AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

Final Report – Queensland and South Australia system separation on 25 August 2018

10 January 2019

An operating incident report for the National Electricity Market

Important notice

PURPOSE

This is AEMO's final report of its review of the separation and load interruption events that occurred on 25 August 2018, as a 'reviewable operating incident' under clause 4.8.15 of the National Electricity Rules (NER).

This report is based on information available to AEMO up to the date of publication.

DISCLAIMER

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Executive summary

This is AEMO's final report on the events that occurred across the National Electricity Market (NEM) power system on 25 August 2018. This event saw the loss of the alternating current (AC) interconnector between the Queensland (QLD) and New South Wales (NSW) regions, followed by loss of the AC interconnector between South Australia (SA) and Victoria (VIC). The two separation events resulted in the interruption of electricity supply to industrial loads in VIC, NSW, and Tasmania (TAS), and some residential and commercial customers in NSW. This document supersedes AEMO's preliminary report released on 10 September 2018.

This report provides data-based analysis and insights about the initiating cause of the event and subsequent performance of the power system. Based on this analysis AEMO has identified specific risks that compromise the power system's resilience to major frequency events. The event highlights a deficit of primary frequency control response from NEM generation, compared with historic levels and with other power systems around the world.

AEMO makes eight recommendations for action and further investigation to improve system resilience.

References to times in this report, unless otherwise specified, are to Australian Eastern Standard Time.

Events of 25 August 2018

On Saturday 25 August 2018, there was a single lightning strike on a transmission tower structure supporting the two circuits of the 330 kilovolt (kV) Queensland – New South Wales interconnector (QNI) lines. The lightning strike triggered a series of reactions creating faults on each of the two circuits of QNI at 13:11:39. The QLD and NSW power systems then lost synchronism, islanding the QLD region two seconds later, at 13:11:41.

At the time, 870 MW of power was flowing from QLD to NSW. QLD experienced an immediate supply surplus, resulting in a rise in frequency to 50.9 Hertz (Hz). The remainder of the NEM experienced a supply deficit, resulting in a reduction in frequency.

In response to the reduction in frequency in the remaining interconnected regions:

- The frequency controller on the Basslink interconnector immediately increased flow from TAS to VIC from 500 MW up to 630 MW. This created a supply deficit in TAS, causing the disconnection of 81 MW of contracted interruptible load under the automatic under-frequency load shedding scheme (AUFLS2) to rebalance the TAS power system at 13:11:46.
- The SA–VIC interconnector at Heywood experienced rapid changes in power system conditions that triggered the Emergency APD Portland Tripping (EAPT) scheme. The scheme responded to those conditions, as designed, to separate the SA region at Heywood. This occurred some 6 seconds after the QNI separation at 13:11:47.

At the time of separation at Heywood, SA was exporting power to VIC. This meant there was a supply surplus in SA immediately after separation, causing frequency to rise. In the remaining VIC/NSW island, the resulting supply deficit caused frequency to fall below 49 Hz, triggering under-frequency load shedding (UFLS) to rebalance supply and demand across those regions. A total of 997.3 MW of supply was interrupted in VIC and NSW, comprising 904 MW of smelter load in both regions and 93.3 MW of consumer load in NSW.

The SA-VIC interconnection was restored at 13:35 on 25 August 2018, and QNI at 14:20. The interrupted TAS load commenced restoration at 13:40 and the NSW and VIC smelters were permitted to reconnect at 13:33 and 13:38 respectively. All NSW consumer load was restored by 15:28.

This event created three separate frequency islands on the mainland NEM and highlights the present challenges of controlling frequency in the NEM, and the potential consequences of the reduction of primary frequency control over a number of years.

Frequency response

Frequency is a measure of how well supply is matched to demand. Frequency in the NEM must be maintained very close to 50 Hz to support stable operation. The frequency operating standard (FOS) allows for small deviations at various levels for classes of events that can occur, including contingencies and islanding. The amount of deviation as a result to a disturbance is a measure of the resilience of the system, which can be managed with primary and secondary control mechanisms.

In conventional power systems around the world[1] frequency control has three distinct components:

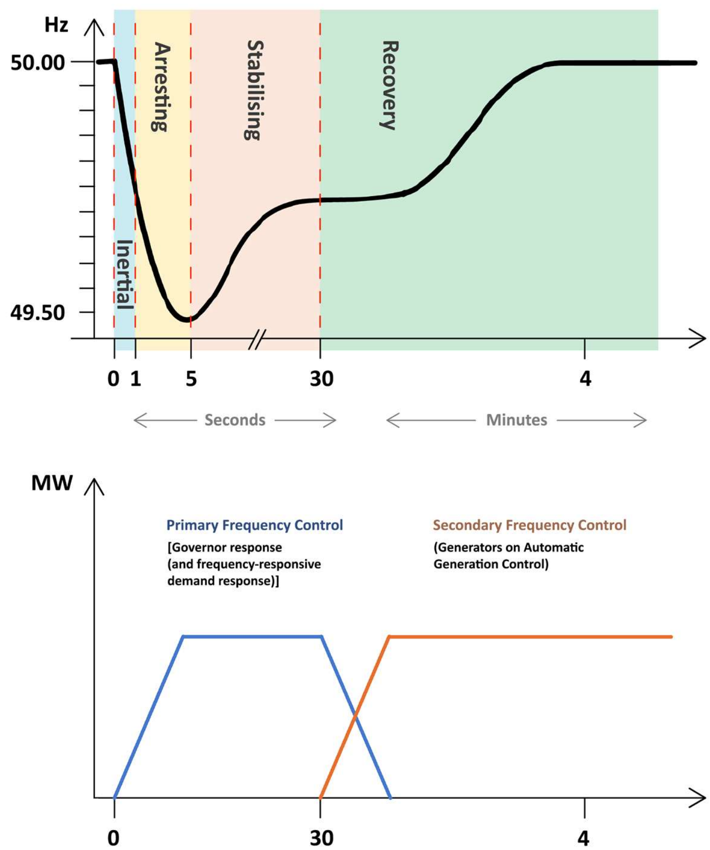
a) inertial response (instantaneous),

b) primary frequency response (within 10 seconds and up 30 seconds)

c) secondary frequency response (within 30 seconds and up to 30 minutes).

An illustration of these kinds of reactions and controls is shown in the figure below, based on potential response times to a frequency disturbance such as caused by loss of a large generator:

Figure 1 Potential response to a power system frequency disturbance



Inertial response is provided through acceleration or deceleration of rotating synchronous machines in response to electrical frequency changes; the level of inertia in the power system will determine how fast the frequency changes in the first few seconds of a frequency disturbance. The inertial response of a power system assists in limiting the rate of change in frequency during large disturbances so that control systems have time to respond and intervene.

[1] International review of frequency control adaptation, October 2016, available at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Reports/2016/FPSS---International-Review-of-Frequency-Control.pdf

Primary frequency control is an autonomous response provided by generator control systems, typically the turbine governors of synchronous generators, which act to arrest frequency disturbances. Primary frequency control typically acts within 6 seconds of a frequency disturbance and provides a response proportional to the magnitude of the frequency disturbance; primary frequency control is a requirement in many power grids as a first line of defence to frequency events and to maintain stable operating frequency[2].

Primary frequency control can generally only be sustained actively for a short while, but this is sufficient for secondary frequency control to respond. Secondary frequency control restores frequency to normal operating levels through coordination of centralised and local control systems. In the NEM and most other grids around the world, secondary frequency control is largely provided by a centralised automatic generation control system (AGC), which takes tens of seconds to minutes to recover frequency. In the NEM the AGC is operated by AEMO.

While not obligatory, active primary frequency control was a common operating protocol for many generators in the Australian power system prior to commencement of the market in the late 1990's. In the NEM, there is no market or regulatory requirement to provide primary frequency control within the normal operating frequency band of 49.85 to 50.15 Hz. Instead, eight real-time frequency control ancillary service (FCAS) markets operate in the NEM for the provision of frequency control. The two markets for regulation of frequency within the normal operating frequency band are implemented via AEMO's AGC. There are six contingency FCAS markets that provide reserve to respond to frequency changes when it exits the normal operating frequency band when contingency events occur.

Only generators enabled for one of the six contingency FCAS markets are required to respond to a contingency event and only generators enabled for regulation FCAS are required to correct frequency during normal operation. The limitations of secondary frequency control are exposed in the absence of significant primary frequency control, particularly when major contingencies occur.

AEMO has assessed the responses of all NEM registered generating systems to the changes in frequency experienced on 25 August 2018. Generation response can be broadly grouped by technology type:

- Synchronous generation

  Synchronous generation was providing 96% of the total generation in the NEM at the time of the event. The responses observed from synchronous generation during this event indicated that, unless enabled in the market for frequency control ancillary services (FCAS), many generators either no longer automatically adjust output in response to local changes in frequency or only respond when frequency is outside a wider band (dead-band) than has historically been set. This lack of response resulted in significant technical challenges controlling power system frequency during this event, delaying the resynchronisation of QLD with NSW.

- Wind generation

  Wind generation was low at 1.4% of total generation across all NEM regions at the time of the event, limiting the impact of the wind fleet. Of the wind generators online at the time, none was observed to assist in correcting the frequency deviations. Four wind farms in SA reduced output to zero due to an incorrect protection setting.

- Transmission-connected large scale solar photovoltaics (PV)

  Large-scale PV generation was also low, at 2.7% of total generation across the NEM. It generally contributed to lowering frequency in SA and QLD but was not able to assist in limiting the initial frequency excursions.

- Distributed (behind the meter) PV

  Approximately 3,096 MW of the total installed capacity of 6,278 MW of distributed (behind the meter) PV across the NEM was generating at the time of the event. Similar to large-scale PV, the distributed fleet of

[2] International review of frequency control adaptation, October 2016, available at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Reports/2016/FPSS---International-Review-of-Frequency-Control.pdf

solar PV generally contributed to assist frequency management in QLD and SA over the course of the event by reducing output. It was not able to assist in VIC or NSW, as those regions required an increase in supply. Detailed analysis of the performance of a sample group of inverters indicated:

  - Approximately 15% of sampled systems installed before October 2016 dropped out during the event.
  - Of the sampled systems installed after October 2016, around 15% in QLD and 30% in SA did not provide the over-frequency reduction capability required by the applicable Australian standard.

- Transmission-connected battery storage

  The large-scale battery storage in SA was valuable in this event, assisting in containing the initial decline in system frequency, and then rapidly changing output from generation back to load, to limit the over-frequency condition in SA following separation from VIC.

This event exposed that frequency control in all regions of the NEM, particularly primary frequency control, was insufficient to respond to a major contingency event. AEMO observed some counterproductive responses that could have been limited or prevented with sufficient primary frequency control present in each region. These responses included:

- Until separate AGC areas could be established for QLD and SA, AEMO's AGC system continued to send signals to QLD and SA regulation raise generators to further increase output.
- Until the constraint sets invoked at 13:16 to suit the post-event network topology took effect in the dispatch interval (DI) ending at 13:25, the NEM Dispatch Engine (NEMDE) continued to dispatch generation in QLD and SA to meet export targets on the physically opened interconnectors from those regions. This resulted in excess, unrequired supply in the already high frequency islands.

Within the NEM operational design, it can take up to 15 minutes, depending on the circumstances, to reconfigure AEMO systems to suit the topology of the system after separation events. During this period, primary frequency control has previously been a proven and reliable way to control frequency.

Improving power system resilience to similar events

The events of 25 August 2018 provide strong evidence of the reduction in the power system's resilience to large contingencies over the last ten years. Although most power system equipment operated within the standards set under the National Electricity Rules (NER), the aggregated responses did not meet expectations for power system resilience as observed internationally.

QLD last separated from the NEM on 28 February 2008. This involved an event in NSW that led to the loss of the QLD-NSW DC interconnector, Directlink, followed by the loss of QNI, isolating QLD from the rest of the NEM. At the time, Directlink was transporting 113 MW from QLD to NSW and QNI was transporting 978 MW from QLD to NSW. This resulted in a total loss of power transfer from QLD to NSW of 1,091 MW as compared to the loss of 870 MW on 25 August 2018.

In 2008, the QLD frequency rose to 50.62 Hz (50.9 Hz on 25 August 2018) and the remaining NEM frequency dipped to a minimum of 49.55 Hz (48.95 Hz in 2018). No additional regions separated, and no load was shed in 2008 (997 MW of UFLS in 2018).

AEMO has identified two key factors that increased the reliance on load interruption to rebalance power system demand with supply on 25 August 2018:

1. Limited or no primary frequency control response from many generators - noting there is no regulatory obligation and no commercial incentive to provide frequency control other than through existing FCAS markets.
2. The distribution of FCAS reserves across the NEM at the time of the event - the allocation of contingency and regulation FCAS reserves does not usually include any need for geographic distribution. In this event there were significant differences between the needs of the power system, and the distribution of frequency response enabled via FCAS markets.

The frequency response of generators during this event highlights the potential for severe adverse consequences of current arrangements that:

- Allow plant to limit or withdraw continuous frequency control capability when not enabled for one of the existing FCAS markets.
- Allocate contingency and regulation FCAS without consideration of geographical dispersion on the assumption that the NEM is a single region for frequency response purposes.
- Rely increasingly on uncontracted interruption of customer load following events larger than the credible contingency events covered by the FCAS markets. Historically, generation primary frequency response beyond the procured FCAS reserves could broadly be relied on to minimise the probability of such load interruption. AEMO's analysis of this event demonstrates this is no longer the case.

In addition to the need for improved primary frequency control, and better dispersion of FCAS reserves, this event has highlighted four other focus areas for NEM resilience:

- The ten minutes and eight seconds of sustained high frequency experienced in QLD following QNI separation highlights a need for AEMO to co-ordinate and stagger frequency protection settings, particularly for new plant, to minimise the risk of multiple generators tripping simultaneously due to near-identical frequency protection settings.
- Initial frequency response from some generation was delayed to the point where it was of no benefit in containing the rapid changes in frequency that immediately follow a major power system event like regional separation. The speed of frequency control response from these generators must be improved where possible, for it to be effective in containing the critical initial deviation.
- The design, settings, and implementation of control and protection schemes impacting alternating current (AC) interconnections are no longer consistently suitable for the wide range of dynamic responses introduced on the power system over a relatively short time. This was the case with the Emergency APD Portland Tripping (EAPT) scheme. Although this scheme operated in accordance with its design to separate SA from VIC on 25 August 2018, it was not designed for the circumstances of that event.
- A few generators did not operate as expected in the conditions - it is vital for generators to ensure their plant can remain in continuous uninterrupted operation when required to do so, and that simulation models are available for all generating units that can be used to fully and accurately predict plant performance.

Recommendations

The analysis of this event has provided AEMO with valuable data to identify the nature and extent of the decline in frequency control capability and system resilience to events larger than single credible contingencies in the NEM. AEMO considers this an immediate risk to the power system.

Primary recommendation – improve primary frequency control

AEMO recommends increasing the provision of primary frequency control from capable generation to arrest the decline in system resilience to larger contingency events and maintain frequency closer to 50 Hz. Given the risks highlighted by this event, AEMO recommends timely measures to secure this capability in the short term, ahead of detailed consideration of a longer term mechanism, as contemplated in the Australian Energy Market Commission (AEMC's) recent Frequency Control Frameworks Review.[3] AEMO proposes to work with the AEMC, AER and generators to finalise suitable interim measures by mid-2019.

Additional recommendations

Additional recommendations to improve resilience or investigate power system response during these events aim to:

[3] AEMC, Frequency control frameworks review, Final report, 26 July 2018. Available at https://www.aemc.gov.au/markets-reviews-advice/frequency-control-frameworks-review

- Reduce the risk of islanding regions from the NEM by reviewing and improving protection schemes and other control and protection schemes.
- Characterise and model the response of distributed PV to system disturbances, including investigation of the potential benefits accessible from a distributed PV response.
- Improve modelling of frequency response and active power control characteristics of the power system.

Table 1 lists AEMO's eight recommendations.

Table 1 AEMO recommendations

	Recommendation
1.	Primary frequency control in the NEM a) AEMO to work with the AEMC, AER and NEM participants to establish appropriate interim arrangements, through rule changes as required, to increase primary frequency control (PFC) responses at both existing and new (synchronous and non-synchronous) NEM generator connection points where feasible, by Q3 2019. b) AEMO to support work on a permanent mechanism to secure adequate PFC as contemplated in the AEMC's Frequency Control Framework Review, with the aim of identifying any required rule changes to be submitted to the AEMC by the end of Q3 2019 with a detailed solution and implementation process completed by mid-2020.
2.	Automating secondary frequency control implementation after separation events AEMO to investigate the opportunity for automation of reconfiguring AEMO's systems including AGC and NEMDE after separation and large system events. AEMO to report on options to industry in Q2 2019.
3.	Circumstances for regional FCAS or frequency control AEMO to investigate whether a minimum regional FCAS requirement is feasible, or whether there may be scope to manage frequency requirements arising from non-credible regional separation under the protected events framework in the NER after interim PFC outcomes at the end of Q3 2019.
4.	Frequency response capability models Commencing in Q1 2019, AEMO to work with participants to obtain information required to fully and accurately model generator frequency response and all other active power controls.
5.	Distributed PV inverter performance standards and analysis Distributed PV – AEMO to work with industry and Standards Australia to: a) immediately assess technical requirements of inverters (AS 4777) and complete by Q2 2019 b) work with stakeholders to implement improved performance standards for inverters by end of 2019 c) establish solutions for obtaining data on the performance of distributed rooftop PV systems, and to develop the necessary simulation models and analysis tools to predict their response to system disturbances progressively up to the end of 2020.
6.	Protection and control schemes a) AEMO to immediately commence a review of the EAPT scheme to identify improvements by 1 July 2019. b) AEMO to also review other existing AC interconnector schemes with TNSPs, to determine whether their performance remains fit for purpose in the changing environment and are properly co-ordinated, by Q1 2020.
7.	Emergency frequency control schemes AEMO to continue implementation and investigate any further functional requirements of Emergency Frequency Control Schemes (EFCS) for each region, commencing with SA and QLD prior Q1 2020
8.	Generator disconnection settings From Q1 2019, AEMO to work with market participants to ensure it is advised of any settings that may result in disconnection that are not currently reflected in their generator models, and review adequacy of existing models.

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Tables

Figures

1. About this report

This is AEMO's final report on its review of into the separation of the Queensland (QLD) and South Australia (SA) regions from the remainder of the National Electricity Market (NEM) and associated load shedding on Saturday 25 August 2018. For National Electricity Rules (NER) purposes, this was a reviewable operating incident.

This final report supersedes the preliminary report on this event published on 10 September 2018. It has been prepared to comply with AEMO's incident reporting obligations under clause 4.8.15 of the NER. The report presents AEMO's findings on the causation and sequence of events, and assesses the adequacy of power system responses, provision of relevant services, and actions taken to restore and maintain power system security.

Based on AEMO's analysis, this report also sets out a number of recommendations aimed at improving the resilience and response of the power system to withstand large frequency events.

1.1 Information sources and expert review

This report is based on detailed analysis of data obtained from AEMO's systems, data provided by transmission network service providers (TNSPs), NEM registered generators, and data from third-party sources including weather service providers, Solar Analytics, and the University of New South Wales (UNSW).

AEMO wishes to thank all NEM registered participants, weather service providers, Solar Analytics, and UNSW for their contribution of data and subject matter expertise.

AEMO invited a panel of electrical engineering and energy market experts to review and provide feedback on AEMO's analysis and account of the 25 August 2018 event. The expert panel consisted of:

- Professor Simon Bartlett AM BE, BSc, FIEAust, FTSE, FAICD, MIEEE, CPEng.
- Mr David Bones BE (Elec) Hons - Executive Manager Risk, Assurance and Regulation, GHD
- Ms Kate Summers BE (Elec) Hons FIE AUST – Manager Electrical Engineering, Pacific Hydro
- Dr Peter Sokolowski BE (Elec) Hons BMath PhD FIEAust CPEng SMIEEE NER APEC Engineer IntPE(Aus) RPEQ - Research Fellow, RMIT University
- Mark Miller BE (Elec) Hons BSc MEngSc MBA – Specialist Advisor, AEMO

AEMO is grateful for their time and expertise, which greatly assisted in the finalisation of this report.

AEMO also invited the AEMC to observe the expert panel meeting. Attending on behalf of the AEMC were:

- Dr Julian Eggleston – BE (Elec) Hons Ph. D Electrical Engineering M.Com Econometrics, Director - Technical Specialist
- Ms Suzanne Falvi – BEcon LLM Executive General Manager, Security and Reliability.

1.2 Report format

This report is divided into the following sections:

- **Pre-event** – the weather and status of the power system across the NEM on 25 August 2018, prior to the events commencing at 13:11:39.
- **Separation events** – the sequence and detail of separation events on the power system that occurred in response to the sudden, non-credible loss of the QNI transmission lines.

- **Frequency response** – a detailed analysis in each region, by generator technology type, of the short-term and longer-term frequency responses to the impact of the separation events on 25 August 2018. This section also details the interruption to loads due to the action of UFLS that occurred to re-balance the system in response to the separation events.
- **Recommendations** – an outline of the work and recommendations arising from detailed review of this event.
- **Appendices** – additional detailed information to support the analysis and provide context of power system security requirements.

References to times in this report, unless otherwise specified, are to Australian Eastern Standard Time.

1.3 Terms, abbreviations and measures

This report uses many terms that are defined in the NER, and are intended to have the same meanings. Common abbreviations for terms and measures are set out in the following table.

Abbreviation	Term
AC	Alternating current
AEMO	Australian Energy Market Operator
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
AEST	Australian Eastern Standard Time
AGC	Automatic generation control system
APD	Alcoa Portland Aluminium
ASEFS	Australian Solar Energy Forecasting System
AUFLS2	Adaptive under frequency load shedding scheme (TAS)
BOM	Bureau of Meteorology
CB	Circuit breaker
DC	Direct current
DER	Distributed energy resources
DFS	Demand Forecasting system
DI	Dispatch interval (5 minutes)
ESB	Energy Security Board
EAPT	Emergency APD Portland Tripping scheme
EFCS	Emergency frequency control scheme
EMS	Energy Management System
FCAS	Frequency control ancillary service
FOS	Frequency operating standard
GPS	Generator performance standard
kV	Kilo-volt (1,000 Volts)
MW	Megawatt (1,000,000 watts)
NEM	National Electricity Market
NEMDE	National Electricity Market Dispatch Engine
NER	National Electricity Rules
NSW	New South Wales
OPDMS	Operations and Planning Data Management System
PFC	Primary frequency control

Abbreviation	Term
PLC	Power Link Carrier
PV	Photovoltaic
QLD	Queensland
QNI	Queensland – New South Wales Interconnector
R6	Fast (6 second) contingency raise FCAS
SA	South Australia
SCADA	Supervisory control and data acquisition
TAS	Tasmania
TNSP	Transmission Network Service Provider
UFLS	Under frequency load shedding
VIC	Victoria

2. Pre-event

This section outlines the environmental conditions and state of the power system moments prior to the events resulting in the separation of QLD and SA from the rest of the NEM and the interruption of load by UFLS schemes. The initiating event was the simultaneous trip of both QNI lines following a lightning strike at 13:11:39 on 25 August 2018.

2.1 Assessment of conditions

On 25 August 2018, AEMO received advice from weather service providers consistent with the summary of conditions in Section 2.3, including thunderstorm activity in southern QLD and northern NSW. As a result, AEMO was tracking storms and monitoring conditions relative to transmission networks through real-time systems, weather service providers, and information provided by TNSPs.

The NEM was in a secure operating state and forecasts were for low electricity demand, with a record winter low electricity demand forecast for SA. Further:

- Wind generation was very low at 1.4% of total NEM generation.
- Large-scale solar generation in NSW was low at 2.7% of total NEM generation.
- Large-scale solar generation in QLD was low at 4.6% of QLD generation.
- Low rooftop photovoltaic (PV) generation in NSW (31% of installed capacity) and moderate rooftop PV generation in QLD (48% of installed capacity) saw some elevated demand from the grid (operational demand) in those regions prior to the event.
- High rooftop PV generation for this time of year in VIC (64% of installed capacity) and SA (65% of installed capacity) saw lower operational demand in those regions.

2.2 Management of power system security

During the separation events that occurred on 25 August 2018, the power system in the islanded QLD region was in a satisfactory, but not secure, operating state for the 68 minutes QLD was islanded.

AEMO's power system security responsibilities are set out in Chapter 4 of the NER. A summary of those responsibilities relevant to this event is in Appendix A2. At a high level:

- AEMO manages the NEM power system from two control rooms in different states that function as a single virtual control room. System management is a minute-by-minute activity that relies on extensive use of large real-time data processing systems.
- AEMO manages the power system to an effective 'N-1' operational standard, meaning that system parameters are within technical limits, and will remain or quickly return within those limits if any single element (such as a generating unit or transmission line) suddenly fails. The failure of a single major power system element is termed a 'credible contingency event' as it is considered reasonably possible in normal power system operation.
- When the power system is operating to this standard, it is in a 'secure operating state'.
- Following a contingency event (credible or otherwise) or other significant change in conditions causing the system to fall below this 'secure' level, AEMO seeks to restore the system to a secure operating state as soon as possible (with a target maximum timeframe of 30 minutes) by adjusting power flows or instructing participants to change plant settings or limits.
- Events beyond the N-1 standard, such as the coincident loss of multiple generating units or transmission lines, are termed 'non-credible contingency events'.

- AEMO can reclassify any non-credible contingency event as credible if unusual conditions mean the risk of occurrence is reasonably possible. Lightning is one example of those conditions, if expected in the vicinity of adjacent transmission lines known to be vulnerable to simultaneous tripping due to lightning strikes.[4] Reclassification usually requires AEMO to apply additional constraints to the transmission network, to maintain a secure operating state if the reclassified event were to occur. This can result in changes to generation dispatch, which may limit the ability of individual plant to generate electricity and may increase regional energy prices.
- AEMO works very closely with market participants and TNSPs to achieve its system security responsibilities. AEMO relies on their assistance and cooperation to stay informed about the state of the power system and address anticipated risks.

2.2.1 Power system security during restoration

During the QLD island operation, there was a deficit of available contingency FCAS to meet operational requirements. Resources to provide the required amounts of FCAS within the QLD island were not available to AEMO due to a number of generators being outside their FCAS enablement zone (FCAS trapezium) and the large credible contingency size in QLD that FCAS is required to cover. FCAS generating units that are not scheduled to provide FCAS cannot be relied upon to provide a primary response in all circumstances, particularly if they are trapped outside their enablement parameters.

As AEMO was unable to enable contingency FCAS to meet operational requirements and a response from generators that aren't enabled cannot be relied on; AEMO has concluded that while in a satisfactory operating state, the QLD power system was in an insecure operating state for the 68-minute duration of the QLD separation.

2.2.2 Consideration of reclassification due to lightning

The simultaneous trip of two circuits of transmission lines due to a single or simultaneous lightning strike is an improbable occurrence. Prior to this event, QNI was not considered vulnerable to lightning as there was no 'probable' or 'proven' risk of lightning strikes impacting both lines. Accordingly, the simultaneous trip of both QNI lines was not reclassified as credible due to the storm activity in the area prior to the event on 25 August 2018. This decision was appropriate and consistent with the published reclassification criteria in AEMO's power system security guidelines.

2.3 Weather on 25 August 2018 – Post event analysis

The relevant weather conditions for Saturday 25 August 2018 are described below.

Southern QLD and northern NSW:

- A low-pressure system shifted slowly eastwards over the southern interior of QLD during the afternoon of 25 August 2018 before moving in a south-easterly direction into NSW on Sunday 26 August.
- This low-pressure system combined with a deepening surface trough produced showers, patchy rain and thunderstorms over southern QLD and northern NSW districts Saturday and into Sunday. No severe thunderstorms were recorded on 25 August 2018.

SA and VIC:

- A high-pressure system moving from the west was dominant over SA and VIC on Saturday afternoon, resulting in clear, still, sunny and above average temperatures.

The location of the low-pressure system affecting QLD and northern NSW and the high-pressure system affecting SA and VIC is shown in the synoptic chart below in Figure 2.

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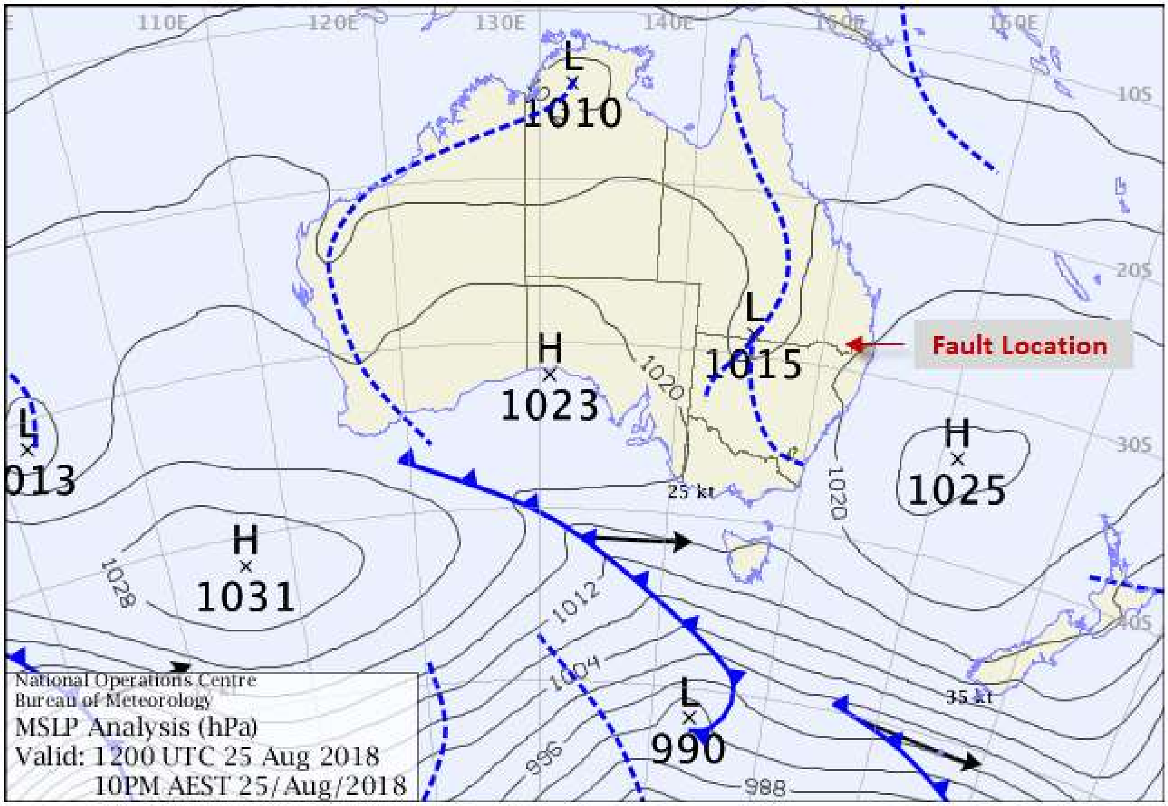
[4] Vulnerable transmission lines are double circuit transmission lines which fall into the categories for Probable or Proven as described in AEMO's Power System Security Guidelines (SO_OP_3715), available at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Power-system-operation/Power-system-operating-procedures.

Figure 2 Weather synoptic analysis for 12:00 Saturday 25 August 2018



2.3.1 Severe weather warnings

Table 2 shows the severe weather warnings current immediately prior to and during the event on 25 August 2018.

Table 2 Severe weather warnings southern QLD and northern NSW in place during the event – 25 August 2018

Issued	Reason	Districts	Areas affected	Cancelled
13:04 Re-issued 15:46	Damaging winds and large hailstones	Maranoa and Warrego forecast district	Charleville, Cunnamulla, Bollon, Augathella and Wyandra	17:24
13:45	Heavy rainfall and damaging winds	Hunter forecast district	Gosford, Cessnock, Maitland and Kulnura	15:36

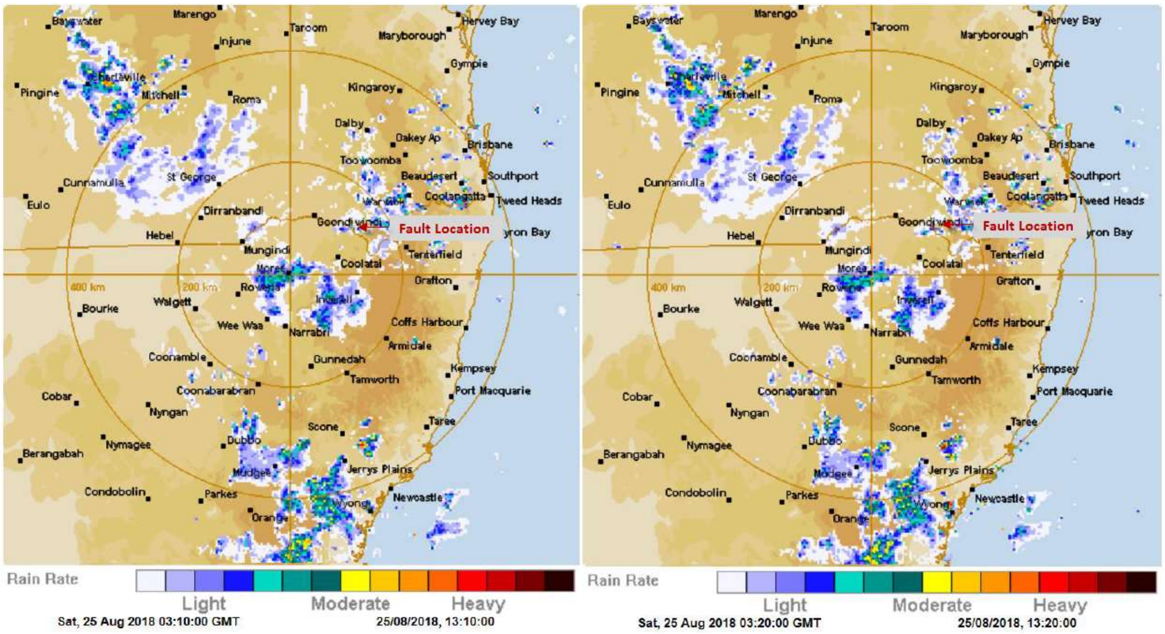
The QNI fault location is well outside the weather districts for which warnings were issued, as shown in Figure 3 below.

Figure 3 Relevant weather forecast districts – QLD and NSW

2.3.2 Storm activity

The following charts in Figure 4 show the radar reflectivity at 13:10 and 13:20, indicating scattered light showers around the location of the fault at the time of the event.

Figure 4 Radar reflectivity 13:10 and 13:20



2.3.3 Lightning strike detection

Initial investigations were unable to identify a likely lightning strike near the 8L and 8M transmission lines around the time of the incident. It is important the exact cause of any fault is determined as there can be ongoing unnecessary market and system impacts if the cause is incorrectly concluded. As Powerlink's visual inspection of the transmission tower revealed evidence consistent with a lightning strike, AEMO worked with two providers of Australia's lightning detection systems, separately performing a detailed data analysis.

A cloud-to-ground lightning strike at 13:11:39 at latitude -28.5333 and longitude 150.8751 was ultimately detected by both lightning network detection networks, striking the ground within approximately 300 metres of the transmission tower where Powerlink discovered flashover marks.

The map in Figure 5 shows the proximity of the lightning strike to the transmission lines.

Figure 5 **Cloud-to-ground lightning strike at the time of the event**

The detailed analysis provided independently by both lightning detection system providers concluded the lightning strike which caused the fault was initially filtered out by both the Global Positioning and Tracking Systems (GPATS)[5] and Weatherzone Total Lightning Network[6] systems due to its specific isolated nature. Strikes can occasionally be filtered in the fine tuning of Australia's lightning detection systems to minimise false-positive readings.

Due to the highly unlikely occurrence of a lightning strike with no other lightning in the vicinity, the strike was filtered out of detection results on a balance of probabilities determined over decades of data analysis and refinement.

Further investigation and wave form analysis determined that the filtered strike was a single cloud-to-ground strike at precisely 13:11:39 within 300 metres of the affected transmission tower. The signal was too strong to have been produced by the flashover on the transmission tower alone.

AEMO is therefore able to conclude that the cause of the fault causing QNI to trip was a lightning strike.

2.4 Pre-event system configuration

The NEM was in a secure, system normal state prior to the event. There were no major network outages or works near the fault. The interconnectors between each NEM region had the following targets for the dispatch interval (DI) ending 13:15:

- QNI target was 828 MW QLD to NSW.
- Directlink target was 97 MW QLD to NSW.
- VIC–SA target was 245 MW SA to VIC.
- Murraylink target was 18 MW SA to VIC.
- VIC – NSW target was 405 MW VIC to NSW.
- Basslink target was 478 MW TAS to VIC.

5 See http://gpats.com.au/.

6 See http://business.weatherzone.com.au/products/total-lightning/.

The operational demand, generation mix, and energy pricing for each region of the NEM for 25 August 2018 is shown in detailed figures in Appendix A1.

2.4.1 Pre-event system conditions

At 13:11:39.0, immediately prior to the event, mainland frequency was 49.99 Hz and TAS frequency was 49.97 Hz. The largest credible contingency event for the DI ending 13:15 was assessed as a Kogan Creek power station trip, from a dispatch target of 750 MW. The largest credible load event was assessed as a trip of 500 MW of potline load at Alcoa's Portland aluminium smelter. The power system was intact, with no credible risk of regional separation identified.

Table 3 shows the generation mix by state and then as a total for the NEM for the DI ending 13:10, 1 minute and 40 seconds prior to the loss of QNI.

Table 3 Generation mix at DI ending 13:10 (Scheduled and semi scheduled market generators)

Source	QLD (MW)	NSW (MW)	SA (MW)	VIC (MW)	TAS (MW)	NEM (MW)
Black Coal	5,690.1	5,919.5				11,609.6
Brown Coal				3,777		3,777
Gas	215.1	0.21	807.8	0.24	202	1225.4
Wind	1.7	94.2	129.2	7.7	43.5	276.3
Hydro	52.1	343.2		0.12	1,386.4	1,781.9
***Other**	0.22	0	0.02			0.24
Large Scale solar	286.1	96.96	88.65	38.4		510.1
Total	6,245.3	6454.1	1025.7	3823.5	1,631.9	19,180.4

*Other includes biomass, battery, kerosene and diesel.

The generation mix for scheduled and semi scheduled market generators at 13:10 on 25 August 2018 was predominately from synchronous generation with only 4% of the total NEM MW contributed from wind and large scale solar.

Generation output listed in Table 4 is measured by SCADA at the generator terminals and is 'as dispatched'. All graphs showing the large-scale generator frequency responses are based on data from high speed monitors unless otherwise stated. This high-speed disturbance recorder data is measured at the generators' grid connection points and will be lower than SCADA values due to in-house consumption at the power station. The difference can be particularly significant for large coal-fired generators, which may consume as much as 10% of their output in-house.

Table 4 Distributed PV generation estimates - 25 August 2018 at 13:10

Region	Aggregate distributed PV output MW*	Distributed PV Installed Capacity*
QLD	1,043	2,177
TAS	65	124
SA	600	919
VIC	862	1,349

Region	Aggregate distributed PV output MW*	Distributed PV Installed Capacity*
NSW	526	1,709
Total NEM	3,096	6,278

*Distributed PV output estimates were obtained from AEMO's ASEFS2 solar forecasting system. Installed capacity was estimated based on installation data registered by the Clean Energy Regulator as at 21 August 2018.

2.4.2 Pre-event FCAS enabled

Table 5 shows the contingency and regulation FCAS MW reserves enabled for the DI ending 13:15. These quantities were determined considering the largest single credible contingency events, regional demand levels and associated load relief, and the requirements of the NEM frequency operating standard (FOS)[7].

Table 5 Dispatch of FCAS

Service	NSW	QLD	SA	VIC	TAS	Total (MW)
Lower 5 min	69	0	40	123	64	296
Lower 60 sec	10	0	59	40	73	182
Lower 6 sec	0	0	13	10	59	82
Raise 5 min	309	24	41	69	0	443
Raise 60 sec	150	155	128	49	0	482
Raise 6 sec	162	137	123	60	0	482
Lower REG	30	0	40	0	50	120
Raise REG	52	95	80	0	0	227

While contingency FCAS enablement is not a useful predictor of system frequency response, particularly for larger, non-credible events like the event described in this report, it does indicate where firm MW headroom is available across the power system.

No contingency lower or regulation lower FCAS reserves were enabled in QLD immediately prior to the event. This was consistent with the market design, under which in normal conditions FCAS is generally acquired from anywhere within a set of interconnected regions to achieve the most economically efficient outcome.

Over 50% of the enabled 6 and 60 second contingency raise FCAS reserves were in SA and QLD, and were therefore unable to assist the remaining regions, where raise response was ultimately required, as a result of QLD and SA separation.

This event indicates that there may be some risk in sourcing FCAS from any location in the NEM for application across the entire NEM. AEMO intends to investigate whether a minimum regional FCAS requirement may be justified, or whether it may be feasible to manage frequency control requirements arising from non-credible regional separation within the scope of the protected events framework in the NER.

