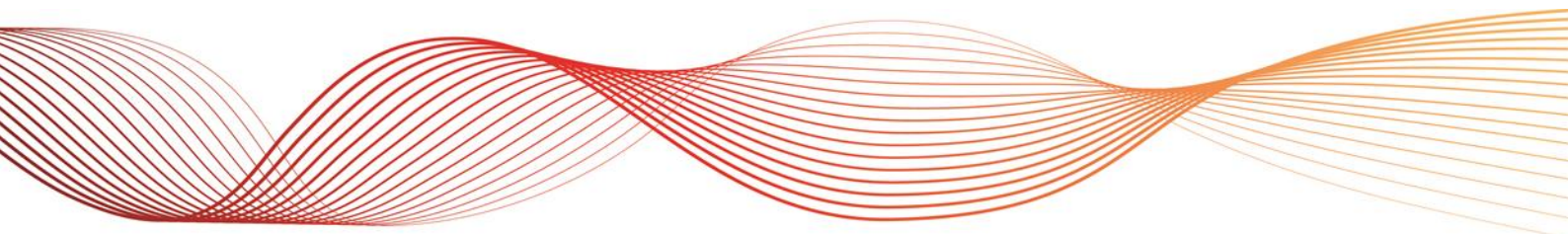




SOUTH AUSTRALIAN ELECTRICITY REPORT

SOUTH AUSTRALIAN ADVISORY FUNCTIONS

Published: **August 2016**





IMPORTANT NOTICE

Purpose

The purpose of this publication is to provide information about South Australia's electricity supply and demand. While some historic price information is provided for completeness, this publication does not present any views on the effectiveness of price signals in the National Electricity Market.

AEMO publishes this South Australian Electricity Report in accordance with its additional advisory functions under section 50B of the National Electricity Law. This publication is based on information available to AEMO as at 1 July 2016, although AEMO has endeavoured to incorporate more recent information where practical.

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Acknowledgement

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

Version control

| Version | Release date | Changes |
|---------|--------------|---------|
| 1 | 31/8/2016 | |

EXECUTIVE SUMMARY

South Australia's mix of electricity supply sources continues to evolve, with 2015–16 marking the end of coal-powered generation in South Australia. Since the closure of Northern Power Station¹, approximately 51% of electricity generated in the region has been from wind and solar resources.

This changing generation mix makes South Australia more reliant on interconnection with Victoria for energy supply and inter-regional exchange of market ancillary services.

Based on current industry-announced closures and committed new projects, AEMO's 2016 *National Electricity Market Electricity Statement of Opportunities* (NEM ESOO²) indicates that South Australia has sufficient supply to meet the NEM reliability standard over the next 10 years. The reliability standard targets no more than 0.002% of expected unserved energy (USE) for any region in any financial year. When high demand coincides with low wind generation, plant outages, or low available import capacity, South Australia may experience supply shortfalls.

In the absence of new development, potential reductions in coal-powered generation capacity across the NEM would pose a risk to future supply reliability in South Australia. Under the 2016 *National Electricity Forecasting Report* (NEFR)³ neutral economic and consumer outlook, if 1,360 megawatt (MW) of coal-powered generation withdraws from the NEM in addition to the already announced 2,000 MW Liddell Power Station closure, reliability standard breaches are projected in South Australia from 2019–20 to 2020–21 and 2024–25 to 2025–26.⁴

Ancillary services are necessary to support the transmission of electric power and maintain reliable operations of the interconnected transmission system. These services have traditionally been supplied by synchronous generators.⁵

- The existing supply of Frequency Control Ancillary Services (FCAS)⁶ is adequate to meet demand for NEM system normal operation. Under these conditions, FCAS requirements can be met by FCAS providers operating in all NEM regions (a region is not limited to its own FCAS sources to manage events).
- Where a credible risk of a NEM region islanding exists, required FCAS must be sourced from within that region, and is therefore dependent on FCAS providers being online at the time of the event (an islanded region is limited to its own available internal FCAS resources to manage events).
 - For the secure operation of South Australia as an island, all registered FCAS providers need to be online and operating at the time of islanding to supply some types of FCAS.
 - The 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.
- In the rare event of the unexpected concurrent loss of both Heywood Interconnector lines, there is a high risk of a region-wide blackout in South Australia. South Australia has separated from the rest of the NEM due to such non-credible contingency events four times since 1999. The likelihood that a region-wide blackout would follow a non-credible islanding event has increased as the region has become more reliant on energy imports, and wind and rooftop photovoltaic (PV) generation, to meet demand.

¹ Analysis in this executive summary since the closure of coal generation includes the period from 10 May 2016 to 31 July 2016.

² AEMO. 2016 *National Electricity Market Electricity Statement of Opportunities*. Available at: <http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities>.

³ 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>.

⁴ The timing of generation withdrawals, growth in rooftop photovoltaic, and variations in underlying demand growth across the NEM reduce the risk of reliability standard breaches in the years between.

⁵ Synchronous generators (most coal, gas, and hydro generators) produce power through directly connected alternating current machines, rotating at a speed synchronised to power system frequency. These generators have inertia, which dampens the impact of changes in power system frequency, resulting in a more stable system. Power systems with low inertia experience faster changes in system frequency following a disturbance, such as the trip of a generator or load.

⁶ 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 must dispatch sufficient FCAS to maintain frequency within prescribed frequency operating standards.

What is the outlook for electricity consumption and maximum demand?

The NEFR provides electricity consumption and demand forecasts⁷ for South Australia for the period to 2035–36. The main forecast trends for South Australia during the first ten years of this period are:

- Annual consumption is forecast to moderately decline from 2015–16 actual consumption of 12,934 gigawatt-hours (GWh) to 11,825 GWh in 2025–26, due to:
 - Continued high uptake of rooftop PV, and energy efficiency savings, being projected to more than offset moderate new connections growth and increasing appliance use by households.
 - Flat business sector consumption, caused by the absence of growth in energy-intensive manufacturing, little growth in services offset by energy efficiency savings, and the expected reduction in automotive manufacturing.
 - Projected increases in electricity prices reducing growth in consumption.
- Maximum demand (MD) is expected to continue to decline.
 - For summer 2015–16, South Australia's actual MD was 2,895 MW.
 - Over the next 10 years, on average the 10% probability of exceedance (POE)⁸ summer MD is forecast to decrease 1.8% annually, from 3,158 MW to 2,639 MW, under the neutral economic and consumer outlook. Trends are similar to those for annual consumption, however the greater contribution of air-conditioning load at peak times adds a greater offset from energy efficiency. South Australia has a large number of aged air-conditioning appliances expected to be replaced in the 10-year outlook, for which the replacement technology is roughly twice as efficient.
- Minimum demand is forecast to continue declining rapidly.
 - The 90% POE minimum demand is expected to become negative in 2027, due to forecast continued strong growth in rooftop PV uptake. This means that, at the time of minimum demand, there could be net export from the distribution network to the transmission network in aggregate, and ultimately from the region, under certain conditions. Negative operational demand is projected to be first observed later than in the 2015 NEFR, mainly due to a downward revision of rooftop PV uptake.
 - South Australia is the first region in the NEM for which high rooftop PV penetration has caused minimum demand to shift from overnight to near midday.

How has electricity been supplied in recent years?

The supply capacity and generation mix in South Australia has continued to evolve in recent years:

- There have been increases in wind farm and rooftop PV capacity, the ongoing upgrade to Heywood Interconnector import and export capability, and permanent closure of coal generation in May 2016. Table 1 summarises the electricity supply breakdown for 2015–16.
- Among the NEM regions, South Australia is comparatively the most reliant on gas generation, and has the highest penetration of intermittent wind generation and rooftop PV. More than 29% of dwellings in South Australia have rooftop PV systems installed.⁹
- Analysis from 10 May to 31 July 2016 gives an indication of the local generation mix following withdrawal of coal, being gas 48.5%, wind 42.9%, rooftop PV 7.8%, and diesel and small non-scheduled generators 0.8%.
- Combined interconnector net imports to South Australia increased 27%, from 1,527 GWh in 2014–15 to 1,941 GWh in 2015–16. Heywood Interconnector import maximum flows are higher since commissioning of the third Heywood transformer progressively increased nominal flow capability by 140 MW between December 2015 and August 2016.¹⁰

⁷ Measured as operational consumption. Operational consumption and demand refers to the electrical energy supplied by scheduled, semi-scheduled, and significant non-scheduled generating units. It does not include the electrical energy supplied by small non-scheduled generation or rooftop PV.

⁸ A probability of exceedance (POE) refers to the likelihood that a demand forecast will be met or exceeded. A 10% POE maximum demand projection, and a 90% POE minimum demand projection, are expected to be exceeded, on average, one year in 10, and a 50% POE projection is expected to be exceeded one year in two.

⁹ Analysis taken from: Australian PV Institute (APVI) Solar Map, funded by the Australian Renewable Energy Agency, accessed from pv-map.apvi.org.au on 24 June 2016.

¹⁰ Due to the market conditions required for testing not yet being obtained, the nominal Heywood export limit has so far been increased by only 40 MW in December 2015.

Table 1 South Australian electricity supply breakdown for 2015–16

| Local generation | Generation in GWh | Share of total |
|--|-------------------|----------------|
| Gas | 4,538 | 36.4% |
| Wind | 4,322 | 34.7% |
| Coal | 2,601 | 20.9% |
| Rooftop PV | 938 | 7.5% |
| Diesel and small non-scheduled generation* | 60 | 0.5% |
| Combined interconnector flows | Flow in GWh | |
| Imports to South Australia | 2,227 | |
| Exports from South Australia | 286 | |

* Small non-scheduled generation includes data from selected non-scheduled generators typically less than 30 MW capacity.

South Australia's average wholesale electricity price for 2015–16 was \$62 per megawatt hour (MWh), approximately 59% higher than for 2014–15 (\$39 per MWh). This compares to 2015–16 average prices of \$52 per MWh in New South Wales (49% higher than for 2014–15), \$60 per MWh in Queensland (13% higher), \$103 per MWh in Tasmania (178% higher¹¹), and \$46 per MWh in Victoria (53% higher).

AEMO analysis suggests the higher prices in South Australia were mainly due to tighter supply conditions and higher gas costs.

Are future reliability standard breaches projected?

The 2015 NEM ESOO¹² reported potential reliability standard breaches in 2019–20 and 2024–25, under a medium demand scenario, if additional generation or transmission capacity was not made available to the region.

Due to changes in both supply capacity and demand forecasts since 2015, reliability standard breaches are no longer projected in South Australia, unless generation surpluses in neighbouring regions are reduced:

- The market has responded to changed market conditions, with a June 2016 announcement that Torrens Island A Power Station (480 MW) would no longer withdraw from the market in 2017. AEMO supply adequacy modelling also now incorporates the committed Hornsdale Stage 1 Wind Farm (102.4 MW)¹³ and Waterloo Wind Farm expansion (19.8 MW).
- Operational consumption and MD are now forecast to be lower than was forecast last year. By 2025–26, 10% POE summer operational MD for South Australia is forecast to be 585 MW lower than the 2015 NEFR forecast.
- In modelling Australia's COP21 commitment¹⁴, AEMO has assumed up to 800 MW of brown coal withdrawals in Victoria and 560 MW of black coal withdrawals in Queensland under the neutral economic and consumer outlook in its 2016 NEM ESOO.¹⁵ In this scenario, in the absence of new supply options, South Australia is forecast to experience breaches in the reliability standard from 2019–20 to 2020–21, and again from 2024–25 to 2025–26.
- ENGIE has advised that half of the Pelican Point Power Station capacity (239 MW) can be assumed to remain out of service for the 10-year period, and that the full power station capacity could be made available within three months, subject to the commercial viability of returning the unit to service.

¹¹ A Basslink Interconnector cable fault separated Tasmania from the rest of the NEM from 20 December 2015 to 10 June 2016.

¹² AEMO. 2015 National Electricity Market Electricity Statement of Opportunities. Available at <http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities/NEM-ESOO-Archive>.

¹³ Since 2016 ESOO modelling was completed, Hornsdale Stage 2 Wind Farm (102.4 MW) has become committed. This supply increase is not expected to materially alter the analysis.

¹⁴ Australia has set a target to reduce carbon emissions by 26% to 28% below 2005 levels by 2030, agreed at the 2015 Paris 21st Conference of Parties. The Council of Australian Governments (COAG) Energy Council 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. AEMO analysis suggests that meeting the COP21 commitment is likely to require both generation withdrawals and investment in low-emission generation capacity.

¹⁵ 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.

The risk of unserved energy (USE) in South Australia is forecast to be greatest in the afternoon (from 2:00 pm to 8:00 pm), when periods of high demand coincide with low wind and solar PV generation, unplanned generation outages, or low levels of imports from Victoria. The risk is projected to shift later in this period over the 10-year outlook, as rooftop PV uptake increases.

Network or non-network developments, potentially including generation, storage, and demand side management services, may provide market benefits and improve reliability if they can increase available supply at these times.

How might electricity supply be met in the future?

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.

Recent investment interest in South Australia, reported by industry, is focused around renewable generation, new transmission interconnection, and energy storage.

Generation

Generation investment in South Australia continues to be focused largely on existing wind farm projects, with Hornsdale Stage 2 wind farm (102.4 MW) becoming committed in July 2016. In the Port Augusta region, two solar thermal power plants (with energy storage), a combined wind and solar PV farm, and a further solar PV farm are also proposed, totalling up to 885 MW.

Rooftop PV installations are expected to continue over the 10-year outlook period, during which time South Australia is projected to have the highest ratio of rooftop PV generation to operational consumption compared to all other regions in the NEM and the Western Australian Wholesale Electricity Market (WEM).

Interconnection

A project to increase the capacity of the existing Heywood Interconnector between Victoria and South Australia, from a nominal 460 MW to 650 MW in both directions, is nearing completion. Its capability is being progressively increased as testing and commissioning activities continue.¹⁶

ElectraNet is also investigating the feasibility of a potential new high-voltage interconnector between South Australia and the eastern states, to facilitate integration of more renewable generation in the region and improve system security. This initiative is one of several options to maintain power system security across the NEM that AEMO will explore in its annual *National Transmission Network Development Plan*, due to be published in November 2016.

Energy storage

The solar thermal proposals at Port Augusta propose different storage technologies as part of their power plant – one using graphite blocks, the other molten salt.

A stand-alone energy storage device was investigated as part of the Energy Storage for Commercial Renewable Integration – South Australia project, undertaken by a consortium of AGL, WorleyParsons, and ElectraNet. It considered a 10 MW (20 MWh) Lithium-Ion battery storage device situated close to the Wattle Point wind farm. The consortium reported the proposal was not considered profitable given current costs, but is considering a similar demonstration project in the future.¹⁷

¹⁶ Refer to information available on AEMO's website: <http://www.aemo.com.au/Consultations/National-Electricity-Market/Heywood-interconnector-upgrade-program-for-internetwork-tests>.

¹⁷ Energy Storage for Commercial Renewable Integration – South Australia (ESCRI-SA). *Phase 1 – General Project Report*. Available at: <http://arena.gov.au/files/2016/04/ESCRI-General-Project-Report-Phase-1.pdf>. Viewed: 13 July 2016.

What are the power system implications for the changing generation mix?

The secure operation of the transmission system relies on services – FCAS to manage day to day operation, and system restart ancillary services (SRAS) to restore the system following a major supply disruption – which synchronous generation has historically provided. The withdrawal of synchronous generation is also withdrawing these services from the NEM.

Frequency control ancillary services

AEMO has reviewed the supply and demand of FCAS for South Australia. The existing registered FCAS facilities are adequate to meet demand, for the following conditions:

- NEM system normal operation, where FCAS can be sourced from anywhere within the NEM.
- Where a credible risk of islanding of South Australia exists and the required FCAS must be sourced locally from within the state, provided the FCAS facilities are operating at that time.

AEMO is observing a reduction in the available capacity of FCAS across the NEM. Changes to the operating patterns of registered FCAS facilities, or closure of these facilities, would reduce future FCAS supply. Reduction in the available FCAS capacity in South Australia would result in additional constraints on interconnector transfers, when a credible risk of separation exists.

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

Further connection of non-synchronous generation may increase the demand for FCAS in South Australia, and unless this generation has FCAS capability this could create additional supply gaps.

In South Australia, FCAS provision is presently from thermal generators. Other generation technologies may be capable of providing FCAS if configured appropriately.

System restart ancillary services

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

While South Australia currently has enough local sources of SRAS to meet the system restart standard¹⁸, the market is tight.

Traditionally SRAS is sourced from coal, gas, or hydro generation, procured through a tender process.¹⁹ Other generation technologies might be able to configure plant to be able to contribute to the provision of SRAS.

Inertia and rate of change of frequency

Synchronous generation has inherent inertia that dampens deviations in the power system frequency. The withdrawal of synchronous generation reduces inertia in the system, and results in higher rates of change of frequency (RoCoF) following a disturbance, such as the trip of a generator or load. This increases the risk of power system plant or load tripping.

At present there is no market mechanism for the provision of services to manage RoCoF.²⁰

Through its Future Power System Security program²¹, AEMO is working to identify any underlying RoCoF limits of the power system, and exploring alternative ways of managing RoCoF through new measures, such as a fast frequency response service or other frequency control mechanisms.

¹⁸ The AEMC Reliability Panel is currently reviewing the system restart standard.

¹⁹ 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>.

²⁰ On 24 June 2016, AGL submitted a rule change request for the Australian Energy Market Commission 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.

²¹ More information on the program is available at: <http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability>.

Management of extreme power system conditions

RoCoF levels depend on the size of the contingency event. AEMO performed a historical review to assess how frequently the South Australian system would have been exposed to high RoCoF if a trip of the Heywood Interconnector had occurred. The assessment indicated that:

- The South Australian power system is now more likely to be operating in a mode that is susceptible to high RoCoF following non-credible separation, after the upgrade of the Heywood Interconnector (which increases the contingency size) and closure of Northern Power Station (which decreased system inertia).
- Emergency frequency control schemes in their current form (such as standard under-frequency load shedding (UFLS) schemes) are increasingly unlikely to prevent a total black system²² across South Australia resulting from a non-credible loss of the Heywood Interconnector. Since 1999, there have been four instances of synchronous separation²³ of South Australia from the rest of the NEM due to non-credible contingency events.

Addressing current challenges

AEMO is progressing work to address challenges resulting from decreasing levels of synchronous generation and system inertia in the region. This work, in consultation with industry, includes:

- Redesign of the current UFLS scheme.
- Design of an over frequency generation shedding (OFGS) scheme.
- Liaising with SA Power Networks on efforts to minimise rapid changes in the supply-demand balance resulting from the 11:30 pm hot water demand peak that will affect system security if South Australia is operating as an islanded network.
- Possible changes to Emergency Control Schemes and Operational Procedures to better manage networks under contingent conditions, including potential separation of South Australia from the rest of the NEM. This may involve promoting a Rule change.

AEMO is also undertaking modelling work to support consideration of new and alternative mechanisms for frequency control in the NEM.

²² 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 (italicised terms have specific meanings in the Rules).

²³ Synchronous separation refers to loss of all of alternating current (AC) network connections with other parts of the power system.



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1. INTRODUCTION

This *2016 South Australian Electricity Report (SAER)* is an executive briefing report, summarising information from the suite of South Australian reports regularly produced by AEMO, as summarised in Table 2. The other reports, most of which will be published over the next six months, will provide more detailed information on topics discussed in this report.

The 2016 SAER reports on South Australia's electricity supply and demand situation, focusing on:

- Consumption and demand, and the impact of rooftop photovoltaic (PV) generation, battery storage, and electric vehicles (EVs).
- Existing and committed supply, including generation and interconnector capacities and historical performance.
- Historical electricity spot market pricing information.
- Supply adequacy and system security outlook.

Table 2 Suite of South Australian reports, 2016

| Report | 2016 content | 2016 publication month |
|--|--|------------------------|
| <i>South Australian Demand Forecasts</i> | Demand forecasts and insights for South Australia, from the <i>National Electricity Forecasting Report</i> . | June |
| <i>South Australian Historical Market Information Report (SAHMIR)</i> | Generation, interconnectors, spot price, demand, basic wind performance, historical electrical energy requirements. | August |
| <i>South Australian Electricity Report (SAER)</i> | Consumption and demand, generation, interconnectors, spot price, basic wind performance, supply developments and withdrawals, supply adequacy, system security in a changing generation mix. | August |
| <i>Independent Review of ElectraNet's Preliminary Capital Expenditure Projects</i> | Independent technical assessment of emerging transmission network investment requirements in South Australia over ElectraNet's regulatory period 2018–19 to 2022–23. | August |
| <i>South Australian Renewable Energy Report (SARER)</i> | Advanced wind performance, rooftop PV performance. | October |
| <i>South Australian Generation Forecasts</i> | Forecast electrical energy requirements. | November |
| <i>Heywood Interconnector Upgrade Assessment Report</i> | Summary of performance of the Heywood Interconnector following completion of the upgrade works. | Late 2016 |
| <i>Independent Review of ElectraNet's Final Capital Expenditure Projects</i> | Independent technical assessment of emerging transmission network investment requirements in South Australia over ElectraNet's regulatory period 2018–19 to 2022–23. | January (2017) |
| <i>South Australian Fuel and Technology Report (SAFTR)</i> | Generation resources and technology survey, including analysis of levelised cost of electricity and emissions. | January (2017) |

Information used in this report is sourced from other AEMO reports, notably the *National Electricity Forecasting Report (NEFR)*, the *Electricity Statement of Opportunities (ESOO)* for the National Electricity Market (NEM), and the *South Australian Historical Market Information Report (SAHMIR)*. Information is also from data provided by market participants and potential investors as at 1 July 2016.

Time has been expressed in Australian Eastern Standard Time (AEST) with no daylight savings applied. This is referred to as NEM time (or market time).

The data that supports the tables and figures in this report is published on AEMO's website.

Chapter 7 provides links to these and other supporting information sources.

2. CONSUMPTION AND DEMAND

2.1 Introduction

On 16 June 2016, AEMO published the 2016 NEFR, which includes consumption and demand forecasts for the entire NEM and each region, including South Australia.²⁴

This chapter summarises key points from the NEFR and 2016 SAHMIR regarding actual and forecast operational consumption and demand in South Australia. It focuses on:

- Average daily demand historical trends over the last five summer and winter seasons.
- Relevant historical changes and drivers for forecasts.
- The impact of rooftop PV, battery storage, and EVs.
- Differences in forecasts between the 2015 NEFR and the 2016 NEFR, where possible.

An explanation of the data reporting terms used in this chapter, as well as important differences in reporting methods, can be found in Appendix A.

2.1.1 Sensitivities modelled

The forecast sensitivities reported in this chapter are taken from the 2016 NEFR and are summarised in Table 3.

Table 3 2016 NEFR modelling sensitivities

| Driver | Weak sensitivity | Neutral sensitivity | Strong sensitivity |
|---|---|--|---|
| Population growth | ABS projection ²⁵ C | ABS projection B | ABS projection A |
| Economic growth and business sentiment | Weak | Neutral | Strong |
| Consumer | Low confidence, less engaged | Average confidence and engagement | High confidence and more engaged |
| Electricity network charges – 5 years | Current AER determinations, fixed after 5 years | | |
| Electricity retail costs and margin | Assume current margins throughout | | |
| Technology uptake, including rooftop PV and batteries | Slower – hesitant consumer in a weak economy | Medium – neutral consumer in a neutral economy | Higher – confident consumer in a strong economy |
| Energy efficiency uptake | Low | Medium | High |

The neutral sensitivity is considered the most likely and is the main focus of this report. It is generally comparable with the medium scenario from 2015. The weak and strong sensitivities are not directly comparable with low and high scenarios from 2015 though, due to changes in the scenario logic:

- The strong sensitivity, while similar to the 2015 high when it comes to population growth and economic outlook, also assumes this will make consumers more likely to invest in rooftop PV, batteries, and energy efficiency. The 2015 high scenario assumed lower investments in all of these, and therefore resulted in a more extreme (higher) forecast for operational consumption.
- The weak sensitivity, correspondingly, is similar to the 2015 low scenario when it comes to population and economic growth assumptions, but assumes lower uptake of rooftop PV, batteries and energy efficiency where the 2015 low scenario assumed a high uptake.

²⁴ A separate summary of demand forecasts for South Australia was also published as *South Australian Demand Forecasts*, June 2016. Available at: <http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/South-Australian-Advisory-Functions>.

²⁵ Australian Bureau of Statistics, 2013, *Population Projections, Australia 2012 (base)*, cat. no. 3222.0.

2.2 Average daily demand

Average daily demand profiles represent the demand (in megawatts (MW)) for each 5-minute dispatch interval of a day, averaged over the relevant days of the selected period.

Changes to the average daily demand profile over time can provide insights into the impact of increasing small-scale renewable generation and demand side management.

Only South Australian workdays are included in the analysis. Weekends and gazetted public holidays are excluded.

Summer

Figure 1 shows the South Australian average workday demand profile for summer 2011–12 to 2015–16. Comparison of these profiles shows that:

- Historically, average demand has been decreasing each summer, particularly between daylight hours (about 8:00 am to 8:00 pm).
- AEMO attributes this reduction to increasing rooftop PV generation due to growth in installations, and energy efficiency gains.
- The reversal of the decreasing trend in average daily profile for 2015–16 may be attributed to:
 - The slowing growth of rooftop PV capacity compared to growth in the years to 2013–14²⁶, as well as natural variations in solar radiation across different years.²⁷
 - Adelaide experiencing one of its hottest summers due to El Niño.²⁸
 - The Port Pirie metals recovery and refining plant returning to pre-2014 levels of consumption in mid-2015 as redevelopment was progressed.²⁹
- Average demand consistently rises at 11:30 pm, due to the controlled switching of electric hot water systems. The Australian Energy Regulator (AER) has noted that “off-peak hot water load caused changes in demand of 15–20% at exactly 11:30 pm each day”.³⁰ South Australia Power Networks³¹ (SAPN) has initiated a project to re-program up to 90 MW³² of hot water demand to reduce the impacts of the switching on system security in the event of South Australia operating as an islanded network.

²⁶ This slowing of growth is relative to the growth in capacity up to 2013–14. However, forecasts presented in Section 2.6.2 still show strong growth overall in the 10-year outlook period.

²⁷ More information on rooftop PV capacity and generation is available in Section 2.6.

