SOUTH AUSTRALIAN HISTORICAL MARKET INFORMATION REPORT

SOUTH AUSTRALIAN ADVISORY FUNCTIONS

Published: **September 2017**

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 Historical Market Information 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 31 July 2017, 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 all participants in providing data and information used in this publication.

Version control

Version	Release date	Changes
1	15/9/2017	
1.1	11/10/2017	Updated 2016–17 rooftop PV capacity, page 4 and 16.

EXECUTIVE SUMMARY

The 2017 *South Australian Historical Market Information Report* (SAHMIR) provides historical information on South Australian electricity market prices, generation, demand, and interconnector flows between South Australia and Victoria, focusing on the past five years (2012–13 to 2016–17, and July 2017 where applicable).

There have been a number of electricity supply changes in the South Australian region in the past two years, notably the end of coal-powered generation in May 2016 and the increase to the Heywood Interconnector capability from December 2015.

The change in electricity supply from 2015–16 to 2016–17 is detailed in Table 1.

Table 1 South Australian electricity supply by fuel type, comparing 2015–16 to 2016–17

Local generation by fuel type	2015–16 (gigawatt hours, GWh)	Percentage share	2016–17 (GWh)	Percentage share	Change (GWh)	% Change
Gas	4,538	36.4%	5,596	50.5%	1,058	23.3%
Wind	4,322	34.6%	4,343	39.2%	21	0.5%
Coal	2,601	20.8%	0	0.0%	-2,601	-100.0%
Diesel + Small non-scheduled generation	113	0.9%	122	1.1%	9	8.0%
Rooftop PV	908	7.3%	1,016	9.2%	108	11.9%
Total	**12,482**	**100%**	**11,077**	**100%**	**-1,405**	**-11.3%**
Combined interconnector flows						
Interconnector net imports	1,941		2,725		784	40.4%
Total imports	2,227		2,889		662	29.7%
Total exports	286		164		-122	-42.7%

Supply mix changes over the last financial year

- Between 2015–16 and 2016–17:
  - South Australia's most significant change in generation mix was a 23.3% (1,058 gigawatt hours (GWh)) increase in gas-powered generation (GPG).
  - Total local electricity generation from scheduled, semi-scheduled, selected[1] non-scheduled South Australian market generators, and estimated rooftop photovoltaic (PV) decreased by 11.3%.
- In 2016 –17, more than 50% of South Australian local generation came from GPG.

Interconnector performance and upgrade

- Combined interconnector net imports to South Australia have generally trended upward since 2007–08. Net imports increased 40% in the past year, from 1,941 GWh in 2015–16 to 2,725 GWh in 2016–17.
- The import capability of the Heywood Interconnector has increased since the commissioning of the third Heywood transformer. The nominal flow capability increased by 140 megawatts (MW) to 600 MW between December 2015 and August 2016.

[1] Selected non-scheduled generators include all wind farms greater than or equal to 30 MW, and Angaston power station and small non- scheduled generation listed in Appendix B.1.

Renewable generation in South Australia

- Over the last five years, South Australia has had the highest penetration of renewables of all National Electricity Market (NEM) regions. Total renewable generation including wind and rooftop PV for 2016–17 was 5,359 GWh, 0.2% higher than in 2015–16.
- Both wind and rooftop PV capacity has increased in the last five years:
  - Rooftop PV rapidly increased from 402 MW in 2012–13 to 781 MW in 2016–17, and more than 30% of dwellings in South Australia now have rooftop PV systems installed.[2]
  - Registered wind capacity increased from 1,203 MW in 2012–13 to 1,698 MW[3] in 2016–17.
- Hornsdale Stage 3 Wind Farm (109 MW) is now a committed project.

South Australian electricity price trends

- Spot prices for South Australia have been volatile throughout 2016–17. There were more occurrences of both negative prices and prices above $100/MWh (megawatt hour) than in each of the previous five years.
- 2016–17 had the highest time-weighted average spot prices ($108.92/MWh) since 2006–07, 187% higher than the average price of the last ten years. The high spot prices can be attributed to high gas prices affecting wholesale electricity prices, reduced firm capacity in South Australia, and high prices across the NEM due to tightening of supply.
- The higher spot prices were generally set by gas generators. The share of prices set by GPG in South Australia increased from 31% to 36% between 2015–16 and 2016–17. The time in which hydro generation from neighbouring NEM regions was the marginal fuel type for South Australia increased from 14% to 20% between 2015–16 and 2016–17.
- Regulation frequency control ancillary services (FCAS) prices reached record levels, averaging about $125/MWh in each service. The main contributors to high regulation FCAS prices in South Australia are:
  - From September 2015, AEMO required a minimum regulation FCAS enablement of 35 MW to be in place for South Australia during times when it is operating as an island, or has a credible risk of separation from the NEM. During these times of local requirements, FCAS prices have been very high due to the limited number of suppliers of these services.
  - Participants changed their FCAS bidding strategies across all mainland states from March 2016. Almost all generators offering these services reduced their quantity of low-priced bids.

Demand trends

- Energy consumption throughout summer 2016–17 decreased from summer 2015–16, and was just above the five-year low in 2014–15.
- The maximum demand for 2016–17 was 3,081 MW, marginally less extreme than a one-in-ten-year maximum demand event.

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[2] Analysis taken from: Australian PV Institute (APVI) Solar Map, funded by the Australian Renewable Energy Agency, accessed from pv-map.apvi.org.au. Viewed 31 July 2017.

[3] AEMO, Generation Information page, https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

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TABLES

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1. INTRODUCTION

The 2017 *South Australian Historical Market Information Report* (SAHMIR) provides historical information on South Australian electricity market prices, generation, demand, and interconnector supply between South Australia and Victoria, focusing generally on the previous five years, 2012–13 to 2016–17, and July 2017 where applicable.

The data that supports the tables and figures in this report is available in spreadsheet form and is published on AEMO's website.[4] Any discrepancy between data presented in the commentary of this report and the derived data is attributable to rounding in the tables and figures.

1.1 Information sources and assumptions

The 2017 SAHMIR reports on as-generated electrical output which includes the electricity supplied to generator auxiliary loads.[5] Table 2 summarises the data sources used in the reporting presented in the 2017 SAHMIR, and any changes from reporting in 2016.

Table 2 SAHMIR data sources summary

Data reported	Data source(s) in 2017 reports
Reporting on: • **Generation output (including for capacity factor and volume-weighting of average prices)** • **Interconnector flows** • **Demand**	5-minute averages of as-generated Supervisory Control and Data Acquisition (SCADA) metering. When not available, 5-minute SCADA snapshots or the last known good SCADA value were used instead.
Capacity	Registered capacity from AEMO Registrations database.[6] Nameplate capacity from AEMO Generation Information database.[7]
Pricing	Average of 6 x 5-minute dispatch prices over 30-minute trading interval.
Greenhouse gas emissions	5-minute averages of as-generated SCADA metering for generators and interconnectors. Emissions factors for AEMO Planning studies.[8]
Small non-scheduled generation – other (ONSG) and photovoltaic (PVNSG)	Aggregated Market Settlement and Transfer Solution (MSATS) 30-minute metering for selected generators.
Rooftop PV capacity and generation estimates	As provided in 2017 *Electricity Statement of Opportunities* for the National Electricity Market (NEM ESOO)[9]. Refer to 2017 NEM ESOO for more information.
Annual consumption, including auxiliary loads and network losses	As provided in 2017 NEM ESOO.

The SAHMIR reports on electricity generated by South Australian power stations that operate in the NEM. The report focuses primarily on scheduled and semi-scheduled generation (generators greater than or equal to 30 megawatts (MW) registered capacity). Chapter 3 and Appendix A primarily provide these insights.

The report provides some commentary on aggregated generation output from small rooftop photovoltaic (PV) non-scheduled power generation (PVNSG), and other smaller embedded (non-scheduled) power plants (ONSG). This data is gathered from the Market Settlements and Transfer Solutions (MSATS)

[4] Data files to accompany the 2017 SAHMIR. Available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/South-Australian-Advisory-Functions.
[5] Auxiliary loads refers to the energy from equipment used by a generating system for ongoing operation.
[6] AEMO. Current registration and exemptions list. Available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Participant-information/Current-participants/Current-registration-and-exemption-lists. Viewed 1 August 2017.
[7] AEMO. Generation Information database, SA-2017, August 11. Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.
[8] AEMO. 2016 *Emissions Factor Assumptions Update* (ACIL Allen). Available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan/NTNDP-database.
[9] AEMO. *Electricity Statement of Opportunities*, August 2017. Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities.

system, and is aggregated to ensure anonymity of individual generators' output. Details of these generators included in this category are in Appendix B.

Historical estimates of rooftop PV installed capacity and generation output are taken from the 2017 *Electricity Statement of Opportunities* (ESOO) for the National Electricity Market (NEM).[10]

Analysis displaying generator outputs, operational demand, and interconnector flows, whether as duration curves, peak output, or daily averages, uses 5-minute generation or power flow data measured in MW. For generator output or interconnector flow analysed over a financial year or season, 5-minute power generation or flow data is aggregated to an equivalent energy amount (measured in gigawatt hours (GWh)).

Key notes made throughout the report

A number of assumptions have been made throughout this report.

- Pricing analysis for five-year and 10-year trends have been presented in real June 2017 dollars, using the Adelaide Consumer Price Index (CPI)[11] as the basis for adjustment. Where analysis has been undertaken within only the most recent two years, nominal dollar values are presented.
- 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).
- Summer has been defined as the period from 1 November to 31 March, and winter from 1 June to 31 August.
- Years (such as 2016–17) mean full financial years from 1 July to 30 June in the following year throughout this report unless otherwise specified.

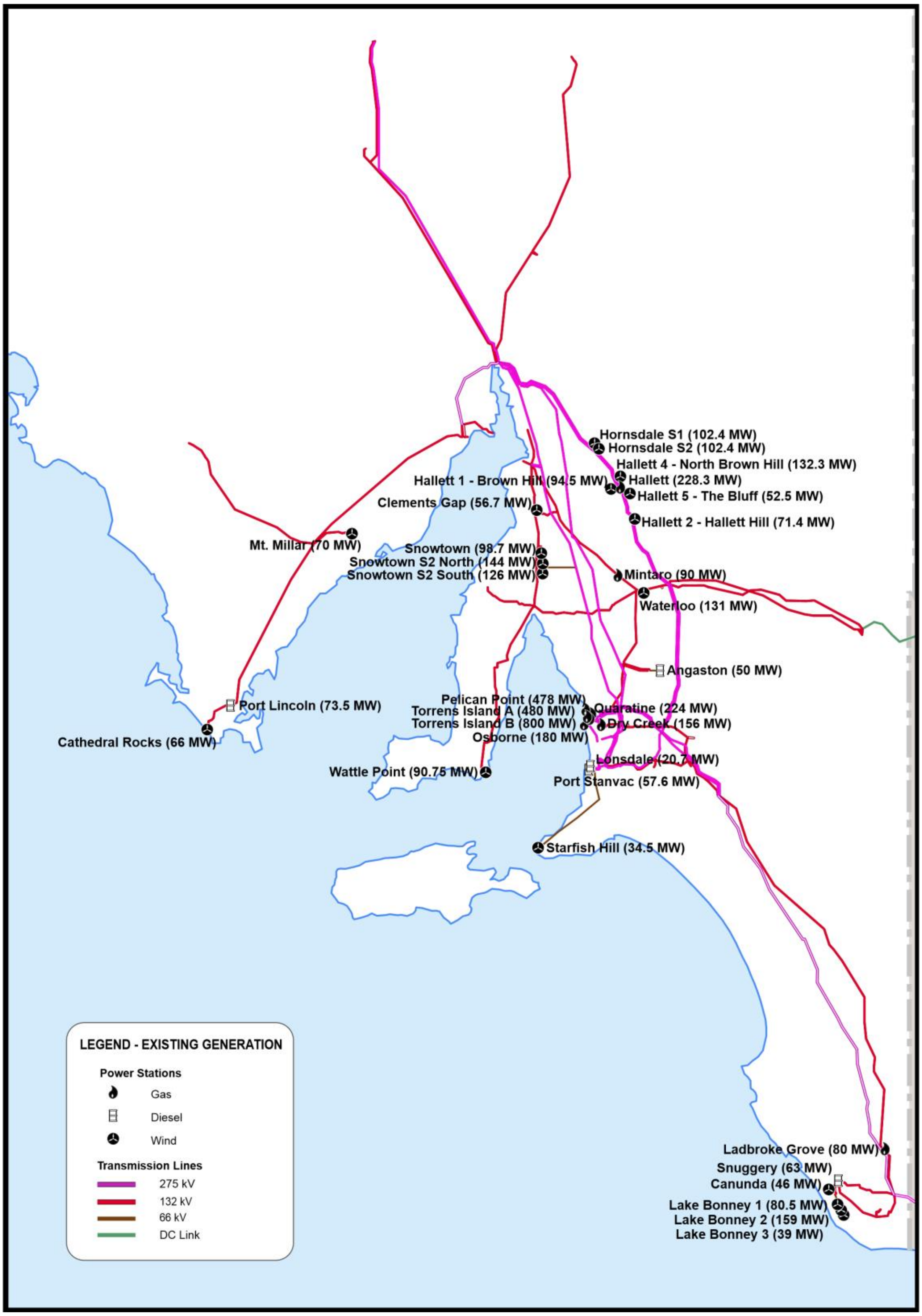
[10] AEMO. *Electricity Statement of Opportunities*, August 2017. Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities.

[11] Australian Bureau of Statistics (ABS). *6401.0 Consumer Price Index (CPI) – Series ID A2325821J (Adelaide CPI)*. Available at: http://www.abs.gov.au/ausstats/abs@.nsf/mf/6401.0. Viewed 28 July 2017.

1.2 Generation map

Figure 1 shows the location and nameplate capacity of South Australian scheduled, semi-scheduled, and significant non-scheduled generators, as at 1 July 2017.

Figure 1 Location and capacity of South Australian generators



2. DEMAND ANALYSIS

This chapter provides an analysis of South Australian demand using demand duration curves and average daily profiles. For further analysis on annual consumption, please see the 2017 *South Australian Electricity Report* (SAER).[12]

For this analysis, demand is the South Australian operational demand. The specific generating units that contribute to meeting operational demand have been defined in Appendix A.

2.1 Demand duration curves

Demand duration curves represent the percentage of time that electricity demand (in MW) is at or above a given level over a defined period.

Figure 2 to Figure 4 show demand duration curves for South Australia. Separate curves are shown for summer and winter. Factors contributing to changes in demand over time include:

- Increasing rooftop PV generation.
- Increasing energy efficiency savings.
- Population changes.
- Changes in residential and business consumption.
- Seasonal weather conditions.

2.1.1 Summer demand duration curves

Both Figure 2 and Figure 3 show the demand duration curves for South Australia for summer 2012–13 to 2016–17. Figure 3 identifies the top 10% of summer demand periods.

Comparison of these curves shows that:

- Energy consumption throughout summer 2016–17 decreased from 2015–16, and was just above the five-year low in 2014–15.
- From 2012–13 to 2016–17, South Australian maximum demand has fluctuated between 2,811 MW and 3,286 MW. In summer 2016–17, maximum demand was 3,081 MW[13], marginally less extreme than a one-in-ten-year maximum demand event.
  - Maximum demand increased over both of the previous two years (the 2016–17 maximum demand was 75 MW higher than 2015–16, and maximum demand in 2015–16 was 194 MW higher than 2014–15).
  - The 2016 –17 maximum demand was, however, a reduction from the maximum demand observed in 2013–14, which was 3,286 MW.

There has been a historical trend of declining operational consumption[14] over the last five years in South Australia. From 2012–13 to 2016–17, operational consumption reduced by 834 GWh (from 13,319 GWh to 12,484 GWh), an average annual decrease of 1.6%. This was driven by a fall in residential consumption, resulting from changing consumer behaviours and increased penetration of rooftop PV generation, energy efficiency measures, and industrial consumption changes.

[12] AEMO. *2016 South Australian Electricity Report*. Available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/South-Australian-Advisory-Functions.

[13] This number reflects operational demand that was met. As this demand occurred during a load shedding event, maximum demand would have been higher had supply been available.

[14] Operational consumption reported here is as sent-out and is based on values reported in the AEMO's 2017 *Electricity Forecasting Insights* and 2017 SAER.

Figure 2 Summer demand duration curves

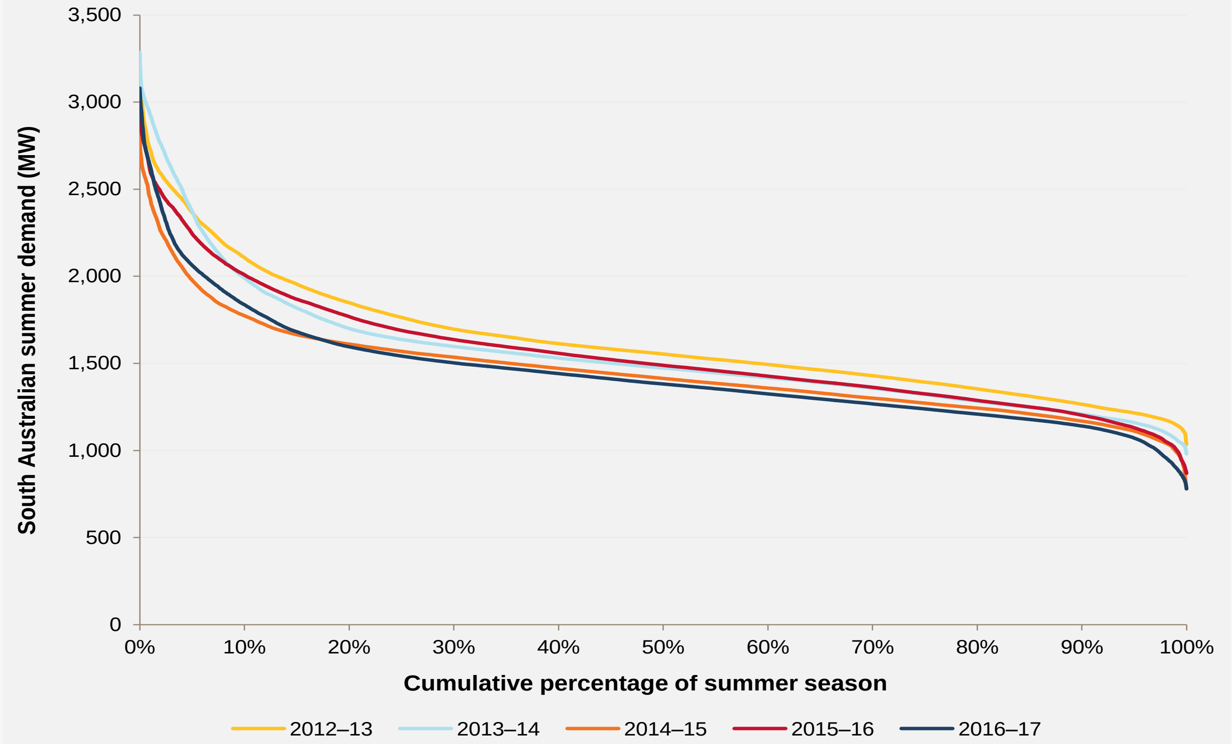
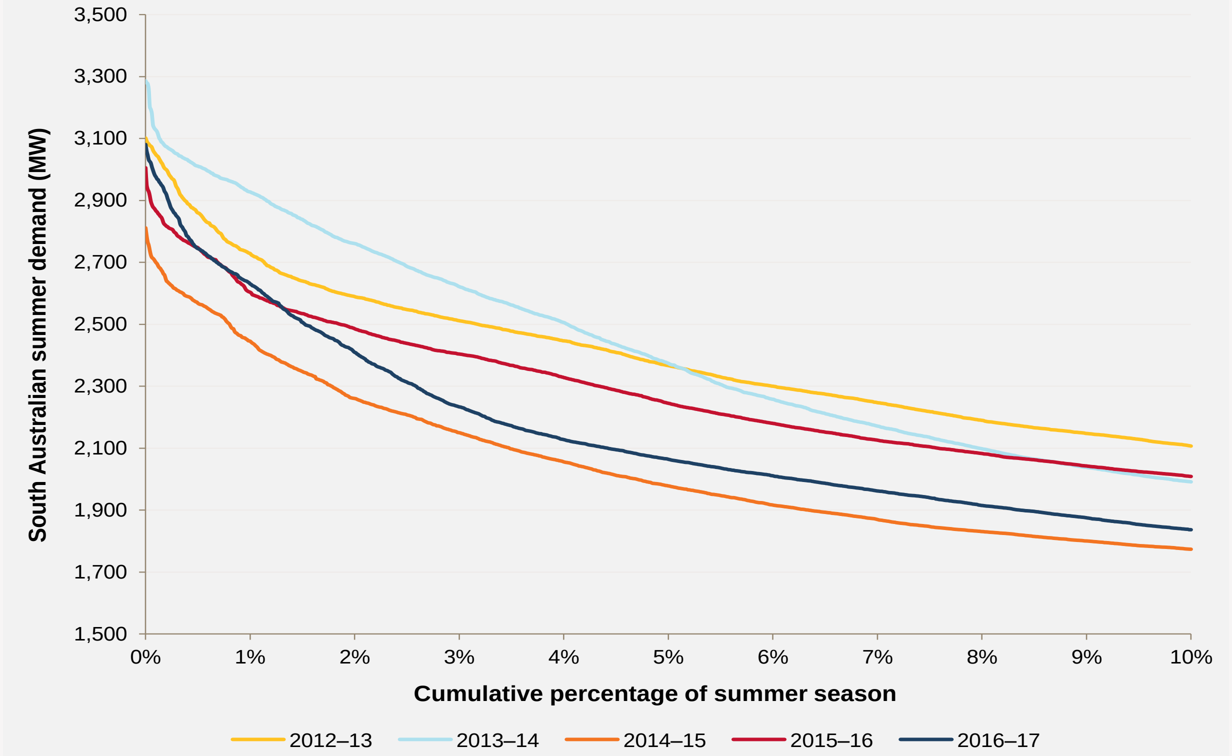


Figure 3 Summer demand duration curves (top 10% of demands)

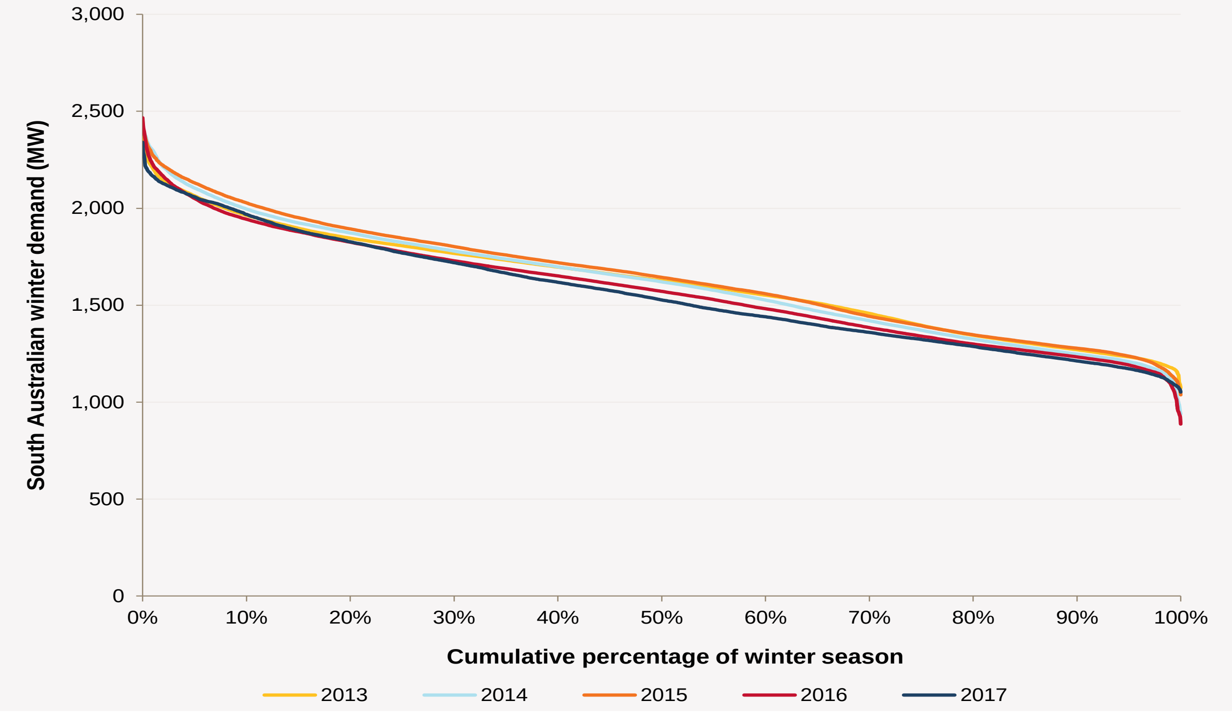


2.1.2 Winter demand duration curves

Figure 4 shows the demand duration curves for winter 2013 to 2017. For winter 2017, only the months of June and July have been included in the analysis.

Comparison of these curves shows that, for most of the season, the winter 2017 in South Australia was lower than for the previous four winters, although the differences between years are relatively small.

Figure 4 Winter demand duration curves



2.2 Average daily demand profiles

Average daily demand profiles represent the demand (in 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.