[7] The NEM Frequency Operating Standard can be found at https://www.aemc.gov.au/sites/default/files/content/c2716a96-e099-441d-9e46-8ac05d36f5a7/REL0065-The-Frequency-Operating-Standard-stage-one-final-for-publi.pdf.

3. Separation events

3.1 Sequence of events

On Saturday 25 August 2018, at 13:11:39, both NSW-QLD interconnector (QNI) lines tripped, resulting in separation of the QLD region from the rest of the NEM power system. This was followed by the separation of SA from the rest of the NEM, and UFLS in NSW, VIC and TAS. All load was successfully restored by 15:28.

A sequence of events and timing is shown in Table 6 below.

Table 6 Sequence of events and timing – event and restoration

Time (hh:mm:ss)	Events/comments
Saturday 25 August 2018	
13:11:39.2	Dumaresq – Bulli Creek 8L 330 kV Line faulted (QNI), 1 out of 3 phases open Dumaresq – Bulli Creek 8M 330 kV Line faulted(QNI), 1 out of 3 phases open
13:11:41.2	Dumaresq – Bulli Creek 8L and 8M lines tripped, AC separation of QLD and NSW
13:11:41	Tamworth – Armidale 86 330 kV Line tripped at Armidale end only
13:11:46.0	Automatic Adaptive UFLS-2 scheme trip of TAS industrial load 81 MW
13:11:46:8	SA separated from VIC at Heywood terminal station
13:11:47.6	Automatic UFLS scheme trip of one Alcoa potline 282 MW (VIC)
13:11:47.8	Automatic UFLS scheme trip of two Tomago potlines 622 MW (NSW)
13:11:48	Automatic UFLS scheme trip of load: • AusGrid (52 MW) • Endeavour Energy (12 MW) • Evoenergy (6 MW) • Essential Energy (7 MW) • TransGrid (16.3 MW)
13:33	Tomago Potlines given permission to restore load
13:35:4646	Vic – SA both circuits restored and synchronised
13:38	Alcoa potline given permission to restore load
13:40	TAS industrial load restoration commences
13:44	AEMO gave permission to restore remaining NSW customer load
13:58	Alcoa potlines restored
14:20:0404	QLD and NSW re-synchronised
15:15	AEMO reclassified simultaneous trip of 8L and 8M lines as a credible contingency and applied reclassification constraints.
15:28	All remaining NSW load restored

3.2 QLD – NSW separation

QNI is the AC interconnection between QLD and NSW. It comprises two 330 kV circuits strung on single tower structures between Bulli Creek terminal station in QLD and Dumaresq terminal station in NSW. The lines comprising the two circuits are known as the 8M and 8L lines. Just prior to the event, 857 MW was being transferred from QLD to NSW via these lines, measured at Dumaresq.

Shortly after 13:11:39 there was a cloud-to-ground lightning strike to tower 1420-STR-0371 in QLD, carrying the 8L and 8M transmission lines. The lightning strike altered the voltage on the tower relative to the circuit ground sufficiently that C (Blue) phase of the 8L and 8M 330 kV circuits both flashed across the insulators to the tower simultaneously. This phenomenon is known as double back flashover.

3.2.1 Double back flashover caused by direct lightning strike

A double back flashover occurs as a result of a direct lightning strike to a tower or the earth wire. The lightning strike causes large amplitude, very steep voltages on the tower. The lightning protection routes the current of the lightning strike to down the legs of the tower and along the earth wires at the speed of light. Voltages at the top of the tower can reach around one-million volts (1 MV).

The insulators for a 330 kV transmission line can typically withstand a voltage of around 1,050 kV. It will not "flash over" unless the voltage across the insulator string exceeds 1,050 kV. In practice, this is equivalent to a voltage of around 850 kV on the tower top, as the other end of the insulators can reach up to -190 kV for one of the phases of a 330 kV line (in this case, the C phase of each circuit).

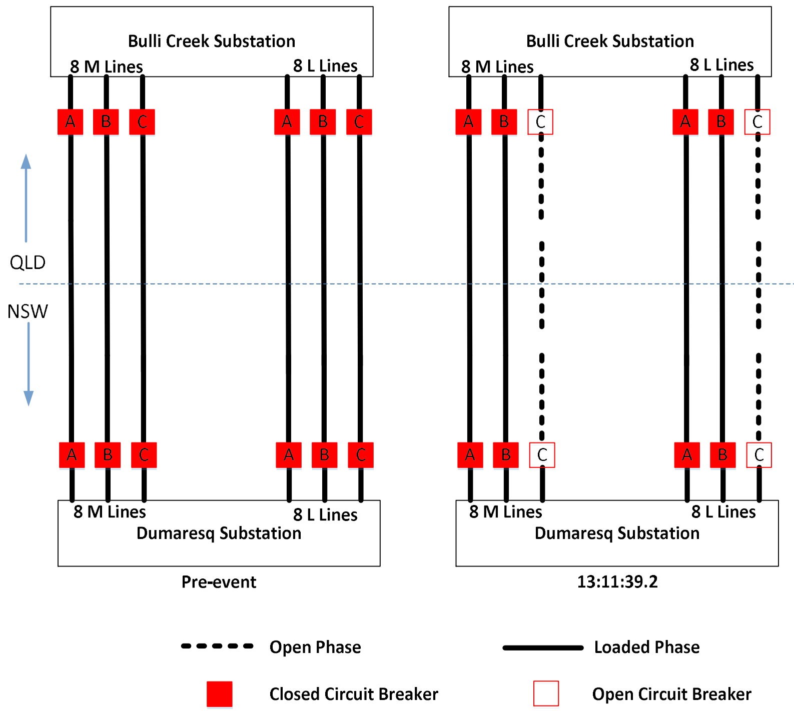
When the voltage on the tower is larger than the withstand voltage of the insulator, lightning can flash over from the tower to the transmission line, ionising the air around the insulator. The ionised air around the insulator provides a path for the current on the transmission line to transfer to the tower and into the tower earthing system, creating a phase to ground fault. One phase on each circuit of the double circuit line will "flash over" at the same time, hence a double back flashover.

The tower footing resistance is important, as the lightning current must pass down the tower legs and through the tower footing earthing resistance. The higher the footing resistance, the higher the voltage for the same lightning current. Continuous dry weather can increase the tower footing resistance which can allow flashovers to occur for lower lightning currents even for lines with contemporary footing designs.

3.2.2 Protection system operation

Protection systems on the 8L and 8M 330 kV lines operated to clear simultaneous C phase faults on both lines. This left only 4 of the 6 phases of the 8L and 8M 330 kV lines connecting QLD and NSW in service. This is shown in Figure 6.

Figure 6 QNI network topology during the event



With only a partial, unbalanced electrical connection between QLD and NSW, the pre-event level of power could no longer be stably transferred. The angular separation between the two regions began to rapidly increase, as the NSW and QLD regions lost synchronism with each other. Frequency in the two regions also began to drift apart with only the partial, electrically unbalanced connection between the two regions.

The loss of synchronism can be seen in a plot of relative voltage angle between QLD and NSW in Figure 7, and in the measured frequency traces in Figure 8. Data for these figures was recorded from synchro phasor measurement units located at Sydney West in NSW, South Pine in QLD, and Para in SA.

Figure 7 Loss of synchronism between QLD and NSW

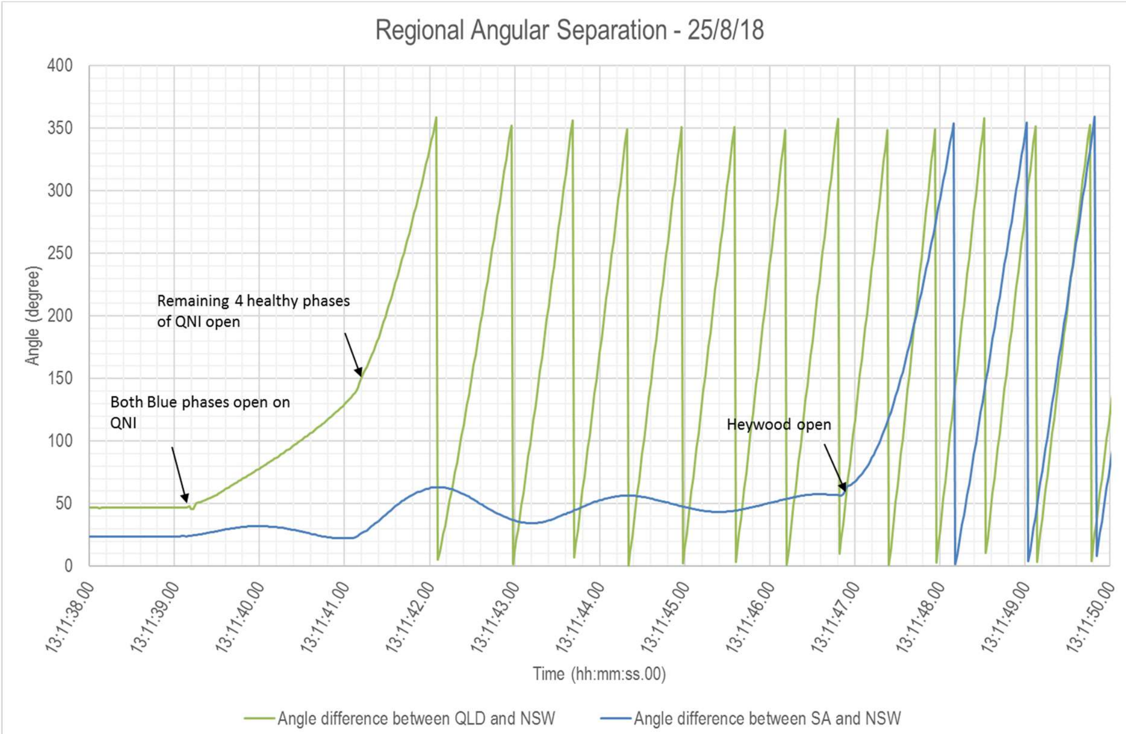
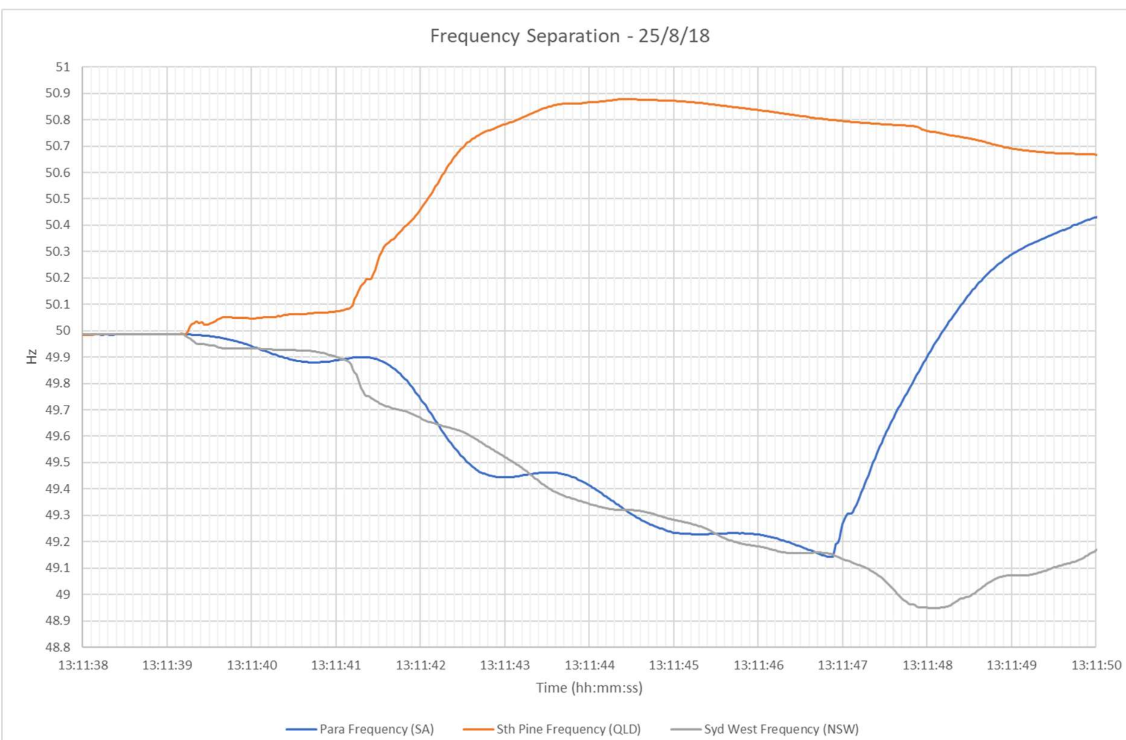
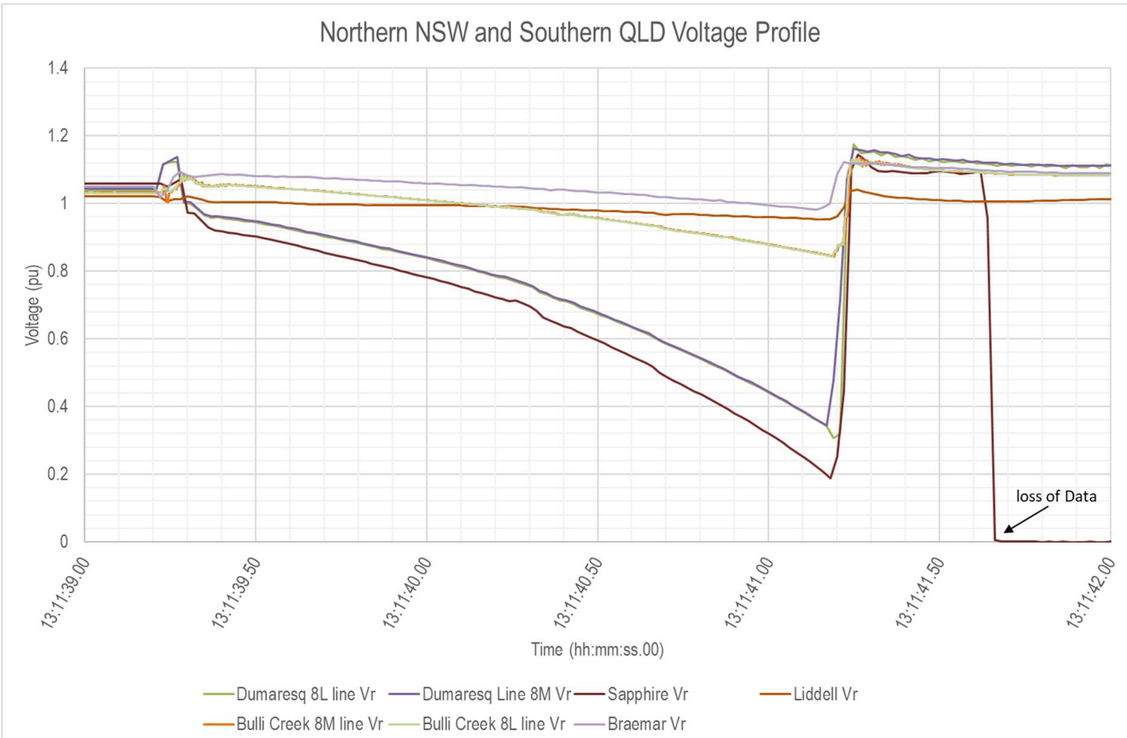


Figure 8 Measured frequency in QLD, NSW, and SA



The increasing angular separation and loss of synchronism between QLD and NSW resulted in a decline in transmission voltages on the in-service un-faulted phases in northern NSW and southern QLD. A (Red)[8] phase voltages are shown below in Figure 9.

Figure 9 A (Red) phase voltage profile – Northern NSW and Southern QLD



Approximately one second after the initial fault, at around 13:11:40.2, single pole auto-reclose systems at Dumaresq substation successfully re-energised C phase of both 8L and 8M transmission lines from the Dumaresq end only.

When both circuits simultaneously have a single phase open, the single-pole auto-reclose system at Bulli Creek tests the difference in frequency, voltage magnitude and angle across the open CBs before closing them. In this event, the measured values across the open CB poles on the 8L and 8M 330 kV lines at Bulli Creek exceeded permissible levels. Therefore, the CBs at Bulli Creek remained open.

At approximately 13:11:41.2, around two seconds after the initial lightning strike, all six phases of the Dumaresq – Bulli Creek 330 kV lines were opened by the TransGrid distance protection relays at Dumaresq, resulting in complete synchronous separation between QLD and NSW. This protection operation was a response to the rapid decline in transmission voltages in the area. This is shown in Figure 10.

The protection equipment on the Dumaresq – Bulli Creek 330 kV lines operated as designed, although the protection design did not cater for the circumstances of this event. The auto-reclose control for the loss of a single phase of both circuits required a successful synchronism check before reclosing the lines after the fault had cleared. Powerlink and TransGrid have since modified the control logic by reducing the reclose time and not requiring the synchronism check prior to re-closing the CBs.

[8] A phase in A-B-C terminology and Red phase in R-W-B terminology.

3.2.3 Reclassification

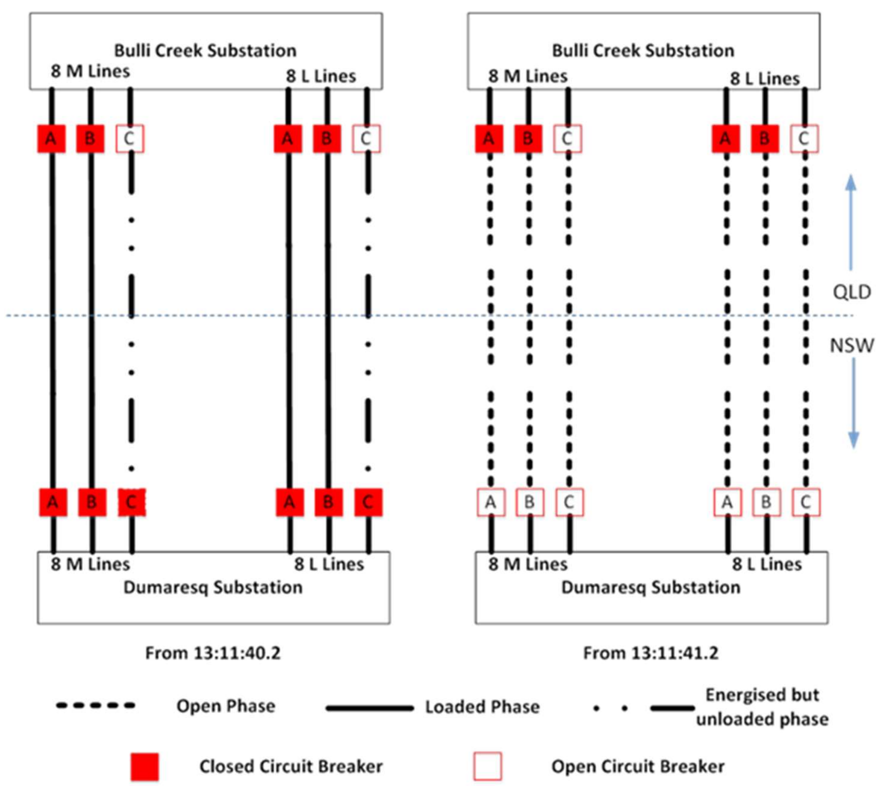
At 15:15, shortly after the resynchronisation of QLD, AEMO reclassified the simultaneous trip of the 8L and 8M lines as a credible contingency and applied reclassification constraints pending identification of the cause.

After receipt of advice from Powerlink that the cause of the simultaneous trip was lightning strikes to transmission infrastructure impacting both circuits, AEMO cancelled the reclassification at 17:45, when there was no longer lightning activity in the vicinity.

In the event of a simultaneous phase to earth fault on the same phase of two separate circuits, the auto-reclose control logic required a successful synchronism check before closing the CBs. Powerlink and TransGrid have since provided AEMO with advice on transfer levels (up to 850 MW) at which it will now be possible to successfully reclose in the same fault scenario more quickly and without a successful synchronism check. AEMO has verified and implemented this limits advice. Accordingly, when there is lightning in the vicinity of QNI:

- The non-credible risk of simultaneous loss of two phases across two circuits is considered credible and the transfer limit of QNI is limited to 850 MW from QLD to NSW.
- As the auto reclose mechanism is designed to operate successfully for that event within the 850 MW limit, the simultaneous loss of both QNI circuits remains non-credible.

Figure 10 QNI network topology during the event



3.3 Trip of the NSW 330 kV Armidale to Tamworth Line (86-line)

At Armidale, an extract of the 86-line data for both the SCADA and control system logs indicate that the 86-line operated immediately after the Dumaresq CBs. The 85-line CB at the Tamworth end of this line did not trip, leaving the line energised from Tamworth.

A review of the protection relay records indicated that the Armidale No. 2 protection received an inter-trip signal at the time of the trip. The source of the signal was isolated to a Power Line Carrier (PLC) communications module at Armidale. The No. 2 protection trips the CB directly if the inter-trip signal coincides with fault detection module within the relay, or the inter-trip signal itself is sustained for more than 0.5 seconds. The relay did not detect a secondary fault, meaning the CB trip could only have been initiated from a sustained inter-trip signal from the PLC module. This PLC module was tested and found to be faulty. The PLC fault may have been initiated by the original QNI separation event, but this cannot be verified.

3.4 VIC – SA separation

At 13:11:46.8, 5.6 seconds after synchronous separation between QLD and NSW, the Heywood interconnector between VIC and SA opened at Heywood, by action of a Heywood Emergency Control Scheme known as the Emergency Alcoa Portland Tripping (EAPT) scheme.

Power transfer on the Heywood interconnector immediately prior to the lightning strike on QNI was about 170 MW towards VIC, measured at the South East Switching Station (SESS) at the SA end.

Immediately after synchronous separation of NSW and QLD, frequency in SA declined in close alignment with the frequency in NSW and VIC, as shown above in Figure 8. This resulted in increased output from generation in SA, increasing MW flow on the Heywood interconnector towards VIC. This MW response included a damped oscillatory component which can be seen in Figure 11 and was due to the MW response from synchronous generation in SA.

MW flow across the Heywood interconnector between loss of QNI and opening of the Heywood interconnector is shown in Figure 11 below. This figure also shows the aggregate output of synchronous generation located in SA.

3.4.1 Reclassification

AEMO was not required to reclassify the simultaneous non-credible loss of the SA-VIC interconnector at Heywood as credible as it was verified by AEMO at the time that the EAPT scheme had operated and that the criteria for its operation were met.

3.4.2 The Emergency Alcoa Portland Tripping (EAPT) scheme

The EAPT scheme is designed to secure the system against separation of the 500 kV network between Moorabool (MLTS) and Heywood (HYTS) terminal stations and prevent the Alcoa Portland Smelter load in VIC from remaining connected to an islanded SA system. The scheme uses active power flow across the interconnector and frequency measured at Heywood to detect a likely separation condition.

The EAPT scheme operates on simultaneous detection of the following three conditions at HYTS:

1) A sudden decrease in active power flow towards HYTS on the MLTS lines of more than 280 MW.
2) A sudden increase in active power flow from SA through the HYTS transformers of more than 200 MW.
3) Frequency on either SESS 275kV line below 49.7 Hz.

The scheme will also operate on simultaneous detection of the following two conditions:

1) A sudden decrease in active power flow towards HYTS on the MLTS lines of more than 280 MW.
2) Voltage on both 500 kV busbars below 80% of nominal for greater than 400 milliseconds, indicating a severe voltage depression.

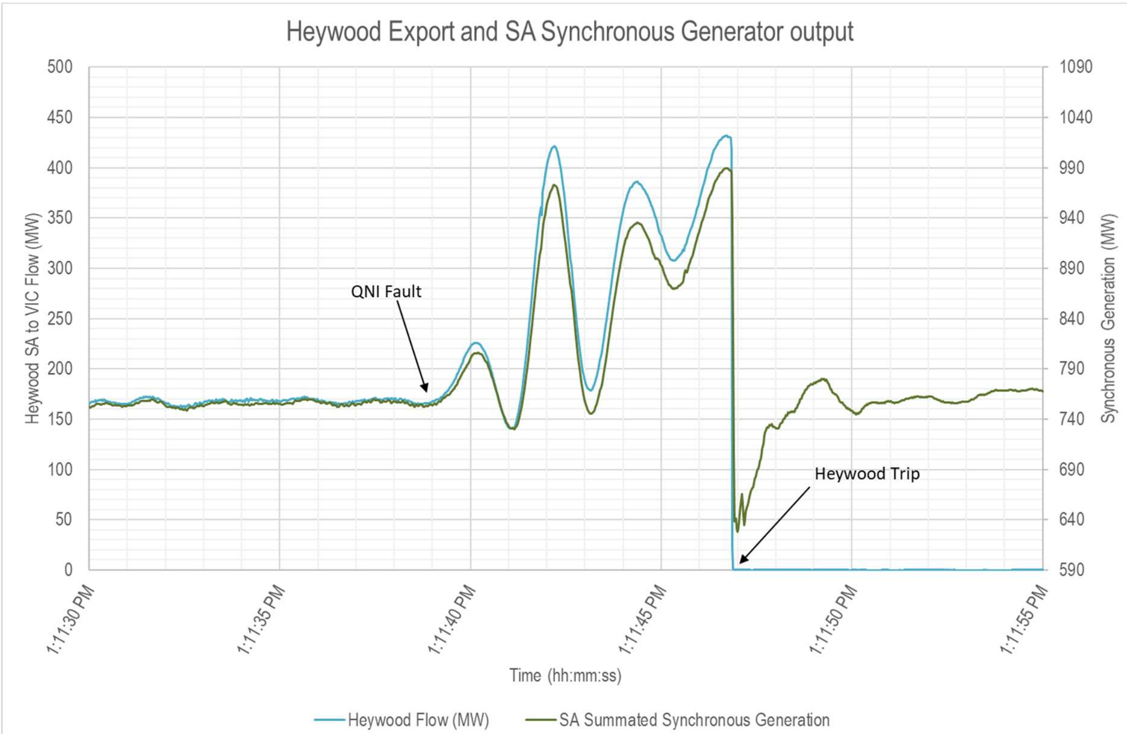
On detection, the scheme disconnects HYTS from the VIC 500 kV network.

During the event of 25 August 2018, the aggregate response of SA generation to the frequency reduction from the QNI separation contributed to a rapid increase in flow on the Heywood interconnector from SA towards VIC. This response, combined with under-frequency conditions, triggered the EAPT scheme, consistent with its design settings, although the design of the scheme did not cater for the events of 25

August. AEMO intends to complete a review of the EAPT scheme by July 2019 to identify improvements to avoid triggering in similar circumstances.

As SA was exporting towards VIC at the time of synchronous separation, frequency in SA immediately reversed its decline on disconnection from the VIC 500 KV network and began to increase.

Figure 11 Heywood interconnector flow and SA synchronous generation output



4. Frequency response

This section provides an overview of frequency response observed during the event. It is based on high-speed monitoring data obtained from both TNSPs and individual generators, AEMO SCADA and MMS market data, and distributed PV data provided to AEMO by Solar Analytics.

Due to the large amount of data, significant analysis performed and the variation of technology types – which all have inherently different responses to frequency deviations, the section is broken down into the following areas:

- General frequency characteristics and observations.
- Frequency response in each frequency region of QLD, NSW/VIC, SA and TAS, further broken down into:
  - Synchronous generation – short-term response (up to one minute).
  - Synchronous generation – long-term response (greater than one minute).
  - Wind generation short-term response.
  - Wind generation long-term response.
  - Large-scale transmission-connected solar short-term response.
  - Large-scale transmission-connected solar long-term response.
  - Distributed behind the meter PV solar short-term response.
  - Distributed behind the meter PV solar long-term response.
  - Large-scale transmission-connected battery short-term response (SA).
  - Large-scale transmission-connected battery long-term response (SA).
  - UFLS and AUFLS2 load interruption

4.1 Primary and secondary frequency control

In a conventional power system, frequency control has three distinct components:

a) inertial response (instantaneous),

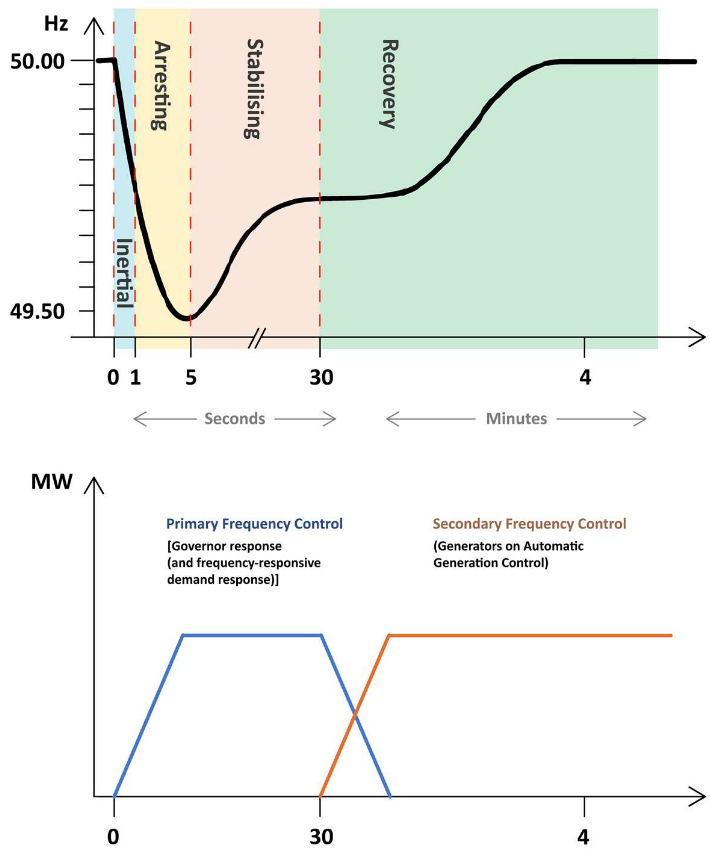
b) primary frequency response (within 10 seconds and up 30 seconds)

c) secondary frequency response (within 30 seconds and up to 30 minutes).

An illustration of these kind of reactions and controls is shown in Figure 12, based on potential response times to a frequency disturbance such as caused by loss of a large generator.

Inertial response is provided through acceleration or deceleration of rotating synchronous machines in response to electrical frequency changes, the level of inertia in the power system will determine how fast the frequency changes in the first few seconds of a frequency disturbance. The inertial response of a power system assists in limiting the rate of change in frequency during large disturbances so that control systems have time to respond and intervene. Primary and secondary response are expanded on in more detail in the following sections.

Figure 12 Common response to a power system frequency disturbance



4.1.1 Primary frequency control

Primary frequency control is typically a closed loop control performed by a generator, which adjusts output proportionally to counteract a frequency deviation. A primary frequency control response is:

- Dependent on locally-measured frequency and not subject to centralised control, communications delays and time synchronisation issues.
- Fast-acting – action to correct frequency typically starts immediately.
- Continuous and proportional, acting in a continual closed-loop manner, adjusting generator output as appropriate to arrest and stabilise frequency in proportion to the measured frequency deviation. This is often referred to as 'droop' control.

Traditionally in the NEM, only synchronous generators have provided primary frequency control. The NER now require all generating systems (including asynchronous machines) to be capable of primary frequency control, although this capability only needs to be active when units are enabled for FCAS.

Contingency FCAS are enabled as a form of large deviation primary frequency control in response to credible contingency events. Once enabled on instruction from AEMO, these sources must respond within a designated time (6 seconds, 60 seconds or 5 minutes) to correct locally-sensed frequency deviations above or below the FOS normal operating frequency band.

Since the introduction of FCAS markets, there is neither a requirement nor an incentive for generators to have frequency control active when not selected to provide a market service. In such circumstances many synchronous generators have effectively withdrawn or limited their primary frequency control response by widening dead-band settings or adjusting active power output. A dead-band is a frequency range that can be specified in a control system, in which no frequency response is given.

This event indicates that the resulting decrease in primary frequency control has significantly reduced the ability of the power system to arrest the impact of non-credible contingency events in time to avoid the risk of cascading failures. AEMO is assessing primary frequency control requirements and intends to continue working with generators and TNSPs, the AEMC, the (ESB), and the AER to restore adequate levels of primary frequency control in the NEM.

4.1.2 Secondary frequency control

Regulation FCAS is a market mechanism tasked with centralised correction of power system frequency and time error and is a secondary frequency control mechanism. This is by nature a slower method of controlling frequency and is administered by AEMO's AGC. Regulation FCAS provides frequency response that is:

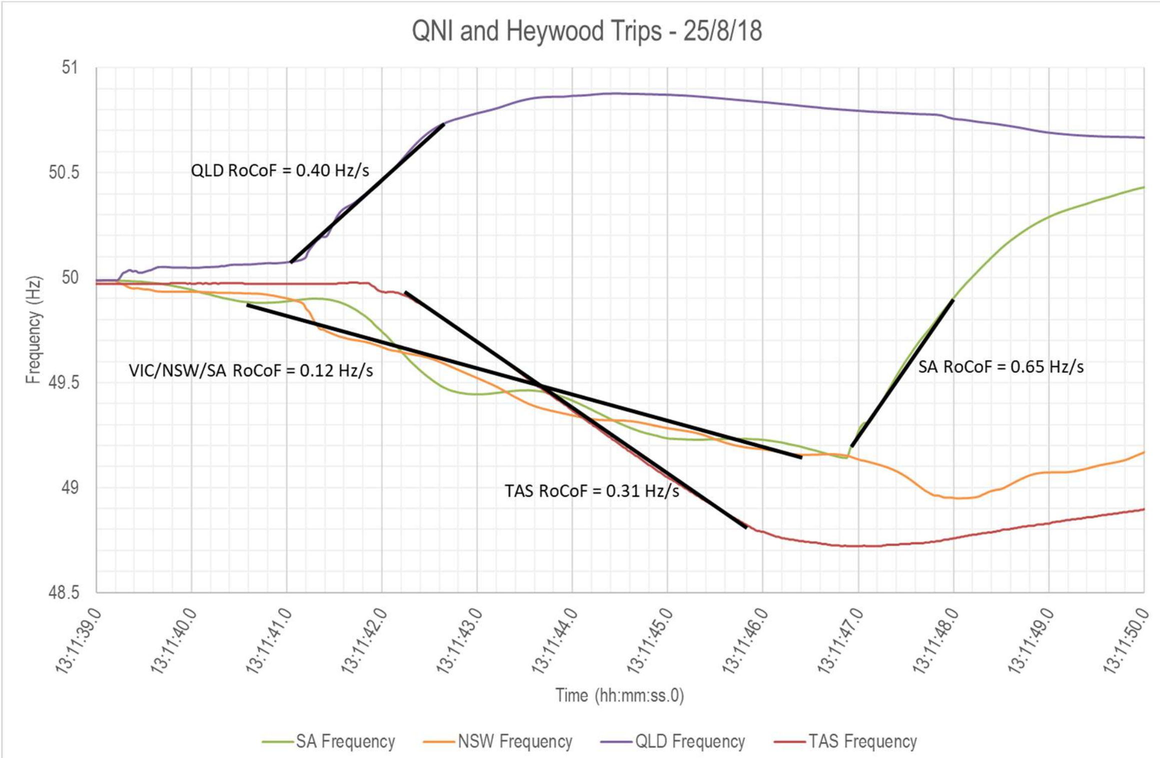
- Dependent on a centralised single frequency reference rather than on individual locally-sensed frequency, with generator response also centrally controlled by AGC.
- Designed to complement primary control, allowing sources providing primary control to return to their normal set-points (and thus be ready for further primary response as required).
- Slower-acting, primarily as a result of centralised control and latency in communications through AGC.
- Not continuous on an islanding event, as AEMO's AGC must first be configured for the islanded region(s) before instructions can resume.

4.2 Rate of Change of Frequency (RoCoF)

Average RoCoF, measured for data measurement durations of at least 1 second, is indicated in Figure 13 for all regions. The highest sustained RoCoF level measured in this manner during the event was around +0.65 Hz/sec in SA, in the period immediately following separation from VIC. Measured RoCoF is strongly influenced by exactly how it is measured. Very different, much higher and more volatile measurements of RoCoF are obtained where a short data measurement time duration is used [9].

[9] Further details can be found in Section 2.2.2.2 of AEMO, *Technology Capabilities for Fast Frequency Response*, 2017, available at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Reports/2017/2017-03-10-GE-FFR-Advisory-Report-Final---2017-3-9.pdf.

Figure 13 Regional Frequencies and RoCoF during the event



4.3 AEMO's Automatic Generation Control (AGC)

The AGC system in AEMO's Energy Management System (EMS) manages secondary frequency regulation across the NEM, by varying the output of generation enabled for frequency regulation duty in the regulation FCAS market.

Due to the latency in AGC operation, it is not a suitable control system for managing fast changes in frequency on the power system. The AGC is designed and intended to work in parallel with primary frequency control. Without sufficient primary frequency control in all NEM regions, the AGC cannot by itself deliver adequate frequency control.

Prior to the separation at QNI, AEMO's AGC system was in a normal configuration, with the NEM mainland operating as a single flat frequency control area, based on system frequency measured from AEMO's NSW control centre.

TAS was operating as its own flat frequency control area, responding to a SCADA measurement of frequency obtained from within TAS.

Following electrical separation between regions, AEMO's AGC must be reconfigured to correctly regulate frequency in each of the separated areas. This requires that:

- A separate AGC control area is established for each island in AEMO's EMS.
- A suitable AGC frequency bias setting is applied to the new control area.
- A suitable frequency measurement reference is used for this islanded AGC control area.
- Sufficient MW volumes of regulation FCAS are enabled locally within the island for AGC control.

These are all manual processes, which typically can take up to 15 minutes to implement following a separation event. Table 7 summarises the timing of changes made relevant to AGC control of the separate frequency areas. Times for electrical separation and re-synchronisation in Table 7 were established from high speed synchro-phasor measurement data, and in some cases differ slightly from those published in AEMO's initial incident report.

Table 7 Sequence of AGC establishment and FCAS application

Time (hh:mm:ss)	Event
13:11:41	Electrical separation between QLD and VIC/NSW
13:11:47	Electrical separation between SA and VIC/NSW
13:16	Network and local FCAS constraints for QLD and SA loaded
13:18:31	Separate AGC control area established for SA
13:19:37	Separate AGC control area established for QLD
DI ending 13:25	Network and Local FCAS constraints for QLD island invoked
DI ending 13:25	Network and Local FCAS constraints for SA island invoked
13:35:46	Re-synchronisation of SA and VIC regions
13:43:48	Separate AGC control area for SA ends
DI ending 13:45	Local FCAS requirements for SA island end
14:20:04	Re-synchronisation of QLD and NSW regions
14:23:02	Separate AGC control area for QLD ends
DI ending 14:45	Local FCAS requirements for QLD and SA island end

No changes were made to TAS AGC arrangements in AEMO's EMS during this event.

4.4 Under-frequency load shedding (UFLS)

Automatic UFLS is implemented to restore the balance of supply and demand if system frequency drops below the operational set point of UFLS relays during a major disturbance.

Each region has several pre-programmed UFLS relays that monitor system frequency. If the frequency drops below the set level, the relay will trigger the opening of a circuit breaker, automatically disconnecting the attached load from the power system. Different frequency set points are programmed across the relays, designed to disconnect progressively larger amounts of load as frequency declines. UFLS operates on the mainland from 49 Hz down to 47.5 Hz and in TAS from 48 Hz down to 47 Hz. The UFLS schemes in VIC and NSW operated as designed and as required in this event.

TAS has an 'adaptive UFLS' scheme (AUFLS2) in addition to its UFLS scheme. AUFLS2 is designed to reduce the amount of contingency raise FCAS required to be enabled by the hydro generators in Tasmania on an ongoing basis. The scheme disconnects interruptible load from TasNetworks' network under a contractual arrangement with the customer if the frequency in TAS falls below 48.8 Hz. This scheme operates prior to 48 Hz, when the UFLS relays will operate. The scheme operated as designed and as required in this event.

4.5 The NEM Frequency Operating Standard (FOS)

As part of its power system responsibilities, AEMO is to use reasonable endeavours to maintain power system frequencies within the applicable frequency operating standard for given operating conditions. The FOS that applied in the NEM mainland regions immediately after the separation of both QLD and SA was the island standard for multiple contingency events. There were four separate frequency areas – QLD, SA, VIC/NSW, and TAS. Under the FOS, frequency in each mainland island should be contained between 47 and 52 Hz, stabilised between 49 Hz and 51 Hz within two minutes and recover to between 49.5 Hz and 50.5 Hz within 10 minutes.

During the events of 25 August 2018:

- The frequency was contained between 47-52 Hz for the duration of the event in all regions.
- The frequency was stabilised to 49-51 Hz within two minutes in all regions.
- The frequency recovered to 49.5-50.5 Hz within 10 minutes in all regions except QLD, which recovered in 10 minutes and 8 seconds.

AEMO considers it used all reasonable endeavours to meet the FOS given the challenges in operating the QLD network during the separation period.

4.6 Regional responses

Detailed information on frequency response is provided for each of the four frequency areas relevant to this event – QLD, SA, NSW/VIC, and TAS.

