2022 Electricity Statement of Opportunities

August 2022

A report for the National Electricity Market

Important notice

Purpose

The purpose of this publication is to provide technical and market data that informs the decision-making processes of market participants, new investors, and jurisdictional bodies as they assess opportunities in the national electricity market over a 10-year outlook period. This publication incorporates a reliability assessment against the reliability standard and interim reliability measure, including AEMO's reliability forecasts and indicative reliability forecasts.

AEMO publishes the National Electricity Market Electricity Statement of Opportunities under clause 3.13.3A of the National Electricity Rules. This publication is generally based on information available to AEMO as at 1 July 2022 unless otherwise indicated.

Disclaimer

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Version control

Version	Release date	Changes
1	31/8/2022	Publication release

AEMO acknowledges the Traditional Owners of country throughout Australia and recognises their continuing connection to land, waters and culture. We pay respect to Elders past and present.

Contents

Executive summary

The *Electricity Statement of Opportunities* (ESOO) provides technical and market data for the National Electricity Market (NEM) over a 10-year period to inform the planning and decision-making of market participants, new investors, and jurisdictional bodies. The ESOO includes a reliability forecast identifying any forecast reliability gaps in the coming five years, defined according to the Retailer Reliability Obligation (RRO)[1], and an indicative projection of any forecast reliability gaps in the second five years of the forecast.

This 2022 ESOO signals a need to urgently progress anticipated generation, storage and transmission developments, including ISP actionable transmission developments, to support the energy transition underway. With the NEM expected to experience a cluster of five announced coal-fired generator retirements in the next decade, and needing resilience for potential future closures as well, the investment need is pressing and widespread across the NEM.

In this 2022 ESOO assessment:

- **Insufficient capacity response has become committed[2]** to address the reliability gaps forecast in the *Update to the 2021 ESOO*.
- **Increased consumption and maximum demands are forecast**, including from industrial load expansions, increasing the required generation commitment and further challenging forecast reliability in some regions.
- **In the short to medium term, without additional investment beyond present commitments, reliability gaps are forecast in**:
  - **South Australia (in 2023-24) and Victoria (from 2024-25)** against the Interim Reliability Measure (IRM)[3].
  - **New South Wales from 2025-26** against the reliability standard.
- **Longer term, indicative reliability gaps are forecast in all NEM mainland regions before 2031-32 against the reliability standard**.
- While there is **a strong pipeline of developments** across variable renewable energy (VRE) generation, storage, demand side solutions, and transmission:
  - **Anticipated generation, storage and transmission developments, including ISP actionable transmission developments, need to progress urgently to committed status** to address reliability challenges and support the energy transition underway. If completed as scheduled, reliability risks for all regions are forecast to be within the relevant reliability standards until 2028-29 when further coal-fired power station retirements are expected.

[1] The RRO came into effect on 1 July 2019. For more information, see https://www.energy.gov.au/government-priorities/energy-programs/retailer-reliability-obligation.

[2] "Committed" projects meet all five commitment criteria listed under Background Information on AEMO's Generation Information updates, at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

[3] The Interim Reliability Measure (IRM) was introduced to reduce the risk of load shedding across the NEM, providing a trigger for the Retailer Reliability Obligation (RRO) of unserved energy (USE) of no more than 0.0006% of energy demanded in a region in any year. The IRM is scheduled to expire in June 2025, after which the reliability standard (USE in each region of no more than 0.002% of energy demanded in any year) will again be used to measure reliability.

- – Various jurisdictional programs are underway to assist in the delivery of greater investment in the short to medium term, including transmission, generation, and storage investments to meet the New South Wales Electricity Infrastructure Roadmap and the second auction of the Victorian Renewable Energy Target. If developed to schedule, and complemented with the remaining actionable and anticipated investments, these additional investments will further improve the outlook over the 10-year ESOO horizon.
  - – **Project commissioning delay risks are emerging**, even for committed projects. Project delays may risk the ability of the system to effectively replace retiring generation as generators are scheduled to decommission.
- AEMO's 2022 *Integrated System Plan* (ISP)[4] forecasts the potential for additional generation closures in several scenarios. **Announced and possible further retirements highlight the urgency for commitment of new developments** to improve the reliability outlook. The ISP also identifies a large scale of investment in generation and storage developments to complement actionable ISP transmission projects. The level of committed and anticipated projects in the NEM requires further material investment to meet the 2022 ISP's *Step Change* development pathway.

Since the 2021 ESOO was released in August 2021:

- A number of thermal generators announced they will retire earlier than previously planned. AEMO published an *Update to the 2021 ESOO* in April 2022 that evaluated the impact of closure announcements, identifying heightened risks of unserved energy (USE) particularly in New South Wales in the next five years.
- During winter 2022, significant challenges emerged in operating the energy markets in eastern Australia. These recent power system and market dynamics demonstrated the operational challenges associated with maintaining reliability and security of electricity supply at times of domestic and international uncertainties.
- AEMO forecasts higher operational consumption and maximum demand in all NEM regions across the ESOO horizon consistent with the *Step Change* scenario. This 2022 ESOO assessment also includes expected new commitments for industrial load expansions in some NEM regions.

Structural reforms to the NEM and amendments to the National Electricity Objective (NEO) agreed by Energy Ministers recently will greatly assist in improving the investment environment and enabling the transformation of the NEM in the medium term, but are unlikely to resolve the immediate challenges. AEMO will continue to work with the Federal Government, NEM jurisdictions (state and territory governments) and other market bodies to manage risks and potential solutions.

Unserved energy (USE) is energy that cannot be supplied to consumers, resulting in involuntary load shedding (loss of customer supply). For example, this may be caused by insufficient levels of generation capacity or demand response.

The **Interim Reliability Measure (IRM)** was introduced to reduce the risk of load shedding across the NEM, providing a trigger for the Retailer Reliability Obligation (RRO) of 0.0006% of energy demanded in a region in any year. It applies until 30 June 2025.

The **reliability standard** is a measure of USE in each region of no more than 0.002% of energy demanded in any year. For the purposes of the RRO, it applies after 30 June 2025.

Any **forecast reliability gap** is based on forecast USE in excess of the IRM or reliability standard in a region in a year. If AEMO reports a forecast reliability gap, this may trigger a reliability instrument request under the **RRO**.

[4] At https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp.

2022-23 outlook

The interim reliability measure is forecast to be met in all NEM regions this summer

- Expected USE is forecast to remain within the IRM in all regions for the coming summer, although risks remain under extreme conditions.
- Energy consumption is forecast to increase marginally, with new increased commitments to industrial load production than previously forecast and the potential for connections of newly electrified loads (switching from alternative energy sources such as gas and diesel), and peak demands are forecast to increase consistent with these trends.
- New generation capacity continues to connect to the NEM. Approximately 800 megawatts (MW) more capacity from a range of technologies is forecast to be operational this summer than was available last summer, given commissioning and decommissioning expectations.

There are supply risks in the year ahead

Significant challenges have emerged in operating the energy markets in eastern Australia in 2022. Since May 2022, extensive forecast and actual NEM lack of reserve (LOR) events, and the need for a range of market interventions to maintain reliability and system security have occurred due to a range of coincident events. These circumstances have highlighted the need for the NEM to be resilient to external events like extreme weather, limitations on fuel availability, and impacts from high global commodity prices.

While this ESOO does not forecast any regions with expected USE above the IRM in 2022-23 under its Central scenario assumptions[5], this does not mean there is no risk to consumer outcomes driven by weather uncertainty or other circumstances such as simultaneous generator and/or transmission outages that may erode available supply when it is required.

On the demand side, industrial facilities are forecast to increase production in the coming year, particularly in South Australia and Victoria. As these forecast increases in demand occur, the NEM will need either enough supply capacity, or greater demand flexibility, to avoid the forecast reduction in reliability.

On the supply side, the reliability of the thermal (coal and gas) generation fleet generally stayed at historically poor levels in 2021-22, and plant operators have advised that overall plant reliability is unlikely to materially improve in 2022-23. Some generating units are expected to return to normal service following extended outages, including the 420 MW Callide C Unit 4 in Queensland (to return to service in advance of winter 2023) and the 90 MW Mintaro power station in South Australia (to return to service in January 2023).

Other risks include:

- Prolonged periods of unavailability of generation or transmission, including forced outages, planned maintenance and/or potential mothballing.
- Delays to the commissioning of new renewable generation, dispatchable capacity and/or transmission.
- Extreme temperatures affecting the output from all generation sources.

[5] The *Step Change* scenario described in the 2022 ISP and the 2021 *Inputs, Assumptions and Scenarios Report* (IASR) has been used as the Central scenario for this ESOO, as it was in the *Update to the 2021 ESOO*.

- The ongoing potential for gas and coal fuel shortfalls, particularly if generators need to operate more frequently to cover prolonged outages of major power stations.

AEMO has a number of tools to mitigate these risks within operational timeframes, such as utilising Reliability and Emergency Reserve Trader (RERT) resources, where appropriate[6].

Beyond 2022-23

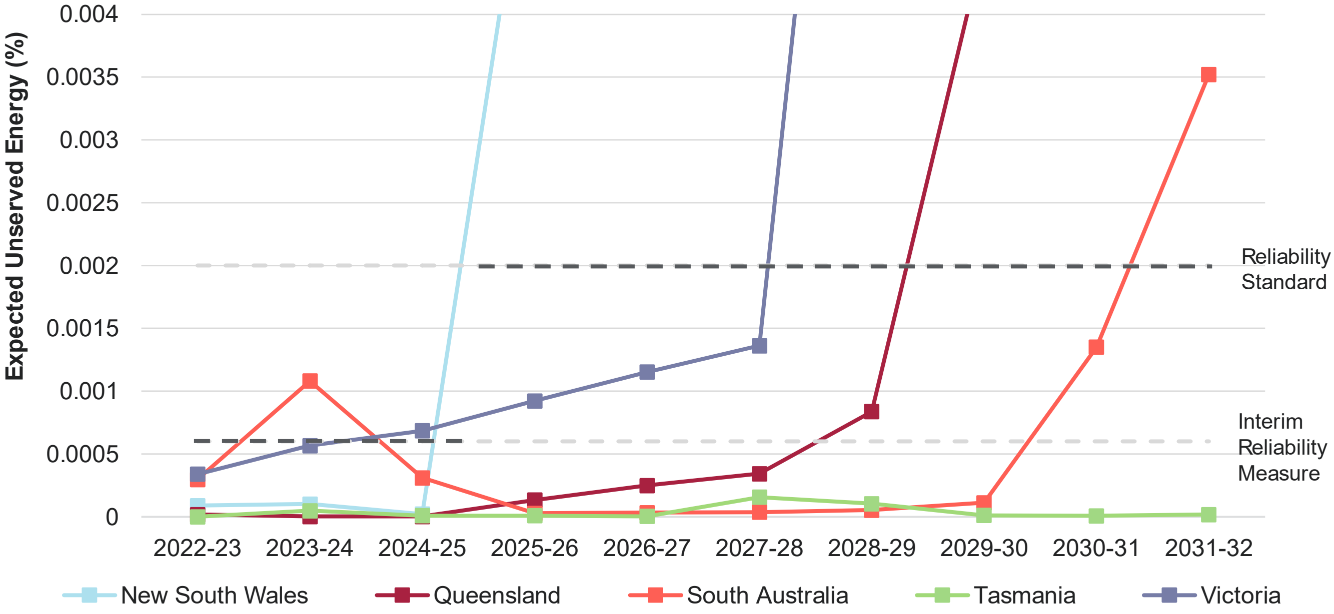
Reliability gaps are forecast in all mainland NEM regions in the next decade, based on existing and committed developments only

Figure 1 shows the reliability forecast and indicative reliability forecast for the 2022 ESOO Central scenario, which considers only existing and committed developments, including announced retirements and project schedule delays.

It highlights that by 2031-32, without additional investments beyond those currently committed, reliability is forecast to worsen in several NEM regions, and USE is forecast to go above the relevant reliability standards in all mainland NEM regions.

In the short to medium term (the next five years), the reliability forecast based on the ESOO Central scenario identifies numerous reliability gaps, including new gaps not identified in the 2021 ESOO or *Update to the 2021 ESOO*.

Figure 1 Expected unserved energy, ESOO Central scenario, 2022-23 to 2031-32 (%)



Since the modelling of the ESOO was conducted, the Mortlake South Wind Farm (approximately 160 MW) has become committed in Victoria. Inclusion of this project in the ESOO modelling would reduce forecast reliability risks in Victoria from 2022-23.

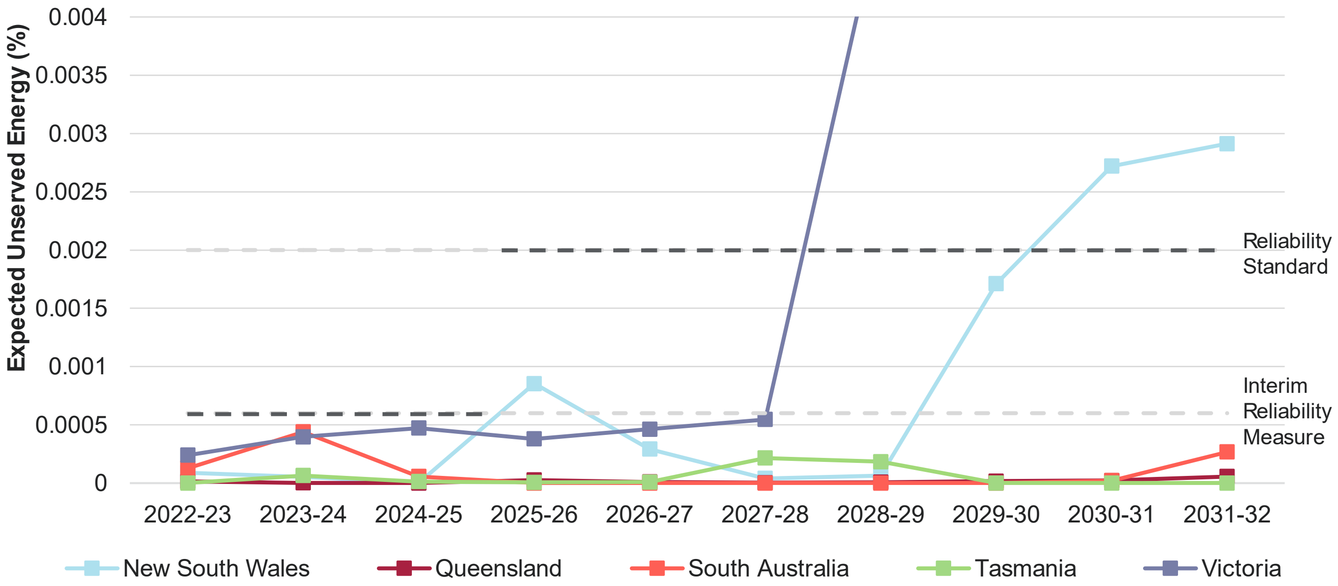
[6] In accordance with AEMO's Short Term Reserve Management Procedure. See https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/power_system_ops/procedures/so_op_3703-short-term-reserve-management.pdf.

While the forecasts based on committed supply demonstrate an increase in reliability risk, an additional 3.4 GW of anticipated investments are in the pipeline and will improve the outlook if they progress as planned. 'Anticipated' developments are projects which meet some of AEMO's commitment criteria, but not enough criteria to be considered committed.

When generation and storage classed as anticipated in the ESOO is considered alongside the anticipated and actionable transmission developments identified in the 2022 ISP[7], based on current schedules, the reliability forecast improves significantly.

Figure 2 shows the improved reliability outlook with the development of these anticipated and actionable projects. It shows that anticipated generation projects reduce forecast USE to below the IRM and within the reliability standard over the coming years, until actionable transmission developments further support the reliability of these regions.

Figure 2 Expected unserved energy, ESOO Central outlook with anticipated and actionable developments, 2022-23 to 2031-32 (%)



The reliability gaps forecast in the next five years are despite new committed investments connecting

There is a large number of committed developments scheduled to connect in the next five years. In total, 7.3 GW of committed new scheduled or semi-scheduled capacity is forecast to become operational by the end of 2026-27. Committed developments include:

- Energy Australia's 320 MW Tallawarra B project in New South Wales, scheduled to be operating from October 2023[8].
- Snowy Hydro's 750 MW Kurri Kurri Power Station in New South Wales, scheduled to be operating from December 2023.

[7] See https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp

[8] Tallawarra B is considered committed*, which means it meets all AEMO's commitment criteria except for either Contracts or Planning, and has begun construction. In accordance with the ESOO and reliability forecast methodology document, committed* projects are modelled to connect on the first day after the end of the "T-1 financial year" defined under the RRO, which for the 2022 ESOO is 1 July 2024.

- Genex Power's 250 MW Kidston Pumped Hydro Energy Storage project in Queensland from February 2025.
- Snowy Hydro's 2 GW Snowy 2.0 project from 2025-26[9].
- Numerous renewable energy developments across the NEM, including approximately 1 GW of wind generation and almost 1.5 GW of utility-scale solar generation.

Committed transmission developments will also improve the NEM's ability to share capacity between generation and load centres, including between regions, as identified in the 2021 ESOO. These projects include Victoria – New South Wales Interconnector (VNI) Minor, Queensland – New South Wales Interconnector (QNI) Minor, and Project EnergyConnect linking South Australia, New South Wales and Victoria.

Since the 2021 ESOO, potential retirements and commissioning delays to committed projects have also influenced the reliability forecast:

- Origin Energy notified AEMO of the expected early retirement of the 2,880 MW Eraring Power Station in New South Wales in August 2025[10]. This was included in the *Update to the 2021 ESOO*.
- Project EnergyConnect, a committed transmission project, has updated its commissioning estimates. Early stages are now expected from 2024-25, rather than 2023-24.

Delays to any other currently committed development may further worsen the reliability outlook.

While generation, storage and transmission developments continue to connect to the power system, the assessment shows these committed developments are not yet sufficient to offset the impact of higher electricity use.

The forecast reliability gaps are in:

- **South Australia in 2023-24**, against the IRM of 0.0006% USE. This gap is emerging due to delayed commissioning of committed generation and transmission developments, including a slower release of the first stage of the Project EnergyConnect transmission project than previously scheduled, and also expected expansions of industrial loads.
- **Victoria from 2024-25,** against the IRM of 0.0006% USE. This gap is attributed to forecast expansions of industrial loads, and updated projected outage rates and ratings on the inter-regional transmission flow paths that supply Victoria during times of high demand. The Mortlake South Wind Farm (approximately 160 MW) has become committed in Victoria since the modelling for the ESOO was conducted and would reduce forecast reliability risks in Victoria to below the Interim Reliability Measure in both 2023-24 and 2024-25
- **New South Wales from 2025-26**, against the reliability standard of 0.002% USE. Consistent with the *Update to the 2021 ESOO*, this reliability gap is four years earlier than forecast in the 2021 ESOO, following changes in generation including the announced earlier closure of the Eraring Power Station.

[9] Despite media reports suggesting a delay to the project, Snowy Hydro has not confirmed any adjustment to its previously provided commissioning schedule of between 2025-26 and 2026-27 for the Snowy2.0 project.

[10] At https://www.originenergy.com.au/about/investors-media/origin-proposes-to-accelerate-exit-from-coal-fired-generation/.

Retailer Reliability Obligation (RRO) requests are required where expected USE is forecast above the relevant reliability standard in the reliability forecast, or ESOO Central scenario, in the T-3 outlook period, or in the T-1 outlook period (where a T-3 instrument already exists for that period). In this 2022 ESOO, the following reliability gaps meet the requirements for RRO instrument requests:

- In **South Australia** in the T-1 outlook period of 2023-24 for the RRO. A T-3 reliability instrument already exists for this period, hence AEMO is requesting a T-1 reliability instrument of the Australian Energy Regulator (AER) for this region and period.
- In **New South Wales** in the T-3 outlook period of 2025-26 for the RRO. AEMO is requesting a T-3 reliability instrument of the AER for this region and period.

In the 2020 ESOO, AEMO reported a reliability gap for New South Wales in 2023-24, which resulted in the AER creating a T-3 reliability instrument. As this reliability gap is no longer forecast, AEMO is advising accordingly.

The indicative reliability forecast in 5-10 years is impacted by expected generation closures and lack of committed supply

In the 5-10-year indicative reliability forecast period shown above in **Figure 1**, expected USE is further influenced by participant expectations for generator retirements, including[11]:

- The continued expectation that the 1,450 MW Yallourn Power Station in Victoria will retire in 2028.
- The continued expectation that the 1,320 MW Vales Point Power Station in New South Wales will retire in 2029.

There is a pipeline of projects (generation, storage and transmission) that are capable of becoming operational prior to these closures, but none are sufficiently progressed to be considered committed.

Electricity consumption and maximum peak demands are forecast to grow across this period, more strongly than in the first five years. Forecast growth is significantly higher than the 2021 ESOO in some regions and marginally higher than the *Update to the 2021 ESOO*.

This growth is forecast as opportunities emerge to electrify residential, commercial, industrial and transportation loads, in addition to industrial expansions in the near term and continued growth in residential and business sectors. Emerging policy support for electric vehicle and gas substitution demonstrate the potential for more significant use of electricity instead of other energy sources across Australia's economy. The forecast sees growth in electrification complementing traditional growth drivers from population and a growing economy, with this growth offset by energy savings from energy efficiency and consumer investments in distributed PV.

The projected electrification of traditional gas loads, particularly heating loads in Victoria, increases forecast consumption and maximum demands in winter. For Victoria in particular, winter peak demands may exceed summer peak demands by the end of the decade.

[11] While AGL has brought forward the expected retirement date for both Bayswater and Loy Yang A power stations, in New South Wales and Victoria respectively, they both remain beyond the 10-year timeframe of the ESOO.

The indicative reliability forecast indicates that without developments in excess of current commitments, expected USE is above the reliability standard of 0.002% USE:

- In **New South Wales** over the entire 5-10-year period.
- In **Victoria from 2028-29** when Yallourn Power Station is expected to close.
- In **Queensland from 2029-30** when Vales Point Power Station in New South Wales is expected to retire (and after the expected closure of Callide B Power Station in Queensland), as expected USE is shared across the two regions.

Reliability forecasts improve significantly if anticipated and ISP actionable developments are included, but more is needed to meet the standard in Victoria and New South Wales in all forecast years

'Anticipated' developments are projects which meet some of AEMO's commitment criteria, but not enough criteria to be considered committed. When generation and storage classed as anticipated in the ESOO are considered alongside the anticipated and actionable transmission developments identified in the 2022 ISP, based on current schedules, the reliability forecast improves significantly. The pipeline of anticipated generation and storage developments currently includes:

- Almost 1,200 MW of wind generation.
- Approximately 850 MW of solar generation.
- Approximately 1,200 MW of battery energy storage systems.
- Approximately 100 MW of peaking capacity operated with gas or diesel fuels.

> Approximately 7.3 GW of committed generation capacity, and numerous committed transmission developments, are scheduled to become operational in the next 10 years.
>
> Additional investments need to be developed urgently to maintain a reliable power system.
>
> The 2022 ISP identifies another 34 GW of capacity that will support the efficient replacement of retiring generation, improve the resilience of the NEM to additional thermal plant closures (beyond those already

The range of transmission developments includes:

- Central West Orana and New England renewable energy zone (REZ) transmission links, and the Hunter Transmission Project (including potentially earlier investments to support the system integrity protection scheme [SIPS]) in New South Wales, and the Western Renewables Link in Victoria.
- Strategic transmission projects which would improve inter-regional transfer capacities, including HumeLink, Marinus Link, and Victoria – New South Wales Interconnector (VNI) West.

The anticipated and actionable sensitivity forecast, shown above in **Figure 2**, illustrates that further investments are forecast to be needed to keep expected USE within the relevant reliability standards in the following regions:

- **Victoria from 2028-29**, against the reliability standard when Yallourn Power Station is expected to retire, although developments arising from the second auction of the Victorian Renewable Energy Target[12] will assist. These developments, if delivered before 2028-29, would improve the reliability outcomes in earlier years also.

[12] See https://www.energy.vic.gov.au/renewable-energy/vret2.

- **New South Wales from 2030-31**, against the reliability standard after the expected retirement of Vales Point Power Station, although developments arising from the New South Wales Electricity Infrastructure Roadmap[13] will assist in addressing requirements. These developments, if delivered before 2030-31, would improve the reliability outcomes in earlier years also.

Even when the 7.3 GW of committed generation and 3.4 GW of anticipated generation and storage developments are combined, these developments are well short of the development opportunity of approximately 45 GW of renewable energy and firming investments over the next decade identified in the 2022 ISP to provide a reliable and resilient NEM to announced and potential additional generator closures.

Projects assessed as anticipated for the ESOO do not include investments that may be delivered to meet a range of jurisdictional initiatives that are underway, such as the Victorian Renewable Energy Target or the New South Wales Electricity Infrastructure Roadmap, including recently announced tenders for firming, as well as initiatives that support the investment in distributed energy resources (DER) orchestration[14].

In addition, a much larger proposed pipeline of 113 GW of variable renewable energy (VRE) and 53 GW of dispatchable resources (including battery, pumped hydro, and other technologies) demonstrate the opportunity for the market to respond to emerging reliability gaps, if developed in a timely manner.

Increasing the NEM's potential to operate at times with 100% renewable resources by 2025

The continued development of new renewable energy resources in the NEM has led to higher records of instantaneous renewable energy penetration[15] across the NEM.

The current NEM record for instantaneous renewable penetration is 61.8%, observed on 15 November 2021.

Based on these trends, and considering the pipeline of committed and anticipated renewable developments and forecasts for consumers' installation of distributed PV, instantaneous renewable energy potential is likely to meet or exceed 100% total generation requirements during certain intervals in 2024-25.

Figure 3 shows:

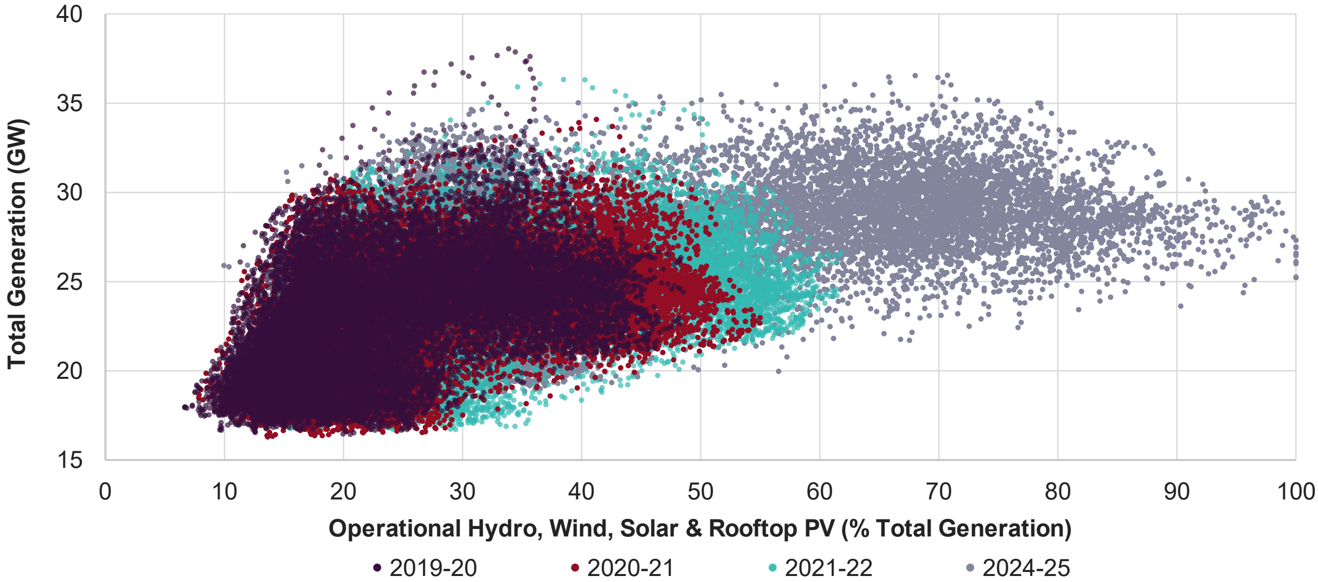
- The recent historical trend (from 2019-20 to 2021-22) for increasing penetration of renewable resources including wind, solar (large-scale and distributed PV), hydro, and biomass. The 2021-22 penetration is shown to reach as far as the record of 61.8%.
- The updated estimate of renewable resource potential for 2024-25 from existing, committed, and anticipated projects and forecast distributed PV uptake from consumers. Figure 3 shows that there is enough resource potential to approach and on occasion reach 100% instantaneous supply from renewable resources.

[13] See https://aemoservices.com.au/publications-and-resources/infrastructure-investment-objectives-report.

[14] Such as support to develop South Australia's Virtual Power Plant. See https://www.energymining.sa.gov.au/consumers/solar-and-batteries/south-australias-virtual-power-plant.

[15] Instantaneous renewable energy penetration is the proportion of total consumer demand (underlying demand) that is met by renewable resources in a given half-hour period.

Figure 3 NEM-wide penetration of renewable resources (large-scale and distributed), 2019-20 to 2021-22, with forecast indicative resource potential in 2024-25 (GW)



The 2024-25 forecast is based on the resource potential of existing, committed, and anticipated projects and distributed PV forecasts.

A high proportion of this renewable generation is from inverter-based resources (IBR, meaning wind and solar generation, including distributed PV). With AEMO's current operating toolkit, it would not be possible to maintain the power system securely under these conditions, which is why AEMO has the goal to be able to operate the power system at 100% instantaneous renewable generation by 2025.

Through the Engineering Framework[16], AEMO is working with stakeholders to establish a structured approach to preparing for these high renewable periods. In June 2022, AEMO released the NEM Engineering Framework Priority Actions report, outlining 46 near-term priorities. In parallel with working through these near-term priorities, AEMO is also working towards a publication in late 2022 that explores pathways to operating with 100% instantaneous penetrations of renewables.

[16] See AEMO's NEM Engineering Framework – priority actions, at https://aemo.com.au/en/initiatives/major-programs/engineering-framework.

1 Introduction

1.1 Purpose and scope

The *Electricity Statement of Opportunities* (ESOO) forecasts electricity supply reliability in the National Electricity Market (NEM) over a 10-year period to inform decisions by market participants, investors, and policy-makers.

It includes information about:

- Existing, committed, and proposed electricity supply and network capabilities.
- Planned generating plant retirements.
- Forecasts, across a range of demand and supply scenarios, of:
  - Operational consumption, maximum and minimum demand forecasts.
  - Potential unserved energy (USE) in excess of the reliability standard and Interim Reliability Measure (IRM).

For the purposes of the National Electricity Rules (NER) clause 3.13.3A(a), the following information should be considered part of the 2022 ESOO:

- The 2022 ESOO report and supplementary information published on the 2022 ESOO webpage[17].
- Demand forecasting data portal[18].
- The July 2022 Generation Information page update[19].
- The August 2022 *Forecasting Assumptions Update* (FAU)[20], and the 2021 *Inputs, Assumptions and Scenarios Report* (IASR)[21], accompanying workbook and supplementary material.

To meet the obligations under the Retailer Reliability Obligation (RRO)[22], the ESOO also includes:

- **Reliability forecasts** identifying any potential reliability gaps for each of this financial year and the following four years (see Section 5.2).
- **Indicative reliability forecasts** of any potential reliability gaps for each of the final five years of the 10-year ESOO forecast period (see Section 5.3).

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

[18] At http://forecasting.aemo.com.au/.

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

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

[21] At https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

[22] The RRO came into effect on 1 July 2019 through changes to the National Electricity Law, the National Electricity Rules, and South Australian regulations. For more information, see http://www.coagenergycouncil.gov.au/publications/retailer-reliability-obligation-rules.

Reliability forecast under the RRO

In the 2022 ESOO, the reliability forecasts and indicative reliability forecasts published in accordance with the RRO constitute Chapter 5 in this report. Key component forecasts and inputs include:

- Consumption and demand forecasts (see Sections 2.2, 2.3, 2.4, the demand forecasting data portal[23], and the demand traces[24]).
- Supply forecasts (see Chapter 3 and the renewable generation traces).
- The accompanying July 2022 Generation Information page[25].
- Sections of the 2022 FAU that comprise the Forecasting Components of the Forecasting Approach for ESOO and Reliability Forecast purposes:
  - Annual consumption forecast components (for large industrial load, commercial, residential, and connections forecasts) and maximum and minimum demand forecasts, including demand traces (Section 2.1 of the 2022 FAU).
  - Distributed energy resources (DER) forecasts (Section 2.1 of the 2022 FAU).
  - Renewable generation traces (Section 2.1 of the 2022 FAU).
  - Demand side participation (DSP) forecasts (Section 2.1 of the 2022 FAU).
  - Generator outage rates (Section 2.2 of the 2022 FAU).

Operational consumption by customer segment and maximum and minimum demand forecasts are provided over a 10-year period from financial year 2022-23 to 2031-32 in Chapter 2. These are primary component forecasts of AEMO's Forecasting Approach[26], used to develop the reliability forecasts and indicative reliability forecasts presented in the following chapters. Secondary forecasting components, such as connections forecasts or DER forecasts, are provided in the 2021 IASR and 2022 FAU.

Operational consumption and maximum and minimum demand forecasts are provided over a 30-year period from the financial year 2022-23 to 2051-52 for each NEM region in Appendices A1-A5. These forecasts are used by stakeholders for a range of other purposes, including longer-term planning studies.

In addition to provision of reliability assessments and forecasts, AEMO has power system security assessment obligations under the NER which are separate from the ESOO. AEMO releases annual assessments of system strength, inertia and Network Support and Control Ancillary Services (NSCAS) needs, including declarations of shortfalls and gaps which are required to be addressed by transmission network service providers (TNSPs) [27].

[23] See https://forecasting.aemo.com.au.

[24] Supporting traces (demand, renewable energy) are available at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities.

[25] At https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

[26] See https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-approach.

[27] AEMO's system security assessments can be accessed via https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/planning-for-operability.

1.2 Key definitions

NEM time – the NEM is operated on Australian Eastern Standard Time, which does not include daylight savings. Time is reported on that basis unless otherwise noted.

Reliability forecast component definitions

Unserved energy (USE)[28] 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 NEM **reliability standard** is a measure of whether sufficient supply resources and inter-regional transfer capability exists to meet 99.998% of annual demand for electricity in each region; that is, a maximum expectation of 0.002% of energy demand to be unmet in a given region per financial year.

The **Interim Reliability Measure (IRM)** is a measure of whether up to 0.0006% of energy demand is expected 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 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 currently set to expire in June 2025, after which the reporting obligation reverts to the previous position under the NER, such that AEMO must report on whether the reliability standard would be exceeded in any financial year from 2025-26.

Definitions for reliability forecast under the RRO

For the RRO, components of any reliability forecast or indicative reliability forecast must include the expected USE, and whether or not there is a **forecast reliability gap**. Such a gap exists for a NEM region if the expected USE exceeds the IRM up until 30 June 2025, or exceeds the reliability standard from 1 July 2025 onwards.

If there is a forecast reliability gap, the reliability forecast must also include:

- The forecast reliability gap period (start and end date), and trading intervals in which forecast USE is likely to occur.
- The expected USE for that forecast reliability gap period.
- The size of the forecast reliability gap (expressed in megawatts).

AEMO's calculation of the size of the forecast reliability gap represents the additional megawatts of firm capacity required to reduce the annual expected USE to the relevant standard, that is, the IRM or the reliability standard as appropriate. For the purposes of calculating the reliability gap, this capacity is assumed to be 100% available during all identified trading intervals within the forecast reliability gap period only.

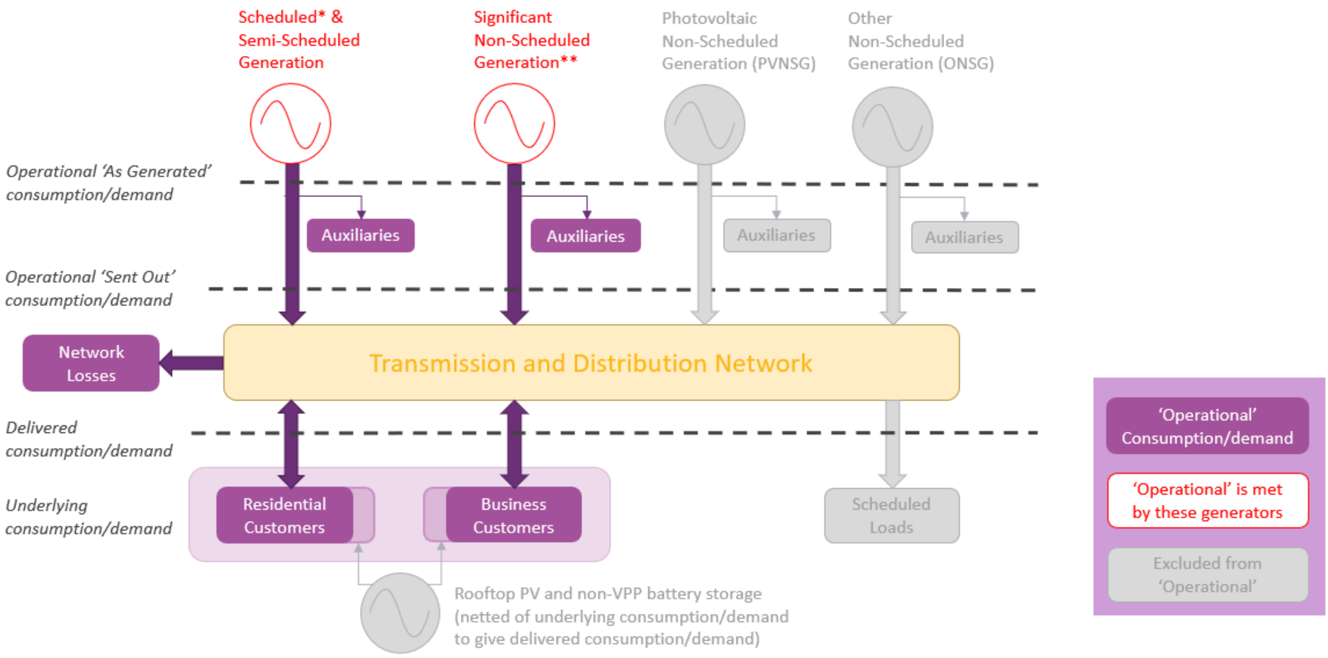
[28] The USE that contributes to the Interim Reliability Measure and the reliability standard excludes power system security incidents resulting from events such as multiple or non-credible generation and transmission events, network outages that do not materially contribute to inter-regional transfers, or industrial action (NER 3.9.3C(b)(2)). 'Expected' in this ESOO refers to the statistical definition of the word, which describes the weighted-average USE over a wide range of simulated outcomes.

Demand forecast definitions

Electricity **consumption** represents electricity consumed over a period of time – in the context of this report, annually – while **demand** is used as a term for the instantaneous consumption of electricity at a particular point in time, typically reported at time of maximum or minimum demand.

Consumption and demand can be measured at different locations in the network. Unless otherwise stated, the forecasts in this report refer to **operational consumption/demand (sent out)**[29]. This is the supply to the grid by scheduled, semi-scheduled, and significant non-scheduled generators (excluding their auxiliary loads, or electricity used by the generator). Also excluded from this definition is consumption/demand from scheduled loads (typically pumping load from pumped hydro energy storage or large-scale batteries). AEMO's demand definitions are shown in **Figure 4**.

Figure 4 Demand definitions used in this report



* Including virtual power plants (VPPs) from aggregated behind-the-meter battery storage.
** For definitions, see https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Dispatch/Policy_and_Process/Demand-terms-in-EMMS-Data-Model.pdf.

This ESOO reports consumption forecasts for each sector (residential and business) as **delivered consumption**, meaning the electricity delivered from the grid to household and business consumers. Annual operational consumption forecasts include this forecast delivered consumption for all consumer sectors, plus electricity expected to be lost in transmission and distribution.

Underlying consumption/demand means all electricity used by consumers, which can be sourced from the grid but also, increasingly, from other sources including consumers' distributed photovoltaics (PV) and battery storage.

Maximum and minimum operational demand means the highest and lowest level of electricity drawn from the grid, measured and averaged from the power system in half-hour intervals in either **summer** (1 November to 31 March for mainland regions and 1 December to 28/29 February for Tasmania) or **winter** (1 June to 31 August).

[29] See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Demand-Forecasts/Operational-Consumption-definition.pdf.

These forecasts are presented as **sent out** (the electricity measured at generators' terminals) and **as generated** (including auxiliary loads).

Maximum and minimum operational demand forecasts can be presented with:

- A **50% probability of exceedance (POE),** meaning they are expected statistically to be met or exceeded one year in two, and are based on average weather conditions (also called one-in-two year).
- A **10% POE** (for maximum demand) or **90% POE** (for minimum demand), based on more extreme conditions that could be expected one year in 10 (also called one-in-10).
- A **90% POE** (for maximum demand) or **10% POE** (for minimum demand), based on less extreme conditions that could be expected nine years in 10.

1.3 Forecasting reliability

Overall approach to forecasting reliability

Following extensive stakeholder consultation, AEMO has forecast reliability of supply for the NEM in the 2022 ESOO by:

- Updating demand forecasts for all regions, taking into account the latest information on economic and population drivers and trends in behaviour by household and business consumers, including electrification impacts. The forecasts for operational consumption and demand also reflect forecasts for implemented energy efficiency measures and growth in DER investments, including distributed PV generation, battery storage systems and electric vehicles (EVs).
- Updating the supply available to meet this demand to include the latest information on existing and committed generation in the NEM (and anticipated developments, where stated) and expected closures.
- Reviewing the performance of existing scheduled generation based on historical performance data, and incorporating forward-looking projections of plant reliability for coal-fired and large gas-fired generators that take into account the impact of maintenance plans, plant deterioration due to age, and reductions in maintenance as generators approach retirement.
- Applying a statistical simulation approach[30] which assesses the ability of existing and committed[31] generation to meet forecast demand in all hours. The model calculates expected USE over a number of forecast conditions impacting demand and renewable generation (based on 11 historical reference years of weather) and random generator outages, weighted by likelihood of occurrence, to determine the probability of any supply shortfalls. These shortfalls have been expressed in terms of the forecast expected USE.

AEMO's ESOO modelling does not include "equitable involuntary load shedding" (an operational measure to spread USE throughout interconnected regions in proportion to demand)[32]. Instead, the forecast annual USE in a region reflects the projected source of any supply shortfall, and is intended to provide participants with the most

[30] See *ESOO and Reliability Forecast Methodology*, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities.

[31] Commitment criteria are explained under the Background Information tab in each regional spreadsheet on AEMO's Generation Information web page, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

[32] See https://www.aemc.gov.au/sites/default/files/content//Guidelines-for-Management-of-Electricity-Supply-Shortfall-Events.PDF.

appropriate locational signals to drive efficient market responses. Forecast expected USE therefore generally reflects the locations (NEM regions) where the greatest supply-demand imbalance is forecast to exist.

The modelling does, however, consider the NEM as an interconnected market, not a collection of independent regions. That means that if a significant imbalance between supply and demand is projected to emerge (potentially following generator withdrawals or a large increase in consumer demand) in one region, it can increase forecast USE and lead to forecast reliability gaps in connected regions.

More details on the methodologies, inputs, and assumptions used to develop the demand and supply forecasts and assess expected USE are available in the accompanying information listed in **Table 3** (in Section 1.5).

USE and investment needs

In this ESOO, AEMO compares the expected USE calculated through the statistical model against the maximum threshold specified by the reliability standard and the IRM.

For the RRO, if the USE is expected to exceed the relevant threshold, AEMO calculates the forecast reliability gap size, indicating the need (in megawatts) for dispatchable generation or equivalent in the forecast reliability gap period to reduce USE so the IRM or reliability standard will be met.

Further investment is possible with sufficient lead time, provided a conducive investment landscape exists. In the medium to longer term, the ESOO indicative reliability forecast highlights opportunities for market investment to meet customer needs, and the risks if investment is not forthcoming. AEMO's 2022 *Integrated System Plan* (ISP) complements the ESOO in this regard, identifying economically efficient generation development opportunities across the NEM that can enable the energy transition while meeting reliability standards.

1.4 Scenarios and sensitivities

In consultation with industry and consumer groups, AEMO developed scenarios and additional sensitivities for use in its 2022 forecasting and planning publications, including the ESOO and the ISP. These scenarios have been applied in this ESOO as follows:

- Consumption and demand have been forecast for each of the four scenarios shown in **Figure 5**, across the 30-year forecast period 2022-23 to 2052-53. The forecasts are presented for each region in Appendices A1-A5.
- For RRO purposes, AEMO's Reliability Forecast Guidelines[33] require that the reliability forecast and indicative reliability forecast are determined on the scenario AEMO considers most likely. For the 2022 ESOO, AEMO considers:
  - The *Step Change* demand scenario the most likely – or Central – scenario for reliability modelling.
  - The individual inputs that specify the *Step Change* demand scenario to be most likely, as they appropriately capture many non-linear effects of a power system and industry in transition.
- The 2022 ESOO includes demand forecasts for all scenarios, as outlined in **Table 1**, and reliability assessments that focus on the ESOO Central scenario, but also assess alternate futures (*Slow Change* scenario, and other sensitivities) over the 10-year outlook.

[33] 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.

Figure 5 2022 scenarios for AEMO's forecasting and planning publications

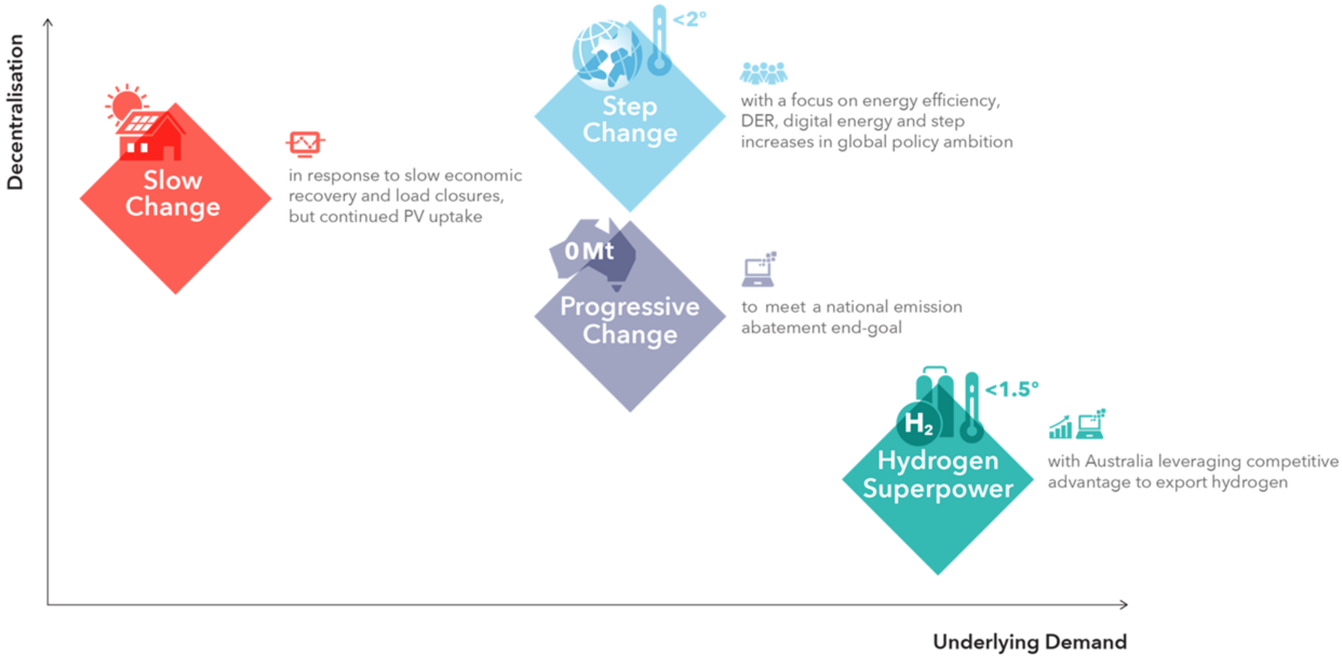


Table 1 summarises the scenarios presented in this ESOO; more information is available in the 2022 ISP[34].

