Trip of South East – Tailem Bend 275 kV lines on 12 November 2022

May 2023

Reviewable Operating Incident Report under the National Electricity Rules

Important notice

Purpose

AEMO has prepared this report in accordance with clause 4.8.15(c) of the National Electricity Rules, using information available as at the date of publication, unless otherwise specified.

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Incident classifications

Classification	Detail
Time and date of Incident	1639 hrs 12 November 2022
Region of incident	South Australia
Affected regions	South Australia and Victoria
Event type	Trip of both South East – Tailem Bend 275 kilovolts (kV) lines No.1 and No.2 and synchronous separation of South Australia
Generation impact	No generation loss
Customer load impact	No load shedding or disconnection
Associated reports	N/A

Abbreviations

Abbreviation	Term
ADMS	Advanced Distribution Management System
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AEST	Australian Eastern Standard Time
APC	Administered Price Cap
APP	Administered Price Period
BESS	Battery Energy Storage System
BoM	Bureau of Meteorology
CPT	Cumulative Price Threshold
DER	Distributed Energy Resource
DNSP	distribution network service provider
DPV	Distributed Photovoltaics
DPVC	Distributed Photovoltaic Contingency
FCAS	Frequency Control Ancillary Services
FFR	Fast Frequency Response
FOS	Frequency Operating Standard
HSM	High Speed Monitoring
HVDC	High Voltage Direct Current
Hz	Hertz
kV	kilovolts
KVA	Kilovolt amperes
MPC	Market Price Cap
ms	milliseconds
MW	Megawatts
NEM	National Electricity Market
NER	National Electricity Rules
NT	Northern Territory
OEM	Original Equipment Manufacturer

Abbreviation	Term
PMU	Phasor Measurement Unit
SA	South Australia
SCADA	Supervisory Control and Data Acquisition
SVC	Static Var Compensator
SWIS	South West Interconnected System
TIPS	Torrens Island Power Station
TNSP	transmission network service provider
VPP	Virtual Power Plant
WEM	Wholesale Electricity Market

Key report terms

Term	Explanation
[clause] 4.8.9 instruction	An instruction issued by AEMO to a registered participant under NER clause 4.8.9, other than in relation to scheduled plant or market generation. A clause 4.8.9 instruction can require a registered participant to do any act or thing if AEMO is satisfied that it is necessary to do so to maintain or re-establish the power system to a secure, satisfactory or reliable operating state. A registered participant must use reasonable endeavours to comply with a direction or clause 4.8.9 instruction.
Australian Solar Energy Forecasting System (ASEFS)	ASEFS is designed to produce solar generation forecasts for large solar power stations and small-scale DPV systems. The system includes two phases: • ASEFS phase 1 (ASEFS1) involves forecast of solar generation for semi-scheduled solar farms, and any non-scheduled and unregistered solar farms that AEMO is required to model in network constraints for power system security reasons. • ASEFS phase 2 (ASEFS2) provides forecasts of solar generation for DPV systems with capacity of less than 100 kilowatts (kW).
Distributed photovoltaic (DPV)	This consists of distribution-connected PV installations, generating at less than 30 megawatts (MW) capacity and exempt from registration in the NEM (exempt generators). These generators cannot be dispatched by AEMO. AEMO uses data from the Distributed Energy Resources (DER) Register and the Clean Energy Regulator to monitor the size and location of new DPV installations. AEMO has access to a limited sample of actual DPV generation data from which expected DPV generation can be forecast.
Enhanced voltage management (EVM)	SA Power Networks, the electricity distributor in South Australia, uses EVM to regulate voltage levels throughout the year and, under normal circumstances, maximise the amount of energy that DPV systems can generate. When using EVM, SA Power Networks increases or decreases the voltage levels at key distribution zone substations (within safe limits). A side-benefit of EVM is that at certain higher voltage levels, a subset of DPV systems trip, disconnecting from the system. This method of disconnecting DPV can be used as a last resort when required to maintain system security.
Non-scheduled generators	Non-scheduled generating systems generally have an aggregate capacity between 5 MW and 30 MW and do not participate in the central dispatch process. Most generation less than 5 MW is not required to register with AEMO. In addition, in South Australia, there are also some wind generating systems that connected to the network prior to the introduction of the semi-scheduled generator classification. These are known as non-scheduled intermittent generating units, ranging in size between 35 MW and 91 MW, and have a total capacity of 389 MW in South Australia. The output of these wind generating systems is forecast using the Australian Wind Energy Forecasting System (AWEFS).
Operational demand	Operational demand in a region is demand that is met by local scheduled generating units, semi-scheduled generating units, non-scheduled intermittent generating units of aggregate capacity greater than or equal to 30 MW, and generation imports to the region. It excludes the demand met by non-scheduled non-intermittent generating units, non-scheduled intermittent generating units of aggregate capacity less than 30 MW, exempt generation , and demand of local scheduled loads. Because it excludes demand met by DPV, operational demand decreases as DPV generation increases.
SCADA-controlled DPV	Larger DPV systems (with a capacity above approximately 200 kW) are required by SA Power Networks to be SCADA-controllable. These larger DPV systems can be turned off directly via SA Power Networks' SCADA system when necessary to maintain system security.
Semi-scheduled generating systems	Since 2008, generating systems with intermittent output (such as wind or solar farms) with an aggregate name plate capacity of 30 MW or more are classified as semi-scheduled. AEMO forecasts wind and solar generation and includes this in the dispatch process. AEMO can constrain

<table>
<tr><th>Term</th><th>Explanation</th></tr>
<tr><td></td><td>semi-scheduled generation down if required for system security reasons. AEMO uses the technical properties of each semi-scheduled generating system together with real-time data to forecast the output of these systems for upcoming dispatch intervals.</td></tr>
<tr><td>Smarter Homes regulations</td><td>From 28 September 2020, DPV systems in South Australia must comply with the “smarter homes” regulations. These regulations mean customers installing or upgrading solar systems in South Australia are required to appoint a relevant agent who will be responsible for disconnecting and reconnecting the solar system during state electricity security emergencies. This capability was implemented by the South Australian Government to manage scenarios such as the one discussed in this report, where system security is at risk and the only means to mitigate this risk is via a last resort tool to actively manage DPV. When disconnection is required to maintain system security, SA Power Networks will contact the relevant agent(s) with a disconnection requirement. The relevant agents will then meet the requirement</td></tr>
<tr><td>Frequency control ancillary services</td><td>AEMO operates eight separate market for the delivery of frequency control ancillary services (FCAS) in the NEM for procuring sufficient FCAS at any given time. These are listed below under the two types of frequency control:
Regulation:
• Regulation Raise: Regulation service used to correct a minor drop in frequency.
• Regulation Lower: Regulation service used to correct a minor rise in frequency.

Contingency:
<table>
<tr><th>Service</th><th>Name</th><th>Name in NER 3.11.2(a)</th></tr>
<tr><td>L6</td><td>Lower 6 second</td><td>Fast lower service</td></tr>
<tr><td>L60</td><td>Lower 60 second</td><td>Slow lower service</td></tr>
<tr><td>L5</td><td>Lower 5 minute</td><td>Delayed lower service</td></tr>
<tr><td>LREG</td><td>Lower regulating</td><td>Regulating lower service</td></tr>
<tr><td>R6</td><td>Raise 6 second</td><td>Fast raise service</td></tr>
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<tr><td>RREG</td><td>Raise regulating</td><td>Regulating raise service</td></tr>
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1 Overview

This is AEMO's full incident report relating to a reviewable operating incident as defined in National Electricity Rules (NER) clause 4.8.15(a)(1)(i) that occurred at 1639 hrs on 12 November 2022 in South Australia (SA). The incident involved non-credible contingency events on multiple transmission lines which resulted in synchronous separation of the majority of the SA power system from the rest of the National Electricity Market (NEM).

The incident was caused by the failure of a double circuit tower supporting the South East – Tailem Bend No. 1 and No. 2 275 kilovolt (kV) lines, causing them to trip. In addition, the Keith – Tailem Bend 132 kV line tripped due to operation of an overload protection scheme. Due to the location of the tower failure, substations between Keith and South East in SA remained connected to the NEM via the Heywood interconnector[1].

The Bureau of Meteorology (BoM) issued several weather warnings for severe thunderstorm activity for the wider Adelaide region on 12 November 2022. These weather warnings covered the area of the affected tower, with the main risks including damaging winds and bursts of heavy rainfall. AEMO did not make any reclassifications prior to the event, because the forecast and wind conditions did not meet the criteria of a destructive wind forecast.

Prior to the incident, the total operational demand[2] in SA was approximately 1,043 megawatts (MW), with scheduled and semi-scheduled generation of approximately 1,352 MW, and distributed photovoltaic (DPV) generation of approximately 470 MW. The Heywood – South East No. 2 275 kV circuit (one circuit of the Heywood interconnector) was on a planned outage. During this outage, Victoria to SA flows on Heywood were limited to 50 MW and SA to Victoria flow was limited to 250 MW across the remaining in-service line.

Following the incident, the majority of the SA region became synchronously separated (islanded) from the rest of the NEM at Tailem Bend substation in SA. There was no loss of transmission generation or customer load as a result of the incident. During the incident, AEMO observed an approximate 90 MW reduction in DPV output in response to the tower failure disturbance. AEMO estimates that approximately two-thirds of this reduction was due to DPV shake-off (unintended disconnections), and the remaining third was a controlled response to the over-frequency condition (required by the AS/NZS4777.2:2020 standard).

SA was operated as an island until temporary structures were erected, allowing the South East – Tailem Bend No. 1 275 kV circuit to return to service on 19 November 2022, reconnecting the SA island to the rest of the NEM.

All requirements necessary to maintain power system security throughout the incident were met. To achieve this, three key challenges had to be managed:

- The size of the maximum credible contingency event had to be maintained within the capability of the available frequency control resources available in the SA island.
- Minimum combinations of scheduled units had to remain online within SA to provide adequate system strength to the region.
- Sufficient levels of frequency control resources had to be online to meet the frequency operating standard (FOS) for any credible contingency event. Due to the SA island condition, AEMO sourced all frequency control

[1] Heywood interconnector is a 275 kV alternating current (AC) overhead electricity transmission line with two circuits connecting the South Australian and Victorian regions.

[2] Operational demand in SA is the demand that is met by local scheduled generating units, semi-scheduled generating units, non-scheduled intermittent generating units of aggregate units of aggregate capacity greater than or equal to 30 MW, and generation imports to the region.

ancillary services (FCAS) from within the SA Island. Due to this, SA FCAS prices experienced significant volatility, with the administered price cap being reached for some FCAS services within the region.

To maintain power system security within the SA island, AEMO optimised the dispatch of scheduled and semi-scheduled generating units and issued 4.8.9 instructions to ElectraNet[3] to maintain operational demand above specified thresholds. To comply with these 4.8.9 instructions, ElectraNet instructed SA Power Networks[4] to maintain the SA operational demand above the necessary threshold each day. SA Power Networks applied a range of mechanisms to curtail DPV on each day from 13 -17 November and 19 November 2022, with curtailment lasting between four and nine hours each day and reaching a maximum of approximately 410 MW. This DPV curtailment successfully reduced the largest credible contingency in the SA island to a secure operating limit.

AEMO's conclusions, recommendations and actions arising from its reviews are summarised in Table 1.

Table 1 Summary of conclusions and recommendations

Findings	Conclusions, recommendations and actions
ElectraNet's preliminary investigation indicates the presence of specific ground conditions at the footings of the failed tower which materially contributed to a footing failure.	AEMO recommends ElectraNet complete its investigation of the tower failure and advise of any additional risks or need for reclassification to manage system security. Once investigations have been completed later this year, AEMO will publish a supplementary or updated report including further details on the results of ElectraNet's investigations and any further actions ElectraNet is taking or considers it will need to take in response to the tower failure.
Following the separation, AEMO kept the Keith – Tailem Bend 132 kV line open at Tailem Bend substation end only until resynchronising the SA island to the rest of the NEM.	AEMO confirmed ElectraNet's advice that SA should not be connected to the NEM via the 132 kV network (Keith – Tailem Bend 132 kV line). This is primarily due to variability in renewable generation causing the flow on the Keith – Tailem Bend 132 kV line to drift. This drift is likely to cause the circuit to become overloaded and increase the potential for a disturbance to exceed the stability limits in the SA network.
DPV curtailment was required during this event to manage the frequency control implications of possible DPV shake-off in response to a fault (associated with legacy DPV systems and non-compliance of newer DPV systems with the disturbance ride-through requirements in AS/NZS4777.2:2020). The size of such a contingency is growing in all regions due to continued poor compliance of new DPV systems, which will increasingly impact on system operations.	AEMO recommends that compliance of distributed energy resources (DER) with technical settings (AS/NZS4777.2:2020) in all regions is improved as an urgent priority, targeting at least 90% of new installations to be set correctly to AS/NZS4777.2:2020 by December 2023. This requires collaborative engagement from many stakeholders. AEMO has released a comprehensive report outlining evidence on non-compliance and proposed next steps[5]. The report identifies a number of rapid improvements that can be implemented under existing frameworks (particularly by distribution network service providers [DNSPs] and original equipment manufacturers [OEMs]) and provides insights to support development of improved enduring governance frameworks. These insights have been shared with the Australian Energy Market Commission (AEMC) for consideration in its review on consumer energy resources technical standards[6].
All curtailment options contributed to managing system security were utilised. Post-incident investigation provided insights on the various methods for DPV curtailment applied: • SCADA-controlled DPV – larger DPV systems (approximately 200 kilowatts [kW] capacity and greater) were curtailed first, and responded as expected. • Directions to Relevant Agents under the Smarter Homes regulations – of the 517 MW of DPV capacity installed under this scheme, 25-42% were observed to respond as required in this event. SA Power Networks estimates that only 51% of systems are set up properly at the point of	AEMO recommends SA Power Networks implement improved frameworks in South Australia to achieve consistently high compliance of DPV systems with curtailment requirements (ensuring systems are properly set up, and maintained over time, to deliver curtailment requirements, and can be curtailed in an accurate and timely manner when directed).

[3] ElectraNet (ElectraNet Pty Ltd), is an electricity transmission company in South Australia.

[4] SA Power Networks is the sole electricity distributor in the state of South Australia.

[5] AEMO (April 2023) Compliance of Distributed Energy Resources with Technical Settings, https://aemo.com.au/-/media/files/initiatives/der/2023/compliance-of-der-with-technical-settings.pdf?la=en.

[6] AEMC, Review into consumer energy resources technical standards, https://www.aemc.gov.au/market-reviews-advice/review-consumer-energy-resources-technical-standards.

Findings	Conclusions, recommendations and actions
commissioning. Response rates were lowest on 13 and 14 November 2022 due to impacts of telecommunications outages caused by severe weather. In addition, response rates varied significantly between different Relevant Agents, with some achieving total response rates of 80-90%, and others achieving a response rate of 10-20% or lower. • Enhanced Voltage Management (EVM) – SA Power Networks uses EVM to regulate voltage levels throughout the year and, under normal circumstances, maximise the amount of energy that DPV systems can generate. A side-benefit of EVM is that at certain higher voltage levels, a subset of DPV systems will disconnect. This method of disconnecting DPV can be used as a last resort when required to maintain system security. It is estimated that at least two-thirds of the DPV curtailment during this event was delivered by EVM. Without this EVM capability, AEMO would have likely been unable to maintain power system security during high DPV periods, especially on 13, 17 and 19 November 2022. However, EVM also led to some DPV systems demonstrating cycling behaviour (repeated switching on/off every 10-20 minutes), and impacted FCAS availability of distribution-connected resources.	
This event highlights a need for DPV curtailment emergency backstop capabilities in all regions, and provides learnings for other regions on factors to consider during implementation.	AEMO recommends emergency curtailment backstop capabilities are to be implemented in all regions (ability to curtail all new DPV installations to zero active power if required as a last resort to maintain power system security) as a priority. NSPs, governments, AEMO and the AEMC will all likely need to play a role in delivering these capabilities, preferably with national consistency. In implementing emergency backstop capabilities, consider: • Mechanisms and frameworks for managing compliance (during initial set-up, and maintained over time). • The robustness of the technical approach applied, especially under conditions where communications networks may be compromised and there may be widespread power outages (due to flooding, bushfires, storm damage, or other reasons). These types of conditions may coincide with challenging grid conditions where emergency backstop capabilities are required. • Suitable fallback settings (default behaviour that each DER inverter is programmed to autonomously perform if communications is lost for an extended period). • Standards-based schemes for DPV management (such as IEEE 2030.5 CSIP-AUS), targeting consistency of approach across jurisdictions, and ensuring inverters respond quickly and consistently, supporting predictable fallback behaviours, and simplifying implementation for DNSPs and equipment manufacturers. • Methods that allow selective curtailment capability on an individual system-by-system basis, for example so that FCAS delivery is not inhibited in periods where active DPV management is in use. Consideration should also be given to the possible use of these curtailment mechanisms to assist in managing DPV during a system restart. • Options for managing cyber security risk including cyber-informed engineering and the capability for achieving redundancy and robustness in data and control pathways for the purpose of being able to isolate and disconnect potentially compromised DER nationally.
Some of the approaches applied in this event to manage DPV impacted the ability of distribution-connected resources to deliver FCAS.	By end of 2023, AEMO, SA Power Networks, and the relevant market participants to investigate the availability of DER to deliver FCAS during periods of DPV curtailment. This analysis should seek to understand how these resources might be affected by the various mechanisms used to manage DPV, and ensure appropriate processes and tools are in place to deliver accurate FCAS availability estimates in real time.
Throughout this incident AEMO lacked real-time visibility of DPV output in SA. This impacted AEMO's, ElectraNet's and SA Power Networks' ability to respond to the incident effectively	By Q1 2024, AEMO to develop a plan for implementing fit-for-purpose improvements to tools that monitor the DPV in operation in real time and the visibility of DPV curtailment when it is occurring.

This report is prepared in accordance with clause 4.8.15 of the NER. It is based on information provided by participants and AEMO.

National Electricity Market time (Australian Eastern Standard Time [AEST]) is used in this report.

2 The incident

2.1 Pre-event conditions

2.1.1 Generation and demand

Table 2 provides a summary of SA system conditions at 1639 hrs on 12 November 2022, just prior to the incident.

Table 2 South Australia key system conditions at 1639 hrs, 12 November 2022

Quantity description	Value (MW)
South Australia operational demand	1,043
South Australia scheduled and semi-scheduled generation	1,352
South Australia DPV	470
Murraylink high voltage direct current (HVDC) interconnector flow (export to Victoria)	122
South East – Tailem Bend 275 kV lines flow (flow from Tailem Bend to South East)	258
Keith – Tailem Bend 132 kV line flow (flow toward Victoria from Tailem Bend to Keith)	19
Heywood interconnector flow (export to Victoria)	208

Table 3 provides a summary of SA scheduled and semi-scheduled generator dispatch at 1639 hrs on 12 November 2022.

Table 3 South Australia scheduled and semi-scheduled generation dispatch at 1639 hrs, 12 November 2022

Station name	Dispatch Unit Identifier (name)	Dispatched generation (MW)	Station name	Dispatch Unit Identifier (name)	Dispatched generation (MW)
Bluff Wind Farm	BLUFF1	19	Lincoln Gap Wind Farm 2	LGAPWF2	43
Bungala Solar Farm 1	BNGSF1	3	Mount Millar Wind Farm	MTMILLAR	1
Bungala Solar Farm 2	BNGSF2	2	North Brown Hill Wind Farm	NBHWF1	50
Canunda (Snuggy) Wind Farm	CNUNDAWF	15	PAREP Wind Farm	PAREPW1	179
Hallett Power Station	AGLHAL	32	Pelican Point	PPCCGT	335
Hallett Wind Farm	HALLWF1	40	Quarantine Power Station 1	QPS1	28
Hornsdale Power Reserve	HPRL1	12 (Charging)	Quarantine Power Station 3	QPS3	29
Hornsdale Wind Farm 1	HDWF1	64	Snowtown North Wind Farm	SNOWNTH1	39
Hornsdale Wind Farm 2	HDWF2	93	Snowtown South Wind Farm	SNOWSTH1	78
Hornsdale Wind Farm 3	HDWF3	100	Starfish Hill Wind Farm	STARHLWF	18
Lake Bonney Wind Farm 2	LKBONNY2	2	Torrens Island Power station B unit 4	TORRB4	60
Lake Bonney Wind Farm 3	LKBONNY3	0.5	Waterloo Wind Farm	WATERLWF	39
Lake Bonney BESS	LBBL1	7 (Charging)	Willogoleche Wind Farm	WGWF1	12
Lincoln Gap Wind Farm 1	LGAPWF1	62			

2.1.2 Prior outages and key constraints

Prior to the incident, the following outages in the vicinity of Tailem Bend were in place:

- Planned outage of the Heywood – South East No. 2 275 kV circuit (part of the Heywood interconnector). This outage commenced at 0405 hrs on 12 November 2022 and was due to return to service by 1700 hrs on 14 November 2022. During this outage, the Victoria to SA Heywood flow was limited to 50 MW and SA to Victoria Heywood flow was limited to 250 MW across the remaining in-service line.
- Planned outage of the Robertstown No. 1 synchronous condenser. This outage commenced at 0832 hrs on 23 October 2022.
- Forced outage of No. 2 static Var compensator (SVC) at Para substation. This outage commenced at 1938 hrs on 4 January 2022.

2.1.3 Weather conditions in South Australia on 12 November 2022

On 12 November 2022, a low-pressure system was deepening over SA with troughs through central and southern Australia ahead of this low. The main trough over SA was moving into a region with significant levels of available atmospheric moisture, instability and upper-level wind dynamics conducive to widespread thunderstorm development. Severe thunderstorms developed over multiple regions but especially across SA and parts of the Northern Territory (NT), where some significant damage was observed around the major population centres of Adelaide and Alice Springs during the afternoon.

2.2 Event

At approximately 1639 hrs on 12 November 2022, the South East – Tailem Bend No.1 and No.2 275 kV lines tripped. This was caused by a double circuit transmission tower failure located approximately 7 km south of Tailem Bend substation. Figure 1 shows the geographical location of the fault and Appendix A1 shows the single line electrical diagram of the SA network near Tailem Bend substation.

