2024 Electricity Statement of Opportunities

August 2024

A 10-year outlook of investment requirements to maintain reliability in the National Electricity Market

We acknowledge the Traditional Custodians of the land, seas and waters across Australia. We honour the wisdom of Aboriginal and Torres Strait Islander Elders past and present and embrace future generations.

We acknowledge that, wherever we work, we do so on Aboriginal and Torres Strait Islander lands. We pay respect to the world's oldest continuing culture and First Nations peoples' deep and continuing connection to Country; and hope that our work can benefit both people and Country.

'Journey of unity: AEMO's Reconciliation Path' by Lani Balzan

AEMO Group is proud to have launched its first Reconciliation Action Plan in May 2024. 'Journey of unity: AEMO's Reconciliation Path' was created by Wiradjuri artist Lani Balzan to visually narrate our ongoing journey towards reconciliation - a collaborative endeavour that honours First Nations cultures, fosters mutual understanding, and paves the way for a brighter, more inclusive future.

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 reliability assessments against the reliability standard and interim reliability measure, including AEMO's reliability forecasts, indicative reliability forecasts, and Energy Adequacy Assessment Projection.

AEMO publishes the National Electricity Market Electricity Statement of Opportunities and Energy Adequacy Assessment Projection under clauses 3.13.3A and 3.7C of the National Electricity Rules respectively. This publication is generally based on information available to AEMO as at 1 July 2024 unless otherwise indicated.

Disclaimer

AEMO has made reasonable efforts to ensure the quality of the information in this publication but cannot guarantee that information, forecasts and assumptions are accurate, complete or appropriate for your circumstances.

Modelling work performed as part of preparing this publication inherently requires assumptions about future behaviours and market interactions, which may result in forecasts that deviate from future conditions. There will usually be differences between estimated and actual results, because events and circumstances frequently do not occur as expected, and those differences may be material.

This publication does not include all of the information that an investor, participant or potential participant in the National Electricity Market might require and does not amount to a recommendation of any investment.

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Executive summary

The *Electricity Statement of Opportunities* (ESOO) provides technical and market data for the National Electricity Market (NEM) over a 10-year period from 2024-25 to 2033-34. The ESOO highlights the opportunities for market participants, investors, governments and other jurisdictional bodies to invest in new assets and systems to maintain a reliable supply of electricity in the NEM.

The energy transition is well underway for Australia's NEM. Investments in renewable generation and storage capacity continue to increase, and the pipeline of potential developments continues to expand, filling gaps being left by the steady retirement of coal fired power stations that commenced in 2012. Over the last 12 months, 5.7 gigawatts (GW) of generation capacity and 365 km of transmission has progressed to committed and anticipated status.

This 2024 ESOO demonstrates that the timely delivery of expected investments in generation, storage and transmission is critical to maintaining reliability for electricity consumers. AEMO forecasts show reliability levels can be maintained over most of the next 10 years if programs and initiatives already established are delivered on time and in full. This includes delivery of planned actionable transmission projects, investments supported by federal and state government energy programs, and coordination of consumer energy resources.

Any delay to the delivery of expected generation, storage or transmission may result in reliability standards not being met, while further investments in dispatchable and renewable energy generation that are not yet sufficiently progressed to be included in this modelling could improve the reliability outlook. Any earlier withdrawal of existing capacity would also deteriorate the outlook for reliability of the power system.

The main findings of this 2024 ESOO are:

- **If delivered on time and in full**, **then federal and state government programs** providing additional renewable generation and dispatchable resources, actionable transmission developments, and coordination of forecast consumer energy resources (CER)[1] **would provide sufficient generation capacity to meet growing electricity demand within relevant reliability standards over most of the next 10 years**. Timely delivery of these expected investments is critical.
- AEMO also considers a development outlook that includes only energy supply infrastructure developments that meet AEMO's commitment criteria[2]. **If further investment beyond current committed and anticipated projects is delayed or does not materialise, AEMO forecasts reliability gaps** will exist over the coming years in some NEM regions. These gaps are smaller than those forecast in the May 2024 Update to the 2023 ESOO and the 2023 ESOO. In this sensitivity, reliability risks are forecast higher than the relevant reliability standard[3] in:

[1] CER are playing a transformative role in the energy transition, and will be a valuable resource in the future energy system. If well coordinated ('orchestrated'), they help deliver reliable and secure energy, offset the need for grid-scale investment, and reduce costs for consumers as well as energy sector emissions.

[2] AEMO defines five commitment criteria regarding a developer's progress towards land procurement, financial commitment, component contracts, relevant planning approvals and construction. Developers demonstrate the achievement of these criteria through direct surveys. The *Committed and Anticipated Investments* sensitivity includes all developments classified as 'existing', 'in commissioning', 'committed', and 'anticipated'. To be classified as 'committed', all the above criteria must be fully met.

[3] The Interim Reliability Measure (IRM) of 0.0006% expected unserved energy (USE) applies until June 2028, after which the reliability standard of 0.002% USE applies.

  - **Victoria** from this coming summer, in 2027-28 and from 2028-29 after Yallourn Power Station is advised to retire.
  - **New South Wales** this coming summer, again in 2027-28 when Eraring Power Station is now advised to retire, and from 2031-32.
  - **South Australia** this coming summer, again in 2026-27 when Torrens Island B and Osborne Power Stations are advised to retire, and in 2033-34.
- AEMO will request the Australian Energy Regulator (AER) to put an obligation on retailers and liable entities to enter sufficient contracts to cover their customers peak demand needs, through the retailer reliability obligation. AEMO will also take prudent action and seek to procure additional reserves for the coming 2024-25 summer, safeguarding consumers in a cost-appropriate manner.
- Alongside energy-related investments that support reliability, investments are also required to ensure that the power system remains stable and resilient. As existing synchronous generators retire, there is a need for system strength services across the NEM and for urgent implementation of the recently published National CER Roadmap.[4]

Several factors are driving the 2024 ESOO forecast to show an improved reliability outlook compared with the 2023 reports:

- New **wind, solar, battery, gas, and pumped hydro developments continue to progress** towards commissioning in the NEM. Approximately 5.7 GW of developments have progressed sufficiently to be newly included since the 2023 ESOO, comprising 3.9 GW/13.5 gigawatt hours (GWh) of batteries, 1.2 GW of large-scale solar, 0.4 GW of wind and 0.2 GW of hydrogen generation.
- Consumers are also investing in **larger rooftop solar systems**, which continues to reduce the proportion of electricity supplied by the transmission system for households and businesses. This means more energy is supplied from these renewable sources. These systems do not tend to contribute to lowering the scale of peak demands during extreme hot conditions in the summer or extreme cold conditions in the winter.
- Origin Energy has given notice that it now expects to close the 2,880 megawatts (MW) **Eraring Power Station** in New South Wales on 19 August 2027, a two-year extension on the previously provided date.
- AEMO now considers **HumeLink**, a new 365 km transmission line which will connect Wagga Wagga, Bannaby and Maragle, to be an anticipated project which will improve reliability risks in New South Wales[5].
- AEMO now projects **lower growth in energy consumption and maximum demand for most NEM regions than was previously forecast**. These forecasts continue to consider growth driven by the potential for electrification of household and businesses, the emergence of the hydrogen production industry, and forecast expansion of industrial facilities including the rapid development of data centres. The growth has, however, been moderated by lower electric vehicle (EV) and business consumption trends relative to 2023 forecasts.

Power system reliability in the ESOO refers to the sufficiency of electricity supply to meet demand in all periods of the year. The ESOO includes reliability forecasts prepared for a range of outlooks, including with state and federal schemes, actionable transmission and coordinated CER and on time delivery of all potential projects. For regulatory purposes the

[4] At https://www.energy.gov.au/energy-and-climate-change-ministerial-council/working-groups/consumer-energy-resources-working-group/national-cer-roadmap.

[5] Following the Australian Energy Regulator's (AER's) approval of the contingent application for HumeLink Stage 2 on 2 August 2024, AEMO now considers HumeLink meets the criteria to be considered anticipated. Further steps are required before this project can be considered as committed.

ESOO includes a reliability forecast to identify any reliability gaps in the coming five years, defined according to the Retailer Reliability Obligation (RRO), and an indicative projection of any reliability gaps in the second five years of the forecast. This particular forecast is prepared for an outlook that includes only existing, in commissioning, committed and anticipated investments. This is not a prediction of what will eventuate as there are many projects in the pipeline of developments and many state and federal schemes currently supporting further investment.

The following definitions apply to this 2024 ESOO:

- **Unserved energy (USE)** represents energy that cannot be supplied to consumers when demand exceeds supply under certain circumstances, resulting in involuntary load shedding (loss of customer supply) in the absence of out of market intervention.
- AEMO forecasts **expected USE** by calculating the weighted-average USE over a wide range of simulated outcomes. Because expected USE is the average of many possible outcomes, a forecast over the relevant standard does not guarantee that a USE event is going to happen, while forecasts below the standard do not mean there are no reliability risks, although events may be less probable.
- The **Interim Reliability Measure (IRM)** is a measure of expected USE in any region of no more than 0.0006% of energy demanded in any financial year. Current National Electricity Rules (NER) provisions specify that the IRM expires for the purposes of the RRO on 30 June 2028[6]. When reliability is forecast consistent with the IRM, consumers should expect larger USE events (on average 10% of average regional demand for five hours) at a frequency of one in every 10 years.
- The **reliability standard** is a measure of expected USE in each region of no more than 0.002% of energy demanded in any financial year. For the purposes of the RRO, it applies when the IRM expires. When reliability is forecast consistent with the reliability standard, consumers should expect larger USE events (on average 10% of average regional demand for nine hours) at a frequency of one in every five years.
- A **forecast reliability gap** occurs when expected USE is forecast in excess of the relevant standard (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.

For the coming summer, the reliability of existing plant will remain critical

For the vast majority of the year, there are surplus generation reserves in the NEM to ensure reliable operation of the power system. During extreme conditions, particularly extreme heat, temperature-sensitive loads such as air-conditioners tend to increase the needs of the power system. During these times, if availability of supply reduces from the fleet of generators across the NEM, reliability may be more challenging to maintain, demonstrating the critical need to maintain high reliability and performance from existing generators.

With relatively stable peak electricity demand forecast from 2023-24 to 2024-25, growing investments in CER, flexible demand resources, and approximately 2.3 GW more new generation and storage capacity expected to be available compared with that which was available last summer, the reliability of the NEM will rely primarily on on-time delivery of the new resources under development, and the continued availability and high performance of the existing generation fleet.

[6] In accordance with NER 11.132.2. In September 2023, the Australian Energy Market Commission (AEMC) amended the NER to extend the application of the IRM to the RRO from 1 July 2025 to 30 June 2028. See https://www.aemc.gov.au/rule-changes/extension-application-irm-rro.

Risks to energy availability, such as drought conditions and/or coal, gas, or diesel fuel shortfalls, also have the potential to reduce reliability in the NEM. The Energy Adequacy Assessment Projection (EAAP) included in **Chapter 6** explores these risks over a 24-month horizon. Under most likely conditions and under a low rainfall scenario, the EAAP identifies similarly low reliability risks. The EAAP identifies increased risks if thermal fuels are more scarce, continuing to highlight the importance of maintaining the availability of coal, gas, and distillate fuels, and the effective management of their supply chains.

Operational procedures may be able to minimise the risks to consumers in some circumstances, such as using Interim Reliability Reserves and Reliability and Emergency Reserve Trader (RERT) resources, where appropriate[7]. AEMO sought tenders[8] from parties for out of market reserves in response to the May 2024 Update to the ESOO, and will tender for reserves in response to this ESOO.

Over the near term, on-time and in-full delivery of committed, anticipated and federal and state government supported generation projects, as well as anticipated and actionable transmission developments and the coordination of embedded consumer resources, is critical for reliability

There are many federal and jurisdictional policies and programs that are actively funding and supporting new developments. Delivering these investments on time, and in full, is critical to maintaining reliability within the relevant standards in most regions, in most years, even after many existing generators close.

Federal and state schemes and programs currently underway include:

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

Further investments in dispatchable capacity and renewable energy generation under these schemes are also expected, but are not sufficiently identifiable to be modelled at this time.

A large pipeline of proposed generation and storage projects – totalling 178 GW of variable renewable energy and 111 GW of dispatchable resources (including battery, pumped hydro, and other technologies) – demonstrates the opportunity for the market to ensure reliability is maintained through the transition, if projects are developed in a timely manner.

Additional developments will complement these schemes, particularly transmission projects identified in the 2024 ISP as actionable, coordinated CER (largely behind-the-meter battery systems) and flexible demand response. The range of actionable transmission developments includes:

- New England Renewable Energy Zone (REZ) Network Infrastructure Projects, Sydney Ring South, the Hunter Transmission Project and the Hunter-Central Coast REZ Network Infrastructure Project in New South Wales.
- Gladstone Grid reinforcement and Queensland SuperGrid South projects in Queensland.

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7 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.

8 At https://aemo.com.au/energy-systems/electricity/emergency-management/reliability-and-emergency-reserve-trader-rert/rert-tendering.

- Mid North South Australia REZ Expansion in South Australia.
- Waddamana to Palmerston transfer capability upgrade in Tasmania.
- East and West Metro projects in Victoria.
- Strategic transmission projects which improve inter-regional transfer capacities, including Marinus Link, Victoria – New South Wales Interconnector West (VNI West) and the Queensland – New South Wales Interconnector (QNI) Connect.

Figure 1 shows that these investments in renewable generation, dispatchable capacity, transmission and coordinated CER are forecast to provide reliability levels within the relevant reliability standard in most regions in most years.

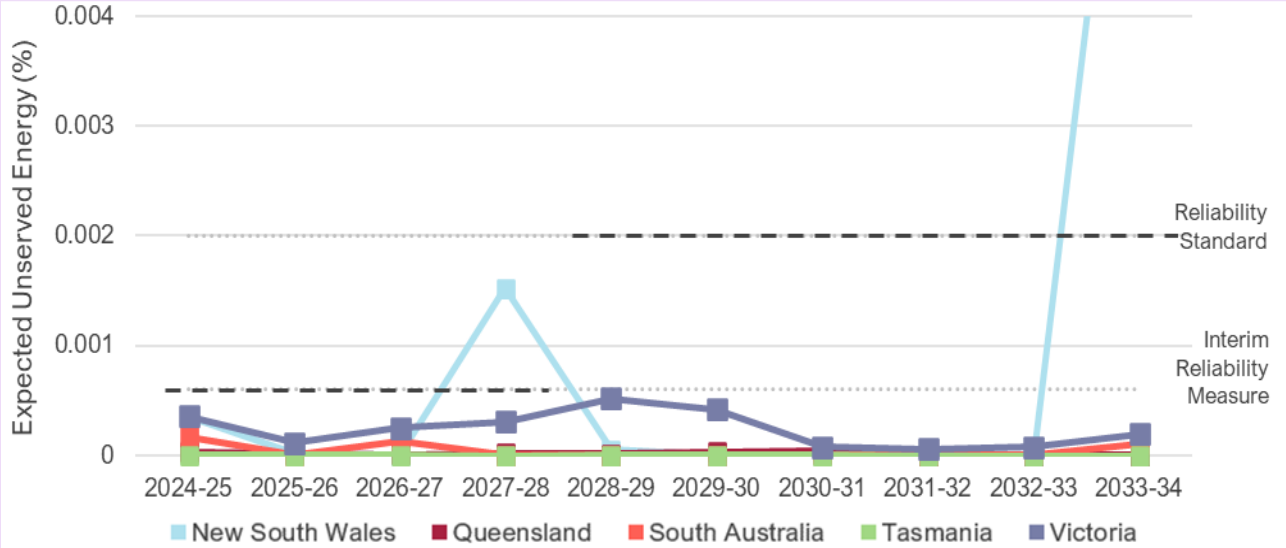
During the transition to new forms of energy supply it is critical for existing ageing coal generators to maintain high levels of availability and reliability prior to closure. Project development delays and broader international and domestic supply chain challenges are emerging as material risks to the delivery of transmission, generation and storage projects. Delays to the delivery of any of the identified projects, relative to the dates envisioned by the schemes and proponents, have the potential to result in periods of high risk throughout the 10-year horizon.

The *Federal and State Schemes* sensitivity in this ESOO includes existing, committed and anticipated developments to meet the ESOO Central demand forecast, delivered to the schedules advised by developers, as well as:

- Actionable transmission investments and forecast growth in coordinated CER and flexible demand resources.
- Firming and some renewable energy developments that have specific funding, development or contracting arrangements under federal, state and territory government schemes and programs.

This sensitivity does not include all policies under active development by jurisdictions, or announced targets within existing policies, and reliability outcomes will improve further if all jurisdictional schemes and programs deliver to their objectives.

Figure 1 Expected USE, additional actionable and anticipated developments, 2024-25 to 2033-34 (%)



This sensitivity includes only those announced and identifiable components of announced federal and state schemes, including various tender stages that have been concluded. Delivering planned subsequent tender stages will support further improvements to this reliability assessment.

If only those projects already committed or anticipated proceed, and if risks of commissioning delays eventuate as they have in recent years, reliability gaps are forecast in Victoria, New South Wales, and South Australia

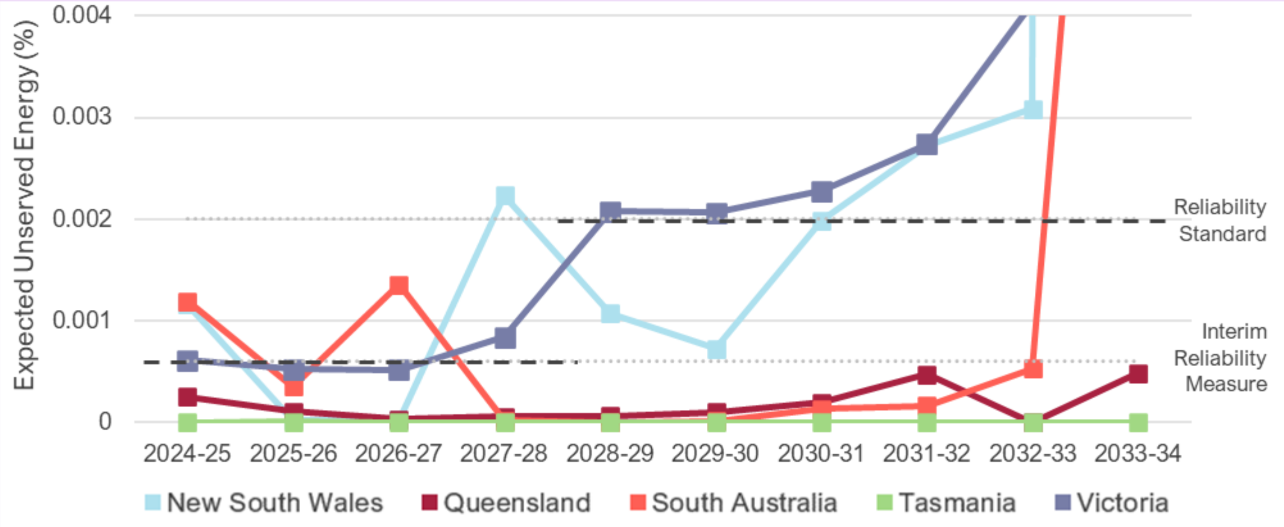
When considering only those energy supply infrastructure developments that have made sufficient progress against AEMO's commitment criteria, reliability gaps are forecast in Victoria, South Australia, and New South Wales in the next decade. This underscores the importance of the support from federal and state schemes to deliver additional generation, transmission, flexible demand resources, and consumer assets such as batteries that can be coordinated to reduce utility-scale investment needs.

In this sensitivity – which is used by AEMO under the National Electricity Rules to produce a reliability forecast and identify further actions to minimise risks under the RRO and AEMO's operational summer readiness processes –New South Wales, South Australia and Victoria are forecast with reliability risks above the IRM of 0.0006% USE. This means that if committed and anticipated projects only are delivered, and if they are delivered later than proponents advise (as has been observed in recent years), then these regions are more likely to experience tighter supply conditions during extreme conditions in summer when customer demand is extreme. During these conditions, out of market reserves may be used by AEMO to operate the system and further reduce the probability of involuntary customer load shedding.

Figure 2 shows the reliability forecast and indicative reliability forecast for the 2024 ESOO. This particular sensitivity, which applies for multiple regulatory requirements, consider only the sub-set of known developments that have demonstrated sufficient commitment towards commissioning in the NEM.

The *Committed and Anticipated Investments* sensitivity (the reliability forecast and indicative reliability forecast) includes existing, in commissioning, committed and anticipated generation, storage and transmission projects, according to AEMO's commitment criteria, as well as committed investments in demand flexibility and consumer batteries that are coordinated to minimise investment needs in utility-scale solutions. With only this pipeline of developments commissioning, and allowing for historically observed commissioning delays, then reliability gaps emerge in New South Wales, South Australia and Victoria at several points across the forecast horizon.

Figure 2 Expected USE, *Committed and Anticipated Investments* sensitivity, 2024-25 to 2033-34 (%)



The timing of each project's completion is a critical input to the reliability assessment. AEMO has observed that many projects are not delivered at the times indicated by proponents, and has assessed the actual completion times for projects compared to advised timing over the past three years. AEMO's reliability forecasting methodology assumed an adjustment to the proponent-supplied timing of project completion for projects not yet in commissioning phases to reflect the average difference in advised and recently observed commissioning. AEMO consulted with stakeholders in 2023 on the approach, with development and commissioning delays of six months for committed projects, and a minimum of 12 months for anticipated projects. AEMO acknowledges there are a variety of reasons for project schedule adjustments and not all projects will experience development and commissioning difficulties. This is a pragmatic approach that can be done within the capability of the modelling tools available. Reliability risks would be lower if these schedules were delivered to for all projects, as modelled in the 'on-time delivery sensitivity' (see **Section 4.2**), whereas longer delays to any other currently considered development may worsen the reliability outlook.

A large number of generation developments are classified as 'in commissioning', 'committed' or 'anticipated'. **In total, 20.2 GW of new scheduled or semi-scheduled generation and storage developments are classified within these commitment categories, and are forecast to be operational by 2033-34 alongside existing capacity.** This includes 5.7 GW of developments that have progressed sufficiently to be newly included since the 2023 ESOO, comprising 3.9 GW/13.5 GWh of batteries, 1.2 GW of large-scale solar, 0.4 GW of wind and 0.2 GW of hydrogen developments.

The developments below include estimated commissioning dates from participants and were included in the reliability forecast with average delay after these dates advised, of a minimum of six months to completion as per the ESOO methodology[9]. AEMO acknowledges that the actual completion dates will vary from this modelling approach:

- Hunter Power Station[10] (750 MW) in New South Wales from December 2024.
- Kidston Pumped Hydro Energy Storage (250 MW/2,000 megawatt-hours [MWh]) in Queensland from February 2025
- Snowy 2.0 (2,200 MW/350,000 MWh) in New South Wales by December 2028.
- Borumba Pumped Hydro (1,998 MW/48,000 MWh) in Queensland from September 2031.
- A 204 MW hydrogen generator as part of the South Australian Hydrogen Jobs Plan from December 2025.
- More than 8,500 MW/22,500 MWh of utility-scale batteries, including Eraring Big Battery, Liddell Battery Energy Storage System (BESS), Orana BESS, Richmond Valley BESS, Swanbank BESS, and Wooreen BESS.
- Numerous renewable energy developments across the NEM, including more than 4,000 MW of wind generation and 4,500 MW of utility-scale solar generation.

Committed and anticipated **transmission developments** will also improve the NEM's ability to share capacity between generation and load centres, including between regions. The developments below include estimated commissioning dates from each developer and were included in the *Committed and Anticipated Investments* sensitivity subject to delays after these dates advised as per the ESOO methodology[11]. Considered projects include:

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[9] *ESOO and Reliability Forecast Methodology Document*, 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.

[10] This Snowy Hydro generator development, comprising two open cycle gas turbines, has previously been referred to as 'Kurri Kurri Power Station' or 'Hunter Power Project'. See https://www.snowyhydro.com.au/hunter-power-project/.

[11] *ESOO and Reliability Forecast Methodology Document*, 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.

- Project EnergyConnect linking South Australia, New South Wales, and Victoria, with full capacity release by July 2027.
- Waratah Super Battery project, a System Integrity Protection Scheme (SIPS) that includes the battery project and transmission upgrades in New South Wales that collectively increase transmission transfer capacity within New South Wales. Full capacity release is advised by August 2025.
- HumeLink, a new transmission line which will connect Wagga Wagga, Bannaby, and Maragle, with full capacity release advised by December 2026.
- Western Renewables Link in Victoria, connecting renewable generation in north-west Victoria to Melbourne with full capacity release by July 2027
- Central-West Orana REZ Network Infrastructure Project, increasing the capacity for new renewable developments in New South Wales, with full capacity release by August 2028.

While reliability risks may be lower if new developments are commissioned on or ahead of schedule, commisioning delays to any other currently considered development are likely to worsen the reliability outlook.

While new developments continue to commission, existing generator operators have advised AEMO of an expected closure schedule[12] that includes approximately 11.2 GW of generation capacity (approximately 34% of the currently registered thermal – coal, gas and diesel – generation fleet) in the next 10 years. Any advancement of this closure schedule, or any additional mothballing of existing generators, would worsen the reliability outlook and necessitate further acceleration of investments in new generation, storage, transmisssion and/or flexible demand resources. The closure schedule includes:

- Torrens Island B Power Station[13] (800 MW) and Osborne Power Station (180 MW) in South Australia on 30 June 2026 and 31 December 2026 respectively.
- Eraring Power Station (2,880 MW) in New South Wales on 19 August 2027.
- Port Lincoln and Snuggery power stations (total 136 MW) in South Australia on 1 January 2028, although both stations are advised to remain mothballed until then.
- Yallourn Power Station (1,450 MW) in Victoria in 2028.
- Callide B Power Station (700 MW) in Queensland in 2028.
- Dry Creek and Mintaro power stations (total 246 MW) in South Australia in 2030.
- Hallett Gas Turbine (240 MW) in South Australia in 2032.
- Bayswater Power Station (2,715 MW) in New South Wales in 2033.
- Vales Point Power Station (1,320 MW) in New South Wales 2033.
- Mt Stuart Power Station (292 MW) in Queensland in 2033.
- Somerton Power Station (170 MW) in Victora in 2033.
- Several small wind and solar (total 160 MW), and BESS facilities (total 95 MW/109 MWh) in mainland regions between 2030 and 2033.

[12] All expected retirement dates are advised by participants.

[13] Torrens Island unit B1 (200 MW) is advised to remain mothballed until its closure date. Mothballing refers to when generating units are unavailable for service but can be brought back with appropriate notification, typically weeks or months.

Actions will be triggered in response to this *reliability forecast*

The Committed and Anticipated Investments sensitivity, which is used for AEMO's reliability forecast, identifies reliability gaps in the first five years of the horizon in:

- **Victoria in 2024-25 and 2027-28** against the IRM of 0.0006% USE and 2028-29 against the reliability standard of 0.002% USE. Forecast reliability gaps identified at the start of the horizon are lower than those forecast in the May 2024 Update to 2023 ESOO.
- **New South Wales in 2024-25 and 2027-28**, against the IRM of 0.0006% USE – forecast reliability gaps are no longer identified in 2025-26 and 2026-27 due to the delayed retirement of Eraring Power Station. The reliability gap identified in 2027-28 is lower than that forecast in the May 2024 Update to the 2023 ESOO, due to lower forecasts of maximum demand and the consideration of HumeLink as an anticipated project.
- **South Australia in 2024-25 and 2026-27** against the IRM of 0.0006% USE – the forecast reliability gap in South Australia has emerged as a result of mothballed gas generators in South Australia, and newly modelled network configurations in Victoria, that reduce reliability risks across both regions but allocate a greater portion to South Australia than the 2023 reliability assessments. The forecast reliability gaps identified in 2026-27 align with the retirement of the Torrens Island B and Osborne power stations in South Australia and are smaller than those identified in the May 2024 Update to 2023 ESOO.

Where this 2024 ESOO reliability forecast identifies a forecast reliability gap for a region, AEMO must request the AER to consider making a reliability instrument under Chapter 4A of the NER (**Retailer Reliability Obligation** [RRO]). In this 2024 ESOO, the forecast reliability gaps above require AEMO to request the AER to consider making the following RRO instruments:

- In **New South Wales**, a T-3 reliability instrument for 2027-28.
- In **Victoria**, a T-3 reliability instrument for 2027-28.

The indicative reliability forecast in the second five years of the horizon, which considered only currently committed and anticipated developments, shows expected USE is above the reliability standard of 0.002% USE:

- In **New South Wales** from 2031-32 to 2033-34.
- In **Victoria** from 2029-30 to 2033-34.
- In **South Australia** in 2033-34.

Additional investments in security and stability services and implementation of the National CER Roadmap are also required to enable a reliable and secure power system

A reliable power system requires more than just sufficient levels of installed capacity and available energy supplies. The system must also maintain an underlying set of security and stability services to ensure that it remains both stable and resilient under normal operating conditions, and following disturbances.

Over the coming decade, the rapid energy transition will result in a significant need for new assets and providers of these essential system services, including for system strength, frequency management, voltage control, ramping capability, and system restart services.

The timing and magnitude of these emerging requirements are influenced by:

- **Retiring thermal generation** – historically, thermal generation has been the source of much of the system strength, inertia, and system restart services in the NEM, and a significant source of voltage control and ramping capability. Replacement services will be needed as these units withdraw.
- **Increases in inverter-based resources (IBR) development** – adequate system strength, voltage control, and ramping capability will be needed to ensure that future levels of IBR can operate stably, and transfer energy to where it is needed.
- **Major network augmentations** – network upgrades can help reduce system security requirements by lowering system impedance and allowing better sharing of existing services across multiple locations. They can also impact the likelihood of regions becoming islanded and reduce the impact of credible network events, putting downward pressure on security needs.
- **Installation of CER** – the level of resources being installed by consumers in their premises has continued at high levels. Other resources such as EVs are also now growing. Integrated operation of these resources with the broader power system is necessary to ensure power system security can be maintained. The National CER Roadmap sets out a range of initiatives that will support integration and help to ensure all consumers can continue to benefit from these resources. Action both in the short and long term is needed as the level of CER continues to grow. This is particularly important for periods where high distributed photovoltaics (PV) relative to underlying demand results in minimum operational demand levels where action may be required to maintain power system security. This is anticipated to occur in all mainland regions in coming years.

Contents

1 Introduction, assumptions and modelling approach

The *Electricity Statement of Opportunities* (ESOO) covers a 10-year period to inform decisions by market participants, investors, and policy-makers in the National Electricity Market (NEM). It provides information on, and projections of:

- Electricity demand and energy requirements.
- Electricity supply from generators and demand response, considering normal transmission and power system limitations.
- Power system reliability, including the reliability forecast and indicative reliability forecast developed in accordance with the Retailer Reliability Obligation (RRO).

This publication also incorporates the Energy Adequacy Assessment Projection (EAAP), which provides additional analyses of broader energy limitations affecting coal, gas and water availability, and the impact on reliability risks over a two-year period.

The ESOO provides a variety of information to inform decisions by market participants, investors and policy-makers in the NEM. It also includes a reliability forecast for RRO purposes which demonstrates the electricity investments required to maintain reliability in the NEM at the relevant reliability standard, including whether any reliability gap exists with only existing, committed and anticipated[14] investments.

Key operational strategies such as maintenance planning, fuel management and contracting for demand response are important in the short term. Over the longer term, sufficient time exists for further transmission, generation, storage developments and/or demand response to be developed to reduce reliability risks.

The RRO requires retailers and other liable entities to hold contracts or invest directly in generation or demand response to support reliability in the NEM, should AEMO identify reliability risks under certain conditions.

To identify the need for further developments in the NEM, the ESOO and EAAP reliability assessments compare the most likely projection of electricity demand to a projection of supply that considers only those developments for which formal commitments have been made. The reliability gaps identified as a result may lead to action by retailers to contract capacity to cover their loads under the retailer reliability obligation framework. With a significant pipeline of announced generation and storage projects, significant opportunity exists for the reliability requirements of the NEM to be met.

In addition to providing reliability assessments and forecasts, AEMO has power system security assessment obligations under the National Electricity Rules (NER). AEMO releases annual assessments of system strength, inertia and network support and control ancillary services (NSCAS) needs following the release of the ESOO, including declarations of shortfalls

[14] Commitment criteria relate to land, contracts, planning, finance, and construction and 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.

and gaps which are required to be addressed by transmission network service providers (TNSPs)[15]. Discussion and further information on some of these services is included in **Chapter 7**.

1.1 Forecasting supply and reliability

Following extensive stakeholder consultation, AEMO has updated its NEM forecasts and supply adequacy assessment 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 energy efficiency measures and growth in consumer energy resources (CER), including distributed photovoltaic (PV) generation, battery energy storage systems (BESS) and electric vehicles (EVs).
- Updating the supply available to meet this demand to include the latest information on existing, committed and anticipated generation and transmission investments in the NEM, as well as expected generator 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[16] which assesses the ability of existing, committed and anticipated generation to meet forecast demand at all times in the year. The model calculates expected unserved energy (USE) over a number of forecast conditions impacting demand and renewable generation (based on 14 historical reference years of weather) and random generator outages, weighted by likelihood of occurrence, to determine the probability of any supply shortfalls.

Explaining unserved energy

Unserved energy (USE) represents energy that cannot be supplied to consumers when demand exceeds supply under certain circumstances, resulting in involuntary load shedding (loss of customer supply) in the absence of out of market intervention, such as the Reliability and Emergency Reserve Trader (RERT)[17] or other voluntary curtailment. For example, USE could be caused by:

- Insufficient levels of generation capacity, generation energy output, or demand response relative to consumer demand.
- Insufficient levels of transmission capacity within each region, assuming that this transmission is never subject to any outages.
- Insufficient levels of transmission capacity between regions, assuming that this transmission is only ever subject to single-circuit, credible outages.

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[15] AEMO's system security assessments are at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/planning-for-operability.

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

[17] In this report, RERT may include interim reliability reserves, as per NER 3.20 and 11.128.

All USE events will be described operationally as a 'Lack of Reserve 3' (LOR3) event, however not all LOR3 events are USE events. Other events that may result in involuntary load shedding, but that are not defined by NER 3.9.3C as USE, include:

- Distribution and transmission network outages that directly impact local supply.
- Transmission outages that curtail generation, resulting in insufficient levels of supply relative to demand.
- Power system security events, for example a double-circuit outage on a transmission line.
- Prolonged generator or transmission outages that persist following power system security events, resulting in insufficient levels of supply relative to demand.

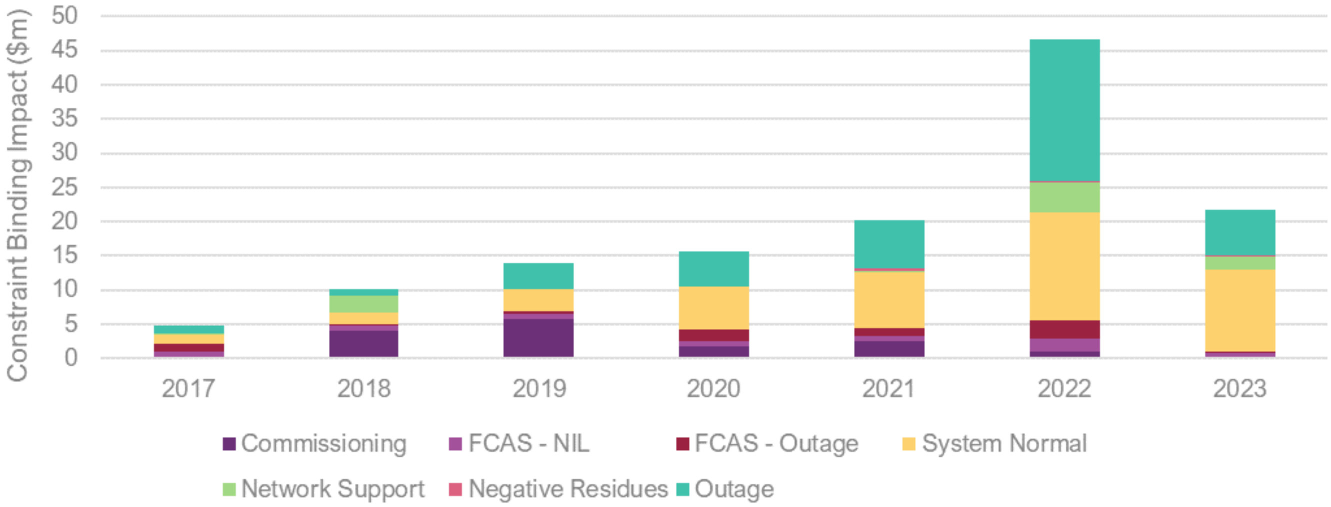
AEMO forecasts **expected USE** by calculating the weighted-average USE over a wide range of simulated outcomes.

Limitations with the current definition of USE

Outages on the transmission network are increasingly responsible for the curtailment of generation, reducing available supply. As these outages are explicitly excluded from the definition of USE, AEMO does not forecast their impact in reliability assessments.

Figure 3 shows the NEM constraint binding[18] impact, which represents the financial impact of the binding constraint equations from 2017 to 2023 as published in the NEM Constraint Report 2023[19]. Constraint binding impact in 2022 was affected by June 2022 market interventions, while 2023 has returned to more typical conditions. While the constraint binding impact has grown across many categories, the impact of transmission outages ('Outage' in the figure) has grown to be one of the largest causes of constraints binding, and generation curtailment.

Figure 3 NEM constraint binding impact



[18] Constraint binding impact is a proxy of the value per megawatt-hour (MWh) of congestion on the power system, and is used to distinguish the severity of different binding constraint equations.

[19] See https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/congestion-information-resource/statistical-reporting-streams.

As the generation fleet becomes more geographically diverse, and the power system becomes more interconnected, the exclusion of transmission outages that impact supply availability from the reliability assessments is likely to result in larger consumer impact risk than that forecast by AEMO in this ESOO and EAAP.

Equitable load shedding

AEMO's modelling does not include "equitable involuntary load shedding" (an operational measure to spread USE throughout interconnected regions in proportion to demand)[20]. Instead, the forecast annual USE in a region reflects the projected location of any supply shortfall, and is intended to provide participants with the most 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 given the availability or expected efficiency of capacity sharing across the transmission system, including interconnector transfers.

The assessment does recognise that the NEM is an interconnected system, not a collection of independent regions. That means that if a significant imbalance between supply and demand is projected to emerge in one region (potentially following generator withdrawals or a large increase in consumer demand), 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 1.3**).

1.1.1 Reliability measures in the NEM

The ESOO measures reliability risks relative to two key standards determined by the Australian Energy Market Commission's (AEMC's) Reliability Panel.

The **Interim Reliability Measure (IRM)** is a measure of expected USE in any region of no more than 0.0006% of energy demanded in any financial year. Current NER provisions specify that the IRM applies for the purposes of the RRO until 30 June 2028. The IRM does not apply to the EAAP. For information purposes, AEMO reports on reliability against this measure for all periods in the ESOO and EAAP horizons.

Reliability under the IRM of 0.0006% expected USE

When expected USE is forecast in a region at the level of the IRM, the following reliability risks are forecast:

- USE events would statistically occur approximately once every five years.
- Larger USE outcomes[21] would occur approximately once every 10 years (equivalent to approximately 10% of average regional demand for five hours, or comprising multiple events that aggregate to this total).
- Load shedding events of even greater magnitude are possible, particularly if combined with transmission outages, and/or persistent generator or transmission outages following power system security events.
- Out of market mechanisms may be available and could be used to mitigate some of the risks with associated costs.

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

[21] When *expected* USE is forecast at the IRM of 0.0006% USE, a larger USE outcome (among the many individual outcomes simulated) is typically 10% probable. A larger USE outcome is assessed as an individual USE outcome above the reliability standard of 0.002% USE.

The **reliability standard** is a measure of expected USE in each region of no more than 0.002% of energy demanded in any financial year. For the purposes of the RRO, it applies at this level unless the IRM applies. For the purposes of the EAAP, it applies over the entire two-year horizon.

For information purposes, AEMO reports on reliability risks against this measure for all periods in the ESOO and EAAP horizons.

Reliability under the reliability standard of 0.002% expected USE

When expected USE is forecast in a region at the level of the reliability standard of 0.002% USE, the following reliability risks are forecast:

- USE events would occur approximately once in every three years.
- Larger USE outcomes[21] would occur approximately once every five years (equivalent to approximately 10% of average regional demand for nine hours, or comprising multiple events that aggregate to this total).
- Load shedding events of even greater magnitude are possible, particularly if combined with transmission outages, and/or persistent generator or transmission outages following power system security events.
- Out of market mechanisms may be available and could be used to mitigate some of the risks with associated costs.

1.1.2 Definitions for the Retailer Reliability Obligation (RRO)

The **reliability forecast** refers to the first five years of the *Committed and Anticipated Investments* sensitivity forecast horizon. For the 2024 ESOO, the reliability forecast covers the financial years 2024-25 to 2028-29.

The **indicative reliability forecast** refers to the second five years of the *Committed and Anticipated Investments* sensitivity forecast horizon. For the 2024 ESOO, the indicative reliability forecast covers the financial years 2029-30 to 2033-34.

Any **forecast reliability gap** is based on forecast USE in excess of the relevant standard in a region in a financial year. Such a gap exists for a NEM region if the expected USE exceeds the IRM of 0.0006% USE up until 30 June 2028, or exceeds the reliability standard of 0.002% USE from 1 July 2028 onwards.

If AEMO reports a forecast reliability gap, AEMO must request for the Australian Energy Regulator (AER) to consider creating a reliability instrument under the RRO. If there is a forecast reliability gap, the reliability forecast must 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 [MW]).

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 (the IRM or the reliability standard, as appropriate). For the purposes of calculating the reliability gap, this capacity is assumed to be 100% available and fully unconstrained during throughout all periods of the forecast year.

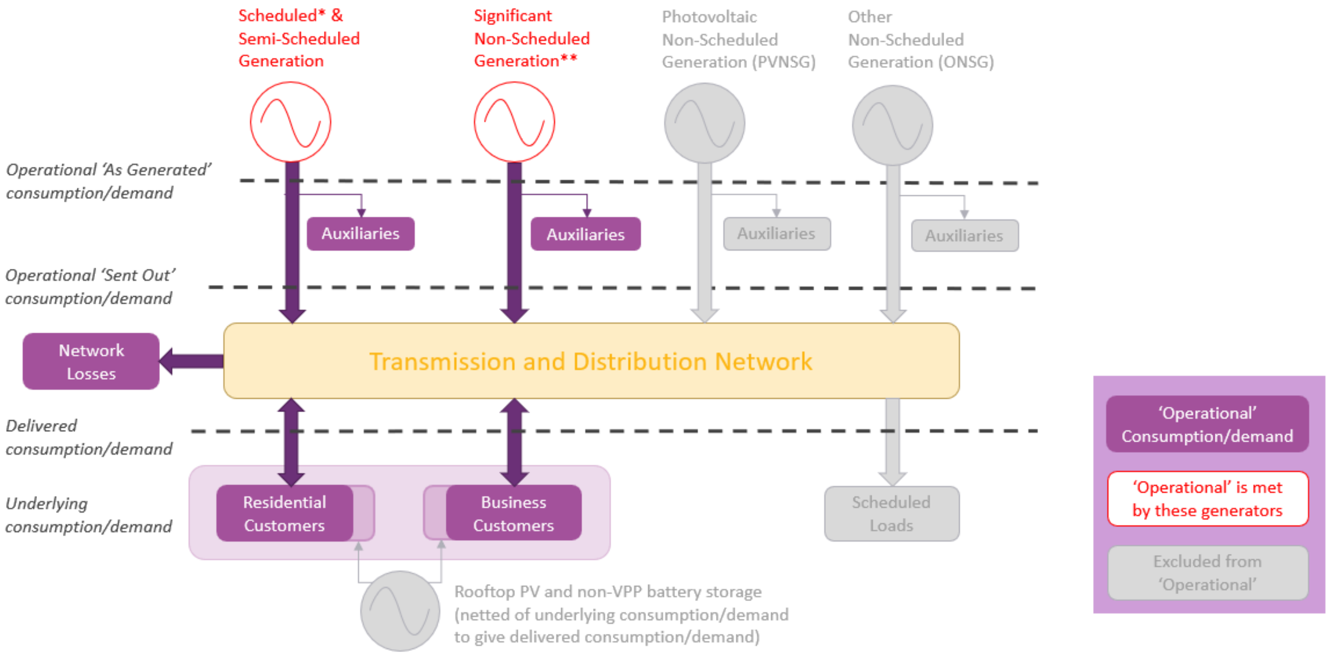
1.2 Forecasting demand

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 times of maximum and minimum demand.

Consumption and demand can be measured at different locations in the electricity network. Unless otherwise stated, the forecasts in this report refer to **operational consumption/demand (sent out)**[22]. This is the supply to the grid by scheduled, semi-scheduled, and significant non-scheduled generators (net of their auxiliary loads, being the electricity used by the generator itself). 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 transmission system to household and business consumers. Delivered consumption also includes electricity required to charge electric vehicles. 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 transmission system but also, increasingly, from other sources including CER, including distributed PV and battery storage.

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

Maximum and minimum operational demand means the highest and lowest level of electricity drawn from the transmission system, measured and averaged from the power system in half-hour intervals in either **summer** (November to March for mainland regions and December to February for Tasmania) or **winter** (June to August). 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-year).
- A **90% POE** (for maximum demand) or **10% POE** (for minimum demand), based on less extreme conditions that could be exceeded nine years in 10.

1.2.1 Demand scenarios

In consultation with a diverse range of stakeholders, AEMO developed the 2023 *Inputs, Assumptions and Scenarios Report* (IASR) for use in its forecasting and planning publications, including the 2024 ESOO and the 2024 *Integrated System Plan* (ISP). Further, AEMO has developed the 2024 *Forecasting Assumptions Update* to incorporate updates to inputs and assumptions which have changed since the 2023 IASR.

Three scenarios were developed for planning the power system and identifying its investment needs. The ESOO forecasts the opportunities for additional generation, transmission and demand response developments beyond those developments for which sufficient commitments have already been made in the power system to meet each scenario's forecast consumer demand, accounting for CER investments and other demand developments.

This ESOO provides insights for each of the scenarios as follows:

- Consumption and demand has been forecast for each of the scenarios shown in **Figure 5**, across a forecast period of approximately 30 years. The forecasts for each region are in Appendices A1-A5.
- For RRO purposes, AEMO's Reliability Forecast Guidelines[23] require that the reliability and indicative reliability forecasts are determined from the scenario AEMO considers most likely. For the 2024 ESOO, AEMO considers the *Step Change* demand scenario the most likely and refers to it as the 2024 ESOO Central scenario. AEMO considers the individual inputs that comprise 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.
- All reliability assessments included in this ESOO apply the ESOO Central scenario (*Step Change* demand scenario), across a range of sensitivities to key assumptions and uncertainties affecting the reliability forecast over the 10-year outlook.

[23] 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 5 2023 IASR scenarios for AEMO's forecasting and planning publications

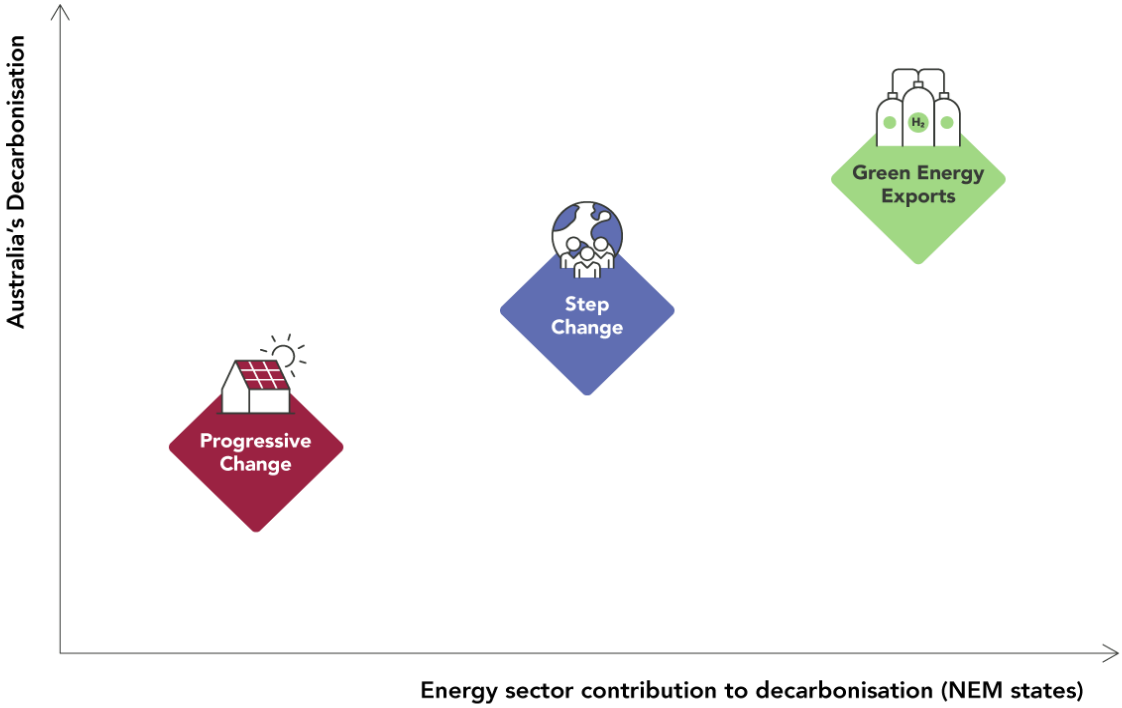


Table 1 summarises the scenarios presented in this ESOO, while **Table 2** summarises inputs for each scenario that are relevant to the demand forecasts. More information is available on the scenarios in the 2023 IASR[24].

Table 1 Descriptions of 2023 scenarios for AEMO's forecasting and planning publications

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

[24] At https://aemo.com.au/consultations/current-and-closed-consultations/2023-inputs-assumptions-and-scenarios-consultation.

Table 2 Scenario drivers of most relevance to the NEM demand forecasts used in this 2024 ESOO

Parameter	*Green Energy Exports*	*Step Change*	*Progressive Change*
Global economic growth and policy coordination	High economic growth, stronger coordination	Moderate economic growth, stronger coordination	Slower economic growth, lesser coordination
Australian economic and demographic drivers	Higher (partly driven by green energy)	Moderate	Lower
CER uptake (batteries, PV and EVs)	Higher	High	Lower
Consumer engagement such as virtual power plant (VPP) and DSP uptake	Higher	High (VPP) and Moderate (DSP)	Lower
Energy efficiency	Higher	Moderate	Lower
Hydrogen use	Faster cost reduction. High production for domestic and export use	Medium-Low production for domestic use, with minimal export hydrogen	Low production for domestic use, with no export hydrogen.
Supply chain barriers	Less challenging	Moderate	More challenging
Global/domestic temperature settings and outcomes[A]	Applies Representative Concentration Pathway (RCP) 1.9 where relevant (~ 1.5°C)	Applies RCP 2.6 where relevant (~ 1.8°C)	Applies RCP 4.5 where relevant (~ 2.6°C)
IEA 2021 World Energy Outlook scenario	Net Zero Emissions (NZE)	Sustainable Development Scenario (SDS)	Stated Policies Scenario (STEPS)

RCPs were adopted in the IPCC's first Assessment Report; see https://www.ipcc.ch/report/ar5/syr/.

1.3 Additional information in the 2024 ESOO

ESOO information under NER 3.13.3A

The following information should be considered part of the 2024 ESOO:

- The 2024 ESOO report and supplementary information published on the 2024 ESOO webpage[25].
- The demand forecasting data portal[26].
- The July 2024 Generation Information page[27].
- The August 2024 Transmission Augmentation Information page[28].
- The 2023 IASR[29], accompanying assumptions workbook and supplementary material.
- The 2024 Forecasting Assumptions Update[30], accompanying assumptions workbook and supplementary material.

[25] 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.

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

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

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

[29] At https://aemo.com.au/en/consultations/current-and-closed-consultations/2023-inputs-assumptions-and-scenarios-consultation.

[30] At https://aemo.com.au/consultations/current-and-closed-consultations/2024-forecasting-assumptions-update-consultation.

To meet the obligations under the RRO[31], the ESOO also includes:

- **Reliability forecasts** identifying any potential reliability gaps for each of this financial year and the following four years (see **Section 4.1.1)**.
- **Indicative reliability forecasts** of any potential reliability gaps for each of the final five years of the 10-year ESOO forecast period (see **Section 4.1.2**).

Reliability forecast under the RRO

In the 2024 ESOO, the reliability forecasts and indicative reliability forecasts published in accordance with the RRO constitute **Section 4.1** in this report. Key component forecasts and inputs include:

- Consumption and demand forecasts (see **Chapter 2**, the demand forecasting data portal[32], and the demand traces[33]).
- Supply forecasts (see **Chapter 3** and the renewable generation traces[33]).
- The accompanying July 2024 Generation Information page[34].
- Sections of the 2024 Forecasting Assumptions Update that comprise the Forecasting Components of the Forecasting Approach for ESOO and Reliability Forecast purposes:
  - Annual consumption forecast components (for large industrial load, commercial, and residential forecasts) and maximum and minimum demand forecasts, including demand traces (Section 2.2 of the 2024 *Forecasting Assumptions Update*).
  - CER forecasts (Section 2.2.2 of the 2024 *Forecasting Assumptions Update*).
  - Renewable generation traces (Section 2.1 of the 2024 *Forecasting Assumptions Update*).
  - Demand side participation (DSP) forecasts (Section 2.2.10 of the 2024 *Forecasting Assumptions Update*).
  - Generator outage rates (Section 2.3.1 of the 2024 *Forecasting Assumptions Update*).

Further information and links

Table 3 provides links to additional information provided either as part of the 2024 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***	https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-approach

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

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

[33] Supporting traces (demand, renewable energy) are available 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.

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

Information source	Website address and link
• ***Demand Side Participation (DSP) Forecasting Methodology*** • ***Reliability Forecast Guidelines*** • ***ESOO and Reliability Forecast Methodology Document***	https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/dsp-forecasting-methodology-and-dsp-information-guidelines-consultation/final-stage/2023-dsp-forecast-methodology.pdf?la=en
2023 *Inputs, Assumptions and Scenarios report* (IASR)	https://aemo.com.au/en/consultations/current-and-closed-consultations/2023-inputs-assumptions-and-scenarios-consultation
2024 Forecasting Assumptions Update	https://aemo.com.au/consultations/current-and-closed-consultations/2024-forecasting-assumptions-update-consultation
2024 ESOO supplementary results, data files, and constraints, including: • **2024 ESOO model and user guide** • **2024 ESOO demand and variable renewable energy traces** • **2024 ESOO reliability outcomes by region**	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.
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
Transmission Augmentation Information page	https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/transmission-augmentation-information
Integrated System Plan	https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp
***Forecasting Best Practice Approach Report* (submitted by AEMO to the AER)**	To be published by the AER.
Consultant reports supporting the development of the 2023 IASR, 2024 *Forecasting Assumptions Update* and ESOO	
Deloitte Access Economics, *Economic Forecasts 2023/24*	https://aemo.com.au/consultations/current-and-closed-consultations/2024-forecasting-assumptions-update-consultation
CSIRO, Electric Vehicle Forecasts Report	https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/2024-forecasting-assumptions-update-consultation-page/csiro---2023-electric-vehicle-projections-report.pdf?la=en
Green Energy Markets, 2023 Consumer Energy Resources Projection Report	https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/2024-forecasting-assumptions-update-consultation-page/green-energy-markets---2023-consumer-energy-resources-projection-report.pdf
CSIRO and ClimateWorks Centre: 2022 Multisector modelling	https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/csiro-climateworks-centre-2022-multisector-modelling-report.pdf?la=en
AEP Elical – *Assessment of Ageing Coal-Fired Generation Reliability*	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.

2 Consumption and demand forecasts

Consumer demand is a key consideration in the assessment of supply adequacy. This chapter discusses the forecasts of annual consumption as well as maximum and minimum demand as forecast for this 2024 ESOO. It focuses commentary on the next 10 years, and includes forecasts over the next 30 years. The key observations are:

- Annual consumption growth over the next decade is predicted to occur at a slower pace than forecast in the 2023 ESOO, due to lower electric vehicle uptake, a slower pace of economic growth affecting small to medium businesses, and higher distributed PV forecasts from households investing in larger PV systems than previously forecast. Accelerating investment in data centres is an emerging driver of growth.
- As a result of these drivers, maximum demand is also forecast to grow at a slower rate than forecast in the 2023 ESOO. Forecasts of minimum demand continue to show a rapid decline, particularly as a result of the impact of continued uptake of distributed PV systems.

Longer-term consumption and demand forecasts to 2054, 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, electrification of other sectors, energy efficiency savings, new household connections, and economic growth – are discussed in AEMO's 2024 *Forecasting Assumptions Update*[36].

Main consumption trends include:

- Business electrification and EV adoption continue to drive consumption growth over the next 10 years. This is despite a downward revision of the EV forecast in this ESOO, based on lower rates of new vehicle purchases and clearer understanding of the now-legislated Federal Government's New Vehicle Efficiency Standard (NVES)[37].
- Hydrogen production continues to be an emerging consumer of electricity, however, the scale and timing of production remains a key uncertainty, similar to the 2023 ESOO.
- Accelerating investment in data centres to cater for the projected demand for streaming services, cloud storage and artificial intelligence (AI) applications, is emerging as a significant contributor to forecast demand. While data centres

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

[36] At https://aemo.com.au/consultations/current-and-closed-consultations/2024-forecasting-assumptions-update-consultation.

[37] At https://www.legislation.gov.au/C2024A00034/asmade/text.

will increase annual consumption, the potential flexibility of these loads and/or the provision of on-site generation means that their impact on maximum demand is uncertain.

- Slower growth in the business mass market (BMM) sector reflects lower economic optimism including weaker consumer spending in the short term, as compared to the 2023 ESOO.
- Sustained growth in distributed PV generation from households adopting larger PV systems, as well as continued improvement in residential and business energy efficiency, both offset energy consumption.

2.1 Drivers of electricity consumption and demand

Australia's transition towards a net zero emission economy by 2050 remains a key influence on forecast consumption and peak demand, as consumers use the NEM's falling emissions intensity to reduce their emissions footprint. Relevant drivers in the *Step Change* scenario – considered the most likely, or Central scenario, in this 2024 ESOO – include a strong influence from growth in electrification of both business and residential sectors, continued uptake of CER including distributed PV, and the electrification of transport, primarily via EVs. The expansion of data centres – specifically with the rise of larger hyperscale facilities – has the potential to be a catalyst for substantial increases in electricity consumption for New South Wales and Victoria in particular. Emerging hydrogen production for primarily domestic use is also an influence beyond the 2030s.

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

Industrial and business consumption is mainly driven by economic factors. An increase in data centre, mining and manufacturing load is responsible for over half of forecast load growth for large industrial users over the next 10 years. Load growth related to the development of new large-scale data centres in particular outpaces projections from previous ESOOs (which have not historically identified these facilities as an explicit driver of new load growth). Consumption by small to medium-sized commercial enterprises (aggregated in AEMO's BMM sector forecasts) is projected to grow at a slower pace than forecast in 2023 due to subdued economic growth, including weaker consumer spending. Businesses are forecast to continue to electrify their operations, fuel-switching from gas to electricity. Slower forecast development of major hydrogen production projects has reduced projected electricity consumption for hydrogen production purposes in this ESOO.

Population growth and a corresponding increase in residential new builds is expected to continue to drive increasing underlying demand for the residential sector. Consistent with the 2023 ESOO households are projected to continue to invest in behind-the-meter PV. A trend towards larger PV systems is expected to continue enabling households to offset a larger share of their electricity needs.

Drivers of annual electricity consumption for business and residential users also influence maximum (and minimum) demand forecasts, but random weather-driven elements and co-incident customer behaviours, have a larger influence on the magnitude of underlying demand peaks, while the extent of co-ordination of consumer battery charging and discharging will also impact operational demand peaks. As previous ESOOs have noted:

- Maximum demand periods are forecast to frequently occur outside daylight hours in all regions, reducing the impact that distributed PV uptake has on maximum demand.

- Minimum demand is continuing to decline, driven by distributed PV output that is eroding daytime operational demand.
- Weather extremes drive peak operational demand variability, which increases reliability risks and makes operability more challenging. Demand flexibility across the day, and the year, can reduce this challenge.

2.2 Underlying consumption continues to increase, with CER and energy efficiency slowing operational consumption growth

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

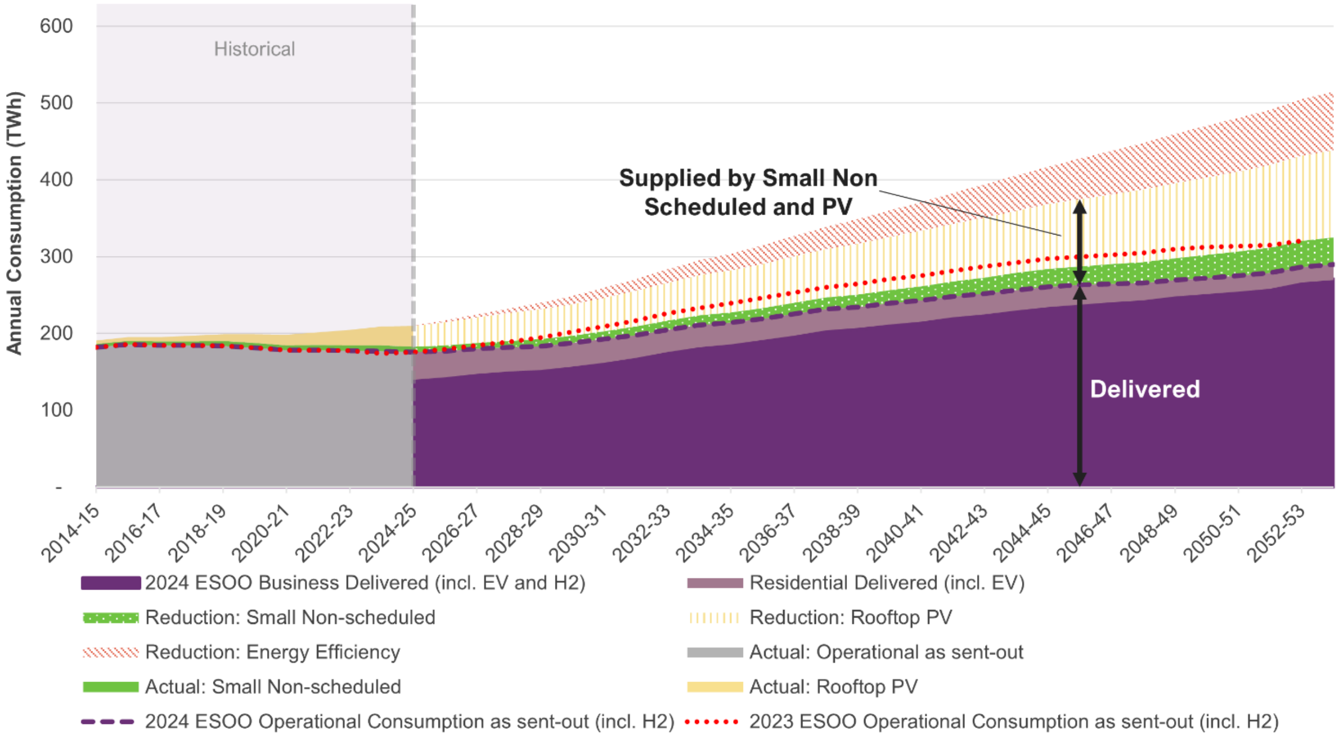
Figures 6 to **8** show forecast annual consumption by segment in the ESOO Central forecast over the next 30 years, and highlights influencing factors contributing to projected changes in consumption over the next decade. This outlook of operational consumption (dark purple dashed line) is also compared to the 2023 ESOO forecast (red dotted line).

Figure 9 provides a breakdown of the different components for forecast consumption in 2033-34 for each of the three scenarios, providing a snapshot of what consumption might look like in a decade.

In all these charts, components that increase operational consumption are drawn in solid colours, while components reducing operational consumption are drawn with a shaded pattern, with the net operational consumption forecast marked either with a dashed line (**Figures 6** to **8**) or with an ‘X’ (**Figure 9**).

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. Each region may also have variations in the level of policy-driven investments affecting forecast electricity consumption for each segment and component. For example, Victoria has more gas heating load and therefore greater potential for residential electrification than other regions, while the proportion of consumption coming from large industrial loads in Tasmania is considerably greater than other NEM regions. Regional trends and drivers are discussed in **Appendices A1** to **A5**.

Figure 6 Actual and forecast NEM electricity consumption, ESOO Central scenario, 2014-15 to 2053-54 (terawatt hours [TWh])



Note: Rooftop PV combines residential and non-residential PV. Small non-scheduled combines PV non-scheduled generation (PVNSG) and Other non-scheduled generation (ONSG) – whereby ONSG is non-scheduled generation that excludes distributed PV, and includes generation sources such as wind power and biomass.