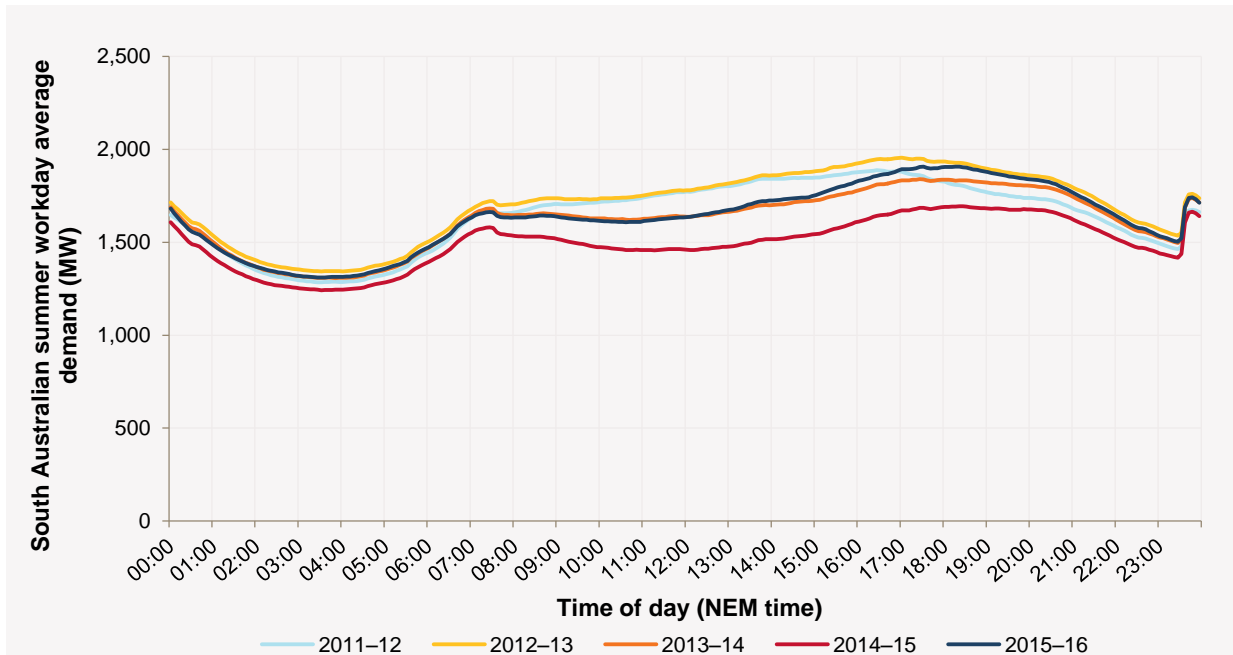
²⁸ Bureau of Meteorology, 7 Jan 2016. *Special Climate Statement 53—widespread record December temperatures in southeast Australia*. Available at: <http://www.bom.gov.au/climate/current/statements/scs53.pdf>.

²⁹ Nyrstar. “Redeveloping Port Pirie for a sustainable future – The Port Pirie Operation”. Available at: <http://www.portpirietransformation.com/index.php/the-port-pirie-operation>. Viewed: 26 August 2016.

³⁰ South Australian Council for Social Services (SACOSS). *High SA Electricity Prices: A Market Power Play?* Page 10. Available at: https://www.sacoss.org.au/sites/default/files/public/131212_CMU%20SACOSS%20Final%20Report_High%20SA%20Electricity%20Prices_0.pdf. Viewed: 25 September 2015.

³¹ SA Power Networks Flexible load strategy October 2014. https://www.aer.gov.au/system/files/SAPN%20-%202014_34%20PUBLIC%20-%20SAPN%20Flexible%20Load%20Strategy.pdf.

³² Refer to Section 6.5.

Figure 1 Summer workday average demand profiles


Winter

Figure 2 shows the South Australian average winter workday demand profile for winter 2012 to 2016.³³

Comparison of these profiles shows that:

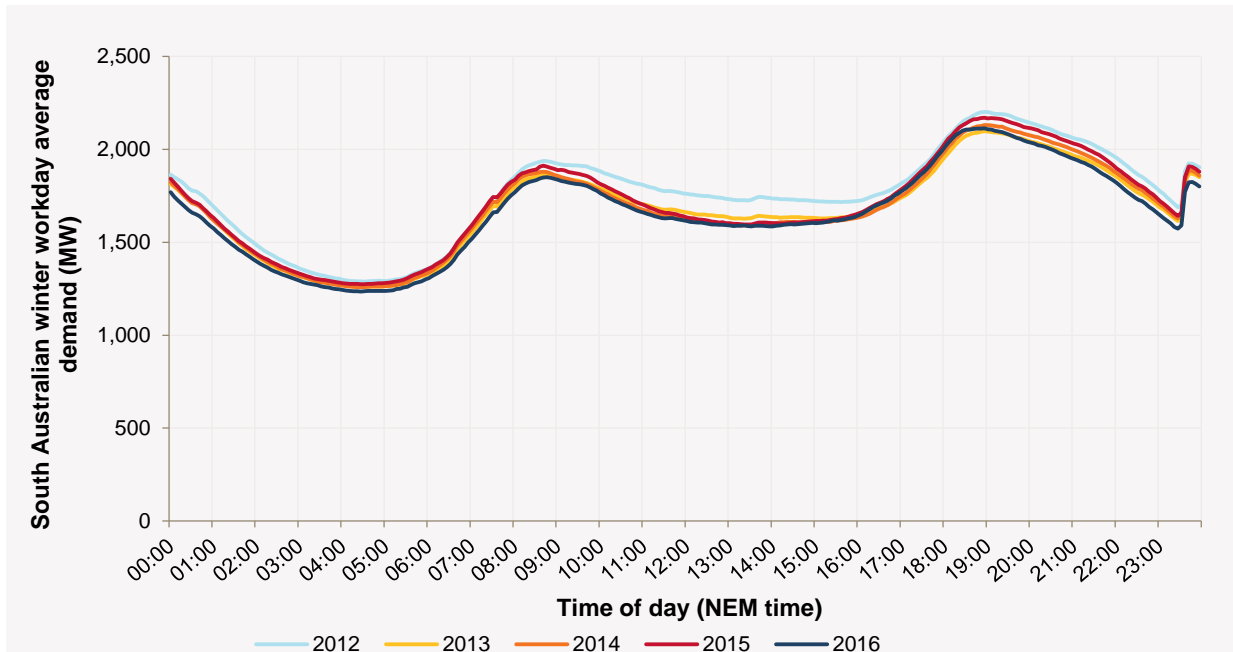
- Average demand has been generally steady each winter, with most variation between years shown in the evenings. The lower evening demand observed in winter 2016 reflects decreased heating load, due to the consistently warmer than average nights during June and July³⁴, with Adelaide reaching its warmest July day in 14 years (noting that a cold front beginning 12 July 2016³⁵ caused unusually high demands on some days).
- The higher demand in winter 2012 is attributed to lower levels of rooftop PV installed. Rooftop PV generation increased by 70% in the 2012–13 financial year.
- Average morning and evening peaks are higher in winter than summer, most likely due to the heating loads in winter and reduced summer demand from rooftop PV generation.
- Average demand consistently rises at 11:30 pm due to the controlled switching of electric hot water systems, as discussed for the average summer workday daily profile.

³³ Winter 2016 includes data for June and July 2016 only.

³⁴ Bureau of Meteorology (BOM). *South Australia in June 2016: above average rainfall and warm nights*. Available at: <http://www.bom.gov.au/climate/current/month/sa/archive/201606.summary.shtml>. Viewed: 3 August 2016.

³⁵ Bureau of Meteorology (BOM). *South Australia in July 2016: Above average rainfall for southeast agricultural areas, average temperatures*. Available at: <http://www.bom.gov.au/climate/current/month/sa/summary.shtml>. Viewed 24 August 2016.

Figure 2 Winter workday average demand profiles



2.3 Operational consumption

This section presents recent historical and long-term forecast annual operational consumption in South Australia. Where possible, forecasts from both the 2016 NEFR and 2015 NEFR are shown for comparison across the different sensitivities.

Recent history

Figure 3 shows the historical trend of declining operational consumption in South Australia from 2010–11. This was driven by a fall in residential and commercial consumption, resulting from sustained high electricity price growth and strong uptake of rooftop PV and energy efficiency. More detail on residential and commercial historical trends is given in Sections 2.3.1 and 2.3.2.

In 2015–16, operational consumption was 12,934 gigawatt hours (GWh). This was 3.7% (466 GWh) higher than the 2014–15 consumption of 12,468 GWh, and 1.6% (206 GWh) higher than forecast in the 2015 NEFR. The increase in 2015–16 is driven by:

- A ramping up of industrial consumption (forecast in the 2015 NEFR), such as Port Pirie metals recovery and refining plant returning to normal operating conditions following a 2-year redevelopment project.
- Increased water pumping and higher air-conditioner usage (by residential and commercial sector), both resulting from warmer and drier than usual weather conditions.

Forecast

Figure 3 shows that, under the 2016 NEFR neutral sensitivity:

- Operational consumption for 2016–17 is forecast to decrease to 12,627 GWh, 2.3% (295 GWh) lower than was forecast in the 2015 NEFR under the medium scenario.
- Operational consumption is forecast to decline in the long-term outlook period (2015–16 to 2025–26). Average annual decline is forecast to be 0.7%, which is broadly consistent with the 0.6% forecast decline in the 2015 NEFR for the same period.

The long-term outlook (to 2025–26) is attributed to:

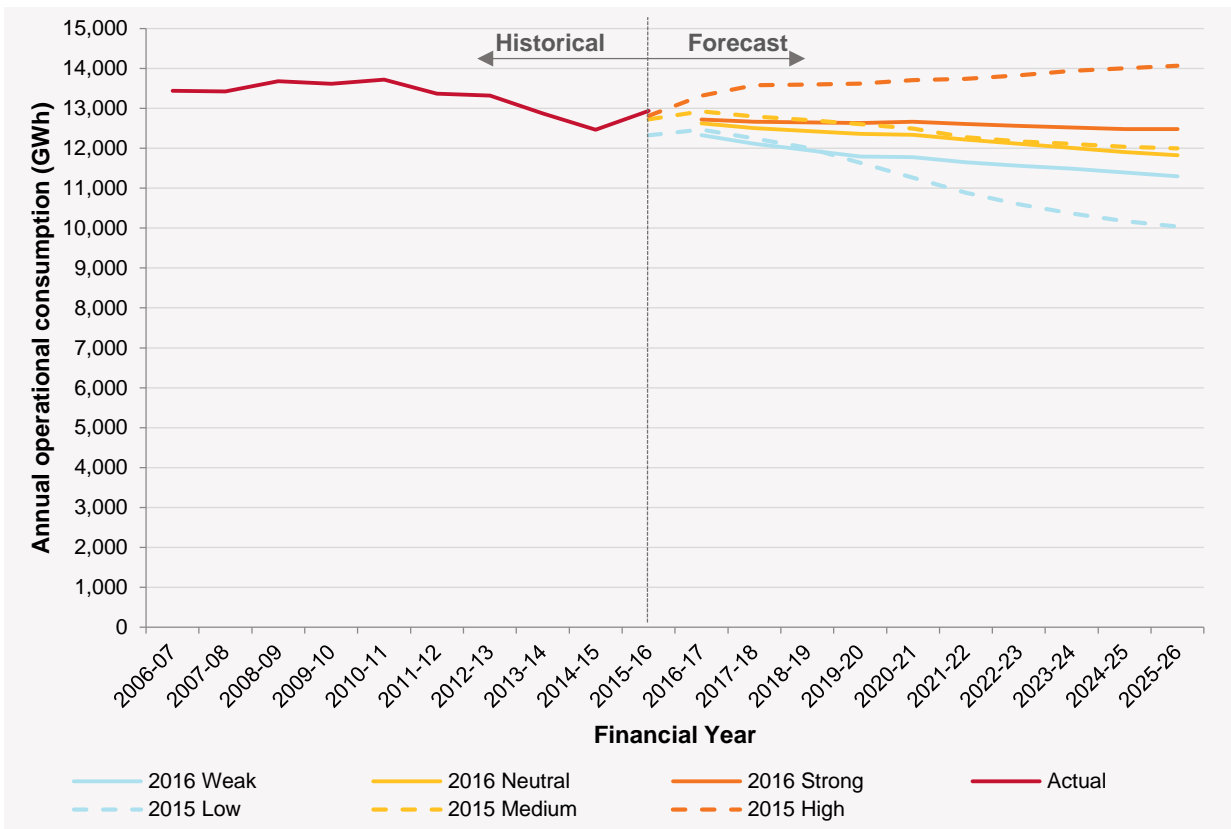
- Continued high uptake of rooftop PV and energy efficiency savings being projected to more than offset moderate new connections growth and increasing appliance use by households.
- Flat business sector consumption, caused by the absence of growth in energy-intensive manufacturing, little growth in services offset by energy efficiency savings, and the expected reduction in automotive manufacturing.
- Projected increases in electricity prices reducing growth in consumption.³⁶

While differences in sector definitions prevent direct comparison at sector level between the 2015 and 2016 forecasts, the total operational forecast for the 2016 neutral sensitivity can be compared with the 2015 medium scenario. Figure 3 shows the two operational forecasts are well aligned, with the 2016 forecast being slightly lower. For the underlying forecast³⁷ the difference between the 2015 and 2016 forecast is much greater, as the estimated rooftop PV generation is ~600 GWh lower in the 2016 forecast by 2025–26. The reason for this change is discussed in Section 2.6.

In addition, the lower underlying forecast is due to energy efficiency being applied differently in 2016, better capturing the expected replacement of air-conditioners with more efficient modern models as units reach end-of-life.

The 2016 strong and weak sensitivities are defined quite differently from the 2015 high and low scenarios and cannot be compared. By design they project less extreme futures and therefore result in a narrower span of projected outcomes.

Figure 3 Annual operational consumption actual and forecast for South Australia



³⁶ Details of the retail price forecasts are provided in Jacobs 2016, *Retail electricity price history and projections*. Available at: <http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Electricity-Forecasting-Report>.

³⁷ Underlying demand is customer demand before netting off rooftop PV, and excluding contribution from small non-scheduled generation.

Components of consumption forecast

The different components of the neutral sensitivity consumption forecast are presented in Figure 4. They highlight the drivers by different components, which affect the overall consumption forecast.

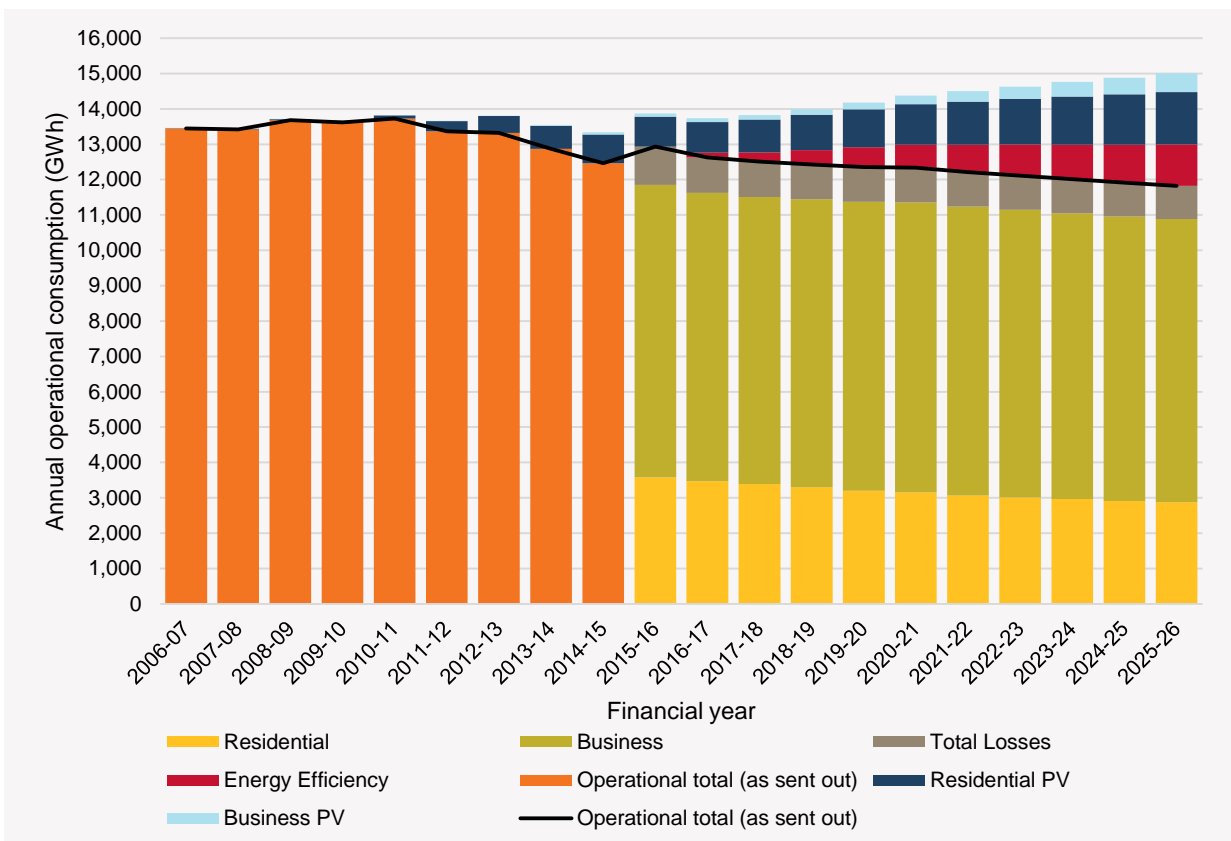
Consumption itself is split into two high-level sectors, residential and business. Network losses are added to these to make up operational consumption.

Figure 4 also shows the impacts of energy efficiency and rooftop PV, to illustrate what the forecast would have been, if it had not been for those factors.

In 2015–16, South Australia’s total operational consumption was made up of 3,581 GWh of residential sector consumption (28% of total), 8,269 GWh of business sector consumption (64%), and 1,084 GWh of total transmission and distribution network losses (8%).³⁸

More information on residential and business sector forecasts is available in the following sections.

Figure 4 Annual operational consumption forecast components



³⁸ Losses reported in previous SAERs included only transmission losses, with distribution losses being included in the estimated energy use by “residential and commercial” and “large industrial load” sectors.

2.3.1 Residential sector

The residential sector considers estimated electricity usage by all residential customers. This is in contrast to previous reporting, which considered residential usage alongside commercial and light industrial usage. As the drivers in electricity consumption differ substantially between residential and non-residential customers, this new approach to segmentation allows AEMO to construct a more finely-tuned residential forecast model. AEMO has not produced retrospective analysis by the new sector splits before 2015–16, therefore no historical residential sector trends are given, and forecasts are not comparable to last year’s reporting.

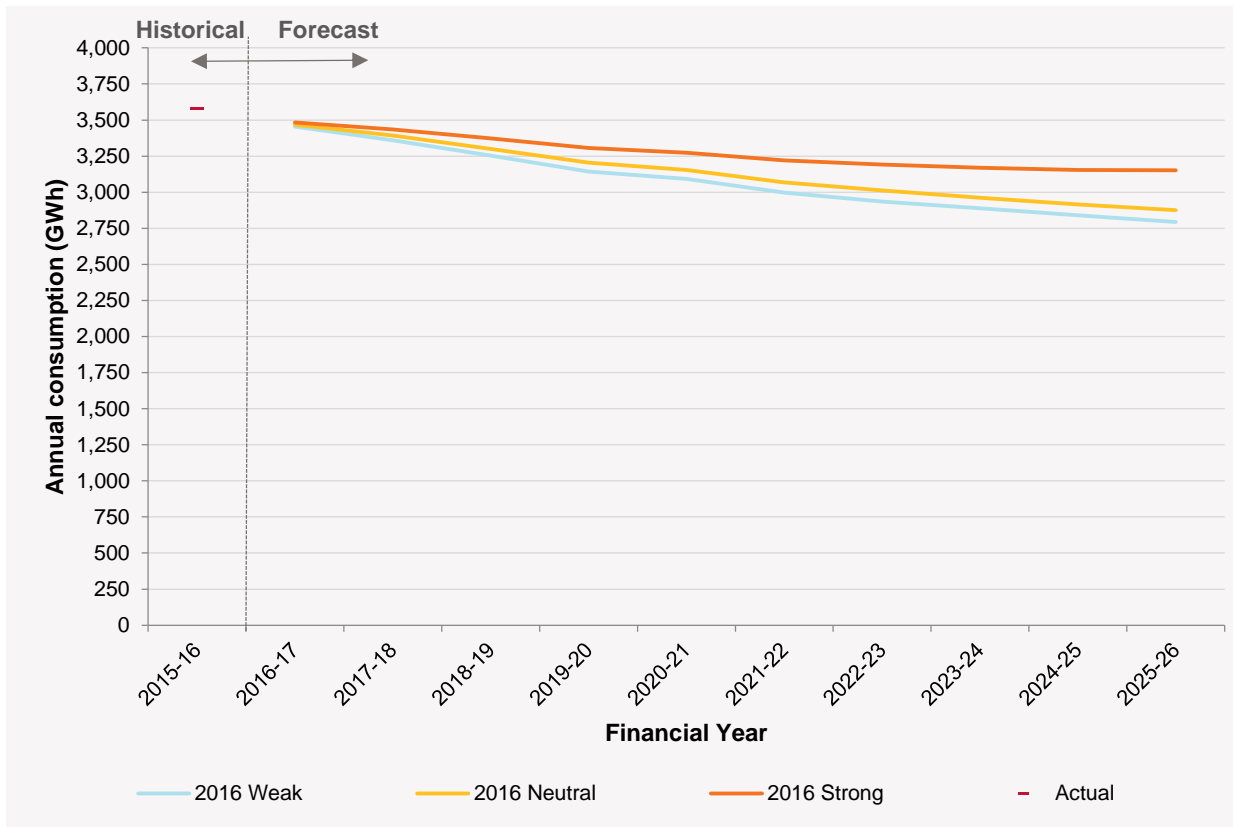
Recent performance and forecast trends

Figure 5 shows that over the long-term outlook period (2015–16 to 2025–26), under the neutral sensitivity, residential sector annual consumption is forecast to decline at an average annual rate of 2.0%. This trend is attributed to the following factors:

- Continued uptake of rooftop PV systems.
- Ongoing improvements in appliance and building energy efficiency.
- Consumer response to forecast retail price increases towards the end of the 10-year horizon.

The declining trend is marginally countered by a forecast increase in switching from gas-fuelled appliances to electricity, which results in an additional 253 GWh of annual electricity consumption by 2025–26.

Figure 5 South Australian residential sector annual consumption



2.3.2 Business sector

The business sector covers electricity usage by all commercial and industrial customers. This is in contrast to previous reporting, which incorporated commercial demand and light industrial demand into the residential and commercial sector, and considered the remainder in the large industrial load sector (sites with an average daily consumption of 10 MW or more for at least 10% of the year).

The business sector in AEMO's 2016 NEFR forecasts was further split into manufacturing, coal mining, liquefied natural gas (LNG), and other business. There is no LNG in South Australia, and with the closure of Leigh Creek coal mine, there are no major coal mining loads either.

In summary, South Australian business consumption is made up of:

- Manufacturing (which includes the large industrial loads from previous years).
- Other business.

AEMO has not produced retrospective analysis by the new business sector splits before 2015–16, therefore no historical business sector trends are given, and forecasts are not comparable to last year's reporting.

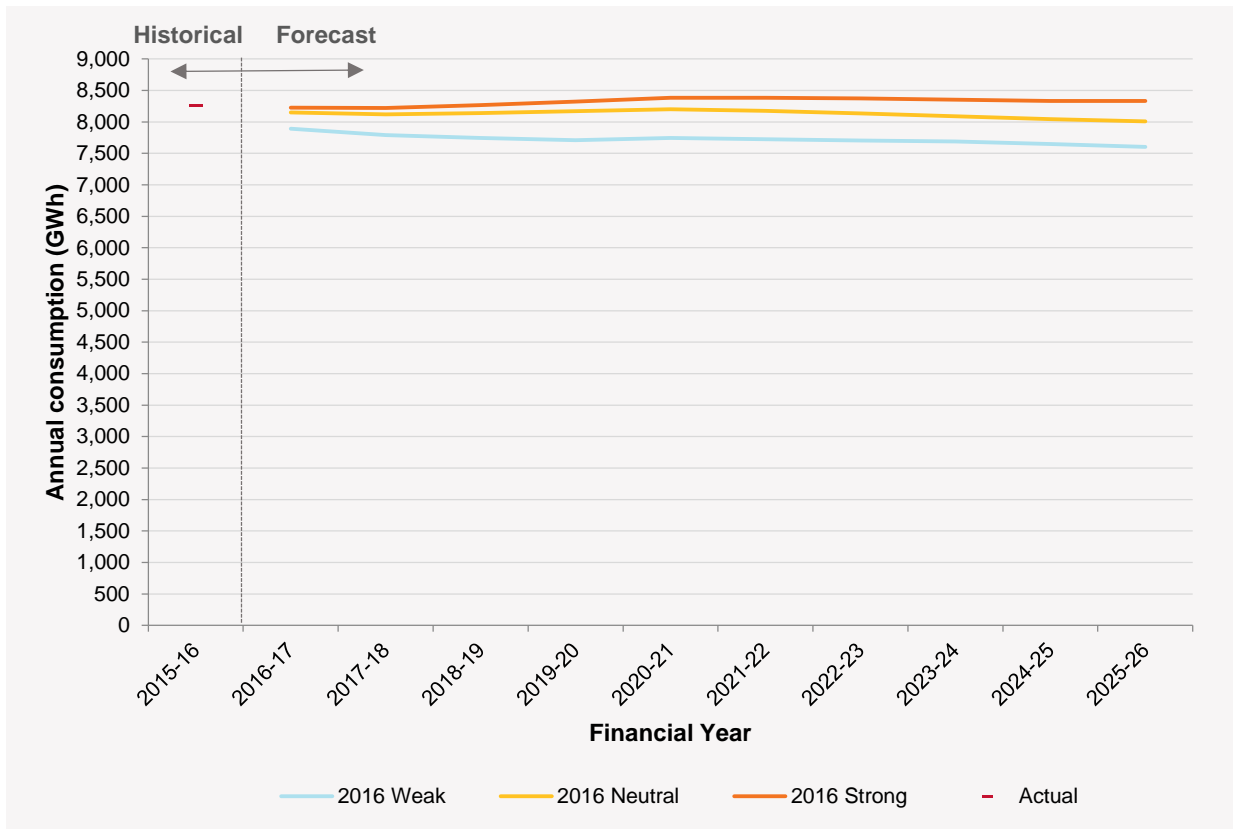
Recent performance and forecast trends

Figure 6 shows that over the long-term outlook period (2015–16 to 2025–26), under the neutral sensitivity, consumption in manufacturing and other business is forecast to remain mostly flat.

Manufacturing sees an initial drop driven by automotive industry closures in 2016–17, followed by a constant annual average increase of 0.21%. Driving this is the increasing gross state product, which is largely offset by a projected decline in consumption in response to expected increasing input costs.

