

2023 Electricity Statement of Opportunities

August 2023

A 10-year reliability outlook for the
National Electricity Market
Including the 2023 Energy
Adequacy Assessment Projection





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 2023 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. This publication does not include all of the information that an investor, participant or potential participant in the National Electricity Market might require and does not amount to a recommendation of any investment.

Anyone proposing to use the information in this publication (which includes information and forecasts from third parties) should independently verify its accuracy, completeness and suitability for purpose, and obtain independent and specific advice from appropriate experts.

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

- make no representation or warranty, express or implied, as to the currency, accuracy, reliability or completeness of the information in this document; and
- are not liable (whether by reason of negligence or otherwise) for any statements, opinions, information or other matters contained in or derived from this publication, or any omissions from it, or in respect of a person's use of the information in this publication.

Copyright

© 2023 Australian Energy Market Operator Limited. The material in this publication may be used in accordance with the [copyright permissions on AEMO's website](#).

Executive summary

The *Electricity Statement of Opportunities* (ESOO) provides technical and market data for the National Electricity Market (NEM) over a 10-year period to inform the planning and decision-making of market participants, new investors, and jurisdictional bodies. The ESOO includes a reliability forecast and identification of 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. The ESOO Central scenario, which incorporates the reliability forecast, assesses power system reliability considering only a sub-set of known developments which have demonstrated sufficient commitment towards commissioning in the NEM. It serves to advise on the additional development needs required to maintain reliability in the NEM.

This ESOO also includes the *Energy Adequacy Assessment Projection* (EAAP), which complements the ESOO by forecasting reliability under scenarios that consider energy limitations, like the impact of drought conditions and potential coal and gas supply shortfalls, over a two-year horizon.

With up to 62% of its coal fleet now expected to close before 2033¹, Australia's NEM is perched on the edge of one of the largest transformations since the market was formed over 20 years ago. The scale of opportunity to meet an imminent and growing need for firm capacity, new forms of energy production, and significant consumer energy investments is unparalleled in Australia's energy history. This ESOO shows that imminent and urgent investment is needed to meet this opportunity, or the reliability of the NEM will be at risk.

In this 2023 ESOO assessment:

- When considering only energy supply infrastructure developments that meet AEMO's commitment criteria², **AEMO forecasts larger reliability gaps** than were forecast in the February 2023 *Update to 2022 Electricity Statement of Opportunities*, and in some cases, larger than forecast in the 2022 ESOO. Over the next 10 years, in the 2023 ESOO Central scenario, reliability risks are forecast to be higher than the relevant reliability standard requires in:
 - **South Australia** in summer 2023-24 (against the Interim Reliability Measure [IRM] of 0.0006% unserved energy [USE]) and from 2028-29 (against the reliability standard of 0.002% USE).
 - **Victoria** this coming summer and over the entire ESOO horizon against the IRM, and from 2026-27 against the reliability standard.
 - **New South Wales** from 2025-26 against the reliability standard.
 - **Queensland** in 2029-30 and 2030-31 against the reliability standard.
- Once federal and state government programs, actionable transmission developments, and orchestration of forecast consumer energy resources (CER) are also considered, **beyond the short term, reliability risks have the potential to be managed within relevant standards over most of the next 10-year horizon.**

¹ Including generators that have advised expected closure dates at or before 2033, and generators identified in the Queensland Energy and Jobs Plan as being subject to possible closure at or before 2033.

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.

- While these programs and developments have not yet progressed far enough to implementation to meet the strict criteria to be included in the ESOO Central outlook, federal and state governments have policies and frameworks to develop and implement delivery plans.
- All jurisdictions have a range of policies that support the development of new capacity to replace retiring generators. Each policy must now prioritise delivering the transmission, and renewable energy and firming generation they target, ahead of announced closures. Just-in-time investment may not maintain suitable reliability, and delivering on the current development opportunities is now essential.
- The impact of potential coal, gas and diesel fuel shortfalls has been identified as a material risk to the reliability of the NEM. In addition to the need for new generation, transmission and other solutions, the ongoing availability of coal, gas and distillate fuels, and effective management of their supply chains, will be critical to the reliability of the NEM.

These forecasts highlight the high value of solutions in which resources owned by consumers, such as residential electricity generation and storage devices, and increased demand flexibility, can help meet power system needs. With a high level of consumer participation and coordination of consumer energy assets and demand to help meet power system needs, the need for utility-scale solutions would be much lower.

Many factors are driving AEMO's 2023 ESOO forecast identifying greater development opportunities than in earlier reports:

- **Generator unplanned outage rates are forecast higher than previously**, reflecting recent trends of poor performance among some generator technologies.
- AEMO has observed that the initial target delivery dates provided by developers of new generation and storage investments often have not accounted for delays that could occur during the project financing, planning, development and delivery stages of projects. To ensure the accuracy of its reliability outlook, AEMO now applies **delays to reflect observed development and delivery risks of new projects** in the reliability forecast.
- New and improved weather data and modelling for renewable generation has **improved the accuracy of variable renewable energy (VRE) correlations with maximum demand**, identifying a higher forecast occurrence of low wind and high demand conditions in Victoria, resulting in higher forecast reliability risks for South Australia and Victoria.
- Many new wind, solar, battery and pumped hydro developments have advanced sufficiently to be considered in the 2023 ESOO, however **solutions which orchestrate and coordinate consumers' generation and storage devices to support reliability have not yet demonstrated success at significant scale**. Consistent with other reliability input assumptions, AEMO has now only assumed consumers will install CER and make them available to be orchestrated to help meet power system needs at current levels; this is lower than the levels of CER orchestration previously assumed.
- **Forecasts of energy consumption and maximum demand are higher in some NEM regions**, driven by projected electrification of households and businesses, and forecast expansion of industrial facilities.

The following definitions apply to this 2023 ESOO:

- **Unserviced 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 2025. 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 12% of average regional demand for eight 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 2023 ESOO, the IRM of 0.0006% USE will apply until 30 June 2025 and the reliability standard of 0.002% USE will apply from then. The Australian Energy Market Commission (AEMC) has proposed that the IRM should provide a trigger for the RRO until 30 June 2028, and is currently consulting on the final rules to implement this extension. If the AEMC determines to extend the application of the IRM, AEMO will take the appropriate steps in accordance with the amended rules requirement.

AEMO believes the current reliability definition exposes consumers to low probability but high impact risks within the 'tail' of the reliability distribution. These risks are demonstrated in this and previous ESOOs. AEMO has recommended that any change to the reliability standard incorporate tail risk more explicitly, which would be expected to deliver a more appropriate relationship between planning and operational outcomes.

2023-24 outlook

Reliability risks are forecast to be greater than the Interim Reliability Measure in South Australia and Victoria this summer

- Electricity consumption over the year is forecast to be marginally lower than in 2022-23, as growth in newly electrified loads (switching to electricity from alternative energy sources such as gas and diesel) is more than offset by business energy efficiency savings and lower household disposable income, lessening previously forecast growth.
- Annual maximum demand forecasts for 2023-24, however, remain similar to those previously forecast, because consumer demand during hot weather is forecast to be less impacted by energy efficiency investments and potential consumer responses to high prices. Annual maximum demand occurs close to or after sunset in most regions, after the impact of distributed photovoltaics (PV) has subsided.
- Approximately 3.4 gigawatts (GW) more new generation and storage capacity from a range of technologies is expected to be available compared to what was available last summer.
- The reliability of the thermal (coal and gas) generation fleet generally stayed at historically poor levels in 2022-23, and most plant operators have advised that overall plant reliability is unlikely to materially improve.
- Expected unserved energy (USE) is forecast to be above the IRM of 0.0006% USE in South Australia and Victoria in the coming year, although risks remain in all regions under extreme conditions. **Table 1** shows the forecast risk for a larger USE outcome³ for the coming summer. The probability is provided for all possible maximum demand outcomes, and under 10% POE demand conditions. Factors that influence when and how USE occurs include occurrences of generator outages and high demand at the same time as low wind and solar generation conditions.

³ 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.

- For the coming summer, the Bureau of Meteorology is currently advising that hot dry conditions, with elevated bushfire risks, and El Niño weather patterns are likely. The maximum demand forecast range is forecast based on all climate conditions and does not target these specific forecast weather conditions. Hence there is an increased likelihood this summer that demand outcomes will fall in the upper end of the forecast range (that is, the 10% probability of exceedance [POE] forecast is more likely), in most regions.

Table 1 Probability of a larger unserved energy outcome³ in 2023-24 by NEM region

Region	Probability of a larger USE outcome	
	All maximum demand outcomes	10% POE maximum demand outcomes
New South Wales	5%	15%
Queensland	2%	5%
South Australia	11%	35%
Tasmania	0%	0%
Victoria	13%	39%

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 EAAP, included in **Chapter 6**, explores these risks over a 24-month horizon. Under most likely conditions, the EAAP identifies reliability risks above the IRM in New South Wales, in addition to South Australia and Victoria which are above the IRM in both the EAAP and the ESOO. The additional risks identified in the EAAP Central scenario in New South Wales are due to low fuel availability expectations from some gas generators. The EAAP also identifies significantly increased risks if thermal fuels are more scarce, highlighting 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 (IRR) and Reliability and Emergency Reserve Trader (RERT) resources, where appropriate⁴. Risks of involuntary load-shedding remain elevated, particularly if El Niño conditions are experienced.

Reliability gaps are forecast in all mainland NEM regions when considering only those developments that meet AEMO’s commitment criteria

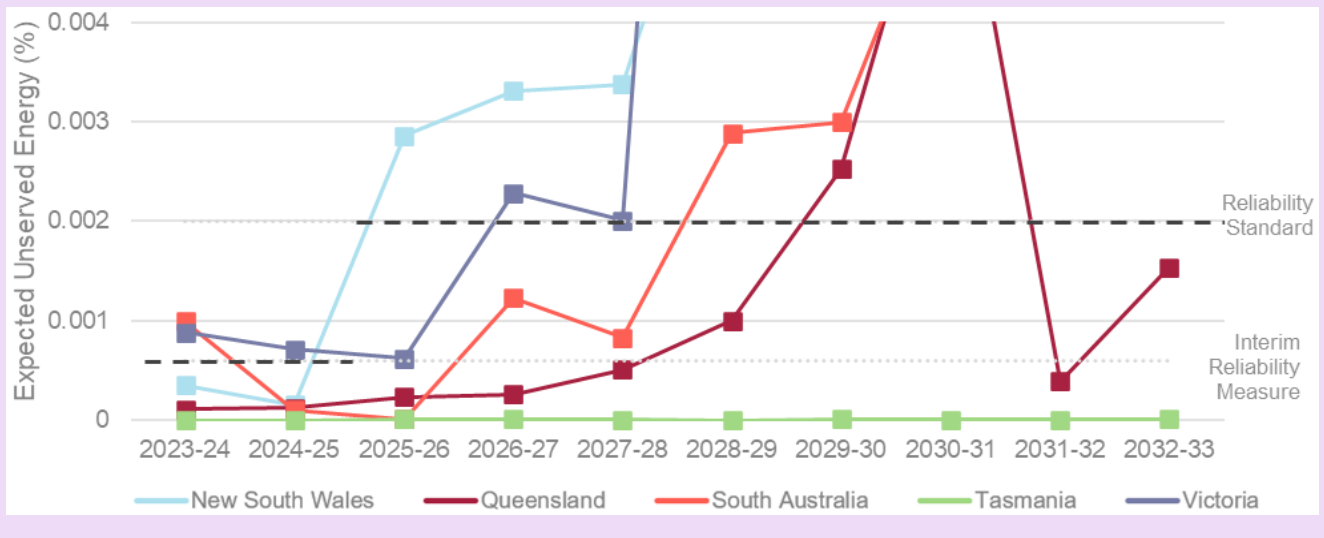
Reliability gaps are forecast in all mainland NEM regions in the next decade when considering only those energy supply infrastructure developments that have made sufficient progress against AEMO’s commitment criteria, signalling a need for further commitment and delivery of generation, transmission, demand side participation (DSP) and consumer assets such as batteries that can be orchestrated to minimise grid requirements.

Figure 1 shows the reliability forecast and indicative reliability forecast for the 2023 ESOO Central scenario. This forecast considers only the sub-set of known developments that have demonstrated sufficient commitment towards commissioning in the NEM (those developments classified as committed or anticipated), including announced retirements, and allows for project delivery schedules that may be slower than proponents have advised based on observed development, approval and commissioning requirements.

⁴ 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.

The ESOO Central scenario includes committed, in commissioning, 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 orchestrated to minimise grid requirements. Projects yet to reach final commissioning phases have been assumed to progress according to typical development, approval and commissioning timelines, which may be later than the dates advised by project developers.

Figure 1 Expected unserved energy, ESOO Central scenario, 2023-24 to 2032-33 (%)



In this ESOO Central scenario, electricity consumption and maximum peak demands are forecast to grow over the next 10 years, more strongly in the second five years than in the first. Forecast growth is higher than the 2022 ESOO in some regions.

This growth is forecast as opportunities emerge to electrify residential, commercial, industrial and transportation sectors. Emerging policy support for electric vehicles (EVs) and gas substitution demonstrate the potential for more significant use of electricity instead of other energy forms across Australia’s economy. The forecast sees growth in electrification complementing traditional growth drivers from population and a growing economy, with this growth offset by energy savings from energy efficiency and consumer investments in distributed PV.

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

Potential development of hydrogen electrolyzers is forecast to increase NEM electricity consumption by up to 10% by 2032-33⁵. The forecast for hydrogen electrolysis development has increased significantly since the 2022 ESOO, due to the introduction of the New South Wales Renewable Fuels Scheme, which is legislated to commence in 2024, and the South Australian Hydrogen Jobs Plan, which includes a 250 megawatts (MW) electrolyser with a target to commence operations in 2025-26.

The ESOO Central scenario includes a large number of generation developments that are classified as ‘in commissioning’, ‘committed’ or ‘anticipated’. In total, 20.8 GW of scheduled or semi-scheduled **generation and**

⁵ Assuming that electrolyzers operate to provide new energy options to consumers, including potential hydrogen-ready gas generators that are not yet advanced enough to consider in the Central scenario. The development of hydrogen generation sources is, however, noted among numerous jurisdictional plans.

storage developments are forecast to be operational by the end of 2032-33 and have been included (in addition to existing capacity). These developments include:

- Tallawarra B (320 MW) in New South Wales from November 2023.
- Kurri Kurri Power Station (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 2025⁶.
- Snowy 2.0 (2,040 MW/350,000 MWh) in New South Wales by December 2029.
- Borumba Pumped Hydro (1,998 MW/48,000 MWh) in Queensland from June 2030⁶.
- More than 5,241 MW/11,054 MWh of utility-scale batteries, including Eraring Big Battery, Hazelwood Battery Energy Storage System (BESS), Orana BESS, Swanbank BESS, Torrens Island BESS, and Wooreen BESS.
- Numerous renewable energy developments across the NEM, including 4,918 MW of wind generation and 5,212 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. These projects, included in the Central outlook, include:

- Project EnergyConnect linking South Australia, New South Wales and Victoria.
- Waratah Super Battery, including the associated System Integrity Protection Scheme (SIPS) and transmission upgrades in New South Wales, that increase transmission transfer capacity within New South Wales.
- Western Renewables Link in Victoria, connecting renewable generation in north-west Victoria to Melbourne.
- Central West Orana Renewable Energy Zone (REZ) transmission, increasing the capacity for new renewable developments in New South Wales.

While new developments continue to commission, existing generator operators have advised AEMO of an expected closure schedule⁷ that represents 6,730 MW of generation capacity (approximately 20% of the currently registered thermal – coal, gas and diesel – generation fleet) in the next 10 years, including:

- Eraring Power Station (2,880 MW) in New South Wales in August 2025.
- Torrens Island B Power Station (800 MW) in South Australia in 2026.
- Osborne Power Station (180 MW) in South Australia in 2026.
- Yallourn Power Station (1,450 MW) in Victoria in 2028.
- Callide B Power Station (700 MW) in Queensland in 2028.
- Numerous smaller gas and diesel generators (total 383 MW) in South Australia in 2030.
- Hallett Gas Turbine (240 MW) in South Australia in 2032.

In contrast, Delta Electricity has updated its expected closure date for Vales Point Power Station (1,320 MW) in New South Wales from 2029 to 2033, just beyond the 10-year outlook.

⁶ Date provided by participant. Modelling applies delays beyond the advised date.

⁷ All expected retirement dates are advised by participants, including the August 2025 potential early retirement of Eraring.

Additionally, the Queensland Energy and Jobs Plan has identified further retirements in the near term, for which expected closure schedules have not yet been provided, that will follow the development of energy hubs and renewable developments.

While generation, storage and transmission developments continue to connect to the power system, the assessment shows these committed and anticipated developments (generation, transmission and other solutions) are not yet sufficient to offset the forecast impact of higher electricity use and advised generator retirements. Delays to any other currently considered development may further worsen the reliability outlook.

The forecast reliability gaps in the first five years of the horizon, in the Central scenario when considering only those developments that meet AEMO's commitment criteria, are in:

- **Victoria in 2023-24 and 2024-25** against the IRM of 0.0006% USE – forecast reliability gaps identified at the start of the horizon did not feature in the Update to 2022 ESOO, but have arisen due to a combination of factors, including an increase in the probability of coincident low wind, and high demand conditions, higher unplanned outage rates, withdrawn gas capacity, reduced CER orchestration, and the modelled derating of short duration storages.
- **South Australia in 2023-24**, against the IRM of 0.0006% USE – forecast reliability gaps identified in 2023-24 did not feature in the Update to 2022 ESOO, but have arisen due to a combination of factors, including an increase in the probability of coincident low wind, and high demand conditions, higher unplanned outage rates, withdrawn gas capacity, reduced CER orchestration, and the modelled derating of short duration storages.
- **New South Wales from 2025-26**, against the reliability standard of 0.002% USE – forecast reliability gaps identified from 2025-26 align with the retirement of the Eraring Power Station and are larger than that forecast in the Update to 2022 ESOO, due to higher forecasts of maximum demand, a reduced contribution from the New South Wales Peak Demand Reduction Scheme, higher unplanned outage rates, reduced CER orchestration, and the modelled derating of short duration storages.
- **Victoria in 2026-27** against the reliability standard of 0.002% USE – forecast reliability gaps identified in 2026-27 align with the retirement of the Torrens Island B Power Station in South Australia and are larger than those identified in the Update to 2022 ESOO, due to a combination of factors, including an increase in the probability of coincident low wind, and high demand conditions, higher unplanned outage rates, withdrawn gas capacity, reduced CER orchestration, and the modelled derating of short duration storages.

Where this 2023 ESOO identifies a forecast reliability gap for a region, AEMO must request the Australian Energy Regulator (AER) to consider making a reliability instrument under Chapter 4A of the NER (**Retailer Reliability Obligation [RRO]**). In this 2023 ESOO, the following forecast reliability gaps meet the requirements for AEMO to make requests to the AER to consider making the following RRO instruments:

- In **New South Wales**, for a T-3 reliability instrument for the period of 2026-27.
- In **Victoria**, for a T-3 reliability instrument for the period of 2026-27.

While the Australian Energy Market Commission (AEMC) has made a draft decision that the IRM should apply as the reliability standard for the purposes of the RRO until 30 June 2028, at the time of publication of this 2023 ESOO a final decision has not yet been made by the AEMC regarding this matter. Should the AEMC make a final decision to extend the application of the IRM until 30 June 2028, AEMO will take the appropriate steps in accordance with the amended rules requirement

While the ESOO Central scenario considers committed and anticipated developments, it does not include the significant policy mechanisms of federal, state and territory governments that are likely to bring in further new VRE, storage, gas and/or hydrogen generation plant, nor does it include specific jurisdictional investments underway if these do not meet the relevant commitment criteria (including those with direct funding, or indirect funding, via government agencies including the Australian Renewable Energy Agency [ARENA]).

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

- In **New South Wales, South Australia and Victoria** over the entire five- to 10-year period (2028-29 to 2032-33).
- In **Queensland** in 2029-30 and 2030-31. Borumba Pumped Hydro is expected to commission prior to 2031-32, reducing risks in Queensland from that year onwards.

Federal and state government programs, actionable transmission developments, orchestrated consumer investments and demand flexibility have the potential to address the majority of forecast reliability risks

While the ESOO Central scenario demonstrates an increase in reliability risk, there are many schemes and developments that have the potential to address the identified risks.

A much larger pipeline of proposed generation and storage projects – totalling 173 GW of VRE and 74 GW of dispatchable resources (including battery, pumped hydro, and other technologies) – demonstrate the opportunity for the market to respond to emerging reliability gaps, if projects are developed in a timely manner. Numerous federal and state government schemes and programs have been implemented to further incentivise or fund the required developments in the NEM. Schemes currently underway include:

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

These schemes, if supported by the development of actionable transmission projects, as identified in the 2022 *Integrated System Plan (ISP)*⁸, and the development of 6.6 GW/16.3 gigawatt hours (GWh) of orchestrated consumer investments (largely behind-the-meter battery systems) and 2.1 GW of flexible demand response that are projected in the *Step Change* scenario by 2032-33, have the potential to significantly improve the outlook if they progress as projected. The range of actionable transmission developments includes:

- New England REZ transmission links, and the Hunter Transmission Project in New South Wales.
- Strategic transmission projects which would improve inter-regional transfer capacities, including HumeLink, Marinus Link, and Victoria – New South Wales Interconnector (VNI) West.

⁸ See <https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp>.

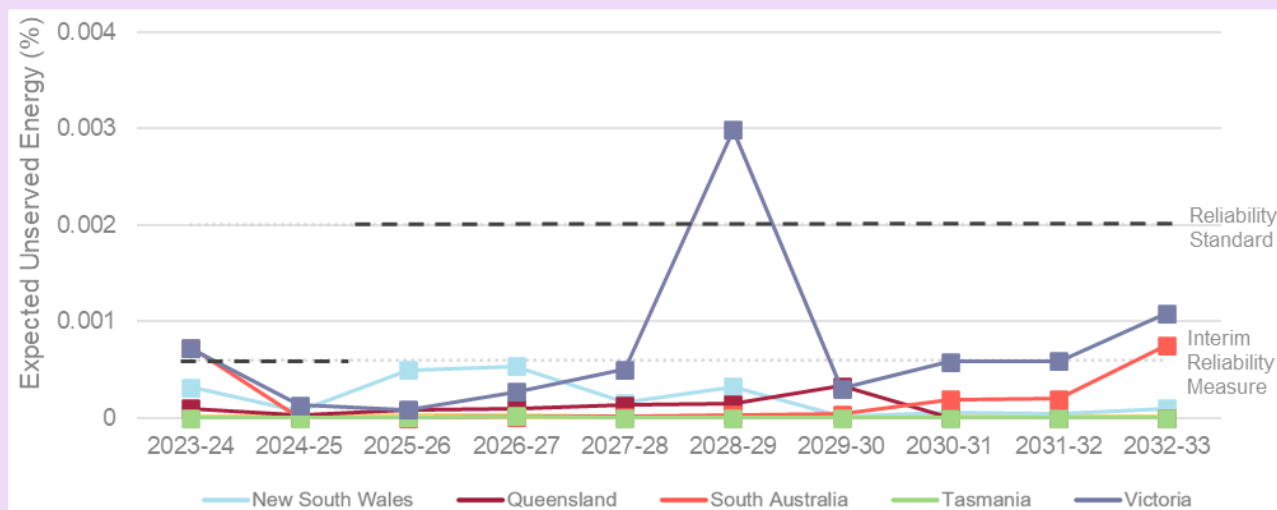
Figure 2 shows that the additional investments in renewable generation, dispatchable capacity, transmission and CER are forecast to further reduce reliability risks to below the relevant reliability standard in most regions. Other policies, such as a longer-term capacity investment scheme, and various renewable energy and storage targets, are developing to support additional firming and renewable capacity that are not included in this sensitivity.

The *Federal and state schemes* sensitivity includes all developments in the *ESOO Central scenario*, delivered to the schedules advised by project developers, as well as:

- Actionable transmission investments and forecast growth in consumer investments (orchestrated CER and DSP).
- 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, and reliability outcomes may improve if all jurisdictional mechanisms deliver to their objectives.

Figure 2 Expected USE, Additional actionable and anticipated developments, 2023-24 to 2032-33 (%)



This sensitivity shows that many of the forecast reliability risks could be managed with the timely delivery of the assets that are being developed by these schemes. Reliability risks are forecast above the reliability standard in Victoria in 2028-29 when Yallourn Power Station retires, but below the reliability standard in 2029-30 when VNI West and the first Marinus Link cable are fully commissioned. Additional policy mechanisms are also under development by various jurisdictions to support the development of renewable energy and firming capacity, but are yet to demonstrate clear development pathways to achieve their objectives. Additional market-led developments in renewable and firming technologies, not modelled in this sensitivity, also have the potential to further reduce risks.

While the sensitivity demonstrates that there is potential to address the majority of the forecast reliability risks for many jurisdictions over the ES00 horizon with existing schemes, additional opportunities and deliverability challenges remain. Project development delays and broader 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.

Contents

Executive summary	3
1 Introduction	14
1.1 Forecasting supply and reliability	15
1.2 Forecasting demand	19
1.3 Additional information for 2023 ESOO	22
2 Consumption and demand forecasts	26
2.1 Drivers of electricity consumption and demand	27
2.2 Underlying consumption continues to increase, with CER and energy efficiency slowing operational consumption growth	28
2.3 Maximum operational demand forecast to grow	34
2.4 Minimum operational demands forecast to rapidly decline	37
2.5 Flexible demand can enhance the NEM's ability to meet forecast peak demand	40
3 Supply and network infrastructure forecasts	43
3.1 Generator commissioning and decommissioning assumptions	43
3.2 Seasonal generator availability	50
3.3 Generator unplanned outage rates	51
3.4 Transmission limitations	53
3.5 Inter-regional transmission unplanned outage rates	57
4 Supply scarcity risks in the next year	58
4.1 While reliability risks are forecast above the IRM in South Australia and Victoria, adverse outcomes remain possible in all regions	59
4.2 Demand outcomes are more likely at the upper range of the maximum demand forecast during El Niño weather conditions	61
4.3 The availability of wind generation at time of maximum demand is a major factor influencing the risk of USE	62
4.4 Risk mitigation and summer readiness	65
5 Reliability forecasts	67
5.1 Key assumptions	67
5.2 The reliability forecast (first five years)	68
5.3 The indicative reliability forecast (second five years)	70
5.4 Delivering transmission, generation, storage and demand response investments is needed to reduce reliability risks	72
5.5 Reliability forecast components	75
6 Energy Adequacy Assessment Projection	80
6.1 Generator Energy Limitations Framework parameters	81
6.2 EAAP Central scenario	83

6.3	EAAP Low Rainfall scenario	86
6.4	EAAP Low Thermal Fuel scenario	89
7	Alternate development sensitivities	92
7.1	Consumer investments and load flexibility have the potential to minimise reliability risks	92
7.2	Actionable transmission developments significantly improve the reliability outlook	96
7.3	Federal and state generation development schemes have the potential to address the majority of longer-term risks	100
7.4	Delaying generator retirement has the potential to address medium-term risks if necessary	104
8	Demonstrating the reliability impacts of 2023 ESOO methodology improvements	106
8.1	Maximum and minimum demand forecast	106
8.2	Reliability Forecasting Guidelines and Methodology Consultation	107
8.3	Short Duration Storage Methodology Consultation	107
8.4	The impact of methodology changes	108
	List of figures and tables	111
A1.	New South Wales outlook	117
A2.	Queensland outlook	126
A3.	South Australia outlook	135
A4.	Tasmania outlook	144
A5.	Victoria outlook	151
A6.	Demand side participation forecast	161
A6.1	DSP definition	161
A6.2	DSP forecast by component	162
A6.3	DSP statistics	166
A7.	EAAP detailed results	172
A7.1	Central scenario	172
A7.2	Low Rainfall scenario	173
A7.3	Low Thermal Fuel scenario	174

Version control

Version	Release date	Changes
1	31/8/2023	Publication release
2	6/9/2023	Correction of figures 11,66 and 67
3	9/10/2023	Correction of wording on page 132

1 Introduction

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 advice on the need for additional further generation, transmission and demand response developments in the power system, beyond those developments for which formal commitments have already been made.

Investment lead times will limit the operational means by which reliability risks may be mitigated, but 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 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 risks identified as a result serve to advise on the risks of inaction and can be viewed in the context of the pipeline of projects for which formal commitments have not yet been made.

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 and gaps which are required to be addressed by transmission network service providers (TNSPs)⁹.

⁹ 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>.

1.1 Forecasting supply and reliability

Following extensive stakeholder consultation, AEMO has updated its forecasts and supply adequacy assessment in the NEM by:

- Updating demand forecasts for all regions, taking into account the latest information on economic and population drivers and trends in behaviour by household and business consumers, including electrification impacts. The forecasts for operational consumption and demand also reflect forecasts for implemented energy efficiency measures and growth in 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 and expected closures.
- Reviewing the performance of existing scheduled generation based on historical performance data, and incorporating forward-looking projections of plant reliability for coal-fired and large gas-fired generators that take into account the impact of maintenance plans, plant deterioration due to age, and reductions in maintenance as generators approach retirement.
- Applying a statistical simulation approach¹⁰ which assesses the ability of existing, committed and anticipated¹¹ 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 13 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)¹² 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.

¹⁰ See *ESOO and Reliability Forecast Methodology*, at <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities>.

¹¹ 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>.

¹² 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:

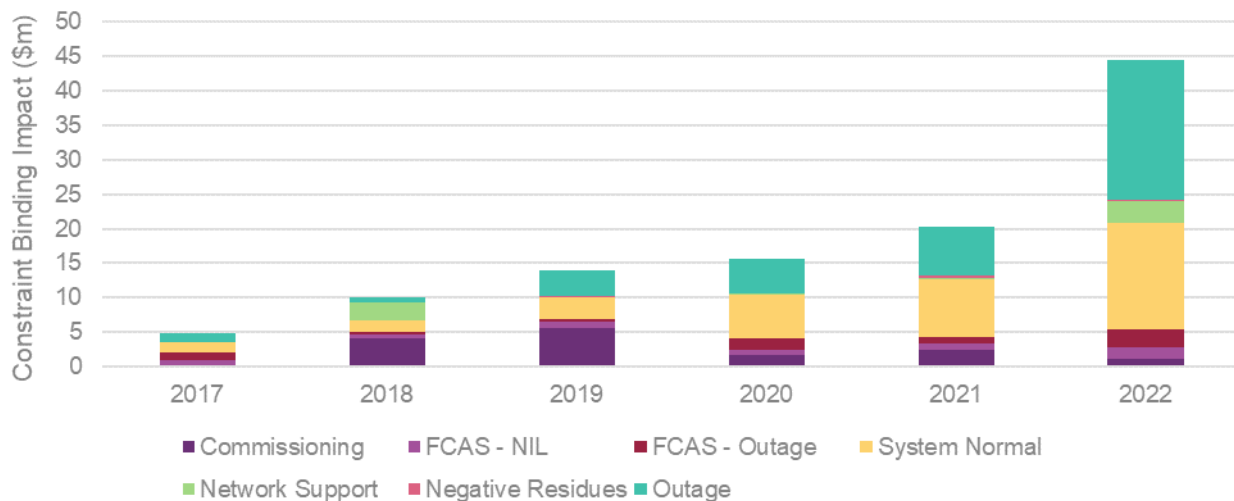
- Distribution and transmission network outages that directly impact local supply.
- Transmission outages that curtail generation, resulting in insufficient levels of supply relative to demand.
- Power system security events, for example a double-circuit outage on a transmission line.
- Prolonged generator 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. **Figure 3** shows the NEM constraint binding¹³ impact, which represents the financial impact of the binding constraint equations from 2017 to 2022 as published in the NEM Constraint Report 2022¹⁴. While the constraint binding impact has grown across many categories, the impact of transmission outages (‘Outage’) has grown to be the largest cause of constraints binding, and generation curtailment. As these outages are explicitly excluded from the definition of USE, AEMO does not forecast their impact in reliability assessments.

Figure 3 NEM constraint binding impact



¹³ 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.

¹⁴ 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 is likely to result in larger consumer load shedding impacts than those 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)¹⁵. Instead, the forecast annual USE in a region reflects the projected source of any supply shortfall in that region, 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.

The assessment does, however, 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 4** (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 2025, however the AEMC has made a draft decision that the IRM should apply to the RRO until 30 June 2028¹⁶. The AEMC is currently consulting on its draft decision and will shortly make a final decision regarding any extension¹⁷.

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.

¹⁵ See <https://www.aemc.gov.au/sites/default/files/content/Guidelines-for-Management-of-Electricity-Supply-Shortfall-Events.PDF>.

¹⁶ In May 2023, the AEMC completed a review of the IRM, recommending an extension of its application to the RRO until 30 June 2028. See <https://www.aemc.gov.au/market-reviews-advice/review-interim-reliability-measure>.

¹⁷ See <https://www.aemc.gov.au/rule-changes/extension-application-irm-rro>.

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 six years.
- Larger USE outcomes¹⁸ 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 utilised to mitigate some of these risks with associated costs.

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 outcomes¹⁸ would occur approximately once every five years (equivalent to approximately 12% of average regional demand for eight hours).
- 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 utilised to mitigate some of these risks with associated costs.

For the 2023 ESOO, the IRM of 0.0006% USE will apply until 30 June 2025 and the reliability standard of 0.002% USE will apply from then. AEMO will review any forecast reliability gaps once the AEMC has made a final decision regarding any extension of the IRM and the rule is in place.

The AEMC and Reliability Panel are currently reviewing the form of the reliability standard to determine if another form better reflects changing reliability risk as the NEM transitions to net zero¹⁹. This review seeks to inform the next Reliability Settings and Standards Review by the Reliability Panel for the period beginning 1 July 2028.

¹⁸ 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.

¹⁹ See <https://www.aemc.gov.au/market-reviews-advice/review-form-reliability-standard-and-apc>.

AEMO believes that the current reliability definition exposes customers to low probability but high impact risks within the ‘tail’ of the reliability distribution. As in previous ESOOs, the 2023 ESOO demonstrates these risks. AEMO has recommended that any change to the reliability standard incorporate tail risk more explicitly, which would be expected to deliver a more appropriate relationship between planning and operational outcomes.

1.1.2 Definitions for the Retailer Reliability Obligation (RRO)

The **reliability forecast** refers to the first five years of the ESOO Central scenario forecast horizon. For the 2023 ESOO, the reliability forecast covers the financial years 2023-24 to 2027-28.

The **indicative reliability forecast** refers to the second five years of the ESOO Central scenario forecast horizon. For the 2023 ESOO, the indicative reliability forecast covers the financial years 2028-29 to 2032-33.

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 2025, or exceeds the reliability standard of 0.002% USE from 1 July 2025 onwards. The AEMC has determined that the IRM should provide a trigger for the RRO until 30 June 2028, and final rules to implement this determination are expected in September 2023. Should the AEMC extend the application of the IRM in this final determination, AEMO will consider issuing an update to this ESOO and Reliability Forecast consistent with the amended rules.

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.

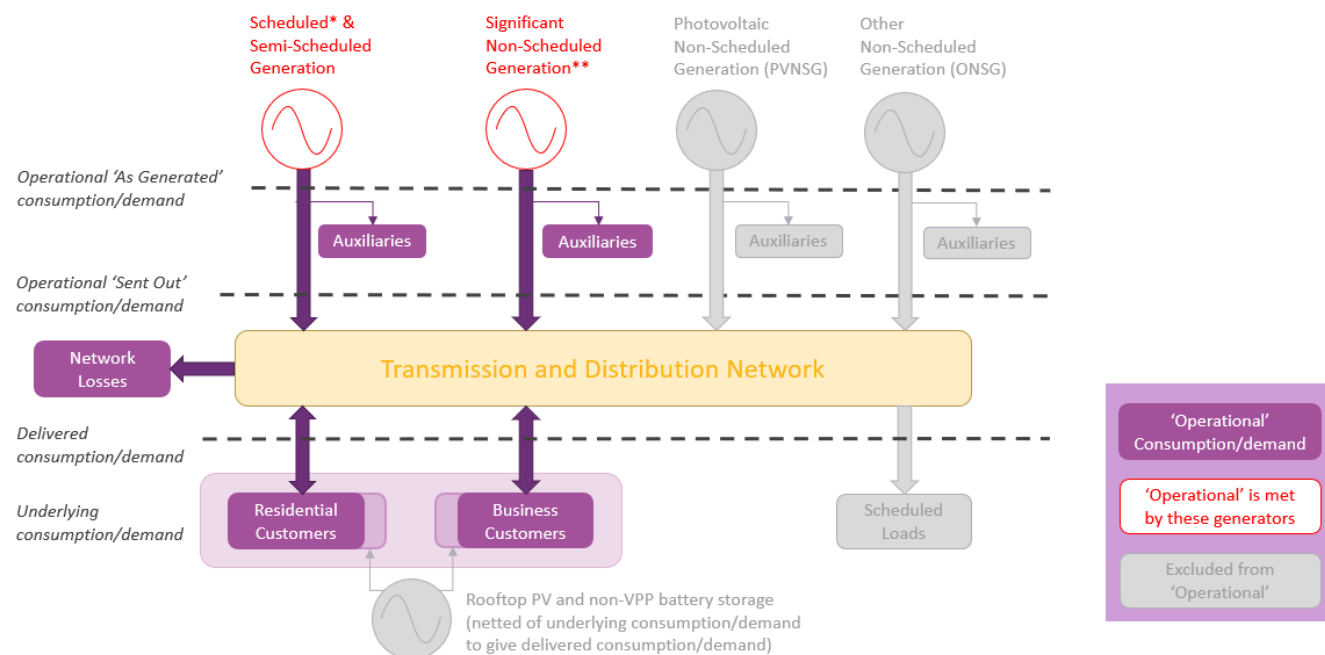
Consumption and demand can be measured at different locations in the electricity network. Unless otherwise stated, the forecasts in this report refer to **operational consumption/demand (sent out)**²⁰. This is the supply to the grid by scheduled, semi-scheduled, and significant non-scheduled generators (net of their auxiliary loads,

²⁰ See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Demand-Forecasts/Operational-Consumption-definition.pdf.

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 grid to household and business consumers. Annual operational consumption forecasts include this forecast delivered consumption for all consumer sectors, plus electricity expected to be lost in transmission and distribution.

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

Maximum and minimum operational demand means the highest and lowest level of electricity drawn from the grid, measured and averaged from the power system in half-hour intervals in either **summer** (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 expected nine years in 10.

1.2.1 Scenarios and sensitivities

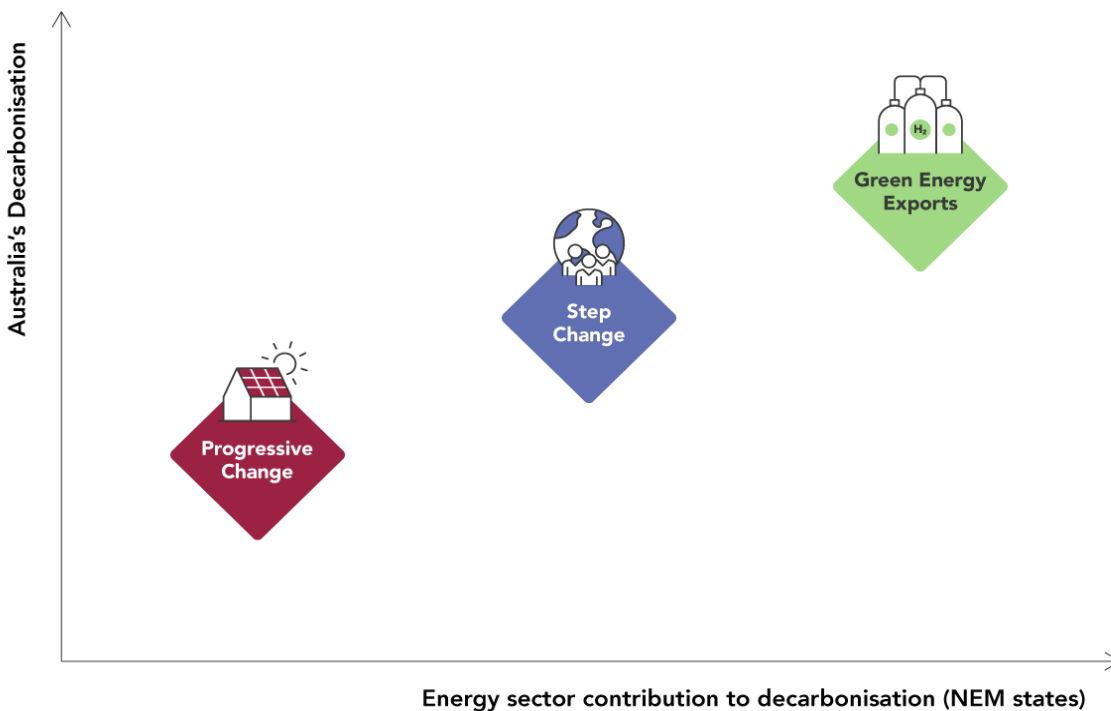
In consultation with a diverse range of stakeholders, AEMO developed the *2023 Inputs, Assumptions and Scenarios Report (IASR)* for use in its forecasting and planning publications, including the 2023 ESOO and the 2024 *Integrated System Plan (ISP)*.

