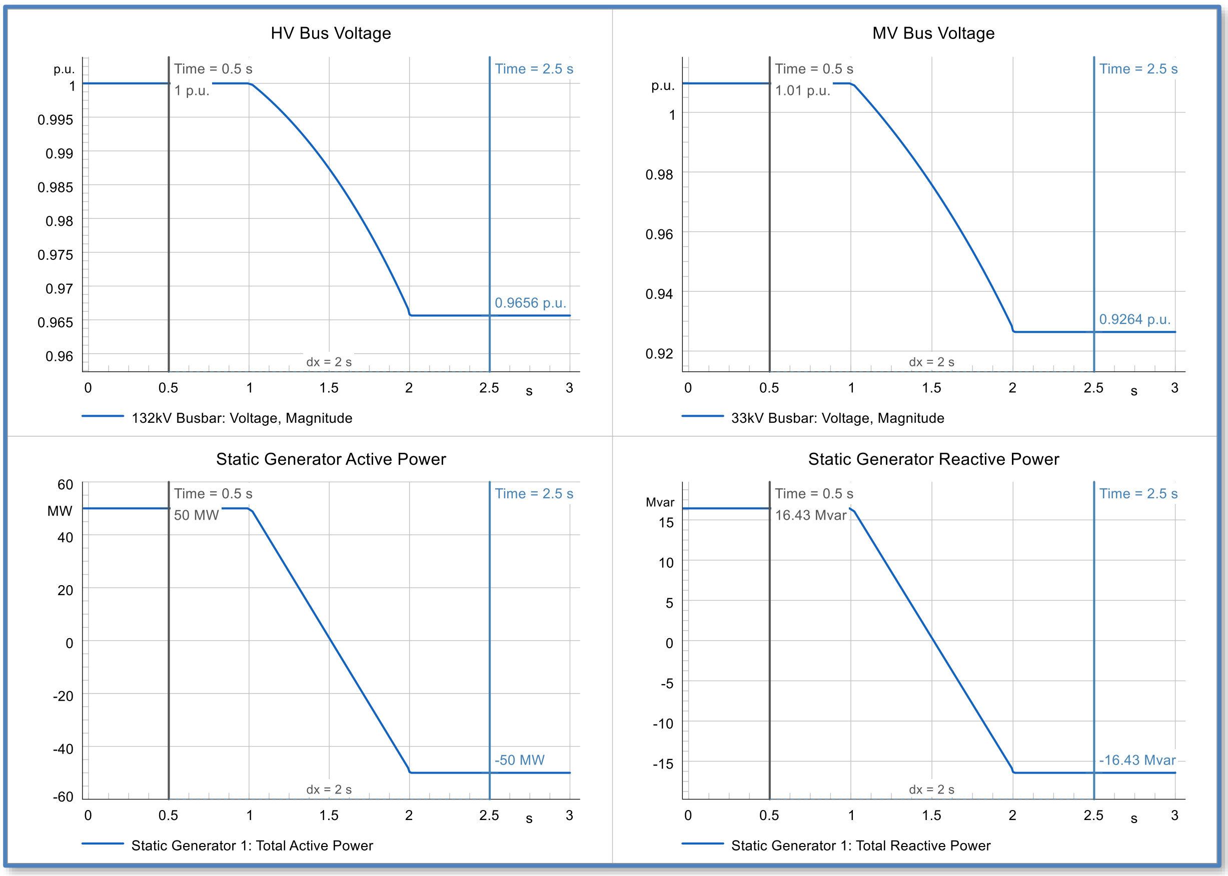

Figure 3-5: Case 2b Export to Import 0.95pf Lagging

3.4.5 Case 3a: Import to Export at 0.95pf Leading

This case shows the BESS ramping from full power import (-50MW) to full power export (+50MW), over a period of 1s, with the power factor remaining constant at 0.95 leading during the operation. The results can be seen below in Figure 3-6.

Of note is the voltage 'swell' that occurs during previous transients is no longer present in this scenario, but the magnitude of the voltage disturbance is much higher (as expected).

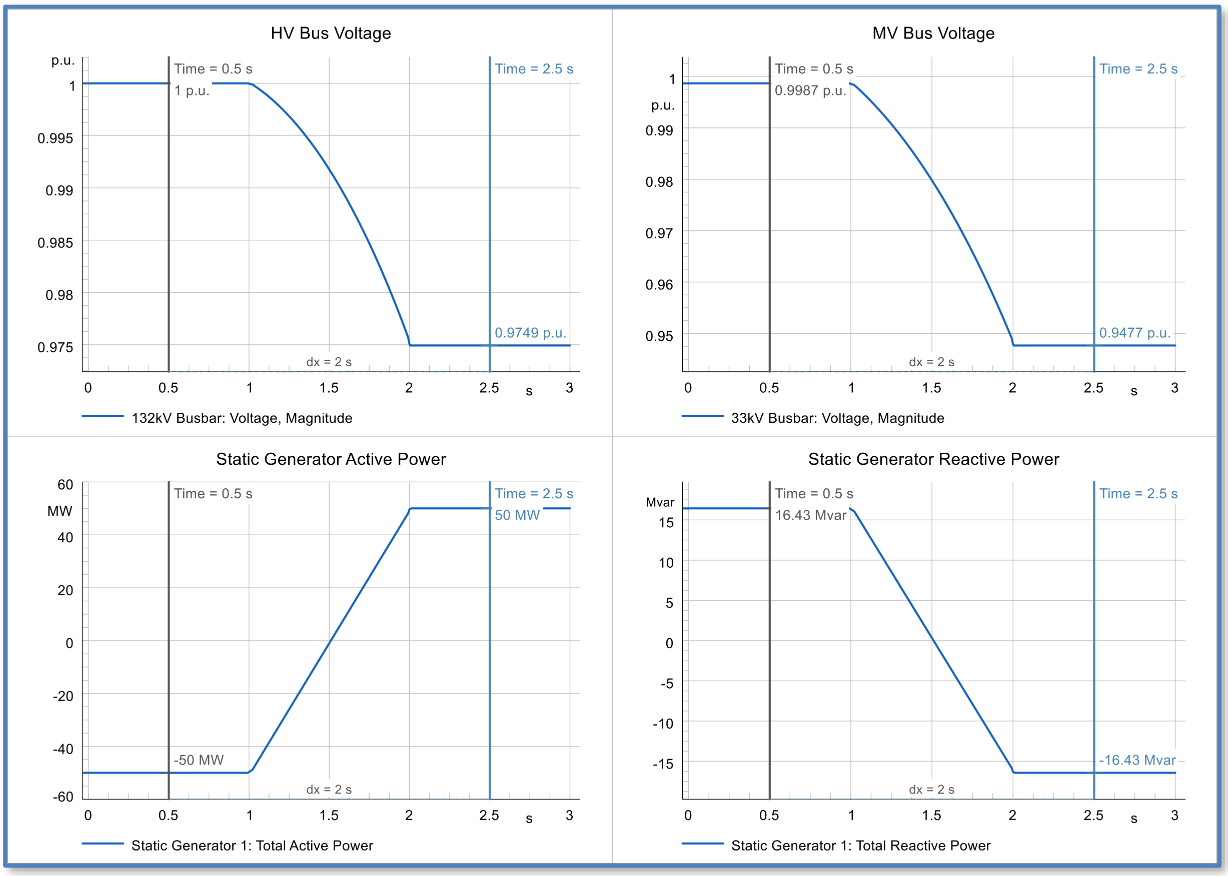

Figure 3-6: Case 3a Import to Export 0.95pf Leading

3.4.6 Case 3b: Export to Import at 0.95pf Leading

This case shows the BESS ramping from full power export (+50 MW) to full power import (-50 MW), over a period of 1s, with the power factor remaining constant at 0.95 leading during the operation. The results can be seen below in Figure 3-7.

