South Australian Electricity Report

November 2018

South Australian Advisory Functions

Important notice

PURPOSE

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

AEMO publishes this South Australian Electricity Report in accordance with its additional advisory functions under section 50B of the National Electricity Law. This publication is based on information available to AEMO as at 1 July 2018, although AEMO has endeavoured to incorporate more recent information where practical.

DISCLAIMER

AEMO has made every effort to ensure the quality of the information in this publication but cannot guarantee that information, forecasts and assumptions are accurate, complete or appropriate for individual circumstances. This publication does not include all of the information that an investor, participant or potential participant in the National Electricity Market might require, and does not amount to a recommendation of any investment.

Anyone proposing to use the information in this publication (including information and reports provided by third parties) should independently verify and check its accuracy, completeness and suitability for that purpose, and obtain independent and specific advice from appropriate experts.

Accordingly, to the maximum extent permitted by law, AEMO and its officers, employees and consultants involved in the preparation of this document:

- make no representation or warranty, express or implied, as to the currency, accuracy, reliability or completeness of the information in this document; and
- are not liable (whether by reason of negligence or otherwise) for any statements or representations in this document, or any omissions from it, or for any use or reliance on the information in it.

Executive summary

The dynamics of the power system in the National Electricity Market (NEM), and South Australia in particular, have changed significantly as ageing coal-fired generation assets have withdrawn and wind generation, behind-the-meter rooftop photovoltaics (PV) generation, and battery storage have grown rapidly. The power system now needs to accommodate more dynamic and technologically diverse plant, including embedded resources that are geographically dispersed, to meet varying energy usage patterns that are vastly different to previous decades.

System strength needs to be more actively managed, and there is increased need for fast-start and rapid-response technologies to accommodate changes in renewable energy output and improve power system security. The shape of operational demand is becoming increasingly peaky, and both demand and supply are exposed to the vagaries of weather, changing the nature and profile of supply scarcity risks.

Recent technology, regulatory, and policy developments in South Australia reflect these changing needs:

- The new Hornsdale Power Reserve Battery Energy Storage System provides a range of services including energy arbitrage, reserve energy capacity, network loading control ancillary services (NLCAS), and frequency control ancillary services (FCAS).
- Government purchase, and subsequent tender for lease of, temporary emergency diesel generation provides off-market back-up power when supply scarcity risks are high.
- Barker Inlet, a 210 megawatt (MW) reciprocating engine power station due for operation in 2019, will be capable of increasing output to full capacity within five minutes.
- South Australian Government policy is supporting the installation of 40,000 residential batteries through a Home Battery Scheme, which will help shift rooftop PV generation to cover the evening peak.
- New synchronous condensers are being installed to supply both system strength and inertia to the South Australia region.
- New interconnection between South Australia and New South Wales (currently being investigated) is projected to improve economic efficiencies, power system security, and dispatchability during minimum demand periods.

It is critical that the investment environment and regulatory mechanisms are capable of supporting a smooth transition to replacement resources that deliver the services required to maintain reliability and security as current generation retires. Industry must actively work towards creating the landscape for this to occur, without disruption to reliability, and at the lowest cost to consumers.

AEMO is working with the Energy Security Board, Reliability Panel, and industry to identify proactive policy, regulatory, and market reforms that may be required to facilitate investment in the public interest, including:

- Proposing a process to make the Integrated System Plan (ISP)[1] actionable. The current transmission planning process must move away from the assessment of developments on a region-by-region,

[1] AEMO, *Integrated System Plan*, July 2018, available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan.

project-by-project basis, to one that incorporates system-wide planning. This will allow transmission development across the NEM to be optimised and the full benefits of those developments to be realised. This is particularly important in the current and forecast environment, where the supply mix is changing and there is more emphasis on the need to share reserves NEM-wide to manage intermittency.

- Proposing alternate or supplementary reliability metrics that measure the shape and severity of the tail risk to better inform industry of supply scarcity risks, and ensuring reliability mechanisms, or strategic reserves, are in place if needed.
- Establishing programs to better integrate distributed energy resources (DER) into the market and system, increasing visibility through establishment of a DER register, establishing technical performance standards and operational processes, and progressing regulatory changes to facilitate DER access to markets.
- Designing improvements to the regulatory arrangements for how grid-scale Emerging Generation and Energy Storage (EGES) registers and participates in the NEM.

The impact of active consumers and growing distributed energy resources (DER)

- **Consumers continue to increase their adoption of behind-the-meter rooftop PV and storage**, with capacity reaching 930 MW of rooftop PV and 15 MW of battery systems after 2017-18, and rooftop PV contributing 1,162 gigawatt hours (GWh) in the 2017-18 year.
- This consumer activity, combined with energy efficiency savings, **kept annual operational consumption in South Australia flat** at 12,203 GWh in 2017-18, despite underlying population growth. It is expected to stay at a similar level for the next 10 years.
- **Rooftop PV contributed 51 MW more at the underlying peak** in 2017-18 than it did in the previous year, delivering 495 MW at the time of peak underlying demand[2] (4.30 pm Adelaide time) and **moving the time of peak grid demand from 6:30 pm in the previous year to 7.30 pm Adelaide time**. Now that maximum demand has moved into the evening, after the sun has set, future rooftop PV installations are unlikely to further reduce this operational peak unless combined with energy storage. The level of maximum demand from the grid is therefore expected to rise as population grows.
- High and growing rooftop PV penetration is also **reducing minimum operational demand**, with times of negative demand[3] forecast by 2023-24. **Minimum demand continues to occur in the middle of the day** in South Australia, with a minimum demand of 645.6 MW recorded at 1:30 pm in 2017-18.
- **Initiatives to further build and integrate DER into the system and market in South Australia** include:
  - South Australian Government policy supporting the installation of 40,000 residential batteries (through a Home Battery Scheme) which will be capable of enrolling in virtual power plant (VPP) aggregations.
  - VPP trials (allowing DER to be dispatched alongside other resources) and progressing regulatory changes to facilitate DER access to energy, ancillary, and reserve markets.
  - Australian Renewable Energy Agency (ARENA)/AEMO trial to explore a strategic reserve model (referencing international market designs) for reliability or emergency demand response.

Supply changes and impacts on exports, emissions, and prices

- **Generation in South Australia increased** 27% in 2017-18 to 14,186 GWh, about half supplied from gas-powered generation (GPG). The extra generation was used to meet local demand and exported to Victoria, with 2017-18 being the **first time in at least nine years that South Australia was a net exporter of energy**.
- **Installed generation capacity (registered, including rooftop PV) in South Australia increased** 14% in 2017-18 (almost 800 MW) to 6,205 MW.

---

[2] Total demand from consumers, whether met from the grid or from their own generation or storage behind the meter.

[3] Negative operational demand means embedded and non-scheduled generation exceeds regional consumption, forcing exports to neighbouring regions.

- By end of July 2018, **committed and publicly announced additional supply developments** in South Australia totalled 8,184 MW across 56 projects. AEMO classifies about 700 MW of this as committed for development[4]. While new wind and solar projects comprise the majority of new investment interest from a capacity perspective, compared to the same time last year there is a noticeable increase in the amount of new battery, pumped hydro, and gas-fired peaking projects publicly announced. The South Australian Government is assisting in the development of several of these projects.
- Given the penetration of renewable generation, there will be increasing need for technologies that can complement the generation's natural variability by providing **rapid start capabilities and high operational flexibility**. The committed Barker Inlet Power Station is an example of this value, with maximum operation achievable within five minutes, at a higher level of efficiency than the pre-existing GPG fleet. This unit replaces the ageing Torrens Island Power Station (TIPS) A, which will progressively close from 2019 to 2021.
- Increased GPG operation meant **emissions** were higher in 2017-18 than the year before, but growth in wind generation led to lower overall average emissions intensity[5].
- **Interconnection developments** include projects to increase Heywood transfer capability and reduce Murraylink congestion, and a new interconnector to New South Wales (at the investment test phase).
- **New sources of supply contributed to lower prices in 2017-18**. Time-weighted average prices were 11% lower than the year before, due to increased supply and fewer high demand periods, while **FCAS prices** were lower as new suppliers including the Hornsdale Power Reserve (HPR)[6] battery system entered the market, and TIPS increased FCAS provision. Trials were also undertaken for FCAS provision from Hornsdale Wind Farm and VPPs.

Actions to maintain reliability and security

- AEMO forecasts risks to supply in the next five years in South Australia, due to the region's interconnectedness with Victoria. To avoid unfairly penalising one region for a supply deficit spread through several interconnected regions, an equitable load shedding principle applies in the NEM. This principle states that load shedding should be spread pro rata throughout interconnected regions when this would not increase total load shedding. Therefore, while the reliability standard is not expected to be exceeded in South Australia, high risks of load shedding projected in Victoria are likely to result in any supply deficit being spread across both Victoria and South Australia:
  - Maintaining the emergency diesel generators under current arrangements through the 2018-19 summer will help mitigate the risk of shortfall in South Australia.
  - AEMO has also identified additional reserves which can be made available through the Reliability and Emergency Reserve Trader (RERT) function to reduce the supply scarcity risk this summer.
  - This risk is forecast to reduce after next summer as more committed generation is commissioned. Over the next four years, forecast unserved energy (USE) for South Australia is within the reliability standard[7].
  - New interconnection between South Australia and New South Wales, currently undergoing investment testing, will be critical to help maintain reliability in an efficient manner following the planned withdrawal of thermal generation such as TIPS A and Liddell Power Station (in New South Wales).

[4] Commitment criteria are outlined under the Background Information tab on AEMO's Generation Information Page, available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

[5] Emissions intensity refers to the average emissions associated with each unit of energy produced. An increase in total emissions can coincide with a larger increase in total regional energy produced, resulting in a lower regional emissions intensity.

[6] HPR Battery Energy Storage System (BESS) also provides services including energy arbitrage, reserve energy capacity, and network loading control ancillary services (NLCAS).

[7] Unserved energy (USE) is energy that cannot be supplied to consumers, resulting in involuntary load shedding (loss of customer supply), as a result of insufficient levels of generation capacity, demand response, or network capability, to meet demand. The reliability standard specifies that expected USE should not exceed 0.002% of total energy consumption in any NEM region in any financial year.

- As well as energy resources to meet demand, the power system also needs services to **maintain system strength**[8] **and keep frequency and voltage within required limits**. These **system security** services are supplied by synchronous generators, but when this generation is not online – such as at times of low operational demand – alternative options are needed.
  - AEMO can direct synchronous generators to stay online. Security directions increased substantially in the last year, with over 140 issued in South Australia as of 23 September 2018.
  - **Synchronous condensers, improved interconnection, and contingency frequency reserves** from renewable generation and large-scale battery storage, as well as fast-start and rapid-response technologies, are all being progressed as more sustainable long-term options.
  - ElectraNet, with support from AEMO, the Australian Energy Regulator (AER), and the South Australian Government, has progressed a project for synchronous condensers to be installed as soon as possible to supply both system strength and inertia to the South Australian region[9].
- **Regulatory changes to improve power system security in South Australia** have also progressed. AEMO recommended in its 2018 Power System Frequency Risk Review (PSFRR) that:
  - A new "Protected Event" be declared by the Reliability Panel, to better manage the risk of interconnector failure causing generation to disconnect and leading to South Australia being islanded and a black system occurring during destructive wind conditions in South Australia. AEMO is currently preparing this request for submission to the Reliability Panel in November 2018.
  - An upgrade to the recently commissioned System Integrity Protection Scheme (SIPS) in South Australia be implemented, to further reduce the likelihood that a loss of multiple generators in South Australia will lead to separation and a black system. AEMO is investigating this with ElectraNet.
- Other regulatory changes that have been or are being implemented to support system security in South Australia and the wider NEM include a new approach to measuring forecasting uncertainty and triggering Lack of Reserve (LOR), keeping long notice RERT to allow an extended lead time for procuring reserves, and establishing a register of DER by the end of 2019 to give AEMO visibility of DER and information including its locations and trip settings.

Looking ahead – proposed ISP developments for South Australia

- AEMO's July 2018 ISP reinforced the need for independent, integrated, NEM-wide planning. The strategic development of a portfolio of network and non-network developments provides critical diversity and reliability benefits from existing and new diverse renewable resources, maximising the value from available resources and infrastructure and minimising the overall investment needs.
- The ISP highlighted that an upgrade to the interconnection between South Australia and New South Wales is expected to be economically beneficial under almost all plausible scenarios. This upgrade, now at the investment test phase, would:
  - Allow generation in other states to be transported to South Australia, providing cost reductions through reduced GPG requirements.
  - Allow for new potential renewable energy zones (REZs)[10] to be developed along this corridor.
  - Improve system security and resilience by reducing the risk of islanding of the South Australian network and helping mitigate system security risks under minimum demand conditions.
- Immediately optimal REZ development areas in the ISP (locations with high quality renewable resources, supported by existing transmission capacity and system strength and capacity) included two candidates in

[8] System strength reflects the sensitivity of power system to disturbances, and the stability and dynamics of generating systems and the power system to remain stable under normal conditions, and to return to steady-state conditions following a disturbance (such as a fault).

[9] See https://www.electranet.com.au/what-we-do/projects/power-system-strength/.

[10] In REZs, clusters of large-scale renewable energy can be developed to promote economies of scale in high-resource areas and capture geographic and technological diversity in renewable resources, providing an effective, least-cost way to integrate new generation, storage, and transmission development.

South Australia: Northern South Australia (solar) and Mid-North (wind). To connect renewable projects beyond the current transmission capacity, further action will be required. Riverland (wind and solar) in South Australia was among the optimal areas identified for development in conjunction with the transmission investments identified in the ISP.

- The ISP also identified the importance of coordinating DER to realise the potential it could provide to the market and system operations.

Contents

Tables

Figures

1. Introduction

The South Australian Electricity Report (SAER) provides a high-level summary of key insights into electricity supply and demand, as well as the latest developments in energy, in South Australia. The report compiles information and insights from a number of AEMO studies and publications, including reporting on historical information and forecasts.

1.1 Purpose and scope

Every year since 2012, AEMO has prepared a collection of independent reports for the South Australian jurisdiction under Section 50B of the National Electricity Law as the South Australian Advisory Functions (SAAF). The 2018 SAER has been updated to a new structure, to more accurately reflect the latest trends in the industry and provide a reference document for all information relevant to South Australia.

The structure of the document will be flexible, to adapt to changes in the industry. The 2018 report contains insights that will replace the following past reports:

- South Australian Electricity Report.
- South Australian Demand Forecasts.
- South Australian Historical Market Information Report.
- South Australian Generation Forecasts (since 2015).
- South Australian Renewable Energy Report (since 2016, previously the South Australian Wind Study Report).

This 2018 SAER is supplemented by a number of Excel files with comprehensive data and figures summarising historical information and forecasts. Where applicable, the content of these files will be updated during the coming year. A list of all these tables and figures, and any corresponding equivalent in this report, is included in the Appendix.

AEMO continues to publish an annual comparison of ElectraNet's Transmission Annual Planning Report (TAPR) projects and their revenue proposal, separately from this report[11].

1.2 Information sources

AEMO has sourced information in this report from other AEMO publications and has also used information from data provided by market participants and potential investors as at 30 June 2018, unless otherwise specified. The Excel data files with the tables and figures accompanying this report are published as supporting information on AEMO's website.

Table 1 provides links to additional information referred to above, or provided either as part of the accompanying information suite for this report, or related AEMO planning information.

[11] All SAAF reports are available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/South-Australian-Advisory-Functions.

Table 1 Information and data sources

Information source	Website address
2018 Gas Statement of Opportunities (GSOO) for eastern and south-eastern Australia	http://aemo.com.au/Gas/National-planning-and-forecasting/Gas-Statement-of-Opportunities
2018 Integrated System Plan	https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan
2018 Electricity Statement of Opportunities (ESOO) for the NEM	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities
2018 AEMO Demand Forecasting Methodology Paper	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities
2018 SAER – tables and figures	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/South-Australian-Advisory-Functions
AEMO observations: Operational and market challenges to reliability and security in the NEM	https://www.aemo.com.au/Media-Centre/AEMO-observations---operational-and-market-challenges
AEMO Pricing Event Reports	https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Market-notices-and-events/Pricing-event-reports
AEMO: Specification for Distributed Energy Resources to provide Contingency FCAS	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Ancillary-services/Market-ancillary-services-specifications-and-FCAS-verification
AEMO: Wind farms and solar farms testing requirements for Contingency FCAS registration	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Ancillary-services/Market-ancillary-services-specifications-and-FCAS-verification
AEMO's Future Power System Security program	https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/FPSSP-Reports-and-Analysish
AEMO's Guide to Ancillary Services in the NEM	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Ancillary-services
AEMO's Summer operations 2017-18 report	https://aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Summer-operations-report
Carbon Dioxide Equivalent Intensity Index	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Settlements-and-payments/Settlements/Carbon-Dioxide-Equivalent-Intensity-Index
Fact sheets – frequency control, system strength, visibility of the power system	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/FPSSP-Reports-and-Analysis
Generation Information page	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information
Hornsdale Wind Farm 2 FCAS Trial	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Strategic-partnerships
Initial operation of the Hornsdale Power Reserve Battery Energy Storage System	http://www.aemo.com.au/Media-Centre/AEMO-Hornsdale-report
Interconnector capabilities report	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Congestion-information/Network-status-and-capability
Maps and network diagrams	http://www.aemo.com.au/aemo/apps/nem_map/index.php
Projections of uptake of small-scale systems	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Electricity-Forecasting-Report

Information source	Website address
Quarterly Energy Dynamics – Q2 2018	https://www.aemo.com.au/Media-Centre/AEMO-publishes-Quarter-Energy-Dynamics---Q2-2018
Retail electricity price history and projections	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Electricity-Forecasting-Report
South Australian Planning Requirements for New Electricity Generation	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/South-Australian-Advisory-Functions

Throughout this report, AEMO has:

- Used National Electricity Market (NEM) time (market time) – Australian Eastern Standard Time (AEST) with no daylight savings applied.
- Presented pricing analysis for five-year and 10-year trends in real June 2018 dollars, using the Adelaide Consumer Price Index (CPI) as the basis for adjustment unless stated otherwise. Where analysis has been undertaken within only the most recent two financial years, nominal dollar values are presented.
- Defined summer as the period from 1 November to 31 March, and winter from 1 June to 31 August, except for winter 2018, which only includes data from 1 June to 30 June 2018.

1.3 Scenarios

Some tables and figures in this report are based on three scenarios for pace of change in the energy industry – Neutral, Slow, and Fast – in line with core scenarios from the 2018 Electricity Statement of Opportunities (ESOO) and 2018 Integrated System Plan (ISP). More detail about the scenarios is provided in these publications (see Table 1 for reference). In summary:

- **Neutral pace of change (Neutral)** scenario – this scenario assumed a range of mid-point projections of economic growth, future demand growth, electric vehicle (EV) uptake, and fuel costs, and existing market and policy settings. It also assumed moderate growth in distributed energy resources (DER) aggregation, such that aggregated distributed batteries could be treated and operated as virtual power plant (VPP) rather than operated to maximise the individual household's benefit.
- **Slower pace of change (Slow change)** scenario – under this scenario, economic growth was assumed to be weak, reducing business investment and resulting in some industrial closures. Assumptions also included lower overall discretionary income at a household level, fewer EVs being purchased, and lower levels of investment in energy efficiency. Regulatory frameworks for DER were assumed to advance at a faster rate than technology advancements, leading to relatively high DER aggregation. Compared to Neutral, the net effect was lower operational (grid) consumption, a smoother operational load profile (due to higher demand-based resources and high DER aggregation), and slower power system transformation.
- **Faster pace of change (Fast change)** scenario – under this scenario, economic growth was assumed to be strong, increasing overall discretionary income at a household level and making stronger emission abatement aspirations economically sustainable. With higher population and more robust economic conditions supporting increasing demand for services reliant on electricity, demand for electricity energy would be higher than projected under the Neutral scenario, including greater uptake of EVs. DER technology improvements were assumed to advance more rapidly than the regulatory frameworks needed for DER to become a reliability resource, leading to relatively low DER aggregation. The net effect was higher operational (grid) consumption, a more 'peaky' operational load profile (due to lower demand-based resources and low DER aggregation), and a faster power system transformation.

These scenarios will be referenced in the sections of this report covering forecast demand, consumption, and supply. The scenarios are different from the three scenarios considered in past publications (Neutral, Strong, and Weak), but will be presented side by side in some figures and tables for comparison where appropriate.

2. Consumer behaviour – behind the meter

South Australian consumers are expected to continue to adopt technologies which may reduce their energy consumption from the grid. These distributed energy resources (DER) affect consumers' overall energy consumption levels and potentially shift energy consumption patterns.

Consumer behaviour, particularly the usage of battery storage and choices of times to charge electric vehicles, will affect consumption patterns over a day.

This section covers forecast uptake of these technologies and outlines the role of DER for the 2018 NEM ESOO[12]. The impact on timing and magnitude of maximum operational demand is covered in Section 3.

2.1 Rooftop photovoltaics (PV)

Rooftop PV systems installed in South Australian residential and commercial premises have a material impact on the region's operational electricity demand[13] by reducing residential and commercial grid consumption during daylight hours, when consumer demand can be met by rooftop PV. Rooftop PV production may also shift minimum demand from overnight to occur in the middle of the day and shift the time of maximum operational demand further into the evening. In South Australia, maximum demand already typically occurs late in the day (7.30 pm Adelaide time in summer 2017-18) when solar irradiance is low.

AEMO's methodologies for forecasting rooftop PV capacity and generation are available in AEMO's *Demand Forecasting Methodology Information Paper*[14].

2.1.1 Rooftop PV capacity

Since 2009, South Australian total installed rooftop PV[15] capacity has grown strongly. More than 32% of South Australian dwellings now have rooftop PV systems installed, the second highest level of penetration in Australia[16]. Only Queensland has a greater proportion of dwellings with a PV system installed.

Rooftop PV systems continue to be installed at a very high rate. An additional 155 megawatts (MW) was estimated to have been installed in 2017-18 across business and residential sectors, bringing the total estimated residential and business PV combined capacity in South Australia to 930 MW. Of the two sectors – business and residential – the business sector saw stronger relative growth by a considerable margin.

---

[12] Available at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities.

[13] 'Operational demand' means demand met by energy supplied to the grid by scheduled, semi-scheduled, and significant non-scheduled generators (excluding their auxiliary loads, or electricity used by the generator). 'Underlying demand' means all the energy consumers use, from sources including the grid and DER behind the meter (on their own premises).

[14] AEMO, *Demand Forecasting Methodology Information Paper*, 2018, Rooftop PV methodology in Section A.3.1. Available at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2018/2018-Demand-Forecasting-Methodology-Information-Paper.pdf.

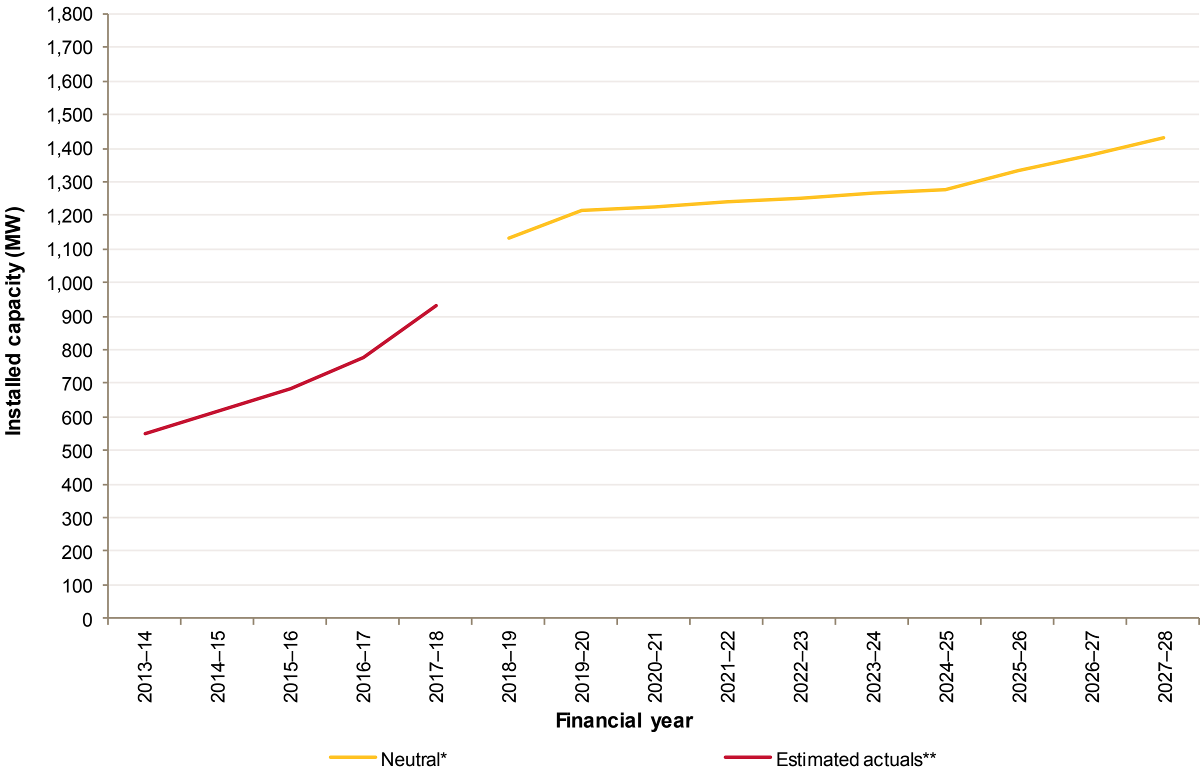
[15] Rooftop PV comprises both business and residential components.