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 appropriate insights for each of the scenarios as follows:

- Consumption and demand has been forecast for each of the scenarios shown in **Figure 5**, across the 30-year forecast period 2023-24 to 2052-53. The forecasts for each region are in Appendices A1-A5.
- For RRO purposes, AEMO’s Reliability Forecast Guidelines²¹ require that the reliability and indicative reliability forecasts are determined from the scenario AEMO considers most likely. For the 2023 ESOO, AEMO considers the *Step Change* demand scenario the most likely and refers to it as the 2023 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.
- Reliability assessments focus on the ESOO Central scenario, and include alternate sensitivities to key assumptions and uncertainties affecting the reliability forecast over the 10-year outlook.

Figure 5 2023 IASR scenarios for AEMO’s forecasting and planning publications



²¹ At <https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo>.

Table 2 summarises the scenarios presented in this ESOO, while **Table 3** summarises inputs for each scenario that are relevant to the demand forecasts. More information is available on the scenarios in the 2023 IASR²².

Table 2 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.

Table 3 Scenario drivers of most relevance to the NEM demand forecasts used in this 2023 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)

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

1.3 Additional information for 2023 ESOO

ESOO information under NER 3.13.3A

The following information should be considered part of the 2023 ESOO:

²² At <https://aemo.com.au/consultations/current-and-closed-consultations/2023-inputs-assumptions-and-scenarios-consultation>.

- The 2023 ESOO report and supplementary information published on the 2023 ESOO webpage²³.
- The demand forecasting data portal²⁴.
- The July 2023 Generation Information page update²⁵.
- The 2023 IASR²⁶, accompanying assumptions workbook and supplementary material.

To meet the obligations under the RRO²⁷, the ESOO also includes:

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

Reliability forecast under the RRO

In the 2023 ESOO, the reliability forecasts and indicative reliability forecasts published in accordance with the RRO constitute **Chapter 5** in this report. Key component forecasts and inputs include:

- Consumption and demand forecasts (see **Chapter 2**, the demand forecasting data portal²⁸, and the demand traces²⁹).
- Supply forecasts (see **Chapter 3** and the renewable generation traces²⁹).
- The accompanying July 2023 Generation Information page³⁰.
- Sections of the 2023 IASR 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 3.3 of the 2023 IASR).
 - CER forecasts (Section 3.3.7 of the 2023 IASR).
 - Renewable generation traces (Section 3.6.2 of the 2023 IASR).
 - Demand side participation (DSP) forecasts (Section 3.3.13 of the 2023 IASR).
 - Generator outage rates (Section 3.4.3 of the 2023 IASR).

²³ At <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities>.

²⁴ At <http://forecasting.aemo.com.au/>.

²⁵ At <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information>.

²⁶ At <https://aemo.com.au/en/consultations/current-and-closed-consultations/2023-inputs-assumptions-and-scenarios-consultation>.

²⁷ The RRO came into effect on 1 July 2019 through changes to the National Electricity Law, the National Electricity Rules, and South Australian regulations. For more information, see <http://www.coagenergycouncil.gov.au/publications/retailer-reliability-obligation-rules>.

²⁸ See <https://forecasting.aemo.com.au>.

²⁹ Supporting traces (demand, renewable energy) are available at <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities>.

³⁰ At <https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information>.

Further information and links

Table 4 provides links to additional information provided either as part of the 2023 ESOO accompanying information suite, or in related AEMO planning information.

Table 4 Links to supporting information

Information source	Website address and link
AEMO Forecasting Approach: <ul style="list-style-type: none"> • <i>Demand Forecasting Methodology Information Paper</i> • <i>Demand Side Participation (DSP) Forecasting Methodology</i> • <i>Reliability Forecast Guidelines</i> • <i>ESOO and Reliability Forecast Methodology Document</i> 	https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-approach
2023 Inputs, Assumptions and Scenarios report (IASR)	https://aemo.com.au/en/consultations/current-and-closed-consultations/2023-inputs-assumptions-and-scenarios-consultation
2023 ESOO supplementary results, data files, and constraints, including: <ul style="list-style-type: none"> • 2023 ESOO model and user guide • 2023 ESOO demand and variable renewable energy traces • 2023 ESOO reliability outcomes by region 	https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo
Reliability Standard Implementation Guidelines (RSIG)	https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/reliability-standard-implementation-guidelines
Demand forecasting data portal	http://forecasting.aemo.com.au/
Forecasting Accuracy Reporting and Forecast Accuracy Report Methodology	https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/forecasting-accuracy-reporting
Generation Information web page	https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information
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)	https://www.aer.gov.au/system/files/AEMO%20-%202022%20Forecasting%20Best%20Practice%20Approach%20Report.pdf
Consultant reports supporting the development of the 2023 IASR and ESOO	
BIS Oxford Economics, 2022 Macroeconomic Projections Report	https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/bis-oxford-economics-2022-macroeconomic-outlook-report.pdf
CSIRO, 2022 Electric Vehicle Forecasts Report	https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/csiro-2022-electric-vehicles-projections-report.pdf?la=en
CSIRO, 2022 Solar PV and Battery Projections Report	https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/

Information source	Website address and link
	supporting-materials-for-2023/csiro-2022-solar-pv-and-battery-projections-report.pdf?la=en
Green Energy Markets, 2022 Solar PV and Battery Projections Report	https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/gem-2022-solar-pv-and-battery-projection-report.pdf?la=en
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	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities

2 Consumption and demand forecasts

Consumer demand is a key consideration in the assessment of supply adequacy. This chapter discusses the consumption and maximum and minimum demand forecasts in the 2023 ESOO. It focuses commentary on the next 10 years, and includes forecasts over the next 30 years. The key observations are:

- Consumption growth over the next decade is predicted to occur at a faster pace than forecast in the 2022 ESOO, despite continued investments in CER that offset the energy supplied from the grid. Primary drivers of growth in consumption include economic activity, population growth, electrification of all sectors of the economy, and the emergence of a domestic hydrogen industry, accelerated by supportive jurisdictional policy.
- Maximum demand is forecast to grow over the forecast horizon, broadly consistent with energy consumption growth, but with much less offset from distributed PV, as operational maximum demand is now typically in the early evening, with little or no contribution from PV systems.
- With the projected sustained uptake of distributed PV, minimum demand forecasts continue to show a rapid decline.

Longer-term consumption and demand forecasts to 2053, 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 Portal³¹.

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 2023 IASR.

Other key themes include:

- Business electrification and EV uptake in the residential and business sectors drive more than three quarters of forecast consumption growth over the next 10 years. This is despite slower business electrification forecasts compared to the 2022 ESOO which gives more consideration to physical constraints on the rate of electrification.
- Stronger growth in residential distributed PV offsets consumption, although lower energy efficiency forecasts in the business sector, following update information received on the impact of some policy measures, such as the

³¹ At <https://forecasting.aemo.com.au/>.

Greenhouse Energy Minimum Standards (GEMS) program, provide some consumption uplift relative to the 2022 ES00.

- The business mass market (BMM) sector is expected to grow steadily in the next decade, following a decline in the near term induced by retail price increases. Strong population growth is expected to drive demand for further expansions of the Commercial and Services³² industries in the medium to long term.
- The pace, scale and location of electrification and other emerging opportunities, such as hydrogen production, remain an uncertain influence on the growth of NEM electricity consumption. Australia's current nationally determined contribution (NDC) to the Paris Agreement³³ commits to 43% emissions reduction by 2030 relative to 2005 emissions levels, as well as achieving net zero emissions by 2050. These commitments provide clear decarbonisation objectives in all scenarios. With all states and territories with similar decarbonisation objectives, reduced breadth exists across the scenarios for the assumed consumer appetite to reduce emissions via electrification, relative to the 2022 ES00 (particularly in the short term). The *Progressive Change* scenario considers some downside risk due to uncertainty from domestic and international challenges such as supply chain considerations and potential industrial closures.

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 demand forecasts, 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 2023 ES00 – 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. Emerging hydrogen production for primarily domestic-use purposes is also an influence.

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 consumption is further driven by local economic conditions, global commodity markets, and in some cases weather. Increased industrial activity is forecast in the short to medium term, in line with the 2022 ES00, although some downside is anticipated in the near term due to production downgrades advised to AEMO by facility operators. Growth trends forecast from multi-sector modelling in the mining and manufacturing sectors increase industrial consumption in the longer term. Small to medium-sized commercial enterprises in the BMM sector are similarly linked to economic conditions. These customers are price-sensitive and can be subject to downturns during periods of elevated electricity prices, as is currently the case.

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

The same drivers influence maximum (and minimum) demand forecasts, but random weather-driven elements, co-incident customer behaviours, and the extent of co-ordination of CER have a larger influence on the magnitude of demand peaks. As previous ES00s have noted:

³² Commercial and Services includes a wide range of industries such as Wholesale and Retail Trade. The extensive list is captured by Australian and New Zealand Standard Industrial Classification (ANZSIC) divisions F, G, H, J, K, L, M, N, O, P, Q, R and S.

³³ See <https://unfccc.int/process-and-meetings/the-paris-agreement/the-paris-agreement>.

- Maximum demand periods are forecast to frequently occur outside daylight hours in all regions. This reduces the impact of distributed PV uptake on the maximum demand forecast, relative to other fundamental drivers of growth such as new connections or appliance uptake. The relatively strong dampening impact of distributed PV on consumption is therefore not observable on maximum demand forecasts, which show stronger growth.
- Minimum demand is continuing to decline driven by distributed PV eroding daytime operational demand. Due to the significant installed capacity of distributed PV, minimum operational demand is forecast to occur in the middle of the day in all regions.

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

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 new customer loads – affect residential, business, and industrial customer segments differently.

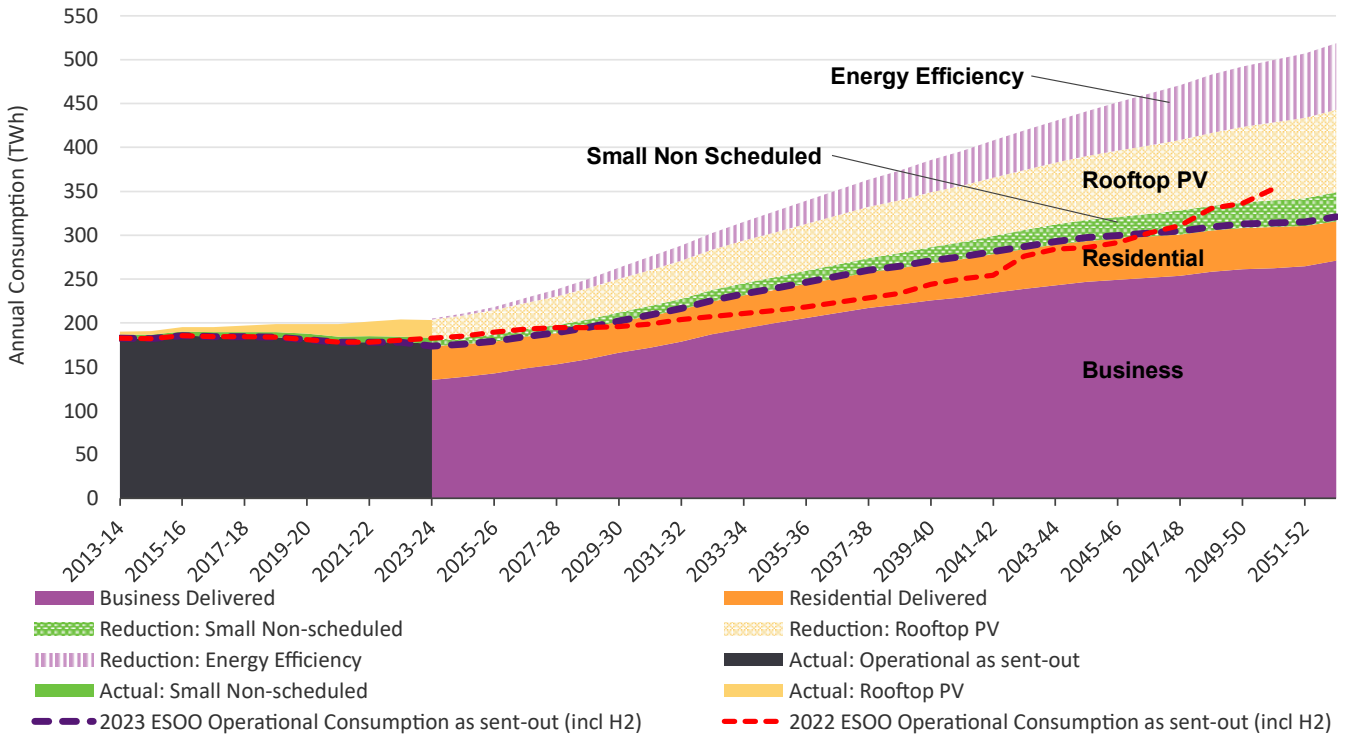
Figures 6 to 8 below show forecast annual consumption by segment in the ESOO Central forecast over the next 30 years, and highlights the various influencing factors contributing to projected changes in consumption over the next decade. This outlook of operational consumption (dark purple dashed line) is also compared to the 2022 ESOO forecast (red dashed line).

Figure 9 provides a breakdown of the different components for forecast consumption in 2032-33 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 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-A5**.

Figure 6 Actual and forecast NEM electricity consumption, ESOO Central scenario, 2013-14 to 2052-53 (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 – this 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, 2023-24 to 2052-53 (TWh)

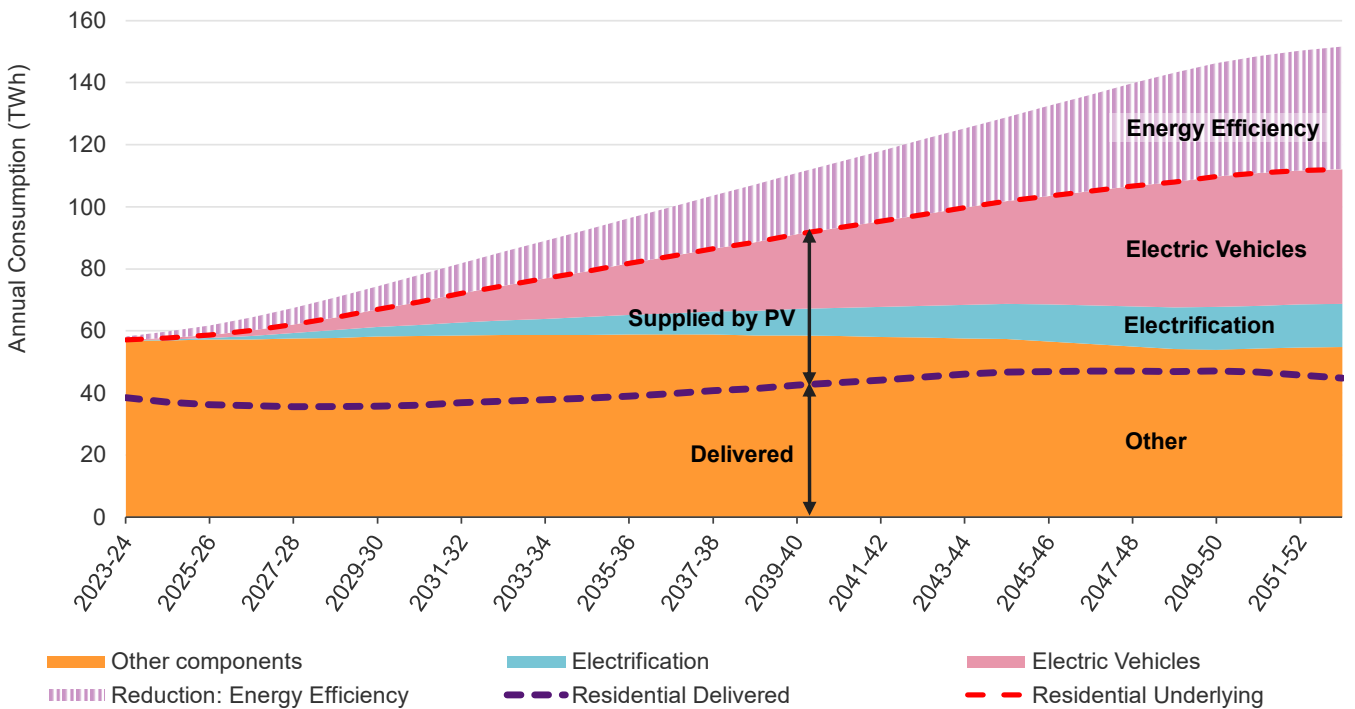
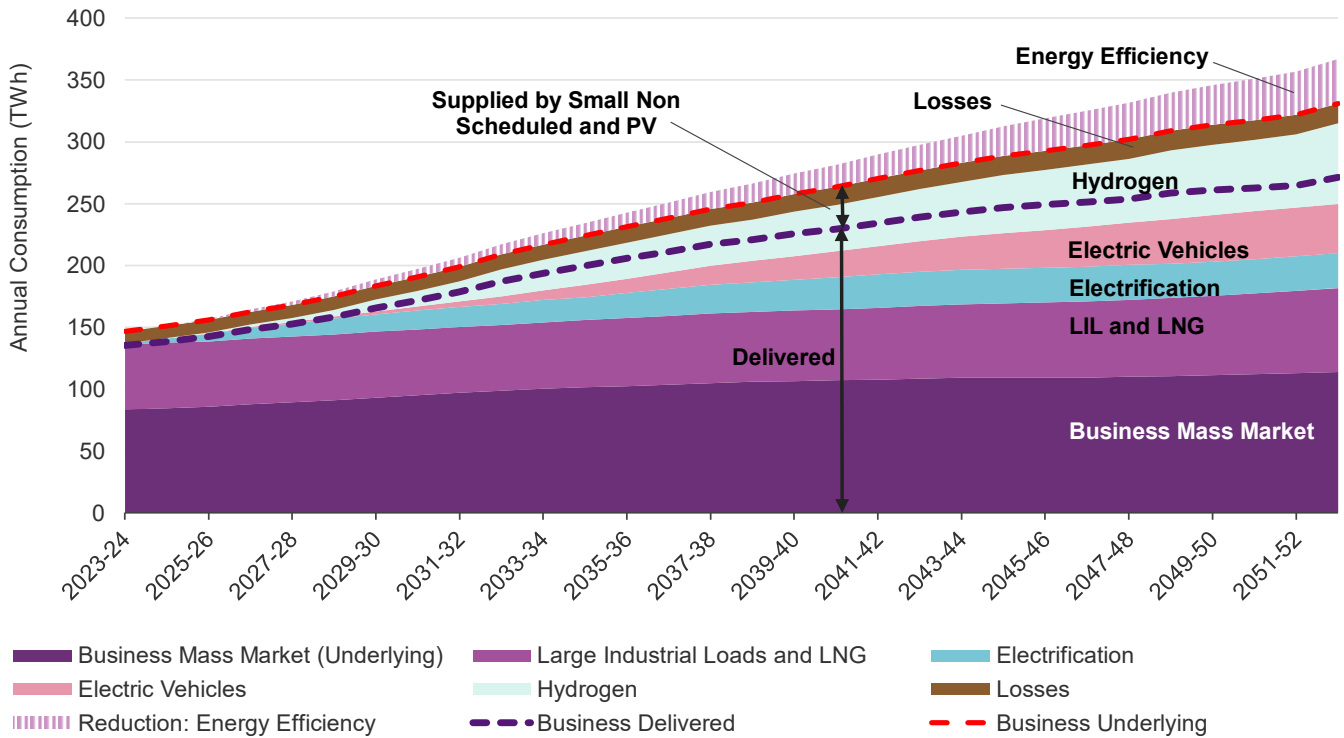
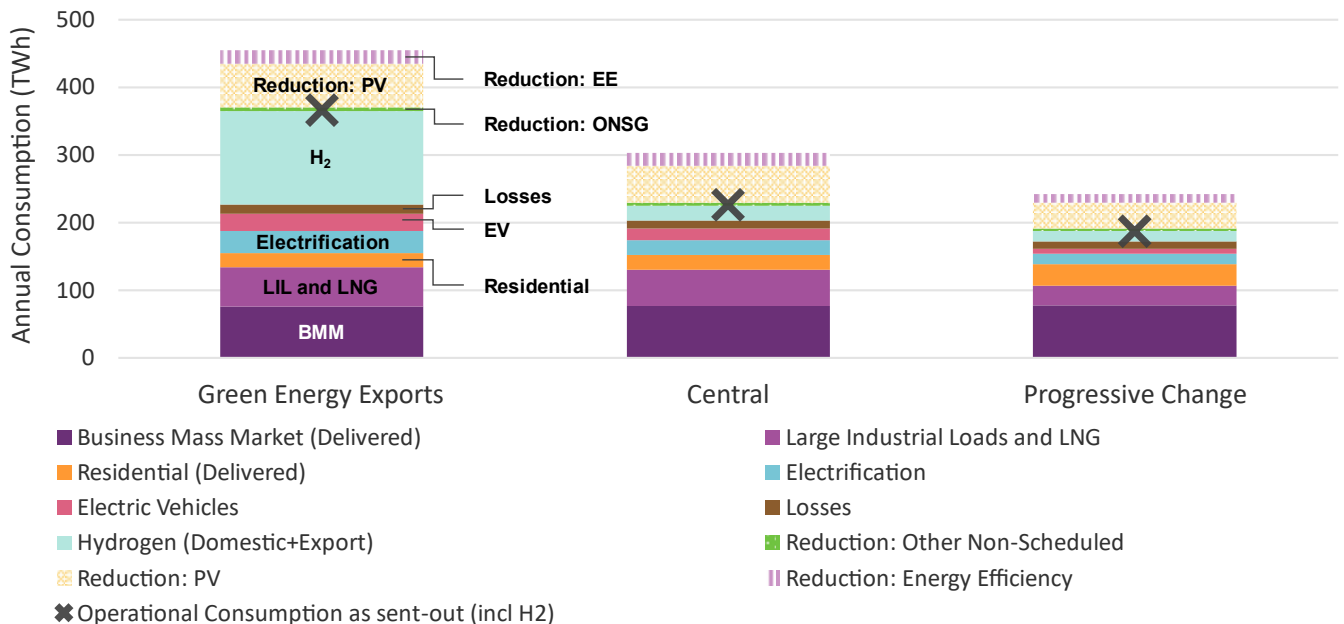


Figure 8 Components of business consumption forecast, ESOO Central scenario, 2023-24 to 2052-53 (TWh)



Note: small non-scheduled combines PVNSG and ONSG.

Figure 9 Forecast NEM consumption (by component) for the three ESOO scenarios, 2032-33 (TWh)

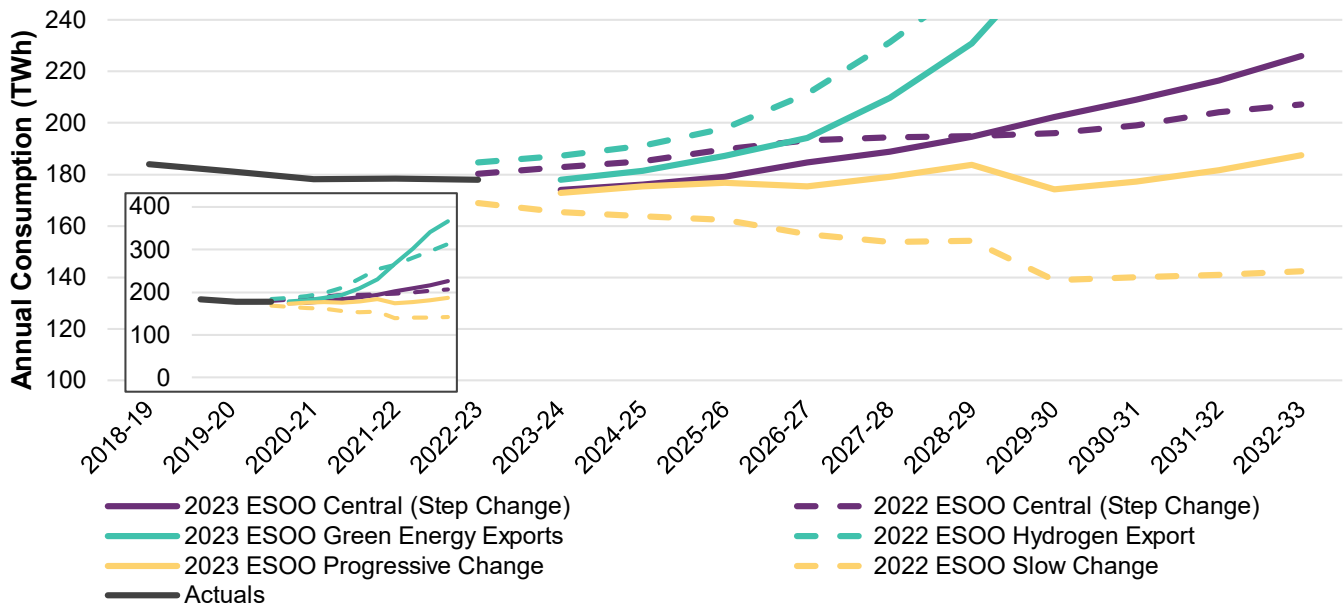


As outlined above, distributed PV and energy efficiency investments will reduce the need for electricity to be provided from traditional sources of generation to meet customer demand. Distributed PV and energy efficiency forecasts have both been updated and published in the 2023 IASR. Compared with the 2022 ESOO, this ESOO forecasts stronger uptake of distributed PV, which is offset by lower revised savings from energy efficiency investments. The net effect of the two updated components is some consumption uplift in the Central scenario.

Operational consumption is forecast in the ESOO Central scenario to increase from 177 terawatt hours (TWh) in 2022-23 to 226 TWh by 2032-33, largely due to projected growth in business and residential electrification, EV adoption, BMM and large industrial load (LIL) load growth as well as hydrogen production. This growth is partially offset by forecast sustained uptake of distributed PV and energy efficiency measures.

AEMO’s alternative scenarios continue to provide a similar spread of consumption uncertainty to 2032-33 as in the 2022 ESOO forecasts (see **Figure 10**). There is, however, a general uplift in the outlook in the longer term compared to the 2022 ESOO, as Australia’s current NDC of 43% emissions reduction target by 2030 and its broader net zero commitment by 2050 set in place decarbonisation objectives in all scenarios, narrowing the spread of the forecasts in the short term³⁴. The potential for significant growth in hydrogen production in the 2030s provides further upside in *Green Energy Exports* in the medium term. Similar to the 2022 ESOO *Slow Change*, *Progressive Change* captures downside risk due to uncertainty from domestic and international challenges such as social license, supply chain considerations and potential industrial closures, although recognises a larger electrification role to meet decarbonisation objectives than 2022’s *Slow Change*.

Figure 10 Actual and forecast NEM operational consumption, including hydrogen exports, all ESOO scenarios and compared to 2022 ESOO, 2018-19 to 2032-33 (TWh)



The *Hydrogen Export* scenario in the 2022 ESOO was thematically equivalent to the *Hydrogen Superpower* scenario used in the 2022 ISP.

The operational consumption forecasts for other scenarios are available to view or download from AEMO’s Forecasting Portal³⁵ and are further discussed for each region in **Appendices A1-A5**.

Residential consumption forecast to grow from rapid uptake of EVs, electrification and new dwellings, tempered by expanding distributed PV

Under the 2023 ESOO Central scenario, underlying residential consumption is forecast to increase 31% over the next decade, from approximately 57 TWh in 2022-23 to 75 TWh in 2032-33. This is primarily due to growth in

³⁴ AEMO’s 2022 ESOO forecasts recognised a wider range of decarbonisation outcomes, with *Slow Change* providing a lower bookend that met the policy objectives of the time for 2030 (26-28% emissions reduction), and had less coordinated achievement of a net zero objective by 2050.

³⁵ At <https://forecasting.aemo.com.au/>.

residential dwellings, and particularly the transition from traditional internal combustion engine vehicles to EVs, with more than 4 million residential EVs (consuming 11 TWh per annum) expected to be on the road by 2032-33 (or approximately 30% of residential passenger vehicles).

EVs are forecast to be close to cost parity with internal combustion engine vehicles by 2026-27 under the ESOO Central scenario. By 2032-33, 1.9 million to 6 million residential EVs are projected to be on the road, depending on the scenario, adding between 8% and 21% to residential consumption (5 TWh to 15 TWh a year).

Over the next decade, construction of around 1.7 million new dwellings is forecast to increase consumption by around 12 TWh a year alone, with further growth in consumption of nearly 5 TWh a year from electrification of space heating, hot water heating, and to a lesser extent from a switch from gas cooking appliances to electric induction. About two-thirds of the NEM's residential electrification is forecast to take place in Victoria, where many households currently use gas for heating³⁶.

Growth in distributed PV generation continues to significantly influence residential operational consumption. Currently, over 2.7 million homes in the NEM have distributed PV, supplying around 29% of the residential sector's overall underlying consumption in 2022-23. By 2032-33, this is expected to extend to 4.8 million homes, meeting roughly half of the residential sector's underlying consumption requirements. Residential PV generation is expected to continue to grow into the 2050s, meeting 60% of underlying demand in 2052-53.

Across all scenarios, underlying residential consumption is forecast to reach around 67-85 TWh in the medium term (by 2032-33), growing to 96-122 TWh in the long term (by 2052-53).

Strong growth in business consumption from electrification, BMM and an emerging hydrogen industry

Under the 2023 ESOO Central outlook, underlying business consumption – from BMM, LILs, liquified natural gas (LNG), EVs, and hydrogen production – is forecast to increase approximately 44% in the next decade, from 137 TWh in 2022-23 to 197 TWh in 2032-33. This forecast growth is primarily due to consumption from business electrification, hydrogen production and, to a lesser extent, BMM growth.

LIL forecasts have been updated for this 2023 ESOO by surveying industrial facilities directly and gathering data on load enquiries from network service providers (NSPs). LIL forecasts in the ESOO Central scenario are marginally lower than reported in the 2022 ESOO, particularly in 2023-24 due to production downgrades for some manufacturers combined with reduced operation from desalination plants following record rainfall in 2022 across much of the east coast of Australia. By 2024-25, the LIL forecasts in the Central scenario closely track the 2022 ESOO with a number of new mines as well as transport infrastructure projects expected to come online.

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

- Electrification continues to be a major growth driver of business consumption, although forecast consumption from business electrification under the ESOO Central scenario is approximately half that forecast in the 2022 ESOO through the mid-2030s. Revisions to the business electrification forecasts are the result of greater consideration of physical limitations to the rate of possible electrification within multi-sector modelling³⁷. The

³⁶ 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.

³⁷ 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.

near-term growth rate in electrification has also been lessened, given relatively little observation to date of widespread electrification.

- Hydrogen production is an emerging consumer of electricity, with the scale and timing of production a key uncertainty. Forecast electricity consumption by hydrogen electrolyzers ranges from 15 TWh and 22 TWh in the *Progressive Change* and ESOO Central scenarios, respectively. This increases to 126 TWh in the *Green Energy Exports* scenario, which expects major breakthroughs in domestic and international hydrogen demand. Compared to the 2022 ESOO, forecast hydrogen consumption has increased due to policy and investment decisions in several states:
 - A New South Wales legislated Renewable Fuel Scheme policy, which involves targets of up to 8 petajoules (PJ) of energy use by 2030 (0.06 million tonnes per annum [Mtpa] of hydrogen)³⁸, from 2024. As part of this policy, gas end users and/or gas retailers will be required to purchase green hydrogen certificates, based on their share of the natural gas market.
 - The South Australian Hydrogen Jobs Plan, funded by the South Australian Government, includes a 250 MW electrolyser located at Whyalla which is to be commissioned by the end of 2025.
- LILs are forecast to grow, due to the development of new sites as well as existing sites that have committed to production expansions. Long-term growth in LIL electricity consumption, particularly in mining and manufacturing, is projected to be fuelled by declining wholesale electricity costs. Similar to the 2022 *Slow Change* scenario, *Progressive Change* also captures downside risks, such as the impact of major industrial closures due to worsening economic conditions. In the *Progressive Change* scenario, which considers closures occurring as soon as by 2026-27, this results in a forecast decline in LIL consumption of approximately 46% relative to recent levels.
- The BMM sector is forecast to grow from 84 TWh in 2022-23 to between 92 TWh and 102 TWh by 2032-33, mostly from the Commercial and Services industries. In the short term, the BMM forecast includes a temporary price-shock contraction in consumption in response to forecast retail price rises of approximately 34% in 2023-24 compared to 2021-22. Elevated prices are expected to subside within five years as more generation capacity from renewable energy is expected to connect to the network, consistent with AEMO's 2022 ISP forecast and recognising the strong policy environment supporting renewable energy development.
 - BMM consumption has increased in a number of NEM regions since the 2022 ESOO, following further improvements to the sectoral split between the residential and the BMM sectors³⁹. The split between residential and business historical data utilises smart meter data to complement data sourced from the AER where smart meters are less common.
- The uptake of commercial EVs such as light commercial vehicles, electric trucks and buses is projected to contribute significantly to business consumption over the next decade, contributing between 2 TWh and 10 TWh across the scenarios.
- Energy efficiency investments are forecast to provide consumption savings of up to 8 TWh in 2032-33, driven by market-led efficiency improvements and policy measures to promote investment in more efficient buildings, appliances and equipment. Relative to the 2022 ESOO, some policy measures such as the GEMS program have been refined, reducing the relative uptake of these investments.

³⁸ Source: <https://legislation.nsw.gov.au/view/html/inforce/current/sl-2014-0523#sec.63>, converted using Higher Heating Value of 141.7 PJ/Mt

³⁹ The improvements in the 2022 ESOO were identified as a targeted improvement in the 2021 *Forecasting Accuracy Report* improvement plan. See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/accuracy-report/forecast-accuracy-report-2021.pdf.

- Conversely, the updated forecasts for distributed PV anticipate greater uptake rates relative to the 2022 ESOO, driving down operational consumption of the business sector by between 7 TWh and 10 TWh in 2032-33 across the scenarios.

The above key drivers result in a range of business consumption forecasts of between 152 TWh and 337 TWh in 2032-33 depending on scenario, and further widening by 2052-53.

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 projected increases in demand from LILs in Queensland and South Australia. Other drivers that affect consumption and also maximum demand are new connections, the number of appliances being used, and how and when those appliances are used.

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 reduce operational consumption, but generally has a much lower impact on maximum demand.
 - By offsetting operational demand in the early to mid afternoon, when underlying demand typically is highest, distributed PV causes maximum demand in all mainland states to generally fall in the early evening, around sunset, where there is little to no generation from PV.
 - In Tasmania, winter cold spells and the associated heating load typically drive maximum demand to be in winter. This can either be in the morning, as residents heat their houses for the morning and businesses start up, or in the evening, when people are back from work and turn up the heating and start cooking. At either time of day, there is generally no distributed PV generation due to the fewer daylight hours in winter.
- Heating and cooling load is a small proportion of overall annual electricity consumption, but on particularly extreme hot or cold days, it can contribute to half the demand in some instances, causing a much higher impact on maximum demand. Relevant drivers 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 orchestrated through a virtual power plant (VPP) will have an even greater impact on lowering peak demand. However, as outlined in **Chapter 8**, the 2023 ESOO assumes only batteries currently on VPP programs will be available to provide a coordinated response at times of maximum demand. All new batteries are assumed to be optimised for minimising the household's purchases from the grid only. A sensitivity exploring the impact of more VPPs is examined in **Section 7.1**.

- EV charging is forecast to add significantly to annual consumption. The charging profiles these EVs may use are highly uncertain; consumers that charge based on pure customer convenience are more likely to have significant impacts at time of peak, while others that charge when there is surplus PV supply during daytime hours will have a much lesser impact. In general, it is expected that charging becomes 'smarter' over time, with less impact at time of peak. Depending on the scenarios (which vary assumptions on charging behaviour and availability of public charging infrastructure), EVs may have a relatively larger impact in early years, and transition to a smaller impact in the longer term. This small impact could be achieved via coordinated charging, where the timing of EV charging is coordinated through a third-party agent/aggregator to occur at times where supply is more readily available. In such instances, EV charging may have little impact at time of peak, but lift demand significantly at time of minimum demand.
- 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). The annual consumption of hydrogen-related loads is forecast to grow to significant levels in some scenarios. The majority of the load is from the operation of electrolysers, which are very flexible, and this load would be expected to provide 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 projected to be very small at time of peak, even when annual consumption is substantial.

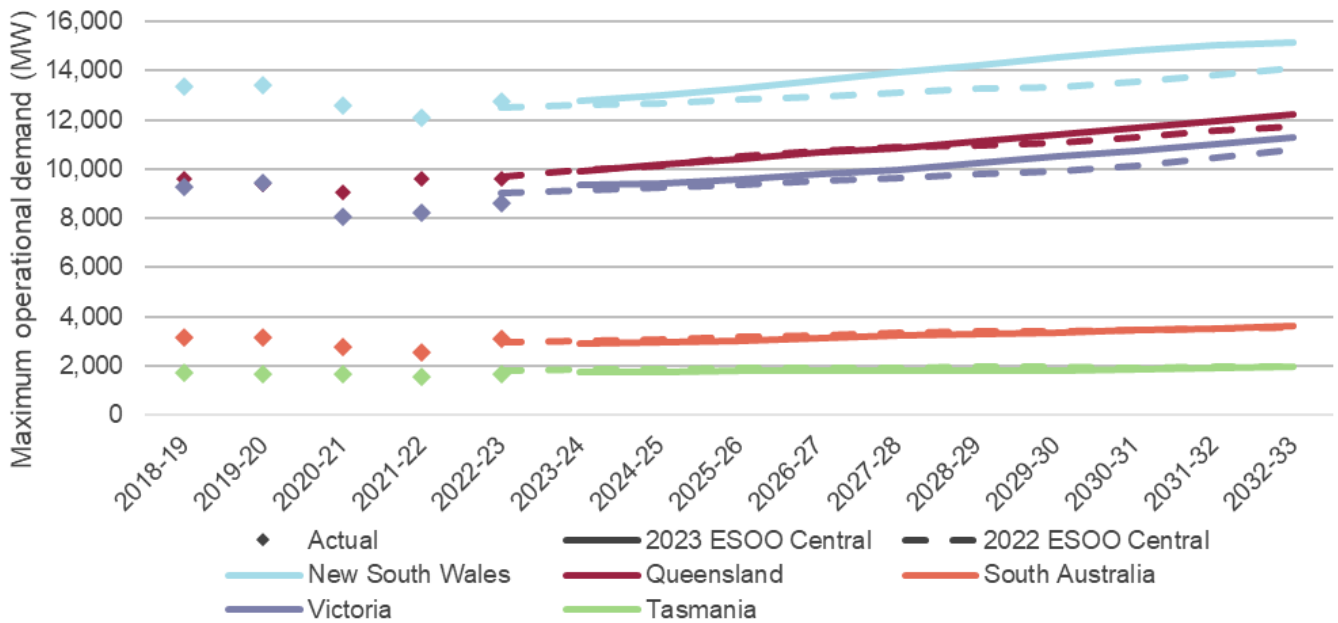
The maximum demand forecast presented in this chapter is unconstrained, and only accounts for customer-controlled battery and EV charging that is not orchestrated. The forecasts presented also do not incorporate potential hydrogen load. Instead:

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

Maximum operational demand forecast to 2032-33

Figure 11 shows the annual actual and forecast maximum operational demand (sent-out, 50% POE) for all NEM regions from 2018-19 to 2032-33 for the 2023 ESOO Central scenario, and compared to the 2022 ESOO Central scenario.

Figure 11 Actual and forecast regional annual 50% POE maximum operational demand (sent-out), 2023 ESOO Central and 2022 ESOO Central scenario, 2018-19 to 2032-33 (MW)



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

The key insights from these forecasts are:

- For the initial year, in 2023-24, forecast 50% POE maximum operational demand is lower in the 2023 ESOO than in the 2022 ESOO in Queensland, South Australia and Tasmania, while forecasts for New South Wales and Victoria start higher. In addition to the models being trained on one additional year of data, the changes to the starting point of the distributions are driven by:
 - Increases in electricity prices resulting in lower forecast maximum demand.
 - Consideration of humidity and refinements to how the magnitude and the width of the forecast distribution are forecast. In New South Wales and Victoria, these changes pushed up the 50% POE forecast, causing a higher starting point even after the adjustment to price⁴⁰. More information on the improvements to the modelling relative to last year is provided in **Chapter 8**.
- In the next four years, to 2027-28, forecast maximum operational demand (50% POE) in the 2023 ESOO is growing, due to underlying growth in the consumption forecast and limited downward pressure from distributed PV, due to the late time-of-day forecast for operational maximum demand.
 - New South Wales starts with a year of limited growth, partly due to the impact of higher prices, but after that sees stronger growth than forecast in 2022 due to a higher forecast for the BMM sector, only partly offset by a lower residential forecast. It ends up higher than forecast in the 2022 ESOO by 2027-28.
 - Queensland, South Australia and Victoria also have flat forecasts (partly due to price impacts) to 2024-25 (2025-26 for Victoria) before growth resumes, with mostly similar drivers to last year’s forecast and all three regions end up with broadly comparable forecast outcomes relative to the 2022 ESOO by 2027-28.

