
South Australian Electricity Report

November 2019

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 14 November 2019, although AEMO has endeavoured to incorporate more recent information where practical.

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Executive summary

The changing energy landscape is continuing to have a profound impact in South Australia, with several records broken in the last 18 months, and grid demand becoming increasingly variable:

- Distributed energy resources (DER), predominantly rooftop photovoltaics (PV), now represent over 10% of total South Australian electricity generation. Approximately 34% of South Australian dwellings now have rooftop PV systems installed, which is the equal highest level of penetration in Australia (shared with Queensland).
- With the growth in rooftop PV, minimum operational demand (from the grid) is now occurring on sunny, low demand days (typically weekends). In 2018-19, a record low minimum operational demand (sent-out¹) for South Australia of 583 megawatts (MW) was observed on 21 October 2018. (This record has since been broken several times during 2019-20, most recently on Sunday 10 November 2019, when a new record low minimum operational demand of 446 MW sent-out was set.)
- On 24 January 2019, a number of temperature records were set across South Australia and operational demand soared to 3,140 megawatts (MW) sent-out, a level not seen since 2011.
- Record high winter operational demand of 2,489 MW sent-out was experienced on 24 June 2019, following three days of cold weather.
- The time-weighted average price for the financial year reached \$109.80/megawatt hour (MWh) in South Australia, the highest on record, with Victorian pricing dynamics strongly influencing South Australia's outcomes.
- The Virtual Power Plant (VPP) Demonstrations were successfully launched in July 2019, with South Australia VPP (SA VPP), controlled by Energy Locals and Tesla, being the first participant. These VPP Demonstrations will provide AEMO with data showing how household batteries can successfully be used, in aggregate, to support system security through frequency control ancillary services (FCAS). The SA VPP is targeting 50,000 installations to establish itself as the largest VPP in the world, and the South Australian Government is also supporting the installation of 40,000 residential batteries through a Home Battery Scheme.
- The first three large-scale solar plants in South Australia commenced operation, with total combined installed capacity of 378 MW.
- Barker Inlet, the first natural gas reciprocating engine power station in South Australia, commenced operation in November 2019. Using modern technology, this power station can provide rapid response to changes in demand or supply.

As highlighted in AEMO's Renewable Integration Study phase 1 report², South Australia has experienced some of the highest instantaneous penetrations of wind and solar generation in the world, second only to Denmark. South Australia operates under more challenging conditions than Denmark given its substantially lower level of interconnection, and the state experiences the lowest proportional minimum demand of the power systems worldwide that were assessed in the study.

These records and extremes reflect the increasing supply and demand variability that is being actively managed by AEMO operationally and studied for planning purposes to maintain a reliable and secure power system now and in the future.

¹ Estimated value, based on actual operational demand as-generated, less estimated auxiliary loads.

² AEMO, Renewable Integration Study, July 2019, at <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Future-Energy-Systems/Renewable-Integration-Study>.

The impact of active consumers and growing DER

- **Consumers continue to increase their adoption of behind-the-meter rooftop PV and storage**, with 151 MW of rooftop PV installed in 2018-19. By July 2019, rooftop PV capacity was 1,078 MW (16.3 % increase on the previous year) and battery systems reached 34 MW (126 % increase). Rooftop PV contributed 1,374 gigawatt hours (GWh) in 2018-19.
- These consumer choices, combined with energy efficiency savings, **kept annual operational consumption in South Australia flat** at 12,147 GWh in 2018-19, despite underlying population growth. It is expected to stay at a similar level for the next 10 years.
- **Rooftop PV contributed 50 MW more at the underlying peak³** in 2018-19 than had been forecast the previous year, delivering 433 MW at the time of peak (5:00 pm Adelaide time) and **keeping the time of peak grid demand to 7:30 pm Adelaide time**. Now that maximum grid demand has moved into the evening, after the sun has set, future rooftop PV installations are unlikely to further reduce the operational peak grid demand unless combined with energy storage.
- High and growing rooftop PV penetration is **reducing minimum operational demand⁴**, with forecast minimum demand approaching zero by 2024-25 in some scenarios⁵. **Minimum demand continues to occur in the middle of the day**, typically at the weekend or on public holidays. A **record low operational minimum demand** (sent-out) of 446 MW was recorded on Sunday 10 November 2019 at 2:00 pm Adelaide time.
- **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 VPP aggregations.
 - The SA VPP⁶, in which Energy Locals and Tesla (with support from the South Australian Government) seek to establish the world's largest VPP across 50,000 homes.
 - The VPP Demonstrations, allowing VPPs to test a new specification to deliver FCAS, and progressing regulatory changes to facilitate VPP integration into the National Electricity Market (NEM) at scale.
 - Australian Renewable Energy Agency (ARENA)/AEMO trial to explore a strategic reserve model (referencing international market designs) for reliability or emergency demand response⁷.

Supply changes and impacts on exports, emissions, and prices

- **Generation⁸ in South Australia increased 2.9%** in 2018-19 to 14,503 GWh, with almost half supplied from gas-powered generation (GPG). **South Australia increased its role as a net exporter of energy in 2018-19**. Compared to 2017-18, total exports remained relatively steady, but 24% less generation was imported from Victoria.
- **Generation capacity in South Australia increased 12.2%** in 2018-19 (by 770 MW) to 7,066 MW (including 1,078 MW of rooftop PV capacity).
- **Expected closure years** of Torrens Island Power Station A (TIPS A) (480 MW, closing between 2020 and 2021) and Osborne Power Station (172 MW, closing in 2023-24)⁹ have been reported to AEMO as part of the new three-year notice of closure rule change.

³ Total demand from consumers, whether met from the grid or from their own generation or storage behind the meter.

⁴ Operational demand is electricity supplied to consumers via the grid, by local scheduled generation, semi-scheduled generation, and non-scheduled wind/solar generation of at least 30 MW aggregate capacity, and by imports, excluding the demand of local scheduled loads.

⁵ AEMO's forecasts in this year's publications are based on a range of plausible scenarios and sensitivities, explained in the body of this report.

⁶ The SA VPP has recently reached a milestone of 1,100 homes. See <https://virtualpowerplant.sa.gov.au/>.

⁷ See <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/DER-program/Pilots-and-Trials>.

⁸ From registered generators, plus small non-scheduled generation and rooftop PV installed estimates.

⁹ Information provided by the operator, current at August 2019, is in the 8 August 2019 update at <https://aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information>.

- By the end of October 2019, announced **energy generation developments** in South Australia totalled 10,773 MW across 65 projects. AEMO classifies about 107 MW of this as committed for development¹⁰. Wind, solar, and battery/VPP projects comprise the majority of new investment interest.
- 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 a high level of operational flexibility**. Barker Inlet Power Station is an example of this capability, with maximum operation achievable within five minutes at a higher level of efficiency than the pre-existing GPG fleet. This unit commenced operation in November 2019 and will replace the ageing TIPS A.
- Decreased GPG operation meant **emissions** were lower in 2018-19 than the year before. The growth in wind generation led to lower overall average emissions intensity¹¹.
- **Interconnection developments** include the proposed EnergyConnect interconnector to New South Wales (now being considered by the Australian Energy Regulator (AER), with a decision expected by end 2019)¹².
- **Highest prices on record in 2018-19**, with time-weighted average prices 12% higher than in 2017-18 due to high gas prices and higher coal-fired generator offers in other regions. **FCAS prices** were lower, with suppliers like the Hornsdale Power Reserve (HPR) battery system in the market, and increased FCAS provision from TIPS A.

Actions to maintain reliability and security

- AEMO forecasts **tightly balanced supply and demand in the next five years** across South Australia and Victoria.
 - AEMO identified additional reserves which could be made available through the Reliability and Emergency Reserve Trader (RERT) function to ensure that reliability of supply meets the reliability standard in Victoria this summer. The operation of all TIPS A this summer will further reduce the risk of unserved energy (USE)¹³ identified in the 2019 Electricity Statement of Opportunities (ESOO)¹⁴.
 - Beyond this summer, only slight improvements in reliability are forecast for peak summer periods until new transmission and dispatchable supply and demand resources become available. Over the next four years, forecast USE for South Australia is within the reliability standard¹⁵. The announced staggered closure of TIPS A from 2020 will reduce available capacity in South Australia, causing a slow increase in expected USE to 0.0004% by 2021-22.
 - EnergyConnect would reduce this risk of USE by improving the sharing of resources across the NEM.
- As well as energy resources to meet demand, the power system also needs services to **maintain system strength¹⁶ and keep frequency and voltage within required limits**. These system security services are mainly 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 to maintain the system in a secure operating state. **Security directions increased substantially in the last year**, with 153 issued (lasting 3,214 hours) in South Australia during 2018-19 compared to 99 issued (lasting 1,912 hours) in 2017-18.

¹⁰ Commitment criteria (relating to site, components, planning, finance, and date) are outlined under the Background Information tab on AEMO's Generation Information Page, at <http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information>.

¹¹ 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.

¹² For more, see <http://www.projectenergyconnect.com.au/> and <https://www.electranet.com.au/projects/south-australian-energy-transformation/>.

¹³ USE is energy that cannot be supplied to consumers, as a result of insufficient levels of generation capacity, demand response, or network capability, to meet demand.

¹⁴ See <http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities>.

¹⁵ USE is energy that cannot be supplied to consumers, 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.

- During 2018-19, approximately 3.3% of South Australian wind output was curtailed due to system limits being reached. This was an increase from the 2.4% of wind generation curtailed in 2017-18.
- **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. For example, ElectraNet, with support from AEMO, the AER, and the South Australian Government, has progressed a project for four synchronous condensers to be installed to supply both system strength and inertia to the South Australian region. The first two synchronous condensers will be installed at the Davenport substation in mid-2020, and the second two will be installed at the Robertstown substation by the end of 2020. They will be commissioned by early 2021¹⁷.
- AEMO has commenced the Renewable Integration Study (RIS) to explore opportunities and risks for maintaining the physical requirements of the power system while integrating variable inverter-based renewable resources at increasing levels of penetration. This in-depth review will inform future ISPs as well as providing foundational engineering advice to government and administrative policy-makers to support their consideration of future changes needed in electricity regulations and market designs. AEMO's first publication reviewed how Australia compares with other leading international power systems¹⁸.
- **Regulatory changes have recently been made or are under consideration to support system security in South Australia** and the wider NEM, including:
 - Declaration of a new "protected event" by the Reliability Panel in June 2019, providing for management of the risks associated with widespread generator failures during destructive wind conditions in South Australia, to reduce the potential for cascading failures including islanding of South Australia and black system events.
 - Establishment of a register of DER by December 2019 to give AEMO visibility of DER and information including its locations and trip settings.
 - Amendments to Australian Standards to update technical performance standards and compliance measures for DER devices¹⁹.
 - AEMO's rule change proposals to the Australian Energy Market Commission (AEMC) to mandate primary frequency response from all capable scheduled and semi-scheduled generating units once frequency moves outside a defined frequency deadband, as well as encouraging generators to provide primary frequency response by removing a number of disincentives²⁰.
 - The AEMC's review on mechanisms to enhance resilience in the power system, which is considering new approaches to power system security contingency risk management, as well as expanding the Power System Frequency Risk Review to risks broader than just frequency-related events.
 - AEMO's rule change proposal to improve the system restart framework to incentivise the provision of both system restart and restoration support capabilities from a range of different technologies and to facilitate more extensive testing to verify the viability of system restart paths.
 - AEMO's rule change proposal to more efficiently accommodate the participation of bi-directional resources including storage facilities in the National Electricity Rules, which would support improvements to central dispatch, reliability forecasting, technical requirements and performance standards.

¹⁷ See <https://www.electranet.com.au/what-we-do/projects/power-system-strength/>.

¹⁸ See <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Future-Energy-Systems/Renewable-Integration-Study>.

¹⁹ See <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/DER-program/Standards-and-Protocol>.

²⁰ Further information available on the AEMC website, at <https://www.aemc.gov.au/rule-changes/primary-frequency-response-requirement>.

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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). In 2018, AEMO condensed several legacy SAAF reports into a single report, and this reporting model continues with the 2019 SAER.

This 2019 SAER is supplemented by several Excel files with comprehensive data and figures summarising historical information and forecasts. These data files contain many more metrics than are presented in this report. Refer to Appendix A2 for a list of equivalent data file tables and figures to those shown in this report.

AEMO continues to publish an annual comparison of ElectraNet's Transmission Annual Planning Report (TAPR) projects and their revenue proposal, separately from this report²¹.

1.2 Information sources

Appendix A1 contains important clarifying information regarding data sources and reporting methodology used throughout the SAER and its data files.

AEMO has sourced information in this report from other AEMO publications and used information from data provided by market participants and potential investors as at 14 November 2019, unless otherwise specified.

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.

Table 1 Information and data sources

Information source	Website address
2019 Electricity Statement of Opportunities (ESOO) – demand forecast	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities
2018 Integrated System Plan (ISP)	https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan
2019 AEMO Electricity Demand Forecasting Methodology Information Paper	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities
2019 Demand side participation forecast and methodology	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities
2019 ESOO – ESOO Methodology Document	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities
2019 Gas Statement of Opportunities (GSOO) for eastern and south-eastern Australia	http://aemo.com.au/Gas/National-planning-and-forecasting/Gas-Statement-of-Opportunities

²¹ SAAF reports are at <http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/South-Australian-Advisory-Functions>.

Information source	Website address
2019 SAER Data File – tables and figures in this report, as well as many additional metrics	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/South-Australian-Advisory-Functions
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 2018-19 Summer Readiness Plan	https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Summer-operations-report
AEMO's Future Power System Security program	https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/FPSSP-Reports-and-Analysis
AEMO's Guide to Ancillary Services in the NEM	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Ancillary-services
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
Hornsedale 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-Hornsedale-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
Quarterly Energy Dynamics – Q3 2019	https://aemo.com.au/-/media/Files/Media_Centre/2019/QED-Q3-2019.pdf
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
AEMO, Renewable Integration Study, July 2019	https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Future-Energy-Systems/Renewable-Integration-Study

1.3 Scenarios

Some tables and figures in this report are based on three scenarios for pace of change in the energy industry – Central, Slow Change, and Step Change – in line with core scenarios from the 2019 *Electricity Statement of Opportunities* (ESOO) for the National Electricity Market (NEM) published August 2019. In some cases, this report also includes the High Distributed Energy Resources (DER) scenario from the 2019-20 *Integrated System Plan* (ISP) for the NEM (now in development). More detail about the scenarios is provided in AEMO's 2019 *forecasting and planning scenarios, inputs and assumptions* report (see Table 1 for references).

In summary:

- The **Central** scenario reflects the current transition of the energy industry under current policy settings and technology trajectories, where the transition from fossil fuels to renewable generation is generally led by market forces and supported by current Commonwealth and South Australian Government policies. This scenario assumes a range of best estimate projections of economic growth, population growth, and electric vehicle (EV) uptake. Existing market settings, tariffs, policies (including the South Australian Retailer Energy Efficiency Scheme) drive energy efficiency activities and DER uptake. Existing trials lead moderate growth in aggregated virtual power plants (VPPs) to offset the need for additional supply, while household batteries operate to maximise the individual household's benefit.
- The **Slow Change** scenario reflects a general slow-down of the energy transition. It is driven by slower advancements in technology and reductions in technology costs, low population growth, and low political, commercial and consumer motivation to make the upfront investments required for significant emissions reduction. The slower population growth outlook lowers broader economic growth and limits household disposable income growth. Weak economic conditions lead to higher risk of industrial demand closures, while business and residential loads seek to lower consumption to manage bill exposure. With less disposable income and fewer policy settings to support DER, investment in rooftop PV, batteries, and EVs is reduced relative to the Central scenario. Australia does not actively promote local EV deployment.
- The **Step Change** scenario reflects strong action on climate change that leads to a step change reduction of greenhouse gas emissions. In this scenario, aggressive global decarbonisation leads to faster technological improvements, accelerated exit of existing generators, greater electrification of the transport sector with increased infrastructure developments, energy digitalisation, and consumer-led innovation. Higher economic and population growth and greater innovation in digital trends leads to stronger investment in energy efficiency, DER, and EVs. Existing VPP trials demonstrate a strong role for VPPs, reducing the need for large-scale supply, while tariff reform enables greater adoption of smarter charging behaviours by customers with batteries and EVs to offset household demand.
- The **High DER** scenario reflects a more rapid consumer-led transformation of the energy sector, relative to the Central scenario. It represents a highly digital world where technology companies increase the pace of innovation in easy-to-use, highly interactive, engaging technologies. This scenario includes reduced costs and increased adoption of DER, with automation becoming commonplace, enabling consumers to actively control and manage their energy costs while existing generators experience an accelerated exit. It is also characterised by widespread electrification of the transport sector.

These scenarios will be referenced in the sections of this report covering forecast demand, consumption, and supply.

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 DER affect consumers' overall energy consumption levels and potentially shift energy consumption patterns. Consumer behaviour, particularly the usage of battery storage and EV charging patterns, will affect consumption patterns across the day.

This section covers forecast uptake of these technologies and outlines the forecast role of DER for the 2019 NEM ESOO²². The impact on timing and magnitude of maximum operational demand is covered in Section 3.

2.1 Rooftop photovoltaics (PV)

Rooftop PV systems (up to 100 kilowatts [kW]) installed on South Australian residential and commercial premises have a measurable impact on the region's operational electricity demand, by reducing residential and commercial grid consumption during daylight hours, when consumer demand can be met by rooftop PV.

From 2012-13, rooftop PV production has shifted minimum demand from overnight to occur in the middle of the day, and the time of maximum operational demand further into the evening. In South Australia, maximum demand now typically occurs late in the day (between 6:30 pm and 8:00 pm Adelaide time in summer 2018-19), when solar irradiance is low.

2.1.1 Rooftop PV forecast methodology

Forecast methodology

AEMO's *Electricity Demand Forecasting Methodology Information Paper*²³ provides a description of both rooftop PV capacity and generation forecasts – as used in the 2019 NEM ESOO – in its Appendix A3. A short summary of capacity and generation estimation is provided below.

Capacity estimation

Historical installed capacity for rooftop PV was extracted from a data set provided by the Clean Energy Regulator (CER).

Generation estimation

The energy generated by a rooftop PV system was estimated using a dataset primarily procured from *Solcast* (2009-19), supplemented from data developed by the University of Melbourne²⁴ with AEMO, covering the period 2000-08.

For each half-hour, the generation model considers solar radiation and cloud coverage. It models inefficiencies related to shading effects and considers the geographic distribution of the rooftop PV installations at that time. An example of the effect of including assumptions around inefficiencies is that the

²² At <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities>.

²³ At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2019/Electricity-Demand-Forecasting-Methodology-Information-Paper.pdf.

²⁴ V.D. Ruelle, M. Jeppesen and M. Brear, *Rooftop PV Model Technical Report*, July 2016, at <http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/-/media/CEDBBF70073149ABAD19F3021A17E733.ashx>.

total rooftop PV generation estimate for South Australia in January 2016 is reduced by 1% once ageing of panels is considered²⁵.

The historical values of rooftop PV generation were obtained by multiplying the existing capacity (calculated from CER data) by the modelled generation of a 1 kW rooftop PV installation.

Rooftop PV capacity

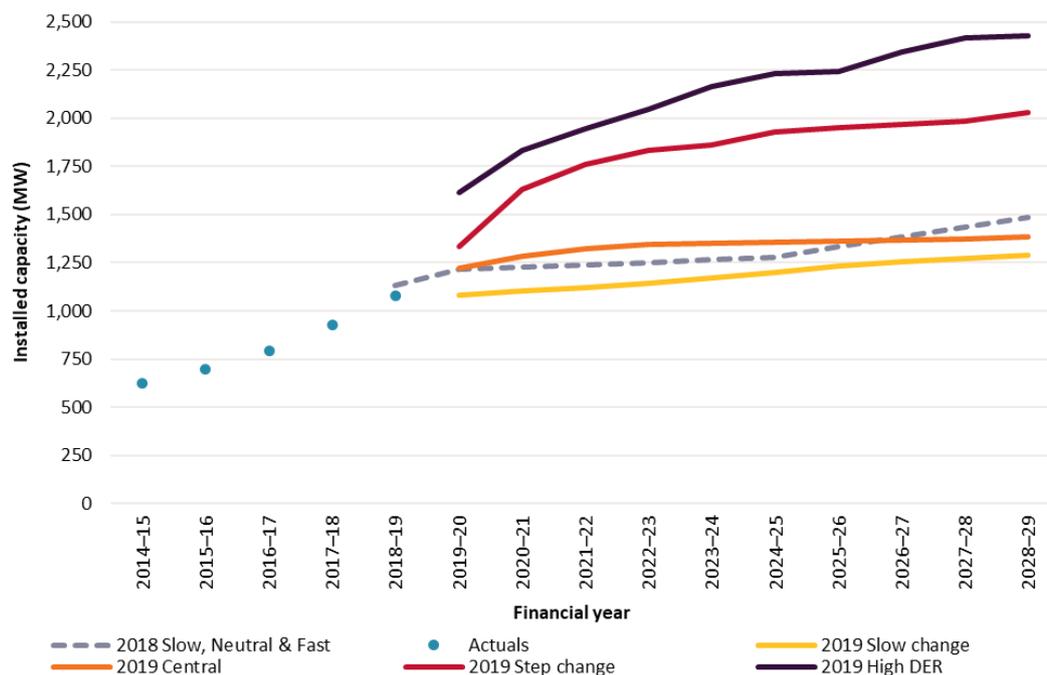
Since 2009, South Australian total installed rooftop PV²⁶ capacity has grown strongly. The proportion of South Australian dwellings that now have rooftop PV systems installed is around 34%, which is the equal highest level of penetration in Australia (shared with Queensland)²⁷.

Rooftop PV systems continue to be installed at a very high rate. An additional 151 MW was estimated to have been installed in 2018-19 across the business and residential sectors, bringing the total estimated combined residential and business PV capacity in South Australia to 1,078 MW. Of the two sectors, the business sector saw stronger relative growth than residential by a considerable margin in 2018-19.

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, falling system costs, reductions in interest rates on mortgages, and high retail prices.

Figure 1 shows the estimated actual and forecast installed rooftop PV capacity (residential and business sectors) for South Australia from 2014-15 to 2028-29. In the Central scenario, rooftop PV installed capacity is forecast to grow steadily over the next few years before plateauing and reaching 1,386 MW in 2028-29.

Figure 1 South Australian rooftop PV installed capacity forecasts to 2028-29



Recent AEMO internal analysis suggests that more rooftop PV (approximately 40 MW) has been estimated to be installed by October 2019 compared with AEMO’s forecast for the Central scenario, indicating that the current DER installation rate sits between the Central and the High DER scenario forecasts.

²⁵ This corresponds to an assumed average panel age across the region of 2.5 years.

²⁶ Rooftop PV comprises both business and residential installations.

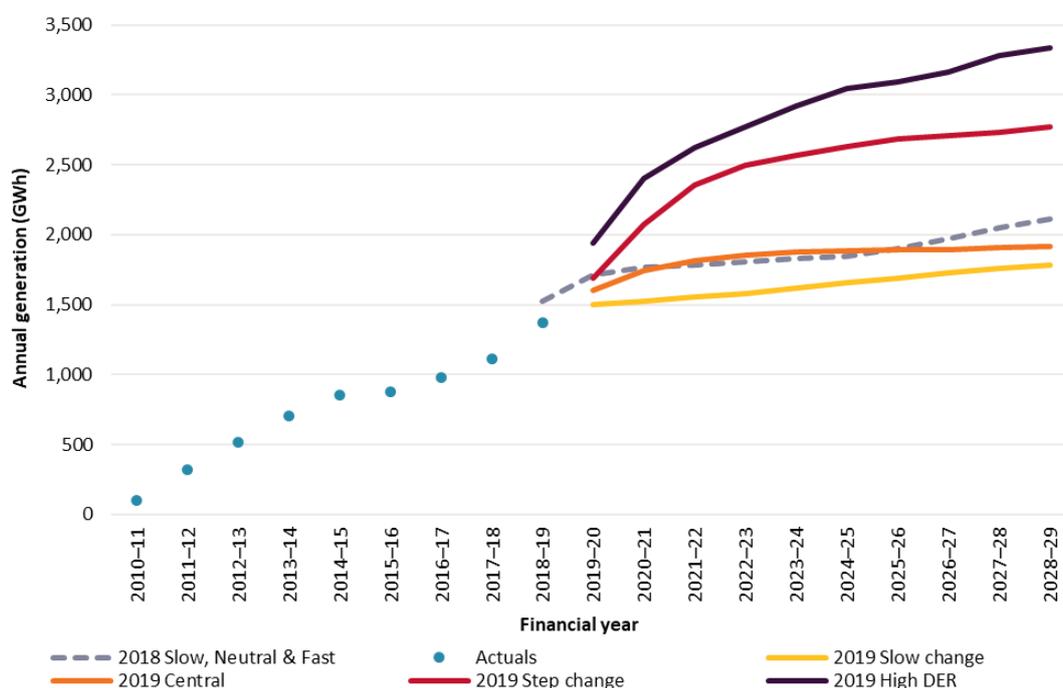
²⁷ Australian PV Institute (APVI) Solar Map, funded by the Australian Renewable Energy Agency, accessed from pv-map.apvi.org.au on 21 October 2019.

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 region's high penetration of rooftop PV installations, good solar resources, and the second-lowest operational consumption of all regions in the NEM. More broadly across Australia, the Wholesale Electricity Market of Western Australia and Northern Territory power systems are expected to have even greater penetration of PV over time.

Figure 2 shows the estimated actuals and forecasts of annual rooftop PV generation for South Australia from 2010-11 to 2028-29. In 2018-19, annual rooftop PV generation was estimated at 1,374 gigawatt hours (GWh). In the Central scenario, it is forecast to increase to 1,917 GWh by 2028-29, which would represent approximately 13% of annual underlying consumption at that time.

Figure 2 South Australian rooftop PV generation forecasts to 2028-29



2.2 PV non-scheduled generation (PVNSG)

PVNSG capacity is between 100 kW and 30 MW and is typically business rooftop PV and small solar farms below AEMO's registration threshold of 30 MW.

South Australia has experienced rapid growth in PVNSG over the last four years, with capacity more than tripling on average each year since 2014-15 (although from a relatively low base). This is driven by commercial decisions in the small to medium commercial sector (100 kW to 30 MW) to avoid energy costs, as well as incentives driven by large-scale renewable electricity generation certificates (LGCs).

Figure 3 shows the estimated amount of PVNSG installed capacity as at 30 June 2019 was 72 MW. However, there is a delay between a PVNSG connection and its registration with the CER for the LGC. SA Power Networks (SAPN) estimates PVNSG capacity to be at approximately 125 MW as at 1 October 2019.

AEMO's Central scenario forecast, provided by the CSIRO, projects no additional PVNSG capacity, due to assumed tapering off of LGC incentives, and in fact forecasts capacity declining, due to panel derating. Actuals have already exceeded the Central scenario by approximately 65 MW.

In the 2019 ESOO, the Step Change scenario has the highest PVNSG forecast, due to including better incentives for business to install PVNSG. PVNSG capacity is currently tracking to meet or exceed the Step

Change scenario forecast, in which capacity is forecast to increase to 129 MW in 2024-25 and 205 MW in 2028-29.