Of note is the voltage 'swell' that occurs during previous transients is no longer present in this scenario, but the magnitude of the voltage disturbance is much higher (as expected).

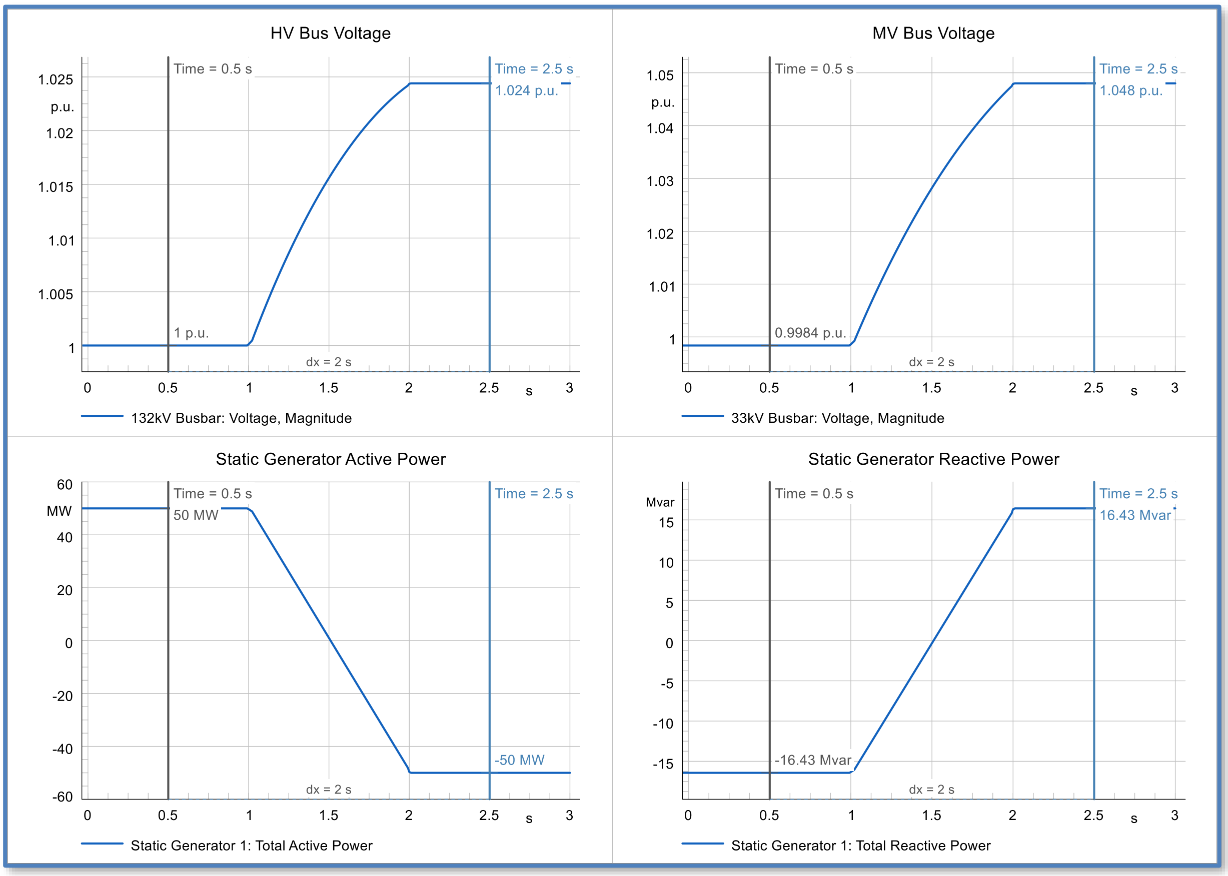

Figure 3-7: Case 3b Export to Import 0.95PF Lead

3.4.7 Case 4a: Import to Export at Unity power factor & 5MVAr Compensation

This case shows the BESS ramping from full power import (-50MW) to full power export (+50MW), over a period of 1s, with the reactive power remaining constant during the operation, i.e. exporting 5MVAr of reactive power. The results can be seen below in Figure 3-8.

Of note is the voltage ‘swell’ that occurs during the transient on the HV (132 kV) busbar, but is much reduced on the MV (33 kV) busbar.

