AUSTRALIAN ENERGY MARKET OPERATOR

South Australian Electricity Report

November 2023

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 30 September 2023, although AEMO has endeavoured to incorporate more recent information where practical (generation information specifically is based on AEMO's 27 October 2023 update).

Disclaimer

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

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Version control

Version	Release date	Changes
1	29/11/2023	Initial release

Executive summary

The *South Australian Electricity Report* (SAER) is an annual report providing key independent insights for the South Australian jurisdiction of the National Electricity Market (NEM) from a range of AEMO publications and studies.

Key historical observations reported in this SAER

- **Generation development dominated by large-scale solar and batteries** – in 2022-23, the major grid-connected capacity increases in South Australia came from large-scale solar (184 megawatts (MW)), large-scale batteries for firming (293 MW), and Bolivar Power Station (123 MW), while no new wind capacity was added. The total installed registered and local capacity of 9,125 MW in 2022-23 is higher than the previous year.
  - Wind farms again provided the largest source of electricity generated, contributing 6,651 gigawatt hours (GWh) and 46.9% of the total electricity generated (up from 44.6% last year).
  - While on a declining trend, gas-powered generation was the second highest contributor to electricity generated, with a 25.4% share (down from 29.5%).
  - Rooftop photovoltaics (PV) provided 17.7% of generation (up from 16.5%) with larger solar (including PV non-scheduled generation (PVNSG)) providing another 8.8% combined. If grouped together, solar technologies for the first time generated more than gas-powered generation in South Australia.
- **South Australia's average wholesale electricity price climbed again** as unprecedented energy market conditions increased prices across the NEM in winter 2022.
- **Minimum demand continued to decline due to continued growth in rooftop PV installations**, with operational demand (sent-out) reaching a then record low of 96 MW on Sunday 16 October 2022[1], when the combination of low weekend demand, mild weather with minimal cooling or heating needs, and solar insolation caused the lowest demand for grid-supplied electricity during the year.
- **Maximum operational demand[2]** occurred on Thursday 23 February 2023, reaching 3,084 MW at 7:30 pm (Adelaide time). La Niña climate conditions meant that, for a third consecutive year, summer did not have any strong heatwaves, moderating the observed demand outcome.
- **Annual consumption saw a reversal of the declining trend observed in recent years.** In 2022-23, operational consumption as sent-out in South Australia was 11,506 GWh, which is 0.5% (59 GWh) higher than the observed 2021-22 total of 11,447 GWh.
- **Net imports from Victoria decreased slightly** from 625 GWh in 2021-22 to 499 GWh in 2022-23 as electricity generation in South Australia grew more than annual consumption.

[1] After the cut-off date for this report, a new record minimum operational demand of 5 MW (as-generated) and 3 MW (sent-out) was reached on Sunday 1 October 2023.

[2] Measured on a sent-out basis, reflecting the demand met by scheduled, semi-scheduled and significant non-scheduled generators.

- Increased penetration of large-scale and distributed renewables saw **total emissions and annual emissions intensity from South Australian generation continue to decline** again in 2022-23, both reaching their lowest level yet (1.94 million tonnes CO2-e and 0.17 tonnes CO2-e per megawatt hour (MWh) respectively).

Major forecasting insights

- **Generation retirements are projected to create reliability risks:**
  - A reliability gap is forecast against the Interim Reliability Measure (IRM) of 0.0006% unserved energy (USE) in 2023-24, due to a combination of factors, including the probability of low wind conditions coincident with high demand. A reliability gap is also forecast in 2026-27, when all four units of Torrens Island B and Osborne Power Station have advised an expectation to have retired.
  - Although the commissioning of Project EnergyConnect Stage 2 is forecast to reduce reliability risks from 2026-27 onwards, AEMO projects a reliability gap against the reliability standard from 2028-29, following the expected retirement of Yallourn Power Station in Victoria and further retirement of gas generators at the end of the horizon including Dry Creek, Mintaro, Port Lincoln and Snuggery power stations.
- Developments on the demand side include:
  - In all scenarios, **distributed PV and battery storage growth is forecast to continue**, although at varied rates with the balance between PV system cost and anticipated retail prices.
  - **Operational consumption (as sent out) is expected to increase** as a result of electrification, including growth in electric vehicle (EV) uptake, as well as growth in business consumption and a slower energy efficiency forecast. Continued growth in distributed PV exceeds that of underlying consumption in the residential sector, reducing the sector's reliance on energy delivered from the grid.
  - **Minimum operational demand is forecast to experience relatively constant decline** of almost 100 MW per year in the shoulder season, where the annual minimum most often occurs. Based on AEMO's central scenario, South Australia may reach negative minimum operational demand (when distributed generation and storage discharge exceeds demand) by 2023-24 in the absence of operational measures to curtail distributed PV.
  - **Maximum operational demand is forecast to continue to occur in summer** around sunset where distributed PV contributes little. It is projected to grow approximately 70 MW per year due to expansion of large industrial loads, and growth in EV uptake and number of electricity connections in general.
- On the supply side:
  - **1,162 MW of new capacity is committed or anticipated, split between wind, solar and storage**; an additional 14,800 MW of projects are proposed but not sufficiently advanced to be committed or anticipated, with around 40% of this being battery storage projects (5,851 MW), while there are 3,369 MW of large-scale solar projects and 4,091 MW wind projects.
  - **Gas-powered generation volumes are forecast to keep falling**, as more renewable energy is connected to the NEM, and Project EnergyConnect increases the capacity to import variable renewable energy (VRE) from New South Wales and Victoria.

- **System security remains a key focus in South Australia**, as the rapid energy transition pushes the system to operate more frequently near its technical boundaries. While AEMO did not declare any new security gaps during 2022-23, and existing gaps are largely expected to reduce following completion of Project EnergyConnect Stage 2, AEMO has increased the size of the previously declared inertia shortfall, and worked closely with ElectraNet on appropriate remediation measures. AEMO is currently performing power system analysis to support its 2023 security reports for publication in December 2023, and will continue to work closely with the South Australian Government, ElectraNet, SA Power Networks, and industry participants to adapt system planning and operations to any newly identified challenges.
- While **the average duration of directions to participants in South Australia has not changed significantly** since the previous SAER, the cost associated with directions compensation has risen sharply in response to the impact of higher-than-average spot prices prevailing in Q2 and Q3 2022.

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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

The SAER provides key independent insights for the South Australian jurisdiction under AEMO's South Australian Advisory Functions (SAAF) in section 50B of the National Electricity Law.

The 2023 SAER consolidates data and insights relevant to South Australia from a range of AEMO publications, including the 2023 *Electricity Statement of Opportunities* (ESOO) for the National Electricity Market (NEM), the 2023 *Gas Statement of Opportunities* (GSOO) for eastern and south-eastern Australia, and the *Quarterly Energy Dynamics* reports. This SAER is supplemented by additional sources that can provide additional data or detail; these sources are listed in Table 1 and noted throughout the report.

Unless otherwise stated, all times are NEM time (equivalent to AEST) and all dollar amounts are in nominal dollars.

1.2 Information sources

AEMO has sourced insights and data in this report from other AEMO publications and used information provided by existing and potential market participants as at 30 September 2023, unless otherwise specified. Generation information specifically is from AEMO's 27 October 2023 update of its Generation Information web page. Reporting of historical observations on the gas and electricity markets is based on the 2022-23 financial year, unless otherwise specified.

Table 1 provides links to additional AEMO information, and Appendix A1 lists additional external sources.

This report is complemented by the 2023 SAER Data File[2], containing the key data used in tables and figures in this report.

Table 1 Information data sources and reference material

Information source	Website address
Relevant publications and methodologies	
2023 *Electricity Statement of Opportunities* (ESOO) ***ESOO and Reliability Forecast Methodology Document***	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities
Electricity Demand Forecasting Methodology ***Demand Side Participation (DSP) Forecasting Methodology***	https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-approach

Information source	Website address
2022 Forecast Accuracy Report	https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/forecasting-accuracy-reporting
2023 Inputs, Assumptions and Scenarios Report **(IASR)**	https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios
2022 *Integrated System Plan* (ISP)	https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan
Transmission Augmentation Information Page	https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/transmission-augmentation-information.
2023 *Gas Statement of Opportunities* (GSOO) for eastern and south-eastern Australia	http://aemo.com.au/Gas/National-planning-and-forecasting/Gas-Statement-of-Opportunities
Quarterly Energy Dynamics	https://www.aemo.com.au/energy-systems/major-publications/quarterly-energy-dynamics-qed
2022 *System Strength Report* **2022 *Inertia Report*** **2022 *Network Support and Control Ancillary Services (NSCAS) Report***	https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/system-security-planning
Additional relevant reference material	
AEMO forecasting portal	http://forecasting.aemo.com.au/
Engineering Framework for the NEM	https://www.aemo.com.au/initiatives/major-programs/engineering-framework
Application of Advanced Grid-scale Inverters in the NEM **– White Paper**	https://www.aemo.com.au/initiatives/major-programs/engineering-framework/reports-and-resources
Distributed Energy Resources (DER) Program	https://www.aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program
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
Generation Information page	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information
Interconnector capabilities report	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Congestion-information/Network-status-and-capability
Historical system strength, inertia and NSCAS assessments	https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/system-security-planning

1.3 Scenarios

AEMO presents forecasts in this SAER and other reports based on scenarios that reflect a plausible range of futures for the pace of change in the energy industry.

Electricity forecasts in the 2023 SAER are consistent with the three scenarios presented in the 2023 ESOO and shown in **Figure 1** and **Table 2** below. **The three scenarios are *Progressive Change*, *Step Change*, and *Green Energy Exports*.** These scenarios were developed in consultation with industry and consumer groups for use in a number of forecasting and planning publications, including the 2023 ESOO and 2024 *Integrated System Plan* (ISP). More information on these scenarios is available in the 2023 *Inputs, Assumptions and Scenarios Report* (IASR).

The 10-year demand and reliability forecasts in the 2023 ESOO and this 2023 SAER include "Central scenario" projections. These Central projections are based on the *Step Change* scenario, to align with the 2023 ESOO. This is consistent with the 2022 SAER, which also reported on the *Step Change* scenario as the Central outlook.

Figure 1 2023 scenarios for AEMO's forecasting and planning publications

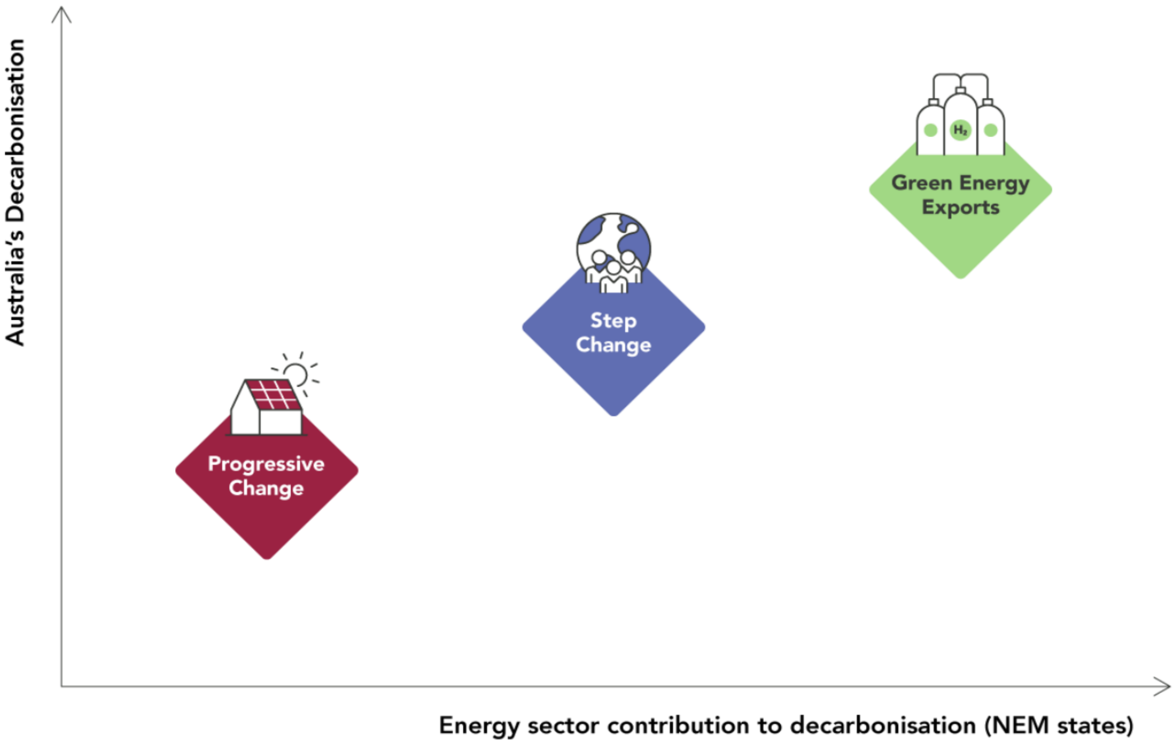


Table 2 Descriptions of AEMO's 2023 forecasting and planning scenarios

Scenario	Scenario description
Progressive Change	Meets Australia's current Paris Agreement commitment of 43% emissions reduction by 2030 and net zero emissions by 2050. This scenario has more challenging economic conditions, higher relative technology costs and more supply chain challenges relative to other scenarios.
***Step Change* (ESOO Central scenario)**	Achieves a scale of energy transformation that supports Australia's contribution to limiting global temperature rise to below 2°C compared to pre-industrial levels. The NEM electricity sector plays a significant role in decarbonisation and the scenario assumes the broader economy takes advantage of this, aligning broader decarbonisation outcomes in other sectors to a pace aligned with beating the 2°C abatement target of the Paris Agreement. The NEM's contribution may be compatible with a 1.5°C abatement level, if stronger actions are taken by other sectors of Australia's economy simultaneous with the NEM's decarbonisation. Consumers provide a strong foundation for the transformation, with rapid and significant continued investments in CER, including electrification of the transportation sector.
Green Energy Exports	Reflects very strong decarbonisation activities domestically and globally aimed at limiting temperature increase to 1.5°C, resulting in rapid transformation of Australia's energy sectors, including a strong use of electrification, green hydrogen and biomethane. The NEM electricity sector plays a very significant role in decarbonisation.

2 Demand and consumption

As projected, operational (grid) consumption in South Australia increased in 2022-23, despite a downward trend in previous years. Consumption is expected to continue to increase in 2023-24, with electrification of stationary energy loads and transport expected to drive up consumption and more than offset the forecast reduction from continued growth in distributed photovoltaics (PV) and energy efficiency.

South Australia's high penetration of distributed PV, which reduces operational consumption during daylight hours, is impacting both maximum and minimum demand. Operational maximum demand now occurs late in the day, at times when distributed PV contributes little to consumers' energy needs. Minimum operational demand now occurs during the middle of the day, when distributed PV operates most, and it is forecast to keep declining as distributed PV penetration continues to grow.

For more information:

- 2023 IASR (used in 2024 ISP) and the 2022 Forecasting Assumption Update, at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp.
- 2023 ESOO, at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nemforecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo.
- AEMO forecasting portal, at http://forecasting.aemo.com.au/.
- AEMO *Forecast Accuracy Report*, at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/forecasting-accuracy-reporting.

2.1 Demand and consumption inputs and assumptions

AEMO updates its projections of energy consumption and demand at least annually[3]. The inputs and assumptions used in these forecasts are developed and refined in significant stakeholder consultation through the Forecasting Reference Group (FRG), industry engagement via surveys, consultant data and recommendations.

The IASR[4] contains detail about inputs, assumptions, and scenarios. AEMO publishes specific detail about how these inputs support forecasts of electricity consumption and maximum/minimum demand in the Electricity Demand Forecasting Methodology[5].

For gas demand forecasting, the GSOO's demand forecasting methodology[6] also outlines the usage of these key inputs.

[3] Updated forecasts within a year can be issued in case of material change to input assumptions.

[4] At https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

[5] At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2023/forecasting-approach_electricity-demand-forecasting-methodology_final.pdf.

[6] At https://aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2023/2023-gas-statement-of-opportunities-methodology---demand-forecasting.pdf.

AEMO uses a range of historical data to train and develop component models, including:

- Operational demand meter reads.
- Estimated network loss factors.
- Other non-scheduled generators.
- Distributed PV uptake.
- Gridded solar irradiance and resulting estimated distributed PV normalised generation.
- Weather data (such as temperature and humidity levels).

Section 2.1.1 summarises scenario-specific drivers and input forecasts related to:

- Electrification pathways (businesses and households switching from other fuels – such as natural gas – to electricity), and uptake and charging of electric vehicles (EVs).
- The potential impacts of a hydrogen industry in Australia.

Section 2.1.2 shows South Australian forecasts for consumer energy resources (CER), specifically rooftop PV, PV non-scheduled generation (PVNSG), and behind-the-meter battery storage. These component forecasts include consideration of CER uptake and generation/charging/discharging patterns, including potential aggregation and coordinated charging/discharging opportunities for CER, such as virtual power plants (VPPs) and vehicle-to-grid (V2G) vehicle charging patterns.

Section 2.1.3 summarises LIL assumptions and outlines alternative assumptions explored by Electranet in their Transmission Annual Planning Report (TAPR).

Other key components in the consumption and demand forecasts include:

- Economic and population growth drivers, including meter connections.
- Climate.
- Energy efficiency.

2.1.1 Electrification and hydrogen

Electrification, including electric vehicles

AEMO has forecast a range of electrification outcomes across different scenarios:

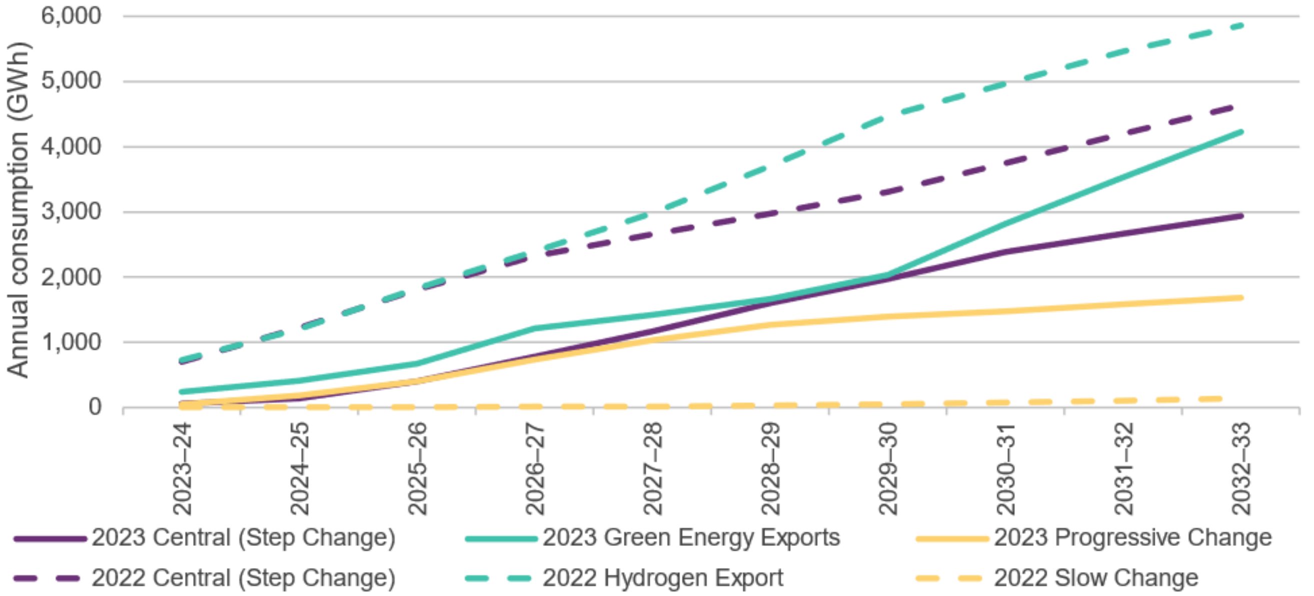
- In the residential and commercial (building) sectors, the scale of electrification will depend on factors including appliance replacement costs, electricity infrastructure capabilities and costs, and the cost and availability of alternative fuels, such as hydrogen or blended hydrogen-natural gas. Additionally, the ongoing costs, efficiency and emissions-intensity of existing fuels such as natural gas, diesel, and other fuel supplies are influences in forecasting electrification outcomes.
- The industrial sector has a broad range of subsectors, each with a different degree of technical potential to switch from traditional fuels such as oil and gas to electricity. A key motivation to a business for making this switch is the extent to which it intends to reduce its carbon emissions (or is required to under policy initiatives, for example to meet its obligations under the Safeguard Mechanism).

- Electrification of road and non-road transport is expected in all scenarios to varying degrees.

Figure 2 shows the magnitude of the electrification forecast, including transport (EVs), for each scenario. The 2023 forecast is lower than that expected in 2022 in the short term, as the scale of electrification previously anticipated is not supported by latest data. Additionally, the multi-sector modelling for 2023 IASR indicated a diminished long-term outlook informed by work on the Australian Industry Energy Transitions Initiative (ETI)[7]. However, electrification remains a large driver for electricity consumption growth, and by 2032-33 the 2023 forecasts still anticipate that between 1,683 gigawatt hours (GWh) and 4,233 GWh of new electricity consumption will emerge. Consumption from EVs is estimated at 13.5 GWh in 2022-23 (7,500 vehicles) to 1192 GWh in 2032-33 (1,437,000 vehicles).

While the SAER focuses on the next 10 years, AEMO has forecast the scenarios to 2052-53[8], and projects an electrification impact for South Australian underlying consumption of just over 9,000 GWh in the *Step Change* scenario, with 3,381 GWh of this being from residential and business stationary loads and the remaining 5,696 GWh from EV adoption. By 2052-53, the forecast electrification impacts are approximately 62% of today's underlying consumption.

Figure 2 Electrification and electric vehicle forecast consumption (GWh) for South Australia, 2023-24 to 2032-33



Hydrogen

The South Australian Government is supporting several green hydrogen projects to promote a local hydrogen industry[9]. In September 2023, the Commonwealth and South Australian governments announced funding for the Port Bonython Hydrogen Hub near Whyalla, which is expected to host hydrogen export projects worth up to $13 billion. The South Australian Hydrogen Jobs Plan[10] intends to build 250 megawatts (MW) of electrolysers, 200 MW of power generation, and hydrogen storage (commissioning is estimated to occur late in 2025). The

[7] See https://energytransitionsinitiative.org/.

[8] The full forecasts are available from AEMO's forecasting portal: http://forecasting.aemo.com.au/Electricity/AnnualConsumption/Operational.

[9] See https://www.energymining.sa.gov.au/industry/modern-energy/hydrogen-in-south-australia.

[10] See https://www.ohpsa.sa.gov.au/projects/hydrogen-jobs-plan.

$240 million H2U Eyre Peninsula Gateway Hydrogen Project is also currently in development. The initial stage includes plans for the installation of a 100 MW electrolysis plant near Whyalla, capable of producing enough hydrogen to create 40,000 tonnes of ammonia each year, and with a target completion date of late 2023[11].

Hydrogen facilities are expected to be capable of operating with high degrees of flexibility, minimising exposure to periods of high scarcity pricing and operating when abundant renewable energy is available.

Hydrogen development remains a key uncertainty affecting the scale of energy consumption for the NEM, and for each region. As such, AEMO's planning scenarios apply differing assumptions to hydrogen development, from a relatively modest development that largely follows current policy drivers only, to the potential for significant green energy exports which would develop if renewable energy were abundant, enabling greater domestic fuel substitution as well.

The 2023 hydrogen forecasts have, however, been tempered relative to the scale of hydrogen development in the previous forecast's *Hydrogen Superpower* scenario.

2.1.2 Consumer energy resources

In the ESOO, AEMO reports on total distributed PV, which includes both small rooftop systems and other non-scheduled PV capacity. The SAER breaks down total distributed PV into individual forecasts for small rooftop PV[12] systems and for larger PV non-scheduled generation (PVNSG)[13], and forecasts growth in both installed capacity and the amount of energy generated by these systems.

The following sub-sections discuss the capacity outlook for each category. AEMO forecasts the uptake of each PV type, and that capacity uses normalised generation half-hourly profiles (source: Solcast) to forecast distributed PV generation. Further information is available in AEMO's consultant reports (CSIRO[14] and GEM[15]) that serve as inputs to AEMO's 2023 forecasts.

Rooftop PV capacity

Total installed rooftop PV capacity in South Australia has grown strongly since 2009, and continues to grow, with South Australia now having over 362,000 residential installations[16] and 45% penetration for dwellings[17] in residential rooftop PV, the highest of all NEM regions.

Current installed capacity estimates for rooftop PV are from the Clean Energy Regulator, validated against AEMO's DER Register.

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[11] See https://www.energymining.sa.gov.au/industry/modern-energy/hydrogen-in-south-australia/hydrogen-projects-in-south-australia/the-hydrogen-utility-h2u-eyre-peninsula-gateway.

[12] Rooftop PV is defined as behind-the-meter systems, installed by households and businesses typically, up to 100 kilowatts (kW) capacity. "Business PV" in this report means business rooftop PV.

[13] PVNSG is defined as PV systems with a capacity between 100 kW and 30 MW. These are typically very large rooftop PV systems and small solar farms below AEMO's registration threshold of 30 MW.

[14] See https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/csiro-2022-solar-pv-and-battery-projections-report.pdf.

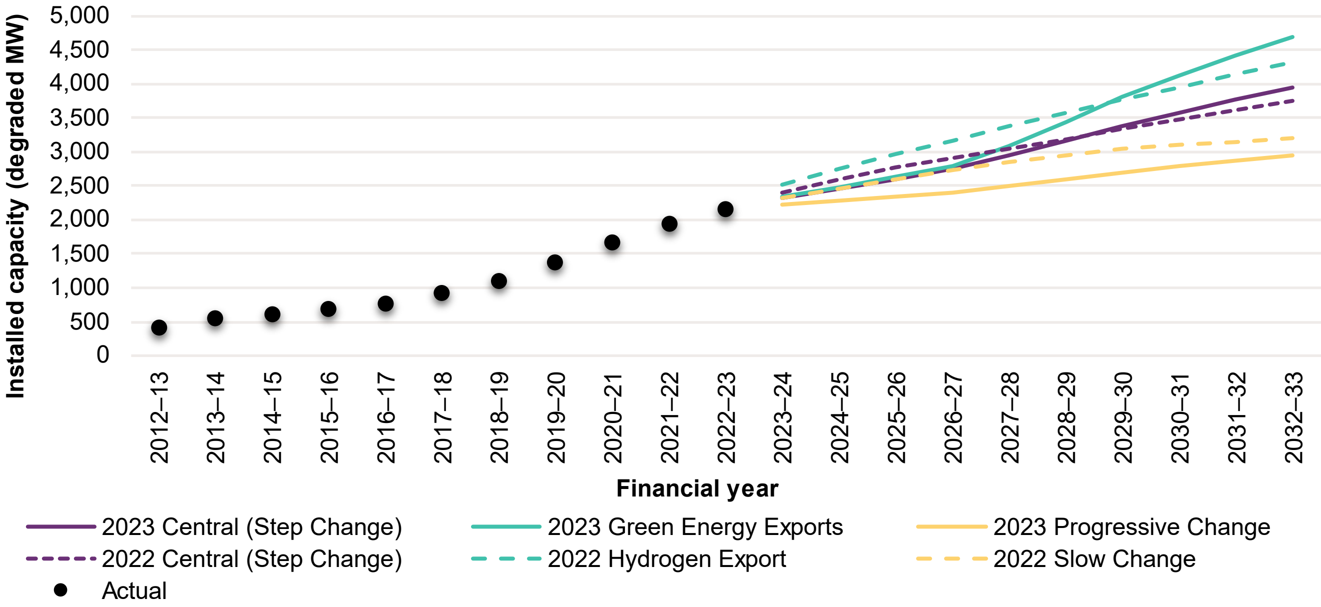
[15] See https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/gem-2022-solar-pv-and-battery-projection-report.pdf.

[16] See *Small generation unit – solar (deemed)* at https://www.cleanenergyregulator.gov.au/RET/Forms-and-resources/Postcode-data-for-small-scale-installations#Postcode-data-files. The data was adjusted by AEMO's known residential/business split.

[17] Dwellings estimated from AEMO's records of residential electricity connections.

Figure 3 shows estimated actual rooftop PV installed capacity since 2012-13 and the 10-year forecast for installed capacity under all scenarios in the 2023 ESOO, including a comparison to the scenarios in the 2022 ESOO.

Figure 3 Actual and forecast South Australian rooftop PV installed capacity, 2012-13 to 2032-33



This shows that under all scenarios but *Green Energy Exports*, growth in installed capacity is forecast to continue at a similar rate (albeit potentially slightly slower in the coming years than in recent years). As PV system costs are forecast to reduce, there is potential for an even faster rate of installation (as observed after 2027 in the forecasts).

