AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

Transition to Fewer Synchronous Generators in South Australia

February 2023

Assessment of Grid Reference

Important notice

Purpose

This report investigates, through power system modelling and simulations, the relationship between synchronous generation and grid reference in the context of the power system in South Australia. This report has been prepared by AEMO based on the power system configuration as of 31 March 2022.

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Version control

Version	Release date	Changes
1.0	16/02/2023	Initial version

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Executive summary

This report presents the results of investigation – through power system modelling and simulations – into the relationship between synchronous generating units and grid reference.

Specifically, this report examines whether there is a need for synchronous generation to provide grid reference in the context of the South Australia (SA) region of the National Electricity Market (NEM).

Grid reference is only one of several aspects of secure and stable grid operation that may be influenced by synchronous generation. Given the specific focus of this report, its conclusions will form part of the analysis required for transition to operation of SA with fewer synchronous generating units online but, cannot in isolation support a reduction in the minimum number of synchronous generating units required to remain online in SA.

Grid reference

A balanced three-phase rotating grid voltage phasor that exists universally across the AC power system and enables power system devices to collectively maintain synchronism.

Based on the results of the investigation via power system modelling and simulations, AEMO has derived the following conclusions:

- Synchronous generation is not required for grid reference.
- The SA power system configuration (as of March 2022), including synchronous condensers (syncons), grid-connected inverter-based resources (IBR) such as wind farms, solar farms and battery energy storage systems (BESS), is capable of sustaining a grid reference in SA, even during conditions when no synchronous generation is online in SA.

In scope of the study ✓

- High level assessment and operating envelope for non-credible separation of SA and operation of SA island without synchronous generation, assuming a self-sufficient SA island following a separation event.
- A maximum of 200 megawatts (MW) of flow on Heywood Interconnector (HIC), to avoid a large frequency excursion triggering under-frequency load shedding (UFLS) or over-frequency generation shedding (OFGS), while still assessing grid reference, which is the focus of this work.
- Proof-of-concept analysis for grid reference without synchronous generation.

Out-of-scope X

- Adequacy of emergency frequency control schemes such as UFLS, OFGS, and supply-demand imbalance.
- Development of granular limit advice and detailed transient stability and voltage stability assessment.
- Specific operating measures to resecure the power system within 30 minutes of a contingency event.
- Protection adequacy, meeting system design standards including power quality.

For all scenarios studied, the success criteria (listed in Section 3) were met and no material adverse impact (such as frequency or voltage collapse) was observed with zero synchronous generating units available online in SA. Only credible contingencies (other than the non-credible separation of SA) were examined in this work, including prior outages of some critical network elements. For the purpose of this analysis, all three BESS in SA were dispatched closer to zero generation to provide maximum frequency control within the control response range. Further studies performed using a smaller sub-network around Davenport and a two-bus conceptual test system resulted in similar conclusions, helping validate the notion that grid reference can be sustained even in the absence of synchronous generation.

The analysis carried out examines the grid reference aspect only and does not develop a detailed technical envelope for operating the SA power system without synchronous generation. There is an ongoing program of work to assess the existing requirement for a minimum of two large synchronous generating units to be kept online in SA and to determine when and how SA can be operated securely with fewer than two synchronous generating units[1].

In conducting the analysis for this report and finalising its conclusions, AEMO has engaged with:

- The original equipment manufacturers (OEMs) for the four SA syncons and ElectraNet.
- The Power System Modelling Reference Group (PSMRG).
- External independent consultants.
- International research organisations.

Their feedback has been taken into account as part of the sensitivities studied in this report.

Although the power system studies carried out indicated that online synchronous generation is not required for the purpose of grid reference, a real-time test of a smaller network is recommended to physically demonstrate the concept of grid reference without synchronous generation within a smaller test network and validate findings from the power system studies.

[1] The ongoing program of work between AEMO and ElectraNet will examine technical requirements including grid reference (focus of this report), adequate voltage control, ramping and reserves, frequency control including emergency frequency control schemes (UFLS, OFGS, system integrity protection schemes [SIPS]), transmission and distribution protection adequacy, and revisions to impacted limit advice.

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1 Introduction

1.1 Background and objective

Currently, there are operational requirements for a minimum number of synchronous generating units to remain online in the South Australia (SA) power system. With the operationalisation of the four ElectraNet syncons, two at Davenport and two at Robertstown, there is sufficient system strength to support up to 2,500 megawatts (MW) of inverter-based resources (IBR) when SA is interconnected to the rest of the National Electricity Market (NEM) and two large synchronous generating units are online in SA[2]. Limited and non-comprehensive studies also identified similar system strength support when the number of synchronous generating units is reduced. However, in addition to system strength, the extent to which other power system requirements need to be supported by synchronous generation must also be examined.

Figure 1 shows the assumptions that AEMO used for the 2018 *Integrated System Plan* (ISP)[3], and outlines various power system requirements and their relationship with synchronous generation in the current and projected SA grid configurations at that time. The 2018 ISP assumptions note that some synchronous generation (at least one unit) could be needed for grid formation (following a separation of SA from the rest of the NEM) after installation of the SA syncons but before Project EnergyConnect is commissioned.

Figure 1 Planning assumptions for 2018 ISP

Power System Requirement	Planning assumptions used in the 2018 ISP				
	At least 4 synchronous generating units	At least 3 synchronous generating units	At least 2 synchronous generating units	At least 1 synchronous generating unit	No synchronous generating units
SYSTEM NORMAL, REQUIREMENT FOR POWER SYSTEM SECURITY					
System strength & fault current	NOW				SYNCONS / ENERGY CONNECT
Operating reserves for ramping			NOW / SYNCONS		ENERGY CONNECT
SYSTEM NORMAL REQUIREMENT TO SURVIVE 1-IN-3 YEAR SEPARATION EVENT†					
Grid formation				NOW / SYNCONS	ENERGY CONNECT
Inertia and RoCoF				NOW‡	SYNCONS / ENERGY CONNECT
Primary frequency control				NOW / SYNCONS	ENERGY CONNECT
Secondary frequency control			NOW / SYNCONS		ENERGY CONNECT
Operating reserves for energy balance			NOW / SYNCONS		ENERGY CONNECT
SYSTEM NORMAL MINIMUM REQUIREMENT					
Minimum requirement	NOW		SYNCONS		ENERGY CONNECT

[2] Limit advice: https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/transfer-limit-advice-system-strength.pdf?la=en.

[3] Page 13 of Assumptions for South Australian GPG in the 2018 ISP, at https://www.aer.gov.au/system/files/AEMO - Assumptions for South Australian GPG in the 2018 ISP - August 2019.pdf.

This report investigates the role of synchronous generation in providing grid reference, which is defined as a balanced three-phase rotating grid voltage phasor that exists universally across the AC power system and enables power system devices to collectively maintain synchronism.

The investigation was based primarily on electromagnetic transient (EMT) modelling and simulations (using PSCAD™/EMTDC™ software), as the EMT models are capable of capturing the Phase-Locked Loop (PLL) dynamics of the IBR. A few test cases presented in Appendix A2 were also used as a further sanity check, based on root-mean square (RMS) modelling and simulations (using PSS®E software) to test the notion of grid reference in the absence of synchronous generation. However, it must be noted that EMT modelling and simulations remain the preferred tool for further studies.

The remaining sections of this report describe the different scenarios evaluated and the assessment outcome.

1.2 Scope of the study

The following different scenarios were assessed as part of the power system studies:

- Scenario 1: Separation of SA island with zero synchronous generating units available in SA, with a focus on assessment of grid reference.
- Scenario 2: Operation of a self-sufficient (load and generation balanced) SA island with zero synchronous generating units available, following a separation event[4] with a focus on grid reference.
- Scenario 3: Conceptual analysis to test the notion of grid reference using a small sub-network around the Davenport 275 kilovolts (kV) bus, comprising a few 275 kV and 132 kV transmission lines, 1 Davenport syncon, transmission-connected IBR and Olympic Dam load.
- Scenario 4: A conceptual 2-bus test system to further investigate and demonstrate the notion of grid reference in a small system with only one grid-following IBR and one syncon interconnected with some transmission line impedance.
- Other additional sensitivity studies as needed for scenarios 1-4 to address feedback from stakeholders (refer Section 6), in relation to grid reference for separation and an islanded SA power system.

The scope of this study did not consider:

- Adequacy of under-frequency load shedding (UFLS) and over-frequency generation shedding (OFGS) operation in SA. This is because the size of the contingencies and Heywood Interconnector (HIC) import/export (up to 200 MW) active power flows were purposefully kept small enough to ensure UFLS and OFGS actions are not triggered. This approach allows the grid reference aspect to be examined in isolation.
  - The load and generation in SA were kept balanced with only allowance for support of active power from battery energy storage systems (BESS) and the Murray Link direct current (MLDC) interconnector.
- Development of limit advice and detailed technical envelope to operate the SA power system with fewer (or zero) synchronous generating units online – noting that several other aspects of grid operation must be analysed in addition to grid reference.
- Specific operating measures to resecure the power system within 30 minutes of a contingency event. It should be noted that if synchronous generation is not required for the purpose of grid reference in the first place, it

[4] This assumes that following a separation event, supply demand balance has been achieved.

would not be required to re-secure the system for the purpose of grid reference. Synchronous generation may still be required to re-secure the system – for example, for sufficient voltage control or inertia – but those needs must be considered separately from grid reference requirements.

- Need for synchronous generation for other system security needs and meeting system standards[5].

[5] An ongoing program of work between AEMO and ElectraNet will examine technical requirements including grid reference (focus of this report), adequate voltage control, ramping and reserves, frequency control including emergency frequency control schemes (UFLS, OFGS, system integrity protection schemes [SIPS]), transmission and distribution protection adequacy, and consider appropriate revisions to impacted limit advice including the minimum number of synchronous generating units required online.

2 Scenarios and modelling inputs

This section describes the various scenarios mentioned in Section 1.2 in more detail. This includes the base case assumptions of in-service elements, prior outages considered and description of any contingencies and network disturbances applied.

2.1 Scenario 1: Separation of SA

The following base case assumptions were applied for all studies on the separation of SA:

- System intact (that is, both HIC circuits were kept in-service).
- Four syncons, two at Robertstown and two at Davenport were kept in-service.
- Three BESS, Hornsdale Power Reserve expansion (HPRx), Dalrymple and Lake Bonney, were in-service.
- Transmission-connected wind and solar generation was dispatched close to 2,100 MW and an additional sensitivity study was considered with IBR dispatch of 1,800 MW during both HIC import and export.
- Static Var Compensators (SVCs) at South-East 275 kV and Para 275 kV were kept in-service.
- MLDC link was kept in-service.
- No synchronous generation online within SA.

Sensitivity studies were performed which considered the following changes to the base case:

- Prior outage of one syncon.
- Prior outage of BESS (HPRx).
- Prior outage of BESS (Dalrymple).
- Prior outage of MLDC link.
- Prior outage of HPRx and Dalrymple BESS.
- Prior outage of one Para SVC.

The disturbance applied was a double line to ground fault near the South-East 275 kV bus on HIC circuit and the subsequent tripping of both HIC lines to clear the fault to simulate a non-credible separation event, assuming normal clearing times from the remote end (120 milliseconds [ms] for 275 kV) as in column 3 of the National Electricity Rules (NER) Table S5.1a.2.

Both import and export conditions up to 200 MW alternating current (AC) transfer levels (and varying MLDC accordingly) to and from SA were studied.

2.2 Scenario 2: SA island

The following base case assumptions were applied for all studies evaluating the SA island system:

- SA islanded (that is, both HIC circuits are out-of-service).
- Four syncons, two at Robertstown and two at Davenport, were kept in-service.

- Three BESS, HPRx, Dalrymple and Lake Bonney, were in-service.
- Transmission-connected wind and solar generation was dispatched close to 2,100 MW.
- SVCs at South-East 275 kV and Para 275 kV were kept in-service.
- MLDC link was kept in-service.
- No synchronous generation online within SA.

The contingencies studied were a double line to ground fault and subsequent tripping of the following elements, assuming normal clearance times per remote end clearing of column 3 per NER Table S5.1a.2, except as noted below for the trip of transmission lines:

- Trip of 1 x syncon (individually at Davenport and Robertstown), with fault applied and cleared at 275 kV point of connection.
- Trip of a large wind farm (WF), with fault applied and cleared at the respective high voltage (HV) point of connection (Hornsdale WF, Snowtown 2 WF and Lincoln Gap WF, each dispatched to around 180 MW and tripped individually was considered).
- Trip of Bungala Solar Farm (SF), with fault applied and cleared at the HV point of connection.
- Olympic dam load from 145 MW, with fault applied and cleared at the 275 kV point of connection.
- Trip of 275 kV and 132 kV transmission line contingencies were considered, with fault applied and cleared as close-in to the from-bus end (including circuit breaker fail clearing times, details in Table 6).
- 180 MW distributed photovoltaics (PV) in the metro area (simulated as a net load increase), with fault applied at Torrens Island Power Station (TIPS) B 275 kV bus.
- Trip of HPRx (operating in Virtual Machine Mode[6] [VMM]), with fault applied and cleared at Hornsdale 275 kV.
- Trip of an SVC (Para and South-East SVC, tripped individually), with fault applied at 275 kV point of connection, including sensitivity of prior outage of 1 x Para SVC assumed out-of-service.
- Trip of MLDC (exporting 118 MW from SA), with fault applied and cleared at the Berri side.

Additional sensitivity studies were also included to consider the prior outage of following elements followed by a credible contingency trip of Robertstown to Tungkillo 275 kV transmission line:

- Prior outage of 1 x syncon (Robertstown and Davenport, individually).
- Prior outage of 1 x BESS (HPRx and Dalrymple, individually).
- Prior outage of MLDC.

2.3 Scenario 3: Sub-network around Davenport

A sub-network portion of the SA island case isolated around Davenport as shown in Figure 2 was developed and investigated to check for grid reference. The purpose was to help rule out the possibility of any fictitious ideal

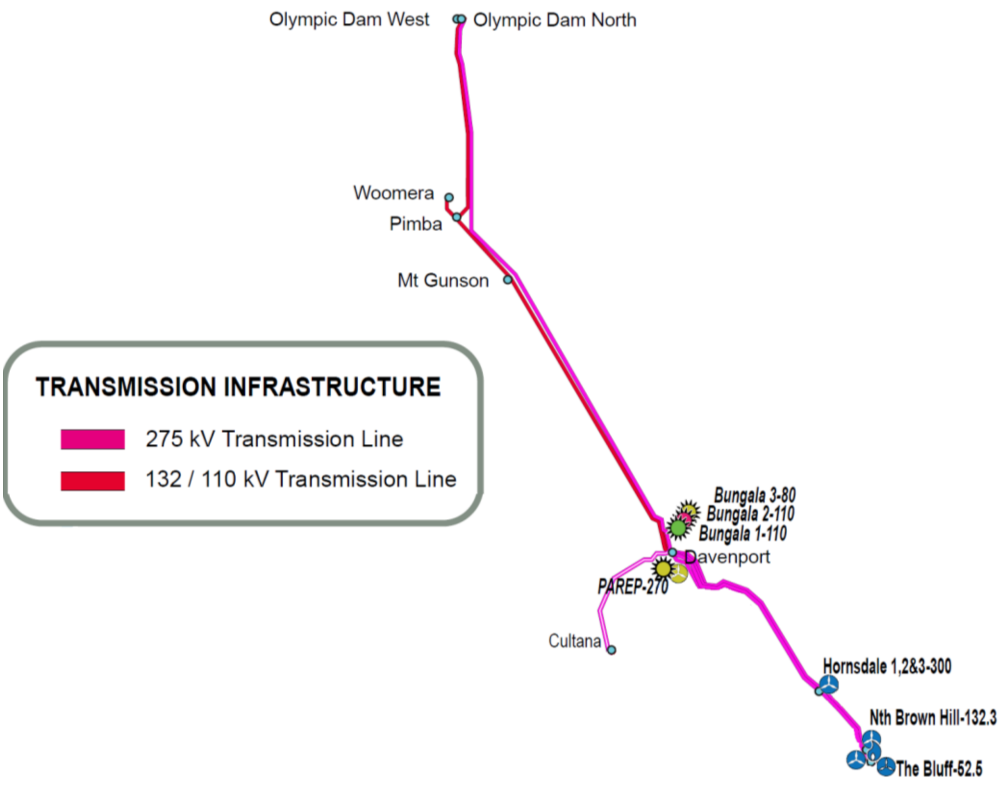
[6] The model used is a beta version of the VMM model. This was provided while two inverters were placed in VMM mode.

voltage source[7] within the extended SA power system EMT model that might have inadvertently provided a grid reference during SA island formation and operation with zero synchronous generating units.

The Davenport sub-network system included the following network elements and base case assumptions:

- One Davenport syncon in-service.
- 275 kV and 132 kV transmission lines as shown in Figure 2.
- Transmission-connected IBR (Bungala SF, PAREP SF, PAREP WF, North Brown Hill WF, Bluff WF and Hornsdale WF).
- Olympic Dam load at 165 MW.
- Other loads associated with the network shown below to balance the generation.
- No synchronous generation in-service within SA.

Figure 2 Davenport sub-network studied



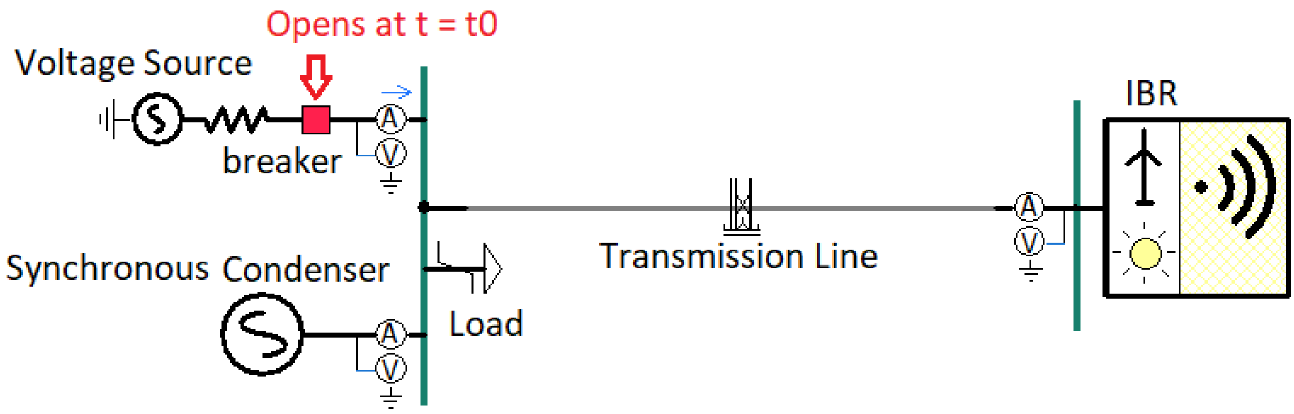
2.4 Scenario 4: Conceptual 2-bus test system

To further investigate the notion of grid reference and to ensure that no ideal voltage sources were inadvertently used in the investigation, a conceptual 2-bus test system as shown in Figure 3 was considered. This simple system includes:

[7] Ideal voltage sources are used in the PSCAD™ model for initialisation of IBR models, however they are disconnected once the IBR model initialises. Using a smaller sub-system it is easy to verify the disconnection of these ideal voltage sources and hence rule out the possibility of these ideal voltage sources providing grid reference.

- One syncon.
- One IBR.
- An ideal voltage source for initialisation[8].
- Some static load to balance generation.

Figure 3 Conceptual 2-bus test system studied



In this test system, the ideal voltage source is disconnected at $t=t_0$ such that the IBR is then supplying the load, supported by the syncon. The load (around 60 MW and variable reactive power) was configured to balance both active and reactive power with the IBR. This was done so that the ideal voltage source generates small active and reactive power when disconnected at $t=t_0$.

The following types of IBR were tested:

- Wind farms of all types (Types 1-4).
- Solar farm.
- BESS.

Studies were performed to test three different syncon models:

- PSCAD™ library syncon model.
- Davenport syncon model.
- Robertstown syncon model.

It is important to note that the syncon models were not tuned specifically for this conceptual 2-bus test system, as the intent here is to only check for grid reference.

[8] This ideal voltage source shown in Figure 3 is used for initialising the IBR operation to enable switching from the source to model operation at t=0. The physical breaker connecting this voltage source however is then disconnected at t = t0, at which point the ideal voltage source is generating small active and reactive power. A t = t0+, the 2-bus system operates without any ideal voltage source, whilst the effect of losing the small active and reactive power contribution from the ideal voltage source shows up in the voltage and frequency responses.

2.5 SA PSCAD™ case setup

For scenarios mentioned in Section 2.1 and Section 2.2, AEMO's detailed PSCAD™ model of the SA power system was used for carrying out the analysis. The case includes the site-specific models of IBR, syncons, MLDC, SVCs, and all transmission elements[9] (such as lines and transformers), in operation as of March 2022. Both HIC circuits are open for SA island studies in Section 2.2 and the series capacitors on South-East to Tailem Bend 275 kV line are bypassed, as per SA island operating procedure. A total of approximately 2,240 MW wind and solar generation was considered in the studies (and adjusted according to the scenario investigated), with the SA demand level being around 2,000 MW.

Table 1 summarises the overall statistics of the model, and Table 2 lists all the wind and solar farms included in the model, with their generation level.

Table 1 PSCAD™ case statistics

Case	Number of network buses	Number of synchronous generators	Number of syncons	Number of grid-scale IBR (WF, SF, SVC, HVDC, BESS)	Number of parallel PSCAD™ cases	Time to run 30 second simulation on a 14-core machine (hrs)
SA Island	~600	0	4	26	36	1.8

Table 2 List of wind and solar farms considered in the study

No	IBR name	Maximum capacity (MW)	Generation dispatched (MW)
1	Bungala SF	220	220
2	Tailem Bend SF	95	90
3	Bluff WF	52.5	52.5
4	Canunda WF	46	10
5	Cathedral Rocks WF	66	10
6	Clements Gap WF	56.7	56
7	Hallett WF	94.5	90
8	Hallett Hill WF	67	65
9	Hornsdale WF	316	315
10	Lake-Bonney WF	280	40
11	Lincoln Gap WF	200	200
12	Mt Millar WF	70	Disconnected
13	North Brown Hill WF	110	110
14	Port Augusta SF and WF	332	325
15	Snowtown WF	98.7	98
16	Sonwtown2 WF	270	195
17	Waterloo WF	129	129
18	Wattle Point WF	90	90

[9] Transmission network elements were modelled with standard modelling approach used in 4-state NEM PSCAD™ models, such as Bergeron PI representation for transmission lines and transformer saturation was ignored.

No	IBR name	Maximum capacity (MW)	Generation dispatched (MW)
19	Willogoleche WF	119.4	119

Table 3 shows the batteries that were integrated in the PSCAD^{TM} case. All the batteries are dispatched to zero MW for islanded studies.

Table 3 List of grid-connected BESS considered during the study

No	BESS name	Maximum capacity (MW / megawatt hours [MWh])	Generation dispatched (MW)
1	HPRx	150 MW / 193.5 MWh	0
2	Lake Bonney BESS	25 MW / 52 MWh	0
3	Dalrymple BESS	30 MW / 8 MWh	0

3 Success criteria

The success criteria used in the power system studies are outlined below:

- After a contingency, no generation or load shedding should occur through the operation of UFLS or OFGS; in other words, the Frequency Operating Standard (FOS) should be maintained[10].
- The high voltage transmission network voltage profile across the state settles within 0.90 pu to 1.1 pu[11] under post-disturbance conditions.
- All online generators return to steady-state conditions following fault clearance[12].
- No IBR should trip or go through multiple fault ride through after the contingency.
- Electromechanical oscillations should meet the 5 seconds halving time requirement.
- Rate of change of frequency (RoCoF) immediately after the fault should not exceed 1 hertz per second (Hz/s)[13].

[10] Only containment band of the FOS (49-51 Hz for island) has been considered as the recovery and stabilisation bands are outside the simulation time and Automatic Generation Control (AGC) has not been modelled. While the assumptions on contingency size were used to limit the triggering of UFLS or OFGS, the network frequency was monitored to ensure it did not result in a collapse.

[11] A brief percentage of overvoltage is permitted within NER S5.1a.4 for credible contingency events.

[12] Unless they are tripped as a part of the contingency.

[13] RoCoF was calculated in a 0.5 second fixed window, right after the contingency is cleared.

4 Assessment outcome

4.1 Results for separation of SA – Scenario 1

Table 4 summarises the results of the power system studies for separation of SA as outlined in Section 2.1.

Table 4 Formation of stable SA island – outcomes

System condition		Davenport (DP) syncon		Robertstown (RT) syncon		BESS			Assessment outcome
		Unit 1	Unit 2	Unit 1	Unit 2	HPRx	Dalrymple (DBESS)	Lake Bonney	
4.1.1 4.1.2	System intact	✓	✓	✓	✓	✓	✓	✓	PASS
A1.1.1	Prior outage of 1 DP syncon	X	✓	✓	✓	✓	✓	✓	PASS
A1.1.2	Prior outage of 1 RT syncon	✓	✓	X	✓	✓	✓	✓	PASS
A1.1.3	Prior outage of HPRx	✓	✓	✓	✓	X	✓	✓	PASS
A1.1.4	Prior outage of DBESS	✓	✓	✓	✓	✓	X	✓	PASS
A1.1.5	Prior outage of type 1 WFs	✓	✓	✓	✓	✓	✓	✓	PASS
A1.1.6	Prior outage of MLDC	✓	✓	✓	✓	✓	✓	✓	PASS
A1.1.7	Prior outage of 1 Para SVC	✓	✓	✓	✓	✓	✓	✓	PASS

✓in-service element X out-of-service element

The results of loss of HIC under system intact conditions are shown in Section 4.1.1 for export condition of 198 MW from SA, and Section 4.1.2 under import condition of 185 MW into SA. Key observations are:

- The network voltages remain satisfactory (Figure 4) and able to meet the success criteria even after the separation of SA from the mainland with no synchronous generation online in SA.
- There is an over-voltage transient (Figure 4) following the fault clearing around 15 seconds, due to reactive power injection by the South-East and Para SVCs, however the over-voltage does not exceed the criteria in NER S5.1a.4 for credible contingency events.
- The frequency[14] (Figure 5 and Figure 10) within SA recovers to a slightly higher value (50.5 Hz) in the case of tripping HIC under export conditions and to a slightly lower value (49.25 Hz) in the case of tripping HIC under import conditions. However, the frequency is contained within the success criteria limits, aided primarily due to the fast response of HPRx, as shown in Figure 8 and Figure 13, response under export and import conditions.
- It may also be noted from Figure 5 and Figure 10 that the speed of Robertstown and Davenport syncons closely matches the Tailem Bend 275 kV bus frequency and remains stable following the disturbance.
- The active power response of IBR during the fault and post-fault conditions exhibits transient fault-ride through behaviour around 15 seconds in Figure 6 and Figure 11, with a reduction in the active power response and

[14] It may be noted that the frequency and speed traces contain small oscillations around 30 Hz, due to PSCAD™ measurements.

brief instance of PLL trying to regain control, however, the active powers are restored mostly[15] to their pre-fault levels, without any significant loss of generation.

4.1.1 Loss of HIC during export of 198 MW from SA

Figure 4 to Figure 8 show the response of various key quantities following a separation event with loss of HIC during export conditions of 198 MW from SA[16].

Figure 4 Network voltages – loss of HIC during export of 198 MW from SA

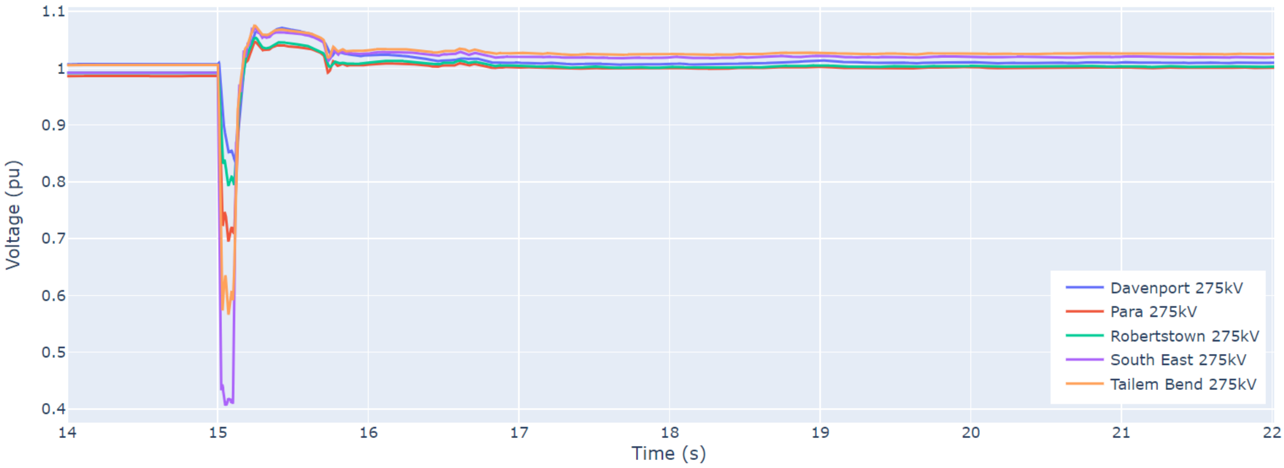
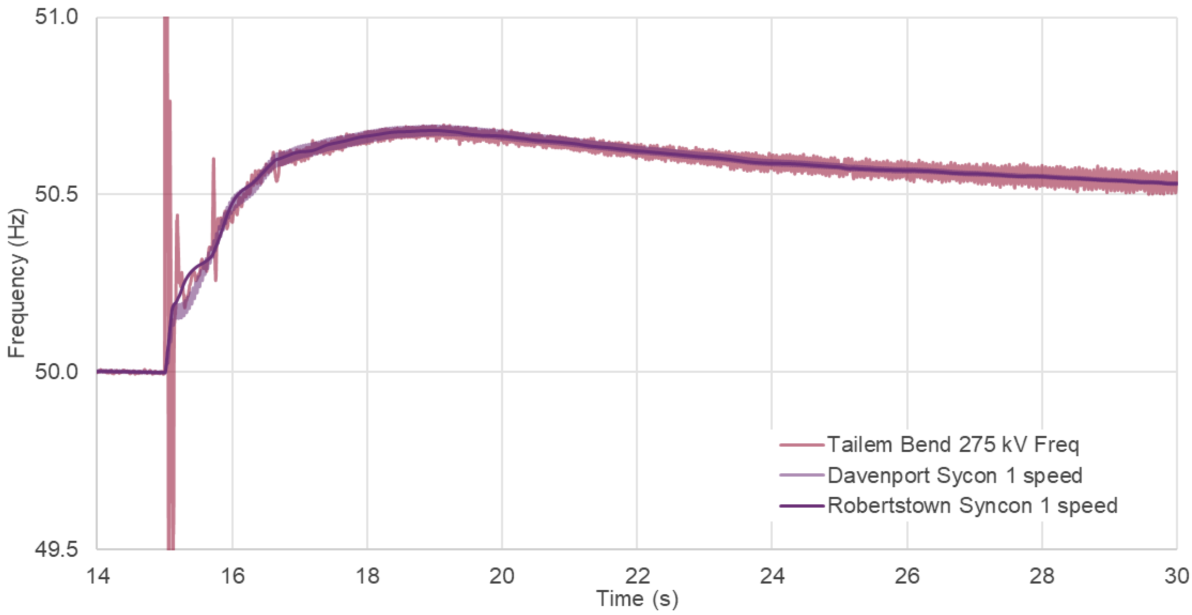


Figure 5 Speed and frequency – loss of HIC during export of 198 MW from SA



*Note: during the disturbance and clearance, the large variation in frequency transient is due to the way PSCAD™ estimates frequency using zero crossing approach, however this initial variation may be ignored.

[15] There is a small dip in active power of SF IBR that can be noticed in Figure 6, which is attributed to the response of PAREP SF, as it interprets the frequency to be outside the dead-band and triggers generation reduction action.

[16] It should be noted that although the flow on the interconnector was approximately 198 MW, the actual export could be higher than that considered. The existing import and export limit over HIC is 550 MW and 600 MW respectively.

Figure 6 IBR active power – loss of HIC during export of 198 MW from SA

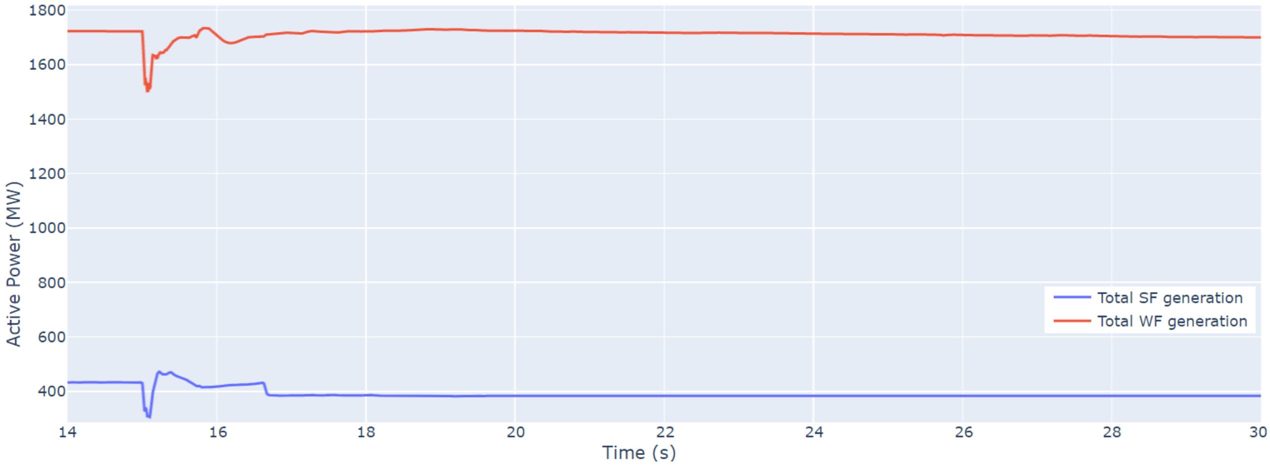
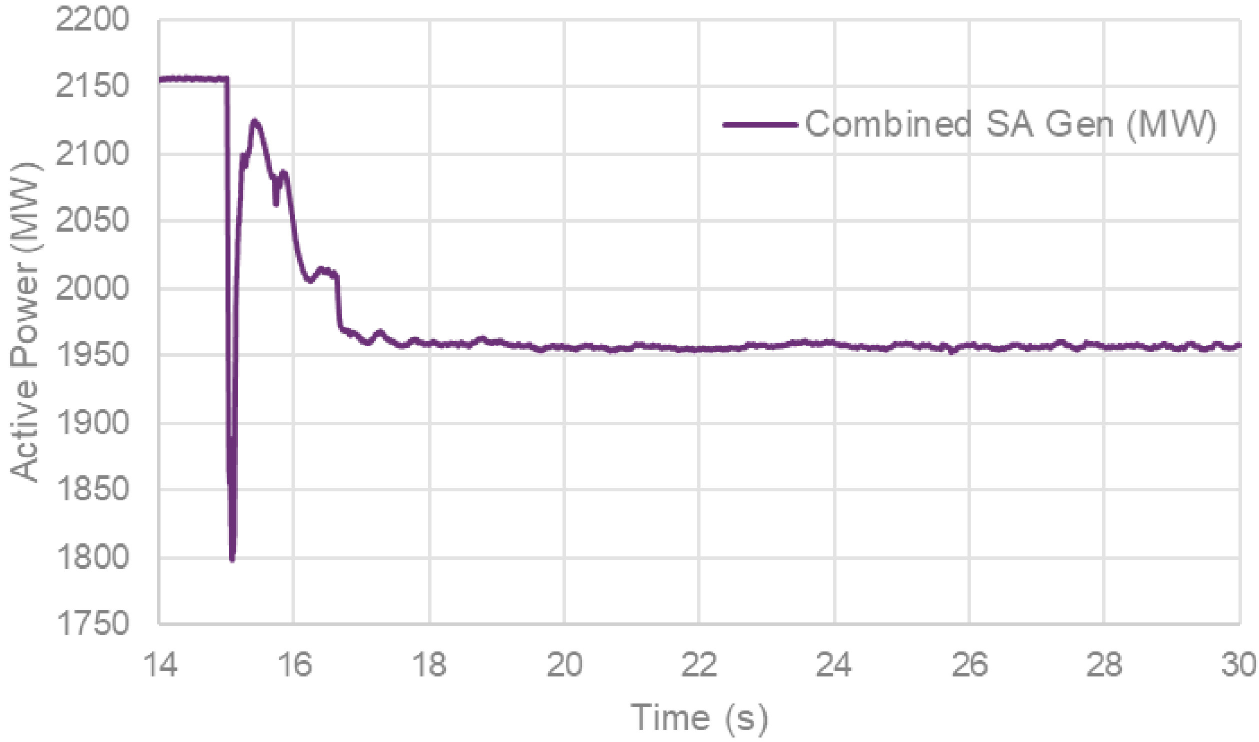
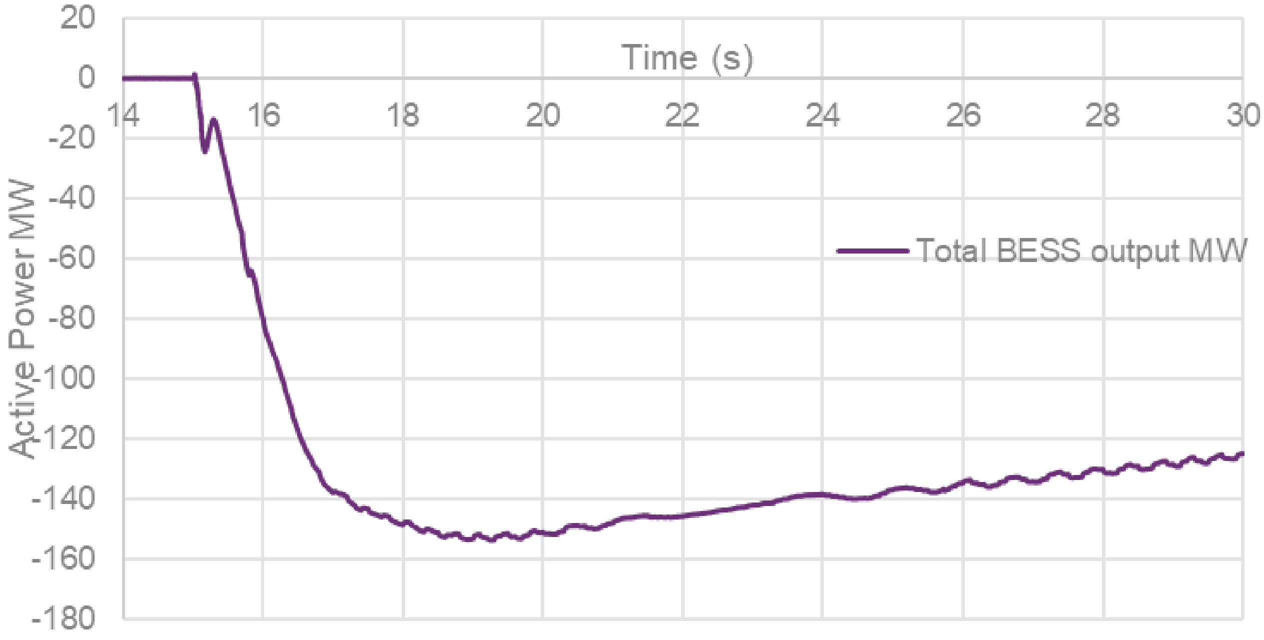


Figure 7 Combined SA generation – loss of HIC during export of 198 MW from SA



*Note: The combined SA generation in Figure 7 includes the contribution of BESS and IBR generation.

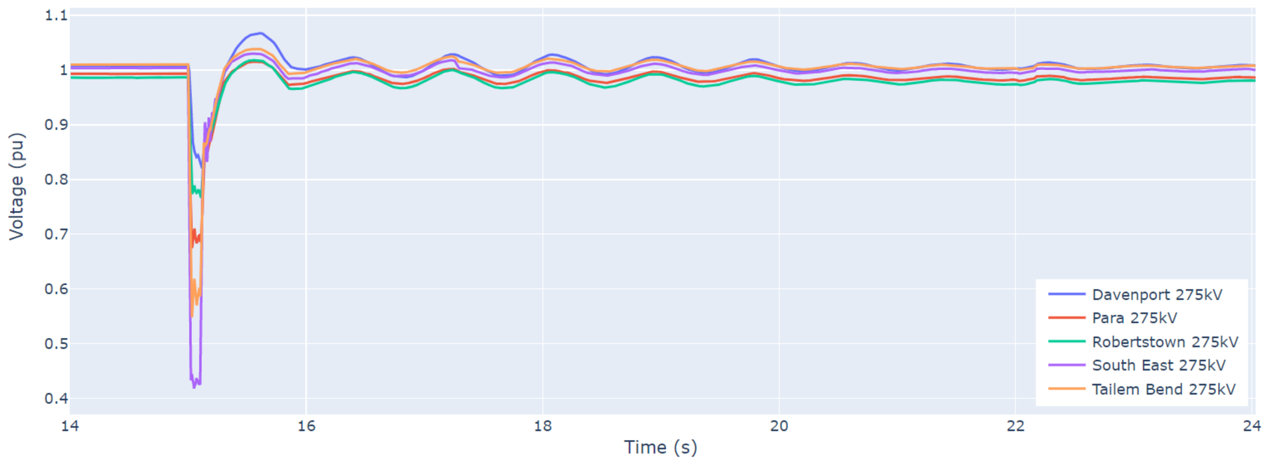
Figure 8 BESS active power – loss of HIC during export of 198 MW from SA



4.1.2 Loss of HIC during import of 185 MW to SA

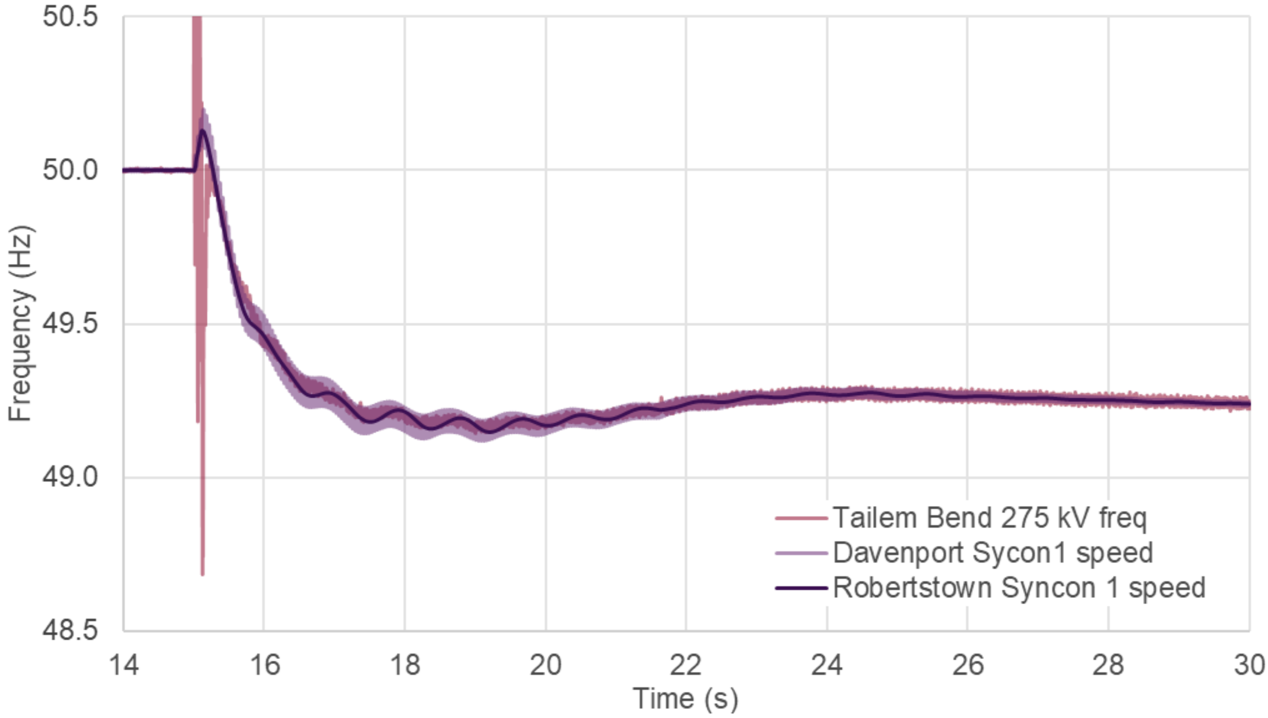
Figure 9 to Figure 13 show the response of the SA power system following a separation event with loss of HIC when importing 185 MW into SA[17].