[16] According to Australian PV Institute Solar PV status (at 17 August 2018), at http://pv-map.apvi.org.au/historical.

This growth has been primarily due to reduced payback periods making rooftop PV generation an attractive investment. This is a result of a combination of government incentives in the form of rebates and feed-in tariffs, the Small-scale Technology Certificate (STC) multiplier, falling system costs, and recent increases in electricity prices.

Figure 1 shows the estimated actual and forecast installed rooftop PV capacity for South Australia from 2013-14 to 2027-28. Rooftop PV installed capacity is forecast to grow steadily over the next 10 years, reaching 1,432 MW in 2027-28.

Figure 1 South Australian rooftop PV installed capacity forecasts



* The 2018 ESOO maintained the same rooftop PV installed capacity forecasts across scenarios.
** After an improvement in the estimation for actual rooftop PV installation data, based on updated Clean Energy Regulator (CER) information and used during the production of the 2018 ESOO, installation data has changed from that reported in 2017 SAAF reports.

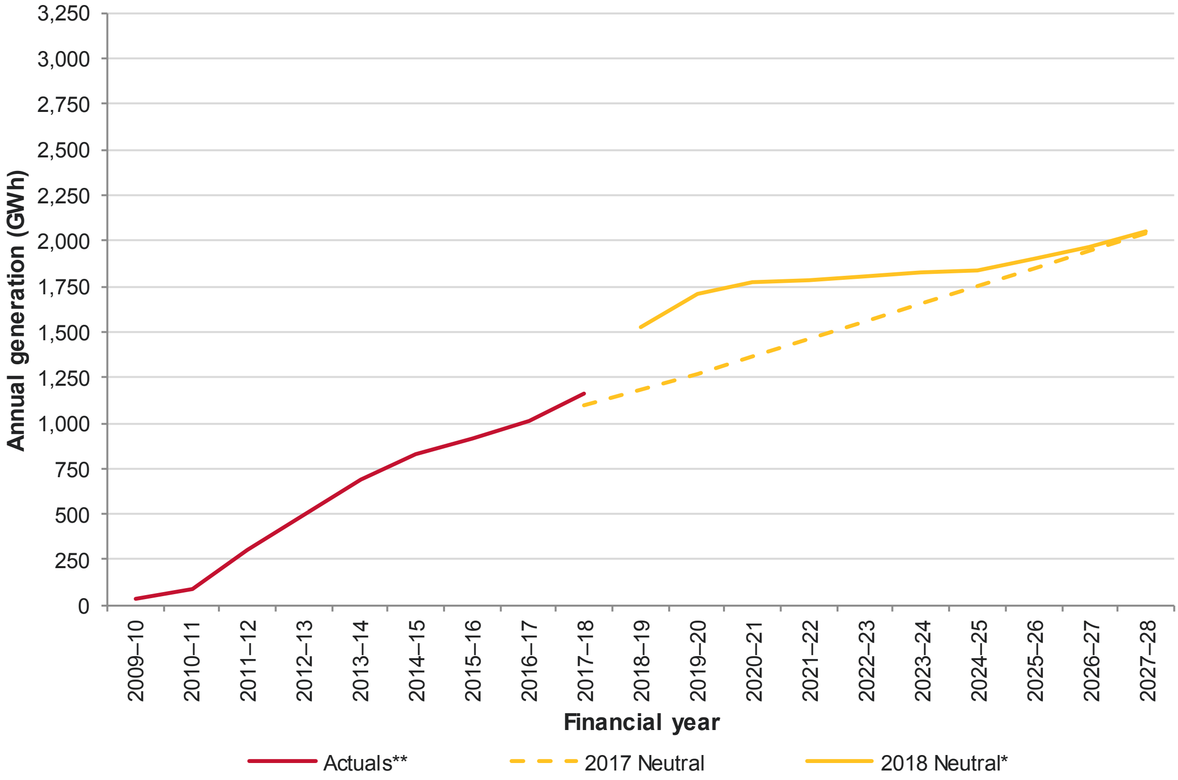
2.1.2 Rooftop PV generation

Over the next 10 years, South Australia is projected to have the highest ratio of rooftop PV generation to operational consumption of all NEM regions. This is attributed to the state's high penetration of rooftop PV installations, good solar resources, and the second-lowest operational consumption of all regions in the NEM and Western Australia's Wholesale Electricity Market (WEM).

Figure 2 shows the estimated actuals and forecasts of annual rooftop PV generation for South Australia from 2009-10 to 2027-28.

In 2017-18, annual rooftop PV generation was estimated at 1,162 gigawatt hours (GWh). It is forecast to increase to 2,050 GWh by 2027-28. This represents approximately 15% of annual underlying consumption.

Figure 2 South Australian rooftop PV generation forecasts



* The 2018 ESOO maintained the same rooftop PV installed capacity forecasts across scenarios.
** After an improvement in the estimation for actual PV installation data, based on updated CER information and used during the production of the 2018 ESOO, PV installation data has changed from that reported in 2017 SAAF reports.

2.1.3 Rooftop PV forecast methodology

Forecast methodology

AEMO's *Demand Forecasting Methodology Information Paper*[17] provides a description of both rooftop PV capacity and generation forecasts – as used in the 2018 NEM ESOO – in its Appendix A3.

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[18]. 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 ageing solar panels, by estimating that a panel loses 0.4% of

[17] Available at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2018/2018-Demand-Forecasting-Methodology-Information-Paper.pdf.

[18] "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.

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 is reduced by 1% once ageing of panels is taken into account[19].

2.2 Battery storage

South Australia currently has an estimated 15 MW of embedded battery systems[20]. Compared to other NEM regions, South Australia has a higher battery forecast over the next five years, as recent State Government policy is supporting the installation of 40,000 residential batteries through a Home Battery Scheme[21]. Other VPP trials are also underway by retailers and technology providers, including trials by AGL and Tesla. With support from the Australian Renewable Energy Agency (ARENA), SA Power Networks (SAPN) and Simply Energy are also delivering a VPP trial, including measures of access to these behind-the-meter resources to address local network constraints.

By 2027-28, uptake of business and residential behind-the-meter battery systems is forecast to reach 180 MW (under a Neutral scenario). Battery uptake is expected to be slower than previous projections, due to revisions to payback periods, technology costs, and linkages to PV uptake rates. Modelling assumed most battery systems would be installed as part of integrated solar and battery systems.

Dependent on pricing incentives, battery storage systems may impact the demand profile, enabling households to store and use surplus solar production (if part of an integrated battery and solar system) and shift this energy for use to meet evening peak demands. As outlined in Section 9, increased benefits are expected if this battery fleet is orchestrated to provide a more certain peak support role.

2.3 Electric vehicles

In 2017-18, there were an estimated 56 sales of EVs in South Australia[20], including plug-in hybrid electric vehicles (PHEVs), bringing the total to 201 vehicles. Relatively low uptake is forecast in South Australia in the next 10 years, mainly due to lower population projections compared to New South Wales and Victoria. By 2027-28, yearly sales of EVs in the state are forecast to be over 15,000 vehicles, taking South Australia's total EV fleet to over 45,000 vehicles.

Annual electricity consumption from EV charging is forecast to be approximately 155 GWh in 2027-28 in South Australia (under a Neutral scenario). The impact of EVs on the daily load profile and maximum demand depends on how and when they are charged. Charging is likely to be influenced by the availability of public infrastructure, tariff structures, any energy management systems, and drivers' routines. For the 2018 ESOO, AEMO assumed a weighting of three charging profiles: convenience, smart day, and overnight. These profiles reflected different incentives to charge during off-peak or overnight periods, relative to convenience-based behaviours which may impact more significantly on peak loads. Implicitly, there is an assumption that some consumers will be incentivised to charge their EVs outside the peak demand period.

The EV consumption forecasts used state-based vehicle activity assumptions, which influence how many vehicles are required in each region to meet travel demand. The kilometres travelled per vehicle by region changes over time (due to adoption of car/ride sharing). The charging profiles per vehicle were also adjusted for weekday/weekend differences and monthly differences based on traffic data. The battery efficiency at the start of the forecast is approximately 0.2 kilowatt hours (kWh) per kilometre for cars, and up to 1.1 kWh/km for trucks and buses, with these efficiencies expected to improve through the forecast period. EVs could potentially have some impact on the peak demand experienced for distribution feeders, depending on uptake and whether changing tariffs incentivise charging outside local peak demand.

---

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

20 For more information, see https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2018/Projections-for-Small-Scale-Embedded-Technologies-Report-by-CSIRO.pdf.

21 For more information, see http://www.renewablessa.sa.gov.au/home-battery-scheme.

3. Operational consumption and demand

The historical decline in operational consumption is forecast to moderate, as continued uptake of rooftop PV along with energy efficiency measures is projected to be balanced by demand growth from increased economic activity, including forecast expansion in mining, and projected uptake of electric vehicles.

The recent decline in maximum operational demand is forecast to be reversed. Due to the high uptake of rooftop PV, South Australian demand is already peaking late in the evening. At this time of day, continued growth in rooftop PV will have little or no impact on moderating maximum demand, which therefore will increase, driven by population increase and economic growth.

The high penetration of rooftop PV in South Australia has caused minimum demand to occur in the middle of the day since 2012-13. The continued strong forecast growth for rooftop PV installations means 90% probability of exceedance (POE) minimum operational demand is forecast to become negative by 2023-24[22].

Section 7 discusses the operational challenges this raises, along with possible solutions.

3.1 Historical and forecast consumption and demand

3.1.1 Operational consumption (sent out)

This section presents recent historical observations and long-term forecasts of annual operational consumption in South Australia[23]. Where possible, forecasts from both the 2018 and 2017 NEM ESOOs are shown for comparison across the different sensitivities.

In 2017-18, operational consumption (sent out) was 12,203 GWh. This was 1.8% (220 GWh) lower than the 2016-17 consumption of 12,423 GWh.

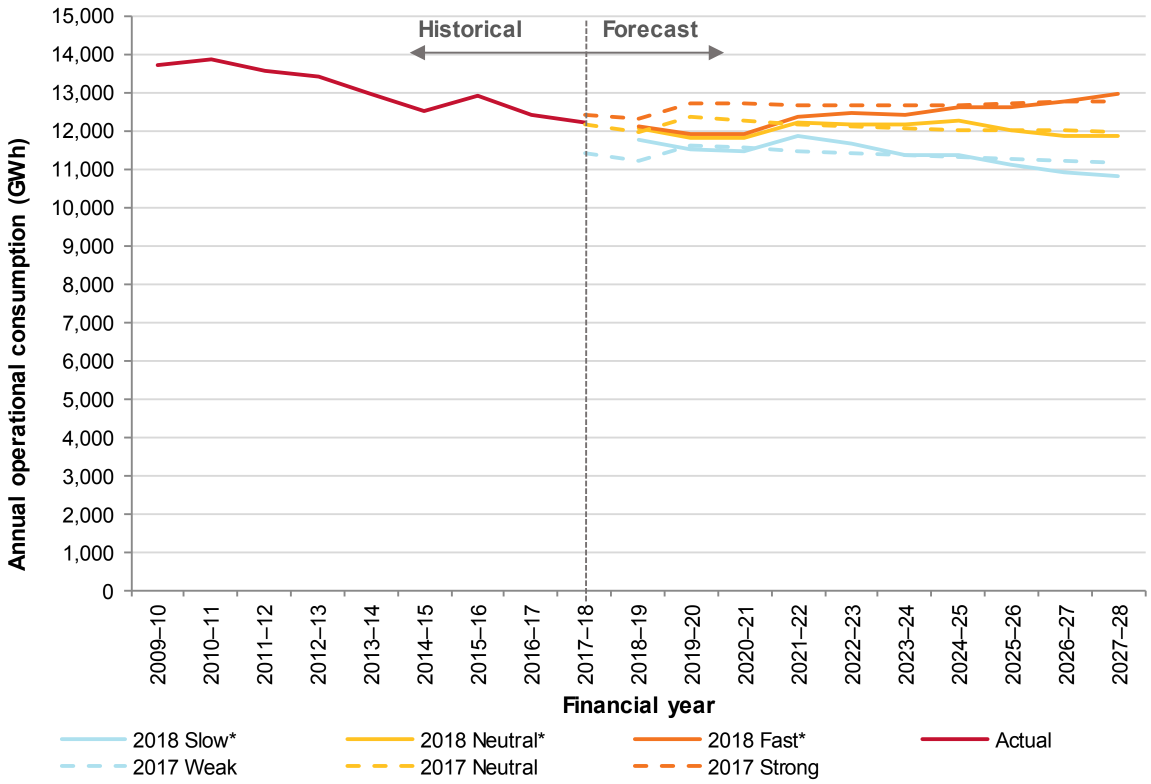
Under the 2018 NEM ESOO Neutral scenario, operational consumption is forecast to decline slightly in the long-term outlook period (2018-19 to 2027-28) from 12,053 GWh in 2018-19 to 11,856 GWh in 2027-28.

[22] Probability of exceedance (POE) means the probability, as a percentage, that a maximum or minimum demand forecast will be met or exceeded (for example, due to weather conditions). A 10% POE maximum demand forecast or a 90% POE minimum demand forecast is expected to be met or exceeded, on average, only one year in 10.

[23] Forecasts are presented on a "sent out" basis, meaning the forecasts exclude generator auxiliary loads. See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/EFI/2018/Operational-Consumption-definition---2018-update.pdf for more on definitions.

Figure 3 shows the historical trend of operational consumption in South Australia from 2009-10, with a noticeable decline from 2011-12 onwards. This has been driven by a fall in residential and commercial consumption as consumers have become more actively engaged in their energy use, with uptake of rooftop PV and incorporating more energy efficiency savings.

Figure 3 Annual operational consumption (sent out) actual and forecast for South Australia



* The 2018 ESOO scenarios considered are different from the ones in ESOO 2017. Details of scenarios are available in the 2018 ESOO .

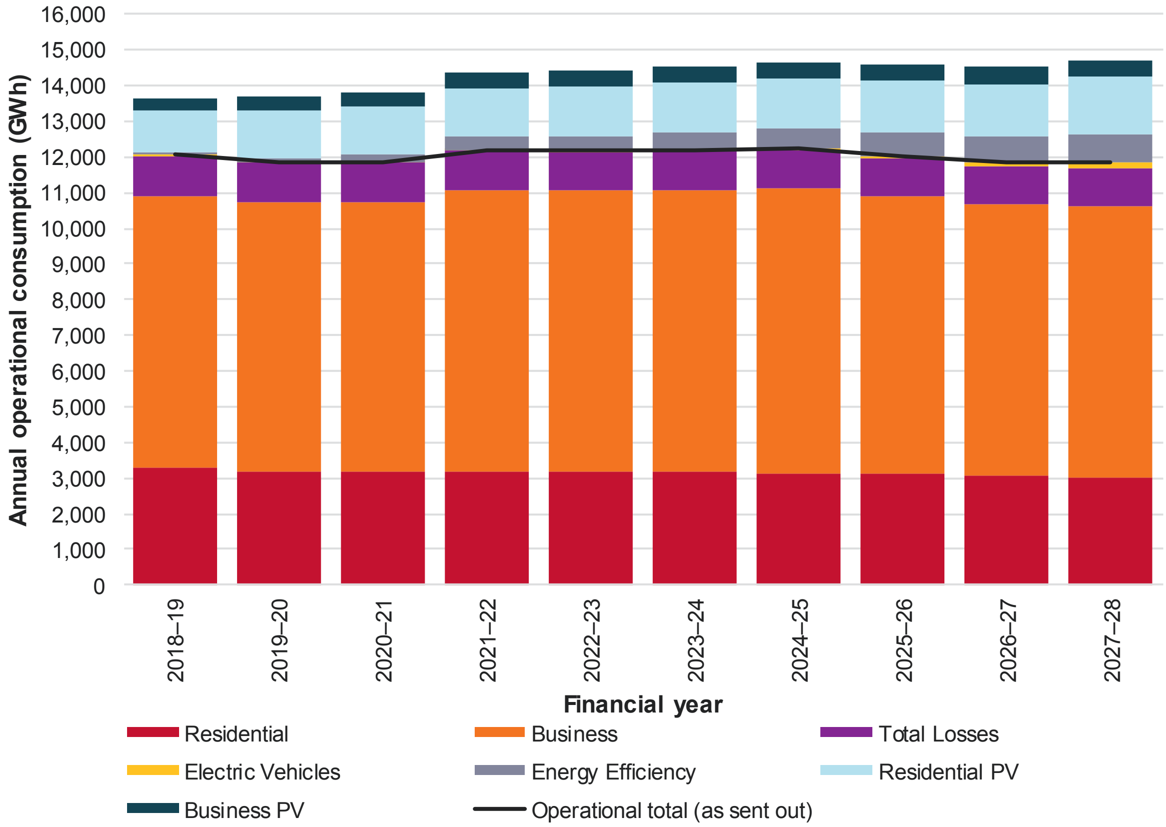
Over the next 10 years, the decline is forecast to level out in aggregate, although there are varying trends projected for individual customer segments.

As shown in Figure 4 below, residential consumption is forecast to continue its decline, driven by only minor growth in population, combined with continued high growth in rooftop PV installations. This is reinforced by ongoing improvement in energy efficiency of appliances, including air-conditioning, and better insulation of houses.

Business consumption remains relatively flat, as growth in the state economy is forecast to offset the decline coming from commercial rooftop PV installations and business sector energy efficiency programs. An assumed expansion in mining load leads to a forecast step change of business consumption around 2021-22.

EV consumption (forecast to reach 155 GWh by 2027-28 in the Neutral scenario) is projected to mostly offset the drop in residential consumption, keeping total forecast operational consumption across South Australia flat overall.

Figure 4 Forecast annual operational consumption (sent out) with stacked components (Neutral scenario)



3.1.2 Operational maximum demand (sent out)

South Australian operational maximum demand (sent out)[24] has historically occurred during periods of hot weather over summer, largely attributed to air-conditioner load.

Impact of rooftop PV on maximum demand

Maximum operational demand used to occur in the mid-afternoon, when cooling demand was at its peak. As rooftop PV capacity has grown, PV generation during daytime has increasingly helped to meet underlying[25] demand, slowly pushing the timing of operational maximum demand to later in the day, when PV generation is lower.

Table 2 shows estimated rooftop PV generation at time of underlying maximum demand for the last four years. As seen, the contribution has grown year on year. The impact on operational maximum demand has been declining as timing has moved to late afternoon/early evening.

As Table 2 also shows, due to the high uptake of rooftop PV in South Australia in recent years, the region already experienced its maximum operational demand at around 7.30 pm (local time) in the summer of 2017-18, and the peak is expected to continue occurring around this time in future.

[24] Maximum demand in this report is the maximum amount of power consumed at any one time in a year. It is measured in megawatts (MW) and averaged over a 30-minute period.

[25] Underlying demand is the energy used by end consumers, from either the grid or other sources behind the meter (on consumers' premises), such as rooftop PV or battery storage.

Table 2 Rooftop PV contribution to underlying and operational maximum demand in South Australia

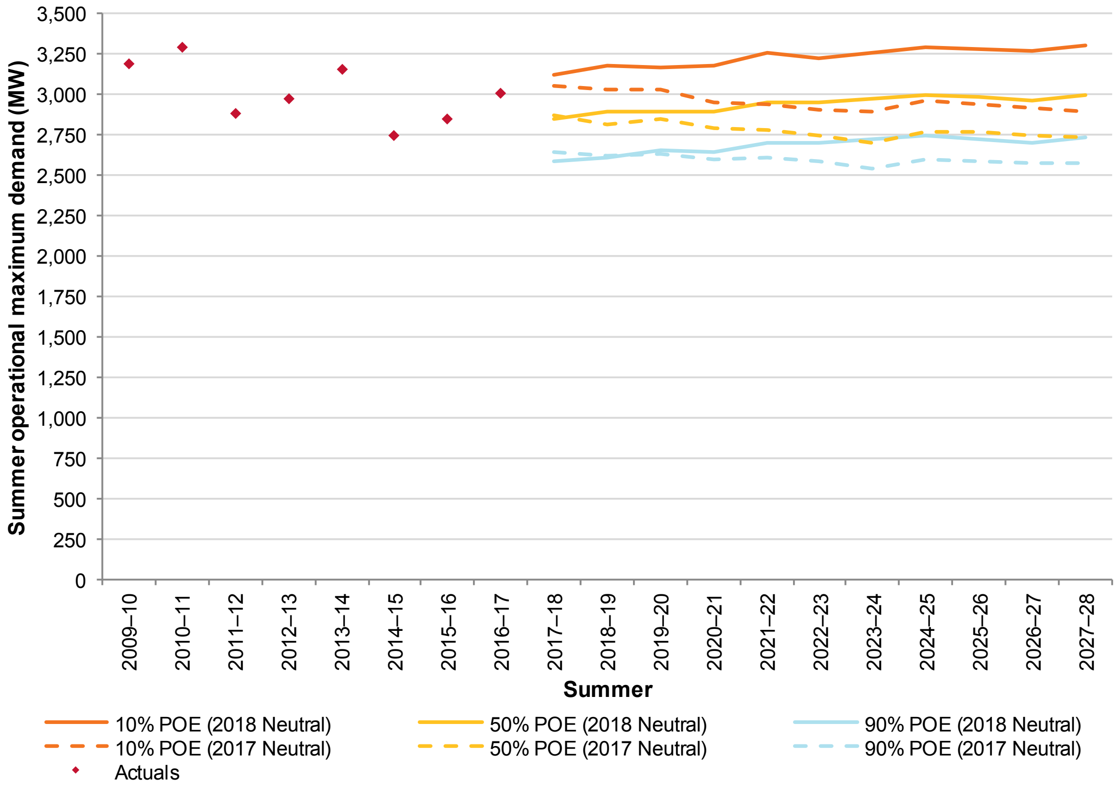
Year	Rooftop PV contribution to underlying maximum demand (MW)	Time of underlying maximum demand (local time)	Rooftop PV contribution to operational maximum demand (MW)	Time of operational maximum demand (local time)
2014-15	308	2:30 pm	152	4:00 pm
2015-16	314	5:00 pm	192	6:00 pm
2016-17	444	4:30 pm	186	6:30 pm
2017-18	495	4:30 pm	82	7:30 pm

Forecast operational maximum demand

Maximum operational demand will continue to be experienced in summer and is expected to be higher due to growth drivers for business load, as well as the expectation that maximum operational demand, on the balance of probability, will peak too late in the day for additional rooftop PV to have a substantial impact offsetting growth in grid demand.

Figure 5 shows historical summer maximum demand actuals since 2009-10, and 10%, 50%, and 90% POE forecasts from the 2018 and 2017 NEM ESOOs (Neutral scenario).

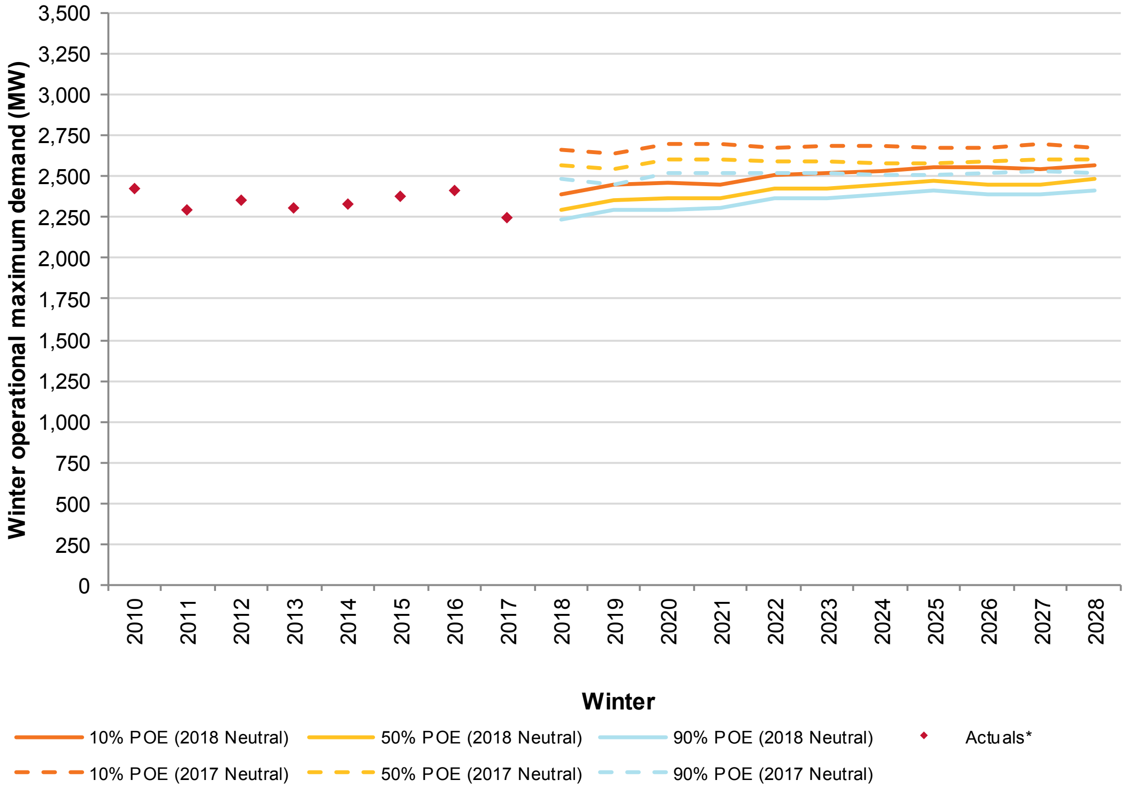
Figure 5 Summer operational maximum demand (sent out) actual and forecast for South Australia, 2009-10 to 2028-29 (Neutral scenario)



The forecast trend differs from that in the 2017 ESOO, due to changes to the forecast impact of energy efficiency on air-conditioner load at time of maximum demand. In addition, the rapid growth of rooftop PV observed in the last year, above what was forecast in 2017, has brought forward the point where rooftop PV is forecast to have a limited contribution to the peak by 3-4 years.

