ELECTRICITY STATEMENT OF OPPORTUNITIES

FOR THE NATIONAL ELECTRICITY MARKET

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AEMO

AUSTRALIAN ENERGY MARKET OPERATOR

IMPORTANT NOTICE

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Acknowledgement

AEMO acknowledges the support, co-operation and contribution of all participants in providing data and information used in this publication.

Version control

Version	Release date	Changes
1	11/8/2016	
2	21/9/2016	Adjustments to input demand data for Queensland and South Australia required further modelling, and republishing after changes to: • Table 1 (page 5), Table 9 (page 18), Table 13 (page 25), Table 15 (page 28), Table 18 (page 31), Table 21 (page 37). • Figure 1 (page 25), Figure 2 (page 26), Figure 3 (page 32), Figure 4 (page 33), Figure 5 (page 40), and Figure 6 (page 41). • Commentary on pages 3, 5, 7, 12, 18, 19, 26, 27, 28, 32, 41, 43. Minor inconsistencies in the reported status of Kiata wind farm have also been addressed. At the time of publication, the 30 MW Kiata wind farm is not a committed project.

EXECUTIVE SUMMARY

The *Electricity Statement of Opportunities* (ESOO) provides technical and market data that informs the decision-making processes of market participants, new investors, and jurisdictional bodies as they assess opportunities in the National Electricity Market (NEM) over a 10-year outlook period.

The 2016 NEM ESOO provides a projected outlook to 2025–26 of supply adequacy under a number of scenarios, and this year has modelled further generation withdrawals in response to Australia's 2015 Paris 21st Conference of Parties emission abatement commitment (COP21 commitment).

The 2016 NEM ESOO highlights that as intermittent generation (such as wind and rooftop photovoltaic (PV) generation) continues to increase, and thermal synchronous generation (such as coal and gas-fired generation) withdraws:

- Total installed generation capacity alone becomes a less reliable indicator of supply adequacy.
- Availability of plant to supply energy when needed, and capability to provide ancillary services, are both key factors to consider when assessing opportunities related to secure operations and supply adequacy in the NEM.

Key points in the 2016 NEM ESOO projections are:

- Under a neutral economic and consumer outlook – and in the absence of new generation, network or non-network development – coal-fired generation withdrawals at the levels assumed may lead to reliability standard[1] breaches:
  - In New South Wales by 2025–26, after the announced withdrawal of 2,000 megawatts (MW) of generation from Liddell in March 2022.
  - In Victoria by 2024–25, assuming up to 800 MW of coal-fired generation is withdrawn in the region in the outlook period in response to the COP21 commitment.
  - In South Australia from 2019−20 to 2021–22 and 2024–25 to 2025−26[2], attributed to assumed coal-fired generation withdrawals in Victoria tightening supply in both Victoria and South Australia. The withdrawal of Northern Power Station (546 MW) in May 2016 has increased South Australia's reliance on imports of energy and support services from Victoria during high demand periods.
  - No other NEM regions are projected to have breaches of the reliability standard to 2025–26.
- The future risk of load shedding is projected to be greatest between 2.00 pm and 8.00 pm, if high demand coincides with low wind and rooftop PV generation, unplanned generation outages, and/or low levels of imports from neighbouring regions.

  Additional intermittent generation alone may not materially improve the reliability of the system. Network or non-network developments, potentially including generation, storage, and demand side management services, may reduce the risk of load shedding if they can increase available supply or decrease demand at these times.

Reliability standard – specifies that the level of expected unserved energy should not exceed 0.002% of consumption per region, in any financial year.

COP21 commitment – Australia has set a target to reduce carbon emissions by 26% to 28% below 2005 levels by 2030.

[1] Australian Energy Market Commission (AEMC) Reliability Panel. NEM Reliability Standard – Generation and Bulk Supply. Available at: http://www.aemc.gov.au/getattachment/f93100d9-72d2-46fb-9c25-ac274a04ae58/Reliability-Standards-(to-apply-from-1-July-2012).aspx.

[2] The timing of generation withdrawals, growth in rooftop PV and variations in underlying demand growth across the NEM reduce the risk of reliability standard breaches in the years between.

The withdrawal of synchronous generation (such as coal and gas-fired generation) is leading to the scarcity of support services in the NEM. These support services include Frequency Control Ancillary Services (FCAS) and System Restart Ancillary Services (SRAS).

Key points on the current position and 2016 NEM ESOO projections are:

- There is adequate supply of FCAS for normal operating circumstances where FCAS can be sourced from anywhere within the NEM.

  Where there is a credible[3] risk of a NEM region islanding (separating from the rest of the NEM), FCAS must be sourced within the islanded region. There is an adequate supply of FCAS within any islanded region in the NEM, if facilities that provide FCAS are operating at the time of islanding.

  As the generation mix continues to evolve, there is a risk that those facilities will not be operating should an islanding event occur. This risk is highest in South Australia, and to a lesser extent in Queensland. Since October 2015, AEMO now procures 35 MW of regulation FCAS from within South Australia where a credible risk of islanding exists.
- In the rare event of the unexpected concurrent loss of both Heywood Interconnector lines, there is a high likelihood of a full region blackout in South Australia. The Heywood Interconnector has separated South Australia from the rest of the NEM due to such non-credible events on four occasions since 1999. The likelihood of a regional blackout after such a non-credible event increases as the region becomes more reliant on energy imports over the interconnector, and wind and rooftop PV generation, to meet demand. AEMO and ElectraNet are implementing generation and load-tripping control schemes to assist system security in the event of islanding.
- All regions currently have enough local sources of SRAS to meet the system restart standard, but supply is becoming scarce as synchronous generation withdraws from the NEM. Any further synchronous generation withdrawals in either South Australia or New South Wales will reduce the ability of those regional systems to be restarted if islanded.

FCAS – Frequency is a measure of the balance between supply and demand in the power system, which needs to be maintained every second of every day. AEMO determines the amount of FCAS capacity required to maintain frequency within prescribed frequency operating standards.

SRAS – A service to enable the power system to be restarted following a complete or partial black-out. A SRAS generating unit can provide its own power to restart, energising the grid and other generators.

Projected supply adequacy

In assessing potential reliability standard breaches, the 2016 NEM ESOO uses:

- Maximum demand and annual operational consumption forecasts published in the June 2016 *National Electricity Forecasting Report* (NEFR).[4]
- Industry-provided information on existing and committed generation capacities.
- Assumptions on additional generation withdrawals that may contribute to meeting the COP21 commitment.[5]

The NEM ESOO does not forecast any new development in response to either potential supply shortfalls or government policy, such as the Large-scale Renewable Energy Target (LRET) or COP21 commitment. Instead, it provides an assessment of supply adequacy in the absence of future development, to help stakeholders assess opportunities in the NEM.

[3] Credible contingency events are unexpected, but reasonably likely to occur. Examples include the outage of a single electricity transmission line, transformer, generating unit, or reactive plant, through one or two phase faults.

[4] AEMO. *2016 National Electricity Forecasting Report*. Available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Electricity-Forecasting-Report.

[5] Meeting the COP21 commitment is likely to require both generation withdrawals and investment in low-emission generation capacity.

Table 1 summarises AEMO's 10-year supply adequacy assessment for each NEM region, noting the earliest projected timing for any potential breach of the reliability standard. If no additional generation capacity withdrawals occur between now and 2025–26, beyond what industry has already announced, potential reliability standard breaches are only projected in New South Wales.

Table 1 Summary of projected supply adequacy shortfalls

Region	Includes announced generation capacity withdrawals and additional modelled withdrawals based on COP21 commitment assumptions						Includes announced generation capacity withdrawals only	
	Weak economic growth, with COP21		Neutral economic growth, with COP21		Strong economic growth, with COP21		Neutral economic growth	
	Timing	Shortfall	Timing	Shortfall	Timing	Shortfall	Timing	Shortfall
NSW	Beyond 2025–26	N/A	2025–26	0.0031%	2022–23	0.0095%	2025–26	0.0025%
QLD	Beyond 2025–26	N/A	Beyond 2025–26	N/A	2022–23	0.0029%	Beyond 2025–26	N/A
SA	2020–21	0.0021%	2019–20	0.0028%	2018–19	0.0029%	Beyond 2025–26	N/A
TAS	Beyond 2025–26	N/A	Beyond 2025–26	N/A	Beyond 2025–26	N/A	Beyond 2025–26	N/A
VIC	Beyond 2025–26	N/A	2024–25	0.0021%	2023–24	0.0026%	Beyond 2025–26	N/A

The forecast risk of unserved energy (USE) leading to reliability standard breaches under a neutral economic and consumer outlook is linked to specific conditions in each region:

- In South Australia and New South Wales, the risk is projected at times when high demand coincides with low wind and rooftop PV generation, unplanned generation outages, and/or low levels of imports from neighbouring regions.
- The risk may appear in each of Victoria, South Australia, and New South Wales, at times of high NEM-wide coincident maximum demand.

Most USE is projected to occur in the period between 2.00 pm and 8.00 pm. The risk is also projected to shift later in this period over the 10-year outlook, and to increase at times when rooftop PV is unavailable due to cloud cover, reflecting the forecast impact of increased rooftop PV uptake on maximum demand.

Network or non-network developments, potentially including generation, storage, and demand side management services, may reduce the risk of load shedding if they can increase available supply at these times.

Modelling to meet the COP21 commitment

Australia's COP21 commitment is to reduce carbon emissions by 26% to 28% below 2005 levels by 2030. For energy sector modelling, the Council of Australian Governments (COAG) Energy Council has agreed that the contribution of the electricity sector should be consistent with national emission reduction targets. COAG has stated that a 28% reduction from 2005 levels by 2030 is an appropriate constraint for AEMO to use in its ongoing forecasting and planning processes.

The 2016 NEM ESOO assumes this COAG commitment is achieved, and has modelled the impact of additional generation withdrawals, beyond those already announced by participants, which may contribute to Australia meeting this target.

Table 2 summarises the range of additional generation withdrawals AEMO has assumed under the NEFR's strong, neutral, and weak demand forecasts. The timing and size of withdrawals has been informed[6] by least-cost modelling of the COP21 emissions constraint, including an assumed emission reduction trajectory towards 2030, and the LRET.

Table 2 Additional generation capacity withdrawals assumed in modelling COP21, strong/neutral/weak economic outlook

	Retirements by Fuel Type	Capacity (MW)	Region
Neutral economic and consumer outlook			
2017–18	Brown coal	400	Victoria
2020–21	Black coal	560	Queensland
	Brown coal	400	Victoria
Strong economic and consumer outlook			
2018–19	Brown coal	400	Victoria
2020–21	Black coal	560	Queensland
Weak economic and consumer outlook			
2017–18	Brown coal	400	Victoria
2018–19	Brown coal	400	Victoria
2019–20	Brown coal	400	Victoria
2020–21	Black coal	560	Queensland
	Brown coal	400	Victoria

More generation withdrawals were assumed under the weak economic and consumer outlook, because lower forecast demand would increase supply surpluses, reducing the financial viability of some generating units.

Supply and demand changes in the NEM since the 2015 ESOO

The 2015 NEM ESOO reported potential breaches of the reliability standard in New South Wales, South Australia, and Victoria over the 10-year period to 2024–25, with breaches projected in South Australia as early as 2019–20 under the medium demand scenario.

In this 2016 NEM ESOO, reliability standard breaches in South Australia and Victoria are only projected with the added assumption that 800 MW of coal-fired generation withdraws in Victoria in response to the COP21 commitment.

The key change since 2015 is the reduced forecast for operational maximum demand from the grid. AEMO's 2016 NEFR attributes the lower forecast mainly to:

- Projections that underlying consumption growth will be increasingly offset by growth in rooftop PV, and increasing energy efficiency.
- Updated LNG production forecasts using actual data, now available since start-up.
- Slightly lower business growth projections, based on surveying large industrial consumers.
- Improved modelling, using bottom-up methods and new data sources, including smart meters, to more accurately understand and forecast trends in residential and business consumption.

Major changes to projected supply are:

- The market has responded to projected tight supply-demand conditions in some regions, with AGL announcing it will defer its planned withdrawal of the 480 MW Torrens Island A power

[6] Decisions to retire generation capacity are based on a number of considerations, not all of which can be captured in market modelling. The condition of assets, portfolio optimisation and financial position, rehabilitation costs, and company policies will all influence any commercial decision to withdraw generation. Therefore, actual location of generation withdrawals, amount of generation withdrawn, and timing could vary from what has been assumed here.

station in South Australia, and Hydro Tasmania returning the 58 MW Tamar Valley peaking power plant to service.

- As certainty around the LRET has increased, an additional 537 MW of wind generation capacity has been committed.[7]

Table 3 summarises the changes in operational maximum demand forecasts, and in existing and committed generation capacity, from the 2015 NEM ESOO to the 2016 NEM ESOO.

Table 3 Supply and demand in 2016 NEM ESOO compared to 2015 NEM ESOO (projected to 2025–26)

	NSW	QLD	SA	TAS	VIC
Summer maximum demand (10% POE)*	1,002 MW lower	320 MW lower	585 MW lower	42 MW higher	653 MW lower
Committed generation capacity announced	175 MW higher	-	122 MW higher	-	240 MW higher
Changes to withdrawal announcements	-	-	480 MW deferred	58 MW returned to service	-
Assumed withdrawals to model COP21 emissions reduction (neutral economic and consumer outlook)	-	Additional 560 MW assumed withdrawn	-	-	Additional 800 MW assumed withdrawn

* Difference between 2015 NEFR and 2016 NEFR 10% probability of exceedance (POE) maximum demand forecasts for each region in 2025–26. POE is the likelihood of the forecast being exceeded – a 10% POE forecast is expected to be exceeded, on average, only one year in 10.

Other potential supply gaps – network support services

The NEM ESOO has traditionally reported on energy supply adequacy, forecasting whether enough energy will be supplied to meet the maximum demand forecasts.

Secure operation of the power system also relies on a range of support services – FCAS, SRAS, and inertia – that synchronous generation has traditionally provided. The withdrawal of synchronous generation is reducing future availability of these services.

New generation development in response to the LRET or COP21 commitment could deliver multiple value streams by configuring plant to be able to contribute to the provision of these network support services.

Strategic coordination of network and non-network developments can also help improve efficient investment in electricity services for the long-term interests of consumers by considering multiple identified needs simultaneously where possible. AEMO's *2016 National Transmission Development Plan* will take a holistic, NEM-wide view of these challenges.

Frequency control ancillary services

The existing registered FCAS facilities are adequate to meet demand for the entire NEM and within each region, for the following conditions:

- NEM system normal operation, when FCAS can be sourced from anywhere within the NEM.
- Where a credible risk of islanding exists and the required FCAS must be sourced from within the islanded region, in circumstances where FCAS facilities are operating at that time.

AEMO is observing a reduction in the available supply of FCAS across the NEM. Changes to operating patterns of the registered FCAS facilities, or closure of these facilities, will reduce future FCAS supply. Reduction in the available FCAS capacity in South Australia and Queensland would

[7] Since 2016 ESOO modelling was completed, Hornsdale wind farm Stage 2 (102 MW) in South Australia and Mount Gellibrand wind farm Stage 1 (66 MW) in Victoria have also become committed. These supply increases are not expected to materially alter the analysis.

result in additional constraints on interconnector transfers for these regions when a credible risk of separation exists.

For the operation of South Australia, Queensland, and Tasmania as islands, all registered FCAS providers need to be online and operating to be able to supply some of the required FCAS. Withdrawal of any registered FCAS providers, or any of their registered FCAS facilities being offline during an islanding event, would increase the risk of widespread load shedding.

FCAS provision is presently from thermal and hydro generators, although other generation technologies may be capable of providing FCAS if configured appropriately.

Inertia and rate of change of frequency

High rates of frequency change increase the risk of power system plant tripping. The withdrawal of synchronous generation reduces inertia in the system, and results in higher rates of frequency change following a disturbance, such as the trip of a generator or load.

AEMO is working to identify any underlying rate of change of frequency (RoCoF) limits of the power system, and is exploring alternative ways of managing RoCoF through new measures such as a fast frequency response service. At present there is no market mechanism for the provision of these services.[8]

System restart ancillary services

Most generating units require power from the grid to restart after a major supply disruption. An SRAS source is able to provide its own power to restart, energising the grid and other generators.