Table 1 Descriptions of 2022 scenarios for AEMO's forecasting and planning publications

Scenario	Description
Slow Change	• **Challenging economic environment** following the COVID-19 pandemic, with greater risk of industrial load closures, and slower net zero emissions action. • Consumers continue to manage their energy needs through DER, particularly distributed PV.
Progressive Change	• **Pursuing an economy-wide net zero emissions 2050 target progressively, ratcheting up emissions reduction goals over time.** • *Progressive Change* delivers a net zero emission economy, with a progressive build-up of momentum ending with deep cuts in emissions across the economy from the 2040s. • The 2020s would continue the current trends of the NEM's emission reductions, assisted by government policies, consumer DER investment, corporate emission abatement, and technology cost reductions. The 2030s would see commercially viable alternatives to emissions intensive heavy industry emerge after a decade or longer of research and development, paving the way for stronger economy-wide decarbonisation and industrial electrification in the 2040s, and nearly doubling the total capacity of the NEM. • EVs become more prevalent over time and consumers gradually switch to using electricity to heat their homes and businesses. • Some domestic hydrogen production supports the transport sector and as a blended pipeline gas, with some industrial applications.
***Step Change* (ESOO Central scenario)**	• **Rapid consumer-led transformation of the energy sector and co-ordinated economy-wide action.** • *Step Change* moves much faster initially to fulfilling Australia's net zero policy commitments that would further help to limit global temperature rise to below 2°C compared to pre-industrial levels. • Rather than building momentum as *Progressive Change* does, *Step Change* sees a consistently fast-paced transition from fossil fuel to renewable energy in the NEM. International action follows a similar fast-pace of expanded policy commitment and investment, supported by rapidly falling costs of energy production, including consumer devices. • Increased digitalisation helps both demand management and grid flexibility, and energy efficiency is as important as electrification.

[34] At https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp.

Scenario	Description
	• By 2050, most consumers rely on electricity for heating and transport, and the global manufacture of internal-combustion vehicles has all but ceased. • Some domestic hydrogen production supports the transport sector and as a blended pipeline gas, with some industrial applications.
Hydrogen Superpower	• **Strong global action and significant technological breakthroughs.** • While the two previous scenarios assume the same doubling of demand for electricity to support industry decarbonisation, *Hydrogen Superpower* nearly quadruples energy consumption to support a NEM-connected hydrogen export industry. • The technology transforms transport and domestic manufacturing, and renewable energy exports become a significant Australian export, retaining Australia's place as a global energy resource. • While household electrification of heating and cooking appliances still occurs, many households with gas connections will progressively switch to a hydrogen-gas blend, before appliance upgrades achieve 100% hydrogen use.

Table 2 summarises inputs for each scenario that are relevant to the demand forecasts.

Table 2 Scenario drivers of most relevance to the NEM demand forecasts used in this 2022 ESOO

Scenario	*Slow Change*	*Progressive Change*	*Step Change* (ESOO Central)	*Hydrogen Superpower*
Economic growth and population outlook	Low	Moderate	Moderate	High
Energy efficiency improvement	Low	Moderate	High	High
Distributed PV	Moderate, but elevated in the short term	Moderate	High	High
Distributed battery storage installed capacity	Low	Moderate	High	High
Battery storage aggregation / virtual power plant (VPP) deployment	Low	Moderate	High	High
Battery electric vehicle (EV) uptake	Low	Moderate	High	Moderate/High
EV charging time switch to coordinated dynamic charging	Low	Moderate	High	Moderate/High
Electrification of other sectors (expected outcome)	Low	Moderate	Moderate/High	Moderate/High
Hydrogen consumption	Minimal	Minimal	Limited to domestic hydrogen consumption	Large NEM-connected export and domestic consumption
Decarbonisation target	26-28% reduction by 2030	26-28% reduction by 2030	Exceeding 26-28% reduction by 2030, consistent with global targets for a <2°C mean rise in temperature by 2100.	Exceeding 26-28% reduction by 2030, consistent with global targets for a <1.5°C mean rise in temperature by 2100.

1.5 Additional information for 2022 ESOO

Table 3 provides links to additional information provided either as part of the 2022 ESOO accompanying information suite, or in related AEMO planning information.

Table 3 Links to supporting information

Information source	Website address and link
AEMO Forecasting Approach: • ***Demand Forecasting Methodology Information Paper*** • ***Demand Side Participation (DSP) Forecasting Methodology*** • ***Reliability Forecast Guidelines*** • ***ESOO and Reliability Forecast Methodology Document***	https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-approach
2021 *Inputs, Assumptions and Scenarios report* (IASR) **2022 *Forecasting Assumptions Update* (FAU)**	https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios 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
2022 ESOO supplementary results, data files, and constraints, including: • **2022 ESOO model and user guide** • **2022 ESOO demand and variable renewable energy traces** • **2022 ESOO reliability outcomes by region**	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
Reliability Standard Implementation Guidelines (RSIG)	https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/reliability-standard-implementation-guidelines
Demand forecasting data portal	http://forecasting.aemo.com.au/
Forecasting Accuracy Reporting* and *Forecast Accuracy Report Methodology	https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/forecasting-accuracy-reporting
Generation Information web page	https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information
Integrated System Plan	https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp
Forecasting Best Practice Approach Report	To be provided to the Australian Energy Regulator (AER) at the time of publishing, and subsequently published by the AER.
Consultant reports supporting the development of the 2021 IASR and ESOO	
BIS Oxford Economics, *2021 Macroeconomic Projections Report*	https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/bis-oxford-economics-macroeconomic-projections.pdf? la=en
CSIRO, *2021 DER Forecasts Report*	https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/csiro-der-forecast-report.pdf?la=en
Green Energy Markets, *2021 DER Forecasts Report*	https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/green-energy-markets-der-forecast-report.pdf?la=en
CSIRO Multi-sector modelling	https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/isp/2021/csiro-multi-sector-modelling.pdf?la=en
AEP Elical – *Assessment of Ageing Coal-Fired Generation Reliability*	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities

2 Consumption and demand forecasts

Consumer demand is a key consideration in the assessment of supply adequacy. This chapter discusses the consumption and maximum and minimum demand forecasts in this ESOO. It focuses commentary on the next 10 years, and includes forecasts over the next 30 years. The key observations are:

- Expanded production from large industrial customers in Victoria and South Australia contributes to a forecast growth in electricity consumption from 2022-23 in these regions, compared to the 2021 ESOO and the *Update to the 2021 ESOO*.
- Electrification, particularly of businesses, and take-up of EVs are the primary drivers of operational consumption being forecast to grow by approximately 15% over the next 10 years.
- Maximum demand is forecast to grow over the forecast horizon, broadly in tune with drivers affecting energy consumption growth. The operation of distributed photovoltaics (PV), battery storages, EVs and demand side response is projected to partially offset the growth in underlying consumption, potentially lessening the relative impact on forecast reliability.
- With the projected sustained uptake of distributed PV, minimum demand forecasts continue to show a rapid decline.
- The pace, scale and location of electrification and other emerging opportunities, such as hydrogen production, remain an uncertain influence on the growth of NEM electricity consumption, particularly as the economy evolves to target net zero emissions. The uncertainty is increased by domestic and international challenges such as social licence and supply chain considerations. The spread of forecast outcomes is therefore wide across scenarios to reflect this uncertainty.

Longer-term consumption and demand forecasts to 2050, used in AEMO's forecasting and planning activities such as the ISP, are briefly discussed in this chapter and presented in Appendices A1-A5 for each region.

The regional and component demand and consumption forecasts are available to view and download from AEMO's Forecasting Portal[35].

The drivers and outlook for consumption and demand forecasting components – such as distributed PV, battery and EV uptake, energy efficiency savings, electrification of other sectors, new household connections, and economic growth – are discussed in AEMO's 2021 IASR and 2022 FAU.

[35] At https://forecasting.aemo.com.au/.

2.1 Drivers of electricity consumption and demand

As Australia transitions towards a net zero emission economy by 2050, electricity consumption and demand forecasts are influenced by a range of new and continuing drivers. The *Step Change* scenario – considered the most likely, or Central scenario, in this 2022 ESOO (see Section 1.4) – incorporates each of these drivers, including a strong influence from electrifying business and residential sectors, and captures continued uptake of DER, including distributed PV and batteries, as well as growing uptake of electrified transport (primarily via EVs).

These drivers are forecast to deliver a future with greater underlying consumption, and more consumer-driven generation and storage behind the meter, than exists today.

While challenging economic conditions exist now, with inflation and interest rates rising in recent times, some increased industrial activity is also emerging. Industrial customers, particularly in South Australia and Victoria, have indicated increasing production commitments in coming years, leading to consumption (and demand) increases in these 2022 ESOO forecasts.

Traditional drivers of consumption and demand – population growth, energy efficiency, DER investment and demand response – will also continue to influence the scale of the NEM's utility-scale investment needs.

By 2050, under some scenarios, NEM consumption is forecast to be at least twice the scale it is today, and up to five times larger if the potential for significant renewable energy exports (via hydrogen) is unlocked.

The same drivers influence maximum (and minimum) demand forecasts, but random weather-driven elements, co-incident customer behaviours, and the extent of co-ordination of customer-owned energy devices also influence the magnitude of demand peaks. As previous ESOOs have noted, maximum demand periods are forecast to frequently occur outside daylight hours in all regions. This reduces the impact that distributed PV uptake has on the forecast, relative to other fundamental drivers of growth such as new connections or appliance uptake. Likewise, and as has also been forecast previously, distributed PV continues to erode daytime operational demand, such that minimum demand is projected to continue to decline. Minimum operational demand is forecast to occur in the middle of the day in all regions.

Weather extremes are expected to drive greater variability in operational demand peaks. This increased forecast variability in daily operational consumption patterns may make the system increasingly challenging to operate, but greater demand flexibility across the day, and the year, can reduce this challenge. Appropriate mechanisms could encourage device owners to improve grid flexibility – the mechanisms could be technological, via digitalisation and orchestration, and/or economic, via tariff reform.

2.2 Forecast shows continuing growth in underlying consumption, with DER and energy efficiency slowing operational consumption growth

The key drivers acting to influence the consumption forecasts – population growth, economic activity, DER investment, and emerging opportunities to electrify new customer loads – affect residential, business, and industrial customer segments differently.

Figure 6 below shows forecast annual consumption by segment in the ESOO Central (*Step Change*) forecast over the next 20 years, and highlights the various influencing factors contributing to projected changes in consumption over the next decade.

Figure 7 zooms in on the relative forecast impact of each component by 2031-32, across the different scenarios, showing the different pathways electricity consumption could take.

In both charts, components that increase operational consumption are drawn in solid colours, while components reducing operational consumption are drawn in shaded patterns, with the net operational consumption forecast marked with the dashed line. This net outlook is also compared to the 2021 ESOO forecast.

Figure 6 Actual and forecast NEM electricity consumption, ESOO Central scenario, 2013-14 to 2051-52 (TWh)

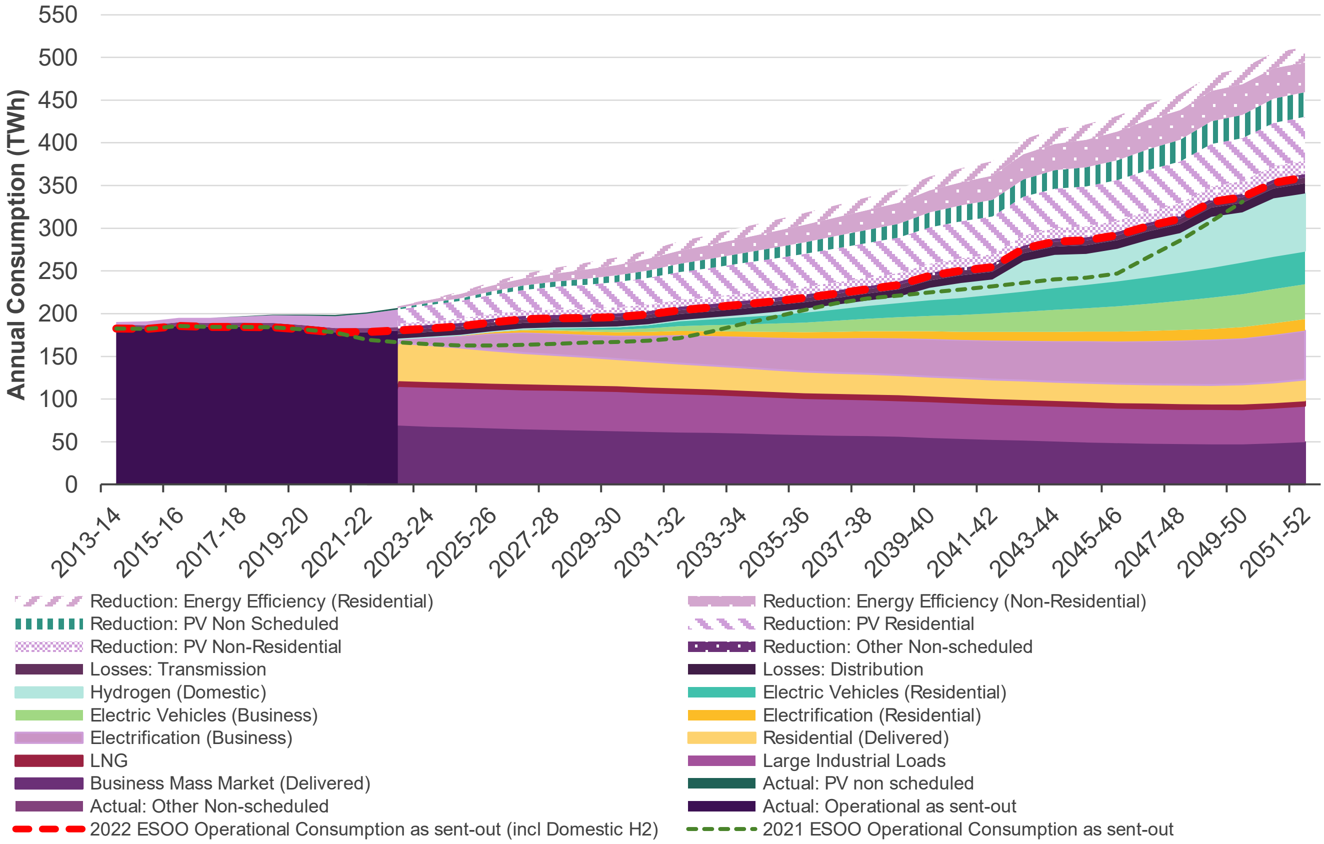
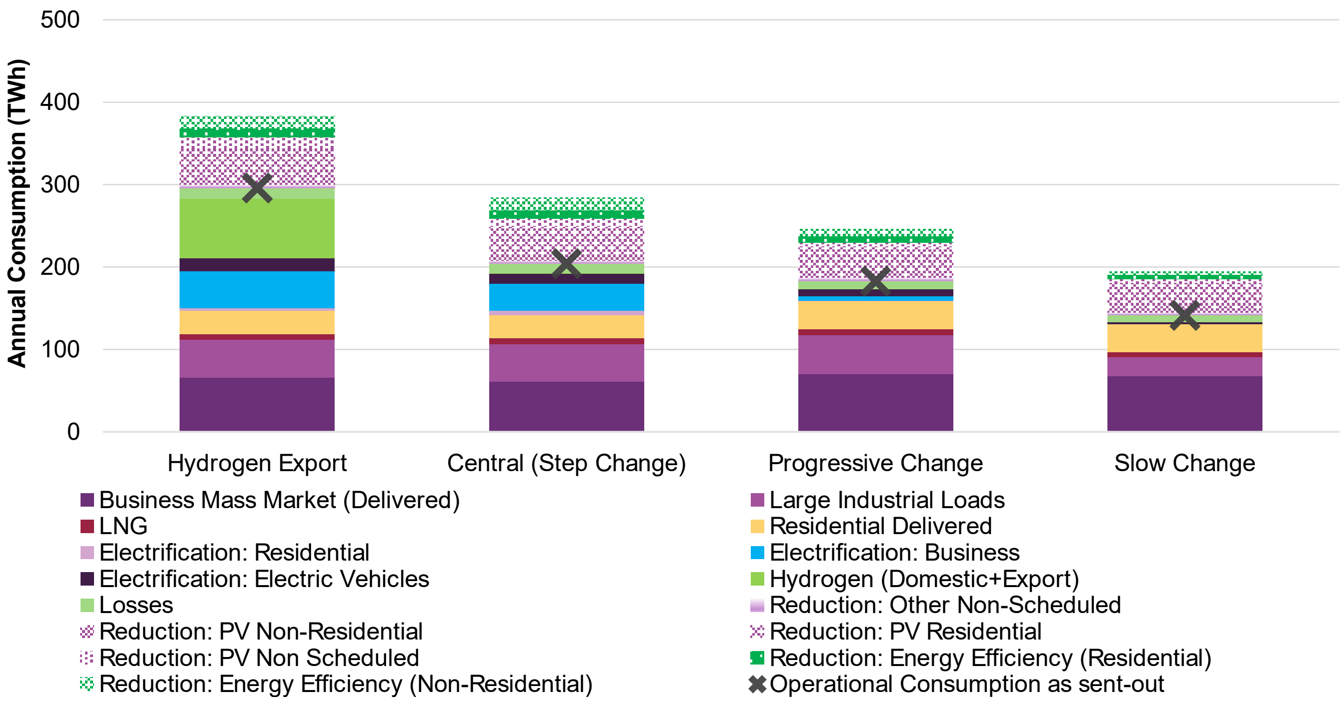


Figure 7 Forecast NEM consumption (by component) for the four ESOO scenarios, 2031-32 (TWh)



Each region in the NEM has similar macro level drivers for population and economic activity, although differences in the size and composition of each sector give rise to regional nuances. For example, Victoria has more gas heating load and therefore greater potential for residential electrification than other regions, while Tasmania and Queensland have a much lower amount of gas usage for heating and therefore a much lower potential for residential electrification. Regional trends and drivers are discussed in Appendices A1 to A5.

As outlined above, distributed PV and energy efficiency investments are projected to reduce the need for electricity to be provided from the grid to meet customer demand. AEMO's 2022 ESOO forecasts of distributed PV remain consistent with the 2021 forecasts, as outlined in the 2022 FAU. As described in the 2022 FAU, minor adjustments to reflect updated actual investments in distributed PV have been incorporated in the 2022 forecasts[36].

Operational consumption is forecast in the ESOO Central scenario to increase from 178 TWh in 2021-22 to 204 TWh by 2031-32, largely due to projected transport, business and residential electrification, which is partially offset by forecast sustained uptake of distributed PV as described in the previous sections.

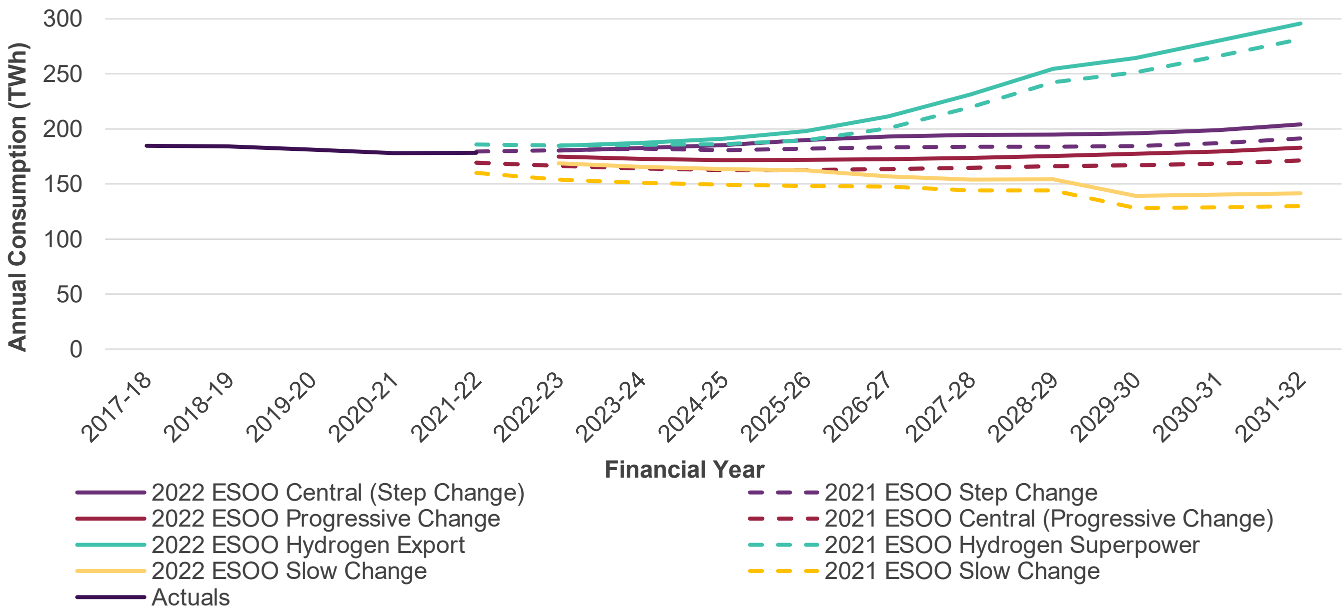
Outside the ESOO Central outlook, AEMO's alternative scenarios continue to provide a similar spread of consumption uncertainty to 2031-32 as in the 2021 ESOO forecasts (see **Figure 8**).

The operational consumption forecasts for other scenarios are available to view or download from AEMO's Forecasting Portal[37] and are further discussed for each region in Appendices A1-A5.

[36] Adjustments re-baseline the starting point of forecast distributed PV uptake considering most recent actual installations, as outlined in the 2022 *Forecasting Assumptions Update*. AEMO also conducts annual reviews of forecast accuracy, which may identify other improvements to forecasting components from year to year. Distributed PV is monitored for this purpose.

[37] At https://forecasting.aemo.com.au/.

Figure 8 Actual and forecast NEM operational consumption, all ESOO scenarios and compared to 2021 ESOO, 2017-18 to 2031-32 (TWh)



Residential consumption forecast to grow, from increasing connections and EVs

Under the ESOO Central scenario, underlying residential consumption is forecast to increase approximately 10% over the next decade, from approximately 60 terawatt hours (TWh) in 2021-22 to 66 TWh in 2031-32. This is due primarily to projected growth in household connections, with new dwelling construction increasing dwellings from 10.5 million in 2021-22 to 12.1 million in 2031-32[38].

There is significant potential for electrification of the residential sector, particularly from gas space heating, some hot water heating, and a small impact from cooking and other appliances. In Victoria in particular, where many households rely on gas for heating, residential sector electrification has the potential to increase consumption by about 8% (or 5.2 TWh) by 2031-32 in some scenarios, with much of this consumption occurring over winter.

EVs are forecast to become cost-competitive with internal combustion engines over the next 30 years, and between 700,000 and 5 million residential EVs are projected to be in use, depending on the scenario (which vary the availability and economics of EV investments). This amounts to between 2% and 16% of additional residential consumption (up to 10 TWh).

Residential operational consumption continues to be significantly influenced by forecast distributed PV generation. Production from distributed PV is estimated to supply approximately 23% of the residential sector's overall underlying consumption in 2021-22. Over 2 million homes have distributed PV generating to meet their own demand and at times exporting electricity to the grid. By 2031-32, this is expected to reach to approximately 46-53% of the residential sector's overall consumption, or approximately 4 million to 4.5 million homes, depending on scenario.

Beyond this decade, these growth drivers will likely continue, although *Slow Change* features minimal forecast electrification, and lower household connections temper growth in consumption compared to other scenarios.

[38] Refer to the 2022 FAU for more detail on AEMO's household connection forecasts.

Across all scenarios, underlying residential consumption is forecast to reach 68-77 TWh in the medium term (by 2041-42), growing to 76-95 TWh in the long term (by 2051-52).

Business sectors show opportunity for industrial expansion and electrification

Under the ESOO Central outlook, underlying consumption by business sectors – business mass market (BMM), large industrial loads (LILs), and liquified natural gas (LNG) – is forecast to increase approximately 25% in the next decade, from 131 TWh in 2021-22 to 168 TWh in 2031-32. This forecast growth is due primarily to projected electrification of industry and transport.

Forecast business consumption growth includes updated advice from large industrial participants. This drives a forecast above that reported in the *Update to the 2021 ESOO*, although the 2022 ESOO forecasts do reflect a re-baselined business sector with slower electrification than projected in the 2021 ESOO, reflecting observable trends in actual consumption.

Several key factors are anticipated to influence business sector consumption in the next decade:

- Industrial consumption is forecast to grow, as some industrial loads have committed to production expansions following reductions in recent years, particularly in Victoria and South Australia. However, economic conditions present uncertainty for other industrials, and if poor conditions were to emerge and be sustained (as forecast in *Slow Change*) there exists the risk of industrial closures. By 2031-32 these influences lead to a scenario spread for industrial consumption between a decline of approximately 50% (if closures occur) to a growth of 8%, compared to 2021-22.
- The BMM sector represents a larger proportion of overall consumption than in previous forecasts, based on an improved split of sectoral consumption[39]. The split between residential and business actuals is now based on smart meter data, rather than data sourced from the Australian Energy Regulator (AER) that was typically 18 months old[40]. This has resulted in a relatively larger share for the BMM sector, most noticeably in Tasmania, where forecasts are higher, reflecting a trend observable in estimated actuals in that region. Across the NEM, the BMM sector in aggregate is forecast to continue to remain relatively flat to 2024-25, before growing between 4% and 14% from 80 TWh in 2021-22 to between 83 TWh and 91 TWh by 2031-32, depending on the scenario. This projected growth is mostly from commercial services.
- The potential electrification of transport and in the business sector drives electrification forecasts by 2031-32, accounting for at least 91% of newly electrified loads across all sectors in all scenarios. Hydrogen production is also a potential emerging consumer of electricity, with the scale and timing of production a key uncertainty.
- Mitigating a significant portion of this forecast growth in consumption for the business sector is the projected rise of energy efficiency and distributed PV. Reduced energy consumption from increased energy efficiency is forecast to save between 4 TWh and 15 TWh by 2031-32 across the scenarios, while distributed PV generation is projected to reduce operational business sector consumption by between 9% and 11% across the scenarios.

These key drivers result in a range of business sector consumption forecasts that reach between 117 TWh and 221 TWh in 2041-42 depending on scenario (and further widen by 2050).

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[39] This was identified as a targeted improvement in the 2021 *Forecasting Accuracy Report* improvement plan. See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/accuracy-report/forecast-accuracy-report-2021.pdf.

[40] The 2020 Forecast Improvement Plan identified this as an opportunity for improvement. See https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/forecast-improvement-plan/forecast-improvement-plan-2020.pdf?la=en.

2.3 Maximum operational demand forecasts set to grow

Maximum demand is influenced by the same drivers described in Section 2.1, however the forecast trend in demand differs from the consumption trends due to each driver impacting the load shape differently across the day and year.

For the mainland NEM regions, maximum operational demand currently typically occurs at the end of a hot summer day while houses and buildings that retain their heat are actively cooled by air-conditioners, and distributed PV generation is low. In Tasmania, where cooler temperatures mean less significant summer peaks, annual maximum demand typically occurs in winter, with both morning and evening maximum operational demand events possible, either just before business hours or just after as residential consumers heat their premises.

The ESOO maximum demand forecast represents uncontrolled or unconstrained demand, free of market-based or non-market-based solutions that might reduce system load during peak (including Reliability and Emergency Reserve Trader [RERT], the Wholesale Demand Response [WDR] mechanism, or DSP). The unconstrained demand forecasts help identify the potential system needs for, and value of, these solutions.

Non-coordinated, customer-controlled battery and EV charging is considered in the unconstrained maximum demand forecasts presented in **Figure 9** and **Figure 10**. A sensitivity exploring the impact of some of these demand side solutions is examined further in Section 6.2.

AEMO prepares the forecasts as a distribution rather than single-point forecasts, given by the 10%, 50%, and 90% POE forecasts – see Section 1.2 for definitions, and Appendices A1-A5 for more detailed regional forecasts.

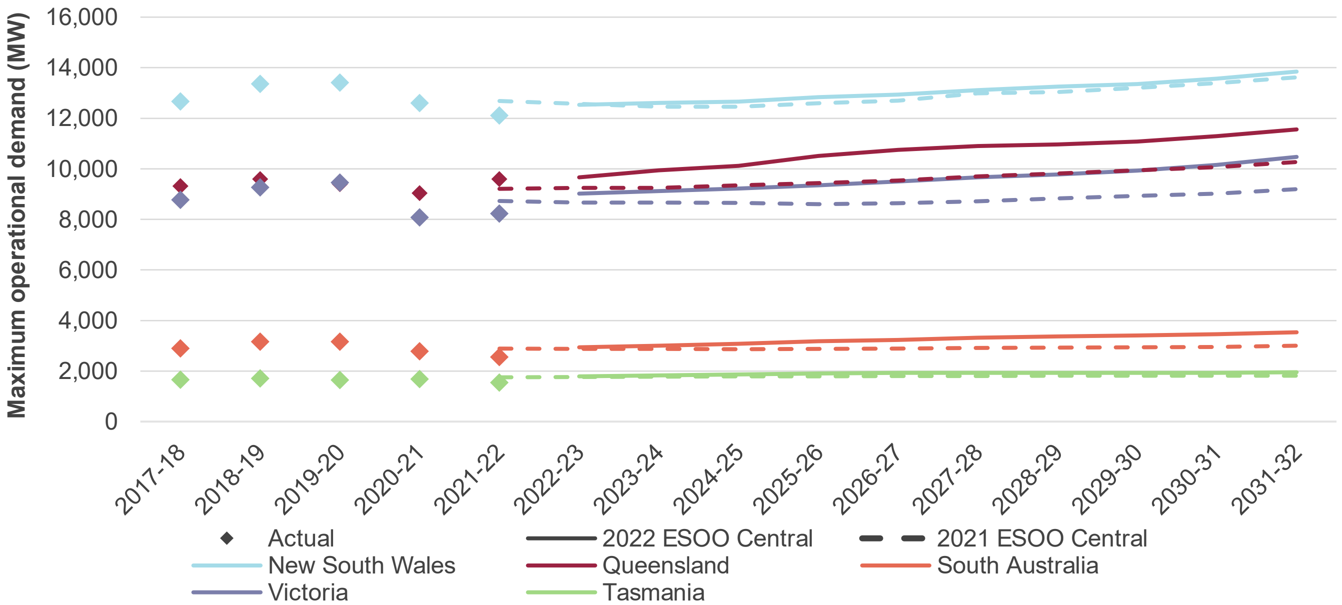
Figure 9 shows the annual actual and forecast maximum operational demand (sent-out, 50% POE) for all NEM regions from 2017-18 to 2031-32 for the 2022 ESOO Central scenario, compared to the 2021 ESOO Central scenario. **Figure 10** shows the same actual actuals and forecasts out to 2050-51.

The key insights from these forecasts are:

- Next year in 2022-23, forecast maximum operational demand is higher in the 2022 ESOO than in the 2021 ESOO in all regions except New South Wales, which is projected to start slightly lower than previously forecast.
  - The higher value forecasts are mostly due to forecast expansion in LILs, particularly in South Australia and Victoria but not Tasmania, as well as electrification and projected increase in underlying demand. LIL forecast demand is only slightly higher in Queensland than in the 2021 ESOO, with the higher values also due to increases from forecast underlying demand, in particular cooling load in response to high temperatures.
  - Compared to the ESOO Central (*Step Change*) scenario forecast in the *Update to the 2021 ESOO* (not shown below, see Appendices A1-A5), forecast maximum operational demand in the 2022 ESOO starts higher in 2022-23 in all regions except for South Australia, which is starting at a similar level, and New South Wales, which is starting slightly lower. While there are net differences in drivers increasing and decreasing demand, the main difference is a forecast increase in LILs in the 2022 ESOO in all regions except Tasmania, where they are slightly lower.
- In the next five years, to 2026-27, forecast maximum operational demand (50% POE) in the 2022 ESOO is higher and grows more compared to the 2021 ESOO in all regions.

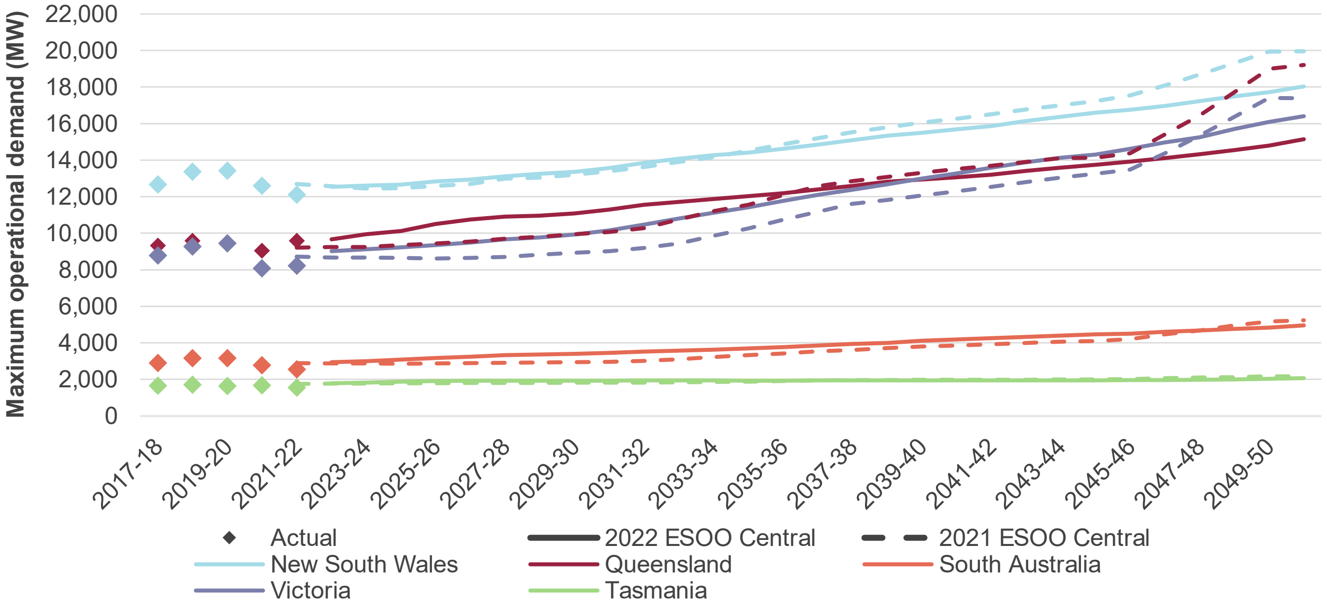
  - Higher maximum operational demand forecasts and growth are mainly due to increased forecasts of electrification, and LIL demands. The shift to *Step Change* as the ESOO Central scenario in the *Update to the 2021 ESOO* also reflected the forecast influence of electrification, but (as described in Section 2.2) the updated information from LIL operators is a new influence on these 2022 ESOO forecasts.
  - The difference in forecast growth between the 2021 ESOO and 2022 ESOO is more subdued in New South Wales, as higher electrification is forecast to be offset by lower underlying demand and higher distributed PV.
- These trends largely repeat in the subsequent five years, from 2027-28 to 2031-32. Compared to the *Update to the 2021 ESOO*, forecast peak demand in all regions is higher and grows more in the 2022 ESOO, mostly due to higher LIL forecasts in all regions except Tasmania, where higher values are mostly due to higher forecast underlying demand, particularly heating load in response to low temperatures. Forecast peak demand in all regions is higher in the 2022 ESOO than the 2021 ESOO, mostly due to higher electrification forecasts in all regions, higher EVs in all regions except Victoria (which already exhibited strong growth in the 2021 ESOO), and higher LIL forecasts in all regions except Tasmania.
- After the next decade, in the 20 years from 2032-33 to 2050-51, peak demand is forecast to grow in all regions, except Tasmania, which remains relatively flat. With forecasts for increased electrification, particularly of winter heating loads, the difference between summer and winter peaks is expected to reduce, and Victoria is forecast to switch seasons and join Tasmania as a winter peaking region from 2031-32 for the 50% POE and from 2040-41 for the 10% POE.

Figure 9 Actual and forecast regional annual 50% POE maximum operational demand (sent-out), 2022 ESOO Central and 2021 ESOO Central scenario, 2017-18 to 2031-32 (MW)



Note: The actuals displayed are not weather-corrected or adjusted for system events and exclude DSP. Also, the 2022 ESOO uses the *Step Change* scenario as its Central outlook, compared to the *Progressive Change* scenario used in the 2021 ESOO (see Section 1.4).

Figure 10 Actual and forecast regional annual 50% POE maximum operational demand (sent-out), 2022 ESOO Central and 2021 ESOO Central scenarios, 2017-18 to 2050-51 (MW)



Note: The actuals displayed are not weather-corrected or adjusted for system events and exclude DSP. Also, the 2022 ESOO uses the *Step Change* scenario as its Central outlook, compared to the *Progressive Change* scenario used in the 2021 ESOO (see Section 1.4).

In the ESOO Central scenario over the next 10 years, the primary influences on maximum operational demand forecast trends are the residential and business drivers discussed in Section 2.1, such as new connections, the number of appliances being used, and how and when those appliances are used. Specifically, forecasts of growing electrification contribute the most to the upwards trends, along with projected increases in LIL production in South Australia.

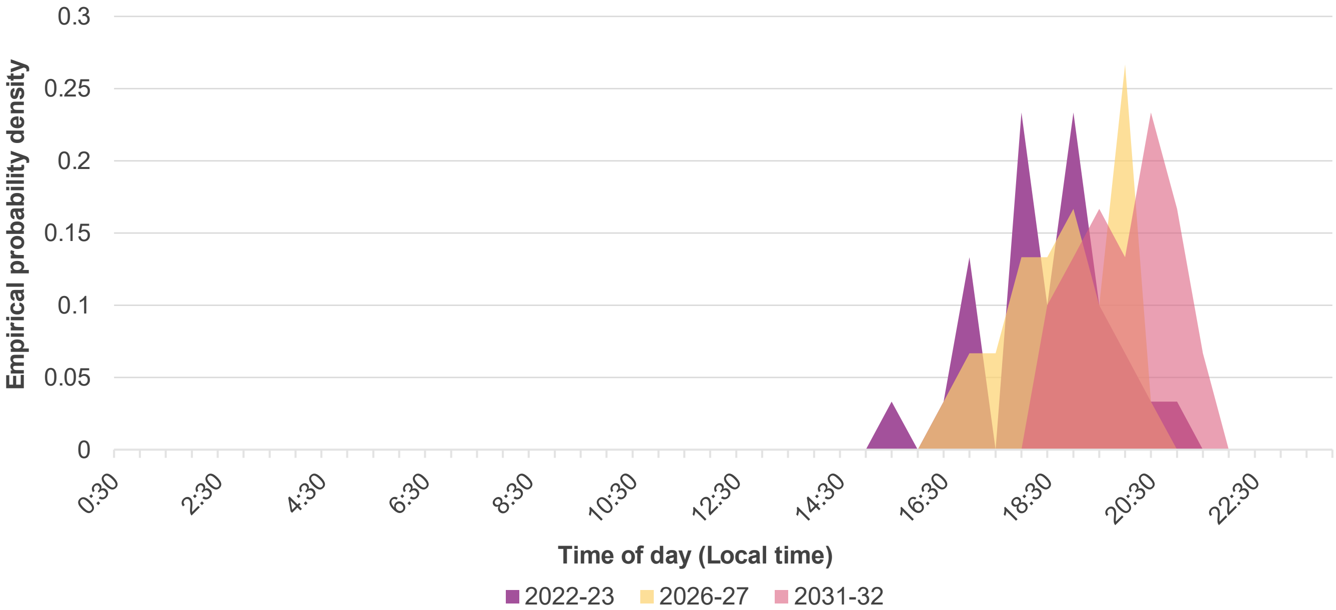
Behind-the-meter batteries are forecast as either uncoordinated – installed to meet the energy needs of the given household only – or as orchestrated to operate when system needs are greatest (through virtual power plants [VPPs] or similar arrangements). AEMO's 2022 ESOO Central scenario assumes a strong increase in coordination and orchestration of these devices to meet power system needs, and those devices that remain uncoordinated are not forecast to materially reduce maximum operational demand, reducing the maximum demand by around 1.4% or less by 2031-32 in the ESOO Central scenario. The share of orchestrated, coordinated devices may more significantly help reduce the scale of maximum demand periods. A sensitivity (discussed in Section 6.2) explores the impact if behind-the-meter batteries and DSP were to be lower than assumed.

EV charging represents a higher driver of forecast maximum operational demand in the ESOO Central scenario than in the 2021 ESOO to 2031-32 in all regions except for New South Wales and Victoria, where it is very similar to previous forecasts. The timing of charging will materially influence the scale of grid demand; more charging during daytime periods when excess solar generation may be available will reduce the peak demands that may otherwise occur if EV charging occurred simultaneous with the traditional evening peak. As state and federal government policies continue to focus on support for EVs and associated infrastructure, this remains an influential uncertainty affecting future investment needs.

Figure 11 shows the ESOO Central scenario forecast distribution of time of day maximum operational demand for New South Wales as an example to demonstrate the trend that evening peaks will progressively shift later over time in mainland NEM regions. As the timing of maximum operational demand has pushed towards and past sunset, this has diminished the impact of distributed PV production on maximum operational demand. To 2031-32, NEM mainland regional peak demand is expected to shift even later in the day, by 1-2 hours to at or just after sunset, due to the contribution from distributed PV. This is also forecast to occur in Tasmania, although with a lesser effect as Tasmania experiences maximum operational demand in winter, in either early morning or late afternoon to early evening when distributed PV generation is relatively low.

Appendices A1-A5 discuss maximum demand forecasts for each region and scenario.

Figure 11 New South Wales time of day 50% POE maximum operational demand (sent-out) distribution for the 2022 ESOO Central scenario, highlighting the shift of summer maximum demand into the evening periods, 2022-23 to 2031-32



2.4 Minimum operational demands forecast to rapidly decline

Minimum operational demand is influenced by the same drivers described in Section 2.1. The strongest influence is distributed PV uptake – as business and household consumers generate more of their own electricity, it drives a rapid decline in demand for electricity generated from scheduled, semi-scheduled, and significant non-scheduled generators during periods of low underlying demand.

The minimum operational demand forecasts represent uncontrolled or unconstrained demand, free of market-based solutions that might increase operational demand (including coordinated storage and EV charging[41], scheduled loads such as pumping load, and demand response) in periods of excess supply.

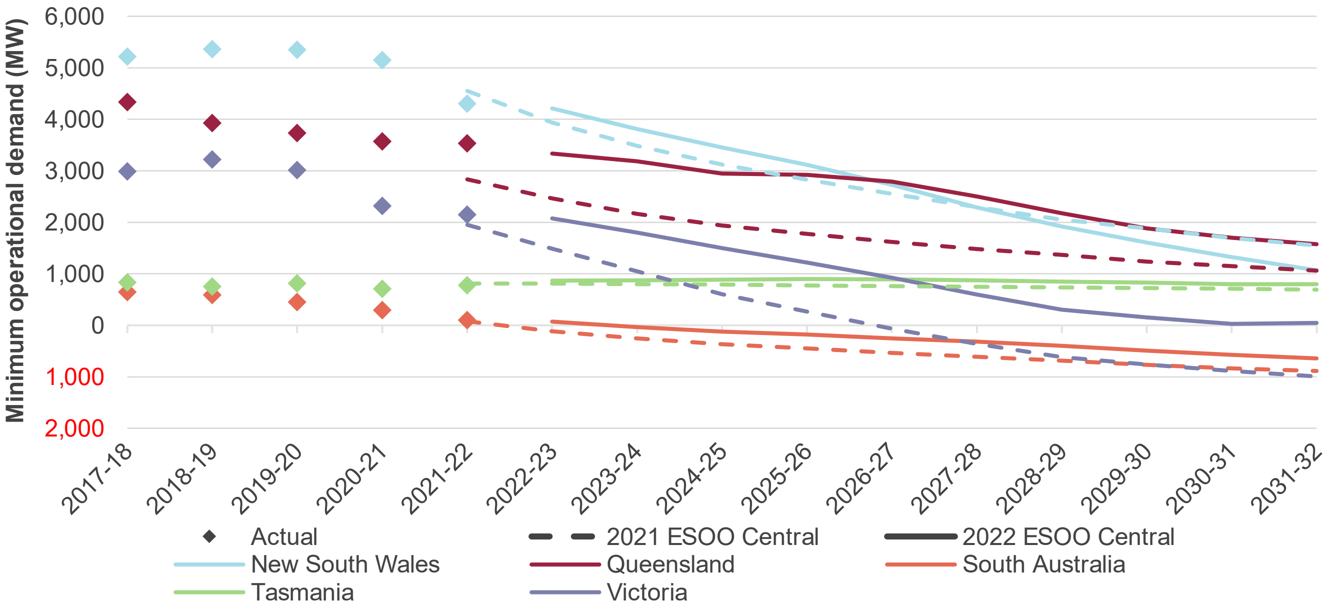
AEMO prepares the forecasts as a distribution rather than single-point forecasts, given by the 10%, 50%, and 90% POE forecasts – see Section 1.2 for definitions, and Appendices A1-A5 for more detailed regional forecasts.

Figure 12 compares the annual actual and forecast minimum operational demand (sent-out) for NEM regions from 2017-18 to 2031-32 for the ESOO Central scenario from the 2022 and 2021 ESOOs. **Figure 13** shows the same actuals and forecasts out to 2050-51.

[41] Non-coordinated, customer-controlled battery and EV charging is considered in the unconstrained minimum demand forecasts.

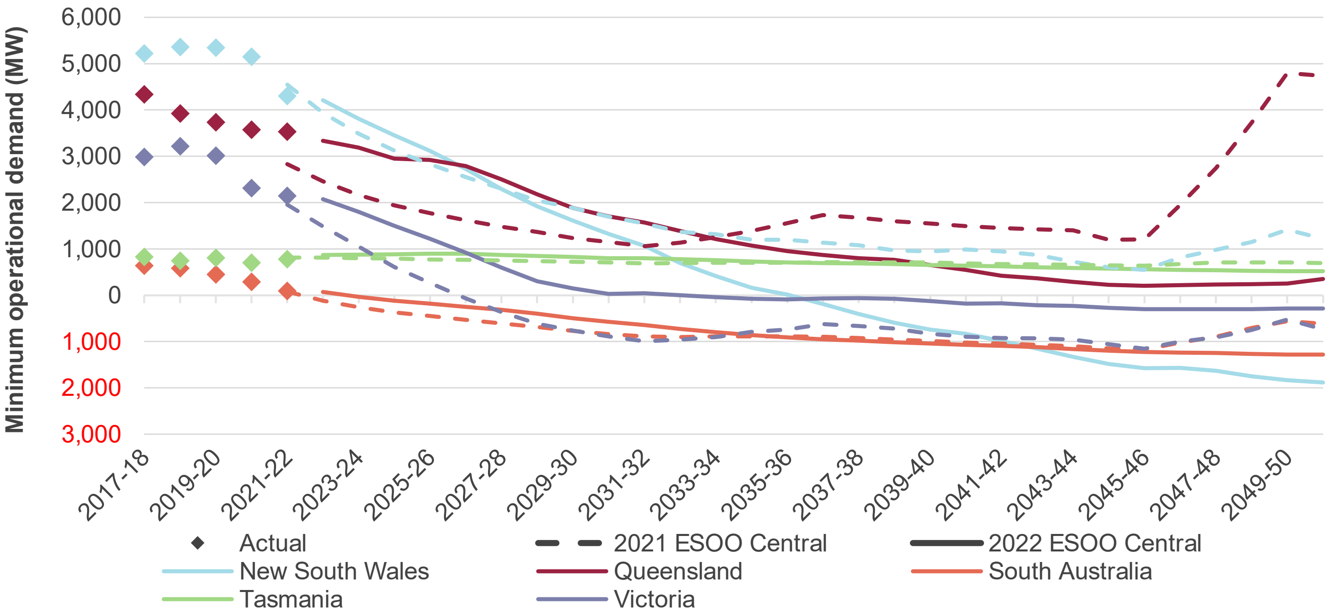
Across the forecast horizon, the decline in minimum operational demand is strongly influenced by distributed PV uptake, electrification, and additional load from behind-the-meter, non-coordinated batteries and EV charging.