⁴⁰ The different POEs were affected differently by the improvements to the modelling; for 10% POE, only the Queensland forecast is higher than what was forecast last year.

- Tasmania, where maximum demand occurs in winter, sees slower growth relative to the 2022 ESOO forecast, driven by lower forecasts for both the residential and business (including large industrial load) sectors.
- In the subsequent five years, from 2028-29 to 2032-33, the drivers start to give more diverse 50% POE forecasts relative to the 2022 ESOO, although all five regions forecast growth in this period. For all regions, assumptions around more flexible EV charging relative to what was assumed in the 2022 ESOO is reducing the impact of EVs at time of peak compared to last year's forecast. Overall:
 - The New South Wales forecast has slower growth than the 2022 ESOO (although remaining higher in absolute terms due to the higher starting point in 2028-29), driven by relatively less electrification along with the more flexible EV charging mentioned above.
 - The Queensland forecast continues with the same growth as in the first five years and ends the forecast period above the 2022 ESOO forecast. The increase relative to the 2022 ESOO is due to stronger demand stemming from electrification assumptions, which is not fully offset by the lower EV charging at time of peak.
 - The South Australian forecast also continues with the same growth as in the first five years, and by the end of the horizon almost reaches the level projected in the 2022 ESOO forecast, which has otherwise been higher until this point. The LIL forecast growing faster than projected in the 2022 ESOO is the main reason for the forecast catching up to the 2022 level.
 - The Tasmanian forecast sees accelerating growth, taking demand from somewhat lower than the 2022 forecast to just below the 2022 ESOO forecast by the end of the 10-year horizon. This is due to higher electrification and LIL growth assumptions relative to the 2022 ESOO forecast during this period of the forecast.
 - The Victorian forecast grows at a pace slightly higher than forecast in 2022, with the additional growth coming from BMM and LIL, which is only partly offset by the lower contribution from EV charging at time of peak.

Appendices A1-A5 discuss maximum demand forecasts for each region and scenario out to 2053-54 based on the forecast prepared for the Draft 2024 ISP⁴¹.

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 charging⁴², scheduled loads such as pumping load, and demand response).

⁴¹ The ISP forecasts differ from the ESOO forecasts in assuming ongoing growth in the uptake of coordinated (VPP-operated) battery storage. As no such growth is committed, these storages are instead assumed to be un-coordinated in the ESOO forecast. The presented forecast outcomes in the appendices, where more batteries are VPP, differ slightly from those presented in this section, which has more un-coordinated batteries, and only those are reflected in the demand forecast (while VPP is modelled as supply). Both forecasts can be viewed at AEMO's Forecasting Portal: <https://forecasting.aemo.com.au/>.

⁴² Non-coordinated, customer-controlled battery and EV charging is considered in the unconstrained minimum demand forecasts.

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. The growth in distributed PV has moved the timing of minimum demand from overnight to occur at approximately midday. 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. If uncontrolled, household battery storages may be fully charged before noon on sunny days and have no impact at time of minimum demand, but if optimised (for example, to take advantage of low intraday electricity prices), their impact in lifting demand could be significant.
- 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 optimised and assumed to operate flexibly.

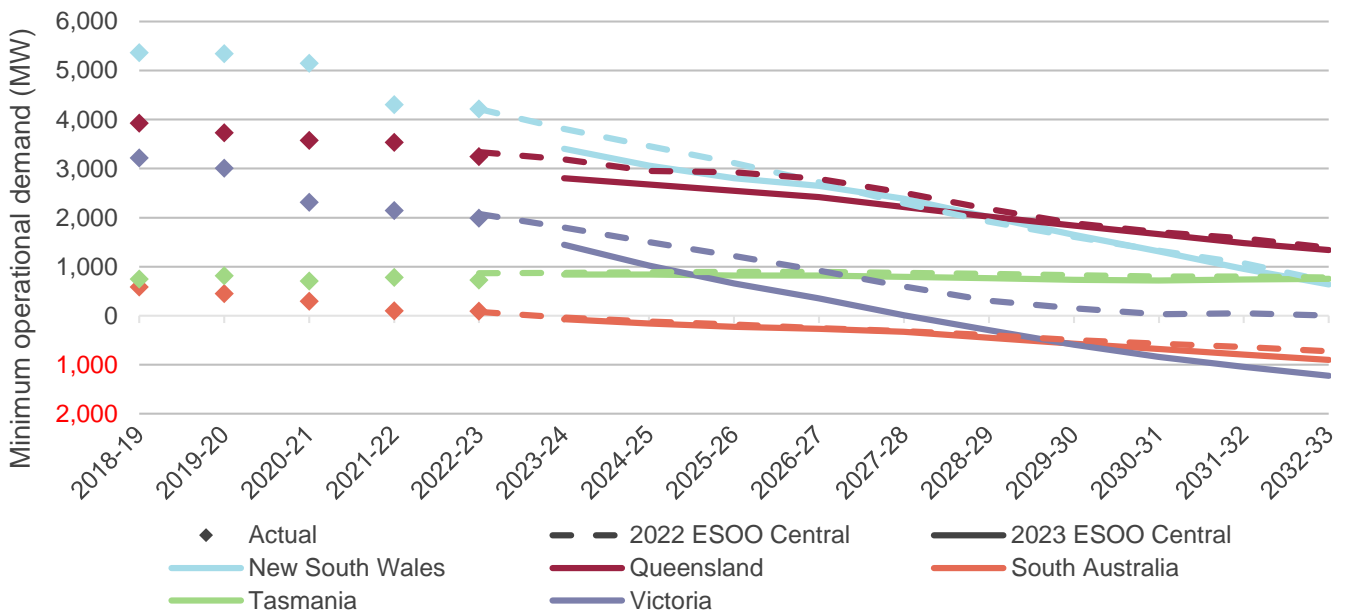
Finally, in some regions, variations in the demand from LILs can affect the minimum demand. This is particularly the case in Tasmania, where LIL at time of minimum demand is more than half the demand overall, and any planned or unplanned outages of large loads at this time can significantly affect the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

Minimum operational demand forecast out to 2032-33

Figure 12 compares the annual actual and forecast minimum operational demand (sent-out) for NEM regions from 2018-19 to 2032-33 for the ESOO Central scenario from the 2023 and 2022 ESOOs.

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

Figure 12 Regional annual actual and forecast 50% POE minimum operational demand (sent-out), 2023 ESOO Central and 2022 ESOO Central scenarios, 2018-19 to 2032-33 (MW)



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

Key additional insights from these forecasts are:

- For the first forecast year, 2023-24, the forecast 50% POE minimum operational demand is lower in all regions than in the 2022 ESOO, due to revised down projections for electrification and updated model formulation, which has been trained on one additional year of data.
- In the next four years (to 2027-28), 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 2023 ESOO than the 2022 ESOO, due to the scaled down projections for electrification (mentioned above), apart from New South Wales, which by 2027-28 is slightly higher, driven by strong growth in the BMM sector more than offsetting the lower electrification forecast. For Victoria, a lower electrification forecast than last year causes a widening gap between the 2023 and 2022 ESOO forecasts.
 - South Australia’s 50% POE minimum operational demand is forecast to go negative in 2023-24 (that is, CER is forecast to generate more than underlying demand in the region, in the absence of any operational control).
 - Minimum demand in Tasmania is forecast to only be declining slightly over the period, due to slower growth in distributed PV compared to other regions, and which is mostly offset by growth in electrification and BMM.
- In the following five years (2028-29 to 2032-33), similar trajectories to the initial years are forecast. Generally, other growth drivers have offset the lower electrification forecast by this time.
 - In Victoria, however, forecast minimum demand remains significantly lower than the 2022 forecast as it is to a lesser extent offset by other drivers, and the spread widens from 2030-31, when the forecast level of distributed PV starts to be higher than was forecast in 2022.

Appendices A1-A5 provide additional information about the minimum demand forecasts for each region and scenario, and cover the period out to 2053-54 based on the forecast to be used for the 2024 ISP⁴³.

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

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

- During the shoulder season in New South Wales and Tasmania throughout the 10-year horizon.
- In winter in Queensland until switching to shoulder season from 2026-27.
- With equal probability between summer and shoulder in South Australia till 2026-27, then slightly more likely in summer.
- In the summer season in Victoria throughout the forecast period.

The contribution from distributed PV to minimum underlying demand in 2031-32 (at the time of the annual 50% POE minimum operational demand for the ESOO Central scenario) ranges from 33.3% of underlying demand in Tasmania to 139.5% in South Australia. Victoria is the only other region with a contribution over 100%, at 119.1%, but both Queensland and New South Wales have contributions exceeding 90%.

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

There are potential market-based solutions to increase operational demand in the daytime. These mechanisms include coordinated charging of storage (both distributed and grid-scale), coordinated EV charging, and demand response (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 respond to dispatch signals in the supply adequacy assessments.

Similarly, operational measures taken by network operators to curtail distributed PV are not reflected and the forecasts will therefore provide a signal to how often such measures may be required.

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

For the 2023 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

⁴³ The ISP forecasts differ from the ESOO forecasts in assuming ongoing growth in the uptake of coordinated (VPP-operated) battery storage. As no such growth is committed, these storages are instead assumed to be un-coordinated in the ESOO forecast. The presented forecast outcomes in the appendices, where more batteries are VPP, differ slightly from those presented in this section, which has more un-coordinated batteries, and only those are reflected in the demand forecast (while VPP is modelled as supply). Both forecasts can be viewed at AEMO's Forecasting Portal: <https://forecasting.aemo.com.au/>.

based on information provided to AEMO by all registered market participants regarding their DSP portfolios as of 31 March 2023, using the methodology described in AEMO's *DSP Forecasting Methodology Paper*⁴⁴.

Projected DSP across the NEM for summer 2023-24 is 910 MW, as shown in **Table 5**. Compared to the 2022 ESOO, AEMO's forecast is showing:

- More DSP response overall in all NEM regions except Tasmania.
 - The major factor that contributes to the general uplift in DSP response in all these regions is higher expected electricity prices relative to earlier years. These higher prices have led to more benefits to customers participating in DSP schemes or responding directly to market signals.
 - Tasmania tends to have greater price separation from the mainland, leading to a lower uplift than mainland regions. Limited frequency of historical high-price events relative to mainland regions reduces the confidence of DSP estimates.
- The observed level of response from WDR was in line with last year's forecast.

Table 5 Projected demand side participation for summer 2023-24 (MW)

Trigger	New South Wales	Queensland	South Australia	Tasmania	Victoria
> \$300/MWh	0	22	26	0	0
> \$500/MWh	0	54	40	6	0
> \$1,000/MWh	54	91	41	6	52
> \$2,500/MWh	62	105	41	6	63
> \$5,000/MWh	94	152	44	6	63
> \$7,500/MWh	95	189	49	6	63
Reliability response	337	262	49	6	257

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

AEMO therefore uses a flat forecast of reliability response for the 10-year horizon of the ESOO⁴⁵ for all regions except New South Wales, where the New South Wales Peak Demand Reduction Scheme (PDRS)⁴⁶ is 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 orchestrated response of behind-the-meter batteries, are already accounted for in other components of the overall demand forecast. The remaining initiatives contribute to the DSP forecast and cause the forecast for New South Wales to grow to almost 1,100 MW by 2032-33 for the ESOO Central (*Step Change*) scenario.

Figure 13 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 statistics⁴⁷.

⁴⁴ At <https://aemo.com.au/consultations/current-and-closed-consultations/demand-side-participation-forecast-methodology-consultation>.

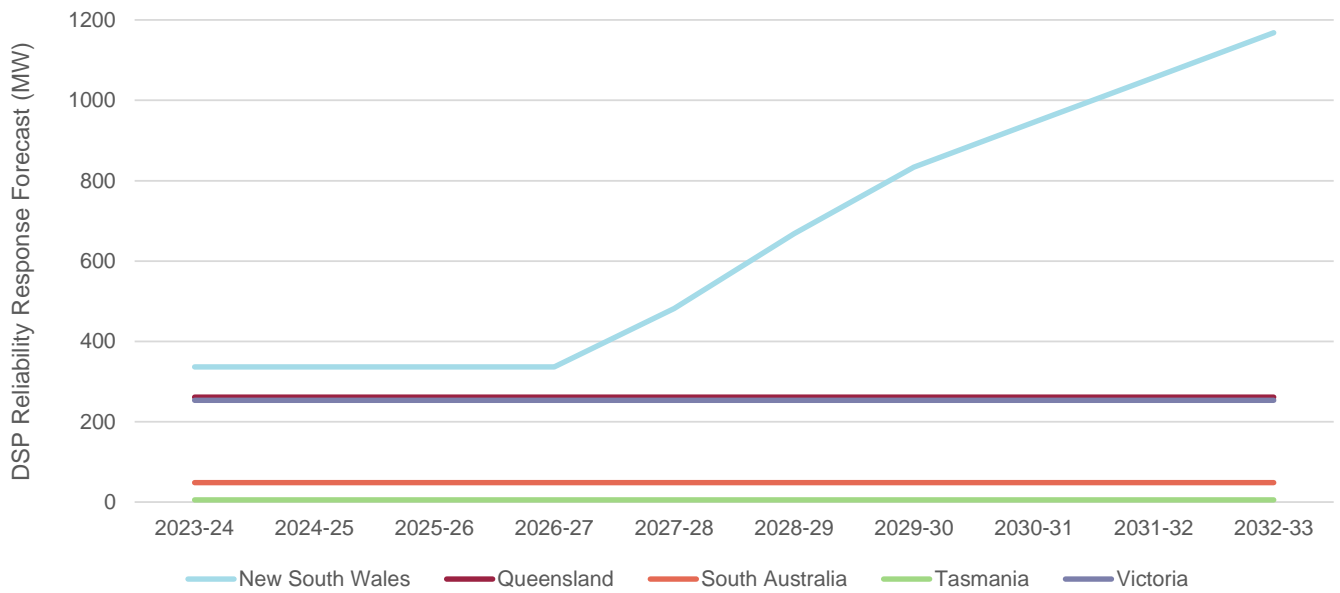
⁴⁵ AEMO does not have visibility of any further committed DSP sources beyond those included in Table 4, other than the New South Wales Peak Reduction Scheme.

⁴⁶ See <https://www.energy.nsw.gov.au/government-and-regulation/energy-security-safeguard/peak-demand-reduction-scheme> for details.

⁴⁷ To fulfil the requirements under NER 3.13.3A(a)(8) and NER 3.7D (d).



Figure 13 DSP reliability response forecast for summer, Central scenario, 2023-24 to 2032-33 (MW)



3 Supply and network infrastructure forecasts

The capability of the power system to generate and securely transmit electricity to consumers is a key input assumption to forecasting reliability. This chapter outlines the infrastructure forecasts 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 future 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 page⁴⁸. Projects that participate in a federal, state or territory funding scheme or incentive mechanism are not given special consideration, but are very likely to meet at least some of AEMO's commitment criteria.

To assess project progression, AEMO applies commitment criteria that consider progress across land, finance, planning, contracts and construction categories⁴⁹. Using these commitment criteria, AEMO defines generation and storage projects as:

- **Existing** generation and storage plant.
- **In commissioning** projects that have met the requirements of the first commissioning hold point (typically at least 30% capacity commissioned). In reliability modelling, projects in commissioning are assumed to become fully available on the full commercial use date (FCUD) provided by the developer⁵⁰.
- **Committed** projects⁵¹ that meet all five of AEMO's commitment criteria but have not yet met the requirements of their first commissioning hold point. In reliability modelling, committed projects are assumed to become fully available six months after the FCUD provided by the developer⁵².

⁴⁸ At <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information>.

⁴⁹ Commitment criteria relate to land, contracts, planning, finance, and construction. For details, see the Background Information tab on each publication at <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information>.

⁵⁰ FCUD 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 NSP.

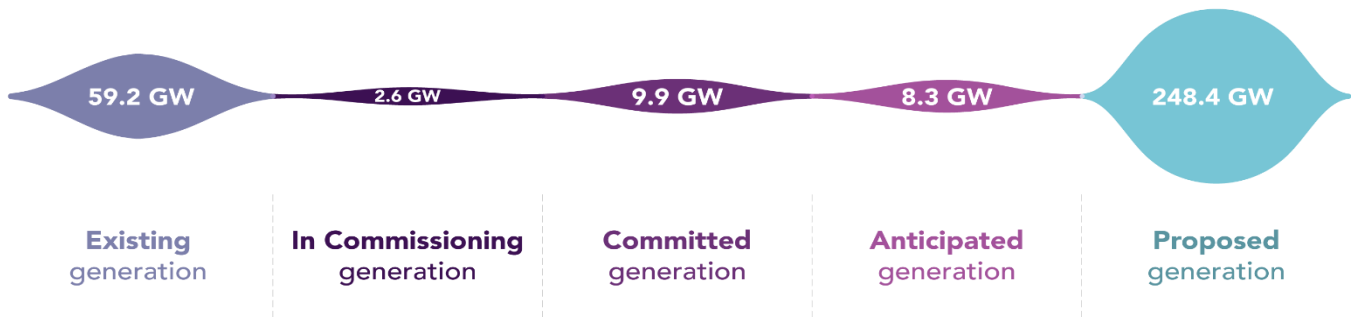
⁵¹ Committed* projects are a subset of the Committed category that are very close to meeting all five commitment criteria. They are applied consistent with Committed projects.

⁵² Commissioning delays are applied based on observed trends as consulted in in the 2022 reliability forecasting guideline and methodology consultation. See <https://aemo.com.au/en/consultations/current-and-closed-consultations/2022-reliability-forecasting-guidelines-and-methodology>.

- **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. In reliability modelling, to reflect uncertainty in the commissioning schedule of these projects, anticipated projects which have provided an expected commissioning date are assumed to become fully available at the latest date of either one year after the FCUD provided by the developer, or the first day after the T-1 year for RRO purposes⁵². For the 2023 ESOO this effectively is no earlier than 1 July 2025.
 - Anticipated projects which are not yet sufficiently progressed to provide an expected commissioning date are assumed to become fully available in reliability modelling on the first day after the T-3 year for RRO purposes, which for the 2023 ESOO is 1 July 2027.
 - Anticipated projects were not considered in the reliability forecast (Central scenario) in the 2022 ESOO, and are being included in the reliability forecast for the first time in 2023 to provide more perspective on the reliability forecast and the investment opportunities. For further details, see AEMO’s *ESOO and Reliability Forecast Methodology Document*⁵³.
- **Proposed** projects that have not progressed sufficiently to meet the requirements of an anticipated, in commissioning or committed project. Proposed projects are not considered in AEMO’s reliability modelling.

Figure 14 shows the scale of the new generation pipeline by depicting the sum of the nameplate capacity for all generation and storage projects, aggregated according to commitment status. In addition to the many projects progressing through AEMO’s commitment criteria, there are a large number of projects at early stages of development. These projects are spread across all regions, with the largest pipeline of capacity presently in New South Wales.

Figure 14 New generation pipeline as of July 2023 Generation Information (gigawatts [GW])



ESOO modelling assumes generator retirements occur on dates provided by participants, either on the dates provided if a closure date is provided under the three-year notice of closure rules⁵⁴ or on 31 December of the provided expected closure year.

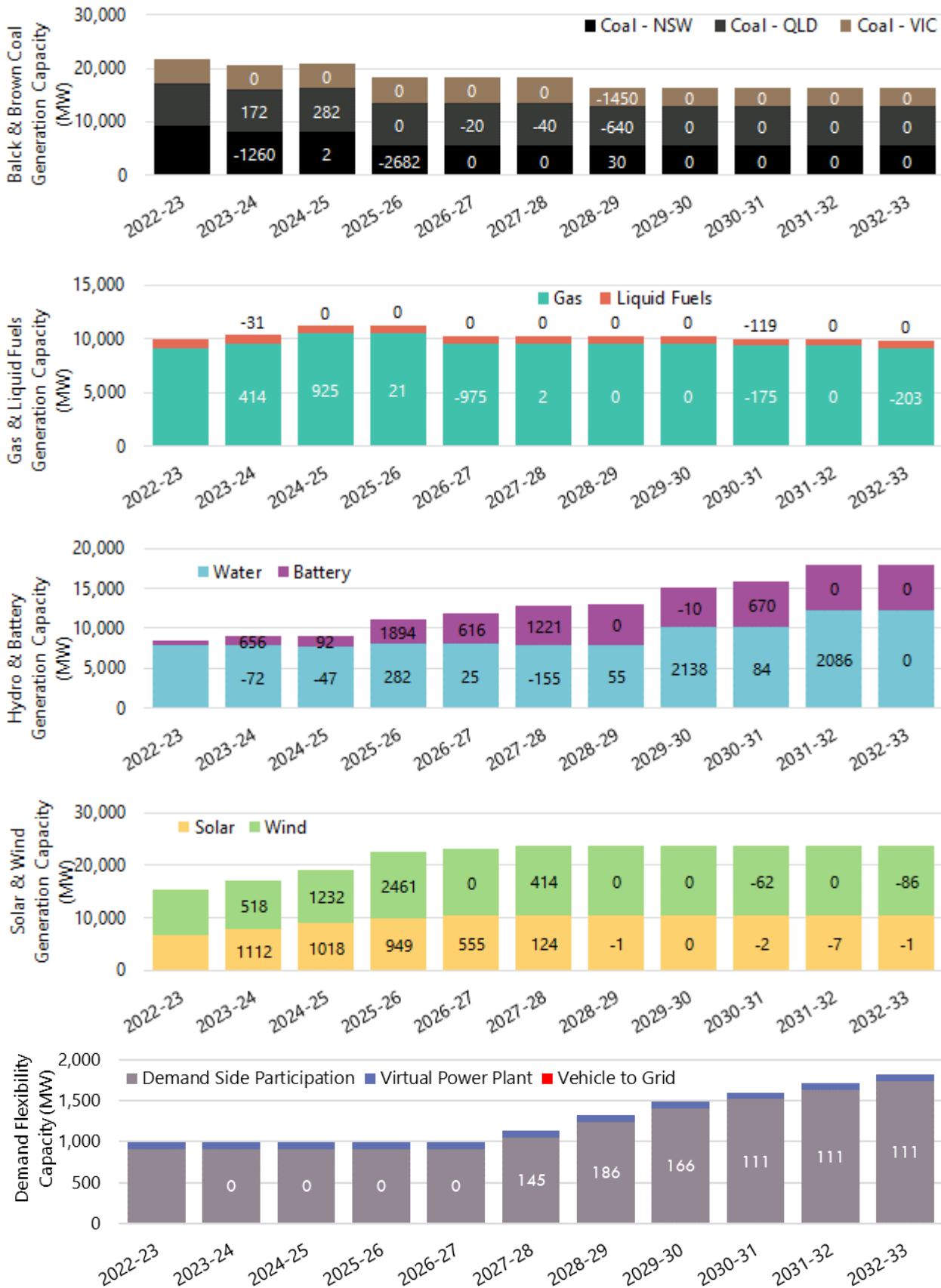
Figure 15 shows the summer typical capacity (the capability of the generating unit during average summer temperatures) assumed per forecast year in the 2023 ESOO, considering the specified commissioning and decommissioning profiles of generation and storage, and the technical advice on the capabilities of each generating unit provided by each relevant operator and/or developer⁵⁵.

⁵³ 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>.

⁵⁴ Clause 2.10.1(C2) of the NER requires generators to provide at least 42 months’ advance notice of a closure.

⁵⁵ Pumped hydro is included within the ‘water’ category.

Figure 15 Assumed capacity available during typical summer conditions, by generation type, 2022-23 to 2032-33 (MW)



The figure demonstrates the reduced availability of some generating technology types as generators retire, as well as the development of replacement capacity that is either committed, in commissioning 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 season. Variability observed year to year in hydro (water) generation arises due to the advised schedule for extended maintenance in Tasmania.

Actual generator performance, commissioning dates or retirement dates may vary from that provided by the relevant operator and/or developer. Such variations are not considered in the ESOO Central scenario.

Large amounts of new generation capacity continue to connect in the NEM. Approximately 3.4 gigawatts (GW) of additional new capacity (based on nameplate rating) is forecast to start operations in time for the 2023-24 summer, compared to that which was assumed to be available last summer, demonstrating increased commitments by NEM participants and developers to deliver additional capacity since the 2022 ESOO. This is offset by an effective reduction of 1.5 GW of generation from the retirement of Liddell Power Station, consistent with assumptions applied in the 2022 ESOO.

In addition to the above, proponents have committed a further 16.4 GW of capacity⁵⁶ (based on nameplate capacity for anticipated projects and summer typical capacity for Committed, In Commissioning and Existing projects⁵⁷) to become available over the rest of the 10-year ESOO horizon.

In commissioning, committed, and anticipated capacity developments assumed to become available over the 10-year ESOO horizon include:

- Dispatchable gas-fired generation projects:
 - Tallawarra B (320 MW) in New South Wales, in November 2023.
 - Kurri Kurri Power Station (750 MW) in New South Wales, in December 2024.
- Dispatchable storage projects (pumped hydro and battery):
 - Torrens Island BESS (250 MW/250 megawatt-hours [MWh]) in South Australia in August 2023.
 - Gnarwarre BESS Facility (290 MW/550 MWh) in Victoria in June 2024⁵⁸.
 - Western Downs Battery (259 MW/400 MWh) in Queensland in July 2024⁵⁸.
 - Kidston Pumped Hydro Energy Storage (250 MW/2,000 MWh) in Queensland in February 2025⁵⁸.
 - Orana BESS (408 MW/1,600 MWh) in New South Wales in May 2025⁵⁸.
 - Swanbank BESS (250 MW/500 MWh) in Queensland in January 2026⁵⁸.
 - Wooreen Energy Storage System (350 MW/1,400 MWh) in Victoria in December 2026⁵⁸.
 - Eraring Big Battery (460 MW/920 MWh) in New South Wales⁵⁹.
 - Snowy 2.0 (2,040 MW/350,000 MWh) in New South Wales in December 2029.
 - Borumba Pumped Hydro (1,998 MW/48,000 MWh) in Queensland, in June 2030⁵⁸.

⁵⁶ Including those projects which are classified as committed, in commissioning and anticipated.

⁵⁷ Seasonal scheduled capacity profiles are provided for committed, committed*, in commissioning and existing generation projects, while anticipated projects are required to provide only nameplate capacity.

⁵⁸ Date provided by the proponent. This project is subject to delays in commissioning in ESOO modelling.

⁵⁹ Projects without advised commissioning dates are applied at 1 July 2027.

- Another 2.97 GW/5.43 gigawatt hours (GWh) of other smaller (< 250 MW) battery projects across NEM regions
- Variable renewable energy (VRE) projects:
 - Approximately 4,918 MW of wind generation developments.
 - Approximately 5,212 MW of solar generation developments.

Based on participant advice, the following generators are now expected to close in or before 2033⁶⁰:

- Eraring Power Station (2,880 MW) in New South Wales in August 2025.
- Torrens Island B (800 MW) in South Australia in 2026.
- Osborne Power Station (180 MW) in South Australia in 2026.
- Callide B Power Station (700 MW) in Queensland in 2028.
- Yallourn W Power Station (1,450 MW) in Victoria in 2028.
- The Dry Creek, Mintaro, Port Lincoln and Snuggery Power Stations (total 383 MW) in South Australia in 2030.
- 12 (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.

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. These retirements are expected to be phased, and subject to the development of replacement capacity including pumped hydro energy storage, grid developments, and new renewable energy zones. This plan identifies that Stanwell (1,460 MW), Tarong (1,400 MW), and Tarong North (450 MW) could also be retired in the ESOO horizon, subject to the successful execution of this plan. These retirements are not formally advised, so were not modelled in the 2023 ESOO Central scenario.

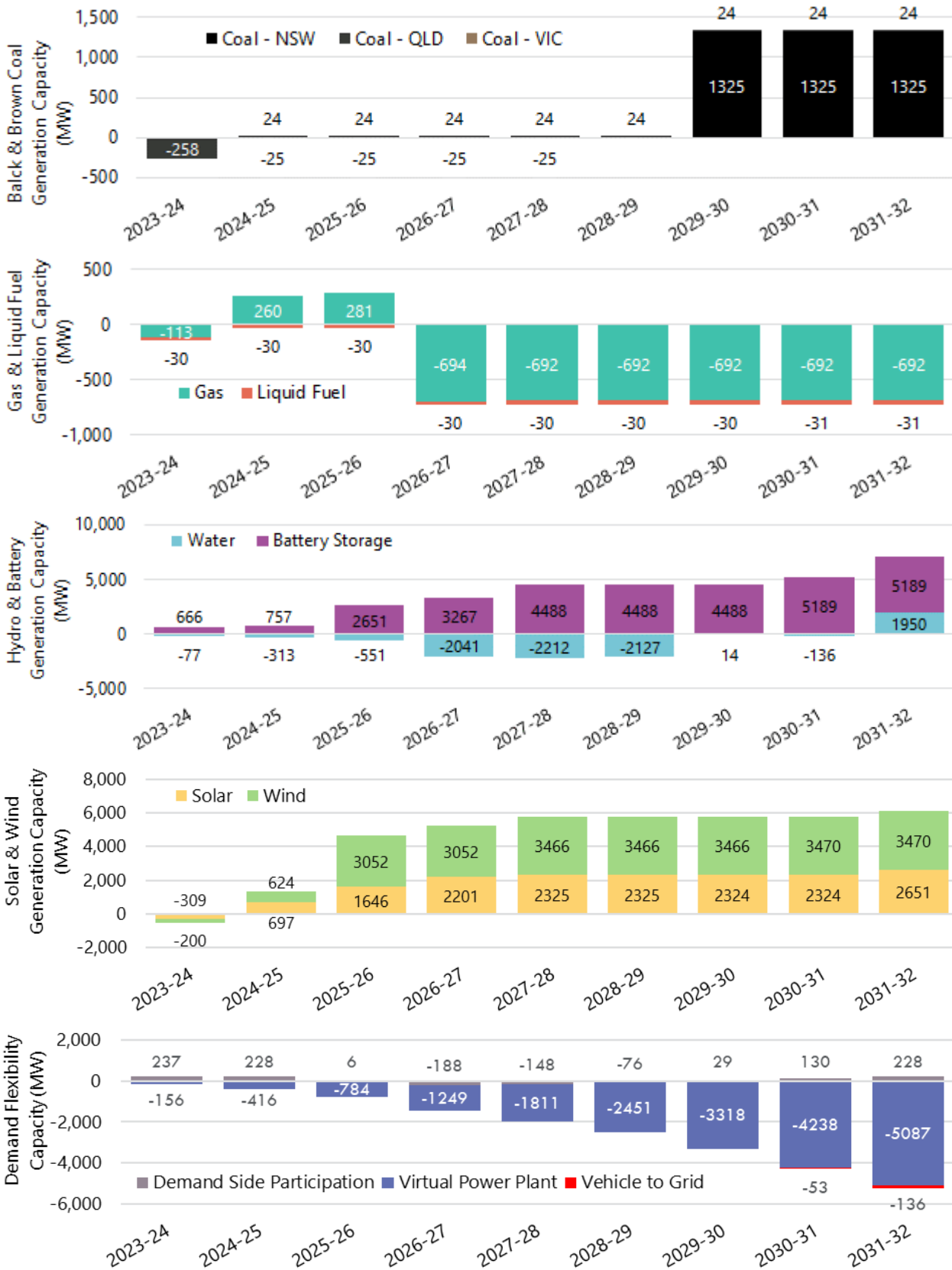
Figure 16 shows the change between the capacity outlook assumed in the 2022 ESOO and the 2023 ESOO Central scenarios. Noteworthy changes to the outlook include:

- Queensland black coal capacity is lower in summer 2023-24 due to the delayed return to service of Callide C units. From 2029-30, New South Wales black coal capacity no longer reduces due to the delayed expected closure year of Vales Point B Power Station.
- Gas capacity is lower in 2023-24 due to an extended outage on some Hallett Gas Turbine units and other deratings which were not advised for the 2022 ESOO. From 2024-25, capacity increases due to the advised return to service of Torrens Island unit B1, and decreases from 2026-27 due to the advised expected closure of all Torrens Island B units.
- Pumped hydro storage capacity is lower in the medium term due to the application of project commissioning delays to Kidston, the revision of maintenance among Tasmanian hydro generators, and the revision to the expected commissioning date of Snowy 2.0 from 2026-27 to 2029-30. At the end of the horizon, more capacity is forecast due to the inclusion of the Borumba Pumped Hydro project.

⁶⁰ All expected retirement dates are advised by participants, including the August 2025 potential early retirement of Eraring.

- Battery capacity is higher over the entire horizon due to the advancement of numerous battery projects across the NEM.
- Solar and wind capacity is lower in 2023-24 due to the application of project commissioning delays in the 2023 ESOO Central scenario, but significant new capacity is included throughout the 2023 ESOO horizon.
- While forecasts of demand side participation are higher across the NEM, revisions to the application of the New South Wales PDRS have resulted in lower forecasts through the middle of the horizon.
- AEMO now applies the orchestration of CER only where an aggregator has demonstrated commitment to a relevant program, as opposed to including a forecast of all CER orchestration, as was the case in the 2022 ESOO. As a result, the majority of forecast CER orchestration (VPPs and Vehicle to Grid [V2G]) is now not included from the 2023 ESOO Central scenario outlook (but included in various sensitivity analyses, presented on in **Chapter 7**).

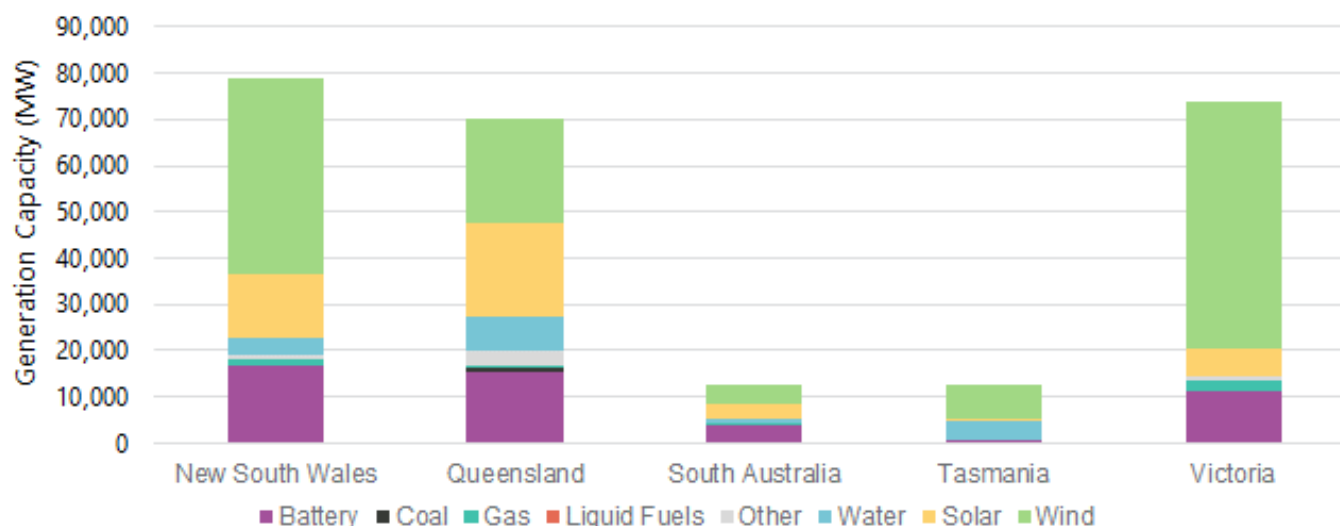
Figure 16 Change between 2022 and 2023 ESOO capacity under summer typical conditions, 2023-24 to 2031-32 (MW)



Proposed generation and storage pipeline

Figure 17 shows proposed storage and generation projects by region and type of generation.

Figure 17 Proposed projects by NEM region and type of generation or storage (MW)



These projects are not yet sufficiently advanced to meet the in commissioning, committed and anticipated commitment criteria. There are a range of jurisdictional initiatives that are also supporting supply side developments, which are discussed further in **Section 7.3**. Key points are:

- By capacity, just under 70% of future projects currently proposed are VRE generation projects, while storage projects (battery or pumped hydro) account for about 25.7%.
- Approximately 22 GW of additional dispatchable capacity projects – including thermal projects, pumped hydro, and batteries – have been added to the pipeline of future projects since the 2022 ES00.
- The average storage duration for battery projects is 2.8 hours in New South Wales, 2.1 hours in Queensland, 1.8 hours in South Australia, and 2.1 hours in Victoria.

Further details, including capabilities of proposed generating units, are on the Generation Information page⁶¹.

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 availability⁶².

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:

⁶¹ See <https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information>.

⁶² See Generation Information, July 2023 update, at <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information>.

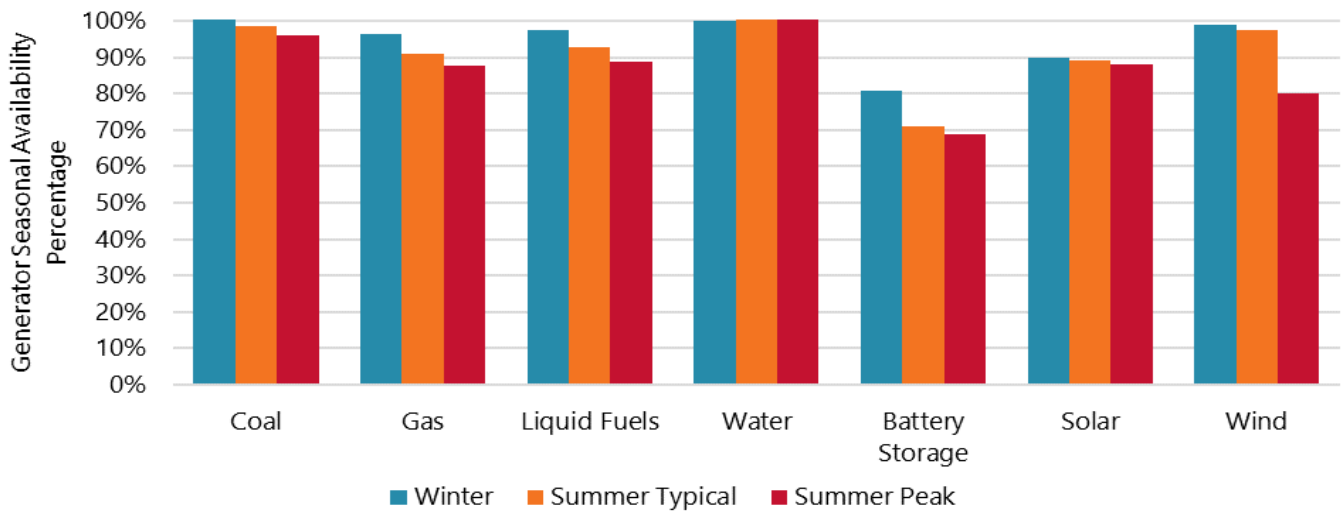
- **Summer peak** – applies to near-maximum demand periods (minimum of five days per year), where generator ratings are reflective of the ambient conditions associated with 10% POE demand events (typically at temperatures 37°C or greater for mainland regions, depending on the region).
- **Summer typical**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

In addition to the above scheduled capacities, VRE generators are also subject to consideration for the availability of wind and solar resources and their variability across hourly, seasonal and annual timeframes.

Figure 18 shows the average winter, summer typical, and summer peak availability relative to nameplate capacity by type of generation, and indicates the reduced availability reported in summer peak compared to winter and summer typical. This is especially noticeable for wind generators, due to some reporting 0 MW availability during summer peak, reflecting high-temperature cut-offs for this generation category.

See the *ESOO and Reliability Forecast Methodology Document*⁶³ for more detail about generation availability.

Figure 18 Winter, summer typical and summer peak availability of nameplate capacity by type of generation (%)



3.3 Generator unplanned outage rates

AEMO collects information from all generators, via an annual survey process, on the timing, duration, and severity of historical unplanned outages. Observed unplanned outages of duration in excess of five months are classified as long duration outages and are assessed separately. The historical data is then used to calculate the observed rate of long duration, full, and partial unplanned outages for each financial year, for each generator.