Figure 1 Geographical location of the failed tower

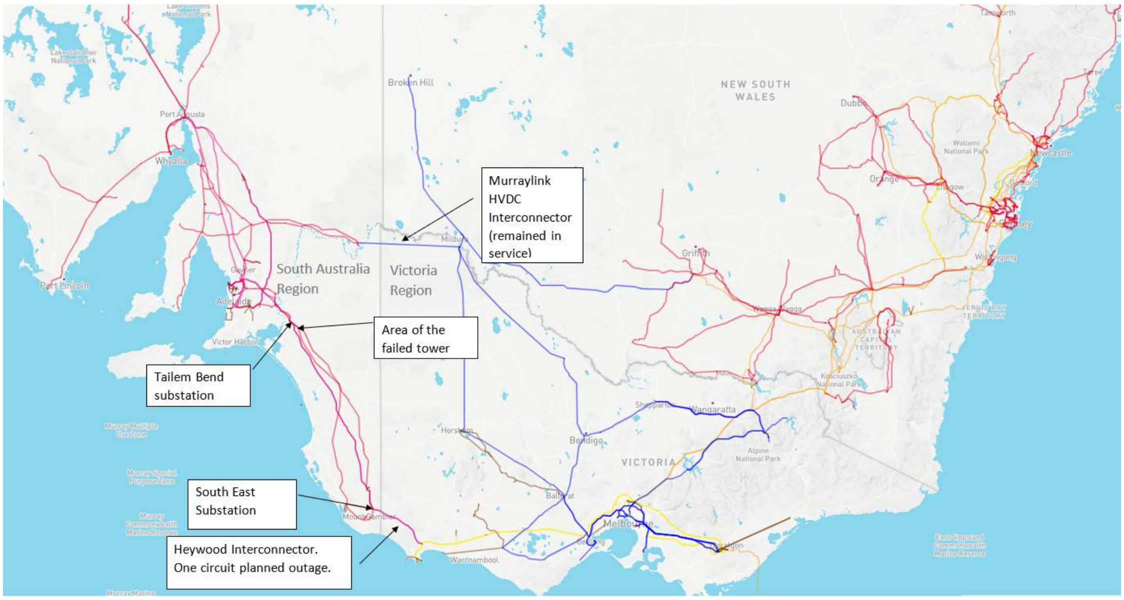


Table 4 provides the summary of subsequent events and conditions due to the tripping of South East – Tailem Bend No.1 and No. 2 275 kV lines.

Table 4 Sequence of events

Operating time (hh:mm:ss.000)	Event
12/11/2022 16:38:55.322	A phase to earth fault on South East – Tailem Bend No. 1 275 kV line.
16:38:55.404	Operation of A phase circuit breakers on South East – Tailem Bend No. 1 275 kV line. This A phase fault was cleared within 81.7 milliseconds (ms).
16:38:55.563	C Phase to earth fault on South East – Tailem Bend No. 1 275 kV line.
16:38:55.654	Operation of C and B phase circuit breakers on South East – Tailem Bend No. 1 275 kV line. This C phase fault was cleared within 90.5 ms.
16:38:56.194	A phase to earth fault on South East – Tailem Bend No. 2 275 kV line.
16:38:56.273	Operation of A phase circuit breakers on South East – Tailem Bend No. 2 275 kV line. This A phase fault was cleared within 79.1 ms.
16:38:56.549	B phase to earth fault on South East – Tailem Bend No. 2 275 kV line.
16:38:56.629	Operation of B and C phase circuit breakers of South East – Tailem Bend No. 2 275 kV line. This B phase fault was cleared within 80 ms.
16:38:57	Current on Keith – Tailem Bend 132 kV line exceeds 880 amps (A).
16:38:57.379	Overload protection scheme trips CBs at Keith – Tailem Bend 132 kV line at Tailem Bend.
16:38:57	The SA (synchronous) island remained electrically connected to the rest of the NEM via the Murraylink HVDC interconnector. (However, frequency control services and system inertia cannot be provided to SA via the Murraylink HVDC interconnector.)
19/11/2022 18:02	South East – Tailem Bend No. 1 275 kV line restored with conductors suspended via a temporary structure.
19/11/2022 18:27	Keith – Tailem Bend 132 kV line returned to service.
23/11/2022 18:02	South East – Tailem Bend No. 2 275 kV line restored with conductors suspended via a temporary structure.
23/11/2022 1829	AEMO revoked all constraints applicable to this incident

In response to this incident, to maintain power system security in the SA island:

- AEMO issued NER clause 4.8.9 instructions to ElectraNet to maintain operational demand in the island above a threshold.
- In response to these instructions, ElectraNet instructed SA Power Networks to maintain the operational demand above the necessary threshold.
- SA Power Networks applied a range of mechanisms to curtail DPV on 13-17 and 19 November 2022 (see Section 4 for further details).

2.3 Cause of South East – Tailem Bend 275 kV tower failure

2.3.1 Tower and Tower condition

ElectraNet's preliminary investigation indicates the presence of specific ground conditions at the site of the failed tower (as shown in Figure 2) materially contributed to tower footing failure and subsequent tower failure, but it is still too early to ascertain the exact tower failure mechanism. Soil sampling and investigations at the site identified highly corrosive soil with high variations in water table. In addition, the rate of steel corrosion observed at the tower failure site is not consistent with the corrosion rate predicted by ElectraNet's soil corrosion model.

Figure 2 Photograph of the failed double circuit tower

ElectraNet is undertaking further investigations to establish the exact tower failure mechanism, including further soil sampling and detailed assessment of tower footings at specific locations. ElectraNet has identified other potential high corrosion soil exposure sites based on the depth of water table, high content of salinity/salts, soil moisture etc, based on government-sourced data. Soil sampling for all identified high corrosion exposure locations along the interconnector tower route has been completed and laboratory testing is underway. Additional on-site testing and investigations may be required.

Based on the information available at this time, ElectraNet believes this is an isolated failure and the probability of a similar weakness in the foundations of other towers on the line is low.

Once investigations have been completed later this year, AEMO will publish a supplementary or updated report including further details on the results of ElectraNet's investigations and any further actions ElectraNet is taking or considers it will need to take in response to the tower failure.

2.3.2 Weather conditions in South Australia

The BoM issued several weather warnings for severe thunderstorm activity for the wider Adelaide region on 12 November 2022, including the area of the affected tower, with the main risks including damaging winds and bursts of heavy rainfall. However, the forecast wind conditions did not meet the criteria of a destructive wind forecast[7].

The detailed severe thunderstorm warnings issued[8] on the day are shown in Figure 3. Specifically, across the SA region some of the highest wind gusts recorded concurrent with these thunderstorms included 106 km/h at Adelaide Airport (1553 hrs local time), while the closest recorded wind gust to Tailem Bend was 61 km/h recorded at Murray Bridge (1643 hrs local time).

Associated with the thunderstorms across the Adelaide region were heavy rainfalls, with several locations recording their highest November daily rainfalls on record for the 24-hour period to 0900 hrs on 13 November

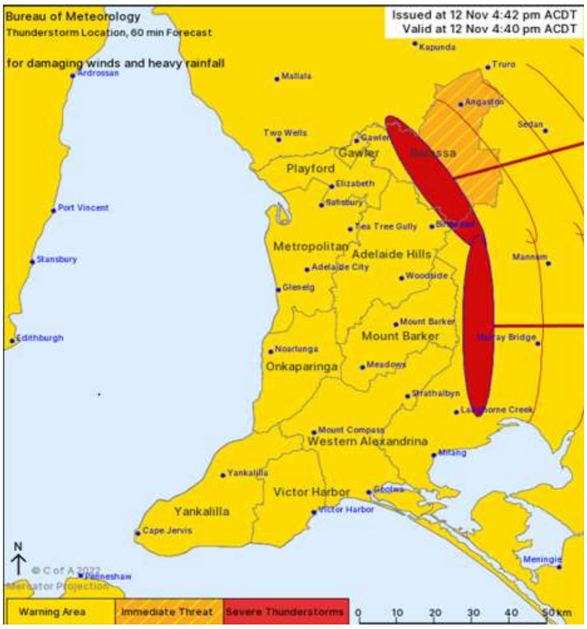
[7] See Power System Security Guidelines, https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/power_system_ops/procedures/so_op_3715-power-system-security-guidelines.pdf?la=en.

[8] See details of destructive wind conditions in the published AEMO request for Protected Event Declaration, https://www.aemc.gov.au/sites/default/files/2019-04/AEMO%20Request%20for%20protected%20event%20declaration.pdf.

2022. These included 52.6 mm at Prospect Hill, 48.2 mm at Strathalbyn Racecourse, and 36 mm at Kangarilla, while the 24-hour rainfall total at Murray Bridge was 21.6 mm.

ElectraNet's further investigation has found that wind conditions in the vicinity of the failed tower on 12 November 2022 remained below the destructive wind condition level. As such, ElectraNet has concluded that weather conditions were not the main cause of the tower failure.

Figure 3 Severe thunderstorm warnings issued by the BOM



2.4 Analysis of the event and power system response

2.4.1 Operation of protection and control schemes

The following protection and control schemes operated, consistent with expected performance:

- Trip of South East – Tailem Bend No. 1 275 kV line:
  - A phase to earth fault detected. Single phase protection operated and cleared the A phase in 81 milliseconds (ms).
  - C phase to earth fault detected. All three phases tripped in 91 ms.
- Trip of South East – Tailem Bend No. 2 275 kV line:
  - A phase to earth fault detected. Single phase protection operated and cleared the A phase in 82 ms.
  - B phase to earth fault detected. All three phases tripped in 82 ms.
- Trip of Keith – Tailem Bend No. 2 132 kV line:
  - Following the tripping of both South East – Tailem Bend No. 1 and No. 2 275 kV lines, the flow in these lines was transferred to the weaker Keith – Tailem Bend 132 kV line. Overload protection operated to disconnect the 132 kV connection at Tailem Bend approximately 1.7 seconds after the second 275 kV line tripped.

Note that the South East – Tailem Bend No.1 and No. 2 275 kV lines are equipped with the following two protection schemes:

- Set-1 relays with a main differential protection scheme and a backup time delayed (400 ms) distance protection scheme.
- Set-2 relays with a distance protection scheme.

Two minutes prior to the incident, the communication system of the Set-1 line differential protection failed on both South East – Tailem Bend No.1 and No. 2 275 kV lines due to a series of faults in the vicinity of the communication corridor. Due to this loss of communication, the differential protection scheme was blocked by the Set-1 protection relays prior to the tower failure.

The multiple faults on both transmission lines caused by the tower failure were cleared by the South East – Tailem Bend No.1 and No. 2 275 kV lines Set-2 distance protection schemes. Both distance protection schemes correctly operated and faults were cleared within the NER maximum fault clearance times. Set-1 backup delayed distance protection did not operate as the faults were cleared prior to operations of the Set-1 backup delayed distance protection.

2.4.2 DPV behaviour during SA separation

Immediately prior to the event, DPV in SA was estimated to be generating 470 MW (252-563 MW[9]).

Based on a sample of five seconds resolution data from 4,004 DPV circuits in SA, it is estimated that DPV generation reduced by approximately 90 MW (a 20% reduction) in response to the disturbance. Approximately two-thirds of this reduction was due to DPV shake-off (unintended disconnections), and the remaining third was a controlled response to the over-frequency condition (required by the AS/NZS4777.2:2020 standard).

As shown in Figure 4, operational demand was measured to increase by approximately 76 MW in response to the disturbance, which is consistent with the estimated total reduction in DPV generation.

Figure 4 Operational demand in South Australia – 12 November 2022

[9] There was high uncertainty in the exact level of DPV generation at the time of the event since DPV was ramping rapidly and estimates from ASEFS2 have a 30min lag. ASEFS2 is the Australian Solar Energy Forecasting System phase 2, which provides forecasts of small-scale (<100 kW) DPV solar energy generation for NEM forecasting processes. Further information at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/operational-forecasting/solar-and-wind-energy-forecasting/australian-solar-energy-forecasting-system.

DPV disconnections

It is estimated that 13% of the total DPV fleet in SA disconnected in response to the disturbance[10]. This rate of disconnections is more than double that observed in previous disturbances with a similar frequency peak[11], indicating that voltage disturbance, phase angle jump, or other phenomena contributed to increased DPV disconnections in this event.

The sample set used to produce this estimate included 99 DPV circuits installed since December 2021 when the AS/NZS4777.2:2020 standard became mandatory. This 2020 standard included new provisions aiming to improve disturbance ride-through capabilities of distributed inverters. Based on this sample, 8% (4-15%) of the DPV inverters installed since December 2021 in SA appeared to disconnect following the separation event. Although the sample set is small, this suggests continuing high rates of installation of inverters that do not comply with the improved disturbance ride-through requirements defined in the AS/NZS4777.2:2020 standard.

DPV over-frequency controlled droop response

Inverters installed under the AS/NZS4777.2 2015 and 2020 standards are required to provide a controlled over-frequency droop response[12]. In this event, frequency reached a peak of 50.53 hertz (Hz) and stayed above 50.15 Hz for more than 35 minutes (based on 20-second averaging). DPV inverters were expected to respond by reducing generation by 15% and remaining at this reduced level for the entirety of that interval. This response is intended to provide a contribution to frequency containment, stabilisation and recovery.

DPV circuits in the sample set installed when the AS/NZS4777.2 2015 or 2020 standards applied were analysed to compare their individual responses to the required responses in the applicable standards.

Responses were categorised as illustrated in Figure 5 (which shows the normalised response of inverters in each category type for the AS/NZS 4777.2:2015 inverters).

Figure 6 shows the proportion of inverters demonstrating behaviours in each type of response category.

In this event, 21% of 2015 standard inverters and 37% of 2020 standard inverters responded as specified. However, 16-19% of inverters did not respond to the over-frequency condition at all. A further 25-32% of inverters only partially responded (with many of these returning to normal operation following a 12-second interval of frequency falling below 50.15 Hz at 16:50).

This indicates continuing high rates of non-compliance with behaviours specified in AS/NZS4777.2 standards, including for new installations under the 2020 standard[13]. This finding is consistent with AEMO's findings in previous disturbances[14].

[10] This is scaled to correct for sample bias, including representation of different manufacturers, AS/NZS4777 standard, and distance from the disturbance, based on a sample of 155 DPV circuits installed under the 2005 standard, 3750 DPV circuits installed under the 2015 standard and 99 DPV circuits installed under the 2020 standard.

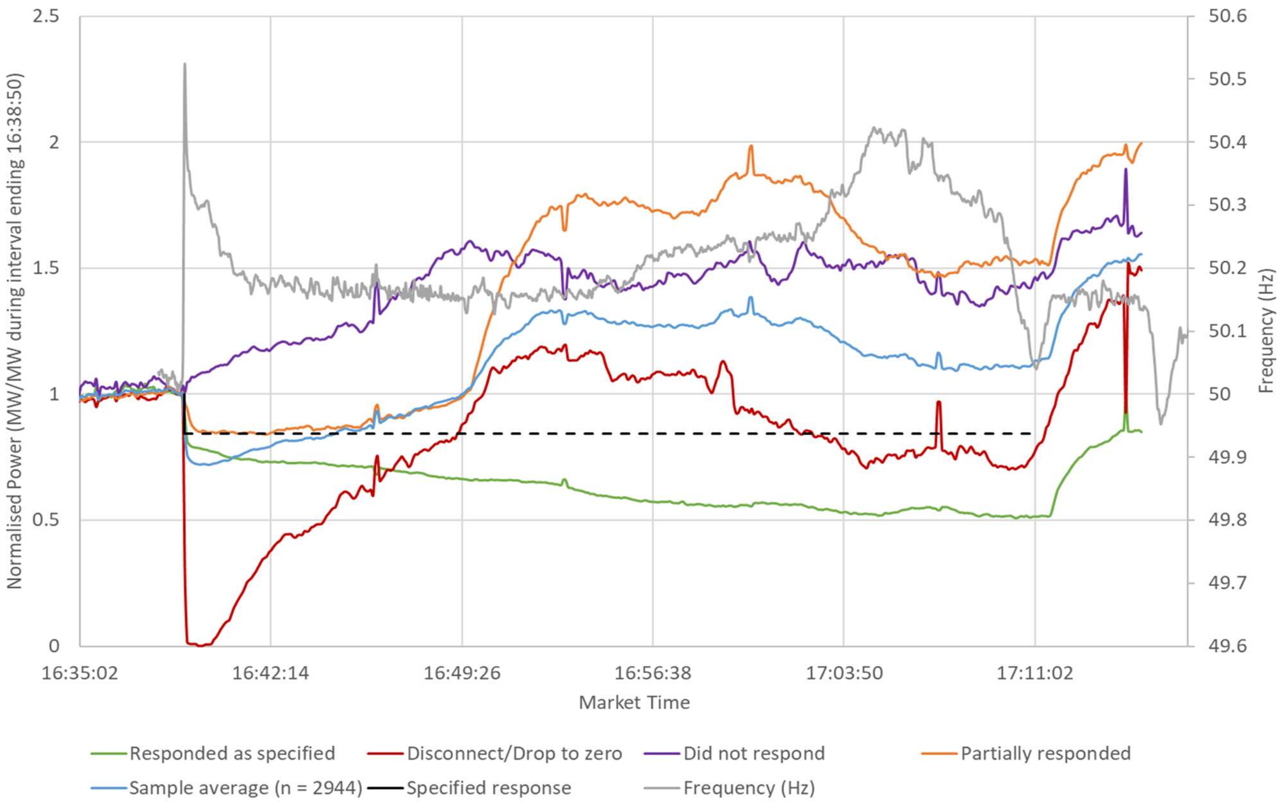
[11] There have been two previous disturbances with frequency peak around 50.4 hertz (Hz); these showed approximately 5% of DPV inverters disconnecting. For more details, see Figure 19 at https://aemo.com.au/-/media/files/initiatives/der/2021/capstone-report.pdf?la=en&hash=BF184AC51804652E268B3117EC12327A.

[12] When frequency exceeds 50.25 Hz, inverters should reduce generation as a linear function of the maximum observed frequency, until 52 Hz. Inverters should maintain this level until the frequency falls below 50.15 Hz for 60 seconds (for inverters under the 2015 standard), or 20 seconds (for inverters installed under the 2020 standard).

[13] AEMO (April 2023) Compliance of Distributed Energy Resources with Technical Settings, https://aemo.com.au/-/media/files/initiatives/der/2023/compliance-of-der-with-technical-settings.pdf?la=en.

[14] AEMO (May 2021) Behaviour of distributed resources during power system disturbances, Section 4.1, https://aemo.com.au/-/media/files/initiatives/der/2021/capstone-report.pdf?la=en&hash=BF184AC51804652E268B3117EC12327A.

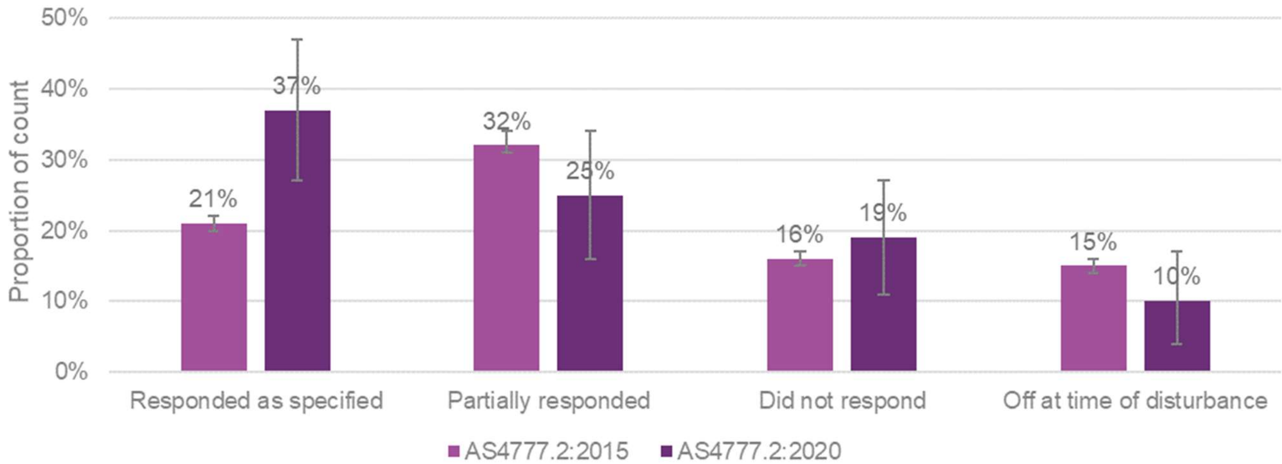
Figure 5 Normalised responses of inverters installed under AS/NZS4777.2:2015 in South Australia



The dashed line indicates the "ideal response", based on the maximum frequency (50.53 Hz).

Responded as specified: The system reduced power by at least 50% of the specified reduction for the whole response period. **Partially responded:** The system reduced power by at least 50% of the specified reduction for at least one measurement interval in the first two minutes but did not sustain the response as specified. **Did not respond:** The system did not demonstrate a significant reduction response. **Off at time of disturbance:** The system was not generating immediately prior to the event.

Figure 6 DPV over-frequency droop response compliance



The total controlled over-frequency droop response from DPV is estimated as 34 MW (7% of the total DPV fleet generation at the time of the event).

3 Power system security

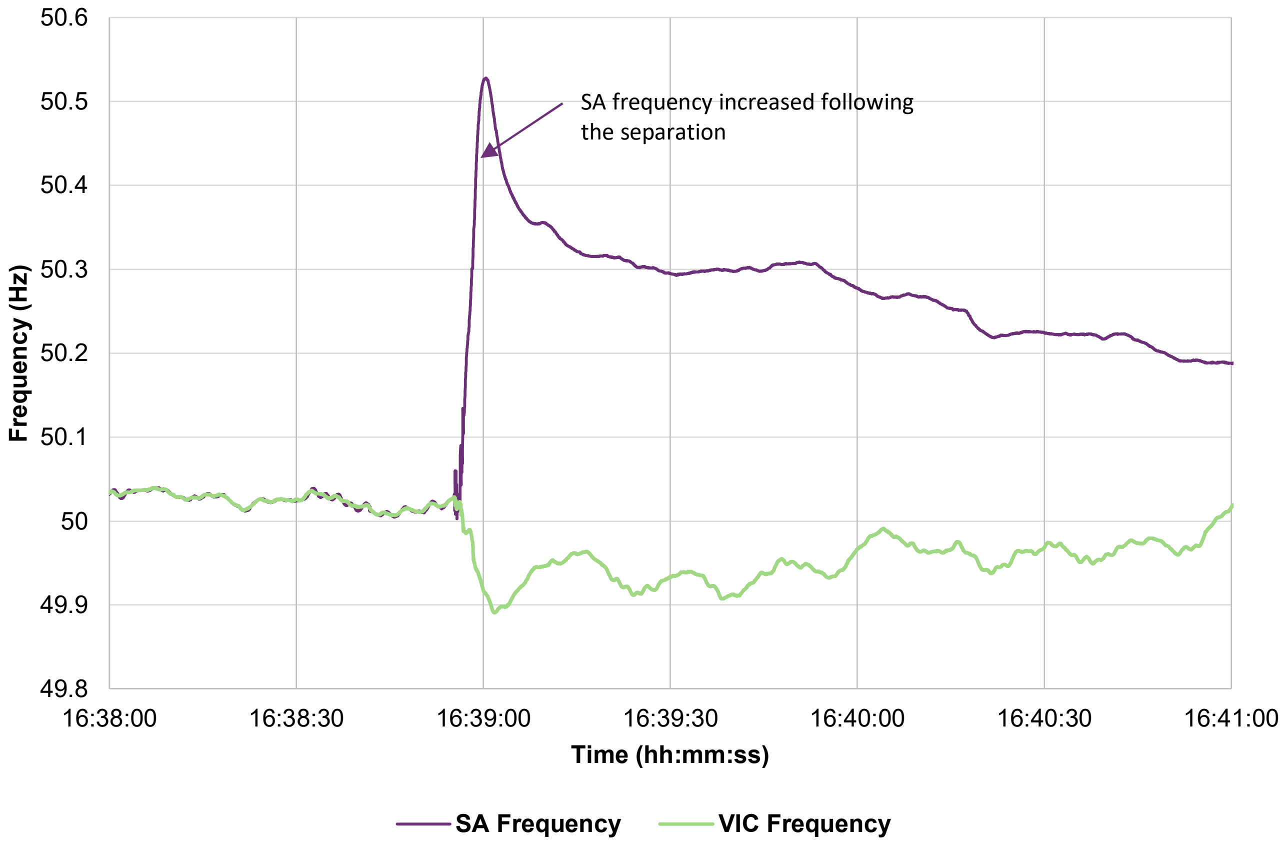
AEMO is responsible for power system security in the NEM. This means AEMO is required to operate the power system in a secure operating state to the extent practicable and take all reasonable actions to return the power system to a secure state following a contingency event in accordance with the NER[15].