Figure 7 Components of residential consumption forecast, ESOO Central scenario, 2024-25 to 2053-54 (TWh)

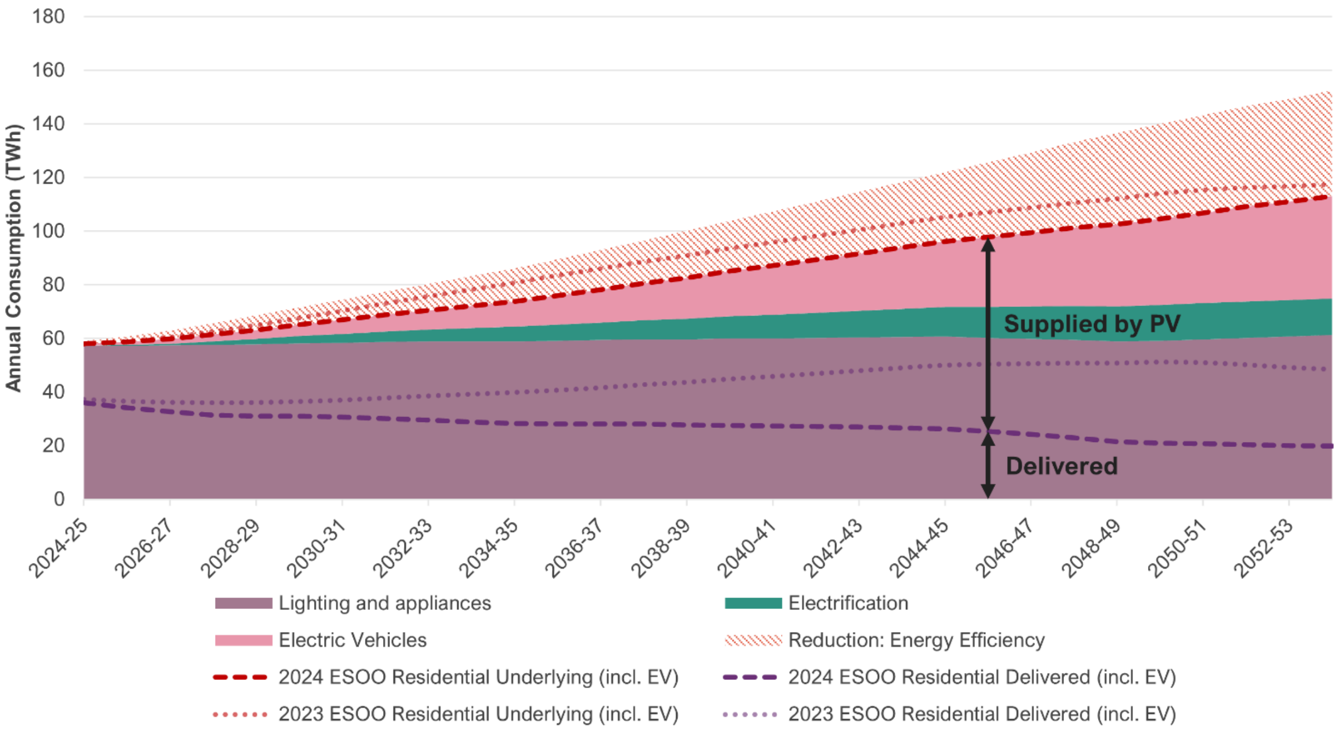
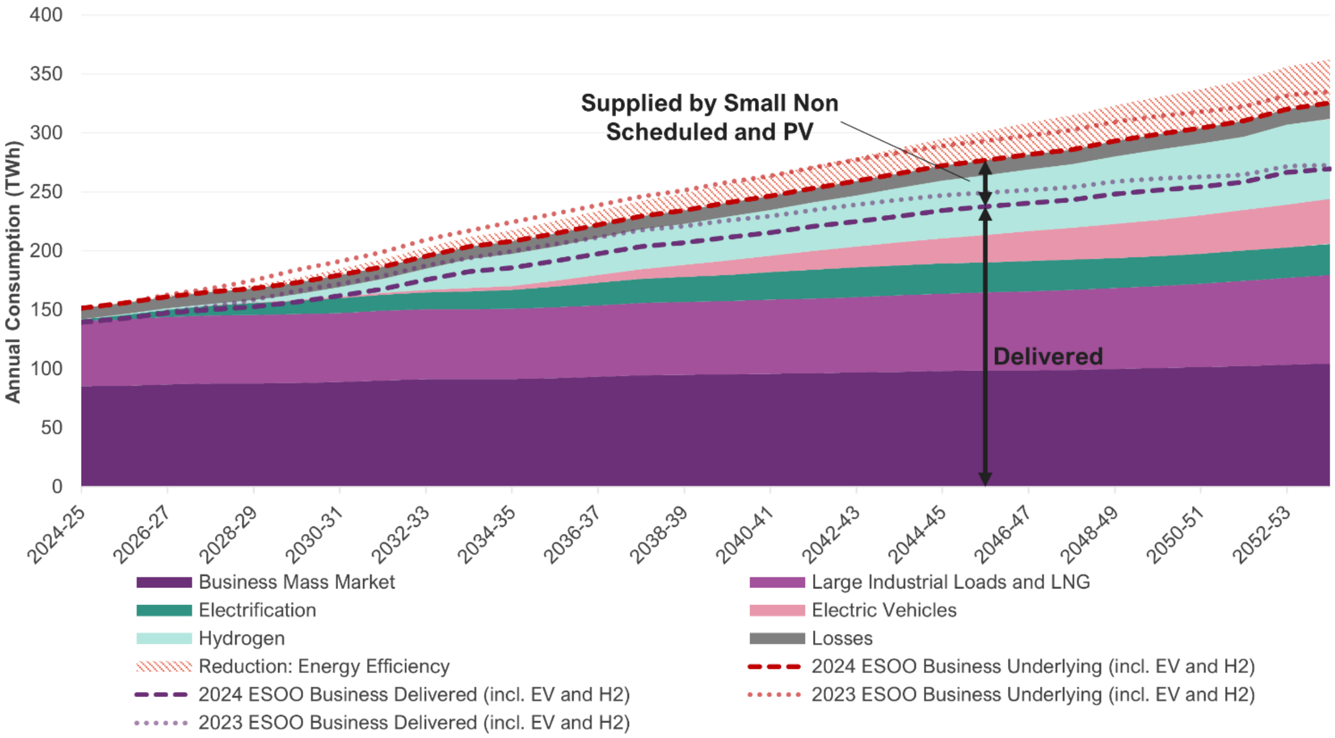
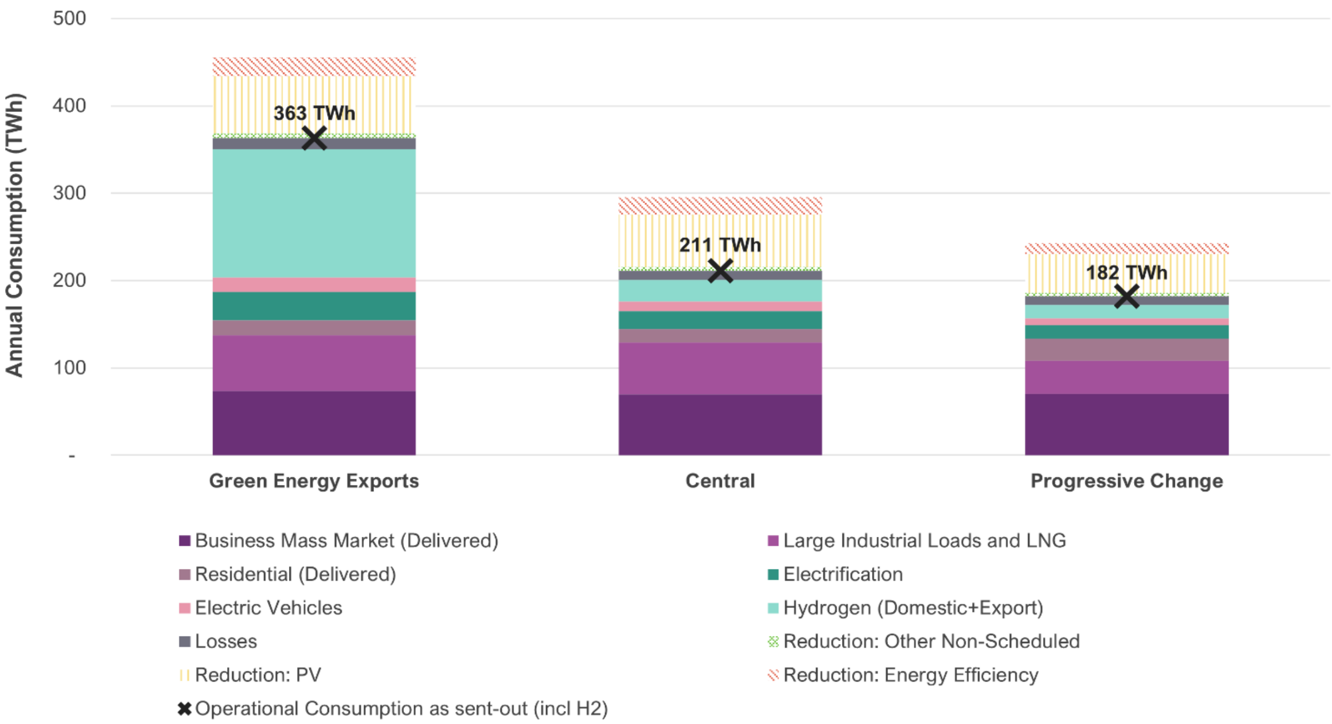


Figure 8 Components of business consumption forecast, ESOO Central scenario, 2024-25 to 2053-54 (TWh)



Note: small non-scheduled combines PVNSG and ONSG.

Figure 9 Forecast NEM consumption (by component) for the three ESOO scenarios, 2033-34 (TWh)



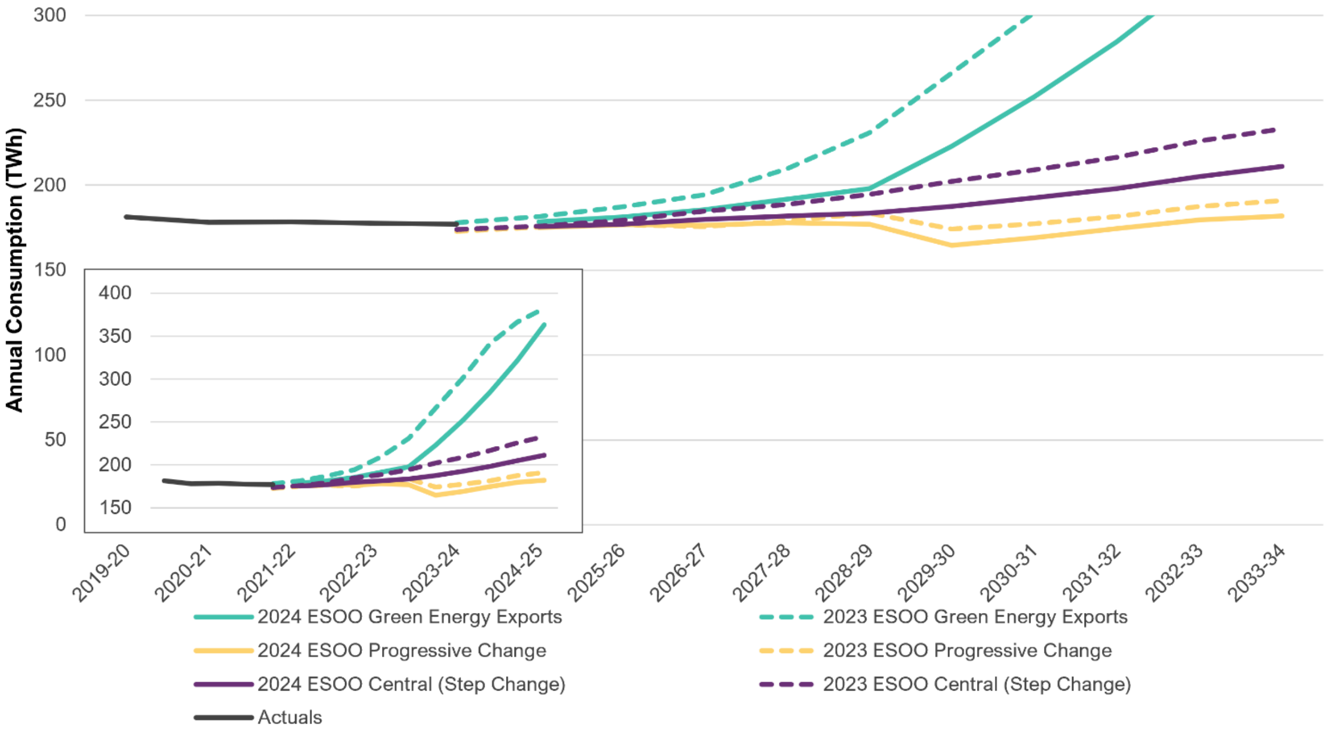
Operational consumption is forecast in the ESOO Central scenario to increase from 175 terawatt hours (TWh) in 2023-24 to around 211 TWh by 2033-34, largely due to projected growth in business and residential electrification, EV adoption, business load growth, and hydrogen production. This growth is partially offset by the sustained uptake of distributed PV and further improvements in energy efficiency.

Compared to the 2023 ESOO there is a net reduction in operational consumption in the ESOO Central scenario in 2033-34, predominantly driven by expectations of slower uptake of EVs, a less optimistic outlook for the BMM sector, and increased generation from household PV.

As outlined above, distributed PV and energy efficiency investments will reduce the need for electricity to be provided from traditional sources of generation to meet customer demand. Distributed PV and energy efficiency forecasts have both been updated and published in the 2024 *Forecasting Assumptions Update*[38]. Compared with the 2023 ESOO, this ESOO forecasts slightly fewer PV systems being installed, however this is outweighed by an increase in the average system size of new installations[39], leading to an overall increase in forecasted distributed PV generation.

AEMO models multiple scenarios to capture a range of possible future outcomes; the alternative scenarios reflect a similar level of spread as was presented in the 2023 ESOO (see **Figure 10**).

Figure 10 Actual and forecast NEM operational consumption, including hydrogen exports, all ESOO scenarios and compared to 2023 ESOO, 2019-20 to 2033-34 (TWh)



The *Green Energy Exports* scenario continues to have the greatest increase in consumption, largely stemming from the potential for hydrogen production from the 2030s. Relative to the 2023 ESOO, this scenario features slower growth in prospective green hydrogen projects as more limited progress has been observed and is now expected in the near term since the 2023 ESOO forecasts. As per the 2023 ESOO, *Progressive Change* captures downside risks including weaker

[38] At https://aemo.com.au/consultations/current-and-closed-consultations/2024-forecasting-assumptions-update-consultation.

[39] Average rooftop PV system size is forecast to increase from approximately 8 kW currently to 9.5 kW on average over the next decade.

economic conditions and more challenging domestic and international supply chain considerations affecting the evolution of consumer demand, and incorporates potential industrial closures in the short to medium term of major industries across the NEM. Under the *Progressive Change* scenario, households and businesses continue to invest in CER to manage their bills in the face of comparatively higher electricity prices.

The operational consumption forecasts for other scenarios are available to view or download from AEMO's Forecasting Portal[40] and are further discussed for each region in **Appendices A1-A5**.

Residential consumption is forecast to grow from uptake of EVs, electrification, and new dwelling construction, offset by additional and larger capacity rooftop PV installations

Under the ESOO Central scenario, underlying residential consumption is forecast to increase by almost 25% over the next 10 years, from approximately 55 TWh in 2023-24 to 70 TWh in 2033-34.

EV uptake continues to be a major driver of this growth, contributing almost 8 TWh per annum from about 4 million residential EVs (or approximately a quarter of residential passenger vehicles) in the ESOO Central scenario by 2023-2034. In other scenarios, 3 million to 6 million residential EVs are forecast to add up to 15% of residential consumption (equivalent to 6 to 11 TWh a year) over the same period.

Growth in the EV forecast is tempered relative to the 2023 ESOO to reflect updated road transport data from the Bureau of Infrastructure and Transport Research Economics (BITRE) that shows longer vehicle lifetimes, leading to lower new sales and slower EV uptake. Further, the New Vehicle Efficiency Standard (NVES) – legislated in May 2024 and to apply from 1 January 2025 – provides flexibility in meeting emissions reductions, and the updated forecast better recognises emissions reductions opportunities in non EV sales, resulting in lower forecast EV sales than previously anticipated.

Over the next decade, population growth will necessitate around 1.6 million new dwellings in the ESOO Central scenario. These additional dwellings are forecast to increase consumption by 10 TWh a year. Further growth in consumption of nearly 5 TWh a year is anticipated from electrification of space heating, hot water heating, and to a lesser extent from a switch from gas cooking appliances to electric alternatives. Recent introduction of policies in Victoria and the Australian Capital Territory to limit gas connections are expected to reduce gas consumption. About two-thirds of the NEM's residential electrification is forecast to take place in Victoria, where many households currently use gas for space heating[41].

Growth in distributed PV generation continues to significantly influence residential operational consumption. Currently 3.0 million residential PV systems supply approximately 20 TWh per annum of energy for domestic users. Under the ESOO Central scenario this is expected to increase to approximately 45 TWh of energy in 2034 and 95 TWh by 2054. Without considering the energy required to charge EVs, residential PV generation is expected to exceed household energy requirements by 2040. Whilst this is true in the aggregate, the differences between PV generation and household consumption patterns mean that households will continue to rely on electricity delivered to them at some times of the day, while potentially exporting energy to the grid to support other consumers at other times.

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

[41] The Victorian Government has banned gas connections in new homes and government buildings, which will likely most impact winter consumption. While the electrification adjustment accounts for customers partially or fully switching away from gas, the announcement has not been explicitly modelled in this ESOO.

The PV rebound effect[42] is the widely observed phenomena where consumers that invest in a PV system actually increase their underlying electricity demand following the installation. This increase in consumption adds to underlying demand for the consumer, although operational demand will be reduced due to the generation of the PV system. In 2034, less than 5 TWh of load is expected due to this effect, rising proportionally with PV generation to less than 10 TWh in 2054.

Across all scenarios, underlying residential consumption is forecast to be around 60-70 TWh in the medium term (by 2033-34), increasing to approximately 70-80 TWh in the long term (by 2053-54).

Forecast business consumption growth is driven by an emerging hydrogen industry and continued uptake of electrification

Under the ESOO Central scenario, aggregate underlying business consumption – from BMM, large industrial loads (LILs), liquified natural gas (LNG) producers, EVs, and hydrogen production – is forecast to increase by approximately 45% in the next 10 years, from 140 TWh in 2023-24 to 205 TWh in 2033-34. This growth is primarily due to consumption from hydrogen production and business electrification.

The LIL forecasts have been updated for the 2024 ESOO by surveying industrial facilities directly and gathering load inquiry data from network service providers (NSPs). LIL forecasts in the ESOO Central scenario are higher than was forecast in the 2023 ESOO, largely due to the reallocation of approximately 60 sites from the BMM to the LIL category. Approximately half of the reclassified loads consist of existing data centres, which have experienced substantial growth since the 2023 ESOO. The resulting increase due to this reclassification is partly offset by a reduction in the BMM consumption. The potential growth in new data centre load is separately analysed in the *Accelerated Data Centre Growth* sensitivity, which considered the realisation of more prospective loads[43].

The following key drivers are anticipated to influence business sector consumption in the next decade:

- Hydrogen production is an emerging consumer of electricity. Similar to the 2023 ESOO, the scale and timing of production remains uncertain. Forecast consumption in 2033-34 remains largely unchanged compared to the 2023 ESOO, contributing around 15 TWh to 25 TWh in the *Progressive Change* and the ESOO Central scenarios, respectively. Consumption in the shorter term, however, has decreased due to slower than expected progress in developing hydrogen projects to Final Investment Decision (FID), modified assumptions for the New South Wales Renewable Fuels Scheme Policy, and adjustments to the assumed utilisation factor for the South Australian Hydrogen Jobs Plan electrolyser[44]. Consumption is expected to ramp up in the early 2030s with continued government support through programs such as Hydrogen Headstart[45]. In the longer term, the potential upside for the sector is forecast as high as almost 150 TWh in the *Green Energy Exports* scenario, which assumed major breakthroughs in hydrogen production costs lead to significant increases in the domestic and international demand for hydrogen products.

[42] In response to recent stakeholder feedback, AEMO has reduced the impact of the PV rebound effect on the residential forecast in this NEM ESOO. More information about the PV rebound effect and its impact on residential consumption can be found in Section 3.2 of the Forecasting Approach – Electricity Demand Forecasting Methodology. https://aemo.com.au/consultations/current-and-closed-consultations/2024-electricity-demand-forecasting-methodology-consultation

[43] AEMO has only considered committed data centre loads in the core scenario forecasts. Anticipated loads whereby proponents may be well progressed with pursuing the connection, although have not yet achieved Final Investment Decision, have only been considered in the *Accelerated Data Centre Growth* sensitivity.

[44] At https://aemo.com.au/consultations/current-and-closed-consultations/2024-forecasting-assumptions-update-consultation.

[45] At https://www.dcceew.gov.au/energy/hydrogen/hydrogen-headstart-program.

- Electrification continues to be a major contributor to forecast growth in business consumption. Forecasts for this ESOO continue to reflect the decarbonisation expectations that were forecast for the 2023 IASR, also adopted in the 2023 ESOO[46]. This analysis identified various opportunities to electrify commercial (building) equipment and appliances, and lower heat industrial processes that currently use oil and gas; policy development since this forecast to encourage fuel-switching towards electricity generally reflect the anticipated direction of the 2023 forecast. For example, the Safeguard Mechanism continues to provide a framework to incentivise adoption of electrification technologies – such as electric boilers, electric arc furnaces and even mechanical vapour recompression – for Australia's largest industrial facilities.
- The LIL forecasts are higher across all scenarios compared to the 2023 ESOO, due to the reclassification of load from the BMM sector. The newly-classified loads account for almost 10% (or nearly 4 TWh) of current total LIL load. Long-term growth in the ESOO Central scenario is driven by data centres, transport, mining and manufacturing. Existing and committed data centres in particular are forecast to make up just over 5% (or approximately 500 MW) of the total LIL load by 2033-34. This is balanced out by production downgrades from some manufacturing sites due to reported high domestic production costs and a growing reliance on imports.
- As in the 2023 ESOO, the *Progressive Change* scenario captures downside risks for LILs, including the impact of major industrial closures due to worsening economic conditions. This is assumed as early as 2026-27, resulting in a forecast decline in LIL consumption of approximately one-third relative to recent levels by the end of the outlook period in that scenario. The possibility of industrial activity decline is a risk that is a feature of the scenario itself, and does not reflect a prediction or specific advice regarding the likelihood of any individual business's ongoing operation.
- The BMM sector accounts for a smaller proportion of total business consumption due to reclassification of several sites as LILs and is predicted to be between 85 TWh and 100 TWh by 2033-34, from 85 TWh in 2023-24. Compared to the 2023 ESOO, forecast growth in the BMM sector is lower across all scenarios, reflecting slower economic growth and weaker consumer spending in the short term. The forecast trajectory for each scenario is primarily driven by a balance between economic growth and energy efficiency savings. Projected fluctuations in retail electricity price levels provide some variability to the otherwise smooth consumption paths.
- Commercial EV uptake is lower compared to the 2023 ESOO, contributing up to 5 TWh across the scenarios by 2033-34. This downward revision is predominantly due to the same factors affecting residential EVs.
- Energy efficiency investments are forecast to provide consumption savings of around 5-10 TWh in 2033-34 across all scenarios. Forecasts for this ESOO are based on the same underlying forecast as was produced for the 2023 IASR, which also applied for the 2023 ESOO and therefore largely follow similar projections[47]. Since the 2023 ESOO was produced, no material change in policy or market settings that support energy efficiency investments have been observed, demonstrating the continued appropriateness of this forecast.
- Business PV forecasts are lower compared to the 2023 ESOO for all three scenarios, driven by a reduction in the number of new PV installations as consumers anticipate lower returns on investment (due to an assumption of more stable energy prices and/or lower feed in tariffs in the future). In contrast to the residential sector, the business PV

[46] CSIRO and ClimateWorks 2022 Multi-sector modelling report, at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/csiro-climateworks-centre-2022-multisector-modelling-report.pdf.

[47] Energy Efficiency Forecasts 2023 – Final Report, at https://aemo.com.au/-/media/files/major-publications/isp/2023/iasr-supporting-material/2023-energy-efficiency-forecasts-final-report.pdf.

forecast does not expect material growth in average systems, as businesses tend to be careful not to oversize their system and rather align its size to their load to maximise financial return[48]. PV non-scheduled generation (PVNSG) forecasts are similar to the 2023 ESOO forecasts in all scenarios. Together, business PV and PVNSG reduce operational consumption by between 10 TWh and 20 TWh by 2033-34.

The above key drivers result in a range of business consumption forecasts of around 160 TWh to 355 TWh in 2033-34 depending on scenario, and further widening by 2053-54.

Exploring the potential for rapid data centre growth

Data centres make up nearly 3 TWh of current load across the BMM and LIL sectors. The ESOO Central scenario forecasts around 5 TWh of data centre load by 2033-34, from existing and committed LIL projects alone. Accelerating investment in data centres to meet the potential growth in demand for streaming services, cloud storage and AI applications – specifically with the rise of larger hyperscale facilities – has the potential to be a catalyst for substantial increases in electricity consumption, particularly in Sydney and Melbourne (but potentially in more regional areas too with the right infrastructure and relevant incentives)[49].

The 2024 ESOO explores potentially large increases in investment in data centres in a sensitivity to the Central scenario, the *Accelerated Data Centre Growth* sensitivity. The sensitivity was informed by 2024 Standing Information Request responses received from NSPs and other industry engagement on data centre application enquiries and non-committed loads.

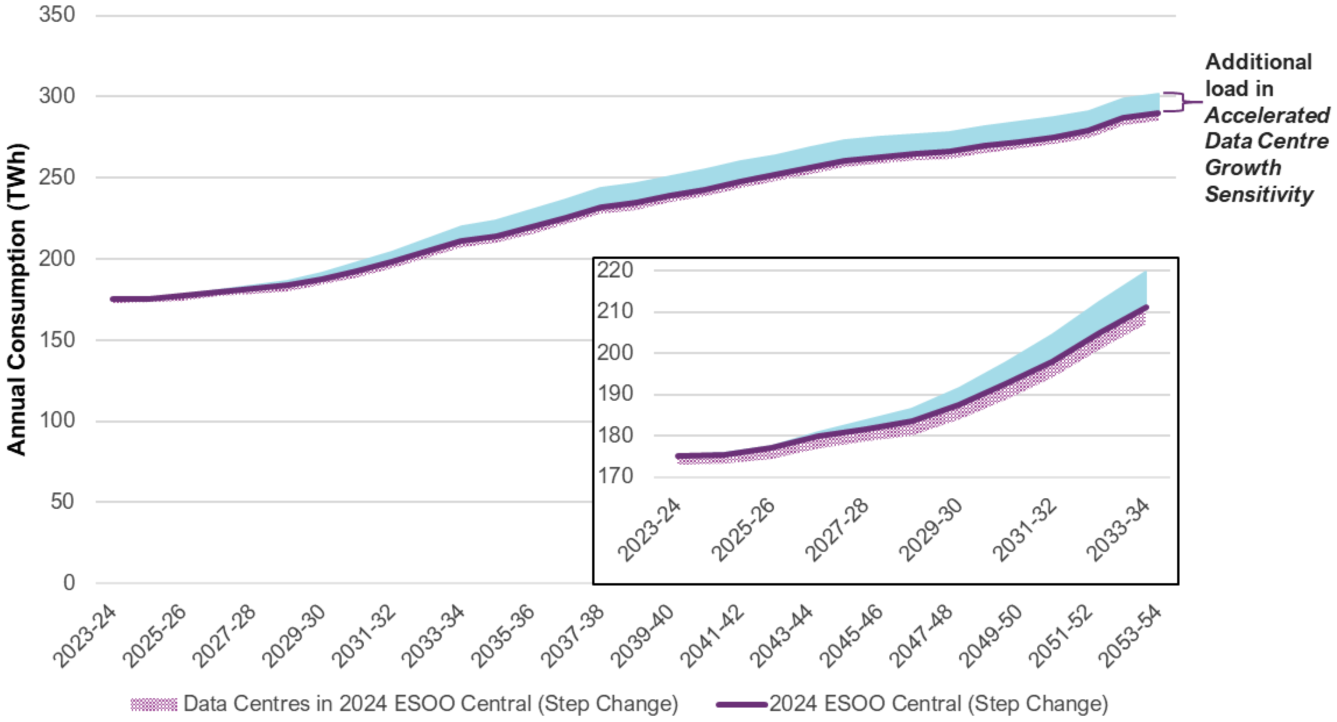
The sensitivity forecasts nearly 10 TWh of additional load per year by 2033-34, which is assumed to continue rising over the next 30 years (see **Figure 11** below). Based on this trajectory, data centres are estimated to make up nearly 15% of LIL consumption and around 5% of total NEM operational consumption by 2033-34, staying at this proportion until 2053-54. Around two-thirds of the consumption from these more prospective projects is assumed to be located in New South Wales, particularly in the Western Sydney area, one-fifth in Victoria, and the remainder in Queensland and Tasmania (see **Figure 12** below).

Increased investment in data centres will increase annual electricity consumption, and impact forecast peak demands. Based on analysis of existing data centres, these facilities are estimated to have a relatively stable demand shape that is not materially temperature sensitive. Ambient temperatures marginally increase summer loads, with cooler ambient temperatures reducing cooling load in winter. Data centres may also have diesel generation backup to potentially reduce peak demand impacts.

[48] GEM 2023 Projections for distributed energy resources report, at https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/2024-forecasting-assumptions-update-consultation-page/green-energy-markets---2023-consumer-energy-resources-projection-report.pdf.

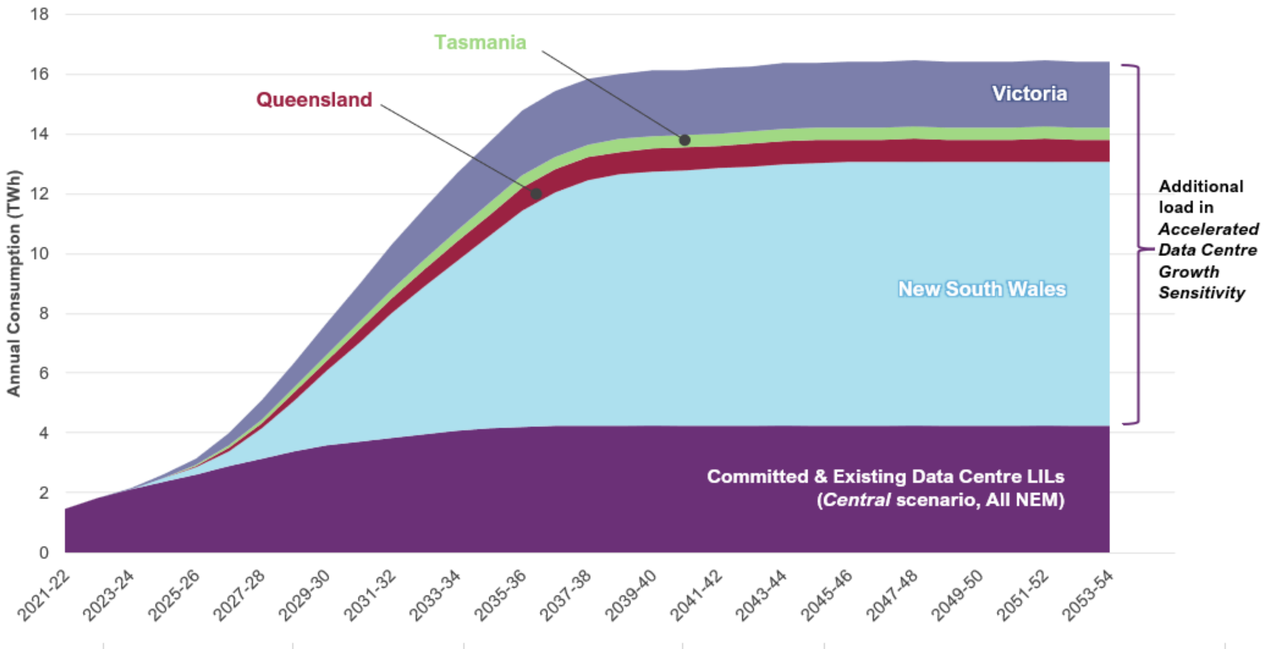
[49] Development opportunities will depend on relevant available infrastructure, including electricity, data connectivity, water as well as labour to develop and maintain facilities and environmental and planning requirements. To date, much of the development interest is within the major capitals, particularly in Sydney and Melbourne. Supporting development in other locations, such as co-locating data centres with new electricity supply developments, may represent an opportunity for governments, data centre developers and infrastructure providers and may influence on power system requirements.

Figure 11 Operational consumption for ESOO Central scenario and *Accelerated Data Centre Growth* sensitivity, 2023-24 to 2053-54 (TWh)



Note: This figure captures loads that are sufficiently large to be considered an LIL. Smaller data centre loads may be present in the BMM forecast. Additional loads presented are not committed and subject to change.

Figure 12 Assumed location of LIL data centre load in the *Accelerated Data Centre Growth* sensitivity compared to ESOO Central scenario 2021-22 to 2053-54 (TWh)



Note: This figure captures loads that are sufficiently large to be considered an LIL. Smaller data centre loads may be present in the BMM forecast. Additional loads presented are not committed and subject to change.

2.3 Maximum operational demand forecast to grow

AEMO prepares maximum demand forecasts as a distribution, represented by the 10%, 50%, and 90% POE forecasts, rather than single-point forecasts – see **Section 1.2** for definitions.

The ESOO maximum demand forecast represents uncontrolled or unconstrained demand, with no USE and free of market-based or non-market-based solutions that might reduce system load during peak events (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.

Maximum demand drivers

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**. Specifically, forecasts of growing electrification contribute the most to the upward trends, along with the expansion of LIL. Other drivers that affect consumption and maximum demand are lower EV and BMM growth rates, which have caused the growth rate of maximum demand to decrease compared to the 2023 ESOO in the mid and late years of the forecasting horizon.

In some cases, the forecast trend in maximum demand differs from consumption trends, due to some drivers impacting the load shape differently across the day and across seasons. For example:

- Distributed PV generation has grown substantially in recent years and is helping to reduce operational consumption, but generally has a much lower impact on maximum demand (with maximum demand now generally falling in the early evening in mainland states, around or after sunset, or in winter (for Tasmania) when PV generation is also lower due to fewer daylight hours).
- Heating and cooling load is a small proportion of overall annual electricity consumption, but on particularly extreme hot or cold days, temperature can contribute up to half the demand in some instances. Relevant additional maximum demand drivers therefore include uptake of air-conditioners, electrification of households currently using gas heating, and building energy efficiency initiatives affecting heating/cooling requirements.
- The impact of battery storage operation on annual consumption is limited to battery losses, which comprises a very small amount relative to overall consumption. The impact on maximum demand, however, is more significant depending on how much batteries discharge during the evening peak to limit households' purchases of electricity from the grid. Batteries which are coordinated through an aggregator or retailer under a virtual power plant (VPP) may have an even greater impact on lowering peak demand. However, AEMO assumed only batteries in existing or committed VPP programs will be available to provide a coordinated response at times of maximum demand for the purposes of the ESOO Central scenario. All new batteries were assumed to be optimised for minimising the household's purchases from the grid only. Additional sensitivities included the impact of greater CER coordination, including additional VPP and vehicle-to-grid (V2G) developments, as well as other developments (**Section 4.3)**.
- EV charging likewise is forecast to increase annual consumption, however, the impact on maximum demand is not a simple proportional increase, because the charging behaviours EV owners may prefer may concentrate charging during peak demand periods, or avoid them if appropriately informed and/or incentivised. In general, AEMO assumed that incentives will develop such that charging becomes 'smarter' over time, with less impact at time of peak (and potentially an increasingly important role to lift minimum demand during the daytime).

- Hydrogen load represents demand for electricity used in the production of hydrogen and the transformation of this into other resources if needed (such as ammonia). Hydrogen electrolysers were assumed to be flexible within commercial limits, capable of providing a natural demand response during high price events such as those associated with extreme demand days or limited supply availability. Hydrogen-associated demand is therefore expected to be low at time of peak, even when annual consumption is substantial.

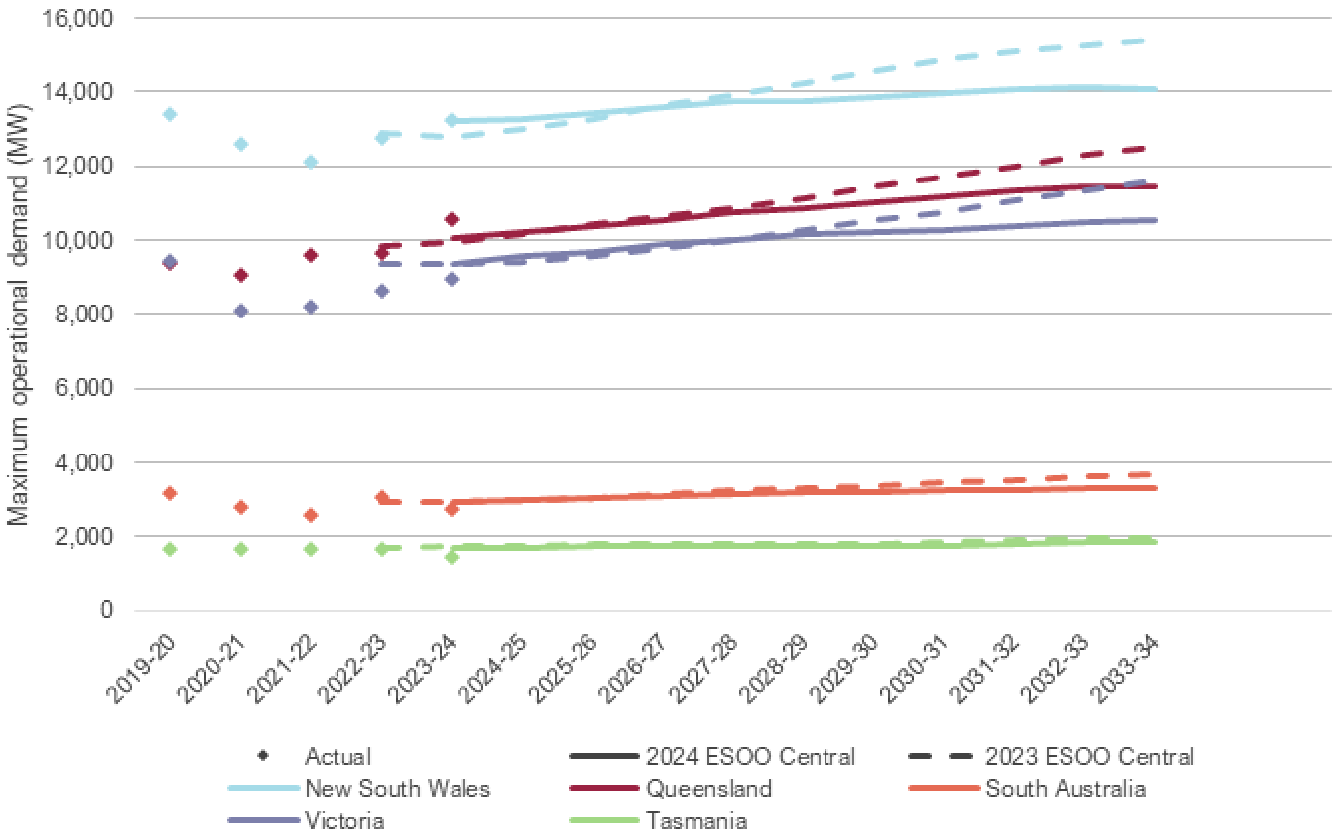
The maximum demand forecast presented in this chapter is unconstrained, and only accounts for customer-controlled battery and EV charging that is not coordinated. The forecasts presented also do not incorporate potential hydrogen load. Instead:

- Coordinated battery operation (via VPPs) and coordinated EV charging were modelled dynamically, optimised within the reliability assessment to mitigate potential supply gaps that may not eventuate with appropriate price signals.
- Hydrogen production was also optimised to operate flexibly and respond to high pricing.

Maximum operational demand forecast to 2033-34

Figure 13 shows the annual actual and forecast maximum operational demand (sent-out, 50% POE) for all NEM regions from 2019-20 to 2033-34 for the 2024 ESOO Central scenario, and compared to the 2023 ESOO Central scenario.

Figure 13 Actual and forecast regional annual 50% POE maximum operational demand (sent-out), 2024 ESOO Central and 2023 ESOO Central scenario, 2019-20 to 2033-34 (MW)



Note: The actuals displayed are not weather-corrected (therefore reflect observed demand under the prevailing weather conditions) or adjusted for system events and exclude DSP. Additionally, this definition excludes demand from scheduled loads, typically pumping load from pumped hydro energy storage or large-scale batteries, as well as hydrogen loads.

The key insights from these forecasts are:

- For the initial year, in 2024-25, forecast 50% POE maximum operational demand is forecast higher in the 2024 ESOO than was forecast in the 2023 ESOO in New South Wales and Queensland. Tasmania starts slightly lower, while Victoria and South Australia is forecast at similar levels to 2023's forecast. In addition to the natural influence of the most recent year of actual observed demand, the changes to the starting point of the distributions are driven by:
  – LIL increases in New South Wales, Queensland and Victoria, including large data centre facility expansion which is forecast to ramp up from 2026.
- In the next four years, to 2028-29, maximum operational demand (50% POE) is forecast to grow, due to the underlying trend of the consumption forecast (and recognising that a key offset for consumption growth – distributed PV generation – has limited effect on operational maximum demand, given the late time-of-day timing of the peak demands).
  – New South Wales has a relatively flat forecast until 2025-26 mainly due to minimal expansion in business consumption in the first two years. The growth trend starts to become slightly faster after primarily due to the larger LIL expansion. In the last two years of this period, the reduction in EV and BMM consumption compared to the 2023 ESOO has contributed to a leveling off of growth rates.
  – South Australia and Tasmania also exhibit relatively flat forecasts, closely mirroring the trends in the 2023 ESOO because of slow underlying consumption growth and minimal changes in industrial loads that meet AEMO's commitment criteria[50].
  – Victoria and Queensland both demonstrate steady growth due to the increase in underlying consumption. Compared to the 2023 ESOO, their growth rates are similar, but maximum demand forecasts slightly exceed the 2023 ESOO due to LIL expansion. However, as the consumption growth rate slows, the difference between the 2024 ESOO and 2023 ESOO diminishes, even falling below the 2023 ESOO.
- Over the next five years, 2029-30 to 2033-34, the growth rates of all five regions are forecast lower than the 2023 ESOO, primarily due to the lessening growth trends affecting consumption, including reduced EV uptake than was previously forecast.
  – New South Wales and South Australia are expected to experience slower electrification growth. BMM consumption has also stabilised with slightly increases. Despite some growth in LILs, it has been offset by the lower EV growth rate compared to the 2023 ESOO. As a result, the forecasts tend to become flat.
  – Victoria and Queensland show a slight growth, primary due to ongoing electrification and LIL expansion. However, a portion of this growth has been offset by lower EV adoption and improved energy efficiency.
  – Tasmania continues to exhibit a flat trend. There have been minimal changes in EV and electrification, and the forecast is slightly lower than 2023 ESOO primarily due to lower BMM consumption.

Appendices A1-A5 discuss maximum demand forecasts for each region and scenario out to 2053-54 based on the same 2024 ESOO inputs for 30-years forecasts.

[50] AEMO is aware of various industrial load developments, and included a sensitivity in the 2024 ISP to explore the investment impacts of higher industrial load growth. This 2024 ESOO does not include industrial loads that have not met AEMO's commitment criteria, as per AEMO's electricity demand forecasting methodology; if these uncertain load developments do connect, greater supply investments may be needed to service their annual, seasonal and peak consumption.

2.4 Minimum operational demands forecast to rapidly decline

The minimum operational demand forecasts represent uncontrolled or unconstrained demand, free of operational measures to constrain PV generation and market-based solutions that might increase operational demand in periods of excess supply (including coordinated storage and EV charging[51], scheduled loads such as pumping load, and demand response).

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

Minimum demand drivers

Minimum operational demand is influenced by the same drivers described in **Section 2.1**. Generally, growth in population, electrification, appliance uptake and economic activity will be positive growth drivers for minimum demand.

As with maximum demand, some drivers affect minimum demand very differently from their impact on consumption. The strongest such influence is the uptake of distributed PV, which drives a rapid decline in operational demand during daylight hours. The growth in distributed PV has moved the timing of minimum demand from overnight to occur at approximately midday[52]. The annual minimum is typically observed on mild weekend days or public holidays, where minimal heating and cooling needs result in low underlying demand.

For each megawatt of installed distributed PV, minimum operational demand tends to reduce between 0.7 MW and 0.8 MW; that is, a contribution of 70-80%, when accounting for the diversity of panel orientation and solar conditions at different locations within the regions. In comparison, a megawatt of distributed PV reduces consumption equivalent to its annual capacity factor (typically about 15%).

While uptake of distributed PV drives a rapid decline in minimum demand, other technologies push in the opposite direction:

- Daytime charging of battery storages and EVs to use the availability of solar resources will increase demand. As with their operation at time of maximum demand, consumer behaviour and the degree of coordination can have a significant impact on how these technologies affect minimum demand. For example, morning charging of battery devices may lead to these resources being fully charged before midday, resulting in little benefit from these devices to improve minimum demand. Coordinating the timing of battery charging may be more difficult to effectively coordinate, given the softer intraday price variance consumers may experience during high solar and low demand conditions, relative to the much greater price volatility that may occur during low solar and high demand conditions. Similarly, vehicles may not always be connected to charging infrastructure to coordinate during daytime periods.
- Demand from the production of hydrogen will also lift minimum demand. As with maximum demand, electricity demand from hydrogen production is not reflected in the minimum demand forecast rather facilities are assumed to operate flexibly.

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

[52] Historically Tasmania has been an exception to this midday minimum demand timing, given its lesser relative penetration of distributed PV, however in future years Tasmania is also expected to mostly observe minimum demand periods in the middle of the day.

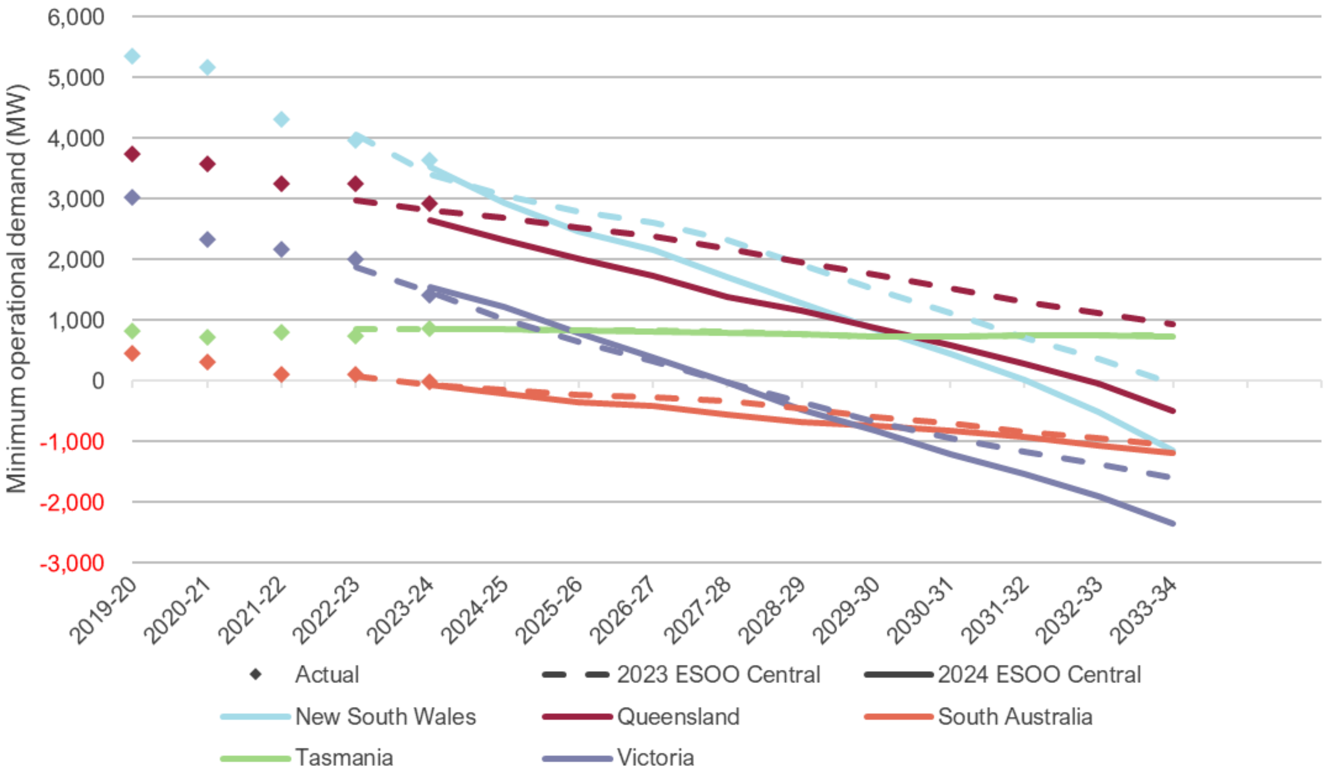
Finally, in some regions, variations in demand from LILs can materially affect the minimum demand. This is particularly the case in Tasmania, where LIL at time of minimum demand is more than half the demand overall, and any planned or unplanned outages of large loads at this time can significantly affect the magnitude of the minimum.

Minimum operational demand forecast out to 2033-34

Figure 14 compares the annual actual and forecast minimum operational demand (sent-out) for NEM regions from 2019-20 to 2033-34 for the ESOO Central scenario from the 2024 and 2023 ESOOs.

Across the forecast horizon, the decline in minimum operational demand is strongly influenced by larger distributed PV systems, as outlined in previous sections. Additionally, compared to the 2023 ESOO, the slower growth in electrification and EV adoption also contributes to the reduction in minimum demand, with this partly offset by the expansion of LIL and the reduction in the behind-the-meter, non-coordinated batteries.

Figure 14 Regional annual actual and forecast 50% POE minimum operational demand (sent-out), 2024 ESOO Central and 2023 ESOO Central scenarios, 2019-20 to 2033-34 (MW)



Note: The actuals displayed are not weather-corrected (therefore reflects observed demand under the prevailing weather conditions) or adjusted for system events and exclude DSP. Additionally, this definition excludes demand from scheduled loads, typically pumping load from pumped hydro energy storage or large-scale batteries, as well as hydrogen loads.

Key additional insights from these forecasts are:

- For the first forecast year, 2024-25, the forecast 50% POE minimum operational demand is higher in New South Wales and Victoria than in the 2023 ESOO, due to the identification of more LIL sites within the LIL category, rather than classification as BMM. Tasmania and South Australia do not experience significant changes, as the various drivers offset each other. Queensland starts slightly lower than the 2023 ESOO as more PV uptake and reduced electrification have been reflected in the model given the observed developments since the 2023 ESOO.

- In the next four years (to 2028-29), 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 lower in the 2024 ESOO than the 2023 ESOO, due to the reduced projections for EV and electrification (mentioned above), apart from Victoria, which by 2027-28 is slightly higher, driven by stronger growth in the BMM sector and LILs more than offsetting the lower electrification and EV forecast.
  - The minimum demand in South Australia, as predicted in the 2023 ESOO, turned negative in 2023-2024. This trend is expected to continue with the 50% POE minimum demand remaining negative (that is, CER is forecast to generate more than underlying demand in the region, in the absence of any operational control) due to the ongoing increase in PV uptakes.
  - Tasmania has not changed significantly compared to the 2023 ESOO, primarily due to the relatively stable demand forecast from LILs, which constitutes the majority of the region's demand. The slower relative growth in distributed PV and the stability of BMM consumption also contribute to little noticeable downward trend in minimum demand unlike in other NEM regions.
- In the following five years (2029-30 to 2033-34), similar trajectories to the initial years are forecast. Generally, PV uptake, lower electrification, and lower EV adoption keep pushing down the minimum demand.
  - 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.

There are potential market-based solutions to increase operational demand in the daytime. These mechanisms include coordinated charging of storage (both distributed and utility-scale), coordinated EV charging, and demand response (shifting demand away from peak times and into minimum demand windows). These have not been included in the minimum operational demand forecasts presented in this ESOO, but are modelled to the extent these components have been forecast in the reliability assessments.

Operational measures taken by network operators to manage security challenges are not reflected in the forecasts (see **Section 7.6**).

2.5 Flexible demand can enhance the NEM's ability to meet forecast peak demand

For the 2024 ESOO, AEMO has updated its estimate of DSP (also called demand response) responding to price and reliability signals, including the 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 2024, using the methodology described in AEMO's *DSP Forecasting Methodology Paper*[53].

Projected DSP across the NEM for summer 2024-25 is 1,185 MW, as shown in **Table 4**. Compared to the 2023 ESOO, AEMO's forecast shows similar or higher forecast DSP response overall in all NEM regions, with higher expected electricity prices relative to assumptions in previous forecasts contributing to growth in expected availability of DSP in several regions.

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

Table 4 Projected demand side participation for summer 2024-25 (MW)

Price trigger	New South Wales	Queensland	South Australia	Tasmania	Victoria
> $300-$500/MWh	1	28	27	0	1
> $500-$7,500/MWh	16	77	45	4	6
> $7,500/MWh	117	197	49	4	339
Reliability response	359	240	49	4	533

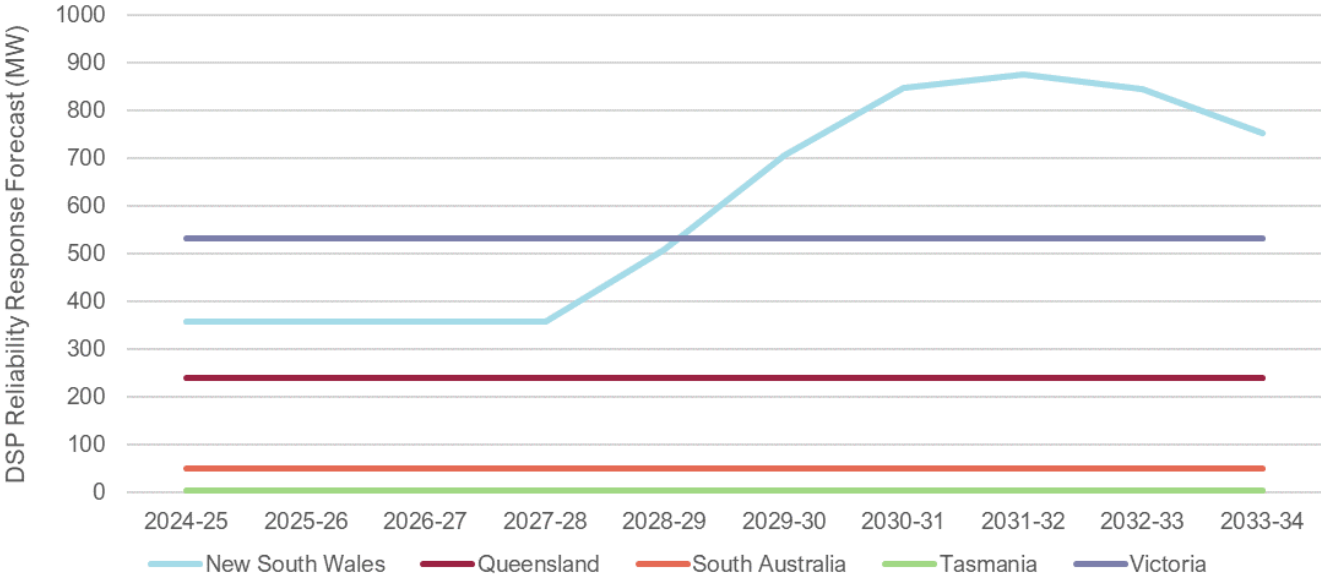
Note: The reliability response is the estimated response during actual LOR 2 and LOR 3 events. For the definition, see https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power_System_Ops/Reserve-Level-Declaration-Guidelines.pdf.

The ESOO reliability forecast includes only existing and committed sources of DSP in the *Committed and Anticipated Investment* sensitivity, consistent with the treatment of generation and transmission developments.

AEMO therefore used a flat forecast of reliability response for the 10-year horizon of the ESOO[54] for all regions except New South Wales, where the New South Wales Peak Demand Reduction Scheme (PDRS)[55] was considered committed and has a significant impact on DSP projections. This scheme creates a financial incentive to reduce electricity consumption during summer peak times. Some initiatives under the PDRS, such as energy efficiency at time of peak and coordinated response of behind-the-meter batteries, are already accounted for in other components of the overall demand forecast. The remaining initiatives contribute to forecast DSP growth to almost 900 MW by 2031-32 in New South Wales. From 2031-32, the New South Wales forecast declines in the Central scenario as asset replacement decisions at end-of-life for incentivised investments are insufficiently committed once deeming periods under the scheme expire.

Figure 15 shows the DSP reliability response forecasts for the ESOO Central (*Step Change*) scenario for the next 10 years. **Appendix A6** provides further DSP forecast details and statistics[56].

Figure 15 DSP reliability response forecast (MW) for summer, Central scenario, 2024-25 to 2033-34 (MW)



[54] 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.

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

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

3 Supply and network infrastructure forecasts

A reliable power system relies on the capability to generate and securely transmit electricity to consumers. This chapter outlines the infrastructure that is forecast to be available to generate and transmit electricity for the next 10 years, including:

- Generator commissioning and decommissioning assumptions.
- Generator seasonal capacities and reliability.
- Transmission commissioning and reliability assumptions.

3.1 Generator commissioning and decommissioning assumptions

There is a substantial pipeline of generation and storage projects in various stages of development, from proposed projects to those that are close to finishing their commissioning in the NEM.

Data on existing and future generation and storage projects is provided to AEMO by both NEM participants and generation/storage project proponents, and is published on AEMO's Generation Information web page[57]. This includes market-led opportunities as well as projects that participate in a federal, state, or territory funding scheme or incentive mechanism.

To assess project progression, AEMO applies commitment criteria that consider a project's progress across land, finance, planning, contracts, and construction categories[58]. Using these criteria, AEMO defines generation and storage projects as:

- **Existing** generation and storage plants which have completed commissioning.
- **In commissioning** projects that are in-progress with the connection and testing of their capacity, with typically at least 30% of their capacity now operational, having been successfully proven against various onboarding requirements (known as the first commissioning hold point).
- **Committed** projects[59] that meet all five of AEMO's commitment criteria but have not yet met the requirements of their first commissioning hold point.
- **Anticipated** projects that have made progress towards at least three of AEMO's commitment criteria, and have provided AEMO confirmation or update of project status in the last six months.
- **Proposed** projects that have not progressed sufficiently to meet the requirements of an in commissioning, committed, or anticipated project.

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

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

[59] The committed category also includes committed* projects, which are very close to meeting all five commitment criteria (satisfying land, finance and construction criteria plus either planning or components criteria). Modelled delays are applied consistent with committed projects.

Table 5 shows the scale of the current new generation and storage pipeline with the sum of the nameplate capacity for all projects, aggregated according to project development status. In addition to the many projects progressing through AEMO's commitment criteria, there are a large number of proposed projects at early stages of development. These proposed projects are spread across all regions, with the largest pipeline of capacity presently in Queensland and New South Wales.

Table 5 New generation pipeline as of July 2024 Generation Information (gigawatts [GW])

	Existing and in commissioning projects	Committed projects	Anticipated projects	Proposed projects
Aggregate GW	64.1	12.5	9.4	290.2

Modelling the availability of generating capacity

AEMO receives project information from proponents relating to the technical capabilities of the projects, as well as the anticipated timing of its availability (referred to as its full commercial-use date). To forecast NEM power system reliability, AEMO has developed a methodology for consideration of these developments; this methodology is consulted with stakeholders regularly, the last refinement and consultation occurring before the 2023 NEM ESOO was published[60]. This refinement included clarification on the treatment of project commissioning dates in AEMO's reliability forecasts, particularly to reflect observed inaccuracies between proponent-provided commissioning schedule estimates and those that were observed to occur. This analysis observed that projects often were observed to commission at least 12 months after their proposed commissioning estimates, and stakeholders supported the methodology to reflect commissioning delays to the various commitment categories. These modelled delays do not reflect that AEMO considers that any specific project is providing inaccurate timing estimates or will hit reasons for delay, but rather reflects prudent modelling treatment to timing uncertainty when assessing forecast power system reliability.

Changing generator availabilities over the next 10 years

All ESOO scenarios and sensitivities assumed generator retirements occur on dates provided by participants, either on the dates provided if a closure date is provided under the three-and-half-year notice of closure rules[61] or on 31 December of the provided expected closure year.

Figure 16 shows the typical summer capacity[62] assumed per forecast year in the 2024 ESOO *Committed and Anticipated Investments* sensitivity; labels show the change in capacity for each forecast year relative to the previous forecast year.

[60] See https://aemo.com.au/en/consultations/current-and-closed-consultations/2022-reliability-forecasting-guidelines-and-methodology.

[61] Clause 2.10.1(c2) of the NER requires generators to provide at least 42 months' advance notice of a closure.

[62] Typical summer capacity is used to represent the capacity that would be available under regular summer conditions in a region, whereas the summer peak capacity represents capacity available at times of very high temperature where annual maximum demand is more likely to occur. See Section 3.2 for further information.

Figure 16 Assumed capacity available during typical summer conditions, by generation type, *Committed and Anticipated Investments* sensitivity, 2023-24 to 2033-34 (MW)

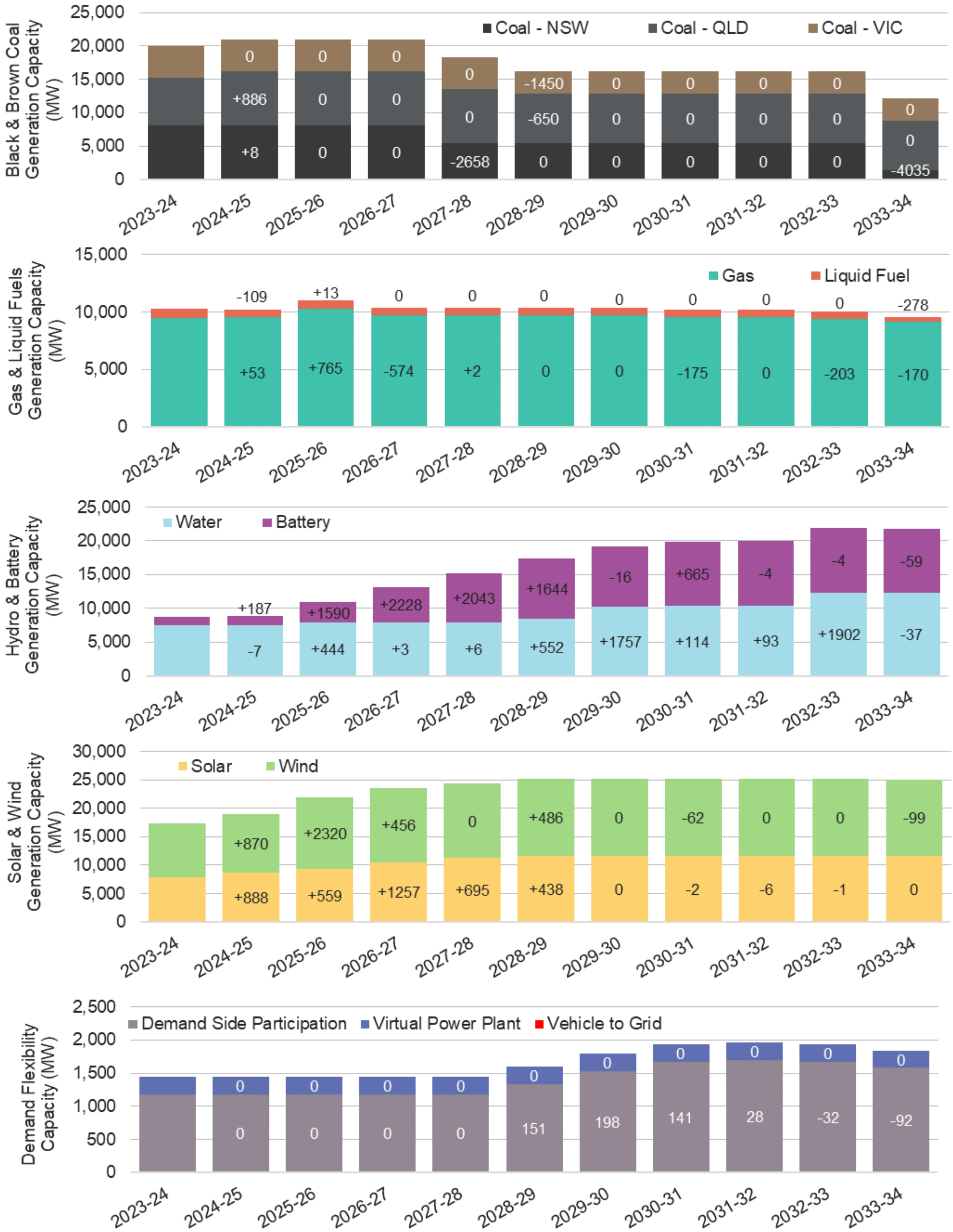


Figure 16 reflects assumed development delays to committed and anticipated projects, and technical advice on the capabilities of each generating unit provided by each relevant operator and/or developer[63]. It demonstrates the reduced availability of some generating technology types as generators retire, as well as the development of replacement capacity that is either in commissioning, committed, or anticipated according to AEMO's commitment criteria. These capacity outlooks typically do not consider planned outages, unless the unit is advised to be inoperable for the majority of the summer season.

Large amounts of new generation and storage capacity continue to connect in the NEM. Approximately 2.3 gigawatts (GW) of new capacity (based on nameplate capacity) is forecast to start operations in time for summer 2024-25, compared to what was available last summer, demonstrating increased commitments by NEM participants and developers to deliver additional capacity since the 2023 ESOO.

In addition to the above, proponents have committed a further 20.2 GW of capacity[64] (based on nameplate capacity) to become available over the rest of the 10-year ESOO horizon. This includes 5.7 GW of developments that have progressed sufficiently to be newly included since the 2023 ESOO, comprising 3.9 GW/13.5 GWh of batteries, 1.2 GW of large scale solar, 0.4 GW of wind and 0.2 GW of hydrogen developments.

Table 6 provides a list of dispatchable generation and storage projects (≥ 250 MW) assumed to become available over the 10-year ESOO horizon, that are in commissioning, committed, and anticipated development status.

Table 6 In commissioning, committed, and anticipated dispatch generation and storage capacity developments (≥ 250 MW), 2024-25 to 2033-34

Region	Project	Commitment status	Nameplate capacity (MW)	Storage capacity (MWh)	Participant-provided full commercial use date [A]
New South Wales	Hunter Power Station[B]	Committed	750	N/A	December 2024
	Waratah Super Battery	Committed	850	1,680	March 2025
	Eraring Big Battery	Committed	460	920	December 2025
	Orana BESS	Anticipated	415	1,600	June 2026
	Liddell BESS	Anticipated	500	2,000	July 2028[C]
	Richmond Valley BESS	Anticipated	275	2,200	October 2026
	Snowy 2.0	Committed	2,200	350,000	December 2028
Victoria	Melbourne Renewable Energy Hub – Side A Battery	Committed	600	1,600	November 2025
	Gnarwarre BESS Facility	Anticipated	290	550	January 2027
	Mortlake Battery	Anticipated	300	600	March 2027
	Wooreen Energy Storage System	Anticipated	350	1,400	December 2027
Queensland	Tarong BESS	Committed	300	600	September 2024
	Western Downs Battery	Committed	255	500	December 2024
	Kidston Pumped Hydro Energy Storage	Committed	250	2,000	February 2025
	Aldoga BESS Stage 1	Anticipated	400	400	November 2025

63 Pumped hydro is included in the 'water' category. Typical summer capacities for 2023-24 are based on the January 2024 Generation Information publication, while capacities for forecast years are based on the July 2024 Generation Information publication.

64 Including those projects which are classified as in commissioning, committed, and anticipated.

Region	Project	Commitment status	Nameplate capacity (MW)	Storage capacity (MWh)	Participant-provided full commercial use date [A]
	Swanbank BESS	Anticipated	250	500	January 2026
	Mount Fox BESS	Anticipated	300	600	November 2026
	Stanwell BESS	Anticipated	300	1,200	August 2027
	Borumba Pumped Hydro	Anticipated	1,998	48,000	September 2031

A. Full commercial use dates are provided by the participants. AEMO's ESOO methodology may apply delays with completion assumed after the proponent-advised dates, with delays reflective of the average of historically-observed schedules, being a minimum of six months. These are applied in the *Committed and Anticipated Investments* sensitivity.
B. This is a gas-fired power station, so storage capacity is not applicable. Hunter Power Station has previously been described as Kurri Kurri and/or Hunter Power Project.
C. This project without a participated-provided full commercial use date is included on July 2028 in ESOO reliability modelling.

Additionally, in commissioning, committed, and anticipated capacity developments assumed to become available over the 10-year ESOO horizon across NEM regions include:

- A total of 2,699 MW/6,382 MWh of other smaller battery projects (< 250 MW).
- A 204 MW hydrogen generator as part of the South Australian Hydrogen Jobs Plan.
- Variable renewable energy (VRE) projects:
  - Approximately 4,092 MW of wind generation developments.
  - Approximately 4,563 MW of solar generation developments.

Based on participant advice, the following generators are now expected to close in or before 2034[65]:

- Torrens Island B Power Station (800 MW) in South Australia on 30 June 2026, although Unit B1 is advised to remain mothballed[66] until then.
- Osborne Power Station (180 MW) in South Australia on 31 December 2026.
- Eraring Power Station (2,880 MW) in New South Wales on 19 August 2027.
- Port Lincoln and Snuggery Power Stations (total 136 MW) in South Australia on 1 January 2028, although both are advised to be mothballed from 1 July 2024.
- Yallourn W Power Station (1,450 MW) in Victoria in 2028.
- Callide B Power Station (700 MW) in Queensland in 2028.
- The Dry Creek and Mintaro Power Stations (total 246 MW) in South Australia in 2030.
- Twelve (240 MW) of the 13 units at Hallett Gas Turbine in South Australia, in 2032.
- Bayswater Power Station (2,715 MW) in New South Wales in 2033.
- Vales Point B Power Station (1,320 MW) in New South Wales in 2033.
- Two (292 MW) of the three units at Mt Stuart Gas Turbine in Queensland in 2033.

[65] All expected retirement dates are advised by participants.

[66] Mothballing refers to when generating units are unavailable for service but can be brought back with appropriate notification, typically weeks or months. While these mothballed generators are not formally retired, the operator has advised that it is not its current intent or expectation to operate these units.

- Somerton (170 MW) in Victoria in 2033.
- Ballarat Energy Storage System, Dalrymple BESS, Gannawarra Energy Storage System, Queanbeyan BESS (total 95 MW) are advised to retire between 2030 and 2033.

Additionally, the Queensland Government has developed the Queensland Energy and Jobs Plan, which suggests that further coal generators could be subject to retirement within this horizon, subject to the development of sufficient replacement capacity including pumped hydro energy storage, grid developments, and new REZs. This includes the Stanwell (1,460 MW), Tarong (1,400 MW), and Tarong North (450 MW) power stations that could also be retired in the ESOO horizon, but acknowledges the critical importance for the Borumba pumped hydro power station (and other developments) that would be needed to successfully execute the plan[67]. These retirements are not formally advised, so were not modelled in the 2024 ESOO *Committed and Anticipated Investments* sensitivity.

Figure 17 shows the changes in the difference in total assumed capacity outlook forecast between the ESOO 2024, the May 2024 Update to the 2023 ESOO, and the 2023 ESOO. Additional capacity since the May 2024 Update to the 2023 ESOO is noted in 2025-26 and 2026-27 due to the delayed closure of Eraring Power Station, however in all other years, most capacity changes occurred prior to the May 2024 Update to the 2023 ESOO. Some reductions in capacity are noted in 2024-25 and 2027-28 due to revised project commissioning dates advised by developers.

Figure 17 Change in summer typical capacity, *Committed and Anticipated Investments* sensitivity, compared with the forecasts since ESOO 2023 and the subsequent May 2024 Update Central scenario (MW)

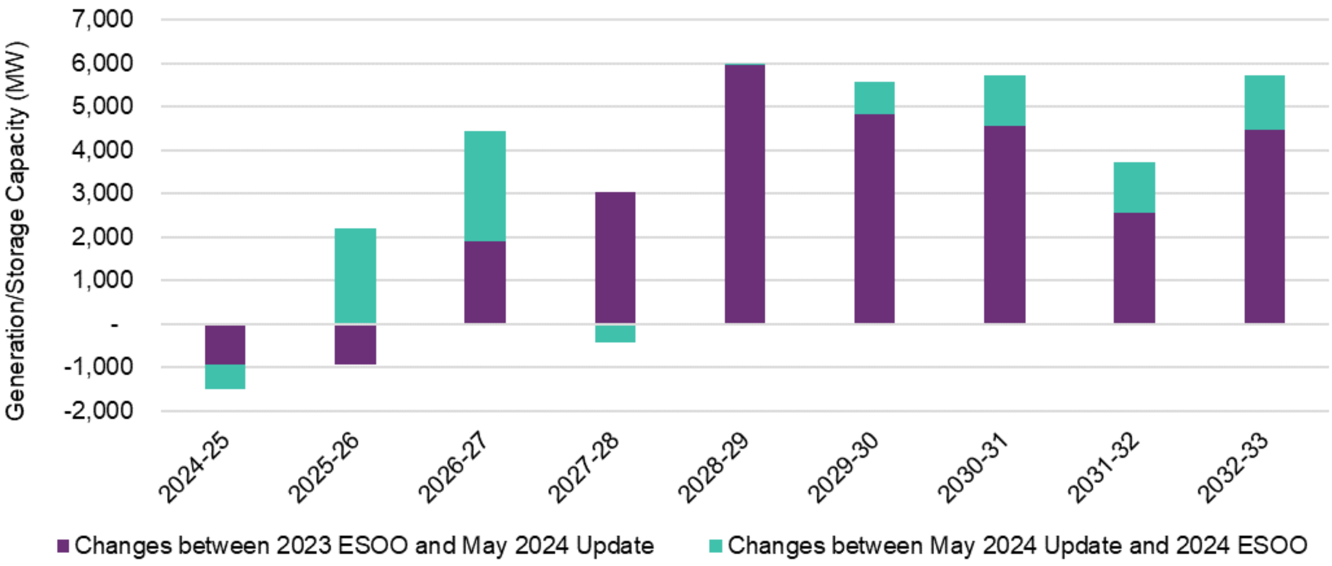


Figure 18 shows the changes in the assumed capacity outlook between the 2023 ESOO and the 2024 ESOO's *Committed and Anticipated Investments* sensitivity by technology, where the labels show the change in capacity for each forecast year relative to the previous year. Noteworthy changes to the outlook include:

- From summer 2024-25, Queensland black coal capacity is lower due to the revised summer scheduled capacities advised for Callide B and Callide C units.