Figure 6 shows the same historical and forecast period for South Australia's operational maximum demand in winter. The 2016 calendar year winter peak was driven by very cold temperatures, while 2017 had much milder weather. Calibrating the model with the latest year of data shifted the forecast values down in 2018.

Figure 6 Winter operational maximum demand actual and forecast for South Australia, 2010 to 2028 (Neutral scenario)



* Actual values are estimates sourced from the 2018 ESOO which are subject to change and are hence different to those in the 2017 SAAF reports.

Demand-side participation (DSP)

An alternative to adding grid generation to help meet the maximum operational demand is to seek resources on the demand side.

Consumption may be reduced voluntarily by customers exposed directly to the wholesale price, in cases where prices are high at times of maximum demand. More commonly, the reduction is automatically controlled by retailers or DSP aggregators which have signed up loads to reduce at different price levels, to provide price hedging in the market.

DSP reflects the capability of demand-side resources (customer load reductions or generation from customers' embedded generators) to reduce operational demand at times of high wholesale prices or emerging reliability issues. DSP captures direct response by industrial users and consumer response through programs run by retailers, DSP aggregators, or network service providers.

The estimated level of DSP available in South Australia for summer 2017-18 and winter 2018 is shown in Table 3 below. It reflects the observed 50% POE DSP resource response to different wholesale price levels in recent years. Reliability response DSP estimates are also included, referring to situations where additional DSP is observed in response to a Lack of Reserve (LOR) notice (LOR 2 or LOR 3) being issued[26].

[26] See National Electricity Rules, rule 4.8.4 for definitions.

Note that:

- Typical response at time of maximum demand by any embedded generators is captured as part of AEMO's forecast for small non-scheduled generation and is excluded from the DSP estimates below.
- Actual responses vary significantly from occasion to occasion, and the amount of time these resources may be reduced or removed from service to lower demand may also vary.

Table 3 shows the estimated cumulative price response is 2 MW for South Australia when prices exceed $500 per megawatt hour (MWh), and 5 MW when prices exceed $5,000/MWh. However, if LOR conditions are declared, the total DSP response is estimated to be 6 MW in South Australia[27].

Table 3 Estimated DSP by wholesale price levels and reliability response* for South Australia

Trigger	Summer 2017-18 (MW)	Winter 2018 (MW)
>$300 / MWh	1	1
>$500 / MWh	2	2
>$5,000 / MWh	5	5
>$7,500 / MWh or in response to LOR notices	6	6

* Reliability response refers to situations where a Lack of Reserve notice (LOR 2 or LOR 3) is issued.

The current average level of DSP from larger customers is relatively small, noting there are times where response can be significant. Additional DSP is, however, available through the ARENA/AEMO DSP program, which can be triggered through the Reliability and Emergency Reserve Trader (RERT) process, as discussed in Section 7.2.1.

3.1.3 Operational minimum demand

Operational minimum demand[28] generally occurs in summer in South Australia, typically during weekends or public holidays. Although underlying demand is higher in summer, rooftop PV provides a higher contribution to offset grid demand. As installed rooftop PV capacity increases, minimum demand has been declining.

AEMO forecasts minimum operational demand because low operational demand introduces operational challenges for balancing the power system. The proposed new interconnector between South Australia and New South Wales, and increased aggregation/central co-ordination of DER, would help mitigate these risks (refer to Section 7 and Section 8 for details on current programs of work to address these challenges).

Figure 7 shows the 90% POE forecasts[29] for South Australian minimum demand. Key insights include:

- South Australia is the first NEM region in which high rooftop PV penetration caused minimum demand to shift from overnight to near midday, in 2012-13.
- Since 2012-13, annual minimum demand has decreased as rooftop PV capacity increased.
- Minimum operation demand (sent out) in 2017-18 was 645.6 MW and occurred at 1:30 pm on 5 November 2017.
- In recent years, South Australia has experienced relatively warm summers. If South Australia was to experience the cold summers it did in 2002 or 2005, the mild temperatures coupled with installed PV capacity could produce significantly lower minimum demand values than seen recently.

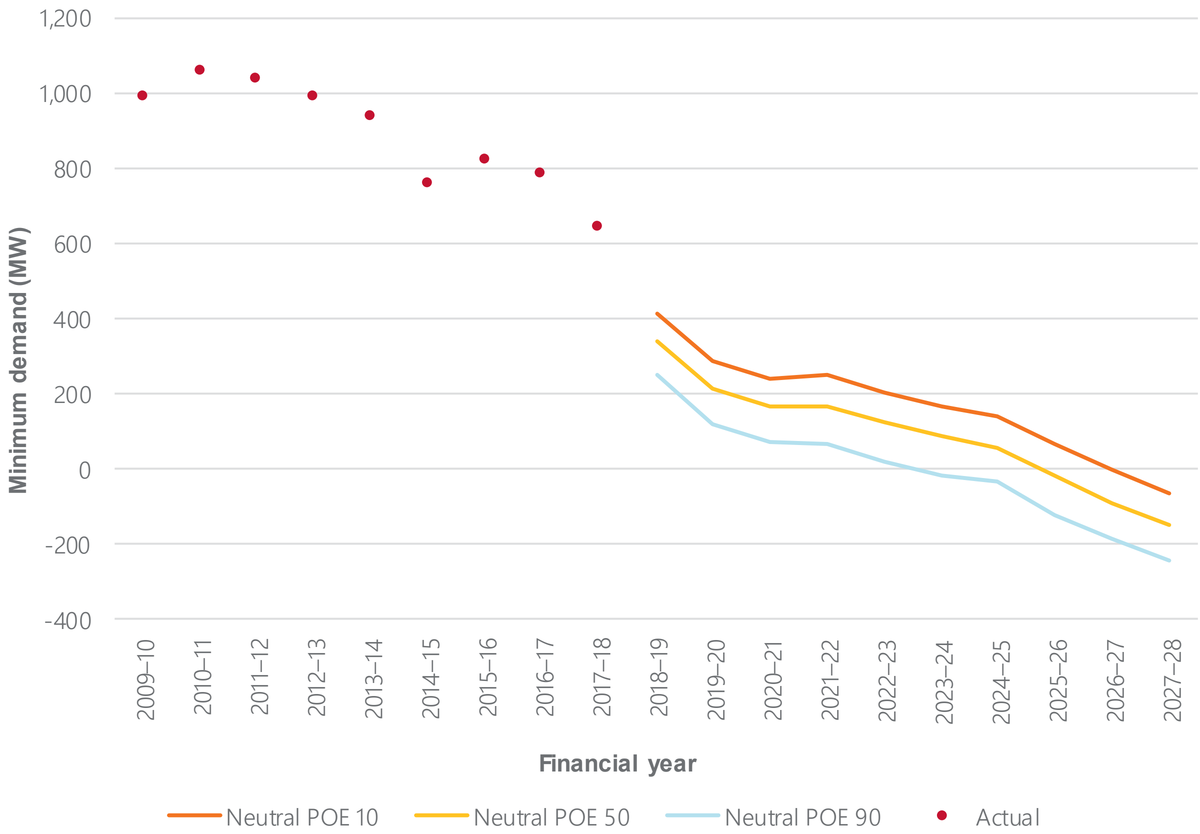
[27] The capacities listed exclude any DSP procured through the Reliability and Emergency Reserve Trader (RERT) process, including the joint DSP program by ARENA and AEMO.

[28] Minimum demand in this report is the lowest amount of power consumed at any one time in a year. It is measured in megawatts (MW) and averaged over a 30-minute period.

[29] Like a 10% POE maximum demand forecast, this is expected to be met or exceeded only one year in 10.

- As Figure 7 shows, AEMO forecasts negative minimum demand for the region under certain conditions by 2023-24. For 90% POE minimum demand days, continued uptake of rooftop PV is forecast to offset 100% of demand in South Australia during the middle of the day.

Figure 7 Minimum demand actual and forecasts for South Australia (Neutral scenario)



AEMO has only recently started forecasting minimum demand and is still improving the accuracy of its forecasts. This includes understanding changing behaviour of consumption of households that install PV systems today, in comparison with those which installed PV systems when there were significant feed-in tariffs. Similarly, SAPN has been moving hot water load to the middle of the day (see next section) which could have affected results. AEMO will seek to capture these aspects better in future forecasts.

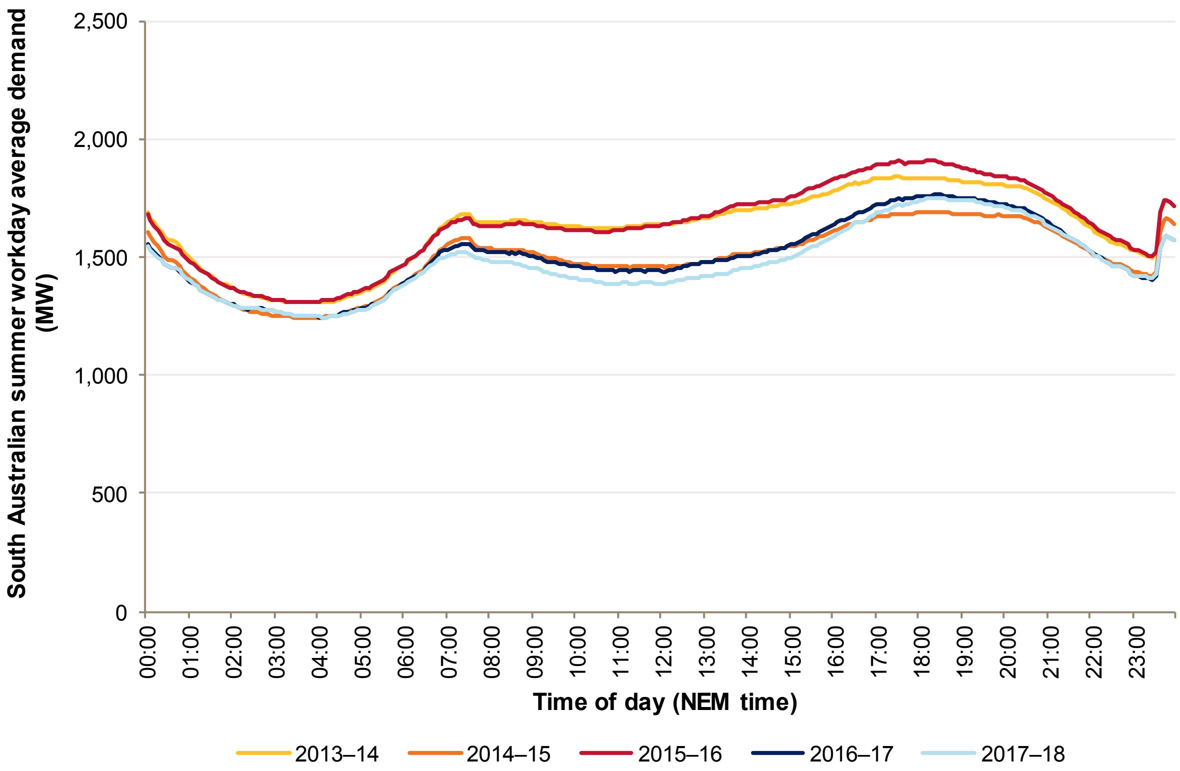
3.2 Daily demand profiles

The average daily demand profiles represent the demand, in megawatts (MW), for each 5-minute dispatch interval of a day, averaged over the relevant days of the selected period. Changes to the average daily demand profile over time can provide insights into the impact of increasing small-scale renewable generation and demand side management. Only South Australian workdays are included in the analysis. Weekends and gazetted public holidays are excluded.

Summer

Figure 8 shows the South Australian average workday demand profile for summer 2013-14 to 2017-18. Average summer demand year-on-year has been generally declining in daylight hours, due to increasing rooftop PV generation following a continual growth in installations (along with overall energy efficiency gains).

Figure 8 Summer workday average demand profiles



Seasonal hot weather still plays a large role in shaping overall demand. For example, in 2015-16, Adelaide experienced heatwaves and record-breaking daytime temperatures which led to a much higher average demand over the summer period than in the adjacent years.

Another noticeable feature in the demand profile is the sharp uptick from 11:30 pm (NEM time[30]), due to the controlled switching of electric hot water storage systems. SAPN has been moving some of the hot water systems away from the night-time timer setting to turn on during mid-day instead. Additional residential customer hot water loads may have been moved by retailers as smart meters are being installed. This has lowered the observed night time peak and reduced the drop in mid-day demand.

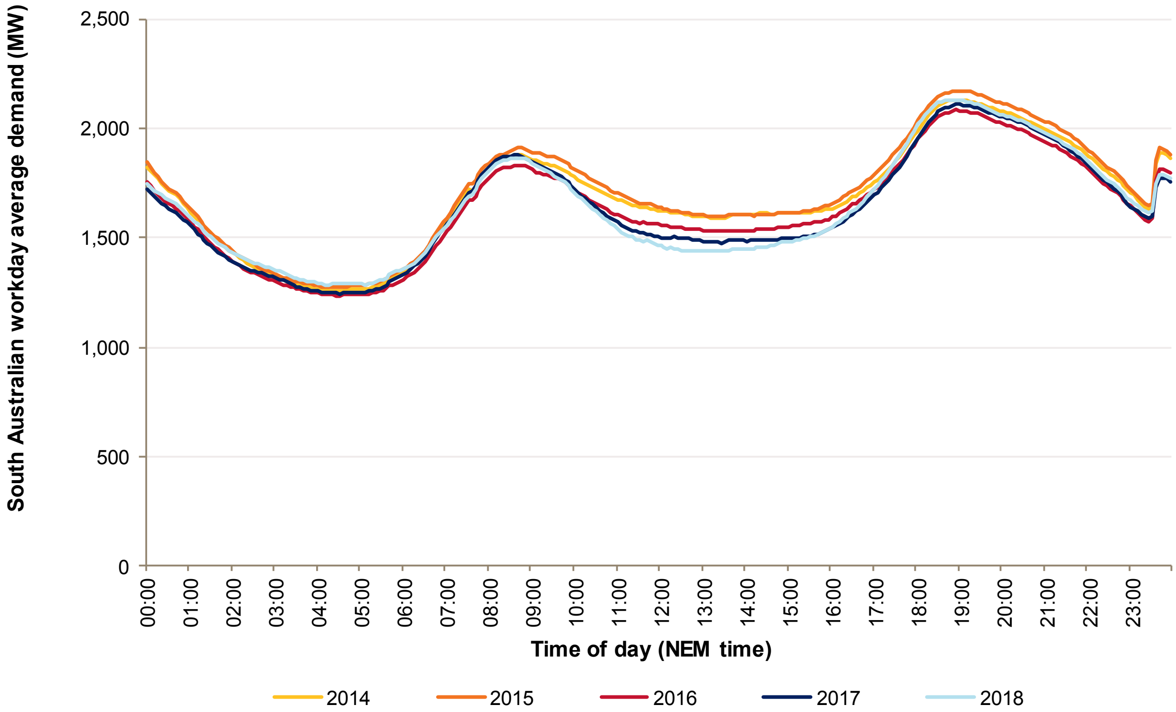
Winter

Figure 9 shows the South Australian average winter workday demand profile for winter 2013-14 to 2017-18.

A noticeable morning peak is followed by an evening peak in winter, reflecting a combination of demand increases as the workday commences/ends. Reduced grid demand is observed in the daylight hours, due to the increased output of rooftop PV. Evening peaks can be attributed to continual demand from the grid, mainly for domestic heating.

[30] NEM time, or market time, is defined as Australian Eastern Standard Time (AEST) with no daylight savings applied.

Figure 9 Winter workday average demand profiles



4. Existing and committed supply

The generation capacity mix in South Australia has continued to evolve, with an overall increase of 14% of total installed capacity[31] in 2017-18 compared with the previous year, mainly due to an increase in wind, rooftop PV, and diesel generation, and large-scale battery storage at Hornsdale Power Reserve (HPR).

Generation increased by 27%, despite a slight reduction in operational consumption, resulting in less reliance on imports and more exports, and was taken up in relatively equal proportion by South Australian consumption and export via the interconnectors. The 2017-18 financial year marked the first time in nine years that South Australia was a net exporter of electricity. Overall the proportion of contribution from different generation sources has remained similar to the previous year, with over 50% coming from gas.

Approximately 700 MW of new generation and storage capacity is committed in South Australia, as of 31 July 2018, comprising wind, solar, gas, and battery storage projects.

4.1 Historical capacity and generation

4.1.1 Historical capacity

The supply capacity mix in South Australia has continued to evolve. As can be seen in Table 4, there have been increases in the 2017-18 financial year in wind, rooftop PV, and diesel installed capacity, as well as new categories for large-scale battery storage capacity (the HPR) and large-scale solar (Bungala One Solar Farm).

The overall registered capacity (excluding other non-scheduled generation, but including rooftop PV) increased 14% from 5,436 MW in 2016-17 to 6,205 MW in 2017-18. This was driven by a combination of the increase in diesel and small non-scheduled capacity nearly doubling from 289 MW to 562 MW (primarily due to temporary diesel generation), increase in wind capacity from 1,698 MW to 1,809 MW (from starting the operation of Hornsdale Wind Farm Stage 3), increase in rooftop PV capacity from 781 MW to 930 MW, and commissioning of Bungala One Solar Farm (110 MW) and the HPR Unit 1 battery (100 MW).

New significant scheduled and semi-scheduled generators that started operation in 2017-18 are:

- Bungala One Solar Farm (110 MW).
- Hornsdale Wind Farm Stage 3 (112 MW).
- HPR Unit 1 (100 MW).
- Temporary Generation North (154 MW).
- Temporary Generation South (123.2 MW).

[31] Registered capacity, excluding other non-scheduled generation, but including rooftop PV.

Table 4 South Australian registered capacity and local generation by energy source in 2017-18

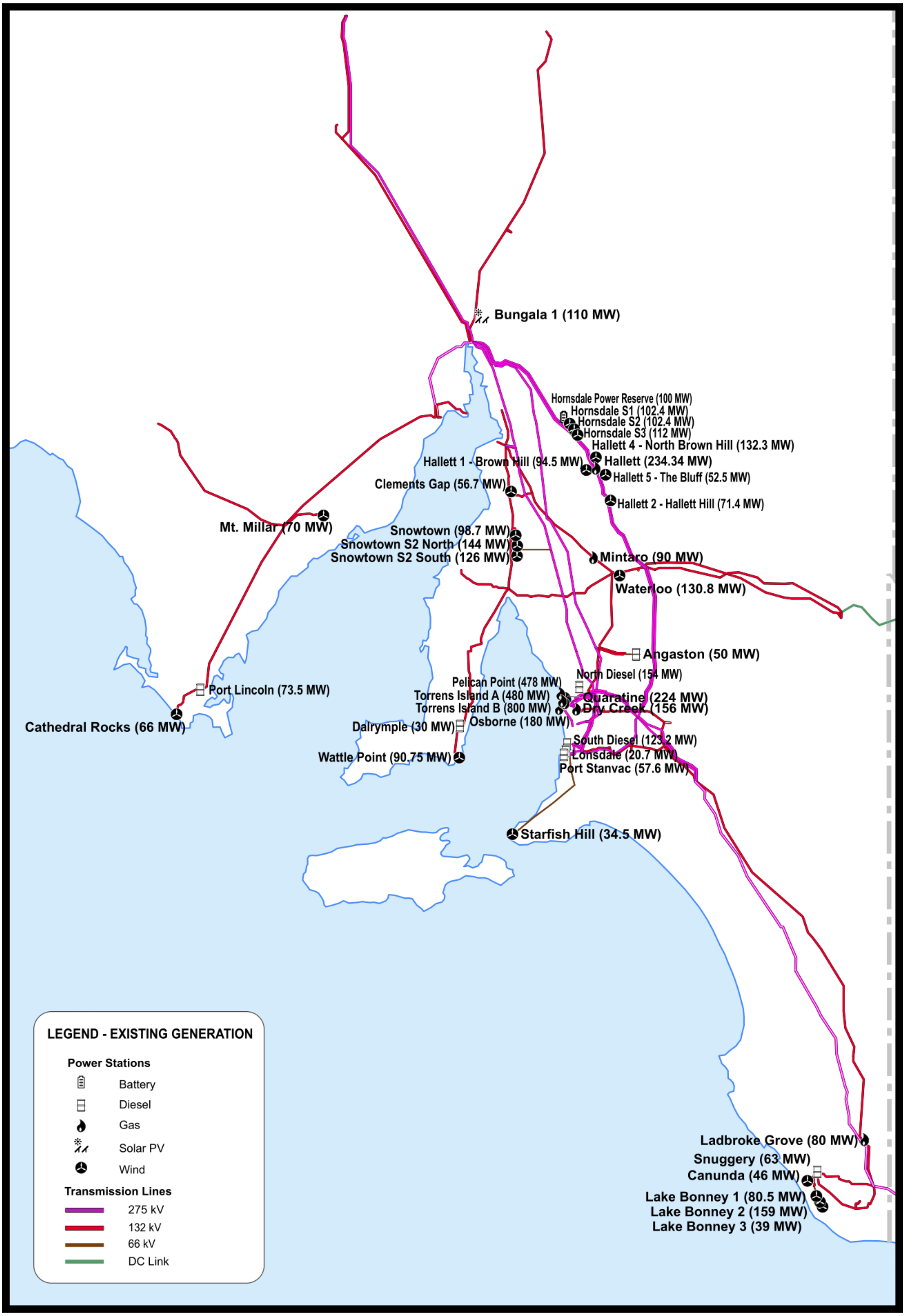
Energy source	Registered capacity		Electricity generated	
	MW	% of total	GWh	% of total
Gas	2,668	43.0%	7,272	51.3%
Wind	1,809	29.2%	5,536	39.0%
Coal	0	0.0%	0	0.0%
Diesel + small non-scheduled generation (SNSG)*	562	9.1%	190	1.3%
Rooftop PV**	930	15.0%	1,162	8.2%
Solar***	135	2.2%	4	0.0%
Storage****	100	1.6%	22	0.2%
Total	6,205	100%	14,186	100%

* Diesel + SNSG includes small and large diesel, small landfill methane, hydro generating systems, and PV non-scheduled generation (PVNSG). After an improvement in the estimation for actual PVNSG installation data based on updated CER information and as used during the production of the 2018 ESOO, PVNSG (and hence SNSG) generation data has changed from what was previously reported in the 2017 SAAF reports.
** Rooftop PV installations are not registered with AEMO but are included here given their material contribution to generation. Rooftop PV capacity and generation estimates as listed build on those presented in the 2018 NEM ESOO forecasts.
*** Solar category was added in this year's report to account for new large-scale solar generators in this category such as Bungala One Solar Farm.
**** Storage category was added in this year's report to account for new entrants such as the Hornsdale Power Reserve Battery

4.2 Historical generation

Figure 10 shows the location, nameplate capacity, and energy source of registered operational generators in South Australia (all scheduled, semi-scheduled, and significant non-scheduled generators used in operational reporting). More details of existing generators can be found in the supporting data pack.

Figure 10 Location and capacity of South Australian generators



Composition of generation

Figure 11 shows the mix of energy generated in South Australia by fuel type from 2013-14 to 2017-18, 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 2018 ESOO).