3.1 Frequency and voltage performance

3.1.1 Frequency performance

As a result of the trip of the South East – Tailem Bend No.1 and No.2 275 kV lines and subsequent trip of the Keith – Tailem Bend 132 kV line (a non-credible contingency event), the SA island frequency increased to 50.53 Hz before reducing to below 50.2 Hz in less than two minutes. The frequency in the remainder of the mainland NEM dropped to a minimum of 49.9 Hz in response to this incident. Figure 7 shows the frequency traces for SA and Victoria during this incident.

Figure 7 South Australia island and Victoria frequency during the incident



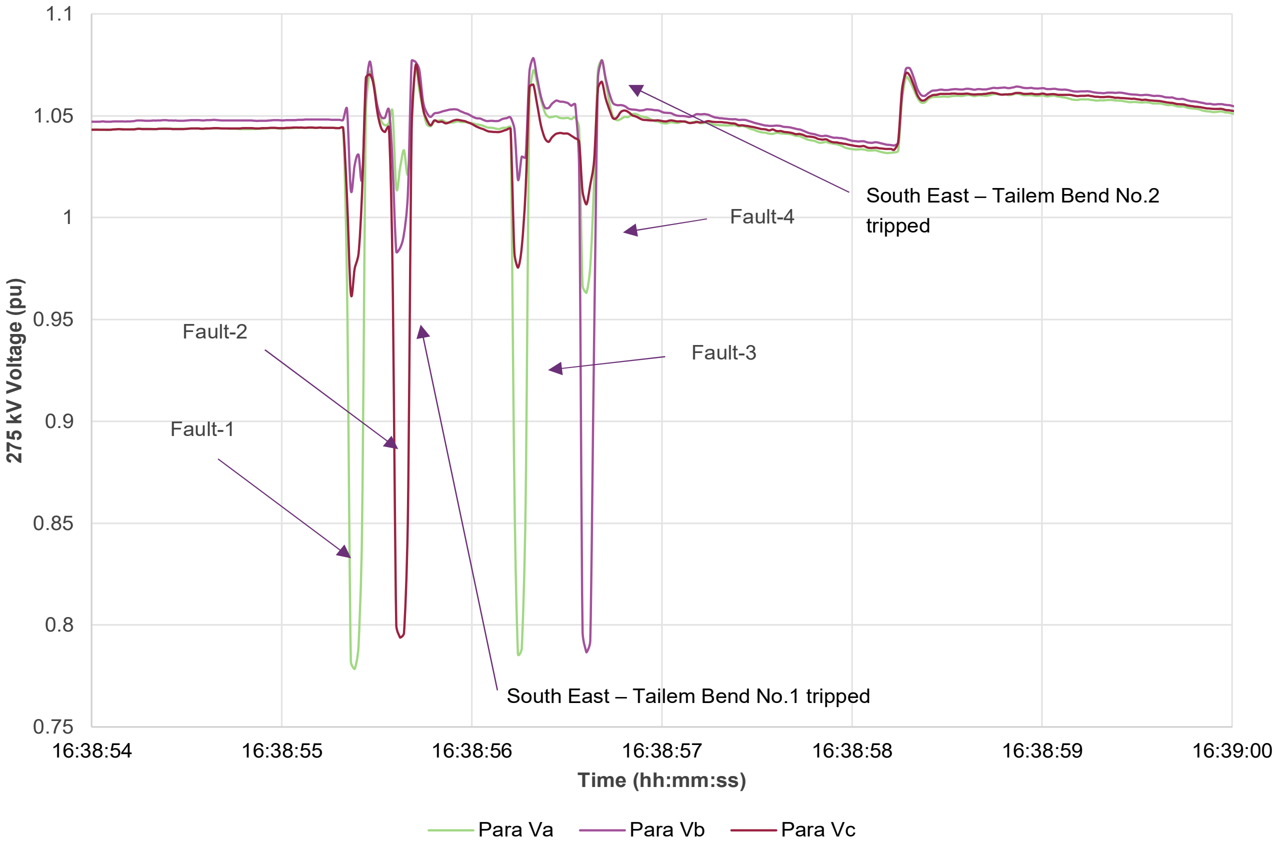
[15] Refer to AEMO's functions in section 49 of the National Electricity Law and the power system security principles in clause 4.2.6 of the NER.

3.1.2 Voltage performance

Figure 8 below shows the voltage performance of the SA system during the incident. As shown, the tower failure resulted in four separate single phase to earth faults with associated voltage dips:

- Fault-1 – "A" phase fault on the South East – Tailem Bend No. 1 275 kV line.
- Fault-2 – "C" phase fault on the South East – Tailem Bend No. 1 275 kV line.
- Fault-3 – "A" phase fault on the South East – Tailem Bend No. 2 275 kV line.
- Fault-4 – "B" phase fault on the South East – Tailem Bend No. 2 275 kV line.

Figure 8 Voltages during incident at Para 275 kV substation



3.2 Generator and BESS performance

As part of AEMO's investigation of this incident, AEMO analysed the performance of a subset of generators and battery energy storage systems (BESS). Table 5 below summarises the findings of AEMO's analysis and the figures included in the report relevant for each generator.

Generators' performance has been assessed against S5.2.5.11 of the NER. Generator performance standards (GPS) are confidential, and as such AEMO cannot discuss specific GPS requirements for each analysed generator; in addition, individual GPS requirements vary for each generator. Compliance statements in the text that follows are therefore general in nature, stating whether a generator complied or not, but without mentioning confidential performance requirements.

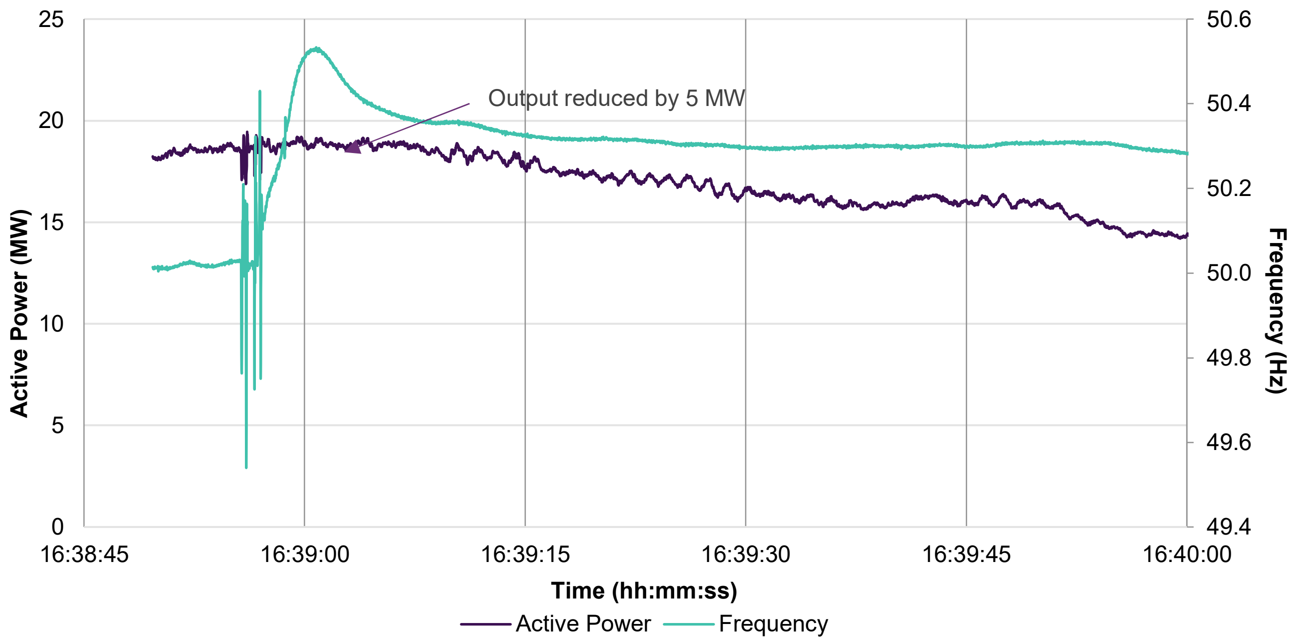
Table 5 Analysed generators

Generator		Response was consistent with expected performance	Figure
Bluff Wind Farm	BLUFF1	Yes	Figure 9
Dalrymple BESS	DALNTHL1	Yes	Figure 10
Hallett Gas Turbine	AGLHAL	Yes	Figure 11
Hallett Wind Farm	HALLWF1	Yes	Figure 12
Hallett Hill Wind Farm	HALLWF2	Yes	Figure 13
Hornsdale Wind Farm 1	HDWF1	Yes	Figure 14
Hornsdale Wind Farm 2	HDWF2	Yes	Figure 15
Hornsdale Wind Farm 3	HDWF3	Yes	Figure 16
Hornsdale Power Reserve	HPRL1	Yes	Figure 17
North Brown Hill Wind Farm	NBHWF1	Yes	Figure 18
Torrens Island Power Station (TIPS) B4	TORRB4	Yes	Figure 19

3.2.1 Bluff Wind Farm

As shown in Figure 9 below, in response to the SA frequency increase at 1639 hrs, Bluff Wind Farm initially continued operating at the same power output then started to gradually decrease its power output. AEMO has concluded that Bluff Wind Farm's response was consistent with expected performance.

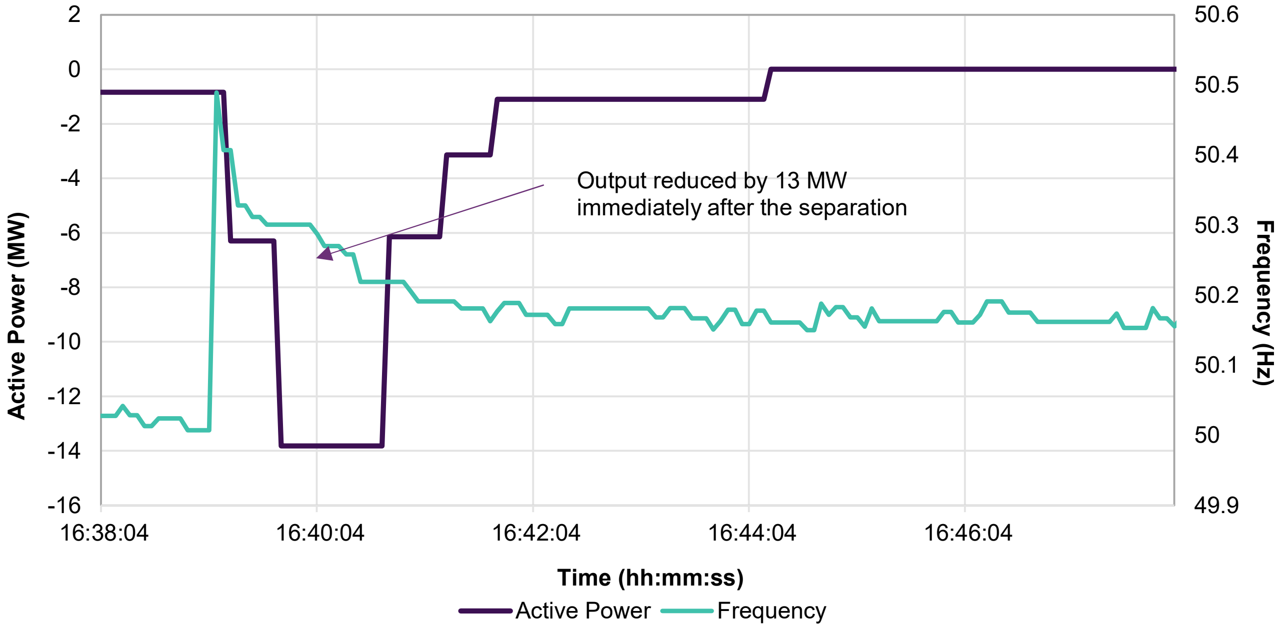
Figure 9 Bluff Wind Farm response



3.2.2 Dalrymple BESS

Dalrymple BESS data was taken from the AEMO PI system[16] (4 seconds resolution). As shown in Figure 10 below, in response to the SA frequency increase at 1639 hrs, Dalrymple BESS started to reduce power, with a maximum reduction of around 13 MW. AEMO has concluded that Dalrymple BESS's response was consistent with expected performance.

Figure 10 Dalrymple BESS response



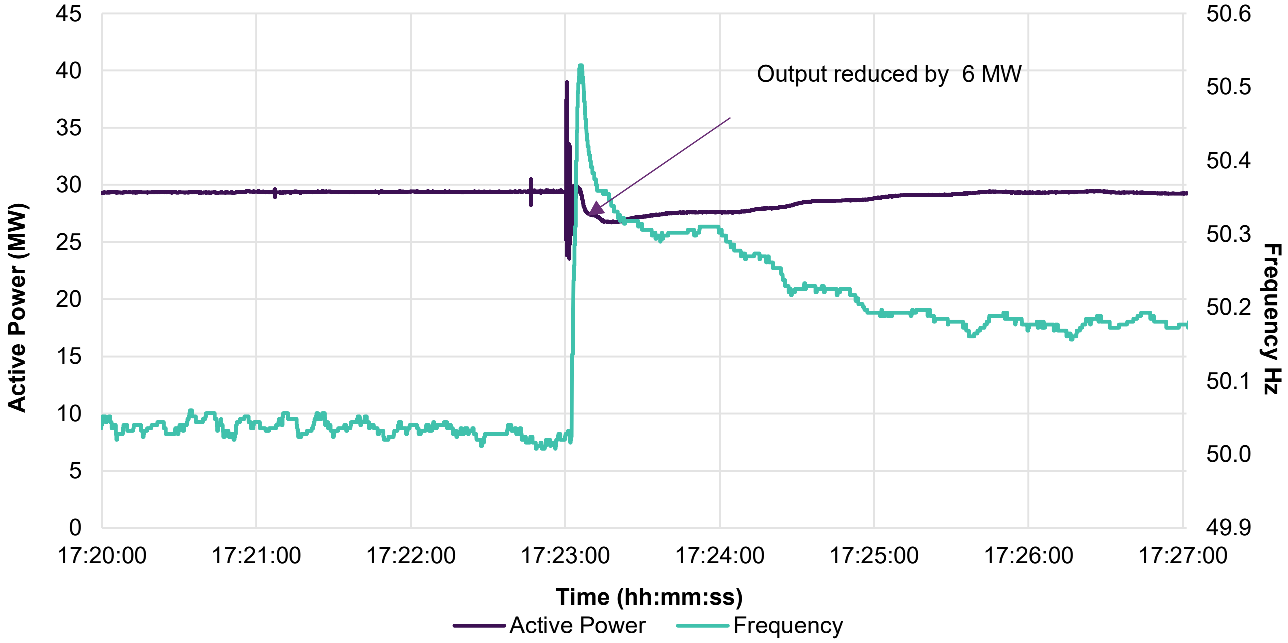
3.2.3 Hallett Gas Turbine

As shown in Figure 11 below[17], in response to the SA frequency increase at 1639 hrs, Hallett Gas Turbine started to reduce power with a maximum reduction of around 6 MW. AEMO has concluded that Hallett Gas Turbine's response was consistent with expected performance.

[16] PI system is a suite of software products that are used for data collection, historicising, finding, analysing, delivering and visualising large amounts of high-fidelity, time -series data from multiple sources to people and systems across all operations. For more information, see https://resources.osisoft.com/pi-system/.

[17] Chart was developed based on data submitted by the participant. The time shown in the graph is not aligned with the with the NEM time stamped data used in this report.

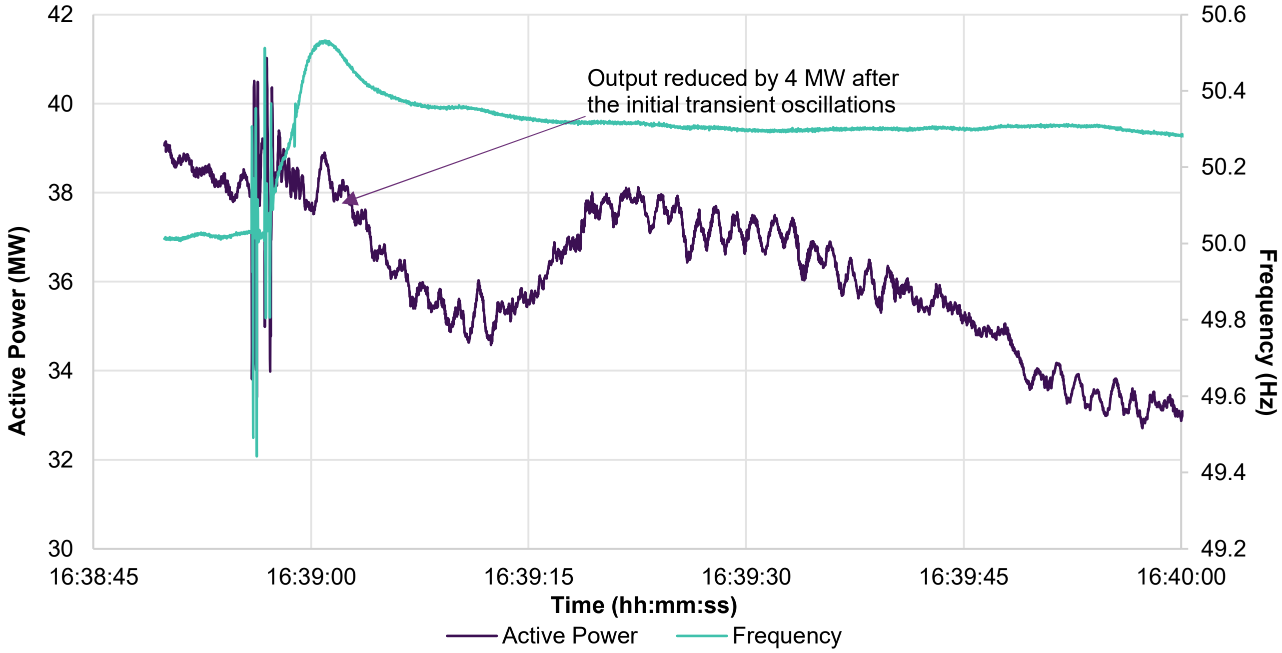
Figure 11 Hallett Gas Turbine response



3.2.4 Hallett Wind Farm

As shown in Figure 12, in response to the SA frequency increase at 1639 hrs, Hallett Wind Farm started to reduce its output after the initial transient oscillations. AEMO has concluded that Hallett Wind Farm's response was consistent with expected performance.

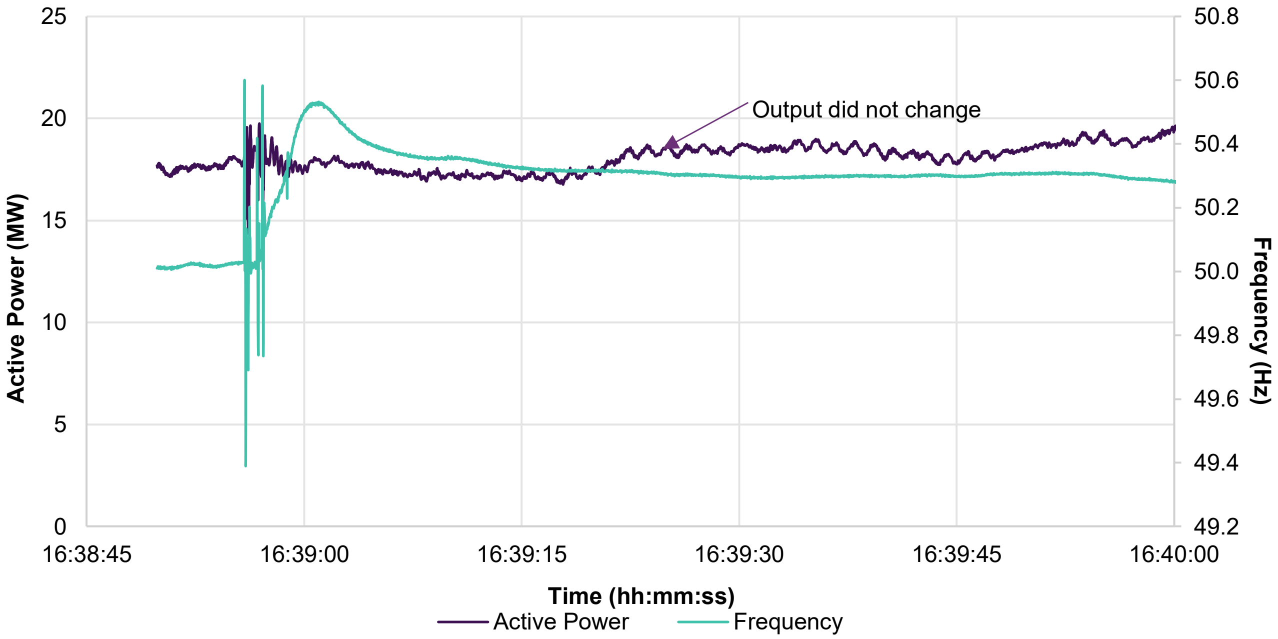
Figure 12 Hallett Wind Farm response



3.2.5 Hallett Hill Wind Farm

As shown in Figure 13, Hallett Hill Wind Farm output did not reduce in response to the frequency increase in SA. AEMO has concluded that Hallett Hill Wind Farm's response was consistent with expected performance, as the wind farm is not required to change its output in responding to a frequency rise.

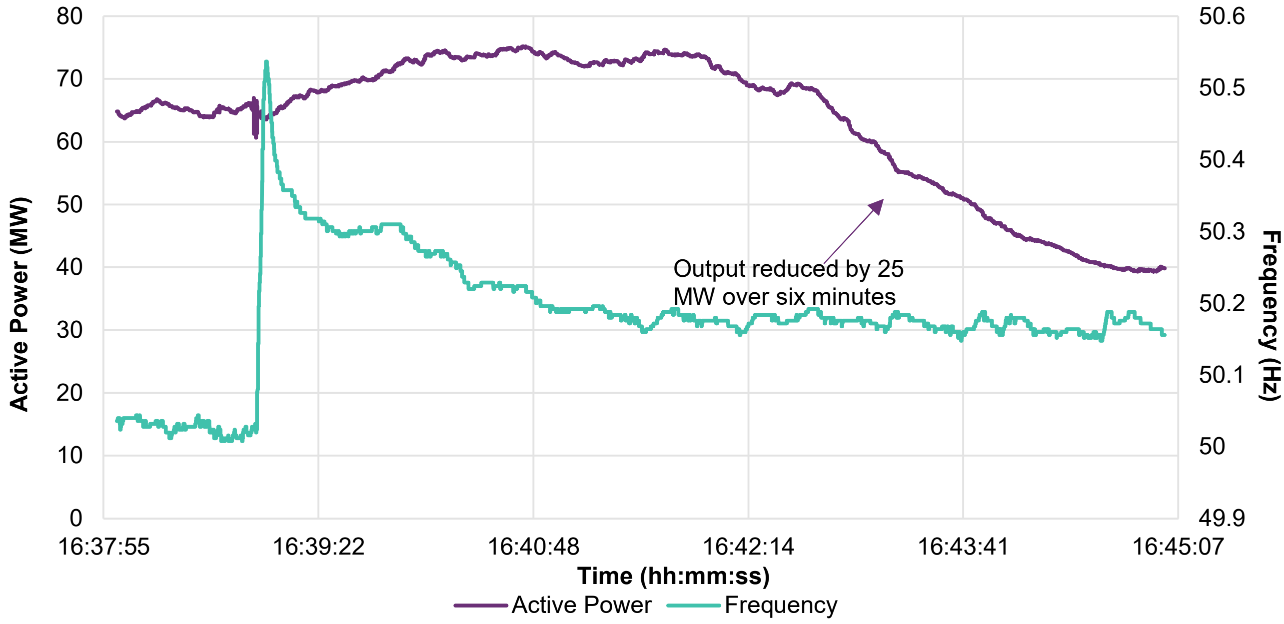
Figure 13 Hallett Hill Wind Farm response



3.2.6 Hornsdale Wind Farm 1

As shown in Figure 14, in response to the SA frequency increase at 1639 hours, Hornsdale Wind Farm 1 reduced its output by 25 MW. AEMO has concluded that the Hornsdale Wind Farm 1's response was consistent with expected performance.