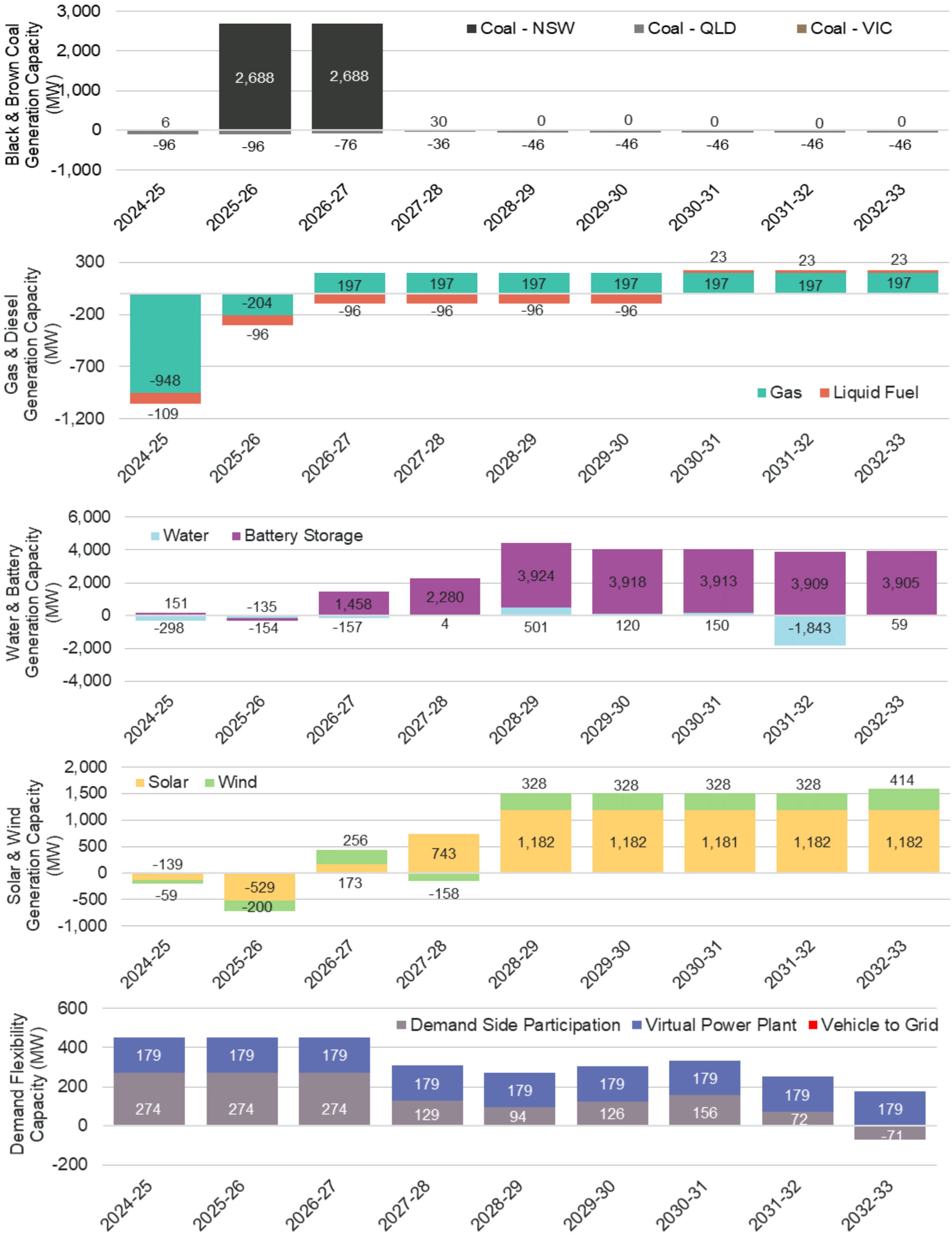
[67] See https://www.epw.qld.gov.au/__data/assets/pdf_file/0030/32988/queensland-supergrid-infrastructure-blueprint.pdf.

- New South Wales black coal capacity increases in 2025-26 and 2026-27 as the expected closure year of Eraring Power Station has been delayed by two years to August 2027.
- In applying AEMO's reliability forecasting methodology[68] to this reliability assessment, AEMO has allowed for potential delays to committed and anticipated projects that are yet to reach final commissioning milestones. This methodology was applied to 5,241 MW of developments across a range of technologies (1,588 MW wind, 1,815 MW/3,590 MWh battery, 838 MW solar, 250 MW pumped hydro, and 750 MW gas turbine) which have been advised to be commissioned immediately preceding or during the 2024-25 summer period. In some cases, this results in less capacity forecast to be available in summer 2024-25 than was considered in the 2023 ESOO.
- As reflected in the May 2024 Update to the 2023 ESOO, the announcements from AGL and Engie regarding mothballed plant have reduced gas and diesel generation availability over the horizon relative to the 2023 ESOO. A 204 MW hydrogen-powered generator in South Australia is now considered from summer 2026-27, increasing availability.
- Many hydro and battery storage developments are noted to be sufficiently progressed to be classified in the commitment categories that are included in the ESOO reliability assessment, with over 3.9 GW/13.5 GWh of battery projects newly considered. Despite this, numerous delays to the development and commissioning of committed and anticipated battery and hydro storage projects have been advised, reducing forecast availability in some years of the horizon for some jurisdictions.
- Many wind and solar developments are noted to be sufficiently progressed to be classified in the commitment categories that are included in the ESOO reliability assessment, with nearly 1.6 GW of projects newly considered. Despite this, numerous delays to the development and commissioning of committed and anticipated wind and solar projects have also been advised, reducing forecast availability in 2025-26 to 2027-28 relative to the 2023 ESOO.
- DSP capacity is forecast to be higher across the NEM in the near to medium term due to increased registered capacity in Victoria[69], while revisions to the application of the New South Wales Peak Demand Reduction Scheme (PDRS) have resulted in lower forecasts for New South Wales from 2027-28.
- AEMO included coordinated CER capacity in the *Committed and Anticipated Investments* sensitivity reliability assessment only where existing or committed. The majority of forecast CER coordination (VPPs and vehicle-to-grid [V2G]) under the *Step Change* scenario does not currently meet commitment criteria for inclusion in the 2024 ESOO's *Committed and Anticipated Investments* sensitivity, but was included in various sensitivities presented in **Chapter 4**.

[68] 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.

[69] See Section 2.5 for further information.

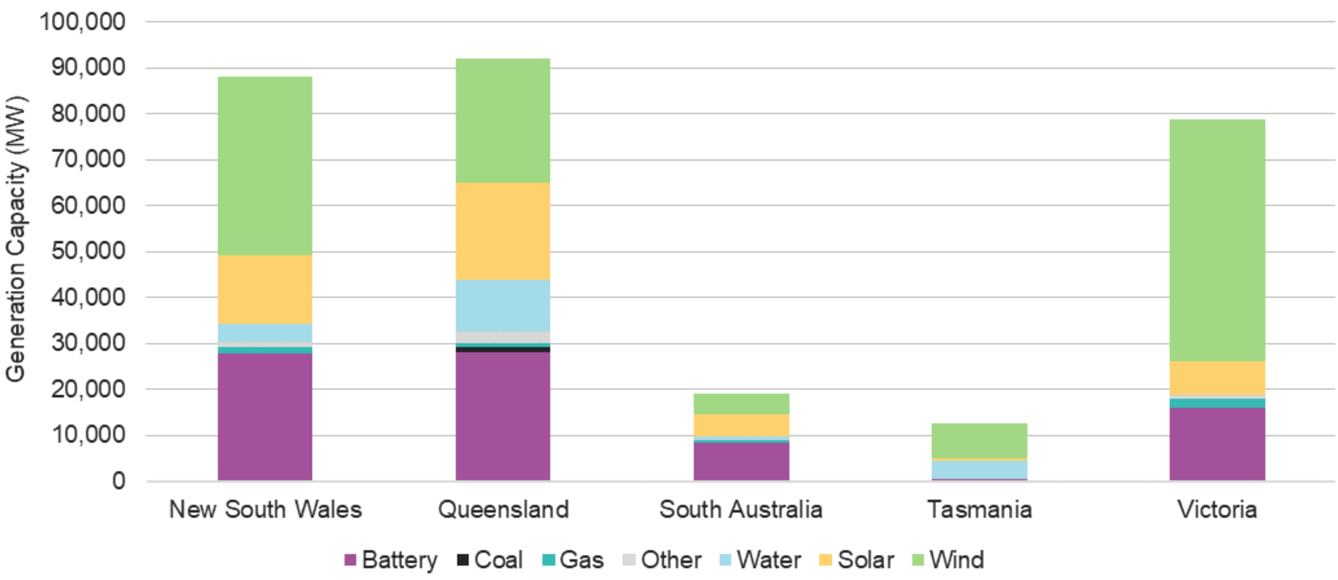
Figure 18 Changes in assumed typical summer capacity between 2023 and 2024 ESOOs, *Committed and Anticipated Investments* sensitivity, 2024-25 to 2032-33 (MW)



Proposed generation and storage pipeline

Figure 19 shows proposed generation and storage projects by region and type of generation. These projects are not yet sufficiently advanced to meet the in commissioning, committed, or anticipated commitment criteria. There are a range of jurisdictional initiatives that are also supporting supply side developments, which are discussed further in **Section 4.4** that may support the development of these projects (as well as assisting to deliver committed or anticipated projects).

Figure 19 Proposed projects by NEM region and type of generation or storage (MW)



Key points are:

- By capacity, 62% of proposed projects are VRE generation projects, while storage projects (battery or pumped hydro) account for about 35%.
- Approximately 40 GW of dispatchable capacity projects – including thermal projects, pumped hydro, and batteries – have been added to the pipeline of proposed projects since the August 2023 ESOO, of which, 12.5 GW have been added since the May 2024 Update to the 2023 ESOO.
- The average battery storage duration for is 2.3 hours in mainland regions and 1.5 hours in Tasmania.

Further details, including capabilities of proposed generating units, are on the Generation Information page[70].

3.2 Seasonal generator availability

AEMO collects existing and committed scheduled and semi-scheduled generation capabilities over the next 10 years to capture seasonal generator availability[71].

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

[71] See July 2024 Generation Information, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

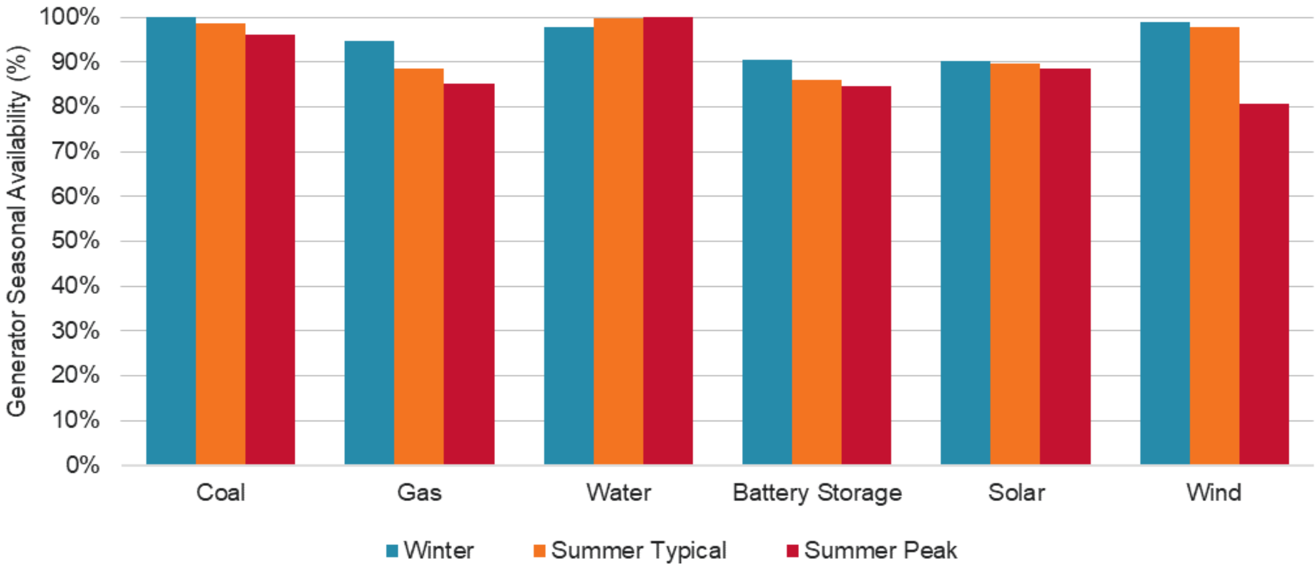
Scheduled capacity values are collected for three seasonal periods, where generator operators and proponents provide ratings consistent with the ambient temperatures associated with the following periods:

- **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 maximum demand events (typically at temperatures 37°C or greater for mainland regions, depending on the region).
- **Typical summer** – aligned with average summer temperatures and is applied in all other summer periods (November to March for mainland regions, 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 define summer peak.
- **Winter** – applied to all non-summer periods.

In addition to the above seasonal definitions that define temperature derated available capacity, VRE generators are also subject to consideration for the availability of wind and solar resources and their variability across hourly, seasonal, and annual timeframes.

Figure 20 shows average winter, typical summer, and summer peak availability relative to nameplate capacity by type of generation. It generally indicates the reduced availability reported in summer peak temperatures compared to winter and typical summer conditions. This is especially noticeable for wind generators, due to some reporting severe high temperature cut-offs for this generation category, including up to 100% derating during summer peak temperatures. See the *ESOO and Reliability Forecast Methodology Document*[72] for more detail about generation availability.

Figure 20 Winter, typical summer, and summer peak availability of nameplate capacity by type of generation (%)



3.3 Generator unplanned outage rates

AEMO collects outage information for existing scheduled generators, including storage units, through an annual survey process. This survey collects data on the timing, duration, and de-rating of historical unplanned outages. The collected data

[72] 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.

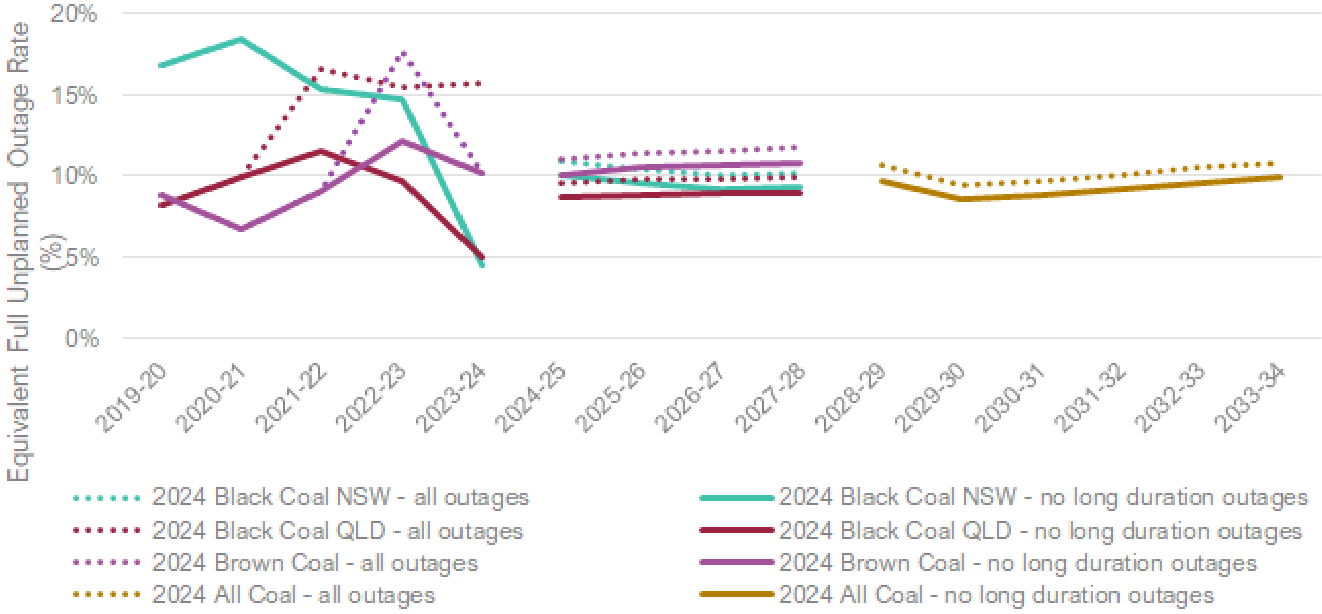
is then used to calculate long duration (full unplanned outages greater than five months), full, and partial unplanned outage rates for each financial year and each station over the ESOO horizon. Planned outages are not modelled in the NEM ESOO; AEMO's methodology reasonably assumes that operators will plan these in lower demand periods, and will shift maintenance events if low reserve conditions were to occur, and therefore will not be a reason for unavailability during events that will risk forecast unserved energy.

AEMO also collected unplanned outage rate projections from the operators for selected coal-fired and large gas-fired generators for each financial year over the ESOO horizon. These operator-provided projections reflect the expected change in performance as generators age, approach retirement, and undergo maintenance cycles. AEMO reviewed these projections against historical outages and consultant derived projections[73]. In limited circumstances where operator-provided projections are mis-aligned with historical and consultant derived trends, and/or are not sufficiently justified, AEMO applies consultant projections in consultation with each relevant operator.

For all other generator and storage types, the unplanned outage rates applied in the ESOO modelling were calculated from those unplanned outages observed over the last four years (2019-20 to 2023-24) as a constant projection.

Figure 21 shows the historical and projected equivalent full unplanned 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 unplanned outage rates. The projection takes into account the generators that are assumed to be included within the generation fleet available in each year, as such improvements in aggregate projected unplanned outage rates for a generation class are mostly due to the expected retirement of units with high outage rates, rather than expectations of improved performance across the asset class.

Figure 21 Actual and projected equivalent full unplanned outage rate projections for coal-fired generation technologies, 2019-20 to 2033-34 (%)



73 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.

Historical coal-fired generation reliability showed performance improvement in 2023-24 compared to previous years in New South Wales, while improvements observed in Queensland are offset by increased occurrences of long duration outages.

Relative to the 2023 ESOO, unplanned outage rates for coal generators are lower than previously projected, while unplanned outage rates for gas generators are higher than previously projected. The 2024 *Forecasting Assumptions Update* provides detailed information on the parameters for unplanned outages for each technology[74].

3.4 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 of network investments that are considered committed or anticipated. These constraint equations act at times to constrain interconnector transfer capacity, as well as intra-regional transfer capacity.

The 2024 ESOO *Committed and Anticipated Investments* sensitivity modelling included committed and anticipated transmission augmentations[75] as described below, consistent with the treatment for generation and storage projects. To determine if a transmission project is committed or anticipated, commitment criteria consistent with the *ISP Methodology*[76] and the AER's Cost Benefit Analysis Guidelines (and the Regulatory Investment Test for Transmission [RIT-T][77]) were applied.

Consistent with AEMO's *ESOO and Reliability Forecast Methodology Document*[78], AEMO applied the following timing regarding the assumed commissioning of transmission infrastructure:

- **Committed** transmission projects were included in the reliability model on the dates provided by the relevant TNSPs and other NEM jurisdictional bodies.
- To reflect the uncertainty in the commissioning of **anticipated** transmission projects, these projects were included in the reliability modelling one year after the commissioning dates provided by the relevant TNSPs and other NEM jurisdictional bodies.

Changes to inter-regional network capacity

AEMO has modelled the increase in inter-regional network capacity resulting from committed and anticipated inter-regional network augmentations.

Table 7 captures the committed inter-regional network augmentation, the approximate increase in network capacity, and the project timing as advised by the TNSPs and updated periodically through the Transmission Augmentation Information

[74] This input was not updated in the May 2024 Update to the 2023 ESOO. At https://aemo.com.au/consultations/current-and-closed-consultations/2024-forecasting-assumptions-update-consultation.

[75] For the purposes of the ESOO, transmission augmentations were included in accordance with AEMO's *ESOO and Reliability Forecast Methodology Document*, at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/reliability-forecasting-guidelines-and-methodology-consultation/final/esoo-and-reliability-forecast-methodology-document.pdf?la=en.

[76] At https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/isp-methodology-2023/isp-methodology_june-2023.pdf?la=en.

[77] At https://www.aer.gov.au/system/files/AER%20-%20Regulatory%20investment%20test%20for%20transmission%20-%2025%20August%202020.pdf.

[78] 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.

page[79]. Service dates were sourced from AEMO's August 2024 update to this page. There are currently no anticipated inter-regional network augmentations.

Table 7 Committed inter-regional network augmentations

Project name	Project status	Project description	Approximate increase in network capacity[A]	Proponent-provided capacity release date
Project EnergyConnect	Committed	A new interconnector between Wagga Wagga in New South Wales and Robertstown in South Australia via Buronga. Stage 1: • A new Robertstown to Bundey 275 kilovolts (kV) double-circuit line and a new Bundey to Buronga 330 kV double circuit line with one circuit connected initially. • Associated reactive plant, transformers, phase shifting transformers and synchronous condensers. • An inter-trip protection scheme to trip the Project EnergyConnect interconnector if South Australia becomes separated from Victoria via the Heywood Interconnector. Stage 2: • A second 330 kV circuit closed on the Bundey–Buronga 330 kV double circuit line. • A new Buronga to Red Cliffs 220 kV[B] and a new Dinawan to Buronga 330 kV double-circuit lines. • A new 500 kV double-circuit line from Dinawan to Wagga Wagga operating at 330 kV. • Associated reactive plant, transformers, phase shifting transformers and synchronous condensers. • Turning the existing 275 kV line between Para and Robertstown into Tungkillo. • A special protection scheme to detect and manage the loss of either of the AC interconnectors connecting to South Australia.	Stage 1: 150 MW Stage 2: 800 MW	Stage 1: December 2024[C] Stage 2: 500 MW in March 2027 and 800 MW capacity July 2027[C]

A. This is an approximate increase in network capacity. Detailed network constraints are used to capture the actual increase in network transfer capacity.
B. The Buronga – Red Cliffs 220 kV double-circuit line is expected in service 30 August 2024, and has been modelled with Stage 1.
C. The capacity release and timing is conditional on availability of suitable market conditions and good test results.

Intra-regional augmentations included in the 2024 ESOO

AEMO has modelled the increase in intra-regional network capacity resulting from committed and anticipated intra-regional network augmentations.

For this 2024 NEM ESOO, AEMO now considers that HumeLink has progressed from an actionable ISP project to an anticipated project following the AER's approval of the HumeLink Stage 2 contingent project application in early August 2024. Generally, AEMO considers transmission projects to be classified as anticipated once they have passed a contingent project application or similar funding approval and are in the process of meeting three out of five committed project criteria. Anticipated projects are not yet committed but are likely to proceed. Further steps are required before this project can be considered as committed.

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

Table 8 shows service dates, as advised by the TNSPs and other NEM jurisdictional bodies, for the intra-regional committed and anticipated augmentations considered in the 2024 ESOO**.** The dates were sourced from AEMO's August 2024 Transmission Augmentation Information page and the 2023 Transmission Annual Planning Reports.

Table 8 Committed and anticipated intra-regional network augmentations

Region	Project	Commitment Status	Approximate increase in network capacity[A]	Proponent provided capacity release date[B]
Queensland	**Northern Queensland REZ (QREZ)** • Establish a third 275 kV connection between Ross and Woree substation by converting one side of the coastal 132 kV double-circuit transmission line to permanently operate at 275 kV.	In service	To allow up to 500 MW of generation in Far North Queensland	June 2024[C]
	CopperString 2032 • Build a new 500 kV transmission line from a new substation (NQ substation) south of Townsville to Hughenden, a new 330 kV transmission line from Hughenden to Cloncurry and a new 220 kV line from Cloncurry to Mount Isa[D]. • Install two 500/275 kV 1,500 megavolt amperes (MVA) transformers at NQ substation. • Cut-in the Strathmore to Ross 275 kV double-circuit 220 kV lines into the network NQ substation.	Anticipated	1,500 MW[E]	June 2029
New South Wales	**Waratah Super Battery** **Transmission network augmentations and system integrity protection scheme (SIPS) control project** This project involves a SIPS to pair Waratah Super Battery with generation in Southern New South Wales and Northern New South Wales to allow the specific transmission lines which transfer power from the southern and northern regions of New South Wales to the Sydney, Newcastle and Wollongong regions at high thermal rating. Upgrade the selected transmission lines to a higher thermal capacity: • Bannaby – Sydney West 330 kV line. • Yass – Collector, Collector – Marulan and Yass – Marulan 330 kV lines. • Substation works at other southern lines, and northern lines.	Committed	Up to 910 MW[F] increase between Central New South Wales (CNSW) and Sydney, Newcastle and Wollongong (SNW)	August 2025. The SIPS control scheme will be for five years.
	HumeLink A 500 kV transmission upgrade between Maragle, Gugaa and Bannaby connecting Project EnergyConnect and the Snowy Mountains Hydroelectric Scheme to Bannaby.	Anticipated[G]	2,200 MW increase between Southern New South Wales and Central New South Wales	December 2026[H]
	Central-West Orana REZ Network Infrastructure Project[I] • A new switching station at Barigan Creek. • A 500/330 kV substation at Merotherie (Merotherie Energy hub) with four 1,500 MVA transformers. • Build two new 500 kV double-circuit line from Barigan Creek to Merotherie.	Anticipated	4,500 MW[J]	August 2028

Region	Project	Commitment Status	Approximate increase in network capacity[A]	Proponent provided capacity release date[B]
	• A 330 kV substation at Elong Elong (Elong Elong Energy Hub). • Build two new double-circuit 500 kV lines from Merotherie to Elong Elong initially operated at 330 kV. • New Bayswater – Liddell and Mount Piper – Wallerawang 330 kV lines. • 7 x 250 megavolt amperes reactive (MVAr) synchronous condensers located at Merotherie and Elong Elong Energy Hubs. • 330 kV transmission lines and switching stations to connect Merotherie and Elong Elong Energy Hubs to REZ User projects.			
Victoria	**REZ Development Plan Stage 1[I]** • South West REZ minor. • Murray River REZ and Western Victoria REZ minor network augmentations. • Central North REZ minor network augmentations. • Mortlake turn-in.	Committed Committed Committed Committed	81 MW 112 MW 12 MW 1,500 MW	December 2024 October 2025 October 2025 October 2025
	Western Renewables Link • A new 500 kV double-circuit transmission line from Sydenham terminal station to Bulgana terminal station with switched shunts on the end of each line. • New 500 kV Bulgana Terminal Station, two 500/220 kV 1,000 MVA transformers and connection of the existing Bulgana 220 kV yard to the new 500/220 kV transformers. • Cut-in of the existing Ballarat – Moorabool No. 2 220 kV line at Elaine terminal station. • 70 MVAr 500 kV bus reactor at Sydenham terminal station. • A range of substations works.	Anticipated	1,460 MW of increased network capacity to Western Victoria REZ	July 2027

A. The increase in network capacity is approximate. For the purpose of reliability assessments, AEMO models the increase in network capacity through network constraint equations.
B. Capacity release dates are provided by the TNSPs or proponents responsible for the project delivery and/or development. As per AEMO's ESOO methodology, anticipated projects are included in the ESOO reliability forecast one year after the commissioning dates provided. This delay is applied in the *Committed and Anticipated Investments* sensitivity.
C. The third Woree – Ross 275 kV was commissioned in June 2024. There is some outstanding work to be completed by December 2024.
D. For the 2024 ESOO, only the 500 kV transmission line from south of Townsville to Hughenden was modelled.
E. The approximate network capacity increase is limited by the existing 275 kV network at the point of connection (the 500/275 kV substation south of Townsville). Flows from CopperString will compete with generation in Far North Queensland for the 275 kV capacity south of NQ 275 kV substation.
F. This transfer limit is an approximate increase in network capacity between CNSW and SNW and is dependent on the output of the generation paired with the SIPS control scheme for a given period in time.
G. AEMO considers HumeLink to now be anticipated following the AER's approval of the contingent project application for HumeLink Stage 2 with the project progressing towards meeting three out of five committed project criteria.
H. The advised in service date for Gugaa – Bannaby 500 kV line is July 2026. The full capacity release of HumeLink and the advised in service date for Gugaa – Maragle and Maragle – Bannaby 500 kV lines is December 2026.
I. For more information on these projects, see AEMO's August 2024 Transmission Augmentation Information Page.
J. Hunter Transmission Project 1.0 is required to address network constraints between CNSW and SNW to enable the increase in network capacity from 3,000 MW to 4,500 MW for Central-West Orana REZ Network Infrastructure Project.

3.5 Inter-regional transmission unplanned outage rates

In forecasting the reliability of the NEM in the ESOO, AEMO applied transmission unplanned outage constraints for some simulated unplanned outages on some inter-regional transmission flow paths, consistent with AEMO's consulted-on methodology that reflects the current limitations of the NER 3.9.3C definition of unserved energy[80]. Information was collated from network service providers for this 2024 NEM ESOO on the timing, duration, and severity of the transmission outages to inform transmission unplanned outage rate forecasts.

Table 9 shows the rates used in the 2024 ESOO. All rates are annual and static over the 10-year horizon, except for those on the Mortlake – South East flow path which is set to zero when Project EnergyConnect (PEC) Stage 2 is advised to release full capacity. Based on current modelling and assumptions once PEC Stage 2 is implemented outages on this flow path are considered too immaterial to model.

Table 9 Projected unplanned outage rates for key inter-regional transmission flow paths

Flow path	2024 ESOO transmission unplanned outage rate (%)	2024 ESOO Mean time to repair (hours)	Outage rate method
Liddell – Bulli Creek (QNI) Credible Contingency	0.2	16	Annual static
Liddell – Bulli Creek (QNI) Reclassification	1.62	4	Annual static
Murraylink – Credible Contingency	1.37	72	Annual static
Basslink – Credible Contingency	5.27	192	Annual static
Mortlake – South East (VSA) Credible Contingency	0.03	2	Annual, set to 0% post PEC Stage 2
Mortlake – South East (VSA) Reclassification	0.01	5	Annual, set to 0% post PEC Stage 2

[80] See Section 1.1 for more information on the definition and limitations with the current definition of USE.

4 Reliability assessments

This chapter provides AEMO's 10-year reliability assessments under different sensitivities, which include different levels of supply with varying degrees of development certainty.

In this 2024 ESOO, AEMO provides four alternative sensitivities, all applied to the ESOO Central demand scenario (see **Section 1.2.1**). These sensitivities acknowledge that a range of market-driven and government-supported developments are progressing to provide new infrastructure over the next 10 years:

- ***Committed and Anticipated Investments* sensitivity** – considering only those developments that are existing, in commissioning, committed and anticipated, incorporating recently observed project commissioning delays. This sensitivity reflects a minimum infrastructure assessment given currently assessed developer commitments and is used as AEMO's reliability forecast for the purposes of the RRO and AEMO's summer readiness preparations.
- ***On-time Delivery* sensitivity** – on-time delivery of generator, storage and transmission projects improves the reliability outlook, particularly in the first half of the horizon.
- ***Actionable Transmission and Coordinated CER* sensitivity** – if actionable transmission developments progress as planned and scheduled, alongside the projected uptake of coordination schemes for CER, the outlook improves further, particularly in the second half of the ESOO forecast horizon.
- ***Federal and State Schemes* sensitivity** – the on-time and full implementation of currently quantifiable federal and state government energy policies and programs further improves the reliability outlook.

Table 10 summarises the generation and storage capacity considered under the reliability assessments included in this ESOO.

Table 10 Transmission, generation and storage capacity inclusion for ESOO reliability modelling under different sensitivities, in order from least to most progressed

Scenario/sensitivity	Existing and in commissioning projects	Committed projects	Anticipated projects	Proposed projects
***Committed and Anticipated Investments* sensitivity**	Yes	Yes, with assumed development delays to participant-provided full commercial use dates	Yes, assuming development delays to participant-provided full commercial use dates	No
***On time delivery* sensitivity**	Yes	Yes, without assumed development delays	Yes, with all projects assumed to be delivered on time	No
***Actionable transmission and coordinated CER* sensitivity**	Yes	Yes, without assumed development delays	Yes, with all projects assumed to be delivered on time	Inclusion of actionable transmission projects
***Federal and state schemes* sensitivity**	Yes	Yes, without assumed development delays	Yes, with all projects assumed to be delivered on time	Inclusion of actionable transmission projects and those generation and storage projects incentivised by federal, state or territory schemes and programs

Note: for more information on the assumed commissioning delays for committed and anticipated projects applied in the *Committed and Anticipated Investments* sensitivity, see the *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.

The *Committed and Anticipated Investments* sensitivity is used to meet AEMO's obligations under NER 4A.B.1 to publish a reliability forecast and an indicative reliability forecast, and the details required under NER 4A.B.2 to provide AEMO's forecast of expected USE and whether there is a forecast reliability gap. This sensitivity is also used to provide indications of how much additional capacity would be needed to bring expected USE within the IRM and reliability standard in each NEM region.

Chapter 6 (the EAAP) complements the reliability assessments in this chapter by presenting the additional impact of energy limitations, considering the same generation, storage and transmission developments as the *Committed and Anticipated Investments* sensitivity described above.

4.1 Considering only committed and anticipated developments, reliability gaps are forecast

The *Committed and Anticipated Investments* sensitivity is AEMO's reliability forecast and indicative reliability forecast in this 2024 ESOO. It applies for the purposes of the RRO and AEMO's summer readiness preparations. This is not a prediction of what will eventuate over the 10-year forecast horizon, as there are many projects in the pipeline of developments and many state and federal schemes currently supporting further investment; however, as AEMO's reliability forecast and indicative reliability forecast, it may be used by AEMO, governments and industry to prepare actions to mitigate these forecast reliability risks.

4.1.1 The reliability forecast (first five years)

In AEMO's reliability forecast, being the first five years of the *Committed and Anticipated Investments* sensitivity, AEMO applied the following assumptions:

- **Existing** projects were modelled as already available and operational.
- **In commissioning** projects were assumed to become fully available on the full commercial use date provided by the developer[81].
- **Committed** projects[82] were assumed to become fully available six months after the full commercial use date provided by the developer[83].
- To reflect uncertainty in the commissioning schedule of **anticipated** projects, the *Committed and Anticipated Investments* sensitivity assumed:
  - Anticipated projects which have provided an expected commissioning date were assumed to become fully available at the latest date of either one year after the full commercial use date provided by the developer, or the first day after the T-1 year for RRO purposes. For the 2024 ESOO this is 1 July 2026.

[81] Full commercial use date indicates the timing for generating unit(s) to become operationally available in the NEM. "Full commercial use" requires the successful completion of all NER 5.7.3 commissioning tests, including sign-off by AEMO and the NSPs.

[82] The committed category also includes committed* projects, which are very close to meeting all five commitment criteria. Modelled delays are applied consistent with committed projects.

[83] Commissioning delays were applied based on observed trends as consulted in the 2022 reliability forecasting guideline and methodology consultation. See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2023/esoo-and-reliability-forecast-methodology-document.pdf.

   - Anticipated projects which are not yet sufficiently progressed to provide an expected commissioning date were assumed to become fully available in reliability modelling on the first day after the T-3 year for RRO purposes, which for the 2024 ESOO is 1 July 2028.
- **Proposed** projects were not considered in the *Committed and Anticipated Investments* sensitivity, but demonstrate the pipeline of projects that exists for the market to progress in order to close identified reliability gaps, or service other investment opportunities.

When conducting this reliability assessment, AEMO applied its consulted-on ESOO methodology[84] that reflects commissioning uncertainty for projects that are committed and anticipated but have not yet met certain commissioning milestones. AEMO considers that applying this approach for the reliability forecast appropriately balances the risk that consumers are exposed to development delays for new projects. See **Chapter 3** for more information on the generation and transmission developments and commissioning assumptions considered in this assessment.

The *Committed and Anticipated Investments* sensitivity, used to produce the reliability forecast and indicative reliability forecast, excluded all investments that have not yet completed all necessary requirements to be classified as in service, in commissioning, committed or anticipated in accordance with AEMO's commitment criteria[85].

Specifically, the 2024 ESOO reliability forecast and indicative reliability forecast excluded:

- Major transmission developments that are not yet classified as committed or anticipated, including:
   - New England REZ Network Infrastructure Projects, Sydney Ring South and the Hunter Transmission Project in New South Wales, Queensland SuperGrid South, and other REZ expansion projects.
   - Strategic transmission projects identified as actionable projects in the 2024 ISP affecting inter-regional transfer capacities, including Marinus Link, Victoria – New South Wales Interconnector West (VNI West), and Marinus Link.
- Generation developments that are not yet classified as committed or anticipated, including those that may be incentivised or underwritten by a federal, state, or territory scheme:
   - These schemes include: the federal Capacity Investment Scheme; the New South Wales Electricity Infrastructure Roadmap; the Queensland Energy and Jobs Plan; the Victorian Renewable Energy Target, Storage Target, and Offshore Wind Policy; and the Tasmanian Renewable Energy Target.
- DSP and coordinated CER developments that are not yet considered committed.
- Any additional out of market capacity that could be made available through IRR or RERT[86].

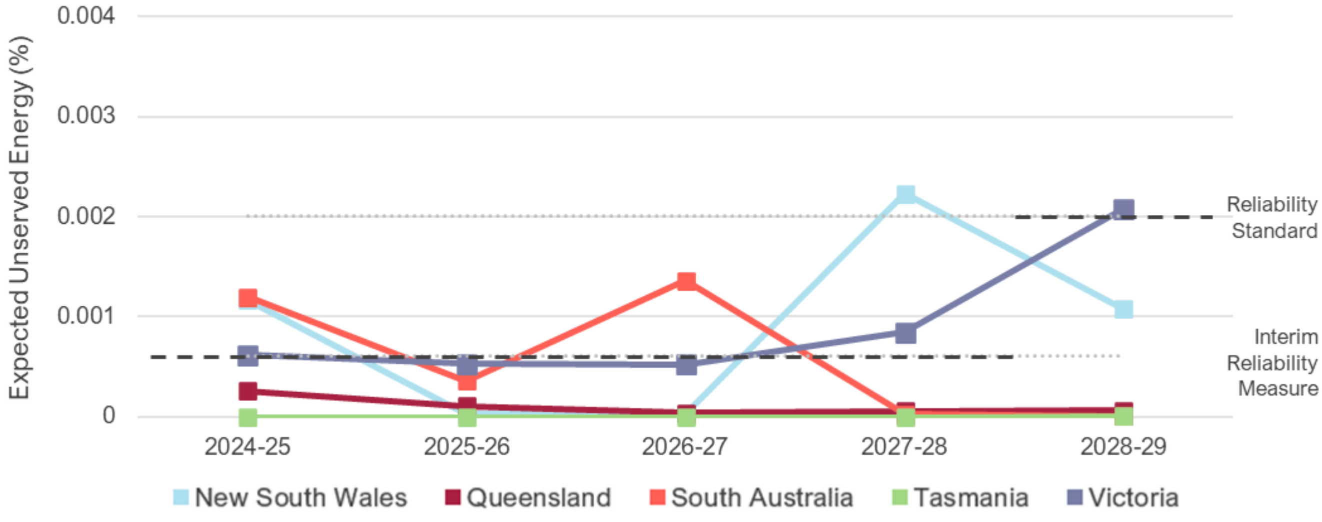
[84] At https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo.

[85] Consistent with AEMO's consulted-on *ESOO and Reliability Forecast Methodology Document*, 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.

[86] 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.

The *Committed and Anticipated Investments* sensitivity over the five-year period from 2024-25 to 2028-29, the reliability forecast (shown in **Figure 22**), shows expected USE above the IRM for New South Wales, South Australia and Victoria in 2024-25, South Australia in 2026-27, and New South Wales and Victoria in 2027-28. In 2028-29 the relevant reliability standard reverts from the IRM to the reliability standard of 0.002% expected USE; the forecast shows expected USE is within the reliability standard in most NEM regions except Victoria.

Figure 22 Reliability forecast, all NEM regions, first five years (2024-25 to 2028-29)



The key outcomes by region are:

- In **New South Wales,** reliability gaps are identified in 2024-25 and 2027-28 against the IRM.
  - A reliability gap is forecast against the IRM in 2024-25. This gap was previously forecast in the May 2024 Update to the 2023 ESOO, but not in the 2023 ESOO. This gap emerges partly because of revised demand distributions across key New South Wales load centres at times of summer supply scarcity which was applied in the May 2024 Update to the 2023 ESOO.
  - Reliability gaps previously forecast in 2025-26 and 2026-27 are no longer forecast due to the revised advised closure date for the Eraring Power Station, from 19 August 2025 to 19 August 2027.
  - A reliability gap is forecast in 2027-28, after Eraring Power Station's advised retirement despite the modelled inclusion of the HumeLink transmission project.
  - Reliability risks are forecast to reduce in 2028-29 with the modelled inclusion of Snowy 2.0, Maryvale BESS, Liddell BESS, Silver City Energy Storage and New England Solar Farm BESS.
- In **Queensland**, expected USE is forecast to be within the IRM and reliability standard across the reliability forecast horizon. Expected USE is forecast to decrease in 2025-26 as numerous new VRE and storage projects come online, including Clarke Creek Wind Farm, MacIntyre Wind Farm, Wambo Wind Farm, Western Downs Battery, Greenbank BESS, Tarong BESS and the Kidston Pumped Storage Hydro Project, to increase supply across the region.
- In **South Australia**, reliability gaps are identified in 2024-25 and 2026-27 against the IRM.
  - Reliability risks in Victoria and South Australia often occur at coincident times and vary subject to generation availability across both regions. Forecast risks across both regions in 2024-25 increased in the May 2024 Update to

  the 2023 ESOO due to the advised mothballing of Torrens Island B1, Port Lincoln and Snuggery power stations in South Australia.

  - In the 2024 ESOO, a change in the allocation of reliability risk between Victoria and South Australia has arisen in 2024-25 due to alternative network configurations applied between the Latrobe Valley and Melbourne at times of high demand, which reduces total risks across Victoria and South Australia, but results in reduced flows towards South Australia.

  - These alternative network configurations allow direct access from Latrobe Valley generators to Melbourne via the 220 kV network, reducing flows on the 500 kV network, and subsequently reducing flows over the 500 kV Heywood interconnector towards South Australia.

  - While reliability risks are now forecast higher in the South Australian region due to these changed flows, most risks remain shared between both regions, and the alternative configuration was assessed to reduce the total risk across both regions. The alternative configuration improves overall expected USE outcomes until 2028 when Yallourn Power Station retires, and another network configuration was assumed.

  - In 2025-26, expected USE is forecast to be within the IRM when Blyth BESS and Goyder South Wind Farms 1A and 1B are included.

  - In 2026-27, all units of Torrens Island B and Osborne Power Station have advised an expectation to retire. As a result, expected USE is forecast above the IRM, but within the reliability standard.

  - In 2027-28, Project EnergyConnect Stage 2 is advised to release the full 800 MW transfer capacity, reducing reliability risks below the IRM to negligible levels for the remainder of the reliability forecast.

- In **Tasmania**, expected USE remains below the IRM and the reliability standard over the reliability forecast horizon.

- In **Victoria**, reliability gaps are identified in 2024-25 and 2027-28 against the IRM.

  - Reliability risks are forecast above the IRM for summer 2024-25. This reliability gap was forecast in the May 2024 Update to the 2023 ESOO and in the 2023 ESOO, but has decreased in this 2024 ESOO due to new storage commitments and the alternative network configuration which allows more flows from the Latrobe Valley into Melbourne.

  - Risks decrease below the IRM for summer 2025-26, as numerous VRE and storage projects are included in the forecast, including Koorangie Energy Storage System, Latrobe Valley BESS, Melbourne Renewable Energy Hub and Rangebank BESS.

  - Over the reliability forecast horizon, the supply-demand balance in Victoria is forecast to progressively tighten as demand is expected to increase, driven by forecast electrification of residential, commercial, industrial and transportation loads. The projected electrification of traditional gas loads, particularly heating loads in Victoria, increases forecast electricity consumption but is expected to have minimal impact on summer maximum demand.

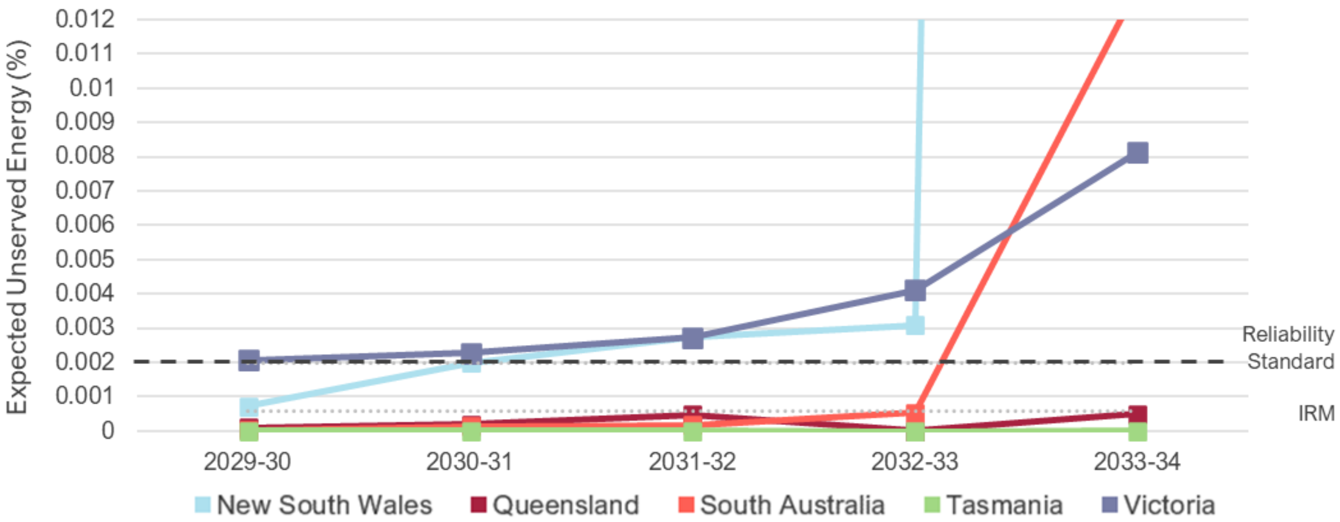
  - In 2027-28, expected USE is forecast above the IRM. By this year, all units of Torrens Island B and Osborne Power Station in South Australia and Eraring Power Station in New South Wales have advised an expectation to have retired, reducing the ability of these neighbouring regions to support reliability in Victoria.

  - In 2028-29, expected USE increases due to the advised retirement of Yallourn, and is forecast just above the reliability standard.

4.1.2 The indicative reliability forecast (second five years)

Figure 23 shows the indicative reliability forecast, covering the five-year period from 2029-30 to 2033-34 from the *Committed and Anticipated Investments* sensitivity.

Figure 23 Indicative reliability forecasts, all regions, second five years (2029-30 to 2033-34)



Note: the scale of the y-axis used for the indicative reliability forecast is three times greater than that used for the reliability forecast.

Over this period, expected USE is forecast above the reliability standard in most regions, and is forecast to progressively increase, apart from a drop in Queensland in 2032-33 with the modelled commissioning of the anticipated Borumba pumped hydro generator (which has advised a commissioning target of 2031-32, but is modelled in this sensitivity to commence operations in 2032-33 in accordance with the *ESOO and Reliability Forecast Methodology*).

The key outcomes by region are:

- In **New South Wales**, indicative reliability gaps are identified from 2031-32 onwards.
  - Maximum demand is forecast to increase more slowly relative to the 2023 ESOO forecast resulting in lower USE outcomes than in both ESOO 2023 and the ESOO 2023 Update reports over the horizon.
  - In 2029-30, Snowy 2.0 is fully commissioned before the summer period, which is supported by HumeLink, now included in modelling from December 2027. While these developments improve the reliability outlook, they are still insufficient to fully replace all retired capacity and to meet forecast increases in demand.
  - In 2033-34, reliability risks significantly increase due to the advised retirement of both Bayswater and Vales Point power stations.
- In **Queensland**, reliability risks remain within the reliability standard over the horizon.
  - Callide B Power Station has advised expected closure in 2028, however supply is forecast to be adequate in its absence.
  - Prior to summer 2032-33, the Borumba Pumped Hydro project is included in the outlook, reducing reliability risks from that point. This timing acknowledges development timing uncertainty in accordance with AEMO's methodology, delaying the anticipated project by 12 months relative to the proponent-advised timing in the reliability modelling.

  - In 2033-34, forecast reliability risks rise due to the advised expected closure of both Bayswater and Vales Point power stations in New South Wales, however reliability risks remain within the reliability standard. These retirements result in less flows from New South Wales into Queensland during high demand low supply periods, as well as the impact of the advised retirement of two of the three Mt Stuart units in Queensland.
- In **South Australia**, reliability risks remain with the reliability standard until 2033-34.
  - Various gas and liquid fuel generators in South Australia have advised retirement in 2030 and 2032, reducing projected supply availability and slightly increasing risks in South Australia.
  - Retirements in other regions are also impacting reliability risks in these regions especially in 2033-34 when Vales Point and Bayswater advised they will retire in New South Wales.
- In **Tasmania**, reliability risks remain within the reliability standard over the horizon.
- In **Victoria**, indicative reliability gaps are identified over the entire horizon against the reliability standard.
  - With few generator and transmission projects coming online in the indicative reliability forecast and increasing demands, reliability risks increase over the horizon.
  - Retirements in other regions are also impacting reliability risks in these regions especially in 2033-34 when Vales Point and Bayswater advised they will retire in New South Wales.

4.1.3 Forecast reliability risks in the reliability forecast and indicative reliability forecast have reduced since the 2023 ESOO publications

AEMO published the 2023 ESOO on 31 August 2023, and on 21 May 2024 published a May 2024 Update to the 2023 ESOO in response to material changes to the supply-demand outlook.

Table 11 summarises the material changes to the reliability forecast between the 2023 ESOO and the May 2024 Update, and between the May 2024 Update and this 2024 ESOO. This section looks at the impacts on the expected USE forecast compared to both the 2023 ESOO and the May 2024 Update to the 2023 ESOO.

Table 11 Material changes to the reliability forecast since the 2023 ESOO

Category	Change between 2023 ESOO and May 2024 Update	Change between May 2024 Update and 2024 ESOO
Demand	No change to demand	Demand forecasts have mostly been revised downwards in all regions
Demand flexibility	No change to demand flexibility	DSP and VPP forecasts higher in some regions, lower in others
Sub-regional demand distribution	Sub-regional demand distribution revised in Queensland and New South Wales to more accurately represent the location of demand within these regions at peak times	No changes to sub-regional demand distributions
Generator and storage commitments	Approximately 4.4 GW of additional projects met AEMO's commitment criteria Some projects advised later commissioning dates	Approximately another 1.3 GW of additional projects met AEMO's commitment criteria
Transmission developments	Advised delays to the commissioning of Project EnergyConnect	AEMO considers HumeLink anticipated

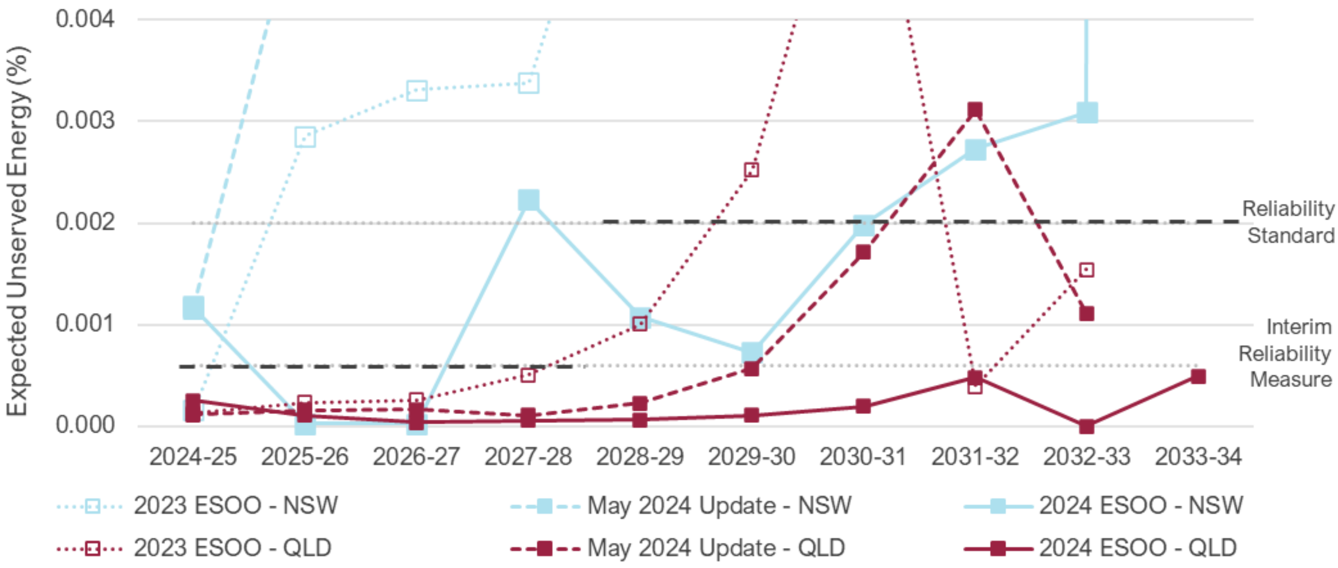
Category	Change between 2023 ESOO and May 2024 Update	Change between May 2024 Update and 2024 ESOO
Outage Rates	No change to outage rates	Black coal outage rates have decreased slightly, while gas generator outage rates have increased slightly
Generator retirements and mothballing	Port Lincoln, Snuggery and Torrens Island B1 in South Australia advised mothballing	Eraring Power Station advised a change of closure date from 2025 to 2027

Reliability outcomes in New South Wales and Queensland tend to be closely related due to inter-connectivity between these regions. Similarly, South Australia and Victoria results are also closely related.

For this reason, **Figure 24** shows a comparison of reliability outcomes in the 2024 ESOO *Committed and Anticipated Investments* sensitivity against the 2023 Central scenario and May 2024 Update to the 2023 ESOO for New South Wales and Queensland.

Figure 25 shows a similar comparison for South Australia and Victoria. Reliability risks in Tasmania are forecast to be negligible, so no comparison is shown.

Figure 24 New South Wales and Queensland expected USE, *Committed and Anticipated Investments* sensitivity in 2024 ESOO, Central scenario in May Update and 2023 ESOO, 2024-25 to 2033-34 (%)



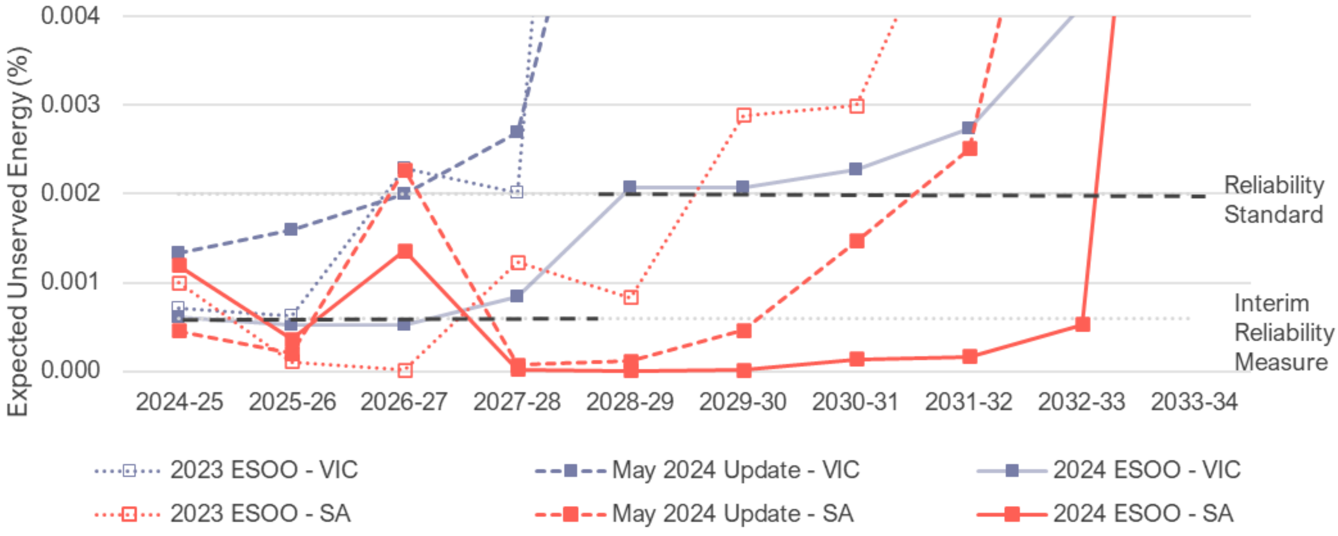
Key changes in New South Wales and Queensland are:

- A reliability gap is forecast against the IRM in New South Wales in 2024-25. This gap was forecast in the 2024 May Update but not in the 2023 ESOO, and emerges partly because of the revised demand distributions across key New South Wales load centres at times of summer supply scarcity used since the May 2024 Update to the 2023 ESOO. Also, AEMO has allowed for potential delays to committed and anticipated projects that are yet to reach final commissioning milestones.
- Reliability gaps in New South Wales previously forecast in 2025-26 and 2026-27 are no longer forecast, due to the revised closure date for the Eraring Power Station, from 19 August 2025 to 19 August 2027. A reliability gap is forecast in 2027-28 in New South Wales following the advised retirement of Eraring, although reliability risks are shown to have

reduced compared to previous forecasts due to new generation and storage developments and lower demand forecasts. Reliability outcomes in Queensland remain low throughout the first half of the horizon.

- Reliability outcomes from 2028-29 onwards are improved from previous forecasts in both New South Wales and Queensland, largely due to reduced demand forecasts, additional generation and storage projects which have progressed and the inclusion of the HumeLink transmission project, which better allows supply in southern New South Wales and southern regions to reach demand centres in New South Wales.

Figure 25 South Australia and Victoria expected USE, *Committed and Anticipated Investments* sensitivity in 2024 ESOO, Central scenario in May Update and 2023 ESOO, 2024-25 to 2033-34 (%)



Key changes in South Australia and Victoria are:

- Forecast risks in 2024-25 have increased in South Australia and decreased in Victoria. This is due to the advised mothballing of Torrens Island B1, Port Lincoln and Snuggery power stations in South Australia, and a revised network configuration in Victoria, which reduces risks across both regions, but allocates a larger portion of this risk to South Australia.
- Since the 2023 ESOO, reliability risks in South Australia have increased due to revised dates for the full capacity release of Project EnergyConnect Stage 2. South Australia has improved outcomes for the remainder of the horizon due to reduced demand forecasts as well as the inclusion of new projects such as the 200 MW Hydrogen Jobs Plan hydrogen generator (which has been included since the May Update), Mannum BESS and Bungama Solar (which have been included since this 2024 ESOO) and an increased level of committed VPP.
- Victoria has improved outcomes throughout the period due to a number of factors including alternative network configurations, reduced demand forecasts post 2027-28, an increase in forecast DSP, increased availability on Basslink and the inclusion of new projects since the 2023 ESOO such as Melbourne Renewable Energy Hub, Latrobe Valley BESS and Horsham Solar Farm.

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

AEMO has projected the additional capacity that would be required to reduce expected USE below the reliability standard and the IRM. This additional capacity assessment, shown in **Table 12** and **Table 13** below:

- Did not consider any reliability improvements that could be achieved with transmission developments, CER coordination or DSP developments, or the impact of transmission limits on future generation development.
- Considered each region separately and did not consider the likely reliability benefits of new capacity that is able to be shared across regions utilising the expected capacity to transfer electricity across regions. Actual capacity requirements may therefore be lower for some regions considering developments in neighbouring regions and the relative strength of inter-regional transmission.
- The identified firm capacity requirements were assumed to be fully unconstrained and continuously available throughout the entire year. Actual capacity requirements may therefore be greater considering potential generator outages, energy limits and/or power system constraints.
- Examined the level of firm, dispatchable and continuously available capacity that would be needed to meet these relevant standards. To achieve this requirement, firm capacity must be operable across the breadth of system challenges that may lead to reliability risks. While short duration batteries, for example, may provide some level of firming capacity, the capability to service reliability risks of longer durations is needed to replace retiring dispatchable capacity through longer and broader risk coverage that addresses these gaps.

Table 12 Reliability gaps and equivalent gaps against the IRM

Region	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34
New South Wales	265	-	-	570	285	105	680	850	890	3,560
Queensland	-	-	-	-	-	-	-	-	-	-
South Australia	200	-	230	-	-	-	-	-	-	870
Tasmania	-	-	-	-	-	-	-	-	-	-
Victoria	10	-	-	130	605	635	675	785	1140	1,505

Table 13 Reliability gaps and equivalent gaps against the reliability standard

Region	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34
New South Wales	-	-	-	55	-	-	-	195	265	3,065
Queensland	-	-	-	-	-	-	-	-	-	-
South Australia	-	-	-	-	-	-	-	-	-	620
Tasmania	-	-	-	-	-	-	-	-	-	-
Victoria	-	-	-	-	20	20	65	165	450	870

To illustrate the contributions of various technologies to reducing expected USE, AEMO built on the analysis presented above to provide indicative technology combinations that are forecast to reduce reliability risks to the reliability standard and IRM. This extended analysis of the estimated additional capacity requirements:

- Did not consider any reliability improvements that could be achieved with transmission developments, CER coordination or DSP developments, or the impact of transmission limits on future generation development.

- Considered each region separately and did not consider the inter-regional benefits of sharing new capacity. Actual capacity requirements may therefore be lower for some regions considering developments in neighbouring regions and the relative strength of inter-regional transmission.
- Identified the capacity required assuming adequate transmission connectivity with fully unconstrained access to supply the major demand centres within each region. Actual capacity requirements may therefore be greater considering power system constraints.
- Considered the reliability needs of the region for the year of study in isolation, without consideration for the long-term requirements of the region and the impact of over-use of stored energy on future supply conditions. Over the longer term, longer duration storages or energy generating plant may prove more effective at mitigating reliability risks that emerge less frequently, but require prolonged dispatch.

Importantly, the estimated capacity requirements shown in this extended analysis does not provide a recommended technology combination, or an optimal technology mix that will appropriately address the needs of the power system over the reliability forecast or indicative reliability forecast period.

Table 14 and **Table 15** show the additional capacity required to reduce the expected USE under the relevant standards for New South Wales and Victoria in 2027-28 (T-3 period for RRO purposes). Build ratios between VRE and storages were assumed[87] based on analysis of the 2024 ISP, however may not be optimal in this application.

Table 14 Additional capacity required, considering a variety of technology combinations (in MW) to reduce expected USE to the reliability standard and IRM, New South Wales 2027-28

Combination	Technology type	Reliability standard of 0.002% USE	IRM of 0.0006% USE
1	Firm, unlimited capacity	55 MW	570 MW
2	Open cycle gas turbine (OCGT)[A]	60 MW	630 MW
3	2 hour storage[B]	140 MW/280 MWh	1,515 MW/3,030 MWh
4	4 hour storage[B]	70 MW/280 MWh	710 MW/2,840 MWh
5	6 hour storage[B]	60 MW/360 MWh	600 MW/3,600 MWh
6	8 hour storage[B]	55 MW/440 MWh	580 MW/4,640 MWh
7	Wind, and	100 MW	920 MW
	4 hour storage	50 MW/200 MWh	460 MW/1,840 MWh
8	Solar, and	100 MW	1,030 MW
	4 hour storage	50 MW/200 MWh	515 MW/2,060 MWh
9	Wind,	90 MW	860 MW
	Solar, and	22.5 MW	215 MW
	4 hour storage	45 MW/180 MWh	430 MW/1,720 MWh

A. Assuming there is sufficient gas to operate the generator throughout potential USE periods.
B. Assuming there is sufficient charge/storage to operate the storage throughout potential USE periods.

[87] These ratios are 2:1 for VRE to storage in combinations 7 and 8 and 4:2:1 for wind to storage to solar in combination 9.

Table 15 Additional capacity required, considering a variety of technology combinations (in MW) to reduce expected USE to the reliability standard and IRM, Victoria 2027-28

Combination	Technology type	Reliability standard of 0.002% USE	IRM of 0.0006% USE
1	**Firm, unlimited capacity**	N/A	130 MW
2	**Open cycle gas turbine (OCGT)[A]**	N/A	145 MW
3	**2 hour storage[B]**	N/A	285 MW/570 MWh
4	**4 hour storage[B]**	N/A	145 MW/580 MWh
5	**6 hour storage[B]**	N/A	135 MW/810 MWh
6	**8 hour storage[B]**	N/A	130 MW/1,040 MWh
7	**Wind, and**	N/A	210 MW
	4 hour storage	N/A	105 MW/420 MWh
8	**Solar, and**	N/A	200 MW
	4 hour storage	N/A	100 MW/400 MWh
9	**Wind,**	N/A	190 MW
	Solar, and	N/A	47.5 MW
	4 hour storage	N/A	95 MW/380 MWh

A. Assuming there is sufficient gas to operate the generator throughout potential USE periods.
B. Assuming there is sufficient charge/storage to operate the storage throughout potential USE periods.

4.1.5 Forecast reliability gaps

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

- Exceeds 0.0006% of the total energy demanded in a region for a given financial year between 2024-25 and 2027-28[88].
- Exceeds 0.002% of the total energy demanded in a region for a given financial year between 2028-29 and 2033-34.

This section outlines any forecast reliability gaps, the associated reliability forecast components where relevant, and the one-in-two-year peak demand forecast consistent with NER 4A.B.2 and NER 4A.A.3. All times refer to Australian Eastern Standard Time.

In the reliability forecast (first five years), forecast reliability gaps occur in South Australia in 2024-25 and 2026-27 against the IRM, in Victoria in 2024-25 and 2027-28 against the IRM and again in 2028-29 against the reliability standard, and in New South Wales in 2024-25 and 2027-28.

The reliability forecast components associated with these forecast reliability gaps are summarised in **Table 16**.

These reliability gaps, published for RRO purposes, reflect the additional capacity required to reduce annual expected USE to the relevant standard, if the capacity is 100% available throughout all periods of the year.

[88] As per NER 11.132.2, which prescribes the IRM as the reliability standard until 30 June 2028.

Table 16 Forecast reliability gaps against the Interim Reliability Measure and reliability standard (MW)

Region	Financial Year	Reliability gap period	Likely trading intervals	Expected USE for the gap period (GWh)	Reliability gap (MW)
New South Wales	2024-25	1 December 2024 - 28 February 2025	3:00pm - 8:00pm, Working Weekdays	0.64	265
	2027-28	1 December 2027 - 29 February 2028	3:00pm - 10:00pm, Working Weekdays	1.22	570
South Australia	2024-25	1 January 2025 - 28 February 2025	5:00pm - 9:00pm, Working Weekdays	0.14	200
	2026-27	1 January 2027 - 28 February 2027	3:00pm - 10:00pm, Working Weekdays	0.15	230
Victoria	2024-25	1 January 2025 - 28 February 2025	4:00pm - 8:00pm, Working Weekdays	0.21	10
	2027-28	1 December 2027 - 31 March 2028	3:00pm - 9:00pm, Working Weekdays	0.30	130
	2028-29	1 January 2029 - 31 March 2029	3:00pm - 10:00pm, Working Weekdays	0.75	20

GWh: gigawatt hours.

Reliability instruments are already current for the following periods:

- T-3 instrument for weekdays between 1 December 2025 to 28 February 2026 in New South Wales.
- T-3 instrument for working weekdays between 12 January 2026 to 13 March 2026 in South Australia.
- T-3 instrument for working weekdays between 1 December 2026 to 31 March 2027 in New South Wales
- T-3 instrument for working weekdays between 1 December 2026 to 28 February 2027 in South Australia.
- T-3 instrument for working weekdays between 1 December 2026 to 28 February 2027 in Victoria.

Based on the reliability gaps identified above, AEMO must request the AER to consider making further reliability instruments as follows:

- A T-3 reliability instrument for working weekdays between the period 1 December 2027 – 29 February 2028 in New South Wales.
- A T-3 reliability instrument for working weekdays between the period 1 December 2027 – 31 March 2028 in Victoria.

As the reliability forecast no longer identifies a reliability gap for New South Wales and South Australia in the T-1 year of 2025-26, AEMO will notify the AER in accordance with NER 4A.C.5 that these reliability gaps are no longer forecast to occur.