2.2.1 Summer workday average daily demand profiles

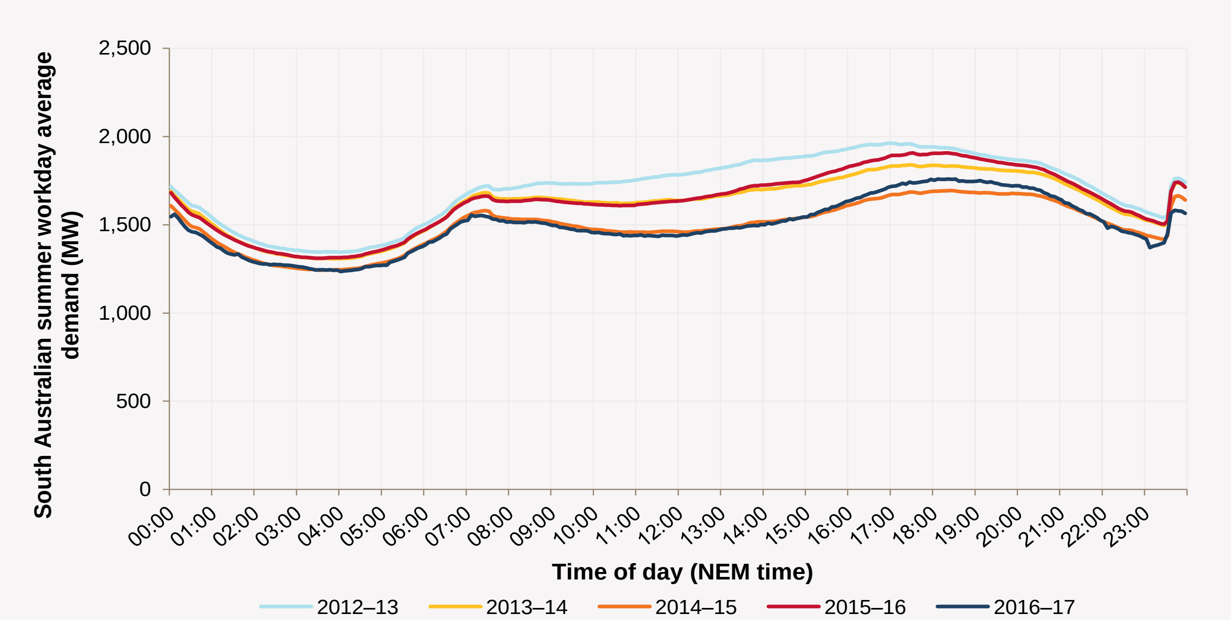
Figure 5 shows the South Australian average workday demand profile for summer 2012–13 to 2016–17. A comparison of these profiles shows that:

- 2016–17 summer workday average demand is approximately the lowest for the last five years, with increasing rooftop PV generation and the impact of energy efficiency measures lowering energy consumption.
- Between 4:00 am and 2:30 pm in 2016–17, the average demand was at a five-year low.
- Average demand consistently rises at 11:30 pm, due to the controlled switching of electric hot water systems at the start of the off-peak period. The Australian Energy Regulator (AER) has noted that "off-peak hot water load caused changes in demand of 15–20% at exactly 2330 each day".[15] SA Power Networks (SAPN) has initiated a project to reprogram up to 90 MW[16] 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.

[15] 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 on 3 August 2017.

[16] SA Power Networks. Flexible load strategy, October 2014. Available at: https://www.aer.gov.au/system/files/SAPN%20-%2020.34%20PUBLIC%20-%20SAPN%20Flexible%20Load%20Strategy.pdf.

Figure 5 Summer workday average demand profiles



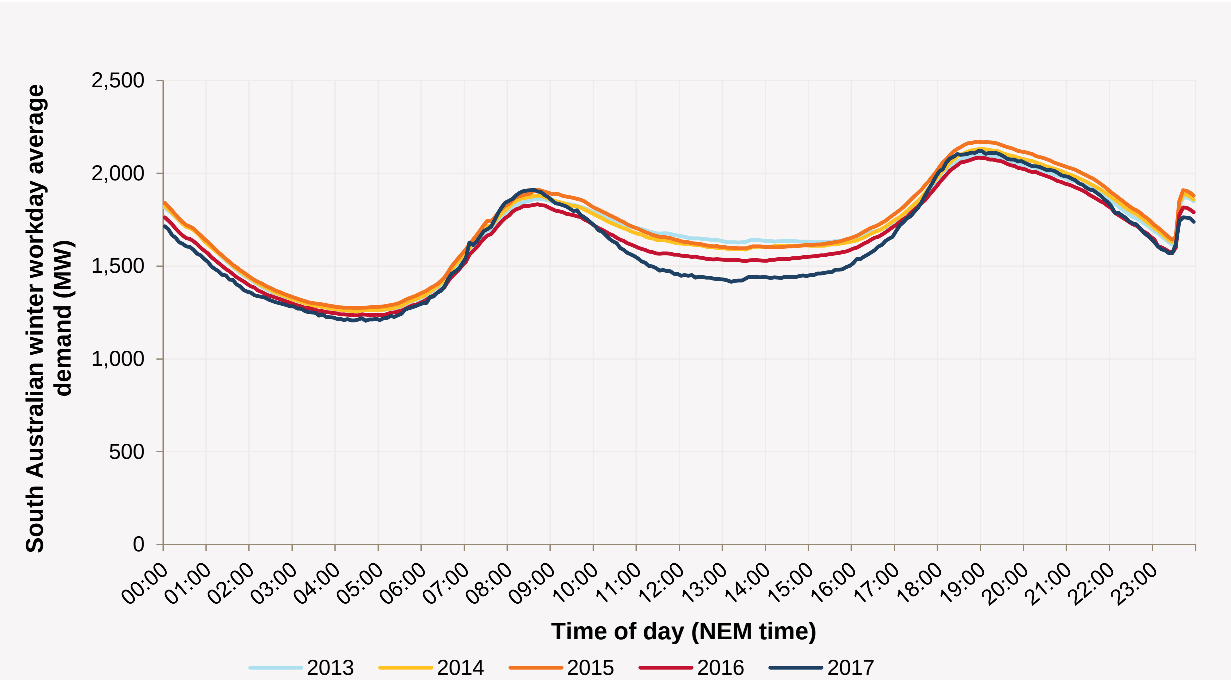
2.2.2 Winter workday average daily demand profiles

Figure 6 shows the South Australian average winter workday demand profile for winter 2013 to 2017.

A comparison of these profiles shows:

- Average demand has been generally steady each winter, with most variation between years shown in the middle of the day. Average demand decreased 101 MW this year between 12:00 noon and 3:00 pm, mainly attributed to increasing rooftop PV generation.
- 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 in Section 2.2.1 for the average summer workday daily profile.

Figure 6 Winter workday average demand profiles



3. HISTORICAL SUPPLY

3.1 Supply changes

The 2016–17 South Australian supply mix is significantly different to 2015–16, due to the retirement of the Northern Power Station in May 2016. This retirement has since led to a significantly increased reliance on gas-powered generation of electricity (GPG) and Victorian imports through the Heywood and Murraylink interconnectors throughout 2016–17.

Previous year

Table 3 summarises the following, for the period from 2012–13 to 2016–17:

- The energy generated by fuel type from scheduled, semi-scheduled, and selected non-scheduled South Australian generators.
- The net interconnector imports into South Australia from Victoria (via the Heywood and Murraylink interconnectors).
- The estimated rooftop PV generation[17] in South Australia.

Refer to Appendix E for a breakdown of the generation on an individual generator basis.

The following key changes occurred from 2015–16 to 2016–17:

- Total GPG increased by 1,058 GWh to 5,596 GWh, the first increase in four years.
- Total coal generation decreased by 2,601 GWh to 0 GWh.
- Total diesel generation increased by 19 GWh to 27 GWh, the highest production in five years.
- Combined interconnector net imports from Victoria increased by 784 GWh to 2,725 GWh, the highest level of net imports in five years.
- Rooftop PV estimated generation increased by 108 GWh to 1,016 GWh.

Table 3 South Australian generation and net interconnector imports (GWh)

Fuel type	2012–13	2013–14	2014–15	2015–16	2016–17
Gas	6,795	5,566	4,599	4,538	5,596
Wind	3,475	4,088	4,223	4,322	4,343
Coal	2,231	2,096	2,645	2,601	0
Diesel	5	2	2	8	27
Interconnector net imports	1,377	1,637	1,528	1,941	2,725
Rooftop PV*	482	672	820	908	1,016
Small non-scheduled generation**	79	82	99	105	95
Total	**14,444**	**14,143**	**13,916**	**14,423**	**13,802**

* Rooftop PV values differ from 2016 SAHMIR due to an improvement in the process to estimate actual generation was performed in AEMO's 2017 demand forecasts
** Small non-scheduled generation differs from 2016 results due to a revision of small non-scheduled generation plants used.

[17] Rooftop PV generation is sourced from the 2017 *Electricity Forecasting Insights*. Available at: http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting.

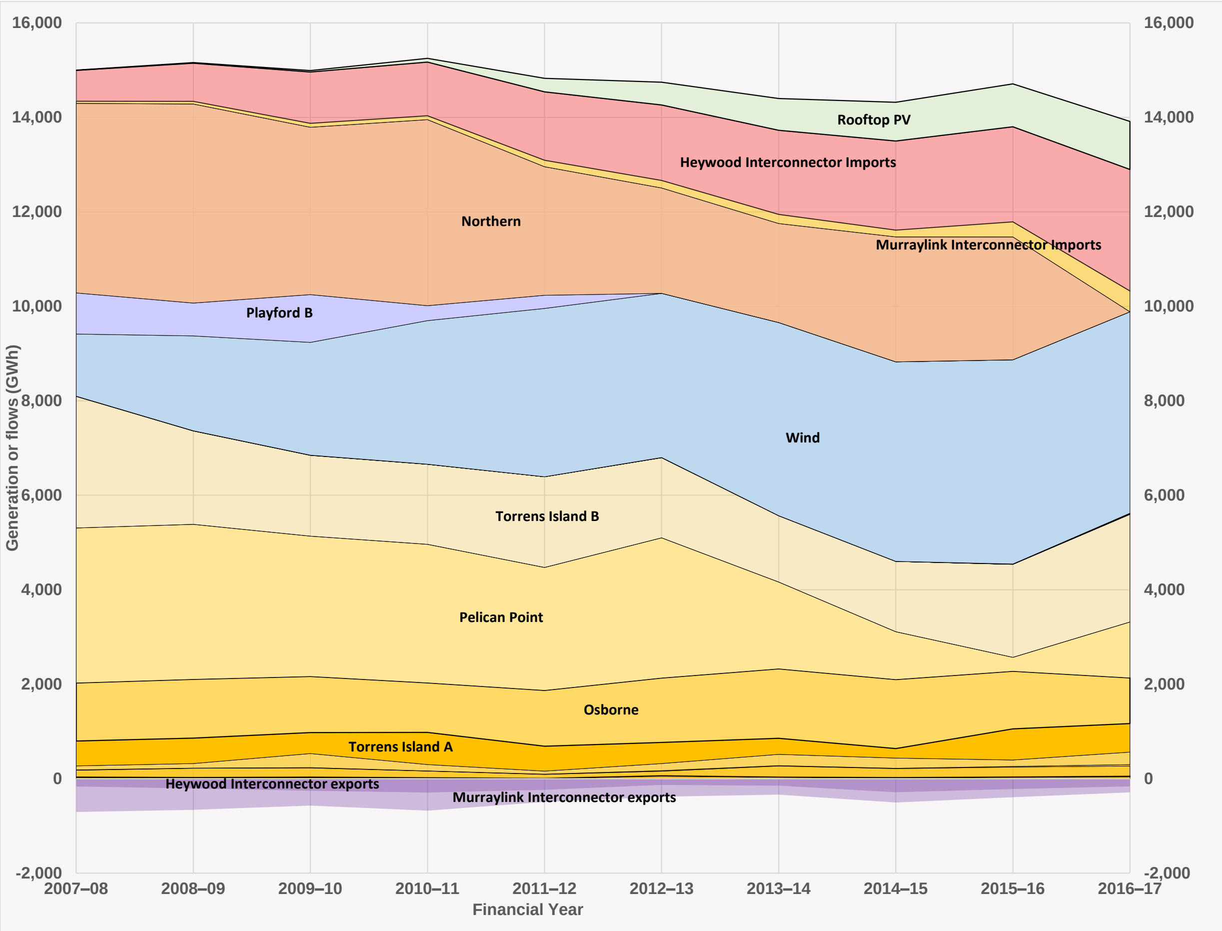
Long-term trend

Table 3 and Figure 7 also illustrate the following trends from 2012–13 to 2016–17:

- Northern Power Station closed on 9 May 2016, resulting in a 2,601 GWh decrease in coal generation.
- Annual generation from Pelican Point Power Station steadily decreased from 2012–13 to 2015–16, however, significantly increased in 2016–17 by 890 GWh to 1,183GWh.
- In 2016–17, a decrease from Osborne and Torrens Island A was largely offset by increased generation from Pelican Point Power station.
- There has been a continued increase in wind generation from 2013–14 to 2015–16, however in 2016–17, total wind generation only increased 21 GWh from 4,322 GWh to 4,343 GWh. This is believed to be due to lower wind quality for sustained periods.
- Rooftop PV generation increased by 534 GWh to 1,016 GWh between 2012–13 and 2016–17, with installed rooftop PV capacity growing to 781 MW in the same period.
- There has been a significant increase in interconnector imports since 2015–16, from both the Heywood and Murraylink interconnectors. In 2016–17, imports increased by 784 GWh, as a direct effect of the reduction in local coal generation. Section 5.1 provides further details on interconnector changes.

Figure 7 displays the changes to generation mix labelled by individual generators over the last ten years. A tabulated version of this information can be found in Appendix E.

Figure 7 Historical generation in South Australia 2007–08 to 2016–17



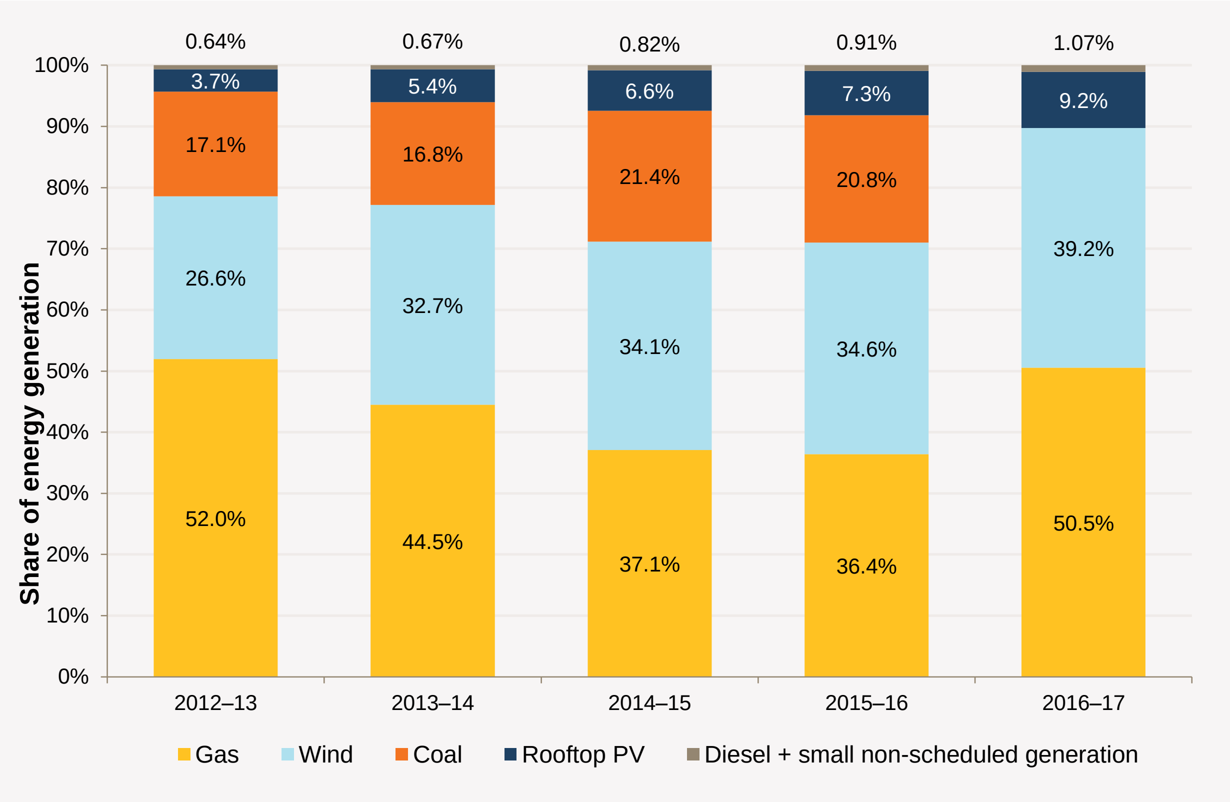
3.2 Generation mix

Figure 8 shows the mix of energy generated in South Australia by fuel type from 2012–13 to 2016–17. This includes generation from:

- All scheduled generators.
- All semi-scheduled and market non-scheduled wind farms.
- Selected smaller market and non-market non-scheduled generators (SNSG).
- Rooftop PV (as estimated in AEMO's 2017 *Electricity Forecasting Insights*).[18]

The figure reflects local generation market share. No adjustments are considered for imports or exports across the interconnectors with Victoria.[19]

Figure 8 South Australian energy generation by fuel type



Comparing 2015–16 and 2016–17, the main differences in South Australia's electricity generation mix in 2016–17 by fuel type, as a percentage of total generation within the state, were:

- Due to the retirement of coal generation, the proportional contribution of every other fuel type increased.
- More than 50% of South Australian local generation came from GPG, a significant increase since 2015–16, with coal retirements and system security requirements affecting gas' market share.

3.2.1 Average daily supply profile

The average daily supply profile for South Australia, seen in Figure 9, represents the supply (in MW) for each 30-minute trading[20] interval of a day, averaged over the 2016–17 financial year. The figure

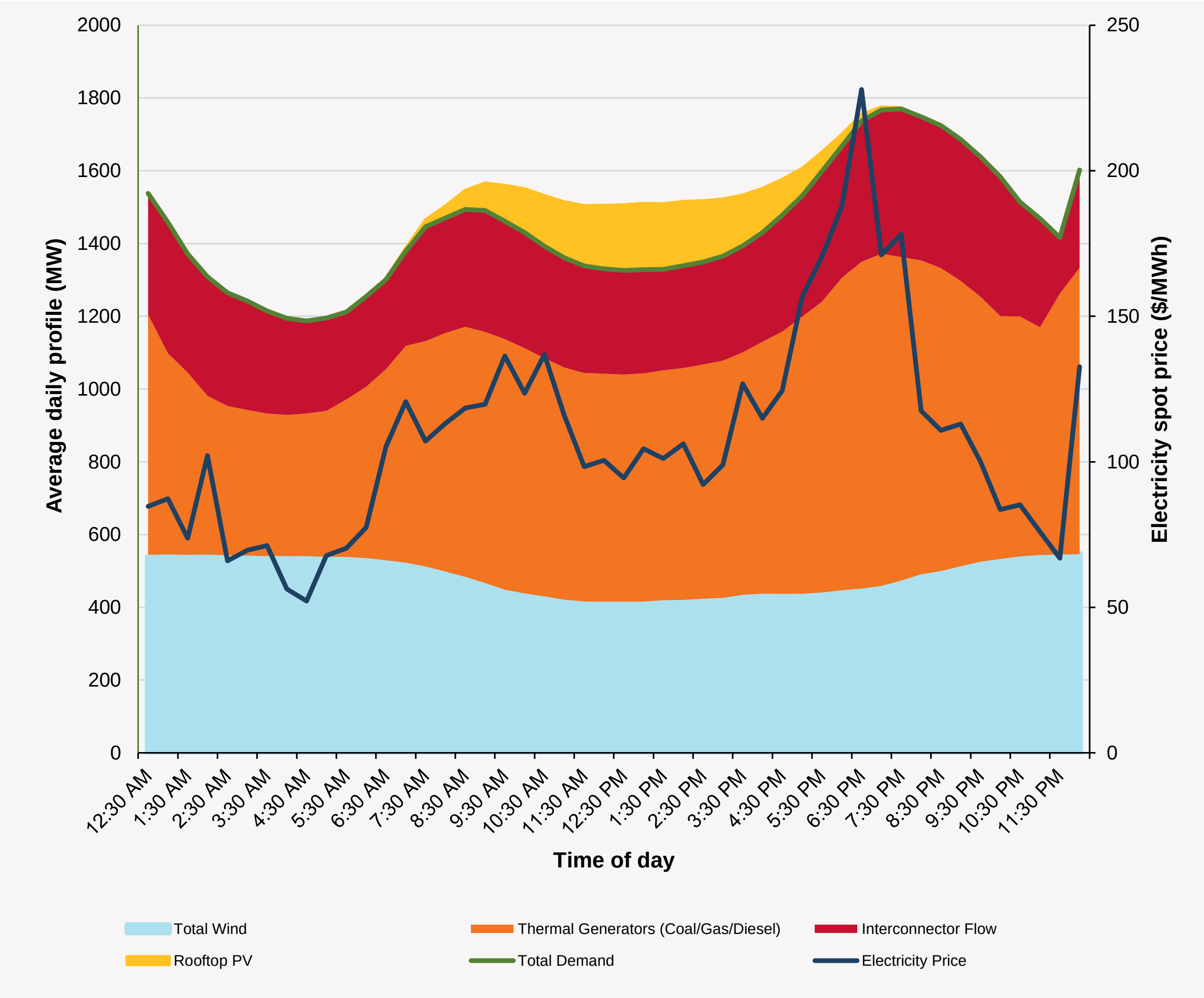
[18] The rooftop PV historical generation calculation methodology is detailed in Appendix F.
[19] This differs to the analysis provided in the 2015 SAHMIR, which did include net interconnector imports. AEMO now considers that the inclusion of net interconnector imports and exports does not provide an accurate fuel mix, as local generation that is exported cannot be feasibly separated by fuel type. This exclusion, and revisions to rooftop PV due to better modelling, account for the material differences in historical values reported.
[20] 5-minute dispatch intervals for scheduled generation, wind generation, and interconnector flows, have been averaged to a 30-minute dispatch interval to better correlate with 30-minute rooftop PV.

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 9 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 contributed the most to the daily profile. On average, at least 388 MW of thermal generation is dispatched in every period (trading interval).
- The average price correlates closely with average demand, particularly in the early morning hours. Price peaks at 6.30 pm are in line with increases in demand from residential loads.
- Interconnectors are relied on throughout the day to provide additional generation, reducing the need for local generation.

Figure 9 Average daily supply profile

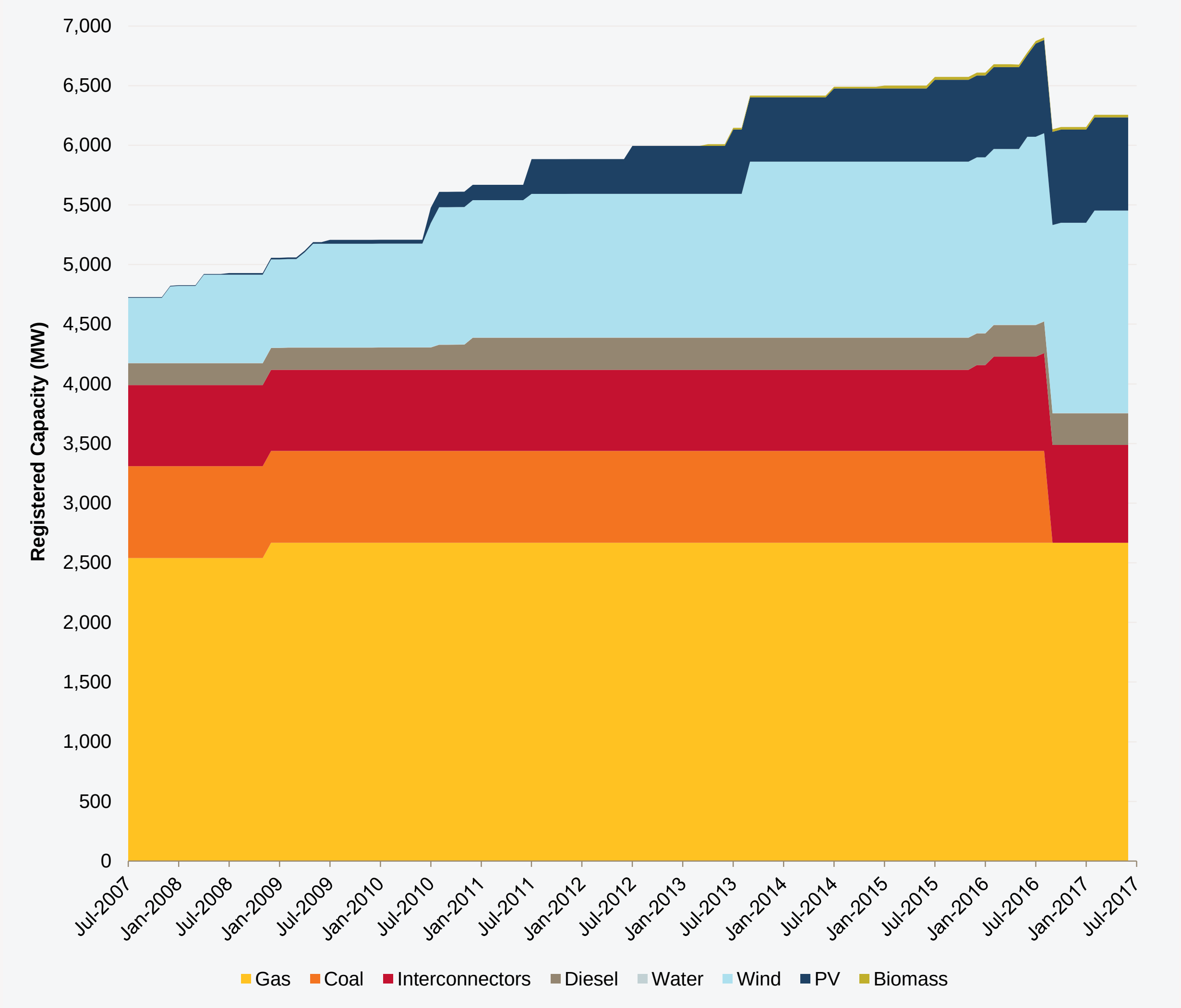


3.3 Generation capacity

Figure 10 shows the registered generation capacity[21] by fuel type in South Australia from 2007–08 to 2016–17, at the end of each calendar month.

[21] Registered capacity values for generators, including pro rata timing of changes during a financial year, have been determined from AEMO registration data.

Figure 10 Registered capacity by fuel type, 2007–08 to 2016–17



This figure shows registered capacity at the end of each calendar month. Biomass includes landfill methane and waste water treatment plant.

It highlights the evolving generation mix in the region over that time:

- With the closure of Northern Power Station, coal capacity reduced to zero by the end of 2015–16 (the point of de-registration represents the capacity reduction).
- Nominal flow import capability increased by 30 MW since 2015–16, to 820 MW at the end of 2016–17.
- Wind registered capacity increased from 547 MW to 1,698 MW in 2016–17, with an average annual growth rate of 14%.
  - Hornsdale Stage 2 Wind Farm was registered in February 2017, and is currently generating.
  - Waterloo Wind Farm’s expansion of 19.8 MW was registered in October 2016, and it is now operating with an increased capacity of 131 MW.
- Rooftop PV capacity was negligible until 2008–09. Since then, there has been average annual growth of 88.6% (6 MW in 2007–08 to 781 MW at the end of 2016–17), although growth has slowed over the last three years.
- Overall registered capacity increased from 4,728 MW in 2007–08 to 6,778 MW in 2015–16. With the closure of Northern and Playford Power Stations, the available capacity has since decreased, to 6,256 MW at the end of 2016–17.

Wind and rooftop PV actual generation capabilities are highly dependent on weather conditions at any given time.

3.4 Capacity factors

A capacity factor is a ratio (expressed as a percentage) of the actual output of generating systems over a period of time, compared to the maximum possible output during that time. Figure 11 and Figure 12 show the financial year capacity factors for South Australian generators based on each power station's historical registered capacity.