Figure 3 South Australian PVNSG installed capacity forecasts

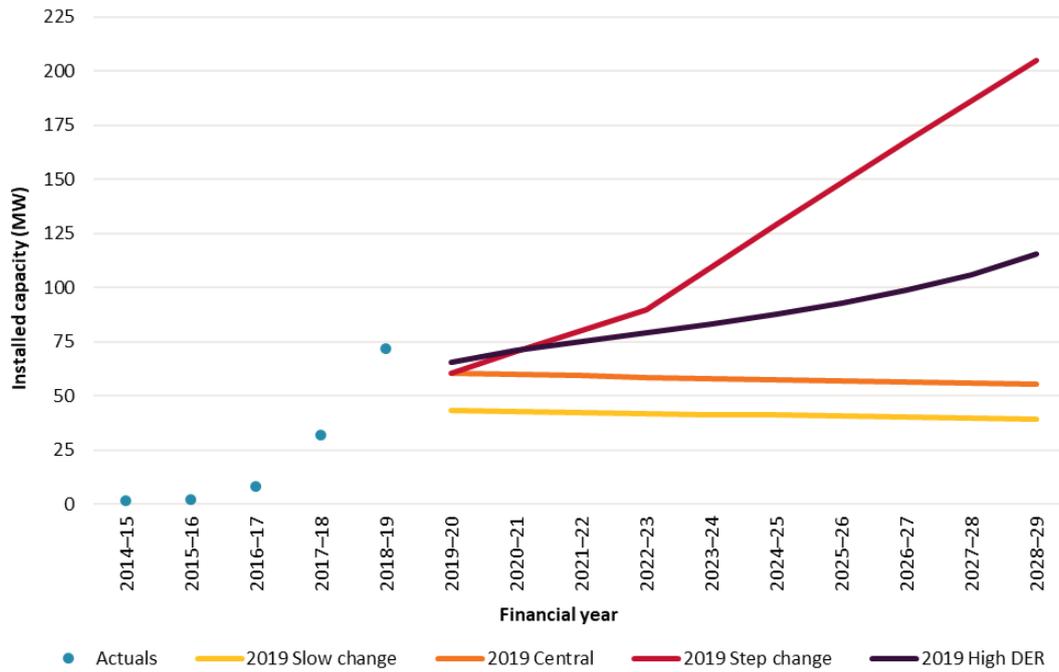
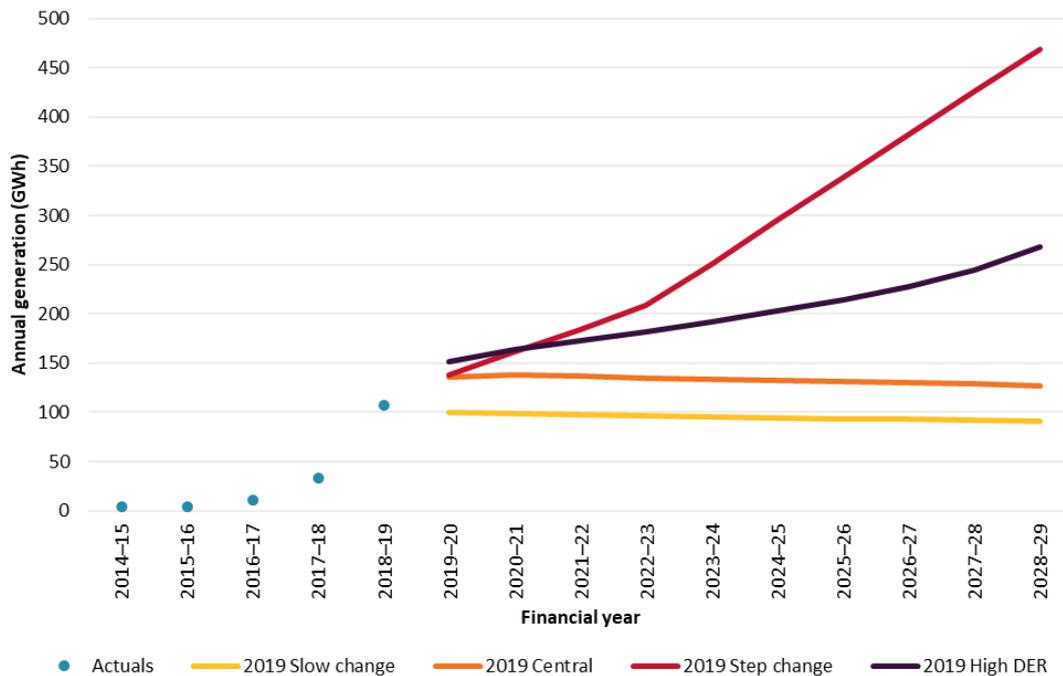


Figure 4 shows the estimated PVNSG annual generation for the capacity forecasts shown in Figure 3.

Figure 4 South Australian PVNSG generation forecasts



2.3 Battery storage

South Australia currently (at June 2019) has an estimated 34 MW (or 8,000 units) of embedded battery systems²⁸. Compared to other NEM regions, South Australia has a higher battery installation forecast over the next five years, as recent State Government policy is supporting the installation of 40,000 residential batteries through a Home Battery Scheme²⁹.

Other VPP trials are also underway by retailers and technology providers, including:

- South Australia VPP (SA VPP) operated by Energy Locals and Tesla with support from the South Australian Government³⁰.
- AGL VPP, with support from the Australian Renewable Energy Agency (ARENA)³¹.
- Simply Energy VPPs, with support from ARENA³².
- SA Power Networks Advanced VPP Grid Integration, with support from ARENA³³.
- AEMO's VPP Demonstrations, with support from ARENA.

AEMO's VPP Demonstrations program is establishing a framework to allow VPPs to demonstrate their capability to deliver services in contingency frequency control ancillary services (FCAS)³⁴ and energy markets.

In July 2019, AEMO opened registrations for participation in this program and SA VPP was first to sign up. The VPP Demonstrations allow participating VPPs to trial a new specification to deliver Contingency FCAS, and AEMO will observe how VPPs respond to energy market price signals as non-scheduled resources. By trialling VPP operations while their aggregated fleets remain small scale, the VPP Demonstrations aim to inform the effective integration of VPPs into the NEM before they reach large scale. Information about the design of the VPP Demonstrations and how to enrol is on AEMO's website³⁵.

By 2028-29, uptake of business and residential behind-the-meter battery systems is forecast to reach 150 MW (in the Central scenario) and 2.5 gigawatts (GW) (in the High DER scenario). Battery uptake is forecast to be slower than previous projections, due to revisions to payback periods, technology costs, and linkages to PV uptake rates. Current modelling assumed most battery systems would be installed as part of integrated solar and battery systems.

Dependent on pricing incentives, battery storage systems may have differing impact on 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 3, increased benefits are expected if this battery fleet is orchestrated to provide a more certain peak support role.

2.4 Electric vehicles

In 2018-19, there were an estimated 300 residential EVs in South Australia including plug-in hybrid electric vehicles (PHEVs), although confidence in the actual number of EVs at this stage is relatively low³⁶.

²⁸ For more information, see https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/2019-Projections-for-Small-Scale-Embedded-Technologies-Report-by-CSIRO.pdf.

²⁹ For more information, see <http://www.renewables.sa.gov.au/home-battery-scheme>.

³⁰ At <https://virtualpowerplant.sa.gov.au/>.

³¹ At <https://arena.gov.au/projects/agl-virtual-power-plant/>.

³² At <https://www.simplyenergy.com.au/energy-solutions/battery-storage/south-australian-virtual-power-plant-vpp>.

³³ At <https://arena.gov.au/projects/advanced-vpp-grid-integration/>.

³⁴ FCAS are services that help AEMO balance supply and demand to maintain system frequency. Contingency FCAS is called on when frequency is disturbed by a contingency event, such as the sudden failure and disconnection of a generator or load.

³⁵ At <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/DER-program/Virtual-Power-Plant-Demonstrations>.

³⁶ CSIRO, 2019 *Projections for small-scale embedded technologies* report, at <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies>.

By 2028-29, in the Central scenario, yearly sales of residential EVs in the state are forecast to be over 8,000 vehicles, and sales of light commercial vehicles above 1,500, taking South Australia's total EV fleet to over 34,000 vehicles.

Annual electricity consumption from EV charging is forecast to be approximately 119 GWh in 2028-29 in South Australia (under the Central 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 2019 ESOO, AEMO assumed a weighting of four charging profiles: convenience, fast charging, 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.

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 EVs.

South Australian demand peaks late in the day, due to historically high uptake of rooftop PV. At this time of day, continued growth in rooftop PV will have little or no impact on moderating maximum demand from the grid.

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 forecast growth for rooftop PV installations means 90% probability of exceedance (POE) minimum operational demand is forecast to continue to decline over the next few years³⁷.

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 Australia³⁸.

In 2018-19, operational consumption (sent-out) was 12,147 GWh. This was 0.7% (91 GWh) lower than the 2017-18 consumption of 12,238 GWh.

Operational consumption is forecast to increase slightly under the 2019 NEM ESOO Central scenario, from 12,276 GWh in 2019-20 to 12,526 GWh in 2028-29 (0.2% average annual growth rate).

Figure 5 shows the historical trend of operational consumption in South Australia from 2009-10 as well as the 10-year forecast. It shows a noticeable decline from 2011-12 onwards, which has been driven by:

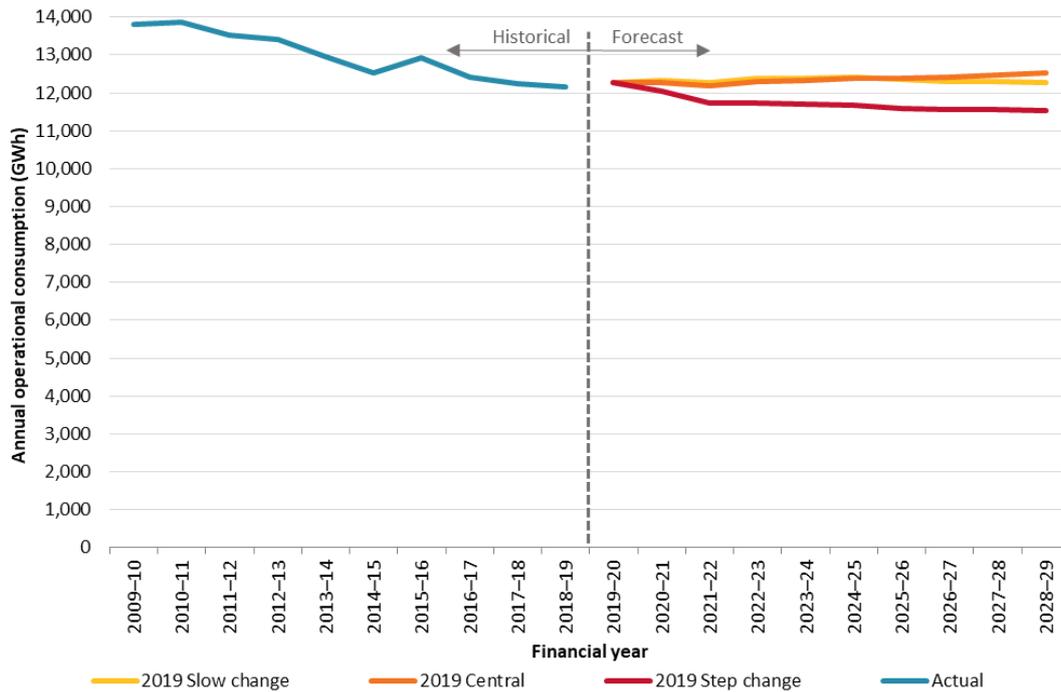
- A fall in residential, commercial, and industrial consumption as consumers have become more actively engaged in their energy use, with uptake of rooftop PV and incorporating more energy efficiency savings.
- Declines in energy-intensive industrial industries such as car manufacturing.

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

³⁷ 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.

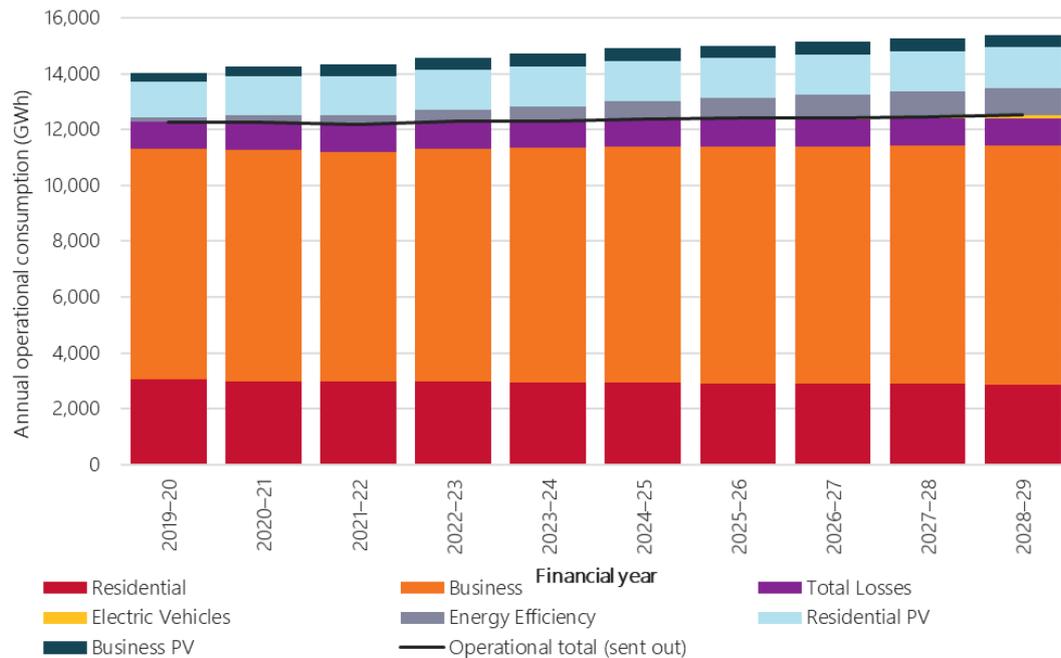
³⁸ Forecasts are presented on a sent-out basis, meaning the forecasts exclude generator auxiliary loads. See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/EFI/2018/Operational-Consumption-definition---2018-update.pdf for more on definitions.

Figure 5 Annual operational consumption (sent-out) actual and forecast for South Australia



As Figure 6 below shows, 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 improvements in energy efficiency through new schemes and appliances, including air-conditioning, and better insulation of houses.

Figure 6 Forecast annual operational consumption (sent-out) with components (Central scenario)



Business consumption is forecast to remain relatively flat (0.4% year on year average growth), as growth in the state economy is forecast to offset the decline coming from commercial rooftop PV installations and business sector energy efficiency programs.

EV consumption (forecast to reach 119 GWh by 2028-29 in the Central scenario) is projected to mostly offset the drop in residential consumption, keeping total forecast operational consumption across South Australia flat overall.

3.1.2 Operational maximum demand (sent-out)

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

On 24 January 2019, South Australia experienced one of the hottest days on record (in many locations the hottest). Operational demand sent-out reached 3,140 MW both at 7:30 pm and 8.00 pm (Adelaide time).

Demand would have been higher, but was restricted due to load reductions through Reliability and Emergency Reserve Trader (RERT) (6 MW), non-scheduled generation directed on (19 MW), and voluntary demand side participation (DSP) (30 MW). There were also up to 20,000 customers without power due to blown fuses in the distribution network. The extent of the outages in the distribution network was highest at 8.00 pm, and AEMO estimates the actual peak would have occurred that half-hour, had it not been for these load restrictions. After also accounting for the effect of the state-wide media call for users to conserve electricity use where possible, AEMO estimates the unrestricted demand for 8.00 pm would have been approximately 3,277 MW³⁹.

Rooftop PV generation reduces maximum demand from the grid (operational demand). The large levels of installed rooftop PV capacity in South Australia to date have resulted in maximum operational demand shifting from the middle of the day to early evening, when rooftop PV is not generating. Table 2 shows that since 2015-16, the time of maximum operational demand has occurred late in the day.

Because the peak now occurs when rooftop PV is not contributing, the 2019 ESOO forecast that further increases in rooftop capacity will likely not have any additional impact on maximum operational demand.

Impact of rooftop PV on underlying maximum demand

Table 2 shows estimated rooftop PV generation at time of underlying maximum demand for the last five years, illustrating that the contribution of rooftop PV has grown year on year since 2015-16.

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 (Adelaide time)	Rooftop PV generation at the time of operational maximum demand (MW)	Time of operational maximum demand (Adelaide time)
2014-15	327	1:30 PM	142	4:00 PM
2015-16	230	5:30 PM	88	7:00 PM
2016-17	334	5:00 PM	178	6:30 PM
2017-18	383	5:00 PM	80	7:30 PM
2018-19	433	5:00 PM	84	7:30 PM

Forecast operational maximum demand

Maximum operational demand is forecast to continue to be experienced in summer and is expected to increase, due to growth drivers for business load (first year increase in particular driven by growth in large

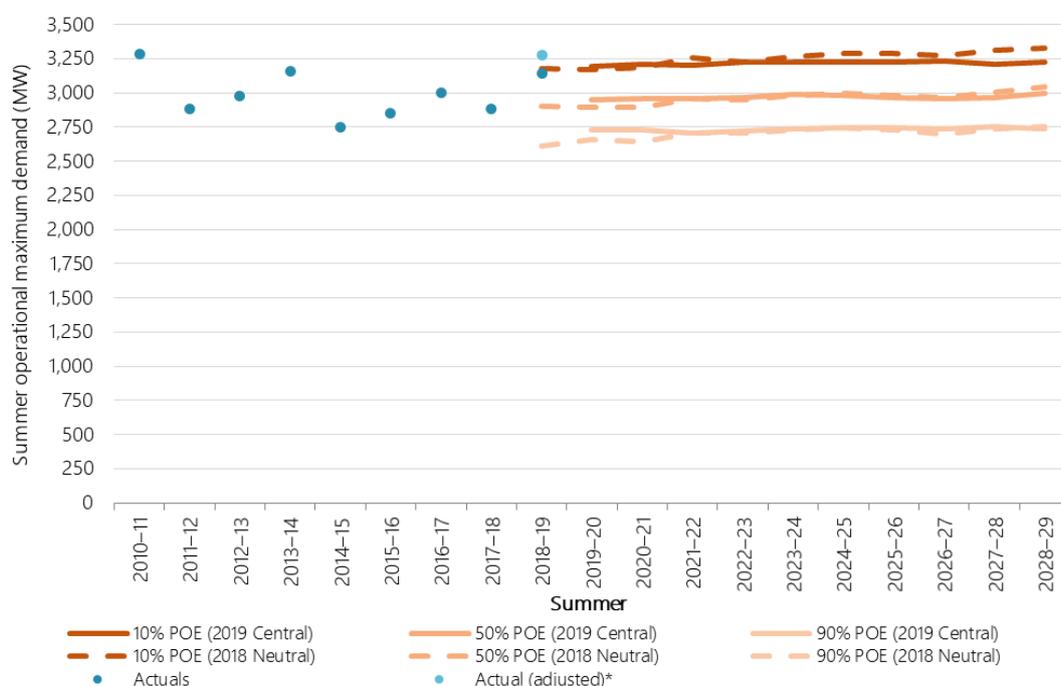
³⁹ For more information please see AEMO, *Summer 2019 Forecast Accuracy Update*, 2019, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Accuracy-Report/2019-Summer-Forecast-Accuracy-update.pdf.

industrial loads), as well as the expectation that operational demand is likely to peak too late in the day for additional rooftop PV to have a substantial impact offsetting growth in grid demand.

Figure 7 shows historical summer maximum demand actuals since 2010-11, and 10%, 50%, and 90% POE forecasts from the 2019 and 2018 NEM ESOOs (Central/Neutral scenario). Over the next 10 years, maximum operational demand (50% POE, Central scenario) is expected to remain relatively flat (0.2% average annual growth). This is mainly due to projected energy efficiency gains reducing total business load, offset by forecast growth in residential loads.

Forecast maximum demand represents the likely distribution of annual maximum demand outcomes if unrestricted (that is in the absence of load shedding and DSP of any sort). Therefore, for comparison with the forecasts, the adjusted (unrestricted) demand of 3,277 MW that could have been reached on 24 January 2019 is most relevant. As Figure 7 shows, the estimated demand that would have been reached that day exceeded the 10% POE line.

Figure 7 Summer operational maximum demand (sent-out) actual and forecast for South Australia, 2010-11 to 2028-29 (Central scenario)



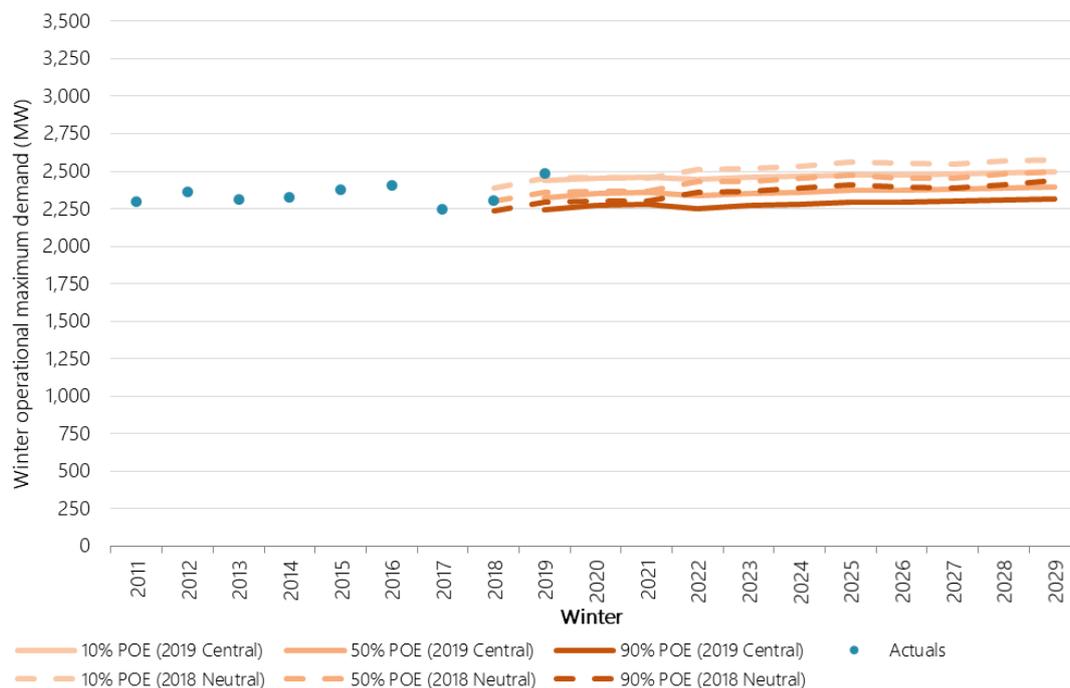
* Adjusted Actual value for 2018-19 is AEMO’s estimate of what would have been reached without load shedding or DSP of any sort.

Figure 8 shows the same period for South Australia’s operational maximum demand in winter. It shows an initial increase in the first year driven by growth in large industrial loads, then remaining relatively constant for the remainder of the time horizon. For winter, a new record high demand of 2,489 MW was set on 24 June 2019, following three very cold days, and exceeding the previous record set back in July 2008.

Insights into AEMO’s forecasting performance are reported annually in its *Forecast Accuracy Report*⁴⁰.

⁴⁰ At <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Forecasting-Accuracy-Reporting>.

Figure 8 Winter operational maximum demand (sent-out) actual and forecast for South Australia, 2011 to 2029 (Central scenario)



Demand side participation (DSP)

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

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.

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.

The estimated level of DSP available in South Australia for summer 2019-20 and winter 2020 is shown in Table 3. It reflects AEMO’s expected (median) DSP resource response to different wholesale price levels. 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 issued⁴¹.

The DSP forecast and methodology is documented in a 2019 AEMO report⁴², which includes a summary of the groups that are included in AEMO’s DSP values, the groups excluded and the reasons why. Notably:

- The typical response at the time of maximum demand by embedded generators is captured as part of AEMO’s forecast for other non-scheduled generation and is excluded from the DSP estimates below to avoid double-counting.
- Responses triggered by the RERT process, as discussed in Section 7.2, are excluded.

⁴¹ LOR conditions indicate times the system may not have enough reserves to meet demand if there is a large, unexpected event. See National Electricity Rules, rule 4.8.4 for definitions, at <https://www.aemc.gov.au/regulation/energy-rules/national-electricity-rules/current>.

⁴² AEMO, *Demand Side Participation Forecast and Methodology*, 2019, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2019/Demand-Side-Participation-Forecast-Methodology-2019.pdf.

- Time of use tariff impacts and controlled-load arrangements are captured in the demand forecast, and are therefore not included in the DSP forecast to avoid double-counting of these effects.

Table 3 shows the estimated cumulative price response is 11 MW for South Australia when prices exceed \$500/MWh, and 27 MW when prices exceed \$5,000/MWh. However, if LOR 2 or LOR 3 conditions are declared, the total DSP response is estimated to be 33 MW in South Australia. On 24 January 2019, AEMO estimated that there was 30 MW of DSP during the South Australian maximum demand event.

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

Trigger	Summer 2019-20 (MW)	Winter 2020 (MW)
>\$300 / MWh	4	4
>\$500 / MWh	11	11
>\$5,000 / MWh	27	27
>\$7,500 / MWh or in response to LOR notices	33	33

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

The current expected level of DSP from larger customers is small relative to total demand of these customers. AEMO notes that there are times where responses can be significant.

3.1.3 Operational minimum demand

Operational minimum demand generally occurs during weekends or public holidays. As installed rooftop PV capacity increases, minimum demand has been declining. South Australia has experienced minimum demand in the middle of the day since 2012-13, due to rooftop PV, and this is forecast to continue to be the case.

In 2018-19, a new record low minimum operational demand (sent-out) of 583 MW was set on 21 October 2018 at 1:30 pm. This record has since been broken several times during October and November 2019.

The most recent record, as seen in Figure 9, occurred on Sunday 10 November 2019 at 2:00 pm (Adelaide time). At this time, demand from the grid dipped to 458 MW (446 MW sent-out), South Australia was a net exporter, and the peak rooftop PV generation was 832 MW, or around 64% of the underlying operational demand. This day was a clear day, with high solar irradiance for the time of the year and daytime temperatures in low to mid 20s, but, being a weekend, a day with low commercial and industrial loads.

Figure 9 Profile of record minimum operational (as-generated) demand day (10 November 2019)

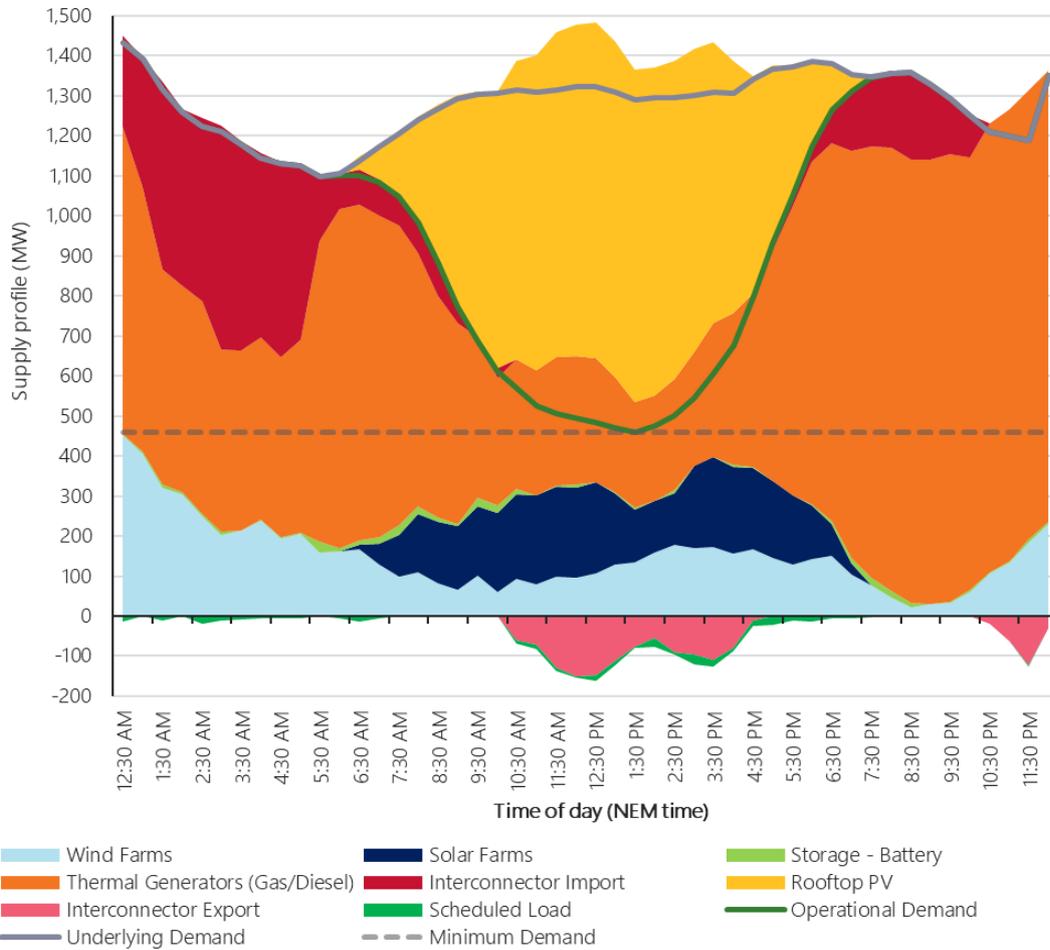
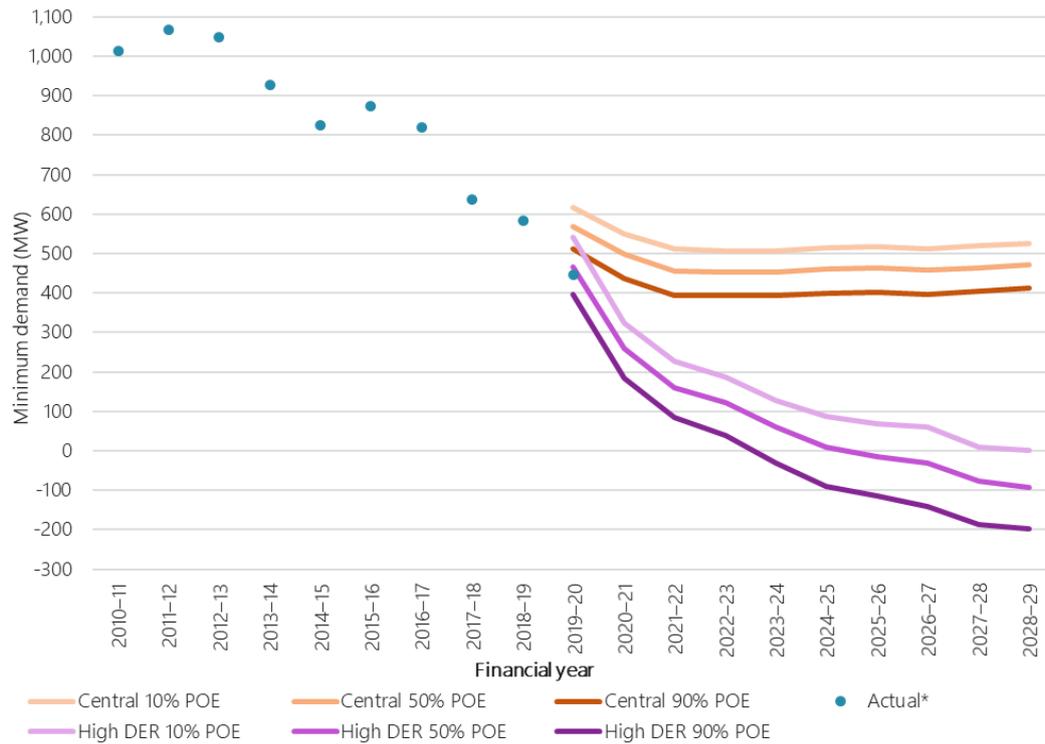


Figure 10 shows that forecast shoulder minimum demand declines over the first three years of the forecast to 2024-25, then remains relatively flat for the central scenario. The High DER scenario has a steep decline the first three years, then a more gradual decline in the following years as PV saturation is reached in some locations.