Figure 12 Regional annual actual and forecast 50% POE minimum operational demand (sent-out), 2022 ESOO Central and 2021 ESOO Central scenarios, 2017-18 to 2031-32



Note: The actuals displayed are not weather-corrected or adjusted for system events and exclude DSP. Also, the 2022 ESOO uses the *Step Change* scenario as its Central outlook, compared to the *Progressive Change* scenario used in the 2021 ESOO (see Section 1.4).

Figure 13 Regional annual actual and forecast 50% POE minimum operational demand (sent-out), 2022 ESOO Central and 2021 ESOO Central scenarios, 2017-18 to 2050-51



Note: The actuals displayed are not weather-corrected or adjusted for system events and exclude DSP. Also, the 2022 ESOO uses the *Step Change* scenario as its Central outlook, compared to the *Progressive Change* scenario used in the 2021 ESOO (see Section 1.4).

Key additional insights from these forecasts are:

- For next year, forecast minimum operational demand in 2022-23 is higher in all regions than in the 2021 ESOO, due to higher projections for electrification and increased operation from LILs. The shift to *Step Change* as the ESOO Central scenario in the *Update to the 2021 ESOO* also reflected the electrification influence. The minimum demand distribution for Queensland has been revised upwards reflecting recent observations of consumer behaviour. As **Figure 12** shows, the 2022 ESOO forecasts align better with history than the 2021 ESOO forecasts.
- In the next five years (2022-23 to 2026-27), forecast minimum operational demand rapidly declines in all mainland NEM regions, because forecast uptake of distributed PV grows faster than projected underlying demand.
  - All minimum demand forecasts are higher in the 2022 ESOO than the 2021 ESOO, due to higher projections for electrification (mentioned above).
  - South Australia's 50% POE minimum operational demand is forecast to go negative in 2023-24 (that is, DER is forecast to generate more than underlying demand).
  - Minimum demand in Tasmania is forecast to slowly increase.
- In the following five years (2027-28 to 2031-32), similar trends are observed.
  - In Victoria, from 2030-31 the pace of change associated with electrification is forecast to exceed the decline associated with distributed PV uptake, slowing the minimum demand decline.
  - In Queensland, the 50% POE minimum operational demand is forecast to switch seasons permanently from winter to the shoulder season from 2027-28.
- In 2032-33 to 2050-51, similar trends to this decade are forecast, with the competing effects of continued distributed PV uptake and electrification resulting in continued decline, and delivering lower minimum demand projections than the 2021 ESOO. Tasmania is forecast to switch seasons with minimum operational demand moving from shoulder to summer in 2037-38, then staying in summer.

Since 2018-19, the majority of annual minimum demand events in mainland NEM regions have occurred in the middle of the day, when distributed PV generation is greatest. While historically Tasmania has been an exception, in future years Tasmania is also expected to observe minimum demand periods in the middle of the day.

In the ESOO Central scenario, the 50% POE annual minimum operational demand is forecast to occur:

- During the shoulder season in New South Wales and South Australia throughout the forecast period.
- In the summer season in Victoria throughout the forecast period.
- In winter in Queensland until switching to shoulder season from 2027-28.
- In the shoulder season in Tasmania until switching to summer in 2037-38.

The contribution from distributed PV to minimum underlying demand in 2031-32 (at the time of the 50% POE minimum operational demand for the ESOO Central scenario) ranges from 34.8% of underlying demand in Tasmania to 136.3% in South Australia. Victoria is the only other region with a contribution over 100%, at 101.9%.

While there is a general trend for minimum demands to be more prevalent during the middle of the day, there remains some uncertainty regarding the level of these minimums across the scenarios for each region throughout the forecast period. Factors such as distributed PV, LIL operations, electrification, and the charging profile of batteries and EVs all influence the distribution of minimum demand outcomes. In particular, battery and EV charging is anticipated to gradually shift away from pure convenience charging towards day charging patterns that better complement generation from distributed PV.

There are potential market-based solutions to increase operational demand in the daytime. These mechanisms include coordinated charging of storage (both distributed and grid-scale), coordinated EV charging, and demand response. These have not been included in the minimum operational demand forecasts presented in the 2022 ESOO, but are modelled to respond to dispatch signals in the 2022 ESOO supply adequacy assessments.

Appendices A1-A5 discuss minimum demand forecasts for each region and scenario further.

2.5 A flexible demand profile can enhance the NEM's ability to meet forecast peak demand

For the 2022 ESOO, AEMO has updated its estimate of DSP (also called demand response) responding to price and reliability signals, including any contribution from Wholesale Demand Response (WDR). The estimates are based on information provided to AEMO by all registered market participants regarding their DSP portfolios as of 31 March 2022, using the methodology described in AEMO's *DSP Forecasting Methodology Paper*[42].

Projected DSP across the NEM for summer 2022-23 is 662 MW as shown in **Table 4**. Compared to the 2021 ESOO, AEMO is forecasting:

- Lower DSP for New South Wales and Victoria, following lower development of WDR than estimated in the 2021 ESOO.
- Lower DSP in South Australia, given less observed DSP last year than was forecast.
- Higher DSP in Queensland, as observed DSP was higher than forecast in the last year following increasing periods of high price events.

Table 4 Projected demand side participation for summer 2022-23 (MW)

Trigger	New South Wales	Queensland	South Australia	Tasmania	Victoria
> $300/MWh	25	35	2	9	7
> $500/MWh	35	48	5	16	9
> $1,000/MWh	45	51	7	16	9
> $2,500/MWh	47	56	8	17	22
> $5,000/MWh	48	68	12	17	32
> $7,500/MWh	48	69	13	17	35
Reliability response	290	133	13	17	209

A. The reliability response is the estimated response during actual lack of reserve (LOR) 2 and 3 events. For the definition, see https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power_System_Ops/Reserve-Level-Declaration-Guidelines.pdf.

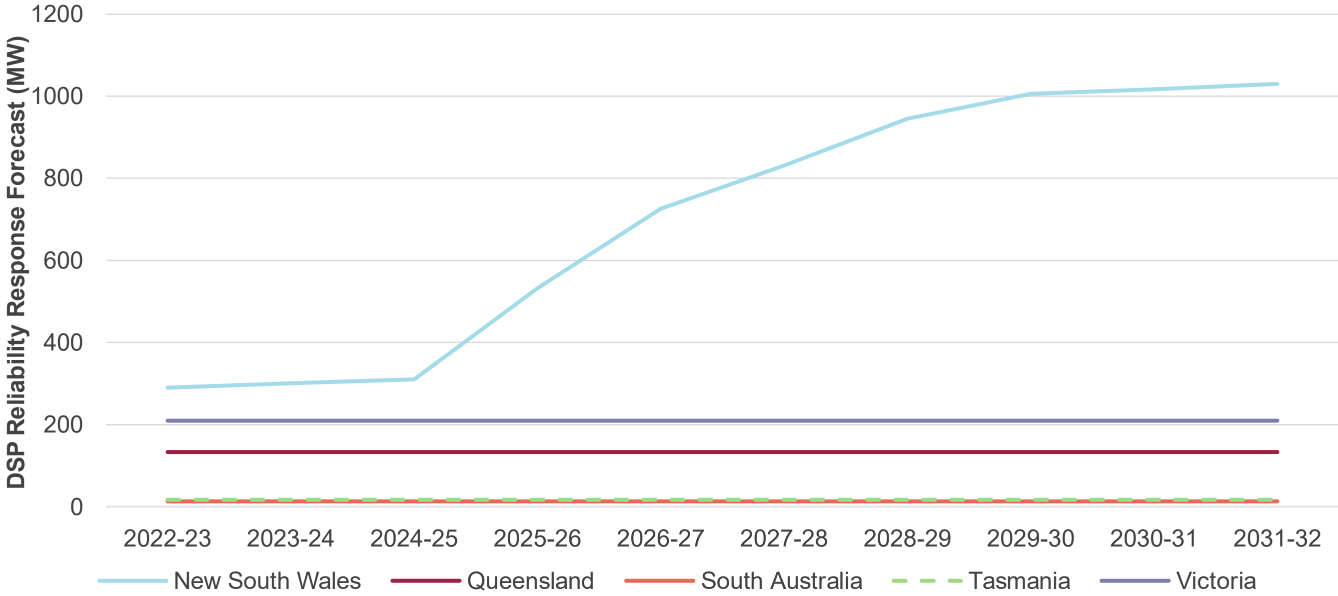
The ESOO reliability forecast only includes existing and committed sources of DSP in the ESOO Central scenario, consistent with the treatment of generation and transmission developments.

[42] At https://aemo.com.au/consultations/current-and-closed-consultations/demand-side-participation-forecast-methodology-consultation.

AEMO uses static estimates of reliability response for the 10-year horizon of the ESOO[43] for all regions except New South Wales, where the New South Wales Peak Demand Reduction Scheme (PDRS)[44] is considered committed, and makes a significant impact on DSP projections. This scheme creates a financial incentive to reduce electricity consumption during summer peak times, and is forecast to reduce peak demand in New South Wales by more than 1 gigawatt (GW) by 2031-32.

Figure 14 shows the DSP reliability response forecasts for all scenarios for the next 10-year reliability and indicative reliability forecast horizon. Appendix A6 provides further DSP forecast details and statistics[45].

Figure 14 DSP reliability response forecast for summer, all ESOO scenarios, 2022-23 to 2031-32 (MW)



43 AEMO does not have visibility of any further committed DSP sources beyond those included in Table 4, other than the New South Wales Peak Reduction Scheme.

44 See https://www.energy.nsw.gov.au/government-and-regulation/energy-security-safeguard/peak-demand-reduction-scheme for details.

45 To fulfil the requirements under NER 3.13.3A(a)(8) and NER 3.7D (d).

3 Supply forecasts

The capability of the power system to generate and securely transmit electricity to consumers is a key input assumption to the supply adequacy assessment in the 2022 ESOO. This chapter outlines the supply forecasts for the next 10 years, including:

- Generator commissioning and decommissioning assumptions.
- Seasonal generator capacities and reliability.
- Transmission developments.

3.1 Generation changes in the ESOO

The supply adequacy assessment in the 2022 ESOO considers existing generation, storage, and transmission and new projects that meet AEMO's commitment criteria.

This data is published on AEMO's Generation Information web page[46], and is provided to AEMO by both NEM participants and generation/storage project proponents.

AEMO applies set criteria to classify generation and storage projects as:

- **Existing** generation and storage plant.
- **Committed projects** – these projects meet all five of AEMO's commitment criteria[47].
  - Committed projects are assumed to become available for full commercial operation on dates provided by participants, with commissioning profiles added only where operational data indicates the project is ahead or behind the schedule provided.
- **Committed* projects –** these projects are under construction and well advanced to becoming committed[48].
  - In the ESOO supply adequacy assessment, committed* projects are assumed to commence operation after the end of the next financial year (1 July 2024), reflecting uncertainty in the commissioning of these projects. For further details, see AEMO's *ESOO and Reliability Forecast Methodology Document*[49].

In assessing the adequacy of supply to meet demand, the capability of the transmission system to deliver generated electricity to consumers is a key influence. The 2022 ESOO includes transmission projects that meet AEMO's ESOO commitment criteria (see Section 3.5).

ESOO modelling assumes generator retirements occur on dates provided by participants, either with precision under the three-year notice of closure rules, or on 31 December of the provided expected closure year.

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

[47] Commitment criteria relate to land, contracts, planning, finance, and construction. For details, see the Background Information tab on each publication at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

[48] In AEMO's Generation Information page these projects are called Committed* or Com*. They are projects that are highly likely to proceed, satisfying the land, finance and construction commitment criteria, plus either of the planning or contracts criteria. Progress towards meeting the final criterion is evidenced, and construction or installation has also commenced.

[49] See Section 2.6. at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo.

Figure 15 shows the summer typical capacity (the capability of the generating unit during average summer temperatures) assumed per forecast year in the 2022 ESOO, considering the specified commissioning and decommissioning profiles of generation and storage, and the technical advice on the capabilities of each generating unit provided by each relevant operator and/or developer.

The figure demonstrates the erosion of some generating technology types as generators retire, as well as the development of replacement capacity that is either committed or committed* according to AEMO's commitment criteria. Actual generator performance, commissioning dates or retirement dates may vary from that provided by the relevant operator and/or developer. Such variations are not considered in the ESOO Central scenario.

As shown in **Figure 15**, large amounts of new generation capacity continue to connect in the NEM. Approximately 1.4 GW of additional new committed[50] capacity is forecast to start operations in time for the 2022-23 summer, compared to that which was assumed to be available last summer, demonstrating the increased commitments by NEM participants and developers to deliver additional capacity since the 2021 ESOO. This is offset by 623 MW of coal and gas capacity that has withdrawn in the last year.

In addition to the 1.4 GW of new generation expected to connect for the coming summer, proponents have committed a further 5.8 GW of capacity[51] to become operational over the rest of the 10-year ESOO horizon, including:

- Dispatchable projects, including:
  - Energy Australia's 320 MW Tallawarra B project in New South Wales, in October 2023[52].
  - Snowy Hydro's 750 MW Kurri Kurri Power Station in New South Wales, in December 2023.
  - Genex Power's 250 MW Kidston Pumped Hydro Energy Storage project in Queensland, in February 2025.
- Renewable energy projects, including:
  - Approximately 1 GW of wind generation developments[53].
  - Approximately 1.5 GW of solar generation developments.

A significant new development in the construction phase is the 2,040 MW Snowy 2.0 project, which has been expected to connect using a staged commissioning schedule during 2025-26 and 2026-27. There has been recent speculation that the project commissioning schedule is likely to be delayed. In the 2022 ESOO, AEMO has:

- Modelled the project according to this staged commissioning schedule, based on information provided by the proponent Snowy Hydro.
- Also conducted sensitivity analysis to consider the impact if a delay consistent with recent speculation was to occur – see Section 6.3.

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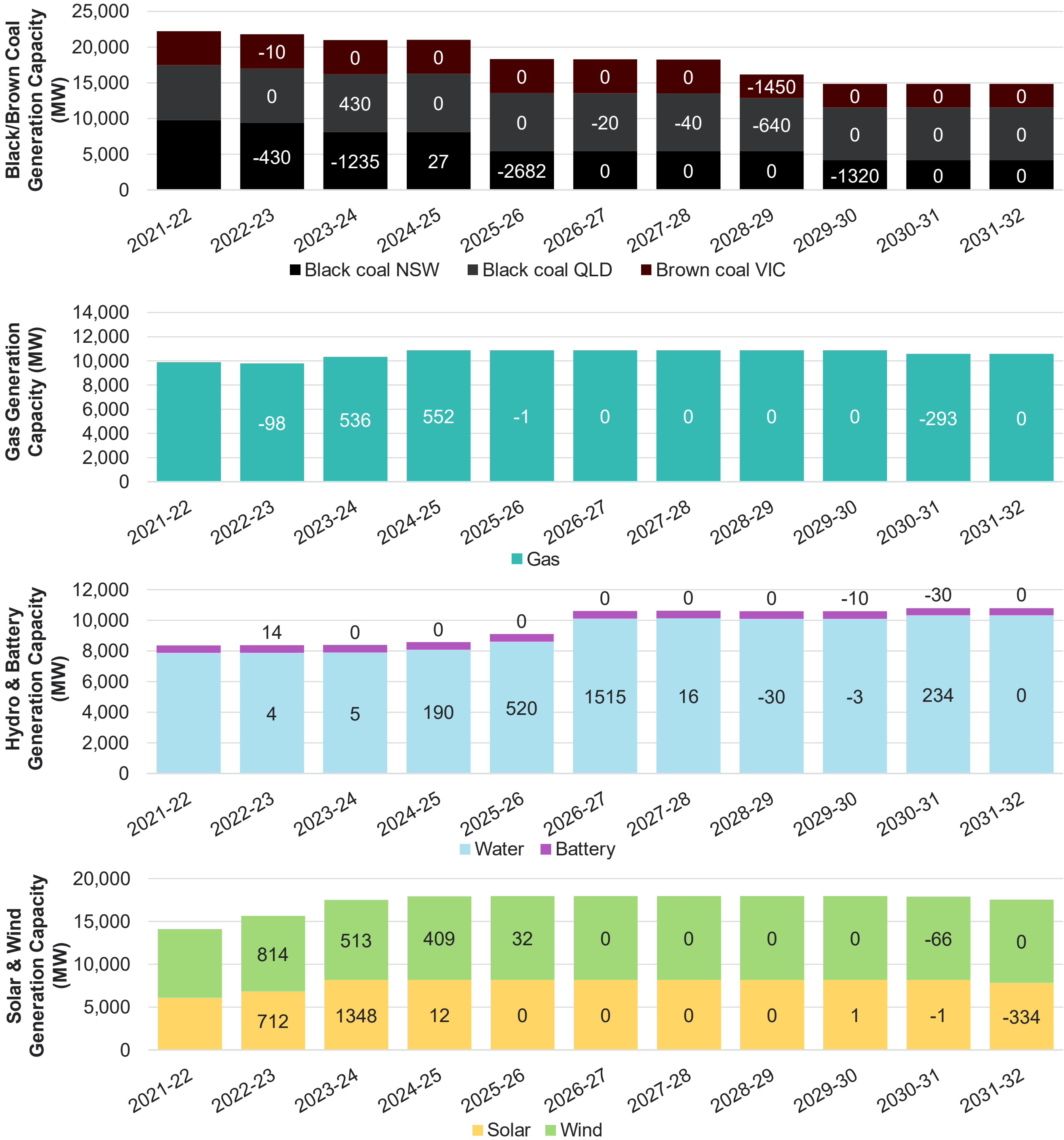
[50] Including those projects which are classified as committed*.

[51] Including those projects which are classified as committed*.

[52] Tallawarra B is considered committed*, which means it meets all of AEMO's commitment criteria except for either the Contracts or Planning criteria, and has commenced construction. In accordance with the ESOO and reliability forecast methodology document, committed* projects are modelled to connect on the first day after the end of the "T-1 financial year" defined under the RRO, which for the 2022 ESOO is 1 July 2024.

[53] Since the modelling of the ESOO was conducted, the Mortlake South Wind Farm (approximately 160 MW) has become committed in Victoria. Inclusion of this project in the ESOO modelling would reduce forecast reliability risks in Victoria from 2022-23.

Figure 15 Assumed available capacity during typical summer conditions, by generation type, 2021-22 to 2031-32 (MW)



Source: AEMO Generation Information. February 2022 version for 2021-22 data and July 2022 version for 2022-23 to 2031-32. At https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

Based on participant advice, the following generators are expected to close within the 10-year ESOO horizon:

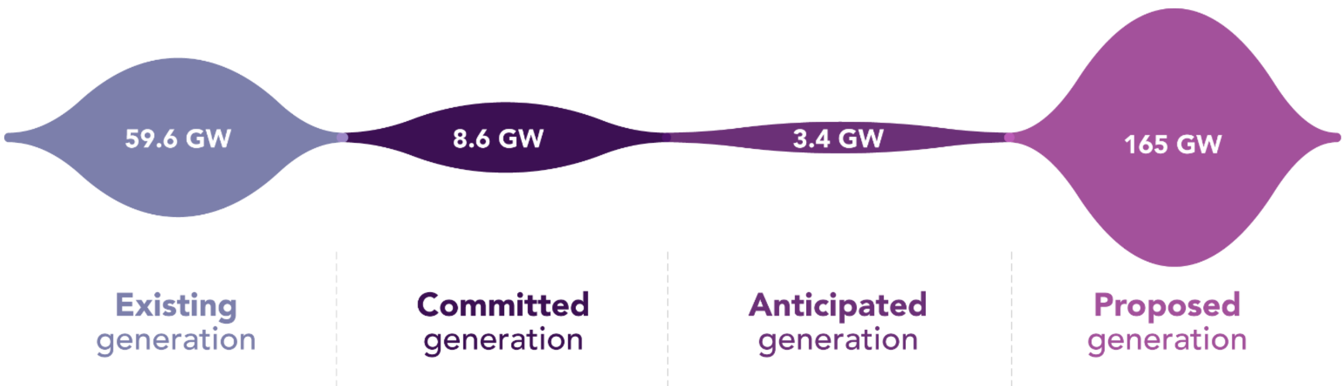
- The currently mothballed unit 3 at Torrens Island A Power Station (TORRA3) in South Australia (September 2022)[54].
- The remaining three units at Liddell Power Station (LD01, LD02, LD04) in New South Wales (April 2023).
- Osborne Power Station in South Australia (December 2023).
- Eraring Power Station in New South Wales (August 2025).
- Callide B Power Station in Queensland (2028).
- Yallourn W Power Station in Victoria (2028).
- Vales Point B Power Station in New South Wales (2029).
- Numerous gas and diesel peaking generators in South Australia in 2030 including the Dry Creek, Mintaro, Port Lincoln, and Snuggery power stations.

3.2 Pipeline of future projects

Beyond projects already committed or committed*, there is a substantial pipeline of future generation and storage projects in various stages of development, from publicly announced (proposed) to anticipated. Anticipated projects are those which meet some, but not all, of the criteria to be classed as committed[55].

As **Figure 16** shows, projects that have been proposed or are anticipated currently total 169 GW.

Figure 16 New generation pipeline as of July 2022 Generation Information (GW)



The projects are spread across all regions, with the largest pipeline of capacity in New South Wales.

Figure 17 shows the current pipeline by region and type of generation, beyond projects that meet the committed and committed* ESOO commitment criteria[56]. There are a range of jurisdictional initiatives that are also supporting supply side developments including the Victorian Renewable Energy Target, New South Wales Electricity

[54] See https://www.agl.com.au/about-agl/how-we-source-energy/agl-torrens.

[55] Anticipated projects are those that are sufficiently progressed towards meeting at least three of the five commitment criteria used by AEMO to be given this status. Typically, anticipated projects are included in integrated system planning, but not in reliability assessments.

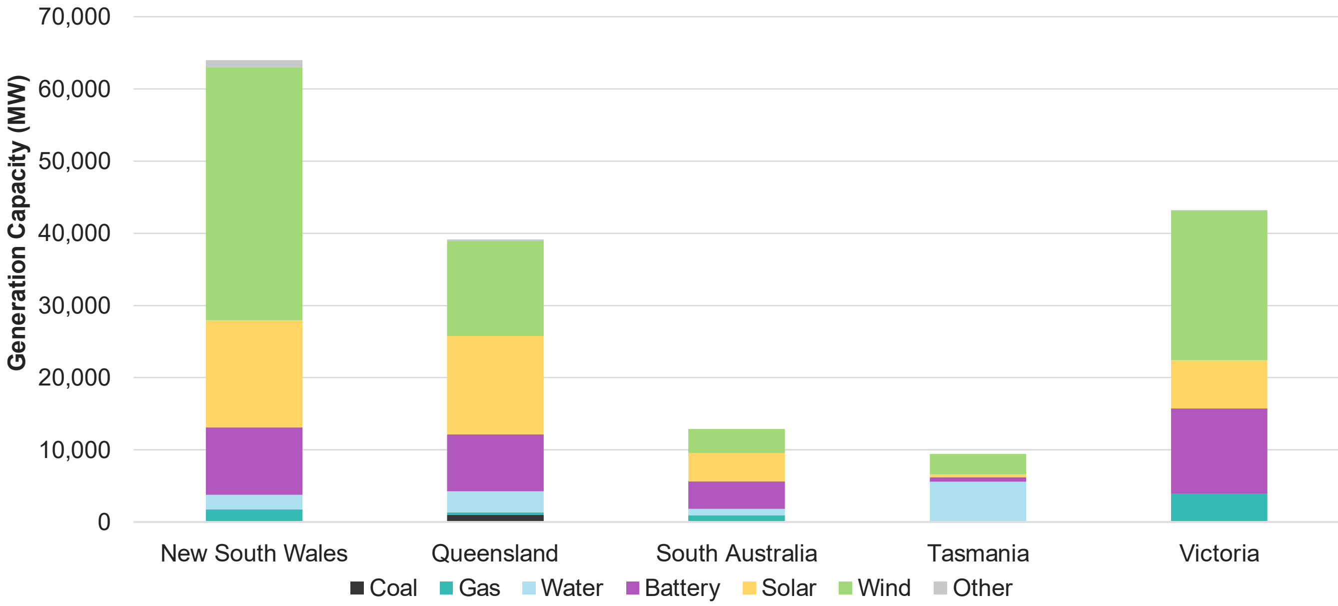
[56] The 8.6 GW of committed generation capacity also includes projects that may have begun commissioning in previous years but are not yet considered 'existing', as well as non-scheduled generators.

Infrastructure Act, Tasmanian Renewable Energy Target, and the Queensland Renewable Energy Target. Key points are:

- By capacity, just over 68% of future projects currently proposed or anticipated are variable renewable energy (VRE) generation projects, and over 26% are storage projects (battery or pumped hydro).
- Approximately 14 GW of additional dispatchable capacity projects – including thermal projects, pumped hydro, and batteries – have been added to the pipeline of future projects since the 2021 ESOO.
- Of the 169 GW of future projects, over 3 GW are reported as being in more advanced stages of development and are classed as anticipated. Section 6.1 of this 2022 ESOO looks at how the timely development of these projects would improve the NEM reliability outlook significantly over the next 10 years.

Further details, including capabilities of proposed generating units, are on the Generation Information page.

Figure 17 Proposed projects by type of generation and storage and NEM region, beyond those already committed (MW)



Source: July 2022 Generation Information, at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

Instantaneous renewable generation penetration

Figure 18 shows the indicative potential impact of existing, committed and anticipated new generation capacity on instantaneous renewable generation penetration.

Instantaneous renewable generation penetration represents the proportion of generation in a half-hourly dispatch period that is met by renewable resources (large-scale wind, solar, hydro and distributed PV). As Figure 18 shows, between 2019-20 and 2021-22, instantaneous renewable generation penetration increased markedly; a record of 61.8% of total NEM generation was set on 15 November 2021.

Based on the indicative resource potential of all committed and anticipated projects, and considering forecast growth in distributed PV installations, AEMO forecasts that there will be sufficient renewable resources to supply all NEM demand with renewable generation in some periods by 2024-25, as also shown in Figure 18, assuming no network or system security limitations. A high proportion of this renewable generation would be from inverter-based resources (IBR – wind and solar generation, including distributed PV).

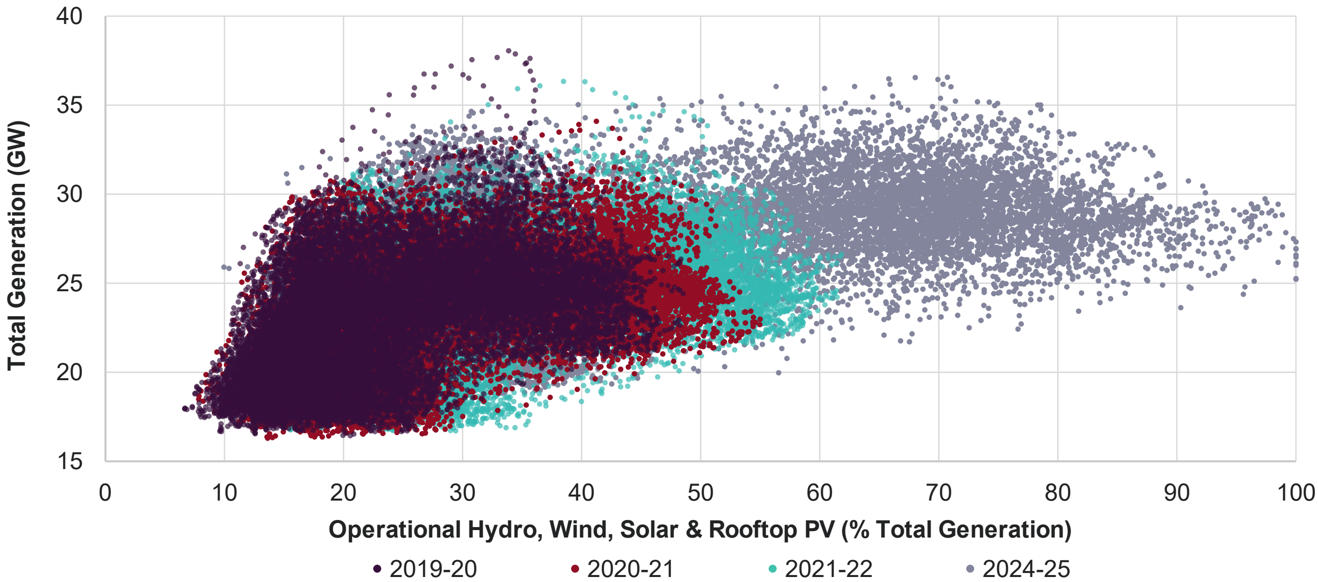
With AEMO's current operating toolkit, it would not be possible to maintain the power system securely under these conditions, which is why AEMO has the goal to be able to operate the power system at 100% instantaneous renewable generation by 2025.

Through the Engineering Framework, AEMO is working with stakeholders to establish a structured approach to preparing for these high renewable periods. In June 2022, AEMO released the NEM Engineering Framework Priority Actions report[57], outlining 46 near-term priorities including:

- Implementation of the new system strength framework in collaboration with network service providers[58].
- Undertaking a program of power system studies to assess power system security in the NEM at times of 100% renewable generation and assess future system requirements with fewer large synchronous generators.
- Progressing opportunities to fast-track the deployment and proof at scale of advanced inverter technologies[59].
- A series of actions to enable the effective integration and utilisation of large volumes of DER.

In parallel with working through these near-term priorities, AEMO is also working towards a publication in late 2022 that explores pathways to operating with 100% instantaneous penetrations of renewables.

Figure 18 NEM-wide penetration of renewable resources (large-scale and distributed), 2019-20 to 2021-22, with indicative resource potential forecast for 2024-25, based on existing, committed, and anticipated projects and distributed PV forecasts



The 2024-25 forecast is based on the resource potential of existing, committed, and anticipated projects and distributed PV forecasts.

[57] See AEMO's NEM Engineering Framework – priority actions, at https://aemo.com.au/en/initiatives/major-programs/engineering-framework.

[58] See AEMO's System Security Reports, at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/planning-for-operability.

[59] Further background on these advanced inverter recommendations is available at https://aemo.com.au/-/media/files/initiatives/engineering-framework/2021/application-of-advanced-grid-scale-inverters-in-the-nem.pdf.

3.3 Seasonal generator availability

AEMO collects existing and committed scheduled and semi-scheduled generation capabilities over the next 10 years to capture seasonal generator availability[60].

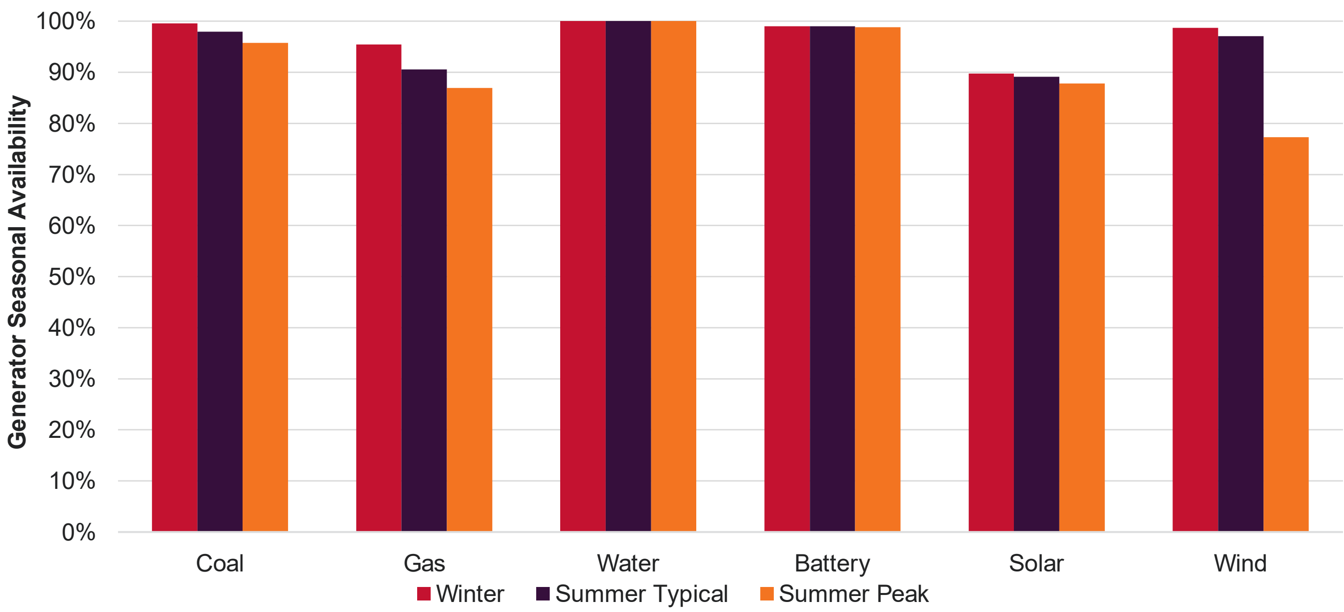
Scheduled capacity values are collected for three seasonal periods, where generator operators and proponents provide ratings consistent with the ambient temperatures associated with the following periods:

- Summer peak – applies to near-maximum demand periods (minimum of five days per year), where generator ratings are reflective of the ambient conditions associated with 10% POE demand events (typically at temperatures 37°C or greater for mainland regions, depending on the region).
- Summer typical – aligned with average summer temperatures and is applied in all other summer periods (November to March for the Australian mainland, December to February for Tasmania). Ambient conditions across these periods are in excess of 30°C, and between 5°C and 10°C cooler than those that may drive a 10% POE peak.
- Winter – applied to all non-summer periods.

In addition to the above scheduled capacities, VRE generators are also subject to consideration for resource availability.

Figure 19 shows the average winter, summer typical, and summer peak availability relative to nameplate capacity by type of generation (both existing, committed and committed*), and indicates the reduced availability reported in summer peak compared to winter and summer typical. This is especially noticeable for wind generators, due to some reporting 0 MW availability during summer peak, reflecting high-temperature cut-offs for this generation category.

Figure 19 Winter, summer typical and summer peak availability of nameplate capacity by type of generation (%)



[60] See Generation Information, July 2022 update, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

See the *ESOO and Reliability Forecast Methodology Document*[61] for more detail about generation availability.

3.4 Generator forced outage rates

AEMO collects information from all generators via an annual survey process on the timing, duration, and severity of historical forced outages. Observed forced outages of duration in excess of five months are classified as long duration outages and are assessed separately.

The historical data is then used to calculate the observed rate of long duration, full, and partial forced outages for each financial year, for each generator.

For all generator types excluding coal-fired and large gas-fired generators, the rates applied in the 2022 ESOO were calculated from observed incidents and are used as projections for each generator.

For coal-fired and large gas-fired generators, AEMO also collected forward-looking forced outage rate projections from the operators. These operator-provided projections reflect the likely change in performance as generators age, approach retirement, and go through maintenance cycles. For an independent cross check, operator-provided projections are compared to, and sometimes supplemented by, forward-looking outage factors that AEMO commissioned in 2020 from AEP Elical[62]. The rates applied in the 2022 ESOO for coal-fired and large gas-fired generators were derived entirely from operator-provided projections, or by supplemented projections developed in consultation and agreement with the operator.

Coal-fired generation reliability continued to demonstrate historically poor performance last year, consistent with recent historical trends. While some improvements to plant are expected in the medium term (due to planned maintenance, expectations regarding coal quality, and other generator investments), most generators are anticipating a trend of decreasing reliability in the longer term.

Figure 20 shows the historical and projected effective forced outage rates for coal-fired generators (aggregated to protect the confidentiality of information provided by participants). These rates are shown with and without long duration outage rates (of five months or more). In several instances, significant improvements in aggregate outage rates for a generation class are due to the expected retirement of units with high outage rates, rather than expectations of improved performance across the asset class.

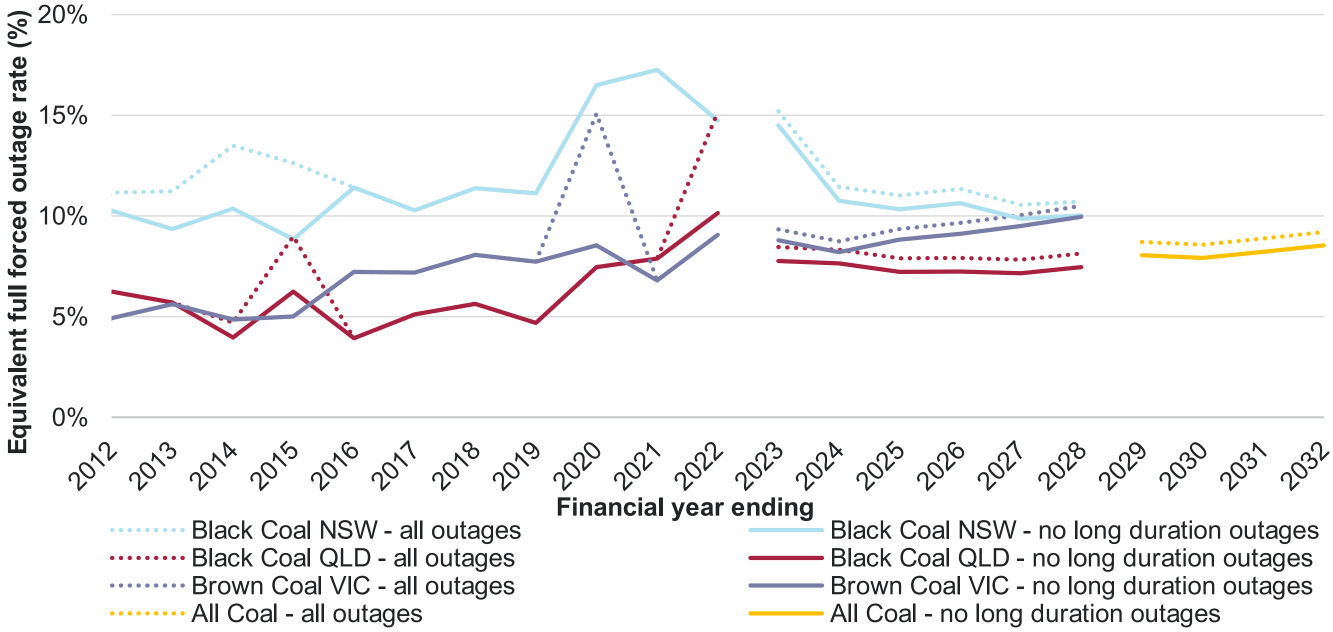
The 2022 ESOO Forecasting Assumptions Update Workbook provides detailed information on the forced outage rate parameters of each technology over time[63].

[61] See 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.

[62] AEP Elical, *Assessment of Ageing Coal-Fired Generation Reliability*, June 2020, 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.

[63] 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.

Figure 20 Actual and projected equivalent full forced outage rate projections for coal-fired generation technologies, 2012-32 (%)



3.5 Transmission limitations

The ESOO model applies a comprehensive set of network constraint equations that represent the thermal and stability limits that currently constrain dispatch in the NEM, as well as projecting potential future constraints across the ESOO time horizon with consideration for network investments that are considered committed by the ESOO and Reliability Forecast methodology. These constraint equations act at times to constrain interconnector transfer capacity, as well as intra-regional transfer capacity.

Compared to the 2021 ESOO, the transfer limit for Murraylink has been revised downwards during periods of high temperature, from 220 MW to 100 MW. This reflects advice from the operator, and operational insights regarding de-rating of this transmission interconnector during periods of high temperature.

Consistent with previous ESOOs, a 478 MW limit is assumed for Basslink in both directions, based on forward-looking transfer capabilities submitted for this interconnector in the Medium-term Projected Assessment of System Adequacy.

The 2022 ESOO Central scenario modelling includes committed transmission augmentations[64] as described below.

Inter-regional augmentations included in the 2022 ESOO

Service dates were sourced from the 2022 ISP[65] and in consultation with TNSPs.

[64] For the purposes of the ESOO, transmission augmentations are included in accordance with AEMO's *ESOO and Reliability Forecast Methodology Document*, 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. In some cases, categorisations as 'committed' and 'anticipated' will differ between the ESOO and the ISP.

[65] At https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp.

- **Victoria to New South Wales Interconnector (VNI) System Integrity Protection Scheme (SIPS)** has been in service since summer 2021-22. This SIPS allows increased import capability up to 250 MW from New South Wales to Victoria during November to March each year. This involved the procurement of a 250 MW SIPS arrangement with a battery in Victoria to rapidly respond by injecting power after a contingency event on VNI.
- **Queensland New South Wales Interconnector (QNI) Minor** upgrade by mid-2023. This project involves uprating of the Liddell – Tamworth, Liddell – Muswellbrook and Muswellbrook – Tamworth 330 kilovolt (kV) transmission lines, installation of shunt capacitor banks at Armidale, Dumaresq, and Tamworth substations, and installation of dynamic reactive plant at Tamworth and Dumaresq.
- **VNI Minor** upgrade by November 2022. This project involves uprating of the South Morang – Dederang 330 kV transmission line, installation of an additional 500/330 kV transformer at South Morang, and addition of power flow controllers on the Upper Tumut – Yass and Upper Tumut – Canberra 330 kV transmission lines.
- **Project EnergyConnect** with updated expected commissioning by July 2026. This project involves construction of new double-circuit 330 kV transmission lines between Robertstown, Buronga, Dinawan and Wagga Wagga, and an additional 220 kV transmission line between Red Cliffs and Buronga. The AER provided expenditure approval for this project in May 2021. Project EnergyConnect is modelled to progressively release transfer capacity from July 2024 onwards with its full capacity available, including completion of inter-network testing, from July 2026. In the 2021 ESOO, Project EnergyConnect was modelled to progressively release transfer capacity from 2023-2024, with full capacity available from June 2025.

Intra-regional augmentations included in the 2022 ESOO

Service dates of intra-regional augmentations were sourced from 2021 Transmission Annual Planning Reports or more recent direct advice from relevant TNSPs.

- **New South Wales** (see TransGrid's 2021 *Transmission Annual Planning Report*[66])):
  - Powering Sydney – a new 330 kV cable between Beaconsfield and Rookwood Road (in service).
  - Powering Sydney – changing Beaconsfield – Sydney South cable operating voltage from 330 kV to 132 kV (in service).
  - Installation of capacitor bank at Wagga Wagga substation in 2022.
  - Uprating Sapphire substation connections on the Armidale – Sapphire – Dumaresq 330 kV lines by July 2023.
- **Queensland** (see Powerlink's 2021 *Transmission Annual Planning Report*[67]):
  - Strathmore substation additional 275/132 kV transformer by May 2023.
  - Lilyvale substation replacement of 2 x 80 megavolt-amperes (MVA) 132/66 kV transformers with 2 x 160 MVA 132/66 kV transformers by September 2024.
- **South Australia** (see ElectraNet's 2021 *Transmission Annual Planning Report*[68]):

[66] At https://www.transgrid.com.au/what-we-do/Business-Planning/transmission-annual-planning/Documents/2020%20Transmission%20Annual%20Planning%20Report.pdf.

[67] At https://www.powerlink.com.au/reports/transmission-annual-planning-report-2020.

[68] At https://www.electranet.com.au/wp-content/uploads/2020/11/2020-ENet-TAPR.pdf.

  - South Australia Power System Strength Project. This project involves installation of two high inertia synchronous condensers at Davenport and two high inertia synchronous condensers at Robertstown (in service).
  - Eyre Peninsula Link – 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 option to be energised at 275 kV in the future, and replacement of the existing 132 kV line between Yadnarie and Port Lincoln with a new double-circuit 132 kV line, in early 2023.
  - Power flow controller on the Templers – Waterloo 132 kV line (in service).
  - Turn-in the Tailem Bend – Cherry Gardens 275 kV line at Tungkillo by June 2023.
  - An additional 1 x 100 megavolt-amperes reactive (MVAr) 275 kV capacitor at South East 275 kV by October 2022.
- **Tasmania** (see TasNetworks' 2021 *Transmission Annual Planning Report*[69]):
  - Burnie – Port Latta – Smithton 110 kV line reconfiguration (in service).
- **Victoria** (see AEMO's 2021 Victorian Transmission Annual Planning Report[70]):
  - Western Victoria Transmission Network Project (Stage 1) – uprating of Moorabool – Terang and Ballarat – Terang 220 kV lines (in service), and uprating of Red Cliffs – Wemen – Kerang – Bendigo transmission lines (in service).
  - Shunt reactors at Keilor and Moorabool terminal stations (in service).

Inter-regional transmission unplanned outages

AEMO applies transmission unplanned outage constraints for some simulated unplanned outages on key inter-regional transmission flow paths, as summarised in **Table 5**.

AEMO consulted on and updated the methodology for inter-regional transmission unplanned outages in 2022. As such, flow path selection and outage rates have varied from the 2021 ESOO, consistent with the updated methodology. Four flow paths were selected for the 2022 ESOO, compared to the six that were included in the 2021 ESOO, and the unplanned outage rate for Basslink has been revised upwards as it now incorporates the potential for further long duration outages.

Table 5 Projected unplanned outage rates for key inter-regional transmission flow paths

Flow path	Unplanned outage rate (%)	Mean time to repair (hours)
Liddell – Muswellbrook – Tamworth – Armidale – Dumaresq – Bulli Creek (QNI)	1.4%	5.0
Murraylink	0.1%	8.9
Mortlake – Heywood – South East (V-SA)	0.3%	20.1
Basslink	6.3%	244.0

69 At https://www.tasnetworks.com.au/Documents/Manual-documents/Planning-and-upgrades/APR/Annual-Planning-Report-2020.

70 At https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/vapr/2020/2020-vapr.pdf?la=en.

4 Supply scarcity risks in the next year

This chapter discusses supply scarcity risks in the coming 2022-23 year:

- Challenging conditions have already occurred in 2022.
- Under normal conditions, unserved energy is forecast to be within the relevant reliability standard, but numerous factors may drive supply scarcity and significant operational challenges.
- Mitigation actions such as the use of RERT may form part of AEMO's operational toolkit to minimise supply disruption risks.

Significant challenges have emerged in operating the energy markets in eastern Australia in 2022.

Since May 2022, extensive NEM lack of reserve (LOR) forecasts emerged and occurred, and a range of market interventions by AEMO were required to maintain reliability and system security. As administered price capping commenced in the NEM in June 2022, generation volumes offered into the spot market began to drop. Combined with a large number of prior outages, this led to shortfalls in actual and forecast reserves which triggered a range of interventions by AEMO to maintain power system reliability and security. The scale of interventions needed to manage the extent of reserve shortfalls made operation of the market in accordance with the NER impossible and AEMO suspended operation of the NEM spot market in all regions between 15 June and 24 June, when full spot market operation recommenced[71].