Figure 4 shows estimated actual annual rooftop PV generation since 2012-13 and the 10-year forecast under all scenarios, including a comparison to the Central scenario in the 2022 ESOO:

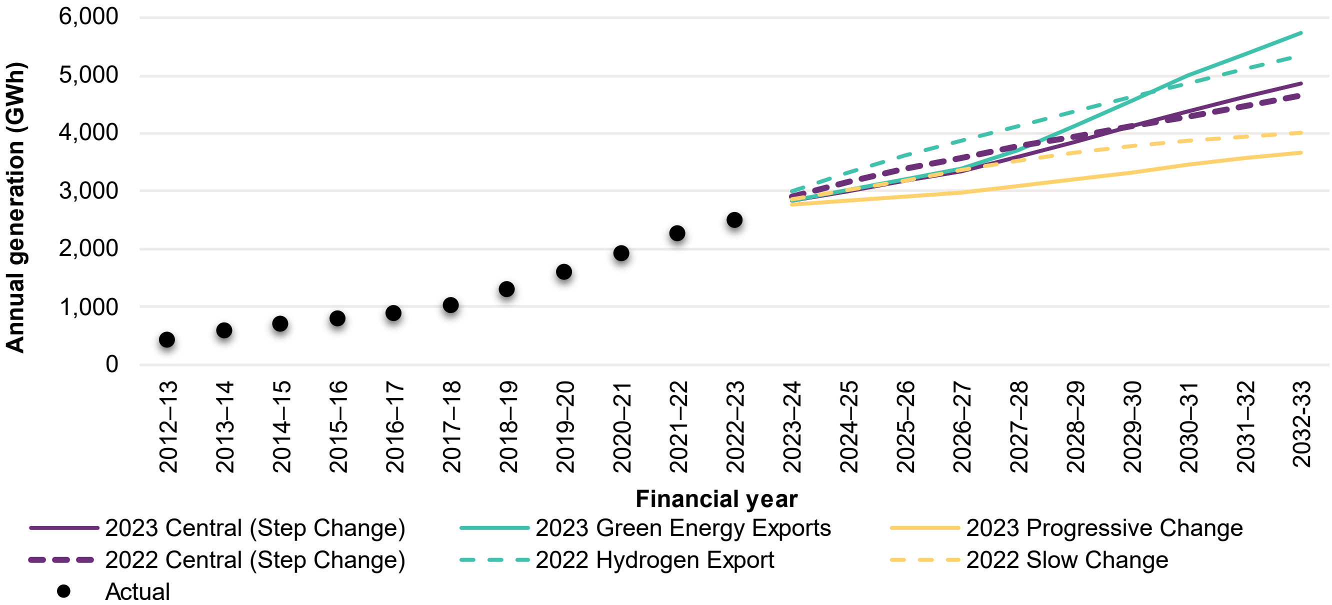
- In 2022-23, annual rooftop PV generation was estimated at 2,505 GWh[18], or 19% of total annual underlying consumption[19].
- In the Central scenario, it is forecast to increase to 4,869 GWh by 2032-33, which would represent approximately 22% of annual underlying consumption at that time in South Australia.
- Over the next 10 years, South Australia is projected to have the highest ratio of rooftop PV generation to operational consumption[20] of all NEM regions.

[18] Estimates calculated for the financial year 2022-23 for the 2023 IASR.

[19] Underlying consumption means all the electricity used by consumers, which can be sourced from the grid but also, increasingly, from other sources including consumers' distributed PV and battery storage.

[20] Operational consumption and demand are drawn from the grid and supplied by large-scale generation.

Figure 4 Actual and forecast South Australian rooftop PV generation, 2012-13 to 2032-33



PV non-scheduled generation (PVNSG) forecasts

Figure 5 shows South Australia's PVNSG capacity since 2016-17, and the 10-year forecast for installed capacity under all scenarios, including a comparison to the Central scenario in the 2021 ESOO:

- PVNSG installations have slowed in the past two years relative to the strong trend otherwise seen since 2016-17, influenced by moderated wholesale electricity prices at time of solar generation. This was also observed in other NEM regions.
- The 2023 IASR estimates PVNSG installed capacity on 30 June 2023 was 251 MW, and is forecast to grow in the Central scenario to 652 MW by 2032-33.

Figure 5 Actual and forecast South Australian PVNSG installed capacity, 2016-17 to 2032-33

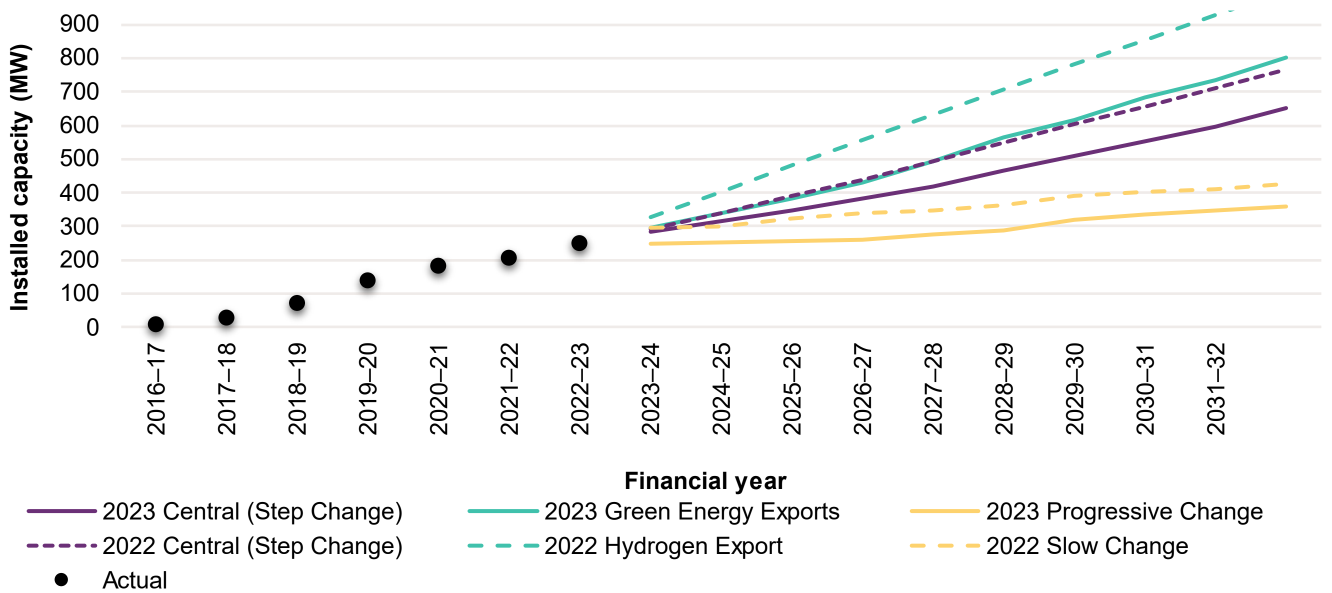
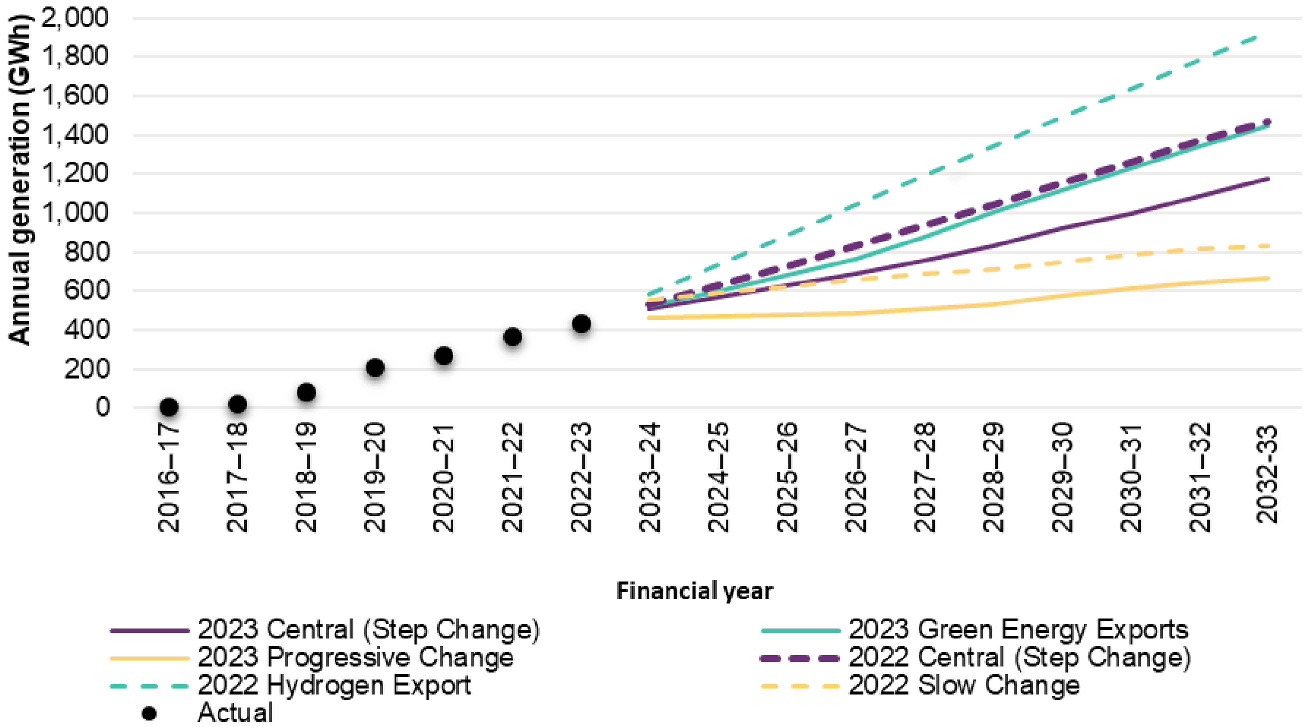


Figure 6 shows PVNSG actual generation since 2016-17 and the 10-year forecast under all scenarios. As shown in the figure, PVNSG generation was estimated at 436 GWh in 2022-23. In the Central scenario, it is forecast to increase to 1,178 GWh by 2032-33.

Figure 6 Actual and forecast South Australian PVNSG generation, 2016-17 to 2032-33



Distributed battery storage forecast

Behind-the-meter residential and commercial battery systems have the potential to change the future demand profile in South Australia, particularly maximum and minimum operational demand.

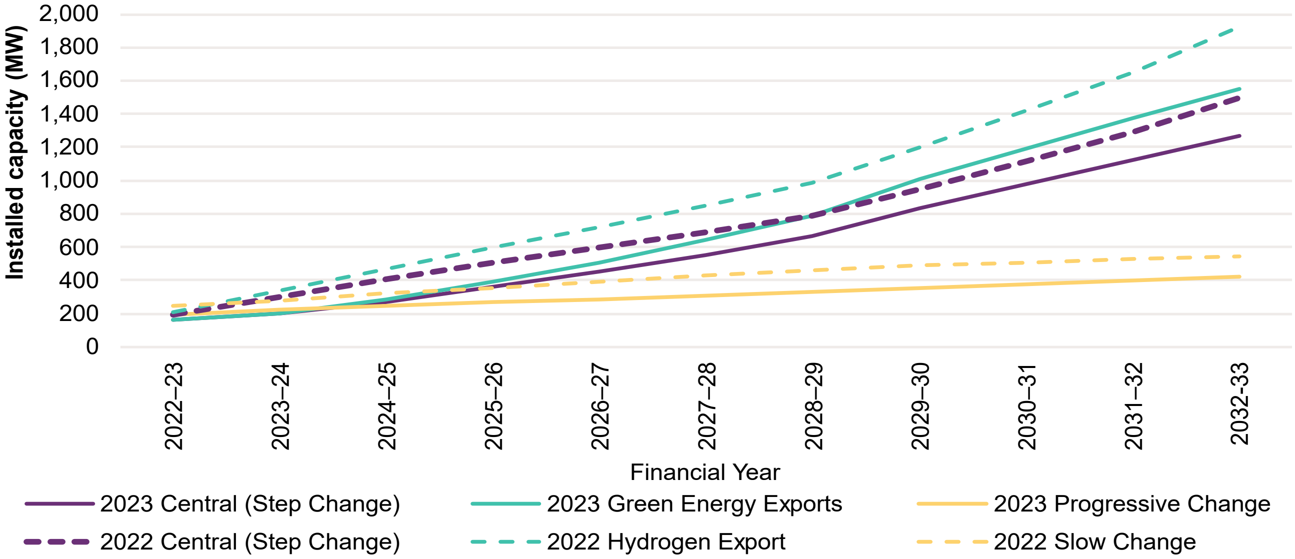
As at 30 June 2023, South Australia has an estimated 165 MW of embedded battery systems (from over 35,000 units[21]).

By 2032-33, uptake of business and residential behind-the-meter battery systems is forecast to reach approximately 1,266 MW (in the Central scenario) and up to 1,553 MW (in the *Green Energy Export* scenario). Battery uptake forecasts in the 2023 forecasts include a delay in the anticipated uptake, as installations have not been observed to be as strongly connecting as had been previously forecast, leading to an adjustment for the 2023 forecasts. The long-term battery uptake outlook reflects the expectation that unit prices will continue to fall.

Figure 7 shows the 10-year forecast installed capacity of customer battery systems in South Australia for all scenarios, relative to the 2022 forecasts.

[21] AEMO's IASR 2023 forecasts estimate approximately 35,813 units.

Figure 7 Behind-the-meter battery capacity forecasts for South Australia, 2022-23 to 2032-33



Battery storage systems will operate to store surplus solar production (if part of an integrated battery and solar system) and shift this energy for use to meet evening peak demands. The effectiveness of battery systems to support household consumption will be influenced by pricing incentives, and there will be broader system benefits if the battery fleet is actively managed, or orchestrated, for example through a VPP arrangement. This orchestration would mitigate the need for more utility-scale resources, and the associated cost savings are assumed to benefit consumers in the 2023 forecasts, as retailers and orchestrators encourage this resource type.

AEMO has recently published the results of Project Edge[22], a trial designed to demonstrate market participants effectively collaborating to deliver VPP services to consumers. The trial, which reports a positive cost benefit analysis for VPP, lends momentum to a variety of earlier South Australian trials in indicating the technical feasibility, technical benefits, and overall benefits of VPP operation.

2.1.3 Large industrial loads

AEMO forecasts LIL across various sectors based on:

- Direct surveying of existing facility operators about expected consumption, maximum demand and closure date (if known).
- Information from ElectraNet and South Australian Power Networks about committed and prospective loads.

AEMO's scenarios presented in the following explore different combinations of future load growth from LIL based on the information sourced above, and modelling of industry developments longer term (including electrification of industrial fossil fuel use and emerging technologies like green steel production).

In addition to LILs included in AEMO's scenarios, ElectraNet has identified several potential projects which, if realised, could represent substantial growth in consumption from LILs, particularly in the mid-North region of the state. These projects are anticipated to start between 2025 and 2028. A predicted consumption profile which

[22] See https://aemo.com.au/en/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-demonstrations/project-edge.

includes these additional loads can be found in Figure 16 of the Electranet Transmission Annual Planning Report 2023[23]. These projects are yet to demonstrate sufficient commitment to meet AEMO's commitment criteria for inclusion in AEMO's 2023 Central scenario. The additional growth in the *2023 Green Energy Exports* scenario exceeds the estimated consumption attributed to these loads from 2027 onwards.

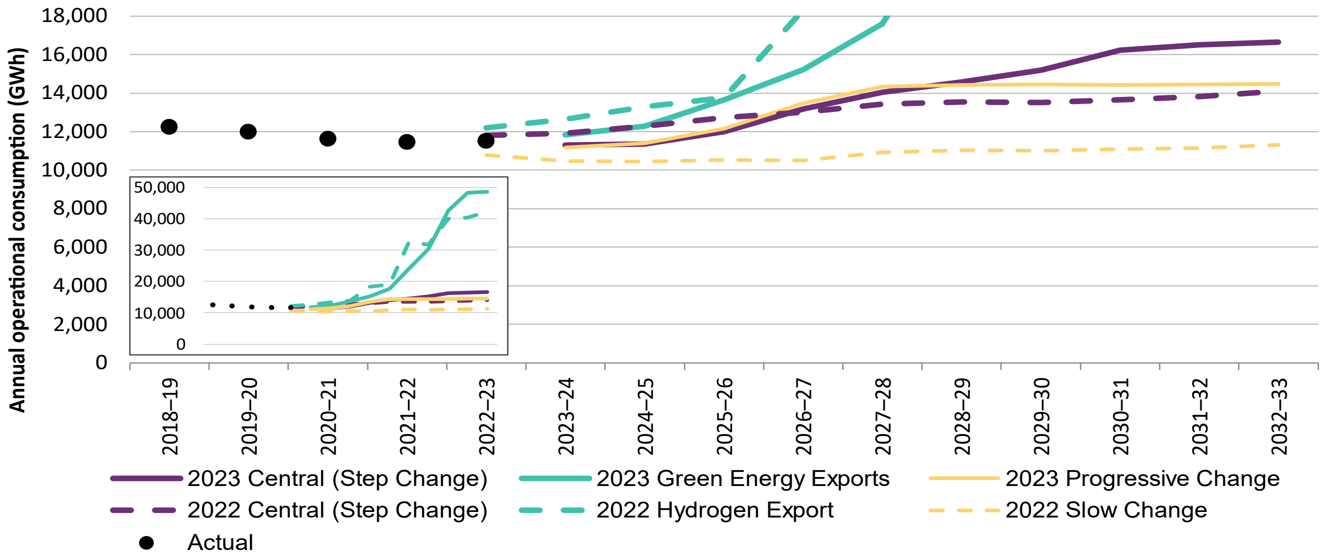
2.2 Historical and forecast consumption

2.2.1 Operational consumption

Figure 8 shows South Australia's actual sent-out operational consumption since 2018-19 and forecast annual sent-out operational consumption to 2032-33[24].

In 2022-23, operational consumption as sent-out in South Australia was 11,506 GWh. This is 0.5% (59 GWh) higher than the 2021-22 total of 11,447 GWh. As discussed in Section 2.1, electricity consumption is expected to increase as a result of electrification, including adoption of EVs, as well as growth in business consumption and a slower forecast of energy efficiency savings. On the other hand, continued growth in rooftop PV helps address increasing electricity needs, reducing operational consumption.

Figure 8 Annual operational consumption (sent-out) actual and forecast for South Australia, 2018-19 to 2032-33 (GWh)



Note: *2023 Green Energy Exports* and *2022 Hydrogen Export* continue beyond the main chart to reach approximately 40,000 GWh and 50,000 GWh in 2032-33, respectively (see inset).

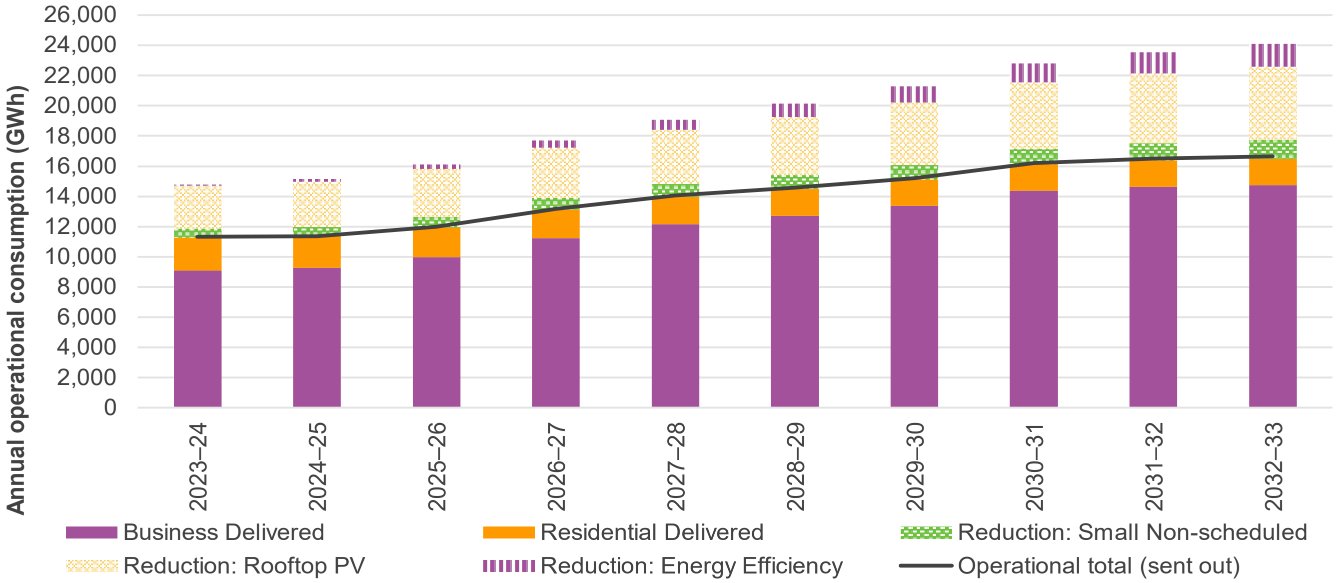
The outlook for South Australia under the Central scenario is an overall increase in operational consumption of 45% to 16,636 GWh in 2032-33. In this scenario, growth in consumption is steeper from 2026-27 due to increased electrification and hydrogen production in the business sector (including due to the development of projects supported by government policy).

[23] See https://www.electranet.com.au/wp-content/uploads/231115_2023-TAPR.pdf.

[24] Operational consumption is supply to the grid by scheduled, semi-scheduled, and significant non-scheduled generators. "Sent-out" excludes auxiliary loads (energy used by the generator to produce electricity). Published sent-out totals may be revised as more data on auxiliary loads becomes available.

Figure 9 shows forecast operational consumption by sector to 2032-33 under the Central scenario. Components below the operational total (sent-out) line are items that consume energy. Components above this line offset growth, for example by saving energy through energy efficiency improvements, or self-generation from distributed PV systems.

Figure 9 Forecast annual South Australia electricity consumption for the Central scenario, 2023-24 to 2032-33 (GWh)



Data source: AEMO forecasting portal, at http://forecasting.aemo.com.au/.

The forecast rise in operational consumption (sent-out) over the next decade is primarily from the business sector, while the residential sector shows a modest decline over this period due to increasing distributed PV uptake. Further breakdowns of the residential and business sector forecasts are presented in Section 2.2.2 and Section 2.2.3

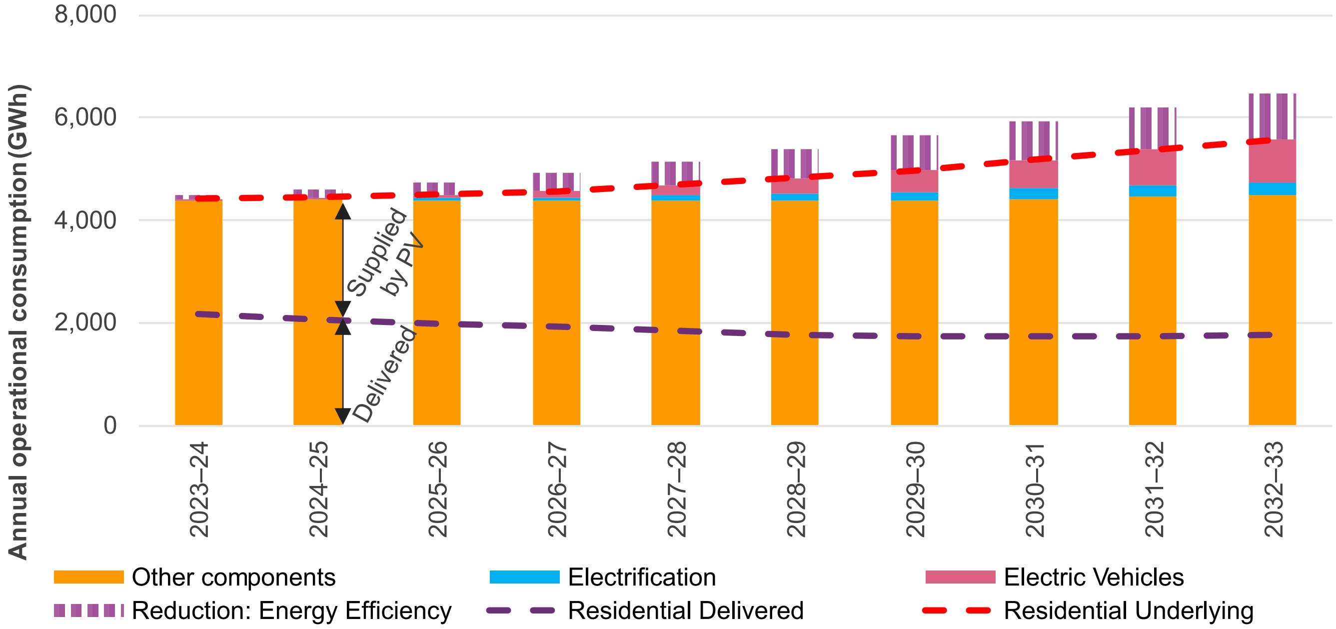
The forecasts vary by scenario from 2022-23 to 2032-33:

- The *Green Energy Exports* scenario sees the greatest net increase in operational consumption, reaching approximately 48,700 GWh by 2032-33. The growth trajectory is dominated by hydrogen production for domestic and export markets, which represents 33,000 GWh of consumption. Additional growth is mainly attributed to electrification of stationary loads and transportation (4,200 GWh). This total growth is partially offset by strong penetration of rooftop PV (5,700 GWh).
- In the *Progressive Change* scenario outlook for 2032-33, hydrogen production is considerably lower (1,300 GWh). Other drivers of consumption growth are steady electrification of stationary loads (1,200 GWh) and EV uptake (500 GWh). Rooftop PV capacity is only projected to reach 3,700 GWh over this decade, leading to an increase in net operational consumption of approximately 3,000 GWh to 14,490 GWh by 2032-33.

2.2.2 Residential sector – underlying and delivered consumption[25]

Figure 10 presents a breakdown of residential sector electricity forecasts for South Australia. Underlying residential consumption is driven predominately by new connections growth and electrification (transport and conversion from gas appliances).

Figure 10 Components of South Australia residential electricity consumption forecast, Central scenario, 2023-24 to 2032-33 (GWh)



Over the next decade, growth in underlying residential consumption is expected to be moderate, increasing from approximately 4,400 GWh in 2022-23 to 5,600 GWh in the Central scenario, 5,000 GWh in *Progressive Change*, and 6,300 GWh in *Green Energy Exports*. Residential rooftop PV generation currently meets approximately 45% of South Australian underlying annual energy consumption, providing 2,000 GWh of generation in 2022-23 and leaving approximately 2,400 GWh to be delivered from the grid. Across all scenarios, strong growth in PV installations in the next decade is forecast to surpass the smaller growth in underlying demand, resulting in a net reduction of energy delivered from the grid.

By 2032-33, residential rooftop PV is forecast to provide approximately 56% to 72% of underlying residential consumption, with grid-delivered electricity ranging from 1,800 GWh to 2,200 GWh across the scenarios.

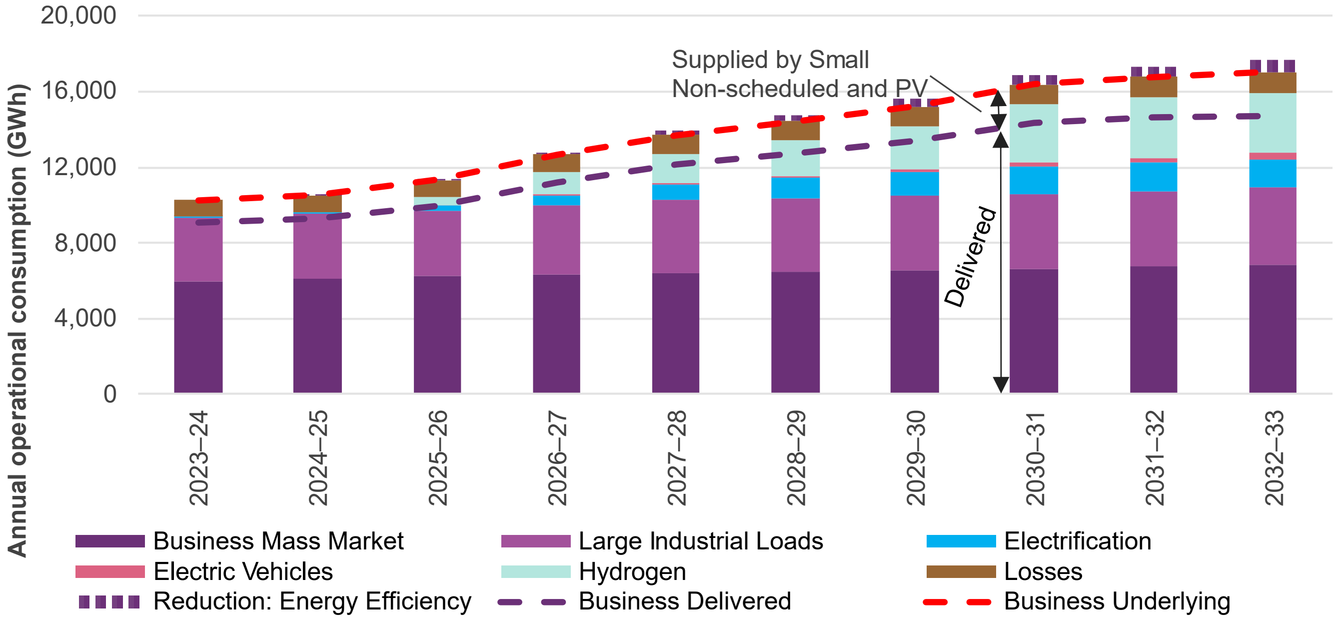
2.2.3 Business sector – underlying and delivered consumption

Figure 11 presents a breakdown of business sector electricity forecasts for South Australia. Underlying business consumption is forecast to increase from approximately 10,200 GWh in 2022-23 to 17,000 GWh in 2032-33 in the Central scenario, and to as high as 49,500 GWh in *Green Energy Export*. This is driven by electrification, LIL

[25] Delivered consumption is underlying consumption less rooftop PV, so the amount of electricity provided from the grid to consumers. Reporting delivered consumption helps in isolating and discussing the impact of rooftop PV.

growth, and emerging hydrogen production to meet the South Australian Hydrogen Jobs Plan, tempered by continued uptake of distributed PV and energy efficiency investment.