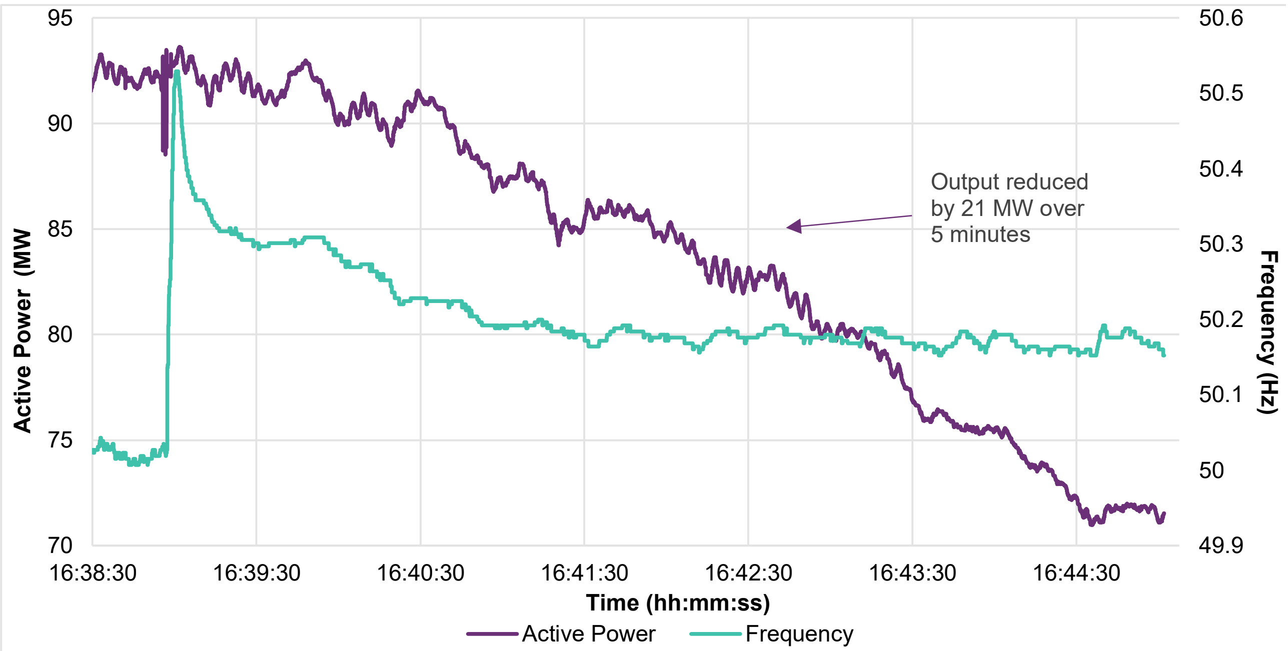
Figure 14 Hornsdale Wind Farm 1 response



3.2.7 Hornsdale Wind Farm 2

As shown in Figure 15, in response to the SA frequency increase at 1639 hrs, Hornsdale Wind Farm 2 started to reduce its output for first five minutes. AEMO has concluded that the Hornsdale Wind Farm 2's response was consistent with expected performance.

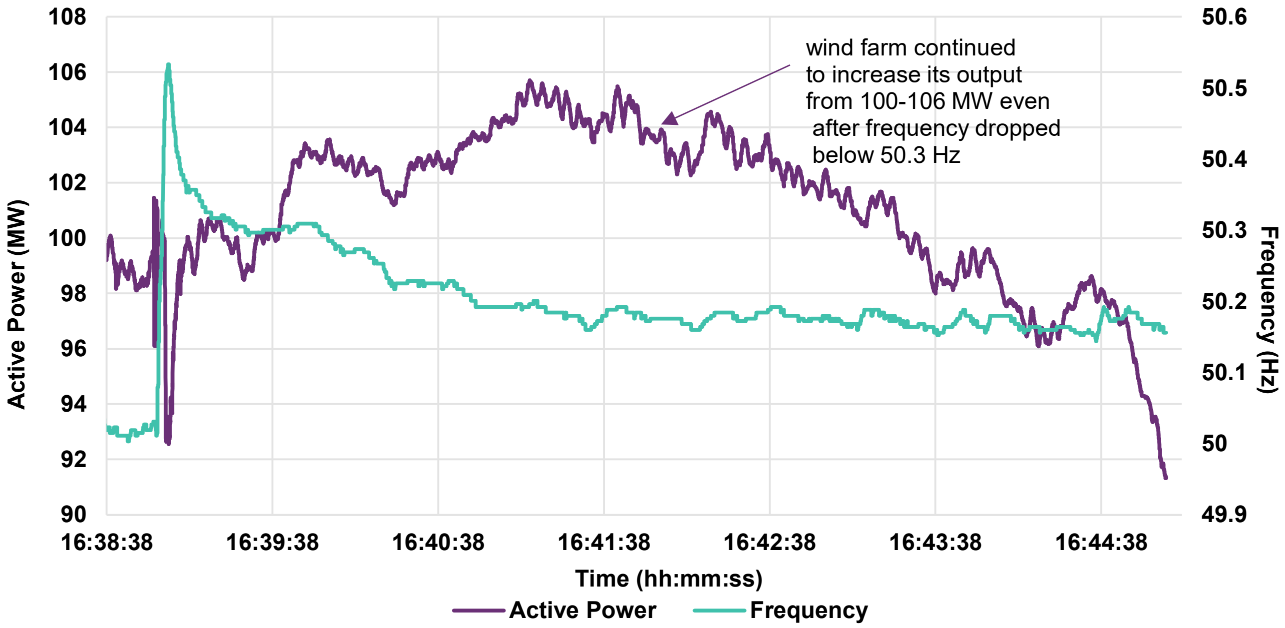
Figure 15 Hornsdale Wind Farm 2 response



3.2.8 Hornsdale Wind Farm 3

As shown in Figure 16, in response to the SA frequency increase at 1639 hrs, Hornsdale Wind Farm 3 initially reduced its output. However, the wind farm returned to its pre disturbance active power level (100 MW) within five seconds. When the frequency returned to below 50.3 Hz, the wind farm continued to increase power output until it reached 106 MW. AEMO has concluded that the Hornsdale Wind Farm 3's response was consistent with expected performance.

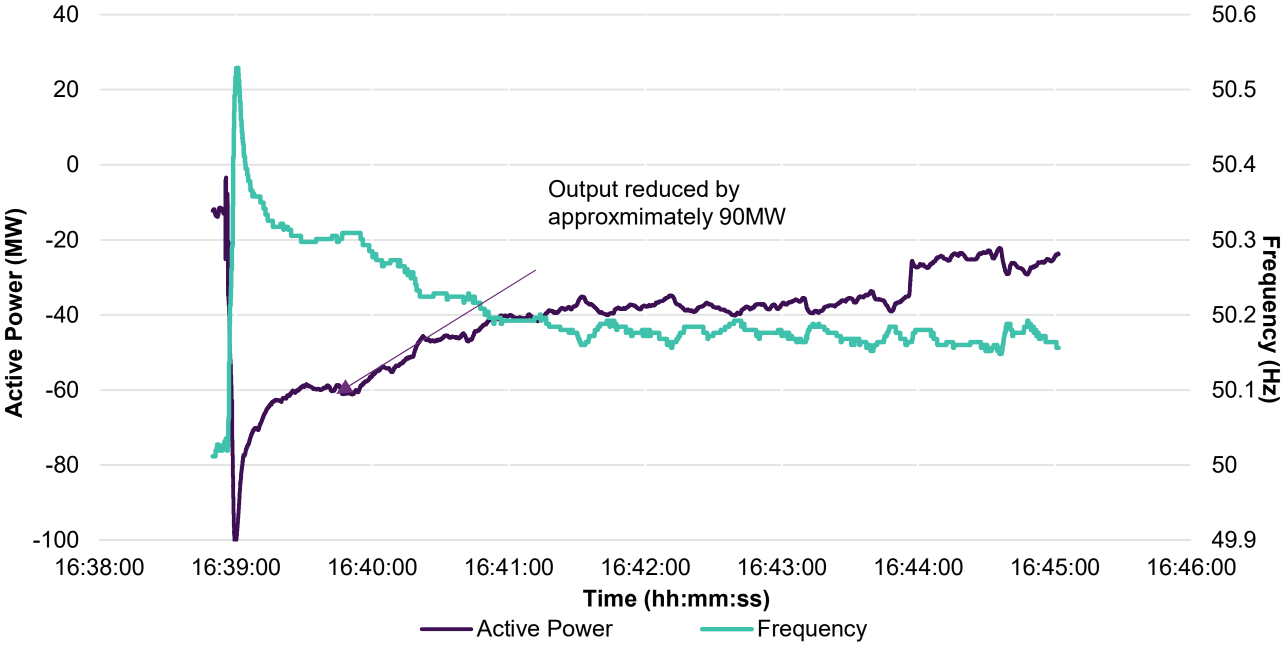
Figure 16 Hornsdale Wind Farm 3 response



3.2.9 Hornsdale Power Reserve

As shown in Figure 17, in response to the SA frequency increase at 1639 hrs, Hornsdale Power Reserve started to reduce its output. AEMO has concluded that Hornsdale Power Reserve's response was consistent with expected performance.

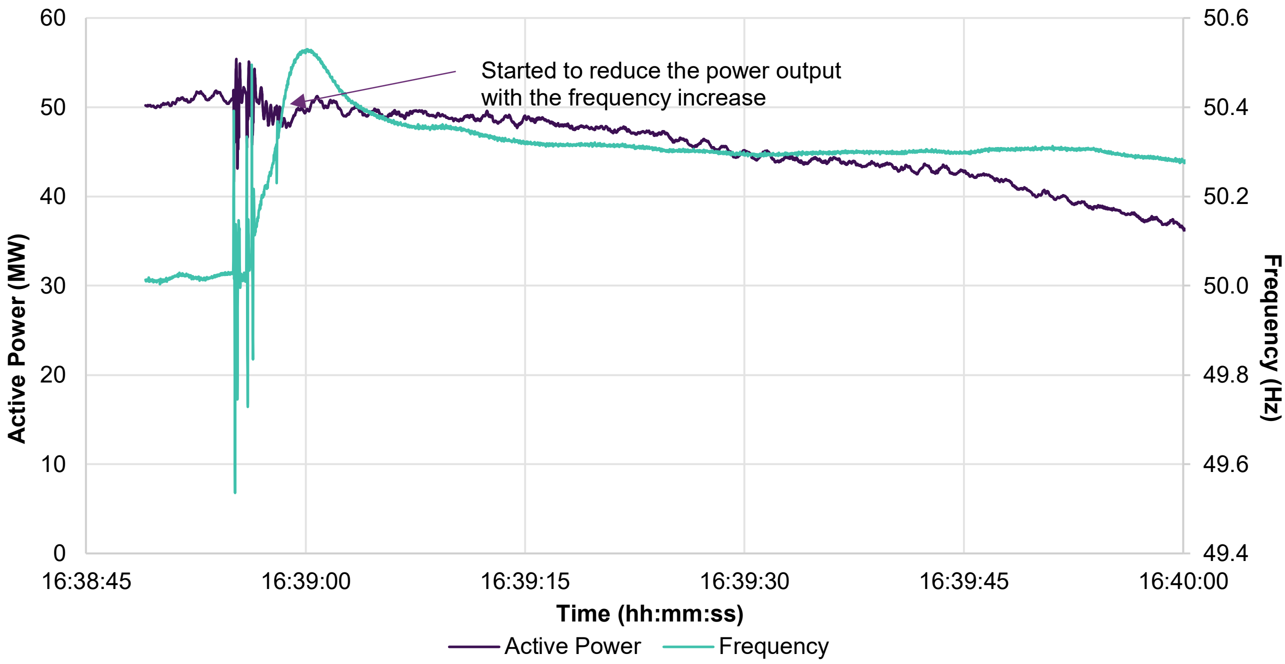
Figure 17 Hornsdale Power Reserve response



3.2.10 North Brown Hill Wind Farm

As shown in Figure 18, in response to the SA frequency increase in SA, North Brown Hill Wind Farm started to reduce its power output. AEMO has concluded that North Brown Hill Wind Farm's response was consistent with expected performance.

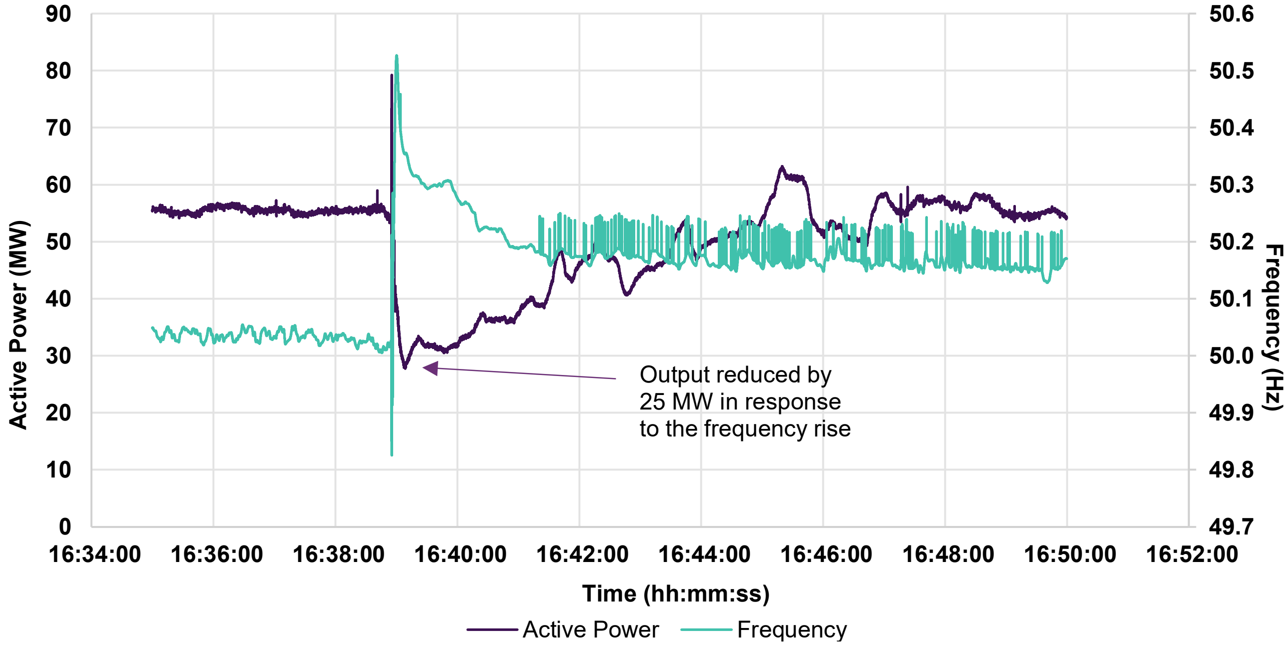
Figure 18 North Brown Hill Wind Farm response



3.2.11 Torrens Island Power Station (TIPS) B4

As shown in Figure 19[18], in response to the frequency increase in SA, Torrens Island Power Station (TIPS) B4 reduced its output by approximately 25 MW. AEMO has concluded that TIPS B4's response was consistent with expected performance. AEMO has confirmed that initially the generator's power output fell to around 30 MW. As the unit's minimum active power (P_{min}) output level is 40 MW, TIPS B4 is not expected to operate at that level.

Figure 19 Torrens Island Power Station (TIPS) B4 response



3.3 System security and system operating limits

Following the separation of SA from the NEM, and in accordance with AEMO's operating guidelines, AEMO kept the Keith – Tailem Bend 132 kV line open at Tailem Bend substation end only. The Keith – Tailem Bend 132 kV line remained open until SA island was resynchronised to the rest of the NEM via the South East – Tailem Bend No. 1 275 kV line on 19 November 2022.

During AEMO's post-incident investigation, AEMO asked ElectraNet to review whether the Keith – Tailem Bend 132 kV line could be closed in future incidents to reconnect SA to the rest of the NEM. This 132 kV line has the potential to improve the strength of the SA region and allow for some power flow and FCAS services between the Victoria and SA regions. Based on this review, ElectraNet advised AEMO that this operating practice should be maintained and SA should not be connected to the NEM via the 132 kV network for the following reasons:

- The variability in renewable generation in SA results in interconnector drift that cannot be maintained within the equipment ratings due to the interval of the NEM dispatch.
- A disturbance under the above mentioned conditions may exceed oscillatory stability limits for SA as defined in NER S5.1a.3.

[18] Frequency trace plotted using High Speed Monitoring (HSM) data due to the absence of the frequency data from the participant. To confirm, during the first hour after the separation SA frequency fluctuated but remained within the FOS.

To manage power system security during operation of the SA island, AEMO dispatched frequency control resources to cover for credible contingency events, accounting for anticipated DPV shake-off. Considering application of an appropriate operating margin, AEMO limited the maximum total SA contingency size to 190 MW. To maintain this threshold, the expected DPV contingency size was limited to 70 MW. AEMO issued a 4.8.9 instruction to ElectraNet to maintain the operational demand above the level that would maintain DPV contingency risk to secure levels. Section 4 provides additional information on DPV contingency size management.

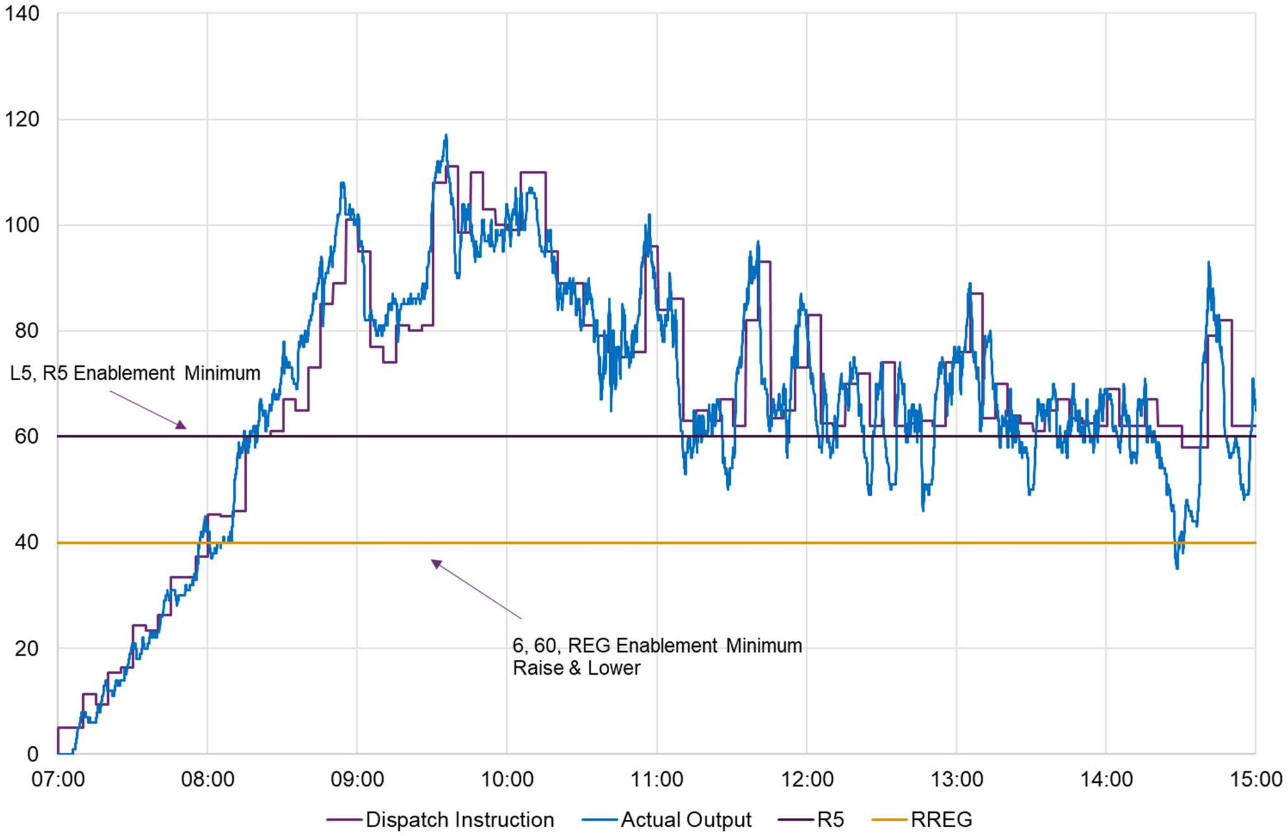
3.4 FCAS management

On 15, 17 and 19 November 2022, AEMO issued directions to up to three generating units to provide market ancillary services (FCAS). AEMO directed these units to provide FCAS as they were not being dispatched by the NEM Dispatch Engine (NEMDE). This was due to the action of AEMO's automatic generation control (AGC), which was controlling these units below their minimum enablement limits and making them unavailable for the next dispatch interval for L5 and R5 and in one case for all FCAS, as shown in Figure 20.

To mitigate against this, AEMO directed these units were directed to be dispatched 10 MW above their minimum enablement limits. This ensured that each directed unit had sufficient margin to provide FCAS

Under the NEM design, FCAS providers in one region cannot participate in a different region's FCAS market when regions are separated. The Lake Bonney BESS (which was located outside of the SA island) was therefore constrained from providing FCAS services during the SA island operation period.

Figure 20 Directed FCAS unit actual energy dispatch



Further investigation is underway to determine the possible impacts of enhanced voltage management (EVM – used to curtail distributed PV during the operation of the island system) on FCAS availability for Virtual Power Plants (VPPs), discussed further in Section 4.2.5.

3.4.1 Distributed BESS behaviour during SA separation

One distributed BESS manufacturer advised AEMO that approximately 42% of its battery fleet in SA disconnected in response to the network disturbance occurring at the time of the separation event and remained disconnected for a further 75 seconds. AEMO understands that this disconnection behaviour was related to grid protection systems specific to this manufacturer. Some of these distributed BESS devices are included in VPPs in SA which are registered to provide FCAS. If a distributed BESS disconnects, it is then not available to deliver a contingency FCAS response until it reconnects. This disconnection behaviour can inhibit contingency FCAS response and as a result, the VPPs impacted by this particular protection system failed to meet their FCAS obligations for the trading interval ending at 1640 hrs on 12 November 2022.