While forecast reliability is expected to remain below the IRM in all regions in 2022-23, the events during winter 2022 highlight the need for the NEM to be resilient to events like extreme weather, fuel availability, and global commodity prices.

4.1 Supply scarcity risks are forecast to be within standard in 2022-23 but adverse outcomes remain possible

The reliability outlook for the coming summer in AEMO's ESOO Central scenario indicates reliability risks are within the IRM in all regions, but the risk has increased since last year's ESOO. The increased risk is driven by higher peak demand and energy consumption forecasts (see Chapter 20), increases in forecast generator and transmission forced outage rates (see Chapter 3), and decreased inter-regional peak transfer capacity (see Chapter 3), but is somewhat offset by the large amounts of new generation, storage, DER, and transmission capacity that continue to connect to the NEM (see Section 33.5).

While reliability in all regions is forecast to be below the IRM, the nature of the reliability risk varies by region:

- In **South Australia** and **Victoria**, the forecast supply scarcity risk for 2022-23 has worsened relative to the 2021 ESOO and the *Update to the 2021 ESOO*, but remains below the IRM. On average, 99.9997% of annual consumption is expected to be met in each region in 2022-23. Forecast increases in LIL consumption,

[71] AEMO Q2 2022 Quarterly Energy Dynamics report: https://aemo.com.au/-/media/files/major-publications/qed/2022/qed-q2-2022.pdf

increased generator forced outage rates, increased transmission unplanned outage rates, and reduced transfer capacity between South Australia and Victoria during times of high temperature have all worsened the outlook.

- In **New South Wales**, **Queensland**, and **Tasmania**, the supply scarcity risk is very low in summer 2022-23 under system normal conditions, with expected USE well below 0.0006% of annual consumption. While demand is forecast to be higher in some regions than in the 2021 ESOO, and projected generator forced outage rates have increased, these impacts have been offset by existing and new supply.

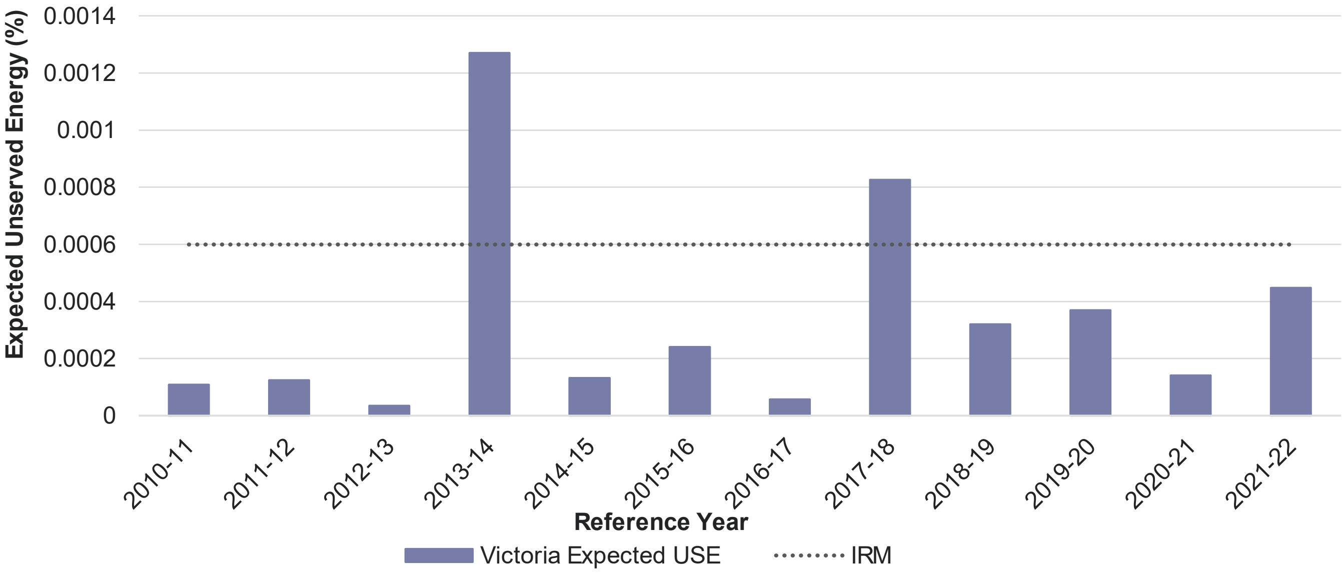
Outcomes vary greatly depending on weather conditions: Victoria example

Historical reference years are used in the ESOO model to capture weather conditions that impact the power system, in different locations and across all times of the day and year. Alternative weather conditions impact for forecasts differently because of their effect on wind generation, solar generation, consumer demand patterns, high temperature periods for thermal plant deratings, and some transmission line ratings (those with dynamic line ratings).

Figure 21 shows the level of expected USE forecast in Victoria for 2022-23, based on each of the historical reference years modelled. Variation in expected USE is due to the relative contribution of VRE during times of high demand, the level of coincidence in demand between regions, or the length of time that consumer demands were at near-peak levels during each of the reference years. The figure shows that:

- If the weather conditions associated with the 2013-14 and 2017-18 reference years were to re-emerge next summer, the forecast level of expected USE next summer would exceed the IRM.
- The weather patterns in all other reference years would lead to much lower levels of expected USE.

Figure 21 Impact of different weather reference years on expected USE in Victoria 2022-23, ESOO Central scenario (%)



Should 2021-22 weather conditions emerge in 2022-23, expected USE is forecast to be above most other weather reference years, but below the IRM. This newly added reference year was a relatively mild summer without frequent high temperature periods that could cause derating. It experienced relatively average VRE availability throughout the year, but below average levels of VRE availability during high demand periods.

Significant risks are observed within the forecast USE distribution: South Australia example

The ESOO and Reliability Forecasting methodology applies a Monte Carlo simulation methodology to simulate the likelihood of USE considering the various statistical likelihoods of outages, weather conditions, and availability of renewable energy resources. The forecast approach is applied to each maximum demand and reference year, creating statistically robust results which capture the impact of uncertainties around key parameters.

Given recent events that have demonstrated the impact of coincident outages and actual and forecast LOR conditions, AEMO is now including additional information on the distribution of possible outcomes included in ESOO modelling. This information demonstrates the long tail of potential high impact outcomes that may occur under some circumstances.

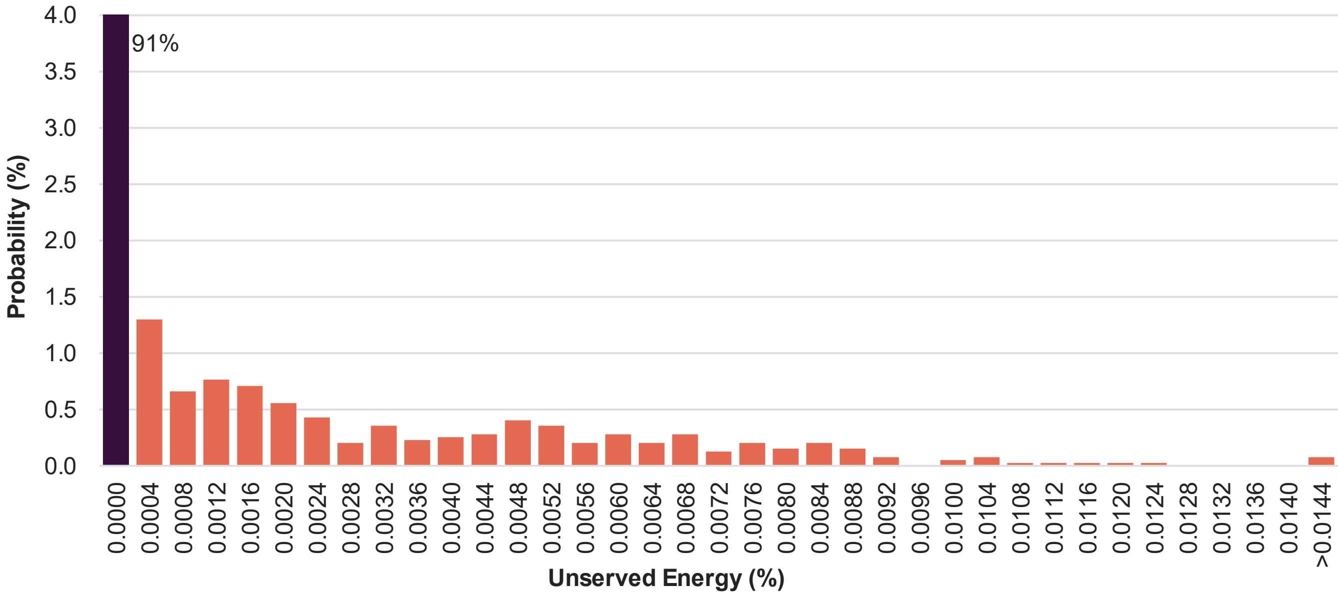
Figure 22 shows the probability density of USE that is forecast in South Australia for the 2022-23 summer, for example. It shows that:

- The most likely outcome (91% probability) is no USE in the coming year (the purple bar in the figure).
- There is still a 9% probability of a reliability incident, approximately equivalent to an expectation of one incident every 11 years. This is the sum of all the non-zero USE probabilities (all the orange bars).
- There is a 1% probability of an outage of greater than 1,000 MWh (greater than 0.008% USE), which is approximately equivalent to a four-hour outage for 100,000 households.

This shows that, while the ESOO may forecast that USE is statistically unlikely in a year, or that – statistically – expected USE is within the relevant standard, it can also identify a risk that events could compound to affect the reliability of the power system and lead to unlikely, but possible, extreme outcomes.

Analysis for all regions is available in Appendices A1-A5. As another example, in Appendix A5, **Figure 66** shows an 18% probability of a reliability incident in 2022-23 in Victoria, consistent with one incident every five years.

Figure 22 Probability density of forecast USE in South Australia 2022-23, ESOO Central scenario (%)



Further, numerous factors excluded from ESOO modelling may further impact consumer outcomes in operational timeframes. These include:

- The risk of abnormal transmission system conditions – the ESOO applies a 'system normal' forecast, where the transmission system in each region is presumed to be available and in full working order. Likely and regular occurrence of security and reliability incidents on the regional transmission systems can have a prolonged impact on the ability for generation to be transmitted to meet customer needs.
- The risk that fuel availability is more limited than foreseen by participants, affecting generator operational capabilities – the ESOO forecast is developed based on assumptions of fuel availability submitted by participants, which project adequate fuel supplies during periods of high demand. Recent events in winter 2022 highlight the potential for high prices, weather conditions and/or extremely low fuel availability to impact consumer outcomes in ways not foreseen by participants.

Collectively, these factors may lead to conditions that challenge the operation of the power system. The tail of the USE distribution – the small probability of extreme outcomes – may therefore be a useful indicator of reliability risks, beyond the single USE (%) outcome that the ESOO reports.

4.2 Risk mitigation and summer readiness

As described in Section 4.1, while expected USE in this ESOO is an annual average representation of the risk of load shedding, using a range of statistically variable inputs, the actual occurrence of load shedding in a given year can be lower than or higher than the relevant reliability standard, and can be considerably higher than the standard if particular combinations of weather events and outages occur.

Operationally, AEMO needs to be prepared to manage the power system if specific events arise, such as:

- Severe weather or power system events that result in prolonged transmission network unavailability.
- Prolonged periods of generation unavailability, including forced outages and/or potential mothballing.
- Delays to the commissioning of new generation or storage capacity.
- Operational impacts of extreme temperature on all generation technologies that may reduce output to below the rated generator capacity.
- Operating the network securely during periods of minimum demand.

Some of these risks are being further considered in AEMO's summer readiness program:

- As with previous years, AEMO will collaborate with industry to identify the preparedness of the system for summer, and operational options to mitigate these risks. AEMO is working closely with generators and TNSPs to ensure outages are co-ordinated and essential work is completed as required.
- AEMO can mitigate some of the supply adequacy risks with the use of supply scarcity mechanisms such as short notice RERT, where appropriate. This form of RERT ensures that consumers do not pay for additional reserves until they are needed, and the benefits of calling on any out-of-market reserves outweigh the costs.

5 Reliability forecasts

This chapter:

- Meets AEMO's obligations under Section 4A.B.1 of the NER related to the publishing of a reliability forecast and an indicative reliability forecast, and
- Provides the details required under 4A.B.2, including AEMO's forecast of expected USE and whether there is a forecast reliability gap.

AEMO has prepared the reliability forecast against the IRM for 2022-23, 2023-24 and 2024-25, and against the reliability standard for 2025-26 and 2026-27 and for the indicative reliability forecasts (2027-28 to 2031-32 inclusive).

In this chapter, AEMO also projects how much additional capacity would be needed to bring USE within the IRM and reliability standard in each NEM region.

Chapter 6 complements and extends the reliability forecasts in this chapter by presenting the impact of additional anticipated investments on forecast reliability, and provides extended analysis of key sensitivities.

5.1 Key assumptions

This reliability assessment includes all existing and committed generation and storage, including retirements, reported in the Generation Information page published in July 2022[72], as well as relevant transmission augmentations that meet AEMO's ESOO commitment criteria (see Chapter 3).

This reliability assessment excludes all investments that have not yet completed all necessary approvals and met AEMO's commitment criteria[73]. While not yet committed, anticipated and ISP actionable developments will improve the reliability forecast significantly if developed to their current anticipated schedules. Section 6.1 provides an additional assessment of forecast reliability that considers anticipated and ISP actionable developments in addition to those that are considered committed. Specifically, the 2022 ESOO reliability assessment excludes:

- Major transmission investments that have not yet completed all necessary approvals[74], including:
  - Central West Orana and New England renewable energy zone (REZ) transmission links, and the Hunter Transmission Project (including potentially earlier investments to support the SIPS) in New South Wales, and the Western Renewables Link in Victoria.
  - Strategic transmission projects identified as actionable projects in the 2022 ISP affecting inter-regional transfer capacities, including HumeLink, Marinus Link, and VNI West.

[72] At https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

[73] Consistent with AEMO's consulted on ESOO and Reliability Forecast Methodology, at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo.

   - Additional REZ expansion transmission elements as specified by the Energy Co of New South Wales.
- Generation investments that have not yet met AEMO's commitment criteria, including those that may be incentivised or underwritten by a state or territory scheme[74].
- Any additional capacity that could be made available through RERT[75].

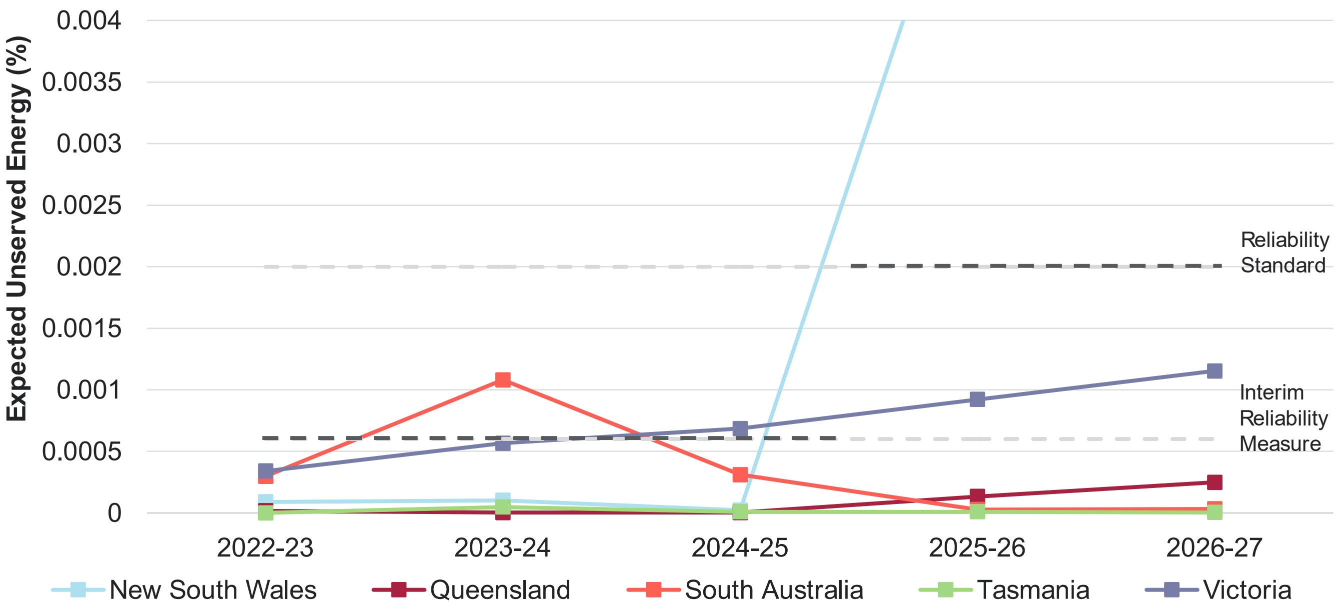
Under section 14G(1) of the National Electricity Law, a forecast reliability gap occurs when the amount of electricity forecast for a region, in accordance with the NER, does not meet the reliability standard (0.002% USE in a financial year) to an extent that, in accordance with the NER, is material. Under NER clause 4A.A.2, a gap is defined to be material if it exceeds the reliability standard.

In November 2020, the NER were amended by the National Electricity Amendment (Retailer Reliability Obligation trigger) Rule 2020, which temporarily changed AEMO's reporting obligations for reliability forecasts. The rule change requires AEMO to report on whether the IRM (0.0006% USE in a financial year) would be exceeded in financial years up until 30 June 2025, after which the reporting obligation reverts to the previous position under the NER, that AEMO must report on whether the reliability standard would be exceeded in any financial year.

5.2 The reliability forecast (first five years)

For the ESOO Central scenario, over the five-year period from 2022-23 to 2026-27, the reliability forecast (shown in **Figure 23**) shows expected USE above the IRM before 2025-26 for both South Australia (in 2023-24) and in Victoria (in 2024-25).

Figure 23 Reliability forecast, first five years (2022-23 to 2026-27)[76]



[74] Schemes include various initiatives under the New South Wales Electricity Infrastructure Roadmap, and auction schemes to meet the Victorian Renewable Energy Target.

[75] The exception being 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. Further information on what reserve is acceptable for RERT is available at https://www.aemo.com.au/energy-systems/electricity/emergency-management/reliability-and-emergency-reserve-trader-rert.

[76] ESOO Central scenario modelling does not consider Mortlake South Wind Farm which has since become committed, and would improve the outlook.

From 2025-26, when the relevant reliability standard reverts to the 0.002% reliability standard, the forecast demonstrates a continued increase in expected USE in Victoria (but within the relevant standard), and a forecast significantly in excess of the standard in New South Wales (from 2025-26).

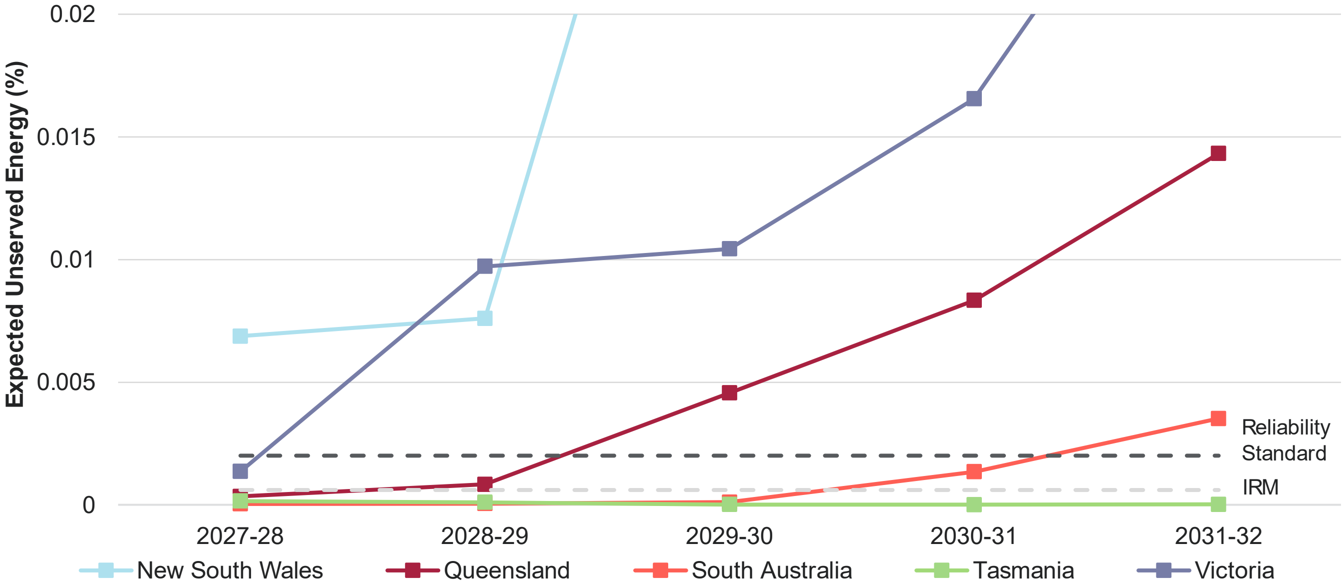
The key outcomes by region are:

- In **South Australia**, a reliability gap is identified in 2023-24 against the IRM.
  - The 2023-24 reliability gap occurs when Osborne Power Station is expected to retire. While this known retirement did not lead to a reliability gap in the 2021 ESOO, a gap has emerged due to several changes since that time, including increased forecast industrial load and generation and transmission outage considerations and an updated commissioning schedule for Project EnergyConnect (from 2024-25, instead of from 2023-24).
  - From 2024-25, the commissioning of Project EnergyConnect significantly improves the outlook.
- In **Victoria**, a reliability gap is identified in 2024-25 against the IRM.
  - Over the reliability forecast horizon, the supply-demand balance in Victoria is forecast to progressively tighten as demand increases, driven by projections for large industrial load expansions, BMM consumption increases, and electrification uptake. This demand growth, and influences from generation and inter-regional transmission outage considerations, result in a tighter outlook than in previous ESOOs. Inclusion of the now committed Mortlake South Wind Farm would likely address the gap in 2024-25.
- In **New South Wales,** a reliability gap is identified in 2025-26 against the reliability standard.
  - In 2023-24, Liddell Power Station is expected to retire, however the commitment of new generation capacity noted in the 2021 ESOO, including the 750 MW Kurri Kurri Power Station, is forecast to achieve reliability within the IRM following the plant's retirement.
  - The forecast 2025-26 reliability gap occurs when Eraring Power Station is expected to retire, as previously identified in the April 2022 *Update to the 2021 ESOO*. Developments proposed by the New South Wales Government that seek to address this gap are not yet sufficiently advanced to be considered in the reliability forecast, hence the identified shortfall remains. As Section 6.1 describes, if the transmission investments are delivered to schedule, and additional firming capacity is connected and is not constrained from delivering capacity when required during extreme conditions, reliability outcomes will improve.
- In **Queensland**, forecast USE increases over the horizon but is forecast to be below the IRM and reliability standard across the reliability forecast period.
  - Given the inter-regional reliability support provided between New South Wales and Queensland, USE in Queensland is forecast to increase from 2025-26, consistent with the gap identified in New South Wales, as tight conditions in one region will impact the other. However, this is not forecast to exceed the relevant reliability standard.
- In **Tasmania**, forecast USE remains at very low levels over the reliability forecast horizon.

5.3 The indicative reliability forecast (second five years)

Over the five-year period from 2027-28 to 2031-32, as **Figure 24** shows, the indicative reliability forecast projects expected USE to increase and to be above the reliability standard by 2031-32 in all mainland regions.

Figure 24 Indicative reliability forecasts, second five years (2027-28 to 2031-32)[77]



The major drivers of this forecast increase in USE are:

- The expected retirement of Yallourn Power Station (1,450 MW) in Victoria in July 2028.
- The expected retirement of Callide B Power Station (700 MW) in Queensland in 2028.
- The expected retirement of Vales Point Power Station (1,320 MW) in New South Wales in 2029.
- The expected retirement of numerous South Australian gas generators (total 383 MW) in 2030, including the Dry Creek, Mintaro, Port Lincoln and Snuggery power stations.
- Expected increases in forced outage rates of coal-fired generators over time.
- Forecast growth in consumer demand across the decade.

5.4 More investment in transmission, generation, storage and demand response will improve the outlook

While the above reliability and indicative reliability forecasts demonstrate a projected increase in reliability risk, additional investments are expected that would improve the outlook significantly.

AEMO applies strict commitment criteria[78] to classify projects as *committed* or *committed**, for inclusion in the reliability and indicative reliability forecasts.

There are also many other generation and storage projects which are advancing but have not yet achieved this classification. The *anticipated* classification includes projects which meet some but not all of AEMO's commitment criteria. These generation and storage projects, alongside the actionable transmission projects identified in the 2022 ISP will improve the reliability forecast significantly if developed to their current anticipated schedules.

[77] ESOO Central scenario modelling does not consider Mortlake South Wind Farm which has since become committed, and would improve the outlook.

[78] Consistent with the ESOO and Reliability Forecast Methodology, 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.

Section 6.1 provides analysis that demonstrates the reliability improvement when these anticipated developments are considered alongside committed projects.

In general, the reliability outlook in all regions would be improved through continued investment in generation, storage and transmission, and more development of DSP resources.

Additional actions to improve the reliability forecast in the three regions identified as most at risk include:

- In South Australia:
  - Continued generation and storage investment and development of additional DSP resources. Anticipated generation and storage projects include the Bolivar Power Station, Torrens Island Battery Energy Storage System (BESS), Lincoln Gap Wind Farm BESS, and the Tailem Bend Battery Project.
- In New South Wales:
  - The development of anticipated generation, storage and transmission projects, including:
    - The HumeLink augmentation (which has not yet completed its regulatory approval process, and therefore is not treated as a committed development) to help unlock the reliability benefits provided by the expected commissioning of Snowy 2.0.
    - The Hunter Transmission Project (including the Waratah Super Battery and other network investments to deliver a system integrity protection scheme [SIPS]), which will help address existing network limitations that restrict the ability to transfer power into Sydney, Newcastle and Wollongong load centres.
  - Continued generation and storage investment, including the investment facilitated through the New South Wales Electricity Infrastructure Roadmap and actions being undertaken through this such as the recent direction to the New South Wales Consumer Trustee to commence a firming tender[79].
- In Victoria:
  - The development of anticipated generation, storage and transmission projects, including:
    - The 350 MW, four-hour, large-scale Wooreen Battery by 2026, as part of Energy Australia's agreement with the Victorian Government to deliver an orderly retirement of Yallourn Power Station[80].
    - The VNI West augmentation (which has not yet completed its regulatory approval process and is therefore not included in the analysis), to increase New South Wales to Victoria transfer limits, and support the development of additional REZs in north-west Victoria and south-western New South Wales.
    - Development of MarinusLink to increase transfer capacity between Tasmania and Victoria.
    - Continued investment to support network asset utilisation, as noted in the 2021 *Victorian Transmission Annual Planning Report*.[81]
  - The second auction for the Victorian Renewable Energy Target (VRET2), which the Victorian Government is conducting to bring online at least another 600 MW of renewable energy capacity[82]. These investments,

[79] See https://www.treasury.nsw.gov.au/sites/default/files/2022-08/Matt-Kean-med-rel-New-firming-tender-to-ensure-energy-reliability_0.pdf.

[80] See https://www.energyaustralia.com.au/about-us/energy-generation/yallourn-power-station/energy-transition.

[81] At https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/Victorian-planning/Victorian-annual-planning-report.

[82] See https://www.energy.vic.gov.au/renewable-energy/vret2.

when identified and progressed, will provide further capacity support to the projects already classified as committed and anticipated in this 2022 ESOO.

Quantifying the additional capacity required to meet the reliability standard and IRM

Separate to the reporting requirements in relation to the RRO, AEMO has projected the additional capacity that would be required – if 100% available throughout all periods of the year – to reduce expected USE below the reliability standard and the IRM. The results are in **Table 6** (for the reliability standard) and **Table 7** (for the IRM). These forecasts do not consider any reliability improvements that could be achieved with transmission developments, or the impact of transmission limits on future generation development.

For RRO purposes, Section 5.5.1 below reports similar information for forecast reliability gap periods only.

Section 6.1 discusses the impacts on forecast gaps if developments currently proposed or anticipated are completed on schedule.

Table 6 Forecast additional capacity required (in MW) to meet the reliability standard (of 0.002%)

Financial year	New South Wales	Queensland	South Australia	Tasmania	Victoria
2022-23	0	0	0	0	0
2023-24	0	0	0	0	0
2024-25	0	0	0	0	0
2025-26	570	0	0	0	0
2026-27	600	0	0	0	0
2027-28	750	0	0	0	0
2028-29	870	0	0	0	990
2029-30	2,230	500	0	0	1,080
2030-31	2,590	910	0	0	1,470
2031-32	2,820	1,280	160	0	1,820

Table 7 Forecast additional capacity required (in MW) to meet the Interim Reliability Measure (of 0.0006%)

Financial year	New South Wales	Queensland	South Australia	Tasmania	Victoria
2022-23	0	0	0	0	0
2023-24	0	0	170	0	0
2024-25	0	0	0	0	50
2025-26	1,130	0	0	0	170
2026-27	1,190	0	0	0	300
2027-28	1,360	0	0	0	410
2028-29	1,510	180	0	0	1,590
2029-30	2,890	1,140	0	0	1,770
2030-31	3,200	1,510	220	0	2,210
2031-32	3,430	1,870	420	0	2,600

The Victorian capacity required provided in Table 6 and Table 7 does not consider Mortlake South Wind Farm which has since become committed, and would reduce the capacity required.

5.5 Reliability forecast components

Consistent with NER clause 4A.A.2, a forecast reliability gap will exist if expected USE:

- Exceeds 0.0006% of the total energy demanded in that region for a given financial year between 2022-23 and 2024-25.
- Exceeds 0.002% of the total energy demanded in that region for a given financial year between 2025-26 and 2031-32.

This section outlines any forecast reliability gaps, and where relevant, the associated reliability forecast components consistent with NER clauses 4A.B.2 and 4A.A.3. All times refer to NEM time.

5.5.1 Forecast reliability gaps

In the reliability forecast (first five years), forecast reliability gaps occur in South Australia in 2023-24, in Victoria in 2024-25, and in New South Wales in 2025-26 and 2026-27, as expected USE exceeds the relevant reliability standard for these regions in these financial years. The reliability forecast components associated with these forecast reliability gaps are summarised in **Table 8**.

These reliability gaps, published for RRO purposes, reflect the additional capacity required to reduce annual expected USE to the relevant reliability standard, if that capacity is available only during likely trading intervals throughout the reliability gap period.

Table 8 Forecast reliability gaps

Region	Financial year	Reliability gap period	Likely trading intervals	Expected USE for the gap period (GWh)	Reliability gap (MW)
South Australia	2023-24[A]	8 January 2024 – 29 February 2024	5.00 pm – 9.00 pm, working weekdays	0.12	230
Victoria	2024-25	1 January 2025 – 31 January 2025	4.00 pm – 7.00 pm, weekdays	0.16	120
New South Wales	2025-26	1 December 2025 – 28 February 2026	2.00 pm – 9.00 pm, weekdays	2.86	790
		1 June 2026 – 30 June 2026	5.00 pm – 9.00 pm, weekdays	0.42	790
	2026-27	1 July 2026 – 31 July 2026	5.00 om – 9.00 pm, weekdays	0.40	1,080
		1 December 2026 – 28 February 2027	2.00 pm – 10.00 pm, weekdays	2.52	1,080
		1 June 2027 – 30 June 2027	5.00 pm – 6.00 pm, weekdays	0.08	1,080

A. Consistent with AEMOs consulted on ESOO and Reliability Forecast Methodology, AEMO calculates T-1 reliability gap periods with consideration for any previously raised T-3 reliability instruments for the relevant period. In January 2021, the South Australian Minister for Energy and Mining declared a T-3 reliability instrument for each working weekday from 8 January 2024 to 15 March 2024 between 3PM and 9PM, hence this calculated gap must be within those defined periods.
GWh: gigawatt hours.

Based on the reliability gaps identified above, AEMO is requesting the AER make RRO reliability instruments for South Australia for 2023-2024 and New South Wales for 2025-26.

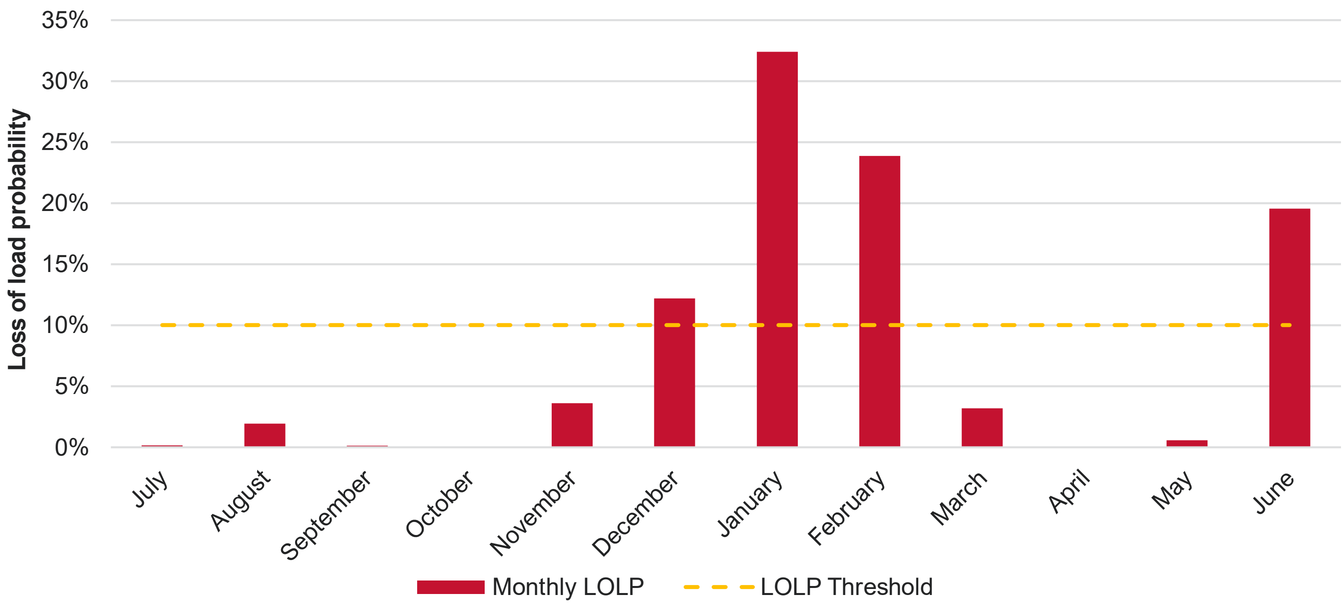
In the 2020 ESOO, AEMO reported a reliability gap for New South Wales in 2023-24, which resulted in the AER creating a T-3 reliability instrument. AEMO is advising that this reliability gap is no longer forecast.

Reliability gaps are increasingly sensitive with tight supply-demand conditions

A forecast reliability gap period is defined in section 14G(2) of the National Electricity Law (NEL) as "the period during which a forecast reliability gap is forecast to occur" and AEMO's reliability forecast must include "the trading intervals during the forecast reliability gap period in which the forecast unserved energy observed during the forecast reliability gap is likely to occur" (NER clause 4A.B.2(c)).

AEMO consulted on a methodology for defining reliability gap periods, likely trading intervals and reliability gaps in 2019[83], which is reflected in AEMO's *ESOO and Reliability Forecast Methodology*[84]. This methodology incorporates stakeholder feedback that suggested a preference for narrower gap periods. It identifies time periods that form reliability gap periods or indicative likely trading intervals as those that exceed specified loss of load probability (LOLP) thresholds as shown in **Figure 25**. As per the methodology, AEMO is to use a 10% LOLP threshold unless the reliability gap is incalculable, then decrease in 2% increments only until it is calculable. In the example shown, December, January, February and June exceed the threshold and are therefore considered part of the reliability gap period.

Figure 25 Conceptual loss of load probability assessment showing months relative to LOLP threshold



2022 ESOO modelling incorporates higher VRE uptake than assumed when this methodology was developed, which has resulted in some outcomes of the application of the LOLP thresholds that no longer meet the requirements of the NEL and NER, because so much of the forecast USE falls outside the identified likely trading intervals of the reliability gap period. **Table 9** and **Table 10** show the calculated reliability gap periods, likely trading intervals, and reliability gaps for a variety of LOLP thresholds for South Australia in 2023-24 and New South Wales in 2025-26 respectively.

[83] At https://aemo.com.au/en/consultations/current-and-closed-consultations/reliability-forecasting-methodology-issues-paper.

[84] 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.

Table 9 Forecast reliability gaps for various LOLP thresholds, South Australia, 2023-24

LOLP threshold	10%	8%	6%	4%	2%	All periods
Reliability gap period	Incalculable	8 Jan – 31 Jan	8 Jan – 31 Jan	8 Jan – 31 Jan	8 Jan – 29 Feb	All periods
Likely trading intervals		6:00 pm – 8:00 pm working weekdays	6:00 pm – 9:00 pm working weekdays	5:00 pm – 9:00 pm working weekdays	5:00 pm – 9:00 pm working weekdays	
Expected USE for the gap period (GWh)		0.07	0.10	0.11	0.12	0.14
Percentage of expected USE captured within the gap period		54%	72%	80%	87%	100%
Reliability gap size (MW)		500	320	270	230	170

Table 10 Forecast reliability gaps for various LOLP thresholds, New South Wales, 2025-26

LOLP threshold	10%	8%	6%	4%	2%	All periods
First reliability gap period	Dec – Feb	Dec – Feb	Dec – Feb	Dec – Feb	Nov-Mar	All periods
First likely trading intervals	2:00 pm – 9:00 pm weekdays	2:00 pm – 10:00 pm weekdays	1:00 pm – 10:00 pm weekdays	1:00 pm – 10:00 pm all days	1:00 pm – 10:00 pm all days	
Second reliability gap period	Jun	Jun	Jun	Jun	Jun	
Second likely trading intervals	5:00 pm – 9:00 pm weekdays	5:00 pm – 9:00 pm weekdays	5:00 pm – 9:00 pm weekdays	4:00 pm – 9:00 pm weekdays	4:00 pm – 10:00 pm weekdays	
Expected USE for the gap periods (GWh)	3.28	3.31	3.34	3.50	3.84	3.90
Percentage of expected USE captured within the gap period	84%	85%	86%	90%	98%	100%
Reliability gap size (MW)	790	770	760	690	590	570

AEMO does not consider the 2023-24 gap periods identified in South Australia by the methodology (using the 8% LOLP threshold) to be consistent with the requirements of the NEL or the NER, in that expected USE within the reliability gap period represents approximately half of the total USE forecast throughout the year. In addition, the reliability gap in MW calculated for the reliability gap period is nearly three times the capacity requirement, should that capacity be available through all periods of the year.

The reliability gap periods identified in New South Wales in 2025-26 (using a 10% LOLP threshold) however capture a larger portion of the annual expected USE, and have a reliability gap closer to the all period capacity requirement.

For South Australia in 2023-24, AEMO has applied a wider gap period in determining the reliability gap, based on a 2% LOLP threshold. This maintains the fundamental approach of the methodology in applying a LOLP threshold in determining the reliability gap period, but selects a lower probability that results in a reliability gap more reflective of the underlying capacity requirement. As the reliability gaps calculated with this methodology for New South Wales capture a larger portion of forecast expected USE and are less sensitive to the choice of threshold, no change to threshold has been made.

In applying this adjustment, the reliability gap period for South Australia widens by only 2 hours per day, for months within the same quarter. AEMO considers this is a relatively insignificant widening of the gap period, which captures a larger portion of the forecast USE, and does not result in a significant increase in the requirement that would otherwise occur. This increase in time is not expected to significantly increase costs to retailers. For example, ASX electricity futures[85] for South Australia are not adjustable for time of day and cover the entire quarter.

AEMO's original consulted-on methodology has been retained for all other reliability gaps and indicative reliability gaps.

5.5.2 Indicative forecast reliability gaps

In the indicative reliability forecast (second five years), forecast reliability gaps occur in New South Wales in all years from 2027-28 to 2031-32, in Victoria in all years from 2028-29 to 2031-32, in Queensland in each year from 2029-30 to 2031-32, and in South Australia in 2031-32. In each of these years, each region's expected USE is forecast to exceed the reliability standard of 0.002% of the total energy demanded. The reliability forecast components associated with these indicative forecast reliability gaps are summarised in **Table 11**.

Table 11 Indicative forecast reliability gaps

Region	Financial year	Reliability gap period	Likely trading intervals	Expected USE for the gap period (GWh)	Reliability gap (MW)
New South Wales	2027-28	1 July 2027 – 31 July 2027	5.00 pm – 9.00 pm, weekdays	0.50	1,240
		1 December 2027 – 29 February 2028	2.00 pm – 10.00 pm, weekdays	2.87	1,240
		1 June 2028 – 30 June 2028	5.00 pm – 9.00 pm, weekdays	0.40	1,240
	2028-29	1 July 2028 – 31 July 2028	5.00 pm – 9.00 pm, weekdays	0.40	1,810
		1 January 2029 – 28 February 2029	2.00 pm – 10.00 pm, weekdays	2.96	1,810
		1 June 2029 – 30 June 2029	4.00 pm – 10.00 pm, weekdays	0.67	1,810
	2029-30	1 July 2029 – 31 July 2029	5.00 pm – 10.00 pm, weekdays	0.71	3,420
		1 December 2029 – 28 February 2030	all hours, all days	17.01	3,420
		1 May 2030 – 30 June 2030	all hours, all days	9.55	3,420
	2030-31	1 July 2030 – 31 August 2030	all hours, all days	14.69	2,810
		1 November 2030 – 28 February 2031	all hours, all days	22.71	2,810
		1 May 2031 – 30 June 2031	all hours, all days	13.26	2,810
	2031-32	1 July 2031 – 30 June 2032	all hours, all days	63.69	2,820
Victoria	2028-29	1 January 2029 – 28 February 2029	12.00 pm – 10.00 pm, all days	3.76	1,560
		1 June 2029 – 30 June 2029	5.00 pm – 9.00 pm, weekdays	0.33	1,560
	2029-30	1 July 2029 – 31 July 2029	6.00 pm – 7.00 pm, weekdays	0.08	2,640
		1 January 2030 – 28 February 2030	2.00 pm – 10.00 pm, all days	3.84	2,640

[85] See https://www2.asx.com.au/markets/trade-our-derivatives-market/overview/energy-derivatives/electricity.

Region	Financial year	Reliability gap period	Likely trading intervals	Expected USE for the gap period (GWh)	Reliability gap (MW)
		1 June 2030 – 30 June 2030	5.00 pm – 9.00 pm, weekdays	0.37	2,640
	2030-31	1 July 2030 – 31 July 2030	5.00 pm – 10.00 pm, weekdays	0.46	2,330
		1 January 2031 – 31 March 2031	1.00 pm – 11.00 pm, all days	5.74	2,330
		1 June 2031 – 30 June 2031	4.00 pm – 10.00 pm, weekdays	1.58	2,330
	2031-32	1 July 2031 – 31 August 2031	4.00 pm – 11.00 pm, weekdays	3.86	2,170
		1 December 2031 – 30 June 2032	1.00 pm – 11.00 pm, all days	12.46	2,170
Queensland	2029-30	1 January 2030 – 31 March 2030	5.00 pm – 10.00 pm, weekdays	2.35	680
	2030-31	1 January 2031 – 31 March 2031	4.00 pm – 11.00 pm, weekdays	4.24	1,550
	2031-32	1 December 2031 – 31 March 2032	4.00 pm – 11.00 pm, weekdays	7.61	1,950
		1 June 2032 – 30 June 2032	5.00 pm – 10.00 pm, weekdays	0.53	1,950
South Australia	2031-32	1 June 2030 – 30 June 2032	6.00 pm – 10.00 pm, weekdays	0.28	440

5.5.3 One-in-two year peak demand forecast

In accordance with NER clause 4A.A.3, AEMO must specify the forecast one-in-two year peak demand in the reliability forecast. As agreed through consultation with industry, AEMO reports the 50% POE operational maximum demand forecast on an 'as generated' basis for this purpose. Performance of these demand forecasts is included in AEMO's *Forecast Accuracy Report*[86].

The only difference between the 'as generated' forecasts, listed in **Table 12**, and the operational maximum demand values reported by region in Appendices A1-A5 on a 'sent out' basis is the inclusion of auxiliary load forecasts at time of maximum demand[87].

Table 12 AEMO's one-in-two year peak demand forecast (50% POE, as generated)

Financial year	New South Wales	Queensland	South Australia	Tasmania	Victoria
2022-23	12,921	10,118	2,989	1,806	9,386
2023-24	12,950	10,403	3,044	1,850	9,503
2024-25	13,001	10,552	3,126	1,886	9,597
2025-26	13,133	10,916	3,223	1,923	9,670
2026-27	13,185	11,131	3,283	1,946	9,760

The forecast auxiliary load amounts at the time of maximum demand for 50% POE demand conditions are shown below in **Table 13**. These values have been determined based on modelling outcomes which apply the auxiliary rates of each generating unit based on information provided by participants.

Average auxiliary load rates at the time of one-in-two year peak demand are forecast to remain relatively static over the next five years in all regions. Coal-fired generation typically has higher auxiliary loads than other

[86] At https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/forecasting-accuracy-reporting.

[87] See AEMO's *Electricity Demand Forecasting Information Paper*, 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 types. Auxiliary loads therefore reduce as coal-fired generators retire, as forecast in New South Wales when Liddell retires.

Table 13 Auxiliary usage (in MW) forecast at time of one-in-two year peak demand (50% POE)

Financial year	New South Wales	Queensland	South Australia	Tasmania	Victoria
2022-23	391	454	45	20	364
2023-24	344	457	43	21	378
2024-25	338	435	51	20	377
2025-26	301	407	48	19	324
2026-27	248	382	48	19	264

6 Alternate development sensitivities

This chapter assesses the reliability outlook under a variety of different sensitivities. It highlights that:

- If anticipated and ISP actionable developments progress as planned, a significantly improved reliability outlook is expected.
- If demand side solutions progress slower than forecast, the need for utility-scale supply solutions will be greater.
- Project commissioning delays have the potential to impact the improved outlook forecast with anticipated and actionable developments.
- Under a low demand scenario, less unserved energy is expected, but New South Wales (from 2028-29) and Victoria (from 2029-30) are still forecast to exceed the reliability standard.

The ESOO scenarios are designed, through extensive industry and consumer consultation, to represent a plausible and probable range of futures for Australia, and particularly the NEM. In representing the possible future conditions facing the NEM, the scenarios do not capture all credible uncertainties, and modelling presented in Chapter 5 for the ESOO Central scenario considers the most likely outlook, rather than all possible outcomes.

Assumptions used in AEMO's forecasts are subject to a range of important uncertainties. AEMO has also forecast reliability using different assumptions, assessing how forecast outcomes could change based on:

- Including anticipated developments (which are well advanced and expected to start operations within the outlook period) and ISP actionable developments (listed in the 2022 ISP as required and urgent), alongside existing and committed supply (see Section 6.1).
- Consumer action on battery installations, VPP services, and/or demand reduction schemes being slower or less significant than the ESOO Central scenario assumptions (Section 6.2).
- The commissioning of Snowy 2.0 being delayed by two years to 2027-28 and 2028-29 (Section 6.3).
- All presently mothballed capacity remaining unavailable during the whole five years of the reliability forecast timeframe (Section 6.4).
- The *Slow Change* scenario's lower demand forecasts, assuming weak economic conditions, including some large industrial load closures (Section 6.5).