Figure 11 Components of South Australia business electricity consumption forecast, Central scenario, 2023-24 to 2032-33 (GWh)



In summary:

- Across all scenarios, consumption from large industrial loads is forecast to increase from 3,200 GWh in 2022-23 to between 3,900 and 5,400 GWh by 2032-33.
- Consumption from business mass market customers is also forecast to rise at a steady rate over the next decade, increasing by 300-900 GWh by 2032-33.
- Hydrogen production is the dominant growth driver in the *Green Energy Exports* scenario, accounting for 32,800 GWh by 2032-33. Smaller amounts of hydrogen production are expected in the Central scenario (3,100 GWh) and *Progressive Change* (1,300 GWh) scenarios over the next decade (to meet primarily policy objectives regarding the *Hydrogen Jobs Plan*).
- Projected electrification of stationary business loads sees a considerable increase in the next decade, reaching 1,000 GWh (*Progressive Change*) to 2,300 GWh (*Green Energy Exports*). Uptake of EVs in the business sector contributes more modest consumption of 100 GWh (*Progressive Change*) to 700 GWh (*Green Energy Exports*) by 2032-33, reaching 400 GWh in the Central scenario.
- Steady uptake of PV generation is forecast to continue in the business sector, offsetting operational consumption. Across the scenarios, rooftop PV is expected to grow by 300-600 GWh, while PVNSG is also expected to grow by between 200 GWh and 1,000 GWh. See Section 2.1.2 for further discussion on PVNSG.
- The resultant delivered consumption for the sector is forecast to increase from 9,100 GWh in 2022-23 to 14,700 GWh in the Central scenario by 2032-33. The equivalent figures for *Progressive Change* and *Green*

Energy Exports scenarios are 12,300 GWh and 46,700 GWh of delivered consumption in the business sector, respectively.

2.2.4 Other potential industrial load growth

In addition to consumption forecasts included in this section, ElectraNet has identified several potential projects which, if realised, could represent substantial growth in consumption from LILs, particularly in the mid-North region of the state. These projects are anticipated to start between 2025 and 2028. A predicted consumption profile which includes these additional loads can be found in Figure 16 of the Electranet Transmission Annual Planning Report 2023[26]. These projects are yet to demonstrate sufficient commitment to meet AEMO's commitment criteria for inclusion in AEMO's 2023 Central scenario. The additional growth in the *2023 Green Energy Exports* scenario exceeds the estimated consumption attributed to these loads from 2027 onwards.

2.3 Maximum demand and minimum demand

2.3.1 Operational maximum demand

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

The large levels of installed distributed PV capacity in South Australia are a major contributing factor for the timing of maximum operational demand. As **Table 3** (later in this section) shows, since 2017-18, the time of maximum operational demand has occurred in the evening, when there is little to no generation from distributed PV.

On Thursday 23 February 2023, operational demand in South Australia reached 3,084 MW (measured on a sent-out basis) at 7:30 pm (Adelaide time) with a temperature of 39.8°C recorded at Adelaide (West Terrace/Ngayirdapira) earlier that day. At the time of the maximum demand, the Adelaide temperature had cooled to approximately 34.5°C, but load remained high in response to the higher daytime temperature. La Niña climate conditions meant that, for a third consecutive year, summer did not have any strong heatwaves with temperatures in the mid to high forties, which have commonly been observed in previous years.

Rooftop PV generation at the time of the maximum demand was very low (estimated 80 MW), due to low solar irradiance in the evening.

With maximum operational demand events tending to occur at times when PV generation is low, further increases in distributed PV capacity will have minimal impact on maximum operational demands.

Forecast operational maximum demand

Annual maximum operational demand is forecast to continue to occur in summer, and is expected to grow slightly, due to expansion of large industrial loads, growth in EVs, and increased connections.

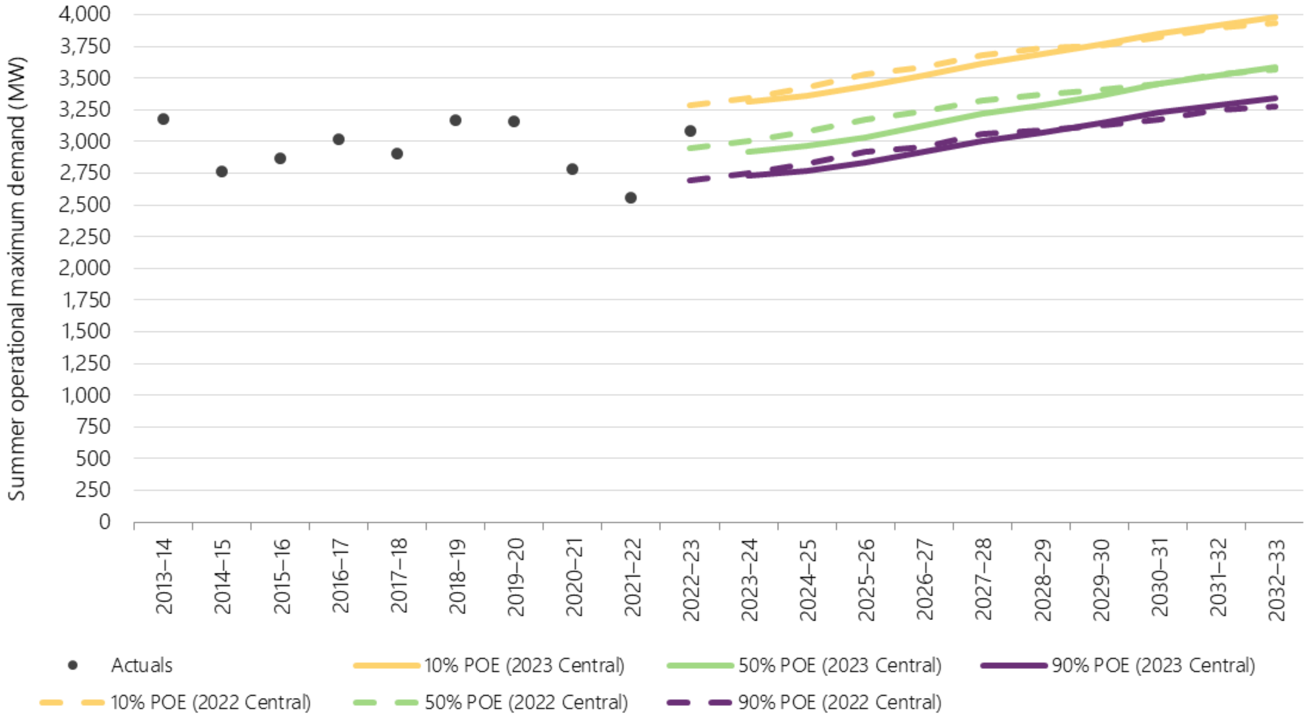
Figure 12 shows historical summer maximum demand actuals since 2013-14, and 10%, 50%, and 90% probability of exceedance (POE)[27] forecasts from the 2023 and 2022 NEM ESOOs (Central scenario). With limited offset for

[26] See https://www.electranet.com.au/wp-content/uploads/231115_2023-TAPR.pdf.

[27] POE is the probability a forecast will be met or exceeded. The 10% POE maximum demand forecast (and 90% minimum demand forecast) is mathematically expected to be met or exceeded once in 10 years and represents demand under more extreme weather conditions than a 50% POE forecast, which is expected to be met or exceeded once every two years.

PV due to the late peaks, maximum operational demand (50% POE, Central scenario) is forecast to grow significantly over the next 10 years driven by forecast growth in population, electrification and the economy overall.

Figure 12 Actual and forecast summer operational maximum demand (sent-out) for South Australia (Central scenario), 2013-14 to 2032-33 (MW)

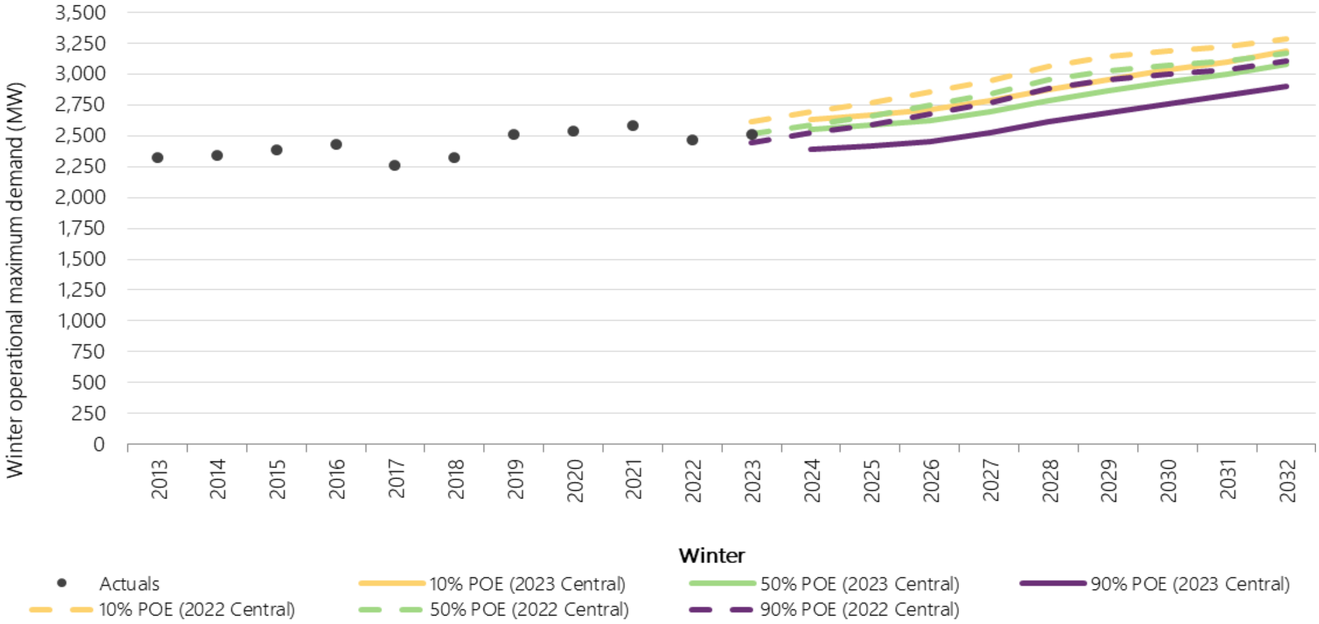


EV growth is projected to have some impact on maximum operational demand, although it will depend on the time of day that vehicle charging occurs. AEMO forecasts several charging profiles, with daytime (to maximise the use of rooftop PV generation) and overnight (taking into account lower tariffs offered for overnight consumption) charging more preferable for grid reliability than convenience charging that may amplify evening peak demands. At this stage of EV adoption, high uncertainty remains regarding the impact that EV charging will have, and will depend on the effectiveness of consumer preferences (and incentives) to operate in a manner that minimises the strain on grid while still maintaining broad convenience.

As Figure 12 shows, the maximum summer operational demand observed in 2022-23 was slightly above the 50% POE forecast. The temperature at time of peak corresponds to a median (50% POE) outcome, but the actual peak demand was higher than 50% POE given the impact of consecutive hot days with little temperature relief (which tends to increase cooling appliance use). For example, the temperature on 23 February 2023 started high, reaching 31.3°C as early as 9:00 AM local time, and the preceding two days had temperatures exceeding 35°C.

Figure 13 below shows the forecast for South Australia's operational maximum demand in winter. In winter 2023, a maximum demand of 2,510 MW was reached on 22 June 2023 at 6:00 pm (Adelaide time). With shorter days in winter, evening peaks have no offset from PV generation, and therefore winter peaks are driven by forecast growth in population, electrification and the economy overall. Winter maximum demand is – like summer demand – projected to grow significantly over the next 10 years.

Figure 13 Actual and forecast winter operational maximum demand (sent-out) for South Australia (Central scenario), 2013 to 2032 (MW)



Note: Winter analysis uses calendar years to capture the full winter period from June to August.

Impact of distributed PV on underlying maximum demand

Over the last decade, growth in rooftop PV generation in South Australia has gradually shifted the time of maximum operational demand from occurring late afternoon or early evening to happen later into the evening. The typical time of peak is now 7:30 pm to 8.00 pm Adelaide time in summer, when solar irradiance is low. In the last five years, no rooftop PV generation has been observed during winter maximum demand periods as they occur in the evening.

Table 3 shows estimated distributed PV generation at the time of underlying and operational maximum demand for the last five years, illustrating that the contribution of distributed PV at time of underlying maximum demand has grown over time, while its contribution at time of operational maximum demand remains low.

Table 4 shows this data for winter maximum demand. Historically, there has been no PV output during either underlying or operational winter maximum demand, but in the last couple of years, cold mornings have caused underlying peak to be 9:30 AM local time, but the generation of distributed PV at that time pushed the operational peak to the evening when PV no longer contributes.

Table 3 Distributed PV contribution to underlying and operational summer maximum demand in South Australia

Year	Distributed PV contribution to underlying maximum demand (MW)	Date and time of underlying maximum demand (Adelaide time)	Distributed PV generation at the time of operational maximum demand (MW)	Date and time of operational maximum demand (Adelaide time)
2017-18	360	19/01/2018 5:00 PM	58	18/01/2018 7:30 PM
2018-19	413	24/01/2019 5:00 PM	19	24/01/2019 8:00 PM
2019-20	490	19/12/2019 5:00 PM	58	19/12/2019 7:30 PM
2020-21	451	18/02/2021 6:00 PM	82	18/02/2021 7:30 PM
2021-22	1,018	11/01/2022 3:30 PM	121	11/01/2022 7:30 PM
2022-23	846	23/02/2023 5:00 PM	80	23/02/2023 7:30 PM

Table 4 Distributed PV contribution to underlying and operational winter maximum demand in South Australia

Calendar year*	Distributed PV contribution to underlying maximum demand (MW)	Date and time of underlying maximum demand (Adelaide time)	Distributed PV generation at the time of operational maximum demand (MW)	Date and time of operational maximum demand (Adelaide time)
2018	0	26/06/2018 6:30 PM	0	26/06/2018 6:30 PM
2019	0	24/06/2019 6:30 PM	0	24/06/2019 6:30 PM
2020	0	7/08/2020 6:30 PM	0	7/08/2020 6:30 PM
2021	0	22/07/2021 6:00 PM	0	22/07/2021 6:00 PM
2022	531	6/07/2022 9:30 AM	0	22/08/2022 6:30 PM
2023	746	19/07/2023 9:30 AM	0	22/06/2023 6:00 PM

* Winter analysis uses calendar year to capture the full winter period from June to August

Demand side participation (DSP)

An alternative to adding grid generation to help meet maximum operational demand is to seek resources on the demand side to reduce consumption. 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 (NSPs).

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 contracted with customers to reduce their consumption at different price levels to provide price hedging in the market.

The estimated level of DSP available in South Australia for summer 2023-24 and winter 2024 is shown in **Table 5**. 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 AEMO issuing a market notice declaring Lack of Reserve (LOR) conditions (LOR 2 or LOR 3)[28].

[28] The declaration of LOR conditions indicates times the system may not or does not have enough reserves to meet demand. See AEMO's reserve level declaration guidelines, at https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/ power_system_ops/

The methodology used is explained in AEMO's DSP forecast methodology[29], which includes a summary of the types of demand flexibility included in, or excluded from, AEMO's DSP forecasts and the reasons why. Notably:

- DSP responses triggered by the Reliability and Emergency Reserve Trader (RERT) process, as discussed in Section 4.3, are excluded.
- Operation of battery storage units, including VPPs, is reflected in AEMO's supply-side forecasts and this is therefore excluded from DSP to avoid double-counting.
- 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.
- Wholesale Demand Response (WDR) is included as DSP, and has been since the 2021 DSP forecast.

Table 5 contains the estimated DSP by wholesale price levels and reliability response for South Australia. It shows the estimated cumulative price response is 40 MW for South Australia when prices exceed $500 per megawatt hour (MWh), and 44 MW when prices exceed $5,000/MWh. However, if prices exceed $7,500/MWh, or if LOR 2 or LOR 3 conditions are declared, the total DSP response is estimated to be 49 MW in South Australia.

Table 5 Estimated DSP by wholesale price levels and reliability response* for South Australia

Trigger	Summer 2022-23 (MW – cumulative for each price band)	Winter 2023 (MW – cumulative for each price band)
>$300 / MWh	26	26
>$500 / MWh	40	40
>$1000 /MWh	41	40
>$2500 /MWh	41	40
>$5,000 / MWh	44	44
>$7,500 / MWh	49	49
Reliability response	49	49

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

The 2022 forecast for WDR in South Australia was linked to the Victorian WDR forecast, because there was no South Australian data on which to base a forecast. This 2022 forecast, based on an assumption of how South Australian WDR would compare proportionally to Victorian WDR, turned out to be significantly higher than actual WDR in South Australia. Now that WDR is occurring in South Australia, albeit in extremely low volumes, AEMO has based its 2023 forecast on actual South Australian WDR outcomes. WDR is not expected to be material in the short term, with less than 1 MW forecast even at the highest price triggers.

2.3.2 Operational minimum demand

South Australia has experienced minimum demand in the middle of the day since 2012-13, and this is forecast to continue. Minimum operational demand typically occurs during weekends or public holidays when demand is low and temperatures are mild, and around noon when distributed PV reduces the need for grid-delivered energy.

reserve-level-declaration-guidelines.pdf. Note that the estimated reliability response DSP applies for when an actual LOR 2 or LOR 3 occurs, not for periods where it was forecast, but did not eventuate.

[29] AEMO, Demand Side Participation Forecast Methodology, at https://aemo.com.au/-/media/files/stakeholder_consultation/ consultations/nem-consultations/2020/demand-side-participation/final/demand-side-participation-forecast-methodology.pdf.

Over the last decade, growth in rooftop PV generation in South Australia has gradually shifted minimum operational demand from overnight to occur in the middle of the day.

Table 6Table 6 shows the time of underlying and operational maximum demand along with an estimated contribution of distributed PV to underlying and operational minimum demand for the last five years.

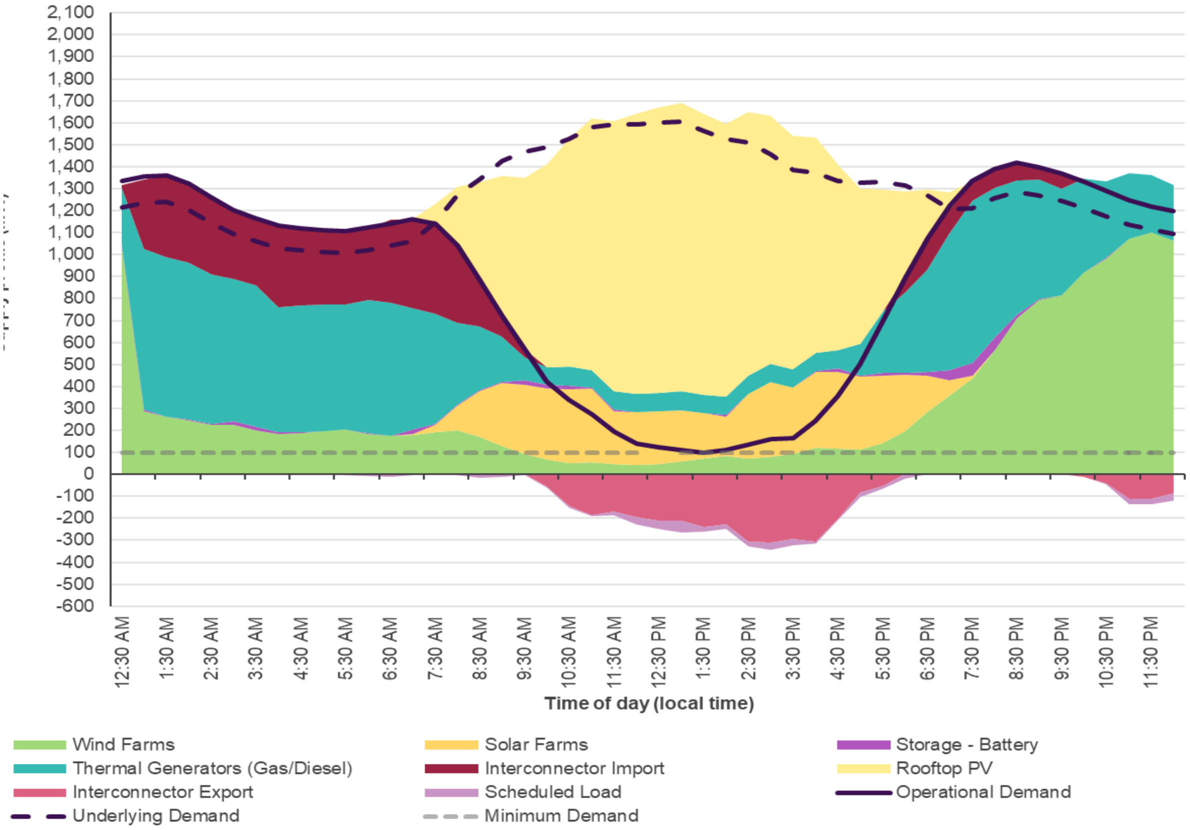
Table 6 Distributed PV contribution to underlying and operational annual minimum demand in South Australia

Year	Distributed PV contribution to underlying minimum demand (MW)	Date and time of underlying minimum demand (Adelaide time)	Distributed PV generation at the time of operational minimum demand (MW)	Date and time of operational minimum demand (Adelaide time)
2017-18	0	22/10/2017 5:00 AM	533	2/10/2017 1:30 PM
2018-19	0	22/04/2019 5:00 AM	670	21/10/2018 1:30 PM
2019-20	0	3/11/2019 6:30 AM	834	10/11/2019 2:00 PM
2020-21	0	11/10/2020 5:00 AM	1,382	11/10/2020 1:00 PM
2021-22	0	3/10/2021 5:00 AM	1,221	21/11/2021 1:30 PM
2022-23	0	3/10/2022 5:00 AM	1,280	16/10/2022 1:30 PM

A new record low minimum operational demand of 100 MW as-generated (and 96 MW sent-out) was set on Sunday, 16 October 2022[30]; this was down 4 MW from the previous record of 104 MW on 21 November 2021. The most recent record, as seen in **Figure 14**, occurred at 1:30 pm (Adelaide time). During that half-hour, estimated rooftop PV output was 1,280 MW, accounting for 93% of the region's underlying electricity demand.

[30] After the cut-off date for this report, a new record minimum operational demand of 5 MW (as-generated) and 3 MW (sent-out) was reached on Sunday 1 October 2023.

Figure 14 Profile of record minimum operational (as-generated) demand day (16 October 2022)

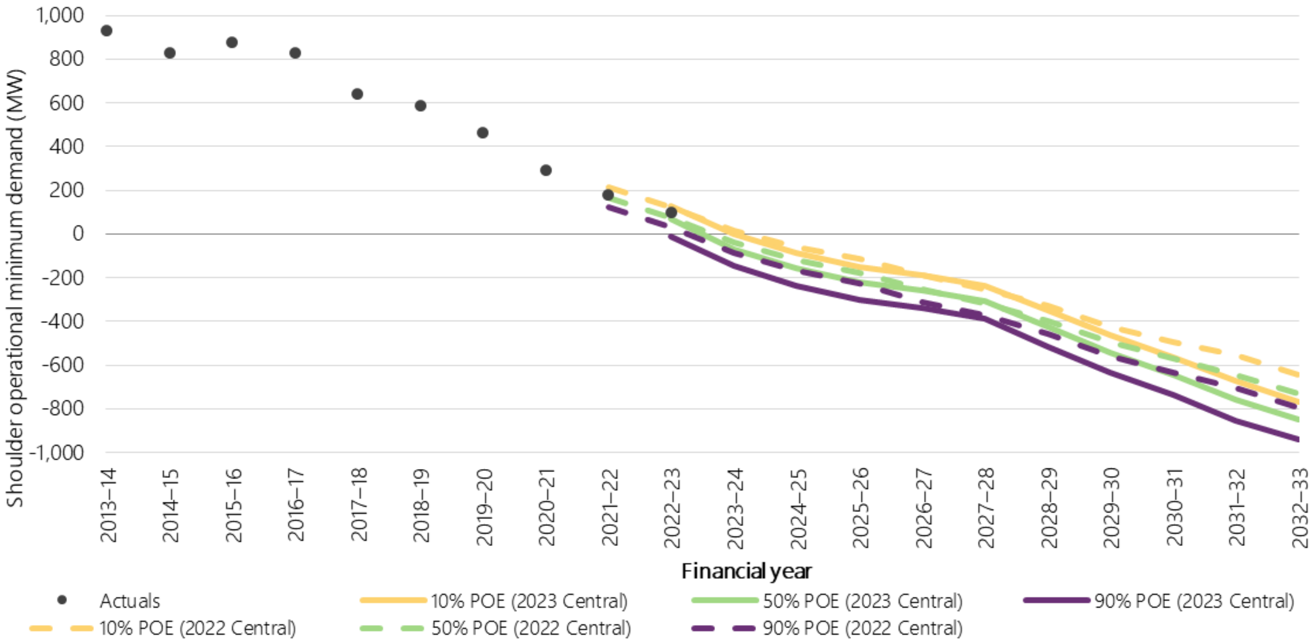


Forecast operational minimum demand

Figure 15 shows the Central scenario forecast of shoulder[31] minimum demand from the 2023 ESOO. It illustrates a relatively constant forecast decline of almost 100 MW per year in minimum demand in the shoulder season, where the annual minimum most often occurs. In the absence of material new loads or distributed storage beyond what was included in the forecast, South Australia may reach negative minimum operational demand (when distributed generation exceeds demand) by 2023-24. A negative operational demand means South Australia must export power to neighbouring regions. The operational challenges of declining minimum demand conditions are discussed in Section 0, together with actions that have been taken, are in progress and are recommended to manage these challenges. The 2023-24 forecast for operational demand to become negative is in line with the forecast in the 2022 ESOO. The minimum demand observed in October 2022 is consistent with the 50% POE Central scenario forecast in the 2023 ESOO.

[31] The shoulder period refers to September, October, April and May months.

Figure 15 Actual and forecast shoulder operational minimum demand (sent-out) for South Australia (Central scenario), 2013-14 to 2032-33



* 2016-17 minimum excludes the black system event day in South Australia on 28 September 2016.