In this analysis, AEMO has calculated capacity factors for each generator based on the proportion of the financial year or season they were listed as registered. Where a generator was seasonally or permanently withdrawn, these periods were excluded from the capacity factor analysis.[22] This gives a representative annual capacity factor for each generator, and should facilitate direct comparison between years.

Consideration was given to newly-constructed or discontinued generators. If a generator was not operating for 90% of the analysis period, it was not considered for analysis, as data would be skewed.

Figure 11 to Figure 16 display the capacity factors for scheduled generators and non-scheduled or semi-scheduled wind farms, by season.

Previous year

Changes of note between 2015–16 and 2016–17 are:

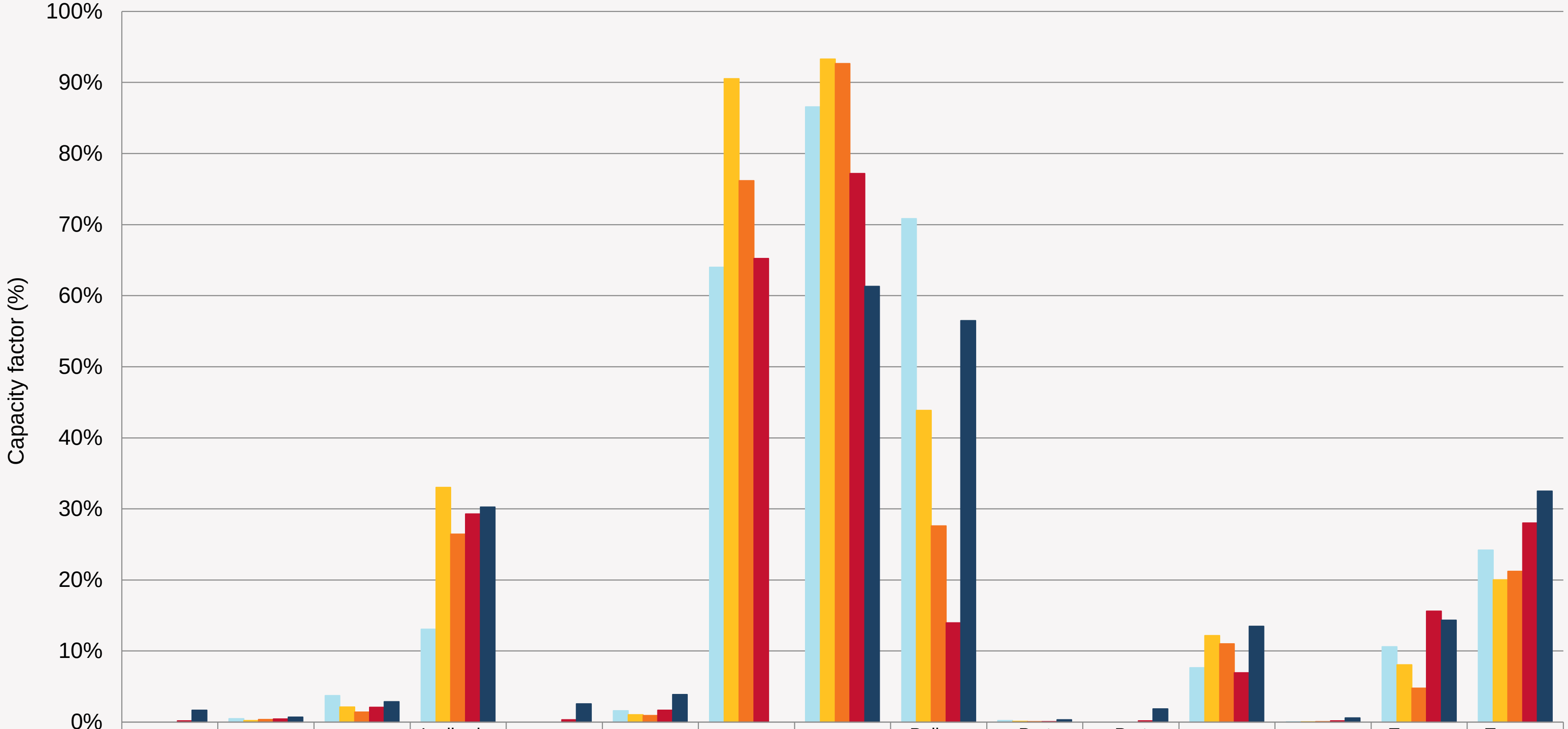
- Northern Power Station's capacity factor reduced from 65.2% in 2015–16 to 0% in 2016–17, due to its closure.
- The capacity factor of Pelican Point Power Station, Quarantine Power Station, and Torrens Island B increased from 14%, 7%, and 28% in 2015–16 to 56.5%, 13.5% and 32.5% in 2016–17, respectively. This was due to market responses to higher market prices and improved gas supply to Pelican Point Power Station.[23]

Long-term trend

Figure 13 to Figure 16 show the capacity factors over the past five years for both summer and winter. They highlight the different seasonal operating patterns for specific generators, and illustrate that wind farms and gas-powered generators on average have higher capacity factors in the winter.

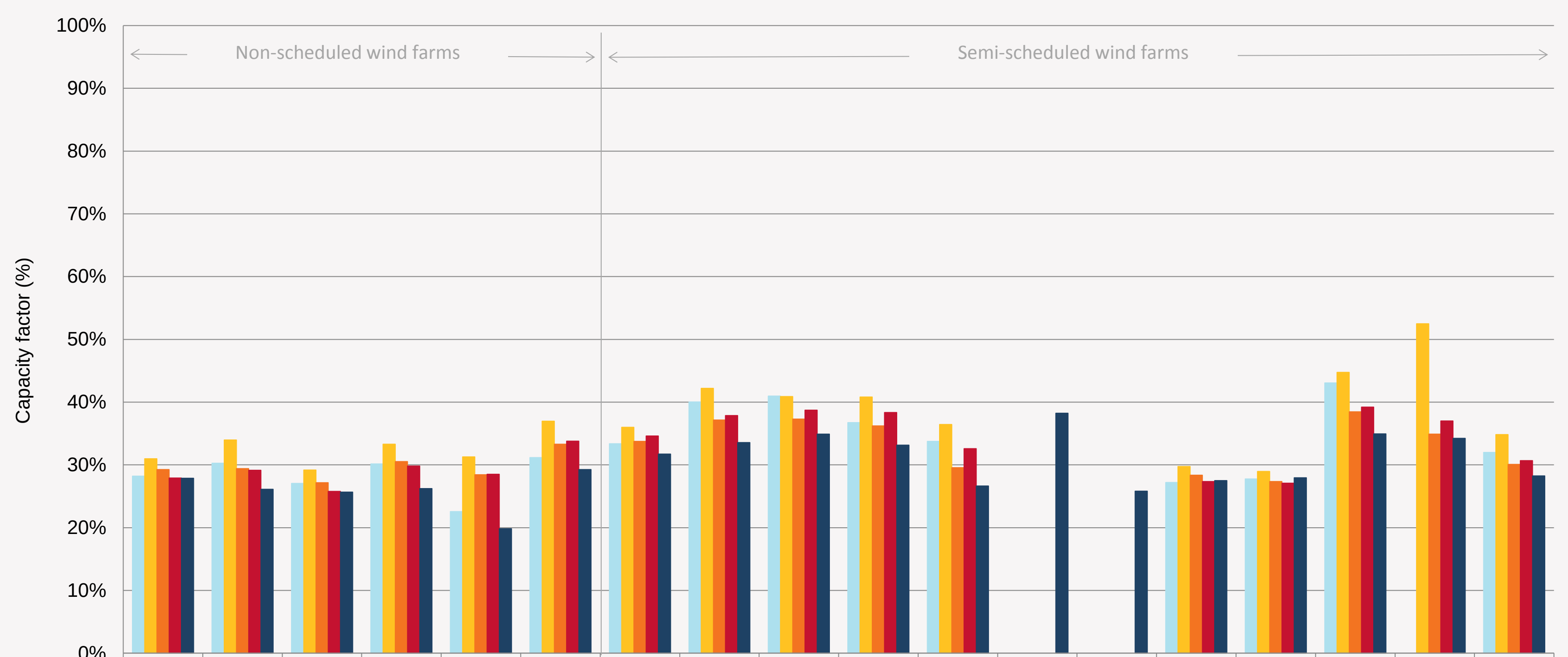
[22] This change in methodology was first used for the 2016 analysis. It means historical capacity factors in the 2016 SAHMIR for Northern and Playford B and in the 2016 and 2017 SAHMIR for Pelican Point are materially different to those capacity factors published in the 2015 SAHMIR.
[23] Origin. Media release, "Origin works with ENGIE to help boost energy security in South Australia" 29 March 2017, Available at: https://www.originenergy.com.au/about/investors-media/media-centre/origin-works-with-engie-to-help-boost-energy-security-in-south-australia.html.

Figure 11 Capacity factors for scheduled generators



	Angaston	Dry Creek	Hallett GT	Ladbroke Grove	Lonsdale	Mintaro	Northern	Osborne	Pelican Point	Port Lincoln GT	Port Stanvac	Quarantine	Snuggery	Torrens Island A	Torrens Island B
2012–13		0.5%	3.8%	13.1%		1.6%	64.0%	86.6%	70.8%	0.2%		7.7%	0.1%	10.6%	24.2%
2013–14		0.2%	2.1%	33.0%		1.0%	90.6%	93.3%	43.9%	0.1%		12.2%	0.0%	8.1%	20.0%
2014–15		0.4%	1.4%	26.5%		0.9%	76.2%	92.7%	27.6%	0.1%		11.0%	0.1%	4.8%	21.2%
2015–16	0.2%	0.5%	2.1%	29.3%	0.4%	1.7%	65.2%	77.2%	14.0%	0.1%	0.2%	7.0%	0.2%	15.6%	28.0%
2016–17	1.7%	0.7%	2.9%	30.3%	2.6%	3.9%		61.3%	56.5%	0.3%	1.9%	13.5%	0.6%	14.4%	32.5%

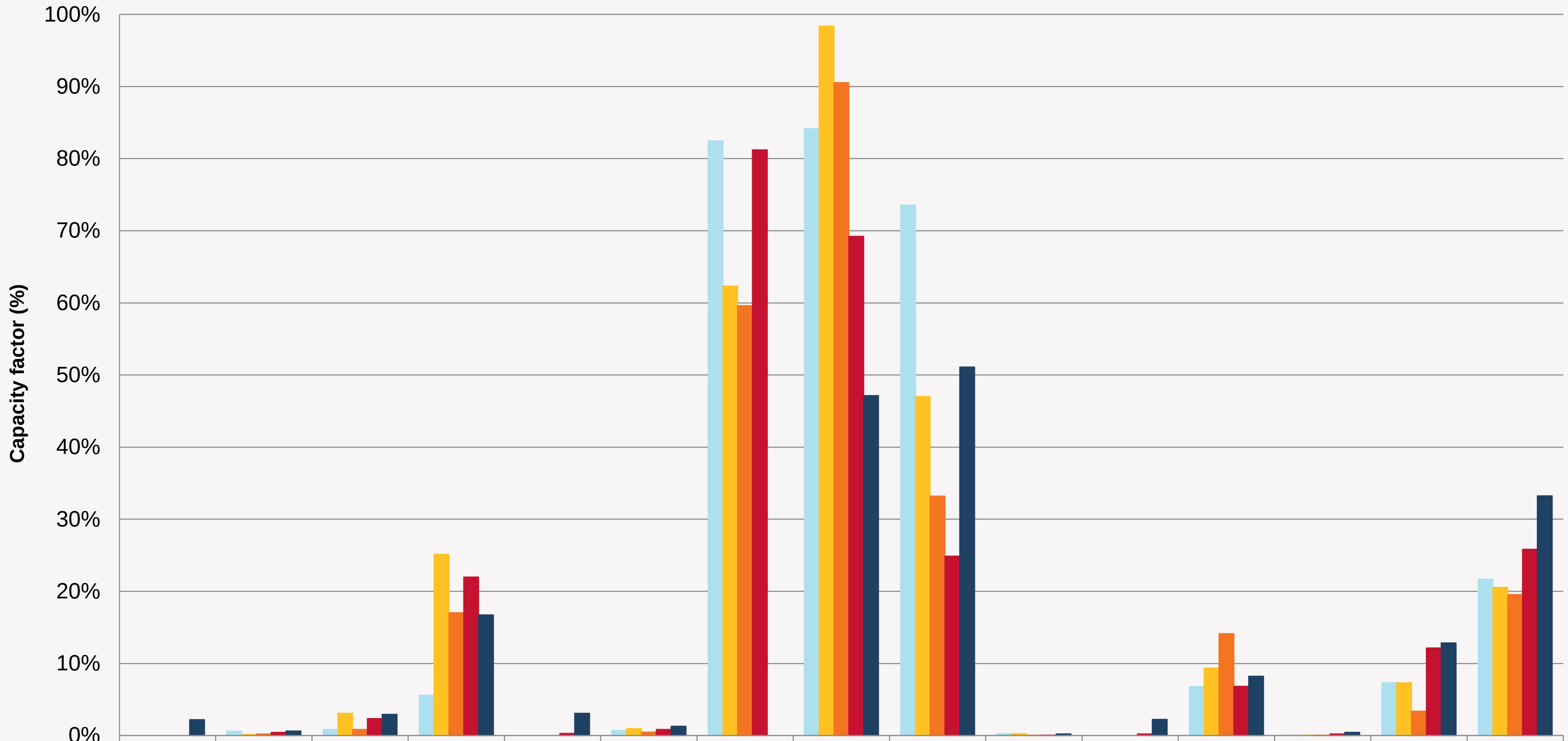
Figure 12 Capacity factors for non-scheduled and semi-scheduled wind farms



	Canunda	Cathedral Rocks	Lake Bonney	Mount Millar	Starfish Hill	Wattle Point	Clements Gap	Hallett 1 (Brown Hill)	Hallett 2 (Hallett Hill)	Hallett 4 (North Brown Hill)	Hallett 5 (The Bluff)	Hornsdale Stage 1	Hornsdale Stage 2	Lake Bonney Stage 2	Lake Bonney Stage 3	Snowtown	Snowtown Stage 2	Waterloo
2012–13	28.2%	30.3%	27.0%	30.2%	22.6%	31.2%	33.4%	40.1%	41.0%	36.7%	33.8%			27.2%	27.8%	43.1%		32.0%
2013–14	31.0%	34.0%	29.2%	33.3%	31.3%	37.0%	36.0%	42.2%	40.9%	40.8%	36.4%			29.7%	29.0%	44.7%	52.5%	34.8%
2014–15	29.3%	29.4%	27.2%	30.5%	28.4%	33.3%	33.8%	37.2%	37.3%	36.2%	29.6%			28.4%	27.4%	38.4%	34.9%	30.1%
2015–16	27.9%	29.1%	25.8%	29.8%	28.5%	33.8%	34.6%	37.8%	38.7%	38.3%	32.6%			27.4%	27.1%	39.2%	37.0%	30.7%
2016–17	27.9%	26.1%	25.7%	26.2%	19.8%	29.3%	31.7%	33.6%	34.9%	33.1%	26.6%	38.2%	25.8%	27.5%	27.9%	34.9%	34.2%	28.2%

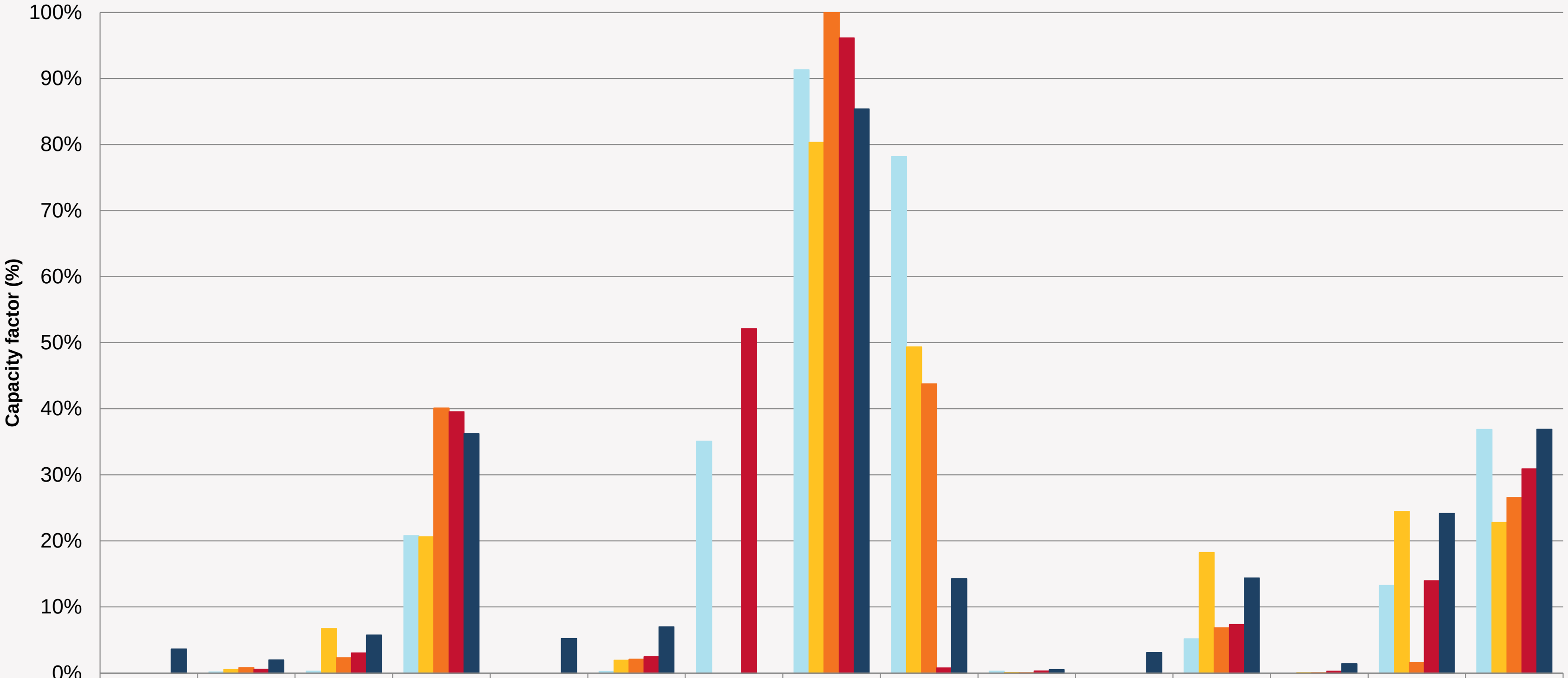
Note: Snowtown Stage 2 capacity factor is calculated for Snowtown Stage 2 North and Snowtown Stage 2 South wind farms combined.

Figure 13 Summer capacity factors for scheduled generators



	Angaston	Dry Creek	Hallett GT	Ladbroke Grove	Lonsdale	Mintaro	Northern	Osborne	Pelican Point	Port Lincoln GT	Port Stanvac	Quarantine	Snuggery	Torrens Island A	Torrens Island B
2012–13		0.6%	0.8%	5.6%		0.7%	82.5%	84.1%	73.5%	0.2%		6.8%	0.1%	7.4%	21.7%
2013–14		0.1%	3.1%	25.1%		0.9%	62.3%	98.4%	47.0%	0.3%		9.4%	0.0%	7.3%	20.5%
2014–15		0.2%	0.9%	17.0%		0.5%	59.6%	90.5%	33.2%	0.0%		14.1%	0.1%	3.4%	19.5%
2015–16		0.4%	2.4%	22.0%	0.3%	0.9%	81.2%	69.2%	24.9%	0.0%	0.2%	6.8%	0.2%	12.2%	25.8%
2016–17	2.2%	0.6%	2.9%	16.7%	3.1%	1.3%		47.1%	51.1%	0.2%	2.2%	8.2%	0.4%	12.8%	33.2%

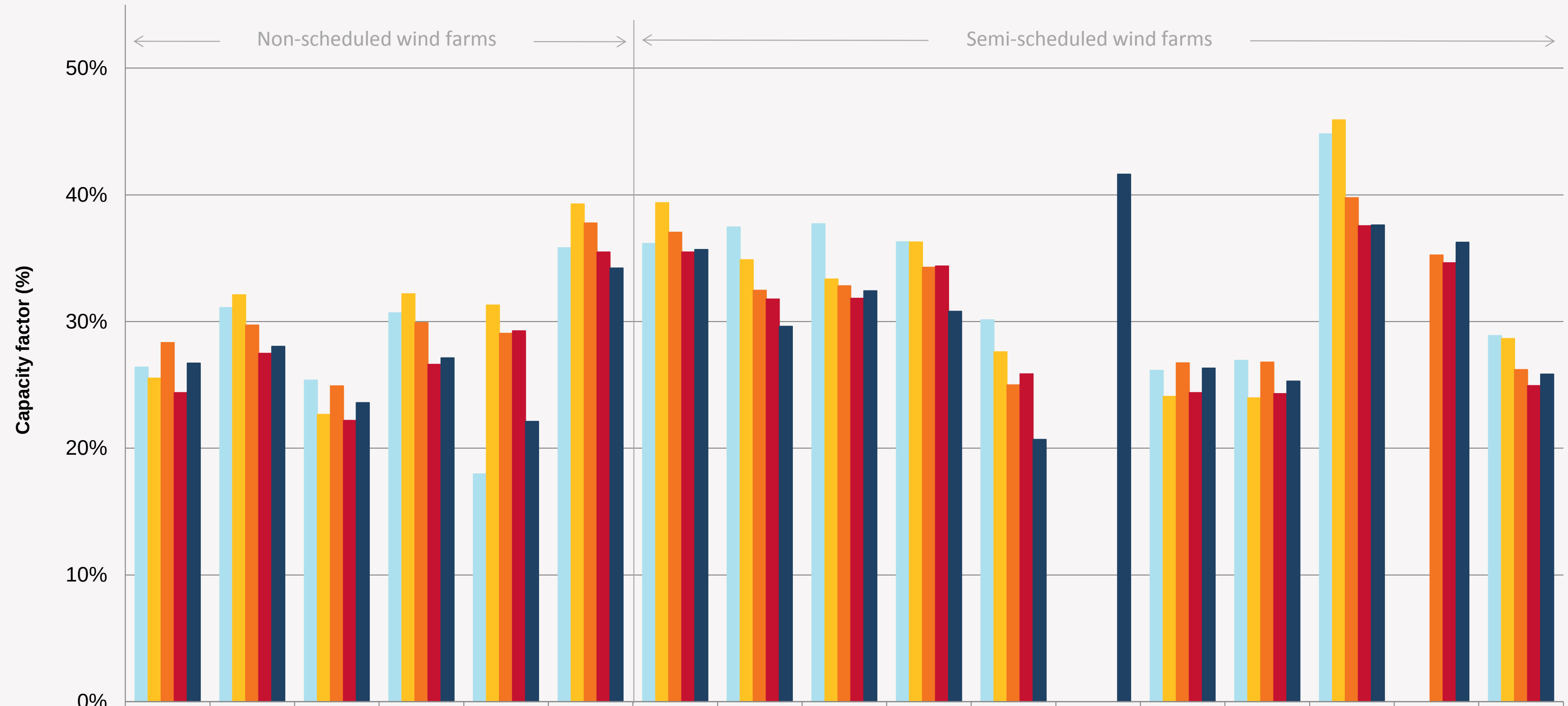
Figure 14 Winter capacity factors for scheduled generators



	Angaston	Dry Creek	Hallett GT	Ladbroke Grove	Lonsdale	Mintaro	Northern	Osborne	Pelican Point	Port Lincoln GT	Port Stanvac	Quarantine	Snuggery	Torrens Island A	Torrens Island B
2012		0.2%	0.3%	20.8%		0.2%	35.1%	91.3%	78.2%	0.3%		5.2%	0.0%	13.3%	36.9%
2013		0.6%	6.7%	20.6%		2.0%		80.3%	49.4%	0.1%		18.2%	0.0%	24.5%	22.8%
2014		0.8%	2.3%	40.1%		2.1%		101.0%	43.8%	0.1%		6.8%	0.0%	1.6%	26.6%
2015		0.6%	3.0%	39.5%		2.5%	52.1%	96.1%	0.8%	0.3%		7.4%	0.3%	14.0%	30.9%
2016	3.6%	2.0%	5.8%	36.3%	5.2%	7.0%		85.4%	14.3%	0.5%	3.1%	14.4%	1.4%	24.2%	36.9%

Note: Osborne Power Station's capacity factor was calculated as greater than 100% for winter 2014. This is due to calculations being made on registered capacity (180 MW), which in this case is substantially lower than both the maximum capacity (204 MW) and the actual generation output levels achieved during this time period.