6.1 Anticipated and ISP actionable developments significantly improve the outlook compared to the ESOO Central scenario

While the 2022 ESOO identifies numerous reliability gaps over the 10-year horizon, significant investments in the NEM are expected in addition to the committed and committed* projects included in the reliability assessment.

Anticipated generation and storage developments are projects which meet some of AEMO's commitment criteria, but not enough to be considered committed. These generation and storage projects, alongside the actionable transmission projects identified in the 2022 ISP, will improve the reliability forecast significantly if developed to their current anticipated schedules.

AEMO assessed the potential impact of these developments by modelling a sensitivity that forecasts expected USE if all anticipated generation, and anticipated and ISP actionable transmission developments, as well as committed and committed* projects, were developed to schedule.

The pipeline of anticipated and actionable developments includes:

- Almost 1,200 MW of wind generation.
- Approximately 850 MW of utility-scale solar generation.
- Approximately 1,200 MW of BESS.
- Approximately 100 MW of peaking capacity operated with gas or diesel fuels.
- Anticipated and actionable transmission projects identified in the ISP:
  - Central West Orana and New England REZ transmission links, and the Hunter Transmission Project (including earlier investments to support the SIPS) in New South Wales, and the Western Renewables Link in Victoria.
  - Strategic transmission projects affecting inter-regional transfer capacities, including HumeLink, Marinus Link, and VNI West.

Figure 26 shows the improved reliability outlook in this sensitivity, compared to the ESOO Central case used in the reliability forecasts in Chapter 5. It highlights that these investments (if they are delivered in accordance with current schedules) would improve the NEM reliability outlook in every mainland region, compared to the forecast with only existing and committed developments.

This sensitivity shows notable improvements in the forecast:

- In **South Australia in 2023-24**, due to the inclusion of four anticipated generation or storage projects.
- In **New South Wales from 2025-26**, when the Hunter Transmission Project (including early investments including the SIPS) and then HumeLink unlock the reliability benefits of already committed generation capacity. By increasing transmission capacity, generation further afield is able to reach the Sydney, Newcastle, Wollongong area, offsetting the capacity withdrawn when Eraring Power Station retires.
- In **Victoria from 2024-25**, due to the inclusion of three anticipated generation or storage projects**.**
- In **Queensland from 2028-29**, when the reliability improvements in New South Wales lead to less sharing of USE across the two regions.
- In **Victoria from 2029-30**, when Marinus Link and then VNI West are commissioned. While these transmission projects improve the outlook (not shown in the figure) by increasing transfer capacity, new generation projects that will take advantage of this transfer capacity are not yet considered committed or anticipated and are therefore not included.

Figure 26 Reliability impact of projects well advanced but not yet committed, mainland NEM regions, 2022-23 to 2031-32 (%)[88]

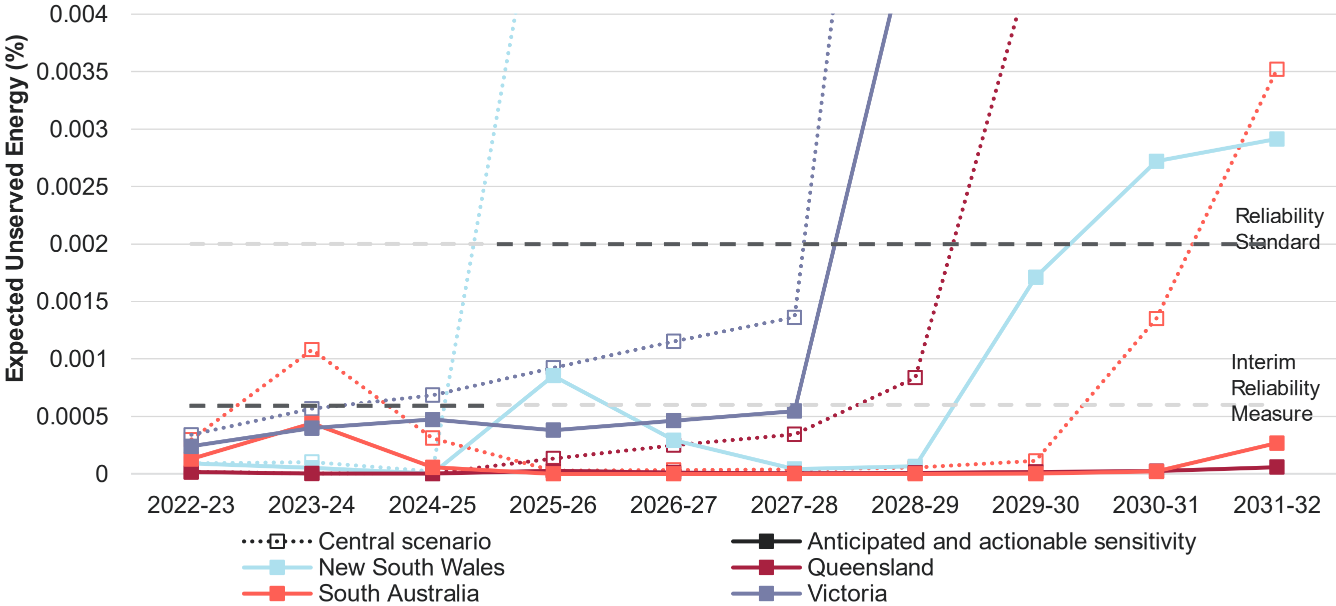


Figure 26 also shows that, while the inclusion of anticipated and actionable projects improves reliability outcomes, USE is still forecast to exceed the relevant standard in New South Wales and Victoria during the next 10 years. Further investments again would be beneficial over the forecast horizon to keep expected USE within the relevant standard[89]:

- **New South Wales in 2025-26**, when Eraring Power Station is expected to retire but transmission capacity is not yet fully developed.
  - In 2025-26 an additional 175 MW is forecast to be required to bring expected USE within the IRM.
- **Victoria from 2028-29**, when Yallourn Power Station is expected to retire.
  - Approximately an additional 555 MW is forecast to be required to bring expected USE within the reliability standard.
  - Approximately an additional 1,075 MW is forecast to be required to bring expected USE within the IRM.
- **New South Wales from 2030-31**, when Vales Point Power Station is expected to retire.
  - Approximately an additional 235 MW is forecast to be required to bring expected USE within the reliability standard
  - Approximately an additional 963 MW is forecast to be required to bring expected USE within the IRM.

Section 3.2 showed a known pipeline of 169 GW of generation and storage projects at various stages of commitment and development, in all NEM regions. As this known pipeline of developments progresses, including

[88] ESOO Central scenario modelling does not consider Mortlake South Wind Farm which has since become committed, however it is considered in the *Anticipated and actionable* sensitivity.

[89] AEMO provides assessments of required capacity against both the IRM and the reliability standard across the entire ESOO horizon to provide transparency, similar to that provided in Chapter 5.

those incentivised and accelerated through state and territory schemes, the reliability outlook will improve under both the ESOO Central scenario and the anticipated and actionable sensitivity.

Firm renewable investments are an economically efficient replacement to retiring capacity

As forecast in the 2022 ISP, retiring capacity will require efficient replacement through generation, storage and transmission investment. Investments in new VRE capacity beyond those committed, committed* and anticipated are needed to meet consumer needs while minimising costs.

The 2022 ISP identified the scale of VRE and firming investments by 2032 that is shown in **Table 14**. This scale of investment, if delivered as forecast, exceeds the required investment to meet the IRM, as outlined in the previous section.

Table 14 New capacity modelled in the 2022 ISP *Step Change* scenario additional to that considered in the 2022 ESOO anticipated and actionable sensitivity by 2031-32

	New South Wales	Queensland	South Australia	Tasmania	Victoria
VRE capacity (MW)	12,588	8,586	2,144	2,497	4,232
Firming capacity (MW)	2,000	872	0	390	0
DSP capacity (MW)	206	300	119	24	267

Numerous state and territory schemes have been implemented to further incentivise appropriate developments. Schemes of interest include:

- **The New South Wales Infrastructure Investment Objectives (IIO) Report**[90], which includes an implementation plan for conducting competitive tenders for the IIO Development Pathway.
  - 2022 tenders indicate 2,500 gigawatt hours (GWh) a year in Long Term Energy Supply Agreements, and will also include the first of the long-duration storage infrastructure, with an indicative size of 600 MW.
- **The New South Wales firming infrastructure tender**[91,92], which anticipates at least 350 MW of firming infrastructure located in the Sydney, Newcastle, Wollongong sub-region, operational by summer 2025-26.
  - While subject to further specification by the New South Wales Consumer Trustee, this additional capacity is larger than the 175 MW required to bring expected USE within the IRM, and is also likely to result in improvements to the longer-term outlook.
- **The Victorian Renewable Energy Target 2**[93], which aims to bring online at least 600 MW of new renewable energy capacity in Victoria.

6.2 Significant consumer action is required to minimise reliability risks

The ESOO Central (*Step Change)* scenario includes a strong influence from electrifying business and residential sectors, and captures continued uptake of DER, including distributed PV and batteries, as well as growing uptake of electrified transport (primarily via EVs). In this scenario, the uptake of DER is accompanied by a relatively

[90] See https://aemoservices.com.au/publications-and-resources/infrastructure-investment-objectives-report.

[91] See https://www.energy.nsw.gov.au/government-and-regulation/electricity-infrastructure-roadmap/energy-security-target-monitor.

[92] See https://aemoservices.com.au/tenders/firming.

[93] See https://www.energy.vic.gov.au/renewable-energy/vret2.

strong increase in coordination and orchestration of these devices to meet power system needs, including via VPP and coordinated EV charging (and discharging in some vehicle-to-grid applications).

The effect of increased DER orchestration will lower the investment requirements of utility-scale generation and storage, as the DER uptake that is orchestrated operates to minimise USE risks. AEMO modelled a 'consumer action' sensitivity to understand the potential impact of delays or under-delivery of the forecast consumer-led deployment of DER, particularly VPPs, and policy-led DSP, compared to ESOO Central scenario assumptions.

Consumer action in the ESOO Central outlook

Virtual power plants

A VPP broadly refers to an aggregation of resources (such as decentralised generation, storage, and controllable loads) coordinated to deliver services for power system operation and electricity markets[94]. There are many technologies and various options for consumers to participate such as through microgrids, controllable loads, EVs, and battery storage. In terms of magnitude and growth potential over the next decade, battery storage represents the largest of these components that AEMO forecasts.

In the NEM regions, VPPs are forecast to reduce maximum demand by between 6-16%, as shown in **Table 15**.

In New South Wales, for example, VPPs are projected to offset maximum demand by 1,800 MW by 2031-32, approximately 13% of the peak forecast in the ESOO Central scenario. While this reduction in peak demand has the potential to significantly reduce the need for utility-scale solutions, it would require the coordination of a significant number of consumer batteries, a process that has demonstrated value in trials, but not at significant scale to date in the NEM.

Table 15 ESOO Central scenario 50% POE maximum demand forecasts relative to VPPs, 2031-32

	New South Wales	Queensland	South Australia	Tasmania	Victoria
Maximum operational demand as sent-out (MW)	13,846	11,563	3,529	1,949	10,470
VPP for batteries (MW)	1,818	1,609	565	125	1,402
% impact on reducing maximum demand	13%	14%	16%	6%	13%
Approximate number of residential batteries in VPPs	379,000	335,000	118,000	26,000	292,000

Battery installations and coordination

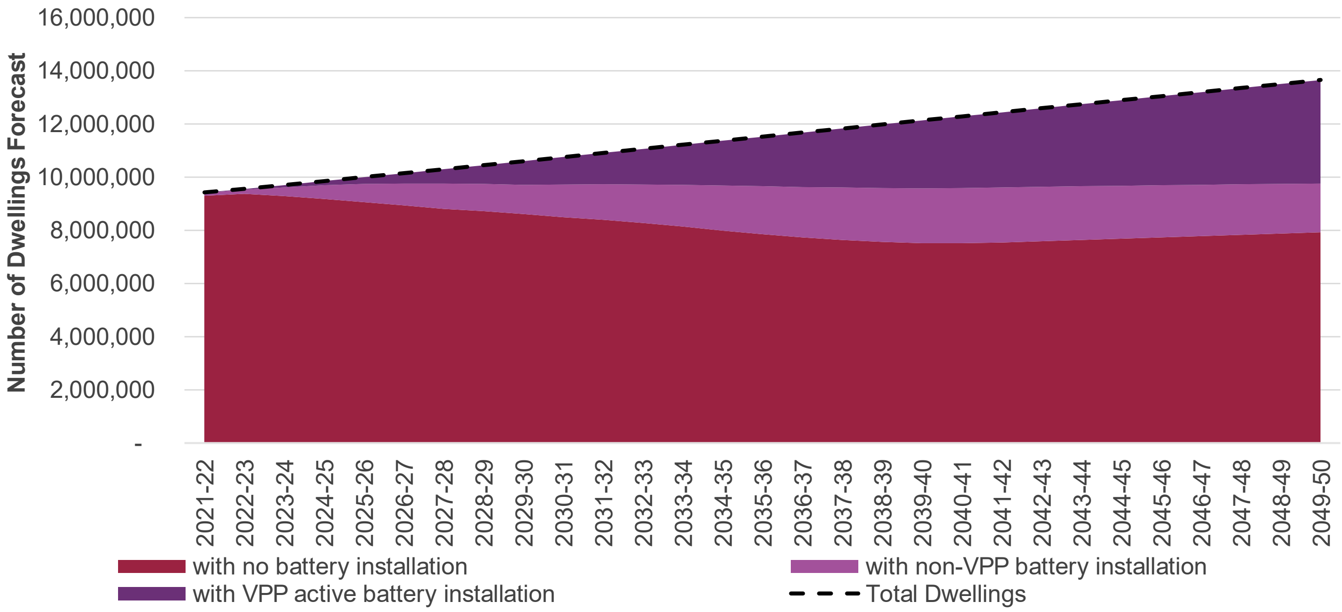
Figure 27 shows the projected proportions of battery installations in the ESOO Central scenario, demonstrating the share of coordinated batteries in the forecast. These uptake projections are dependent on consumer trends which can be influenced by various factors such as a customer's own cost-benefit analysis and usage requirements, market opportunities, and the value that the retailer or aggregator can find for future revenue[95].

[94] See https://aemo.com.au/-/media/files/initiatives/der/2021/vpp-demonstrations-knowledge-sharing-report-4.pdf.

[95] See https://ieefa.org/wp-content/uploads/2022/03/What-Is-the-State-of-Virtual-Power-Plants-in-Australia_March-2022_2.pdf.

While there is some policy support and expectations of cost reductions in the long term[96,97], there remains a large degree of uptake and orchestration uncertainty, relying on homeowners to both install battery systems and to sign up for these to provide grid services.

Figure 27 NEM dwelling forecast with associated battery installations, ESOO Central scenario, 2021-22 to 2049-50



Demand side participation

DSP is also forecast to grow substantially in the 2022 ESOO Central scenario due to the commitment of the New South Wales Peak Demand Reduction Scheme. The scheme aims to reduce New South Wales' maximum demand by approximately 1,400 MW by 2031-32, based on AEMO projections of maximum demand.

Alternate outlook with less consumer action shows reduced performance compared to the anticipated and actionable sensitivity

Should these battery installations, VPP services, and/or demand reduction schemes occur slower than forecast or underdeliver, the reliability forecast may worsen and the need for further utility-scale solutions may increase. AEMO modelled a supply adequacy sensitivity where:

- All assumptions of the anticipated and actionable sensitivity from Section 6.1 are applied.
- Distributed battery uptake continues as forecast, but coordination of batteries fails to develop.
- The New South Wales Peak Demand Reduction Scheme does not occur.

The purpose of the sensitivity is to demonstrate the importance of policy and consumer support for demand side solutions, and the increased requirement for utility-scale solutions should these forecast solutions not materialise.

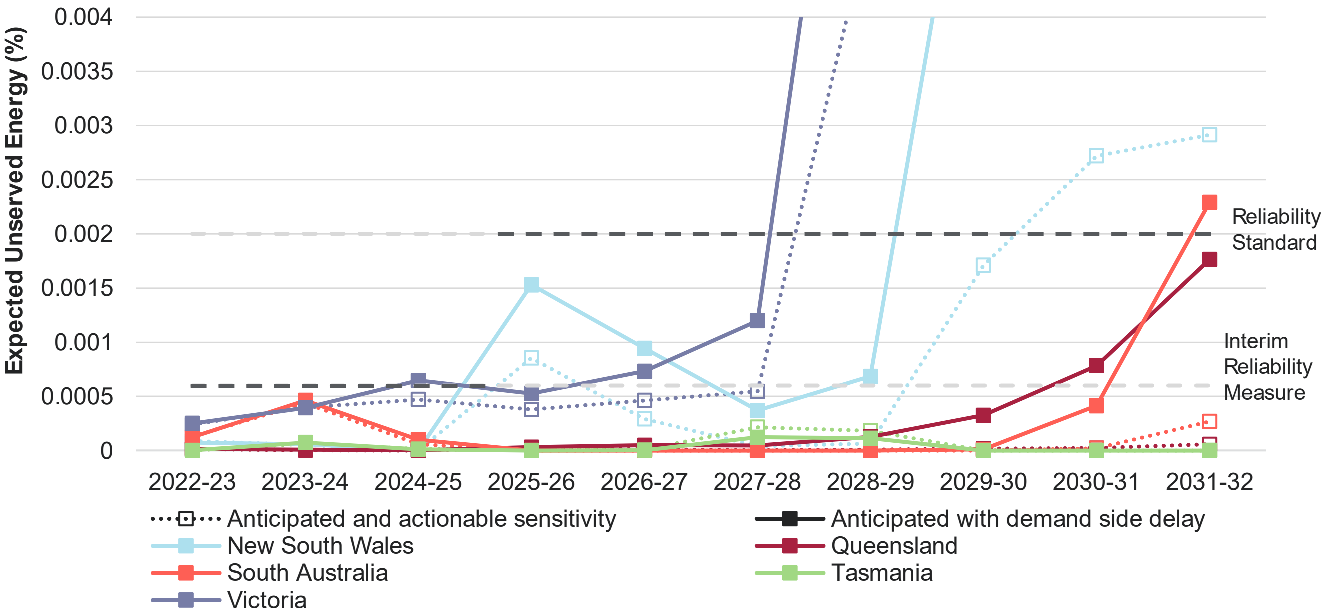
[96] See https://aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2021/CSIRO-DER-Forecast-Report.

[97] See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/green-energy-markets-derforecast-report.pdf?la=en.

Figure 28 shows the results of the anticipated and actionable outlook if demand side coordination services fail to materialise. It shows that:

- Forecast expected USE is higher in all regions in the sensitivity where demand side coordination services fail to materialise.
- In New South Wales, the region with the largest forecast increase in demand side solutions, the sensitivity shows USE above the reliability standard from 2029-30.
  - To reduce USE to the reliability standard in New South Wales, approximately 880 MW more firm utility-scale capacity would be required than in the anticipated and actionable sensitivity where demand side solutions were assumed to develop (see Section 6.1).
- In Victoria, USE is forecast to be greater than the reliability standard after the retirement of Yallourn in 2028-29.
  - To reduce USE to the reliability standard in Victoria, approximately 275 MW more firm utility-scale capacity would be required than in the anticipated and actionable sensitivity where demand side solutions were assumed to develop (see Section 6.1).
- In South Australia, the forecast USE is greater than the reliability standard in 2031-32.
  - To reduce USE to the reliability standard in 2031-32 in South Australia, 35 MW more firm utility-scale capacity would be required than in the anticipated and actionable sensitivity where demand side solutions were assumed to develop (see Section 6.1).

Figure 28 Reliability impact of demand side solution delays, 2022-23 to 2031-32 (%)



6.3 Potential Snowy 2.0 project commissioning delays are not expected to materially impact supply adequacy

The Snowy 2.0 development is a key storage development presently committed and under construction. It will utilise improved connectivity with New South Wales consumers with the development of new transmission investments, particularly the HumeLink and VNI West actionable ISP projects. These transmission investments are yet to meet AEMO's commitment criteria, limiting the capacity for Snowy 2.0 to improve the modelled reliability outlook in the ESOO Central scenario.

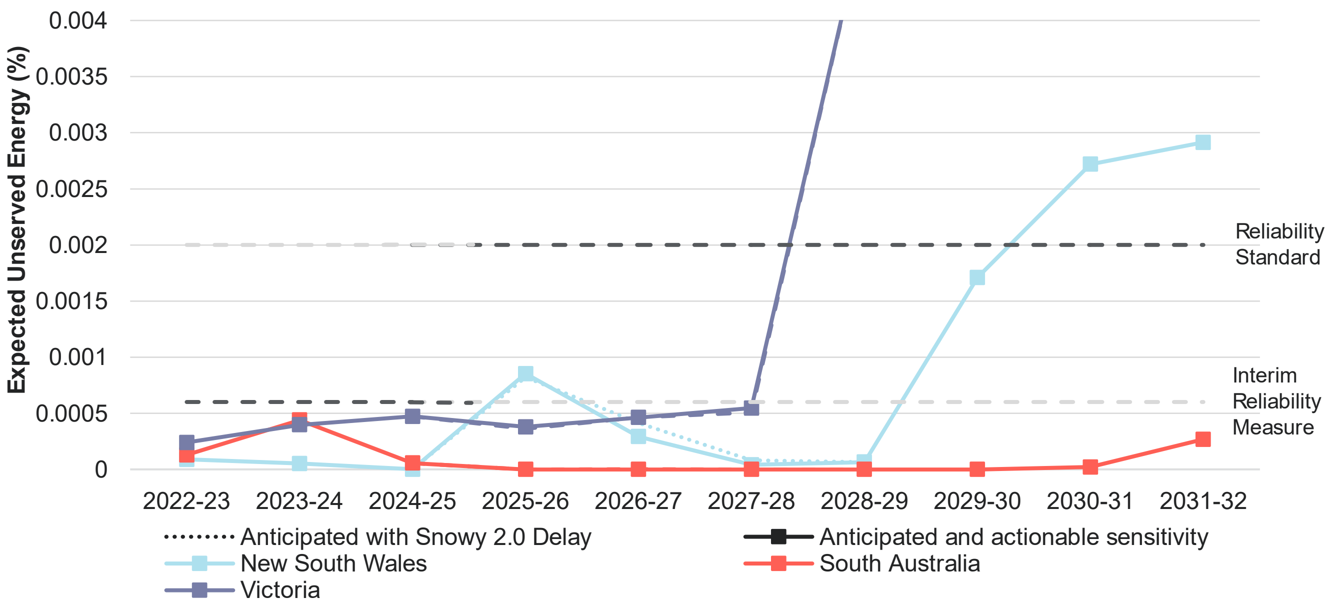
Recent media speculation has suggested a likely delay to the project, however the project proponent, Snowy Hydro, has provided unchanged advice regarding the intended commissioning schedule of Snowy 2.0 between 2025-26 and 2026-27 since the 2021 ESOO.

Without the development of HumeLink, the project is not able to deliver a reliability benefit in the ESOO Central scenario, and likewise does not reduce reliability if it were delayed in this case.

However an improved reliability outcome is expected with consideration of anticipated developments, including actionable ISP transmission projects. To assess the impact that a delay to Snowy 2.0's commissioning schedule would have on reliability outcomes in New South Wales with anticipated and actionable investments, AEMO modelled a sensitivity where the commissioning of Snowy 2.0 is delayed by two years, to 2027-28 and 2028-29.

Figure 29 shows the reliability impact that is forecast to occur under the anticipated and actionable sensitivity with delayed commissioning of Snowy 2.0. It demonstrates that a delay in Snowy 2.0 would have a small impact on forecast reliability, with an increase in New South Wales USE in 2026-27 and 2027-28. Without Snowy 2.0, the HumeLink and Hunter Transmission projects allow extra generation to flow into the major New South Wales load centres of Sydney, Newcastle and Wollongong, from other generators in southern New South Wales, Victoria and/or South Australia prior to Snowy 2.0 commissioning.

Figure 29 Reliability impact of a potential delay to Snowy 2.0 commissioning on the anticipated and actionable outlook, 2022-23 to 2031-32 (%)



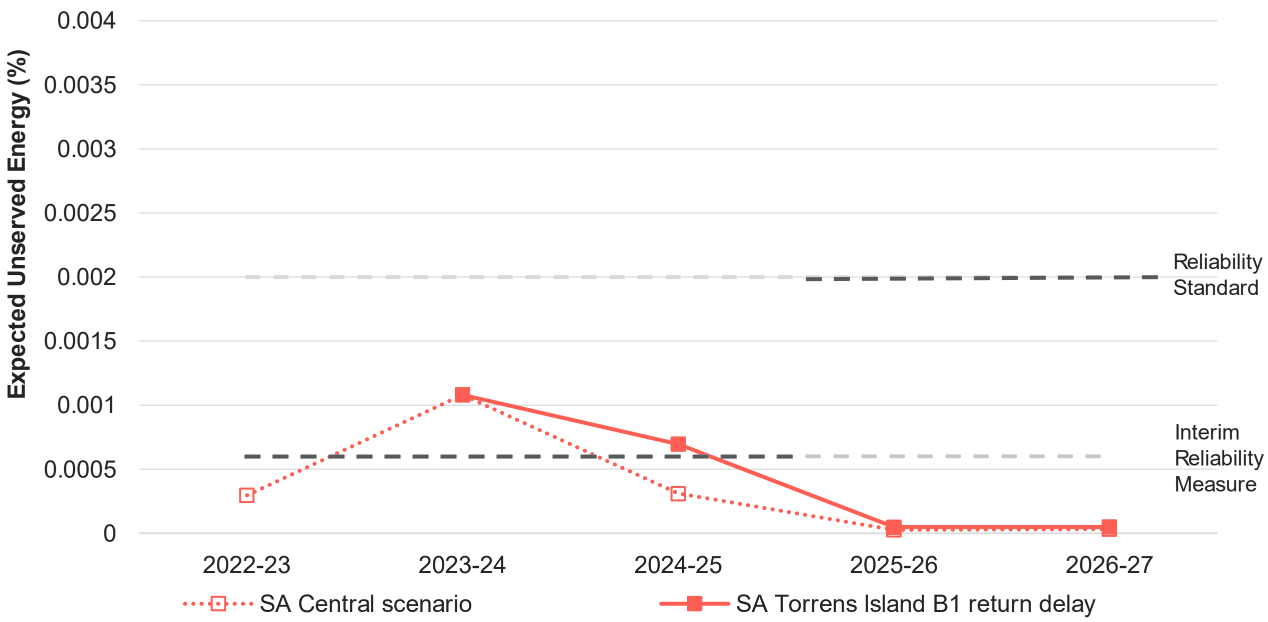
6.4 The South Australian reliability outlook will worsen if mothballed units are not returned to service to schedule compared to the ESOO Central scenario

Occasionally, market conditions necessitate a generator owner mothballing excess capacity, typically to reduce operational expenditure when surplus capacity exists. AGL presently has one of its Torrens Island B units mothballed, meaning that it is unavailable for use, and can only be returned to service subject to an extended recall time. Participant advice collected for the July 2022 Generation Information data release declares that this unit should return to service in advance of summer 2024-25.

AEMO developed a sensitivity to assess the reliability impact if this unit remained in its presently mothballed state for the entire five-year reliability forecast timeframe. AEMO has included this sensitivity to demonstrate the relative reliability impact if conditions do not improve sufficiently to enable the operator to proceed with its present return to service strategy.

Figure 30 shows the impact on reliability in South Australia in this sensitivity relative to the ESOO Central scenario. The figure demonstrates the forecast reliability deterioration that deferring its return to service would likely cause in 2024-25 prior to the full commissioning of Project EnergyConnect. In this year, expected USE would increase above the IRM. Continuing to mothball the unit would have much lesser impacts following the expected full commissioning of Project EnergyConnect.

Figure 30 Reliability impact of a potential delay to return from mothballing of Torrens Island B1, 2022-23 to 2026-27 (%)



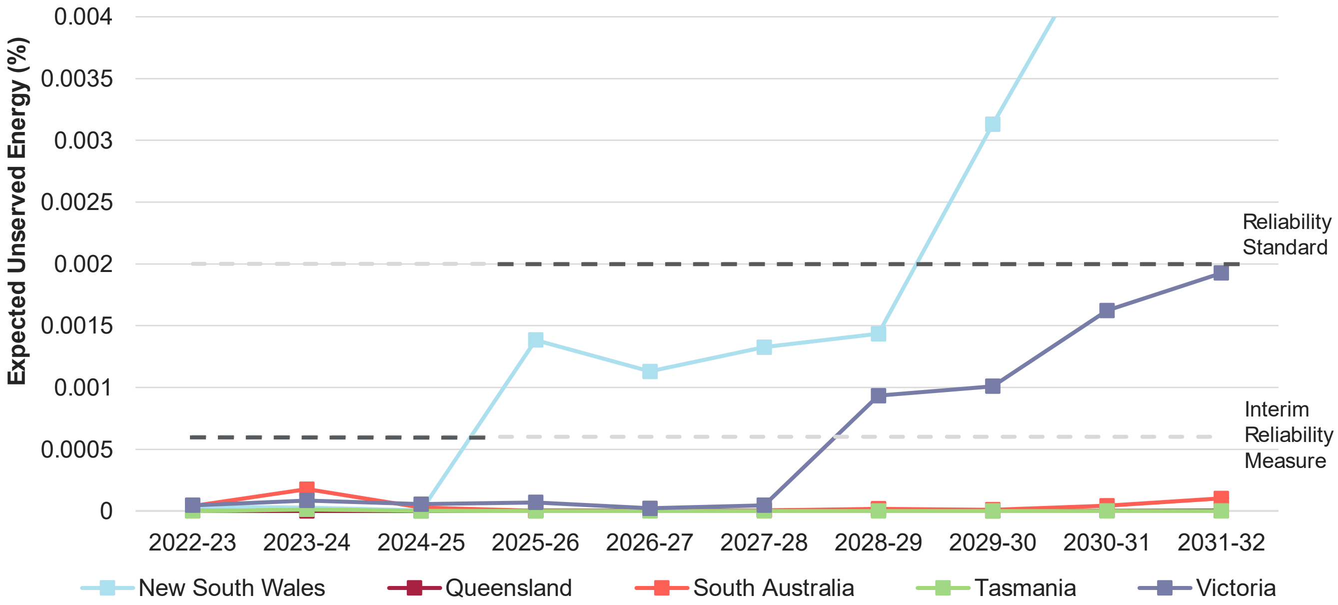
6.5 A low demand scenario delivers a more favourable reliability outlook compared to the ESOO Central scenario

The *Slow Change* scenario considers weak economic conditions, including large industrial load closures. Should such low demand conditions emerge, the reliability outlook is considerably more favourable, as **Figure 31** shows:

- While reliability risks still emerge in New South Wales in 2025-26, expected USE is less than the reliability standard until 2029-30, when both Eraring and Vales Point power stations are expected to have retired.
- In Victoria, expected USE remains less than the reliability standard but worsens from 2028-29 when Yallourn Power Station has retired.
- All other regions show low levels of reliability risk.

While this scenario demonstrates a statistically acceptable near-term level of reliability risk, it is reliant on the potential closure of industrial loads to meet the relevant reliability standards. Given the reliability risks in the later years, it demonstrates that additional commitments to deliver generation and storage capacity are needed in all scenarios.

Figure 31 Expected unserved energy, *Slow Change* scenario, 2022-23 to 2031-32 (%)



List of figures and tables

Tables

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A1. New South Wales outlook

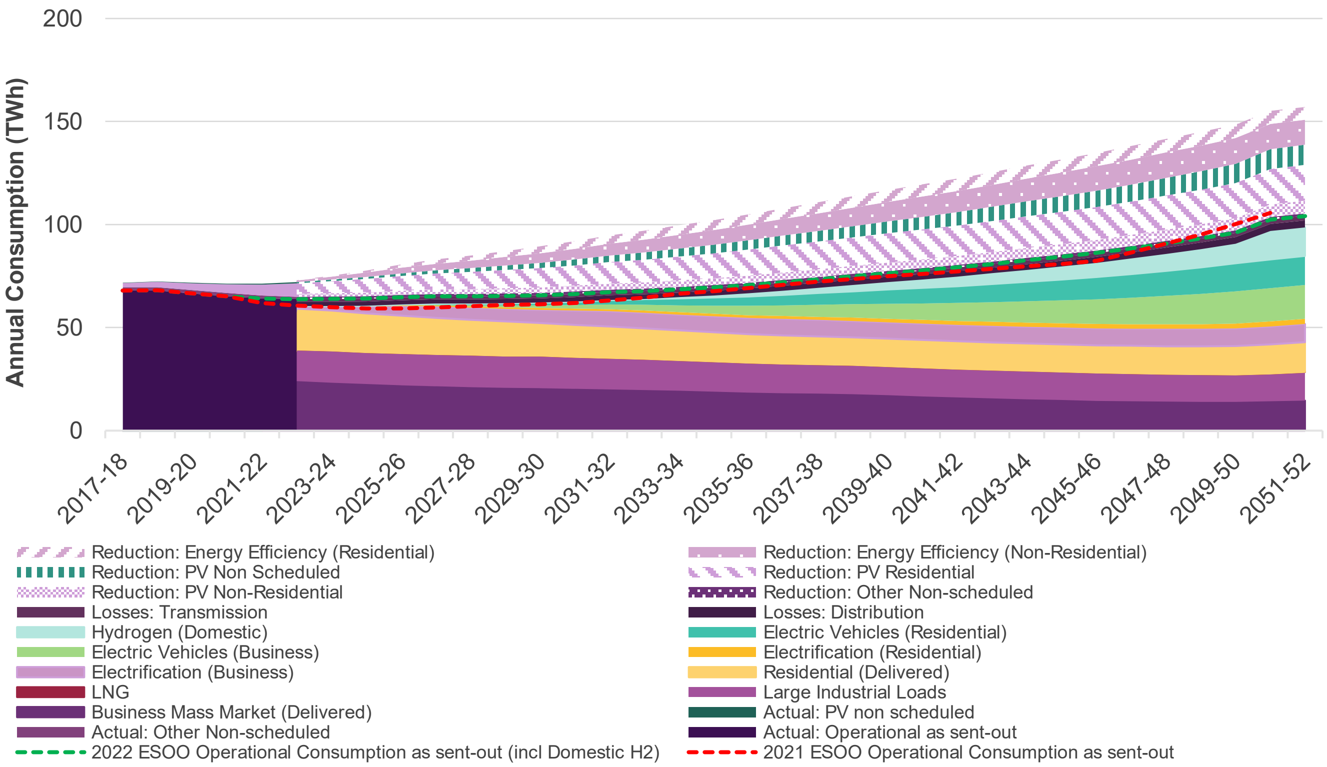
The following sections present, for New South Wales:

- Operational consumption, maximum demand, and minimum demand outlooks for all four scenarios to 2051-52.
- Supply adequacy assessments for the next 10 years, for the ESOO Central scenario, *Slow Change*, and other sensitivities.

Annual consumption outlook

Figure 32 shows the component forecasts for operational consumption in New South Wales under the ESOO Central (*Step Change*) scenario.

Figure 32 Actual and forecast New South Wales electricity consumption, ESOO Central scenario, 2017-18 to 2051-52 (TWh)



In this scenario, AEMO forecasts:

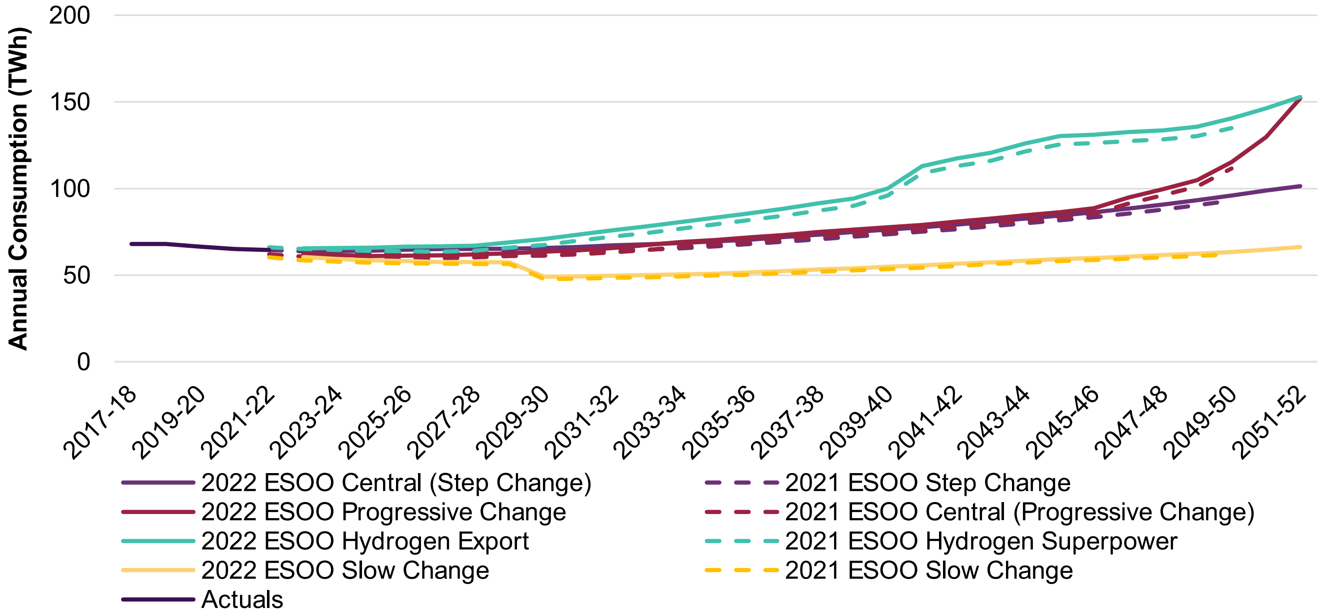
- Short term (1-10 years) – continued strong growth of distributed PV, and a lower forecast from the BMM sector than in the 2021 ESOO Central scenario, an outcome due in part to the shift in Central scenario definition to *Step Change*. In addition, this lower BMM forecast is influenced by a revised approach to apportion historical consumption between the residential and business sectors based on smart meter data rather than AER data that is typically 18 months old. There is a corresponding increase in the residential consumption forecast.

- Medium term (11-20 years) – consumption growing strongly due to growth in electrification and EVs (residential and business) despite continued growth in distributed PV and energy efficiency.
- Long term (21-30 years) – similar growth trends continuing from the preceding decade, with the emergence of hydrogen production for domestic usage, resulting in strong growth in consumption from the mid-2040s.

Figure 33 shows all the scenarios, highlighting that:

- *Progressive Change*, while initially tracking closely to the *Step Change* scenario, has relatively limited long-term electrification impacts until the mid-2040s, when a significant uptick takes place.
- Domestic hydrogen production dominates the growth trajectory of *Hydrogen Export*.
- *Slow Change*, with large industrial load closure risks, short-term rapid distributed PV growth and limited electrification, has the lowest forecast consumption.

Figure 33 Actual and forecast New South Wales operational consumption, all scenarios, 2017-18 to 2051-52 (TWh)



Maximum operational demand outlook

Figure 34 shows the actual and forecast 50% POE maximum operational (sent-out) demand (MW) from 2017-18 to 2050-51 for the 2022 ESOO compared to the 2021 ESOO for all scenarios in New South Wales. The key insights from these forecasts are:

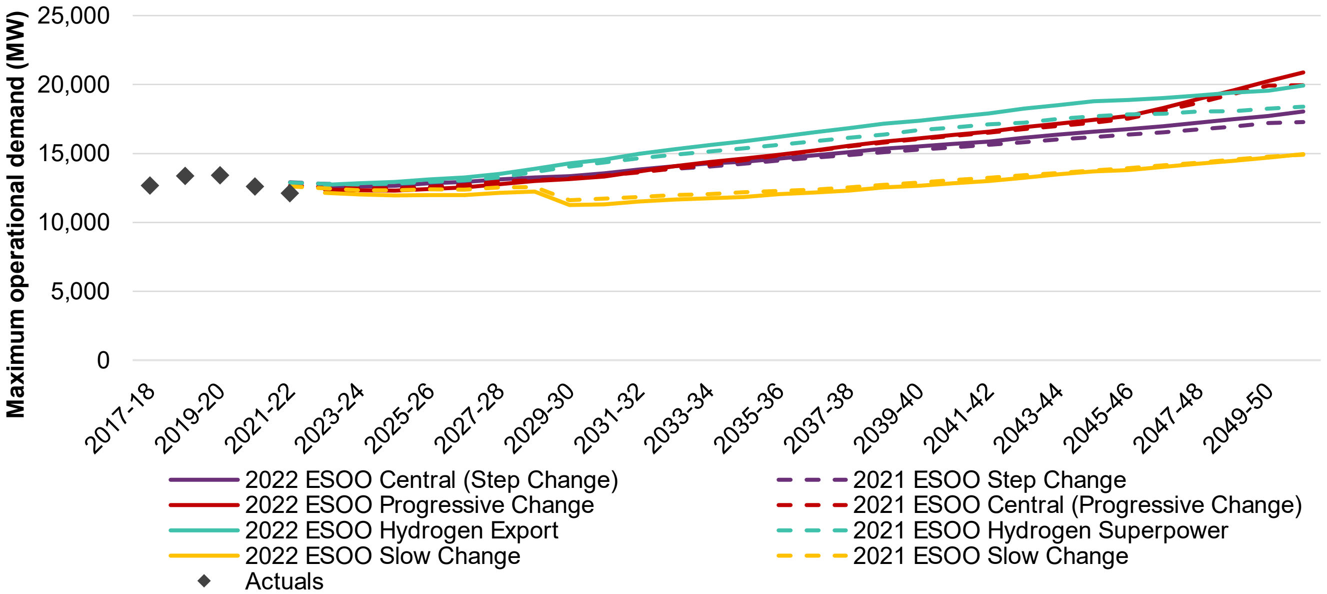
- 2022-23 to 2031-32 (1-10 years):
  - Maximum operational demand is forecast to start at a lower level in 2022-23 than in the 2021 ESOO due to a greater PV generation forecast in all scenarios as well as a lower electrification forecast in the *Slow Change* and *Progressive Change* scenarios[98].
  - Risks of LIL closures result in a reduction in forecast maximum operational demand in the *Slow Change* scenario in 2029-30 in both the 2021 and 2022 ESOO.

[98] The *Slow Change* scenario projects zero electrification growth in both the 2021 ESOO and 2022 ESOO.

  - The LIL forecast is higher in all scenarios compared to the 2021 ESOO.
- 2032-33 to 2041-42 (11-20 years):
  - Maximum operational demand is forecast to grow, with electrification and EVs as the major contributors.
  - All scenarios except *Progressive Change* forecast a higher growth rate in maximum operational demand than in the 2021 ESOO.
- 2042-43 to 2050-51 (21-29 years):
  - While the *Hydrogen Export* scenario projects the highest maximum operational demand across all scenarios in the first two decades, the *Progressive Change* scenario increases its rate of growth from 2046-47 due to an increase in the rate of electrification and is forecast to exceed the *Hydrogen Export* scenario in 2048-49.
  - By 2050-51, electrification (including the contribution from EVs) is forecast to contribute 28% and 23% to the 50% POE maximum operational demand in the *Progressive Change* and *Step Change* scenarios, respectively.

The maximum operational demand forecast represents uncontrolled or unconstrained demand, free of market-based or non-market based solutions that might reduce system load during peak (including RERT, the WDR mechanism, or DSP. No components relating to hydrogen industries are included in the maximum operational demand forecasts presented in **Figure 34**.

Figure 34 Actual and forecast New South Wales 50% POE maximum operational (sent-out) demand, 2022 ESOO all scenarios and 2021 ESOO all scenarios, 2017-18 to 2050-51 (MW)



Note: The actuals displayed are not weather-corrected or adjusted for system events and exclude DSP.

Table 16 shows maximum summer and winter operational demand (sent-out) forecasts for 10% POE and 50% POE for the ESOO Central (*Step Change*) scenario. For both 10% and 50% POE outcomes, the summer forecast remains higher than winter in New South Wales as the cooling demand on extreme summer days is higher than the heating demand on the coldest winter days.

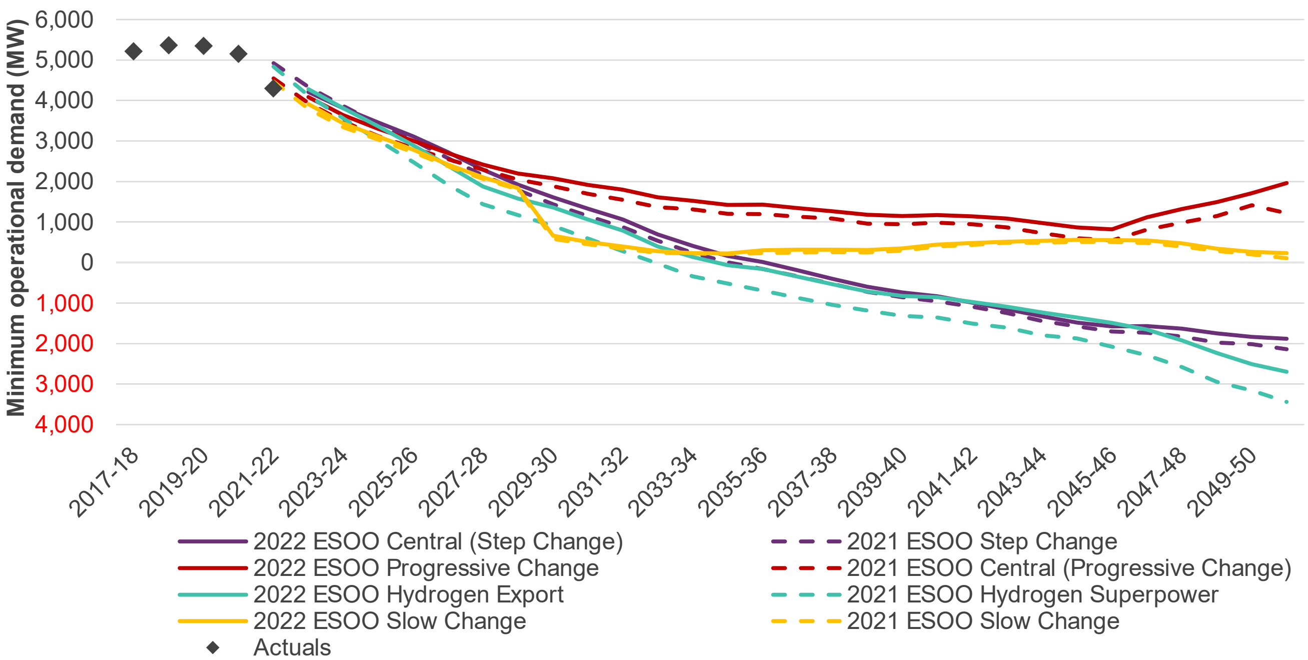
Table 16 New South Wales summer and winter 10% and 50% POE maximum operational (sent-out) demand forecast, ESOO Central scenario, 2022-23 to 2041-42 (MW)

Financial year	Summer		Calendar year	Winter	
	10% POE	50% POE		10% POE	50% POE
2022-23	13,680	12,530	2023	12,732	12,086
2026-27	14,263	12,938	2027	13,489	12,843
2031-32	15,382	13,846	2032	14,464	13,822
2041-42	18,124	15,857	2042	16,275	15,611

Minimum operational demand outlook

Figure 35 shows the actual and forecast 50% POE minimum operational (sent-out) demand (MW) from 2017-18 to 2050-2051 for the 2022 ESOO compared to the 2021 ESOO for all scenarios in New South Wales.