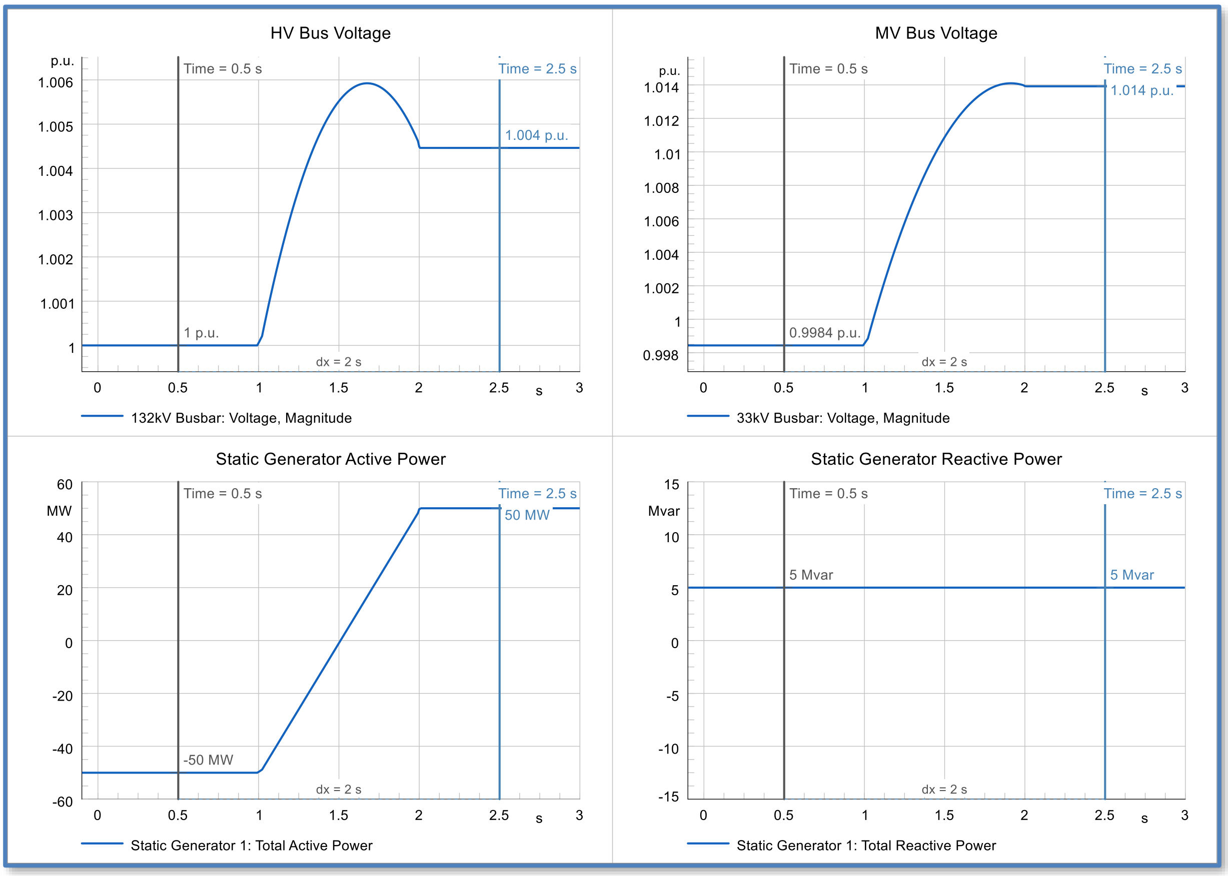

Figure 3-8: Case 4a Import to Export & +5MVAr

3.4.8 Case 4b: Export to Import at Unity power factor & +5MVArCompensation

This case shows the BESS ramping from full power export (+50MW) to full power import (-50MW), over a period of 1s, with the reactive power remaining constant during the operation, i.e. exporting 5MVAr of reactive power. The results can be seen below in Figure 3-9.

Of note is the voltage 'swell' that occurs during the transient on the HV (132 kV) busbar but is much reduced on the MV (33 kV) busbar.

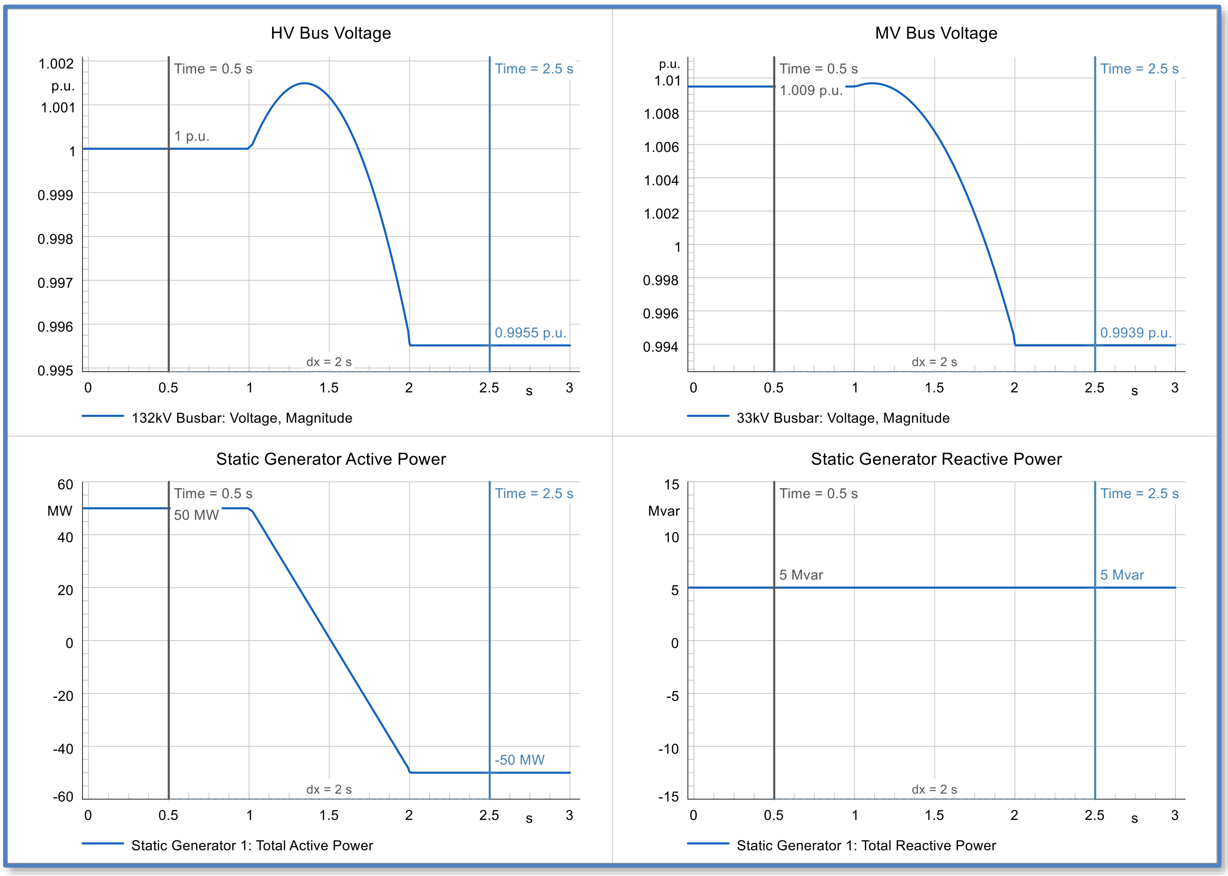

Figure 3-9: Case 4b Export to Import at + 5MVAr

3.5 Dynamic Analysis – Voltage 'Swell'

During the various dynamic studies, a voltage 'swell' was identified in some of the results, and have been noticed in other studies related to BESS operation. There are three fundamental reasons for seeing a voltage swell in the dynamic simulation study results on a system during a ramp change of the input or output from a BESS: the first is due to a using a simplified dynamic modelling approach that does not correctly consider BESS behaviour and the control system operation, the second is due to an actual physical phenomena and the third relates to the configuration of the PPC. These are considered in turn below:

3.5.1 Simplified Modelling Approach

Many developers and consultants carry out an EREC P28 study in the early stages of a project, before the PPC is correctly defined and parameterised. The modelling approach uses a single equivalent generator and a basic control signal to ramp its power output up from export to import and vice versa; this was the method used in section 3.4 of this report. This approach has the advantage that it is quick and easy to do, however it is not fully technically correct. In an actual system, the PPC is responsible for dispatching P and Q setpoints to the inverters based on a measurement Point of Interface (POI), which is usually the metering circuit breaker. As the active power output increases / decreases to meet the target P setpoint the BESS inverters should provide more / less reactive power to maintain the nominal power factor defined at the POI. This reactive power required by for the transformer and balance of plant as the active power changes. When the simplified modelling approach is used, this does not happen and the reactive power is provided by the grid instead, which is not correct.