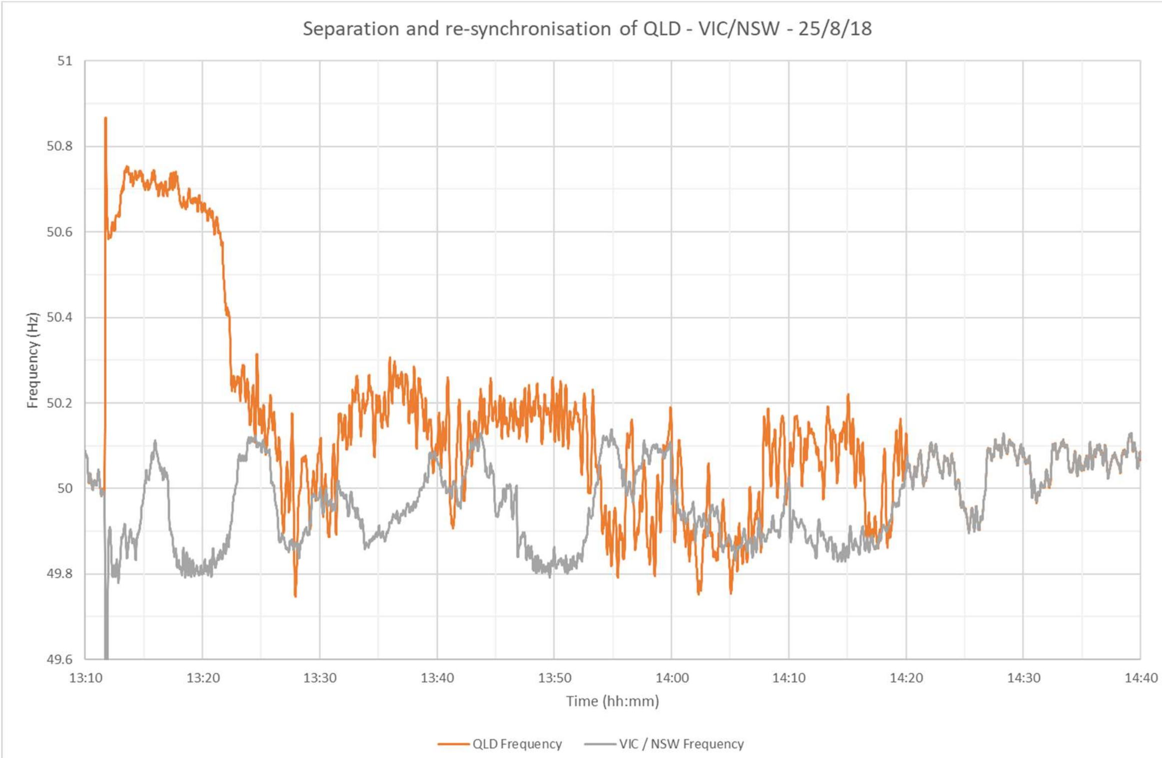
The frequency response for each frequency area is broken down by technology type and then timeframe, being short duration (1 minute) and longer duration. The short duration frequency response is based on measurements obtained from high speed monitoring devices throughout the network and at participant facilities. The longer-term frequency response while the regions remained separated is based on measured SCADA data.

4.7 Queensland

QLD was separated at 13:11:41 and remained separated from NSW until 14:20:04. As QLD was exporting power at the time of separation, frequency increased in QLD following separation. Frequency peaked at around 50.9 Hz, initially settling to around 50.6 Hz, then increasing again and remaining above 50.6 Hz for around seven minutes. In total, the frequency exceeded 50.5 Hz for 608 seconds, marginally over the ten minute target for frequency recovery in the FOS. Insufficient primary frequency control response and the fact that no contingency or regulation lower FCAS was enabled in QLD at the time of separation were key factors preventing a faster recovery.

The frequency while QLD was separated is shown in Figure 14.

Figure 14 QLD and VIC/NSW frequency



The Terranora high voltage direct current (HVDC) interconnector between NSW and QLD remained in service during this event. As it did not trip and does not provide any MW response to frequency changes at either end of the link, it had no impact on this event.

4.7.1 QLD – short-term frequency response

The initial generation response in QLD to the separation event was determined by governor response on synchronous generation, and active power control systems on non-synchronous generation sensing and responding to local over-frequency. This event occurred near the daily output peak from PV generation and a material reduction in transmission-connected PV generation was observed. However, these responses were not enough to lower frequency below 50.5 Hz within 10 minutes.

As shown in Table 5, no contingency lower FCAS services were enabled in QLD prior to this event, so FCAS market enablement played no role in QLD short-term frequency response.

Table 8 lists the approximate pre-event output of QLD generation, by category.

Table 8 Approximate pre-event QLD generation

Generation technology	Generation output (MW)	Online capacity (MW)
Synchronous	5957.5	7,490
Transmission-connected PV	286.1	586
Distributed PV	1,043	2,177
Wind	1.7	180

4.7.2 QLD – longer-term frequency response

QLD frequency remained high for 608 seconds following the initial separation. This level of sustained frequency deviation indicates a lack of coordinated control to restore system frequency.

4.7.3 AGC control of QLD generation

Over longer timeframes, AGC frequency regulation and market dispatch also influence frequency outcomes, in addition to synchronous generator governors, and other locally acting active power control systems.

Dispatch constraints to obtain 110 MW of lower regulation FCAS locally within QLD were active from the DI ending 13:25, although NEMDE was unable to obtain the full requirement during the separation period.

AEMO observed that the generation enabled to provide 95 MW of raise regulation FCAS immediately prior to the event increased its output after the separation event, until a separate AGC control area for QLD could be established and local FCAS constraints applied in dispatch. This occurred because, until a separate AGC control area is established for an islanded region, the AGC continues to calculate regulation frequency control requirements on the reference frequency. In this case, the reference frequency in NSW was low, while QLD was in a high frequency condition. The resulting increase in the output of enabled raise regulation generation in QLD exacerbated the over-frequency conditions.

4.7.4 Market dispatch of QNI

Constraints setting a 0 MW limit on QNI were loaded into AEMO's systems at 13:16. These were picked up by NEMDE in the 13:20 dispatch run for the DI ending 13:25. Prior to that, NEMDE did not recognise the physical change in system conditions. For the DI ending 13:20, QNI had a target of 318 MW south, resulting in market dispatch of additional generation in QLD above that required to meet the forecast regional load for that DI. This contributed to high system frequency conditions, particularly where generation acts to prioritise absolute compliance with dispatch rather than MW output accounting for a response to the system frequency.

Figure 15 Actual flow, transfer limits and target flow on the QNI interconnector

All | Properties | Export Limit | Import Limit | Total Cleared (MW Flow) | Initial MW

	DateTime	NSW1-QLD1 Export Limit	NSW1-QLD1 Import Limit	NSW1-QLD1 Total Cleared	NSW1-QLD1 Initial MW
153	25/08/2018 12:50:00	255.6346	-1086.0387	-836.2932	-810.2432
154	25/08/2018 12:55:00	251.7881	-1086.0684	-840.0523	-915.0066
155	25/08/2018 13:00:00	254.1586	-1086.098	-844	-885.8687
156	25/08/2018 13:05:00	251.2446	-1086.1212	-833.2939	-899.4663
157	25/08/2018 13:10:00	252.6174	-1086.1379	-832.4287	-854.3189
158	25/08/2018 13:15:00	264.0982	-1086.1555	-828.3552	-834.2905
159	25/08/2018 13:20:00	301.549	-1086.494	-318.0255	0
160	25/08/2018 13:25:00	0	0	0	0
161	25/08/2018 13:30:00	0	0	0	0
162	25/08/2018 13:35:00	0	0	0	0
163	25/08/2018 13:40:00	0	0	0	0
164	25/08/2018 13:45:00	0	0	0	0
165	25/08/2018 13:50:00	0	0	0	0

4.7.5 FCAS co-optimisation and unit dispatch

From the DI ending 13:25, local QLD FCAS requirements were set, requiring minimum levels of regulation FCAS and contingency FCAS to be enabled from units within the QLD region. Contingency raise FCAS requirements are a function of the largest generation contingency size, and FCAS constraints in NEMDE will automatically co-optimise the maximum contingency size in QLD, considering FCAS costs and availability. This typically results in reducing the largest generator contingency size by reducing output from large synchronous generating units. This reduces the corresponding volume of contingency raise FCAS reserves required to cover the loss of the largest generator.

AEMO considers that greater primary frequency control participation with tight dead-bands would have assisted the control of frequency during this prolonged high frequency period. In addition, rapid changes in QLD energy and FCAS prices also contributed to the physical system volatility. These factors all extended the time needed to resynchronise the QLD and NSW regions.

4.7.6 Resynchronisation

Ongoing rapid and large changes in QLD frequency during this period delayed resynchronisation with NSW, which occurred at 14:20:04, just under 1 hour and 10 minutes after the separation event. Resynchronisation of two regions requires voltages at the separation point to remain close enough – in magnitude, frequency, and angular difference – for long enough to satisfy system synchronism checks. When frequency is poorly controlled in either area, the time taken to satisfy the synchronism conditions is prolonged and resynchronising will take longer than conditions where frequency is well controlled.

4.7.7 QLD synchronous generation – short-term response

Table 9 shows the synchronous generation that disconnected almost immediately following QLD separation.

Table 9 Generation disconnection

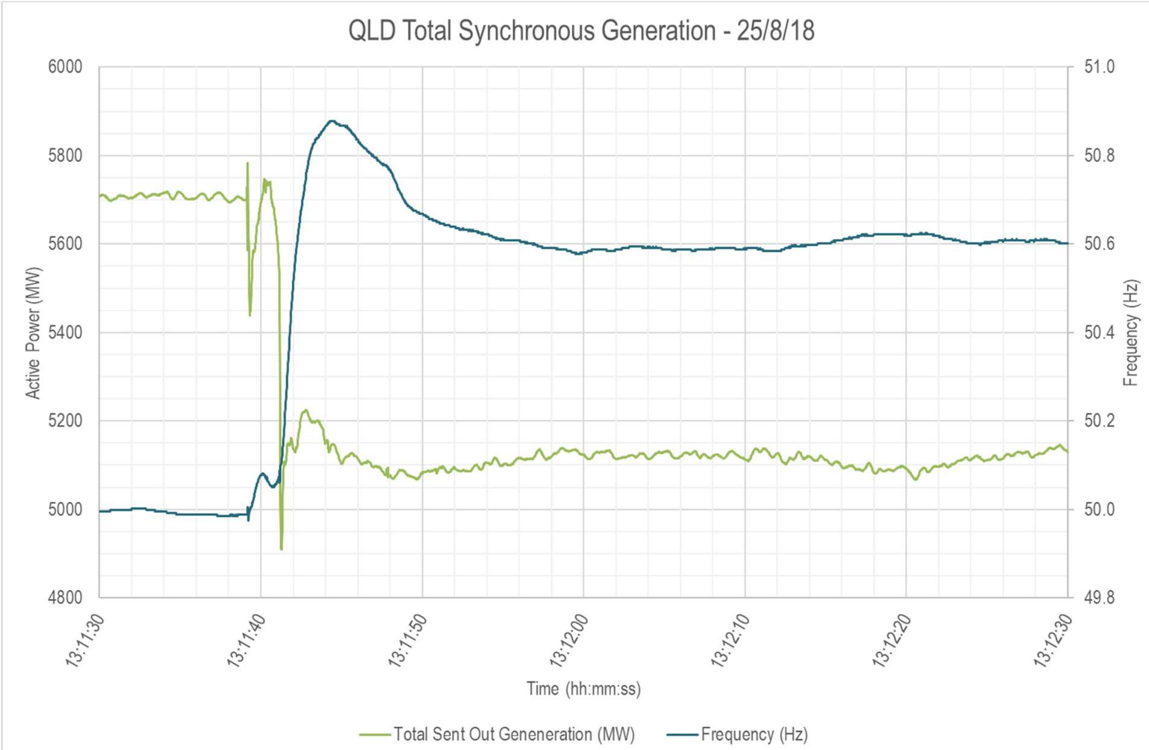
Generating unit	MW
Condamine combined-cycle gas turbine (CCGT)	85
Barron Gorge Unit 2	5

Barron Gorge unit 2 had just synchronised to the power system immediately prior to the event and was starting to increase load as the event occurred. The unit 2 governor responded to the rising QLD frequency by reducing output into a reverse power level, resulting in a trip.

The Condamine Power Station operator advised that a voltage disturbance caused the unit trip. Measured phase voltages at the 132kV connection point for Condamine showed large and rapid changes associated with the initial loss of synchronism between QLD and NSW.

Figure 16 shows the aggregate response of QLD synchronous generation to the initial separation and over-frequency condition.

Figure 16 Aggregate synchronous generation response – short-term



In addition to inherent inertial response to the over-frequency event from synchronous generation, there was a sustained aggregate reduction in synchronous generation output of around 600 MW. Much of this response was delivered prior to the peak system frequency and was effective at arresting the maximum frequency to prevent an excursion beyond frequency limits. Excluding the 90 MW of generation output lost due to generation tripping, the controlled reduction in output from synchronous generation was around 510 MW, or about 6.9% of the synchronous capacity remaining online.

The change in system frequency resulting in this controlled 6.9% reduction was around 0.6 Hz (1.2%), implying an aggregate sustained droop characteristic from the QLD region synchronous generation fleet of 17.3%. This represents an aggregated regional response 'actual' and does not consider frequency response dead-bands, or hard physical limits on units' ability to lower output. Some units did provide good primary frequency control, although the aggregated response across the region was below typical international industry practice.

This aggregate primary response compares poorly with international practice, where all technically capable generators are typically required to operate with droop characteristics in the range of 3-5%, with response to be provided beyond a very small frequency response dead-band. This is particularly the case for over-frequency events, where the opportunity cost of maintaining response headroom is normally low.

A wide range of different short-term responses from synchronous generators to QLD separation and over-frequency were identified. In some cases, similar units at the same power station responded differently during the event for varying reasons.

As an example, the response of Stanwell Power Station Units 1 and 2 at is shown in Figure 17. This shows Unit 1 exhibited a much larger sustained reduction in output than Unit 2, for the same frequency disturbance, and same pre-event loading. Stanwell advised that control systems on Unit 2 have been upgraded and allow the MW response to a frequency event from this unit to be limited in accordance with FCAS enablement targets. Unit 1 did not have those control arrangements as it had yet to undergo its control systems upgrade at the time of the event. Both responses are compliant with generator performance standards (GPS) established under the NER and were consistent with FCAS enablement targets for those units.

Figure 17 Stanwell unit 1 and unit 2 response

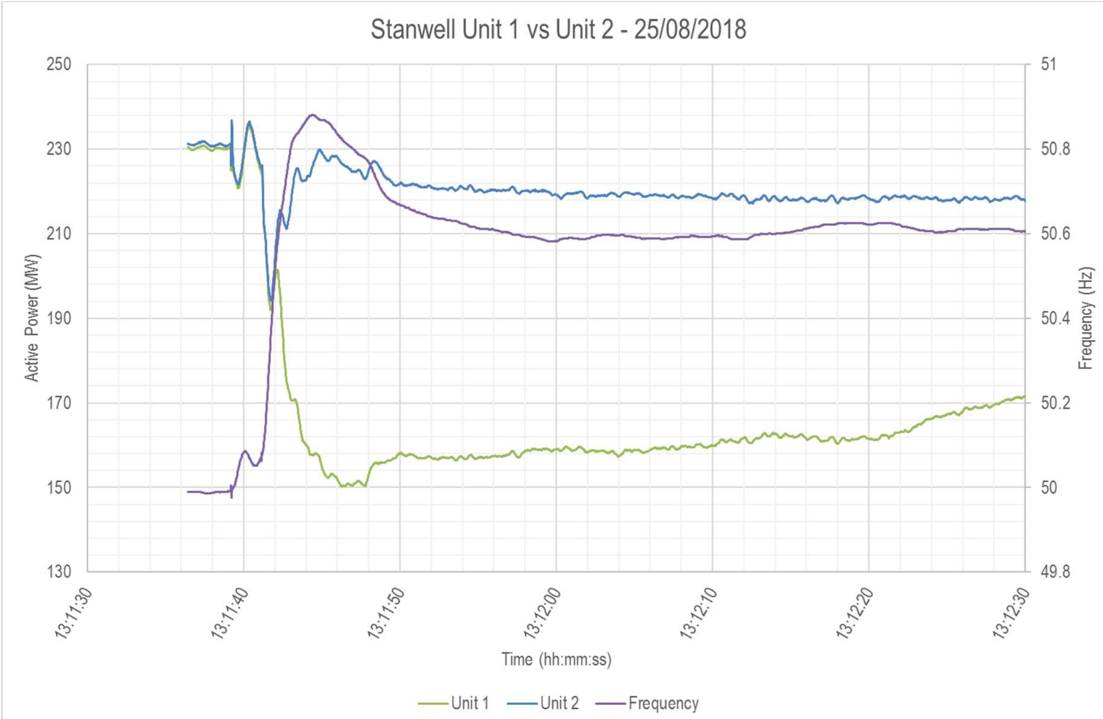
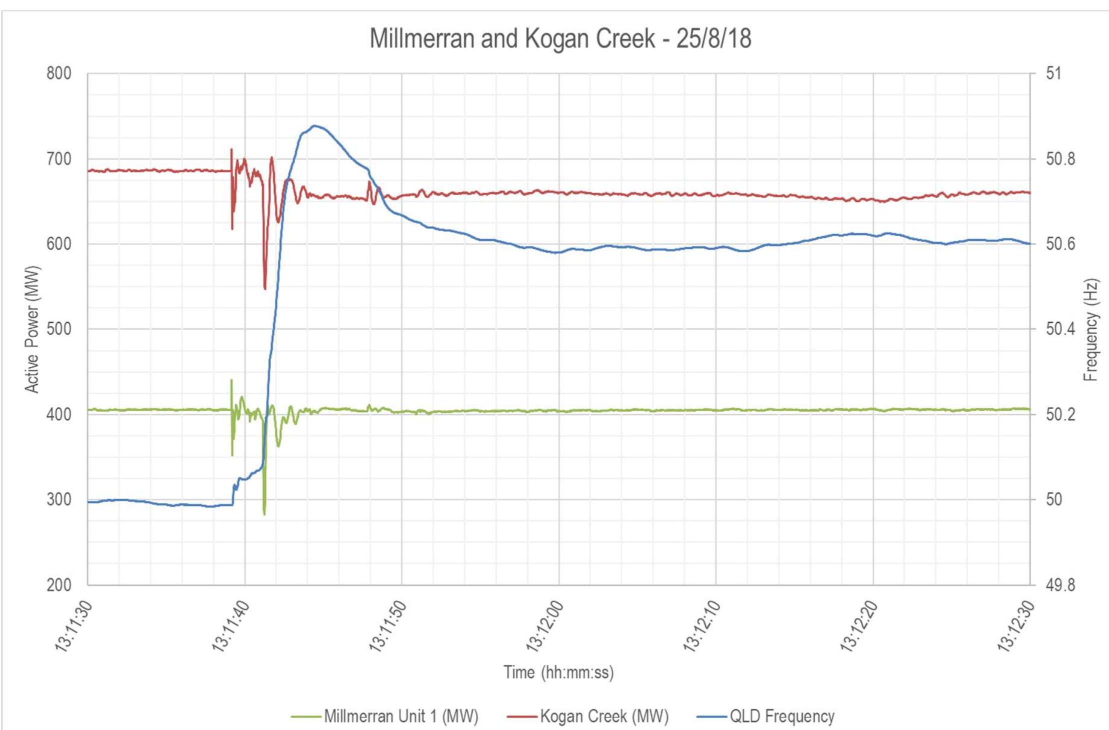


Figure 18 shows the output (sent out = as generated minus the station consumption) of Kogan Creek and Millmerran Unit 1, which both exhibited little or no sustained reduction in MW output, in response to a sustained rise in system frequency to around 50.6 Hz.

Figure 18 Millmerran and Kogan Creek generation response (sent out generation)



For the dispatch interval commencing 13:10 and ending 13:15, Millmerran had an initial MW of 430 MW (as generated at 13:10) and a dispatch target of 432MW (to be achieved by 13:15). The actual output (as generated) of Millmerran at 13:15 was 434MW, in line with the MW dispatch target and in compliance with the NER, even though the frequency seen by the Millmerran generator approached 50.9 Hz and was sustained at 50.7 Hz during this interval. As Millmerran was not enabled for an FCAS service it did not, and was not required to, counter a response to the high frequency by reducing output.

AEMO considers this lack of primary response to the system frequency to conflict with frequency control principles which ideally would have all generators online naturally reduce their output in response to the high frequency through their local controls – primary frequency control.

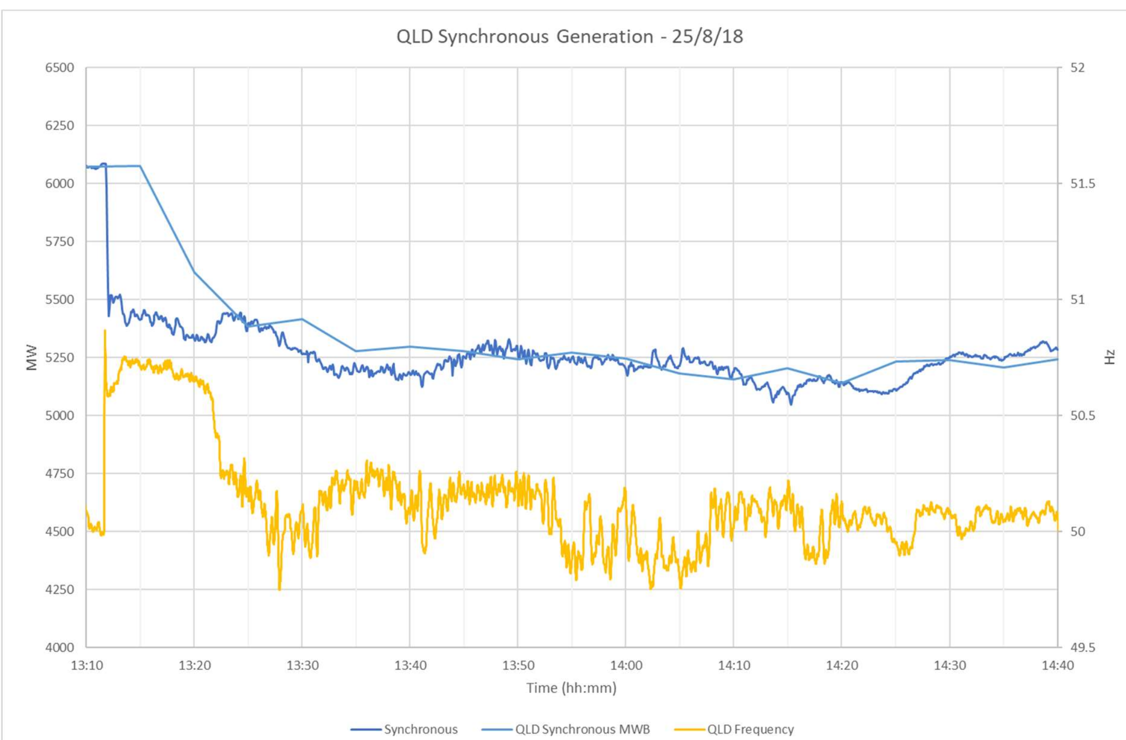
Large non-credible contingency events such as occurred on 25 August 2018, where the location and level of contingency FCAS reserves enabled via the FCAS market are unlikely to correspond with the requirements of the power system following the event, increasingly present a risk of cascading failures on the power system at current levels of primary frequency control response. The analysis of this event underlines the need for all generation to respond to changes in frequency where it is feasible. This will minimise the amount of uncontracted load shedding that occurs via UFLS for under-frequency events, and more fundamentally, provide critical support to arrest, stabilise and correct large deviations in power system frequency.

The current FCAS markets cannot deliver the resilience needed for the power system to withstand this type of event. It is a reality that many generators have limited the provision of frequency response, particularly for larger frequency deviations, only to periods where they are enabled to provide contingency FCAS. A trial conducted in TAS earlier in 2018 where governor dead bands were reduced demonstrated a significant improvement of primary frequency control.

4.7.8 QLD synchronous generation – long-term response

Figure 19 shows the longer-term response of synchronous generation in QLD, and system frequency in the islanded region, until resynchronisation at 14:20:04.

Figure 19 QLD synchronous generation – longer-term response



After initially peaking at 50.9 Hz, QLD power system frequency stabilised at around 50.6 Hz. Frequency increased again to 50.7 Hz and remained at around these levels for just over 10 minutes in total before returning below 50.5 Hz. This undesirable response again highlights the need for all generation to respond to correct frequency deviations to the extent of their capability to do so. Multiple large synchronous generators in QLD were observed to continue to closely comply with MW dispatch targets during this period as required by the NER, even with system frequency at 50.7 Hz.

4.7.9 QLD wind generation – response

Only one QLD wind farm was operating at the time of the event. Its MW output was too low prior to and during the event to materially affect outcomes.

4.7.10 QLD transmission-connected PV generation - short-term response

Figure 20 shows the aggregate response of QLD transmission-connected PV to the initial over-frequency condition in QLD following separation.

Figure 20 Aggregate QLD transmission-connected PV response

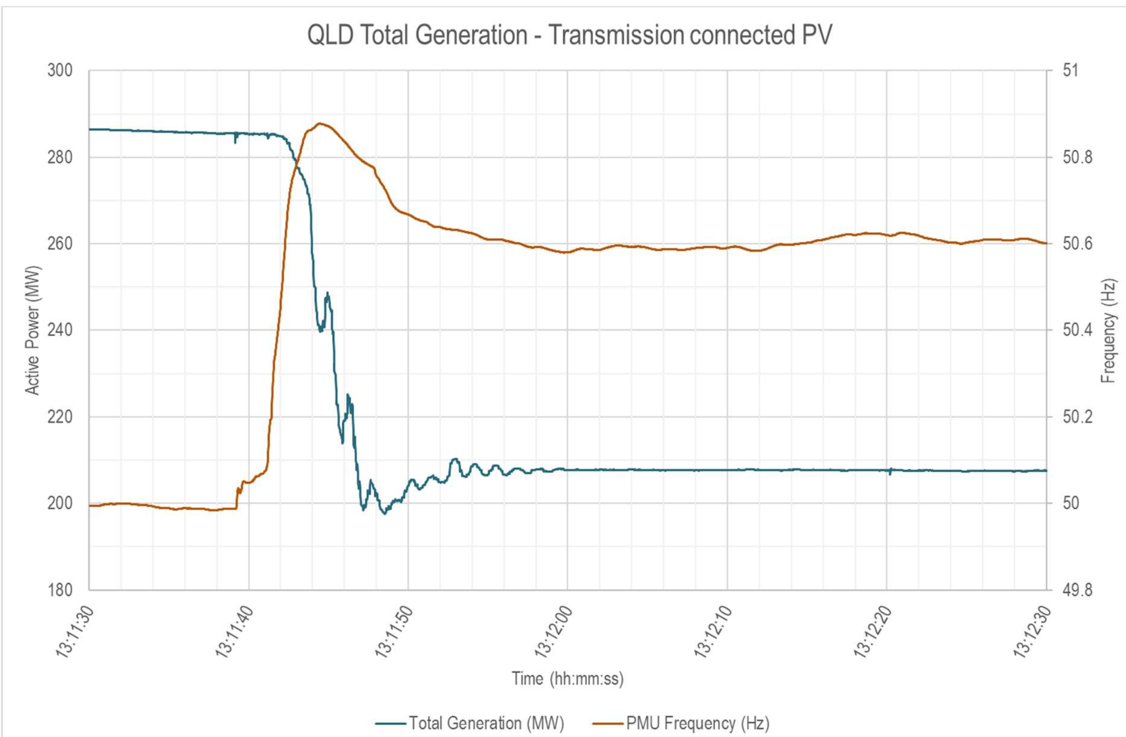
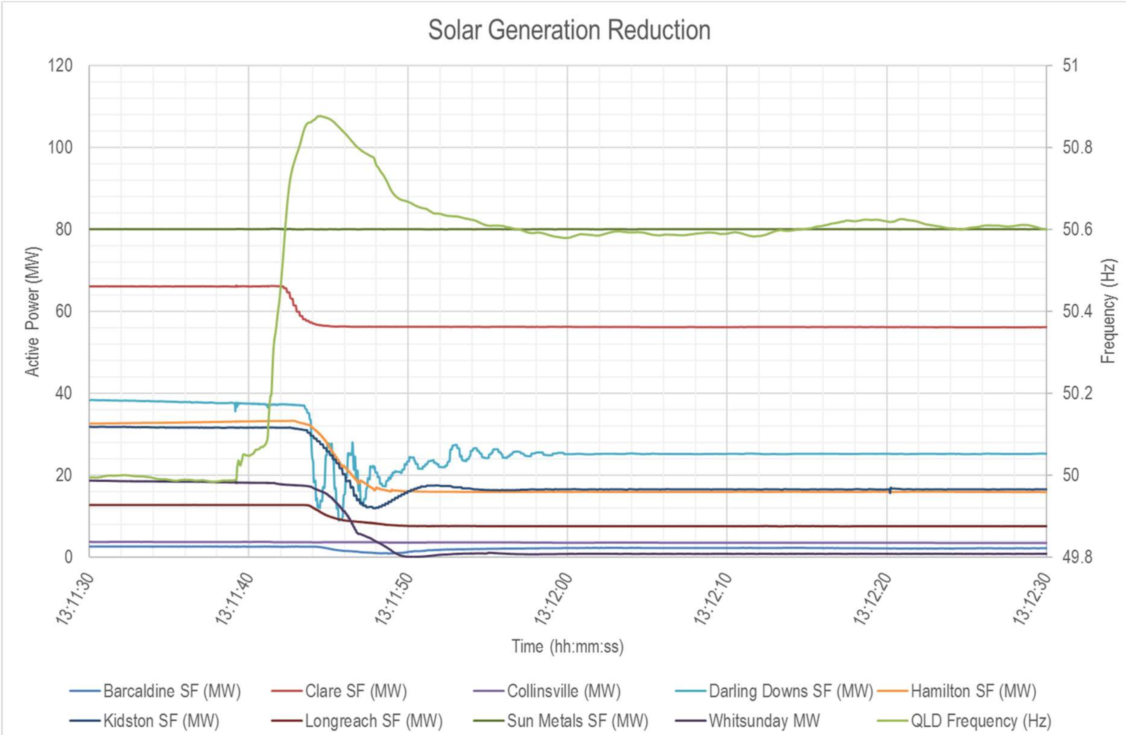


Figure 21 shows the response of online large-scale transmission-connected PV generators (solar farms) to high frequency conditions in QLD. All but one of these solar farms reduced output. This observed reduction was a result of 'built in' control system settings (consistent with the relevant GPS) and was unrelated to FCAS market outcomes. Poorly damped MW response was observed from one solar farm in this event. The operator has subsequently updated active power control systems settings to address this.

The MW reductions from individual solar farms varied significantly in size, timing relative to the peak in frequency, and as a percentage of rated capacity. The variation was due to the application of different frequency response settings between plants, and different control system arrangements for delivery of the response.

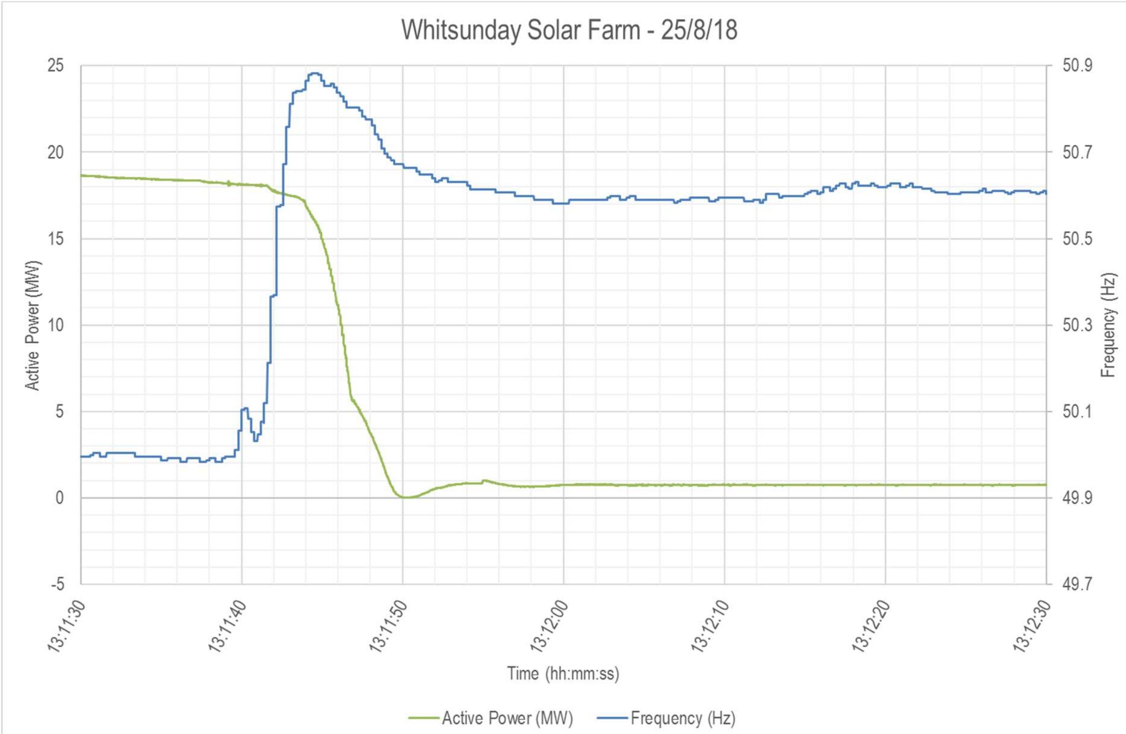
Figure 21 Individual QLD transmission-connected PV generation response



Much of the aggregate reduction in generation output from transmission-connected PV systems was delivered after peak frequency was reached in QLD. This reduced the effectiveness of their response to arrest the rise in QLD frequency, as only MW response provided before the frequency peak acts to arrest the frequency rise. To minimise rapidly escalating deviations in system frequency, it is critical that response to a significant frequency deviation is delivered with the smallest possible delay.

No immediate disconnection of transmission-connected PV generation was noted during this event. It was observed that some solar farms reduced output almost to zero, which is a desirable response to an increase in system frequency. An example is shown below in Figure 22, for 57 MW Whitsunday Solar Farm which was in the commissioning process.

Figure 22 Whitsunday solar farm response



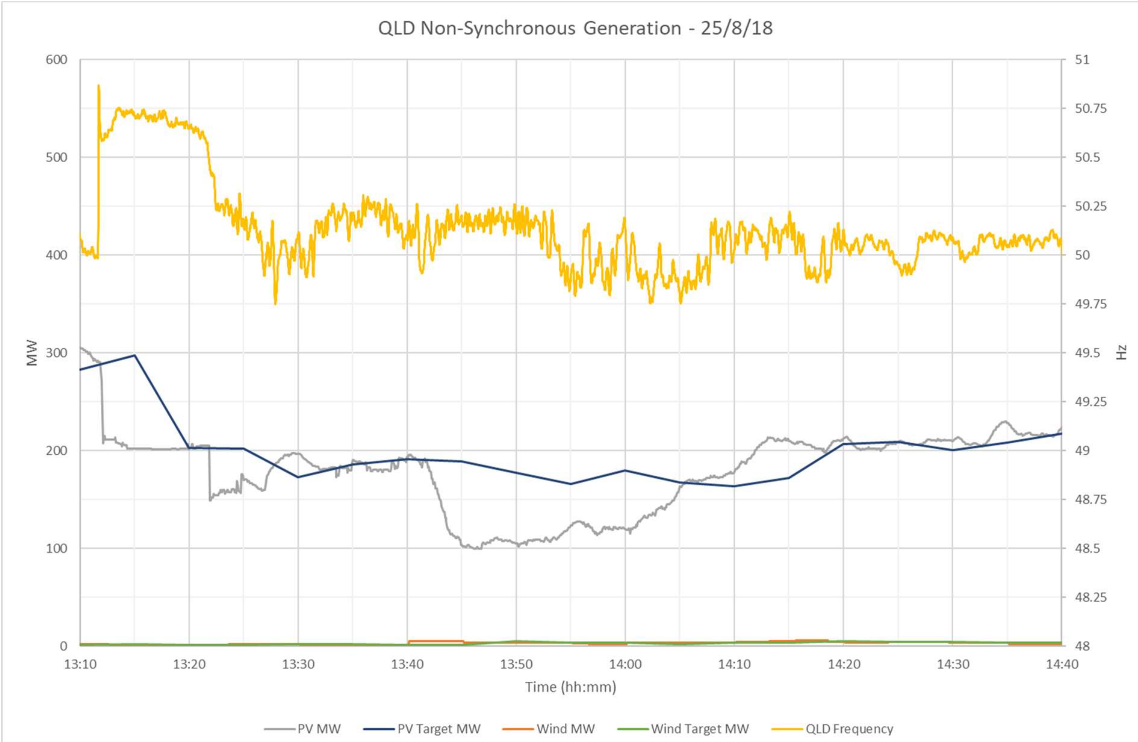
The aggregate reduction in output from transmission-connected PV generation once frequency stabilised at around 50.6 Hz was around 78 MW, representing 13.3% of the online installed PV capacity of 586 MW. The sustained increase in system frequency was around 0.6 Hz (1.2%), implying an aggregate sustained actual droop from the transmission-connected PV generation fleet operating in QLD at the time of the event of around 9.0%.

Several solar farms provided a 'one-shot' sustained reduction in output, responding and sustaining their output response to the maximum frequency of 50.9 Hz reached during the event. Output was not restored to pre-event levels until frequency had recovered and remained close to 50 Hz for a defined period. This is different from the typical frequency response of synchronous generators, which will typically progressively recover output while frequency returns towards 50 Hz.

4.7.11 QLD transmission-connected PV generation – longer-term response

The aggregated response of transmission-connected PV in QLD during the event is shown below in Figure 23. This figure is based on 4-second SCADA MW output data and covers the entire QLD separation period. It shows sustained reduction in aggregate QLD PV generation output, below AEMO's ASEFS forecasts, shown as the PV Target MW.

Figure 23 QLD non-synchronous generation – longer-term response



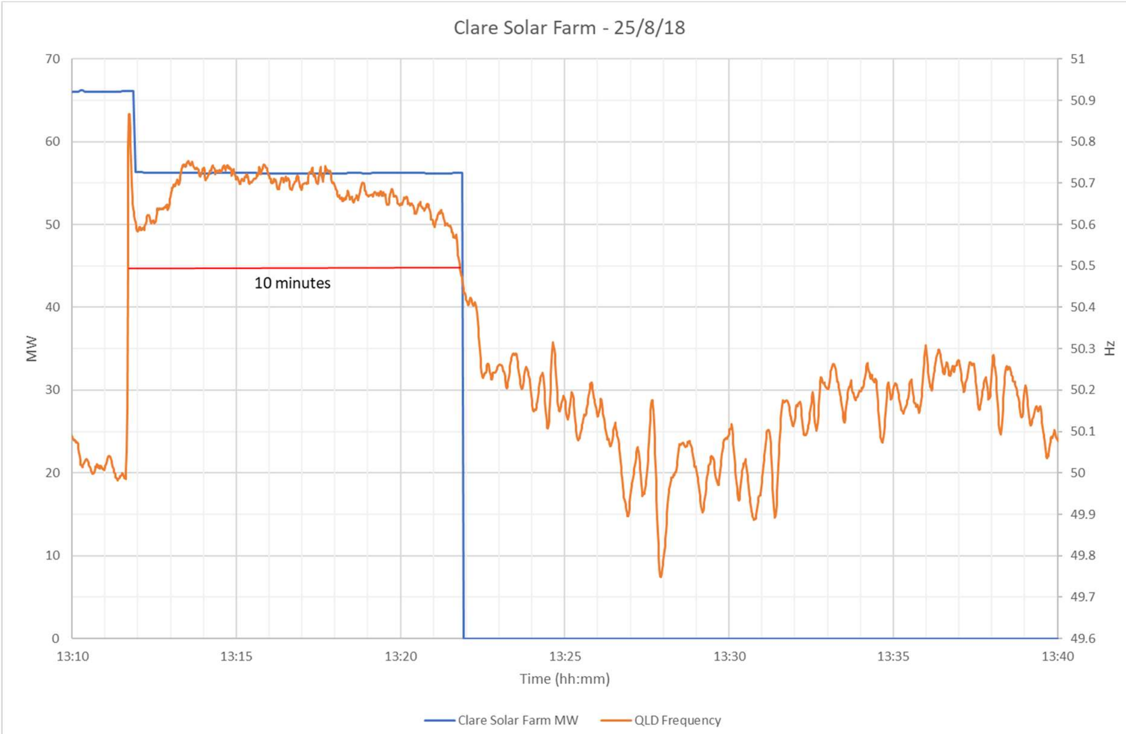
Referring to Figure 23, the large-scale PV output reduced after two minutes by approximately 100 MW. This was the initial, though slow response. The next reduction was observed at 13:21:41, 10 minutes from the time of the event. PV inverters commenced tripping when they reached a 600 second sustained high frequency limit within the inverter. Two inverters disconnected at this time, being the minimum period required by the GPS. Combined with the AEMO's AGC commencing to reduce generator outputs in the island at the same time, this reduced the QLD frequency enough to bring it under 50.5 Hz 608 seconds after the event.