The “other business” sector trend is driven by a slowing population growth rate. Any further increase in consumption, attributable to increased consumer confidence, is either offset by energy efficiency gains or met by increased rooftop PV generation, resulting in a flat forecast for the other business sector operational consumption.

Figure 6 South Australian business sector annual consumption



2.3.3 Small non-scheduled generation

Small non-scheduled generation (SNSG) refers to the output from selected non-scheduled generating units that typically have a capacity less than 30 MW. Operational consumption is net of output from these units. In South Australia, the annual generation from SNSG is relatively small compared to the region’s annual operational consumption, resulting in a limited impact overall.

Table 4 highlights the estimated contribution from SNSG in the region, from the 2016 NEFR. Annual operational consumption is also shown for comparison. The increase in forecast SNSG over the 10-year period is due to inclusion of non-scheduled solar PV larger than 100 kW. In previous years, this was included in the rooftop PV used to offset residential and business demand.

Small non-scheduled generators typically do not have the same NEM registration and metering requirements as scheduled, semi-scheduled, and significant non-scheduled generators. Therefore it is not practical for AEMO to report on SNSG capacity or output as it does for those generators supplying operational consumption. AEMO’s reporting of SNSG output is an estimate based on selected generators, and the estimates may be refined from year to year.

Note that the 2016 NEFR reported a reduced list of small non-scheduled generators, so SNSG output is not directly comparable between the 2015 and 2016 SAER.

Table 4 Estimated annual contribution from small non-scheduled generation in South Australia (GWh)

| Financial Year | Source | Small non-scheduled generation | Operational consumption |
|----------------|------------------------------|--------------------------------|-------------------------|
| 2011–12 | Actual | 62 | 13,367 |
| 2012–13 | Actual | 58 | 13,319 |
| 2013–14 | Actual | 60 | 12,872 |
| 2014–15 | Actual | 59 | 12,468 |
| 2015–16 | Actual | 52 | 12,934 |
| 2016–17 | Neutral sensitivity forecast | 49 | 12,627 |
| 2017–18 | Neutral sensitivity forecast | 56 | 12,508 |
| 2018–19 | Neutral sensitivity forecast | 64 | 12,432 |
| 2019–20 | Neutral sensitivity forecast | 83 | 12,359 |
| 2020–21 | Neutral sensitivity forecast | 89 | 12,339 |
| 2021–22 | Neutral sensitivity forecast | 102 | 12,214 |
| 2022–23 | Neutral sensitivity forecast | 112 | 12,111 |
| 2023–24 | Neutral sensitivity forecast | 125 | 12,008 |
| 2024–25 | Neutral sensitivity forecast | 134 | 11,909 |
| 2025–26 | Neutral sensitivity forecast | 143 | 11,825 |

2.4 Operational maximum demand

South Australian operational maximum demand (MD) has historically occurred during periods of hot weather over summer.

For the last 10 years, South Australia's load factor has continued to be the lowest of all NEM regions.³⁹ This indicates that South Australia has the greatest difference between average hourly consumption and MD, largely attributed to air-conditioner load.

Figure 7 shows recent historical summer MD actuals, and 10%, 50%, and 90% POE forecasts from the 2016 (neutral sensitivity) and 2015 (medium scenario) NEFR publications.

Recent history

Figure 7 shows that historically (2006–07 to 2015–16), South Australian MD ranged from approximately 2,697 MW to 3,256 MW. In summer 2015–16, MD was 2,895 MW, which was 7.3% (198 MW) higher than the 2014–15 MD, and 361 MW lower than the record MD of 3,256 MW in 2010–11.

The 2015–16 actual summer MD was 3.8% (106 MW) higher than the 2015 NEFR's 50% POE forecast under the medium scenario. In terms of the span between the POE 10% and 90% forecasts, this is relatively close to the central 50% POE estimate. The MD occurred on 17 December 2015 at 5:30 pm. As the conditions at that time were those of a relatively typical maximum (week day, average temperature over the previous three hours was about 35 degrees) an actual close to the 50% POE is to be expected.

Forecast – summer

Figure 7 shows that, under the NEFR neutral sensitivity, forecast 10% and 50% POE summer MD is expected to decrease at annual averages of 1.8% and 1.6% respectively, over the long-term outlook period (2015–16 to 2025–26). The forecast decreasing MD plays a key role in the outcome of supply adequacy modelling discussed in Chapter 5, where no breaches in the reliability standard are forecast unless generation surpluses in neighbouring states are reduced.

³⁹ Load factors for all NEM regions can be calculated by comparing average hourly consumption to maximum demand. Data is available at: <http://forecasting.aemo.com.au/>. Viewed: 17 June 2016.

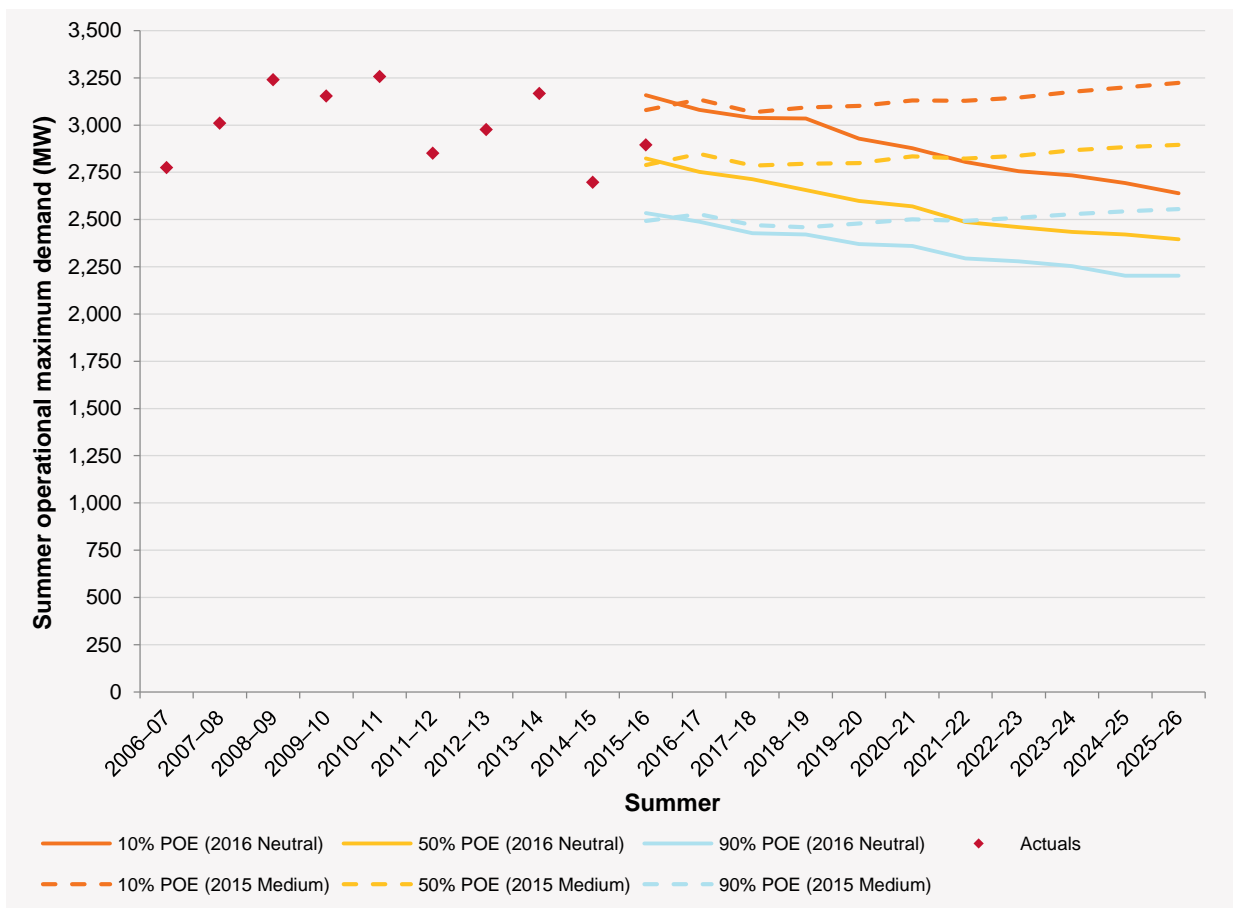
Comparison of the 2015 NEFR medium scenario and 2016 NEFR neutral sensitivity MD forecasts shows:

- The 2016 forecast 10% POE summer MD for 2016–17 is 1.7% (54 MW) lower than the 2015 forecast.
- Over the long-term outlook period (2015–16 to 2025–26), the 10% POE summer MD is forecast to decrease on average 1.8% annually, compared with the 0.5% increase forecast in 2015.
- By 2025–26, 10% POE summer operational MD for South Australia is forecast to be 585 MW lower than the 2015 NEFR forecast.

The differences between the 2015 and 2016 NEFR MD forecasts are attributed to changes in modelling assumptions, especially:

- Different modelling of appliance uptake and energy efficiency gains that impact maximum demand in particular. This is largely driven by expected replacement of old air-conditioners reaching end-of-life with new appliances that are almost twice as efficient.
- Higher forecast retail prices putting downward pressure on electricity consumption. This includes a price impact from assumed carbon emission abatement policies to meet the COP21 commitment.⁴⁰
- Slower forecast growth of population and new electricity connections.

Figure 7 Summer operational maximum demand actual and forecast for South Australia (neutral sensitivity)



⁴⁰ Australia has set a target to reduce carbon emissions by 26% to 28% below 2005 levels by 2030, agreed at the 2015 Paris 21st Conference of Parties. The Council of Australian Governments (COAG) Energy Council 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. AEMO analysis suggests that meeting the COP21 commitment is likely to require both generation withdrawals and investment in low-emission generation capacity.

Forecast – winter

Figure 8 shows that, under the NEFR neutral sensitivity, forecast 10% and 50% POE winter MD is expected to remain flat over the forecast period (2015–16 to 2025–26). As the projected summer MD declines (shown in Figure 7), the two will converge. By 2025–26 the 50% POE forecasts are basically identical, indicating South Australia could be winter peaking in an average year.

The replacement of old air-conditioners with new efficient ones is also projected to lower the MD contribution from reverse-cycle air-conditioner heating, but this is offset by forecast fuel switching from gas to electric heating.

Figure 8 Winter operational maximum demand (neutral sensitivity)



2.4.1 Small non-scheduled generation

Table 5 summarises the 2016 NEFR estimated output from SNSG in South Australia, at the time of the region’s operational MD, for the past five years and forecast to 2025–26.⁴¹

It shows that in 2015–16, for example, operational MD was 2,895 MW and at that time small non-scheduled generation was estimated to be producing 6.5 MW of electricity. In effect, operational MD would have been about 6.5 MW higher were it not for that portion of the state’s electricity needs being supplied by small non-scheduled generation.

The contribution to demand reduction by small non-scheduled generation is smaller than reported in the 2015 SAER, as the list of generators included in the small non-scheduled generation category has reduced in 2016, due to generator reclassification.

⁴¹ The full set of forecast values in each year is available on the NEFR’s Forecasting Dynamic Interface. Available at: <http://forecasting.aemo.com.au/>. Viewed: 2 August 2016.

Table 5 Estimated output from small non-scheduled generation in South Australia, at time of operational MD (MW)

| Financial Year | Source | Small non-scheduled generation output at time of operational MD | Operational MD |
|--------------------|--|---|-----------------------------------|
| 2011–12 | Actual | 10.8 | 2,850 |
| 2012–13 | Actual | 9.7 | 2,975 |
| 2013–14 | Actual | 7.8 | 3,167 |
| 2014–15 | Actual | 8.1 | 2,697 |
| 2015–16 | Actual | 6.5 | 2,895 |
| 2016–17 to 2025–26 | Neutral sensitivity forecast, 10%, 50% and 90% POE | Ranges between 5.7 to 6.8 MW | Ranges between 2,202 and 3,158 MW |

2.5 Operational minimum demand

AEMO also forecasts operational minimum demand in South Australia in the NEFR, to investigate the impact of rooftop PV on the daily load profile. This provides useful information on network usage, which can inform further studies to evaluate operational implications.

Figure 9 shows the components that make up forecast operational minimum demand in the 2016 NEFR, in particular the impact of rooftop PV reducing the demand over time.

Key insights include:

- The minimum demand in 2015–16 was 834 MW on 25 March 2016 at 12:30 pm. Minimum demand generally occurs on a sunny day in summer⁴², typically on a public holiday (25 March 2016 was Good Friday). At that time, 1,286 MW of underlying demand was offset by 468 MW generated by rooftop PV.
- By 2026–27, on 90% POE minimum demand days⁴³, continued uptake of rooftop PV is forecast to offset 100% of demand in South Australia, during midday periods. From that year, AEMO forecasts negative minimum demand under certain conditions. This results in net exports from the distribution network to the transmission grid in aggregate, and ultimately from the region, during those periods.
- South Australia is the first region in the NEM for which high rooftop PV penetration has caused the observed minimum operational demand in a particular year to shift from overnight to near midday.⁴⁴
- Negative operational demand is projected to occur later than forecast in the 2015 NEFR, mainly due to a downward revision of forecast rooftop PV uptake.
- Battery storage uptake has been included in the model, assuming a specific usage profile. Different charge/discharge patterns adopted by users could have an effect on both the minimum and maximum demand. Currently, it lifts minimum demand as batteries are assumed to be charged in the middle of the day when the solar panel generation is at its maximum.

The minimum demand model did not incorporate potentially material impacts of:

- Customer response to tariff changes – including the expiration of rooftop PV feed-in tariffs and tariff reforms towards more cost-reflective pricing.
- EV uptake and charging.⁴⁵

These factors will be explored in future NEFR publications. More information on minimum demand forecasts can be found in the 2016 NEFR.⁴⁶

⁴² For reporting on NEM mainland regions, summer refers to the period 1 November – 31 March.

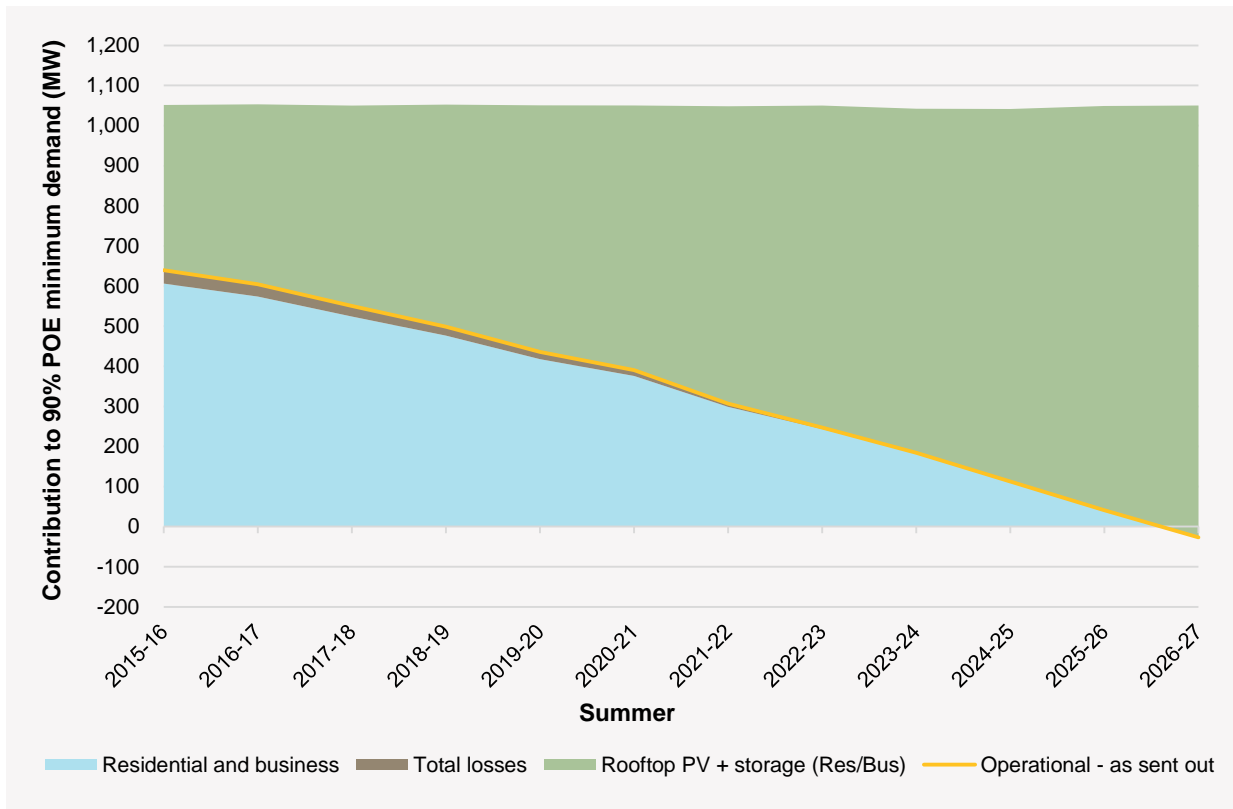
⁴³ This represents the forecast minimum demand in a 1-in-10 low demand year, with 9-in-10 years forecast to have a higher minimum demand.

⁴⁴ In 2016, South Australia's winter minimum demand also occurred near midday, reaching a record winter low of 918 MW for the trading interval ending 12:30 pm on Sunday 28 August.

⁴⁵ Information on electric vehicle forecasts is available in *AEMO Insights, August 2016, Electric Vehicles*. Available at: <http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Electricity-Forecasting-Report>.

⁴⁶ 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>.

Figure 9 Summer 90% POE minimum demand forecast segments for South Australia (neutral sensitivity)



2.6 Impact of rooftop PV, battery storage, and electric vehicles

2.6.1 Introduction

Rooftop PV systems installed in South Australian residential and commercial premises have a material impact on the region’s electricity demand. This is due to the cumulative effect of their generation output in reducing residential and commercial electricity demand during daylight hours. Information on the methodology employed in rooftop PV and battery storage analysis is given in Appendix B.

A more comprehensive analysis of rooftop PV in South Australia will be published in AEMO’s October 2016 *South Australian Renewable Energy Report (SARER)*. A brief summary of key information is presented below to highlight the impact on the region’s actual and forecast consumption and demand.

EV uptake is expected to have a smaller impact than rooftop PV and battery storage, but is another emerging technology AEMO is tracking. Forecast impacts are discussed in Section 2.6.4.

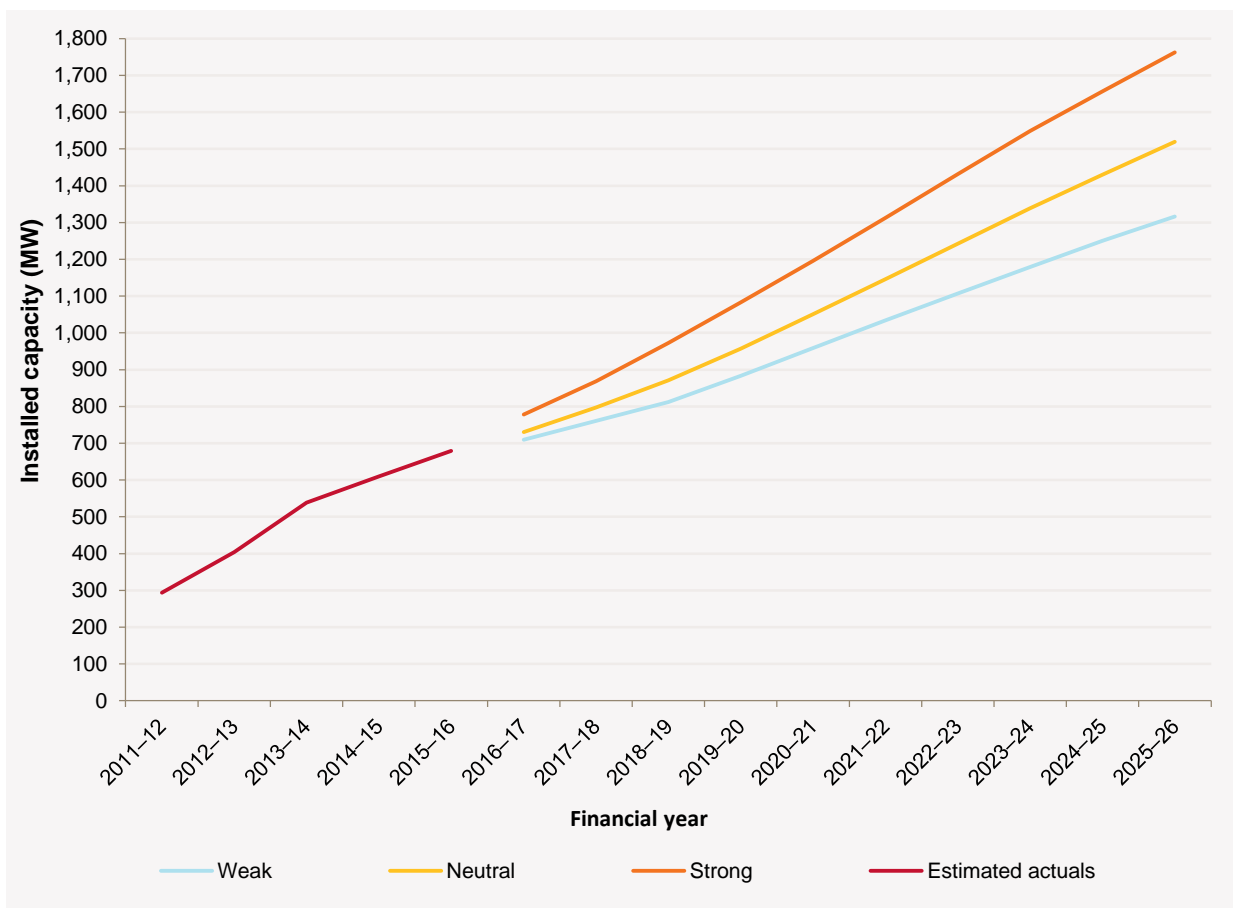
2.6.2 Rooftop PV

Capacity

Since 2009, South Australian total installed rooftop PV capacity has grown strongly. This has been primarily due to government incentives in the form of rebates and feed-in tariffs, the Small-scale Technology Certificate (STC) multiplier, falling system costs, and increasing electricity prices. These factors helped reduce payback periods, making rooftop PV generation an attractive option for households, particularly from 2010 to 2012. More than 29% of dwellings in South Australia now have rooftop PV systems installed.⁴⁷

The rooftop PV installed generation capacity estimated actuals and forecasts for South Australia are shown in Figure 10. The estimates include all residential and business systems⁴⁸, including those with battery storage systems. Differences between the forecasts for the strong, neutral, and weak sensitivities are primarily due to differences in rooftop PV and battery storage systems capital costs assumed across the sensitivities.

Figure 10 South Australian rooftop PV installed capacity forecasts*



* Data for 2011-12 to 2014-15 is different to that presented in the 2015 SAER, due to AEMO's additional data cleaning of raw CER input data to rooftop PV capacity estimates.

⁴⁷ Analysis taken from: Australian PV Institute (APVI) Solar Map, funded by the Australian Renewable Energy Agency, accessed from pv-map.apvi.org.au on 24 June 2016.

⁴⁸ For installations up to 100 kW capacity. Forecasts for installations greater than 100 kW capacity are included in the small non-scheduled generation (SNSG) forecasts discussed in Section 2.3.3.

Generation

Over the next ten years, South Australia is projected to have a higher ratio of rooftop PV generation to operational consumption than any other NEM region and Western Australia's Wholesale Electricity Market (WEM). This is attributed to the state's high penetration of rooftop PV installations, good solar resources, and the second-lowest operational consumption of all NEM and WEM regions.

Figure 11 shows rooftop PV estimated generation actuals and forecasts from 2006–07 to 2025–26. This figure illustrates that rooftop PV generated an estimated total of 938 GWh in 2015–16 and is expected to reach 2,015 GWh by 2025–26 (under the neutral sensitivity).

Analysis of the drivers behind the 2015 and 2016 NEFR forecasts for rooftop PV in South Australia, for the medium scenario and neutral sensitivity respectively, shows:

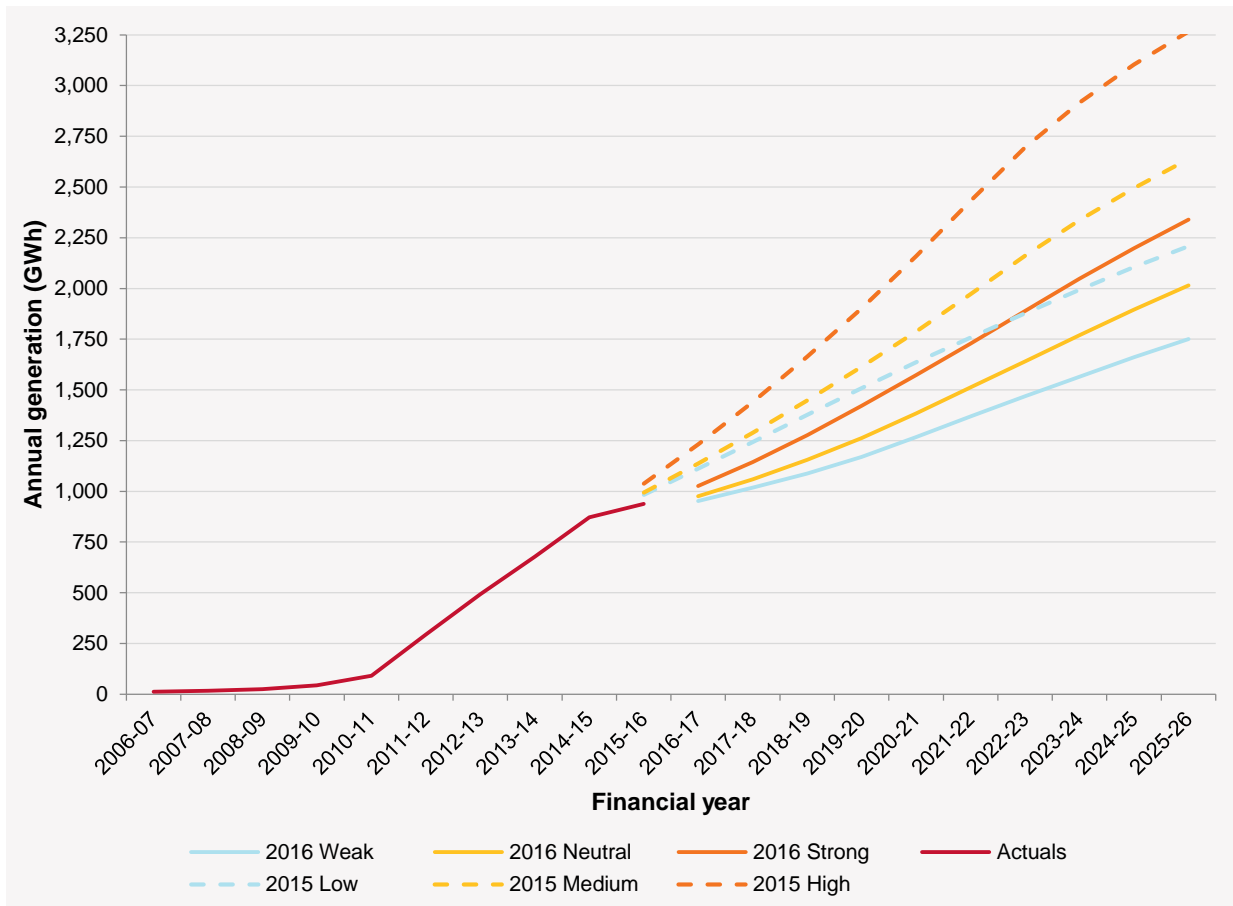
- The 2016 forecasts are lower than the 2015 forecasts, due to a downward revision of forecast growth of installed capacity for both the residential and business sectors. This revision has been driven by a new model developed by consultancy Jacobs⁴⁹, combined with revised electricity price assumptions, global economic outlook (including foreign exchange rate), and lower capacity saturation limits.