This is best demonstrated via a simple test network. The simple network shown in Figure 3-1: Test Network was used, and the 132/33kV transformer rating was set at 90MVA and the impedance was adjusted across a range of Z=10%, Z=15%, Z=20% and Z=25%. Dynamic simulations were carried out with a fixed upstream fault level of 10kA & X/R ratio of 10. The results are shown in Figure 3-10, where it can be seen that the voltage swell becomes more pronounced as the transformer impedance rises, this is because the grid is providing more reactive power in each case, as high impedance transformers require more reactive power than an equivalent lower impedance transformer. As noted above, in a fully detailed model this transient swell should be much smaller and the BESS would be responsible for providing the reactive power for the site.

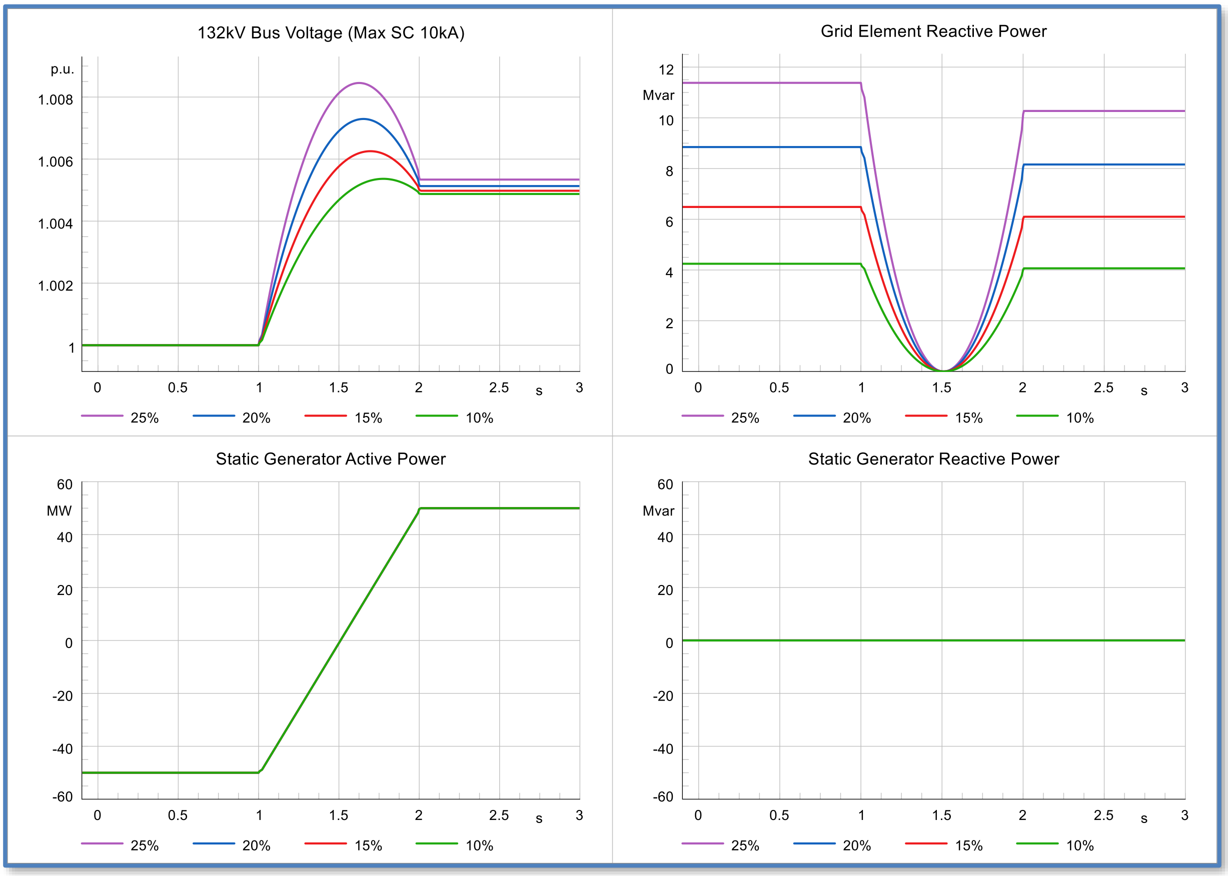

Figure 3-10: Swell Detail for Simplified Modelling

3.5.2 Actual Phenomena

In many cases the voltage swell will be due to incorrect modelling as described above, however in certain circumstance a real voltage swell might also occur. This requires specific network conditions to be present. From simple circuit theory, the grid fault level is the defining parameter of the magnitude of the voltage change; when the grid fault level is low there will be a large voltage changes, and when the system fault level is high, there will be a smaller voltage change, associated with a change in BESS import / export active power. However, there is an interesting "second order" effect related to the grid X/R ratio which can have an effect on the magnitude of the voltage change.

When a linear active power ramp occurs in a BESS, it would be typical to expect a corresponding linear voltage change. i.e. if active power is ramped up from import to export in a straight line you would expect the voltage to ramp up from 1.00pu to a higher value in a straight line. However, this is not the case, as a linear ramp in voltage only occurs when the grid is purely resistance (X/R = 0). In all real systems the X/R is non-zero. Given the system impedance (Z = R +jX), and the voltage dropped across the network is given as $V_{drop} = I(R+jX)$, *i*f the fault level (kA value) remains constant, then the value of Z stays constant, but the value of R and X change and the angle of the impedance changes and therefore the angle of the voltage drop also changes. From a network impedance calculation perspective, if the voltage angle changes to become more impedance based, this will result in a parabola shape voltage change occurring for a linear ramp in active power.

As the value of X becomes increasingly large it is possible to detail this phenomena further through the use of phasor diagrams and formula derivations, but this would serve limited benefit in the B.2 workstream report.

The phenomena can be seen through carrying out and a test network. A simple test network shown below, with a 33 kV grid busbar and a 33 kV terminal busbar, connected via a short impedance. A series of dynamic simulations were carried with a constant grid fault level of 10kA and increasing levels of X/R ratio from 20, 30, 40 & 50. The results can be seen below in Figure 3-12, where the magnitude of the voltage swell increases for higher X/R ratios, but a constant network fault level.