While all regions currently have enough local sources of SRAS to meet the system restart standard[9], there is not a lot of liquidity in the market. Traditionally SRAS is sourced from coal, gas, or hydro generation, procured through a contracting process.[10] If units capable of providing SRAS become unavailable or retire from the NEM, the capability to restart some regional systems if islanded may be reduced.

To date, only conventional thermal and hydro generation have provided SRAS. Other generation technologies may be capable of providing SRAS if configured appropriately.

[8] On 24 June 2016, AGL submitted a rule change request for the Australian Energy Market Commission (AEMC) to consider introducing a NEM Inertia Ancillary Services Market. AEMO is examining the need for inertia services in the next five years as part of its Network Support Control Ancillary Services studies, to be published with the *National Transmission Network Development Plan* in November 2016.
[9] The AEMC Reliability Panel is currently reviewing the system restart standard.
[10] For information on the tender process please refer to SRAS guidelines: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Ancillary-services/System-restart-ancillary-services-guidelines.

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CHAPTER 1. ABOUT THE ELECTRICITY STATEMENT OF OPPORTUNITIES

1.1 Purpose and scope

The NEM ESOO has traditionally focused on using existing and committed electricity supply information provided by industry, and operational consumption and maximum demand[11] forecasts, to identify potential breaches of the reliability standard (which targets a maximum expected unserved energy of 0.002% of native consumption per region, in any financial year)[12] over a 10-year outlook period under a range of demand scenarios.

The 2016 NEM ESOO goes beyond this, to:

- Assess potential supply shortfalls if additional generation withdrawals occur in response to Australia's commitment to reduce emissions by 26% to 28% below 2005 levels by 2030, agreed at the 2016 Paris 21st Conference of Parties.
- Identify conditions in which additional network or non-network developments could improve system security within the next 10 years.

These enhancements are intended to better meet stakeholders' changing information and data needs, as the market responds to declining electricity consumption from the grid, an increasing focus on renewable and embedded generation, and withdrawal of thermal synchronous generation (such as coal and gas-fired generation).

1.2 Assumptions, methodology and data

The 2016 NEM ESOO modelling incorporates two models of the NEM[13], referred to as the generation outlook and time-sequential models:

- The generation outlook modelling provides insight into future generation withdrawals and entry of new generation capacity that could occur, over and above current industry announcements, to efficiently meet future operational demand and climate change policies.
- The time-sequential modelling takes the industry-announced new entry and generation capacity withdrawals and the assessed future generation withdrawals from the generation outlook model, and runs hourly Monte Carlo simulations to determine potential future supply shortfalls. The Monte Carlo simulations capture the impact of key uncertainties such as generator outage patterns, weather sensitive demand, intermittent generation availability, and coincidence of demand across NEM regions.

The NEM ESOO time-sequential modelling does not include any new development in response to either potential supply shortfalls or government policy. Instead, it provides an assessment of supply adequacy in the absence of future development, to help stakeholders assess opportunities in the NEM.

Further details of the NEM ESOO methodology are in the *2016 NEM ESOO methodology* document.[14]

[11] Operational consumption is electricity used by residential and business (commercial and industrial) consumers, drawn from the electricity grid. It includes electricity supplied by scheduled, semi-scheduled, and significant non-scheduled generating units, but not generation from rooftop PV and other small non-scheduled generation. It also includes distribution and transmission losses. Maximum demand is the highest level of electricity drawn from the transmission grid at any one time in a year. It is measured on a daily basis, averaged over a 30 minute period.

[12] Australian Energy Market Commission (AEMC) Reliability Panel. NEM Reliability Standard – Generation and Bulk Supply. Available at: http://www.aemc.gov.au/getattachment/f93100d9-72d2-46fb-9c25-ac274a04ae58/Reliability-Standards-(to-apply-from-1-July-2012).aspx.

[13] Using PLEXOS Integrated Energy Model simulation software, developed by Energy Exemplar.

[14] AEMO. *2016 ESOO Methodology*, August 2016. Available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities.

Input data used in the 2016 NEM ESOO is based on AEMO's *Planning Methodology and Input Assumptions*[15] document, updated to reflect the latest operational consumption and maximum demand forecasts developed for the *2016 National Electricity Forecasting Report* (NEFR)[16], transmission developments, and committed and existing generator availabilities, as at 1 July 2016. Committed and existing generator availabilities are based on AEMO's latest generator survey results.[17] As part of the generator survey, participants also provided comments on which previously announced projects were now unlikely to proceed.

Chapter 5 provides links to these and other supporting information sources.

1.3 Scenario modelling

The 2016 NEM ESOO scenarios, listed in Table 4, are based on the NEFR neutral, strong, and weak demand sensitivities. Three of the four scenarios assumed additional generation withdrawals (beyond those announced by industry) in response to Australia's COP21 commitment. The NEFR neutral demand sensitivity was also modelled using only industry-announced generation capacity changes as inputs (as in past NEM ESOO modelling).

The COAG Energy Council has agreed that the contribution of the electricity sector should be consistent with national emission reduction targets, and stated that a 28% reduction from 2005 levels by 2030 is an appropriate constraint for AEMO to use in its ongoing forecasting and planning processes.

In the 2016 NEM ESOO, the timing and size of assumed withdrawals has been informed by least-cost modelling of the COP21 emissions constraint, including an assumed emission reduction trajectory towards 2030, and the LRET. The amount of generation withdrawn in each ESOO scenario is influenced by several factors including the climate change policies, projected operational consumption growth, and the resulting revenue sufficiency of incumbent generators. By 2030, higher operational consumption would require a greater market response in order to meet the absolute emission target. In the medium term, however, higher operational consumption would improve profitability for coal-fired generators by reducing price and volume risk associated with continued uptake of renewable generation. Consequently, in the next ten years, fewer retirements are assumed in the strong NEFR demand sensitivity, and more are assumed in the weak NEFR demand sensitivity.

It is acknowledged that decisions to retire generation capacity are based on a number of considerations, not all of which can be captured in market modelling. The condition of assets, portfolio optimisation and financial position, rehabilitation costs, and company policies will all influence any commercial decision to withdraw generation. Therefore, actual location of generation withdrawals, amount of generation withdrawn, and timing could vary from what has been assumed here.

[15] AEMO's models and common assumptions have been updated for 2016 forecasting and planning reports, and will be published in late 2016 to accompany the 2016 National Transmission Network Development Plan. The previous version, Planning Methodology and Input Assumptions, January 2014, still provides some relevant detail and is available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan/-/media/FBBF4E5174DF472DAAB429E57799F4F0.ashx.

[16] AEMO. *2016 National Electricity Forecasting Report*, June 2016. Available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Electricity-Forecasting-Report.

[17] http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

Table 4 2016 ESOO scenario reference table

2016 ESOO scenario	2016 NEFR sensitivity	Additional withdrawals	Assumed timing and level of coal-fired generation withdrawals
Neutral Growth	Neutral economic and consumer growth sensitivity	No – industry-announced closures only	2021–22: 2,000 MW in NSW (Liddell)[18]
Neutral Growth, with COP21	Neutral economic and consumer growth sensitivity	Yes – contributing to meeting the COP21 commitment	2017–18: 400 MW in VIC 2020–21: 400 MW in VIC and 560 MW in QLD 2021–22: 2,000 MW in NSW (Liddell)
Strong Growth, with COP21	Strong economic and consumer growth sensitivity	Yes – contributing to meeting the COP21 commitment	2018–19: 400 MW in VIC 2020–21: 560 MW in QLD 2021–22: 2,000 MW in NSW (Liddell)
Weak Growth, with COP21	Weak economic and consumer growth sensitivity	Yes – contributing to meeting the COP21 commitment	2017–18: 400 MW in VIC 2018–19: 400 MW in VIC 2019–20: 400 MW in VIC 2020–21: 560 MW in QLD and 400 MW in VIC 2021–22: 2,000 MW in NSW (Liddell)

1.4 Improvements for the 2016 NEM ESOO

AEMO has included a number of methodology improvements in the 2016 NEM ESOO, some of which were flagged in the 2015 NEM ESOO. Improvements included:

- Improved assessment of the supply adequacy impact of year-on-year weather variations, including coincident demand, wind and rooftop photovoltaic (PV) availability.
- Establishment of withdrawal categories to better understand the future availability of withdrawn generation.
- Publication of more detailed information relating to potential supply shortfalls in each region.

Multiple reference years to capture variable climate conditions

As part of improving the NEM ESOO, AEMO this year modelled intermittent generation and demand profiles using multiple reference years (six financial years, 2009–10 to 2014–15). In previous NEM ESOO analysis, a single historical reference year was used to represent the pattern of demand and intermittent generation across the NEM, with 2009–10 deemed to be a representative year. The new approach better represents the variable weather conditions that can occur during high demand periods, as well as the variability of coincident demand across regions. More information on this approach is provided in the *2016 NEM ESOO methodology* document.

Categories of withdrawal

Generation plant withdrawal categories, informed by consultation with market participants, have been developed based on recall times to distinguish between generation plant that could be recalled to service and plant that is decommissioned.

These withdrawal categories were developed to explore the impact of returning short-term or seasonally withdrawn generation to service, where it could improve supply adequacy in a region at risk of breaching the reliability standard.

As the only Low Reserve Condition (LRC) point[19] under the Neutral Growth scenario was in New South Wales, and no generators were available to be recalled in that region, this withdrawal sensitivity was not required in this year's NEM ESOO.

[18] Based on advice received from AGL: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

[19] An LRC point indicates where the reliability standard is expected to be breached.

Table 5 provides a list of all industry-announced generation withdrawals, categorised according to the recall time indicated by participants.

More information about the newly developed withdrawal categories is in Appendix A.

Table 5 Announced withdrawals of plants in the NEM and their ability to be recalled

Participant	Plants	Region	Capacity (MW)	Fuel Type	Withdrawal date	Short-term withdrawal *Able to be recalled within three months*	Seasonal withdrawal *Able to be recalled within 3–6 months*	Long-term withdrawal *Able to be recalled within 6–12 months*
Energy Australia	Wallerawang	NSW	1,000	Black coal	Nov 2014	No	No	No
Hydro Tasmania	Tamar Valley CCGT	TAS	208	Gas	Aug 2015[20]	Yes	--	--
ENGIE	Pelican Point	SA	239	Gas	Apr 2015	Yes	--	--
Marubeni	Smithfield	NSW	175	Gas	July 2017	No	No	No
AGL	Liddell	NSW	2,000	Black coal	Mar 2022	No	No	No
Stanwell	Swanbank E	QLD	385	Gas	Feb 2014 – Nov 2017	Yes	--	--
Stanwell	MacKay GT	QLD	34	Liquid Fuel	Jul 2021	Yes	--	--

Information on potential supply shortfalls

The reliability standard targets no more than 0.002% of expected USE in any region in a given financial year. While expected USE may be below the reliability standard target, there may still be supply shortfalls under some Monte Carlo samples, driven by combinations of high demand, unplanned generation outages, and reduced availability of intermittent generation.

This year's NEM ESOO reports on the forecast frequency and magnitude (in MW) of regional USE across Monte Carlo samples, to provide stakeholders with more information to help in their assessments of development opportunities.

[20] This power station was temporarily returned to service between January and May 2016 to increase local supply in Tasmania while Basslink was out of service.

CHAPTER 2. GENERATION CAPACITY CHANGES

The major supply and demand changes impacting this energy supply adequacy projection, from the 2015 NEM ESOO to the 2016 NEM ESOO, are summarised in Table 6.

Table 6 Surplus capacity changes (MW) by region since the 2015 ESOO (all projected to 2025–26)

	NSW	QLD	SA	TAS	VIC
Summer maximum demand (10% POE)*	1,002 MW lower	320 MW lower	585 MW lower	42 MW higher	653 MW lower
Committed plant capacity announced	175 MW higher	-	122 MW higher	-	240 MW higher
Changes to withdrawal announcements	-	-	480 MW deferred	58 MW returned to service	-
Assumed withdrawals to model COP21 emissions reduction (neutral economic and consumer outlook)	-	Additional 560 MW assumed withdrawn	-	-	Additional 800 MW assumed withdrawn

* Difference between 2015 NEFR and 2016 NEFR 10% probability of exceedance (POE) maximum demand forecasts for each region in 2025–26. POE is the likelihood of the forecast being exceeded – a 10% POE forecast is expected to be exceeded, on average, only one year in 10.

2.1 NEM generation changes and investment trends

The NEM's current installed capacity[21] is 48,116 MW, comprising a range of technologies (51% coal, 22% gas, 8% wind, 17% water, <2% other).

The following changes have occurred since the 2015 NEM ESOO:

- 109 MW of large-scale solar projects previously committed are now operational in New South Wales.
- 705 MW of large-scale wind projects are now committed. Table 7 summarises new generation committed since 1 July 2015. As indicated in the table, some generators did not reach committed status until after 1 July 2016, and were therefore not included in the 2016 NEM ESOO modelling.
- 572 MW of generation previously withdrawn, or announced for withdrawal, is now available over the 10-year outlook period due to withdrawal decisions being reversed or deferred.[22] This includes:
  - Torrens Island A Power Station (480 MW).
  - Tamar Valley Peaking Plant (58 MW).
- Playford B Power Station (240 MW) and Northern Power Station (546 MW) have now closed, one year earlier than assumed in the 2015 NEM ESOO.
- Minor revisions have been made to summer, winter, or year-round generation capacity due to plant maintenance or plant capability reassessment (see Table 8).

[21] Including scheduled, semi-scheduled, and non-scheduled installed capacity, but excluding rooftop PV and capacity currently withdrawn.
[22] AEMO had been advised that Mackay GT (34 MW) would be withdrawn by 2017–18. The availability of this generator has now been extended to at least 2020–21, but this was too late to be incorporated in the 2016 NEM ESOO modelling (so is also not included in Table 6). Inclusion of Mackay GT would be unlikely to materially impact the results. Stanwell advises that the generator's availability will be regularly assessed based on future dynamics and outlook in the electricity and gas markets.

Table 7 New scheduled and semi-scheduled generation committed since the 2015 ESOO

Generator	Region	Capacity (MW)	Type	Assumed commissioning date	Included in 2016 NEM ESOO
Large Scale Wind		**705.2**			
White Rock	NSW	175	Wind	Dec 2018	Yes
Hornsdale Stage 1	SA	102.4	Wind	Nov 2016	Yes
Waterloo Stage 2	SA	19.8	Wind	Nov 2016	Yes
Ararat	VIC	240	Wind	May 2017	Yes
Hornsdale Stage 2	SA	102	Wind		No
Mt Gellibrand	VIC	66	Wind		No

Table 8 Minor revisions to generation capacity since the 2015 ESOO

Generator	Region	Capacity change (MW)	Reason
Boco Rock Wind Farm	NSW	60	Fully operational
Colongra	NSW	-76	Summer only
Mt Piper	NSW	-30	2016–17 only
Braemar 2	QLD	9	Summer only
Pelican Point	SA	5	Summer only
Tungatinah	TAS	26	Summer only
Fisher	TAS	-46	Summer 2016–17 only
Yallourn W	VIC	12	Summer and Winter
Murray 1	VIC	95	Winter only

AEMO is also tracking 19,102 MW of proposed[23] new generation capacity:

- This includes 65% (12,471 MW) wind, 25% (4,680 MW) gas, 9% (1,724 MW) solar, and 1% (193 MW) other[24] generation.
- As these projects are not committed, they are not incorporated in the 2016 NEM ESOO. AEMO will continue to monitor the status of generation projects, and keep the market informed of developments through the Generation Information page on AEMO's website.[25]

[23] 'Proposed' includes publicly announced and advanced projects only.
[24] 'Other' means geological heat and biomass fuels.
[25] http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

CHAPTER 3. NEM-WIDE OUTLOOK

3.1 NEM overview

The NEM ESOO assesses the adequacy of existing and committed electricity supplies to meet projected consumption across the NEM, by identifying LRC points. The LRC points indicate when the NEM reliability standard is expected to be breached.

These potential breaches signal opportunities for an efficiently operating market to adjust and respond.

The energy market of today is much more complex than it was historically, with rapid growth in areas such as demand side management, rooftop PV, intermittent generation, and storage technologies. At the same time, synchronous generation is withdrawing from the market. As a result, total installed generation capacity alone becomes a less reliable indicator of supply adequacy.

This creates opportunities for the market or policy-makers to address issues such as:

- The availability of plant to supply energy at specific times it is needed.
- The capacity of plant to provide support services, such as system restart or frequency control capability.