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

Figure 11 South Australian energy generation by fuel type

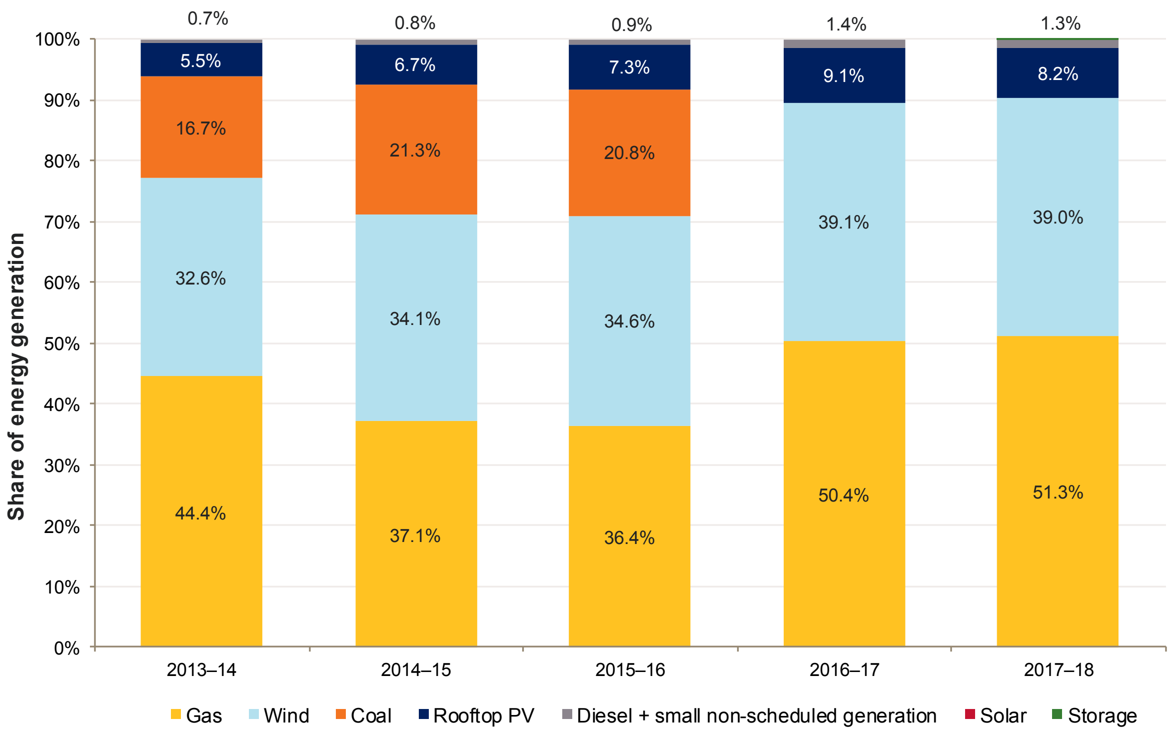


Table 5 expands on the data in Figure 11, focusing primarily on the differences between 2016-17 and 2017-18, and including interconnector flow metrics.

Overall South Australian consumption remained flat between 2016-17 and 2017-18, however South Australia's generation in 2018 increased by 27%. This increase in generation has been split between local use and export, reversing the trend from the past which saw South Australia increasing its imports since 2011-12. After the retirement of Hazelwood Power Station in Victoria, the interconnector flows in 2017-18 were more balanced between exports, with South Australia becoming a net exporter to Victoria. Section 5 provides further insights on interconnector changes.

Generation by fuel type has increased to various degrees between 2016-17 and 2017-18, from 15.5% for rooftop PV to 29.9% for gas, however, the relative contribution of different fuel sources within the total generation mix has stayed close to 2016-17 values. More than 50% of South Australian generation is coming from gas-powered generation (GPG), with coal retirements and system security requirements continuing to affect gas' market share. Pelican Point and Osborne GPG plants saw the largest increases in capacity factor between 2016-17 and 2017-18, with Pelican Point returning to full service. Rooftop PV also saw large increases in installed capacity, particularly in the commercial sector, with new wind capacity and battery storage also contributing to increased generation.

Table 5 South Australian electricity supply by fuel type (GWh), comparing 2016-17 to 2017-18

Local generation by fuel type	2016-17 (GWh)	Percentage share (%)	2017-18 (GWh)	Percentage share (%)	Change (GWh)	Percentage change (%)
Gas	5,596	50.4	7,272	51.3	1,676	29.9
Wind	4,343	39.1	5,536	39.0	1,193	27.5
Coal	0	0.0	0	0.0	0	0.0
Diesel + SNSG	153	1.4	190	1.3	37	22.2
Rooftop PV	1,006	9.1	1,162	8.2	156	15.5
Solar	0	0.0	4	0.0	4	-
Storage	0	0.0	22	0.2	22	-
Total	**11,098**	**100.0**	**14,186**	**100.0**	**3,088**	**27.8**
Interconnector net imports	2,725		-292		-3,017	-111.0
Total imports	2,889		1,039		-1,850	-64.0
Total exports	164		1,331		1,167	712.0

Wind generation summary

South Australia has the highest registered wind generation capacity of any NEM region. Table 6 shows the total capacity for all South Australian semi-scheduled and non-scheduled wind farms registered with AEMO, with the maximum 5-minute generation output, from 2013-14 to 2017-18, and information on installed wind capacity and maximum 5-minute generation.

Table 6 Total South Australian wind generation and capacity

Financial year	Annual wind generation (GWh)	Annual change in wind generation (%)	Annual capacity factor* (%)	Registered capacity (MW)**	Reason for increase in capacity	Maximum five-minute generation (MW) **
2013-14	4,088	-	32	1,473	NA	1,325
2014-15	4,223	3	33	1,473	NA	1,365
2015-16	4,322	2	31	1,576	Hornsdale Stage 1 (102.4MW)	1,384
2016-17	4,343	0	29	1,697	Hornsdale Stage 2 (102.4MW), Waterloo expansion (19.8 MW)	1,546
2017-18	5,536	27	35	1,809	Hornsdale Stage 3 (112MW)	1,618

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

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

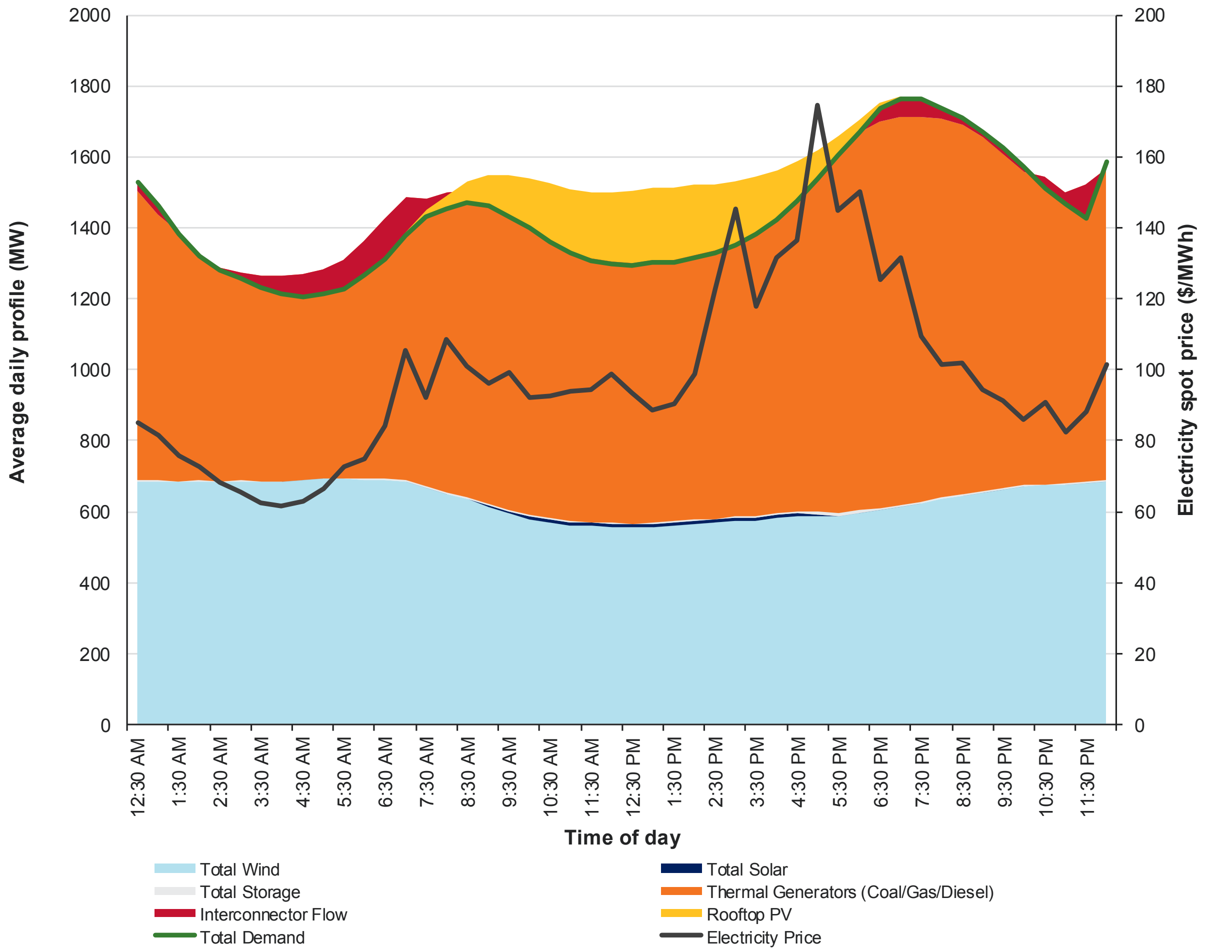
From Table 6, it can be observed that:

- Although installed capacity increased from 2016-17 to 2017-18, wind generation increased by an even greater amount, hence the annual capacity factor for wind increased from 29% to 35%. This was underpinned by increases across all the wind fleet in the state.
- Hornsdale Wind Farm Stage 3 (112 MW) was registered in 2017-18.

4.3 Historical typical day dispatch

The average daily supply profile for South Australia, seen in Figure 12, represents the supply (in MW) for each 30-minute trading interval of a day, averaged over the 2017-18 financial year.

Figure 12 Average daily supply profile averaged for the 2017-18 financial year



The figure displays the average mix of generation dispatched on an average day, split between wind, thermal (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 12 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, providing the requisite energy when necessitated by higher demand or when other generation sources were low.

- The average price correlates closely with average demand, particularly in the early morning hours. Price peaks in the evening are in line with increases in demand from residential loads.
- Interconnector imports mainly occurred in the off-peak periods when solar was not operational.

4.4 Proposed changes to supply

4.4.1 Summary of existing and proposed generation

The nameplate capacity of existing or withdrawn generation, and committed or proposed projects, in South Australia is shown by energy source in Table 7. This includes scheduled, semi-scheduled, and non-scheduled generation information, based on AEMO's July 2018 generator survey results for South Australia[32].

Table 7 Capacity of existing or withdrawn generation, and committed or proposed projects (MW) as at 31 July 2018

Status	CCGT **	OCGT ***	Gas other	Solar ****	Wind	Water	Biomass	Storage	Other	Total
Existing*	662.5	1,198.0	1280.0	121.6	1809.5	3.9	20.5	100.0	144.7	**5340.6**
Announced withdrawal	-	-	480.0	-	-	-	-	-	-	**480.0**
Existing less announced withdrawal	662.5	1,198.0	800.0	121.6	1809.5	3.9	20.5	100.0	144.7	**4860.6**
Committed	-	-	210.0	218.0	251.0	-	-	30.0#	-	**709.0**
Proposed	45.0	624.0	-	2387.5	3329.8	755.0	15.0	488.0	30.0	**7674.3**
Withdrawn	-	-	-	-	-	-	-	-	-	**0.0**

* Existing includes announced withdrawal.
** CCGT: Combined-cycle gas turbine.
*** OCGT: Open-cycle gas turbine.
**** Solar is large-scale solar and excludes rooftop PV installations.
# ElectraNet's 30MW 8MWh Battery Storage system at Dalrymple is now operational.

4.4.2 Generation capacity for the year ahead

Table 8 shows scheduled, semi-scheduled, and significant non-scheduled generation available capacity and estimated firm capacity for summer 2018-19 and winter 2019. The figures are provided by market participants. Differences in scheduled and semi-scheduled generation available capacity between seasons arise from seasonal temperature variations.

In general, summer available capacity for thermal generators is lower than winter, due to higher thermal generation efficiencies at cooler ambient temperatures.

[32] The total South Australian capacity of 6,205 MW in Table 4 in Section 4.1.1 is higher than shown here because a) it includes rooftop PV capacity and additional small non-scheduled generation, and b) it reports the originally registered capacity, not the current nameplate capacity as in Table 7.

Table 8 Scheduled, semi-scheduled, and significant non-scheduled generation available capacity

Energy source*	Summer 2018-19 available capacity (MW)	Winter 2019 available capacity (MW)
Diesel	453	511
Gas	2,520	2,696
Wind (semi-scheduled)	1,399	1,659
Wind (significant non-scheduled)**	388	388
Solar	110	110
Storage	100	100
Total	4,970	5,464

* Coal generation is permanently withdrawn from the market and is therefore excluded from this table.
** Significant non-scheduled wind farms do not provide 10-year availability forecasts to AEMO, therefore available capacities are based on nameplate rating.

4.4.3 Committed supply developments

As of 31 July 2018[33], 218 MW of new solar generation projects and approximately 251 MW of new wind generation projects are committed in South Australia:

- Bungala Two Solar Farm (110 MW), due to be operational by November 2018[34].
- Tailem Bend Solar Farm (108 MW) due to be operational by Winter 2019.
- Lincoln Gap Wind Farm Stage 1 (126 MW) due to be operational by April 2019.
- Willogoleche Wind Farm (95 MW to 125 MW) due to be operational by October 2018[35].

In addition to the committed solar and wind generation projects mentioned above, there are also committed projects focusing on rapid-start gas technology and battery storage:

- Barker Inlet Power Station (210 MW), due to be operational by August 2019, is expected to be capable of operating at full capacity within five minutes.
- ESCRI Dalrymple Battery Storage (30 MW / 8 MWh)[36].

Commentary on publicly announced and other future generation is presented in Section 8.3.

4.5 Emissions intensity

Annual NEM emissions for the 2017-18 financial year were the lowest on record, in terms of both absolute emissions and emissions intensity[37]. Drivers behind the downward trend in annual NEM emissions include the closure of Hazelwood Power Station and increased renewable generation[38].

[33] Date based on latest AEMO Generation Information Page at time of writing. A more recent version may be available by time of publication at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

[34] Considered committed at time of publication.

[35] Considered committed at time of publication.

[36] Considered operational at time of publication.

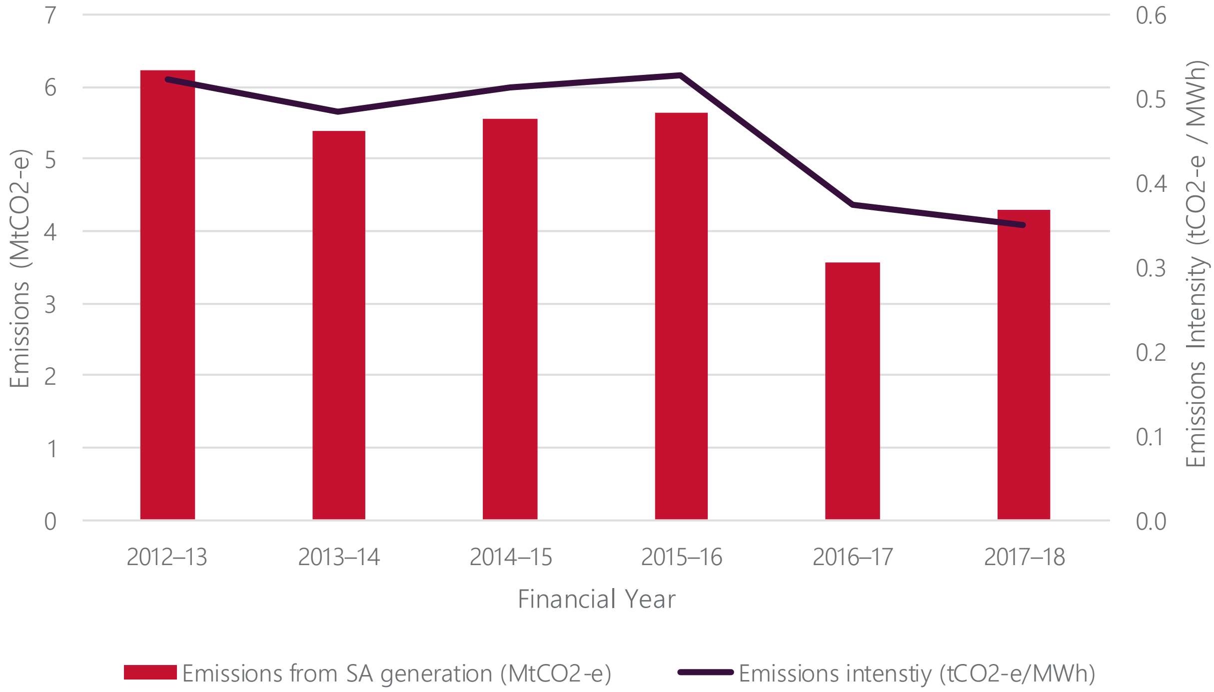
[37] See http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Settlements-and-payments/Settlements/Carbon-Dioxide-Equivalent-Intensity-Index.

[38] AEMO *Quarterly Energy Dynamics – Q2 2018*, available at https://www.aemo.com.au/-/media/Files/Media_Centre/2018/QED-Q2-2018.pdf.

In South Australia, as can be seen in in Figure 13, the emissions from generation in 2017-18 increased compared to 2016-17, due to an absolute increase in regional generation, however, the emissions intensity of the grid reduced by 6%[39]:

- Higher emissions were a function of increased local GPG, particularly at Pelican Point which returned to full capacity in early 2017.
- The continued decline in emissions intensity reflects increased wind penetration in the region.

Figure 13 South Australian annual emissions and emissions intensity



[39] See http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Settlements-and-payments/Settlements/Carbon-Dioxide-Equivalent-Intensity-Index.

5. Transmission interconnectors

South Australia is connected to the rest of the NEM via two interconnectors, Heywood and Murraylink. While imports to South Australia have been growing over the past nine years, in 2018 the trend was reversed, and South Australia was a net exporter.

Following completion of testing, an increase in transfer capacity on Heywood from Victoria to South Australia is expected in late 2018. Murraylink is also undergoing work to reduce congestion for summer readiness, with the New South Wales Murraylink Runback scheme expected to be in service from late 2018, removing some congestion on that link.

The ISP identified the need for upgrades and a new interconnector between South Australia and New South Wales to help use resources more efficiently between South Australia, New South Wales, and Victoria and help mitigate power system security risks.

5.1 Historical imports and exports

South Australia currently imports and exports power to the rest of the NEM through two interconnectors – Heywood and Murraylink:

- The Heywood interconnector represents the 275 kilovolt (kV) lines between Heywood substation in Victoria and South East substation in South Australia. This interconnector was originally commissioned in 1989, and was upgraded in 2015-16 to a nominal design limit of up to 650 MW in either direction of flow. To realise this capacity, a testing program must be completed to verify stability limits. This is expected to be completed in late 2018.
- Murraylink is the direct current (DC) cable between Red Cliffs in Victoria and Monash in South Australia. It is a 220 MW DC cable that was commissioned in 2002.

Figure 14 shows the total actual interconnector imports and exports for South Australia from 2008-09 to 2017-18. Total interconnector imports from Victoria to South Australia decreased significantly while total exports increased significantly between 2016-17 and 2017-18. This caused South Australia to be a net exporter of electricity for the first time in the past 10 years. As already discussed, this change is driven by the continued increase in wind and solar generation in South Australia and the decrease of coal-fired generation in Victoria following Hazelwood Power Station's closure at the end of March 2017.

In Figure 14:

- The orange column bars above the 0 GWh line (x-axis) shows the annual energy imported into South Australia from Victoria. From 2008-09 to 2016-17, there has been a steady increase in annual imports from Victoria to South Australia. In 2017-18, the average annual import decreased to almost one-third of the annual imports in 2016-17.
- The yellow bar below the line shows the energy exported from South Australia to Victoria. Over the past 10 years, the highest annual export is observed in 2017-18.

Figure 14 Total interconnector imports and exports

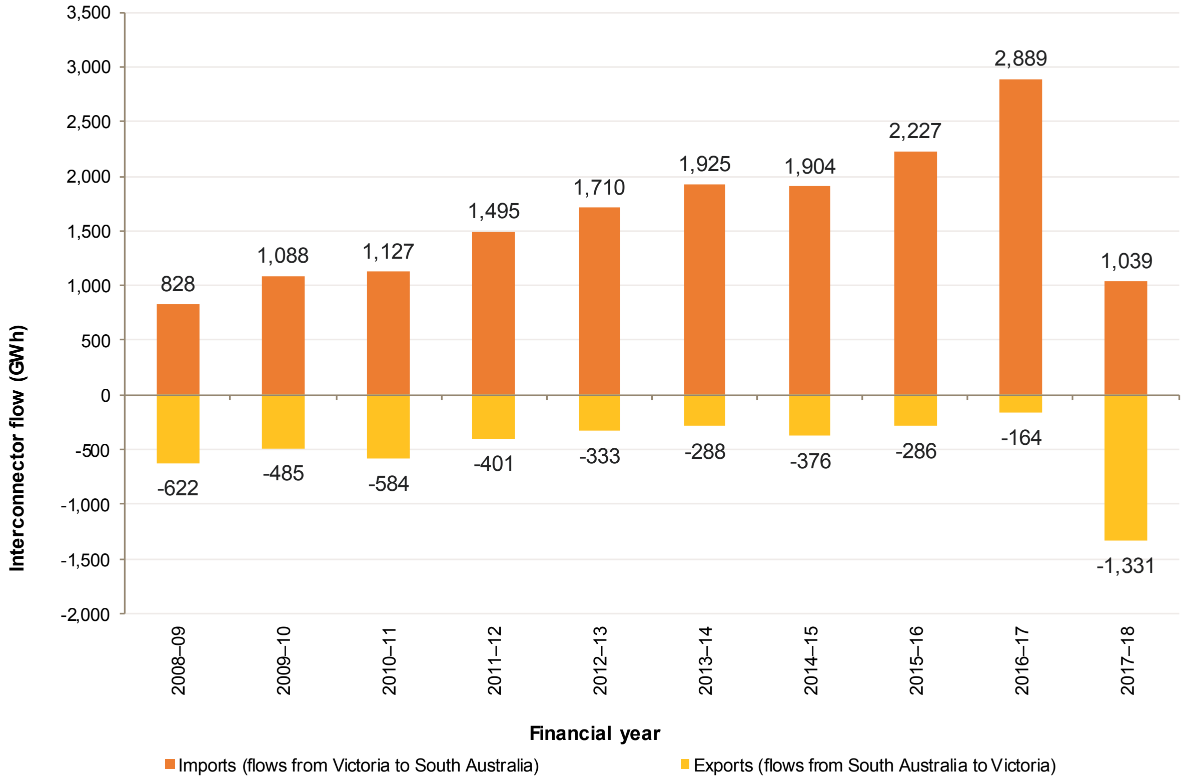
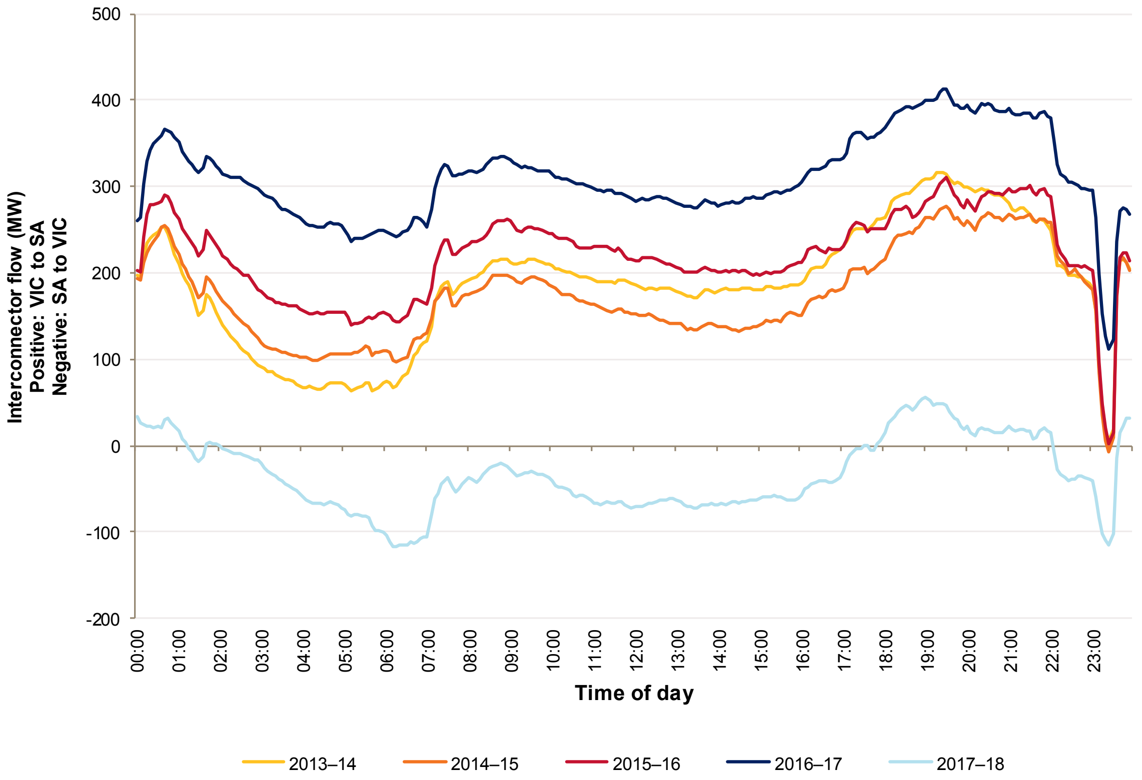


Figure 15 shows the annual flow patterns for combined interconnector imports (from Victoria to South Australia), averaged by the time of day (with times expressed in NEM time).