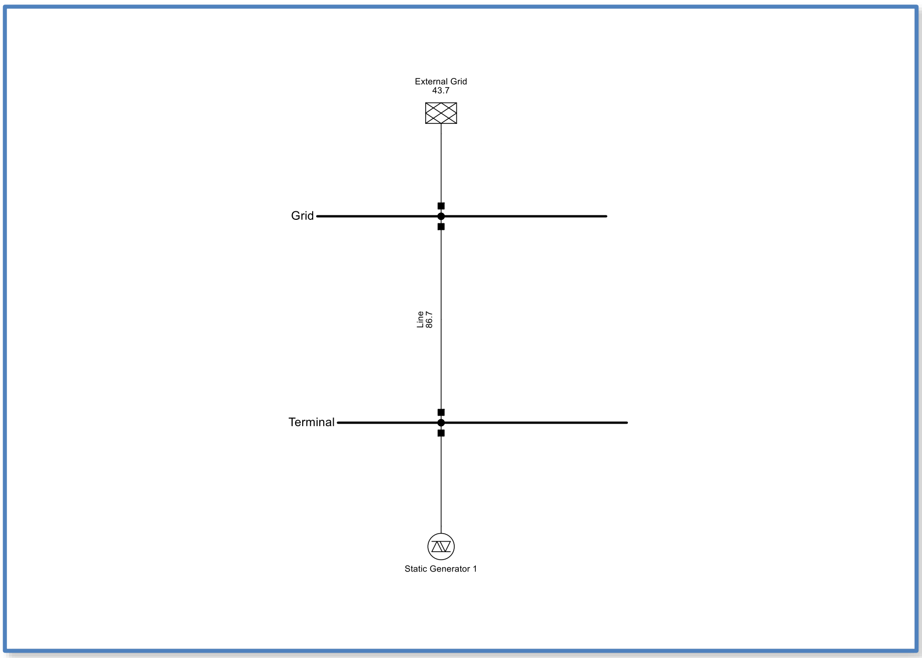

Figure 3-11: Simple Test Network

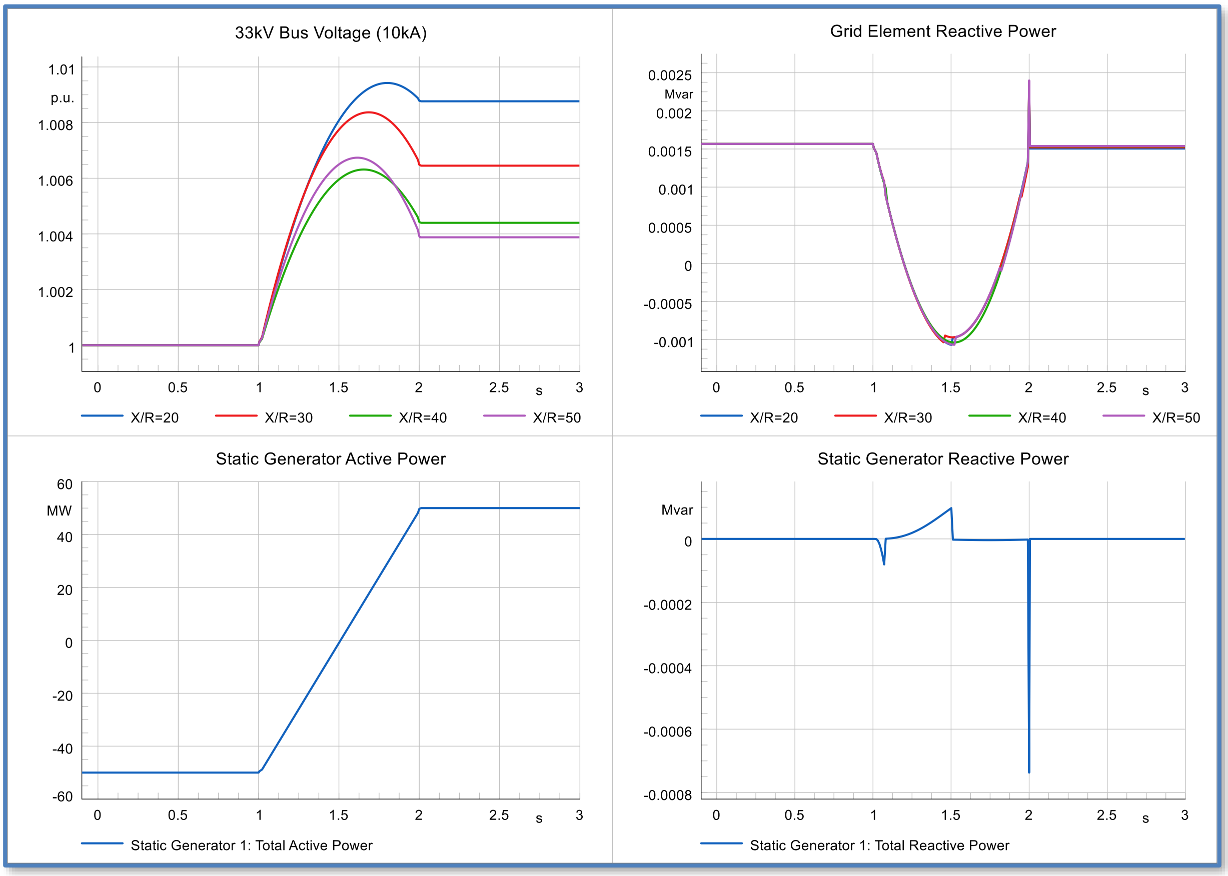

Figure 3-12: Swell for High X/R Ratios

3.5.3 Further Considerations – PPC Tuning

A final consideration related to the voltage swell is the tuning of the PPC controller. If the PPC gain factors for the PI controller are set very fast / high there are likely to be overshoots and more complex dynamics occurring during the power ramp. This can also create results similar to the voltage swell seen in the simplified modelling approach; if the active power control loop has a faster control time than the reactive power control loop, the grid will have to provide the increased reactive power instead of the BESS inverters – as they will not be able to respond quickly enough.

These issues depend on the speed with which the power change ramp occurs. Should a fast (1s) ramp occur, the PPC control loops must have a quick response in order to deliver the power, and any transient overshoots and mismatches between the active and reactive power control loops will be more notable. However, a slower ramp would allow the controllers to run-up slowly allowing any drift between the active and reactive control loops to be minimal.

This configuration and tuning of controllers is much more subjective, and relate to the controller setting and target rise and settling times, rather than to the system fault level and X/R ratio. This issue will be discussed further in the workstream B.3 report.

3.5.4 Summary

It has been shown that a transient voltage swell can occur for three reasons. Firstly, it can be due to a simplified modelling approach, and is less important, although reviewers should be aware of the phenomena. Second, is a real physical phenomena associated with high X/R ratio networks; this can occur in real systems where the network is supplied by large transformers and where the network short circuit level is low. A common case where this could occur is for substations where the upstream grid level is weak and the step-down transformers have a high impedance (resulting in a high X/R value). Thirdly, it can occur due to the settings in the active and reactive power control loops of a PPC, and drift between the two loops can become pronounced during fast ramps.