2.4 Daily demand profiles

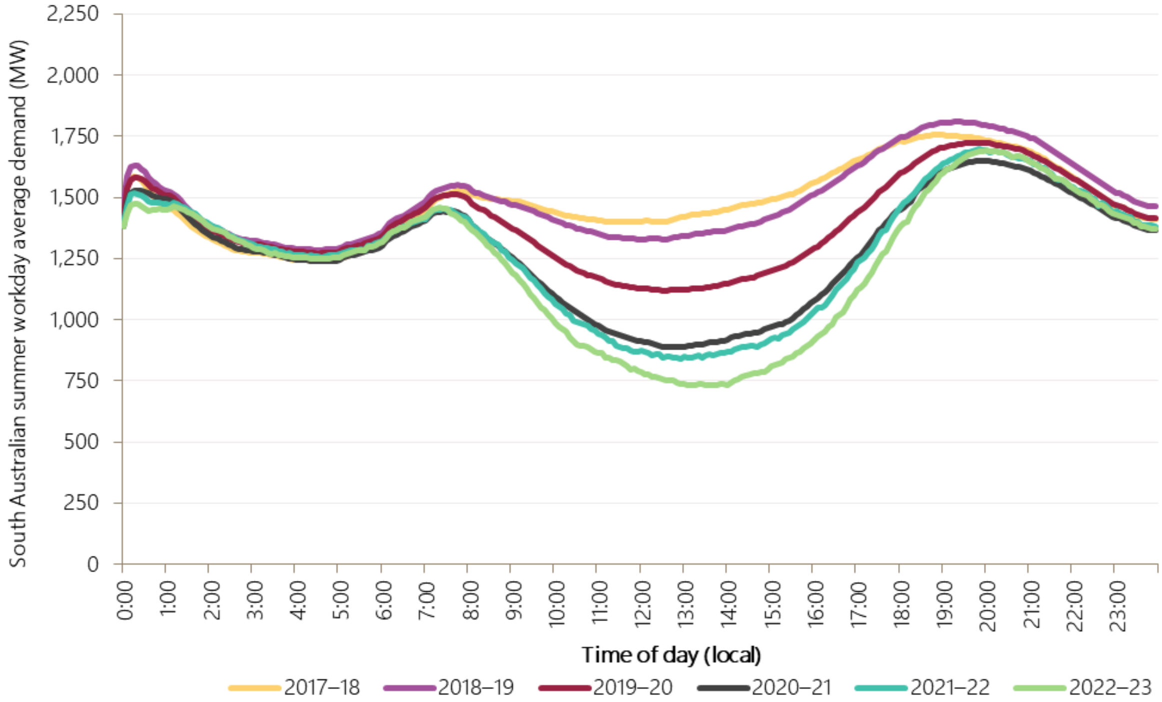
The average daily demand profiles presented in this section represent the operational (as-generated) demand, in megawatts, for each 5-minute dispatch interval of a day, averaged over the relevant days of the selected period. Changes to the average daily demand profile over time can provide insights into the impact of increasing distributed PV generation and demand side management. Only South Australian workdays have been included in the analysis; weekends and gazetted public holidays were excluded.

Summer daily demand

Figure 16 shows the South Australian average workday operational demand profile for summer from 2017-18 to 2022-23. Average summer operational demand year on year has been generally declining during daylight hours, due to increasing distributed PV generation, changing the shape of operational demand and lowering morning and evening peak demands. The average daily peak in operational demand has shifted from 6:30 pm to around 8.00 pm when solar irradiance reduces the generation from distributed PV installations.

Another noticeable feature in the demand profile is the sharp uptick at midnight (local time, or 11:30 pm NEM time), due to the controlled switching of electric hot water storage systems. SA Power Networks has been progressively moving some of its customers' hot water systems away from the night-time timer setting to turn on during the middle of the day instead. Additional residential customer hot water loads may have been moved by retailers, or by customers themselves, as smart meters are being installed or to increase the amount of PV self-consumption. This has lowered the observed night-time peak significantly in recent years and may be reducing the decline in minimum demand.

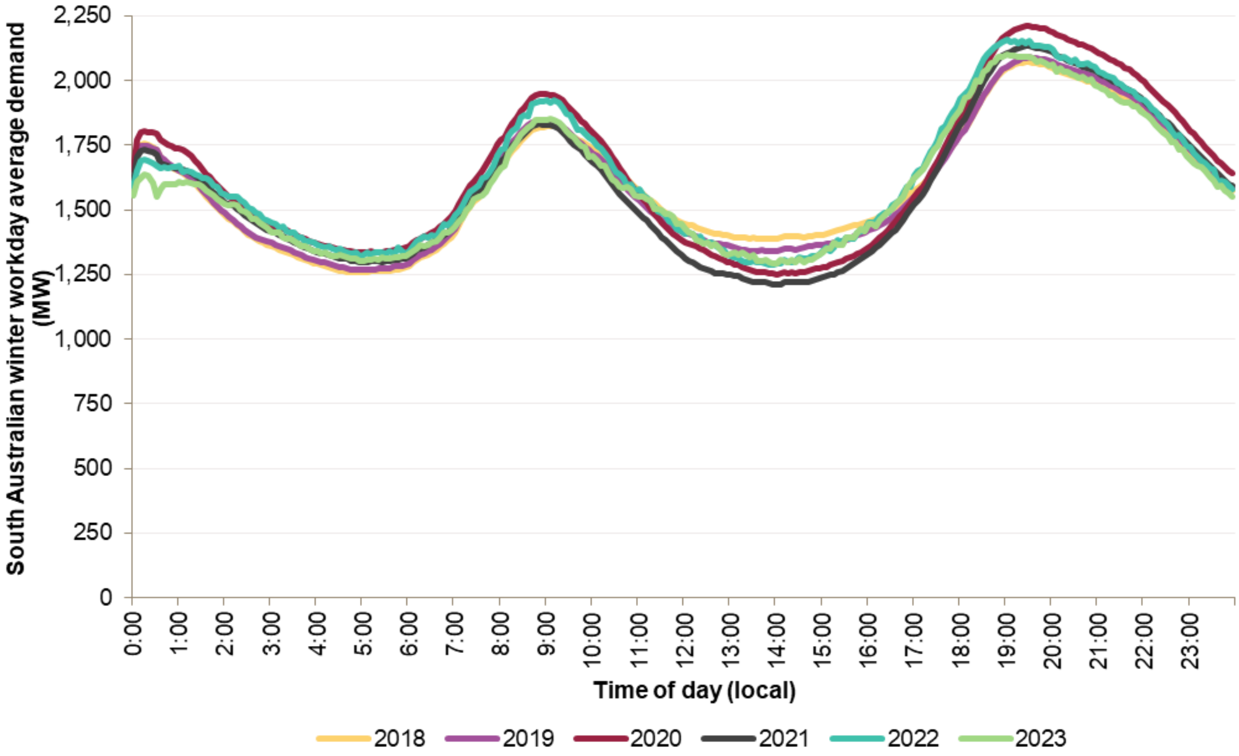
Figure 16 Summer workday average operational demand profiles



Winter daily demand

Figure 17 shows the South Australian average winter workday demand profile for winter 2018 to 2023. Clear morning and evening peaks in electricity consumption continue to be observable. Similar to summer, reduced grid demand is observed in the daylight hours, due to the increased output of distributed PV.

Figure 17 Winter workday average operational demand profiles



3 Existing supply and new developments

The supply mix in South Australia continues to evolve, with new developments particularly of firming large-scale batteries and solar generators in the last year.

For more information:

- Generation information, October 2023 update, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.
- 2023 ESOO, at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo.
- Generation forecast for South Australia, published May 2023, at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/South-Australian-Advisory-Functions.
- NEM generation maps, at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/participate-in-the-market/network-connections/nem-generation-maps.

In outlining supply developments, the SAER applies commitment categories in accordance with AEMO's Generation Information Page definitions:

- **Existing** generation and storage.
- **In commissioning** projects[32], which have met the commissioning requirements of their first hold point. In Commissioning projects are included in the ESOO Reliability Forecast at the Full Commercial Use Date (FCUD) submitted by the developer.
- **Committed** projects[33], that meet all five of AEMO's commitment criteria[34] but have not yet met the commissioning requirements of their first hold point.
- **Committed*** projects[35] are those that are highly likely to proceed, satisfying Land, Finance and Construction criteria plus either Planning or Components criteria. Progress towards meeting the final criteria is also evidenced and construction or installation has also commenced.
- **Anticipated** projects[36] are projects that are likely to proceed and have demonstrated progress towards meeting at least three of the commitment criteria, and have updated their submission in the previous six months.
- **Proposed** projects are earlier in their project development cycle and have not yet met sufficient commitment criteria to be included in either reliability assessments or system planning.

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[32] Projects that are in commissioning are included in reliability assessments and integrated system planning.

[33] Committed projects are included in the ESOO Reliability Forecast at six months after the FCUD submitted by the developer. These projects are included in reliability assessments and integrated system planning.

[34] For details about commitment criteria, see the Background Information tab on each spreadsheet at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

[35] Committed* projects are included in the ESOO Reliability Forecast at six months after the FCUD submitted by the developer. These projects are included in reliability assessments and integrated system planning.

[36] Anticipated projects are included in the ESOO Reliability Forecast at the furthest date of either 1) the first day after the T-1 year for Retailer Reliability Obligation (RRO) purposes, or 2) one year after the FCUD submitted by the developer. These projects are included in reliability assessments and integrated system planning.

3.1 Existing generation and storage

Table 7 shows all generation and storage capacity in South Australia at the end of 2022-23. Gas-powered generators remained the largest source of capacity; wind farms were the largest source of generated electricity.

Table 7 South Australian registered capacity and local generation by energy source in 2022-23

Energy source	Registered capacity		Electricity generated	
	MW	% of total	GWh	% of total
Gas	2,683	29.40%	3,598	25.4%
Wind	2,348	25.73%	6,651	46.9%
Diesel + Other Non-Scheduled Generation (ONSG)	482	5.28%	116	0.8%
Rooftop PV	2,193	24.03%	2,505	17.7%
PVNSG	251	2.75%	436	3.1%
Solar	697	7.64%	804	5.7%
Storage - Battery	471	5.16%	74	0.5%
Total	**9,125**	**100.00%**	14,185	100.0%

Table 8 shows differences in generation between 2021-22 and 2022-23, including interconnector flow metrics. Despite a slight increase in operational consumption in 2022-23, gas-powered generation continued to decline from 30% to 25% of total generation. Wind generation remained the largest source of energy and increased its share. Rooftop PV and large-scale solar slightly increased their shares of total generation (from 17% to 18% and 5.1% to 5.7%, respectively).

Gas-powered generation and interconnector imports continued to be required to meet South Australian demand in periods with combinations of high demand, low solar irradiance and/or low wind. Gas-powered generation continued to be required to maintain power system stability, however requirements for gas generators to maintain system services reduced following the installation of synchronous condensers (see Section 6.2). Given the importance of gas-powered generation, it will be discussed in detail in Section 3.4.

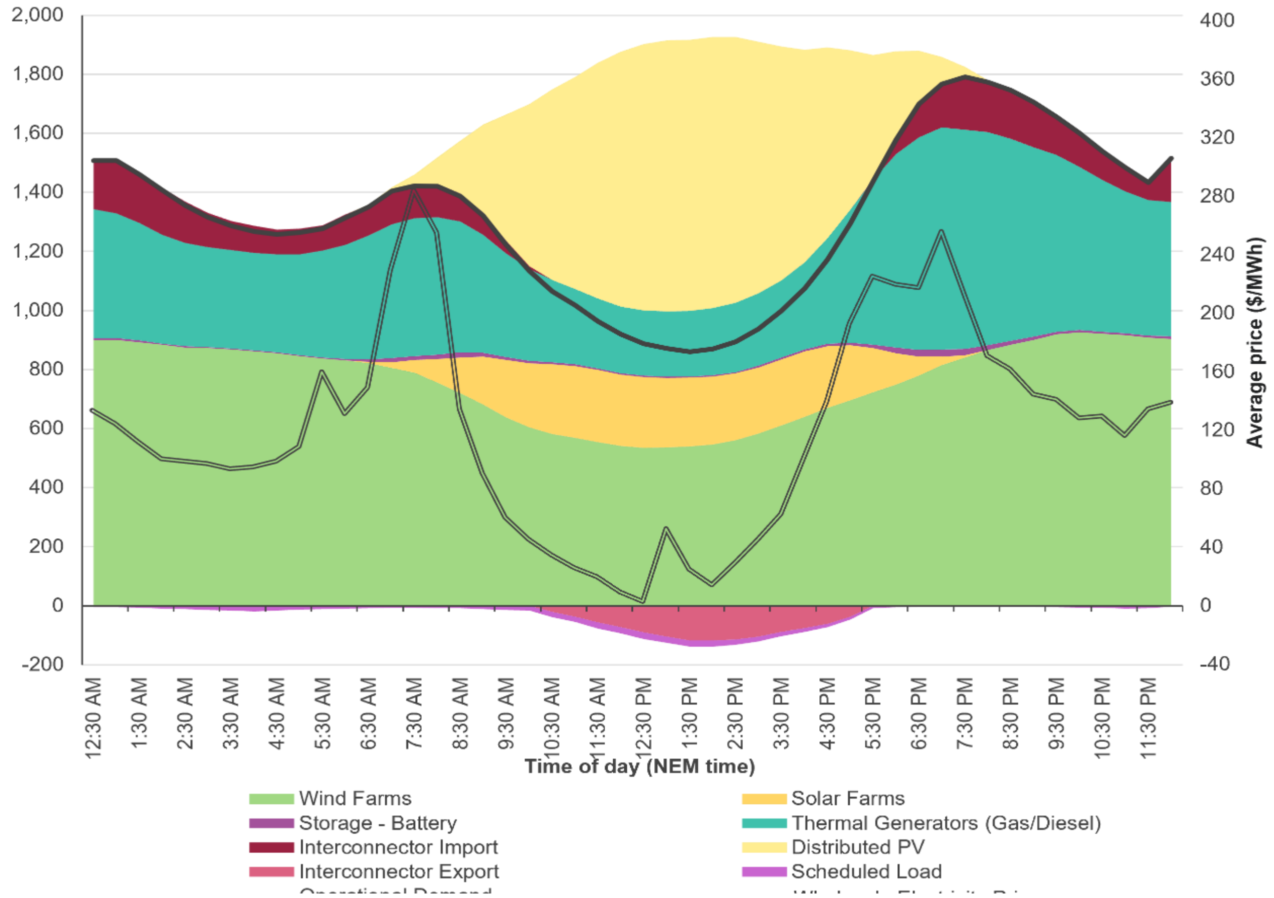
Table 8 South Australian electricity generation by fuel type, comparing 2021-22 to 2022-23

Supply source	2021-22 (GWh)	2022-23 (GWh)	Change (GWh)	Percentage change (%)	2021-22 percentage share (%)	2022-23 percentage share (%)	Change in percentage share (%)
Gas	4,055	3,598	- 457	-11.3%	29.5%	25.4%	-4.1%
Wind	6,131	6,651	521	8.5%	44.6%	46.9%	2.3%
Diesel + ONSG	139	116	- 23	-16.5%	1.0%	0.8%	-0.2%
Rooftop PV	2,269	2,505	236	10.4%	16.5%	17.7%	1.2%
PVNSG	371	436	65	17.4%	2.7%	3.1%	0.4%
Solar	698	804	106	15.2%	5.1%	5.7%	0.6%
Storage – Battery	88	74	- 14	-15.6%	0.6%	0.5%	-0.1%
Total local generation	**13,751**	**14,185**	**434**	**3.2%**	100.0%	100.0%	
Energy imports	1,467	1,377	- 90	-6.2%			
Energy exports	842	877	36	4.2%			

Supply source	2021-22 (GWh)	2022-23 (GWh)	Change (GWh)	Percentage change (%)	2021-22 percentage share (%)	2022-23 percentage share (%)	Change in percentage share (%)
Net energy imports	625	499	- 126	-20.1%			

Figure 18 shows the average daily supply profile observed across 2022-23. While each actual day varied subject to actual consumer demand, wind, and solar output, the profile clearly shows that daytime solar generation enabled excess electricity to be exported to neighbouring regions, while South Australia is, on average, a net importer overnight. Average prices also follow this distinct intra-day trend, with low or negative prices during daylight hours, and higher prices in the evening (see Section 5.2).

Figure 18 Average daily supply profile, 2022-23 (MW)



3.2 Changes in generation and storage over the last five years

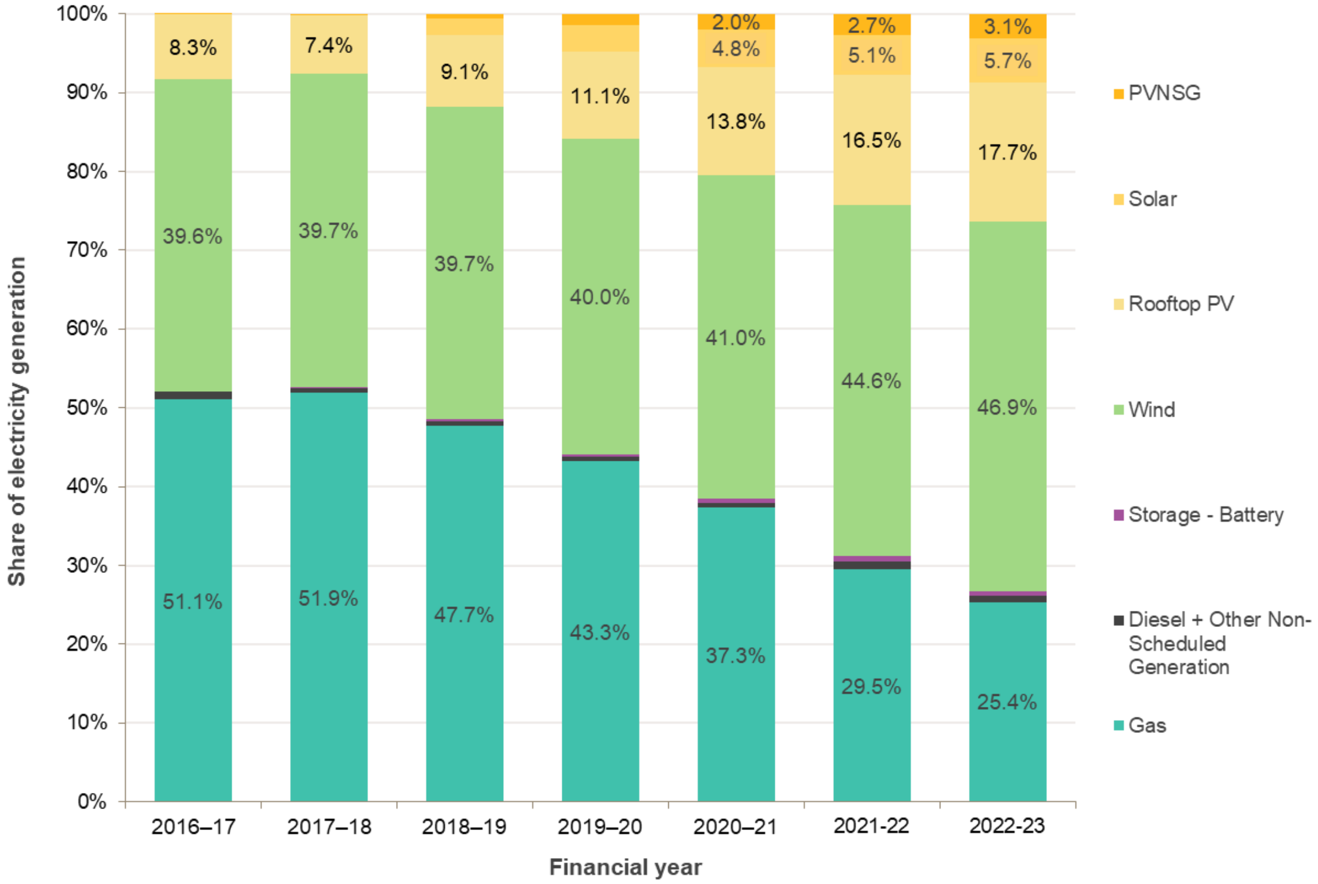
Figure 19 shows the mix of electricity generated in South Australia by fuel type[37] from 2018-19 to 2022-23, from:

- All scheduled generators, including storage.
- All semi-scheduled and market non-scheduled wind farms.

[37] Generation has been aggregated based on each power station's primary fuel type, and does not capture generation by secondary fuel type. The figure reflects the local generation market share. No adjustments have been considered for imports or exports across the interconnectors with Victoria, or scheduled load.

- All semi-scheduled solar farms.
- Selected smaller market and non-market non-scheduled generators (NSGs).
- Estimated distributed PV.

Figure 19 South Australian electricity generation by fuel type, 2016-17 to 2022-23



The sections below provide changes in each technology grouping for 2022-23, including the average volume-weighted prices achieved for each technology (see Section 5.1 for more detail on pricing trends).

Wind farm capacity changes

Wind capacity was materially unchanged in 2022-23, as shown in **Table 9**, with no new significant developments.

Table 9 Wind generation changes in registered capacity, generation and volume-weighted price, 2017-18 to 2022-23

Financial year	Nameplate capacity (MW)*	Reason for increase in capacity	Maximum five-minute generation (MW)*	Volume weighted price ($/MWh)
2017–18	1,810	Hornsdale Stage 3 (112 MW)	1,618	81.15
2018–19	2,141	Lincoln Gap (212.4MW), Willogoleche (119.36 MW)	1,713	84.18
2019–20	2,141	NA	1,823	45.25

Financial year	Nameplate capacity (MW)*	Reason for increase in capacity	Maximum five-minute generation (MW)*	Volume weighted price ($/MWh)
2020–21	2,141	NA	1,826	30.16
2021-22	2,351	Port Augusta Renewable Energy Park (210 MW)	2,050	79.38
2022-23	2,348	NA	2,111	81.54

* Nameplate capacity taken from Generation Information publication and may change slightly from year to year.

Large-scale solar capacity changes

In 2022-23, growth in large-scale solar continued, with two new projects leading to an additional 184 MW of registered capacity during the year, as shown in **Table 10**.

Table 10 Large-scale solar generator changes in registered capacity, generation and volume-weighted price, 2017-18 to 2022-23

Year	Nameplate capacity (MW)*	Reason for increase in capacity	Maximum five-minute generation (MW)*	Volume weighted price ($/MWh)
2017-18	135	Bungala One Solar Farm (135 MW)	31	92.91
2018-19	378	Bungala Two Solar Farm (135 MW), Tailem Bend Solar Project 1 (108 MW)	209	126.26
2019-20	378	NA	227**	55.74
2020-21	411	Adelaide Desalination Plant (11 MW), Morgan-Whyalla Pipeline Pumping Station No’s 1-4 (22 MW)	326**	21.80
2021-22	488	Adelaide Desalination Plant expansion (13 MW), Bolivar Waste Water Treatment Plant (8 MW), Happy Valley WTP (11 MW), Mannum-Adelaide Pipeline Pumping Station No's 2 and 3 (32 MW), Murray Bridge-Onkaparinga Pipeline Pumping Station No. 2 (13 MW)	342	56.52
2022-23	661	Tailem Bend Stage 2 Solar (105 MW) Port Augusta Renewable Energy Park – Solar (79 MW)	451	52.53

* Nameplate capacity taken from Generation Information publication and may change slightly from year to year.
** This figure increased more than registered capacity because Bungala Two was registered in 2018-19, was in commissioning and generating at lower levels in 2019-20, then generated at higher levels from July 2020.

3.3 Expected changes in generation and storage

Table 11 summarises combined nameplate capacity data, by generation source, for all scheduled, semi-scheduled, and non-scheduled generation in South Australia[38] that is currently (at 27 October 2023) either:

- Operating.
- Expected to connect (definitions of committed and anticipated are discussed above at the start of Section 3.1).
- Expected to withdraw (as advised by participants).
- Proposed.

[38] The total South Australian capacity in Table 7 in Section 3.1 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 11.

The key generation and storage forecast trends highlighted by this data, and by AEMO's 2023 South Australian Generation Forecasts[39], are:

- **Wind generation** is the highest single generation technology with over 2 gigawatts (GW) of capacity and is expected to continue growing with committed projects (and the largest amount of proposed projects by megawatts).
- **Retirements of gas and diesel generation,** which have been advised, will reduce the capacity share from these technologies. Far fewer gas-powered generation proposals exist compared with renewable and storage projects. Reduced operation is further anticipated when Project EnergyConnect increases connectivity with other regions.
- **Battery storage** has continued to increase and is expected to become a larger proportion of capacity with committed and anticipated projects and also has a large number of projects proposed.

Table 11 Capacity of existing, announced withdrawal, committed, anticipated and proposed projects (MW) at October 2023

Status	CCGT [B]	OCGT [C]	Gas other	Solar [D]	Wind	Water	Biomass	Storage – Battery	Other	Total
Existing [A]	713	1,272	1,010	697	2,348	3	20	471	148	**6,681**
Announced withdrawal			800							**800**
Existing less Announced withdrawal	713	1,272	210	697	2,348	3	20	471	148	**5,881**
Committed				30	413			42		**484**
Anticipated				357				321		**678**
Proposed		465	45	3,369	4,091	780		5,851	200	**14,800**
Withdrawn										

A. Existing includes Announced withdrawal.
B. CGT: Combined-cycle gas turbine.
C. OCGT: Open-cycle gas turbine.
D. Solar is large-scale solar and excludes rooftop PV installations.

3.3.1 Capacity for next summer

Table 12 shows:

- The expected available capacity of scheduled, semi-scheduled, and significant non-scheduled generation in summer 2023-24 – for both peak and typical temperatures – and for winter 2024.
- How this expected capacity compares with the forecast capacity available last summer (2022-23), in peak and typical temperatures, and in winter 2023.

[39] At https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/south-australian-advisory-functions.

Table 12 Scheduled, semi-scheduled, and significant non-scheduled generation available capacity, summer (peak and typical) 2022-23 and 2023-24 and winter 2023 and 2024

Energy source	Summer peak available capacity A (MW)		Summer typical available capacity C (MW)		Winter available capacity A (MW)	
	2022-23	2023-24	2022-23	2023-24	2023	2024
Diesel	369	338	392	361	428	397
Gas	2,022	2,105	2,155	2,229	2,370	2,387
Wind B	1,544	1,553	2,021	2,197	2,021	2,395
Solar	477	594	488	605	579	609
Storage – battery	219	470	219	470	261	511
Total	**4,631**	**5,060**	5,276	**5,862**	5,660	**6,300**

Source: AEMO Generation Information published October 2022 and October 2023.
A. Summer peak available capacity incorporates the impact of expected derating in response to high temperatures.
B. 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.
C. Summer typical available capacities represent the capacity available over summer during typical temperatures.

Notable changes since last summer include the return to service of Mintaro gas-powered generator, and connection of new large-scale solar projects. Summer peak available capacity incorporates the impact of expected derating in response to high temperatures.

3.3.2 Generation developments by commitment classification

The following sub-sections outline the key developments affecting generation developments and withdrawals, informed by submissions to AEMO's Generation Information dataset. This section represents the October 2023 release of the Generation Information dataset[40], unless otherwise stated.

Generation withdrawals

Projects recently withdrawn from service in South Australia include:

- Torrens Island B unit 1 (200 MW) was mothballed on 30 September 2021 and have advised it will not return to service and will close in 2026.
- Osborne Power Station closure was delayed; it is now expected to close by 31 December 2026.

Committed developments

Committed and 'In Commissioning' projects in South Australia include:

- Torrens Island Battery Energy Storage System (BESS) (250MW/250MWh of storage).
- Tailem Bend Stage 2 Solar Project (105 MW of solar).
- Tailem Bend Battery Project (42MW/84MWh of storage).
- Mannum Solar Farm 2 (30 MW).
- Goyder South Wind Farm 1A (209 MW of solar).
- Goyder South Wind Farm 1B (204 MW of solar).

[40] At https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

Anticipated developments

The following projects are classified as anticipated developments:

- Blyth BESS (200 MW/400 MWh of battery storage).
- Lincoln Gap Wind Farm BESS (10 MW/10 MWh of battery storage)
- Cultana Solar Farm (357 MW of solar).
- Templers BESS (111 MW/291 MWh of battery storage)

Other proposed developments

A total of 77 proposed electricity generation and storage developments are classified as proposed in South Australia, being neither committed nor anticipated, totalling 14,800 MW. **Table 13** aggregates these developments by generation source.

Given the increasing penetration of renewable generation, there will be growing value in generation technologies that can complement the natural variability of the weather by providing rapid start capabilities and increased operational flexibility, such as battery (including VPP) or pumped hydro storages, flexible thermal generation, or flexible load. The South Australian Government is supporting the development of the world's largest VPP, and is also supporting several green hydrogen projects as part of its efforts in scaling up the South Australian hydrogen industry (see Section 2.1.1).

As noted above, proposed new generation investment in South Australia continues to focus on renewable developments and energy storage.

Table 13 Proposed generation and storage developments, October 2023

Wind farms	Solar farms	Gas or hydrogen projects	Storage developments	Hybrid developments [A]
• GEP - SRBE1 Wind Farm (2,001 MW). • Yorke Peninsula Wind Farm (636 MW). • Twin Creek Wind Farm (302 MW). • Palmer Wind Farm (294 MW). • Lincoln Gap Wind Farm stage 3 (277 MW).	• Bridle Track Solar Project (300 MW). • Port Pirie Solar Farm (300 MW). • Australia Plains Solar Farm (200 MW) • The Solar River Project - Stage 1 (200 MW) • The Solar River Project - Stage 2 (200 MW)	• Green Hydrogen Power Station (200 MW) • Hydrogen Jobs Plan (200 MW)	• Bundey Energy Hub Battery Energy Storage A + B (500 MW). • Highbury Pumped Hydro Energy Storage (300 MW). • Davenport BESS (270 MW) • Baroota Pumped Hydro (250 MW) • Pacific Green Energy Park - Limestone Coast North (250 MW, 500 MWh) • Pacific Green Energy Park - Limestone Coast West (250 MW, 500 MWh) • Goat Hill Pumped Hydro (230 MW). • Para Substation/Gould Creek BESS (225 MW). • Tailem Bend Stage 3 (204 MW, 408 MWh) • Goyder South Hub – BESS (200 MW) • Koolunga BESS (200 MW, 400 MWh) • Mobiling BESS (200 MW, 200 MWh)	• Robertstown Solar and Battery (750 MW, 500 MWh) • Riverland Solar Storage – Solar (330 MW). • Bungala Three Battery Energy Storage System (300 MW, 1,200 MWh) • Solar River Solar and BESS Project (256 MW) • Geranium Plains Solar and BESS (250 MW). • Bungama Solar (280 MW, 300 MWh)

Wind farms	Solar farms	Gas or hydrogen projects	Storage developments	Hybrid developments [A]
			• South East BESS (200 MW) • Templers B BESS (200 MW)	

A. Hybrid developments refers to generation projects that incorporate multiple technologies within the one project, for example a solar far with a battery storage solution. The capacity refers to the wind or solar farm. See the Generation Information dataset for more information on the storage capacity.

