Broken Hill Battery Energy Storage System

System Strength Modelling Knowledge Sharing Report

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The purpose of this document is to provide a summary of the System Strength Modelling of the Broken Hill Battery Energy Storage Project.

This Project received funding from ARENA as part of ARENA's Advancing Renewables Program.

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Acronyms and Abbreviations

Acronym/abbreviation	Definition
AEMO	Australian Energy Market Operator
ARENA	Australian Renewable Energy Agency
BESS	Battery Energy System
BHBESS	Broken Hill Battery Energy Storage System
BHSF	Broken Hill Solar Farm
DF	Damping Factor
DMAT	Dynamic Model Acceptance Testing
EMT	Electromagnetic Transients
EPC	Engineering, procurement and Construction
FRT	Fault Ride Through
GPS	Generator Performance Standards
GT	Gas Turbines
HIL	Hardware in the Loop
HVDC	High Voltage Direct Current
HVRT	High Voltage Ride Through
Hz	Hertz
IBR	Inverter Based Resource
IC	Inertia Constant
Km	Kilometre
kV	kilovolts
LVRT	Low Voltage Ride Through

MFRT	Multiple Fault Ride Through
Ms	Milli second
MVA	Mega Volt Amperes
MVAr	Mega Volt Ampere (reactive)
MW	Megawatts
MWh	Megawatt Hour
NEM	National Electricity Market
NER	National Electricity Rules
NSP	Network Service Provider
OEM	Original Equipment Manufacturer
p.u	Per Unit
POC	Point of Connection
PoI	Point of Interest
PPC	Power Point Controller
PSCAD	Power System Computer Aided Design
PSMG	Power System Modelling Guidelines
PSS®E	Power System Simulator for Engineering
RIT-T	Regulatory Investment Test for Transmission
RMS	Root Mean Square
RoCoF	Rate of Change of Frequency
RTS	Real Time Simulators
SCR	Short Circuit Ratio
SMIB	Single Machine Infinite Bus
SOC	State of Charge

TRC	Transient Reactive Current
TNSP	Transmission Network Service Provider
UNSW	University of New South Wales

1. Document Purpose and Distribution

1.1. Purpose of Document

This document is a public report issued as part of the Knowledge Sharing commitments of AGL for the Broken Hill Battery Energy System (BHBESS) Project, in accordance with the Funding Agreement between AGL and the Australian Renewable Energy Agency (ARENA), which has contributed funding support through its Advancing Renewables Programme.

Broken Hill BESS involves a 50MW/100MWh voltage source inverter (grid-forming) Battery Energy Storage System (BESS) at Broken Hill, Central West New South Wales.

This System Strength Modelling Knowledge Sharing report focusses specifically on detailing the modelled performance of the grid-forming inverters, how their modelled performance differs from grid-following inverters, and how their use has the potential to improve system strength in the Broken Hill BESS Project, including:

- The modelling methodologies,
- Overview of the results and their implications
- Experience achieving grid connection approvals including the results of AEMO's Full Impact Assessment
- Overview on how the Project's expected system strength performance will be further verified during operations.
- Conclusions relating to the potential for grid-forming inverters to be used to address system strength challenges.

Over the course of the Project, a wide range of Knowledge Sharing work is being undertaken, including delivery of a range of reports, presentations, meetings and site visits.

Access to the full list of Knowledge Sharing resources as well as operational information and data is available at the Project Portal, at https://www.agl.com.au/about-agl/how-we-source-energy/broken-hill-battery-energy-storage-system?zcf97o=vlx3ap.

1.2. Intended distribution

This document is intended for the public domain and has no distribution restrictions.

2. Introduction

2.1. Project Overview

There has been apprehension across the NEM about how the changing nature of generating plant from traditional rotating machines to inverter-based resources may alter the dynamic behaviour of the grid.

System Strength is a term used to describe how impervious the voltage is to the alteration of the 50Hz sinusoidal waveform. Large rotating generators are able to dominate the local voltage and subsume aberrant waveforms. The previous generation of inverters have been current source inverters which have filtering to supress the inherent higher order harmonics but otherwise are not intended to optimise the voltage waveform.

In 2016, an outage of the Buronga to Redcliffs 220kV line resulted in Broken Hill being at the end of a single 700km circuit and electrically remote from stronger part of the grid. In this weak grid environment, sub-synchronous oscillations of around 7Hz between the Broken Hill Solar Farm and the SVCs at the Broken Hill substation reached a magnitude of 4.5% of the fundamental frequency.

Uncertainty of what the implications were of sub-synchronous oscillations in electrically remote locations led AEMO to limit generation from solar farms in the "Western Murray" area including Broken Hill for many months. Many studies and physical tests were performed on the Western Murray region with the issue eventually being resolved by relaxing Generator Performance Standards with less aggressive settings for the solar farm inverters in that area.

ARENA has supported a proposal to evaluate the potential for a battery with a voltage source inverter emulating the characteristics of synchronous generator to mitigate the effects of low system strength. As a consequence, a 50MW battery with a Grid-Forming inverter is being constructed at Broken Hill.

This System Strength Modelling Knowledge Sharing report covers the modelling and testing conducted during the Stage 1 and Stage 2 activities under the Testing plan to confirm the Project's potential to improve system strength.

The intention of this System Strength Modelling Knowledge Sharing report is to describe the journey and lessons learnt during modelling the grid-forming inverters in the Broken Hill BESS Project.

Section 1 describes the Report's purpose, the intended audience and any distribution restrictions. This section also includes a link to the on-line portal where all Project Knowledge Sharing information is located.

Section 2 provides an overview of the Project and key project objectives.

Section 3 describes the modelling and testing conducted.

Section 4 describes the low short circuit ratio (SCR) and inertia.

Section 5 describes the virtual inertia and damping factor sensitivity in a low SCR network.

Section 6 describes the mechanism of the switching between the grid-forming and the grid-following modes.

Section 7 describes the effect on grid hosting capacity.

Section 8 describes the grid-forming performance for shallow unbalanced faults.

Section 9 describes the coordination of the power point controller with the inverters.

Section 10 describes the islanding studies.

Section 11 summarises the key lessons learnt during the system strength modelling of the Broken Hill Battery Energy System.

2.2. Key Project Objectives

The project objectives are to evaluate the ability of a Grid-Forming battery to provide system strength characteristics by:

1. Computer modelling of the behaviour of a Grid-Forming inverter in an area of weak system strength.
2. Studying the behaviour of the Grid-Forming inverter on a real-time test bench.
3. Monitoring the behaviour of the Grid-Forming inverter when installed at Broken Hill.
4. Confirming that a Grid-Forming inverter can both avoid contributing to the symptoms of poor system strength and potentially compensate for non-grid-forming inverters.
5. Identifying obstacles to connecting Grid-Forming inverters to the National Electricity Market (NEM).

3. Modelling and Testing Conducted

This section describes the list of all tests that have been performed during different stages of the project, namely the grid connection studies which are required as part of grid connection application process to show the generator performance requirements as per the NER, AEMO and Transgrid requirements, including real time digital simulations which were performed by UNSW to gauge the effect of introducing the Broken Hill Battery Energy Storage System into the local Broken Hill network, and Hardware in the Loop tests results which have been performed by UNSW as per AEMO guidelines as part of standard grid connection application and registration process.

3.1. The standard GPS tests

Modelling and testing conducted for the BHBESS was based upon the National Electricity Rule (NER) version 186. This version of the rules contained 14 generator performance standards and 8 customer performance standards. A standard set of tests is required to demonstrate compliance for a battery energy storge system, with all customer performance standards overlapping with specific generator performance standards. The key differentiator between a BESS and traditional generator is the requirement to perform all standard tests at a maximum charging condition and some additional tests at no active power output.

The following sections summarise the typical performance standard tests conducted and whether any additional test types were required due to the unique nature of the BHBESS connection location and grid-forming functionality.

Table 1 The standard GPS tests

NER Clause	Description	Tested performed
S5.2.5.1 / S5.3.5	Reactive power capability	Standard tests performed to determine PQ capability at 40°C and 50°C for 0.9pu, 1.0pu and 1.1pu voltage at the connection point. No additional tests required.
S5.2.5.2 / S5.3.6 / S5.3.7 / S5.3.8	Quality of electricity generated	Standard assessment of harmonic voltage distortion and flicker performed. No additional tests required. If harmonic cancellation is implemented on the inverters, additional tests may be required in future projects.
S5.2.5.3	Generating system response to frequency disturbance	Drop or rise in single-machine infinite bus (SMIB) voltage due to active power change driven by the BHBESS frequency response were initially performed under an abnormally low (non-credible) short circuit ratio (SCR) of 1.19. Later studies were undertaken at a higher, (credible) SCR of 1.997 as well as at maximum SCR to demonstrate the issue is SCR related and not driven by the plant. The voltage sensitivity to active power under low SCR phenomena is outlined in greater detail in Section 4.1.
S5.2.5.4	Generating system response to voltage disturbance	Standard tests performed with an ideal voltage source (infinite SCR). Grid-forming inverter low voltage ride-through and low voltage protection observed to be lower than typical grid-forming. No additional tests required.
S5.2.5.5	Generating system response to	Initial studies were performed under an abnormally low (non-credible) short circuit ratio (SCR) of 1.19 but

	disturbances following contingency events	encountered compliance issues with meeting reactive current response rise and settling times while maintaining ride through stability. Later studies were undertaken at a higher, (credible) SCR of 1.997 following discussion with the network service provider (NSP) and AEMO and wide-area PSCAD studies showed no network instability when the plant was tuned for a higher minimum SCR. No additional test types required, just a change in minimum SCR. Key differences in response rather than test types.
S5.2.5.6	Quality of electricity and continuous uninterrupted operation	No tests typically performed as only minimum access standard exists.
S5.2.5.7	Partial load rejection	Standard tests performed and same issues as to S5.2.5.3 around low SCR sensitivity encountered in SMIB.
S5.2.5.8 / S5.3.10	Protection of generating systems from power system disturbances	No tests typically performed as only minimum access standard exists.
S5.2.5.9 / S5.3.3	Protection systems that impact on power system security	No tests typically performed. Compliance evidence provided through protection design report. No additional information provided compared to standard process.
S5.2.5.10	Protection to trip plant for unstable operation	Standard tests performed and same issues as to S5.2.5.3 around low SCR sensitivity encountered in SMIB. A large frequency droop (5% compared to the minimum value of 1.7%) was required to ensure

		voltage collapse did not occur due to an active power change.
S5.2.5.11	Frequency control	Drop or rise in single-machine infinite bus (SMIB) voltage due to active power change driven by the BHBESS frequency response under low SCR required additional tests. Additional tests included studies at a higher, more normal, SCR as well as at maximum SCR to demonstrate the issue is SCR related and not driven by the plant. The voltage sensitivity to active power under low SCR phenomena is outlined in greater detail in Section 4.1.
S5.2.5.12	Impact on network capability	Standard tests performed on network loading and dynamic interconnector capability. No additional tests required
S5.2.5.13	Voltage and reactive power control	Low SCR voltage sensitivity to reactive power required additional studies at higher SCR to demonstrate that reactive power reference and power factor reference step changes would not drive the plant into FRT. NEM PSS®E studies also performed to show that reactive power step changes in the network would not cause issues. Additionally, although no additional studies were required, larger active power swings due to a grid voltage change or setpoint change compared to other types of grid-following inverters was observed. The active power swing was driven by the virtual inertia control loop and reduced with a smaller inertia constant.
S5.2.5.14	Active power control	Drop or rise in single-machine infinite bus (SMIB) voltage due to active power change under low SCR required additional tests. Additional tests included studies at a higher, more normal, SCR as well as at

		maximum SCR to demonstrate the issue is SCR related and not driven by the plant. NEM PSS®E studies also included to demonstrate it isn't a physical network issue. The voltage sensitivity to active power under low SCR phenomena is outlined in greater detail in Section 4.1.
S5.2.6.1 / 4.11.1	Remote monitoring	Standard set of monitored quantities required. Additional information on state of charge required due to BESS, but no grid-forming specific requirement.
S5.2.6.2 / 4.11.3	Communications equipment	No tests typically performed. Compliance evidence provided through communication design report. No additional information provided compared to standard process.
S5.2.7	Power station auxiliary supplies	Not relevant to BHBESS.
S5.2.8	Fault current	Standard short circuit tests performed based off manufacturer information. Slightly higher fault level expected from grid-forming compared to grid-following depending on if BESS over-sizing is implemented. This was not a factor for BHBESS. No additional tests required.

In addition to standard GPS studies outlined in Table 1 above, the following tests have also been performed as part of grid connection application and registration process requirements:

- Dynamic Model Acceptance Testing (DMAT) as per AEMO DMAT guidelines[1]; and
- PSSE and PSCAD Benchmarking Studies as per AEMO guidelines.[2]

[1] Dynamic Model Acceptance Test Guideline, AEMO, February 2021.
[2] GENERATOR CONNECTION APPLICATION CHECKLIST, AEMO, Version 3, May 2021.

3.2. Additional GPS tests

Dynamic Model Acceptance Testing (DMAT) was completed for BHBESS to demonstrate alignment with the Power System Model Guidelines. AEMO's DMAT Guideline version 2 was used, released in November 2021. The DMAT Guideline requires a number of simulation studies to be performed at an SCR of 3 but due to BHBESS having a minimum SCR of 1.997, additional tests were required at this SCR beyond the normal set of studies. All studies were performed for both charging and discharging conditions due to the battery connection as opposed to a generating only device like wind and solar. Some ad-hoc studies were required, such as HVRT and LVRT activation tests at a higher SCR, to demonstrate that a particular issue is SCR dependent or provide practical results. Minimum state of charge (SOC) tests are included in the DMAT Guideline but could not be performed due to the PSS®E and PSCAD models not containing an SOC representation. Beyond this, no grid-forming specific tests were performed or required.

3.3. Real – time Digital Simulations

Modern real-time digital simulators (RTSs) are powerful multicore processor platforms that can accurately simulate power systems and their evolving components [1]. These platforms solve the set of equations defining the model in synchronism with a real-time clock. This capability of RTSs allows them to interface with physical equipment (e.g., controllers, protection schemes, etc.) in closed loop, testing and validating their operation in a controlled and flexible environment.

This Section provides a demonstration of the system strength capabilities of the Broken Hill BESS via detailed RTS modelling. These capabilities are defined as:

- Stable operation after a fault at the Buronga – Red Cliffs 220 kV transmission line during steady-state conditions.
- Damping of voltage oscillations during maximum generation of renewable energy in the Broken Hill area.

3.3.1. Network Model

The wide-area network model extends from Broken Hill to the NSW and NW Victoria transmission network, as shown in Figure 1. It consists of detailed network, load, and parameters setting information as well as openly available real-time power electronics models and OEM's built-in grid-forming solutions.

Since proprietary models, including solar farms, wind farms, SVCs, HVDC links, among others were not available, they were originally replaced by Thévenin equivalent circuits. However, to better represent the Broken Hill substation and its dynamic behaviour, generic detailed real-time EMT models with fully detailed power electronics converters and controllers have been implemented for Broken Hill Solar Farm, Silverton Wind Farm, and Broken Hill SVCs [2] – [3].

The Broken Hill BESS has been modelled as a combination of openly available models [2] – [3] with the built-in grid-forming functionalities as defined by the OEM [4].

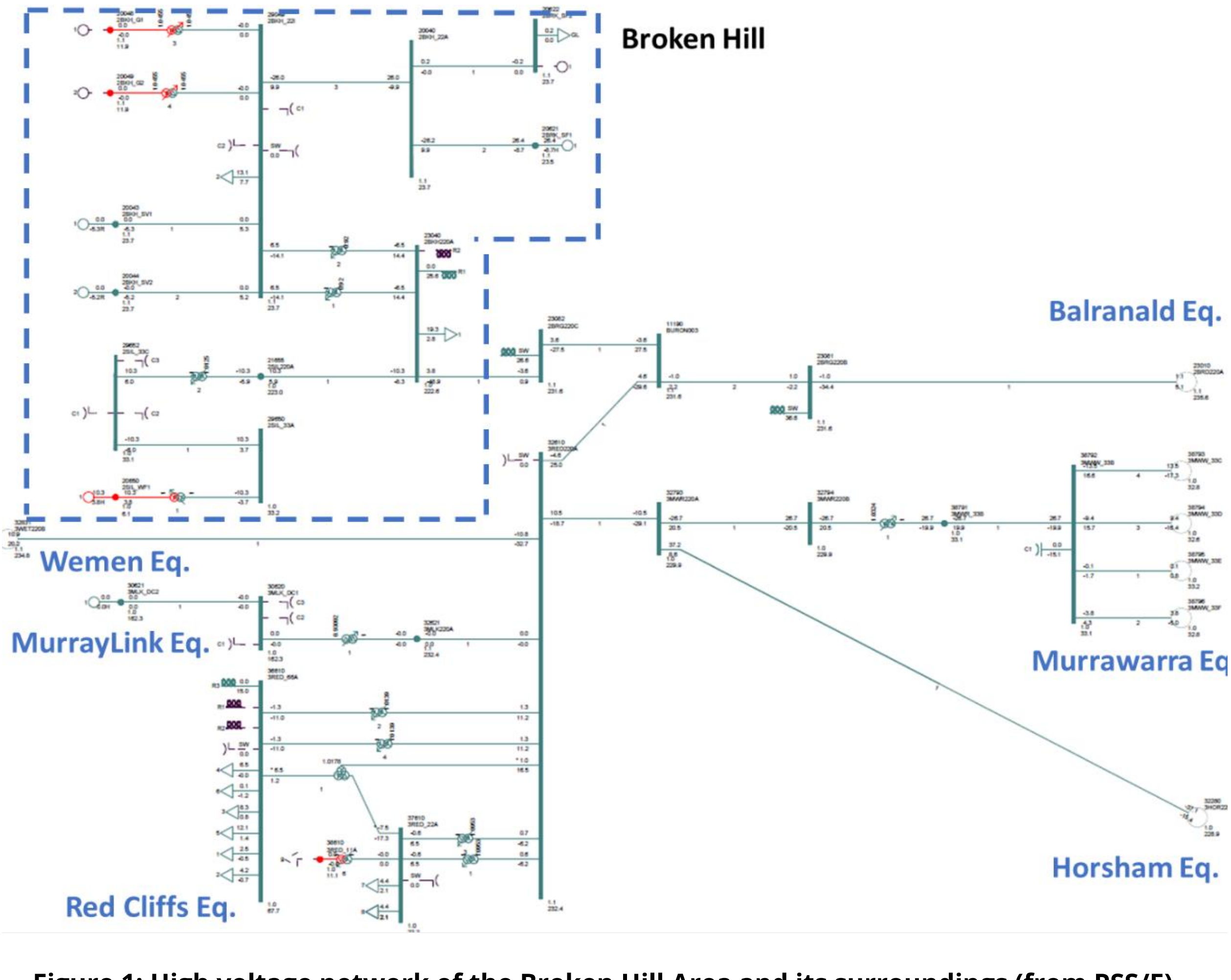


Figure 1: High voltage network of the Broken Hill Area and its surroundings (from PSS/E).