The use of dynamic studies to assess the impact of BESS ramps, is a useful tool, as it can identify the potential for voltage swells to occur during the transition between export and import and vice versa. The different modelling approaches (simple model with no controller vs. full model) have different advantages and drawbacks – the simple approach can be done quickly and at the early stages of a project, bit may give overly pessimistic results. A more detailed method considering a PPC will be more accurate, but typically cannot be done until much later in a project, but will identify any transient problems far more accurately. For BESS ramps, the use of RMS modelling is therefore recommended; there is no specific need for EMT based analysis as this will provide minimal benefit and create much more work.

3.6 Summary of Dynamic Analysis

A summary of the key results is shown below, for each of the study cases shown. It can be seen that consideration of a MVAr swing significantly increases the voltage fluctuations on the MV and HV busbar – which is an expected result. Scenarios 1 and 4, produce almost identical voltage results, even though in Scenario 4 the BESS is also providing 5 MVAr constant compensation; this is expected as the total MVAr change remains the same between the two scenarios.

Scenario	Case	Steady State ΔV % on MV busbar (33kV)	Steady State ΔV % on HV busbar (132kV)
1a	Unity power factor Import-Export	+1.6	+0.4
1b	Unity power factor Export-Import	-1.57	-0.45
2a	0.95pf Lagging Import-Export	+7.9	+3.3
2b	0.95pf Lagging Export-Import	-8.36	-3.44
3a	0.95pf Leading Import-Export	-5.1	-2.51
3b	0.95pf Leading Export-Import	+4.96	+2.4
4a	Unity power factor & +5MVAr Import-Export	+1.56	+0.4
4b	Unity power factor & +5MVAr Export-Import	-1.51	-0.45

The values in the table above exclude the transient voltage 'swell' identified during the simulation.

3.7 Steady-State Analysis of Step Voltage Changes

The dynamic studies conducted above show that considering a reactive power swing occurring at the same time as an active power swing results in a significant increase in the voltage step change on the MV and HV busbars as compared to the unity power factor case or the fixed reactive power case.

In order to quantify just how much the requirement to consider 0.95pf lag to 0.95pf lag is constraining the amount of BESS that can be connected to a EHV feeder, assuming that each BESS connection permits a power change from full registered capacity import to export, as compared to a unity power factor approach, a series of steady-state load flows have been conducted in DIgSILENT PowerFactory to determine the maximum amount of BESS (in MW) that can be connected to a EHV feeder for various fault levels. That is, for a given fault level, we wish to find the amount of BESS in MW that could be connected to a 33kV PCC such that the maximum voltage step change just hit the EREC P28/2 3% limit.

This analysis has been carried out by conducting steady-state load flows on a typical 33kV circuit, i.e., one that has a rating of 40MVA. The steady-state load flow approach only considers the difference in voltage magnitude before and after the power change and ignores any voltage 'swell' that may occur during the power ramp. As the modelling tools NPg designers use currently have limited ability to carry out transient studies, the steady-state approach replicates NPg's existing methodology for carrying out voltage step change assessments using IPSA and DINIS software.

3.7.1 Steady-State Step Voltage Change Methodology

The steady state Step Voltage Change (SVC) assessment is one of the tools used by NPg in assessing the suitability of a BESS connection, along with other aspects such as circuit rating, fault level, thermal limits and NPg connection policy etc. and can often be a significant constraint to connection.

When considering the SVC limit, assuming there are no other significant constraints (i.e. network capacity, fault level, thermal rating etc.), the step voltage change depends largely on the network X/R ratio and to some degree as well as the overall fault level in kA. A range of values for typical X/R ratio and minimum fault levels for a 33 kV network have been considered as follows:

- Minimum 33kV fault level at the PCC of: 5 kA, 10 kA, or 15 kA
- X/R ratio at the 33kV PCC of: 10 or 15

The fault level and X/R ratio have been converted to a simple impedance (X and R) representation of the 33kV network as shown below in Figure 3-13. For each combination of fault level and X/R ratio two steady-state load flows have been carried out: one load flow with the BESS importing maximum active power, and the second with the BESS exporting maximum active power.

Two modes of reactive power control have been considered:

1. Initial load flow: Maximum real power import at 0.95pf Lagging, Final load flow: Maximum real power export at 0.95pf Lagging (as per current NPg policy)
2. Initial load flow: Maximum real power import at Unity power factor, Final load flow: Maximum real power export at Unity power factor.

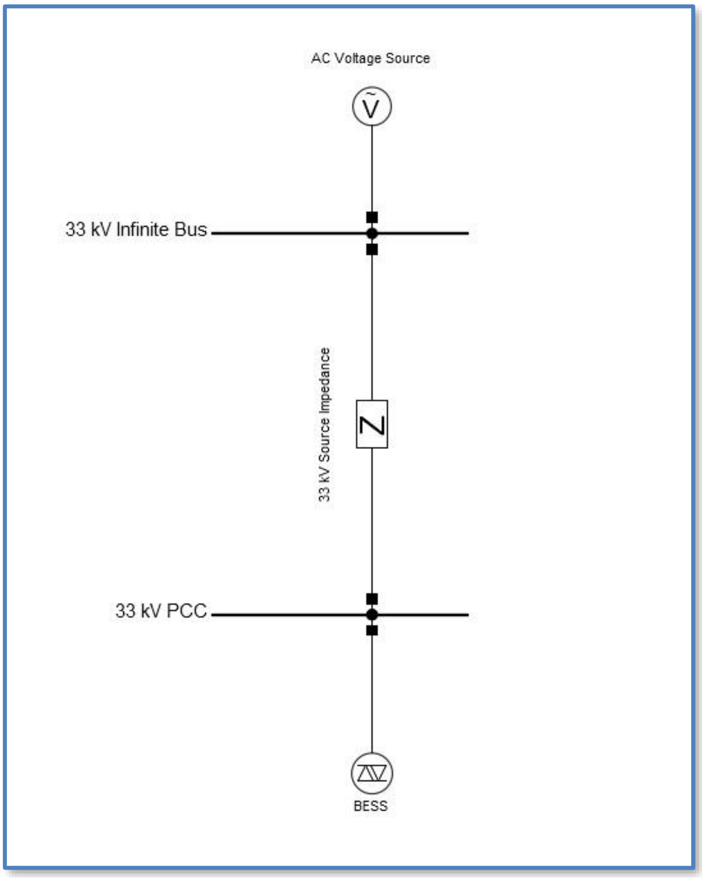

Figure 3-13: Steady-State Analysis of 33kV Step Voltage Change due to BESS Power Step Change

In each case, the BESS active power has been varied using an iterative process to find the maximum value of real power at which the difference between the voltage at the 33kV PCC during the initial load flow and the final load flow precisely equals the EREC P28/2 limit of 3% for step voltage changes. This value then represents the maximum amount of unrestrained BESS that could be connected to the 33kV PCC whilst complying with the EREC P28/2 step voltage change limits, assuming that there are no other network constraints.