The growth in rooftop PV generation estimated in 2015–16 is slower than the relative growth in installed capacity over the same period. This is attributed to two factors:

- The data source for solar radiation used over the 2015–16 period (European Centre for Medium-Range Weather Forecasts (ECMWF)) is different from that used for the previous years (Australian Bureau of Meteorology (BoM)). The two data sources estimate the solar radiation used in AEMO's models in different ways, with the ECMWF data typically 2% lower than equivalent data from the BoM.
- The natural variation of solar radiation at the surface across different years. Sources of variation include cloud cover and humidity levels.

⁴⁹ Jacobs' consultancy report, *Projections of uptake of small-scale systems*, is available on AEMO's website at: <http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Electricity-Forecasting-Report>.

Figure 11 South Australian rooftop PV generation forecasts



2.6.3 Battery storage

The 2016 NEFR forecasts include battery storage uptake projections for the first time. The forecast of battery uptake was prepared by Jacobs.⁵⁰ Battery systems have been assumed to be installed in conjunction with solar systems in an Integrated PV and Storage System (IPSS). Retrofits of existing PV systems are considered uneconomic under the current assumptions and have not been considered.

Uptake of battery storage is forecast to start slowly and pick up especially after 2020, in both the residential and business sectors, reaching 489 MWh installed in 2025–26. The forecast used in the 2016 NEFR estimates that in 2025–26, 18.4% of new PV systems will be IPSS.

In the 2016 NEFR maximum and minimum demand analysis, a specific charge/discharge pattern was assumed (refer to Appendix B.2 for more details). Under the assumptions, the impact of battery storage in shedding the peak demand is estimated to be negligible in the short-term forecast and to reach approximately 2% of the peak demand in 2025–26.

More information on battery storage can be found in AEMO’s 2016 SARER, to be published in October 2016.

⁵⁰ Jacobs’ consultancy report, *Projections of uptake of small-scale systems*, is available on AEMO’s website: <http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Electricity-Forecasting-Report>.

2.6.4 Electric vehicles

In 2016, AEMO commissioned Energeia to produce a forecast for EV uptake and the impacts on regional annual consumption and maximum/minimum demand for each of the three sensitivities presented in the 2016 NEFR.⁵¹

The forecast shows a very modest impact within the 10-year horizon, even for the strong sensitivity, which has the strongest uptake.

Table 6 Forecast share of EVs as percentage of total vehicle stock in South Australia

| | 2015–16 | 2020–21 | 2025–26 |
|----------------------------|---------|---------|---------|
| Strong sensitivity | 0.1% | 1.8% | 11.0% |
| Neutral sensitivity | 0.1% | 0.8% | 3.9% |
| Weak sensitivity | 0.1% | 0.3% | 1.2% |

Table 7 Forecast consumption from EVs in South Australia (GWh)

| | 2015–16 | 2020–21 | 2025–26 |
|----------------------------|---------|---------|---------|
| Strong sensitivity | 1.2 | 35 | 257 |
| Neutral sensitivity | 1.0 | 13 | 88 |
| Weak sensitivity | 0.9 | 5 | 26 |

Table 7 shows the annual consumption impact is forecast to be limited to 88 GWh by 2025–26 in the neutral sensitivity. The impact on the daily demand shape is larger, but as charging is mostly assumed to happen at night, it has no impact on forecast regional maximum demand. EVs could potentially have some impact on the maximum demand experienced for distribution feeders, depending on both EV uptake and whether changing tariffs incentivise charging outside local peak demand.

AEMO notes that there are major uncertainties affecting the emergence of EVs that need to be investigated to better appreciate their likely impact on the energy system. These include:

- The design, technology, and commercialisation of future public charging infrastructure.
- Potential development of government policies affecting transport, such as transportation fleet energy efficiency standards or local policy measures that further support EV uptake.
- Price and tariff structures to accommodate electric vehicles.
- Heavy transport, which was outside the scope of the study.
- The role of electric vehicles in the future power grid, in particular their contribution of energy storage to households and the grid, and their contribution of network support services to address the management of frequency, energy, and voltage.

⁵¹ *AEMO Insights, August 2016, Electric Vehicles*. Available at: <http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Electricity-Forecasting-Report>.

3. SUPPLY

This chapter summarises South Australia's electricity supply in recent years, focusing on generation and interconnection with Victoria. The information is sourced from the 2016 SAHMIR. As noted in Section 1.1 of the SAHMIR, there are some changes to data inputs in 2016 analysis which explain some differences in previous historical values reported for generation, interconnector flows, and capacity factors.

Summary

The supply capacity and generation mix in South Australia has continued to evolve in recent years. There have been increases in wind farm and rooftop PV capacity, the ongoing upgrade to Heywood Interconnector import and export capability, and permanent closure of coal generation in May 2016. Potential supply developments are focused mostly on wind farms, several large-scale solar projects, two gas generation proposals, and potential new interconnection with the eastern states.

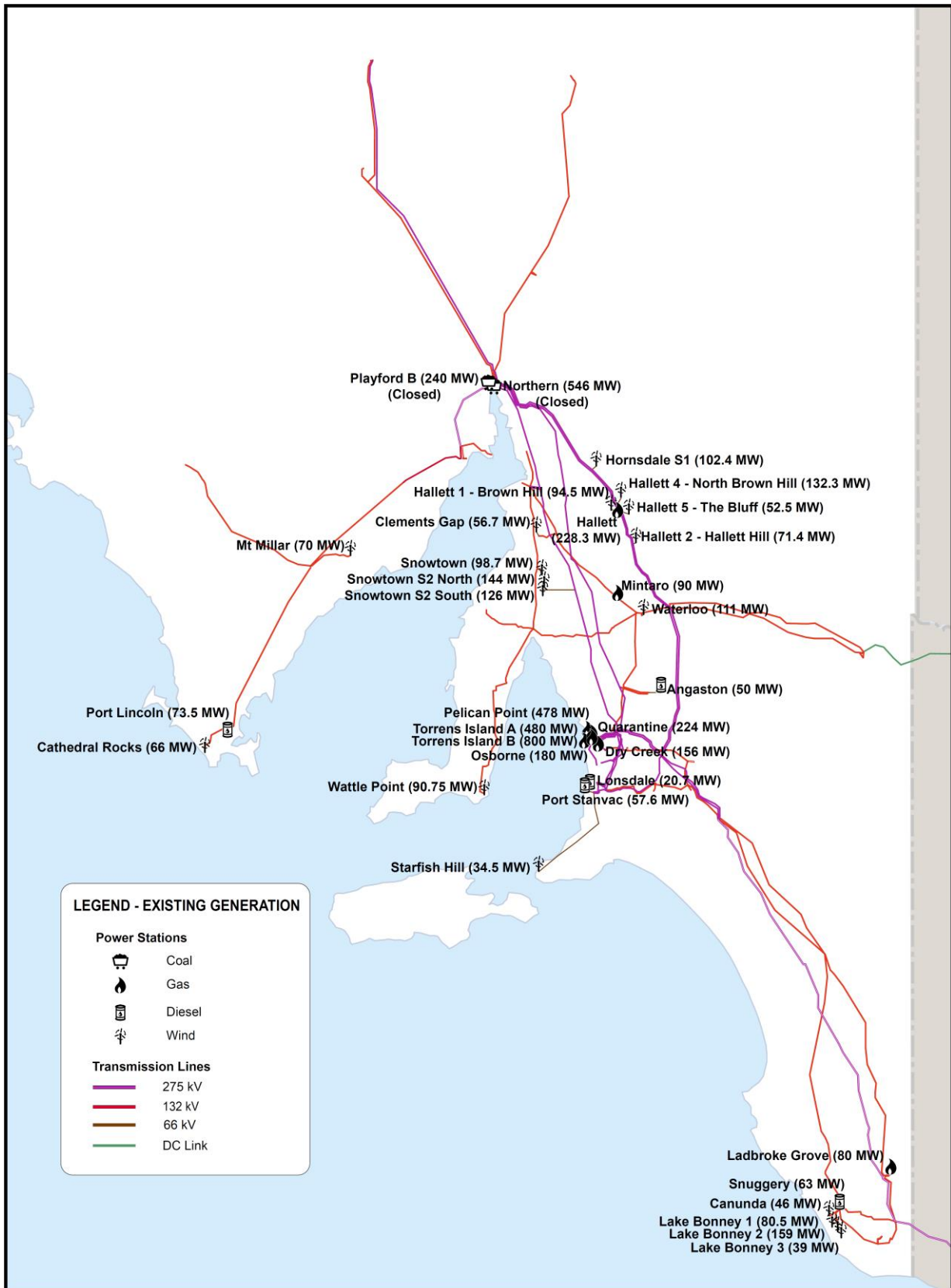
3.1 Generation

3.1.1 Historical summary

Generators – location, capacity and fuel type

Figure 12 shows the location, nameplate capacity, and fuel type of registered operational generators in South Australia (all scheduled, semi-scheduled, and significant non-scheduled generators used in operational reporting). More details of existing generators can be found in Appendix C.

Figure 12 Location and capacity of South Australian generators



Local generation capacity and output

Table 8 summarises the local electricity supply breakdown for 2015–16.

In South Australia, in 2015–16, local gas-powered generation was the largest proportion of:

- Registered capacity, at approximately 45% of total registered capacity.
- Energy generation, at approximately 36.4% of total generation.

Local wind generation produced approximately 34.7% of total generation, from just 26% of the total registered capacity in the region.

Table 8 South Australian registered capacity and local generation by energy source in 2015–16

| Energy source | Registered capacity | | Electricity generated | |
|-----------------|---------------------|-------------|-----------------------|-------------|
| | MW | % of total | GWh | % of total |
| Gas | 2,668 | 45% | 4,538 | 36.4% |
| Wind | 1,576 | 26% | 4,322 | 34.7% |
| Coal | 770 | 13% | 2,601 | 20.9% |
| Rooftop PV* | 679 | 11% | 938 | 7.5% |
| Diesel + SNSG** | 289 | 5% | 60 | 0.5% |
| Total | 5,982 | 100% | 12,459 | 100% |

* Rooftop PV installations are not registered with AEMO, but are included here given their material contribution to generation in 2014–15. Rooftop PV capacity and generation estimates as listed build on those presented in the 2016 NEFR, but incorporate nine months of input data instead of six months.

** Diesel + SNSG includes small and large diesel, and small landfill methane and hydro generating systems.

Analysis from 10 May⁵² to 31 July 2016 gives an indication of the change in local generation mix since the withdrawal of coal from the region. The generation share of gas has increased to 48.5%, wind to 42.9%, rooftop PV⁵³ to 7.8%, and diesel and small non-scheduled generators to 0.8%. It is too early to discern any trend in the mix between local generation and imported supply from Victoria, due to the confluence of a number of South Australian supply variations in winter 2016 including generation and transmission outages and variable wind conditions.

Capacity factors

Figure 13 (scheduled generation) and Figure 14 (semi-scheduled and non-scheduled wind farms) show the capacity factors for South Australian generation based on registered capacity. Generating systems that respond to peak demand generally have lower capacity factors, as they operate for short time periods and are idle most of the year. Base-load generating systems typically have higher capacity factors as they tend to run continuously unless shut down for maintenance. The capacity factor analysis excludes periods when the generating system was seasonally or permanently withdrawn from service.⁵⁴

Capacity factor calculations are only presented where there was a sufficient period of generation from a generator during the financial year. Thus Hornsdale Stage 1 Wind Farm is excluded, as it only began generating in the last few days of the 2015–16 financial year.

Changes of note between the 2014–15 and 2015–16 financial years are:

- Northern Power Station's capacity factor reversed the recent increase in 2014–15 from 76% back down to 65% in 2015–16, due to its impending and ultimate closure.
- Pelican Point Power Station's capacity factor continued to decline, reducing from 24.3% in 2014–15 to 14.0% in 2015–16. This reduction was in due to the mothballing of 50% of the station's capacity from April 2015⁵⁵ and an outage during winter 2016 of the remaining capacity.
- Osborne Power Station's capacity factor decreased by 15.5% to 77%.

⁵² The last day of generation for Northern Power Station was 9 May 2016, and Playford B Power Station was already mothballed at this time.

⁵³ Rooftop PV generation estimates for this period are taken from the Australian Solar Energy Forecasting System ASEFS2 half hourly estimates, converted to GWh.

⁵⁴ This change in methodology for 2016 analysis means historical capacity factors for Northern and Playford B are materially different to those capacity factors published in the 2015 SAER.

⁵⁵ AEMO. Generation Information Pages. Available at: <http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information>.

- Torrens Island A and B have an increased capacity factor, as these power stations covered the load in the absence of some of Pelican Point’s capacity.

Figure 13 Financial year capacity factors for scheduled generating systems

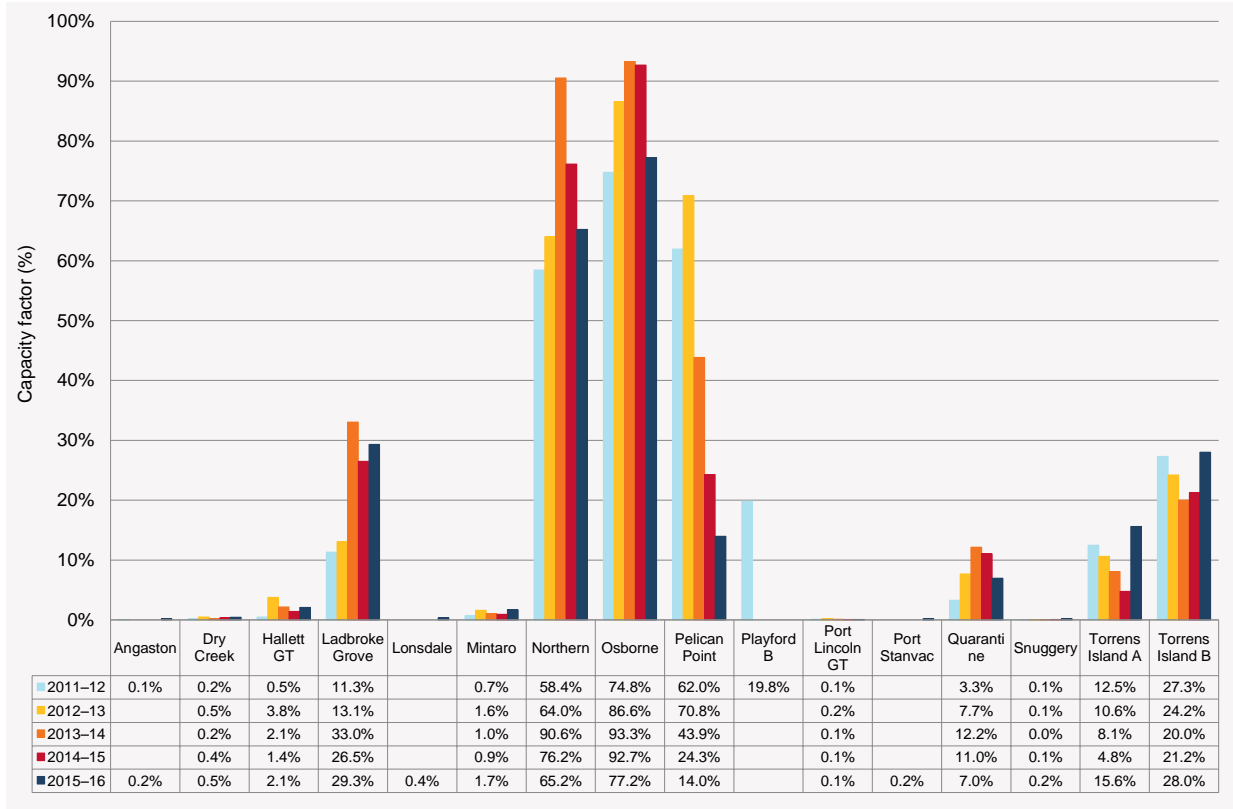
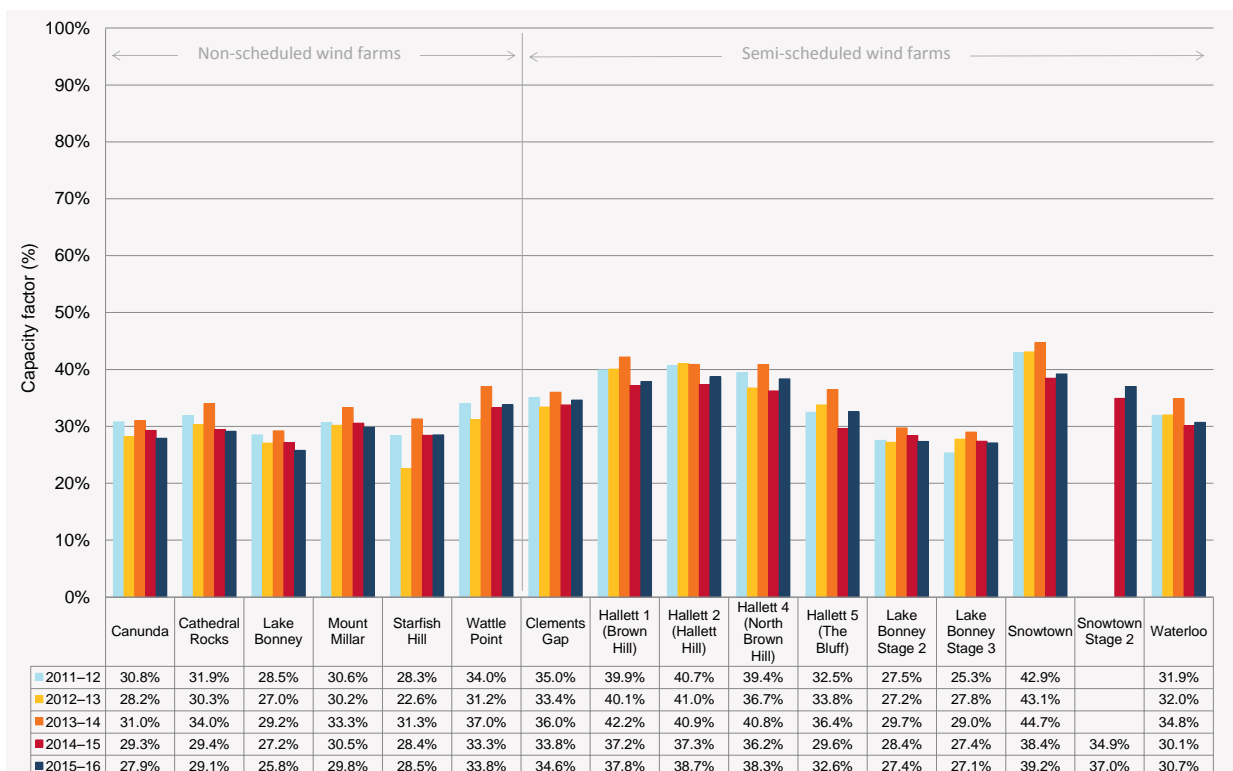


Figure 14 Financial year capacity factors for non-scheduled and semi-scheduled wind farms*



* Snowtown Stage 2 capacity factor is calculated for Snowtown Stage 2 North and Snowtown Stage 2 South wind farms combined.

Wind generation summary

South Australia has the highest registered wind generation capacity of any NEM region in Australia. Table 9 shows the total capacity for all South Australian semi-scheduled and non-scheduled wind farms registered with AEMO, together with the maximum 5-minute generation output, over the past five financial years from 2011–12 to 2015–16.

Maximum generation can change each year because geographic diversity means not all windfarms contribute their maximum generation in the same 5-minute period. Hornsdale Wind Farm Stage 1 was registered in June 2016, and began generating in this month although it is still under construction at the time this report was published.⁵⁶

Table 9 Registered wind generation capacity and maximum 5-minute wind generation

| Financial Year | Registered capacity (MW)* | Reason for increase in capacity | Maximum 5-minute generation (MW)* |
|----------------|---------------------------|---------------------------------|-----------------------------------|
| 2011–12 | 1,203 | NA | 1,096 |
| 2012–13 | 1,203 | NA | 1,067 |
| 2013–14 | 1,473 | Snowtown Stage 2 (270MW) | 1,325 |
| 2014–15 | 1,473 | NA | 1,365 |
| 2015–16 | 1,576 | Hornsdale Stage 1 (102.4MW) | 1,384 |

* Data is captured from when each wind farm was entered into AEMO systems, and includes the commissioning period.

Table 10 summarises annual wind generation and its annual change from 2011–12 to 2015–16.

Key observations are:

- Annual wind generation in South Australia has increased in line with installed capacity increases since 2010–11. In 2012–13, when there was no new registered wind capacity and lower wind speeds, a 2% reduction in annual output was observed.
- In 2013–14, Snowtown Stage 2 Wind Farm was brought online, and first reached 90% of its registered capacity in June 2014. Growth in wind generation in 2014–15 was largely driven by Snowtown Stage 2 Wind Farm's availability for the full financial year. Growth in 2015–16 is attributed to windier conditions at wind farm sites.
- Annual capacity factors for individual wind farms can vary by up to 5% year on year (as seen in Figure 14), though in aggregate the variation is no more than 2%.

Table 10 Total South Australian wind generation

| Financial year | Annual South Australian wind generation (GWh) | Annual change in wind generation | Annual capacity factor* |
|----------------|---|----------------------------------|-------------------------|
| 2011–12 | 3,563 | | 34% |
| 2012–13 | 3,475 | -2% | 33% |
| 2013–14 | 4,088 | 18% | 32% |
| 2014–15 | 4,223 | 3% | 33% |
| 2015–16 | 4,322 | 2% | 33%** |

* Capacity factor is based on the annual generation in this table compared to theoretical maximum possible assuming the annual capacity reported in Table 9.

** Capacity factor calculation does not include Hornsdale Stage 1 wind farm, currently under construction.

⁵⁶ As reported in the 2016 SAHMIR, Appendix F, Hornsdale Stage 1 Wind Farm output less than 1 GWh of energy in 2015–16 (in June 2016), and did not contribute to the maximum 5-minute generation in 2015–16, which occurred in May 2016.

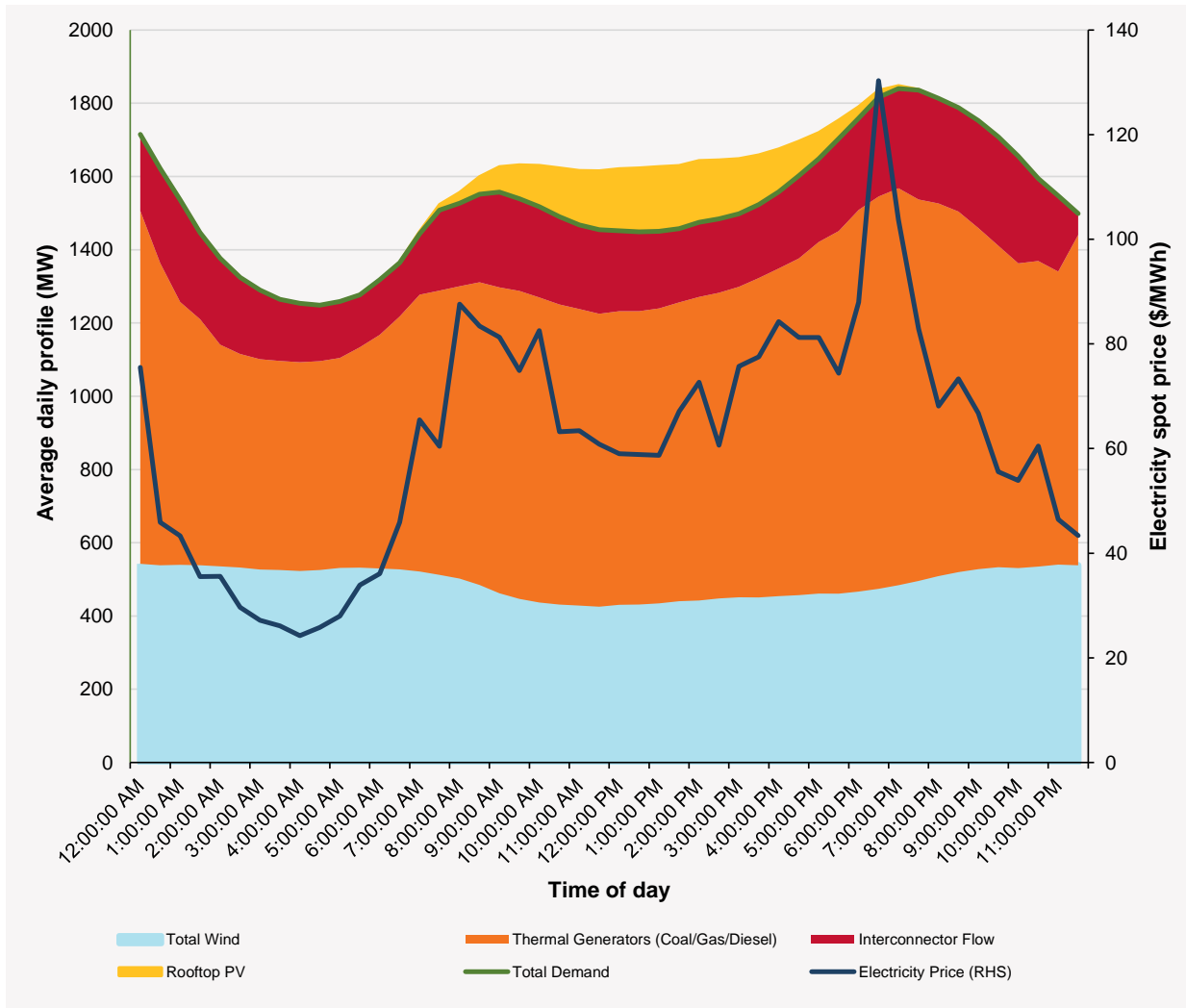
Average daily supply profile 2015–16

The average daily supply profile for South Australia, seen in Figure 15, represents the supply (in MW) for each 30-minute trading⁵⁷ interval of a day, averaged over the 2015–16 financial year. It displays the average mix of generation dispatched on an average day, split between wind, thermal (coal, gas and diesel), and combined interconnector flows. Rooftop PV is displayed above the demand curve, and shows the underlying energy that is consumed at the household level. Figure 15 shows that:

- Average wind output is slightly higher during the evening and early morning periods, complementing average rooftop PV generation, which produces most of its output between 8:00 am and 6:00 pm.
- Scheduled generation includes coal, gas, and diesel power generation for 2015–16, and contributed the most to the daily profile. On average, at least 570 MW of thermal generation is dispatched in every period.
- The average price correlates closely with average demand, particularly in the early morning hours. Price peaks at 6:00 pm, in line with increases in demand from residential loads.
- Interconnectors are consistently relied upon throughout the day to make up the shortfall that local generation does not meet. This chart is based on averaged interconnector data across the year. Times of excess supply will reduce import from Victoria or result in net export.