The transmission network and Broken Hill models have been initially validated and then further adapted based on comments and feedback provided by the Modelling Working Group (which includes members from Transgrid and AEMO). The changes, as well as the resulting modelling approach and assumptions have been endorsed by the Modelling Working Group.

Additionally, the OEM has reviewed the grid-forming BESS model with its controllers and has confirmed that the implementation of the control system used in the RTS is accurate and sufficient to reflect the behaviour of the inverter for the purposes of these tests.

3.3.2. Two-phase to Ground fault at Buronga – Red Cliffs 220 kV Line

The following steady-state condition is considered when analysing the response of the system for a two-phase to ground fault at Buronga – Red Cliffs 220 kV line with a clearance of 120/220 ms:

- Broken Hill SVCs operating with a voltage reference of 1.027 p.u.
- Broken Hill Solar Farm operating at its rated power (52 MW) with a power factor of 0.97 (absorbing).
- Silverton Wind Farm operating at a quarter of its rated power (50 MW) with a voltage reference of 1.072 p.u.
- Reactive power compensation at Broken Hill substation is connected.

The simulations are performed with and without the Broken Hill BESS ($P_{ref} = Q_{ref} = 0$) for a variety of inertia and damping factors. Table 2 summarises the obtained results. During these conditions, and independent of the parameters used for the Broken Hill BESS, the system remains stable when it is connected to the grid.

Table 2. Summary of two-phase to ground faults during steady-state conditions.

Conditions	Resulting System
No BESS	**Voltage oscillations**
BESS with $\boldsymbol{H = 5\ s\ /\ D = 50}$	**Stable**

BESS with $\boldsymbol{H = 5\ s\ /\ D = 75}$	Stable
BESS with $\boldsymbol{H = 5\ s\ /\ D = 100}$	Stable
BESS with $\boldsymbol{H = 8\ s\ /\ D = 50}$	Stable
BESS with $\boldsymbol{H = 8\ s\ /\ D = 75}$	Stable
BESS with $\boldsymbol{H = 8\ s\ /\ D = 100}$	Stable

Figure 2 and Figure 3 below depict how this fault in the system causes voltage oscillations in the Broken Hill Area. These oscillations occur in the case when no BESS is connected and also in the case when a BESS in grid-feeding[3] mode is connected in Broken Hill. These oscillations have a frequency of 10 Hz and an amplitude of 0.8 p.u. The amplitude of the oscillations observed is a characteristic of the current model and the generic dynamic representation of the Broken Hill Solar Farm, Silverton Wind Farm and SVCs used in the simulations. These oscillations do not appear when the Broken Hill BESS is connected to the grid, as shown in Figure 4.

Remark: *These results demonstrate how the Broken Hill BESS helps to maintain the system stable for two-phase to ground faults in the grid that cause voltage oscillations.*

[3] To allow a qualitative comparison of the **grid-forming functionality** provided by the BESS, an additional independent mode of operation is also implemented in the BESS, the **grid-feeding mode (or grid-feeding inverter)**. The grid-feeding mode, which is not the solution to use in the project, consists of active/reactive control loops in cascade with a current controller that provides voltage references for each phase of the BESS inverter. A PLL is used to synchronise the inverter to the grid and to generate angle references for all other functions of the controller.

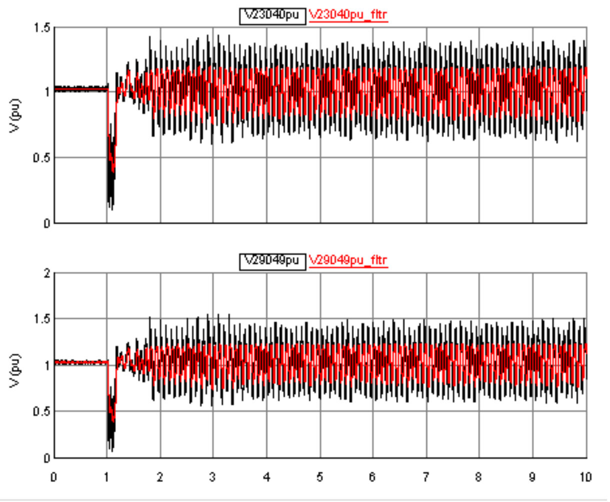


Figure 2. Two-phase to ground fault during steady-state conditions: Fault at Buronga – Red Cliffs 220 kV without BESS. Broken Hill voltages. Oscillations based on current model characteristics.

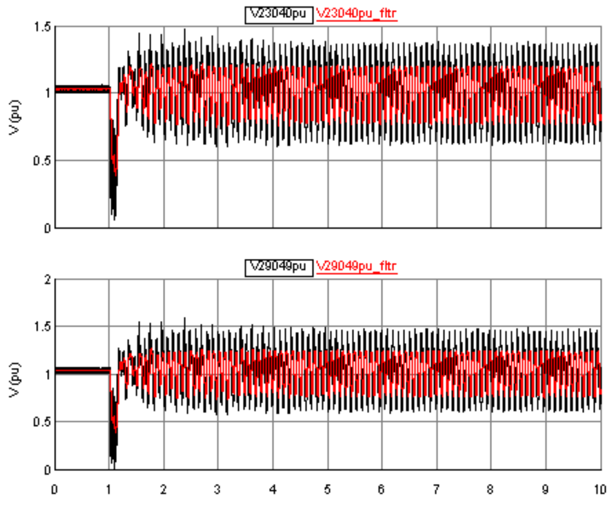


Figure 3. Two-phase to ground fault during steady-state conditions: Fault at Buronga – Red Cliffs 220 kV with grid-feeding BESS. Broken Hill voltages[4]. Oscillations based on current model characteristics.

[4] To allow a qualitative comparison of the **grid-forming functionality** provided by the BESS, an additional independent mode of operation is also implemented in the BESS, the **grid-feeding mode (or grid-feeding inverter)**. The grid-feeding mode, which is not the solution to use in the project, consists of active/reactive control loops in cascade with a current controller that provides voltage references for each phase of the BESS inverter. A PLL is used to synchronise the inverter to the grid and to generate angle references for all other functions of the controller.

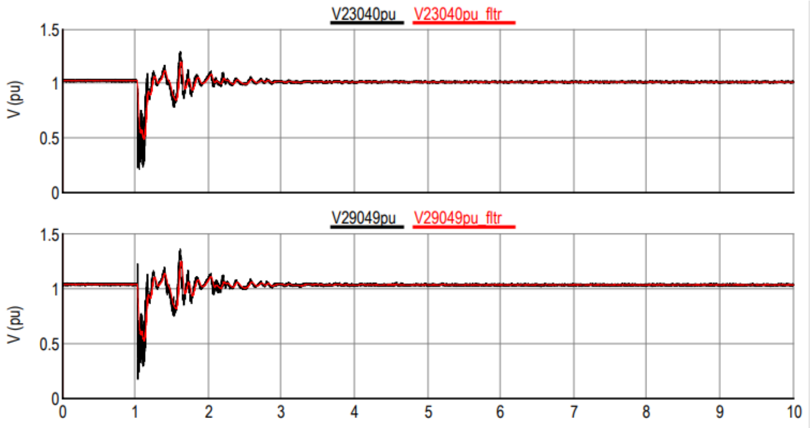


Figure 4. Two-phase to ground fault during steady-state conditions: Fault at Buronga – Red Cliffs 220 kV with grid-forming BESS (H = 5 s, D = 50, P=Q=0). Broken Hill voltages. Stable operation is observed.

3.3.3. Voltage Oscillations During Maximum Renewable Generation

For the developed model, voltage oscillations are observed if no BESS is connected to the system when the renewable generation in Broken Hill is increased to its maximum (i.e., 252 MW, 200 MW from the wind farm and 52 MW from the solar farm). These oscillations, shown in Figure 5, have a frequency of 9 Hz and, for the conditions and models of the current study, exhibit an amplitude of 0.9 pu[5].

[5] *The amplitude of the oscillations observed is a characteristic of the current model and the generic dynamic representation of the Broken Hill Solar Farm, Silverton Wind Farm and SVCs used in the simulations.*

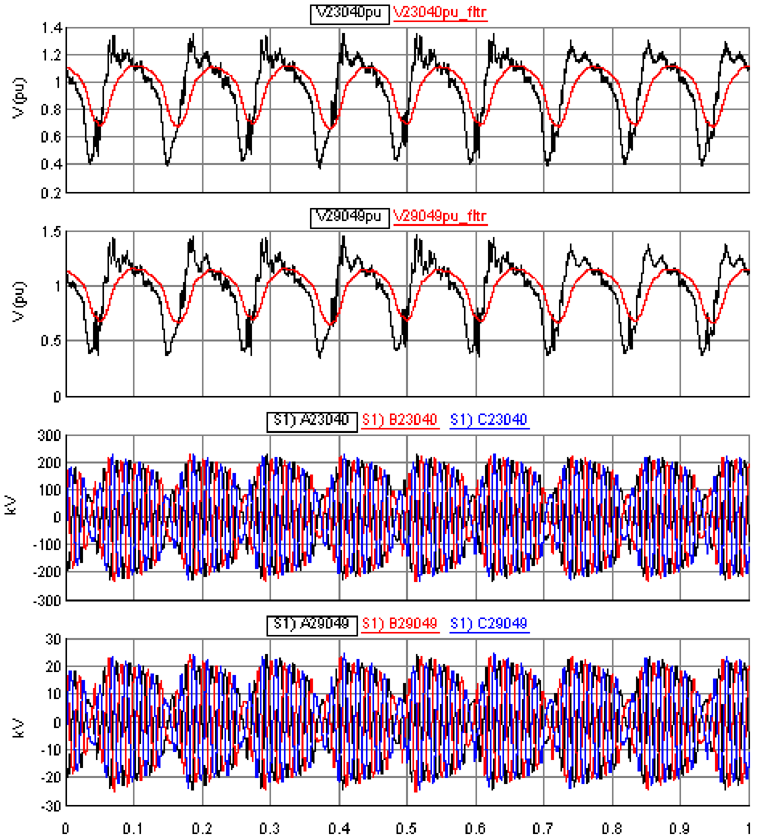


Figure 5. Voltage oscillations: without BESS. Broken Hill voltages. Oscillations based on current model characteristics.

To assess the impact of connecting the Broken Hill BESS ($P_{ref} = Q_{ref} = 0$) for a variety of inertia and damping factors, the BESS breaker was closed at $t = 1\ s$. Table 3 summarises the obtained results. During these conditions, and independent of the parameters used for the BESS, the grid-forming BESS is capable of successfully contributing to the damping of the oscillations.

Table 3. Summary of BESS impact during voltage oscillations.

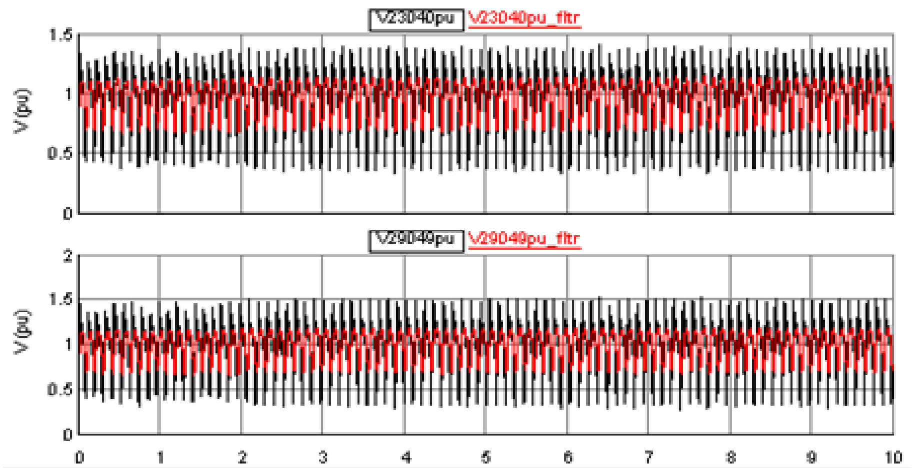
Conditions	Resulting System
No BESS	**Voltage Oscillations**
BESS with $\boldsymbol{H = 5\ s\ /\ D = 50}$	**Oscillations are damped**
BESS with $\boldsymbol{H = 5\ s\ /\ D = 75}$	**Oscillations are damped**
BESS with $\boldsymbol{H = 5\ s\ /\ D = 100}$	**Oscillations are damped**

BESS with $\boldsymbol{H = 8\ s\ /\ D = 50}$	**Oscillations are damped**
BESS with $\boldsymbol{H = 8\ s\ /\ D = 75}$	**Oscillations are damped**
BESS with $\boldsymbol{H = 8\ s\ /\ D = 100}$	**Oscillations are damped**

Figure 6 shows how these oscillations are not damped if a grid-feeding BESS is connected. Nevertheless, these oscillations are successfully damped when connecting the Broken Hill BESS, as shown in Figure 7.

Remark: *Even though the frequency is within the range of observable oscillations in the Broken Hill Area, the amplitude of oscillations is much larger and not aligned with previous experience[6]. As the model and setup used in this study presents a worse scenario when compared to what may happen in the real system, it is expected that any analysis and conclusions made based on these results will also apply to oscillations with a* $\pm$*4% variation in magnitude.*

Remark: *These results demonstrate how the Broken Hill BESS helps to damp the oscillations, allowing a stable operation of the system and improving overall system strength.*



[6] This is attributed to the use of generic models and parameters. Furthermore, to maintain Broken Hill Solar Farm and Silverton Wind Farm connected to the grid, protective functions have been removed.

Figure 6. Voltage oscillations: grid-feeding BESS. Broken Hill voltages. Oscillations based on current model characteristics.

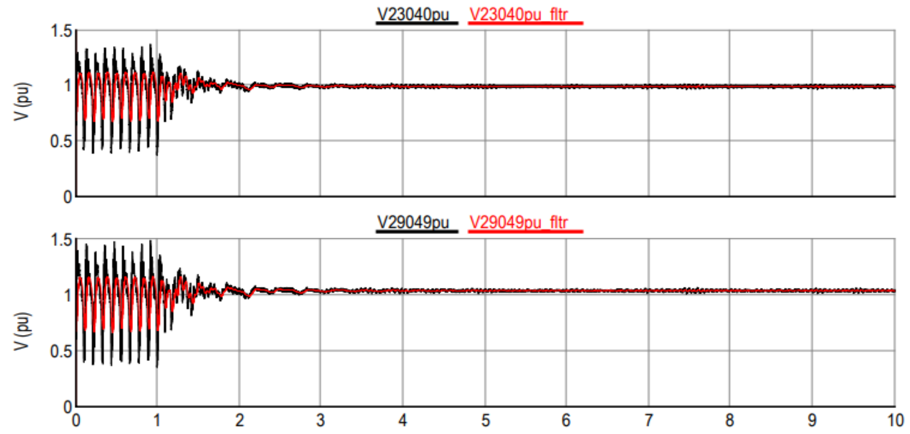


Figure 7. Voltage oscillations: grid-forming BESS (H = 5 s, D = 50, P=Q=0). Broken Hill voltages. Oscillations based on current model characteristics.

3.3.4. Summary of Real-Time Simulation Results

Table 4 summarises the system strength capabilities when considering the Broken Hill BESS connected to the grid.

Table 4. Summary of system strength capabilities provided by the Broken Hill BESS

Capability	Without BESS	With BESS
Stable operation (after fault)	**Voltage oscillations**	Stable
Damping of voltage oscillations (max. generation)	**Voltage oscillations**	Successfully Damped

These results demonstrate that:

1. Faults in the network can cause oscillations and instability in the Broken Hill Area. *The inclusion of the Broken Hill BESS can damp such oscillations contributing to system strength.*
2. Interactions between power electronics converters and other network elements in the area during periods of high generation from IBRs can cause sub-synchronous voltage oscillations in the Broken Hill Area. *The inclusion of the Broken Hill BESS can damp such oscillations contributing to system strength.*

Although the BESS is capable of providing stable voltage and damping with the inclusion of inertia (H) and damping parameters (D), it is crucial to finely tune these parameters. Otherwise, a poor selection of the damping factor (D) and inertia factor (H) might cause an unstable voltage profile in a low SCR network if any network change event occurs, such as a frequency change or an active power step.

3.4. Hardware in the Loop (HIL) Tests

In addition to network modelling during grid connection studies which have been performed by Aurecon and Real – time Digital Simulations which was performed by UNSW, UNSW has also been conducting various HIL tests to gauge the performance of the inverter in real time situation. The HIL Test Scope to demonstrate the ability to operate at the nominate SCR and X/R ratio and validate DMAT results as per the AEMO connection application check list, R1 (pre-connection) submission check list, DMAT guidelines (section 2.2) and PSMG. Table 5 summarises all tests required for generator connection application and registration purposes. The results for those tests will be submitted to AEMO and Transgrid as part of Broken Hill BESS connection application and registration.

Test ID	Type	Description	Site Condition at the POC / CHIL Test Description
1	LVRT balanced	Different balanced faults to show the evidence demonstrating ability to operate at the nominated SCR and X/R ratio.	SCR = 4.115 and X/R = 6.2 P=50 MW, Q=0 MVAr, P=-50 MW, Q=0 MVAr One three-phase deep fault and one three-phase shallow fault- Udip= 0.1 pu and Udip=0.8 pu at the POC
			• Inputs: 1) SMIB model provided by EPC and 2) EPC's grid-forming control with the latest firmware. • Not considered: power plant controller. • Simulations: 4 (charging/discharging, two faults). • Methodology: set source impedance based on SCR and X/R. Set fault impedance based on source impedance, X/R, and respective voltage dip. Initialise simulation, enable BESS inverter, set active and reactive power set points, wait for steady state condition, apply three-phase to ground fault, record variables, finish.