Figure 35 Actual and forecast New South Wales 50% POE minimum operational (sent-out) demand, 2022 ESOO all scenarios and 2021 ESOO all scenarios, 2017-18 to 2050-51 (MW)



Note: The actuals displayed are not weather-corrected or adjusted for system events and exclude DSP.

The key insights from these forecasts are:

- 2022-23 to 2031-32 (1-10 years):
  - Minimum operational demand is forecast to start lower in 2022-23 compared to the 2021 ESOO for the ESOO Central (*Step Change*) scenario due to a reduction in electrification forecast and a marginal increase in distributed PV forecast.
  - Minimum operational demand is forecast to decline rapidly in all scenarios due to uptake of distributed PV.
  - Risks of LIL closures result in a further reduction in forecast minimum operational demand in the *Slow Change* scenario from 2029-30. This is similar to the 2021 ESOO forecast.
  - The time of 50% POE minimum operational demand is forecast to occur in the shoulder season for the duration of the forecast horizon.

- 2032-33 to 2041-42 (11-20 years):
  - Negative minimum operational demand is forecast for the *Hydrogen Export* scenario from 2034-35 and for the *Step Change* scenario from 2036-37.
- 2042-43 to 2050-51 (21-29 years):
  - The *Progressive Change* scenario is expected to revert to trending upwards in 2046-47 as EVs and electrification continue to increase.
  - Compared to the 2021 ESOO, the *Progressive Change*, *Slow Change* and *Hydrogen Export* scenarios forecast a higher minimum operational demand over the 30-year forecast horizon, due to an increase in the expected LIL and underlying demand.

Supply adequacy assessment

Expected changes to existing and committed supply in New South Wales are:

- Between summer 2021-22 and 2022-23, about 263 MW of additional VRE generation is expected to become operational.
- The 254 MW Avonlie Solar Farm, 472 MW New England Solar Farm, 396 MW Rye Park Wind Farm, and 280 MW Wollar Solar Farm are assumed to connect in 2023-24.
- Based on information provided by Snowy Hydro, the Snowy 2.0 project retains its previously advised commissioning schedule of between 2025-26 and 2026-27.
- Energy Australia's 320 MW gas generator Tallawarra B is considered committed*.
- The remaining three units of Liddell are scheduled to retire in April 2023, followed by the 2880 MW Eraring Power Station in August 2025 and Vales Point B Power Station 2029-30.

Figure 36 shows the aggregate impact of generator and storage commissioning and decommissioning assumptions on assumed capacity (or in the case of VRE, availability) during typical summer conditions.

Figure 36 New South Wales assumed capability during typical summer conditions, by generation type, 2021-22 to 2031-32 (MW)

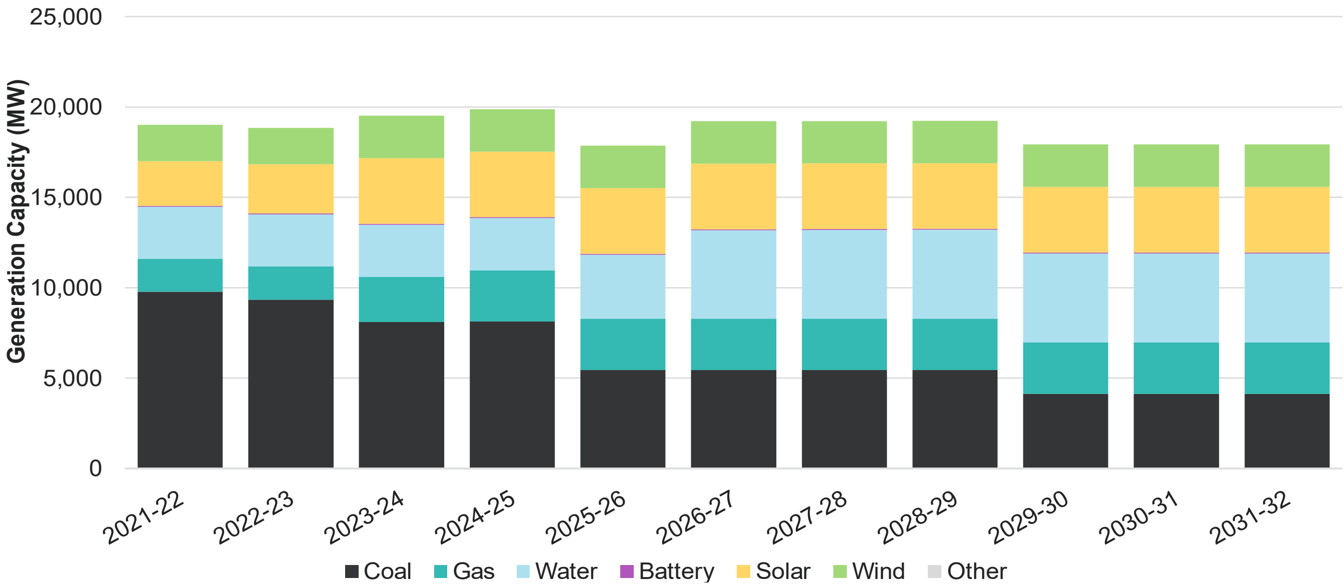


Figure 37 shows forecast USE for New South Wales under the relevant modelled scenarios and sensitivities:

- Low levels of expected USE are forecast under all scenarios before 2025-26, when Eraring Power Station is assumed to retire.
- Under the ESOO Central (*Step Change*) scenario, USE is forecast above the reliability standard from 2025-26 until the end of the modelling horizon.
- Following the retirement of Vales Point Power Station, expected USE increases from 2029-30 to above the reliability standard under all scenarios.
- Under the *Anticipated and actionable* sensitivity, expected USE is forecast lower all other scenarios and sensitivities, due to major network developments and additional new entrants. This sensitivity still projects USE in 2025-26 above the IRM, and after 2029-30 being above the reliability standard however further developments are expected again, as discussed in Section 6.1.

Figure 37 New South Wales expected USE, scenarios and sensitivities, 2022-23 to 2031-32

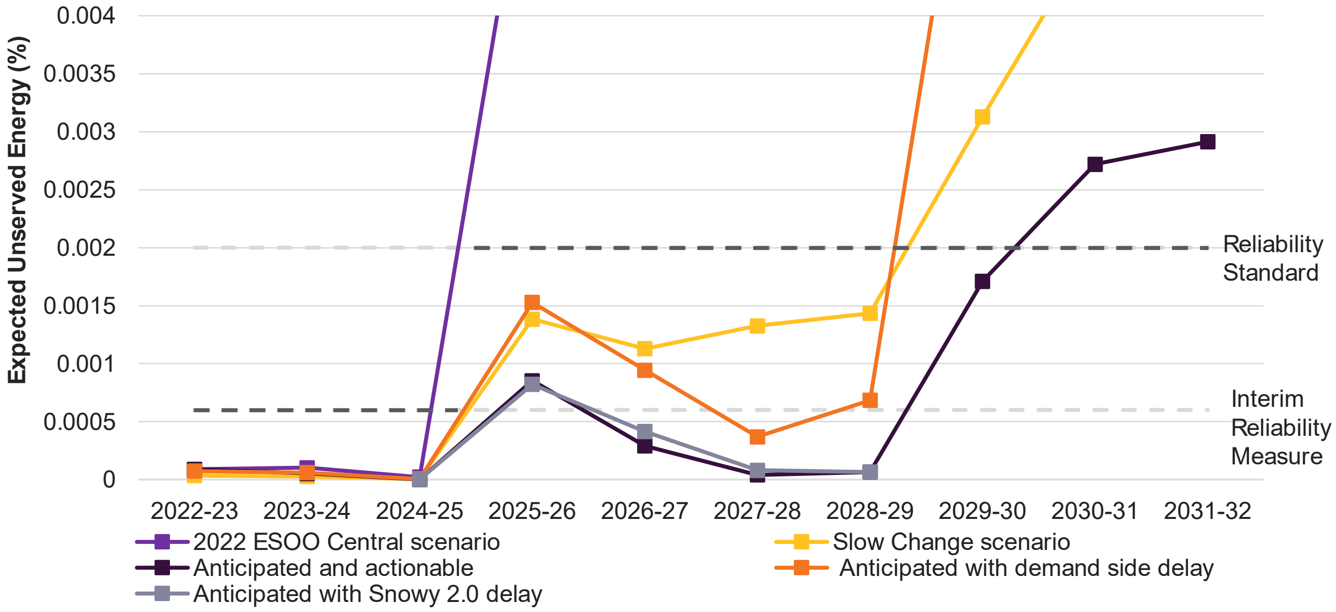
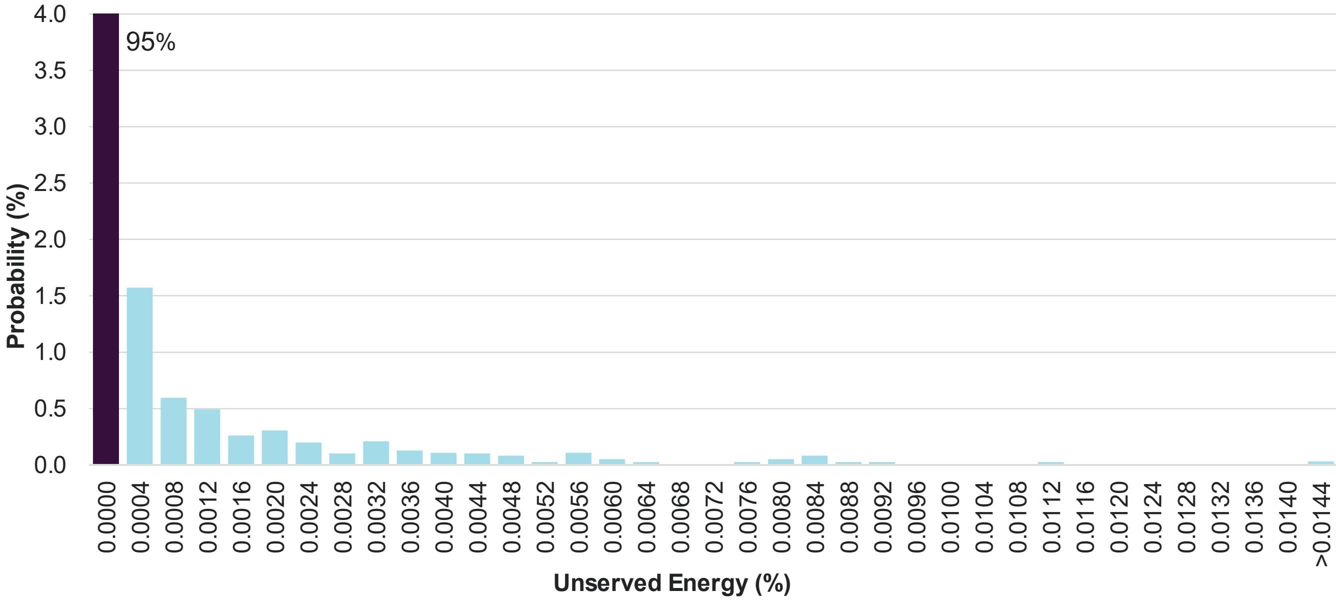


Figure 38 shows the probability density of USE forecast in New South Wales for the 2022-23 summer in the ESOO Central scenario, similar to that described in Section 4.1. It shows that the most likely outcome is that USE does not occur in the coming year (the purple bar in the figure), but that there is a 5% probability of a reliability incident, approximately equivalent with an expectation of one incident every 20 years (the sum of all non-zero USE probabilities shown in the blue bars).

Figure 38 Probability density for forecast USE in New South Wales 2022-23, ESOO Central scenario (%)



A2. Queensland outlook

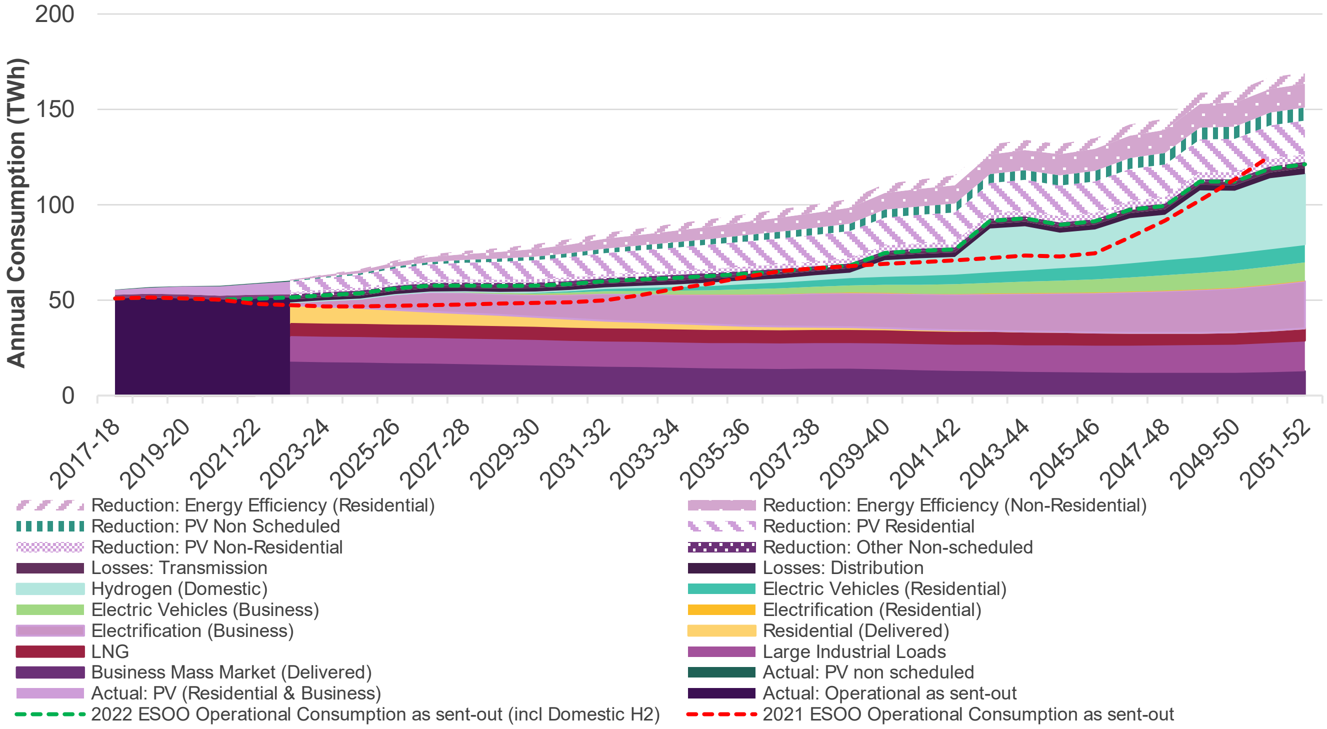
The following sections present, for Queensland:

- Operational consumption, maximum demand, and minimum demand outlooks for all four scenarios to 2051-52.
- Supply adequacy assessments for the next 10 years for the ESOO Central scenario, *Slow Change*, and other sensitivities.

Annual consumption outlook

Figure 39 shows the component forecasts for operational consumption in Queensland under the ESOO Central (*Step Change*) scenario.

Figure 39 Actual and forecast Queensland electricity consumption, ESOO Central scenario, 2017-18 to 2051-52 (TWh)



In this scenario, AEMO forecasts:

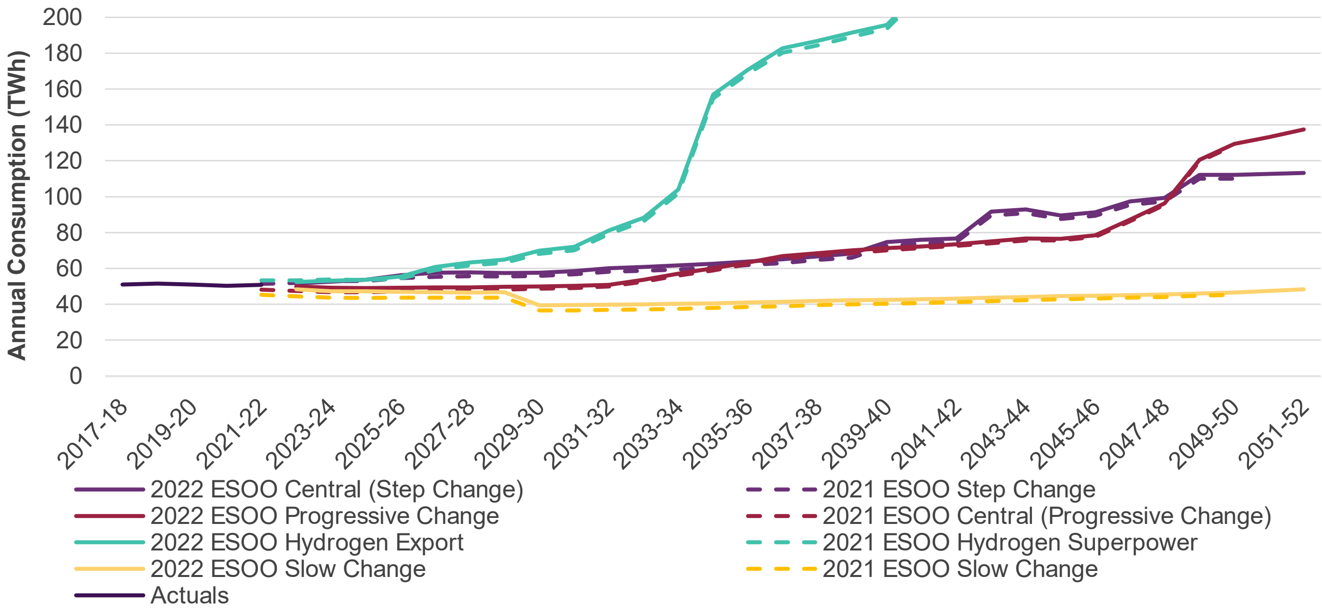
- Short term (1-10 years) – residential consumption starting higher compared to the 2021 ESOO Central scenario, an outcome due in part to the shift in Central scenario definition to *Step Change* in the 2022 ESOO and an improved allocation of historical consumption between the residential and business sectors. Strong growth of distributed PV rapidly lowers residential consumption, and more moderately impacts business consumption by the end of this period. This is coupled with generally stable LIL and LNG forecasts.

- Medium term (11-20 years) – consumption growing strongly due to growth in electrification from the transport and the business sectors, despite continuing growth in distributed PV and energy efficiency. In the case of the residential sector, growth in distributed PV almost entirely offsets consumption growth.
- Long term (21-30 years) – similar growth trends continue from the preceding decade, with strongly growing consumption from the mid-2040s with the emergence of hydrogen production for domestic usage.

Figure 40 shows the consumption forecast across the scenarios, highlighting:

- Under *Progressive Change*, electrification increasing from 2032-33, with a significant uptick taking place in the mid-2040s.
- Electrification and hydrogen production for domestic and, in particular, export purposes dominates the strong growth trajectory presented in *Hydrogen Export*.
- *Slow Change*, with LIL closure risks, short-term rapid distributed PV growth and limited electrification, has the lowest consumption of the scenarios.

Figure 40 Actual and forecast Queensland operational consumption, all scenarios, 2013-14 to 2051-52 (TWh)



Note: *Hydrogen Export* continues beyond the chart to reach approximately 720 TWh in 2051-52.

Maximum operational demand outlook

Figure 41 shows actual and forecast 50% POE maximum operational (sent-out) demand (MW) from 2017-18 to 2050-51 for the 2022 ESOO compared to the 2021 ESOO for all scenarios in Queensland.

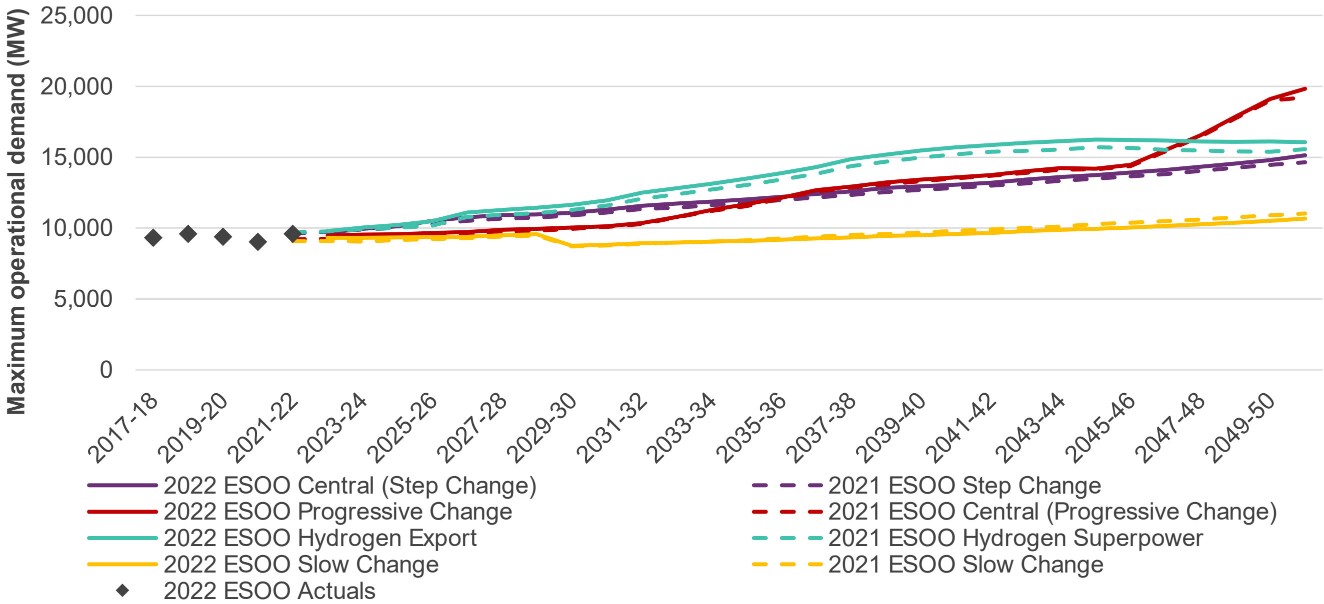
The key insights are:

- 2022-23 to 2031-32 (1-10 years):
  - Maximum operational demand is forecast to start at similar levels in 2022-23 as in the 2021 ESOO for the *Step Change* and *Hydrogen Export* scenarios. The *Progressive Change* and *Slow Change* scenarios will start marginally higher due to greater contributions from LILs and underlying demand.

- Maximum operational demand is forecast to increase in the *Step Change* and *Hydrogen Export* scenarios due to growth in electrification. The *Progressive Change* and *Slow Change* scenarios show milder growth.
- Risks of LIL closures result in a reduction in forecast maximum operational demand in the *Slow Change* scenario from 2029-30 onwards.
- All scenarios are forecast to be generally higher than the 2021 ESOO, with electrification being the key driver for the *Step Change* and *Hydrogen Export* scenarios.

- 2032-33 to 2041-42 (11-20 years):
  - Maximum operational demand is forecast to continue growing, with electrification continuing to be a major contributor in all scenarios except *Slow Change*.
- 2042-43 to 2050-51 (21-29 years):
  - Maximum operational demand is expected to see continual growth in all scenarios, with *Hydrogen Export* flattening out from 2044-45 due to a projected reduction in electrification.
  - The *Progressive Change* scenario sharply rises from 2046-47 due to a large forecast growth in electrification.

Figure 41 Actual and forecast Queensland 50% POE maximum operational (sent-out) demand, 2022 ESOO all scenarios and 2021 ESOO all scenarios, 2017-18 to 2050-51 (MW)



Note: The actuals displayed are not weather-corrected or adjusted for system events and exclude DSP.

The maximum operational demand forecast represents uncontrolled or unconstrained demand, free of market based or non-market based solutions that might reduce system load during peak (including RERT, the WDR mechanism, or DSP). No components relating to hydrogen industries are included in the maximum operational demand forecasts presented here.

Table 17 shows maximum summer and winter operational demand (sent out) forecasts for 10% POE and 50% POE for the *Step Change* scenario. Maximum operational demand in Queensland is forecast to keep occurring in summer over the forecast horizon.

Table 17 Forecast maximum operational demand (sent out) in Queensland, *Step Change* scenario (MW)

Financial year	Summer		Calendar year	Winter	
	10% POE	50% POE		10% POE	50% POE
2022-23	10,099	9,664	2023	8,547	8,223
2026-27	11,193	10,749	2027	9,642	9,326
2031-32	11,970	11,563	2032	10,456	10,145
2041-42	13,729	13,198	2042	12,070	11,749

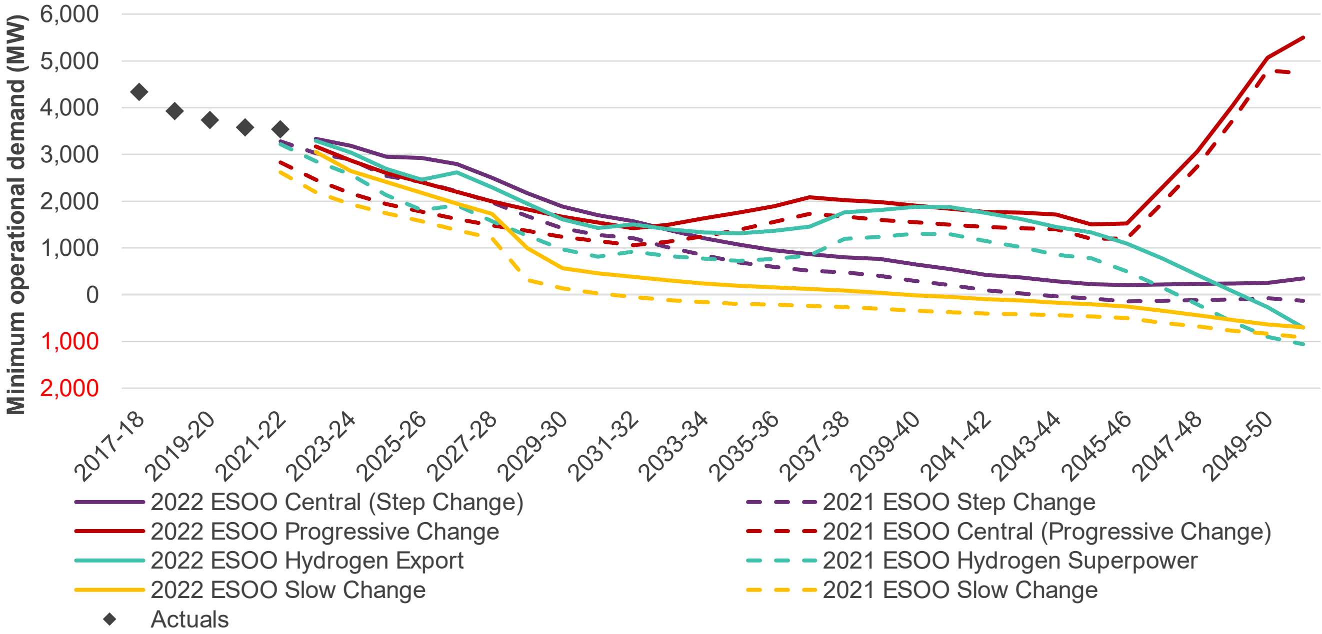
Minimum operational demand outlook

Figure 42 shows actual and forecast 50% POE minimum operational (sent-out) demand (MW) from 2017-18 to 2050-51 for the 2022 ESOO compared to the 2021 ESOO for all scenarios in Queensland.

The key insights are:

- 2022-23 to 2031-32 (1-10 years):
  - Minimum operational demand is forecast to start higher than the 2021 ESOO forecasts due to higher LILs. The minimum demand distribution for Queensland has been revised upwards reflecting recent observations of consumer behaviour. As **Figure 42** shows, the 2022 ESOO forecasts align better with history than the 2021 ESOO forecasts.
  - Minimum operational demand is forecast to decrease rapidly due to forecast uptake of distributed PV across all scenarios.
  - Risks of LIL closures result in a further reduction in forecast minimum operational demand in the *Slow Change* scenario from 2029-30.
  - The 50% POE minimum operational demand is forecast to occur in winter until 2026-27 for the *Step Change* scenario, then to switch to the shoulder season. A similar transition is forecast to occur in 2023-24 for the *Progressive Change* and *Slow Change* scenarios and 2028-29 for the *Hydrogen Export* scenario.
- 2032-33 to 2041-42 (11-20 years):
  - Minimum operational demand is forecast to continue to decrease in the *Step Change* and *Slow Change* scenarios. The *Progressive Change* and *Hydrogen Export* scenarios are expected to begin trending upwards as EVs, behind-the-meter batteries and electrification increase.
  - Negative minimum operational demand is forecast for the *Slow Change* scenario from 2040-41 onwards
- 2042-43 to 2050-51 (21-29 years):
  - Minimum operational demand is forecast to decline in all scenarios except the *Progressive Change* scenario, which increases from 2046-47 due to a large projected growth in electrification.
  - Minimum operational demand for the *Hydrogen Export* scenario reverts to trending downwards.
  - Negative minimum operational demand is forecast for the *Slow Change* and *Hydrogen Export* scenarios from 2045-46 and 2050-51 respectively.

Figure 42 Actual and forecast Queensland 50% POE minimum operational (sent-out) demand, 2022 ESOO all scenarios and 2021 ESOO all scenarios, 2017-18 to 2050-51 (MW)



Note: The actuals displayed are not weather-corrected or adjusted for system events and exclude DSP.

Supply adequacy assessment

Expected changes to existing and committed supply include:

- Between summer 2021-22 and 2022-23, 469 MW of additional VRE generation is expected to become operational.
- The 173 MW Dulacca Wind Farm, 180 MW Edenvale Solar Park, and 160 MW Wandoan South Solar Stage 1 are assumed to connect in 2023-24, followed by the expected connection of 450 MW Clarke Creek Wind Farm in 2024.
- The 420 MW Callide C unit 4 remains on extended outage with expected return to service before winter 2023.
- The 700 MW Callide B Power Station is scheduled to retire in 2028-29.

Figure 43 shows the aggregate impact of generator and storage commissioning and decommissioning assumptions.

Figure 43 Queensland assumed capability during typical summer conditions, by generation type, 2021-22 to 2031-32 (MW)

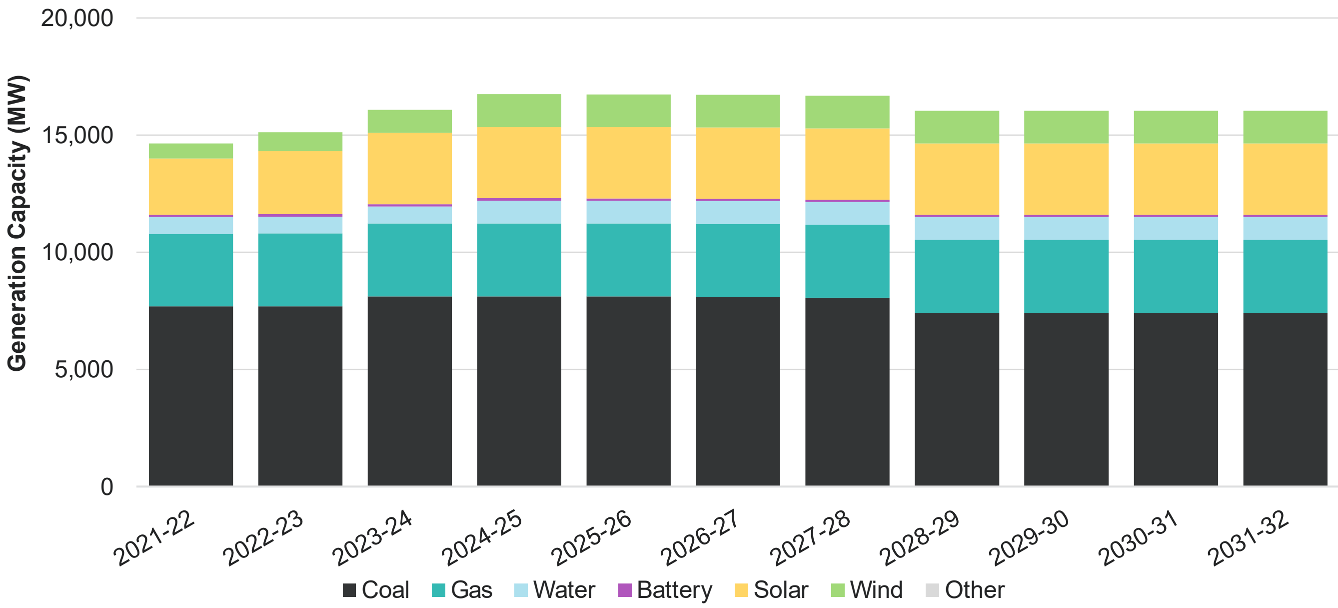
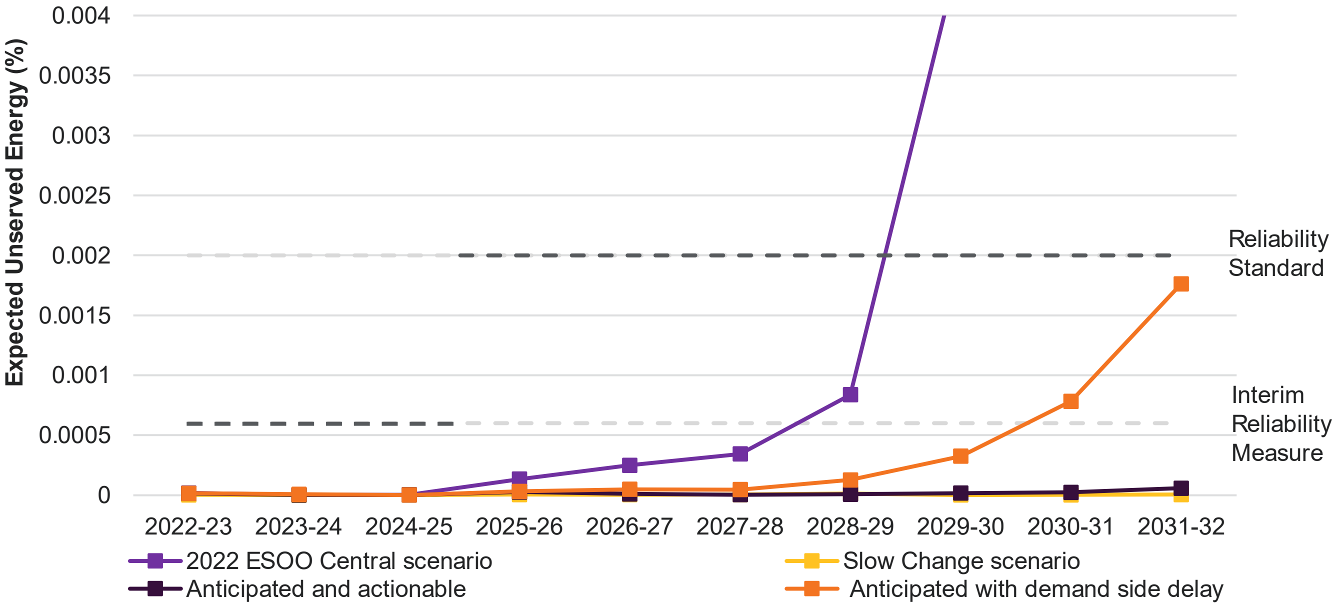


Figure 44 shows the forecast USE for Queensland under the relevant modelled scenarios and sensitivities.

Figure 44 Queensland expected USE, scenarios and sensitivities, 2022-23 to 2031-32



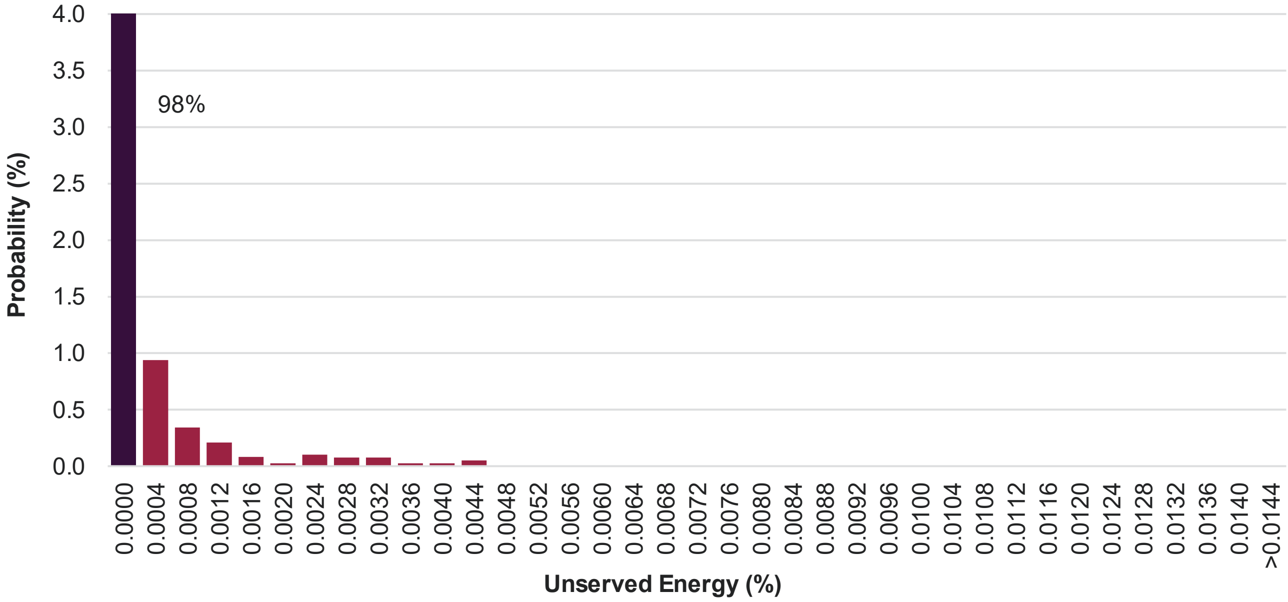
It highlights that:

- Forecast USE in the ESOO Central scenario remains below the IRM until 2028-29, after which expected USE is above the IRM, mainly due to retirements in other regions. In 2029-30, expected USE rises to above the reliability standard due to:
  - The influence of limited supply sharing available from New South Wales after retirements in that region, and

  - The retirement of Callide B Power Station.
- In the *Anticipated and actionable* sensitivity, and the *Slow Change* scenario, negligible USE is forecast in Queensland.
- Under the *Anticipated with demand side delay* sensitivity, USE is forecast to remain low until the retirement of Callide B Power Station. In the final two years of this sensitivity, USE is forecast to be above the IRM but below the reliability standard.

Figure 45 shows the probability density of USE forecast in Queensland for the 2022-23 summer in the ESOO Central scenario, similar to that described in Section 4.1. It shows that the most likely outcome is that USE does not occur in the coming year (the purple bar), but that there is a 2% probability of a reliability incident, approximately equivalent with an expectation of one incident every 50 years (the sum of all non-zero USE probabilities shown in the maroon bars).

Figure 45 Probability density for forecast USE in Queensland 2022-23, ESOO Central scenario (%)



A3. South Australia outlook

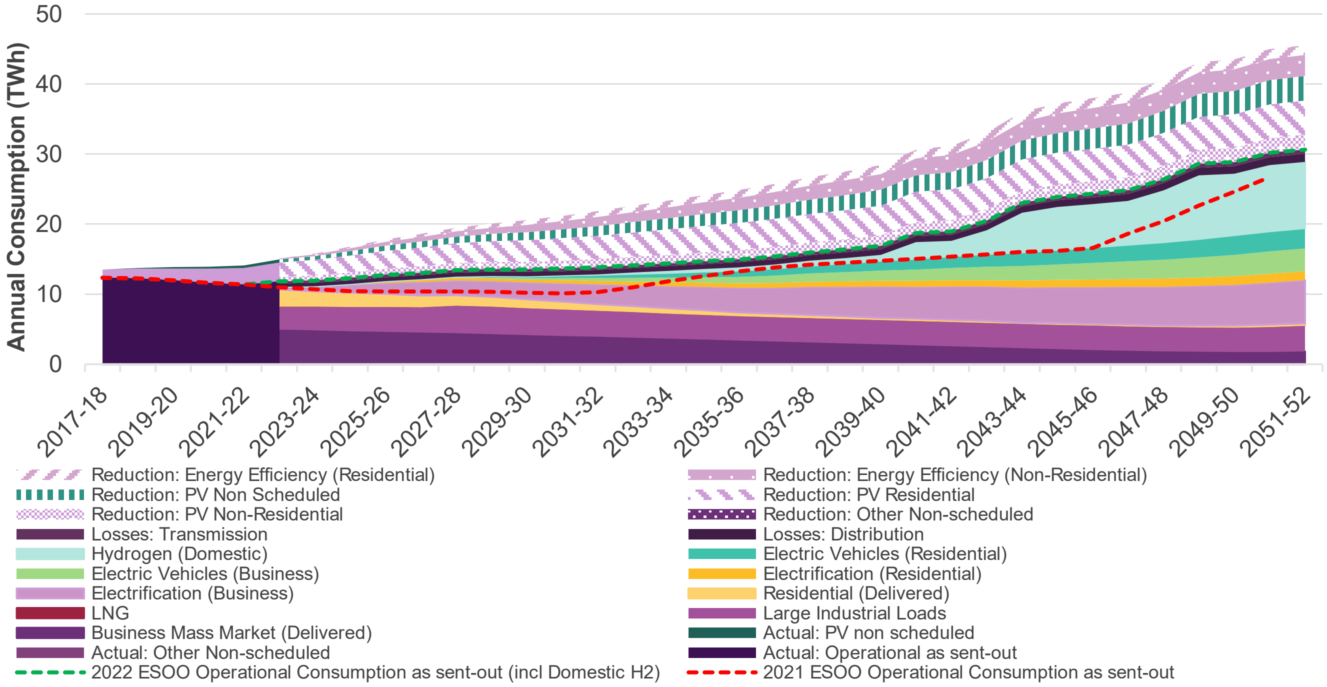
The following sections present, for South Australia:

- Operational consumption, maximum demand, and minimum demand outlooks for all four scenarios to 2051-52.
- Supply adequacy assessments for the next 10 years, for the ESOO Central scenario, *Slow Change*, and other sensitivities.

Annual consumption outlook

Figure 46 shows the component forecasts for operational consumption in South Australia under the ESOO Central (*Step Change*) scenario.

Figure 46 Actual and forecast South Australia electricity consumption, ESOO Central scenario, 2017-18 to 2051-52 (TWh)



In this scenario, AEMO forecasts:

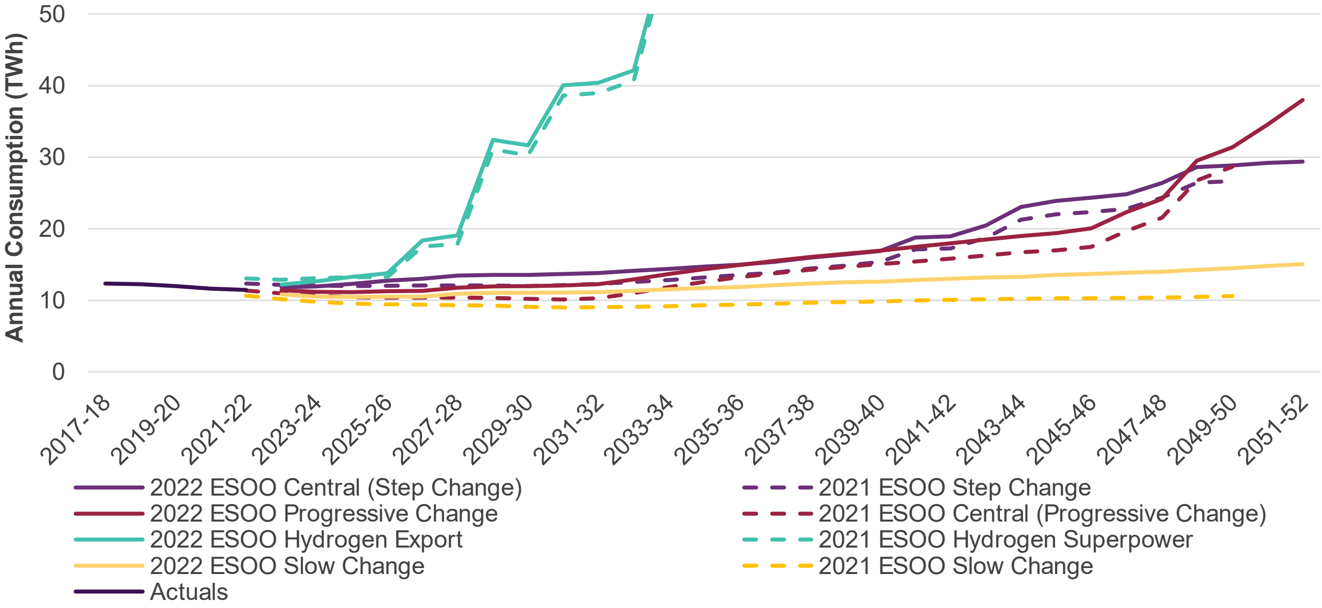
- Short term (1-10 years) – continued strong growth of distributed PV and energy efficiency, resulting in lower residential and BMM sector consumption. This is offset by a significant increase in the LIL forecast from 2027-28 compared to the *Update to the 2021 ESOO*, due to information about expansion in production provided by LIL operators for the 2022 ESOO.
- Medium term (11-20 years) – consumption growing strongly due to electrification growth from the transport, business and residential sectors, despite continuing growth in distributed PV and energy efficiency offsetting increases in BMM and residential delivered energy, and a reduction in the LIL forecast to 2035-36.

- Long term (21-30 years) – similar growth trends continuing from the preceding decade, with continued increase of electrification (including the contribution from EVs), and strongly growing consumption as hydrogen production for domestic usage emerges.

Figure 47 shows forecasts across the scenarios, highlighting that:

- Under *Progressive Change*, electrification is forecast to increase from 2032-33, with a significant lift in the mid-2040s.
- Hydrogen production for domestic and, in particular, export purposes dominates the growth trajectory of the *Hydrogen Export* scenario.
- *Slow Change*, with LIL closure risks, short-term rapid distributed PV growth, and limited electrification, sees it as the lowest scenario in consumption terms.