Commencing at 13:41, Sun Metals Solar Farm ramped output down by approximately 71 MW, over a period of several minutes. The reduction in PV generation output corresponded with a reduction in the site load (the solar farm has a zero-export limit).

Figure 24 shows the response from Clare Solar Farm during the event, which ceased output at around 13:22. This can also be observed in Figure 23. The protection trip occurred when system frequency remained above 50.5 Hz for more than 600 seconds. This is consistent with the GPS established in relation to NER clause S5.2.5.3 – Generating system response to frequency disturbances. This requires that inverters remain in operation for a period of 10 minutes when the frequency exceeds 50.5 Hz but is less than 51 Hz.

AEMO notes that a requirement in the NER to withstand a specified frequency level for at least a minimum time should not be interpreted as a 'must trip' or 'shall trip' for any greater length of time above (or below) the specified frequency level. Beyond the minimum level, AEMO considers that protection on plant ought to be set at a level that is appropriate to match the plant capability or protect the plant from damage.

Figure 24 Clare Solar Farm response



The operators of Barcaldine Solar Farm advised AEMO of a similar protection trip at the same time as Clare Solar Farm, however the output of Barcaldine Solar Farm was too low at the time to clearly observe the change in output in the SCADA data available to AEMO.

While this response was broadly helpful in this event, removing MW from a high frequency condition, many solar farms have very similar protection settings that may create a risk of large-scale, simultaneous uncoordinated protection responses causing undesirable power system outcomes.

After reviewing and analysing the responses of all generators in this event, AEMO will investigate the possible implementation of additional over-frequency Emergency Frequency Control Schemes (EFCS) for each region, commencing with SA and QLD as a part of the Power System Frequency Risk Review (PSFRR) in 2019.

4.7.12 QLD distributed PV – short-term response

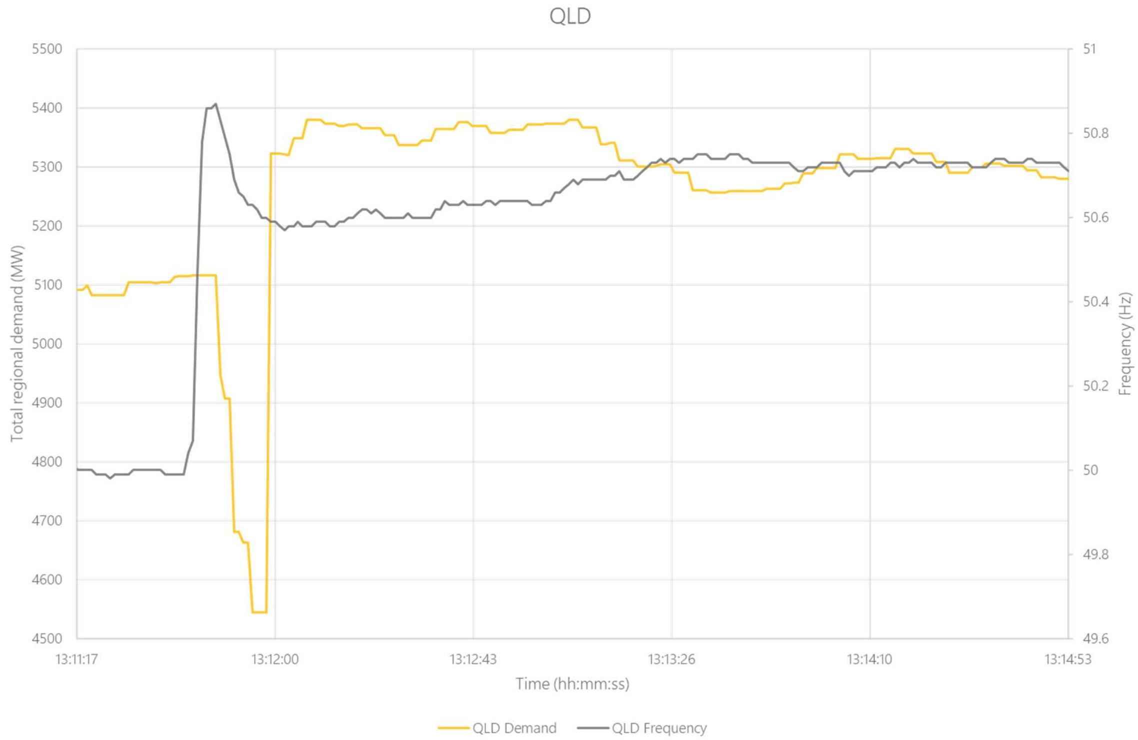
Reduction in output from distributed behind the meter PV (including rooftop PV) appears as an increase in the demand on the transmission network, which is beneficial in managing a high frequency condition. The observed change in regional demand in QLD immediately after the separation is illustrated in Figure 25.

This regional demand calculation is the sum of the output of QLD generation visible in AEMO's SCADA system, plus imports from tie-lines, and is equal to the load supplied from the QLD transmission network, plus transmission losses.

As no high-speed data is available, this measurement of demand is subject to the variable and unpredictable delays involved in SCADA measurements of generator output and transmission lines flows over short time periods. These issues can lead to significant variation in calculated demand over short time periods.

An increase of approximately 200-250 MW in QLD demand is evident following the event.

Figure 25 Total regional demand in Queensland on 25 August 2018



The detailed studies of the distributed PV responses are shown in Appendix 1.

The studies look at a sample response from monitored installations and apply the response across the remaining fleet with the same inverter AS 4777 standards. To estimate the behaviour of aggregate PV generation across the region during this event, the systems monitored by Solar Analytics were divided into tranches, as follows:

- Capacity (kW) – PV systems were divided into different size tranches (<30kW and 30-100kW) because larger systems may have additional protection or other installation requirements, determined by distribution businesses as a condition of connection. This may cause different behavioural trends for these systems in response to disturbances.
- Date of installation – PV systems are required to comply with different standards based on installation dates:
  - Installed prior to Oct 2015 – should be compliant with AS/NZ4777.3-2005.
  - Installed after Oct 2016 – should be compliant with AS/NZ4777.2-2015.
  - Transition systems (installed between Oct 2015 and Oct 2016) – may be compliant with either standard (a one-year grace period was allowed following the publication of the new standard).

The studies yielded the following conclusions:

- A reduction in generation was observed from 15% of inverters installed prior to October 2015. This reduction appears to be mostly associated inverters suddenly reducing generation to zero (consistent with disconnection of the device)[10]. The reasons for this disconnection behaviour are not clear. Further investigation is underway to understand why these inverters did not respond as expected.
- At least 15% of inverters installed after October 2016 did not exhibit the over-frequency reduction specified in AS/NZ4777.2-2015.

[10] A small subset of inverters also exhibited more mild ramping behaviour that appears consistent with cloud shading.

- For inverters installed after October 2016 there is a clear correct aggregate response, suggesting that the designed control response is correctly implemented in a fair proportion of the PV inverters. This response from distributed PV inverters post October 2016 assisted frequency management during this event and is likely to become increasingly important in future disturbances as the proportion of distributed PV generation grows.

4.7.13 QLD distributed PV – longer-term response

Output from distributed PV generation in QLD was restored over a period of 10-20 minutes following the initial disturbance.

4.8 Tasmania

Immediately prior to the event frequency in TAS was 49.97 Hz. TAS load, generation, and Basslink transfers were all stable.

In response to the fall in the reference power system frequency on the mainland as measured by AEMO in NSW, on the loss of QNI, the Basslink HVDC interconnector automatically increased power transfer in the TAS to VIC direction. This occurred through the Basslink frequency controller, which rapidly and automatically adjusts the MW flow on Basslink based on the difference in frequency between the TAS and VIC ends of the link. This action provided support to frequency on the mainland, and caused frequency to fall in TAS.

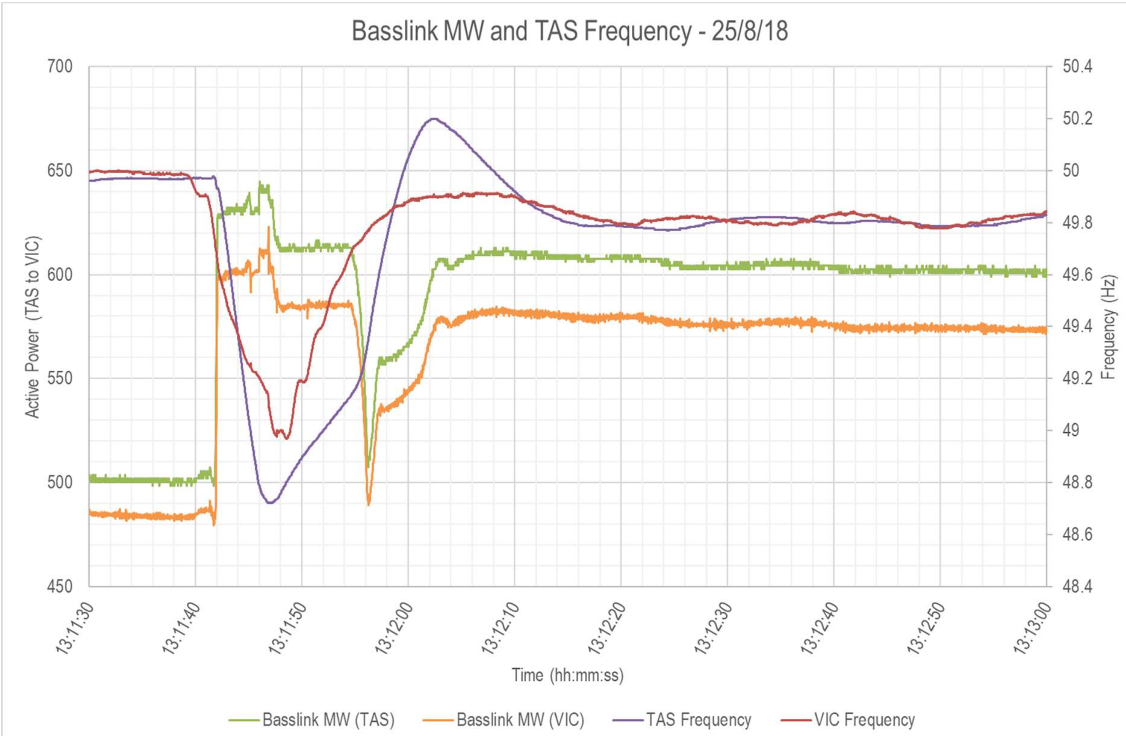
Basslink was initially operating at around 500 MW transfer from the TAS end towards VIC, and rapidly increased transfer to the maximum 630 MW equipment limit, as measured at the TAS end of the link. This resulted in a decline in frequency in TAS to below the 48.8 Hz frequency trigger point of the AUFLS2 control scheme, automatically interrupting industrial load in TAS that is contracted to provide this facility.

System frequency in TAS did not reach 48 Hz, therefore no generalised UFLS was triggered in TAS. No other disconnection of load or generation in TAS was observed during the event. TAS remained connected to the mainland via the Basslink interconnector throughout the event.

4.8.1 Basslink short-term response

Figure 26 shows the increase in Basslink MW transfers towards VIC in response to the frequency decline in VIC, and the resulting decline in TAS frequency. MW recordings from the TAS and VIC ends of the HVDC link are shown, the difference representing transmission losses.

Figure 26 Basslink power transfer and TAS frequency



Initial flow on the link was at the maximum dispatch limit of 500 MW ex TAS (478 MW received into VIC). AEMO's dispatch system will not provide a base MW target for Basslink above this level. However, Basslink retains a short-term overload capability of around 630 MW at the TAS end, which will be used when there is significant frequency difference between the ends of the link, as during this event.

Note that the different post-contingency frequency standards applied in TAS and on the mainland are relevant to the action of the Basslink frequency controller, which broadly tries to ensure a similar proportional deviation in frequency, relative to the allowable post-contingency frequency standard.

The Basslink response commenced around 2 seconds after frequency declined at the VIC end of the link, with Basslink not providing a large increase in MW transfer until mainland frequency had declined below 49.75 Hz. This is consistent with the design of the Basslink frequency controller, which provides increased response once the frequency difference between the ends of the link exceeds this level.

As TAS was initially in MW balance, and operating very close to 50 Hz, this Basslink response appeared as a sudden load increase of around 130 MW on the TAS system. The sudden increase in load in TAS resulted in TAS frequency declining at an initial rate of approximately 0.31 Hz/sec, as shown in Figure 13.

This decline in frequency continued until frequency reached 48.8 Hz, the trigger point for the AUFLS2 control scheme, at 13:11:45.9, when the scheme interrupted 80.4 MW of contracted industrial load. This load occurred before separation of SA from VIC at around 13:11:46.8, and prior to interruption of load in NSW and VIC by general UFLS commencing at around 13:11:47.6.

The AUFLS2 load interruption partially balanced the increase in TAS system load created by Basslink. Frequency response from TAS synchronous generation, and ongoing changes in Basslink MW transfer as a response to the difference between TAS and mainland frequency, resulted in frequency in TAS recovering close to 50 Hz, with a peak measured frequency of around 50.2 Hz.

4.8.2 TAS generation pre-event

Table 10 lists the pre-event output of generation in TAS.

Table 10 Pre-event TAS generation

Generation	Output (MW)	Online Capacity (MW)
Synchronous	1588.4	1,803
Wind	43.5	308
Distributed PV	65	124

Tasmania does not currently have transmission-connected PV generation. Data on the output of distributed PV in TAS has not been examined at this time.

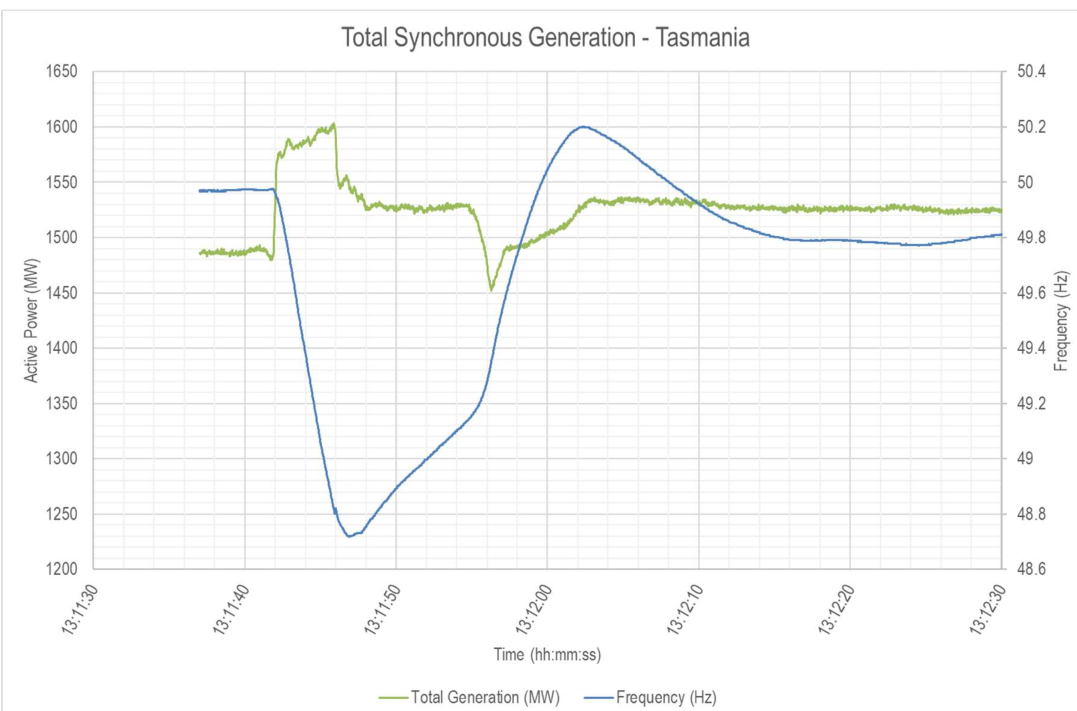
4.8.3 TAS synchronous generation – short-term response

Figure 27 shows the aggregated response of TAS synchronous generation for which AEMO obtained high speed data was obtained, noting that high speed data was not available for around 170 MW of online generation. Synchronous generation provided a rapid and initially sustained increase in MW output, prior to disconnection of load by the AUFLS2 control scheme.

Synchronous generation operating in TAS at the time of the event comprised hydro generation and the Tamar Valley gas turbine. The ongoing response of synchronous generation was complicated by the relatively rapid reversal of frequency, which requires a relatively rapid increase then decrease in water flow. This can be challenging for some hydro machines to achieve quickly, depending on design.

As indicated in Table 5, no contingency raise FCAS was enabled in TAS for the DI ending 13:15. All TAS synchronous generator frequency response to this event was unrelated to FCAS market outcomes. The AUFLS 2 scheme reduces the requirement for Raise FCAS in Tasmania.

Figure 27 Aggregated TAS synchronous generation response – short-term*



* AEMO was unable to obtain high resolution data for some of the TAS generation therefore their response is not included in this figure.

4.8.4 TAS synchronous generation – longer-term response

Figure 28 shows the longer-term response of TAS synchronous generation, for the period until resynchronisation of both SA and QLD.

Figure 28 Aggregated TAS synchronous generation response – longer-term

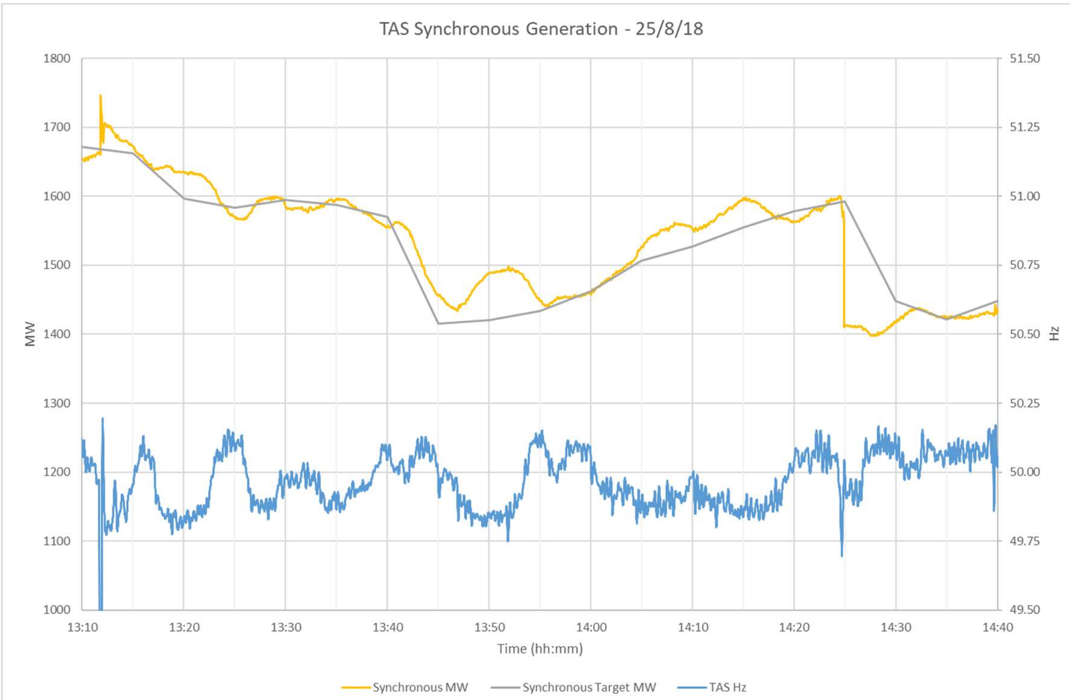


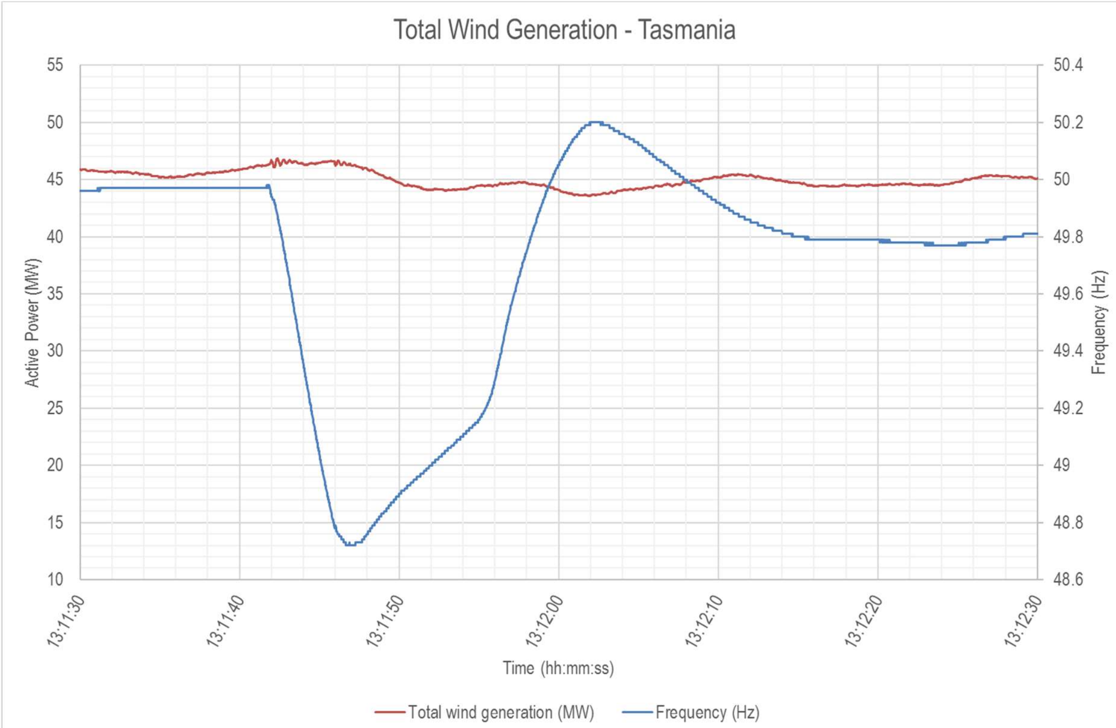
Figure 28 shows expected movement of TAS synchronous generation in response to system frequency, both under local governor control, and more slowly via centralised AGC control.

A generation reduction of approximately 200 MW can be seen at around 14:25, which was unrelated to the separation or resynchronisation of QLD or SA. At 14:24:30 the Tamar Valley Combined Cycle GT in TAS reduced output from around 206 MW to zero, triggering a disconnection of around 117 MW of contracted industrial load in TAS via control scheme action, resulting in a net generation loss of around 89 MW. This deficit was mostly corrected by a rapid and automatic reduction in TAS export to VIC on Basslink due to the Basslink Frequency Controller responding to an initial frequency decline in TAS.

4.8.5 TAS wind generation – short-term response

Figure 29 shows the short-term response of TAS wind generation to the event. Around 5 MW of wind generation is missing, where data could not be obtained. As expected, there was no increase in output in response to the falling TAS frequency, as this generation was not operating with MW headroom to raise output and was not operating in a mode where it would respond to the levels of high frequency seen in this event.

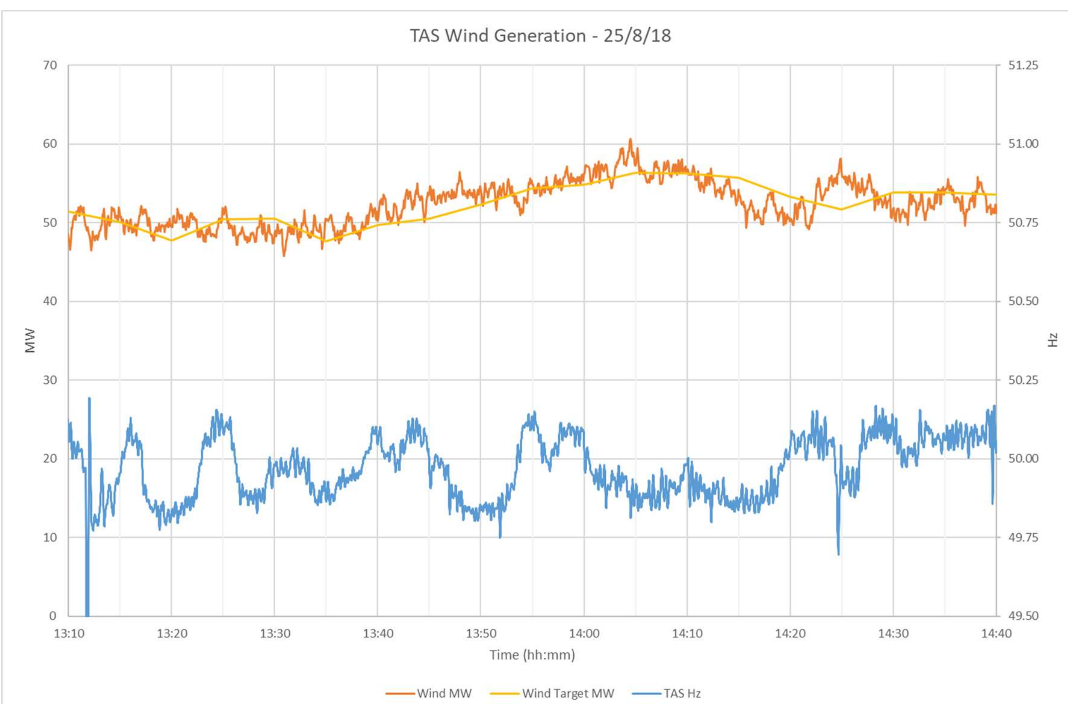
Figure 29 Aggregate TAS transmission-connected wind generation – short-term response



4.8.6 TAS wind generation – longer-term response

Figure 30 shows the longer-term output of wind generation in TAS. Wind generation in TAS was not a material factor in system frequency response during this event.

Figure 30 Aggregated TAS transmission-connected wind generation response – longer-term



4.8.7 Automatic Under Frequency Load Shedding V2 (AUFLS2) control scheme

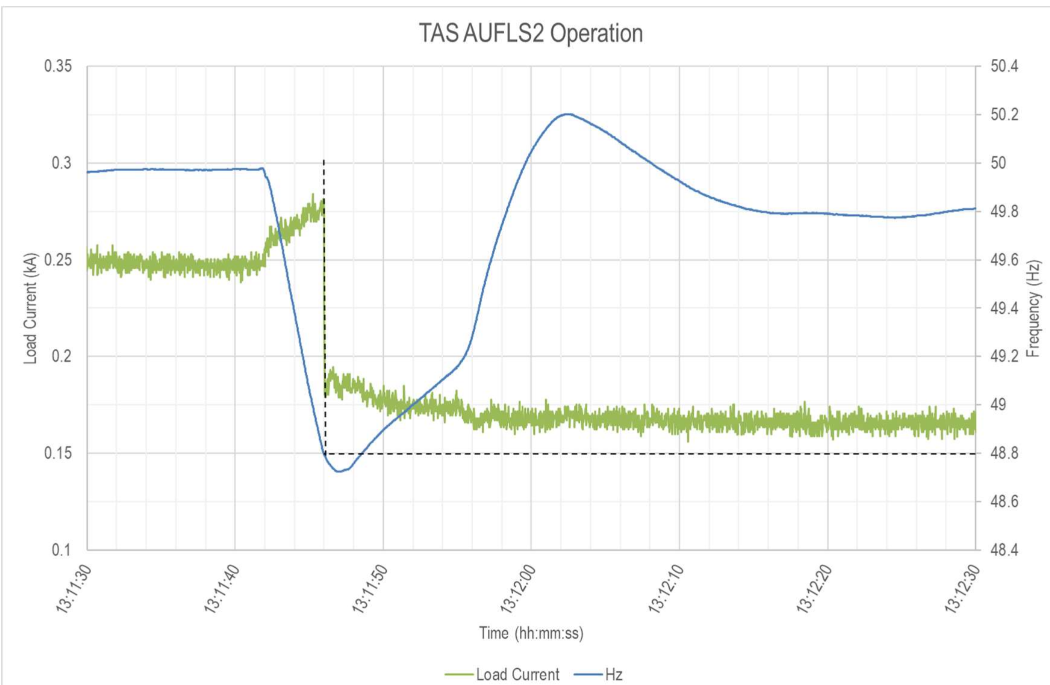
The AUFLS2 control scheme was installed in TAS early in 2018 and offers contingency raise FCAS service in TAS by interruption of contracted industrial loads. The amount of load interrupted at the 48.8 Hz trigger level is variable, and is calculated by the scheme immediately prior to interruption, considering the measured RoCoF following the event, and other system operating conditions.

The scheme is designed to avoid interrupting more load than necessary, particularly to avoid the risk of frequency over-shoot for smaller contingency events that only just reach the frequency trigger threshold.

Note, as shown in Table 5, no contingency raise FCAS was enabled in TAS for the DI ending 13:15. Delivery of this AUFLS2 MW response was therefore unrelated to FCAS market outcomes.

Figure 31 shows measured load current for the interrupted load.

Figure 31 TAS AUFLS2 operation



4.9 South Australia

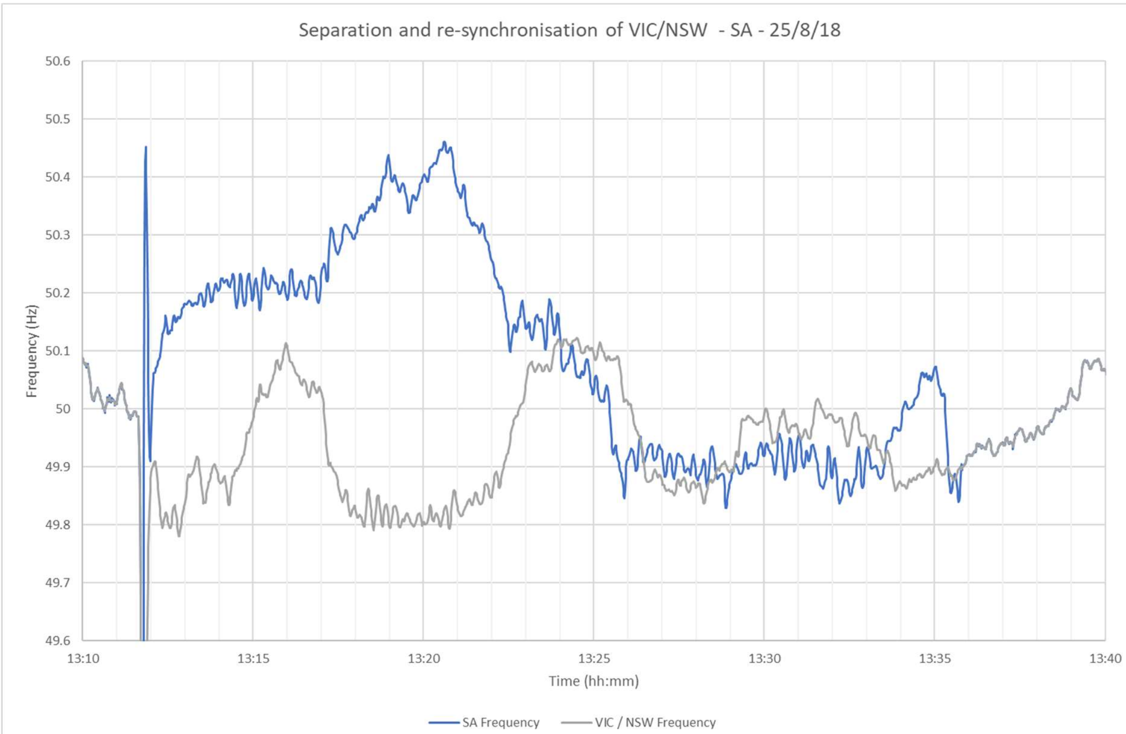
SA was separated from VIC at 13:11:47 and remained separated until 13:35:46. In the seconds prior to separation, frequency in SA, NSW and VIC had initially reduced after the loss of QNI at around 13:11:41. This is shown earlier in Figure 8.

As SA was exporting power to VIC, frequency immediately increased in the SA region following separation, reaching an initial peak of 50.46 Hz, from around 49.14 Hz immediately prior to separation. Both raise and lower contingency FCAS was enabled from sources within SA (see Table 5) at the time, enabling a governor response from the FCAS-enabled generators that assisted both in limiting frequency excursions in the SA/NSW/VIC regions immediately after the QLD separation and in the SA region immediately after its separation from VIC.

The Murraylink HVDC interconnector between SA and VIC remained in service during this event. As it did not trip and does not provide any MW response to frequency changes at either end of the link, it had no impact on this event.

Figure 32 shows frequency in SA and VIC/NSW while SA was separated. The FOS for island operation was met for the SA region for the duration of the separation.

Figure 32 SA and VIC/NSW frequency



4.9.1 SA – short-term response

The short-term frequency response in SA to the separation event was determined by governor response on synchronous generation, and active power control systems on non-synchronous generation, including wind, PV, and batteries changing MW output in response to changes in frequency.

Frequency response in SA was complicated by the fact that frequency fell to around 49.14 Hz at a rate of around 0.12 Hz/sec when QLD separated, and then rose more rapidly to a maximum of around 50.46 Hz, at a peak rate of around 0.65 Hz/sec, as shown in Figure 13. This is a challenging frequency trajectory for some generation to respond to, requiring an increase and then decrease in output within a short time period while frequency is changing rapidly.

This event occurred shortly after the daily solar output peak in SA. Reduction in output from solar generation in response to the over-frequency condition in SA is described further below.

Table 11 lists the pre-event output and online capacity of generation in SA.

Table 11 SA generation prior to the event

Generation Technology	Generation Output (MW)	Online Capacity (MW)
Synchronous	807.8	1,454
Transmission-connected PV	89	110
Distributed PV	600	919
Wind	129.2	1,811
Battery	-40	+100/-80

4.9.2 SA – longer-term frequency response

SA frequency after separation from VIC was arrested at around 50.46 Hz and returned to within the range 49.85-50.15 Hz within 60 seconds of the event.

However, as shown in Figure 32, frequency then increased over a period of minutes, and again reached just under 50.5 Hz, remaining there for almost three minutes. It is undesirable for frequency to remain so far away from 50 Hz without returning towards that level over many minutes. This indicates a lack of coordinated frequency control arrangements in SA.

4.9.3 AGC control of SA generation

As noted in Table 7, AEMO established a separate AGC control area for the SA island at 13:18:31, less than 7 minutes after the initial separation of SA from VIC. Dispatch constraints to obtain regulation FCAS reserves were active from the DI ending 13:25, though lower and raise regulation FCAS reserves were already incidentally available in SA in earlier dispatch intervals, as part of the overall NEM requirements at the time.

As in QLD, until a separate AGC control area was established for the SA island, dispatched regulation FCAS reserves in SA were controlled in response to frequency measured at the NEM reference in NSW, even though the SA island did not share that frequency.

As shown in Figure 32, there was an under-frequency condition in NSW, which resulted in AGC requiring increased output from generation enabled to provide raise regulation FCAS in SA, contributing to the increase in system frequency in SA during this period.

NEMDE set a 0 MW target on Heywood for the DI ending 13:25. For the DI ending 13:20, the Heywood interconnector had a dispatch target of 164 MW towards VIC, resulting in dispatch of generation in SA above that required to meet the forecast loading during this period, further contributing to high system frequency conditions in SA.

4.9.4 SA synchronous generation – short-term response

Figure 33 shows the aggregate response of SA synchronous generation to the initial under-frequency condition following loss of QNI, then the over-frequency condition in SA following subsequent operation of the EAPT scheme and separation of SA from VIC.

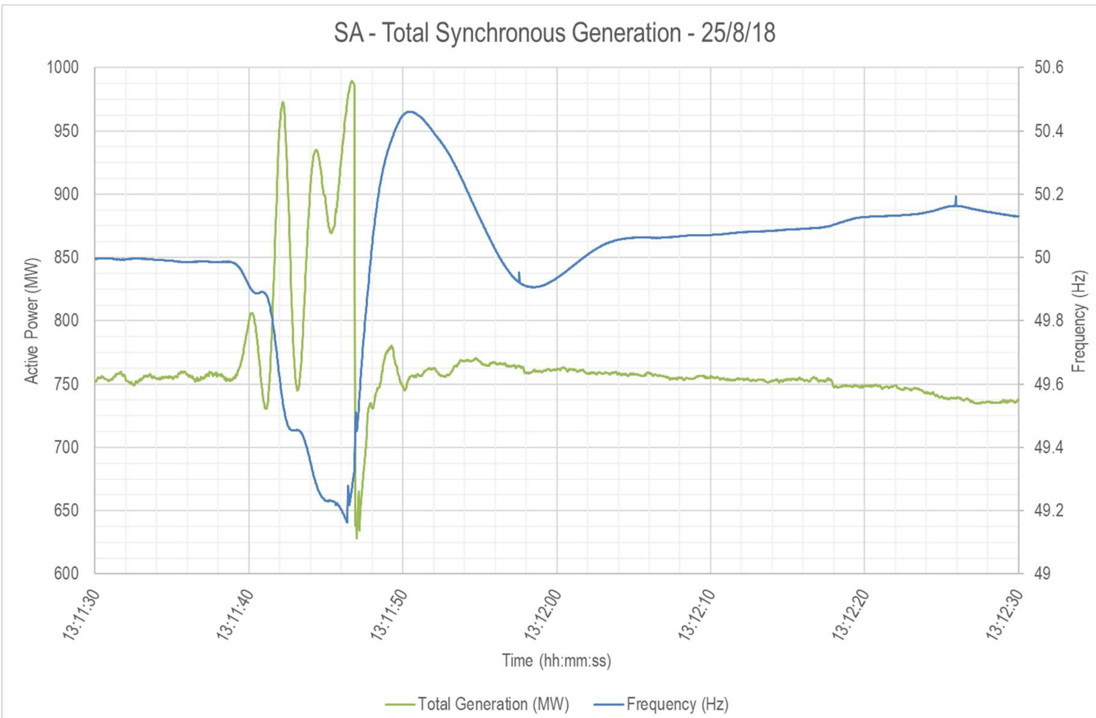
There was a material aggregate response from synchronous generation in SA to provide a controlled increase in output in response to the initial low frequency condition in SA. This increase in output was overlaid with an oscillatory component, at a frequency around 3.0 radians per second. The oscillatory active power response overlaid on the underlying controlled response was damped, and close to a known system mode frequency, involving SA synchronous machines oscillating as a group against generators in other regions of the NEM.

There was some reduction in generation output in response to the over-frequency condition on the subsequent separation of SA from VIC. Some of this reduction in output was delivered before reaching maximum frequency condition in SA, and contributed to limiting the over-frequency excursion.

There was almost no sustained response from synchronous generation in SA once the SA island was formed and the frequency returned to below the upper edge of the 49.85-50.15 Hz normal operating frequency band specified in the FOS for an interconnected system.

No synchronous generation in SA disconnected during this event. Unit 3 at Torrens Island A Power Station had received an initial 5 MW target and was about to synchronise around the time of the event but did not come online or generate during the SA separation period.

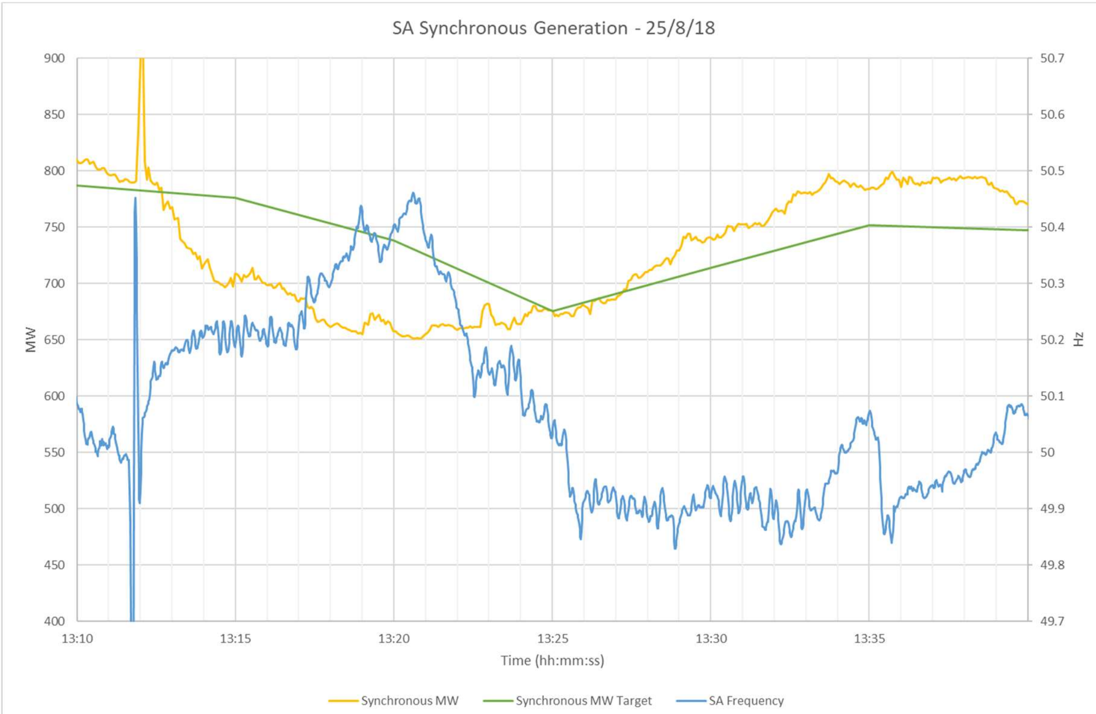
Figure 33 Aggregate SA synchronous generation response – short-term



4.9.5 SA synchronous generation longer-term response

Figure 34 shows the aggregate output of synchronous generation in SA during the islanding event.