Test ID	Type	Description	Site Condition at the POC / CHIL Test Description
2	LVRT Unbalanced	Different unbalanced faults with nominated SCR = 1.997 & X/R = 6.2 to show the evidence demonstrating ability to operate at the nominated SCR and X/R ratio.	SCR = 4.115 and X/R = 6.2 P=50 MW, Q=0 MVAr, P=-50 MW, Q=0 MVAr One phase to phase to ground fault (BCG) at the POC ($Z_f = 0\Omega$) One single phase to ground fault (AG) at the POC ($Z_f = 0\Omega$)
			Similar to test 1: • Simulations: 4 (charging/discharging, two faults). • Methodology: set source impedance based on SCR and X/R. Set fault impedance as 0Ω. Initialise simulation, enable BESS inverter, set active and reactive power set points, wait for steady state condition, apply corresponding fault, record variables, finish.

<table>
<tr>
<td>3</td>
<td>MFRT</td>
<td>Several consecutive faults (Normally 15) are going to be simulated to confirm the capability of the plant and models.</td>
<td>
SCR = 4.115 & X/R = 6.2

P=50 MW, Q=0 MVAr,

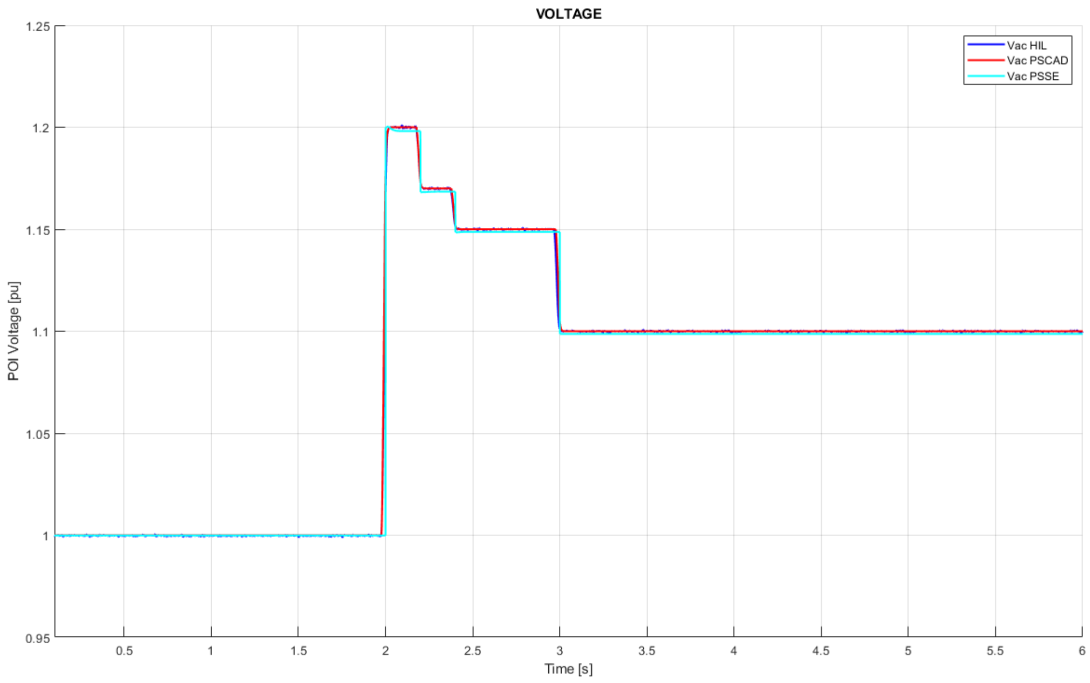
P=-50 MW, Q=0 MVAr

Type of faults and their duration and time between recurring faults and its impedance can be selected from table below.

Table 5 MFRT random event selection for EMTP model test
<table>
<tr><th>Sequence</th><th>RANDOM (Fault Type)</th><th>RANDOM (Fault Duration [ms])</th><th>RANDOM (Time between recurring events [s])</th><th>RANDOM (Fault Impedance)</th></tr>
<tr><td>S2 to S5</td><td>6 x 1PHG, 7 x 2PHG, 2 x 3PHG</td><td>8 x 120ms, 6 x 220ms, 1 x 430ms</td><td>0.01, 0.01, 0.2, 0.2, 0.5, 0.5, 0.75, 1, 1.5, 2, 2, 3, 5, 7, 10</td><td>7 x Zf = 0
5 x Zf = 3 x Zs
3 x Zf = 2 x Zs</td></tr>
</table>

<table>
<tr><th>Test</th><th>Fault duration [s]</th><th>Fault type</th><th>Fault impedance Zf [pu]</th><th>SCR</th><th>X/R</th><th>Active Power [pu]</th><th>Reactive Power [pu]</th></tr>
<tr><td>121.</td><td>Sequence S1*</td><td>See note A</td><td>Zf=0.25 x Zs</td><td>POC</td><td>POC</td><td>1</td><td>0</td></tr>
<tr><td>122.</td><td>Sequence S2</td><td>S2</td><td>S2</td><td>POC</td><td>POC</td><td>1</td><td>0</td></tr>
<tr><td>123.</td><td>Sequence S3</td><td>S3</td><td>S3</td><td>POC</td><td>POC</td><td>1</td><td>0</td></tr>
<tr><td>124.</td><td>Sequence S4</td><td>S4</td><td>S4</td><td>POC</td><td>POC</td><td>1</td><td>0</td></tr>
<tr><td>125.</td><td>Sequence S5</td><td>S5</td><td>S5</td><td>POC</td><td>POC</td><td>1</td><td>0</td></tr>
</table>
</td>
</tr>
</table>

Test ID	Type	Description	Site Condition at the POC / CHIL Test Description
			Similar to test 1: • Simulations: 10 (charging/discharging, five sequences). • Methodology: set source impedance based on SCR and X/R. Set fault sequence as in Table 5 of the DMAT. Initialise simulation, enable BESS inverter, set active and reactive power set points, wait for steady state condition, apply fault sequence, record variables, finish.

4	HVRT	An overvoltage event is going to be simulated to validate the HVRT control of the model.	SCR = Infinity (No SCR branch) P=50 MW, Q=0 MVAr, P=-50 MW, Q=0 MVAr Voltage profile at the POC as per below figure 

Test ID	Type	Description	Site Condition at the POC / CHIL Test Description
			Similar to test 1: • Simulations: 2 (charging/discharging, one voltage profile). • Methodology: set source as an ideal source. Initialise simulation, enable BESS inverter, set active and reactive power set points, wait for steady state condition, apply voltage profile to the source, record variables, finish.

Table 5 List of HIL Tests as per AEMO Guidelines

4. Low Short Circuit Ratio and Inertia

4.1. Voltage Sensitivity in a lower system strength network

The Broken Hill BESS has a minimum SCR of 1.997. This low SCR results in significant RMS voltage sensitivity and, especially in a SMIB environment, strong coupling between RMS voltage and power flow. Power flow and voltage coupling in the network itself was not expected or observed to be nearly as significant. This is outlined in detail in the following section but can be shown below in Figure 8 with a comparison of minimum SCR (SCR of 1.997) and high SCR (SCR of 10) conditions for a 5 MW active power reference step change.

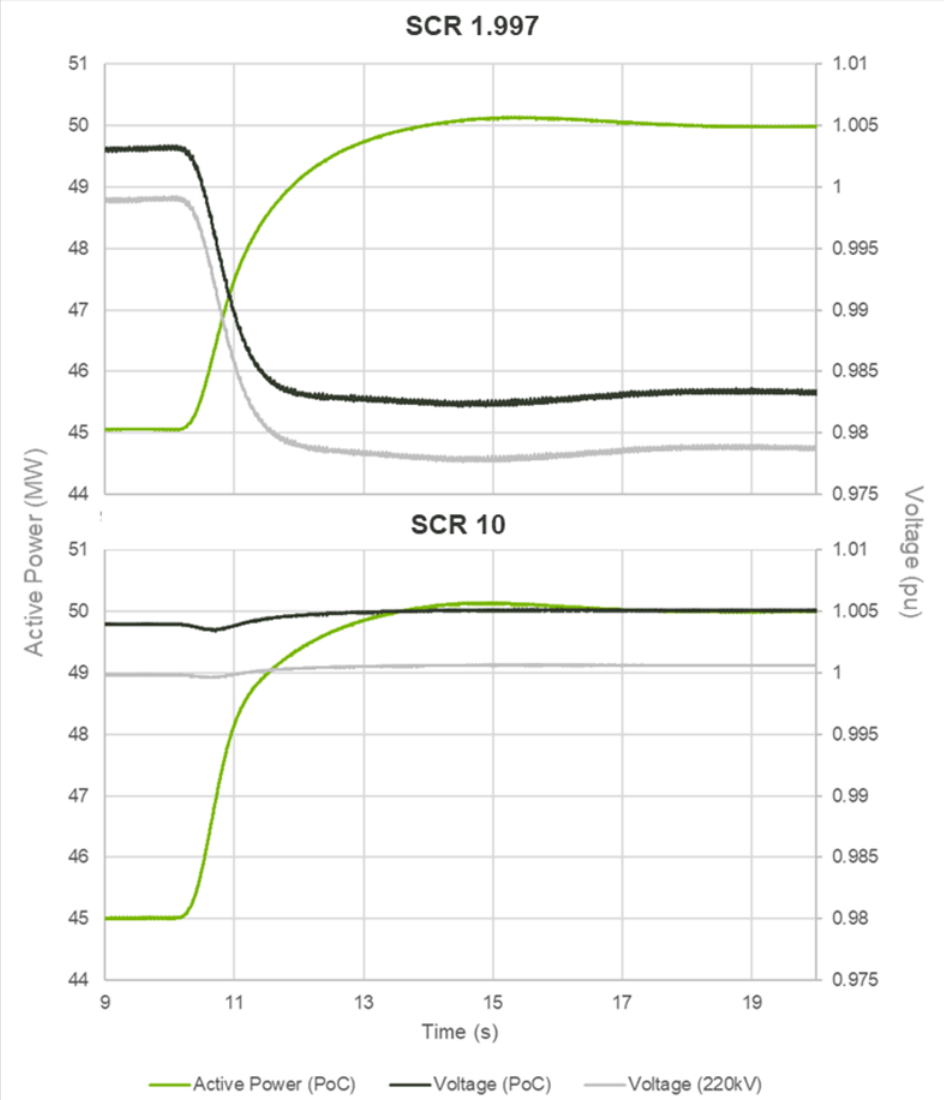


Figure 8 Active power reference step change from 45MW to 50MW comparison at minimum SCR (1.997) and high SCR (10) [7]

At minimum SCR, a 5 MW change in active power can be seen to drive a 0.02 pu drop in point of connection (PoC) voltage, while at an SCR of 10, the same 5 MW change in active power causes a rise in PoC voltage by 0.001pu. Small magnitude damped oscillations, in the order of 1-2MW, present in active power due to voltage, reactive power or power factor setpoint changes or grid voltage changes can therefore elicit damped voltage oscillations in the order of 0.01pu magnitude or greater. With respect to a 5% voltage disturbance, this can cause network voltage settling times to exceed 5s in some circumstances.

[7] Broken Hill BESS has a 22kV point of connection but remotely regulates the voltage at the 220kV Broken Hill terminal station busbar.

When the plant operates in voltage control mode, the control system actively damps voltage oscillations and hence meets automatic access standard requirements. However, when functioning in reactive power or power factor control modes there is no voltage feedback and, as such, despite reactive power rise and settling times meeting automatic access standard requirements, in some circumstances voltage exceeds automatic access standard settling times due to small changes in active power.

4.2. Active power change triggering FRT condition

Active power transfer between two buses is defined by Equation 1 and rearranged in Equation 2.

Equation 1: AC power transfer equation [8]

$$P = (|V_G| \times |V_N|)/X \times \sin(\delta_1 - \delta_2)$$

Equation 2: Equation 1 rearranged for V_G

$$V_G = (P \times X)/(V_N \times \sin(\delta_1 - \delta_2))$$

Where V_G is the sending side voltage and the 220kV voltage control bus in the instance of BHBESS; V_N is the network side voltage on the grid side of the SMIB impedance; P is the active power flow across the grid impedance; X is the total reactance seen between the generator and network impedance; and $\delta_1 - \delta_2$ is the phase angle difference between the plant and network sides.

V_N is a fixed value set to achieve a desired initial power flow condition. When solving Equation 2, due to the use of complex voltage and power, a square root term is introduced and results in two possible solutions. An example of the two possible solutions is shown in Figure 9.

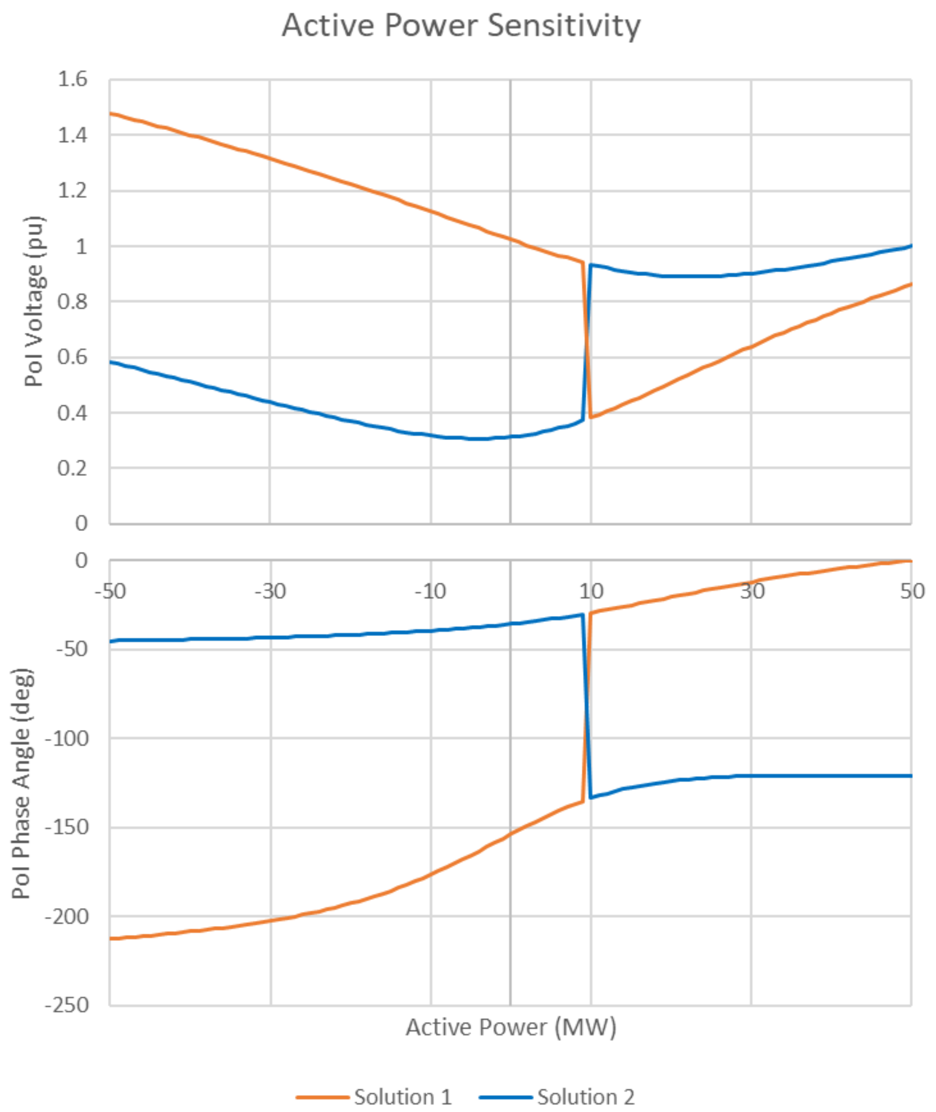


Figure 9 Point of interest (PoI) voltage sensitivity to active power flow

When an active power change occurs during a simulation, the corresponding 220kV voltage will change regardless of which solution is achieved. This magnitude of increment or reduction is dependent on the grid impedance and SCR values. Under an SCR condition of 1.997, a large active power change results in a voltage rise or drop large enough to enter generating system into FRT condition. This is exacerbated when the plant is close to reactive power limits and can provide limited support to maintain 220kV voltage. The full NEM system does not exhibit this same behaviour as power is not flowing through a single high impedance element and additional voltage support is provided by the network such that active power changes do not materially shift the voltage.

The parameters used for the example displayed in Figure 9 are outlined in Table 6 below.

Table 6 Minimum SCR = 1.249, X/R ratio = 5.9 active power sensitivity example parameters

Parameter	Value	Units
Grid Impedance	1.295 + 7.641j	ohms
Reactive Power	20	MVAr
Infinite Source Voltage Magnitude	0.919	pu
Infinite Source Phase Angle	-53.2	deg

Power transfer stability

A single machine infinite bus (SMIB) setup is shown in Figure 10 below.

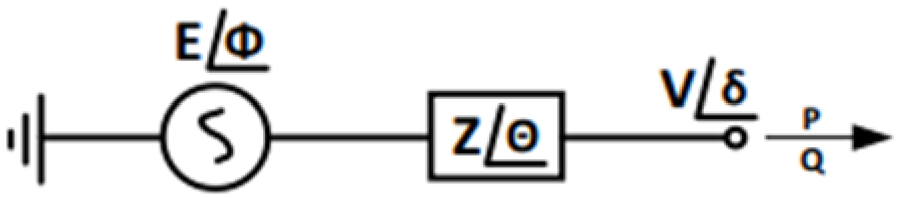


Figure 10 Two bus SMIB equivalent source and impedance setup [9]

Equation 3: Infinite source voltage magnitude [9]

$$E = \left|(P - jQ + V^2/Z\angle-\theta)/\left(V/Z\angle(-\delta-\theta)\right)\right| = \sqrt{\{(\quad\}(P + V^2/Z\cdot\cos\theta)^2 + (Q + V^2/Z\cdot\sin\theta)^2)}/(V/Z)$$

Equation 4: Infinite source voltage phase angle [9]

$$\Phi = angle((P - jQ + V\text{^}2/Z\angle-\theta)/(V/Z\angle(-\delta-\theta))) \\ = \delta + \theta - \tan\text{^}(-1)\;((Q + V\text{^}2/Z\cdot\;\sin\;\theta)/(P + V\text{^}2/Z\cdot\;\cos\;\theta))$$

Where P is the Active power transfer; Q is the Reactive power transfer; Φ is the Infinite source bus phase angle; V is the Voltage at the point connection; Z is the Grid impedance; Θ is the Grid impedance Phase angle.