Table 14 shows that since the October 2022 Generation Information (reported on in the 2022 SAER) there has been an increase of 2,613 MW of aggregate capacity proposed in South Australia driven by wind and battery storage projects.

Table 14 South Australian proposed generation projects by energy source, as of October 2023

Energy source	Number of projects	Capacity (MW)	Capacity (% of total projects tracked)	Change in number of projects from November 2022	Change in capacity from November 2022 (MW)
Gas	4	510	3.4%	0	-155
Diesel	0	0	0.0%	0	0
Solar	21	3,369	22.5%	-3	-267
Biomass	0	0	0	0	0
Wind	9	4,291	29.0%	-3	1002
Water	3	780	5.3%	-1	-90
Storage – battery and VPP	40	5,851	39.5%	14	2123
Total	**77**	**14,800**	**100.0%**	**7**	**2,613**

3.4 Gas-powered generation

For more information:

- **2023 GSOO, at http://aemo.com.au/Gas/National-planning-and-forecasting/Gas-Statement-of-Opportunities.**
- **2023 South Australian Generation Forecasts, at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/south-australian-advisory-functions.**
- **AEMO forecasting portal, at http://forecasting.aemo.com.au/.**

South Australia observed a continued decline in electricity production from gas-powered generation in 2022-23, with last summer recording the lowest volumes in South Australia since market start. The decline in gas-powered generation resulted from:

- Significant additional supply from renewables, including ramping of commissioning at Lincoln Gap Wind Farm and new solar and wind farms at Port Augusta Renewable Energy Park.

- Reduction in the minimum number of synchronous generators required for system security during normal operation from four to two, following full commissioning of all four synchronous condensers at Davenport and Robertstown in November 2021. This had the effect of reducing the volume of renewable energy that was constrained off from operating.
- Low electricity spot prices resulted in less frequent economic operation of gas-powered generation.

The start of 2023 saw the operators of gas generators elect to decommit their units during periods of high variable renewable energy (VRE) output, resulting in more directions required by AEMO to maintain minimum synchronous generation levels (albeit still at substantially lower volumes than before operation of all four synchronous condensers). AEMO was also required to direct gas-powered generators to remain online for frequency control ancillary services (FCAS) provision following the failure of a transmission tower structure near Tailem Bend on 12 November 2022 which caused most of the South Australia region to electrically isolate from the rest of the NEM for seven days[41]. During this event, high penetration of renewables meant energy prices remained low and gas generators observed a reduced incentive to remain online when FCAS markets breached the cumulative price threshold (CPT) and an administered pricing period (APP) was triggered.

In September 2022, Torrens Island A officially closed after not generating at all during the previous 12 months. Meanwhile at Torrens Island B Power Station, TIPS_B1 unit that has been mothballed since October 2021 will continue to remain mothballed until retirement[42], and AGL announced in November 2022[43] the closure date for Torrens Island B would be brought forward from 2035 to 2026. Conversely, Osborne Power Station's closure has been delayed from 2023 to 2026[44], and Bolivar Power Station became fully operational in December 2022.

Medium- and long-term gas-powered generation forecasts for South Australia are uncertain. The reliance on gas-powered generation will largely be determined by the speed at which new wind, solar and battery storage developments are able to connect in South Australia and Victoria to replace retiring thermal units. Increased electrification, EV uptake and hydrogen production resulting from the South Australian Hydrogen Jobs plan may place additional demands on the electricity grid. Other factors – such as weather volatility, coal outages and seasonal mothballing in neighbouring regions, and project delays for replacements to dispatchable capacity – risk greater dependence on gas-powered generation.

AEMO's latest projections[45] show a continuation of the downward trend for gas-powered generation in South Australia until 2026, driven by:

- Continued forecast installation of distributed PV causing lower operational demand.
- Increasing supply from wind and grid-scale solar as new facilities are connected and commissioned.

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[41] For more detail, see AEMO's incident report at https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2022/trip-of-south-east-tailem-bend-275-kv-lines-november-2022.pdf.

[42] As advised in AEMO's Generation Information updates, at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

[43] See https://www.agl.com.au/about-agl/media-centre/asx-and-media-releases/2022/november/torrens-island-b-power-station-to-close-in-2026.

[44] As advised in AEMO's Generation Information updates, at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

[45] As per the 2023 South Australian Generation Forecasts, at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/South-Australian-Advisory-Functions.

- Growing imports of low-cost electricity at times of surplus in neighbouring regions, as new VRE capacity comes online in Victoria.
- New grid-scale batteries[46] that will compete with gas-powered generation to provide firming and grid services during low-VRE and peak demand periods.
- Planned completion of the Project EnergyConnect interconnector in 2026 that will enable increased sharing of VRE resources between New South Wales and South Australia. Full operation of Project EnergyConnect may alleviate the requirement for a minimum number of synchronous generating units online under normal operating conditions.

Despite this uncertainty in the volume of energy required from gas generators, AEMO anticipates that flexible gas generators will continue to play a critical role in the NEM by providing power system security services, peaking capacity, and backup capacity during periods of renewable drought. As grid penetration of VRE increases, gas-powered generation will need to be increasingly flexible to firm renewable resources, for example ramping up during the early evening as output from large-scale solar and distributed PV drops.

Currently, during periods of low wind generation in South Australia, gas-powered generation and imports from Victoria are critical to meet reliability requirements, especially outside daylight hours. In the future it is expected that additional large-scale and distributed storage, as well as additional interconnection, will also contribute to managing the variability of renewable energy supply.

3.5 Emissions intensity of South Australian generation

Annual NEM emissions intensity, measured as the Carbon Dioxide Equivalent Intensity Index (CDEII), continued to decline, with emissions at their lowest level during the 2022-23 financial year[47] in South Australia, as **Figure 20** shows. Notably:

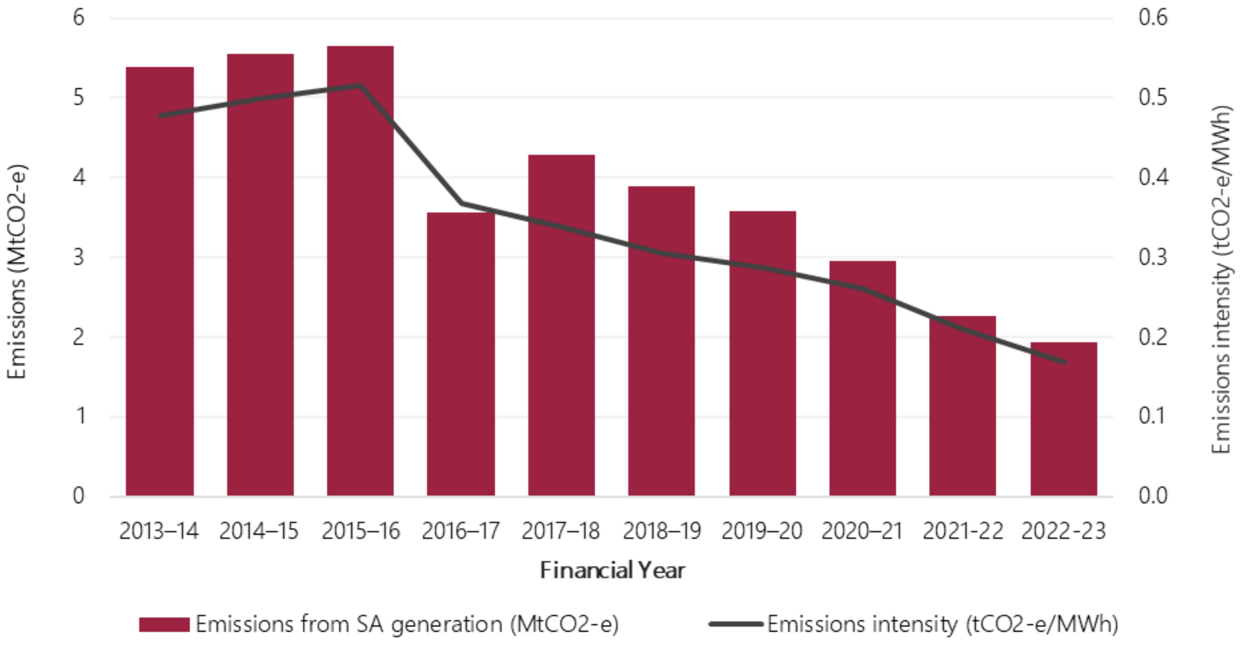
- Total emissions from South Australian generation in 2022-23 were 1.94 million tonnes (Mt) CO_2-e, a decrease of 0.33 Mt (or 14%) compared to 2021-22.
- Emissions intensity reduced by 19% from 0.21 t/MWh in 2021-22 to 0.17 t/MWh in 2022-23, the lowest levels to date.

These reductions reflect increased penetration of rooftop PV and large-scale solar, and reduced gas-powered generation.

[46] The 250 MW/250 MWh Torrens Island BESS and 200 MW/400 MWh Blyth BESS are expected to be operational in 2023-24 and 2025-26 respectively.

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

Figure 20 South Australian annual emissions and emissions intensity, 2013-14 to 2022-23

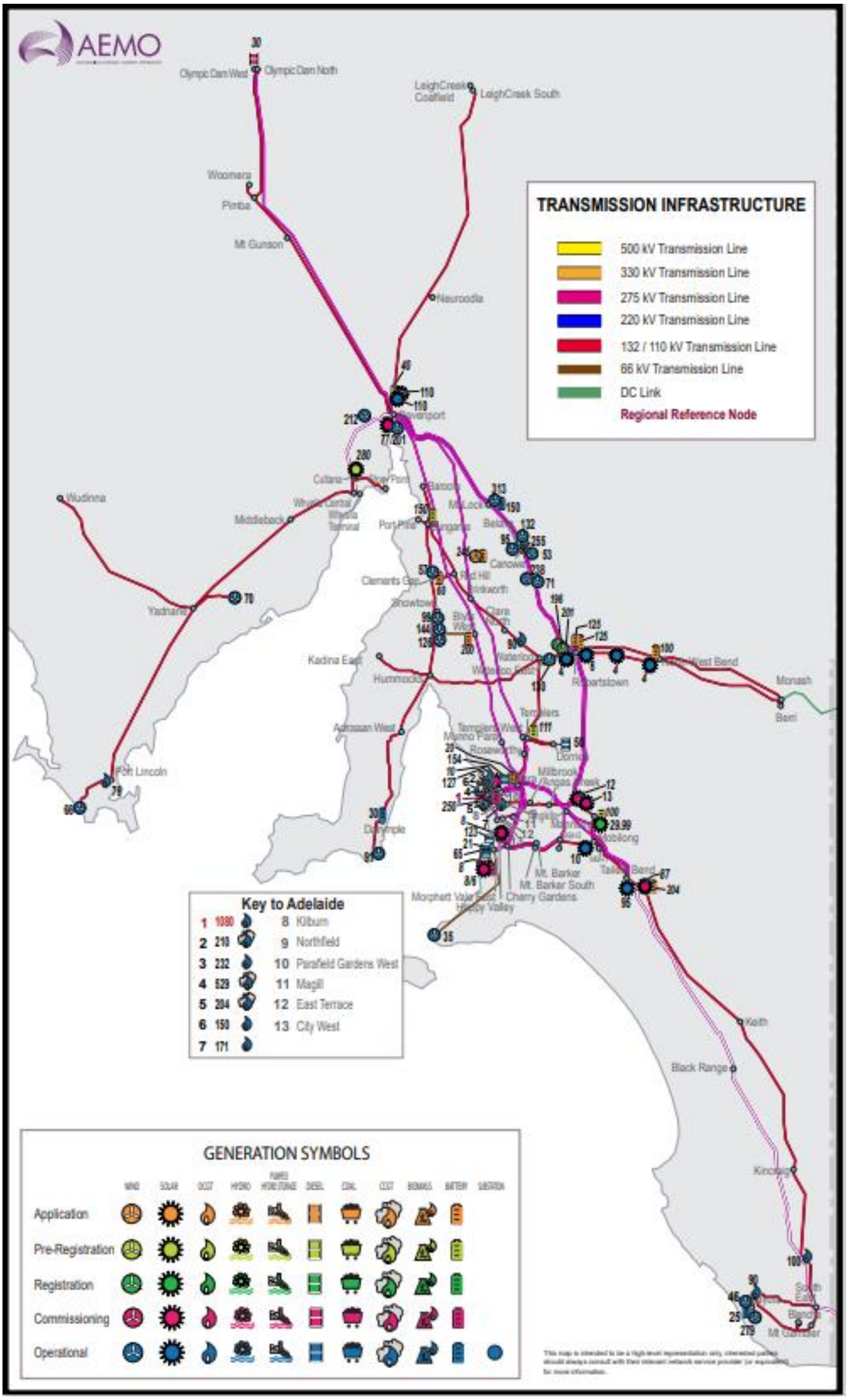


3.6 Location of South Australian generation and storage

Figure 21 shows the locations of existing and proposed generation and storage projects in the state, with existing transmission[48].

[48] This map version is dated September 2023. The map is regularly updated on AEMO's website at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/participate-in-the-market/network-connections/nem-generation-maps.

Figure 21 Locations of generation and storage in South Australia



3.7 Existing and future transmission

For more information:

- Transmission Augmentation Information Page, at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/transmission-augmentation-information.
- 2023 IASR, at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.
- 2022 ISP and 2024 ISP (when published), at https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp and https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp.

3.7.1 Status of transmission upgrade projects

A number of critical network infrastructure projects are underway or have recently been completed in South Australia to support its energy transition:

- **Project EnergyConnect** will be a new interconnector between the electricity systems of South Australia and New South Wales, with an added connection also to Victoria. The Australian Energy Regulator (AER) provided expenditure approval for this project in May 2021. The project will be delivered in two stages and involves:
  - Stage 1 (expected to be in service by December 2023, with capacity release expected in June 2024[49]):
    - A new Robertstown to Bundey 275 kilovolts (kV) double-circuit line and a new Bundey to Buronga 330 kV double-circuit line with one circuit connected initially.
    - Associated reactive plant, transformers, phase shifting transformers and synchronous condensers.
    - An inter-trip protection scheme to trip the Project EnergyConnect interconnector if South Australia becomes separated from Victoria via the Heywood Interconnector.
  - Stage 2 (expected in service by December 2024, with capacity release expected in July 2026[31]):
    - A second 330 kV circuit closed on the Bundey–Buronga 330 kV double-circuit line.
    - New Buronga to Red Cliffs 220 kV and Dinawan to Buronga 330 kV double-circuit lines.
    - A new 500 kV double-circuit line from Dinawan to Wagga Wagga operating at 330 kV.
    - Associated reactive plant, transformers, phase shifting transformers and synchronous condensers.
    - Turning the existing 275 kV line between Para and Robertstown into Tungkillo.
    - A special protection scheme to detect and manage the loss of either of the AC interconnectors connecting to South Australia
- ElectraNet has recently completed these projects within South Australia[50]:
  - **Eyre Peninsula Link,** in service since February 2023. This involved replacement of the existing 132 kV lines between Cultana and Yadnarie with a new double-circuit line that is initially energised at 132 kV, with the

[49] The capacity release and timing is conditional on availability of suitable market conditions and good test results.

[50] ElectraNet, 2023 Transmission Annual Planning Report, at https://www.electranet.com.au/wp-content/uploads/231101_2023-TAPR.pdf.

option to be energised at 275 kV in the future, as well as replacement of the existing 132 kV line between Yadnarie and Port Lincoln with a new double-circuit 132 kV line[51].

- **Strengthen the Eastern Hills Transmission corridor,** in service since June 2023. This project involved the turn-in of the Tailem Bend – Cherry Gardens 275 kV line at Tungkillo.
- **Smart Wires Power Guardian Technology Trial,** in service since June 2023. This project included the installation of Smart Wires Power Guardian units on the Templers to Waterloo 132 kV line and the uprating of the Robertstown to Para 275 kV and the Robertstown to Tungkillo 275 kV lines to increase the transfer capacity of the transmission network in the Mid North region of South Australia.
- **Emergency Transmission Network Voltage Control,** in service since September 2023**.** This involved the installation of a 275 kV 50 megavolt amperes reactive (MVAr) reactor at Cherry Gardens substation to manage the high voltages at times of low or negative operational demand.

3.7.2 Renewable energy zones (REZs)

AEMO's ISP identifies REZs, which are high-quality resource areas where clusters of large-scale renewable energy projects can be developed using economies of scale.

The 2022 ISP, published in June 2022, included an updated set of REZ scorecards for South Australia[52]. These scorecards will shortly be updated with the release of the Draft 2024 ISP and will be available on AEMO's website from 15 December 2023[53]. The scorecards include characteristics such as indicative resource availability, indicative geographic area of the REZ, generator capacity factor assessed against a number of reference years, potential climate risk, and transmission expansion outlooks.

In the 2022 ISP, AEMO requested preparatory activities from ElectraNet for the South East South Australia REZ and Mid-North South Australia REZ, as future ISP projects. Preparatory activities may be triggered for future ISP projects to improve the assessment of these projects in future ISPs. The preparatory activities for these two REZs were provided in June 2023 and are available via AEMO's website[54,55]. Updated information will be available in the Draft 2024 ISP, including information from sensitivity analysis considering potential new load uptake in South Australia, on AEMO's website from 15 December 2023[56]. ElectraNet also considers the relationship between these potential projects and future load commitments in South Australia, as noted in the 2023 TAPR and referred to in Section 2.2.4 of this report.

[51] Further information about the project is available at ElectraNet's website, at https://www.electranet.com.au/projects/eyre-peninsula-link/.

[52] AEMO. 2022 ISP Appendix 3 Renewable Energy Zones. At https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/a3-renewable-energy-zones.pdf.

[53] AEMO's 2024 ISP materials will be made progressively available at https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp.

[54] ElectraNet. South East South Australia Renewable Energy Zone Preparatory Activities Final Report. June 2023. At https://aemo.com.au/-/media/files/major-publications/isp/2023/teor-reference-materials/electranet---south-east-south-australia-rez-expansion.pdf.

[55] ElectraNet. Mid-North South Australia Renewable Energy Zone Preparatory Activities Final Report. June 2023. At https://aemo.com.au/-/media/files/major-publications/isp/2023/teor-reference-materials/electranet---mid-north-south-australia-rez-expansion.pdf.

[56] AEMO's 2024 ISP materials will be made progressively available at https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp.

4 Reliability of supply

As reported in the 2023 ESOO and 2023 ESOO Update, reliability risks are forecast in South Australia under the Central scenario. A reliability gap is forecast against the Interim Reliability Measure (IRM) of 0.0006% USE in 2023-24 and 2027-28. In following years, reliability risks are forecast to increase at the end of the horizon due to the expected retirement of numerous gas generators.

4.1 Forecast power system reliability

AEMO's ESOO assesses the NEM's adequacy of supply in meeting forecast demand over the next 10 years, evaluating supply scarcity risks that may result in expected unserved energy (USE) exceeding the IRM of 0.0006%[57] or, from 30 June 2028, the reliability standard of 0.002%[58].

The assumptions used to develop the 2023 ESOO's reliability forecasts are outlined in AEMO's 2023 IASR Assumptions Workbook[59]. The supply data used in this assessment is from the July 2023 Generation Information update available at the time of ESOO modelling.

Unserved energy (USE) is the amount of energy demanded, but not supplied due to reliability incidents. This may be caused by factors such as insufficient levels of generation capacity, demand response or inter-regional network capability to meet demand.

The **Interim Reliability Measure (IRM)** is set to ensure that sufficient supply resources and inter-regional transfer capability exist to meet 99.9994% of annual demand for electricity in each NEM region, by helping keep expected USE in each region to no more than 0.0006% in any year.

Any forecast reliability gap is based on expected USE not meeting the IRM (or, from 30 June 2028, not meeting the reliability standard, which is 0.002% of expected USE in a region in a year).

If AEMO reports a forecast reliability gap, this triggers a reliability instrument request under the **Retailer Reliability**

4.1.1 South Australian reliability outlook for the next 10 years

A reliability gap was identified for summer 2023-24 in the 2022 ESOO, but was not forecast in the February 2023 *Update to the 2022 Electricity Statement of Opportunities*. The gap has re-emerged in the 2023 ESOO due to a combination of factors, including a slight increase in the forecast probability of low wind conditions coincident with high demand.

Between 2024-25 and 2025-26, expected USE is forecast to be within (below) the IRM due to the development of numerous battery, wind and solar developments, and Project EnergyConnect Stage 1. The return to service of the Torrens Island B1[60] unit which has been mothballed for several years also impacted the USE outcomes.

[57] The IRM allows for a maximum expectation of 0.0006% of energy demand to be unmet in a given region per financial year. It was introduced by the National Electricity Amendment (Interim Reliability Measure) Rule 2020 (IRM Rule). The IRM Rule and changes to the Retailer Reliability Obligation (RRO) rules are intended to support reliability in the system while more fundamental reforms are designed and implemented. The use of the measure for contracting reserves and for the RRO is set to expire in June 2028, after which the reporting obligation reverts to the previous position under the National Electricity Rules (NER), that AEMO must report on whether the reliability standard would be exceeded in any financial year.

[58] The NEM reliability standard is set to ensure sufficient supply resources and inter-regional transfer capability exists to meet 99.998% of annual demand for electricity in each region. The standard allows for a maximum expectation of 0.002% of energy demand to be unmet in a given region per financial year.

[59] At https://aemo.com.au/-/media/files/major-publications/isp/2023/2023-iasr-assumptions-workbook.xlsx.

[60] Since the 2023 ESOO, AEMO has been advised that this unit no longer intends to return to service. While this would increase expected USE in the 2024-25 and 2025-26 years in South Australia, AEMO forecasts expected USE to remain below the IRM in these years.

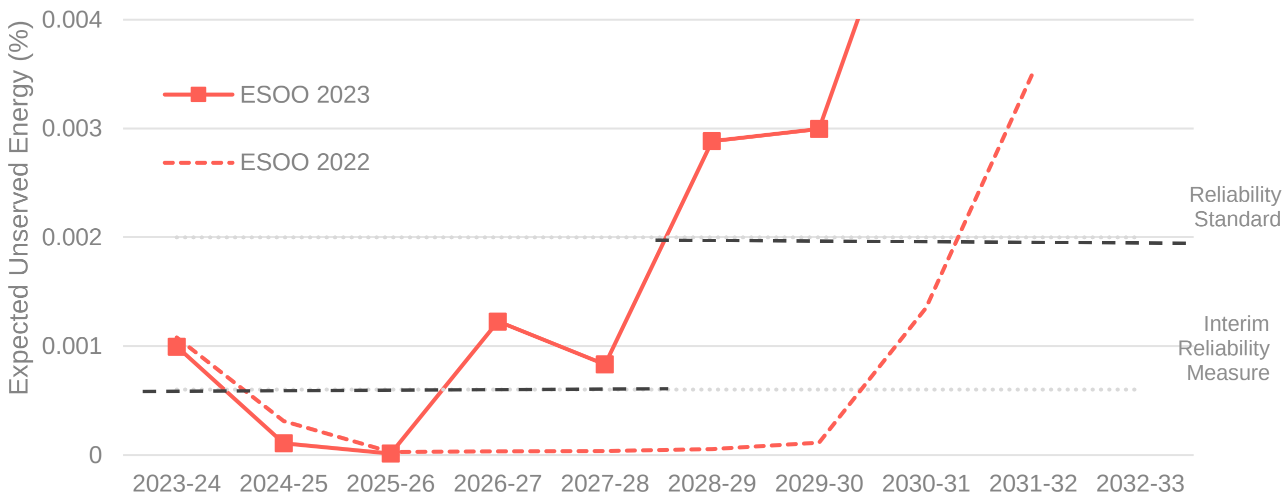
From 2026-27, all four units of Torrens Island B and Osborne Power Station have advised an expectation to have retired. Despite these retirements, expected USE is forecast above the IRM, but within the reliability standard, as stronger network connection from Project EnergyConnect between southern New South Wales (Snowy/Canberra area), Victoria and South Australia is forecast to reduce potential reliability risks.

AEMO has requested the AER's approval to trigger the Retailer Reliability Obligation (RRO) by making a T-3 reliability instrument for South Australia in 2026-27 in response to this reliability gap[61].

Reliability gaps against the reliability standard are projected from 2028-29 (until 2032-33) due to the retirement of Yallourn Power Station in Victoria and in later years the additional retirement of various gas and liquid fuel generators including Dry Creek, Mintaro, Port Lincoln and Snuggery power stations.

Figure 22 shows the forecast USE outcomes for South Australia under the 2023 ESOO Central scenario compared against the 2022 ESOO Central scenario.

Figure 22 Forecast USE outcomes for South Australia – existing, committed and anticipated projects only



This reliability assessment includes all existing, committed and anticipated generation and storage, reported in the Generation Information page published in July 2023, as well as committed and relevant anticipated transmission augmentations[62] and generation retirements.

Specifically, this assessment:

- Does not include any additional capacity that could be made available through RERT[63].
- Represents USE outcomes before any equitable load shedding principles are applied.

[61] At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2023/reliability-instrument-request-sa-t-3.pdf.

[62] This includes major and minor committed augmentations. In AEMO's Generation Information page, Committed projects meet five criteria, while Committed* (or Com*) and anticipated projects are considered highly likely to proceed, but only satisfying some of these criteria. See the 2023 ESOO for more details.

[63] The exception being demand side participation (DSP) responses from RERT panel members delivered outside RERT, which have been included in the DSP forecasts. See DSP methodology for more details, at https://aemo.com.au/consultations/current-and-closed-consultations/demand-side-participation-forecast-methodology-consultation.

- Includes the return to service of Torrens Island B unit 1 (TORRB1) for summer 2024-25 and 2025-26. AEMO notes that this unit no longer intends to return to service, which would increase expected USE in the 2024-25 and 2025-26 years in South Australia, but expects the USE to remain below the IRM in these years.

As **Figure 22** shows, reliability gaps are identified in 2023-24 and 2026-27 against the IRM and from 2028-29 to 2032-33 against the reliability standard.

The main changes to last year's forecast[64] that impact this assessment are:

- AGL has brought forward its expected closure date for the 800 MW gas-powered Torrens Island B Power Station in South Australia from 2035 to 2026.
- Origin Energy no longer advises closure on 31 December 2023 for Osborne Power Station, and now has reported a three-year extension to 2026 for the operation of the 180 MW gas-powered generator.
- The 123 MW gas-powered Bolivar Power Station is now classified as an existing project, and is modelled as available over summer 2022-23.
- AEMO now applies the orchestration of CER only where an aggregator has demonstrated commitment to a relevant program, as opposed to including a forecast of all CER orchestration, as was the case in the 2022 ESOO. As a result, the majority of forecast CER orchestration (VPPs and V2G) is now not included in the 2023 ESOO Central scenario outlook.
- Increase in the probability of coincident low wind, and high demand conditions.
- Anticipated projects are now included in the modelling, and commissioning delays are applied to most new developments to manage commissioning risks that are not yet in the commissioning phase of their development.
- Higher unplanned outage rates, based on updated generator outage information provided by participants.
- Gas capacity is lower in 2023-24 due to an extended outage on some Hallett Gas Turbine units.
- AEMO now applies a derating to short duration storages in the model to address the over-optimised of the availability for shallow storage devices to operate with perfect foresight at the precise time of peak demand. Previously there was no de-rating applied.

Figure 23 below shows the level of expected USE forecast in South Australia for the 2023-24 summer in each of the historical reference years.

The chart shows that under the weather conditions associated with the 2010-11, 2014-15, 2017-18 and 2018-19 reference years, the forecast level of expected USE next summer would exceed the IRM. The reference years forecast to have high expected USE have high electricity demands during low VRE conditions.

[64] Some of these changes were applied to the February 2023 Update to the 2022 ESOO.