Figure 9 Network voltages – loss of HIC during import of 185 MW to SA



[17] It should be noted that although the flow studied on the interconnector was approximately 185 MW, the actual import could be higher than the considered. The existing import and export limit over HIC is 550 MW and 600 MW respectively. However, for the purpose of this study, it was necessary as pointed out in Section 1.2, to keep the flow at a reasonable level to study the grid reference aspect of operation in isolation without triggering UFLS or OFGS. Higher levels of active power flow on HIC is not expected to impact the conclusions of this report.

Figure 10 Speed and frequency – loss of HIC during import of 185 MW to SA



*Note: during the disturbance and clearance, the large variation in frequency transient is due to the way PSCAD™ estimates frequency using zero crossing approach, however this initial variation may be ignored.

Figure 11 IBR active power – loss of HIC during import of 185 MW to SA

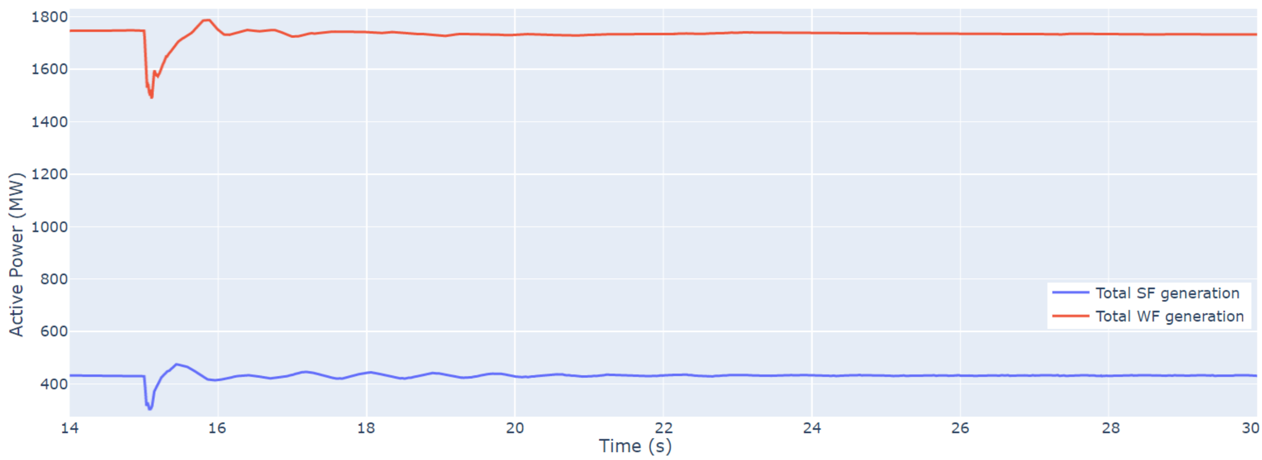
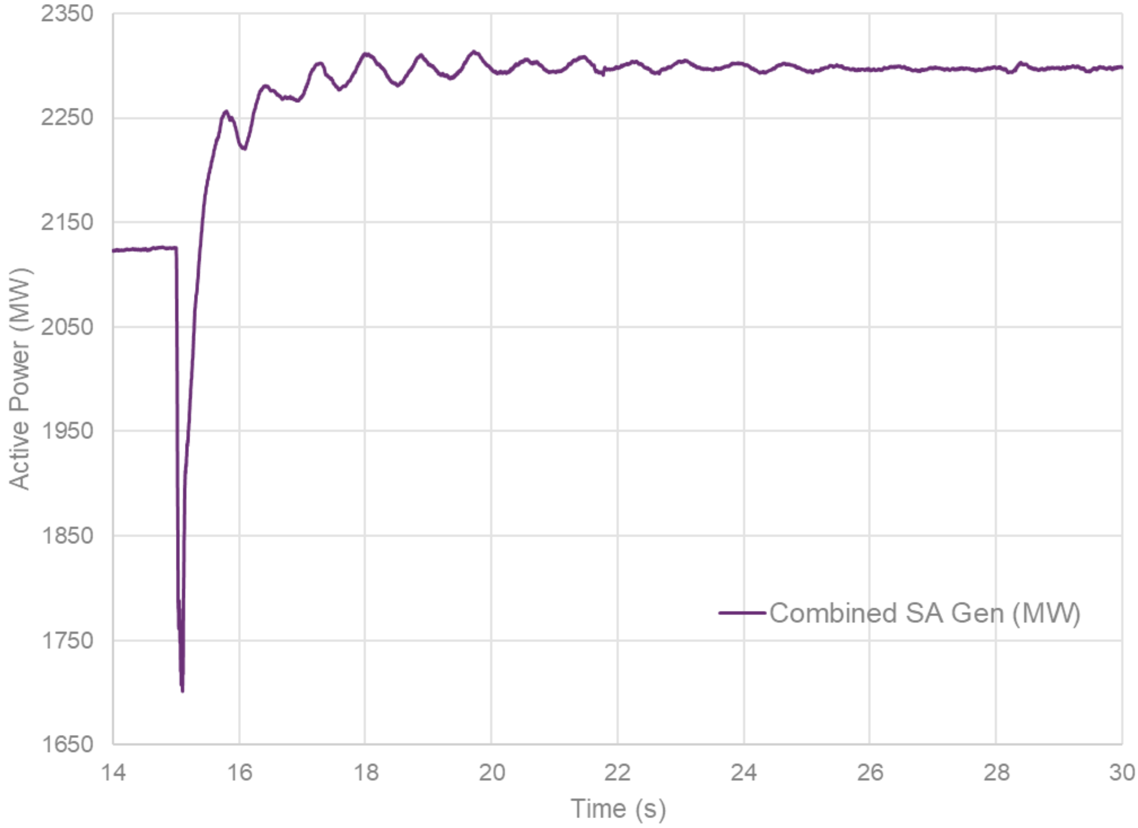
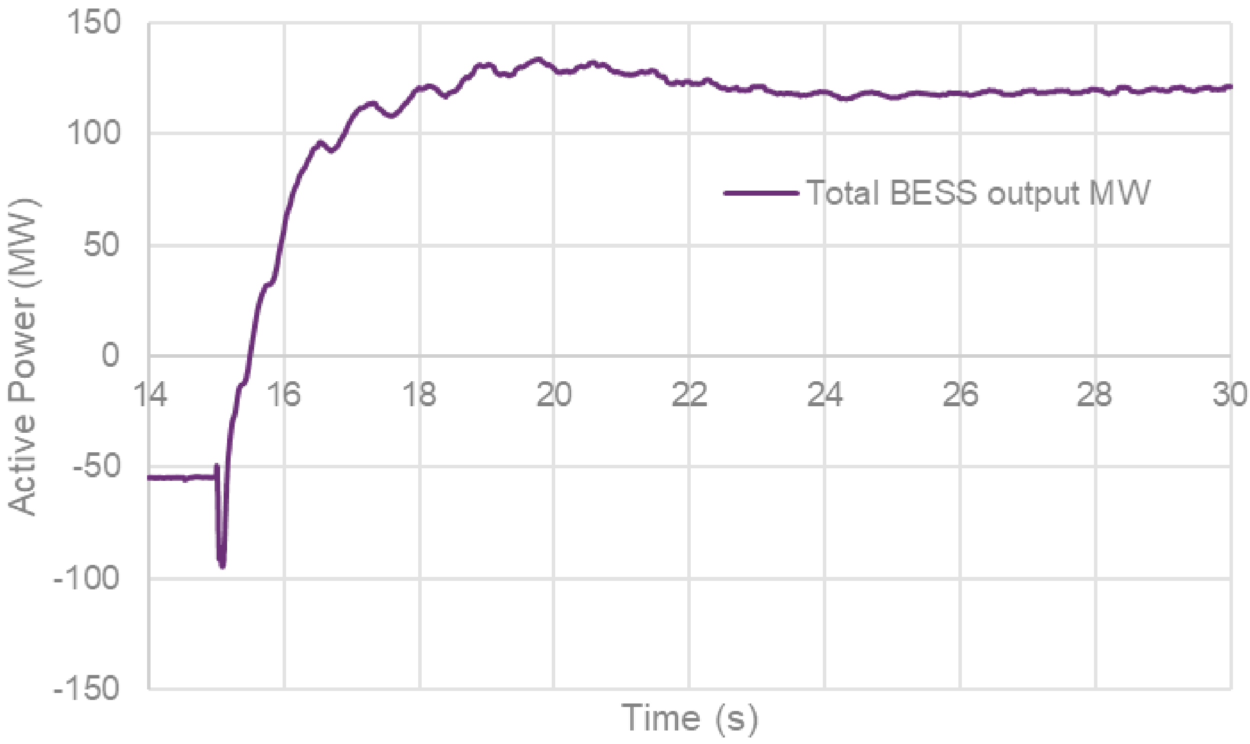


Figure 12 Combined SA generation – loss of HIC during import of 185 MW to SA



*Note: The combined SA generation in Figure 12 includes the contribution of BESS and IBR generation.

Figure 13 BESS active power response – loss of HIC during import of 185 MW into SA



4.2 Results for SA island – Scenario 2

To assess whether the islanded SA power system needs synchronous generation for the purpose of grid reference, a number of contingencies within the islanded SA power system were considered, as shown in Table 5 and Table 6. The intent of this contingency analysis was to simulate a power system disturbance with no synchronous generation in service and assess if the disturbance resulted in SA power system performance within a reasonable envelope.

Table 5 summarises the results of the power system studies as outlined in Section 2.2 for the SA island system with zero synchronous generating units online.

Table 5 SA island – outcomes

System condition		DP Syncon		RT Syncon		BESS			Assessment outcome
		Unit 1	Unit 2	Unit 1	Unit 2	HPRx	DBESS	Lake Bonney	
4.2.1	Trip of Davenport Unit 1	✓	✓	✓	✓	✓	✓	✓	PASS
A1.2.1	Trip of Robertstown Unit 1	✓	✓	✓	✓	✓	✓	✓	PASS
A1.2.2	Trip of Bungala SF	✓	✓	✓	✓	✓	✓	✓	PASS
A1.2.3	Trip of a large WF (Hornsdale, Snowtown 2, Lincoln Gap)	✓	✓	✓	✓	✓	✓	✓	PASS
A1.2.4	Trip of Olympic Dam load	✓	✓	✓	✓	✓	✓	✓	PASS
A1.2.5	Trip of a transmission line*	✓	✓	✓	✓	✓	✓	✓	PASS
A1.2.6	Trip 180 MW distributed PV**	✓	✓	✓	✓	✓	✓	✓	PASS
4.2.2	Trip of HPRx (VMM)	✓	✓	✓	✓	✓	✓	✓	PASS
A1.2.7	Trip of one Para SVC	✓	✓	✓	✓	✓	✓	✓	PASS
A1.2.8	Trip of one South-East SVC	✓	✓	✓	✓	✓	✓	✓	PASS
A1.2.9	Trip of MLDC	✓	✓	✓	✓	✓	✓	✓	PASS

* See Table 6 for the expanded list of transmission lines
** Distributed PV simulated as a load increase
✓ Element in-service

Table 6 SA island – transmission line contingencies

Transmission line tripped*	Assessment outcomes
Davenport – Belalie 275 kV**	PASS
Davenport – Bungala 275 kV**	PASS
Davenport – Corraberra Hill 275 kV	PASS
Davenport – Mt Lock 275 kV	PASS
Robertstown – Canowie 275 kV	PASS
Robertstown – Mokota 275 kV	PASS
Robertstown – Para 275 kV**	PASS
Robertstown – Tungkillo 275 kV**	PASS
Tailem Bend – Cherry Gardens 275 kV**	PASS
Tailem Bend – South-East 275 kV**	PASS

Transmission line tripped*	Assessment outcomes
Tailem Bend – Keith 132 kV**	PASS
Robertstown – North West Bend 132 kV**	PASS
Bungama – Red Hill 132 kV**	PASS

* For all contingencies simulated above, the fault was applied as 2L-G close-in fault near the from bus end and cleared assuming the times below.
** Several of the above contingencies marked with double asterisk were evaluated for both normal and delayed clearing following a circuit breaker fail scenario. For circuit breaker fail clearance, extended fault duration and clearance per column 4 of NER table S5.1a.2, up to 250 ms for 275 kV and 430 ms for 132 kV was used. However, the station bus configuration or respective breaker tripping schemes were not considered. Normal clearance times were in accordance with column 3 of NER table S5.1a.2, up to 120 ms for 275 kV and up to 220 ms for 132 kV, assuming remote end clearing times.

The results of SA island power system for the trip of Davenport unit 1 syncon and trip of HPRx are shown in Section 4.2.1 and Section 4.2.2, respectively. Key observations are:

- The network voltages remain satisfactory and able to meet the success criteria following the respective contingency events. The voltage oscillations meet the 5 second halving time requirement with adequate damping.
- Following the trip of Davenport unit 1 syncon in Section 4.2.1, the frequency in SA (as seen in Figure 15) stabilises close to 50 Hz. However, following the trip of HPRx in Section 4.2.2, the frequency (seen in Figure 20) takes longer to stabilise due to the lack of fast frequency control resources within SA, following the tripping of HRPx. In both cases, the frequency remains within the containment band of 49-51 Hz.
- The active power response of IBR during the fault and post-fault conditions exhibits transient fault-ride through behaviour around 15 seconds in Figure 16 and Figure 21. However, most IBR generation returns to pre-fault levels, without any significant generation loss or multiple fault ride-through behaviour. It is noted that the dip in active power is more pronounced (around 1,100 MW temporary dip, seen in Figure 16) due to the trip of Davenport unit 1 syncon, compared to Figure 21. This may be due to the reduction in fault levels following the tripping of the syncon compared to the trip of a BESS.

4.2.1 Trip of one Davenport syncon under SA island

Figure 14 Network voltages – trip of one Davenport syncon under SA island

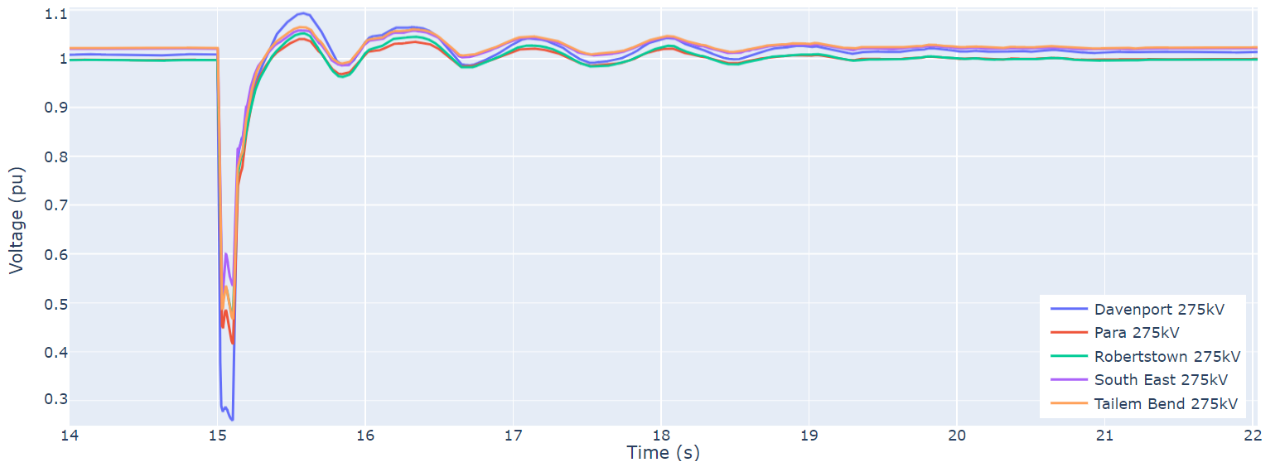
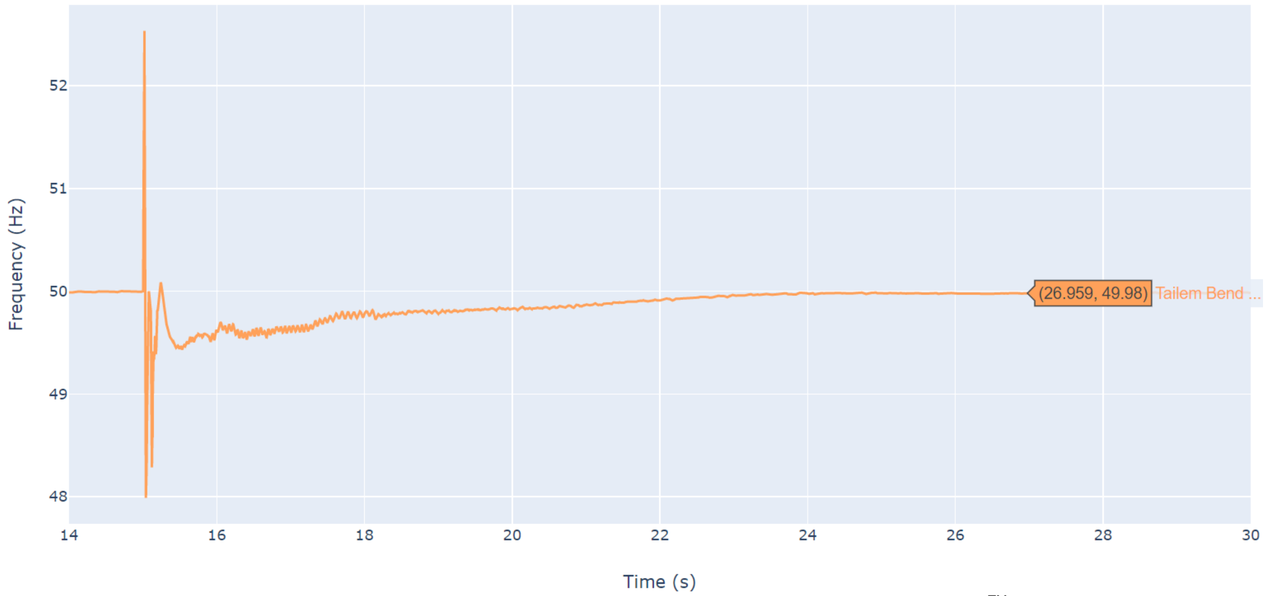


Figure 15 Frequency – trip of one Davenport syncon under SA island



*Note: during the disturbance and clearance, the large variation in frequency transient is due to the way PSCAD™ estimates frequency using zero crossing approach, however this initial variation may be ignored.

Figure 16 IBR active power – trip of one Davenport syncon under SA island

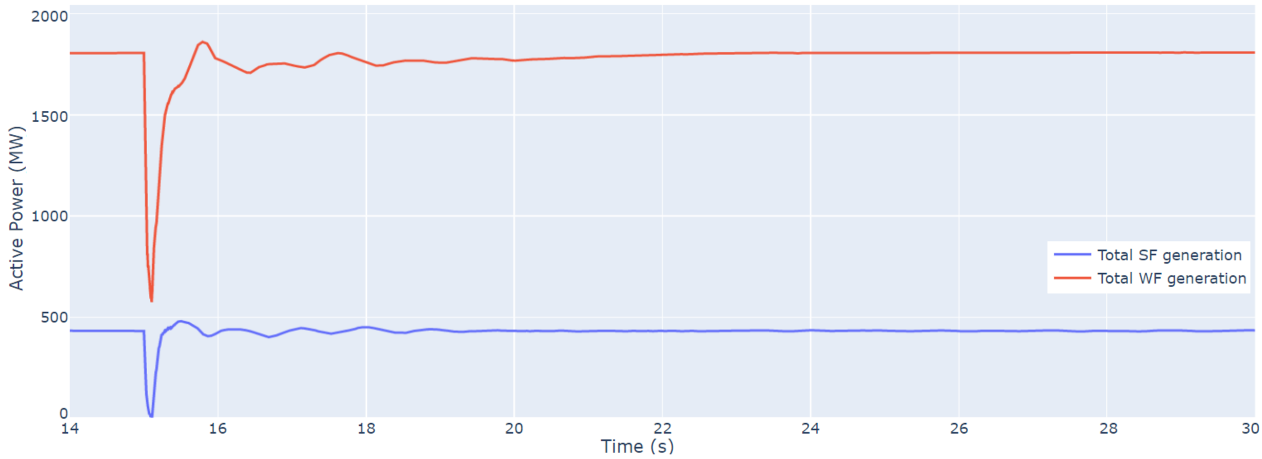
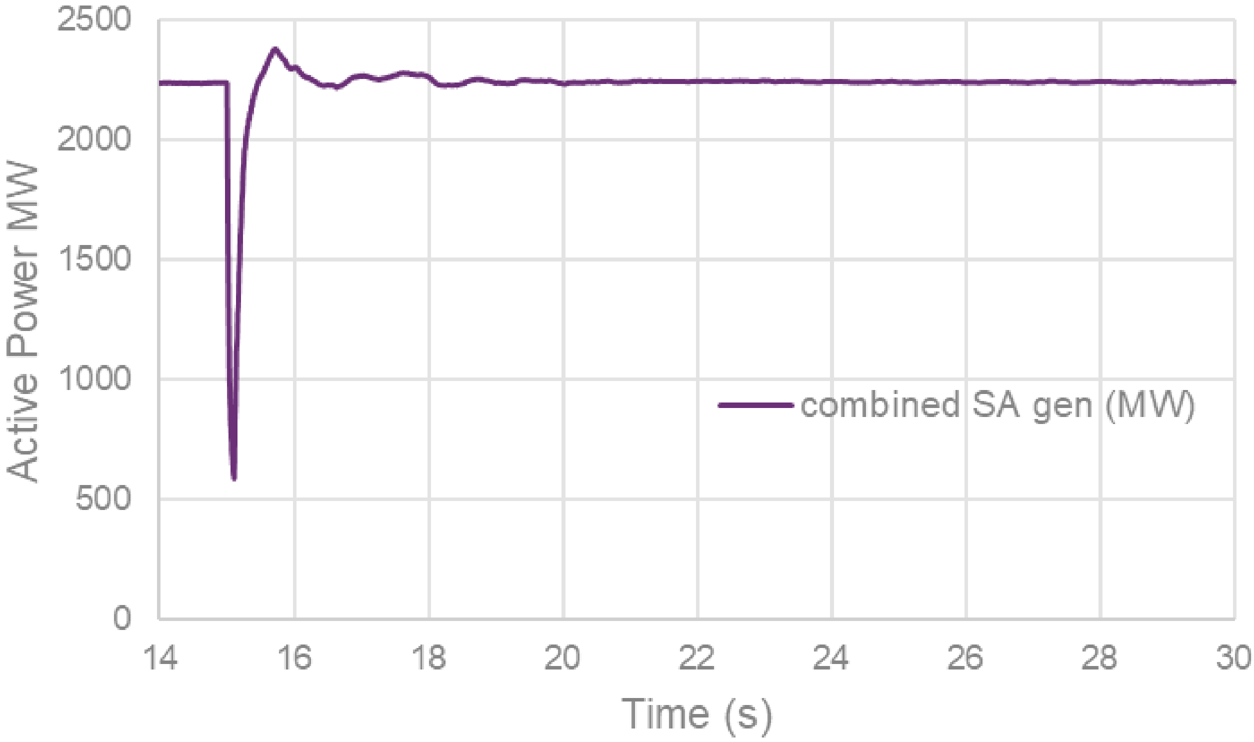
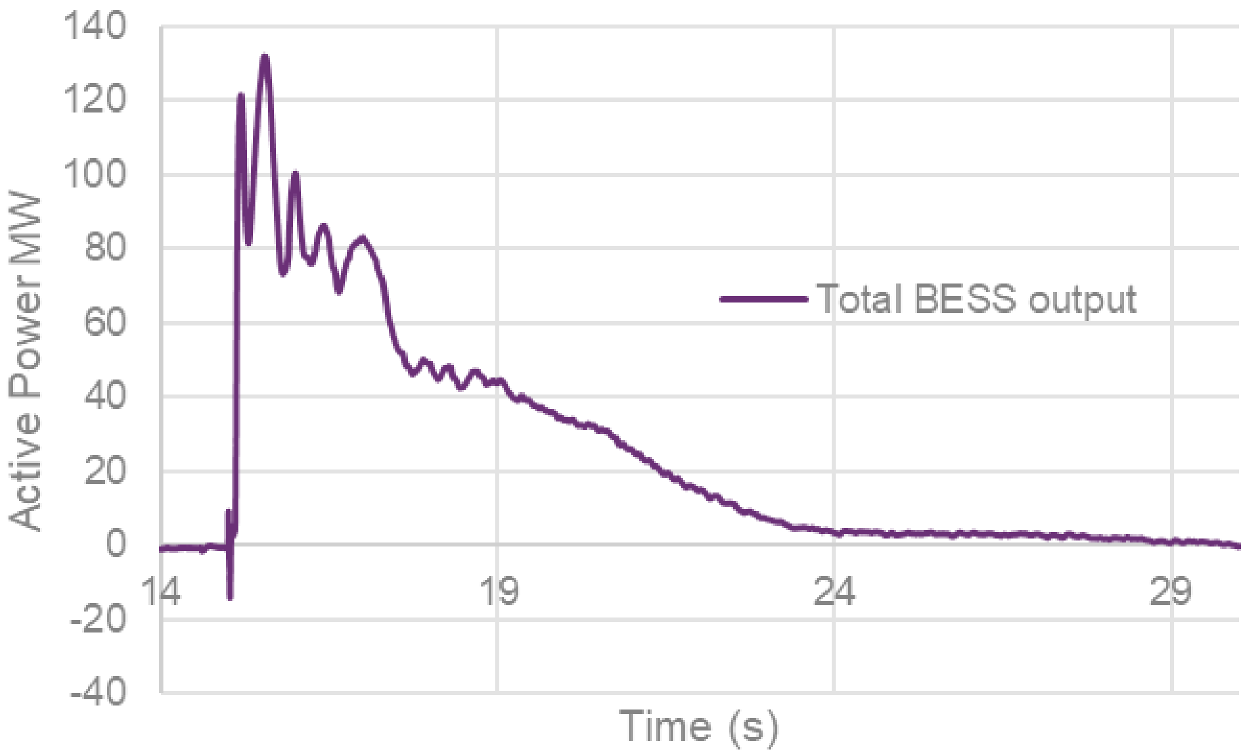


Figure 17 Combined SA generation – trip of one Davenport syncon under SA island



*Note: The combined generation in Figure 17 includes the contribution of BESS and IBR generation.

Figure 18 Total BESS output in SA – trip of one Davenport syncon under SA island



4.2.2 Trip of HPRx (VMM) under SA island

Figure 19 Network voltages – trip of HPRx (VMM) under SA island

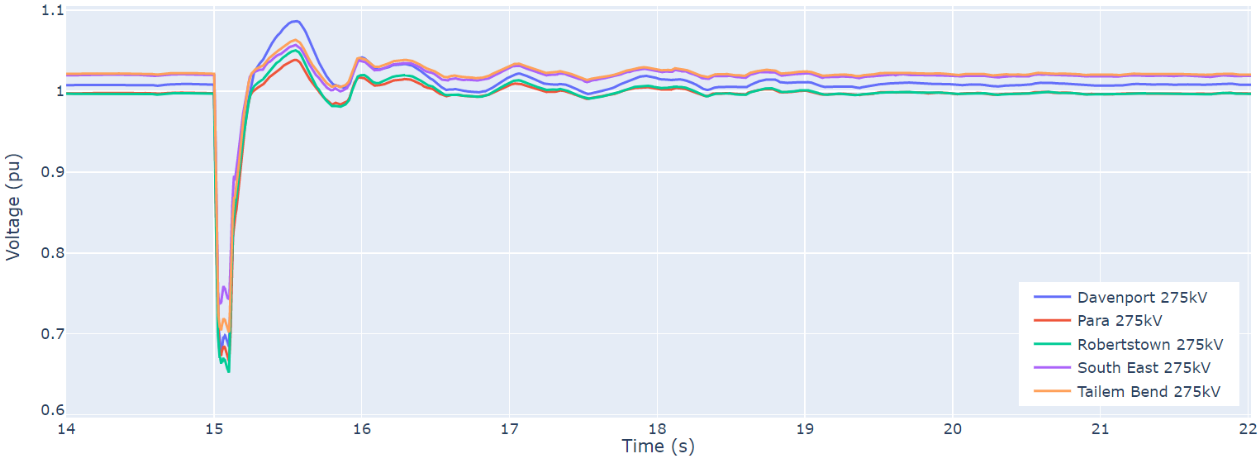
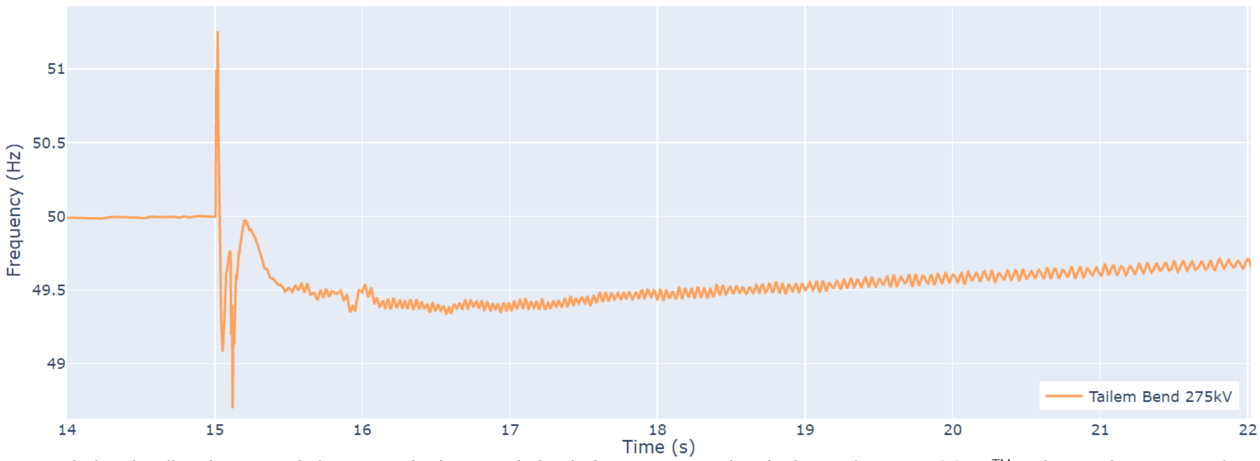


Figure 20 Frequency – trip of HPRx (VMM) under SA island



*Note: during the disturbance and clearance, the large variation in frequency transient is due to the way PSCAD™ estimates frequency using zero crossing approach, however this initial variation may be ignored.

Figure 21 IBR active power – trip of HPRx (VMM) under SA island

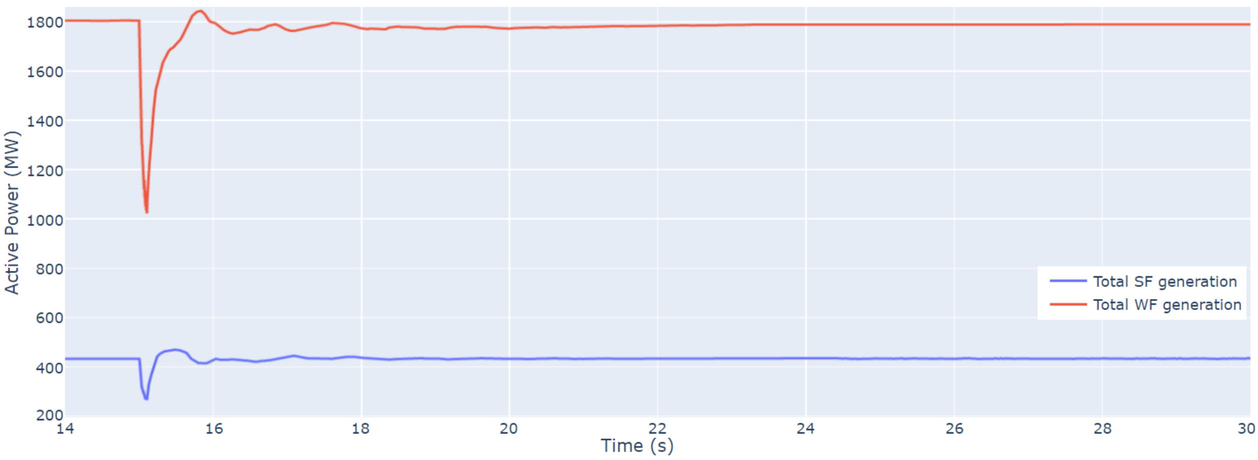
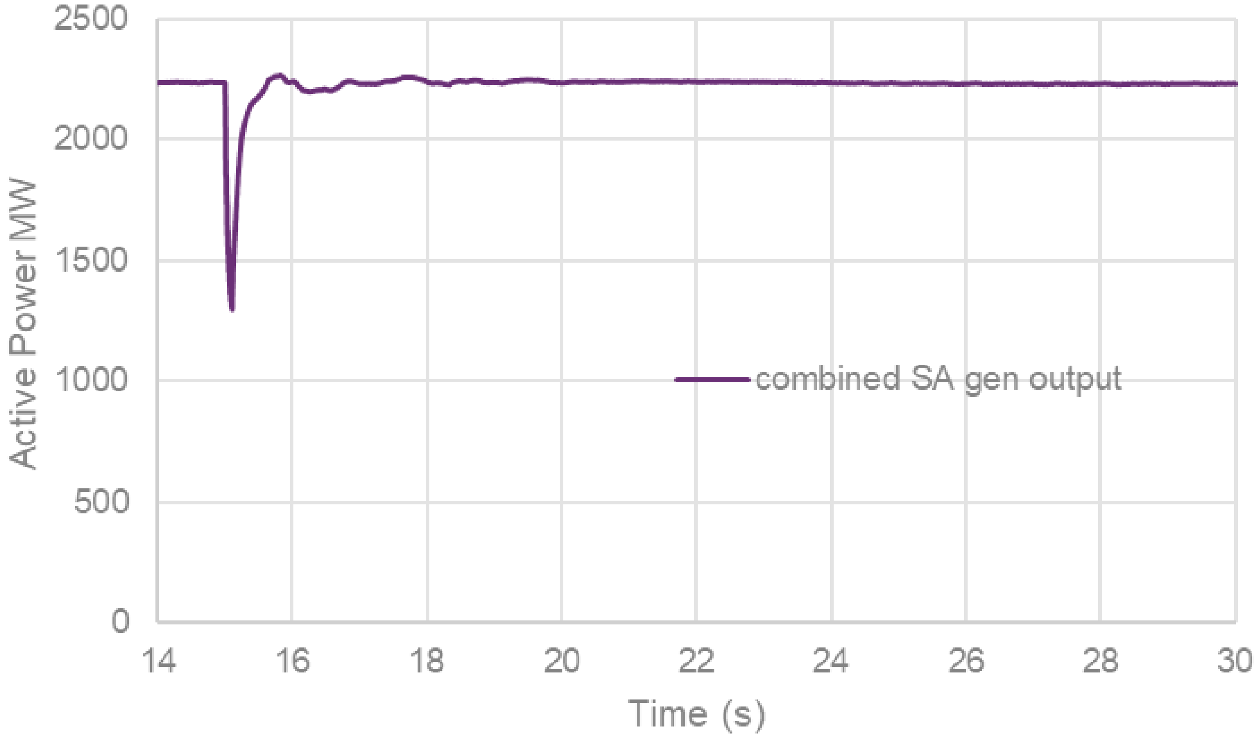
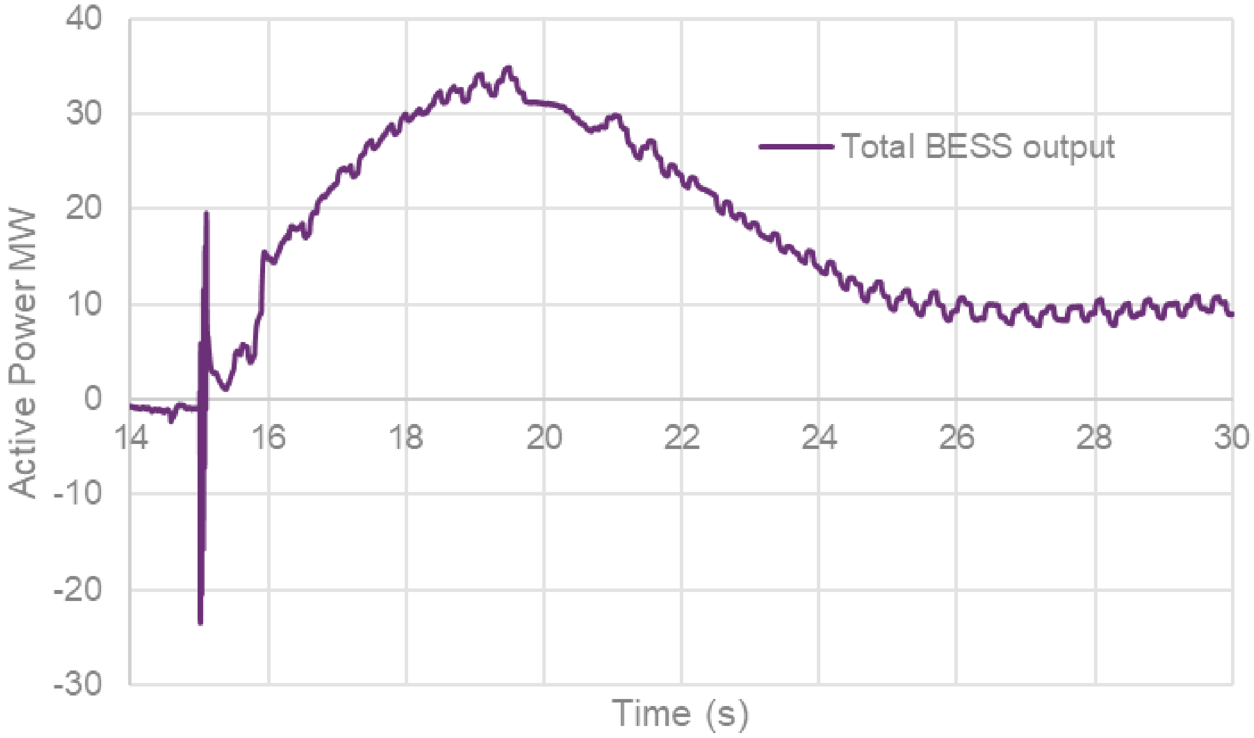


Figure 22 Combined SA generation output – trip of HPRx (VMM) under SA island



*Note: The combined SA generation in Figure 22 includes the contribution of BESS and IBR generation.

Figure 23 Total BESS output in SA – trip of HPRx (VMM) under SA island



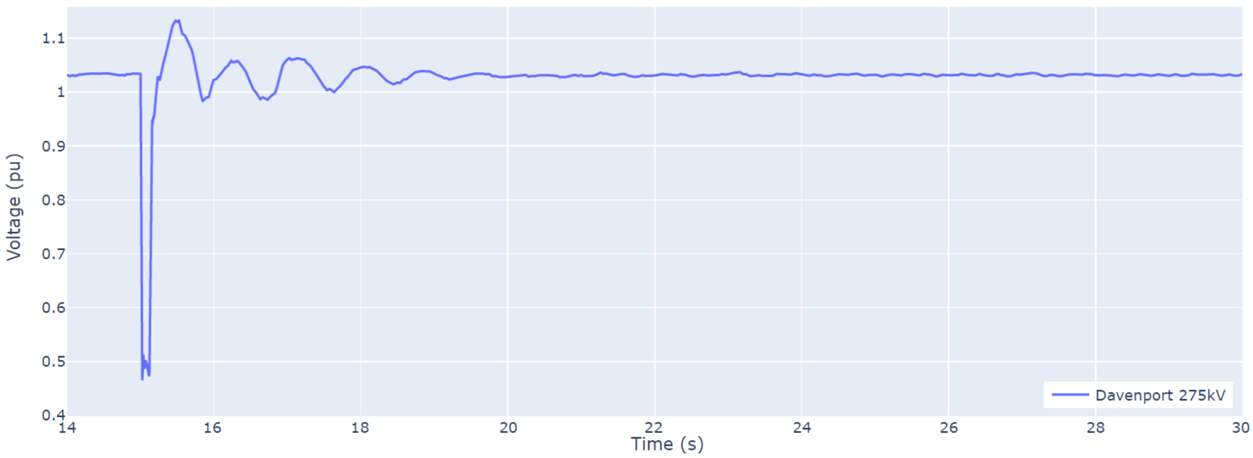
4.3 Results for the sub-network isolated around Davenport – Scenario 3

Results of power system studies for the sub-network described in Section 2.3 around Davenport are shown in Section 4.3.1 below. The contingency applied in this case is a double line to ground fault, near the Davenport 275 kV end and trip of Davenport – Cultana 275 kV transmission line, with normal remote end clearing (120 ms) assumed per column 3 of NER table S5.1a.2. Key observations are:

- The network voltages (as seen in Figure 24), remain satisfactory and able to meet the success criteria. The voltage oscillations meet the 5 second halving time requirement with adequate damping.
- Following the trip of Davenport – Cultana 275 kV transmission line, the frequency (as seen in Figure 25) recovers to around 50 Hz.
- The active power response of the IBR (as seen in Figure 26), while presenting some large transients following the fault clearing, did not cause the IBR to trip and all of the IBR eventually returned to pre-fault MW levels. It may be noted that this system, in addition to being isolated around Davenport as shown in Figure 2, contains only one Davenport syncon in-service. As a result, the system strength available during IBR fault ride-through is minimal, hence the large transients in IBR response.
- While tuning the IBR response for this smaller isolated system around Davenport is not the objective of this work, this section helps highlight the response of a handful of IBR, without the inclusion of any BESS and with only one syncon in-service.
- Additional sensitivity was also confirmed by clean tripping the only remaining syncon in this smaller sub-network, which resulted in the collapse of network voltages and frequency, as expected[18]. This helped confirm that there were no ideal voltage sources included inadvertently in this smaller sub-network that might have provided a fictitious voltage source for the IBR to ride-through, and that grid reference can be sustained via the network configuration comprising of syncons and IBR, even when no synchronous generating units are online.