Figure 34 Aggregate SA synchronous generation response – longer-term



Frequency control in SA during this event was poor, with significant movements in system frequency, but little corresponding short-term movement in the output of synchronous generation to correct frequency. This indicates a lack of primary frequency control within the FOS normal operating frequency band.

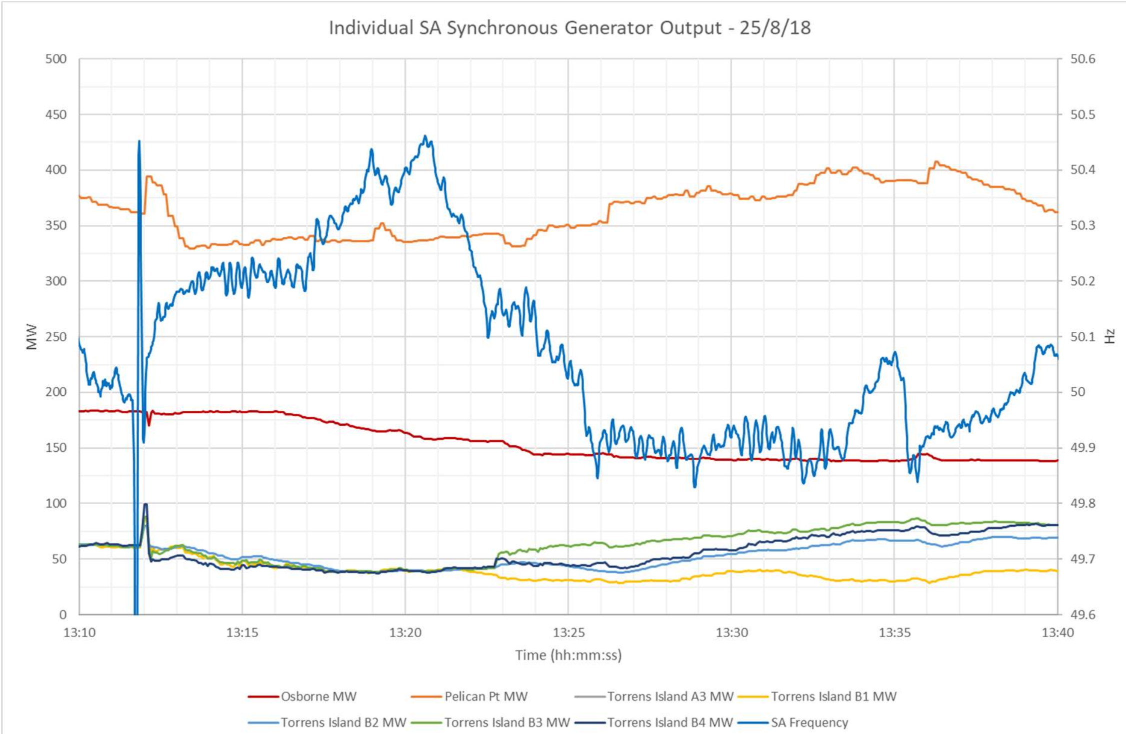
Figure 35 shows the individual responses of synchronous generating units online in SA during this event. Torrens Island units were already operating at low output during the period of high SA island frequency, restricting their ability to further reduce output while maintaining stable operation. Other synchronous generation remained at relatively high outputs, even during periods of the highest island system frequency in SA.

Synchronous generators in SA showed only slow and limited response to system frequency, both for large frequency deviations, and particularly once frequency returned to within the 'normal' band. The responses are, however, consistent with obligations established under GPS.

In the DI ending 13:20, before a 0 MW target was established for the Heywood interconnector, the interconnector was targeted for 164MW export from SA to VIC. This meant that generation dispatch in SA exceeded the regional demand in this DI, further contributing to the high frequency condition.

Once a separate AGC control area had been established and 0 MW target set on the open Heywood interconnector for DI ending 13:25, frequency in the SA island was able to be controlled within the 50 +/- 0.15 Hz 'normal' band.

Figure 35 Individual SA synchronous generation response – longer-term



4.9.6 SA wind generation – short-term response

Figure 36 shows the aggregate response from wind generation in SA to the separation event.

Due to low wind speed conditions, total SA wind generation output was low at the time of the event, at around 7% of the 1811MW SA installed capacity. Several wind farms were at or near zero output, and no individual wind farm was generating above 20 MW.

Figure 36 Aggregate SA transmission-connected wind generation response – short-term

Four wind farms in SA were observed to cease output during this event. All use the same wind turbine model. AEMO has been advised that this was caused by incorrect turbine protection operation, in response to the rapid decline, then increase, in system frequency.

The proposed rectification for this issue involves a turbine software update, which is subject to verification by AEMO.

The same wind turbine model is also used at other wind farms in SA, but their output was too low during this event to observe any change in output. AEMO is working with the manufacturer and each relevant wind farm operator across SA, VIC and NSW to verify the proposed upgrade to rectify this protection operation, and is investigating whether other wind turbine models have a similar protection operation.

AEMO is also requesting advice from all generators about any operating mode that could impact the ability of their plant to ride through disturbances as required by their GPS and the NER.

On this occasion, the loss of generation output was small, and assisted in correcting the over-frequency condition in SA. However, any unexpected and widespread failure to ride through frequency deviations that remain within the prescribed technical envelope presents a significant risk to the secure operation of the power system. It was fortunate that wind output was very low at the time of this event.

As was the case with the protection feature that resulted in the disconnection of turbines across several wind farms prior to the SA Black System on 28 September 2016, the protection mode triggered in the wind turbines during this event is not included in simulation models available to AEMO. It is vital that AEMO has all the information necessary to simulate and accurately predict the likely response of generators to power system events. AEMO is working with operators to ensure the simulation models accurately reflect plant behaviour.

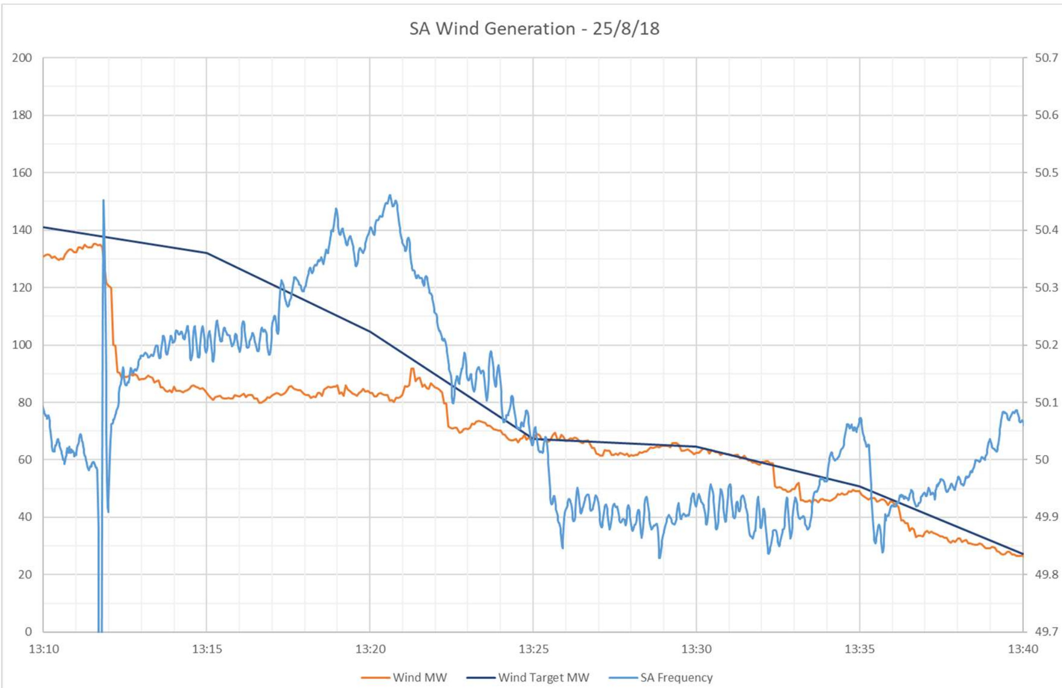
No other short-term responses to frequency were identified from wind generation in SA during this event. No wind generation was enabled to provide contingency FCAS reserves, and no other obligations to provide short-term response to frequency are established in the relevant GPS.

4.9.7 SA wind generation – longer-term response

The longer-term response of wind generation in SA during this event is shown in Figure 37. Wind farm output declined while SA was islanded from the NEM, due to falling wind speed conditions.

Other than the previously noted output reductions and loss of generation at the time of the initial separation event, no further material changes in wind farm output were noted during the event. Consistent with their GPS obligations, wind farms in SA did not respond to frequency changes in SA, or act to correct system frequency.

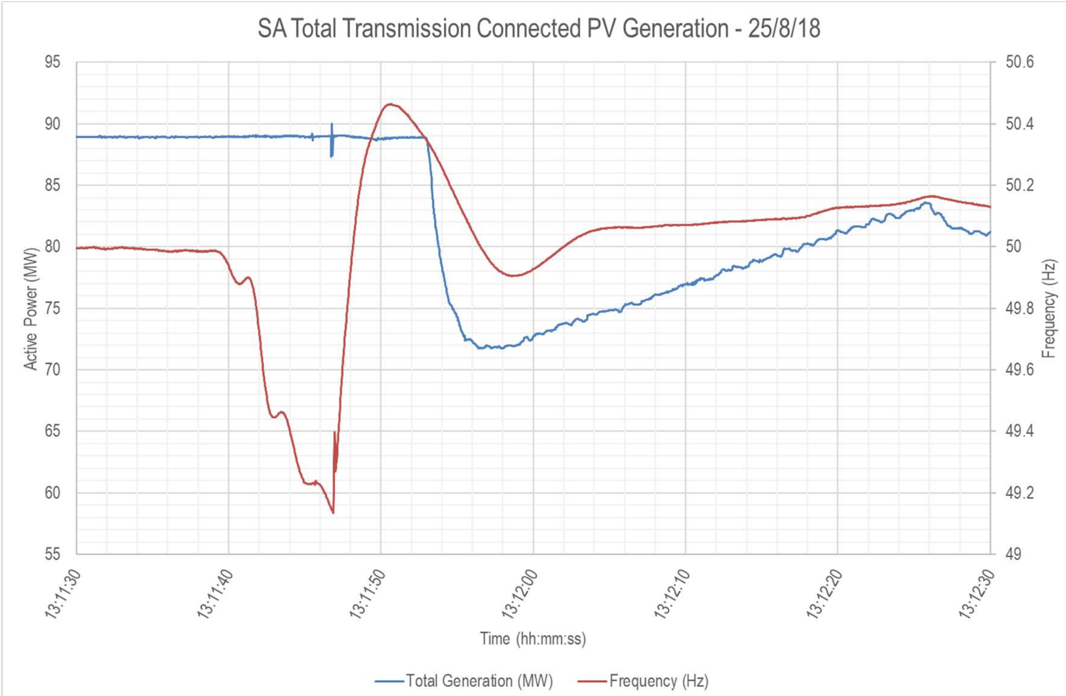
Figure 37 Aggregate SA wind generation response – longer-term



4.9.8 SA transmission-connected PV generation – short-term response

Figure 38 shows the response of 110 MW Bungala Solar Farm, the only transmission-connected PV generation in service in SA at the time of the event.

Figure 38 Aggregate SA transmission-connected PV response – short-term



As expected, there was no response to the initial under-frequency condition in SA, as the solar generation was running without headroom. There was a reduction in solar farm output in response to the high frequency condition following SA separation from VIC. The plant response has been found compliant with the GPS and NER requirements for response to frequency outside the normal frequency operating band. However, as this response only commenced around 1 second after the high-frequency condition in SA had already peaked, it did not contribute to arresting the frequency rise in SA.

AEMO observed that output continued to decline for 4 seconds from the pre-event level, even when frequency was below 50.15 Hz. The reason for this seems to be a 4 second delay from reading frequency to plant reaction as assessed during the testing and commissioning where 4 second delays were recorded. The reduction was partially restored at a ramp rate of 25MW/min once frequency had returned below the 50.15 Hz upper edge of the 'normal' frequency band described in the FOS, this initial restoration ramp up was interrupted by a new over-frequency exceeding 50.15Hz, that activated the active power reduction. Once the frequency entered the 50.15Hz the active power continued the recovery at a rate of 25MW/min.

Although not required under the NER and associated GPS, it would have assisted power system frequency control if the reduction in solar farm output during this event had been delivered without the observed delay, to help limit the frequency rise.

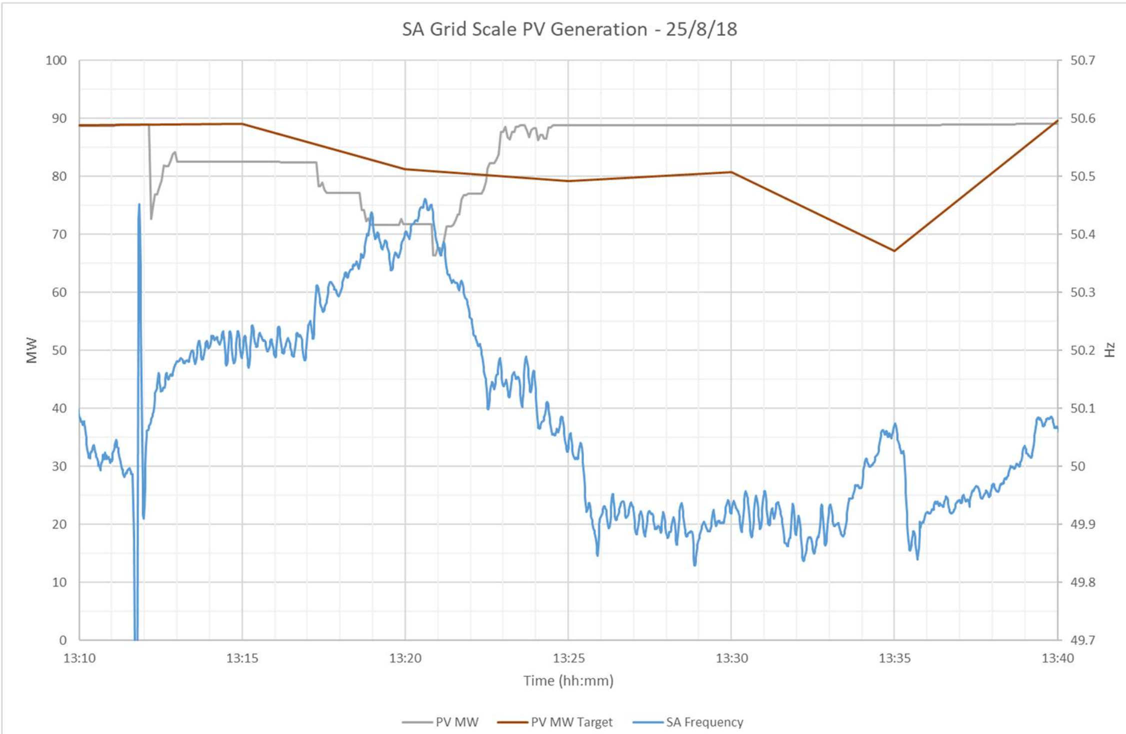
4.9.9 SA transmission-connected PV generation – longer-term response

Figure 39 shows the output of Bungala Solar Farm over the period SA was separated from VIC. It shows variations between generation targets (as determined by AEMO's ASEFS forecasting system) and actual generation typical for a single PV generator.

Given the relatively small size of the islanded SA system, active power variations of this size can be material to the overall supply demand balance of the region, impacting system frequency control. This is particularly the case for frequency control within the 'normal' band where there is little primary frequency control available to balance these active power variations.

The reduction in active power output between 13:16 and 13:25 is consistent with the response to high frequency conditions in SA immediately following separation, shown in Figure 39, and within the capability required in the GPS for response to frequency outside the normal frequency operating band.

Figure 39 Aggregated SA transmission-connected PV response – longer-term



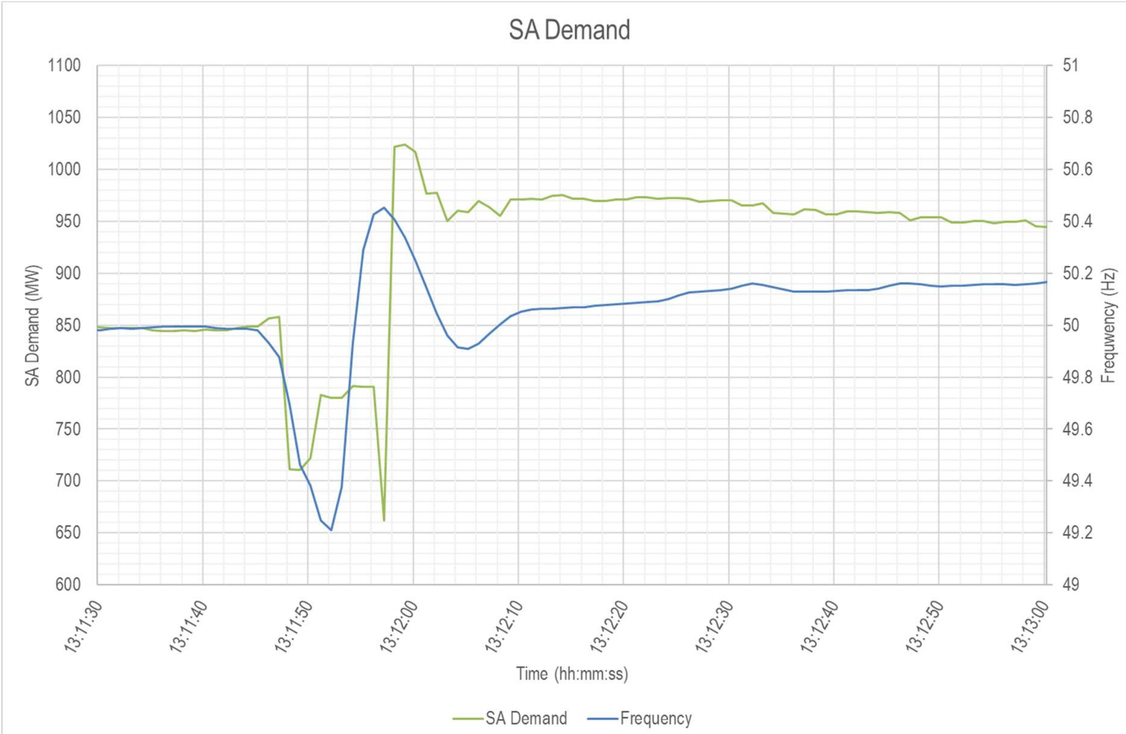
4.9.10 SA distributed PV – short-term response

A trace showing SA regional demand, calculated by ElectraNet from SCADA data, at a rate of 1 sample per second, is shown in Figure 40. This regional demand calculation is the sum of the output of generation visible in the ElectraNet SCADA system, plus imports from tie-lines, and is equal to the load supplied from the SA transmission network, plus transmission losses.

This measurement of demand is subject to the variable and unpredictable delays involved in SCADA measurements of generator output and transmission line flows. It can lead to significant changes in calculated demand over short time periods due to SCADA measurement issues.

The measured longer-term increase in regional SA demand of around 120 MW gives an initial indication of the reduction in output from distributed PV generation during this event.

Figure 40 **SA total demand**



AEMO's analysis of data from SA distributed PV systems is detailed in Appendix 1. It yielded the following conclusions:

- There was an observed reduction in generation from SA distributed PV systems installed prior to October 2015. Around half this reduction appears to be associated with the disconnection of around 13% of systems installed prior to October 2015. The causes of this behaviour are unknown. Frequency did not exceed 50.5 Hz in SA, and AEMO's survey of manufacturers[11] did not reveal any with default trip settings in that range. There was no known voltage disturbance in SA which might have caused inverter tripping. Further investigation is underway to understand why these inverters did not respond as expected.
- At least 30% of distributed PV inverters (<100 kW) in SA installed after October 2016 did not exhibit the over-frequency response specified in AS/NZ4777.2-2015.

4.9.11 SA transmission-connected batteries – short-term response

SA has two transmission-connected battery systems, at Dalrymple and Hornsdale. Only the Hornsdale battery, with a capacity of +100 MW/-80 MW, was in operation at the time of the event, charging at -38 MW immediately prior to the event.

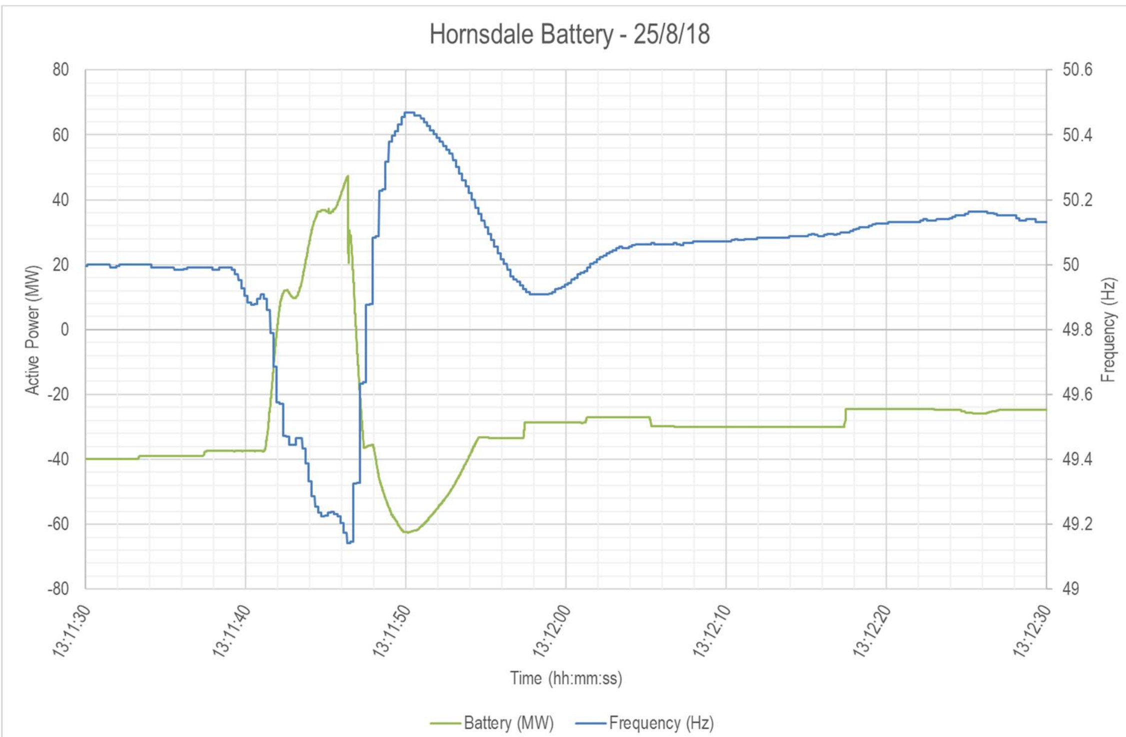
The frequency response of this battery is a simple proportional response and will result in a 100 MW increase in output from the battery for a frequency decline from 50 Hz to 49 Hz. The response of the Hornsdale battery during this event is shown in Figure 41.

[11] AEMO, April 2016, Response of existing PV inverters to frequency disturbances. Available at: https://www.aemo.com.au/-/media/Files/PDF/Response-of-Existing-PV-Inverters-to-Frequency-Disturbances-V20.pdf

This response is consistent with the design. It contributed to both arresting the initial decline in system frequency, and then by rapidly changing output from generation back to load, to arrest the over-frequency condition in SA following separation from VIC.

Only active power response delivered prior to the minimum or maximum frequency condition in an event such as this contributes to arresting the change in frequency. The very rapid speed of delivery of frequency response from the Hornsdale battery was valuable in this event, and ensured the response contributed to limiting the under- and over-frequency conditions.

Figure 41 SA transmission-connected battery response – short-term



The fast response of the Hornsdale battery during the event contributed to operation of the EAPT scheme. The active power response to the initial under-frequency condition seen in SA was a component of the overall rapid increase in power transfer from SA towards VIC following the initial loss of QNI, as shown in Figure 11.

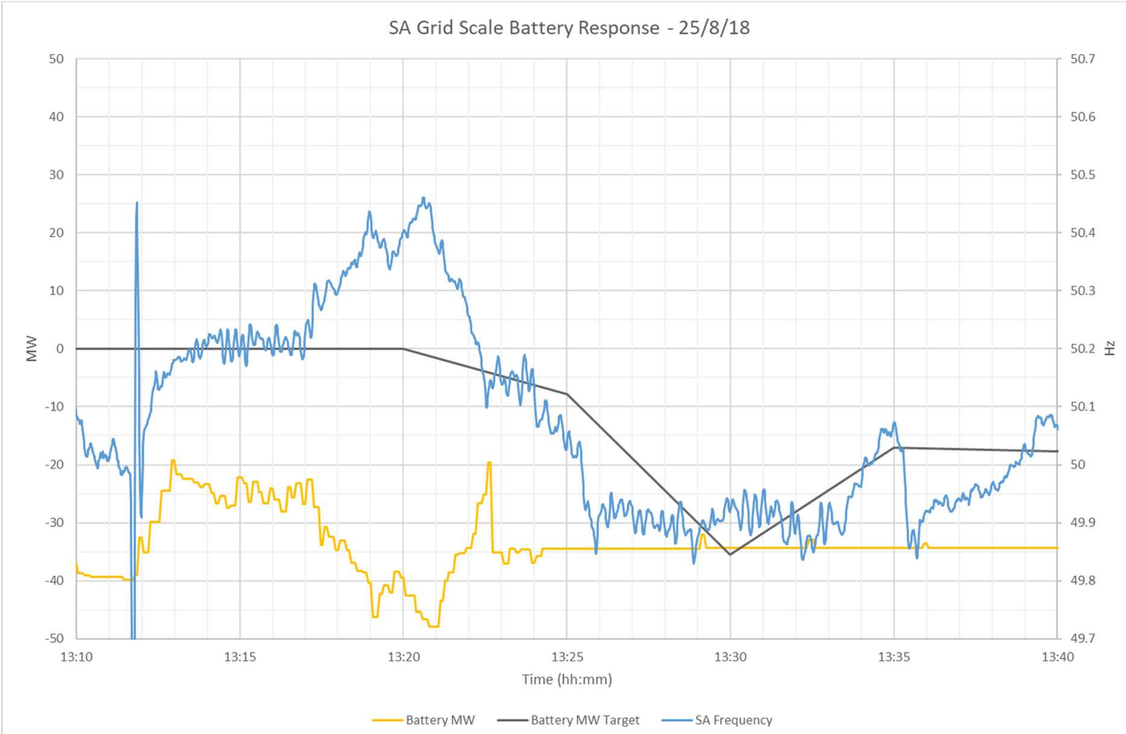
A larger and faster active power response from installed battery systems for the same frequency change would further increase the likelihood of triggering the EAPT scheme, and islanding of SA in any future system events. As a result of these recent and continuing developments in the SA power system, the design settings of the EAPT scheme now require review.

4.9.12 SA transmission-connected batteries – longer-term response

Figure 42 shows the longer-term response of the Hornsdale battery during this event.

While frequency remained within its frequency response dead-band, the battery followed AGC setpoint changes. These setpoints were based on both energy market dispatch and provision of regulation FCAS services. When frequency in SA was outside its frequency response dead-band, the Hornsdale battery also provided frequency response additive to its AGC base point, based on proportional droop control.

Figure 42 SA transmision-connected battery response – longer-term

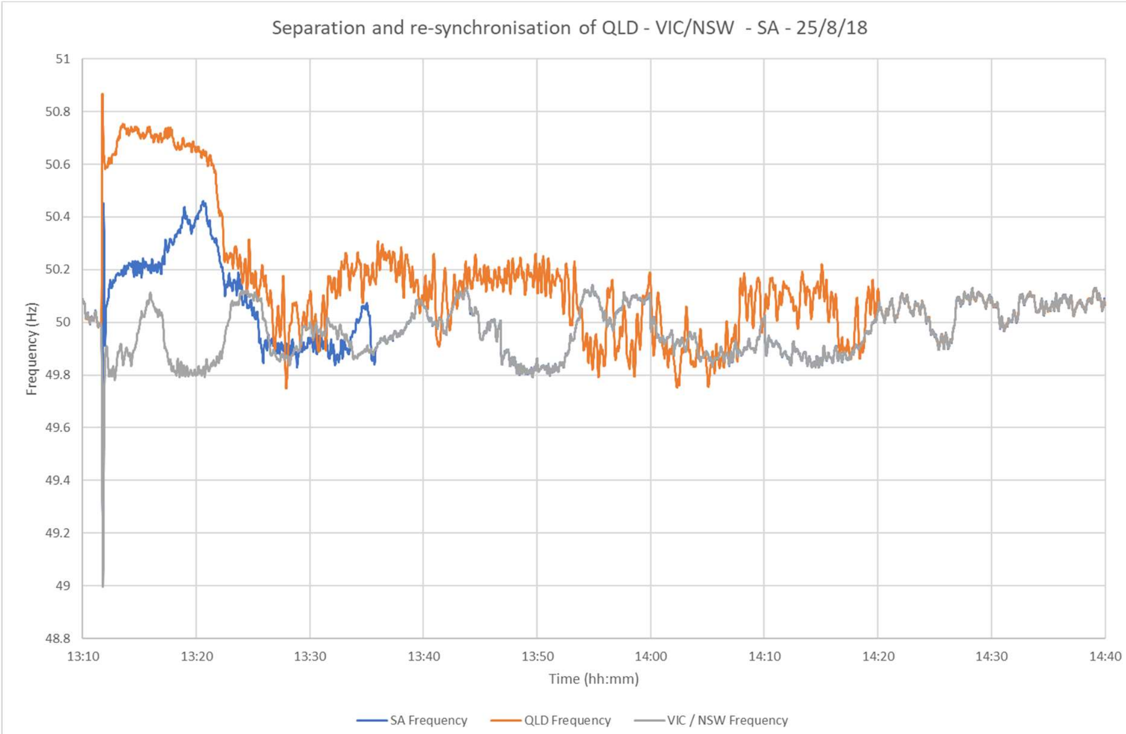


4.10 Victoria and New South Wales

Figure 43 shows frequency in VIC, NSW, SA, and QLD during the event, covering the period of separation of SA from VIC, and QLD from NSW, up to and including resynchronisation of these regions. The VIC region remained connected to NSW throughout the event and remained connected to TAS via the Basslink HVDC interconnector.

As shown in Figure 43 , following the initial loss of QNI at a transfer of around 857 MW, and subsequent loss of infeed from SA of around 170 MW, frequency declined at a rate of around -0.12 Hz/sec in VIC and NSW, reaching a minimum of 48.95 Hz at 13:11:48.1, 6.9 seconds after the loss of QNI.

Figure 43 QLD, VIC/NSW, and SA frequency



4.10.1 VIC and NSW interruptions to load

In NSW and VIC, 997.3 MW of uncontracted UFLS occurred between 13:11:47.6 and 13:11:48.1, after frequency fell below 49 Hz. The load interruption comprised 904 MW of smelter load in both NSW and VIC, and 93.3 MW of other industrial, residential and commercial load in NSW.

This load shedding was sufficient to replace the original loss of power flow from QLD and SA, with frequency in VIC and NSW initially recovering to around 49.9 Hz.

4.10.2 VIC and NSW generation pre-event

Table 12 and Table 13 list the pre-event output of generation in VIC and NSW.

Table 12 Pre-event generation – VIC

Generation technology	Generation output (MW)	Online capacity (MW)
Synchronous	3777.4	3,759
Wind	7.7 plus 14 non-scheduled = 21.7	1,523
Transmission-connected PV	38.4	53
Distributed PV	862	1,349

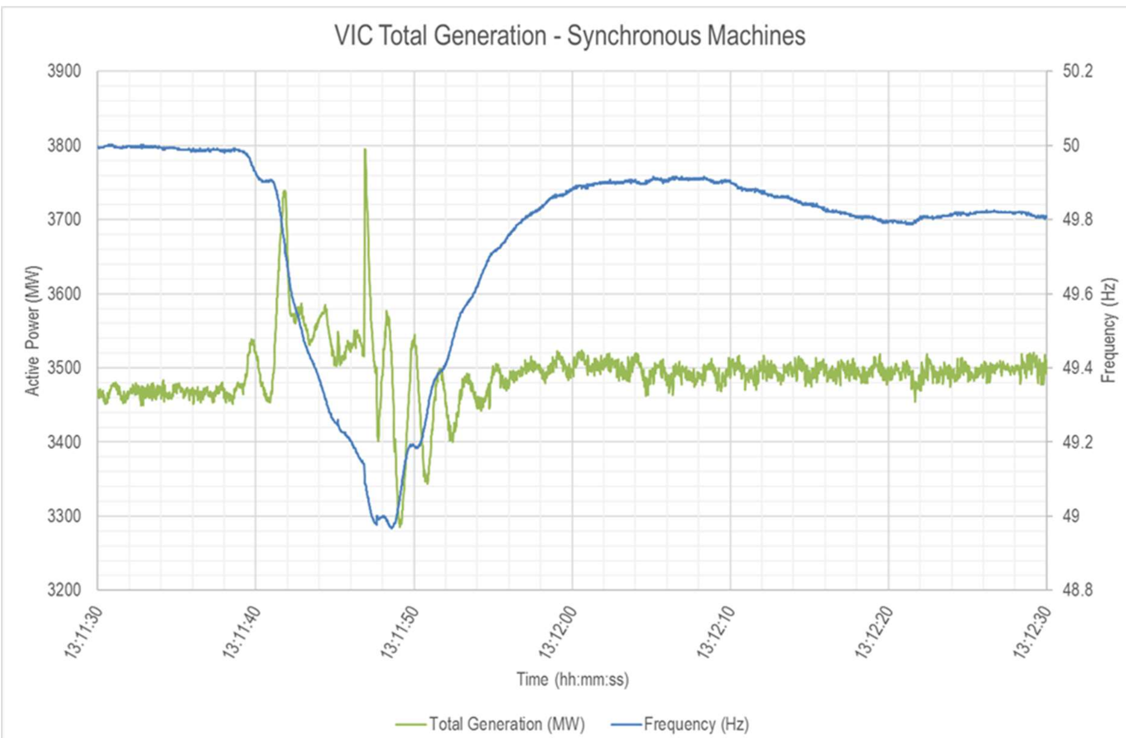
Table 13 Pre-event generation – NSW

Generation technology	Generation output (MW)	Online capacity (MW)
Synchronous	6,263	8,339
Wind	94.2	1,385
Transmission-connected PV	97 plus 38 non-scheduled = 135	398
Distributed PV	526	1,709

4.10.3 VIC synchronous generation – short-term response

Figure 44 shows the aggregate output of synchronous generation in VIC.

Figure 44 Aggregate VIC synchronous generation response – short-term



The FCAS service relevant over the early part of an under-frequency event is R6 – fast contingency raise FCAS. This service provides a firm MW reserve, or headroom, to be delivered within 6 seconds, to assist in arresting an initial decline in frequency following a contingency event.

Three VIC synchronous units were enabled to provide an aggregate total of 17 MW of R6 FCAS for the DI ending 13:15. A further 43 MW of R6 was enabled in VIC via switched load reduction.

There was some transient inertial response from VIC synchronous generation, particularly immediately after the initial loss of QNI and subsequent separation of SA at Heywood. Figure 44 shows that synchronous generation in VIC provided 100 MW of sustained and controlled active power response prior to the frequency nadir, as frequency declined from 50 Hz to just below 49 Hz.

4.10.4 VIC synchronous generation raise capability

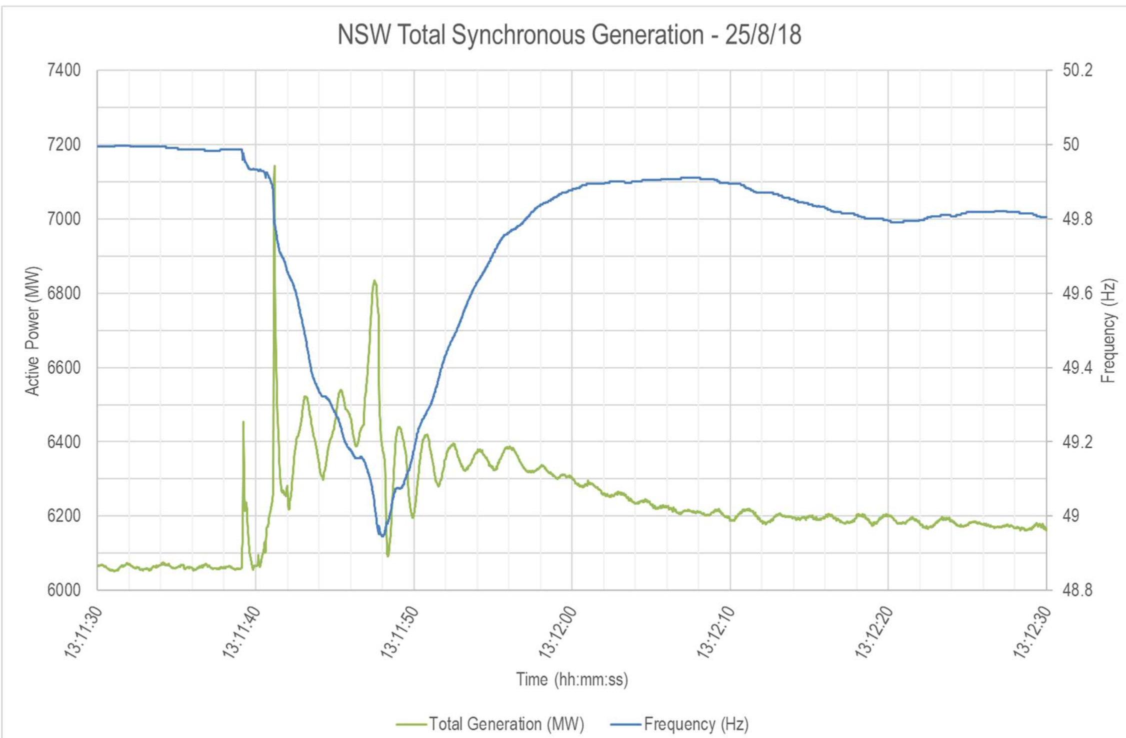
At the time of the event, all but one of the online synchronous generating units in VIC were operating at their maximum offered availability in the energy market, with several units already operating above rated or 'nameplate' capacity. As a result, there was little headroom for synchronous generation to provide sustained increase in output, particularly over periods of minutes, irrespective of either control system settings or FCAS market outcomes.

However, the ability of units to provide short-term frequency response, on timeframes of seconds rather than minutes, is more complex. Some thermal units are capable of providing a short-term response, particularly using short-term energy stored in power stations steam systems. This is dependent on the design, operating practices, and control systems of individual units.

4.10.5 NSW synchronous thermal generation – short-term response

Figure 45 shows the aggregate output of synchronous generation in NSW.

Figure 45 Aggregate NSW synchronous generation response – short-term



Eight NSW synchronous units were enabled to provide an aggregate total of 145 MW of R6 contingency raise FCAS for the DI ending 13:15, with amounts between 11 MW and 20 MW allocated to individual units. A further 16 MW of R6 FCAS was enabled in NSW via switched load reduction.

Figure 45 shows that up to 370 MW of controlled increase in MW output was delivered from synchronous generation in NSW, as frequency declined from 50 Hz, prior to the nadir at 48.95 Hz. This response was oscillatory. There was an additional, unavoidable inertial response, and a further large oscillatory component overlaid. As this increase in active power was delivered before the frequency nadir was reached, it contributed to arresting the fall in frequency.

Around 100 MW of sustained increase in output was ultimately delivered in NSW from synchronous generation, in response to system frequency ultimately settling around 49.8 Hz.

There is a 2,000 MW difference in Table 13 between NSW synchronous generation output and online rated capacity. However, the actual headroom available on NSW generation to provide sustained increase in output during the event was much lower than this, because the capacity offered into the energy market for several large thermal units was well below their full rated, or 'nameplate' capacity. As noted in relation to VIC synchronous generation, the ability to provide short-term frequency response is more complex. Some units can provide a short-term response for periods of seconds, above the level that can be sustained for periods of minutes.

4.10.6 VIC/NSW synchronous generation – aggregate response

The VIC and NSW frequency response from synchronous generation in the period prior to UFLS was estimated at around 470 MW. This represents a 3.7% change in output, based on the 12,100 MW online capacity listed in Table 12 and Table 13. As this was delivered for a 2% change in frequency to 49 Hz, this represents an aggregate system droop characteristic of over 50%, as delivered within this relatively short timeframe.