Figure 15 Combined interconnector daily 5-minute average flow



The figure shows that, on average, both interconnectors tended to export electricity, except during early off-peak hours (hour 00:00 to 03:00, 23:00) and peak hours (hour 18:00 to 22:00), where they tended to import electricity. On average, the highest combined interconnector import was between 6:00 pm and 10:00 pm and exports between 2:00 am and 7:00 am – coinciding with the peaks and troughs in South Australian demand. The sudden dip and subsequent spike in imports occurring around 11:30 pm to midnight is caused by automated "off-peak" electric hot water systems in South Australia.

5.2 Progress of transmission upgrade projects

To facilitate better sharing of reserves at times of low renewable generation and better export opportunities at times of high renewable generation, South Australia will benefit from stronger interconnection to neighbouring regions.

A series of upgrades and new projects are in progress:

- Heywood:
  - Increase the rating of the interconnector in the direction from Victoria to South Australia from 600 MW to 650 MW (following completion of testing expectedly in late 2018).
  - Implement an over-frequency generator shedding scheme by ElectraNet, which when tested is expected to lift the transfer limit in the direction from South Australia to Victoria from 500 MW to 550 MW (by the end of 2019).
- Murraylink:
  - The NSW Murraylink Runback scheme (expected to be in service from late 2018), will reduce the risk of voltage collapse and network issues in southern New South Wales – normally associated with high demand conditions – so that a stability constraint doesn't limit transfer of power from Victoria to South Australia. This will improve the ability to access the full capacity of the Murraylink interconnector.
- Proposed build of New South Wales interconnector with South Australia, which is in the investment test phase[40].

[40] See https://www.electranet.com.au/projects/south-australian-energy-transformation/ for more information.

6. Electricity spot price

With increased availability and operation of GPG and increased renewable generation, time-weighted average wholesale prices in South Australia decreased in real terms between 2016-17 and 2017-18 and price volatility was reduced.

FCAS prices were also lower than 2016-17 levels.

6.1 Historical wholesale electricity prices

Table 9 shows that in 2017-18, the time-weighted average price (TWAP) was $98.10/MWh, an 11% decrease in real terms from the previous financial year average.

Contributors to the price reduction included:

- Increased supply – Pelican Point combined-cycle gas turbine (CCGT) returned to full service (from partial mothballing) in April 2017, resulting in average 2017-18 output increasing to 309 MW (from 135 MW in 2016-17). In addition, increased availability of Osborne Power Station enabled it to increase its average output by 40 MW.
- Reduced price volatility – see Section 6.1.1 for more detail.

Compared to other regions, South Australia remains the highest priced region in the NEM.

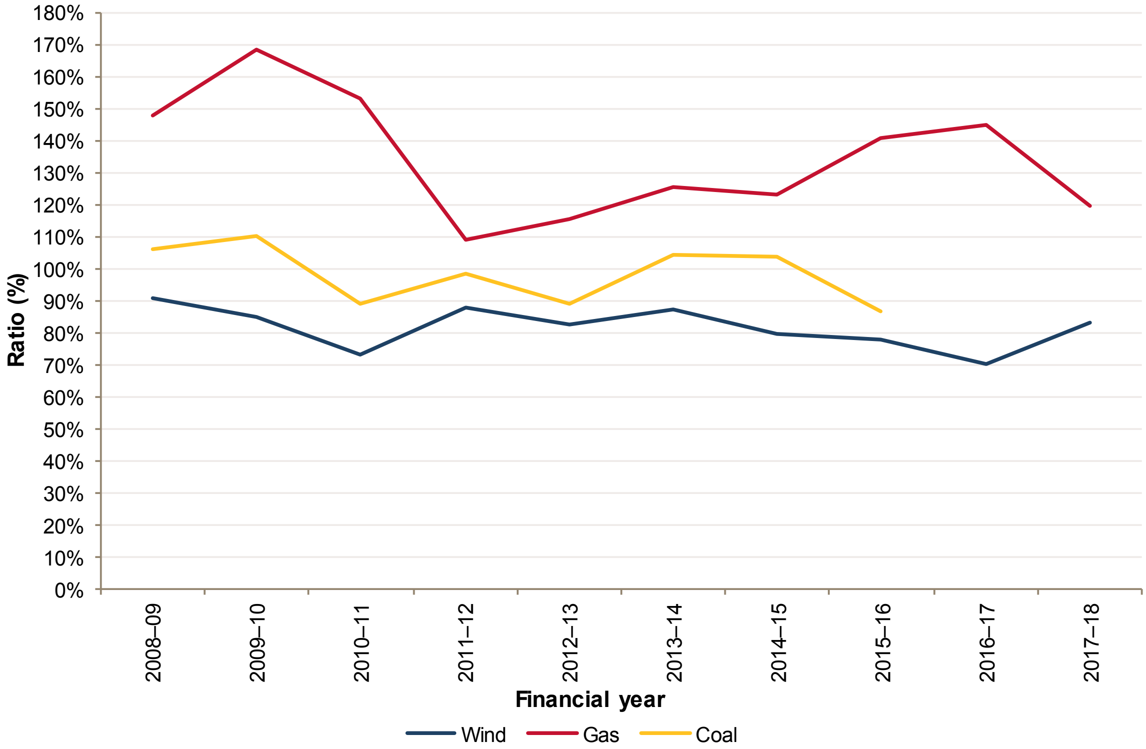
Table 9 2017-18 time-weighted average prices for the NEM (nominal)

	Queensland	New South Wales	Victoria	South Australia	Tasmania
Time-weighted average	72.87	82.27	92.33	98.10	86.98

The volume-weighted average price (VWAP) by fuel type represents the average price received by each fuel technology. Higher operation during high-priced periods will result in a higher VWAP, and as a relative percentage to the TWAP, as shown in Figure 16, the following is observed:

- Gas VWAP remained above the TWAP, reflecting the tendency for gas generators to operate during high priced events and operate less (or cycle offline) during low prices.
- Wind VWAP remained below the TWAP, as high wind generation, typically bid at low prices, tends to drive down the wholesale price. Also, average wind generation tends to be higher during overnight periods, which is also when demand, and prices, are typically low.
- In 2017-18 the ratio between TWAP and VWAP for wind and gas have moved closer together than in 2016-17, indicating a reduction in price volatility.

Figure 16 Ratio of VWAP by fuel to total TWAP



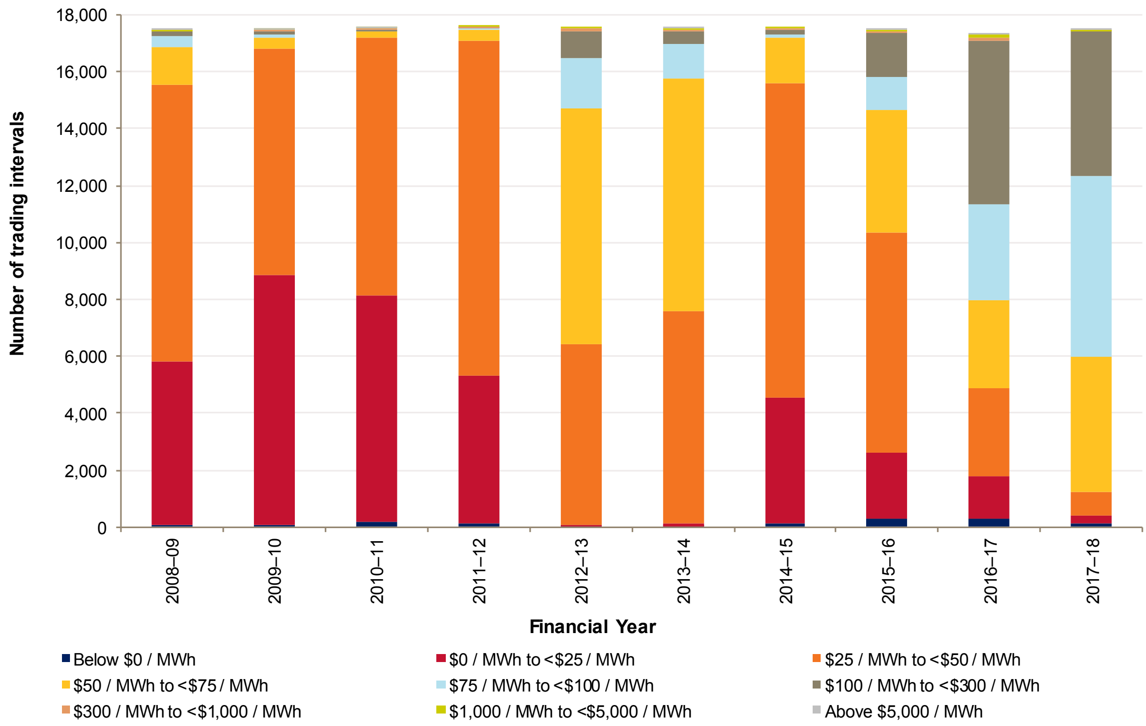
6.1.1 Price volatility

In 2017-18, there were fewer occurrences of both negative prices and prices above $300/MWh than in 2016-17. The following points outline noticeable changes over 2017-18:

- Negative prices occurred 0.8% of the time, down from 1.7% in 2016-17, representing the lowest number of negative price periods since 2013-14. Negative prices typically occurred during periods of high wind output, low demand, and when thermal plants typically bid below operating costs to maintain generation volumes at or above minimum stable levels. Section 6.4.1 provides further details on negative price periods.
- Prices exceeded $300/MWh 0.7% of the time in 2017-18, a significant decrease from 2016-17 (where prices exceeded $300/MWh 2.3% of the time). Contributors to this reduction included:
  - Increased supply, particularly from Pelican Point and Osborne power stations.
  - A reduction in high demand periods. In 2017-18, South Australian operational demand exceeded 2,500 MW 0.47% of the time, representing a 25% decrease on 2016-17 levels. This was despite summer temperatures in Adelaide being warmer in 2017-18 than 2016-17, suggesting that rooftop PV installations contributed to lower relative operational demand levels.
- Occurrence of prices in the $0-25/MWh and the $25-50/MWh bands continued to reduce, with corresponding increases in the $50-75/MWh and $75-100/MWh bands. This reflects changes in the marginal cost of generation following retirement of coal in both South Australia and Victoria.

South Australia has experienced varying levels of electricity spot price volatility throughout its participation in the NEM. This can be shown by the frequency of spot price occurrence in different pricing bands, as seen in Figure 17.

Figure 17 Frequency of occurrence of spot prices for South Australia



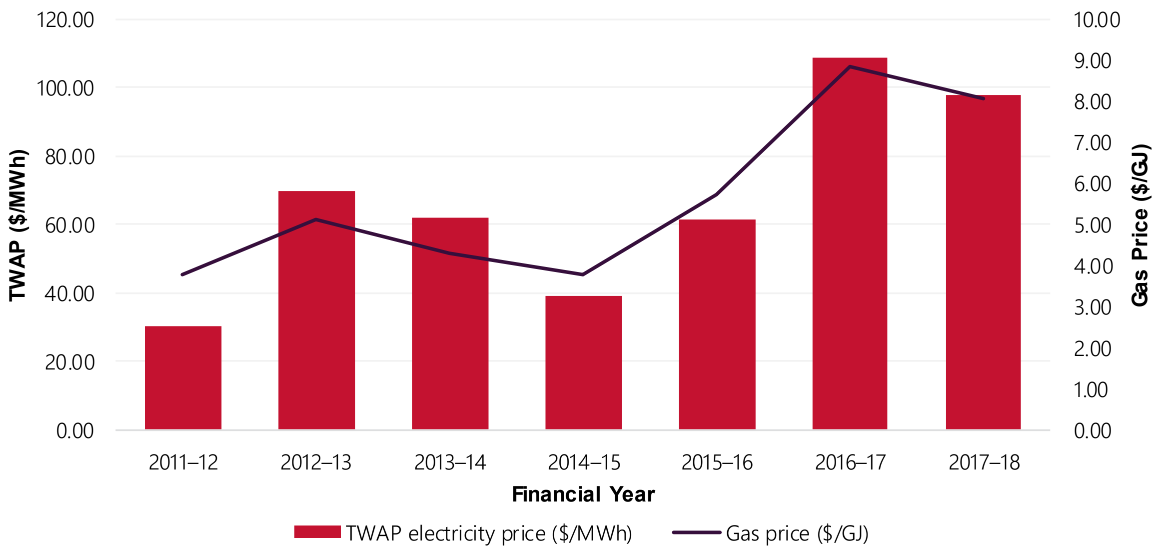
6.2 Impact of changes in generation mix

6.2.1 South Australian energy and price trends

Historical average electricity and gas price trends are shown in Figure 18. Both electricity and gas prices have fluctuated each year, following a similar trend to each other. This demonstrates the inter-relationship between the two, given the relatively large role of GPG in the South Australian energy mix.

Between 2016-17 and 2017-18, average electricity TWAP and gas prices both decreased in South Australia by approximately 9-10%.

Figure 18 South Australian electricity prices relative to gas prices



6.2.2 Gas spot price impact on electricity spot prices

In all NEM regions (except Victoria), GPG set the electricity spot price less frequently in 2017-18 than in 2016-17, with hydro generation playing an increasing role in 2018.

Overall, GPG demand for gas in 2017-18 was slightly higher than in 2016-17. Higher NEM prices following the closure of Hazelwood in March 2017 resulted in a substantial increase in GPG demand for gas in the first half of 2017-18. However, in the second half of 2017-18, increased hydro and variable renewable generation has contributed to reduced GPG demand.

Gas prices were lower across all wholesale gas markets for 2017-18, compared to the same period a year earlier. This coincided with increased Queensland supply and record Longford output in 2017.

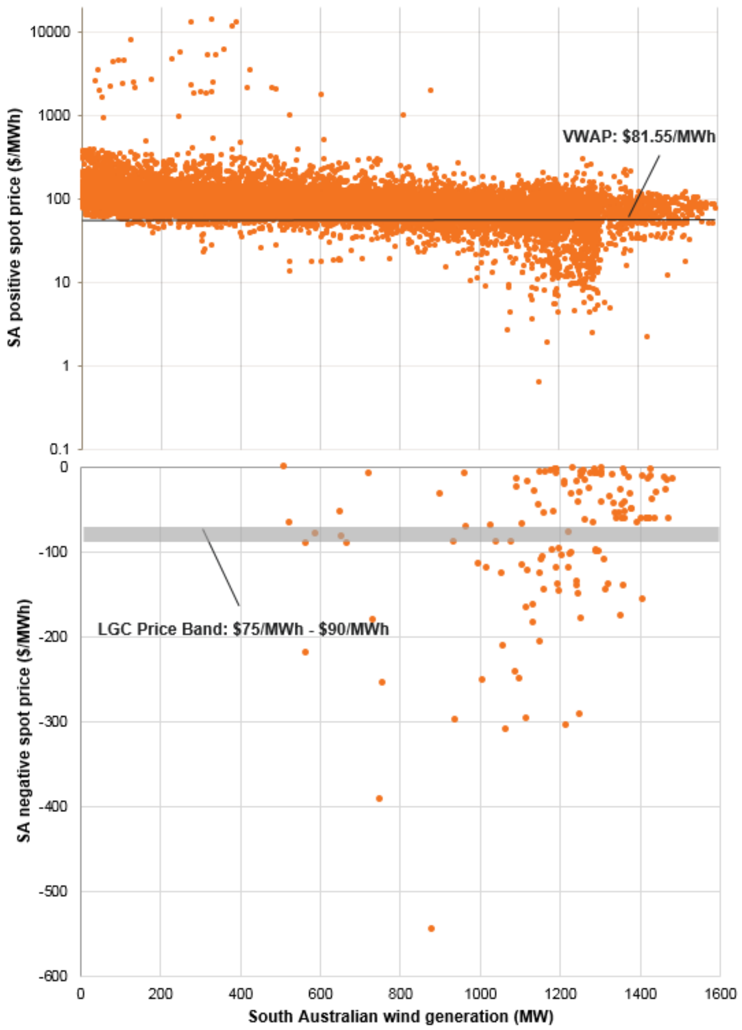
6.2.3 Spot prices and wind generation

Market prices are not typically set by wind generators, except during periods of high wind and low demand. However, the volume of wind generation online does reduce the need for conventional thermal generation, influencing spot prices even if not setting them by being the marginal generator.

Figure 19 shows spot prices for the South Australian region and the corresponding average wind generation levels for each 30-minute dispatch interval for 2017-18. Key points include:

- 75% of prices above $1,000/MWh occurred when wind generation was lower than 400 MW.
- 87% of the negative price occurred when wind generation was greater than 1,000 MW.

Figure 19 South Australian 30-minute spot prices and average wind generation for 2017-18

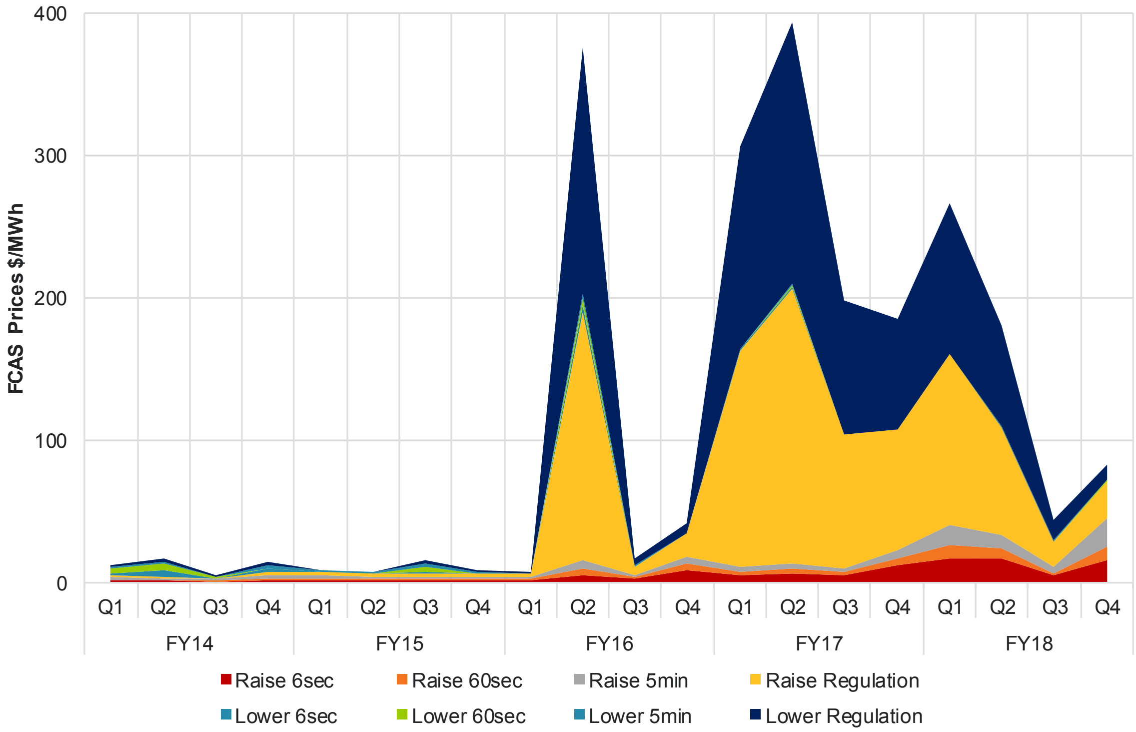


6.3 Frequency control ancillary services (FCAS) market price

In the NEM, generation and demand are balanced through the central dispatch process for both energy and FCAS. FCAS is a market mechanism that uses generation or load to correct the imbalances between supply and demand in real time[41].

During 2017-18, South Australian FCAS prices decreased from the record levels of 2016-17 (Figure 20), primarily in the Regulation FCAS markets.

Figure 20 Quarterly average South Australian FCAS prices by service



Drivers of reduced Regulation FCAS prices included:

- The 35 MW FCAS constraint[42] binding less frequently – in 2017-18, the FCAS constraint was binding for 49.5 hours, down from 646 hours in 2016-17. The high frequency of constraint binding hours in 2016-17 was primarily due to outages during the Heywood upgrade. In 2017-18, Heywood spent less time as a single line and hence less time on a credible contingency.
- Additional supply from new technologies – towards the end of 2017, two participants (HPR and EnerNOC) entered the FCAS markets. In the first half of 2018, HPR captured approximately 5% of the NEM-wide Regulation FCAS market, displacing higher-priced supply from existing technologies (largely coal)[43].

---

[41] 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.

[42] For system security purposes, AEMO requires the local 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.

[43] See the AEMO *Quarterly Energy Dynamics* – Q1 2018 for more information.

– For example, in Q1 2018, HPR provided Regulation FCAS to South Australia during the activation of the 35 MW FCAS constraint on 14 January and 8 March 2018. Historically, during the times that this constraint has bound, Regulation FCAS prices in South Australia have typically exceeded $9,000/MWh due to the limited number of suppliers of these services in the region. However, on 14 January 2018, HPR provided additional supply into FCAS regulation markets, and average Raise and Lower Regulation prices were $248/MWh during the event. AEMO estimates that this reduced the cost of regulation services by about $3.5 million during the five-hour period in which the constraint bound[44].

- Increased FCAS supply from TIPS – in 2017-18, TIPS lowered the price of its FCAS offers, resulting in increased enablement. For example, in the first half of 2018, TIPS increased its average Raise Regulation enablement to 19 MW (up from 5 MW in 2017), making up 11% of the NEM-wide Raise Regulation FCAS market.

6.4 Pricing events

A summary of AEMO's published pricing events[45] for South Australia for the last three financial years is given in Table 10.

There has been a material decrease in the quantity of pricing event reports in 2017-18 compared to 2016-17. The reason for this decrease is twofold:

- A change in reporting method has favoured publishing events in table form[46] as opposed to event report form, to reduce publication delays.
- An increase in market directions has reduced the number of pricing events reported through this method.

Table 10 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
Number of reported events, 2017-18	2	3	5

* 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.

6.4.1 Frequency of negative pricing events

Figure 21 shows the count of negative South Australian market prices from 2007-08 to 2017-18. In 2017-18 there were 139 negative priced 30-minute trading intervals, lower than the previous three years. In general, negative prices have occurred 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.

Key points relating to the reduction in negative price periods in 2017-18 included:

- Shifting generator commitment decisions – in 2017-18 there was a shift in generator behaviour, with South Australian GPG units often de-committing from the market during conditions that could lead to negative or low prices (such as coincident high wind output and low demand). This is one of the key drivers of

[44] AEMO 2018. *Quarterly Energy Dynamics* – Q1 2018, at www.aemo.com.au/Media-Centre/AEMO-publishes-Quarter-Energy-Dynamics---Q1-2018.

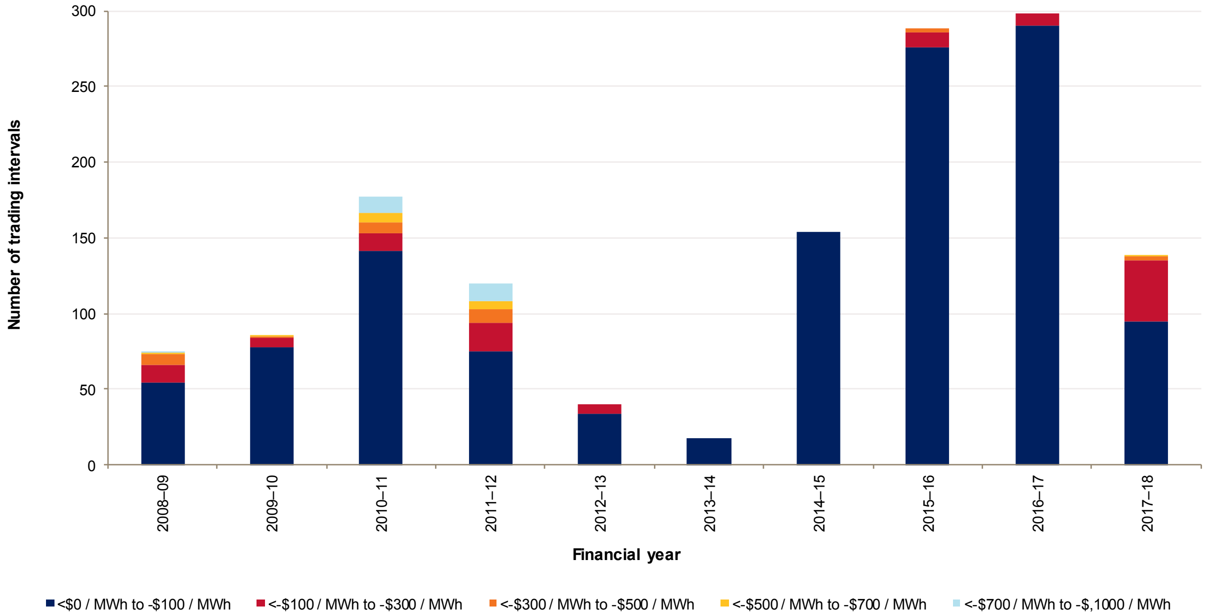
[45] See https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Market-notices-and-events/Pricing-event-reports.