Under the High DER scenario, minimum demand (90% POE) is forecast to reach zero in South Australia in 2024-25. The minimum demand observed in November 2019 is more consistent with the High DER scenario than the Central scenario, primarily due to more PV installations in the year to date than was forecast under the Central scenario.

Figure 10 Shoulder operational minimum demand (sent-out) actual and forecasts for South Australia (Central and High DER scenarios)

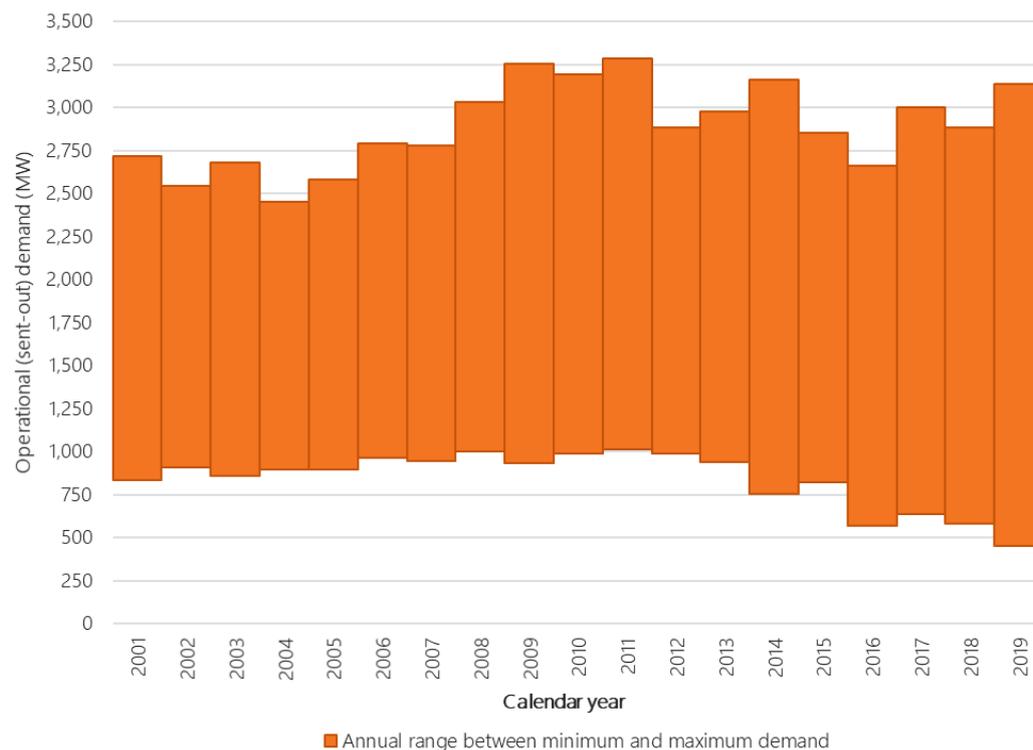


* Record minimum demand on 10 November 2019 has been included in the 2019-20 financial year actual, despite this not being a complete year. The 2016-17 minimum excludes the black system event in South Australia on 28 September 2016.

3.1.4 Trends in maximum and minimum demand

Figure 11 shows the annual operating range of South Australian sent-out demand for the last 18 years.

Figure 11 South Australian historical annual range of operational (sent-out) demand



Note: analysis excludes black system event in South Australia on 28 September 2016.

Between 2001 and 2010, demand for energy rose, with higher increases in summer maxima. Since 2012, annual maxima have remained at a similar level.

In December 2012, annual minima switched from overnight to daytime. Since then, minima have continued to occur during the day, further reducing in line with rooftop PV installations.

As a result, the difference between maxima and minima has grown from approximately 1,800 MW to approximately 2,600 MW.

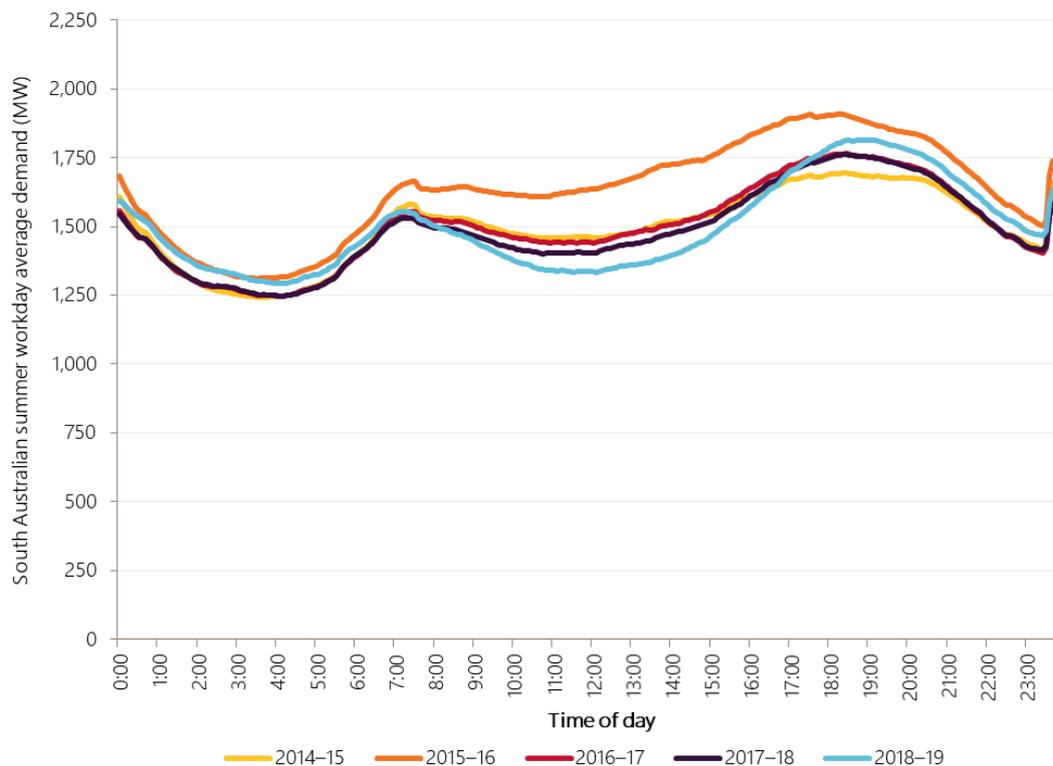
3.2 Daily demand profiles

The average daily demand profiles represent the operational (as-generated) demand, in megawatts, 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 12 shows the South Australian average workday demand profile for summer from 2014-15 to 2018-19. 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 12 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.

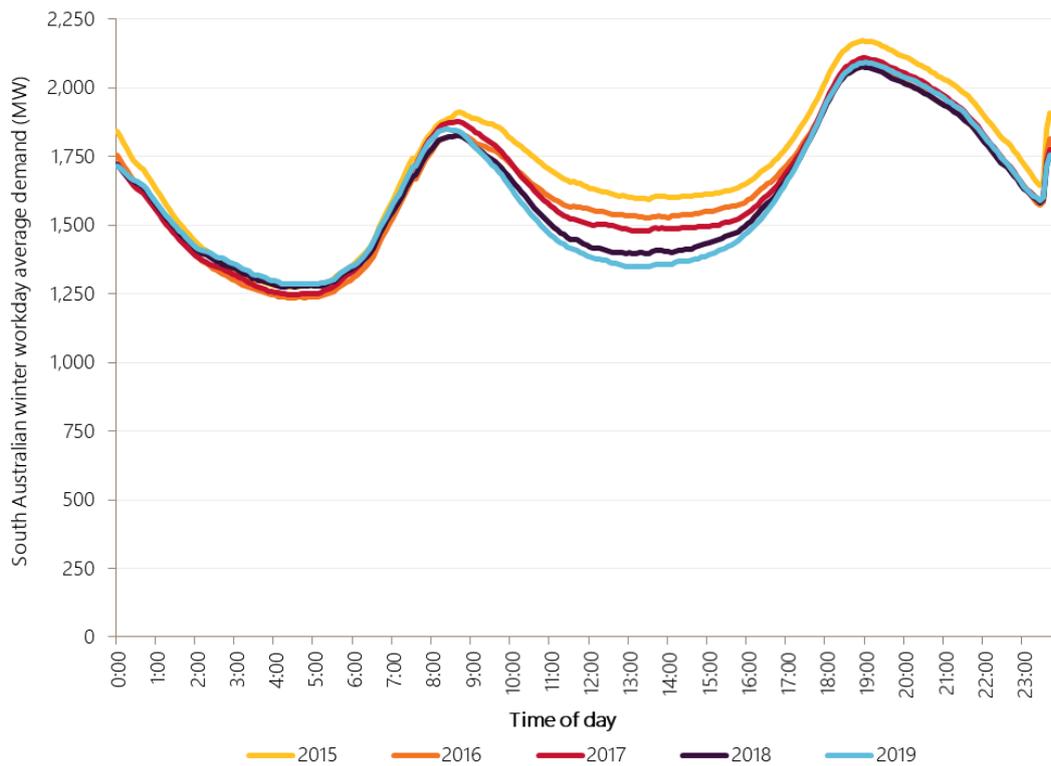
Another noticeable feature in the demand profile is the sharp uptick from 11:30 pm, due to the controlled switching of electric hot water storage systems. SAPN has been moving some of the hot water systems away from the night-time timer setting to turn on during mid-day instead. Additional residential 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 13 shows the South Australian average winter workday demand profile for winter 2015 to 2019. 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.

Figure 13 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 12.2% of total installed capacity⁴³ to 7,066 MW in 2018-19 compared with the previous year, mainly due to an increase in wind, rooftop PV, and large-scale solar generation. Approximately 107 MW of new generation and storage capacity was committed in South Australia at 14 November 2019, comprising wind and battery storage/VPP projects.

Generation slightly increased by 2.9% to 14,503 GWh, with South Australia continuing to be a net exporter of electricity in 2018-19. The proportion of contribution from wind remained similar to the previous year, while gas decreased slightly to 47.4%, and large-scale solar and rooftop PV increased to 11.6%.

4.1 Historical capacity and generation

4.1.1 Historical capacity

The supply capacity mix in South Australia has continued to evolve. Table 4 shows the capacity mix at the end of 2018-19.

Table 4 South Australian registered capacity and local generation by energy source in 2018-19

Energy source	Registered capacity		Electricity generated	
	MW	% of total	GWh	% of total
Gas	2,673	37.8%	6,877	47.4%
Wind	2,142	30.3%	5,725	39.5%
Diesel + small non-scheduled generation (SNSG)	665	9.4%	184	1.3%
Rooftop PV	1,078	15.3%	1,374	9.5%
Solar	378	5.3%	303	2.1%
Storage – Battery	130	1.8%	41	0.3%
Total	7,066	100%	14,503	100%

Compared to the end of 2017-18⁴⁴, the biggest increases were in wind, rooftop PV, and large-scale solar capacity. New semi-scheduled generators that were registered in 2018-19 are:

⁴³ Includes AEMO registered capacity, as well as estimated rooftop PV capacity and estimated SNSG capacity.

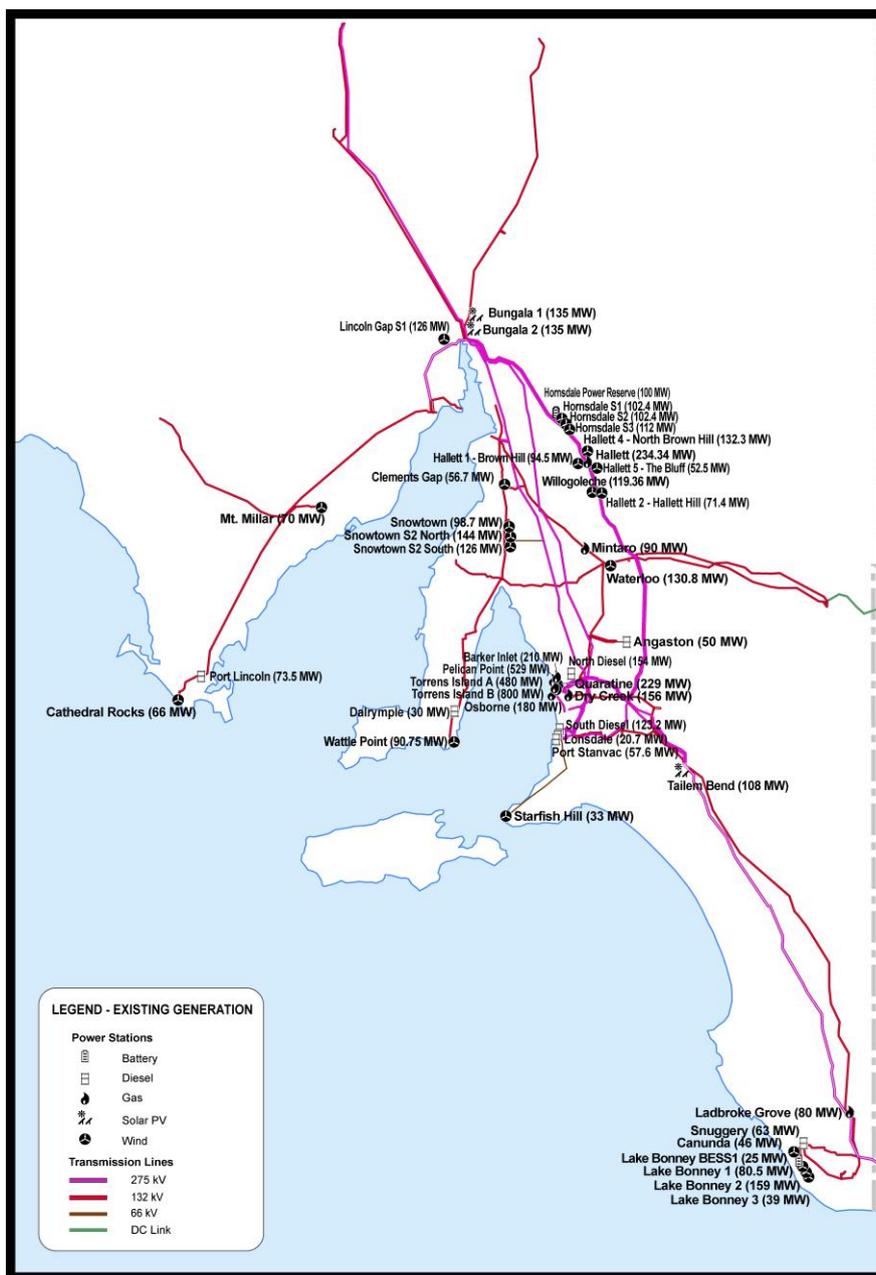
⁴⁴ Refer to 2019 SAER data file, Table 4.24.

- Lincoln Gap Wind Farm⁴⁵ (212.4 MW).
- Willogoleche Wind Farm (119.36 MW).
- Taillem Bend Solar Project 1 (108 MW).
- Bungala Two Solar Farm (135 MW).

4.2 Historical generation

Figure 14 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 14 Location and capacity of South Australian generators



⁴⁵ Lincoln Gap Wind Farm (registered capacity 212.4 MW) currently has nameplate capacity of 126 MW, with an additional 86.4 MW to be completed by August 2020, as reported in the 14 November 2019 update at <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information>.

Composition of generation

Figure 15 shows the mix of energy generated in South Australia by fuel type from 2014-15 to 2018-19, from:

- All scheduled generators.
- All semi-scheduled and market non-scheduled wind farms.
- All semi-scheduled solar farms.
- Temporary generation north and south (now registered as non-scheduled).
- Selected smaller market and non-market non-scheduled generators (SNSG).
- Estimated rooftop PV.

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

Figure 15 South Australian energy generation by fuel type

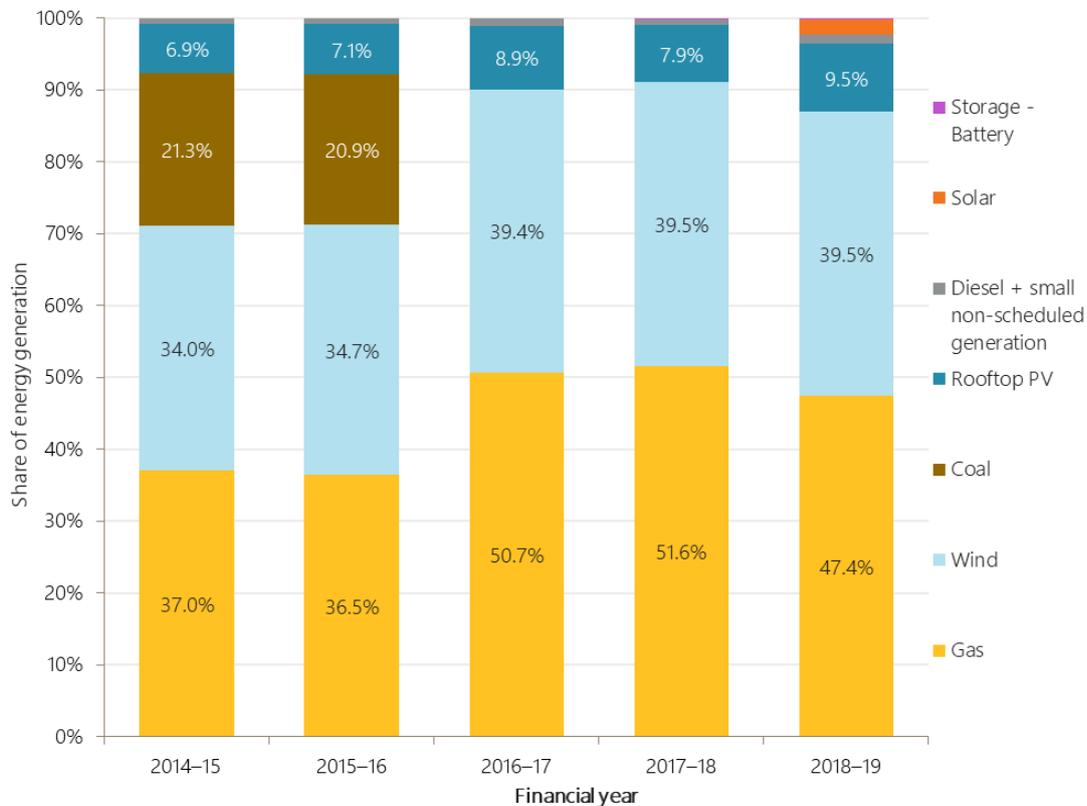


Table 5 expands on the data in Figure 15, focusing on the differences between 2017-18 and 2018-19, and including interconnector flow metrics. Section 5 provides further insights on interconnector changes.

Between 2017-18 and 2018-19, generation increased by 2.9% for wind, decreased by 5.4% for gas, and large-scale solar had its first full year of operation. Almost 50% of South Australian generation continues to be coming from gas-powered generation (GPG), with system security requirements continuing to affect gas' market share. Also, GPG, as well as interconnector imports, are required to meet South Australian demand in periods when the sun is not shining, and there is little or no wind.

Table 5 South Australian electricity supply by fuel type (GWh), comparing 2017-18 to 2018-19

Supply source	2017-18 (GWh)	2018-19 (GWh)	Change (GWh)	Percentage change (%)	2017-18 Percentage share (%)	2018-19 Percentage share (%)
Gas	7,273	6,877	-396	-5.4%	51.6%	47.4%
Wind	5,563	5,725	162	2.9%	39.5%	39.5%
Diesel + SNSG	117	184	67	57.3%	0.8%	1.3%
Rooftop PV	1,114	1,374	259	23.3%	7.9%	9.5%
Solar	4	303	299	7,768%	0.03%	2.1%
Storage – Battery	22	41	19	87.4%	0.2%	0.3%
Total	14,093	14,503	411	2.9%	100%	100%
Interconnector net imports	-292	-468	-176	60.3%		
Interconnector total imports	1,039	791	-248	-23.9%		
Interconnector total exports	1,331	1259	-72	-5.4%		

Wind generation summary

South Australia has the second highest registered wind capacity by region in the NEM and Western Australia's Wholesale Electricity Market (WEM). 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 2014-15 to 2018-19, and information on registered 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 average capacity factor* (%)	Registered capacity (MW)**	Reason for increase in capacity	Maximum 5-minute generation (MW) **
2014-15	4,223	-	32.0%	1,473	NA	1,365
2015-16	4,322	2.3%	32.4%	1,576	Hornsedale Stage 1 (102.4 MW)	1,384
2016-17	4,343	0.5%	29.5%	1,698	Hornsedale Stage 2 (102.4 MW), Waterloo expansion (19.8 MW)	1,546
2017-18	5,563	28.0%	34.7%	1,810	Hornsedale Stage 3 (112 MW)	1,618
2018-19	5,725	2.9%	34.7%	2,142	Lincoln Gap*** (212.4 MW), Willogoleche (119.36 MW)	1,712

* Based on the average capacity factor across all wind farms. Periods before a wind farm first reached 90% of registered capacity are excluded, or where this period was for too short a length of time in the financial year.

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

*** Lincoln Gap Wind Farm (registered capacity 212.4 MW) currently has nameplate capacity of 126 MW, with an additional 86.4 MW to be completed by August 2020, as reported on AEMO's Generation Information page (14 November 2019).

Table 6 shows that:

- Lincoln Gap Wind Farm⁴⁶ (212.4 MW) and Willogoleche Wind Farm (119.4 MW) were registered in 2018-19.
- Registered capacity increased from 2017-18 to 2018-19 by 18%, while generation only increased by 3%, reflecting that the two new wind farms were not operating at close to registered capacity for some or all of the 2018-19 financial year.

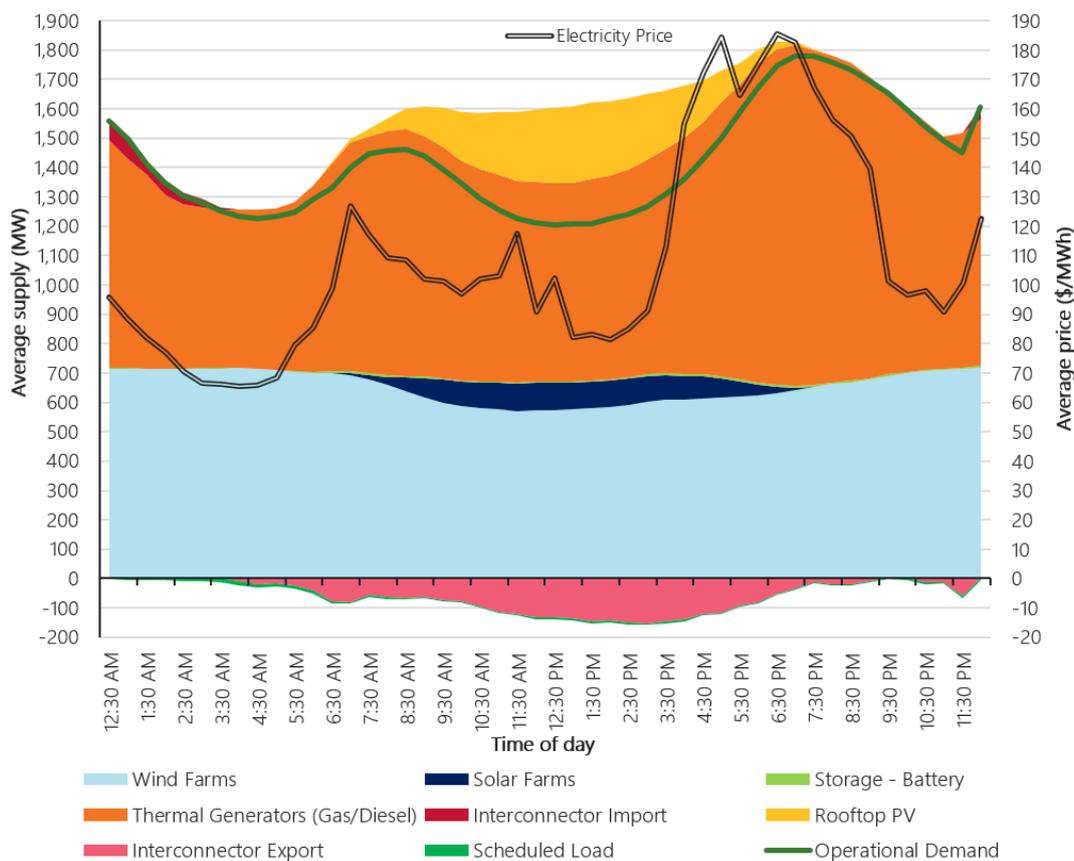
4.3 Historical typical day dispatch

The average daily supply profile for South Australia, seen in Figure 16, represents the supply (in MW) and spot price (in \$/MWh) for each 30-minute trading interval of a day, averaged over the 2018-19 financial year.

Figure 16 shows the average mix of generation dispatched on an average day, split between wind, solar, 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 16 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 occurring at the same time as solar generation is declining.
- Interconnector imports mainly occurred in the off-peak periods when solar was not operational.

Figure 16 Daily supply profile for South Australia averaged for the 2018-19 financial year



⁴⁶ Lincoln Gap Wind Farm (Registered Capacity 212.4 MW) currently has Nameplate Capacity of 126 MW, with an additional 86.4 MW to be completed by August 2020, as reported on AEMO's Generation Information page, 14 November 2019.

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 14 November 2019 generator survey results for South Australia⁴⁷.

Table 7 Capacity of existing or withdrawn generation, and committed or proposed projects (MW) at 14 November 2019

Status	CCGT **	OCGT ***	Gas other	Solar ****	Wind	Water	Biomass	Storage – battery and VPP	Other	Total
Existing*	713.4	1,224.0	1,490.0	390.8	2,053.3	3.2	18.2	155.5	179.7	6,228.1
Announced withdrawal	0.0	0.0	480.0	0.0	0.0	0.0	0.0	0.0	0.0	480.0
Existing less announced withdrawal	713.4	1,224.0	1,010.0	390.8	2,053.3	3.2	18.2	155.5	179.7	5,748.1
Committed	0.0	0.0	0.0	0.0	86.4	0.0	0.0	21.0	0.0	107.4
Proposed	45.0	670.0	0.0	3,270.8	3,941.0	995.0	0.0	1,744.0	0.0	10,665.8
Withdrawn	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	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.

4.4.2 Generation capacity for the year ahead

Table 8 shows scheduled, semi-scheduled, and significant non-scheduled generation estimated available capacity for summer 2019–20 and winter 2020. 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 gas generators is lower than winter, due to higher thermal generation efficiencies at cooler ambient temperatures.