⁵⁷ 5-minute dispatch intervals for scheduled generation, wind generation and interconnector flows, have been averaged to a 30-minute dispatch interval, Rooftop PV 30-minute average estimated output is sourced from ASEFS2 from 17 Feb 2016, and from connection point forecasts prior to that.

Figure 15 Average daily supply profile



3.1.2 Proposed changes to supply

This section describes:

- South Australia’s scheduled, semi-scheduled, and significant non-scheduled generation capacity.
- Generation changes that AEMO considers in its planning.
- Other more speculative developments that might occur over the 10-year outlook period (2016–17 to 2025–26).

Summary of existing and proposed generation

The capacity of existing or withdrawn generation, and committed or proposed projects, in South Australia is shown in Figure 16 and Table 11 by fuel type.

This includes scheduled, semi-scheduled, and non-scheduled generation information, based on AEMO’s latest generator survey results for South Australia.⁵⁸

⁵⁸ AEMO. Generation Information (2016 August 11, SA). Available at: <http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information>. Viewed: 11 August 2016.

Figure 16 Capacity of existing or withdrawn generation, and committed or proposed projects (MW)

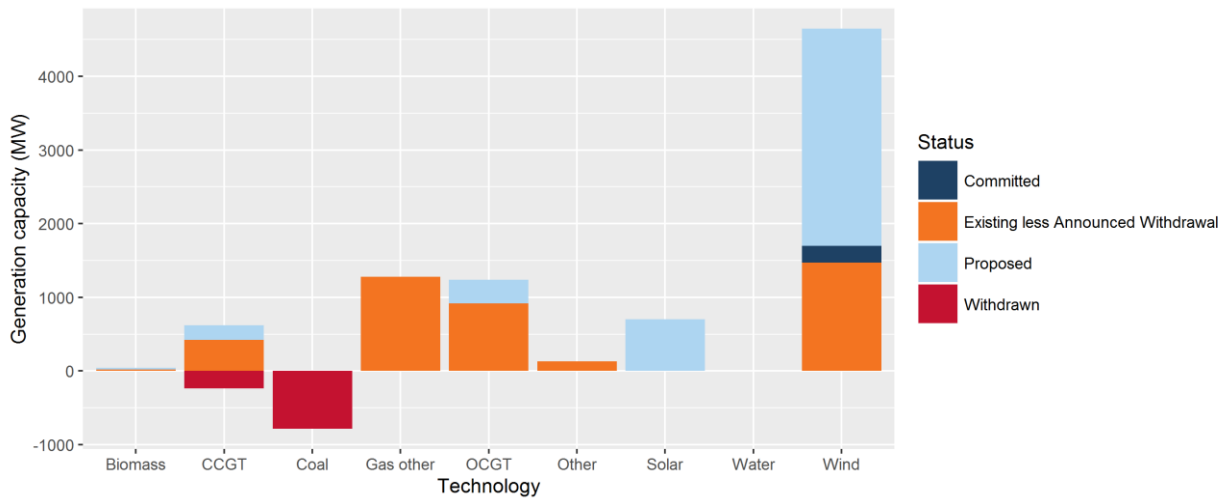


Table 11 Capacity of existing or withdrawn generation, and committed or proposed projects (MW)

| Status | Coal | CCGT | OCGT | Gas other | Solar | Wind | Water | Biomass | Other | Total |
|----------------------|------|------|------|-----------|-------|-------|-------|---------|-------|---------------|
| Existing* | 0 | 419 | 915 | 1,280 | 0 | 1,473 | 3 | 21 | 129 | 4,240 |
| Announced withdrawal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Committed | 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 |

* Note: Existing includes any announced withdrawal.

Generation capacity for the year ahead

Table 12 shows scheduled, semi-scheduled, and significant non-scheduled generation available capacity, and estimated firm capacity for summer 2016–17 and winter 2017. The figures are based on information provided by market participants.⁵⁹

Differences in scheduled and semi-scheduled generation available capacity between seasons, and also compared with the nameplate rating, arise from:

- Higher thermal generation efficiencies at cooler ambient temperatures.⁶⁰
- The need to operate wind farm generating systems safely at higher ambient temperatures in summer.

⁵⁹ Additional data for the entire 10-year outlook period is available at: <http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information>.

⁶⁰ These figures are based on the regional reference for South Australian temperatures of 43 °C for summer and 11 °C for winter.

Table 12 Scheduled, semi-scheduled, and significant non-scheduled generation available capacity

| Energy source* | Summer 2016–17 available capacity (MW) | Winter 2017 available capacity (MW) |
|-------------------------------------|--|---|
| Diesel | 238 | 265 |
| Gas | 2,293 | 2,440 |
| Wind (semi-scheduled)** | 1,074 | 1,188 |
| Wind (significant non-scheduled)*** | 388 | 388 |
| Total | 3,993 | 4,281 |

* Although still registered, coal generation is permanently withdrawn from the market, and is therefore excluded from this table.

** Includes Hornsdale Stage 1 Wind Farm, but an available capacity of 0 is currently provided for Hornsdale Stage 2 Wind Farm, and the Waterloo expansion.

*** Significant non-scheduled wind farms do not provide 10-year availability forecasts to AEMO, therefore available capacities are based on nameplate rating.

Committed and potential supply developments

Generation investment in South Australia continues to be focused largely on existing wind farm proposals, with the largest projects being:

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

As at 31 August 2016, AEMO was aware of about 24 publicly announced electricity generation developments in South Australia, totalling 4,418 MW. Table 13 aggregates the new developments by energy source.

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

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

South Australia has two publicly announced gas-powered generation proposals:

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

Hornsdale Stage 1 Wind Farm (102.4 MW) was reported as committed in the 2015 SAER and is now under construction, with full operation expected by November 2016. The second stage of Hornsdale Wind Farm (102.4 MW) became committed in July 2016, but AEMO is yet to be advised of the full operation date.

An additional 19.8 MW of capacity for the existing 111 MW Waterloo Wind Farm is committed and under construction, with completion expected in November 2016.

AEMO is not aware of any NEM-connected geothermal power plant proposals currently being pursued in South Australia.

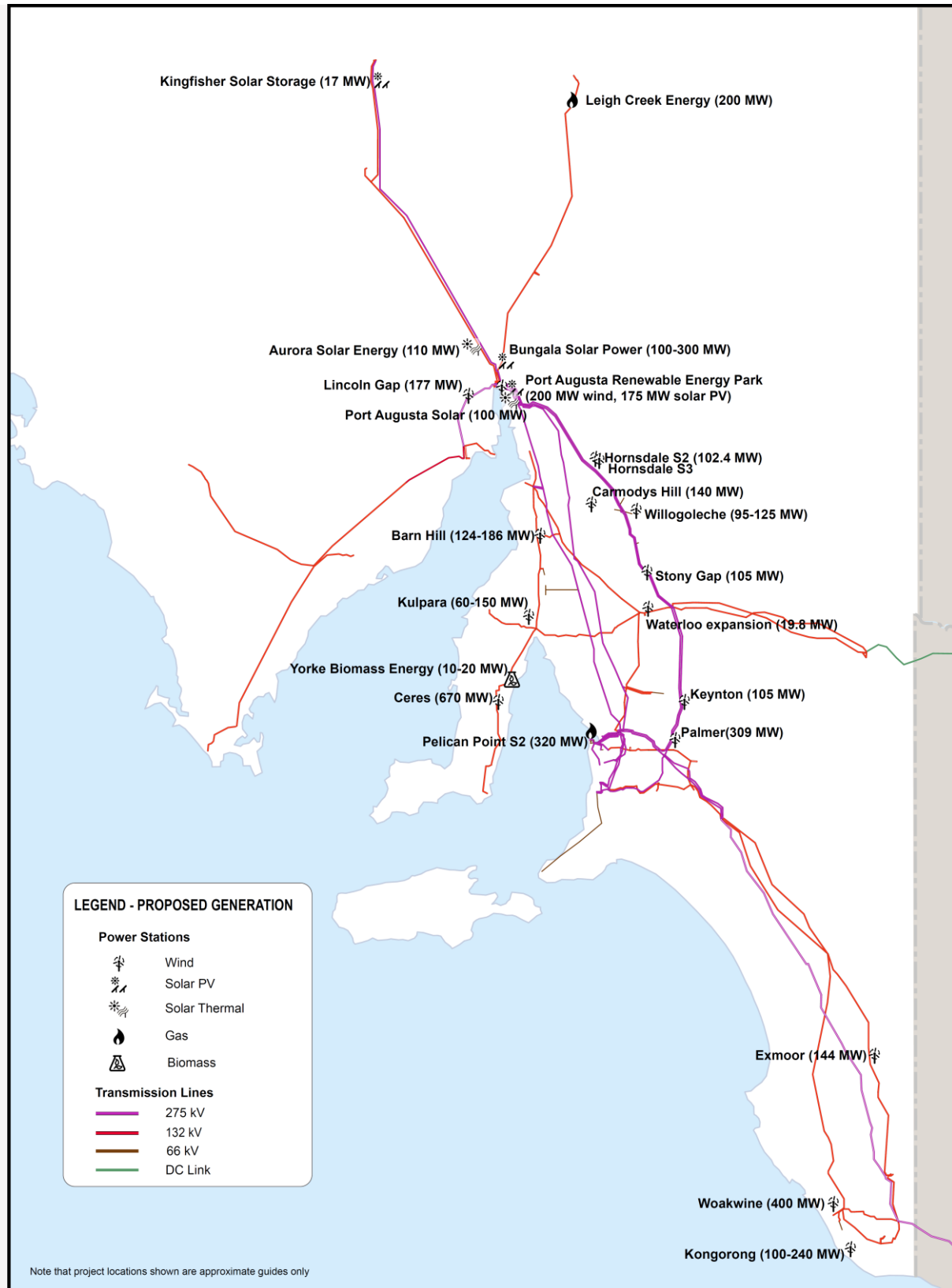
Table 13 Publicly announced and committed generation projects by energy source as at 31 August 2016

| Energy source | Number of projects | Capacity (MW) | Capacity (%) |
|---------------|--------------------|---------------|--------------|
| Solar | 5* | 702 | 15.9 |
| Gas | 2 | 520 | 11.8 |
| Biomass | 1 | 20 | 0.5 |
| Wind | 17* | 3,176 | 71.9 |
| Total | 24 | 4,418 | 100.0 |

* Port Augusta Renewable Energy Park (combined wind and solar PV project) capacity is included in both the solar and wind categories, but is counted once in the total number of projects.

Figure 17 shows the location and capacity of the publicly announced generation projects discussed above.

Figure 17 Location and capacity of South Australian proposed generation projects



Generation withdrawals

The 2015 SAER reported 1,505 MW of announced South Australian generation withdrawals. Table 14 summarises what has happened in relation to these announcements since then.

Table 14 Publicly announced generation withdrawal changes since the 2015 SAER

| Station Name | Fuel Type | 2015 Proposed Capacity Change (MW) | Update |
|------------------|-----------|------------------------------------|--|
| Northern | Coal | -546 | As announced, plant retired, but earlier than assumed (in May 2016). |
| Playford B | Coal | -240 | As announced, plant retired, but earlier than assumed (in May 2016). |
| Torrens Island A | Gas | -480 | Planned 2017 withdrawal was deferred (in June 2016). |
| Pelican Point | Gas | -239 | As announced, plant continues to operate at half capacity. |

Northern and Playford B power stations

The full retirement of Northern and Playford B power stations in May 2016 marked an end to coal-powered power generation in South Australia. Playford B had previously (from 2012) been mothballed with a recall time of around 90 days. Northern's last day of generation was 9 May 2016.

Torrens Island A power station

In June 2016, AGL announced it will defer its planned 2017 withdrawal of the 480 MW Torrens Island A Power Station in South Australia, due to a tightening of generation supply to the market.⁶¹

Pelican Point power station

Pelican Point Power Station has been available at half capacity (one unit, 239 MW) from 1 April 2015. ENGIE has advised that the full power station capacity could be made available within three months, subject to the commercial viability of returning the withdrawn unit.

Minor revisions to capacity

Since the 2015 SAER, AEMO has been advised of a 5 MW capacity increase for summer only for Pelican Point power station, throughout the 10-year outlook period (2016–17 to 2025–26).

3.2 Interconnection

South Australia's transmission network is connected to the rest of the NEM via the Murraylink and Heywood interconnectors. These interconnectors allow electricity to flow between South Australia and Victoria. Electricity typically flows from South Australia to Victoria during periods of high generation in South Australia, and vice versa.

The Murraylink Interconnector connects South Australia to north-west Victoria via the Riverland region. It has a nominal rating of 220 MW, although its actual limit depends on flow direction and local conditions. Murraylink is a direct-current (DC) transmission link, and cannot currently transfer frequency control capability.

The Heywood Interconnector is an alternating-current (AC) link connecting South Australia to south-west Victoria. A project is nearing completion to increase its nominal capacity from 460 MW to 650 MW in both directions, but many other factors can limit interconnector flow to less than its capacity, including:

- Thermal limitations and voltage stability in the south-east South Australian transmission network.

⁶¹ AGL. Generation Information. Available at: <https://www.agl.com.au/about-agl/media-centre/article-list/2016/june/agl-to-defer-mothballing-of-south-australian-generating-units>. Viewed: 8 July 2016.

- Thermal limitations and transient stability around South Morang in the Victorian transmission network.
- Oscillatory stability limits between Victoria and South Australia.

More detailed information about constraints affecting power transfer capability between South Australia and Victoria is available in AEMO's *NEM Constraint Report*.⁶²

3.2.1 Historical summary

Figure 18 shows total interconnector imports and exports for South Australia from 2006–07 to 2015–16. Energy imported into South Australia from Victoria during the year is plotted in the orange column bars above the 0 GWh line (x-axis), and energy exported from South Australia to Victoria is shown below the line.

Over the last decade, South Australia has predominantly been a net importer from Victoria. From 2007–08 there has been a steady increase in annual imports from Victoria to South Australia. Import in 2015–16 was 2,227 GWh, mainly via the Heywood Interconnector. This was the highest import in ten years, and a 961 GWh or 6% increase since 2006–07.

A variety of factors led to greater imports, including:

- Reduction in local installed baseload capacity due to generating plant withdrawals.
- Increase in interconnector capacity

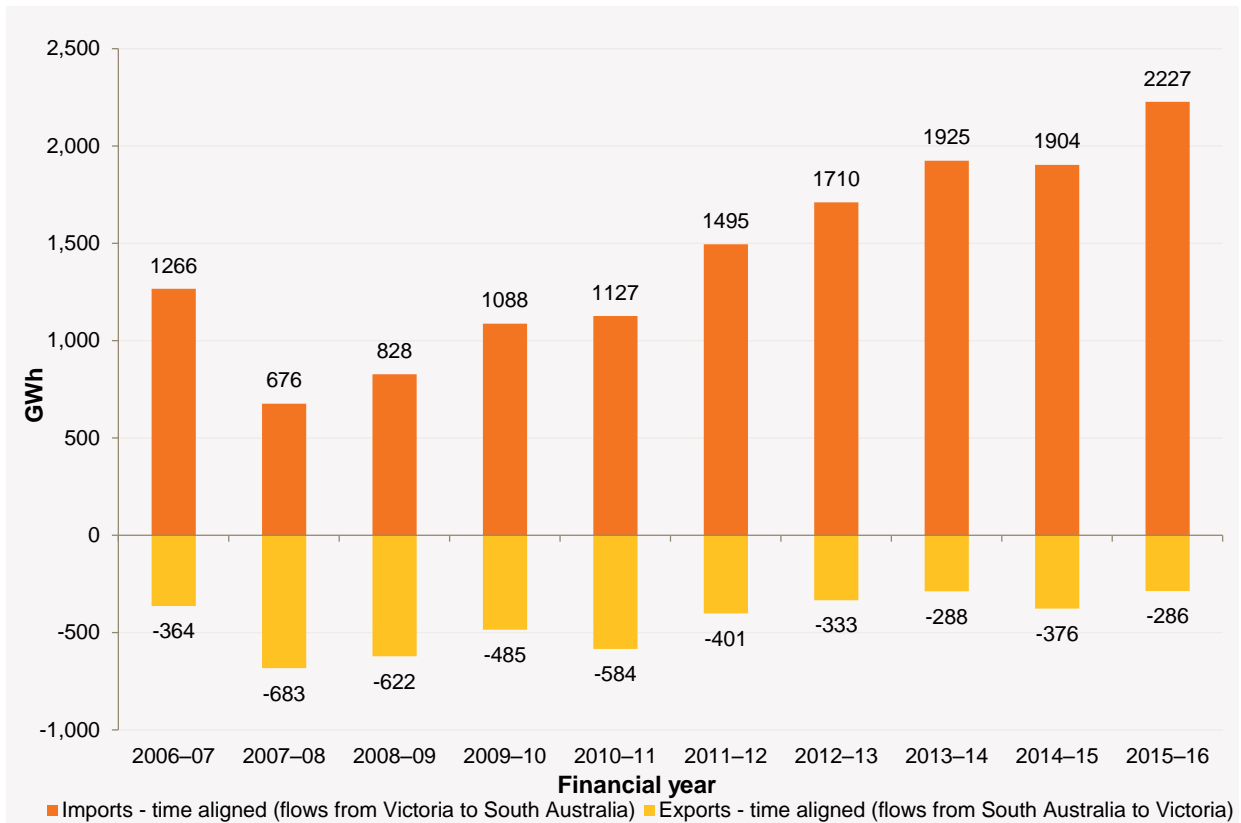
The factors that drive exports include:

- Drier or drought conditions affecting interstate hydro generation supplies.
- Availability of interstate supply.
- An increase in the number of wind farm generators in South Australia and increased wind generation, predominantly at times of low overnight demand when coal generation is at minimum stable generation.
- Increases in rooftop PV generation.

In 2015–16, total imports from Victoria represented approximately 17% of South Australian operational consumption (as presented in Section 2.3), while net imports (total imports less total exports) accounted for around 15%.

⁶² AEMO. *NEM Constraint Report 2015*. Sections 5.5 and 5.6. Available at: <http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Congestion-information/Statistical-Reporting-Streams>.

Figure 18 Total interconnector imports and exports*



* In some cases import and export totals from 2006-07 to 2014-15 are significantly different to values presented in the 2015 SAHMIR. The key reason for material changes is because AEMO has in 2016 calculated net interconnector flow at each 5-minute interval considered, and then aggregated the total imports and exports. In previous SAHMIRs, AEMO had aggregated total Heywood and Murraylink imports and exports separately, then aggregated to total imports and exports, without consideration of time-alignment of flows across the two interconnectors. The new approach in 2016 gives a measure of the actual net regional boundary flow to and from South Australia across every 5-minute interval, which is consistent with the daily average flow and flow duration curve analysis.

3.2.2 Current and proposed capacity increases

Heywood upgrade project

A project to increase the capacity of the existing Heywood Interconnector between Victoria and South Australia, from a nominal 460 MW to 650 MW in both directions, is nearing completion and its capability is being progressively increased as testing and commissioning activities continue.⁶³ A separate report on the performance of the interconnector during the upgrade will be published in late 2016.⁶⁴

Average flows following capacity increases

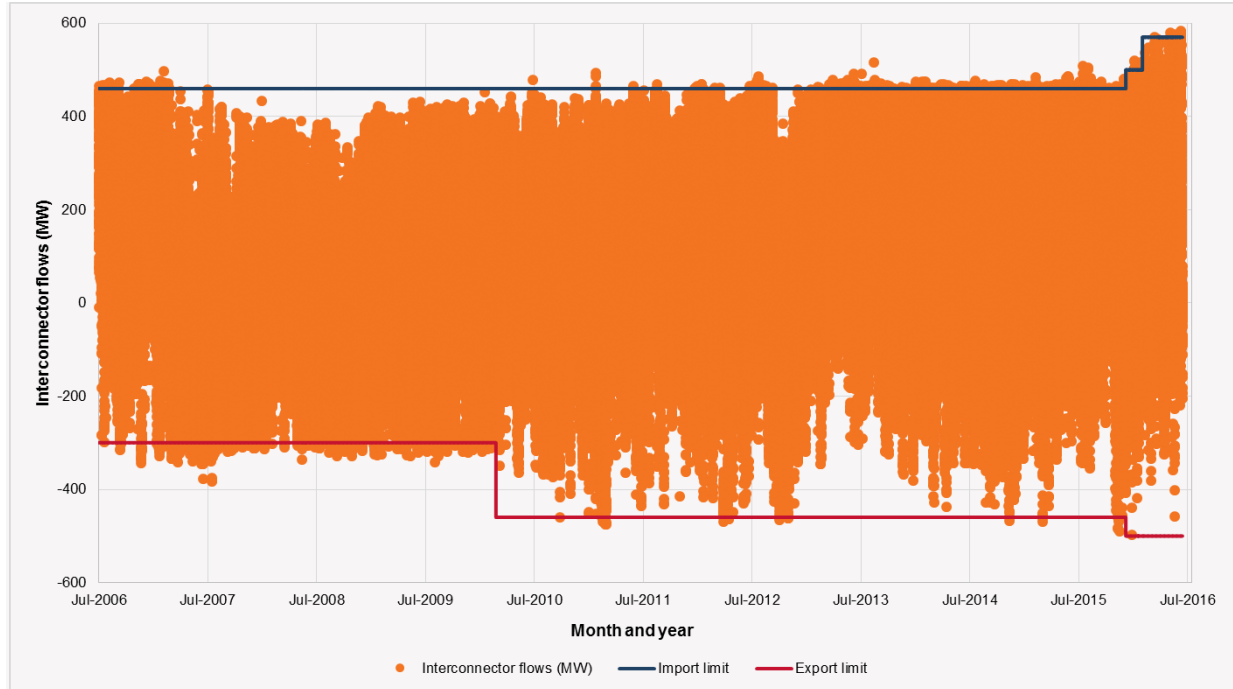
Heywood Interconnector import maximum flows are higher since commissioning of the third Heywood transformer progressively increased nominal flow capability by 140 MW between December 2015 and August 2016. Due to the market conditions required for testing not yet being obtained, the nominal Heywood export limit has not been increased beyond the 500 MW capacity set in December 2015.

⁶³ Refer to information available on AEMO's website: <http://www.aemo.com.au/Stakeholder-Consultation/Consultations/Heywood-interconnector-upgrade---program-for-inter-network-tests>.

⁶⁴ Report will be available on AEMO's website at: <http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/South-Australian-Advisory-Functions>.

Figure 19 illustrates the last 10 financial years of nominal capacities and 30-minute average flow values in MW.

Figure 19 Heywood Interconnector flows



New interconnection

ElectraNet is investigating the feasibility of a potential new high-voltage interconnector between South Australia and the eastern states, to facilitate integration of more renewable generation in the region and improve system security. This initiative is one of several options to maintain power system security across the NEM that AEMO is exploring in its annual *National Transmission Network Development Plan*, due to be published in November 2016.

4. ELECTRICITY SPOT PRICE

4.1 Average electricity prices

South Australia's time-weighted average wholesale electricity price⁶⁵ for 2015–16 was \$62 per MWh (nominal), approximately 59% higher than for 2014–15 (\$39 per MWh). This compares to 2015–16 average prices of \$52 per MWh in New South Wales (49% higher than for 2014–15), \$60 per MWh in Queensland (13% higher), \$103 per MWh in Tasmania (178% higher)⁶⁶, and \$46 per MWh in Victoria (53% higher).

Table 15 presents 10 financial years of time-weighted average prices (TWAP) for South Australia, with prices adjusted for quarterly CPI changes, using June 2016 as the reference.⁶⁷ Also shown is volume-weighted average price, which takes into account the amount and price of electricity for a given interval.

Table 15 Volume-weighted average prices for South Australia (real June 2016 \$/MWh)

| Financial year | Time-weighted average | Volume-weighted average |
|----------------|-----------------------|-------------------------|
| 2006–07 | 63.92 | 73.74 |
| 2007–08 | 88.09 | 110.54 |
| 2008–09 | 59.35 | 75.41 |
| 2009–10 | 62.98 | 86.52 |
| 2010–11 | 35.86 | 41.98 |
| 2011–12 | 32.54 | 32.80 |
| 2012–13 | 73.45 | 74.73 |
| 2013–14 | 63.42 | 68.96 |
| 2014–15 | 39.73 | 40.84 |
| 2015–16 | 61.81 | 65.08 |

AEMO analysis suggests the higher prices in South Australia in 2015–16, compared to 2014–15, were mainly due to tighter supply conditions (less available lower-cost generation during high demand periods) and higher gas costs (domestic wholesale gas prices are now linked to international markets, following the start-up of Queensland's LNG facilities).

4.2 South Australian energy and price trends

AEMO analysis suggests the average annual electricity spot market prices are strongly influenced by gas prices due to South Australia's high reliance on gas-powered generation. Historical average electricity and gas price trends for the last 10 financial years are shown in Figure 20, which shows that both electricity and gas prices have fluctuated each year, following a similar trend to each other.

The figure includes:

- TWAP, with an estimate of the effect of carbon pricing during 2012–13 and 2013–14.
- Time-weighted average gas prices. Ex-ante prices have been used for the Short Term Trading Market (STTM) Adelaide hub which began operation on 1 September 2010.

⁶⁵ Time-weighted average price (TWAP) is a simple average of 30-minute spot market prices over a period of time, and does not take into account the different volumes of energy sold within the interval. TWAP represents the average price a generator would have received if it generated at full capacity for the financial year.