[46] See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Pricing-Event-Reports/Pricing-Event-Report-Summary.xlsx.

reduced incidence of negative pricing. The retirement of Hazelwood and corresponding increase in South Australian exports to Victoria during periods of low demand were also contributors. The shift in generator behaviour has coincided with AEMO introducing new system strength measures (minimum combinations of synchronous generators)[47] to maintain system strength in the second half of 2017. See Section 7 for further information on system strength and other system security issues.

- The reduction in negative price periods has occurred despite a large increase in the periods in which operational demand less South Australian wind output has been below zero. In 2017-18, it was below zero for 363.3 hours, representing a 162% increase on 2016-17 levels.

Figure 21 Count of negative price trading intervals per year



[47] AEMO, *South Australia System Strength Assessment*, September 2017, available at https://www.aemo.com.au/-/media/Files/Media_Centre/2017/South_Australia_System_Strength_Assessment.pdf, and AEMO, *Transfer Limit Advice – South Australia System Strength,* December 2017, available at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Congestion-Information/2017/Transfer-Limit-Advice---South-Australian-System-Strength.pdf.

7. Reliability and security of supply

This section discusses managing reliability and security today in light of the changing generation mix, and forecast reliability over the next 10 years. The key points are:

- AEMO is working closely with the South Australian Government, ElectraNet, and industry parties to ensure power system reliability and security in the state.
- The power system is adapting to decommissioning of thermal generation in South Australia and Victoria and increasing levels of renewable generation. New flexible generation and storage units are being built, and FCAS services are being provided from storage and a wind farm.
- South Australia is forecast to meet the reliability standard in the coming summer, but there is risk of supply interruptions, both as a result of potential shortfalls in South Australia, and potentially due to shortfalls in Victoria, which could impact South Australia due to the equitable load shedding agreement in place in the NEM.

7.1 Reliability and security with a changing generation mix

Operating a power system requires resources that can be dispatched to ensure supply at any point in time matches demand.

Other system services are needed to maintain system frequency and voltage around the network within the defined operating limits under normal operation and to return the system to within these limits after any credible contingency.

As the generation mix changes, the way these system services are obtained will have to change too[48].

7.1.1 Maintaining frequency and voltage

Traditionally, these system services were generally provided by large synchronous generators. With the growth in renewable generation, fewer of these are operating and during periods of lower demand and very high wind and solar generation, synchronous plants may not be required to provide energy at all. Forecasting minimum demand is therefore increasingly important for AEMO.

During periods with low demand, AEMO may issue directions to keep synchronous plant operating, primarily for system strength reasons. This may increase costs if that means constraining off renewable generation. Further discussion on directions is presented in Section 7.2.4.

For South Australia, alternatives are being considered and progressed as discussed in the following sections. This includes improving interconnection to neighbouring regions, commissioning synchronous condensers to

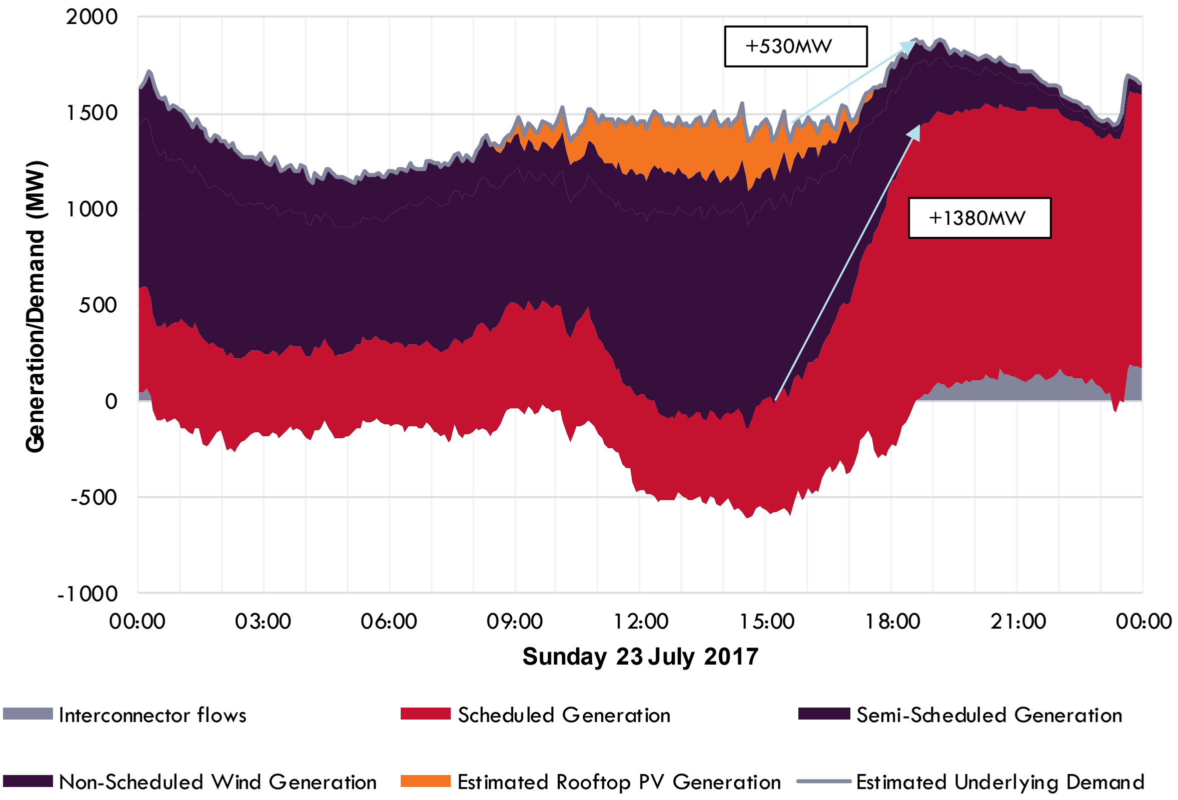
[48] AEMO, *Power System Requirements*, March 2018, available at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power-system-requirements.pdf.

help maintain voltage and frequency, and having contingency frequency reserves provided by battery or renewable generators.

7.1.2 Dealing with variability of generation

With the growth in solar and wind generating capacity comes increased variability of the generation output. This needs to be managed. For example, as illustrated in Figure 22 below, near sunset, when PV generation declines and demand is rising towards its evening peak, there can be an increased need for ramping up supply from other sources.

Figure 22 Generation/demand mix in South Australia for Sunday 23 July 2017



To deal with the significant ramping events, flexible technologies are needed to continuously be able to match supply and demand. Suitable technologies include fast-start gas engines and storage (pumped storage or battery). It may also be possible to alter demand to match supply though DSP.

To ensure sufficient flexible resources (whether generation, demand side, or storage) are available to ramp when required, it is critical to have accurate forecasts of these events ahead of when the resources are needed. Forecast accuracy can be improved through increased visibility of the number, type, and location of DER and though use of advanced weather forecasting models.

7.2 Managing reliability and security to date

Summer 2017-18 was the second-warmest summer on record nationally. All NEM regions experienced prolonged widespread warm weather and had mean temperatures among the 10 warmest on record. This warmer than average weather posed challenges from both increased demand and risks of failure of generation and transmission assets.

The supply margin was tight over summer 2017-18 in Victoria and South Australia. The projected risks of load shedding in these two regions were managed in accordance with AEMO's summer operations plan[49]. In the highest risk periods which materialised during summer for these two regions (late November 2017 and January 2018), additional reserves were procured, which were sufficient to be able to manage at least one large generation contingency without the need to interrupt customer load.

AEMO's summer operations plan objectives were achieved through:

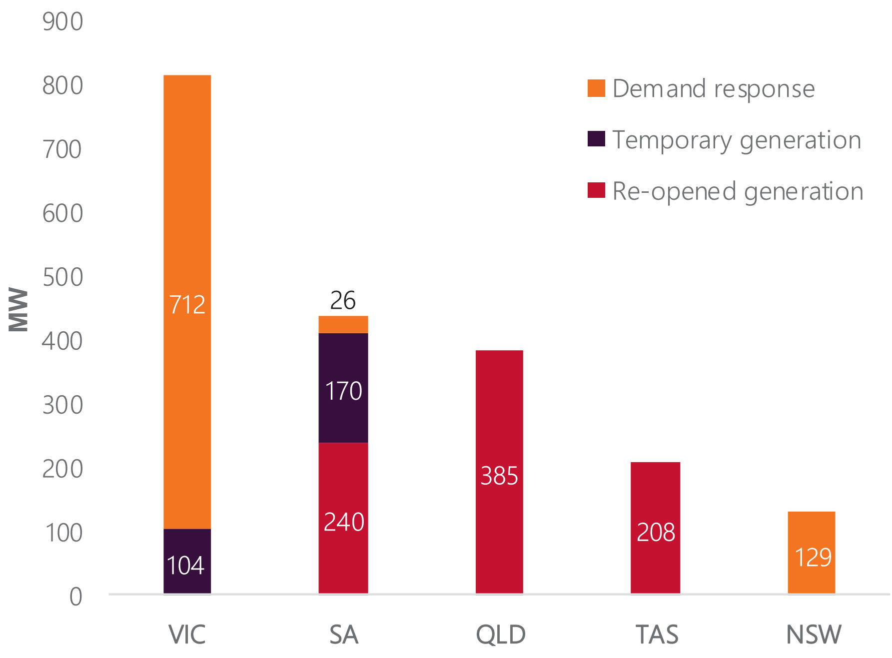
- Increasing the generation and demand resources in the NEM before summer.
- Increasing availability of generation.
- Maximising transmission network availability.
- Implementing operational improvements and extensive contingency planning.
- Collaboration and communication across AEMO, the energy industry, and federal and state governments.

In South Australia, the total additional resources made available as part of summer operations for the 2017-18 summer were:

- 240 MW of additional generation at Pelican Point.
- 170 MW off-market temporary diesel generation through RERT.
- 26 MW of demand response largely through the joint demand response pilot program operated by AEMO and ARENA.

The total additional resources made available for summer 2017-18 for the entire NEM are detailed in Figure 23 and Table 11.

Figure 23 Total additional resources made available in summer 2017-18 (MW, by region)



[49] AEMO's summer 2017-18 operations reports are available at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Summer-operations-report/Summer-operations-report-2017-18.

Table 11 Total additional resources made available in summer 2017-18 as part of summer readiness

	Source	Capacity	Comparison to plan
Market generation	Pelican Point Power Station, South Australia	240 MW	Same
Market generation	Swanbank E Power Station, Queensland	385 MW	Same
Market generation	Tamar Valley Power Station CCGT, Tasmania	208 MW	Same
	Total market generation resources	**833 MW**	**Same**
RERT demand	AEMO/ARENA trial	141 MW	- 2 MW
RERT demand	Other tendered demand resources	726 MW	- 15 MW
	Total RERT demand resources	**867 MW**	**- 17 MW**
RERT generation	South Australia temporary diesel generators	170 MW	Same (nominal capacity was 277 MW)
	Victoria diesel generators	104 MW	+ 8 MW (confirmed and increased after report publication)
	Total RERT generation resources	**274 MW**	**+ 8 MW**
	Total RERT (off-market) reserves	**1,141 MW**	**+ 87 MW**
	Total additional resources	**1,974 MW**	**+ 87 MW**

From AEMO's *Summer 2017-18 Operations Review*, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Summer-operations-report/Summer-operations-report-2017-18.

7.2.1 RERT for summer 2017-18

Under the 2017-18 summer readiness program, these RERT reserves were procured:

- RERT – procurement of RERT by AEMO (long notice, medium notice, and short notice) from generation and demand response for the period 1 November 2017 to 31 March 2018; and
- AEMO/ARENA demand response pilot program – procurement of demand response reserves that would sit within the RERT framework (short notice). The program is for three years and began on 1 December 2017.

Before summer, AEMO estimated the total cost of these resources may be up to $67 million. AEMO's review of summer 2017-18 found the total cost to have the reserves on call and to activate RERT twice was $51.26 million[50]. This equates to an annual average of less than $6.00 (about 0.3% of an average household bill) per household bill. Following the end of the 2017-18 financial year, the costs have been updated to account for the full costs of RERT, leading to a minor change as summarised in Table 12 below[51].

[50] See https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Summer-operations-report.

[51] See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/RERT-Update---cost-of-RERT-2017-18.pdf.

Table 12 NEM-wide RERT costs associated with 2017-18 financial year ($ million)

	Availability payments	Pre-activation costs	Activation costs	Other costs[A]	Total costs[B]
RERT costs in financial year 2017-18	$27.03	$21.56	$3.23	$0.17	$51.99

A. "Other costs" represent compensation paid to Market Participants due to the intervention event (for example, to compensate for energy generation which is displaced by RERT capacity), and to Eligible Persons due to changes in interconnector flows, and therefore changes in the value of Settlement Residues.
B. Costs are passed through to Market Customers in the relevant region in accordance with the NER.

AEMO activated RERT twice in summer 2017-18, on 30 November 2017 (in Victoria) and on 19 January 2018 (in Victoria and South Australia) when consumer supply was at risk due to severe weather conditions. Details of the mechanisms for activation of RERT, the review of the 2017-18 summer 2017-18, and reports on the RERT events are published in AEMO's *Summer 2017-18 operations review*[52].

While Victoria's summer was warmer than average, the hottest day of 41.7°C occurred on a Saturday early in January, so the maximum demand was not as high as it could otherwise have been. There was record demand for a non-work day on 28 January 2018, while 29 January 2018 was on track for very high demand before a cool change swept through in the afternoon.

7.2.2 AEMO/ARENA demand response pilot program

This pilot program is a three-year joint initiative between AEMO and ARENA, seeking to enable up to 160 MW of demand response in Victoria, South Australia, and New South Wales.

The program's aim is to trial a strategic reserve model (referencing international market designs) for reliability or emergency demand response, to inform future market design as well as contributing reserves for the 2017-18 and future summers.

AEMO and ARENA designed the demand response pilot around defined products (see Table 13) and availability of reserves when required during the year. The design of these products was based on input from a stakeholder session in May 2017, AEMO control room requirements, and international experiences. The benefits of defining standard products are that it:

- Is more manageable for the AEMO control room to operate (compared to working through bespoke contracts).
- Allows auctions to be run in the future, if a strategic reserve model is pursued. This could lead to better price discovery and competitive price outcomes.

Table 13 AEMO/ARENA demand response trial product specifications

Feature	Product 1	Product 2
Notification period	60 minutes	10 minutes
Activation duration	4 hours	4 hours
Activation triggers	LOR 2, LOR 3, System Security	LOR 2, LOR 3, System Security
Availability	10.00 am to 10.00 pm business days	10.00 am to 10.00 pm business days
Activation frequency	10 per year (i.e. 40 hours)	10 per year (i.e. 40 hours)

[52] See https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Summer-operations-report.

ARENA will, over a period of three years starting 2017-18, provide up to $22.5 million of funding for projects outside New South Wales, and ARENA together with the New South Wales Government (on 50-50 basis) will provide up to $15 million of funding for New South Wales projects.

Successful awardees receive ARENA capital funding grant in the form of availability payments over three years and were required to sign onto the AEMO short notice RERT Panel and offer and be available for short notice RERT if requested. If this RERT is activated, awardees receive usage payments capped at $1,000/MWh, and Market Customers pay for the activation charges in accordance with the current cost recovery mechanism for RERT under the NER.

This program has made 141 MW available in year 1 (2017-18), and will make up to 190 MW available in year 2, rising to up to 202 MW in year 3, across New South Wales, Victoria, and South Australia.

7.2.3 Contribution of inverter-based technologies to reliability and security

Batteries, and some other inverter-based technologies, have demonstrated in the last year that they are capable of rapid delivery of a large and sustained response to a change in frequency. In some circumstances this can be particularly valuable, such as following a large disturbance, or when the power system is operating with low inertia.

Hornsdale Power Reserve (HPR)

In response to reliability concerns following the South Australian blackout, the State Government tendered for the establishment of a large battery storage facility.

Tesla, together with NEOEN, won the tender and built the HPR next to NEOEN's Hornsdale Wind Farm, which is located near Jamestown, north of Adelaide. The HPR battery is rated at 100 MW discharge and 80 MW charge, and has a storage capacity of 129 MWh. This capacity represents approximately 75 minutes at full discharge. The HPR shares the same 275 kV network connection point as the 300 MW Hornsdale Wind Farm.

The HPR provides a range of services under commercial agreements between the South Australian Government, Tesla (the battery technology provider), and NEOEN (the operator of the Hornsdale Wind Farm). The services include energy arbitrage, reserve energy capacity, network loading control ancillary services (NLCAS), and FCAS.

The HPR participates (to date) in two FCAS markets: Regulation FCAS and Contingency FCAS. Regulation FCAS in South Australia has seen high prices for this service for the two years prior to the battery becoming operational. Regulation FCAS incrementally adjusts the output of the battery up or down, away from an underlying energy dispatch target, to correct slow moving frequency changes across the NEM. Up to 30 MW of the battery's output capacity is available for provision of Regulation FCAS. This is the first time Regulation FCAS has been provided in the NEM by any technology other than conventional synchronous generation. Data available to AEMO demonstrates that the Regulation FCAS provided by the HPR is both rapid and precise, compared to the service typically provided by a conventional synchronous generation unit.

The HPR has been configured to provide a Contingency FCAS response at all times, irrespective of FCAS market outcomes, using the full technical operating range of the battery. Because major frequency deviations in the NEM are (fortunately) rare, actual full delivery of this service has not yet been demonstrated.

Hornsdale Wind Farm 2 FCAS trial

In May 2017, AEMO and ARENA signed a Memorandum of Understanding (MOU) to facilitate collaboration between the organisations in areas such as power system security and reliability.

The Hornsdale Wind Farm 2 (HWF2) trial[53] is a result of this MOU and is the first in-market technical demonstration of a wind or solar farm providing FCAS in the NEM. It was undertaken by AEMO and ARENA in conjunction with NEOEN (owner and operator of the Hornsdale group of projects) and Siemens-Gamesa Australia (equipment provider for the Hornsdale group of wind farms).

[53] See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Strategic-Partnerships/2018/HWF2-FCAS-trial-paper.pdf.

The trial ran from August 2017 until February 2018, and was implemented in three stages:

1. Technical modelling of plant performance and demonstration of capability via on-site plant testing.
2. Review of modelling and on-site test results, leading to registration of HWF2 as an ancillary service generating unit.
3. In-market demonstration of FCAS delivery for all registered services through 48 hours of live bidding and dispatch under a range of wind conditions, referred to in this report as the 'market trial'.

Following submission of modelling and on-site capability tests, HWF2 was registered to provide six of the eight NEM FCAS products. HWF2 was not able to register for Fast Raise and Lower Contingency FCAS, after preliminary modelling suggested wind turbines were likely to be in 'fault-ride-through' mode providing voltage support in the first few seconds following a frequency event. Obligations in Generator Performance Standards (GPS) for wind farms to support system voltage and prioritise provision of reactive power over active power following a fault may prevent delivery of active power within six seconds of the frequency event.

The market trial component of this project was undertaken during the peak summer period for 2017-18. All six registered services were delivered during 48 hours of bidding from the HWF2 control room, between December 2017 and February 2018, under a variety of wind and market conditions.

During the trial, operation of HWF2 FCAS in conjunction with HPR FCAS helped to reduce otherwise high FCAS prices during planned maintenance of the Heywood interconnector on 14 January 2018. Regulation prices peaked at $248/MW on this date, compared to an average of over $9,000/MW during previous Heywood outages.

Since completion of the trial, HWF2 has continued to provide Contingency and Regulation services to the market. Other market participants with wind farms are also looking to register as ancillary service generating units and AEMO has in October 2018 published testing requirements for renewable plants seeking to provide Contingency FCAS[54].

Possibility of VPP providing grid services

A number of VPP projects (see Section 2) have been proposed in South Australia. These can potentially provide some of the same services as the Hornsdale battery, including energy arbitrage, reserve energy capacity, and Regulation FCAS. In June 2018, AEMO published its draft DER FCAS specification[55], which contains the minimum conditions that AEMO proposes to apply to parties that may participate in a future trial of contingency FCAS from aggregated DERs.

7.2.4 Managing power system security

To manage power system security during periods of high renewable generation offsetting the need for synchronous generation to generate, AEMO has published studies outlining the minimum number of synchronous machines required to maintain system strength in South Australia.

System strength reflects the sensitivity of the power system to disturbances, and the stability and dynamics of generating systems and the power system to both:

- Remain stable under normal conditions, and
- Return to steady-state conditions following a disturbance (such as a fault).

Large synchronous machines (hydroelectric, gas, coal generation, and synchronous condensers) inherently contribute to system strength. Non-synchronous generation (batteries, wind, and solar generation) do not presently provide inherent contribution to system strength.

[54] AEMO, *Wind farms and solar farms testing requirements for Contingency FCAS registration*, available at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Ancillary_Services/Wind-farms-and-solar-farms-testing-requirements-for-Contingency-FCAS-registration.pdf.

[55] AEMO, *Specification for Distributed Energy Resources to provide Contingency FCAS*, available at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Ancillary_Services/Distributed-Energy-Resources-FCAS-Specification.pdf.

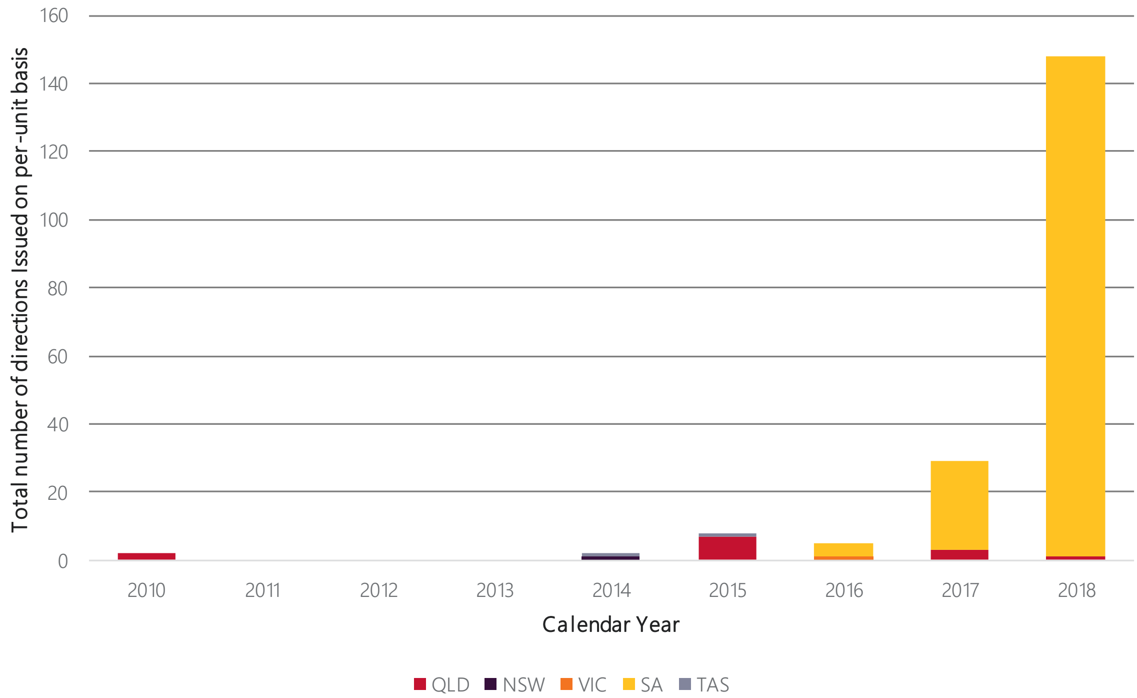
Operating procedures are currently in place to ensure a minimum number of synchronous generating units are in service in South Australia at all times, until a permanent technical solution is commissioned. This solution (installation of synchronous condensers) is expected to be operational by mid-2020 (see Section 8).

AEMO's operating procedures identify the conditions and generator dispatch combinations needed to satisfy the system strength requirements. Where natural market outcomes do not deliver the specific needs for system strength, AEMO has powers under the National Electricity Law and National Electricity Rules (NER) to direct the necessary resources into service.

As at 23 September 2018, AEMO has issued over 140 directions to South Australian generator units to ensure the correct level of system strength was maintained at all times. These were security directions, for the provision of fault current, not for energy. Where AEMO issues a direction for energy, this is a reliability direction. Apart from two directions in 2017, which were for reliability/shortfall reasons, all South Australia directions have been for system strength reasons.

Figure 24 compares the total number of directions issued on a per-unit basis in the NEM over the last eight calendar years, as at 23 September 2018.

Figure 24 Total number of directions issued by AEMO for the NEM on a per-unit basis (as at 23 September 2018)



7.3 Forecast power system reliability

AEMO's ESOO for the NEM assesses the adequacy of supply in meeting forecast demand, and evaluates any shortfall resulting in unserved energy (USE) against the reliability standard.

7.3.1 ESOO scenarios and sensitivities

AEMO's 2018 ESOO[56] modelled three scenarios (Neutral, Slow change, and Fast change) and two sensitivities with varying outlooks for future supply and demand.

[56] Available at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities.

As required by the NER, the ESOO models only committed generators[57] entering the market over the ESOO timeframe.