⁴⁷ The total South Australian capacity of 7,066 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 2019-20 available capacity* (MW)	Winter 2020 available capacity* (MW)
Diesel (scheduled)**	236	263
Gas (scheduled)	2,757	2,724
Wind (semi-scheduled)	1,660	1,660
Wind (significant non-scheduled)***	386	386
Solar (semi-scheduled)	315	315
Storage – Battery (scheduled)	165	165
Total	5,519	5,513

* AEMO Generation Information for South Australia, published 14 November 2019, at <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information>.

** Excludes the SA Temporary Generation North and South diesel generators. Refer to Section 7.4.1 for details of their status in reliability forecasts.

*** Available capacity for wind farms classed as significant non-scheduled is based on nameplate rating, since 10-year availability forecasts are not provided to AEMO for these units.

4.4.3 Committed supply developments

As of 14 November 2019⁴⁸, 21 MW of battery storage/VPP projects and approximately 86 MW of new wind generation projects are committed in South Australia:

- SA Government VPP – Stage 2 (5 MW).
- Simply Energy VPP (6 MW/16 MWh).
- Lincoln Gap Wind Farm – Battery Energy Storage System (BESS) (10 MW).
- Lincoln Gap Wind Farm Stage 2⁴⁹ (86.4 MW), due to be operational by August 2020.

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

4.5 Emissions intensity

Annual NEM emissions intensity for the 2018-19 financial year was the lowest on record⁵⁰.

In South Australia, as Figure 17 shows, emissions from generation in 2018-19 decreased by 9.2% compared to 2017-18, while the emissions intensity of the grid reduced by 10%⁵¹. Lower emissions were a function of decreased local GPG, and the continued decline in emissions intensity reflects increased wind and solar penetration in the region.

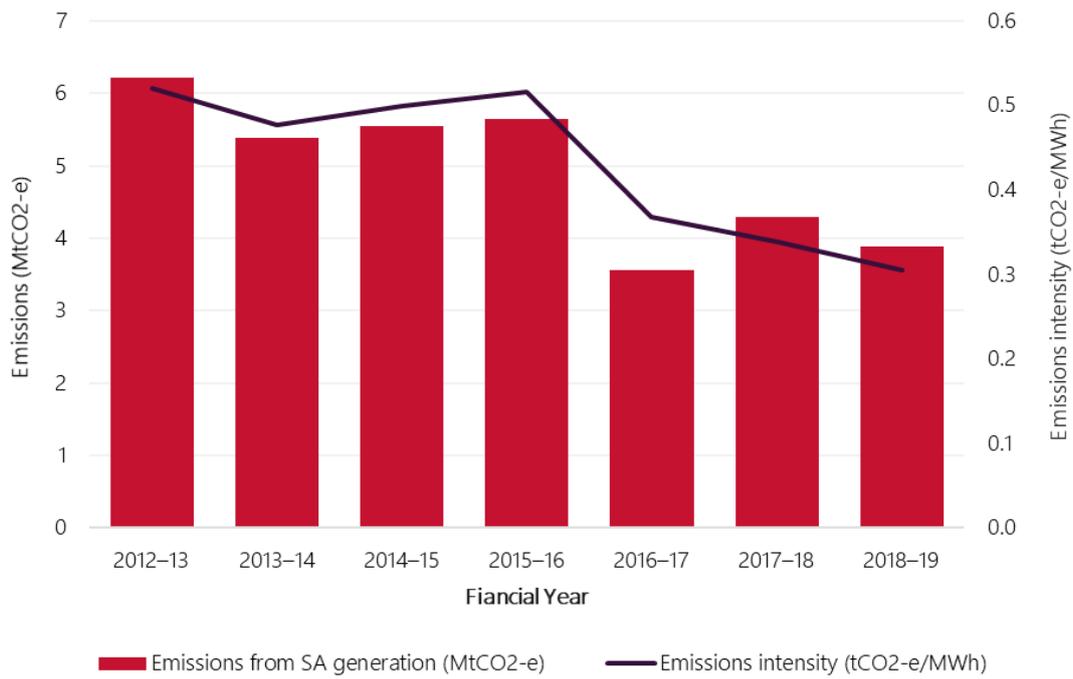
⁴⁸ Date based on latest (14 November 2019) AEMO Generation Information Page at time of writing. More recent information may be available by time of publication, at <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information>.

⁴⁹ Lincoln Gap Wind Farm (registered capacity 212.4 MW) currently has nameplate capacity of 126 MW, with an additional 86.4 MW to be completed by August 2020, as reported on AEMO's Generation Information Page, 14 November 2019.

⁵⁰ See <http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Settlements-and-payments/Settlements/Carbon-Dioxide-Equivalent-Intensity-Index>.

⁵¹ Ibid.

Figure 17 South Australian annual emissions and emissions intensity



5. Transmission interconnectors

South Australia is connected to the rest of the NEM via two interconnectors, Heywood and Murraylink. While imports to South Australia had been growing until the closure of Hazelwood Power Station in 2017, the trend has since reversed, with South Australia being now a net exporter.

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. However, due to stability issues, Heywood’s nominal capacity has been 600 MW from Victoria to South Australia since August 2016, and 500 MW from South Australia to Victoria since December 2015.
- 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 18 shows the total actual interconnector imports and exports for South Australia from 2009-10 to 2018-19.

Results for 2018-19 were similar to 2017-18, with South Australia again being a net exporter into Victoria. This change has been 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 and outages of some of the remaining brown coal-fired generators over 2018-19. Pelican Point Power Station in South Australia also returned to full capacity in July 2017.

In Figure 18:

- The orange column bars above the 0 GWh line (x-axis) shows the annual energy imported into South Australia from Victoria. From 2009-10 to 2016-17, there was a steady increase in annual imports from Victoria to South Australia. In 2017-18 and 2018-19, the average annual import decreased to almost one-third of the annual imports in 2016-17.
- The yellow bars below the line show the energy exported from South Australia to Victoria. Over the past 10 years, the highest annual export occurred in 2017-18, with 2018-19 also recording comparatively high exports.
- The red diamond points show net flows for the financial years, with positive values showing net importing and negative values indicating net exporting.

Figure 18 Combined interconnector total imports and exports, and net flows

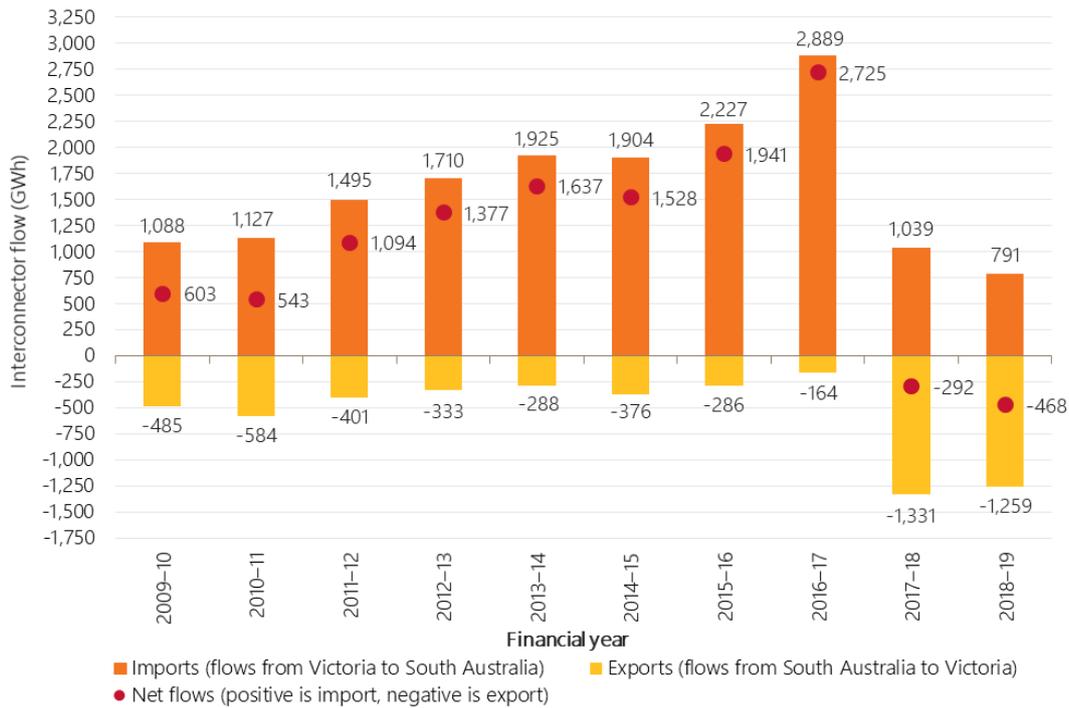


Figure 19 shows the annual flow patterns for combined interconnector imports (from Victoria to South Australia), averaged by the time of day (with times expressed in NEM time).

Figure 19 Combined interconnector daily 5-minute average flow

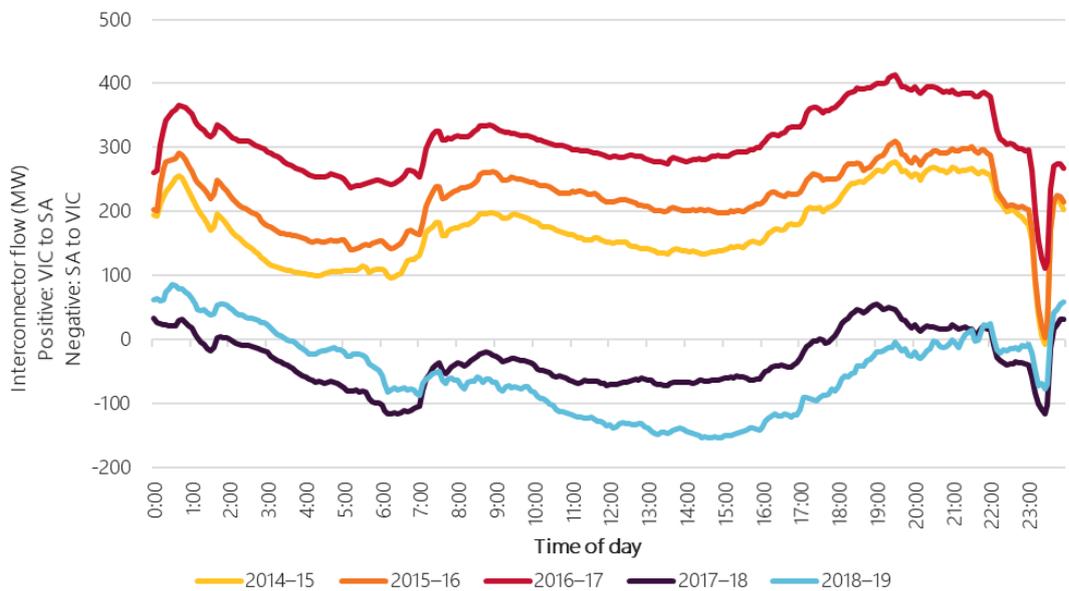


Figure 19 shows that, on average, in 2018-19, combined interconnector flow tended to export electricity, except during early off-peak hours (around midnight to 3.00 am), where they tended to import. On average, the highest exports were between approximately 10.00 am and 5.00 pm – coinciding with increased output from grid-scale and rooftop PV. As with previous years, 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.

The status of a series of upgrades and new projects are as follows:

- Heywood:
 - The increase in the transfer limit in the direction from Victoria to South Australia (from 600 MW to 650 MW) is currently under review.
 - An over-frequency generator shedding scheme has recently been commissioned 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.
- Murraylink:
 - The New South Wales Murraylink Runback scheme (not yet in service), will reduce the risk of voltage collapse and network issues in southern New South Wales – normally associated with high demand conditions – so a stability constraint does not limit transfer of power from Victoria to South Australia. This will improve the ability to access the full capacity of the Murraylink interconnector.
- Project EnergyConnect:
 - The 2016 *National Transmission Network Development Plan* (NTNDP)⁵² recommended that a new interconnector be established between New South Wales and South Australia. This outcome was confirmed in the inaugural ISP in July 2018.
 - In February 2019, ElectraNet completed the final stage in the South Australia Energy Transformation Regulatory Investment Test for Transmission (RIT-T), which demonstrated that a new South Australia to New South Wales interconnector would deliver economic benefits and reduce residential electricity bills. The next stage of this project, now called EnergyConnect, is awaiting AER advice, expected by the end of 2019⁵³. If approved, the interconnector has an estimated delivery time of 2022 to 2024, depending on the time taken to gain environmental and other necessary approvals.

⁵² AEMO. 2016 NTNDP, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NTNDP/2016/Report/2016-NATIONAL-TRANSMISSION-NETWORK-DEVELOPMENT-PLAN.pdf.

⁵³ For more, see <http://www.projectenergyconnect.com.au/> and <https://www.electranet.com.au/projects/south-australian-energy-transformation/>.

6. Electricity spot price

With tight supply conditions in the southern regions and high gas prices, time-weighted average wholesale prices in South Australia increased to record levels, including a high level of price volatility.

FCAS prices continued the downward trend which has occurred since 2016-17, primarily due to reduced prices in the Regulation FCAS markets.

6.1 Historical wholesale electricity prices

Table 9 shows that in 2018-19, the time-weighted average price (TWAP) was \$109.80/MWh, the highest on record and a 12% increase from the previous financial year average. Compared to other regions, South Australia remained the equal highest-priced region in the NEM (equal with Victoria).

During the year, South Australia and Victoria shared a common marginal price-setting unit for 90% of dispatch intervals (with this common unit varying across different dispatch intervals). This resulted in Victorian pricing dynamics strongly influencing South Australia's outcomes. Key contributors to the price increase in South Australia and Victoria included:

- Increased price volatility – see Section 6.2 for more detail.
- High gas prices – wholesale gas prices in South Australia in 2018-19 reached record high levels, which were reflected in higher-priced GPG offers. Compared to 2017-18, the average availability of GPG priced below \$100/MWh reduced by approximately 120 MW (14%).
- Higher-priced offers from black coal-fired generators – since 2015-16, black coal-fired generators in New South Wales and Queensland have increased the price of their offers. This contributed to black coal-fired generation setting South Australia's price at an average of \$90/MWh in 2018-19, compared to \$62/MWh in 2015-16.
- Tight energy after the Hazelwood closure – since the closure of Hazelwood Power Station in March 2017, output from new renewable energy projects (as at the end of 2018-19) is yet to fully replace the lost output from Hazelwood Power Station, resulting in tight supply conditions.
- Brown coal-fired generator outages – average brown coal-fired generation in Victoria reduced by 173 MW compared to 2017-18 due to a higher number of planned and unplanned outages, further tightening supply conditions. This includes the outage of Loy Yang A Unit 2 since 18 May 2019, damaged following an electricity short internal to the generator.

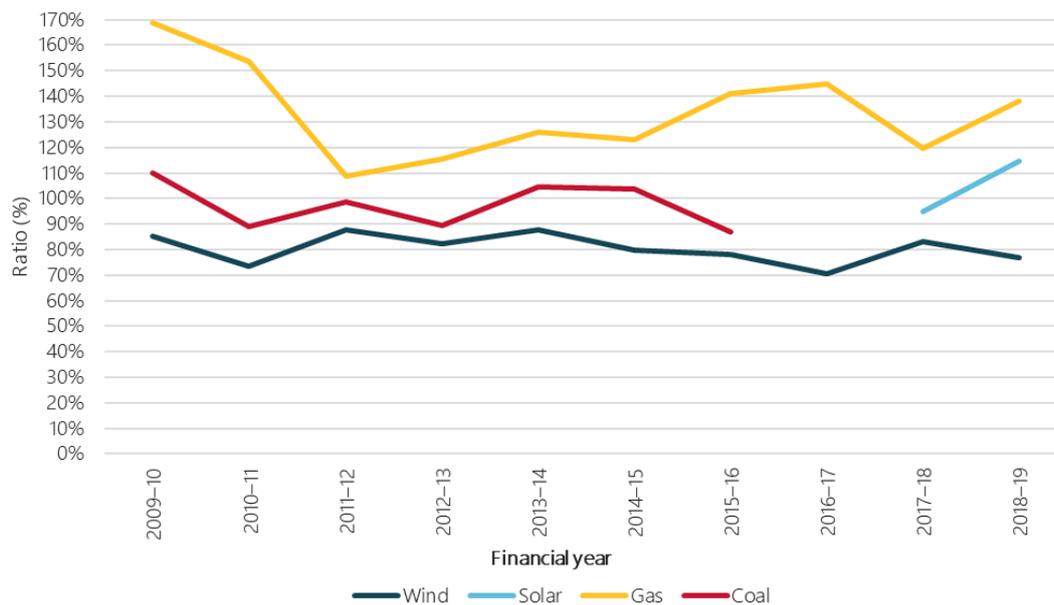
Table 9 2018-19 time-weighted average prices for the NEM

	Queensland	New South Wales	Victoria	South Australia	Tasmania
Time-weighted average (\$/MWh)	80.29	88.56	109.81	109.80	90.01

The volume-weighted average price (VWAP) by fuel type represents the average price received by each fuel technology. Higher output during high-priced periods will result in a higher VWAP. As a relative percentage to the TWAP, shown in Figure 20, the following occurred over 2018-19:

- Gas VWAP remained above the TWAP, reflecting the tendency for gas generators to operate at elevated levels during high priced events and operate less (or cycle offline) during low prices. The VWAP for gas increased compared to 2017-18 due to an increase in high-priced periods.
- Wind VWAP remained below the TWAP, as high wind generation, typically bid at low or negative prices, tends to result in lower spot prices. Also, average wind generation tends to be higher during overnight periods, which is also when demand, and prices, are typically low.
- Solar VWAP increased from approximately 94% to approximately 115% of TWAP. This increase was driven by high daytime prices over Q1 2019. South Australian solar VWAP over this period was \$207/MWh (grid-scale solar was not in the South Australian market in the summer of 2017-18).
- The ratio between TWAP and VWAP for wind and gas have moved further apart than in 2017-18, indicating an increase in price volatility.

Figure 20 Ratio of VWAP by fuel to total TWAP (based on real June 2019 \$/MWh)



6.2 Price volatility

In 2018-19, there were more occurrences of both negative prices and prices above \$300/MWh than in 2017-18.

6.2.1 High prices

Prices exceeded \$300/MWh 0.78% of the time in 2018-19, a small increase from 2017-18 (where prices exceeded \$300/MWh 0.66% of the time). This included an almost doubling of extremely high-priced trading intervals (>\$5,000)/MWh, which contributed to annual cap returns⁵⁴ increasing to \$14.52/MWh (from \$8.34/MWh).

This price volatility largely occurred on two days, due to a confluence of events in Victoria and South Australia. Victoria and South Australia's daily average prices of \$3,378/MWh and \$3,360/MWh on 24 January 2019 were their highest since NEM start. The continuation of price volatility into 25 January resulted in the

⁵⁴ A measure of volatility in electricity prices is the presence of high price events (prices above \$300/MWh), calculated as the sum of the NEM half-hourly price minus the \$300 cap price for every half-hour in the financial year where the pool price exceeds \$300/MWh, divided by the number of half-hours in the year.

Cumulative Price Threshold (CPT)⁵⁵ being triggered, limiting the maximum price to \$300/MWh once it came into effect.

Contributors to these pricing outcomes included:

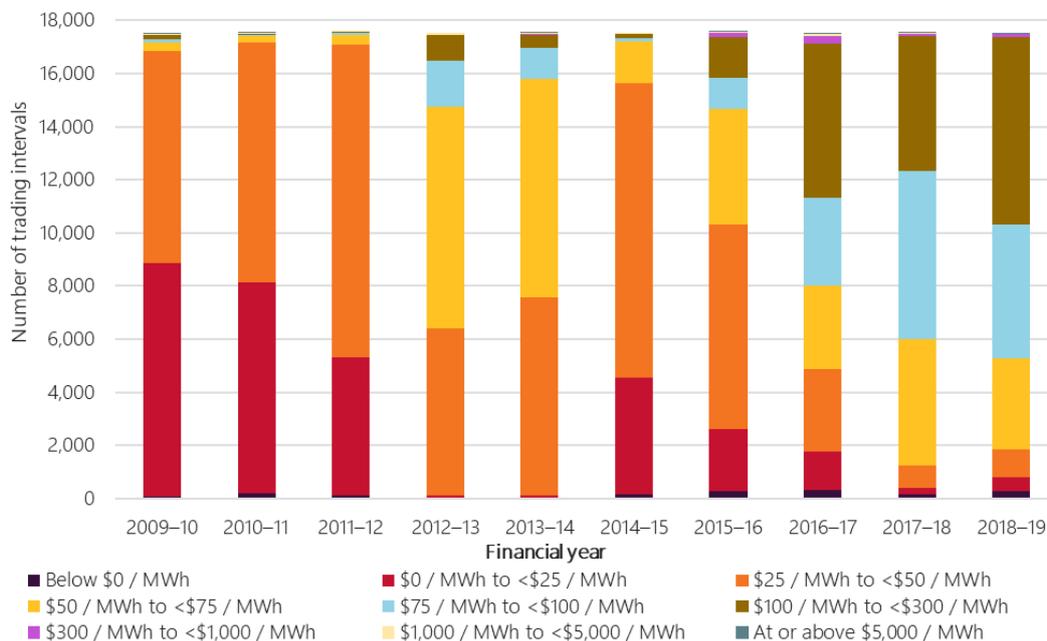
- Simultaneous high temperatures in South Australia and Victoria resulted in high electricity demand across both regions, with coincident maximum operational demand of 12,463 MW on 24 January 2019 (the highest coincident peak since Q1 2014). On this day, temperatures in South Australia broke new records, while parts of country Victoria experienced extreme heat (close to record levels).
- A series of brown coal-fired generator outages on these days reduced thermal capacity in Victoria by up to 1,600 MW.
- Wind capacity factors were comparatively low during the high-priced periods (average of 15% during the high prices, compared to average capacity factors of 30% during high demand periods in Victoria).

Extreme conditions on these days also led to AEMO activating RERT contracts and (as a last resort) AEMO instructing load shedding on both 24 and 25 January to balance demand with available supply. AEMO’s report *Load Shedding in Victoria on 24 and 25 January 2019*⁵⁶ provides more details on these events.

6.2.2 Negative prices

As Figure 21 highlights, negative prices occurred 1.6% of the time, up from 0.8% in 2017-18. Negative prices typically occurred during periods of high wind output, low demand, restricted interconnector transfers, and when thermal plants typically bid below operating costs to maintain generation volumes at or above minimum stable levels.

Figure 21 Frequency of occurrence of spot prices for South Australia



In the NEM, electricity is bought and sold either through the spot market, or wholesale contract market. Spot prices are an important part of the process that drives daily unit commitment signals, new investment and exit decisions. Many retailers and generators prefer to enter wholesale hedging contracts to reduce their exposure

⁵⁵ The cumulative price threshold imposes a limit on sustained high prices in the wholesale market. For further details on the CPT, see Reliability Panel 2018, *Reliability standard and setting review 2018*, at www.aemc.gov.au/sites/default/files/2018-04/Reliability%20Panel%20Final%20Report.pdf.

⁵⁶ At www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Power_System_Incident_Reports/2019/Load-Shedding-in-VIC-on-24-and-25-January-2019.pdf.

to the spot market. Wholesale hedging contracts allow retailers to manage financial risk associated with volatile spot prices, and provide generators a more certain revenue stream.

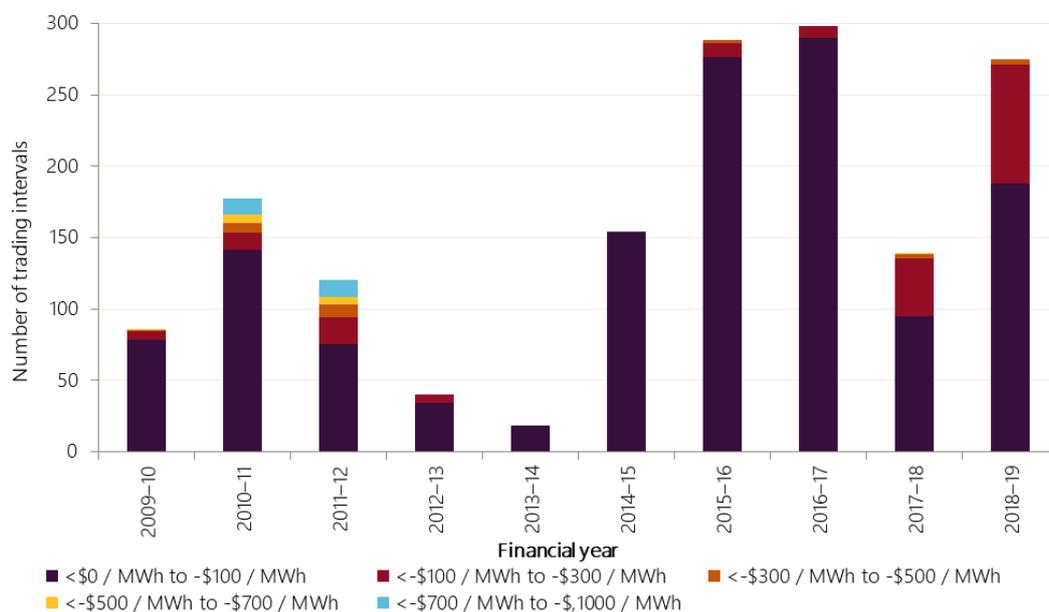
While negative spot prices lower the average spot electricity price, they do not necessarily lead to lower prices for end consumers. This is because the wholesale component of a consumer’s bill reflects the hedging cost incurred by retailers rather than spot price outcomes (which typically take some time to flow into the contract market).

Figure 22 shows the count of negative South Australian market prices from 2009-10 to 2018-19. In 2018-19, there were 275 negative priced 30-minute trading intervals, much higher than in 2017-18, but similar to the preceding two years.

Key points relating to the increase in negative price periods in 2018-19 include:

- Increased periods of high variable renewable energy⁵⁷ (VRE) output – in 2018-19, there was a 70% increase in periods of high VRE output (>1,200 MW) compared to 2017-18. This was due to revised operating guidance with respect to system strength in South Australia at the end of 2018⁵⁸.
- Timing of interconnector restrictions – in 2018-19, flows from South Australia to Victoria on the Heywood interconnector were coincidentally more than three times more likely to be restricted (from 500 MW to below 350 MW) during a period of high VRE and/or low demand.
- Shifting generator commitment decisions – in 2018-19, South Australian GPG units were more likely to remain committed in the market during conditions that could lead to negative or low prices (such as coincident high wind output and low demand). This reduced the amount of time on direction and had the practical effect of keeping their supply in the market when the clearing price is determined⁵⁹, increasing the likelihood of negative prices.

Figure 22 Count of negative price trading intervals per year



⁵⁷ Variable renewable energy (VRE) is a renewable energy source that is non-dispatchable due to its fluctuating nature, like wind power and solar power, as opposed to a controllable renewable energy source such as dammed hydroelectricity, or biomass, or a relatively constant source such as geothermal power.

⁵⁸ Previous AEMO guidance set a single fixed limit on non-synchronous generation of 1,295 MW given minimum synchronous unit combinations. The revised procedure introduced different levels of non-synchronous generation allowed (ranging from 1,000 MW to 1,460 MW) based on the synchronous unit combinations available.

⁵⁹ Under current intervention pricing arrangements, supply from a directed unit is not included in the supply stack for pricing purposes.

Wind and solar response to negative prices

VRE generators have traditionally been bid to maximise output regardless of price. However, during recent negative price events in South Australia, some VRE generators have chosen to turn off rather than incur these negative prices.

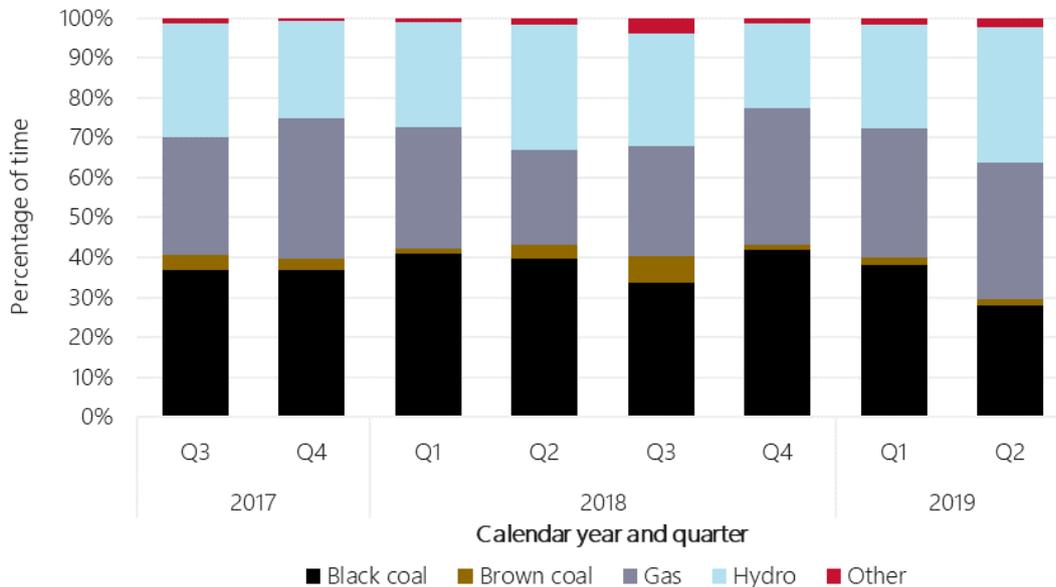
As an example, on 30 April 2019, low demand, high VRE output, and network constraints drove negative prices for more than five hours. On this day, more than half of South Australia's VRE generators reduced their output due to the negative prices. Semi-scheduled VRE achieved the reduction in output by re-bidding output to higher prices and subsequently not being dispatched by AEMO, while some non-scheduled VRE opted to self-curtail output.