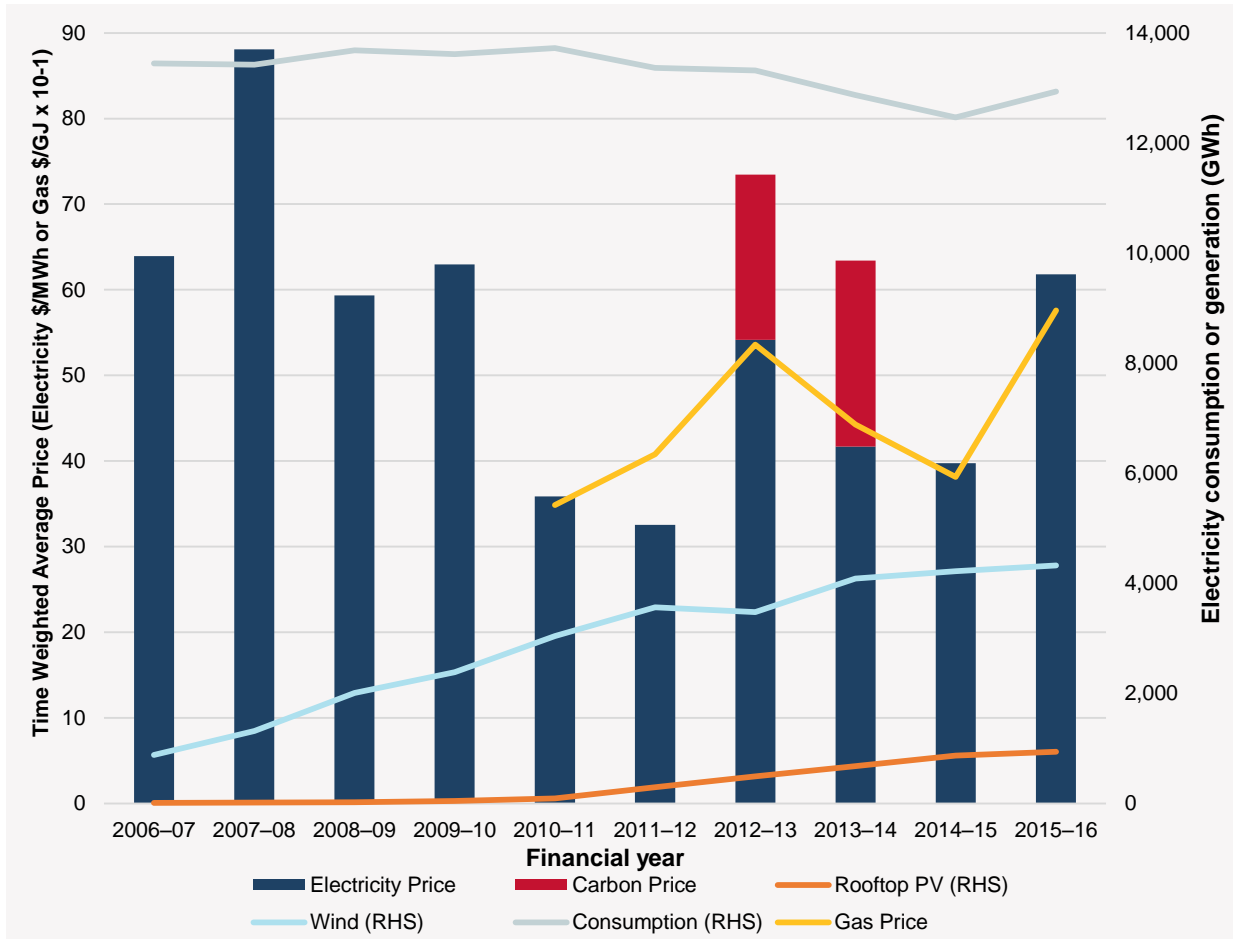
⁶⁶ A Basslink Interconnector cable fault separated Tasmania from the rest of the NEM from 20 December 2015 to 10 June 2016.

⁶⁷ CPI values taken from Australian Bureau of Statistics Series ID A2325821J (Adelaide).

- Rooftop PV generation estimates (as presented in Section 2.6.2).
- Wind generation (as reported in the 2016 SAHMIR, Chapter 7).

The growth of renewables has also been highlighted in the figure. Both rooftop PV and wind have increased more than three-fold since 2006–07, but this does not correlate with annual TWAP trends.

Figure 20 South Australian energy and price trends



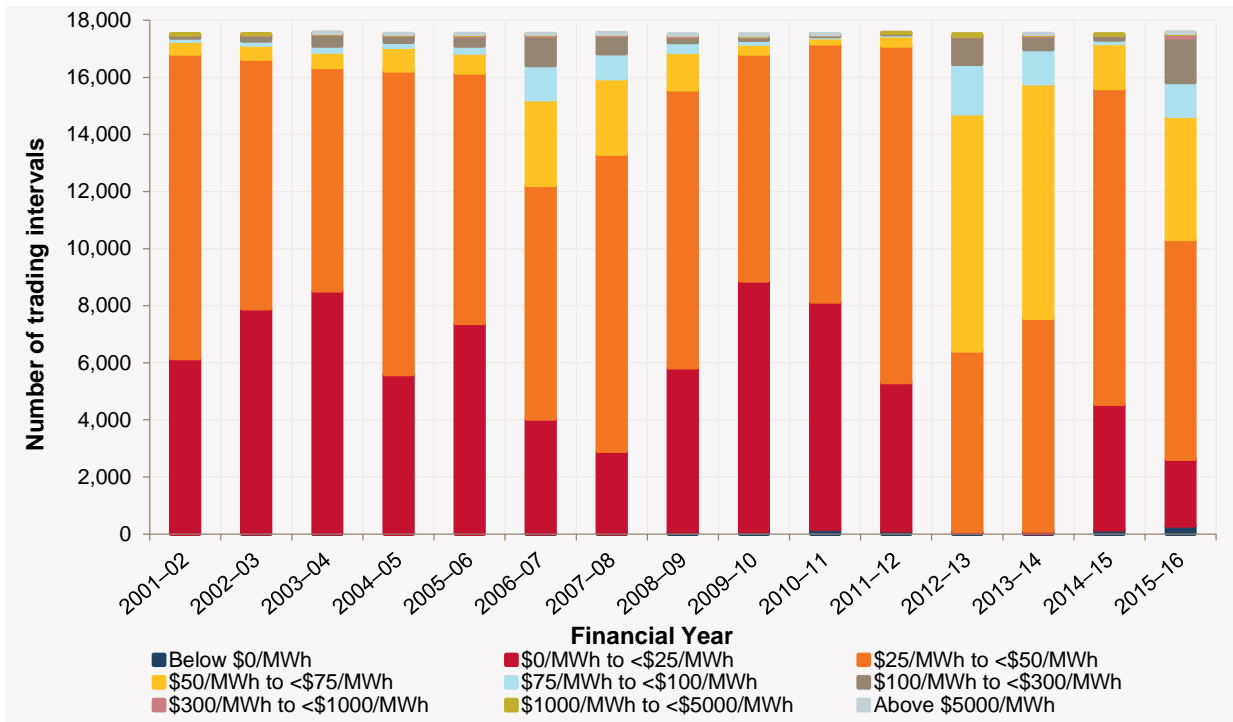
4.3 Price volatility

South Australia has experienced varying levels of electricity spot price volatility throughout its participation in the NEM, which can be shown by the frequency of spot price occurrence in different pricing bands, as summarised in Figure 21.

In the past year, spot price volatility has been greater than observed in the previous four years, due to more intermittent generation, and the closure of coal generation placing greater reliance on gas generation (in an environment of higher gas prices).

All NEM regions experience price volatility to varying degrees.

Figure 21 South Australian spot prices frequency by price bands 2001–02 to 2015–16 (nominal \$/MWh)



AEMO monitors and reports on significant pricing events in the NEM.⁶⁸ “Significant pricing events” are trading intervals where either:

- The wholesale electricity spot price is above the threshold of \$2,000/MWh.
- The wholesale electricity spot price is below -\$100/MWh.
- The sum of all eight⁶⁹ frequency control ancillary services (FCAS) half-hourly averaged prices exceeds \$150/MWh.⁷⁰

The major factors that influenced South Australian pricing events in 2015–16 were:

- Planned and unplanned network outages and generator outages.
- Low wind generation.
- Changes in generation offers.
- High regional demand.
- Daily changes in hot water load, as some 300,000⁷¹ hot water systems are set to switch on at 11:30 pm when the off-peak tariff starts.

High electricity spot prices – July 2016

Figure 22 shows that the monthly time-weighted average South Australian wholesale electricity price in July was higher than in any other NEM region.

A confluence of factors contributed to the high electricity spot prices in this month, including high wind variability and low solar production, planned transmission outage impacting interconnector flows between Victoria and South Australia, availability of thermal generating units, and cold weather which increased demand for both electricity and gas, driving higher than average gas and diesel prices.

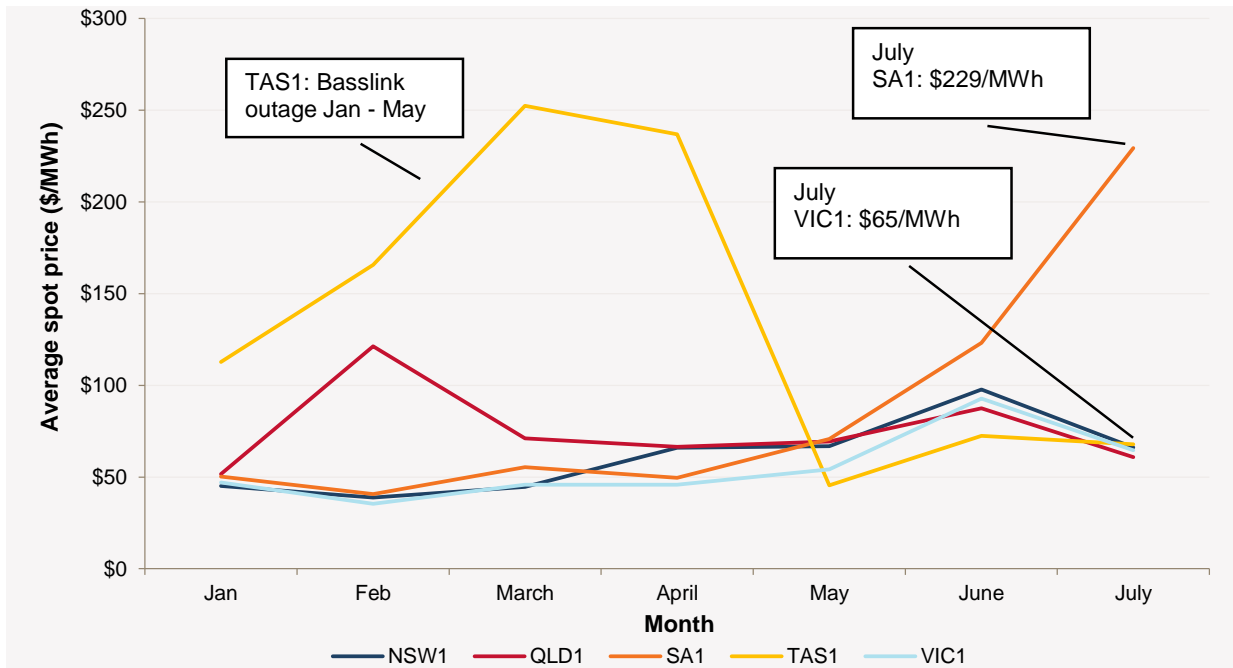
⁶⁸ Significant price event reports are published on the AEMO website at: <http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Market-noticesand-events/Pricing-event-reports>.

⁶⁹ The eight FCAS include: raise regulation, lower regulation, fast raise, slow raise, delay raise, fast lower, slow lower and delay lower prices for a half hour period. More information is available in 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>.

⁷⁰ In Tasmania, the FCAS threshold is \$3,000/MWh.

⁷¹ SAPN Flexible Load Strategy, October 2014, Section 3.4. Available at: <https://www.aer.gov.au/system/files/SAPN%20-%202020.34%20PUBLIC%20-%20SAPN%20Flexible%20Load%20Strategy.pdf>. Viewed 3 August 2016.

Figure 22 Monthly electricity spot prices by NEM region in 2016 (nominal \$/MWh)

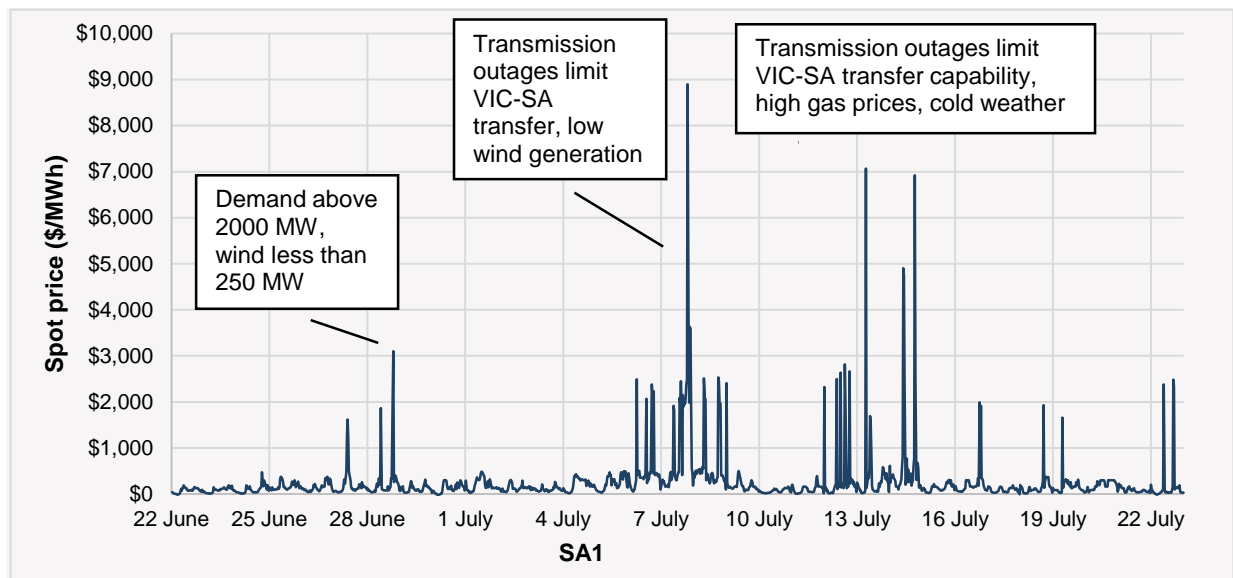


To highlight the various factors that can contribute to a pricing event, a case study of major pricing events that occurred in South Australia during July 2016 is detailed below.

Between 4–14 and 16–24 July 2016, there were planned outages of the Tailem Bend – South East No. 1 and 2 275 kV line.

During this period, wholesale electricity spot prices in South Australia were volatile and higher than average, ranging between \$501.46/MWh and \$8,897.80/MWh for 77 trading intervals between 6 July and 22 July 2016, as shown in Figure 23.

Figure 23 South Australian price events from 22 June to 22 July 2016



The high spot prices can be attributed to a combination of factors in this period, including:

- Planned network outages of each of the Tailem Bend – South East lines limited energy transfer on the Heywood Interconnector from Victoria to South Australia. This was due to a transient stability limit, which co-optimises the flow on the Heywood Interconnector with generation in the south-east area of South Australia. As a result, energy transfer was forced from South Australia to Victoria across the Heywood Interconnector. Since the price in South Australia was high, Murraylink imported into South Australia at the maximum allowable limit.
- Generation supply in South Australia was tight at various times, as several local units were bid unavailable, including up to 1,270 MW of generation capacity unavailable from Torrens Island A and B Power Station and Pelican Point combined-cycle gas turbine (CCGT) Power Plant. The lower availability of generation contributed to AEMO declaring lack of reserve (level 1)⁷² conditions in South Australia on six occasions.
- The bulk of South Australian generation capacity was offered at either low-priced bands or high-priced bands, with very little offered in between. This resulted in a steep supply curve in South Australia during some of the high-priced dispatch intervals.
- While wind generation varied between high and low levels, high wind speeds caused some turbines to cut out resulting in sudden drops in wind generation, most noticeably on 12 and 22 July.
- As a result of colder weather, South Australia's actual maximum demand in July was 150 MW higher than the June maximum regional demand, as forecast in AEMO's pre-dispatch systems.
- Gas prices were also higher than average, reflecting tightening of supply due to a combination of cold weather and increases in usage for gas-powered power generation.

Negative prices

There were 288 negative priced 30-minute trading intervals during 2015–16, higher than the previous four years. Most negative prices occurred during times when wind energy generation was above average, and typically when South Australia was net exporting electricity to Victoria. In general, negative prices may occur due to generating unit commitment decisions to maintain generation at minimum levels, rather than shutting down, during lower operational demand and high wind generation conditions.

As wind farms can gain revenue from large-scale generation certificates (LGCs) in addition to the spot market, it is not unusual for wind farms to continue operating during negative pricing events, provided the LGC revenue exceeds the cost of continuing to generate.

A return to negative prices lower than $-\$100/\text{MWh}$ occurred over four separate days in 2015–16, during network outages. Prices lower than $-\$100/\text{MWh}$ had not been observed since 2012–13.

⁷² Lack of reserve (level 1) is declared when AEMO considers there are insufficient capacity reserves available in an operational forecasting timeframe to replace the contingency capacity reserve if the most significant credible contingency event occurs in that period. This is generally be the instantaneous loss of the largest generating unit on the power system, but could be the loss of an interconnector under some conditions.

5. SUPPLY ADEQUACY OUTLOOK

This chapter compares the current and future generation capacity outlook announced by industry against forecast operational consumption and MD to identify low reserve condition (LRC) points. LRC points indicate when the NEM reliability standard⁷³ is projected to be breached. The reliability standard requires that a maximum of 0.002% of all operational consumption can go unserved for any region in any financial year. Projected LRC points signal opportunities for an efficiently operating market to adjust and respond.

The 2016 SAER supply adequacy results are taken from AEMO's 2016 NEM ESOO. 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.

5.1 Overview

- In South Australia, no LRC points are observed in the outlook period under the Neutral Growth scenario, based on announced withdrawals.
- Under the Neutral Growth COP21 scenario, the reliability standard may first be breached in 2019–20.
- An LRC point is projected under the Strong Growth COP21 scenario in 2019–20.
- No LRC points are observed in the outlook period under the Weak Growth COP21 scenario.

5.2 Scenarios modelled

The 2016 NEM ESOO considered the neutral, strong, and weak demand sensitivities listed in Table 16. The scenarios in ESOO modelling take their consumption and maximum demand inputs from the 2016 NEFR's neutral, strong and weak sensitivities explained in Table 3 in Section 2.1.1.

Each of these three scenarios was modelled assuming differing levels of additional generation withdrawals (beyond those announced by industry) in response to Australia's COP21 commitment.

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, 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.

The Neutral Growth scenario was also modelled using only industry announced generation changes as inputs (as in past NEM ESOO modelling).

Additional detail about each of the 2016 NEM ESOO scenarios and methodology is available on the NEM ESOO page on AEMO's website.⁷⁴

⁷³ Australian Energy Market Commission (AEMC). 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](http://www.aemc.gov.au/getattachment/f93100d9-72d2-46fb-9c25-ac274a04ae58/Reliability-Standards-(to-apply-from-1-July-2012).aspx). Viewed: 21 August 2016.

⁷⁴ The 2016 ESOO and all supporting documents are available at: <http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities>.

Table 16 2016 NEM ESOO scenario reference table

| 2016 NEM ESOO scenario | 2016 NEFR sensitivity ⁷⁵ | Additional withdrawals | Assumed timing and level of coal-powered generation withdrawals |
|------------------------|-------------------------------------|--|---|
| Neutral Growth | Neutral sensitivity | No – industry announced closures only | 2021– 22: 2,000 MW in NSW (Liddell) ⁷⁶ |
| Neutral Growth COP21 | Neutral 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 COP21 | Strong 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 COP21 | Weak 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) |

5.2.1 Supply and demand changes in South Australia since the 2015 supply adequacy assessment

Table 17 summarises the changes to forecast supply and demand since last year’s supply adequacy assessment was reported in the 2015 NEM ESOO. These differences help to explain the changes seen in this year’s results discussed in Section 5.3.

Table 17 Supply and demand changes in South Australia since the 2015 assessment (all projected to 2025–26)

| Quantity | Change |
|---|-----------------|
| Summer maximum demand (10% POE)* | 585 MW lower |
| Committed plant capacity announced** | 122 MW higher |
| Changes to withdrawal announcements | 480 MW deferred |
| Assumed withdrawals (within South Australia) to model COP21 emissions reduction (neutral economic and consumer outlook) | - |

* Difference between 2016 NEFR and 2016 NEFR 10% probability of exceedance (POE) maximum demand forecasts for each region in 2025–26.

** Hornsdale Stage 2 Wind Farm is not included as its announcement of committed status was too late for inclusion in 2016 ESOO modelling.

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.

5.3 Supply adequacy assessment

Low Reserve Conditions

Table 18 summarises the timing of forecast LRC points in South Australia:

- 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-powered generation capacity across the NEM would 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 2020–21 and 2024–25 to 2025–26, due to the assumed withdrawal of coal-powered generation capacity in neighbouring regions.⁷⁷

⁷⁵ AEMO. *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>.

⁷⁶ Based on advice received from AGL. Available at: <http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information>.

⁷⁷ 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.

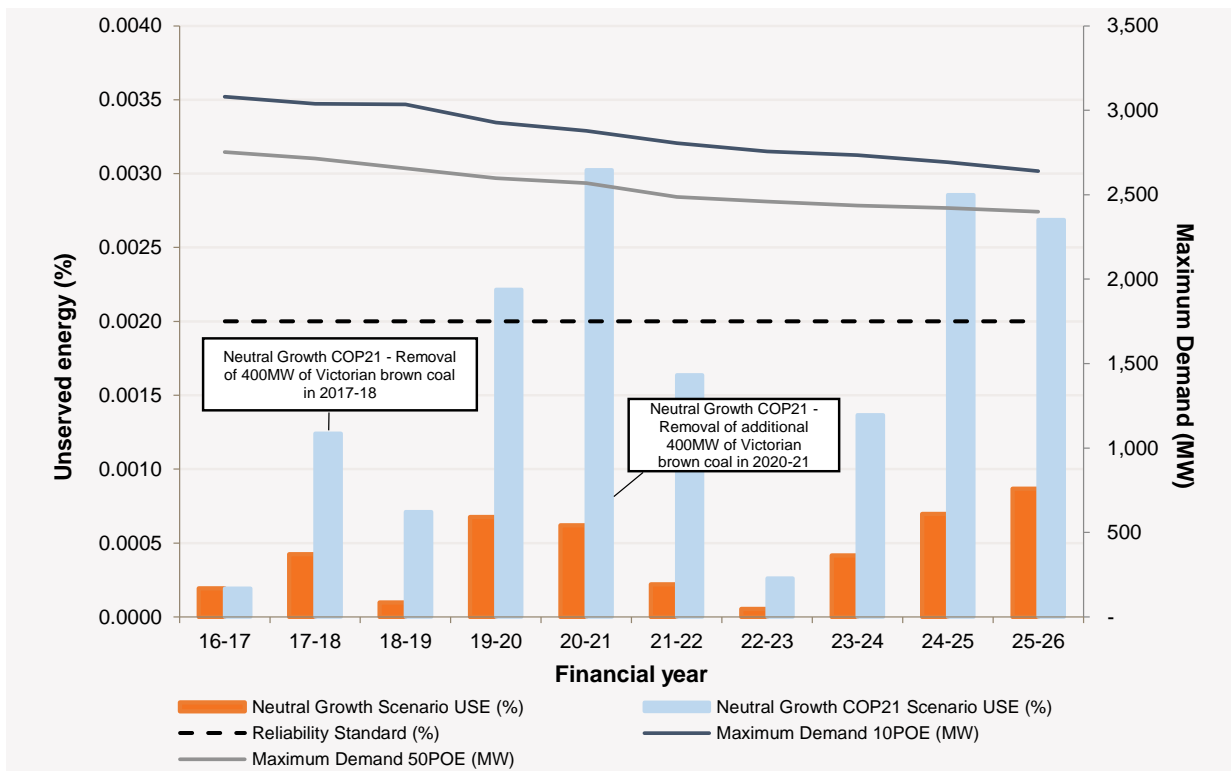
- LRC points are also projected in South Australia from 2019–20 in the Strong Growth COP21 scenario, due to increased forecast demand, despite fewer additional coal-powered generation withdrawals across the NEM.
- No LRC points are projected in South Australia under the Neutral Growth or Weak Growth COP21 scenarios.

Table 18 South Australia LRC timing and USE

| 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 |
| Beyond 2025–26 | N/A | 2019–20 | 0.0022% | 2019–20 | 0.0043% | Beyond 2025–26 | N/A |

To highlight LRC points, Figure 24 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 24 South Australia supply adequacy (Neutral Growth and Neutral Growth COP21 scenarios)



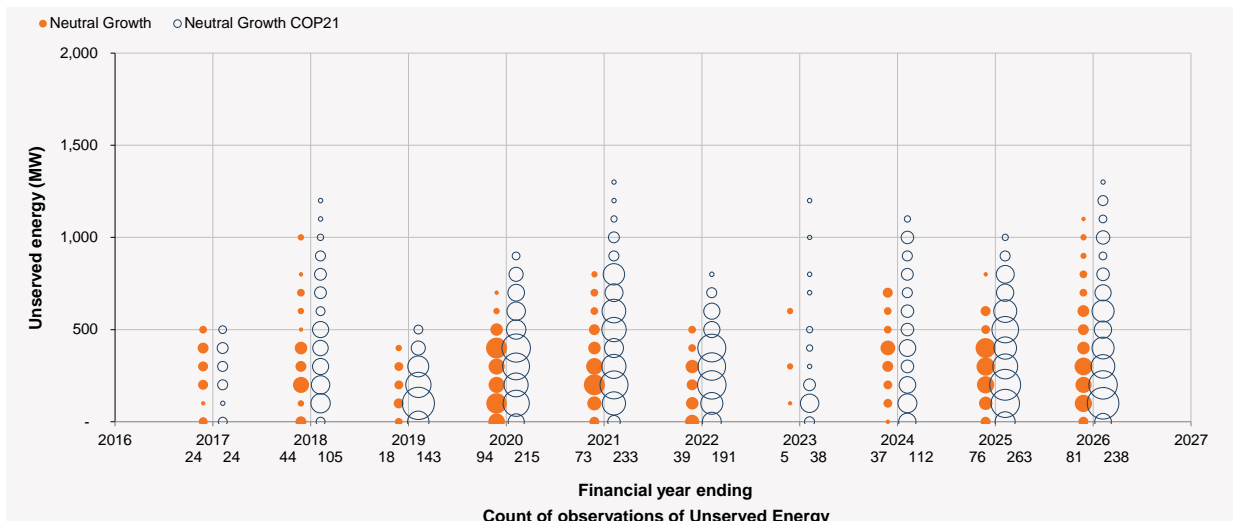
In South Australia, the projected risk of USE is highest at times when high demand in both South Australia and Victoria coincides with low local wind, unplanned generation outages, and/or low levels of imports. The risk is projected to increase at times when rooftop PV is unavailable due to cloud cover.