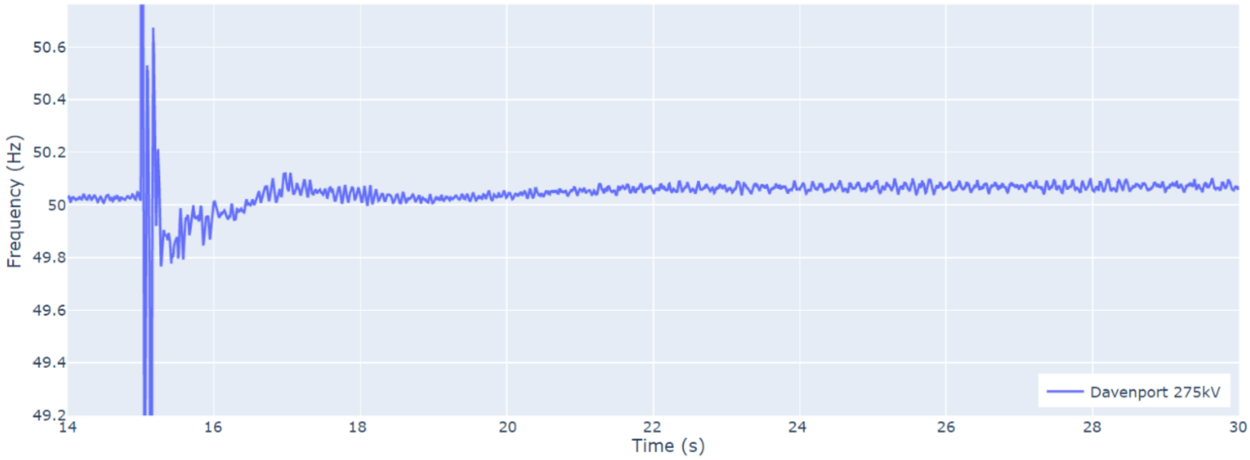
4.3.1 Davenport sub-network with one Davenport syncon

Figure 24 Network voltages – trip of Davenport – Cultana 275 kV line for Davenport sub-network



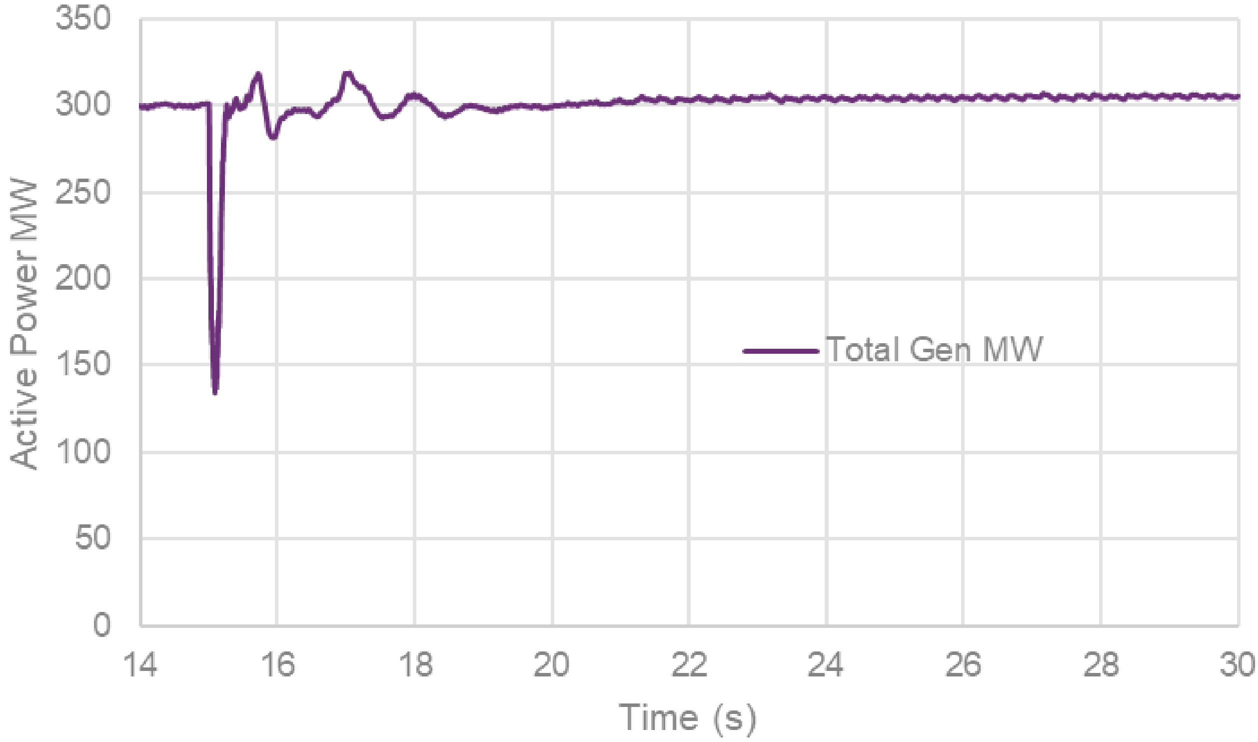
[18] Refer to Appendix A3.4, showing network voltage and frequency collapse at Davenport 275 kV bus when the remaining syncon in this small sub-network system is clean tripped.

Figure 25 Frequency – trip of Davenport – Cultana 275 kV line for Davenport sub-network



*Note: during the disturbance and clearance, the large variation in frequency transient is due to the way PSCAD™ estimates frequency using zero crossing approach, however this initial variation may be ignored.

Figure 26 IBR active power – trip of Davenport – Cultana 275 kV line for Davenport sub-network



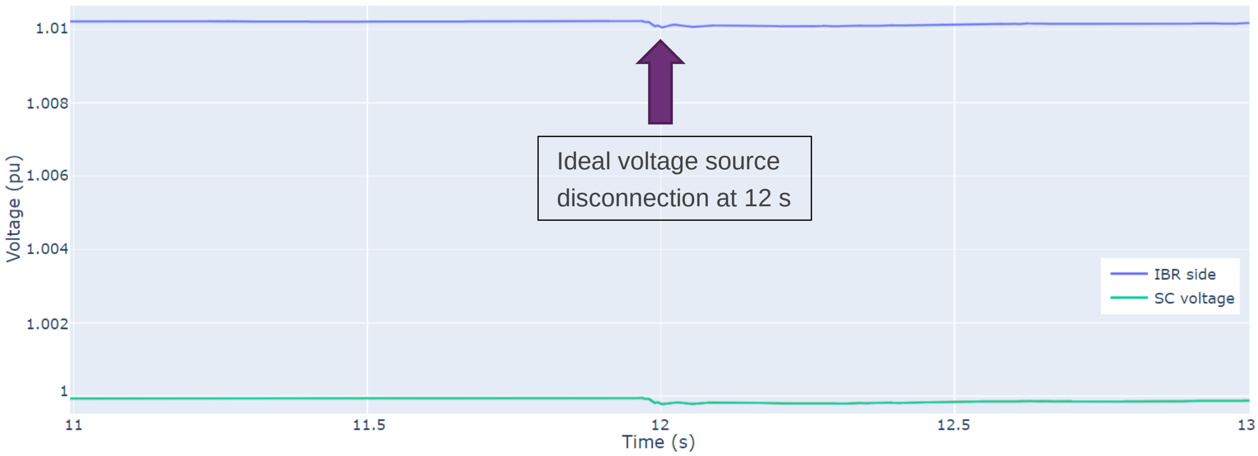
4.4 Results for the conceptual 2-bus test system – Scenario 4

Results of power system studies for the conceptual 2-bus test system described in Section 2.4 and Figure 3 are presented below for the case assuming a Type-4 IBR WF and assuming the Robertstown syncon model. The aim of this conceptual 2-bus test system is to test the notion of grid reference in the absence of synchronous generators; however, the syncon model was not tuned specifically for this conceptual 2-bus test system. Key observations are:

- The network voltages (as seen in Figure 27) remain satisfactory and able to meet the success criteria, following the disconnection of the ideal voltage source at 12 seconds. Similarly, for the case with switching of a small (around 10 megavolt amperes reactive [MVAR]) reactor (in Figure 30) resulted in the voltages remaining stable. The voltage dip resulting from the switching of the reactor was around 2%, which is within acceptable limits[19].
- The frequency (in Figure 28 and Figure 31) begins to drift below 50 Hz after disconnection of the ideal voltage source at 12 seconds, due to lack of any frequency control resources[20] in this system with just a Type-4 IBR WF and due to the fact that the ideal voltage source was providing a small amount of active and reactive power support. However, this did not result in an immediate case collapse following the disturbance, as evidenced by the response of IBR and syncon active power and network voltages.
- The active power response of the IBR (as seen in Figure 29 and Figure 32) remained stable, while the syncon absorbed some no-load losses (around 1.5 MW) fed by the IBR generation to sustain its operation.
- Based on the simulation results of this conceptual 2-bus test system, the notion of grid reference was tested and found sufficient as the syncon and IBR helped sustain the load in a stand-alone system with no synchronous generation.

4.4.1 Type 4 WF with no disturbance

Figure 27 Voltages – type 4 WF with no disturbance



[19] The 2% change in voltage is within the usual limits of the IEC61000-3-7 for rapid voltage changes.

[20] This drift in frequency behaviour will not be observed if there are additional frequency control resources, such as fast acting BESS, as evident in Section 4.1 and Section 4.2. Also, a sensitivity study with BESS instead of type-4 WF is shown in Appendix A3.3.1.

Figure 28 Frequency – type 4 WF with no disturbance

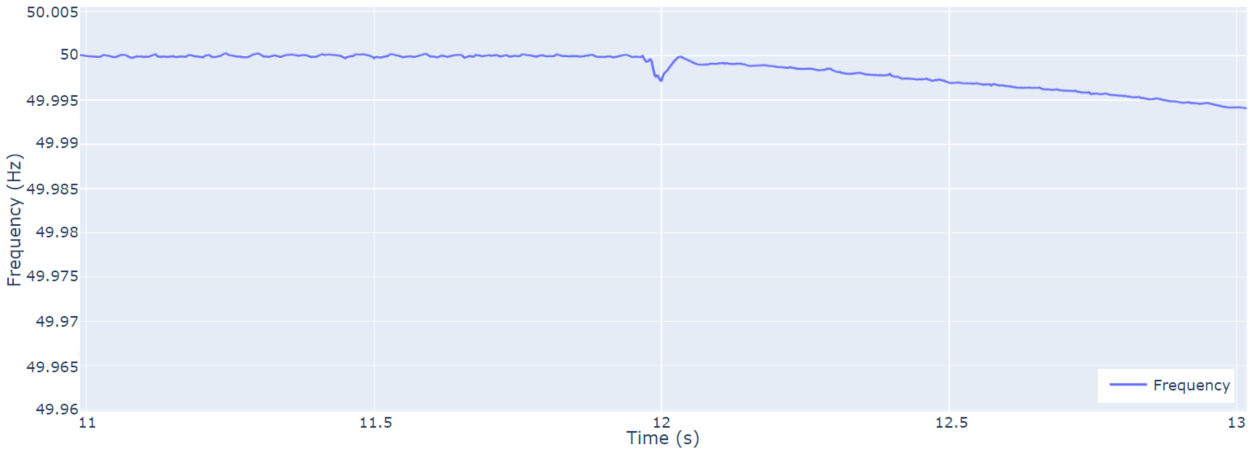
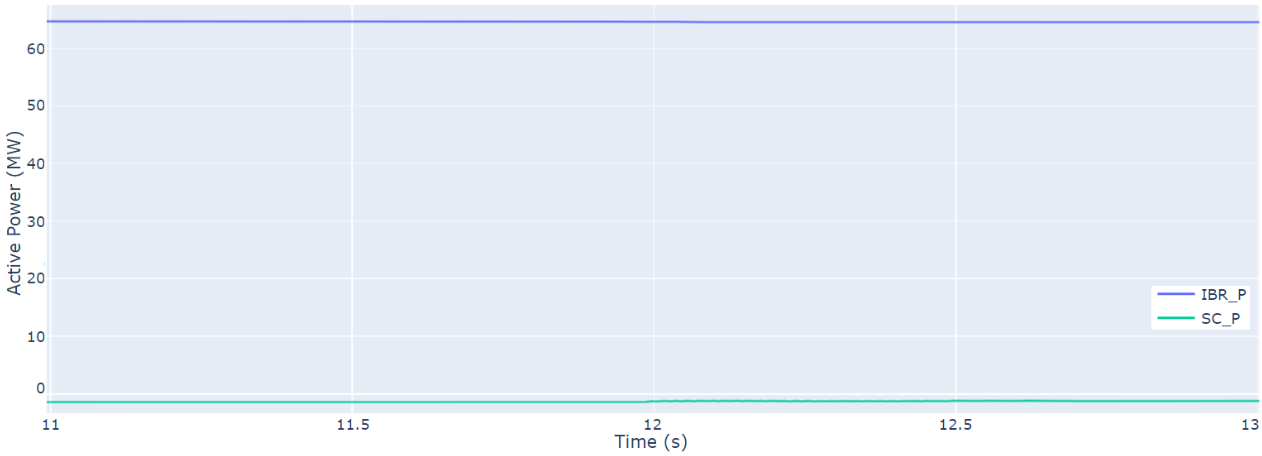


Figure 29 Active power – type 4 WF with no disturbance



4.4.2 Type 4 WF with reactor switching

Figure 30 Voltages – type 4 WF with reactor switching

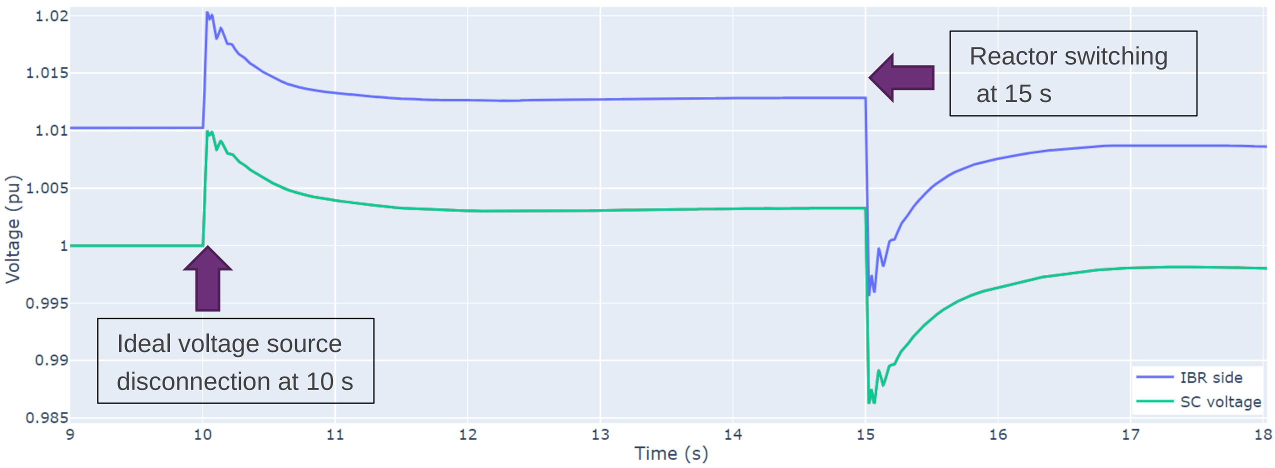


Figure 31 Frequency – type 4 WF with reactor switching

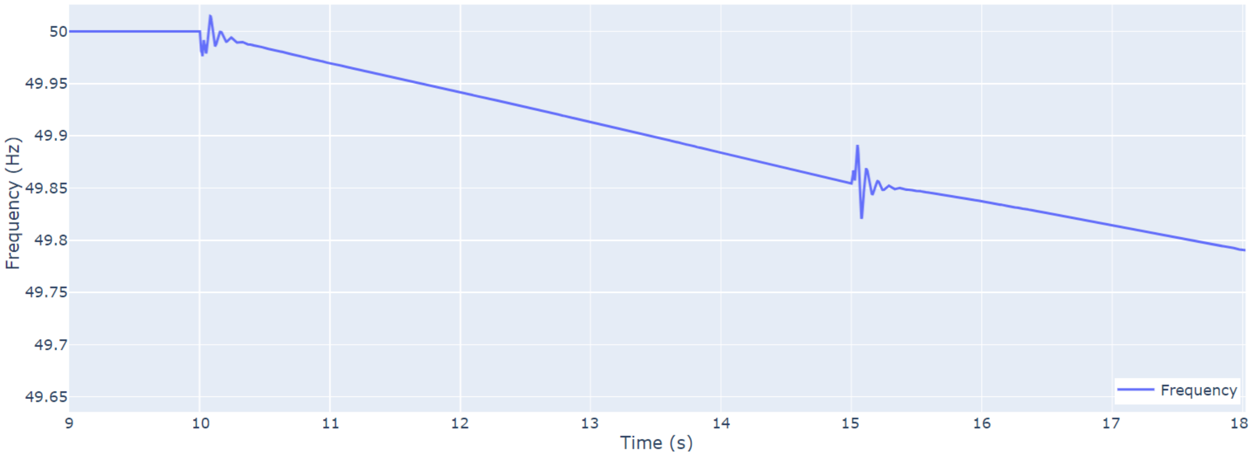
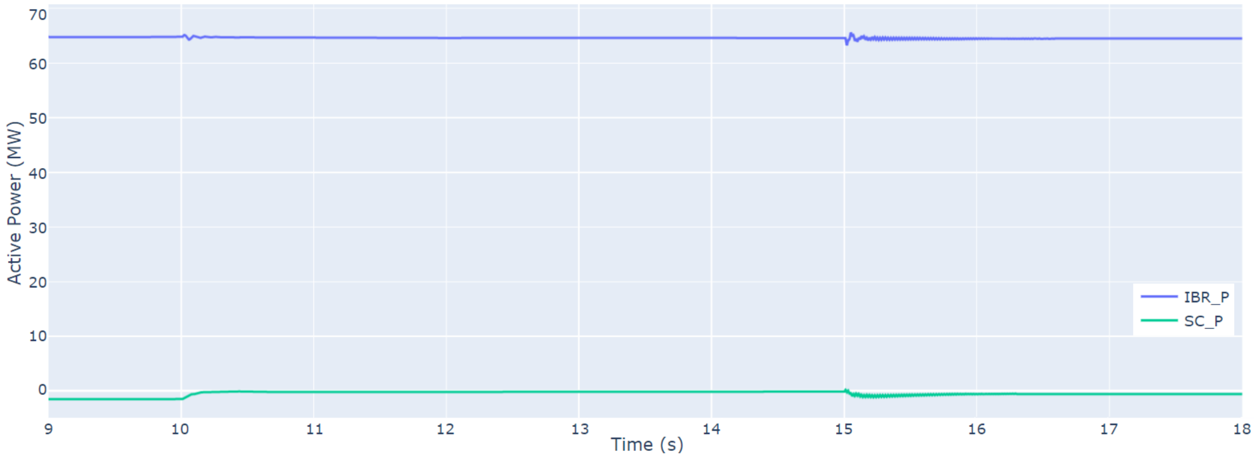


Figure 32 Active power – type 4 WF with reactor switching



5 Synchronous condenser modelling

The original equipment manufacturer (OEM)-supplied EMT (PSCAD™/EMTDC™) and RMS (PSS®E) models available for the four syncons in SA were further investigated to ensure their adequacy for the purposes of this study. The following aspects were noted:

- The models suitably accounted for the dependency of syncon excitation supply system on grid voltages, in installations where the automatic voltage regulator (AVR) system of syncons is auxiliary bus fed or grid-supplied configuration with AC or DC switchover capability.
- On the other hand, for an AVR system that is supplied by a permanent magnet generator (PMG), it is expected that the impact of grid faults (and voltages) on the supply of the excitation system will be negligible, and thus they are modelled appropriately as independent of grid supply.

From a modelling standpoint, therefore, the following details are noted:

- The auxiliary or bus fed AVR system was modelled based on IEEE excitation system AC7CU1 in both EMT (PSCAD™/EMTDC™) and RMS (PSS®E) software platforms. Both the programs account for grid voltage dependency (Kp = non-zero value), as shown in Figure 33.
- The PMG fed AVR system was modelled based on IEEE excitation system AC7B in both EMT (PSCAD™/EMTDC™) and RMS (PSS®E) software platforms. This does not account for grid voltage dependency for the reasons explained above and assumes a constant supply for the field excitation (Kp = 0 pu), as shown in Figure 34.

Figure 33 AC7CU1 AVR excitation system based on IEEE 421.5-2016 (SW1= A, SW2 =A, grid-fed)

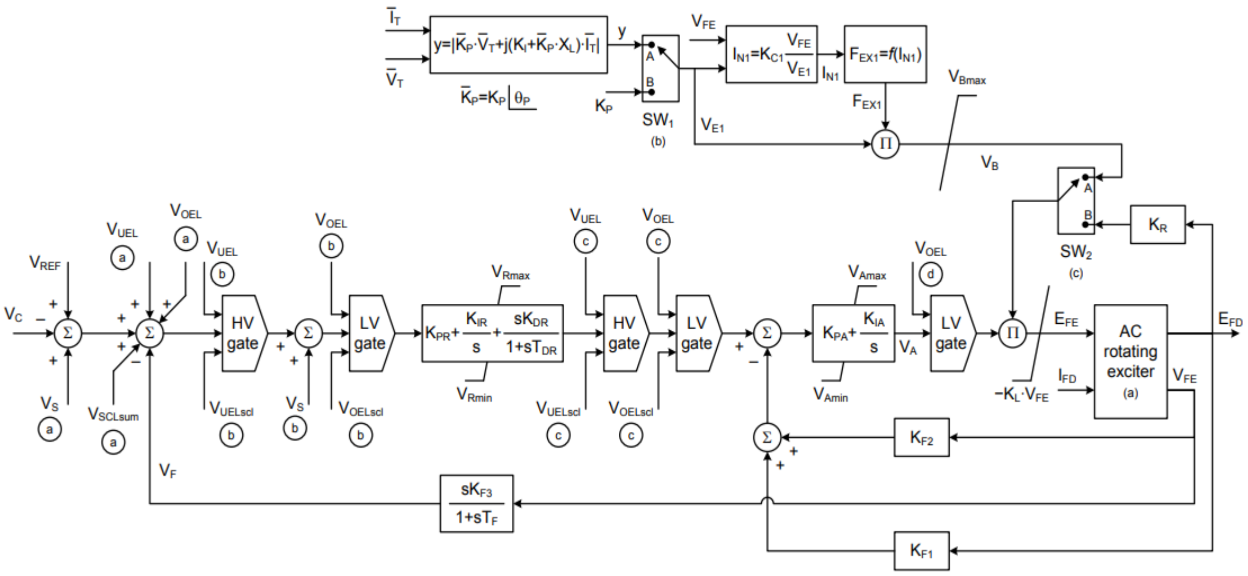
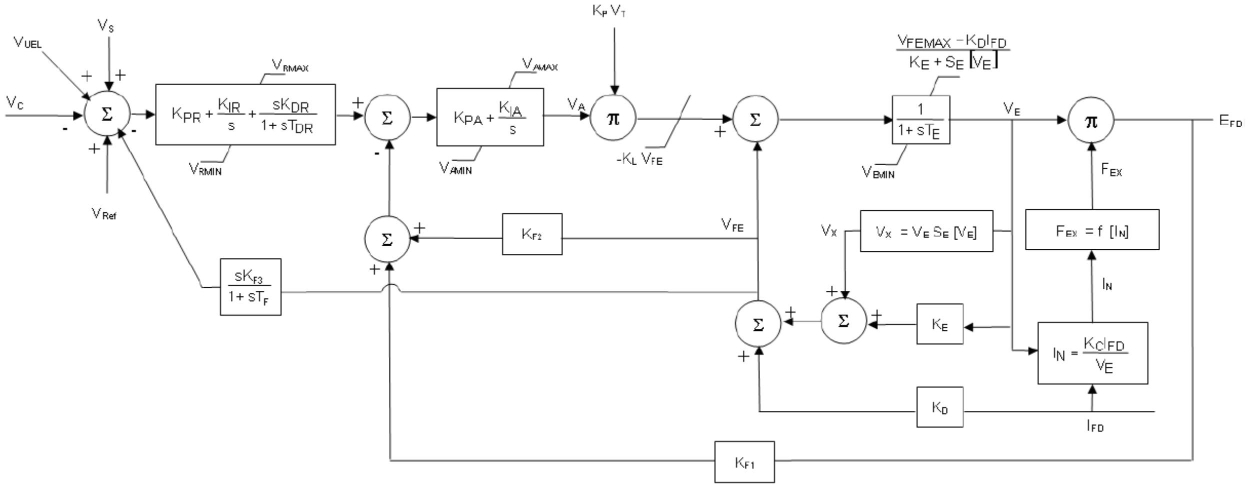


Figure 34 AC7B AVR excitation system based on IEEE 421.5-2005 (Kp = 0 pu, PMG-fed independent AVR supply)



6 Feedback from stakeholder engagement

The following feedback items obtained by AEMO from key stakeholders were addressed in the studies or, in one case, identified for follow-up.

Table 7 Feedback items from stakeholder engagement

Name of stakeholder	Feedback items/discussion provided	How the comments were addressed
PSMRG working group	• What is the effect of load ramping during SA islanded operation?	• While it is understood that it would be relatively challenging to handle large load ramps (or generation ramp), to objectively tackle load ramp a 50 MW ramp in 3 seconds was studied with SA operating as self-sufficient island. The results are included in A3.1; no adverse impact on voltages and frequency was observed. However, the load ramp is relatively small here.
Synchronous condenser OEM1	• What will be the effect of synchronous condenser size to the IBR ratio? • What will be the effect of varying the series line impedance between the synchronous condenser and the IBR in 2-bus system? • What will be the impact of modelling dynamic load such as motors in PSCAD™ simulations instead of static load? • Have you compared any test scenarios in RMS tools like PSS®E? • Protection considerations for the synchronous condenser and effect on negative sequence unbalance?	• Addressed in A3.3. • Addressed in A3.3. • Addressed in A3.2, with motor load modelled at Morgan – Whyalla pipeline pumps, Olympic dam load. • Addressed in A2– benchmarked results from Section 4.1.2. • Need further discussion with TNSP and OEM (outstanding task).
Synchronous condenser OEM2	• Results seem to be reasonable	• No action items.
Synchronous condenser OEM3	• Results seem to be reasonable	• No action items.
Independent consultant	• Effect of circuit breaker fail or delayed clearing on faults? • Other comments similar to synchronous condenser OEM1.	• Addressed in Section 4.2, Table 6. • Other comments addressed as above.
Research Organisation 1	• Comments similar to synchronous condenser OEM1	• Comments addressed as above.
Research Organisation 2	• Similar results seen in some hardware in the loop testing, with only synchronous condenser and IBR and no synchronous generators	• No action items.

7 Conclusions

This report has investigated the need for synchronous generation in SA for the purpose of grid reference.

The following observations are made based on the results of the power system studies:

- Following the separation of SA from the rest of the NEM (Scenario 1, Section 4.1), with zero synchronous generating units online in SA, the post-fault network voltages and frequency were satisfactory and met all success criteria. This scenario was also tested with prior outage of a syncon, BESS, MLDC, and Para SVC, and the results were satisfactory. This analysis demonstrated that synchronous generation is not required for grid reference.
- A self-sufficient[21] SA island scenario was also studied (Scenario 2, Section 4.2), with zero synchronous generating units online in SA. This scenario investigated several contingency trips of network elements, with and without prior outages. This also resulted in satisfactory post-fault network voltages, frequency and met all success criteria. This analysis also demonstrated that synchronous generation is not required for grid reference in the operation of a self-sufficient SA island.
- A smaller sub-system (Scenario 3, Section 4.3) including a few 275 kV and 132 kV transmission lines around Davenport was investigated, with a handful of IBR in the region, just one syncon available, and no BESS included. This system resulted in similar conclusions. However, a clean trip of the syncon resulted in a complete collapse of the system, as expected (results in Appendix A3.4). This confirmed that grid reference can be sustained via the network configuration comprising of syncon and IBR, even when no synchronous generating units are online.
- A conceptual 2-bus test system (Scenario 4, Section 4.4) was further used to test the notion of grid reference with just one syncon supporting an IBR serving load. This conceptual system also held together and did not show any adverse response such as a network voltage or frequency collapse. Including a BESS instead of a wind or solar generator afforded better frequency control in this conceptual system, results included in Appendix A3.3.1.
- A number of sensitivity studies were also investigated including a load ramp in the SA islanded system, the effect of dynamic load modelling (such as a motor start), and a non-credible separation of SA with prior outage of both HPRx and Dalrymple BESS (with HIC held close to zero MW transfer), however, no adverse impact was observed, and the network voltages and frequency remained satisfactory even when no synchronous generating units were online in SA.

Based on this investigation, therefore, it may be concluded that synchronous generation is not needed solely for the purpose of grid reference in SA and that grid reference can be sustained in SA with the existing network configuration of syncons, IBR and BESS. This report does not consider whether synchronous generation may be required in SA for other power system security needs, such as adequate protection system operation, frequency control, and ramping reserve management, or for power quality purposes.

[21] This assumes that following a separation event, supply demand balance has been achieved.

8 Next steps

The following next steps are recommended:

- Plan for a self-sufficient (with load and generation balanced) sub-network or sub-regional field test that includes a syncon and IBR to physically test the notion that grid reference can be sustained in operation of a smaller network; that is, conduct a real-time test of a smaller network to physically demonstrate the concept of grid reference without synchronous generation within a smaller test network and validate findings from the models.
- Incorporate the results of the studies as validated by tests into the broader work program by AEMO and ElectraNet to confirm if, when and how the SA power system can be operated with fewer than the current requirement of two large synchronous generating units online.

9 International experience – operating without synchronous generation

The operation of an AC power system without synchronous generation is not a novel concept. This has been demonstrated with microgrids and several stand-alone power system installations around the world, primarily with BESS, including the deployment of grid forming converters. However, the investigation of grid reference in this report is a world-first for a gigawatt-scale power system without synchronous generation. This section lists a few existing installations based on literature review, where AC power systems have been operated without synchronous generation:

- SMA project, St Eustatius Island[22] – SMA has demonstrated a 100% renewable grid with 4.15 MW of solar generation installed along with 5.9 megawatt hours (MWh) of BESS capacity up to 2 MW overload (connected via grid forming converters), capable of supplying the utility load and maintaining grid frequency with diesel-off mode. This system has been proven to withstand normal day-to-day operations including fast moving cloud cover and load variations. SMA has also demonstrated similar projects with 100% renewable penetration, in the island of Saba and the town of Bordesholm, Germany.
- Siemens Gamesa La Plana hybrid project, Spain[23] – Siemens Gamesa owns a test plant with 850 kilowatts (kW) wind turbine generators, 245 kW solar PV, 3 x 222 kW diesel generators and 0.5 MW/0.5MWh BESS with grid forming capability with a 1.1MW/0.75 MVAR load bank. This system has been demonstrated to operate in zero diesel generation mode, including blackstart capability.
- Micanopy microgrid, Florida, United States of America (USA) [24] – Duke Energy Florida, a major generation and utility company, operates an 8.25 MW /11.7 MWh BESS to support the town of Micanopy and nearby neighbours during grid outages, including a section of a distribution feeder. The primary application is for islanding and frequency regulation. Duke Energy also operates other similar microgrid standalone projects, with BESS used to firm renewable generators and serve load as stand-alone power systems in events such as hurricanes. When not needed, the excess energy from the BESS is also exported to the grid.
- National Renewable Energy Laboratory (NREL) campus, Colorado USA[25] – the NREL campus houses a multi-energy test facility, including wind, PV generation and BESS operated in grid forming mode, and a 7 megavolt amperes (MVA) power controller acting as a controllable grid interface. This 13.2 kV microgrid is connected to the transmission grid via 13.2 kV/115 kV step-up substation, which can run either connected to the main grid or islanded to support microgrid operation, with 100% renewables.

While this list is not comprehensive, it provides a sample of projects that have been successfully demonstrated to operate as a microgrid or standalone installation without synchronous generation. It should be noted that several other projects have demonstrated the use of grid-forming converters (including BESS and back-to-back high voltage direct current [HVDC]) for providing a grid reference and blackstart purposes (including Dalrymple BESS in SA), but not necessarily in a grid operated without synchronous generation.

[22] For more, see https://www.sma-sunny.com/en/st-eustatius-100-solar-power-in-the-caribbean/.

[23] For more, see https://www.gamesaelectric.com/gamesa-electric-at-siemens-gamesas-la-plana-hybrid-pilot-plant/.

[24] For more, see https://news.duke-energy.com/releases/duke-energy-florida-announces-three-new-battery-storage-sites-including-special-needs-shelter-and-first-pairing-with-utility-solar.

[25] For more, see https://www.nrel.gov/news/program/2021/nothing-to-fear-for-high-renewable-systems-nrel-shows-scalable-resilient-and-secure-systems-with-communication-less-controls.html.

A1. Results

A1.1 Formation of SA island

A1.1.1 Prior outage of 1 Davenport (DP) syncon – loss of HIC during import of 184 MW to SA

Figure 35 Network voltages – loss of HIC during 184 MW import to SA (prior outage of 1 DP syncon)

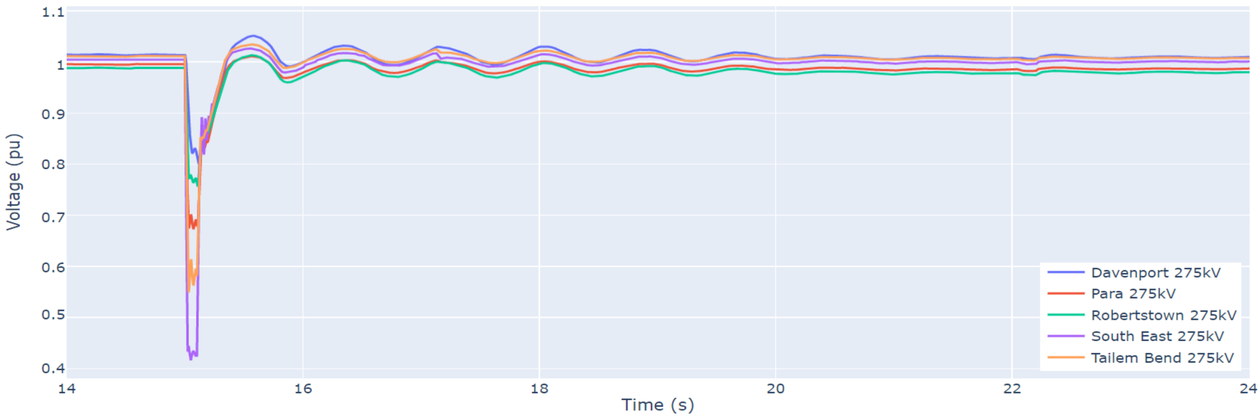
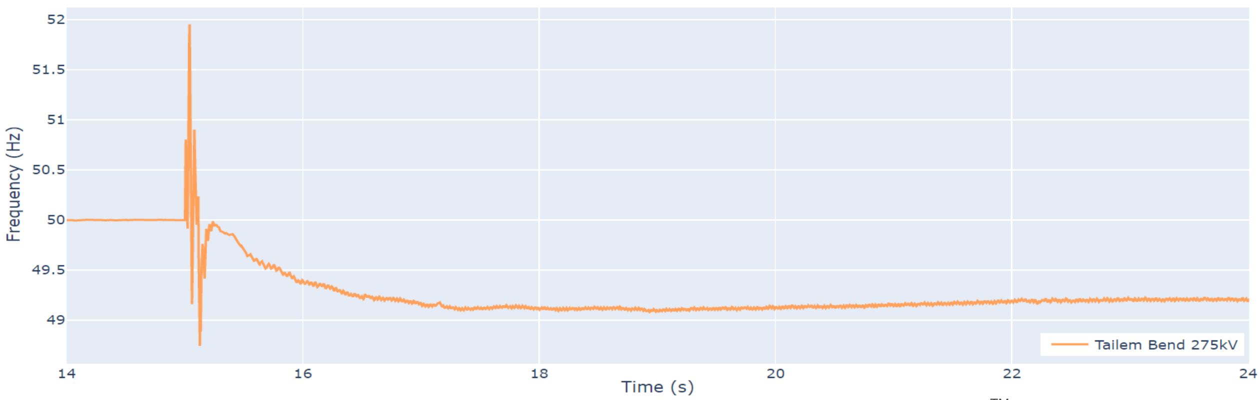
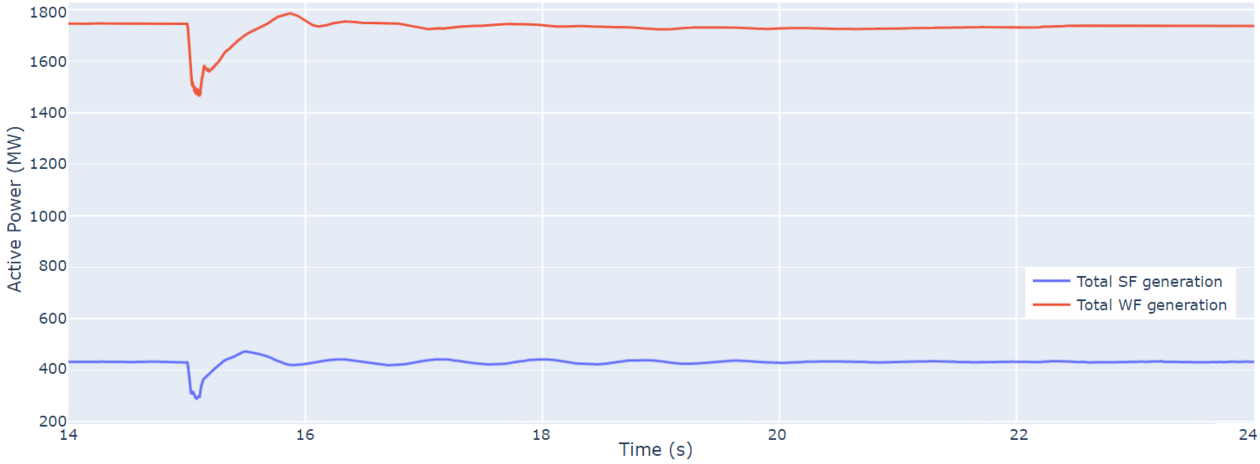


Figure 36 Frequency – loss of HIC during 184 MW import to SA (prior outage of 1 DP syncon)



*Note: during the disturbance and clearance, the large variation in frequency transient is due to the way PSCAD™ estimates frequency using zero crossing approach, however this initial variation may be ignored.

Figure 37 IBR active power – loss of HIC during 184 MW import to SA (prior outage of 1 DP syncon)



A1.1.2 Prior outage of 1 Robertstown (RT) syncon – loss of HIC during import of 172 MW to SA

Figure 38 Network voltages – loss of HIC during 172 MW import to SA (prior outage of 1 RT syncon)

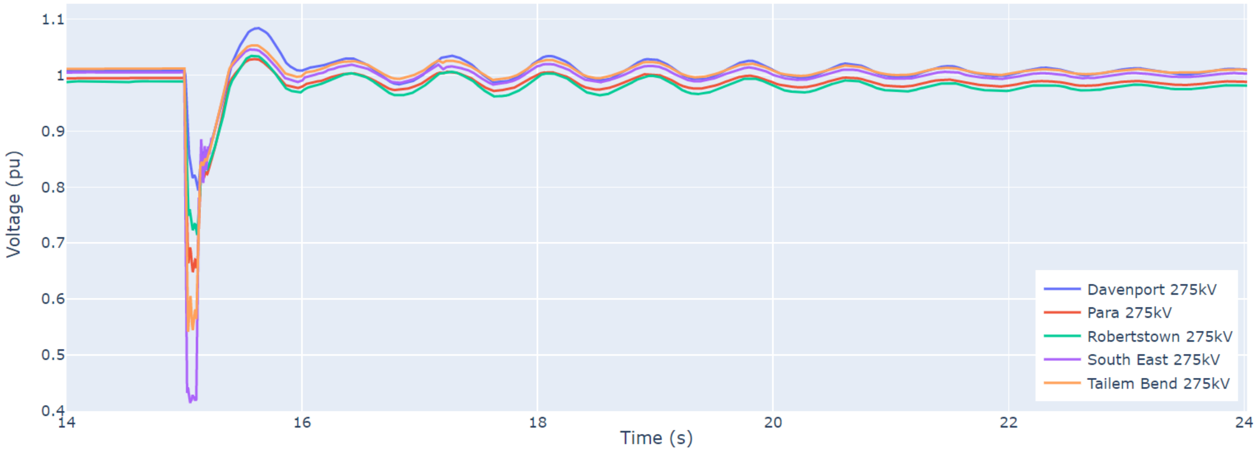
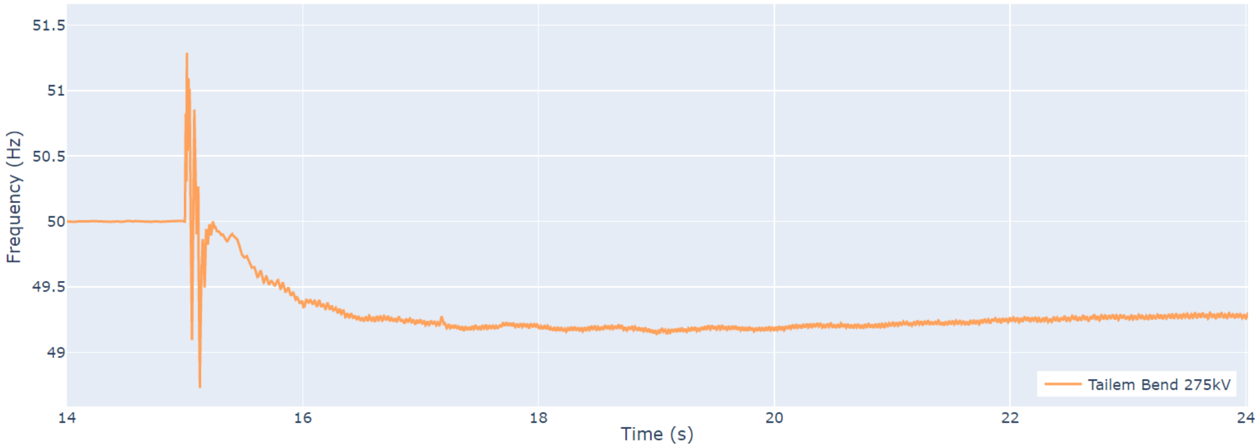
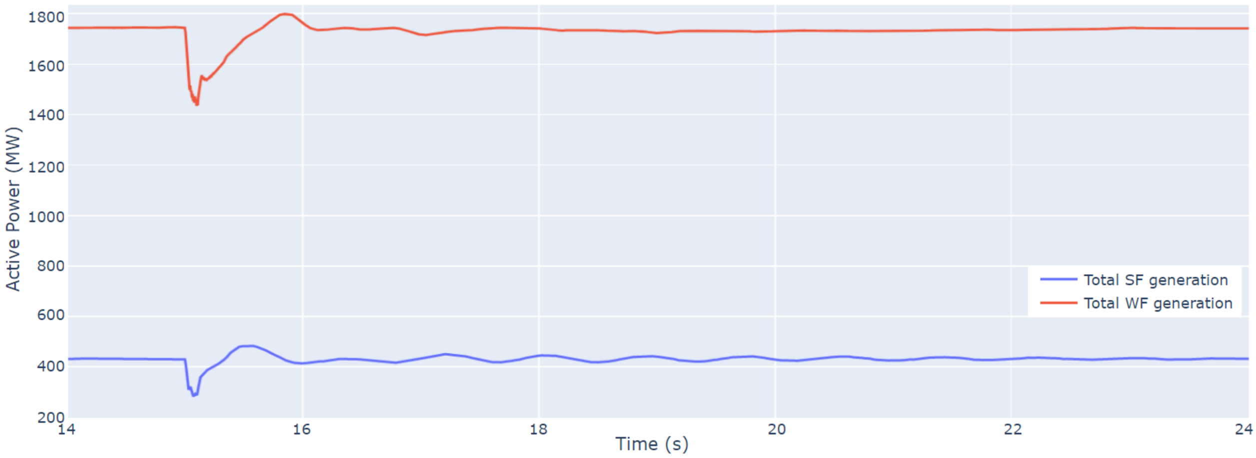


Figure 39 Frequency – loss of HIC during 172 MW import to SA (prior outage of 1 RT syncon)



*Note: during the disturbance and clearance, the large variation in frequency transient is due to the way PSCAD™ estimates frequency using zero crossing approach, however this initial variation may be ignored.