Figure 23 Impact of different reference years on expected USE in South Australia 2023-24, Central scenario

While the 2023 ESOO identifies numerous reliability gaps over the 10-year horizon, significant investments in the NEM are expected in addition to the committed, committed* and anticipated projects included in the reliability assessment. A much larger pipeline of proposed generation and storage projects – as described in Section 3.3 for South Australia – demonstrate the opportunity for the market to respond to emerging reliability gaps, if projects are developed in a timely manner. Numerous federal and state government schemes and programs have been implemented to further incentivise or fund the required developments across the NEM. Schemes currently underway include:

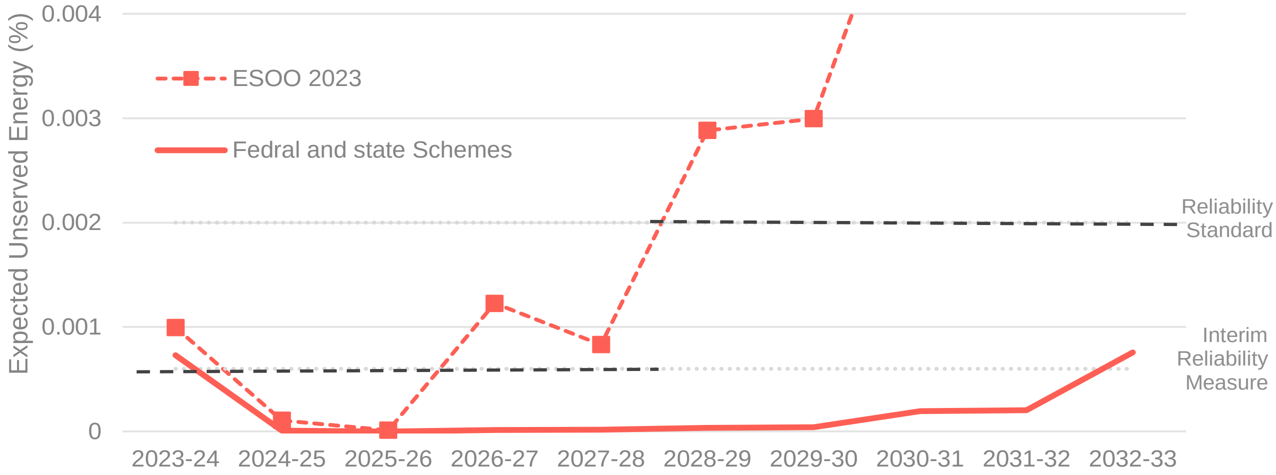
- The federal Capacity Investment Scheme.
- The New South Wales Electricity Infrastructure Roadmap, and firming tenders.
- The Victorian Renewable Energy Target Auction 2.
- The Queensland Energy and Jobs Plan.
- The South Australian Hydrogen and Jobs Plan.

These schemes, if supported by the development of actionable transmission projects, as identified in the 2022 ISP, and the development of 6.6 GW/16.3 GWh of orchestrated consumer investments (largely behind-the-meter battery systems) and 2.1 GW of flexible demand response that are projected in the *Step Change* scenario by 2032-33, have the potential to significantly improve the outlook if they progress as projected. Extra developments relating specifically to South Australia include:

- The South Australian Hydrogen Jobs Plan, which includes 200 MW of power generation and a 250 MW electrolyser with a target to commence operations in 2025-26.
- The development of 630 MW/1,563 MWh of orchestrated consumer investments.

Figure 24 shows that the additional investments in renewable generation, dispatchable capacity, transmission and CER are forecast to further reduce reliability risks to below the relevant reliability standard in most regions. Other policies, such as a longer-term capacity investment scheme, and various renewable energy and storage targets, are developing to support additional firming and renewable capacity that are not included in this sensitivity.

Figure 24 Reliability impact of federal and state schemes, 2023-24 to 2032-33 (%)



4.2 Energy Adequacy Assessment Projection

The Energy Adequacy Assessment Projection (EAAP) forecasts electricity supply reliability in the NEM over a 24-month outlook period. The EAAP complements the ESOO reliability assessments, providing a focus on the impact of energy constraints on forecast reliability.

The EAAP focuses on the reliability impact of limited water and thermal fuel availability by considering the following three energy adequacy scenarios:

- EAAP Central scenario – the most likely fuel and water availability used for generation purposes.
- EAAP Low Rainfall scenario – considering water availability during drought conditions, and most likely fuel availability for thermal production units. Severe drought conditions observed during the Millennium Drought[65] are applied in this scenario.
- EAAP Low Thermal Fuel scenario – considering thermal fuel availability limits under 1-in-10-year low fuel availability conditions[66] for each power station in the NEM. Hydro generators apply most likely water availability.

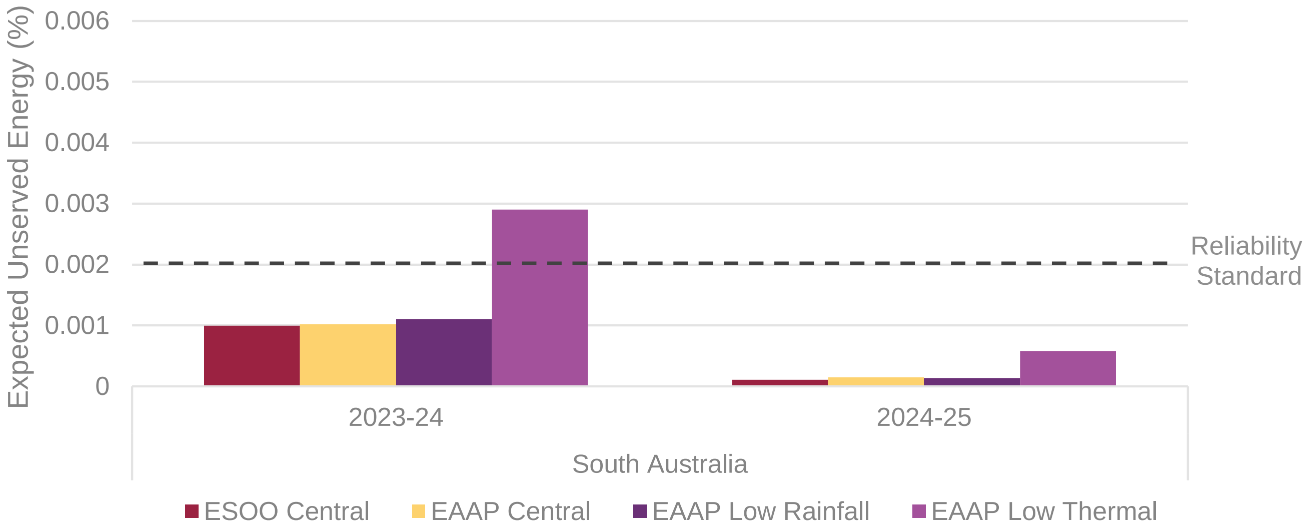
The EAAP assesses reliability by comparing expected USE against the reliability standard of 0.002% USE, as the IRM does not apply for the purposes of the EAAP.

Figure 25 shows expected USE in South Australia under the three EAAP scenarios and the 2023 ESOO Central scenario. The EAAP low fuel scenario shows USE above the reliability standard in 2023-24 in South Australia, but as this scenario is based on participant provided energy limits under a 1-in-10-year fuel unavailability scenario, it does not reflect an expected outlook. This scenario, however, demonstrates the importance of maintaining ongoing availability of fuel and fuel supply chains throughout the energy transition.

[65] The Millennium Drought is categorised as the period between 1997 to 2009, but inflows in 2006 (and therefore affecting the 2006-07 financial year) were at or near the lowest on record in many parts of the NEM, including the Murray Darling basin. For power stations in Queensland, Victoria, South Australia and Tasmania, parameters are provided based on the rainfall experienced between 1 July 2006 and 30 June 2007. For power stations located in New South Wales, parameters are provided based on the rainfall experienced between 1 June 2006 and 31 May 2007.

[66] When developing 1-in-10-year low fuel availability limits, participants are asked to consider the potential impacts of wet coal, longwall moves, train and truck deliveries, loader outages, likely market limitations, pipeline constraints, gas supply issues, and whether these events could occur over a prolonged period, or for shorter events only.

Figure 25 EAAP annual expected USE by scenario (%)



4.3 Managing reliability risks

RERT for summer 2022-23

- For summer 2022-23, the 2022 ESOO did not forecast expected USE to exceed the reliability standard or the IRM in any NEM region. As a result, no long notice RERT or interim reliability reserves were contracted in the NEM[67].
- During the summer of 2022-23, AEMO had up to 2,136 MW of potential RERT reserves across the NEM, including 121 MW in South Australia, under short notice panel arrangements that could be contracted in the event of a forecast LOR event. No short notice reserves were contracted for South Australia during summer 2022-23, and no costs were incurred.

RERT for summer 2023-24 and beyond

- The 2023 ESOO projected expected USE to exceed the IRM in both South Australia and Victoria in 2023-24.
- AEMO is currently considering expressions of interest for additional short notice RERT panel arrangements in South Australia for the 2023-24 summer[68].
- Due to expected USE forecast above the IRM in 2023-24 (see Section 4.1.1), AEMO has published a tender for interim reliability reserves and is currently evaluating these offers. AEMO is seeking to contract for interim reliability reserves in South Australia up to the determined interim reliability exceedance of 118 MW.

[67] AEMO, RERT End of Financial Year Report 2022-23 at https://aemo.com.au/-/media/files/electricity/nem/emergency_management/rert/2023/rert-end-of-financial-year-report-2022-23.pdf.

[68] See https://aemo.com.au/energy-systems/electricity/emergency-management/reliability-and-emergency-reserve-trader-rert/rert-tendering.

5 Electricity spot prices

South Australia witnessed a record high average monthly wholesale electricity price this year, following the unprecedented energy market conditions across the NEM in winter 2022. FCAS markets also experienced significant price volatility following the failure of a tower structure in a storm in November 2022, causing the synchronous separation of a major part of the South Australian power system. The Lower Regulation market eventually breached the cumulative price threshold (CPT), and an administered pricing period (APP) was automatically triggered.

5.1 Historical wholesale electricity prices

In financial year 2022-23, South Australia's time-weighted average price (TWAP) reached $126.25/MWh, marking an 11.3% increase compared to the previous year's average of $113.41/MWh (**Figure 26**, **Table 15**). The pattern of South Australian prices by time of day is shown in **Figure 27**, illustrating an upward shift across all hours[69].

Figure 26 Average South Australian spot electricity price (real June 2023 $/MWh)

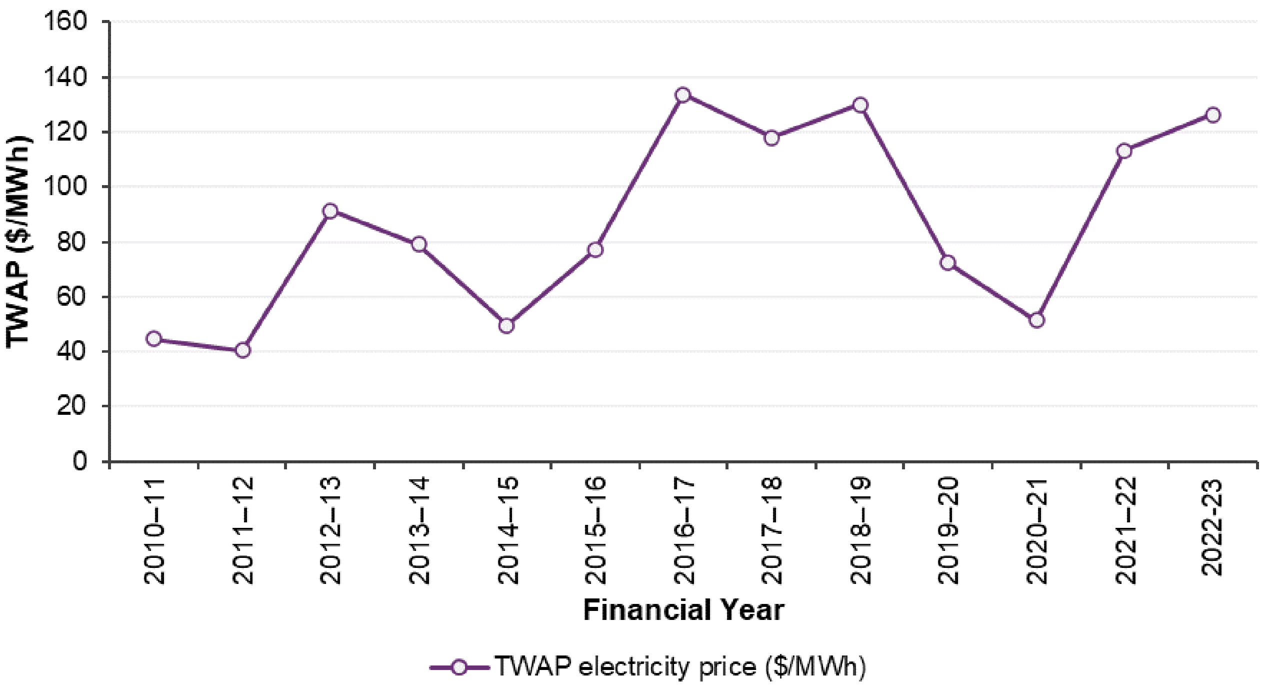
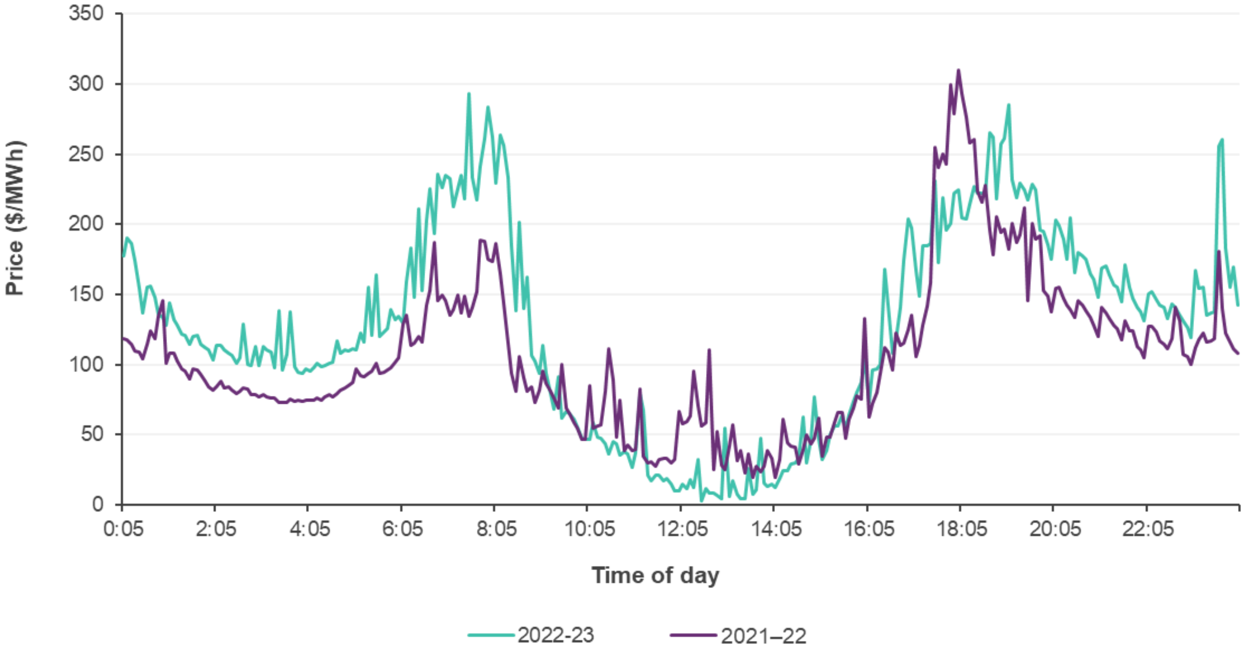


Table 15 2022-23 time-weighted average prices for the NEM

	Queensland	New South Wales	Victoria	South Australia	Tasmania
Time-weighted average price ($/MWh)	149.08	148.28	102.26	126.25	114.09

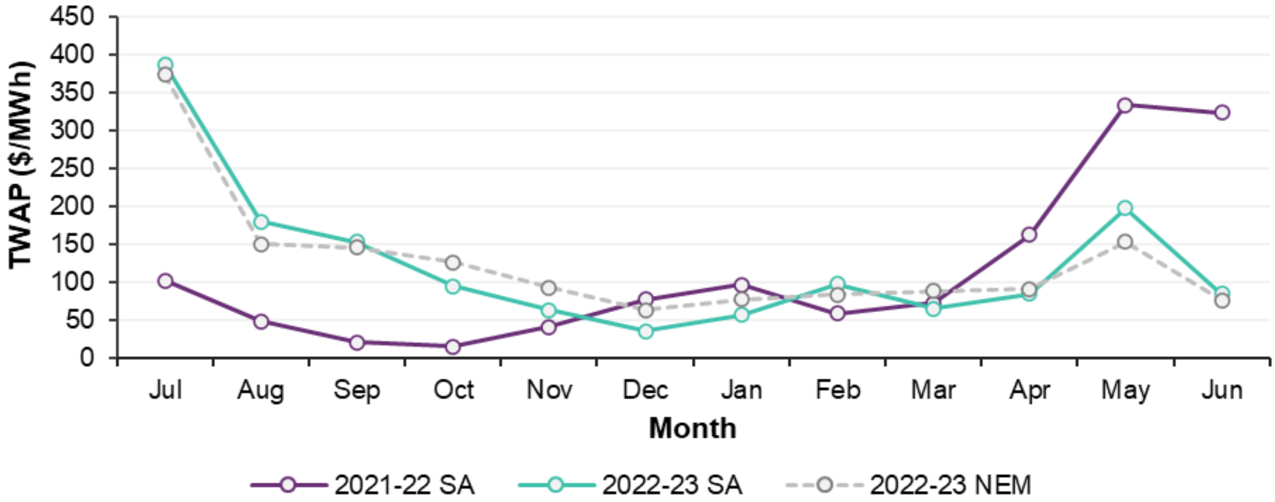
[69] Since commencement of Five-minute settlement (5MS) from 1 October, electricity spot prices are now shown on 5-minute basis for current and previous years.

Figure 27 Average South Australian spot electricity price by time of day (real June 2023 $/MWh)



Continuing the record highs of June 2022, financial year 2022-23 began with very high spot prices across the NEM. July 2022, in particular, stands out as it recorded the highest-ever monthly average in the NEM at $374/MWh. South Australia also hit a historical high in July 2022, with a monthly average price of $388/MWh. Subsequently, South Australia experienced a decreasing trend in monthly average prices through the first half of the year, returning to levels similar to those observed just before the peaks in June and July. The latter half of the financial year saw a contrasting pattern, with average monthly spot prices in South Australia on an upward trajectory from the beginning of 2023, reaching $198/MWh in May, before falling sharply to $86/MWh in June.

Figure 28 Average South Australian spot electricity price by month – FY22-23 and FY21-22 (real June 2023 $/MWh)

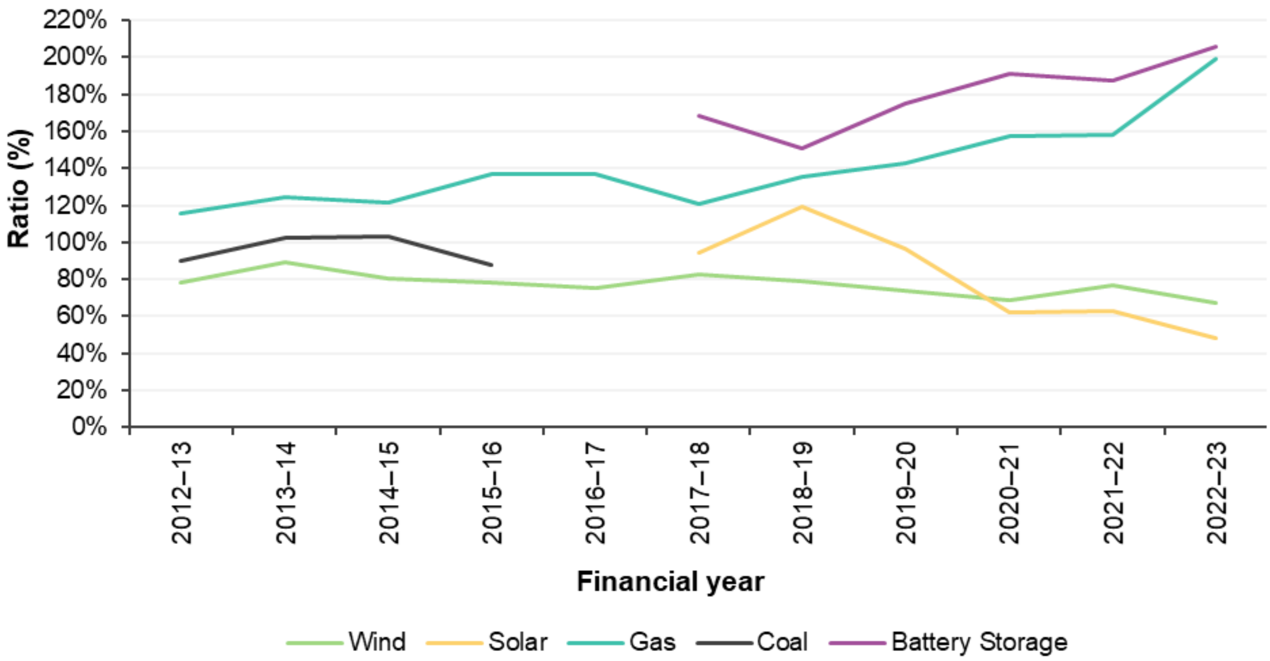


During 2022-23, South Australia saw an increase in the proportion of spot prices set by renewable generators, notably wind and grid-scale solar, which collectively set prices in 20% of the intervals. Conversely, the frequency of price-setting by thermal generators decreased, with black coal, brown coal and gas generators setting prices 17%, 13% and 14% of the intervals respectively. However, the average price set by coal, gas and hydro generators (when they were the marginal fuel type) saw significant increases compared to previous year. This exerted upward pressure on average spot price (as per Figure 26). Key contributors to the overall price increase and the price setting outcomes during 2022-23 are discussed in Section 5.3.

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. **Figure 29** illustrates the ratio of VWAP as a relative percentage to TWAP. In summary:

- **Gas** – VWAP remained above TWAP at 199% this year, similar to the previous year (2021-22) when it was at 158%. This high VWAP to TWAP ratio reflects that gas generators tended to operate at elevated levels during high priced events and reduced their operation during periods of low prices. This trend was particularly evident at the beginning of the year when there was an increase volume of gas-powered generation offered to the market amid elevated east coast gas prices.
- **Battery** – among all fuel types, the VWAP to TWAP ratio for batteries remained the highest at 206% this year.
- **Wind** – the VWAP to TWAP ratio for wind farms decreased from 77% in 2021-22 to 67% in 2022-23, marking its lowest level since 2012-13.
- **Grid-scale solar** – VWAP remained below TWAP at 48%, largely driven by the increased occurrence of low and negative prices during the middle of the day, particularly during the first half of the year.

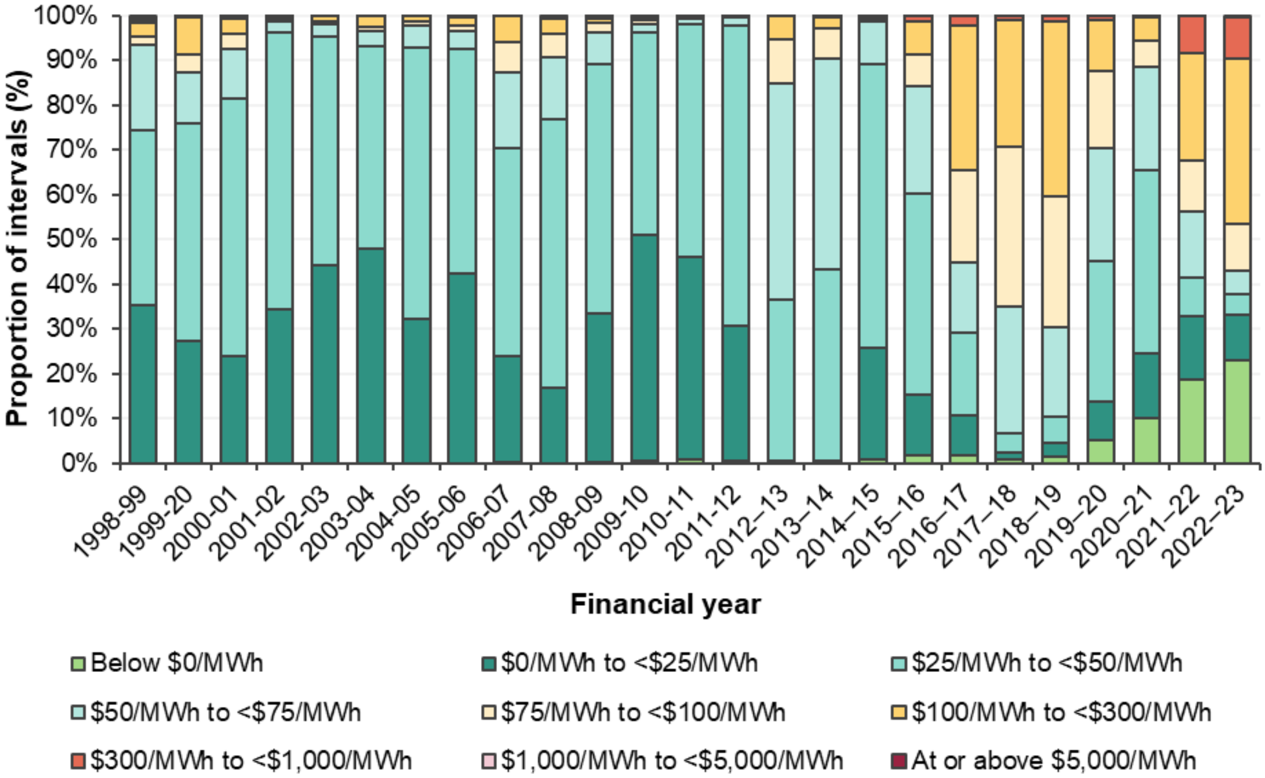
Figure 29 Ratio of VWAP by fuel to total TWAP for South Australian generators



5.2 Price volatility

In 2022-23, South Australia saw 9.7% of intervals with prices above $300/MWh, up by 1.3 percentage points (pp) from the previous year's 8.4%. The price band of $100-300/MWh saw the largest year-to-year growth, with a 13 pp increase to average 36.9% this year. Conversely, only 5.4% intervals in FY 2022-23 witnessed spot prices between $50/MWh and $75/MWh, marking a reduction of 9.5 pp from 14.8% in the previous year. South Australia also experienced an increase in the occurrence of negative prices, reaching new highs at 23% (see **Figure 30**).

Figure 30 Frequency of occurrence of spot prices for South Australia, 1998-99 to 2022-23



5.2.1 High prices

Spot price volatility, as measured by cap returns (the contribution of spot prices in excess of $300/MWh to the annual average) increased to $30/MWh (**Figure 31**) from the previous year's $20/MWh. These cap returns were mostly driven by instances of extremely high spot prices, which occurred on the back of tight supply-demand balance conditions and/or other constraints. While South Australia experienced several of these volatile events during 2022-23, they were more pronounced in the September quarter when the impact of the extremely high prices in June 2022 persisted into the following months. During the September quarter of 2022, prices exceeded $300/MWh in an unprecedented proportion of dispatch intervals.

Figure 32 illustrates the breakdown of the aggregate cap returns in South Australia, differentiating between spot prices higher than $1,000/MWh and those between $300/MWh and $1,000/MWh. While volatility arising from extreme spot prices (>$1,000/MWh) remained high in the September quarter, it remained within historic precedents in other quarters of the year. Notably, the contribution from spot prices occurring in the lower range (>$300/MWh to $1,000/MWh) was much greater than in recent years.

Figure 31 South Australian cap returns

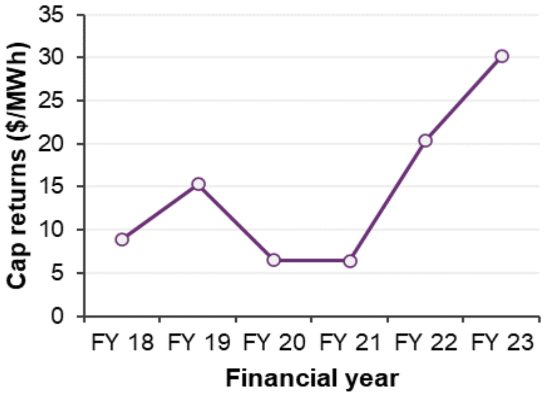
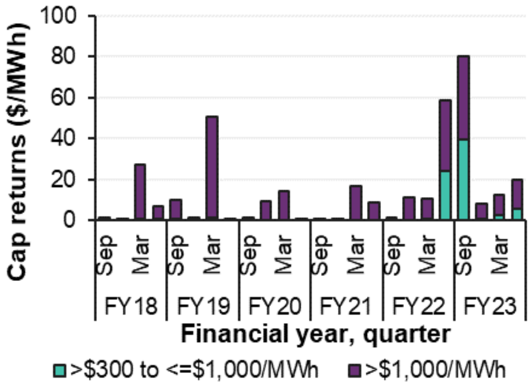


Figure 32 Contribution to total South Australian cap return by price range – quarters



5.2.2 Negative prices

In 2022-23, South Australia saw an increase in negative spot prices, with 23% of dispatch intervals experiencing such occurrences, marking a record high for a financial year and 4 pp increase from the previous year (see **Figure 33**). Consistent with previous years, negative price occurrence continued to be more frequent in daytime hours when operational demand is lower due to high distributed PV output and large-scale VRE generation is higher. Notably, between 1000 hrs and 1500 hrs (NEM time), spot prices were negative 54% of the time in 2022-23, up from 44% in 2021-22 (see **Figure 34**).