Indicative forecast reliability gaps

In the indicative reliability forecast (second five years), forecast reliability gaps occur in New South Wales in years 2031-32 to 2033-34, in South Australia in 2033-34 and in Victoria in years from 2029-30 to 2033-34. In each of these years, each region’s expected USE is forecast to exceed the reliability standard of 0.002% of total energy demanded.

The reliability forecast components associated with these indicative forecast reliability gaps are summarised in **Table 17**.

Table 17 Forecast reliability gaps against the reliability standard (MW)

Region	Financial year	Reliability gap period	Likely trading intervals	Expected USE for the gap period (GWh)	Reliability gap (MW)
New South Wales	2031-32	1 December 2031 - 31 March 2032	3:00pm - 11:00pm, Working Weekdays	1.56	195
	2032-33	1 July 2032 - 31 July 2032	6:00pm - 8:00pm, Working Weekdays	0.06	265
		1 December 2032 - 31 March 2033	3:00pm - 11:00pm, Working Weekdays	1.65	265
		1 June 2033 - 30 June 2033	5:00pm - 8:00pm, Working Weekdays	0.10	265
	2033-34	1 July 2033 - 31 August 2033	5:00pm - 10:00pm, Working Weekdays	0.13	3,065
		1 November 2033 - 30 June 2034	All Hours, All Days	242.57	3,065
South Australia	2033-34	1 June 2033 - 30 June 2033	All Hours, All Days	1.80	620
Victoria	2029-30	1 January 2030 - 31 March 2030	4:00pm - 10:00pm, Working Weekdays	0.78	20
	2030-31	1 January 2031 - 28 February 2031	4:00pm - 9:00pm, Working Weekdays	0.87	65
	2031-32	1 January 2032 - 29 February 2032	4:00pm - 10:00pm, Working Weekdays	1.08	165
	2032-33	1 December 2032 - 31 March 2033	4:00pm - 10:00pm, Working Weekdays	1.65	450
		1 June 2033 - 30 June 2033	5:00pm - 8:00pm, Working Weekdays	0.13	450
	2033-34	1 July 2033 - 31 July 2033	5:00pm - 9:00pm, Working Weekdays	0.10	870
		1 December 2033 - 30 June 2034	4:00pm - 11:00pm, Working Weekdays	3.44	870

One-in-two-year peak demand forecast

In accordance with NER 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 calculates the one-in-two-year demand forecast by adjusting the 50% POE operational maximum demand forecast provided in **Section 2.3** to take into account a variety of operational considerations. The purpose of these adjustments is to ensure that that value calculated for this purpose is on a like-for-like basis with demand as reported by AEMO operationally on a five-minute basis. The following formula applies:

> *One-in-two-year demand forecast = Forecast 50% POE maximum demand + forecast generator auxiliaries at time of maximum demand – forecast demand flexibility (DSP and distributed aggregated storages) + a 30-minute to five-minute demand adjustment*[89] *(reflecting that AEMO forecasts on a 30-minute average demand basis, while five-minute average demand values may reach higher maximums).*

[89] Calculated as the average difference between 5-minute and 30-minute maximum demands over the last three annual peak demand events.

AEMO's one-in-two-year peak demand forecast is listed in **Table 18,** alongside key adjustments that ensure the value is comparable with demand as published operationally.

Table 18 AEMO's one-in-two-year peak demand forecast

Region	Financial year	Operational 'sent out' 50% POE maximum demand	Auxiliaries	Forecast demand flexibility	30-minute to five-minute maximum demand adjustment	One-in-two-year peak demand forecast
New South Wales	2024-25	13,278	+366	-156	+42	13,530
	2025-26	13,436	+263	-154	+42	13,587
	2026-27	13,593	+259	-144	+42	13,751
	2027-28	13,755	+251	-124	+42	13,924
	2028-29	13,777	+212	-183	+42	13,848
Queensland	2024-25	10,225	+419	-45	+32	10,631
	2025-26	10,380	+476	-40	+32	10,847
	2026-27	10,563	+478	-42	+32	11,031
	2027-28	10,755	+401	-32	+32	11,155
	2028-29	10,864	+377	-34	+32	11,239
South Australia	2024-25	2,975	+46	-32	+25	3,015
	2025-26	3,028	+46	-26	+25	3,074
	2026-27	3,108	+14	-18	+25	3,130
	2027-28	3,161	+13	-27	+25	3,172
	2028-29	3,180	+15	-23	+25	3,197
Tasmania	2024-25	1,704	+18	-1	+7	1,729
	2025-26	1,722	+17	-1	+7	1,746
	2026-27	1,730	+19	-1	+7	1,755
	2027-28	1,731	+18	0	+7	1,756
	2028-29	1,734	+18	-1	+7	1,759
Victoria	2024-25	9,578	+342	-136	+96	9,880
	2025-26	9,677	+350	-128	+96	9,995
	2026-27	9,894	+350	-120	+96	10,220
	2027-28	10,008	+321	-122	+96	10,303
	2028-29	10,141	+222	-115	+96	10,344

4.2 On-time delivery of projects improves reliability

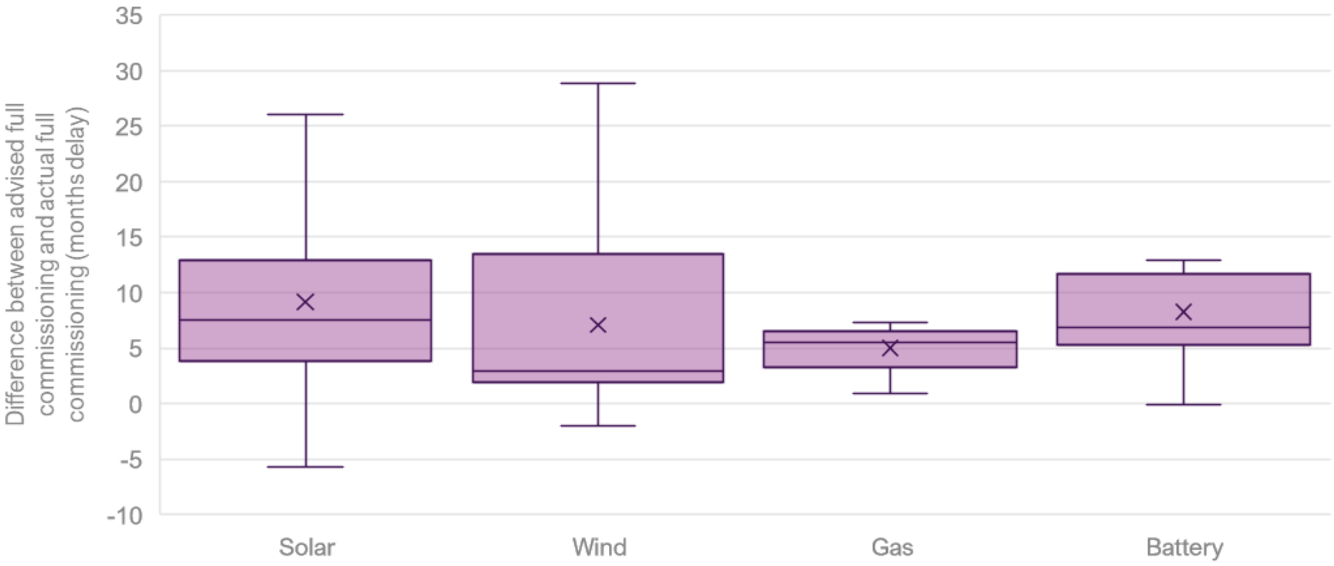
The 2024 ESOO *Committed and Anticipated Investments* sensitivity applied an adjustment to the participant-submitted timing of project completion for projects not yet in commissioning phases. This is to reflect the average difference in advised and actual completion dates observed in recent years, ensuring the increased accuracy of ESOO reliability forecasts. Delays were applied depending on the status of the projects:

- 'In Commissioning' projects were included in the *Committed and Anticipated Investments* sensitivity with the submitted full commissioning date advised by the developer.

- 'Committed' projects were delayed in the *Committed and Anticipated Investments* sensitivity by six months past the date advised by the developer.
- 'Anticipated' projects were included in the *Committed and Anticipated Investments* sensitivity at the latter of the first day after the T-1 period for RRO purposes (1 July 2026 for this 2024 ESOO) and one year after the full commissioning date advised by the developer. If the proponent of an 'Anticipated' project had not yet advised a full commissioning date, the first day after the T-3 period for RRO purposes was used (1 July 2028 for this 2024 ESOO).
- 'Publicly Announced' projects were not modelled in the *Committed and Anticipated Investments* sensitivity.

Figure 26 shows a box plot of differences between actual and advised full commissioning dates for committed projects between 2021-22 and 2023-24. The box plot shows the distribution of outcomes observed, where the average outcome is shown by the 'X'. Between 2021-22 and 2023-24, committed projects had an average difference of approximately eight months between the advised and actual date of commissioning completion. The graph also shows that new gas projects advised full commissioning dates most accurately, although this is influenced by limited number of new gas projects. Solar projects had the largest difference between advised and actual dates, with an average of nine months. The results show that the treatment of project timing assumptions applied in the *Committed and Anticipated Investments* sensitivity as per the ESOO methodology remains prudent.

Figure 26 Box plot of differences between actual and advised full commissioning dates for committed projects, 2021-22 to 2023-24

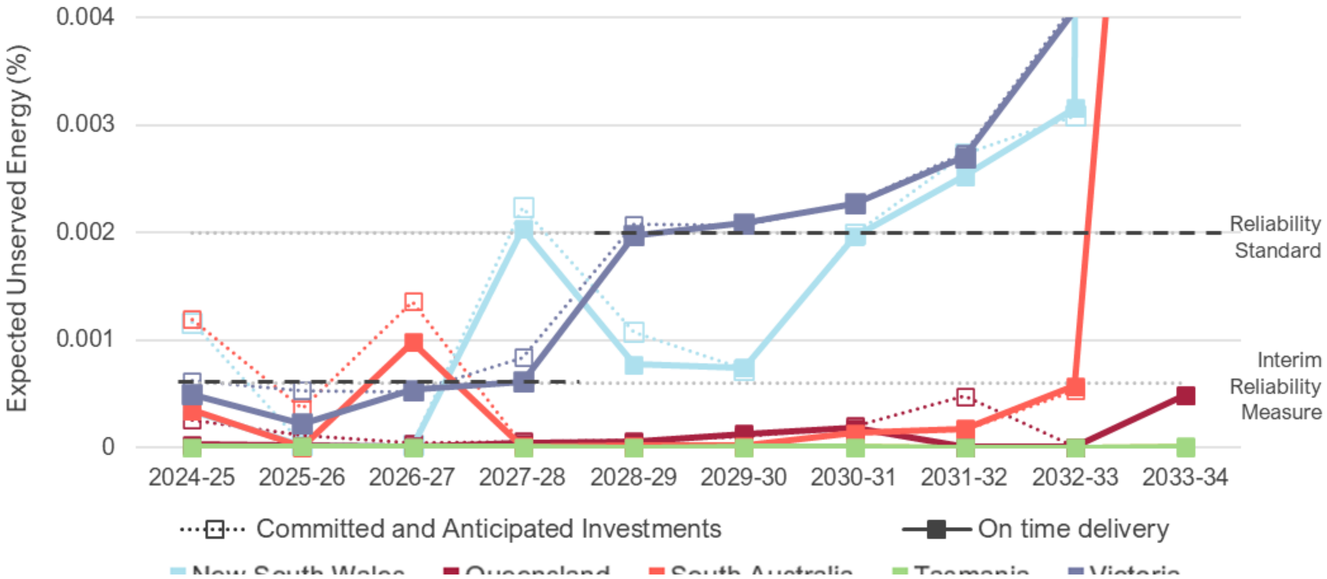


To assess the impact on reliability outcomes if all developers deliver to their announced schedules, AEMO simulated an *On-time Delivery* sensitivity with the following assumptions applied:

- Committed and anticipated generation and transmission projects were applied at the full commercial use date advised by the project developer (not applying the delays assumed in the 2024 ESOO *Committed and Anticipated Investments* sensitivity).
- All other assumptions aligned with the *Committed and Anticipated Investments* sensitivity described in **Section 4.1**.

Figure 27 shows the *On-time Delivery* sensitivity relative to the *Committed and Anticipated Investments* sensitivity.

Figure 27 Reliability impact of on-time delivery, 2024-25 to 2033-34 (%)



Key insights from this sensitivity, compared to the *Committed and Anticipated Investments* sensitivity, are:

- Forecast reliability risks are lower in all regions, due to the earlier assumed commissioning of committed and anticipated generation and storage projects, particularly in the first five years of the ESOO horizon.
- In **New South Wales**, the sensitivity shows expected USE would fall below the IRM in 2024-25 if projects are delivered to schedule. Expected USE outcomes in this sensitivity still remain above the IRM in 2027-28, suggesting that current projects which are advanced sufficiently to meet AEMO's committed criteria are not enough to close this reliability gap, and earlier (or additional) developments will be required to address risks in this year (as explored in other sensitivities).
- In **Queensland,** lower USE is expected in the early years of the forecast due to earlier assumed commissioning of generation and storage projects including Aldoga BESS Stage 1, Greenbank BESS, Kidston Pumped Storage Hydro Project, Swanbank BESS, Tarong BESS, Ulinda Park BESS and Western Downs Battery. Expected USE is also lower in 2031-32 if Borumba is assumed to commission to its intended schedule, being in this year of the forecast.
- In **South Australia,** expected USE is forecast within the IRM in 2024-25, primarily due to the assumed on-time commissioning of Blyth BESS and Goyder South Wind Farms 1A and 1B. Expected USE still exceeds the IRM in 2026-27 when all units of Torrens Island B and Osborne Power Station are advised to retire, although outcomes are improved in this year relative to the *Committed and Anticipated Investments* sensitivity, due to the on-time inclusion of Clements Gap BESS.
- In **Tasmania,** the reliability outlook is for minimal USE under both the *Committed and Anticipated Investments* and *On-time Delivery* sensitivities.
- In **Victoria,** USE is forecast within the IRM in 2024-25, with lower USE due to the earlier assumed commissioning of generation and storage projects in time for the 2024-25 summer including Hawkesdale Wind Farm, Rangebank BESS and Ryan Corner Wind Farm. USE remains within the relevant standard until 2029-30 onwards in this sensitivity, at

which point it exceeds the reliability standard and shows little variation from the *Committed and Anticipated Investments* sensitivity.

Equivalent gaps calculated consistent with the reliability gaps presented in **Section 4.1.4** are shown below for the *On-time Delivery* sensitivity.

Table 19 Reliability gaps and equivalent gaps against the IRM, *On-time Delivery* sensitivity (MW)

Region	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34
New South Wales	-	-	-	545	125	115	655	775	910	3,580
Queensland	-	-	-	-	-	-	-	-	-	-
South Australia	-	-	140	-	-	-	-	-	-	865
Tasmania	-	-	-	-	-	-	-	-	-	-
Victoria	-	-	-	10	580	645	665	765	1,115	1,580

Table 20 Reliability gaps and equivalent gaps against the reliability standard, *On-time Delivery* sensitivity (MW)

Region	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34
New South Wales	-	-	-	10	-	-	-	145	280	3,080
Queensland	-	-	-	-	-	-	-	-	-	-
South Australia	-	-	-	-	-	-	-	-	-	620
Tasmania	-	-	-	-	-	-	-	-	-	-
Victoria	-	-	-	-	-	25	65	155	435	930

4.3 Actionable transmission developments and the coordination of CER significantly improve the reliability outlook

The *Committed and Anticipated Investments* sensitivity included only transmission developments that are existing, or considered committed or anticipated, as classified in AEMO's Transmission Augmentation Information page[90]. In addition to those transmission projects, the 2024 ISP identified a variety of projects that were defined as 'actionable', meaning that they should progress as soon as possible. Several of these projects are progressing under relevant jurisdictional frameworks (such as the New South Wales actionable projects being delivered under the New South Wales Electricity Infrastructure Roadmap), and under the traditional RIT-T framework. Should these projects progress as identified in the ISP, they have the potential to significantly improve the reliability outlook, particularly in the second half of the ESOO horizon.

AEMO modelled an *Actionable Transmission and Coordinated CER* sensitivity to demonstrate the potential reliability improvement of these additional transmission developments, alongside significant CER coordination and DSP uptake, compared to the *Committed and Anticipated Investments* sensitivity. The purpose of the sensitivity is to demonstrate the importance of the actionable transmission developments for power system reliability, and the reduced requirement for utility-scale solutions should these proceed to schedule alongside the timely development of all other generation, transmission, DSP and CER coordination.

[90] See https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/transmission-augmentation-information.

These are the modelled actionable transmission developments identified in the 2024 ISP, and shown in **Figure 28**[91]:

- **Hunter-Central Coast REZ Network Infrastructure Project** – the intended network capacity for this project is 1 GW. The REZ is to be developed in the region between and around Muswellbrook and Newcastle, and the northern areas of the Central Coast. This REZ infrastructure project is advised to be available from December 2027.
- **Sydney Ring South** – this new 330 kV switching station in the Greater Sydney region with new modular power flow controllers at the new switching station, and rearrangement of existing 330 kV lines 39, 76 and 77 into the new switching station, is advised to be available from September 2028.
- **Hunter Transmission Project** 1.0 (shown on the map as the Sydney Ring North) – this project comprises a new 500 kV double-circuit line between new switching stations near Eraring and near Bayswater, two new transformers at Eraring, 500 kV connections between Bayswater and near Bayswater substations and between Eraring and near Eraring substations, and associated substation augmentation work at Bayswater and Eraring. It is advised to be available in December 2028.
- **Gladstone Grid Reinforcement** – this proposed upgrade to the existing transmission network in Gladstone, Queensland, includes a new 275 kV high capacity double-circuit line between Calvale and Calliope River, rebuilding Calliope River – Larcom Creek 275 kV and Larcom Creek – Bouldercombe 275kV as high capacity double-circuit lines, and a new (third) 275/132 kV transformer at Calliope River. Its advised in service date is March 2029.
- **Waddamana to Palmerston transfer capability upgrade** – this is a proposed upgrade to increase transfer capacity of the existing network between Waddamana and Palmerston by 690 MW. Its advised in service date is July 2029.
- **Mid North SA REZ Expansion** – this would increase the capacity of the existing REZ from the current installed capacity of 1.7 GW to a proposed 2 GW. Its advised in service date is July 2029.
- **VNI West** – this is a new 500 kV double-circuit transmission line to connect Western Renewables Link (at Bulgana) with Project EnergyConnect (at Dinawan) via a substation near Kerang. The capacity release is advised to be fully available in December 2029.
- **Marinus Link Stage 1** – this 750 MW capacity undersea and underground interconnector between North West Tasmania and the Latrobe Valley in Victoria is advised to be available in December 2030.
- **New England REZ Network Infrastructure Project Stage 1** – this stage includes four new substation hubs (Central Hub 500/330 kV, Central-South and North Hubs 330 kV capable of future expansion to 500 kV and East Hub 330 kV switchyard) and a combination of 500 kV and 330 kV double-circuit transmission lines (Bayswater – Central Hub 500 kV line, Central-South Hub – Central Hub and Central Hub – North Hub 500 kV line operated at 330 kV, and a Central Hub – East Hub 330 kV line) to unlock 2.4 GW of transfer capacity for New England REZ. The project is advised to be available in June 2031.
- **Queensland SuperGrid South** – this upgrade and extension, linking Central and South Queensland energy grids, includes the Borumba connection (two 500 kV transmission lines around 140 kilometres in length) and the Southern

[91] HumeLink was specified as actionable in the 2024 ISP but is now considered anticipated and was modelled in the 2024 ESOO *Committed and Anticipated Investments* sensitivity.

Queensland and Central Queensland connection (one 500 kV transmission line around 290 kilometres in length). It is advised to be available in September 2031[92].

- **Marinus Link Stage 2** – this second 750 MW capacity undersea and underground interconnector between north-west Tasmania and the Latrobe Valley in Victoria is advised to be available in December 2032.
- **QNI Connect** – this is a proposed 330 kV double-circuit transmission line that would connect the New England REZ Transmission Link to Queensland. It is advised to release capacity in March 2033.
- **New England REZ Network Infrastructure Project Stage 2** – this stage to further increase transfer capacity between New England REZ and Bayswater to 6 GW, includes expanding Northern and Central South Hub as part of New England REZ Network Infrastructure Stage 1 to 500/330 kV substations, a new double-circuit 500 kV line between Central South Hub and Bayswater and converting the operation of Central Hub to Central South Hub and Central Hub to North Hub lines from 330 kV to 500 kV. It is advised to release capacity in June 2033.

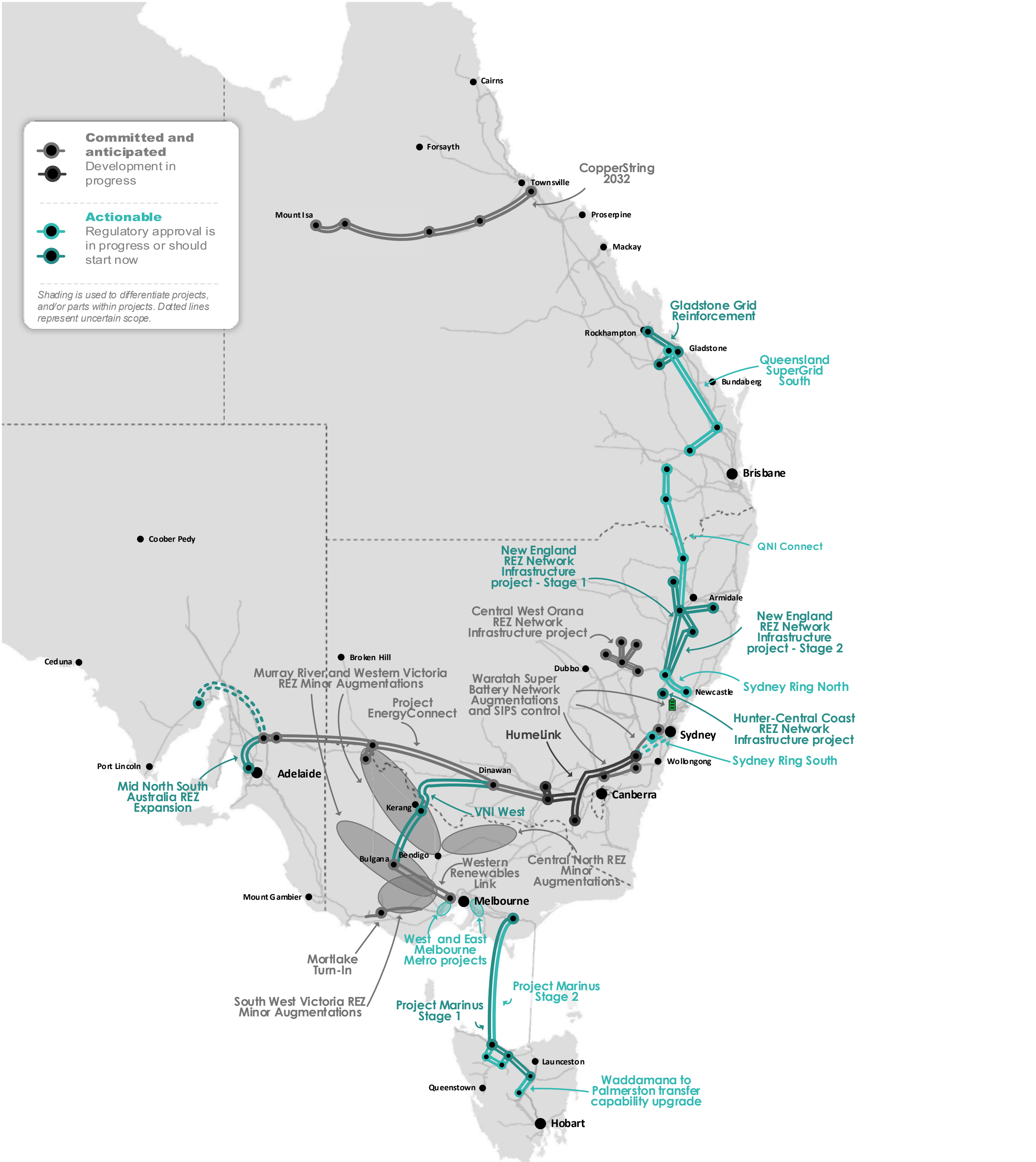
This sensitivity also included transmission projects that materially influence reliability but are smaller in scale than the above actionable transmission developments. Given their smaller scale, they do not progress through actionable frameworks but are progressing through other relevant regulatory processes.

The additional transmission developments included in this sensitivity are:

- **Western Melbourne Metro** project – this involves smaller-scale projects that address a variety of limitations on 220 kV and 500 kV transmission infrastructure between Geelong, Moorabool, Deer Park and Keilor. The project is assumed to release capacity by July 2028.
- **Eastern Melbourne Metro** project – this involves smaller-scale projects that address a variety of limitations on 220 kV and 500 kV transmission infrastructure between Hazelwood, Yallourn, Cranbourne, Rowville, Ringwood and Templestowe. The project is assumed to release capacity by July 2030.

[92] For the 2024 ESOO, AEMO modelled the easterly route for Queensland SuperGrid South aligned with the latest information at the time of modelling. On 30 July 2024, Powerlink issued an update for SuperGrid South moving the route to the west and noting that the Borumba connection will be built at 275 kV.

Figure 28 Map of network investments considered in the *Actionable Transmission and Coordinated CER* sensitivity



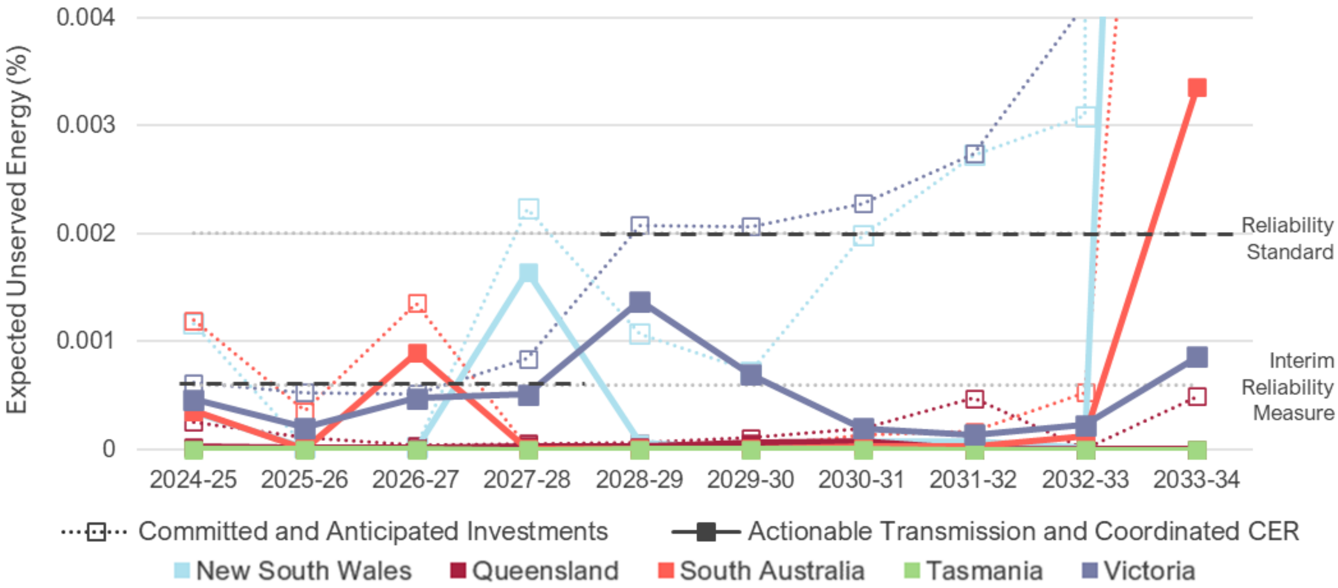
† Grey bubbles indicate anticipated and committed REZ augmentation projects that may include non-network augmentations. Teal bubbles indicate transmission projects that are progressing through other relevant regulatory processes and are included in the Actionable Transmission sensitivity. Dotted lines represent uncertain scope.

In this sensitivity, the following assumptions were applied:

- Committed and anticipated generation and transmission projects were applied at the full commercial use date advised by the TNSP or proponents responsible for the project delivery and/or development without the application of delays (consistent with the *On-time Delivery* sensitivity in **Section 4.2)**.
- Actionable and other transmission developments were included at the full commercial use date advised by the TNSP or proponents responsible for the project delivery and/or development.
- While actionable transmission developments were applied consistent with the 2024 ISP, the additional generation and storage developments projected as necessary by the ISP were not included in this sensitivity. Significant opportunities to improve the reliability outlook therefore exist if generation and storage developments are delivered to complement actionable transmission developments (as may be expected considering various policy drivers such as the federal and jurisdictional renewable energy targets – described further in **Section 4.4**).
- CER coordination and demand flexibility growth in DSP, VPP and V2G projections were applied, in addition to the existing and committed DSP, VPP and V2G developments considered in the *Committed and Anticipated Investments* sensitivity.
- All other assumptions aligned with the *Committed and Anticipated Investments* sensitivity described in **Section 4.1**.

Figure 29 shows the results of the *Actionable Transmission and Coordinated CER* sensitivity relative to the *Committed and Anticipated Investments* sensitivity.

Figure 29 Reliability impact of actionable transmission, CER coordination and DSP developments under on-time delivery of committed and anticipated generation and storage developments, 2024-25 to 2033-34 (%)



Key insights from this sensitivity are:

- Forecast expected USE is lower in all regions due to the earlier commissioning of committed and anticipated generation and storage projects, the increase in transmission capacity, and the additional demand flexibility.

- Consistent with findings from the 2024 ISP and the *Committed and Anticipated Investments* sensitivity, additional generation and storage investments, beyond those that are committed or anticipated, are required to ensure reliability within the relevant standards; however, the transmission developments in this sensitivity provide increased capability to share resources between regions, lowering the reliability risks relative to the *On-time Delivery* sensitivity.
- In **New South Wales**, the sensitivity shows reliability risks under the IRM until 2027-28, and significantly lower reliability risks over the ESOO horizon.
  - Reliability risks are lower relative to the *Committed and Anticipated Investments* sensitivity, due to the inclusion of additional CER coordination and the modelled on-time delivery of all included generation and storage projects.
  - Expected USE continues to exceed the IRM in 2027-28 following the advised retirement of Eraring Power Station, although risks are lower than the reliability standard due to the Sydney Ring South transmission project which will allow generation and storage projects already considered in the *Committed and Anticipated Investments* sensitivity to gain access to the major demand centres of Sydney, Newcastle and Wollongong.
  - In 2028-29, the Hunter Transmission Project was assumed to commission, reducing expected USE relative to the *Committed and Anticipated Investments* sensitivity in the following years, due to further improving transfer capabilities to the major demand centres of Sydney, Newcastle and Wollongong.
  - In 2033-34, reliability risks significantly increase due to the retirement of both Bayswater and Vales Point power stations, as in the *Committed and Anticipated Investments* sensitivity and the *On-time Delivery* sensitivity.
- In **Queensland**, the sensitivity shows USE within the relevant reliability standard over the entire horizon, with all expected USE outcomes lower than the *Committed and Anticipated Investments* sensitivity. The lower reliability risk is due to the on-time delivery of all included generation and storage projects, increased coordinated CER developments, and additional inter-regional capacity sharing enabled by a more interconnected NEM. There is a significant reduction in expected USE in 2031-32 due to the assumed commissioning of Borumba during that year; it was assumed to be delayed to 2032-33 in the *Committed and Anticipated Investments* sensitivity.
- In **South Australia**, the sensitivity shows lower levels of expected USE that remain within the relevant reliability standard apart from in 2026-27 and 2033-34.
  - Reliability risks are lower than the *Committed and Anticipated Investments* sensitivity, due to the assumed on-time delivery of all included generation and storage projects, and the additional inter-regional capacity sharing enabled by a more interconnected NEM with the additional actionable transmission projects.
  - Expected USE outcomes are beneath the IRM in 2024-25 in this sensitivity.
  - In 2026-27, reliability increases above the IRM as all units of Torrens Island B and Osborne Power Station have advised an expectation to have retired.
  - In 2033-34, expected USE increases due to the retirement of Vales Point and Bayswater in New South Wales.
- In **Tasmania,** the reliability outlook is for minimal USE under both the *Committed and Anticipated Investments* sensitivity and this sensitivity.
- In **Victoria**, the sensitivity shows reliability risks under the relevant reliability standard throughout the horizon, with risks lower than the *Committed and Anticipated Investments* sensitivity.

- Reliability risks are forecast within the IRM in 2024-25 in this sensitivity, due to the assumed on-time delivery of generation and storage projects including Hawkesdale Wind Farm, Rangebank BESS and Ryan Corner Wind Farm.
- Between 2025-26 and 2027-28, reliability risks continue to be lower relative to the *Committed and Anticipated Investments* sensitivity due to the inclusion of additional CER coordination, and the modelled on-time delivery of all included generation and storage projects.
- From 2028-29, when Yallourn Power Station is expected to have retired, current limitations impacting transmission capability within the western side of the 500/220 kV Melbourne ring in Victoria were assumed to be addressed by small-scale transmission projects currently being investigated as part of the Western Metro RIT-T. Reliability risks increase at this point due to the retirement of Yallourn, however these forecast reliability risks are considerably lower than the *Committed and Anticipated Investments* sensitivity (and lower than if only the forecast CER is coordinated).
- In 2029-30, VNI West is advised to release capacity, which improves reliability outcomes in Victoria. While the new transmission link was modelled to be available, the development of further generation along the transmission corridor that is not already identified as committed or anticipated was not, thereby understating the potential reliability impact of this development.
- In 2030-31 and 2032-33, stages 1 and 2 of Marinus Link respectively are advised to commission, improving reliability further. While these new cables were modelled to be available, the development of further generation in Tasmania was not, potentially understating the potential reliability improvement of these developments.

Equivalent gaps calculated consistent with the reliability gaps presented in **Section 4.1.4** are shown below for the *Actionable Transmission and Coordinated CER* sensitivity.

Table 21 Reliability gaps and equivalent gaps against the IRM, *Actionable Transmission and Coordinated CER* sensitivity (MW)

Region	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34
New South Wales	-	-	-	450	-	-	-	-	-	2,615
Queensland	-	-	-	-	-	-	-	-	-	-
South Australia	-	-	110	-	-	-	-	-	-	510
Tasmania	-	-	-	-	-	-	-	-	-	-
Victoria	-	-	-	-	430	45	-	-	-	180

Table 22 Reliability gaps and equivalent gaps against the reliability standard, *Actionable Transmission and Coordinated CER* sensitivity (MW)

Region	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34
New South Wales	-	-	-	-	-	-	-	-	-	1,890
Queensland	-	-	-	-	-	-	-	-	-	-
South Australia	-	-	-	-	-	-	-	-	-	185
Tasmania	-	-	-	-	-	-	-	-	-	-
Victoria	-	-	-	-	-	-	-	-	-	-

4.4 Federal and state generation development schemes have the potential to address the majority of longer-term risks

Numerous federal, state and territory government schemes and programs are being implemented to further incentivise or directly fund additional generation and storage developments in the NEM. Schemes typically focus on dispatchable capacity needs, or renewable energy developments. The 2024 ESOO *Committed and Anticipated Investments* sensitivity, presented in **Section 4.1**, included only those generation and storage projects that are defined by AEMO as meeting the 'in commissioning', 'committed' or 'anticipated' commitment criteria, and does not explicitly consider additional developments that may arise as a result of federal, state or territory programs.

The *Federal and State Schemes* sensitivity applied these additional dispatchable generation and storage projects, alongside forecast growth in CER coordination and DSP uptake and actionable transmission developments.

While developments to meet various government renewable energy targets have the potential to further improve reliability, those developments were not considered in these sensitivities, unless specific projects have been awarded government tenders. Given that many of these renewable energy targets do not provide specific geographical or technological requirements (other than the capacity needs to rely on a renewable form of generation), AEMO considers it premature to consider the reliability impacts of these targets at this time in this sensitivity, as the specific location and technology is crucial in then assessing the reliability impacts of the overall scheme.

Schemes and programs considered in these two sensitivities therefore do not reflect the full extent of the support anticipated by these schemes, but include:

- The **ARENA Large Scale Battery Storage Funding Round** – this supplied conditional funding to eight grid-scale battery projects across Australia, which are expected to be operational by 2025. While these projects have received conditional funding, only some of the projects have progressed sufficiently to pass the relevant commitment criteria to be considered in the *Committed and Anticipated Investments* sensitivity. This sensitivity considered all announced projects.
- The **New South Wales Infrastructure Investment Objectives (IIO) Report**[93] – this includes an implementation plan for conducting competitive tenders for the IIO Development Pathway. All awarded projects not already considered committed or anticipated were included in this sensitivity.
  - Four IIO tenders have now been successfully completed. This includes a firming infrastructure tender, which included additional funding from the Federal Government as part of its Capacity Investment Scheme (discussed further below).
  - The pathway includes the construction of 2 GW of long-duration (eight or more hours) storage by 2030, of which 50 MW was awarded in the first tender and 524 MW was awarded in the third tender (the second tender did not include any long duration storage projects).
  - While the IIO Development Pathway includes further development of VRE generators, these were not included in this sensitivity.

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

- The **Queensland Energy and Jobs Plan** – this will fund new dispatchable investments, including the Swanbank BESS and the Borumba Pumped Hydro Project (both of which are already considered as anticipated, and were included in the Committed and Anticipated Investment outlook), and a hydrogen-ready gas peaking power station at Kogan Creek to be commissioned by June 2026.
- The **South Australia Hydrogen Jobs Plan** – this plan will fund a 200 MW green hydrogen power station, to be operational by December 2025, alongside hydrogen electrolyser and hydrogen storage projects near Whyalla. This project is considered anticipated and thus was already included in the *Committed and Anticipated Investments* sensitivity (subject to development delay assumptions only in the *Committed and Anticipated Investments* sensitivity).
- The **Victorian Renewable Energy Target Auction 2** – this has funded six projects to bring forward 623 MW of new renewable generation capacity and 365 MW/600 MWh of new battery energy storage. While these projects have received funding, only some of the projects have progressed sufficiently to meet relevant commitment criteria to be considered in the *Committed and Anticipated Investments* sensitivity, while this sensitivity considered all announced projects.
- The first stage tender of the **Capacity Investment Scheme in South Australia and Victoria** – this will fund the development of an indicative amount of 600 MW of generation or storage, with an indicative duration of four hours, making 2,400 MWh.

In this sensitivity, the following assumptions were applied:

- The schemes listed above were applied at the dates envisioned by the schemes. Where a specific recipient has not been announced, the projects were assumed to be developed with unconstrained access to major demand centres, on the basis that the generators will either connect to strong and available parts of the electricity network, or appropriate transmission developments will accompany the generation and storage projects. For storage projects, the minimum storage duration was applied.
- For schemes that have not yet awarded recipients, the recipient was assumed to be additional to those already considered in the *Committed and Anticipated Investments* sensitivity.
- Committed and anticipated generation and transmission projects were applied at the full commercial use date advised by the project developer (consistent with the *On-time Delivery* sensitivity in **Section 4.2**).
- Actionable transmission developments were included at the full commercial use date advised by the project developer (consistent with the *Actionable Transmission and Coordinated CER* sensitivity in **Section 4.3**).
- DSP, VPP and V2G projections were applied in this sensitivity, in addition to the existing and committed DSP, VPP and V2G developments that were considered in the *Committed and Anticipated Investments* sensitivity.
- All other assumptions aligned with the *Committed and Anticipated Investments* sensitivity described in **Section 4.1**.

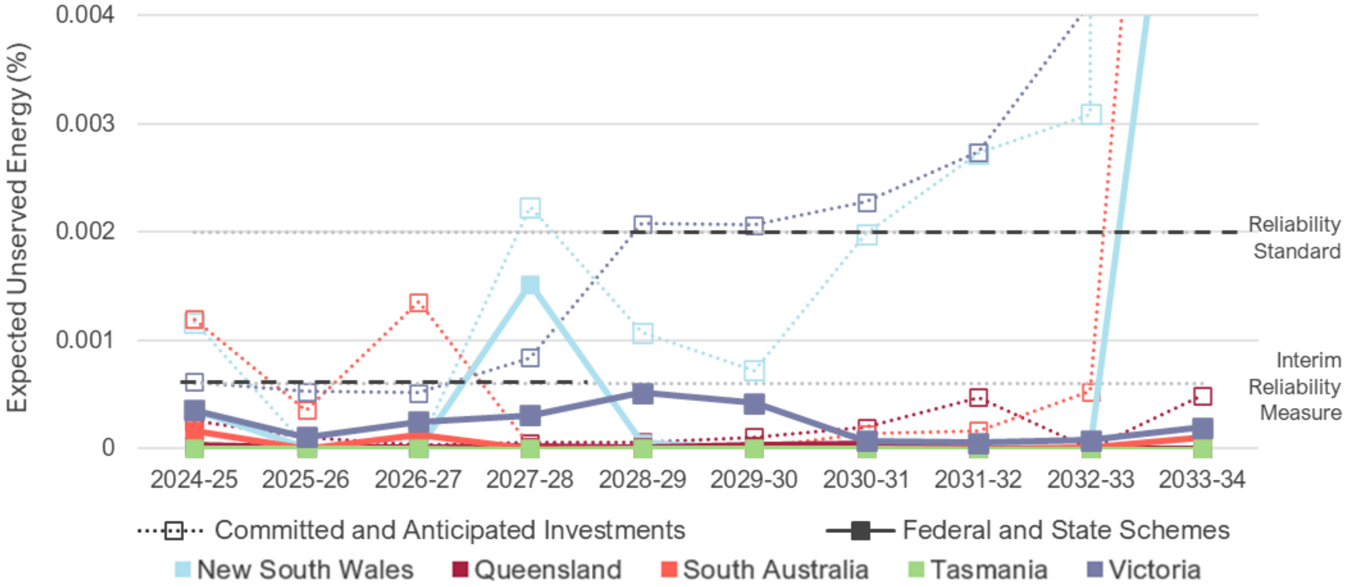
There remain numerous other government schemes in development that have the potential to bring forward this pipeline of proposed projects, in addition to the schemes included in the *Federal and State Schemes* sensitivity, which will further address the residual reliability risks forecast, but have not been included in this analysis. These schemes include:

- Further developments as part of the federal Capacity Investment Scheme, which seeks to unlock at least 6 GW of dispatchable power (beyond the first stage tenders, which have been included).

- Further developments as part of the New South Wales Electricity Infrastructure Roadmap.
- Further developments as part of the Queensland Energy and Jobs Plan.
- Further developments as part of the Victorian Renewable Energy Target, Storage Target, and Offshore Wind Policy.
- Developments to meet the Tasmanian Renewable Energy Target.
- Further developments to support the Federal Government's commitment to increase renewable energy generation to 82% of NEM supply by 2030.

Figure 30 shows the results of the *Federal and State Schemes* sensitivity, relative to the *Committed and Anticipated Investments* sensitivity.

Figure 30 Reliability impact of federal and state generation development schemes, 2024-25 to 2033-34 (%)



Key insights from these sensitivities are:

- Forecast expected USE is lower in all regions due to the earlier commissioning of committed and anticipated generation and storage projects, the increase in transmission, generation and storage capacity, and the additional demand flexibility.
- Forecast USE is within the relevant reliability standard in all regions across the horizon, except for New South Wales exceeding the IRM in 2027-28 and the reliability standard in 2033-34.
- Consistent with the findings from the 2024 ISP and the *Committed and Anticipated Investments* sensitivity, additional generation and storage investments, beyond those that are committed or anticipated, are required to ensure reliability to adequately replace announced retirements.
- In **New South Wales**, outcomes show reliability risks within the relevant reliability standard over all years of the horizon apart from 2027-28 and 2033-34.

- In 2024-25, reliability risks are lower than the *Committed and Anticipated Investments* sensitivity due to the modelled on-time delivery of all included transmission, generation and storage projects, and are reduced below the IRM.
- In 2025-26, there is further reliability benefit due to the assumed completion of projects awarded tenders under the first and second IIO tenders, as well as forecast increase in CER coordination.
- In 2027-28, a reliability gap against the IRM is forecast due to the advised retirement of Eraring Power Station, despite improvement due to projects constructed under the IIO tenders assumed to come online before this date. Further stages of the New South Wales roadmap or Capacity Investment Scheme were not included in this sensitivity and have the potential to address this risk, if they are suitably progressed in advance of the identified risk.
- Outcomes improve from 2028-29 due to the completion of Snowy 2.0 and Liddell BESS and the inclusion of forecast growth in coordinated CER. The Hunter Transmission Project was also assumed to have commissioned in this year.
- In 2033-34, reliability risks significantly increase due to the retirement of both Bayswater and Vales Point power stations.

- In **Queensland**, reliability risks are forecast within the relevant reliability standards throughout the horizon. Expected USE is lower than the *Committed and Anticipated Investments* sensitivity due to the modelled on-time delivery of all included generation and storage projects, forecast increases in CER coordination, the development of the Kogan Creek gas turbine, and the enhanced ability of available generation in New South Wales to provide additional capacity in times of supply scarcity.
- In **South Australia**, reliability risks are forecast within the relevant reliability standards throughout the horizon. Expected USE is lower than the *Committed and Anticipated Investments* sensitivity due to the modelled on-time delivery of all included generation and storage projects, forecast increases in CER coordination, the initial Victoria – South Australia tender as part of the federal Capacity Investment Scheme, and the enhanced ability of neighbouring regions to provide additional capacity in times of supply scarcity.
- In **Tasmania,** the reliability outlook is for minimal USE under both the *Committed and Anticipated Investments* sensitivity and this sensitivity.
- In **Victoria**, this sensitivity shows reliability risks within the relevant reliability standards throughout the horizon. Reliability risks are lower relative to the *Committed and Anticipated Investments* sensitivity due to the modelled on-time delivery of all included transmission, generation and storage projects, projects funded by the Victorian Renewable Energy Target Auction 2 and the initial Victoria – South Australia tender as part of the federal Capacity Investment Scheme, coordinated CER development, and actionable transmission projects such as Marinus Link and VNI West.

Equivalent gaps calculated consistent with the reliability gaps presented in **Section 4.1.4** are shown below for the *Federal and State Schemes* sensitivity.

Table 23 Reliability gaps and equivalent gaps against the IRM, *Federal and State Schemes* sensitivity (MW)

Region	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34
New South Wales	-	-	-	420	-	-	-	-	-	2,035
Queensland	-	-	-	-	-	-	-	-	-	-
South Australia	-	-	-	-	-	-	-	-	-	-
Tasmania	-	-	-	-	-	-	-	-	-	-
Victoria	-	-	-	-	-	-	-	-	-	-

Table 24 Reliability gaps and equivalent gaps against the reliability standard, *Federal and State Schemes* sensitivity (MW)

Region	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34
New South Wales	-	-	-	-	-	-	-	-	-	1,185
Queensland	-	-	-	-	-	-	-	-	-	-
South Australia	-	-	-	-	-	-	-	-	-	-
Tasmania	-	-	-	-	-	-	-	-	-	-
Victoria	-	-	-	-	-	-	-	-	-	-

5 Reliability risks in the next year

This chapter discusses reliability risks in 2024-25 as forecast in the Committed and Anticipated Investments reliability forecast. AEMO will seek to mitigate these risks through prudent preparations for summer including appropriate procurement of off-market measures, such as IRR and RERT.

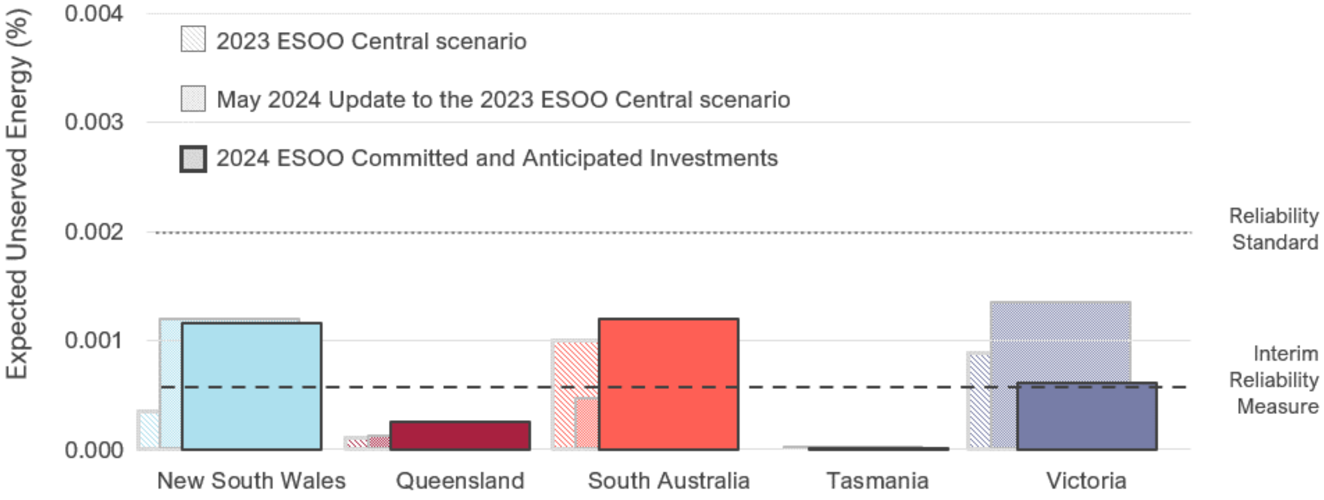
Power system reliability risks are characterised by the infrequent forecast occurrence of USE in circumstances when factors combine to tighten the balance between available supply and demand. In the coming year, there are risks of involuntary load shedding in all mainland regions, with risks in New South Wales, South Australia and Victoria forecast above the IRM. The factors which contribute to forecast supply shortfall conditions are:

- The magnitude of **maximum demand** when coincident consumer behaviour in response to high temperatures results in large increases in demand, the number of high demand periods and the coincidence of peak demand conditions in connected regions.
- The degree to which **demand flexibility and CER** can offset underlying demand.
- **Low wind availability** at the time of high demand. The contribution of solar generation at the time of maximum demand is already low, as peaks are occurring in the early evening.
- The availability of scheduled generators to meet demand, including the impact of **scheduled generator unplanned outages**.
- The availability of battery storage, and the **degree to which batteries are charged** in advance of supply scarcity events. For longer duration peak demand events, battery storage duration will also influence the capability for battery projects to mitigate reliability risks.
- The **availability of fuel and water** for use in generation (this is explored in the EAAP, published in **Chapter 6**).

5.1 Reliability risks in the reliability forecast are above the IRM in New South Wales, South Australia and Victoria

The reliability outlook for the coming summer in the *Committed and Anticipated Investments* sensitivity shows risks above the IRM in New South Wales, South Australia and Victoria. **Figure 31** shows the *Committed and Anticipated Investments* sensitivity forecast of expected USE, compared to the Central scenario in the 2023 ESOO May 2024 Update to the 2023 ESOO, for all NEM regions for the coming year.

Figure 31 Expected USE, all NEM regions, *Committed and Anticipated Investments* sensitivity, 2024-25 (%)



The nature of the reliability risk varies by region:

- Both **South Australia** and **Victoria** have forecast reliability risk above the IRM. In **South Australia** the forecast reliability risk for 2024-25 has increased relative to the May 2024 Update to the 2023 ESOO. In **Victoria** the forecast reliability risk for 2024-25 has decreased relative to the May 2024 Update to the 2023 ESOO.
  - Reliability risks in Victoria and South Australia often occur at coincident times and vary subject to generation availability across both regions. Forecast risks across both regions increased in the May 2024 Update to the 2023 ESOO relative to the 2023 ESOO due to the advised mothballing of Torrens Island B1, Port Lincoln and Snuggery power stations in South Australia.
  - In the 2024 ESOO, the balance of reliability risk across Victoria and South Australia has changed since the 2023 ESOO and its May 2024 Update, due to new storage commitments in Melbourne that have allowed alternative network configurations to be applied between the Latrobe Valley and Melbourne at times of high demand, which help reduce total risks across both regions.
  - These alternative network configurations allow direct access from Latrobe Valley generators to Melbourne via the 220 kV network, reducing flows on the 500 kV network, and subsequently reducing flows over the 500 kV Heywood interconnector towards South Australia.
  - While reliability risks are now forecast higher in the South Australian region due to these changed flows, most risks remain shared between both regions, and developments in either regions may therefore improve reliability outcomes in both regions.
- In **New South Wales**, the forecast reliability risk for 2024-25 is forecast to be greater than the IRM.
  - The forecast reliability risk in New South Wales is similar to that forecast in the May 2024 Update to the 2023 ESOO. This reliability risk emerged in the May 2024 Update to the 2023 ESOO due to a revision to improve the distribution of consumer demand in the New South Wales region at times of peak demand included in the ESOO model.
- In **Queensland** and **Tasmania**, reliability risks are forecast within the IRM.

As shown in **Chapter 4**, if generation and storage developments commission at the timeframes advised by each developer, rather than with the assumed delays AEMO applies for the *Committed and Anticipated Investments* sensitivity, then reliability risks have the potential to be managed within the IRM in all regions for 2024-25.

5.2 Unserved energy remains possible in all mainland regions

The 2024 ESOO applied a Monte Carlo simulation methodology to simulate the likelihood of USE considering the various statistical likelihoods of generator unplanned outages, alongside 14 years of weather conditions (2010-11 to 2023-24) that influence the associated availability of VRE resources and the conditions that drive peak demand. The forecast approach was applied to each forecast maximum demand and reference year, creating statistically robust results which capture the impact of uncertainties around key parameters.

A weighted average was applied to these Monte Carlo simulations to represent the 'expected' outcome for the coming year[94]. Within the simulations, there are combinations of inputs that lead to USE events in all regions, however the probability of these events varies between regions, and over time.

Expected USE, being the average of many possible outcomes, is forecast above the IRM for New South Wales, South Australia and Victoria for the coming year. While the expected USE is over the relevant standard, this does not guarantee that a USE event is going to happen – in fact, the most likely outcome is for there to be sufficient supply to meet the peak demand. Conversely, other regions that are not forecast over the IRM are not immune to reliability risks, although events may be less probable.

As an example, **Figure 32** shows a bubble plot of the distribution of USE outcomes that are forecast in South Australia for the 2024-25 summer, under a neutral/unknown climate outlook (that is, by considering all historical reference years equally). It includes the total USE duration and average depth in each simulation. The area of each bubble represents the probability of an outcome in the neighbourhood of that point. Analysis for all regions is available in **Appendices A1-A5**.

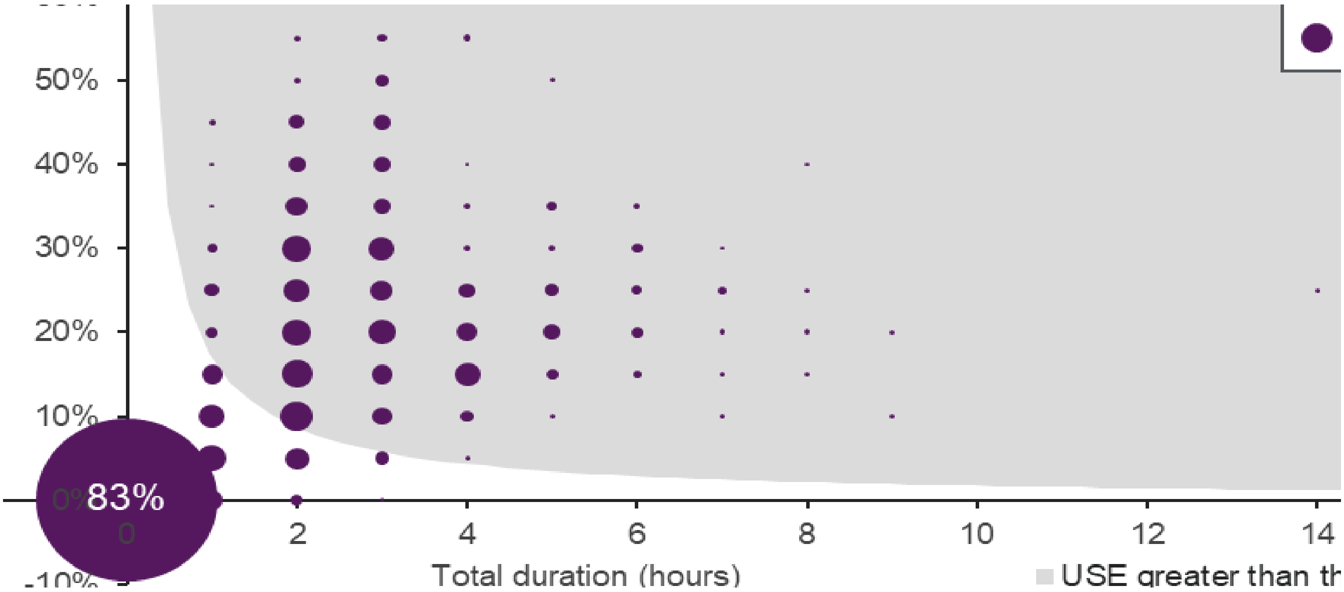
The figure shows that:

- The most likely outcome for the coming summer is that no USE events will occur in South Australia. This outcome is 83% probable and is represented by the large circle at the intersection of zero USE hours and 0% USE depth, as a measure of the proportion of average regional demand. The remainder of simulations, which are collectively 17% probable, are represented by the other bubbles on the chart.
- Should USE occur in the simulations, it is most likely to be forecast for between one hour and three hours and be of an average USE magnitude equivalent to between 5% and 35% of average regional demand. Within each event, larger magnitudes of USE than the average may occur during the duration of the event.
- There is a very low probability for USE to be forecast as deep as 68% of average regional demand, or as long as 14 total hours, which may occur over multiple individual USE events, for example across four different evenings. These outcomes each represent the result of a single annual simulation, with an estimated probability of approximately 1-in-4,600.

[94] AEMO calculates expected USE using 10% POE, 50% POE, and 90% POE maximum demand outcomes. 10% POE and 50% POE outcomes are weighted at 30.4% and 39.2% respectively, with the remaining 30.4% weighting assigned to 90% POE outcomes with zero USE assumed.

- Bubbles within the grey section represent individual forecast USE outcomes that each exceed the reliability standard of 0.002% USE. These forecast USE outcomes are collectively 14% probable in the coming year in South Australia.

Figure 32 Forecast USE duration and depth in South Australia, *Committed and Anticipated Investments* sensitivity, 2024-25



Should 10% POE demand conditions occur in the coming summer, the probability of USE increases. **Table 25** shows the probability of any USE outcome occurring, and the probability of a larger USE outcome[95], in all NEM regions for 2024-25.

Table 25 Probability of USE in 2024-25 by NEM region

Region	Probability of any USE		Probability of a larger USE outcome, above the reliability standard	
	Under all maximum demand outcomes	Under 10% POE demand conditions	Under all maximum demand outcomes	Under 10% POE demand conditions
New South Wales	36%	75%	17%	43%
Queensland	16%	41%	4%	11%
South Australia	17%	54%	14%	43%
Tasmania	0%	0%	0%	0%
Victoria	20%	63%	10%	33%

In addition to the reliability risks described above, 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 to transmission availability, 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.

[95] When expected USE is forecast at the IRM of 0.0006% USE, a larger USE outcome (among the many individual outcomes simulated) is typically 10% probable. A larger USE outcome is assessed as an individual USE outcome above the reliability standard of 0.002% USE.

- The risk that fuel availability is more limited than foreseen by participants, affecting generator operational capabilities – the ESOO forecast was developed based on assumptions of fuel availability submitted by participants, which project adequate fuel supplies during periods of high demand. The EAAP, published in **Chapter 6**, includes scenarios that assess the potential impact of water and fossil fuel supply shortfalls.
- The availability and use of off-market reserves to avoid or minimise actual USE events, such as RERT, as described in **Section 5.4** below.

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 possible reliability risks, beyond the single USE (%) outcome that the ESOO reports.

5.3 The availability of wind generation at times of high demand is a major factor influencing the risk of USE

AEMO applies historical 'reference years' in the ESOO model to capture the impact of weather conditions that impact the power system, in different locations and across all times of the day and year. Weather conditions impact 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).

The 2024 ESOO applied 14 reference years (from financial year 2010-11 through to 2023-24), each of which have different combinations of peak demand timing, wind and solar availability, and other power system weather impacts.

Figure 33 shows the level of expected USE forecast in Victoria for 2024-25 based on each of the historical reference years modelled as an example of the variance that may exist depending on renewable generation availability[96]. It also shows the average capacity factor of Victorian wind generators during forecast Victorian USE periods. Variation in expected USE is due to the relative contribution of VRE during times of high demand (mostly wind, as peak demand typically occurs after sunset), the level of coincidence in high 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:

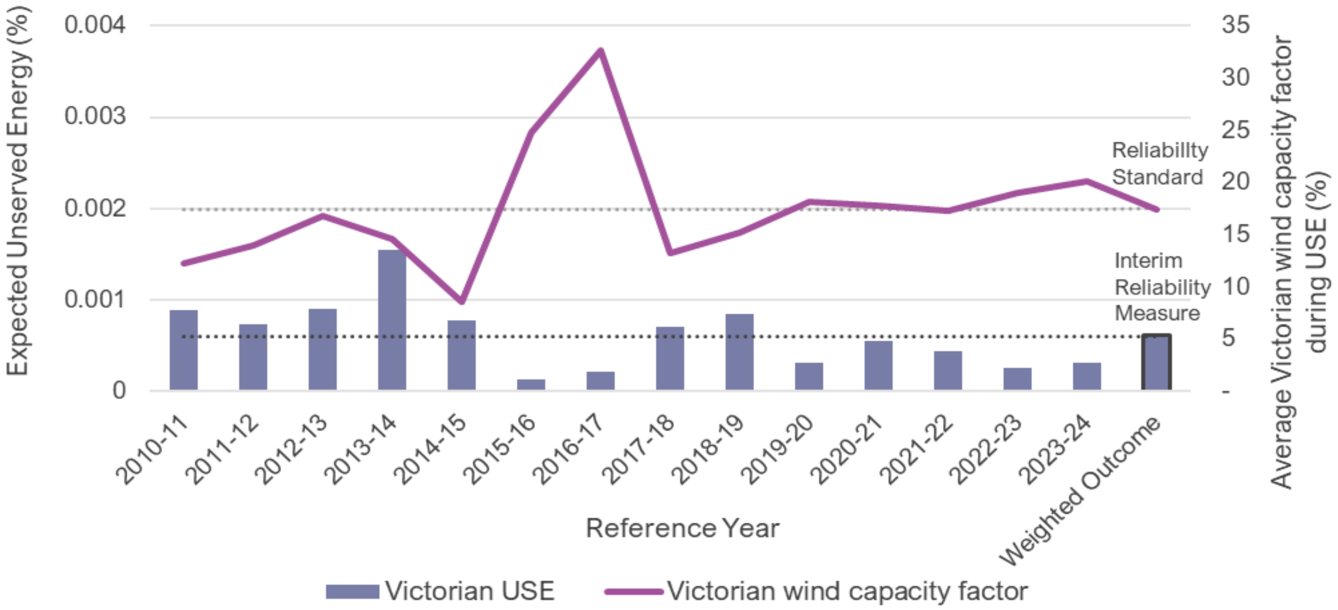
- If the weather conditions associated with the 2010-11, 2011-12, 2012-13, 2013-14, 2014-15, 2017-18 or 2018-19 years were to re-emerge next summer, expected USE would be higher than the IRM, meaning the occurrence of high demand and low generator availability would likely lead to involuntary load shedding. These reference years have weather patterns leading to conditions that have high evening demands (when solar generation is low) often in multiple regions which coincide with lower wind speeds creating a greater risk of supply shortfall.
- If the weather conditions associated with the 2015-16, 2016-17, 2019-20, 2020-21, 2021-22, 2022-23 and 2023-24 years were to re-emerge next summer, expected USE would be below the IRM, suggesting that wind availability at time of high demand in these reference years is likely to be higher. For example:
  - The average capacity factor or output of all Victorian wind farms during forecast Victorian USE periods is between 8-33% of their maximum output across the different reference years.
  - The years where wind availability is highest tend to have the lowest reliability risks.

[96] Similar variances exist in all regions, to varying extent depending on the tightness of supply versus demand, the penetration of renewable generation, and the geographical concentration of the renewable resources.

- In years where wind output is lower, higher reliability risks can be observed, however other factors continue to contribute including the shape of daily demand, the shape of daily wind availability, variation in availability across regions and generator and transmission outages.

The 2024 ESOO included the most recent 2023-24 reference year, which shows lower levels of reliability risk compared to the average of other reference years.

Figure 33 Impact of weather reference years on expected USE in Victoria 2024-25 (%)



5.4 Risk mitigation and summer readiness

As described in **Section 5.2**, expected USE in this ESOO is an annual average representation of the risk of load shedding, using a range of statistically variable inputs. However, 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 under all reasonable and plausible operating conditions, and establishes a comprehensive summer readiness program to mitigate reliability risks ahead of the risk period, including:

- As in 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 Interim Reliability Reserves (IRR) and RERT, where appropriate.

6 Energy Adequacy Assessment Projection

The EAAP forecasts electricity supply reliability in the NEM over a 24-month outlook period, complementing the ESOO reliability assessments by providing a focus on the impact of energy constraints on reliability.

AEMO publishes the EAAP in accordance with NER 3.7C. Inputs and assumptions align with the ESOO reliability forecast (see **Chapter 4**), but provide additional insights on energy limitations using scenarios defined in the EAAP Guidelines[97] and information provided by market participants. Potential energy constraints include water availability for hydro generation and as cooling water for thermal generation during drought conditions, and constraints on fossil fuel supply.

Consistent with the EAAP principles, EAAP Guidelines and the Reliability Standard Implementation Guidelines[98] (RSIG), the EAAP assesses reliability by comparing expected USE against the reliability standard of 0.002% USE; the IRM does not apply for the purposes of the EAAP. The EAAP focuses on the reliability impact of water and thermal fuel availability by considering the following three energy adequacy scenarios:

- **EAAP Central scenario** – the most likely fuel and water availability used for generation purposes apply in this scenario.
- **EAAP Low Rainfall scenario** – considering water availability during drought conditions and most likely fuel availability for thermal production units. Severe drought conditions observed during the Millennium Drought[99] are applied in this scenario.
- **EAAP Low Thermal Fuel scenario** – considering thermal fuel availability limits under one-in-10-year low fuel availability conditions for each power station in the NEM. Hydro generators apply their most likely water availability in this scenario. When developing one-in-10-year low fuel availability limits, participants consider the potential impacts of wet coal, longwall moves, train and truck deliveries, loader outages, likely market limitations, pipeline constraints, gas supply issues, and whether these events could occur over a prolonged period, or for shorter events only.

Figure 34 shows the annual expected USE forecast for these three EAAP scenarios relative to the *Committed and Anticipated Investments* sensitivity. The only difference between the ESOO and the EAAP is that the EAAP applies participant-provided energy limits in addition to all other ESOO inputs.

While each scenario is explored in detail later in this chapter, the following key insights are noted:

- Expected USE is forecast to be within the reliability standard in the EAAP Central and EAAP Low Rainfall scenarios for all regions in the next 24 months.
  - The EAAP Central scenario forecasts slightly higher reliability risks for the coming year relative to the *Committed and Anticipated Investments* sensitivity in South Australia and Victoria, due to the application of

[97] At https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/rsig/final-documents/eaap-guidelines.pdf.

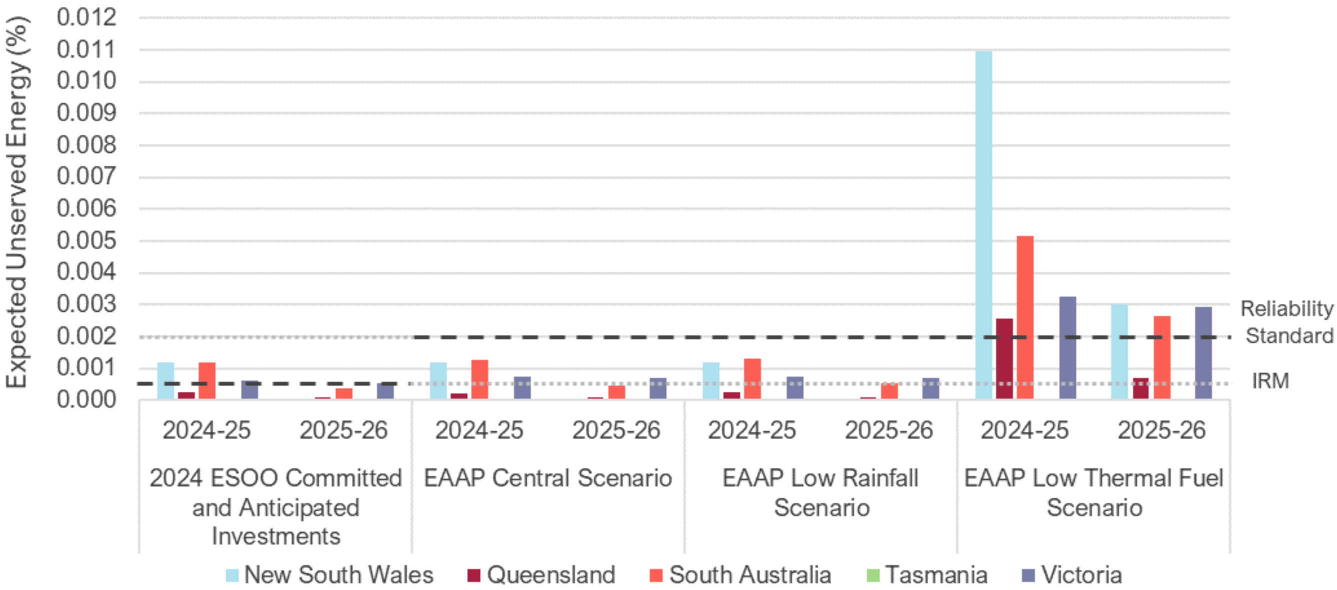
[98] At https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/reliability-standard-implementation-guidelines.