Therefore, the 2016 NEM ESOO has broadened its focus to investigate potential supply gaps in providing these electricity support services in future.

3.2 NEM supply adequacy

Table 9 summarises the forecast timing of the first LRC point for each region, as well as the USE observed for that LRC point in each scenario.

Table 9 Regional LRC timing and USE

Region	Includes announced plant withdrawals and additional modelled withdrawals based on COP21 commitment assumptions						Includes announced plant withdrawals only	
	Weak economic growth, with COP21		Neutral economic growth, with COP21		Strong economic growth, with COP21		Neutral economic growth	
	Timing	Shortfall	Timing	Shortfall	Timing	Shortfall	Timing	Shortfall
NSW	Beyond 2025–26	N/A	2025–26	0.0031%	2022–23	0.0095%	2025–26	0.0025%
QLD	Beyond 2025–26	N/A	Beyond 2025–26	N/A	2022–23	0.0029%	Beyond 2025–26	N/A
SA	2020–21	0.0021%	2019–20	0.0028%	2018–19	0.0029%	Beyond 2025–26	N/A
TAS	Beyond 2025–26	N/A	Beyond 2025–26	N/A	Beyond 2025–26	N/A	Beyond 2025–26	N/A
VIC	Beyond 2025–26	N/A	2024–25	0.0021%	2023–24	0.0026%	Beyond 2025–26	N/A

New South Wales, Queensland, South Australia, and Victoria may all observe LRC points within the 10-year outlook under certain scenarios and conditions:

In the Neutral Growth scenario:

- An LRC point is projected in New South Wales in 2025–26, due to tightening supply conditions after the withdrawal of Liddell Power Station in March 2022.

In the Neutral Growth COP21 scenario:

- An LRC point is projected in New South Wales in 2025–26, consistent with the Neutral Growth scenario.
- An LRC point is projected in Victoria in 2024–25, due to limited supply in the region after 800 MW of coal-fired generation is assumed to be withdrawn.
- Some LRC points are projected in South Australia from 2019–20, due to limited supply in South Australia and limited availability of imports from Victoria.

In the Weak Growth COP21 scenario:

- An LRC point is projected in South Australia in 2020–21, due to limited supply in South Australia and limited availability of imports from Victoria.

In the Strong Growth COP21 scenario:

- In New South Wales and Victoria, LRC points are projected earlier than in the Neutral Growth COP21 scenario, despite fewer assumed generation withdrawals, due to higher forecast consumption and maximum demand.
- In Queensland, LRC points are projected from 2022–23, due to the higher consumption and maximum demand forecast in this scenario.
- In South Australia, some LRC points are projected from 2018–19, due to limited supply in South Australia and limited availability of imports from Victoria.

Timing of unserved energy

Most USE is projected to occur in summer, between 2.00 pm and 8.00 pm, during periods of high demand that coincides with low wind or rooftop PV generation, generation outages, or low levels of inter-regional support. The risk is also projected to shift later in this period over the 10-year outlook, reflecting the forecast impact of increased rooftop PV uptake.

To improve future supply adequacy, new developments would need to increase accessibility to, or availability of, supply under these conditions.

3.3 Other potential supply gaps – support services

The withdrawal of synchronous generation is increasing the scarcity of support services in the NEM. These support services include frequency control ancillary services (FCAS) and system restart ancillary services (SRAS).

3.3.1 Frequency control ancillary services

The NEM power system operates with a set frequency ranges around 50 Hertz (Hz). This underpins the safe, secure and reliable transmission of power through the electricity supply chain from generators to consumers.

Controlling power system frequency requires the constant balancing of electricity supply and demand. If electricity supply exceeds demand at an instant in time, power system frequency will increase. If electricity demand exceeds supply at an instant in time, power system frequency will decrease. If the frequency change is too great, generation and load can be disconnected.

AEMO uses FCAS to maintain the frequency on the electrical system, at any point in time, close to fifty cycles per second as required by the NEM frequency operating standards.[26,27]

[26] This is being explored in AEMO's Future Power System Security program. Reports and analysis from this program are available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/FPSSP-Reports-and-Analysis.

[27] For introductory information on Frequency Control Ancillary Services, see AEMO's *Guide to Ancillary Services in the National Electricity Market*. Available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Ancillary-services.

The existing supply of both regulation and contingency FCAS (see below) is adequate to meet demand for the entire NEM and within each region, for the following conditions:

- NEM system normal operation, when FCAS can be sourced from anywhere within the NEM.
- Where a credible risk of islanding exists and the required FCAS must be sourced from within the islanded region, in circumstances where FCAS facilities are operating at that time.

AEMO is observing a reduction in the available supply of FCAS across the NEM. Changes to operating patterns of the registered FCAS facilities, or closure of these providers, will reduce future FCAS supply.

FCAS provision is presently from thermal and hydro generators, although other generation technologies may be capable of providing FCAS if configured appropriately.

Regulation FCAS

Regulation FCAS is enabled to continually correct the generation/demand balance in response to minor deviations in load or generation. These minor deviations in power system frequency can arise from a range of factors that create small mismatches between generation and demand. These can include any (or a combination) of:

- Aggregate variations in wind or solar generation output within the dispatch interval.
- Aggregate variations between actual and forecast demand within the five minute dispatch interval.
- Scheduled generation not meeting central dispatch targets.

There are two types of regulation FCAS:

- Raise (used to correct a minor drop in frequency).
- Lower (used to correct a minor rise in frequency).

The minimum requirement for regulation FCAS for the NEM is 120 MW of lower, and 130 MW of raise. This requirement is automatically increased in response to accumulated frequency errors.

In 2015, the requirement reached maximum values of 450 MW of raise and 325 MW of lower. The duration curve for regulation FCAS requirements in 2015 is included in Appendix B.

There is 7,055 MW of supply of regulation raise registered in the NEM, and 7,023 MW of regulation lower.[28] This far exceeds the requirements in 2015, supporting AEMO's projection that a regulation shortfall is unlikely during normal conditions, where FCAS can be sourced from anywhere in the NEM, over the next ten years.

In future, the requirement for regulation FCAS is likely to increase, with growth in variable generation (such as wind and PV) contributing to increased generation variability. Utility-scale PV, in particular, is likely to contribute significant variability that will need to be managed by regulation FCAS.

AEMO's preliminary analysis indicates that the increase in regulation FCAS requirements will be moderate in the next ten years, and will remain within the regulation FCAS capacity registered in the NEM.[29]

Contingency FCAS

Contingency FCAS is enabled to correct the generation/demand balance following a major contingency event, such as the loss of a generating unit or major industrial load, or a large transmission element. Contingency services are enabled in all periods to cover contingency events, but are only occasionally used (if the contingency event actually occurs).

[28] Data up to date at 11 April 2016.
[29] This is being explored in AEMO's Future Power System Security program. More information about the program is available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability.

There are six types of contingency FCAS, outlined in the following table.

Table 10 Types of contingency FCAS

	Response time	Purpose
Fast raise	6 Seconds	To ***arrest*** a major drop in frequency following a contingency event
Fast lower	6 Seconds	To ***arrest*** a major rise in frequency following a contingency event
Slow raise	60 Seconds	To ***stabilise*** frequency following a major drop in frequency
Slow lower	60 Seconds	To ***stabilise*** frequency following a major rise in frequency
Delayed raise	5 Minutes	To ***recover*** frequency to the normal operating band following a major drop in frequency
Delayed lower	5 Minutes	To ***recover*** frequency to the normal operating band following a major rise in frequency

The requirement for contingency FCAS is mostly determined by the size of the largest load or generation contingency event.[30]

In the 2015 calendar year, contingency raise FCAS requirements were as high as the maximum values listed in Table 11. The duration curves for contingency FCAS requirements in the NEM in 2015 are in Appendix B.

Table 11 also lists the total quantities of Contingency FCAS registered in the NEM.[31]

Table 11 Supply and demand for contingency FCAS in 2015 (all regions) (MW)

	Maximum capacity required in 2015		Total capacity registered with AEMO	
	Raise	Lower	Raise	Lower
Fast (6 seconds)	596	576	4,576	3,570
Slow (60 seconds)	856	662	9,529	7,335
Delayed (5 minutes)	721	550	9,188	8,518

The supply of contingency FCAS in the NEM far exceeds the demand for each service, so AEMO projects that a shortfall in contingency FCAS is unlikely during normal conditions, where FCAS can be sourced from anywhere in the NEM, over the next ten years.

Future supply gaps may arise if there is significant withdrawal of the synchronous generation units that have provided these services in the past, and these are not replaced by new entrants registering to provide these services. The potential for region-specific supply gaps is discussed in the regional summaries in Chapter 4, where applicable.

3.3.1 Inertia and rate of change of frequency

Synchronous generation provides an inherent inertial response to frequency deviations, slowing the RoCoF. High RoCoF threatens power system security by compromising the effectiveness of frequency control mechanisms. As synchronous generation is progressively withdrawn, the level of synchronous inertia will eventually become too low to maintain RoCoF within secure levels.

Synchronous inertia is plentiful in the NEM, and power system security issues related to RoCoF are not anticipated in the next ten years while the NEM is fully interconnected. Specific regional issues are discussed in Chapter 4.

[30] It is also affected by power system demand levels, the amount of regulation FCAS procured, and in some regions the local inertia level.
[31] Data up to date at 11 April 2016.

AEMO is seeking to quantify the underlying RoCoF limits of the power system, while also exploring the technical feasibility of alternative ways of managing RoCoF through a fast frequency response service.[32] At present there is no market mechanism for the provision of these services.[33]

3.3.2 System restart ancillary services

Most generating units require energy from the grid to be able to start generating electricity. If supply from the system is lost, these generating units would not be capable of independently restarting.

Some generating units have specialised equipment that allows them to restart without external support. These units would then be available to energise a point on the transmission system, restore other generating units, and hence begin restoring the power system. AEMO has contracts with a number of generators to provide this SRAS.

The current system restart standard requires re-energisation of the transmission network and other generation capacity to a level sufficient to supply 40% of peak demand within four hours of a major disruption. To achieve this, it is necessary to restart a sufficient quantity of SRAS-capable and non-SRAS-capable synchronous generation within the specified timeframes. Further withdrawal of any synchronous generation, whether or not contracted to provide SRAS, will increase the time required to restore supply and could reduce the ability of some regional systems to be restarted to meet the standard if islanded. Specific regional issues are discussed in Chapter 4.

To date, only conventional thermal and hydro generation have provided SRAS. Other generation technologies may be capable of providing SRAS if configured appropriately.

AEMO has contracts for the provision of SRAS in all NEM regions until 2018, with further extensions possible for up to two years. The Australian Energy Market Commission (AEMC) Reliability Panel is currently undertaking a review of the system restart standard[34] (the review is due for completion by the end of 2016), which may change the required amount and locations of SRAS, and the manner in which it is specified. AEMO will respond to any changes to this standard as required.

[32] This is being explored in AEMO's Future Power System Security program. More information about the program is available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability.

[33] On 24 June 2016, AGL submitted a rule change request for the AEMC to consider introducing a NEM Inertia Ancillary Services Market. AEMO is examining the need for inertia services in the next five years as part of its Network Support Control Ancillary Services studies to be published with the *National Transmission Network Development Plan* in November 2016.

[34] For more information, see http://www.aemc.gov.au/Markets-Reviews-Advice/Review-of-the-System-Restart-Standard#.

CHAPTER 4. REGIONAL OUTLOOK

This chapter provides a supply adequacy overview for each NEM region, including:

- Overview of trends and projections.
- Summary of generation changes and investment trends.
- The supply-demand outlook, highlighting any LRC points and projected USE.
- Any supply gaps for support services, such as FCAS and SRAS.

4.1 New South Wales

Overview

- Since the 2015 ESOO, no new generation withdrawals have been announced in New South Wales and 175 MW of new wind and 23 MW of new solar generation has been committed (see Table 12). Two solar farms, previously committed, became operational in 2015–16 (53 MW Broken Hill Solar Farm, and 56 MW Moree Solar farm).
- Most projected USE is due to the announced withdrawal of 2,000 MW of generation from Liddell in March 2022, combined with a slight increase in forecast underlying consumption and maximum demand[35] (see Figure 1).
- Under the Neutral Growth and Neutral Growth COP21 scenarios, projected USE in New South Wales could exceed the reliability standard from 2025–26, three years later than projected in the 2015 NEM ESOO. This is primarily due to reductions in operational consumption and maximum demand forecasts compared to the 2016 NEM ESOO (see Table 13). Forecast USE is slightly higher under the Neutral Growth COP21 scenario than under the Neutral Growth scenario, as the assumed removal of additional generation in Queensland and Victoria means those regions are forecast to provide less support to New South Wales via exports.
- In the Strong Growth COP21 scenario, projected USE is higher, due to an increase in forecast maximum demand and consumption, and a potential breach of the reliability standard is projected in 2022–23, immediately following the withdrawal of Liddell.
- No LRC point is projected under the Weak Growth COP21 scenario.

Generation changes and investment trends

Table 12 shows the current capacity of New South Wales' existing and withdrawn generation, and committed and publicly announced projects, by generation type.

[35] Underlying demand is behind the meter consumption for a household or business, and includes demand that could be met by rooftop PV.

Table 12 New South Wales generation and project capacity by generation type (MW)

Status/Type	Coal	CCGT[a]	OCGT[b]	Gas other	Solar	Wind	Water	Biomass	Other	Total
Existing[c]	10,240	591	1,488	147	231	666	2,745	131	51	16,289
Committed	0	0	0	0	23	175	0	0	0	198
Proposed	0	0	500	15	212	4,723	0	16	0	5,466
Withdrawn	0	0	0	0	0	0	0	0	0	0
Publicly announced withdrawals[d]	2,000	171	0	0	0	0	0	0	0	2,171

a. Combined-cycle gas turbine.
b. Open-cycle gas turbine.
c. Existing includes announced withdrawals.
d. These are withdrawals that have been announced to occur within the next 10 years.

New South Wales has three committed projects:

- White Rock Wind Farm (175 MW).
- Mugga Lane Solar Park (13 MW) – small, non-scheduled generation.
- Williamsdale Solar Farm (10 MW) – small, non-scheduled generation.

Generation investment interest in New South Wales is primarily focused on wind generation projects, with AEMO aware of 24 proposed projects totalling 4,723 MW. The larger proposed projects include:

- Uungula (622.5 MW).
- Jupiter Wind Farm (350 MW).
- Rye Park (350 MW).
- Sapphire (319 MW).
- Yass Valley (310 MW).
- Bango Wind Farm (280 MW).

Solar generation investment interest also remains strong in New South Wales, with seven proposed projects. The larger projects include:

- Parkes Solar (60 MW).
- Manildra PV Solar farm (50 MW).
- Capital Solar (33.7 MW).

The only gas-powered generation (GPG) proposal AEMO has been informed of is the Dalton (500 MW) project.

Supply adequacy assessment

Key points are:

- Forecast USE increases materially under both the Neutral Growth and the Neutral Growth COP21 scenarios from 2022–23, after the closure of Liddell Power Station in March 2022 (shown in Figure 1).
- USE is projected to reach an LRC point in 2025–26 due to an increase in underlying maximum demand (from 14,207 MW in 2022–23 to 14,598 MW in 2025–26, based on the 2016 NEFR 10% POE forecast). Operational maximum demand is plateauing, driven by the projected uptake of rooftop PV, and increasing energy efficiency. Under cloudy conditions, when rooftop PV generation falls, the system reliability impact of the growth in underlying maximum demand is forecast to become more pronounced.