Figure 25 shows the forecast frequency and magnitude (in MW) of USE in South Australia, 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 across the 126 Monte Carlo simulations.

The figure highlights that:

- When USE is projected in the Neutral Growth COP21 scenario, half of the observed supply shortfalls are less than 294 MW.
- The most frequent occurrence is in the 400–500 MW band for the year 2019–20. Across the Monte Carlo simulations, there were 40 observations within this band in the Neutral Growth COP21 scenario.
- The maximum projected USE in a period exceeds 1,000 MW, under conditions of high demand, concurrent 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 25 South Australia distribution of unserved energy (Neutral Growth and Neutral Growth COP21 scenarios)



In the Neutral Growth scenario, 99% of projected USE in South Australia in 2025–26 occurs between 3:00 pm and 7:00 pm. In the Neutral Growth COP21 scenario, 97% 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.

To improve future supply adequacy, and reduce the risk of load shedding, new developments would need to increase accessibility to, or availability of, supply, during these times. These developments could include network or non-network options (including generation), storage, and demand side management services.

6. SYSTEM SECURITY IN A CHANGING GENERATION MIX

6.1 Introduction

Secure operation of the transmission system involves maintaining the power system within technical and safety limits even after the unplanned disconnection of a network element, generating unit, or major industrial load (a credible contingency event).

Managing the electrical characteristics of the power system relies on a range of services, including FCAS. Another critical service is system restart ancillary services (SRAS), which is procured to restore the system following a major supply disruption. The withdrawal of synchronous generation (such as coal and gas-powered generation), which has provided these services and contributed inertia, is leading to scarcity of these support services in the NEM.

This chapter discusses each of these system services in South Australia.

6.2 Frequency control ancillary services

The NEM power system operates within a set frequency range around 50 hertz (Hz). This underpins the safe, secure, and reliable transmission of power through the electricity grid.

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.

For introductory information on FCAS, refer to AEMO's *Frequency Control* factsheet⁷⁸, AEMO's *Guide to Ancillary Services in the National Electricity Market*⁷⁹, the *2016 NEM Electricity Statement of Opportunities*⁸⁰, and the *2016 Future Power System Program – Progress Report*.⁸¹

Under normal operating conditions, AEMO can procure FCAS from anywhere in the NEM. AEMO analysis indicates that, during normal conditions, a shortfall in FCAS is unlikely.

Under some less common operating conditions, AEMO may need to obtain some FCAS from plant located within a particular region of the mainland NEM. These conditions are typically when that NEM region is at credible risk of losing, or has actually lost, all of its alternating current network connections with the rest of the mainland NEM.

Network outages involving components of the Heywood Interconnector result in periods where synchronous separation of South Australia from the rest of the NEM is a credible risk. During these periods, AEMO enables contingency lower and, more recently, regulation FCAS, locally in South Australia to maintain system security in the event of separation.

To provide context on the likely occurrence of these periods, 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. There was one actual separation event, on 1 November 2015, with a duration of 35 minutes.

There are currently only three registered participants in the FCAS market in South Australia. Only the generating units at Torrens Island, Pelican Point, and Quarantine power stations are registered

⁷⁸ AEMO. *Fact sheet – frequency control*, August 2016. Available at: <http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/-/media/80004354B88B4FEF96EAB673DDC99820.ashx>.

⁷⁹ AEMO. *Guide to Ancillary Services in the National Electricity Market*, April 2015. Available at: <http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Ancillary-services>.

⁸⁰ AEMO. *2016 National Electricity Market Electricity Statement of Opportunities*. Available at: <http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities>.

⁸¹ AEMO. *Future Power System Security Progress Report*, August 2016. Available at: <http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/FPSSP-Reports-and-Analysis>.

to provide FCAS (with Quarantine unit 5 registering in December 2015 to provide regulation raise and lower services, but not contingency FCAS) – see sections 6.2.1 and 6.2.2 for more about these services.

The limited number of registered suppliers tends to result in high prices for FCAS in South Australia at times when these services must be sourced locally (see the case study in Section 6.2.3).

6.2.1 Regulation FCAS in South Australia

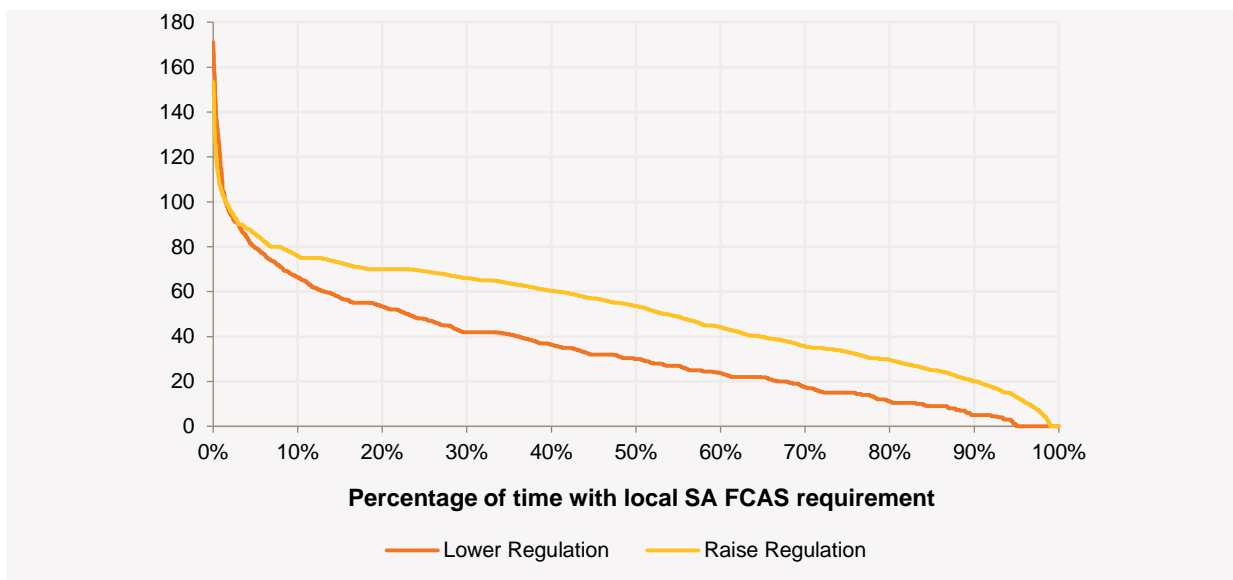
Regulation FCAS is enabled to continually correct the generation/demand balance in response to minor deviations in load or generation. There are two types of regulation FCAS:

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

When there is a credible risk of loss of the Heywood Interconnector, AEMO enables 35 MW of both raise and lower regulation locally within South Australia. The total registered capacity to supply regulation services in South Australia is 410 MW for regulation raise, and 350 MW for regulation lower, which far exceeds this requirement. However, to provide these services in the event of synchronous separation, these units must be online and generating at a favourable operating point at that time, which cannot be assured based on current generation patterns. For this reason, AEMO now proactively, pre-contingently, enables regulation FCAS in South Australia during periods when there is a credible risk of loss of the Heywood Interconnector.

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 separation. There were short periods where the supply of lower regulation FCAS was exactly equal to the demand, indicating no excess supply capacity, as shown in Figure 26.

Figure 26 Supply minus demand for local regulation FCAS in South Australia (MW)



Generating units at Torrens Island, Pelican Point, and Quarantine are currently registered to provide FCAS in South Australia. Northern Power Station was retired in May 2016, withdrawing 20 MW of both raise and lower regulation FCAS. Quarantine unit 5 was registered in December 2015 to provide 50 MW of both regulation raise and lower FCAS.

Increasing connection of semi-scheduled generation, such as wind and utility-scale PV, in South Australia may increase demand for regulation FCAS. AEMO’s preliminary analysis suggests that utility-scale PV, in particular, may in future contribute significant variability within the 5-minute period,

increasing the need for regulation FCAS.⁸² At present there are no such 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 is currently registered to provide these services.

6.2.2 Contingency FCAS in South Australia

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).

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

Table 19 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 |

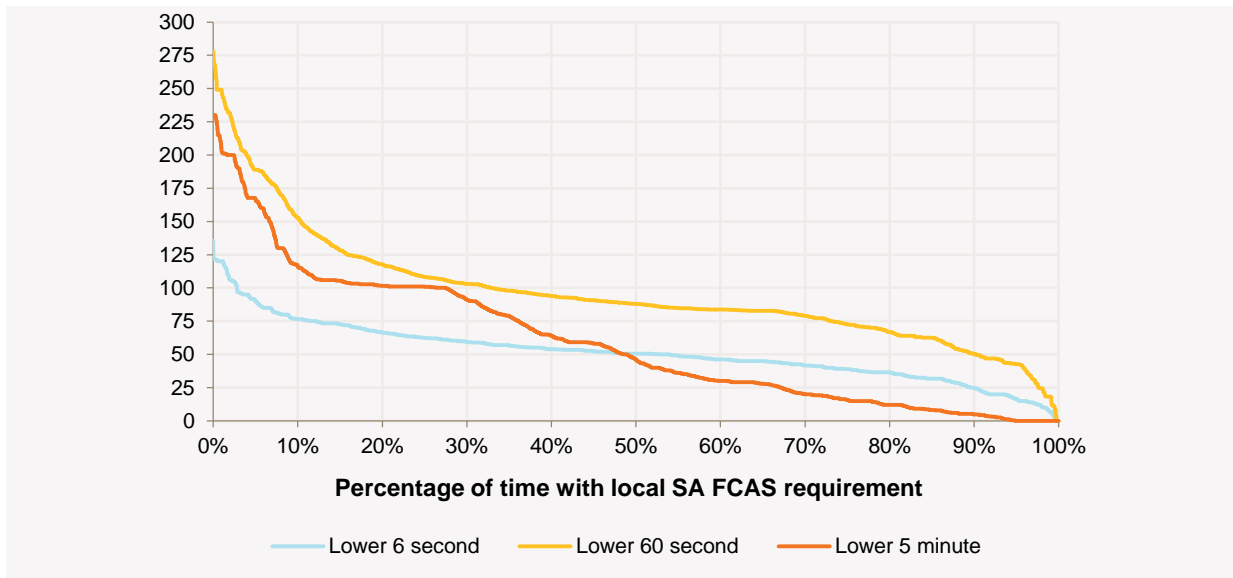
When there is a credible risk of South Australia separating from the rest of the NEM, and South Australia is exporting power to Victoria, AEMO sources contingency lower FCAS from generation within South Australia. In this case, the NEM dispatch algorithm co-optimises power transfer between Victoria and 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 (FOS) applicable to South Australia, AEMO does not source contingency raise FCAS locally from within South Australia, unless South Australia is actually operating as an island. When there is a credible risk of synchronous separation, and power flow is from Victoria to South Australia, AEMO relies on the action of under-frequency load shedding (UFLS) in South Australia to manage low frequency conditions that would result from an actual separation event.

During 2015, there was an adequate supply of contingency lower FCAS in South Australia to manage periods of credible risk of synchronous 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, which limited transfer of power from South Australia to Victoria, as shown in Figure 27.

⁸² This analysis is preliminary in nature, as there is limited data on the performance of utility-scale PV plants in the NEM based on the small number of plants and the length of their operation.

Figure 27 Supply minus demand for local contingency lower FCAS in South Australia (MW)



The closure of Northern Power Station in May 2016 further reduced the supply of contingency FCAS in South Australia, removing 14 MW of 6 second lower, 72 MW of 60 second lower, and 12 MW of raise 6 second services. This left Pelican Point and Torrens Island A and B as the only registered providers of contingency FCAS in South Australia. For delayed contingency FCAS (raise and lower 5-minute services), Torrens Island B is the only registered provider. To provide FCAS, generating units must be already online and generating at a favourable operating point. This may not be possible at short notice.

Table 20 lists the amount of registered contingency FCAS capacity available to AEMO from facilities located in South Australia.

Table 20 Contingency FCAS services in the South Australia region⁸³

| South Australia | Contingency Raise | Local enablement in 2015* | Contingency Lower | Local enablement in 2015** |
|----------------------------|-------------------|---------------------------|-------------------|----------------------------|
| 6 second (R6/L6) | 150 | -- | 150 | 0–124 |
| 60 second (R60/L60) | 318 | -- | 318 | 0–235 |
| 5 Minute (R5/L5) | 200 | -- | 200 | 0–138 |

* Due to the frequency standards applicable for South Australia when it is at risk of islanding, there is no local requirement in South Australia 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.

For the operation of South Australia as an island, all registered contingency FCAS facilities are required to be online and operating to be able to supply the required contingency lower FCAS.

During the 1 November 2015 synchronous separation event:

- The majority of FCAS was priced at the Market Price Cap (\$13,800/MWh).
- Local FCAS supply was limited. While the demand for local FCAS was well below the maximum registered supply, these services had to be obtained from the relatively small group of generators who were already online in South Australia during this unplanned separation event. Due to the long start-up time of generation capable of supplying contingency FCAS in South Australia, no additional units were able to come online during this event.
- The AEMO dispatch algorithm co-optimised the output of several large generating units in South Australia with the contingency raise FCAS requirement to minimise the total cost (of energy plus FCAS). This automatically reduced the output of several large generating units in South Australia. This in turn reduced the requirement for some contingency raise FCAS, but the demand remained

⁸³ The FCAS capability of Northern Power Station has been removed from these totals in South Australia, as this plant shut down in May 2016

above the available supply in South Australia. At the same time, the reduction in generation output also affected the ability of those units to provide FCAS.

- AEMO was also 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 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 resolved 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.

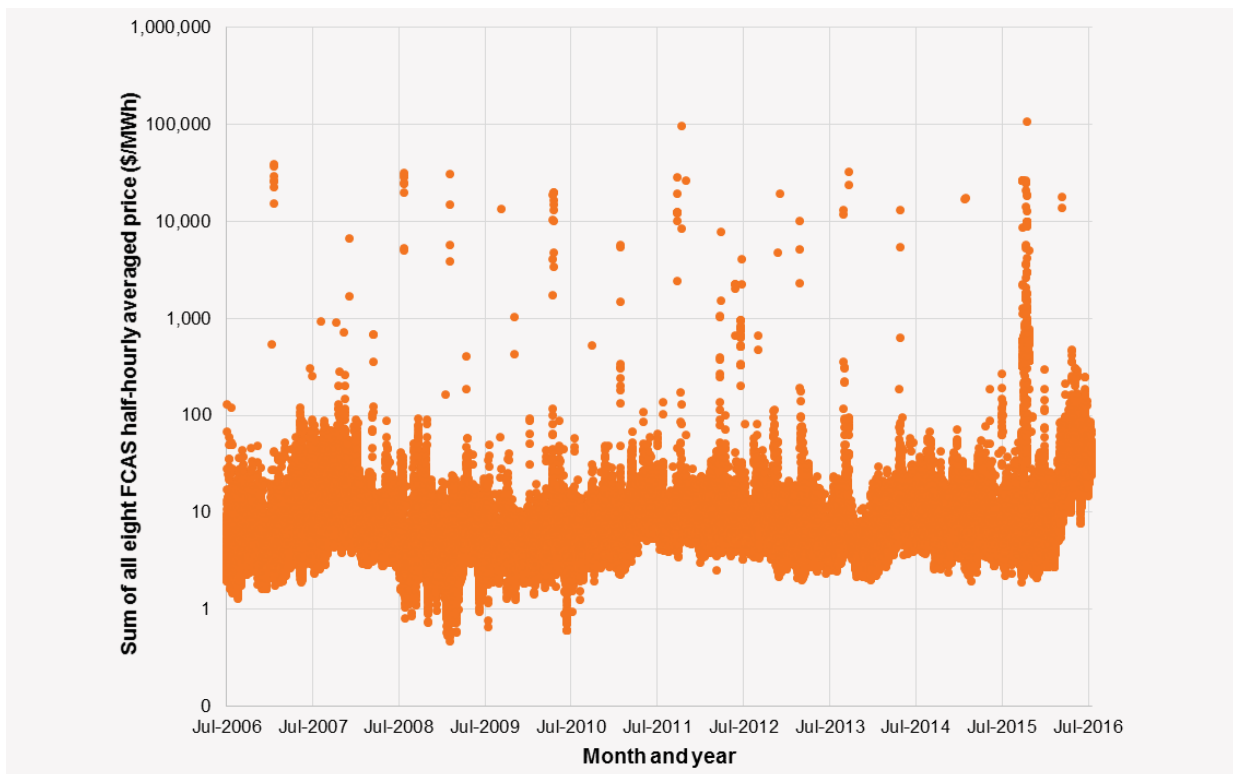
This situation was ultimately resolved by the reconnection of the South Australia region to the remainder of the NEM after 35 minutes of separation. This removed the need to obtain contingency FCAS from generation located within the region.

This separation event highlights a potential shortage of contingency FCAS 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 synchronous separation.

6.2.3 FCAS prices

Figure 28 shows a summary⁸⁴ of South Australian FCAS prices for the past 10 years, from July 2006 to July 2016. It highlights a spike in prices in October and November 2015 as discussed below, as well as generally higher FCAS prices from around April 2016. Prices are plotted on a logarithmic axis to better represent the variance.

Figure 28 South Australian FCAS prices – July 2006 to July 2016



NOTE: Logarithmic scale applied to vertical axis.

⁸⁴ The data displayed comprises the sum of all eight FCAS half-hourly averaged prices in nominal \$/MWh.

High FCAS prices – October to November 2015⁸⁵

Between 11 October and 10 November 2015, there were multiple planned network outages of the South East – Heywood No.1 and No.2 275 kV transmission lines.

During these planned network outages:

- Regulation FCAS prices in South Australia spiked several times.
- FCAS prices reached the reporting threshold for 1,027 trading intervals.
- On 1 November 2015, the highest sum of FCAS prices occurred. For the half hour trading interval ending 11:30 pm, the FCAS price for fast raise, slow raise, delayed raise, regulation raise, and fast lower services reached the Market Price Cap (\$13,800/MWh), and the prices for slow lower, delayed lower, and regulation lower services were \$12,199.97/MWh, \$12,200/MWh, and \$13,000/MWh respectively.
- The sustained high prices triggered an administered price period⁸⁶ on three occasions, and resulted in the application of the administered price cap⁸⁷ to 19 trading days in South Australia.

The high FCAS prices in South Australia in this period can be attributed to a combination of factors:

- The credible risk of synchronous separation⁸⁸ between South Australia and Victoria during the planned outages required AEMO to pre-contingently source a minimum of 35 MW of raise and lower regulation FCAS from within the South Australian region to maintain system security.
- The limited supply of registered sources of regulation FCAS in South Australia, which at that time were Pelican Point (unavailable at times over this period), Northern, and Torrens Island power stations.
- During a planned outage on 1 November 2015, a synchronous separation⁸⁹ of South Australia from Victoria occurred when the remaining line tripped. Contingency FCAS prices in South Australia also increased at this time due to increased contingency FCAS requirements.

6.3 Inertia and rate of change of frequency

Synchronous generation provides an inherent inertial response to frequency deviations, slowing the rate of change of frequency (RoCoF). High RoCoF threatens system security by compromising the effectiveness of frequency control mechanisms. As synchronous generation is progressively withdrawn, the level of synchronous inertia may eventually become too low to maintain RoCoF within levels that are operationally manageable following significant contingency events, unless alternative mechanisms can be used to manage RoCoF.

At present, synchronous inertia is plentiful in the NEM, and system security issues related to RoCoF are not anticipated in the next ten years while the NEM is fully interconnected.

The amount of system inertia is, however, critical when parts of the power system become synchronously separated from the rest of the NEM, as the separation event would result in high RoCoF. In the case of South Australia, this can happen when the alternating current connection with Victoria is disconnected anywhere along the Heywood Interconnector. If this was to occur, the RoCoF experienced would depend on the inertia in South Australia, and the size of the contingency (determined by the amount of power transfer immediately prior to the contingency event).

When there is a credible risk of synchronous separation, AEMO manages the potential RoCoF from a separation event to ± 1 hertz per second (Hz/s) by reducing the amount of interconnector flow. AEMO cannot do this when the separation is a non-credible contingency event.

⁸⁵ AEMO, *Market Event Report – High FCAS Prices in SA – October and November 2015*. Available at: <http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Market-notices-and-events/-/media/BFB1F25446E5486CAFDC1ECC0AE04C7B.ashx>.

⁸⁶ An administered price period (APP) is triggered in a region when:

- The sum of the regional spot prices for the previous 336 trading intervals (equivalent to seven days) reaches the cumulative price threshold (\$207,000 for 2015–16 financial year).
- The sum of the regional ancillary service prices for a market ancillary service in the previous 2,016 dispatch intervals (equivalent to seven days) exceeds six times the cumulative price threshold.

⁸⁷ The administered price cap and administered floor price are invoked to apply upper and lower limits on the published regional dispatch prices during an administered price period, under clause 3.14.2 of the NER. The value of the administered price cap for each region is \$300/MWh.

⁸⁸ Synchronous separation refers to loss of all of alternating current (AC) network connections with other parts of the power system.

⁸⁹ In this synchronous separation, South Australia was separated from the rest of the NEM, due to both Heywood Interconnector AC transmission lines being disconnected.

In future, in the rare event of the non-credible loss of the Heywood Interconnector, the RoCoF could become very high depending on the generation online and interconnector flow prior to the separation. The Heywood Interconnector has separated South Australia from the rest of the NEM on nine occasions since 1999 – five of these occasions were credible events and four were due to non-credible events.

A non-credible separation event that results in RoCoF levels exceeding $\pm 4\text{Hz/s}$ would almost certainly result in cascading generation tripping and a black system in South Australia. This black system 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, and would continue to increase if the region becomes more reliant on energy imports over the interconnector and local wind and rooftop PV generation to meet demand.

RoCoF exposure in South Australia, upon a non-credible separation event, is now expected to exceed $\pm 1\text{Hz/s}$ for a large part of the year, and $\pm 4\text{Hz/s}$ some of the time. The ability of the system to sustain these non-credible separation events becomes increasingly uncertain for RoCoF levels exceeding $\pm 1\text{Hz/s}$.

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, such as a fast frequency response service or other frequency control mechanisms.

6.4 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 in the event of tripping off.

Some generating units have specialised equipment that allows them to restart without external support. These generating units would then be available to energise parts of the transmission system, restore other generating units, and hence begin restoring the power system.

The current system restart standard requires re-energisation of the transmission network and generation sources to a level sufficient to supply 40% of peak demand within four hours of a major supply disruption. These requirements may limit the size and type of generation capable of providing SRAS. To date, only coal, gas, and hydro-powered generation have provided this service. Other generation technologies may be able to configure plant to be able to contribute to the provision of SRAS.

AEMO has procured contracts for the provision of SRAS in South Australia until 2018, with two further one-year options.

However, the withdrawal of Northern Power Station has highlighted:

- There is a limited pool of strategically-located SRAS sources in South Australia to meet the current standard.
- All non-SRAS synchronous generation in South Australia that can be started by SRAS services in a reasonable time (four hours) are gas-powered generating units.

This indicates reliance on a single fuel source for all generation involved in the system restoration process in South Australia. Many of these gas-powered generating units do not have dedicated fuel storage facilities, exposing South Australia to further risk if there was a gas supply interruption during system restoration.

The AEMC Reliability Panel is currently undertaking a review of the system restart standard (due to be completed in November 2016). This may change the amount and location of SRAS that needs to be procured, and the manner in which it is specified. AEMO will respond to any changes to this standard as required.

6.5 Addressing current challenges

The AEMO and ElectraNet joint report in February 2016⁹⁰ identified actions that can be taken by AEMO and the South Australian transmission and distribution network operators to minimise impacts that are expected to result from decreasing levels of synchronous generation and system inertia in the region. Work is progressing to address challenges identified in the report, including:

- Redesign of the current UFLS scheme – AEMO is redesigning the current UFLS to better mitigate the impact of non-credible contingency events leading to high RoCoF. The redesign entails modifying the size of load blocks and investigating the potential to shed load on the basis of RoCoF in addition to fixed frequency values. This approach has been used in Tasmania for RoCoF above 1 Hz/s and could enable the South Australia UFLS scheme to better respond under conditions of higher RoCoF than the existing scheme.
- Design of an over frequency generation shedding (OFGS) scheme – AEMO is working with ElectraNet to design and implement an OFGS scheme to arrest the rise in frequency following the non-credible trip of the Heywood Interconnector at times when South Australia is exporting power into Victoria. Discussions are currently in progress between AEMO and ElectraNet on how to implement the scheme once an initial design is finalised.
- Minimising rapid changes in the supply-demand balance resulting from the 11:30 pm hot water demand peak – AEMO is liaising with SA Power Networks on efforts to minimise the impacts of the 11:30 peak as hot water systems are set to switch on for the start of the off-peak tariff, which will affect system security if South Australia is operating as an islanded network. SA Power Networks has initiated a project to re-program up to 90 MW of hot water demand to reduce the impacts of the switching. AEMO is modelling the anticipated performance of the South Australian power system when operating as an electrical island at the time of the hot water demand peak, to determine if this change will allow AEMO to maintain system security. The SA Power Networks project is due to be completed prior to summer 2016–17.
- Possible changes to Emergency Control Schemes and Operational Procedures to better manage networks under contingent conditions, including potential synchronous separation of South Australia from the rest of the NEM. This may involve promoting a Rule change.

⁹⁰ *Update to Renewable Energy in South Australia – Joint AEMO and ElectraNet Report*, February 2016. Available at: <http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/FPSSP-Reports-and-Analysis>.

7. LINKS TO SUPPORTING INFORMATION

Table 21 provides links to additional information provided either as part of the 2016 SAER accompanying information suite, or related AEMO planning information.