Figure 47 Actual and forecast South Australia operational consumption, all scenarios, 2017-18 to 2051-52 (TWh)

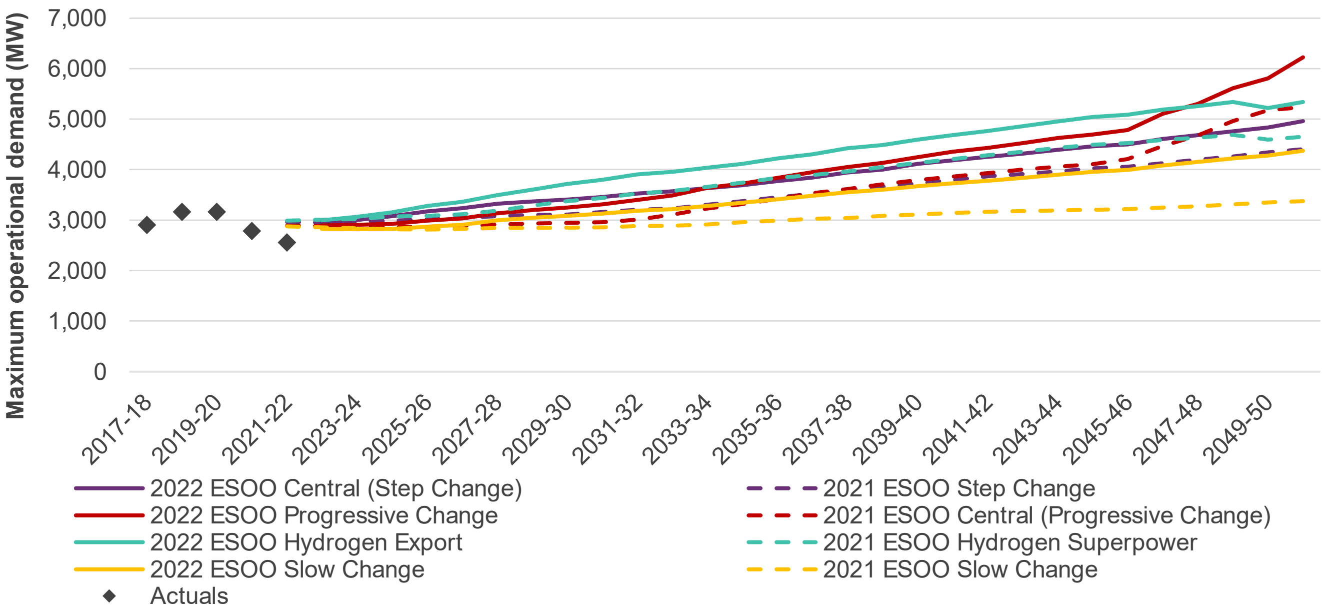


Note: *Hydrogen Export* continues beyond the chart to reach approximately 275 TWh in 2051-52.

Maximum operational demand outlook

Figure 48 shows actual and forecast 50% POE maximum operational (sent-out) demand (MW) from 2017-18 to 2050-51 for the 2022 ESOO compared to the 2021 ESOO for all scenarios in South Australia.

Figure 48 Actual and forecast South Australia 50% POE maximum operational (sent-out) demand, 2022 ESOO all scenarios and 2021 ESOO all scenarios, 2017-18 to 2050-51 (MW)



Note: The actuals displayed are not weather-corrected or adjusted for system events and exclude DSP.

The key insights are:

- 2022-23 to 2031-32 (1-10 years):
  - Maximum operational demand is forecast to start at very similar levels in 2022-23 as the 2021 ESOO for all scenarios.
  - Maximum operational demand is forecast to be higher from 2023-24 onwards than the 2021 ESOO, due to projected expansion in LILs and other drivers affecting underlying demand later in the decade.
  - Maximum operational demand is forecast to increase for all scenarios, due to increasing underlying demand as well as EVs and electrification in the second half of the decade.
- 2032-33 to 2041-42 (11-20 years):
  - Maximum operational demand is forecast to continue to increase due to growth in underlying demand, and EVs and electrification.
  - LILs are forecast to remain relatively flat throughout this period.
- 2042-43 to 2050-51 (21-29 years):
  - Maximum operational demand is forecast to grow for all scenarios. The *Progressive Change* scenario increases its rate of growth from 2046-47 due to an increase in the projected rate of electrification.
  - By 2050-51, EVs and electrification together are forecast to contribute 38% to the 50% POE maximum operational demand in the *Progressive Change* scenario, the highest contribution of all scenarios.

The maximum operational demand forecast represents uncontrolled or unconstrained demand, free of market-based or non-market based solutions that might reduce system load during peak (including RERT, the WDR mechanism, or DSP). No components relating to hydrogen industries are included in the maximum operational demand forecasts presented here.

Table 18 shows maximum summer and winter operational demand (sent out) forecasts for 10% POE and 50% POE for the ESOO Central (*Step Change*) scenario. Maximum operational demand in South Australia is forecast to continue occurring in the summer season over the forecast horizon.

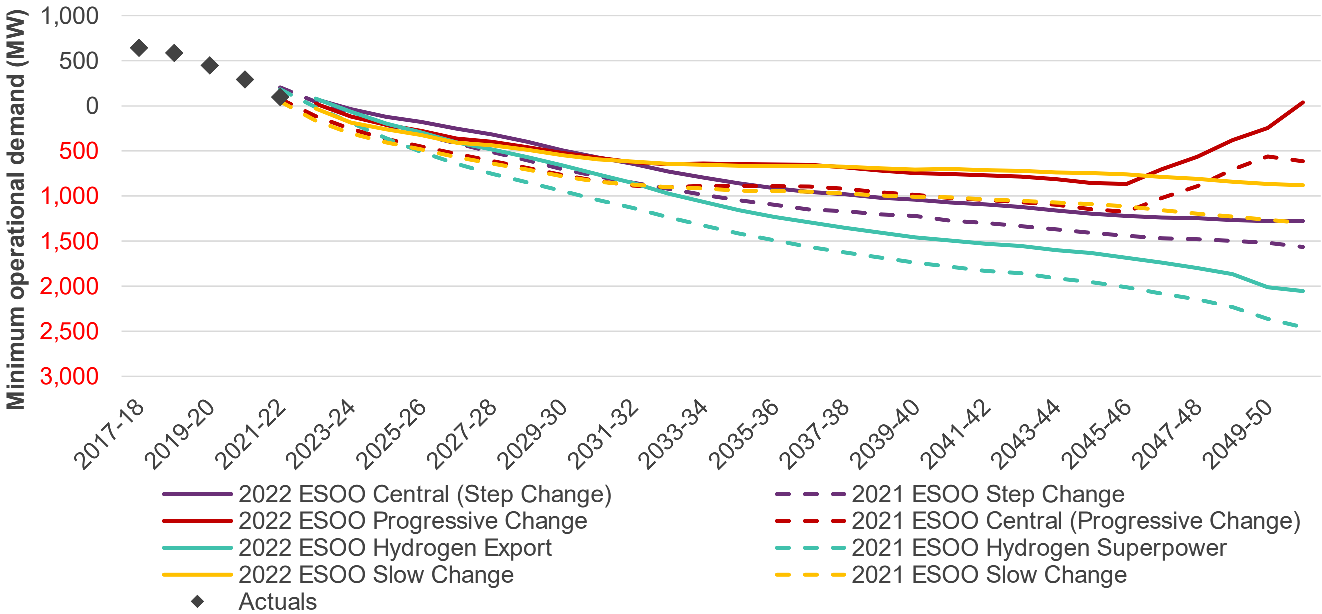
Table 18 South Australia summer and winter 10% and 50% POE maximum operational (sent-out) demand forecast, ESOO Central scenario (MW)

Financial year	Summer		Calendar year	Winter	
	10% POE	50% POE		10% POE	50% POE
2022-23	3,284	2,944	2023	2,695	2,589
2026-27	3,585	3,235	2027	3,063	2,954
2031-32	3,894	3,529	2032	3,358	3,242
2041-42	4,652	4,253	2042	4,070	3,939

Minimum operational demand outlook

Figure 49 shows actual and forecast 50% POE minimum operational (sent-out) demand (MW) from 2017-18 to 2050-51 for the 2022 ESOO compared to the 2021 ESOO for all scenarios in South Australia.

Figure 49 Actual and forecast South Australia 50% POE minimum operational (sent-out) demand, 2022 ESOO all scenarios and 2021 ESOO all scenarios, 2017-18 to 2050-51 (MW)



Note: The actuals displayed are not weather-corrected or adjusted for system events and exclude DSP.

The key insights are:

- 2022-23 to 2031-32 (1-10 years):
  - Minimum operational demand is forecast to start higher in 2022-23 than in the 2021 ESOO for all scenarios, due to higher underlying demand, including an expansion in LILs and a slightly lower contribution from distributed PV, being partly offset by a reduction in electrification.
  - Maximum operation demand is forecast to be higher for all scenarios than the 2021 ESOO due to higher LILs and lower distributed PV, partly offset by a reduction in electrification in the first half of the decade.

   - The uptake of distributed PV is a key driver in the rate of decline affecting all scenarios. By 2023-24, all scenarios are forecast to become negative for the 50% POE minimum operational demand.
- 2032-33 to 2041-42 (11-20 years):
   - Minimum operational demand is forecast to continue to decline for all scenarios. The *Progressive Change* and *Slow Change* scenarios decline at a much slower rate due to lower projected uptake of distributed PV.
   - EVs and electrification are forecast to continue increasing and applying upwards pressure on minimum operational demand, in part offsetting the uptake of distributed PV.
- 2042-43 to 2050-51 (21-29 years):
   - Minimum operational demand is forecast to continue to decline in all scenarios except *Progressive Change*. The *Progressive Change* scenario initially declines, before increasing after 2045-46 due to a significant increase in the projected rate of electrification.

Supply adequacy assessment

Expected changes to existing and committed supply include:

- Between summer 2021-22 and 2022-23, 457 MW of additional VRE generation is expected to become operational – predominantly with the commissioning of the wind and solar facilities at the Port Augusta Renewable Energy Park – as measured in summer typical capacity.
- The 105 MW Tailem Bend Stage 2 Solar Project is assumed to connect in 2023-24, followed by the expected connection of 12 MW Mannum Adelaide Pumping Station No 3 - MAPL3 (Tungkillo) in 2024-25.
- The 120 MW Torrens Island A Unit 3 is mothballed until it is scheduled to retire in September 2022.
- One Torrens Island B unit (200 MW) is currently mothballed, but is due to return to service in summer 2024-25.
- The 90 MW Mintaro Power Station has advised an expected return to service date of January 2023.
- The 180 MW Osborne gas generator is scheduled for retirement in December 2023, followed by numerous gas generators (total 383 MW) in 2030, including Dry Creek, Mintaro, Port Lincoln and Snuggery power stations.

Figure 50 shows the aggregate impact of generator and storage commissioning and decommissioning assumptions.

Figure 50 South Australia assumed capability during typical summer conditions, by generation type, 2021-22 to 2031-32 (MW)

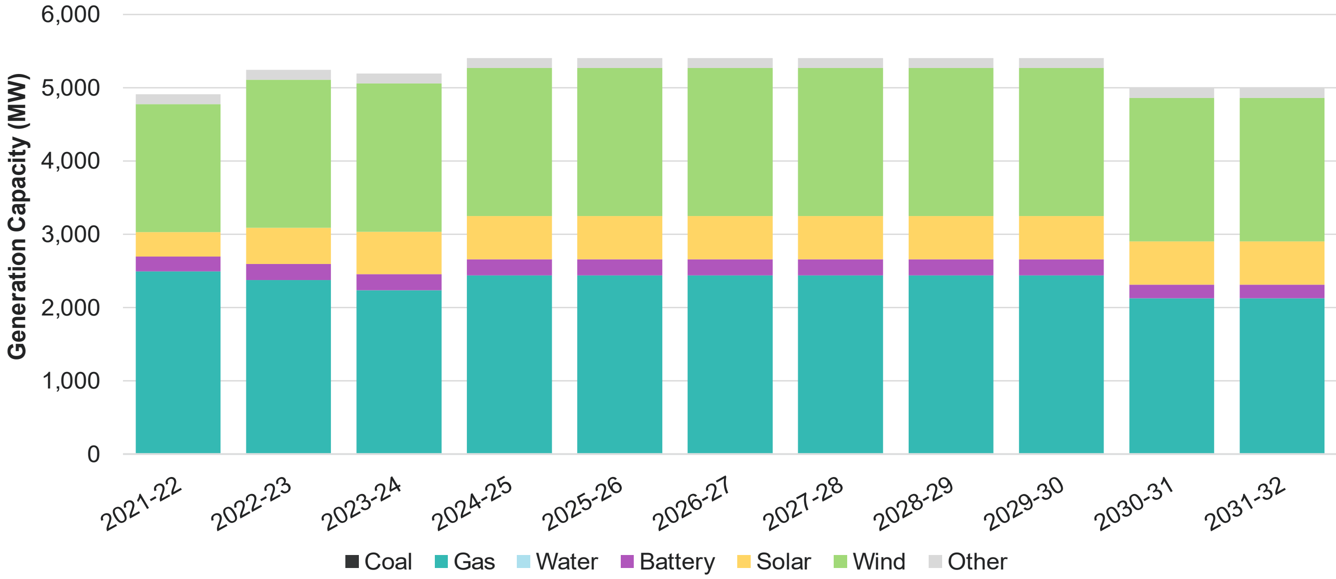


Figure 51 shows forecast USE for South Australia under the relevant modelled scenarios and sensitivities:

- The ESOO Central (*Step Change*) scenario projects USE greater than the IRM in 2023-24 and then again in 2030-31, before breaching the reliability standard from 2031-32.
- Expected USE is forecast above the IRM again in 2024-25 under the *Torrens Island B1 return delay* sensitivity.
- In the *Slow Change* scenario and *Anticipated and actionable* sensitivity, expected USE remains below both the reliability standard and the IRM during the 2022 ESOO modelling horizon.
- Besides the ESOO Central scenario, the *Anticipated with demand side delay* sensitivity is the only other forecast where expected USE is greater than the reliability standard in 2031-32.

Figure 51 South Australia expected USE, scenarios and sensitivities, 2022-23-2031-32 (%)

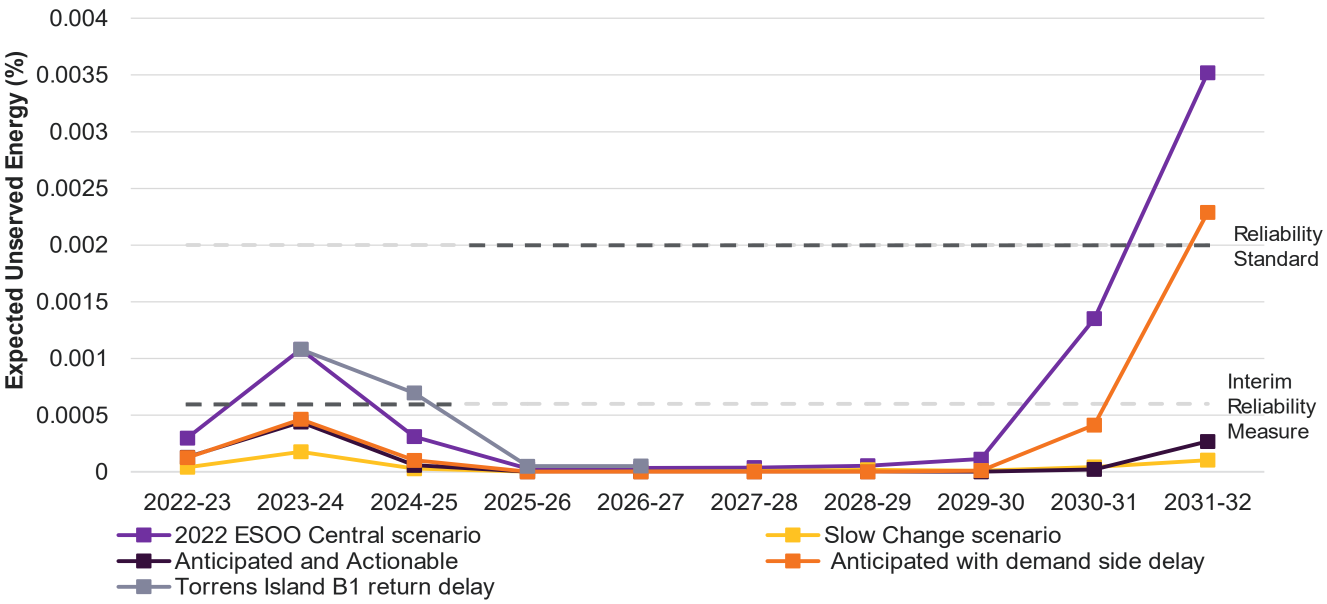
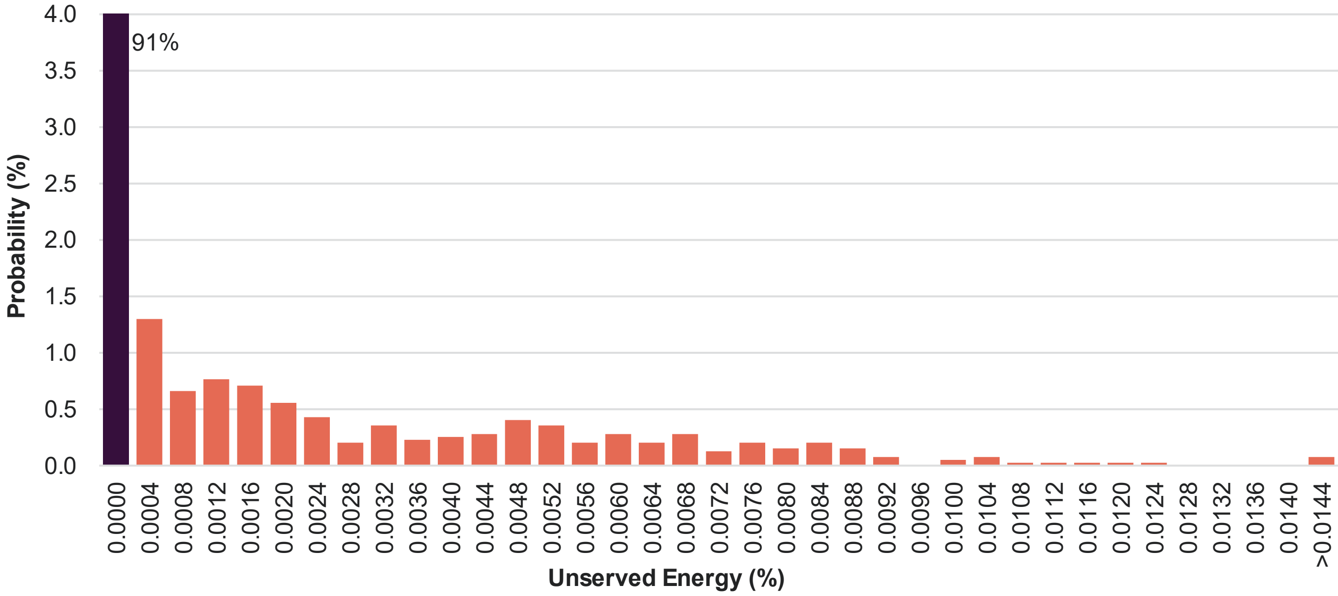


Figure 52 shows the probability density of USE forecast in South Australia for the 2022-23 summer in the ESOO Central scenario, similar to that described in Section 4.1. It shows that the most likely outcome is that USE does not occur in the coming year (the purple bar), but that there is a 9% probability of a reliability incident, approximately equivalent with an expectation of one incident every 11 years (the sum of all non-zero USE probabilities shown in the orange bars).

Figure 52 Probability density for forecast USE in South Australia 2022-23, ESOO Central scenario (%)



A4. Tasmania outlook

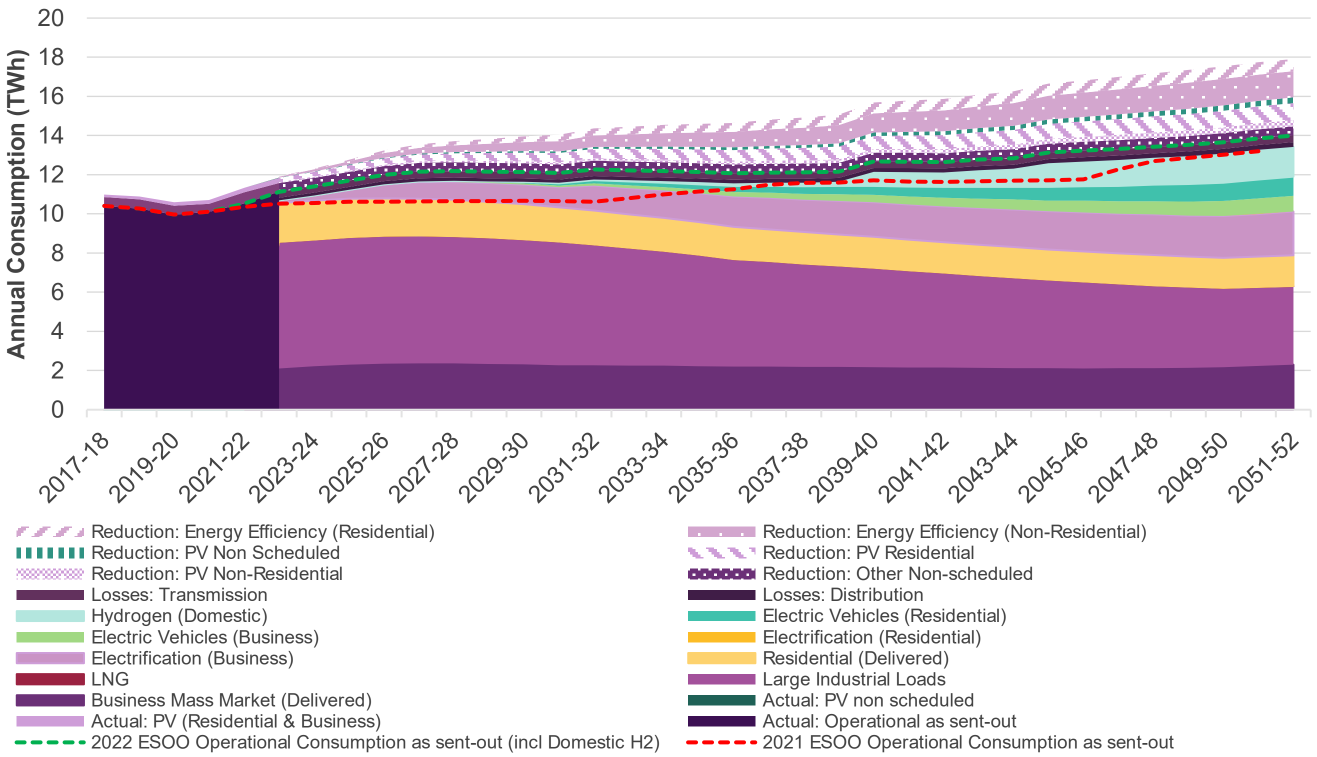
The following sections present, for Tasmania:

- Operational consumption, maximum demand, and minimum demand outlooks for all four scenarios to 2051-52.
- Supply adequacy assessments for the next 10 years, for the ESOO Central scenario, *Slow Change*, and other sensitivities.

Annual consumption outlook

Figure 53 shows the component forecasts for operational consumption in Tasmania under the ESOO Central (*Step Change*) scenario.

Figure 53 Actual and forecast Tasmania electricity consumption, ESOO Central scenario, 2017-18 to 2051-52 (TWh)



In this scenario, AEMO forecasts:

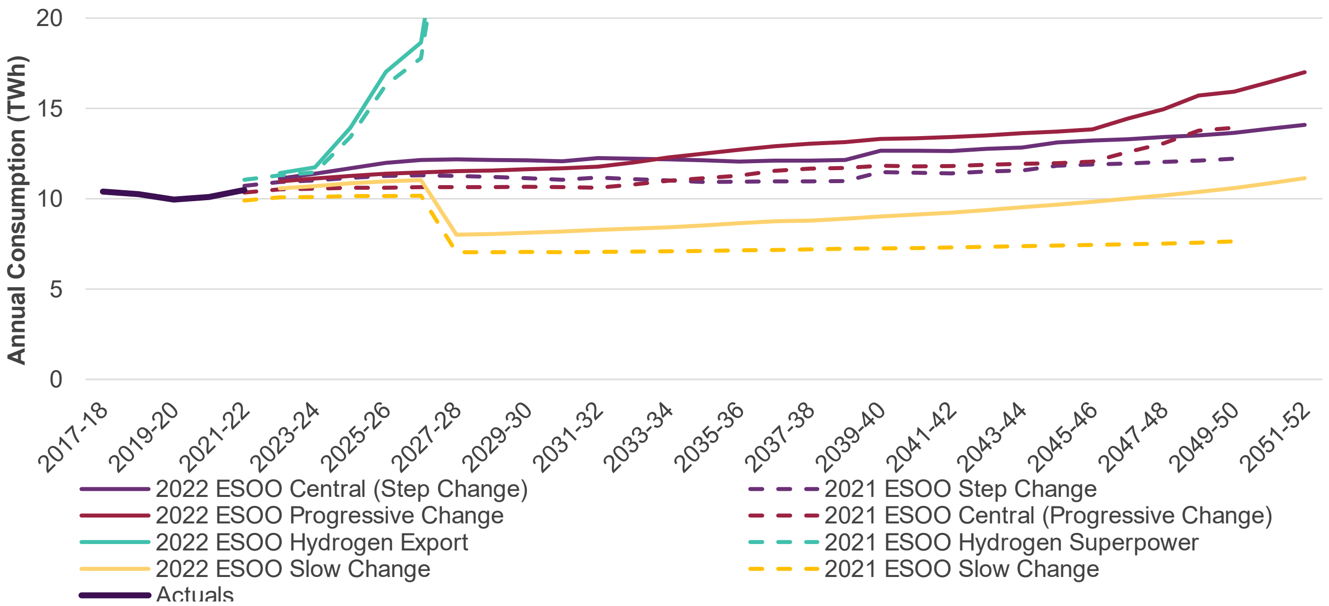
- Short term (1-10 years) – BMM consumption starting higher than in the 2021 ESOO, due to an improved allocation of historical consumption between the residential and business sectors. The revised approach identifies a growth trend for BMM underlying consumption in Tasmania, likely from increased data centre load and electrification of the business sector, which is partially offset by business energy efficiency. Distributed PV and residential energy efficiency partially offset underlying residential consumption growth.

- Medium term (11-20 years) – electrification growth from the transport and business sectors increasing consumption, partially offset by business and residential energy efficiency as well as declining LIL consumption.
- Long term (21-30 years) – similar growth trends continuing from the preceding decade, with strong consumption growth driven by electrification in the business and transport sectors and significant growth of hydrogen production for domestic usage from the early 2040s, partially offset by continued reductions in LILs.

Figure 54 shows forecasts across the scenarios, highlighting that:

- The source of growth under *Progressive Change* comes from projected electrification of the business sector.
- Hydrogen production for domestic and, in particular, export purposes, as well as electrification, is forecast to complement existing LILs under *Hydrogen Export*, potentially replacing activities that decline.
- *Slow Change*, which assumes LIL closure risks and limited electrification, has the lowest forecast consumption of the scenarios.

Figure 54 Actual and forecast Tasmania operational consumption, 2022 ESOO all scenarios and 2021 ESOO all scenarios, 2017-18 to 2050-51 (TWh)



Note: *Hydrogen Export* continues beyond the chart to reach approximately 210 TWh in 2051-52.

Maximum operational demand outlook

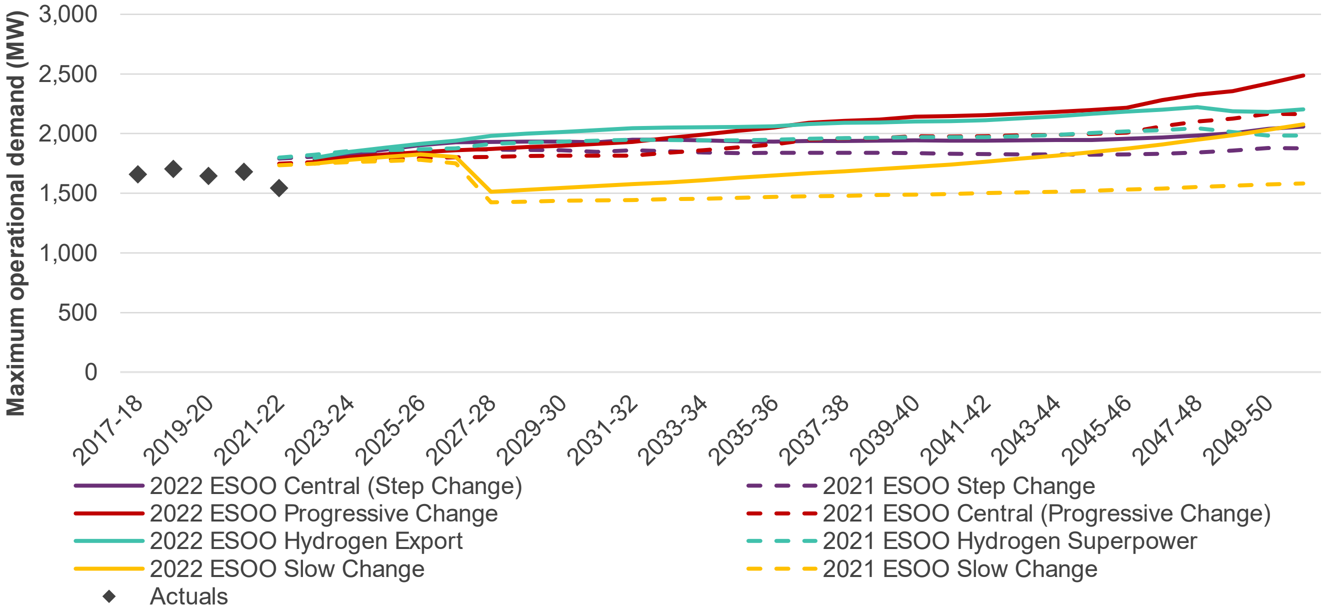
Figure 55 shows the component forecasts for operational consumption in Tasmania under the ESOO Central (*Step Change*) scenario.

The key insights are:

- 2022-23 to 2031-32 (1-10 years):
  - Maximum operational demand is forecast to start higher in 2023 than in the 2021 ESOO for all scenarios, due to an increase in underlying demand offset in part by lower heating load and LILs.
  - All scenarios are forecast to be higher than the 2021 ESOO due to increases in underlying demand.

  - Maximum operation demand is projected to increase in all scenarios except *Slow Change*, due to growth in EVs and electrification, particularly in the ESOO Central (*Step Change*) and *Hydrogen Export* scenarios.
  - Maximum operation demand is forecast to flatten out in the ESOO Central scenario from 2026-27 as the rate of growth in electrification is projected to slow.
  - In the *Slow Change* scenario, maximum operational demand is projected to increase before risks of LIL closures result in a reduction in 2027-28, then it is forecast to continue growing.
- 2032-33 to 2041-42 (11-20 years):
  - While maximum operational demand is forecast to remain relatively flat in the ESOO Central scenario, it is projected to slightly increase in all other scenarios. Forecast increases in EVs and electrification are largely offset by projected reductions in LILs.
- 2042-43 to 2050-51 (21-29 years):
  - Maximum operational demand is forecast to continually grow in all scenarios, with the *Hydrogen Export* scenario flattening out from 2048-49. Projected growth in underlying demand is influenced by growth in EVs and electrification, slightly offset by a forecast reduction in LILs.
  - EVs are expected to contribute around 8% of 50% POE maximum operational demand by 2042-43, and only grow to 9% by 2050-51 in the ESOO Central scenario. This is the lowest forecast proportion of the NEM regions, because industrial load represents higher proportions of maximum operational demand in Tasmania.

Figure 55 Actual and forecast Tasmania 50% POE maximum operational (sent-out) demand, 2022 ESOO all scenarios and 2021 ESOO all scenarios, 2017-18 to 2050-51 (MW)



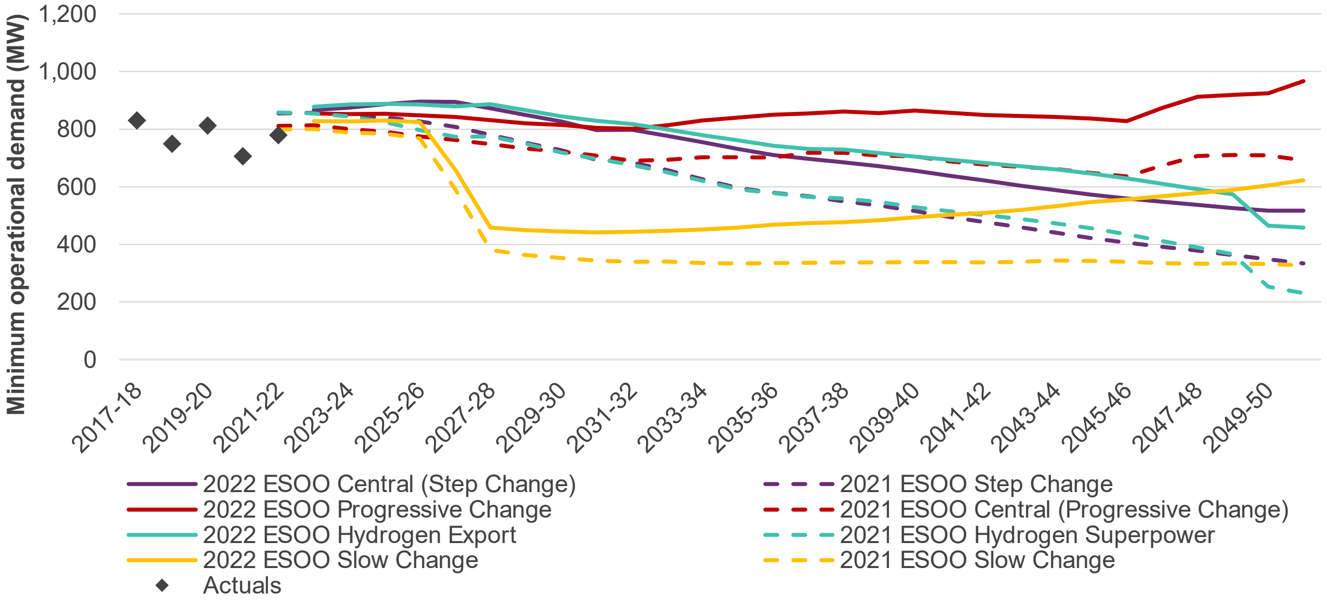
Note: The actuals displayed are not weather-corrected or adjusted for system events and exclude DSP.

The maximum operational demand forecast represents uncontrolled or unconstrained demand, free of market-based or non-market based solutions that might reduce system load during peak (including RERT, the WDR mechanism, or DSP). No components relating to hydrogen industries are included in the maximum operational demand forecasts.

Minimum operational demand outlook

Figure 56 shows actual and forecast 50% POE minimum operational (sent-out) demand (MW) from 2017-18 to 2050-51 for the 2022 ESOO compared to the 2021 ESOO for all scenarios in Tasmania.

Figure 56 Actual and forecast Tasmania 50% POE minimum operational (sent-out) demand, 2022 ESOO all scenarios and 2021 ESOO all scenarios, 2017-18 to 2050-51 (MW)



Note: The actuals displayed are not weather-corrected or adjusted for system events and exclude DSP.

The key insights are:

- 2022-23 to 2031-32 (1-10 years):
  - Minimum operational demand is forecast to start slightly higher in 2022-23 than in the 2021 ESOO for all scenarios, mostly due to higher underlying demand, slightly offset by lower electrification.
  - Minimum operational demand is forecast to be higher for all scenarios than in the 2021 ESOO, due to higher underlying demand.
  - Minimum operational demand is forecast to initially increase and then decrease due to initial increases in underlying demand, including growth from LILs, which flatten out and decrease respectively in the latter half of the decade, in all scenarios except *Slow Change*. The projected uptake of distributed PV applies downward pressure on minimum operational demand.
  - In the *Slow Change* scenario, minimum operational demand is forecast to be relatively flat before risks of LIL closures result in a reduction in 2027-28, then continuing flat.
- 2032-33 to 2041-42 (11-20 years):
  - Minimum operational demand is forecast to decline in the ESOO Central (*Step Change*) and *Hydrogen Export* scenarios due to decreasing LILs.
  - In the *Progressive Change* and *Slow Change* scenarios, it is forecast to increase as the drivers applying upward pressure (broad drivers of underlying demand including EVs across both scenarios, and also

influenced by electrification for the *Progressive Change* scenario) are projected to grow faster than the drivers applying downward pressure (like uptake of distributed PV and decreasing LILs).

  - Minimum operational demand for the 50% POE is forecast to switch from the shoulder to the summer season in the *Hydrogen Export* and *Step Change* scenarios from 2034-35 and 2037-38 respectively.
- 2042-43 to 2050-51 (21-29 years):
  - Minimum operational demand is forecast to decrease in the *Step Change* and *Hydrogen Export* scenarios.
  - In the *Progressive Change* and *Slow Change* scenarios, it is forecast to increase for the reasons outlined above for the previous decade.

Supply adequacy assessment

There are currently no committed projects expected to commence operations in Tasmania during the 2022 ESOO modelling horizon.

Figure 57 shows the aggregate impact of generator and storage commissioning and decommissioning assumptions. The variation in the capacity for water shown in the figure represents intended temporary withdrawals of existing plant for seasonal maintenance purposes, based on information from Hydro Tasmania.

Figure 57 Tasmania assumed capability during typical summer conditions, by generation type, 2021-22 to 2031-32 (MW)

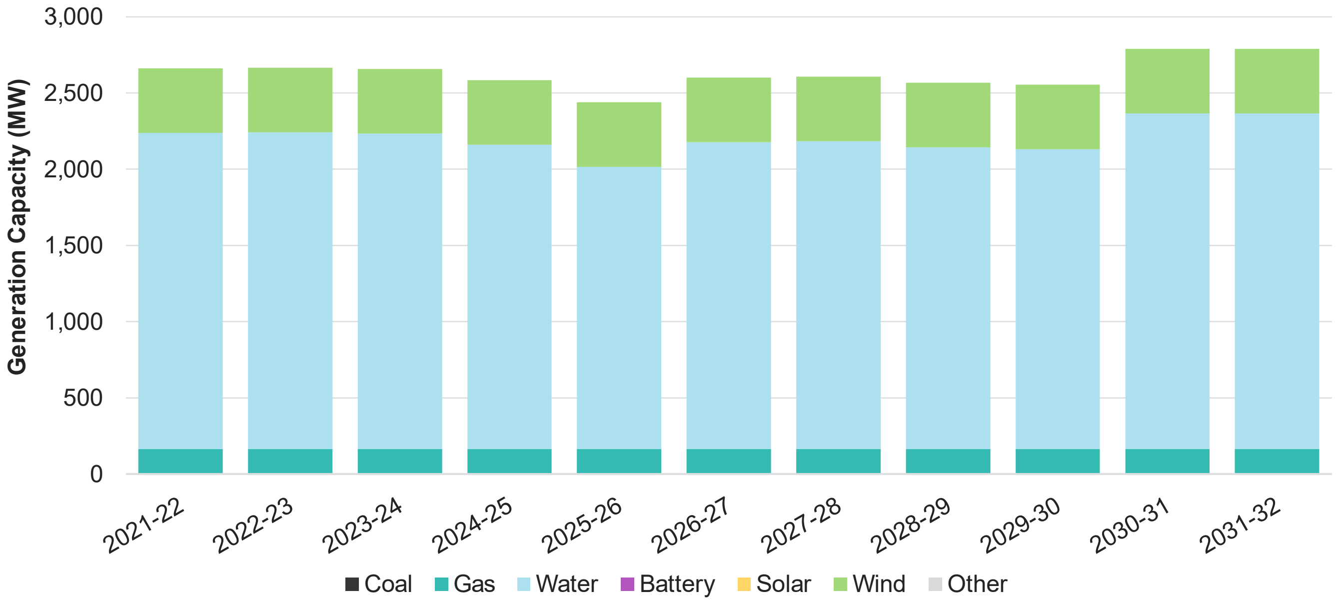


Figure 58 shows forecast USE for Tasmania under the relevant modelled scenarios and sensitivities. Under all scenarios and sensitivities, expected USE is less than the IRM and reliability standard.

Figure 58 Tasmania expected USE, scenarios and sensitivities, 2022-23 to 2031-22 (%)

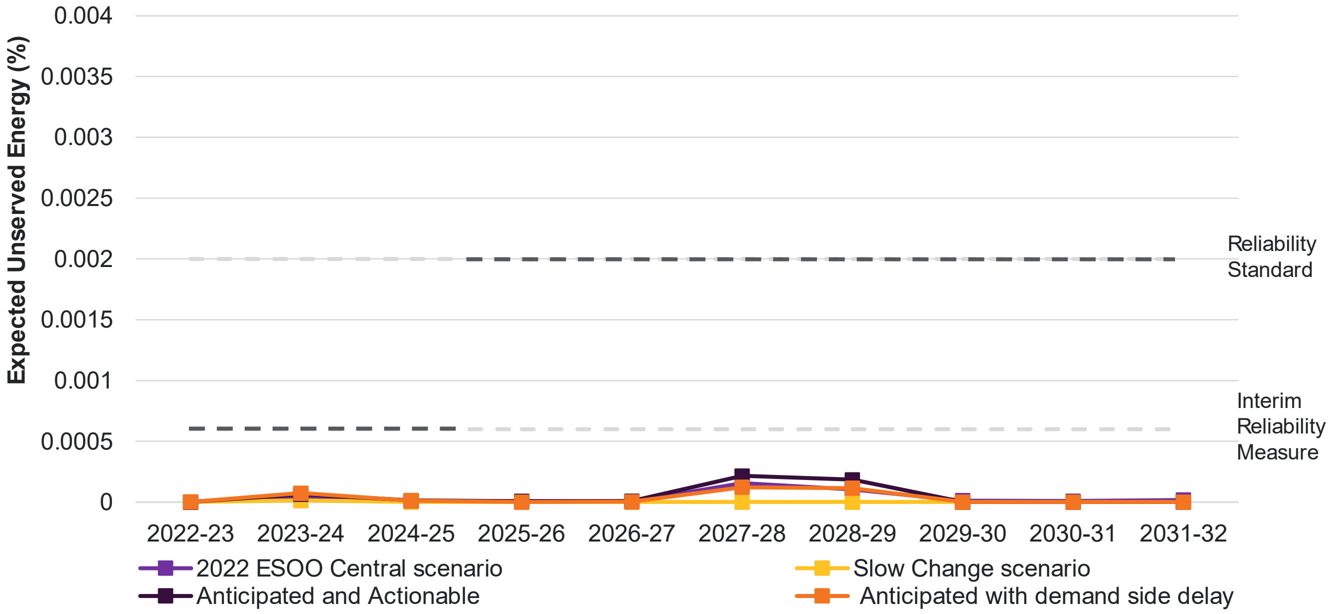
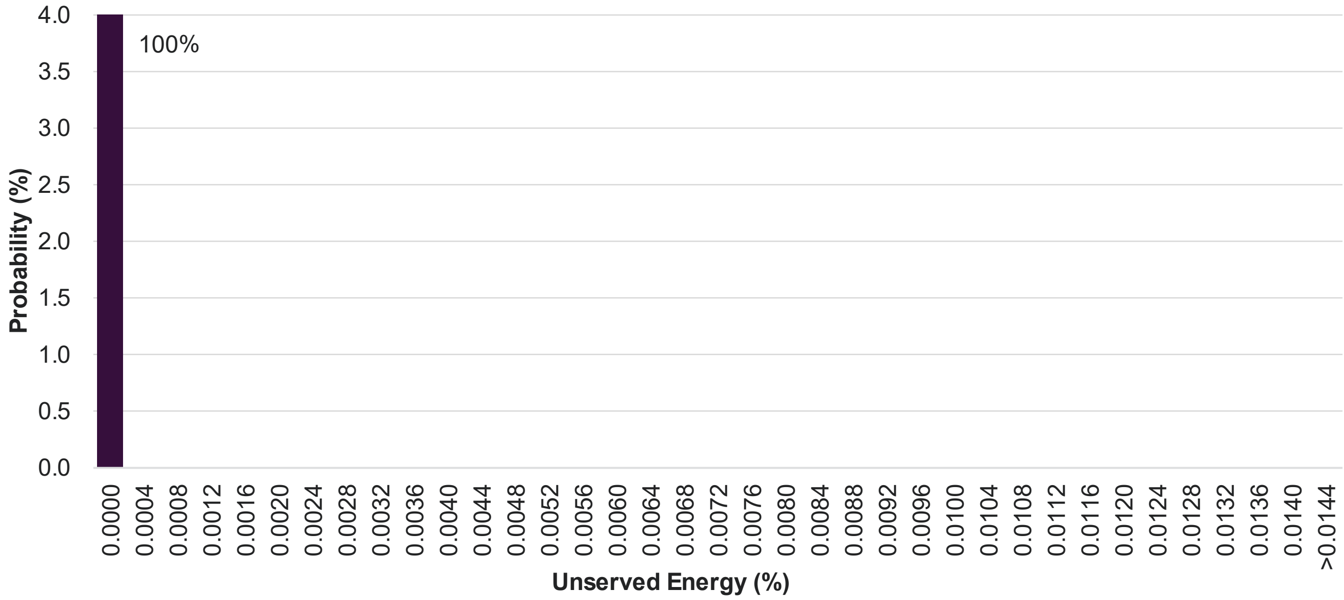


Figure 59 shows the probability density of USE forecast in Tasmania for the 2022-23 summer, similar to that described in Section 4.1. It shows that the most likely outcome is that USE does not occur in the coming year (the purple bar), and there is no simulated probability of a reliability incident.

Figure 59 Probability density for forecast USE in Tasmania 2022-23, ESOO Central scenario (%)



A5. Victoria outlook

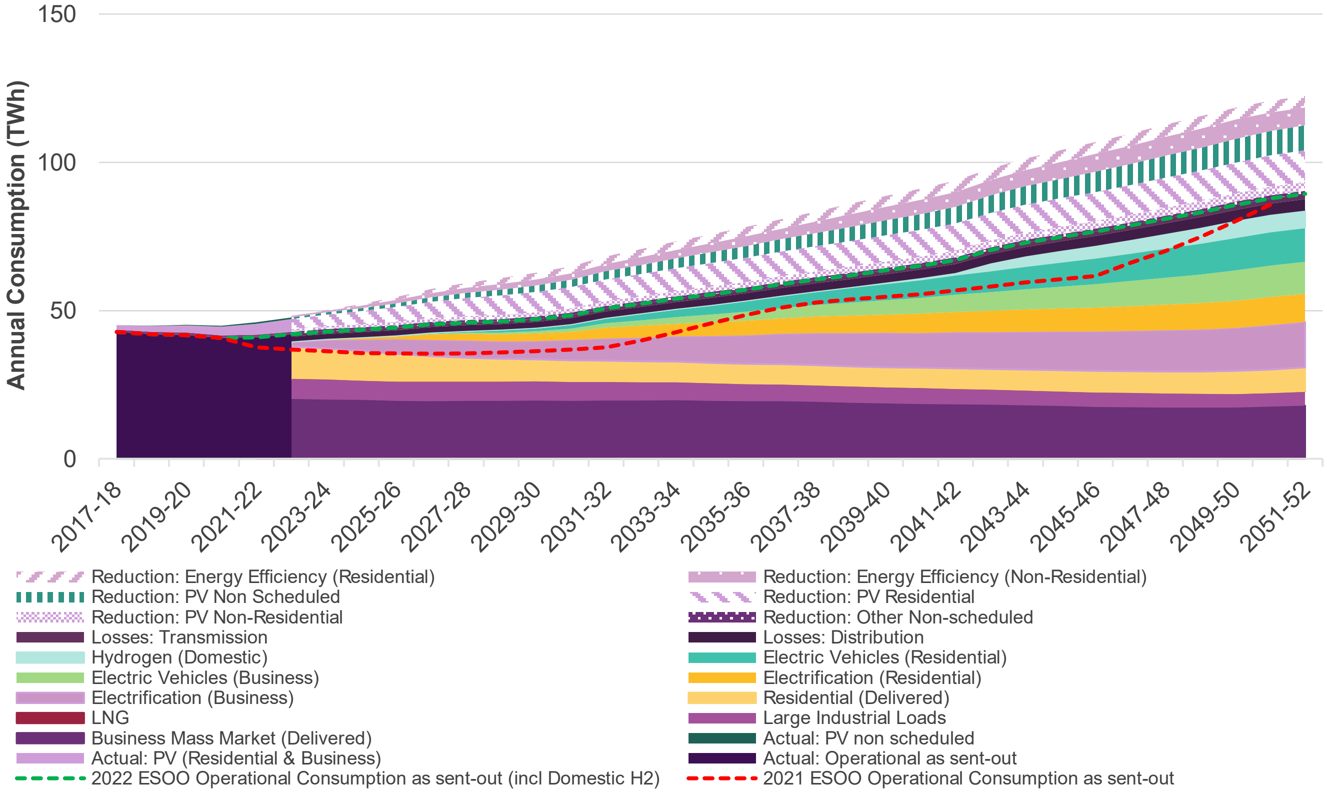
The following sections present, for Victoria:

- Operational consumption, maximum demand, and minimum demand outlooks for all scenarios to 2051-52.
- Supply adequacy assessments for the next 10 years, for the ESOO Central scenario, *Slow Change*, and other sensitivities.