For all generator types excluding coal-fired and large gas-fired generators, the rates applied in the 2023 ES00 were calculated from incidents observed over the last four years and used as projections for each generator.

⁶³ At <https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo>.

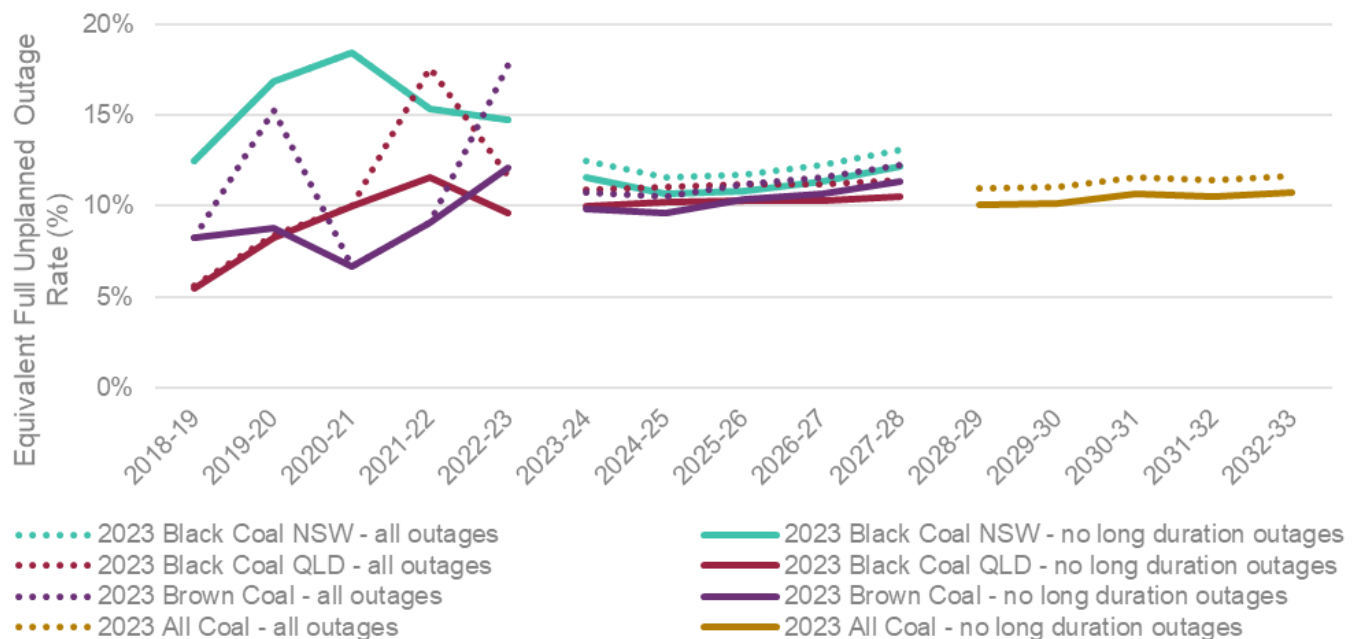
For coal-fired and large gas-fired generators, AEMO also collected forward-looking unplanned outage rate projections from the operators of each power station. These operator-provided projections reflect the expected change in performance as generators age, approach retirement, and go through maintenance cycles. For an independent cross check, operator-provided projections have been compared to, and sometimes supplemented by, forward-looking outage factors that AEMO commissioned in 2020 from AEP Elical⁶⁴. In each instance when this supplementary data influenced the applied forward-looking unplanned outage rates, AEMO engaged with each operator to confirm the reasonableness of this approach.

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

Figure 19 shows the historical and projected equivalent 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 outage rates (of five months or more).

In several instances, significant improvements in aggregate outage rates for a generation class are due to the expected retirement of units with high outage rates, rather than expectations of improved performance across the asset class.

Figure 19 Actual and projected equivalent full unplanned outage rate projections for coal-fired generation technologies, 2018-19 to 2032-33 (%)

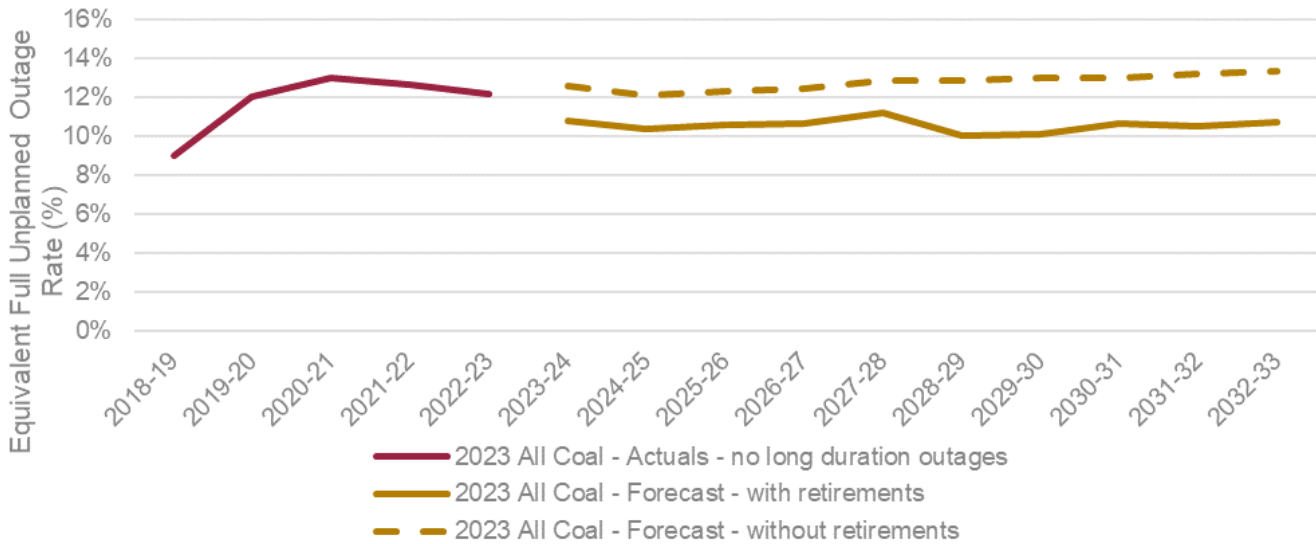


For comparison, **Figure 20** shows an aggregate outage rate that has been calculated assuming no generator retirements occur. For generators that retire during the horizon, the last year of their projection is applied for the remainder of the horizon. This figure demonstrates the slight upward trend projected amongst most generators.

⁶⁴ 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>.

The 2023 IASR Assumptions Workbook provides detailed information on the unplanned outage rate parameters of each technology over time⁶⁵.

Figure 20 Actual and projected equivalent full unplanned outage rate projections for coal-fired generation technologies, 2018-19 to 2032-33 (%), with and without generator retirements



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 2023 ESOO Central scenario modelling included committed and anticipated transmission augmentations⁶⁶ as described below. To determine if a transmission project is committed or anticipated, commitment criteria consistent with the ISP methodology⁶⁷ and CBA Guidelines (and the Regulatory Investment Test for Transmission [RIT-T] instrument⁶⁸) were applied.

Consistent with AEMO’s *ESOO and Reliability Forecast Methodology Document*⁶⁹, AEMO applied the following timing regarding the assumed commissioning of transmission infrastructure:

⁶⁵ At <https://aemo.com.au/en/consultations/current-and-closed-consultations/2023-inputs-assumptions-and-scenarios-consultation>.

⁶⁶ 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. The categorisations of ‘committed’ and ‘anticipated’ project are now aligned between the ESOO and the ISP following the April 2023 update to AEMO’s *ESOO and Reliability Forecast Methodology Document*.

⁶⁷ At https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/isp-methodology-2023/isp-methodology_june-2023.pdf?la=en.

⁶⁸ At <https://www.aer.gov.au/system/files/AER%20-%20Regulatory%20investment%20test%20for%20transmission%20-%2025%20August%202020.pdf>.

⁶⁹ 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>.

- **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 updated the transfer limit capacity for Basslink for the 2023 ESOO. The transfer limit for Basslink was revised from 478 MW (in the 2022 ESOO) to 462 MW in both directions, based on the forward-looking transfer capabilities submitted for this interconnector in the Medium Term Projected Assessment of System Adequacy (MT PASA).

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

Table 6 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 Page⁷⁰. Service dates were sourced from AEMO’s July 2023 update to this page. There are currently no anticipated inter-regional network augmentations.

Table 6 Committed inter-regional network augmentations

Project name	Project status	Project description	Approximate increase in network capacity ^A	Capacity release date
Victoria – New South Wales Interconnector (VNI) System Integrity Protection Scheme (SIPS)	In service	A protection scheme designed to increase the pre-contingency import capabilities of the VNI by up to 250 MW between November to March each year, by rapidly discharging Victoria Big Battery following a critical contingency event to reduce loading on critical lines.	Up to 250 MW increase in the southerly direction between 1 November and 31 March each year.	In service from 1 November to 31 March each year until 31 March 2032
Queensland – New South Wales Interconnector (QNI) Minor Upgrade	In service with inter-network testing progressing	This project includes the uprating of the existing 330 kilovolts (kV) Liddell – Tamworth lines, the installation of new dynamic reactive support at Tamworth and Dumaresq substations, and the installation of new shunt connected capacitor banks at Tamworth, Armidale and Dumaresq substations.	150 MW in the northerly direction 145-245 MW in the southerly direction	Northerly Direction: Staged capacity release to February 2024 ^B Southerly direction: Staged capacity release to June 2024 ^B
VNI East Upgrade	In service	In Victoria this project includes the uprating the South Morang – Dederang 330 kV transmission line and the installation of an additional 500/330 kV transformer at South Morang, In New South Wales this project includes the installation of power flow controllers on the Upper Tumut – Yass and Upper Tumut – Canberra 330 kV transmission lines.	Staged release of export capacity of up to 170 MW ^C	July 2023
Project EnergyConnect	Committed	A new interconnector between Wagga Wagga in New South Wales and Robertstown in South Australia via Buronga. Stage 1:	Stage 1: 150 MW Stage 2: 800 MW	Stage 1: July 2024 ^D Stage 2: 500 MW in October 2025 and 800 MW capacity July 2026 ^D

⁷⁰ At <https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/transmission-augmentation-information>.

Project name	Project status	Project description	Approximate increase in network capacity ^A	Capacity release date
		<ul style="list-style-type: none"> A new Robertstown to Bunday 275 kV double-circuit line and a new Bunday 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. <p>Stage 2:</p> <ul style="list-style-type: none"> A second 330 kV circuit closed on the Bunday–Buronga 330 kV double circuit line. A new Buronga to Red Cliffs 220 kV 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. 		

- 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 ability to undertake testing will depend upon when flows are at high levels, as well as other power system and external conditions at the time. Modifications to the inter-regional test plan document are being prepared for market consultation, with an aim to increase the number of conditions under which appropriate testing can be carried out and (pending successful testing outcomes) additional QNI capacity can be released. For the 2023 ESOO, for the northerly direction, AEMO assumed an increase in transfer capacity of 100 MW by October 2023 and a further 100 MW increase by February 2024 to a total approximate northerly transfer of 950 MW. In the southerly direction, AEMO assumed an increase in transfer of 50 MW by October 2023, a 100 MW increase by April 2024 and an additional 100 MW increase by June 2024 to a total approximate transfer capacity of 1,450 MW.
- C. For more information on the increase in transfer limits, please see the VNI upgrade RIT-T Project Assessment Conclusions Report (PACR) at <https://www.transgrid.com.au/media/24nhbaux/victoria-to-new-south-wales-interconnector-upgrade-rit-t-pacr.pdf>.
- D. The capacity release and timing is conditional on availability of suitable market conditions and good test results.

Intra-regional augmentations included in the 2023 ESOO

The service dates, as advised by the TNSPs and other NEM jurisdictional bodies, for the intra-regional committed and anticipated augmentations considered in the 2023 ESOO are in **Table 7**. The dates were sourced from AEMO’s July 2023 Transmission Augmentation Information Page and the 2022 Transmission Annual Planning Reports.

Table 7 Committed and anticipated intra-regional network augmentations

Region	Project	Status	Approximate increase in network capacity ^A	Capacity release date
Queensland	<p>Northern Queensland REZ (QREZ)</p> <ul style="list-style-type: none"> 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. 	Committed	To allow up to 500 MW of generation in Far North Queensland	November 2023

Region	Project	Status	Approximate increase in network capacity ^A	Capacity release date
	CopperString 2032 <ul style="list-style-type: none"> 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^B. 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 ^C	June 2029
New South Wales	Wagga Wagga Capacitor Bank <ul style="list-style-type: none"> A new 330 kV 100 megavolt amperes reactive (MVA) capacitor bank at Wagga Wagga 	Committed	30 MW (VNI southerly direction) 75 MW (VNI northerly direction)	July 2023
	Waratah Super Battery Network Augmentations and SIPS control project and transmission <p>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 northern and southern 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:</p> <ul style="list-style-type: none"> 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 ^D increase between Central New South Wales (CNSW) and Sydney, Newcastle and Wollongong (SNW)	The SIPS and uprating of Bannaby – Sydney West 330 kV line is expected to be completed by July 2025, with the remainder of the minor network augmentations to be completed by August 2025. The SIPS control scheme will be for five years.
	Central-West Orana Renewable Energy Zone (REZ) Transmission Link^E <ul style="list-style-type: none"> Build two new 500 kV double-circuit line from Wollar to Merotherie, two new double-circuit 500 kV line from Merotherie to Elong Elong initially operated at 330 kV, and 330 kV lines from Merotherie to Uarbry East and Merotherie to Uarbry West. New Bayswater – Liddell and Mount Piper – Wallerawang 330 kV lines. 7 x 250 MVA synchronous condensers. Four 500/330/33 kV 1,500 MVA transformers at Merotherie. 	Anticipated	At least 3,000 MW of increase in network capacity in Central-West Orana REZ.	September 2027
Victoria	REZ Development Plan Stage 1 ^E : <ul style="list-style-type: none"> South West REZ minor. Koorangie Energy Storage System. Ararat synchronous condenser. Murray River REZ and Western Victoria REZ minor network augmentations. Central North REZ minor network augmentations. Mortlake turn-in. 	Committed Anticipated Anticipated Committed	81 MW Up to 300 MW ^F Not applicable 112 MW	December 2024 March 2025 September 2025 October 2025
	Western Renewables Link. <ul style="list-style-type: none"> 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. 	Anticipated	1,460 MW of increased network capacity to Western Victoria REZ	July 2027

Region	Project	Status	Approximate increase in network capacity ^A	Capacity release date
	<ul style="list-style-type: none"> 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 MVA 500 kV bus reactor at Sydenham terminal station. A range of substations works. 			

- 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. For the 2023 ES00, only the 500 kV transmission line from south of Townsville to Hughenden was modelled.
- C. 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).
- D. This transfer limit 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.
- E. For more information on these projects, see AEMO's July 2023 Transmission Augmentation Information Page.
- F. This project with Koorangie Energy Storage is expected to improve the system strength in the Murray region and allow the stable connection of up to 300 MW of additional renewable generation.

3.5 Inter-regional transmission unplanned outage rates

AEMO applies 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 energy⁷¹. Information is collated on the timing, duration, and severity of the transmission outages to inform transmission unplanned outage rate forecasts.

Table 8 shows the rates used in the 2023 ES00. All rates are annual and static over the 10-year horizon.

Consistent with the methodology updated through consultation, AEMO applied separate outage rates for single credible contingency and reclassification events for two of the flow paths in 2023, rather than combining them into a single rate.

Table 8 Projected unplanned outage rates for key inter-regional transmission flow paths

Flow path	Unplanned outage rate (%)		Mean time to repair (hours)	
	Single credible contingency	Reclassification	Single credible contingency	Reclassification
Liddell – Muswellbrook – Tamworth – Armidale – Dumaresq – Bulli Creek (QNI)	0.19%	1.40%	14.5	4.3
Murraylink	0.07%	Not applicable	12.4	Not applicable
Mortlake – Heywood – South East (Victoria – South Australia)	0.09%	0.01%	7.8	4.7
Basslink	5.39%	Not applicable	213.9	Not applicable

⁷¹ See **Section 1.1** for more information on the definition and limitations with the current definition of USE.

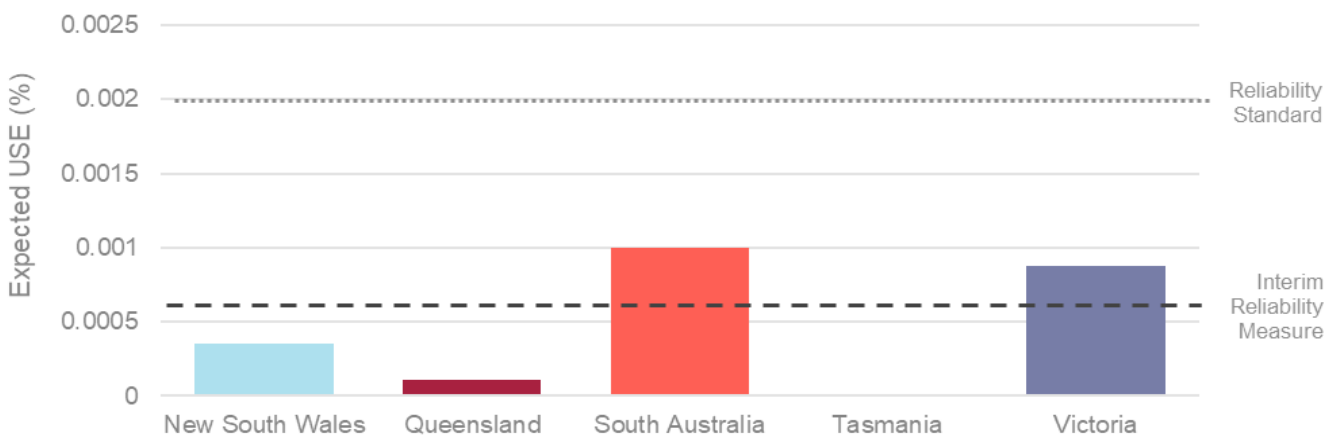
4 Supply scarcity risks in the next year

This chapter discusses supply scarcity risks in the coming 2023-24 year:

- There is an elevated risk of involuntary load shedding due to supply shortfalls across all mainland regions, with risks in South Australia and Victoria forecast above the IRM.
- With El Niño weather patterns projected for the coming summer, outcomes at the upper range of the maximum demand forecast are more likely.
- The availability of wind resources at the time of high demand, and the number of coincident generator outages, are key determining factors of reliability risk.
- Mitigation actions such as the use of RERT may form part of AEMO’s operational toolkit to minimise supply disruption risks.

The reliability outlook for the coming summer in AEMO’s ESOO Central scenario indicates reliability risks have increased since the Update to the 2022 ESOO, and are above the IRM in South Australia and Victoria. **Figure 21** shows the ESOO Central scenario forecast of expected USE for all NEM regions for the coming year.

Figure 21 Expected USE, all NEM regions, 2023-24, ESOO Central scenario (%)



The nature of the reliability risk varies by region:

- In **South Australia** and **Victoria**, the forecast supply scarcity risk for 2023-24 has increased relative to the *Update to the 2022 ESOO*, and is now forecast above the IRM.
 - The application of project commissioning delays, higher generator unplanned outage rates, and a higher forecast probability of coincident low wind and high demand conditions have all worsened the outlook relative to previous reliability assessments.
- In **New South Wales**, the forecast supply scarcity risk for 2023-24 is forecast within the IRM. The EAAP Central scenario (shown in **Section 6.2**), however, shows risks above the IRM once advice regarding limited

fuel availability from some gas generators is considered. Securing fuel supplies for all fossil-fuelled generators to enable sufficient operation during peak periods is important to mitigate reliability risks.

- Higher forecasts for maximum demand, the application of project commissioning delays, higher generator unplanned outage rates, and the reduced application of VPP have all increased the forecast risk.
- In **Queensland** and **Tasmania**, supply scarcity risks are forecast within the IRM.

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, the projected confluence of these factors leads to an elevated risk of involuntary load shedding in all mainland regions. These factors are:

- Maximum demand, and the degree to which demand flexibility and CER can offset underlying demand.
- Low wind availability at the time of maximum demand. The contribution of solar generation at the time of maximum demand is already very low, as peaks are occurring in the early evening.
- The availability of scheduled generators to meet demand, including the impact of scheduled generator outages, and the availability of these generators to meet demand.
- The availability of fuel and water for use in generation (this is explored in the EAAP, published in **Chapter 6**).

4.1 While reliability risks are forecast above the IRM in South Australia and Victoria, adverse outcomes remain possible in all regions

The ESOO applies a Monte Carlo simulation methodology to simulate the likelihood of USE considering the various statistical likelihoods of generator outages, alongside 13 years of weather conditions with the associated availability of VRE resources. The forecast approach is applied to each maximum demand and reference year, creating statistically robust results which capture the impact of uncertainties around key parameters.

A weighted average is applied to these Monte Carlo simulations to represent the ‘expected’ outcome for the coming year. 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.

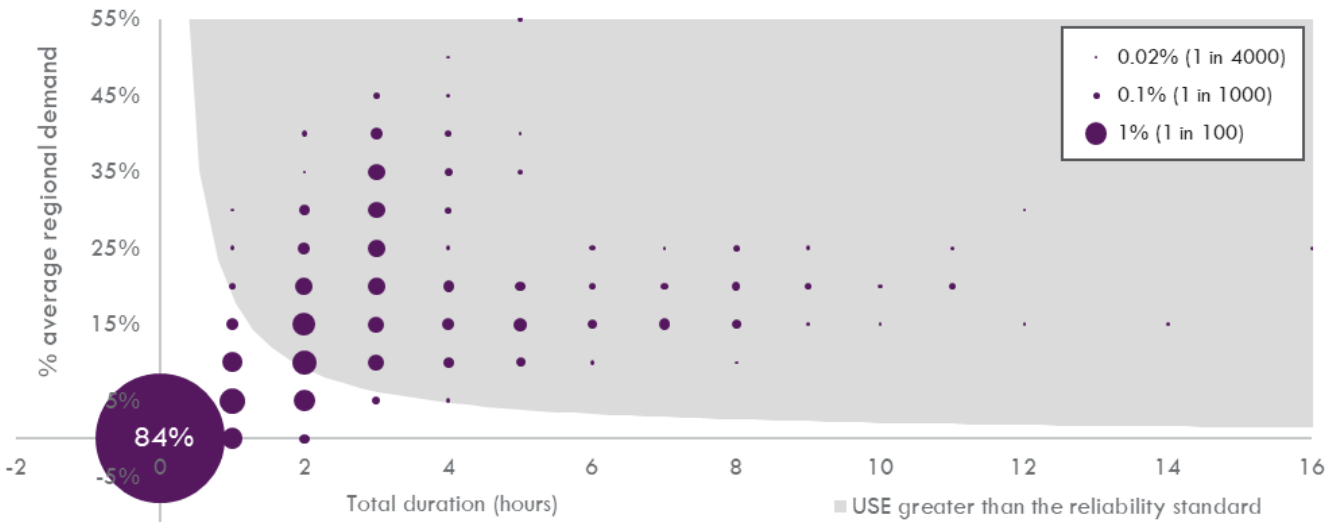
Expected USE, being the average of many possible outcomes, is forecast above the IRM for South Australia and Victoria for the coming year. While the expectation is over the relevant standard, this does not guarantee that a USE event is going to happen – in fact the most likely outcome is for there to 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 22** shows a bubble plot of the distribution of USE outcomes that are forecast in South Australia for the 2023-24 summer, under a neutral/unknown climate outlook. It includes the total outage 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 84% 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 16% probable, are represented by the other bubbles on the chart. Should USE occur, it is most likely to occur for between one hour and three hours and be of an average USE magnitude equivalent to between 5% and 30% 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 as deep as 55% of average regional demand, or as long as 16 total hours, which may occur over multiple individual USE events, for example four different evenings. These outcomes each represent the result of a single annual simulation, with an estimated probability of approximately 1 in 4,000.
- Bubbles within the grey section represent individual USE outcomes that each exceed the reliability standard of 0.002% USE. These USE outcomes are collectively 11% probable in the coming year in South Australia.

Figure 22 Forecast outage duration and depth in South Australia 2023-24, ESOO Central scenario



Should 10% POE demand conditions occur in the coming summer, the probability of USE increases. Given El Niño conditions are forecast for the coming summer, 10% POE demand conditions may be more probable.

Figure 9 shows the probability of any USE outcome occurring, and the probability of a larger USE outcome⁷², across all NEM regions for the coming year.

Table 9 Probability of USE in 2023-24 by NEM region

Region	Probability of any USE		Probability of a larger USE outcome	
	All maximum demand outcomes	10% POE demand	All maximum demand outcomes	10% POE demand
New South Wales	16%	41%	5%	15%
Queensland	7%	19%	2%	5%
South Australia	16%	48%	11%	35%
Tasmania	0%	0%	0%	0%
Victoria	25%	72%	13%	39%

⁷² 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.

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.
- The risk that fuel availability is more limited than foreseen by participants, affecting generator operational capabilities – the ESOO forecast is developed based on assumptions of fuel availability submitted by participants, which project adequate fuel supplies during periods of high demand. The EAAP, published in **Chapter 6**, includes scenarios that assess the potential impact of water and fossil fuel supply shortfalls.

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.

4.2 Demand outcomes are more likely at the upper range of the maximum demand forecast during El Niño weather conditions

The El Niño-Southern Oscillation (ENSO) is one of the largest drivers of year-to-year climate variability in eastern Australia. The Bureau of Meteorology advises that El Niño development remains likely for the coming summer. El Niño conditions are typically associated with reduced rainfall, warmer temperatures, more heatwaves and increased fire danger risk in southeast Australia. These weather factors have the potential to increase risks for the power system.

Maximum demand forecasts are expressed as a distribution, where a range of annual climate outcomes are included. Should hotter, drier conditions conducive to the occurrence of heatwaves and exceptionally high temperatures occur, this has the potential to result in demand outcomes in the upper end of the forecast distribution. Due to complex interactions between temperature, humidity, heatwaves and electricity consumer behaviour, the relationship between ENSO and maximum demand cannot be quantified definitively. However, there is an increased likelihood that demand outcomes will fall in the upper end of the forecast range (that is, above the 50% POE forecast), in particular in the southern states where humidity is less of a compounding factor.

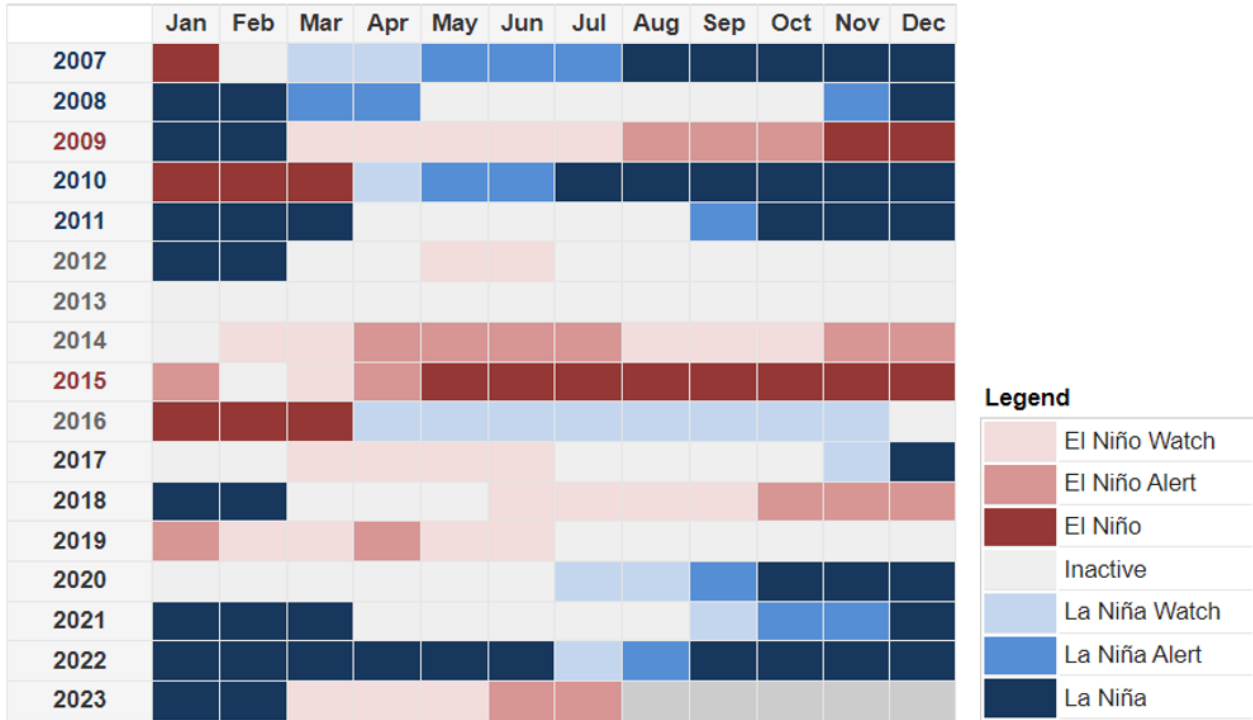
Additionally, the heightened risk of bushfires during El Niño events can disrupt power infrastructure, leading to supply interruptions and increased demand for emergency services. While these risks are elevated, the impact of bushfires is predominantly excluded from the reliability analysis in this ESOO outlook, as discussed in **Section 1.1**.

Figure 23 displays historical ENSO values, as reported by the Bureau of Meteorology⁷³. Demand forecasts used in this ESOO utilise historical weather data spanning from 2010-11 to 2022-23, which includes a variety of ENSO outcomes, including previous El Niño events.

⁷³ Bureau of Meteorology Monthly ENSO Outlook Values, at <http://www.bom.gov.au/climate/enso/outlook/#tabs=ENSO-Outlook-history>.



Figure 23 Monthly ENSO outlook values



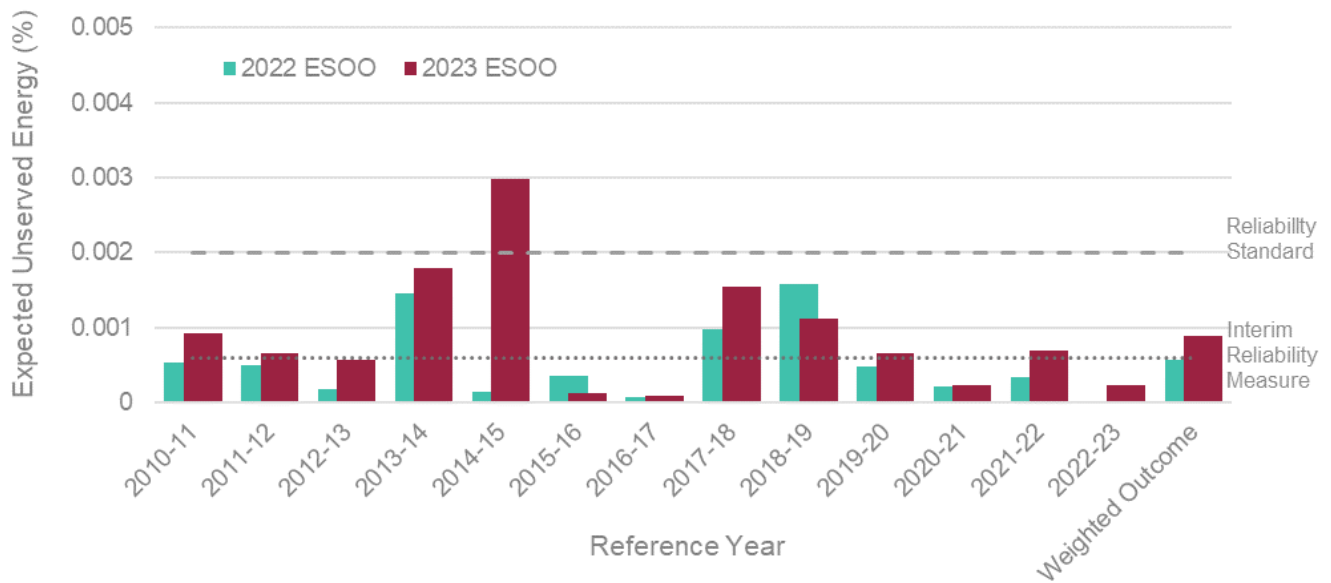
4.3 The availability of wind generation at time of maximum demand is a major factor influencing the risk of USE

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. Alternative 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 2023 ESOO applies 13 reference years (from financial year 2010-11 through to 2022-23), each of which have different combinations of peak demand timing, wind and solar availability, and other power system weather impacts.

Figure 24 shows the level of expected USE forecast in Victoria for 2023-24 based on each of the historical reference years modelled, and compares this to the 2022 ESOO forecast. 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 demand between regions, or the length of time that consumer demands were at near-peak levels during each of the reference years.

Figure 24 Impact of different weather reference years on expected USE in Victoria 2023-24, 2022 ESOO and 2023 ESOO (%)



The figure shows that:

- If the coincident weather conditions associated with the 2015-16, 2016-17, 2020-21 or 2022-23 years (which had higher wind availability at the time of maximum demand) were to re-emerge next summer, expected USE would be low. That means the risk of involuntary load shedding would be low, and high demand, or some generator outages, could occur with limited risk to consumers.
- If the weather conditions associated with the 2013-14, 2014-15, 2017-18 or 2018-19 years (which had lower wind availability at the time of maximum demand) were to re-emerge next summer, expected USE would be higher, meaning the occurrence of high demand or generator outages would likely lead to involuntary load shedding.
- For the first time, the 2023 ESOO includes the 2022-23 reference year, which shows low levels of reliability risk due to the high availability of wind generation at the time of maximum demand.
- For most reference years, expected USE is slightly higher in the 2023 ESOO than it was in the 2022 ESOO. This is consistent with updates that have occurred since the publication of the 2022 ESOO, such as higher generator unplanned outage rates and the application of project commissioning delays.
- For the 2014-15 reference year, risks have emerged in the 2023 ESOO that were not forecast in 2022. Improvements in AEMO’s wind data source that improve the accuracy of correlations of estimated wind output and actual wind generation observations has identified a higher risk of very low wind conditions coincident with the timing of the maximum demand event (discussed below).

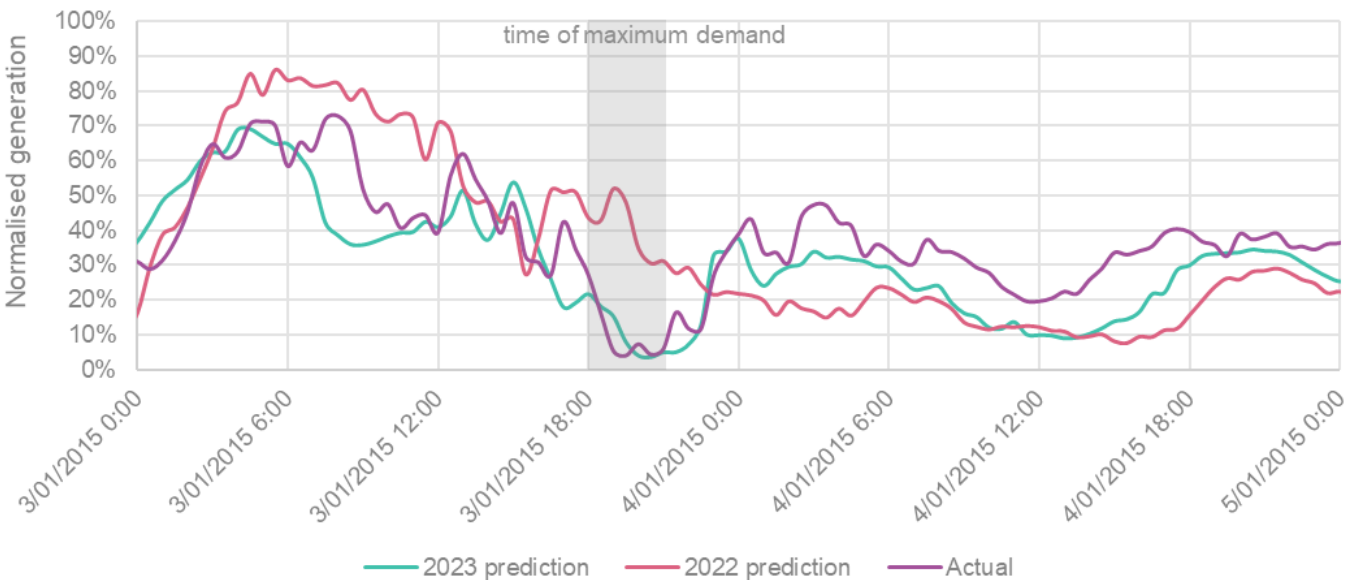
Forecasting wind generation at time of maximum demand

Where AEMO has quality historical data available for a wind farm, that data is applied in modelling each historical reference year. For many wind farms, where there is no or limited history (resulting in only a subset of historical reference years with observed generation outcomes), a prediction of the generation is developed based on wind speed and temperature data available for the location.

Wind is a challenging weather variable to predict with high levels of accuracy. It is not measured comprehensively across Australia and wind speed at a given location can vary due to many climatic and topographic features. AEMO applies statistical downscaling of global or regional reanalysis to predict wind farm output⁷⁴. These predictions can be accurate in terms of annual energy production, seasonal trends and general output profiles, but may not always be perfectly accurate for every hour interval of modelling.

To demonstrate this, **Figure 25** shows the normalised generation for wind farms in Victoria that were operating in January 2015, at the time of 2014-15 maximum demand (6.00 pm on 3 January 2015). It demonstrates that while wind availability can be at times very high (observed on the morning of 3 January), where aggregate output is above 60% of the nameplate capacity, the contribution of wind generation to service peak demands can also be highly volatile. At the time of the maximum demand, aggregate output was below 10% (as shown in the 'Actual' series in the figure).

Figure 25 2022 and 2023 wind output prediction compared to actual generation for wind farms in Victoria that were operating in January 2015



Depending on the source of weather data, the estimate of wind generation can vary. Wind data used in the 2022 ES00 contained gradually declining wind conditions all day on 3 January, with aggregate wind output estimated to be above 30% during the peak demand period. For the 2023 ES00, AEMO applied an alternative wind data source which contains a similar declining trend in wind conditions, however the estimated wind generation drops away more significantly after 7.00 pm on this day. Actual generation observed in 2015 indicates that the wind data and modelling used in the 2023 ES00 has a higher correlation to generator observations, and that wind availability in Victoria at the time of this maximum demand event was actually very low.

As the majority of wind generators in Victoria were not in operation in 2015, these predictions apply to many wind farms. Wind predictions are available with reasonable spatial granularity that reflects the variations in wind generation potential across each region. As a result of the timing of the drop in wind speed, a material decrease in the level of wind availability at the time of maximum demand in the 2014-15 reference year is now forecast.

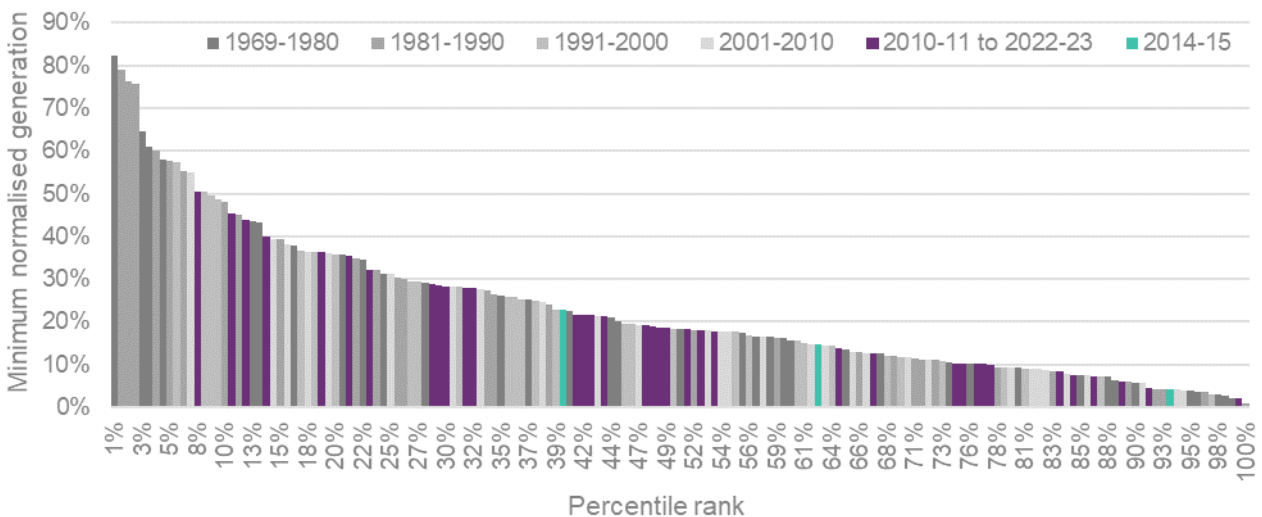
⁷⁴ In the 2022 ES00, AEMO applied wind modelling from the CSIRO CCAM model which applied regional downscaling of ERA5 global reanalysis. In the 2023 ES00, AEMO applied statistical downscaling of ERA5 global reanalysis.