Figure 40 IBR active power – loss of HIC during 172 MW import to SA (prior outage of 1 RT syncon)



A1.1.3 Prior outage of Hornsdale Power Reserve expansion (HPRx) – loss of HIC during export of 53 MW from SA

Figure 41 Network voltages – loss of HIC during 53 MW export from SA (prior outage of HPRx)

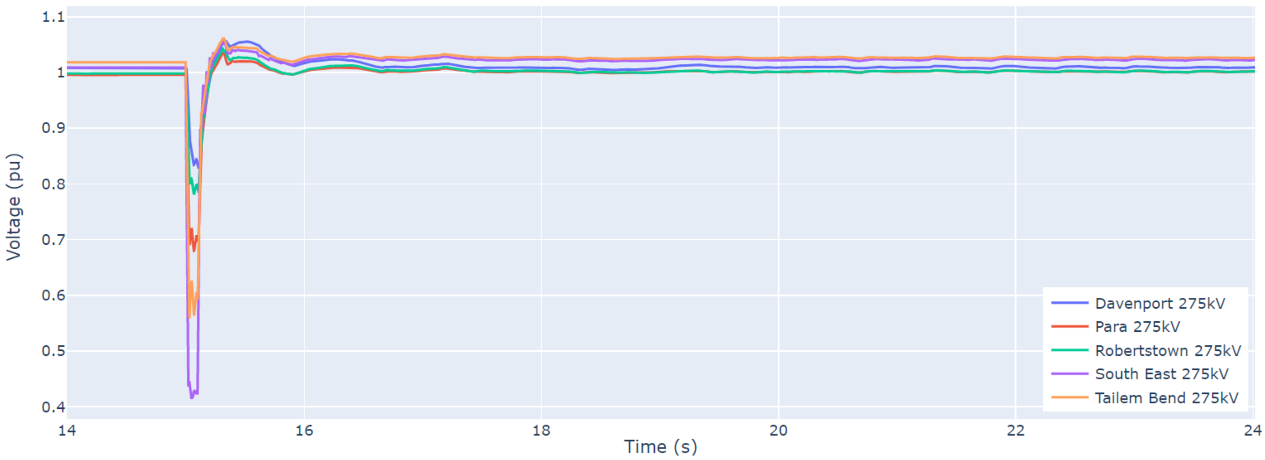
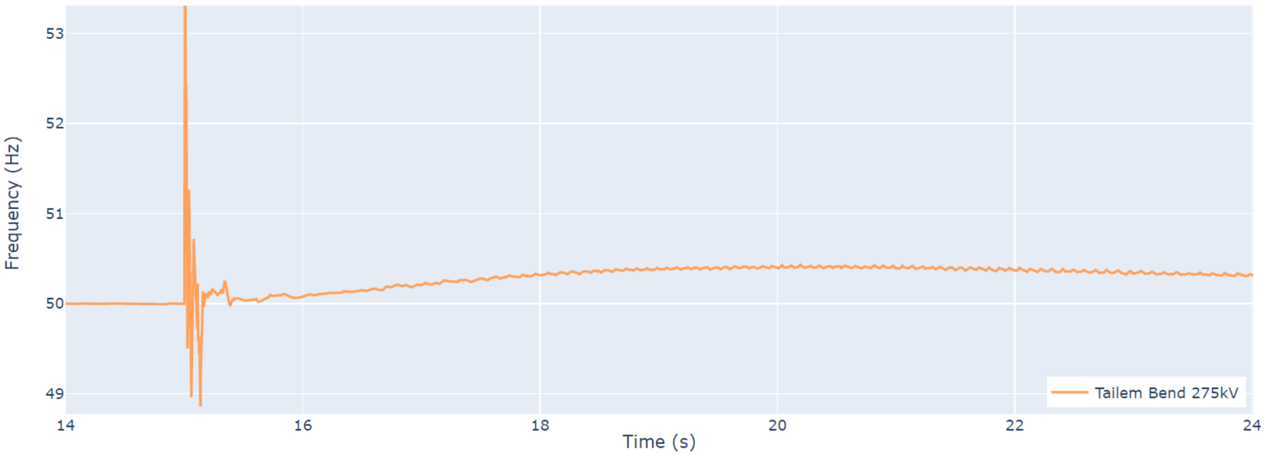
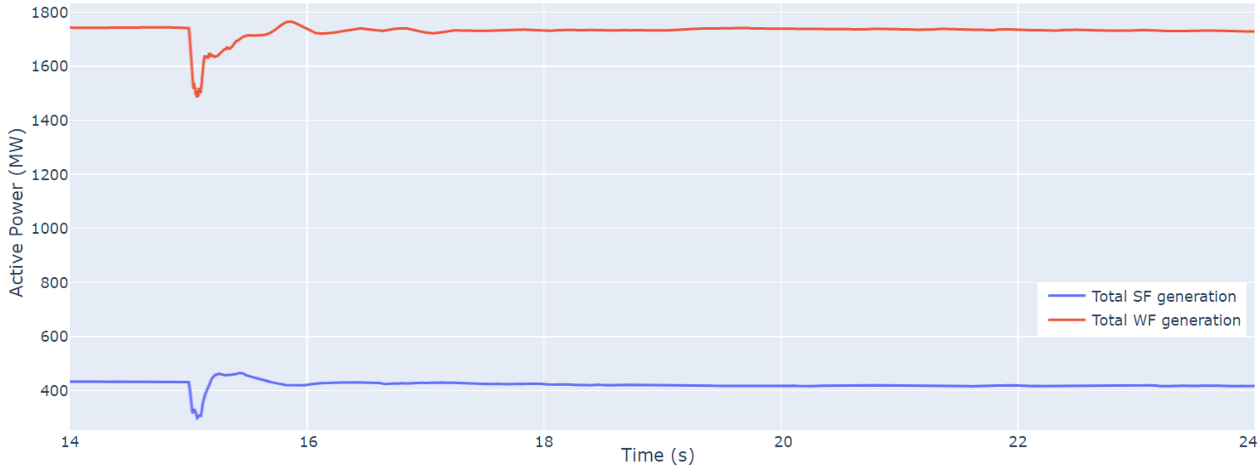


Figure 42 Frequency – loss of HIC during 53 MW export from SA (prior outage of HPRx)



*Note: during the disturbance and clearance, the large variation in frequency transient is due to the way PSCAD^{TM} estimates frequency using zero crossing approach, however this initial variation may be ignored.

Figure 43 IBR active power – loss of HIC during 53 MW export from SA (prior outage of HPRx)



A1.1.4 Prior outage of Dalrymple BESS – loss of HIC during export of 173 MW from SA

Figure 44 Network voltages – loss of HIC during 173 MW export from SA (prior outage of Dalrymple BESS)

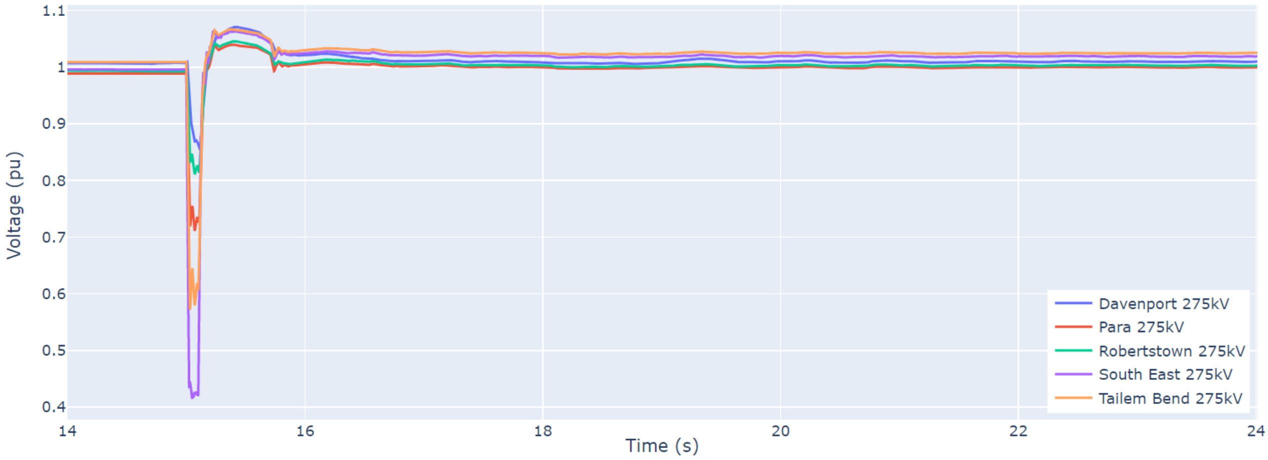
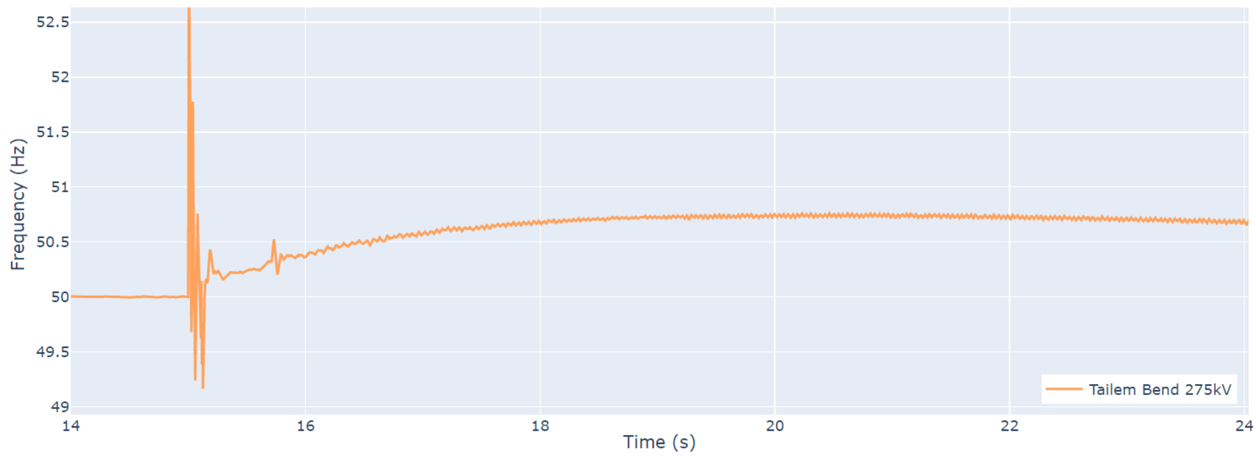
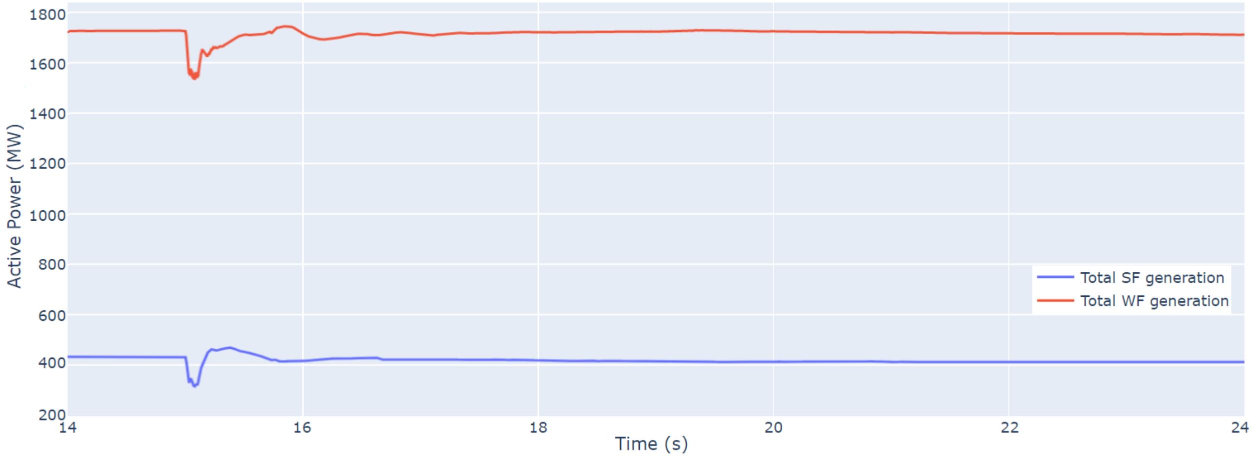


Figure 45 Frequency – loss of HIC during 173 MW export from SA (prior outage of Dalrymple BESS)



*Note: during the disturbance and clearance, the large variation in frequency transient is due to the way PSCAD™ estimates frequency using zero crossing approach, however this initial variation may be ignored.

Figure 46 IBR active power – loss of HIC during 173 MW export from SA (prior outage of Dalrymple BESS)



A1.1.5 Prior outage of type 1 WFs – loss of HIC during import of 182 MW to SA

Figure 47 Network voltages – loss of HIC during 182 MW import to SA (prior outage type 1 WFs)

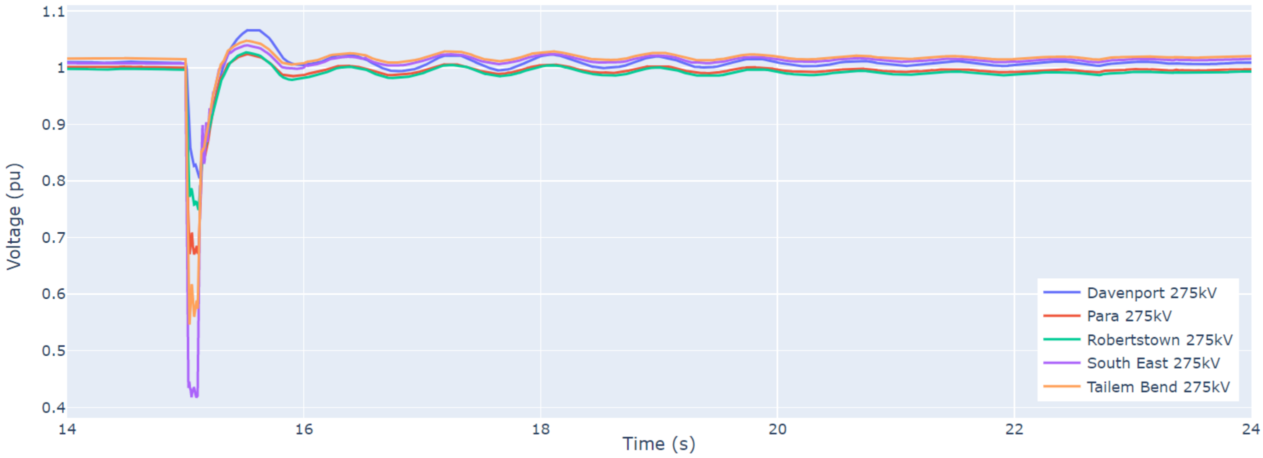
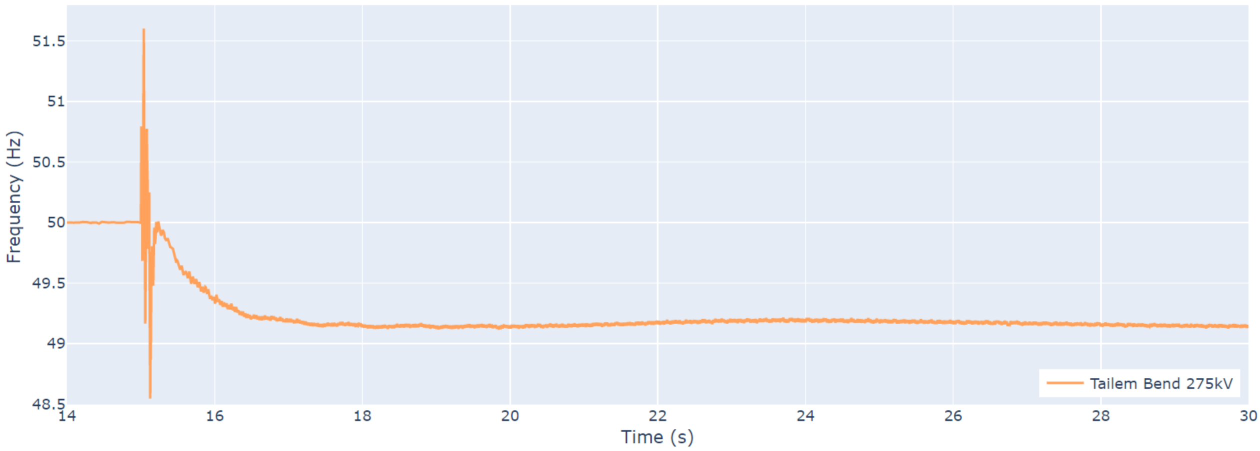
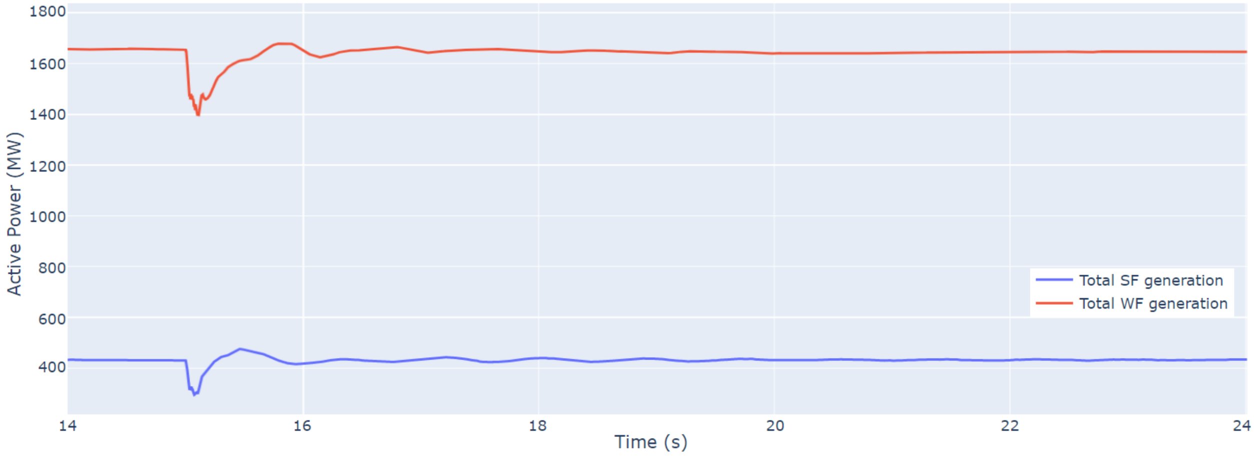


Figure 48 Frequency – loss of HIC during 182 MW import to SA (prior outage type 1 WFs)



*Note: during the disturbance and clearance, the large variation in frequency transient is due to the way PSCAD™ estimates frequency using zero crossing approach, however this initial variation may be ignored.

Figure 49 IBR active power – loss of HIC during 182 MW import to SA (prior outage type 1 WFs)



A1.1.6 Prior outage of Murray Link direct current (MLDC) interconnector – loss of HIC during export of 180 MW from SA

Figure 50 Network voltages – loss of HIC during 180 MW export from SA (prior outage of MLDC)

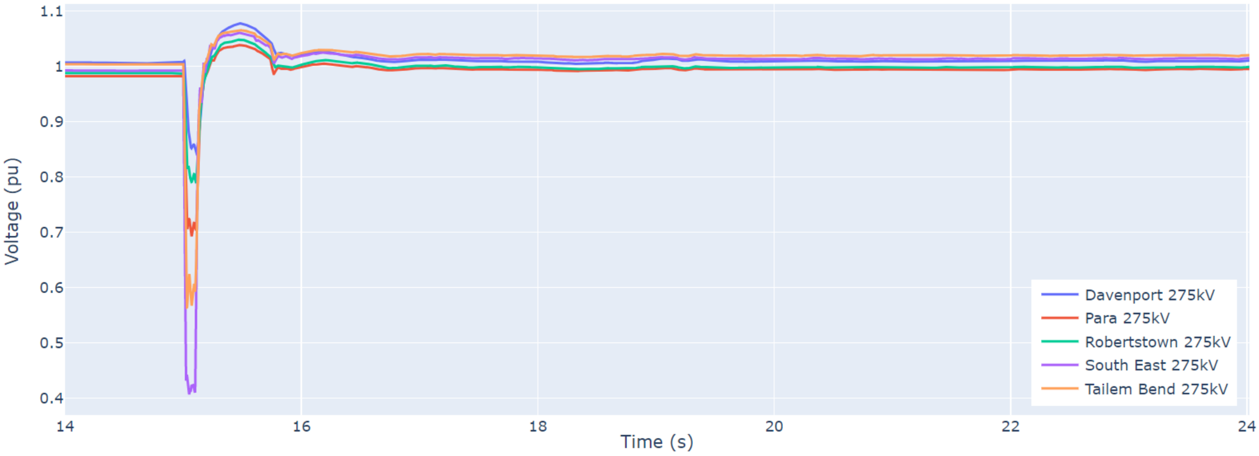
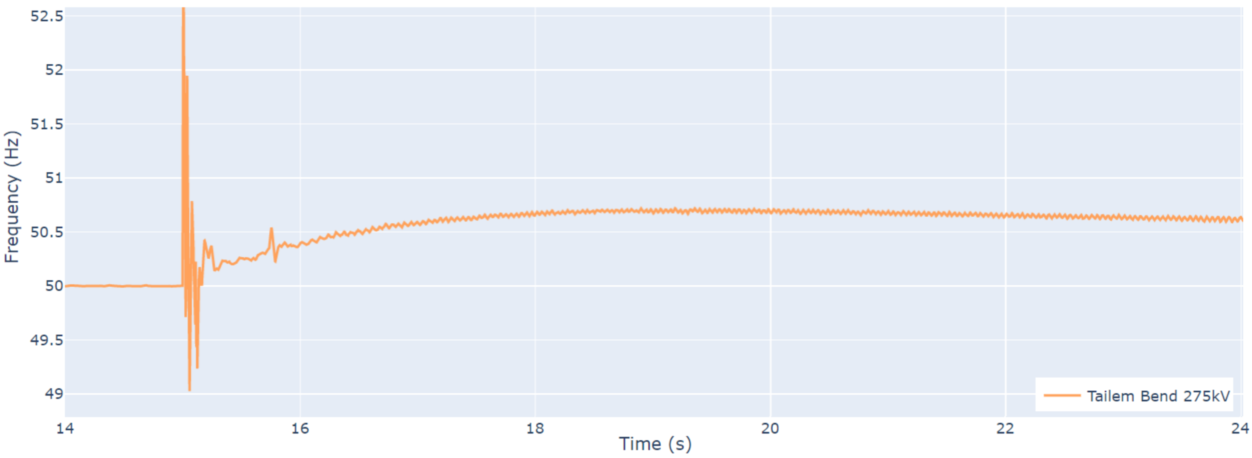
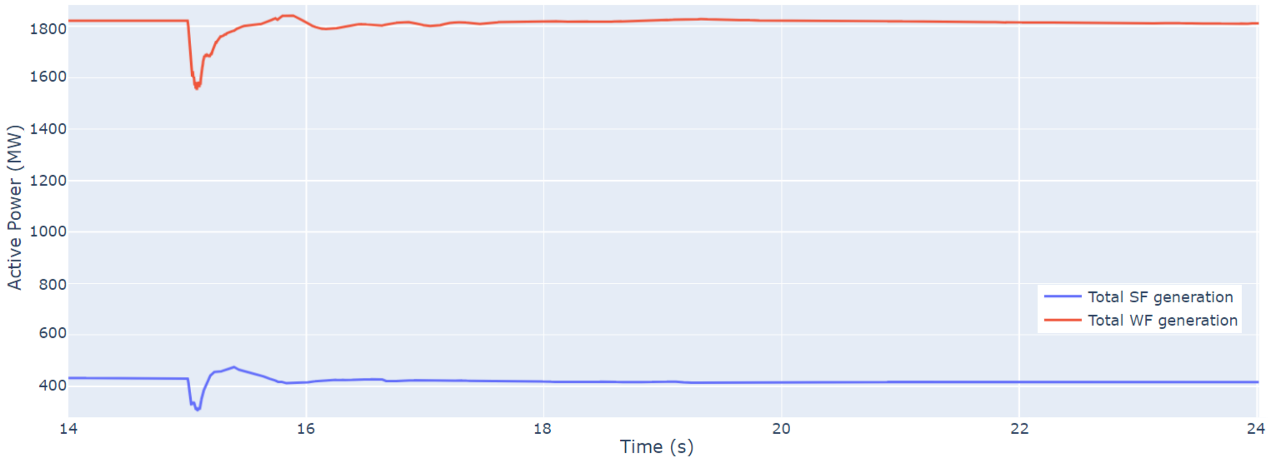


Figure 51 Frequency – loss of HIC during 180 MW export from SA (prior outage of MLDC)



*Note: during the disturbance and clearance, the large variation in frequency transient is due to the way PSCAD™ estimates frequency using zero crossing approach, however this initial variation may be ignored.

Figure 52 IBR active power – loss of HIC during 180 MW export from SA (prior outage of MLDC)



A1.1.7 Prior outage of 1 Para SVC – loss of HIC during export of 180 MW from SA

Figure 53 Network voltages – loss of HIC during import of 180 MW to SA (prior outage of 1 Para SVC)

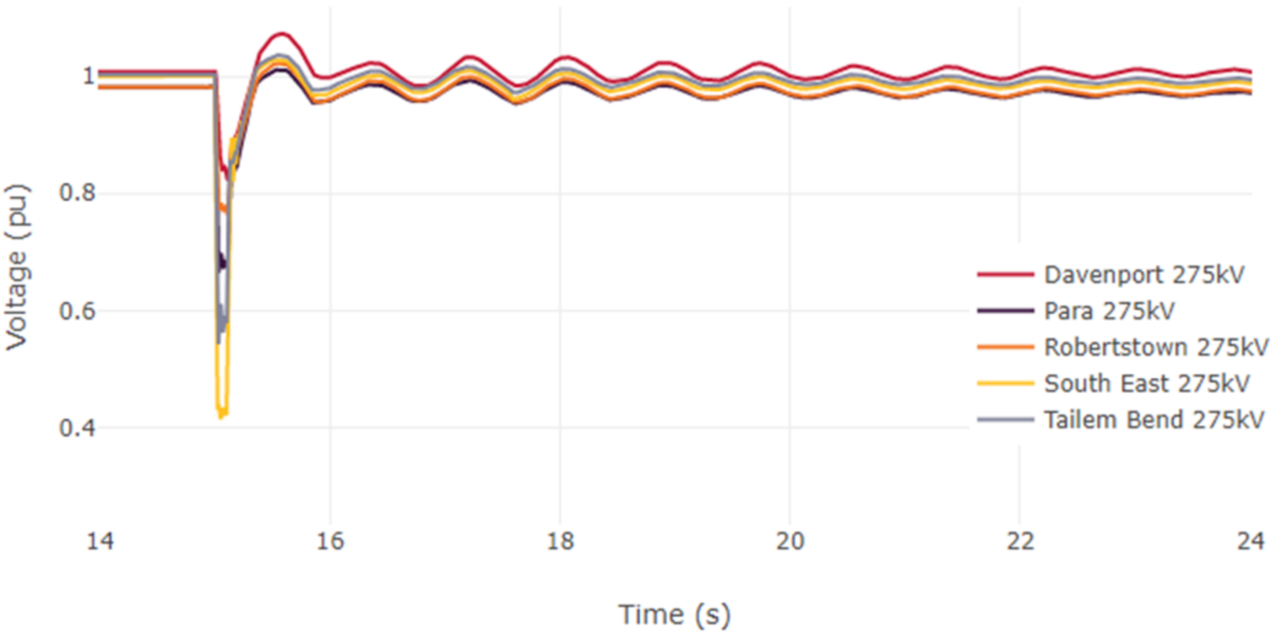
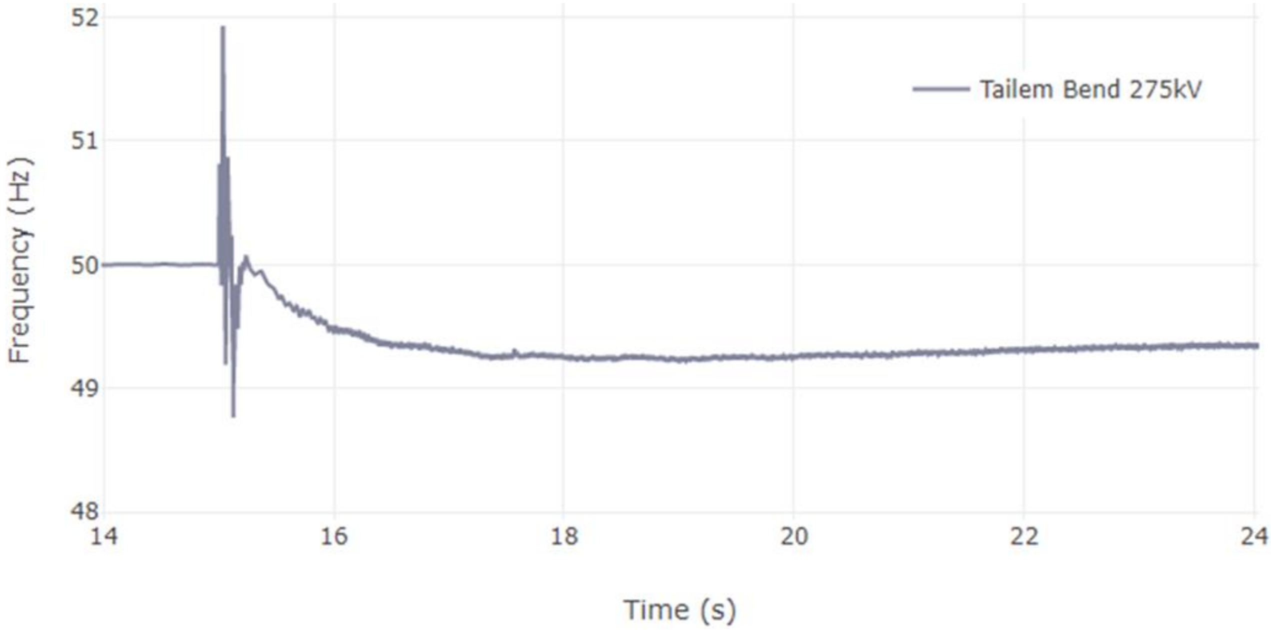
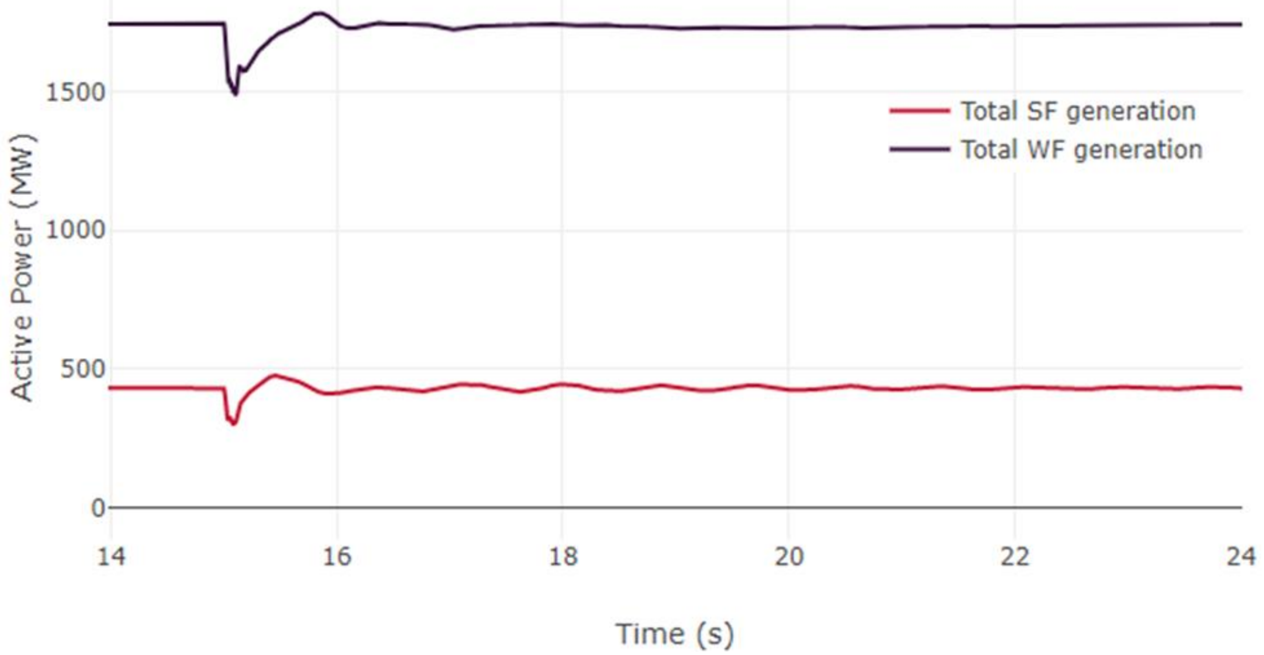


Figure 54 Frequency – loss of HIC during import of 180 MW to SA (prior outage of 1 Para SVC)



*Note: during the disturbance and clearance, the large variation in frequency transient is due to the way PSCAD[TM] estimates frequency using zero crossing approach, however this initial variation may be ignored.

Figure 55 IBR active power – loss of HIC during import of 180 MW to SA (prior outage of 1 Para SVC)



A1.2 Operation of SA island

A1.2.1 Trip of Robertstown Unit 1

Figure 56 Network voltages – trip of Robertstown Unit 1 under SA island

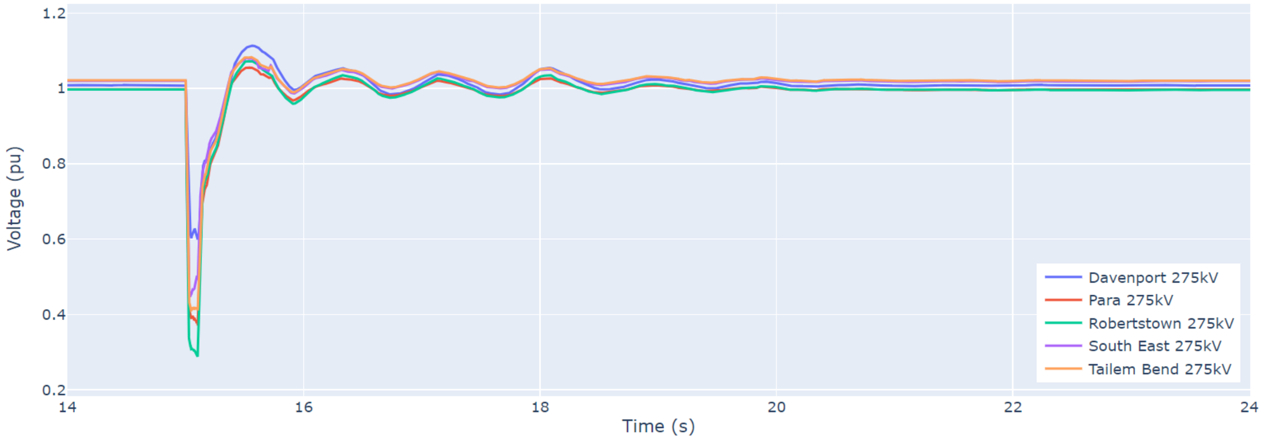
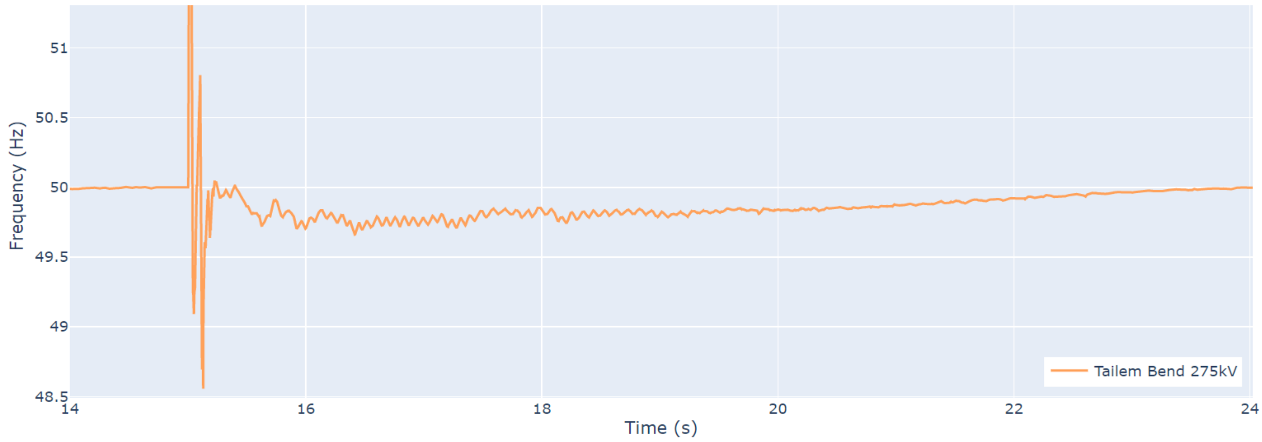
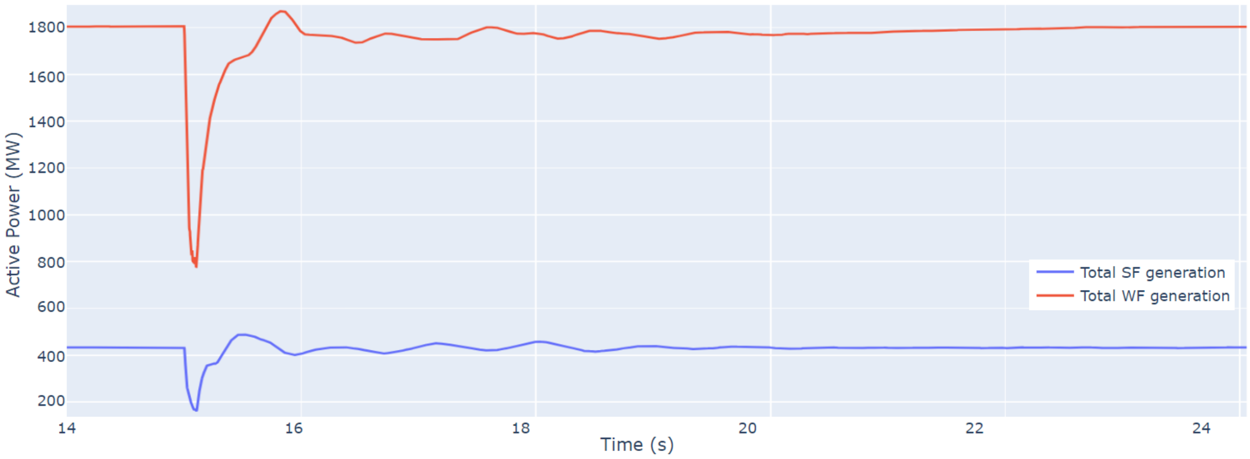


Figure 57 Frequency – trip of Robertstown Unit 1 under SA island



*Note: during the disturbance and clearance, the large variation in frequency transient is due to the way PSCAD^{TM} estimates frequency using zero crossing approach, however this initial variation may be ignored.

Figure 58 IBR active power – trip of Robertstown Unit 1 under SA island



A1.2.2 Trip of a solar farm

Figure 59 Network voltages – trip of a solar farm under SA island

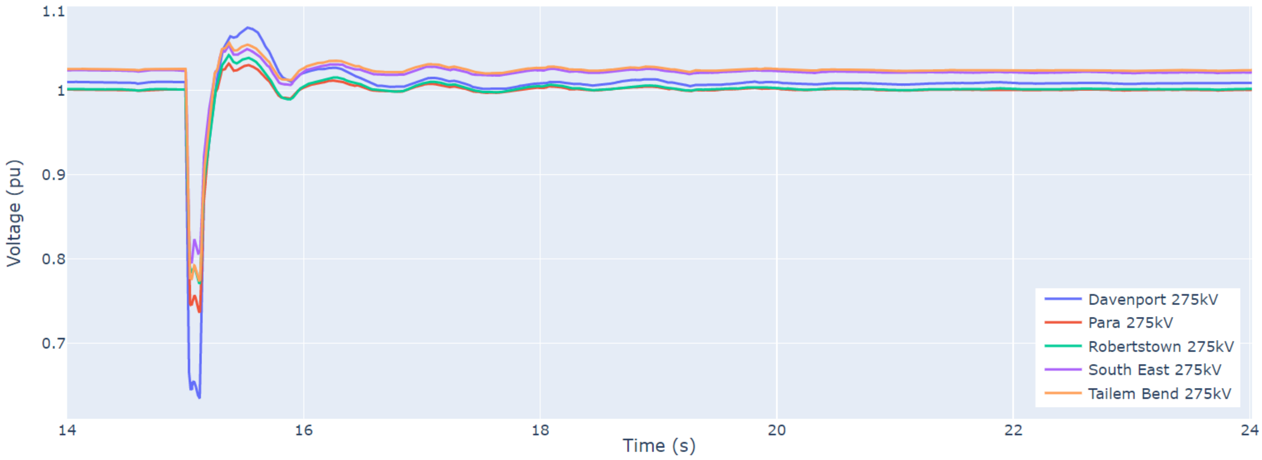
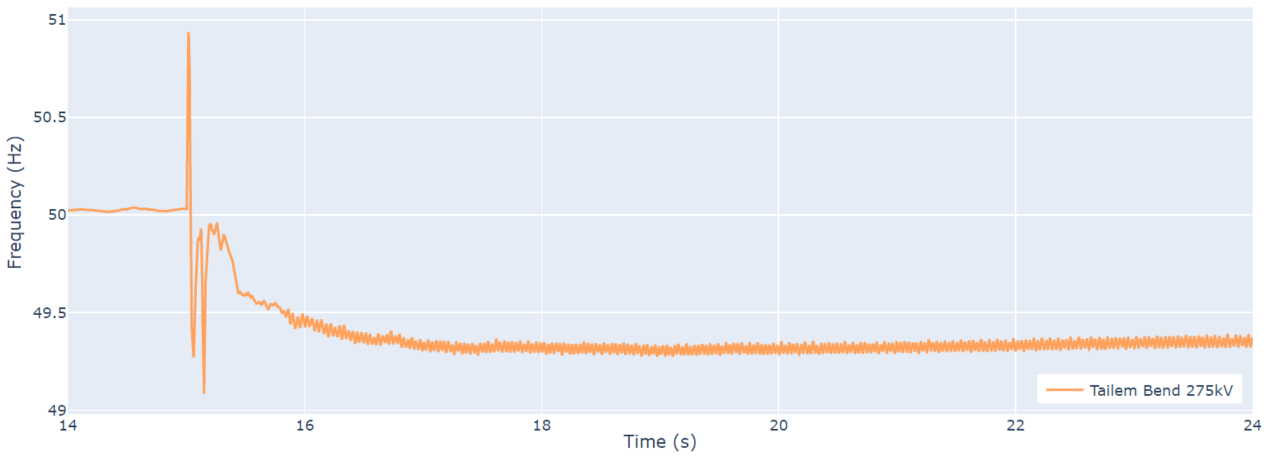
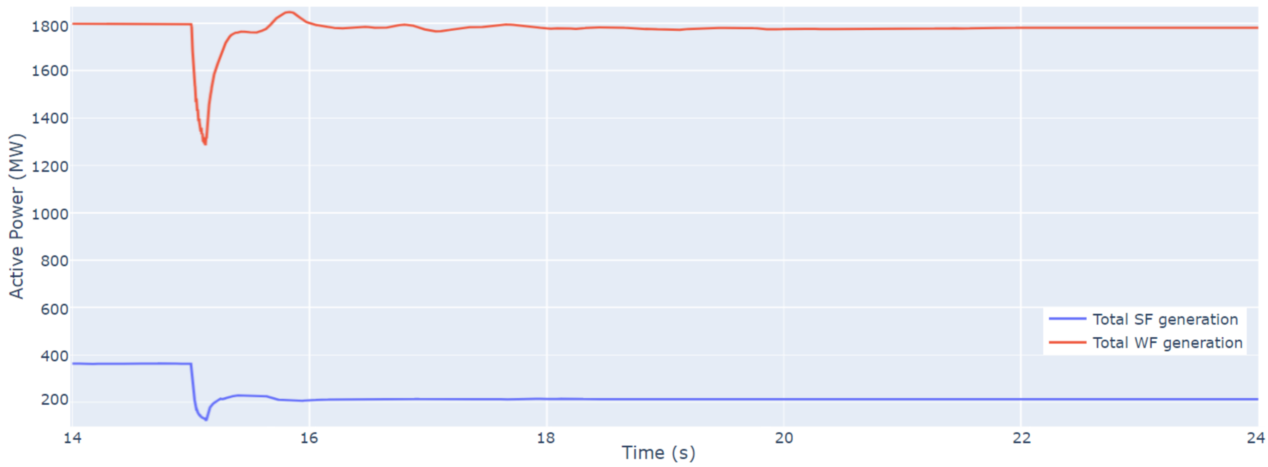


Figure 60 Frequency – trip of a solar farm under SA island



*Note: during the disturbance and clearance, the large variation in frequency transient is due to the way PSCAD^{TM} estimates frequency using zero crossing approach, however this initial variation may be ignored.