By populating the information in Table 7 into Equation 3 and Equation 4, Figure 11 can be generated and assumes grid impedance, active power flow and reactive power flow are constant.

Table 7 Minimum SCR = 1.249, X/R ratio = 5.9 infinite grid voltage sensitivity example parameters

Parameter	Value	Units
Grid Impedance	1.295 + 7.641	ohms
Base Voltage	220	kV
Active Power Transfer	-50	MW
Reactive Power Transfer	-20	MVAr

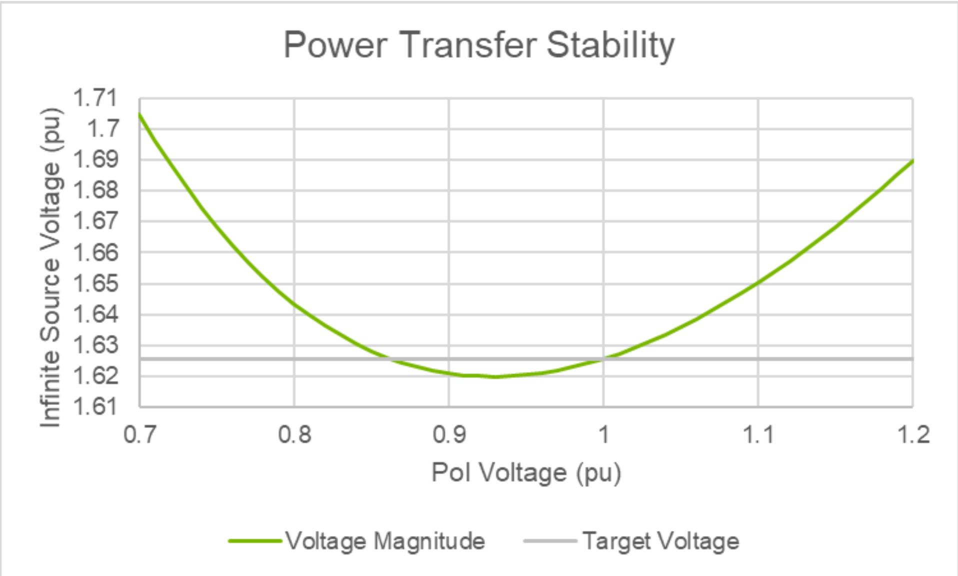


Figure 11 Grid voltage magnitude to achieve point of interest (PoI)

As can been seen in Figure 11 above, an infinite voltage source magnitude of 1.625pu can result in a PoI voltage of either 1.0 pu or 0.86 pu dependant on the voltage phase angle. If PoI voltage drops below the asymptote of the curve, a subsequent increase in the infinite source voltage magnitude can cause the PoI voltage to drop further and settle at lower voltage point (0.86 pu) instead of the intended PoI voltage (1.0 pu). The plant then remains stuck in this state and is unable to exit it without an external change to the grid voltage and phase angle, or plant voltage setpoint change.

4.3. FRT Triggering under Reactive power and Power Factor Control

Under low SCR conditions in a SMIB environment where the infinite source voltage magnitude is fixed, voltage becomes more sensitive to power flow changes through the infinite source impedance. Under some non-credible operating conditions at Broken Hill exposing the BESS to an SCR of 1.19, a ±10% change in reactive power flow through the SMIB impedance could result in a 15% change in point of interest (PoI) voltage. This change is large enough to drive the plant outside a continuous uninterrupted operation range of 90% to 110% nominal voltage, and potentially enters into HVRT or LVRT depending on the pre-disturbance condition. This phenomenon is shown in Figure 12, and Table 8 outlines the SMIB conditions used to generate the figure.

Table 8 Minimum SCR = 1.249, X/R ratio = 5.9 reactive power sensitivity example parameters

Parameter	Value	Units
Grid Impedance	1.295 + 7.641	ohms
Active Power	-50	MW
Infinite Source Voltage Magnitude	1.6256	pu
Infinite Source Phase Angle	26.915	deg

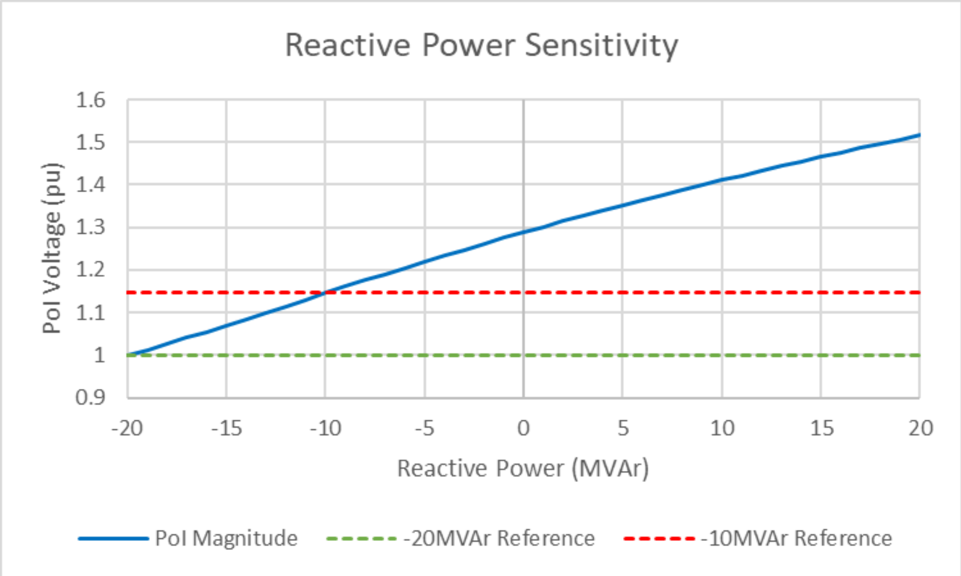
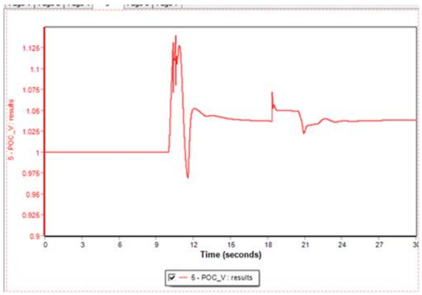
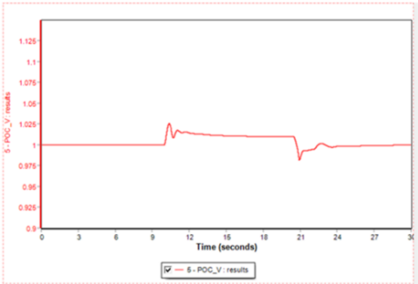
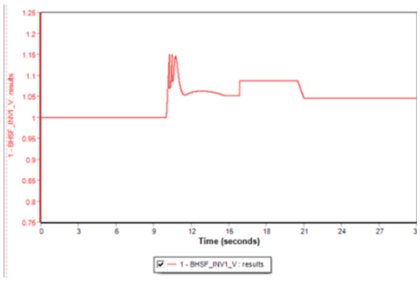
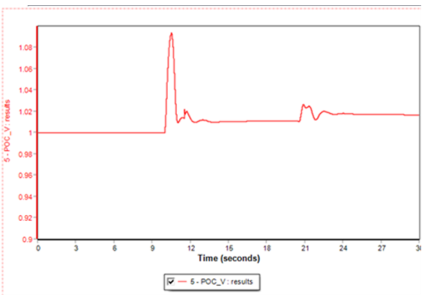


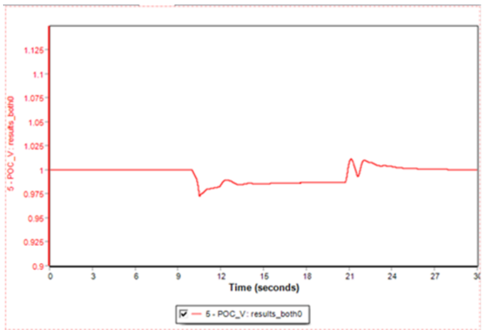
Figure 12 Point of interest voltage magnitude impact by reactive power flow

To confirm whether voltage rise/drop issues would materially impact network operation, a single machine infinite bus setup in PSS®E was developed containing both Broken Hill BESS and the existing Broken Hill Solar Farm, with an equivalent short circuit level of 205.8 MVA at the 22 kV bus used (5.4 kA at 22kV). The results are summarised in.

As Table 9 shows, BHBESS does not cause voltage to exceed more than 1.14 pu due to its frequency response and that without BHBESS, BHSF can cause voltage to exceed 1.15pu. BHSF is also shown to trip for a frequency excursion regardless of whether BHBESS is present, indicating that BHBESS does not negatively impact the network response with its frequency control response.

Table 9 Broken Hill BESS and SF SMIB Frequency Tests

BHBESS Dispatch	BHSF Dispatch	Frequency Disturbance	Response (22kV PoC Voltage)
50 MW	53 MW	Rise to 52 Hz	 BHSF tripped
50 MW	Disconnected	Rise to 52 Hz	
Disconnected	53 MW	Rise to 52 Hz	 BHSF tripped
0 MW	53 MW	Rise to 52 Hz	 BHSF tripped

0 MW	0 MW	Drop to 47 Hz	

4.4. Difference in Inertia between Synchronous Generator and Virtual Inertia from Grid-Forming Inverters

The inertial power derived from synchronous generator and the synthetic or virtual inertial power derived from grid-forming inverters are equivalent, but not equal in terms of impacts and quantity. In other words, both systems have an inertia constant, but as for the same inertia constant value, the inertial power acquired from synchronous machine will not be the same to the inertial power derived from grid-forming inverters. This is because both systems have their own physical characteristics as synchronous generator is a physical rotating machine while grid-forming inverter is a power-electronic based device which tries to mimic synchronous generator behaviours using inertia constant feeding into swing equation. Therefore, during system imbalance when both load and generation mismatch occurs, the synchronous generator as a result of its inherent inertia characteristics, either accelerates or slows down the rotor to arrest the system imbalance. On the other hand, within a grid-forming BESS inverter, the swing equation coupled with the virtual or synthetic inertia constant controls the energy transfer between grid and the generator by storing and releasing energy from the battery storage system. The physics working behind the inertia of a synchronous generator and synthetic inertia of a grid-forming BESS inverter is similar but not identical. The synthetic inertia of the BESS incorporates a slight delay and a limit to the magnitude of inertia that can be replicated at very high Rates of Change of Frequency.

4.5. Physical Inertia and Synthetic Inertia Factor

BHBESS virtual inertia is characterised by the control loop shown in Figure 13. This control loop is intended to replicate the swing equation shown in Equation 6. Unlike a synchronous generator, the inertia constant, H, is a controllable parameter. A synchronous generator has an inertia constant defined by the physical inertia of the rotor itself.

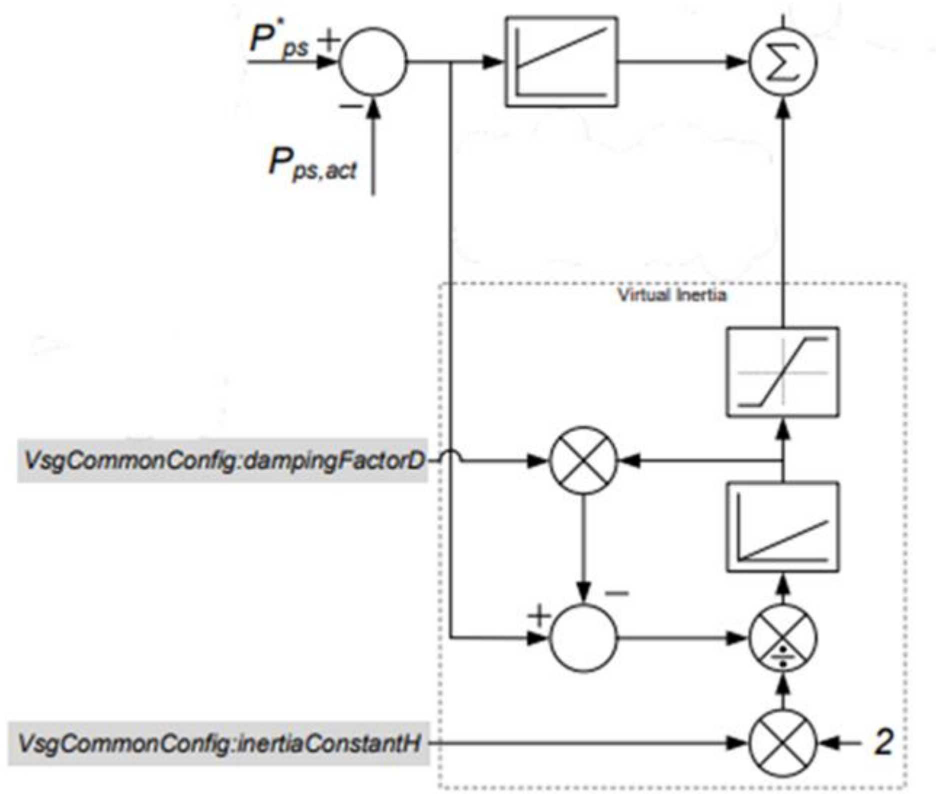


Figure 13 BHBESS Virtual Inertia Control Loop

Equation 5: Synchronous machine rotor motion

$$J(d^2\theta_m)/(dt^2) = T_m - T_e$$

Equation 6: Swing equation

$$2H/\omega_s(d^2\delta)/(dt^2) = P_m - P_e$$

Throughout the BHBESS project, the impact of the inertia constant was investigated. Inertia itself responds inherently to resist a change in frequency and a large virtual inertia constant replicated this behaviour by driving a greater active power response resisting a change in frequency. An example of different inertia constants and the BHBESS response is provided in Figure 14.

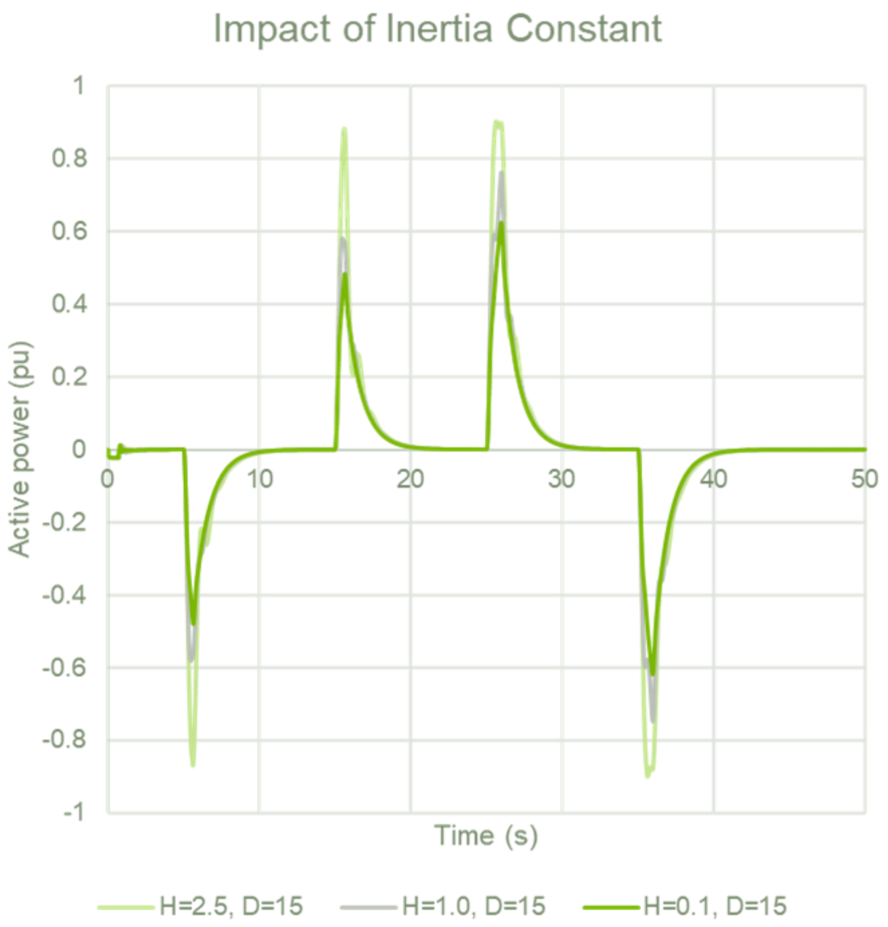


Figure 14 Impact of virtual inertia constant to 4Hz/s and 3Hz/s RoCoF

For BHBESS, when connected to such a weak network, a very small inertia constant was found to be practical. Larger inertia response when combined with low SCR active power and voltage sensitivity could cause voltage collapse and due to the 50 MW size of BHBESS, its impact on network frequency was minimal. For stronger network locations and larger battery sizes, the virtual inertia will be a critical parameter to providing network contingency frequency support and limiting network RoCoF.

4.6. Impact of various Damping Factors

In comparison to the virtual inertia factor, the damping factor is another quantity defined in the BHBESS virtual inertia control loop. Also configurable, the damping factor controls the transient response of BHBESS when recovering back to nominal due to a change in frequency. The value of the damping constant is dependent on the inertia constant, but trends are observed depending on the damping constant value used. An overly large damping constant will cause an over-damped response with slow recovery back to nominal. An overly small damping constant will result in an under-damped, oscillatory response as the plant returns to nominal output. A suitably selected damping constant results in critical damping, with the plant returning quickly to nominal without overshoot or oscillations. An example of the impact of different damping constants is shown in Figure 15, below.