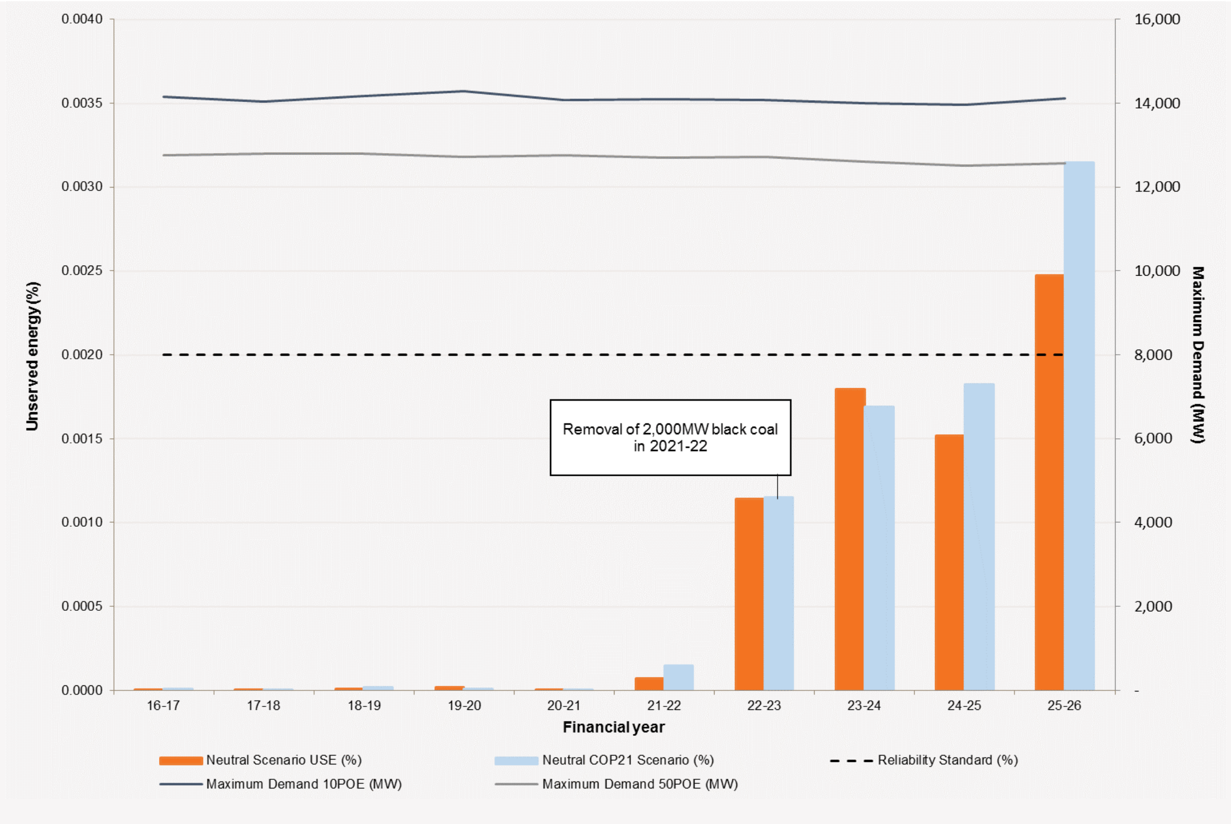
Low Reserve Conditions

Table 13 New South Wales LRC timing and USE

Region	Includes announced plant withdrawals and additional modelled withdrawals based on COP21 commitment assumptions						Includes announced plant withdrawals only	
	Weak Growth COP21		Neutral Growth COP21		Strong Growth COP21		Neutral Growth	
	Timing	Shortfall	Timing	Shortfall	Timing	Shortfall	Timing	Shortfall
NSW	Beyond 2025–26	N/A	2025–26	0.0031%	2022–23	0.0095%	2025–26	0.0025%

To highlight LRC points, Figure 1 shows the levels of projected USE as a percentage of total demand, and compares this with the reliability standard of 0.002% USE and the NEFR 10% POE and 50% POE operational maximum demands.

Figure 1 New South Wales supply adequacy (Neutral Growth and Neutral Growth COP21 scenarios)



Unserved energy

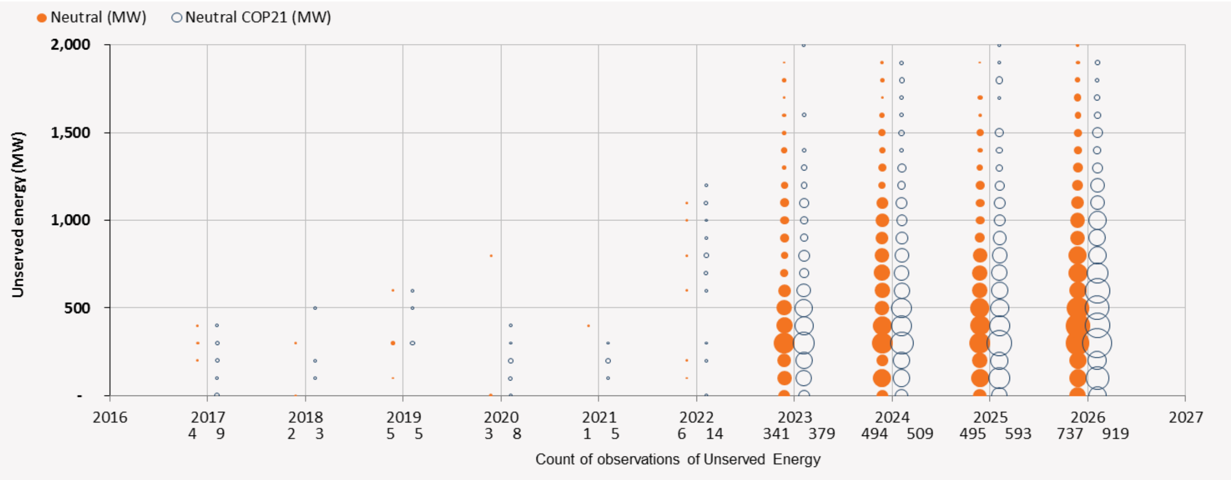
The projected risk of USE in New South Wales is highest at times when high demand coincides with low wind and rooftop PV generation, unplanned generation outages, and/or low levels of imports from neighbouring regions. In the Neutral Growth and Neutral Growth COP21 scenarios, more than 90% of USE in New South Wales in 2025–26 is projected to occur between 2.00 pm to 8.00 pm, under these limited supply conditions.

Figure 2 shows the forecast frequency and magnitude (in MW) of USE in New South Wales across all the Monte Carlo simulations for the Neutral Growth and Neutral Growth COP21 scenarios. For each financial year, it shows a bubble at the magnitude of USE observed in the projection, with the size of the bubble indicating how often that level of USE is forecast to occur.

The figure highlights that:

- USE in both the Neutral Growth and Neutral Growth COP21 scenario occurs infrequently in New South Wales before the closure of Liddell Power Station in 2022. After 2022, the frequency of USE in both scenarios increases, illustrated by more and larger bubbles.
- When USE is projected in the Neutral Growth COP21 scenario, half the observed shortfalls are less than 457 MW. The most frequent occurrence is in the 300–400 MW band for the year 2025–26. Across the 126 Monte Carlo simulations, there were 90 and 112 observations in this band in the Neutral Growth and Neutral Growth COP21 scenarios respectively.
- The maximum projected USE in a period exceeded 2,500 MW, under conditions of high demand, several concurrent unplanned generation outages and low intermittent generation.

Figure 2 New South Wales distribution of unserved energy (Neutral Growth and Neutral Growth COP21 scenarios)



4.1.1 Frequency control ancillary services

New South Wales has multiple connections with the rest of the NEM, and therefore does not have a credible risk of islanding under foreseeable planned outage conditions. This means the supply-demand balance for FCAS services in New South Wales is similar to the NEM-wide situation, which shows no anticipated shortfall in the next ten years.

4.1.2 Inertia and rate of change of frequency

New South Wales has multiple connections with the rest of the NEM, and therefore does not have a credible risk of islanding. This means low synchronous inertia and associated exposure to high RoCoF is not likely to pose a system security challenge in New South Wales in the next ten years.

4.1.3 System restart ancillary services

AEMO has contracts for the provision of SRAS in New South Wales until 2018, with further extensions possible for up to two years. Presently there are a large number of SRAS-capable sources in the Northern and Southern New South Wales sub-networks.

The majority of non-SRAS-capable generation, which must be restarted by the SRAS sources, is conventional coal-fired stations. Coal-fired generation typically takes over six hours to restore, much longer than generating units based on gas or hydro technologies. Therefore, the majority of New South Wales' non-SRAS-capable generation cannot be used within the first six hours of system restoration.

Opportunity exists for retrofitting the current fleet of non-SRAS-capable large coal-fired generation, in particular those closest to load centres, to diversify and enhance the current fleet of SRAS-capable generation. Additionally, new generation that can be restarted within six hours would help restart the region sooner if New South Wales were to experience a major supply disruption.

4.2 Queensland

Overview

- Since 1 July 2015, no new generation capacity commitments or withdrawals have been announced in Queensland, although Mackay GT (34 MW) has extended its availability at least until 2020–21. The 28 MW Cook Shire Solar project and the 15 MW Oaky Creek 2 gas project, committed small non-scheduled generators were accounted for in the operational demand forecast used for the NEM ESOO modelling, and not in the generation modelling.
- LRC points are projected under the Strong Growth COP21 scenario from 2022–23.
- No LRC points are projected under the other scenarios.

Generation changes and investment trends

Table 14 shows the current capacity of Queensland's existing and withdrawn generation, and committed and publicly announced projects, by generation type.

Table 14 Queensland generation and project capacity by generation type (MW)

Status/Type	Coal	CCGT[a]	OCGT[b]	Gas other	Solar	Wind	Water	Biomass	Other	Total
Existing[c]	8,216	1,213	1,894	172	0	12	664	367	1	12,540
Committed	0	0	0	15	28	0	0	0	0	43
Proposed	0	0	2,545	0	646	989	0	158	0	4,338
Withdrawn	0	385	0	0	0	0	0	0	0	385
Publicly announced withdrawals[d]	0	0	0	0	0	0	0	0	0	0

a. Combined-cycle gas turbine.
b. Open-cycle gas turbine.
c. Existing includes announced withdrawal.
d. These are withdrawals that have been announced to occur within the next 10 years.

AEMO is aware of seven proposed wind generation projects in Queensland, totalling 954 MW. The largest projects are:

- Coopers Gap (350 MW).
- Crows Nest (200 MW).
- Mt Emerald (180 MW).
- Archer Point (120 MW).

Interest in GPG continues in Queensland with:

- Westlink Power proposals (up to 1,000 MW).
- Braemar 3 (550 MW) and Braemar 4 (495 MW).
- Darling Downs 2 (500 MW).

Queensland also has increased generation interest in large-scale solar projects, with 12 projects proposed. The major solar projects are:

- Lilyvale (150 MW).
- Darling Downs Solar (106 MW).
- Clare (100 MW).

Supply adequacy assessment

- No breaches are projected under the Weak Growth COP21, Neutral Growth COP21, or Neutral Growth scenarios.
- LRC points are projected in Queensland from 2022−23 in the Strong Growth COP21 scenario, as shown in Table 15, due to increased forecast demand.

Table 15 Queensland LRC timing and USE

Region	Includes announced plant withdrawals and additional modelled withdrawals based on COP21 commitment assumptions						Includes announced plant withdrawals only	
	Weak Growth COP21		Neutral Growth COP21		Strong Growth COP21		Neutral Growth	
	Timing	Shortfall	Timing	Shortfall	Timing	Shortfall	Timing	Shortfall
QLD	Beyond 2025–26	N/A	Beyond 2025–26	N/A	2022–23	0.0029%	Beyond 2025–26	N/A

4.2.1 Frequency control ancillary services

Reduction in the supply of FCAS in Queensland would result in additional constraints on interconnector transfers between New South Wales and Queensland, when a credible risk of separation exists.

For the operation of Queensland as an island, high numbers of registered FCAS providers would be required to be online and operating to be able to supply the required FCAS. Withdrawal of FCAS providers, or any registered FCAS facilities being offline during an islanding event, would increase the risk of widespread load shedding.

Regulation FCAS

At present, AEMO only procures regulation FCAS locally within Queensland when an actual separation event occurs and Queensland must be managed as an island. In this case, AEMO procures 110 MW of both raise and lower regulation FCAS, sourced within Queensland.

There is currently 1,026 MW of regulation raise and 1,054 MW of regulation lower capacity registered in Queensland. Within the 10-year outlook period, AEMO’s modelling assumes the retirement of 100–200 MW of regulation FCAS capacity from Queensland in 2021 as coal-fired generation withdraws in response to the COP21 commitment. Even taking into account these assumed withdrawals, the anticipated supply of registered providers in Queensland remains far in excess of the 110 MW islanded regulation requirement.

To provide regulation FCAS, units must be already online and generating at a favourable operating point at the time of separation. This may not be possible at short notice (following separation) for many thermal units, due to long start-up times. In future, if the operating patterns and unit commitment decisions of the incumbent generation fleet change, additional generating units with very short start-up times may assist in maintaining system security.

Contingency FCAS

Network outages involving components of the QNI Interconnector result in periods where the synchronous separation[36] of Queensland from the rest of the NEM is a credible risk. During these periods, AEMO obtains contingency FCAS locally from generation within Queensland to manage the frequency deviation that would result from the separation.[37]

In 2015, Queensland was considered at credible risk of separation for around 252 hours, or around 2.9% of the year. No actual Queensland separation events occurred. For the majority of the time where a local FCAS contingency requirement existed, supply exceeded demand. However, there were short periods where demand (ranging between 0 MW and 256 MW) equalled available online supply in Queensland (see Appendix B). During these periods, power transfer between New South Wales and Queensland was constrained.

During an actual islanding event in Queensland, the supply of FCAS in real time could be low if some of the generating units registered to provide these services were not already online. This could be the case particularly for contingency lower FCAS, as the largest load contingency in Queensland is large (approximately 400–450 MW), relatively constant, and cannot be optimised in the dispatch process.

AEMO's modelling assumed the possible retirement of around 40–50 MW of contingency lower FCAS capacity from Queensland in 2021. Further reductions in the availability of contingency lower FCAS within Queensland, beyond the assumed withdrawals, could challenge AEMO's ability to manage frequency within required limits under conditions of an actual Queensland island, increasing the risk of load shedding.

Table 16 lists the registered contingency FCAS capacity available to AEMO from participants located in Queensland, and the contingency FCAS enabled in 2015 (from periods in 2015 when Queensland was at credible risk of islanding, so there was a local requirement for contingency lower FCAS). To provide FCAS, these registered units must be already online and generating at a favourable operating point, which may not be possible at short notice.

Table 16 Contingency FCAS services in the Queensland region (MW)

	Contingency raise registered capacity	Local enablement in 2015	Contingency lower registered capacity	Local enablement in 2015
6 second (R6/L6)	1,184	0–179	688	0–179
60 second (R60/L60)	2,023	0–220	923	0–182
5 Min (R5/L5)	1,617	0–287	3,373	0–90

4.2.2 Inertia and rate of change of frequency

Significant growth in non-synchronous (wind and PV) generation in Queensland could lead to reduced periods of operation by synchronous generation, reducing system inertia. This could expose Queensland to high RoCoF upon non-credible loss of the QNI interconnector during some periods, increasing the risk of load shedding. AEMO's Future Power System Security Program is examining a range of ways this risk could be managed.[38]

4.2.3 System restart ancillary services

AEMO has contracts for the provision of SRAS in Queensland until 2018, with further extensions possible for up to two years.

[36] Synchronous separation is when a NEM region loses all of its alternating current network connections with the rest of the NEM.
[37] Raise or lower service, depending on the direction of flow on the remaining transmission line, with the quantity determined by the interconnector flow.
[38] More information about the program is available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability.

No shortfall in SRAS capability is anticipated in Queensland in the next ten years, unless more than two gigawatts (GW) of SRAS-capable synchronous generation retires in the region.

4.3 South Australia

Overview

- Generation capacity reserves in South Australia reduced in 2015–16, with the closure of Northern and Playford power stations. This is placing greater reliance on imports from Victoria to meet underlying demand in periods when local wind generation or rooftop PV availability is low.
- Under the Neutral Growth COP21 scenario, the reliability standard may first be breached in 2019−20 (see Table 18).
- LRC points are projected under the Strong Growth COP21 from 2018–19 and under the Weak Growth COP21 scenario in 2020–21.
- No LRC points are observed in the outlook period under the Neutral Growth scenario.

Generation changes and investment trends

Table 17 shows the current capacity of South Australia's existing and withdrawn generation, and committed and publicly announced projects, by generation type.

Table 17 South Australia generation and project capacity by generation type (MW)

Status/Type	Coal	CCGT[a]	OCGT[b]	Gas other	Solar	Wind	Water	Biomass	Other	Total
Existing[c]	0	419	915	1,280	0	1,473	3	21	129	4,240
Committed[d]	0	0	0	0	0	225	0	0	0	225
Proposed	0	200	320	0	702	2,951	0	20	0	4,193
Withdrawn	786	239	0	0	0	0	0	0	0	1,025
Publicly announced withdrawals[e]	0	0	0	0	0	0	0	0	0	0

a. Combined-cycle gas turbine.
b. Open-cycle gas turbine.
c. Existing includes announced withdrawal.
d. This includes the Waterloo Wind Farm expansion (19.8 MW) which reached "committed" status based on AEMO's criteria in August 2016.
e. These are withdrawals that have been announced to occur within the next 10 years.