Similarly, at 1705 hrs on 19 November 2022, in response to voltage and frequency fluctuations that remained within normal operating limits, the same protection system operated . This protection system operation led to the disconnection of approximately 70% of the battery fleet of this manufacturer in the SA island. This meant the VPPs impacted by this particular protection system also failed to meet their FCAS obligations in this trading interval.

Subsequently, this manufacturer has advised AEMO that this specific protection setting has now been disabled for its devices associated with VPPs that are registered to provide FCAS.

3.5 Fast Frequency Response management

At the time of the incident, ElectraNet had existing Fast Frequency Response (FFR) contracts[19] with four FFR providers. The facilities contracted and their performance against their contract is described in Table 6.

Table 6 FFR contracts

Facility	Raise FFR (MW)	Lower FFR (MW)	Performance
Dalrymple BESS	30	7	Satisfactory *
Hornsdale Power Reserve	130	63	Satisfactory
Lake Bonney BESS1	20	20	Not applicable – Lake Bonney was not part of the SA island
Tesla VPP (Energy Locals)	20	20	Satisfactory

* Performance was not as exactly as expected, however was considered satisfactory as discussed below.

This section describes the performance of these facilities against their contract requirements.

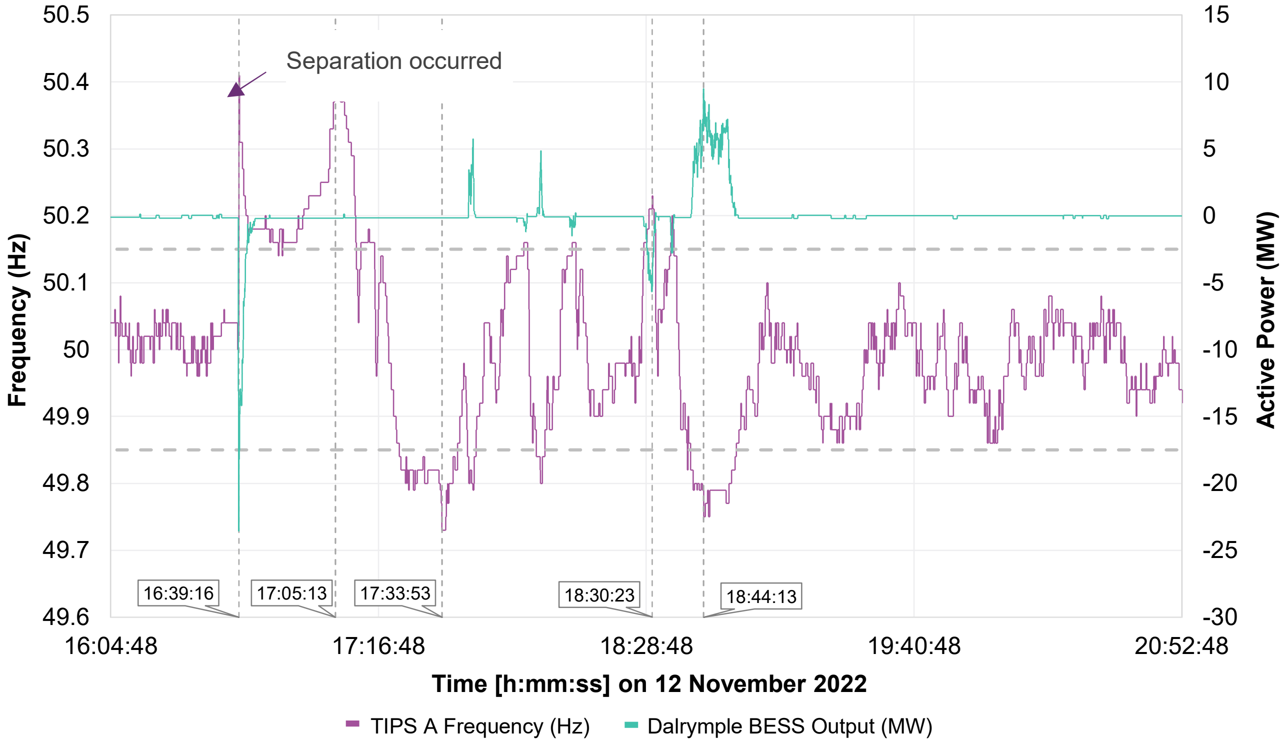
As outlined in Table 6, Lake Bonney BESS1 could not provide FFR services, as it remained connected to the NEM and was not part of the SA island. Therefore, the FFR performance of Lake Bonney BESS1 was not assessed for this incident.

[19] FFR contracts are activated when frequency deviates outside the frequency trigger range of 49.85 Hz to 50.15 Hz, and must be sustained for at least one minute. Following a completed activation and the frequency returning to normal operating frequency range, the plant shall be re-enabled for activation as soon as practical and otherwise within 30 minutes.

3.5.1 Dalrymple BESS

When the frequency increased at 1639 hrs on 12 November 2022, Dalrymple BESS provided 23.6 MW of lower FFR services. This exceeded the contracted amount of 7 MW lower FFR to maintain the FOS. Dalrymple BESS did not respond to the subsequent frequency peak at 1705 hrs; however, as this frequency peak was within 30 minutes of the separation event at 1639 hrs, a response was not required under the FFR contract. Dalrymple BESS provided no response when the frequency dropped below 49.85 Hz and reached a minimum at 1733 hrs (Figure 21). The lack of raise FFR during the second frequency drop was due to plant settings[20]. AEMO is working with ElectraNet to confirm whether changes to these plant settings or the FFR specification are required to more effectively manage system security in these circumstances.

Figure 21 Dalrymple BESS generation during the incident

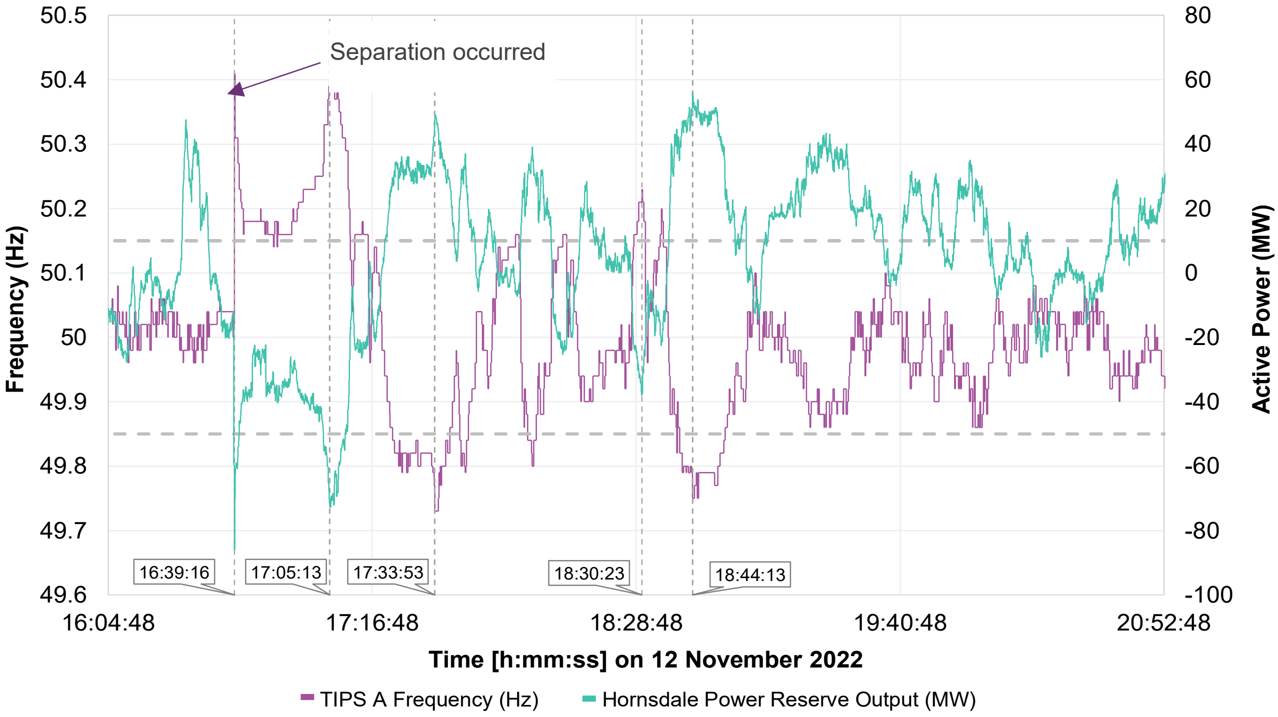


3.5.2 Hornsdale Power Reserve

It was observed that Hornsdale Power Reserve BESS successfully provided a droop response based on system frequency during the incident. When the first frequency increase occurred at 1639 hrs, the BESS reduced its active power output and continued to provide the correct droop response for longer than its FFR contract requirements while frequency remained outside the normal operating frequency range. The BESS continued to provide a similar response for all other frequency increases, as shown in Figure 22.

[20] Following an activation of >7.5 MW lower FFR response, the plant requires 60 mins recovery time.

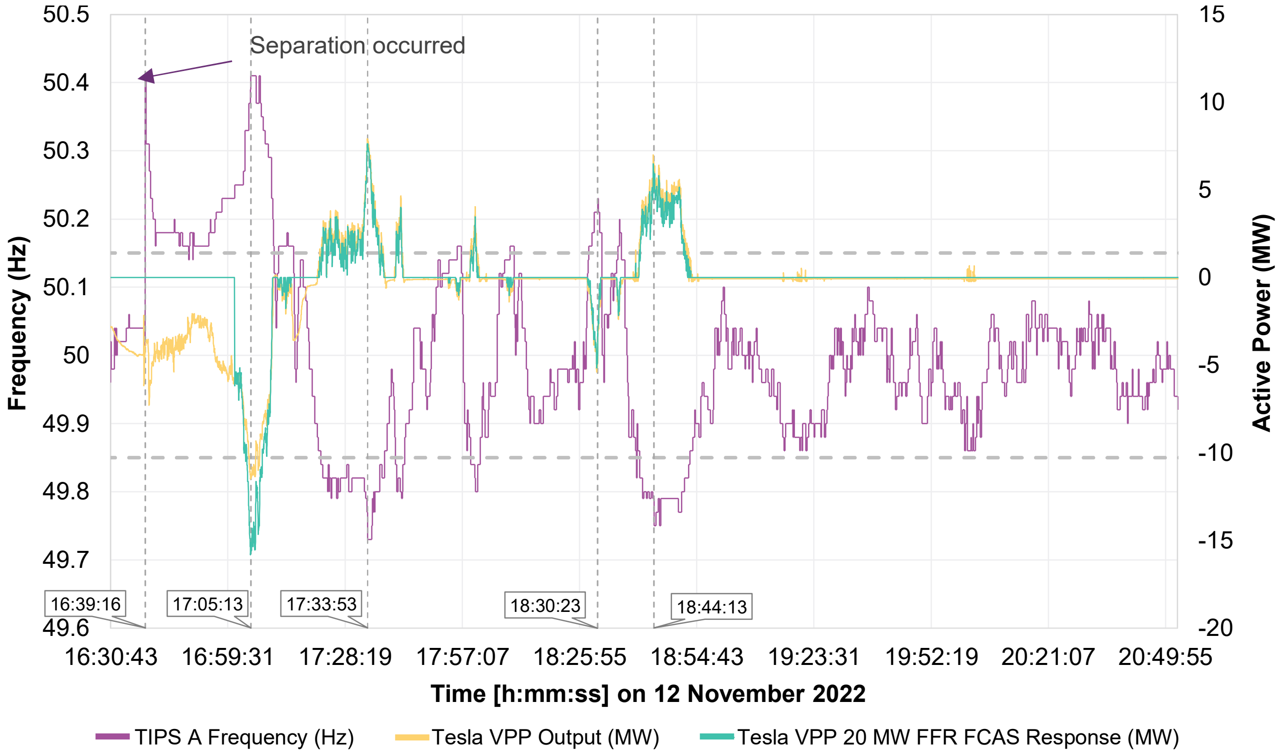
Figure 22 Hornsdale Power Reserve during the incident



3.5.3 Tesla Virtual Power Plant

Tesla VPP facility performed as expected by providing its contracted 20 MW FFR when frequency deviated outside the defined response trigger range (Figure 23).

Figure 23 Tesla VPP generation during the incident



4 DPV management during island operation

4.1 Managing power system security under high DPV conditions

4.1.1 Overview

To manage power system security during operation of the SA island, AEMO dispatched frequency control resources to cover for credible contingency events, accounting for anticipated DPV shake-off. Based on field measurements from previous incidents and other evidence, AEMO has developed power system models that indicate approximately 32% of DPV and 13% of underlying load could trip in response to a severe but credible fault in the Adelaide metropolitan 275kV network[21,22].

During the period of SA island operation high peak levels of DPV generation (exceeding 1,000 MW) were forecast in SA from 13-17 November and 19 November 2022. This included a forecast maximum capacity factor[23] of 71% (equating to a forecast maximum output of 1,600 MW from DPV in SA) on 17 November 2022. This forecast DPV presented an estimated DPV contingency risk (the level of net DPV generation that could be lost due to a credible fault in the network) of 260 MW.

During high DPV generation periods on 13-17 November and 19 November 2022, AEMO optimised the dispatch of the scheduled and semi-scheduled generating units to minimise the credible contingency size as much as possible, and maximise the availability of frequency control resources. Power system studies indicated that the maximum generation contingency size that could be managed in low demand conditions in a typical SA island, while maintaining the FOS, was the instantaneous loss of 190-205 MW. Incorporating an operating margin, AEMO took action to limit the maximum total credible contingency size to 190 MW.

Minimum combinations of scheduled units must also remain online within SA to provide adequate system strength to the region. To remain online, these units must be dispatched above their minimum dispatch levels, with some of these units having a minimum dispatch level of 110 MW. This meant that the DPV contingency size had to be maintained below 80 MW to keep the total generation contingency size below 190 MW. On further review, due to the non-standard location of the SA separation and the exclusion of Lake Bonney BESS from the SA island, AEMO revised the maximum DPV contingency size down to 70 MW.

On 17 November and 19 November 2022, the DPV curtailment required to maintain the DPV contingency below 70-80 MW was forecast to exceed the available DPV curtailment capabilities. AEMO completed further power system analysis and identified selected combinations of scheduled units that could operate at lower minimum generation levels while meeting system strength and frequency control requirements. The lower minimum dispatch levels on these selected scheduled units presented a smaller generation contingency risk and allowed AEMO to increase the maximum permitted DPV contingency size to 110 MW for these days. This alternative

[21] AEMO (May 2021) Behaviour of distributed resources during power system disturbances, https://aemo.com.au/-/media/files/initiatives/der/2021/capstone-report.pdf?la=en&hash=BF184AC51804652E268B3117EC12327A.

[22] AEMO (November 2022) PSS®E models for load and distributed PV in the NEM, https://aemo.com.au/-/media/files/initiatives/der/2022/psse-models-for-load-and-distributed-pv-in-the-nem.pdf?la=en.

[23] Capacity factor is a measure of generator output as a product of installed capacity. As an example, if 10 gigawatts (GW) of DPV was installed within a network and 7 GW of that installed DPV capacity was forecast to be generated, the forecast capacity factor would be 70%.

approach reduced DPV curtailment requirements to achievable levels, but also limited the combinations of units available for system strength and required additional manual management of reserve and frequency control services to maintain their adequacy. These limitations mean this operating state can only be applied under a limited range of system conditions.

4.1.2 Clause 4.8.9 instructions and related market notices

To reduce the overall credible contingency size to within secure limits, AEMO issued a 4.8.9[24] instruction to ElectraNet on 13-17 November 2022 and 19 November 2022. AEMO instructed ElectraNet to maintain operational demand above levels that would reduce the DPV contingency risk to within secure levels. This translated to operational demand thresholds of between 714 MW and 855 MW, depending on system conditions, as shown in Table 7.

To comply with these 4.8.9 instructions, ElectraNet instructed SA Power Networks to maintain operational demand above the necessary threshold. SA Power Networks applied a range of mechanisms[25] to curtail DPV on 13-17 and 19 November 2022 for approximately 4-9 hours (up to a maximum of approximately 410 MW of DPV curtailment on 17 November 2022). This DPV curtailment successfully reduced the largest credible contingency in the SA island to within secure operating limits.

The 4.8.9 instruction and resulting DPV curtailment was the only action available to manage the high DPV contingency condition and maintain the SA island in a secure operating state. The primary reason for instructing DPV curtailment in this event was to limit DPV contingency size and enable AEMO to operate the SA island according to the requirements of the FOS. This DPV contingency size reduction could not be achieved by increasing demand.

This event is significant because it involved active management of residential, commercial and industrial DPV. This is recognised as a 'last resort' measure, to be considered only when other options to maintain power system security are not available or have been exhausted.

AEMO issued multiple DPV contingency (DPVC) market notices[26] – DPVC1, DPVC2 and DPVC3 – each day to inform market participants when DPV curtailment was anticipated, when it was occurring, and when it was no longer required, as summarised in Table 7.

[24] NER Clause 4.8.9 – AEMO may require a registered participant to do any act or thing if AEMO is satisfied that it is necessary to do so to maintain or re-establish the power system to a secure operating stage, a satisfactory operating state, or a reliable operating state

[25] See Section 4.2 for a summary of the main mechanisms used by SA Power Networks to curtail DPV.

[26] The market notices advise the market of forecast operational challenges and (where the market has not been able to take sufficient action to clear the risk) actions taken by AEMO. For further details on these market notices, see https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/power_system_ops/consumer-fact-sheet.pdf.

Table 7 AEMO instructions and market notices for DPV management

	Peak DPV generation forecast (MW)	Peak DPV capacity factor forecast (%)	Minimum operational demand threshold (AEMO instruction to ElectraNet) (MW)	DPVC2 notice issued (Market time)	DPVC3 notice cancelled (Market time)	Maximum DPV curtailment (estimated post event)* (MW)	Duration of DPV curtailment (hrs)
13 Nov	1,338	60%	714	7:36	17:30	400-600	10hrs
14 Nov	1,001	45%	855	11:34	15:29	200-350	4hrs
15 Nov	1,106	49%	819	8:18	16:32	150-250	8hrs
16 Nov	1,152	51%	827	8:23	17:24	160-200	9hrs
17 Nov	1,602	72%	820	7:59	17:01	360-430	9hrs
18 Nov	790	35%	N/A	N/A	N/A	Nil	N/A
19 Nov	1,288	57%	812	8:34	15:11	380-520	7hrs

* Estimated based on the difference between the forecast operational demand (last forecast before DPV curtailment commenced) and the operational demand actual values measured during the curtailment period. This method of estimating DPV curtailment is the best available with present visibility and tools, but has significant limitations. It is subject to the uncertainty in the operational demand forecast which can lead to inaccuracies, particularly on days with intermittent cloud cover (such as 13 November 2022).

4.1.3 Impact of clause 4.8.9 instructions on operational demand

Figure 24 shows the forecast operational demand (as forecast at the start of each day, assuming no DPV curtailment) compared with actual operational demand that was measured as DPV curtailment occurred. The difference between these measures provides an estimate of the amount of DPV curtailment that occurred each day.

Figure 24 Operational demand forecasts and actuals during period of SA island operation

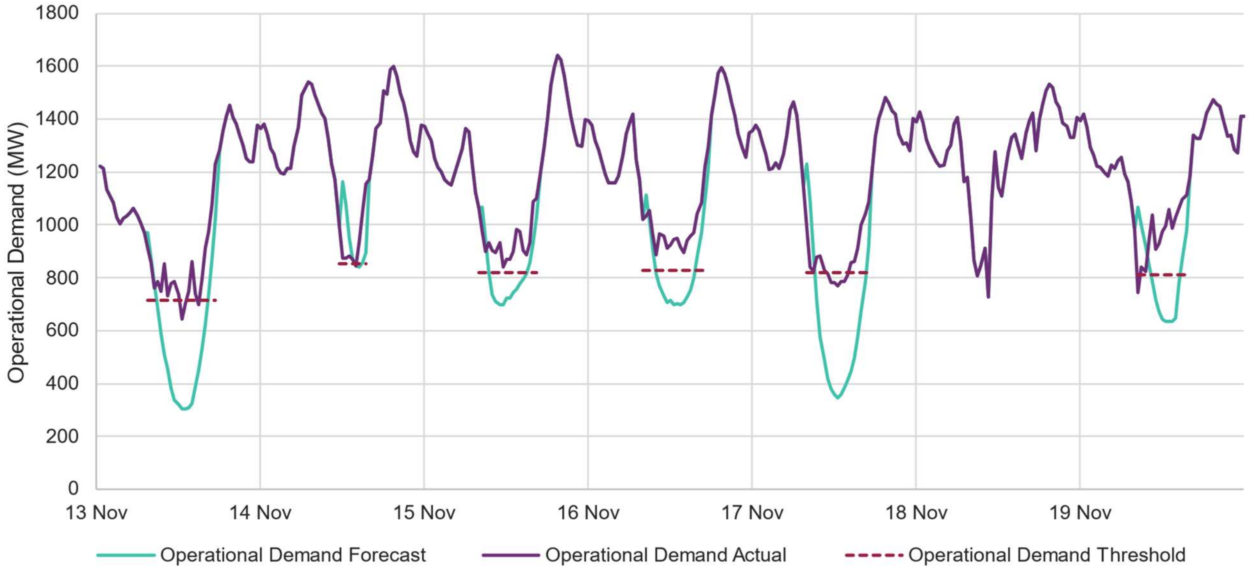
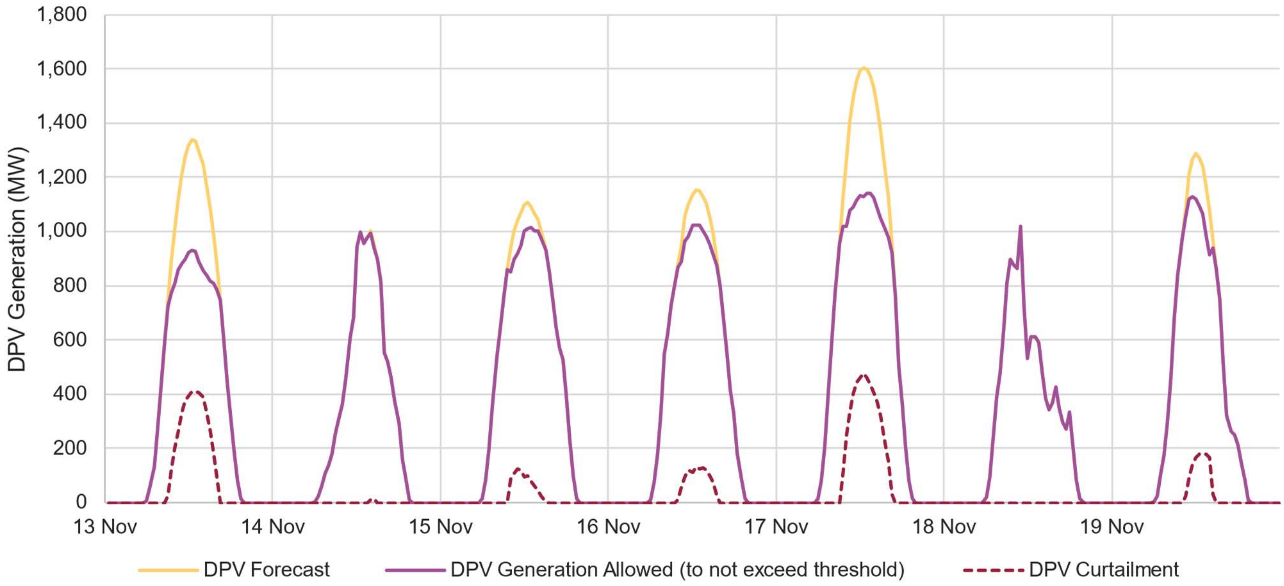


Figure 25 shows the DPV generation forecasts each day during 13-17 November 2022, with an indication of the targeted DPV curtailment that informed the operational demand thresholds in AEMO's instructions to ElectraNet.