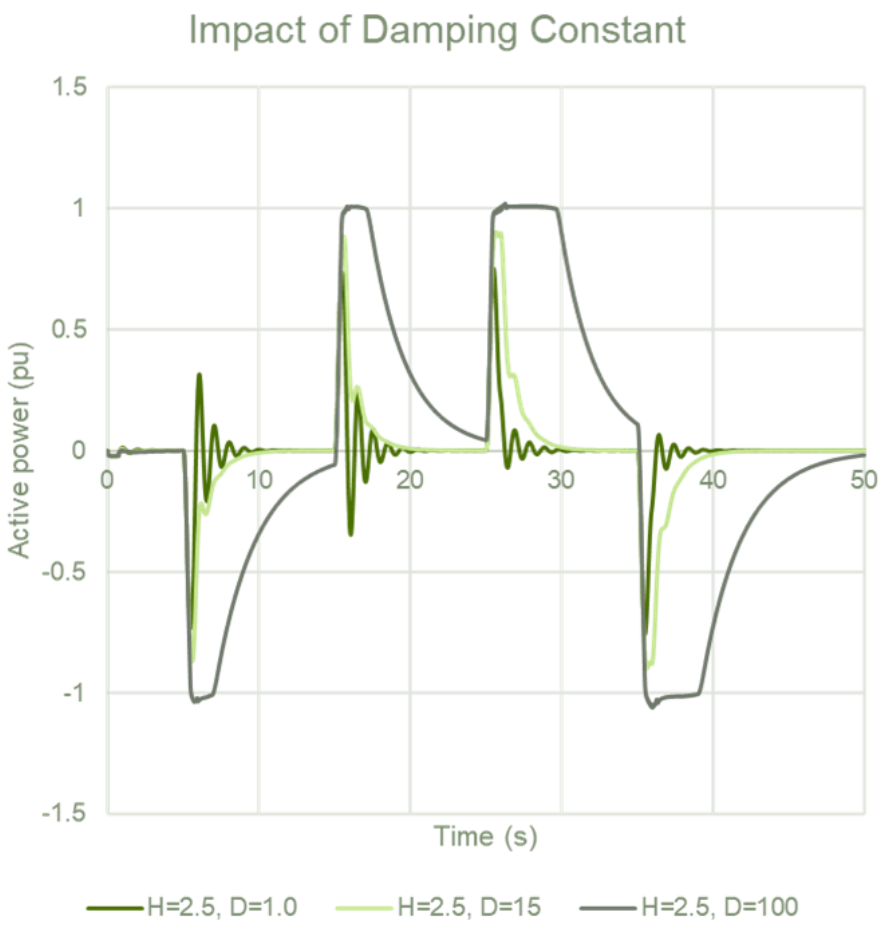


Figure 15 Impact of virtual inertia damping constant to 4Hz/s and 3Hz/s RoCoF

4.7. Delay Time and Inertia

Inverter based resource are switching, current controlled devices regardless of whether grid-following or grid-forming. The consequence of their nature is that they rely on digital measurement devices to dictate their control and don't have the same kind of inherent physical properties that a large rotating mass in a synchronous generator does. The inertia behaviour of a synchronous generator begins instantly when a change in frequency occurs, whereas even for grid-forming inverters, an inverter-based resource must measure the frequency or voltage phase angle and adjust their switching operation to output the intended current. Inverter based resources operate on very high measurement frequencies, in the order of kilohertz, but this still results in some very small inherent delay before an inverter-based resource commences in comparison to a synchronous generator. An example of the very slightly delay in active power response of BHBESS is observed in Figure 16 where although frequency begins to move at a constant rate, the plant does not begin to respond for at least 20-30ms.

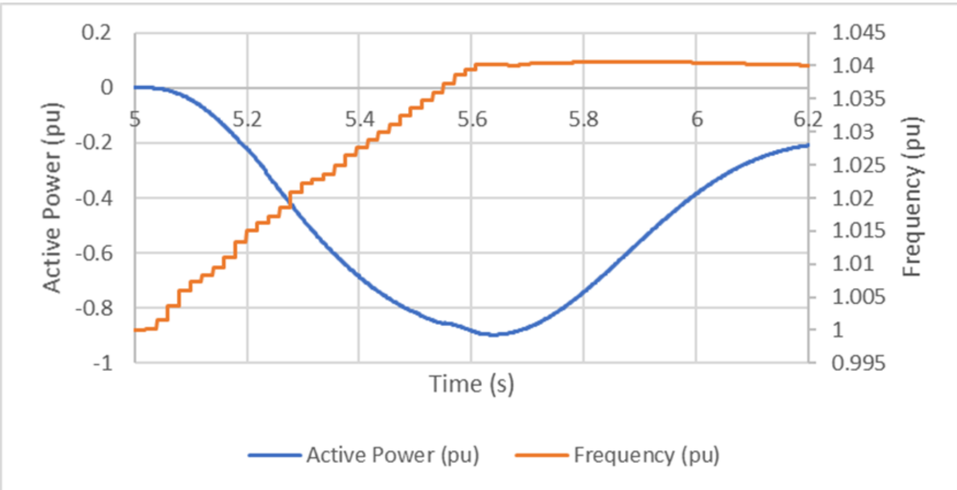


Figure 16 Active power response to frequency change, zoomed

Although this does not have significant impact on network performance, it is a factor to be mindful of in extremely weak grids or microgrids where this small delay could have a larger impact.

5. Virtual Inertia and Damping Factor Sensitivity in a Low SCR Network

5.1. Frequency Disturbance Assessment

To investigate the virtual inertia and damping factor setting sensitivity, a set of frequency disturbance events with the minimum SCR network (SCR = 1.99, X/R = 6.2 at 22 kV side) was performed. All tests were performed with the ROCOF of 4 Hz/s, 3 Hz/s and lower. Table 10 includes the summary of test conditions carried out for the purpose of virtual inertia and damping factor sensitivity analysis.

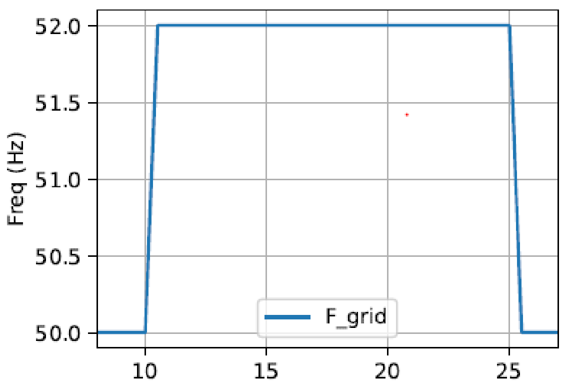
Table 10 Frequency Disturbance Test Conditions with Different Virtual Inertia and Damping Factor Settings

Parameters	Frequency Disturbance	ROCOF	Operating Points
DF = 12, IC = 0.1	+/- 0.5 Hz, +/- 1.0 Hz, +/- 2.0 Hz, - 3 Hz	4 Hz/, 3 Hz/s, 2 Hz/s, 1 Hz/s, 0.5 Hz/s	PmaxQmax, PmaxQzero, PmaxQmin, PzeroQzero, PzeroQmax, PzeroQmin, PminQmax, PminQzero, PminQmin
DF = 10, IC = 0.1	Same as above	Same as above	Same as above
DF = 20, IC = 0.5	Same as above	Same as above	Same as above
DF = 62, IC = 2.5	Same as above	Same as above	Same as above

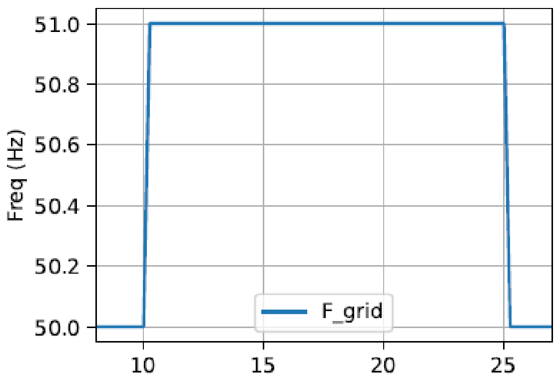
Frequency disturbance tests with different virtual inertia and damping factor settings showed that with lower virtual inertia constant, the damped voltage oscillation observed for frequency disturbance events was significantly improved. The combination of DF = 10 or 12 and IC = 0.1 exhibited the best performance when compared to the higher plant settings of DF = 62 and IC = 2.5. The only exception was that for the PminQmin operating conditions, a frequency disturbance from 50 Hz to 47 Hz still resulted in a significantly fast and large active power change and corresponding swing in terminal voltage which caused the plant to enter FRT and re-strike, driving a temporary oscillatory voltage response at the point of connection. Test results also suggested that generating system response for a frequency disturbance with ROCOF of 4 Hz/s and 3 Hz/s didn't make any significant difference to this observed behaviour.

Figure 17 depicts the different frequency disturbances with a ROCOF of 4 Hz/s used for this assessment. Figure 18 and Figure 20 show a comparison of the sensitivity analysis for the four considering pairs of DF and IC parameter settings for different frequency disturbance tests. For visualisation purposes, PmaxQmax and PminQmin conditions only are presented as these two operating points showed the most onerous response during the investigation. The frequency disturbance with ROCOF 4 Hz/s was applied at 10s and returned to 50 Hz at 25s. It was observed that the generating system voltage response at the point of connection with DF = 10 or 12 and IC = 0.1 showed more stable behaviour for any onerous frequency disturbance as compared to the existing value DF = 62 and IC = 2.5. Additionally, the large active power dip previously observed at some operating conditions (e.g. PmaxQmax) on frequency disturbance clearance (i.e. around 20s) was reduced by up to 50% with the lower virtual inertia constant value (IC = 0.1). When the plant is at Pmax, with a lower virtual inertia constant, it was also observed that the active power transient which normally occurred 3-5s after the disturbance with the current higher virtual inertia settings, was shifted to occur closer to the disturbance as the virtual inertia response of the inverter did not drive the plant into its Pmax limit as aggressively or for as long (e.g. Figure 17a).

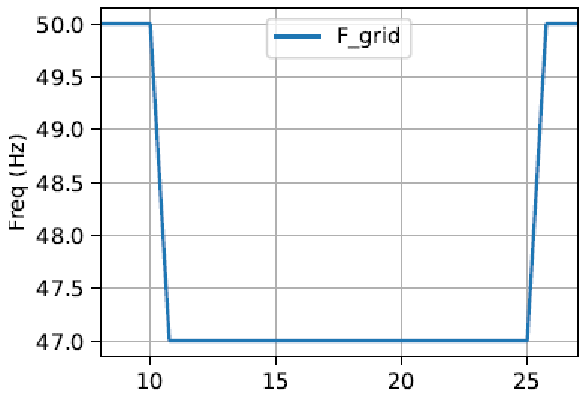
Figure 17 Different Frequency Disturbances for Sensitivity analysis: 4 Hz/s of ROCOF



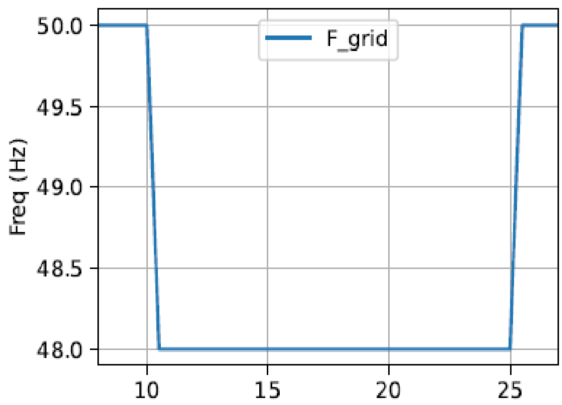
(a) 50 Hz to 52 Hz



(b) 50 Hz to 51 Hz



(c) 50 Hz to 47 Hz

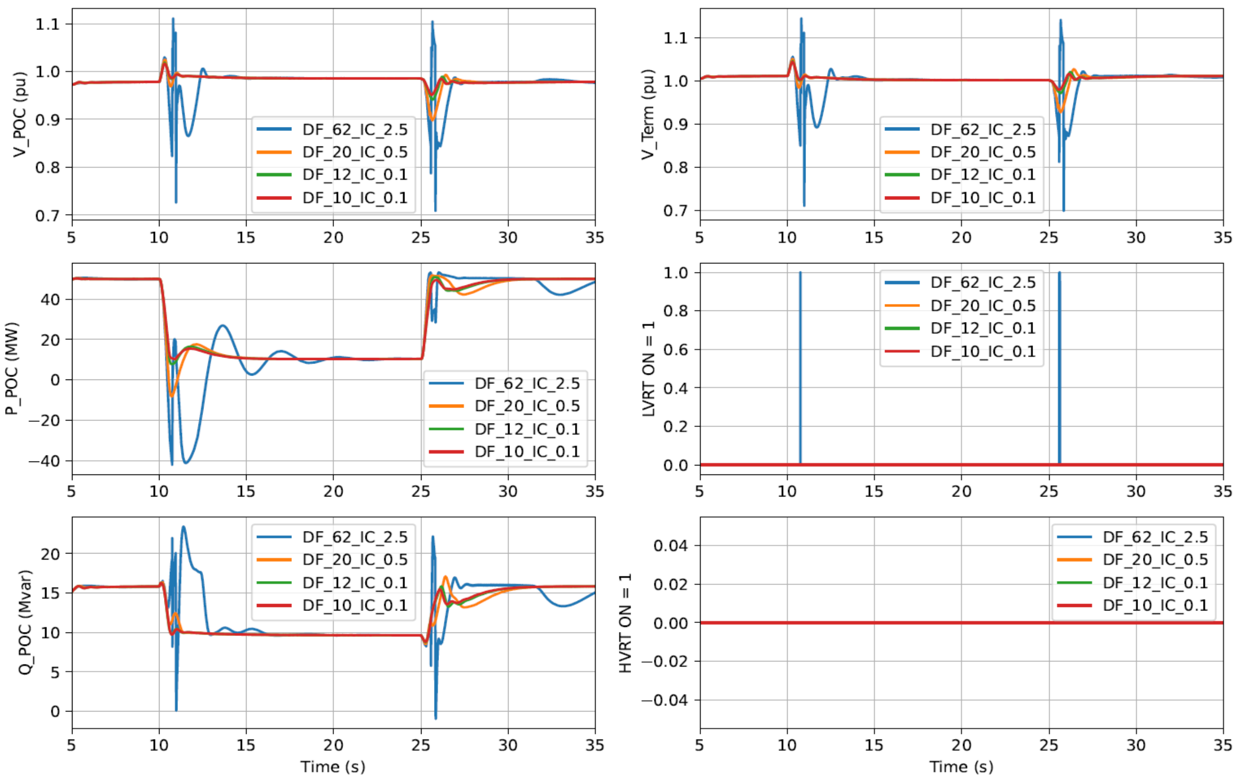


(d) 50 Hz to 48 Hz

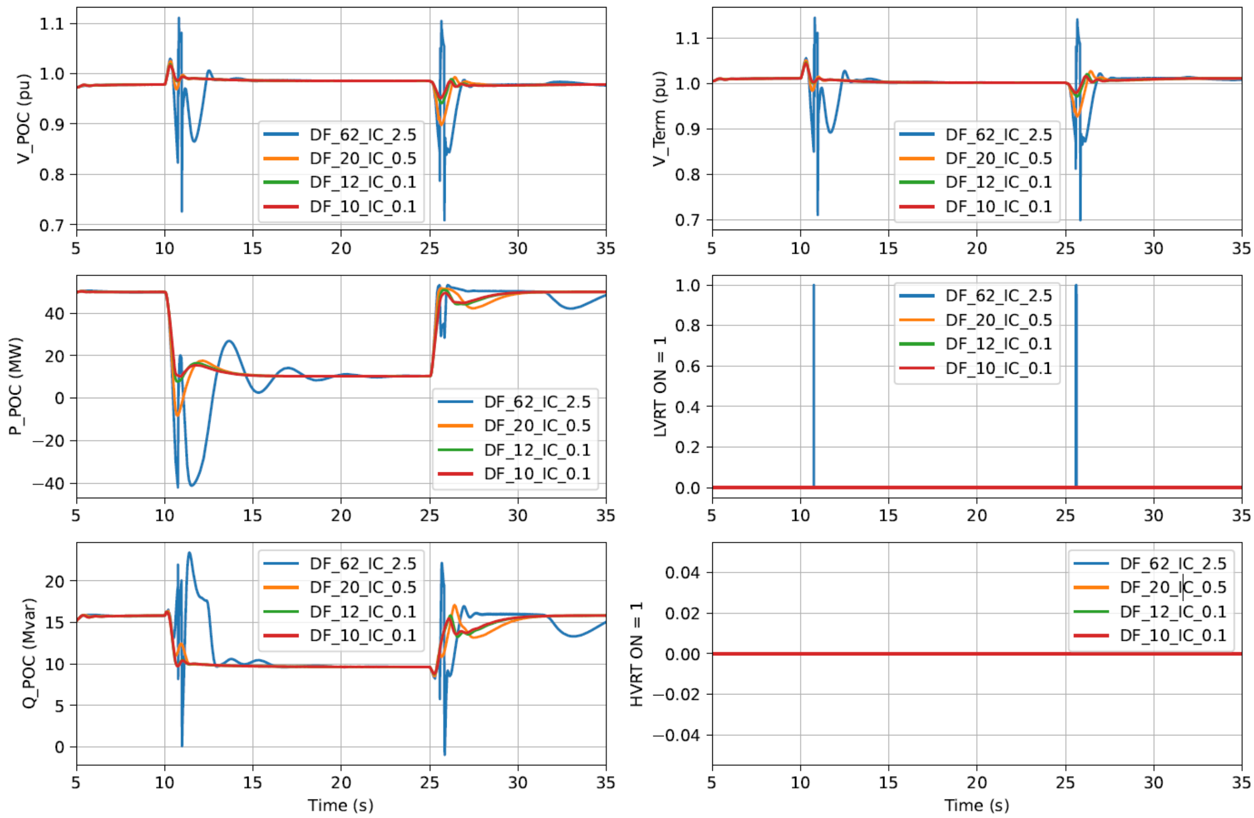
It is also noted that there is a slight dip in active power and reactive power around 15s into the simulation when there is no frequency change at such point, for example in Figures 18(c), 18(d) and 19(a). This is considered an ordinary occurrence due to the plant operating at a limit for a brief duration after the frequency disturbance is introduced at 10s. Once the plant corrects itself and backs off the limit, a slight dip is observed in the opposite direction before returning to the nominal set-point.