South Australia has three committed wind farm projects:

- Hornsdale Stage 1 (102.4 MW) currently under construction.
- Hornsdale Stage 2 (102.4 MW).
- Waterloo expansion (19.8 MW) currently under construction.

Generation investment interest in South Australia is focused on wind generation, with 17 proposed projects, totalling 3,176 MW. The largest projects are:

- Ceres (up to 670 MW).
- Woakwine (400 MW).
- Palmer (309 MW).
- Kongorong (up to 240 MW).

In the Port Augusta area, several large solar proposals have also been announced since the 2015 NEM ESOO:

- Port Augusta Renewable Energy Park – combined wind and solar PV farm (175 MW solar and 200 MW wind, totalling 375 MW).
- Aurora Solar Energy – solar thermal plant with molten salt energy storage (110 MW).
- Port Augusta Solar – solar thermal plant with graphite block energy storage (100 MW).
- Bungala Solar Power – solar PV farm (100–300 MW).

South Australia has two publicly announced GPG proposals:

- Pelican Point Stage 2 (320 MW).
- Leigh Creek Energy Project (200 MW).

A project is currently nearing completion to increase the capacity of the Heywood Interconnector from nominal 460 MW to 650 MW in both directions, although the realised capacity may be lower under certain operating conditions. The 2016 ESOO modelled constraint equations for the Heywood Interconnector which assume a nominal capacity of 650 MW in both directions from 1 July 2016.

Supply adequacy assessment

Low Reserve Conditions

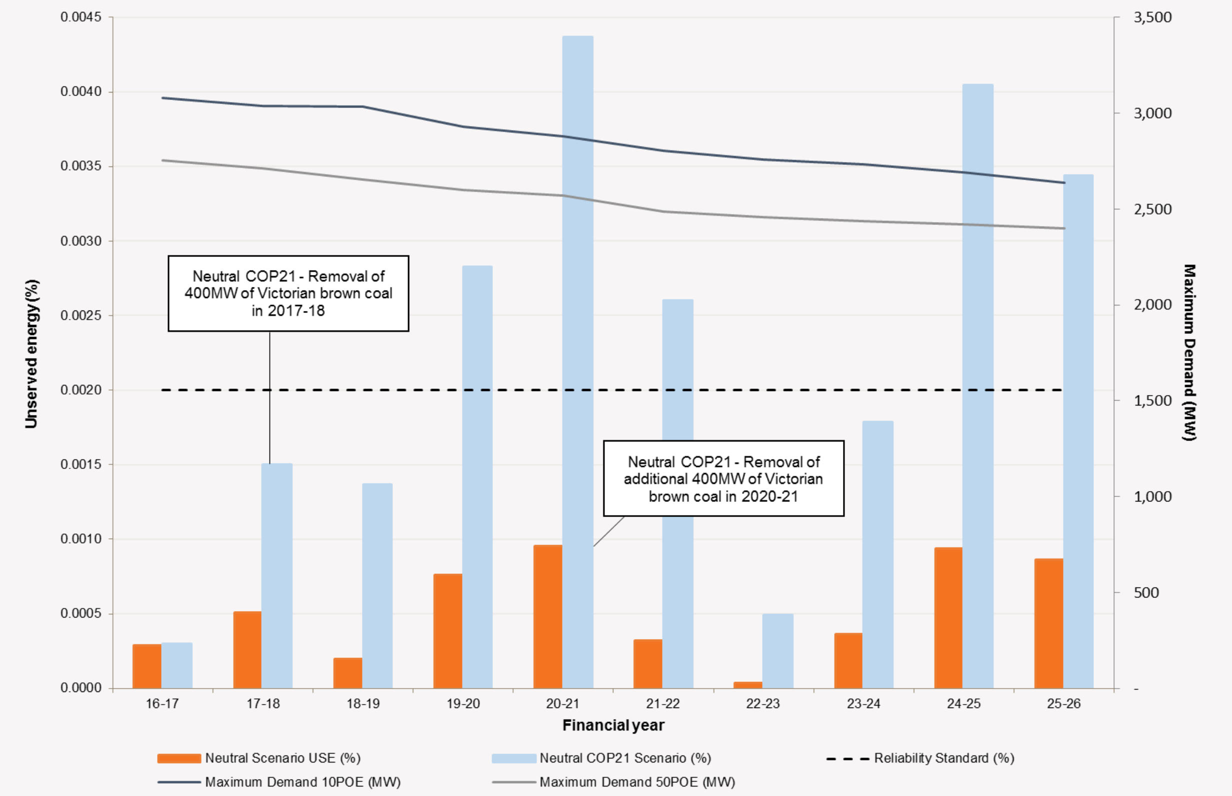
- Since the closure of Northern Power Station in May 2016, South Australia has become more reliant on interconnection with Victoria for energy supply. In the absence of new development, potential reductions in coal-fired generation capacity across the NEM will pose a risk to future supply reliability in South Australia. Under the Neutral Growth COP21 scenario, reliability standard breaches are projected in South Australia from 2019−20 to 2021–22 and 2024–25 to 2025−26 due to withdrawal of coal-fired generation capacity in neighbouring regions.
- LRC points are also projected in South Australia from 2019−20 in the Strong Growth COP21 scenario, due to increased forecast demand, despite fewer additional coal-fired generation withdrawals across the NEM.
- In the Weak Growth COP21 scenario, one LRC point is projected in South Australia in 2020-21, when the last of the assumed brown coal generation withdrawals occur in Victoria. Forecast growth in rooftop PV in South Australia reduces operational demand in subsequent years resulting in no ongoing LRC points under this scenario.
- No LRC points are projected in South Australia under the Neutral Growth scenario.

Table 18 South Australia LRC timing and USE

Region	Includes announced plant withdrawals and additional modelled withdrawals based on COP21 commitment assumptions						Includes announced plant withdrawals only	
	Weak Growth COP21		Neutral Growth COP21		Strong Growth COP21		Neutral Growth	
	Timing	Shortfall	Timing	Shortfall	Timing	Shortfall	Timing	Shortfall
SA	2020–21	0.0021%	2019–20	0.0028%	2018–19	0.0029%	Beyond 2025–26	N/A

To highlight LRC points, Figure 3 shows the levels of projected USE as a percentage of total demand, and compares this with the reliability standard of 0.002% USE and the NEFR 10% POE and 50% POE operational maximum demands.

Figure 3 South Australia supply adequacy (Neutral Growth and Neutral Growth COP21 scenarios)



Unserved energy

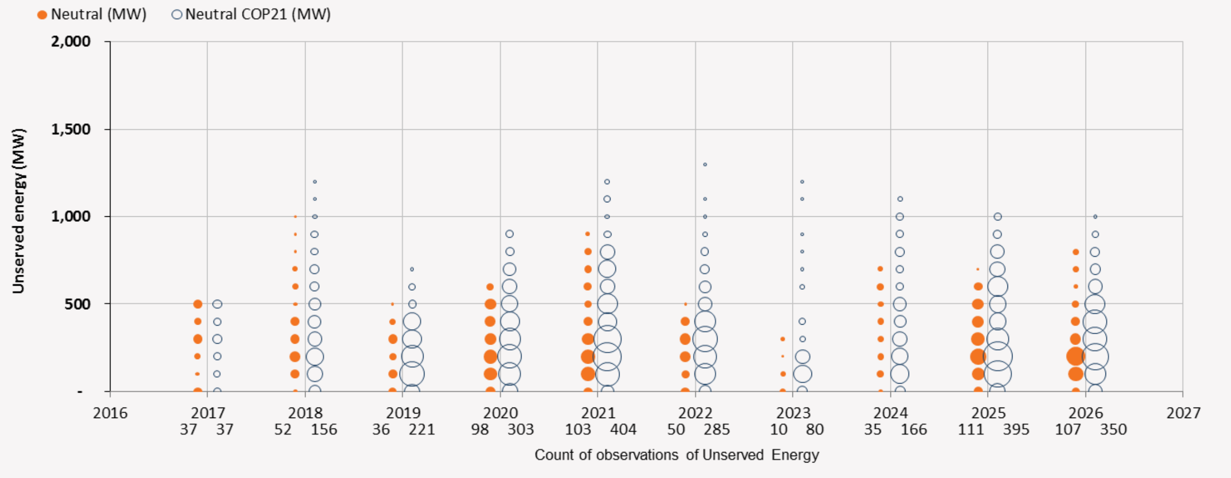
In South Australia, the projected risk of USE is highest at times when high demand in both South Australia and Victoria coincides with low local wind and rooftop PV generation, unplanned generation outages, and/or low levels of imports. The risk is projected to increase at times when rooftop PV is unavailable due to cloud cover.

Figure 4 shows the forecast frequency and magnitude (in MW) of USE in South Australia across all the Monte Carlo simulations for Neutral Growth and Neutral Growth COP21 scenarios. For each financial year, it shows a bubble at the magnitude of USE observed in the projection, with the size of the bubble indicating how often that level of USE is forecast to occur.

The figure highlights that:

- When USE is projected in the Neutral Growth COP21 scenario, half of the observed supply shortfalls were less than 268 MW.
- The most frequent occurrence when an LRC point was first observed was in the 100–200 MW band for the year 2019–20. Across the 126 Monte Carlo simulations, there were 47 observations within this band, in the Neutral Growth COP21 scenario.
- The maximum projected USE in a period exceeded 1,000 MW, under conditions of high demand, unplanned generation outages, and low intermittent generation.
- Although USE is forecast in both the Neutral Growth and Neutral Growth COP21 scenarios, the larger supply shortfalls are observed more frequently in the Neutral Growth COP21 scenario, resulting in LRC points from 2019–20. This typically occurs at times of high demand in both South Australia and Victoria, and is due to a projected reduction in support from Victoria in that scenario, if 400 MW of thermal generation is removed from Victoria in 2017–18 and a further 400 MW in 2020–21.

Figure 4 South Australia distribution of unserved energy (Neutral Growth and Neutral Growth COP21 scenarios)



In the Neutral Growth scenario, 91% of projected USE in South Australia in 2025–26 occurs between 3.00 pm and 7.00 pm. In the Neutral Growth COP21 scenario, 88% of USE is projected to occur between 2.00 pm and 8.00 pm, widening the time period in which USE is forecast to occur.

4.3.1 Frequency control ancillary services

Further reduction in FCAS capacity in South Australia would result in additional constraints on interconnector transfers between South Australia and Victoria, when a credible risk of synchronous separation exists.

Management of the rapid load ramp at 11.30 pm, when a significant number of electric hot water systems are set to switch on to take advantage of the off-peak tariff, is a further frequency control challenge when South Australia is islanded.

Regulation FCAS

When there is a credible risk of South Australia separating from the rest of the NEM due to loss of the Heywood Interconnector, AEMO enables a minimum of 35 MW of both raise and lower regulation FCAS locally within South Australia.

Conditions of credible separation risk have historically existed for 5–10% of the time, normally due to planned maintenance or upgrades along the interconnector. In 2015, South Australia was considered at credible risk of synchronous separation from the rest of the NEM for 813 hours, or around 9.3% of the year. Some of these periods were related to major works committed for the upgrade of the Heywood Interconnector.

The total registered regulation FCAS capacity in South Australia is 380 MW for regulation raise, and 320 MW for regulation lower.[39] However, to provide these services, these units must be online and generating at a favourable operating point when separation occurs. Under current operating patterns, many of them are frequently offline. For this reason, AEMO now, pre-contingently, enables regulation FCAS in South Australia during periods when separation is a credible contingency event.

In 2015, the available supply of local regulation FCAS from within South Australia was sufficient to meet the 35 MW demand for regulation FCAS during periods where South Australia was at credible risk of

[39] Data up to date at 11 April 2016.

separation. There were short periods where the supply of lower regulation FCAS was exactly equal to the demand, indicating no excess supply capacity, as illustrated in Appendix B.

There are currently only three registered participants in the regulation FCAS market in South Australia (using the generating units at Torrens Island, Pelican Point, and Quarantine).[40]

Increasing connection of semi-scheduled generation in South Australia may increase demand for regulation FCAS. AEMO's analysis suggests that large-scale PV, in particular, may in future contribute significant variability, increasing the need for regulation FCAS (at present there are no large-scale PV plants operating in South Australia). New or modified existing semi-scheduled generation plant may itself be capable of providing regulation FCAS in the NEM, to help meet this potential need in South Australia, although none are currently registered to provide these services.

Contingency FCAS

When there is a credible risk of South Australia separating from the rest of the NEM via the Heywood Interconnector, and South Australia is exporting power to Victoria, AEMO sources contingency lower FCAS from generation within South Australia. In this case, the NEM dispatch process co-optimises power transfer between Victoria and South Australia with the value of FCAS. This optimisation allows conditions of low contingency lower FCAS supply in South Australia to be managed by reducing power exports into Victoria, which reduces the demand for these contingency FCAS services.

Due to unique frequency operating standards applicable to South Australia, AEMO does not source contingency raise FCAS locally from within South Australia unless an actual islanding event occurs. When there is a credible risk of separation, and South Australia is importing power from Victoria, AEMO relies on the initiation of under-frequency load shedding in South Australia to manage low frequency conditions that would result from an actual separation event.

During 2015, there was adequate supply of contingency lower FCAS in South Australia to manage periods of credible risk of separation of South Australia from the rest of the NEM, although market liquidity was low at times. There were short periods where the local supply of contingency lower FCAS in South Australia equalled the demand (ranging between 0 MW and 235 MW), which limited transfer of power from South Australia to Victoria (see Appendix B).

The closure of Northern Power Station in May 2016 further reduced the supply of contingency FCAS services in South Australia, removing 14 MW of 6 second lower, 72 MW of 60 second lower and 12 MW of 6 second raise services.

Table 19 lists the registered contingency FCAS capacity in South Australia, and the contingency FCAS enabled in South Australia during 2015.

Table 19 Contingency FCAS services in the South Australia region[a] (MW)

	Contingency raise registered capacity	Local enablement in 2015^	Contingency lower registered capacity	Local Enablement in 2015*
Fast (6 seconds)	150	--	150	0–124
Slow (60 seconds)	318	--	318	0–235
Delayed (5 minutes)	200	--	200	0–138

[a] The FCAS capability of Northern Power Station, which shut down in May 2016, has been removed from these totals in South Australia.
^ Due to the frequency standards applicable for SA when it is at risk of islanding, there is no local requirement in SA for Contingency Raise FCAS during these periods.
* This data is taken only from periods in 2015 when South Australia was at credible risk of islanding, so when there was a local requirement for contingency lower FCAS.

[40] Northern Power Station retired in May 2016, withdrawing 20 MW of both raise and lower regulation FCAS. This was replaced when Quarantine was registered in December 2015 to provide 50 MW of both raise and lower regulation FCAS.

There are now a limited number of registered contingency FCAS facilities in South Australia:

- Pelican Point and Torrens Island A and B are the only registered providers of raise and lower contingency FCAS (6 second and 60 second services) in South Australia.
- For delayed contingency FCAS (raise and lower 5 minute services), Torrens Island B is the only registered provider.

To provide these services, generating units must be already online and generating at a favourable operating point, which may not be possible at short notice for generating units with long start-up times. Start-up times from a cold state can be as long as several hours for some FCAS providers.

It is for this reason that AEMO enables contingency lower FCAS locally in South Australia under conditions where a credible risk of South Australian synchronous separation exists and South Australia is exporting power to Victoria.

For the operation of South Australia as an island, all registered FCAS facilities are required to be online and operating to be able to supply the required contingency lower FCAS. A South Australia separation event on 1 November 2015, with a duration of 35 minutes, highlighted a potential shortage of contingency FCAS services in the South Australia region, due to insufficient numbers of generating units capable of providing FCAS being online and capable of providing these services at short notice at the time of a separation event.