Figure 26 shows the minimum wind output prediction for currently operational wind farms in Victoria in the period between 6.00 pm and 9.00 pm on the three hottest days of each year between 1969 and 2023. The reference years used in this ESOO are coloured purple or teal, while years that pre-date the reference years used in this ESOO apply various shades of grey grouped generally by decade. Key conclusions of this figure are:

- The 2010-11 to 2022-23 reference years, shown in purple, as applied in this ESOO, are seen to be well distributed between the historical dataset, indicating that they reflect a reasonable range of outcomes. The exception to this is for very high wind availability days during the hottest weather conditions, which are not observed after 1990 above approximately 60% of capacity.
- The 2014-15 reference year, shown in teal, can be identified as having very low wind contribution on some days, but that this reference year is not an outlier (at least in so far as the wind contribution during the hottest weather conditions).
- Other reference years are shown to have even lower wind availability on some days than the 2014-15 reference year. This suggests that other factors, such as the timing and coincidence of maximum demand, and the coincidence of VRE output in other regions, are also critical factors that determine the level of reliability risk.

The volatility of wind availability demonstrates the importance of continual improvements in forecast granularity, and considerations of generator availability, including VRE intermittency.

Figure 26 Minimum wind output prediction for the evenings of the three hottest days per year between 1969 and 2023, Victorian wind farms



4.4 Risk mitigation and summer readiness

As described in **Section 4.1** 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 if specific events arise, such as:

- Severe weather or power system events that result in prolonged transmission network unavailability.
- Periods of generation unavailability, including planned and unplanned outages.
- Delays to the commissioning of new transmission, generation or storage capacity.
- Operational impacts of extreme temperature on all generation technologies that may reduce output to below the rated generator capacity.
- Periods of low minimum demand that risk the security of the power system.

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

- 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.

5 Reliability forecasts

This chapter:

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

AEMO has prepared the reliability forecast against the IRM for 2023-24 and 2024-25, and against the reliability standard for 2025-26, 2026-27 and 2027-28 and for the indicative reliability forecasts (2028-29 to 2032-33 inclusive).

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

Chapter 6 (the EAAP) complements the reliability forecasts in this chapter by presenting the additional impact of energy limitations, under a variety of scenarios. **Chapter 7** complements the reliability forecasts by presenting the impact of additional anticipated investments on forecast reliability, and provides extended analysis of key sensitivities.

5.1 Key assumptions

This reliability assessment includes all existing, committed and anticipated generation and storage, including retirements, reported in the Generation Information July 2023 publication⁷⁵, as well as all existing, committed and anticipated transmission augmentations reported in the Transmission Augmentation Information⁷⁶ page published in July 2023. See **Chapter 3** for more information on the generation and transmission developments and the commissioning assumptions considered in this assessment.

This reliability assessment excludes all investments that have not yet completed all necessary requirements to be classified as committed or anticipated in accordance with AEMO's commitment criteria⁷⁷. Commissioning delays are applied to most new developments to manage commissioning risks that are not yet in the commissioning phase of their development.

Specifically, the 2023 ESOO reliability forecast and indicative reliability forecast excludes:

⁷⁵ At <https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information>.

⁷⁶ At <https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/transmission-augmentation-information>.

⁷⁷ Consistent with AEMO's consulted-on ESOO and Reliability Forecast Methodology, at <https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo>.

- Major transmission developments that are not yet considered committed or anticipated, including:
 - New England REZ transmission links, the Hunter Transmission Project in New South Wales, and other REZ expansion transmission elements as specified by the Energy Corporation of New South Wales.
 - Strategic transmission projects identified as actionable projects in the 2022 ISP affecting inter-regional transfer capacities, including HumeLink, Marinus Link, and Victoria – New South Wales Interconnector (VNI) West.
- Generation developments that are not yet considered committed or anticipated, including those that may be incentivised or underwritten by a federal, state or territory scheme:
 - Schemes that may incentivise or fund developments, but are not explicitly included in the reliability forecast, include the federal Capacity Investment Scheme, the New South Wales Electricity Infrastructure Roadmap, the Queensland Energy and Jobs Plan, the South Australian Hydrogen Jobs Plan, the Victorian Renewable Energy Target, Storage Target, and Offshore Wind Policy, and the Tasmanian Renewable Energy Target.
- DSP and CER orchestration developments that are not yet considered committed.
- Any additional out of market capacity that could be made available through IRR or RERT⁷⁸.

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

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

The AEMC has made a draft rule to extend the IRM as a trigger for the RRO until 30 June 2028, however a final decision on this rule change will not be made until after the 2023 ESOO is published. If the AEMC determines to extend the application of the IRM, AEMO will take the appropriate steps in accordance with the amended rules requirement.

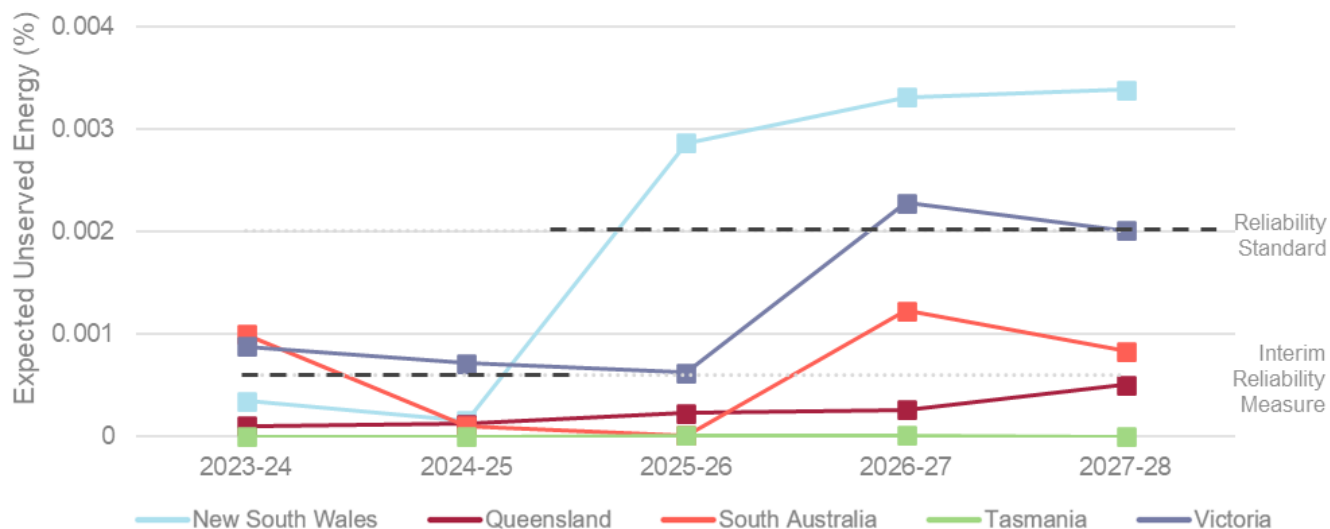
5.2 The reliability forecast (first five years)

For the ESOO Central scenario, over the five-year period from 2023-24 to 2027-28, the reliability forecast (shown in **Figure 27**) shows expected USE above the IRM for both South Australia (in 2023-24) and in Victoria (in 2023-24 and 2024-25).

From 2025-26, when the relevant standard reverts to the 0.002% reliability standard, the forecast shows expected USE above the reliability standard in both New South Wales (from 2025-26) and Victoria (from 2026-27).

⁷⁸ 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>.

Figure 27 Reliability forecast, all regions, first five years (2023-24 to 2027-28)



The key outcomes by region are:

- In **South Australia**, a reliability gap is identified in 2023-24 against the IRM.
 - A reliability gap was identified for this summer in the 2022 ESOO, but was not forecast in the February 2023 *Update to 2022 Electricity Statement of Opportunities*. The gap has re-emerged in the 2023 ESOO due to a combination of factors, including a slight increase in the forecast probability of low wind conditions coincident with high demand.
 - Between 2024-25 and 2025-26, expected USE is forecast to be within the IRM due to the return to service of the Torrens Island B1 unit which has been mothballed for several years, and the development of numerous battery, wind and solar developments, and Project EnergyConnect stage 1.
 - From 2026-27, all four units of Torrens Island B and Osborne Power Station have advised an expectation to have retired. Despite these retirements, expected USE is forecast above the IRM, but within the reliability standard as stronger network connection from Project EnergyConnect between southern New South Wales (Snowy/Canberra area), Victoria and South Australia, is forecast to reduce potential reliability risks.
 - While not modelled, any delays to the commissioning of Project EnergyConnect are likely to lead to significantly higher reliability risks in 2026-27, due to the quantity of generation that has advised retirement at the time this transmission development is advised to complete commissioning.
 - While numerous battery, wind and solar projects are expected to commission during the five-year horizon in South Australia and Victoria, the developments included in the reliability assessment are as yet insufficient to offset forecast increases in demand and advised generation retirements in South Australia (despite South Australia having an increased capability to draw on excess electricity supply from New South Wales via Project EnergyConnect), affecting South Australia and Victoria’s forecast reliability.
- In **Victoria**, reliability gaps are identified in 2023-24 and 2024-25 against the IRM, and in 2026-27 against the reliability standard.
 - Reliability risks are forecast above the IRM for the coming summer and again in summer 2024-25. Reliability gaps were not identified for these periods in the 2022 ESOO and have emerged in the 2023

ESOO due to a combination of factors, including a slight increase in the forecast probability of coincident high demand and low wind conditions.

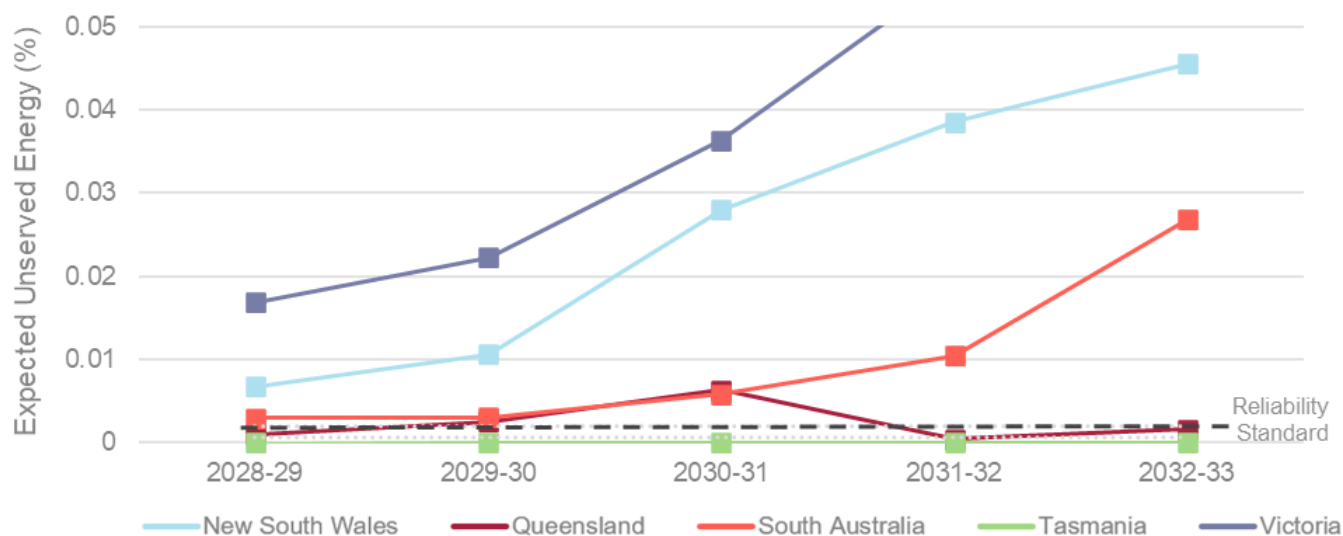
- Over the reliability forecast horizon, the supply-demand balance in Victoria is forecast to progressively tighten as demand increases, driven by projections for the electrification of residential, commercial, industrial and transportation loads. The projected electrification of traditional gas loads, particularly heating loads in Victoria, increases forecast consumption but is expected to have minimal impact on summer maximum demand.
- In 2026-27, expected USE is forecast above the reliability standard. In this year, all four units of Torrens Island B and Osborne Power Station in South Australia have advised an expectation to have retired, reducing available generation capacity across these tightly coupled regions (despite numerous new developments expected to commission, as noted in the commentary on South Australia outcomes above).
- In **New South Wales**, reliability gaps are identified from 2025-26 against the reliability standard.
 - From 2025-26, maximum demand is forecast to increase higher than previously forecast in the 2022 ESOO, DSP is forecast to be less impactful, and CER orchestration is now only applied subject to an assessment of commitment. Collectively these factors have increased forecast operational demand and therefore increased electricity supply requirements for New South Wales.
 - Reliability gaps are identified in 2025-26, when Eraring Power Station has advised it will have retired. The retirement of Eraring is however partially offset by committed developments including the Waratah Super Battery project (including transmission upgrades, BESS and SIPS). The project is expected to be fully available by 2025-26, as well as numerous wind, solar and additional battery developments in New South Wales.
 - These reliability gaps were identified in the 2022 ESOO, but reduced considerably in the February 2023 *Update to 2022 Electricity Statement of Opportunities*. The gaps have increased again, predominantly due to the treatment of demand side components, including a reduction in the forecast contribution of the New South Wales PDRS, and higher demand forecast. **Section 7.2** demonstrates the reduced need for utility-scale capacity should orchestrated CER resources and actionable transmission developments develop to improve the outlook.
- In **Queensland**, expected USE increases over the horizon but is forecast to be within the IRM and reliability standard across the reliability forecast period.
- In **Tasmania**, expected USE remains below the IRM and the reliability standard over the reliability forecast horizon.

5.3 The indicative reliability forecast (second five years)

Figure 28 shows the indicative reliability forecast, covering the five-year period from 2028-29 to 2032-33.

Over this period, expected USE is forecast above the reliability standard in most regions, and is forecast to progressively increase.

Figure 28 Indicative reliability forecasts, all regions, second five years (2028-29 to 2032-33)



Note: the scale of the y-axis used for the indicative reliability forecast is more than 10 times greater than that used for the reliability forecast.

The key outcomes by region are:

- In **New South Wales**, indicative reliability gaps are identified over the entire horizon against the reliability standard.
 - Maximum demand is forecast to increase more rapidly over the indicative reliability forecast horizon than in the reliability forecast horizon. This, combined with the revised treatment of CER orchestration, has increased forecast demand requirements for New South Wales relative to the 2022 ESOO forecast.
 - Since the 2022 ESOO, Delta Electricity has updated its expected closure year for Vales Point Power Station from 2029 to 2033, resulting in a relative improvement in the outlook from 2029-30.
 - In 2028-29 and 2029-30, the expected commissioning of various anticipated battery developments somewhat offsets the impact of the increased demand forecast.
 - From 2030-31, reliability risks are forecast to increase because currently committed and anticipated battery developments and other wind and solar generation developments are as yet insufficient to offset forecast increases in electricity demand.
- In **Queensland**, indicative reliability gaps are identified against the reliability standard in 2029-30 and 2030-31.
 - Reliability risks start to increase from 2028-29, when the Callide B Power Station will have fully retired, and are forecast to exceed the reliability standard from 2029-30.
 - Prior to summer 2031-32, the Borumba Pumped Hydro project is expected to complete commissioning, reducing reliability risks from that point.
- In **Tasmania**, reliability risks remain within the reliability standard and IRM over the horizon.
- In **South Australia** and **Victoria**, indicative reliability gaps are identified over the entire horizon against the reliability standard.
 - Yallourn Power Station in Victoria has advised retirement prior to the 2028-29 summer, increasing reliability risks in the indicative reliability forecast compared to the reliability forecast. The assumed commissioning of

Western Renewables Link in this year improves transmission access within Victoria but is insufficient to offset the retirement of Yallourn on its own.

- Various gas and liquid fuel generators in South Australia have advised retirement in 2030 and 2032, further reducing projected supply availability.
- While new wind, solar and battery storage developments continue to commit to commissioning in South Australia, Victoria and interconnected regions, these developments are not yet sufficient to offset expected generator retirements and the forecast increases in electricity demand.

5.4 Delivering transmission, generation, storage and demand response investments is needed to reduce reliability risks

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

AEMO applies strict commitment criteria⁷⁹ to classify projects as *in commissioning*, *committed*, *committed* or anticipated*, for inclusion in the reliability and indicative reliability forecasts.

There is a pipeline of projects (generation, storage and transmission) that are capable of becoming operational over the horizon, but none are sufficiently progressed to meet the criteria for consideration in the ESOO Central forecast. A total of 6.6 GW/16.3 GWh of CER orchestration and 2.1 GW of DSP developments are also forecast in the *Step Change* scenario by 2032-33, which have the potential to improve the outlook if integrated effectively with NEM market operations, minimising the need for utility-scale capacity.

Chapter 7 provides analysis of several sensitivities that demonstrates significant reliability improvement where:

- CER orchestration and DSP demand flexibility is successfully integrated within NEM market operations.
- Actionable transmission developments such as the Hunter Transmission Project, HumeLink, Marinus Link and VNI West progress and develop as scheduled.
- Numerous federal and state generation development schemes progress to their target schedules and quantities.

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

In addition to the RRO requirements which are addressed throughout this chapter, 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 10** below:

- Does not consider any reliability improvements that could be achieved with transmission developments, CER orchestration or DSP developments, or the impact of transmission limits on future generation development.
- Considers each region separately and does not consider the likely reliability benefits of new capacity shared 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.

⁷⁹ Consistent with the ESOO and Reliability Forecast Methodology, at <https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo>.

- The identified firm capacity requirements are 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.
- Examines 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 10 Forecast additional capacity required (in MW) to meet the reliability standard (0.002% USE) and IRM (0.0006% USE)

Financial Year	New South Wales		Queensland		South Australia		Tasmania		Victoria	
	Reliability Standard	IRM	Reliability Standard	IRM	Reliability Standard	IRM	Reliability Standard	IRM	Reliability Standard	IRM
2023-24	0	0	0	0	0	118	0	0	0	120
2024-25	0	0	0	0	0	0	0	0	0	55
2025-26	191	786	0	0	0	0	0	0	0	13
2026-27	250	796	0	0	0	205	0	0	70	738
2027-28	285	888	0	0	0	96	0	0	4	618
2028-29	732	1,376	0	235	101	413	0	0	1,246	1,994
2029-30	1,085	1,748	102	765	114	441	0	0	1,408	2,189
2030-31	1,944	2,607	722	1,460	348	672	0	0	1,819	2,512
2031-32	2,183	2,842	0	0	529	834	0	0	2,117	2,830
2032-33	2,305	2,967	0	568	874	1,159	0	0	2,484	3,224

To better illustrate the contributions of various technologies to reducing expected USE, AEMO has built on the analysis presented in **Table 10** to provide indicative technology combinations that are forecast to reduce reliability risks to the reliability standard and IRM. This extended analysis of the additional capacity required:

- Does not consider any reliability improvements that could be achieved with transmission developments, CER orchestration or DSP developments, or the impact of transmission limits on future generation development.
- Considers each region separately and does not consider the inter-regional benefits of new capacity. Actual capacity requirements may therefore be lower for some regions considering developments in neighbouring regions.
- Identifies 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.
- Considers 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.
- Does not identify an optimal development path, or recommend a particular solution.

Table 11 and **Table 12** show the additional capacity required to reduce the expected USE under the relevant standards for New South Wales and Victoria in 2026-27 (T-3 period for RRO purposes). Build ratios between VRE and storages were assumed⁸⁰ based on analysis of the 2022 ISP, however may not be optimal in this application.

Table 11 Additional capacity required, considering a variety of technology combinations (in MW) to reduce expected USE to the reliability standard and IRM, New South Wales 2026-27

Combination	Technology type	Reliability standard of 0.002% USE	IRM of 0.0006% USE
1	Firm, unlimited capacity	250 MW	796 MW
2	Open cycle gas turbine (OCGT) ^A	258 MW	821 MW
3	2 hour storage ^B	657 MW/1,315 MWh	2,305 MW/4,610 MWh
4	4 hour storage ^B	312 MW/1,247 MWh	1,011 MW/4,043 MWh
5	6 hour storage ^B	262 MW/1,570 MWh	833 MW/5,001 MWh
6	8 hour storage ^B	252 MW/2,014 MWh	801 MW/6,408 MWh
7	Wind	389 MW	1,252 MW
	4 hour storage	194 MW/778 MWh	626 MW/2,503 MWh
8	Solar	477 MW	1,596 MW
	4 hour storage	238 MW/954 MWh	798 MW/3,192 MWh
9	Wind	370 MW	1,197 MW
	Solar	92 MW	299 MW
	4 hour storage	185 MW/739 MWh	599 MW/2,394 MWh

A. Assuming there is sufficient gas to operate the generator throughout potential USE periods.

B. Assuming there is sufficient energy and/or water to charge/pump ahead of potential USE periods.

Table 12 Additional capacity required, considering a variety of technology combinations (in MW) to reduce expected USE to the reliability standard and IRM, Victoria 2026-27

Combination	Technology type	Reliability standard of 0.002% USE	IRM of 0.0006% USE
1	Firm, unlimited capacity	70 MW	738MW
2	Open cycle gas turbine (OCGT) ^A	72 MW	761 MW
3	2 hour storage ^B	171 MW/343 MWh	1,701 MW/3,402 MWh
4	4 hour storage ^B	85 MW/339 MWh	843 MW/3,372 MWh
5	6 hour storage ^B	73 MW/437 MWh	750 MW/4,500 MWh
6	8 hour storage ^B	71 MW/564 MWh	738 MW/5,906 MWh
7	Wind	123 MW	1,257 MW
	4 hour storage	61 MW/246 MWh	629 MW/2,515 MWh
8	Solar	104 MW	1,130 MW
	4 hour storage	52 MW/209 MWh	565 MW/2,261 MWh
9	Wind	110 MW	1,132MW
	Solar	28 MW	283 MW
	4 hour storage	55 MW/220 MWh	566 MW/2,264 MWh

A. Assuming there is sufficient gas to operate the generator throughout potential USE periods.

B. Assuming there is sufficient energy and/or water to charge/pump ahead of potential USE periods.

⁸⁰ 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.

5.5 Reliability forecast components

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

- Exceeds 0.0006% of the total energy demanded in a region for a given financial year between 2023-24 and 2024-25⁸¹.
- Exceeds 0.002% of the total energy demanded in a region for a given financial year between 2025-26 and 2032-33.

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

Forecast reliability gaps

In the reliability forecast (first five years), forecast reliability gaps occur in South Australia in 2023-24 against the IRM, in Victoria in 2023-24 and 2024-25 against the IRM, in Victoria in 2026-27 and 2027-28 against the reliability standard, and in New South Wales in 2025-26, 2026-27, and 2027-28 against the reliability standard. The reliability forecast components associated with these forecast reliability gaps are summarised in **Table 13** and **Table 14**.

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.

Table 13 Forecast reliability gaps against the Interim Reliability Measure (MW)

Region	Financial year	Reliability gap period	Likely trading intervals	Expected USE for the gap period (GWh)	Reliability gap (MW)
South Australia	2023-24	1 January 2024 – 29 February 2024	5.00 pm – 9.00 pm, working weekdays	0.11	118
Victoria	2023-24	1 January 2024 – 29 February 2024	3.00 pm – 9.00 pm, working weekdays	0.32	120
	2024-25	1 January 2025 – 28 February 2025	4.00 pm – 9.00 pm, working weekdays	0.27	55

⁸¹ As per NER 11.132.2, which prescribes the IRM as the reliability standard until 30 June 2025.

Table 14 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)
Victoria	2026-27	1 December 2026 – 28 February 2027	3.00 pm – 9.00 pm, working weekdays	0.86	70
	2027-28	1 December 2027 – 29 February 2028	3.00 pm – 9.00 pm, working weekdays	0.73	4
New South Wales	2025-26	1 December 2025 – 31 March 2026	3.00 pm – 10.00 pm, working weekdays	1.54	191
	2026-27	1 July 2026 – 31 July 2026	5.00 pm – 9.00 pm, working weekdays	0.16	250
		1 December 2026 – 31 March 2027	3.00 pm – 10.00 pm, working weekdays	1.64	250
		1 June 2027 – 30 June 2027	5.00 pm – 9.00 pm, working weekdays	0.18	250
	2027-28	1 July 2027 – 31 August 2027	5.00 pm – 10.00 pm, working weekdays	0.21	285
		1 November 2027 – 28 February 2028	2.00 pm – 11.00 pm, working weekdays	1.70	285
		1 May 2028 – 30 June 2028	4.00 pm – 10.00 pm, working weekdays	0.22	285

Reliability instruments are already current for the following periods:

- T-1 instrument for working weekdays between 8 January 2024 to 29 February 2024 in South Australia.
- T-3 instrument for weekdays between 1 December 2025 to 28 February 2026 in New South Wales.
- T-3 instrument for working weekdays between 13 January 2025 to 14 March 2025 in South Australia.
- T-3 instrument for working weekdays between 12 January 2026 to 13 March 2026 in South Australia.

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 2026 – 31 March 2027 in New South Wales.
- A T-3 reliability instrument for working weekdays between the period 1 December 2026 – 28 February 2027 in Victoria.

The following reliability gaps are now outside the allowable timeframes for reliability instruments to be requested:

- The reliability gap identified between 1 July 2026 and 31 July 2026 in New South Wales.
- The reliability gaps identified in 2023-24 and 2024-25 in Victoria.

As the reliability forecast no longer identifies a reliability gap for South Australia in the T-1 year of 2024-25, AEMO will advise the AER in accordance with NER 4A.C.5 that this reliability gap is 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 all years from 2028-29 to 2032-33, in Queensland in 2029-30 and 2031-32, in South Australia in all years from 2028-29 to 2032-33, and in Victoria in all years from 2028-29 to 2032-33. 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 15**.

Table 15 Indicative forecast reliability gaps against the reliability standard

Region	Financial year	Reliability gap period	Likely trading intervals	Expected USE for the gap period (GWh)	Reliability gap (MW)
New South Wales	2028-29	1 July 2028 – 31 August 2028	5.00 pm – 10.00 pm, working weekdays	0.77	732
		1 December 2028 – 28 February 2029	3.00 pm – 10.00 pm, working weekdays	2.35	732
		1 June 2029 – 30 June 2029	5.00 pm – 10.00 pm, working weekdays	1.11	732
	2029-30	1 July 2029 – 31 August 2029	5.00 pm – 10.00 pm, working weekdays	1.96	1,085
		1 December 2029 – 28 February 2030	3.00 pm – 11.00 pm, working weekdays	3.35	1,085
		1 June 2030 – 30 June 2030	5.00 pm – 10.00 pm, working weekdays	1.40	1,085
	2030-31	1 July 2030 – 30 June 2031	all hours, all days	21.58	1,944
	2031-32	1 July 2031 – 30 June 2032	all hours, all days	30.06	2,183
	2032-33	1 July 2032 – 30 June 2033	all hours, all days	35.86	2,305
	Victoria	2028-29	1 July 2028– 31 July 2028	5.00 pm – 9.00 pm, working weekdays	0.12
1 November 2028 – 31 March 2029			12.00 pm – 11.00 pm, working weekdays	6.44	1,246
1 June 2029 – 30 June 2029			5.00 pm – 10.00 pm, working weekdays	0.34	1,246
2029-30		1 July 2029 – 31 August 2029	8.00 am – 10.00 pm, working weekdays	0.68	1,408
		1 November 2029 – 31 March 2030	1.00 pm – 11.00 pm, all days	8.65	1,408
		1 June 2030 – 30 June 2030	8.00 am – 10.00 pm, working weekdays	0.98	1,408
2030-31		1 July 2030 – 31 August 2030	4.00 am – 11.00 pm, weekdays	1.58	1,819
		1 November 2030 – 30 June 2031	all hours, all days	16.06	1,819
2031-32		1 July 2031 – 31 August 2031	all hours, all days	5.42	2,117
		1 November 2031 – 30 June 2032	all hours, all days	23.77	2,117
2032-33		1 July 2032 – 30 June 2033	all hours, all days	51.93	2,484
Queensland		2029-30	1 January 2030 – 31 March 2030	4.00 pm – 10.00 pm, working weekdays	1.27

Region	Financial year	Reliability gap period	Likely trading intervals	Expected USE for the gap period (GWh)	Reliability gap (MW)
	2030-31	1 January 2031 – 31 March 2031	4.00 pm – 10.00 pm, working weekdays	3.31	722
South Australia	2028-29	1 July 2028 – 31 July 2028	6.00 pm – 10.00 pm, working weekdays	0.02	101
		1 January 2029 – 28 February 2029	5.00 pm – 11.00 pm, working weekdays	0.22	101
		1 June 2029 – 30 June 2029	5.00 pm – 10.00 pm, working weekdays	0.18	101
	2029-30	1 July 2029 – 31 August 2029	5.00 pm – 10.00 pm, working weekdays	0.21	114
		1 January 2030 – 28 February 2030	5.00 pm – 10.00 pm, working weekdays	0.19	114
		1 June 2030 – 30 June 2030	5.00 pm – 10.00 pm, working weekdays	0.05	114
	2030-31	1 January 2031 – 28 February 2031	5.00 pm – 11.00 pm, working weekdays	0.58	348
		1 June 2031 – 30 June 2031	5.00 pm – 10.00 pm, working weekdays	0.24	348
	2031-32	1 July 2031 – 31 July 2031	5.00 pm – 10.00 pm, working weekdays	0.17	529
		1 January 2032 – 29 February 2032	5.00 pm – 11.00 pm, all days	0.95	529
		1 June 2032 – 30 June 2032	5.00 pm – 10.00 pm, working weekdays	0.54	529
	2032-33	1 July 2032 – 31 August 2032	5.00 pm – 10.00 pm, working weekdays	0.51	874
		1 December 2032 – 28 February 2033	all hours, all days	1.88	874
		1 May 2033 – 30 June 2033	5.00 pm – 11.00 pm, working weekdays	2.16	874

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 reports the 50% POE operational maximum demand forecast on an 'as generated' basis for this purpose. Performance of these demand forecasts is included in AEMO's *Forecast Accuracy Report*⁸².

The only difference between the 'as generated' forecasts, listed in **Table 16**, and the operational maximum demand values reported in **Section 2.3** on a 'sent out' basis, is the inclusion of auxiliary load forecasts at time of maximum demand⁸³.

⁸² At <https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/forecasting-accuracy-reporting>.

⁸³ See AEMO's *Electricity Demand Forecasting Information Paper*, at <https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-approach/forecasting-and-planning-guidelines>.

Table 16 AEMO's one-in-two year peak demand forecast (50% POE, as generated)

Financial year	New South Wales	Queensland	South Australia	Tasmania	Victoria
2023-24	13,142	10,381	2,963	1,755	9,735
2024-25	13,331	10,617	3,013	1,774	9,793
2025-26	13,520	10,803	3,077	1,802	9,872
2026-27	13,890	11,027	3,137	1,822	10,040
2027-28	14,113	11,184	3,233	1,829	10,257

The forecast auxiliary load amounts at the time of maximum demand for 50% POE demand conditions are shown below in **Table 17**. These values have been determined based on modelling outcomes which apply the auxiliary rates of each generating unit provided by participants.

Average auxiliary load rates at the time of one-in-two year peak demand are forecast to remain relatively static over the next five years in all regions. Coal-fired generation typically has higher auxiliary loads than other generation types. Auxiliary loads therefore reduce as coal-fired generators retire and are replaced with alternative capacity.

Table 17 Auxiliary usage (in MW) forecast at time of one-in-two year peak demand (50% POE)

Financial year	New South Wales	Queensland	South Australia	Tasmania	Victoria
2023-24	343	449	41	18	366
2024-25	333	430	47	20	358
2025-26	254	397	44	19	310
2026-27	259	366	15	19	263
2027-28	194	333	15	19	279

6 Energy Adequacy Assessment Projection

The Energy Adequacy Assessment Projection (EAAP) forecasts electricity supply reliability in the NEM over a 24-month outlook period. The EAAP complements the ESOO reliability assessments, providing a focus on the impact of energy constraints on reliability. Inputs and assumptions used in the EAAP align with the ESOO reliability forecast (as per **Chapter 5**), but apply additional insights on energy limitations using scenarios defined in the EAAP guidelines⁸⁴ 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 guidelines and the Reliability Standard Implementation Guidelines⁸⁵ (RSIG), the EAAP assesses reliability by comparing expected USE against the reliability standard of 0.002% USE, as the IRM does not apply for the purposes of the EAAP. 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.
- **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 Drought⁸⁶, are applied in this scenario.
- **EAAP Low Thermal Fuel scenario** – considering thermal fuel availability limits under 1-in-10-year low fuel availability conditions for each power station in the NEM. Hydro generators apply most likely water availability. When developing 1-in-10-year low fuel availability limits, participants are asked to consider the potential impacts of wet coal, longwall moves, train and truck deliveries, loader outages, likely market limitations, pipeline constraints, gas supply issues, and whether these events could occur over a prolonged period, or for shorter events only.

Figure 29 shows the annual expected USE forecast for these three EAAP scenarios relative to the ESOO Central scenario. 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 Low Rainfall scenarios for all regions in the coming summer.
- The EAAP Central scenario forecasts slightly higher reliability risks for the coming year relative to the ESOO Central scenario in New South Wales, South Australia and Victoria, due to the application of participant provided energy limits, some of which are more onerous than assumed in the ESOO.

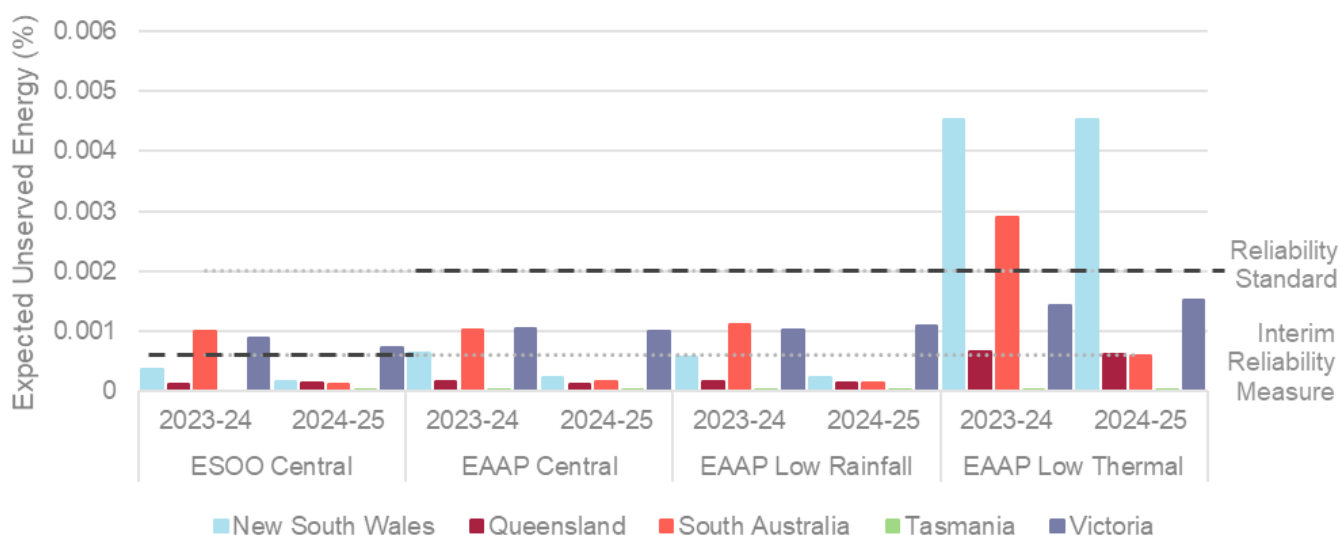
⁸⁴ At https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/rsig/final-documents/eaap-guidelines.pdf.

⁸⁵ At <https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/reliability-standard-implementation-guidelines>.

⁸⁶ 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.

- For example, some gas generators in New South Wales have advised low energy limits in their submission for the EAAP Central scenario, which are not considered in the ESOO. Reliability risks in this scenario are forecast above the IRM in the coming year in New South Wales, as well as South Australia and Victoria, however the IRM does not apply for the purposes of the EAAP.
- If severe drought conditions emerge, they are unlikely to result in a material increase in reliability risk compared to normal rainfall conditions, as demonstrated by the small difference in USE outcomes between the EAAP Central and Low Rainfall scenarios⁸⁷.
- The EAAP Low Thermal Fuel scenario demonstrates vulnerabilities to 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 1-in-10-year fuel unavailability scenario, it does not reflect an expected outlook. This scenario, however, demonstrates the importance of maintaining ongoing availability of fuel, and fuel supply chains throughout the energy transition. Based on participant provided information, the largest vulnerabilities are in New South Wales, Queensland and South Australia.

Figure 29 EAAP annual expected USE by scenario (%)



6.1 Generator Energy Limitations Framework parameters

Generator Energy Limitations Framework (GELF) parameters 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:

- Static GELF parameters (including technical specifications of the power stations, relevant water and fossil fuel storage infrastructure, and operational limits).

⁸⁷ 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.

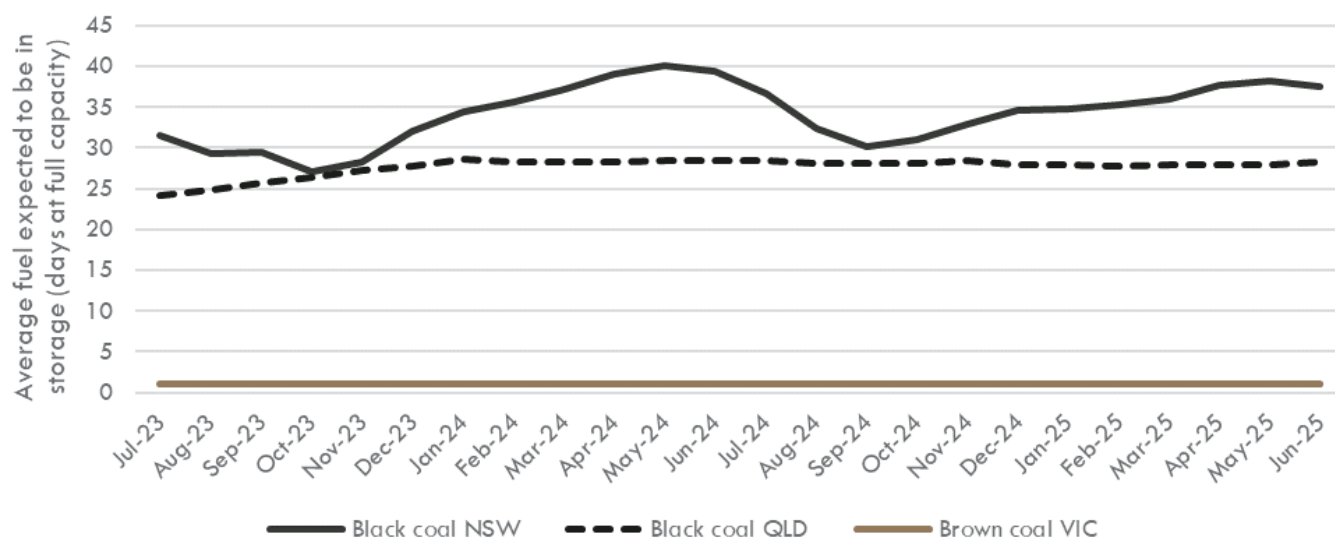
- Variable GELF parameters (including monthly generation capabilities and monthly water and energy production supply information relevant to each scenario).

Please see the EAAP Guidelines⁸⁸ for details of the GELF parameters.