Figure 25 DPV generation forecasts during period of South Australia island operation



4.1.4 Visibility of DPV generation during periods of DPV curtailment

Preliminary analysis suggests that AEMO's Australian Solar Energy Forecasting System for DPV (ASEFS2) somewhat overestimated the amount of DPV curtailment that was occurring during these intervals. This means there was more DPV still generating than indicated by AEMO real-time systems. This resulted in an underestimate of total contingency sizes, and a small under-procurement of FCAS during these intervals. AEMO corrected this in real time by "hand-dressing" (manually entering) the DPV generation estimates during these periods and updating constraints to use these hand-dressed values. AEMO is investigating these systems further and exploring improvements to the accuracy of DPV generation estimates in periods where DPV curtailment is occurring.

At present, AEMO's instruction to ElectraNet to manage the size of the DPV generation contingency risk is delivered as an instruction to maintain operational demand above a minimum threshold. This approach is used because there is limited visibility of aggregate DPV generation in real time, and an instruction to maintain DPV generation below a specified threshold would not be able to be followed or verified with the present systems at AEMO, ElectraNet and SA Power Networks. This approach can lead to inefficiencies and may result in higher amounts of DPV curtailment under some circumstances, such as when there is uncertainty in the demand forecasts. In future, an improvement to these procedures would be for AEMO to directly provide a threshold for maximum DPV generation in the region. This requires improvements to real-time visibility of DPV generation at both AEMO and NSPs such as SA Power Networks.

4.2 DPV curtailment mechanisms

Acting on AEMO's instruction, SA Power Networks used a number of agreed methods to maintain operational demand above the threshold provided by AEMO to maintain system security. These included:

- Curtailment of SCADA controlled generation systems more than 200 kilowatts (kW).
- Directions to Relevant Agents under the Smarter Homes regulations to reduce generation.

- Directions to Flexible Exports enabled DPV systems to reduce generation.
- Enhanced voltage management (EVM) to increase distribution network voltages at the feeder level, and lead to decreased DPV generation on the relevant feeder.

These are enacted by SA Power Networks in a priority order based on their impact on customers, targeting larger systems first, and utilising enhanced voltage management last.

Further details on each method used by SA Power Networks during this event are provided in the sections below.

4.2.1 SCADA-controlled DPV

Description

Larger DPV systems (typically with export capacity above approximately 200 kW) are required by SA Power Networks to be SCADA-controllable. These larger DPV systems can be turned off or set to zero export via SA Power Networks' SCADA system when necessary to maintain system security. At present, SA Power Networks has a total nameplate capacity of 244 MW of large SCADA-controllable DPV systems connected to their network.

Performance during this event

When required, the majority of SCADA-controlled generators were issued a "Permission Denied" signal, which prevented any generation. However, due to the extended nature of the event and potential impact on some commercial and industrial sites, some generators were instead issued a zero export signal. The immediate impact of this mechanism was able to be measured, as SCADA can be used to observe the total generation of all large DPV systems at any given time. However, during a longer curtailment event, the future behaviour of these systems is dependent on both weather and market outcomes. As such, if a solar farm was generating 0.5 MW at 1000 hrs when it was curtailed, this does not necessarily equate to 0.5 MW of curtailment throughout the day. This is because, without curtailment, that solar farm may have increased its output throughout the day due to higher solar insolation or decreased its output due to lower market prices. The times and durations when SCADA-controlled generating systems connected to SA Power Networks were curtailed are shown in Table 8.

Table 8 SA Power Networks enactment of SCADA-controlled generation curtailment

	Disconnection		Reconnection	
	Time commenced	Time completed	Time commenced	Time completed
13 Nov	9:35	9:52	18:04	18:23
14 Nov	12:22	12:35	16:01	16:46
15 Nov	8:57	8:59	16:36	16:53
16 Nov	9:45	9:47	16:38	16:51
17 Nov	8:34	8:48	17:11	17:28
18 Nov	NA	NA	NA	NA
19 Nov	8:44	8:58	15:11	15:26

During this event, due to the storm damage to the distribution network, it generally took 10-20 minutes to complete curtailment of all SCADA-controlled generators.

The SCADA-controlled generators responded to signals as expected during this event, and SA Power Networks was able to confirm a correct curtailment response via SCADA systems.

4.2.2 Smarter Homes regulations

Description

From 28 September 2020, DPV systems in SA must comply with the Smarter Homes regulations[27]. These regulations mean customers installing or upgrading solar systems in SA are required to appoint a Relevant Agent who will be responsible for managing the active power from DPV systems during state electricity security emergencies[28]. This capability was implemented by the South Australian government to manage scenarios where system security is at risk and the only means to mitigate this risk is via a last resort tool to actively manage DPV. When DPV curtailment is required to maintain system security, SA Power Networks instructs the Relevant Agent(s).

The regulations allow different types of response between different Relevant Agents and technology types, with some limiting DPV to zero export (and thus curtailing generation) and some disconnecting generation. SA Power Networks acts as the Relevant Agent for embedded generation systems with SCADA controls, as well as providing a partnered Relevant Agent service for many original equipment manufacturers (referred to as Technical Providers).

A list of Relevant Agents is available on the South Australian Government website[29].

Expected performance under normal operating conditions

Approximately 517 MW[30] of non-SCADA-controlled DPV has been installed in SA since the commencement of the Smarter Homes regulations. Of this capacity, SA Power Networks estimates that only 51% of DPV has been properly commissioned or maintained with the required DPV curtailment functionality available online and responsive to instructions[31]. SA Power Networks has a work program under development to improve this rate of compliance (described further below).

SA Power Networks perform routine disconnection testing of a sample of the Relevant Agent scheme to monitor for issues and assess performance. Feedback received from this testing suggests that the response rates for the correctly commissioned (online) DPV fleet is 75-80% under normal operating conditions.

This indicates that of the 517 MW of DPV installed in SA since September 2020, approximately 38-41% of this capacity is expected to respond to a curtailment instruction under normal operating conditions. This equates to 196-212 MW of installed capacity that is available to respond.

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[27] For more information on the Smarter Homes regulations, see https://www.energymining.sa.gov.au/industry/modern-energy/solar-batteries-and-smarter-homes/regulatory-changes-for-smarter-homes.

[28] The Smarter Homes regulations also introduced a new technical standard for smart meters, requiring that they be capable of separately measuring and controlling an electricity generating plant and controllable load from essential load. This provided additional data to support assessment of the compliance of the response of Relevant Agents during this event. Further information is available at Government of South Australia, Energy and Mining, Smart meter requirements, https://www.energymining.sa.gov.au/industry/modern-energy/solar-batteries-and-smarter-homes/regulatory-changes-for-smarter-homes/smart-meter-requirements.

[29] Government of South Australia, Energy and Mining, Remote disconnect and reconnection of electricity generating plants, https://www.energymining.sa.gov.au/industry/modern-energy/solar-batteries-and-smarter-homes/regulatory-changes-for-smarter-homes/remote-disconnect-and-reconnection-of-electricity-generating-plants.

[30] This is the capacity of non-SCADA controlled DPV approved between 28 September 2020 and 13 November 2022 (effectively the capacity of DPV that required non-SCADA Relevant Agents up to the events outlined in this report).

[31] The relevant agent must be aware of the operating state of the electricity generating plant and be able to respond to reasonable requests for information from the Technical Regulator, Australian Energy Market Operator or other party with lawful powers to direct the relevant agent, both prior to, and after, the completion of the disconnect and reconnect. Such requests may require the relevant agent to report on their performance in relation to a direction received. Reference: Technical Regulator Guideline, Relevant Agent Roles and Responsibilities, https://www.energymining.sa.gov.au/__data/assets/pdf_file/0008/671714/Technical_Regulator_Guideline_-_Relevant_Agent_Roles_and_Responsibilities.pdf.

Performance during this event

The times at which relevant agents provided confirmation of DPV disconnection/reconnection during this event on each day are shown in Table 9. SA Power Networks issued instructions to Relevant Agents following AEMO's 4.8.9 instructions (issued at the times noted in Table 7), after issuing instructions to SCADA-controlled generation.

Table 9 Relevant agents reporting of disconnect/reconnect times

	Disconnection (Relevant Agents confirmed disconnection had occurred)		Reconnection (Relevant Agents confirmed reconnection had occurred)	
	Earliest	Latest	Earliest	Latest
13 Nov	9:23	12:04	17:30	21:00
14 Nov	12:19	12:49	15:24	16:46
15 Nov	9:00	10:08	16:04	17:17
16 Nov	10:01	10:48	15:58	17:37
17 Nov	8:52	10:01	16:37	17:57
18 Nov	NA	NA	NA	NA
19 Nov	8:19	11:09	14:43	15:45

Relevant Agents are required to disconnect within 15 minutes of receiving an instruction and report confirmation as soon as possible[32]. In practice, capabilities vary widely, and in some cases this can result in confirmation arriving hours after the initial disconnection instruction. The delay in reporting means that the confirmation times noted in Table 9 may not accurately reflect when a system actually responded, and creates complexities in understanding the operational state of DPV.

Table 10 shows the average response rates of Relevant Agents observed on each day of this event. The left column indicates the response rate of the correctly commissioned online fleet, based on Relevant Agent self-reporting. The middle column provides the estimated total response rate, assuming 51% of the fleet is properly commissioned and maintained online. The right column provides a comparison with an independent assessment based on advanced metering infrastructure (AMI) data (described further below).

As shown in Table 10, the response rate varied between days. Based on reporting from Relevant Agents, response rates of the correctly commissioned online fleet on 13 and 14 November 2022 were especially low, achieving a response rate of only 57% and 49% respectively. These lower-than-expected response rates are likely due to communication and power losses affecting the distribution network and internet and telecommunication services. These outages affected 163,000 customers, with outages progressively restored throughout the week. The response rate on 17 November 2022 once power and communications were restored to the majority of customers was 82% of the correctly commissioned online fleet, or 42% of the total fleet (based on relevant agents self-reporting).

[32] Government of South Australia, Department for Energy and Mining, Technical Regulator Guideline Relevant Agent Roles and Responsibilities, https://www.energymining.sa.gov.au/__data/assets/pdf_file/0008/671714/Technical_Regulator_Guideline_-_Relevant_Agent_Roles_and_Responsibilities.pdf.

Table 10 Response rates of relevant agents in this event

	Estimated response rate (% of systems responding as required)		
	Proportion of the correctly commissioned fleet that responded (Based on Relevant Agent self-reporting)	Proportion of the total fleet installed since Sept 2020 that responded (assuming only 51% of systems are commissioned correctly and online) (Based on Relevant Agent self-reporting)	Proportion of the total fleet installed since Sept 2020 that responded (Based on AMI data analysis, systems observed to not export >0.1 kWh/hr)
13 Nov	57%	29%	40%
14 Nov	49%	25%	35%
15 Nov	71%	36%	37%
16 Nov	76%	39%	42%
17 Nov	82%	42%	53%
18 Nov	NA	NA	NA
19 Nov	78%	40%	43%

AEMO also independently assessed the observed responses of sites associated with relevant agents based on AMI data. AMI data was collected for 38,313 sites individually associated with Relevant Agents and matched against data in the DER Register[33]. This AMI dataset covers approximately 70% of the capacity of DPV sites installed since September 2020.

Based on this independent AMI dataset, AEMO identified sites that were exporting during the period where Relevant Agents reported a response from their systems[34]. Correctly responding sites should not be exporting at any level during these periods. Based on this independent assessment, 47% of systems were observed to be exporting during these periods on 17 November 2022. This indicates a total overall response rate of 53% or less from Smarter Homes enabled DPV systems on 17 November 2022. Actual response rates from Relevant Agents were likely lower than indicated based on AMI observations of site exports, because some sites likely stopped exporting due to EVM, or may not have been exporting regardless of a Relevant Agent signal. In addition, lower response rates were observed on earlier days, as shown in Table 10[35].

Responses of individual Relevant Agents

AEMO believes its analysis of Relevant Agent response from AMI datasets represent a maximum upper estimate of response rates associated with each Relevant Agent. Actual response rates may have been much lower in some cases for the following reasons:

- Some responses may have been in response to EVM, rather than a Relevant Agent signal. It is estimated that EVM alone produces a response rate of ~20%.
- A site that was observed to not export above thresholds is considered a site that has responded. In some cases, the site may not have been exporting regardless of an export limit.
- The dataset used for this analysis excludes sites that did not have accurate entries in the Distributed Energy Resource (DER) Register, or had other data quality issues (such as multiple Relevant Agents listed as

[33] The analysis was also calibrated against a subset of 1,072 sites with individual monitoring of separated DPV and site load.

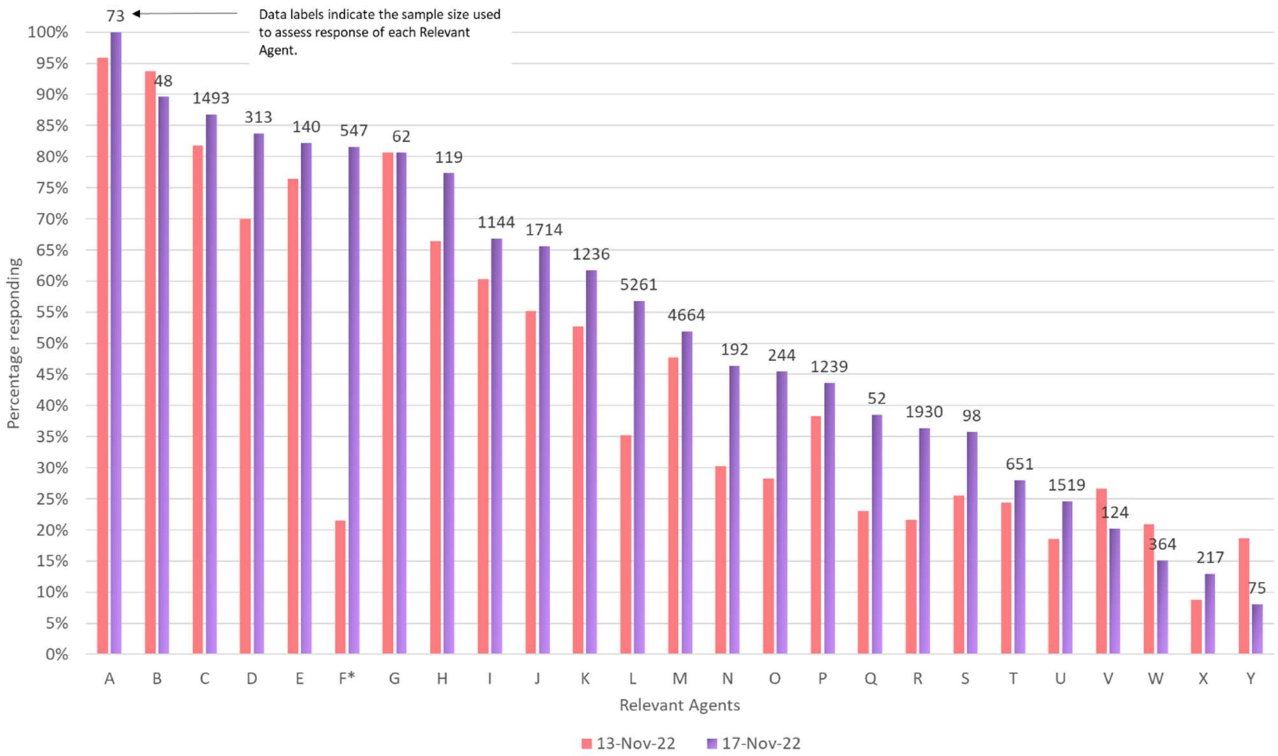
[34] Sites exporting more than 0.1 kilowatt-hours per hour (kWh)/hr were identified as not responding correctly.

[35] The time window applied for assessment of exports was varied day to day, based on the period where Relevant Agents were directed to respond on each day.

associated with a site). This likely means that this dataset is biased towards sites that have been commissioned correctly, and excludes a proportion of sites that have not been commissioned correctly.

Figure 26 below shows the response rates for individual Relevant Agents (anonymised), based on export observations from AMI data, comparing response rates of each Relevant Agent on 13 November 2022 (in red) and 17 November 2022 (in purple)[36]. The total DPV sample size associated with each Relevant Agent in the AMI dataset is shown at the top of each column.

Figure 26 Response rates for different relevant agents



The percentage responding was assessed based on AMI data from 38,313 sites with DPV installed since 28 September 2020 and associated with known relevant agents. Percentage responding was calculated based on the percentage of systems observed to not export >0.1 kWh/hr during the period where relevant agents reported responding on the relevant day. Compliance rates may be lower than indicated, since some sites may have responded due to EVM activation, or may not have been exporting significantly at the time regardless of Relevant Agent signals.

* Relevant Agent "F" was undertaking pre-scheduled testing of its Relevant Agent systems on 13 November, and has reported that none of its systems responded on this day. This was rectified by 17 November, with systems responding normally on that day. The response rate indicated for Relevant Agent "F" on 13 November is indicative of the response related to EVM only.

Key observations from Figure 26 are:

- There is significant diversity in the response rates of different Relevant Agents. Some Relevant Agents achieved total response rates of 80-90% while others demonstrated response rates of only 10-20% on both days. A 10-20% response rate is indicative of the minimum response expected based on activation of EVM alone on these days. This indicates that actual compliance could have been close to zero for Relevant Agents showing response rates in this range.
- Many Relevant Agents showed somewhat lower response rates on 13 November 2022 compared with 17 November 2022, with response rates likely affected by the telecommunications outages occurring on 13 November 2022.

[36] Only Relevant Agents with a sample size of more than 30 sites are included in this figure.

- In general, the dataset suggests that Relevant Agents using direct 3G/4G telecommunications (not using customers' internet) tended to show higher overall response rates on both days. Relevant Agents that communicate with the DPV system via "piggybacking" on customers' internet connection either via WiFi or Ethernet (utilising API control of internet-connected inverters) showed a wide diversity of response rates. All of the Relevant Agents showing response rates below 50% are ones that rely on customer internet connections (although there were some examples of Relevant Agents utilising customer internet connections that achieved relatively high response rates). This trend may be related to compounding factors rather than directly related to the communications technology itself (for example, some Relevant Agents may have greater incentives to commission and maintain system communications, such as if the devices are participating as part of a VPP).

These findings suggest that the type of communications technology and communications outages can impact the response rates of Relevant Agents. However, there are significant underlying differences in the compliance rates between Relevant Agents (regardless of these factors) that appear to drive very large differences in response rates. This might be related to differences in the commissioning processes and ongoing compliance monitoring between different Relevant Agents.

4.2.3 Flexible exports

Description

SA Power Networks has begun introducing dynamic export limits for grid-connected inverters to manage network constraints such as high voltages and transformer thermal limitations. The Flexible Exports program is currently in a trial phase with customers connected to a small number of select substations able to enrol. This scheme enables customers to have a larger per-phase export capability, without the drawbacks of localised distribution network issues caused by an oversaturation of embedded generators.

From 1 July 2023, all exporting residential and medium sized inverters installed in SA will need to be Dynamic Exports capable, with the option to opt-in to the Dynamic Exports limits system or remain at a fixed export limit of 1.5 kW. Unlike the Smarter Homes regulations, Flexible Exports enables a more sophisticated level of control whereby DPV can be discretely controlled. This represents an improvement on the control available under the Relevant Agent's framework which only allows for on/off/zero export signals to be sent as a last resort to maintain system security. It is anticipated that Flexible Exports will offer several improvements, including:

- Standards-based communication and device requirements using the IEEE 2030.5 Common Smart Inverter Profile Australia (CSIP-AUS). This facilitates standardised inverter response (including export limiting, generation curtailment and disconnection), as well as remotely configurable communications fail-safe mechanisms (local behaviours to be undertaken by the device autonomously if communications is lost for a period of time).
- Standardised commissioning process with immediate feedback to distribution network service provider (DNSP) and installer.
- Visibility of fleet status, control acknowledgement and real-time telemetry, with immediate control acknowledgement signals and regular monitoring data sent back to DNSP systems.
- Enablement of ancillary service responses while DPV curtailment is active (FCAS raise).
- Providing customers access to significantly more export capacity during normal system operating conditions.

In the case of large power system events where significant curtailment is required, all devices enrolled in Flexible Exports can be issued a zero export control, which allows connected sites to self-consume energy generated during the event. Controls for this type of event are applied at the substation level, with controls to all devices across nine substations able to be issued within minutes. Flexible Exports devices also have the capability for generator gross output to be limited to zero or to be disconnected from the network if export limiting is insufficient to meet curtailment requirements.

Flexible Exports is in a trial phase, and the capacity involved in the trial is small at present (<1 MW). The performance of the Flexible Exports systems is reported here for relevance in future events where the capacity of Flexible Exports DPV systems will likely be much larger.

Performance during this event

The average response rate for Flexible Exports devices throughout this event was approximately 80% of the correctly commissioned and online devices. The response rates on 13 and 14 November 2022 were lower, at 63% and 75% of correctly commissioned and online systems respectively, as shown in Table 11. These lower response rates on 13 and 14 November 2022 are likely due to communications loss resulting from widespread power outages caused by storm activity on 12 November 2022.

Table 11 Flexible Exports performance (market time)

Date	Time disconnected	Time reconnected	Response rate (% of Flexible Exports correctly commissioned systems)	Response rate (% of all Flexible Exports approved Systems)
13 Nov	9:52	18:07	63%	37%
14 Nov	12:55	15:52	75%	44%
15 Nov	9:48	16:32	86%	50%
16 Nov	12:01	16:29	84%	49%
17 Nov	9:47	17:14	84%	49%
18 Nov	NA	NA	NA	NA
19 Nov	8:52	15:22	83%	48%

This data illustrates similar installation and commissioning compliance rates to the Smarter Homes scheme. These compliance rates may be related to non-optimal commissioning processes during the Flexible Exports trial and are anticipated to improve from 1 July 2023.

Flexible export systems responded to the curtailment instruction within 3 minutes and 27 seconds on average, which is well within the 5-minute polling interval configured in the trial systems.

Any flexible export system that did not respond due to communications outages were constrained to a fall-back export limit of 1.5 kW. Compared with the Smarter Homes arrangements, this automated fall-back provides an improvement to management of power system security under conditions of wide-spread communications outages such as occurred during this event. However, in isolation, reliance on fall-back thresholds alone is unlikely to be sufficient to maintain power system security in the long term. AEMO therefore recommends that concurrent improvements are made to allow reliable activation of zero generation constraints for the majority of new DER installations, as a last resort, if required for system security.