This change in behaviour from VRE generators is likely to be influenced, at least in part, by the terms of new power purchase agreements (PPAs). Anecdotal evidence provided to AEMO suggests that new PPAs tend to be firm only to \$0/MWh or the negative of the LGC price, whereas historically they were firm to the market floor price. This means some VRE generators have greater exposure to the risks of negative prices than previously observed.

6.3 Price setting outcomes

Figure 23 shows South Australia's quarterly price setting outcomes by fuel type for 2017-18 and 2018-19. In 2018-19, price setting results were similar to 2017-18, with black coal-fired generators (in Queensland and New South Wales) setting South Australia's prices approximately 40% of the time, and GPG and hydro generation setting the price almost 30% of the time. The most common price setting power stations were Torrens Island Power Station (which set the price around 15% of the time) and Murray Power Station in Victoria (which set the price around 10% of the time).

Figure 23 South Australian price setting by fuel type



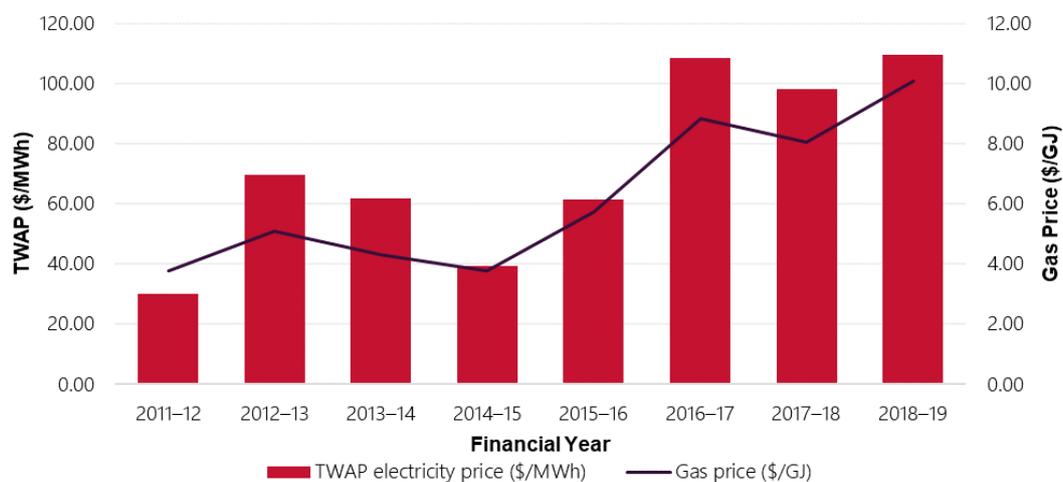
6.4 Impact of changes in generation mix

6.4.1 South Australian energy and price trends

Historical average electricity and gas price trends are shown in Figure 24. 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 2017-18 and 2018-19, South Australia’s average electricity TWAP increased by 12% and gas prices in Adelaide’s Short-Term Trading Market increased by 25%.

Figure 24 South Australian electricity prices relative to gas prices



6.4.2 Gas spot price impact on electricity spot prices

In all NEM regions, GPG set the electricity spot price more frequently in 2018-19 than in 2017-18. In South Australia, GPG set the price 32% of the time, up from 30% of the time in 2017-18 due to reduced South Australian price-setting by coal-fired units in other regions⁶⁰.

Overall, GPG gas consumption in 2018-19 was approximately 17% lower than in 2017-18, and was particularly low in the first half of 2018-19. Drivers of low GPG over this period included:

- Increased penetration of VRE.
- High domestic and international gas prices in the second half of 2018.
- Comparatively high hydro generation output in 2018.

However, in the second half of 2018-19, high NEM spot prices and reduced hydro generation due to dry conditions contributed to increased GPG demand.

Gas prices were higher across all wholesale gas markets for 2018-19 than in 2017-18. This coincided with reduced Longford output since 1 January 2018 and increased gas demand for liquefied natural gas (LNG) export from Curtis Island.

6.4.3 Spot prices and wind generation

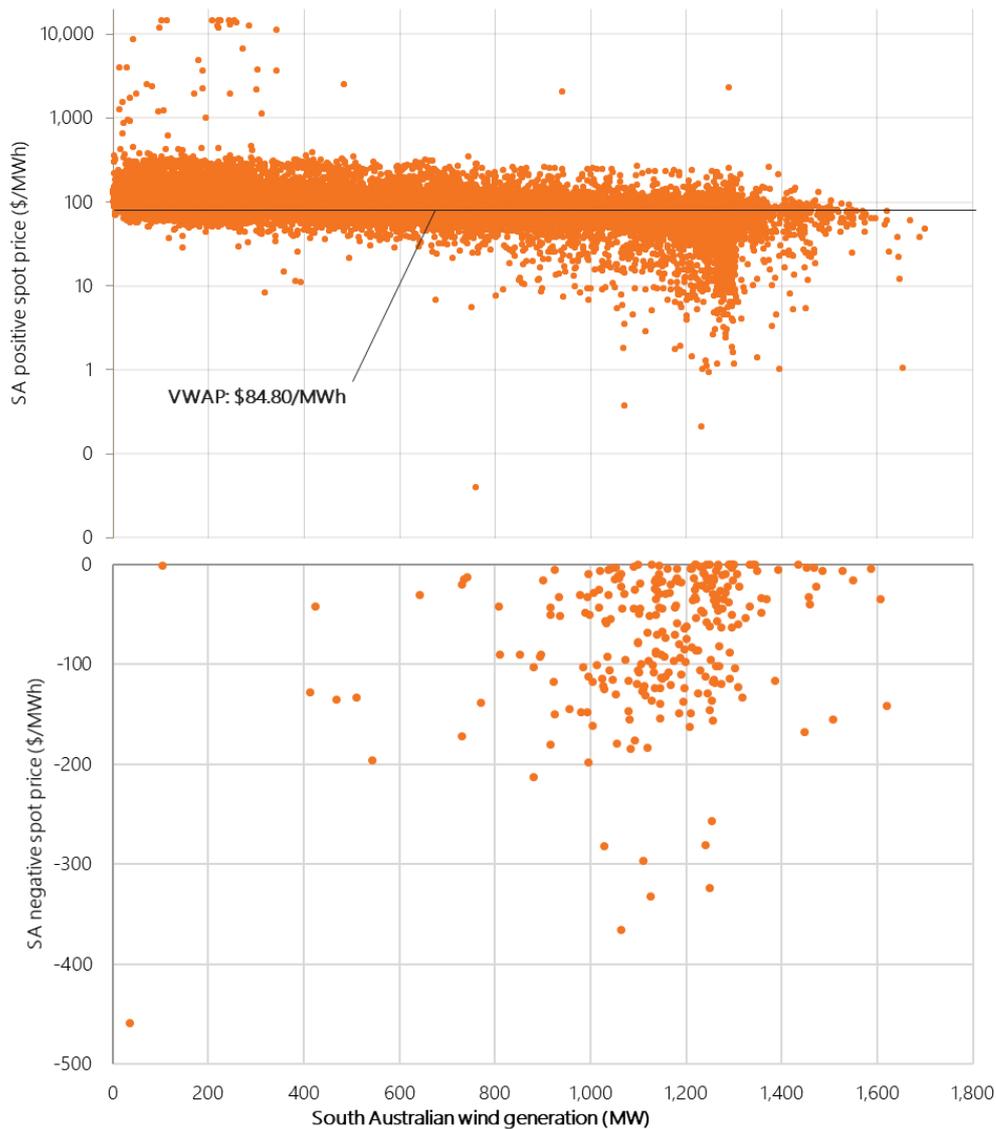
Market prices are not typically set by wind generators, except during periods of high wind and low demand. However, the volume of wind generation online does reduce the need for conventional thermal generation, influencing spot prices even if not setting them by being the marginal generator.

Figure 25 shows spot prices for the South Australian region and the corresponding average wind generation levels for each 30-minute dispatch interval for 2018-19. Key points include:

- 92% of prices above \$1,000/MWh occurred when wind generation was lower than 400 MW.
- 87% of the negative prices occurred when wind generation was greater than 1,000 MW.

⁶⁰ Due to the interconnected nature of the NEM, South Australia’s price can be set by units in other NEM regions.

Figure 25 South Australian 30-minute spot prices and average wind generation for 2018-19



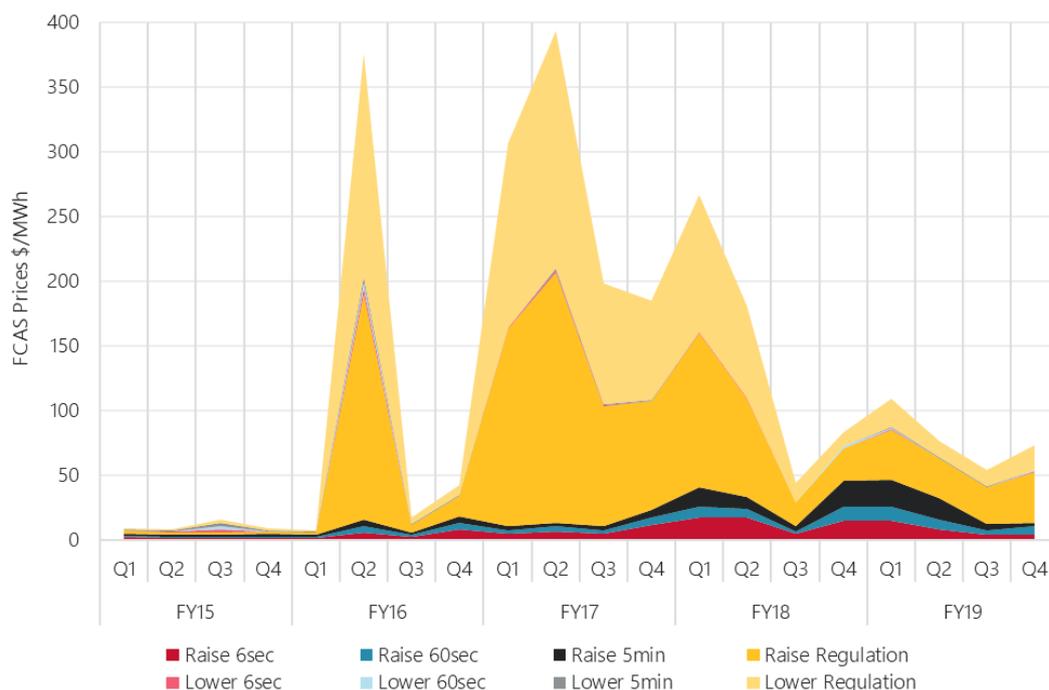
6.5 Frequency control ancillary services (FCAS) market price

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 time⁶¹.

During 2018-19, South Australian FCAS prices continued the downward trend which has occurred since 2016-17 (shown in Figure 26), primarily due to reduced prices in the Regulation FCAS markets.

⁶¹ 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*, at www.aemo.com.au/-/media/Files/PDF/Guide-to-Ancillary-Services-in-the-National-Electricity-Market.ashx.

Figure 26 Quarterly average South Australian FCAS prices by service



Drivers of reduced Regulation FCAS prices included:

- Removal of the 35 MW FCAS constraint⁶² in September 2018, based on analysis completed by AEMO which confirmed that the constraint was no longer needed, with the South Australian system strength requirements met and Hornsdale Power Reserve (HPR) in service.
- Increased supply from batteries – there was a continuation of increased Regulation FCAS from batteries, as new projects entered the market. By the end of 2018-19, three of the NEM’s grid-scale batteries were being enabled for Regulation FCAS, increasing average market share to approximately 8% (from around 4% in 2017-18).

Contingency FCAS prices were comparatively high in the first half of 2018-19, but reduced in the second half:

- Higher prices in the first half of the year were a function of reduced hydro supply and a high-priced event.
 - Reduced hydro supply – in Q3 2018, hydro generators such as Hydro Tasmania made offers to optimise energy dispatch rather than FCAS dispatch. In addition, the Jindabyne pump at Guthega and Wivenhoe Power Station (historically, two of the largest providers of Raise FCAS) did not provide any FCAS supply during the quarter. These factors led to a halving of Raise FCAS supply from hydro generators.
 - High-priced event – more than \$10 million in FCAS costs accumulated on 25 August 2018, due to the trip of the Queensland to New South Wales interconnector (QNI) and subsequent separation of Queensland and South Australia from the rest of the NEM. During this period, AEMO required provision of local FCAS in Queensland and South Australia; due to the limited local FCAS providers on this day, very high prices and costs occurred in all NEM regions (particularly in Queensland).
- Lower prices in the second half of the year were driven by increased supply.
 - Batteries – for example, over Q1 2019, batteries increased their share of the Raise FCAS markets from 10% in Q4 2018 to 17% in Q1 2019. HPR’s share of the market remained relatively stable, with increased

⁶² For system security purposes, AEMO required the local procurement of 35 MW of Regulation FCAS in South Australia at times when the separation of the region at the Heywood interconnector was a credible contingency. During these times of local requirements, FCAS prices were very high due to the limited number of suppliers of these services.

FCAS provision coming from Dalrymple North BESS (5% of Raise FCAS) and Ballarat BESS (3% of Raise FCAS). This additional supply displaced higher-priced supply from other technologies, largely coal.

- Hydro – in addition to new supply from the two batteries, there was also a reduction in the price of offers (or return to the market) from some existing hydro providers, resulting in increased dispatch. For example, in Q1 2019 Wivenhoe Power Station returned to the Raise 5 Minute FCAS market, offering approximately 150 MW more at prices below \$10/MWh than in Q4 2018.

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 during this energy transition to enable a secure and reliable power system.
- 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 over the next five years, but there remains 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 principle 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 also have to change⁶³.

7.1.1 Maintaining frequency and voltage

Traditionally, system services to maintain the technical operating envelope 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.

However, AEMO may issue directions to keep synchronous plant operating, primarily to maintain the power system in a secure operating state. This may increase costs due to the impacts of intervention pricing. Further discussion on directions is presented in Section 7.2.3.

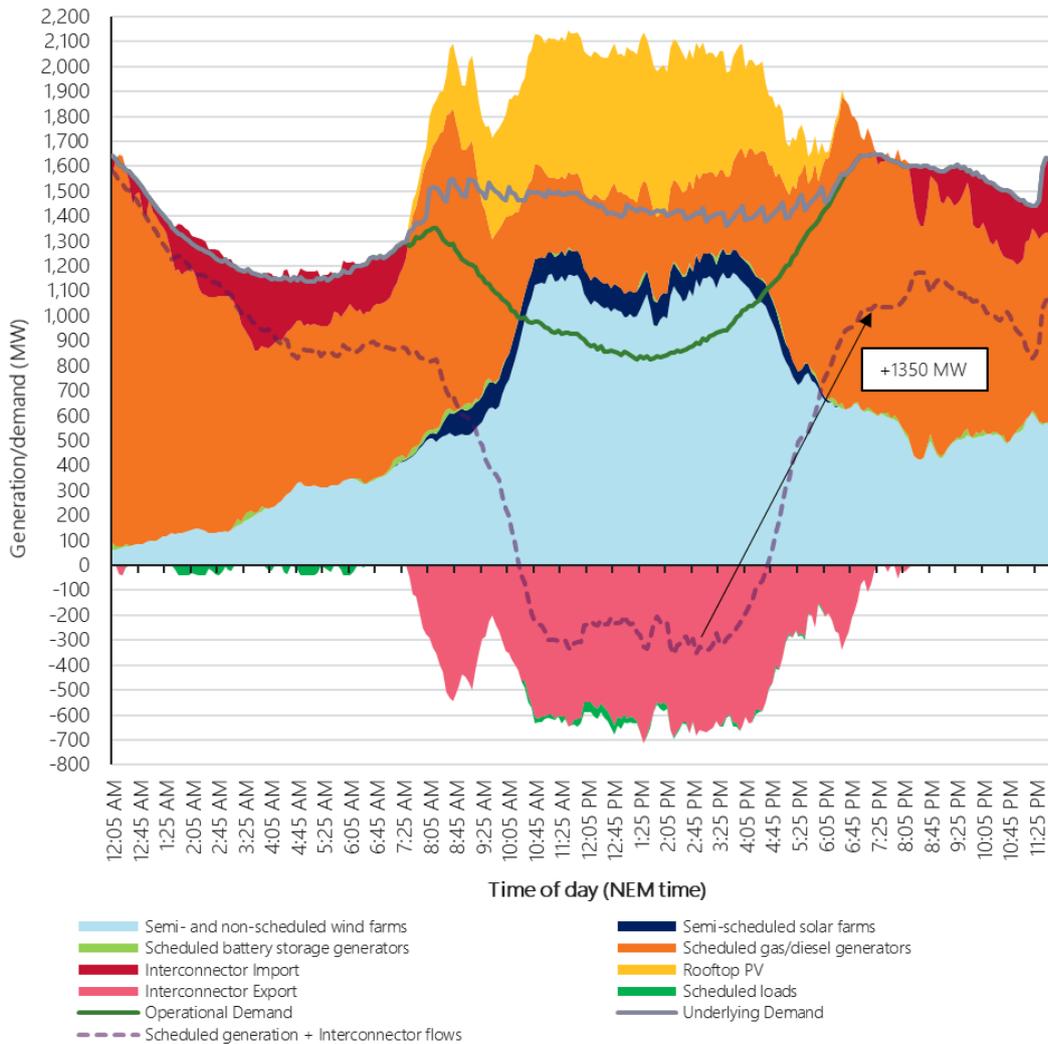
For South Australia, due to the high volume of system security directions made by AEMO, options to reduce intervention are being reviewed or implemented. This includes improving interconnection to neighbouring regions and commissioning synchronous condensers to help maintain voltage across the South Australia region.

⁶³ AEMO, *Power System Requirements*, March 2018, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power-system-requirements.pdf.

7.1.2 Dealing with variability of generation

Growth in solar and wind generating capacity results in increased variability of the generation output, which needs to be managed. For example, as illustrated in Figure 27 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 27 Generation/demand mix in South Australia for Saturday 8 September 2018



To deal with large ramping events, flexible technologies (or headroom on interconnectors) are needed to continuously match supply and demand. Suitable technologies include fast-start gas engines, storage (pumped hydro or battery), and DSP.

AEMO is undertaking detailed analysis as part of the Renewable Integration Study (see Section 7.3) to understand how ramping challenges are likely to emerge in the NEM with increasing levels of variable wind and solar generation. Of particular focus will be quantifying how system variability changes as more VRE is installed, and the level of inherent uncertainty in forecasting the output of variable generators on any day.

7.2 Managing reliability and security to date

RERT for summer 2018-19

In 2018, AEMO's ES00 modelling identified a particular risk of supply interruptions in Victoria exceeding the reliability standard for unserved energy (USE)⁶⁴ in 2018-19. This risk was observed to arise from reductions in supply from thermal generation as a result of coincident unplanned outages at times of expected low VRE and high demand.

Based on these forecasts, AEMO established a pool of RERT providers under the National Electricity Rules (NER) that could offer reserves on various notice periods. In consultation with the Victorian and South Australian Governments, AEMO secured all resources offered in Victoria and South Australia that met the required NER, cost, technical, and verification criteria.

For 2018-19, RERT resources were secured on a usage only basis. In 2017-18, some RERT contracts had both availability and usage cost components. As a result, the RERT costs over summer 2018-19 were significantly lower, at around 66% of the 2017-18 costs.

Costs of RERT

RERT was used on 24 and 25 January 2019 to minimise load shedding during periods of high demand⁶⁵, as summarised in Table 10.

Table 10 Thursday 24 January 2019, South Australia and Victoria RERT volume activated

Trading Interval ending	RERT activated (MW) SA	RERT activated (MW) VIC	RERT activated – cumulative total (MW)
24/01/2019 16:30	0	20	20
24/01/2019 17:00	6	105	111
24/01/2019 17:30	216	176	392
24/01/2019 18:00	216	176	392
24/01/2019 18:30	216	180	396
24/01/2019 19:00	216	180	396
24/01/2019 19:30	216	180	396
24/01/2019 20:00	216	124	340
24/01/2019 20:30	216	120	336
24/01/2019 21:00	216	120	336
24/01/2019 21:30	6	60	66
24/01/2019 22:00	0	40	40
24/01/2019 22:30	0	20	20
Total megawatt hour (MWh)			1,621

⁶⁴ USE is energy that cannot be supplied to consumers, as a result of insufficient levels of generation capacity, demand response, or network capability, to meet demand.

⁶⁵ For more information, see https://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Power_System_Incident_Reports/2019/Load-Shedding-in-VIC-on-24-and-25-January-2019.pdf.

In summary:

- **Thursday 24 January** – reserve conditions reached LOR 2 in South Australia and LOR 3 in Victoria. AEMO used the available RERT – 396 MW in total. This comprised 366 MW of Short Notice Reserves (contracted on the day) and 30 MW of Long Notice Reserve (previously contracted).
- **Friday 25 January** – reserve conditions reached LOR 3 in Victoria. AEMO used all available RERT – 625 MW in total. Of this, 596 MW were Short Notice Reserves (contracted on the day) and 29 MW were Long Notice Reserve (previously contracted). No RERT in South Australia was used on 25 January.

All available reserve contracts which were able to be activated in time were activated on 24 January 2019. One contract could not be activated in time, as its pre-activation requirements could not be met on the day.

Without the use of RERT, AEMO estimates that a further 1,252 MWh of load would have been required to be shed involuntarily. The RERT mechanism in this instance mitigated the additional economic and social impacts of more widespread load shedding⁶⁶. Applying the 2019 value of customer reliability (VCR)⁶⁷, the cost of the load shedding avoided by using RERT would have been \$52 million.

The total cost of RERT⁶⁸ on 24 and 25 January 2019 in Victoria and South Australia was \$34.5 million (see Table 11).

Table 11 Costs associated with NEM wide RERT 2018-19 (\$ million)

Date	Pre-activation costs	Activation costs	Other costs*	Total cost
24 January 2019	0.015	6.554	3.337	9.906
25 January 2019	12.005	12.301	0.237	25.543

* Other costs represent the 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 (SRA holders) due to changes in interconnector flows, and therefore changes in the value of Settlement Residues.

The average cost of RERT for 24 and 25 January 2019 was approximately \$10,000/MWh, representing a lower cost per MWh for energy consumers than the market price cap and price of wholesale energy at the time of load shedding, of \$14,500/MWh.

For South Australia, AEMO’s RERT report⁶⁹ indicates average RERT costs on an annualised basis of \$0.16/MWh (commercial and industrial) and \$0.80 per residential consumer.

7.2.1 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 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 2018-19 and future summers.

AEMO and ARENA designed the demand response pilot around defined products (see Table 12) 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).

⁶⁶ See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Power_System_Incident_Reports/2019/Load-Shedding-in-VIC-on-24-and-25-January-2019.pdf. As referenced, load shedding on 24 January 2019 was limited to the Alcoa Portland aluminium smelter.

⁶⁷ VCR measures a consumer’s willingness to pay for reliable electricity supply, as a proxy measure to help planning. For more information, see <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Value-of-Customer-Reliability-review>.

⁶⁸ See https://aemo.com.au/-/media/Files/Electricity/NEM/Emergency_Management/RERT/RERT-report-for-2018-19.pdf.

⁶⁹ See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Emergency_Management/RERT/RERT-report-for-2018-19.pdf.

- 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.

ARENA is, over a period of three years (2017-20), providing up to \$22.5 million of funding for projects in Victoria and South Australia. ARENA together with the New South Wales Government (on a 50-50 basis) will provide up to \$15 million of funding for New South Wales projects for three years (2017-20).

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.

Table 12 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 (40 hours)	10 per year (40 hours)

This program made 141 MW available in year 1 (2017-18) and up to 190 MW available in year 2 (2018-19), rising to up to 202 MW in year 3, across New South Wales, Victoria, and South Australia. Details of the trial year 1 are available from ARENA⁷⁰.

7.2.2 Contribution of inverter-based technologies to reliability and security

Batteries and a wind farm in South Australia have recently proven that they are capable of rapid delivery of a sustained response to a change in frequency. This can be particularly valuable, following a disturbance.

Hornsedale Power Reserve (HPR)

The HPR is registered to provide Contingency FCAS response.

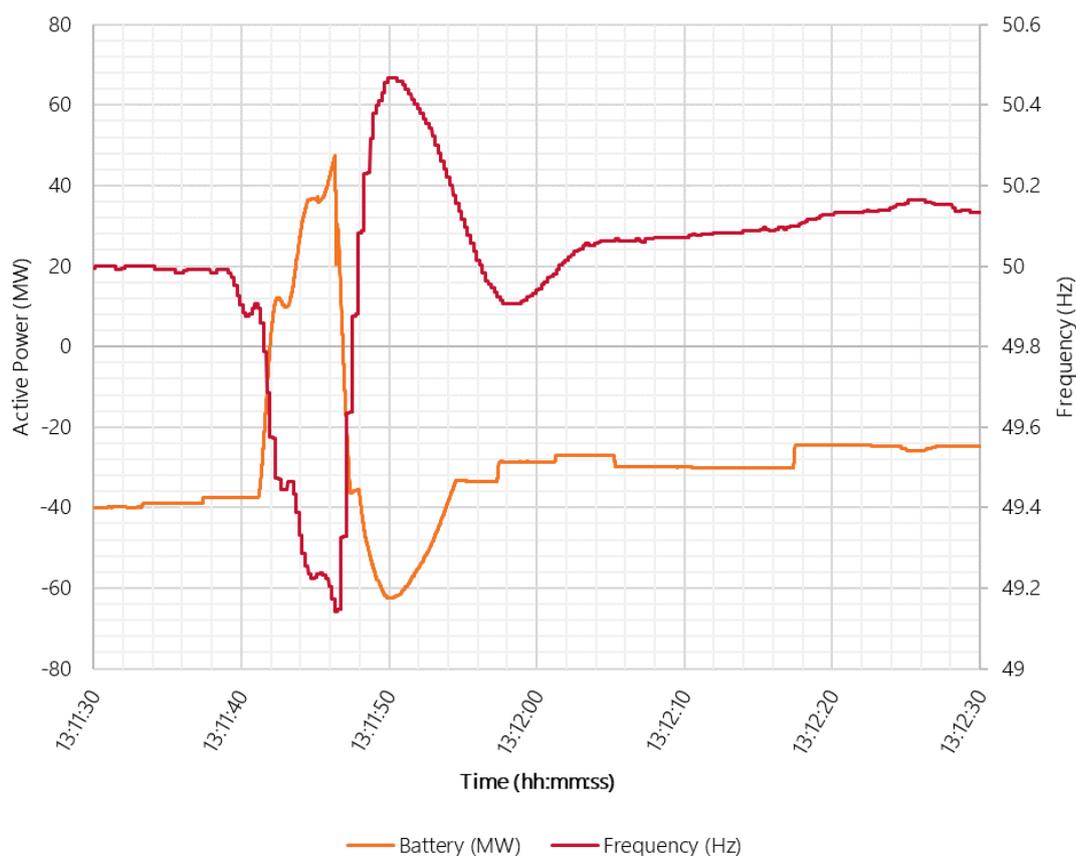
During the QNI separation event on 25 August 2018, it was observed that HPR started responding to under-frequency and over-frequency in the sub-second time frame. Figure 28 shows the response from HPR during the event. The frequency response of this battery is a simple proportional response and will result in a 100 MW increase in output from the battery for a frequency decline from 50 Hz to 49 Hz.

The rapid, proportional frequency response from the Hornsdale battery, from charging at -38 MW to discharging +48 MW, can be seen in Figure 28 and is an example of the capability of power electronic devices on the power system.

This response is consistent with the design. However, it was observed that the response was so rapid that settings on some network schemes were required to be updated to account for the rapid changes in power flow from the battery.

⁷⁰ See <https://arena.gov.au/assets/2019/03/demand-response-rert-trial-year-1-report.pdf>.