Two additional sensitivities assumed demand consistent with the Neutral scenario, but assumed additional development consistent with the portfolio of new resources and transmission identified for development in the first 10 years of the ISP base cases:

- ISP without Snowy 2.0 ("Base development plan" in the ISP).
- ISP with Snowy 2.0 ("Base development plan with storage initiatives" in the ISP).

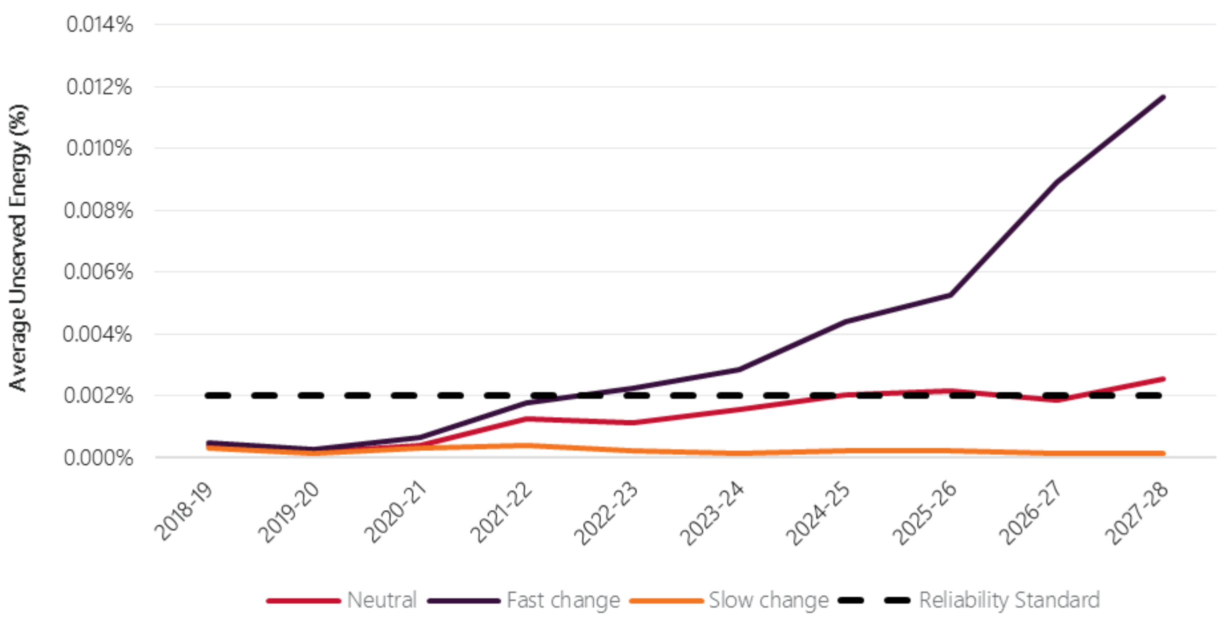
7.3.2 ESOO estimates of USE in the next ten years

For South Australia, over the next four years, forecast USE for the Fast change, Slow change, and Neutral scenarios is within the reliability standard, as shown in Figure 25. The staged retirement of TIPS A starting 2019 is initially forecast to be balanced by the entry of Barker Inlet Power Station in August 2019. The level of USE is seen to increase as the third and fourth Torrens Island A units retire in 2020 and 2021, respectively.

Forecast USE continues to rise as forecast peak demands increase across Victoria and South Australia. In the absence of new investment, the level of USE is forecast to exceed the 0.002% standard by 2022-23 in the Fast change scenario and by 2024-25 in the Neutral scenario. The reliability standard is forecast to be met in the Slow change scenario.

It should be noted that the reliability projections provided in both the ESOO and in the Medium Term Projected Assessment of System Adequacy (MT PASA) do not incorporate the impact of the temporary diesel generators in South Australia or transmission or generation investment that is not yet committed, nor do they include any actions that may be taken under RERT this summer. They also represent USE outcomes before any equitable load shedding principles are applied, as discussed in the next section.

Figure 25 Forecast USE outcomes for South Australia – existing and committed projects only



57 NER clause 3.13.3(q)(2). Note that 2018 ESOO modelling did not include the impact of the temporary generators, which are 'out-of-market' and are therefore not modelled.

7.3.3 Short-term reliability risks

Figure 25 indicates that the level of USE is projected to be below the reliability standard over the next three years. However, the projections provided in the ESOO do not incorporate the impact of the equitable load shedding principle. Instead, the annual USE reported in a region reflects the source of any supply shortfall and is intended to provide participants with the most appropriate locational signals to drive efficient market responses.

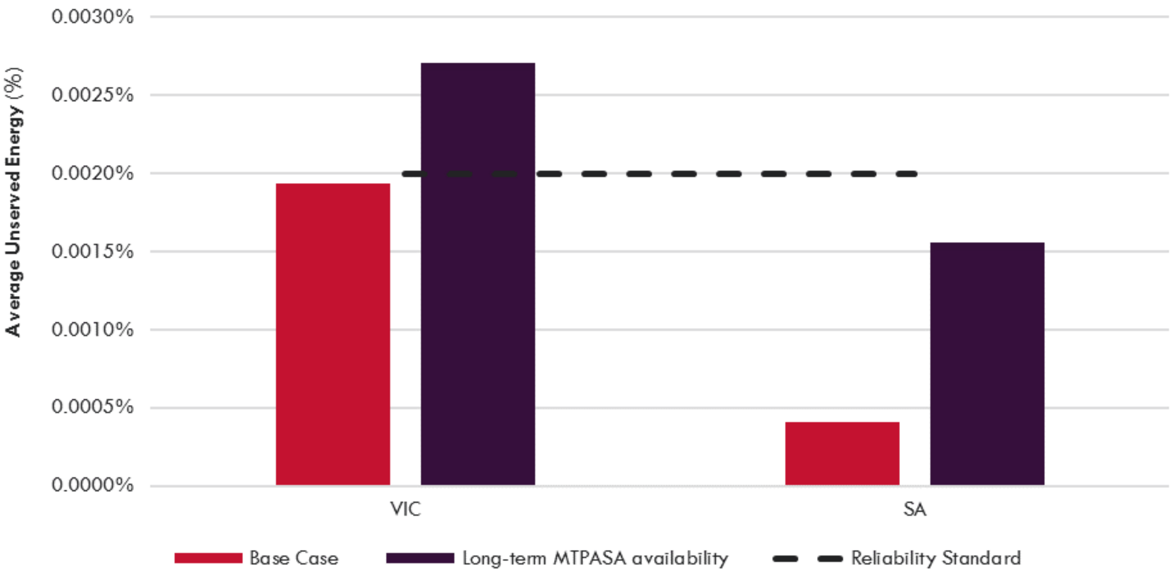
To avoid unfairly penalising one region for a supply deficit spread through several interconnected regions, an equitable load shedding principle applies in the NEM[58]. This principle states that, as far as practicable, load shedding should be spread pro rata throughout interconnected regions. While the ESOO analysis does not consider this principle, high risks of load shedding projected in Victoria are likely to result in any supply deficit being spread across both Victoria and South Australia.

Based on the information provided by participants as part of the 2018 Energy Adequacy Assessment Projection (EAAP), the impact of drought conditions on mainland reservoir levels is unlikely to affect reliability in the coming summer, even if low hydro inflow conditions continue. This is because there remains sufficient flexibility for limited resources to be used effectively to avoid shortfalls at times of high demand.

7.3.4 ESOO versus current MT PASA estimates

The current MT PASA offers in South Australia for next summer are approximately 250 MW lower than the total summer capacity modelled in the 2018 ESOO. An ESOO sensitivity which withdrew 250 MW from South Australia this summer resulted in a large increase in USE across both South Australia and Victoria and put both regions at risk of exceeding the reliability standard, as shown in Figure 26. Like the ESOO forecasts shown in Figure 25, this does not incorporate the impact of the temporary diesel generators in South Australia, nor does it include any actions that may be taken under RERT this summer.

Figure 26 ESOO versus MT PASA forecast USE for summer 2018-19



7.3.5 Managing forecast reliability risks

ESOO, EAAP and MT PASA show that even without considering the application of equitable load shedding, there remains some risk of supply shortfalls in South Australia over the next three years, and that without further investment the forecast level of USE increases after the complete retirement of TIPS A.

[58] See NER clause 4.8.9(i) and the Reliability Panel's Guidelines for Management of Electricity Supply Shortfall Events, at https://www.aemc.gov.au/sites/default/files/content//Guidelines-for-Management-of-Electricity-Supply-Shortfall-Events.PDF.

Although USE remains within the reliability standard in the short term, the ESOO projects an 11% chance of some level of load shedding in South Australia this summer. The current MT PASA offers submitted by generators shows a lower level of capacity available in South Australia. As such, the MT PASA forecasts indicate a much higher level of USE for this summer.

Given the high USE forecast in Victoria, the application of the equitable load shedding principle could result in a significant increase in the level of USE in South Australia. AEMO is working with the State Government and relevant industry parties to lower the risks. This includes procuring RERT to supplement the AEMO/ARENA DSP project, which is still running, and also working with generators and transmission network service providers (TNSPs) to maximise resource availability during the summer months.

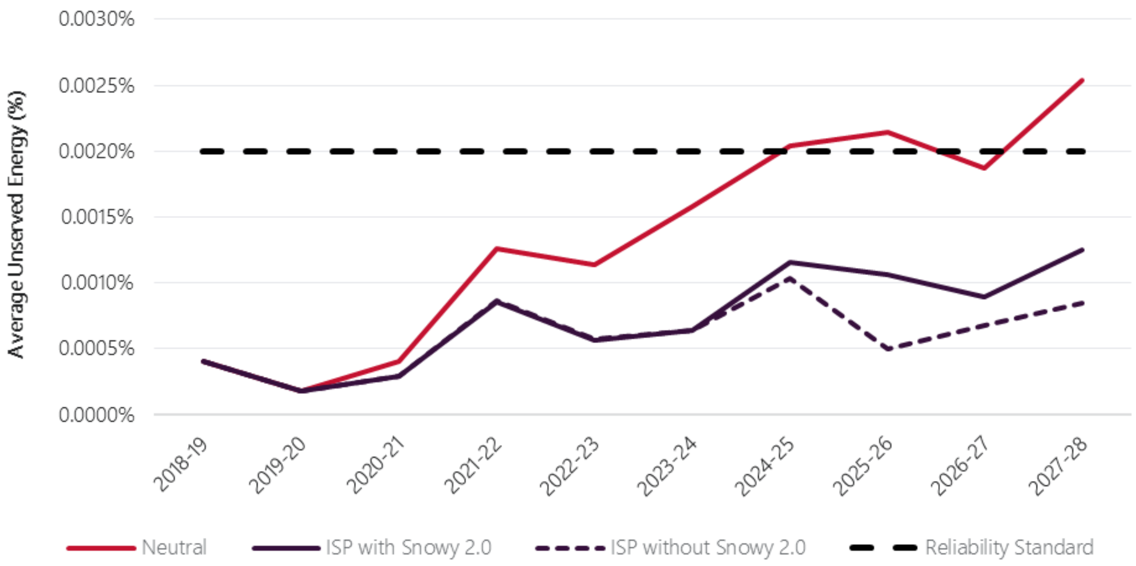
Furthermore, although the reliability projections do not include the temporary diesel generation in South Australia, these resources are available for use as a last resort and would reduce the risk of supply shortfalls this summer.

7.3.6 Long-term reliability risks

In the Neutral ESOO scenario, the retirement of TIPS A and the increase in peak demand across Victoria and South Australia results in an increase in the level of USE. In this scenario, the level of USE is above the reliability standard by 2024-25. This scenario is based on no additional investment in generation or transmission beyond what is classified by AEMO as committed.

The ESOO also modelled the implementation of the generation and transmission development projected in the Neutral ISP plans (with and without deep storage). Under both these plans, the level of USE remains within the reliability standard in South Australia over the 10-year modelling horizon.

Figure 27 Forecast USE outcomes, South Australia, ESOO vs ISP development plans



7.4 Regulatory changes to improve reliability and security

7.4.1 Power System Frequency Risk Review (PSFRR)

Following on from the Emergency Frequency Control Schemes rule change[59] published in March 2017 by the Australian Energy Market Commission (AEMC), the first full NEM-wide PSFRR was published in June 2018[60].

[59] See https://www.aemc.gov.au/rule-changes/emergency-frequency-control-schemes-for-excess-gen.

[60] See http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Power-System-Frequency-Risk-Review.

With this PSFRR, AEMO recommended the following actions be taken in relation to the South Australian network:

- AEMO to make a request to the Reliability Panel for the declaration of a new Protected Event to manage risks relating to transmission line failure causing generation disconnection and subsequent islanding and black system during destructive wind conditions in South Australia.
- As part of the management of the new Protected Event, implement an upgrade to the recently commissioned System Integrity Protection Scheme (SIPS) in South Australia, to further reduce the likelihood that a loss of multiple generators in South Australia will lead to separation and a black system.

Protected Event submission

Following the 28 September 2016 black system event in South Australia, AEMO initiated an operational action plan to limit flow on the Heywood interconnector during destructive wind conditions in South Australia (under NER 4.3.1(v)). For transparency, and to provide certainty to the market, AEMO recommended that a request be submitted to the Reliability Panel to declare these conditions as a Protected Event. If approved by the Reliability Panel, AEMO expects this Protected Event will be activated approximately twice per year, based on historical weather conditions.

AEMO is submitting this request to the Reliability Panel in November 2018, as well as working with ElectraNet on investigations into potential SIPS upgrades.

7.4.2 Recent regulatory changes

Several important changes to the NEM's regulatory framework are also being implemented that will support security and reliability of the South Australian power system, as discussed below.

Declaration of lack of reserve (LOR) conditions

The declaration of LOR conditions is a key mechanism by which AEMO communicates the short-term risk of involuntary load shedding, signalling to the market the need for more capacity. AEMO has improved the methodology applied in determining LOR. Declaration of LOR is now based on a probabilistic approach rather than a contingency-based framework, a risk assessment technique that is fit-for-purpose in the evolving NEM[61].

The new approach minimises the potential for involuntary load shedding, as AEMO can more accurately signal to the market that more supply is required.

Reliability and Emergency Reserve Trader (RERT) mechanism

The RERT allows AEMO to contract additional generation or demand response not already in the market to ensure that the reliability standard is met.

Following an AEMO rule change proposal, the AEMC has reinstated long notice RERT, extending the maximum procurement lead time for emergency reserves from 10 weeks to nine months. The new Rule increases the options available to AEMO to reduce the risk of involuntary load shedding in excess of the reliability standard[62].

Further work is underway to improve RERT processes, with the AEMC considering an AEMO rule change request regarding the trigger for RERT procurement and to further extend the lead time beyond nine months[63].

---

[61] For more information, see https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power_System_Ops/Overview-of-new-method-for-determining-Lack-of-Reserve-V2.docx.

[62] The reliability standard expresses the level of reliability sought from the NEM's generation and transmission interconnector assets. This level accepts that it is inefficient to build sufficient generation to avoid all involuntary load shedding. The RERT mechanism is a safety net AEMO can use to ensure the reliability standard will be met.

[63] For more on the enhanced RERT rule change, see https://www.aemc.gov.au/rule-changes/enhancement-reliability-and-emergency-reserve-trader.

As part of this rule change request, AEMO is also proposing delinking the procurement of RERT from the reliability standard and instead creating a standing reserve to provide an insurance function in the overall reliability framework. The reliability framework should set the level of the required standing reserve over a defined horizon by taking account of:

- The nature of the tail risk – using a range of supplementary reliability metrics.
- The risk appetite for different levels of load shedding expressed both in cost and limits terms.
- The cost structure and optimal mix of resources that can prevent or mitigate load shedding.

This approach would lead to a more stable investment environment that provides greater certainty to developers of resources as well as reducing the risk of load shedding.

Generator Performance Standards

Under Essential Services Commission of South Australia licensing conditions, South Australia has the strongest performance requirements of new connecting generators in the NEM, with minimum capability levels that are among world's best practice. This includes enhanced capability for generators to stay connected during disturbances. These standards, which include learnings from the 2016 black system event, have been adjusted to suit the broader NEM, and from 1 February 2019 all new generators will be required to deliver performance capabilities like those required in South Australia, improving security and resilience in the interconnected system[64].

DER Register

A Group 2 action in AEMO's ISP is for work to be undertaken now for implementation by the mid-2020s which would coordinate DER[65] in South Australia. To manage the aggregate impact of DER on the power system, visibility of these devices is required[66].

AEMO worked with the Council of Australian Governments (COAG) Standing Committee of Officials in developing a rule change proposal that will require Network Service Providers to collect and provide AEMO data on DER, such as location and trip settings. The AEMC made a final rule change in support of this proposal on 13 September 2018[67]. The DER Register is expected to be operational by the end of 2019.

Retailer Reliability Obligation

The Energy Security Board (ESB) is continuing to develop legislation to give effect to a Retailer Reliability Obligation, as contemplated in the National Energy Guarantee[68]. The objective of this obligation is to incentivise retailers and other market customers to support the reliability of the NEM through contracting and investment in resources. The ESB is currently consulting on a draft bill that is an amended version of the National Energy Guarantee draft bill issued by the COAG Energy Council in August 2018, with the emissions reduction requirement and related provisions removed.

---

[64] For more on the new generator performance standards, see https://www.aemc.gov.au/rule-changes/generator-technical-performance-standards.

[65] DER is typically generation less than 5 MW in size, such as small-scale solar PV or battery storage systems.

[66] For more information on the need for visibility of DER refer to AEMO's *Visibility of DER report*, available at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Reports/2016/AEMO-FPSS-program----Visibility-of-DER.pdf.

[67] For more information on this rule change, see https://www.aemc.gov.au/rule-changes/register-of-distributed-energy-resources.

[68] For more on the Retailer Reliability Obligation, see http://www.coagenergycouncil.gov.au/publications/consultation-retailer-reliability-obligation-legislative-amendments.

8. Future developments

The Integrated System Plan (ISP) identified several strategic developments that would support economic utilisation of NEM generation assets to deliver energy to consumers reliably, securely and at least cost. For South Australia, this included the development of the New South Wales – South Australia interconnector currently being investigated by ElectraNet, synchronous condensers to address issues of system strength, and orchestration methods for DER. Recent market developments and government initiatives are also providing strong signals for increased generation supply in the future.

8.1 Relating the Integrated System Plan to South Australia

In July 2018, AEMO published the inaugural ISP[69]. The ISP focused on the optimal integration of renewable energy zones (REZs) into an overall strategic NEM-wide network development plan.

The ISP has reinforced the need for independent, integrated, transparent, NEM-wide planning, rather than project-by project-assessments, to optimise local project requirements. The strategic developments of a portfolio of network and non-network developments provide critical diversity and reliability benefits from existing and new diverse renewable resources, maximising the value from available resources and infrastructure and minimising the overall investment needs.

Outcomes from the ISP studies relating to the South Australian network included:

- The need for synchronous condensers to be progressed as soon as possible to supply both system strength and inertia to the South Australian region.
- The need for a new interconnection between South Australia and New South Wales.
- The importance of coordinating DER to realise the potential it could provide to the market and system operations.

The ISP demonstrated potential REZ development areas in South Australia which are supported by existing transmission capacity and system strength. These were Northern South Australia (solar) and Mid-North (wind). The Riverland REZ was identified as an optimal area for development in conjunction with new transmission investment between South Australia and New South Wales.

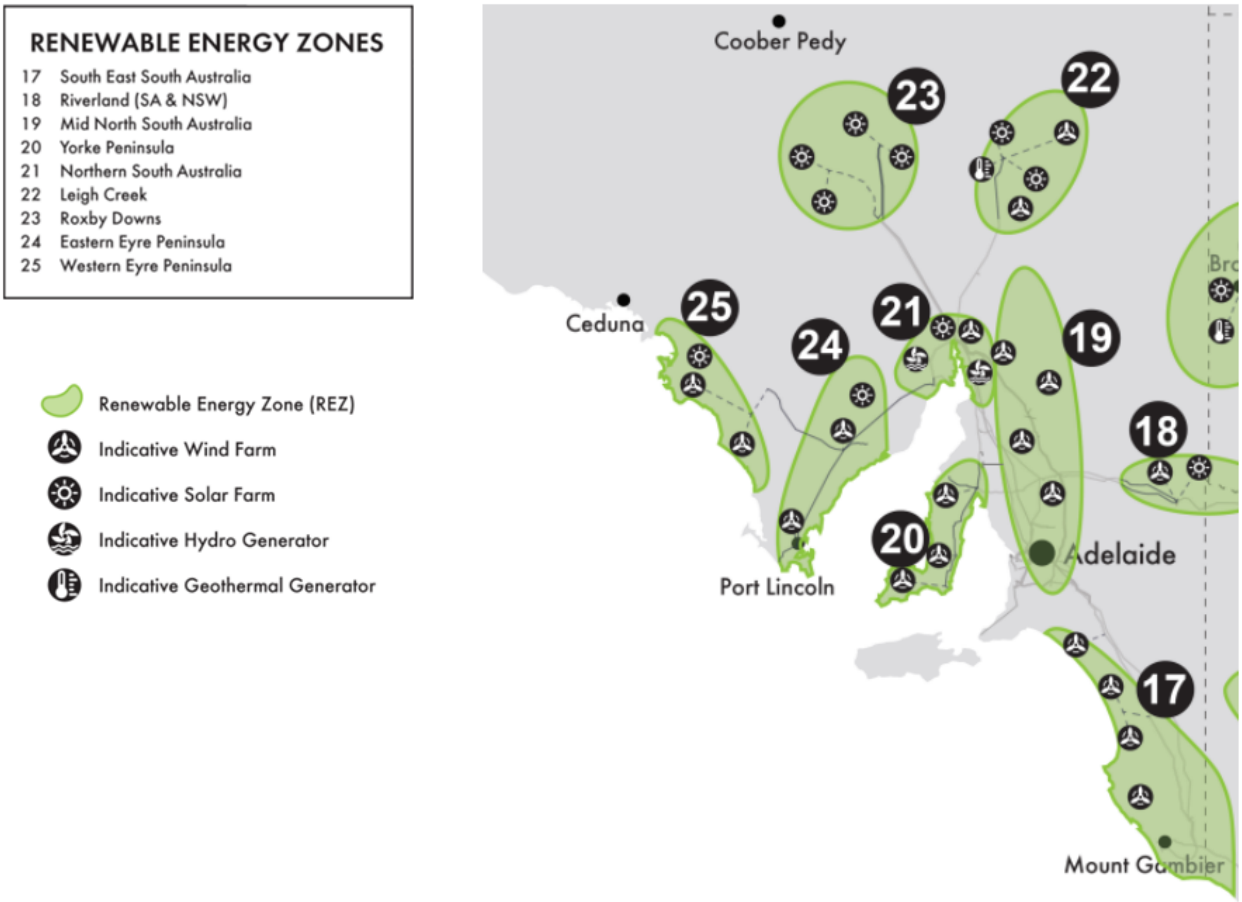
Figure 28 below shows the potential South Australian REZs considered in the analysis.

AEMO notes that the ESB is currently undertaking a review on how to best make this ISP actionable[70].

[69] See http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan.

[70] See http://coagenergycouncil.gov.au/publications/energy-security-board-converting-isp-action.

Figure 28 South Australian Renewable Energy Zone candidates



8.1.1 Progress of transmission projects

System strength

Following AEMO's declaration[71] of a system strength gap in South Australia in October 2017, ElectraNet has been investigating options to address system strength and inertia while also keeping costs down. The installation of synchronous condensers on the network has been determined to be the most efficient, cost-effective option.

A synchronous condenser operates in a similar way to large electric motors and generators. It contains a synchronous motor whose shaft spins freely and can adjust technical conditions on the power system. Synchronous condensers are an important source of system strength and inertia, and are essential irrespective of future new interconnection development.

This project is progressing using transitional provisions within the NER relating to system strength rather than the RIT-T process. Under this alternate approach, it is anticipated that ElectraNet will lodge an economics evaluation report with the Australian Energy Regulator (AER) in November 2018.

[71] As identified in the Update to the 2016 *National Transmission Network Development Plan* (NTNDP), October 2017, accessible at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NTNDP/2017/Second_Update_to_the_2016_NTNDP.pdf.