Even allowing for headroom limitations on a range of units, particularly in VIC, limitations on units' ability to respond rapidly over short timeframes, and the complexities of response provided from SA via the Heywood interconnector prior to its separation, this outcome compares poorly with typical international requirements for all technically capable generation to operate with droop responses in the range 3-5%.

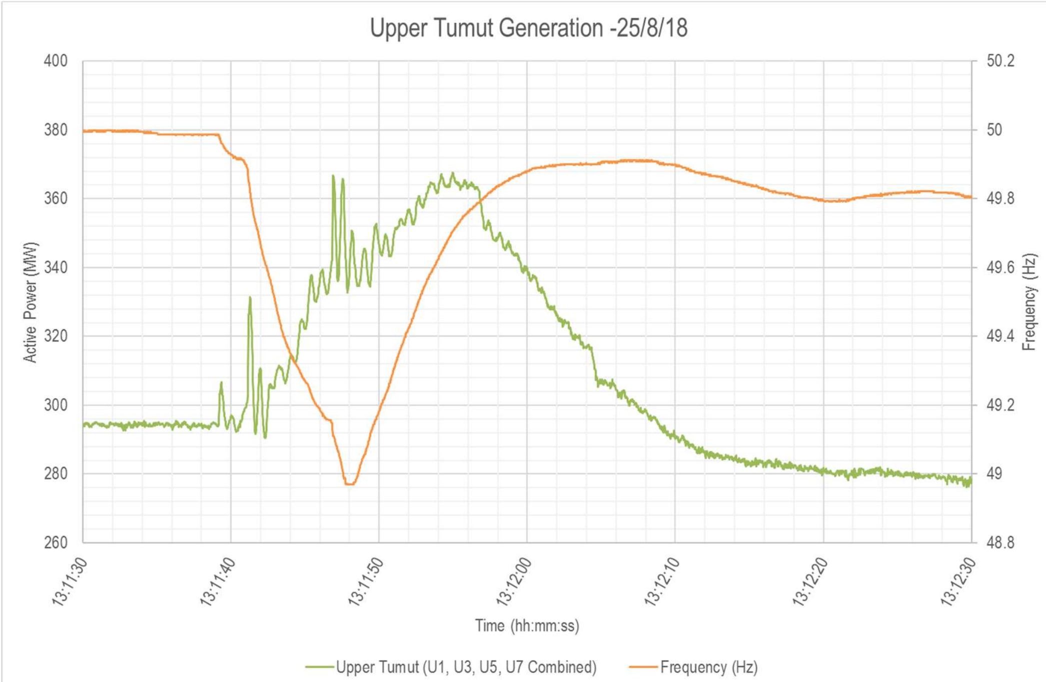
As discussed earlier in this report in relation to QLD generator response, it is vital for the resilience of the power system to large, non-credible events of this type that all generation respond to correct frequency generation to the extent of their capability. This will minimise the amount of uncontracted load shedding that occurs via UFLS for under-frequency events, and more fundamentally, provide support to arrest, stabilise, and correct large deviations in power system frequency.

4.10.7 NSW synchronous hydro generation response

There was around 250 MW of headroom available between the actual generation and the capacity offered to the energy market on Upper Tumut hydro power station immediately prior to the frequency events. Though not enabled to provide any raise response in the contingency FCAS market, Upper Tumut increased output by 50 MW prior to the frequency nadir, as shown in Figure 46.

The individual responses of other synchronous units in NSW show a range of increases in output, often overlaid with a significant inertial component, and oscillations in the active power response. The observed MW response from Upper Tumut was larger than from thermal units in NSW.

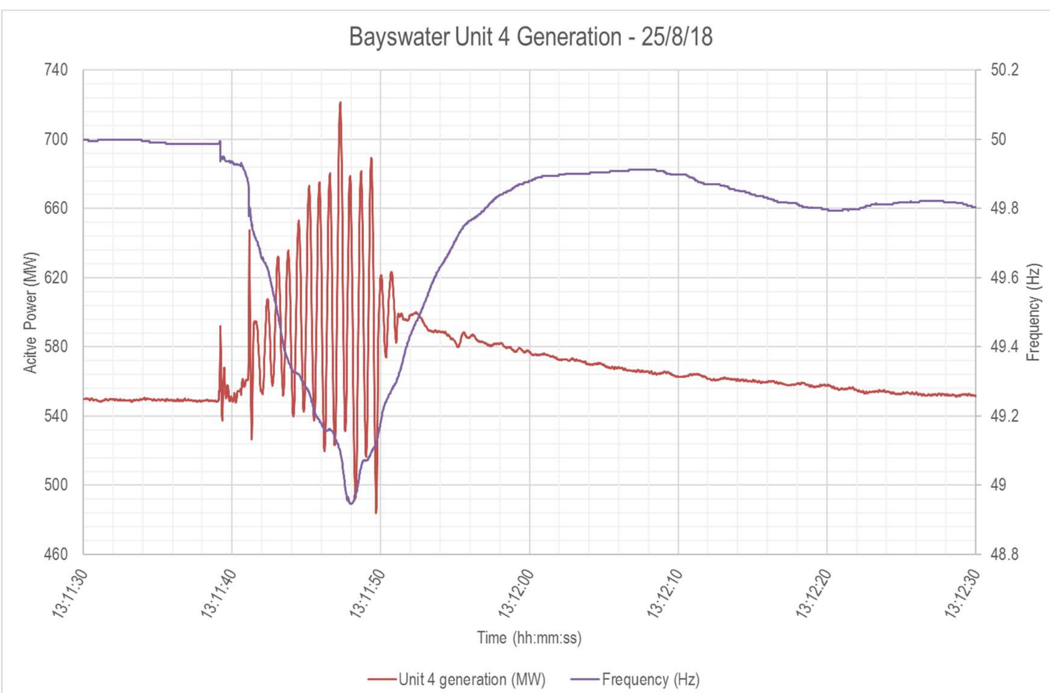
Figure 46 Upper Tumut response



4.10.8 NSW active power oscillations

As shown in Figure 47, immediately after the disconnection of QNI, large, undamped oscillations were observed on active power output of Bayswater unit 4, with a frequency of around 1.2 Hz. The oscillations ceased once NSW frequency started to recover. This is not a desired or compliant response.

Figure 47 Bayswater unit 4 response



The Bayswater Power Station operator notified AEMO shortly after the event of this unstable response. Bayswater Unit 4 was excluded from contingency FCAS markets while the response was investigated.

The excitation systems at Bayswater Power Station have been in service since original commissioning. The analogue control hardware is separated into discrete control sections, with a duplicate controller structure identified as Channel 1 and Channel 2. The automatic excitation regulator channels are configured to be as near identical as possible and are intended to be used as an active channel and a hot standby channel. Channel 2 was the active channel at the time of the incident.

Very soon after the incident, AGL engaged DIgSILENT to investigate possible causes of the undamped behaviour on Unit 4. DIgSILENT provided an interim report on 29 September 2018. Key DIgSILENT findings and observations were:

- V/Hz limiter analogue settings had 'drifted'. As found setting was at 1.027 for Channel 2 (active at the time). DIgSILENT adjusted the settings to its design value of 1.05.
- One Power System Stabilizer speed path (lead-lag) had a damaged potentiometer (this has since been replaced).

AEMO also determined that Unit 4 reactive power was deep in under-excitation territory during the oscillations which could have contributed to the undamped behaviour. The excitation system is due for replacement in 2019.

Similar, but lower amplitude, oscillations in active power output were observed from other synchronous generators in NSW, probably in response to the oscillations occurring at Bayswater Unit 4. Figure 48 and Figure 49 show active power oscillations on Vales Point Unit 6 and Liddell Unit 4, which were typical of several other synchronous units in NSW.

Figure 48 Vales Point Unit 6 response

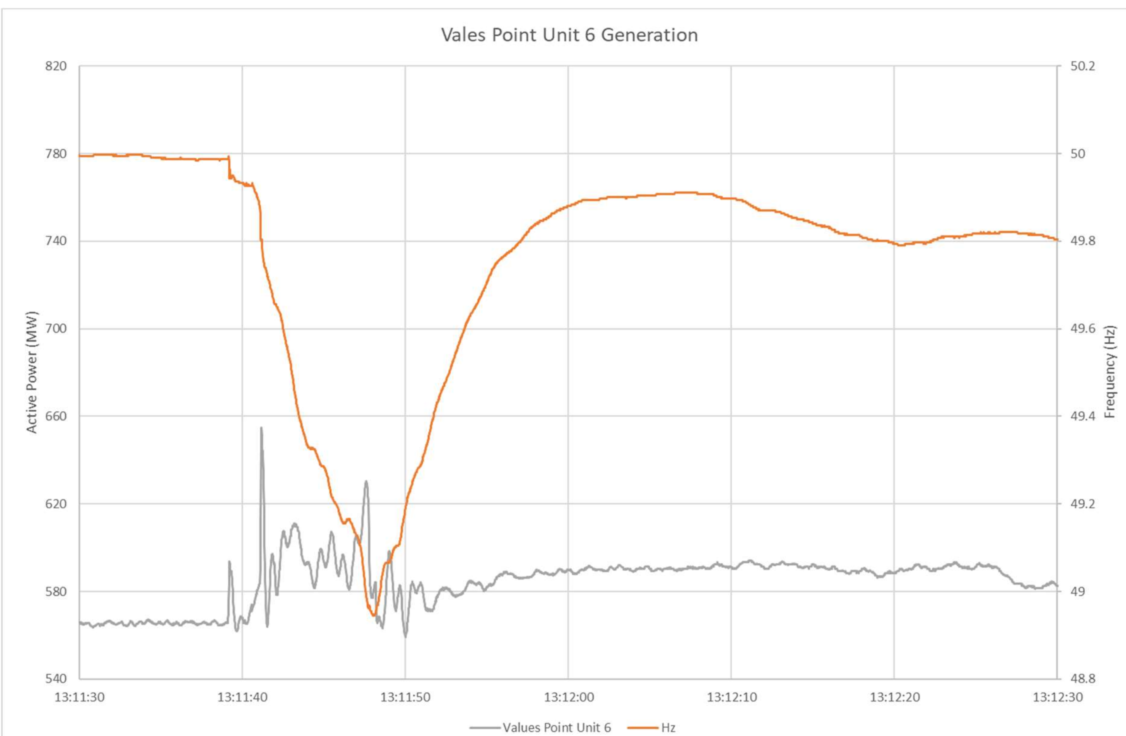
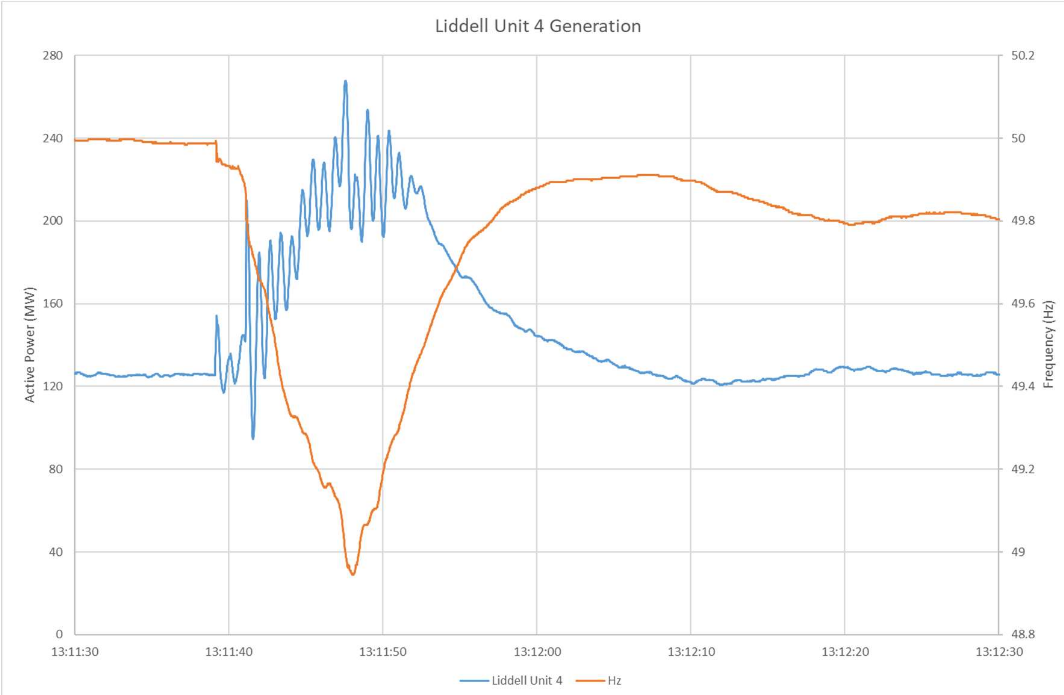


Figure 49 Liddell Unit 4 response



4.10.9 VIC and NSW synchronous generation – longer-term response

Figure 50 shows the output of synchronous generation in VIC, and frequency in the VIC and NSW regions. Figure 51 shows the output of synchronous generation in NSW.

Figure 50 Aggregate VIC synchronous generation response – longer-term

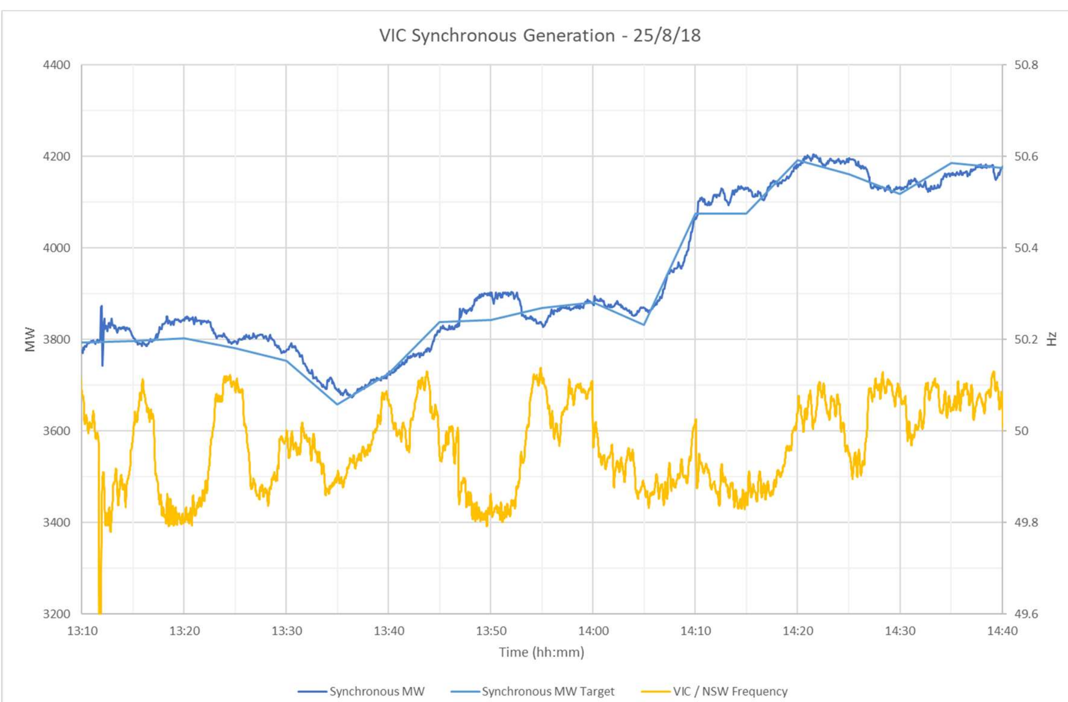
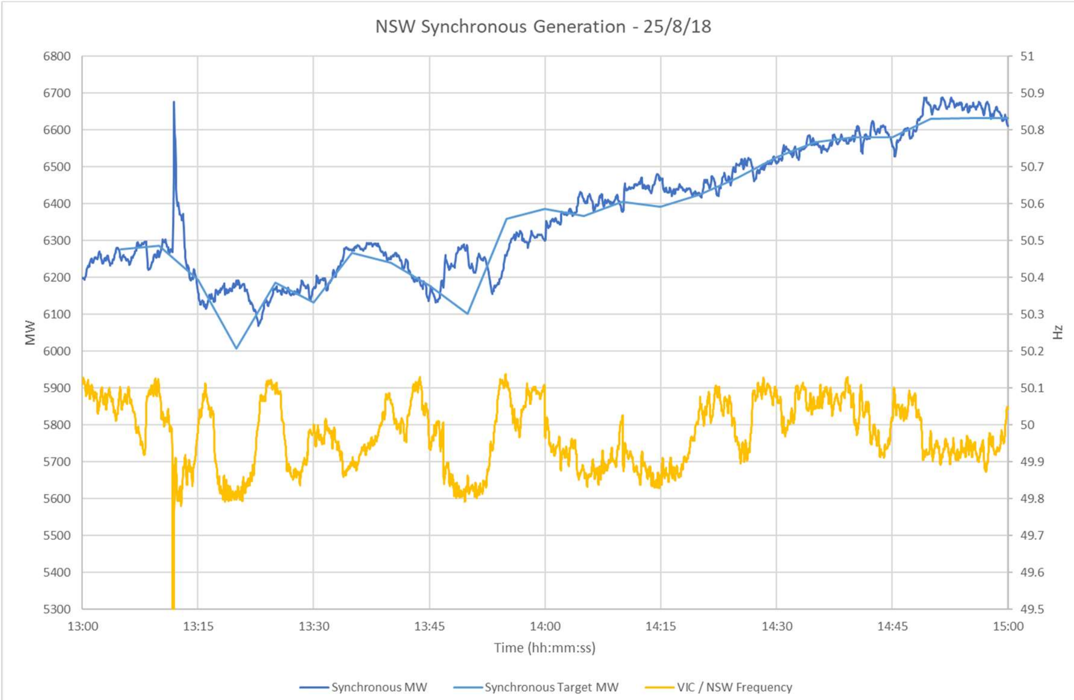


Figure 51 Aggregate NSW synchronous generation response – longer-term

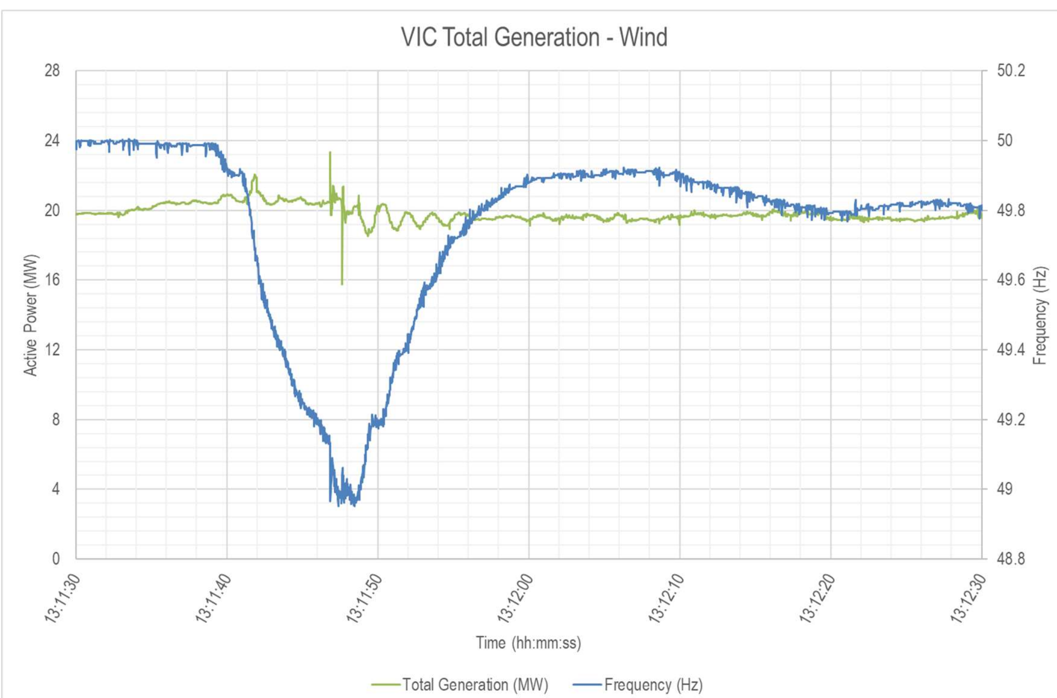


No disconnection of synchronous generation in VIC and NSW was observed during this event.

4.10.10 VIC wind generation – short-term response

Figure 52 shows the short-term response from VIC wind generation.

Figure 52 Aggregate transmission-connected wind generation response – short-term

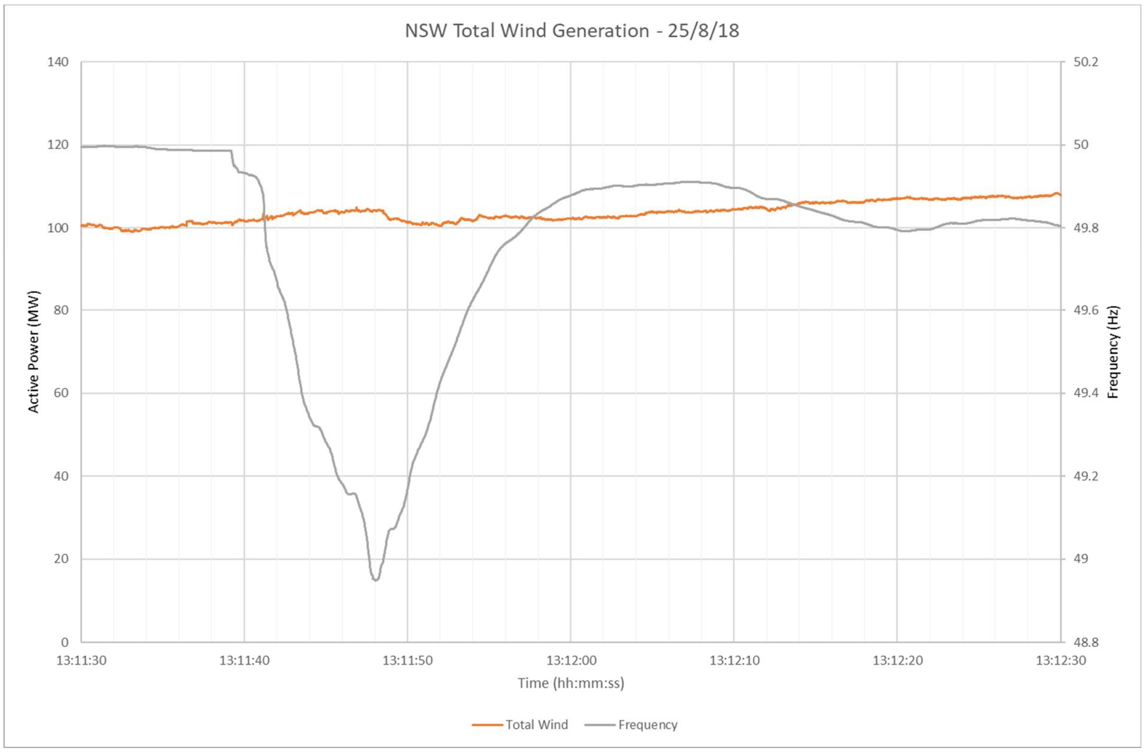


While installed VIC wind capacity was around 1,520 MW at the time of the event, due to low wind conditions wind generation was only around 20 MW. No material change in short-term wind generation output was observed in response to the decline in system frequency.

4.10.11 NSW wind generation short-term response

Figure 53 shows the aggregate response of operating wind generation in NSW. As expected, no change in short-term wind generation output was observed in response to the decline in system frequency.

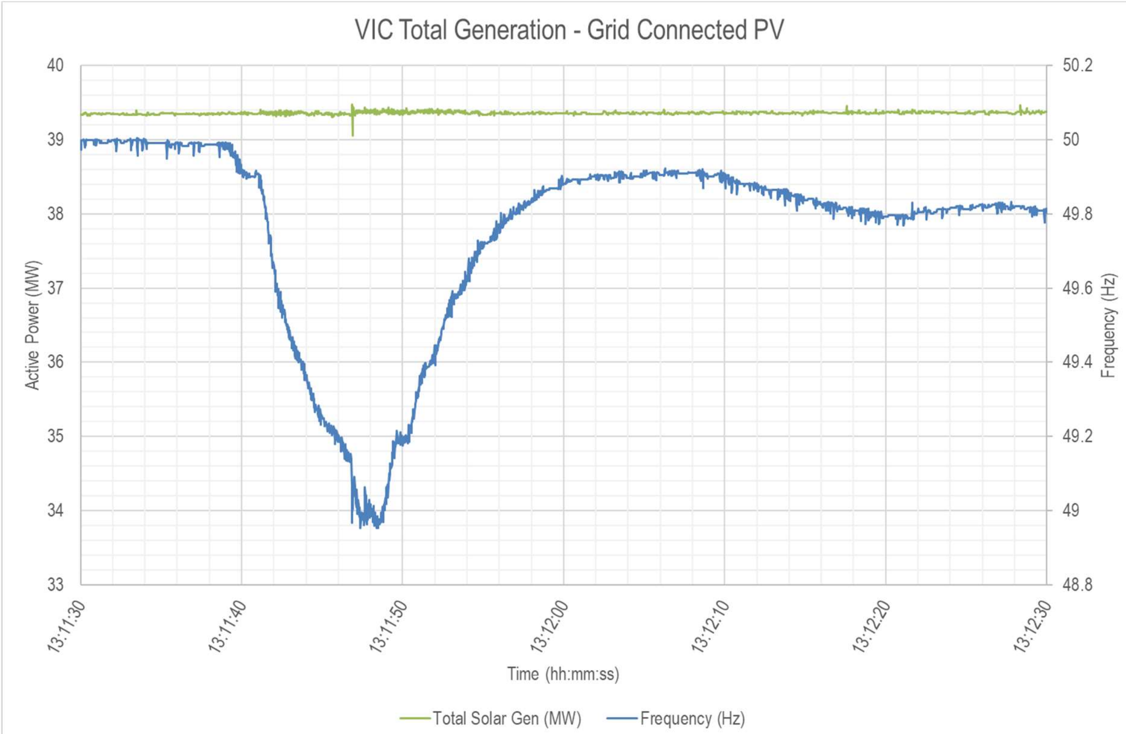
Figure 53 Aggregate NSW transmission-connected wind generation – short-term response



4.10.12 VIC transmission-connected PV generation – short-term response

Figure 54 shows the output of the 53 MW Gannawarra solar farm, the only large-scale PV generator in VIC in operation at the time of the event. As expected, there was no response from the solar farm, as no headroom was available to increase output during this under-frequency event.

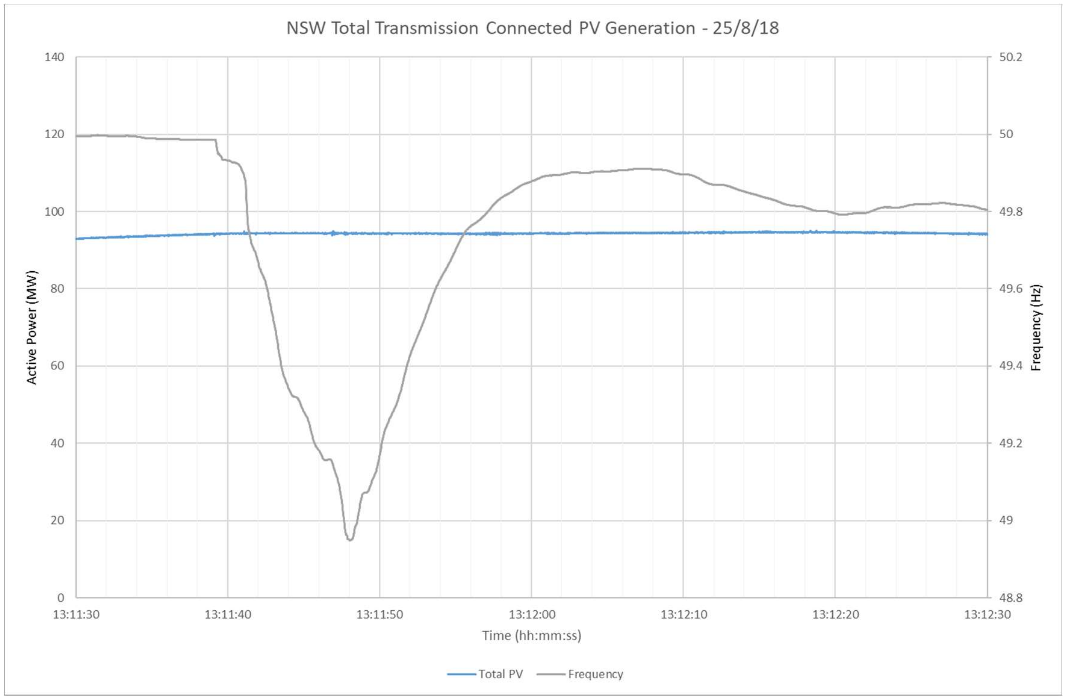
Figure 54 Aggregate VIC transmission-connected PV response – short-term



4.10.13 NSW transmission-connected PV generation – short-term response

Figure 55 shows the aggregate response of 211 MW of the 398 MW of total installed NSW transmission-connected PV generation for which AEMO has obtained high speed monitoring data. As expected, no frequency response was noted. There is no evidence of response from other transmission-connected PV generation in NSW.

Figure 55 Aggregate NSW transmission-connected PV response – short-term



4.10.14 VIC/NSW wind and large-scale PV generation – longer-term response

Figure 56 and Figure 57 show the output of wind and transmission-connected PV generation in VIC and NSW.

In both regions, the changes in output from these generators were small and do not appear to have been material to frequency control in this event.

Figure 56 VIC transmission-connected wind and solar generation response – longer-term

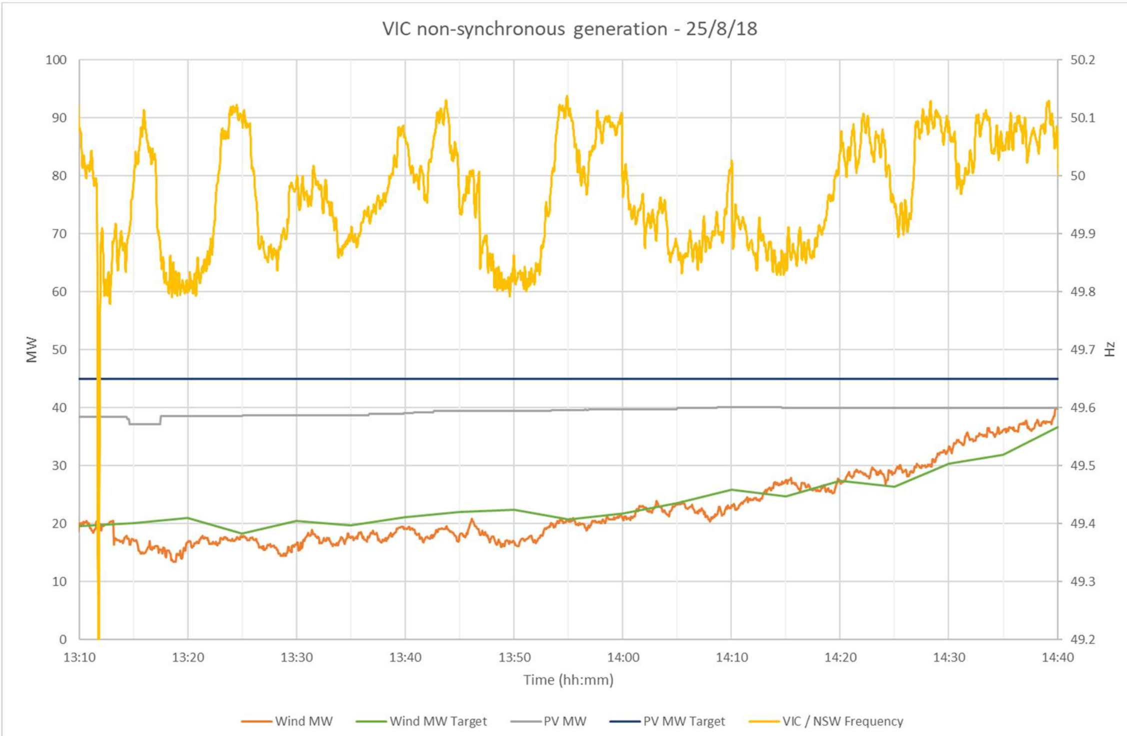
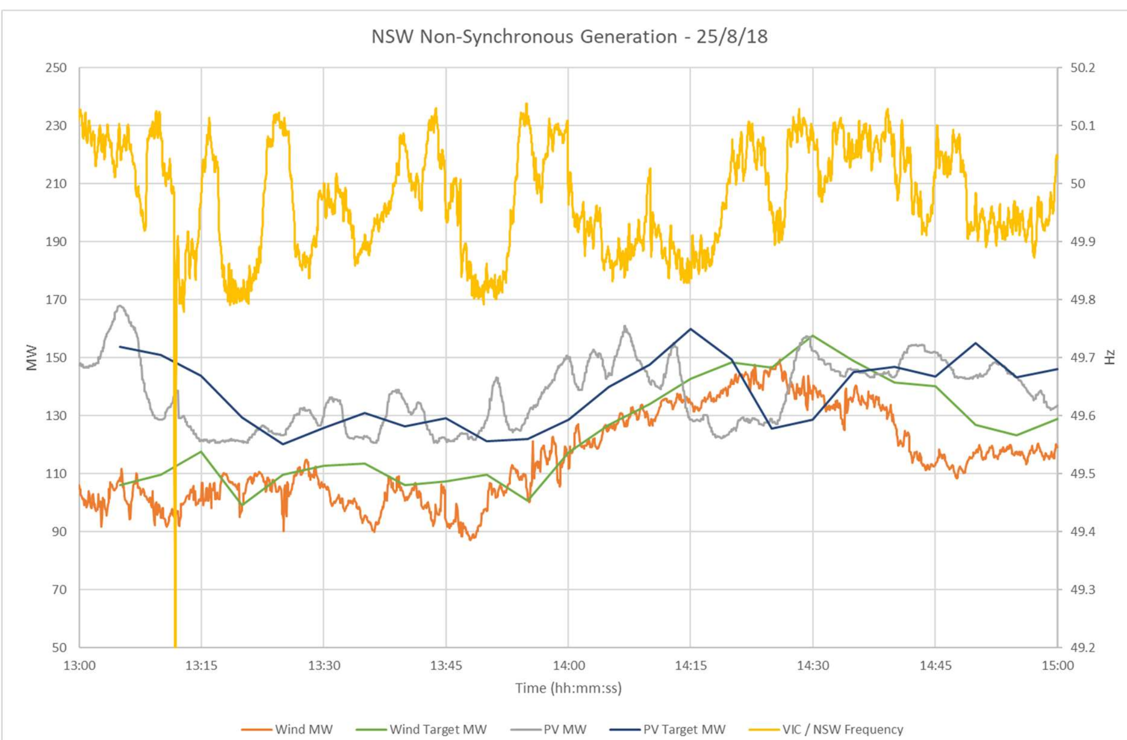


Figure 57 NSW transmission-connected wind and solar generation response – longer-term



4.10.15 VIC/NSW distributed PV generation – short-term response

Table 14 VIC – behaviour of distributed PV systems

	Percentage of sites that disconnected*	Proportion of observed generation reduction attributable to disconnections	Frequency response	Voltage response
2005 Standard (systems installed prior to Oct 2015)	10%	~100%	As for NSW, AEMO's survey of frequency trip settings suggests ~17% of systems should disconnect.	There was no significant voltage disturbance experienced in VIC.
2015 Standard (systems installed after Oct 2016)	8%	~100%	As for NSW, systems installed under the 2015 standard should remain in continuous, uninterrupted operation until frequency reaches 47Hz, which did not occur during this event.	There was no significant voltage disturbance experienced in VIC.

* Based on monitored sample sites. Disconnection is inferred from generation at a site suddenly reducing to zero.

Table 15 NSW and ACT – combined behaviour of distributed PV systems

	Percentage of sites that disconnected*	Proportion of observed generation reduction attributable to disconnections	Frequency response	Voltage response
2005 Standard (systems installed prior to Oct 2015)	26%	~70% (remainder likely attributable to shading)	Frequency was below 49Hz for 0.73 seconds. AEMO's survey of manufacturer's default settings** suggested that 17% of devices installed in the NEM as of May 2015 have frequency trip settings within this range. This suggests that some of the observed disconnections are due to frequency trip settings, in line with expectations.	The fault at QNI may have caused further disconnections based on inverter exposure to under-voltage, especially in Northern NSW. This is consistent with the spatial trends observed (a higher proportion of disconnections occurred closer to the fault location.
2015 Standard (systems installed post Oct 2016)	10%	~88% (remainder likely attributable to shading)	AS/NZ4777.2-2015 requires inverters installed from Oct 2016 to remain in continuous, uninterrupted operation until frequency reaches 47Hz for a duration of at least one second. Inverters on this standard should not have disconnected due to the frequency experienced during this event.	The fault at QNI is a likely cause of observed disconnections in Northern NSW based on inverter exposure to under-voltage. This is consistent with the spatial trends observed (a higher proportion of disconnections occurred closer to the fault location.

* Disconnection is inferred from generation at a site suddenly reducing to zero.
** AEMO, April 2016, Response of existing PV inverters to frequency disturbances, available at https://www.aemo.com.au/-/media/Files/PDF/Response-of-Existing-PV-Inverters-to-Frequency-Disturbances-V20.pdf.

4.10.16 Summary of response in NSW and VIC prior to load shedding

The loss of active power import from QLD and SA into the combined NSW/VIC area was 1,030 MW during this event. To avoid UFLS, this loss of import must be replaced before the resulting frequency decline reaches 49 Hz.

The following factors were observed acting to arrest the decline in frequency in the VIC and NSW regions:

- Increased supply into VIC from Basslink of around 130 MW (described further in the section on the TAS response).
- Controlled frequency response from synchronous generation in VIC and NSW – estimated at around 100 MW and 370 MW respectively.
- Load reduction in VIC and NSW via switched FCAS services – measured at 14 + 26 MW (based on data obtained from FCAS providers).

The estimated loss of 190 MW of distributed PV generation in VIC and NSW described earlier will have contributed to the decline in frequency during this event.

A range of smaller load and generation loss events were also reported by distribution network businesses and small generation operators during this event. These include:

- Loss of 36 MW of industrial load in VIC due to the frequency change.
- Estimated loss of 13 MW of embedded generation, at five sites in VIC, due to frequency changes.
- Loss of eight small generating units across VIC, NSW, QLD, and ACT. Output of these units is unknown.

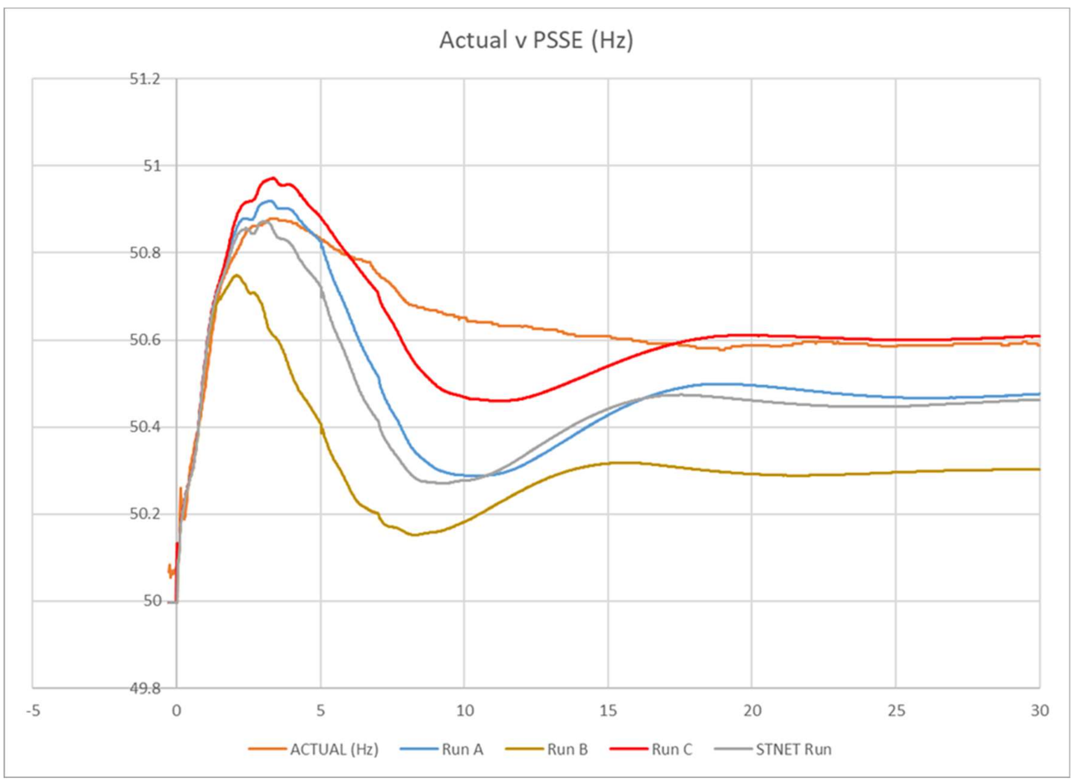
5. AEMO models and simulations

AEMO records power system snapshots along with associated validated PSS/E® dynamic modelling data in its Operations and Planning Data Management System (OPDMS). These are referred to as R2 models and are validated during generator commissioning tests to verify and update the model accuracy. R2 validated models are the most accurate and accessible models available for modelling whole of system performance. Relevant system snapshots and dynamic simulation model data for this event were downloaded from OPDMS, where available, and used to simulate the observed system frequency response.