Figure 28 HPR response during 25 August 2018 event



Dalrymple North Battery Energy Storage System

ElectraNet’s objective with the Dalrymple Energy Storage for Commercial Renewable Integration (ESCRI-SA) project⁷¹ was to demonstrate that a battery with a grid forming inverter can operate a small localised islanded load after a major power outage has occurred. The grid-connected 30 MW/8 MWh BESS system connects via 33 kV underground line cable into the Dalrymple substation. The BESS system has a design life of 12 years.

The Dalrymple North BESS provides a range of services under commercial agreements between ElectraNet and AGL. The system and its capacity have been optimised to provide fast response as part of South Australian System Integrity Protection Scheme (SIPS)⁷² to reduce constraints on the interconnector, trade FCAS in the NEM, and provide a fallback to support local loads and nearby Wattle Point Wind Farm during loss of supply. The project is partly funded by ARENA.

System Integrity Protection Scheme

The SIPS is designed to rapidly identify unstable conditions within South Australia and make use of available energy from BESSs to avoid potential instability of the region. The reserve energy of HPR and available energy from Dalrymple BESS discharges to the grid if the protection scheme identifies unstable conditions.

The analysis carried out to understand the effectiveness of this scheme, which uses inverter-based technologies to rapidly discharge energy to the grid, demonstrated that such technologies, especially BESS, can improve performance of the South Australian system and could help in avoiding unstable conditions following the loss of multiple generators within South Australia.

⁷¹ See <https://www.escri-sa.com.au/about/>.

⁷² See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Reports/2017/FFR-Working-Paper---Final.pdf.

Possibility of VPP providing grid services

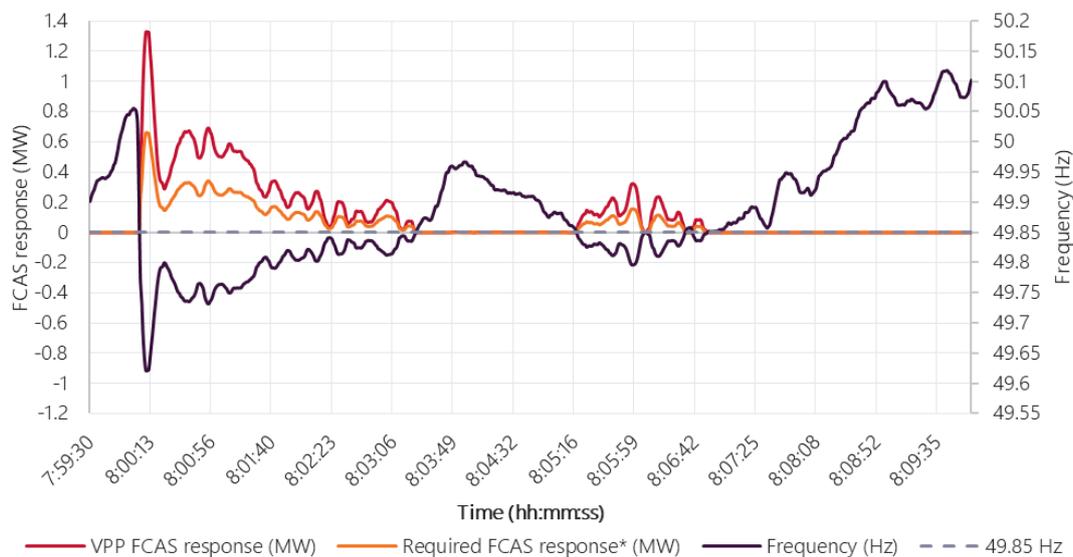
A few VPP projects (see Section 2) have been proposed in South Australia. These can potentially provide some of the same services as the Hornsdale battery, including energy arbitrage, reserve energy capacity, and Contingency FCAS.

In July 2019, AEMO launched the VPP Demonstrations⁷³, which allows participating VPPs to test a new specification to delivery Contingency FCAS. This makes it easier for VPPs to access FCAS as a value stream that can be shared with consumers, and provides AEMO with operational visibility of the VPPs so that AEMO can learn how to integrate VPPs into the NEM at large scale.

The South Australian VPP (SA VPP), controlled by Energy Locals and Tesla, is the first participant in the VPP Demonstrations and it has benefitted from unusually high FCAS prices in the first few weeks since enrolling.

On 9 October 2019, there was a 748 MW trip of a generating unit at Kogan Creek power station in Queensland, resulting in an instantaneous drop in frequency to 49.61 Hertz (Hz) (see Figure 29). The SA VPP was enabled for 1 MW of Raise Contingency FCAS at the time, and automatically responded as expected to the frequency excursion. This is a real-world example of how VPPs with household consumer devices can contribute to power system security and earn new value streams that can be shared with consumers.

Figure 29 VPP FCAS Response to Contingency Event on 09 Oct 2019



* Based on 0.7% droop and 1MW Raise Contingency FCAS dispatch

7.2.3 Managing power system security

AEMO has published studies outlining the minimum number of synchronous machines required to maintain the minimum required fault current levels in South Australia⁷⁴.

System strength is the ability of the power system to maintain the voltage waveform at any given location, with or without a disturbance. This includes resisting changes in the magnitude, phase angle, and waveshape of the voltage.

Fault current level, which is the current flow generated during a fault to keep the system operating, is a guide to a strong system. As such, where fault current level is above the minimum desired amount, the system strength is deemed to be sufficient. Large synchronous machines (hydroelectric, gas, and coal generation, and synchronous condensers) contribute to system strength by their inherent inertia and ability to deliver fault current at up to eight times their rated current. Inverter-connected generation (batteries, wind, and solar

⁷³ AEMO, *NEM VPP Demonstrations*, at <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/DER-program/Pilots-and-Trials>.

⁷⁴ At <https://www.aemo.com.au/Media-Centre/South-Australia-System-Strength-Assessment>.

generation) presently require a strong system to operate securely and do not presently provide inherent contribution to system strength.

Operating procedures are currently in place to ensure a minimum number of synchronous generating units are in service in South Australia at all times to prevent the power system breaching secure operating limits, until a permanent technical solution is completed. 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 fault current requirements. Where natural market outcomes do not deliver the specific minimum secure fault current level, AEMO has powers under the National Electricity Law and the NER to direct the necessary resources into service.

In 2018-19, AEMO has issued around 153 directions (lasting 3,214 hours) to South Australian generator units to ensure the correct level of fault current was always maintained. In 2017-18, 99 directions were issued (lasting 1,912 hours). These were security directions for the provision of fault current, not for energy. Where AEMO issues a direction for energy, this is a reliability direction⁷⁵.

Figure 30 compares the total number of directions issued on a per-unit basis in the NEM over the last 10 financial years, and Table 13 shows the equivalent directed hours.

Figure 30 Total number of directions issued by AEMO for the NEM on a per-unit basis

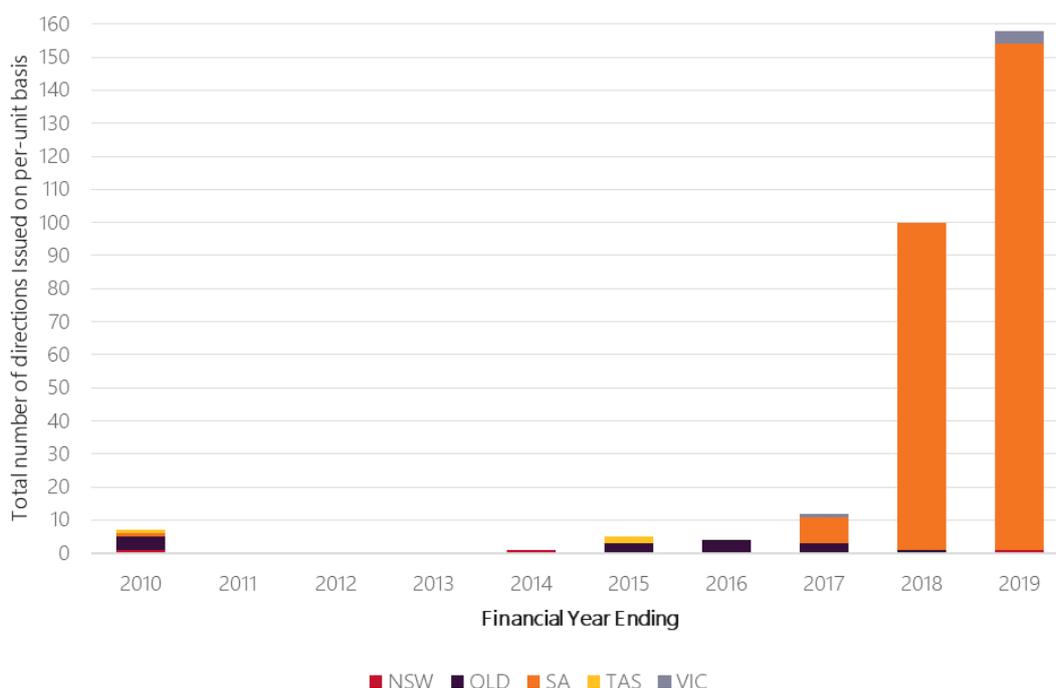


Table 13 Total number of directed hours from AEMO directions across the NEM

Financial year ending	NSW	QLD	SA	TAS	VIC
2010	1.58	12.07	0.17	0.83	
2011					
2012					
2013					

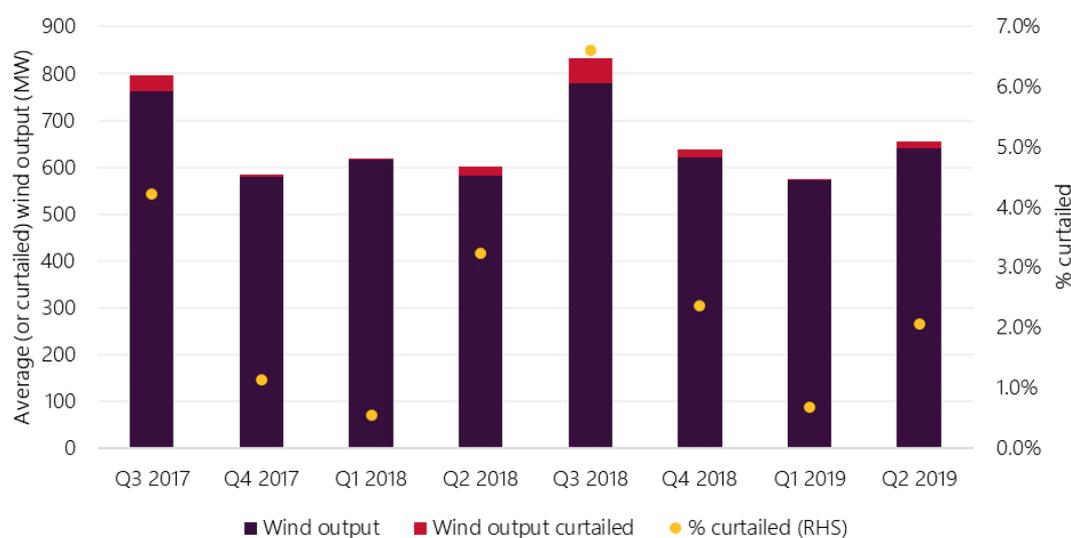
⁷⁵ There were no reliability directions in South Australia in 2017-18 or 2018-19.

Financial year ending	NSW	QLD	SA	TAS	VIC
2014	4.67				
2015		12.08		1.17	
2016		5.25			
2017	1.05	13.33	60.95		5.25
2018		0.67	1,912.17		
2019	4.60		3,214.50		67.17

Another aspect of AEMO’s system strength arrangements for South Australia involves the curtailment of wind generation during periods of very high wind output.

During 2018-19, approximately 3.3% of South Australian wind output was curtailed to maintain the power system within secure limits. This was an increase from 2.4% of wind generation curtailed in 2017-18, as illustrated in Figure 31. In 2018-19, South Australian wind output exceed 1,250 MW 13% of the time, compared to 8% of the time in 2017-18.

Figure 31 Estimated curtailment of South Australian wind generation for system limit reasons



7.3 Renewable Integration Study

As a supplement to developing the 2020 ISP, AEMO commenced the Renewable Integration Study (RIS)⁷⁶ as a deeper review into the specific system implications and challenges associated with the integration of large amounts of variable inverter-based renewable generation and decentralised energy on the power system.

AEMO’s *Power System Requirements* reference paper presented an overview of the specific requirements of a power system⁷⁷. The RIS builds on that paper, to explore the specific opportunities and risks for maintaining the physical requirements of the power system while integrating variable inverter-based renewable resources at increasing levels of penetration. This in-depth review will inform future ISPs as well as providing

⁷⁶ At <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Future-Energy-Systems/Renewable-Integration-Study>.

⁷⁷ At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power-system-requirements.pdf.

foundational engineering advice to government and administrative policy-makers to support their consideration of future changes needed in electricity regulations and market designs.

The RIS is being undertaken in a series of steps:

1. A review of leading international experience in wind and solar PV integration.
2. Detailed analysis of phenomena specifically related to wind and solar PV technologies⁷⁸, including:
 - Managing changes in wind and solar output.
 - Assessing the adequacy of frequency control in the power system.
 - Operating with increasing levels of DER.
3. Presenting a view of what operating the NEM could look like over the next decade. This will include the combined results of this international review, AEMO's detailed analysis in the RIS, and the results of ongoing industry investigation into the more localised limits to wind and solar PV penetration (for example, network congestion and localised system strength).
4. Engaging with local and international organisations and independent experts to review and collaborate on AEMO's preliminary findings.
5. A final report in Q1 2020 into the technical challenges and any possible identified system limits associated with integrating increasing levels of variable inverter-based resources, and a roadmap of priorities to manage these challenges.

In its first deliverable, AEMO supplemented previous studies with a review on how Australia compares with other international power systems⁷⁹. The objectives of the international review were:

- First, comparison of the technical challenges that Australia has experienced or identified with the experience of other jurisdictions to reveal any previously undetected challenges.
- Second, updating understanding of how other jurisdictions are managing the technical requirements of their power systems during the transformation, and what practices appear effective from a technical perspective.
- Third, evaluating these various approaches to see if there are lessons that can be applied to achieve better outcomes in Australia's NEM and WEM.

AEMO stresses that this international review is to help inform potential approaches to current and emerging technical challenges, not necessarily to prescribe specific approaches that have worked overseas.

Although the physics underlying power system operation are universal, the need for a particular solution is impacted by different features of each system, including the level of interconnection with adjacent systems, geographic size, generation mix, and local climate conditions.

Prevailing regulatory and market design considerations also influence how any necessary requirements can be most effectively implemented in a particular jurisdiction.

This international review identified five key insights, which are summarised below and explored in more detail in the full RIS report:

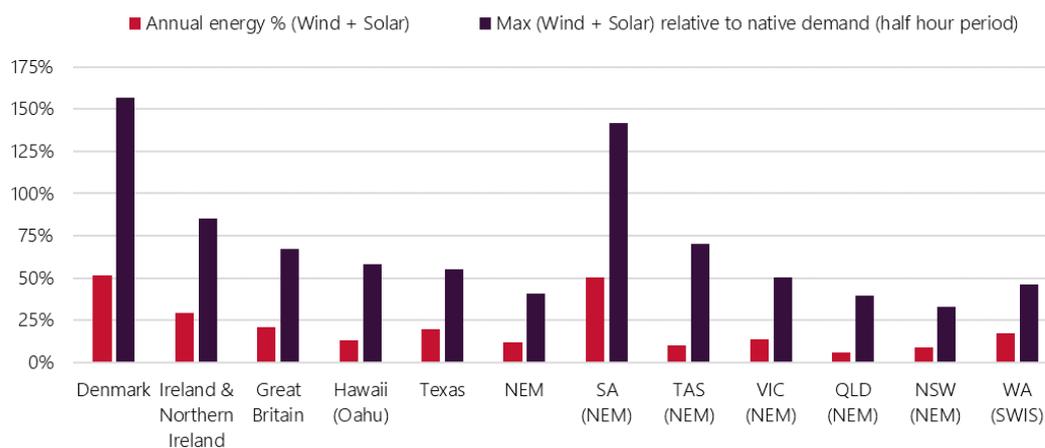
1. South Australia is already experiencing some of the highest levels of wind and solar generation in the world, including one of the highest levels of residential solar PV.
2. Successfully integrating high levels of DER requires an increasing level of visibility, predictability, and controllability of these small distributed devices. Australia can learn from several jurisdictions in its approaches to these challenges.

⁷⁸ The study uses a projected generation mix and network configuration in 2025 as a focus for its detailed analysis. 2025 was chosen as the focus for the first stage of the RIS to enable more detailed focus and increase confidence and certainty in outcomes of power system models, because AEMO has a reasonable level of information about the generation projects that might be connected out to 2025.

⁷⁹ See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Future-Energy-Systems/2019/AEMO-RIS-International-Review-Oct-19.pdf.

3. Managing variability and uncertainty is increasingly challenging at higher levels of wind and solar generation. Australia can learn from others in their approaches, including the assessment of system ramping requirements and fleet capability.
4. Australia should consider international approaches to frequency management in high renewable generation systems, including approaches to maintaining sufficient inertia and enablement of primary frequency response on all generators.
5. International power system operators have taken a staged approach to operating power systems with progressively less synchronous generation online. A similar approach could be considered in Australia.

Figure 32 Large international power systems operating with high instantaneous penetrations of wind and solar generation, and Australian comparisons



Data sources: Denmark (https://docstore.entsoe.eu/Documents/Publications/Statistics/Factsheet/entsoe_sfs2018_web.pdf and <http://osp.energinet.dk/Layouts/Markedsdata/framework/integrations/markedsdatatemplate.aspx?language=en>), Ireland and Northern Ireland (<http://www.eirgridgroup.com/site-files/library/EirGrid/System-and-Renewable-Data-Summary-Report%20July%202019t.xlsx>), Great Britain (<https://www.gov.uk/government/statistics/uk-energy-in-brief-2019> and <https://gridwatch.co.uk/>), Hawaii (<https://www.hawaiianelectric.com/about-us/power-facts>), Texas (http://www.ercot.com/content/wcm/lists/172484/ERCOT_Quick_Facts_01.17.19.pdf), Australia (<https://assets.cleanenergycouncil.org.au/documents/resources/reports/clean-energy-australia/clean-energy-australia-report-2019-fact-sheet.pdf>, and internal database).

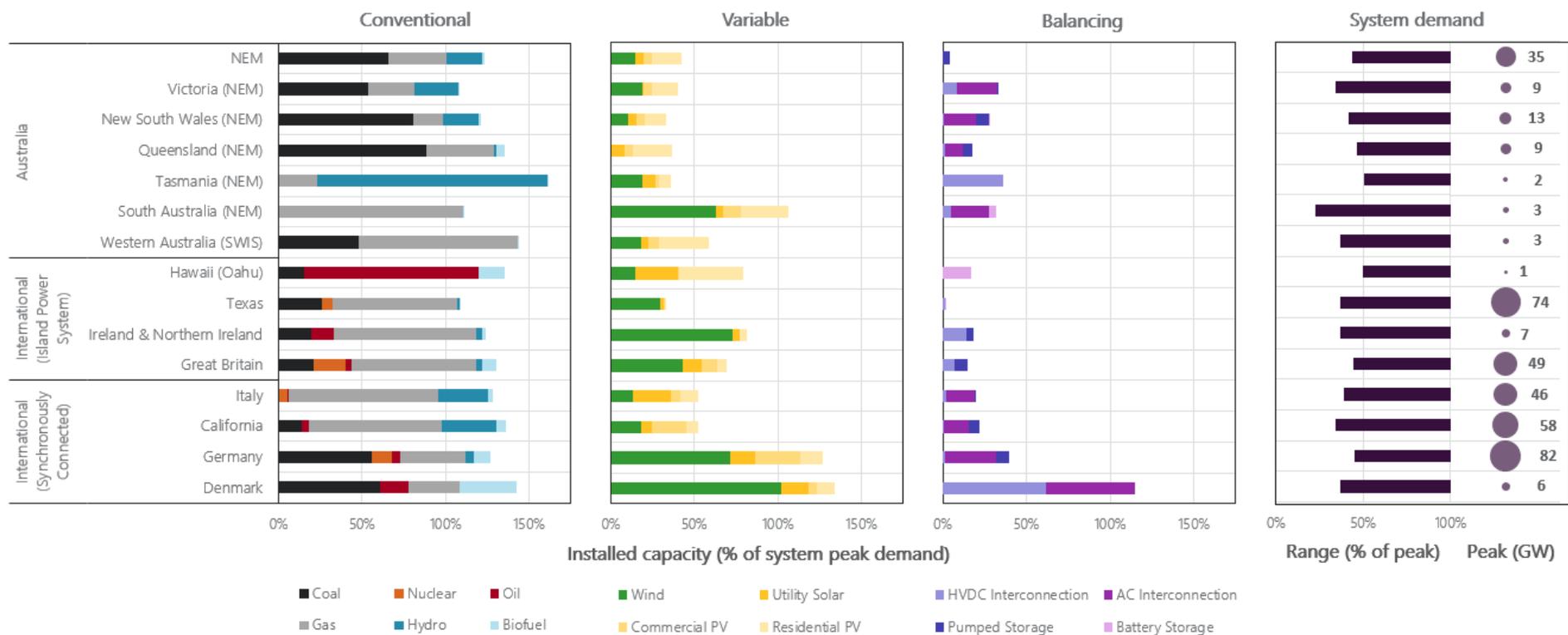
The review found that South Australia has experienced some of the highest instantaneous penetrations of wind and solar generation in the world, second only to Denmark (see Figure 32).

The report identified that South Australia operates under more challenging conditions than Denmark given its substantially lower level of interconnection, as shown in Figure 33 below. It can also be seen that South Australia experiences the lowest proportional minimum demand of any of the power systems assessed.

The results of AEMO’s detailed studies will be published in a final RIS report, currently planned for the first quarter of 2020. Further information on the RIS, supplementary resources, and links to other related projects are available on the AEMO website⁸⁰.

⁸⁰ At <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Future-Energy-Systems/Renewable-Integration-Study>.

Figure 33 Installed components of large international power systems relative peak demand



Data sources: Australia (AEMO, Generation Information: <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information>, Australian PV Institute, PV Postcode Data: <https://pv-map.apvi.org.au/postcode>) Great Britain (Department for Business, Energy & Industrial Strategy, Digest of UK Energy Statistics: <https://www.gov.uk/government/statistics/electricity-chapter-5-digest-of-united-kingdom-energy-statistics-dukes>; Department for Business, Energy & Industrial Strategy, Solar Photovoltaics Deployment: <https://www.gov.uk/government/statistics/solar-photovoltaics-deployment>) Oahu (Hawaiian Electric, Power Facts: <https://www.hawaiianelectric.com/about-us/power-facts>; Hawaii State Energy Office, Hawaii Renewable Energy Projects Directory: <https://energy.ehawaii.gov/epd/public/energy-projects-list.html>) Ireland (EirGrid, All-Island Generation Capacity Statement 2018-2027: http://www.eirgridgroup.com/site-files/library/EirGrid/Generation_Capacity_Statement_2018.pdf; Sustainable Energy Authority of Ireland, Ireland's Solar Value Chain Opportunity: <https://www.seai.ie/publications/Solar-Chain-Opportunity-report.pdf>) Denmark (Energi Data Service, Capacity Per Municipality Data: <https://www.energidataservice.dk/en/dataset/capacitypermunicipality>; IEA PV Power Systems Programme, National Survey Report of Photovoltaic Applications in Denmark 2017: http://iea-pvps.org/index.php?id=93&elD=dam_frontend_push&docID=4457) Germany, Italy (ENTSO-E, Net Generating Capacity: <https://www.entsoe.eu/data/power-stats/net-gen-capacity/>; ENTSO-E, Ten Year Network Development Plan 2018 Executive Report, Appendix: <https://tyndp.entsoe.eu/Documents/TYNDP%20documents/TYNDP2018/consultation/Main%20Report/TYNDP18%20Exec%20Report%20appendix.pdf>, Bloomberg New Energy Finance, New Energy Outlook 2019 data viewer: <https://about.bnef.com/new-energy-outlook/>) Texas (ERCOT, Capacity changes by fuel type: http://www.ercot.com/content/wcm/lists/162615/Capacity_Changes_by_Fuel_Type_Charts_November_2018.xlsx; ERCOT, Unregistered DG Installed Capacity Quarterly Report, <http://www.ercot.com/services/rq/re/dgresource>; U.S. Energy Information Administration, Electric Power Monthly with Data for July 2019: https://www.eia.gov/electricity/monthly/current_month/epm.pdf Table 6.2.B) California (California ISO, Key Statistics August 2019: California Energy Commission, Electric Generation Capacity & Energy: <http://www.caiso.com/Documents/MonthlyStats-August2019.pdf> https://www2.energy.ca.gov/almanac/electricity_data/electric_generation_capacity.html; California Distributed Generation Statistics: <https://www.californiadgstats.ca.gov/charts/nem>; Self-Generation Incentive Program, State-wide Report: https://www.selfgenca.com/documents/reports/statewide_projects).

7.4 Forecast power system reliability

AEMO’s ESOO for the NEM assesses the adequacy of supply in meeting forecast demand over a 10-year period, and evaluates any shortfall resulting in USE against the reliability standard⁸¹.

At the time the 2019 ESOO was published, AGL was seeking permission from the South Australian Government to operate all four TIPS A units over summer 2019-20. Without this permission, only two of the four units could operate at any point in time, and this limitation was incorporated in the ESOO reliability assessment. The 2019 ESOO included the possibility of approval being granted in a sensitivity which examined the impact of all units of TIPS A remaining available in summer 2019-20, effectively increasing available capacity in South Australia this summer by 240 MW.

Since the release of the 2019 ESOO, the South Australian Government has approved the return of the two units of TIPS A that had previously been assumed to be mothballed in summer 2019-20⁸². The following sections therefore focus on reliability forecasts assuming all four TIPS A units are operational this summer and then progressively retired.

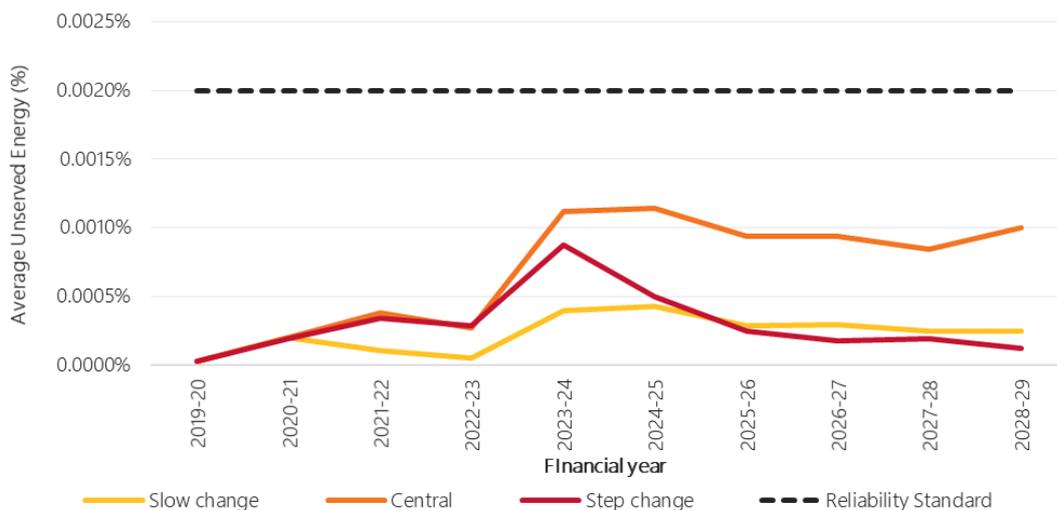
7.4.1 South Australian reliability forecasts for the next 10 years

For South Australia, supply shortfall risks remain relatively low over the first four years in all ESOO scenarios, and expected USE is below the reliability standard throughout the next 10 years, as shown in Figure 34.

The retirement of TIPS A (480 MW) is only partially offset by the new capacity provided at Barker Inlet Power Station (210 MW). Therefore, as the TIPS A units withdraw from the market (three before summer 2020-21 and the final unit before summer 2021-22), the level of expected USE is forecast to increase (except in the Slow Change scenario, due to its falling forecast peak demand).

After the decommissioning of Osborne (172 MW) in 2023-24, expected USE is projected to rise sharply to 0.0011% in the Central scenario. The projected level of USE risk in the Step Change scenario remains below the Central scenario and reduces from 2023-24, due to an increasing number of VPPs coming online driven by strong business cases from existing trials assumed in the Step Change scenario. In the Slow Change scenario, expected USE remains low, due to forecast low maximum demand growth driven by lower economic activity and population growth compared to other scenarios.

Figure 34 Forecast USE outcomes for South Australia – existing and committed projects only



⁸¹ The reliability standard in the NER specifies that expected USE should not exceed 0.002% of total energy consumption in any region in any financial year.