3.7.2 Steady-State Step Voltage Change Results

The results are shown below in Figure 3-14 and Table 3-1.

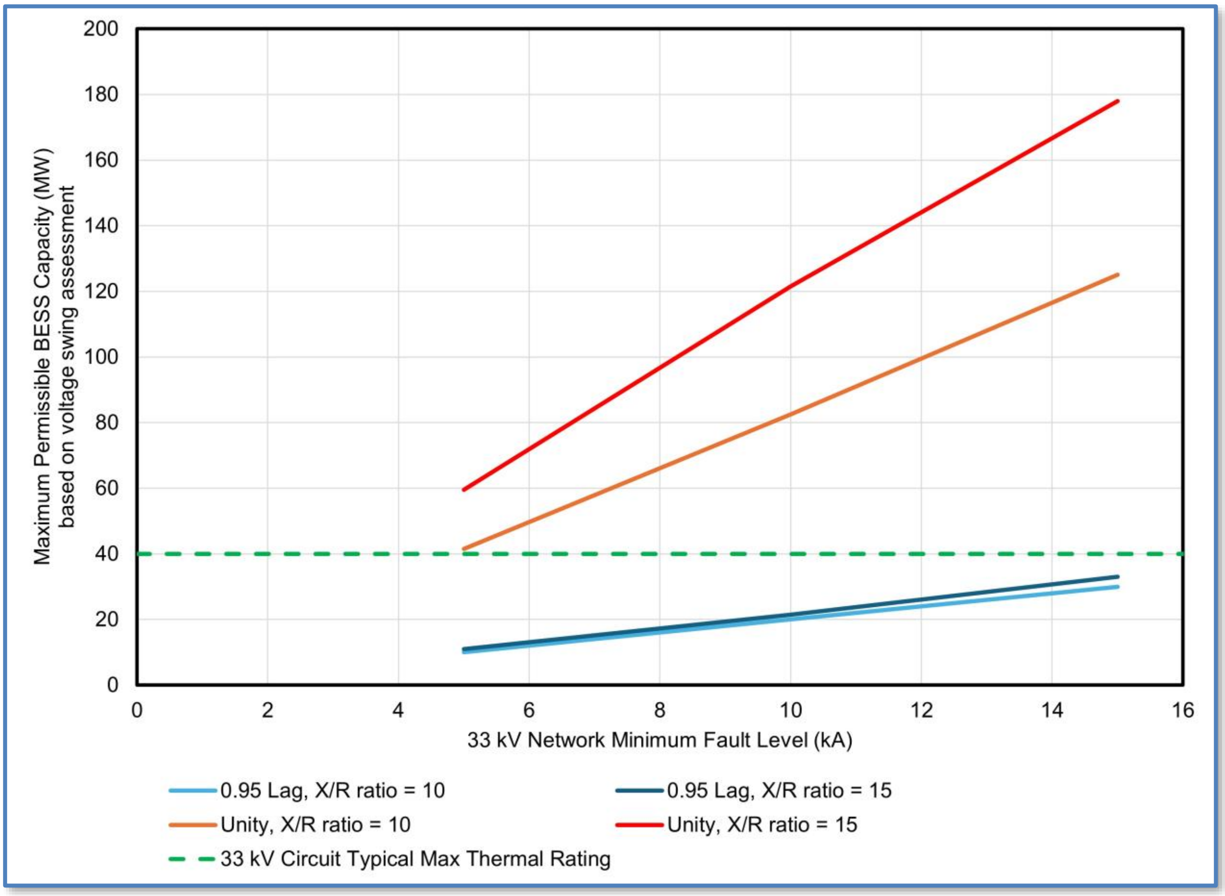

Figure 3-14: Maximum Permissible BESS Capacity vs. Network Fault Level considering Steady-state Analysis of Step Voltage Changes

A summary of the key results is shown in the table below; however, it should be noted that these are based on a simple system strength (fault level and X/R) basis, and do not consider other limiting factors such as cable ratings, thermal limits, etc. Where a BESS is sized at the typical thermal limit of 40MW for a 33 kV circuit then, for the usual range of fault levels and X/R ratios, it can be unconstrained if operated at unity power factor, however, if it is required to operate at 0.95 pf, then the BESS capacity becomes constrained.

Table 3-1 Maximum Permissible BESS Capacity vs. Network Fault Level

33 kV Fault Level (kA)	X/R Ratio	Maximum Permissible BESS (MW)	
		0.95pf Lagging to 0.95pf Lagging	Unity power factor
5	10	10	41.5
10		20	82.5
15		30	125
5	15	11	59.5
10		21.5	121.5
15		33	178

As can be seen from the results, there is a significant reduction in the capacity of a BESS with unrestricted network access that can be connected to a 33kV circuit when power changes are assessed based on 0.95pf Lagging to 0.95pf Lagging compared to assessing power changes based on unity power factor operation.

The X/R ratio of the network also has some affect, with a higher X/R ratio allowing a higher capacity BESS to be connected for the same fault level. Interestingly, the effect of X/R ratio is more pronounced when assessing voltage changes based on unity power factor as compared to 0.95pf Lagging to 0.95pf Lagging.

The reason for this is because, in the limit, as the X/R ratio increases and becomes infinite (purely reactive connection), provided the site is operating a unity power factor, there is no difference between the initial voltage magnitude when importing full active power and the final voltage magnitude when exporting full active power. However, there may be a transient voltage 'swell' in the voltage magnitude in the middle of the active power change, which is more significant for high X/R ratios. This voltage 'swell' becomes most pronounced when the X/R ratio is infinite. The above analysis, however, and NPg's existing policy does not consider this swell in the middle of the power change, as it is based solely on assessing the steady-state initial voltage and the steady-state final voltage, rather than transient voltages in the middle of the change.

Further modelling in workstream B.3 will quantify the magnitude of transient voltage 'swells' in the middle of active power swings and determine how they are related to X/R ratio, to ascertain if initial and final steady-state load flows alone are sufficient for assessing BESS step voltage changes against P28.

3.8 Summary of Dynamic and Steady-State Analysis

This section concludes that consideration of a BESS operating at unity power factor significantly reduces the voltage step changes on the 33 kV busbars, which is in keeping with the expected behaviour. If the BESS is operating at unity power factor then the associated step voltage changes on the DNO network are minimised.

SECTION 4 - DISCUSSION & CONCLUSION

The activities in Workstream B.2 reviewed the overall policy of NPg for connection of BESS units to the system. It was identified that the general policy approach was reasonable in most areas and assessing the active power swinging from import to export and vice versa was reasonable. However, it was identified that the NPg policy approach to setting power factor values and assessing a corresponding reactive power change was very onerous and may not be desirable. There are a number of specific reasons for this:

1. Operating a BESS providing dynamic services to NESO at a non-unity power factor is not necessarily beneficial to NPg, as when providing dynamic services, the BESS real power output will change continuously in response to the system frequency. This means, that the reactive power flow will also vary continuously and is therefore unlikely to be beneficial to ensuring a stable system voltage.
2. Operating a BESS providing dynamic services to NESO at unity power factor significantly reduces the voltage step change on the network when providing dynamic services to NESO and allows larger BESS units to connect.