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

As shown in **Figure 30**, coal generators advise their expected coal supply over the two-year EAAP horizon. On average, coal generators across New South Wales and Queensland advised an expectation to increase coal stockpiles, with as much as 40 and 29 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 30 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

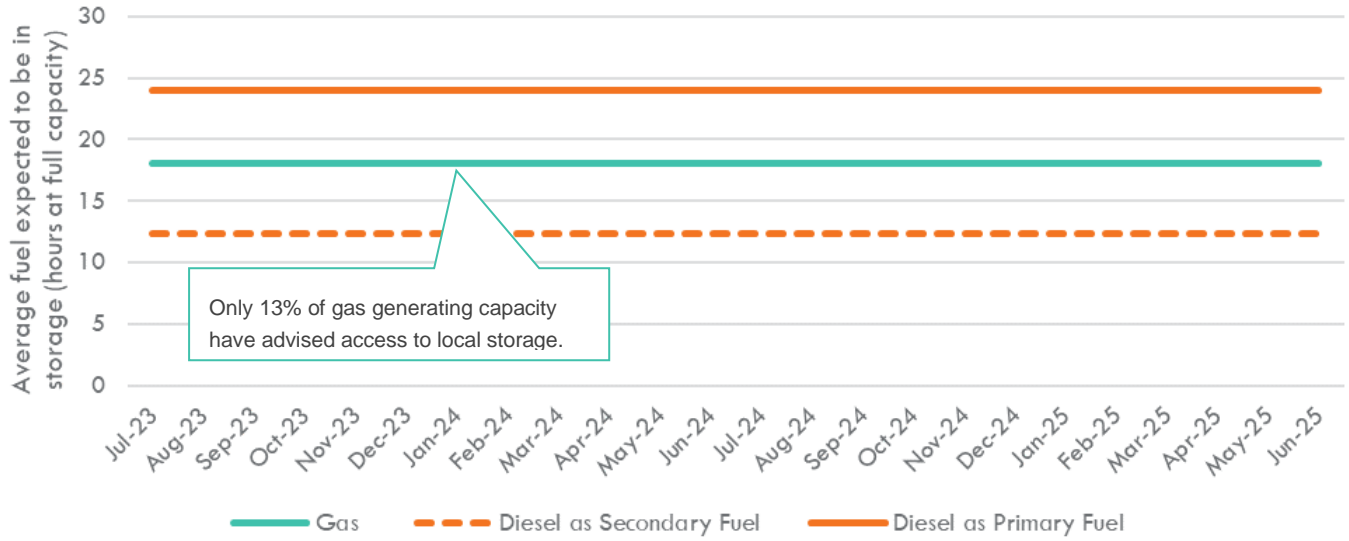
Most gas generators rely on natural gas supplied continuously through the gas network as their primary fuel source and have no on-site gas storage capacity. A minority (13% by capacity) of gas generators have advised access to an average of 18 hours of gas storage, predominantly through access to local linepack that is within the control of the operator.

Most gas generators do not have secondary fuel capabilities. Of the generators which have diesel as a secondary fuel source, the diesel storage was expected to be suitable for an average of 12 hours of operation. For those generators that use diesel only, on-site storage was advised to be suitable for an expected 24 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 31**.

⁸⁸ 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>.

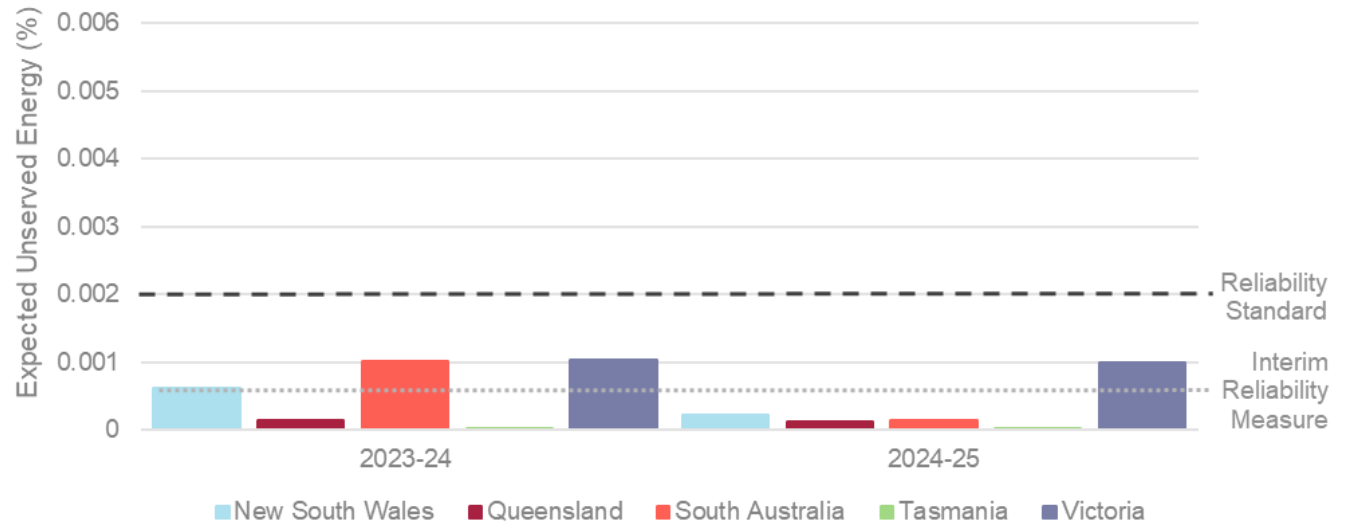
Figure 31 GELF expected storage for gas and liquid fuel generation (hours of generation at full capacity)



6.2 EAAP Central scenario

The EAAP Central Scenario applies participant provided energy limits that represent the most likely outlook. As shown in **Figure 32**, this scenario identifies that reliability risks are forecast within the reliability standard over the two-year EAAP horizon. In limited cases, some participants have provided energy limits which are lower than applied in the ES00, resulting in slightly higher risks than the ES00 Central scenario.

Figure 32 Expected USE, EAAP Central scenario (%)



Information on the monthly and time of day distribution of reliability risks can be found in **Appendix A7**. Forecast reliability risks are concentrated in the summer months for Queensland, South Australia and Victoria, are shared between summer and winter for New South Wales, and are concentrated in winter for Tasmania.

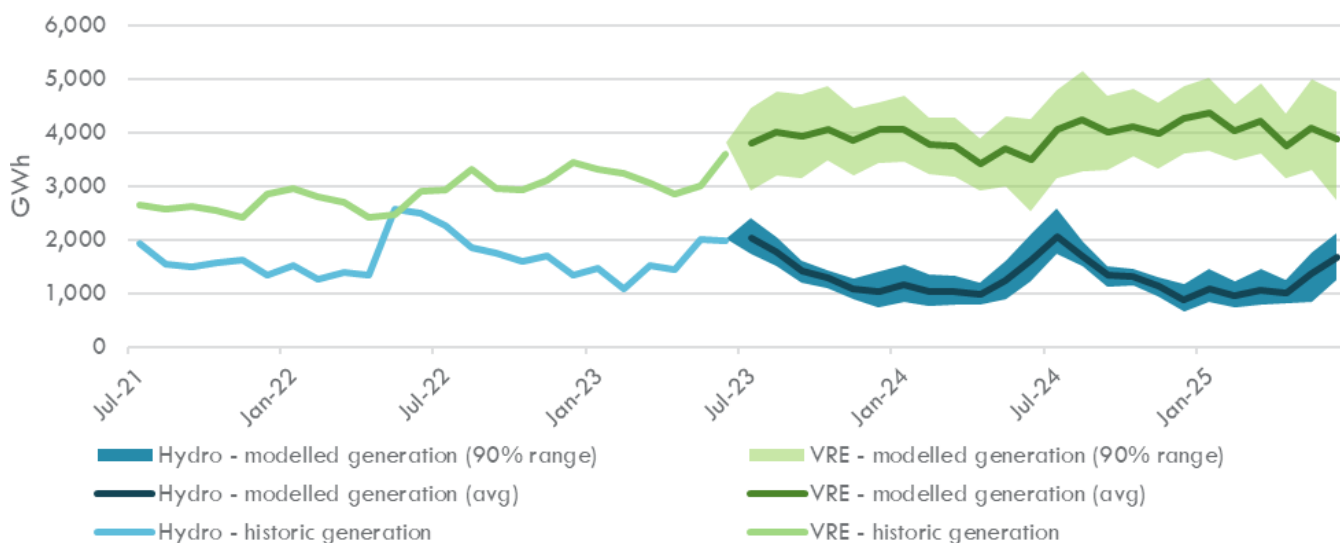
Figure 34 shows the energy production projections for coal generators in New South Wales, Queensland and Victoria, as well as a NEM-aggregate projection for gas and liquid-fuelled generators, relative to historical

operation and the participant provided energy limits. Similarly, **Figure 33** shows projected VRE and hydro generation compared to history.

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 can procure more fuel if required.
- Significant headroom to the provided energy limits exists for more gas to be procured if needed⁸⁹, however in aggregate it is unclear the degree to which forecast gas production decline in southern regions, as reported in the 2023 *Gas Statement of Opportunities*⁹⁰, is reflected in the limits provided in aggregate, and may present a risk if proponents are assuming gas remains available to be procured from the spot market.
- 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.

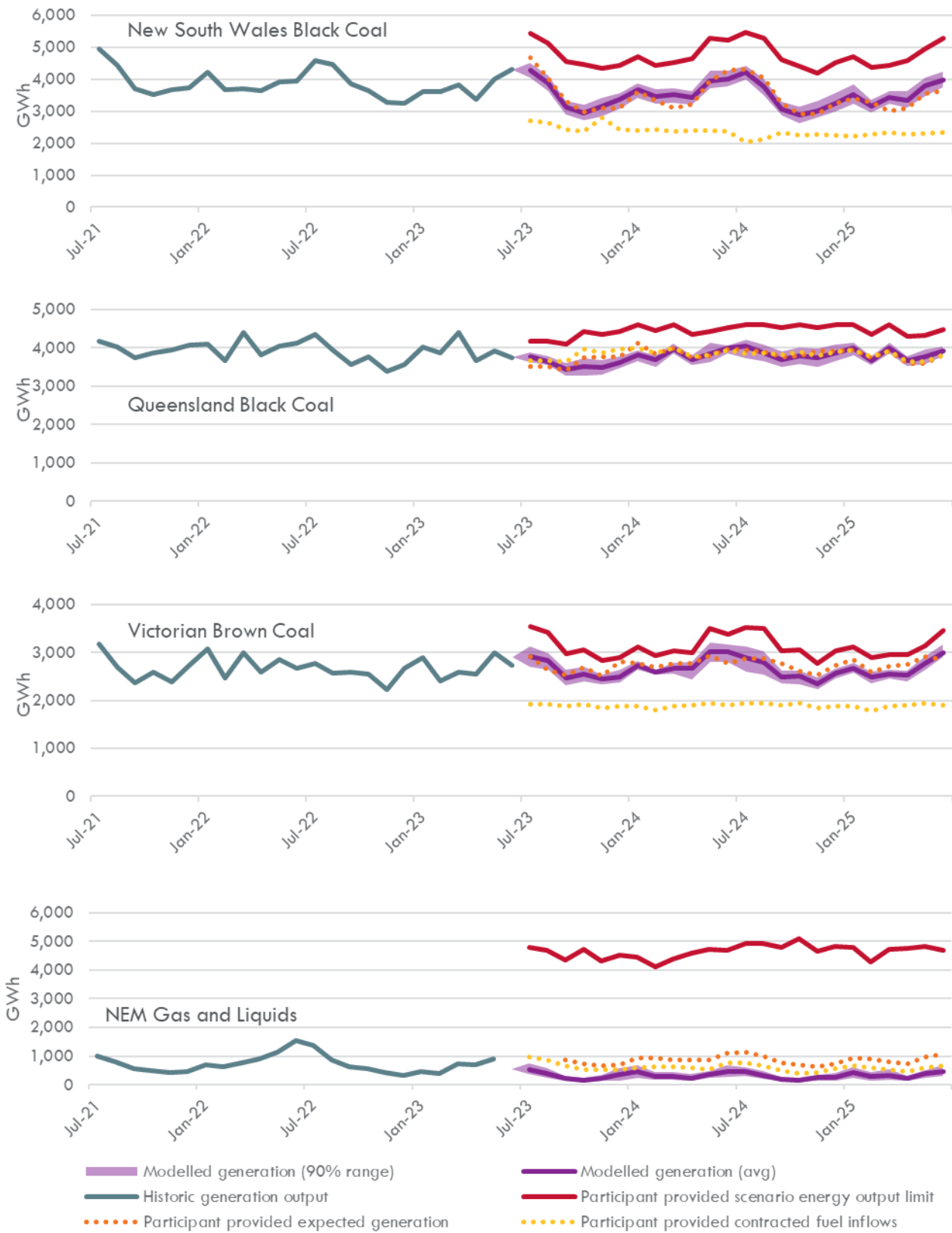
Figure 33 NEM hydro and VRE monthly generation projection, EAAP Central scenario (GWh)



⁸⁹ Projected generation for gas and liquid-fuelled generation is naturally lower than the participant provided expected production, an outcome of the reliability forecasting methodology that focuses on least-cost operation rather than strategic bid-based dispatch forecasting.

⁹⁰ At <https://aemo.com.au/en/energy-systems/gas/gas-forecasting-and-planning/gas-statement-of-opportunities-gsoo>.

Figure 34 Monthly energy production projection relative to energy production limit, expected generation and contracted fuel inflows, EAAP Central scenario (GWh)

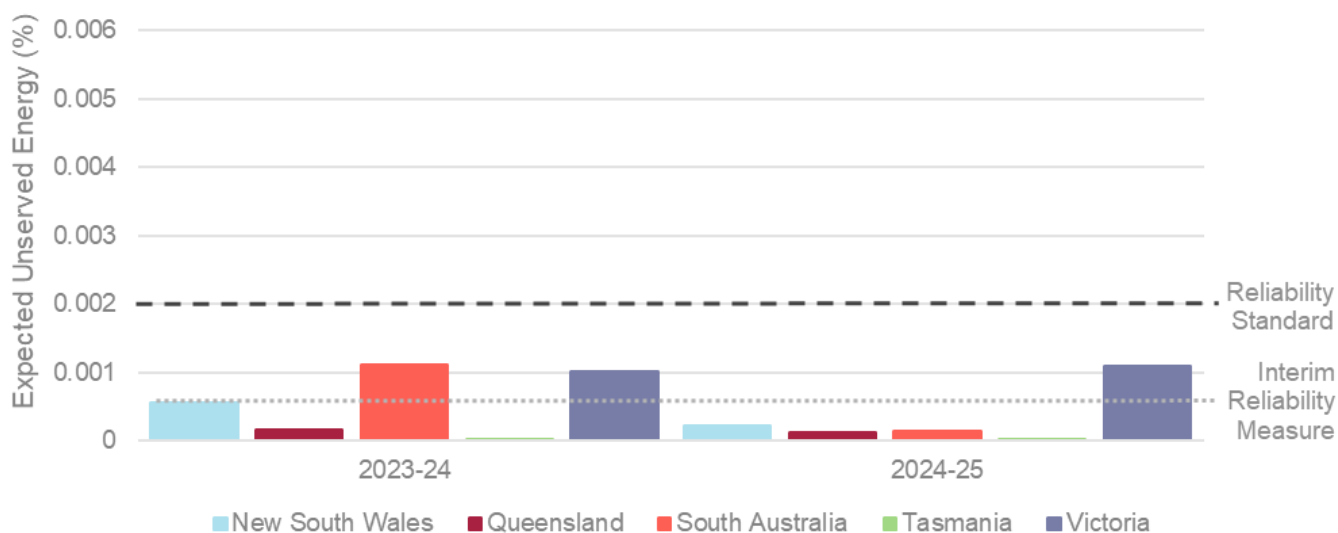


6.3 EAAP Low Rainfall scenario

The EAAP Low Rainfall scenario applies participant provided energy limits for thermal generators, and severe drought conditions reflecting low water inflows for hydro generators. No thermal generator provided materially different energy limits due to the impact of droughts.

As shown in **Figure 35**, this scenario identifies that reliability risks are forecast within the reliability standard over the two-year 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 slightly higher risks than the EAAP Central scenario. While expected USE for the NEM aligns closely with the EAAP Central scenario, some variation is observed region-by-region, largely due to the location of reduced energy availability of the Snowy Hydro Scheme which is located at the boundary of the Victorian and New South Wales regions.

Figure 35 Expected USE, EAAP Low Rainfall scenario (%)



Information on the monthly and time of day distribution of reliability risks can be found in **Appendix A7**. Only limited variation to outcomes are observed relative to the EAAP Central scenario.

Figure 37 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 36** shows projected VRE and hydro generation compared to history.

Key insights unique to this scenario include:

- Provided energy limits for thermal generators are unchanged relative to the EAAP Central scenario, suggesting that participants do not expect drought conditions to impact cooling water availability, or any other operational water requirement that could reduce production.
- Projected generation for New South Wales black coal and, to a lesser degree, Victorian brown coal is higher than the EAAP Central scenario, and higher than the participant-provided expectations. This indicates that coal in these regions has the potential to replace hydro generation lost due to drought conditions.

- Projected generation for gas and liquid-fuelled generation is higher than projected in the EAAP Central scenario, suggesting that gas and liquids also have the potential to replace lost energy production.
- Hydro generators are projected to reserve as much available water for high energy consumption periods in winter.

Figure 36 NEM hydro and VRE monthly generation projection, EAAP Low Rainfall scenario (GWh)

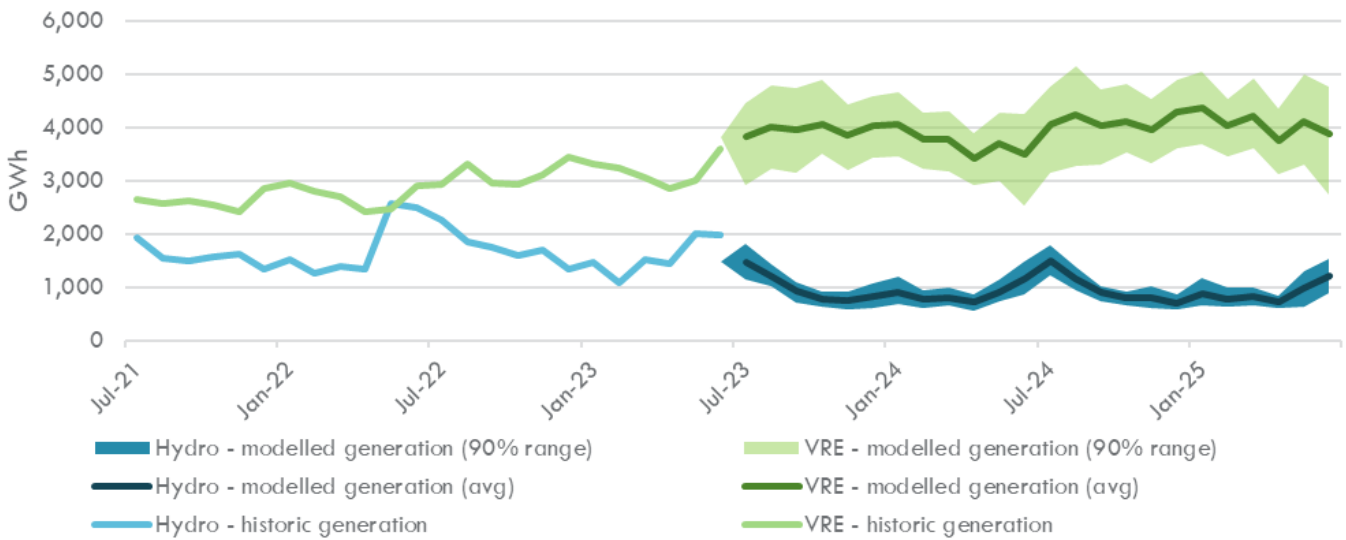
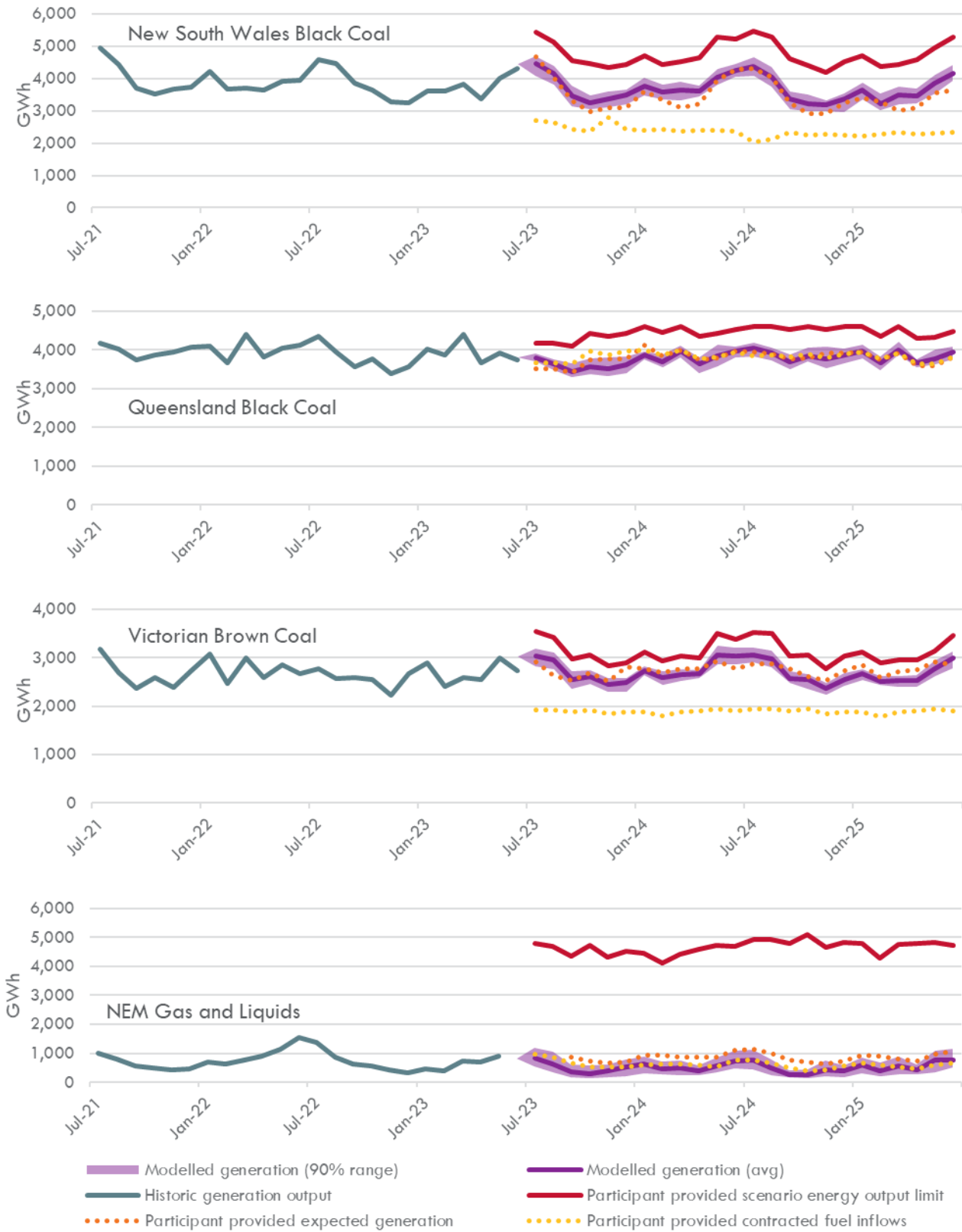


Figure 37 Monthly energy production projection relative to energy production limit, expected generation and contracted fuel inflows, EAAP Low Rainfall scenario (GWh)



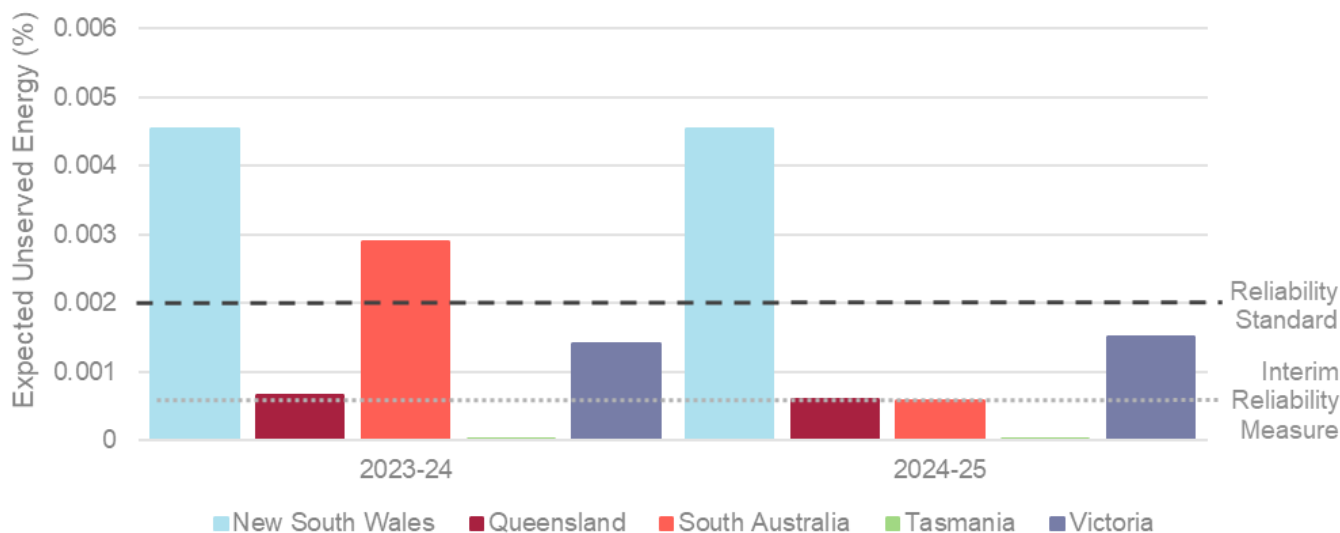


6.4 EAAP Low Thermal Fuel scenario

The EAAP Low Thermal Fuel scenario applies participant-provided energy production limits applicable under 1-in-10-year low fuel availability conditions for each power station in the NEM. Hydro generators apply most likely water availability. 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.

As shown in **Figure 38**, this scenario identifies that significant reliability risks emerge, above the reliability standard in New South Wales and South Australia in at least one of the two years, if severe fuel shortfall events arise. These events are 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. 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 38 Expected USE, EAAP Low Thermal Fuel scenario (%)



Information on the monthly and time of day distribution of reliability risks can be found in **Appendix A7**. While additional USE is forecast, there is limited variation in the monthly and time of day distribution of outcomes relative to the EAAP Central scenario.

Figure 40 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 39** 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 for short-duration events affecting coal generators, and in Queensland for longer-term events for coal. For gas and liquid-fuelled generators, energy limits reduce by approximately 40% 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 39 NEM hydro and VRE monthly generation projection, EAAP Low Thermal Fuel scenario (GWh)

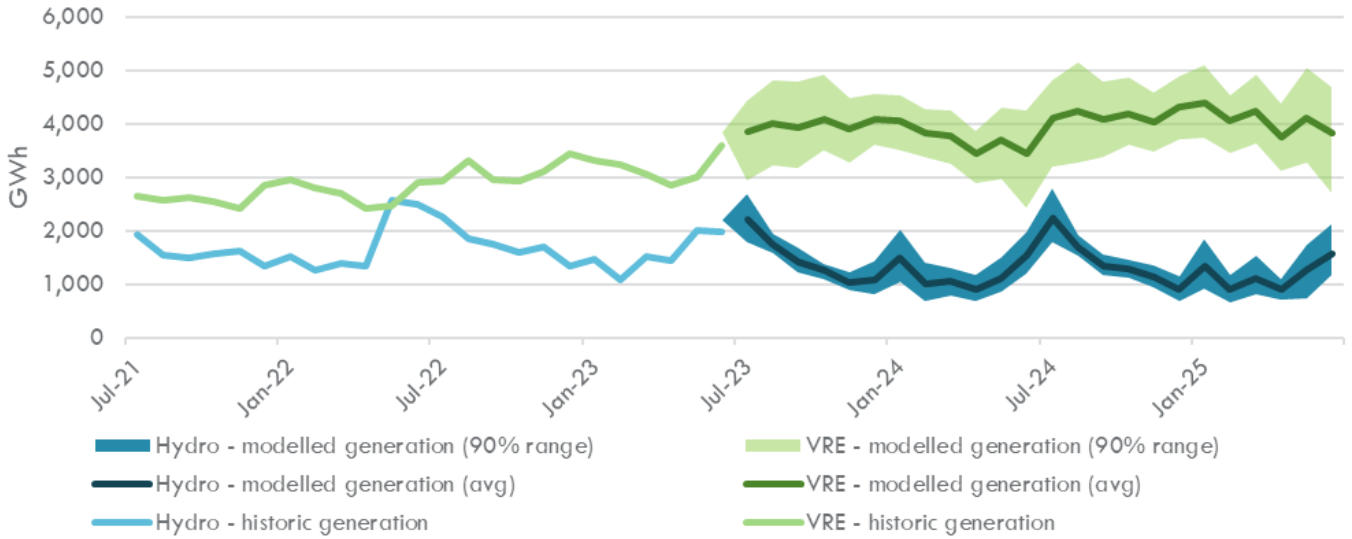
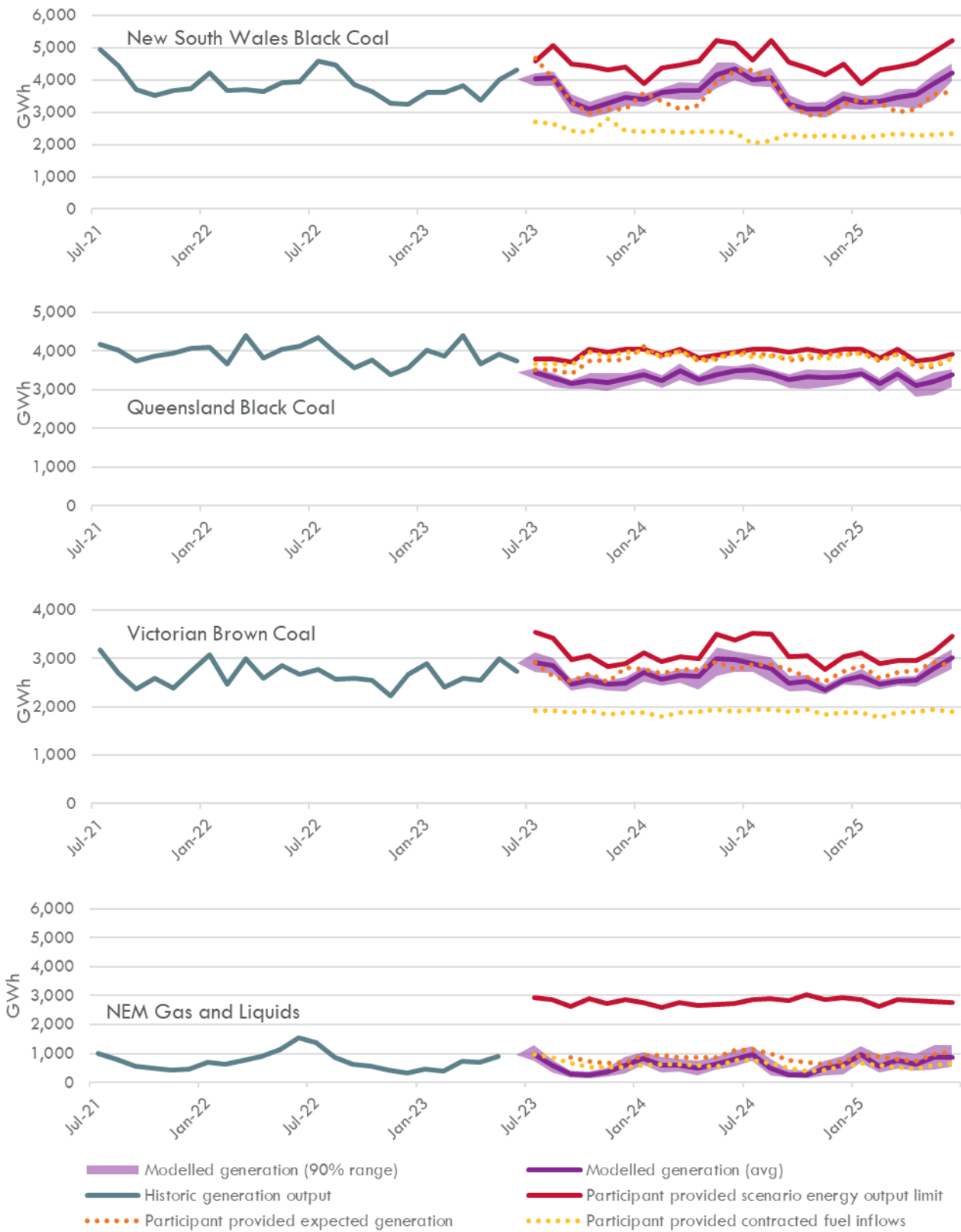


Figure 40 Monthly energy production projection relative to energy production limit, expected generation and contracted fuel inflows, EAAP Low Thermal Fuel scenario (GWh)



7 Alternate development sensitivities

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

- If demand side solutions such as the orchestration of CER and growth in DSP occur at scale, the need for utility-scale supply solutions will be reduced.
- If actionable transmission developments progress as planned and scheduled, a significantly improved reliability outlook is expected.
- Federal and state generation development schemes will further mitigate reliability risks, if delivered to schedule, with appropriate transmission connectivity.
- Delaying generator retirements may also be effective in reducing reliability risks but coal generators expect rising outage risks as they approach retirement.

7.1 Consumer investments and load flexibility have the potential to minimise reliability risks

The 2023 ESOO Central scenario includes a strong influence from electrifying business and residential sectors, and captures continued uptake of CER, including distributed PV and batteries, as well as growing uptake of electrified transport (primarily via EVs). While the 2023 ESOO Central scenario includes this forecast rapid uptake of CER, AEMO does not assume for reliability forecasting purposes that sufficient coordination and orchestration of these devices is successfully enabled to meet power system needs, including via VPPs and coordinated EV charging (and discharging in some V2G applications).

The ESOO Central scenario also includes only existing and committed levels of DSP, excluding potential growth in demand flexibility for most regions.

Increased CER orchestration and DSP has the potential to significantly lower the need for utility-scale generation and storage, if orchestrated and developed to reduce grid demand during periods of high demand. AEMO modelled a *CER orchestration and DSP growth* sensitivity to demonstrate the potential reliability improvement of CER orchestration at scale, and DSP growth, compared to the 2023 ESOO Central scenario assumptions.

Significant growth potential is forecast for consumers to engage with virtual power plants

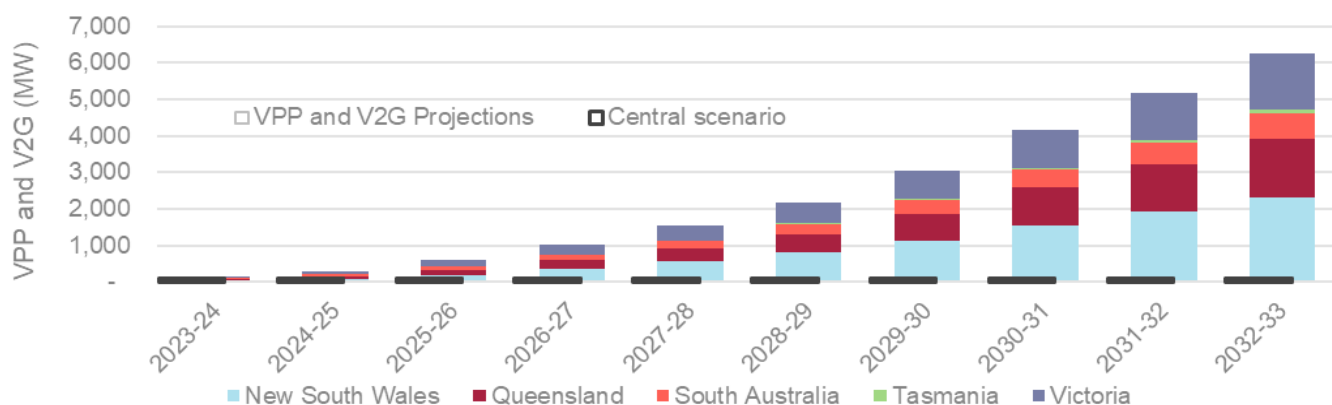
A VPP broadly refers to an aggregation of resources (such as decentralised generation, storage, and controllable loads) coordinated to deliver services for power system operation and electricity markets⁹¹. There are many technologies and various options for consumers to participate such as through microgrids, controllable loads, EVs, and battery storage. In terms of magnitude and growth potential over the next decade, battery storage represents the largest of these components that AEMO forecasts.

⁹¹ See <https://aemo.com.au/-/media/files/initiatives/der/2021/vpp-demonstrations-knowledge-sharing-report-4.pdf>.

In New South Wales, for example, VPPs are projected to have the potential to offset maximum demand by 2,330 MW by 2032-33, approximately 14% of the peak demand forecast in the ESOO Central scenario. While this reduction in peak demand has the potential to significantly reduce the need for utility-scale solutions, it would require the coordination of a significant number of consumer batteries, a process that has demonstrated value in trials, but not at significant scale to date in the NEM.

Figure 41 shows projected VPP and V2G uptake over the ESOO horizon compared to the assumptions used in the 2023 ESOO Central scenario. Over 6 GW of orchestrated CER uptake is projected as possible by 2033 across the NEM, but which is not included in the 2023 ESOO Central scenario. These uptake projections are dependent on consumer trends which can be influenced by various factors such as consumers' own purchase decisions and usage requirements, market opportunities, and the value that a retailer or aggregator can find for future revenue⁹².

Figure 41 Projected VPP and V2G per region, relative to the ESOO Central scenario, 2023-24 to 2032-33 (MW)



While there is some policy support and expectations of cost reductions in the long term^{93,94}, there remains a large degree of uptake and orchestration uncertainty, relying on homeowners to both install battery systems and to sign up for these to provide grid services.

AEMO is collaborating with market bodies and industry on a range of initiatives aimed at encouraging and enabling VPPs over the ESOO forecast horizon, and efficiently, securely and reliably integrating CER orchestration within market and power system operation at scale. These initiatives include:

- **Pathways for participation of aggregated price-responsive resources in the energy market** – the AEMC recently commenced a consultation⁹⁵ on approaches to better integrate the wide range of residential, community, commercial and industrial energy resources and load that are, or could be, managed to respond to market price signals. The price-responsive behaviour of these resources is not currently visible to AEMO, creating a range of operational challenges for which its existing toolkit was not designed. This initiative includes incentivising distributed resources to provide visibility and participate in the centralised scheduling and dispatch process of the NEM.

⁹² See https://ieefa.org/wp-content/uploads/2022/03/What-Is-the-State-of-Virtual-Power-Plants-in-Australia_March-2022_2.pdf.

⁹³ See https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/csiro-2022-solar-pv-and-battery-projections-report.pdf?la=en.

⁹⁴ See https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/qem-2022-solar-pv-and-battery-projection-report.pdf?la=en.

⁹⁵ See <https://www.aemc.gov.au/rule-changes/integrating-price-responsive-resources-nem>.

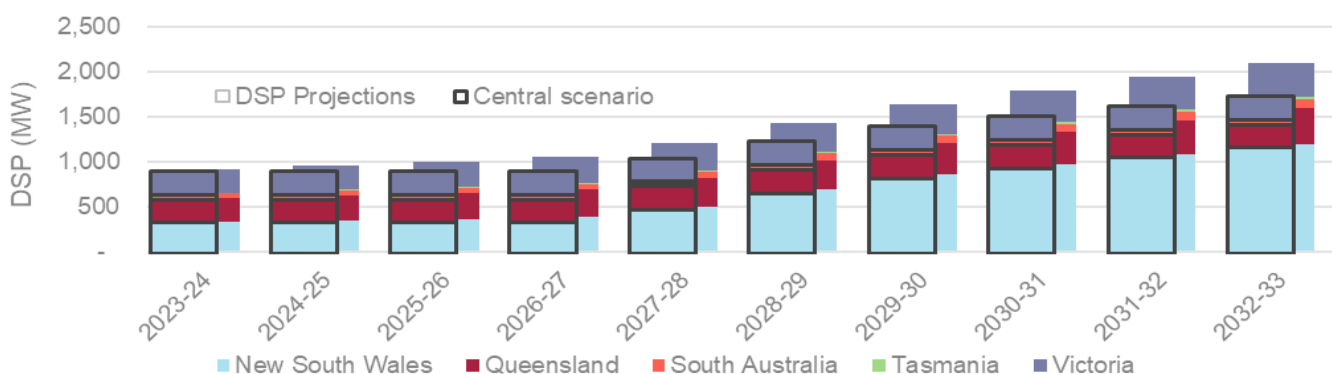
- **Optimising the value of CER flexibility** – ongoing AEMC consultation⁹⁶ on opportunities to reduce the barriers and costs for consumers (directly or through retailers or aggregators acting on their behalf) to identify and manage flexible resources independent of their ‘passive’ load. This can support integration of consumer energy resources and participation in VPPs, enabling expanded consumer choice around products and services which reward and harness the value of CER flexibility.
- **Behind-the-meter interoperability** – the Australian Renewable Energy Agency (ARENA) Distributed Energy Integration Program (DEIP) Interoperability Steering Committee is leading cross-industry collaboration on interoperability standards, use cases and reference architectures to enable consumer choice, coordination and management and the coexistence of multiple standards and mapping between a range of protocols applicable for different devices (such as EVs, distributed PV and storage inverters, and loads). These continual standards developments include refining and detailing the minimum requirements for visibility, controllability, physical performance and cybersecurity for these devices.
- **Scalable operational coordination across parties** – AEMO is progressing an Engineering Roadmap priority action⁹⁷ to technically define functional requirements for securely and reliably operating a high CER power system. This includes arrangements for operational coordination and data exchange between AEMO, distribution network service providers (DNSPs), energy service providers fit for integrating significant levels of CER orchestration within the centralised dispatch processes (including operational forecasting, scheduling and constraints) and to ensure distribution network limits are appropriately managed.