While South Australia was separated from the rest of the NEM on 1 November 2015:

- The majority of FCAS services were priced at the Market Price Cap ($13,800/MWh).
- Local FCAS supply was limited. While the demand for most local FCAS was below the maximum registered supply, these services had to be obtained from the relatively small group of generating units already online in South Australia during this unplanned separation event. No additional units were able to start up in time to increase the supply of FCAS.
- AEMO was unable to obtain sufficient contingency lower FCAS to ensure power system frequency could be controlled within the required frequency limits.
  - Even if all registered FCAS providers were online, there would have been insufficient supply under the prevailing conditions. With insufficient contingency lower FCAS supply, there was heightened risk of load or generation shedding and possibly a black system[41] in South Australia if a contingency event were to have occurred (such as a sudden, unexpected outage of a large load).
  - AEMO has operational arrangements in place to curtail the largest single load in South Australia, if generation cannot meet the requirement for contingency lower FCAS. While this option would have been sufficient to resolve the lower FCAS insufficiency for this particular separation event, it is regarded as a last resort option and was not invoked given the short duration of the outage.

This situation was ultimately resolved by the reconnection of the South Australia region to the remainder of the NEM after 35 minutes of separation.

4.3.2 Inertia and rate of change of frequency

In future, in the rare event of non-credible loss of the Heywood Interconnector, the RoCoF could become very high in South Australia (depending on the generation online and interconnector flow prior to the separation).

This risk has increased following the retirement of Northern Power Station (which contributed significant inertia when it was online) and the expansion of the Heywood Interconnector capacity to 650 MW.

[41] A black system is defined in the National Electricity Rules as the absence of *voltage* on all or a significant part of the *transmission system* or within a *region* during a *major supply disruption* affecting a significant number of customers.

RoCoF exposure in South Australia, upon a non-credible separation event, is now expected to exceed ±1 Hz/s for the majority of the time, and ±4 Hz/s some of the time.

The ability of the system to sustain secure operation through these non-credible separation events becomes increasingly uncertain for RoCoF levels exceeding ±1 Hz/s. A rare non-credible separation event that results in RoCoF levels exceeding ±4 Hz/s would almost certainly result in cascading generation tripping and a total black system in South Australia.

Failure or loss of the Heywood Interconnector has separated South Australia from the rest of the NEM on nine occasions since 1999. Five of these were credible events and four were non-credible. The likelihood of widespread or regional blackouts after non-credible events increases as the region becomes more reliant on energy imports over the interconnector, and local wind and rooftop PV generation, to meet demand.

AEMO is seeking to better quantify the underlying RoCoF limits of the power system, while also exploring the technical feasibility of alternative ways of managing RoCoF through a fast frequency response service.[42] However, at present there is no market mechanism for the provision of these services.[43]

4.3.3 System restart ancillary services

AEMO has contracts for the provision of SRAS until 2018 in South Australia, with further extensions possible for up to two years. However, since the withdrawal of Northern Power Station, there is a very limited pool of strategically located SRAS sources capable of restarting the South Australian sub-network. Further, the vast majority of non-contracted synchronous generation, which must be restarted by the SRAS sources within four hours to meet the system restart standard, are gas-powered generating units. Many of these units do not have dedicated fuel storage facilities, exposing South Australia to further risk if there was a gas supply interruption during system restoration.

4.4 Tasmania

Overview

- Since the 2015 NEM ESOO, no new generation capacity commitments or withdrawals have been announced in Tasmania.
- The 208 MW combined cycle gas turbine (CCGT) at Tamar Valley was temporarily returned to service between January and May 2016 to increase local supply in Tasmania while Basslink was out of service.
- Tamar Valley Peaking Power Station (58 MW), which was previously withdrawn, returned to service in April 2016
- No LRC points are projected in Tasmania under any scenario.

Generation changes and investment trends

Table 20 shows the current capacity of Tasmania’s existing and withdrawn generation, and committed and publicly announced projects, by generation type.

[42] This is being explored in AEMO’s Future Power System Security program. More information about the program is available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability.

[43] On 24 June 2016, AGL submitted a rule change request for the AEMC to consider introducing a NEM Inertia Ancillary Services Market. AEMO is examining the need for inertia services in the next five years as part of its Network Support Control Ancillary Services studies to be published with the *National Transmission Network Development Plan* in November 2016.

Table 20 Tasmania generation and project capacity by generation type (MW)

Status/Type	Coal	CCGT[a]	OCGT[b]	Gas other	Solar	Wind	Water	Biomass	Other	Total
Existing[c]	0	0	178	0	0	308	2281	5	0	2,772
Committed	0	0	0	0	0	0	0	0	0	0
Proposed	0	0	0	0	0	329	0	0	0	329
Withdrawn	0	208	0	0	0	0	0	0	0	208
Publicly announced withdrawals[d]	0	0	0	0	0	0	0	0	0	0

a. Combined-cycle gas turbine.
b. Open-cycle gas turbine.
c. Existing includes announced withdrawal.
d. These are withdrawals that have been announced to occur within the next 10 years.

Generation investment interest in Tasmania is focused on wind generation, most notably proposals for these wind farm projects:

- Cattle Hill (200 MW).
- Granville Harbour (99 MW).
- Low Head (29.7 MW).

Supply adequacy assessment

No LRC point is projected in Tasmania in any scenario, as shown in Table 21.

Table 21 Tasmania LRC timing and USE

Region	Includes announced plant withdrawals and additional modelled withdrawals based on COP21 commitment assumptions						Includes announced plant withdrawals only	
	Weak Growth COP21		Neutral Growth COP21		Strong Growth COP21		Neutral Growth	
	Timing	Shortfall	Timing	Shortfall	Timing	Shortfall	Timing	Shortfall
TAS	Beyond 2025–26	N/A	Beyond 2025–26	N/A	Beyond 2025–26	N/A	Beyond 2025–26	N/A

Tasmania's large fleet of hydro generation plant and modest local consumption insulate the region from short-term supply shortfalls.

However, Tasmania's capacity for continuous generation may be affected under protracted drought conditions. NEM ESOO modelling does not account for energy limitations under such conditions. AEMO publishes an *Energy Adequacy Assessment Projection* (EAAP)[44] report at least once every 12 months that provides more relevant information about projected energy limitations and reliability in Tasmania and other NEM regions.

4.4.1 Frequency control ancillary services

Regulation FCAS

The Tasmania region must have access to 50 MW of both raise and lower regulation FCAS at all times, irrespective of how Basslink is operating. This can be provided partially or completely through Basslink from the mainland, or locally from generation within Tasmania.

[44] AEMO. *Energy Adequacy Assessment Projection* (EAAP). Available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Energy-Adequacy-Assessment-Projection.

There is currently 2,141 MW of both regulation raise and lower FCAS capacity registered in the Tasmania region, far exceeding the 50 MW local requirement. When the additional supply of regulation FCAS via Basslink is also considered, no shortage of supply of regulation FCAS is expected in Tasmania in the foreseeable future.

Contingency FCAS

In 2015, there was adequate supply of the slower contingency services (60 second and 5 minute) in Tasmania. However, there were significant periods where there was tight balance in Tasmania between the available supply and demand for the fast contingency FCAS services (6 second raise and 6 second lower). This is partly related to the fact that hydro generation is generally less capable than other generation technologies of responding favourably to frequency deviations in short timeframes.

Withdrawal of generation in Tasmania may lead to a supply gap for fast contingency FCAS. More information illustrating the supply-demand balance is provided in Appendix B.

Since December 2014, Basslink has been unable to transfer contingency raise services into Tasmania from the mainland NEM during periods when Basslink is transferring power into Tasmania.[45] Due to this limitation, all contingency raise services required in Tasmania have to be obtained locally, from generation within Tasmania, when Basslink is transferring power into Tasmania. This has increased the reliance on local provision of this service in Tasmania, and highlighted the underlying tight supply-demand balance for this service.

Table 22 lists the capacity of contingency FCAS services registered in the Tasmanian region, and the contingency FCAS enabled in Tasmania in 2015.

Table 22 Contingency FCAS services in the Tasmania region (MW)

	Contingency raise registered capacity	Local enablement in 2015	Contingency lower registered capacity	Local enablement in 2015
Fast (6 seconds)	386	0–166	630	0–325
Slow (60 seconds)	1,850	0–427	2,435	0–510
Delayed (5 minutes)	2,071	0–274	2,171	0–306

4.4.2 Inertia and rate of change of frequency

Although Tasmania is a comparatively small system, with no synchronous link to the mainland NEM, many of the hydro units in Tasmania are able to operate as synchronous condensers, which can provide inertia without contributing significant energy. Therefore, there is no supply gap identified for synchronous inertia in Tasmania.

4.4.3 System restart ancillary services

AEMO has contracts for the provision of SRAS in Tasmania until 2018, with further extensions possible for up to two years.

No shortfall in SRAS capability is anticipated in Tasmania in the next ten years, due to:

- The availability of several SRAS-capable generating units in various strategic network locations.
- The fast restart time of non-SRAS-capable generation (all of which are conventional hydro units).

[45] This is due to a number of unexpected trips of Basslink in late 2014, and subsequent reclassification as credible of the simultaneous trip of Basslink coincident with some transmission line faults in Tasmania. At this time there is no date for when this reclassification of Basslink will end. Refer to AEMO Market Notices 47315 and 47360.

4.5 Victoria

Overview

- Since the 2015 NEM ESOO, no new generation withdrawals have been announced in Victoria, and Mt Gellibrand's 66 MW wind farm project has been committed (although the announcement came too late to be included in the 2016 NEM ESOO modelling). The Ararat wind farm reached committed status prior to the 2015 NEM ESOO.
- An LRC is projected under the Neutral Growth COP21 and Strong Growth COP21 scenarios in 2024–25 and 2023–24 respectively.
- No breaches are projected under the Weak Growth COP21 or Neutral Growth scenarios.

Generation changes and investment trends

Table 23 shows the current capacity of Victoria's existing and withdrawn generation, and committed and publicly announced projects, by generation type.

Table 23 Victoria generation and project capacity by generation type (MW)

Status/Type	Coal	CCGT[a]	OCGT[b]	Gas other	Solar	Wind	Water	Biomass	Other	Total
Existing[c]	6,230	21	1,904	523	0	1,249	2,296	53	2	12,276
Committed	0	0	0	0	0	306	0	0	0	306
Proposed	0	500	600	0	164	3,449	34	0	0	4,747
Withdrawn	0	0	0	0	0	0	0	0	0	0
Publicly announced withdrawals[d]	0	0	0	0	0	0	0	0	0	0

a. Combined-cycle gas turbine.
b. Open-cycle gas turbine.
c. Existing includes announced withdrawal.
d. These are withdrawals that have been announced to occur within the next 10 years.

Victoria has two committed wind farm projects:

- Ararat (240 MW), due to be commissioned May 2017.
- Mt Gellibrand (66 MW).

Generation investment interest in Victoria is focused on wind generation, with 23 project proposals totalling 3,153 MW, including:

- Stockyard Hill (514 MW).
- Darlington (350 MW).
- Dundonnell (312 MW).
- Willatook (261 MW).
- Moorabool (between 214 MW and 342 MW).
- Penshurst (198 MW).
- Kiata (30 MW).

Victoria has two publicly announced GPG proposals:

- Tarrone GT (500–600 MW), which would likely draw gas from the Otway basin if it proceeded.
- Shaw River (500 MW).

Supply adequacy assessment

Low Reserve Conditions

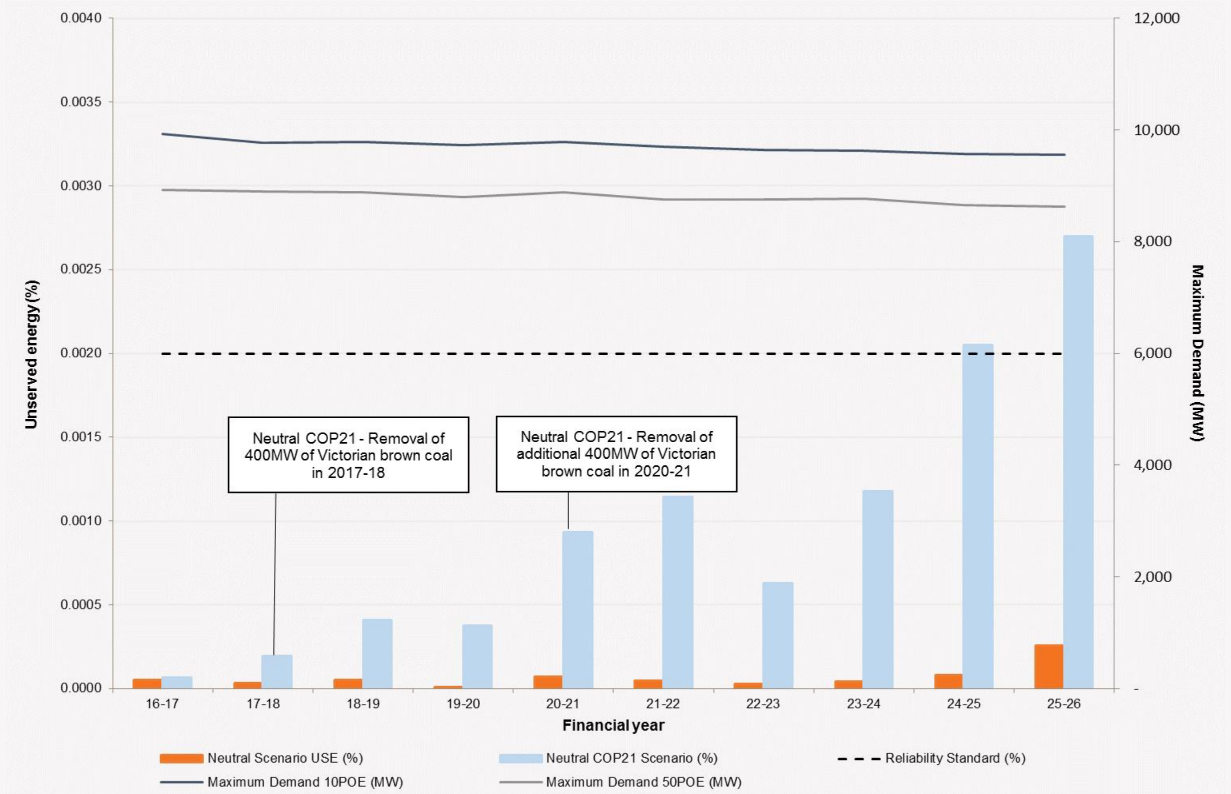
- An LRC point is first projected in 2024–25 under the Neutral Growth COP21 scenario (see Table 24). This is due to the assumed removal of 800 MW of thermal generation in the region.
- In the Strong Growth COP21 scenario, the LRC point is brought forward one year to 2023–24, due to higher operational maximum demand, despite fewer assumed withdrawals of thermal generation compared to the Neutral Growth COP21 scenario.
- No LRC point is projected under the Weak Growth COP21 or Neutral Growth scenarios.

Table 24 Victoria LRC timing and USE

Region	Includes announced plant withdrawals and additional modelled withdrawals based on COP21 commitment assumptions						Includes announced plant withdrawals only	
	Weak Growth COP21		Neutral Growth COP21		Strong Growth COP21		Neutral Growth	
	Timing	Shortfall	Timing	Shortfall	Timing	Shortfall	Timing	Shortfall
VIC	Beyond 2025–26	N/A	2024–25	0.0021%	2023–24	0.0026%	Beyond 2025–26	N/A

To highlight LRC points, Figure 5 shows the levels of projected USE as a percentage of total demand, and compares this with the reliability standard of 0.002% USE and the NEFR 10% POE and 50% POE operational maximum demands.