⁸² See <https://www.abc.net.au/news/2019-08-02/agl-delays-defers-power-plant-closures-to-avoid-summer-blackouts/11377876>; also published in the 14 November 2019 update at <https://aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information>.

Although expected USE remains below the current reliability standard, from 2023-24 additional strategic reserves would be required in the Central scenario to reduce the risk of a major load shedding event to a one-in-10-year event, as shown in Table 14.

Table 14 Additional reserves required to reduce risk of major load shedding to a one-in-10 year event

Financial Year	Additional reserves (MW) required to reduce risk of major load shedding >0.002% to a one-in-10 year event
2019-20	0
2020-21	0
2021-22	0
2022-23	0
2023-24	135
2024-25	150
2025-26	95
2026-27	100
2027-28	70
2028-29	105

It should be noted that the reliability projections do not incorporate:

- The impact of the temporary diesel generators in South Australia this summer (or their change to market scheduled generators next year). These generators are expected to be available for use as a last resort to avoid load shedding in South Australia and may be offered for service in the RERT.
- Transmission or generation investment that is not yet committed. EnergyConnect was not assumed committed in the assessment, as the AER is yet to make its final decision on this investment.
- Any actions that may be taken under RERT this summer.

They reliability forecasts also represent USE outcomes before any equitable load shedding principles are applied, as discussed in the next section.

7.4.2 Short-term reliability risks this summer

Figure 34 indicates that the level of USE in South Australia is projected to be below the reliability standard this summer. However, the projections provided in the ESOO do not incorporate the impact of the equitable load shedding principle applied in the NEM. 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.

An equitable load shedding principle applies in the NEM to avoid unfairly penalising one region for a supply deficit spread through several interconnected regions⁸³.

While the ESOO analysis does not consider this principle, any risks of load shedding projected in Victoria could result in the supply deficit being shared across both Victoria and South Australia if there is headroom on the interconnectors.

⁸³ 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>.

For Victoria, prior to actions being taken to procure additional reserves, the expected level of USE is just above the reliability standard for this summer, with a tight supply-demand balance exacerbated by the risk of delayed return to service of units currently on long-term outages (Loy Yang A2 and Mortlake Unit 12).

7.4.3 Managing forecast reliability risks

Given the potential USE risk forecast in Victoria, the application of the equitable load shedding principle could result in greater supply scarcity risks in South Australia this summer than forecast in the ESOO. AEMO is working with the Victorian and South Australian Governments and relevant industry parties to lower this risk. This includes:

- Procuring RERT, where permitted by the NER, to supplement the AEMO/ARENA demand response trial (see Section 7.2.1) which is still running.
- Working with generators and transmission network service providers (TNSPs) to maximise resource availability during the summer months.

7.5 Regulatory changes to improve reliability and security

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

Protected event declaration

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 submitted a request to the Reliability Panel to declare these conditions as a protected event, which was approved by the Reliability Panel in June 2019. Based on historical weather conditions, AEMO expects this protected event will be activated approximately twice per year.

Frequency control and power system resilience

In response to both the findings of the 28 August 2018 system event and overall long-term degradation in frequency control quality, AEMO has submitted two new rule change requests to the AEMC. These aim at significantly increasing primary frequency response (PFR) in the NEM, which is a key component of frequency control that is poorly catered for in the current NER.

AEMO's two rule change proposals focus on:

- Changes to the NER requiring all capable scheduled and semi-scheduled generating units to operate continuously in a frequency responsive mode as defined in a proposed instrument called the PFRR (Primary Frequency Response Requirements).
- Changes to the NER to remove a number of disincentives to generators providing PFR. AEMO has also commenced a targeted scope consultation on the Causar Pays Procedure and the Market Ancillary Services Specification (MASS) to address elements of these existing disincentives. This Consultation is expected to be completed in the first quarter of 2020, but has some dependency on the progress of the AEMC's rule change process.

The AEMC has combined the above two proposals with another rule change request by Dr Peter Sokolowski that proposes a mandatory PFR, similar to AEMO's first proposal⁸⁴.

Final determinations on these proposed Rules are expected in early 2020.

⁸⁴ See <https://www.aemc.gov.au/news-centre/media-releases/consultation-commences-proposed-rules-better-control-power-system>.

Mechanisms to enhance power system resilience

The Council of Australian Governments (COAG) Energy Council asked the AEMC to identify and report on any systemic issues which contributed to the black system event in South Australia on 28 September 2016.

As part of this review, the AEMC has proposed measures to identify and manage different categories of power system security risk, including expanding the way in which AEMO manages power system security risk from two sources of uncertainty (credible indistinct risks and non-credible indistinct risks).

The measures proposed by the AEMC include:

- Adding a variable margin to the largest single credible contingency for which AEMO maintains a secure operating state for credible indistinct risks.
- Expanding the existing power system frequency risk review to cover a broader range of potential risks impacting power system security (beyond frequency events).
- Streamlining and extending the protected events framework and providing for an 'ad hoc protected operation' framework, allowing AEMO to manage 'non-credible indistinct' risks emerging in real time without a protected event declaration.
- Monitoring interconnector flows against a standard for non-credible indistinct risks.

AEMO has closely engaged with the AEMC throughout the review process and provided two submissions to the AEMC's staff discussion paper⁸⁵. A final report is expected to be published in December 2019.

System restart services, standards, and testing

The NEM power system continues to transition away from the traditional synchronous generation and load centres that characterised the grid when the current system restart ancillary services (SRAS) framework was introduced. To maintain reliable and sustainable capability to restart the NEM power system, AEMO submitted a rule change proposal to the AEMC on 29 July 2019 to change the NER for the purposes of:

- Incentivising the provision of both system restart and restoration support capabilities from a range of different technologies.
- Facilitating more extensive testing to verify the viability of system restart paths, increasing the level of assurance that system restoration will succeed.

On 19 September 2019, the AEMC commenced consultation on this rule change proposal⁸⁶, consolidated with a rule change request from the AER that aims to improve clarity and transparency of obligations of parties involved in the SRAS framework.

The final determination is expected to be published in May 2020.

Retailer Reliability Obligation

In 2018-19, the Energy Security Board (ESB) developed legislation and NER amendments to give effect to the Retailer Reliability Obligation (RRO)⁸⁷. 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 RRO commenced on 1 July 2019 with the first reliability gap assessments in the 2019 ESOO for the NEM.

No T-3 reliability instrument request has been made by AEMO this year for South Australia or any other NEM region, since the expected USE forecast for 2022-23 in the 2019 ESOO did not meet the "material reliability gap" threshold of 0.002% of total energy consumed.

⁸⁵ AEMO's submission is at <https://www.aemc.gov.au/sites/default/files/2019-09/AEMO%20-%20Submission%20to%20the%20Discussion%20Paper%20-%20EPR0057.pdf>.

⁸⁶ The consultation paper is on the AEMC's website, at <https://www.aemc.gov.au/rule-changes/system-restart-services-standards-and-testing>.

⁸⁷ For more on the Retailer Reliability Obligation, see <http://www.coagenergycouncil.gov.au/publications/consultation-retailer-reliability-obligation-legislative-amendments> and Chapter 4A of the NER.

Under the South Australian application legislation⁸⁸, the South Australian Minister has powers to make a T-3 reliability instrument for the South Australian region three years out (and 15 months out in transitional years).

Modifying the reliability standard

The current reliability standard is based on the expected USE within a given financial year not exceeding 0.002%. Because applying this standard requires the averaging of annual USE over all possible outcomes, it effectively averages out the risk of experiencing the rapidly growing number of events which can cause severe load shedding over the summer period. While AEMO has attempted to 'operationalise' the risks within the existing standard as much as possible, a modified reliability framework that enables AEMO to ensure customers are not exposed to significant involuntary load shedding in nine out of 10 years is necessary. As highlighted in the 2019 ESOO, AEMO is exploring the development of a modified standard that can more cost-effectively and reliably provide the requisite level of dispatchable resources.

Integrating energy storage systems into the NEM

AEMO has submitted a rule change request to the AEMC that would more efficiently accommodate increasing numbers of connection points with bi-directional electricity flows⁸⁹. Various elements of this proposal would support power system reliability and security outcomes, including:

- Clarifying the treatment of bi-directional facilities in the reliability standard and the RRO.
- Improving the way in which bi-directional facilities are accounted for in market forecasting processes.
- Improving the information in the central dispatch process for bi-directional facilities.
- Applying appropriate technical requirements and performance standards to bi-directional facilities.

This request is pending initiation by the AEMC.

DER Register

AEMO is in the final stages of the initial implementation of a DER Register for the NEM, which is scheduled to commence on 1 December 2019. This follows the AEMC's September 2018 approval of amendments to the NER. The register will provide AEMO, NSPs, and other stakeholders with static data about DER. This will support improvements to AEMO's forecasting and power system modelling and improved power system and network operation, and promote better investment decisions for NSPs.

Updates to Australian Standards

The current performance standards for smaller distribution-connected generation do not capture all the performance requirements needed to optimise and support a secure power system under high levels of DER penetration, support energy affordability energy and allow consumers to pursue individualised services. AEMO is currently working on reviewing both AS/NZS4777.2 and AS/NZS4755 to better support power system security⁹⁰, including amendments to:

- Improve clarity regarding withstand requirements and align with international best practice and the NER.
- Optimise and coordinate both Volt-Var and Volt-Watt settings to maximise these capabilities.
- Define measurement accuracy for protection and control functions.
- Review mechanisms for promoting compliance within the standards.
- Introduce appropriate measures to coordinate or remote query device settings, while supporting system wide cyber-security.

These adaptations are occurring as part of the Australian Standards processes.

⁸⁸ National Electricity (South Australia) (Local Provisions) Regulations 2019.

⁸⁹ For more on this Rule change request, see <https://www.aemc.gov.au/rule-changes/integrating-energy-storage-systems-nem>.

⁹⁰ See <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/DER-program/Standards-and-Protocols>.

8. Future developments

The 2018 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 interconnection between South Australia and New South Wales (EnergyConnect, currently pending regulatory approval), 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 ISP⁹¹. The ISP focused on the optimal integration of renewable energy zones (REZs) into an overall strategic NEM-wide network development plan. The next ISP will be published in 2020, with a Draft due to be published for consultation in December 2019.

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.

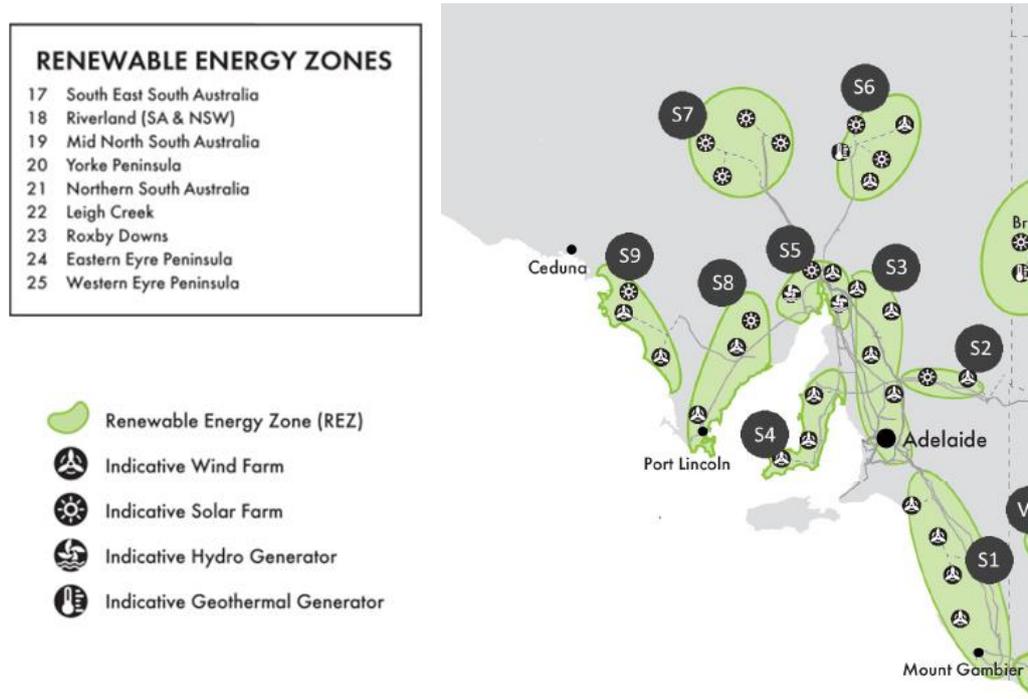
Figure 35 shows the South Australian REZ candidates considered in the analysis.

The ESB is currently undertaking a review on how to best make the ISP actionable⁹².

⁹¹ See <http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan>.

⁹² See <http://coagenergycouncil.gov.au/publications/energy-security-board-converting-isp-action>.

Figure 35 South Australian Renewable Energy Zone candidates



8.1.1 Progress of transmission projects

System strength

Following AEMO’s declaration⁹³ of a system strength gap in South Australia in October 2017, ElectraNet investigated options to address system strength and inertia while also keeping costs down (refer to the Main Grid System Strength Contingent Project)⁹⁴. The installation of synchronous condensers on the network was 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.

From a regulatory standpoint, ElectraNet’s project utilised transitional provisions within the NER relating to system strength, rather than the RIT-T process. Under this alternate approach, ElectraNet lodged an economic evaluation report with the AER on 18 February 2019⁹⁵. After submitting a contingent project application (to allow ElectraNet to access funds for this project) on 28 June 2019, the AER approved funding for the project on 9 August 2019.

In August 2019, ElectraNet provided an update on this project⁹⁶, estimating that the first two of four planned synchronous condensers will be installed at the Davenport substation in mid-2020, and the second two will be installed at the Robertstown substation by the end of 2020. ElectraNet estimates that the full solution will be commissioned by early 2021.

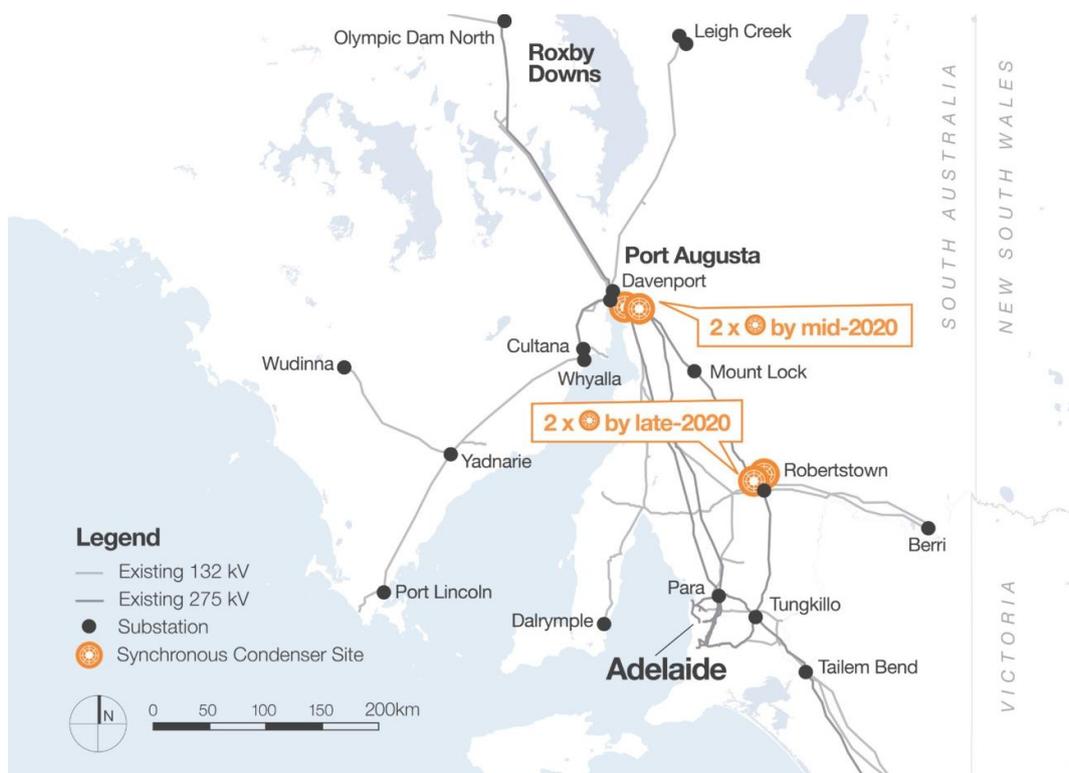
⁹³ As identified in the Update to the 2016 NTNDP, October 2017, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NTNDP/2017/Second_Update_to_the_2016_NTNDP.pdf.

⁹⁴ AER. *ElectraNet – Main Grid System Strength Contingent Project*, at <https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/contingent-projects/electranet-main-grid-system-strength-contingent-project>.

⁹⁵ ElectraNet. *Addressing the System Strength Gap in SA*, at <https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/contingent-projects/electranet-economic-evaluation-main-grid-system-strength-project-contingent-project-trigger>.

⁹⁶ ElectraNet. *Strengthening South Australia’s power system*, at <https://www.electranet.com.au/what-we-do/projects/power-system-strength/>.

Figure 36 Proposed synchronous condenser solution in South Australia



Source: ElectraNet

EnergyConnect – a new interconnection between South Australia and New South Wales

The 2016 NTNDP⁹⁷ recommended that a new interconnector be established between New South Wales and South Australia. This outcome was confirmed in the 2018 ISP, which indicated that a major new interconnector between South Australia and New South Wales was expected to be economically beneficial, under almost all plausible futures⁹⁸.

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

In February 2019, ElectraNet completed the South Australia Energy Transformation RIT-T, which demonstrated that a new South Australia to New South Wales interconnector would deliver economic benefits and reduce residential electricity bills⁹⁹.

The option recommended by ElectraNet is consistent with the ISP¹⁰⁰ and is shown in Figure 37.

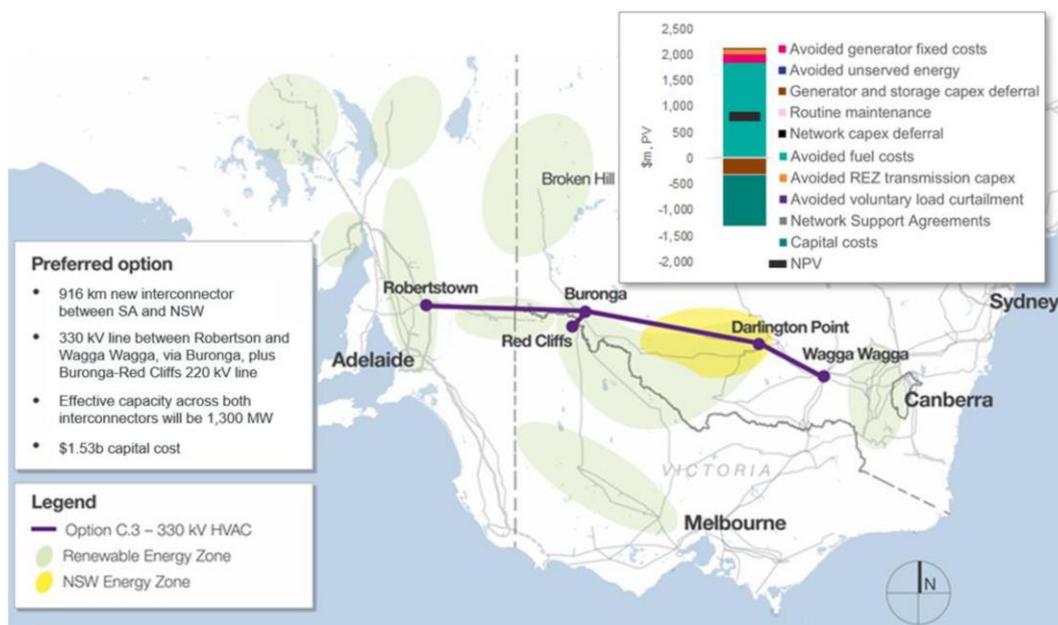
⁹⁷ AEMO. 2016 NTNDP, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NTNDP/2016/Report/2016-NATIONAL-TRANSMISSION-NETWORK-DEVELOPMENT-PLAN.pdf.

⁹⁸ The ISP assessed potential developments under a range of scenarios so modelling outcomes would be robust. See Chapter 2 of the ISP, at <http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan>.

⁹⁹ See <https://www.electranet.com.au/projects/south-australian-energy-transformation/> for more information.

¹⁰⁰ ElectraNet. South Australia Energy Transformation RIT-T, at <https://www.electranet.com.au/projects/south-australian-energy-transformation/>.

Figure 37 Interconnector options and variants assessed by ElectraNet in the SAET RIT-T



Source: ElectraNet

The regulatory approval for EnergyConnect is currently pending the AER’s determination that the RIT-T has been satisfied. If approved, the interconnector has an estimated delivery time of 2022 to 2024, depending on the time taken to gain environmental and other necessary approvals. The South Australian Government is supporting the early completion of this link in stages.

8.2 Integration of Distributed Energy Resources (DER)

AEMO has established a DER Program¹⁰¹ focused on optimising the integration of these resources into the grid. The aim is to create a DER market that will allow consumers to maximise the full value of their systems by enabling them to not just generate and export energy, but for DER to also provide system security services or potentially peer-to-peer energy trading.

To deliver this, the DER Program is trialling VPPs, including one in South Australia, implementing a DER Register, and working on improving inverter Standards. These Standards will ensure DER deliver state-of-art capabilities that support system security while also enabling consumers to access such new services at a time of their choosing.

AEMO is working in collaborative partnership with Energy Networks Australia, and AEMO and distribution network service providers (DNSPs) are designing the Distribution System and Distribution Market Operator roles that will enable the operating framework for VPPs to integrate into AEMO’s management of the power system.

In South Australia, the focus is also on system analysis, so AEMO can better operate a power system with high levels of DER penetration. This includes work in collaboration with SAPN on managing minimum demand and considering any technical limits to DER export into the transmission system.

¹⁰¹ See <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/DER-program> for more information.

8.3 Additional supply developments

As at 14 November 2019¹⁰², new generation investment in South Australia continues to focus on renewable developments and battery storage/VPP, with the largest projects in these categories being:

- Goyder South hub – wind (1,200 MW).
- Yorke Peninsula Wind Farm (up to 635.8 MW).
- Goyder South Hub – solar (600 MW).
- Bridle Track Solar Project (up to 300 MW).
- Goyder South Hub – BESS (900 MW).
- SA Government VPP – stage 3 (245 MW).

Given the penetration of renewable generation, there will be increasing 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 14 November 2019, AEMO's Generation Information update identified 65 energy generation developments in South Australia, totalling 10,773 MW. Table 15 aggregates these developments by energy source, while Figure 38 shows the location and capacity of only those projects whose status is reported as more advanced than Publically announced¹⁰³.

Table 15 South Australian prospective generation projects by energy source, as at 14 November 2019

Energy source	Number of projects	Capacity (MW)	Capacity (% of total projects tracked)	Change in number of projects from July 2018	Change in capacity from July 2018 (MW)
Gas	9	715	6.6%	3	-164
Diesel	0	-	0.0%	-1	-30
Solar	23	3,271	30.4%	2	665
Biomass	0	-	0.0%	-1	-15
Wind	13	4,027	37.4%	0	1,083
Water	7	995	9.2%	4	240
Storage – battery and VPP	13	1,765	16.4%	3	1,247
Total	65	10,773	100.0%	10	3,026

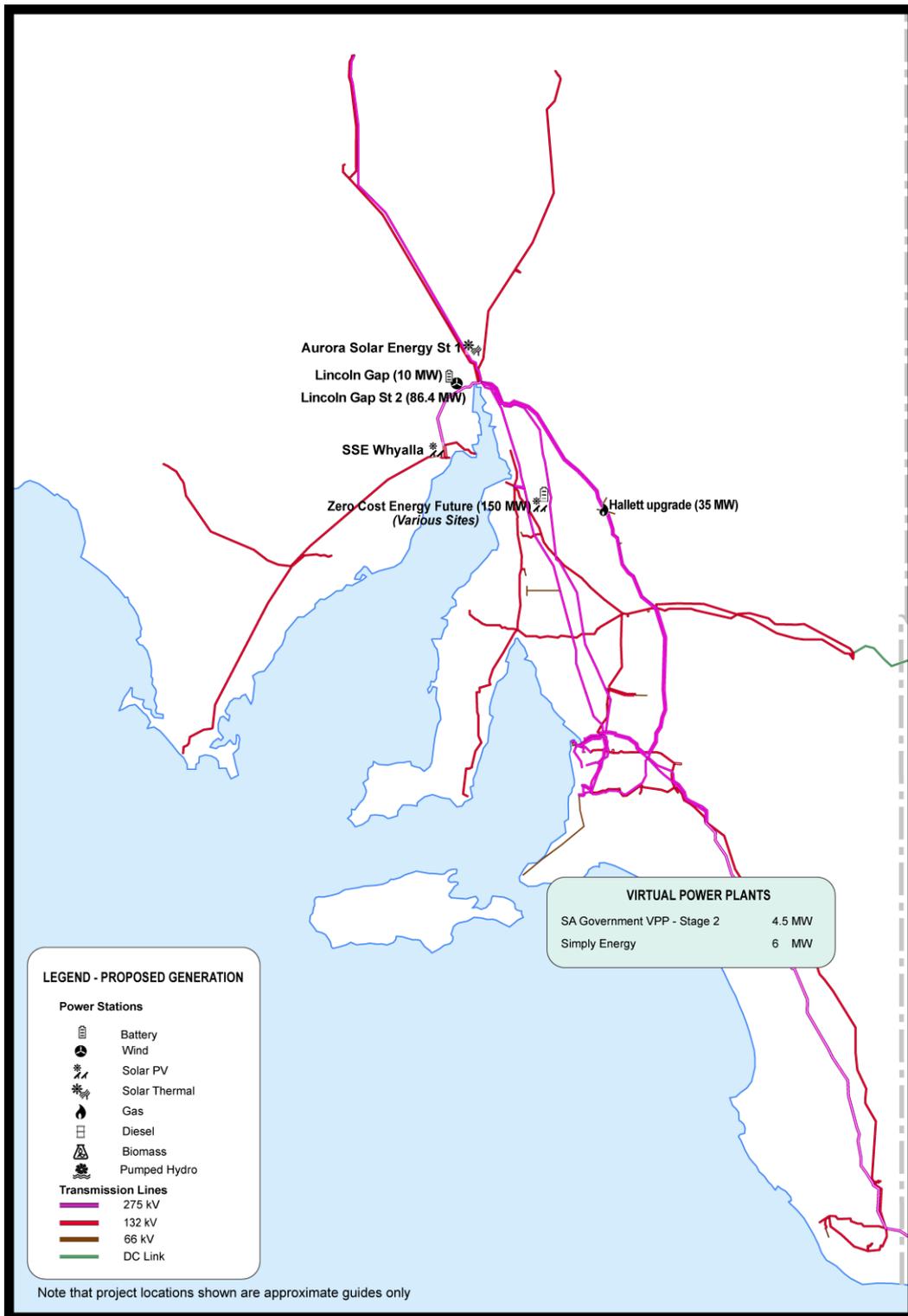
Note: on 19 November 2019, Neoen announced¹⁰⁴ that Hornsdale Power Reserve will be expanded by 50% to 150 MW capacity, however this announcement was outside of the reporting period for Generation Information reported in the 2019 SAER. Therefore, it is not included in this table or the report commentary.

¹⁰² Date based on latest AEMO Generation Information Page at 14 November 2019. More recent information may be available by time of publication, at <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information>.

¹⁰³ Refer to project status definitions on AEMO's Generation Information Page, 14 November 2019, at <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information>.