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

participant-provided energy limits, some of which are more onerous than assumed in the ESOO. For example, some gas generators in Victoria have advised low energy limits in their submission for the EAAP Central scenario, which were not considered in the ESOO.

- If severe drought conditions emerge, they are unlikely to result in a material increase in reliability risk compared to normal rainfall conditions in the next 24 months, as demonstrated by the similar USE outcomes observed in the EAAP Central and EAAP Low Rainfall scenarios[100].
- The EAAP Low Thermal Fuel scenario demonstrates vulnerabilities to power system reliability in all mainland regions should coincident shortfalls of coal, gas and diesel, or interruptions to their supply chains, occur. As this scenario is based on participant-provided energy limits under a one-in-10-year fuel unavailability scenario, it does not reflect an expected outlook. This scenario, however, demonstrates the importance of maintaining ongoing availability of fuel, and fuel supply chains throughout the energy transition.
  - Based on participant-provided information, reliability risks are above the reliability standard in New South Wales, South Australia, and Victoria in both 2024-25 and 2025-26, and in Queensland in 2024-25 (but not in 2025-26).

Figure 34 EAAP annual expected USE by scenario (%)



6.1 Generator Energy Limitations Framework parameters

Generator Energy Limitations Framework (GELF) parameters[101] are confidential information submitted by scheduled generators including limitations on their ability to supply energy relating to the EAAP scenarios, such as hydro storage (including pump storage), thermal generation fuel supply, cooling water availability, and gas supply. These parameters are classified into two categories:

[100] For modelling purposes, EAAP considers that the dam levels must return to their initial values by the end of every simulation year. Therefore, the present dam levels, that are applied in the simulation as initial values, do not materially affect the expected USE results observed in any of the EAAP scenarios.

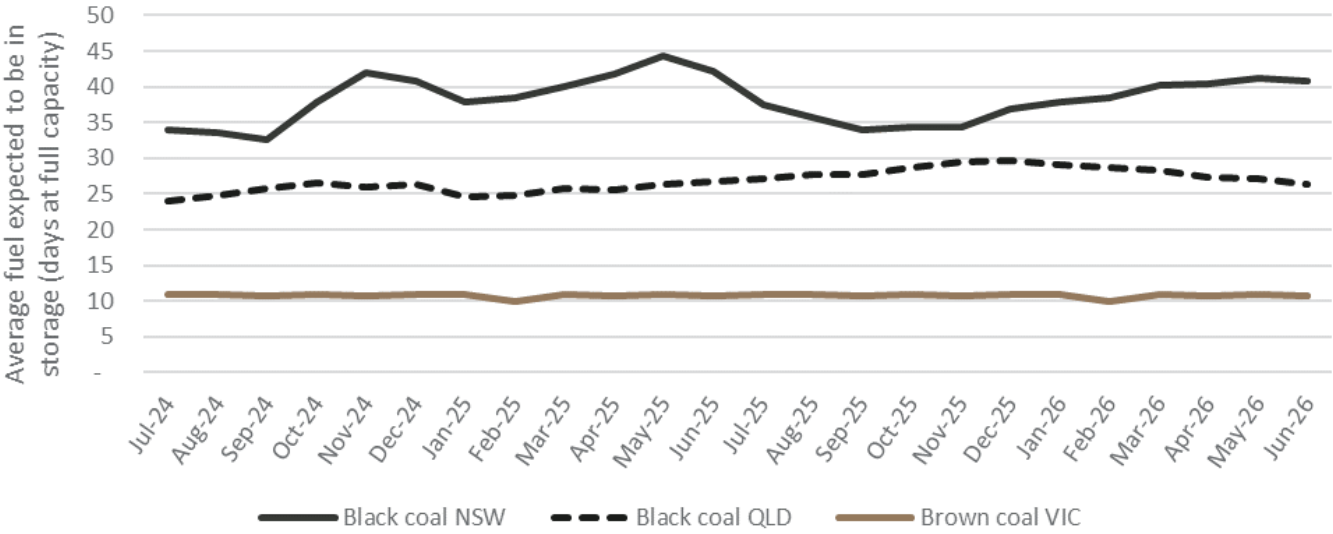
[101] Please see the EAAP Guidelines for details of the GELF parameters, at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/energy-adequacy-assessment-projection-eaap.

- Static GELF parameters (including technical specifications of the power stations, relevant water and fossil fuel storage infrastructure, and operational limits).
- Variable GELF parameters (including monthly generation capabilities and monthly water and energy production supply information relevant to each scenario).

On-site storage of coal varies between regions, but many generators have access to co-located mines

As shown in **Figure 35,** coal generators advise their expected coal supply over the two-year EAAP horizon**.** For this 2024 EAAP, on average, coal generators across New South Wales and Queensland advised an expectation to increase coal stockpiles, with as much as 44 and 30 days of storage, respectively. Victorian coal generators advised of limited on-site stockpiles, but noted that additional supply is available at co-located coal mines.

Figure 35 GELF expected storage for coal generation (days of generation at full capacity)



Limited gas supplies are stored on site, but gas generators may have improved access to local storage via linepack, and spot market gas supply as needed

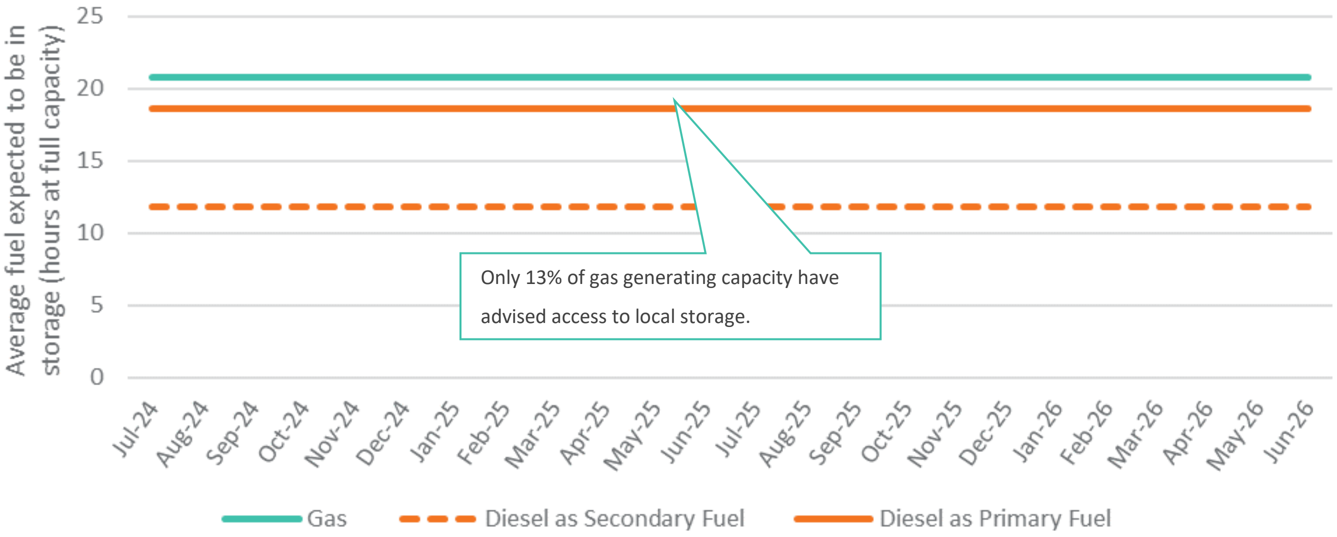
Most gas generators rely on gas supplied through the gas network as their primary fuel source and have no on-site gas storage capacity. A minority (13% by capacity) of gas generators have advised access to an average of 21 hours of gas storage, predominantly through access to local linepack[102] that is within the control of the operator.

Most gas generators have not advised secondary fuel storage capabilities. Of the generators which have diesel as a secondary fuel source, participants advised that diesel storage was expected to be suitable for an average of 12 hours of operation. For those that use diesel only, on-site storage was advised to be suitable for an expected 18.5 hours of operation on average.

These expected storage values, as provided by relevant participants, did not vary over the EAAP horizon for any gas or liquid-fuelled generator and are shown in **Figure 36**.

[102] Linepack is gas "stored" in pipelines at any time.

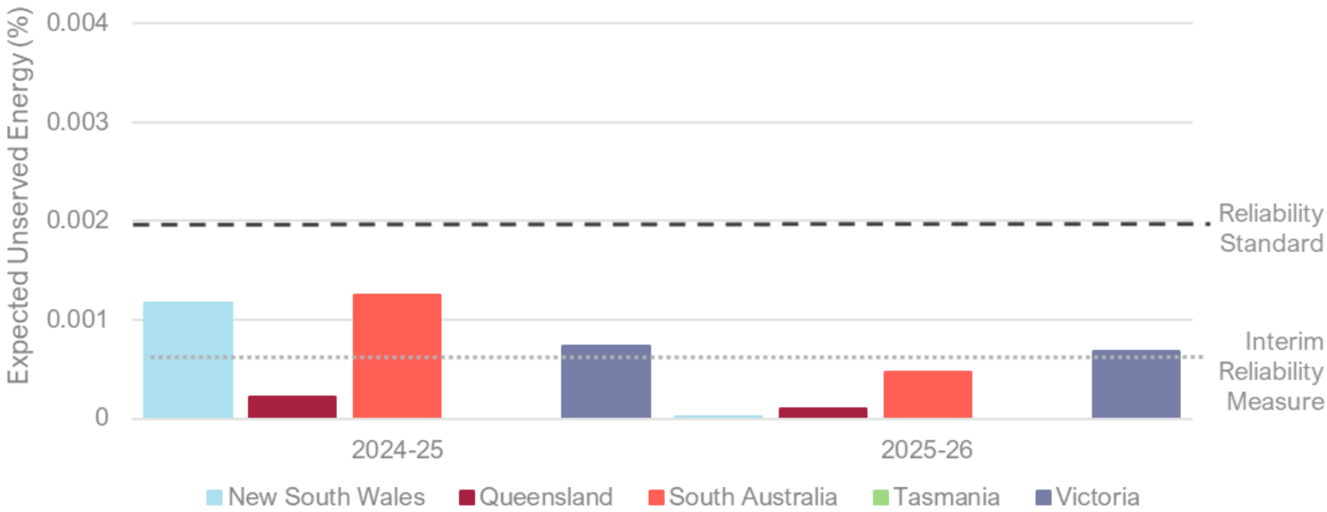
Figure 36 GELF expected storage for gas and liquid fuel generation (hours of generation at full capacity)



6.2 EAAP Central scenario

The EAAP Central Scenario applied participant-provided energy limits that represent the most likely outlook. As shown in **Figure 37**, this scenario identifies that reliability risks are forecast within the reliability standard over the two-year EAAP horizon. Slightly higher expected USE outcomes are observed in South Australia and Victoria compared to the *Committed and Anticipated Investments* sensitivity. This is mainly due to some generators being impacted by their expected energy limitations under some conditions in this scenario, compared to the *Committed and Anticipated Investments* sensitivity, which did not consider these limitations.

Figure 37 Expected USE, EAAP Central scenario (%)



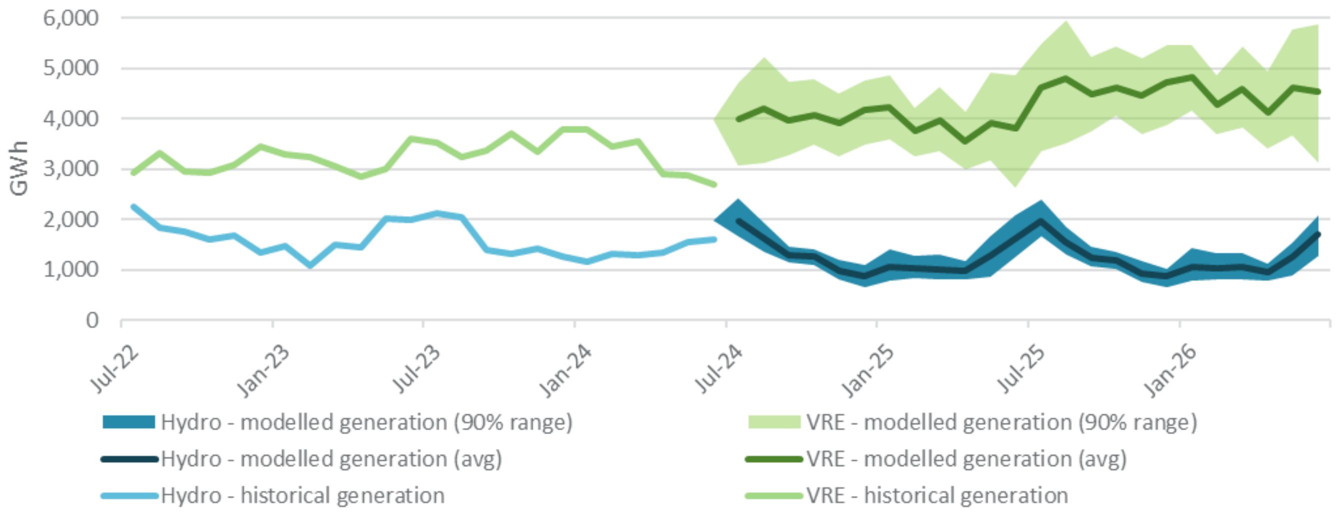
Information on the monthly distribution of reliability risks is in **Appendix A7**. Forecast reliability risks are concentrated in the summer months for all NEM regions except Tasmania, where minimal risks are observed.

Figure 38 shows the energy production projections for VRE and hydro generators in the NEM, relative to historical operation. Similarly, **Figure 39** shows projected energy production for coal generators in New South Wales, Queensland and Victoria, as well as a NEM-aggregate projection for gas and liquid-fuelled generators, compared to history and participant-provided energy limits.

Key insights include:

- Participant expectations for coal generation volumes align closely with AEMO's forecast generation outcomes, and align well with history for all coal generators. Reasonable headroom exists to coal generation fuel limits, suggesting that participants believe that they will have access to sufficient coal fuel to produce more electricity from coal generation if market conditions warrant it.
- Significant headroom to the provided energy limits exists for more gas to be procured for gas generation if needed[103], however in aggregate it is unlikely that the forecast gas production decline in southern regions, as reported in the 2024 *Gas Statement of Opportunities*[104], is reflected in the limits provided by participants. This may present a longer-term risk if proponents continue to assume gas remains available to be procured from the spot market should that not be the case.
- Approximately 80% of expected coal generation is subject to firm contracts for supply in New South Wales and Victoria.
- VRE generation is projected to increase in volume over the EAAP horizon, as new VRE generators commission, while hydro generators are projected to maintain a strong seasonal pattern in output.
- The figure demonstrates the low generation from wind farms across NEM southern regions between April 2024 and June 2024, relative to the expected generation levels that are reflective of forecasts from July 2024. In response to the low renewable energy yields in these months, gas and liquid production reached volumes that generally exceed contracted fuel inflows (but are below the expected availability of gas and liquid fuels indicated by participants).

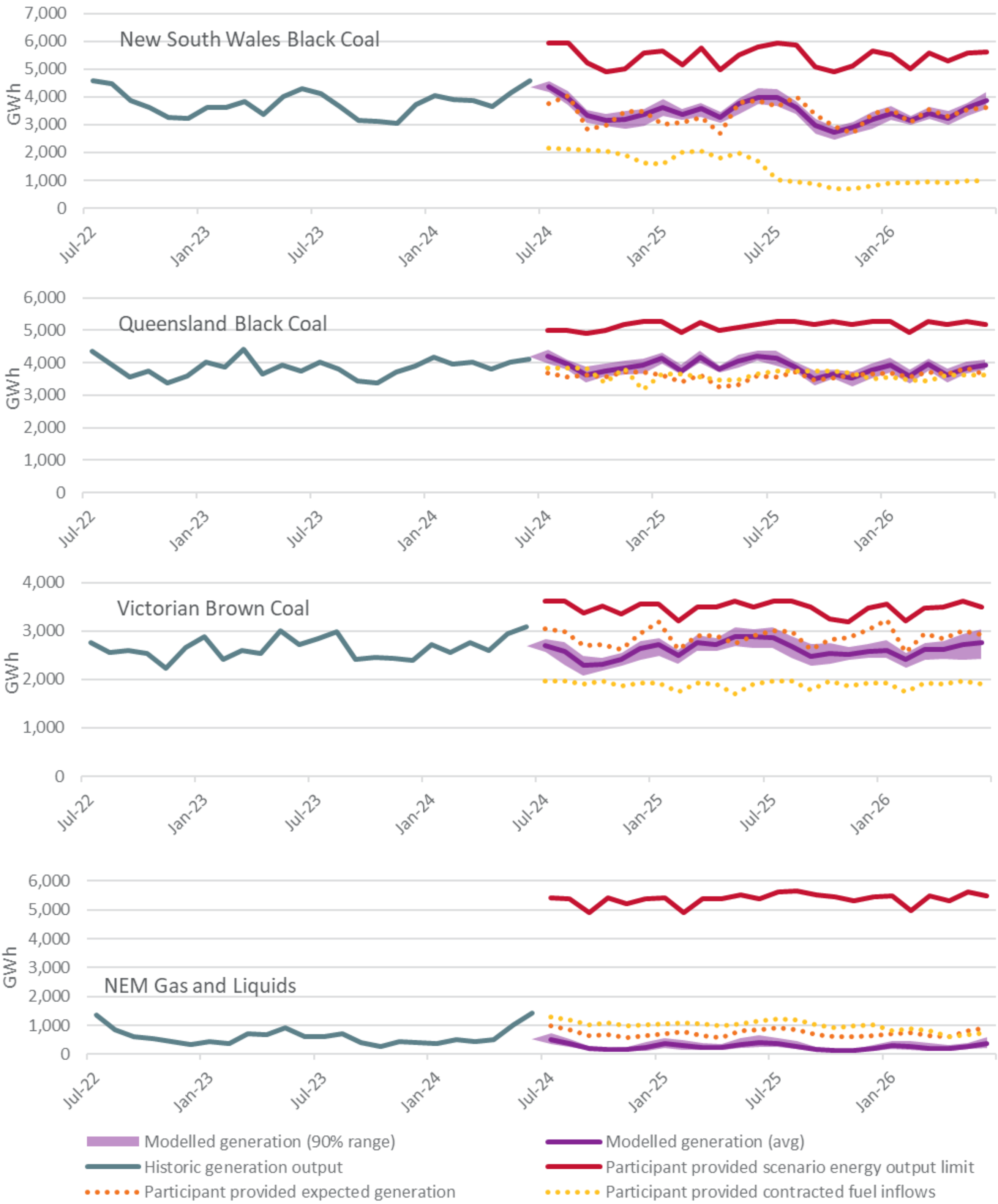
Figure 38 NEM hydro and VRE monthly generation projection, EAAP Central scenario (GWh)



[103] Projected generation for gas and liquid-fuelled generation is naturally lower than the participant-provided expected production; this is an outcome of the reliability forecasting methodology that focuses on least-cost operation rather than strategic bid-based dispatch forecasting.

[104] At https://aemo.com.au/en/energy-systems/gas/gas-forecasting-and-planning/gas-statement-of-opportunities-gsoo.

Figure 39 Monthly energy production projection relative to energy production limit, expected generation and contracted fuel inflows, EAAP Central scenario (GWh)

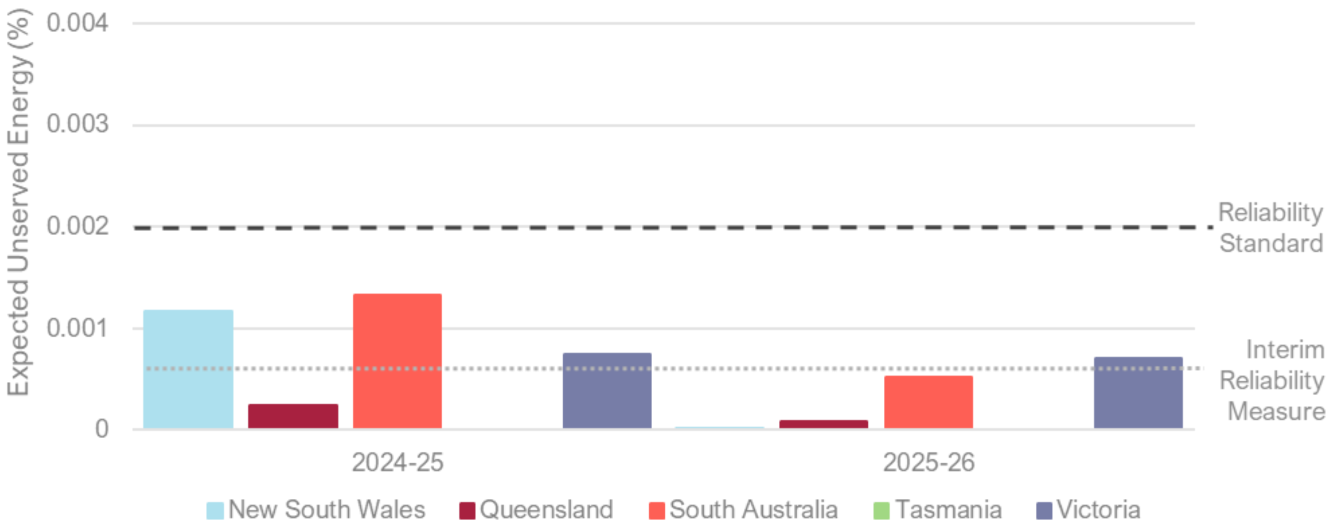


6.3 EAAP Low Rainfall scenario

The EAAP Low Rainfall scenario applied participant-provided energy limits for thermal generators, and severe drought conditions reflecting low water inflows for hydro generators.

As shown in **Figure 40**, this scenario identifies that reliability risks are forecast within the reliability standard over the 24-month EAAP horizon. The scenario shows a relatively similar forecast to the EAAP Central scenario, demonstrating that the NEM has sufficient flexibility in energy production to avoid significant impacts from low rainfall conditions, with only very minor variances in reliability risks compared to the EAAP Central scenario.

Figure 40 Expected USE, EAAP Low Rainfall scenario (%)



Information on the monthly distribution of reliability risks can be found in **Appendix A7**. Only limited variation to outcomes is observed relative to the EAAP Central scenario. Key variations include:

- Provided energy limits for thermal generators are unchanged relative to the EAAP Central scenario, suggesting that participants did not expect drought conditions to impact cooling water availability, or any other operational water requirement that could reduce production.
- Coal and gas generators are expected to have sufficient fuel available to replace hydro generation lost due to drought conditions.
- During low rainfall conditions, interconnectors (especially Basslink) are also able to help distribute energy to regions that are impacted by lower generation due to low rainfall.

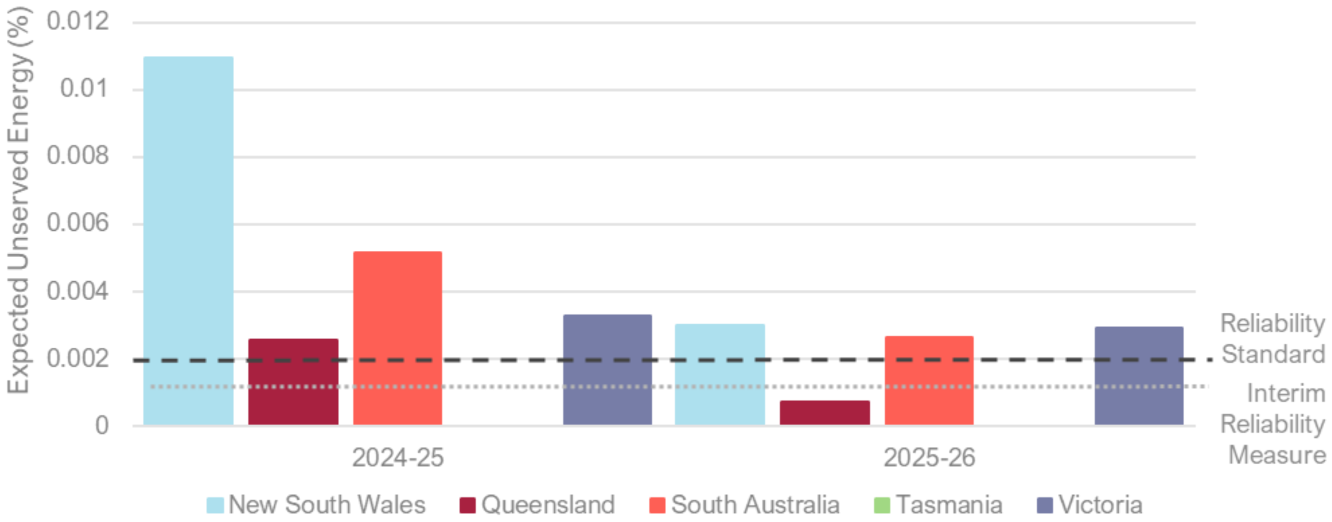
6.4 EAAP Low Thermal Fuel scenario

The EAAP Low Thermal Fuel scenario applied participant-provided energy production limits applicable under one-in-10-year low fuel availability conditions for each power station in the NEM. These conditions distinguished between short-term events (that would limit supply in January and July only), or longer duration events that would apply across the 24-month EAAP horizon. Hydro generators applied their most likely water availability in this scenario.

As **Figure 41** shows, this scenario identifies that significant reliability risks emerge if thermal fuels were limited to one-in-10-year supply availability conditions. Reliability risks are forecast above the reliability standard across all NEM regions (except Tasmania) in at least one of the two years.

Short-term events were modelled in this scenario to apply coincidentally across all NEM thermal generators, and so while not of high probability, they confirm that the NEM is subject to a large vulnerability to thermal fuel availability if fuel supply chains impact thermal generators simultaneously. It signals that maintaining the availability of thermal fuels for energy production throughout the energy transition will be essential for the reliability of the NEM.

Figure 41 Expected USE, EAAP Low Thermal Fuel scenario (%)



Information on the monthly distribution of reliability risks is in **Appendix A7**. Forecast reliability risks are concentrated in the summer months for Queensland, South Australia and Victoria. In New South Wales, reliability risks are identified in both summer and winter, while risks in Tasmania are forecast to be negligible.

Figure 42 shows the energy production projections for coal generators in New South Wales, Queensland and Victoria, as well as a NEM-aggregate projection for gas and liquid-fuelled generators, relative to historical operation and the participant-provided energy limits. Similarly, **Figure 43** shows projected VRE and hydro generation compared to history.

Key insights unique to this scenario include:

- Energy limits provided for fossil fuel generators across the NEM are materially lower than provided for the EAAP Central scenario, particularly in New South Wales and Queensland for short-duration events affecting coal generators (assumed during January and July). For gas and liquid-fuelled generators, energy limits reduce by approximately 30% relative to the EAAP Central scenario.
- No technology category can be seen generating up to its energy limits for the entire month, indicating that the higher levels of reliability risk forecast are occurring as energy limits impact individual generators during periods of tight supply conditions, rather than whole technology categories running out of fuel across a month.

Figure 42 NEM hydro and VRE monthly generation projection, EAAP Low Thermal Fuel scenario (GWh)

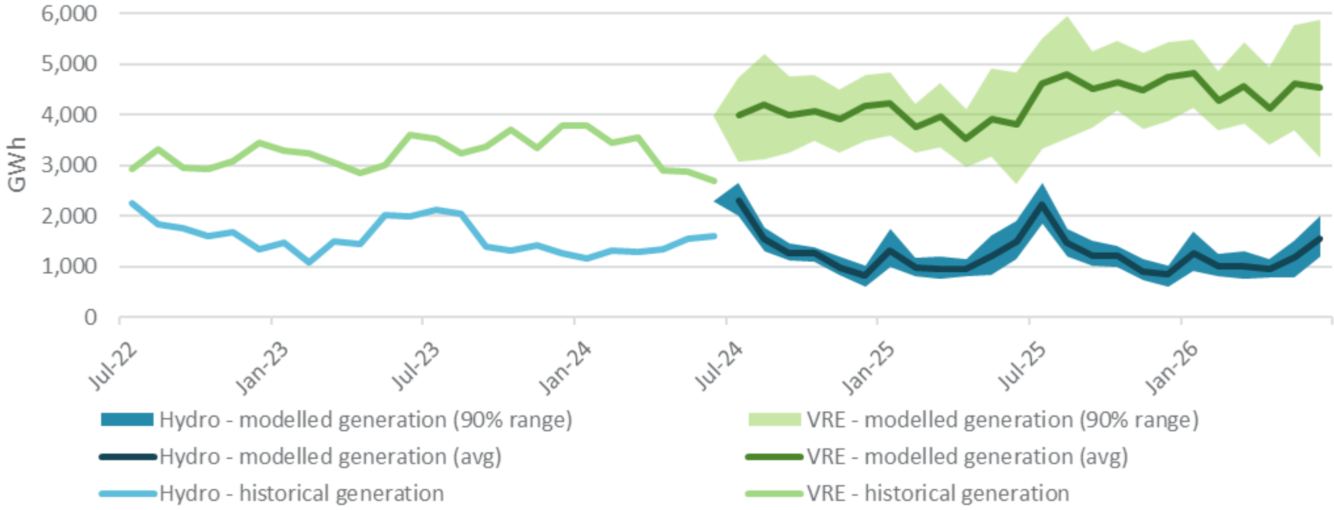
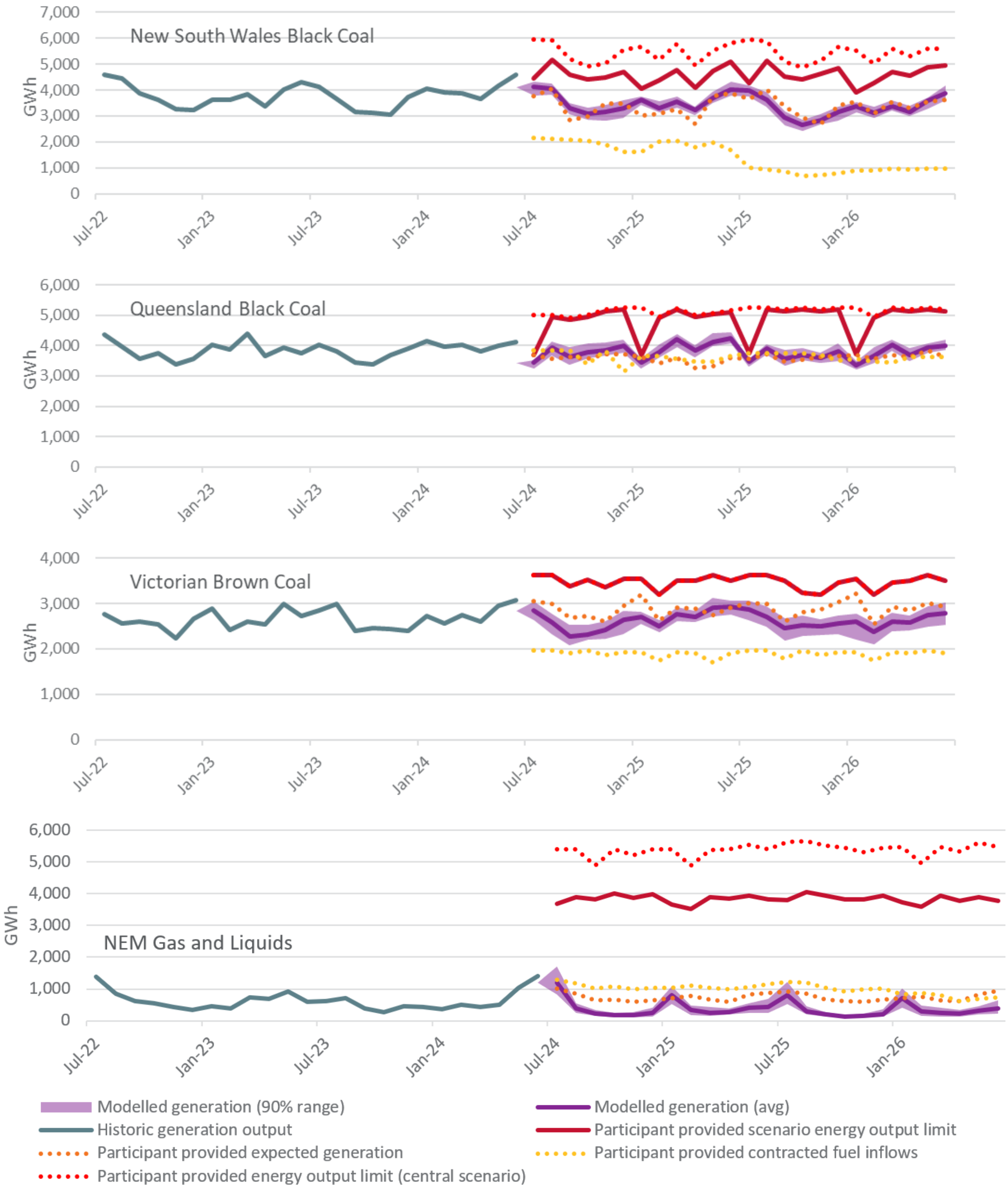


Figure 43 Monthly energy production projection relative to energy production limit, expected generation and contracted fuel inflows, EAAP Low Thermal Fuel scenario (GWh)



7 Maintaining a stable and resilient power system

This chapter provides summary information on the system security outlook. It highlights that:

- There are opportunities for the development of system security services across the 10-year ESOO horizon.
- There is a need to urgently implement the recently published National CER Roadmap to address both short-term and long-term operability challenges.

A reliable power system requires more than just sufficient levels of installed capacity and available energy supplies. The system must also maintain an underlying set of security and stability services, and have appropriate technical standards to respond well and predictably to power system disturbances. This is required to ensure that the system remains both secure and resilient under intact operating conditions, and following larger events that can occur on the power system during major disturbances.

Over the coming decade, the rapid energy transition will result in a significant need for new assets and providers of essential system services. This includes services both at high and low voltage levels of the power system providing system strength, frequency management, voltage control, ramping capability, and system restoration services.

The timing and magnitude of these emerging requirements are influenced by:

- **Retiring thermal generation** – historically, thermal generation has been the source of much of the system strength, inertia, and system restart services in the NEM, and a significant source of voltage control and ramping capability. Replacement services will be needed as these units withdraw.
- **Increases in inverter-based resources (IBR) development** – adequate system strength, voltage control, and ramping capability will be needed to ensure that future levels of IBR can operate stably, and transfer energy to where it is needed.
- **Major network augmentations** – network upgrades can help reduce system security requirements by lowering system impedance and allowing better sharing of existing services across multiple locations. They can also impact the likelihood of regions becoming islanded and reduce the impact of credible network events, putting downward pressure on security needs.
- **Levels of investment in CER –** periods where the level of distributed solar PV generation is very high relative to the underlying demand are projected to continue to increase as more distributed PV is installed by consumers. All NEM mainland regions are now beyond or close to thresholds where action may be required to maintain power system security, especially in the event of unplanned outages. During these periods, there is limited demand being supplied from the main transmission system, such that large-scale plant which delivers a range of system security services (system strength, inertia, system restart, voltage management and ramping) cannot be relied on to be dispatched through market mechanisms.

Action must be taken to ensure appropriate technical standards, compliance with those standards, and other response capabilities are in place along with procurement of the assets and services necessary to meet all system security needs. However, these actions and investments can be subject to regulatory delays and extended lead times, limiting their flexibility to adapt to rapid changes in the short term. When available response and security services are inadequate to maintain system security in operational timeframes, AEMO may reduce or increase the output of specific generators, limit or reconfigure network transfers, or disconnect customer load as part of re-securing the system. This represents both a risk and an opportunity for new proponents. As existing sources of these services withdraw, new providers are sought to meet these needs.

In July 2024, building on the Energy Security Board's (ESB's) earlier advice[105,106], Australia's Energy Ministers agreed to a National CER Roadmap[107], which sets out an overarching vision and plan to unlock CER at scale across Australia, and reflects the need to implement critical technical capabilities to support the continued security of the power system. If well integrated, CER including distributed PV present an opportunity to support a lower-cost and faster energy transition, and to help manage consumers' energy bills. The implementation of measures agreed by Energy Ministers is urgent, to ensure operational solutions are implemented as soon as possible. These, alongside longer-term strategic solutions and investments, can facilitate the continued growth in all NEM regions of distributed PV as a resource on the power system to the benefit of all energy consumers.

System security is an umbrella term that encompasses a range of different power system characteristics working together – including system strength, inertia, voltage control, frequency control, ramping capability, system restart needs, and broader system resilience behaviours. AEMO has assessed the adequacy of these services over the coming decade against the associated regional and national requirements.

While this assessment considers such services independently, the most efficient solutions are likely to be those that can address multiple needs in parallel. Findings in this section are largely drawn from AEMO's analysis in the annual system security reports[108] and the 2024 ISP.

7.1 System strength

System strength is likely to be the most onerous emerging requirement in all regions and is projected to require significant investment in new assets and contracted services over the coming decade.

System strength describes the ability of the power system to maintain a voltage waveform at a given location, both during steady state operation and following a disturbance. It supports the stable operation of network protection, voltage control devices, and IBR connections. Sufficient levels of system strength, in the right locations, are vital to maintaining a secure and reliable power system that supports efficient investment.

Key findings relating to system strength are:

[105] ESB, Post 2025 Market Design final advice to Ministers, July 2021.

[106] Consumer Energy Resources and the Transformation of the NEM, 2023, at https://www.energy.gov.au/sites/default/files/2024-02/ESB%20report%20-%20CONSUMER%20ENERGY%20RESOURCES%20AND%20THE%20TRANSFORMATION%20OF%20THE%20NEM.pdf.

[107] Energy and Climate Change Ministerial Council, National Consumer Energy Resources Roadmap, July 2024, at https://www.energy.gov.au/sites/default/files/2024-07/national-consumer-energy-resources-roadmap.pdf.

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

- Available system strength is projected to decline sharply over the next decade, driven by expected synchronous generator closures.
- There is a current requirement for the equivalent of approximately 25 of the existing large synchronous units to be online and distributed across the NEM. There are more than 40 existing large units capable of contributing directly to this need[109], however the 2024 ISP forecasts that about 90% of the NEM's coal fleet may retire before 2035. Replacement investments will be needed to ensure system strength requirements can continue to be met.
- In the medium term, AEMO expects that at least 22 optimally placed large synchronous machines with some support from existing hydro units will be needed to meet minimum fault level requirements[110]. These machines must be capable of providing protection-quality fault current, and could include new synchronous condensers, service contracts with existing thermal or hydro units, new gas turbine units fitted with clutches, or the retrofit of existing generators as they retire from the energy market.
- While grid-forming technology continues to develop, it has not yet been demonstrated to satisfy protection-quality fault current requirements at scale in Australia, so is unlikely to contribute towards meeting the minimum system strength requirements associated with fault current and protection operation in the near term.

However, significant system strength investment above minimum requirements will also be needed to accommodate new IBR connections. The need for these system strength services above minimum requirements can be met by a variety of existing and new technologies with the ability to stabilise local voltages, including grid-forming inverters[111].

7.2 Inertia

Without new investment, available inertia is projected to fall sharply alongside declining thermal generator utilisation and retirements over the coming decade. This will offer opportunities for both synchronous and synthetic inertia providers to offer replacement services.

In the context of the power system, inertia describes an immediate, inherent, electrical response from connected devices that acts to oppose changes in system frequency. A power system with sufficient inertia can resist large changes in frequency that arise following a contingency event, which provides time for other automated protection and control systems to respond[112].

Key findings relating to inertia include[113]:

[109] The values here represent only those large synchronous units with significant contributions to regional system strength requirements. While additional small or remote gas and hydro generation can also contribute operationally, these typically provide only a fractional contribution towards the 25 units requirement.

[110] This differs from the above 25 units requirement due to the impact of future network projects, and on the basis of expressing this as a uniform synchronous condenser size rather than in terms of existing large units which vary in size, location, and contribution factors.

[111] More information is available in AEMO's 2023 System Strength Report, at https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-strength-requirements/2023-system-strength-report.pdf, and Appendix 7 of the 2024 ISP, at https://aemo.com.au/-/media/files/major-publications/isp/2024/2024-integrated-system-plan-isp.pdf.

[112] For definitions and descriptions of inertia and power system security, please refer to AEMO's *Power System Requirements*, updated July 2020, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power-system-requirements.pdf.

[113] More information is available in AEMO's 2023 Inertia Report, at https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-strength-requirements/2023-inertia-report.pdf, and Appendix 7 of the 2024 ISP, at https://aemo.com.au/-/media/files/major-publications/isp/2024/2024-integrated-system-plan-isp.pdf.

- Operating levels of inertia are projected to fall significantly as existing generators close, and thermal generation utilisation declines. AEMO expects a variety of assets and services of various sizes and technologies will be required to meet the emerging inertia deficits.
- Inertia requirements are already being closely managed in South Australia and Tasmania, and a new shortfall is projected to emerge in Queensland from 2027-28. While Victorian capabilities are also forecast to fall, strong interconnection with other regions means that Victoria is largely able to meet local requirements from interstate.
- In response to rule changes introduced in March 2024 that will require AEMO to set a minimum system-wide inertia level from 1 December 2024[114], AEMO is consulting[115] on updates to the Inertia Requirements Methodology to be applied. This would add an additional safety net for inertia during interconnected operation of the system and could present further opportunities for new synchronous or synthetic inertia providers in all regions. This consultation also explores the potential for synthetic inertia to replace traditional synchronous inertia sources in the NEM by proposing a methodology and criteria for synthetic inertia providers to qualify as inertia network services. However, it is likely that a fundamental floor of synchronous inertia will remain a core component in meeting inertia requirements across the current 10-year planning horizon.
- While inertia is distinct from system strength, opportunities exist for optimised investment that meets both needs concurrently. This could include contracts with generators or batteries capable of providing both services, or the incremental addition of flywheels to new synchronous condensers.

7.3 Ramping

The magnitude of potential ramping events across the NEM continues to grow as new weather-dependent resources are connected on both sides of the supply-demand balance.

AEMO's 2023 Network Support and Control Ancillary Services (NSCAS) report[116] found that the typical ramping events currently faced by the system are in the same range as most large network contingency events, and existing power system mechanisms are generally sufficient to manage these conditions. However, this is changing rapidly, and there will be a growing need for dynamic reactive support as voltages become increasingly sensitive to changes in power flow not previously experienced in the NEM. This may present opportunities for new flexible plant and BESS.

7.4 System restart

Several major thermal generating units provide system restart ancillary services (SRAS) in the form of trip to house load capability. In addition, restart of major thermal generating units from smaller restart services is generally an early step in the process to restore the power system following a black system event. AEMO must use reasonable endeavours to acquire SRAS to meet the system restart standard[117], and has recently concluded its most recent procurement process under the

[114] At https://www.aemc.gov.au/rule-changes/improving-security-frameworks-energy-transition.

[115] At https://aemo.com.au/consultations/current-and-closed-consultations/amendments-to-the-inertia-requirements-methodology.

[116] At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-strength-requirements/2023-nscas-report.pdf?la=en.

[117] At https://www.aemc.gov.au/markets-reviews-advice/system-restart-standard.

System Restart Ancillary Service Guidelines[118]. Continued retirement of existing service providers will require careful case-by-case monitoring and may open opportunities for new service providers.

7.5 Voltage control

In the near term, periods where the level of distributed PV generation is very high relative to the underlying demand are increasing and will present significant security risks that require active operational management. In the longer term, steady-state voltage control will be increasingly provided by the reactive capabilities of new IBR.

Overall, increasing system volatility will place greater emphasis on the system's dynamic reactive capabilities, and changes in the geographic spread of services will result in challenging voltage management issues that require active management and could emerge at short notice. This may warrant trialling of new services and new network investment in some locations.

7.6 Supporting secure operation with high levels of distributed resources

As **Section 2.4** outlines, periods where the level of distributed PV generation is very high relative to the underlying demand are projected to continue to increase in most NEM regions as more distributed PV is installed by consumers. For example, the NEM experienced a record minimum operational demand of 11,009 MW (11 GW) at 13:30 on 29 October 2023. In this half-hour interval, distributed PV supplied 52% of the underlying demand in the NEM.

Minimum operational demand in the NEM has been falling on average more than 1.2 GW per year, and is projected to continue on this trajectory.

During these periods, there is limited demand being supplied from the main transmission system, such that large-scale plant which delivers a range of system security services (system strength, inertia, system restart, voltage management and ramping) cannot be relied on to be dispatched through market mechanisms.

There are a range of solutions to these challenges, with many of these being actively considered, noting that implementation of these through regulatory mechanisms can take some time while the need for action is already urgent, and more so in some regions:

- **Reduce the amount of generation that needs to remain online to provide essential services** – this can be done by reducing the minimum safe operating level (MSOL) of essential units, or through investment in new assets that can provide system services in other ways (such as synchronous condensers, batteries, and/or reactors)[119]. These assets take time to develop, and other operational levers are required for operational management when gaps arise.
- **Increase demand** – practical options to increase responsive demand may evolve over time, which are operationally very limited at present. This may include new industries which increase baseload or flexible levels of demand. This also may also include electrification of appliances and transport, and increased demand response and co-ordination of CER.

[118] At https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/ancillary-services/system-restart-ancillary-services-guideline.

[119] The *Engineering Roadmap to 100% Renewables* outlines the transition to other ways of providing system services as coal retires, allowing the requirement for synchronous generation to eventually reduce to zero; see: https://aemo.com.au/initiatives/major-programs/engineering-roadmap.

- **Store energy** – storage can help move energy from daytime periods to other periods, particularly during emergency conditions. This capability is very limited at present, but will likely increase due to increased investment in storage technologies, and through the co-ordination of CER storages.
- **Improve CER disturbance ride-through capabilities** – continuing improvement in compliance with inverter standards (AS/NZS4777.2:2020)[120] to improve disturbance ride-through capabilities for new distributed PV installations to limit further escalation in contingency sizes.
- **Decrease distributed PV generation** – along with reducing generation from non-essential generating units (scheduled, semi-scheduled, and non-scheduled), it is crucial that sufficient operational levers are available under high-risk conditions to curtail distributed PV, as an emergency backstop to maintain system security when the above options are insufficient[121].
- **Reduce size of the largest generating unit** – this can be achieved by moving to a smaller unit combination, or dispatching the unit at lower levels if possible.
- **Decrease the potential contingency size from distributed PV generation** – in some cases, the only option available to maintain system security may be to curtail distributed PV to reduce the total contingency size down to a level that can be managed within network limits and with available frequency reserves.

7.6.1 Imminent operational risks under outage conditions

AEMO estimates that a minimum of approximately 4.3 GW of operational demand is required in the NEM to support the minimum generation levels of units providing required essential services across the NEM, with the present operational toolkit. This is the demand that is needed to be supplied from the transmission network and supports generation from synchronous generation which is currently required to provide essential power system security services. This could increase to as high as approximately 7 GW in the event of unplanned network or unit outages. These thresholds are indicative at present, and further analysis is underway to refine these levels.

AEMO's forecasts, shown in **Figure 44**, indicate that demand supplied from the transmission network (operational demand) could fall below 7 GW by as early as spring 2025 (under low demand 90% POE conditions which are most likely to occur during spring); under emergency conditions (involving unplanned outages), action which increases demand supplied from the transmission network may be required as a last resort to maintain power system security.

These response mechanisms are currently uncertain. An emergency backstop capability to curtail distributed PV is already in place in some market regions with higher levels of distributed PV and is being progressed in others to provide this capability across the NEM. The current capability of the emergency backstop mechanism is also shown in **Figure 44**, noting there is uncertainty regarding the level of compliance with this requirement, even where implemented.

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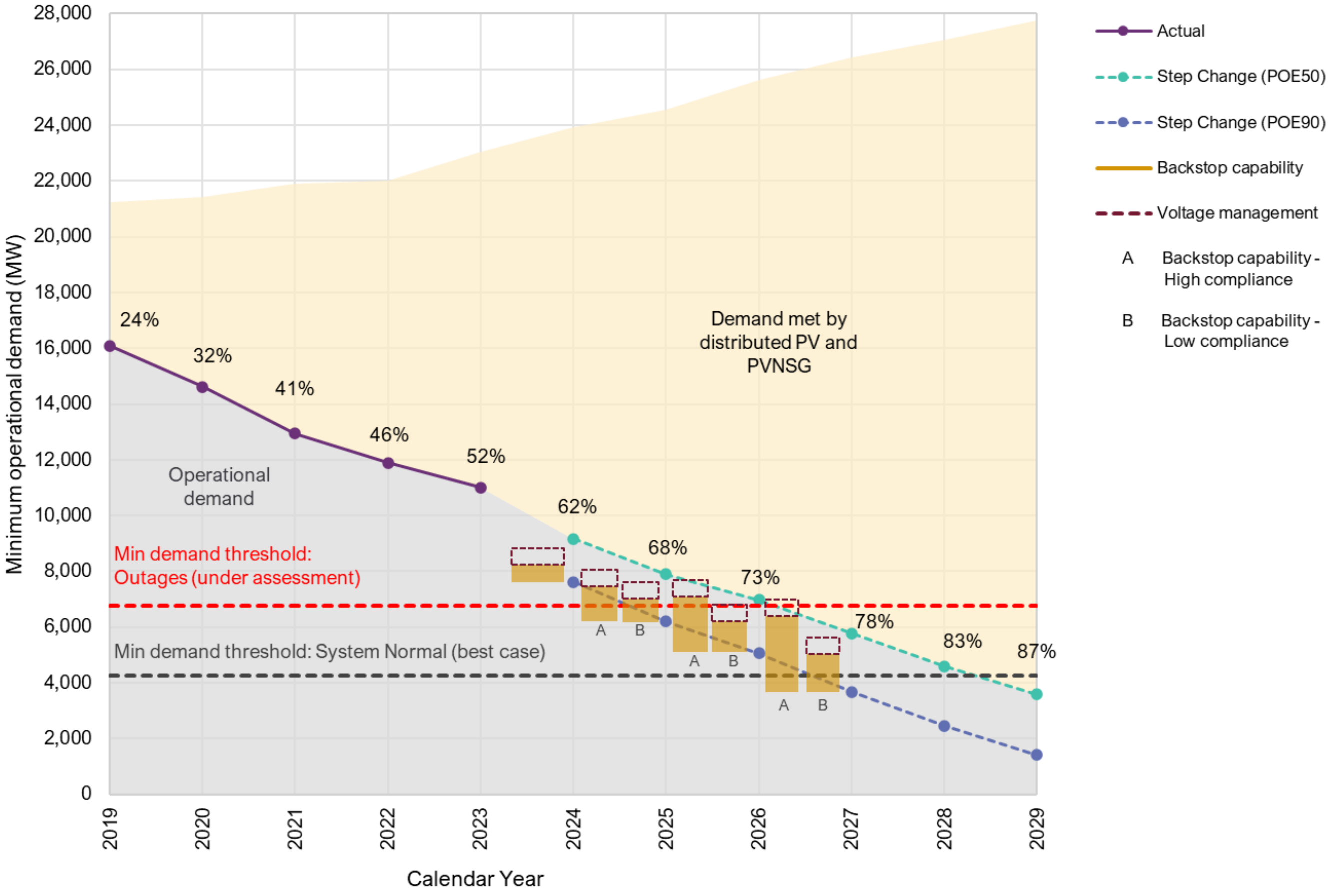
[120] AEMO, (December 2023) Compliance of Distributed Energy Resources with Technical Settings: Update, December 2023, at https://aemo.com.au/-/media/files/initiatives/der/2023/oem_compliance_report_2023.pdf?la=en&hash=E6BEA93263DE58C64FCC957405808CA6.

[121] AEMO remains committed to the National CER Roadmap, which sets out an implementation plan to put in place foundational reforms for better integrating CER across the industry, to ensure the operational requirement to use the emergency backstop is as limited as possible. See https://www.energy.gov.au/sites/default/files/2024-07/national-consumer-energy-resources-roadmap.pdf.

Figure 44 Minimum operational demand in the NEM



Note: PVNSG means PV non-scheduled generation. POE50 and POE90 values represent NEM minimum outcomes from regional 50% POE and 90% POE traces respectively. Forecast NEM minimum demands were calculated for 14 historical reference years. The POE50 value shown represents the mean value across reference years, and the 90POE value represents the minimum value across reference years. The POE90 value represents historically observed weather and solar insolation patterns leading to low demand conditions, as well as the modelled coincidence of minimum demand conditions across NEM regions, and reflects design needs for emergency mechanisms that maintain system security under high-risk conditions.

All minimum demand projections in this section are presented as operational demand[122], as generated (including generator auxiliaries), for the lowest minimum demand in the year (regardless of season when it occurs), presented by calendar year (annual minimum daytime demand typically occurs during the October to December period in most NEM regions).

Mechanisms for secure operation of the NEM are progressing, including:

- Measures to reduce the MSOL of essential units.
- Measures to shift demand or increase it at times of high PV generation.
- Investment in new assets that can provide system security system services that would otherwise be required from the large synchronous units in other ways (such as synchronous condensers, batteries, and/or reactors).

The Federal Government's National CER Roadmap sets out an implementation plan to put in place the foundational reforms for better integrating CER across the industry so it can be coordinated and behave in a visible, predictable manner[123]. AEMO

[122] AEMO, Demand Terms in the EMMS Data Model, June 2024, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Dispatch/Policy_and_Process/Demand-terms-in-EMMS-Data-Model.pdf.

[123] Energy and Climate Change Ministerial Council, National Consumer Energy Resources Roadmap, July 2024, at https://www.energy.gov.au/sites/default/files/2024-07/national-consumer-energy-resources-roadmap.pdf.

is committed to the implementation of the National CER Roadmap to ensure this resource is well integrated into the power system and operational mechanisms support its integration, noting this will take some time.

In the nearer term, there is a rapidly escalating risk of power system conditions where there are insufficient available operational tools to maintain security, especially if unplanned outages occur. NSPs may be required to deploy interventions that have an increasingly high impact on customers if the currently available tools including emergency backstop capability are not available at the scale required. These interventions could include:

- **Distribution voltage management** – this involves increasing distribution voltages to outside of the normal range, to deliberately trip or curtail distributed PV (based on the high voltage response settings in the individual distributed PV inverters). This method of increasing operational demand is a higher risk control, and its adoption may have significant impact on customers and delivery of system services from distribution connected resources.
- **Shedding of reverse flowing feeders** – this involves shedding whole distribution feeders which are in reverse flow (this is where the level of distributed PV generation is higher than the underlying demand), tripping all the distributed PV and customer load on the circuit. Customers connected to feeders that are shed will have no electricity supply during these periods, which has a very high impact on households and businesses. This is the only mechanism to increase operational demand in many areas of the NEM at present.

While these periods of very high distributed PV levels relative to underlying demand are currently not frequent, they will increase over time and could occur during unusual events and outage conditions. In these circumstances, if these more extreme tools are exhausted, this could mean the NEM could be operating insecure outside the permissible range specified in the NER. A credible disturbance could lead to reliance on emergency frequency control schemes which are known to be compromised in such low operational demand periods[124,125], escalating risks of system collapse and blackouts.

Conditions where there are insufficient operational tools to manage the conditions are foreseeable and anticipated, possibly as early as spring 2024 in some regions under unusual conditions. Urgent actions are therefore required to implement suitable response mechanisms including emergency backstop capabilities and minimise these risks while the CER Roadmap implementation establishes longer term solutions.

Table 26 summarises the total quantity of emergency backstop capability available in the NEM, based on advice from distribution network service providers (DNSPs). These available emergency backstop quantities are also shown above in **Figure 44** with bars for 2024 and 2025, indicating the level of demand increase that is feasible from the 90% POE minimum demand forecast levels.

Based on these estimates, if no further action is taken, the capability of emergency backstop mechanisms for managing NEM-wide low demand conditions could become tight from the spring season of 2026. The quantity of required emergency backstop capability is expected to grow rapidly beyond this date. There are already shortfalls in emergency backstop capability within some NEM regions for managing region-specific system security issues. These need to be addressed more urgently.

[124] AEMO, *Adapting and managing Under Frequency Load Shedding at Times of Low Demand*, at https://aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/operations/adapting-and-managing-under-frequency-load-shedding-at-times-of-low-demand.

[125] AEMO, Emergency Under Frequency Response for South Australia, May 2024, at https://aemo.com.au/-/media/files/initiatives/der/2024/2024-05-21-emergency-underfrequency-requirements-for-south-australia.pdf?la=en&hash=200839621941320C557B67B6DC4DF59A.

Table 26 Emergency backstop capability available in the NEM (based on information available July 2024)

	Spring 2023	Spring 2024	Spring 2025	Spring 2026	Spring 2027
Total backstop available* including: • **Increasing load, or** • **Active curtailment of distributed PV**	~432 MW	~ 600 MW	925-1,284 MW	1,197-1,981 MW	1,528-2,737 MW
Voltage management to increase demand	~300 MW	~ 593 MW	~ 593 MW	~ 593 MW	~593 MW
Backstop capability required to maintain system security in NEM-wide low demand conditions	~ 0 MW	~ 0 MW	~ 555 MW	~ 1,684 MW	~ 3,065 MW
Shortfall	-	-	-	Possible emerging shortfall (depends on actions taken)	~ 1,054 MW (depends on actions taken)

*Available emergency backstop quantities include all NEM DNSP capabilities to increase load, and active curtailment of distributed PV. Use of voltage management approaches to curtail distributed PV and increase load is shown separately. These values exclude shedding of reverse flowing loads to increase regional demand. Note: October values have been used as an indicative representation of the amount of emergency backstop capability available for spring.

Implementation of robust emergency backstop capabilities at operational scale is complex, and NEM experience to date implementing emergency backstop capabilities indicates significant implementation challenges may be encountered, with substantial work programs required for emergency backstop mechanisms to perform to the necessary levels. There is significant urgency around developing a sufficient quantity of emergency backstop capability.

7.6.2 Risks emerging in system normal conditions

AEMO's forecasts indicate that total NEM operational demand could fall below approximately 4.3 GW by 2027. Activation of emergency backstop capabilities could be required even in system normal conditions (with no outages) to maintain power system security below this threshold, with the present operational toolkit.

Within individual NEM regions, the need for emergency backstop under system normal conditions will likely emerge earlier than this date. This indicates urgency around foundational reforms and investment in capability to support more efficient operation of the system and market, suitable for regular use in system normal conditions.

List of figures and tables

Tables

Figures

A1. New South Wales outlook

The following sections present, for New South Wales:

- Operational consumption, maximum demand, and minimum demand outlooks for all three scenarios to 2053-54.
- Supply adequacy assessments for the next 10 years, for the *Committed and Anticipated Investments* sensitivity, and other sensitivities published in this ESOO.

Annual consumption outlook

Figure 45 to **Figure 47** show the component forecasts for operational consumption in New South Wales under the ESOO Central scenario for the aggregate regional load, residential sector and business sector respectively.

Figure 45 Actual and forecast New South Wales electricity consumption, ESOO Central scenario, 2014-15 to 2053-54 (TWh)

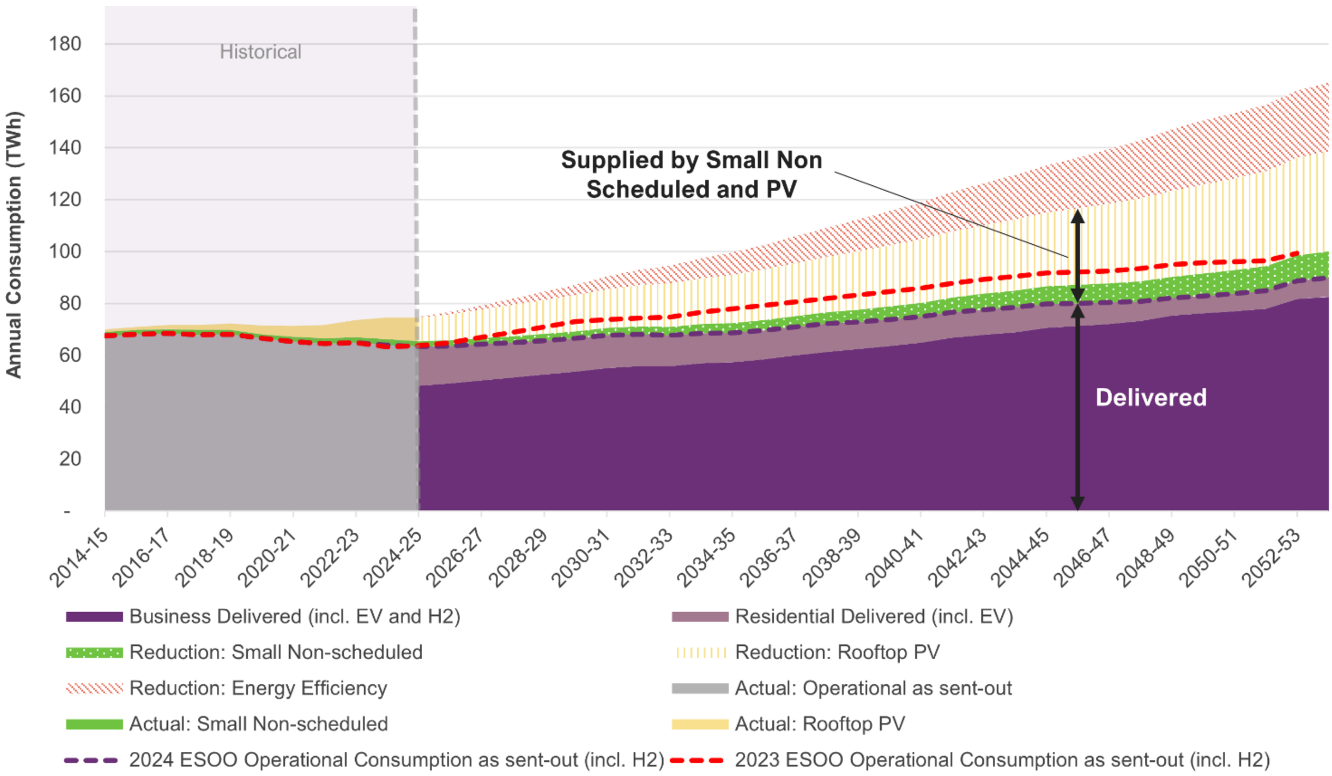


Figure 46 Components of New South Wales residential electricity consumption forecast, ESOO Central scenario, 2024-25 to 2053-54 (TWh)

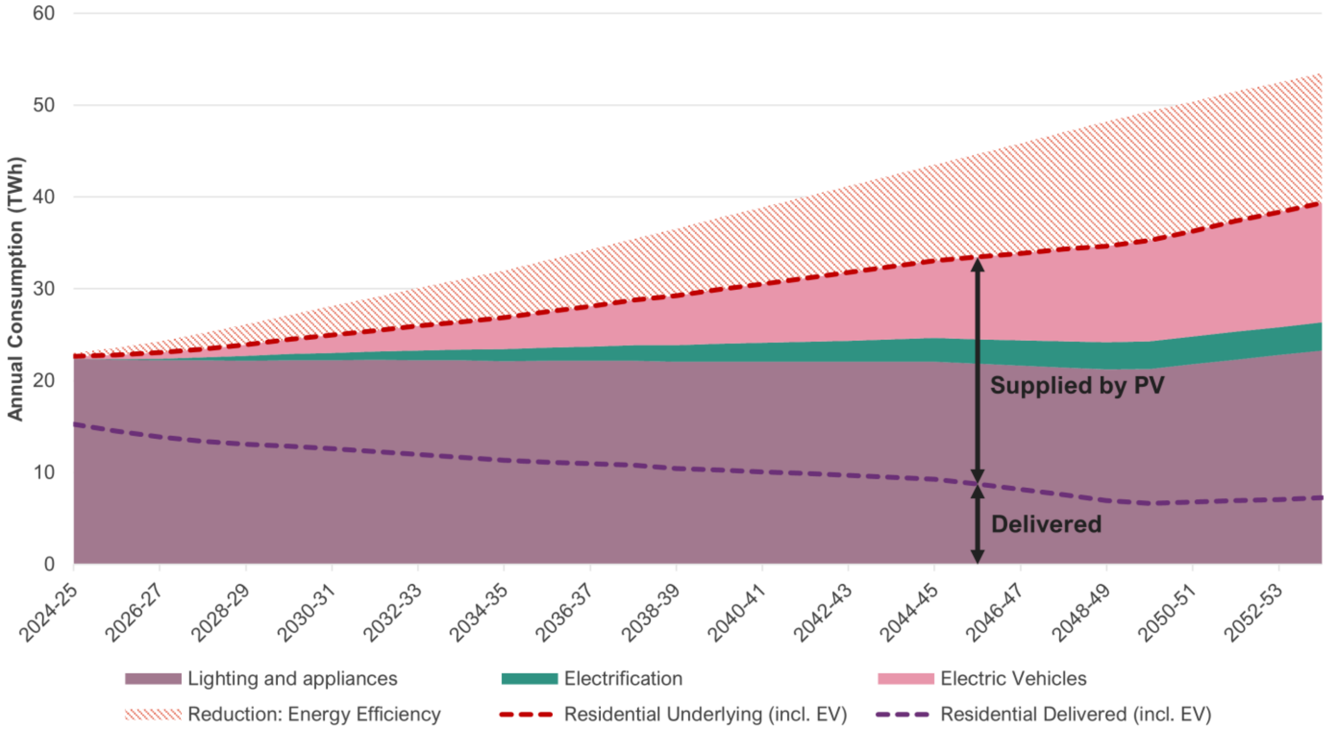
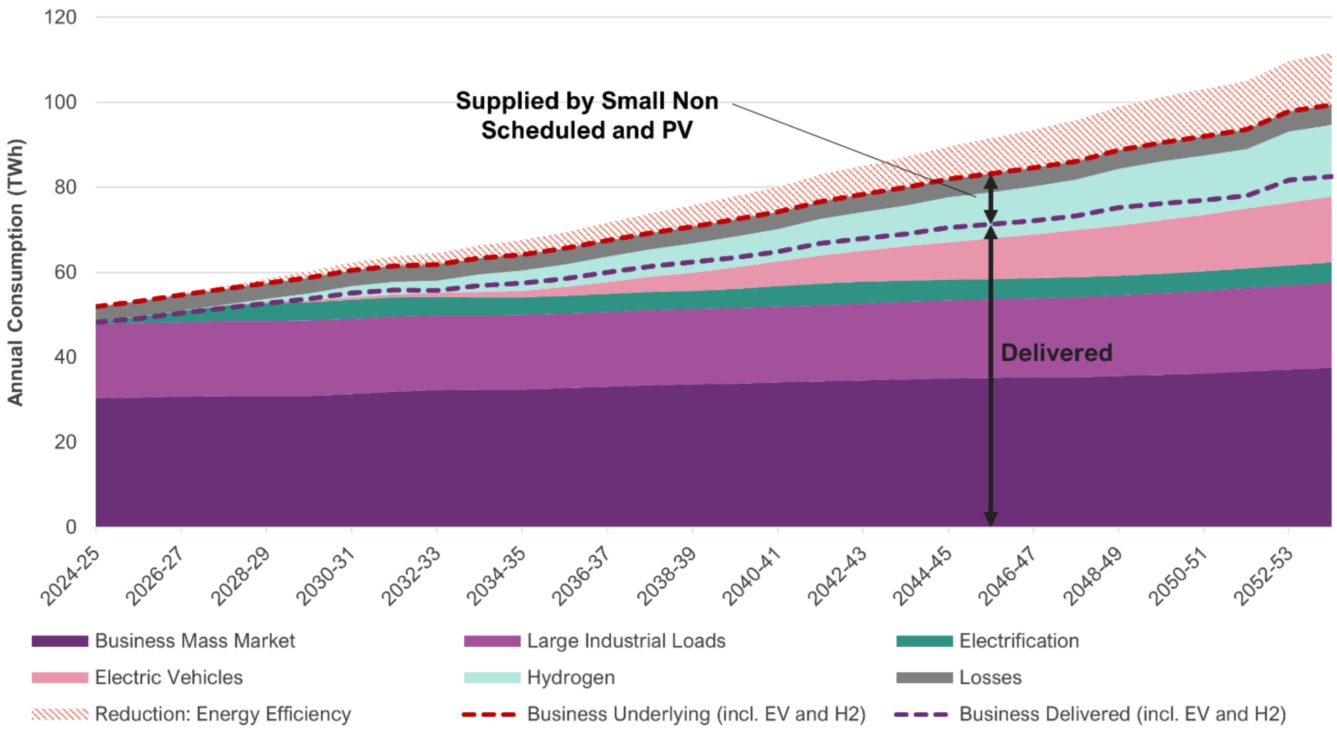


Figure 47 Components of New South Wales business electricity consumption forecast, ESOO Central scenario, 2024-25 to 2053-54 (TWh)



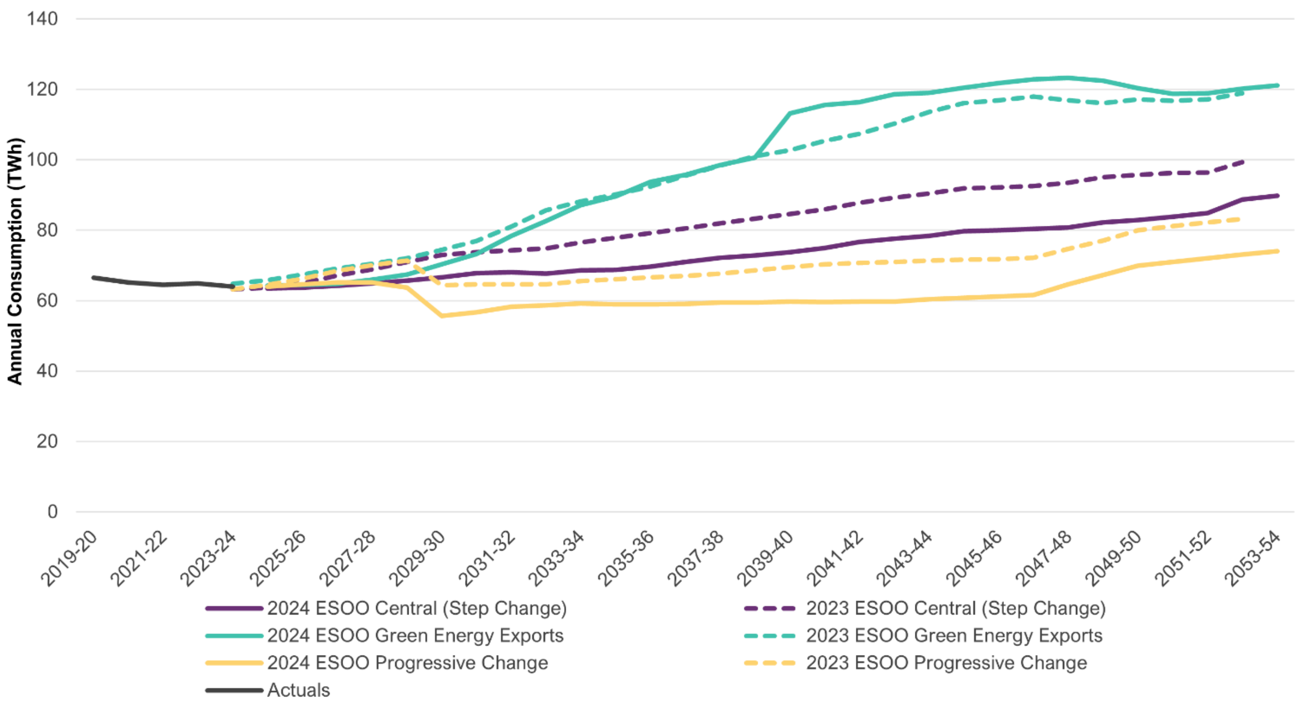
Note: Small non-scheduled combines PVNSG and ONSG.