Figure 5 Victoria supply adequacy (Neutral Growth and Neutral Growth COP21 scenarios)



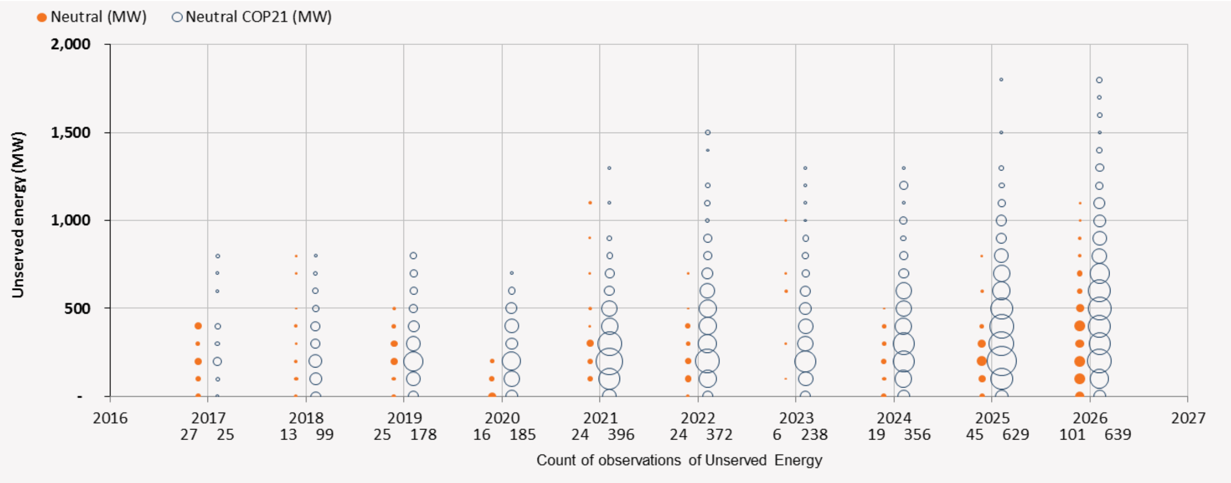
Unserved energy

Figure 6 shows the forecast frequency and magnitude (in MW) of USE in Victoria across all the Monte Carlo simulations for Neutral Growth and Neutral Growth COP21 scenarios. For each financial year, it shows a bubble at the magnitude of USE observed in the projection, with the size of the bubble indicating how often that level of USE is forecast to occur.

The figure highlights that:

- When USE occurs in the Neutral Growth COP21 scenario, half of the observed supply shortfalls are less than 314 MW.
- The most frequent occurrence was in the 200–300 MW band for the year 2024–25. Across the 126 Monte Carlo simulations, there were 106 observations within this band in the Neutral Growth COP21 scenario.
- The maximum USE in a period exceeded 1,800 MW, under conditions of high demand, unplanned generation outages, and low intermittent generation.
- Although USE occurs in both the Neutral Growth and Neutral Growth COP21 scenarios, the higher frequency and level of USE in the Neutral Growth COP21 scenario results in a projected reliability standard breach.

Figure 6 **Victoria supply distribution of unserved energy (Neutral Growth and Neutral Growth COP21 scenarios)**



In the Neutral Growth scenario, 84% of projected USE in Victoria in 2025–26 is forecast to occur between 3.00 pm and 7.00 pm. In the Neutral Growth COP21 scenario, 89% of USE is projected to occur between 2.00 pm and 8.00 pm, widening the time period in which USE is forecast to occur.

4.5.1 Frequency control ancillary services

Victoria has multiple connections with the rest of the NEM, and therefore does not have a credible risk of islanding. This means the supply-demand balance for FCAS services in Victoria is similar to the NEM-wide situation, showing no anticipated shortfall in the next 10 years.

4.5.2 Inertia and rate of change of frequency

Victoria has multiple connections with the rest of the NEM, and therefore does not have a credible risk of islanding. This means low synchronous inertia and associated exposure to high RoCoF is not likely to pose a system security challenge in Victoria in the next 10 years.

4.5.3 System restart ancillary services

AEMO has contracts for the provision of SRAS in Victoria until 2018, with further extensions possible for up to two years.

Under the 2016 NEM ESOO scenarios, with generation withdrawals at the levels assumed, no shortfall in SRAS capability in Victoria is anticipated in the next 10 years.

CHAPTER 5. LINKS TO SUPPORTING INFORMATION

Table 25 provides links to additional information provided either as part of the 2016 ESOO accompanying information suite, or related AEMO planning information.

Table 25 Links to supporting information

Information Source	Website Address
2016 ESOO Constraints Workbook	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities
2016 ESOO Methodology	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities
2016 ESOO supplementary results and data files	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities
2016 ESOO time-sequential modelling (PLEXOS) database	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities
2016 National Electricity Forecasting Report	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Electricity-Forecasting-Report
Archive of previous ESOO reports	2014 and 2015 ESOO: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities (Search for pre-2014 reports on http://www.aemo.com.au/, selecting Archives search filter)
***Energy Adequacy Assessment Projection* (EAAP)**	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Energy-Adequacy-Assessment-Projection
Generation Information page	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information
Guide to Ancillary Services in the National Electricity Market	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/-/media/2C771C82C8054929B16E4545216ACE03.ashx
Fact sheet – Frequency Control	http://www.aemo.com.au/~/media/Files/Electricity/NEM/Security_and_Reliability/Reports/AEMO
Fact Sheet – System Strength	http://www.aemo.com.au/~/media/Files/Electricity/NEM/Security_and_Reliability/Reports/AEMO
Fact Sheet – Visibility of the Power System	http://www.aemo.com.au/~/media/Files/Electricity/NEM/Security_and_Reliability/Reports/AEMO
Joining the NEM Guide	http://www.aemo.com.au/Datasource/Archives/Archive1384
MT PASA	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Data/Market-Management-System-MMS/Projected-Assessment-of-System-Adequacy
Maps and network diagrams	http://www.aemo.com.au/aemo/apps/nem_map/index.php
New Investors Guide	http://www.aemo.com.au/Datasource/Archives/Archive1366

MEASURES AND ABBREVIATIONS

Units of measure

Abbreviation	Unit of measure
GWh	Gigawatt hours
Hz	Hertz
Hz/s	Hertz/second
MW	Megawatts
MWh	Megawatt hours

Abbreviations

Abbreviation	Expanded name
ACT	Australian Capital Territory
AEMO	Australian Energy Market Operator
ESOO	Electricity Statement of Opportunities
LRC	Low Reserve Condition
FCAS	Frequency Control Ancillary Services
MD	Maximum Demand
NEFR	National Electricity Forecasting Report
NEM	National Electricity Market
NEMDE	National Electricity Market Dispatch Engine
NSW	New South Wales
POE	Probability of Exceedance
PV	Photovoltaic
QLD	Queensland
RoCoF	Rate of Change of Frequency
Rooftop PV	Rooftop photovoltaic
SA	South Australia
SRAS	System Restart Ancillary Services
TAS	Tasmania
USE	Unserved energy
VIC	Victoria

GLOSSARY

The 2016 ESOO uses many terms that have meanings defined in the National Electricity Rules (NER). The NER meanings are adopted unless otherwise specified.

Term	Definition
black system	The absence of voltage on all or a significant part of the transmission system or within a region during a major supply disruption affecting a significant number of customers.
committed projects	Generation that is considered to be proceeding under AEMO's commitment criteria (see Generation Information Page, link in Table 25).
electrical energy	Average electrical power over a time period, multiplied by the length of the time period.
contingency FCAS	Contingency FCAS is enabled to correct the generation/demand balance following a major contingency event, such as the loss of a generating unit or major industrial load, or a large transmission element.
electrical power	Instantaneous rate at which electrical energy is consumed, generated, or transmitted.
frequency control ancillary services (FCAS)	Used by AEMO to maintain the frequency on the electrical system, at any point in time, close to fifty cycles per second as required by the NEM frequency standards
generating capacity	Amount of capacity (in megawatts (MW)) available for generation.
generating unit	Power stations may be broken down into separate components known as generating units, and may be considered separately in terms (for example) of dispatch, withdrawal, and maintenance.
Heywood Interconnector	The Heywood Interconnector is a connection between the Victorian and South Australian power systems. It consists of two 275 kV AC electricity transmission lines, between Heywood Terminal Station in Victoria and South East Switching Station in South Australia. Following the completion of upgrade works currently underway, it will have a rated capacity of 650 MW power transfer in either direction.
installed capacity	The generating capacity (in megawatts (MW)) of the following (for example): • A single generating unit. • A number of generating units of a particular type or in a particular area. • All of the generating units in a region. Rooftop PV installed capacity is the total amount of cumulative rooftop PV capacity installed at any given time.
Low Reserve Condition (LRC)	When AEMO considers that a region's reserve margin (calculated under 10% Probability of Exceedance (POE) scheduled and semi-scheduled maximum demand (MD) conditions) for the period being assessed is below the Reliability Standard.
maximum demand (MD)	Highest amount of electrical power delivered, or forecast to be delivered, over a defined period (day, week, month, season, or year) either at a connection point, or simultaneously at a defined set of connection points.
mothballed	A generation unit that has been withdrawn from operation but may return to service at some point in the future.
network support control ancillary services	Non-market ancillary service contracts designed to maintain power system security and reliability, and to maintain or increase the power transfer capability of the transmission network.
non-scheduled generation	Generation by a generating unit that is not scheduled by AEMO as part of the central dispatch process, and which has been classified as a non-scheduled generating unit in accordance with Chapter 2 of the NER.
operational electrical consumption	The electrical energy supplied by scheduled, semi-scheduled, and significant non-scheduled generating units, less the electrical energy supplied by small non-scheduled generation.
probability of exceedance (POE) maximum demand	The probability, as a percentage, that a maximum demand (MD) level will be met or exceeded (for example, due to weather conditions) in a particular period of time. For example, a 10% POE MD for a given season means a 10% probability that the projected MD level will be met or exceeded – in other words, projected MD levels are expected to be met or exceeded, on average, only one year in 10.

Term	Definition
proposed projects	Includes both advanced proposals at an intermediate stage of development, and publicly announced proposals at an early stage of development.
reliability standard	The power system reliability benchmark set by the Reliability Panel. The reliability standard for generation and inter-regional transmission elements in the national electricity market is a maximum expected unserved energy (USE) in a region of 0.002% of the total energy demanded in that region for a given financial year.
regulation FCAS	Regulation FCAS is enabled to continually correct the generation/demand balance in response to minor deviations in load or generation. There are two types of regulation FCAS: • Raise (used to correct a minor drop in frequency), • Lower (used to correct a minor rise in frequency).
scenario	A consistent set of assumptions used to develop forecasts of demand, transmission, and supply.
rate of change of frequency (RoCoF)	Synchronous generation provides an inherent inertial response to frequency deviations, slowing the rate of change of frequency.
scheduled generation	Generation by any generating unit that is classified as a scheduled generating unit in accordance with Chapter 2 of the NER.
semi-scheduled generation	Generation by any generating unit that is classified as a semi-scheduled generating unit in accordance with Chapter 2 of the NER.
summer	Unless otherwise specified, refers to the period 1 November – 31 March (for all regions except Tasmania), and 1 December – 28 February (for Tasmania only).
system restart ancillary services (SRAS)	A requirement to enable the power system to be restarted following a complete or partial black-out. This can be provided by generating units that can start and supply energy to the transmission grid without any external source of supply, or by generating units that can, upon sensing a system failure, fold back onto their own internal load and continue to generate until AEMO is able to use them to restart the system.
winter	Unless otherwise specified, refers to the period 1 June – 31 August (for all regions).

APPENDIX A: WITHDRAWAL CATEGORIES

Previous ESOO publications were not able to distinguish between fully-retired generation units (decommissioned) and units that may return to service (mothballed), making it difficult to accurately project adequacy and reliability.

In the 2016 ESOO, AEMO sought to understand the sensitivity of its modelling results to the possible return to service of withdrawn generators. It consulted widely with generators on criteria to categorise "withdrawn" plant, and all stakeholders indicated the likely timeframe within which they would be able to recall plant to service. This enabled AEMO to identify three distinct timeframes for recall, and construct a simple matrix.

Through consultation, AEMO developed the following withdrawal categories:

- Short term withdrawal – if a plant is able to be recalled within three months.
- Seasonal withdrawal – if the recall time is three to six months.
- Long-term withdrawal – if the recall time is from six to 12 months.
- Anything greater than 12 months will treated as decommissioned and therefore not available to be recalled.

Table 26 Announced withdrawals of plants in the NEM and their ability to be recalled

Participant	Plants	Region	Able to be recalled	Able to be recalled within three months *Short-term withdrawal*	Able to be recalled 3–6 months *Seasonal withdrawal*	Able to be recalled 6–12 months *Long-term withdrawal*
Energy Australia	Wallerawang	NSW	No	No	No	No
Hydro Tasmania	Tamar Valley CCGT	TAS	Yes	Yes	--	--
ENGIE	Pelican Point	SA	Yes	Yes	--	--
Marubeni	Smithfield	NSW	No	No	No	No
AGL	Liddell	NSW	No	No	No	No
Stanwell	Swanbank E	QLD	Yes	Yes	--	--

APPENDIX B: 2015 FCAS SUPPLY-DEMAND

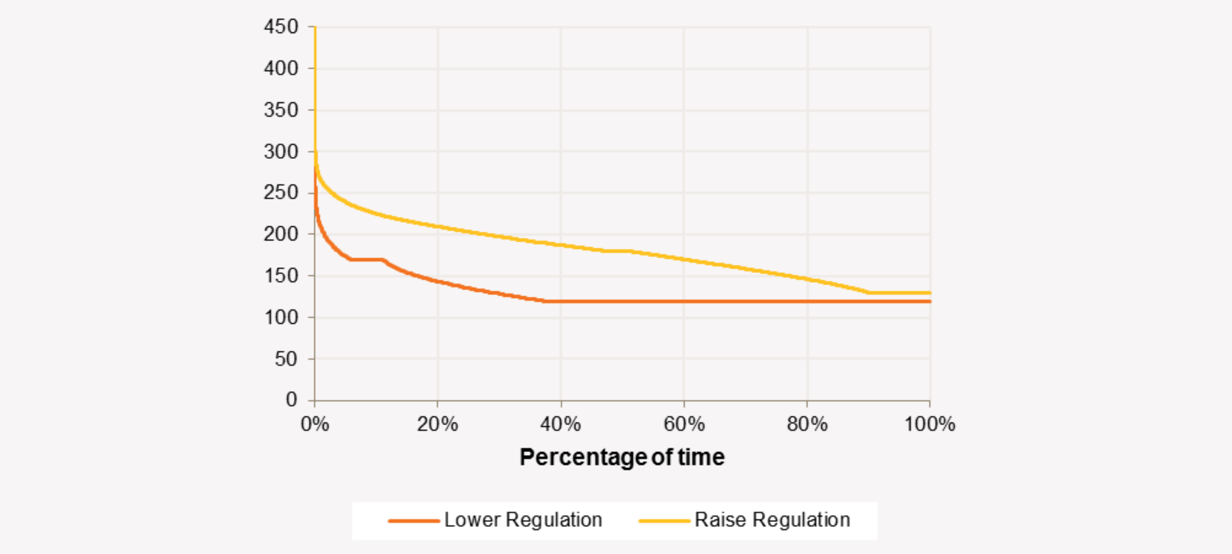
A.1 NEM-wide

A.1.1 Regulation FCAS

Figure 7 shows the total NEM requirement for regulation FCAS services in 2015.

The enablement for regulation is more than the minimum requirement for a significant proportion of the time. This is partly due to increased regulation FCAS being enabled to reduce the requirement for 5 minute contingency FCAS. The National Electricity Market Dispatch Engine (NEMDE) does this automatically to minimise the cost of regulation and delayed contingency FCAS.

Figure 7 NEM regulation FCAS enabled (MW) in 2015



A.1.2 Contingency FCAS

Figures 8 and 9 show the total NEM requirements for contingency raise and lower FCAS in 2015.