4.2.4 Enhanced voltage management (EVM)

Description

SA Power Networks uses EVM to regulate voltage levels throughout the year and, under normal circumstances, maximise the amount of energy that DPV systems can generate. When using EVM, SA Power Networks increases or decreases the voltage levels at key distribution zone substations (within safe limits). A side-benefit of EVM is that at certain higher voltage levels, a subset of DPV systems trip, disconnecting from the system. This method of disconnecting DPV can be used as a last resort when required to maintain system security.

EVM is split into 12 normal and three critical blocks containing different zone substations, as not all blocks are required in each event. EVM DPV curtailment is rotated between the normal blocks for each event, like rotational load shedding. The three critical blocks are only used when extra curtailment is required.

Performance during this event

During this event EVM was only used when other DPV curtailment methods above were exhausted, and further action was required to secure the power system. Table 12 shows the times in which EVM was applied to curtail DPV during this event.

Table 12 Times that enhanced voltage management was applied to curtail distributed photovoltaics

Date	EVM commenced		EVM ceased	
	Earliest block	Latest block	Earliest block	Latest block
13 Nov	10:46	12:15	13:48	17:58
14 Nov	12:42	14:15	15:28	15:57
15 Nov	11:46	15:27	14:16	15:27
16 Nov	10:44	14:20	15:16	15:49
17 Nov	8:51	10:42	15:48	17:36
18 Nov	NA	NA	NA	NA
19 Nov	8:57	9:56	12:47	14:20

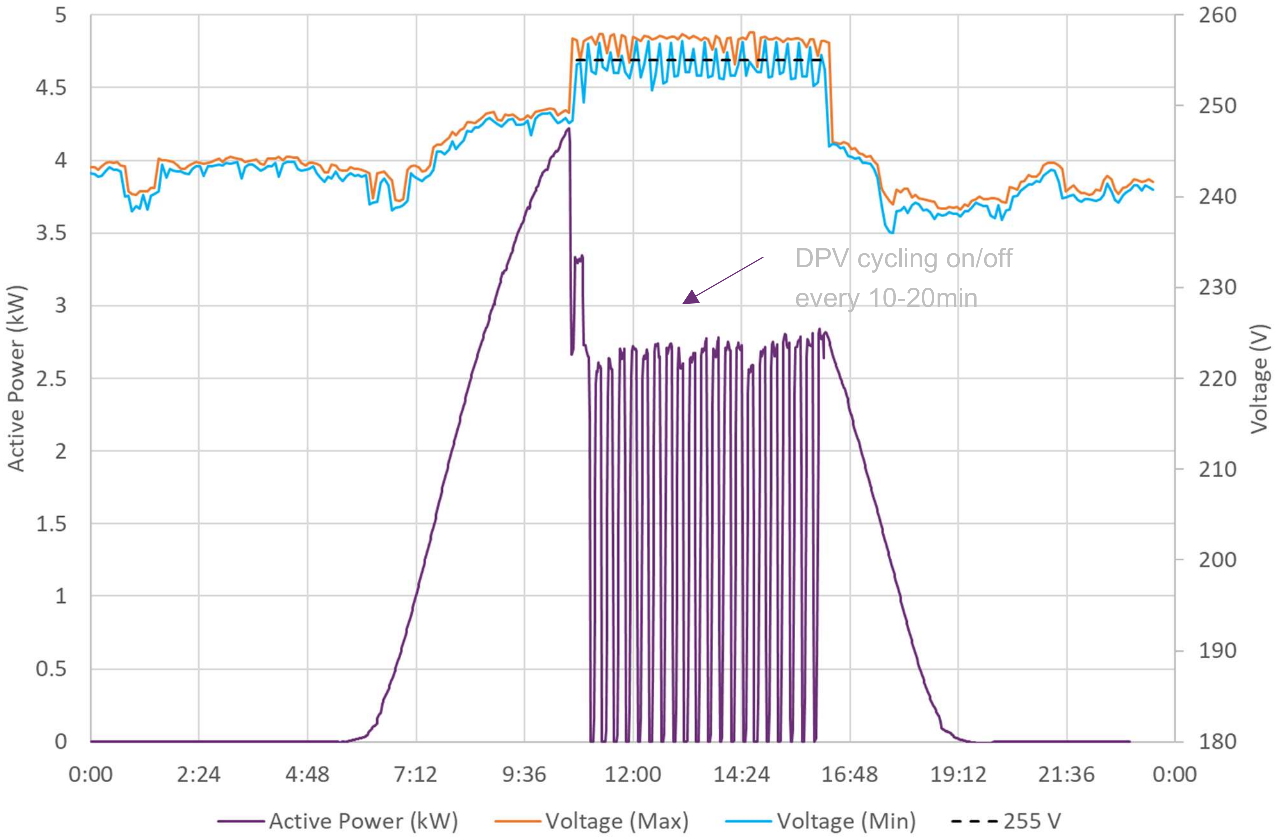
It is estimated that at least two-thirds of the DPV curtailment during this event was delivered by EVM. Without this EVM capability, AEMO would have likely been unable to maintain a secure operating state in SA during high DPV periods, especially on 13, 17 and 19 November 2022. If there were greater levels of compliance in the Smarter Homes scheme, EVM would still have been needed to maintain power system security during this event, but would not have needed to be enacted as extensively or for as long a duration.

The delivery of an effective EVM response only requires SCADA communication to zone substations, and does not rely on any further availability of internet or telecommunications systems. This means EVM was able to deliver a consistent and reliable DPV curtailment response even on 13 and 14 November 2022, when there was communications loss resulting from both distribution network and communication outages caused by storm activity on 12 November 2022.

However, EVM has important limitations, and is only used as the final last resort.

For example, EVM was observed to result in repeated cycling behaviour for some DPV systems, as illustrated by the example in Figure 27. The system shown in this example was observed to ramp up and down in regular cycles approximately every 15 minutes throughout the course of EVM activation. Approximately 10-15% of systems were estimated to exhibit behaviour of this type. This behaviour is likely related to interactions between the load, DPV and local system voltage. Distributed resources designed to meet the 2015 and 2020 standards should trip after 10 minutes of average voltages exceeding 244-258 volts (V). When voltages are deliberately increased to exceed this level and cause DPV to trip, this can result in a site alternating between high voltage and disconnecting the generation, which in turn reduces the voltage at the site to below allowable levels, thus allowing the DPV to reconnect. The overall response from EVM across the network is distributed, which means EVM does deliver an effective aggregate reduction in DPV generation as required. However, this behaviour is generally undesirable, which is why SA Power Networks only uses EVM as the final last resort to secure the power system after all other methods have been exhausted[37]. AEMO recommends that DNSPs in other jurisdictions consider these factors when considering whether to utilise EVM in their networks for these kinds of purposes (this and other recommendations are outlined in Section 4.3).

Figure 27 Enhanced voltage management impact on an example distributed photovoltaic system on 17 November 2022



EVM also cannot discriminate between DPV systems on a feeder; all DPV systems on the feeder are exposed to the high voltage and may disconnect or curtail in response. In contrast, remote management methods such as Flexible Exports, Smarter Homes and SCADA control can selectively manage individual DPV systems based on

[37] The ramping behaviour illustrated in Figure 27 may also mean that EVM is not suitable for application to manage DPV in a system restart process, since stable load is required during a restart process to support the start-up of the restart generators. If whole feeders are fluctuating by a significant amount, this could negatively impact the restart process. AEMO is investigating this further with SA Power Networks. Having alternative effective methods of actively managing DPV during a restart process would be preferrable.

their properties (if suitable procedures and tools are in place). This selective curtailment capability will become increasingly important in future, for example to selectively curtail only DPV systems that are known to have poor disturbance ride-through capabilities while allowing systems with effective disturbance ride-through capabilities to operate unhindered. Selective curtailment could also enable NSPs to more effectively manage cybersecurity threats, or ensure that resources delivering FCAS can operate without interruption while other distributed systems are being managed.

4.2.5 Implications of DPV management for FCAS delivery

During this event, a proportion of FCAS was procured from resources connected to SA Power Networks' distribution network, including distribution-connected scheduled generators and storage systems, non-scheduled commercial generators and storage systems, and VPPs. These distributed resources were able to leverage their geographic diversity to continue to provide FCAS throughout the event, despite extensive storm-related disruptions to transmission, distribution and communications networks.

It is also possible that DPV curtailment strategies may have impacted the FCAS availability of these resources through the following mechanisms:

- Distribution connected SCADA-controlled generation (including battery storage sites) restricted from generating (for example, through a Permission Denied signal), and hence unable to provide ancillary services.
- Household batteries in VPPs impacted by EVM, either by being disconnected due to sustained over-voltages, or put at risk of disconnecting on instantaneous over-voltage settings if called on to provide a FCAS raise response.

Early investigation suggests that the aggregate discharging and charging capacity available for frequency response from distributed battery systems may have been reduced by up to 30% during periods where DPV curtailment was enacted across the network (such as on 17 November 2022). Some VPP operators may already have systems that account for this reduction in real time in their FCAS bidding; AEMO is investigating this with the relevant participants.

EVM may also mean that distributed battery systems are operating close to instantaneous over-voltage trip settings, and delivery of the required contingency raise response could lead to further escalation of distribution feeder voltages, leading to over-voltage tripping and resulting in reduced VPP fleet capacity and possible under-delivery of FCAS. This is difficult to account for in real-time FCAS availability assessments, and requires further investigation.

AEMO is continuing investigation on these factors with the relevant market participants and SA Power Networks to determine:

- The degree to which these factors impacted FCAS availability.
- Any adjustments that should be made to AEMO and SA Power Networks operating procedures to account for these factors.
- The degree to which these market participants have adequate tools in place to adjust their FCAS offers accordingly during these periods of unusual grid operation.

4.2.6 Adjustment for location of separation

In this event, the separation occurred near the Tailem Bend substation, with the Keith and South East substations remaining connected to Victoria via the Heywood interconnector. When directed to enact DPV curtailment, SA Power Networks applied standard procedures, without distinguishing between DPV that remained within the SA island, and DPV connected at Keith and South East substations. This was for the following reasons:

- All SCADA-controlled DPV curtailment is enacted via automated switching programs which have been pre-written in the SA Power Networks system to allow for fast control activation. Given extensive operational pressures during this event, it was not feasible to edit or adjust these programs during the event to exclude substations in the non-islanded region.
- SA Power Networks systems for activation of Smarter Homes Relevant Agents are not designed with substation level control, and therefore it was not possible to distinguish activation of these systems based on location.
- All Flexible Exports sites were located within the SA island.
- EVM is enacted via automated switching programs which have been pre-written in the SA Power Networks Advanced Distribution Management System (ADMS) to allow for fast control activation. Given extensive operational pressures during this event, it was not feasible to edit or adjust these programs during the event to exclude substations in the non-islanded region.

Less than 5% of the DPV in SA was located outside the islanded region, so this approach did not lead to extensive unnecessary DPV curtailment, and provided a feasible management approach in the context of the operational pressures during this event.

4.3 Recommendations on DPV management

Based on learnings from this event, AEMO makes the following recommendations.

4.3.1 Compliance with technical standards

In this event, poor compliance of DPV with disturbance ride-through requirements was the primary reason why DPV curtailment was required. Furthermore, poor compliance with curtailment capability requirements then reduced the ability of the power system to manage the resulting contingency risk.

Improvements in DER compliance with technical settings (AS/NZS4777.2:2020) in all regions as an urgent priority, targeting at least 90% of new installations to be set correctly to AS/NZS4777.2:2020 by December 2023, particularly including:

- Compliance with disturbance ride-through requirements and other technical settings specified in the AS/NZS4777.2:2020 standard.
- Compliance with the requirements to properly set up and maintain distributed systems to respond to directions to curtail active power generation when required as a last resort for system security.

Continuous improvements over time, based on ongoing learnings, will likely be required. AEMO has released a comprehensive report[38] outlining evidence on non-compliance, and proposed next steps. The report identifies a number of rapid improvements that can be implemented under existing frameworks (particularly by DNSPs and original equipment manufacturers [OEMs]), and provides insights to support development of improved enduring governance frameworks. These insights have been shared with the Australian Energy Market Commission (AEMC) for consideration in its review on consumer energy resources technical standards.

SA Power Networks work in progress to improve compliance

To improve levels of DER compliance, SA Power Networks has developed and is systematically implementing a DER compliance program. The program will establish mechanisms to make DER non-compliances visible for relevant parties and work with industry to implement appropriate controls, incentives and penalties. SA Power Networks' DER compliance program is being implemented in the following phased approach(see Table 13).

Table 13 SA Power Networks DER compliance program

Phase	Focus and capability
1	**Network Application Close-out** This phase ensures SA Power Networks is provided inverter serial numbers to facilitate the commissioning of a site for Smarter Homes. In lieu of this information, a majority of sites will not be controllable in an emergency event. This phase will automate close-out non-compliance detection (missing serial numbers) and prevent applicants from receiving future network approvals if their compliance level falls below a threshold. We expect this will be complete by the end of May 2023.
2	**Flexible Exports Device Registration & Capability Test** This phase aims to ensure Flexible Exports enrolled devices electronically register and perform automated tests. This phase is targeted to coincide with the beginning of SA Government's Dynamic Exports requirements in SA.
3	**Export Limits** Automates detection of sites which do not have network approval and/or breach export limits. This automated analysis will use data from retail metering.
4	**Inverter Region Settings** SA Power Networks' existing manual methods of detection and action are replaced by automatic detection of non-compliant inverter operation through time-series data.
5	**Remote Inverter Configuration Over DOE Interface** Engagement with the DER Integration API Technical Working Group (DERAPITWG) to update the Australian implementation of IEEE 2030.5 (CSIP-AUS) to include reading and writing of inverter settings.

This program complements manual methods and activities SA Power Networks is undertaking with AEMO and industry to improve compliance to region settings and emergency backstop mechanisms.

4.3.2 Emergency backstop DPV curtailment capabilities

Implementation of emergency backstop capabilities in all regions

This event illustrates a scenario where large amounts of DPV curtailment was required, as a last resort, to maintain power system security. Similar needs are anticipated in other NEM regions and in Western Australia's Wholesale Electricity Market (WEM) in the near future, and should be implemented as a priority.

[38] AEMO (April 2023) Compliance of Distributed Energy Resources with Technical Settings, https://aemo.com.au/-/media/files/initiatives/der/2023/compliance-of-der-with-technical-settings.pdf?la=en.

NSPs, Governments, AEMO, and the AEMC will all likely need to play a role in delivering these capabilities, preferably with national consistency.

At present, DPV emergency backstop curtailment capabilities are a requirement for new DPV installed in:

- SA for all new DPV systems.
- Western Australia's South-West Interconnected System (SWIS) for systems with an inverter capacity of 5 kW or less (while larger systems are subject to export limits)[39,40] .
- Queensland for systems with an aggregate capacity of 10 kilovolt-amperes (kVA) and above[41]

In Victoria, New South Wales and Tasmania, DPV curtailment is only required for large commercial systems connected at higher voltage levels.

These requirements should be expanded to include all new DER installations as soon as possible, in all jurisdictions, to ensure this capability is available if required as a last resort for system security.

AEMO also recommends that all DNSPs implement schemes for accurate, close to real-time DPV management as the long-term solution. This should aim to ensure inverters respond quickly and consistently, support predictable fallback behaviour, consider cyber security requirements, and simplify implementations for DNSPs and equipment manufacturers.

Learnings from this event on performance of various DPV management mechanisms

There are various technical options and various regulatory frameworks that could be used to implement emergency backstop DPV curtailment capabilities in other jurisdictions. When exploring these options, other jurisdictions should draw learnings from this incident and the broader experiences from implementing these capabilities in SA.

Key learnings include:

- Consider regulatory frameworks and technical processes that support and drive high rates of installation compliance, and conformance monitoring to monitor and maintain ongoing compliance over time.
- Consider the robustness of the curtailment response under a wide range of possible conditions, including widespread outages of communications systems (due to flooding, bushfires, storm damage, cyber comprise or other factors) that may be co-incident with difficult grid conditions where emergency backstop curtailment is more likely to be required.
- Consider local "fall-back" or "fail-safe" behaviour which DER systems should perform if communications systems are lost for an extended period of time (for example, defaulting to zero exports from the site). This is especially relevant during severe storm, bushfire and black system events, which can have coincident impacts on multiple, usually redundant communications networks as well as the power system. These fall-back behaviours reduce the amount of DPV curtailment required under already difficult grid conditions (when communications outages are likely so instructing DPV curtailment can be challenging). It also provides an

[39] Meeting the Emergency Solar Management requirements may be impractical for a limited number of metering configurations. In recognition of this, all customers have the option to opt out of meeting the Emergency Solar Management requirements if their system is export-limited at all times and all energy export payments are foregone.

[40] Government of Western Australia (2023), Emergency Solar Management, https://www.wa.gov.au/organisation/energy-policy-wa/emergency-solar-management.

[41] Queensland Government (2023), Emergency Backstop Mechanism, https://www.epw.qld.gov.au/about/initiatives/emergency-backstop-mechanism.

incentive for customers to maintain connectivity of their systems over time (since the system will default to minimal exports if communications are lost for an extended period). This is especially important if the communications pathway relies on a connection via the customer's internet. These local fail-safes need to be carefully designed to ensure that telecommunications network issues do not cause significant inadvertent or unexpected sudden losses of PV generation, which may pose a risk to power system security. SA Power Networks and AEMO will continue to collaborate to fine tune the design of appropriate fail-safe behaviours for periods with communications outages, which may include the development of procedures to pre-arm specific behaviours during high-risk periods. It is also noted that fall-back mechanisms will not be sufficient to maintain power system security in the longer term in the absence of concurrent work to enable robust and reliable active management of DPV systems to allow zero generation controls if required for system security.

- Consider the reporting mechanisms and data sharing requirements. Ideally, there would be systems in place that allow real-time visibility of any curtailment as it is occurring, as well as the ability to confirm delivery of these functions following an event. Suitable datasets are also required to monitor DER commissioning compliance, availability for curtailment response over time, and curtailment compliance when enacted in an event.
- This event provides an opportunity to explore the possible use of the various DPV curtailment mechanisms during a system restart process. AEMO will explore this further.

  This event may also provide further insights into cyber-informed engineering and the capability for achieving redundancy and robustness in data and control pathways for the purpose of being able to isolate and disconnect potentially compromised DER nationally.

4.3.3 Operational processes and tools

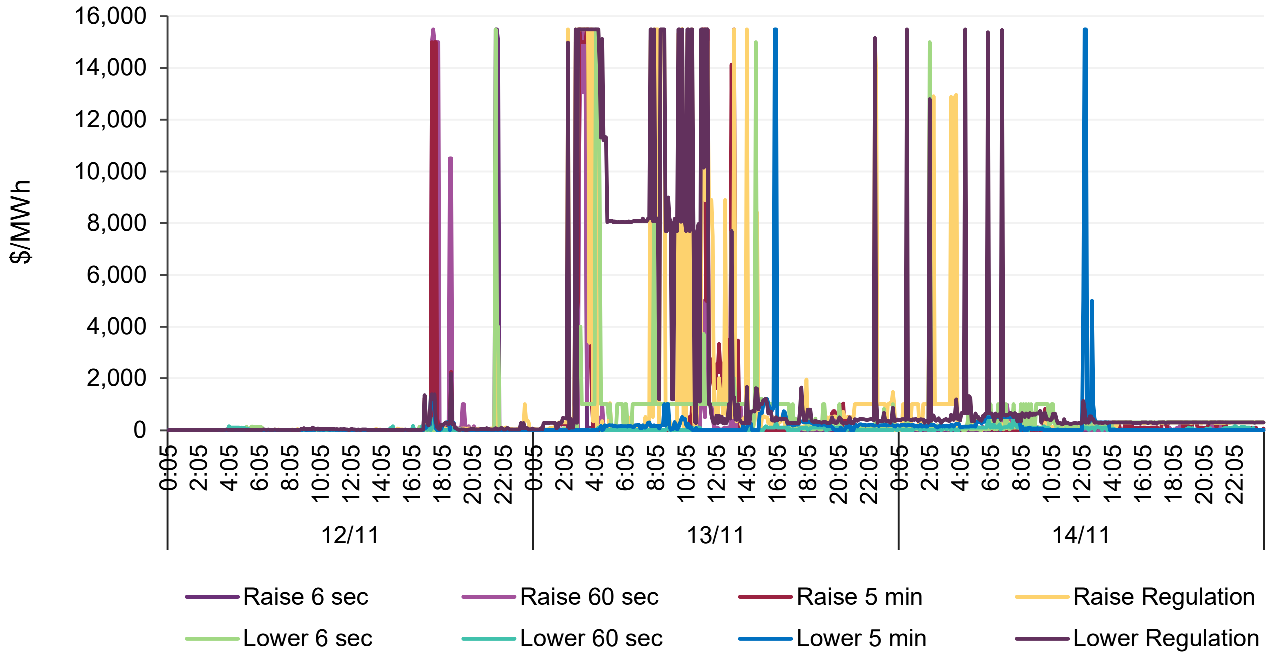
This event highlighted a number of other areas for improvement and further investigation:

- **Visibility of DPV curtailment** – AEMO and SA Power Networks to explore options to improve real-time visibility of DPV curtailment when it is occurring. This should include short-term uplifts to existing systems (such as improvements to the ASEFS2 solar forecasting system and improvements to SA Power Networks tools), as well as longer term development of more sophisticated and automated tools and processes. During this incident AEMO, ElectraNet and SA Power Networks had to rely on operational demand and demand forecasts as a proxy for monitoring DPV curtailment, increasing uncertainty and system risk
- **FCAS delivery from DER** – By end of 2023, AEMO, SA Power Networks, and the relevant market participants to investigate the availability of DER to deliver FCAS during periods of DPV curtailment. This analysis should seek to understand how these resources might be affected by the various mechanisms used to manage DPV, and ensure appropriate processes and tools are in place to deliver accurate FCAS availability estimates in real time. In this incident, preliminary investigation suggests that FCAS availability from distribution connected resources was impacted by the various mechanisms used to actively manage DPV.
- **Procedures and tools** – a suite of minor improvements to procedures and tools to refine and streamline management of these types of conditions. This event highlighted a range of opportunities to improve these processes.

5 Market impact

Following the event, SA FCAS prices experienced significant volatility. All FCAS markets except for the Lower 60 seconds market reached the market price cap (MPC) of $15,500/megawatt-hour (MWh) at various trading intervals between 12 and 14 November 2022 (see Figure 28).

Figure 28 South Australia FCAS dispatch price by market – 12 to 14 November 2022



Under normal conditions, FCAS services can be supplied globally, where offers from generators or loads in any NEM region can be procured to meet the FCAS requirements determined by AEMO[42]. However, with the majority of SA synchronously separated from the rest of the NEM, FCAS requirements could only be procured or supplied by local providers within the SA island. This subsequently resulted in an increase in prices across all FCAS markets within SA, substantially above the typical price levels.

While high prices occurred across all SA FCAS markets, price volatility was particularly elevated in the lower regulation market due to the change in fuel mix (see Figure 29). During this period, gas generation was providing the majority of the service, as SA batteries offering capacity to the regulation market were constrained to provide FFR when SA was operating in an islanded network (see Section 3.2)[43].