For example, in Figure 19(a), though a little difficult to discern from the plot, the active power does dip very slightly more negative after the frequency disturbance, given that it wants to reduce when faced with the rise in system frequency, however, as this is the plant minimum limit, there is a brief accumulation until ~15s, before it corrects over the following 3 seconds, which is witnessed in the slight rise above –50 MW. Such behaviour is not observed when the plant is not pushed to a limit during a frequency disturbance, for example, in Figure 18(a).

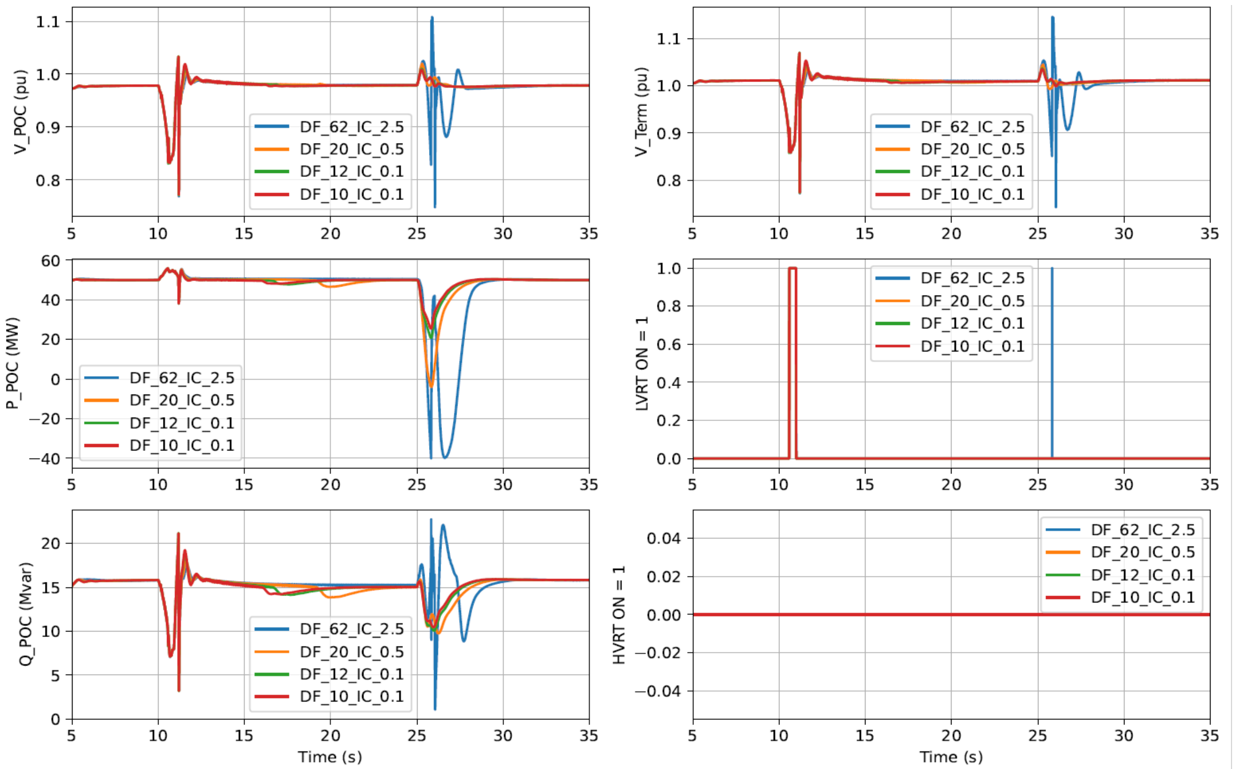
Figure 18 Comparative Analysis for PmaxQmax Operating Point Under Most Onerous Frequency Disturbance, SCR = 1.99, X/R = 6.2 and ROCOF 4 Hz/s



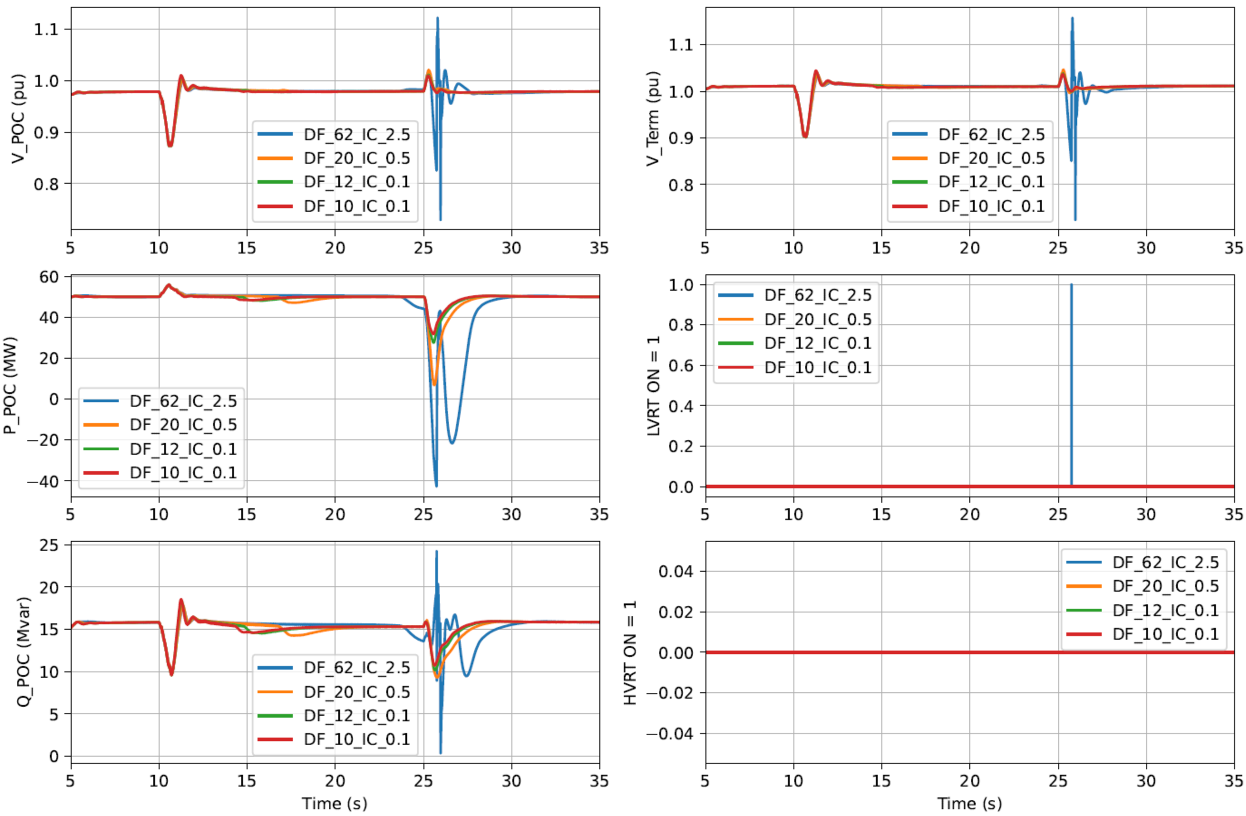
(a) 50 Hz to 52 Hz



(b) 50 Hz to 51 Hz

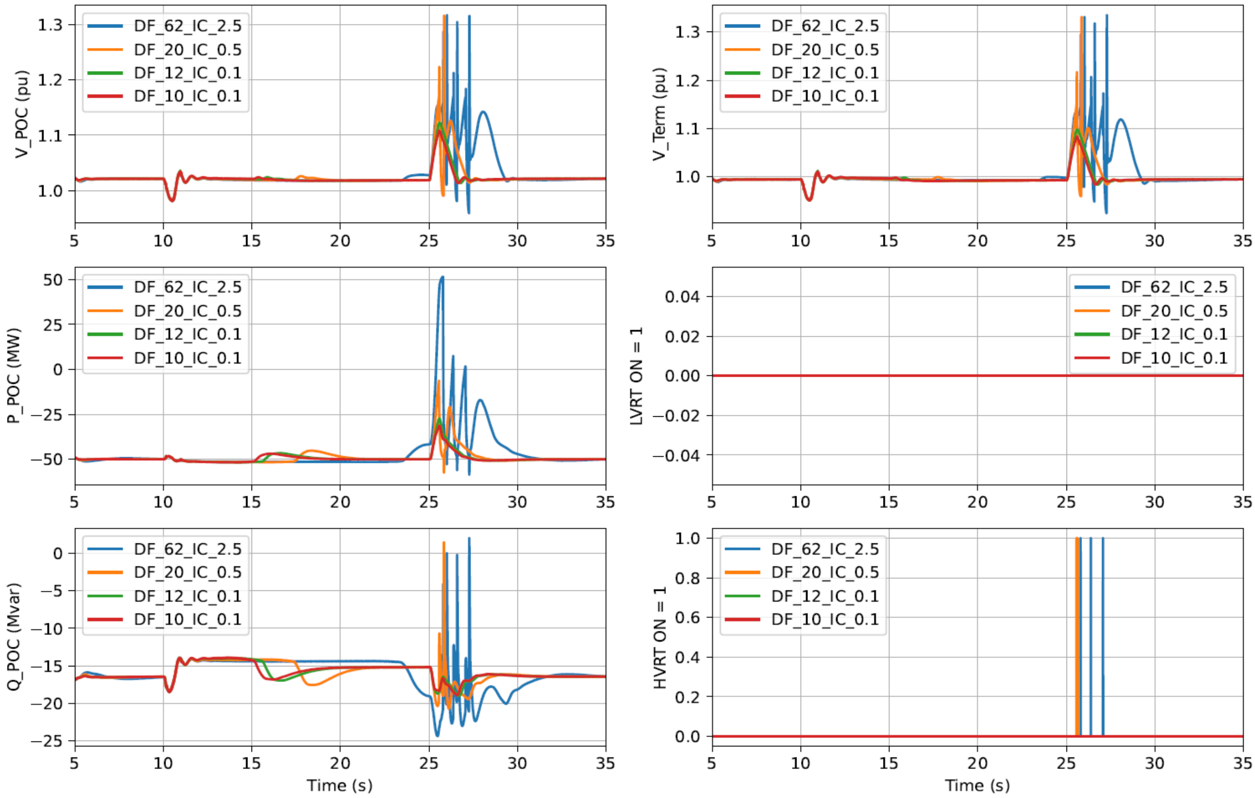


(c) 50 Hz to 47 Hz

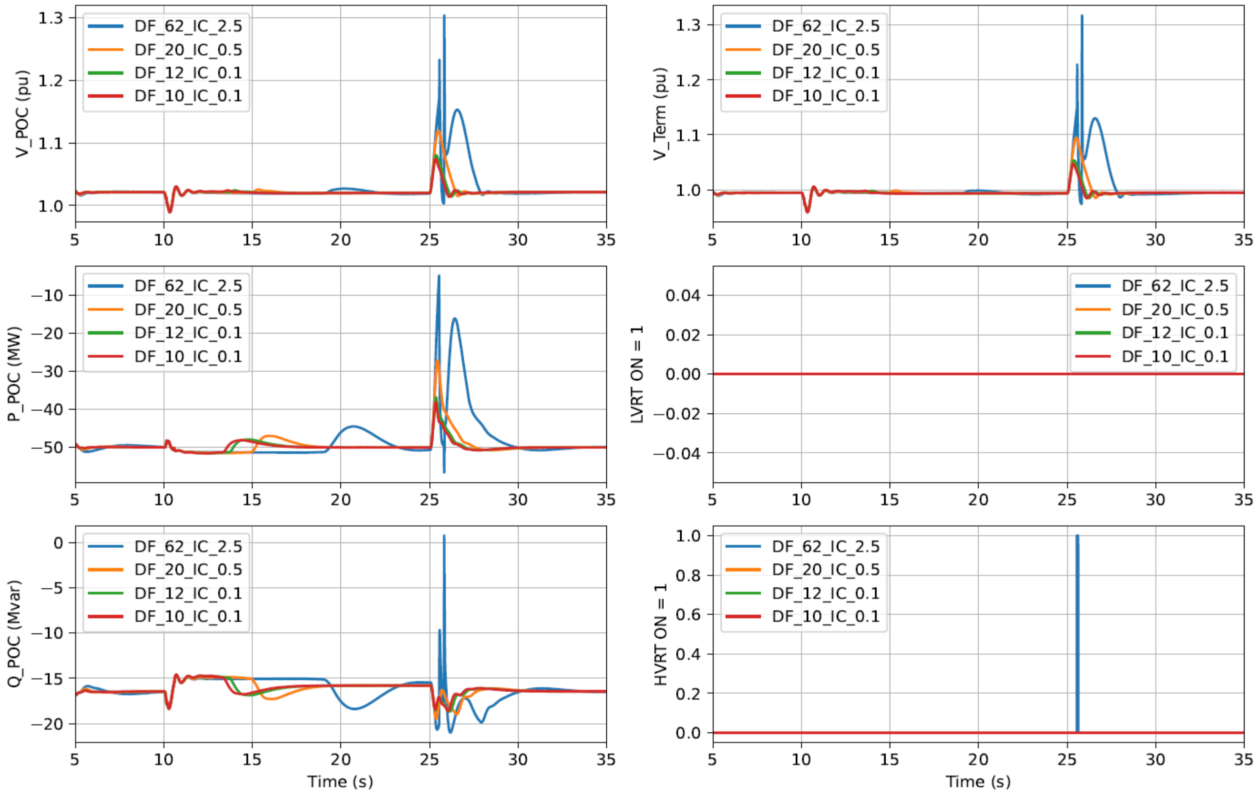


(d) 50 Hz to 48 Hz

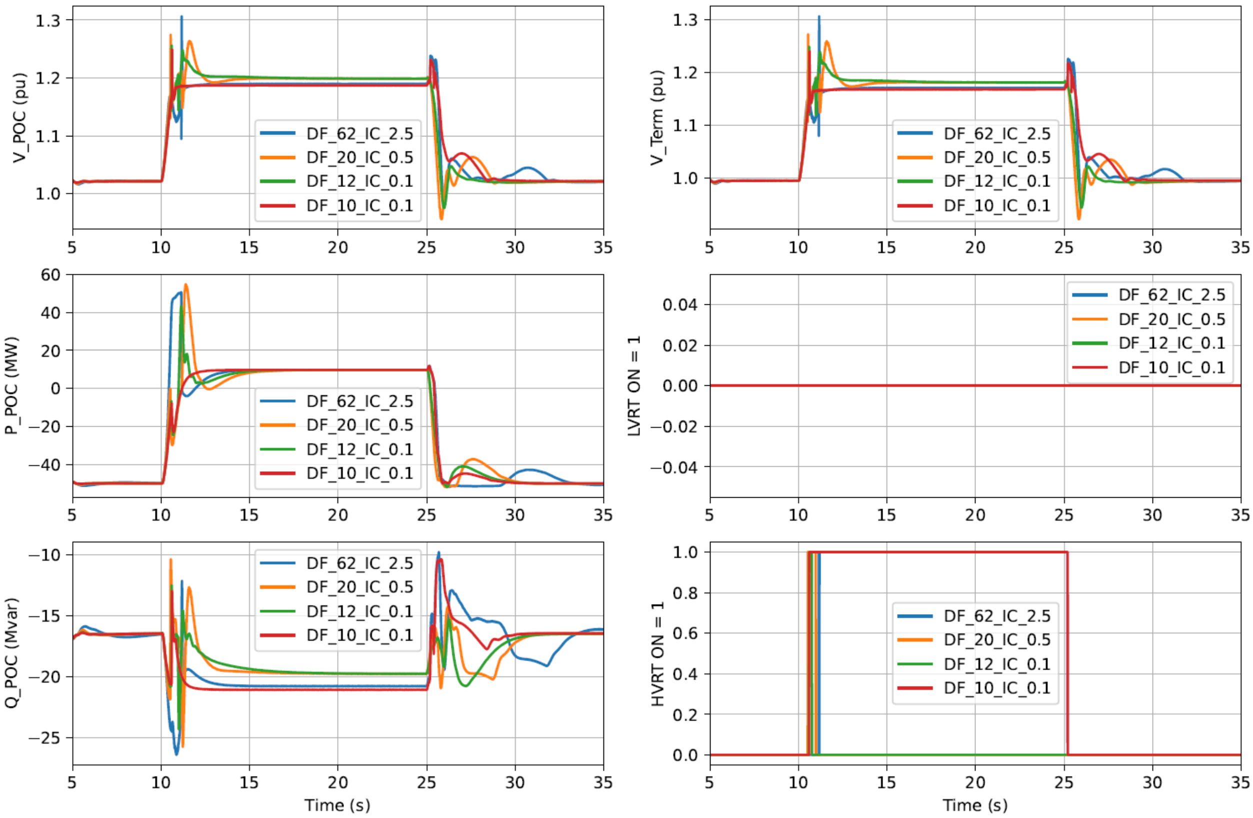
Figure 19 Comparative Analysis for PminQmin Operating Point Under Most Onerous Frequency Disturbance; SCR = 1.99, X/R = 6.2 and ROCOF 4 Hz/s