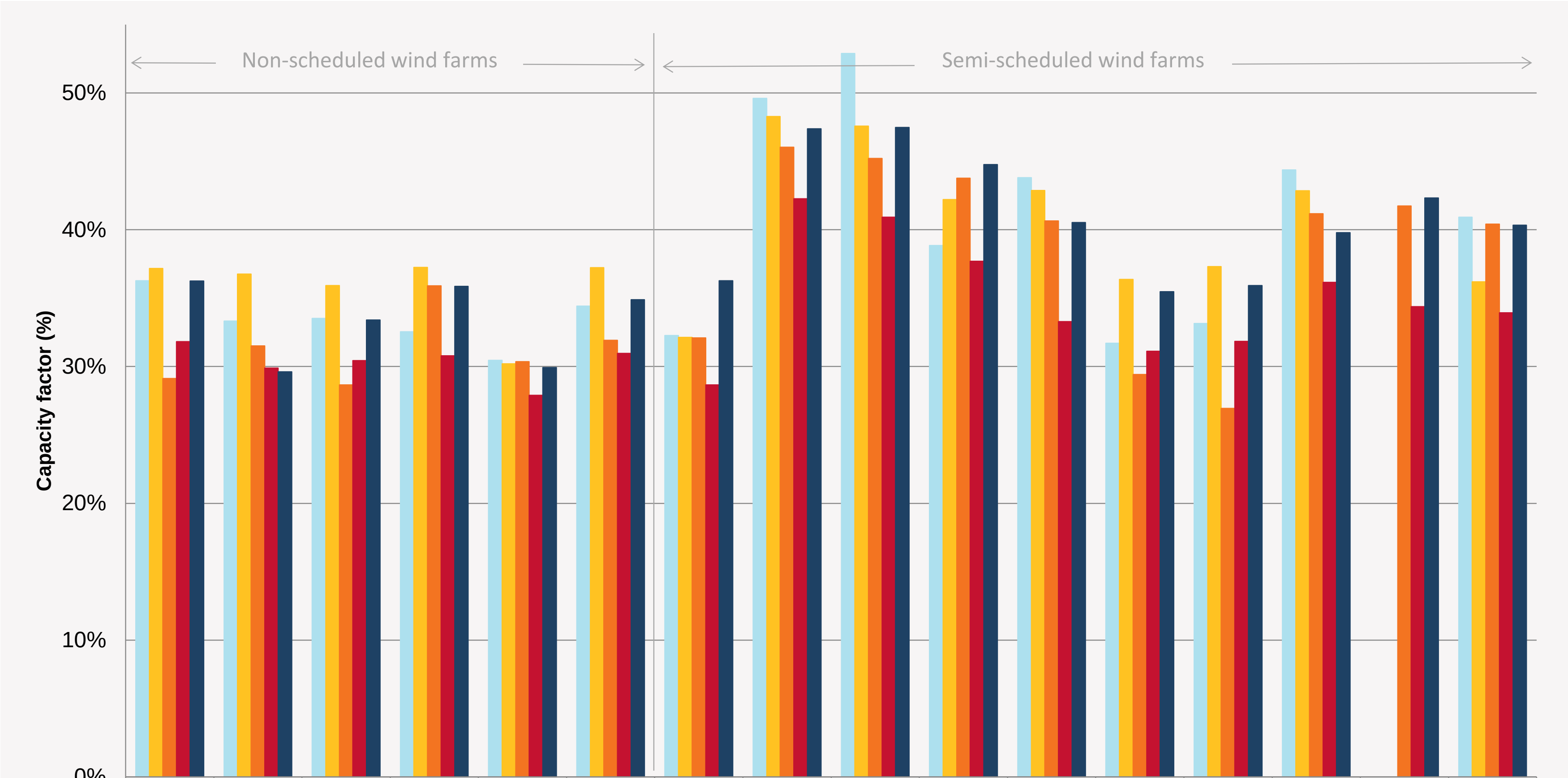
Figure 15 Summer capacity factors for non-scheduled and semi-scheduled wind farms



	Canunda	Cathedral Rocks	Lake Bonney	Mount Millar	Starfish Hill	Wattle Point	Clements Gap	Hallett 1 (Brown Hill)	Hallett 2 (Hallett Hill)	Hallett 4 (North Brown Hill)	Hallett 5 (The Bluff)	Hornsdale Stage 1	Lake Bonney Stage 2	Lake Bonney Stage 3	Snowtown	Snowtown Stage 2	Waterloo
2012–13	26.4%	31.1%	25.4%	30.7%	18.0%	35.8%	36.2%	37.5%	37.7%	36.3%	30.1%		26.2%	26.9%	44.8%		28.9%
2013–14	25.5%	32.1%	22.7%	32.2%	31.3%	39.3%	39.4%	34.9%	33.4%	36.3%	27.6%		24.1%	24.0%	45.9%		28.7%
2014–15	28.3%	29.7%	24.9%	29.9%	29.1%	37.8%	37.1%	32.5%	32.8%	34.3%	25.0%		26.7%	26.8%	39.8%	35.3%	26.2%
2015–16	24.4%	27.5%	22.2%	26.6%	29.3%	35.5%	35.5%	31.8%	31.8%	34.4%	25.9%		24.4%	24.3%	37.6%	34.7%	24.9%
2016–17	26.7%	28.0%	23.6%	27.1%	22.1%	34.2%	35.7%	29.6%	32.4%	30.8%	20.7%	41.6%	26.3%	25.3%	37.6%	36.3%	25.9%

Note: Snowtown Stage 2 capacity factor is calculated for Snowtown Stage 2 North and Snowtown Stage 2 South wind farms combined

Figure 16 Winter capacity factors for non-scheduled and semi-scheduled wind farms



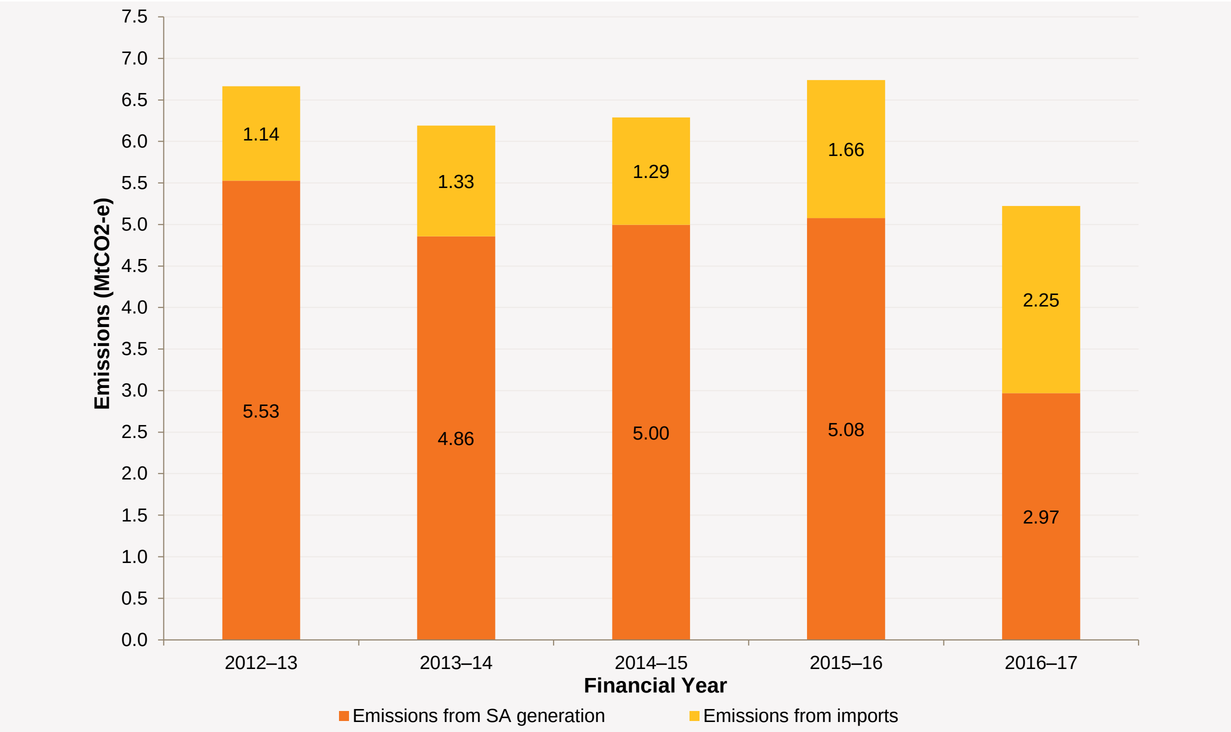
	Canunda	Cathedral Rocks	Lake Bonney	Mount Millar	Starfish Hill	Wattle Point	Clements Gap	Hallett 1 (Brown Hill)	Hallett 2 (Hallett Hill)	Hallett 4 (North Brown Hill)	Hallett 5 (The Bluff)	Lake Bonney Stage 2	Lake Bonney Stage 3	Snowtown	Snowtown Stage 2	Waterloo
2012	36.3%	33.3%	33.5%	32.6%	30.5%	34.4%	32.3%	49.6%	52.9%	38.8%	43.8%	31.7%	33.2%	44.4%		40.9%
2013	37.2%	36.8%	35.9%	37.2%	30.2%	37.2%	32.1%	48.3%	47.6%	42.2%	42.9%	36.4%	37.3%	42.9%		36.2%
2014	29.1%	31.5%	28.7%	35.9%	30.4%	31.9%	32.1%	46.0%	45.2%	43.8%	40.6%	29.4%	26.9%	41.2%	41.7%	40.4%
2015	31.8%	29.9%	30.4%	30.8%	27.9%	31.0%	28.6%	42.3%	40.9%	37.7%	33.3%	31.1%	31.8%	36.2%	34.4%	33.9%
2016	36.3%	29.6%	33.4%	35.9%	29.9%	34.9%	36.3%	47.4%	47.5%	44.8%	40.5%	35.5%	35.9%	39.8%	42.3%	40.3%

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

3.5 Greenhouse gas emissions

Figure 17 illustrates the level of greenhouse gas emissions in metric tonnes of carbon dioxide equivalent (MtCO2-e) produced from South Australian electricity generation, and the emissions associated with electricity imported into South Australia from the remainder of the NEM. It shows that total emissions increased by 0.45 MtCO2-e (an annual increase of 7%) from 2014–15 to 2015–16, but significantly declined by 1.51 MtCO2-e (annual average decrease of 22%) from 2015–16 to 2016–17, due to the withdrawal of black coal generation and increased GPG.

Figure 17 Greenhouse gas emissions for South Australia per year



Emissions calculations include:

- **Thermal efficiencies and emission factors** for each generation unit, as published in August 2016[24], which are used to calculate state based emissions.
- **State-based emissions**, determined using actual annual generation for South Australian power stations, and then added to interconnector emissions.
- **Interconnector emissions**, calculated using:
  - Net annual interconnector imports into South Australia.
  - Average emissions intensity of all NEM-based emissions (based on actual annual generation from all NEM power stations excluding those in South Australia).
  - An assumption that the emissions intensity of generation exported to South Australia is the same as the NEM-wide average excluding South Australia.

During 2016–17, due to a significant decline in production from coal generators, emissions decreased greatly (22%) from 2015–16 values. Despite the drop in local emissions, there has been an increase in

[24]All assumptions and inputs used for AEMO's planning studies, including thermal efficiencies and emission factors, are available at: http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan/NTNDP-database.

net imports and their associated emissions (increased by 36% since 2015–16). Refer to Section 3.1 for details of generation and to Section 5.1 for information about interconnector changes.

Factors affecting the historical decline in emissions from 2012–13 to 2013–14 include increased wind generation, reduced coal and GPG, and declining electricity consumption from the grid, due in part to increasing rooftop PV.

4. WIND GENERATION PERFORMANCE

4.1 Registered capacity and maximum wind generation

South Australia has the highest wind generation capacity and penetration of any NEM region in Australia. Table 4 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 years from 2012–13 to 2016–17.

Hornsdale Wind Farm Stage 2 (102.4 MW) was registered in 2017 and Waterloo Wind Farm increased in registered capacity as a result of an expansion (19.8MW). Changes in registered wind farm capacity do not always match changes in maximum 5-minute generation. Maximum generation can change each year because geographic diversity means not all wind farms contribute their maximum generation in the same 5-minute period.

Table 4 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)*
2012–13	1,203	NA	1,067
2013–14	1,473	Snowtown Stage 2 (270 MW)	1,325
2014–15	1,473	NA	1,365
2015–16	1,576	Hornsdale Stage 1 (102.4 MW)	1,384
2016–17	1,698	Hornsdale Stage 2 (102.4 MW) Waterloo (19.8 MW)	1,546

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

4.2 Total wind generation

4.2.1 Annual energy from wind generation

Table 5 summarises annual wind generation and its annual change from 2012–13 to 2016–17.

Key observations are:

- Annual wind generation in South Australia increased in line with installed capacity increases from 2012–13 to 2016–17.
- 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.
- Annual capacity factors for individual wind farms can vary by up to 9% year on year, though in aggregate the variation is no more than 4%.

Table 5 Total South Australian wind generation

Financial Year	Annual South Australian wind generation (GWh)*	Annual change in wind generation	Annual capacity factor
2012–13	3,475		33%
2013–14	4,088	18%	32%
2014–15	4,223	3%	33%
2015–16	4,322	2%	31%
2016–17	4,343	0%	29%

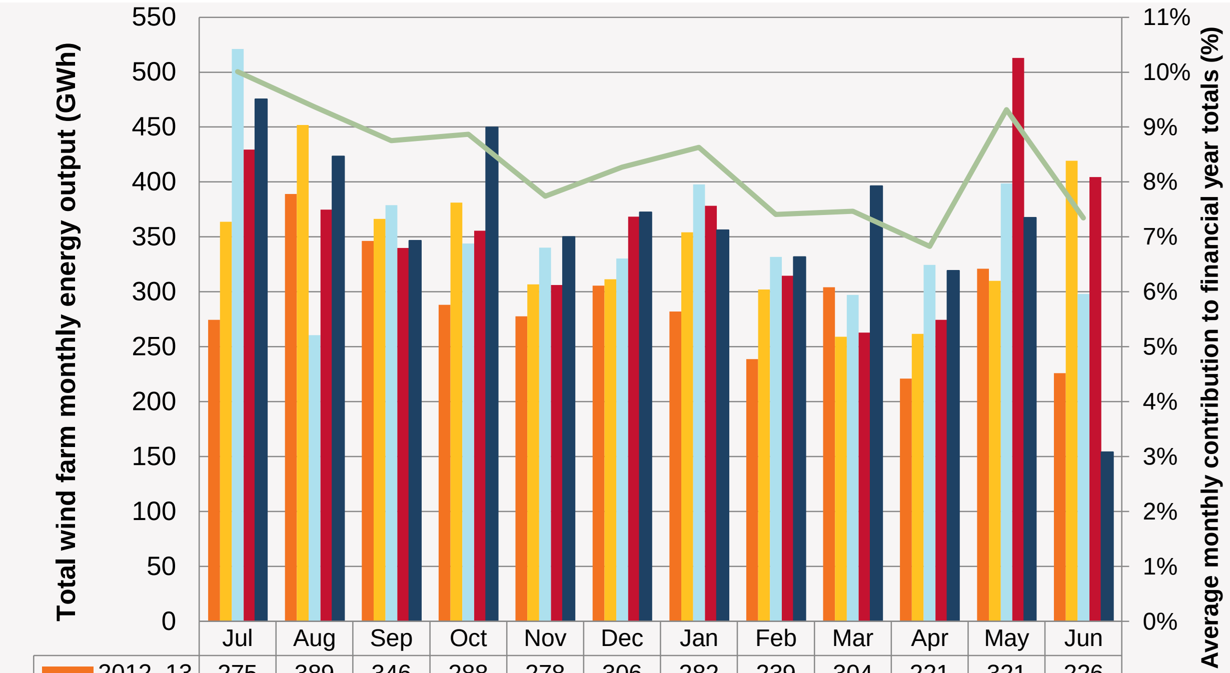
* Capacity factor is based on the annual generation in this table compared to theoretical maximum possible assuming the annual capacity reported in Table 4.

4.2.2 Monthly wind generation variability

Figure 18 shows the monthly South Australian wind generation in GWh over the last five years, from 2012–13 to 2016–17. Also shown is the average monthly contribution to annual totals.

Monthly totals show noticeable variation and some underlying seasonal deviations with average contribution peaking through winter (namely July), and some reduction from February to April. The wind output in June 2016–17 was significantly lower than previous years, due to poor wind conditions in May and June 2017. In the last year, wind output has been highest during July and October.

Figure 18 South Australian total monthly wind energy output and average monthly contribution



	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun
2012–13	275	389	346	288	278	306	282	239	304	221	321	226
2013–14	364	452	366	381	307	311	354	302	259	262	310	419
2014–15	521	261	379	344	340	330	398	332	297	325	399	298
2015–16	429	375	340	356	306	368	378	315	263	274	513	404
2016–17	476	423	347	450	350	373	356	332	396	319	367	154
Avg %	10%	9%	9%	9%	8%	8%	9%	7%	7%	7%	9%	7%

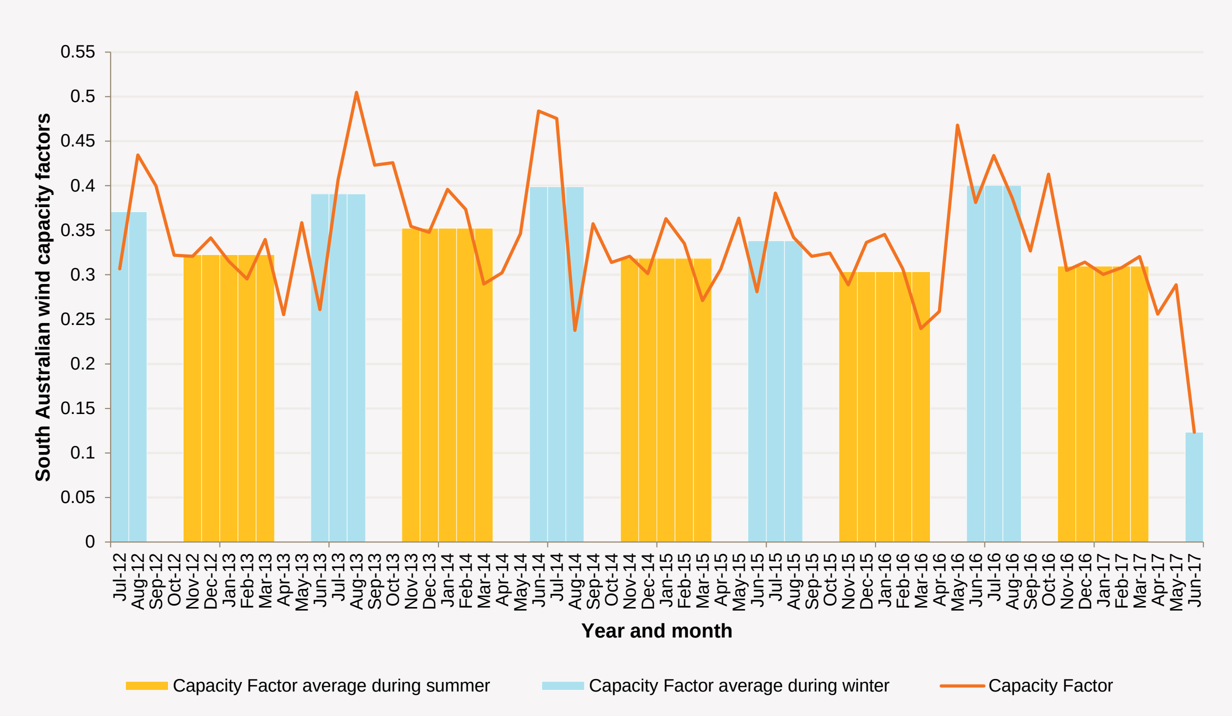
Seasonal capacity factors

Figure 19 shows the capacity factors for South Australian wind generation, based on the total registered capacity for each month, over the last five years from 2012–13 to 2016–17.[25]

Key observations are:

- Capacity factors are usually higher in the winter months than the summer and shoulder months. June 2017 has the lowest capacity factor in the last five years, due to mild wind conditions.
- There are variations across the years for any given month or season due to seasonal changes in wind speeds across the region's wind farm sites.

Figure 19 South Australian wind generation capacity factors



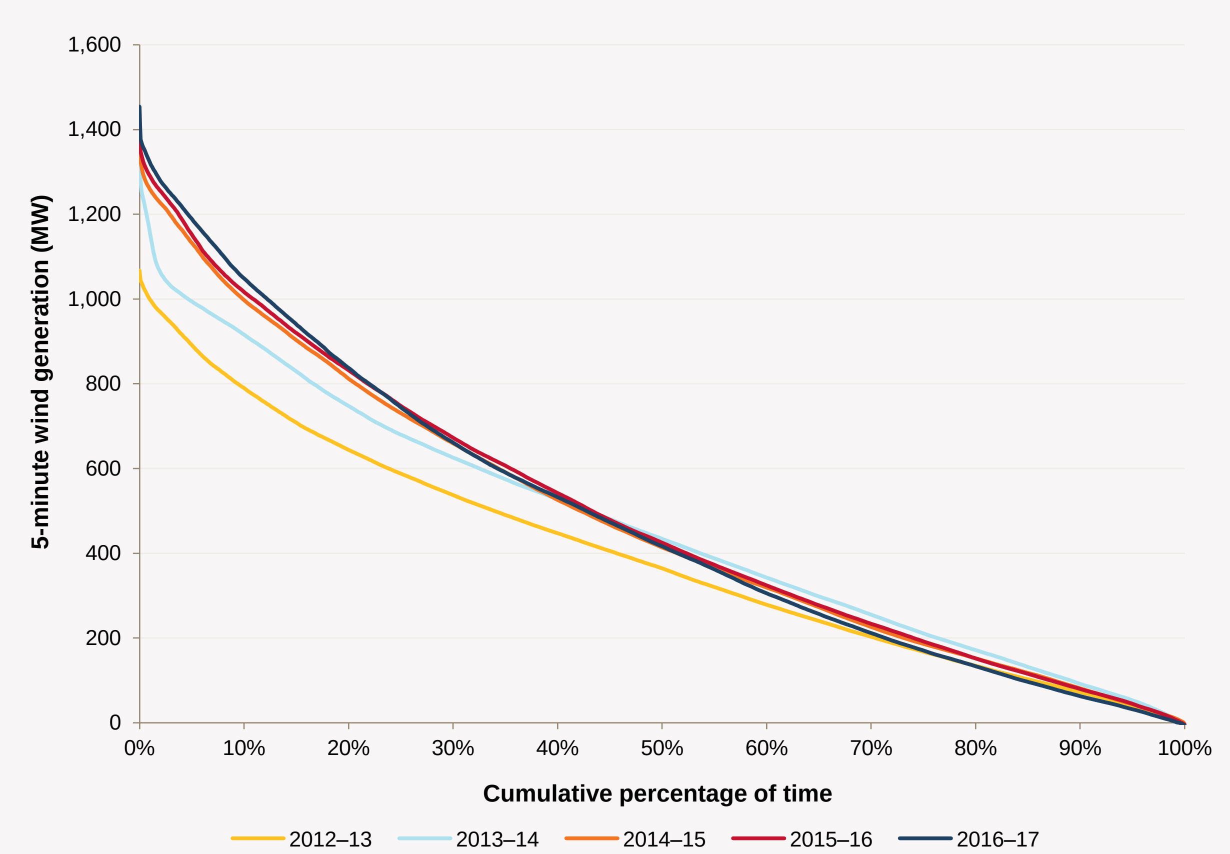
[25] Values prior to July 2015 differ to those reported in the 2015 *South Australian Wind Study Report* due to improved methodology.

4.2.3 Wind generation duration curves

Figure 20 shows the wind generation duration curves for 2012–13 to 2016–17, indicating the percentage of time wind generation was at or above a given level for each year. Calculations are based on 5-minute average generation, aligned to dispatch intervals.

These duration curves clearly show the increase in total wind output from 2013–14 after Snowtown Stage 2 Wind Farm was brought online. Little change was seen in the last three years.

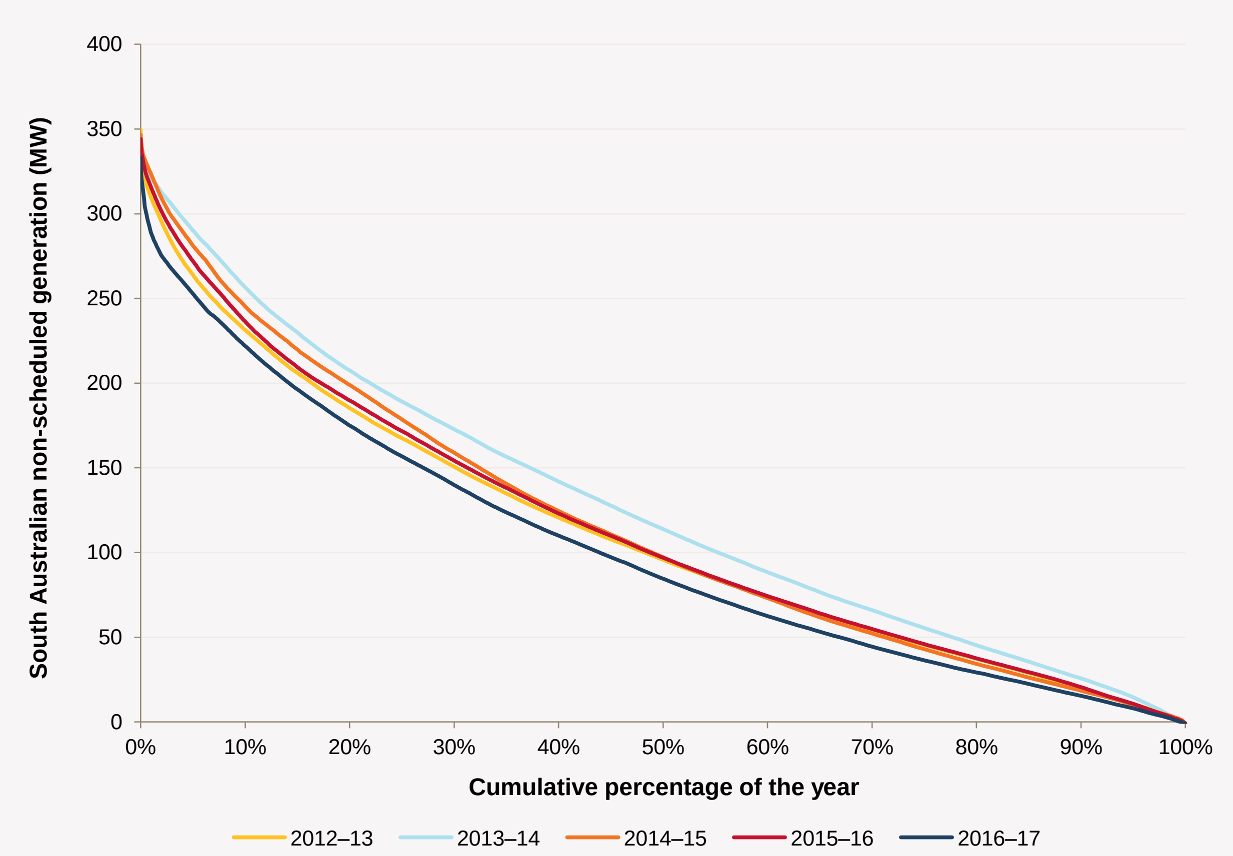
Figure 20 Annual South Australian wind generation duration curves



4.2.4 Non-scheduled wind generation duration curves

Figure 21 shows the aggregate annual generation duration curves from the six South Australian significant non-scheduled wind generating systems (outlined in Appendix A), for 2012–13 to 2016–17. In 2015–16, aggregate non-scheduled wind generation decreased by 1.6% (16 GWh) compared with a decrease of 10.4% in 2016–17.[26]

Figure 21 Annual generation duration curves for non-scheduled wind generating systems



[26] There was little difference in total wind generation and an increase in semi-scheduled wind generation, reflecting wind speeds across the region.