[42] NER 3.8.11(a1)

[43] Lake Bonney BESS was not connected to the SA electrical island.

Figure 29 South Australia lower regulation market FCAS fuel mix – 12 to 14 November 2022

High price volatility in the lower regulation market resulted in the cumulative price progressively increasing towards the cumulative price threshold (CPT) of $1,398,100[44]. At 1300 hrs on 14 November 2022, the application of automatic market price caps was triggered in the lower regulation market as the rolling sum of the uncapped prices over the previous seven days (or 2016 trading intervals) exceeded the CPT (see Figure 30). Administered price period (APP) commenced, with Administered Price Cap (APC) applied across all eight FCAS markets in SA under National Electricity Rules (NER) 3.14.2. APP did not apply to the energy markets. Under NER 3.14.2(d2), within an APP, AEMO is required to set ancillary service price to administered price cap of $300/MWh[45] if an ancillary service price for any market ancillary services for the region exceeds APC.

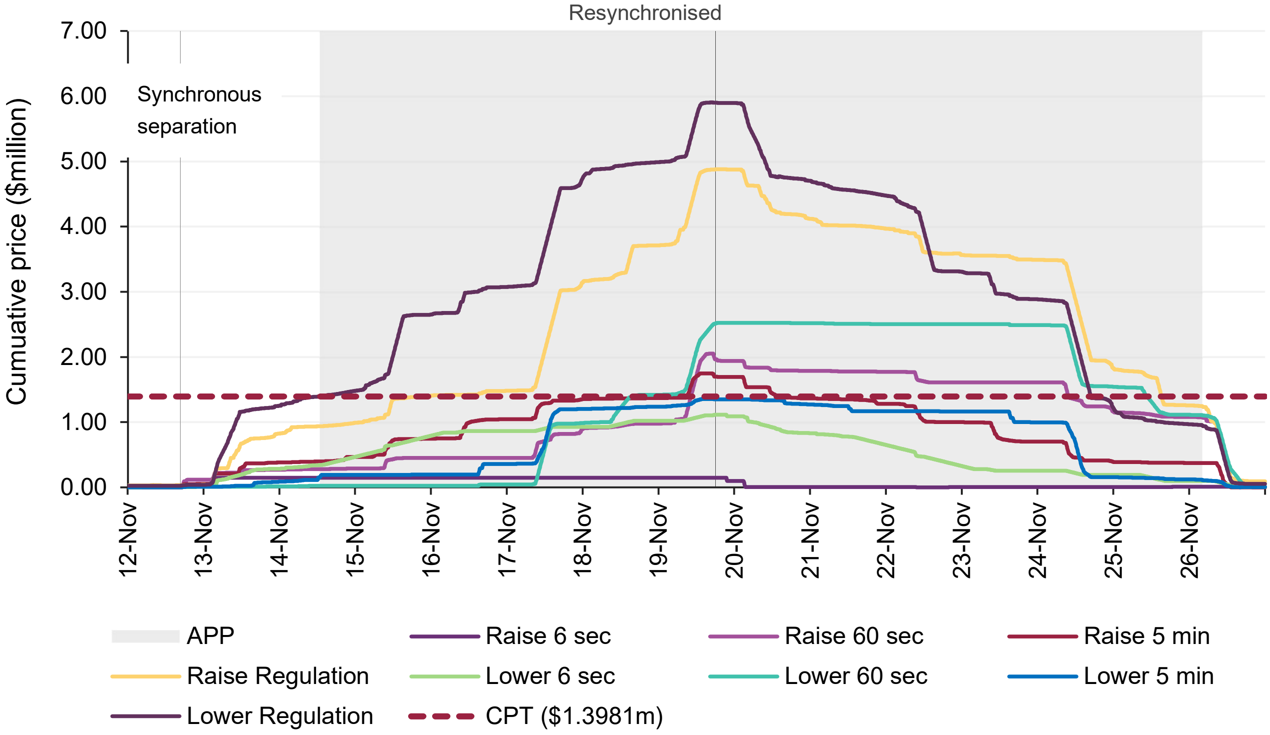
Shortly after the commencement of APP on FCAS markets on 14 November 2022, there were noticeable changes in generator bidding. As prices were capped at $300/MWh, this reduced incentive for gas generators to remain online, with several gas units in SA rebidding capacity to higher price bands, resulting in AEMO directing some gas-fired units online to provide FCAS services to manage power system security. The first direction for FCAS services was issued on 15 November 2022 and remained in place between the trading intervals ending 0705 hrs and 1500 hrs. Further directions for FCAS provision were issued again on 17, 18 and 19 November 2022. Under NER 3.9.3, intervention pricing was applied when these directions were in place[46]. Total market costs relating to these intervention events are still being assessed by AEMO.

[44] Applicable for the 2022-23 financial year. For further details, see https://www.aemc.gov.au/news-centre/media-releases/2022-23-market-price-cap-now-available.

[45] Note that during this event administered price cap was $300/MWh. APC has since increased to $600/MWh as of 1 December 2023; see https://www.aemc.gov.au/rule-changes/amending-administered-price-cap.

[46] In accordance with clause 3.9.3 of the NER, AEMO must apply intervention pricing when it intervenes in the NEM by exercising RERT or issuing a direction to obtain a service. For intervention events that fit the criteria set out in clause 3.9.3(b) of the NER, AEMO must set the energy and ancillary service prices during the intervention at the levels that would have applied had the intervention not occurred. For more information on intervention pricing methodology, see https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/dispatch/policy_and_process/intervention-pricing-methodology.pdf?la=en.

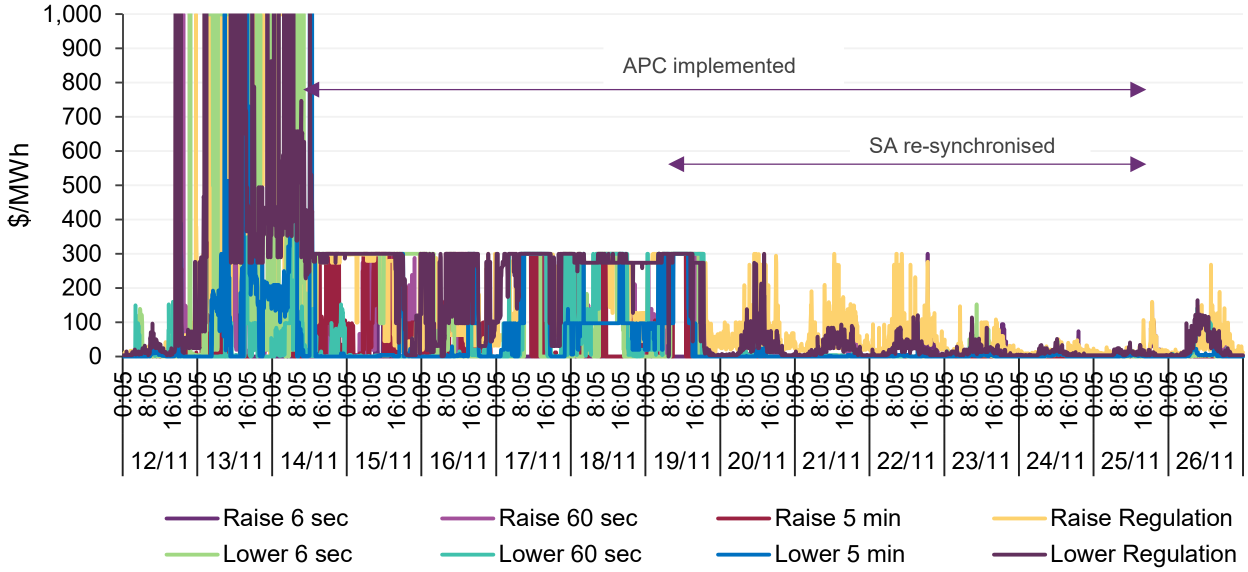
Figure 30 South Australia FCAS cumulative prices by market – 12 to 26 November 2022



Although the APC was applied to all FCAS markets in SA, the cumulative price is calculated as if the cap was not in place. Consequently, other FCAS markets (raise regulation, lower 60 seconds, raise 5 minutes and raise 60 seconds) also exceeded the CPT in the following days after APP commenced and APC continued to apply to all services. Cumulative prices continued to increase across several FCAS markets, peaking on 19 November 2022, seven days after the initial event (cumulative prices are calculated on a rolling sum of uncapped prices over the previous seven days). On the same day at 1804 hrs, SA re-synchronised with the rest of NEM following the return to service of the South East – Tailem Bend No.1 275 kV.

With SA being synchronised with the NEM, that meant FCAS services could now be procured on a global basis; consequently prices returned to more typical levels, although still capped as APC remained in place (see Figure 31.

Figure 31 South Australia FCAS dispatch price by market – 12 to 26 November 2022



Note: FCAS prices scale (y-axis) is adjusted to only show $0/MWh to $1,000/MWh.

Cumulative prices progressively declined following resynchronisation of SA to the NEM on 19 November 2022, with raise 5 minutes being the first market to fall below the CPT on 20 November 2022. APC however continued to apply to all services until the end of the trading day when the cumulative FCAS prices for all services fell below the CPT. In the following days, other services including raise 60 seconds, lower 60 seconds, lower regulation and raise regulation progressively fell under the CPT on 24 and 25 November 2022. APC was however only lifted at 0400 hrs on 26 November 2022, the next trading day after the last market (raise regulation) fell below CPT at 1510 hrs on 25 November 2022[47].

Elevated SA FCAS prices during the islanding event resulted in high SA FCAS costs, with aggregated costs estimated to be $31.1 million between 12 and 26 November 2022. In particular, significant price volatility prior to the APP (12-14 November 2022) contributed to majority of the total costs during this event.

[47] See Market Notice 103964.

6 Reclassification

Prior to the event, forecast weather conditions around South Australia did not meet any of the reclassification criteria outlined in the published power system security guidelines[48]. When the South East – Tailem Bend 275 kV No. 1, the Keith – Tailem Bend 132 kV and the South East – Tailem Bend 275 kV No. 2 275 kV circuits were returned to service, AEMO did not reclassify the simultaneous trip of both circuits as credible because:

- The South East – Tailem Bend No. 1 and No. 2 275 kV circuits were returned to service only after each circuit had been transferred to a temporary transmission tower. As an effective temporary repair had been made prior to each circuit's return to service, AEMO was satisfied that this event was unlikely to reoccur.
- ElectraNet had confirmed the cause of the Keith – Tailem Bend 132 kV circuit trip as operation of an automated tripping scheme which operated consistent with its expected performance.

[48] See https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/power_system_ops/procedures/so_op_3715-power-system-security-guidelines.pdf?la=en.

7 Constraints

AEMO invoked over 150 constraints to manage the incident and operate the SA island. Table 14 summaries the main constraint sets invoked between 12 November and 23 November 2022 to manage the system.

Table 14 Constraints set invoked between 12 to 23 November 2022

Set name	Time invoked	Time revoked	Description
F-SA_ESTN_ISLE_REG	12/11/2022 16:50	23/11/2022 18:40	Invoked for SA island – separation point between Tailem Bend and South East.
SA_ESTN_LG_ISLE	12/11/2022 16:50	19/11/2022 18:40	SA/Eastern Separation between Tailem Bend and South East (TBSS-SESS).
SA_ISLE_LB_FFR_ZERO	12/11/2022 21:30	19/11/2022 18:40	Invoked when 4 hours of FFR is completed.
SA_LG_ISLE_FFR0_70M	17/11/2022 9:00	17/11/2022 17:00	Invoked when 70 MW max metro generator option is enabled. See Section 3.4 for details.
SA_LG_ISLE_FFR0_70M	19/11/2022 8:35	19/11/2022 15:15	Invoked when 70 MW max metro generator option is enabled. See Section 3.4 for details.

Since the separation was some distance from the region boundary (that is, at Tailem Bend substation), the invoked constraints balanced demand in Southeast SA with supply from local generation and the Heywood interconnector from Victoria. In the constraint formulation, the Tailem Bend Solar Farm 1 was considered connected to the Victorian region, but remained connected to the remaining SA region during the separation event. A scheduling error occurred due to the Tailem Bend Solar Farm 1 being incorrectly included on the left-hand side (LHS). This issue occurred because the applied constraints used a pre-defined formulation based on likely points of separation between South Australia and Victoria. AEMO subsequently adjusted the constraint by removing the Tailem Bend Solar Farm 1 as more information became available on the actual points of separation and island operation on 14 November 2022.

8 Market notices

AEMO issued over 150 market notices (MNs) to manage the incident and operate the SA island. Table 15 summarises the types of MNs issued 12-23 November 2022

Table 15 Market notices issued 12 to 23 November 2022

Notice type	Description
Administered Price Cap	MNs related to commencement and termination of Administered Price Period
Market Intervention	MNs related to possible intervention by AEMO to manage power system security in SA region including constraining DPVs to manage DPV contingency
Power System Events	MNs related notify the significant system event, the separation of majority of SA due to a non-credible contingency event
Reserve Notice	MNs related to lack of reserve level in SA region during the island operation period
General Notice	MNs related to DPV contingency management in SA

9 Conclusions

AEMO has assessed this incident in accordance with clause 4.8.15(b) of the NER. In particular, AEMO has assessed the adequacy of the provision and response of facilities or services, and the appropriateness of actions taken to restore or maintain power system security.

AEMO has concluded that:

1. ElectraNet's preliminary investigation indicates the presence of specific ground conditions at the footings of the failed tower which materially contributed to a footing failure. Based on the information available at this time, ElectraNet believes this is an isolated failure and the probability of a similar weakness in the foundations of other towers on the line is low.
2. AEMO confirmed ElectraNet's advice that SA should not be connected to the NEM via the 132 kV network (Keith – Tailem Bend 132 kV line). This is primarily due to variability in renewable generation causing the flow on the Keith – Tailem Bend 132 kV line to drift. This drift is likely to cause the circuit to become overloaded and increase the potential for a disturbance to exceed the stability limits in the SA network.
3. DPV curtailment was required during this event to manage the frequency control implications of possible DPV shake-off in response to a fault (associated with legacy DPV systems and non-compliance of newer DPV systems with the disturbance ride-through requirements in AS/NZS4777.2:2020). The size of such a contingency is growing in all regions due to continued poor compliance of new DPV systems, which will increasingly impact on system operations.
4. All curtailment options contributed to managing system security were utilised. Post-incident investigation provided insights on the various methods for DPV curtailment applied:
   - SCADA-controlled DPV – larger DPV systems (approximately 200 kW capacity and greater) were curtailed first, and responded as expected.
   - Directions to Relevant Agents under the Smarter Homes regulations – of the 517 MW of DPV capacity installed under this scheme, 25-42% were observed to respond as required in this event. SA Power Networks estimates that only 51% of systems are set up properly at the point of commissioning. Response rates were lowest on 13 and 14 November 2022 due to impacts of telecommunications outages caused by severe weather. In addition, response rates varied significantly between different Relevant Agents, with some achieving total response rates of 80-90%, and others achieving a response rate of 10-20% or lower.
   - EVM – SA Power Networks uses EVM to regulate voltage levels throughout the year and, under normal circumstances, maximise the amount of energy that DPV systems can generate. A side-benefit of EVM is that at certain higher voltage levels, a subset of DPV systems will disconnect. This method of disconnecting DPV can be used as a last resort when required to maintain system security. It is estimated that at least two-thirds of the DPV curtailment during this event was delivered by EVM. Without this EVM capability, AEMO would have likely been unable to maintain power system security during high DPV periods, especially on 13, 17 and 19 November 2022. However, EVM also led to some DPV systems demonstrating cycling behaviour (repeated switching on/off every 10-20 minutes), and impacted FCAS availability of distribution connected resources.
5. This event highlights a need for DPV curtailment emergency backstop capabilities in all regions, and provides learnings for other regions on factors to consider during implementation.

6. Some of the approaches applied in this event to manage DPV impacted the ability of distribution-connected resources to deliver FCAS.
7. Throughout this incident AEMO lacked real-time visibility of DPV output in SA. This impacted AEMO's, ElectraNet's and SA Power Networks' ability to respond to the incident effectively.

10 Recommendations

As a result of this incident review, AEMO has identified a number of issues that require further investigations and potential opportunities to improve operation and processes related SA operation and DPV management following a regional separation with the intention of enhancing the reliability of the power system. AEMO's recommendations on these matters are set out in this section.

1. AEMO recommends ElectraNet complete its investigation of the tower failure and advise of any additional risks or need for reclassification to manage system security. Once investigations have been completed later this year, AEMO will publish a supplementary or updated report including further details on the results of ElectraNet's investigations and any further actions ElectraNet is taking or considers it will need to take in response to the tower failure.
2. AEMO recommends that compliance of DER with technical settings (AS/NZS4777.2:2020) in all regions is improved as an urgent priority, targeting at least 90% of new installations to be set correctly to AS/NZS4777.2:2020 by December 2023. This requires collaborative engagement from many stakeholders. AEMO has released a comprehensive report outlining evidence on non-compliance, and proposed next steps. The report identifies a number of rapid improvements that can be implemented under existing frameworks (particularly by DNSPs and OEMs) and provides insights to support development of improved enduring governance frameworks. These insights have been shared with the AEMC for consideration in its review on consumer energy resources technical standards.
3. AEMO recommends SA Power Networks implement improved frameworks in South Australia to achieve consistently high compliance of DPV systems with curtailment requirements (ensuring systems are properly set up, and maintained over time, to deliver curtailment requirements, and can be curtailed in an accurate and timely manner when directed). See Section 4.3.1 for further recommendations.
4. AEMO recommends emergency curtailment backstop capabilities are to be implemented in all regions (ability to curtail all new DPV installations to zero active power if required as a last resort to maintain power system security) as a priority. NSPs, governments, AEMO and the AEMC will all likely need to play a role in delivering these capabilities, preferably with national consistency. In implementing emergency backstop capabilities, consider:
   - Mechanisms and frameworks for managing compliance (during initial set-up, and maintained over time).
   - The robustness of the technical approach applied, especially under conditions where communications networks may be compromised and there may be widespread power outages (due to flooding, bushfires, storm damage, or other reasons). These types of conditions may coincide with challenging grid conditions where emergency backstop capabilities are required.
   - Suitable fallback settings (default behaviour that each DER inverter is programmed to autonomously perform if communications is lost for an extended period).
   - Standards-based schemes for DPV management (such as IEEE 2030.5 CSIP-AUS), targeting consistency of approach across jurisdictions, and ensuring inverters respond quickly and consistently, supporting predictable fallback behaviours, and simplifying implementation for DNSPs and equipment manufacturers.
   - Methods that allow selective curtailment capability on an individual system-by-system basis, for example so that FCAS delivery is not inhibited in periods where active DPV management is in use. Consideration

should also be given to the possible use of these curtailment mechanisms to assist in managing DPV during a system restart.

- Options for managing cyber security risk including cyber-informed engineering and the capability for achieving redundancy and robustness in data and control pathways for the purpose of being able to isolate and disconnect potentially compromised DER nationally.

8. By end of 2023, AEMO, SA Power Networks, and the relevant market participants to investigate the availability of DER to deliver FCAS during periods of DPV curtailment. This analysis should seek to understand how these resources might be affected by the various mechanisms used to manage DPV, and ensure appropriate processes and tools are in place to deliver accurate FCAS availability estimates in real time.
9. By Q1 2024, AEMO to develop a plan for implementing fit-for-purpose improvements to tools that monitor the DPV in operation in real time and the visibility of DPV curtailment when it is occurring.

A1. System diagram

The network configuration before and after the event is shown in the figures below.

Figure 32 Network configuration prior to the event

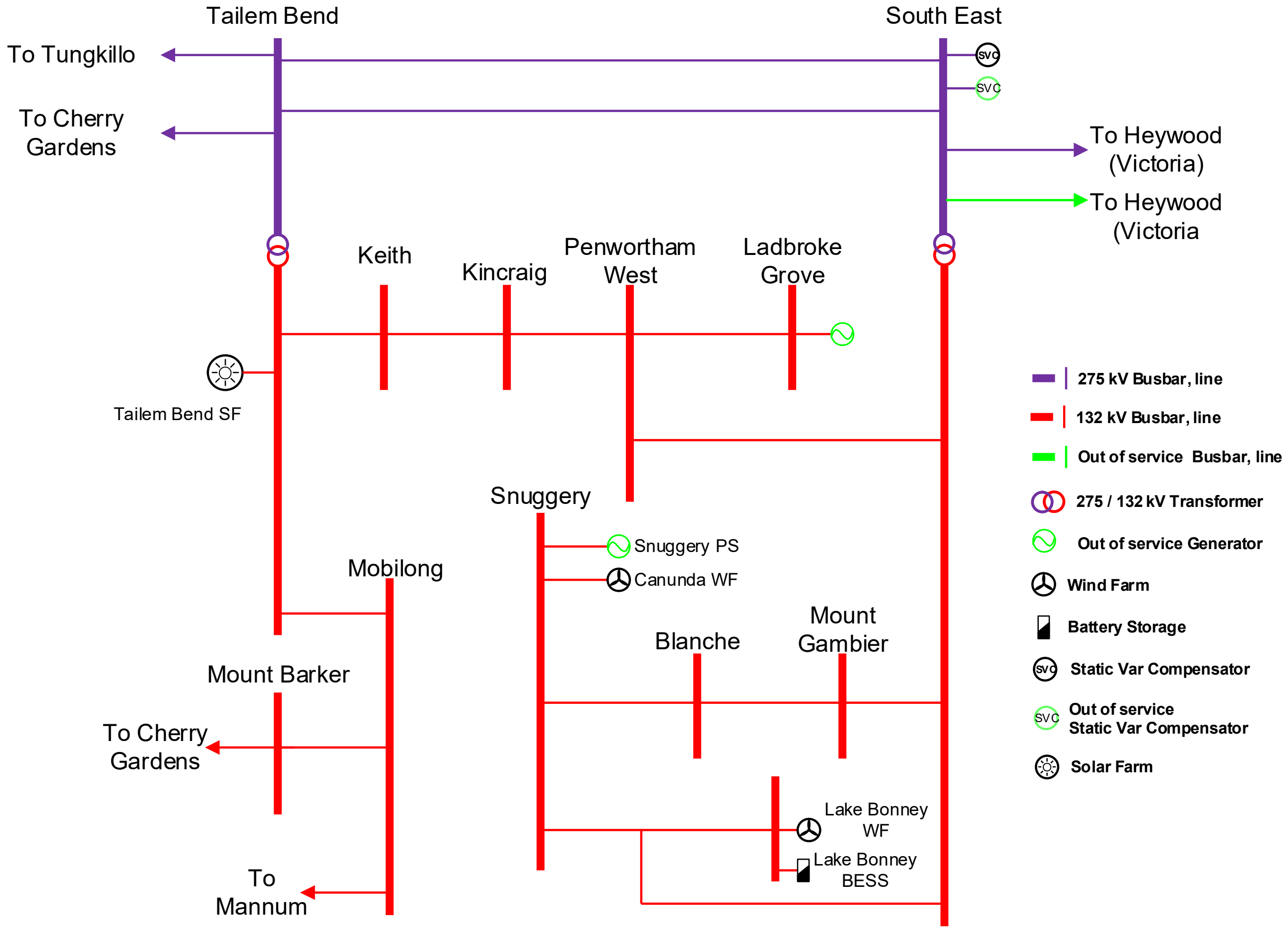


Figure 33 Network configuration after the event