Figure 61 IBR active power – trip of a solar farm under SA island



A1.2.3 Trip of a wind farm

Figure 62 Network voltages – trip of a wind farm under SA island

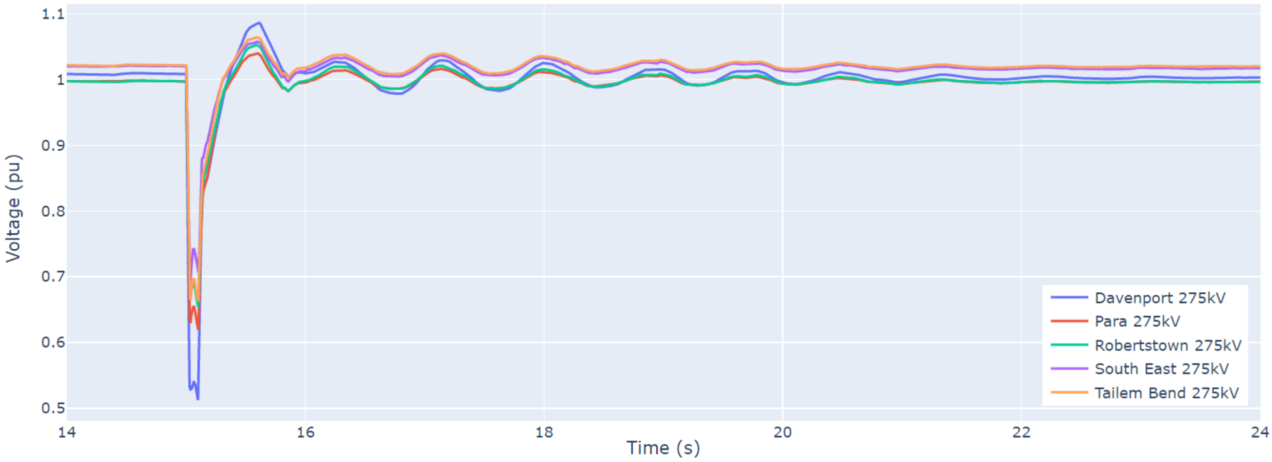
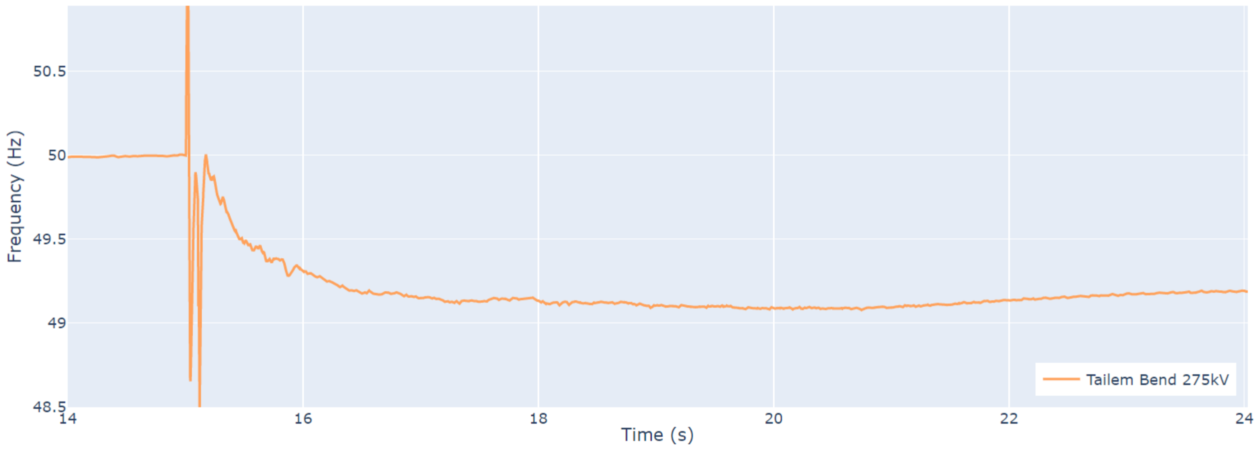
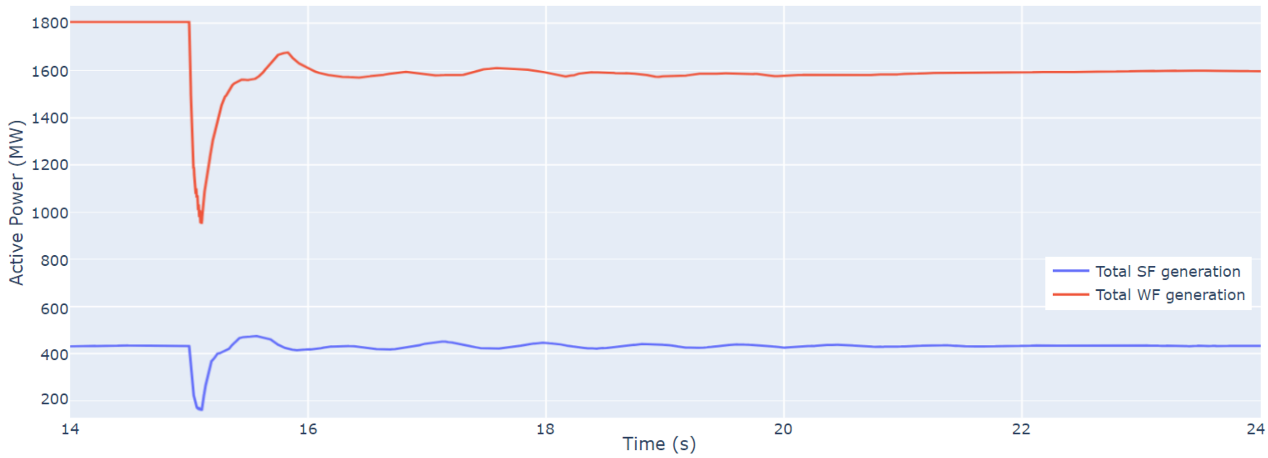


Figure 63 Frequency – trip of a wind farm under SA island



*Note: during the disturbance and clearance, the large variation in frequency transient is due to the way PSCAD™ estimates frequency using zero crossing approach, however this initial variation may be ignored.

Figure 64 IBR active power – trip of a wind farm under SA island



A1.2.4 Trip of Olympic Dam load

Figure 65 Network voltages – trip of Olympic Dam load under SA island

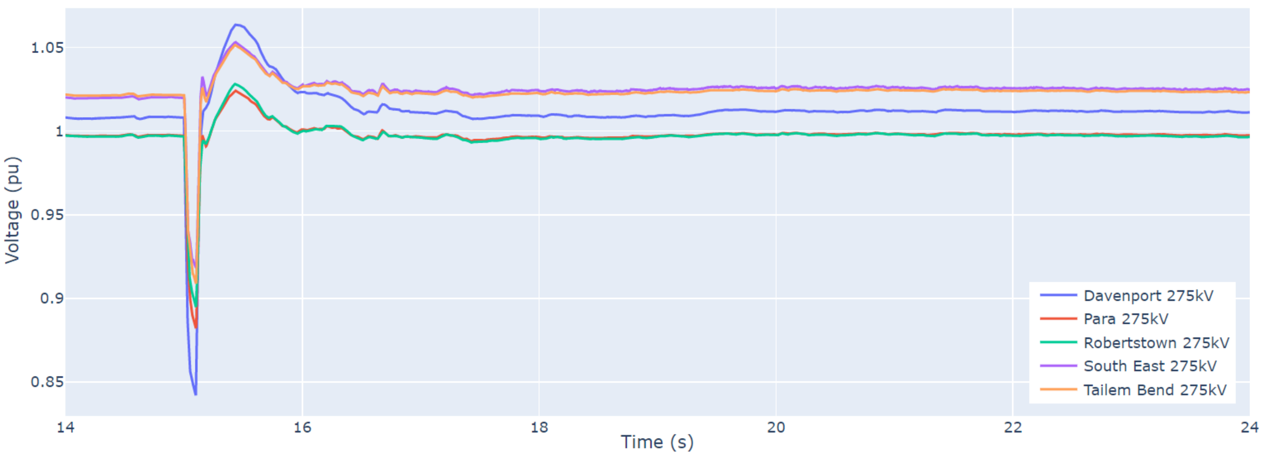
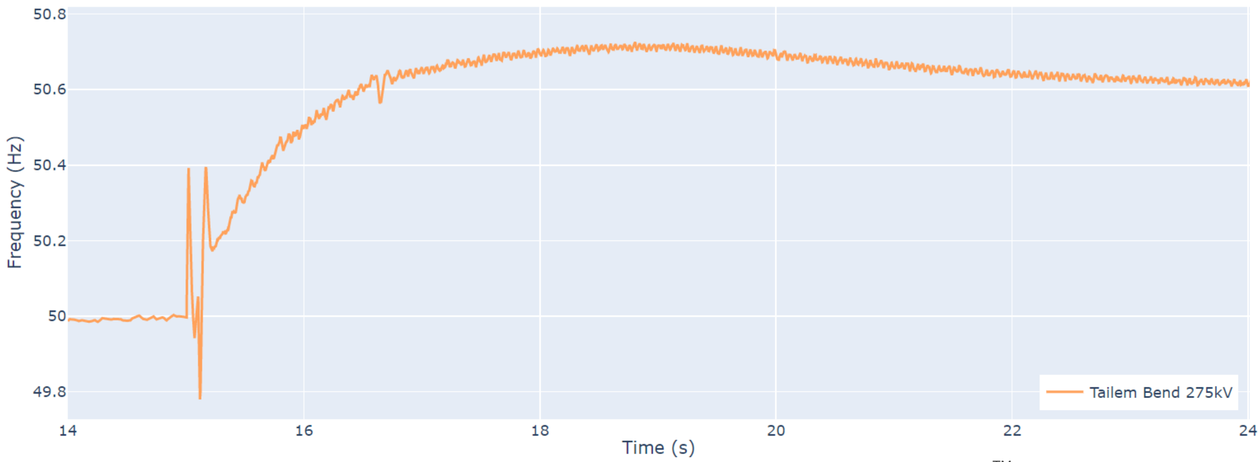
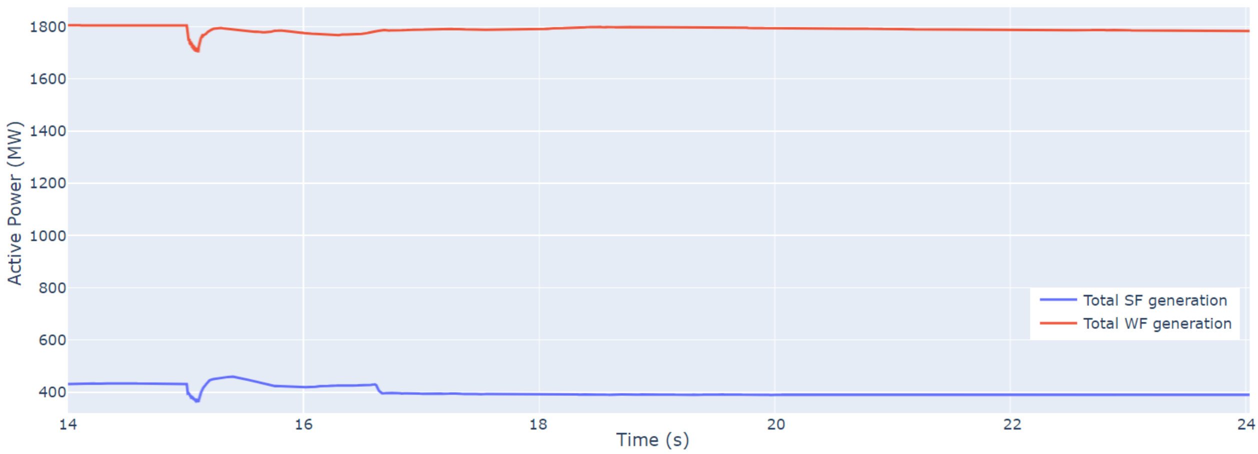


Figure 66 Frequency – trip of Olympic Dam load under SA island



*Note: during the disturbance and clearance, the large variation in frequency transient is due to the way PSCAD™ estimates frequency using zero crossing approach, however this initial variation may be ignored.

Figure 67 IBR active power – trip of Olympic Dam load under SA island



A1.2.5 Trip of a transmission line

Figure 68 Network voltages – trip of a transmission line under SA island

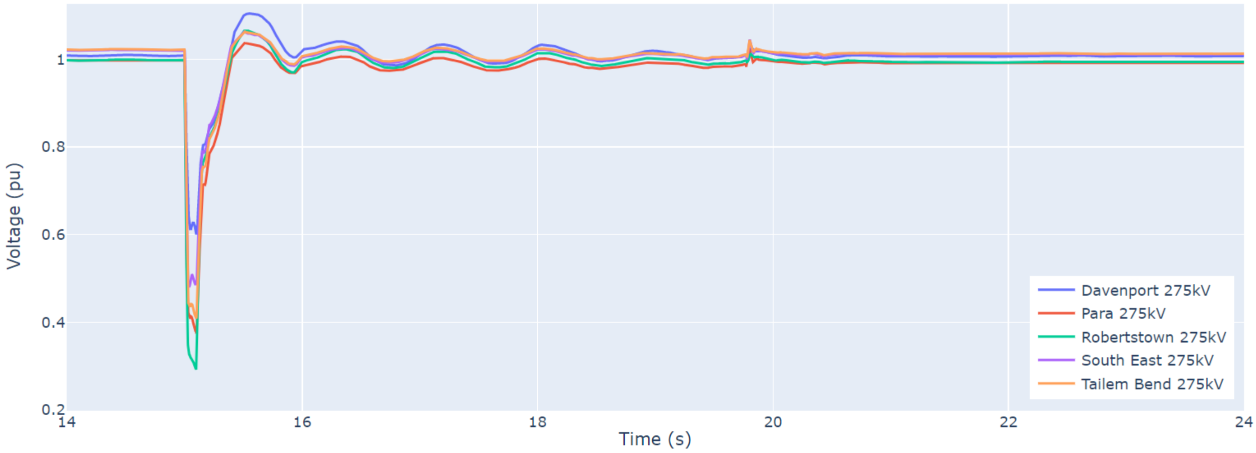
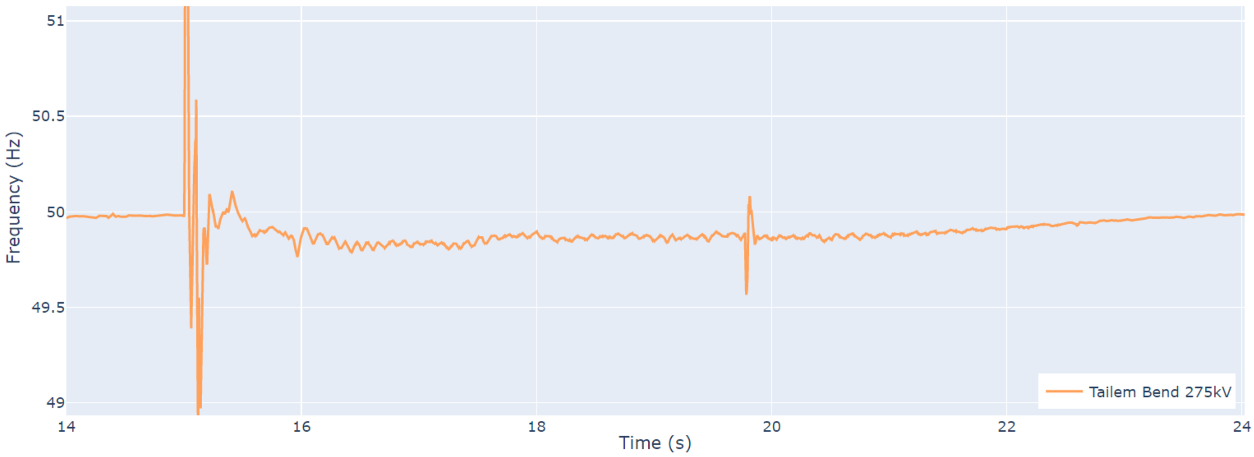
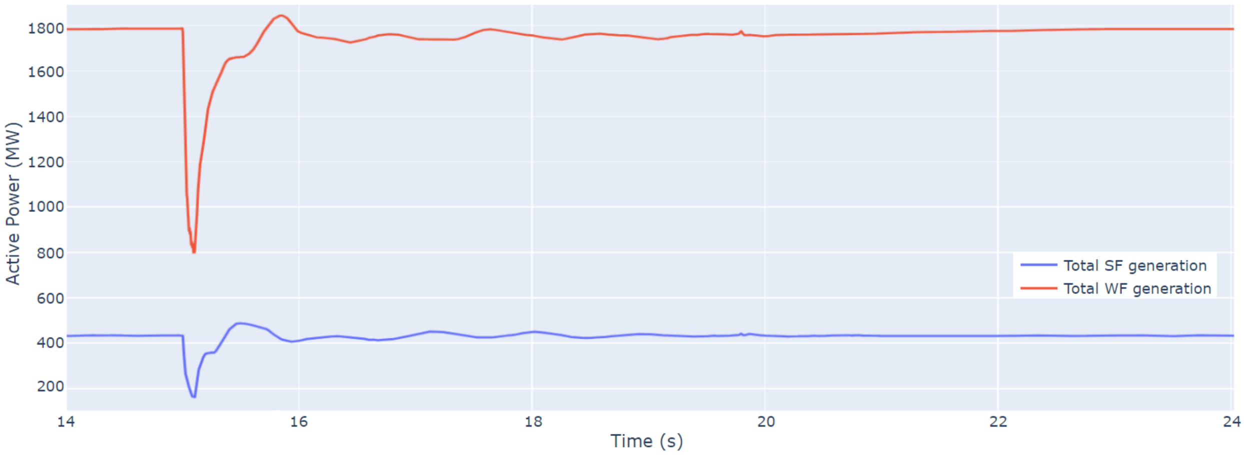


Figure 69 Frequency – trip of a transmission line under SA island



*Note: during the disturbance and clearance, the large variation in frequency transient is due to the way PSCAD™ estimates frequency using zero crossing approach, however this initial variation may be ignored.

Figure 70 IBR active power – trip of a transmission line under SA island



A1.2.6 Trip of distributed PV

Figure 71 Network voltages – trip of distributed PV under SA island

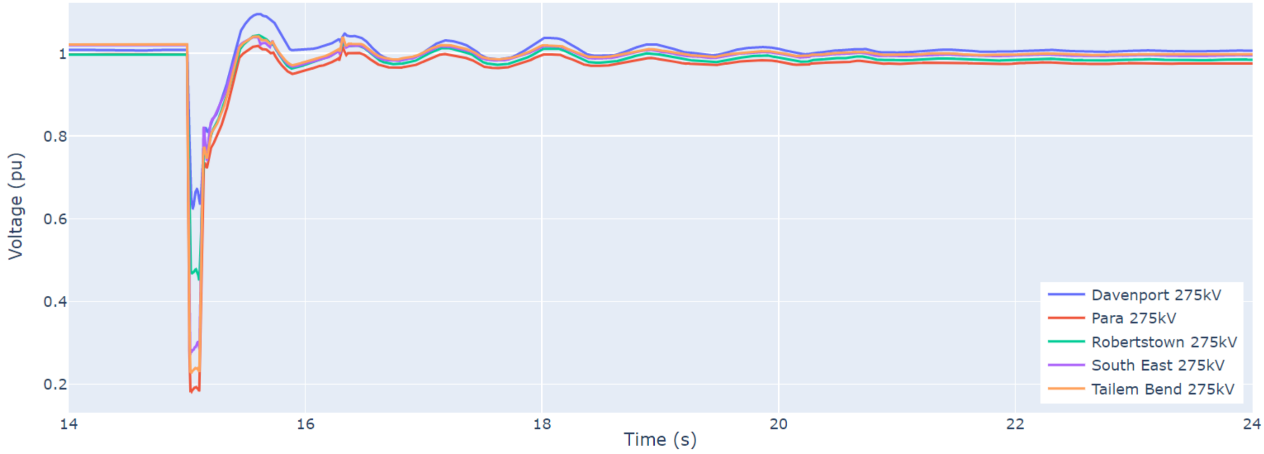
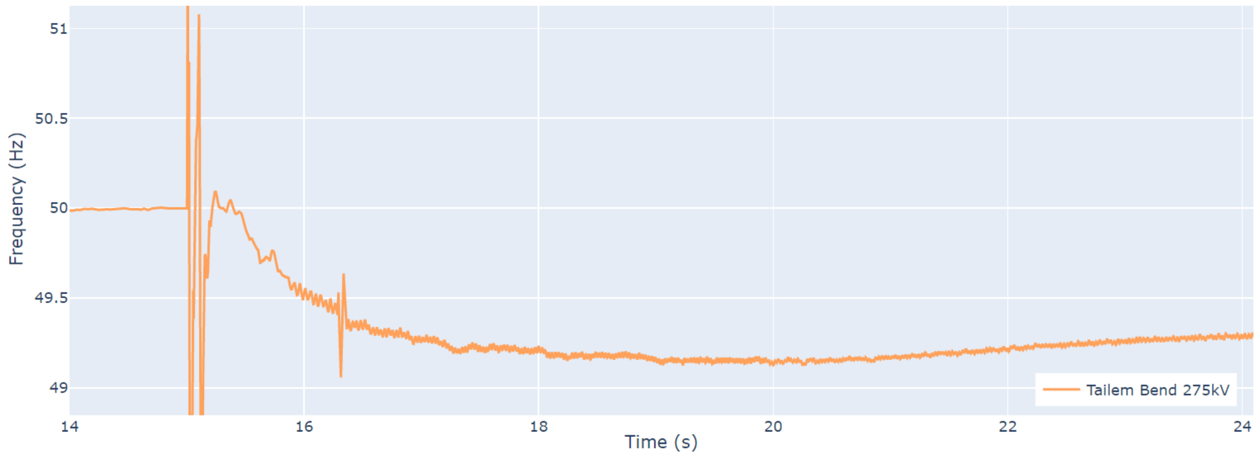
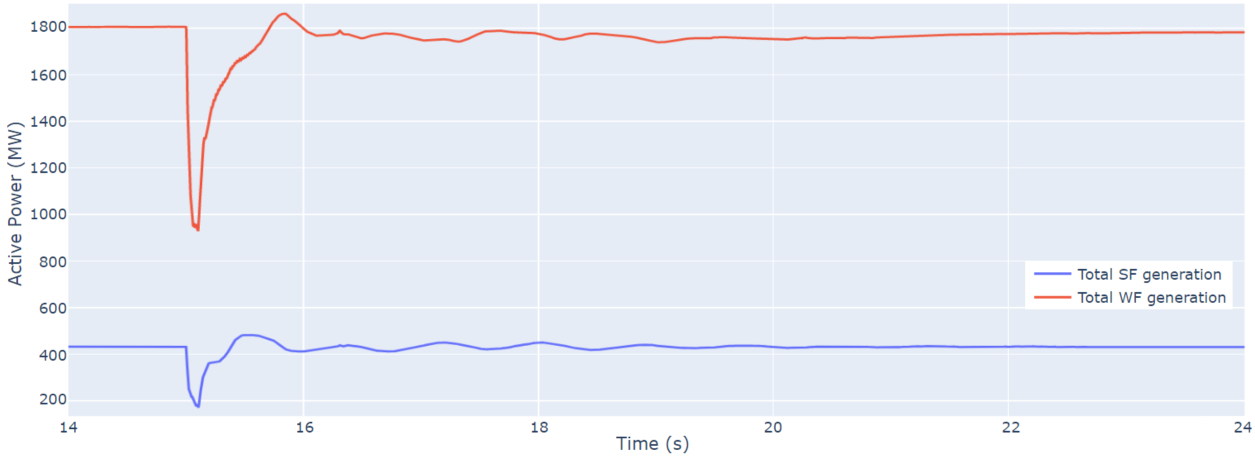


Figure 72 Frequency – trip of distributed PV under SA island



*Note: during the disturbance and clearance, the large variation in frequency transient is due to the way PSCAD™ estimates frequency using zero crossing approach, however this initial variation may be ignored.

Figure 73 IBR active power – trip of distributed PV under SA island



A1.2.7 Trip of one Para SVC

Figure 74 Network voltages – trip of one Para SVC under SA island

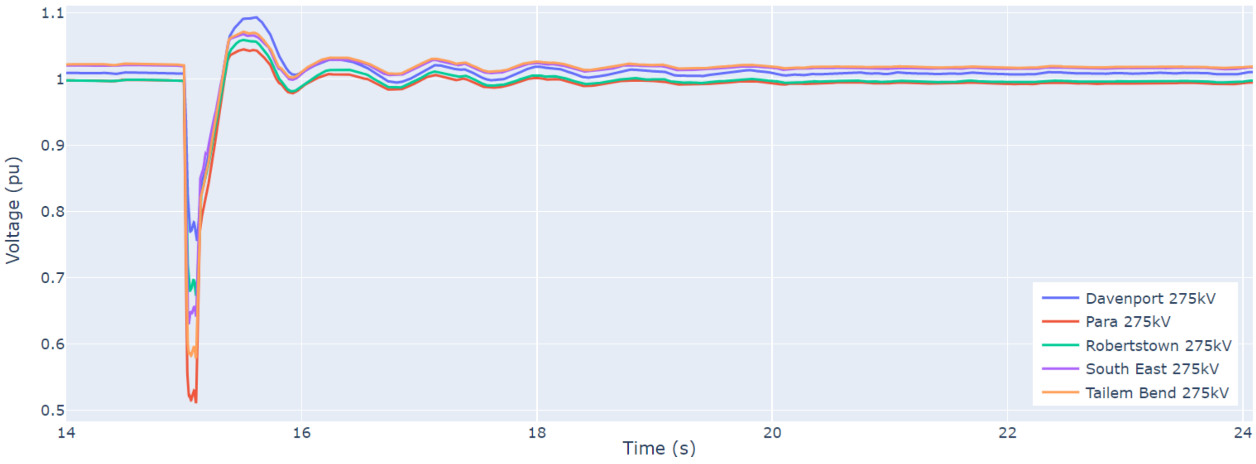
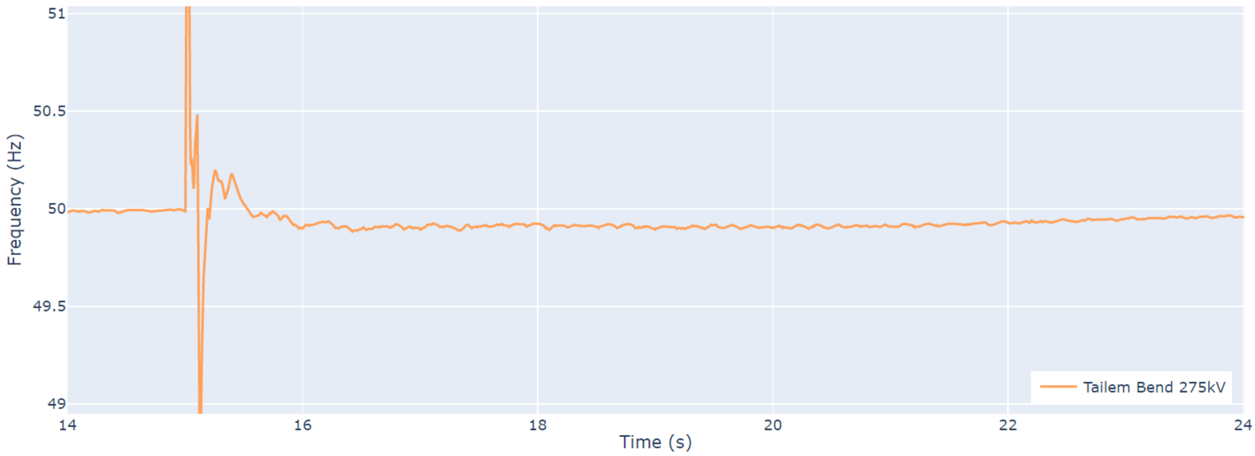
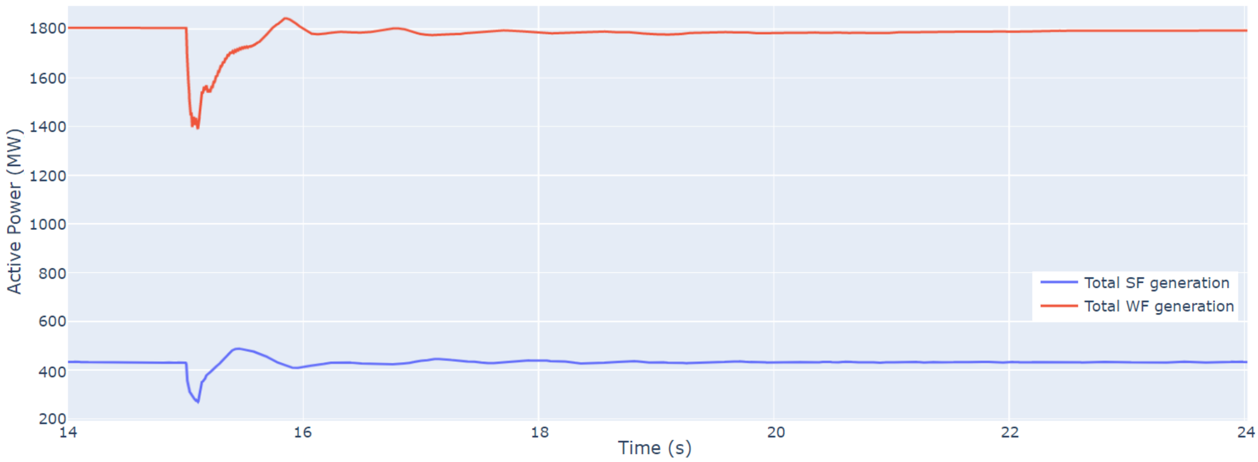


Figure 75 Frequency – trip of one Para SVC under SA island



*Note: during the disturbance and clearance, the large variation in frequency transient is due to the way PSCAD[TM] estimates frequency using zero crossing approach, however this initial variation may be ignored.

Figure 76 IBR active power – trip of one Para SVC under SA island



A1.2.8 Trip of one South-East SVC

Figure 77 Network voltages – trip of one South-East SVC under SA island

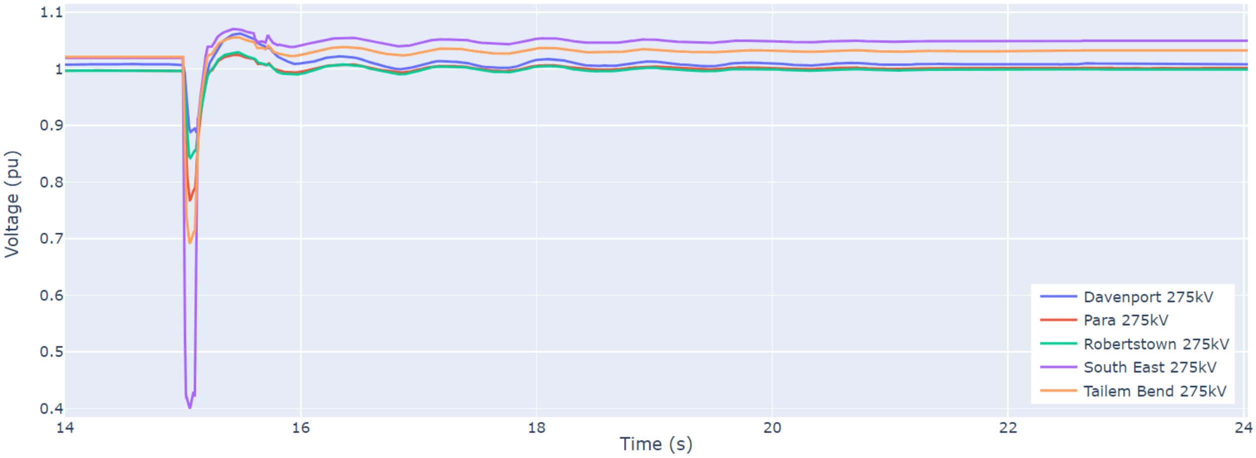
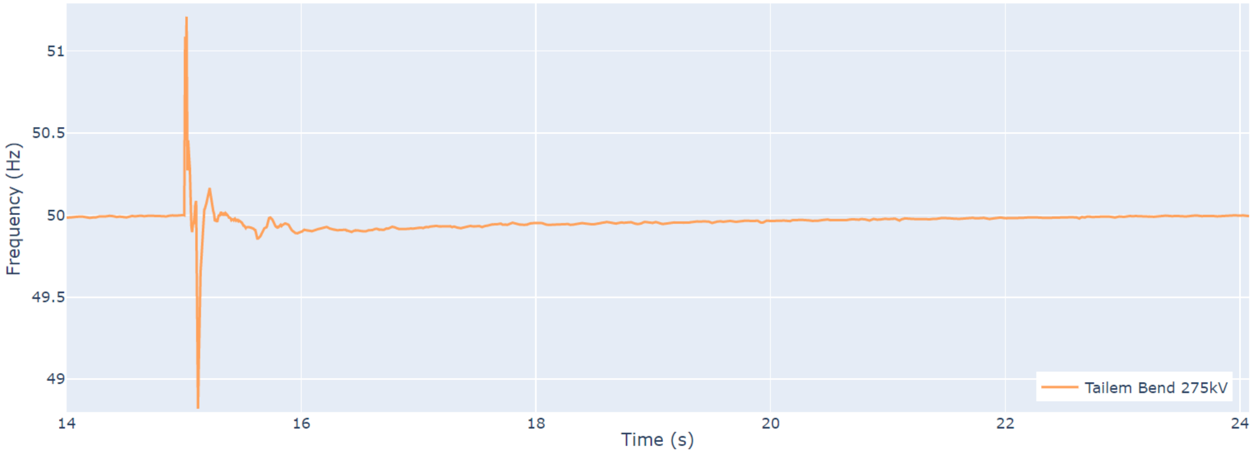
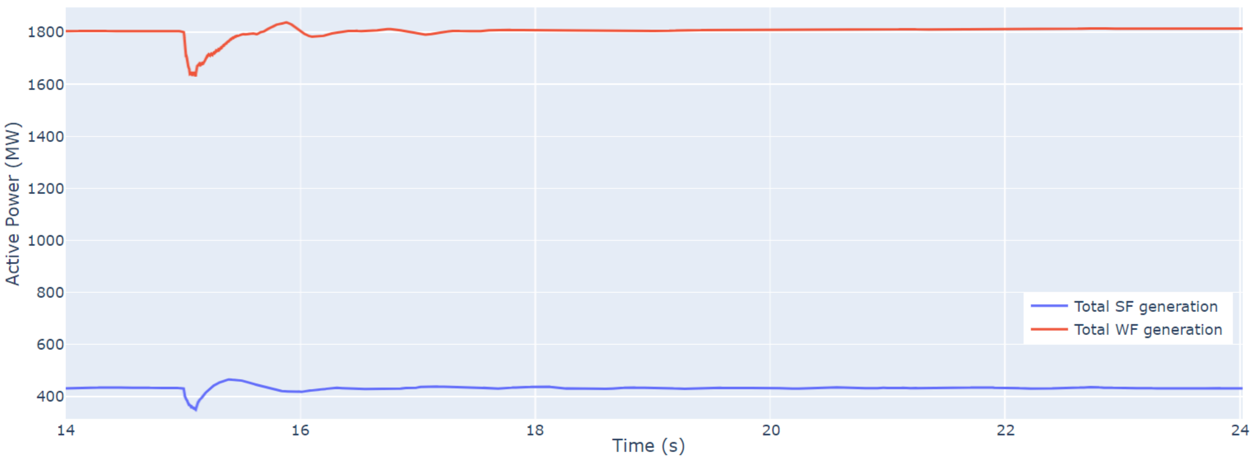


Figure 78 Frequency – trip of one South-East SVC under SA island



*Note: during the disturbance and clearance, the large variation in frequency transient is due to the way PSCAD^{TM} estimates frequency using zero crossing approach, however this initial variation may be ignored.

Figure 79 IBR active power – trip of one South-East SVC under SA island



A1.2.9 Trip of MLDC

Figure 80 Network voltages – trip of MLDC under SA island

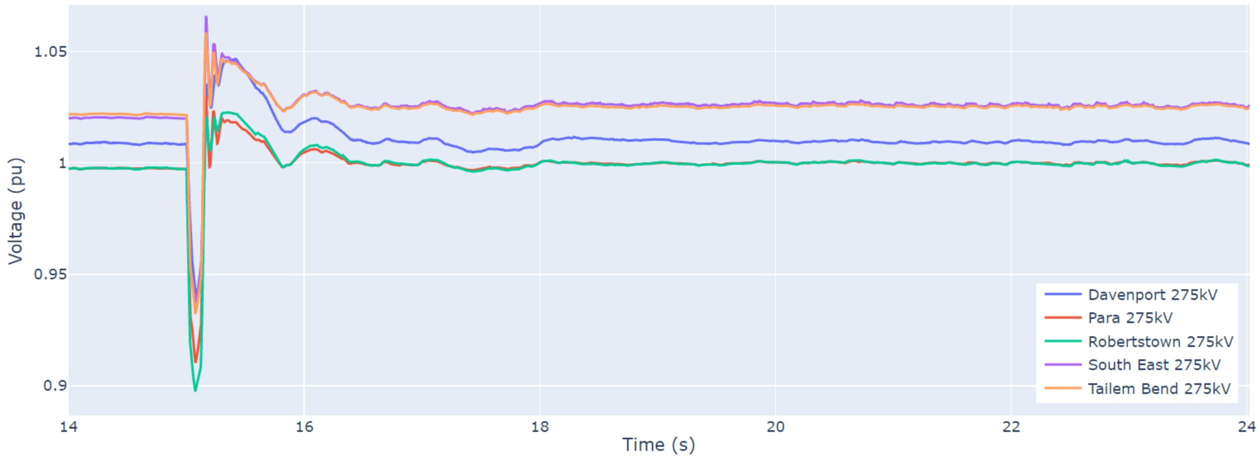
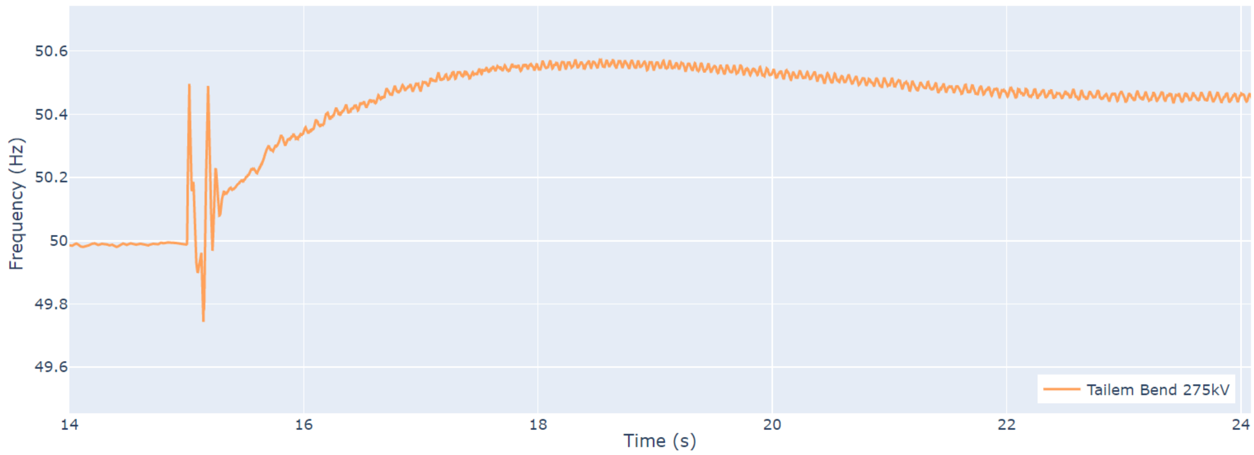
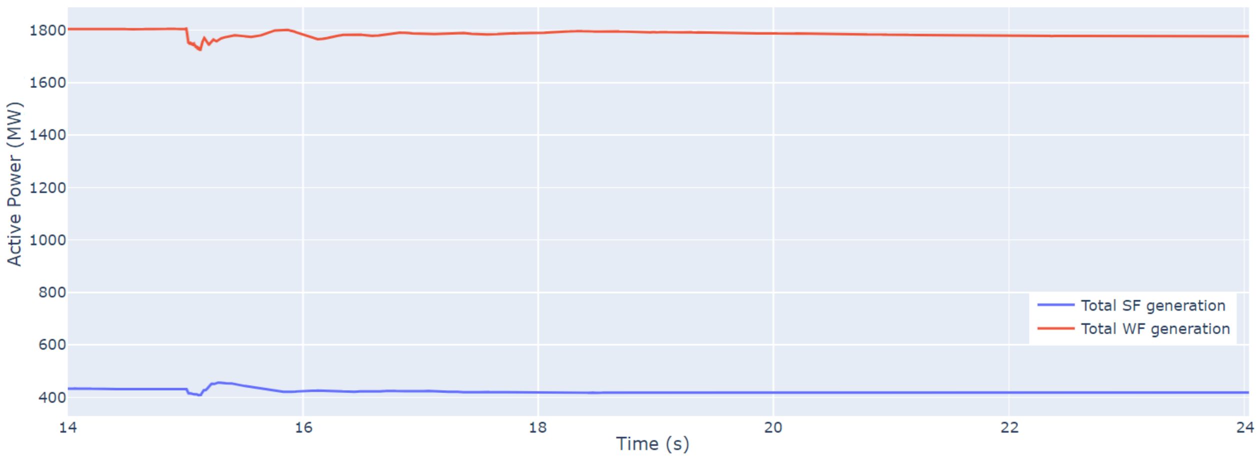


Figure 81 Frequency – trip of MLDC under SA island



*Note: during the disturbance and clearance, the large variation in frequency transient is due to the way PSCAD™ estimates frequency using zero crossing approach, however this initial variation may be ignored.

Figure 82 IBR active power – trip of MLDC under SA island



A2. RMS simulations

This section presents the results of the comparison between EMT (PSCAD™/EMTDC™) and RMS (PSS®E) simulations for the scenario studied in Section 4.1.2, with loss of HIC (at 15 seconds) during import conditions and zero synchronous generating units available online in SA. As can be inferred from the plots below, the RMS and EMT tools result in quite similar response. Most importantly, the notion of grid reference was also proved using RMS tools with zero synchronous generators available online in SA.