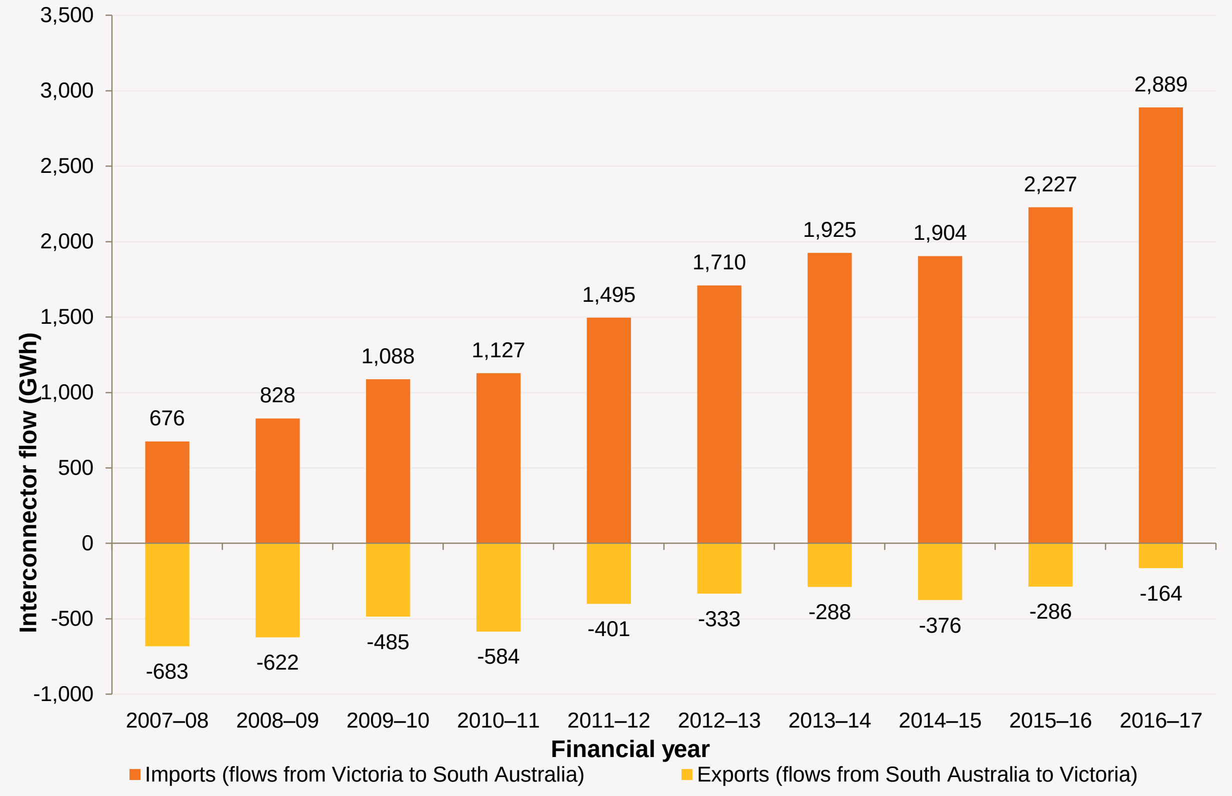
5. INTERCONNECTOR PERFORMANCE

This chapter analyses power flows between South Australia and Victoria across the Heywood and Murraylink interconnectors. Import is defined as the energy flow from Victoria to South Australia, and export as energy flow from South Australia to Victoria.

5.1 Annual interconnector flows

Figure 22 shows total interconnector imports and exports for South Australia from 2007–08 to 2016–17. 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.

Figure 22 Total interconnector imports and exports



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, due to reduction of local GPG and coal fired generation.

In 2016–17, South Australia imported 2,889 GWh, mainly via the Heywood Interconnector. This was the highest import in ten years. The average annual import increase through Victoria to South Australia since 2007–08 is 246 GWh, or 18%.

A variety of factors have led to greater imports, including:

- Reduced local installed baseload capacity in South Australia, due to generating plant withdrawals.
- Increased interconnector capacity.

Table 6 to Table 8 show the annual energy imported and exported from 2007–08 to 2016–17, and the annual total power flows for the Heywood and Murraylink interconnectors. Heywood Interconnector's average import during 2016–17 and Murraylink's average import and export during 2016–17 were the highest in ten years. For the combined[27] Heywood and Murraylink interconnector power flow, compared to 2015–16:

- Total imports increased by 662 GWh (from 2,227 GWh to 2,889 GWh), or 30%.
- Total exports decreased by 122 GWh (from 286 GWh to 164 GWh), or 43%.
- Net imports increased by 784 GWh (from 1,941 GWh to 2,725 GWh), or 40%.

This indicates a greater reliance on interconnectors to meet South Australian operational demand.

Table 6 Historical Heywood Interconnector power flow

	Total imports (GWh)	Total exports (GWh)	Import average (MW)	Export average (MW)	Maximum exports (MW)	Maximum imports (MW)
2007–08	653	539	140	131	457	383
2008–09	808	451	159	122	431	329
2009–10	1,087	313	181	114	453	364
2010–11	1,136	381	194	132	493	476
2011–12	1,448	255	216	122	469	469
2012–13	1,598	248	243	113	491	466
2013–14	1,781	188	254	108	516	437
2014–15	1,887	215	265	130	486	469
2015–16	2,013	172	275	118	583	498
2016–17	2,573	125	338	108	713	499

* Maximum imports and exports have been derived from 30-minute average flows.

Table 7 Historical Murraylink Interconnector power flow

	Total imports (GWh)	Total exports (GWh)	Import average (MW)	Export average (MW)	Maximum exports (MW)	Maximum imports (MW)
2007–08	46	166	15	29	217	160
2008–09	57	208	21	34	221	162
2009–10	84	256	33	42	223	173
2010–11	83	295	43	43	223	171
2011–12	138	237	47	41	223	169
2012–13	160	133	38	29	223	174
2013–14	194	149	48	32	223	174
2014–15	144	289	45	52	222	181
2015–16	320	220	67	55	223	182
2016–17	442	164	73	62	224	178

* Maximum imports and exports have been derived from 30-minute average flows.

[27] The combined power flow is the sum of directional flow on Heywood and Murraylink at each dispatch interval.

Table 8 Historical combined Heywood and Murraylink interconnector power flow

	Total imports (GWh)	Total exports (GWh)	Net imports (GWh)	Maximum exports (MW)	Maximum imports (MW)
2007–08	676	683	-7	661	493
2008–09	828	622	206	589	474
2009–10	1,088	485	603	640	466
2010–11	1,127	584	543	673	614
2011–12	1,495	401	1,094	657	590
2012–13	1,710	333	1,377	689	581
2013–14	1,925	288	1,637	680	549
2014–15	1,904	376	1,528	676	592
2015–16	2,227	286	1,941	801	607
2016–17	2,889	164	2,725	867	619

* Maximum imports and exports have been derived from 30-minute average flows.

5.2 Daily average interconnector flow patterns

Figure 23 to Figure 26 show interconnector flow patterns, averaged by the time of day. Values above the horizontal axis mean the interconnector is importing into South Australia, while negative values mean it is exporting.

Figure 23 shows the annual flow patterns for combined interconnector imports (from Victoria to South Australia), with times expressed in NEM time. On average, combined interconnector imports exhibit a peak from around 6:00 pm to 10:00 pm, and a trough from around 2:00 am to 7:00 am. These correlate with the peaks and troughs in South Australian daily operational consumption.

The sudden dip then subsequent spike in imports occurring around 11:30 pm to midnight is caused by automated "off-peak" electric hot water systems switching on in Victoria, followed by South Australia.

Figure 23 Combined interconnector daily 5-min average flow

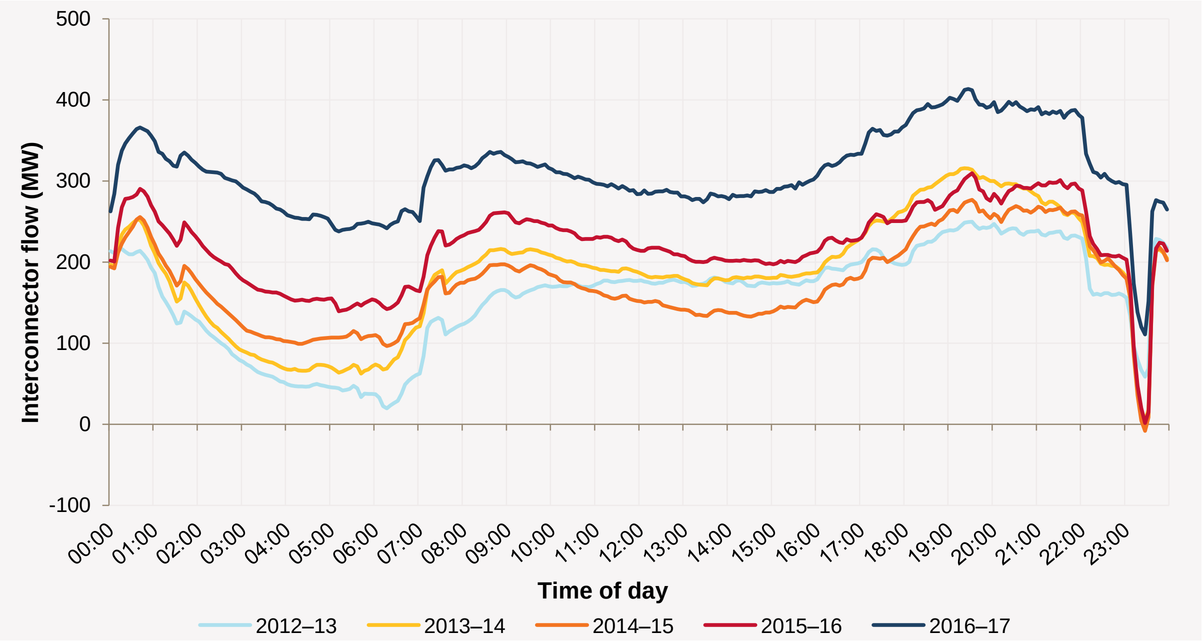


Figure 24 provides a breakdown of the interconnector flow patterns for 2016–17. It shows that, on average, Heywood tends to import electricity, whereas Murraylink tends to import or export depending on the time of day, although both follow a similar profile over the day.

Figure 24 2016–17 Heywood, Murraylink and combined interconnector daily 5-min average flow

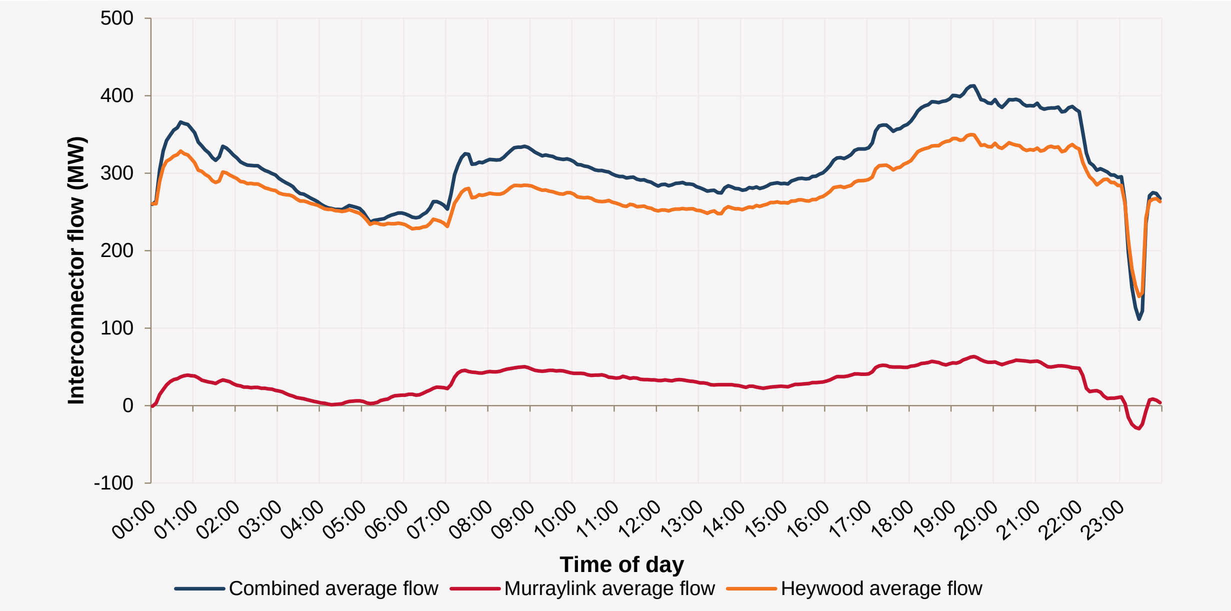


Figure 25 and Figure 26 show interconnector flow averages for each 5-minute dispatch interval of each day over the past five years for workdays in summer and winter. Note that the winter 2017 curve only includes data for June and July 2017. Daily average imports are generally higher during winter, generally due to a reduction in PV generation.

In 2016–17, average daily winter imports were lower than the previous two years, due to planned outages on the Heywood Interconnector. However, the average daily summer imports were significantly higher than the previous four years, due to the retirement of Northern Power Station and increased interconnector transfer capability.

Figure 25 Combined interconnector summer daily 5-min average flow (workdays only)

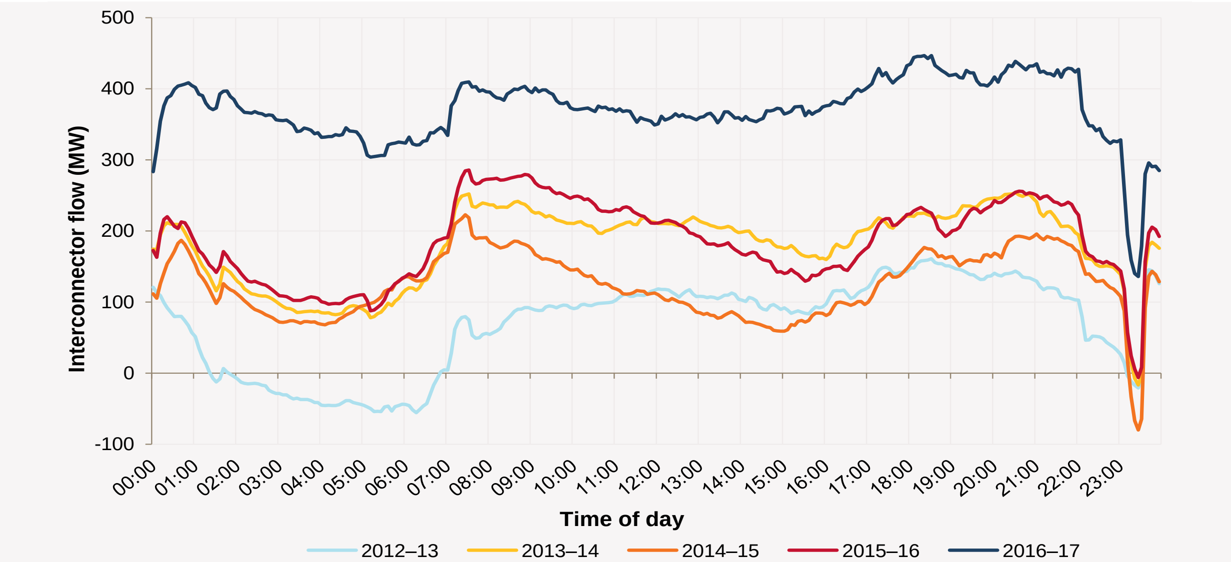
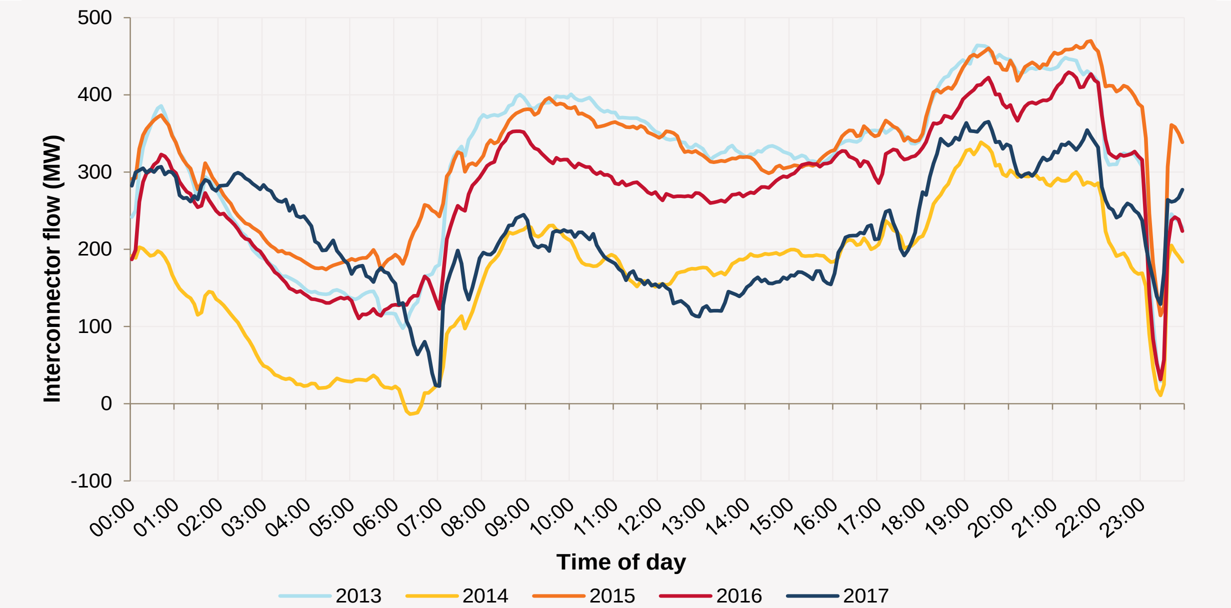


Figure 26 Combined interconnector winter daily 5-min average flow (workdays only)



5.3 Flow duration curves

Flow duration curves are a graphical representation of the percentage of time that electricity transferred via interconnectors (in MW) is at or above a given level over a defined period. Lines above the x-axis indicate imports from Victoria into South Australia. The area between the curves and the x-axis represents the amount of energy being transferred between these regions. Flow duration curves indicate interconnector utilisation.

Heywood and Murraylink currently have a nominal import capacity of 600 MW [28] and 220 MW respectively, and a combined nominal import capacity of 820 MW from August 2016. Under normal system operating conditions, combined export capability is 650 MW, due to electricity network stability constraints.[29] Under certain conditions, the interconnectors can exceed the maximum nominal import capacity for brief periods; this typically depends on the short-term equipment ratings.

Figure 27 and Figure 28 show flow duration curves for the Heywood and Murraylink interconnectors over the past five years. The stepped nature of the flow duration curves for Murraylink reflects its banded transfer constraints. The figures also illustrate the utilisation of the Heywood and Murraylink interconnector import capacity.

Table 9 quantifies the percentage of time, in each of the past five years, where each interconnector was being utilised at or above 100% of its nominal import capacity. Network constraints are one factor that can force interconnectors to be utilised below nominal import capacity. For more information about how constraints affect the actual capability of these interconnectors, see AEMO's *NEM Constraint Report*.[30]

Table 9 Percentage of year having full utilisation of nominal import capacity

Interconnector	2012–13	2013–14	2014–15	2015–16	2016–17
Heywood	3.7%	2.6%	3.0%	2.2%	3.0%
Murraylink	0.6%	0.2%	0.1%	1.7%	4.9%

[28] The final testing of the Heywood upgrade is yet to be completed. Once complete, its nominal import capacity will be 650 MW.
[29] ElectraNet. *South Australian Transmission Annual Planning Report*, May 2015. Available at: https://www.electranet.com.au/wp-content/uploads/report/2016/06/20160630-Report-SouthAustralianTransmissionAnnualPlanningReport.pdf. Viewed: 29 July 2015.
[30] AEMO. *NEM Constraint Report*, 2016.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 27 Heywood Interconnector flow duration curves

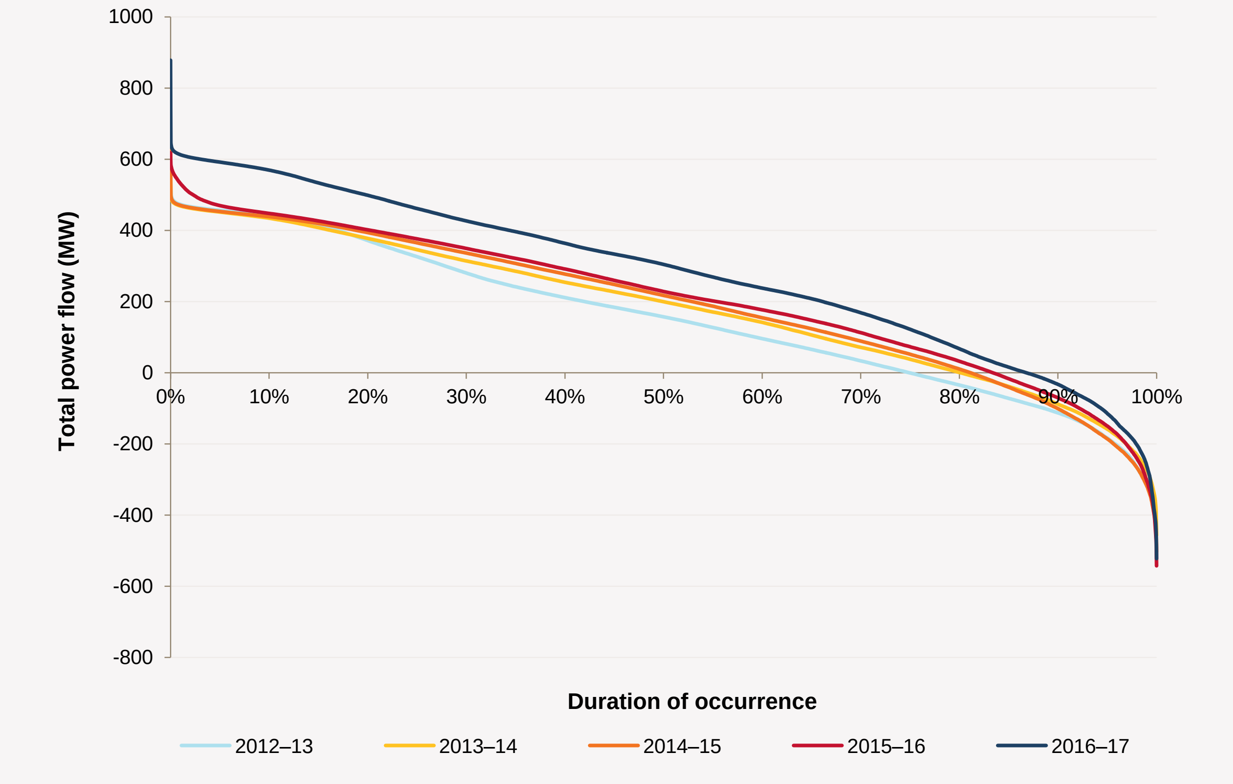


Figure 28 Murraylink Interconnector flow duration curves

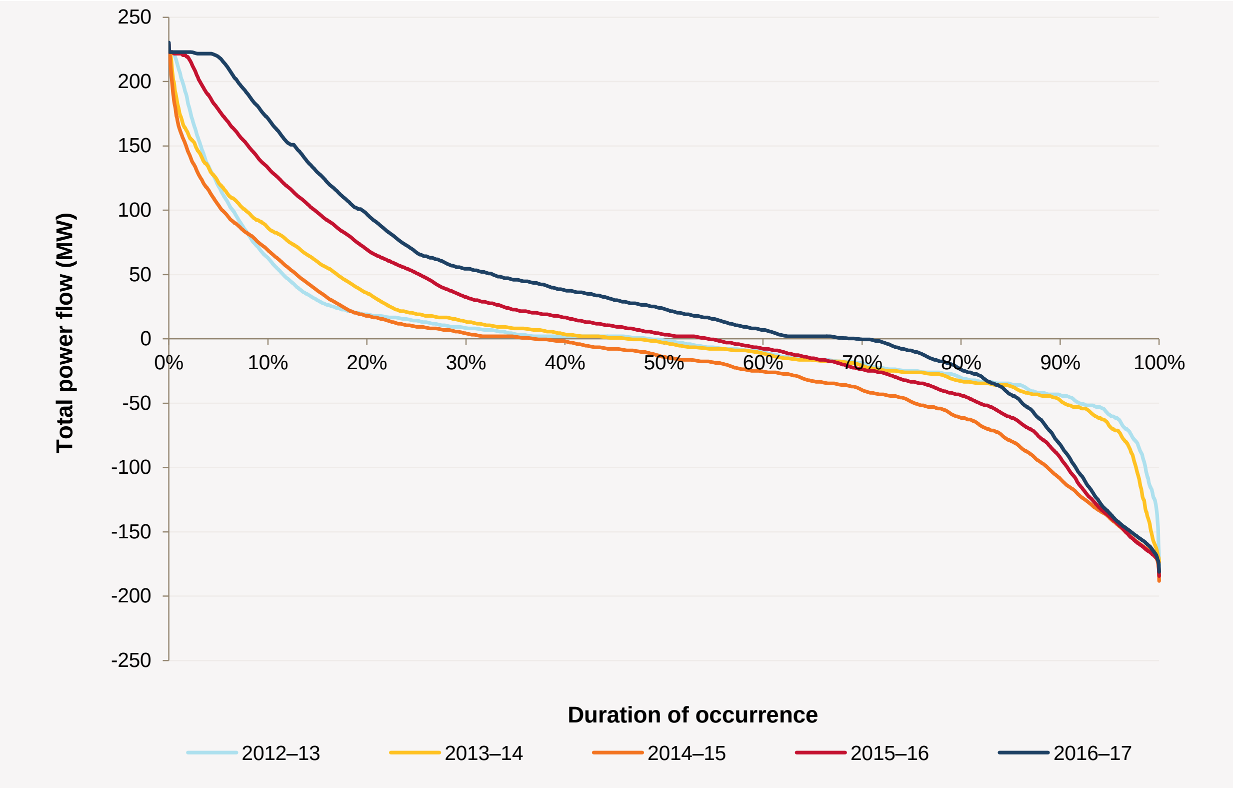


Figure 29 shows the combined Heywood and Murraylink electricity flows, and further demonstrates that South Australia increased its net import from Victoria compared to previous years, while net exports have decreased from 2015–16 to 2016–17.

Figure 30 shows interconnector utilisation as a percentage of total transfer capacity. This indicates that imports over the Heywood Interconnector are closer to its total capacity compared to Murraylink, which conversely shows better utilisation of its export capacity.

The different characteristics observed between Murraylink import and export trends are a product of the NEM's constrained optimisation, which includes the following pertinent factors:

- Network constraints, which can lower the observed utilisation.
- Location of generation, particularly South Australian wind farms.
- Transmission network electrical and geographical characteristics.
- Location of major load centres.
- Generator operating patterns.
- Transmission losses.