In this scenario, AEMO forecasts:

- Short term (1-10 years) – steady growth in consumption due to a combination of increasing load from the BMM sector combined with population growth increasing residential loads. EV uptake is forecast to gradually pick up pace resulting in increased consumption associated with EV charging in the 2030s. Electrification of both business and to a lesser extent households is another important driver of operational consumption growth. Consumption due to hydrogen production under the New South Wales Renewable Fuel Scheme emerges toward the end of the next decade.
  - Compared to 2023 forecasts, this year's projections are lower primarily due to dampened growth from the BMM sector due to a softer economic outlook and weakened consumer spending. A slower uptake of EVs compared to the 2023 ESOO and delays to anticipated hydrogen production projects further lowers the forecasts compared to the 2023 ESOO.
- Medium term (11-20 years) – consumption growing moderately due to sustained uptake of EVs and steady growth in BMM load and electrolyser loads for hydrogen production. Growth is offset partially by the impact of energy efficiency investments combined with continued uptake of distributed PV. Residential electrification continues at a steady rate while business electrification is expected to slow.
- Long term (21-30 years) – growth trends from the medium term continue into the long term.

Figure 48 shows all the scenarios.

Figure 48 Actual and forecast New South Wales operational consumption, including hydrogen exports, all scenarios, 2019-20 to 2053-54 (TWh)



This figure highlights that:

- *Progressive Change* tracks closely with the ESOO Central scenario until the late 2020s, when several factors pull it lower, including LIL closure risks, a decline in the BMM sector in response to weaker economic activity, lower hydrogen production and slower electrification. The scenario considers only the hydrogen production needed to support the New South Wales Renewable Fuel Scheme.

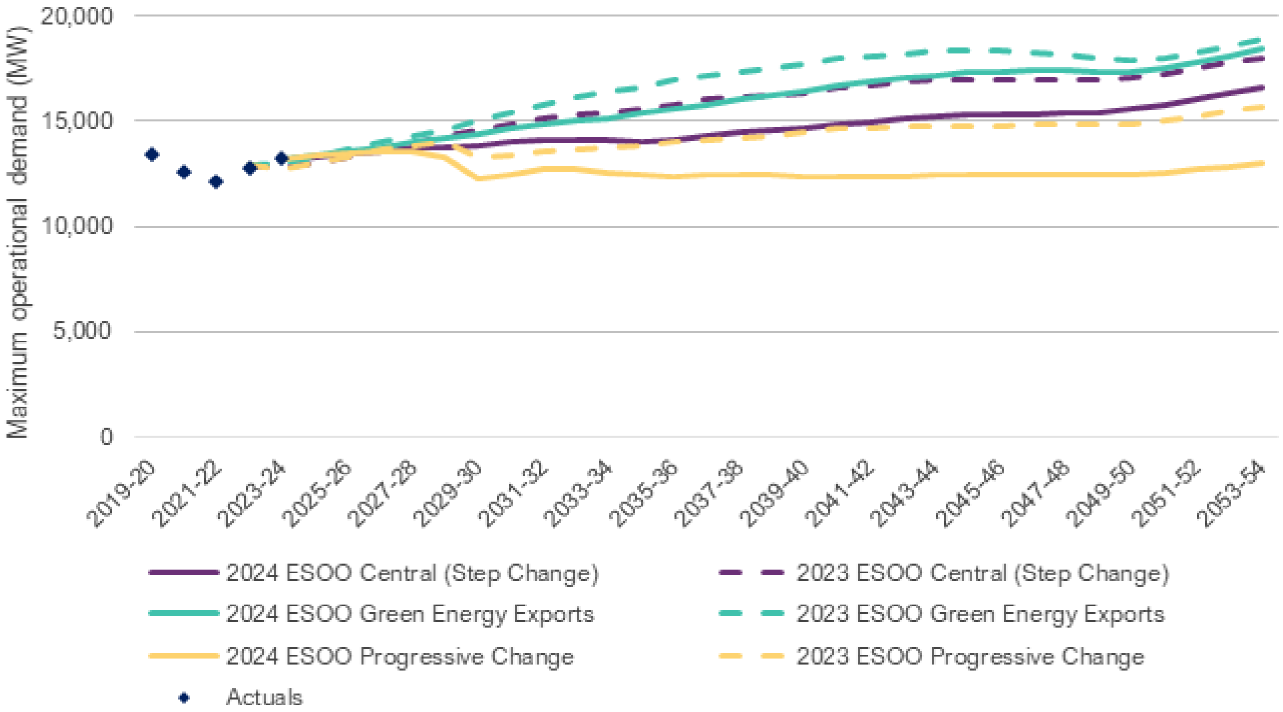
- For *Green Energy Exports*, EV uptake and hydrogen production for domestic use account for the majority of consumption growth (relative to the ESOO Central scenario), with higher levels of energy efficiency and rooftop PV investment softening growth that is due to higher economic activity. Growth exceeds the 2023 ESOO in the 2040s due to additional hydrogen production forecast to support the production of green steel[126].

Maximum operational demand outlook

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.

Figure 49 shows actual and forecast 50% POE maximum operational (sent-out) demand[127] from 2019-20 to 2053-54 in New South Wales for all scenarios, compared to the 2023 ESOO.

Figure 49 Actual and forecast New South Wales 50% POE maximum operational (sent-out) demand, 2024 ESOO all scenarios and 2023 ESOO all scenarios, 2019-20 to 2053-54 (MW)



Note: The actuals displayed are not weather-corrected (therefore reflect observed demand under the prevailing weather conditions) or adjusted for system events and exclude DSP. Additionally, this definition excludes demand from scheduled loads, typically pumping load from pumped hydro energy storage or large-scale batteries, as well as hydrogen loads.

[126] Green steel is less carbon intensive than traditional steel making which is achieved through substituting green hydrogen (produced via renewable energy sources) in place of coking coal.

[127] The maximum and minimum forecasts presented here differ slightly from the ESOO forecasts presented in Chapter 2 in assuming ongoing growth in the uptake of coordinated (VPP-operated) battery storage. In accordance with AEMO's updated methodology, forecast growth that is not committed is assumed to be un-coordinated in the ESOO forecast. The ESOO thus has more un-coordinated batteries, and only those are reflected in the demand forecast, while VPP is modelled as supply and excluded from the forecasts presented here in the appendix. Both forecasts can be viewed at AEMO's Forecasting Portal: https://forecasting.aemo.com.au/.

The key insights from these forecasts are:

- 2024-25 to 2033-34 (1-10 years):
  - In all three scenarios, the forecasts trend lower than the 2023 ESOO forecasts, primarily as a consequence of weaker consumption growth from business customers and EVs.
  - The *Progressive Change* scenario forecasts weaker demand from the BMM sector, including consideration of the risks of LIL closures.
  - While the forecasts from the ESOO Central scenario flatten towards the end of the 10-year forecast horizon, the forecasts for *Green Energy Exports* continue to increase. This growth is driven by increasing forecasts for BMM and EV sectors.
- 2034-35 to 2043-44 (11-20 years):
  - Maximum operational demand forecasts are lower than the 2023 ESOO projections in all three scenarios due to lower-than-expected growth in BMM and EV sectors.
  - Forecasts for the ESOO Central scenario and *Green Energy Exports* continue to grow due to increasing projections for underlying BMM and EV sectors. The Green Energy Exports forecast grows at a faster rate than the ESOO Central scenario, driven by higher growth rates in LIL, EV and BMM forecasts.
  - The *Progressive Change* forecasts show a continued decrease, flattening towards the end of the 11-20 year forecast horizon. This trend is primarily due to the decline in forecasts for BMM, LIL and electrification.
- 2043-44 to 2052-53 (21-30 years) follow similar drivers described in the annual consumption trends.

Table 27 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. The 50% POE forecast for winter is only slightly lower than in summer though, and in some years, statistically the annual maximum demand will fall in winter.

Table 27 New South Wales summer and winter 10% and 50% POE maximum operational (sent-out) demand forecast, *Step Change* scenario, 2024-25 to 2049-50 (MW)

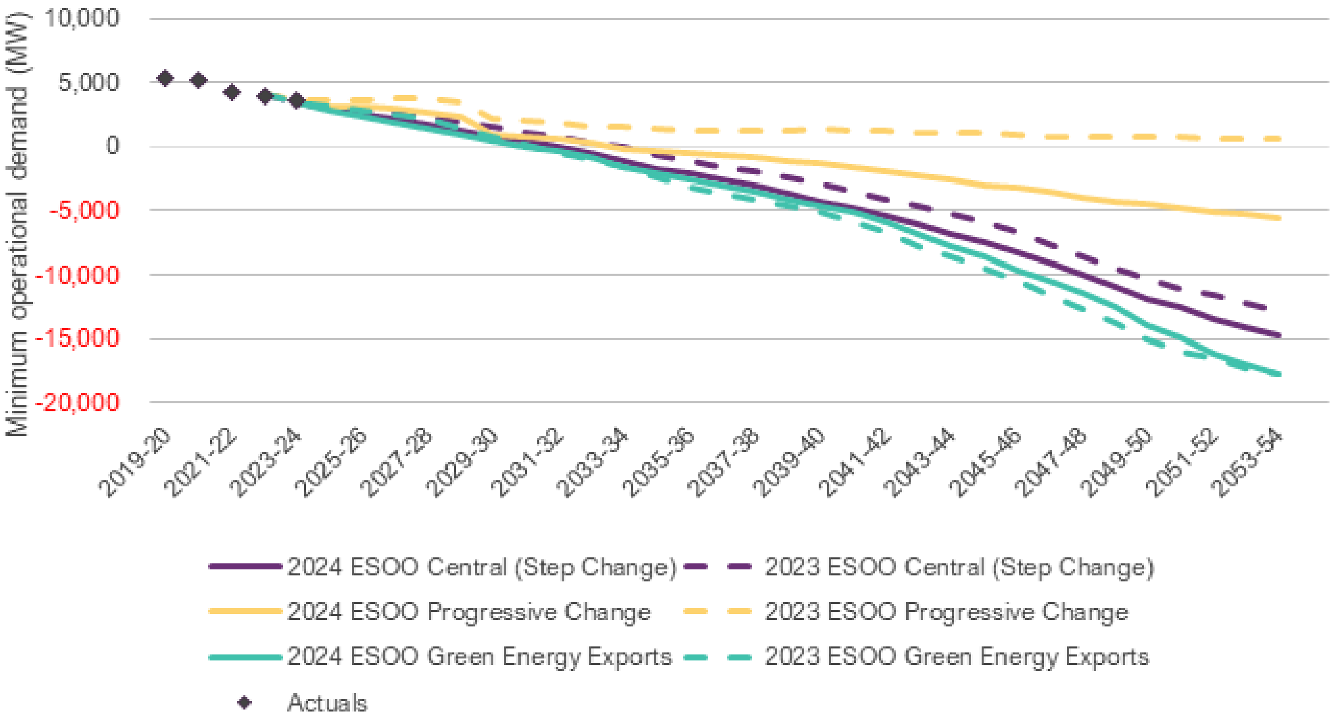
Financial year	Summer		Calendar year	Winter	
	10% POE	50% POE		10% POE	50% POE
2024-25	14,064	13,278	2025	12,893	12,529
2029-30	14,851	13,838	2030	13,833	13,447
2039-40	15,704	14,530	2040	15,112	14,662
2049-50	16,175	15,003	2050	16,065	15,569

Minimum operational demand outlook

Figure 50 shows the actual and forecast 50% POE minimum operational (sent-out) demand from 2018-19 to 2053-54 for the 2024 ESOO compared to the 2023 ESOO forecasts for all scenarios in New South Wales. Minimum operational demand is strongly linked to PV capacity, with minimums occurring frequently during daytime hours. The key insights from these forecasts are:

- Minimum demand forecasts for the ESOO Central and *Progressive Change* scenarios decline faster and are lower than the 2023 ESOO forecasts, driven by higher PV uptake and weaker relative growth in underlying forecasts for BMM.
- Minimum demand forecasts for the *Green Energy Exports* scenario decline faster and are lower than the 2023 ESOO forecasts, driven by higher forecasts for PV.

Figure 50 Actual and forecast New South Wales 50% POE minimum operational (sent-out) demand, 2024 ESOO all scenarios and 2023 ESOO all scenarios, 2019-20 to 2053-54 (MW)



Note: The actuals displayed are not weather-corrected (therefore reflect observed demand under the prevailing weather conditions) or adjusted for system events and exclude DSP. Additionally, this definition excludes demand from scheduled loads, typically pumping load from pumped hydro energy storage or large-scale batteries, as well as hydrogen loads.

Supply adequacy assessment

Table 28 lists all committed and anticipated generator and storage projects included in the *Committed and Anticipated Investments* sensitivity in New South Wales, while **Figure 51** shows the aggregate impact of generator and storage commissioning and decommissioning assumptions on assumed capacity during typical summer conditions.

Table 28 New South Wales anticipated and committed generators and storages in *Committed and Anticipated Investments* sensitivity

Site name	Commitment status	Technology type	Nameplate capacity (MW)	Storage capacity (MWh)	Participant provided full commercial use date	Modelled commissioning date
Capital Battery	Committed	Storage – Battery	100	200	Aug-24	Feb-25
Crookwell 3 Wind Farm	Committed	Wind Turbine – Onshore	58	0	Jun-24	Dec-24
Culcairn Solar Farm	Committed	Solar PV – Single axis tracking	350	0	Jul-26	Jan-27
Eraring Big Battery	Committed	Storage – Battery	460	920	Dec-25	Jun-26

Site name	Commitment status	Technology type	Nameplate capacity (MW)	Storage capacity (MWh)	Participant provided full commercial use date	Modelled commissioning date
Hunter Power Station	Committed	Turbine – OCGT	750	0	Dec-24	Jun-25
Liddell BESS	Anticipated	Storage – Battery	500	2,000	Not provided	Jul-28
Limondale BESS	Committed	Storage – Battery	50	400	Jan-26	Jan-27
Lockhart Hybrid Facility – Battery	Committed	Storage – Battery	10	20	Jun-25	Dec-25
Lockhart Hybrid Facility – Solar	Anticipated	Solar PV – Single axis tracking	10	0	Jun-25	Dec-25
Maryvale Solar and Energy Storage System	Anticipated	Storage – Battery	172	344	Feb-27	Feb-28
Maryvale Solar and Energy Storage System	Anticipated	Solar PV – Single axis tracking	172	0	Feb-27	Feb-28
New England Solar Farm	Anticipated	Solar PV – Single axis tracking	320	0	Not provided	Jul-28
New England Solar Farm BESS	Anticipated	Storage – Battery	50	50	Dec-26	Dec-27
Orana BESS	Committed	Storage – Battery	415	1,660	Jun-26	Jun-27
Quorn Park Hybrid	Committed	Solar PV – Single axis tracking	97	0	Dec-25	Jun-26
Quorn Park Hybrid	Anticipated	Storage – Battery	28	40	Dec-25	Jun-26
Richmond Valley BESS	Committed	Storage – Battery	275	2,200	Oct-26	Oct-27
Riverina Solar Farm	Anticipated	Solar PV – Single axis tracking	32	0	Jun-25	Dec-25
Sapphire Wind Farm	Committed	Storage – Battery	30	38	Jun-25	Jul-26
Sebastopol Solar Farm	Anticipated	Solar PV – Single axis tracking	90	0	Jan-23	Jul-23
Silver City Energy Storage	Committed	Storage – Other	200	1,600	Dec-27	Dec-28
Snowy 2.0	Committed	Storage – Pumped hydro	2,200	349,980	Dec-28	Start commissioning Jun-28, finish commissioning Jun-29
Stubbo Solar Farm	Anticipated	Solar PV – Single axis tracking	400	0	Aug-24	Feb-25
Tamworth BESS – Valent	Anticipated	Storage – Battery	200	400	Nov-26	Nov-27
Tamworth Solar Farm	Committed	Solar PV – Single axis tracking	65	0	Apr-26	Apr-27
Tilbuster Solar Farm	Anticipated	Solar PV – Fixed	249	0	Mar-26	Sep-26
Uungula Wind Farm	Committed	Wind Turbine – Onshore	414	0	Feb-28	Feb-29
Walla Walla Solar Farm	Committed	Solar PV – Single axis tracking	304	0	May-24	Nov-24

Site name	Commitment status	Technology type	Nameplate capacity (MW)	Storage capacity (MWh)	Participant provided full commercial use date	Modelled commissioning date
Waratah Super Battery[A]	Committed	Storage – Battery	850	1,680	Mar-25	Aug-25
Wellington North Solar Farm (Lightsource)	Committed	Solar PV – Single axis tracking	437	0	Oct-24	Apr-25
Wollar Solar Farm	Committed	Solar PV – Single axis tracking	280	0	Jun-24	Dec-24

A. Waratah Super Battery is included predominantly as a transmission project, as part of a System Integrity and Protection Scheme. It is described in Section 3.4.

Figure 51 New South Wales assumed capability during typical summer conditions, by generation type, 2023-24 to 2033-34 (MW)

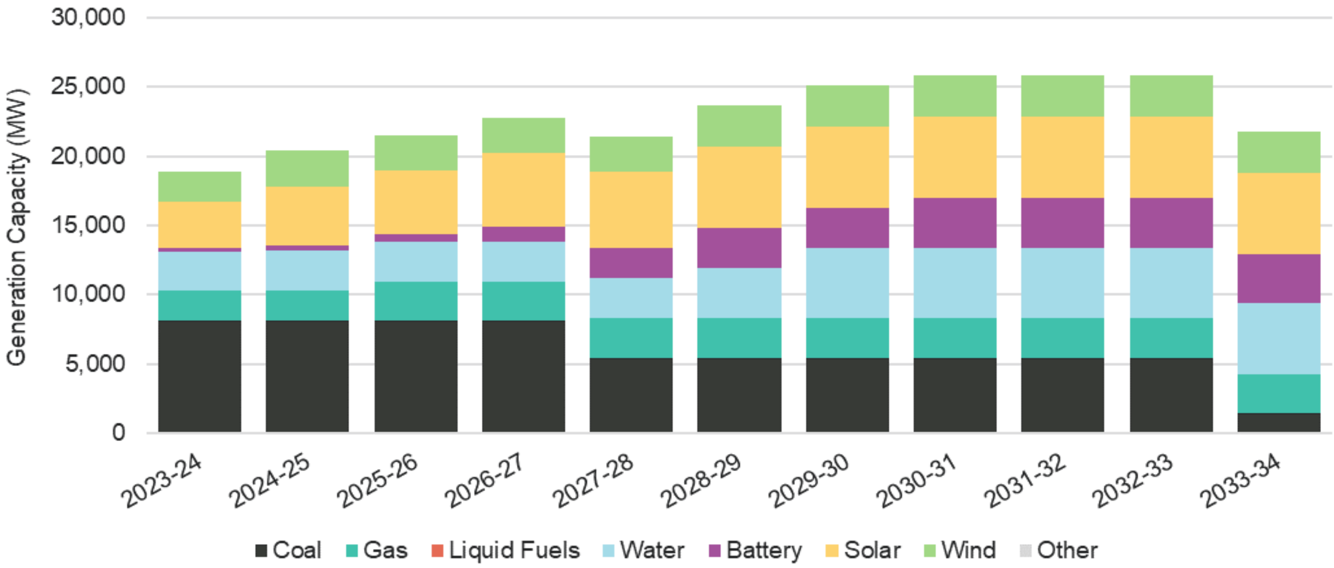


Figure 52 shows forecast expected USE for New South Wales under the modelled scenarios and sensitivities. It shows that:

- Under the *Committed and Anticipated Investments* sensitivity, expected USE is forecast above the IRM in 2024-25. Should all currently committed and anticipated projects be delivered to their advised schedules, then reliability risks would lower to within the IRM, as forecast in the *On-time Delivery* sensitivity.
- In all 2024 ESOO reliability assessments, expected USE is forecast within the IRM in 2025-26 and 2026-27 due to additional generation projects as well as the extended availability of Eraring Power Station in these years compared to the previous 2023 ESOO forecasts.
- In 2027-28, reliability risks re-emerge when Eraring is now advised to retire, partially offset by the development of the anticipated HumeLink transmission project and a number of anticipated solar and battery projects, including Orana BESS and Richmond Valley BESS. This is followed by numerous committed and anticipated wind, solar, hydro and battery developments in 2028-29, including Liddell BESS and partial commissioning of Snowy 2.0 pumped hydro.
- From 2030-31, increases in forecast demand are greater than the capability of currently committed and anticipated generator developments.
- A significant gap emerges in 2033-34 with the retirement of Bayswater Power Station and Vales Point Power Station.

- The *Actionable Transmission and Coordinated CER* and *Federal and State Schemes* sensitivities are shown to have significantly lower reliability risks over the ESOO horizon than the *Committed and Anticipated Investments* sensitivity, due to the assumed delivery of additional transmission developments including Hunter Transmission Project from 2028-29, further improving transfer capabilities to the major demand centres of Sydney, Newcastle and Wollongong, and additional generator developments including long duration storage developments in the *Federal and State Schemes* sensitivity.

Figure 52 New South Wales expected USE, scenarios and sensitivities, 2024-25 to 2033-34

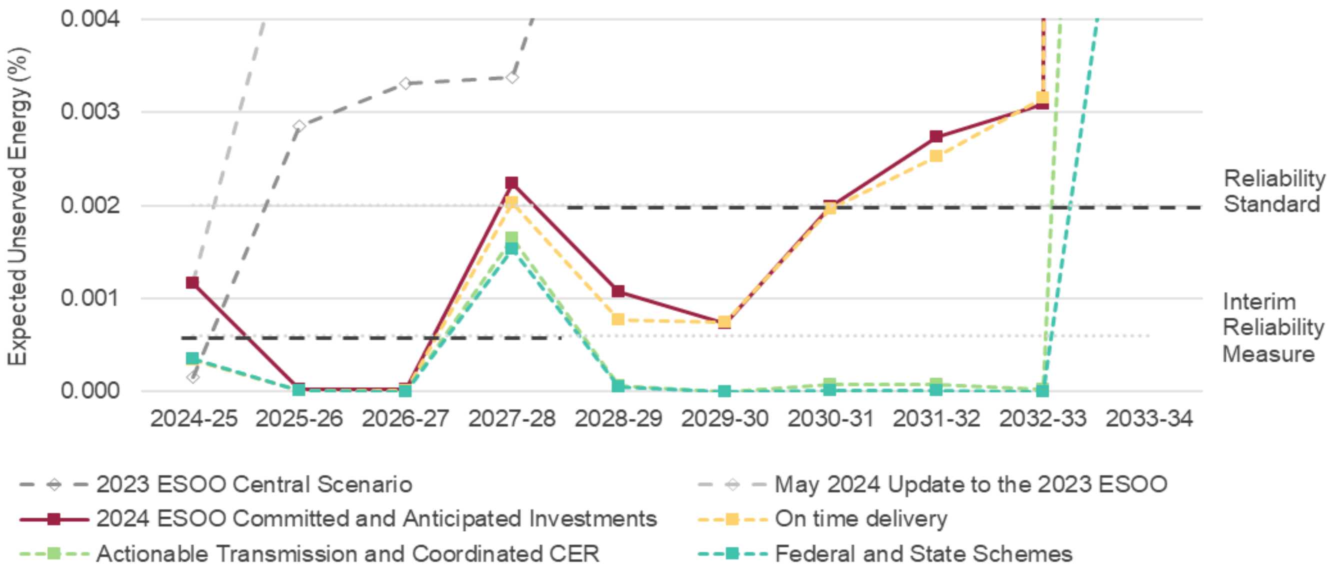


Figure 53 shows the reliability outcomes for the *Committed and Anticipated Investments* sensitivity for New South Wales in 2024-25 under different weather years, demonstrating the reasonable variance that is expected depending upon the weather conditions (affecting consumer load profiles, as well as renewable generator resources).

Figure 53 Reliability outcomes for New South Wales in 2024-25 under different weather reference years, *Committed and Anticipated Investments* sensitivity

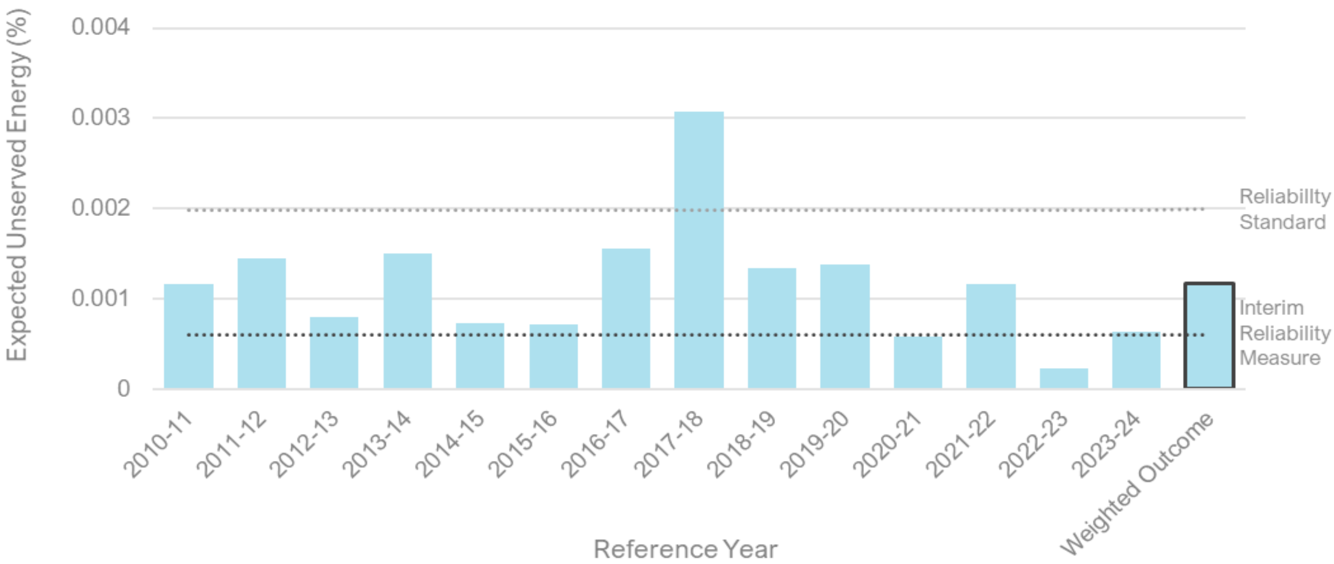
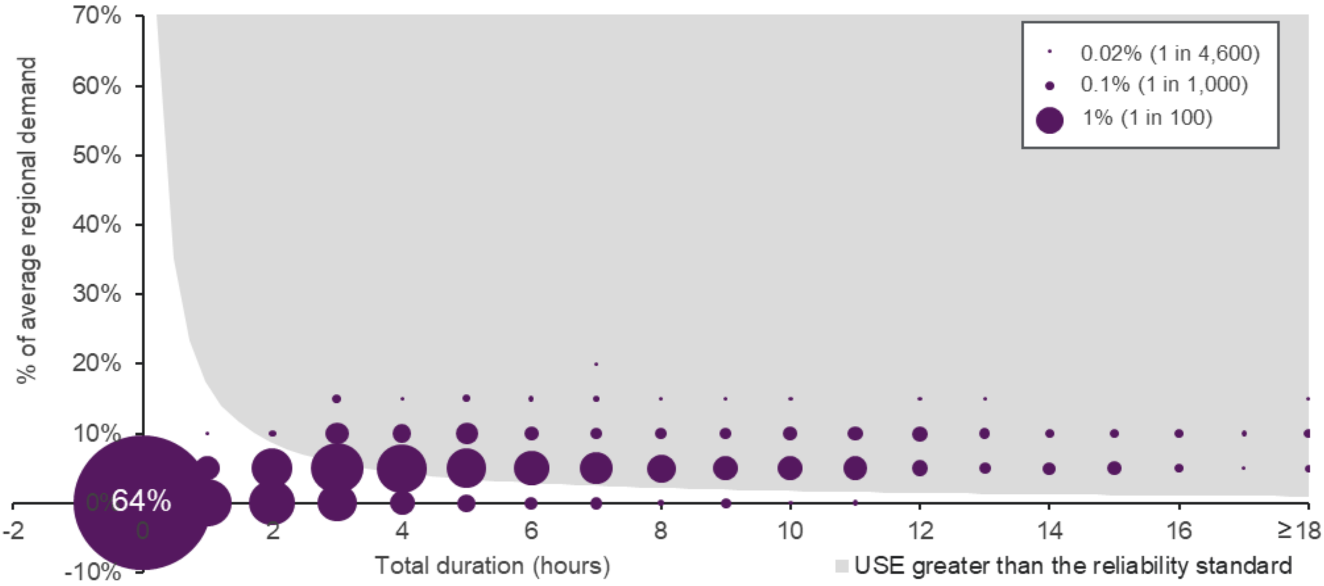


Figure 54 shows a bubble plot of the depth and duration of USE forecast in New South Wales for 2024-25 in the *Committed and Anticipated Investments* sensitivity, similar to that shown in **Section 5.2**. It shows that the most likely outcome for New South Wales is that USE does not occur in the coming year (the large purple dot), but that there is a 36% probability of a USE outcome. For those simulations that did have USE, the number of hours unserved was likely to be approximately 1-12 hours, and of average depth up to 10% of average regional load.

Figure 54 Bubble plot of depth and duration of forecast USE New South Wales 2024-25, *Committed and Anticipated Investments* sensitivity



A2. Queensland outlook

The following sections present, for Queensland:

- Operational consumption, maximum demand, and minimum demand outlooks for all three scenarios to 2053-54.
- Supply adequacy assessments for the next 10 years for the *Committed and Anticipated Investments* sensitivity, and other sensitivities published in this ESOO.

Annual consumption outlook

Figure 55 to Figure 57 show the component forecasts for operational consumption in Queensland under the ESOO Central scenario for the aggregate regional load, residential sector and business sector respectively.

Figure 55 Actual and forecast Queensland electricity consumption, ESOO Central scenario, 2014-15 to 2053-54 (TWh)

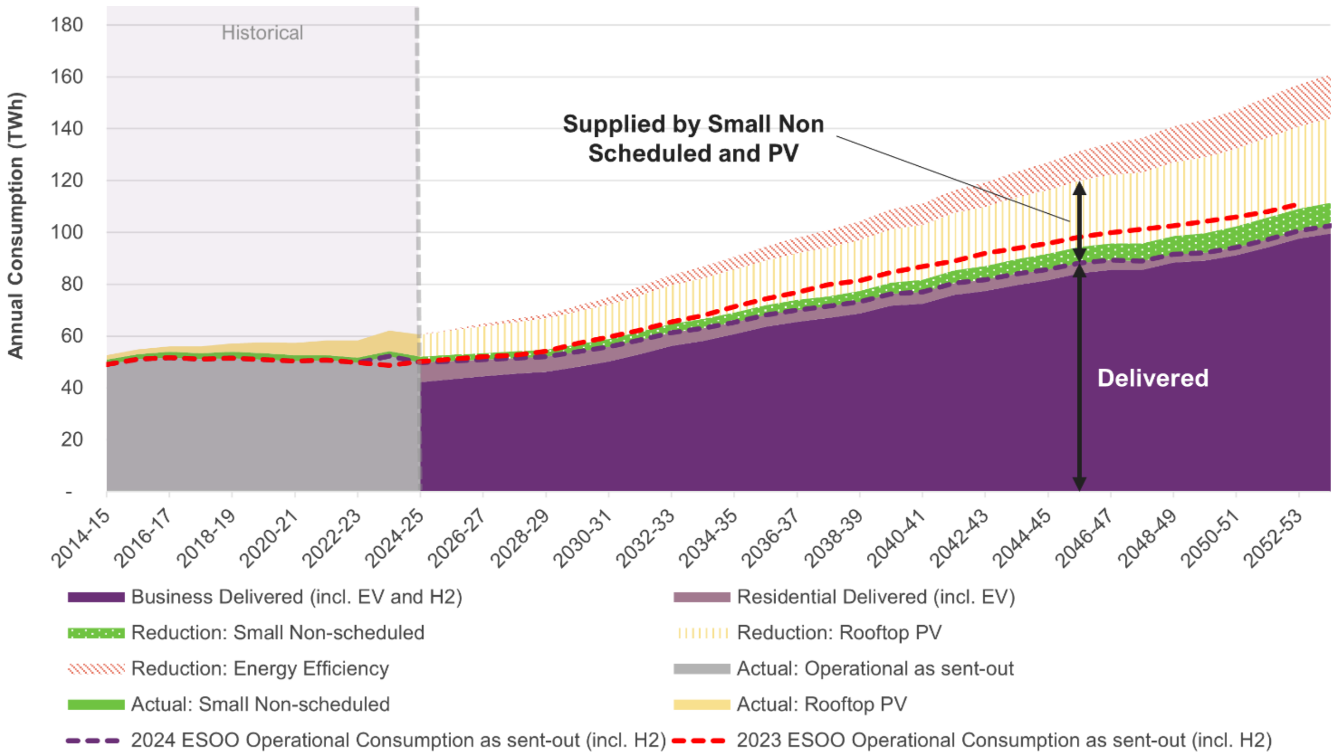


Figure 56 Components of Queensland residential electricity consumption forecast, ESOO Central scenario, 2024-25 to 2053-54 (TWh)

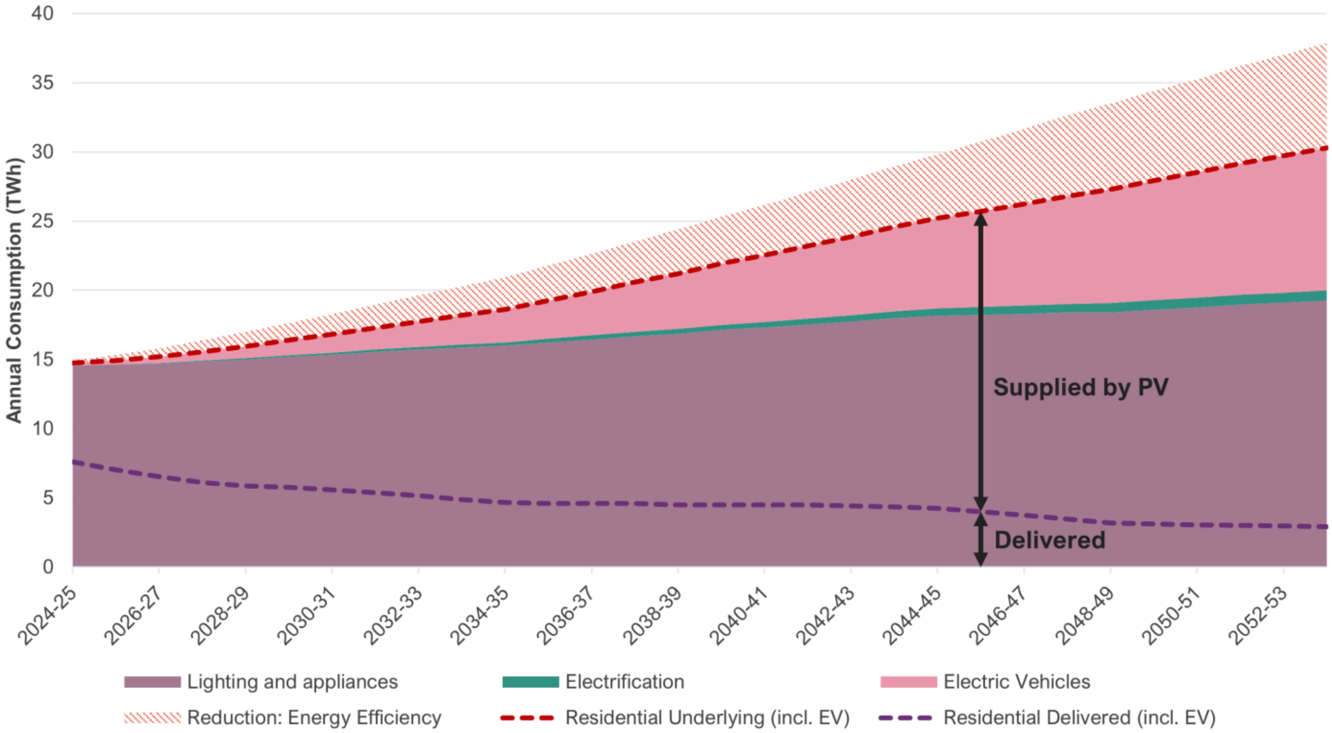
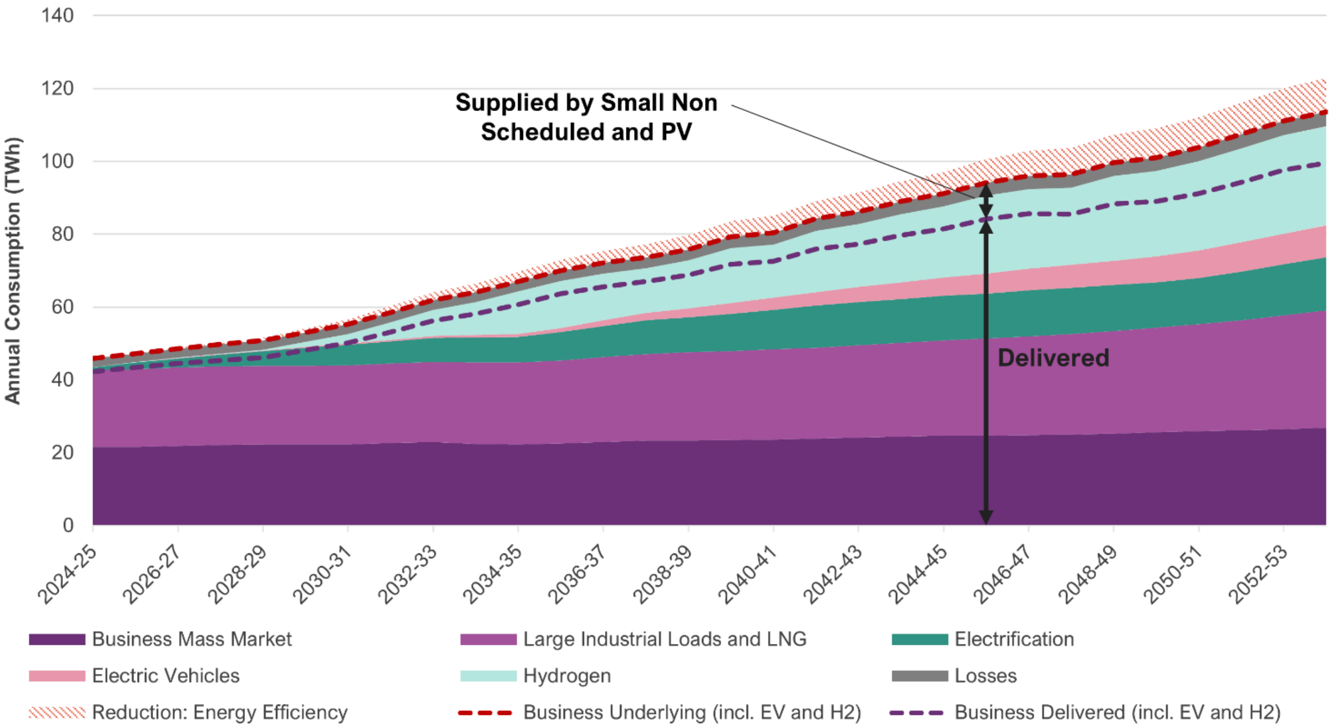


Figure 57 Components of Queensland business electricity consumption forecast, ESOO Central scenario, 2024-25 to 2053-54 (TWh)



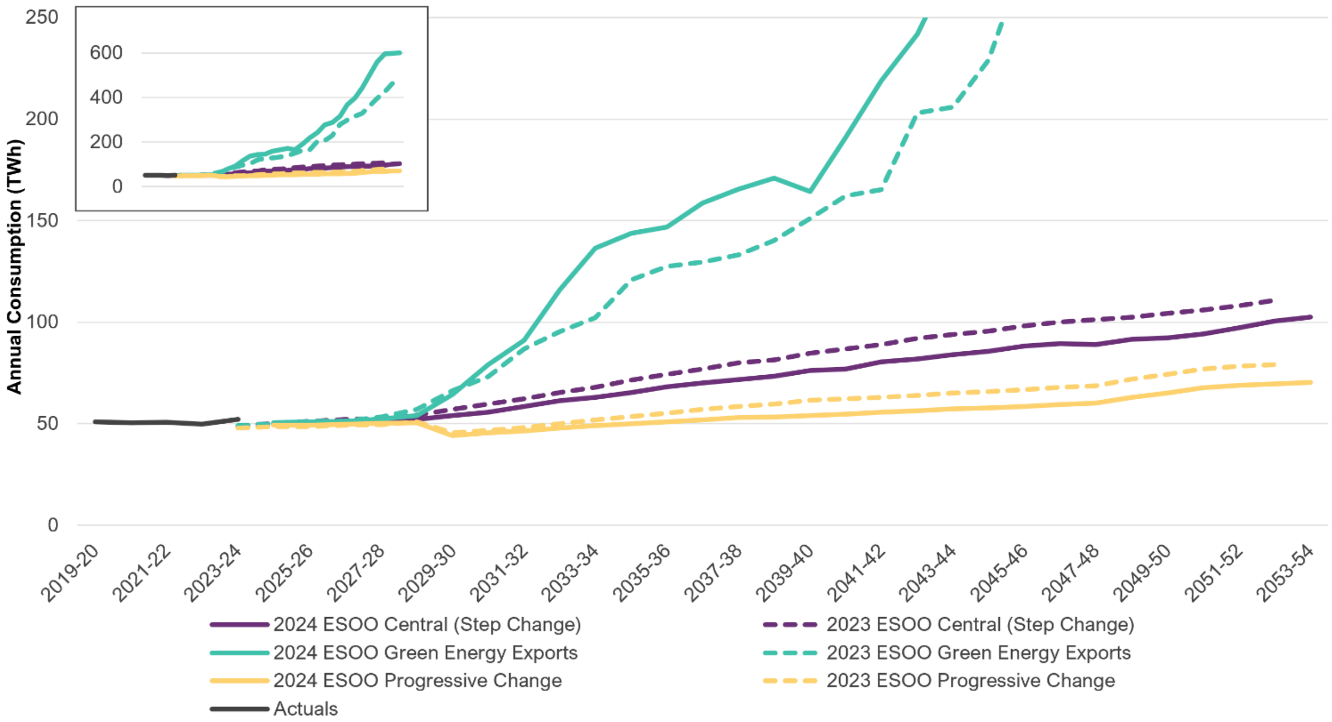
Note: Small non-scheduled combines PVNSG and ONSG.

In this scenario, AEMO forecasts:

- Short term (1-10 years) – softer growth in consumption relative to the 2023 ESOO. Residential household consumption is very similar to the 2023 forecast, however EV consumption is lower with slower than anticipated uptake. Steady, moderate growth is forecast for the LIL sector across this period. Hydrogen production for domestic and international markets emerges from late 2020s with growth ramping into the middle of the 2030s. Continued uptake of distributed PV tempers growth in grid-delivered consumption.
- Medium term (11-20 years) – consumption growth lower than in 2023. Continued growth in consumption is attributed to hydrogen production, LIL and business electrification. Hydrogen production for domestic use remains a strong growth area, while increases in the number and size of rooftop PV systems means aggregate residential household consumption is forecast to be met by the generation from distributed PV systems by the end of this decade.
  - The reduction compared to the 2023 ESOO is attributed to slower growth in EV and rooftop PV meeting more residential demand. LNG consumption follows forecast global demand for LNG and the ESOO Central scenario reflects a potential moderation of LNG operation from mid 2030s.
- Long term (21-30 years) – growth to continue with continued EV uptake and LIL consumption as the main drivers. This growth is offset partially by falling LNG exports, greater adoption of energy efficiency measures and continued uptake of distributed PV.

Figure 58 shows the consumption forecast across these scenarios.

Figure 58 Actual and forecast Queensland operational consumption, including hydrogen exports, all scenarios, 2019-20 to 2053-54 (TWh)



Note: 2023 ESOO and 2024 ESOO *Green Energy Exports* forecasts continue beyond the chart to reach approximately 462 TWh in 2052-53 and 600 TWh in 2053-54 respectively.

The figure highlights that:

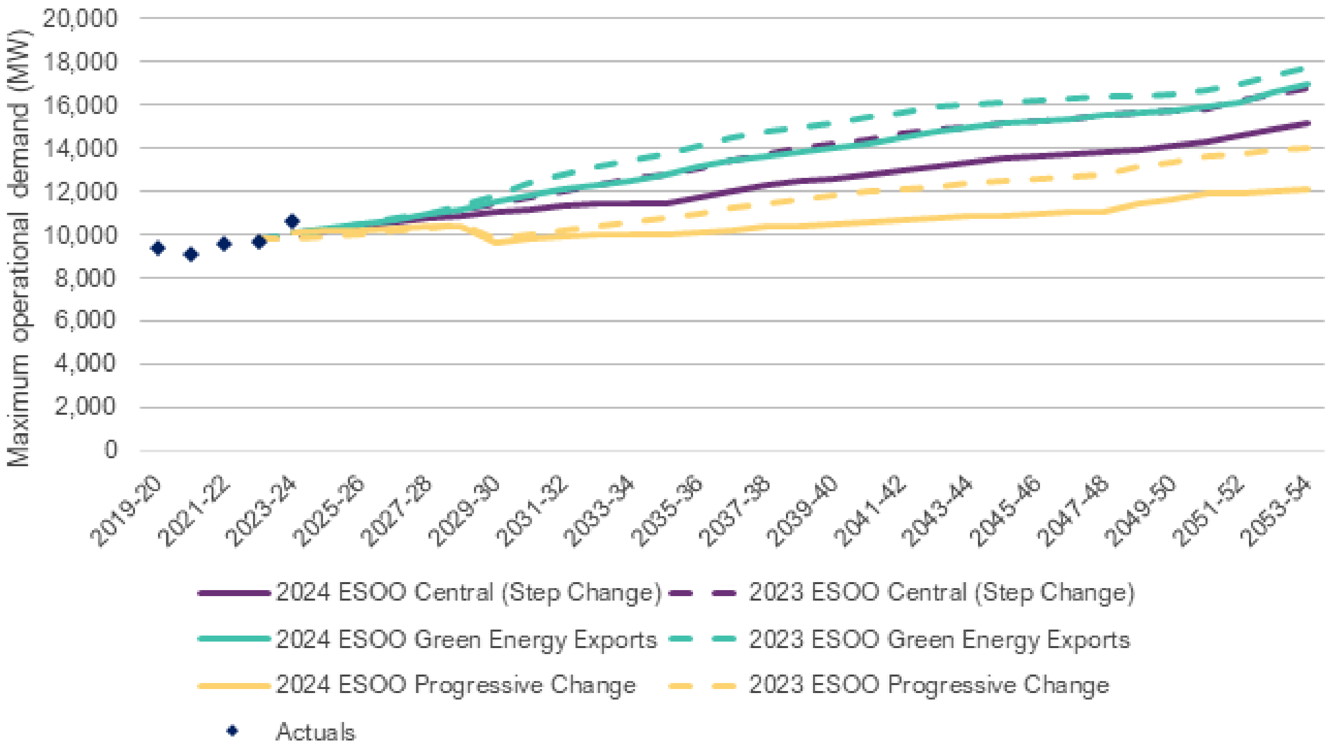
- *Progressive Change* is lower than the ESOO Central scenario, particularly from the early 2030s, due to weaker economic activity leading to assumed LIL closures, lower rates of electrification and delayed EV uptake.
- *Green Energy Exports* is higher than the ESOO Central scenario, as higher economic activity and more domestic and international demand for green products increase hydrogen demand, while EVs and electrification grow faster than other scenarios.

Maximum operational demand outlook

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.

Figure 59 shows actual and forecast 50% POE maximum operational (sent-out) demand[128] from 2019-20 to 2053-54 in Queensland for all scenarios, compared to the 2023 ESOO.

Figure 59 Actual and forecast Queensland 50% POE maximum operational (sent-out) demand, 2024 ESOO all scenarios and 2023 ESOO all scenarios, 2019-20 to 2053-54 (MW)



Note: The actuals displayed are not weather-corrected (therefore reflects observed demand under the prevailing weather conditions) or adjusted for system events and exclude DSP. Additionally, this definition excludes demand from scheduled loads, typically pumping load from pumped hydro energy storage or large-scale batteries, as well as hydrogen loads.

[128] The maximum and minimum forecasts presented here differ slightly from the ESOO forecasts presented in Chapter 2 in assuming ongoing growth in the uptake of coordinated (VPP-operated) battery storage. In accordance with AEMO's updated methodology, forecast growth that is not committed is assumed to be un-coordinated in the ESOO forecast. The ESOO thus has more un-coordinated batteries, and only those are reflected in the demand forecast, while VPP is modelled as supply and excluded from the forecasts presented here in the appendix. Both forecasts can be viewed at AEMO's Forecasting Portal: https://forecasting.aemo.com.au/.

The key insights are:

- 2024-25 to 2033-34 (1-10 years):
  - In all three scenarios, the forecasts trend lower than the 2023 ESOO forecasts, primarily as a consequence of weaker consumption growth from business customers and EVs.
  - For the ESOO Central scenario, there is a relatively steady growth mainly driven by EVs and electrification, although EV uptake is slower than was forecast in 2023.
  - For the *Green Energy Exports* scenario, greater economic activity supports higher growth trends, and decarbonisation activity is faster leading to greater electrification and EV uptake than the Central scenario.
  - The *Progressive Change* scenario continues to quantify weaker economic conditions, leading to some major industrial load assumed to close in response in the next decade
- 2034-35 to 2043-44 (11-20 years):
  - Across all scenarios, the 2024 ESOO forecasts continue to grow, but are lower than those for the 2023 ESOO. For the ESOO Central scenario, growth is forecast to increase in the early 2030s due to the accelerating rate of EV uptake.
- 2044-45 to 2053-54 (21-30 years) follow similar drivers described in the annual consumption trends.

Table 29 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 continue occurring in summer over the forecast horizon.

Table 29 Queensland summer and winter 10% and 50% POE maximum operational demand (sent out) forecast, *Step Change* scenario, 2024-25 to 2049-50 (MW)

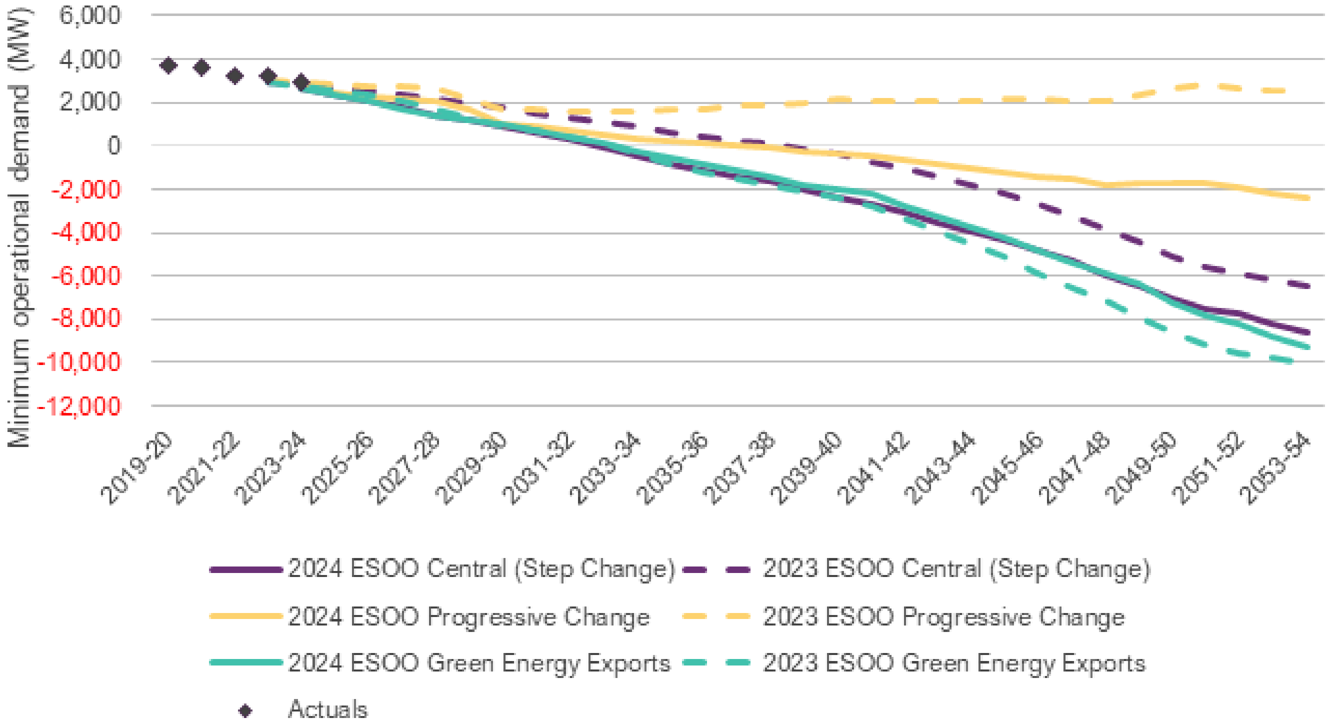
Financial year	Summer		Calendar year	Winter	
	10% POE	50% POE		10% POE	50% POE
2024-25	10,645	10,225	2025	8,632	8,417
2029-30	11,537	11,024	2030	9,497	9,258
2039-40	13,044	12,590	2040	11,216	10,953
2049-50	14,491	14,051	2050	12,724	12,396

Minimum operational demand outlook

Figure 60 shows actual and forecast 50% POE minimum operational (sent-out) demand (MW) from 2019-20 to 2053-54 for the 2024 ESOO compared to the 2023 ESOO for all scenarios in Queensland. Minimum operational demand is strongly linked to PV capacity, with minimums occurring frequently during daytime hours. The key insights are:

- Minimum operational demand is forecast to decrease rapidly due to the uptake of PV in the ESOO Central and *Green Energy Exports* scenarios. For the ESOO Central scenario, the rate of decline in this 2024 ESOO is higher than in the 2023 ESOO, driven by slower relative growth in EVs and higher relative growth in PV capacity. A similar pattern is observed for the *Green Energy Exports* scenario.
- For the *Progressive Change* scenario, there is a gradual decline in minimum operational demand with increased PV uptake and a declining trend in BMM operation.

Figure 60 Actual and forecast Queensland 50% POE minimum operational (sent-out) demand, 2024 ESOO all scenarios and 2023 ESOO all scenarios, 2019-20 to 2053-54 (MW)



Note: The actuals displayed are not weather-corrected (therefore reflect observed demand under the prevailing weather conditions) or adjusted for system events and exclude DSP. Additionally, this definition excludes demand from scheduled loads, typically pumping load from pumped hydro energy storage or large-scale batteries, as well as hydrogen loads.

Supply adequacy assessment

Table 30 lists all committed and anticipated generator and storage projects included in the *Committed and Anticipated Investments* sensitivity in Queensland, while **Figure 61** shows the aggregate impact of generator and storage commissioning and decommissioning assumptions on assumed capacity during typical summer conditions.

Table 30 Queensland anticipated and committed generators and storages in *Committed and Anticipated Investments* sensitivity

Site name	Commitment status	Technology type	Nameplate capacity (MW)	Storage capacity (MWh)	Participant provided full commercial use date	Modelled commissioning date
Aldoga BESS Stage 1	Anticipated	Storage – Battery	400	400	Nov-25	Nov-26
Aramara Solar Farm	Anticipated	Solar PV – Single axis tracking	101	0	Jun-26	Jun-27
Banksia Solar Farm	Anticipated	Solar PV – Single axis tracking	70	0	Not provided	Jul-28
Borumba	Anticipated	Storage – Pumped hydro	1,998	48,000	Sep-31	Sep-32
Brendale BESS	Anticipated	Storage – Battery	205	410	Jun-26	Jun-27
Broadsound Solar Farm	Anticipated	Solar PV – Single axis tracking	368	0	Not provided	Jul-28

Site name	Commitment status	Technology type	Nameplate capacity (MW)	Storage capacity (MWh)	Participant provided full commercial use date	Modelled commissioning date
Bundaberg Solar Farm	Committed	Solar PV – Single axis tracking	78	0	Aug-25	Feb-26
Clarke Creek Wind Farm	Committed	Wind Turbine – Onshore	450	0	Sep-25	Mar-26
Greenbank BESS	Committed	Storage – Battery	200	400	Apr-25	Oct-25
Kidston Pumped Storage Hydro Project 250 MW	Committed	Storage – Pumped hydro	250	2,000	Feb-25	Aug-25
MacIntyre Wind Farm	Committed	Wind Turbine – Onshore	923	0	Dec-24	Jun-25
Mt Fox BESS	Anticipated	Storage – Battery	300	600	Nov-26	Nov-27
Munna Creek Solar Farm	Anticipated	Solar PV – Single axis tracking	154	0	Aug-27	Jul-26
Stanwell BESS	Anticipated	Storage – Battery	300	1,200	Jan-26	Aug-28
Swanbank BESS	Anticipated	Storage – Battery	250	500	Sep-24	Jan-27
Tarong BESS – Stanwell	Committed	Storage – Battery	300	600	Dec-25	Mar-25
Ulinda Park BESS	Anticipated	Storage – Battery	155	298	Feb-25	Dec-26
Wambo Wind Farm	Committed	Wind Turbine – Onshore	252	0	Dec-24	Aug-25
Western Downs Battery	Committed	Storage – Battery	255	500	Nov-25	Jun-25

Figure 61 Queensland assumed capability during typical summer conditions, by generation type, 2023-24 to 2033-34 (MW)

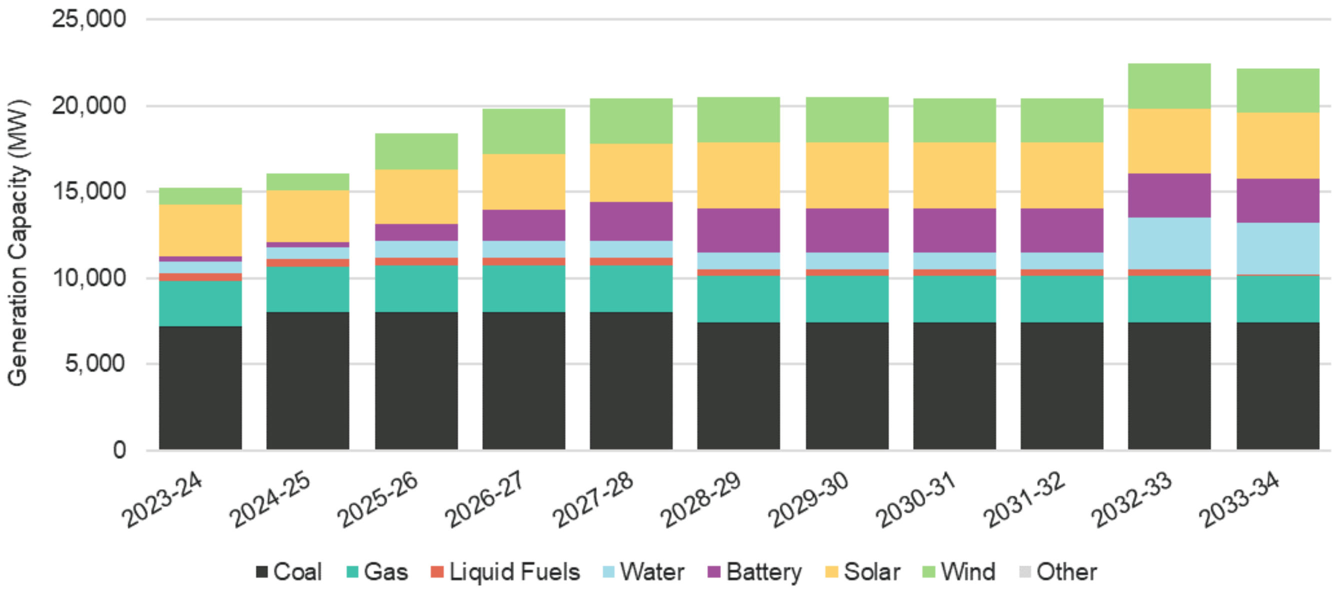


Figure 62 shows expected USE for Queensland under relevant modelled scenarios and sensitivities. It shows that:

- In the *Committed and Anticipated Investments* sensitivity, expected USE remains below the reliability standard and IRM for the entire ESOO horizon. In 2033-34, there is an increase in expected USE due to the part retirement of Mount Stuart Power Station as well as closure of neighbouring New South Wales' Bayswater and Vales Point power stations, however reliability risks remain within the IRM.
- The *Committed and Anticipated Investments* sensitivity shows generally reduced USE compared to the 2023 ESOO and the May 2024 Update to the 2023 ESOO, due to the progression of additional projects and a reduction in demand forecasts. Should all currently committed and anticipated projects be delivered to their advised schedules then reliability risks would lower, as forecast in the *On-time Delivery* sensitivity.
- Further investments in transmission, generation and coordinated CER developments (observed in the *Actionable Transmission and Coordinated CER* and *Federal and State Schemes* sensitivities) demonstrate a very low reliability risk with the delivery of key infrastructure projects.

Figure 62 Queensland expected USE, scenarios and sensitivities, 2024-25 to 2033-34

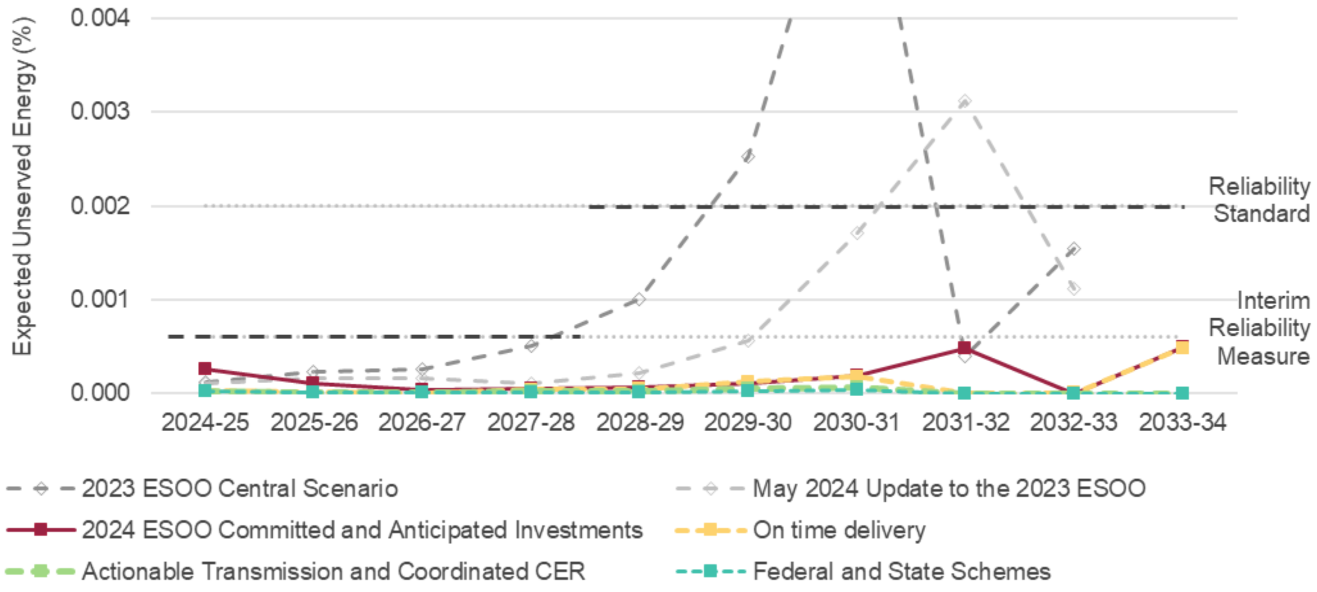


Figure 63 shows the reliability outcomes for the *Committed and Anticipated Investments* sensitivity for Queensland in 2024-25 under different weather years, demonstrating the reasonable variance that is expected depending upon the weather conditions (affecting consumer load profiles, as well as renewable generator resources).

Figure 63 Reliability outcomes for Queensland in 2024-25 under different weather reference years, *Committed and Anticipated Investments* sensitivity

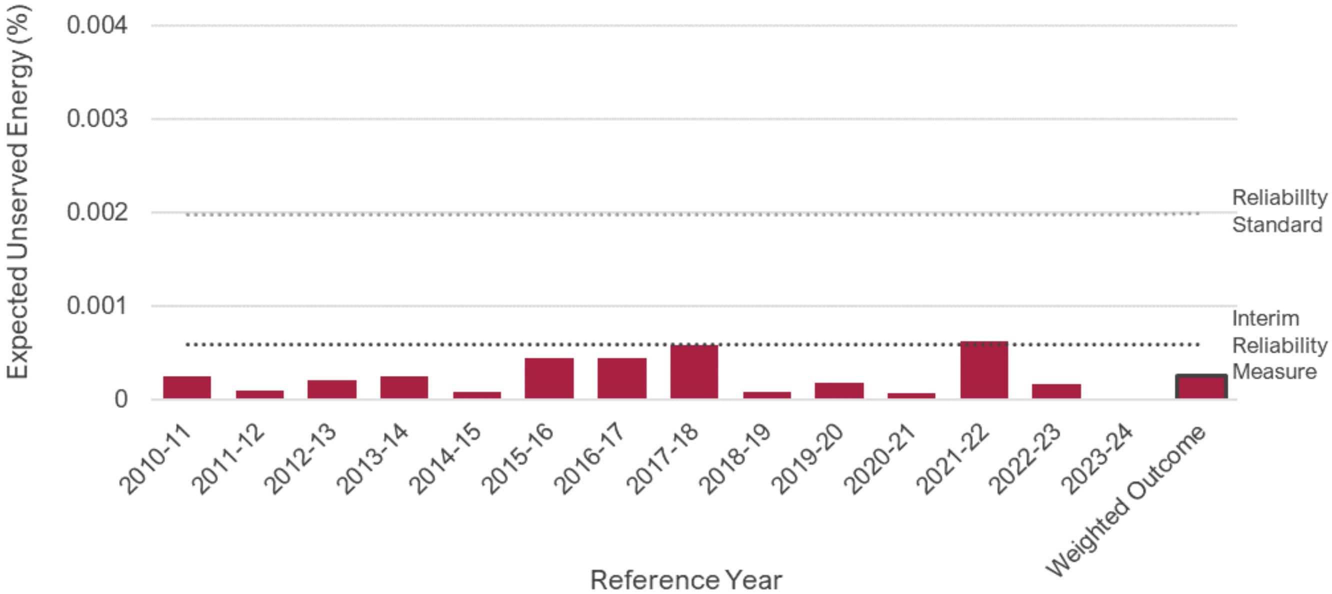
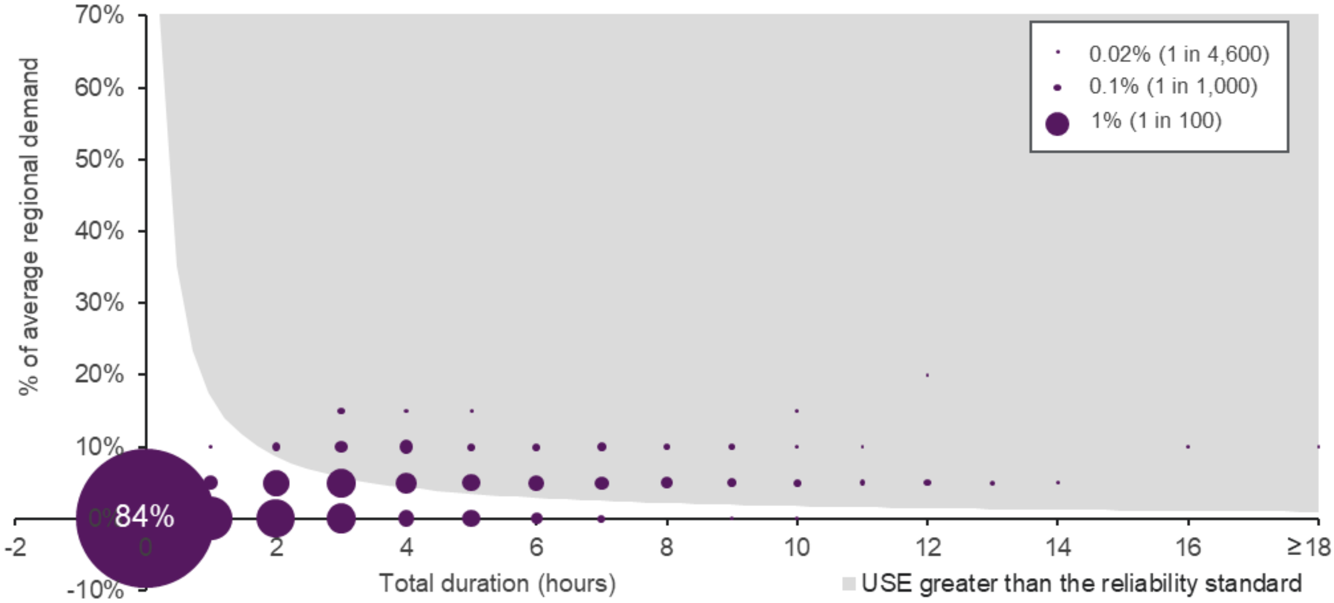


Figure 64 shows a bubble plot of the depth and duration of USE forecast in Queensland for 2024-25 in the *Committed and Anticipated Investments* sensitivity, similar to that shown in **Section 5.2**. It shows that the most likely outcome for Queensland is that USE does not occur in the coming year (the large purple dot), but that there is a 16% probability of a USE outcome. For those simulations that did have USE, the number of hours unserved was likely to be up to five hours, and of average depth up to 10% of average regional load.