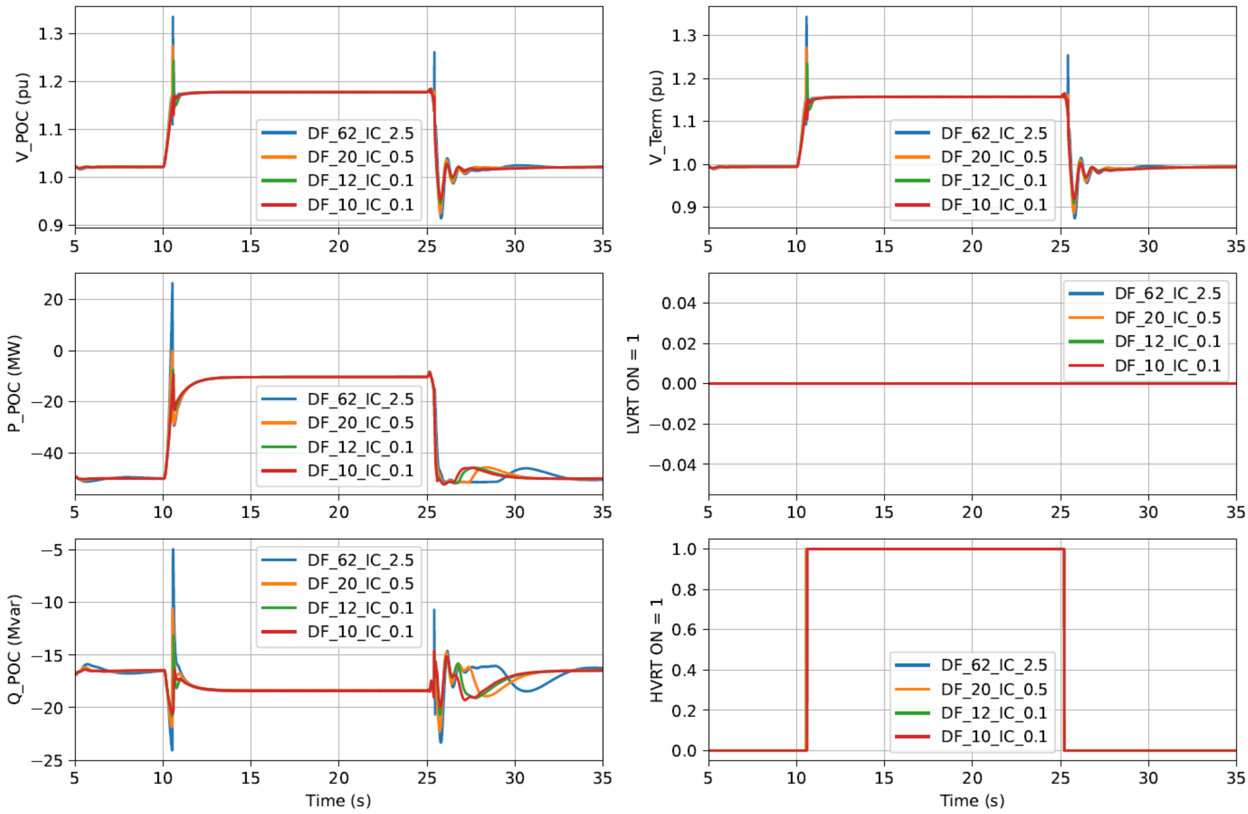
(a) 50 Hz to 52 Hz



(b) 50 Hz to 51 Hz



(c) 50 Hz to 47 Hz

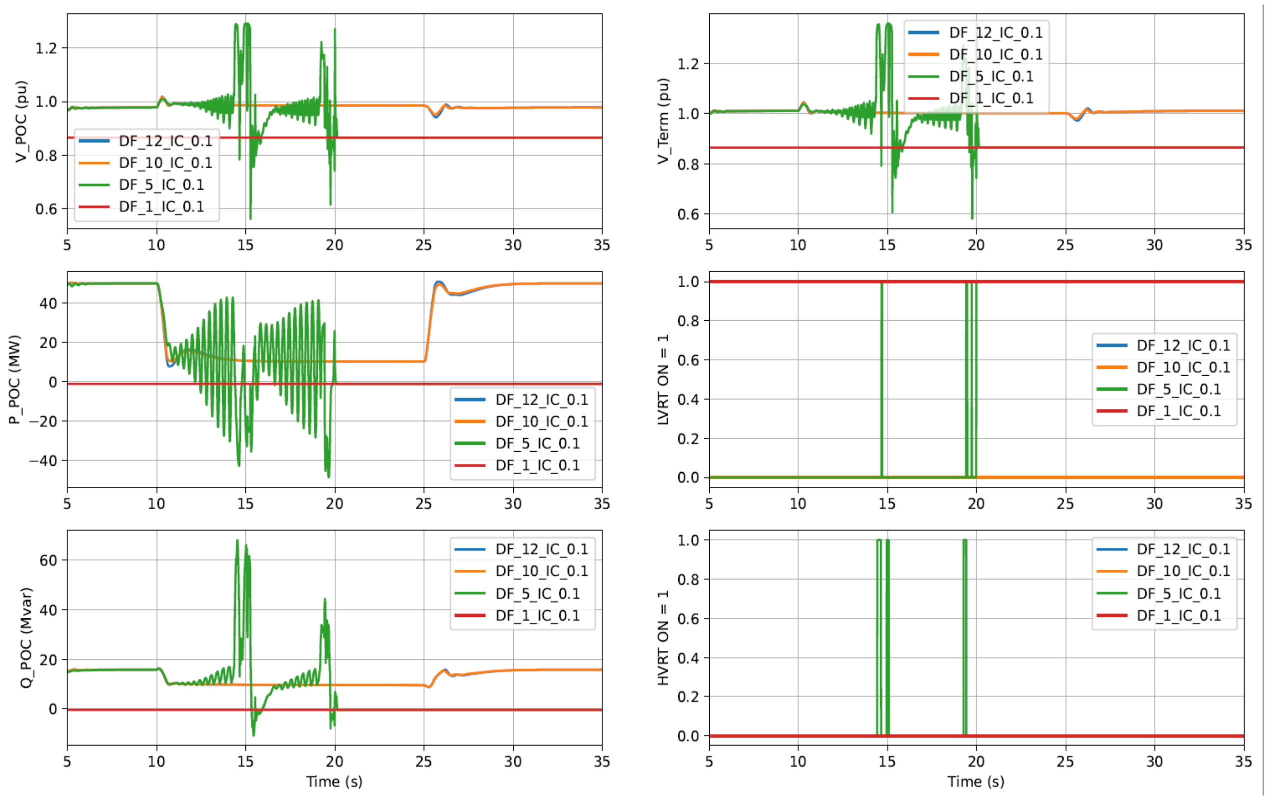


(d) 50 Hz to 48 Hz

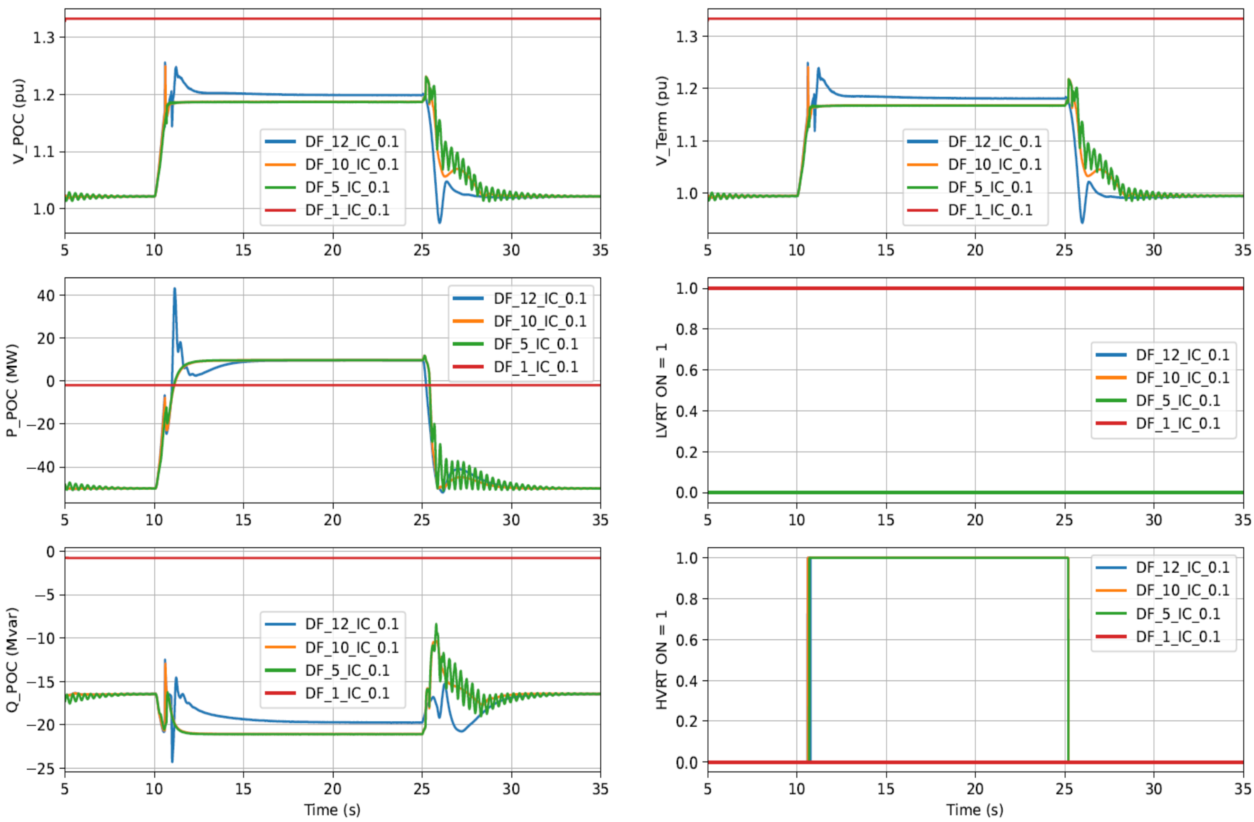
5.2. Impact of Reduced Damping Factor

From Section 5.1, it is anticipated that a pair of DF = 10 or 12 and IC = 0.1 shows the best performance under any frequency disturbance events. However, it is a question to investigate whether the further reduction of damping factor less than 10 with the virtual inertia constant IC = 0.1 can improve the modelling performance at any frequency disturbance test or is there any potential impacts if the damping factor is reduced to below 10. To examine further, a sensitivity analysis was carried out with four different damping factors (DF = 10, 12, 5, and 1) at virtual inertia constant IC = 0.1 and it is found that there is a minimal difference found in active power, reactive power, and voltage response with DF = 10 and DF = 12 at the point of connection. On the other hand, the reduced damping factor DF = 5 and IC = 0.1 causes worsening the plant's performance and is likely to introduce oscillatory active/reactive power and voltage profile for any frequency disturbance as seen in Figure 20. Moreover, the further reduction of the Damping factor (e.g. DF = 1) has serious impacts causing the PSCAD model to crash and initialisation failure.

Figure 20 Sensitivity Analysis: Damping Factor, SCR =1.99, X/R =6.2 and ROCOF = 4 Hz/s



(a) PmaxQmax, 50 Hz to 52 Hz



(b) Pmin Qmin, 50 Hz to 47 Hz

The findings from frequency disturbance tests provide a reasonable indication that the higher virtual inertia constant (IC > 0.1) results in large swings in active power and corresponding swings in POC voltage which may cause the plant to enter FRT and restrike under some disturbances. On the other hand, the outcomes from the reduced damping factor investigation provide a good indication the pair of DF = 10 or 12 with IC = 0.1 are close to the most suitable settings for the plant across its operating range for any dynamic frequency disturbance event.

6. Grid-Following Mode Switching

6.1. Benefits of Switching

BHBESS implements a switch to grid-following functionality when voltage moves outside the normal operating range. This was to meet the previous, more stringent GPS requirements to inject significant reactive current during a fault. When this switch occurs, it facilitates BHBESS operating with traditional, current controlled fault ride through behaviour. Some key benefits of this behaviour are:

1. Control of both positive and negative sequence currents independently, unless a limit is reached
2. Direct current control, rather than voltage control, which provides better current settling times
3. Directly controllable reactive current injection proportional to voltage
4. Improved stability under unbalanced faults

Due to recent NER rule changes, the reactive current response to network disturbances has been somewhat relaxed and further work may facilitate implementation of BHBESS with a grid-forming fault ride through functionality. Regardless, reactive current settling times and unbalanced fault stability are the two critical areas where further work may be required to facilitate this.

6.2. Reactive Current Injection in the Rules

The BHBESS connection application was submitted under version 186 of the Rules. This was to meet the previous, more stringent GPS requirements to inject significant reactive current during a fault. The NER requirements for reactive current injection under version 186 defines the following:

1. Minimum of 2% reactive current injection (for under-voltage) or absorption (for over-voltage) for every 1% voltage beyond the fault ride through activation range.

2. 40ms rise time for reactive current injection or absorption from commencement of the disturbance.
3. 70ms settling time for reactive current injection or absorption from commencement of the disturbance.

Current NER requirements under version 199 defines the following:

4. Minimum of 0% reactive current injection (for under-voltage) or absorption (for over-voltage) for every 1% voltage beyond the fault ride through activation range.
5. 40ms rise time for reactive current injection or absorption from commencement of a response by the plant.

The removal of the settling time requirement removes this as a key restriction from implementing grid-forming fault ride through capability and for future grid-forming projects in Australia.

6.3. Delay Times between the Switching of Modes

A delay time exists when switching between grid-forming and fault ride through grid-following mode for BHBESS. The delay times are driven by two factors:

1. Time to detect voltage has moved above or below the activation threshold
2. Time to switch modes and change the current controller targets

These two delay times happen in the order of 10-20ms depending on the network voltage itself but are a considerable factor in the plant's ability to meet NER reactive current rise times.

The control mode change is triggered by detection of the fault based on the static voltage threshold level for each phase voltage. Since measured phase voltage magnitudes are filtered, there is a delay between the actual fault event and detection of fault based on threshold level. During that time, inverter operates in grid-forming and the response is defined by the voltage and frequency controllers. This typically lasts for a few milliseconds. After control mode is changed to grid-following, the reactive current support is applied when voltage deviation goes below the dead band threshold level of inverter (e.g. 85%). Improving rise and settling times would cause more oscillatory responses and most probably compromise stability for low SCR.

6.4. Grid Following to Grid-Forming Transient Switching

When voltage has recovered to within nominal range (typically 0.9 – 1.1pu), the inverters will transition back from grid-following mode to grid-forming after a 250ms delay time. This 250ms delay is intended to prevent any switch-over transients during fault clearance which could cause spikes in voltage and trigger a further network event. When the switch in mode occurs, the inverter resets internal states to pre-disturbance conditions. If pre-disturbance conditions are the same as post-disturbance, then very little switching transient is observed, and a smooth transition occurs. However, if network phase angle, frequency and voltage have recovered to a sufficiently different operating point following disturbance clearance, the inverter internal grid-forming states will not align with the pre-disturbance operating condition. A transient is then introduced as the inverters resettle to the new grid conditions. A transient due to change in states is unavoidable for all scenarios, but the transient has been observed to be sufficiently small such as to not drive an additional network disturbance.

6.5. Fault Ride Through, Fault Clearance and Ride Through Performance

Grid-forming inverters, depending on implementation, typically control voltage and frequency with the intention of replicating aspects of a synchronous generator. Regardless of if during normal operation or during a fault, a grid-forming inverter will respond to the voltage and frequency. A grid-following inverter, in contrast to grid-forming, will control the active and reactive current. By controlling voltage and frequency rather than active and reactive current, a grid-forming inverter is prone to more movement in its response as network voltage and frequency move. The impact of the additional movement is an increase in current settling times during the fault and a less controlled reactive current injection. A less controlled reactive current injection refers to the inability to directly specify a k-factor as in a grid-following device, and a potentially non-linear response to change in voltage during a fault. The keys points referred to above in the paragraph are summarised in Section 5.1.

To manage the lack of direct current control, BHBESS implemented a switch to grid-following mode during fault ride through to apply constant current control. Constant current control also allows for direct parameterisation and prioritisation of the following characteristics:

1. Reactive current injection proportional to voltage (k-factor)
   - BHBESS has an inverter level k-factor of 3.0 implemented for network stability rather than plant capability
2. Reactive and active current priorities
   - BHBESS utilise reactive current priority during a fault to meet NER requirements.
3. Positive and negative sequence priorities
   - Positive sequence current is prioritised over negative sequence.
   - Grid-forming functionality operates on positive sequence only for shallow faults where FRT does not occur.

Due to the extremely low SCR of 1.997, BHBESS inverter current controllers were tuned to provide ride through stability which resulted in slow reactive current response times during a fault. Compliance was a concern to meet the rule requirements of 40ms rise time and 70ms settling time. When considering a higher SCR of 4.115, the current controller could be sped up to meet these requirements without jeopardising fault ride through stability. The faster current control stability was also confirmed through wide-area PSCAD studies performed by Transgrid and AEMO.

BHBESS inverters also contain an early fault clearance detection functionality intended to reduce the reactive current injection on fault clearance and minimise any over-voltage that could occur. Over-voltages under an SCR of 1.997 in a single machine infinite bus (SMIB) environment observed large over-voltages in the order of 1.2pu and greater. However, with a higher SCR and in the network itself, BHBESS was not observed to drive over-voltages on fault clearance as high.

Another learning from the wide-area PSCAD modelling is that, unlike a windfarm or solar farm, when inverter level AC voltage exceeds a threshold, the BESS may lose control or stability. This voltage can be less than the protection settings on the inverter but result in uncontrolled response from the inverter. For BHBESS, this threshold was approximately 1.3pu, which if connection point voltages reach a high enough value to exceed 1.3pu at the inverter would be in excess of NER S5.1a.4 network voltage frequency standards.

6.6. Multiple Fault Ride Through

BHBESS inverters contain a restrike mask time to prevent unintended re-triggering of fault ride through due to transients on fault clearance or due to the grid-following to grid-forming switch-over. With respect to multiple fault ride through (MFRT), this does result in the plant not responding with the normal reactive current injection profile for subsequent faults close together. The restrike mask time is not a feature specific to grid-forming technology, but without the mode switch-over the mask time could potentially be shortened to have less of an impact.

Multiple fault ride through performance and potential impacts can result in subsequent faults being masked. BHBESS is still able to ride through these faults without tripping or exhibiting any unstable behaviour. The critical component of multiple fault ride through is to prevent cascaded tripping in the network, not to meet reactive current injection and active power recovery requirements for all faults. Initial tuning showed that BHBESS would trip for some multiple fault ride through tests, but this was attributed to the specific faults and durations applied, not the multiple fault component, and further tuning was able to resolve the trip behaviour. As such no MFRT compliance issue remained for BHBESS but unlike a synchronous generator, consistent fault ride through performance for close duration faults (within 250ms of each other) will not be maintained.

7. Effect on Grid Hosting Capacity

The effect on grid hosting capacity by the Broken Hill BESS in the surrounding area has been preliminarily assessed using real-time EMT digital simulations [5]. Increasing the output of existing renewable generation plants in the Broken Hill Area beyond their rated output allows to test these scenarios of higher inverter-based resources (IBRs) and measure the effect on grid hosting capacity.