Figure 29 Combined interconnector flow duration curves

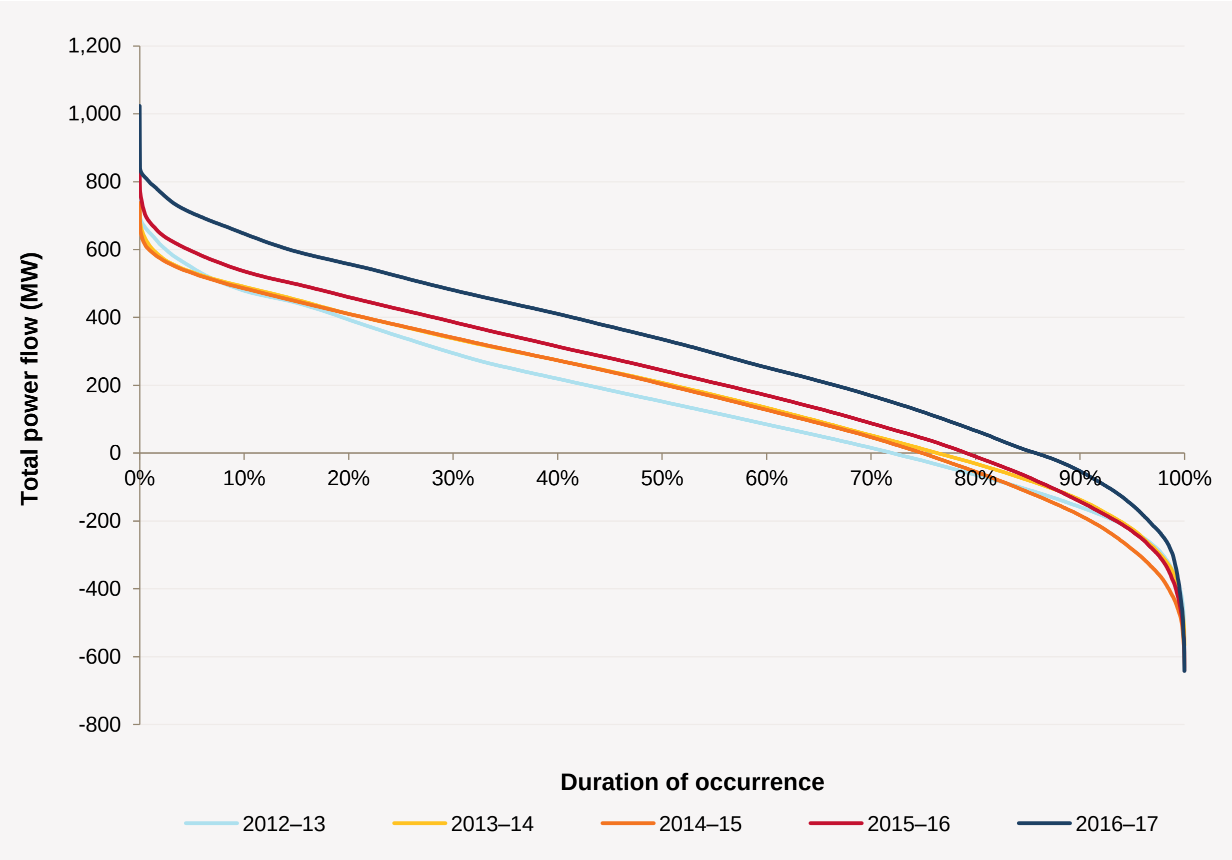
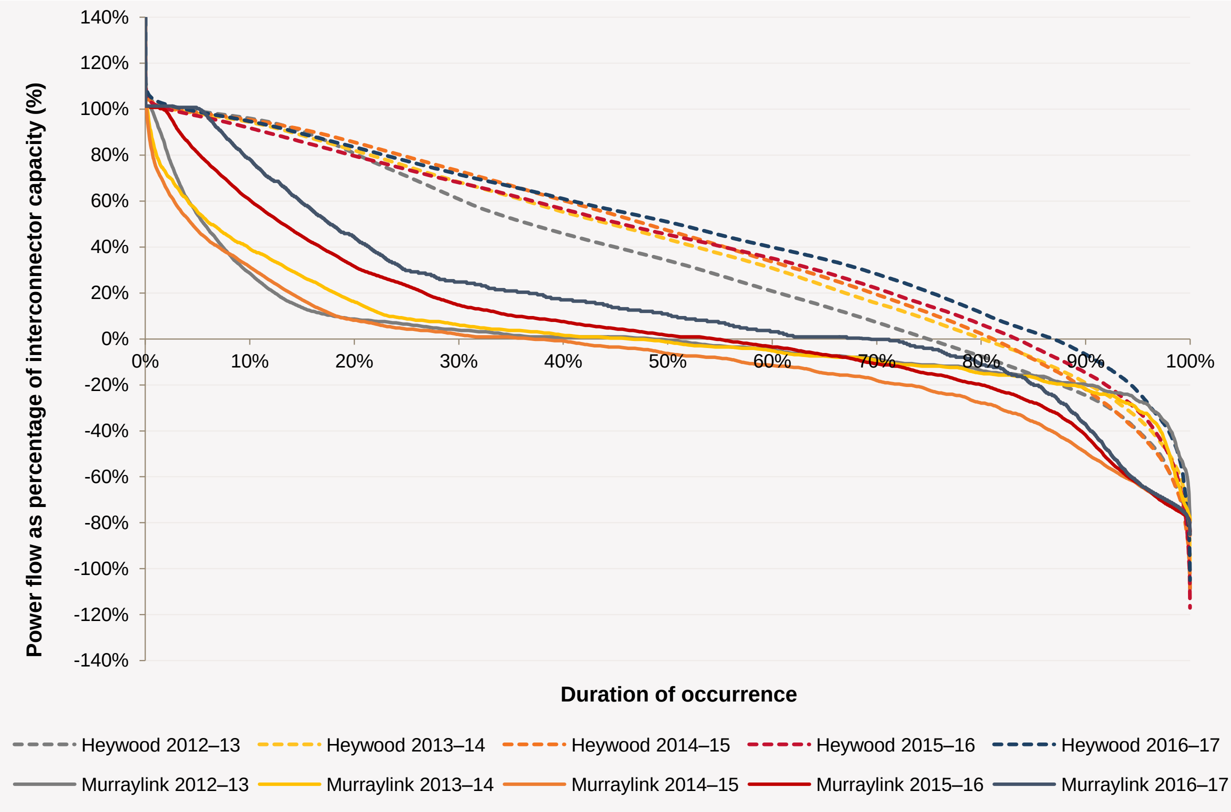


Figure 30 Interconnector flow as a percentage of interconnector nominal capacity



Heywood Interconnector upgrade

Maximum flows from Victoria into South Australia through the Heywood Interconnector have been higher since commissioning of the third Heywood transformer. The interconnector's nominal flow import capability was upgraded by 40 MW in December 2015, by 70 MW in February 2016, and by 30 MW in August 2016, to 600 MW. At the same time in December 2015, the nominal export capability was upgraded by 40 MW to 500 MW.

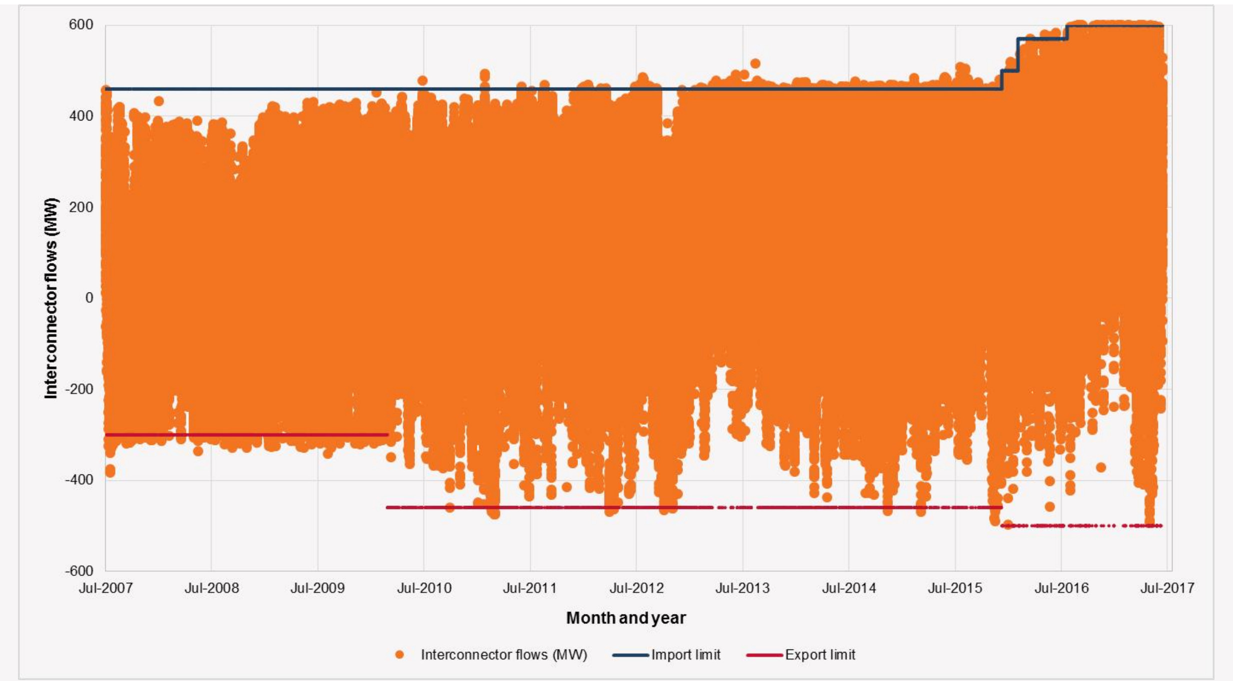
Figure 31 illustrates that the interconnector maximum flows into South Australia have increased since commissioning of the upgrade.[31]

An upgrade to the export capability occurred in 2010, from 300 MW to 460 MW, shown in Figure 31.

Continued upgrades are being undertaken on the import and export capability of the Heywood Interconnector, to increase to a total capacity of 650 MW. Certain market conditions are required for testing before the nominal limits can be increased.

[31] Note that flows are derived from 30-minute averages.

Figure 31 Heywood Interconnector flows and limits



6. ELECTRICITY PRICE ANALYSIS

6.1 Introduction

A number of supply and consumption factors influence the electricity spot price and its volatility over time.

Supply factors include:

- The available capacity of generating systems.
- The availability of wind generation and wind conditions.
- The availability of solar generation and degree of cloud cover.
- The costs of generation (for example, changes in fuel costs).
- Non-market generation, which includes rooftop PV and some embedded generation.
- Interconnector flows and network constraints and outages.
- Bidding behaviour of generation portfolios.

Consumption factors include:

- Temperature-dependent loads (heating and cooling).
- Consumer behaviour (for example, residential and commercial consumer response to higher prices reflected in increased energy efficiency savings).
- Large industrial loads (for example, manufacturing and mining consumption).
- Off-peak electricity hot water load switching.

Policy changes (for example, carbon pricing, the COP21 commitment[32], and the Renewable Energy Target) and individual company electricity and gas contracting positions can affect both supply and consumption.

6.2 Spot market price

6.2.1 Time-weighted average price

In 2016–17, the time-weighted average price (TWAP) was $108.92/MWh (megawatt hour), the highest since 2007–08, including the two carbon-price affected years (as seen in Table 10).

This has been attributed, in part, to:

- Reduced firm capacity. In particular, the closure of Northern Power Station changed the region's fuel mix, increasing dependence on higher cost GPG.
- High prices inter-regionally, due to tightening of supply in Victoria (following the retirement of Hazelwood Power Station in early 2017).
- Exposure of GPG to higher gas prices. Adelaide spot gas prices increased in the past year (from an average ex-ante price of $5.74/GJ (gigajoules) in 2015–16 to $8.83/GJ in 2016–17).

South Australian TWAPs increased 74% from 2015–16 to 2016–17, mainly due to the reduction in low-priced capacity including closure of Hazelwood Power Station, generators submitting comparatively higher-priced offers, and high gas prices.

[32] Australia's commitment to emissions reduction targets at the 21st Conference of Parties (COP21) held in Paris in 2015.

6.2.2 Volume-weighted average price

Volume-weighted average price (VWAP) takes into account the amount and price of electricity for a given interval, while TWAP does not take into account the different volumes of energy sold within the interval.

Table 10 compares the VWAP for South Australian renewable generation[33], thermal generation, and total market generation, on a financial year basis and each summer from 2006–07 to 2016–17. This is also displayed graphically in Appendix B.

The TWAP for each financial year is also shown for comparison.

Table 10 shows that South Australian thermal generation has a higher VWAP than renewable generation, with this difference increasing considerably in 2016–17.

VWAP values are based on 30-minute average generation volumes and the corresponding spot price (in real June 2017 dollars). A comparison of VWAPs using nominal values is available in Appendix D.

Summer VWAPs were typically higher than financial year VWAPs, due to the greater proportion of high demand days throughout summer. This difference was reasonably pronounced until 2010–11, after which summer and financial year VWAPs have converged as summer peaks have reduced, mainly due to increased rooftop PV and energy efficiency trends seen in air-conditioning. A noticeable upward shift in VWAPs occurred in 2012–13 and 2013–14, due to carbon pricing.

Table 10 South Australian spot price trends, in real June 2017 $/MWh, 2007–08 to 2016–17

	SA wind generation		SA thermal generation		Total SA market generation		SA spot price
	Financial year	Summer*	Financial year	Summer*	Financial year	Summer*	Financial year
	VWAP ($/MWh)	VWAP ($/MWh)	VWAP ($/MWh)	VWAP ($/MWh)	VWAP ($/MWh)	VWAP ($/MWh)	TWAP ($/MWh)
2007–08	77.10	109.25	115.74	187.35	112.18	180.37	89.41
2008–09	54.81	79.22	80.09	131.71	76.54	124.00	60.23
2009–10	54.47	94.16	94.79	170.83	87.81	158.63	63.92
2010–11	26.71	28.11	47.03	66.61	42.60	58.15	36.40
2011–12	28.97	26.57	34.92	30.95	33.28	29.74	33.02
2012–13	61.49	57.28	81.37	71.07	75.84	67.63	74.55
2013–14	56.38	57.48	77.24	90.66	69.99	80.65	64.36
2014–15	32.23	28.97	46.82	41.65	41.45	37.17	40.32
2015–16	49.05	45.30	76.33	66.35	66.05	59.46	62.73
2016–17	76.65	71.69	161.46	183.98	124.50	131.93	108.92

* Summer is defined as November to March inclusive for NEM reporting on the Australian mainland states.

Figure 32 shows the ratio of wind, coal, and GPG VWAP to TWAP by financial year. TWAP represents the average price a generator would have received if it generated at full capacity for the full financial year. This figure highlights that during times of high wind generation, spot prices are typically lower than average.

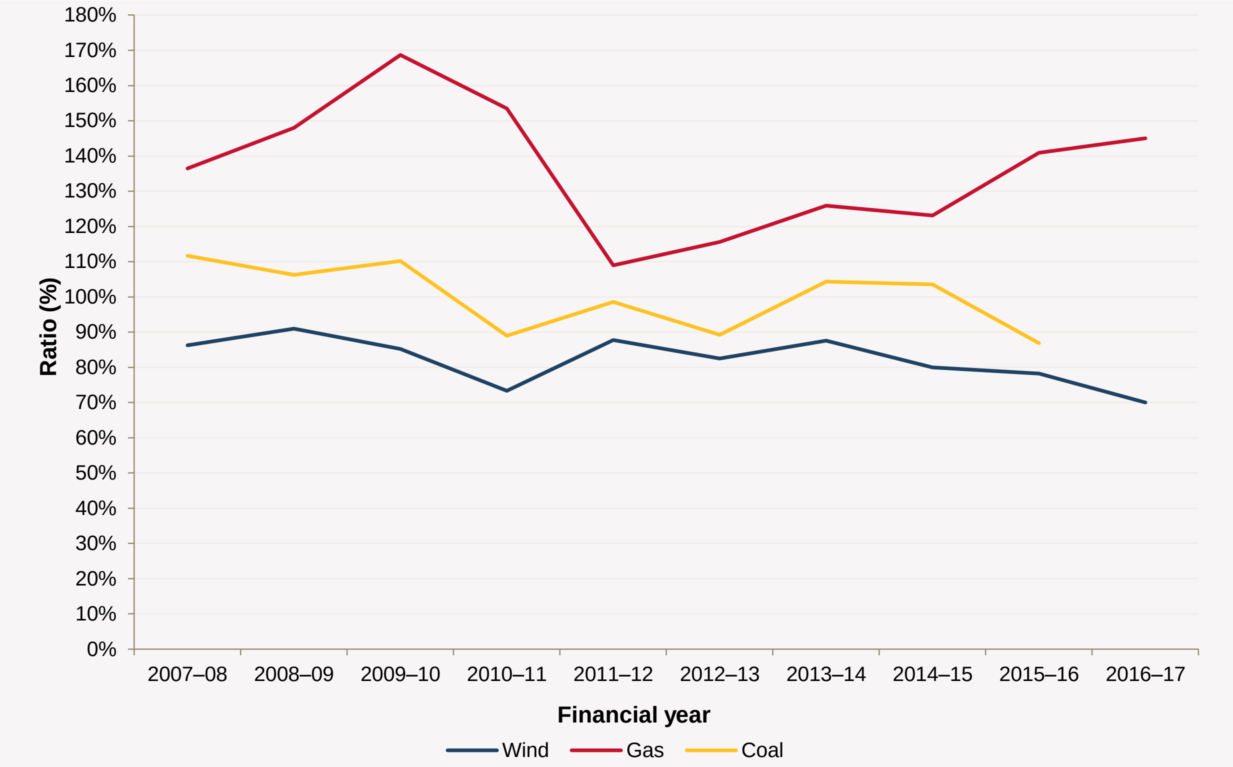
In 2016–17, the VWAP received by wind generators was 70% of the total TWAP. The average VWAP for gas was 145% of the TWAP.

The higher gas VWAP reflects the operating mode of these generators, typically during higher demand periods, or when supply availability is reduced. For more information on these trends for wind

[33] Renewable generation here comprises the semi-scheduled and non-scheduled wind farms listed in Appendix C.

generators, refer to the *South Australian Renewable Energy Report* (SARER), due to be published in October 2017.[34]

Figure 32 Ratio of VWAP by fuel to total TWAP



6.2.3 Spot price duration curves

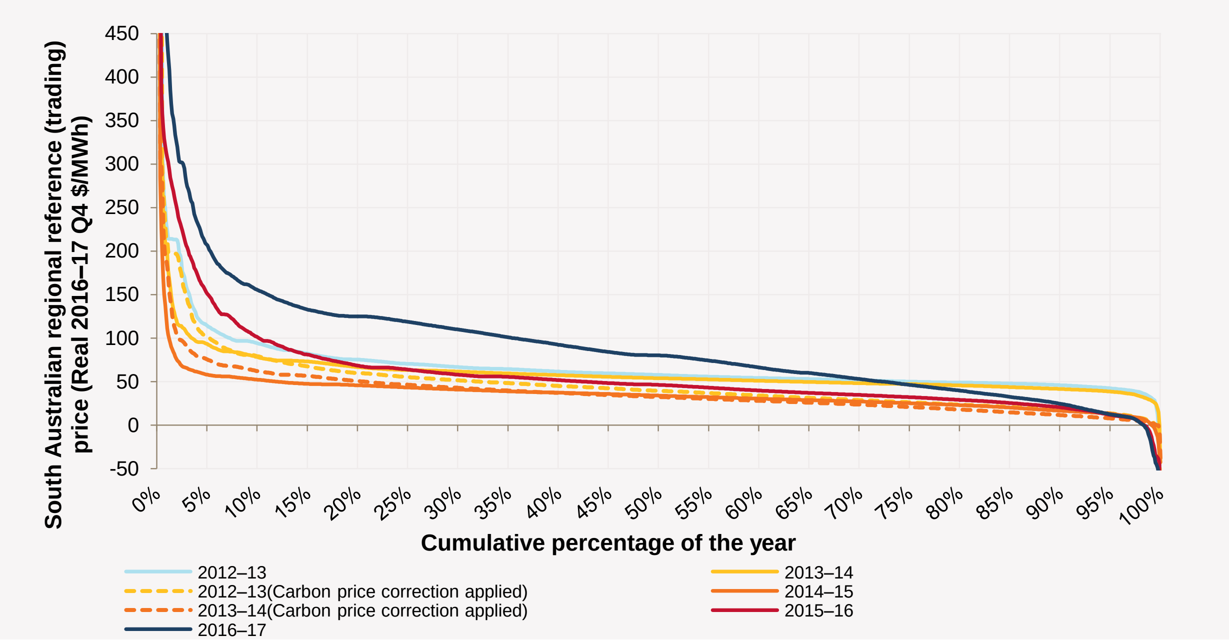
Spot price duration curves show how frequently a particular 30-minute spot price occurs or is exceeded over a given period. Spot prices have been CPI-adjusted, with June 2017 used as the reference price.

Figure 33 shows the spot price duration curves for 2012–13 to 2016–17. Analysis has been undertaken to estimate the electricity price had the carbon price not been imposed during 2012–13 and 2013–14, and this is represented by the dashed lines.

Figure 33 highlights that for about 70% of time, spot prices for 2016–17 were higher than the previous four years. Section 6.2.4 discusses reasons for 2016–17 price changes in more detail.

[34] AEMO. *South Australian Renewable Energy Report*, December 2016. Before 2016, wind generation information was published as the *South Australian Wind Study Report*. Available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/South-Australian-Advisory-Functions.

Figure 33 South Australian spot price duration curves



6.2.4 Price volatility

In 2016–17, there were more occurrences of both negative prices and prices above $100/MWh than observed in the previous five years, as well as a greater dispersion throughout multiple price bands. The following points outline significant changes over 2016–17:

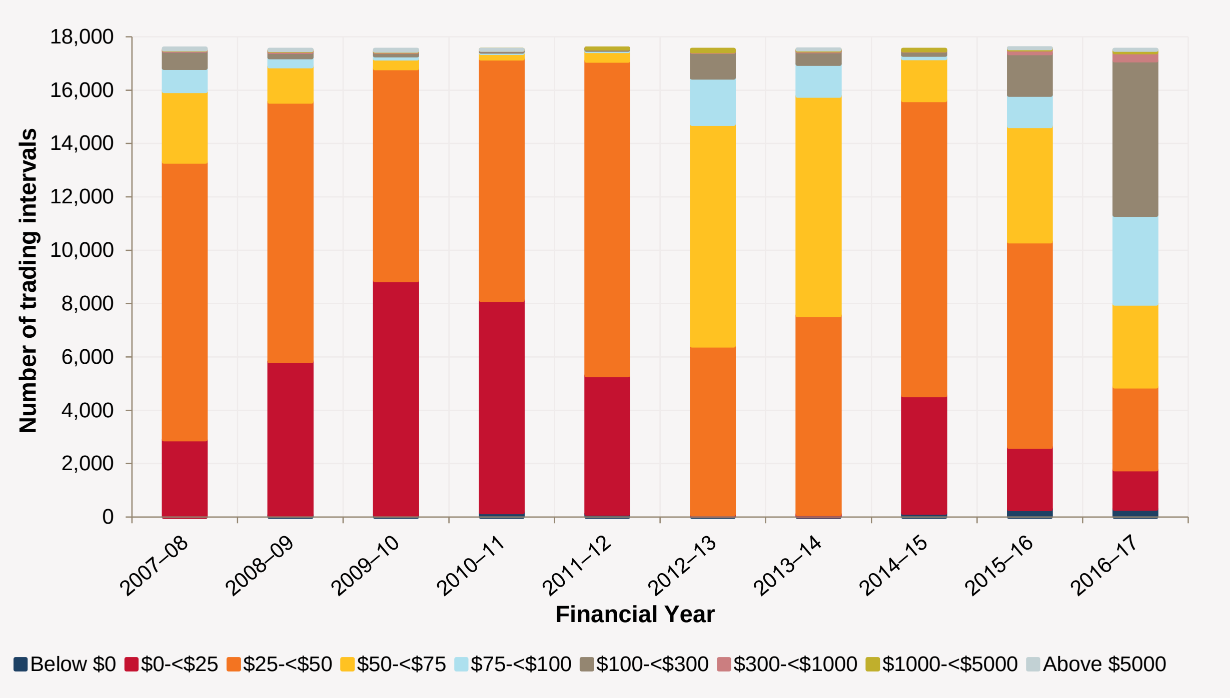
- Negative prices were observed 1.7% of the time, a similar level to 2015–16. This typically occurred when wind energy output was above average, most commonly overnight (coinciding with times of low demand) or during the middle of the day (coinciding with times of high rooftop PV), when dispatch of thermal plants was close to minimum stable levels. See Section 6.3 for further details.
- Prices exceeding $100/MWh were observed 33% of the time, a significant increase from 2015–16 (where prices exceeding $100/MWh were observed 9% of the time). These higher spot prices were driven by a variety of factors, including high demand (high temperature days or hot water load management), reduced baseload capacity due to generator retirements (Northern Power Station in early 2016), planned and unplanned generator outages, transmission outages impacting the Heywood Interconnector, higher gas spot prices, and low levels of wind generation.
- Reduction in occurrence of prices in the $0–25/MWh and the $25–50/MWh bands, with corresponding increases in the $75–100/MWh and $100–300/MWh bands.

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, summarised in Table 11 and Figure 34.