Figure 64 Bubble plot of depth and duration of forecast USE Queensland 2024-25, *Committed and Anticipated Investments* sensitivity



A3. South Australia outlook

The following sections present, for South Australia:

- Operational consumption, maximum demand, and minimum demand outlooks for all three scenarios to 2053-54.
- Supply adequacy assessments for the next 10 years, for the *Committed and Anticipated Investments* sensitivity, and other sensitivities published in this ESOO.

Annual consumption outlook

Figure 65 to Figure 67 show the component forecasts for operational consumption in South Australia under the ESOO Central scenario for the aggregate regional load, residential sector and business sector respectively.

Figure 65 Actual and forecast South Australia electricity consumption, ESOO Central scenario (TWh)

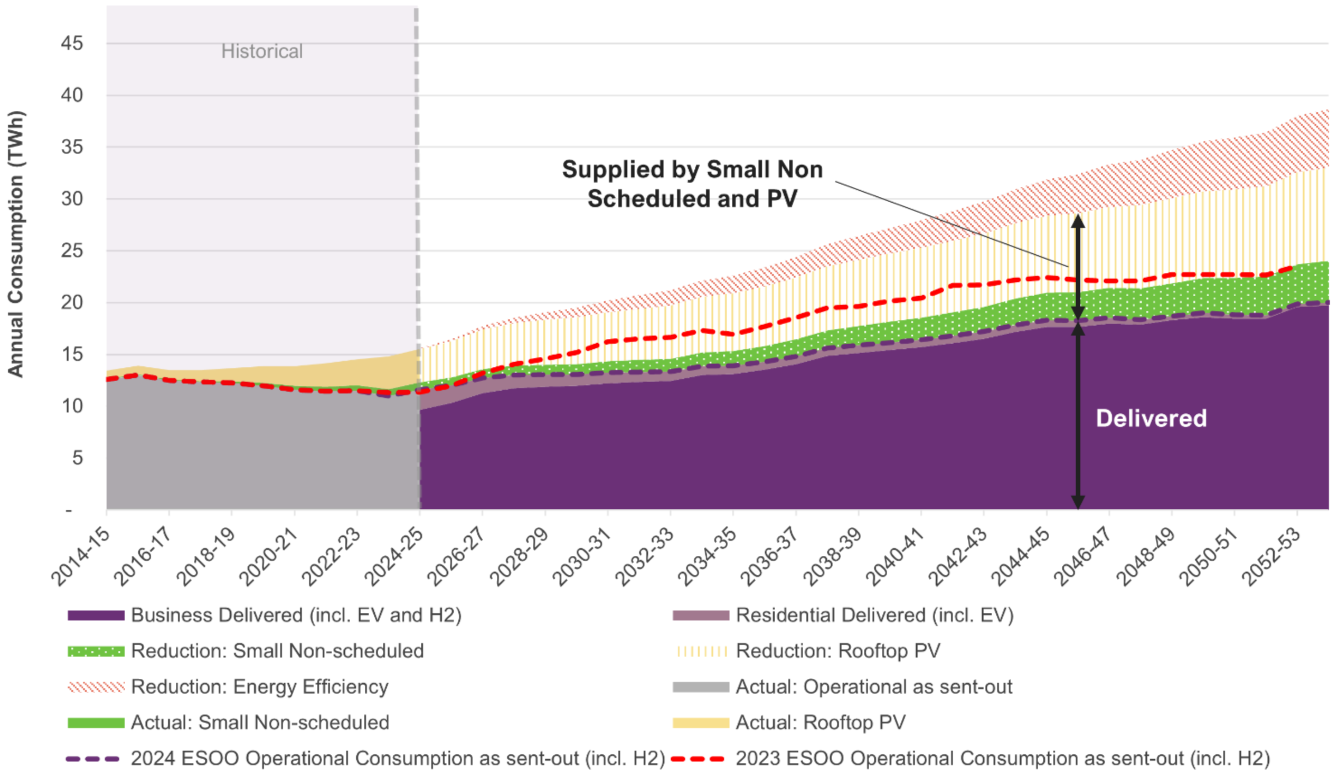


Figure 66 Components of South Australia residential electricity consumption forecast, ESOO Central scenario, 2024-25 to 2053-54 (TWh)

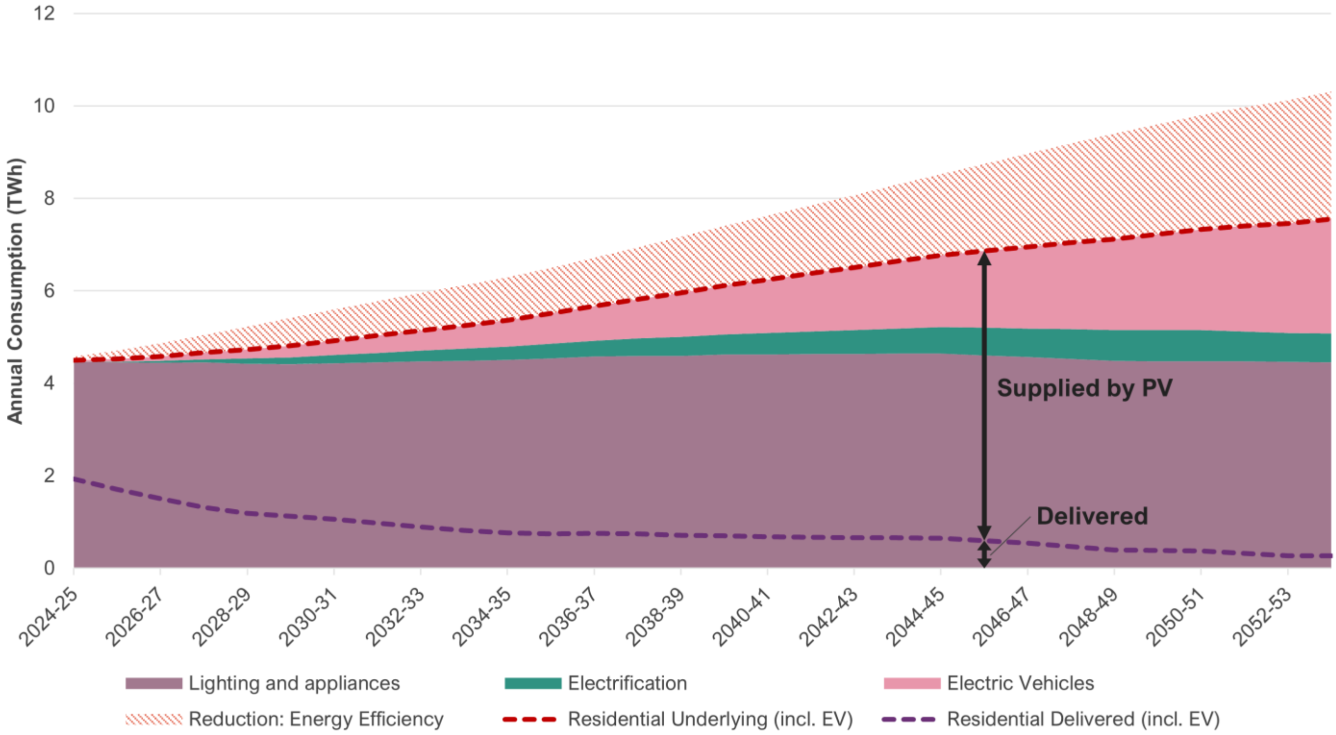
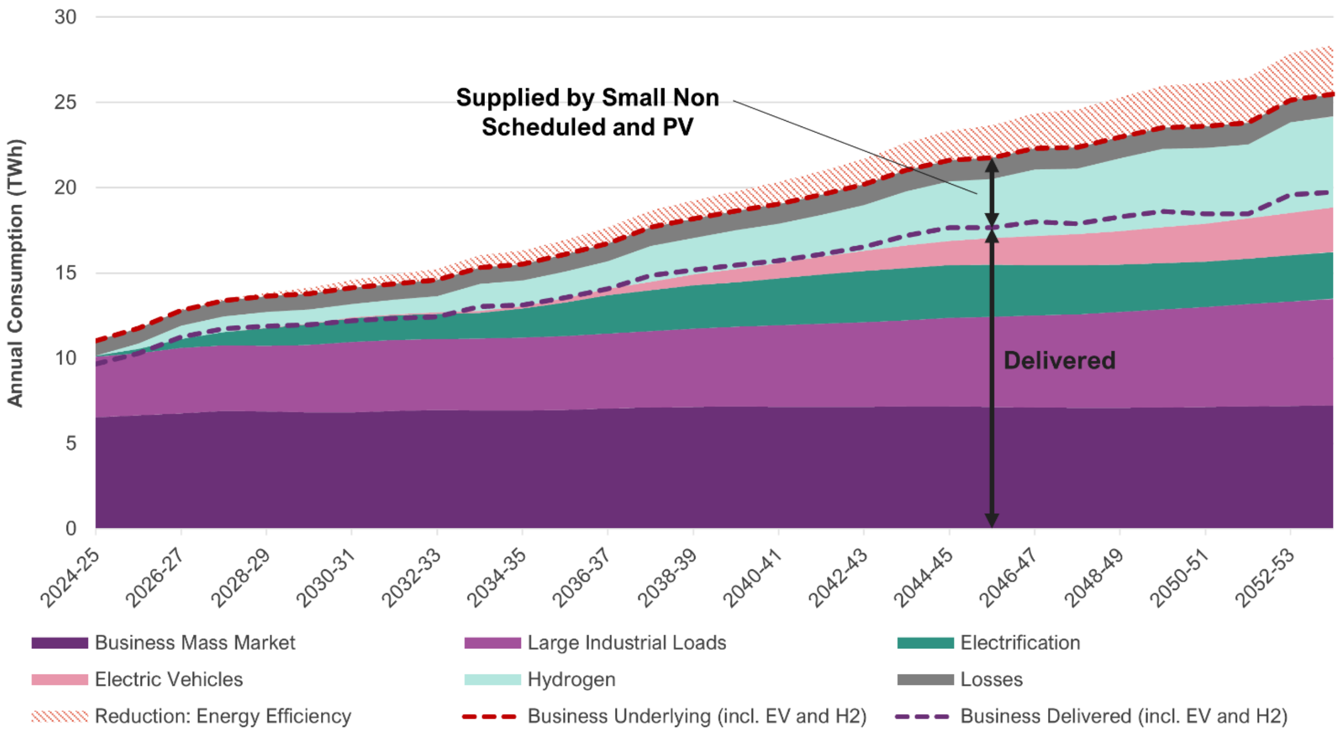


Figure 67 Components of South Australia business electricity consumption forecast, ESOO Central scenario, 2024-25 to 2053-54 (TWh)



Note: Small non-scheduled combines PVNSG and ONSG.

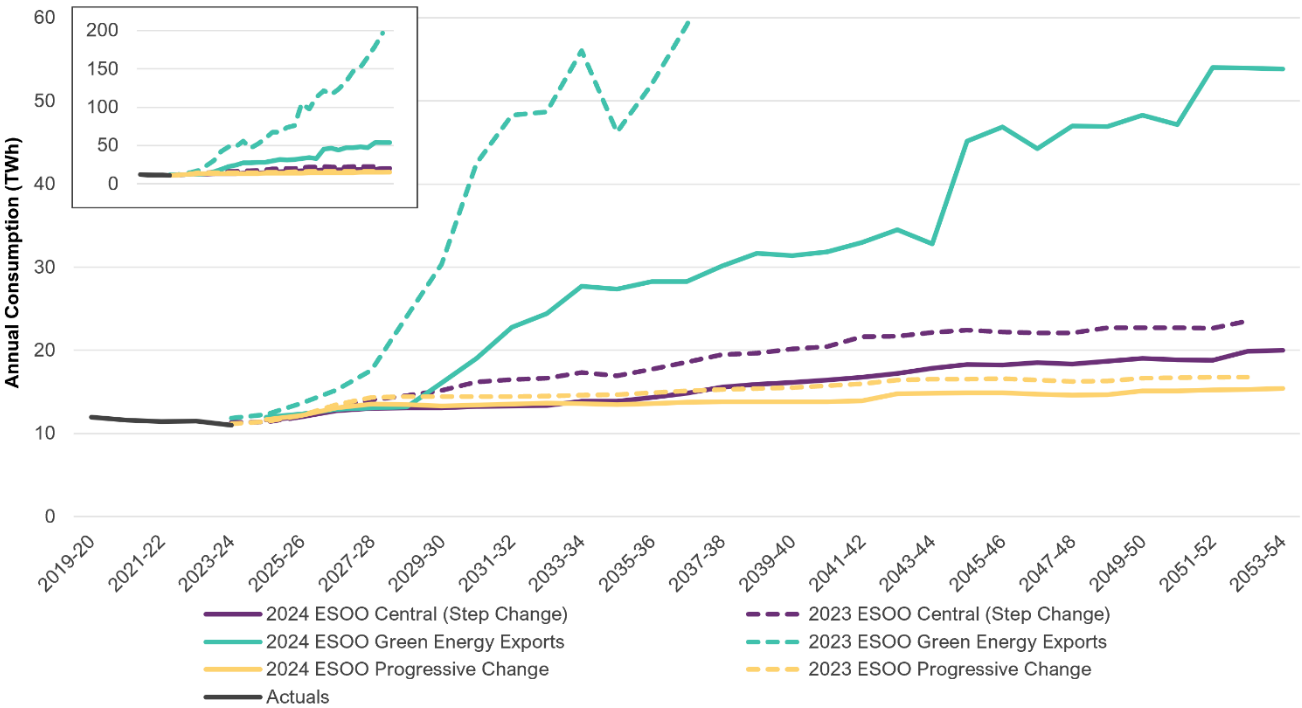
In this scenario, AEMO forecasts:

- Short term (1-10 years) – consumption growing steadily, driven by electrification, BMM load, hydrogen for domestic use and LIL consumption growth, tempered by continued uptake of distributed PV and energy efficiency investment. Growth in residential PV generation is expected to exceed the growth in other residential consumption drivers and reduce the overall operational consumption of that sector.
- Medium term (11-20 years) – increasing electrification, EV uptake and hydrogen for domestic use driving consumption up, partially offset by distributed PV and energy efficiency investments.
- Long term (21-30 years) – increasing domestic hydrogen use, EV uptake and growth in the business sector. Continued investment in PV and energy efficiency measures reduce the pace of operational consumption growth. The hydrogen produced for export is forecast to grow more slowly, whereas an increase in growth for domestic hydrogen is forecast, compared to the 2023 ESOO.

AEMO is aware of various industrial load developments in South Australia, and included a sensitivity in the 2024 ISP to explore the investment impacts of higher industrial load growth. This 2024 ESOO does not include industrial loads that have not met AEMO's commitment criteria, as per AEMO's *Electricity Demand Forecasting Methodology*.

Figure 68 shows forecasts across the scenarios.

Figure 68 Actual and forecast South Australia operational consumption, all scenarios, 2019-20 to 2053-54 (TWh)



Note: *2023 Green Energy Exports* continue beyond the chart to reach approximately 196 TWh in 2052-53.
Numerous industrial loads, particularly in northern South Australia, have been identified as potential load developments, but do not meet AEMO's commitment criteria for inclusion in the ESOO. Short and medium term growth could therefore increase above that which is forecast in the Central scenario, if these potential developments commit; AEMO's methodologies preclude these uncertain developments from being considered in the ESOO.

It highlights that:

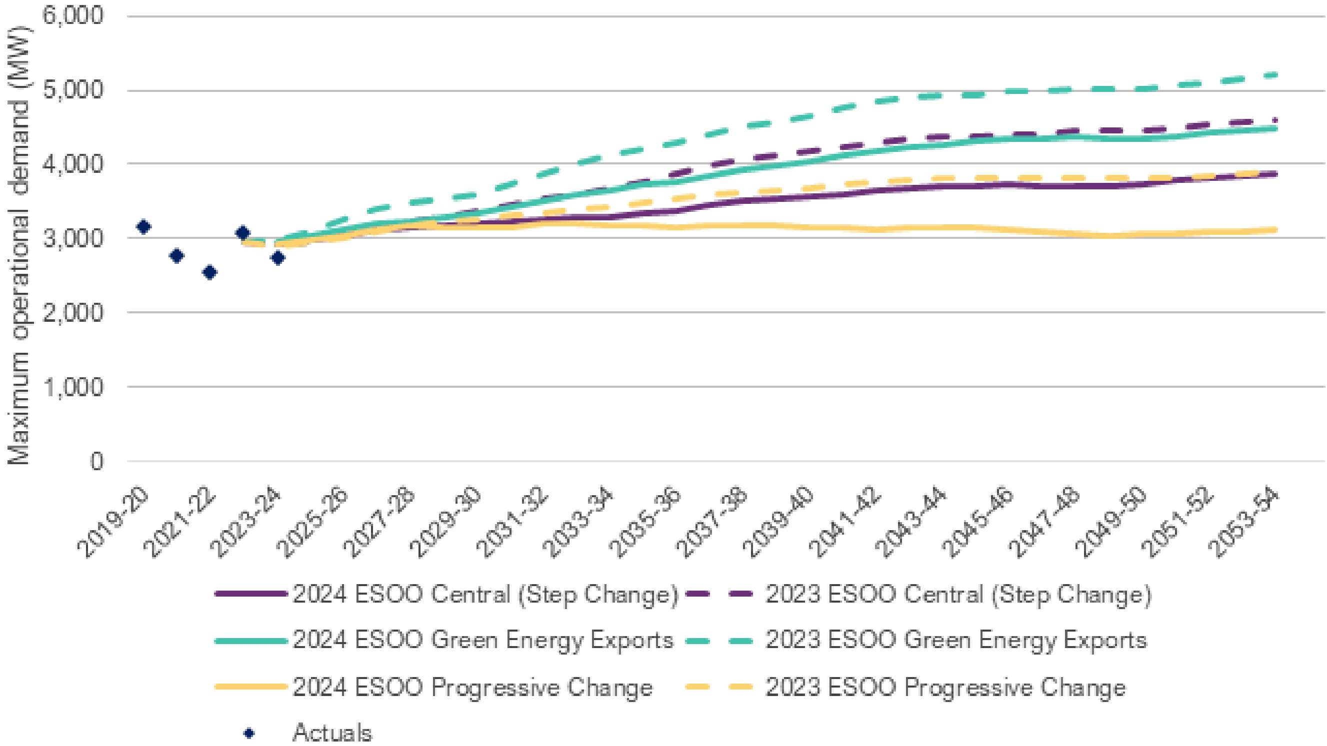
- *Progressive Change* tracks closely to the ESOO Central scenario until the mid-2030s, after which the BMM sector slows. Both scenarios show a slower growth than in the 2023 ESOO.

- A slower EV uptake in the ESOO Central scenario and a higher PV uptake in the *Prospective Change* scenario cause the lower forecasts in the 2024 ESOO compared with these scenarios in the 2023 ESOO.
- Hydrogen production for domestic and export purposes dominates the growth trajectory of *Green Energy Exports*. The growth in this scenario is lower than in the 2023 ESOO. This is mainly due to a reduced forecast of hydrogen export. Domestic hydrogen consumption in the *Green Energy Exports scenario* is forecast to grow slightly faster than both the ESOO Central and the *Prospective Change* scenarios.

Maximum operational demand outlook

Figure 69 shows actual and forecast 50% POE maximum operational (sent-out) demand[129] from 2019-20 to 2053-54 for all scenarios in South Australia, compared to matching 2023 ESOO scenarios.

Figure 69 Actual and forecast South Australia 50% POE maximum operational (sent-out) demand, 2024 ESOO all scenarios and 2023 ESOO all scenarios, 2019-20 to 2053-54 (MW)



Note: The actuals displayed are not weather-corrected (therefore reflect observed demand under the prevailing weather conditions) or adjusted for system events and exclude DSP. Additionally, this definition excludes demand from scheduled loads, typically pumping load from pumped hydro energy storage or large-scale batteries, as well as hydrogen loads.

The key insights are:

- 2024-25 to 2033-34 (1-10 years):

[129] The maximum and minimum forecasts presented here differ slightly from the ESOO forecasts presented in Chapter 2 in assuming ongoing growth in the uptake of coordinated (VPP-operated) battery storage. In accordance with AEMO's updated methodology, forecast growth that is not committed is assumed to be un-coordinated in the ESOO forecast. The ESOO thus has more un-coordinated batteries, and only those are reflected in the demand forecast, while VPP is modelled as supply and excluded from the forecasts presented here in the appendix. Both forecasts can be viewed at AEMO's Forecasting Portal: https://forecasting.aemo.com.au/.

- Across all scenarios, there is steady growth in demand driven by growth for EV and, to a lesser extent, for electrification and LILs for the first five years in the forecast horizon.
- For the *ESOO Central* scenario, from 2028 onwards, the 2024 ESOO forecast increases at a slower rate compared to the 2023 ESOO primarily due to lower EV forecasts. Similar trends are observed for *Progressive Change*.
- For the *Green Energy Exports* scenario, the 2024 ESOO forecasts are lower than 2023, due mainly to lower EV and lower LIL forecasts.

- 2034-35 to 2043-44 (11-20 years):
  - For the *ESOO Central* scenario, the forecasts increase at a steady rate but are lower than in the 2023 ESOO. This is driven by lower EV uptake and, to a lesser extent, lower LIL, BMM, and residential consumption forecasts.
  - For the *Green Energy Exports* scenario, demand increases at a steady rate but lower than in the 2023 ESOO, mainly due to lower EV uptake, and to a lesser extent, lower LIL, electrification, and residential consumption forecast. These lower values are partially offset by higher BMM.
  - For the *Progressive Change* scenario, aggregate regional demand is not forecast to increase, as BMM consumption growth is soft, offset by energy efficiency investments and offsetting the impact of increasing EV uptake.
- 2044-45 to 2053-54 (21-30 years) growth in the scenarios flattens relative to other periods.

Table 31 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 South Australia is forecast to continue occurring in the summer season over the forecast horizon.

Table 31 South Australia summer and winter 10% and 50% POE maximum operational (sent-out) demand forecast, *ESOO central* scenario, 2024-25 to 2049-50 (MW)

Financial year	Summer		Calendar year	Winter	
	10% POE	50% POE		10% POE	50% POE
2024-25	3,383	2,975	2025	2,751	2,678
2029-30	3,610	3,192	2030	3,066	2,976
2039-40	3,974	3,575	2040	3,596	3,475
2049-50	4,038	3,689	2050	3,907	3,746

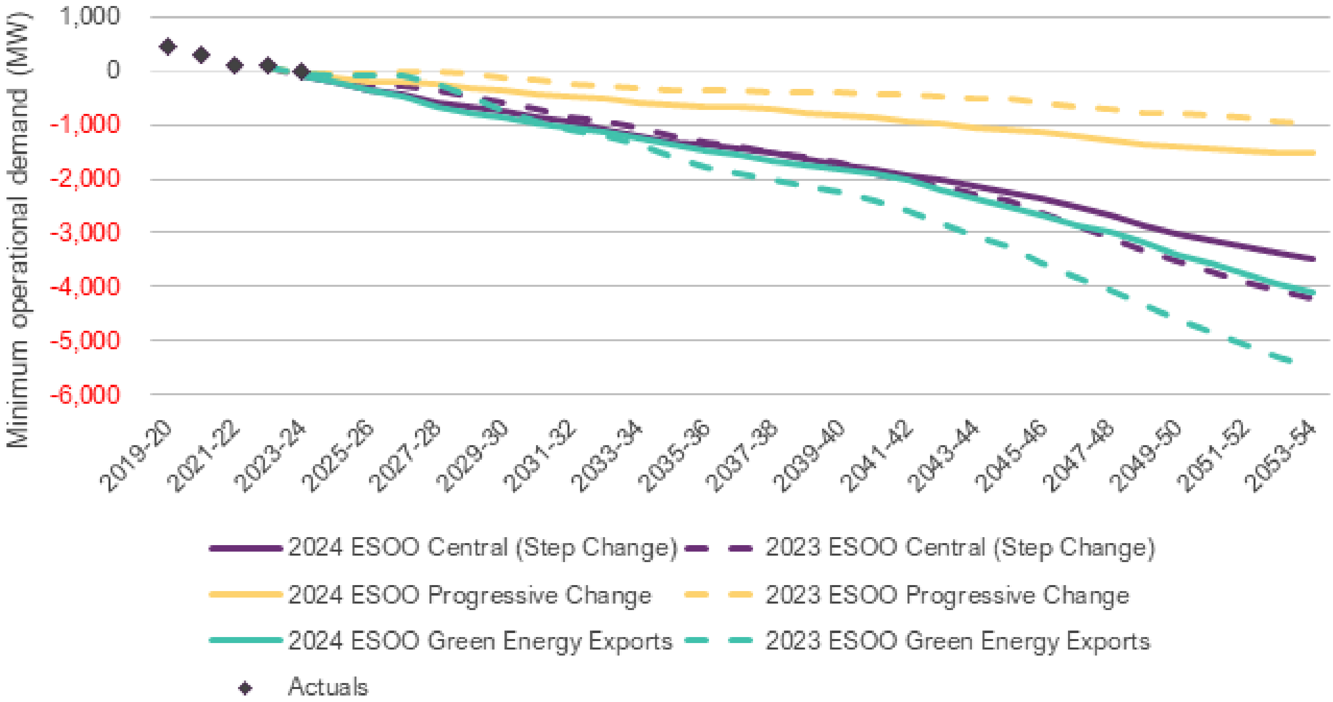
Minimum operational demand outlook

Figure 70 shows actual and forecast 50% POE minimum operational (sent-out) demand (MW) from 2019-20 to 2053-54 for the 2024 ESOO compared to the 2023 ESOO for all scenarios in South Australia. Minimum operational demand is strongly linked to PV capacity, with minimums occurring frequently during daytime hours. The key insights are:

- For the ESOO Central scenario, the minimum demand forecast shows a similar pattern to the 2023 forecast, and they both decline with a steady rate albeit stronger rate in this 2024 ESOO forecast due to PV capacity and lower EV uptake.
- For the *Green Energy Exports* scenario, up to 2032, the forecast of minimum demand for 2024 ESOO is lower compared to 2023 ESOO, driven by higher PV forecasts of 2024 ESOO during this period. However, from 2032 to 2034, minimum demand forecasts for 2024 ESOO become higher than 2023 ESOO, driven by lower PV and PVNSG forecasts.

- For the *Progressive Change* scenario, forecasts for 2024 ESOO are lower than 2023 ESOO, driven by higher PV uptake and lower EV uptake.

Figure 70 Actual and forecast South Australia 50% POE minimum operational (sent-out) demand, 2024 ESOO all scenarios and 2023 ESOO all scenarios, 2019-20 to 2053-54 (MW)



Note: The actuals displayed are not weather-corrected (therefore reflect observed demand under the prevailing weather conditions) or adjusted for system events and exclude DSP. Additionally, this definition excludes demand from scheduled loads, typically pumping load from pumped hydro energy storage or large-scale batteries, as well as hydrogen loads.

Supply adequacy assessment

Table 32 lists all committed and anticipated generator and storage projects included in the *Committed and Anticipated Investments* sensitivity in South Australia, while **Figure 71** shows the aggregate impact of generator and storage commissioning and decommissioning assumptions on assumed capacity during typical summer conditions.

Table 32 South Australia anticipated and committed generators and storages in *Committed and Anticipated Investments* sensitivity

Site name	Commitment status	Technology type	Nameplate capacity (MW)	Storage capacity (MWh)	Participant provided full commercial use date	Modelled commissioning date
Blyth BESS	Committed	Storage – Battery	200	400	Dec-24	Jun-25
Bungama Solar	Anticipated	Storage – Battery	150	300	Oct-25	Oct-26
Clements Gap – BESS	Committed	Storage – Battery	60	120	May-26	Nov-26
Cultana Solar Farm	Anticipated	Solar PV – Single axis tracking	357	0	Jul-26	Jul-27
Goyder South Wind Farm 1A	Committed	Wind Turbine – Onshore	209	0	Dec-24	Jun-25

Site name	Commitment status	Technology type	Nameplate capacity (MW)	Storage capacity (MWh)	Participant provided full commercial use date	Modelled commissioning date
Goyder South Wind Farm 1B	Committed	Wind Turbine – Onshore	204	0	Dec-24	Jun-25
Hydrogen Jobs Plan	Anticipated	Turbine – OCGT	204	0	Dec-25	Dec-26
Lincoln Gap Wind Farm – BESS	Anticipated	Storage – Battery	10	10	Sep-24	Jul-26
Mannum BESS	Anticipated	Storage – Battery	100	200	Sep-25	Sep-26
Templers BESS	Committed	Storage – Battery	111	291	Aug-25	Feb-26

Figure 71 South Australia assumed capability during typical summer conditions, by generation type, 2023-24 to 2033-34 (MW)

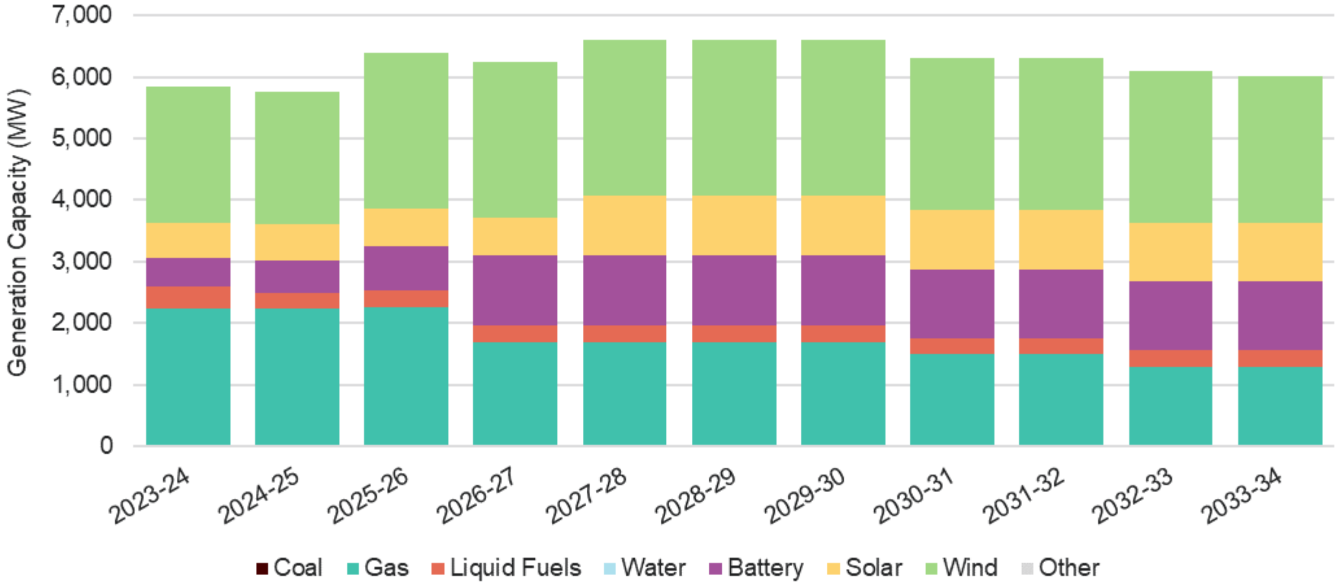


Figure 72 shows forecast USE for South Australia under the relevant modelled scenarios and sensitivities. It shows that:

- Under the *Committed and Anticipated Investments* sensitivity, expected USE is forecast above the IRM in 2024-25, before decreasing in 2025-26 when Blyth BESS and Goyder South Wind Farms 1A and 1B are completed. Should all currently committed and anticipated projects be delivered to their advised schedules, then reliability risks would lower to within the IRM, as forecast in the *On-time Delivery* sensitivity.
- From 2026-27, forecast risks increase materially due to the advised retirement of Osborne Power Station and Torrens Island B Power Station, with expected USE forecast above the IRM.
- From 2027-28, the advised availability of the full transfer capacity of Project EnergyConnect Stage 2 reduces reliability risks significantly, allowing better connection between South Australia, Victoria and New South Wales.
- In 2033-34, expected USE increases due to announced retirements of gas and liquid fuel generators in South Australia, and the impact of Bayswater and Vales Point power stations closure in New South Wales.
- Compared to the 2023 ESOO and May 2024 Update to the ESOO:

  - USE is lower over most of the horizon, due to lower demand forecasts as well as the inclusion of new projects such as the 200 MW Hydrogen Jobs Plan hydrogen generator (which has been included since the May 2024 Update to the 2023 ESOO), Mannum BESS and Bungama Solar (newly included in this 2024 ESOO).
  - In 2024-25, reliability risks have increased since previous publications due to the advised mothballing of Torrens Island B1, Port Lincoln and Snuggery power stations in South Australia, and a revised network configuration in Victoria that reduces risks across both regions but allocates a greater portion of the risk to South Australia. Reliability risks have further increased in 2026-27 due to revised dates for the full capacity release of Project EnergyConnect Stage 2 (included since the May 2024 Update to the 2023 ESOO).
- Under the *Actionable transmission and coordinated CER* sensitivity, expected USE is forecast below the relevant standard except for in 2026-27 and 2033-34 where retirement of generation in South Australia and New South Wales increases supply scarcity. Additional assumed capacity developments under the *Federal and State Schemes* sensitivity, including the first tender of the Victoria and South Australia Capacity Investment Scheme tender and coordinated CER developments, are shown to largely address the reliability risks in 2026-27 and beyond.

Figure 72 South Australia expected USE, scenarios and sensitivities, 2024-25 to 2033-34

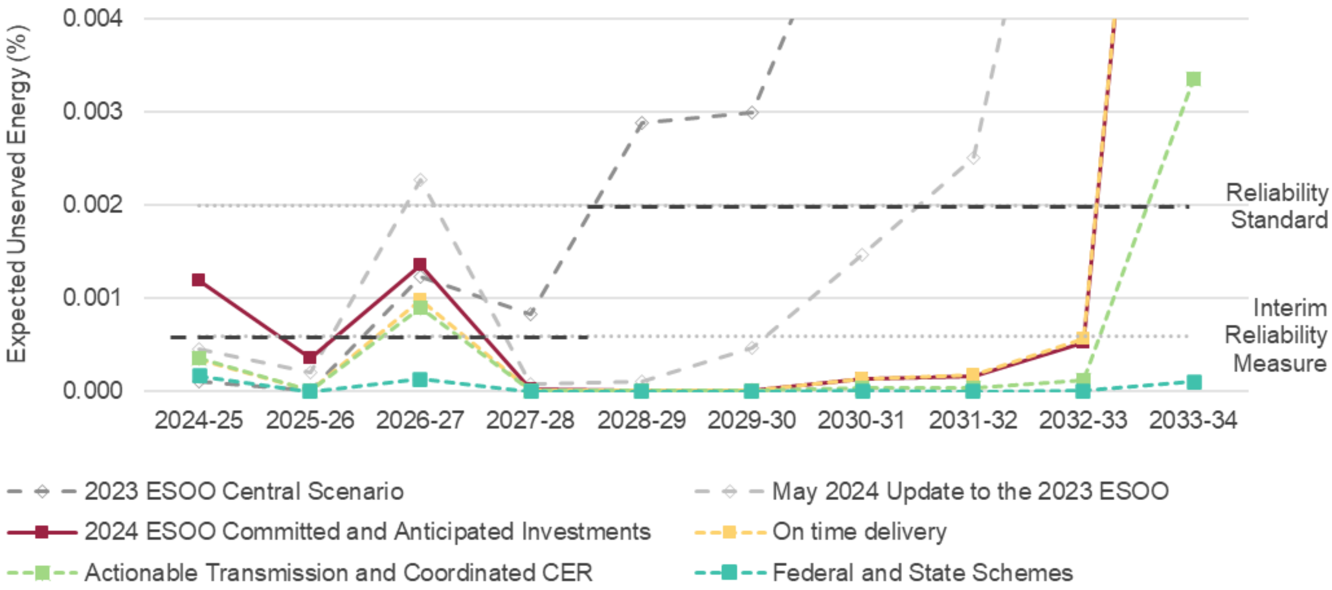


Figure 73 shows the reliability outcomes for South Australia in 2024-25 under different weather years, demonstrating the significant variance that is expected depending upon the weather conditions (affecting consumer load profiles, as well as renewable generator resources).

Figure 73 Reliability outcomes for South Australia in 2024-25 under different weather reference years, *Committed and Anticipated Investments* sensitivity

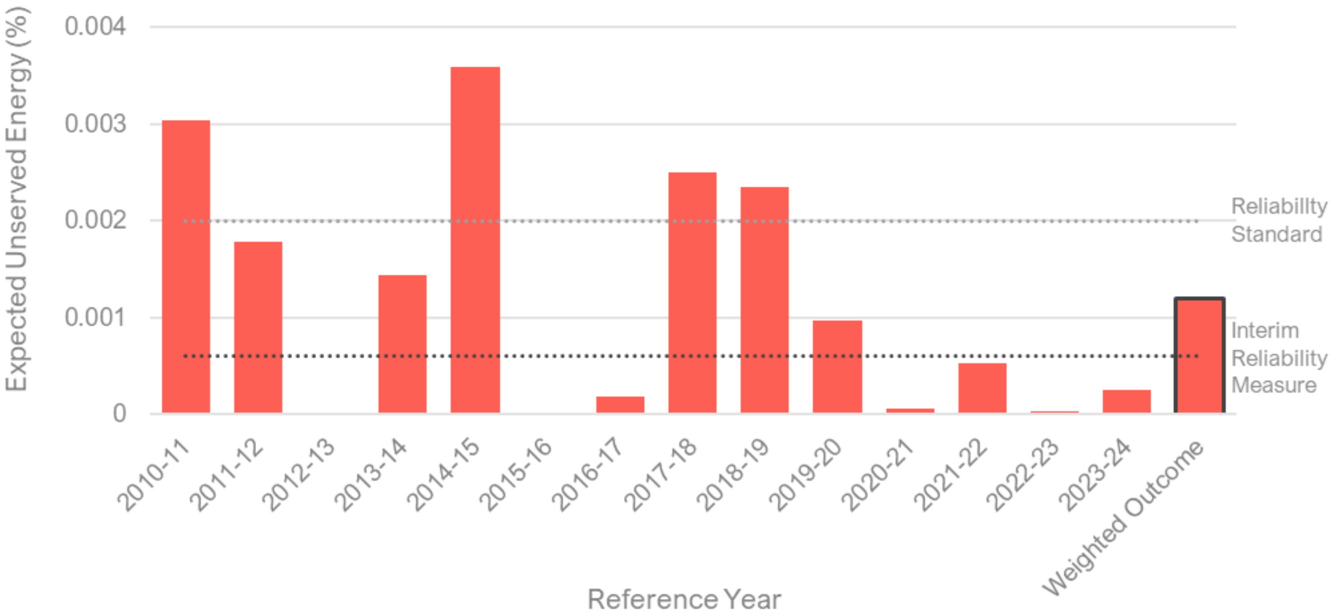
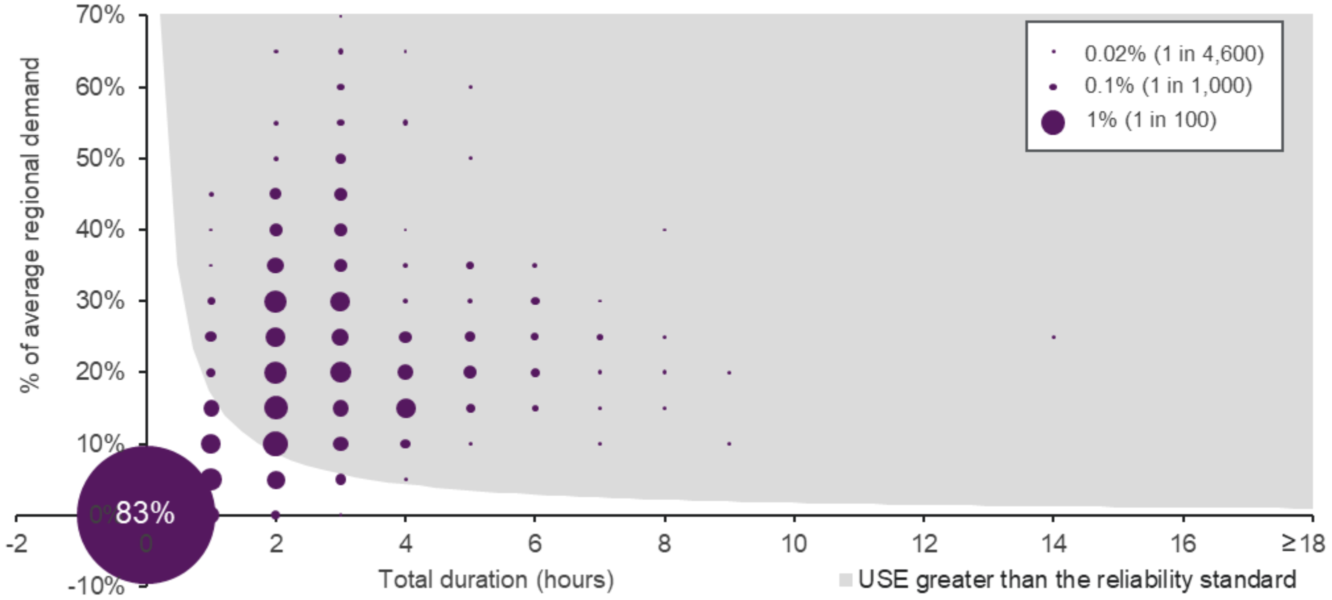


Figure 74 shows a bubble plot of the depth and duration of USE forecast in South Australia for 2024-25 in the *Committed and Anticipated Investments* sensitivity, as also shown in **Section 5.2**. It shows that the most likely outcome for South Australia is that USE does not occur in the coming year (the large purple dot), but that there is a 17% probability of a USE outcome. For those simulations that did have USE, the total number of hours unserved was likely to be up to four hours in duration, and of average depth up to 35% of average regional demand.

Figure 74 Bubble plot of depth and duration of forecast USE in South Australia 2024-25, *Committed and Anticipated Investments* sensitivity



A4. Tasmania outlook

The following sections present, for Tasmania:

- Operational consumption, maximum demand, and minimum demand outlooks for all three scenarios to 2053-54.
- Supply adequacy assessments for the next 10 years, for the *Committed and Anticipated Investments* sensitivity, and other sensitivities published in this ESOO.

Annual consumption outlook

Figure 75 to Figure 77 show the component forecasts for operational consumption in Tasmania under the ESOO Central scenario for the aggregate regional load, residential sector and business sector respectively.

Figure 75 Actual and forecast Tasmania electricity consumption, ESOO Central scenario, 2014-15 to 2053-54 (TWh)

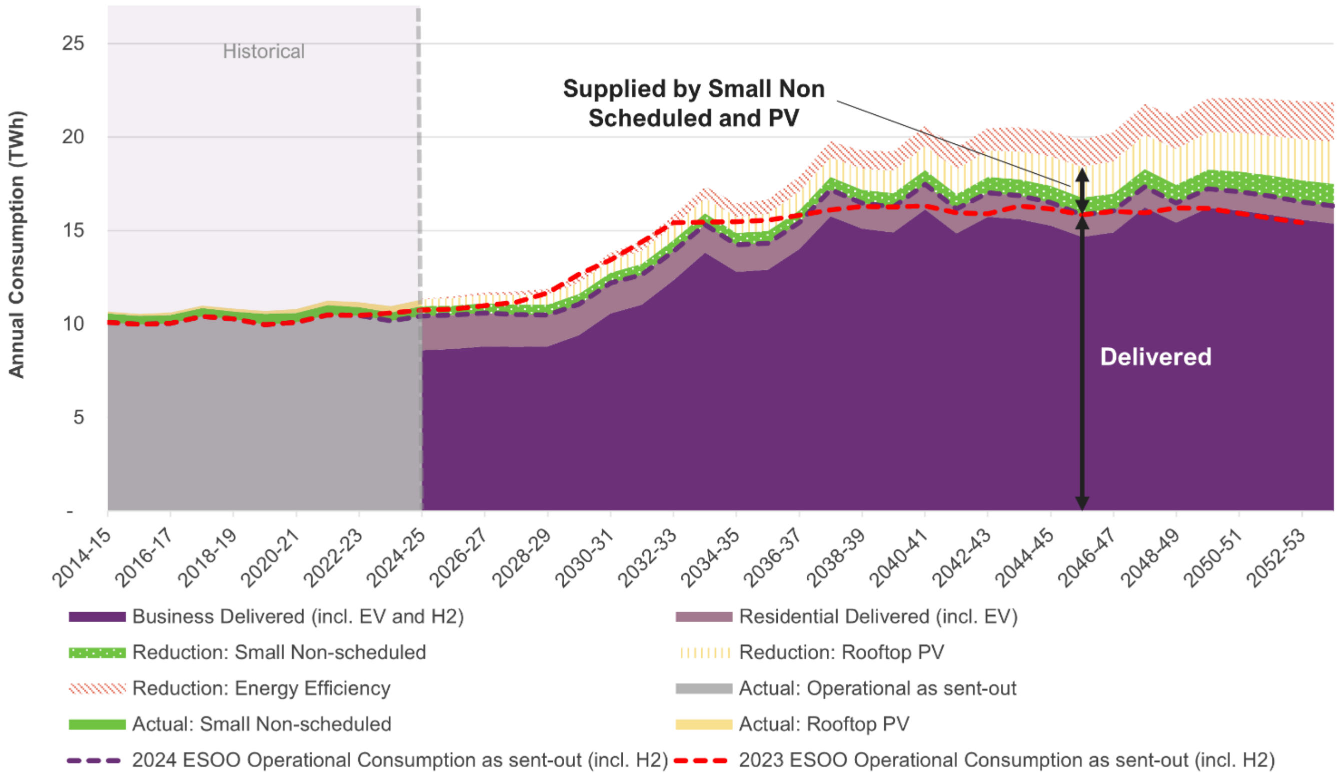


Figure 76 Components of Tasmania residential electricity consumption forecast, ESOO Central scenario, 2024-25 to 2053-54 (TWh)

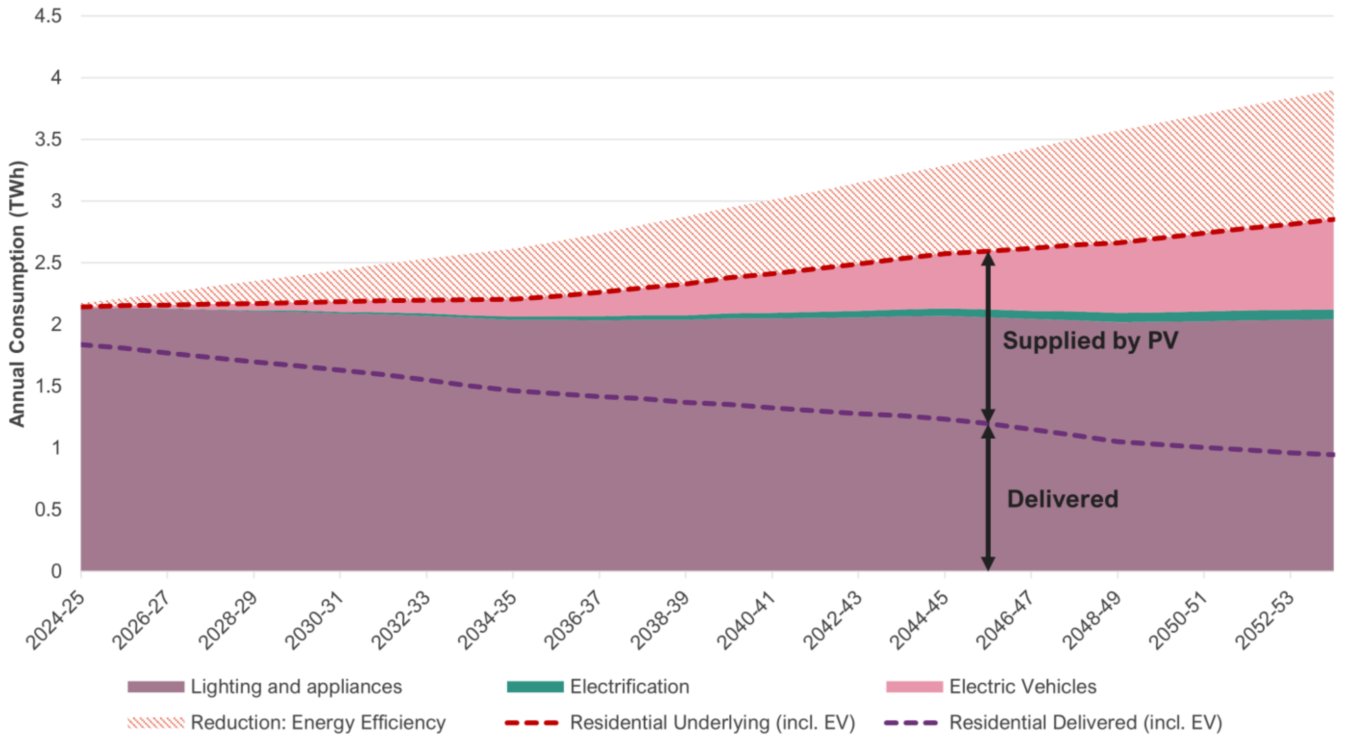
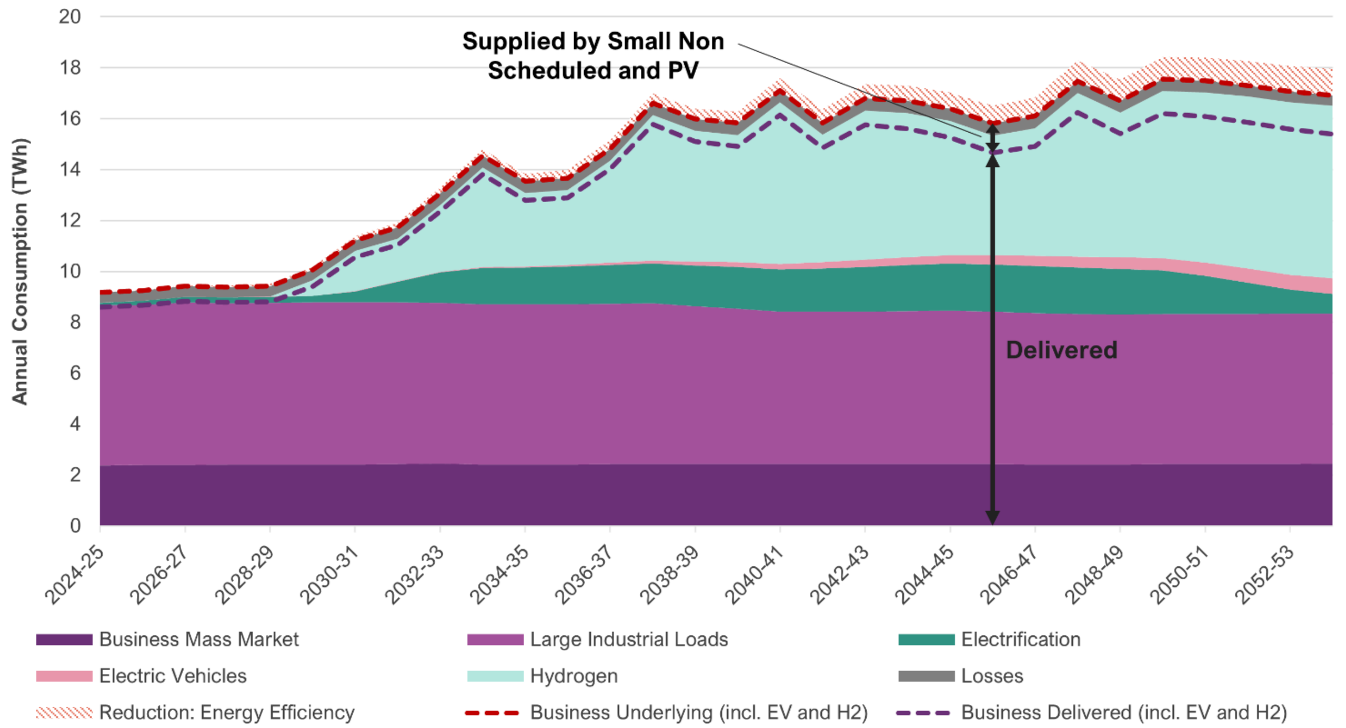


Figure 77 Components of Tasmania business electricity consumption forecast, ESOO Central scenario, 2024-25 to 2053-54 (TWh)



Note: Small non-scheduled combines PVNSG and ONSG.

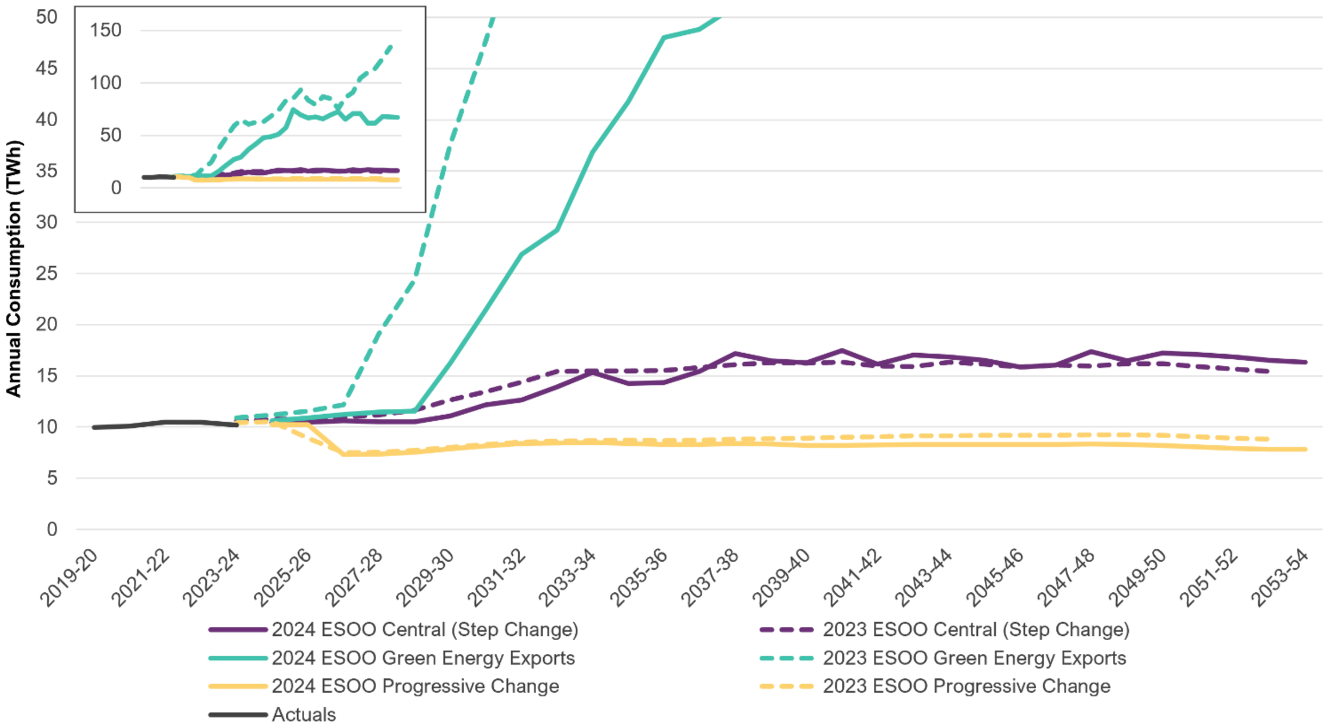
In this scenario, AEMO forecasts:

- Short term (1-10 years) – a relatively flat outlook until a rise in business consumption in the early 2030s, stemming from the anticipated emergence of a hydrogen production industry in addition to business electrification.
- Medium term and long term (11-20 years and 21-30 years) – similar growth trajectories as presented in the 2023 ESOO. Electrification and hydrogen development are forecast to continue to progress, with electrification growth particularly forecast for the agricultural sector. EVs are forecast to be progressively adopted in Tasmania, although at a slower pace than was projected in the 2023 ESOO. Both households and businesses are forecast to become more energy efficient and to increasingly invest in larger PV systems; both serve to reduce grid-supplied energy (although less growth is forecast for Tasmania than other mainland NEM regions due to lower solar yields for the southern-most region of the NEM).

Figure 78 shows forecasts across the scenarios, highlighting that:

- *Progressive Change* follows a similar trajectory to the 2023 ESOO, and continues to explore the impact of potential LIL closure risk. Decarbonisation drivers such as electrification and particularly domestic hydrogen use are lower relative to the ESOO Central scenario.
- *Green Energy Exports* considers a buoyant market for hydrogen exports and the production of green steel in Tasmania, and a stronger economy more generally. Under this scenario, energy consumption in Tasmania is forecast to grow rapidly through the 2030s with energy consumption to fuel hydrogen for export to exceed current Tasmanian operational consumption by a factor of four.

Figure 78 Actual and forecast Tasmania operational consumption, all scenarios, 2019-20 to 2053-54 (TWh)



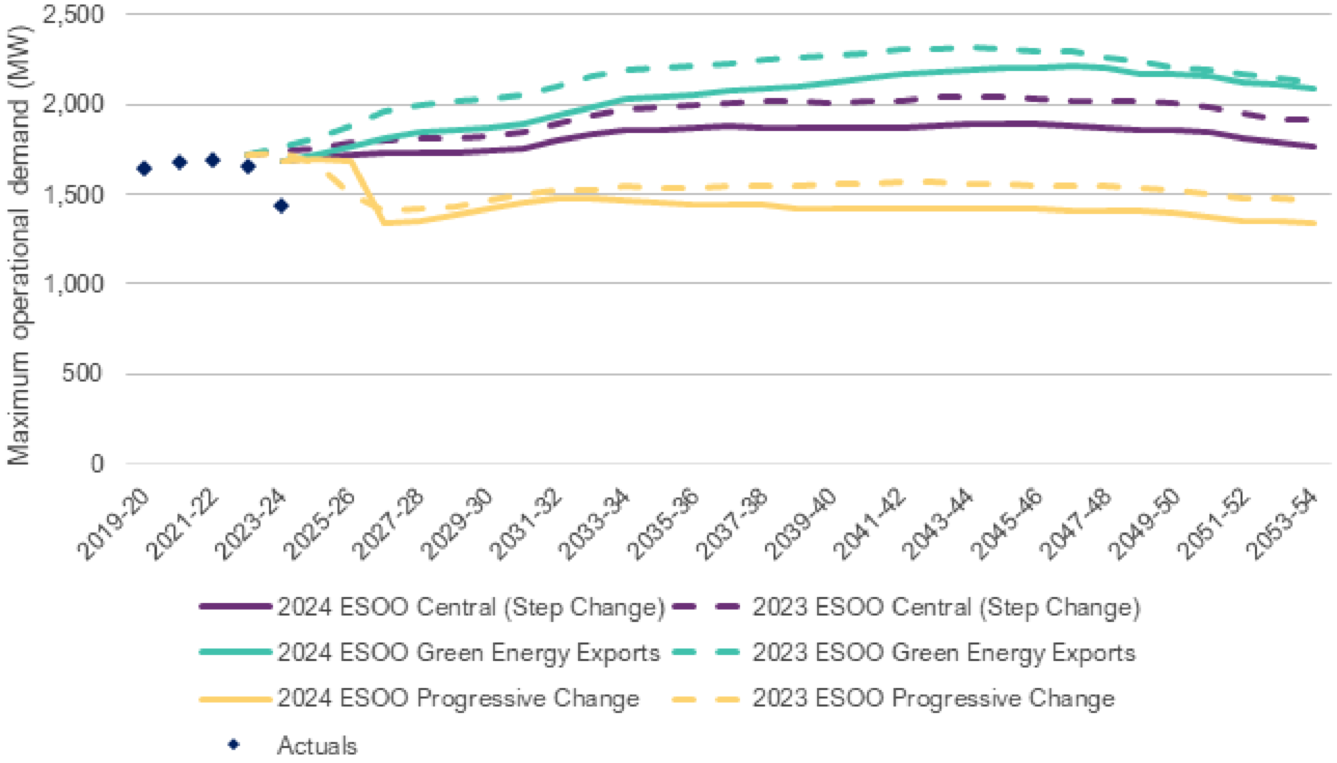
Note: 2023 ESOO and 2024 ESOO *Green Energy Exports* forecasts continue beyond the chart to reach approximately 134 TWh in 2052-53 and 67 TWh in 2053-54 respectively.

Maximum operational demand outlook

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.

Figure 79 shows actual and forecast 50% POE maximum operational (sent-out) demand[130] from 2019-20 to 2053-54 for all scenarios in Tasmania, compared to matching 2023 ESOO scenarios.

Figure 79 Actual and forecast Tasmania 50% POE maximum operational (sent-out) demand, 2024 ESOO all scenarios and 2023 ESOO all scenarios, 2019-20 to 2053-54 (MW)



Note: The actuals displayed are not weather-corrected (therefore reflect observed demand under the prevailing weather conditions) or adjusted for system events and exclude DSP. Additionally, this definition excludes demand from scheduled loads, typically pumping load from pumped hydro energy storage or large-scale batteries, as well as hydrogen loads. The key insights are:

- 2024-25 to 2033-34 (1-10 years):
  - Maximum demand forecasts from the ESOO Central scenario remain relatively flat, while the *Green Energy Exports* scenario show a slight increasing trend, driven primarily from the BMM sector. As in other regions, the *Progressive Change* scenario explores risks of LIL closures.
  - Forecasts for all scenarios start to increase from the middle of this decade as electrification is forecast to increase in Tasmania.

130 The maximum and minimum forecasts presented here differ slightly from the ESOO forecasts presented in Chapter 2 in assuming ongoing growth in the uptake of coordinated (VPP-operated) battery storage. In accordance with AEMO's updated methodology, forecast growth that is not committed is assumed to be un-coordinated in the ESOO forecast. The ESOO thus has more un-coordinated batteries, and only those are reflected in the demand forecast, while VPP is modelled as supply and excluded from the forecasts presented here in the appendix. Both forecasts can be viewed at AEMO's Forecasting Portal: https://forecasting.aemo.com.au/.

  - Maximum operational demand forecasts are lower than the 2023 ESOO due to lower projections for the BMM and EV sectors.
- 2034-35 to 2043-44 (11-20 years) and 2044-45 to 2053-54 (21-30 years):
  - During the second decade of the 30-year forecast horizon, maximum demand forecasts from the ESOO Central scenario remain relatively flat, while those for the *Green Energy Exports* scenario steadily increase, following the rising trend in electrification and to a lesser-extent underlying consumption forecasts for BMM.
  - Maximum demand forecasts under the *Progressive Change* scenario continue to decrease and diverge from the 2023 ESOO forecasts due to declining BMM forecasts, also partially affected by a drop in LILs later in the forecast horizon
  - During the last 10 years of the forecast horizon, maximum operational demand forecasts from the ESOO Central scenario remain flat until 2049-50, then begin to decrease as electrification forecasts decline.

Table 33 shows maximum summer and winter operational demand (sent out) forecasts for 10% POE and 50% POE for the ESOO Central scenario. Maximum operational demand in Tasmania is forecast to continue occurring in the winter season over the forecast horizon.

Table 33 Tasmania summer and winter 10% and 50% POE maximum operational (sent-out) demand forecast, *Step Change* scenario, 2023-24 to 2049-50 (MW)

Financial year	Summer		Calendar year	Winter	
	10% POE	50% POE		10% POE	50% POE
2024-25	1,464	1,427	2025	1,759	1,704
2029-30	1,479	1,445	2030	1,791	1,737
2039-40	1,582	1,559	2040	1,922	1,862
2049-50	1,560	1,537	2050	1,929	1,861

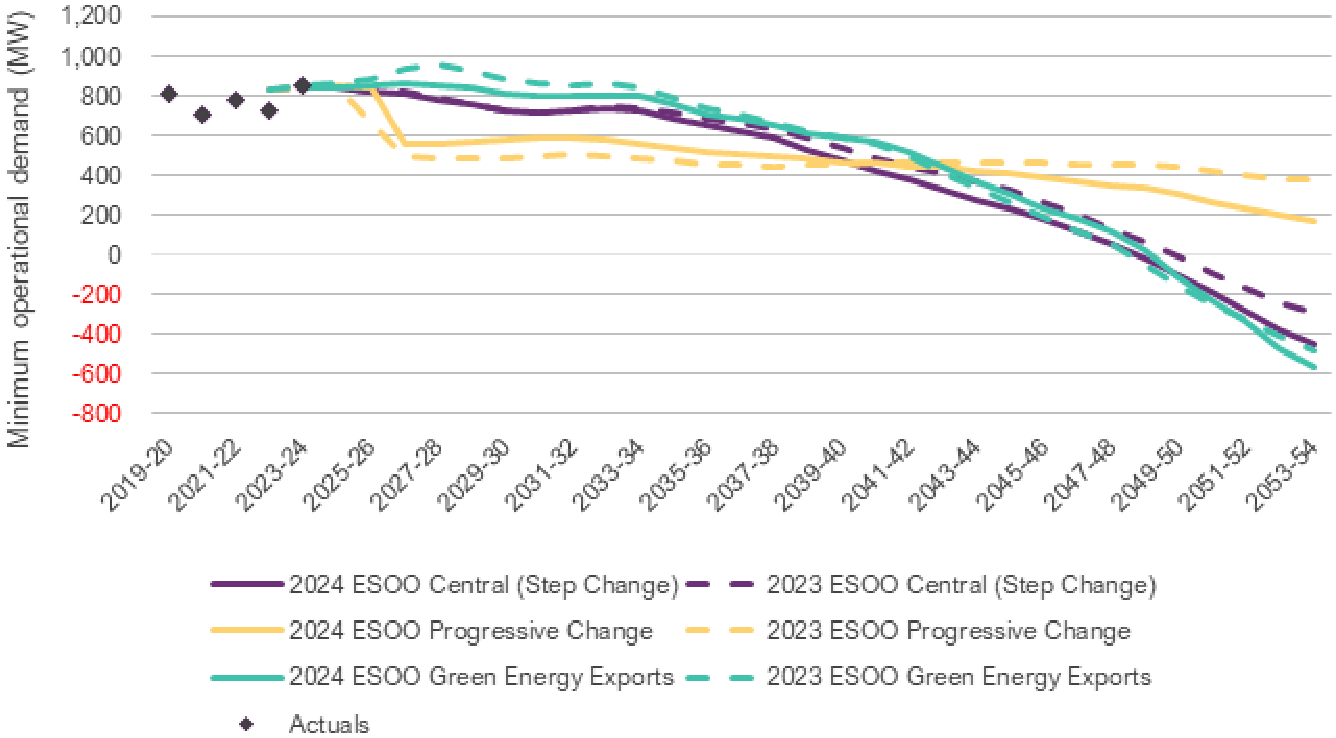
Minimum operational demand outlook

Figure 80 shows actual and forecast 50% POE minimum operational (sent-out) demand (MW) from 2019-20 to 2053-54 for the 2024 ESOO compared to the 2023 ESOO for all scenarios in Tasmania. Minimum operational demand is strongly linked to PV capacity, with minimums occurring frequently during daytime hours.

The key insights are:

- Minimum operational demand forecasts under the ESOO Central scenario slightly decrease initially, due to growing electrification and EV uptake, however a declining trend emerges towards the early 2030's as trends impacting annual consumption influence the maximum demand forecasts.
- Similar overall trends are observed between the 2023 and 2024 forecasts.