5.1 Queensland models

Figure 58 below shows the actual frequency trajectory in the QLD region and several different simulated trajectories for this event. Manual adjustments were made to QLD synchronous machine governor models between these different simulation runs.

Figure 58 Actual vs simulated frequency – QLD region



Although the simulated and actual frequency trajectories appear reasonably well aligned in some simulations, closer examination of individual generation responses shows poor alignment between simulated and actual responses. The following was specifically observed:

- Synchronous generator governor models in the QLD region significantly over-estimated the frequency response delivered during this event.

- Many synchronous generators online in QLD during this event do not have a governor model available in OPDMS, including several of the largest units in QLD. In simulation these units were modelled as operating with locked governors.
- Only two of the grid-scale PV plants in QLD online during this event currently have R2 validated simulation models available in OPDMS.
- Alignment between actual and simulated response was improved for several important QLD units by removing the available governor models, as the actual unit response was significantly lower than that predicted by the simulation models.

The apparent alignment of system frequency trajectory at the whole of system level in Figure 58 appears to represent the combination of a range of differences in individual simulated generating unit responses effectively cancelling each other out.

As noted earlier, there was material frequency response from all but one of the transmission-connected PV generation plants in QLD, with a range of delivery speeds observed for this response. Manual adjustments were made in the simulations shown in Figure 58, to account for the observed response of new entrant PV generation without available simulation models during this event.

In addition to generation response, the frequency trajectory of the QLD region was also affected by a reduction in output from distributed PV systems as described earlier. This is not included in current load models used by AEMO. Existing bulk load models used by AEMO also assume a load relief factor of 1.5% for each 1% change in system frequency. As noted earlier, actual system frequency response in the VIC/NSW area suggests load relief may have been lower than the historically assumed 1.5% during this event.

5.2 Victoria and New South Wales models

The system frequency response in the NSW and VIC region in the period prior to UFLS was more complicated than QLD, due to the injection of power from TAS via Basslink, reduction in load from switched FCAS providers in VIC and NSW, and the frequency response of SA units via the Heywood interconnector before SA disconnected.

As noted earlier, there was also demand-side response from distributed PV generation in VIC and NSW. Distribution businesses in VIC and NSW advised AEMO of many smaller changes in both generation and load in their supply areas in response to the system frequency changes, although the timing of these changes is not known. These demand-side responses are not included in existing load models.

Investigation of the model data for NSW and VIC concluded:

- Only one synchronous generator online in NSW during this event has a turbine governor model available in OPDMS.
- None of the synchronous generators in VIC region online during this event currently include a turbine governor model.

Due to the lack of R2 validated turbine governor models, AEMO was unable to simulate frequency response of the NSW and VIC region during this event.

The PSS/E modelling software used by AEMO has historically limited the total number of custom user-written dynamic models that could be used in a simulation. The NEM has many custom user-written dynamic models, particularly for excitation control systems. Many of the turbine governor models developed for NEM generation have also been custom user-written models.

These software limitations, along with a focus on system stability problems associated with the performance of excitation control systems, have led to a lower focus by manufacturers on the maintenance of turbine governor models across the NEM. Recent versions of the PSS/E software allow a higher number of custom user-written dynamic models to can be used in simulations.

6. Comparison to 2008 separation event

On 28 February 2008 at 05:43, a non-credible event in NSW led to the loss of the QLD – NSW DC connection known as Directlink and the loss of QNI. In 2018 Directlink remained connected. Table 16 below shows a comparison of the conditions and impact of the 2008 QLD separation with the 2018 QLD separation:

Table 16 QNI Separation event comparison 2008 and 2018

	2008	2018
Date / Time of day	28 February, 05:43	25 August, 13:11
Net power loss QLD to NSW	1,091 MW	870 MW
Other regions separated	NIL	South Australia
Net power loss to NSW / VIC regions	1,091 MW	1,040 MW
Max frequency QLD	50.62 Hz	50.9 Hz
Min frequency NSW	49.55 Hz	48.85 Hz
Load interrupted	0 MW	997.3MW UFLS 82 MW Contracted

The magnitude of the initiating events in each case was fairly similar (about 200 MW higher in 2008). However, the resilience of the system in 2018 is substantially lower than in 2008, evidenced by the larger frequency deviation for what was initially a smaller power loss across QLD to NSW.

In 2008 20 MW of contingency lower FCAS was enabled within QLD prior to the event, compared with 0 MW in 2018. The 2008 event took 9 minutes to operate within the stable island operating band and the 2018 event took 10 minutes and 8 seconds; both are of a similar order.

In both events, the AGC was not established independently in QLD for several minutes and the relevant constraint equations required two dispatch intervals to become invoked, a symptom of NEMDE design and dispatch processes. As such, the same counterproductive actions from NEMDE and the AGC were experienced in 2008 as in 2018.

Both events saw Queensland insecure for the duration of the separation event due to the inability to procure the desired volumes of contingency raise and lower FCAS from within the Queensland island.

A key difference is that in 2018 we can observe that the online generation mix and time of day can significantly impact the scenario for better or worse. In 2008 the generation mix was constant and predictable. In 2018 the variation in supply technologies and frequency response is wide, far more distributed and significantly less certain, with responses driven more by computerised control settings than known physical properties. Immediately before the 2018 event only about 4% of NEM generation was from non-synchronous wind and solar sources; this value could have been very different at another time. AEMO's review of the incident for this report has yielded much-needed data for analysis on the frequency response of many technologies during major under and over frequency excursions in the NEM.

7. Conclusions and recommendations

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:

- The trip of QNI 330 kV transmission line was the result of a lightning strike.
- Reclassification decisions before and after the event were appropriate and consistent with the relevant reclassification criteria.
- The QNI protection and control schemes operated as designed, although the design did not cater for this event. Changes have been made by Powerlink and TransGrid to cover similar events in future.
- The FOS in Queensland was marginally exceeded. AEMO is satisfied that it used all reasonable endeavours to meet the applicable standard.
- The AUFLS scheme in Tasmania operated as expected to provide an effective Raise FCAS service.
- The UFLS in NSW and VIC operated correctly and as expected
- Non-compliant performance of four wind and two thermal generating systems was identified as a result of the event, with operators providing all relevant information to AEMO.
- The EAPT scheme operated as designed, although the design did not cater for this event. The EAPT scheme is to be reviewed by AEMO.
- There was a delay in synchronising the QLD and NSW networks due to the lack of frequency control available in QLD.
- Distributed (rooftop) PV response suggested a material percentage of systems may not be compliant with the applicable Australian standard.
- The power system in QLD was not in a secure operating state for the entire 68-minute period of separation from NSW. While AEMO took all reasonable steps to return the power system to a secure operating state, during this period AEMO could not procure enough contingency raise FCAS to cover the loss of the largest generator (Kogan Creek) or contingency lower FCAS to cover the loss of the largest load (Boyne Island smelter) from within QLD. Re-connecting QLD with NSW enabled the FCAS requirements for QLD to be met from other regions. The actions taken by AEMO were appropriate and in accordance with the NER and published procedures.

This event saw a loss of supply into the VIC/NSW/TAS region of the NEM of 1,030 MW, resulting in 997.3 MW of uncontracted load interruption.

A key contributing factor to the need for uncontracted load interruption was limited primary frequency control from generators across the NEM, which had no obligation, and no commercial incentive, to provide an immediate response to the changed conditions.

Another contributing factor was the distribution of enabled contingency lower FCAS reserves across the NEM at the time of the event, with none in QLD where it was needed after the separation of QLD from the NEM. By design, there is no regional allocation of these reserves to allow for the possibility of non-credible contingency events resulting in frequency islands.

Lack of frequency response, particularly from many of the synchronous generation fleet, seen during this event highlights the potential for severe adverse consequences of current arrangements that:

- Allow plant not to provide frequency control capability when not enabled for one of the existing FCAS markets. Generators were following their dispatch targets as required under the NER, even though the dispatch targets were contrary to improving the frequency in most cases.
- Allocates contingency and regulation FCAS reserves without consideration to geographical dispersion, assuming the NEM is a single bus for frequency response purposes, other than for credible transmission contingencies.
- Rely increasingly heavily on uncontracted interruption of customer load following events larger than the credible contingency events provided for in FCAS markets. Historically, frequency response beyond the procured FCAS reserves could broadly be relied on to minimise the probability of such load interruption, but AEMO's analysis of this event and other studies AEMO has been completing, demonstrates this is no longer the case.

This event demonstrates the extent of the decline in system resilience, and its correlation with the reduction of continuous primary frequency control over the past several years. Restoring primary frequency control is essential to reversing the decline in resilience. AEMO considers that action to address the resulting risks is required as soon as possible, recognising that a longer-term mechanism to appropriately incentivise the provision of primary frequency control is necessary, but will take some time to develop.

The AEMC recognised the possibility of such interim measures in its Frequency Control Frameworks Review[12] if a need was established to address the degradation of frequency performance before a longer-term mechanism could be implemented. At the time of finalising the AEMC's report, published only a month before this event, AEMO advised that there was no immediate need for those measures, pending completion and assessment of a range of short term investigative actions, including primary frequency control trials across the NEM. However, AEMO's analysis of this event has provided compelling evidence that prompt interim action is required to require the provision of sufficient frequency response from capable generators.

The event revealed a range of disparate frequency responses, including responses that combined to exacerbate frequency deviations, delaying recovery and resynchronisation, between QLD and NSW in particular. Analysis of these responses has highlighted:

- The need for frequency response to be rapid (seconds to minutes), to be effective in arresting rapid changes in frequency. Frequency response from some new generators was delayed to the point where it made little or no contribution to arresting the frequency change. The frequency response capability from new entrant generation is not being offered in FCAS markets at present.
- The risk, particularly for new, similar-technology plant, of multiple generators tripping based on near-identical frequency protection settings. Minimising this risk may require co-ordinated frequency protection settings, or additional co-ordinated over-frequency generator shedding schemes where appropriate.
- The design, settings, and implementation of the EAPT control scheme require review to ensure they remain appropriate. The system risk this control scheme was originally installed to manage still exists, however the power system has changed significantly around it within a short timeframe, including the installation of battery systems with very rapid frequency response.
- The importance of generation remaining in uninterrupted operation when required to do so and ensuring simulation models are available that will fully and accurately predict plant performance.

[12] [12] AEMC, Frequency control frameworks review, Final report, 26 July 2018, pages 38, 62

Table 17 AEMO Recommendations

	Recommendation
1.	Primary frequency control in the NEM a) AEMO work with the AEMC, AER and NEM participants to establish appropriate interim arrangements, through rule changes as required, to increase primary frequency control (PFC) responses at both existing and new (synchronous and non-synchronous) NEM generator connection points where feasible, by Q3 2019. b) AEMO support work on a permanent mechanism to secure adequate PFC as contemplated in the AEMC's Frequency Control Framework Review, with the aim of identifying any required rule changes to be submitted to the AEMC by the end of Q3 2019 with a detailed solution and implementation process completed by mid-2020.
2.	Automating secondary frequency control implementation after separation events AEMO investigate the opportunity for automation of reconfiguring AEMO systems including AGC and NEMDE post separation and large system events. AEMO to report to industry the options in Q2 2019.
3.	Circumstances for regional FCAS or frequency control AEMO investigate whether a minimum regional FCAS requirement is feasible, or whether there may be scope to manage frequency requirements arising from non-credible regional separation under the protected events framework in the NER after interim PFC outcomes at the end of Q3 2019
4.	Frequency response capability models Commencing in Q1 2019, AEMO to work with participants to obtain information required to fully and accurately model generator frequency response and all other active power controls.
5.	Distributed PV inverter performance standards and analysis Distributed PV – AEMO to work with industry and Standards Australia to: a) immediately assess technical requirements of inverters (AS 4777) and complete by Q2 2019 b) work with stakeholders to implement improved performance standards for inverters by end of 2019 c) establish solutions for obtaining data on the performance of distributed rooftop PV systems, and to develop the necessary simulation models and analysis tools to predict their response to system disturbances progressively up to the end of 2020.
6.	Protection and control schemes AEMO immediately commence a review of the EAPT scheme and identify improvements by 1 July 2019. AEMO also review other existing AC interconnector schemes with TNSPs, to determine whether their performance remains fit for purpose in the changing environment and are properly co-ordinated, by Q1 2020.
7.	Emergency frequency control schemes AEMO continue implementation and investigate any further functional requirements of Emergency Frequency Control Schemes (EFCS) for each region, commencing with SA and QLD prior to Q1 2020.
8.	Generator disconnection settings From Q1 2019, AEMO to work with market participants to ensure it is advised of any settings that may result in disconnection that are not currently reflected in their generator models, and review adequacy of existing models.

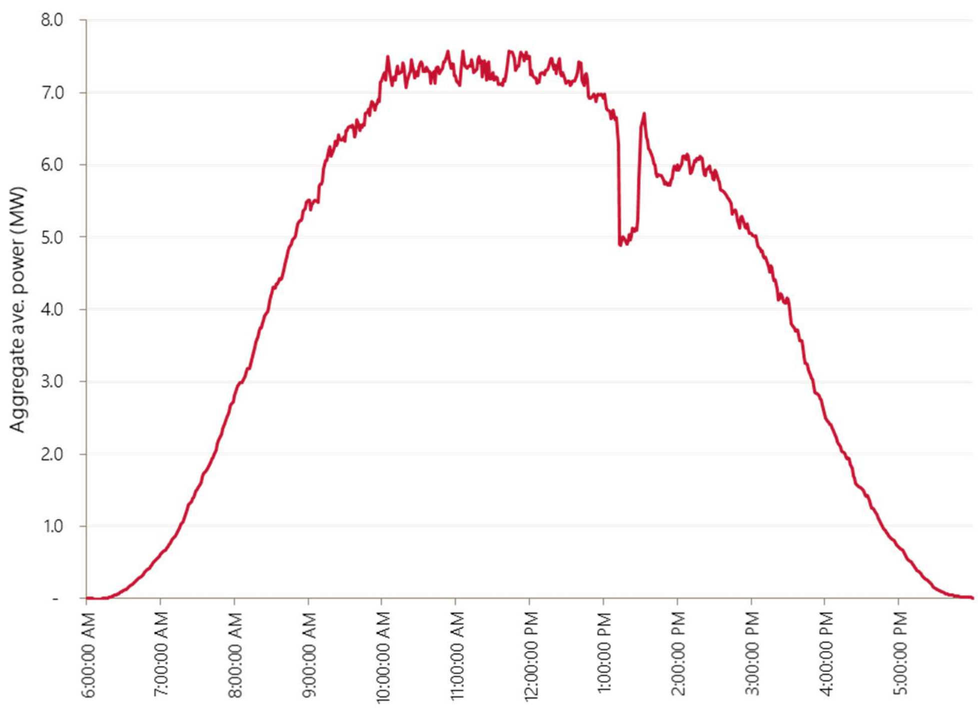
A1. Distributed PV Solar Response Analysis

To investigate the response of distributed PV during this event, AEMO partnered with the University of New South Wales (UNSW) via an ARENA-funded collaboration[13], and Solar Analytics. Solar Analytics provided data from approximately 5,000 monitoring devices at sites with distributed PV. These devices record PV system generation at one-minute intervals. The research team at UNSW[14] collaborated with AEMO to develop the approaches required for analysis and interpretation of the data.

A1.1 Queensland Distributed PV Response

Figure 59 shows the total aggregate generation from the distributed PV systems in QLD monitored by Solar Analytics devices (around 1,300 systems). A reduction in aggregate generation from these monitored systems is evident at the time of the event. The timing and speed of this reduction in generation relative to the initial peak in QLD frequency is unclear, given the 1-minute sampling interval. AEMO has a work program underway to develop improved monitoring and analysis approaches to understand this behaviour on shorter timescales.

Figure 59 Aggregated generation by distributed PV systems in QLD with Solar Analytics monitoring devices (~1,300 sites, <100 kW), 25 August 2018*



* Data provided by Solar Analytics with support from a CRC for Low Carbon Living project RP1036U1, analysis by UNSW via an ARENA-funded collaboration with AEMO and industry partners TasNetworks and ElectraNet.

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[13] UNSW, Addressing Barriers to Efficient Renewable Integration. More information is available at: https://arena.gov.au/projects/addressing-barriers-efficient-renewable-integration/.

[14] Naomi Stringer, Navid Haghdadi, Anna Bruce, Iain MacGill.

To estimate the behaviour of aggregate PV generation across the region during this event, the systems monitored by Solar Analytics were divided into tranches, as follows:

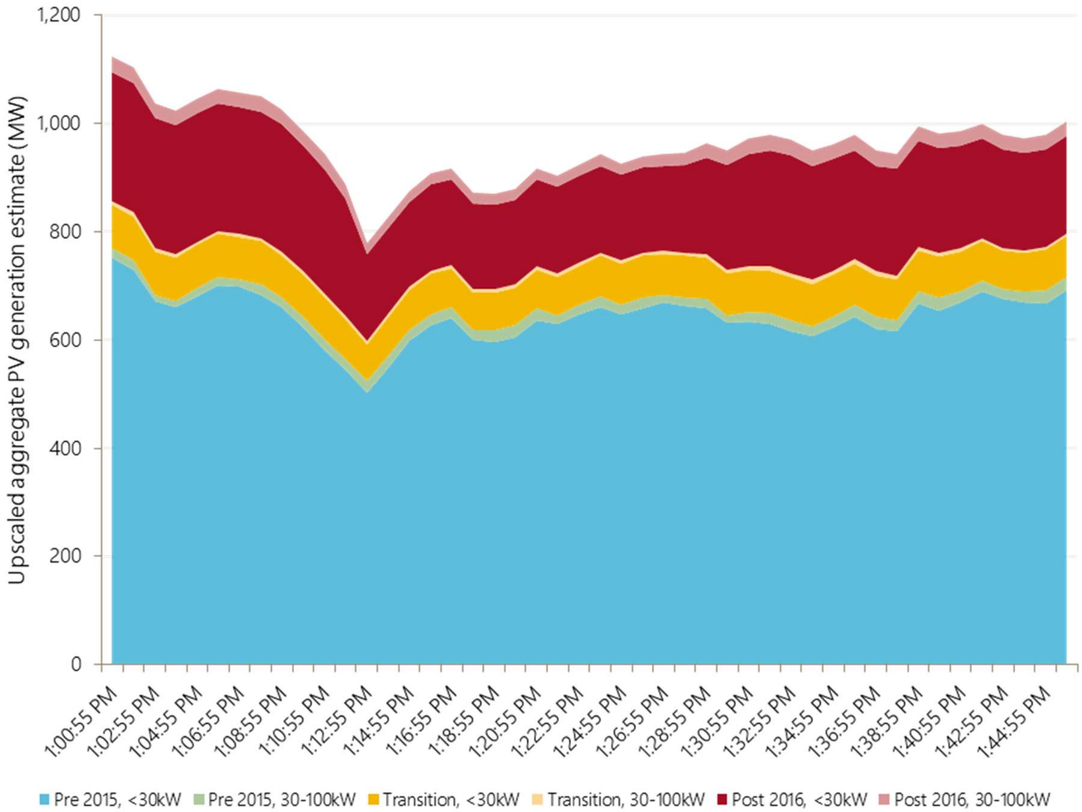
- Capacity (kW) – PV systems were divided into different size tranches (<30kW and 30-100kW) because larger systems may have additional protection or other installation requirements, determined by distribution businesses as a condition of connection. This may cause different behavioural trends for these systems in response to disturbances.
- Date of installation – PV systems are divided into different installation dates:
  - Installed prior to Oct 2015 – should be compliant with AS/NZ4777.3-2005.
  - Installed after Oct 2016 – should be compliant with AS/NZ4777.2-2015.
  - Transition systems (installed between Oct 2015 and Oct 2016) – may be compliant with either standard (a one-year grace period was allowed following the publication of the new standard).

The aggregate behaviour of PV systems in the Solar Analytics data set in each tranche was upscaled based on the proportion of distributed PV systems in that same tranche in QLD at the time of the event. The resulting estimate of aggregate distributed PV behaviour in QLD is shown in Figure 60.

Although the Solar Analytics dataset includes less than 80 distributed PV systems that are <30 kW and installed prior to Oct 2015, this tranche represents most of the distributed PV installed in QLD. This adversely impacts the accuracy of the upscaling estimate. AEMO has a work program underway to further understand the behaviour of these legacy PV systems and improve the accuracy of future estimates.

This upscaling estimate suggests that generation from distributed PV in QLD reduced by approximately 165 MW (17%) at the time of the event. This compares reasonably closely with the estimated increase in QLD regional demand at the time of the event, which averages to around 200 MW on a comparable one-minute sampling interval. The remaining difference between 165 MW and 200 MW may be due to load relief, or other unrecorded changes or responses to the event within distribution networks.

Figure 60 Upscaled estimate of aggregate PV generation in QLD, 25 August 2018*



* Data provided by Solar Analytics with support from a CRC for Low Carbon Living project RP1036U1, analysis by UNSW Sydney via an ARENA-funded collaboration with AEMO and industry partners TasNetworks and ElectraNet.

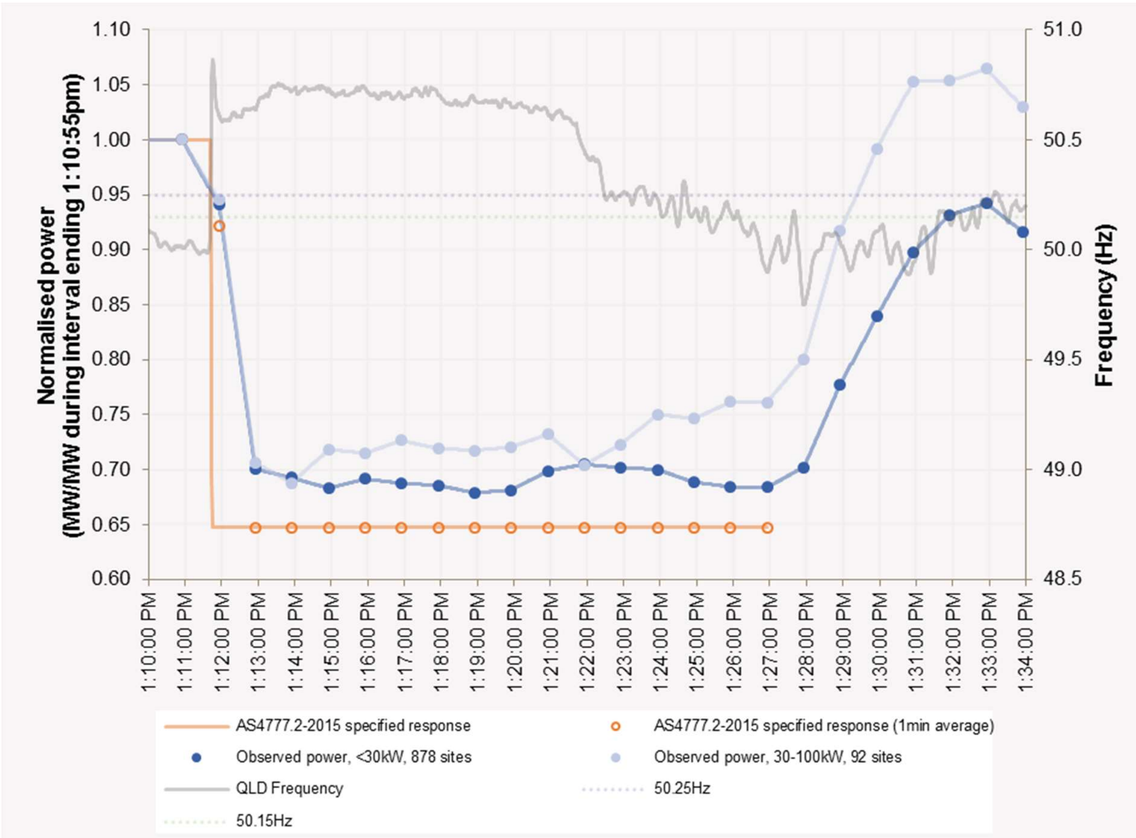
The behaviour of the different tranches of PV systems was analysed separately. The response of distributed PV systems installed after October 2016 is illustrated in Figure 61. These systems should be compliant with AS/NZ4777.2-2015, which requires inverters to provide an over-frequency droop response once frequency exceeds a dead-band of 50.25 Hz (with a linear ramp to zero generation by 52 Hz). Inverters are allowed to gradually ramp back up once frequency moves below 50.15 Hz for at least 60 seconds.

The 50.25 Hz dead-band was exceeded in QLD during this event, and frequency remained above 50.15 Hz for around 15 minutes. Figure 61 shows the aggregate response of post-October 2016 inverters in the two size categories (<30 kW and 30-100 kW), compared with the over-frequency response specified in AS/NZ4777.2-2015 (orange line)[15]. There is a clear aggregate response of the correct shape and approximate magnitude, suggesting that this designed control response is correctly implemented in some proportion of the PV inverters. This response from distributed PV inverters assisted frequency management during this event and is likely to become increasingly important in future disturbances as the proportion of distributed PV generation grows.

Further analysis of individual inverter responses suggests that at least 15% of these inverters (installed after October 2016) did not exhibit the over-frequency reduction specified in AS/NZ4777.2-2015. The lack of response from this subset of inverters was compensated for by periodic shading and over-response of other inverters during the fifteen-minute period (since this event occurred on an intermittently cloudy day). Further investigation is underway to explore why these inverters did not respond as specified to over-frequency, and whether changes to compliance and accreditation processes may be warranted.

[15] AS/NZ4777.2-2015 allows inverters to curtail below this specified response, and only specifies a maximum ramp rate for inverters to return to unconstrained output.

Figure 61 **Comparison of the AS4777.2-2015 specified response with behaviour of post-2016 distributed PV inverters in QLD, 25 August 2018***



* Data provided by Solar Analytics with support from a CRC for Low Carbon Living project RP1036U1, analysis by UNSW Sydney via an ARENA-funded collaboration with AEMO and industry partners TasNetworks and ElectraNet.

In addition to the controlled over-frequency response from post-2016 inverters, a reduction in generation was also observed from inverters installed prior to October 2015. This reduction appears to be mostly associated with 15% of pre-2015 inverters suddenly reducing generation to zero (consistent with disconnection of the device)[16]. The reasons for this disconnection behaviour are not clear:

- AEMO's survey of frequency trip settings for PV inverters in this tranche did not identify any manufacturers applying frequency trip settings below 50.98 Hz[17]. Frequency during this event did not reach this level, and therefore should not have been high enough to trip distributed PV inverters. It is possible that some manufacturers not covered by AEMO's survey have applied trip settings below this level. In QLD, the survey results represented only 34% of total installed capacity in May 2015.
- Disconnections did not show any clear spatial trends. For example, some disconnections occurred in far north QLD, while others occurred in south-east QLD. Disconnections associated with a fault (causing phenomena such as a voltage dip or phase angle jump) would be expected to show a stronger response closer to the originating event. However, these results are not conclusive; the Solar Analytics dataset only includes 82 devices in this tranche, meaning the dataset may be too small to show a clear spatial pattern.

As illustrated in Figure 61, the aggregate behaviour of all distributed PV in QLD is dominated by the response of <30kW systems installed prior to 2015, which makes it particularly important to understand the behaviour of this tranche. AEMO has an ongoing work program to explore this further.

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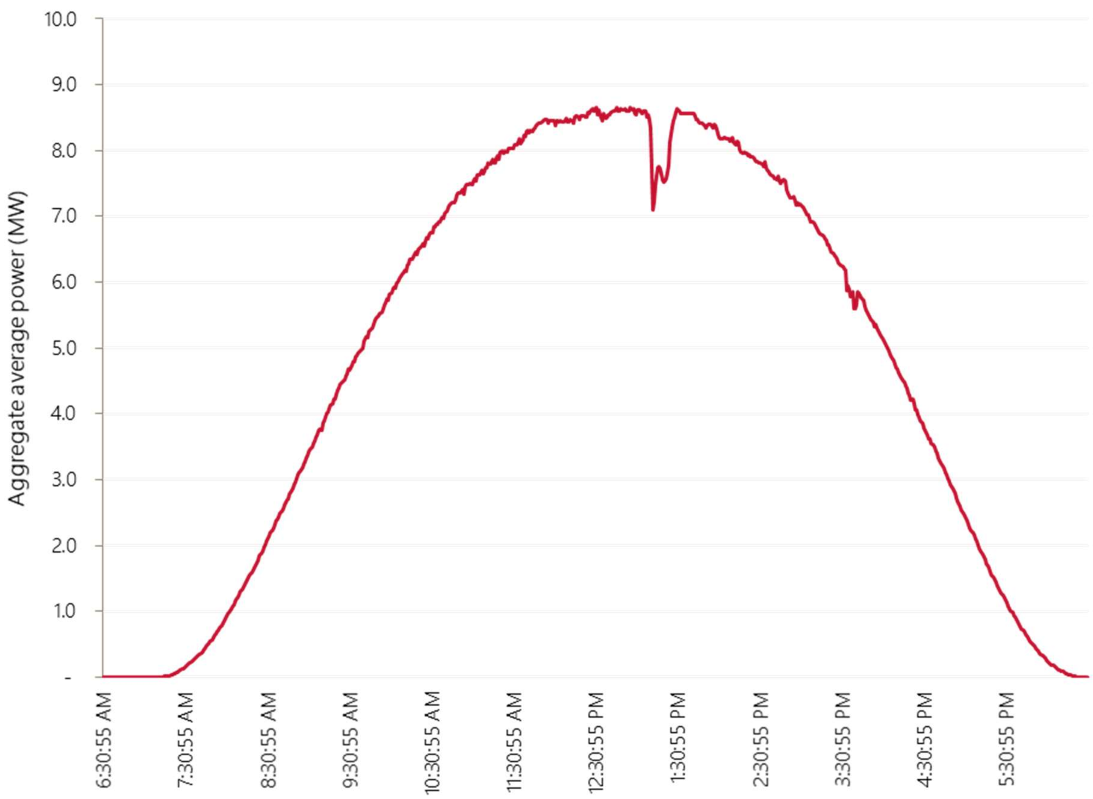
[16] A small subset of inverters also exhibited more mild ramping behaviour that appears consistent with cloud shading.

[17] AEMO, April 2016, Response of existing PV inverters to frequency disturbances. Available at: https://www.aemo.com.au/-/media/Files/PDF/Response-of-Existing-PV-Inverters-to-Frequency-Disturbances-V20.pdf

A1.2 South Australia Distributed PV Response

Solar Analytics provided AEMO with one-minute resolution data from approximately 1,700 distributed PV systems in SA. This data was analysed by UNSW as part of an ARENA-funded collaboration with AEMO[18]. Figure 62 shows the aggregate generation from distributed PV systems monitored by Solar Analytics in South Australia. A reduction in distributed PV generation at the time of the event is clearly apparent.

Figure 62 Aggregate average generation from distributed PV devices in SA monitored by Solar Analytics (~1,700 sites, <100kW) *, 25 August 2018**



Note the scale of this graph is showing output of the 1,700 monitored distributed rooftop sites in SA only, which is less than 10 MW in generation.

** Data provided by Solar Analytics with support from a CRC for Low Carbon Living project RP1036U1, analysis by UNSW Sydney via an ARENA-funded collaboration with AEMO and industry partners TasNetworks and ElectraNet.

The total generation from distributed PV systems in SA was estimated by scaling up the aggregate generation from systems monitored by Solar Analytics in tranches, as previously described for QLD. The resulting upscaled generation estimate for SA distributed PV systems is illustrated in Figure 63. The estimated reduction in total generation in the region at the time of the event is approximately 60 MW, or around 12% of distributed PV generation[19]. This compares reasonably with the measured increase in load at the time of the event of approximately 100 MW when measured on a one-minute average comparable with the Solar Analytics dataset.

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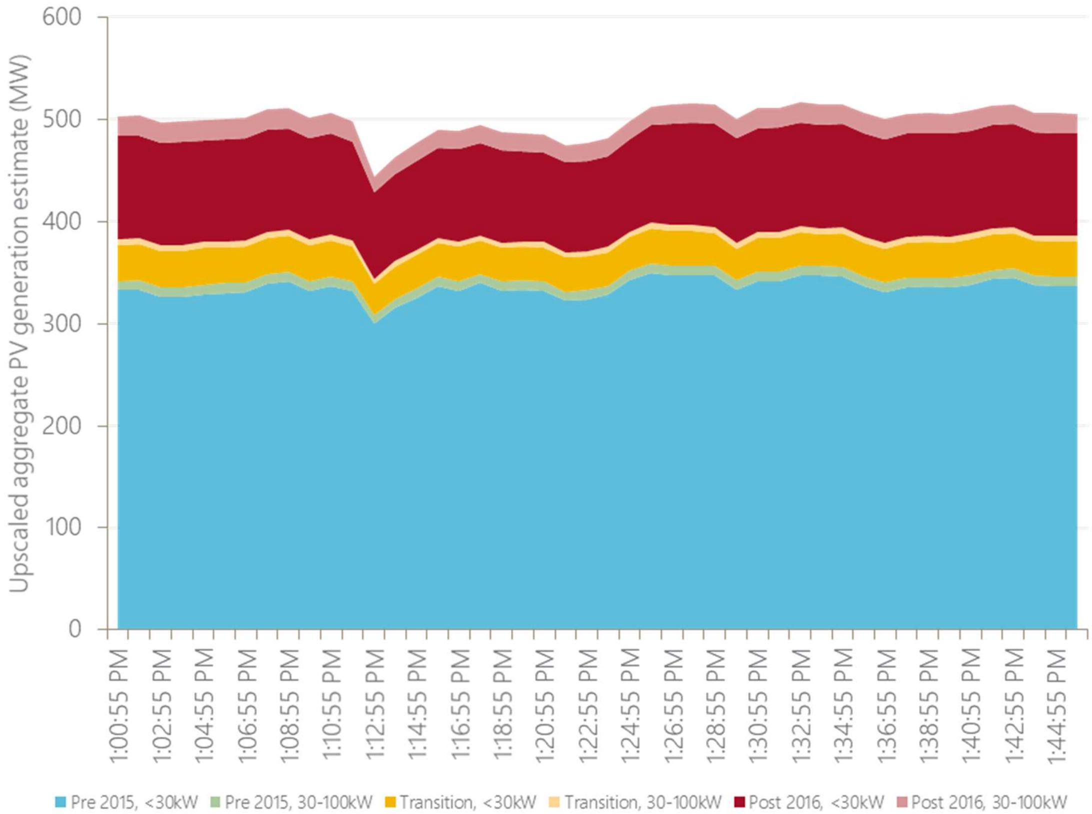
[18] https://arena.gov.au/projects/addressing-barriers-efficient-renewable-integration/

[19] As mentioned earlier, the accuracy of this upscaling is limited by the relatively small representation of <30 kW systems installed prior to October 2015 (less than 50 systems monitored by Solar Analytics in South Australia), given that this tranche represents the majority of distributed PV generation in South Australia.

Figure 63 **Estimated upscaled aggregate distributed PV generation in South Australia, 25 August 2018***

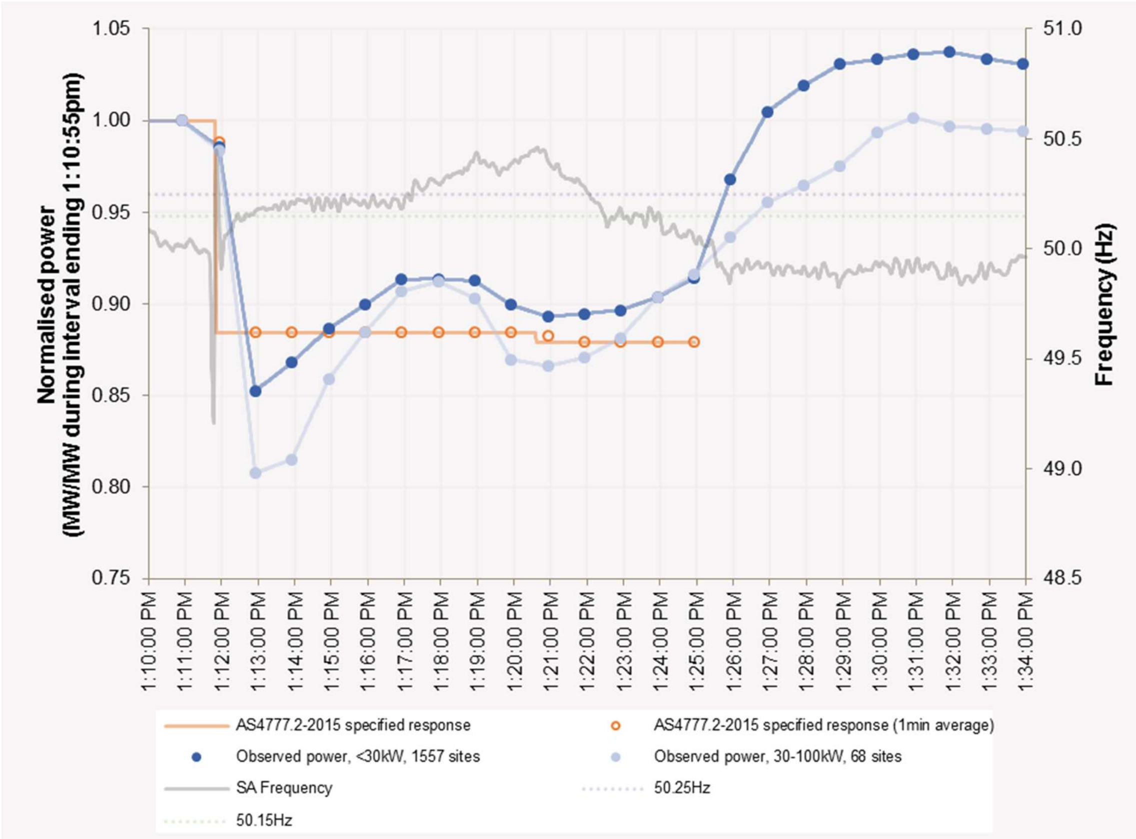


*Data provided by Solar Analytics with support from a CRC for Low Carbon Living project RP1036U1, analysis by UNSW Sydney via an ARENA-funded collaboration with AEMO and industry partners TasNetworks and ElectraNet.

The normalised aggregate response of distributed PV systems installed after October 2016 is illustrated in Figure 64, compared with the over-frequency droop response specified in AS/NZ4777.2-2015. A clear response is evident, of a similar magnitude and shape to that specified in the standard, indicating that many systems are compliant. This controlled over-frequency response from distributed PV inverters assisted in managing frequency during this event and will become increasingly important as the installation of distributed PV grows.

Further analysis of the response of individual inverters indicates that at least 30% of distributed PV inverters (<100 kW) in SA installed after October 2016 did not exhibit the over-frequency response specified in AS/NZ4777.2-2015. This was partially compensated by the over-response and temporary shading of a subset of other inverters in the sample.

Figure 64 **Comparison of specified AS4777.2-2015 response with behaviour of post-2016 distributed PV inverters in SA on 25 August 2018***



*Data provided by Solar Analytics with support from a CRC for Low Carbon Living project RP1036U1, analysis by UNSW Sydney via an ARENA-funded collaboration with AEMO and industry partners TasNetworks and ElectraNet.

In addition to the controlled reduction in generation from post-2016 inverters, there was an observed reduction in generation from SA distributed PV systems installed prior to October 2015. Around half this reduction appears to be associated with the disconnection of around 13% of systems installed prior to October 2015. The causes of this behaviour are unknown. Frequency did not exceed 50.5 Hz in SA, and AEMO's survey of manufacturers[20] did not reveal any with default trip settings in that range. There was no known voltage disturbance in SA which might have caused inverter tripping.

A1.3 VIC distributed PV Response

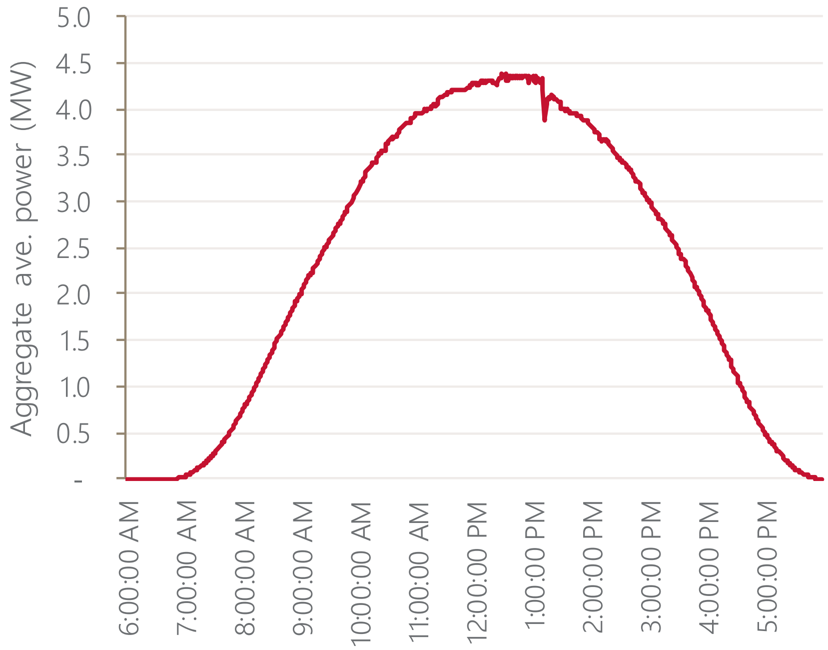
Solar Analytics provided 1-minute resolution data on the behaviour of around 1,600 distributed PV systems in NSW and the ACT, and around 380 systems in VIC. UNSW's analysis of this data (in collaboration with AEMO via a joint ARENA-funded project[21]) is presented below.