There is ambiguity and lack of clarity throughout industry about sign conventions used when a BESS transitions between lagging power factor when exporting and importing. This can lead to confusion of design engineers and software development engineers for PPCs about the direction of flow of reactive power.

EREC G99 is silent about the required reactive power requirement of a BESS during import conditions, and it is suggested that this is followed up with the ENA.

NPg connection requirements require generators to be able to operate between 0.95pf lagging and 0.95pf lead in export conditions, unless otherwise agreed, and to stay within 0.95pf lagging (i.e. reactive power import) and unity power factor in import conditions, unless otherwise agreed. This may not be beneficial as importing reactive power will usually not help DNO networks although may be required to enable to DNO to comply with their agreement with NESO.

For some connections it may be necessary for a BESS to provide reactive power compensation at its connection point, to account for losses due to cable and transformers in the BESS system. If such requirements are necessary, then an alternative to operating at unity power factor would be for the BESS to operate in fixed MVAr mode. This would provide a more stable system MVAr output into the DNO network, as this would avoid the BESS MVAr altering continually as its active power output changes. It is however noted that the majority of BESS sites are located close to main substations, so the need for MVAr compensation is often minimal.

Overall, it is suggested that consideration should be given to either requiring BESSs providing dynamic services to NESO to operate at unity power factor or that they operate at a fixed reactive power, instead of a specific power factor. This would help NPg to regulate system voltages more effectively and help release network capacity for existing and future BESS connections. If this recommendation is adopted, then the current assessment process of considering a real power change from import to export and export to import is credible, but considering a coincident reactive power change during the active power change is no longer required.

It was identified that when carrying out dynamic studies a transient voltage 'swell' was sometimes observed during the power ramp event. There are a number of different reasons for this swell, and it can be due to simplified modelling approaches, issues associated with networks with high X/R ratios or tuning issues with PPCs. The key finding from this investigation is that simplified steady state loadflows to assess EREP P28/2 compliance may miss important dynamic events that occurring during power ramps, some of which could be significant for networks with low fault levels and high X/R ratios and in poorly tuned controllers where a fast ramp occurs.

The following recommendations are made:

1. Assess new BESSs, providing dynamic services to NESO, at unity power factor, unless there is a need to provide fixed reactive power compensation.
2. Review the import and export operating power factor requirements for new BESSs where they are operating in the balancing mechanism or the wholesale market or where the BESS developer would like to retain flexibility in the way that the plant can be operated, with a view to operation at unity power factor, subject to further consideration for example whether operation at unity power factor could materially affect network losses. Where there are associated conditions in the bilateral connection agreement between NPg and NESO relating to reactive power exchange at the transmission interface substation, then the BESS output should be based on a fixed reactive power value.
3. Contact the owners/operators of existing BESSs providing dynamic services to NESO installations to discuss the operation at unity power factor if that helps to remove or reduce any existing constraints.

4. Clarify the wording used for power factor and reactive power flow conventions used within NPg.
5. Revise wording in new connection offers to clarify the position on BESSs reactive power import / export requirements.
6. Ensure that NPg staff understand sign conventions and possible mismatches that can occur when BESS real and reactive power flows transition from export to import.
7. Ensure that developers provide an EREC P28/2, RMS based dynamic study for power ramps of the BESS showing operating from full import to full export and full export to full import over 1s, to ensure any transient 'swells' in the system voltage are understood.
8. It is also suggested that policy IMP/001/007, wording in section 3.5.6.3 be expanded to allow NPg the right to request that a BESS be moved from power factor control mode, to fixed MVAr mode, or voltage control mode.

Assessment of the suitability of operating in voltage control mode, will be considered in more detail in Workstream B.3, along with consideration of coincidence factors for adjacent BESS units.

It is important to note, as in accordance with the defined scope of work, this report and its recommendations are only applicable where the BESS owner/operator has contracted to provide dynamic services to NESO and not where the BESS owner/operator deploys their plant in the wholesale electricity market or in the balancing mechanism. When assessing a BESS connection application, it is important to respect the customers' requirements as expressed in their submitted Standard Application Form, as at the application stage the customer may not have finalised how they intend to operate there BESS.

It is also recognised that the recommendations relate to BESS and not to other forms of generation, and hence consideration should be given to whether there are any discrimination issues associated with the requirements on non-BESS customers who also provide dynamic services to NESO. Such consideration is outside the scope of this work.

A key issue noted within the study is that there are competing requirements for power factor setpoints when a BESS is providing dynamic services to NESO, and when a BESS is trading in wholesale market or in the balancing mechanism, as these place very different constraints on the host DNO network, in the former low reactive power exchange with the DNO network is desirable to limit voltage disturbance, whilst in the latter, the use of a unity power factor may not be beneficial to the DNO in this operation mode, as the lack or surplus of reactive power may cause other constraints. Further complications also arise as it is possible for a BESS to revenue stack and provide a mixture of both dynamic services and wholesale market or in the balancing mechanism.

This issue goes beyond the scope of this NIA project, and needs wider discussion within the DNOs and NESO. However one obvious solution would be for the EREC G99 requirements to be expanded to allow DNOs to specify power factor values as required. Typically a BESS would have three main ‘modes’ of operation: 1) Steady state power export, 2) Steady state power import and 3) Dynamic services provision. Each of these services place very different constrains on the host DNO network, and an ability of the host DNO to specify different power factor depending on the operating condition would be advantageous to the DNO.

Lastly, it is also noted that DNOs have implemented ‘Tactical Solution 1’, where BESS units would be constrained during 1st circuit outages on the network [15]. This has significant impact for the BESS assessment process, as one of the requirements for EREC P28/2 assessment is that it is carried out against minimum fault level conditions. If the customers connection agreement stated that they would be de-energised in non-system intact conditions, then the ‘minimum fault level conditions’ should reflect that under system intact conditions only. The impacts of this policy is outside the scope of this report and therefore not considered further.

SECTION 5 - REFERENCES

The following specifications, documents and standards are referenced within this report:

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[3] "ENA G99 Requirements for the connection of generation equipment in parallel with public distribution networks on or after 27 April 2019".

[4] NESO, "Grid Code: Issue 6 Revision 20".

[5] NPG, "IMP/001/007 – Code of Practice for the Economic Development of Distribution Systems with Distributed Generation".

[6] NPG, "IMP/001/007/001 - Battery Energy Storage System Guidance Document".

[7] NPG, "IMP/001/007/002 - Application guide for modelling generator reactive power control modes".

[8] NPG, "IMP/001/915 - Code of Practice for Managing Voltages on the Distribution System".

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