Figure 80 Actual and forecast Tasmania 50% POE minimum operational (sent-out) demand, 2024 ESOO all scenarios and 2023 ESOO all scenarios, 2019-20 to 2053-54 (MW)



Note: The actuals displayed are not weather-corrected (therefore reflect observed demand under the prevailing weather conditions) or adjusted for system events and exclude DSP. Additionally, this definition excludes demand from scheduled loads, typically pumping load from pumped hydro energy storage or large-scale batteries, as well as hydrogen loads.

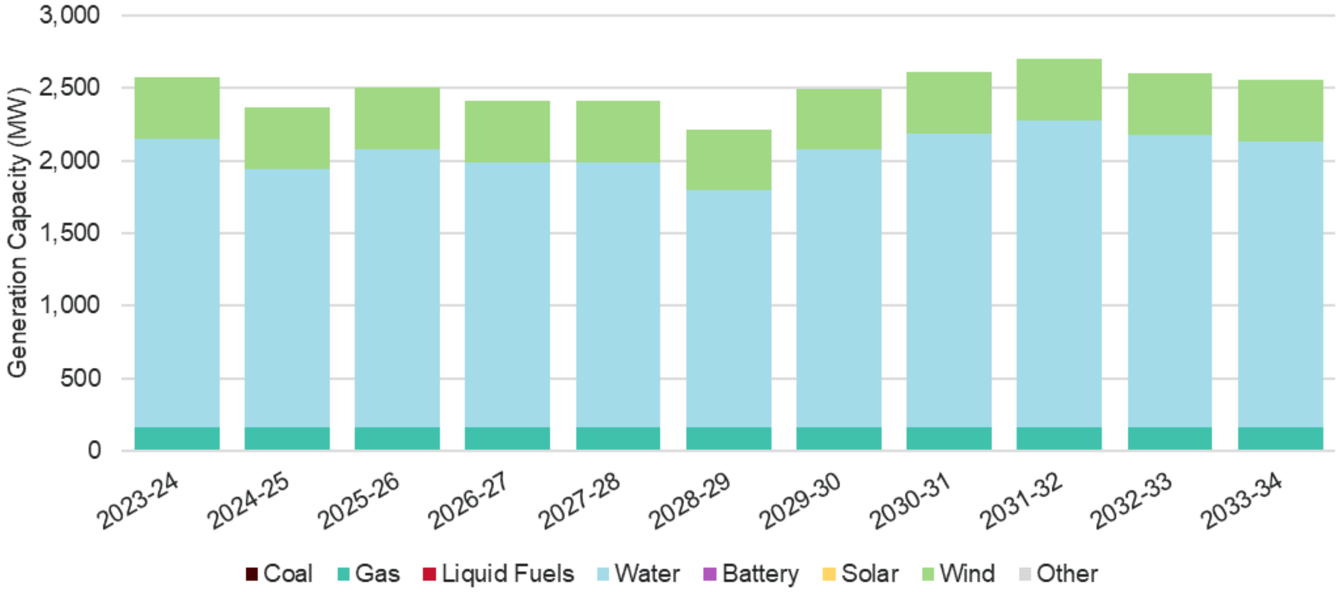
Supply adequacy assessment

There are currently no projects that are classified as either committed or anticipated in Tasmania, when compared against AEMO's commitment criteria.

Figure 81 shows the aggregate impact of generator and storage commissioning and decommissioning assumptions. The variation in the capacity for water shown in the figure represents seasonal maintenance plans, based on information provided by Hydro Tasmania. As Tasmania has greater capacity requirements in winter, summer maintenance schedules are typical.

No USE is forecast for Tasmania in any of the scenarios or sensitivities modelled in this ESOO.

Figure 81 Tasmania assumed capability during typical summer conditions, by generation type, 2023-24 to 2033-34 (MW)



A5. Victoria outlook

The following sections present, for Victoria:

- Operational consumption, maximum demand, and minimum demand outlooks for all three scenarios to 2053-54.
- Supply adequacy assessments for the next 10 years, for the *Committed and Anticipated Investments* sensitivity, and other sensitivities published in this ESOO.

Annual consumption outlook

Figure 82 to Figure 84 show the component forecasts for operational consumption in Victoria under the ESOO Central scenario for the aggregate regional load, residential sector and business sector respectively.

Figure 82 Actual and forecast Victoria electricity consumption, ESOO Central scenario, 2014-15 to 2053-54 (TWh)

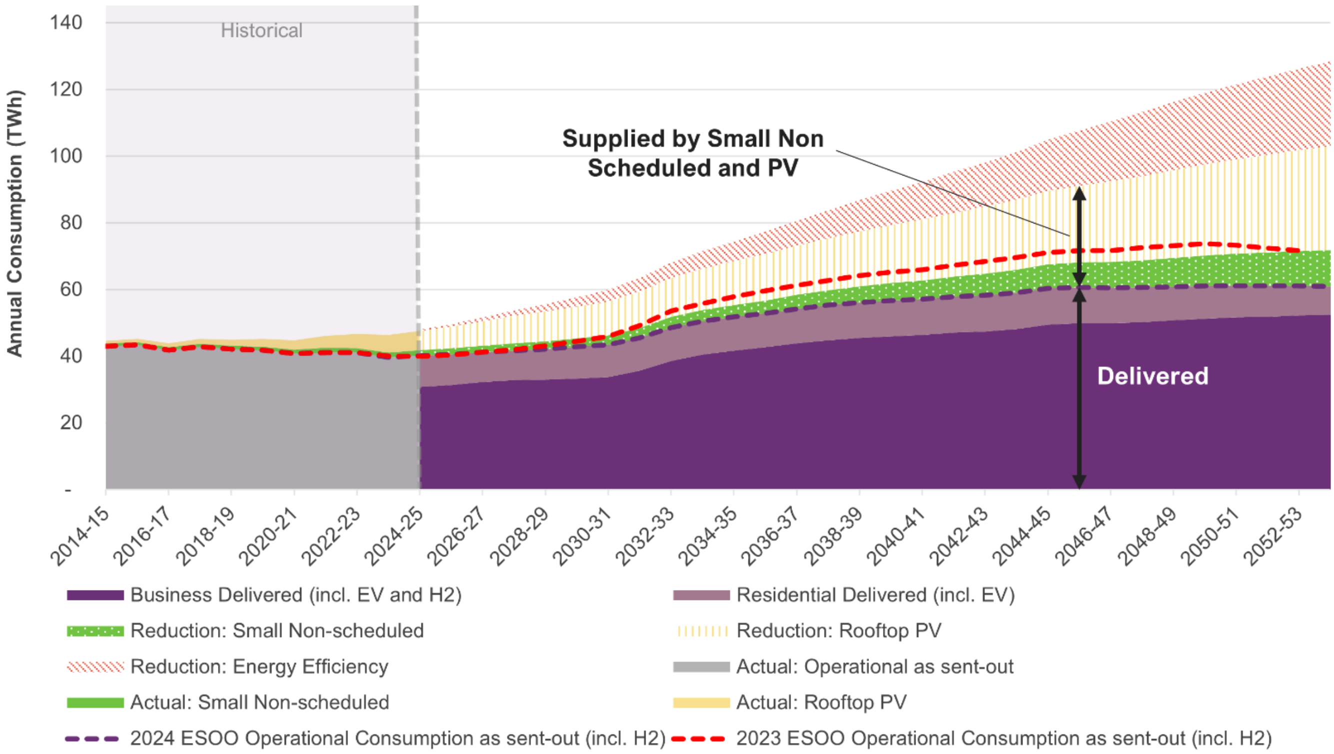


Figure 83 Components of Victoria residential electricity consumption forecast, ESOO Central scenario, 2024-25 to 2053-54 (TWh)

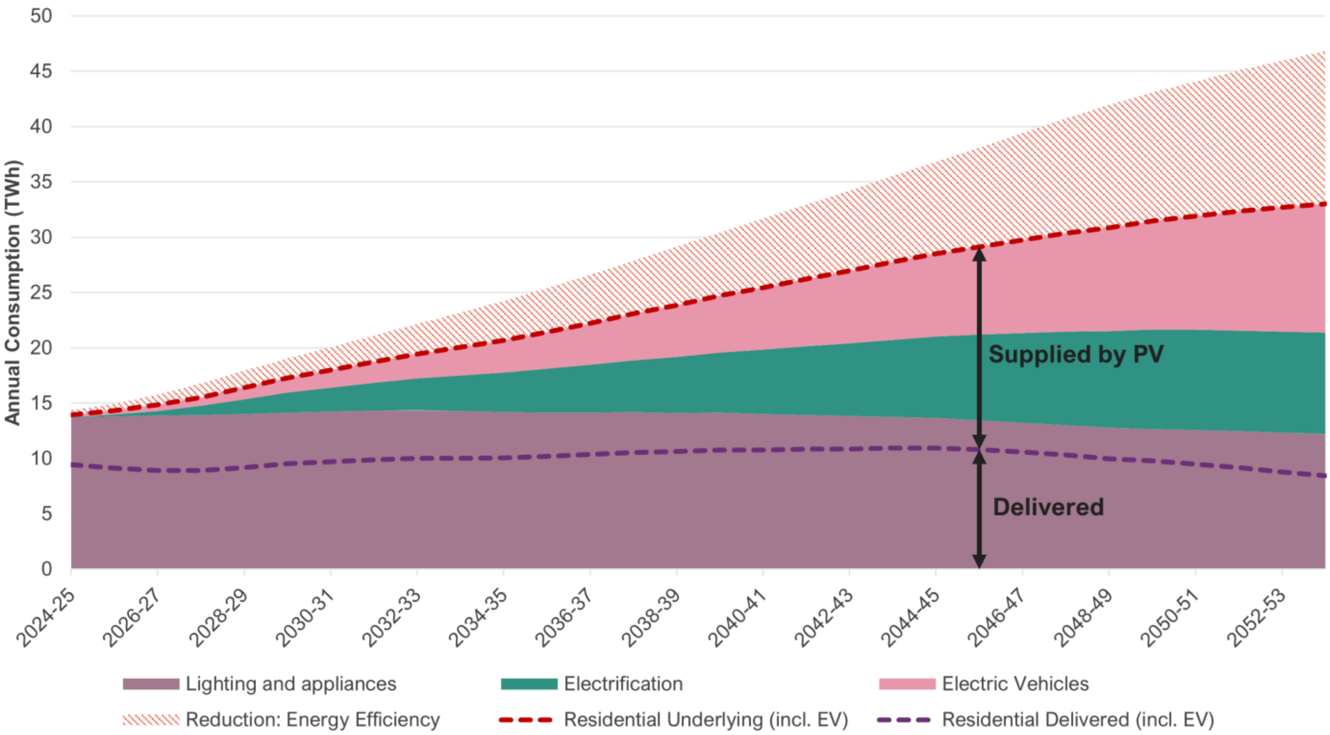
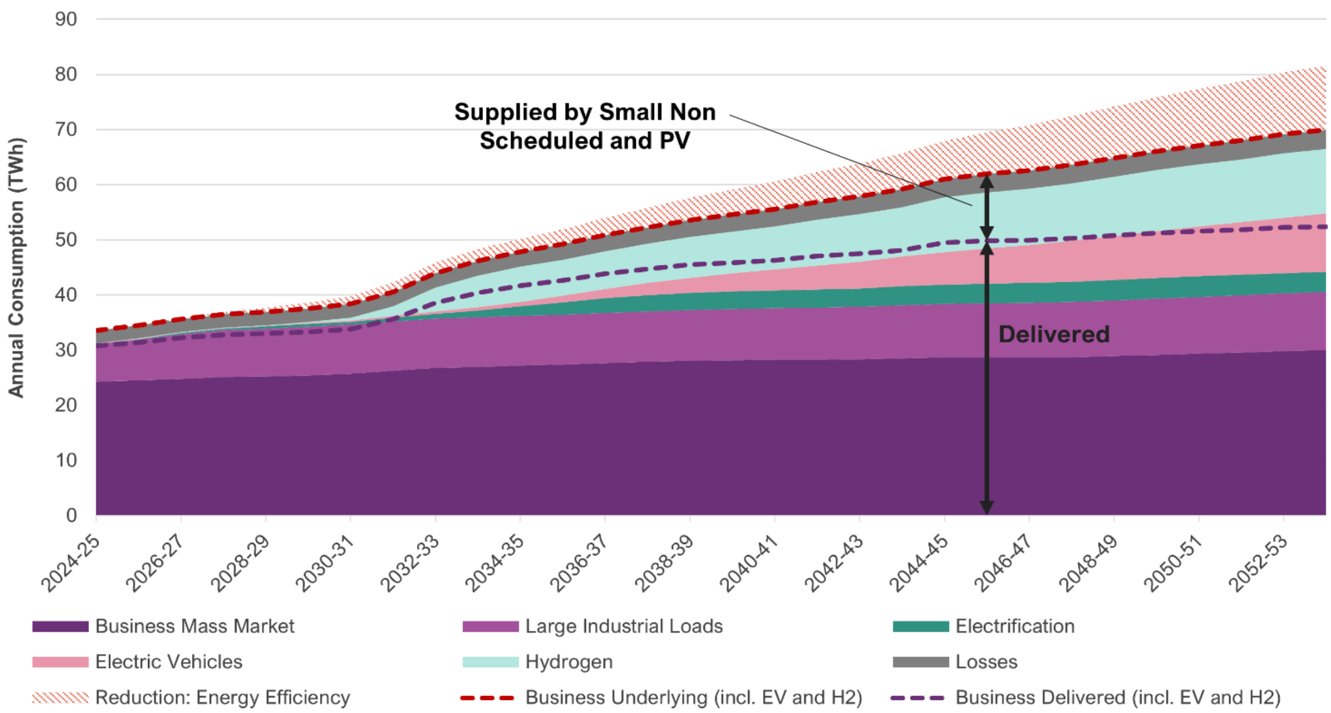


Figure 84 Components of Victoria business electricity consumption forecast, ESOO Central scenario, 2024-25 to 2053-54 (TWh)



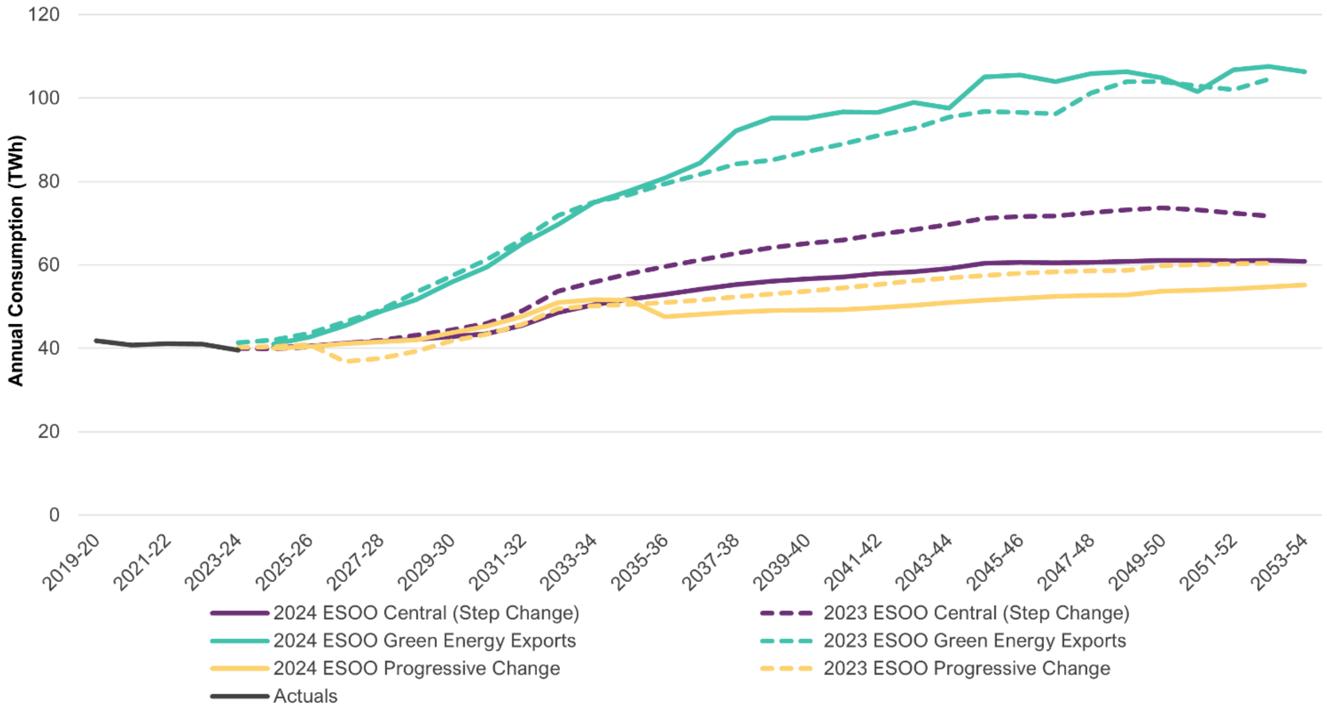
Note: Small non-scheduled combines PVNSG and ONSG.

In this scenario, AEMO forecasts:

- Short-term (1-10 years) – a gradual increase in consumption in the first half of the decade, mostly from growth in the business sector which is partially offset by uptake of residential and business PV. In the second half of the decade, domestic hydrogen production ramps up, leading to more pronounced growth in projected consumption despite a milder increase in LIL consumption compared to the first five years. EV adoption also rises, although at a less aggressive rate than in the 2023 ESOO for the same period[131].
- Medium-term (11-20 years) – growth in consumption extends into the medium term, driven by residential and business electrification, continued EV adoption, and domestic hydrogen production. Increases in consumption are offset by energy efficiency savings and PV uptake.
- Long-term (21-30 years) – while drivers of consumption growth continue at a similar rate to the previous decade, increased PV and energy efficiency result in a lower net increase in operational consumption.

Figure 85 shows forecasts across the scenarios.

Figure 85 Actual and forecast Victoria operational consumption, including hydrogen exports, all scenarios, 2019-20- to 2053-54 (TWh)



This figure highlights that:

- Prior to 2035, consumption in the *Progressive Change* scenario is similar to the ESOO Central scenario, higher in some years due to lower PV uptake. The scenario explores LIL closure risks, with industrial load consumption declining assumed in the early 2030s. Coupled with weaker economic activity and relatively lower electrification and hydrogen production, these differences lead to *Progressive Change* being lower than the ESOO Central scenario.

[131] The Victorian Government has banned gas connections in new homes and government buildings, which will likely most impact winter consumption. While the electrification adjustment accounts for customers partially or fully switching away from gas, the announcement has not been explicitly modelled in this ESOO.

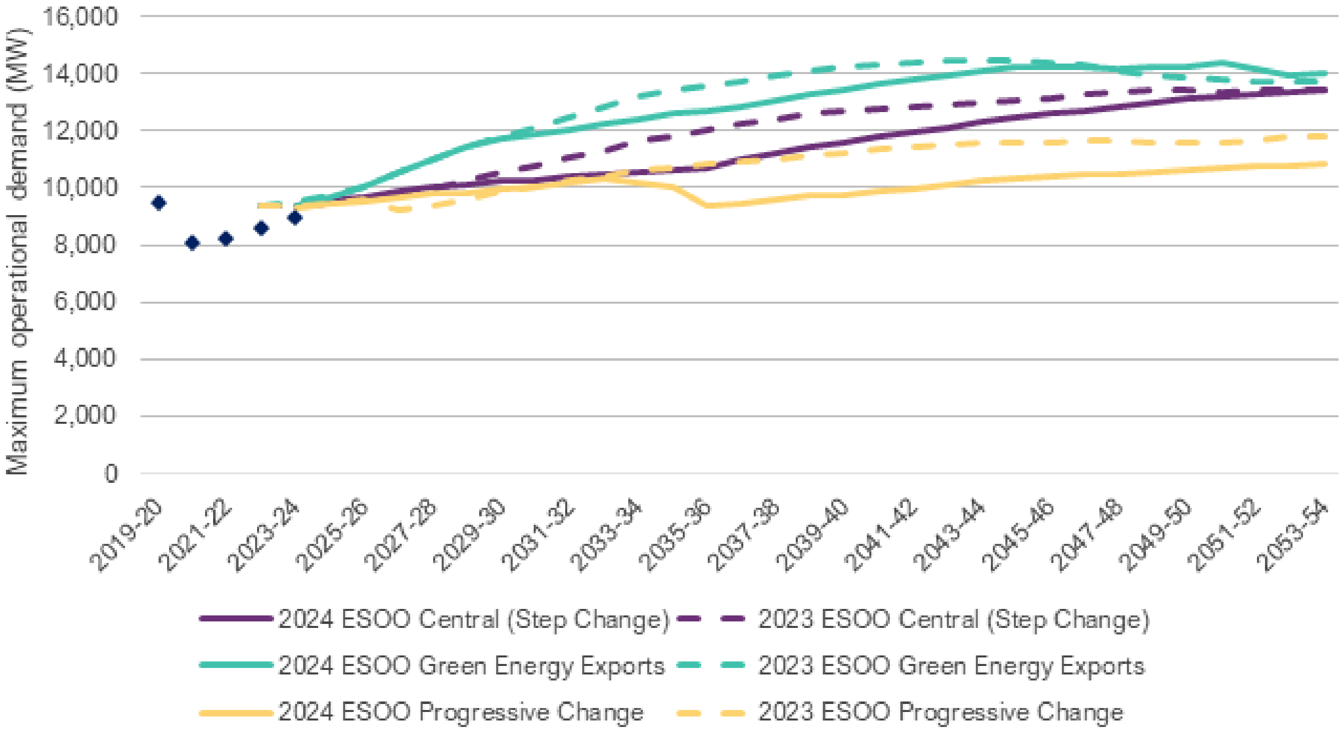
- Production of hydrogen dominates the *Green Energy Exports* growth trajectory. Domestic hydrogen production is projected to start a year later compared to the 2023 ESOO *Green Energy Exports* scenario but catches up by 2034. Production of hydrogen for export and green steel in Victoria is assumed to begin in 2028 in this scenario, accounting for 10 TWh of consumption or around one-third of all hydrogen production by 2044 and more than 20 TWh (45% of hydrogen production) in 2054.

Maximum operational demand outlook

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.

Figure 86 shows actual and forecast 50% POE maximum operational (sent-out) demand[132] 2019-20 to 2053-54 for all scenarios in Victoria, compared to matching 2023 ESOO scenarios.

Figure 86 Actual and forecast Victoria 50% POE maximum operational (sent-out) demand, 2024 ESOO all scenarios and 2023 ESOO all scenarios, 2019-20 to 2053-54 (MW)



Note: The actuals displayed are not weather-corrected (therefore reflect observed demand under the prevailing weather conditions) or adjusted for system events and exclude DSP. Additionally, this definition excludes demand from scheduled loads, typically pumping load from pumped hydro energy storage or large-scale batteries, as well as hydrogen loads.

The key insights are:

[132] The maximum and minimum forecasts presented here differ slightly from the ESOO forecasts presented in Chapter 2 in assuming ongoing growth in the uptake of coordinated (VPP-operated) battery storage. In accordance with AEMO's updated methodology, forecast growth that is not committed is assumed to be un-coordinated in the ESOO forecast. The ESOO thus has more un-coordinated batteries, and only those are reflected in the demand forecast, while VPP is modelled as supply and excluded from the forecasts presented here in the appendix. Both forecasts can be viewed at AEMO's Forecasting Portal: https://forecasting.aemo.com.au/.

- 2024-25 to 2033-34 (1-10 years):
  - In the first half of the decade, maximum demand forecasts under the ESOO Central scenario are higher than the 2023 ESOO forecasts, primarily driven by higher LIL and to a lesser extent by higher BMM forecasts.
  - Maximum demand forecasts under the *Green Energy Exports* scenario steadily increase but remain slightly lower than the 2023 forecasts. This is driven by lower underlying consumption forecasts for BMM, EV and electrification, which offset higher forecasts for LIL. Furthermore, maximum demand forecasts for the *Green Energy Exports* scenario are significantly higher than those for the ESOO Central scenario, driven by higher forecasts for electrification.
  - Forecasts for the *Progressive Change* scenario steadily increase.
- 2034-35 to 2043-44 (11-20 years):
  - Maximum operational demand forecasts under all three scenarios are lower than the 2023 ESOO forecasts, primarily due to lower forecasts for EV and partially due to lower forecasts for underlying BMM and electrification.
  - Forecasts under the ESOO Central scenario begin to increase at a higher rate from 2035-36, driven by a higher rate of increase in EV forecasts. In contrast, forecasts for the *Green Energy Exports* scenario continue to increase at a slower rate than in the last decade due to slower growth rates for BMM and residential forecasts.
  - As described previously, the *Progressive* Change scenario explores the impact of LIL closure risks, which are assumed from the early 2030's resulting in a step down in forecast maximum demand.
  - After 2035-36, forecasts start to increase due to continued growth in EV and electrification offsetting the slight decrease in BMM forecasts
- 2044-45 to 2053-54 (21-30 years) follow similar trends described in the prior decade, and impacted by the drivers described in the annual consumption trends:

Table 34 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 2039-40, impacted by gas to electricity fuel-switching for new developments) in the 50% POE and 10% POE forecasts.

Table 34 Victoria summer and winter 10% and 50% POE maximum operational (sent-out) demand forecast, *Step Change* scenario, 2023-24 to 2049-50 (MW)

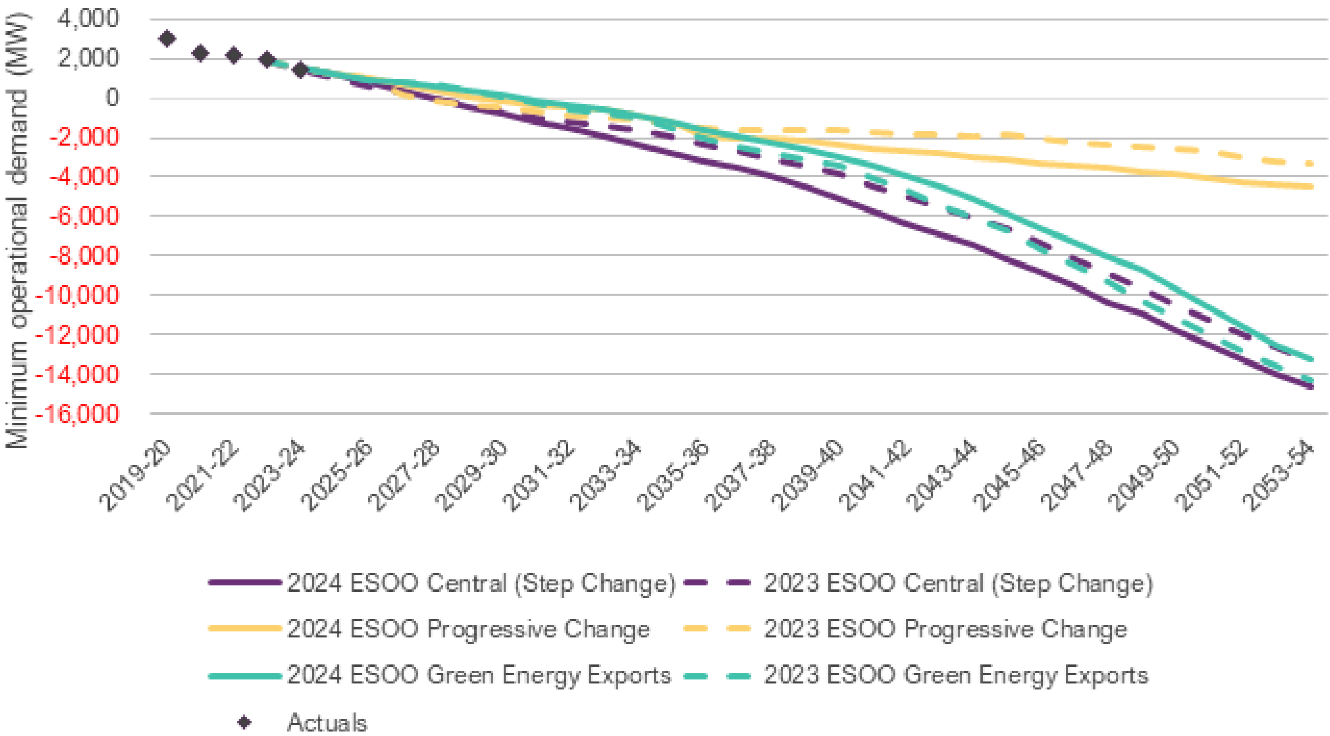
Financial year	Summer		Calendar year	Winter	
	10% POE	50% POE		10% POE	50% POE
2024-25	10,472	9,578	2025	7,982	7,825
2029-30	11,079	10,233	2030	9,323	9,153
2039-40	11,642	10,937	2040	11,785	11,605
2049-50	11,298	10,621	2050	13,284	13,102

Minimum operational demand outlook

Figure 87 shows actual and forecast 50% POE minimum operational (sent-out) demand from 2017-18 to 2053-54 for the 2024 ESOO compared to the 2023 ESOO forecasts for all scenarios in Victoria. Minimum operational demand is strongly linked to PV capacity, with minimums occurring frequently during daytime hours.

Minimum operational demand for Victoria under all scenarios follow a generally declining trend with higher rooftop PV forecasts. Longer-term forecasts are lower than 2023, due to lower EV forecasts and weaker economic conditions.

Figure 87 Actual and forecast Victoria 50% POE minimum operational (sent-out) demand, 2024 ESOO all scenarios and 2023 ESOO all scenarios, 2019-20 to 2053-54 (MW)



Note: The actuals displayed are not weather-corrected (therefore reflects observed demand under the prevailing weather conditions) or adjusted for system events and exclude DSP. Additionally, this definition excludes demand from scheduled loads, typically pumping load from pumped hydro energy storage or large-scale batteries, as well as hydrogen loads.

Supply adequacy assessment

Table 35 lists all committed and anticipated generator and storage projects included in the *Committed and Anticipated Investments* sensitivity in Victoria, while **Figure 88** shows the aggregate impact of generator and storage commissioning and decommissioning assumptions on assumed capacity during typical summer conditions.

Table 35 Victoria anticipated and committed generators and storages in *Committed and Anticipated Investments* sensitivity

Site Name	Commitment status	Technology type	Nameplate capacity (MW)	Storage capacity (MWh)	Participant provided full commercial use date	Modelled commissioning date
Derby Solar Farm	Anticipated	Solar PV – Single axis tracking	95	0	Mar-25	Jul-26
Frasers Solar Farm	Anticipated	Solar PV – Single axis tracking	77	0	Oct-25	Oct-26
Girgarre Solar Farm	Committed	Solar PV – Single axis tracking	93	0	Dec-24	Jun-25
Gnarwarre BESS Facility	Anticipated	Storage – Battery	290	550	Jan-27	Jan-28

Site Name	Commitment status	Technology type	Nameplate capacity (MW)	Storage capacity (MWh)	Participant provided full commercial use date	Modelled commissioning date
Golden Plains Wind Farm East	Committed	Wind Turbine – Onshore	756	0	Aug-25	Feb-26
Hawkesdale Wind Farm	Committed	Wind Turbine – Onshore	97	0	Apr-24	Oct-24
Horsham Solar Farm	Anticipated	Solar PV – Single axis tracking	119	0	Dec-24	Jul-26
Koorangie Energy Storage System	Committed	Storage – Battery	185	370	Apr-25	Oct-25
Latrobe Valley BESS	Committed	Storage – Battery	100	200	Jul-25	Jan-26
Melbourne Renewable Energy Hub – Side A	Committed	Storage – Battery	600	1,600	Nov-25	May-26
Mortlake Battery	Anticipated	Storage – Battery	300	600	Mar-27	Mar-28
Rangebank BESS	Committed	Storage – Battery	200	400	Oct-24	Apr-25
Ryan Corner Wind Farm	Committed	Wind Turbine – Onshore	218	0	Aug-24	Feb-25
Terang BESS	Anticipated	Storage – Battery	144	200	Jun-26	Jun-27
Woolsthorpe Wind Farm	Anticipated	Wind Turbine – Onshore	72	0	Not provided	Jul-28
Wooreen Energy Storage System	Anticipated	Storage – Battery	350	1,400	Dec-27	Dec-28
Wunghnu Solar Farm	Committed	Solar PV – Single axis tracking	94	0	Oct-24	Apr-25

Figure 88 **Victoria assumed capability during typical summer conditions, by generation type, 2023-24 to 2033-34 (MW)**

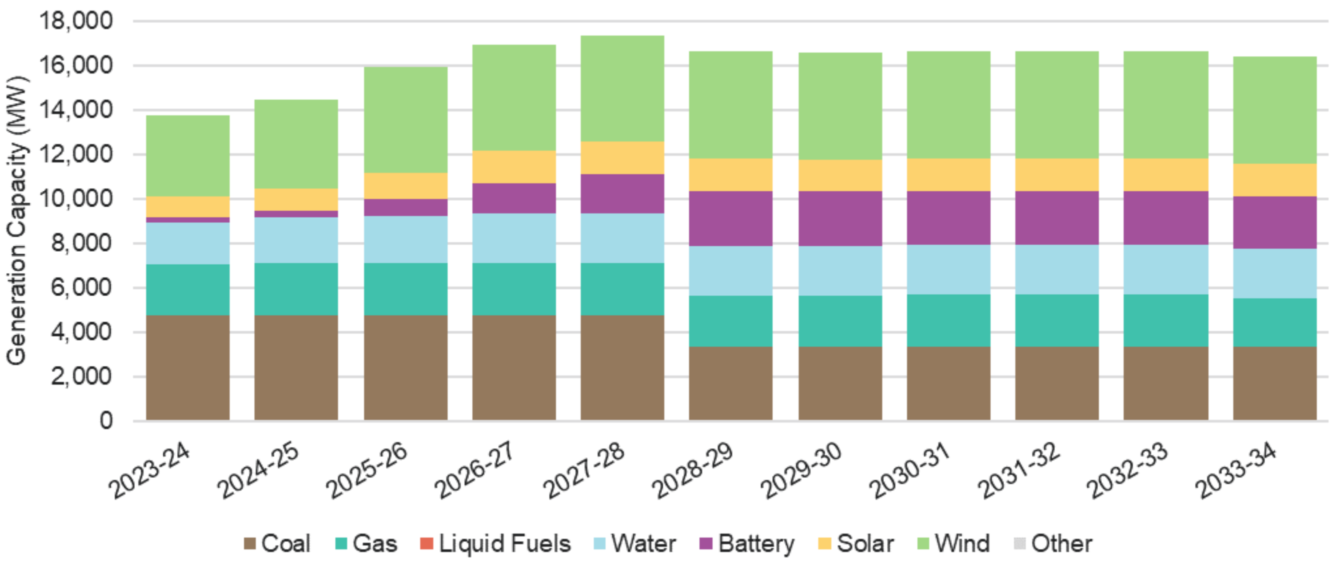


Figure 89 shows expected USE for Victoria under the relevant modelled scenarios and sensitivities. It shows that:

- In the *Committed and Anticipated Investments* sensitivity, expected USE exceeds the IRM in 2024-25 and 2027-28 and then exceeds the reliability standard from 2028-29. Should all currently committed and anticipated projects be delivered to their advised schedules then reliability risks would lower to within the IRM, as forecast in the *On-time Delivery* sensitivity.
- In 2028-29, reliability risks are forecast to be above the reliability standard following the announced retirement of Yallourn Power Station. While new wind, solar and battery storage developments continue to connect in Victoria, South Australia and interconnected regions, these developments are not yet sufficient to offset expected generator retirements and the forecast increases in electricity demand.
- Compared to the 2023 ESOO and May 2024 Update to the 2023 ESOO Central scenarios, the *Committed and Anticipated Investments* sensitivity has lower USE throughout the period due to a number of factors. These include reduced demand forecasts, higher demand side participation, increased availability on Basslink, and the inclusion of new projects since the 2023 ESOO such as Melbourne Renewable Energy Hub, Latrobe Valley BESS and Horsham Solar Farm. Projects in Melbourne have enabled further consideration for alternative network configurations between the Latrobe Valley and Melbourne to increase the transfer effectiveness at times of peak demand through the 220 kV and 500 kV networks.
- Under the *Actionable Transmission and Coordinated CER* sensitivity, reliability risks are forecast after 2024-25 to be within the IRM until 2027-28 and under the reliability standard for the remainder of the modelling horizon. Reliability risks progressively lower relative to the *Committed and Anticipated Investments* sensitivity over the entire horizon from 2029-30 as Melbourne Metro West, VNI West, Melbourne Metro East and Marinus Link are included in this sensitivity, improving capacity sharing within the region and with other NEM regions.
- Reliability risks are forecast lower still under the *Federal and State Schemes* sensitivity. This sensitivity includes on-time delivery of committed and anticipated projects, as well as additional capacity funded by the Victorian Renewable Energy Target Auction 2 and the initial Victoria – South Australia tender as part of the federal Capacity Investment Scheme, coordinated CER development, and actionable transmission projects such as Marinus Link and VNI West. With these investments, reliability risks are forecast to be within the relevant reliability standards throughout the horizon.

Figure 89 Victoria expected USE, scenarios and sensitivities, 2024-25 to 2033-34

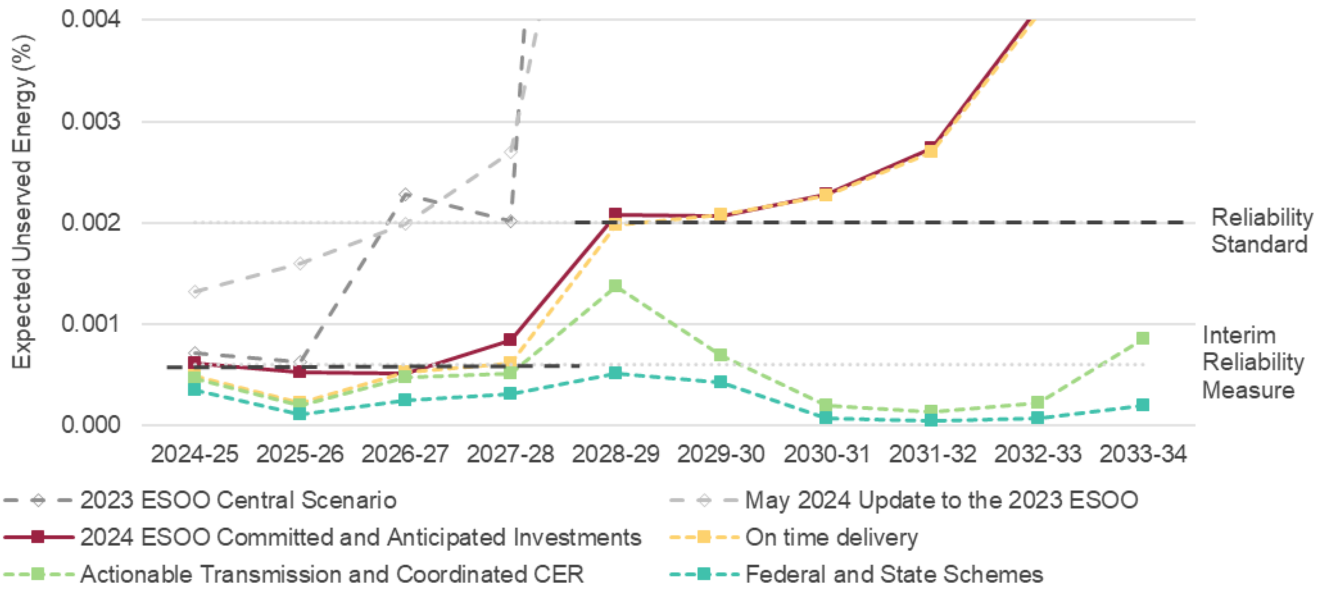


Figure 90 shows the reliability outcomes for the *Committed and Anticipated Investments* sensitivity for Victoria in 2024-25 under different weather years, demonstrating the reasonable variance that is expected depending on weather conditions (affecting consumer load profiles, as well as renewable generator resources).

Figure 90 Reliability outcomes for Victoria in 2024-25 under different weather reference years, *Committed and Anticipated Investments* sensitivity

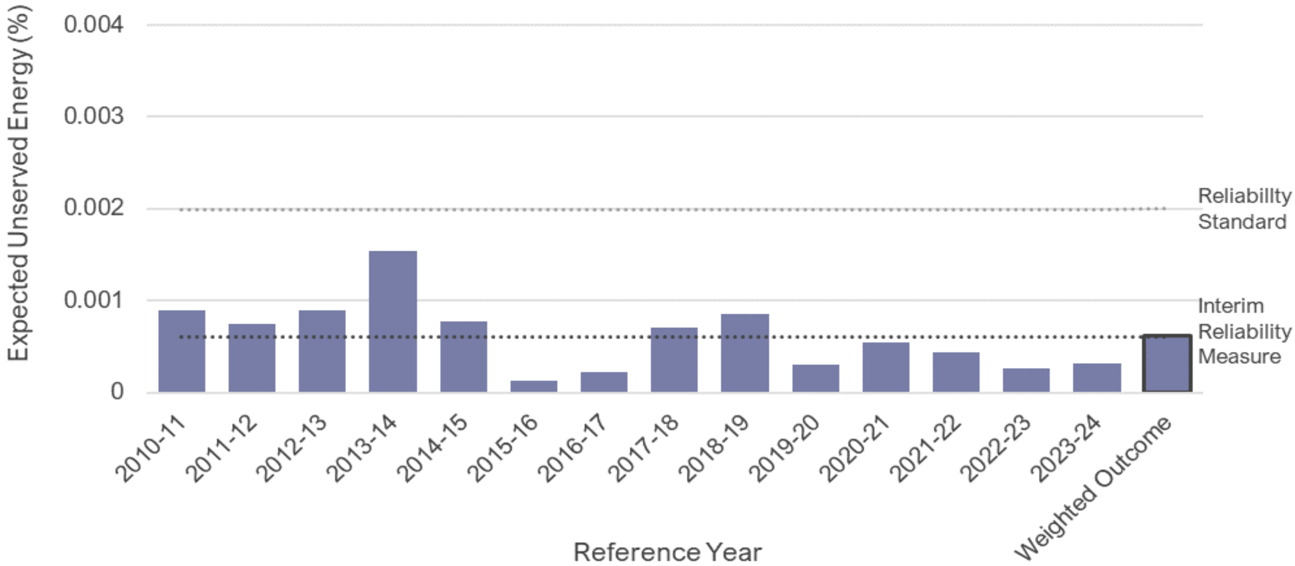
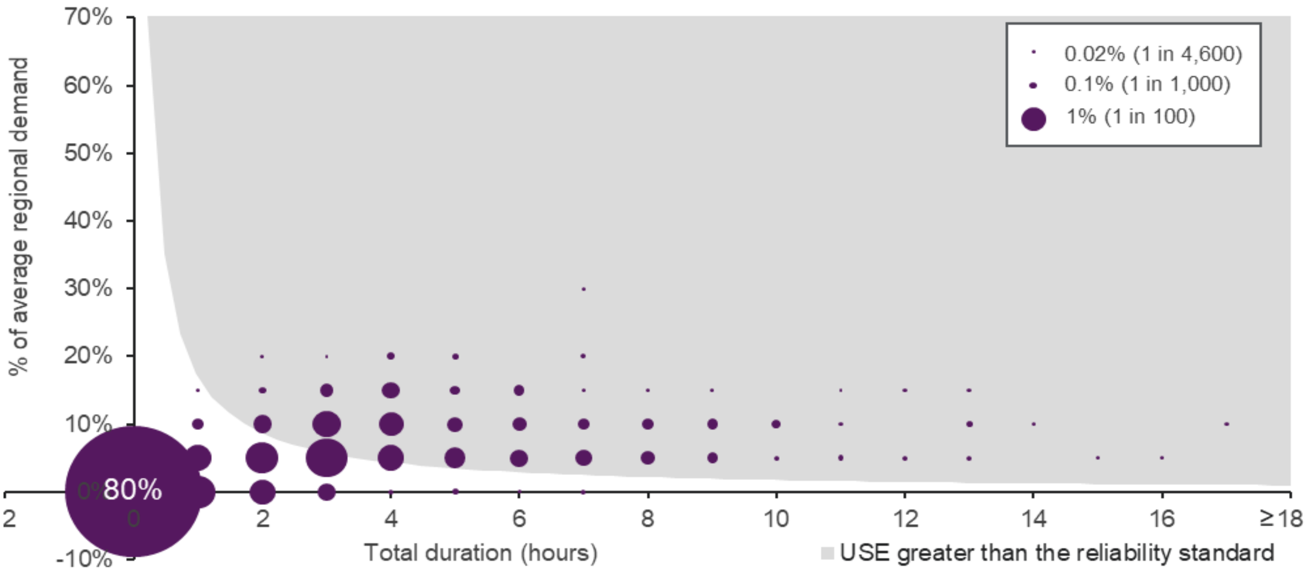


Figure 91 shows a bubble plot of the depth and duration of USE forecast in Victoria for 2024-25 in the *Committed and Anticipated Investments* sensitivity, similar to that shown in **Section 5.2**. It shows that the most likely outcome for Victoria is that USE does not occur in the coming year (the large purple bubble at the intersection of 0 hours and 0% depth), indicating that there is a 20% probability of a reliability incident. For those simulations that did have USE, the number of hours unserved was likely to be up to six hours in duration, and of average depth up to 15% of average regional load.

Figure 91 Bubble plot of depth and duration of forecast USE Victoria 2024-25, *Committed and Anticipated Investments* 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 NER 3.7D 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 2024 ESOO, in fulfilment of its obligation under the NER, and explains the key differences from the 2023 ESOO forecast.

A6.1 DSP definition

AEMO's DSP forecast represents 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 and/or loss of reserve conditions.

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 92**:

- The categories listed to the left column in **Figure 92** 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 92**).
- The categories that are included in DSP are listed in the middle column of **Figure 92**.

Figure 92 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)

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.

A6.2 DSP forecast by component

The 2024 DSP forecast is based on information collected from registered participants through AEMO's DSP Information Portal during April 2024. 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[133]. The response is determined as the difference between the observed consumption and the calculated baseline consumption. This is performed 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.

The WDR mechanism was introduced in October 2021[134]. Contribution of demand response service providers (DRSPs) via the WDR mechanism have been taken into account, and based on the dispatch data for the 12 months until March 2024. 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 was higher than that trigger. **Table 36** 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 36 WDR observations (2023-24)

Region	Trigger	Counts of intervals with WDR	Counts of intervals with price above the trigger	Calculated weight
NSW	>$500/MWh	66	2,898	0.02
NSW	>$2,500/MWh	66	303	0.22
NSW	>$7,500/MWh	20	50	0.40
VIC	>$500/MWh	29	996	0.03
VIC	>$2,500/MWh	53	89	0.60
VIC	>$7,500/MWh	15	26	0.58
QLD	>$500/MWh	75	1,930	0.04
QLD	>$2,500/MWh	51	351	0.15

[133] The most recent three years of history are used by default with the cut-off date as the end of March 2023.

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

Region	Trigger	Counts of intervals with WDR	Counts of intervals with price above the trigger	Calculated weight
QLD	>$7,500/MWh	10	96	0.10
SA	>$500/MWh	9	3,317	0.00
SA	>$2,500/MWh	34	430	0.08
SA	>$7,500/MWh	27	95	0.28

The WDR forecasts for 2024 are broadly consistent with the predictions published in the 2023 ESOO. As of June 2024, WDR had been dispatched in all NEM regions except Tasmania, thus the data presented here reflect the actual WDR data received from the participating wholesale demand response units (WDRUs). Based on the actual operation of WDR in 2023-24, the 2024 ESOO forecasts for WDR are as shown in **Table 37.**

Table 37 Price-driven WDR forecast (MW)

Trigger	New South Wales	Queensland	South Australia	Tasmania	Victoria
>$300-$500/MWh	1	1	1	0	1
>$500-$7,500/MWh	5	1	1	0	6
>$7,500/MWh	9	1	1	0	6

In addition, there is another category of market-driven response that are typically triggered in respect to the price of electricity. Examples are consumers that agree to let their load/battery be controlled by a third party or are incentivised to switch off loads such as air-conditioners and/or switch on on-site small non-scheduled generators at these times, offsetting local consumption.

The total price-driven DSP forecasts including the WDR response are summarised in **Table 38.**

Table 38 Price-driven DSP forecast including WDR (cumulative response in MW)

Trigger	New South Wales	Queensland	South Australia	Tasmania	Victoria
>$300-$500/MWh	1	28	27	0	1
>$500-$7,500/MWh	16	77	45	4	6
>$7,500/MWh	117	197	49	4	339

Focusing on the DSP forecasts above the $7,500/MWh trigger, and comparing to the 2023 ESOO:

- There was more DSP response overall in all NEM regions except Tasmania (as per **Table 39**). One of the main contributors to the general uplift in DSP response is the higher electricity prices observed in recent years. These higher prices have led to more benefits to customers participating in DSP schemes or acting directly to respond to market signals. Moreover, DSP programs are getting more attention across the NEM given recent volatility over an extended duration. In contrast, Tasmania had relatively low price-driven DSP, and had only limited observations of the high-price events required to estimate the DSP response with reasonable confidence.
- Victoria registered substantial increase in the DSP forecasts. This is stemming from the price-based DSP forecasts from the market exposed customers. In 2023, the region had only 63 MW of price-triggered DSP response for over $7,500/MWh, however, in 2024, the value is 339 MW for the similar price band. AEMO's improved identification and

classification of virtual power plants and data centres has helped to recognise this larger DSP participation in Victoria, and similarly, to a smaller extent in New South Wales.

Forecast DSP responses by region are presented in **Table 39**.

Table 39 Forecast levels of DSP (MW) for prices exceeding $7,500/MWh in the 2022 ESOO, 2023 ESOO and 2024 ESOO

DSP response	New South Wales	Queensland	South Australia	Tasmania	Victoria
2022 ESOO forecast	48	69	13	17	35
2023 ESOO forecast	95	189	49	6	63
2024 ESOO forecast	117	197	49	4	339

Reliability response

The reliability response forecast represents the estimated DSP response during reliability events, which AEMO defines as cases where an actual LOR2 or LOR3 is declared[135]. The estimates are based on the estimated price response for a 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[136].

In this year's DSP forecast, AEMO has modelled network event programs in Queensland and Victoria. In Queensland, customers can purchase a PeakSmart air-conditioner which is managed by the DNSP at times of high network demand. In Victoria, the Critical Peak Demand program incentivises customers who use more than 160 MWh per annum to shift their demand away from peak periods on five high-demand days each summer. These programs have a DSP contribution of approximately 43 MW in Queensland and 45 MW in Victoria, and are only available in summer. As such, AEMO's forecasts differentiate between summer and winter.

AEMO has maintained the assumptions made in the 2022 DSP reliability forecast for New South Wales and Victoria. These assumptions reflect the average of the response seen across the periods where LOR 2 conditions were in the regions in the last three years plus any anticipated increase in the responses, which summed to[137]:

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

Based on this, the combined DSP forecasts for the coming summer 2024-25 and winter 2025 are shown in **Table 40**. For most regions, AEMO has no information about committed additional DSP resources, hence these estimates are used for the entire 10-year ESOO horizon.

[135] 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.

[136] The reliability response is the estimated response during actual LOR 2 and LOR 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.

[137] See reliability response, A6, in 2023 ESOO at: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2023/2023-electricity-statement-of-opportunities.pdf.

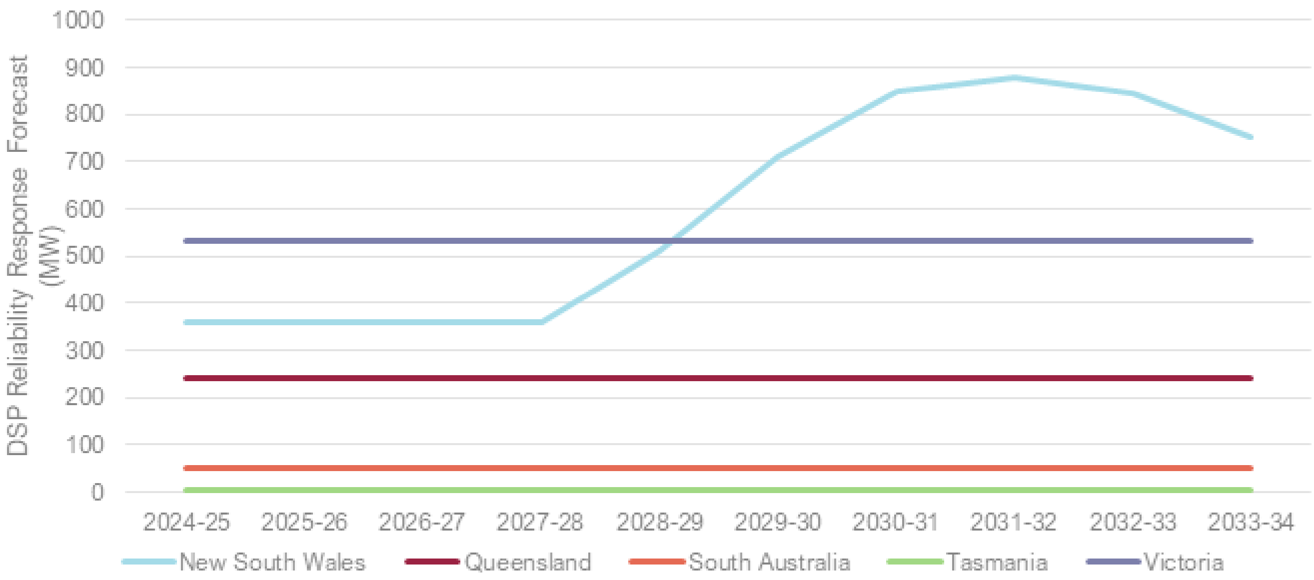
Table 40 Estimated DSP responding to price or reliability signals

Trigger	New South Wales		Queensland		South Australia		Tasmania		Victoria	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
> $300-$500/MWh	1	0	28	28	27	27	0	0	1	1
> $500-$7,500/MWh	16	16	77	77	45	45	4	4	6	6
> $7,500/MWh	117	117	197	197	49	49	4	4	339	339
Reliability response	359	359	240	197	49	49	4	4	533	488

For New South Wales, the PDRS will create a financial incentive to reduce electricity consumption during peak times in summer in New South Wales[138]. AEMO has included this scheme in all scenarios, resulting in a DSP forecast which increases above the tabulated values, based on information provided by the New South Wales Government, adjusted to reflect the components included in AEMO's DSP definition. Specifically, the DSP forecast assumed 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 93 shows the New South Wales DSP forecast, including the PDRS, for the next 10 years. The scheme will, in its current design, only provide additional DSP during summer[139].

Figure 93 DSP applied in forecasts for the summer period in New South Wales, 2023-24 to 2033-34 (MW)



138 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.

139 For New South Wales' summer, the forecasts shown in Figure 93 are used in the 2024 ESOO while the winter forecasts stay the same as the values listed in Table 40.

Reliability response outlook in the longer term

The tables above show the DSP forecast for use in the 2024 ESOO, only accounting for existing and committed DSP. For longer-term planning studies, such as the ISP, AEMO uses different scenario-specific projections that apply over the longer term to account for DSP resources that may be developed consistent with the defined scenario settings[140].

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[141] in 2020, NER 3.7D(c) has required 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.

A key part of the statistics is the reported National Meter Identifier (NMI) for each site that has demand flexibility of some sort. **Table 41** shows how many NMIs were submitted per region.

Table 41 Submitted NMIs per region

Region	Number of NMIs submitted
New South Wales	2,358,727
Queensland	1,479,272
South Australia	815,963
Tasmania	3,179
Victoria	1,089,273

Participant programs delivering demand flexibility

Table 42 and **Table 43** 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. Moreover, the change in categories challenges the ability to make direct comparisons to previous years.

[140] These longer-term DSP projections can be found in AEMO's 2023 IASR, at https://aemo.com.au/en/consultations/current-and-closed-consultations/2023-inputs-assumptions-and-scenarios-consultation.

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

In 2020, in response to the WDR rule change[142], AEMO was required to review and consult on changes to the DSP information guidelines[143], which resulted in changes to the categories of DSP programs that could be identified in submissions. The number of programs allocated to the new set of categories is shown in **Table 43**. Moreover, in 2023, the DSP information guidelines and demand-side participation forecast methodology were further reviewed, consulted on and updated in accordance with NER rule 3.7D.

In 2024, there were increases in program numbers submitted in most categories when compared to past years, partly driven by participants' provision of more fulsome information under NER rule 3.7D. The number of "Market exposed connections" was particularly high in 2022 as many sites were listed as individual programs, whereas from year 2023, the number came down as more were reported as programs of multiple sites.

After 2020, there has been no 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 (VPP) to respond dynamically to price and/or reliability signals are still required to be reported, although by using the generic DSP categories.

Table 42 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 43 Program numbers from DSP Information portal, 2021-24

Category	2021	2022	2023	2024
Market exposed connections	143	211	141	168
Connections on dynamic event tariffs	5	16	19	17
Directly controlled connections (dynamic operation)	33	37	50	66
Directly controlled connections (fixed schedule)	6	17	27	28
Connections on fixed time-of-use tariffs	49	62	56	70
Other	14	35	25	22

Statistics by program category

Table 44 summarises category-level information from submissions to AEMO's DSP Information Portal in 2024. Participants reported each individual customer connection, based on their NMIs, which belong to each program. Some customer connections may belong to multiple programs: for example, a residential customer's NMI could appear as both having a controlled hot water tank (directly controlled load – fixed schedule) and an interruptible air-conditioner (directly controlled load – dynamic schedule).

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

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

Table 44 Program statistics grouped by program category for 2024 submissions

Category	Number of programs	Number of connections A	Number of programs that included firm response information in submission
Connections on dynamic event tariffs	17	3,412	13
Connections on fixed time-of-use tariffs	70	2,374,306	5
Directly controlled connections (dynamic operation)	66	683,247	14
Directly controlled connections (fixed schedule)	28	2,271677	2
Market exposed connections	168	413,496	113
Other	22	276	5

A Connections may appear in more than one program.

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, though a large number of the reported NMIs are for controlled hot water systems, which is done on any day when the demand in the local network exceed a certain threshold. It makes it closer to the "fixed schedule" operation discussed above. The next categories of participants in terms of the number of connections are market exposed customers which behave according to the wholesale market spot prices and the customers under dynamic event tariffs whose energy prices will be different for specific periods/months/seasons of the year. These specific timeframes are determined by the regional NSPs. Customers who do not fit into any of the above-mentioned categories would submit under the category 'Other'.

Participants may report their firm response in megawatts for each program. **Table 44** 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.

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. Not specifying the load type has been an increasing trend, noting that specifying the load type is optional. The load type categories for 2024 are summarised in **Table 45**, with the numbers of distinct connections reported since 2022 for comparison.

As shown in **Table 45**, there is a large number of NMIs whose connection types are not specified, and this could be one reason for the lower number of commercial and industrial load connections compared to previous years.

For each load type:

- In the submissions with no specified load type, 'Fixed-time-of-use tariff' is the dominant program category and could cover programs targeting both residential and commercial customers.
- Commercial load type connections also had 'Fixed-time-of-use tariff' as the dominant category.

- Industrial load type predominantly had 'Other' listed as category, although in previous years 'Market exposed connections' has been the dominant category.
- Residential loads are dominated by programs targeting appliances like electric hot water systems and pool pumps though 'Directly controlled connections (fixed schedule)' and 'Directly controlled connections (dynamic schedule)' programs with a very even split.

Table 45 Load types of reported connections

Load type	2022	2023	2024	Dominant program category in each load type as a percentage (2023)
< not specified >	3,405,255	3,569,964	4,031,255	More than 50% are on fixed time-of-use tariffs
Commercial	9,415	3,190	3,197	94% are Dynamic event tariffs
Industrial	90	182	113	Market exposed connections is the only listed category
Residential	1,735,756	2,086,902	1,711,849	More than 70% submissions are fixed schedule and the rest are under the dynamic operation category.

Number of connections by category and type

Table 46 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 5,032 MW of firm response exists, although more could be unquantified or simply not reported. This value is slightly lower than what was provided in the 2023 ESOO. It is important to note that the reported 2,498 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. Embedded generation – including distributed PV – in all categories is modelled separately in the reliability forecast and therefore not included in the DSP forecast presented in this appendix. The same applies for programs with 'Energy Storage' as the DSP type in all categories. The reported responses are directly modelled in the reliability forecast rather than through the DSP forecast.

Table 46 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	360,775	2,498	64
	Energy storage	51,327	247	38
	Load reduction	543	244	39
	Load reduction; Embedded generation	5	90	1
	<not specified>	846	107	26
Connections on dynamic event tariffs	Embedded generation	36	689	9
	Energy storage	420	2	2
	Load reduction	2,956	115	2
	<not specified>	0		0

Category	DSP type	Distinct number of connections	Reported sum of firm response (MW)	Number of programs
Directly controlled connections (dynamic operation)	Embedded generation	4	27	2
	Energy storage	1,221	13	9
	Load reduction	494,462	281	9
	<not specified>	187,560	7	46
Directly controlled connections (fixed schedule)	Load reduction	1,227,090	632	5
	<not specified>	1,044,587	0	23
Connections on fixed time-of-use tariffs	Embedded generation	10	10	1
	Load reduction	388,356	0	6
	<not specified>	1,985,940	3	63
Other	Embedded generation	0	0	0
	Energy storage	119	12	8
	Load reduction	157	49	10
	<not specified>	0	0	0

Tariffs used by network service providers and retailers

Table 47 summarises the number of connections reported for the different tariff categories for both retailers and NSPs. The high number of market exposed connections reported by NSPs reflects submissions of customers with rooftop PV which may in some cases be curtailed technically, rather than economically.

Table 47 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	3,412	0
Connections on fixed time-of-use tariffs	344,168	2,030,138
Directly controlled connections (dynamic operation)	495,614	187,633
Directly controlled connections (fixed schedule)	1,227,090	1,044,587
Market exposed connections	412,024	1,472
Other	134	142

A7. EAAP detailed results

Consistent with the EAAP Guidelines, AEMO must publish expected USE for the first 12 months and second 12 months in the EAAP study period for each of the scenarios on a regional basis. These results are presented in this section aggregated annually and monthly for the full EAAP forecast horizon, from July 2024 to June 2026.

A7.1 Central scenario

Annual regional expected USE values for the EAAP Central scenario are expressed in **Table 48** in both megawatt hours and as a percentage of regional demand. Expected USE in Tasmania in 2024-25 is negligible.

Table 48 Annual expected USE in EAAP Central scenario

Region	2024-25 USE		2025-66 USE	
	(MWh)	(% of regional demand)	(MWh)	(% of regional demand)
New South Wales	827	0.0013%	17	0.0000%
Queensland	125	0.0002%	58	0.0001%
South Australia	166	0.0014%	65	0.0005%
Tasmania	0	0.0000%	1	0.0000%
Victoria	330	0.0008%	314	0.0007%

Table 49 shows the EAAP Central scenario regional expected USE per month over the EAAP's two-year horizon.

Table 49 Monthly expected USE in EAAP Central scenario, MWh

Month	New South Wales	Queensland	South Australia	Tasmania	Victoria
Jul-24	6.6	0.0	0.0	0.1	0.0
Aug-24	1.7	0.0	0.0	0.0	0.0
Sep-24	0.0	0.0	0.0	0.0	0.0
Oct-24	0.0	0.0	0.0	0.0	0.0
Nov-24	11.0	0.0	0.1	0.0	13.6
Dec-24	168.7	5.8	0.2	0.0	1.2
Jan-25	244.7	28.1	97.7	0.0	203.7
Feb-25	381.1	72.8	65.8	0.0	97.9
Mar-25	9.2	18.4	2.5	0.0	13.5
Apr-25	0.0	0.0	0.0	0.0	0.0
May-25	0.1	0.0	0.0	0.0	0.0
Jun-25	3.7	0.0	0.0	0.2	0.0
Jul-25	0.0	0.0	0.0	0.2	0.0
Aug-25	0.0	0.0	0.0	0.1	0.0
Sep-25	0.0	0.0	0.0	0.0	0.0
Oct-25	0.0	0.0	0.0	0.0	0.0

Month	New South Wales	Queensland	South Australia	Tasmania	Victoria
Nov-25	1.0	0.0	0.0	0.0	3.3
Dec-25	4.7	2.5	0.0	0.0	1.7
Jan-26	2.8	15.5	30.8	0.0	175.6
Feb-26	7.1	32.4	33.9	0.0	124.1
Mar-26	1.2	7.6	0.2	0.0	8.9
Apr-26	0.0	0.0	0.0	0.0	0.0
May-26	0.0	0.0	0.0	0.0	0.0
Jun-26	0.0	0.0	0.0	0.3	0.0

A7.2 Low Rainfall scenario

Annual regional expected USE values for the EAAP Low Rainfall scenario are expressed in **Table 50** in both megawatt hours and as a percentage of regional demand. Expected USE in Tasmania in 2024-25 is negligible.

Table 50 Annual forecast expected USE in EAAP Low Rainfall scenario

Region	2024-25 USE		2025-26 USE	
	(MWh)	(% of regional demand)	(MWh)	(% of regional demand)
New South Wales	823	0.0013%	15	0.0000%
Queensland	138	0.0003%	50	0.0001%
South Australia	175	0.0014%	71	0.0006%
Tasmania	0	0.0000%	1	0.0000%
Victoria	338	0.0008%	323	0.0008%

Table 51 shows expected USE per month for the EAAP Low Rainfall scenario over the two-year horizon.

Table 51 Monthly forecast expected USE in EAAP Low Rainfall scenario, MWh

Month	New South Wales	Queensland	South Australia	Tasmania	Victoria
Jul-24	6.5	0.0	0.0	0.2	0.0
Aug-24	1.1	0.0	0.0	0.1	0.0
Sep-24	0.0	0.0	0.0	0.0	0.0
Oct-24	0.0	0.0	0.0	0.0	0.0
Nov-24	12.8	0.0	0.3	0.0	13.7
Dec-24	204.5	6.6	0.1	0.0	2.3
Jan-25	234.8	31.5	100.3	0.0	190.3
Feb-25	351.7	87.1	71.4	0.0	117.2
Mar-25	7.0	12.5	2.9	0.0	14.8
Apr-25	0.0	0.0	0.0	0.0	0.0
May-25	0.0	0.0	0.0	0.0	0.0
Jun-25	4.4	0.0	0.0	0.1	0.0
Jul-25	0.0	0.0	0.0	0.3	0.0

Month	New South Wales	Queensland	South Australia	Tasmania	Victoria
Aug-25	0.0	0.0	0.0	0.0	0.0
Sep-25	0.0	0.0	0.0	0.0	0.0
Oct-25	0.0	0.0	0.0	0.0	0.0
Nov-25	0.6	0.0	0.0	0.0	4.7
Dec-25	2.8	3.7	0.0	0.0	2.6
Jan-26	2.7	15.1	36.3	0.0	186.0
Feb-26	7.0	23.8	34.9	0.0	110.5
Mar-26	1.6	7.7	0.1	0.0	18.8
Apr-26	0.0	0.0	0.0	0.0	0.0
May-26	0.0	0.0	0.0	0.0	0.0
Jun-26	0.4	0.0	0.0	0.4	0.0

A7.3 Low Thermal Fuel scenario

Annual expected USE for the EAAP Low Thermal Fuel scenario is shown in both megawatt hours and % USE in **Table 52**.

Table 52 Annual forecast expected USE in EAAP Low Thermal Fuel scenario

Region	2024-25 USE		2025-26 USE	
	(MWh)	(% of regional demand)	(MWh)	(% of regional demand)
New South Wales	7,695	0.0117%	2,125	0.0032%
Queensland	1,433	0.0028%	400	0.0008%
South Australia	682	0.0055%	362	0.0028%
Tasmania	5	0.0000%	7	0.0001%
Victoria	1,471	0.0035%	1,330	0.0031%

Table 53 shows expected USE per month for the EAAP Low Thermal Fuel scenario over the two-year horizon.

Table 53 Monthly forecast expected USE in EAAP Low Thermal Fuel scenario, MWh

Month	New South Wales	Queensland	South Australia	Tasmania	Victoria
Jul-24	626.7	42.5	3.1	0.9	1.6
Aug-24	21.3	0.0	0.3	0.6	0.4
Sep-24	0.1	0.0	0.0	0.0	0.0
Oct-24	0.0	0.0	0.0	0.0	0.0
Nov-24	64.2	0.0	2.0	0.0	41.4
Dec-24	626.0	6.2	3.2	0.0	24.5
Jan-25	5024.7	1249.8	334.6	0.0	799.9
Feb-25	1234.6	113.2	299.9	0.0	519.2
Mar-25	45.6	21.1	37.9	0.0	83.9
Apr-25	0.1	0.0	0.0	0.0	0.0
May-25	1.6	0.0	0.0	1.2	0.0

Month	New South Wales	Queensland	South Australia	Tasmania	Victoria
Jun-25	50.3	0.0	1.3	2.2	0.1
Jul-25	195.3	1.6	1.8	2.3	1.6
Aug-25	0.5	0.0	0.0	0.6	0.0
Sep-25	0.0	0.0	0.0	0.1	0.0
Oct-25	0.0	0.0	0.0	0.0	0.0
Nov-25	13.1	0.0	0.0	0.0	16.9
Dec-25	119.0	5.2	1.1	0.0	19.9
Jan-26	1528.2	320.6	169.3	0.0	673.8
Feb-26	204.0	60.5	179.4	0.0	538.2
Mar-26	58.1	11.6	8.1	0.0	79.3
Apr-26	0.0	0.0	0.0	0.2	0.0
May-26	0.0	0.0	0.0	0.6	0.0
Jun-26	6.7	0.0	1.7	3.4	0.0