The aggregate generation from distributed PV systems monitored by Solar Analytics in NSW and VIC is shown in Figure 65. A reduction in distributed PV generation is clear at the time of the event in both regions.

[20] AEMO, April 2016, Response of existing PV inverters to frequency disturbances. Available at: https://www.aemo.com.au/-/media/Files/PDF/Response-of-Existing-PV-Inverters-to-Frequency-Disturbances-V20.pdf

[21] See https://arena.gov.au/projects/addressing-barriers-efficient-renewable-integration/.

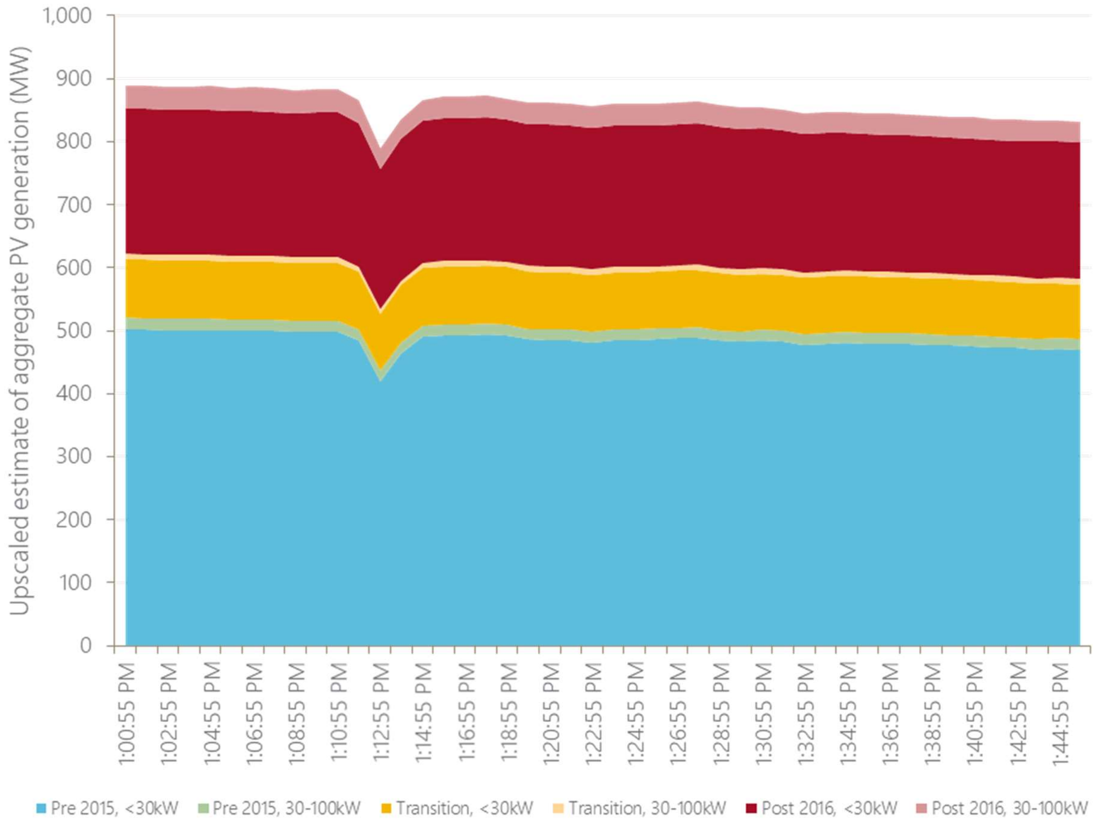
Figure 65 **Aggregate generation from VIC distributed PV devices monitored by Solar Analytics, 25 August 2018***



*Data provided by Solar Analytics with support from a CRC for Low Carbon Living project RP1036U1, analysis by UNSW Sydney via an ARENA-funded collaboration with AEMO and industry partners TasNetworks and ElectraNet.

The upscaled estimate of aggregate PV generation in the region, calculated in tranches as described earlier, is illustrated in Figure 66 for VIC and Figure 68 for New South Wales. This suggests a loss of around 90 MW of distributed PV in VIC (around 11% of distributed PV generation at the time and a loss of around 100 MW of distributed PV in New South Wales (around 19% of distributed PV generation at the time).

Figure 66 Upscaled estimate of aggregate generation by distributed PV in VIC, 25 August 2018*



*Data provided by Solar Analytics with support from a CRC for Low Carbon Living project RP1036U1, analysis by UNSW Sydney via an ARENA-funded collaboration with AEMO and industry partners TasNetworks and ElectraNet.

Table 18 summarises the behaviour of the monitored distributed PV systems in VIC, exploring possible explanations for the observed responses. 10% of systems installed prior to October 2015 were observed to disconnect (six sites). Some distributed PV systems installed prior to October 2015 are known to have frequency trip settings within the range experienced during this event[22], indicating that frequency tripping likely explains the majority of these disconnections.

For distributed PV systems installed after October 2016, 8% (23 sites) were observed to disconnect. These systems should be compliant with AS/NZ4777.2-2015, which requires systems to remain in continuous, uninterrupted operation until a frequency of 47 Hz is reached for at least 1 second. This did not occur during this event. Given that there was no significant voltage disturbance in VIC, and no other clear explanations for this disconnection behaviour, it suggests that ~8% of distributed PV systems installed post-Oct 2016 may not be compliant with the frequency ride-through requirements of the standard.

Table 18 VIC – behaviour of distributed PV systems

	Percentage of sites that disconnected*	Proportion of observed generation reduction attributable to disconnections	Frequency response	Voltage response
2005 Standard (systems	10%	~100%	As for NSW, AEMO's survey of frequency trip settings	There was no significant voltage disturbance experienced in VIC.

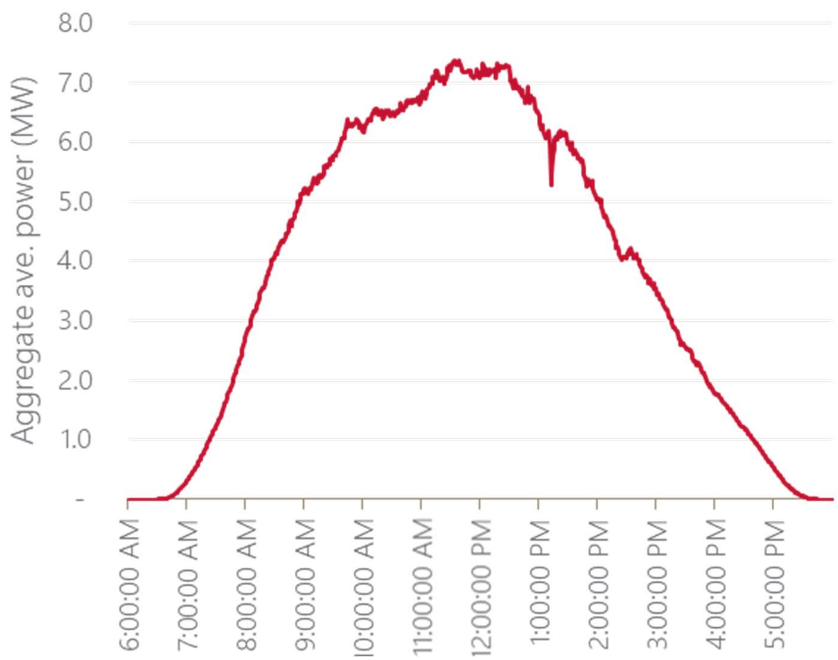
[22] AEMO, *Response of Existing PV inverters to Frequency Disturbances*, April 2016, available at https://www.aemo.com.au/-/media/Files/PDF/Response-of-Existing-PV-Inverters-to-Frequency-Disturbances-V20.pdf.

	Percentage of sites that disconnected*	Proportion of observed generation reduction attributable to disconnections	Frequency response	Voltage response
installed prior to Oct 2015)			suggests ~17% of systems should disconnect.	
2015 Standard (systems installed after Oct 2016)	8%	~100%	As for NSW, systems installed under the 2015 standard should remain in continuous, uninterrupted operation until frequency reaches 47Hz, which did not occur during this event.	There was no significant voltage disturbance experienced in VIC.

*Based on monitored sample sites. Disconnection is inferred from generation at a site suddenly reducing to zero.

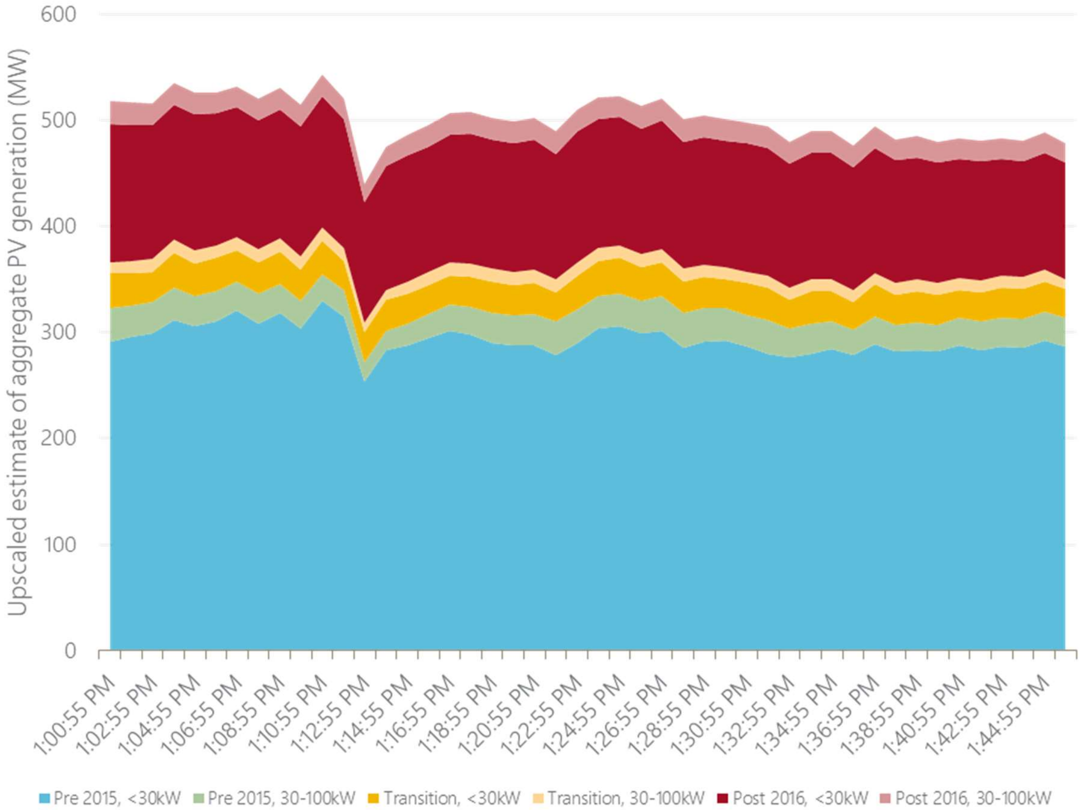
A1.4 NSW distributed PV response

Figure 67 Aggregate generation from VIC distributed PV devices monitored by Solar Analytics, 25 August 2018*



*Data provided by Solar Analytics with support from a CRC for Low Carbon Living project RP1036U1, analysis by UNSW Sydney via an ARENA-funded collaboration with AEMO and industry partners TasNetworks and ElectraNet.

Figure 68 Upscaled estimate of aggregate generation from distributed PV in NSW (including ACT), 25 August 2018*



*Data provided by Solar Analytics with support from a CRC for Low Carbon Living project RP1036U1, analysis by UNSW Sydney via an ARENA-funded collaboration with AEMO and industry partners TasNetworks and ElectraNet.

Table 19 summarises the behaviour of distributed PV inverters in NSW, exploring possible causes of observed disconnections. 26% of the sites with inverters connected prior to October 2015 were observed to disconnect, likely due to a combination of frequency tripping (for inverters with frequency trip settings within the range experienced during this event), and voltage tripping of systems in Northern NSW due to the fault at QNI.

For distributed PV systems installed after October 2016, 10% of systems were observed to disconnect. These inverters should be compliant with AS/NZ4777.2-2015, which requires they remain in continuous, uninterrupted operation until frequency reaches 47 Hz (which did not occur during this event). The disconnection of systems in Northern NSW could have been an allowable response to the voltage disturbance caused by the fault at QNI. However, disconnections in other parts of NSW may be attributable to a lack of compliance with the frequency ride through requirements in the 2015 standard.

It appears that the observed disconnections of distributed PV systems were unrelated to the action of UFLS because loads monitored at almost all these sites were observed to continue operation during the event.

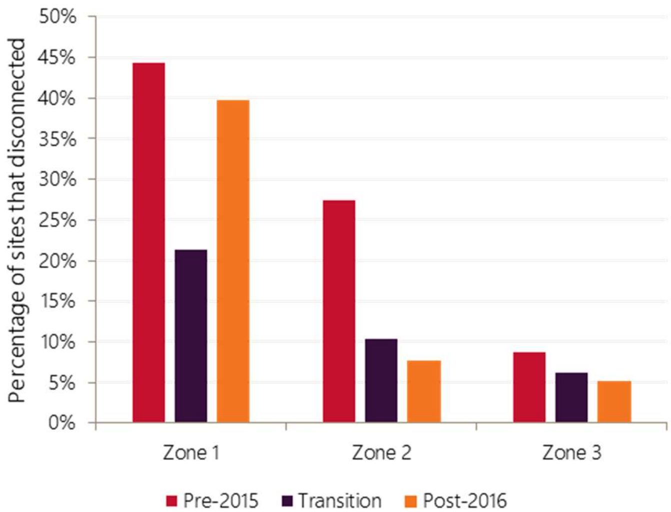
Table 19 NSW and ACT – combined behaviour of distributed PV systems

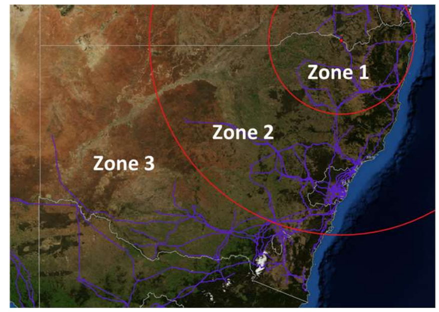
	Percentage of sites that disconnected*	Proportion of observed generation reduction attributable to disconnections	Frequency response	Voltage response
2005 Standard (systems installed prior to Oct 2015)	26%	~70% (remainder likely attributable to shading)	Frequency was below 49Hz for 0.73 seconds. AEMO's survey of manufacturer's default settings** suggested that 17% of devices installed in the NEM as of May 2015 have frequency trip settings within this range. This suggests that some of the observed disconnections are due to frequency trip settings, in line with expectations.	The fault at QNI may have caused further disconnections based on inverter exposure to under-voltage, especially in Northern NSW. This is consistent with the spatial trends observed (a higher proportion of disconnections occurred closer to the fault location, as illustrated in Figure 69).
2015 Standard (systems installed post Oct 2016)	10%	~88% (remainder likely attributable to shading)	AS/NZ4777.2-2015 requires inverters installed from Oct 2016 to remain in continuous, uninterrupted operation until frequency reaches 47Hz for a duration of at least one second. Inverters on this standard should not have disconnected due to the frequency experienced during this event.	The fault at QNI is a likely cause of observed disconnections in Northern NSW based on inverter exposure to under-voltage. This is consistent with the spatial trends observed (a higher proportion of disconnections occurred closer to the fault location, as illustrated in Figure 69).

*Disconnection is inferred from generation at a site suddenly reducing to zero.
**AEMO, April 2016, Response of existing PV inverters to frequency disturbances, available at https://www.aemo.com.au/-/media/Files/PDF/Response-of-Existing-PV-Inverters-to-Frequency-Disturbances-V20.pdf.

Figure 69 shows the spatial distribution of distributed PV disconnections in NSW. Disconnections were concentrated around the zone closest to QNI. In Zone 1, closest to the fault at QNI, almost 45% of distributed PV inverters installed prior to October 2015 were observed to disconnect. In contrast, in Zone 3, furthest from the fault (and not experiencing a significant voltage dip), less than 10% of distributed PV inverters disconnected.

Figure 69 Geographic distribution of monitored PV system sites disconnecting in NSW during 25 August 2018 event*





*Disconnection is inferred from generation at a site suddenly reducing to zero. Data provided by Solar Analytics with support from a CRC for Low Carbon Living project RP1036U1, analysis by UNSW Sydney via an ARENA-funded collaboration with AEMO and industry partners TasNetworks and ElectraNet.

A2. Supply mix and energy spot prices for each region, 25 August 2018

Figure 70 Supply mix and energy spot price in QLD region

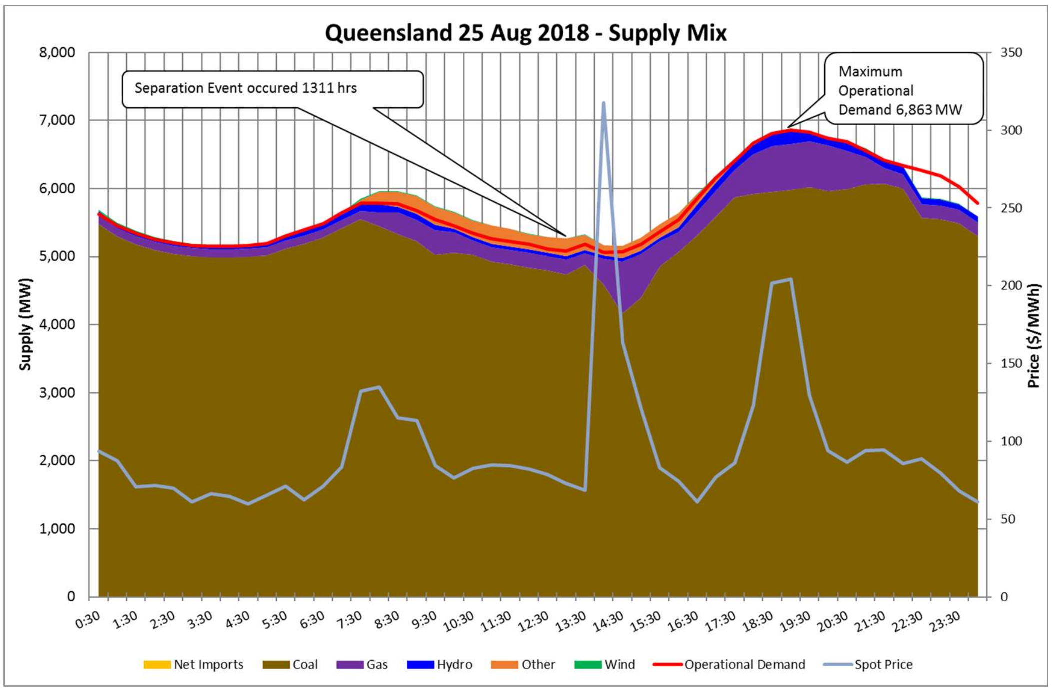


Figure 71 Supply mix and energy spot price in SA region

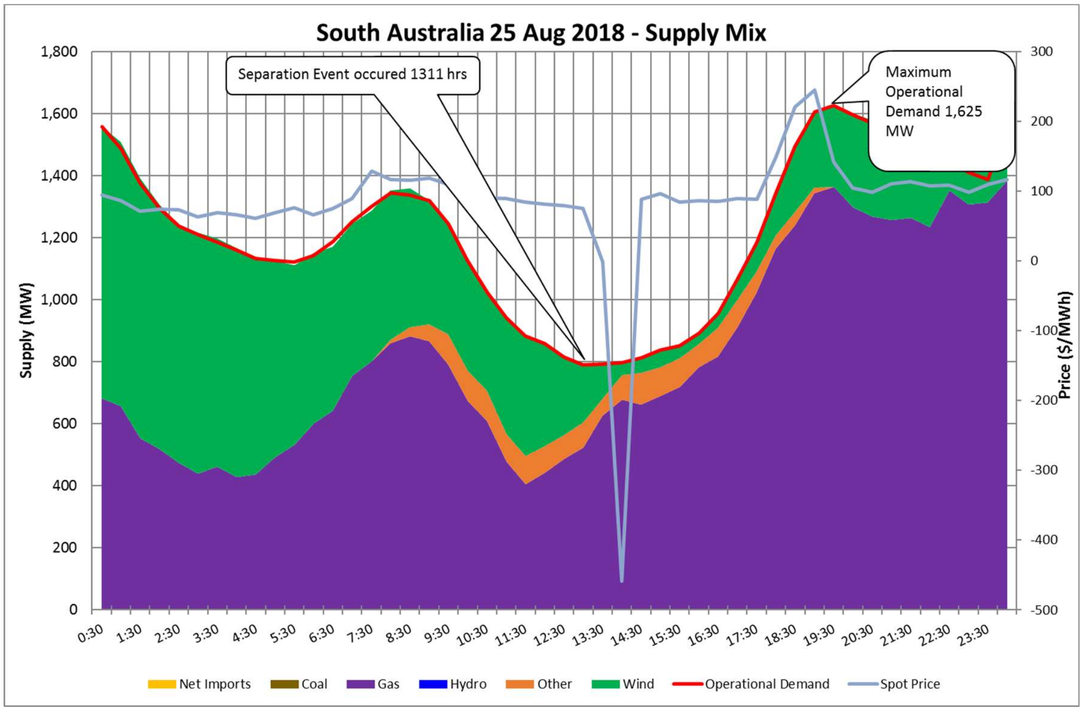


Figure 72 Supply mix and energy spot price in NSW region

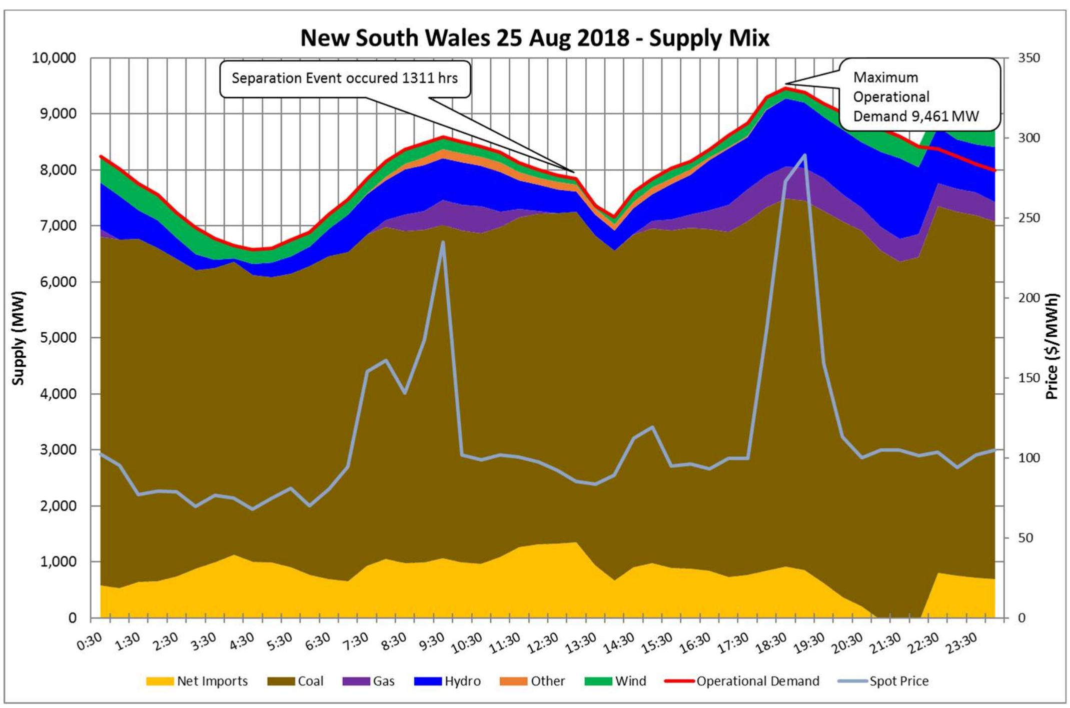


Figure 73 Supply mix and energy spot price in VIC region

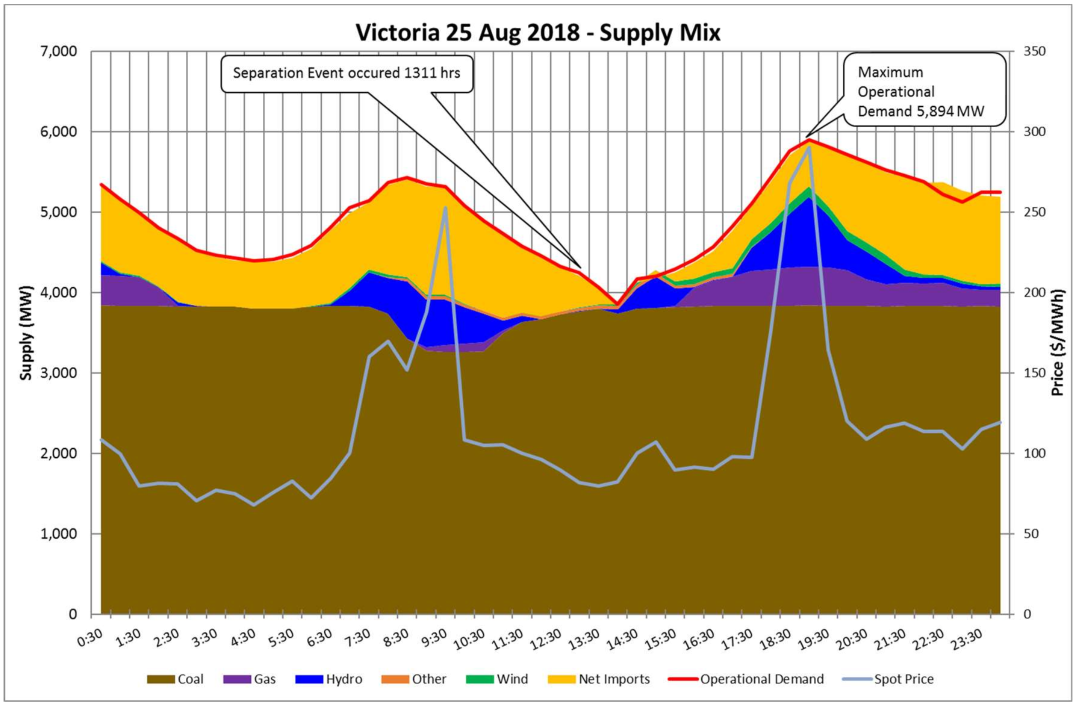
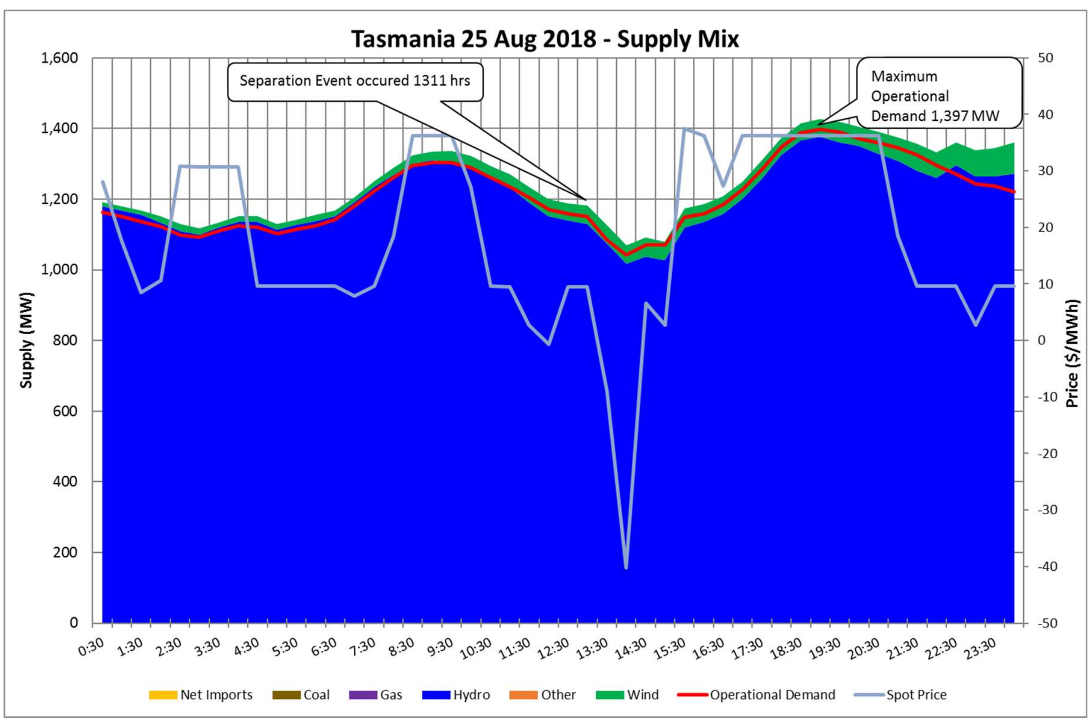


Figure 74 Supply mix and energy spot price in TAS region



A3. Power system security management

A3.1 AEMO's roles and responsibilities

AEMO operates the power system in the NEM from two control rooms in different states. These co-primary centres operate 24 hours/365 days a year and are equipped with identical telecommunication and information technology systems. They operate as a virtual single control room with one on-shift manager who coordinates the control room daily activities and immediate operational response to emergencies.

The NER and AEMO's operating procedures govern the operation of the NEM and the power system. Chapter 4 of the NER sets out the rules and framework for AEMO's power system security responsibilities.

Clause 4.3.1 lists those responsibilities including, most relevantly for current purposes, to maintain 'power system security'. Under clause 4.3.2, AEMO must use its reasonable endeavours to achieve those responsibilities, recognising that AEMO is heavily reliant on the actions and responses of registered participants and the performance of their equipment to maintain power system security. AEMO's ability to control power system equipment is limited to its powers and functions in relation to the central dispatch process, instructions, approvals, directions and two-way information flow with registered participants.

The concepts and principles that define power system security are described in sections A3.3 onwards.

A3.2 Preparedness

AEMO works in conjunction with Registered Participants to develop plans, where required, to cover planned and unplanned outages on the power system to an N-1 operational standard[23]. These plans are developed to ensure the power system is prepared for the credible contingency event that would have the largest impact on the power system[24]. This may be the loss of a single generating unit, load, or transmission element. AEMO continuously assesses the state of the power system and environmental conditions that can impact either demand or security of the network, with AEMO control rooms having a range of real-time diagnostic tools to assist with the monitoring of the power system and automatic control schemes during normal and abnormal power system conditions.

AEMO's situational awareness and response capability to conditions on the power system are provided through resources and processes including:

- Dedicated services providing detailed current weather conditions and weather forecasts up to seven days ahead.
- Lightning and bushfire detection systems.
- Monitoring of geo-magnetic disturbance.
- Various control schemes to safeguard equipment and manage loading of equipment within ratings following contingencies.
- Established procedures specifying action when the monitored conditions change beyond acceptable thresholds.

[23] N-1 redundancy is a standard of resilience that ensures system availability in the event of failure of any single transmission element, load, or generation unit.

[24] Credible contingency events are events that are considered as reasonably likely to occur in normal operation of the electricity supply system, including the trip of any single item of plant. AEMO must prepare the power system to be secure should the event occur. Non-credible contingency events are considered to be events that are less likely to occur such as the loss of a multiple items of plant at the same time – these include the loss of double circuit transmission lines or multiple generating units.

- Dispatch of generation considering power transfer limits of the power system, and environmental conditions.
- Manual and automatic UFLS across the power system where required.
- Availability of under-voltage load shedding at various locations, where required.
- Procurement of system restart ancillary services (SRAS).

A3.3 Secure operating state and power system security principles

A secure operating state is defined in clause 4.2.4 of the NER as follows:

(a) The power system is defined to be in a secure operating state if, in AEMO's reasonable opinion, taking into consideration the appropriate power system security principles described in clause 4.2.6:

(1) the power system is in a satisfactory operating state; and

(2) the power system will return to a satisfactory operating state following the occurrence of any credible contingency event in accordance with the power system security standards.

(b) Without limitation, in forming the opinions described in clause 4.2.4(a), AEMO must:

(1) consider the impact of each of the potentially constrained interconnectors; and

(2) use the technical envelope as the basis of determining events considered to be credible contingency events at that time.

The power system security principles (clause 4.2.6) most relevantly include:

(a) To the extent practicable, the power system should be operated such that it is and will remain in a secure operating state.

(b) Following a contingency event (whether a credible contingency event) or a significant change in power system conditions, AEMO should take all reasonable actions:

(1) to adjust, wherever possible, the operating conditions with a view to returning the power system to a secure operating state as soon as it is practical to do so, and, in any event, within thirty minutes; or

(2) if any principles and guidelines have been published [by the Reliability Panel], to adjust, wherever possible, the operating conditions, in accordance with such principles and guidelines, with a view to returning the power system to a secure operating state within at most thirty minutes.

(c) Emergency frequency control schemes should be available and in service to:

(1) restore the power system to a satisfactory operating state following protected events; and

(2) significantly reduce the risk of cascading outages and major supply disruptions following significant multiple contingency events.

A3.4 Satisfactory operating state

The power system is defined as being in a satisfactory operating state (clause 4.2.2) when:

(a) the frequency at all energised busbars of the power system is within the normal operating frequency band, except for brief excursions outside the normal operating frequency band but within the normal operating frequency excursion band;

(b) the voltage magnitudes at all energised busbars at any switchyard or substation of the power system are within the relevant limits set by the relevant Network Service Providers in accordance with clause S5.1.4 of schedule 5.1;

(c) the current flows on all transmission lines of the power system are within the ratings (accounting for time dependency in the case of emergency ratings) as defined by the relevant Network Service Providers in accordance with schedule 5.1;

(d) all other plant forming part of or impacting on the power system is being operated within the relevant operating ratings (accounting for time dependency in the case of emergency ratings) as defined by the relevant Network Service Providers in accordance with schedule 5.1;

(e) the configuration of the power system is such that the severity of any potential fault is within the capability of circuit breakers to disconnect the faulted circuit or equipment; and

(f) the conditions of the power system are stable in accordance with requirements designated in or under clause S5.1.8 of schedule 5.1.

A3.5 Definition of a contingency event

A contingency event is defined in clause 4.2.3(a) of the NER as an event affecting the power system which AEMO expects would be likely to involve the failure or removal from operational service of one or more generating units and/or transmission elements.

A contingency event is sudden and unexpected, generally instantaneous. The intentional removal from service of transmission network equipment by a TNSP, whether due to routine maintenance or in response to unusual conditions, is regarded as a planned or short notice outage; not a contingency event.

A3.6 Definition of a credible contingency event

A credible contingency event is defined in clause 4.2.3(b) of the NER as a contingency event the occurrence of which AEMO considers to be reasonably possible in the surrounding circumstances including the technical envelope. Without limitation, examples of credible contingency events are likely to include:

(1) the unexpected automatic or manual disconnection of, or the unplanned reduction in capacity of, one operating generating unit; or

(2) the unexpected disconnection of one major item of transmission plant (e.g. transmission line, transformer or reactive plant) other than as a result of a three-phase electrical fault anywhere on the power system.

A3.7 Definition of a non-credible contingency event

A non-credible contingency event is defined in clause 4.2.3(e) of the NER as a contingency event other than a credible contingency event. Without limitation, examples of non-credible contingency events are likely to include:

(1) three phase electrical faults on the power system; or

(2) simultaneous disruptive events such as:

(i) multiple generating unit failures; or

(ii) double circuit transmission line failure (such as may be caused by tower collapse).

Events which are normally considered to be non-credible contingency events include:

- The trip of any busbar in the transmission network (these involve multiple disconnections of transmission or generation assets).
- The simultaneous trip of more than one transmission element or generating unit.
- The trip of transmission plant in a manner not normally considered likely (for example, a transmission line that trips at one end only).

- The trip of more than one load block where the combined load lost exceeds that which would normally be considered a credible contingency event in that region.
- The trip of a combination of transmission plant, scheduled generating units or load, where that combination is not normally considered likely.

A3.8 Technical envelope

The technical envelope is defined in clause 4.2.5 of the NER as follows:

a) The technical envelope means the technical boundary limits of the power system for achieving and maintaining the secure operating state of the power system for a given demand and power system scenario.

b) AEMO must determine and revise the technical envelope (as may be necessary from time to time) by considering the prevailing power system and plant conditions as described in clause 4.2.5(c).

c) In determining and revising the technical envelope AEMO must consider matters such as:

   1) AEMO's forecast of total power system load;
   2) the provision of the applicable contingency capacity reserves;
   3) operation within all plant capabilities of plant on the power system;
   4) contingency capacity reserves available to handle any credible contingency event;
   5) advised generation minimum load constraints;
   6) constraints on transmission networks, including short-term limitations;
   7) ancillary service requirements;
   8) [Deleted]
   9) the existence of proposals for any major equipment or plant testing, including the checking of, or possible changes in, transmission plant availability; and
   10) applicable performance standards.

d) AEMO must, when determining the secure operating limits of the power system, assume that the applicable performance standards are being met, subject to:

   I. a Registered Participant notifying AEMO, in accordance with rule 4.15(f), that a performance standard is not being met; or
   II. AEMO otherwise becoming aware that a performance standard is not being met.

A3.9 Contingency management

Only credible contingency events are considered when assessing whether the system is in a secure operating state.

Contingency management refers to AEMO's operational management of the power system so that the power system remains within the pre-defined technical limits (primarily related to voltage, frequency, and asset loading) following a credible contingency.

A contingency on the power system may result in any number of abnormal conditions, some of which are listed below:

- Reduced transmission capacity between generators and load centres.
- Reduced interconnector transmission capacity.
- Separation of parts of the network into islands.

- Generation and loads relying on single connections resulting in larger than normal credible contingencies.

The majority of single contingency events are considered as being credible at all times. Some however, are defined as being credible or non-credible depending on the surrounding circumstances at the time.

A3.10 Reclassifying contingency events

Reclassification of a non-credible contingency event to a credible contingency event may be necessary at times to adequately reflect current or expected conditions. Abnormal conditions may result in reclassification. The reclassification is based on an assessed increase in the likelihood of a trip of equipment to occur, the occurrence of which is normally considered to be relatively low. If AEMO determines that the occurrence of the non-credible event is reasonably possible, based on established criteria, then AEMO must reclassify the event as credible.

The reclassification of a non-credible contingency event to a credible contingency event is to be advised to participants by the issue of a Market Notice.

Abnormal conditions are conditions posing added risks to the power system including (without limitation) severe weather conditions, lightning storms, and bushfires. Whenever AEMO receives information on abnormal conditions, AEMO will discuss the situation with the relevant TNSP to determine whether any non-credible contingency event is more likely to occur because of the existence of the abnormal condition. If abnormal conditions exist near a regional boundary, all relevant TNSPs will be consulted.

The usual outcome of a reclassification is the introduction of a system constraint which depending on circumstances:

- May increase prices in one or more NEM regions.
- May restrict flows on interconnectors between regions.

A3.11 Reclassifying contingency events due to lightning

Reclassification of a non-credible contingency event to a credible contingency event could be necessary at times to reflect current or expected conditions, known as 'abnormal conditions'. AEMO's Power System Security Guidelines[25] detail the process undertaken by AEMO, and criteria used when assessing whether such a reclassification is warranted. If AEMO determines that the occurrence of the non-credible contingency event is reasonably possible, AEMO will reclassify the event as a credible contingency event.

Lightning causing the trip of two adjacent transmission line circuits is considered to be highly unlikely and is generally not taken into consideration for reclassification.

A3.11.1 Vulnerable transmission lines

Lightning in the vicinity of a double circuit transmission line that is considered 'vulnerable' means the event is eligible to be reclassified as a credible contingency event during a lightning storm if a cloud to ground lightning strike is detected within a specified distance of the relevant line.

The criteria used to determine whether a line should be classified as 'vulnerable' include whether the line has tripped due to lightning in the last three years and where the TNSP has advised AEMO that the line has deteriorated to an extent that warrants reclassification[26]. These classifications are reviewed every two years. In general, the higher the operating voltage of a transmission line, the less it is likely to be affected by lightning.

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25 See http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Power-system-operation.

26 See Section 11.4 of AEMO's Power System Security Guidelines for further information, available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Power-system-operation.