Furthermore, 2022-23 witnessed grid-scale VRE output in Victoria and South Australia reaching a combined average of 2,235 MW, increasing by 12% from the previous year. This year saw extended periods of very high VRE output in both Victoria and South Australia. The combined VRE output between 1000 hrs and 1500 hrs exceeded 2,000 MW 53% of the time, compared to 48% in 2021-22. This, coupled with low daytime demand contributed to periods of oversupply in both regions. Overnight negative price occurrence in South Australia also rose slightly, driven by periods of high wind output.

Figure 33 Count of negative price dispatch intervals per year

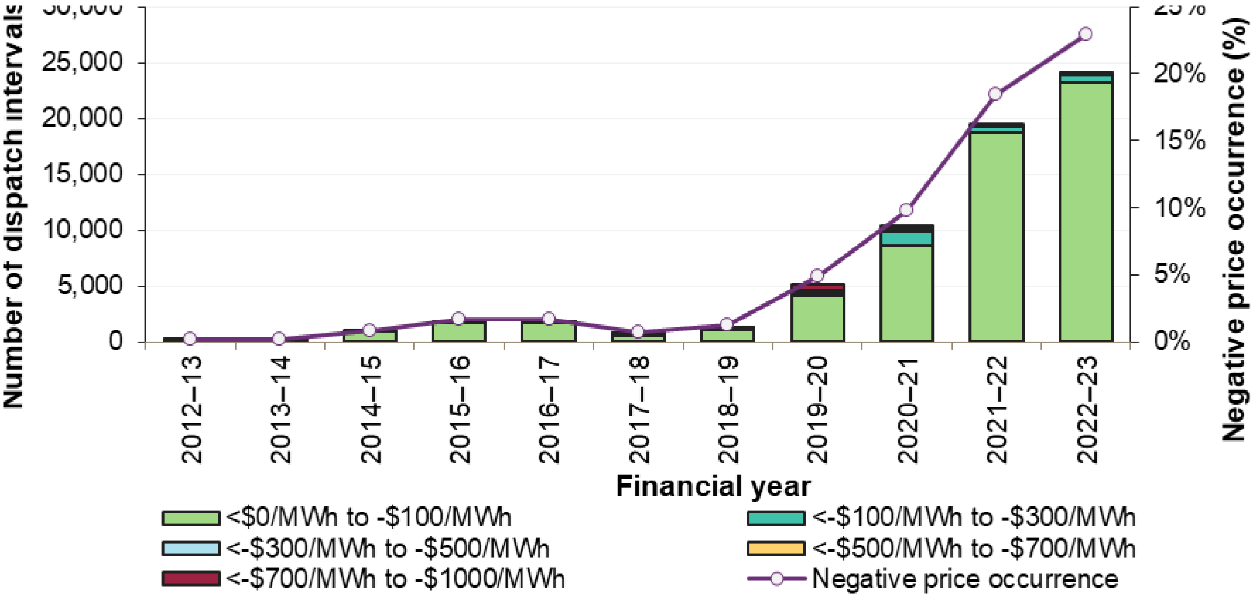
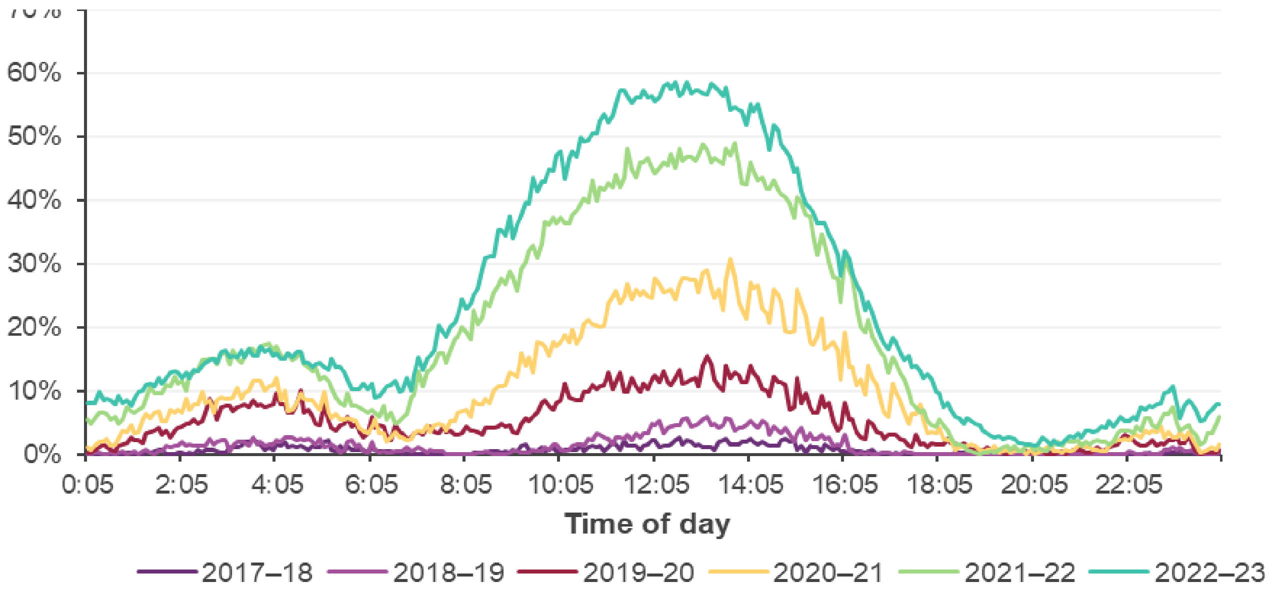


Figure 34 Percentage of time South Australian price was negative by time of day

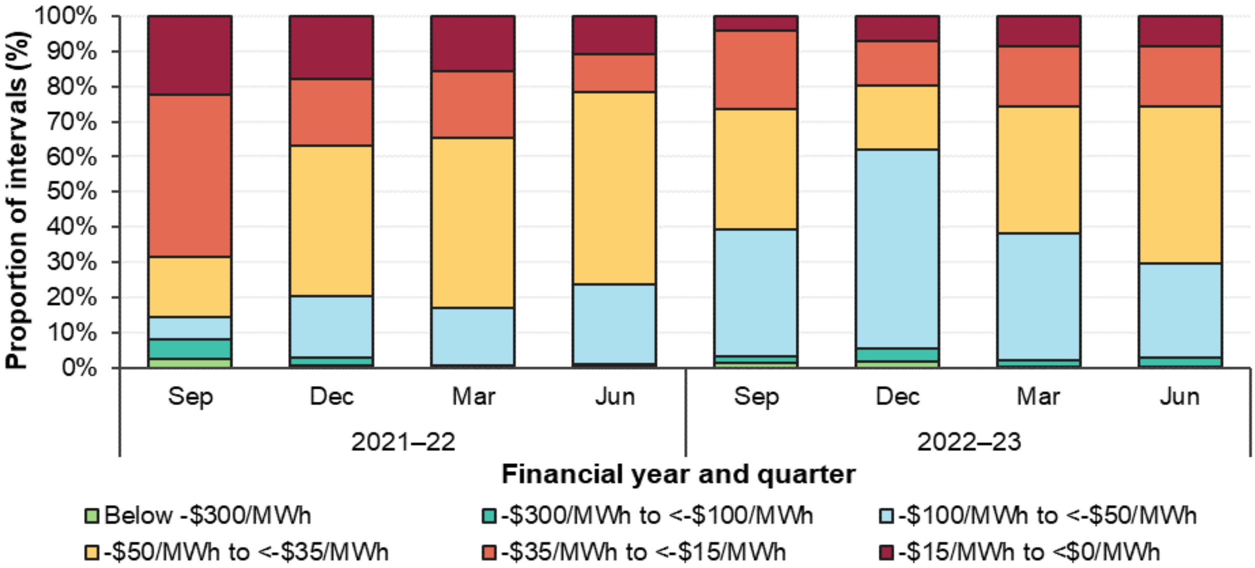


As the overall frequency of negative spot prices rose significantly, the negative price impact[70] this year increased to approximately $13/MWh, up from approximately $9/MWh in the previous year. This increase exerted downward pressure on average spot price in South Australia. Notably, the higher impact of negative spot prices was more evident in the -$100 to -$50/MWh range, with 42% of negative prices having occurred within this range (**Figure 35**). This represented an increase of 27 pp from the previous year and coincided with an increase in spot prices of large-scale renewable certificates (LGCs) created by renewable generation. Spot LGC prices showed an

[70] This refers to by how much the average annual wholesale price was lowered due to negative prices. The higher the negative price impact, the lower the average will be.

upward trend in the first half of the year and reached an average of $65/certificate in the December quarter before declining to $49/certificate in the March quarter.

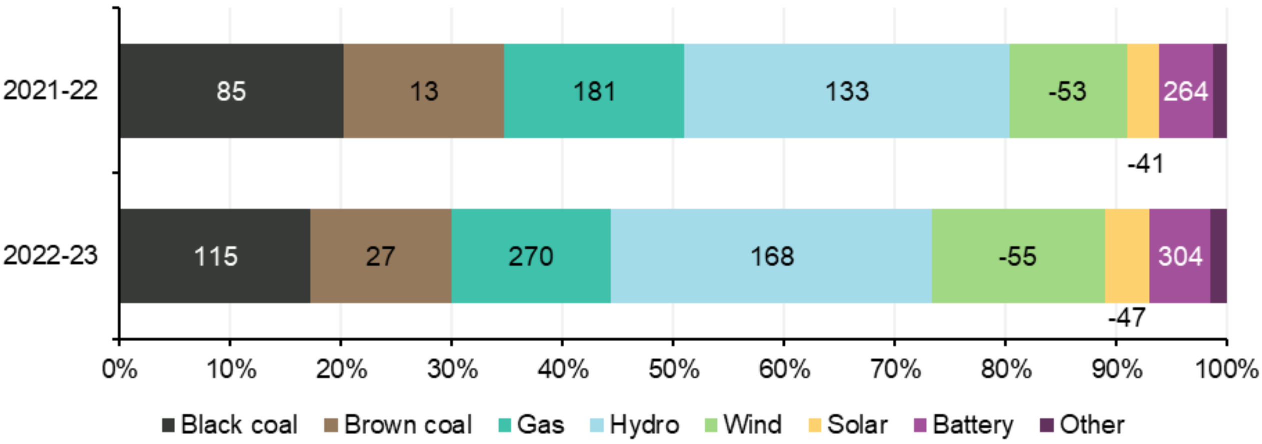
Figure 35 South Australian negative spot price band – proportion of intervals when price was negative



5.3 Price setting outcomes

Figure 36 shows South Australia's annual price setting outcomes by fuel type for 2021-22 and 2022-23.

Figure 36 South Australia price setting by fuel type



Note: June quarter 2022 data only includes periods up to commencement of Administered Price Period in Queensland (12 June 2022).

Key price setting outcomes[71] in 2022-23 included:

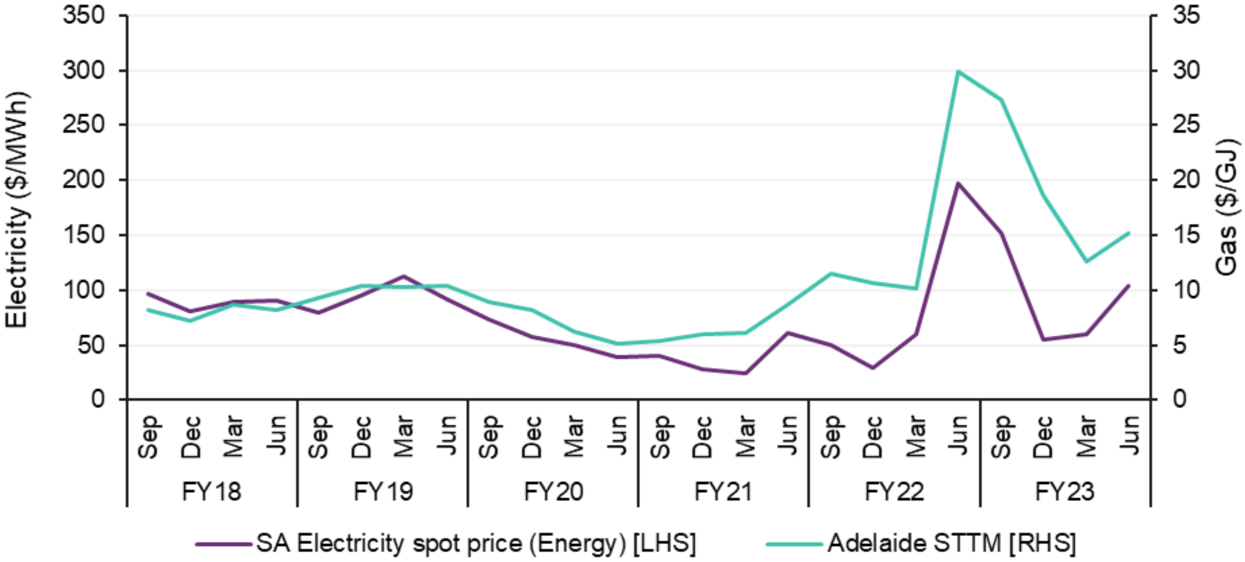
[71] The NEM's interconnected structure allows prices in one region to be set by market offers in a different region provided that interconnector flows are not constrained, meaning for example that offers from black coal generators in New South Wales or Queensland may at times set price in southern NEM regions as well as in those generators' home regions.

- Generators with renewable fuel sources set the price more often – hydro, wind and grid-scale solar set the price in 49% of intervals in 2022-23, an increase of 6 pp. Almost all of the increase was in wind and grid-scale solar price-setting frequency, rising by 5 pp and 1 pp respectively. Offsetting these increases were decreases in price setting frequency from black coal (-3 pp), brown coal (-2 pp) and gas-powered generation (-2 pp).
- For coal generators specifically:
  - The average price set when black coal generators were the marginal generator was $115/MWh this financial year compared to $85/MWh last financial year. In the first half of the year, black coal generators repriced their offer volumes to higher price bands, driven by a combination of elevated thermal coal prices and fuel supply restrictions. This resulted in an increase average price set by black coal units.
  - Similarly, the average price when brown coal was the marginal price setter was $27/MWh, up from $13/MWh previous year. This contributed to the increase in average price across the year.
- Gas-powered generators' price-setting role declined 2 pp to an average of 14% of the time in 2022-23. When gas-powered generation was the marginal price setter the average price was $270/MWh, higher than 2021-22 when the average price set by gas-powered generation when it was the marginal generation was $181/MWh.
- Grid-scale solar and wind's combined price setting role was 20% this year, increasing from 13% in 2021-22, while batteries also increased its price setting frequency 0.6 pp from last financial year to 5.5% this year. VRE generation as well as batteries frequently set prices during the middle of the day leading to increased occurrence of negative spot prices (Section 5.2.1).
- Murray Hydroelectric Power Station in Victoria continued to remain the most common price setting power station during 2022-23, setting prices 11.8% of the time, followed by Loy Yang B Power Station (6.5%) as the second most common price setter. Pelican Point Power Station set the price 4.8% of the time, the highest contribution from a South Australian generator.
- Price setting from hydro as a fuel source did not change significantly (29% in both years), although the average price set when hydro was the marginal fuel increased significantly to $168/MWh from $133/MWh.

5.4 Gas spot price impact on electricity spot prices

Historical average electricity and gas prices are shown in **Figure 37**. The strong relationship between the movements of the South Australian electricity price and Adelaide's STTM across time reflects the key role of gas-powered generation as a key marginal supply source in South Australia.

Figure 37 South Australian electricity and gas price



Note: To remove the impact of electricity price volatility, South Australian electricity spot prices are capped at $300/MWh to prepare this chart.

Overall, between 2021-22 and 2022-23, South Australia's average TWAP increased by 18% while Adelaide STTM increased by 19% to $18/GJ. High prices following the energy crisis in June 2022 continued into the September quarter, with Adelaide hub prices peaking at $59.23/GJ on 18 July, corresponding to cold weather and high gas-powered generation.

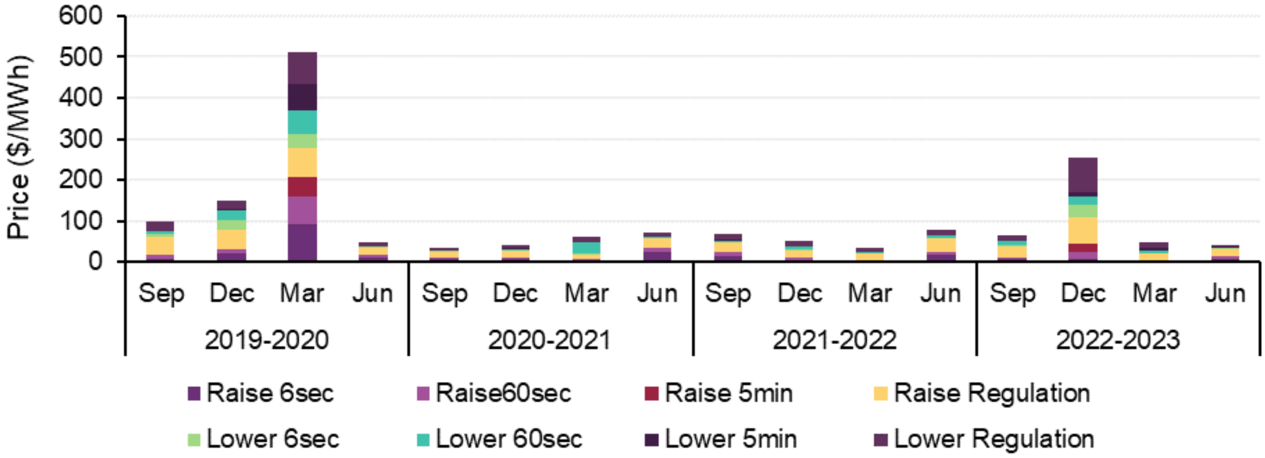
By August 2022, domestic gas market prices eased, with a large gap emerging between domestic and international prices. Milder weather driving lower heating demand, reduced gas-powered generation, and an increased supply in domestic gas supply from Queensland to southern markets eased a previously tight supply-demand balance, driving down prices.

On 9 December 2022, the Federal Government published a consultation paper that proposed a temporary emergency price cap, and a mandatory code of conduct. The mandatory code of conduct aims to provide a 'reasonable pricing framework', which will set out the guidelines for producers and buyers to negotiate wholesale domestic gas contracts at 'reasonable prices'. The price cap and code of conduct apply to the east coast of Australia, including the Northern Territory, while Western Australia is excluded. The legislation for the price cap and mandatory code of conduct was assented into law on 16 December 2022, and the emergency price cap became effective from 23 December 2022 for 12 months. While the price cap is set at $12/GJ, the cap does not apply to the STTMs, and only to gas supply offers made three days in advance of the delivery date.

5.5 Frequency control ancillary services market prices

South Australian FCAS prices during 2022-23 averaged $13/MWh in the region across all eight FCAS markets compared to $7/MWh in 2021-22. Despite application of the administered price cap in November 2022, aggregate South Australian FCAS costs were several times larger in Q4 2022 than in recent quarters, reaching their highest quarterly level since Q1 2020 (**Figure 38**).

Figure 38 Quarterly average South Australia FCAS prices by service – stacked



On 12 November 2022, two South East – Tailem Bend 275 kV transmission lines tripped on failure of a tower structure in a storm, causing the synchronous separation of a major part of the South Australian power system from the rest of the NEM. This area of the system remained electrically 'islanded' until one of the lines was returned to service on 19 November[72].

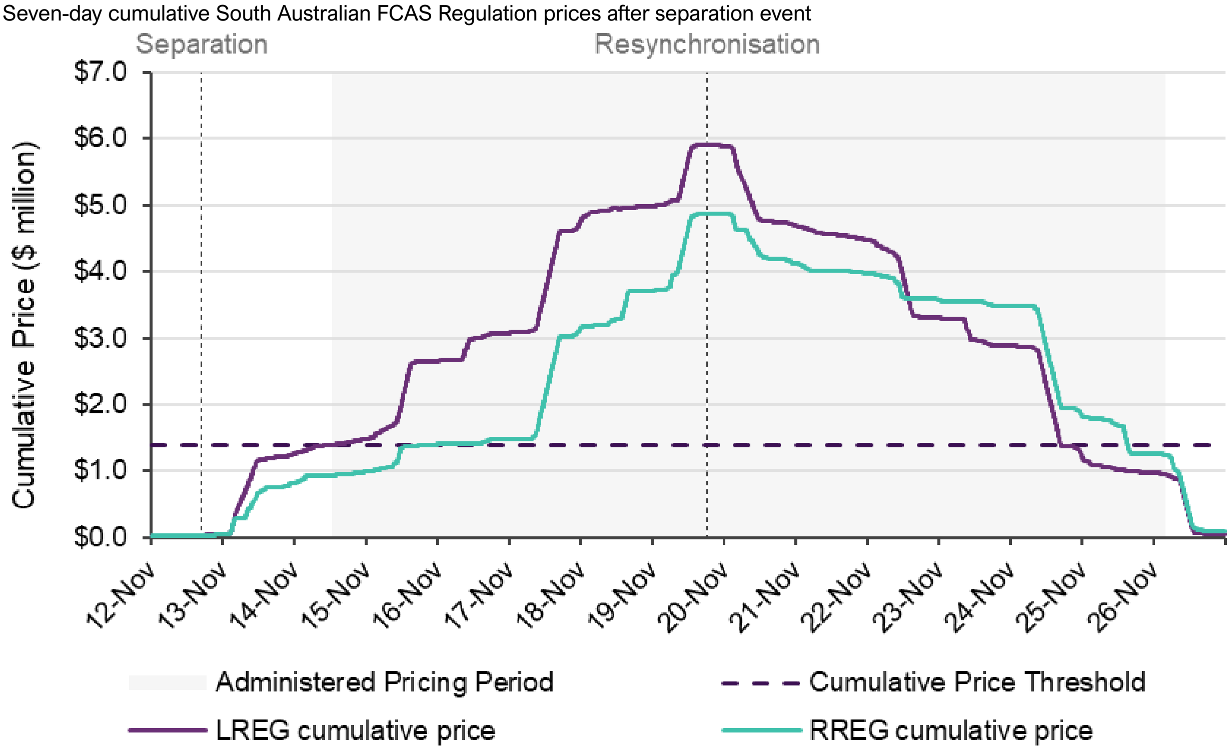
Without support from the rest of the NEM, only sources within the islanded area could be used to meet South Australian FCAS requirements. As a result, all FCAS markets experienced significant price volatility. The Lower Regulation market had the highest prices and, on 14 November 2022 at 1300 hrs NEM time, this market breached the CPT and an APP was automatically triggered. A cap of $300/MWh was applied to all eight FCAS markets, limiting the amount of FCAS payments. The APP ended on 26 November 2022 (at 0400 hrs), which was the first trading day which commenced with the seven-day cumulative prices (calculated as if the $300/MWh cap had not been applied) below the CPT for all services.

Figure 39 shows the cumulative prices in the FCAS markets which triggered the start of the APP (Lower Regulation), and the last market to fall below the CPT (Raise Regulation).

[72] For more detail, see AEMO's preliminary event report at https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2022/preliminary-report--trip-of-south-east-tailem-bend.pdf?la=en.

Figure 39 High cumulative prices triggered administered pricing for South Australian FCAS

Seven-day cumulative South Australian FCAS Regulation prices after separation event



6 System security

This section discusses the maintenance of power system security[73] in South Australia, considering the changing generation mix, increased distributed PV uptake, and decreasing minimum operational demand. AEMO continues to work closely with the South Australian Government, ElectraNet, SA Power Networks, and industry participants to adapt system planning and operations during this energy transition so consumers can continue to exercise choice and access reliable, low-cost energy.

Across Australia, solar and wind energy resources are being installed at a rapid pace, and power system dynamics are being increasingly influenced by the generation of millions of individual CER, such as rooftop PV systems, EVs and batteries. Patterns of power flow are changing quickly as generation moves behind the meter or to remote parts of the grid.

While the system was once able to operate well inside its technical envelope, the energy transition is pushing the system to operate more frequently near its boundaries. This has highlighted new security concerns in the short term while major network, generation, and energy storage projects deliver improvements in the longer term.

6.1 Declining minimum demand

As households and businesses supply more of their own energy from distributed PV and storage, they draw less electricity from the grid. Operating a power system with unprecedented levels of distributed PV and declining levels of operational demand creates challenges and opportunities that are particularly pertinent to South Australia. While these trends are forecast to continue, AEMO's system security studies are increasingly finding that new utility-scale inverter-based resources (IBR) can also provide additional reactive power capabilities that improve voltage control in the system, providing additional balancing services to mitigate emerging challenges.

6.1.1 Challenges associated with minimum demand

South Australia has experienced periods where up to 99%[74] of estimated underlying demand was supplied by distributed PV and is, to AEMO's knowledge, the first gigawatt-scale power system in the world to be close to supplying 100% of underlying demand from distributed PV. AEMO forecasts that South Australia could experience periods in the near future where distributed PV supplies all of the underlying demand.

The whole NEM power system is experiencing declining minimum operational demand, but it is particularly noticeable for South Australia as a direct result of its high and growing uptake of distributed PV and higher proportion of load being residential or commercial rather than industrial[75].

[73] Power system security means the power system is operating within defined technical limits and is likely to return within those technical limits after a disruptive event occurs, such as the disconnection of a major power system element (such as a power station or major powerline).

[74] The highest observed penetration as of 16 September 2023.

[75] For more, see 2021 ESOO, Section 6.1.2 and Appendix Sections A3.3 and A3.5, at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo.

The associated challenges that South Australia is managing include:

- **Maintaining sufficient levels of operation from synchronous generating units** that are needed to provide essential system security services.
- **Managing unintended disconnection of distributed PV during power system disturbances**. The disconnection of distributed PV following disturbances increases contingency sizes, which increases the need for frequency control services, and adversely affects network stability limits.
- **Maintaining transmission voltages within the necessary ranges**, particularly when operational demand is low and the network is lightly loaded. In June 2023, ElectraNet provided AEMO with a revised set of limits advice which stipulated that operation with fewer than two units online is only possible when a specific set of voltage controls conditions are met – including that demand remains above 600 MW, that a set of specific reactive power control devices are available, and that South Australia is not at credible risk of separating from the NEM.
- **Delivering sufficient emergency under-frequency response to manage non-credible disturbances**. Distributed PV is reducing the net load on under-frequency load shedding (UFLS) circuits, reducing its effectiveness in arresting a frequency decline. This capability needs to be restored, as UFLS is an important last line of defence to protect against system collapse.
- **Maintaining the ability to perform a system restart under conditions of very low operational demand**. At present, system restart requires the start-up of transmission-connected synchronous generators. These generating units require a minimum level of stable load to operate above their minimum loading levels. In high distributed PV periods, there may not be enough stable load available in the vicinity.

AEMO's operating procedures include a minimum operational demand threshold of 600 MW in periods when South Australia is separated from the rest of the NEM, and a dynamic threshold when South Australia is at credible risk of separation from the rest of the NEM. These thresholds can be higher depending on estimated contingency sizes associated with distributed PV shake-off in response to a disturbance.

6.1.2 Mechanisms to support declining minimum demand

Investment in new voltage control network assets

In December 2022, ElectraNet commenced a regulatory investment test for transmission (RIT-T) to deliver sufficient static and dynamic voltage control capability within South Australia to address a gap of approximately 200-400 MVAr reactive power support capability in the Adelaide Metropolitan region, and a further 50-100 MVAr in the South East of South Australia[76]. This need was driven by:

- Up to 1,200 MVAr of transmission line charging on the transmission network during low or zero demand conditions related to distributed PV offsetting demand.
- An increasingly frequent need to offset transmission line charging by using up the reserve dynamic capability on the network that is needed to manage credible and non-credible contingency events.

[76] See https://www.electranet.com.au/projects/south-australian-transmission-network-voltage-control/.

- An emerging trend of connected loads becoming less inductive (to the point of becoming capacitive) across the day reducing the network's capability to offset line charging.
- An increase in rapid daily load fluctuations caused by intermittent distributed PV (due, for example, to rapidly changing cloud cover) as well as the more predicable forecast daily load profile dominated by distributed PV, which requires increased automation of reactive and voltage control plant to manage the consequent voltage changes.
- Forecast closures of metropolitan thermal generators leading to a loss of voltage control capability.

ElectraNet identified three credible network options and sought additional options from non-network service providers who may be capable of meeting the requirements. Submissions closed on its Project Specification Consultation Report (PSCR) in March 2023, and its Project Assessment Draft Report (PADR) is expected to be published by the end of 2024.