Table 11 Frequency of occurrence of spot prices for South Australia

Price Band	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15	2015–16	2016–17
Below $0/MWh	0.0%	0.4%	0.5%	1.0%	0.7%	0.2%	0.1%	0.9%	1.6%	1.7%
$0/MWh to <$25/MWh	16.5%	32.9%	50.2%	45.4%	29.5%	0.3%	0.5%	25.1%	13.3%	8.5%
$25/MWh to <$50/MWh	59.2%	55.6%	45.4%	51.6%	67.1%	36.1%	42.6%	63.1%	43.8%	17.7%
$50/MWh to <$75/MWh	15.0%	7.5%	2.0%	1.2%	2.0%	47.4%	46.9%	9.0%	24.6%	17.7%
$75/MWh to <$100/MWh	5.0%	2.0%	0.7%	0.3%	0.3%	9.9%	6.8%	0.7%	6.7%	19.0%
$100/MWh to <$300/MWh	3.6%	1.1%	0.7%	0.3%	0.2%	5.5%	2.7%	0.9%	8.9%	33.1%
$300/MWh to <$1000/MWh	0.2%	0.3%	0.1%	0.0%	0.0%	0.1%	0.2%	0.1%	0.8%	1.7%
$1000/MWh to <$5000/MWh	0.1%	0.1%	0.2%	0.0%	0.1%	0.4%	0.2%	0.2%	0.3%	0.5%
Above $5000/MWh	0.3%	0.2%	0.3%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%

Figure 34 Frequency of occurrence of spot prices for South Australia



6.2.5 Impact of changes in generation mix

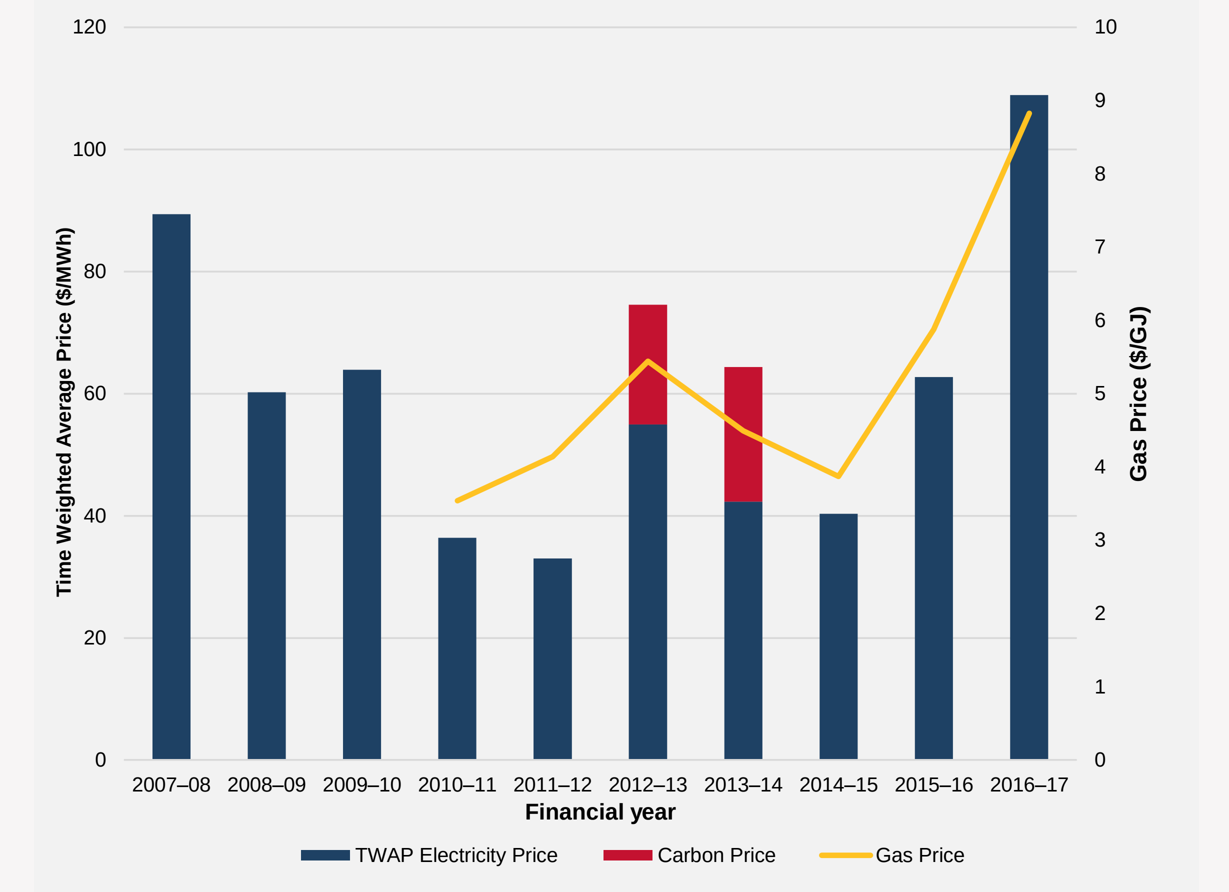
South Australian energy and price trends

Historical average electricity and gas price trends are shown in Figure 35. The analysis includes:

- Average annual electricity prices, with an adjustment made to consider the estimated price with the carbon price removed during 2012–13 and 2013–14.
- Average annual gas prices. Ex-ante prices have been used for the Short Term Trading Market (STTM) Adelaide hub which began operation on 1 September 2010.

Figure 35 shows that both electricity and gas prices have fluctuated each year, following a similar trend to each other. This suggests the average annual spot market prices are strongly influenced by gas prices, due to South Australia’s high reliance on GPG. Annual TWAP variation has considerably increased between 2015–16 and 2016–17.

Figure 35 South Australian price trends



Gas spot price impact on electricity spot prices

Across the NEM, GPG set the electricity spot price more frequently in 2016–17 than in 2015–16. Higher NEM prices and substantial baseload generation unavailability (including the closure of Hazelwood Power Station in Victoria at the end of March 2017) saw a large increase in GPG demand. Prices were higher across all wholesale gas markets for 2016–17, compared to the same period a year earlier, which coincided with tighter supply and demand in the east coast gas market.

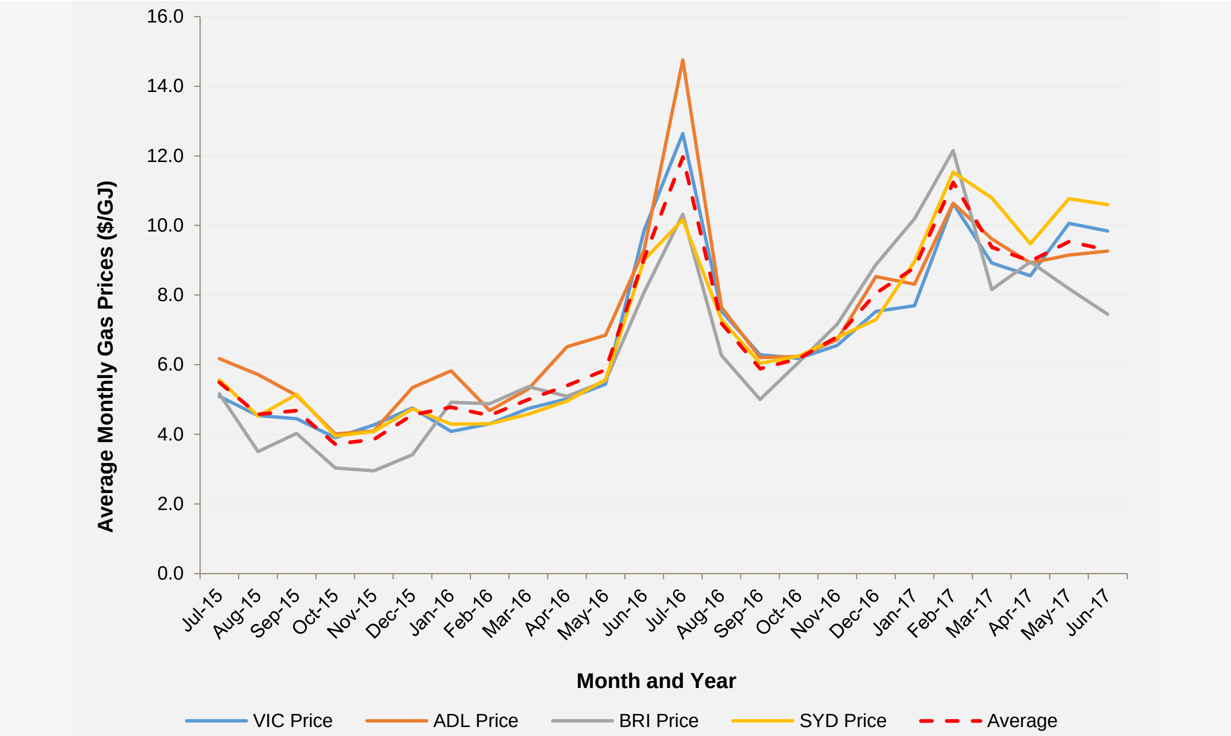
Between September and December 2016, gas prices increased due to tight supply with outages at Longford gas plant. Hot weather during summer 2016–17 resulted in very high electricity demand and high NEM spot prices. This resulted in high operations in the NEM regions which saw gas prices spike across all markets in February 2017.

The reduction in demand towards the end of March 2017, and consequent increase in availability of gas supply due to one liquefied natural gas (LNG) train outage, saw a decrease in gas prices across all gas markets. While prices on average have been higher across all markets, June 2017 lacked the price volatility seen in June 2016.

Average gas spot prices have increased in the past two years across all jurisdictions (for Adelaide, the price grew from an average of $5.74/GJ in 2015–16 to $8.83/GJ in 2016–17). A spot price increase raises generation costs in cases where gas supplies are not fully contracted, and ultimately influences electricity prices as discussed above.

The dynamics of Queensland’s LNG facilities have linked domestic wholesale gas prices to international markets, resulting in increased gas prices for domestic gas supplies across the NEM. Figure 36 shows average monthly ex-ante gas prices across AEMO gas jurisdictions from July 2015 onwards.

Figure 36 Monthly average of wholesale gas market prices from July 2015 to June 2017

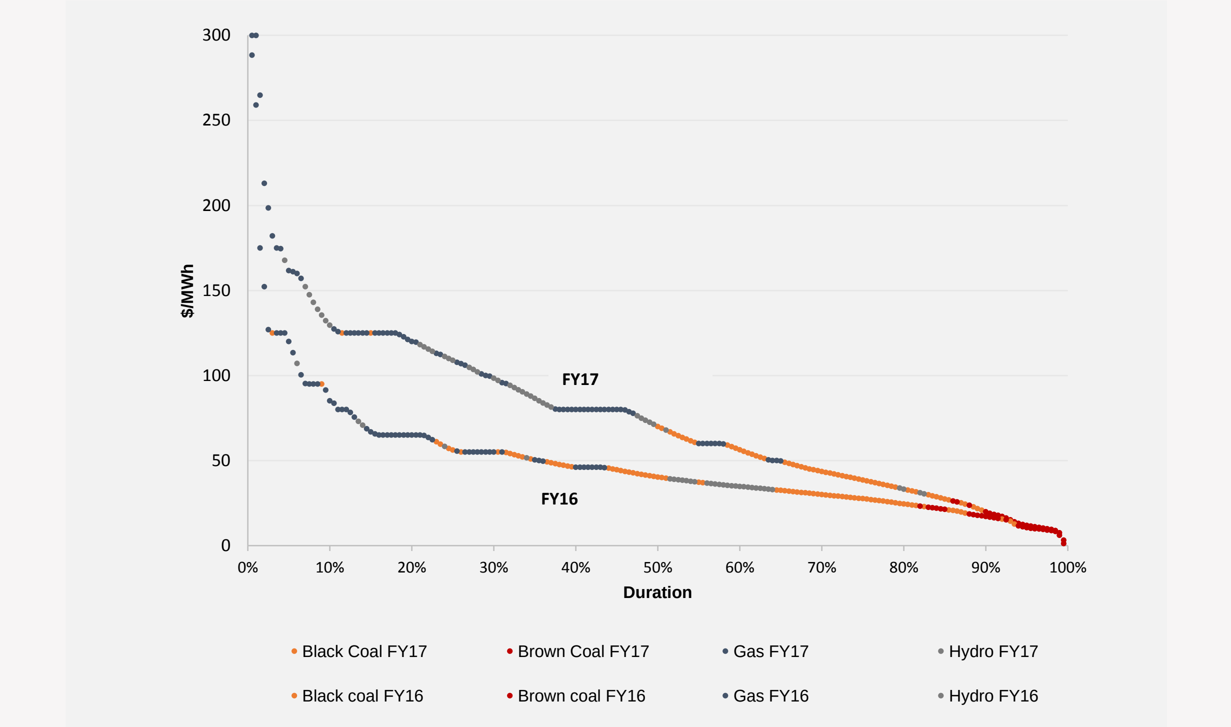


Note: STTM (Adelaide, Brisbane and Sydney) prices are ex-ante. DWGM (Victoria) prices are for the 6.00am daily interval.

The increasing influence of GPG setting the electricity spot price in South Australia can be seen in Figure 37. This shows the fuel responsible for setting the price, and compares 2015–16 and 2016–17, and highlights:

- The closure of Hazelwood and Northern Power Stations led to a decline in coal-fired generator’s price-setting role.
- In 2016–17, gas set the price more often than in 2015–16 at 36% (+5%).
- The time in which hydro generation from neighbouring NEM regions was the marginal fuel type for South Australia increased from 14% to 20% from 2015–16 to 2015–17.
- That tightening electricity supply led to a strong shift upwards in the cost curve, in particular at the upper end of the curve (0–50%).

Figure 37 South Australia price duration curve by setting fuel price



Spot prices and wind generation

Market prices are not typically set by wind generators, except during periods of low demand, since:

- Wind generators have no fuel cost, and have additional revenue from participation in the Large-scale Renewable Energy Target (LRET) scheme. The creation of Large Scale Generation Certificates (LGCs) provides an incentive for wind generation to bid near the negative LGC price.
- Average wind generation is slightly higher overnight when demand is low, corresponding to periods when baseload thermal generation typically bid low to remain scheduled on.[35]
- Wind generators depend on wind availability. Wind farms are limited to bidding at times when wind is available, and cannot increase generation in response to high market prices.

However, the volume of wind generation does have some influence on spot prices. Figure 38 shows spot prices for the South Australian region and the corresponding average wind generation levels for each 30-minute dispatch interval for 2016–17. Spot prices are plotted on a logarithmic axis to better represent the variance; it is split between the positive (upper graph) and negative (lower graph) prices.

The 2016–17 VWAP (in nominal dollars) for South Australian wind generation over the 12-month period is also displayed (as a horizontal line), for reference against the positive prices ($76.46/MWh as in Table 18). The VWAP was 59% higher in 2016–17 than 2015–16 (from $48.23 /MWh to $76.46/MWh).

Figure 38 shows that 85% of prices above $1,000/MWh occurred when wind generation was lower than 400 MW, while 92% of the negative price occurred when wind generation was greater than 900 MW.

The 2016–17 negative LGC spot price band, -$76.15/MWh to -$89.50/MWh[36], is highlighted in grey. Wind farms are able to receive one LGC for every MWh generated. It should be noted that wind farms that have forward contracted the delivery of LGCs through an off-take agreement are likely receiving a price per LGC that would result in a lower negative price band. This provides an incentive for wind

[35] For further detail on typical wind generation, please see the AEMO 2015 *South Australia Wind Study Report*. Available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/South-Australian-Advisory-Functions.

[36] LGC price band from Green Markets Energy correspondence, 15 August 2017.

generators to continue operating during negative price events, provided the electricity spot price does not fall below the negative of the LGC price band. Further historical information on spot prices and wind generation in South Australia will be published in 2017 SARER.[37]

Figure 38 South Australian 30-minute spot prices and average wind generation for 2016–17

Logarithmic axis

[37] To be available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/South-Australian-Advisory-Functions.

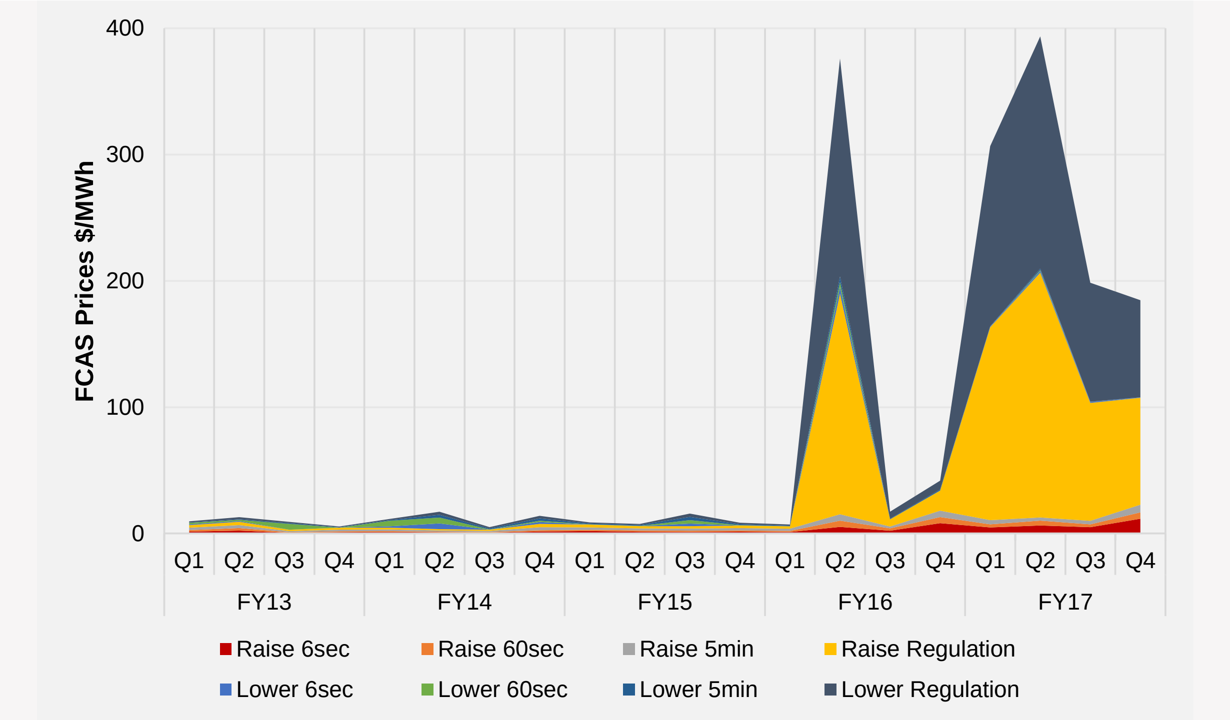
6.3 Frequency control ancillary services (FCAS) market price

6.3.1 FCAS price trend

In the NEM, generation and demand are balanced through the central dispatch process for both energy and frequency control ancillary services (FCAS). FCAS is a market mechanism that uses generation or load to correct the imbalances between supply and demand.[38]

During 2016−17, South Australian (and NEM-wide) FCAS prices increased substantially in the regulation services (averaging about $125/MWh in each service, representing a 74-fold increase on historical levels) and to a lesser extent in the contingency raise services (Figure 39).

Figure 39 Quarterly average South Australian FCAS prices by service



Historically, FCAS prices across all services have typically been very low (about $1–2/MWh for each service). This pricing dynamic changed in 2015−16 and 2016−17, influenced by two key factors[39]:

- The pre-emptive procurement of 35 MW of regulation FCAS in South Australia at times when the separation of the region at the Heywood Interconnector is a credible contingency. During these times of local requirements, FCAS prices have been very high, due to the limited number of suppliers of these services in the region.
- Generators offering these services to the NEM have reduced their quantity of low-priced bids in regulation and contingency raise services.[40] For example, in Q2 2017, meeting the NEM-wide

[38] Regulation FCAS is enabled to continually correct the generation/demand balance in response to minor deviations in load or generation. 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 eight types of FCAS: six types of contingency FCAS, and two types of regulation FCAS, to raise or lower frequency at different speeds. For more details see: AEMO. *Guide to ancillary services in the National Electricity Market*. Available at: www.aemo.com.au/-/media/Files/PDF/Guide-to-Ancillary-Services-in-the-National-Electricity-Market.ashx.

[39] AEMO's FCAS requirements have remained broadly flat over the past two years, so this has not materially contributed to the cost increases.

[40] FCAS is generally procured NEM-wide rather than in particular regions.

average raise regulation requirement[41] (135 MW) cost around $25/MWh, up from around $4/MWh in Q2 2017. Higher FCAS prices led to record FCAS costs in South Australia in 2016−17 of $34 million, 81% higher than the next highest year (2015−16).

The largest cost increases occurred in the regulation FCAS services, increasing by $18.6 million (+160%). Contingency FCAS costs in South Australia were relatively flat.

6.4 Pricing events

AEMO monitors and reports on “significant pricing events” in the NEM.[42] 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.
- FCAS half-hourly averaged prices, for any FCAS service, exceeds $300/MWh.[43]

6.4.1 Summary of pricing events in 2016–17

Table 12 summarises the number of pricing events and affected hours in South Australia during 2016–17. There were 76 pricing events reported, including events where both the energy spot price and the sum of FCAS price reporting thresholds were exceeded.[44] In some cases, the reporting threshold was exceeded for several consecutive days, while other events only exceeded the threshold for a single trading interval.

Table 12 Summary of AEMO’s published pricing events for South Australia

	Reporting criteria		
	Spot price > $2000/MWh	**Spot price < -$100/MWh**	**FCAS price > $300/MWh**
Number of reported events 2015–16	38	7	15
Number of reported events 2016–17**	35	12	54

* Some of these spot price and FCAS price events occurred at the same time and are counted as a single reported event in the total number of reported events noted above.
** The change in thresholds occurred in December 2016.

Pricing events can be attributed to a number of factors. The major factors that have influenced South Australian price events are listed below:

- **Network outages:** Planned and unplanned network outages reduce the transfer capability across transmission lines, including the interconnectors. Network outages related to interconnectors can reduce the amount of FCAS support available from adjoining states, as well as constraining energy transfer capability.
- **Generator outages**: Planned and unplanned generator outages reduce the amount of available generation capacity, thereby steepening the supply curve.
- **Low wind generation**: Wind generators generally submit offers at the bottom of the price merit order. Low wind generation can lead to high prices, as higher-priced generation is dispatched to meet demand.
- **Changes in generation offers**: Scheduled and semi-scheduled generators may adjust their commercial offers for diverse reasons, including changing market conditions or on the basis of the physical or technical capabilities of their plant (technical parameters).

[41] Raise regulation requirement is one of the FCAS requirements determined by AEMO to maintain the power system security. The NEM-wide raise regulation requirement is the amount of raise regulation FCAS service required, which can be sourced from any region within the NEM.
[42] Significant price event reports are published on the AEMO website: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Market-notices-and-events/Pricing-event-reports.
[43] In Tasmania, the FCAS threshold is $3,000/MWh.
[44] A single price event report can include a combination of spot price and FCAS events as well as a combination of high and low spot price events.

- **High regional demand:** Higher bid-priced generation needs to be dispatched during periods of high demand.
- **Changes in hot water load**: In South Australia, an off-peak electricity tariff is available to certain classes of devices, including electric hot water systems and slab heating. These devices are designed to take advantage of the lowest price and demand period of the day, traditionally between 11.30 pm and 7.30 am. Approximately 300,000[45] hot water systems are set to switch on at 11.30 pm, when the off-peak tariff starts.

6.4.2 Frequency of negative pricing events

Figure 40 shows the count of negative South Australian market prices from 2007–08 to 2016–17, with the colours indicating the frequency of different price band occurrences.

There were 298 negative priced 30-minute trading intervals during 2016–17, higher than the previous five years. 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. Due to additional revenue that wind farms can gain from LGCs, it is not unusual for wind to continue operating during negative pricing events, provided the LGC revenue exceeds the price they pay to continue generating. Negative prices lower than -$100/MWh occurred on eight trading intervals during 2016–17.

Figure 40 Count of negative price trading intervals per year

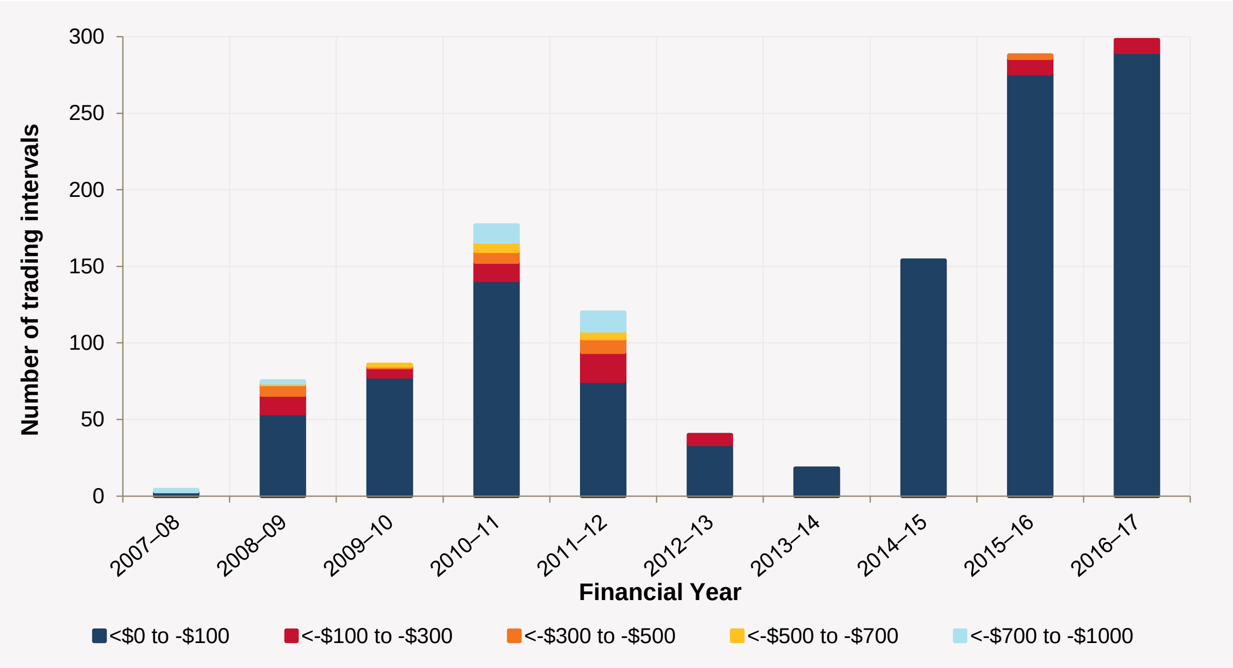
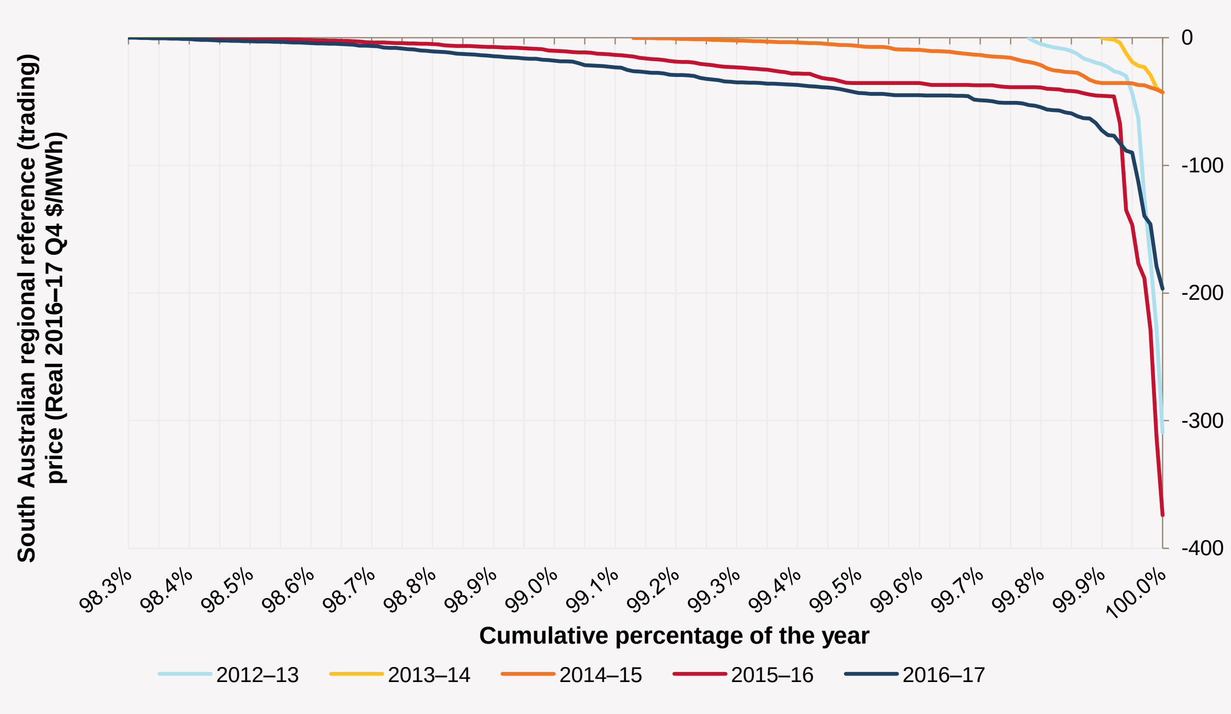


Figure 41 shows the price duration curves for negative price events, it also indicates the increased frequency of negative price events in 2016–17, compared to the previous four years.