New interconnection between South Australia and New South Wales

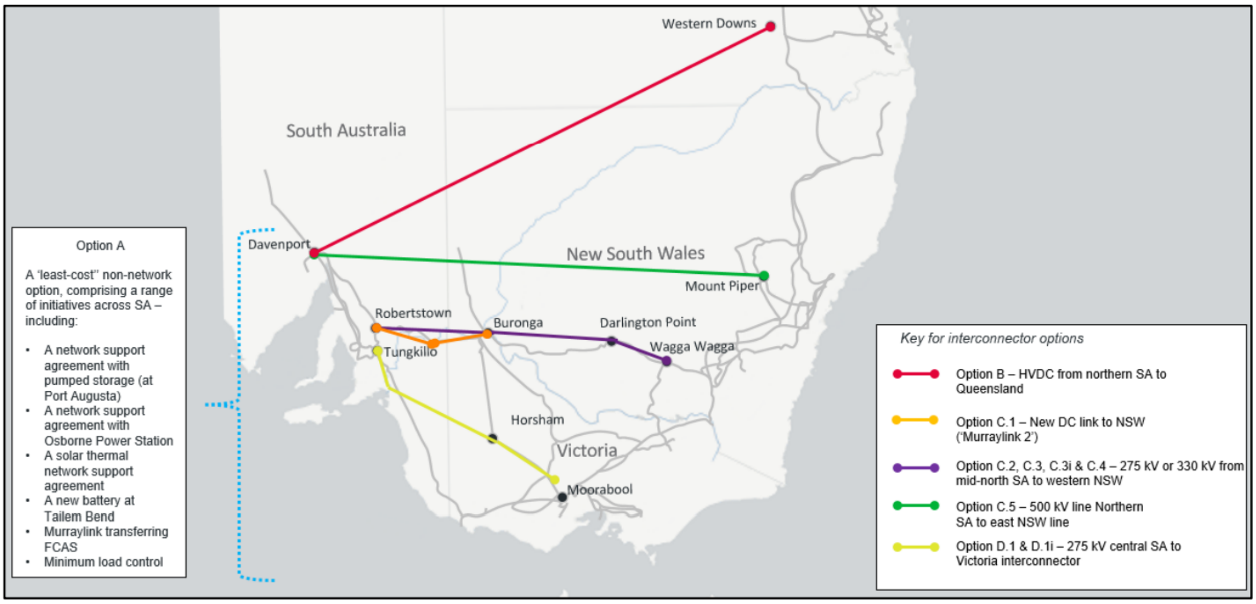
The 2018 ISP analysis indicated that a major new interconnector between South Australia and New South Wales was expected to be economically beneficial, under almost all plausible futures[72].

This upgrade would:

- Allow energy from other NEM regions to be transported to South Australia, providing cost reductions in South Australia through fuel savings from reduced GPG requirements.
- Allow for potential new REZs to be accessed along the new transmission corridor.
- Help use resources more efficiently across the NEM, with greater supply sharing between New South Wales, Victoria, and South Australia

This development is the most progressed interconnector upgrade at this time, with ElectraNet undertaking a South Australia Energy Transformation (SAET) RIT-T and having recommended this option in its June 2018 report[73]. The transmission development options under investigation within the RIT-T for South Australia and Victoria are shown in Figure 29.

Figure 29 Interconnector options and variants assessed by ElectraNet in the SAET RIT-T



ElectraNet is currently in the process of finalising a Project Assessment Conclusion Report (PACR), after publishing a Project Assessment Draft Report (PADR) on 29 June 2018[74]. The estimated cost of the preferred interconnector is estimated at approximately $1.5 billion across South Australia and New South Wales[75].

The South Australian Government is supporting the early completion of this link, with staging including earlier expansion from Buronga into Victoria to connect to renewable generation in northern Victoria.

[72] The ISP assessed potential developments under a range of scenarios so modelling outcomes would be robust. See Chapter 2 of the ISP, available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan.

[73] ElectraNet. South Australia Energy Transformation RIT-T, available at https://www.electranet.com.au/projects/south-australian-energy-transformation/.

[74] ElectraNet South Australia Energy Transformation RIT-T Project Assessment Draft Report, available at https://www.electranet.com.au/projects/south-australian-energy-transformation/.

[75] Cost estimate according to ElectraNet's SAET PADR, available at https://www.electranet.com.au/wp-content/uploads/projects/2016/11/2018-07-06-SAET-PADR-Final.pdf.

DER aggregation

The ISP forecasts substantial wholesale benefits from DER, with these benefits best realised when those resources are coordinated and used effectively. AEMO is continuing to investigate the requirement for increased coordination of DER, the infrastructure to support and integrate those resources, and their impact on the operation and cost of the distribution system. The DER integration is being progressed through a co-ordination project between AEMO and Energy Networks Association (ENA). The DER program will use collaborations and pilot projects to learn more about possible DER market frameworks, new operational processes, technical standards, and data required to deliver the best outcomes for consumers[76].

8.2 Delivering reliability through a portfolio of resources

AEMO's 2018 ESOO assessed the adequacy of existing and committed projects, and the forecast developments from the ISP, to deliver sufficient reliability to meet the reliability standard.

In the ISP development plans, the commissioning of a new interconnector between New South Wales and South Australia reduces reliance on more costly GPG. This reliance on South Australian GPG capacity is replaced in the ISP plans as shown in Table 14.

Table 14 ISP developments in South Australia

Source	Capacity (MW)	ISP Plan
Large-scale storage	649	Without Snowy 2.0
	233	With Snowy 2.0
Additional wind and solar generation in South Australia	975	Without Snowy 2.0
	230	With Snowy 2.0
Additional interconnection with New South Wales	750	Both development plans
Additional interconnection with Victoria[A]	100	Both development plans

A. Due to the transmission works associated with a new South Australia to New South Wales interconnector.

Figure 27 in Section 7.3.6 compares forecast USE in South Australia between the ISP sensitivities and the ESOO Neutral scenario. It shows that both ISP development plans are projected to deliver improved reliability outcomes compared to the ESOO Neutral scenario for South Australia, despite the assumed reduction in dispatchable capacity in the region. This demonstrates that additional generation and transmission infrastructure in South Australia can effectively compensate for reductions in local dispatchable capacity.

8.3 Additional supply developments

As at 31 July 2018[77], publicly announced new generation investment in South Australia continues to focus on renewable developments, storage, and gas, with the largest projects being:

- Ceres Project (up to 636 MW).
- Yorke Peninsula Wind Farm (635.8 MW).
- Woakwine Wind Farm (400 MW).

[76] For more information about the DER program, see https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/DER-program.

[77] Date based on latest AEMO Generation Information Page at 31 July 2018. A more recent version may be available by time of publication, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

The committed Barker Inlet Power Station demonstrates the technical capabilities that will be increasingly valuable for new flexible generation in South Australia. That power station will be able to achieve maximum operation within five minutes, at a higher level of efficiency than the pre-existing GPG fleet.

Given the penetration of renewable generation, increasingly there will be value in generation technologies that can complement the natural variability of renewable generation by providing rapid start capabilities and increased operational flexibility, such as battery or pumped hydro storages, or flexible thermal generation.

As at 31 July 2018, AEMO's Generation Information update identified 56 committed and publicly announced energy generation developments in South Australia, totalling 8,184 MW. Table 15 aggregates these new developments by energy source, while Figure 30 shows the location and capacity of only the publicly announced generation projects.

While new wind and solar projects comprise the majority of new investment interest from a capacity perspective, compared to the same time last year, there is a noticeable increase in the amount of new battery, pumped hydro, and gas-fired peaking projects publicly announced.

Table 15 Publicly announced and committed generation projects by energy source published on 31 July 2018

Energy source	Number of projects	Capacity (MW)	Capacity (% of total projects tracked)	Change in number of projects from June 2017	Change in capacity from June 2017 (MW)
Gas	6	879	10.7	4	99
Diesel	1	30	0.4	-	1
Solar	21	2,606	31.8	12	1,091
Biomass	1	15	0.2	-	-
Wind	14	3,382	41.3	-1	204
Water	3	755	9.2	2	555
Storage	10	518	6.3	10	518
Total	56	8,184	100.0	27	2,467

The South Australian Government is assisting in the development of several projects within the above list:

- The world's largest VPP, through 50,000 homes being fitted with battery storage systems[78].
- Development of a solar thermal project (150 MW) in Port Augusta in the state's north.
- Feasibility studies into the potential for pumped hydro storage.

In addition to the above list, the South Australian Government has also co-invested in four green hydrogen projects as supply chain demonstrators[79]. The largest project is a feasibility study for a hydrogen electrolyser at Port Pirie (50 MW of hydrogen production capacity, 110 MW of wind generation, 100 MW of solar generation, and 100 MW of battery storage). If the feasibility study is successfully concluded, the project is expected to commence in 2021 and would be the largest co-located wind, solar, battery, and hydrogen facility in the world.

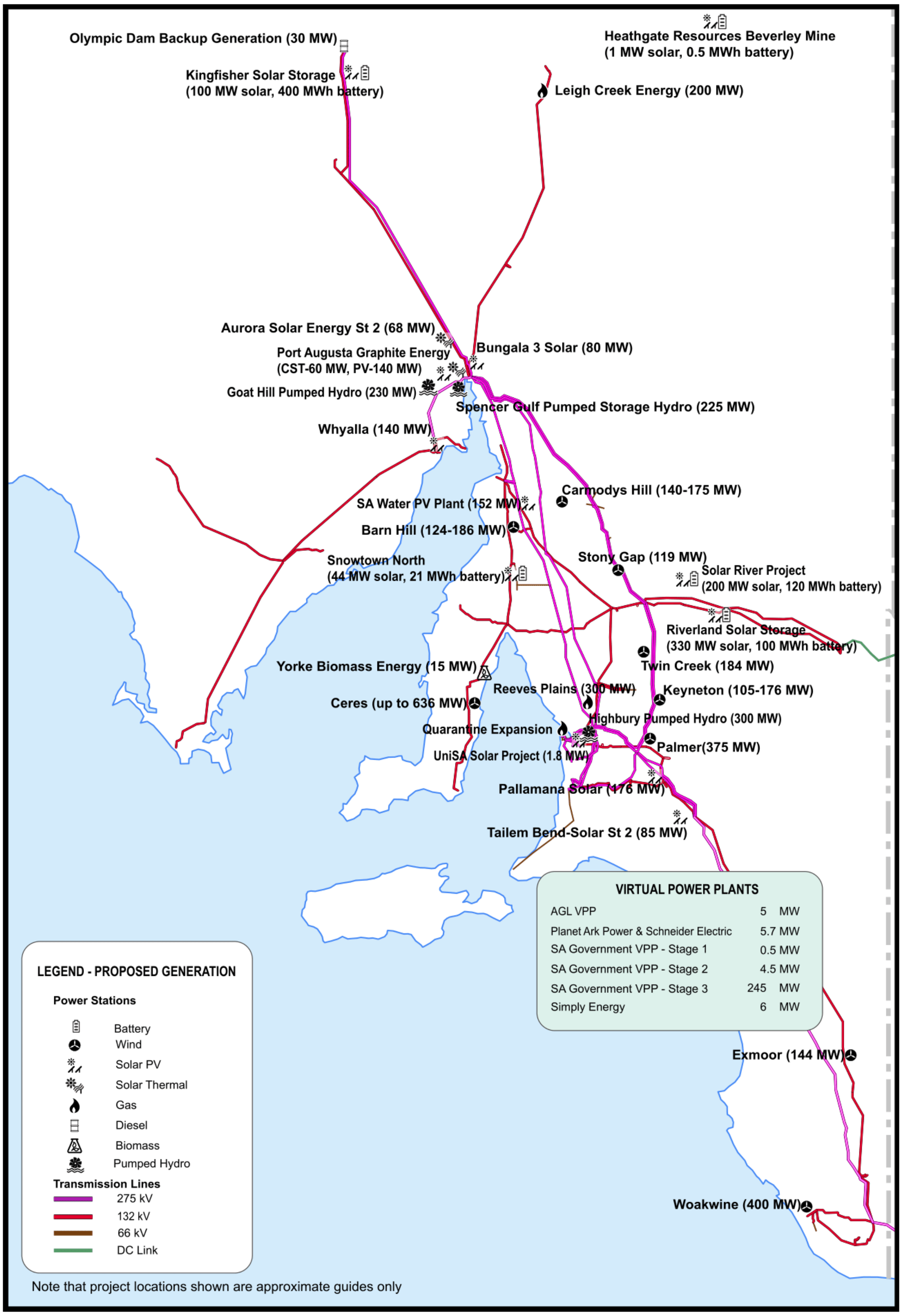
[78] For more information, see https://virtualpowerplant.sa.gov.au/virtual-power-plant

[79] For more information, see http://www.renewablessa.sa.gov.au/topic/hydrogen/hydrogen-projects.

AEMO is currently seeking stakeholder engagement to help design improvements to the regulatory arrangements for how grid-scale Emerging Generation and Energy Storage (EGES) registers and participates in the NEM.[80]

The role VPPs may have, and the rollout of trial programs for these, is outlined further in Section 2.2.

Figure 30 Location and capacity of South Australian proposed generation projects



[80] For more information about the consultation, see http://www.aemo.com.au/Media-Centre/Emerging-Generation-and-Energy-Storage---Grid-Scale-Stakeholder-Engagement.

9. Gas supply for GPG

AEMO's 2018 Gas Statement of Opportunities[81] (GSOO) for eastern and south-eastern Australia projected that the risk of gas supply gaps had reduced, although the balance of supply and demand would remain tight through to 2030. From 2030, it projected that additional gas supply infrastructure would be needed to deliver gas to southern customers, unless early exploration and development programs brought highly uncertain – and as yet undiscovered – southern prospective resources to market.

The 2018 GSOO supply adequacy forecasts for eastern and south-eastern Australia do not identify region-specific risks, but the report contains further information on gas adequacy, and on potential opportunities for infrastructure investment or reserves development, under a range of future scenarios.

9.1 South Australian gas demand forecasts

Residential and commercial demand for gas is forecast to be stable over the next 20 years in South Australia, while industrial demand is forecast to have a small but steady increase, due to increased economic activity in some industrial sectors.

Nonetheless, South Australia's demand for natural gas is expected to reduce over the next few years compared to historical usage, due primarily to reduced demand for gas for GPG, as shown in Figure 31. This projection is based on generation and interconnector outcomes in AEMO's 2018 ISP[82], with new interconnector development and high penetration of new renewable generation and storage technologies. The South Australian GPG forecasts show the projected impact of a changing role for gas in power generation after construction of an interconnector with New South Wales, plus an ongoing contribution of the Victorian Renewable Energy Target (VRET) and federal Large-scale Renewable Energy Target (LRET) to renewable generation and pumped hydro storage in the NEM.

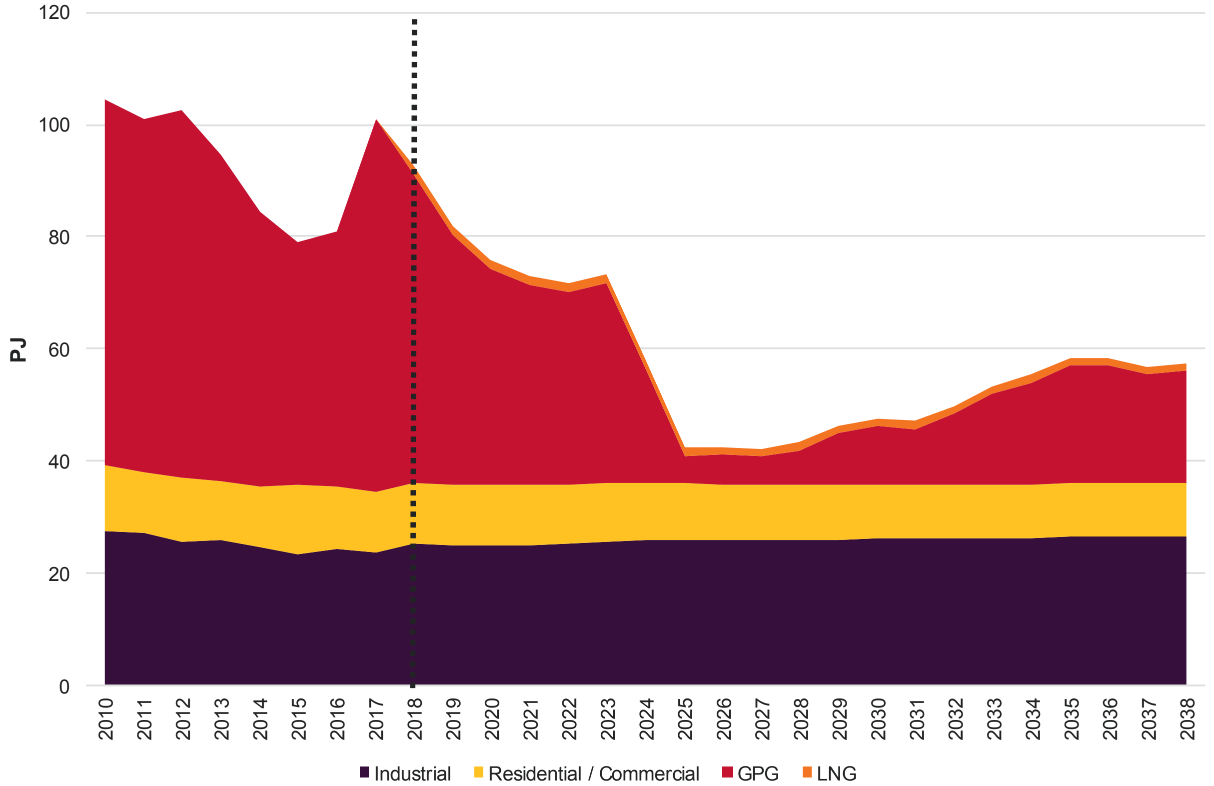
The role for GPG is forecast to change significantly over time, with this generation type being used flexibly to complement variable renewable generation.

While GPG usage in South Australia is forecast to increase between 2025 and 2038 as further coal generation is forecast to retire in the NEM, AEMO does not forecast GPG levels returning to the levels seen historically.

[81] AEMO, *Gas Statement of Opportunities*, June 2018, available at http://aemo.com.au/Gas/National-planning-and-forecasting/Gas-Statement-of-Opportunities. The published GSOO report does not include region-specific forecasts, but forecast data is available at http://forecasting.aemo.com.au/.

[82] The ISP delivers a strategic infrastructure development plan based on sound engineering and economics, which can facilitate an orderly energy system transition under a range of scenarios. Available at http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan.

Figure 31 South Australian gas demand – historical and forecast (Neutral scenario), 2010 to 2038



9.2 Natural gas reserves and resources, and infrastructure

South Australia has traditionally sourced natural gas from the Cooper and Eromanga basins[83]. Over the past several years, the liquefied natural gas (LNG) export market has changed domestic contract dynamics, such that a large portion of the supply from the Cooper and Eromanga basins is being used for LNG export.

As at 31 December 2017, eastern and south-eastern Australian proven plus probable (2P) natural gas reserves[84] totalled 45,180 PJ. Based on advice from gas producers, and as reported in the 2018 GSOO, total gas production across eastern and south-eastern Australia is forecast to increase from 1,938 PJ in 2019 to 2,082 PJ in 2022.

Natural gas is delivered to South Australia through an interconnected pipeline network from Victoria, New South Wales, and Queensland, as well as from the Cooper Basin. Table 16 lists the major gas pipelines that supply natural gas to South Australian consumers. Gas can flow from Queensland to South Australia via the South West Queensland Pipeline and the Moomba processing facility in the Cooper Basin. Gas supplied from offshore Victoria can be delivered to South Australia either:

- Directly along the South East Australia Pipeline, or
- Via multiple pipelines in an anti-clockwise direction through the Victoria – New South Wales Interconnector, the Moomba to Sydney Pipeline, then south along the Moomba to Adelaide Pipeline System.

[83] The Cooper and Eromanga basins span South Australia, New South Wales, and Queensland, and the point of gas extraction may not necessarily be in South Australia.

[84] 2P is considered the best estimate of commercially recoverable reserves.

Table 16 Major gas pipelines relating to South Australia

Gas pipeline	Length (km)	Year of first gas flow	Capacity reported (Terajoules [TJ]/d)
Moomba to Adelaide Pipeline	1,185	1969	241 (South), 85 (North)
Moomba to Sydney Pipeline	2,030	1998	489 (South-East), 120 (North-West)
South East Australia Gas Pipeline	680	2004	314
South West Queensland Pipeline*	937	1996	384 (West), 340 (East)
Victoria – New South Wales Interconnector	143	1998	223 (North), 150 (South)

* Includes the Queensland – South Australia – New South Wales (QSN) Link.

A1. Data spreadsheet index

As part of the SAAF suite, several data spreadsheets are available online for download[85]. These data spreadsheets contain all the tables and data underpinning the figures presented in this report, as well as additional tables and figures not covered in this report, with a separate data spreadsheet corresponding to each section in this report.

The tables below allow for the mapping of the tables and figures in this report to their corresponding items in the data spreadsheets, where applicable.

Report table number	Corresponding data pack table number
Table 1	N/A
Table 2	Table 3.3
Table 3	Table 3.2
Table 4	Table 4.3
Table 5	Table 4.15
Table 6	Table 4.4 and Table 4.5
Table 7	Table 4.8
Table 8	Table 4.9
Table 9	Table 6.1
Table 10	Table 6.4
Table 11	Table 7.2
Table 12	Table 7.3
Table 13	Table 7.4
Table 14	Table 8.1
Table 15	Table 8.2
Table 16	Table 9.1

[85] At https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/South-Australian-Advisory-Functions.

Report figure number	Corresponding data pack figure number
Figure 1	Figure 2.1
Figure 2	Figure 2.2
Figure 3	Figure 3.1
Figure 4	Figure 3.2
Figure 5	Figure 3.10
Figure 6	Figure 3.11
Figure 7	Figure 3.13
Figure 8	Figure 3.8
Figure 9	Figure 3.9
Figure 10	N/A
Figure 11	Figure 4.2
Figure 12	Figure 4.7
Figure 13	Figure 4.10
Figure 14	Figure 5.1
Figure 15	Figure 5.2
Figure 16	Figure 6.1
Figure 17	Figure 6.3
Figure 18	Figure 6.14
Figure 19	Figure 6.7
Figure 20	Figure 6.8
Figure 21	Figure 6.9
Figure 22	Figure 7.7
Figure 23	Figure 7.6
Figure 24	Figure 7.2
Figure 25	Figure 7.3
Figure 26	Figure 7.5
Figure 27	Figure 7.4
Figure 28	N/A
Figure 29	N/A
Figure 30	N/A
Figure 31	Figure 9.1

Glossary, measures, and abbreviations

Glossary

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

Term	Definition
committed projects	Generation that is considered to be proceeding under AEMO's commitment criteria (see Generation Information on AEMO's website, link in Table 1).
electrical energy	Average electrical power over a time period, multiplied by the length of the time period.
electrical power	Instantaneous rate at which electrical energy is consumed, generated, or transmitted.
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.
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. For rooftop PV, the total amount of cumulative rooftop PV capacity installed at any given time.
maximum demand	Highest amount of electrical power delivered, or forecast to be delivered, over a defined period (day, week, month, season, year) either at a connection point or simultaneously at a set of connection points.
non-scheduled generation	Generation by a generating unit that is not scheduled by AEMO as part of the central dispatch process and has been classified as a non-scheduled generating unit in accordance with Chapter 2 of the NER.
operational consumption	The electrical energy supplied by scheduled, semi-scheduled, and significant non-scheduled generating units, less the electrical energy supplied by small non-scheduled generation.

Units of measure

Abbreviation	Expanded name
GWh	Gigawatt hour
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt hour

Abbreviation	Expanded name
MW	Megawatt
MWh	Megawatt hour
TJ	Terajoule

Abbreviations

Abbreviation	Expanded name
AEMC	Australian Energy Market Commission
AEMO	Australia Energy Market Operator
AER	Australian Energy Regulator
AEST	Australian Eastern Standard Time
ARENA	Australian Renewable Energy Agency
CCGT	Combined-cycle gas turbine
CER	Clean Energy Regulator
COAG	Council of Australian Governments
CPI	Consumer Price Index
CSIRO	The Commonwealth Scientific and Industrial Research Organisation
DC	Direct current
DER	Distributed energy resources
DSP	Demand side participation
EAAP	Energy Adequacy Assessment Projection
EGES	Emerging Generation and Energy Storage
ENA	Energy Networks Australia
ESB	Energy Security Board
ESOO	Electricity Statement of Opportunities
EV	Electric vehicle
FCAS	Frequency control ancillary services
GPG	Gas-powered generation
GPS	Generator Performance Standards
GSOO	Gas Statement of Opportunities
HPR	Hornsdale Power Reserve
HWF2	Hornsdale Wind Farm 2

Abbreviation	Expanded name
ISP	Integrated System Plan
LNG	Liquefied natural gas
LOR	Lack of Reserve
LRET	Large-scale renewable energy target
MT PASA	Mid-term Projected Assessment of System Adequacy
NEM	National Electricity Market
NER	National Electricity Rules
NLCAS	Network loading control ancillary services
OCGT	Open-cycle gas turbine
PHEV	Plug-in hybrid electric vehicle
POE	Probability of exceedance
PSFRR	Power System Frequency Risk Review
PV	Photovoltaic
PVNSG	Photovoltaic non-scheduled generation
QSN	Queensland – South Australia – New South Wales
RERT	Reliability and Emergency Reserve Trader
REZ	Renewable energy zone
SAAF	South Australian Advisory Functions
SAER	South Australian Electricity Report
SAET	South Australia Energy Transformation
SAPN	SA Power Networks
SIPS	System Integrity Protection Scheme
SNSG	Small Non-scheduled Generation
STC	Small-scale Technology Certificates
TAPR	Transmission Annual Planning Report
TNSP	Transmission network service provider
TWAP	Time-weighted average price
USE	Unserved energy
VPP	Virtual power plant
VRET	Victorian Renewable Energy Target
VWAP	Volume-weighted average price
WEM	Wholesale Electricity Market (in Western Australia)