Annual consumption outlook

Figure 60 shows the component forecasts for operational consumption in Victoria under the ESOO Central (*Step Change*) scenario.

Figure 60 Actual and forecast Victoria electricity consumption, ESOO Central scenario, 2017-18 to 2051-52 (TWh)



In this scenario, AEMO forecasts:

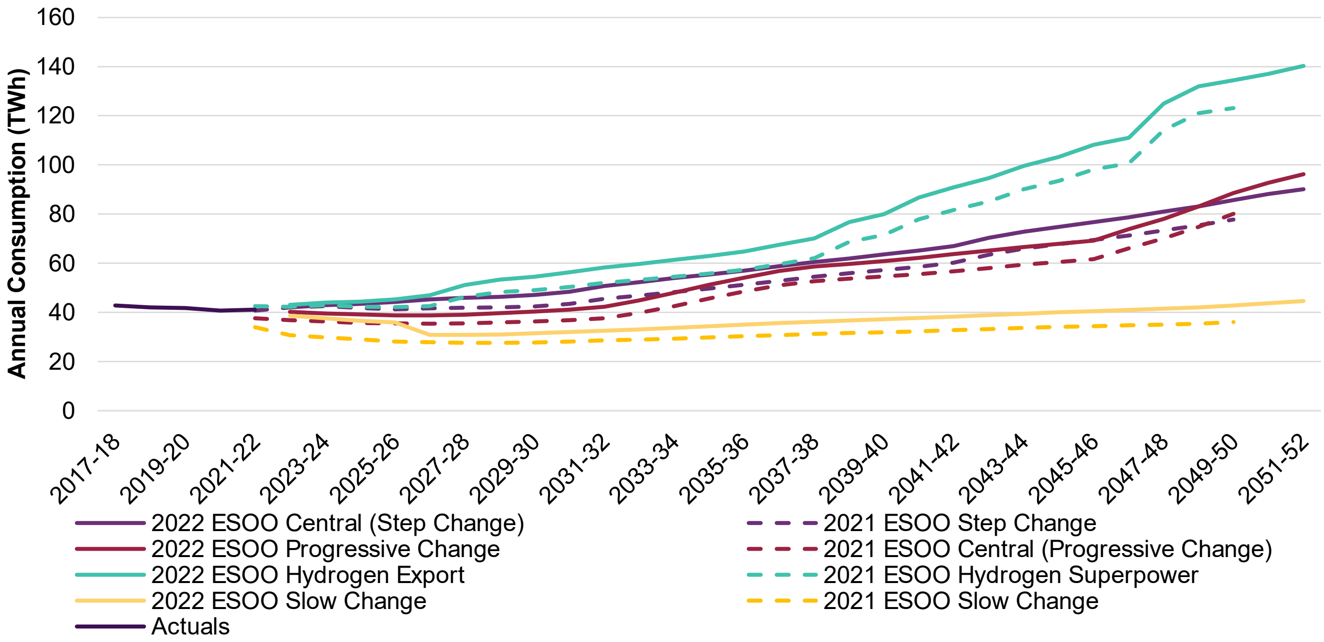
- Short-term (1-10 years) – consumption growth driven by an increase in LIL consumption from 2022-23 compared to the *Update to the 2021 ESOO*, due to expansion in production identified in the LIL survey process for the 2022 ESOO. Projected growth in residential and business electrification further increases forecast consumption, although this is offset by forecasts for energy efficiency and strong growth in distributed PV.

- Medium-term (11-20 years) – electrification growth from the transport, residential (in particular gas heating), and business sectors driving strong consumption growth; this is partially offset by projected growth in distributed PV.
- Long-term (21-29 years) – consumption growing strongly, due to electrification growth from the transport, residential, and business sectors, partially offset by modest growth in energy efficiency and distributed PV. Unlike the other NEM regions, Victoria's natural gas availability is expected to lead to greater opportunity for hydrogen production from steam methane reforming (SMR) technology, which has a limited effect on electricity demand[99].

Figure 61 shows forecasts across the scenarios, highlighting that:

- In *Progressive Change*, electrification has a slower uptake compared to the ESOO Central forecast, although it is projected to drive an increase in consumption from 2032-33 and again more rapidly in the mid-2040s.
- Domestic production of hydrogen dominates the growth trajectory of the *Hydrogen Export* outlook.
- *Slow Change* contains the lowest consumption forecast, due to early LIL closure risks, strong distributed PV growth, and limited electrification.

Figure 61 Actual and forecast Victoria operational consumption, 2022 ESOO all scenarios and 2021 ESOO all scenarios, 2017-18 to 2050-51 (TWh)

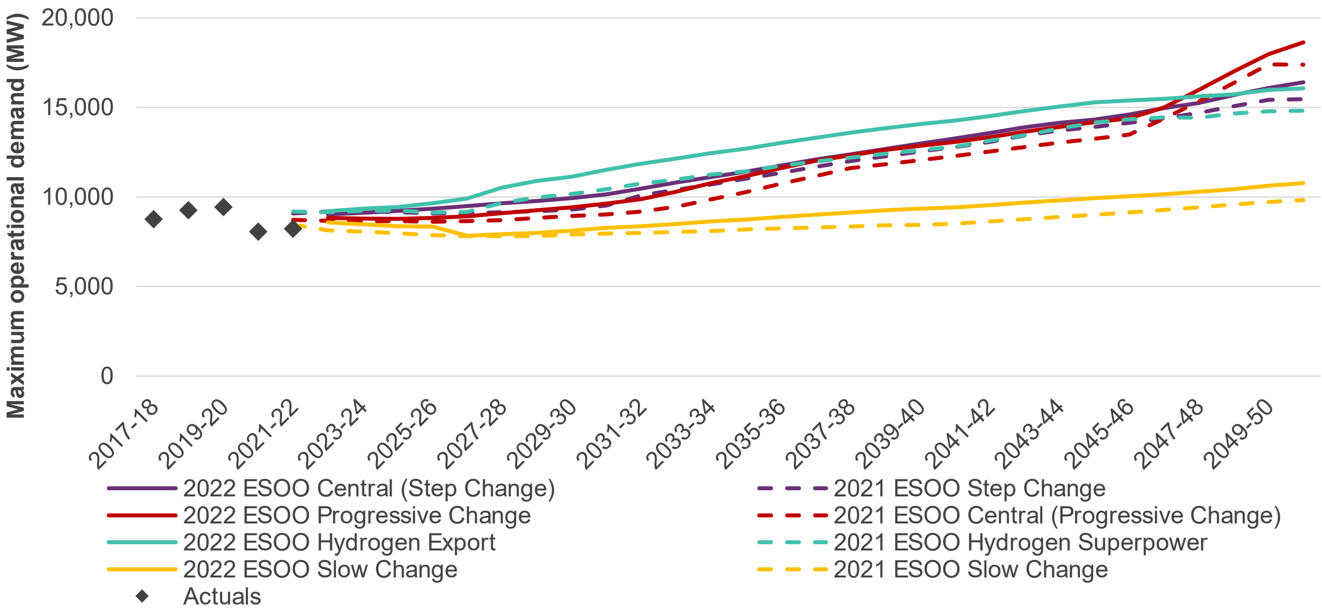


Maximum operational demand outlook

Figure 62 shows actual and forecast 50% POE maximum operational (sent-out) demand (MW) from 2017-18 to 2050-51 for the 2022 ESOO compared to the 2021 ESOO for all scenarios in Victoria.

[99] See https://www.aemc.gov.au/rule-changes/wholesale-demand-response-mechanism.

Figure 62 Actual and forecast Victoria 50% POE maximum operational (sent-out) demand, 2022 ESOO all scenarios and 2021 ESOO all scenarios, 2017-18 to 2050-51 (MW)



Note: The actuals displayed are not weather-corrected or adjusted for system events and exclude DSP.

The key insights are:

- 2022-23 to 2031-32 (1-10 years):
  - Maximum operational demand is forecast to start higher in 2022-23 than in the 2021 ESOO for all scenarios except for ESOO Central (*Step Change*), due to expansions of LILs. The ESOO Central (*Step Change*) scenario starts slightly lower than *Step Change* in the 2021 ESOO, due to the expansion of LILs being more than offset by a reduction in electrification.
  - Maximum operational demand is forecast to increase for all scenarios except *Slow Change*, due to projected growth in EVs and electrification. A step increase in *Hydrogen Export* from 2027-28 is due to a projected step increase in electrification.
  - In the *Slow Change* scenario, risks of LIL closures result in a reduction in forecast maximum operational demand from 2026-27.
  - All scenarios are forecast to be generally higher than the 2021 ESOO due to higher forecast underlying demand, including growth from LILs.
- 2032-33 to 2041-42 (11-20 years):
  - Maximum operational demand is forecast to continue to increase for all scenarios due to growth in base load, EVs, and electrification (except the *Slow Change* scenario).
  - Maximum operational demand is forecast to switch from occurring in the summer season to the winter season in the ESOO Central (*Step Change*), scenario due to the higher contribution from electrification to peak demand, especially the electrification of heating load.
- 2042-43 to 2050-51 (21-29 years):

  - Maximum operational demand is forecast to continue to occur during the winter season in the ESOO Central (*Step Change*) scenario and in summer in the *Slow Change* scenario. In *Hydrogen Export* and *Progressive Change* scenarios, maximum operational demand switches seasons from summer to winter in the latter half of the decade.
  - Maximum operational demand is forecast to increase in all scenarios, with a sharper increase in the *Progressive Change* scenario after 2045-46 due to a projected higher uptake of electrification investments.

The maximum operational demand forecast represents uncontrolled or unconstrained demand, free of market-based or non-market-based solutions that might reduce system load during peak (including RERT, the WDR mechanism, or DSP). No components relating to hydrogen industries are included in the maximum operational demand forecasts.

Table 19 shows maximum summer and winter operational demand (sent out) forecasts for 10% POE and 50% POE for the ESOO Central (*Step Change*) scenario. Victoria is expected to become winter-peaking by around 2031-32 in the 50% POE forecast. The 10% POE summer forecast remains higher than the winter in the medium term, due to the cooling demand on extremely hot summer days exceeding the heating demand on extremely cold winter days.

Table 19 Forecast maximum operational demand (sent out) in Victoria, ESOO Central scenario (MW)

Financial year	Summer		Calendar year	Winter	
	10% POE	50% POE		10% POE	50% POE
2022-23	10,109	9,021	2023	7,923	7,612
2026-27	10,643	9,497	2027	9,188	8,874
2031-32	11,552	10,435	2032	10,796	10,470
2041-42	13,820	12,623	2042	13,925	13,581

Minimum operational demand outlook

Figure 63 shows actual and forecast 50% POE minimum operational (sent-out) demand (MW) from 2017-18 to 2050-51 for the 2022 ESOO compared to the 2021 ESOO for all scenarios in Victoria. The key insights are:

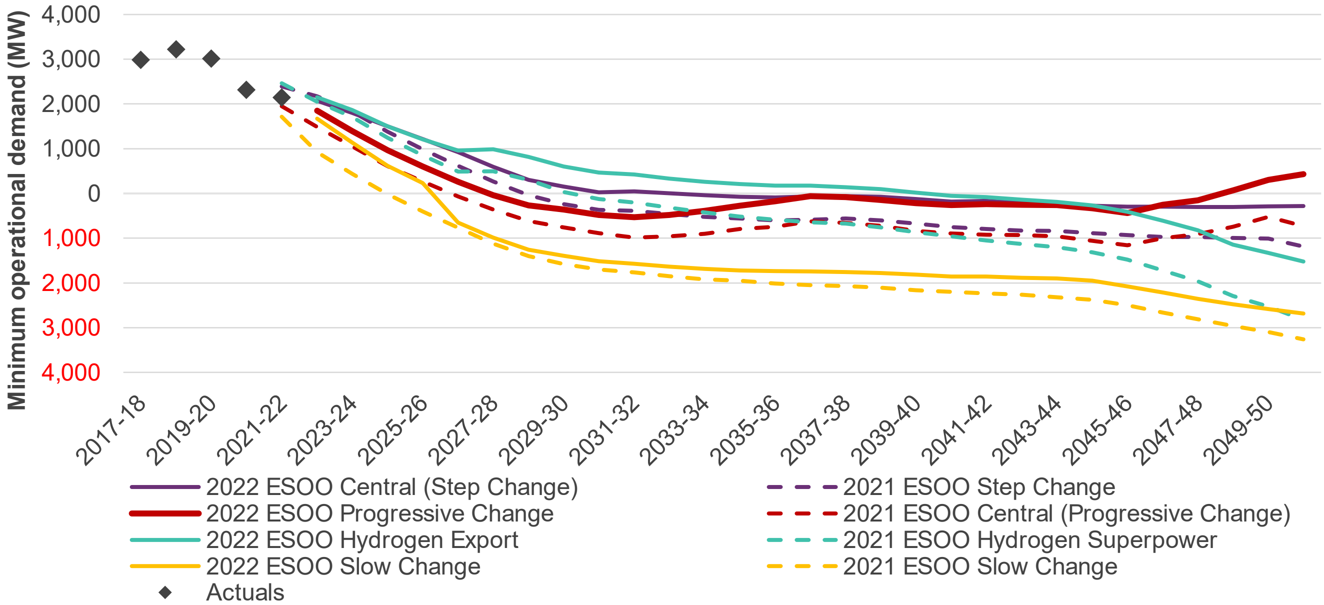
- 2022-23 to 2031-32 (1-10 years):
  - Minimum operational demand is forecast to start higher in 2022-23 than in the 2021 ESOO in all scenarios except ESOO Central (*Step Change*) due to expansions of LILs, and noticeably higher in the *Slow Change* scenario due to a delay in LIL closure risks. The ESOO Central (*Step Change*) scenario starts slightly lower than in the 2021 ESOO due to the expansion of LILs being more than offset by a reduction in electrification.
  - Minimum operational demand is forecast to decline rapidly in all scenarios due to the projected uptake of distributed PV.
  - Minimum operational demand is forecast to go negative for the 50% POE in *Slow Growth* and *Progressive Change* scenarios in 2026-27 and 2027-28 respectively, a couple of years later than in the 2021 ESOO.
- 2032-33 to 2041-42 (11-20 years):
  - Minimum operational demand is forecast to decline at a much slower rate in all scenarios except *Progressive Change* as the uptake of distributed PV is projected to be increasingly offset by the uptake of EVs and electrification. The *Progressive Change* outlook increases until 2036-37 then declines, due to the

interactions between the various rates of change in the drivers, particularly due to a higher projected rate of electrification.

- Minimum operational demand is forecast to be negative for the 50% POE for the *Hydrogen Export* scenario from 2040-41.

- 2042-43 to 2050-51 (21-29 years):
  - While minimum operational demand is forecast to remain relatively flat in the ESOO Central (*Step Change*) scenario, it is forecast to decline in the *Hydrogen Export* and *Slow Change* scenarios. In the *Progressive Change* scenario, it is forecast to slightly decline and then increase after 2045-46 due to a projected step up in the rate of electrification.

Figure 63 Actual and forecast Victoria 50% POE minimum operational (sent-out) demand, 2022 ESOO all scenarios and 2021 ESOO all scenarios, 2017-18 to 2050-51 (MW)



Note: The actuals displayed are not weather-corrected or adjusted for system events and exclude DSP.

Supply adequacy assessment

Between summer 2021-22 and 2022-23, 358 MW of additional VRE is expected to become available as measured by typical summer capacity. All four units of the 1,450 MW Yallourn Power Station are scheduled to retire in 2028.

Figure 64 shows the aggregate impact of generator and storage commissioning and decommissioning assumptions which does not include the now committed Mortlake South Wind Farm.

Figure 64 Victoria assumed capability during typical summer conditions, by generation type, 2021-22 to 2031-32 (MW)

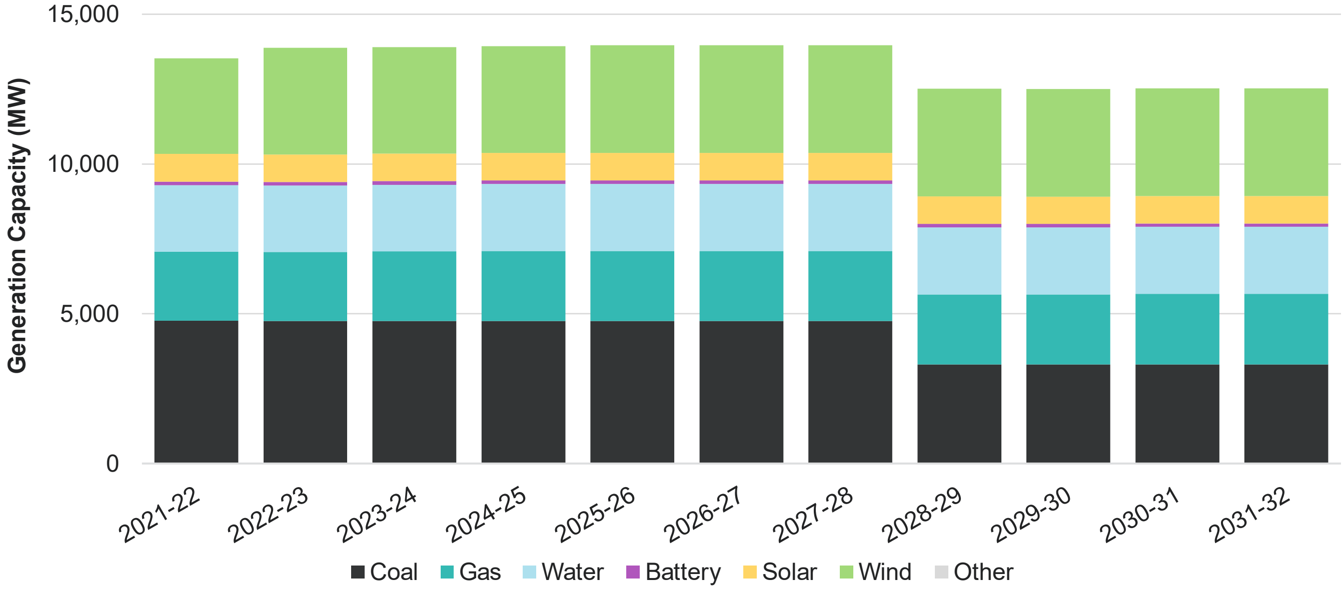
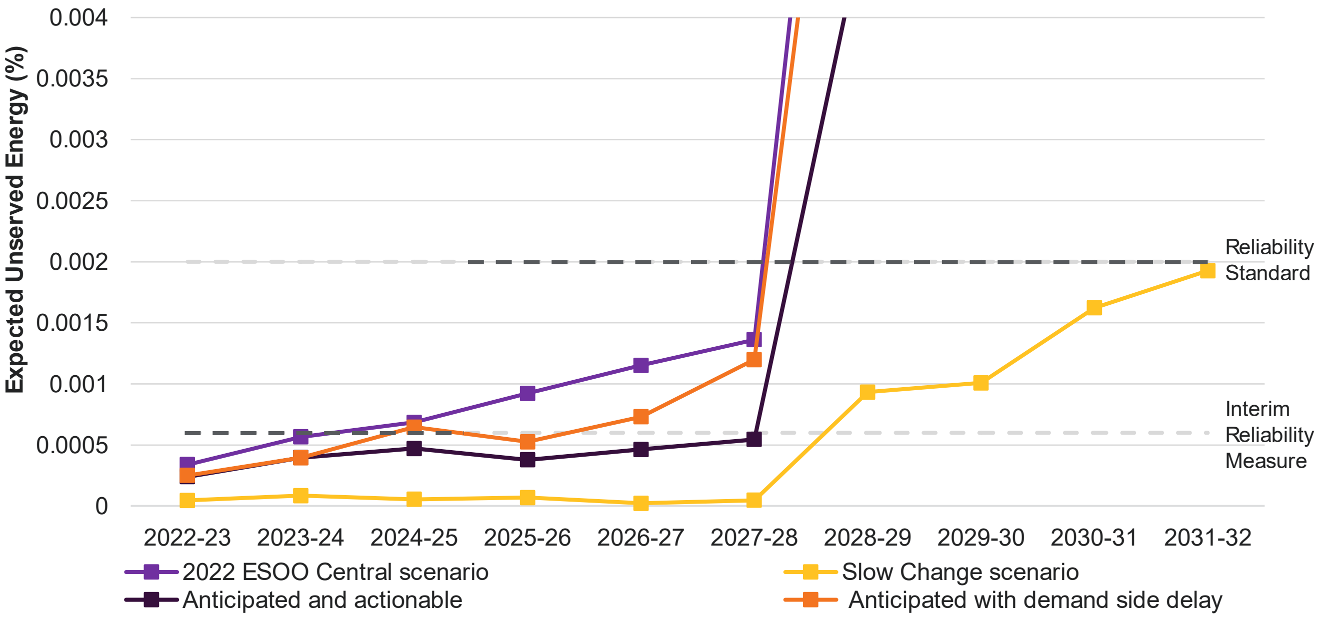


Figure 65 shows forecast USE for Victoria under the relevant modelled scenarios and sensitivities.

Figure 65 Victoria expected USE, scenarios and sensitivities, 2022-23 to 2031-32 (%)[100]



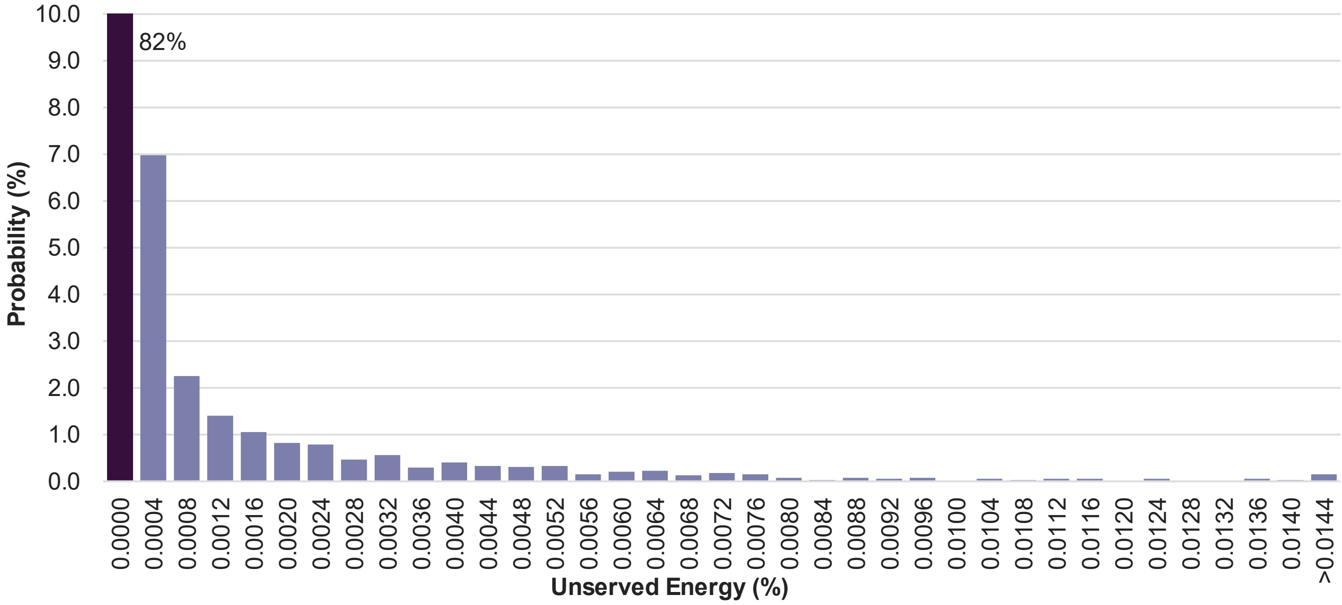
100 ESOO Central scenario modelling does not consider Mortlake South Wind Farm which has since become committed, however it is considered in the *Anticipated and actionable* sensitivity.

It shows that:

- In the ESOO Central scenario, expected USE is greater than the IRM in 2024-25 and the reliability standard from 2028-29, following the expected retirement of Yallourn Power Station[101].
- The *Anticipated and actionable* sensitivity remains below the ESOO Central outlook, due mainly to anticipated transmission upgrades. Despite the assumed commissioning of Marinus Link and VNI West in the final years of the horizon, expected USE is still above the reliability standard, as further generation developments are not yet considered committed or anticipated.
- Expected USE remains negligible in the early years of the *Slow Change* scenario due to lower demand assumptions, but is still impacted by the retirement of Yallourn Power Station from 2028-29 onwards.

Figure 66 shows the probability density of USE forecast in Victoria for the 2022-23 summer, similar to that described in Section 4.1. It shows that the most likely outcome is that USE does not occur in the coming year (the purple bar), but that there is an 18% probability of a reliability incident, approximately equivalent with an expectation of one incident every five years (the sum of all non-zero USE probabilities shown in the dark blue bars). Should the now committed Mortlake South Wind Farm be included in the ESOO Central scenario, the probability density forecast would improve.

Figure 66 Probability density for forecast USE in Victoria 2022-23, ESOO Central scenario (%)



[101] ESOO Central scenario modelling does not consider Mortlake South Wind Farm which has since become committed, however it is considered in the *Anticipated and actionable* sensitivity.

A6. Demand side participation forecast

AEMO must publish details, no less than annually, on the extent to which, in general terms, DSP information received under rule 3.7D of the NER has informed AEMO's development or use of load forecasts for the purposes of the exercise of its functions under the NER. This appendix outlines AEMO's DSP forecast for the 2022 ESOO, in fulfilment of its obligation under the NER, and explains the key differences from the 2021 ESOO forecast.

A6.1 DSP definition

DSP as forecast by AEMO is a subset of overall demand flexibility and is sometimes also referred to as demand response.

Demand flexibility describes consumers' capability to shift or adjust their demand. This flexibility is usually achieved through the use of (automated) technology, but also involves consumers making manual adjustments to load or generation resources, typically in response to price signals.

Demand flexibility exists in many forms, from residential consumers on time-of-use tariffs or using battery storage, to large industrial facilities capable of reducing consumption or starting embedded generators during high-price events.

DSP, in AEMO's forecasts, only includes a limited number of categories of demand flexibility – those which are not more effectively represented in the demand forecasts or modelled as an electricity supply resource. All demand flexibility categories are included in AEMO's reliability forecasts, although they are represented differently, depending on the type of demand flexibility, as discussed below and shown in **Figure 67**:

- The categories listed to the left in **Figure 67** are all captured in AEMO's demand forecasts. These generally operate based on daily patterns which are unrelated to wholesale price or reliability signals. This includes an offset from other non-scheduled generation (ONSG) for generators that are not responding to prices.
- Categories that are dispatched as generation (such as aggregated storage systems operated as a VPP) are modelled as supply in AEMO's forecasting processes (right column of **Figure 67**).
- The categories that are included in DSP are listed in the middle column of **Figure 67**.

It should also be noted that AEMO's DSP forecast specifically excludes RERT. The DSP forecast is used in the ESOO and in the Medium-Term Projected Assessment of System Adequacy (MT PASA), which highlights the risk of shortfalls to determine the need for RERT capacity, so the analysis needs to exclude it in the first instance.

The Wholesale Demand Response (WDR) mechanism was introduced in October 2021[102]. In the 2021 ESOO, in absence of any dispatch WDR data, the forecast used the historical response from capacity on Short Notice RERT from the 2020 summer as a proxy for potential WDR contributions. This year, WDR is forecast based on dispatch data during the first 160 days of the 2022 calendar year. Analysing the data during this period showed that the dispatched WDR was lower than was forecast in the 2021 ESOO.

[102] See https://www.aemc.gov.au/rule-changes/wholesale-demand-response-mechanism.

Figure 67 Flexible demand sources included in AEMO's DSP forecast

- Hot water load control
- Time of Use tariffs
- Energy storage
- EV charging (non V2G)
- ONSG – non peaking type

- Market exposed customers
- ONSG – peaking type
- Aggregated dynamic customer response
- Wholesale demand response
- Network reliability programs

- Energy storage VPP
- EV vehicle to grid (V2G)
- Scheduled loads (pumped storage)

A6.2 DSP forecast by component

The 2022 DSP forecast was based on information collected by registered participants through AEMO's DSP Information Portal during April 2022. It is mandatory for participants to provide this information to AEMO every year. The forecast has been broken down into two main components, explained in detail below:

- Price-driven response.
- Reliability response.

Price-driven response

This is determined by examining how flexible loads, as reported to AEMO (including those with embedded generators), have responded to various price levels in recent history[103]. The response is determined as the difference between the observed consumption and the calculated baseline consumption. This is done for an aggregation of sites/programs with similar characteristics for which the same baseline method is appropriate. AEMO uses the 50th percentile as a single-point representation of the distribution of responses observed when these price levels have been reached.

A new type of response considered this year is an estimate of the contribution of demand response service providers (DRSPs) via the WDR mechanism which came into effect in October 2021. Registration for DRSP started in June 2021, and minimal voluntary reporting[104] occurred through the DSP Information Portal in April 2021. In the absence of detailed participant information being available last year, AEMO assumed the WDR response could be estimated in the 2021 ESOO forecast using the 50th percentile of historical responses from Short Notice RERT providers by price trigger. This year, WDR is forecast based on the dispatch data during the first 160 days of the 2022 calendar year. WDR estimates are calculated as a weighted average response of dispatched WDR for each price trigger. For each trigger, the weights were calculated based on the ratio between the number of settlement intervals WDR was dispatched and the number of settlement intervals where the price

[103] The most recent three years of history are used by default with the cut-off date as the end of March 2022.

[104] Stakeholders could report expected WDR capacity voluntarily as part of AEMO's DSP data collection process in April 2021.

was higher than that trigger. **Table 20** provides some examples of how weights are calculated. For each price trigger, the WDR forecast is estimated as the multiplication of the median of the observed WDR and the calculated weight.

Table 20 Price-driven WDR forecast (MW)

Region	Trigger	Counts of intervals with WDR	Counts of intervals with price above the trigger	Calculated weight
NSW	>$500/MWh	269	778	0.35
NSW	>$2500/MWh	32	40	0.8
NSW	>$7500/MWh	26	32	0.81
VIC	>$500/MWh	25	341	0.07
VIC	>$2500/MWh	11	11	1
VIC	>$7500/MWh	6	6	1

The WDR forecasts for 2022 are lower than the predictions published in the 2021 ESOO. As of June 2022, WDR had only been dispatched in New South Wales and Victoria. The estimates for these regions have been used as approximations for the other regions as follows:

- WDR in Queensland was assumed to be at the same level as in Victoria based on its market size.
- WDR in South Australia was assumed to be one-third of the WDR forecast in Victoria, based on its market size.
- Due to the low incentive for DSP in Tasmania, WDR in Tasmania was assumed to be zero.

The 2022 WDR forecasts are as follows.

Table 21 Price-driven WDR forecast (MW)

Trigger	New South Wales	Queensland	South Australia	Tasmania	Victoria
>$300/MWh	0	0	0	0	0
>$500/MWh	0	0	0	0	0
>$1,000/MWh	9	1	0	0	1
>$2,500/MWh	14	3	1	0	3
>$5,000/MWh	15	6	2	0	6
>$7,500/MWh	15	6	2	0	6

The price-driven DSP forecasts are summarised in **Table 22**.

Table 22 Price-driven DSP forecast including WDR (cumulative response in MW)

Trigger	New South Wales	Queensland	South Australia	Tasmania	Victoria
>$300/MWh	25	35	2	9	7
>$500/MWh	35	48	5	16	9
>$1,000/MWh	45	51	7	16	9
>$2,500/MWh	47	56	8	17	22
>$5,000/MWh	48	68	12	17	32
>$7,500/MWh	48	69	13	17	35

For DSP forecast when prices exceed $7,500/MWh, relative to the 2021 ESOO:

- More DSP is forecast in Queensland (69 MW compared to 45 MW). The Callide Power Station event, capacity constraints, and the resulting increase in high price periods drove interest in DSP and building capability for demand-side management, leading to the higher forecast this year.
- Less DSP is forecast in New South Wales (48 MW compared to 66 MW) due to revisions in WDR forecasts and a lower response observed from DSP participants.
- Less DSP is forecast in Victoria (35 MW compared to 65 MW) mainly due to revisions in WDR forecasts.
- Less DSP is forecast in South Australia (13 MW compared to 33 MW) and Tasmania (17 MW compared to 26 MW). In South Australia, the difference comes mainly from the lower response observed from industrial load participants.

Reliability response

The reliability response represents the estimated DSP response during reliability events, which AEMO defines as cases where an actual LOR2 or LOR3 is declared[105].

The estimates are based on the estimated price response for half-hourly price exceeding $7,500/MWh (50th percentile as above) along with any network event programs and any additional adjustments to reflect responses that have not otherwise been captured[106].

In this year's program, AEMO has modelled network event programs in Queensland and Victoria. Excluding any loads overlapping with RERT, these amount to:

- Approximately 65 MW in Queensland.
- 25 MW in Victoria.

AEMO has been advised these programs are only available in summer, necessitating that different aggregate DSP forecasts be developed for summer and winter.

AEMO has maintained the adjustments made in the 2020 DSP forecast for New South Wales and increased the adjustment value for Victoria. The adjustments reflect significant responses observed from RERT providers outside what was contracted (and/or on periods where RERT was not needed). These adjustments reflect the average of the response seen across the periods where LOR2 conditions were in the regions in the last three years[107] plus any anticipated increase in the responses and sum to:

- 242 MW in New South Wales.
- 149 MW in Victoria.

Based on this, the combined DSP forecasts for the coming summer 2022-23 and winter 2023 are shown in **Table 23** and **Table 24** respectively.

[105] See AEMO's reserve level declaration guidelines, at https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/power_system_ops/%20reserve-level-declaration-guidelines.pdf.

[106] The reliability response is the estimated response during actual lack of reserve (LOR) 2 and 3 events. For the definition, see https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/power_system_ops/%20reserve-level-declaration-guidelines.pdf.

[107] Cut-off date is the end of March 2022.

Table 23 Estimated DSP responding to price or reliability signals, summer 2022-23)

Trigger	New South Wales	Queensland	South Australia	Tasmania	Victoria
> $300/MWh	25	35	2	9	7
> $500/MWh	35	48	5	16	9
> $1000/MWh	45	51	7	16	9
> $2500/MWh	47	56	8	17	22
> $5000/MWh	48	68	12	17	32
> $7500/MWh	48	69	13	17	35
Reliability response	290	133	13	17	209

Table 24 Estimated DSP responding to price or reliability signals, winter 2023

Trigger	New South Wales	Queensland	South Australia	Tasmania	Victoria
> $300/MWh	25	35	2	9	7
> $500/MWh	35	48	5	16	9
> $1000/MWh	45	51	7	16	9
> $2500/MWh	47	56	8	17	22
> $5000/MWh	48	68	12	17	32
> $7500/MWh	48	69	13	17	35
Reliability response	290	69	13	17	184

The reliability response estimate is a key input to the ESOO process, showing the megawatts of estimated demand reduction possible to avoid USE during supply shortfalls. In general, AEMO has no information about committed additional DSP resources, hence the estimates in **Table 23** and **Table 24** are used for the entire 10-year ESOO horizon.

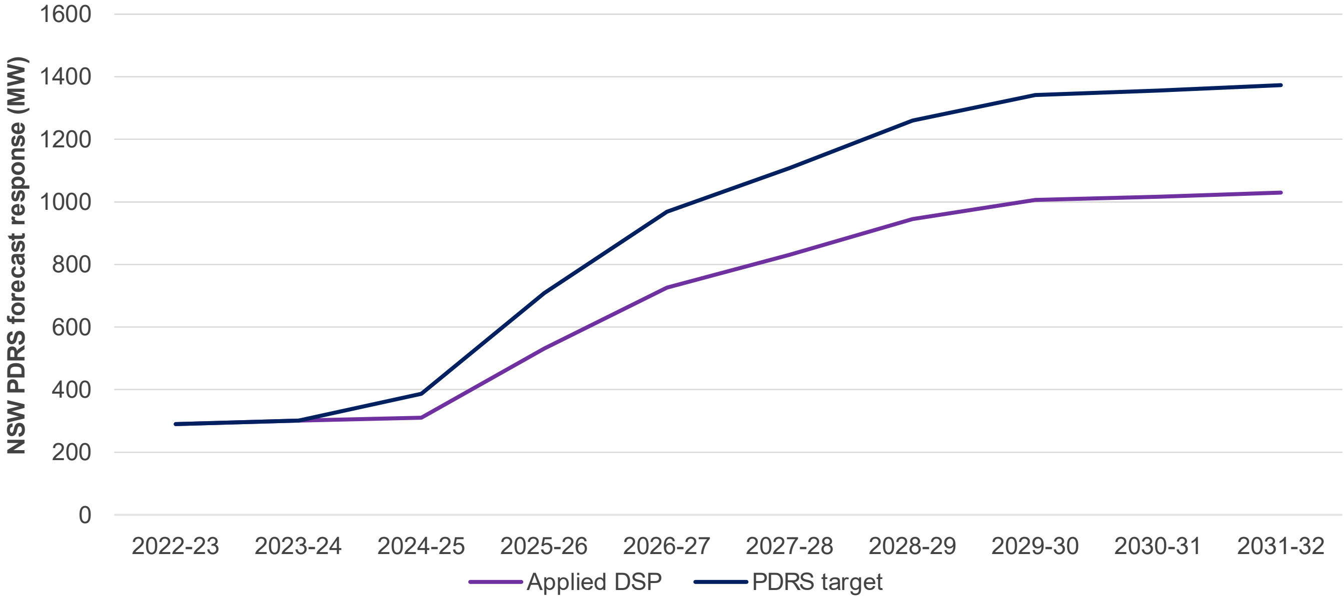
For New South Wales, the committed NSW Peak Demand Reduction Scheme (PDRS) policy will create a financial incentive to reduce electricity consumption during peak times in New South Wales[108]. AEMO includes this scheme in all scenarios, resulting in a DSP forecast which increases over time and beyond the above tabulated values. The PDRS has been applied from 2022-23 with the target growing to 10% of forecast peak demand by 2029-30 and then staying flat. The DSP forecast assumes that 25% of the PDRS target will be delivered through energy efficiency and battery storage initiatives rather than through DSP, which are components accounted for separately in AEMO's forecasts.

Figure 68 shows the PDRS targets in megawatt values as well as the adjusted targets expected to be achieved through DSP. The scheme will, in its current design, only provide additional DSP during summer[109].

[108] This is for the New South Wales state only. The NEM region of New South Wales also includes the Australian Capital Territory, so adjustments have been made to ensure the target reflects the New South Wales state demand only.

[109] For New South Wales' summer, the forecasts shown in are used in the 2022 ESOO while the winter forecasts stay the same as the values listed in Table 24.

Figure 68 PDRS target and DSP applied in forecasts for the summer period in New South Wales, 2022-23 to 2031-32 (MW)



Reliability response outlook to 2052

The tables above show the DSP forecast for use in the ESOO, only accounting for existing and committed DSP. For longer-term planning studies, such as the ISP, AEMO uses different scenario-specific projections out to 2052 to account for DSP resources that may be developed consistent with the defined scenario settings.

A6.3 DSP statistics

Understanding the status of demand flexibility in the NEM, both within the categories included in AEMO's DSP forecast and more widely, is important for market participants, network operators, and policy-makers.

Furthermore, following the rule change on WDR[110] in 2020, NER clause 3.7D(c) requires AEMO since October 2021 to include analysis of volumes and types of demand response in its reporting, including:

- Information on the types of tariffs used by NSPs to facilitate demand response and the proportion of retail customers on those tariffs, and
- An analysis of trends, including year-on-year changes, in the DSP information in respect of each relevant category of Registered Participant.

This section presents statistics on the full set of submitted DSP information to provide transparency about demand flexibility in the NEM. As it covers demand flexibility beyond what was included in the DSP forecast, the reported potential in megawatts differs from the forecast provided in Section A6.2 above. Also, three late submissions have been included in the analysis to ensure the most comprehensive coverage of reported DSP in the NEM.

[110] See https://www.aemc.gov.au/rule-changes/wholesale-demand-response-mechanism.

Participant programs delivering demand flexibility

Table 25 and **Table 26** present the change in program numbers as submitted by participants to AEMO's DSP Information Portal over time. Note that 2019 was the first year in which all parties with significant DSP resources (to AEMO's knowledge) submitted information, so 2018 data is not directly comparable with subsequent years.

In 2020, in response to the WDR rule change[111], AEMO was required to review and consult on changes to the DSP information guidelines[112], which resulted in changes being made to the categories of DSP programs available in submissions. The number of programs allocated to the new set of categories is shown in **Table 26**.

The category change challenges the ability to make direct comparisons to previous years, however, it suggests that the new categories are delivering more informative submissions.

A marked decrease in the "Other" category from 2020 to 2021 was the result of the removal of the requirement that all large (>1 MW) programs fall under this category. In 2022 there were increases in all categories partly driven by increased compliance with NER clause 3.7D requiring all participants to submit DSP information.

There is also no longer a requirement to report on connections with energy storage systems, as this information is now being collected through AEMO's DER Register. Energy storage systems controlled by an aggregator to respond dynamically to price and/or reliability signals are still required to be reported, although by using the generic DSP categories. From other data entry fields (not shown), it was observed that 18 out of 378 of the programs have batteries.

Table 25 Program numbers from DSP Information Portal, 2018-20

Category	2018	2019	2020
Market exposed connections	12	20	49
Connections on network event tariffs	1	1	7
Connections on retail time-of-use tariffs	20	29	29
Connections with energy storage	7	11	16
Connections with network controlled load	54	58	58
Other (larger programs)	35	45	117

Table 26 Program numbers from DSP Information portal, 2021-22

Category	2021	2022
Market exposed connections	143	211
Connections on dynamic event tariffs	5	16
Directly controlled connections (dynamic operation)	33	37
Directly controlled connections (fixed schedule)	6	17
Connections on fixed time-of-use tariffs	49	62
Other	14	35

[111] See https://www.aemc.gov.au/rule-changes/wholesale-demand-response-mechanism.

[112] See https://aemo.com.au/en/consultations/current-and-closed-consultations/dspi-guidelines.

Statistics by program category

Table 27 summarises category-level information from submissions to AEMO's DSP Information Portal in 2022. Participants reported each individual customer connection, based on their National Meter Identifiers (NMIs), that belong to each program. Some customer connections may belong to multiple programs; for example, a residential customer's NMI could appear both with having a controlled hot water tank (directly controlled load) and an interruptible air-conditioner.

The categories containing connections participating in regular demand flexibility incentives – time-of-use tariffs and directly controlled connections (fixed schedule) – dominated the total number of connections submitted. Those categories capture large-scale residential and commercial price incentives for time-insensitive loads such as hot water heating and pool pumps. The other very large NMI counts in the directly controlled connections (dynamic operation) mostly capture network programs involving residential appliances that have been deployed to address high or extreme demand events.

Participants may also, for each program, report their firm response in megawatts. **Table 27Table 27** highlights that, in many cases, the firm response of the program is not known or reported. This makes it more difficult for AEMO to use the provided values as verification of the DSP forecast. AEMO therefore relies on the historical analysis of observed responses for all participating NMIs against their estimated baseline consumption.

Table 27 Program statistics grouped by program category for 2022 submissions

Category	Number of programs	Number of connections (connections may appear in more than one program)	Number of programs that included firm response information in submission
Connections on dynamic event tariffs	16	8,626	1
Connections on fixed time-of-use tariffs	62	2,033,814	12
Directly controlled connections (dynamic operation)	37	401,042	21
Directly controlled connections (fixed schedule)	17	1,683,929	6
Market exposed connections	211	823,779	57
Other	35	199,326	24

Load types of reported connections

The types of connections reported to the DSP Information Portal are mainly residential, however, for a significant portion of the connections the type was not specified. The load type categories for 2022 are summarised in **Table 28,** with the numbers of distinct connections reported in 2020 and 2021 for comparison.

The unreported number of NMIs for one program in 2020 explains most of the increase in residential connections seen in 2021 that are part of a DSP program. More programs and NMIs have been reported in 2022, however, **Table 28** highlights that for a greater portion of the NMIs, the connection types were not specified, and as result, in 2022 a decrease was observed in the number of connections reported as being residential. 'Fixed-time-of-use tariff' is the dominant category in the submissions with missing connection types (suggesting some of these programs may cover both residential and commercial customers) as well as commercial connections. In addition, the majority of the industrial connections lie in the 'Market exposed' category.

Table 28 Load types of reported connections

Load type	Number of distinct connections			Dominant program category in each load type as percentage (2022)
	2020	2021	2022	
< not specified >	1,701,821	2500,874	3,405,255	60% Connections on fixed time-of-use tariffs
Commercial	2,884	10,806	9,415	67% Connections on fixed time-of-use tariffs
Industrial	361	92	90	76% Market exposed connections
Residential	1,674,967	2085,018	1,735,756	38% Directly controlled connections (fixed schedule) 27% Market exposed connections

Number of connections by category and type

Table 29 lists the number of connections in each category by DSP type. This table also includes the sum of all reported firm megawatt responses of each program, including programs excluded from AEMO's DSP forecast. In total, it suggests 2,748 MW of firm response exists, although more could be unquantified or simply not reported. It is important to note that the reported 69 MW of firm response for 'Market exposed' connections with embedded generation includes all the reported distributed and rooftop PV. The ability for distributed and rooftop PV to respond is primarily in minimum demand events where they can curtail generation, rather than maximum demand events to provide additional capacity in reliability events.

Table 29 Number of connections grouped by program category and DSP type

Category	DSP type	Distinct number of connections	Reported sum of firm response (MW)	Number of programs
Market exposed connections	Embedded generation	318,191	69	69
	Energy storage	23,764	1	11
	Load reduction	480,214	125	30
	Load reduction; Embedded generation	5	0	1
	<not specified>	1,605	606	100
Connections on dynamic event tariffs	Energy storage	5,706	30	1
	Load reduction	2,914	0	3
	<not specified>	6	0	12
Directly controlled connections (dynamic operation)	Embedded generation	85	104	6
	Energy storage	1	1	1
	Load reduction	394,758	240	6
	<not specified>	6,198	109	24
Directly controlled connections (fixed schedule)	Load reduction	667,495	491	2
	<not specified>	1,016,434	113	15
Connections on fixed time-of-use tariffs	Load reduction	840	0	2
	<not specified>	2,032,974	533	60
Other	Embedded generation	18	23	2
	Energy storage	1,044	6	1
	Load reduction	196,821	226	18
	<not specified>	1,443	71	14

A6.4 Tariffs used by network service providers and retailers

Table 30 summarises the number of connections reported for the different tariff categories for both retailers and NSPs.

Table 30 Number of connections reported by network service providers and retailers

Category	Network service providers – number of reported connected NMIs	Retailers – number of reported connected NMIs
Connections on dynamic event tariffs	8,610	16
Connections on fixed time-of-use tariffs	319,635	1,714,179
Directly controlled connections (dynamic operation)	1	401,041
Directly controlled connections (fixed schedule)	812,870	871,059
Market exposed connections	822,090	1,689
Other	99,671	99,655