Table 21 SAER topics and source publications

| Information Source | Website Address |
|---|---|
| 2016 SAER – Tables and Figures | http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/South-Australian-Advisory-Functions |
| 2016 South Australian Demand Forecasts | http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/South-Australian-Advisory-Functions |
| 2016 Electricity Statement of Opportunities | 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 |
| 2016 NEFR Forecasting Methodology Information Paper | http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Electricity-Forecasting-Report |
| Retail electricity price history and projections | http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Electricity-Forecasting-Report |
| Projections of uptake of small-scale systems | http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Electricity-Forecasting-Report |
| 2016 South Australian Historical Market Information Report | http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/South-Australian-Advisory-Functions |
| Generation Information page | http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information |
| South Australian Planning Requirements for New Electricity Generation | http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/South-Australian-Advisory-Functions |
| Maps and network diagrams | http://www.aemo.com.au/aemo/apps/nem_map/index.php |
| AEMO's Future Power System Security program | http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability |
| AEMO Insights, August 2016, Electric Vehicles | http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Electricity-Forecasting-Report |
| AEMO's Guide to Ancillary Services in the National Electricity Market | http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Ancillary-services |
| Fact sheets – frequency control, system strength, visibility of the power system | http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/FPSSP-Reports-and-Analysis |

APPENDIX A. DATA REPORTING DEFINITIONS

A.1 Operational consumption and operational maximum demand definitions

A.1.1 Consumption and demand

Consumption refers to electrical energy needed over a period of time and is measured in GWh, whereas demand refers to electrical power needed at a particular point in time (or the average over a short period of time like 5 or 30 minutes) and is measured in MW. This report generally considers consumption or demand over particular reporting periods such as a financial year, summer, winter or calendar month.

A.1.2 Operational reporting

This report presents AEMO's operational data for historical results, estimates, and forecasts. Operational data comprises the electricity consumed by the NEM's transmission and distribution networks to supply residential and business customers as well as the inherent electrical losses in the networks.

Furthermore, operational reporting is defined as that electricity supplied by scheduled, semi-scheduled, and significant non-scheduled generating units, and includes net interconnector imports when reporting on a particular NEM region. It excludes electricity supplied by SNSG, which is discussed in Sections 2.3.3 and 2.4.1, and rooftop PV, which is discussed in Section 2.6.2.

Underlying consumption and demand refers to electricity consumed by customers at their premises, and is that supplied from both the grid and rooftop PV combined, but it does not include contribution from SNSG.

A.1.3 “Sent-out” versus “as-generated” data

Sent-out data is measured at each generating system's connection point. This represents the electricity supplied to the market, and excludes its auxiliary loads. As-generated data, measured at each generating unit terminal, represents its entire output, including the energy supplied to its auxiliary loads.

Usage in this report

Chapter 2 (excluding Section 2.2) of the SAER reports sent-out data for both operational consumption and operational minimum and maximum demand.

Chapter 3 (and Section 2.2) of the SAER reports on findings in the *South Australian Historical Market Information Report* (SAHMIR) and uses as-generated data for both generator electrical output and operational demand.

A.1.4 Probability of demand exceedance

A probability of exceedance (POE) refers to the likelihood that a maximum demand or minimum demand forecast will be met or exceeded.

For a given reporting period, a 10% POE MD projection is expected to be exceeded, on average, one year in 10, and a 50% POE MD projection is expected to be exceeded, on average, five years in 10 (or one year in two). In the case of minimum demand however, 90% POE means demand is expected to exceed the forecast nine years out of 10, or to only be under the forecast minimum one year in 10.

A.2 Inputs to operational consumption forecasts

AEMO’s forecasts are based on a wide range of inputs:

The key inputs into the residential forecast are:

- Historical consumption data.
- Historical and forecast weather data.
- Forecast population growth and building construction.
- Forecast appliance ownership.
- Forecast retail price projections.
- Forecast rooftop PV and storage uptake and generation.
- Forecast energy efficiency savings.
- Forecast gas to electric appliance switching.

The business sector forecast uses:

- Historical consumption data.
- Historical and forecast weather data.
- Forecast developments of macroeconomic variables, including:
 - Household disposable income forecasts.
 - Gross state product forecasts.
- Forecast retail price projections.
- Forecast rooftop PV and storage uptake and generation.
- Forecast energy efficiency savings.

Part of the business forecast is informed by surveying larger customers directly.

A.3 Differences between the 2016 SAER and the 2016 NEFR

As this report is released two months after the NEFR, the 2015–16 data reported in the SAER covers the full 2015–16 financial year. For rooftop PV estimates, the SAER incorporates nine months of input data compared with six months in the NEFR. Details of the differences in the data are outlined in Table 22.

Table 22 Comparison of SAER and NEFR data sources

| | 2016 SAER | 2016 NEFR |
|---|---|---|
| All components of annual operational consumption and demand, except for rooftop PV | Actuals for all of 2015–16 | Actuals: July 2015 to March 2016 Estimates: April 2016 to June 2016 |
| Rooftop PV capacity and generation output | Estimates based on nine months of input data (July 2015 – March 2016) ⁹¹ | Estimates based on six months of input data (July 2015 – December 2015) |

A.4 Differences between 2016 and 2015 historical data and forecasts

A.4.1 Analysis of consumption sectors

In previous SAERs, annual consumption was split into the residential and commercial sector, and the large industrial sector. Due to changes in the consumption analysis in the 2016 NEFR, the 2016 SAER

⁹¹ AEMO uses registrations of small PV generation systems for Small-scale Technology Certificates (STC) under the Renewable Energy (Electricity) Act 2000 (Cth), in order to calculate capacity and hence generation estimates. Although there can be up to 12 months’ delay from installation to registration of a system, AEMO’s analysis of historical data indicates that registrations from July 2014 to March 2015 are sufficiently representative to be included in the 2014–15 financial year estimates.

now reports on the residential sector versus business sector. As the sector splits are not directly comparable, the sector forecasts this year are not comparable to those presented in 2015.

As explained in 2.2.2, for South Australia the business sector forecast is furthermore split into manufacturing (which includes the large industrial loads from previous years) and other business. This breakdown allows better forecasting models to be made.

A.4.2 Reporting of maximum and minimum demand

AEMO now reports maximum and minimum demand as sent-out generation to be consistent with the annual consumption, which traditionally has been presented that way. In previous years, AEMO had presented maximum and minimum demand as-generated, which includes auxiliary loads consumed by the power stations themselves.⁹² (Definitions are in Section A.1.3.)

Note that historical and forecast values presented from the 2015 NEFR are adjusted to be on a sent-out basis by subtracting the auxiliary loads presented in the 2015 NEFR.

A.4.3 Generators included in small non-scheduled generation estimates

Table 23 shows the small non-scheduled generators included in this year's reporting (2016 NEFR and 2016 SAER).

Table 23 South Australian small non-scheduled generating systems for 2016

| Generating system | Generation type | Fuel type | Capacity (MW) |
|---|-------------------------------------|-----------|---------------|
| Amcor Glass, Gawler Plant* | Compression Reciprocating Engine | Diesel | 4 |
| Blue Lake Milling Power Plant | Compression Reciprocating Engine | Diesel | 1 |
| Highbury Landfill Gas Power Station** | Spark Ignition Reciprocating Engine | Biogas | 2 |
| Pedler Creek Landfill Gas Power Station | Spark Ignition Reciprocating Engine | Biogas | 3 |
| SA Water Seacliff Park Mini Hydro | Hydro - Gravity | Water | 1.155 |
| Tatiara Bordertown Plant | Compression Reciprocating Engine | Diesel | 0.5 |
| Tea Tree Gully Landfill Gas Power Station** | Spark Ignition Reciprocating Engine | Biogas | 1 |
| Terminal Storage Mini Hydro Power Station | Hydro - Gravity | Water | 2.5 |
| Wingfield 1 Landfill Gas Power Station | Spark Ignition Reciprocating Engine | Biogas | 4.12 |
| Wingfield 2 Landfill Gas Power Station | Spark Ignition Reciprocating Engine | Biogas | 4.12 |

* Amcor Glass, Gawler Plant became de-registered from the NEM effective 1 January 2016.

** Highbury Landfill Gas Power Station and Tea Tree Gully Landfill Gas Power Station became de-registered from the NEM effective 19 June 2016.

⁹² The reason is that auxiliary loads are a function of the generation mix that is market-driven and rapidly changing, and consequently attempting to forecast these loads from regression analysis of historical auxiliary load patterns is no longer relevant. Forecasts for auxiliary loads are provided, but should only be used for shorter term (1–3 years) studies.

APPENDIX B. ROOFTOP PV AND BATTERY STORAGE METHODOLOGY

B.1 Rooftop PV – historical

B.1.1 Capacity estimation

Historical capacity for rooftop PV installations up to 100 kW was extracted from a data set provided by the Clean Energy Regulator (CER). The dataset contains anonymous data of existing installations with more detail than is regularly reported on the CER public website, allowing AEMO to keep track of daily variations.

B.1.2 Generation estimation

The energy generated by a rooftop PV system was estimated using a model developed by the University of Melbourne.⁹³ For each half-hour, the generation model takes into account solar radiation and cloud coverage. It models inefficiencies related to shading effects and takes into account the geographic distribution of the rooftop PV installations at that time.

The historical values of rooftop PV generation were obtained by multiplying the existing capacity (calculated from CER data) by the modelled generation of a 1 kW rooftop PV installation. AEMO then applied corrections for assumed loss in performance of ageing solar panels, by estimating that a panel loses 0.4% of its efficiency for every year since its installation. An illustrative example of the effect of this assumption is that the total rooftop PV generation estimate for South Australia in January 2016 was reduced by 1% from the energy estimated without taking into account ageing of panels.⁹⁴

B.2 Rooftop PV – forecast

B.2.1 Capacity estimation

AEMO's 2016 forecast of installed capacity for rooftop PV systems up to 100 kW was based on advice from external consultancy Jacobs. Jacobs' report provides details of the approach.⁹⁵

The main drivers behind the forecast rooftop PV uptake are:

- Financial incentives, such as Small Technology Certificates (STCs) and feed-in tariffs (FITs).
- Declining installation costs:
 - Short-term cost reductions are expected to come mainly in non-hardware “soft costs”, including marketing and customer acquisition, system design, installation labour, permitting and inspection costs, and installer margins.
 - In the longer term, cost reductions are expected to come from better system efficiencies and cost reductions from production of PV system components.
- An increase in retail electricity tariffs from 2020.
- Projected steady population growth across most states in Australia, allowing for more rooftop PV systems to be adopted before saturation is reached.

As solar panel output is expected to degrade over time, AEMO has built a stock model of the installations forecast by Jacobs, to be able to calculate the average age of the panels. Based on the average panel age, AEMO has calculated the effective rooftop PV capacity, taking into account the projected degradation by region and across the NEM.

⁹³ “Rooftop PV Model Technical Report”, V.D. Ruelle, M. Jeppesen and M. Brear, July 2016. Available at: <http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Electricity-Forecasting-Report>.

⁹⁴ This corresponds to an assumed average panel age across the region of 2.5 years.

⁹⁵ Jacobs' consultancy report, *Projections of uptake of small-scale systems*, is available on AEMO's website at: <http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Electricity-Forecasting-Report>.

Further to this, AEMO has assumed a westerly shift in rooftop panel orientation, commencing from zero at the start of 2016–17 and resulting in 10% of Jacob's capacity projections having a westerly panel orientation by 2035–36. This reflects AEMO's assumptions that:

- Consumer incentives will continue to evolve over the period.
- Grid-supplied electricity will increase in cost, relative to the value of exporting rooftop PV generation to the grid before the evening peak.
- West-facing panels, which better align rooftop PV generation with the period of peak consumption and assumed higher energy cost, will remain economic for installation and use and add approximately 10% to generation output during the late afternoon compared to north-facing panels.

B.2.2 Generation estimation

Forecasts of rooftop PV generation were estimated by multiplying the forecast of effective capacity with a forecast of normalised generation for a standardised 1 kW unit of effective capacity. This product was separately calculated for each region and sector (residential and business).

The rooftop PV generation model (discussed in Appendix B.1.) produces a measure of total generation, as well as the average generation of a notional 1 kW unit of capacity.⁹⁶

For the production of forecasts for the NEFR, this model has been modified and extended in the following way to produce a forecast of rooftop PV generation:

1. Re-weighted normalised generation.

The University of Melbourne rooftop PV generation model was modified so its measure of normalised generation was 're-weighted' from the spatial and temporal character of installed capacity at each time-step from 1 January 2000, to that which is indicative of actual installed capacity as of summer 2015–16. This step normalised the measure of historic generation per unit of capacity so it corrected for a possible technology diffusion bias that diminishes with time. For PV, this corrected for a possible greater tendency of earlier installations to occur in more affluent suburbs with lower installation inefficiency (due to panel orientation and shading, for example).

2. Re-directed and re-weighted normalised generation.

The modified model was run to produce a 're-weighted' measure of normalised generation for each 30-minute period from 1 January 2000. It was then run again with a 90 degree panel orientation shift to produce a westerly measure of normalised generation.

3. 50% POE forecast of normalised generation.

The 30-minute data from Step 2 was used to determine an annual probability distribution for normalised generation, from which the 50% POE was used in the annual consumption forecasts.

4. Rooftop PV generation forecast.

For annual consumption, the output of Step 3, representing a 50% POE measure of annual normalised generation, was multiplied with the annual forecast of rooftop PV installed capacity to produce a forecast of annual PV generation. Two forecasts were produced, one with a northerly orientation, and one with a westerly orientation. For forecasts of annual consumption, the northerly and westerly forecasts were combined to forecast the generation outcomes of a westerly shift. This shift started with zero input from the westerly data at the start of the 20-year forecast period, with a linear adjustment to achieve a 10% input from the westerly data at the end of this outlook period.

B.3 Battery storage forecast

The forecast capacity of Integrated PV and Storage Systems (IPSS) was also based on external advice from Jacobs. The IPSS forecast captures new combined PV and storage installations only. The model does not consider rooftop PV being retrofitted with battery storage.

⁹⁶ "Rooftop PV Model Technical Report", V.D. Ruelle, M. Jeppesen and M. Brear, July 2016. Available at: <http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Electricity-Forecasting-Report>.

Projecting the contribution of battery storage to consumption and maximum/minimum demand depends heavily on the assumed charging and discharging profile. This profile represents, for each 30-minute period, a proportion of the energy storage capacity of Integrated PV and Storage Systems (see Section 2.5). The following explains AEMO's assumptions and method for determining the forecast for battery storage and discharge:

1. Charging and discharging profile.

- a. It was assumed a battery storage system is installed with an energy management system that will schedule charging and discharging.
- b. The charge/discharge logic assumed alignment with deemed dispatch costs in the wholesale market (so charging when dispatch costs are lowest and discharging when they are highest).
- c. There are three charging/discharging periods:
 - i, Overnight: charging to 25% capacity (or specified) for discharge during the day. Even charging from 30-minute intervals 1 to 12 (of 48 per calendar day, starting at midnight). Even discharge during intervals 13 to 34.
 - ii, Daytime: charging when clear-day solar radiation is >50 watts per square metre (W/m^2), with clear-day radiation used as a charging weight, to a cap of $500 W/m^2$. Discharge during intervals 35 to 46. Discharge occurs with an even/flat profile, stepped up/down at each end over three intervals with a unit gradient.

A clear-day radiation model was used to create a diffuse charging bias. Diffuse radiation remains relatively consistent on cloudy days. Also, by capping radiation to $\sim 50\%$ it brings the clear-day estimate closer to typical received radiation. If the day is fully cloudy, the model will slightly over charge because diffuse radiation can vary between 10% and 30% on a cloudy day. But this could happen in the real world – the programming logic may not be so dynamic – and overcharging may be close to optimal anyway if future retail prices and incentives move to align with the daily solar cycle.
 - iii, Overlapping charge in the evening: Allowing greater capacity use over the day when solar conditions are sustained into the evening peak period. The daytime charging/discharging logic is assumed into the evening period when clear-day radiation is sustained above $50 W/m^2$.

2. Round trip efficiency. This was assumed to be 90%, implemented via the charging and discharging profile, such that the sum of the discharge profile for the calendar day is 10% less than the sum of the charging profile. A round trip efficiency factor was used to enable this adjustment (0.9), applied on a 30-minute basis to the discharge profile.

3. Price elasticity of demand (PED). A PED adjustment was made that further adjusted the discharge profile for an assumed increase in consumption resulting from a lower cost of stored energy compared to the cost of grid-supplied energy. This was represented by reducing the level of discharge by an elasticity factor. This had the effect of causing consumption to be higher.

- a. Daytime charging: AEMO used a PED⁹⁷ of -0.1. This reduced the discharge factor to 90% of the outcome from Step 2.

Overnight charging: AEMO used a PED of -0.05. This reduced the discharge factor to 95% of the outcome from Step 2.

⁹⁷ A PED of -0.1 means a 1% increase in price is associated with a 0.1% reduction in consumption.

APPENDIX C. GENERATION INCLUDED IN REPORTING

Table 24 presents the name, dispatchable unit identifier (DUID), fuel type, and nameplate and registered capacity of the scheduled, semi-scheduled, and significant non-scheduled generating systems used in this report's analysis. They make up the generation used in operational⁹⁸ generation, consumption, and demand analysis in this report. Small non-scheduled generation and embedded generation are discussed in Appendix A.4.3.

Due to changes in their scheduling type in 2015–16, Angaston, Lonsdale, and Port Stanvac power stations are included in operational demand and generation analysis only from 12 January 2016. Angaston power station is also included in reporting on individual generating system outputs and capacity factors before this date.

A generating system's registered capacity is the nominal MW capacity registered with AEMO. The registered capacity is often the same as a generating system's nameplate capacity. Nameplate capacity represents the maximum continuous output or consumption in MW, as specified by the manufacturer, or as subsequently modified. Nameplate capacity can change for a number of reasons, such as upgrade projects, age or a review of performance.

Table 24 South Australian generating systems and capacities including in reporting

| Generating System | Current DUID(s)* | Fuel type | Nameplate capacity (MW) | Registered Capacity (MW) |
|-------------------------------------|--|-----------|-------------------------|--------------------------|
| Scheduled generating systems | | | | |
| Angaston** | ANGAST1 | Diesel | 50 | 50 |
| Dry Creek | DRYCGT1, DRYCGT2, DRYCGT3 | Gas | 156 | 156 |
| Hallett GT | AGLHAL | Gas | 228.3 | 205.6 |
| Ladbroke Grove | LADBROK1, LADBROK2 | Gas | 80 | 80 |
| Lonsdale*** | LONSDALE | Diesel | 20.7 | 20 |
| Mintaro | MINTARO | Gas | 90 | 90 |
| Northern | NPS1, NPS2 | Coal | 546 | 530 |
| Osborne | OSB-AG | Gas | 180 | 180 |
| Pelican Point | PPCCGT | Gas | 478 | 478 |
| Playford B | PLAYB-AG | Coal | 240 | 240 |
| Port Lincoln GT | POR01, POR03 | Diesel | 73.5 | 73.5 |
| Port Stanvac*** | PTSTAN1 | Diesel | 57.6 | 57.6 |
| Quarantine | QPS1, QPS2, QPS3, QPS4, QPS5 | Gas | 224 | 224 |
| Snuggery | SNUG1 | Diesel | 63 | 63 |
| Torrens Island A | TORRA1, TORRA2, TORRA3, TORRA4 | Gas | 480 | 480 |

⁹⁸ Operational reporting includes the electrical energy supplied by scheduled, semi-scheduled, and significant non-scheduled generating units. Operational reporting does not include the electrical energy supplied by small non-scheduled generating units or rooftop PV. On a regional basis, as in this South Australian report, it also includes net interconnector imports for the state.

| Generating System | Current DUID(s)* | Fuel type | Nameplate capacity (MW) | Registered Capacity (MW) |
|---|---|-----------|-------------------------|--------------------------|
| Torrens Island B | TORRB1, TORRB2, TORRB3, TORRB4 | Gas | 800 | 800 |
| Semi-scheduled generating systems | | | | |
| Clements Gap Wind Farm | CLEMGPWF | Wind | 56.7 | 57 |
| Hallett 1 (Brown Hill) Wind Farm | HALLWF1 | Wind | 94.5 | 94.5 |
| Hallett 2 (Hallett Hill) Wind Farm | HALLWF2 | Wind | 71.4 | 71.4 |
| Hallett 4 (North Brown Hill) Wind Farm | NBHWF1 | Wind | 132.3 | 132.3 |
| Hallett 5 (The Bluff) Wind Farm | BLUFF1 | Wind | 52.5 | 52.5 |
| Hornsedale Stage 1 Wind Farm | HDWF1 | Wind | 102.4 | 102.4 |
| Lake Bonney Stage 2 Wind Farm | LKBONNY2 | Wind | 159 | 159 |
| Lake Bonney Stage 3 Wind Farm | LKBONNY3 | Wind | 39 | 39 |
| Snowtown Wind Farm | SNOWTWN1 | Wind | 98.7 | 99 |
| Snowtown Stage 2 Wind Farm | SNOWNTH1, SNOWSTH1 | Wind | 270 | 270 |
| Waterloo Wind Farm | WATERLWF | Wind | 111 | 111 |
| Significant non-scheduled generating systems | | | | |
| Canunda Wind Farm | CNUNDAWF | Wind | 46 | 46 |
| Cathedral Rocks Wind Farm | CATHROCK | Wind | 66 | 66 |
| Lake Bonney Wind Farm | LKBONNY1 | Wind | 80.5 | 80.5 |
| Mount Millar Wind Farm | MTMILLAR | Wind | 70 | 70 |
| Starfish Hill Wind Farm | STARHLWF | Wind | 34.5 | 34.5 |
| Wattle Point Wind Farm | WPWF | Wind | 90.8 | 90.75 |

* Some generators have used different DUIDs historically.

** Angaston was scheduled from 2004 to 2012, was then non-scheduled but still reportable, and became a scheduled generator again on 27 May 2016.

*** Lonsdale and Port Stanvac became scheduled generators on 12 January 2016.

MEASURES AND ABBREVIATIONS

Units of measure

| Abbreviation | Unit of measure |
|--------------|-----------------|
| GWh | Gigawatt hour |
| Hz | Hertz |
| Hz/s | Hertz/second |
| kW | Kilowatt |
| kWh | Kilowatt hour |
| MW | Megawatt |
| MWh | Megawatt hour |

Abbreviations

| Abbreviation | Expanded name |
|--------------|---|
| AEMC | Australian Energy Market Commission |
| AEMO | Australian Energy Market Operator |
| AER | Australian Energy Regulator |
| COP21 | 21 st Conference of Parties |
| CPI | Consumer Price Index |
| ESOO | Electricity Statement of Opportunities |
| LGC | Large-scale generation certificate |
| LRC | Low Reserve Condition |
| LRET | Large-scale renewable energy target |
| MD | Maximum demand |
| NEFR | National Electricity Forecasting Report |
| NEM | National Electricity Market |
| POE | Probability of exceedance |
| PV | Photovoltaic |
| SA | South Australia |
| SAER | South Australian Electricity Report |
| STC | Small-scale Technology Certificates |
| USE | Unserved energy |
| VIC | Victoria |

GLOSSARY

Definitions

The 2016 SAER uses many terms that have meanings defined in the National Electricity Rules (NER). The NER meanings are adopted unless otherwise specified. Other key terms used in the 2016 SAER are listed below.

| Term | Definition |
|--|---|
| as-generated | A measure of demand or energy (in megawatts (MW) and megawatt hours (MWh), respectively) at the terminals of a generating system. This measure includes consumer load, transmission and distribution losses, and generating system auxiliary loads. |
| 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. |
| capacity factor | The output of generating units or systems, averaged over time, expressed as a percentage of rated or maximum output. |
| 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. |
| COP21 | Paris 21 st Conference of Parties, 2015, where countries including Australia committed to emissions reduction targets. Australia set a target to reduce carbon emissions by 26% to 28% below 2005 levels by 2030. The Council of Australian Governments (COAG) Energy Council 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. AEMO analysis suggests that meeting the COP21 commitment is likely to require both generation withdrawals and investment in low-emission generation capacity. |
| feed-in tariff | A tariff paid to consumers for electrical energy they export to the network, such as rooftop PV output that exceeds the consumers' load. |
| 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): <ul style="list-style-type: none"> • 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. |
| interconnector power transfer capability | The power transfer capability (in megawatts (MW)) of a transmission network connecting two regions to transfer electricity between those regions. |
| large-scale generation certificates (LGCs) | Under the LRET target, generators are awarded large-scale generation certificates (LGCs) by the Clean Energy Regulator for every MWh of renewable energy they produce, and sell these LGCs in a market to RET-liable entities, who must meet a yearly target for certificates to cover their electricity purchases. |
| large-scale renewable energy target (LRET) | The large-scale renewable energy target is set as 41,000 GWh of utility-scale renewable generation in Australia by 2020, compared with 1997 levels. |
| load factor | This is a measure of MD relative to annual consumption; the lower the load factor, the greater the difference between average hourly energy and MD. |
| 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. |
| mothballed | A generation unit that has been withdrawn from operation but may return to service at some point in the future. |

| Term | Definition |
|---|---|
| native consumption | This includes all residential, commercial, and large industrial consumption, and transmission losses (as supplied by scheduled, semi-scheduled, significant non-scheduled, and small non-scheduled generating units). Native consumption equals operational consumption plus generation from small non-scheduled generating units. |
| nominal dollars | The actual price in dollars at the time a cost was incurred, without any CPI adjustment. See real dollars. |
| 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 consumption | This includes all residential, commercial, and large industrial consumption, and transmission losses (as supplied by scheduled, semi-scheduled and significant non-scheduled generating units). Significant non-scheduled generation is: wind generators greater than 30 MW, generators treated as scheduled generators in dispatch, generators that are required to model network constraints, and generators previously classified as scheduled. |
| payback period | The time required for the return on an investment to equal the original investment amount. |
| 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, for a 10% POE MD for any given season, there is a 10% probability that the corresponding 10% POE projected MD level will be met or exceeded. This means that 10% POE projected MD levels for a given season are expected to be met or exceeded, on average, 1 year in 10. |
| real dollars | An adjusted price in dollars, as referenced from a particular period in time. In this report, CPI is the basis for adjustment. See nominal dollars. |
| 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: <ul style="list-style-type: none"> • 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. |
| 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. |
| sent-out | A measure of demand or energy (in megawatts (MW) or megawatt hours (MWh), respectively) at the connection point between the generating system and the network. This measure includes consumer load and transmission and distribution losses. |
| small non-scheduled generation | This represents non-scheduled generating units that typically have a capacity less than 30 MW. |
| summer | Unless otherwise specified, refers to the period 1 November – 31 March. |
| synchronous generation | The output from a synchronous generating unit, which is an alternating current generator typical of most thermal and hydro (water) driven power turbines which operate at the equivalent speed of the frequency of the power system in its satisfactory operating state. |
| system restart ancillary services (SRAS) | Services that 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. |
| transmission losses | Electrical energy losses incurred in transporting electrical energy through a transmission network. |
| winter | Unless otherwise specified, refers to the period 1 June – 31 August. |