[45] SA Power Networks. Flexible load strategy, October 2014, Section 3.4. Available at: https://www.aer.gov.au/system/files/SAPN%20-%2020.34%20PUBLIC%20-%20SAPN%20Flexible%20Load%20Strategy.pdf.

Figure 41 South Australian spot price duration curves, negative values only

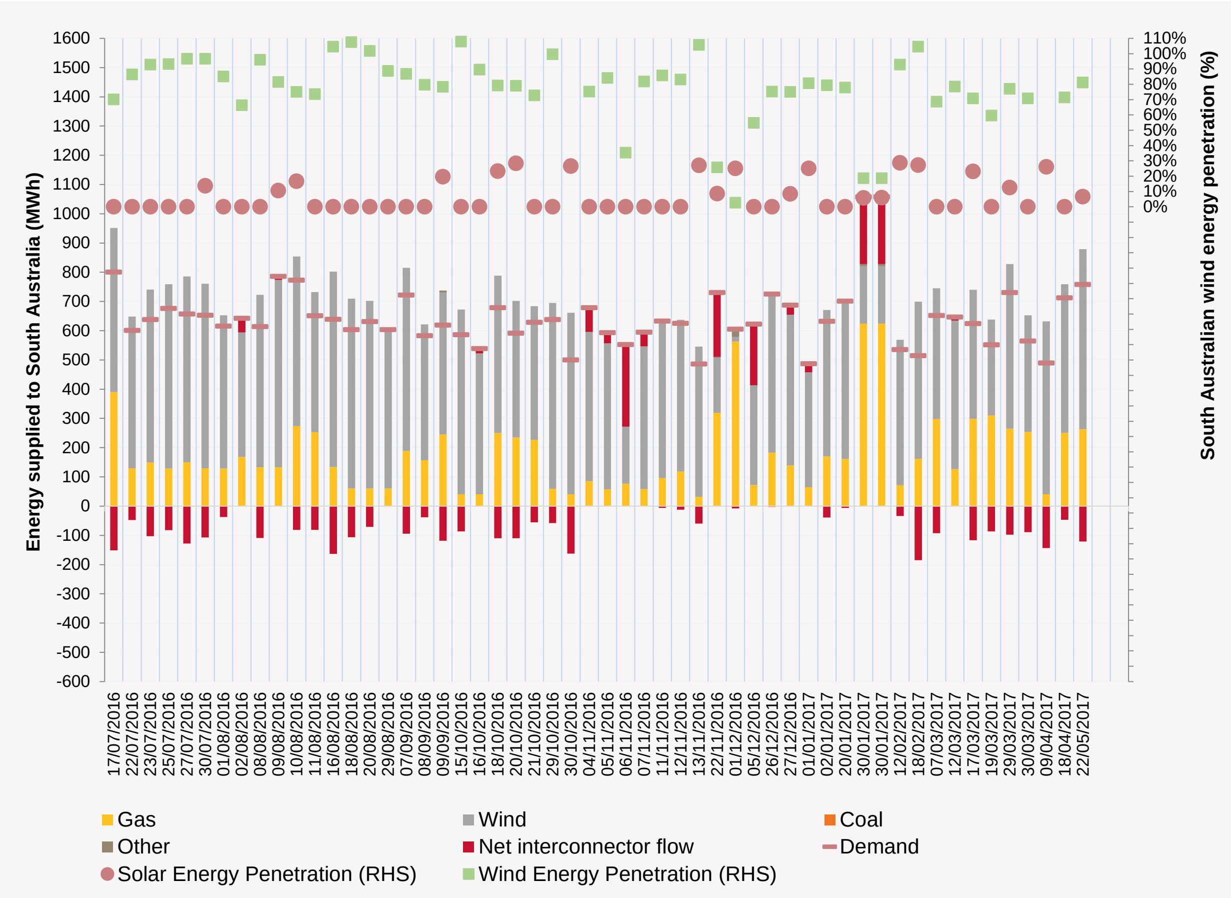


6.4.3 Generation mix during negative spot price intervals

Figure 42 provides details on the mix and magnitude of South Australian generation and net interconnector import during 30-minute periods that had negative prices. As all 298 negatively priced trading intervals occurred across 54 days, only the most extreme negative price is shown for each day.

In 2016–17, most negative prices occurred during times when wind energy penetration was above the typical average, and often when South Australia was net exporting electricity to Victoria and operational demand was low. Rooftop PV additionally reduced demand during a number of the negative price periods.

Figure 42 Supply summary at selected times of negative South Australian spot price during 2016–17



Wind energy penetration (%) refers to the fraction of wind generation to operational demand, while solar energy penetration (%) refers to the fraction of solar energy generation to underlying demand.

7. ELECTRICAL ENERGY REQUIREMENTS

This chapter reports the historical underlying energy breakdown for South Australia from 2007–08 to 2016–17, showing different sources of energy production on the one side and different consumption of that energy on the other side.

Underlying energy here refers to what is needed in total by electricity grid-connected consumers, and is supplied from, not only operational generators and the interconnectors (as discussed in Appendix A), but also SNSG and rooftop PV (with both of these contributions being estimates).

With reference to Table 13 below:

- The "South Australian generation" and "NEM balancing" sections present actual generation and interconnector flows for South Australia, as calculated in Chapters 3 and 5 respectively.
- Data in the "South Australian consumption" section is sourced from the 2017 NEM ESOO forecasts.[46]
- Most data is aggregated from, or further derived from analysis of, high resolution average Supervisory Control and Data Acquisition (SCADA) data. The exception is ONSG data, which is revenue metered data sourced from the MSATS system.[47]
- The "Balancing residual" column seeks to compare total South Australian generation plus imports with total South Australian consumption plus exports.
  - Ideally, the value would always equal zero, but data quality in some metering, accumulated rounding, and necessary estimations used in calculations of some quantities mean this is not always the case.
  - One identified anomaly is the comparatively larger NEM balancing residuals in 2007–08. This is due to lower quality SCADA readings from non-scheduled wind farms captured at that time.

[46] AEMO. *Electricity Statement of Opportunities*, August 2017. Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities.

[47] Refer to Appendix G of the 2016 *National Electricity Forecasting Report Forecasting Methodology Information Paper*. Available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Electricity-Forecasting-Report.

Table 13 Annual electrical energy requirement breakdown (GWh)

	SA generation						NEM balancing			SA consumption							
	Wind (SS/NS)	SNSG	PVNSG	Rooftop PV	Scheduled (S)*	Total generation	Imports Vic-SA	Balancing residual	Exports SA-Vic	Total Electricity Requirement	Auxiliary energy use	Total electricity requirement excl. auxiliary	Transmission network losses	Distribution network losses	Residential + Business Consumption	SNSG	Rooftop PV
Historical output																	
2007–08	1,316	92	-	6	12,981	14,394	676	26	-683	14,362	840	13,522	247	764	12,418	92	6
2008–09	2,008	87	-	13	12,275	14,383	828	1	-622	14,589	807	13,782	296	779	12,620	87	13
2009–10	2,388	87	-	30	11,403	13,907	1,088	-2	-485	14,512	780	13,733	313	706	12,626	87	30
2010–11	3,039	84	-	79	10,914	14,116	1,127	2	-584	14,657	769	13,888	311	699	12,794	84	79
2011–12	3,563	80	-	286	9,392	13,322	1,495	1	-401	14,415	681	13,734	310	650	12,693	80	286
2012–13	3,475	79	-	482	9,031	13,066	1,710	-3	-333	14,446	567	13,879	312	639	12,849	79	482
2013–14	4,088	82	-	672	7,665	12,507	1,925	-2	- 288	14,146	520	13,626	335	699	12,510	82	672
2014–15	4,223	99	6	820	7,247	12,388	1,904	2	-376	13,914	528	13,386	357	651	12,279	99	820
2015–16	4,322	105	10	908	7,147	12,482	2,227	-1	-286	14,424	445	13,979	380	798	12,696	105	908
2016–17	4,343	95	17	1,016	5,623	11,078	2,889	3	-164	13,800	204	13,596	409	788	12,304	95	1,016

The following should be noted when interpreting this table:

- AER data was used for transmission and distribution losses in the 2017 NEM ESOO forecast.
- Wind generation includes generation that occurred during commissioning of the site.
- SS stands for Semi-scheduled, NS for Non-scheduled, S for Scheduled, and SNSG for Small non-scheduled including PVNSG and ONSG.
- SNSG, on both sides of the table is, materially different to the 2016 SAHMIR results, due to a revision of SNSG plants used and AEMO's introduction of the PVNSG category for its 2017 *Electricity Forecasting Insights*.
- Following an improvement in the estimation for actual PV panel generation during the production of the 2017 *Electricity Forecasting Insights,* rooftop PV generation data has changed from what was previously reported in the 2016 SAAF reports.
- Scheduled generation includes Angaston power station, including periods when it was registered as non-scheduled.

APPENDIX A. GENERATION INCLUDED IN REPORTING

Table 14 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 operational[48] generation, consumption, and demand analysis in this report. SNSG and embedded generation are discussed in Appendix B.

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 14 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
Osborne	OSB-AG	Gas	180	180
Pelican Point	PPCCGT	Gas	478	478
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
Torrens Island B	TORRB1, TORRB2, TORRB3, TORRB4	Gas	800	800

[48] 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 SNSG 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)
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
Hornsdale Stage 1 Wind Farm	HDWF1	Wind	102.4	102.4
Hornsdale Stage 2 Wind Farm	HDWF2	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	131	131
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.

APPENDIX B. SMALL NON-SCHEDULED AND EMBEDDED GENERATORS

B.1 Small non-scheduled generators

Table 15 and Table 16 presents the ONSG and PVNSG included in this year's reporting, as in AEMO's 2017 *Electricity Forecasting Insights*.

Table 15 South Australian other small non-scheduled generating systems for 2017

Generating system	Generation type	Fuel type	Capacity (MW)
Blue Lake Milling Power Plant	Compression reciprocating engine	Diesel	1
Coopers Brewery Cogeneration	Thermal co-gen	Natural gas	4.4
KCA Millicent	Thermal co-gen	Natural gas	21
SA Water Bolivar Waste Water Treatment Plant	Waste water	Sewage gas	9.9
SA Water Seacliff Park Mini Hydro	Hydro – gravity	Water	1.155
Tatiara Bordertown Plant	Compression reciprocating engine	Diesel	0.5
Terminal Storage Mini Hydro Power Station	Hydro – gravity	Water	2.5
Vibe Energy Bordertown Power Station	Compression reciprocating engine	Diesel	4
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

Table 16 South Australian small rooftop PV non-scheduled generating systems for 2017

Name of project	Capacity (MW)
Adelaide Zoo Solar System	0.15
Bianco Construction Supplies Solar System	0.20
Bianco Precast Solar System	0.20
KJM Contractors Solar	0.50
Living Choice Fullarton Solar	0.20
Redmud Green Energy 1	0.19
Redmud Green Energy 2	0.19
Redmud Green Energy 3	0.19
Redmud Green Energy 4	0.60
Redmud Green Energy 5	0.21
Renmark Self Storage	0.18
S.G.U. Deemed Solar	4.38

B.2 Embedded generators

In 2016, AEMO engaged ORC International to survey selected local government, educational, medical, industrial, and business entities, to provide the South Australian Government with a sample of generators across the state which are either off-grid or embedded within the electricity distribution networks. In total, 132 entities were surveyed.

This was not an exhaustive survey, nor does it necessarily represent a complete picture of particular sectors or geographical regions. Information is based on information volunteered by survey participants.

Table 17 summarises the generation capacity by fuel type, with full details available in a separate data file on AEMO's website.[49]

Table 17 Summary of other South Australian generating systems

Primary fuel source	Aggregate generating capacity in kilowatts (kW)
Diesel / fuel oil	7,104
Gas	480
Solar	6,704
Wind	4
Total	14,292

[49] AEMO. *2016 SAHMIR Data File – Embedded Generators Survey worksheet*. Available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/South-Australian-Advisory-Functions.

APPENDIX C. VOLUME-WEIGHTED AVERAGE PRICE COMPARISON

Figure 43 and Figure 44 illustrate the values shown in Table 10 in Section 6.2.2, of VWAP trends for renewable, thermal, and total market generation.

Renewable generation comprises the semi-scheduled and non-scheduled wind farms, while thermal generation refers to all scheduled, semi-scheduled, and non-scheduled generators as detailed in Appendix A. VWAPs have been adjusted to real June 2017 values.

Figure 43 Comparison of financial year volume-weighted average prices

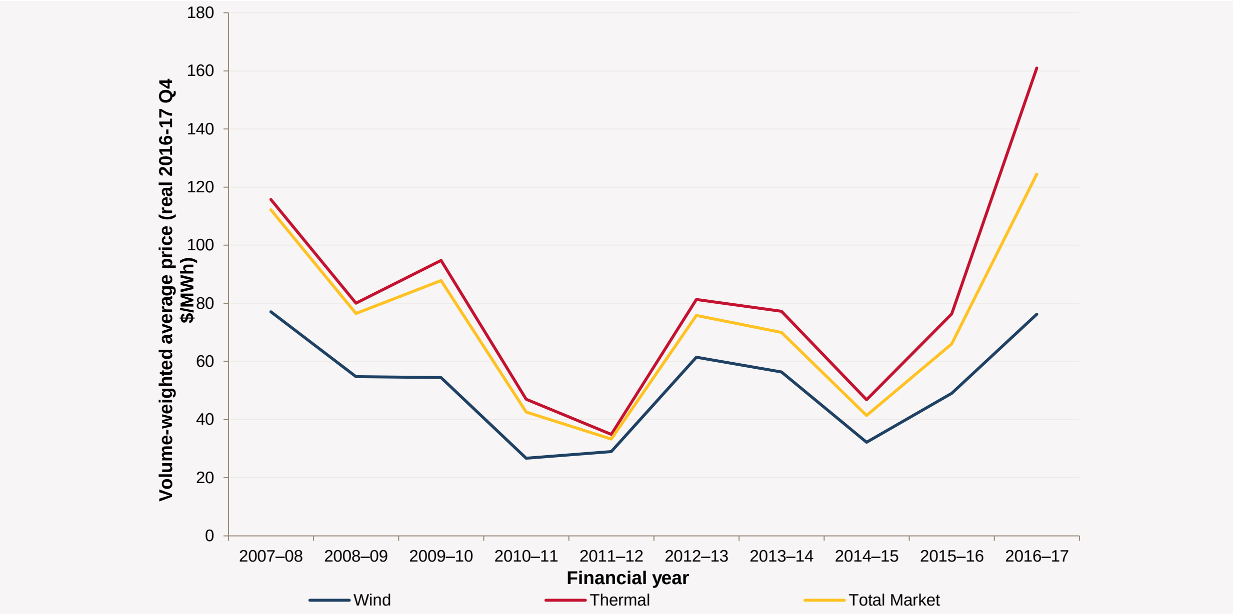
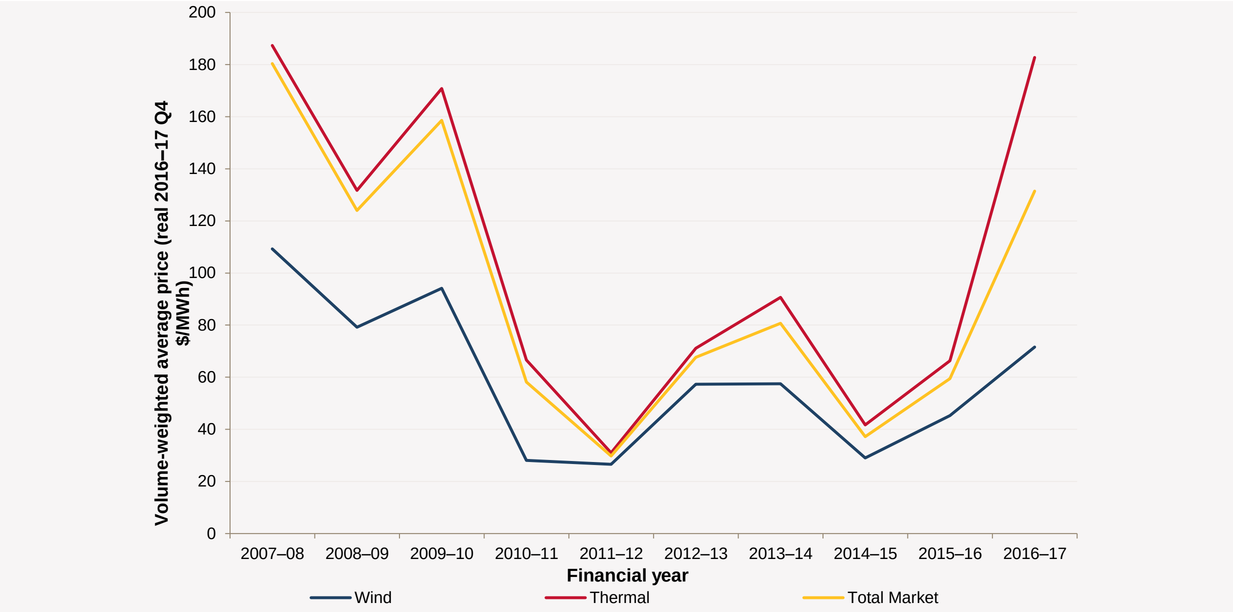


Figure 44 Comparison of summer volume-weighted average prices



APPENDIX D. NOMINAL VOLUME-WEIGHTED AVERAGE PRICE

The VWAPs using nominal electricity spot prices are shown in Table 18. A similar analysis is shown in Table 10, except where prices have been CPI-corrected, using June 2017 as the reference quarter.

Table 18 Nominal volume-weighted average price

	SA renewable generation		SA thermal generation		Total SA market generation		SA spot price
	Financial year	Summer*	Financial year	Summer*	Financial year	Summer*	Financial year
	VWAP ($/MWh)	VWAP ($/MWh)	VWAP ($/MWh)	VWAP ($/MWh)	VWAP ($/MWh)	VWAP ($/MWh)	TWAP ($/MWh)
2007–08	63.40	90.05	95.20	154.44	92.28	148.68	73.50
2008–09	46.38	66.95	67.77	111.31	64.76	104.80	50.98
2009–10	47.11	81.46	82.02	147.77	75.98	137.22	55.31
2010–11	23.92	25.17	42.11	59.76	38.15	52.16	32.58
2011–12	26.56	24.34	32.02	28.35	30.52	27.24	30.28
2012–13	57.51	53.61	76.12	66.51	70.95	63.29	69.75
2013–14	54.04	55.23	74.11	87.12	67.13	77.50	61.71
2014–15	31.40	28.21	45.61	40.57	40.38	36.20	39.29
2015–16	48.23	44.48	75.03	65.16	64.93	58.39	61.67
2016–17	76.46	71.62	161.07	183.84	124.19	131.83	108.66

As seen in Table 18, the average wholesale electricity price for South Australia for 2016–17 was $108.66/MWh (in nominal time-weighted average dollars), approximately 76% higher than for 2015–16 ($61.67/MWh).

This compares to 2016–17 average prices of:

- $81/MWh in New South Wales (57% higher than for 2015–16).
- $93/MWh in Queensland (55% higher).
- $75/MWh in Tasmania (27% lower).
- $67/MWh in Victoria (44% higher).

APPENDIX E. HISTORICAL ENERGY GENERATION FOR SOUTH AUSTRALIAN POWER STATIONS

Table 19 Historical energy generation for South Australian power stations (GWh)

Generator name	Schedule type	Fuel type	2012–13	2013–14	2014–15	2015–16	2016–17
Angaston Power Station	Scheduled	Diesel	-	-	-	0.91	7.46
Dry Creek Power Station	Scheduled	Gas	6.79	2.96	4.95	6.34	9.82
Hallett GT Power Station	Scheduled	Gas	59	34	22	33	46
Ladbroke Grove Power Station	Scheduled	Gas	92	232	186	206	212
Lonsdale Power Station	Scheduled	Diesel	-	-	-	0.62	4.55
Mintaro Power Station	Scheduled	Gas	13	8.21	7.33	13	31
Northern Power Station	Scheduled	Coal	2,231	2,096	2,645	2,601	-
Osborne Power Station	Scheduled	Gas	1,365	1,471	1,461	1,221	967
Pelican Point Power Station	Scheduled	Gas	2,967	1,837	1,012	293	1,183
Playford B Power Station	Scheduled	Coal	0.00	0.00	0.00	0.00	-
Port Lincoln Power Station	Scheduled	Diesel	1.39	0.81	0.39	0.50	2.23
Port Stanvac Power Station	Scheduled	Diesel	-	-	-	0.95	9.50
Quarantine Power Station	Scheduled	Gas	150	239	216	137	265
Snuggery Power Station	Scheduled	Diesel	0.31	0.09	0.43	1.00	3.24
Torrens Island A Power Station	Scheduled	Gas	447	340	201	659	604
Torrens Island B PowerStation	Scheduled	Gas	1,697	1,403	1,488	1,969	2,278
Clements Gap Wind Farm	Semi-scheduled	Wind	167	180	169	173	158
Hallett 1 (Brown Hill) Wind Farm	Semi-scheduled	Wind	332	349	308	314	278
Hallett 2 (Hallett Hill) Wind Farm	Semi-scheduled	Wind	256	256	233	243	218
Hallett 4 (North Brown Hill) Wind Farm	Semi-scheduled	Wind	426	473	420	446	384
Hallett 5 (The Bluff) Wind Farm	Semi-scheduled	Wind	155	168	136	150	123
Hornsdale Stage 1 Wind Farm	Semi-scheduled	Wind	-	-	-	0.48	306
Hornsdale Stage 2 Wind Farm	Semi-scheduled	Wind	-	-	-	-	81
Lake Bonney Stage 2 Wind Farm	Semi-scheduled	Wind	379	414	395	382	383
Lake Bonney Stage 3 Wind Farm	Semi-scheduled	Wind	95	99	94	93	95
Snowtown Stage 2 Wind Farm	Semi-scheduled	Wind	-	302	826	877	810
Snowtown Wind Farm	Semi-scheduled	Wind	374	388	333	341	303
Waterloo Wind Farm	Semi-scheduled	Wind	311	339	293	299	306
Angaston Power Station	Non-scheduled	Diesel	3.35	1.59	1.26	4.11	-
Canunda Wind Farm	Non-scheduled	Wind	114	125	118	113	112
Cathedral Rocks Wind Farm	Non-scheduled	Wind	175	196	170	169	151
Lake Bonney Wind Farm	Non-scheduled	Wind	191	206	192	182	181
Mount Millar Wind Farm	Non-scheduled	Wind	185	204	187	183	161
Starfish Hill Wind Farm	Non-scheduled	Wind	68	95	86	86	60
Wattle Point Wind Farm	Non-scheduled	Wind	248	294	265	269	233
Total			**12,509**	**11,754**	**11,470**	**11,467**	**9,966**

Dashes (-) in the table indicate that the generator was not registered with AEMO in that financial year, or was not registered as a particular schedule type.

APPENDIX F. ROOFTOP PV METHODOLOGY

Capacity estimation

Historical installed capacity for rooftop PV 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.

Generation estimation

The energy generated by a rooftop PV system was estimated using a model developed by the University of Melbourne.[50] 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 kilowatt (kW) rooftop PV installation. AEMO then applied corrections for assumed loss in performance of aging 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% once aging of panels was taken into account.[51]

[50] "Rooftop PV Model Technical Report", V.D. Ruelle, M. Jeppesen and M. Brear (July 2016). Available at http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/-/media/CEDBBF70073149ABAD19F3021A17E733.ashx

[51] This corresponds to an assumed average panel age across the region of 2.5 years.

MEASURES AND ABBREVIATIONS

Units of measure

Abbreviation	Unit of measure
GJ	Gigajoules
GWh	Gigawatt hour
kW	Kilowatt
$MtCO_2$-e	Metric tonnes of carbon dioxide equivalent
MW	Megawatt
MWh	Megawatt hour

Abbreviations

Abbreviation	Expanded name
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AEST	Australian Eastern Standard Time
CER	Clean Energy Regulator
COP21	21st Conference of Parties
CPI	Consumer Price Index
DUID	Dispatchable unit identifier
ESOO	Electricity Statement of Opportunities
FCAS	Frequency control ancillary services
LGC	Large-scale generation certificate
LNG	Liquefied natural gas
LRET	Large-scale renewable energy target
MSATS	Market Settlement and Transfer Solution
NEM	National Electricity Market
ONSG	Other non-scheduled generation
PV	Photovoltaic
PVSNG	Photovoltaic non-scheduled generation
SAER	South Australian Electricity Report
SAHMIR	South Australian Historical Market Information Report
SAPN	SA Power Networks
SARER	South Australian Renewable Energy Report
SCADA	Supervisory Control and Data Acquisition
SNSG	Small non-scheduled generation
STTM	Short Term Trading Market
TWAP	Time-weighted average price
VWAP	Volume-weighted average price

GLOSSARY

Definitions

The 2017 SAMHIR uses many terms that have meanings defined in the National Electricity Rules (NER). The NER meanings are adopted unless otherwise specified.

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.
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 21st 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.
frequency control ancillary services (FCAS)	Used by AEMO to maintain the frequency on the electrical system, at any point in time, close to fifty cycles per second as required by the NEM frequency standards
generating capacity	Amount of capacity (in megawatts (MW)) available for generation.
generating unit	Power stations may be broken down into separate components known as generating units, and may be considered separately in terms (for example) of dispatch, withdrawal, and maintenance.
Heywood Interconnector	The Heywood Interconnector is a connection between the Victorian and South Australian power systems. It consists of two 275 kV AC electricity transmission lines, between Heywood Terminal Station in Victoria and South East Switching Station in South Australia. Following the completion of upgrade works currently underway, it will have a rated capacity of 650 MW power transfer in either direction.
installed capacity	The generating capacity (in megawatts (MW)) of the following (for example): • A single generating unit. • A number of generating units of a particular type or in a particular area. • All of the generating units in a region. Rooftop PV installed capacity is the total amount of cumulative rooftop PV capacity installed at any given time.
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.
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.

Term	Definition
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.
regulation FCAS	Regulation FCAS is enabled to continually correct the generation/demand balance in response to minor deviations in load or generation. There are two types of regulation FCAS: • Raise (used to correct a minor drop in frequency), • Lower (used to correct a minor rise in frequency).
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.
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.