Figure 83 RMS and EMT simulation response for BESS and HIC active power

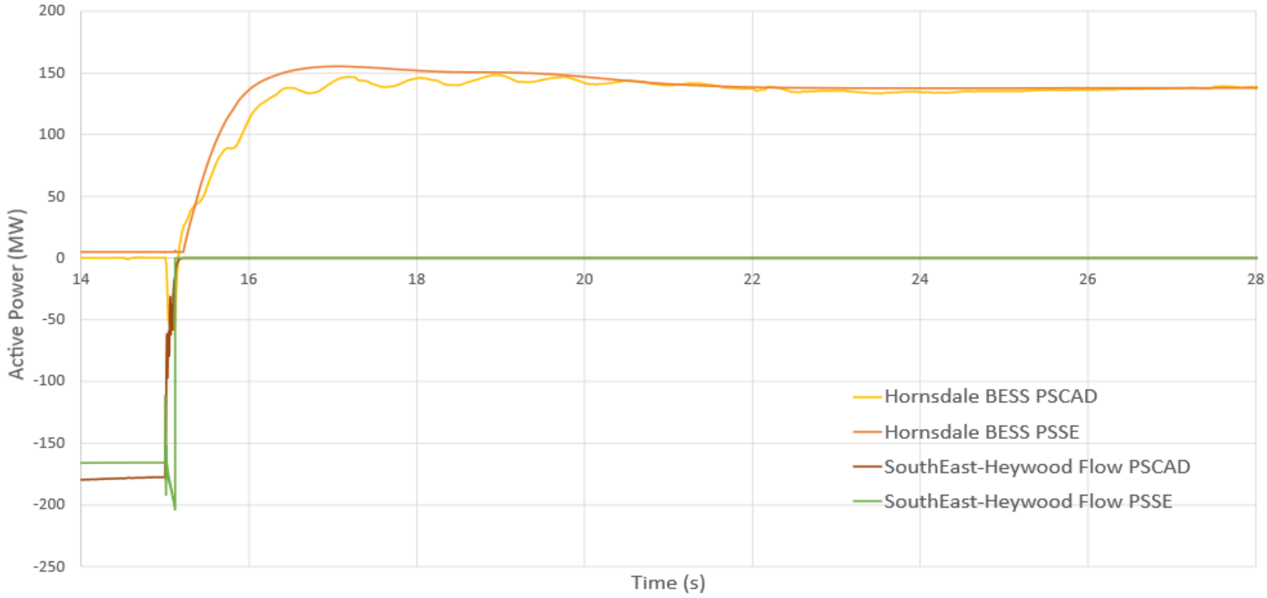


Figure 84 RMS and EMT simulation response of frequency and syncon speed

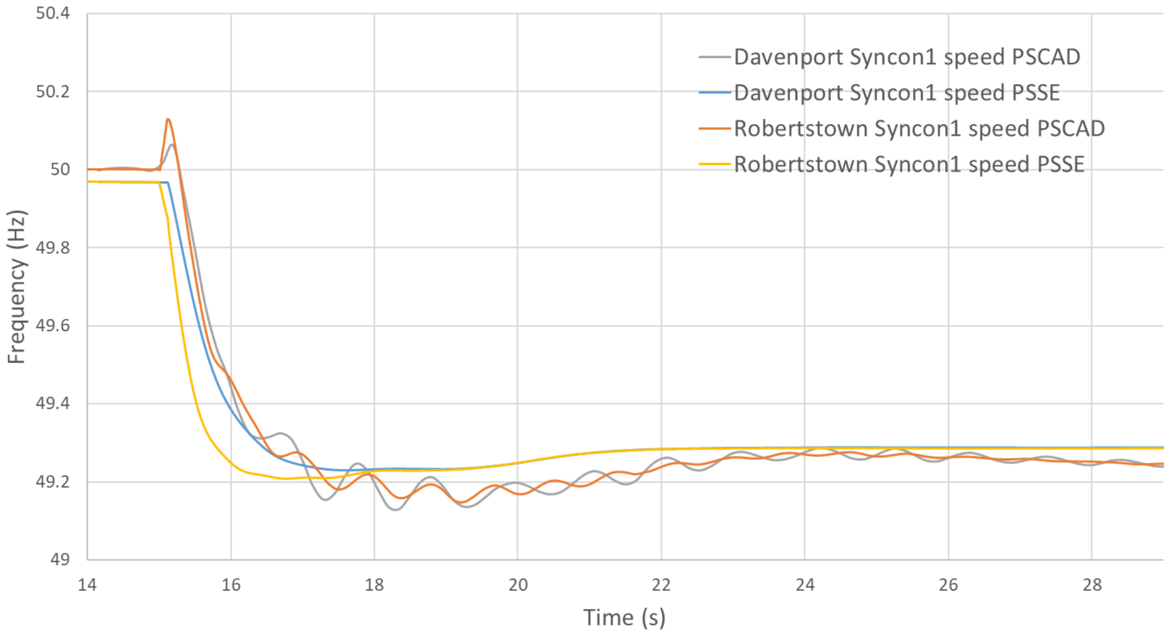


Figure 85 RMS and EMT simulation response of syncon active power response

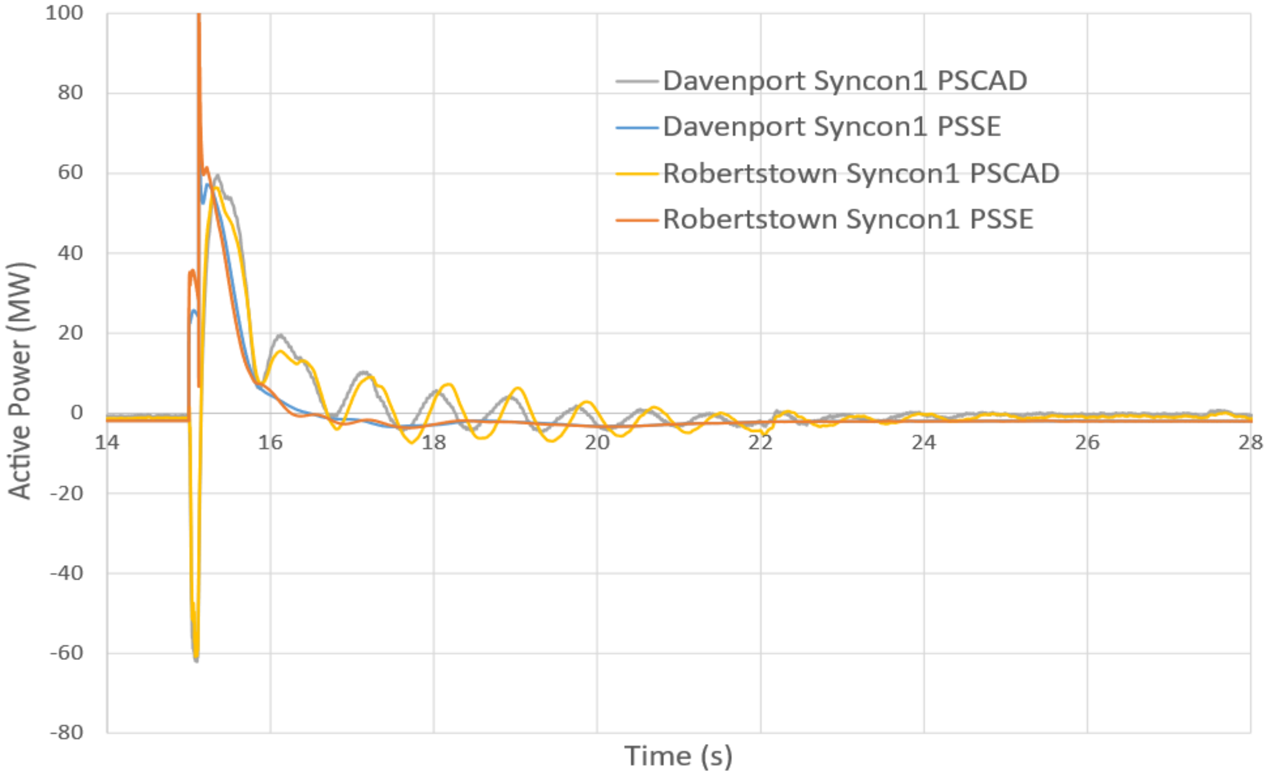


Figure 86 RMS and EMT simulation response of syncon reactive power response

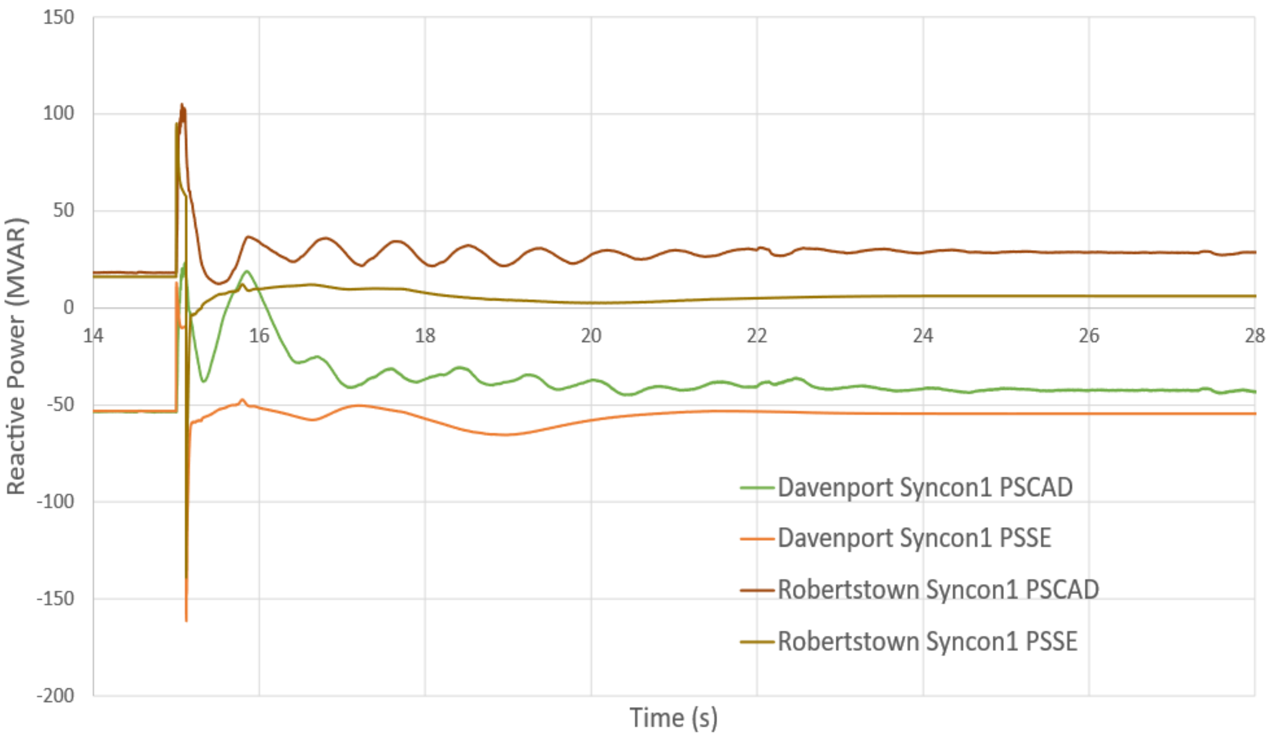
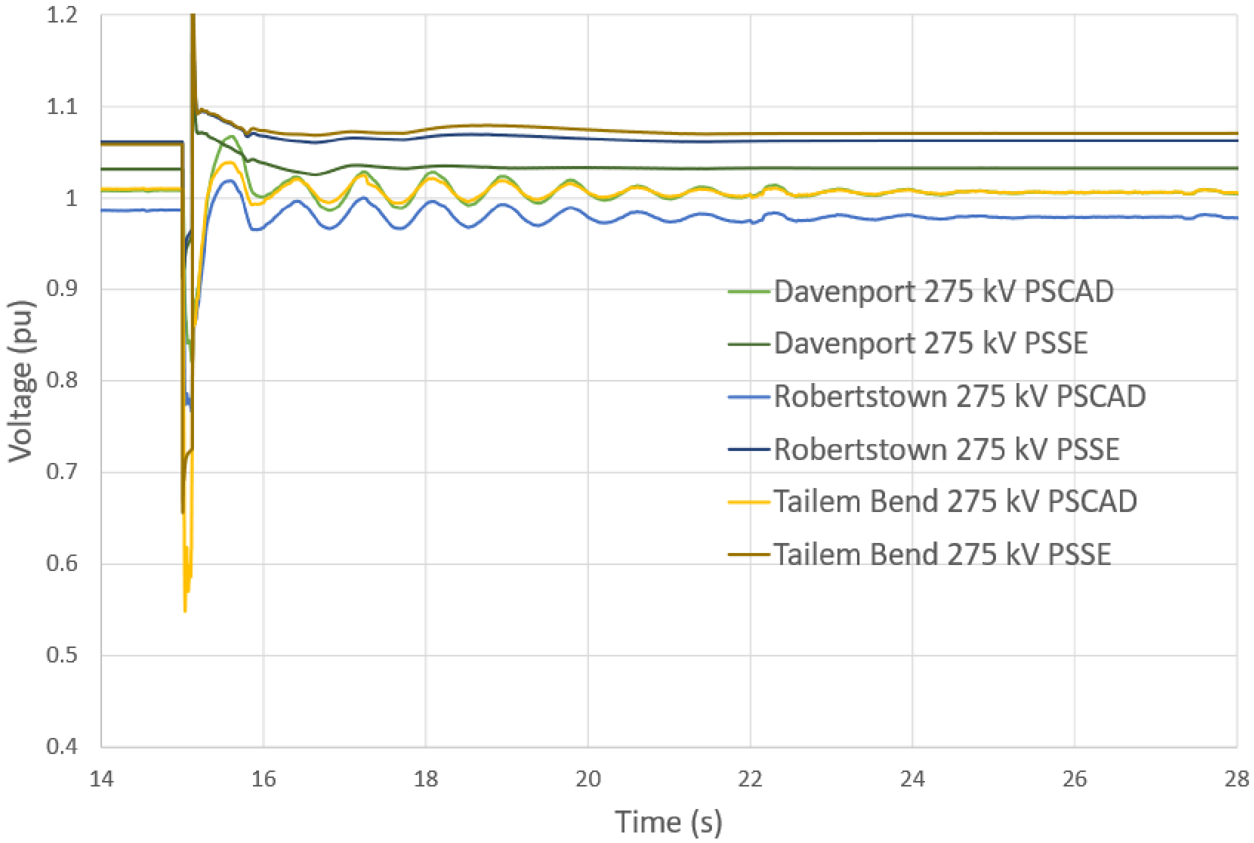


Figure 87 RMS and EMT simulation response of SA network voltages following HIC separation



A3. Additional sensitivity

A3.1 Effect of 50 MW load ramping in 3 seconds – SA island operation

Figure 88 Network voltages – effect of 50 MW load ramping in 3 s under SA island

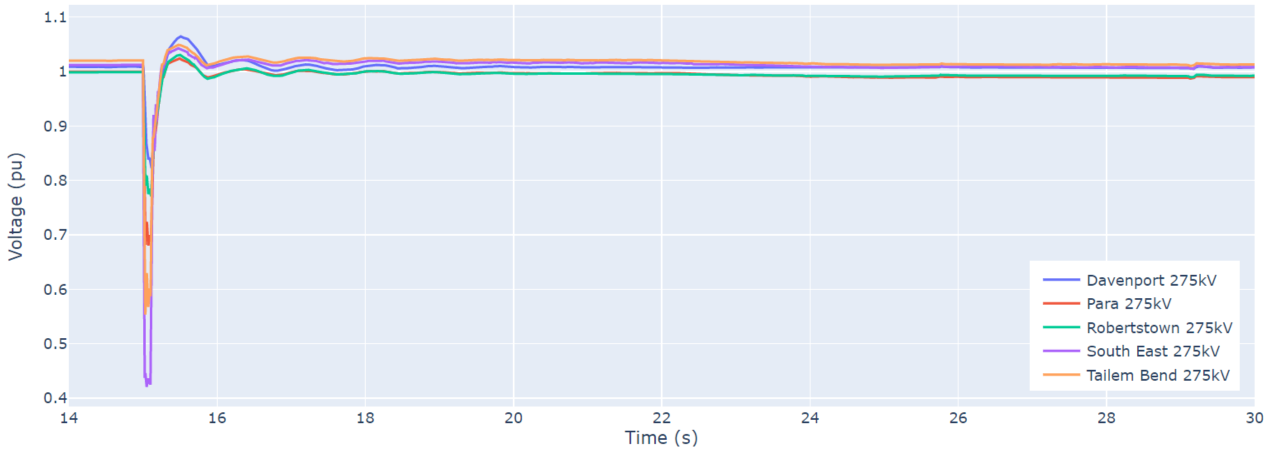
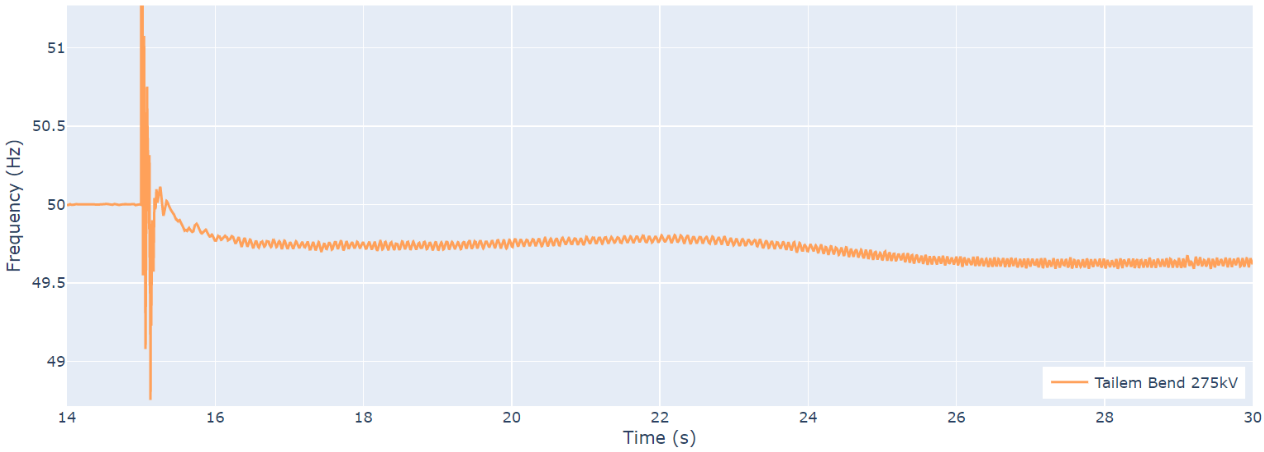
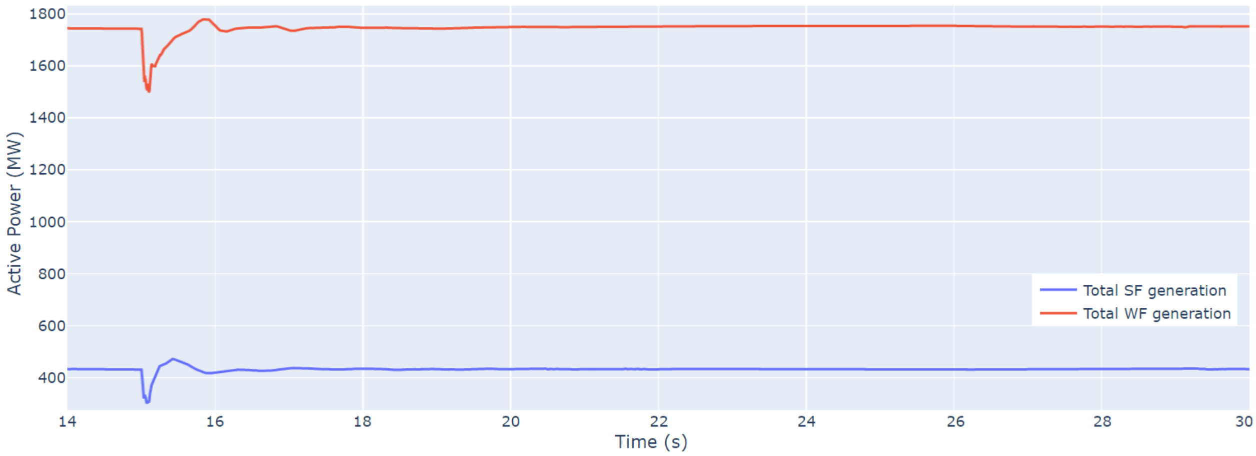


Figure 89 Frequency – effect of 50 MW load ramping in 3 s under SA island



*Note: during the disturbance and clearance, the large variation in frequency transient is due to the way PSCAD™ estimates frequency using zero crossing approach, however this initial variation may be ignored.

Figure 90 IBR active power – effect of 50 MW load ramping in 3 s under SA island



A3.2 Effect of dynamic load modelling assumptions

Induction motors (using the PSCAD™ generic library) were modelled at Morgan – Whyalla Pipeline pumps (12 x 6 MVA) and also at Olympic Dam Load (4 x 6 MVA). The induction motors are started at 12 seconds, following which at 20 seconds the Davenport syncon is tripped. However, as seen in the results, the system holds together with acceptable response of network voltages (Figure 91), frequency(Figure 92) and IBR active power(Figure 93) and the case does not collapse.

Figure 91 Network voltages – effect dynamic load modelling assumptions under SA island

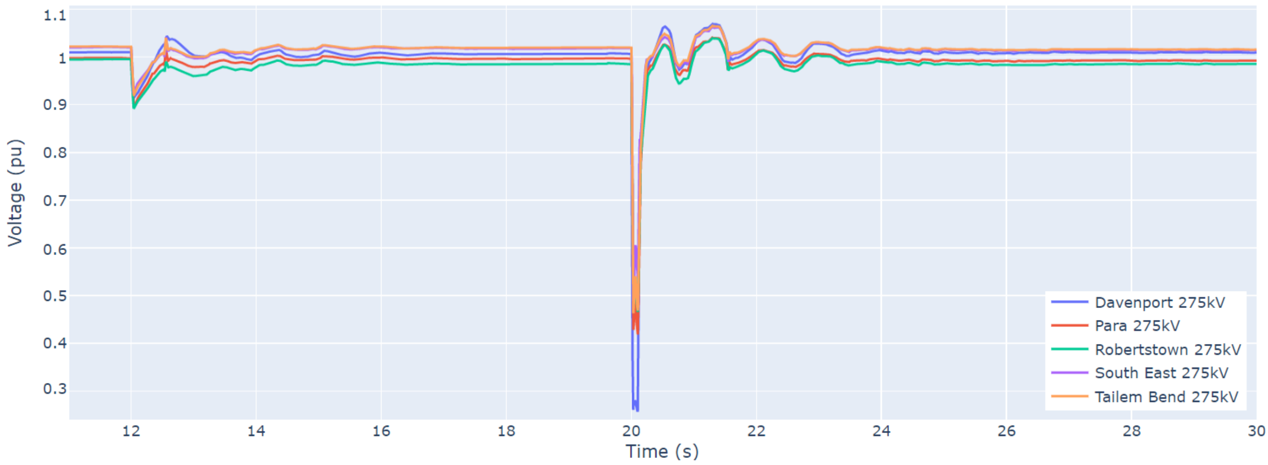
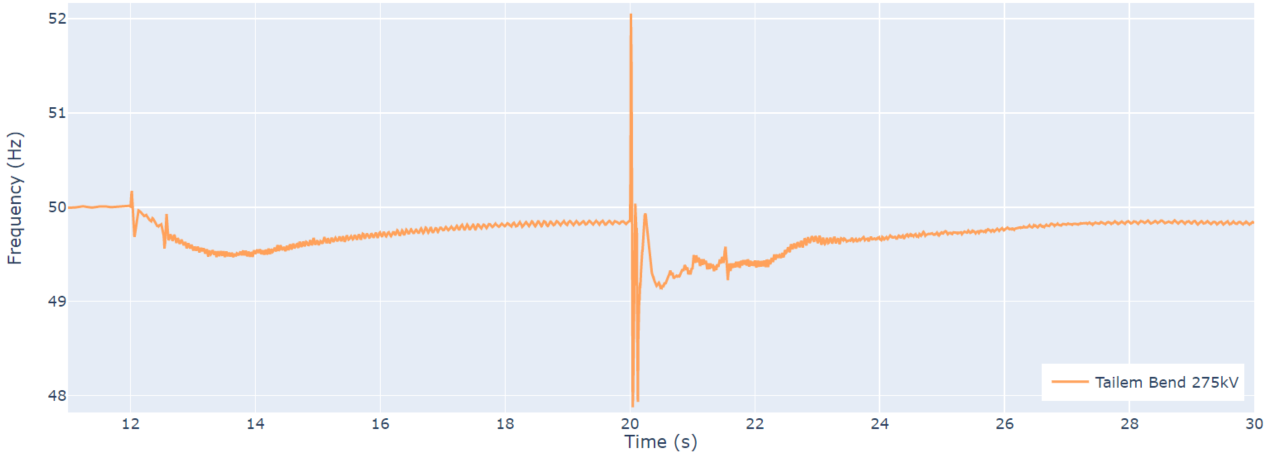
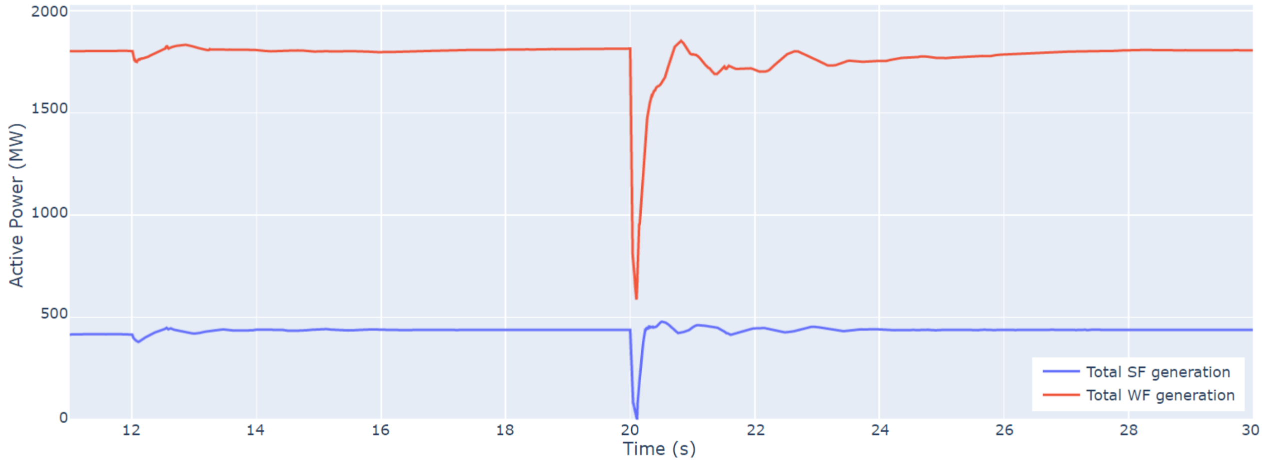


Figure 92 Frequency – effect dynamic load modelling assumptions under SA island



*Note: during the disturbance and clearance, the large variation in frequency transient is due to the way PSCAD™ estimates frequency using zero crossing approach, however this variation may be ignored.

Figure 93 IBR active power – effect dynamic load modelling assumptions under SA island



A3.3 Sensitivity studies with the conceptual 2-bus test system

To assess the sensitivity of syncons in the absence of synchronous generation, sensitivity studies have been carried out using the conceptual 2-bus test system. Two aspects were investigated:

1. Sensitivity to the ratio of syncon size to IBR size.
2. Sensitivity to the series impedance between syncon and IBR.

The results are presented in Table 8 and Table 9 for Robertstown syncon and Davenport syncon, respectively. The test carried out for each cell was disconnecting the voltage source at $t=t_0$ while the active and reactive power generation by the voltage source is very close to zero. The FAIL cases are the ones in which the IBR has gone unstable post disconnection of the voltage source, or the voltage has collapsed. In the PASS cases, the IBR remained stable after disconnecting the voltage source. The results indicate that the size of the syncons (MVA size) needed for stable operation of the power system for a given MW of IBR generation, increases as the system becomes weak (5 x series line impedance). However, in a strong system (1 x series line impedance), IBR up to 3.0 times[26] the size of the syncon can be hosted successfully.

Table 8 Impact of MVA ratio of IBR to SC and series impedance of the line – Robertstown syncon

1 x line impedance = 0.0152 + j0.108 p.u.					
MVA ratio of IBR to syncon	**1 x line**	**2 x line**	**3 x line**	**4 x line**	**5 x line**
1.032	PASS	PASS	PASS	PASS	FAIL
2.064	PASS	PASS	PASS	FAIL	FAIL
3.096	PASS	FAIL	FAIL	FAIL	FAIL
4.128	FAIL	FAIL	FAIL	FAIL	FAIL

Table 9 Impact of MVA ratio of IBR to SC and series impedance of the line – Davenport syncon

1 x line impedance: 0.0152 + j0.108 p.u.							
MVA ratio of IBR to syncon	**1 x line**	**2 x line**	**3 x line**	**4 x line**	**8 x line**	**10 x line**	**11 x line**
1.032	PASS	PASS	PASS	PASS	PASS	PASS	FAIL
2.064	PASS	PASS	PASS	FAIL	FAIL	FAIL	FAIL
3.096	PASS	FAIL	FAIL	FAIL	FAIL	FAIL	FAIL
4.128	FAIL	FAIL	FAIL	FAIL	FAIL	FAIL	FAIL

A3.3.1 Conceptual 2-bus test system with 1 x BESS and 1 x Robertstown Syncon

This section presents the results of the conceptual 2-bus test system described in Section 2.4, assuming 1 x BESS (using HPRx in grid following mode), 1 x Robertstown syncon, and the ideal voltage source which is used for initialisation only. Once the ideal voltage source was disconnected, a load disturbance of 30 MW was applied to the system at t =15 s, the network voltages and frequency do not collapse (see Figure 94 and Figure 95). Further, the frequency does not drift as in Section 4.4 owing to the superior frequency control capability of the BESS. The BESS active power output in Figure 96 can be seen ramping an additional 30 MW to supply the new demand in this system.

[26] While this ratio depends on the impedance of the line, this is a general observation based on the system investigated here.

Figure 94 Sensitivity test – network voltages in 2-bus test system with BESS and 1 x Robertstown syncon

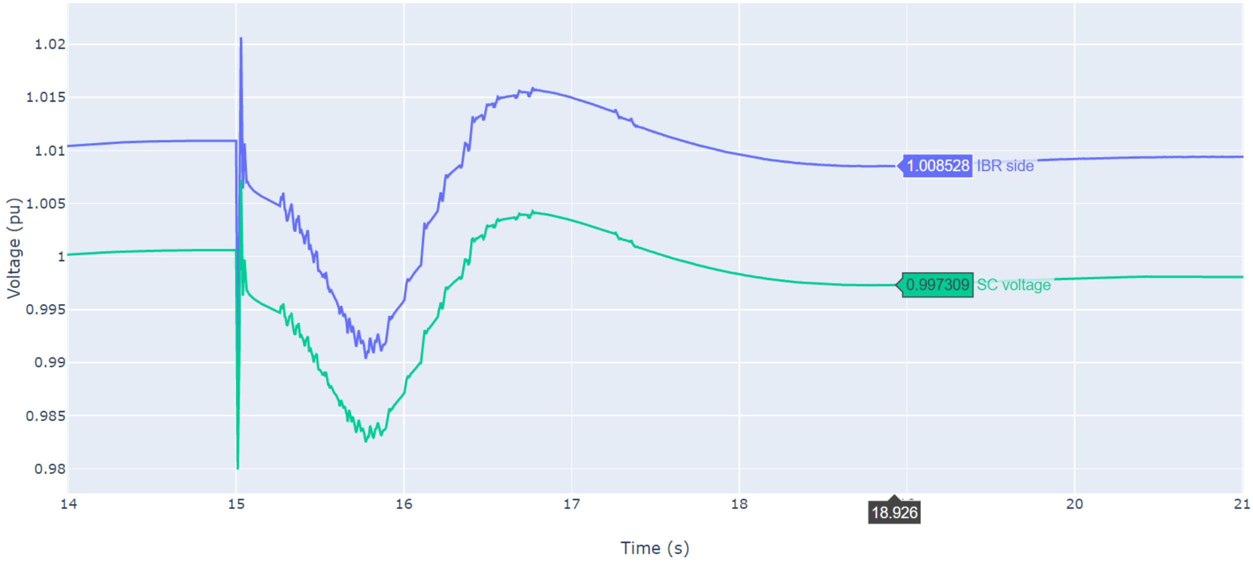
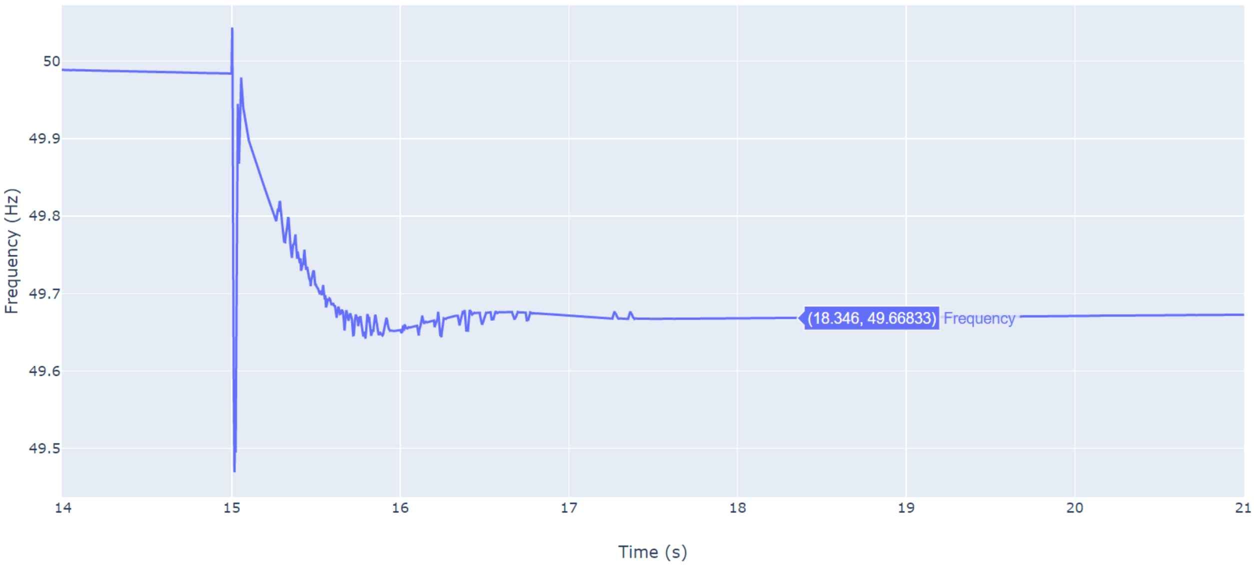
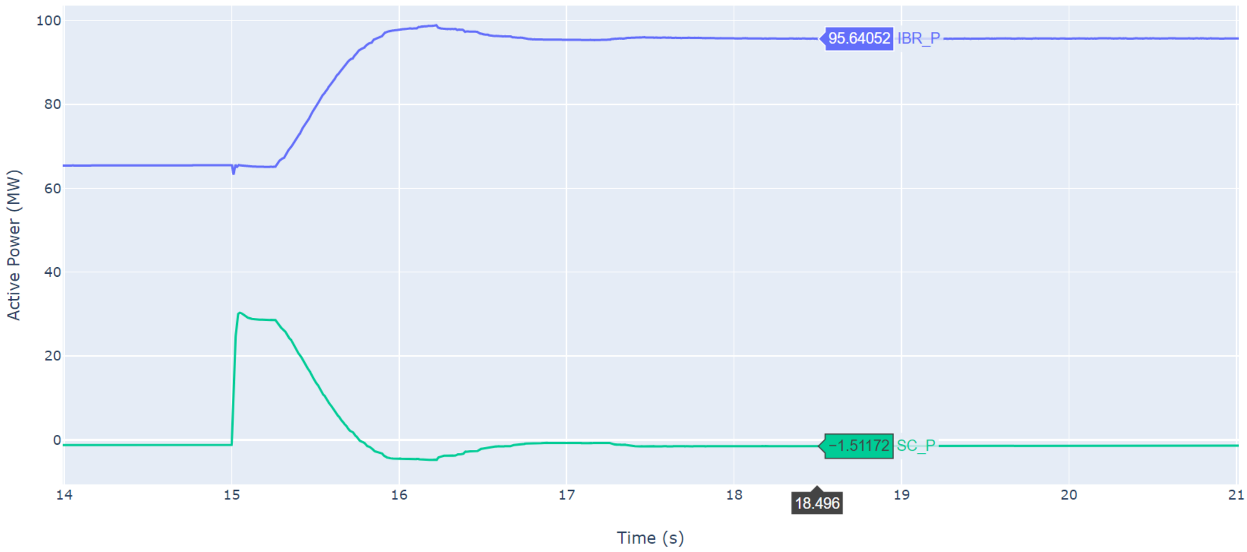


Figure 95 Sensitivity test – frequency in 2-bus test system with BESS and 1 x Robertstown syncon



*Note: during the disturbance, the large variation in frequency transient is due to the way PSCAD™ estimates frequency using zero crossing approach, however this initial variation may be ignored.

Figure 96 Sensitivity test – active power in 2-bus test system with BESS and 1 x Robertstown syncon



A3.4 Sensitivity studies for Davenport sub-network with clean trip of remaining syncon resulting in collapse

With reference to Section 4.3 (Scenario 3), the figures below (Figure 97 and Figure 98) show the network voltage and frequency at Davenport 275 kV bus when the one remaining Davenport syncon in the simulation model is clean tripped at 15 seconds, resulting in a system collapse, as expected. This helps validate the notion of grid reference in the absence of synchronous generation and that there were no fictitious voltage sources inadvertently present in the simulation model. The network configuration of IBR and syncons in this sub-network system were sufficient to sustain the grid reference even with zero synchronous generation.

Figure 97 Davenport 275 kV network voltage collapse upon clean trip of the remaining syncon

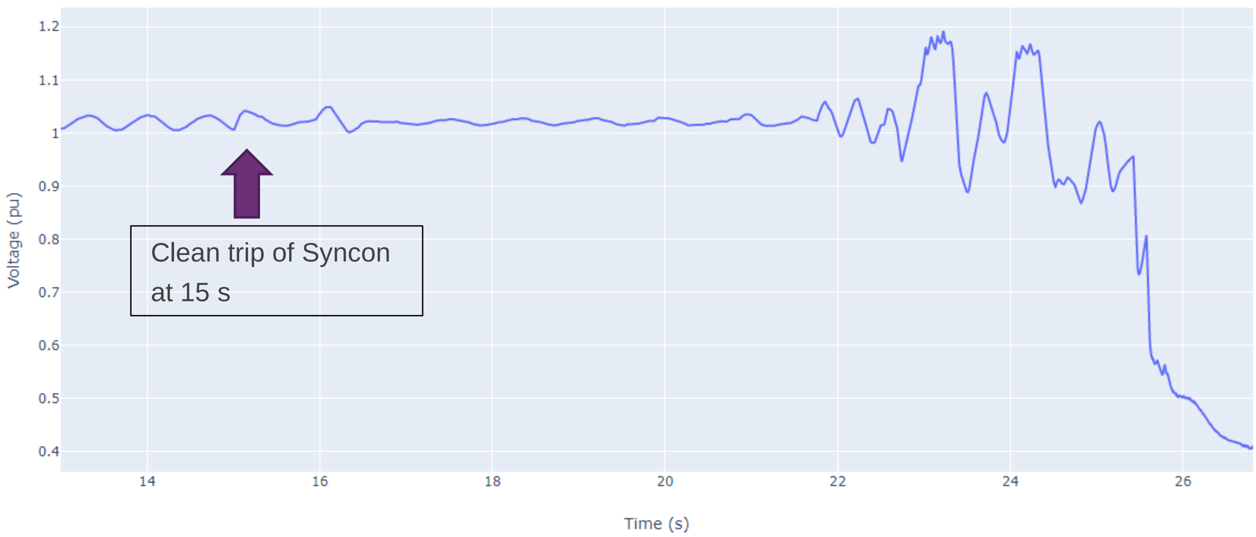
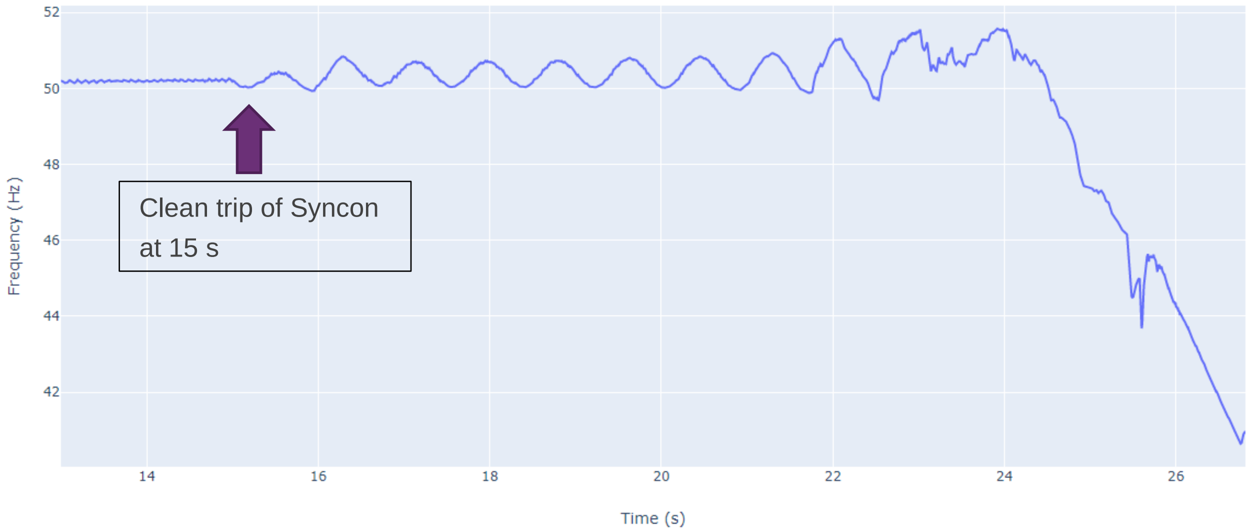


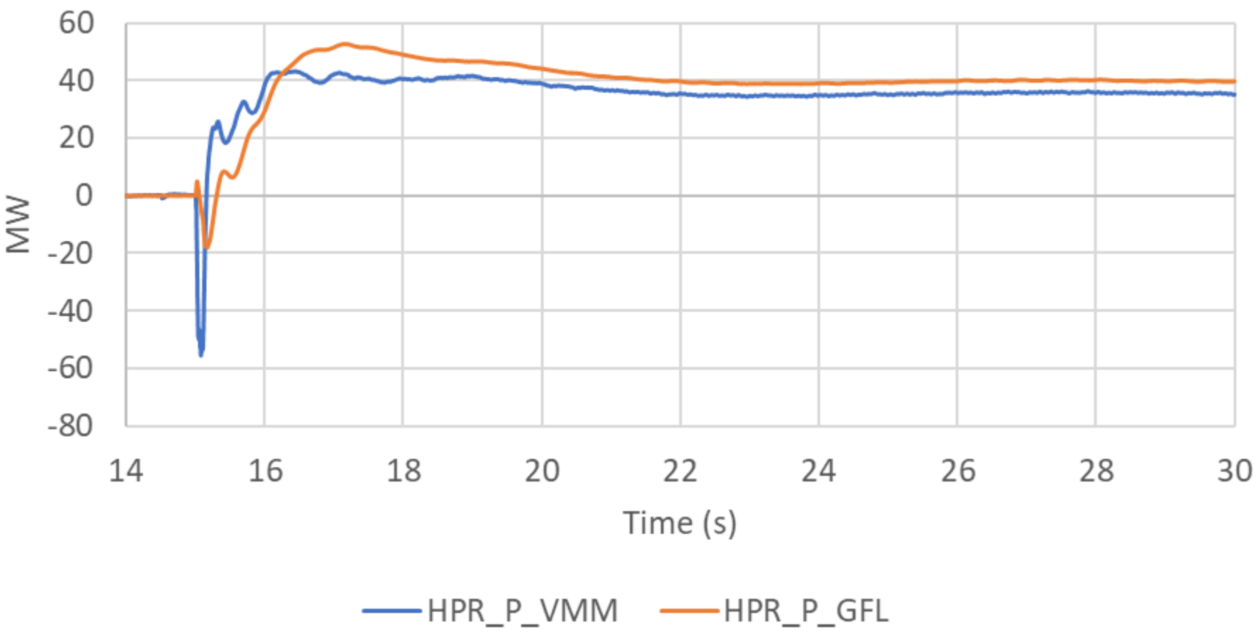
Figure 98 Davenport 275 kV frequency collapse upon clean trip of the remaining syncon



A3.5 Sensitivity study grid forming versus grid following mode of operation for Hornsdale Power Reserve expansion (HPRx)

With reference to Section 4.1 (Scenario 1) for SA following a non-credible separation involving a fault and subsequent trip of HIC, Figure 99 shows the comparison of HPRx operation in grid following mode versus grid forming VMM, when HIC is importing approximately 50 MW to SA during grid following and VMM mode of operation for HPRx. There was no major difference in response between the two modes, as the grid reference is sustained through the network configuration of syncons, IBR and BESS, irrespective of the grid forming mode of operation of the BESS.