¹⁰⁴ See <https://hornsdalepowerreserve.com.au/hornsdale-power-reserve-to-be-expanded/>

Figure 38 Location and capacity of South Australian generation projects



9. Gas supply for GPG

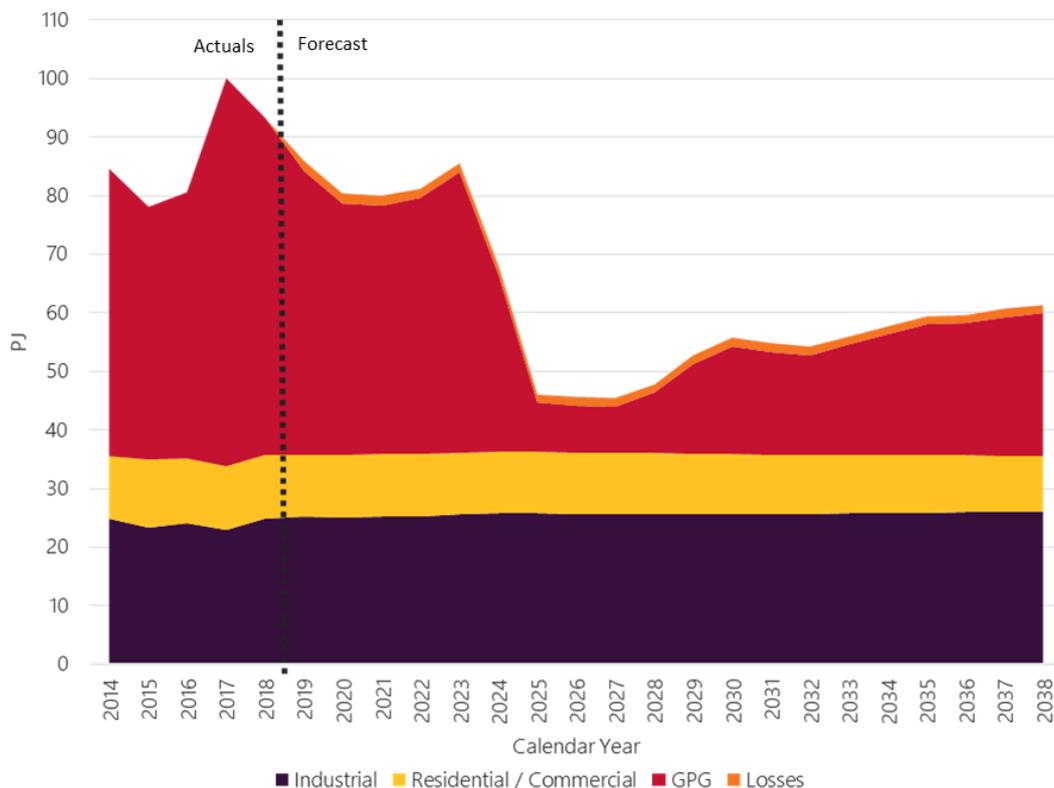
AEMO’s 2019 Gas Statement of Opportunities¹⁰⁵ (GSOO) for eastern and south-eastern Australia highlights that the gas supply-demand balance is projected to remain tight, with production in Southern Australia continuing to decline, and supplies from Queensland limited by pipeline capacity. The 2019 GSOO forecasts the potential for supply gaps from 2024 onwards, unless additional southern reserves and resources, or alternative infrastructure, are developed.

The 2019 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 consumption forecasts

Over the next 10 years, significant reductions in South Australia’s total demand for natural gas are expected compared to historical usage, due primarily to reduced demand for gas for GPG, as shown in Figure 39.

Figure 39 South Australian gas consumption – historical and forecast (Neutral scenario), 2014 to 2038



This GPG projection is based on generation and interconnector outcomes from AEMO’s 2018 ISP, with new interconnector development and high penetration of new renewable generation and storage technologies.

¹⁰⁵ AEMO, 2019 GSOO, March 2019, 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/>.

The potential construction of the EnergyConnect interconnector between South Australia and New South Wales, combined with new renewable generation driven by the Victorian Renewable Energy Target (VRET) and federal Large-scale Renewable Energy Target (LRET), are forecast to lead to lower levels of annual generation from South Australian GPG. GPG will still be required to meet South Australian demand in periods when the sun is not shining and there is little or no wind, but demand for gas will become more variable across the year.

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, within this timeframe AEMO does not forecast GPG levels returning to the levels seen historically.

Over this same period, residential and commercial gas consumption is forecast to have a very minor decline, due to connections growth being outpaced by the expectation of further energy efficiency measures and increases in the preference for fuel switching to using electrical appliances instead of gas. The industrial sector is forecast to remain stable at current levels out to 2038, with no strong drivers for growth identified that would alter consumption patterns for the industrial segments.

9.2 Natural gas reserves and resources, and infrastructure

South Australia has traditionally sourced natural gas from the Otway, Cooper and Eromanga basins¹⁰⁶. Over the past several years, the 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. However, declining supplies from the Otway basin are driving this trend to reverse again, with Cooper and Eromanga basin gas and further supplies from Queensland being sent south to meet demand in South Australia and the other southern states.

As at 31 December 2018, eastern and south-eastern Australian proven plus probable (2P) natural gas reserves¹⁰⁷ totalled 42,633 petajoules (PJ), of which 12,830 PJ was classified as developed.

The total gas produced across eastern and south-eastern Australia during the 2018 calendar year was 1,818 PJ. Based on advice from gas producers, and as reported in the 2019 GSOO, total gas production across eastern and south-eastern Australia is forecast to increase from 1,933 PJ in 2019 to 2,063 PJ in 2022. These production forecasts, however, include volumes from fields not yet producing, with some level of uncertainty as to whether they will eventuate. If these anticipated projects are removed from the production forecasts and only currently producing fields and committed projects are considered, the east coast production forecasts indicate that only 1,984 PJ may be produced in 2022, a difference of 79 PJ.

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, and Figure 39 shows the gas producing basins and infrastructure supplying eastern and south-eastern Australia.

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.

¹⁰⁶ 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.

¹⁰⁷ 2P is considered the best estimate of commercially recoverable reserves.

Figure 40 Gas producing basins and infrastructure supplying eastern and south-eastern Australia

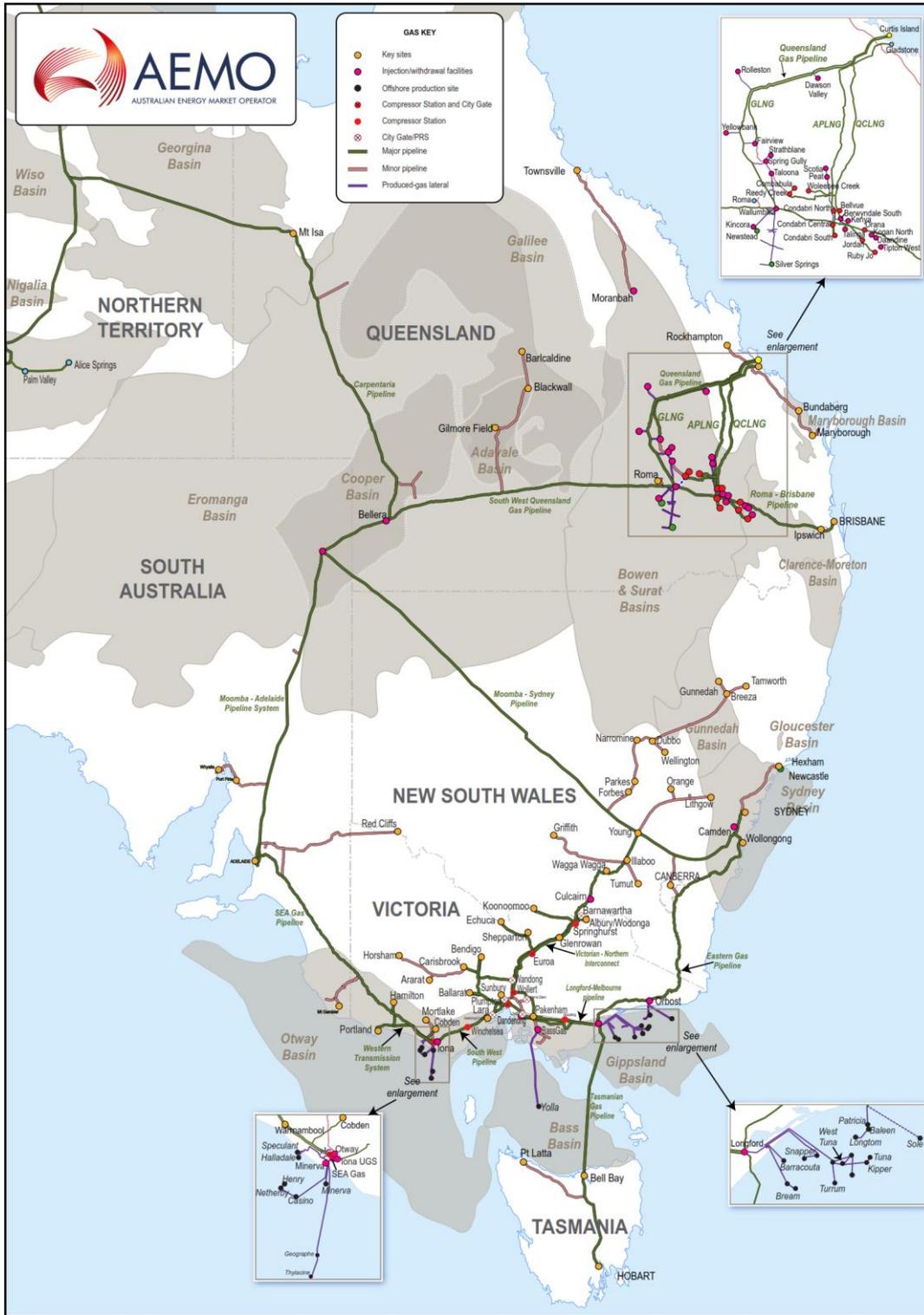


Table 16 Major gas pipelines relating to South Australia

Gas pipeline	Length (km)	Year of first gas flow	Capacity reported (Terajoules [TJ]/d)
Moomba to Adelaide Pipeline	1,185	1969	246 (South), 85 (North)
Moomba to Sydney Pipeline	2,030	1998	489 (South-East), 120 (North-West)
South East Australia Gas Pipeline	680	2004	250**
South West Queensland Pipeline*	937	1996	404 (West), 340 (East)
Victoria – New South Wales Interconnector	143	1998	223 (North), 159 (South)

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

** South East Australia Gas Pipeline capacity has been reduced to 250 TJ/d as some of the capacity has been converted to storage.

9.2.1 Daily demand for GPG supply

In 2018–19 GPG continued to play an important role in meeting South Australia’s electricity demand, particularly when the wind was still and solar generation output was low, as demonstrated in Figure 27 (in Section 7.1.2).

Since the closure of Northern Power Station in May 2016 and Victoria’s Hazelwood Power Station in March 2017, South Australia’s reliance on GPG when VRE generation is low has increased and, coupled with more VRE being installed, has led to increases in daily gas demand and more frequent peaks. Since summer 2018–19 the variability in gas demand for power generation has become increasingly apparent, with clear peaks and troughs in demand as wind generation varied due to passing weather systems. The recent poor reliability of Victorian coal-fired generators has further contributed to this increase in GPG gas demand volatility.

Figure 41 shows that there has been an increase in the number of days when total gas demand (gas system demand¹⁰⁸ and power generation) exceeded 300 TJ/d compared to 2015. The increase in South Australian gas system demand during the winter months for residential heating is also apparent. Total gas demand approached 400 TJ/d on several days during winter 2018 and winter 2019.

The figure also shows that, over the same time period, combined gas pipeline capacity (Moomba to Adelaide Pipeline and South East Australia Gas Pipeline) has been reducing, with daily demand for gas getting close to pipeline capacity several times in 2019.

During periods of very high South Australian GPG, liquid fuel (usually diesel) is used to supplement gas supplies. Figure 42 compares the output of GPG compared to the natural gas usage information from the Gas Bulletin Board (GGB). This additional information has only been available on the GGB since 1 October 2018. Outside of Victoria, AEMO does not have real-time gas pipeline flow information, and it does not have access to liquid fuel usage and inventories for any power stations. Discrepancies between the generation data and GGB data in Figure 42 are an indicator of when liquid fuel may have been used to supplement gas supplies.

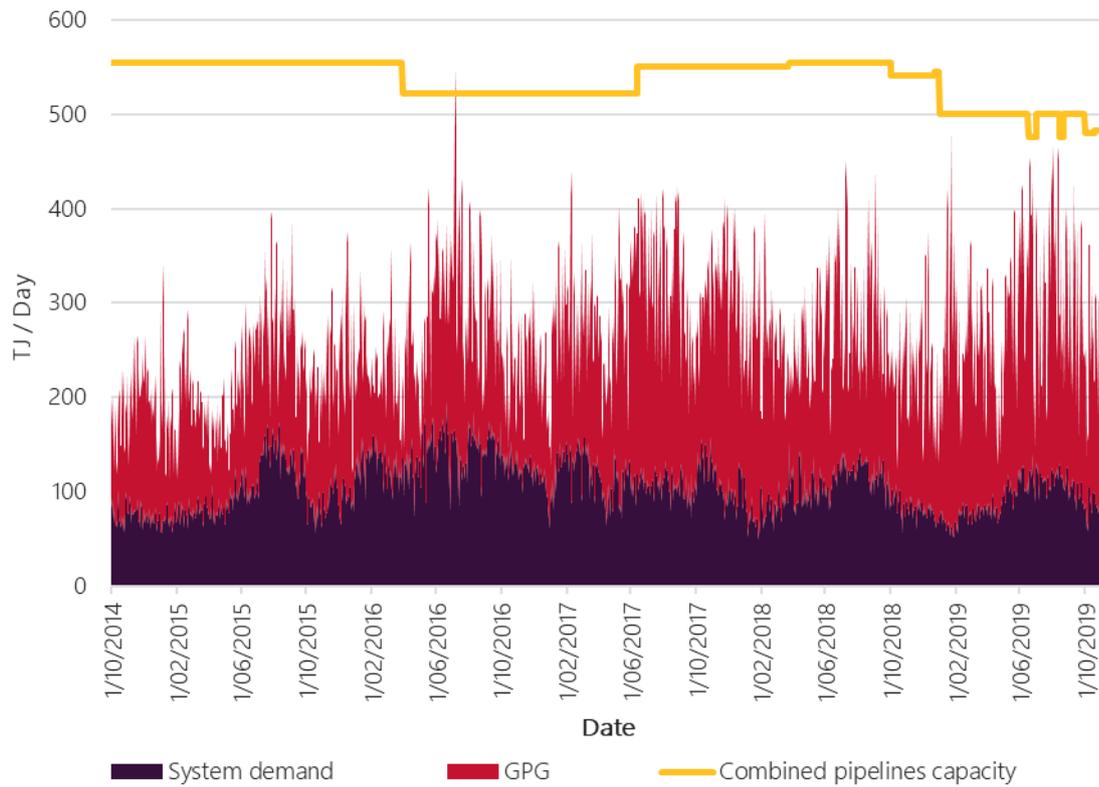
In both Figure 41 and Figure 42 two large spikes in “gas” powered generation output are evident:

- The winter 2016 event coincided with an outage on the Victoria – South Australia interconnector. AEMO was advised of very high diesel use for power generation during this outage.
- The second spike, in late January 2019, was during the heat event that impacted South Australia and Victoria. This event included Victorian load shedding on 24 and 25 January due to high electricity demand coupled with coal-fired generator outages (the 24 January Victorian demand reduction also assisted South Australia).

Liquid fuel was also used to support gas fired generation output during this heat event.

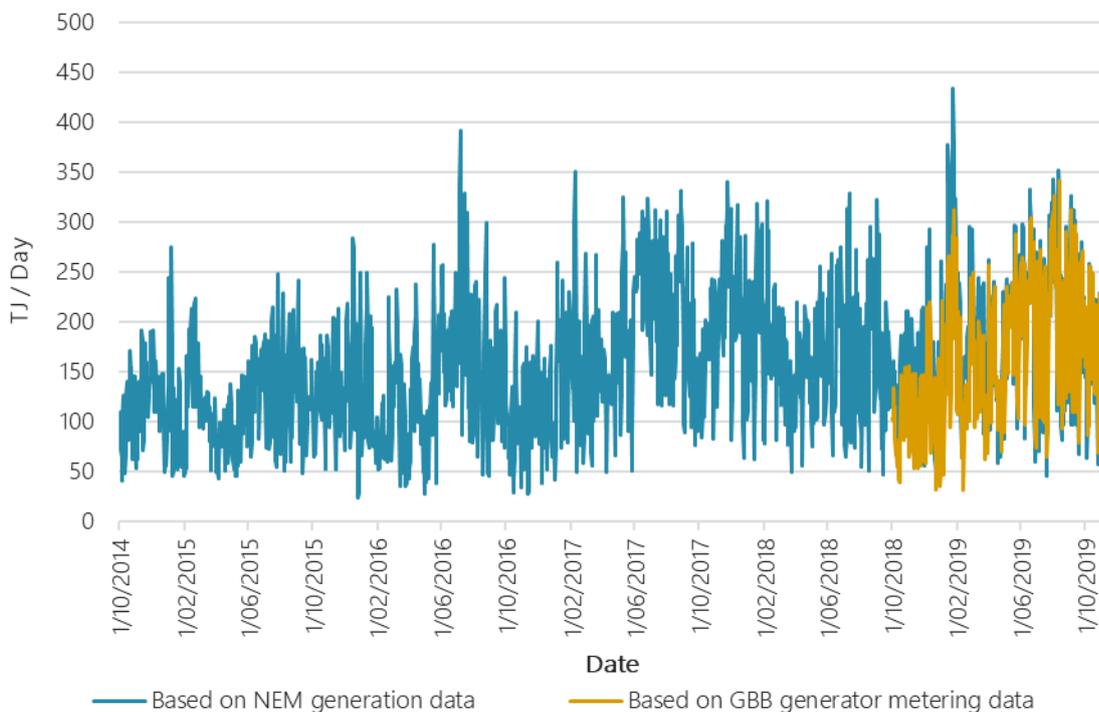
¹⁰⁸ System demand comprises of residential, commercial and industrial gas usage.

Figure 41 South Australian daily gas usage and pipelines capacities (October 2014 to October 2019)



Note: data is derived from analysis of GBB flows and capacities, and NEM generation data.

Figure 42 South Australian gas generation demand (October 2014 to October 2019)



A1. Data sources and reporting methodology

A1.1 Introduction

This section outlines and clarifies the various data sources used throughout the 2019 SAER and its corresponding data files, as well as relevant analysis/reporting methodologies employed.

Each aspect considered can be assumed to apply throughout the report and data files, except where noted by any listed exceptions.

A1.2 Times and dates

Timestamps shown in analysis (figures and tables) are NEM time (market time) – that is, Australian Eastern Standard Time (AEST) with no daylight savings, unless otherwise indicated. However, where times are written throughout the report text, they will be in local time (Adelaide time, and adjusted where necessary for daylight savings).

In line with electricity industry seasonal forecasting and reporting, “summer” refers to the period from 1 November to 31 March, and “winter” from 1 June to 31 August. “Shoulder” refers to 1 September to 31 October and 1 April to 31 May.

For selected metrics, denoted in their title by use of the word “workday”, all Saturdays, Sundays and gazetted South Australian public holidays have been excluded from analysis.

A1.3 Prices

A1.3.1 Electricity

Electricity price analysis used 30-minute (ending) spot prices for each NEM region as relevant to the metric. Unless otherwise stated in the title of the metric, analysis is using nominal dollar values. For certain metrics labelled as “real June 2019”, the trends (or input to the trends) are presented in real June 2019 dollars, using the Adelaide Consumer Price Index (CPI) as the basis for adjustment.

A1.3.2 Gas

Reported prices come from the average of daily ex-ante price for each market analysed. The markets referenced, with regards to the figures as numbered in the data file, are:

- Short Term Trading Market (STTM) Adelaide Hub for “ADL” in Figure 6.5, and “South Australia” in Figure 6.14.
- STTM Sydney Hub for “SYD” in Figure 6.5.
- STTM Brisbane Hub for “BRI” in Figure 6.5.
- Victorian declared wholesale gas market (DWGM) for “VIC” in Figure 6.5.

A1.5 Generation capacity

The SAER and its data files report on a variety of capacities for the supply sources reported on. The megawatt capacity used in any given analysis will depend on what is available and what is reasonable for the metric being sought.

The general principles for capacity sources are:

- AEMO registered capacity is used for registered generators.
 - ONSG references AEMO registered capacity if available, otherwise an approximate value obtained by AEMO.
- Estimated aggregate capacity is used for rooftop PV and PVNSG, as outlined in Section A1.8.
- Nameplate capacity (including forecast nameplate capacity) is used for metrics concerning AEMO published Generation Information.
- Interconnector capacity is not included in analysis of generation capacity, but where reporting on interconnector power flows, it is sometimes compared to its nominal capacity at a point in time (without considering shorter-term constraints that can apply).

Capacity analysis rules include:

- Exclusion of wind farm output and/or capacity applies for the time before the wind farm first reached 90% of registered capacity, unless specifically noted otherwise.
- For “capacity factor” analysis, all generators exclude periods when, for the analysis period in question, there was not a long enough portion of the time that had generator at normal availability. Such exclusion reasons could include market withdrawals or commissioning periods.

A1.6 Data sources for generation and supply

Most of the analysis for electricity generation and supply (including consumption and demand) is based on 5-minute averages of AEMO’s SCADA metering, including scheduled generators and loads, significant non-scheduled wind farms and diesel generators, as well as interconnector flows. In cases where analysis is at the 30-minute level, the six relevant 5-minute averages are averaged further to a 30-minute value.

Exceptions include:

- Rooftop PV and PVNSG – refer to Section A1.8.
 - Note that Figure 9 uses ASEFS2 estimates for rooftop PV rather than the ESOO modelling used in the rest of the reporting.
- ONSG – aggregated from settled market meter data.
- Historical minimum or maximum operational demand as measured over a given period, for example, daily, seasonal and yearly values in various figures and tables – these are taken from 30-minute averages of AEMO’s SCADA metering.
- Figure 9 and Figure 30 use either 5-minute *snapshots* or 30-minute averages of AEMO’s SCADA metering.
 - Figure 30 also makes estimates of expected wind farm output had there been no curtailment directed.
- Figure 31 and Figure 32 have specific data sources as listed under the figures in the report.

A1.7 Consumption and demand definitions

Consumption refers to electricity used over a period of time and is measured in GWh, whereas demand refers to electricity used at a particular time (or the average over a short period of time like five or 30 minutes) and is measured in MW.

This report generally considers consumption or demand over reporting periods such as a financial year, summer, winter or calendar month.

For historical and forecast consumption or demand based on annual or seasonal periods, the 2019 SAER uses outcomes from the 2019 ESOO, noting that the 2018-19 annual consumption value builds on the 2019 ESOO value by providing full year actual estimates.

A1.7.1 Operational reporting

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

Furthermore, operational reporting is defined as that electricity supplied by scheduled, semi-scheduled, and significant non-scheduled generating units, and includes net interconnector imports when reporting on a particular NEM region. It excludes electricity used by scheduled loads (such as scheduled battery storage units) or electricity supplied by SNSG and rooftop PV.

Table 4.12 in the data file lists the South Australian generators included in the operational reporting for the 2019 SAER. The exception is Figure 9 in the report, which uses a slightly different set of generators, as there were some changes that occurred to the operational list from October 2019 (due to reclassification of the Temporary Generation North and South diesels to be excluded, and the registration of Barker Inlet Power Station and Lake Bonney BESS1).

A1.7.2 Underlying reporting

Underlying consumption and demand refer to electricity consumed by customers at their premises, supplied from both the grid and rooftop PV combined (including any estimated battery storage assumed charge/discharge patterns), but it does not include any contribution from SNSG.

A1.7.3 "Sent-out" versus "as-generated" data

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

Analysis in this report and its data files is as-generated, except where explicitly noted that it is sent-out.

A1.8 Generator fuel grouping

When reporting on generation supply by fuel or energy groupings, whether for capacity or generation:

- Gas refers to scheduled gas generation only.
- Wind refers to semi-scheduled and significant non-scheduled wind farms.
- Solar refers to semi-scheduled solar PV farms only.
- "Storage – Battery" refers to the generation output of scheduled battery energy storage systems.
- Rooftop PV refers to behind-the-meter rooftop solar PV systems up to 100 kW capacity (so excluding PVNSG).

- ONSG refers to other non-scheduled generation as described in Table 4.16 of the data file. Note that the fuel types in the ONSG category could overlap with other categories, but the reporting remains in the ONSG (and SNSG) category only.
- PVNSG refers to PV non-scheduled generation as described in Section 2.2 of the report.
- SNSG refers to ONSG plus PVNSG.
- “Diesel + SNSG” refers to scheduled diesel units, the Temporary Generation North and South generators and SNSG.
 - Diesel, if mentioned apart from the above definition, comprises only scheduled and diesel units plus Temporary Generation North and South generators.

A1.9 Solar PV estimates

A1.9.1 Rooftop PV

Capacity and generation methodology for rooftop PV are outlined in Section 2.1. Noting that methodology is improved for 2019 compared to 2018 reporting, rooftop PV related metrics will not be the same as in the 2018 SAER, even for coincident time periods analysed.

Furthermore, in the 2019 SAER and data files, the rooftop PV capacity and generation estimates build further on those used for the 2019 ESOO, incorporating updated estimates principally for 2018-19.

For comparisons in reporting year, shown in various metrics, it is to be noted that the 2018 ESOO (and likewise the 2018 SAER) maintained the same rooftop PV installed capacity forecasts (and hence generation forecasts) across all its scenarios.

A1.9.2 PVNSG

The 2019 ESOO modelled PVNSG capacity using estimates from APVI data available at <https://pv-map.apvi.org.au/power-stations>, for generators in the range 100 kW to 30 MW, with data up to April 2019. This is contrasted to the 2018 ESOO, which used CER data directly.

For PVNSG generation analysis, the 2019 ESOO used the Solar Advisory Model (<https://sam.nrel.gov/>), which is different to the modelling for the 2018 ESOO.

The SAER uses ESOO outcomes for PVNSG in both the 2018 and 2019 reports, so reported data for 2019 will not match that of 2018 (due to above capacity input and generation modelling differences), even for coincident time periods analysed.

Furthermore, the 2019 SAER’s PVNSG capacity and generation estimates build further upon those used for the 2019 ESOO, incorporating updated estimates for the entire historical reporting period, based on more recent APVI capacity data.

A1.10 Interconnector flows

In some interconnector-related metrics, individual interconnectors are reported on separately, and will be named as appropriate (Heywood or Murraylink).

However, for many metrics, the “combined” or “total” interconnector flows are reported, and this is assumed to be the case even without these qualifying descriptors denoted.

In these cases, the data reported is taken as the time-aligned net MW flow in to or out of South Australia, at every 5-minute (averaged) period considered. The time-aligned data is then averaged further (to say 30 minutes) or aggregated, to say an annual GWh amount.

Thus, the combined or total interconnector metrics represent analysis of net boundary flows to or from South Australia at each point in time.

A2. Data spreadsheet index

As part of the SAAF suite, several data spreadsheets are available online for download¹⁰⁹. 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.

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.

A2.1 Tables

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 4.25
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 7.5
Table 11	Table 7.3
Table 12	Table 7.4
Table 13	Table 7.6
Table 14	Table 7.7
Table 15	Table 8.2
Table 16	Table 9.1

¹⁰⁹ At <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/South-Australian-Advisory-Functions>.

A2.2 Figures

Report figure number	Corresponding data pack figure number	Report figure number	Corresponding data pack figure number
Figure 1	Figure 2.1	Figure 22	Figure 6.9
Figure 2	Figure 2.2	Figure 23	Figure 6.15
Figure 3	Figure 2.3	Figure 24	Figure 6.14
Figure 4	Figure 2.4	Figure 25	Figure 6.7
Figure 5	Figure 3.1	Figure 26	Figure 6.8
Figure 6	Figure 3.2	Figure 27	Figure 7.9
Figure 7	Figure 3.10	Figure 28	N/A
Figure 8	Figure 3.11	Figure 29	N/A
Figure 9	Figure 3.15	Figure 30	Figure 7.2
Figure 10	Figure 3.14	Figure 31	Figure 7.11
Figure 11	Figure 3.16	Figure 32	N/A
Figure 12	Figure 3.8	Figure 33	N/A
Figure 13	Figure 3.9	Figure 34	Figure 7.3
Figure 14	N/A but PDF available online ¹¹⁰	Figure 35	N/A
Figure 15	Figure 4.2	Figure 36	N/A
Figure 16	Figure 4.7	Figure 37	N/A
Figure 17	Figure 4.10	Figure 38	N/A but PDF available online ¹¹¹
Figure 18	Figure 5.1	Figure 39	Figure 9.1
Figure 19	Figure 5.2	Figure 40	N/A
Figure 20	Figure 6.1	Figure 41	N/A
Figure 21	Figure 6.3	Figure 42	N/A

¹¹⁰ At <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/South-Australian-Advisory-Functions>.

¹¹¹ At <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/South-Australian-Advisory-Functions>.

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) 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) of the following (for example): <ul style="list-style-type: none"> • A single generating unit. • A number of generating units of a particular type or in a particular area. • All of the generating units in a region. 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
MW	Megawatt

Abbreviation	Expanded name
MWh	Megawatt hour
PJ	Petajoule
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
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
GSOO	Gas Statement of Opportunities
HPR	Hornsedale Power Reserve
ISP	Integrated System Plan
LNG	Liquefied natural gas
LOR	Lack of Reserve
LRET	Large-scale renewable energy target
NEM	National Electricity Market

Abbreviation	Expanded name
NER	National Electricity Rules
OCGT	Open-cycle gas turbine
PHEV	Plug-in hybrid electric vehicle
POE	Probability of exceedance
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
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)