Figure 8 NEM contingency raise FCAS requirement (MW) in 2015

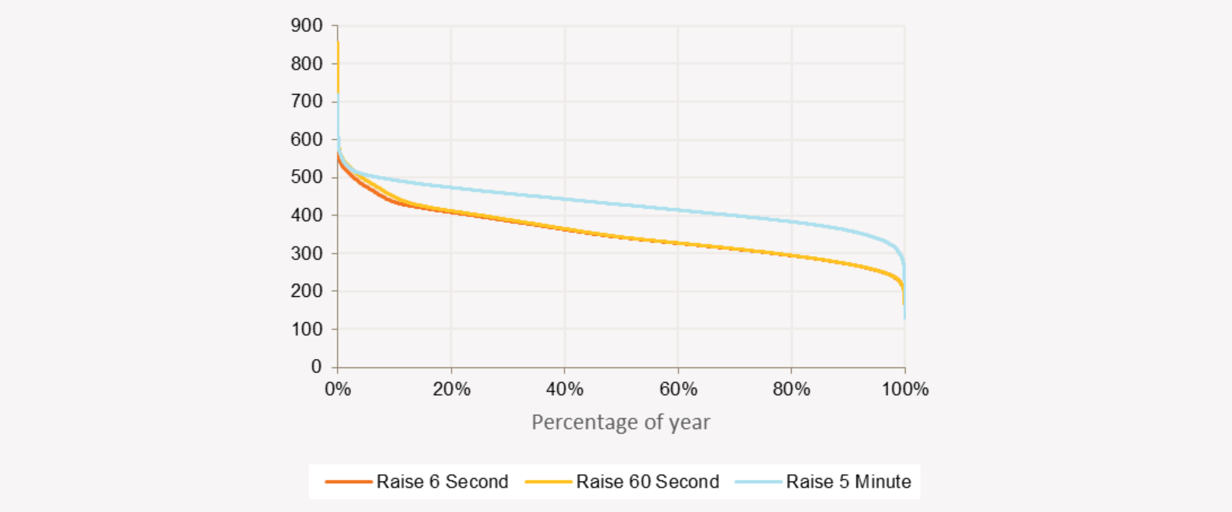
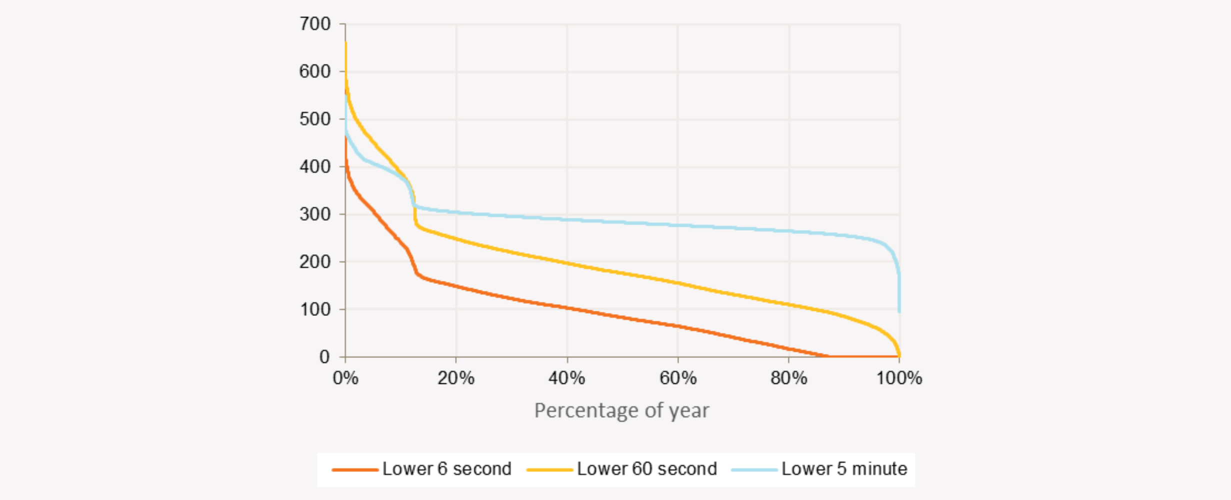


Figure 9 NEM contingency lower FCAS requirement (MW) in 2015



5.1 Queensland

A.1.3 Contingency FCAS

Figures 10 and 11 show the supply-demand balance for contingency FCAS in Queensland (the available local supply of FCAS minus the local demand), during periods when Queensland was at credible risk of separation during 2015 (around 252 hours, or 2.9% of the year).

Figure 10 Supply minus demand for local contingency raise FCAS in Queensland (MW)

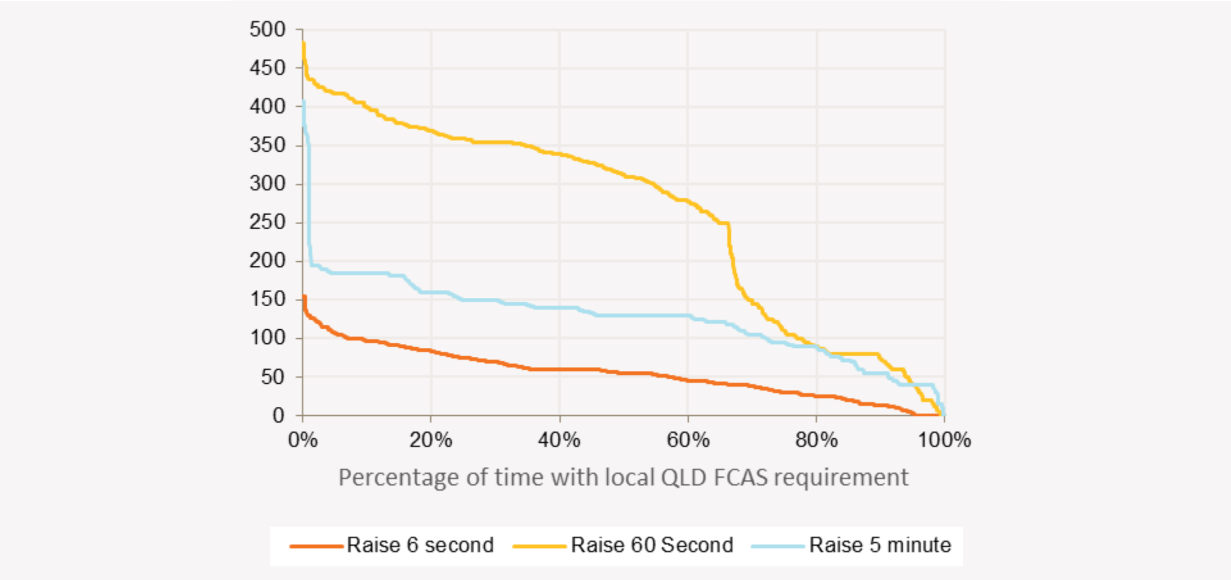
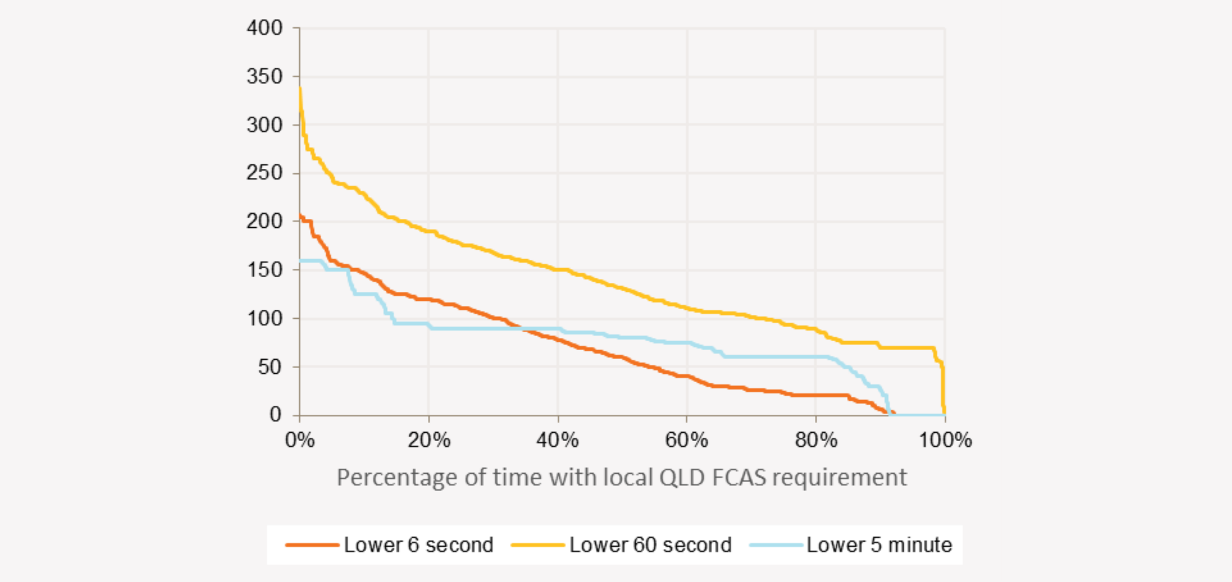


Figure 11 Supply minus demand for local contingency lower FCAS in Queensland (MW)

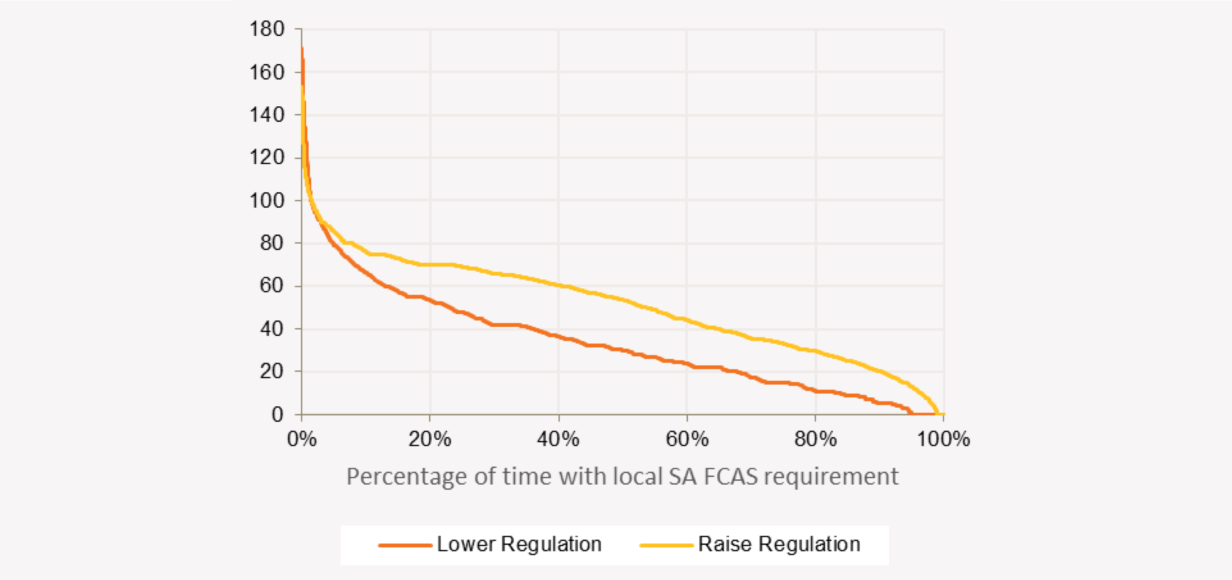


5.2 South Australia

A.1.4 Regulation FCAS

Figure 12 shows the supply-demand balance for regulation FCAS locally in South Australia, during periods in 2015 when South Australia was at credible risk of separation. For each five minute dispatch interval where a separation risk existed or South Australia was islanded, this figure shows the available supply, minus the demand, for regulation FCAS in South Australia. This comparison is shown only for the 624 hours in 2015 where AEMO required local provision of regulation FCAS.[46]

Figure 12 Supply minus demand for local regulation FCAS in South Australia (MW)

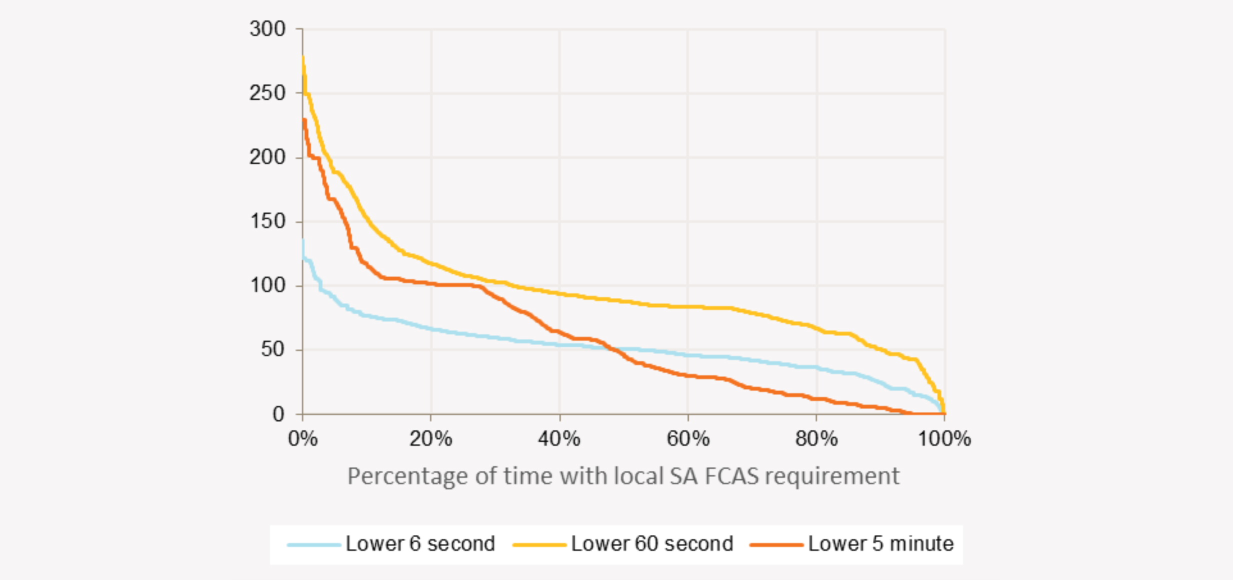


[46] In calendar year 2015, South Australia was considered at credible risk of separation for 813 hours. However, the requirement for 35 MW of local regulation during periods of credible separation was introduced during calendar year 2015, resulting in AEMO requiring local provision of regulation FCAS from generation located within South Australia for only 624 hours in 2015.

A.1.5 Contingency FCAS

Figure 13 shows the supply-demand balance for contingency FCAS in South Australia (the available supply minus the enabled contingency lower FCAS in South Australia), during periods of credible risk of separation during 2015. During the periods of actual separation on 1 November 2015, the shortfall does not appear on this chart, because there was insufficient capacity of contingency FCAS available at that time so that the enablement was less than the underlying demand. At present, there is no simple method to calculate the underlying demand for FCAS in South Australia during these periods.

Figure 13 Supply minus demand for local contingency lower FCAS in South Australia (MW)



5.3 Tasmania

A.1.6 Contingency FCAS

Figures 14 and 15 show the local supply-demand balance for contingency FCAS (the available local supply minus the demand for contingency lower FCAS) in Tasmania in 2015.

Figure 14 Supply minus demand for local contingency raise FCAS in Tasmania (MW)

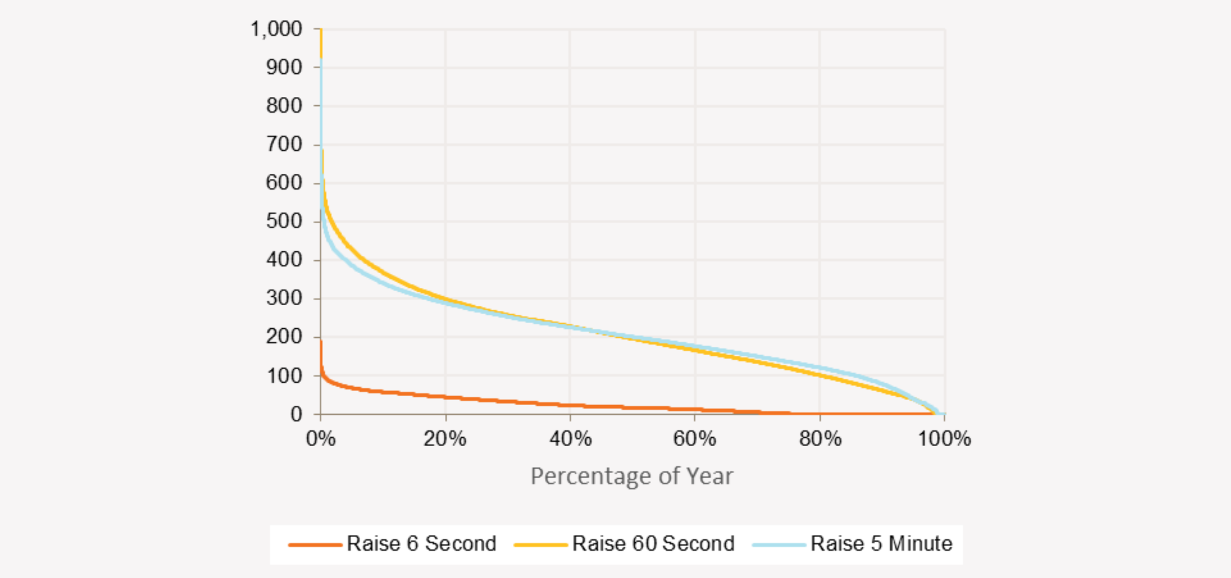


Figure 15 Supply minus demand for local contingency lower FCAS in Tasmania (MW)