Figure 99 HPRx active power VMM vs grid following mode of operation



A3.6 Sensitivity study – 1,800 MW of asynchronous generation dispatch in SA with 180 MW import on Heywood Interconnector (HIC)

This sensitivity was used to cover a different level of IBR dispatch in SA (around 1,800 MW) compared to 2,100 MW which was studied in Section 4.1. Also, the response of MLDC was monitored (see Figure 103) to ensure the behaviour was as expected.

Figure 100 Network voltages – 1,800 MW of asynchronous generation dispatch with 180 MW import on HIC

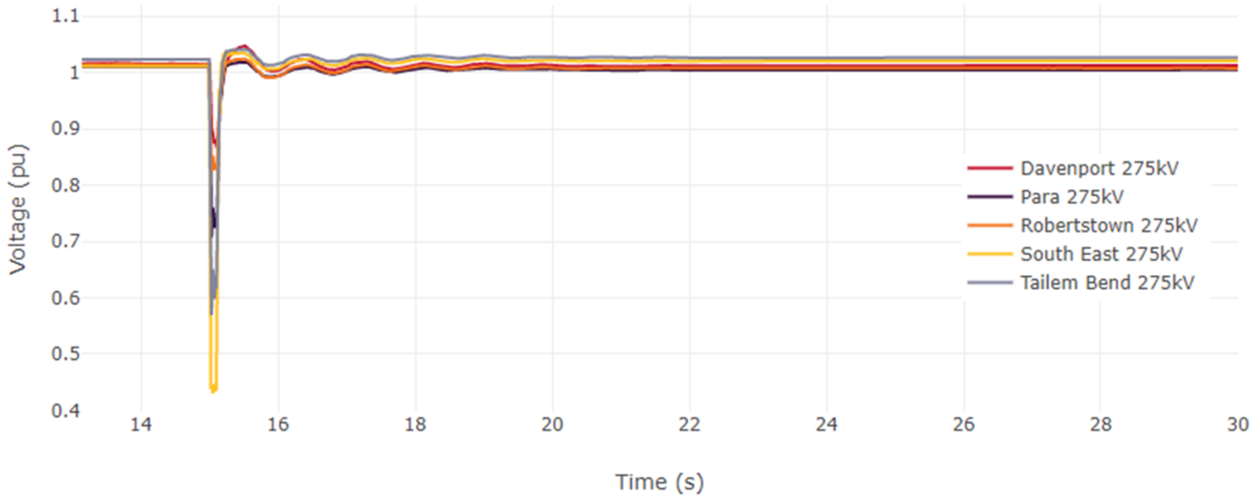
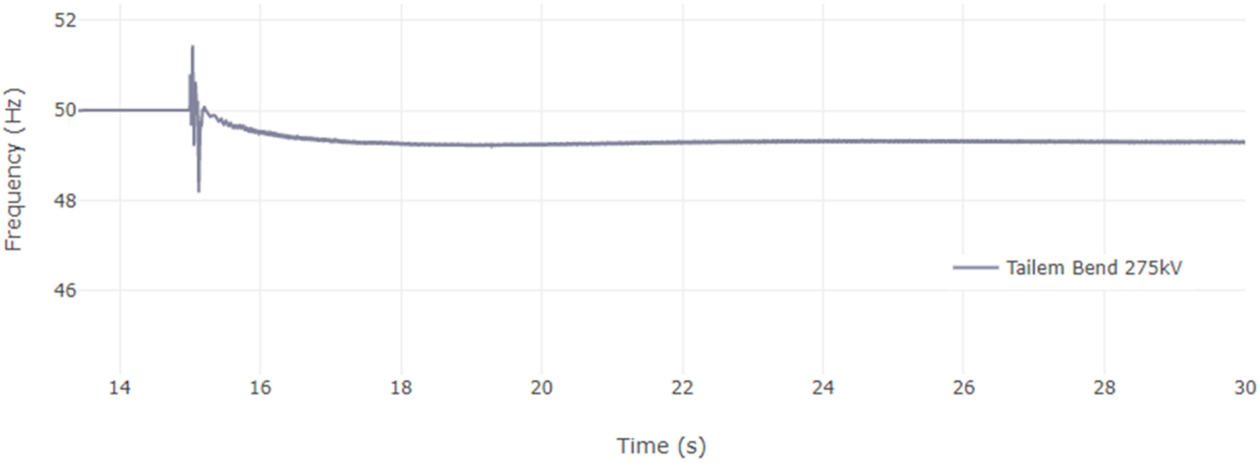


Figure 101 Frequency – 1,800 MW of asynchronous generation dispatch with 180 MW import on HIC



*Note: during the disturbance, the large variation in frequency transient is due to the way PSCAD^{TM} estimates frequency using zero crossing approach, however this initial variation may be ignored.

Figure 102 IBR active power – 1,800 MW of asynchronous generation dispatch with 180 MW import on HIC

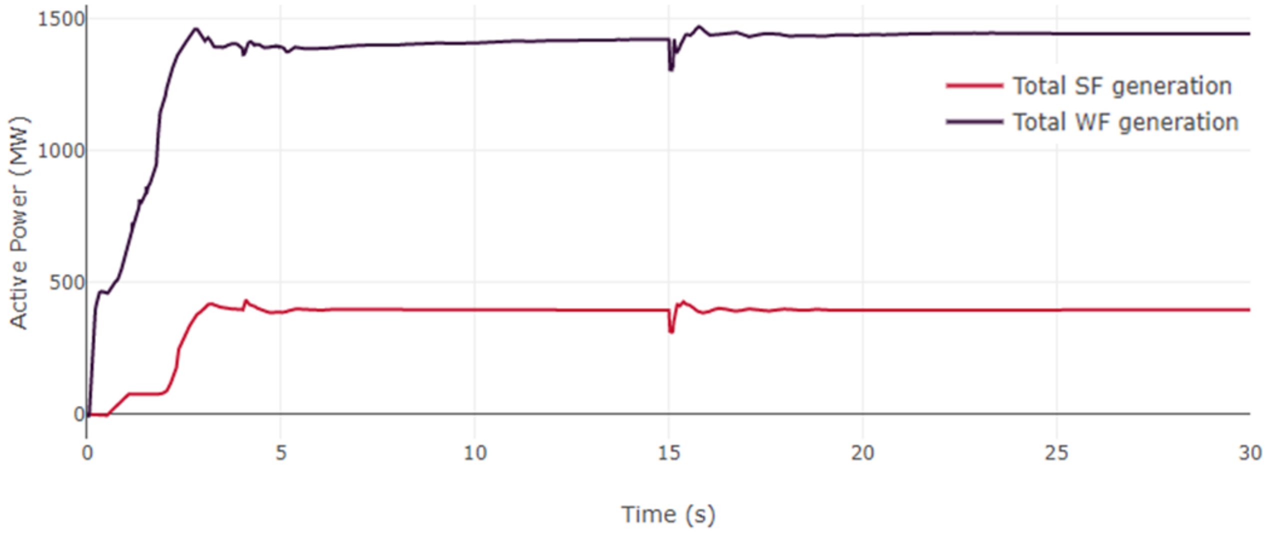
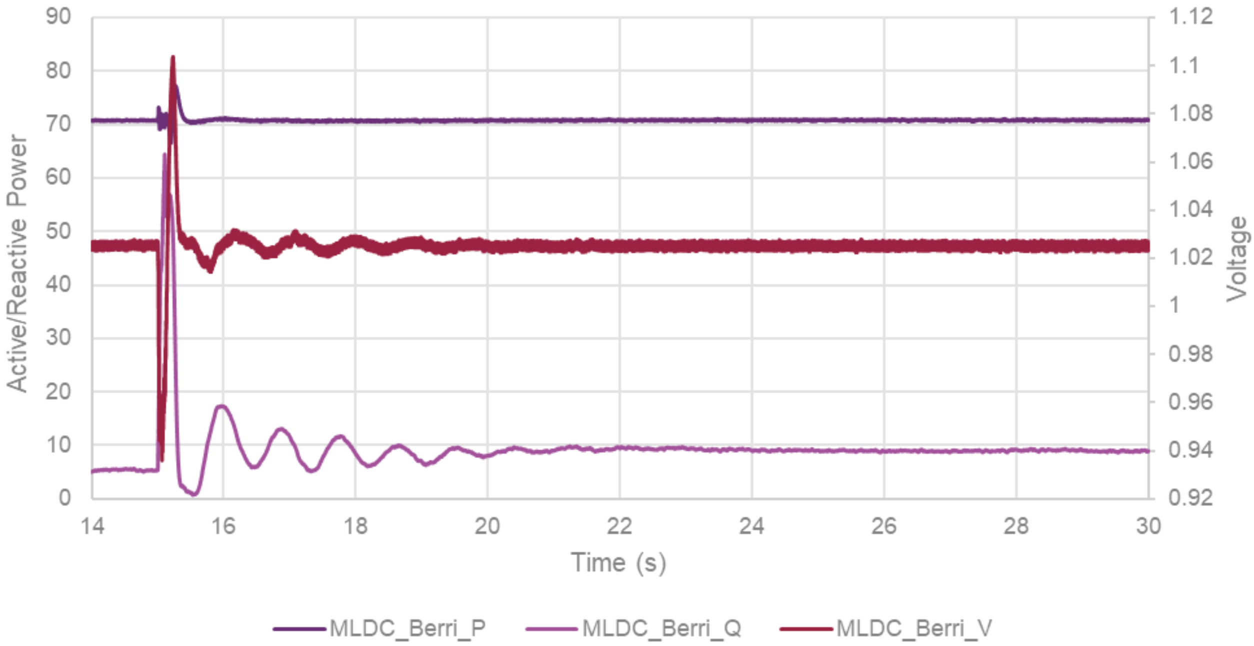


Figure 103 MLDC response – 1,800 MW of asynchronous generation dispatch with 180 MW import on HIC



A3.7 Sensitivity study – trip of HIC at 0 MW with prior outage of Hornsdale Power Reserve expansion (HPRx) and Dalrymple BESS

This sensitivity was done to test for grid reference and rule out the contribution of any grid forming BESS in the system. With a trip of HIC at near 0 MW, the frequency deviation was kept to the minimum possible, but importantly this sensitivity helped establish that even with grid forming devices disabled in the simulations, grid reference can be sustained with the existing network configuration in SA comprising of syncons, IBR and grid-following BESS with zero synchronous generation.

Figure 104 Network voltage – trip of HIC at 0 MW with prior outage of HPRx and Dalrymple BESS

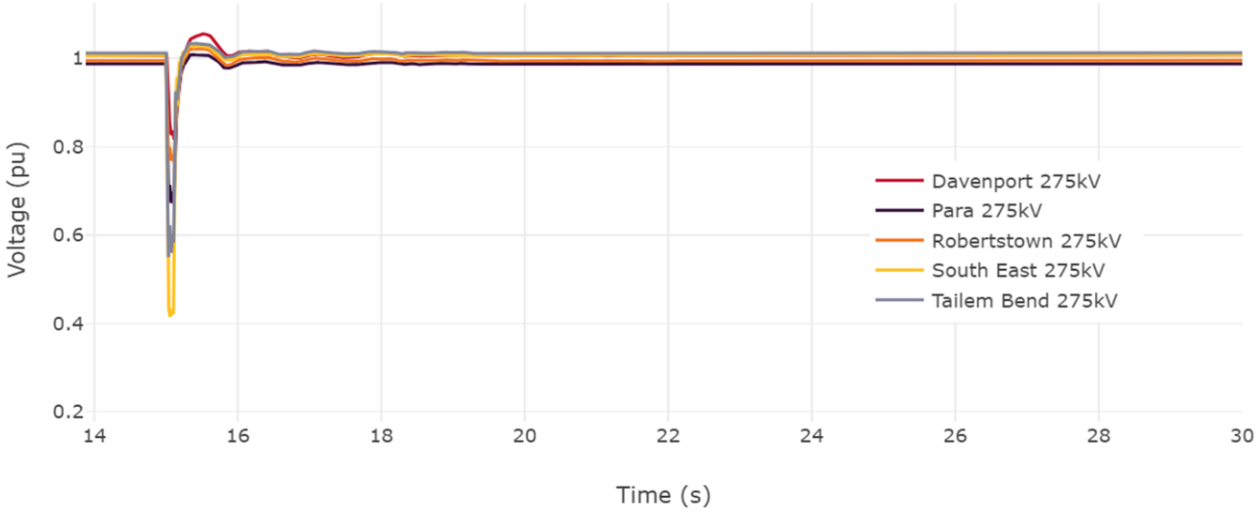
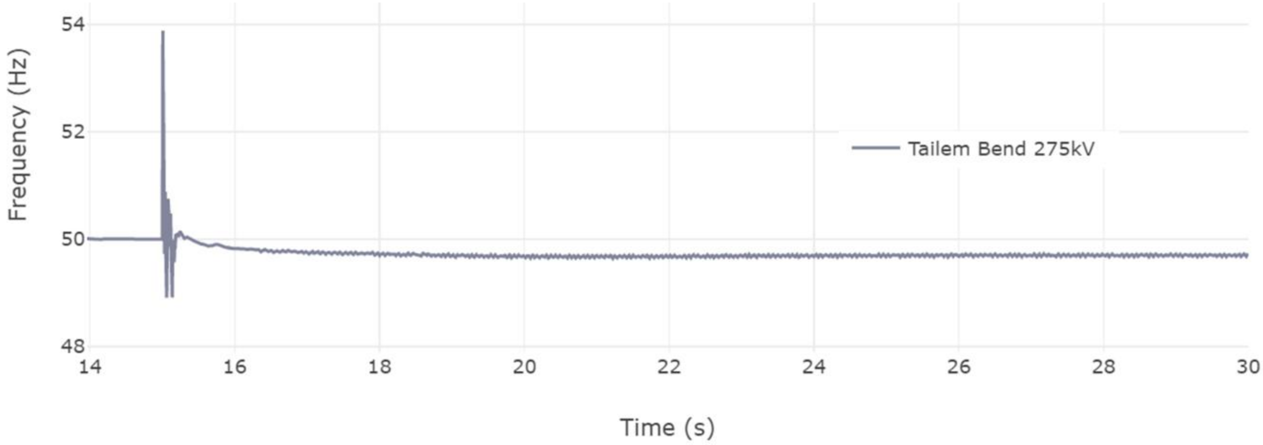
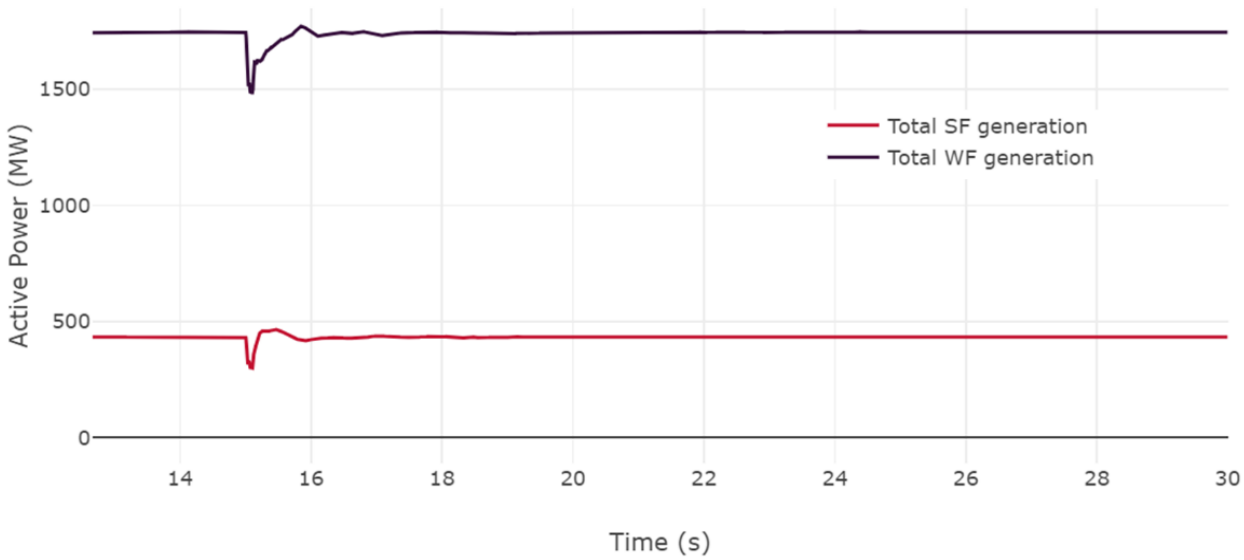


Figure 105 Frequency – trip of HIC at 0 MW with prior outage of HPRx and Dalrymple BESS



*Note: during the disturbance, the large variation in frequency transient is due to the way PSCAD™ estimates frequency using zero crossing approach, however this initial variation may be ignored.

Figure 106 IBR active power – trip of HIC at 0 MW with prior outage of HPRx and Dalrymple BESS



A3.8 Sensitivity study with higher pre-fault voltages

This sensitivity was undertaken to address the concern that voltages at key buses in SA may be going down slightly below 1.0 pu and likely the operational preference to keep it above 1.0 pu. As can be seen with slightly higher pre-fault voltages, the network voltages recover and remain above 1.0 pu.

A3.8.1 Prior outage of Davenport syncon and HIC trip (import 195 MW to SA)

Figure 107 Network voltages at key buses – prior outage of Davenport syncon and HIC trip

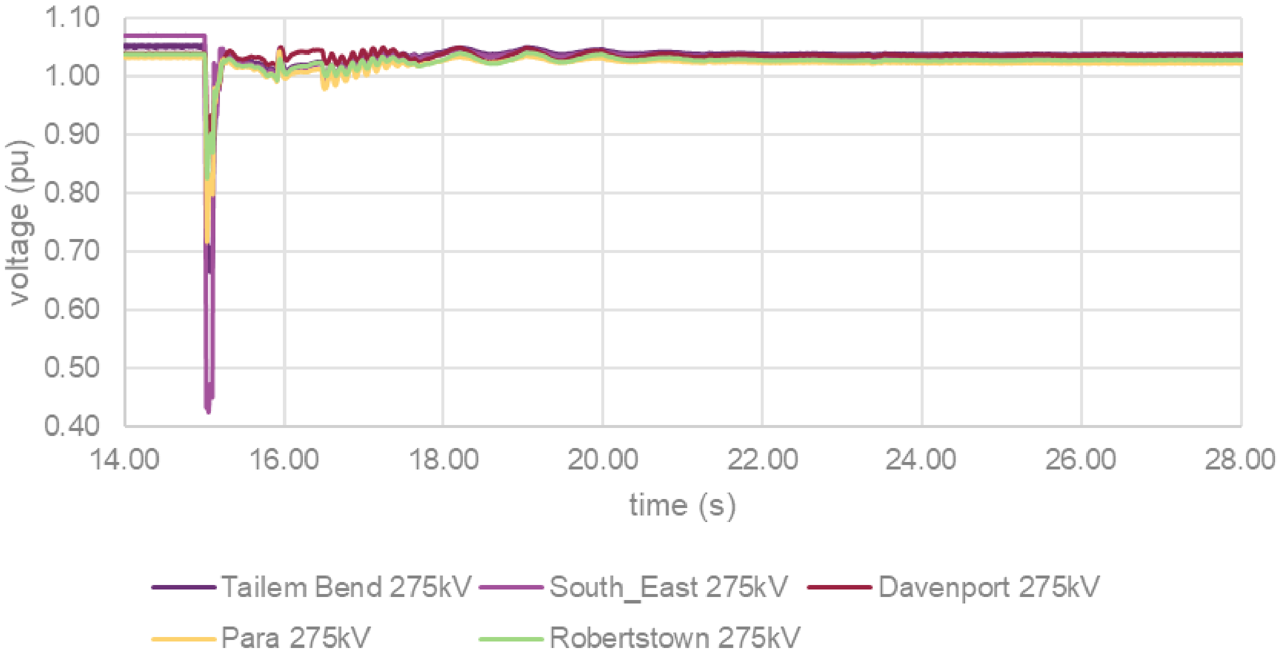


Figure 108 Voltages at end of radials – prior outage of Davenport syncon and HIC trip

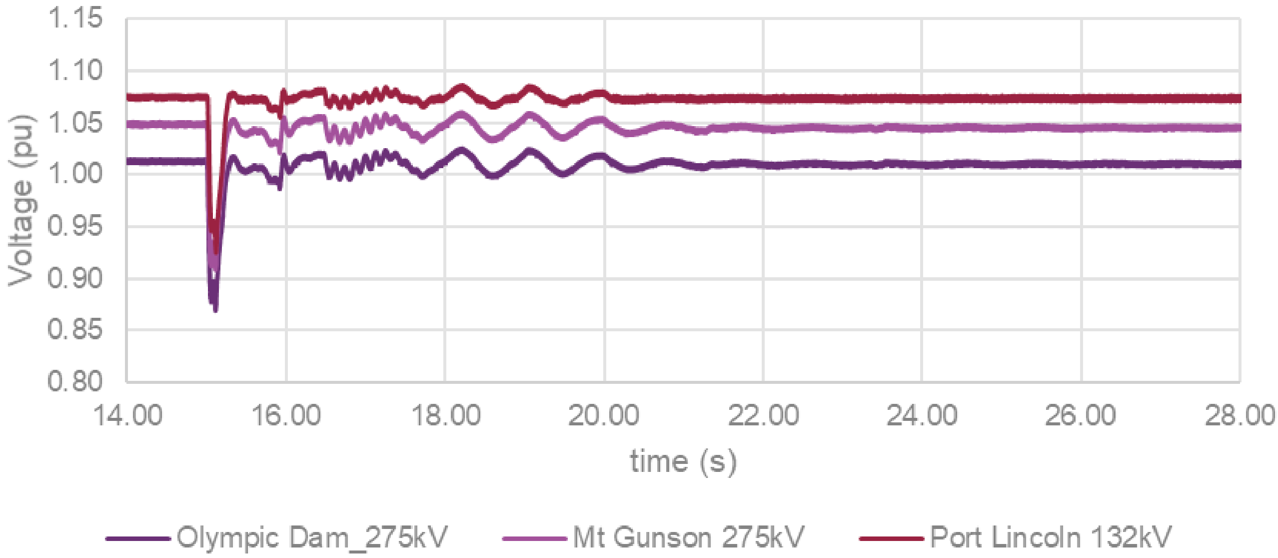
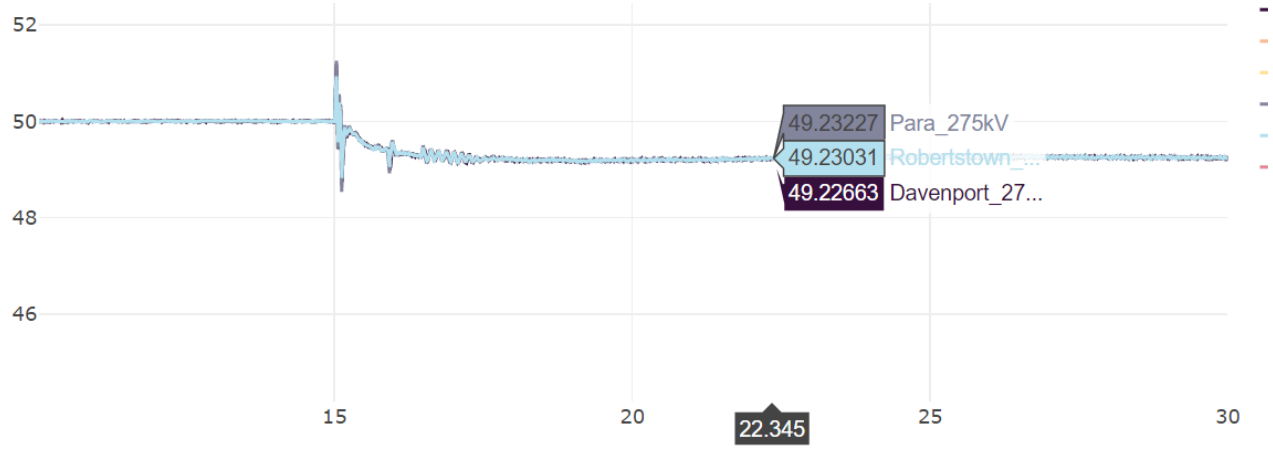


Figure 109 Network frequency – prior outage of Davenport syncon and HIC trip



*Note: during the disturbance, the large variation in frequency transient is due to the way PSCAD™ estimates frequency using zero crossing approach, however this initial variation may be ignored.

Figure 110 IBR active power – prior outage of Davenport syncon and HIC trip

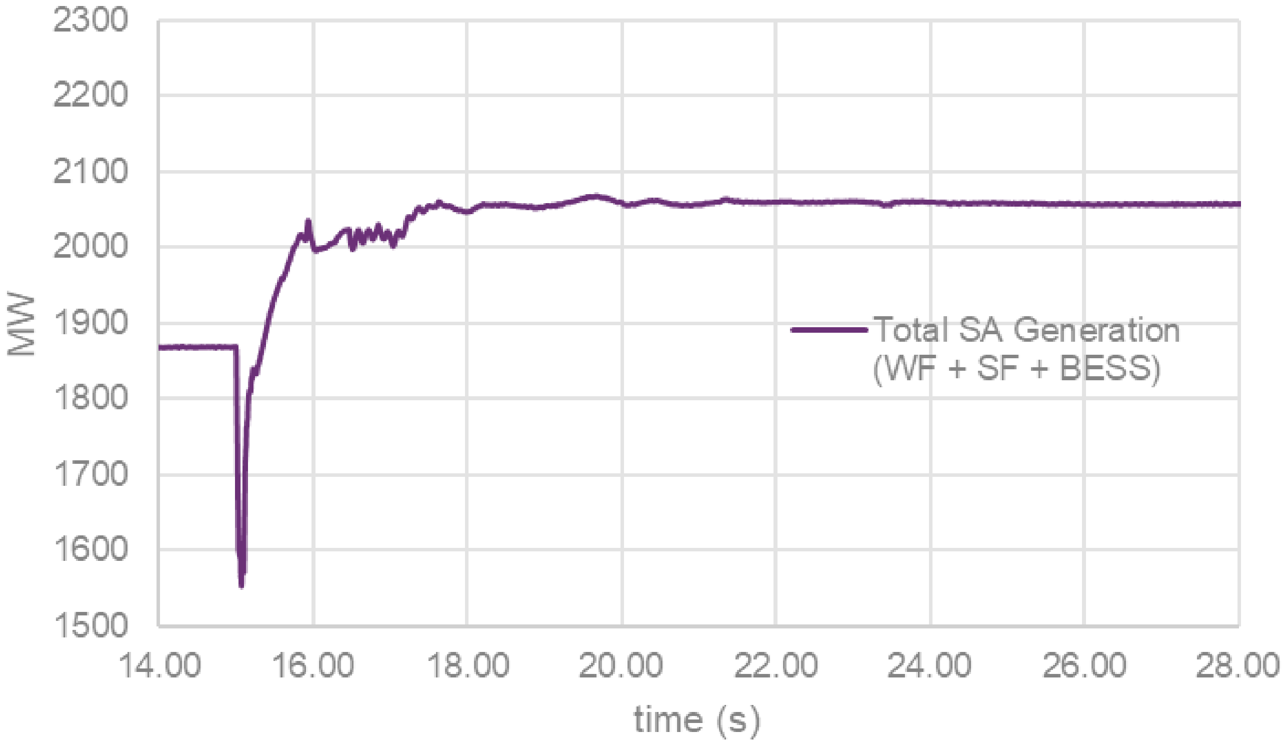
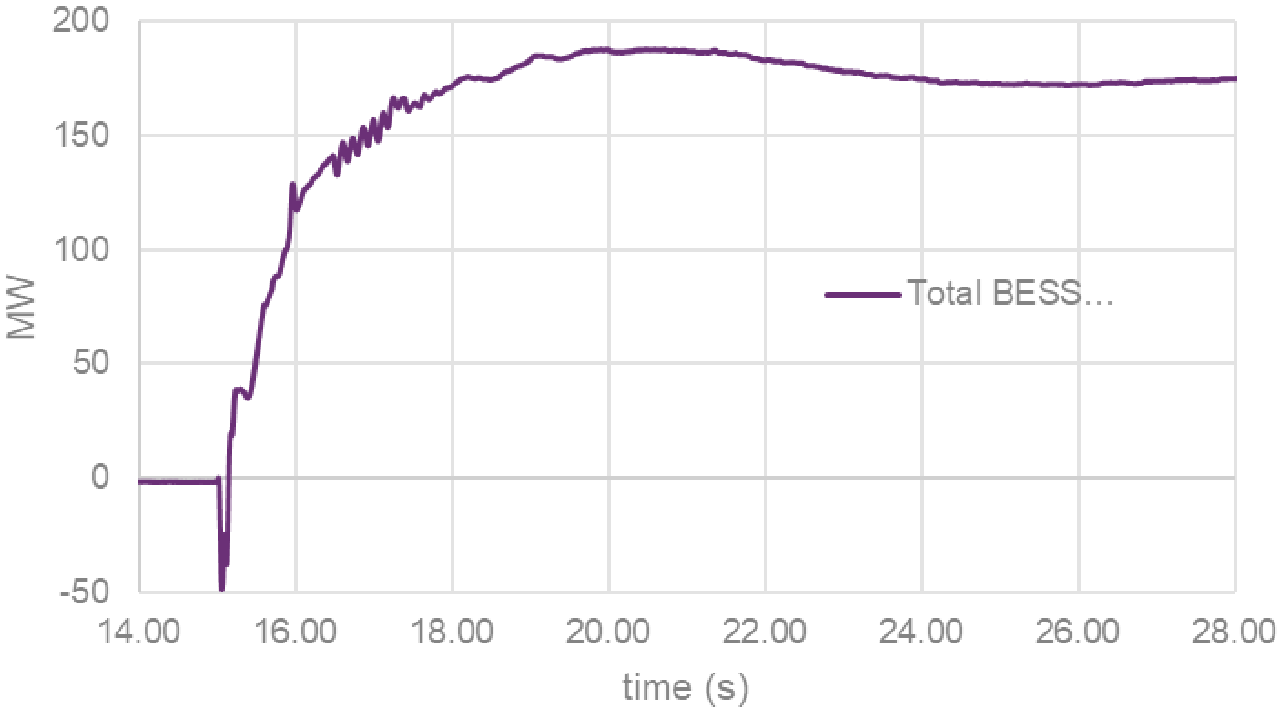


Figure 111 Total BESS output in SA – prior outage of Davenport syncon and HIC trip



A3.8.2 SA island – prior outage of Davenport syncon and trip of Robertstown – Tungkillo 275 kV line

Figure 112 Network voltages at key buses – prior outage of Davenport syncon and trip of Robertstown – Tungkillo 275 kV line during SA island

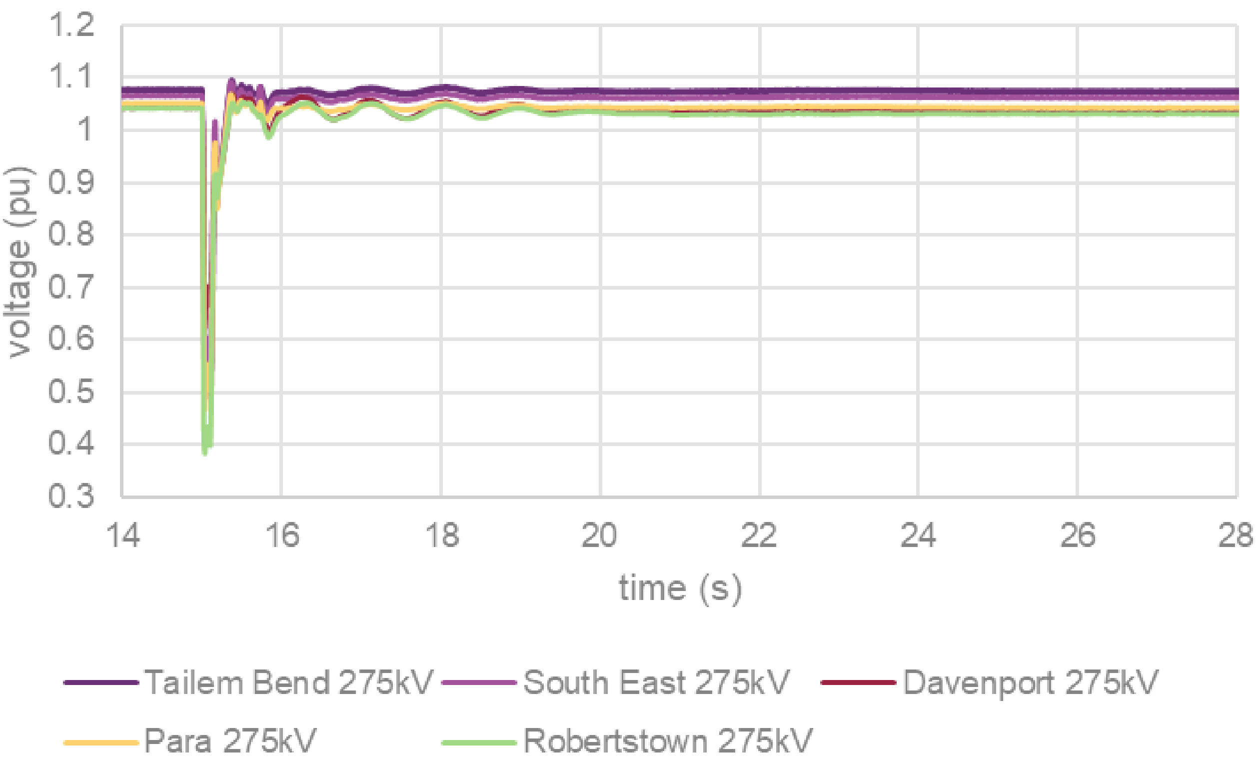


Figure 113 Voltage at end of radials – prior outage of Davenport syncon and trip of Robertstown – Tungkillo 275 kV line during SA island

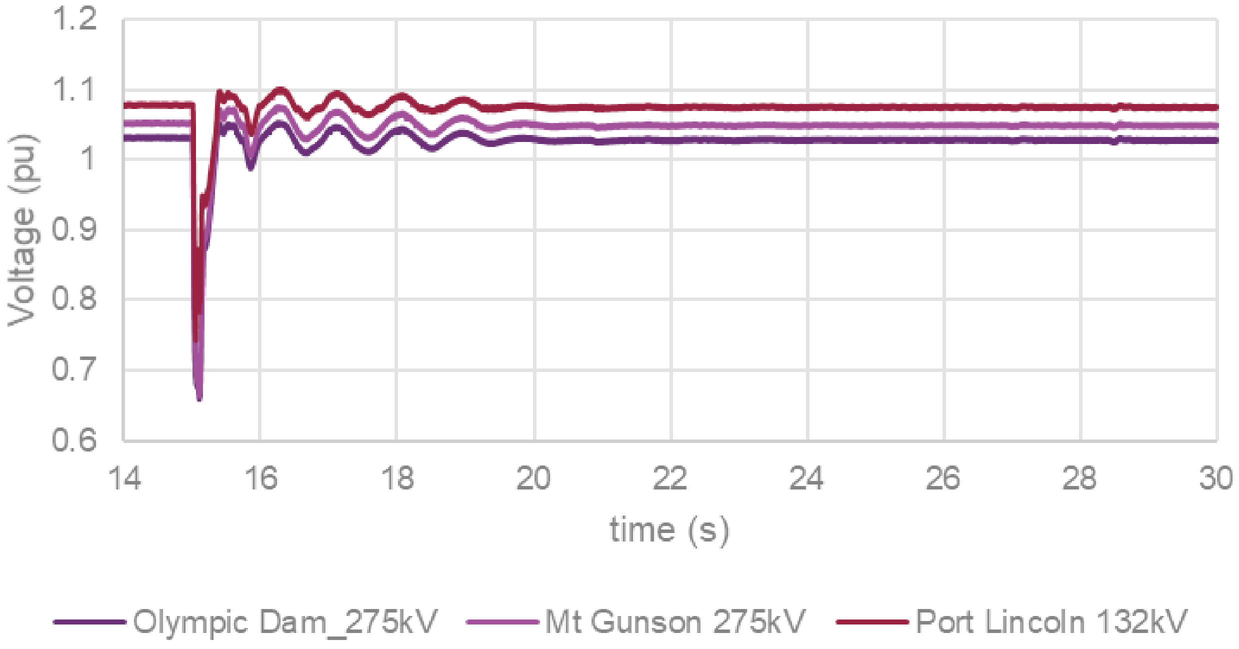
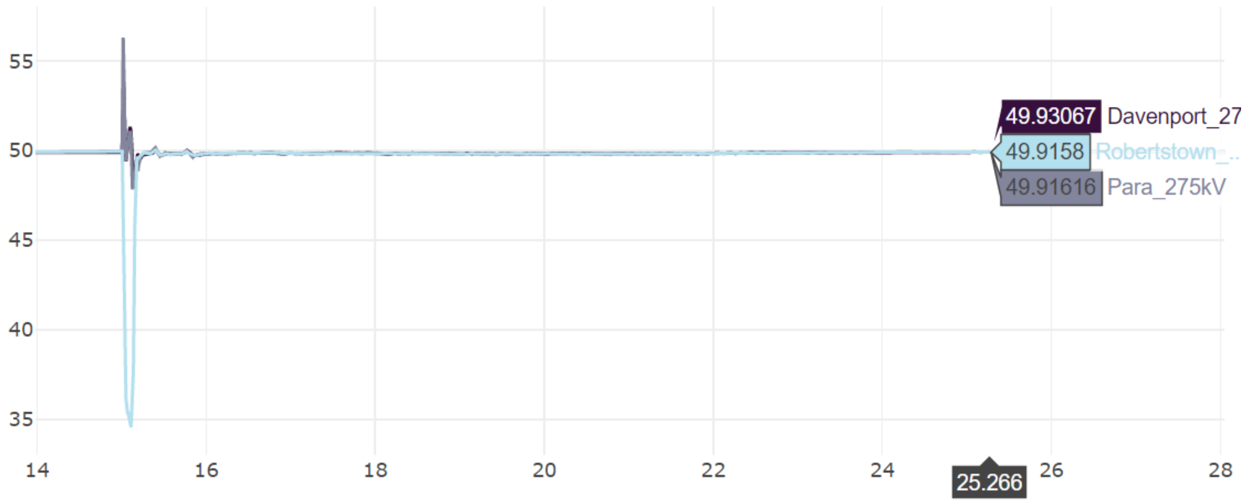


Figure 114 Network frequency at key buses – prior outage of Davenport syncon and trip of Robertstown – Tungkillo 275 kV line during SA island



*Note: during the disturbance, the large variation in frequency transient is due to the way PSCAD™ estimates frequency using zero crossing approach, however this initial variation may be ignored. Moreover, in this case fault was applied close to Robertstown 275 kV.