Greater potential for demand side participation exists

DSP is forecast to grow substantially in the ESOO Central scenario due to the commitment of the New South Wales PDRS. The scheme aims to reduce New South Wales’ maximum demand by approximately 1,200 MW by 2032-33, based on AEMO projections of maximum demand.

In addition to the ESOO Central scenario, which considers only existing and committed developments, AEMO projects potential uptake of further DSP developments in all regions of the NEM. **Figure 42** shows the projected DSP for each financial year relative to the ESOO Central scenario assumptions.

Figure 42 Projected DSP per region, relative to the ESOO Central scenario, 2023-24 to 2032-33 (MW)



⁹⁶ See <https://www.aemc.gov.au/rule-changes/unlocking-CER-benefits-through-flexible-trading>.

⁹⁷ See Section 2.1 <https://aemo.com.au/-/media/files/initiatives/engineering-framework/2023/nem-engineering-roadmap-fy2024--priority-actions.pdf?la=en>.

Delivering on higher consumer potential will improve the reliability of the NEM

Should these orchestrated consumer resources and demand reduction schemes occur to the scale projected, the reliability forecast is expected to improve considerably, reducing the need for utility-scale solutions.

AEMO has forecast an alternative sensitivity to the 2023 ESOO Central scenario, with the following differences:

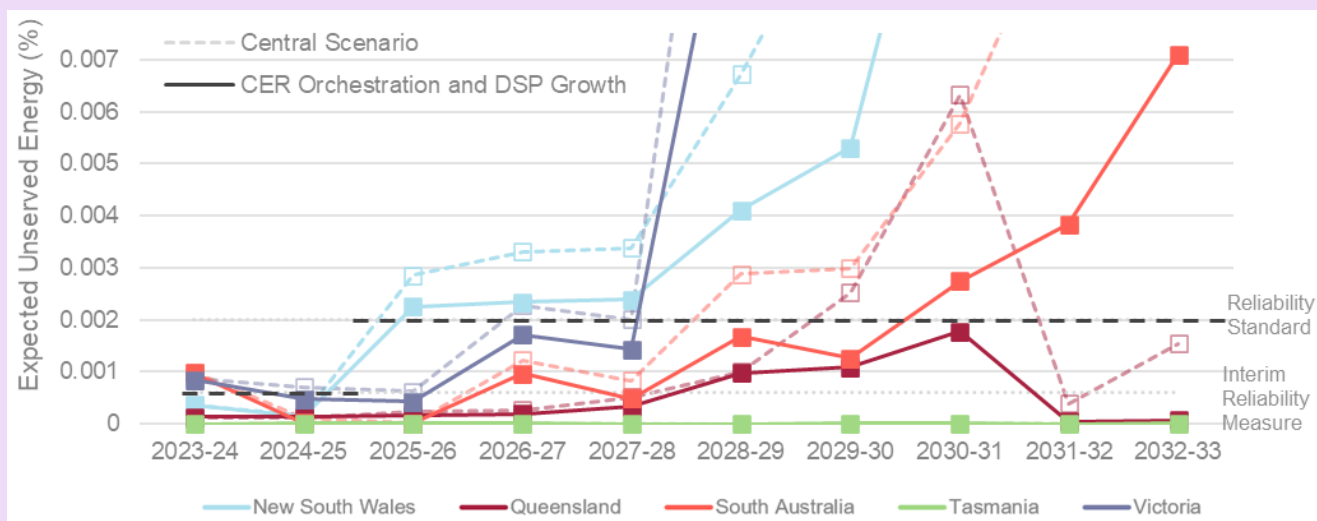
- DSP, VPP and V2G projections were applied, in addition to the existing and committed DSP, VPP and V2G developments that were considered in the 2023 ESOO Central scenario.
- All other assumptions aligned with the 2023 ESOO Central scenario, described in **Chapter 5**.

The purpose of the sensitivity is to demonstrate the importance of policy and consumer support for demand side solutions, and the reduced requirement for utility-scale solutions should these forecast solutions develop to the scale and effectiveness projected.

Figure 43 shows the results of this *CER orchestration and DSP growth* sensitivity, relative to the 2023 ESOO Central scenario. It shows that:

- Forecast expected USE is lower in all regions with increased demand flexibility.
- In New South Wales, the sensitivity shows expected USE above the reliability standard from 2025-26, consistent with the ESOO Central scenario, however reliability risks are forecast to be lower over the horizon.
- In South Australia, the sensitivity shows lower levels of expected USE that remain within the reliability standard until 2030-31, when reliability risks increase.
- In Victoria, the sensitivity shows expected USE within the reliability standard in 2026-27 and 2027-28, however above the reliability standard from 2028-29, consistent with the ESOO Central scenario.

Figure 43 Reliability impact of projected CER and DSP developments, 2023-24 to 2032-33 (%)



7.2 Actionable transmission developments significantly improve the reliability outlook

The 2023 ESOO Central scenario includes only transmission developments that are existing, or considered committed or anticipated, as classified in AEMO's Transmission Augmentation Information page⁹⁸. In addition to those transmission projects, the 2022 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 processes (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* sensitivity to demonstrate the potential reliability improvement of these additional transmission developments, alongside significant CER orchestration and DSP uptake (as described in **Section 7.1**), compared to the 2023 ESOO Central scenario.

The actionable transmission developments identified in the 2022 ISP, as shown in **Figure 44**, include:

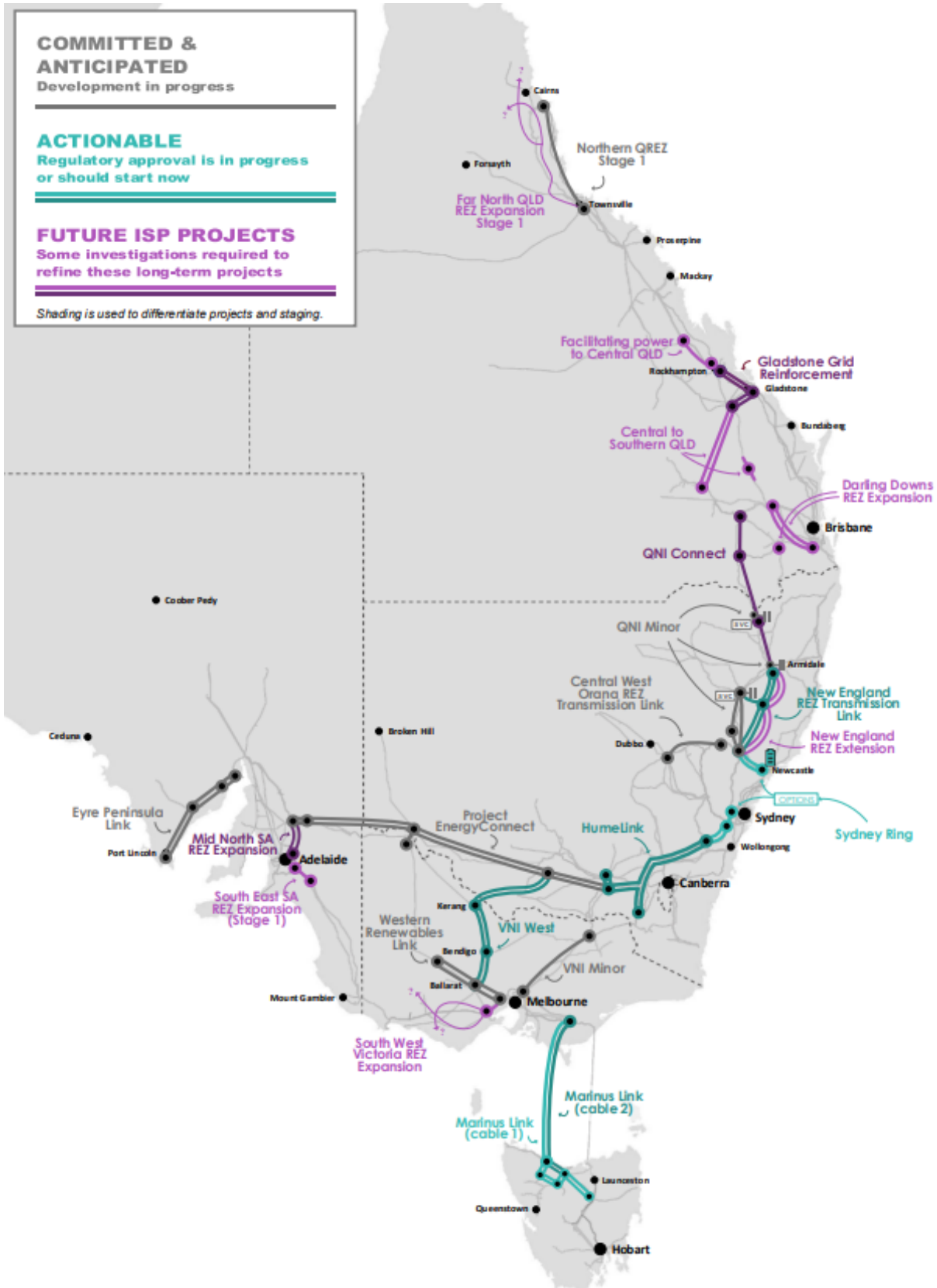
- **HumeLink** – a 500 kV transmission upgrade between Maragle, Gugaa and Bannaby connecting Project EnergyConnect and the Snowy Mountains Hydroelectric Scheme to Bannaby. It is assumed to be available in this sensitivity by July 2026.
- **Marinus Link** – two new symmetrical monopole high voltage direct current (HVDC) links between the Burnie area in Tasmania and the Hazelwood area in Victoria, each with 750 MW of transfer capacity and associate alternating current (AC) transmission. The capacity release from Stage 1 is assumed to be available in this sensitivity in July 2029, with Stage 2 assumed in July 2031.
- **VNI West** – 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 assumed to be available in this sensitivity prior to summer 2029-30⁹⁹.
- **Hunter Transmission Project** (shown on the map as the northern option of the 'Sydney Ring') – a new 500 kV double-circuit line between Earing and Bayswater, two new transformers at either Earing or a new substation near Earing, and associated substation augmentation work at Bayswater and Earing. This project is assumed to be available in this sensitivity by December 2027.
- **New England REZ Transmission Link** – a combination of new 500 kV and 330 kV double-circuit transmission lines connecting four new substation hubs to the existing network between Bayswater and the Tamworth – Armidale line. This project is assumed to be available in this sensitivity by September 2028.

To demonstrate the reliability improvement of the above actionable projects, this sensitivity also removed the potential impact of other transmission limitations within Victoria, particularly within the Latrobe Valley and the 500/220 kV Melbourne ring where small-scale transmission projects are under investigation. These limitations were removed from the ESOO modelling from July 2028.

⁹⁸ See <https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/transmission-augmentation-information>.

⁹⁹ Updated timing on VNI West's schedule has been included in the August 2023 Transmission Augmentation Information page update. See <https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/transmission-augmentation-information>.

Figure 44 Map of network investments in the 2022 ISP, actionable investments shown in green



Note: the map shows network investments as specified in the 2022 ISP and it does not show any scope or location changes that may have been announced since.

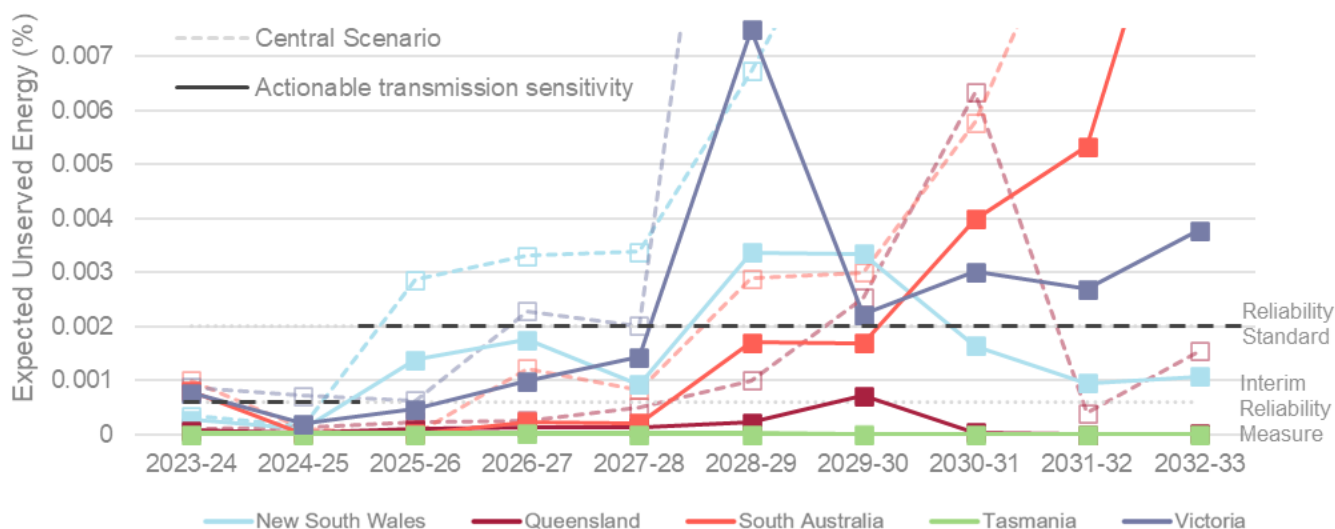
In this sensitivity, the following assumptions were applied:

- Committed and anticipated generation and transmission projects were applied at the full commercial use date advised by the project developer (not applying the delays of the 2023 ESOO Central scenario).
- Actionable transmission developments were included at the full commercial use date advised by the project developer.
- While actionable transmission developments were applied consistent with the 2022 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).
- CER orchestration 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 ESOO Central scenario (consistent with the sensitivity in **Section 7.1**).
- All other assumptions aligned with the ESOO Central scenario described in **Chapter 5**.

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 orchestration.

Figure 45 shows the results of the *Actionable transmission* sensitivity relative to the ESOO Central scenario.

Figure 45 Reliability impact of Actionable transmission, CER orchestration and DSP developments under on-time delivery of committed and anticipated generation and storage developments, 2023-24 to 2032-33 (%)



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 the findings from the 2022 ISP and the 2023 ESOO Central scenario, additional generation and storage investments, beyond those that are committed or anticipated, are required to ensure reliability.

- In New South Wales, the sensitivity shows reliability risks under the reliability standard until 2027-28, and significantly lower reliability risks over the ESOO horizon.
 - Reliability risks are lower relative to the Central scenario, due to the inclusion of additional CER orchestration and the modelled on-time delivery of all included generation and storage projects.
 - In 2026-27 and 2027-28, the HumeLink and Hunter Transmission Project developments commission respectively, reducing expected USE considerably relative to the Central scenario, as increased transmission capacity allows generation and storage projects already considered in the Central scenario to gain access to the major demand centres of Sydney, Newcastle and Wollongong. Expected USE, however, still increases in 2028-29 as currently considered committed and anticipated generation is not yet sufficient to offset forecast increases in maximum demand and replace retiring generation.
 - In 2029-30 and 2030-31, Snowy 2.0 is expected to commission, further reducing expected USE relative to the Central scenario, to be within the reliability standard when fully commissioned.
- In Victoria, the sensitivity shows reliability risks under the reliability standard until (and including) 2027-28, with risks lower than the Central scenario over the entire horizon.
 - Between 2023-24 and 2027-28, reliability risks are lower relative to the Central scenario due to the inclusion of additional CER orchestration, 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 Latrobe Valley and the 500/220kV Melbourne ring in Victoria are removed from the ESOO modelling, on the basis that these limitations are expected to be addressed by small-scale transmission projects currently being investigated by AEMO Victorian Planning. Reliability risks worsen at this point due to the retirement of Yallourn, however these are considerably lower than the Central scenario (and lower than if only the forecast CER is orchestrated).
 - In 2029-30, Stage 1 of Marinus Link and VNI West commissions. Marinus Link provides greater connectivity with Tasmania and improving reliability outcomes in Victoria. While the new transmission link is modelled to be available, the development of further generation in Tasmania is not, thereby understating the potential reliability impact of this development. VNI West provides greater connectivity with New South Wales, and in particular to the Snowy Hydro Scheme, which also significantly improving reliability outcomes in Victoria.
 - In 2031-32, Stage 2 of Marinus Link commission. While further interconnection has the potential to improve reliability further, it is not demonstrated in this sensitivity as the development of further generation in Tasmania is not modelled. Further generation developments in Tasmania would improve the outlook if developed.
- In South Australia, the sensitivity shows lower levels of expected USE that remain within the reliability standard until 2030-31. Reliability risks are considerably lower than the Central scenario, due to the on-time delivery of all included generation and storage projects, and the additional inter-regional capacity sharing enabled by a more interconnected NEM.
- In Queensland, the sensitivity shows USE within the reliability standard over the entire horizon, which is significantly lower than the Central scenario. The lower reliability risk is forecast due to the on-time delivery of all included generation and storage projects, increased orchestrated CER developments, and additional inter-regional capacity sharing enabled by a more interconnected NEM.

7.3 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 have been 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 2023 ESOO Central scenario, presented in **Chapter 5**, includes only those generation and storage projects that are defined by AEMO as ‘in commissioning’, ‘committed’ or ‘anticipated’, and does not explicitly consider additional developments that may arise as a result of federal, state or territory programs.

AEMO modelled two sensitivities to demonstrate the potential reliability improvement of these additional dispatchable generation and storage projects:

- The *Federal and state schemes* sensitivity applied these additional dispatchable generation and storage projects, alongside large-scale CER orchestration and DSP uptake (as described in **Section 7.1**), and actionable transmission developments (as described in **Section 7.2**).
- The *Schemes without CER orchestration* sensitivity similarly applied these additional dispatchable generation and storage projects alongside actionable transmission developments, but did not assume the further development of CER orchestration and DSP growth.

While developments to meet the 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. 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.

Schemes and programs considered in these two sensitivities were:

- The **ARENA Large Scale Battery Storage Funding Round**, which 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 be considered in the ESOO Central scenario, while these sensitivities considered all announced projects.
- The **New South Wales firming infrastructure tender**¹⁰⁰, which includes additional funding from the Federal Government as part of its **Capacity Investment Scheme**, and anticipates an indicative amount of 930 MW of firming infrastructure, available for a minimum of two hours, targeting an operational date of December 2025.
- The **New South Wales Infrastructure Investment Objectives (IIO) Report**¹⁰¹, which includes an implementation plan for conducting competitive tenders for the IIO Development Pathway.
 - The pathway includes the construction of 2 GW of long-duration (eight or more hours) storage by 2030, of which 50 MW has been awarded in the first tender. The draft 2023 IIO report assumes the majority of this capacity will be commissioned in 2028 and 2030.

¹⁰⁰ See <https://aemoservices.com.au/tenders/firming>.

¹⁰¹ See <https://aemoservices.com.au/publications-and-resources/infrastructure-investment-objectives-report>.

- The first IIO tender announced 1,395 MW of renewable generation and 50 MW of long duration storage. Only some of these first tender projects have progressed sufficiently to be considered in the ESOO Central scenario, while these sensitivities considered all announced projects.
- While the IIO Development Pathway includes further development of VRE generators, these were not included in this sensitivity.
- The **Queensland Energy and Jobs Plan**, which will fund new dispatchable investments including the Swanbank BESS, and the Borumba Pumped Hydro Project (both of which are already considered as anticipated, and are included in the Central outlook), and a hydrogen-ready gas peaking power station at Kogan Creek to be commissioned by June 2026.
- The **South Australia Hydrogen Jobs Plan**, which will fund a 200 MW green hydrogen power station, to be operational by December 2025 alongside hydrogen electrolyser and hydrogen storage projects near Whyalla.
- The **Victorian Renewable Energy Target Auction 2**, which 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 be considered in the ESOO Central scenario, while these sensitivities considered all announced projects.
- The first stage tender of the **Capacity Investment Scheme in South Australia and Victoria**, which will fund the development of an indicative amount of 600 MW of generation or storage, with an indicative duration of four hours.

Other schemes, such as further stages of the Capacity Investment Scheme, renewable developments as part of the IIO Pathway, and jurisdictional renewable energy targets are not included in this sensitivity.

In these sensitivities, the following assumptions were applied:

- The schemes listed above were applied in the sensitivities 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 has been applied.
- For schemes that have not yet awarded recipients, the recipient was assumed to be additional to those already considered in the ESOO Central scenario.
- Committed and anticipated generation and transmission projects were applied at the full commercial use date advised by the project developer (delays are not applied).
- DSP, VPP and V2G projections were applied only in the *Federal and state schemes* sensitivity, in addition to the existing and committed DSP, VPP and V2G developments that were considered in the ESOO Central scenario (consistent with the sensitivity in **Section 7.1**). These projections were not applied to the *Schemes without CER orchestration* sensitivity, which maintained the level of CER orchestration within the Central scenario.
- Actionable transmission developments were included at the full commercial use date advised by the project developer (consistent with the sensitivity in **Section 7.2**).
- All other assumptions aligned with the ESOO Central scenario described in **Chapter 5**.

The purpose of these sensitivities is to demonstrate the expected benefit of these schemes assuming the generation and storage projects are developed to maximise their benefit to power system reliability.

Figure 46 shows the results of the *Federal and state schemes* sensitivity, relative to the ESOO Central scenario, while **Figure 47** shows the results of the *Schemes without CER orchestration* sensitivity.

Figure 46 Reliability impact of federal and state generation development schemes, 2023-24 to 2032-33 (%)

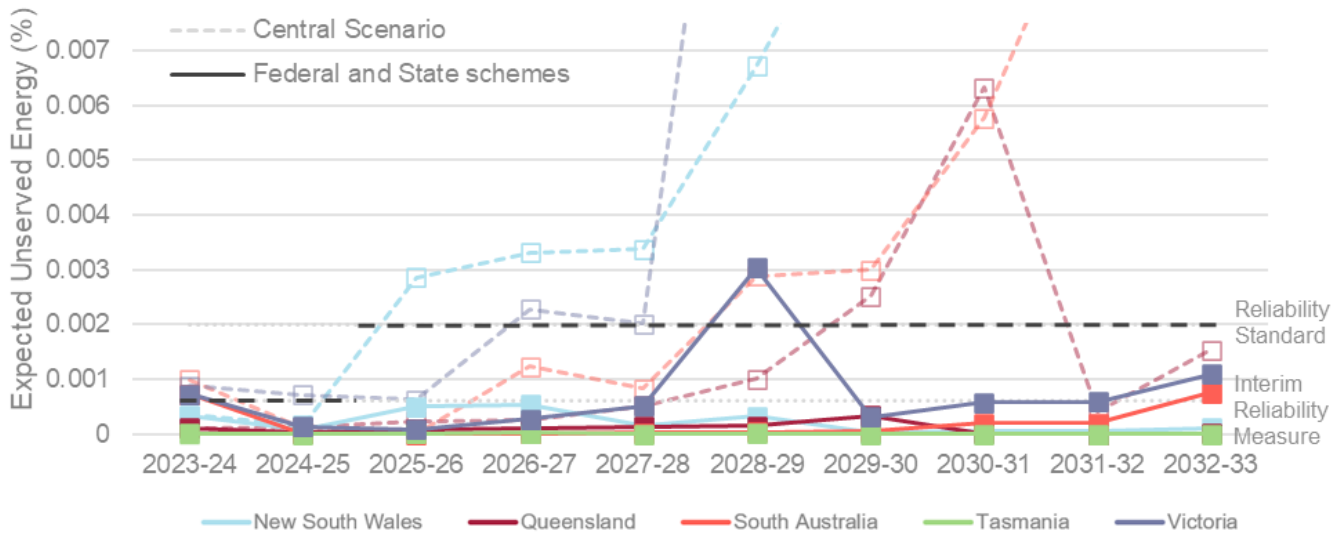
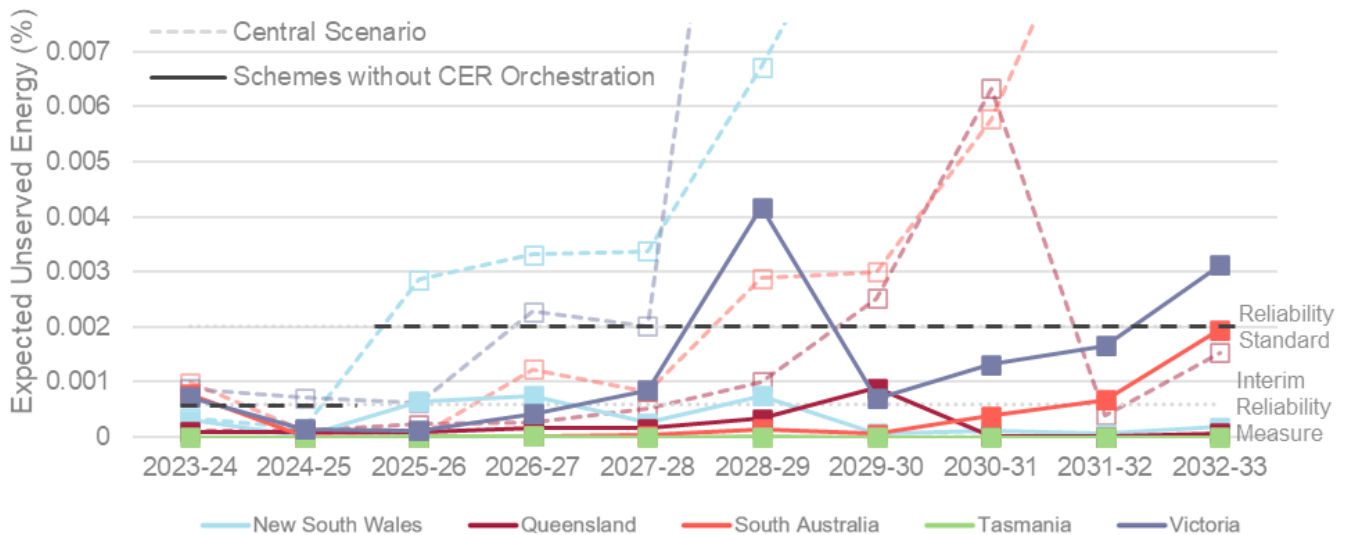


Figure 47 Reliability impact of federal and state generation development schemes, without further uptake of CER orchestration, 2023-24 to 2032-33 (%)



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.

- Consistent with the findings from the 2022 ISP and the ESOO Central scenario, 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**, both sensitivities show reliability risks within the reliability standard over the entire horizon, demonstrating the expected effectiveness of the developments from the various schemes.
 - In 2023-24 and 2024-25, reliability risks are lower relative to the Central scenario due to the modelled on-time delivery of all included transmission, generation and storage projects, and projects funded by the first IIO tender.
 - In 2025-26, the additional firming infrastructure from the firming infrastructure tender and additional Capacity Investment Scheme support, alongside the Waratah Super Battery project, is expected to offset the retirement of Eraring Power Station, such that reliability risks are forecast just within the IRM. Without CER orchestration developments, the risks are slightly higher.
 - Between 2026-27 and 2030-31, the HumeLink and Hunter Transmission Project developments commission, as well as Snowy 2.0 and the IIO long duration storage projects, reducing USE to low levels regardless of the CER orchestration developments that occur.
- In **Victoria**, both sensitivities show reliability risks within the reliability standard before 2028-29. At this point, further developments are required to maintain reliability consistent with the reliability standard.
 - In 2023-24 to 2027-28, reliability risks are lower relative to the Central scenario due to the modelled on-time delivery of all included transmission, generation and storage projects, and projects funded by the Victorian Renewable Energy Target Auction 2 and the federal Capacity Investment Scheme.
 - In 2028-29, reliability risks are above the reliability standard, but risks are reduced relative to the Central scenario due to the development of Actionable transmission projects, and the included schemes. The scale of the additional generation development needed to reduce USE to below the reliability standard in this year varies dependent on the scale of CER orchestration developed.
 - In 2029-30, Stage 1 of Marinus Link and VNI West commission, significantly improving reliability outcomes in Victoria which stay below the reliability standard for the remainder of the modelling horizon with orchestrated CER development. Without orchestrated CER development, the reliability risks are above the reliability standard in 2032-33.
- In **South Australia**, reliability risks are forecast within the reliability standard over the horizon, with the level of risk determined by the scale of CER orchestration. Reliability improvements arise relative to the Central scenario due to the modelled on-time delivery of all included generation and storage projects, the development of the 200 MW hydrogen generator, the federal Capacity Investment Scheme and the enhanced ability of neighbouring regions to provide additional capacity in times of supply scarcity.
- In **Queensland**, reliability risks are forecast within the reliability standard over the horizon, with the level of risk determined by the scale of CER orchestration. Reliability improvements arise relative to the Central scenario due to the modelled on-time delivery of all included generation and storage projects, 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.

While the above sensitivities demonstrate that there is potential to address the majority of the forecast reliability risks for many jurisdictions over the ESOO horizon with existing schemes, additional development opportunities

remain, and delivery challenges will exist. Project commissioning delays are emerging as a material risk to the delivery of transmission, generation and storage projects. Delays to the delivery of projects, relative to the dates envisioned by the schemes and proponents, has the potential to result in periods of high risk throughout the horizon.

As described in **Section 3.1**, the pipeline of projects is approximately four times larger than the size of the current NEM, indicating that there are sufficient projects at various stages of consideration to resolve any residual reliability risks.

There remain numerous other government schemes in development that have the potential to bring forward this pipeline of proposed projects, which will further address the residual reliability risks forecast. These schemes include:

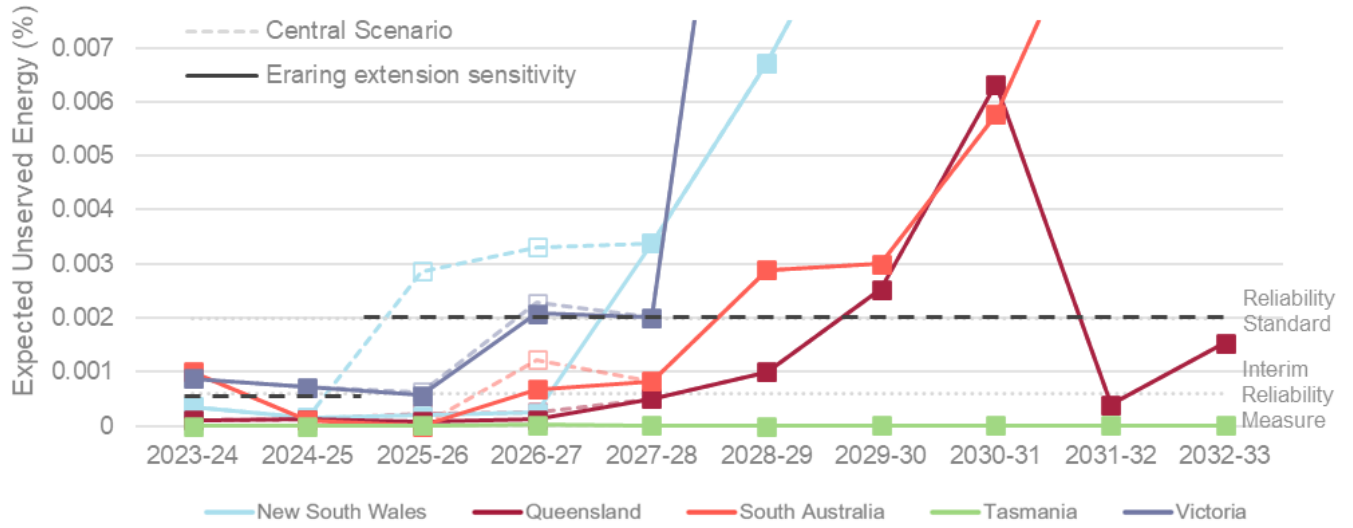
- Further developments as part of the federal Capacity Investment Scheme, which seeks to unlock at least 6 GW of dispatchable power (beyond the first stage tenders, which has been included).
- Further developments as part of the New South Wales Electricity Infrastructure Roadmap.
- Further developments 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.

7.4 Delaying generator retirement has the potential to address medium-term risks if necessary

In February 2022 Origin notified AEMO of the potential early retirement of Eraring in August 2025, at the end of the three-and-a-half year notice period. AEMO has modelled the impact of a two-year delay to the retirement of two units of Eraring Power Station. This sensitivity is not informed by specific insights on possible courses of action regarding the retirement of Eraring, but seeks to demonstrate the potential impact on reliability risks of a partial extension. For this sensitivity, two units remain in operation for a further two years, until August 2027, assuming the generator can maintain the reliability of its plant (equivalent to its unplanned outage expectations in the year of its announced retirement).

The reliability impacts of this sensitivity are shown in **Figure 48** relative to the ESOO Central scenario. The additional 1.4 GW of dispatchable capacity reduces reliability risks, leading to expected USE being within the reliability standard and the IRM in New South Wales during the two years of retirement delay (2025-26 and 2026-27). Reliability risks in Victoria, South Australia and Queensland also reduce relative to the Central scenario in these years, particularly in South Australia in 2026-27, when Torrens Island B and Osborne Power Station retire, and the full commissioning of Project EnergyConnect increases inter-regional transfer capacity between New South Wales and South Australia.

Figure 48 Reliability impact of a two-year delay to two units of Eraring Power Station, 2023-24 to 2032-33 (%)



8 Demonstrating the reliability impacts of 2023 ESOO methodology improvements

This chapter assesses the impact of various changes in methodology driven by stakeholder consultation and continuous improvement on the reliability forecast. Methodology improvement to increase forecast accuracy and transparency is important in every annual reliability forecast.

The methodology improvements applied in this 2023 ESOO have generally reduced the forecast reliability risk across the forecast horizon, relative to the methodology applied in 2022. This chapter documents some of the changes that apply in the 2023 ESOO, and in some cases, demonstrates their relative impact.

8.1 Maximum and minimum demand forecast

As part of its 2022 forecast improvement plan¹⁰², AEMO implemented improvements to better reflect the seasonality and annual variability of weather in the maximum and minimum demand forecast methodology. These changes include:

- The application of an enhanced machine learning model, that better captures the numerous non-linear relationships between weather and demand.
- New explanatory variables including impacts of humidity.
- Annual, rather than fortnightly, simulation of weather to better reflect annual patterns such as the ENSO.

Due to the increased accuracy that better reflects the observed relationship between weather and demand in this machine learning model, AEMO no longer required the use of its Generalised Extreme Value (GEV) model¹⁰³ for calibrating the shape and scale of the maximum and minimum demand forecasts; instead, the GEV model was applied for validation purposes only.

As an example of the improved accuracy observed, **Table 18** shows the Mean Absolute Percentage Error (MAPE) of the 2022 ESOO and 2023 ESOO 'half-hourly' models compared with a set of actuals data that they had not been trained on (out of sample). It highlights that the 2023 model exhibits significantly lower error (lower error reflects improved accuracy), across the full half-hourly data set, as well as at the extreme 99th and 1st percentiles which are most important for maximum and minimum demand forecasting.

¹⁰² See <https://aemo.com.au/en/consultations/current-and-closed-consultations/2022-forecast-improvement-plan-consultation>.

¹⁰³ The GEV model is described in the 2022 Electricity Demand Forecasting Methodology, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2022/forecasting-approach-electricity-demand-forecasting-methodology.pdf.

Table 18 Forecasting accuracy in New South Wales assessed with MAPE

Model	MAPE – all intervals	MAPE – 99 th percentile	MAPE – 1 st percentile
2022 model – out of sample set	5.40%	8.35%	5.53%
2023 model – out of sample set	1.57%	1.91%	1.27%

8.2 Reliability Forecasting Guidelines and Methodology Consultation

Between November 2022 and April 2023, AEMO undertook a two stage consultation¹⁰⁴ with stakeholders on numerous reliability forecasting guidelines and methodologies, which included the ESOO and Reliability Forecast Methodology. As a result of this consultation, the following changes now apply to this 2023 ESOO:

- Changes were made to the application of **new projects** in the ESOO, such as the application of project commissioning delays based on project progression, and including anticipated projects for the first time. Approximately 8.3 GW of anticipated projects were considered in the 2023 ESOO that would not have been considered using the previous methodology. This change also simplified and standardised the treatment of committed and anticipated transmission projects on a similar basis as generation and storage projects.
- Similarly, the treatment of **orchestration of CER** was adjusted to standardise the treatment of new projects with other developments such as transmission, generation and storage. This resulted in approximately 6.5 GW of VPP projections that were no longer assumed to develop in the 2023 ESOO Central scenario, that would have been considered using the previous methodology. The potential reliability benefit of these projections is demonstrated via sensitivity analysis in **Section 7.1**.
- Improvements were made to the calculation of **generator unplanned outage rates**, to ensure all unplanned outages are effectively calculated within the reliability forecast. Unplanned outage rates have increased on average for most technologies by about 2%. The impact of the methodology change is discussed in the published 2023 Forecast Reference Group (FRG) consultation¹⁰⁵ on unplanned outage rates.
- Adjustments were made to the calculation of **reliability gap periods** for RRO purposes, resulting in more stable definitions of gap periods that better reflect the periods in which reliability risks are forecast.

8.3 Short Duration Storage Methodology Consultation

Between April and May 2023, AEMO undertook an FRG consultation¹⁰⁶ with industry stakeholders on an adjusted methodology for the treatment of short duration storages in the reliability forecasts. This methodology change sought to better reflect a more realistic reliability contribution for short duration storages, given the methodology applied in the 2022 ESOO likely over-optimised the availability for shallow storage devices to operate with perfect foresight at the precise time of peak demand, and thereby likely exaggerated reliability benefits of these technologies. This proposed methodology was also consulted upon in the ISP Methodology consultation¹⁰⁷ to

¹⁰⁴ At <https://www.aemo.com.au/consultations/current-and-closed-consultations/2022-reliability-forecasting-guidelines-and-methodology>.

¹⁰⁵ At https://aemo.com.au/-/media/files/stakeholder_consultation/working_groups/other_meetings/frg/2023/frg-consultation---2023-generation-and-transmission-unplanned-outage-rates.zip?la=en.

¹⁰⁶ At https://aemo.com.au/-/media/files/stakeholder_consultation/working_groups/other_meetings/frg/2023/frg-consultation---2023-short-term-storage-methodology.zip?la=en.

¹⁰⁷ At <https://aemo.com.au/consultations/current-and-closed-consultations/consultation-on-updates-to-the-isp-methodology>.

apply for the 2024 ISP; while the ISP Methodology consultation concluded that the change was not appropriate for ISP purposes (when daily energy shifting was a key consideration), AEMO concluded that for reliability forecasting purposes it was appropriate to apply the proposed methodology (with minor changes considering stakeholder feedback).

In the 2023 ESOO, the following storage capacity derates were applied to address this foresight over-optimisation. Storages with a duration less than 7.5 hours were subject to the following adjustments:

- For all orchestrated CER (VPP and V2G) and devices with less than 1.5 hours of storage, storage energy (MWh) was reduced by 50%.
- For devices with 1.5 to (less than) 3.5 hours of storage, storage capacity was reduced by 25%.
- For devices with 3.5 to (less than) 7.5 hours of storage, storage capacity was reduced by 10%.

For each of these derates, no change was applied to the peak discharge capacity of the devices.