To achieve this, the output of one renewable source (i.e., Broken Hill Solar Farm or Silverton Wind Farm) is increased until the system experiences instabilities (oscillations of a magnitude $\geq 1\%$). When increasing the renewable generation from Silverton Wind Farm, the maximum hosting capacity of the Broken Hill Area increases 16.7% (i.e., from 252 MW to 294 MW), as shown in Table 11. This increase is due to the strengthening of the grid (i.e., system strength) and the additional reactive power support and capacity provided by the Broken Hill BESS. As shown in Table 11, when the Broken Hill BESS is providing reactive power to the grid, it increases the hosting capacity, as there is more room for existing SVCs to regulate the voltage of the grid. Similar results are obtained when increasing the capacity of the Broken Hill Solar Farm instead of the Silverton Wind Farm.

Table 11 Grid hosting capacity enabled by the Broken Hill BESS.

Condition	Hosting Capacity
No BESS	$\approx$ 252 (100%)
Broken Hill BESS with $P_{ref} = Q_{ref} = 0$	$\approx$ 263 (+4.4%)
Broken Hill BESS with $P_{ref} = -50\ MW, Q_{ref} = 0\ MVAr$	$\approx$ 273 (+8.3%)
Broken Hill BESS with $P_{ref} = 0\ MW, Q_{ref} = 50\ MVAr$	$\approx$ 294 MW (+16.7%)

It is important to highlight that in this analysis:

- The Broken Hill BESS is allowing not only to host more renewables in the area but also to damp severe voltage oscillations which appear in the grid if no BESS is included. The Broken Hill BESS, then, provides system strength while enabling further hosting capacity.
- Simulations were performed at the minimum system strength scenario defined by AEMO. In other words, the *worst-case* scenario for system stability was modelled. Consequently, stronger system conditions would allow extra renewable generation exports out of Broken Hill substation.
- Thermal limitations have not been considered, for example in transmission lines, transformers, and inverters. Thermal limits can further constrain the hosting capacity in the area.
- The additional renewable energy was interfaced to the grid via inverters operating in grid-feeding/grid-following mode. Furthermore, no additional equipment such as transformers, transmission lines, reactive power compensation, have been included, which may provide additional support to the Broken Hill area.
- It has been found that the hosting capacity is limited by the available reactive power support provided in the area, and power transfer capability of the 220 kV single-circuit transmission line connecting Broken Hill substation to the rest of the grid. In other words, the area is subjected to voltage and transient instabilities if there is no network augmentation or new infrastructure but only the Broken Hill BESS.

In summary, considerations for estimating additional hosting capacity in a given location depend on:

1. Local loads,
2. Existing power system infrastructure,
3. Existing renewable generation,
4. BESS characteristics (e.g., sizing) and point of common coupling (e.g., high-voltage network, medium-voltage network) [6],
5. Control function of the BESS (e.g., grid-following vs grid-forming, grid-forming technology),

6. Thermal overloads of existing components (e.g., transmission lines, transformers),
7. Available system strength,
8. Other local factors.

The above conclusions are in alignment with previous research work funded by ARENA. For example, in the Powerlink assessment report [7], which considers a substantially stronger network, all IBRs (including the BESS) were connected directly to the 275 kV high-voltage network. Outcomes of this study have shown that a 100 MW BESS can support the connection of 300 MW of IBRs for the specific location and particular case examined.

8. Grid-Forming Performance for Shallow Unbalanced Faults

During shallow faults, when the voltage events of undervoltage or overvoltage remain within predefined threshold levels, the inverter stays in grid-forming mode and does not trigger transient reactive current (TRC) support, which is characteristic of grid-following mode. As a result, the response of the inverter differs from the response during TRC due to the specific control properties associated with grid-forming mode.

In the case of a voltage dip without a phase jump, both the real power and reactive power will momentarily decrease. However, these simplifications only hold for a very brief period. Once the inverter detects the change in terminal voltage, the various control loops come into play and start influencing the magnitude and angle of the inverter terminal voltage, thereby altering the power flow.

According to the inverter control logic, during shallow faults, the Fault Ride-Through (FRT) logic block is not functional, and the current references are derived solely from the frequency and voltage control. The response of the inverter during shallow faults in grid-forming mode can be discussed further by examining its behaviour in the context of both balanced and unbalanced faults.

8.1. Shallow Balanced Faults

In the case of balanced faults occurring during grid-forming mode, the response for each phase should be identical, and there are no oscillating components present in the real and reactive powers as seen in asymmetrical fault events. To simplify the analysis, we can assume that the innermost control loop, which is the current control, operates quickly enough to ensure that the actual current always follows the reference.

During shallow balanced faults when the inverter is in grid-forming mode, two independent control loops come into play. The first control loop, known as the inner control loop, responds to the sudden drop in voltage magnitude after a short delay. The voltage control mechanism will request more Q-axis current when the actual voltage magnitude is lower than the reference, leading to an increase in reactive power flow. Depending on the magnitude of the phase jump, the frequency controller may also react and adjust the D-axis current reference, thereby affecting the real power flow.

The outermost control loop of the inverter is responsible for real power (inertia response) and reactive power control. The reactive power controller considers the increased reactive power flow caused by the voltage fault and the increased reactive current command from the voltage control. Since the actual reactive power exceeds the reference value, the controller starts reducing the voltage reference. Similarly, the inertia response considers changes in real power flow and adjusts the frequency reference based on integral action defined by the inertia constant.

The frequency and voltage droops, which define the relationship between frequency/voltage deviation and the corresponding changes in references, also influence the frequency and voltage references derived from the inertia response and reactive power control based on the real and reactive current flow. However, the impact of these droops is typically minor compared to the response from the power controllers and can be disregarded in this simplified analysis.

In addition, since the shallow fault is not classified as a FRT situation, there will also be a change in the PPC real and reactive power commands during the fault, thus the inverter will respond to the change in reference values as usual.

It's important to consider that the current limits of the inverter may be reached during unbalanced fault events, depending on the operating conditions before the fault and the type of fault that occurs. The inverter has separate limits for the D-axis and Q-axis currents, as well as a circular limit based on the maximum apparent current.

In such cases, the priority of limitation can be defined, considering the maximum apparent current. It is worth noting that there are separate parameters to determine the priority when Fault Ride-Through (FRT) is triggered. The default value for priority, as seen in the Broken Hill BESS project, is typically set to "P," which means that frequency control is given higher priority.

When the D-axis current limit is reached, both the integration of the frequency controller and the response of the inertia are frozen. Similarly, when the Q-axis current limit is reached, both the voltage controller and the reactive power controller are frozen.

In summary, depending on the fault type and operating conditions, the inverter may encounter current limits. The priority of limitation, usually favouring frequency control, determines the freezing of specific control elements, such as the frequency controller and inertia response in the case of D-axis current limitation, or the voltage controller and reactive power controller in the case of Q-axis current limitation.

8.2. Shallow Unbalanced Faults

The response of inverter control to unbalanced faults is more intricate and differs from the analysis conducted for balanced faults. Unbalanced faults result in varying phase voltages and the introduction of negative sequence voltage, which adds its own dynamics to the voltage control process. Consequently, the control error experienced by the frequency and voltage controllers is expected to be slightly worse compared to balanced faults.

During shallow unbalanced faults, when the inverter is still in grid-forming mode, the voltage control system will demand more reactive power due to the decrease in phase voltages as discussed earlier. However, since reactive power control only considers the positive sequence, the reduction in voltage reference is applied equally to all phases. This leads to different power flows between the phases, which further alters the voltage reference due to the droop curves.

Additional findings during the grid connection studies and full impact assessment studies are summarised as follows:

- The grid-side current is not directly measured by the inverter, but it is estimated based on a model from measured converter-side current and grid voltage. The estimation is having finite bandwidth resulting into estimation error in case of transients. During the fault event, the estimate does not jump but change with slower ramp-like dynamics.

- The grid voltage measurement has also finite measurement bandwidth. This contributes to the delayed response of the grid current estimation as well as forming voltage control.
- The phase angle of the voltage changes during this event by only a few degrees. Although, the control is able to realign its internal angle and maintain the correct orientation, there is still a transient period when voltage orientation isn't correct. This will cause that momentarily portion of the D-axis current that is observed as Q-axis current.

9. Power Point Controller coordination with Inverters

Grid-forming inverters typically control voltage and frequency, similar to a synchronous generator. Grid-following type inverters control active and reactive power or current. Power plant controllers (PPC) for existing inverter-based resources are most commonly designed to send active and reactive power commands to inverters in alignment with grid-following control logic. For BHBESS, due to the grid-forming need for a voltage and frequency reference, an additional layer of control is required to convert the PPC active and reactive power commands into usable voltage and frequency commands. For active power, this is done through the virtual inertia control loop outlined in Section 4.6 and for reactive power a PI controller is implemented. A simplified outline of these different control components is shown in Figure 21.

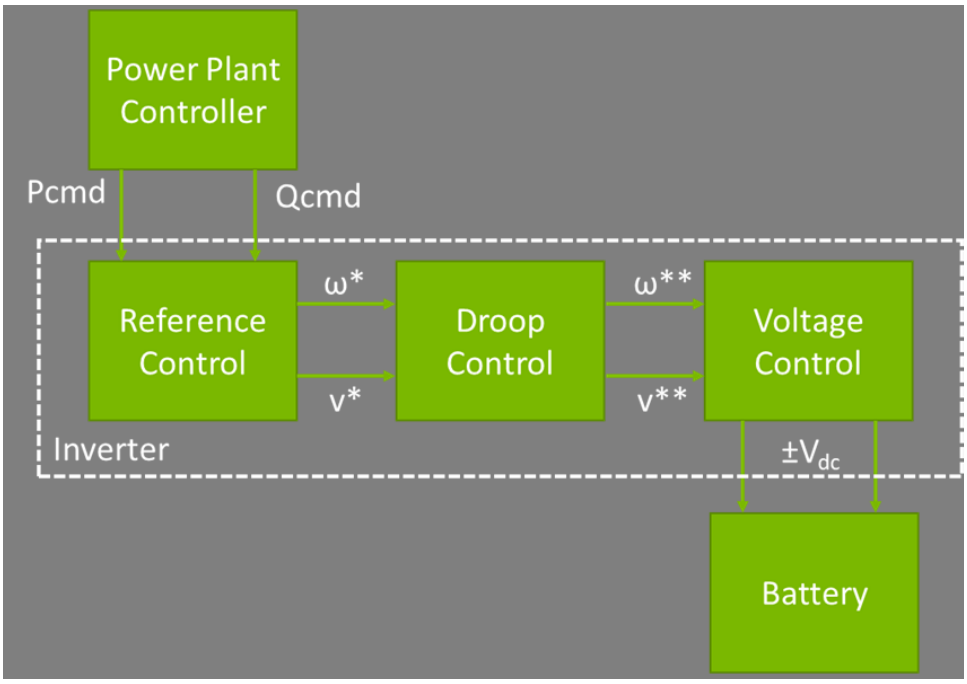


Figure 21 Simplified BHBESS control structure

The virtual inertia and PI controller control loops are not present in a grid-following inverter and are an extra layer of control that requires tuning and coordination. The virtual inertia response of the plant is typically slow compared to grid-following devices, in the order of 1s response times, and as such a slow active power output from the PPC is required to ensure stability and control of the overall plant is maintained. A smaller virtual inertia response from the inverters can facilitate a faster PPC active power control. Reactive power response of the plant is less constrained, but still relies upon the control parameters of the inverter PI controller for suitable tuning of the PPC reactive power control.

10. Islanding Studies

It had been hoped that the Broken Hill Battery could be used to supply the Broken Hill load in the event of supply from the grid not being available due to faults or maintenance outages.

This service had previously been provided by Essential Energy using two 25MW GTs running on diesel.

When Essential Energy decided that it no longer wished to provide this service, AGL offered to configure the battery to operate in island mode in conjunction with the Broken Hill solar farm, Silverton wind farm and the existing GTs which they had an option to purchase.

Transgrid ran a RIT-T process to select its preferred provider of standby supply for Broken Hill and chose a compressed air storage alternative. As a consequence, and to avoid adverse interaction between the battery and the compressed air system, the battery has been configured under Transgrid guidance to include an anti-islanding scheme.

The battery provider is still contracted to include islanding functionality, but this functionality will be inhibited to avoid interaction with the compressed air scheme.

10.1. System Restart Service (SRS)

The anti-islanding scheme (described above) being implemented on the Broken Hill battery will prevent the battery from being able to provide System Restart Services.

To be able to provide System Restart Services, the battery would need to be able to energise a local section of the grid, isolated from the main grid. The anti-islanding scheme prevents this from happening.

11. Key Lessons Learnt

A detailed lessons learnt report on the System Strength Modelling has been provided as a separate document.

Key lessons learnt during the System Strength Modelling are outlined below.

- To assess the overall stability of the grid in the long-term and not only when commissioning a new project, the connection application process should also include tests which enable evaluating future scenarios, site specific capabilities of grid-forming Inverter based resources (IBRs).
- AEMO and TNSPs should establish guidelines and/or recommendations for inclusion of generic models for preliminary wide-area and feasibility studies
- Early education on a new technology such as grid-forming inverters at the commencement of the project has been shown to be crucial in facilitating the future integration of IBRs. Similar discussions should be held in order to educate the industry on any other new or emerging technology.
- During the grid connection approval process, conducting regular meetings with AEMO, Transgrid and the OEM, ensured that all model issues are being actively addressed and progress is being made towards resolving them. These meetings also provide a platform for discussing and sharing feedback on each specific issue and served as a valuable mechanism to track the progress of resolving model issues, gather feedback from all team members, and prioritize the resolution of these issues.
- By proactively obtaining the required documents from the OEM and ensuring their timely submission, the connection application process can be streamlined, minimizing delays, and facilitating smoother communication with AEMO and Transgrid
- The importance of effective communication and collaboration between all parties involved. Establishing appropriate channels of communication and ensuring the timely sharing of relevant information can facilitate a smoother and more efficient connection application evaluation process.

- It is crucial for the functional block diagrams which are essential for conducting due diligence by Transgrid and AEMO, to be made available to AEMO and Transgrid in a timely manner, providing them with the necessary information required for their assessments, while noting that the functional block diagrams fall under Grid-Forming Inverter core intellectual property (IP) resources.
- Direct involvement of the OEM throughout the due diligence process was proved beneficial as OEMs have a comprehensive understanding of the controller and hence enabled assisting proponents and the industry in comprehending the technology, facilitating the access to control's firmware to perform additional tests, and easing the integration of grid-forming inverters to the grid.
- A virtual inertia constant (IC) of 0.1 and Damping Factor (DF) of 12 resulted in the most stable voltage response across the range of frequency disturbance tests applied.
- Optimise the settling times for reactive current response to ensure efficient and effective operation during faults which will minimizing the time it takes for the reactive current to reach a stable state after a disturbance.
- Further work is needed to address stability of the inverter's response to unbalanced faults and ensure reliable operation during unbalanced fault conditions.
- The control response and performance can vary based on the fault type and system conditions. During shallow faults, where voltage events like undervoltage or overvoltage remain within predefined thresholds, the inverter operates in grid-forming mode without triggering transient reactive current (TRC) support, which is typical of grid-following mode. This leads to a different response during both shallow balanced and unbalanced faults compared to the response during TRC, as the control properties specific to grid-forming mode come into play.
- In grid-following inverters the PI controllers which are responsible for regulating the voltage and reactive power exchange with the grid are not present, and their absence means that additional efforts are required to ensure proper tuning and coordination of the control parameters.

- In projects where consultation is a condition of approval, it is recommended to allocate additional time in the project schedule for the development and approval of the required management plans.
- Direct engagement of referral agencies by the regulator can significantly aid proponents in obtaining the necessary approvals within a shorter timeframe.
- There is an absence of an Australian Standard or Legislative Guidance specifically addressing fire risk assessment for large-scale battery facilities. Each Fire Authority has yet to clearly define the assessment criteria, leaving the requirements open-ended and causing difficulty in adequately addressing or understanding what is needed.

12. Associated Parties and Project Contact Details

	Proudly Australian for more than 185 years, AGL operates Australia's largest private electricity generation portfolio within the National Electricity Market, comprising coal and gas-fired generation, renewable energy sources such as wind, hydro and solar, batteries and other firming technology, and gas production and storage assets. We are building on our history as one of Australia's leading private investors in renewable energy to now lead the business of transition to a low emission, affordable and smart energy future in line with the goals of our Climate Transition Action Plan. AGL owns and maintains the 50MW / 100MWh battery, which provides both regulated network services and competitive market services.
Australian Government Australian Renewable Energy Agency ARENA	ARENA is the Australian Renewable Energy Agency and supports improvements in the competitiveness of renewable energy and enabling technologies, increase the supply of renewable energy in Australia, and to facilitate the achievement of Australia's greenhouse gas emissions targets by providing financial assistance and sharing knowledge to accelerate innovation that benefits all Australians. ARENA is partially funding this project as part of ARENA's Advancing Renewables Program.
	Aurecon Group Pty. Ltd. is an engineering, management, design, planning, project management, consulting and advisory company based in Australia. Aurecon is undertaking the power system network modelling for this Project.
	The University of New South Wales (UNSW) is a public research university based in Sydney, New South Wales, Australia. UNSW, in conjunction with AGL is undertaking the power system studies and the simulations for this Project.

FLUENCE A Siemens and AES Company	Fluence Energy brings proven energy storage products and services, and digital applications for renewables and storage to support the modernization of our energy networks. Fluence Energy is the Engineering, Procurement and Construction (EPC) Contractor for this project.
Advisian Worley Group	Advisian Pty. Ltd. is the advisory and specialist consulting arm of Worley Pty. Ltd. Advisian is the Knowledge Sharing Partner for the Project.

For more information on the Project, please log into the Broken Hill BESS Project Portal located at the following address: https://www.agl.com.au/about-agl/how-we-source-energy/broken-hill-battery-energy-storage-system?zcf97o=vlx3ap

The portal contains the ability to ask questions of the project team. It also contains relevant information including:

- Construction update of the Broken Hill BESS
- Planning and environmental approvals

All publicly published Knowledge Sharing material, including key reports, operational updates, presentations and access to live and historical data from the operational BESS will be uploaded progressively as they are made available.

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