Figure 115 Total SA generation – prior outage of Davenport syncon and trip of Robertstown – Tungkillo 275 kV line during SA island

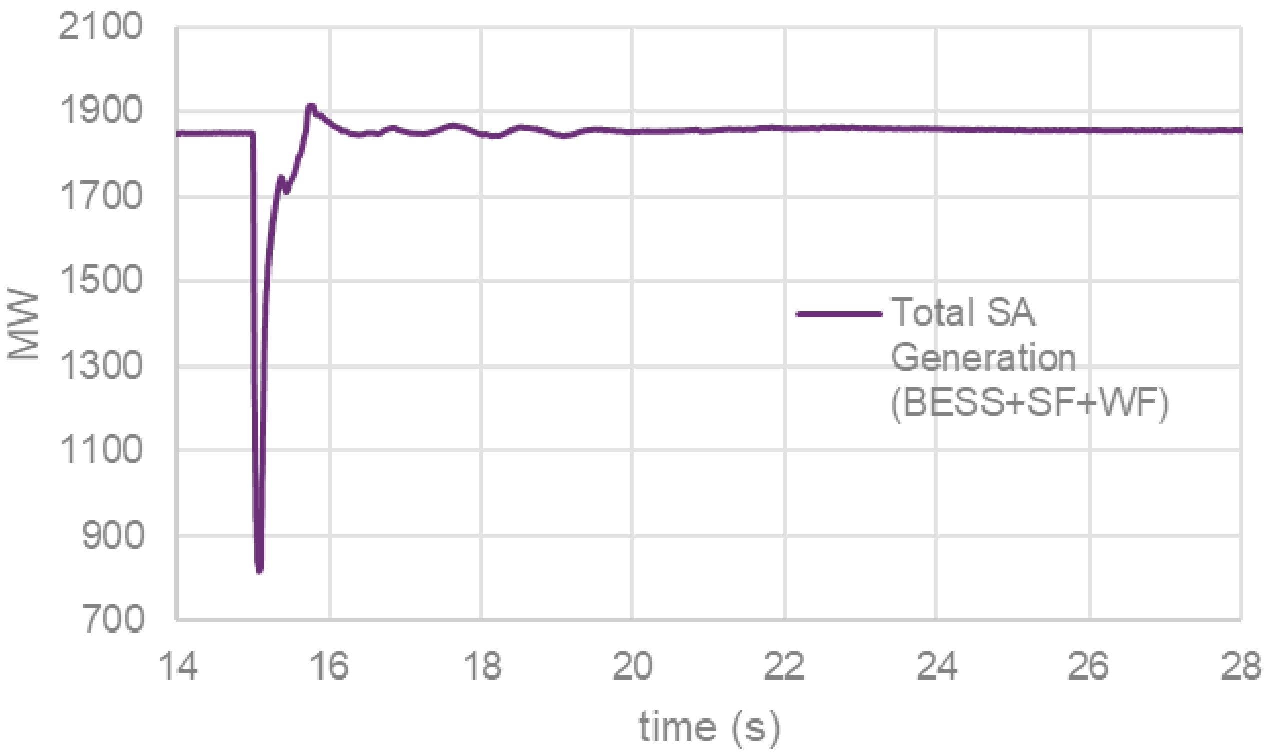
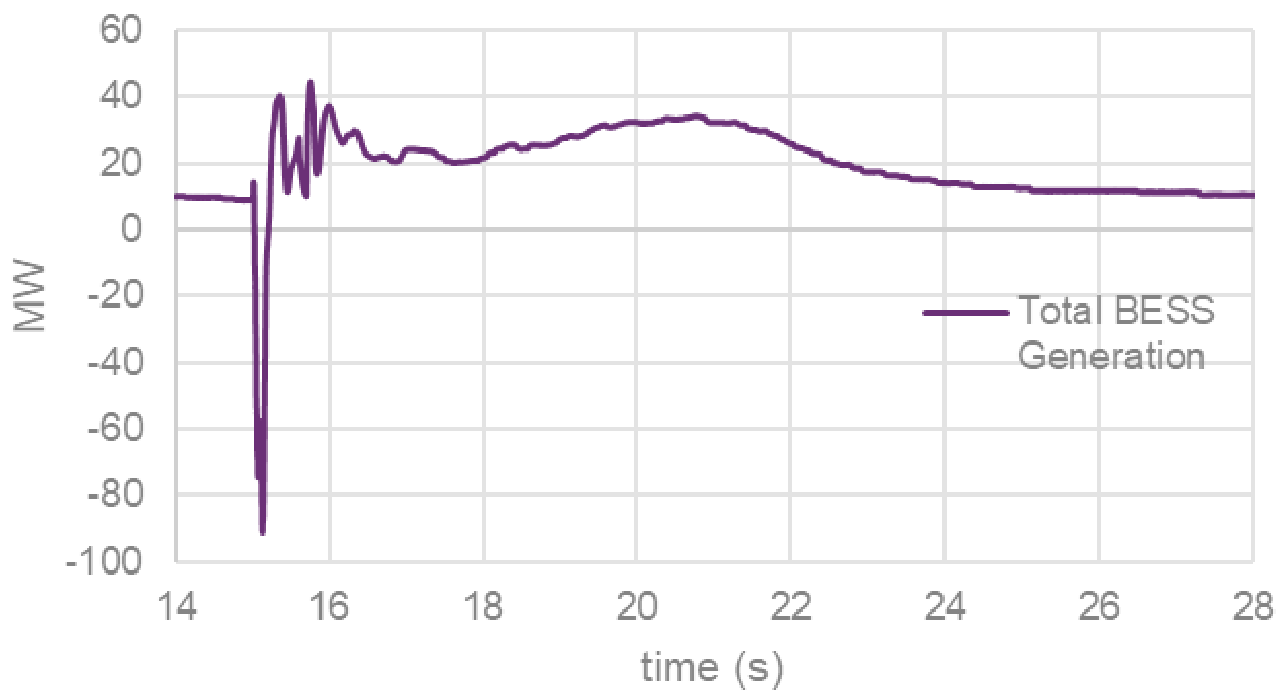


Figure 116 Total BESS output – prior outage of Davenport syncon and trip of Robertstown – Tungkillo 275 kV line during SA island



A3.9 SA island sensitivity studies

A3.9.1 Prior outage of Para SVC1 and trip of Para SVC2

Figure 117 Network voltages – prior outage of Para SVC1 and trip of Para SVC2

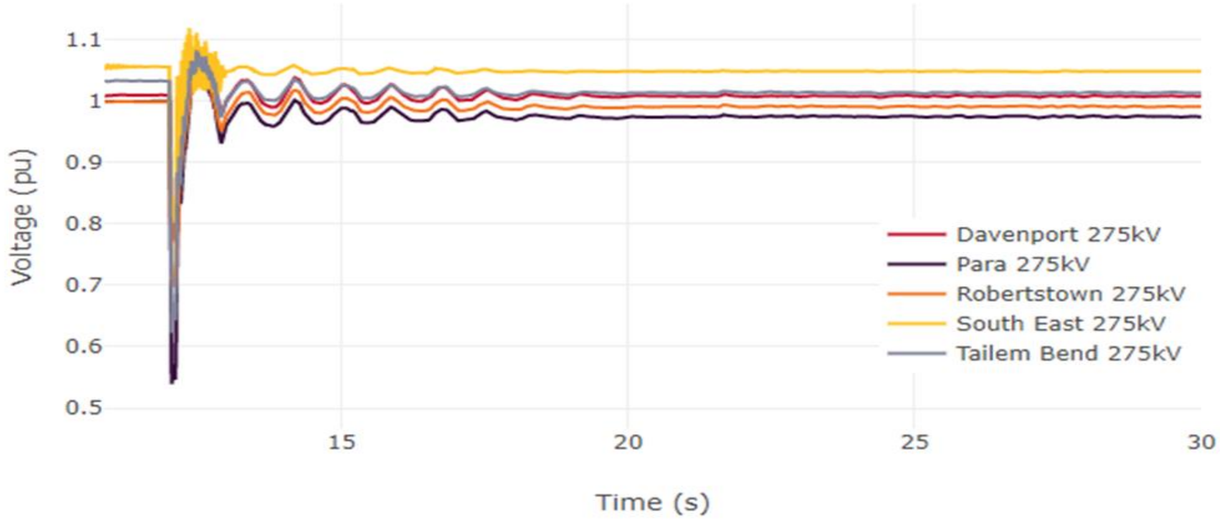
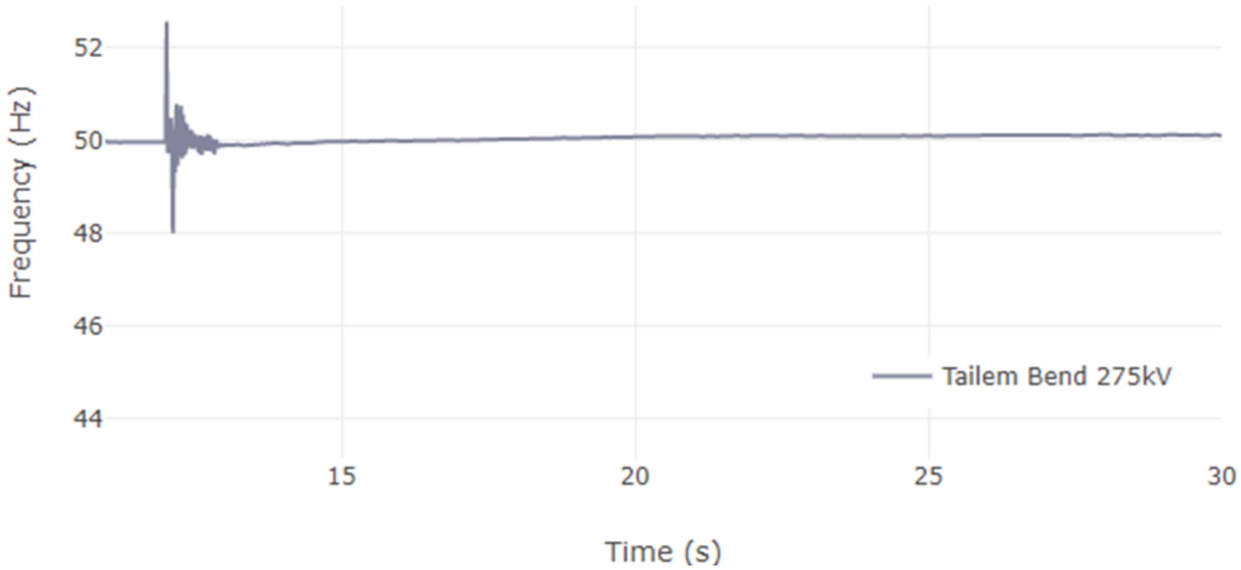
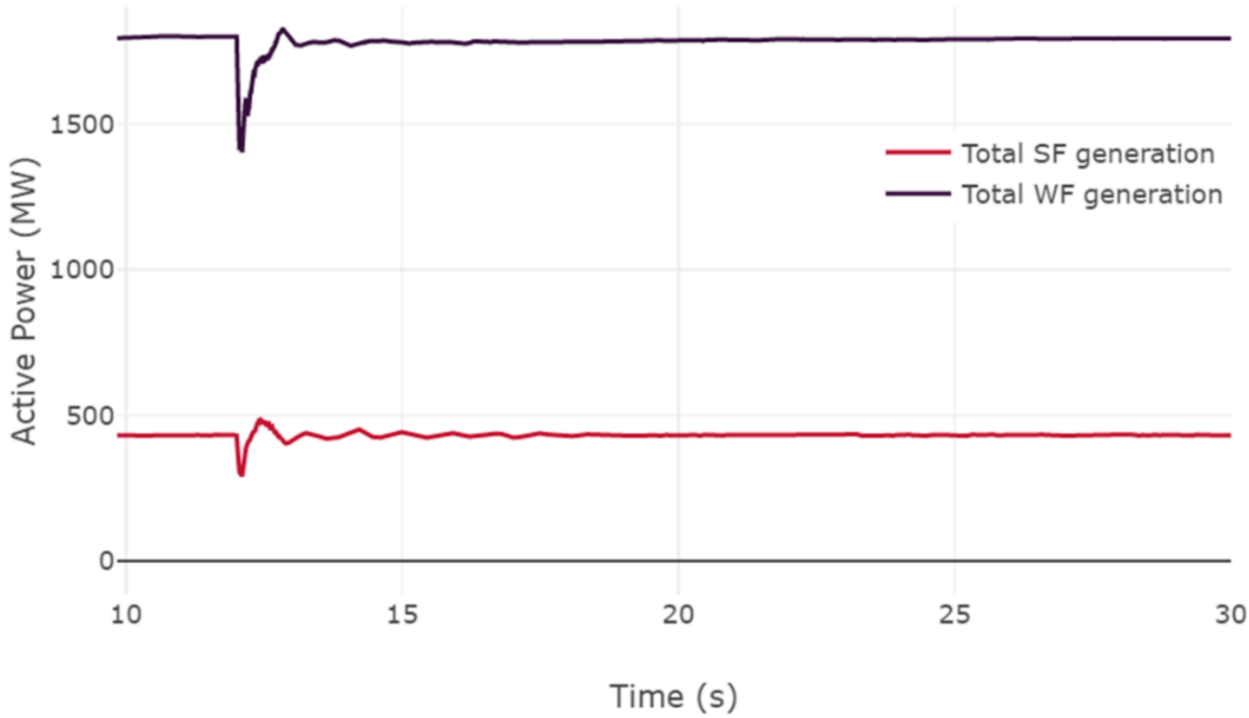


Figure 118 Frequency – prior outage of Para SVC1 and trip of Para SVC2



*Note: during the disturbance, the large variation in frequency transient is due to the way PSCAD™ estimates frequency using zero crossing approach, however this initial variation may be ignored.

Figure 119 IBR active power – prior outage of Para SVC1 and trip of Para SVC2



A3.9.2 Prior outage of one syncon and trip of Robertstown – Tungkillo 275 kV

Figure 120 Network voltages – prior outage of one Davenport syncon and trip of Robertstown – Tungkillo 275 kV

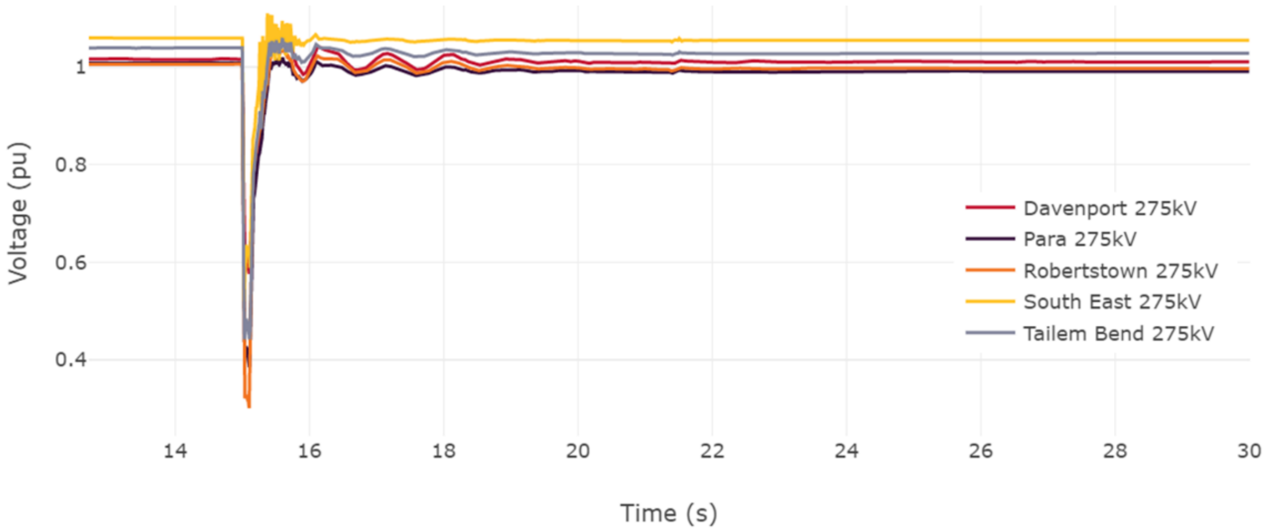
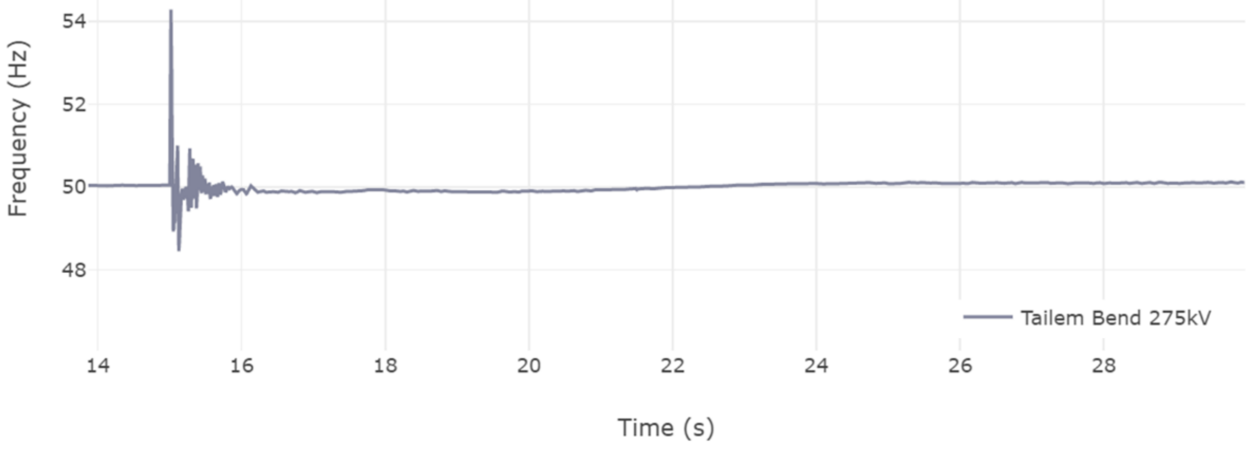


Figure 121 Frequency – prior outage of one Davenport syncon and trip of Robertstown – Tungkillo 275 kV



*Note: during the disturbance, the large variation in frequency transient is due to the way PSCAD[TM] estimates frequency using zero crossing approach, however this initial variation may be ignored.

Figure 122 IBR active power response – prior outage of one Davenport syncon and trip of Robertstown – Tungkillo 275 kV

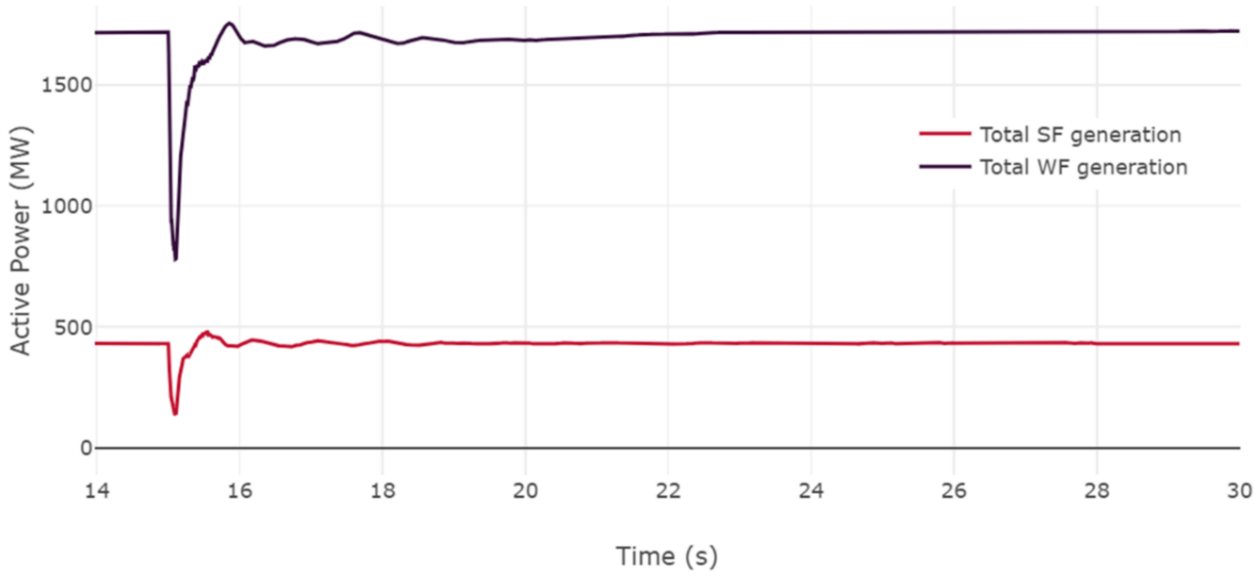


Figure 123 Network voltages – prior outage of one Robertstown syncon and trip of Robertstown – Tungkillo 275 kV

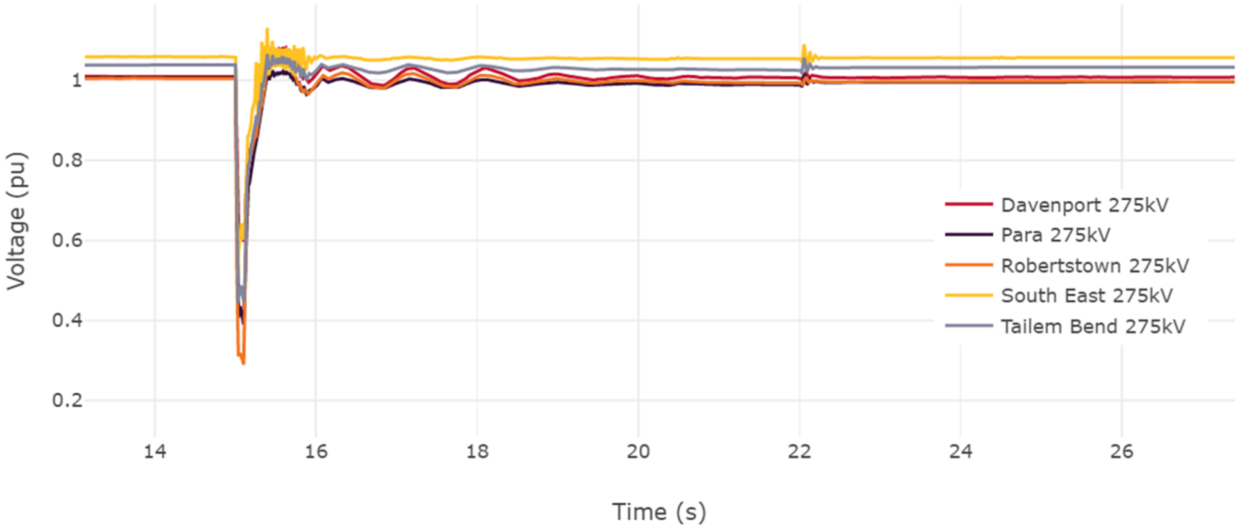
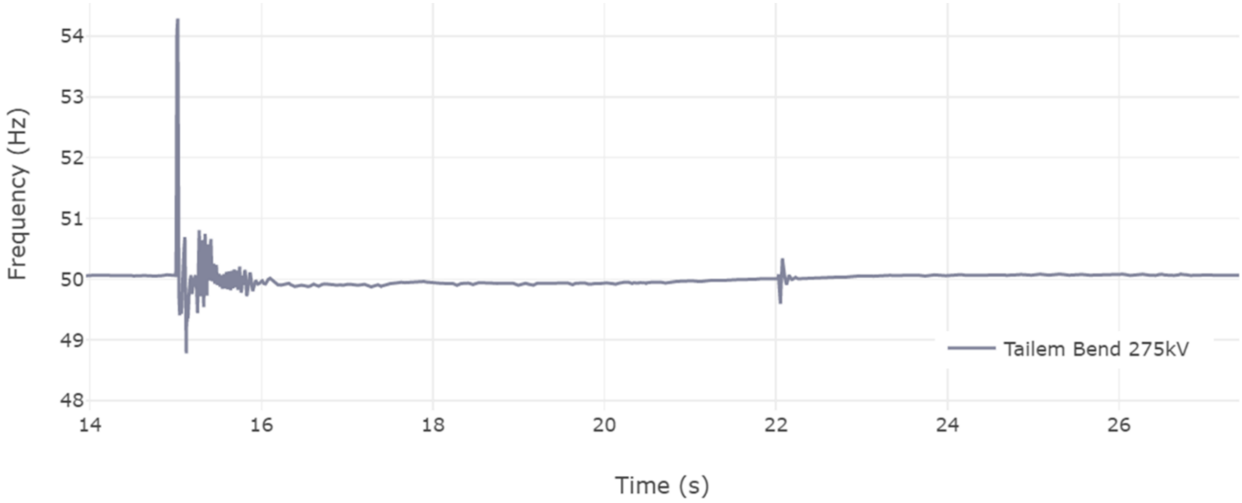
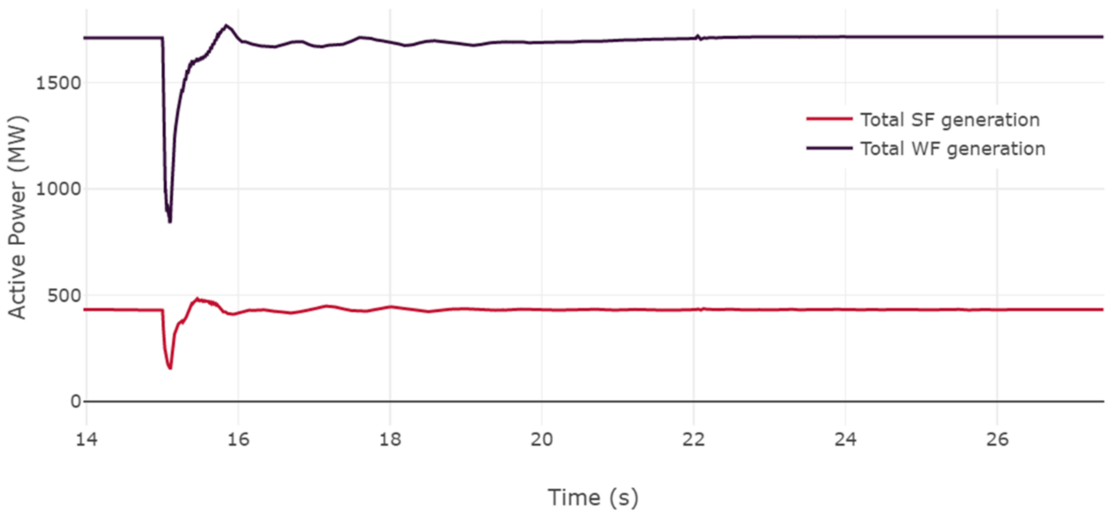


Figure 124 Frequency – prior outage of one Robertstown syncon and trip of Robertstown – Tungkillo 275 kV



*Note: during the disturbance, the large variation in frequency transient is due to the way PSCAD™ estimates frequency using zero crossing approach, however this initial variation may be ignored.

Figure 125 IBR active power – prior outage of one Robertstown syncon and trip of Robertstown – Tungkillo 275 kV



A3.9.3 Prior outage of one BESS and trip of Robertstown – Tungkillo 275 kV

Figure 126 Network voltages – prior outage of HPRx and trip of Robertstown – Tungkillo 275 kV

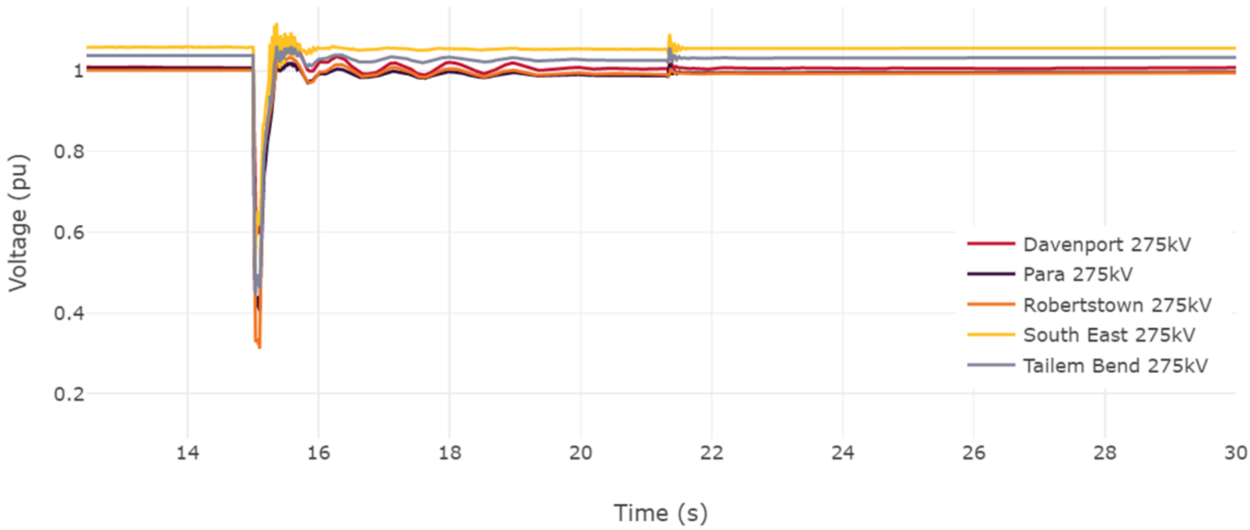
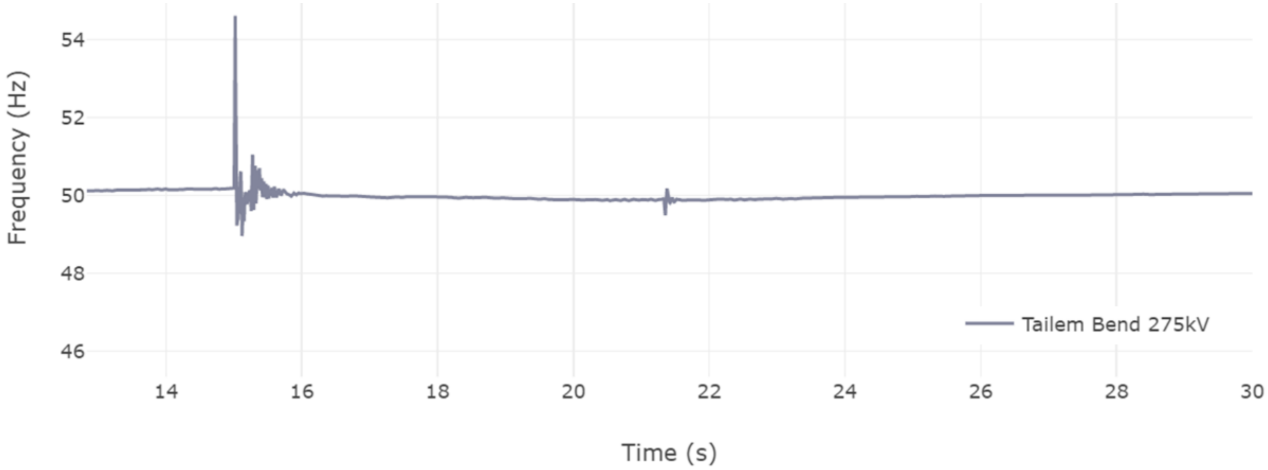


Figure 127 Frequency – prior outage of HPRx and trip of Robertstown – Tungkillo 275 kV



*Note: during the disturbance, the large variation in frequency transient is due to the way PSCAD[TM] estimates frequency using zero crossing approach, however this initial variation may be ignored.

Figure 128 Active power – prior outage of HPRx and trip of Robertstown – Tungkillo 275 kV

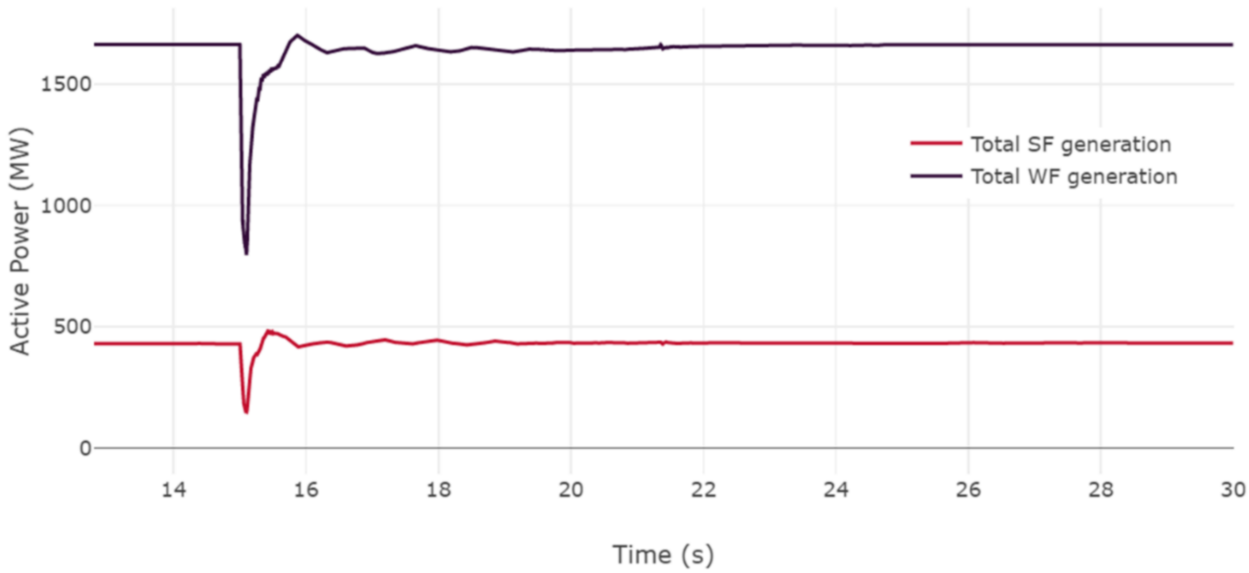


Figure 129 Network voltages – prior outage of Dalrymple BESS and trip of Robertstown – Tungkillo 275 kV

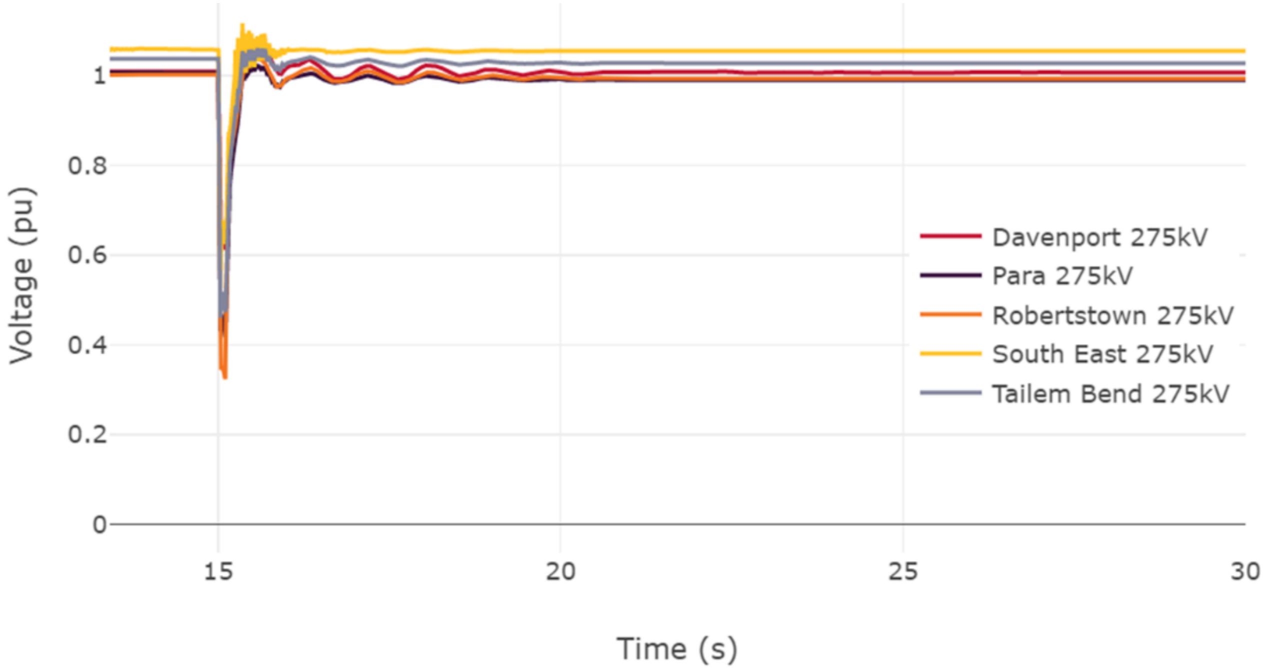
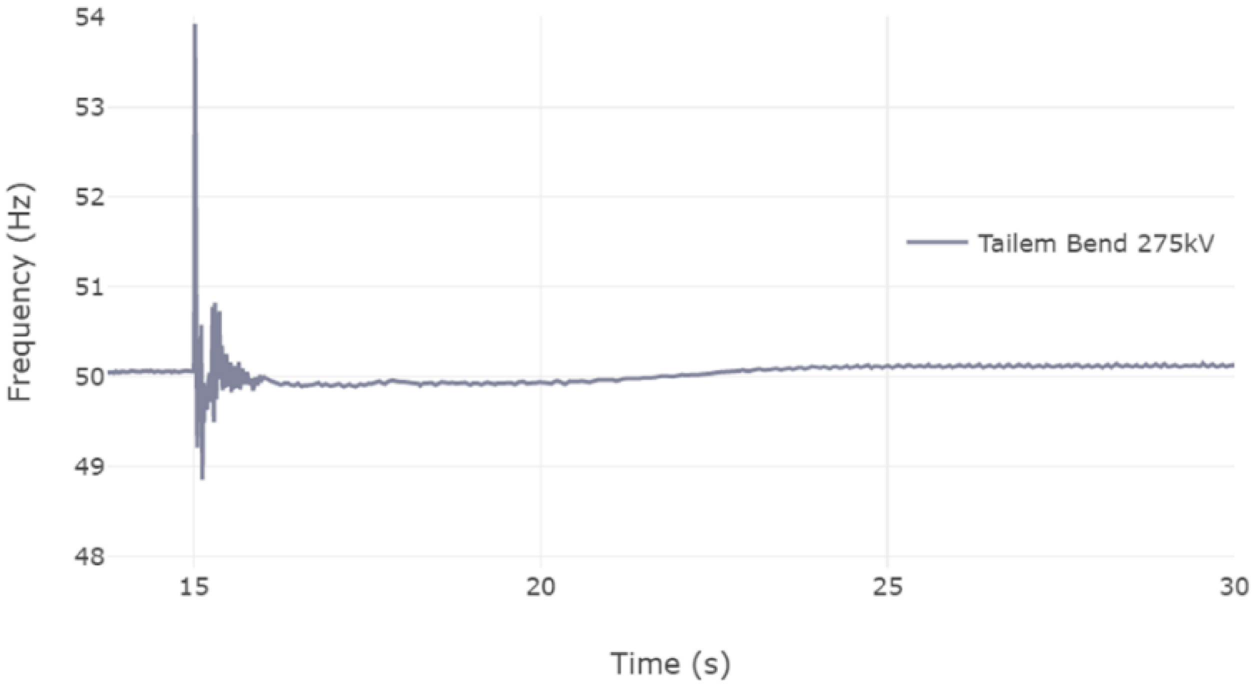
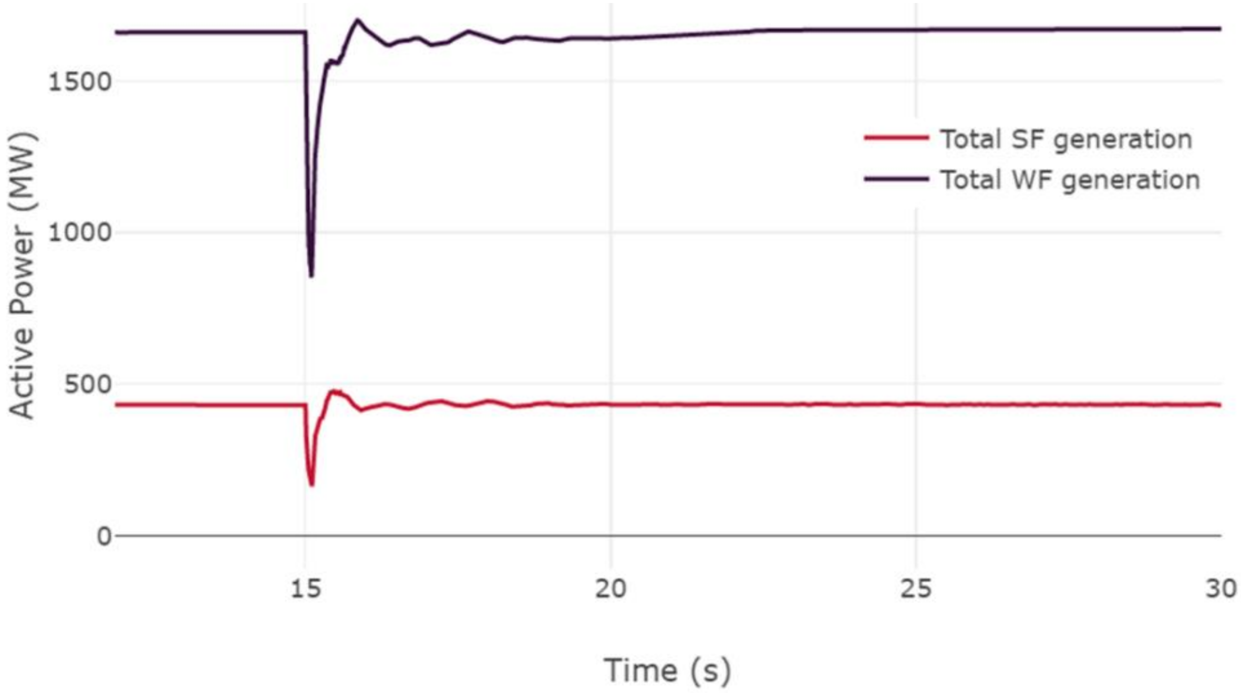


Figure 130 Frequency – prior outage of Dalrymple BESS and trip of Robertstown – Tungkillo 275 kV



*Note: during the disturbance, the large variation in frequency transient is due to the way PSCAD™ estimates frequency using zero crossing approach, however this initial variation may be ignored.

Figure 131 IBR active power – prior outage of Dalrymple BESS and trip of Robertstown – Tungkillo 275 kV



A3.9.4 Prior outage of MLDC and trip of Robertstown – Tungkillo 275 kV

Figure 132 Network voltages – prior outage of MLDC and trip of Robertstown – Tungkillo 275 kV

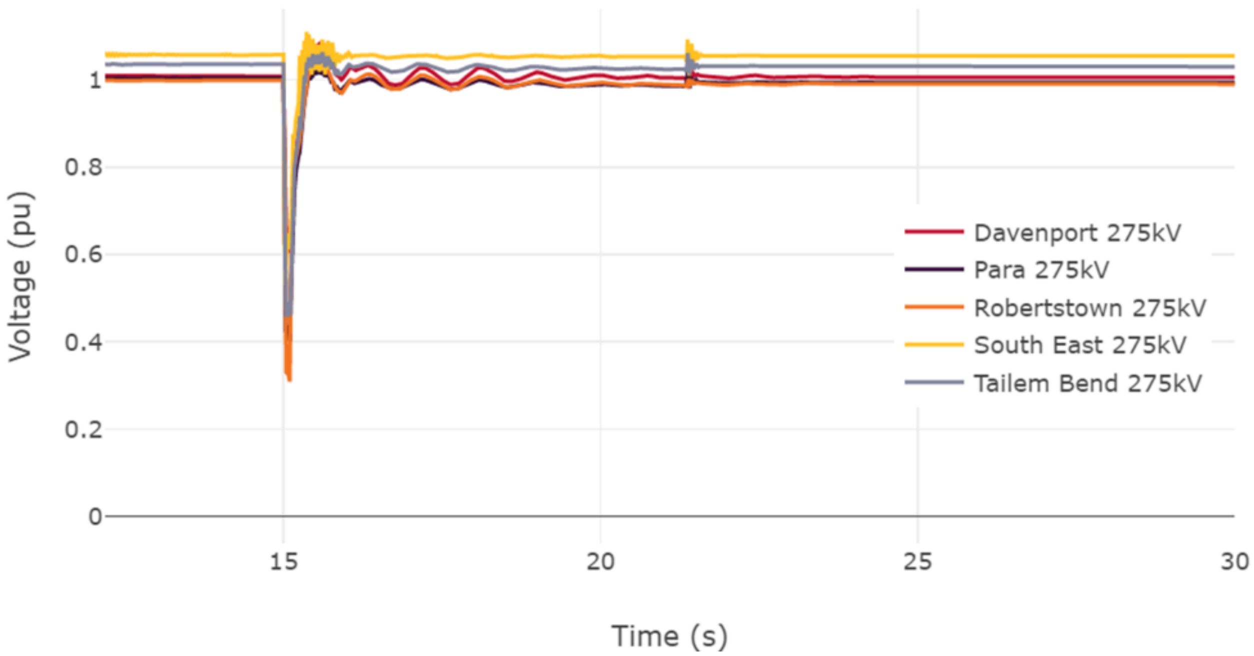
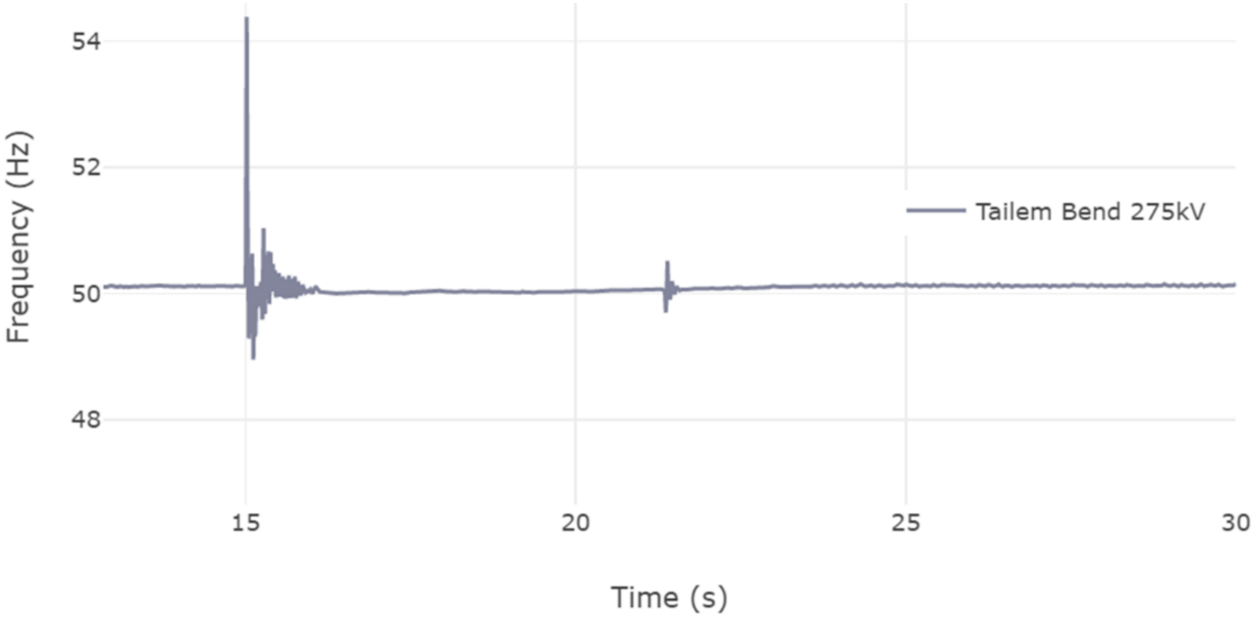


Figure 133 Frequency – prior outage of MLDC and trip of Robertstown – Tungkillo 275 kV



*Note: during the disturbance, the large variation in frequency transient is due to the way PSCAD™ estimates frequency using zero crossing approach, however this initial variation may be ignored.

Figure 134 Active power – prior outage of MLDC and trip of Robertstown – Tungkillo 275 kV