Increased capabilities for distributed PV

In 2020, AEMO recommended a number of measures to the South Australian Government to address challenges associated with declining minimum demand[77]. Since then, the following actions have been undertaken:

- AEMO has worked extensively with stakeholders to update Australian Standard AS/NZS 4777.2, aiming to minimise unintended self-disconnections of future consumer rooftop PV in response to system disturbances. The updated standard came into effect in December 2021. It aims to improve the ability of new installations of consumer rooftop PV to stay connected and operational following power system disturbances, and in so doing, reduce the need for South Australia to manage increasing generation contingency sizes that could otherwise arise from unexpected disconnection of a growing level of distributed PV. Investigation to date indicates that the new standard appropriately defines the required behaviours, but compliance with the new standard is poor, with only ~35% of distributed PV systems installed in January to March 2022 correctly set to the new standard[78]. AEMO is working with inverter manufacturers, the Clean Energy Council and distribution network service providers (DNSPs) to improve compliance, and engaging with the Australian Energy Market Commission (AEMC) on a review of governance frameworks for inverter compliance[79]. This has significantly increased compliance levels.
- South Australia introduced a requirement for all new distributed energy generating installations to have the ability to be remotely curtailed. Curtailment may be used as an emergency last resort measure to maintain power system security. The requirement does not apply to the legacy fleet of distributed PV installed in South Australia[80]. This last resort capability was effective from 28 September 2020. It was used to manage contingency risks related to distributed PV shake-off (unintended disconnection in response to a power system disturbance) during an incident that resulted in operation of South Australia as an island from 12-19 November

[77] AEMO (May 2020) Minimum operational demand thresholds in South Australia, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/sa_advisory/2020/minimum-operational-demand-thresholds-in-south-australia-review.pdf.

[78] AEMO (July 2022), Power System Frequency Risk Review, Section 3.3.1, at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/psfrr/2022-final-report---power-system-frequency-risk-review.pdf.

[79] AEMC (29 September 2022), Review into consumer energy resources technical standards, at https://www.aemc.gov.au/market-reviewsadvice/review-consumer-energy-resources-technical-standards.

[80] AEMO (May 2021) Behaviour of distributed resources during power system disturbances, at https://aemo.com.au/-/media/files/initiatives/der/2021/capstone-report.pdf.

2022, particularly during periods of very high generation from distributed PV. Post event analysis indicated that of the 517 MW of distributed PV capacity installed under this scheme, only 25-42% were observed to respond as required in this event[81]. SA Power Networks is currently implementing improvements to the associated compliance frameworks.

- SA Power Networks has implemented a "Flexible Exports" mechanism from July 2023 to deliver longer-term technical capabilities for more sophisticated active management of distributed PV[82]. AEMO is investigating pathways by which SA Power Networks' DER management systems can be more effectively integrated with AEMO's dispatch systems to improve automation and efficiency in dispatch and scheduling coordinated within both distribution and transmission system limits.

AEMO is continuing to monitor and review the appropriateness of its system operational procedures.

Enhancement to South Australia's System Integrity Protection Scheme (SIPS)[83]

ElectraNet is finalising its upgrade to the existing SIPS in the form of a Wide Area Protection Scheme (WAPS). Specifically, the WAPS aims to further reduce the risk that multiple network events cause up to 500 MW loss of generation in South Australia, lead to a South Australia separation, or lead to a potential South Australian black system. The WAPS has been designed by ElectraNet to accurately detect conditions that are approaching loss of synchronism between South Australia and Victoria using phasor point measurement unit data.

The scheme has three stages of response which trigger when system conditions exceed relevant WAPS settings:

- **Stage 1 (Lowest trigger level)** – the scheme will inject active power from BESS within South Australia to reduce interconnector flows into SA and avoid interconnector tripping.
- **Stage 2 (Higher trigger level)** – the scheme will shed loads at pre-determined locations to reduce interconnector flows into South Australia and avoid interconnector tripping.
- **Stage 3 (Highest trigger level)** – where the WAPS detects a loss of synchronism at South East Substation it will immediately trip both Heywood – South East 275 kV lines (islanding South Australia from the NEM).

ElectraNet, in consultation with AEMO, is planning to place the WAPS into operational service before the end of 2023.

Under-frequency load shedding

AEMO is working with SA Power Networks and ElectraNet to implement a suite of measures to provide suitable emergency under frequency response (EUFR), and manage the impacts of distributed PV on the functionality of

[81] AEMO (May 2023) Trip of South East – Tailem Bend 275kV lines on 12 November 2022, at https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2022/trip-of-south-east-tailem-bend-275-kv-lines-november-2022.pdf.

[82] See SA Power Networks, Flexible Exports, at https://www.sapowernetworks.com.au/industry/flexible-exports/.

[83] See AEMO, Power System Frequency Risk Review – Stage 2, at https://aemo.com.au/en/energy-systems/electricity/national-electricitymarket-nem/system-operations/power-system-frequency-risk-review.

UFLS. SA Power Networks has advised that as of September 2023, approximately one-third of its proposed dynamic arming of UFLS circuits has been rolled out[84,85].

Further analysis is underway to determine suitable targets for EUFR capability in periods with low operational demand, to manage plausible non-credible contingency events.

Management of non-credible separations of South Australia from the rest of the NEM

AEMO has completed extensive analysis of non-credible separations of South Australia from the rest of the NEM[86]. These studies were undertaken following a recommendation, initially in the 2020 Power System Frequency Risk Report (PSFRR), to request the Reliability Panel declare the non-credible separation of South Australia a protected event under the NER.

AEMO has identified a range of preferred management actions which do not require a protected event, and has decided not to further progress the protected event request.

6.2 System strength

System strength is a critical requirement for a secure and stable power system. A minimum level of system strength is required for the power system to maintain a stable voltage waveform, both during normal operation, and following a disturbance[87]. System strength is often approximated by the amount of electrical current available during a network fault (fault current), however the concept also includes a range of electrical characteristics and complex power system interactions.

Historically, system strength has been provided by fossil-fuelled generators in well-connected parts of the network. As these generators are replaced by renewable generation in other locations, it is increasingly difficult to accommodate new IBR investment while maintaining stable power system operation.

System strength requirements are sensitive to changes in the transmission network and generation mix in a region, and AEMO publishes an annual update of system strength requirements and shortfalls in December each year. This section summarises the current system strength outcomes for South Australia.

6.2.1 New system strength framework

The AEMC introduced an initial 'do no harm' framework in 2017[88] that aimed to address emerging system strength challenges by requiring that new connection applicants remediate any negative system strength impacts caused by their plant. While this improved the certainty of these services, the framework remained reactive to the order of new connection applications and did not consider the impact of synchronous plant withdrawals.

[84] AEMO, South Australian Under Frequency Load Shedding – Dynamic Arming, May 2021, at https://aemo.com.au/-/media/files/initiatives/der/2021/south-australian-ufls-dynamic-arming.pdf.

[85] AER, SA Power Networks – Cost pass through – Emergency standards 2021-22, at https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/cost-pass-throughs/sa-power-networks-cost-pass-through-emergency-standards-2021%E2%80%9322.

[86] AEMO (May 2023) Separation leading to under-frequency in South Australia, at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/psfrr/non-credible-separation-of-south-australia.pdf.

[87] For definitions and descriptions of system strength and power system security, see AEMO's Power System Requirements, updated in July 2020, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power-system-requirements.pdf.

[88] AEMC, Managing Power System Fault Levels 2017, at https://www.aemc.gov.au/rule-changes/managing-power-system-fault-levels.

In October 2021, the AEMC made further amendments[89] to drive more proactivity in the provision of system strength services, and to leverage the economies of scale and operational benefits of larger, centralised investments. These amendments introduced new power system standards, added new investment obligations on network businesses, and defined new minimum access standards for connecting parties. A new charging mechanism was also introduced to allow connection applicants to decide whether to self-remediate or to contribute towards a fleet of centrally provided services.

Under the previous framework, AEMO declared system strength shortfalls to be remediated by the local transmission network service provider (TNSP) as a last-resort planning mechanism. The new framework explicitly designates ElectraNet the System Strength Service Provider (SSSP) for South Australia and requires that ElectraNet undertake ongoing investment in services to meet an underlying set of system strength standards published by AEMO. This new requirement takes effect from 2 December 2025, and associated investments must be justified through a reliability corrective action RIT-T.

Investments made by the SSSPs to meet their system strength obligations are treated as prescribed transmission services, with costs passed through to consumers. This cost is offset by system strength charges payable by connecting parties, where they elect to do so instead of self-remediating.

6.2.2 Current system strength assessment for South Australia

AEMO published its most recent *System Strength Report* in December 2022[90], which applied the new system strength framework, including an assessment of shortfalls until 1 December 2025 and a decade-ahead system strength standard for key locations within South Australia.

The report found that existing minimum fault level requirements in South Australia had remained unchanged, and that no system strength shortfalls were forecast in South Australia following commissioning of ElectraNet's four synchronous condensers at Robertstown and Davenport substations.

AEMO has previously updated its operational procedures to incorporate these additional synchronous condensers[91], and limits advice confirms that the South Australian system has sufficient system strength to operate with up to 2,500 MW of non-synchronous generation while intact and connected to the rest of the NEM.

System strength nodes and minimum fault level requirements

South Australia system strength nodes and their minimum fault level and requirements remain unchanged from previous reports. **Table 16** presents the current minimum fault levels and their projected values over the decade ahead. AEMO is also considering a possible system strength node at Tailem Bend, which may be declared in a future *System Strength Report* subject to new connections and ongoing changes to the power system.

AEMO notes that the magnitude of minimum fault level requirements, particularly at the Robertstown 275 kV node, may be impacted by the commissioning of Project EnergyConnect and the associated reduction in network impedance and additional synchronous condensers.

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[89] AEMC. Rule determination. National Electricity Amendment (Efficient management of system strength on the power system) Rule 2021. October 2021, at https://www.aemc.gov.au/rule-changes/efficient-management-system-strength-power-system.

[90] At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-strength-requirements/2022-system-strength-report.pdf.

[91] See AEMO, Transfer limit advice – System strength in SA and Victoria, September 2022, at https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/transfer-limit-advice-system-strength.pdf.

Table 16 Pre- and post-contingent minimum fault level requirement projections for the decade ahead (MVA)

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Davenport 275 kV	2,400	2,400	2,400	2,400	2,400	2,400	2,400	2,400	2,400	2,400	2,400
Para 275 kV	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250
Robertstown 275 kV	2,550	2,550	2,550	2,550[A]	2,550[A]	2,550[A]	2,550[A]	2,550[A]	2,550[A]	2,550[A]	2,550[A]
Tailem Bend 275 kV	Potential future system strength node, which may be declared to accommodate connection of nearby IBR.										

A: The magnitude of this minimum fault level requirement may change in response to Project EnergyConnect commissioning and the associated changes to network impedance. Further study will be required to establish this value in future system strength assessments.

Fault level projections and shortfalls

Under the NER, AEMO must continue to assess and declare fault level shortfalls until December 2025 when new obligations take effect (See Section 6.2.1). **Table 17** shows the projected minimum fault levels for each system strength node declared in South Australia.

Table 17 Projected minimum fault levels and shortfalls in South Australia for the next five years

System strength node	Projections (*Step Change*) and shortfalls						Shortfalls and comments
	Projected minimum three phase fault level for 99% of the time						
	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	
Davenport 275 kV	2,029	2,037	2,101	1,983	1,983	1,981	No shortfall.
Para 275 kV	2,952	2,975	3,008	2,307	2,300	2,296	No shortfall.
Robertstown 275 kV	2,442	2,468	2,815	2,863	2,873	2,866	No shortfall.

IBR projections

AEMO's 10-year forecast of the level and type of IBR for the South Australian system strength nodes is provided in **Figure 40** and **Table 18**. This highlights a continued trend of investment in IBR, particularly wind technology. Solar and storage type investments are also present over the horizon, with a substantial volume of additional solar investments expected through consumer-side rooftop PV uptake (outside the system strength framework).

ElectraNet, as the local SSSP, is required to provide sufficient system strength to allow the stable operation of this quantity and type of new IBR connections. The forecast is consistent with the 2022 ISP *Step Change* scenario results[92] and the Central scenario demand forecast from the 2022 ESOO[93] but has been updated to include committed and anticipated projects from the 22 July 2022 Generation Information page[94].

[92] AEMO, 2022 *Integrated System Plan*, page 9, at https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/2022-integrated-system-plan-isp.pdf.

[93] AEMO, 2022 *Electricity Statement of Opportunities*, page 34, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2022/2022-electricity-statement-of-opportunities.pdf.

[94] AEMO, NEM Generation Information, at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

Figure 40 Forecast level and type of IBR at each system strength node for the next 10 years

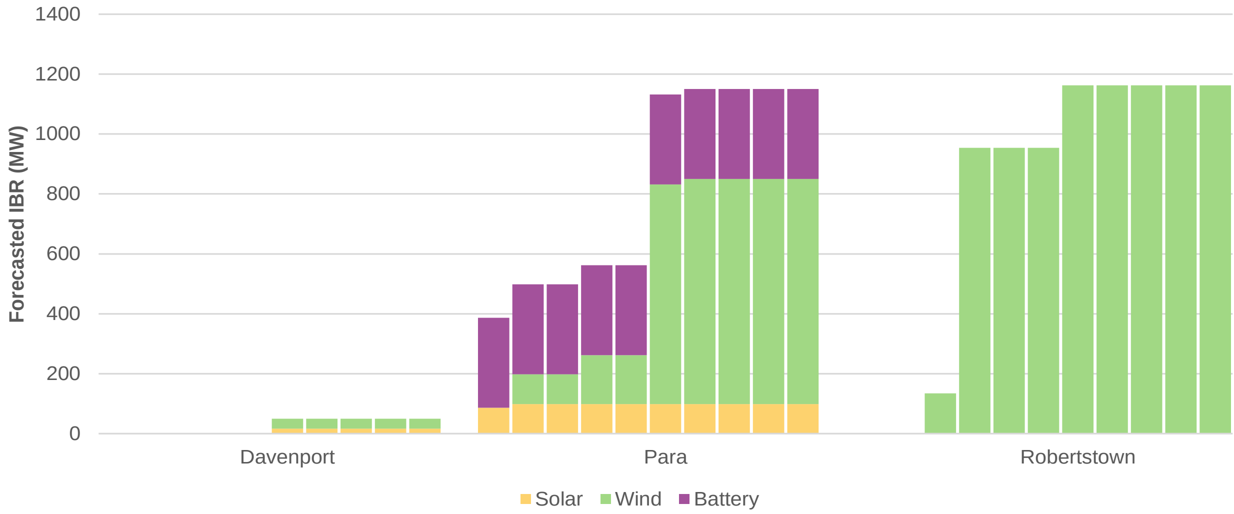

Table 18 Forecast level and type of IBR at each system strength node for the next 10 years

System strength node	Technology	Existing IBR	Forecast IBR (MW) by financial year ending[A]										
			2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Davenport	Solar	278	0	0	0	0	0	0	17	17	17	17	17
	Wind	526	0	0	0	0	0	0	33	33	33	33	33
	Battery	180	0	0	0	0	0	0	0	0	0	0	0
	Total IBR	**984**	**0**	**0**	**0**	**0**	**0**	**0**	**50**	**50**	**50**	**50**	**50**
Para	Solar	141	0	87	99	99	99	99	99	99	99	99	99
	Wind	351	0	0	99	99	162	162	733	751	751	751	751
	Battery	25	0	300	300	300	300	300	300	300	300	300	300
	Total IBR	**517**	**0**	**387**	**498**	**498**	**562**	**562**	**1,132**	**1,150**	**1,150**	**1,150**	**1,150**
Robertstown	Wind	1,414	0	0	135	954	954	954	1,163	1,163	1,163	1,163	1,163
	Total IBR	**1,414**	**0**	**0**	**135**	**954**	**954**	**954**	**1,163**	**1,163**	**1,163**	**1,163**	**1,163**

A. This forecast includes utility-scale IBR only. Distributed energy resources, including rooftop PV, are not included.

6.3 Inertia

Inertia is a critical requirement for a secure and stable power system and is used in conjunction with other frequency control services to maintain the power system frequency within appropriate limits.

AEMO publishes an annual assessment of inertia requirements and shortfalls across the NEM in December each year[95], and results are sensitive to the changing generation mix and both the quantity and response of CER during network disturbances. This section summarises the current inertia outcomes for South Australia.

[95] At https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/system-security-planning.

6.3.1 Current inertia assessment for South Australia

AEMO published its most recent *Inertia Report* in December 2022[96], which considered inertia requirements and shortfalls in each region over a five-year outlook period. The report confirmed the existing shortfall for inertia against the secure operating level requirements in South Australian. This shortfall was first declared in 2021 and persists until Project EnergyConnect Stage 2 is operational[97] and until ElectraNet has implemented a scheme to effectively manage the non-credible loss of either of the Project EnergyConnect or Heywood interconnectors[98].

ElectraNet subsequently entered into inertia support agreements that closed the shortfall until 1 July 2023, and entered into further support agreements following AEMO's 2022 report which confirmed the shortfall magnitude and duration. ElectraNet currently has approximately 360 MW of fast frequency response (FFR) services available to address the shortfall until 1 July 2024.

While the shortfall is projected to continue beyond this date, the magnitude may be affected by the provision of services through a newly established very fast FCAS market (from October 2023), or updates to a special protection scheme for South Australia (scheduled for July 2024). AEMO and ElectraNet will monitor these and other events and will re-assess the shortfall if required.

Table 19 provides the inertia requirements, projections, and shortfalls for South Australia. AEMO has also assessed the relationship between inertia and FFR services when expressing inertia shortfall values. This provides some flexibility in allowing inertia requirements to be met by a combination of synchronous inertia and contracted FFR service providers.

There is likely to be a lower bound of synchronous inertia where additional FFR is no longer able to act as a substitute. Further analysis would be required to quantify these limits and diminishing returns, however they currently appear to be beyond the typical range of available inertia and FFR services in South Australia.

Table 19 Inertia requirements and projections for South Australia

Quantity	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28
Secure operating level	6,200 megawatt seconds (MWs) with 360 MW FFR	6,200 MWs with 360 MW FFR	6,200 MWs with 360 MW FFR	4,400 MWs with 367 MW FFR	4,400 MWs with 367 MW FFR	4,400 MWs with 367 MW FFR
Available inertia for 99% of time	6,200 MWs	6,200 MWs	6,200 MWs	4,400 MWs	4,400 MWs	4,400 MWs
Inertia shortfall	200 MW of FFR (or equiv. MWs)	360 MW of FFR (or equiv. MWs)	360 MW of FFR (or equiv. MWs)	360 MW of FFR (or equiv. MWs)	None	None

6.4 Network support and control ancillary services

The network support and control ancillary services (NSCAS) framework is one of the mechanisms in the NEM for AEMO to manage power system security and reliability of supply, and is part of the broader joint system planning processes between ElectraNet and AEMO for South Australia.

[96] At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-strength-requirements/2022-inertia-report.pdf.

[97] Including a minimum period of operation and minimum commissioning tests successfully completed.

[98] Including operational measures in place to manage any periods where the scheme is not effective.

This framework requires that, at least annually, AEMO assesses the system requirements over a five-year period to keep the network operating within minimum acceptable security and reliability requirements, or to relieve network constraints where this maximises net economic benefits to the market. ElectraNet is expected to procure services or other solutions to address any need for South Australia that AEMO has declared as an NSCAS gap. AEMO may seek to acquire these services itself in cases where ElectraNet does not.

Voltage control challenges in South Australia

In its most recent NSCAS assessment in December 2022, AEMO did not identify any new NSCAS gaps in South Australia over the coming five years. Newly committed and anticipated transmission, generation, and storage projects were projected to improve voltage control in the region, and to close the previously declared gap of 40 MVAr reactive power absorption at Blyth West.

However, voltage control continues to be a priority issue in South Australia, particularly as supply and demand conditions result in fewer synchronous generating units online. Since November 2021, South Australia has been operated with a minimum requirement of two large synchronous machines online. This represented a reduction from previous levels, following commissioning of four new synchronous condensers in the region to address more onerous system strength requirements (see Section 6.2).

In June 2023, ElectraNet provided AEMO with a revised set of limits advice that considers system operation with even fewer synchronous units online. As part of this advice, ElectraNet stipulated that operation with a single unit may be possible when a specific set of voltage controls conditions are met – including that demand remains above 600 MW, that a set of specific reactive power control devices are available, that at least one 275 kV-connected synchronous generators online, and that South Australia is not at credible risk of separating from the NEM[99].

The advice effectively confirms that voltage control is a key factor driving the existing two-unit requirement; and that this could potentially be relaxed to a one-unit requirement under conditions where additional voltage control measures are met; both pre- and post-contingent.

AEMO is currently assessing this latest advice from an NSCAS perspective to determine whether a voltage control gap exists, and if so, what viable short-term remediation options are available. ElectraNet is already progressing a RIT-T[100] which is expected to further address voltage control needs in combination with commissioning of Project EnergyConnect[101].

AEMO is preparing to release its 2023 *NSCAS Report*, which will include an assessment of the current status of voltage control needs and activities in South Australia.

6.5 Directions to maintain system security

AEMO may, where it considers necessary, direct a registered participant in the NEM to take relevant actions to maintain or restore the security or reliability of the power system. AEMO's *Quarterly Energy Dynamics* reports[102]

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[99] Two synchronous generating units are recommended for management of ramping events when South Australia is at credible risk of separation from the NEM or when South Australia is operating as an island.

[100] See https://www.electranet.com.au/projects/south-australian-transmission-network-voltage-control/.

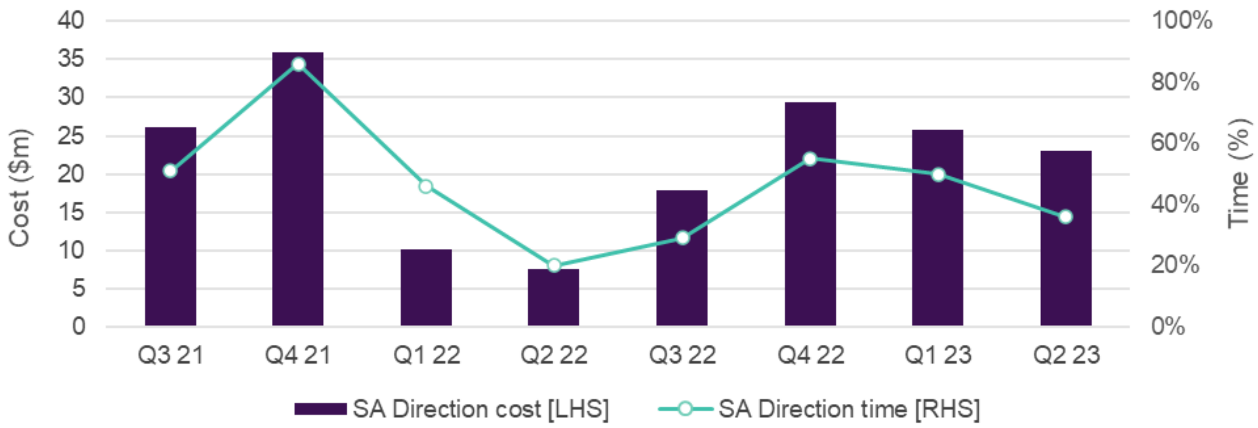
[101] The satisfactory provision of grid reference without synchronous generation in South Australia is still subject to additional evidence of successful operation such as an appropriately scaled system testing.

[102] At https://aemo.com.au/energy-systems/major-publications/quarterly-energy-dynamics-qed.

have noted recent trends in time on direction and total costs for directions issued to gas-powered generation in South Australia to maintain system security in the region:

- In FY 2022-23, overall direction costs for energy amounted to $96.0 million, up from $79.6 million in the previous financial year (2021-22). While system security direction costs rebounded during the first half of the year (Q3 and Q4 2022) relative to Q1 and Q2 2022, they still remained lower than the same period in FY22. However, the second half of the year (Q1 and Q2 2023) witnessed an increase in system security time and costs compared to the same period the previous year.
- Record high electricity prices in Q3 2022 meant it was more economic for gas-powered generators to remain online. This, coupled with full operation of newly commissioned synchronous condensers in the region, reduced requirements for AEMO to direct synchronous units to maintain system strength in South Australia. This trend continued into Q4 2022, however, relatively lower spot prices in South Australia and increased levels of VRE generation resulted in a rise in direction time and costs in Q4 2022 compared to Q3 2022.
- During the second half of the year (Q1 and Q2 of 2023), system security direction time and costs were lower compared to Q4 of 2022, but still higher than the same period in FY 2021-22. Gas-powered generators more frequently chose to decommit their units from the system due to relatively lower electricity spot prices and higher VRE output in comparison to the same period in the previous year. This behaviour, observed in both gas offer curves and actual market dynamics, led to an increase in directions required to maintain minimum synchronous generation levels to ensure system security.
- In Q1 2023, the direction costs experienced a sharp rise, increasing to $25.7 million, from $10.1 million the previous year. This increase was influenced by a substantial rise in the compensation price paid to directed participants, surging from $112/MWh in Q1 2022 to $349/MWh in Q1 2023. The uplift in this compensation price flows directly from the extremely high spot prices prevailing in Q2 and Q3 2022[103].

Figure 41 Time and cost of system security directions (energy only) in South Australia



Note: direction costs are preliminary costs which are subject to revision.

AEMO publishes specific details on market directions issued in South Australia in the Direction reports section of the market event reports page of its website[104].

[103] Directed generators receive a compensation price calculated as the 90th percentile level of spot prices over a trailing 12-month window.

[104] At https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-events-and-reports/market-event-reports.

A1. Resource availability and technology review

As well as the AEMO publications listed in Table 1 (in Section 1.2), the following sources provide more detail on resource availability and relevant technologies.

Table 20 Additional data sources

Information source	Website address
Aurecon: 2022 Cost and Technical Parameters Review	https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/aurecon-2022-cost-and-technical-parameter-review.pdf
Aurecon: 2022 Cost and Technical Parameters Review – Workbook	https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/aurecon-2022-cost-and-technical-parameters-review--workbook.xlsb
BIS Oxford Economics: 2022 Macroeconomic Projections Report	https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/bis-oxford-economics-2022-macroeconomic-outlook-report.pdf
CSIRO: 2022 Solar PV and Battery Projections Report	https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/csiro-2022-solar-pv-and-battery-projections-report.pdf
CSIRO: 2022 Electric vehicle Forecasts Report	https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/csiro-2022-electric-vehicles-projections-report.pdf
CSIRO and ClimateWorks Centre: 2022 Multi-sector modelling,	https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/csiro-climateworks-centre-2022-multisector-modelling-report.pdf
GEM: 2022 Solar PV and Battery Projections Report	https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/gem-2022-solar-pv-and-battery-projection-report.pdf

A2. Generation and demand breakdown

	SA generation								NEM balancing			SA consumption							
Financial Year	Wind (SS/NS)	Solar (SS)	Storage - battery (S)	ONSG	PVNSG	Rooftop PV	Coal, gas, diesel (S)	Total SA generation	Imports VIC-SA	Net Imports	Exports SA-VIC	Total electricity requirement	Auxiliary energy use	Transmission network losses	Distribution network losses	Scheduled loads	Residential + business consumption	Consumption met by SNSG	Consumption met by Rooftop PV
2011–12	3,562	0	0	80	3	253	9,391	13,290	1,495	1,094	-401	14,384	469	293	665	0	12,976	84	253
2012–13	3,473	0	0	79	3	434	9,031	13,021	1,710	1,377	-333	14,398	395	309	651	0	13,063	82	434
2013–14	4,087	0	0	82	3	582	7,664	12,417	1,925	1,637	-288	14,055	352	364	710	0	12,651	85	582
2014–15	4,218	0	0	92	4	716	7,246	12,276	1,904	1,528	-376	13,805	386	368	661	0	12,413	96	716
2015–16	4,317	0	0	94	4	812	7,145	12,373	2,227	1,941	-286	14,314	413	424	799	0	12,707	99	812
2016–17	4,340	0	0	77	8	904	5,620	10,950	2,889	2,725	-164	13,675	193	327	718	0	12,456	86	904
2017–18	5,561	4	22	71	22	1,041	7,282	14,003	1,039	-292	-1,331	13,713	221	313	676	27	12,494	94	1,041
2018–19	5,725	303	41	65	83	1,314	6,886	14,417	791	-468	-1,259	13,952	202	341	639	51	12,735	149	1,314
2019–20	5,798	483	47	67	209	1,610	6,278	14,492	922	-413	-1,335	14,085	179	334	701	59	12,849	276	1,610
2020–21	5,739	673	85	69	274	1,930	5,235	14,005	1,147	123	-1,023	14,097	144	324	696	104	13,045	343	1,930
2021-22	6,131	698	88	76	371	2,269	4,118	13,751	1,467	625	-842	14,404	112	300	556	111	13,325	447	2,269
2022-23	6,651	804	74	70	436	2,505	3,644	14,185	1,377	499	-877	14,685	79	381	618	97	13,517	506	2,505