8.4 The impact of methodology changes

Where possible, AEMO has modelled the impact of the methodology changes in a *2022 methodology* sensitivity. This sensitivity applied the following methodologies as they applied in the 2022 ESOO:

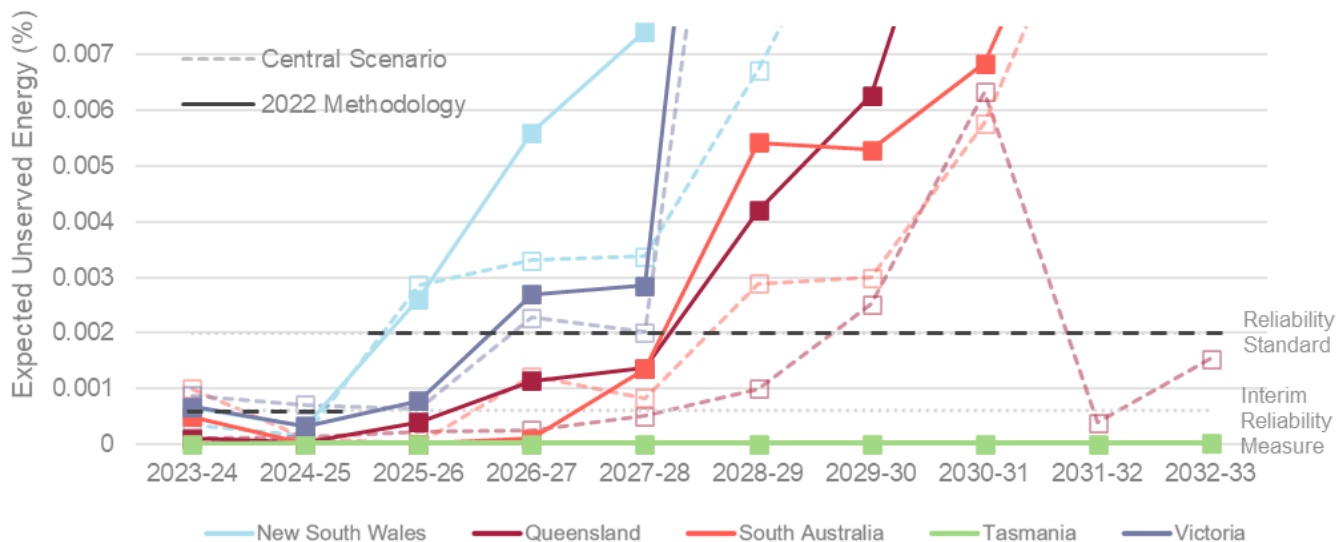
- New generation and storage projects were applied using a different schedule of default commissioning delays, and anticipated projects were excluded.
- Some new transmission projects that would not have met the criteria for inclusion in 2022 (that is, did not meet the 2022 commitment criteria) were excluded, and default commissioning delays were not applied.
- All forecast CER orchestration and DSP growth was included.
- Derating of short duration storage capacity was not applied.

Updated input data for this 2023 ESOO, including wind data (as discussed in **Section 4.3**), unplanned outage rates, and maximum demand forecasts (which were also subject to some changes), and all other inputs remained consistent with the 2023 ESOO Central scenario in this sensitivity.

The reliability impacts of this sensitivity are shown in **Figure 49** relative to the 2023 ESOO Central scenario. Key insights from this sensitivity are:

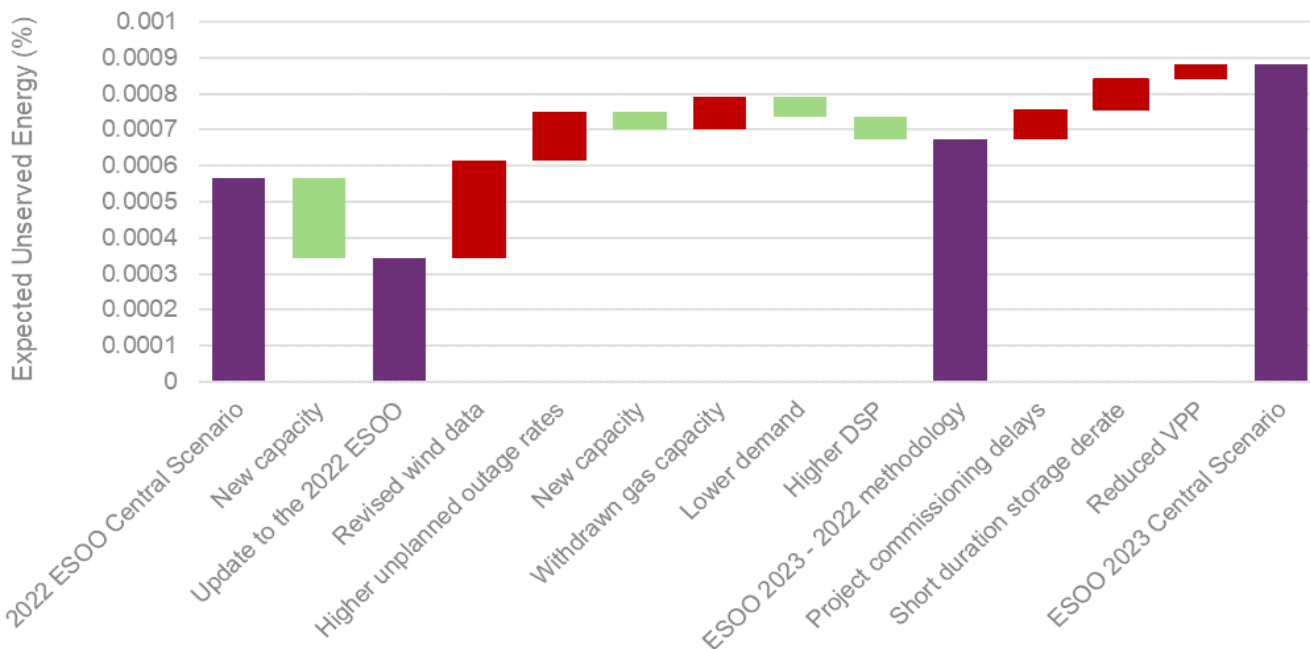
- In 2023-24, reliability risks in New South Wales are higher with the application of the 2022 methodology, above the IRM, due to the application of 2022 project commissioning delay rules to Committed* generation projects.
- In 2023-24, reliability risks in South Australia and Victoria are lower with the application of the 2022 methodology. South Australia would be forecast within the IRM without the modelled default commissioning delays on Committed generation and storage projects within the 2023 methodology.
- From 2025-26, reliability risks would be forecast higher than the 2023 ESOO Central scenario in all regions in the majority of years, suggesting that the 2023 addition of anticipated projects reduces reliability risks more than the effect of excluding CER orchestration that is not committed, and the shallow storage derating.

Figure 49 Reliability impact of 2023 ESOO Methodology, 2023-24 to 2032-33 (%)



To further assist stakeholders in understanding the sources of variation applied in this 2023 ESOO, AEMO developed waterfall charts for Victoria in 2023-24 as shown in **Figure 50**, and for New South Wales in 2025-26 as shown in **Figure 51**. For each major source of variation identified, the indicative contribution of this source has been estimated relative to the 2022 and 2023 ESOO Central scenarios. These regions and years were chosen due to the magnitude of the change and their relative importance due to the significance of the risks.

Figure 50 Indicative source of variation in USE from 2022 ESOO to 2023 ESOO, Victoria 2023-24 (%)

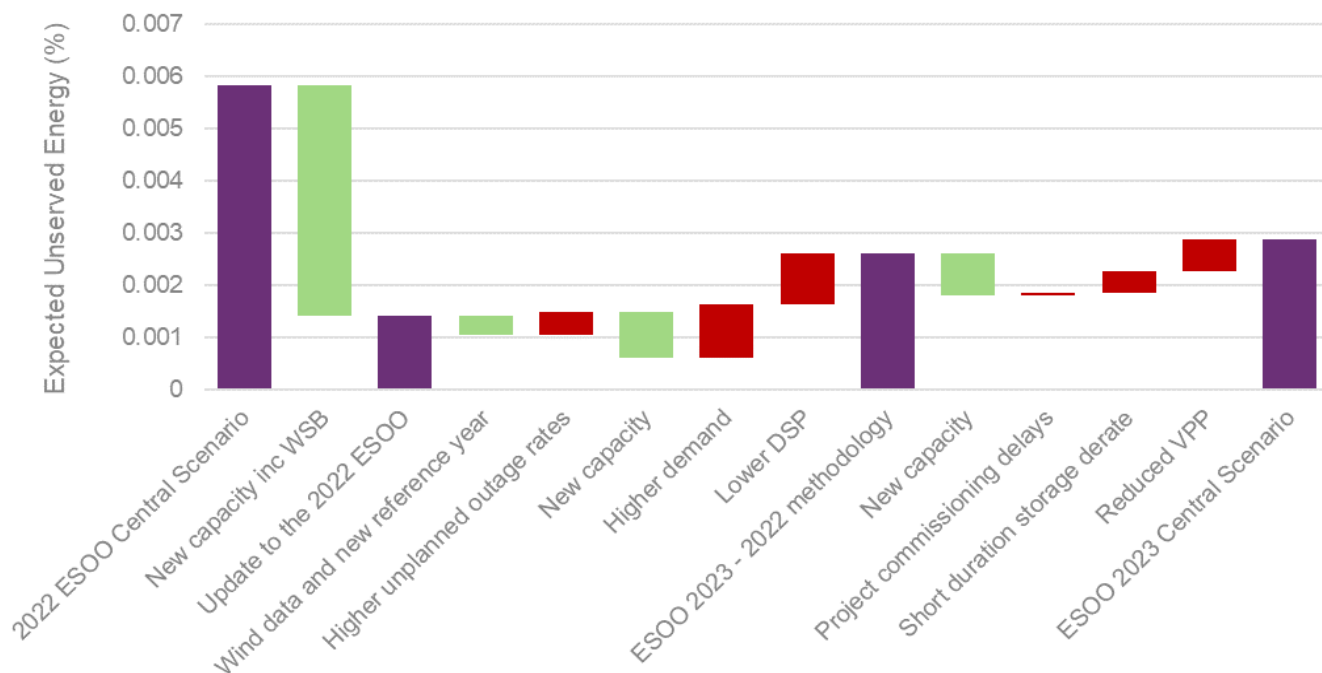


For **Victoria** in 2023-24:

- Between the 2022 ESOO, published in August 2022, and the Update to 2022 ESOO, published in February 2023, new capacity met AEMO’s commitment criteria, reducing reliability risks.

- Since the Update to 2022 ESOO, numerous input improvements apply, with the largest source of variance attributable to the revision of wind data (as discussed in **Section 4.3**), and higher unplanned outage rates (as discussed in **Section 3.3**), that better reflect observed outages in the generation fleet.
- The application of methodology changes, discussed above, further increases the level of reliability risk forecast between the 2022 methodology and the 2023 ESOO Central scenario, which now better reflects reliability risks in 2023-24.

Figure 51 Indicative source of variation in USE from 2022 ESOO to 2023 ESOO, New South Wales 2025-26 (%)



For **New South Wales** in 2025-26:

- Between the 2022 ESOO, published in August 2022, and the Update to the 2022 ESOO, published in February 2023, significant new capacity met AEMO’s commitment criteria, including the commitment of the Waratah Super Battery (WSB) Network Augmentations and SIPS control project and transmission, significantly reducing reliability risks.
- Since the Update to the 2022 ESOO, numerous input improvements apply, with the largest source of variance attributable to the revision of maximum demand (as discussed in **Section 2.3**), and a downward revision to the contribution of the PDRS to DSP (as discussed in **Section 2.5**).
- Unlike Victoria, the revised wind data, and the addition of the 2022-23 reference year has resulted in a net reduction in expected USE.
- The application of methodology changes, discussed above, further increases the level of reliability risk forecast between the 2022 methodology and the 2023 ESOO Central scenario, which AEMO now considers better reflects reliability risks in 2025-26.

List of figures and tables

Tables

Table 1	Probability of a larger unserved energy outcome ³ in 2023-24 by NEM region	6
Table 2	Descriptions of 2023 scenarios for AEMO's forecasting and planning publications	22
Table 3	Scenario drivers of most relevance to the NEM demand forecasts used in this 2023 ES00	22
Table 4	Links to supporting information	24
Table 5	Projected demand side participation for summer 2023-24 (MW)	41
Table 6	Committed inter-regional network augmentations	54
Table 7	Committed and anticipated intra-regional network augmentations	55
Table 8	Projected unplanned outage rates for key inter-regional transmission flow paths	57
Table 9	Probability of USE in 2023-24 by NEM region	60
Table 10	Forecast additional capacity required (in MW) to meet the reliability standard (0.002% USE) and IRM (0.0006% USE)	73
Table 11	Additional capacity required, considering a variety of technology combinations (in MW) to reduce expected USE to the reliability standard and IRM, New South Wales 2026-27	74
Table 12	Additional capacity required, considering a variety of technology combinations (in MW) to reduce expected USE to the reliability standard and IRM, Victoria 2026-27	74
Table 13	Forecast reliability gaps against the Interim Reliability Measure (MW)	75
Table 14	Forecast reliability gaps against the reliability standard (MW)	76
Table 15	Indicative forecast reliability gaps against the reliability standard	77
Table 16	AEMO's one-in-two year peak demand forecast (50% POE, as generated)	79
Table 17	Auxiliary usage (in MW) forecast at time of one-in-two year peak demand (50% POE)	79
Table 18	Forecasting accuracy in New South Wales assessed with MAPE	107
Table 19	New South Wales summer and winter 10% and 50% POE maximum operational (sent-out) demand forecast, <i>Step Change</i> scenario, 2023-24 to 2049-50 (MW)	121
Table 20	Queensland summer and winter 10% and 50% POE maximum operational demand (sent out) forecast, <i>Step Change</i> scenario, 2023-24 to 2049-50 (MW)	130
Table 21	South Australia summer and winter 10% and 50% POE maximum operational (sent-out) demand forecast, <i>Step Change</i> scenario, 2023-24 to 2049-50 (MW)	139
Table 22	Tasmania summer and winter 10% and 50% POE maximum operational (sent-out) demand forecast, <i>Step Change</i> scenario, 2023-24 to 2049-50 (MW)	148
Table 23	Victoria summer and winter 10% and 50% POE maximum operational (sent-out) demand forecast, <i>Step Change</i> scenario, 2023-24 to 2049-50 (MW)	155
Table 24	WDR observations (2022-23)	163
Table 25	Price-driven WDR forecast (MW)	163
Table 26	Price-driven DSP forecast including WDR (cumulative response in MW)	163

Table 27	Forecast levels of DSP for prices exceeding \$7,500/MWh in the 2023 ESOO and 2022 ESOO (MW)	164
Table 28	Estimated DSP responding to price or reliability signals, summer 2023-24	165
Table 29	Estimated DSP responding to price or reliability signals, winter 2024	165
Table 30	Submitted NMs per region	167
Table 31	Program numbers from DSP Information Portal, 2018-20	167
Table 32	Program numbers from DSP Information portal, 2021-23	168
Table 33	Program statistics grouped by program category for 2023 submissions	168
Table 34	Load types of reported connections	169
Table 35	Number of connections grouped by program category and DSP type	170
Table 36	Number of connections reported by network service providers and retailers	171
Table 37	Annual expected USE in EAAP Central scenario	172
Table 38	Monthly expected USE in EAAP Central scenario, MWh	172
Table 39	Annual forecast expected USE in EAAP Low Rainfall scenario	173
Table 40	Monthly forecast expected USE in EAAP Low Rainfall scenario, MWh	173
Table 41	Annual forecast expected USE in EAAP Low Thermal Fuel scenario	174
Table 42	Monthly forecast expected USE in EAAP Low Thermal Fuel scenario, MWh	174

Figures

Figure 1	Expected unserved energy, ESOO Central scenario, 2023-24 to 2032-33 (%)	7
Figure 2	Expected USE, Additional actionable and anticipated developments, 2023-24 to 2032-33 (%)	11
Figure 3	NEM constraint binding impact	16
Figure 4	Demand definitions used in this report	20
Figure 5	2023 IASR scenarios for AEMO's forecasting and planning publications	21
Figure 6	Actual and forecast NEM electricity consumption, ESOO Central scenario, 2013-14 to 2052-53 (TWh)	29
Figure 7	Components of residential consumption forecast, ESOO Central scenario, 2023-24 to 2052-53 (TWh)	29
Figure 8	Components of business consumption forecast, ESOO Central scenario, 2023-24 to 2052-53 (TWh)	30
Figure 9	Forecast NEM consumption (by component) for the three ESOO scenarios, 2032-33 (TWh)	30
Figure 10	Actual and forecast NEM operational consumption, including hydrogen exports, all ESOO scenarios and compared to 2022 ESOO, 2018-19 to 2032-33 (TWh)	31
Figure 11	Actual and forecast regional annual 50% POE maximum operational demand (sent-out), 2023 ESOO Central and 2022 ESOO Central scenario, 2018-19 to 2032-33 (MW)	36
Figure 12	Regional annual actual and forecast 50% POE minimum operational demand (sent-out), 2023 ESOO Central and 2022 ESOO Central scenarios, 2018-19 to 2032-33 (MW)	39

Figure 13	DSP reliability response forecast for summer, Central scenario, 2023-24 to 2032-33 (MW)	42
Figure 14	New generation pipeline as of July 2023 Generation Information (gigawatts [GW])	44
Figure 15	Assumed capacity available during typical summer conditions, by generation type, 2022-23 to 2032-33 (MW)	45
Figure 16	Change between 2022 and 2023 ESOO capacity under summer typical conditions, 2023-24 to 2031-32 (MW)	49
Figure 17	Proposed projects by NEM region and type of generation or storage (MW)	50
Figure 18	Winter, summer typical and summer peak availability of nameplate capacity by type of generation (%)	51
Figure 19	Actual and projected equivalent full unplanned outage rate projections for coal-fired generation technologies, 2018-19 to 2032-33 (%)	52
Figure 20	Actual and projected equivalent full unplanned outage rate projections for coal-fired generation technologies, 2018-19 to 2032-33 (%), with and without generator retirements	53
Figure 21	Expected USE, all NEM regions, 2023-24, ESOO Central scenario (%)	58
Figure 22	Forecast outage duration and depth in South Australia 2023-24, ESOO Central scenario	60
Figure 23	Monthly ENSO outlook values	62
Figure 24	Impact of different weather reference years on expected USE in Victoria 2023-24, 2022 ESOO and 2023 ESOO (%)	63
Figure 25	2022 and 2023 wind output prediction compared to actual generation for wind farms in Victoria that were operating in January 2015	64
Figure 26	Minimum wind output prediction for the evenings of the three hottest days per year between 1969 and 2023, Victorian wind farms	65
Figure 27	Reliability forecast, all regions, first five years (2023-24 to 2027-28)	69
Figure 28	Indicative reliability forecasts, all regions, second five years (2028-29 to 2032-33)	71
Figure 29	EAAP annual expected USE by scenario (%)	81
Figure 30	GELF expected storage for coal generation (days of generation at full capacity)	82
Figure 31	GELF expected storage for gas and liquid fuel generation (hours of generation at full capacity)	83
Figure 32	Expected USE, EAAP Central scenario (%)	83
Figure 33	NEM hydro and VRE monthly generation projection, EAAP Central scenario (GWh)	84
Figure 34	Monthly energy production projection relative to energy production limit, expected generation and contracted fuel inflows, EAAP Central scenario (GWh)	85
Figure 35	Expected USE, EAAP Low Rainfall scenario (%)	86
Figure 36	NEM hydro and VRE monthly generation projection, EAAP Low Rainfall scenario (GWh)	87
Figure 37	Monthly energy production projection relative to energy production limit, expected generation and contracted fuel inflows, EAAP Low Rainfall scenario (GWh)	88
Figure 38	Expected USE, EAAP Low Thermal Fuel scenario (%)	89
Figure 39	NEM hydro and VRE monthly generation projection, EAAP Low Thermal Fuel scenario (GWh)	90
Figure 40	Monthly energy production projection relative to energy production limit, expected generation and contracted fuel inflows, EAAP Low Thermal Fuel scenario (GWh)	91

Figure 41	Projected VPP and V2G per region, relative to the ESOO Central scenario, 2023-24 to 2032-33 (MW)	93
Figure 42	Projected DSP per region, relative to the ESOO Central scenario, 2023-24 to 2032-33 (MW)	94
Figure 43	Reliability impact of projected CER and DSP developments, 2023-24 to 2032-33 (%)	95
Figure 44	Map of network investments in the 2022 ISP, actionable investments shown in green	97
Figure 45	Reliability impact of Actionable transmission, CER orchestration and DSP developments under on-time delivery of committed and anticipated generation and storage developments, 2023-24 to 2032-33 (%)	98
Figure 46	Reliability impact of federal and state generation development schemes, 2023-24 to 2032-33 (%)	102
Figure 47	Reliability impact of federal and state generation development schemes, without further uptake of CER orchestration, 2023-24 to 2032-33 (%)	102
Figure 48	Reliability impact of a two-year delay to two units of Eraring Power Station, 2023-24 to 2032-33 (%)	105
Figure 49	Reliability impact of 2023 ESOO Methodology, 2023-24 to 2032-33 (%)	109
Figure 50	Indicative source of variation in USE from 2022 ESOO to 2023 ESOO, Victoria 2023-24 (%)	109
Figure 51	Indicative source of variation in USE from 2022 ESOO to 2023 ESOO, New South Wales 2025-26 (%)	110
Figure 52	Actual and forecast New South Wales electricity consumption, ESOO Central scenario, 2018-19 to 2052-53 (TWh)	117
Figure 53	Components of New South Wales residential electricity consumption forecast, ESOO Central scenario, 2023-24 to 2052-53 (TWh)	118
Figure 54	Components of New South Wales business electricity consumption forecast, ESOO Central scenario, 2023-24 to 2052-53 (TWh)	118
Figure 55	Actual and forecast New South Wales operational consumption, including hydrogen exports, all scenarios, 2018-19 to 2052-53 (TWh)	119
Figure 56	Actual and forecast New South Wales 50% POE maximum operational (sent-out) demand, 2023 ESOO all scenarios and 2022 ESOO all scenarios, 2018-19 to 2052-53 (MW)	120
Figure 57	Actual and forecast New South Wales 50% POE minimum operational (sent-out) demand, 2023 ESOO all scenarios and 2022 ESOO all scenarios, 2018-19 to 2052-53 (MW)	122
Figure 58	New South Wales assumed capability during typical summer conditions, by generation type, 2022-23 to 2032-33 (MW)	123
Figure 59	New South Wales expected USE, scenarios and sensitivities, 2023-24 to 2032-33	124
Figure 60	Reliability outcomes for New South Wales in 2023-24 under different weather reference years, ESOO Central scenario	125
Figure 61	Bubble plot of depth and duration of forecast USE New South Wales 2023-24, ESOO Central scenario	125
Figure 62	Actual and forecast Queensland electricity consumption, ESOO Central scenario, 2018-19 to 2052-53 (TWh)	126
Figure 63	Components of Queensland residential electricity consumption forecast, ESOO Central scenario, 2023-24 to 2052-53 (TWh)	127

Figure 64	Components of Queensland business electricity consumption forecast, ESOO Central scenario, 2023-24 to 2052-53 (TWh)	127
Figure 65	Actual and forecast Queensland operational consumption, including hydrogen exports, all scenarios, 2018-19 to 2052-53 (TWh)	128
Figure 66	Actual and forecast Queensland 50% POE maximum operational (sent-out) demand, 2023 ESOO all scenarios and 2022 ESOO all scenarios, 2018-19 to 2052-53 (MW)	129
Figure 67	Actual and forecast Queensland 50% POE minimum operational (sent-out) demand, 2023 ESOO all scenarios and 2022 ESOO all scenarios, 2018-19 to 2052-53 (MW)	131
Figure 68	Queensland assumed capability during typical summer conditions, by generation type, 2022-23 to 2032-33 (MW)	132
Figure 69	Queensland expected USE, scenarios and sensitivities, 2023-24 to 2032-33	133
Figure 70	Reliability outcomes for Queensland in 2023-24 under different weather reference years, ESOO Central scenario	134
Figure 71	Bubble plot of depth and duration of forecast USE Queensland 2023-24, ESOO Central scenario	134
Figure 72	Actual and forecast South Australia electricity consumption, ESOO Central scenario, 2018-19 to 2052-53 (TWh)	135
Figure 73	Components of South Australia residential electricity consumption forecast, ESOO Central scenario, 2023-24 to 2052-53 (TWh)	136
Figure 74	Components of South Australia business electricity consumption forecast, ESOO Central scenario, 2023-24 to 2052-53 (TWh)	136
Figure 75	Actual and forecast South Australia operational consumption, all scenarios, 2017-18 to 2051-52 (TWh)	137
Figure 76	Actual and forecast South Australia 50% POE maximum operational (sent-out) demand, 2023 ESOO all scenarios and 2022 ESOO all scenarios, 2018-19 to 2052-53 (MW)	138
Figure 77	Actual and forecast South Australia 50% POE minimum operational (sent-out) demand, 2022 ESOO all scenarios and 2021 ESOO all scenarios, 2018-19 to 2052-53 (MW)	140
Figure 78	South Australia assumed capability during typical summer conditions, by generation type, 2022-23 to 2032-33 (MW)	141
Figure 79	South Australia expected USE, scenarios and sensitivities, 2023-24 to 2032-33 (%)	142
Figure 80	Reliability outcomes for South Australia in 2023-24 under different weather reference years, ESOO Central scenario	142
Figure 81	Bubble plot of depth and duration of forecast USE in South Australia 2023-24, ESOO Central scenario	143
Figure 82	Actual and forecast Tasmania electricity consumption, ESOO Central scenario, 2018-19 to 2052-53 (TWh)	144
Figure 83	Components of Tasmania residential electricity consumption forecast, ESOO Central scenario, 2023-24 to 2052-53 (TWh)	145
Figure 84	Components of Tasmania business electricity consumption forecast, ESOO Central scenario, 2023-24 to 2052-53 (TWh)	145
Figure 85	Actual and forecast Tasmania operational consumption, including hydrogen exports, all scenarios, 2018-19 to 2052-53 (TWh)	146
Figure 86	Actual and forecast Tasmania 50% POE maximum operational (sent-out) demand, 2022 ESOO all scenarios and 2021 ESOO all scenarios, 2018-19 to 2052-53 (MW)	147
Figure 87	Actual and forecast Tasmania 50% POE minimum operational (sent-out) demand, 2023 ESOO all scenarios and 2022 ESOO all scenarios, 2018-19 to 2052-53 (MW)	149

Figure 88	Tasmania assumed capability during typical summer conditions, by generation type, 2022-23 to 2032-33 (MW)	150
Figure 89	Actual and forecast Victoria electricity consumption, ESOO Central scenario, 2018-19 to 2052-53 (TWh)	151
Figure 90	Components of Victoria residential electricity consumption forecast, ESOO Central scenario, 2023-24 to 2052-53 (TWh)	152
Figure 91	Components of Victoria business electricity consumption forecast, ESOO Central scenario, 2023-24 to 2052-53 (TWh)	152
Figure 92	Actual and forecast Victoria operational consumption, including hydrogen exports, all scenarios, 2018-19 to 2052-53 (TWh)	153
Figure 93	Actual and forecast Victoria 50% POE maximum operational (sent-out) demand, 2023 ESOO all scenarios and 2022 ESOO all scenarios, 2018-19 to 2052-53 (MW)	154
Figure 94	Actual and forecast Victoria 50% POE minimum operational (sent-out) demand, 2023 ESOO all scenarios and 2022 ESOO all scenarios, 2018-19 to 2052-53 (MW)	156
Figure 95	Victoria assumed capability during typical summer conditions, by generation type, 2022-23 to 2032-33 (MW)	157
Figure 96	Victoria expected USE, scenarios and sensitivities, 2023-24 to 2032-33 (%)	158
Figure 97	Reliability outcomes for Victoria in 2023-24 under different weather reference years, ESOO Central scenario	159
Figure 98	Bubble plot of depth and duration of forecast USE Victoria 2023-24, ESOO Central scenario	160
Figure 99	Flexible demand sources included in AEMO's DSP forecast	162
Figure 100	DSP applied in forecasts for the summer period in New South Wales, 2023-24 to 2032-33 (MW)	166

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 2052-53.
- Supply adequacy assessments for the next 10 years, for the ESOO Central scenario, and other sensitivities published in this ESOO.

Annual consumption outlook

Figures 52 to 54 shows the component forecasts for operational consumption in New South Wales under the ESOO Central scenario.

Figure 52 Actual and forecast New South Wales electricity consumption, ESOO Central scenario, 2018-19 to 2052-53 (TWh)

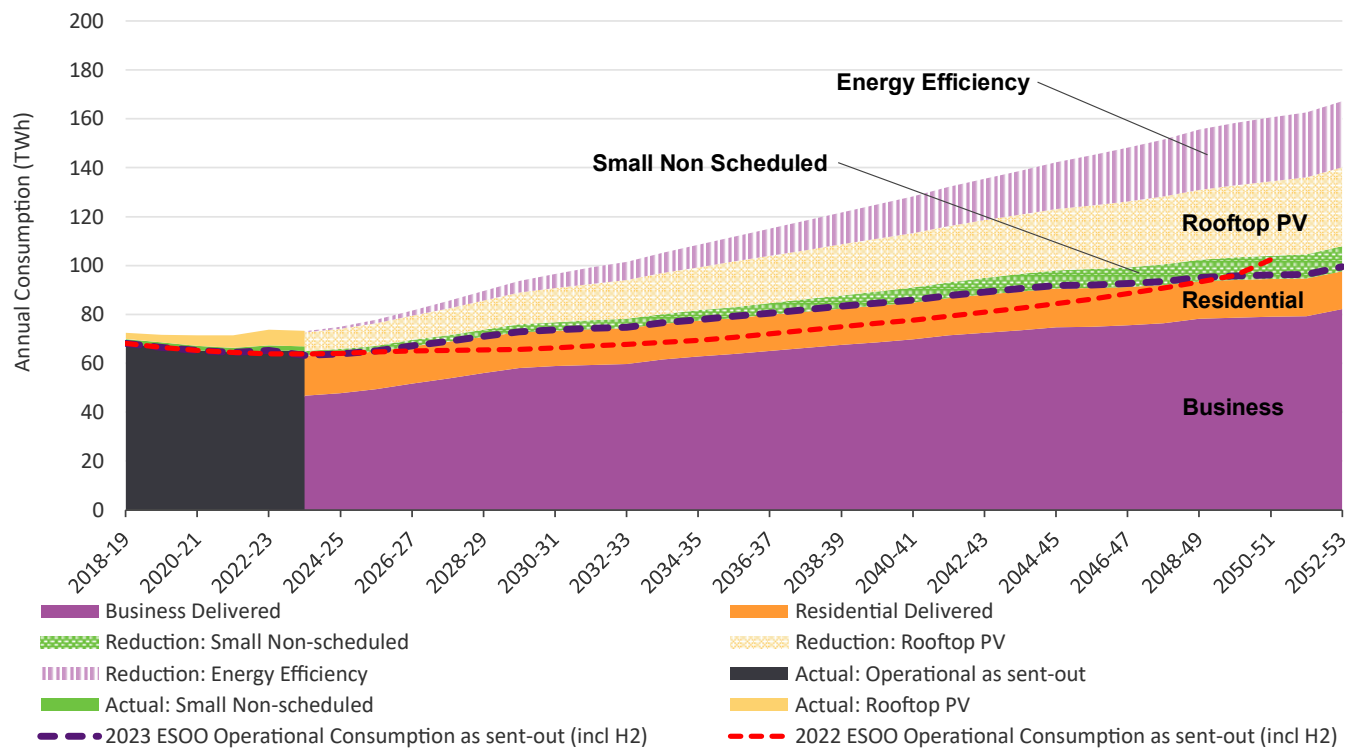


Figure 53 Components of New South Wales residential electricity consumption forecast, ESOO Central scenario, 2023-24 to 2052-53 (TWh)

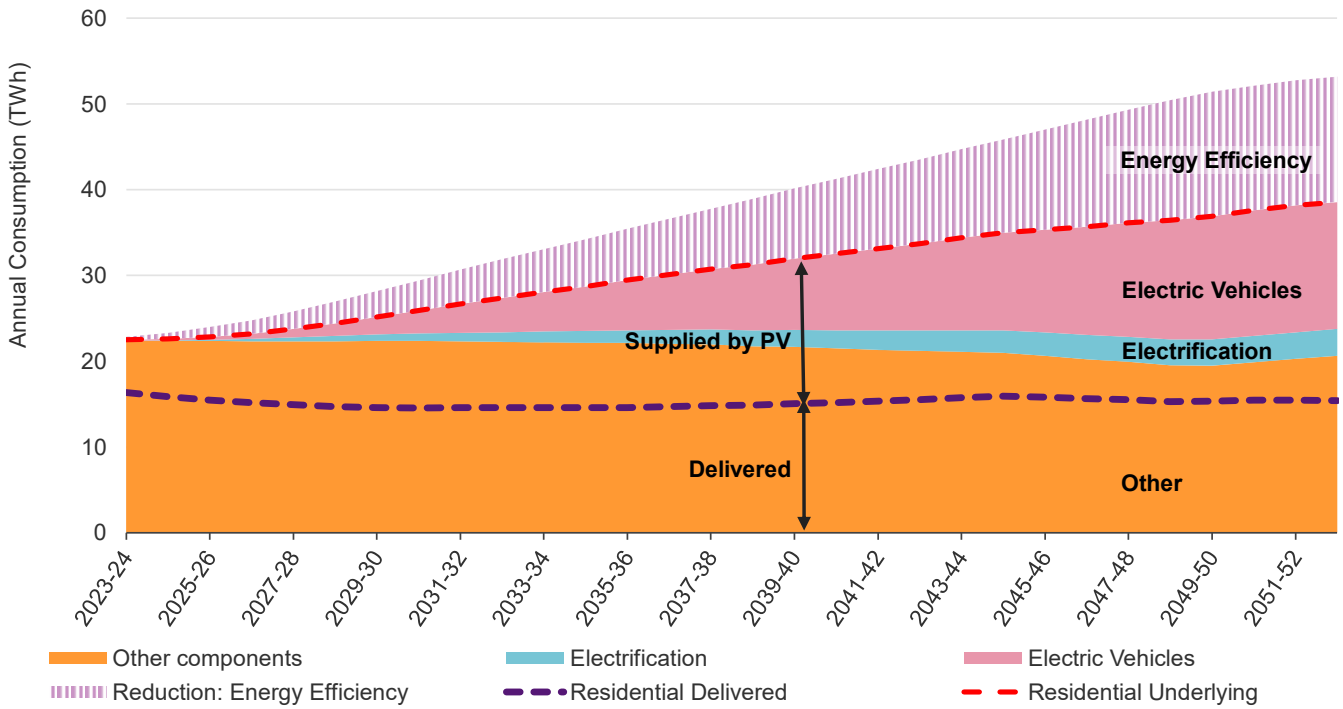
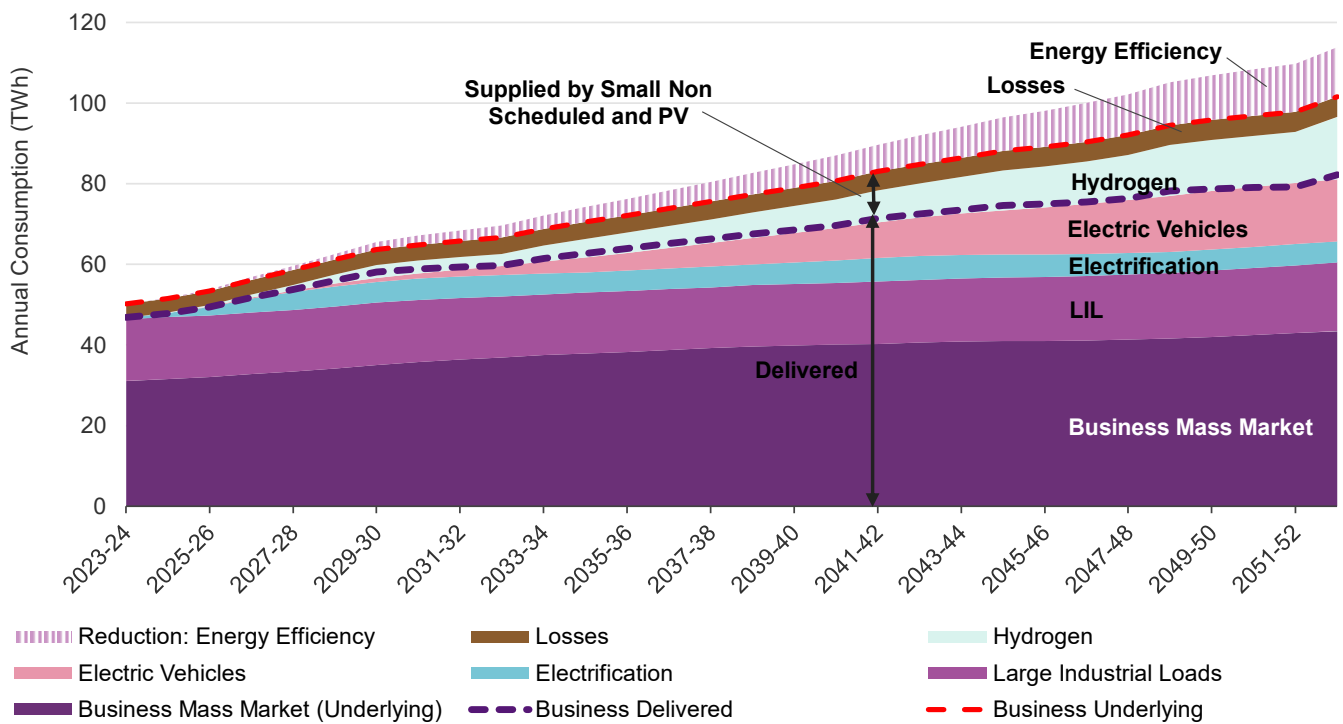


Figure 54 Components of New South Wales business electricity consumption forecast, ESOO Central scenario, 2023-24 to 2052-53 (TWh)



Note: Small non-scheduled combines PVNSG and ONSG.

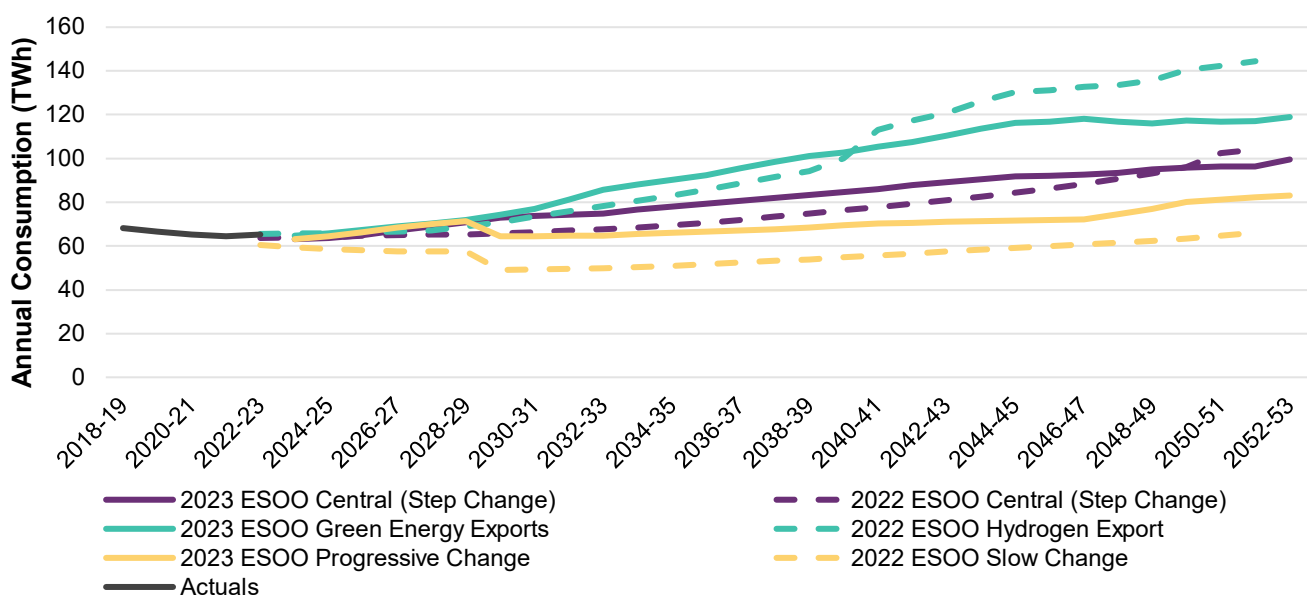
In this scenario, AEMO forecasts:

- Short term (1-10 years) – growth in operational consumption mainly from EV uptake, business electrification and to a lesser extent BMM load increases. Despite modest residential electrification, delivered residential consumption trends downward due to growth in distributed PV and energy efficiency. Hydrogen production for domestic use also emerges toward the end of the period. Compared to 2022 forecasts, this year’s projections are higher primarily because of hydrogen production commencing earlier in response to the New South Wales Renewable Fuel Scheme, stronger growth in BMM and lower energy efficiency forecasts for the business sector. BMM consumption is higher than in the 2022 ESOO, mainly due to an improved allocation of historical consumption between the residential and business sectors.
- Medium term (11-20 years) – consumption growing strongly due to continued uptake of EVs and increasing hydrogen production tempered by sustained growth in distributed PV and energy efficiency. Residential electrification continues at a steady rate while business electrification slows down.
- Long term (21-30 years) – growth trends from the medium term continue into the long term.

Figure 55 shows all the scenarios, highlighting that:

- *Progressive Change* tracks closely with ESOO Central until 2030, when several factors pull it below ESOO Central: slower electrification and EV uptake; LIL closure risks; and lower hydrogen production. The higher forecasts relative to the 2022 ESOO *Slow Change* scenario reflect the inclusion of electrification, consistent with Australia’s efforts to meet its NDC to the Paris Agreement of 43% reduction in emissions levels by 2030 relative to 2005 levels, and achieving net zero emissions by 2050. The scenario also considers 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, tempered by high levels of energy efficiency and PV towards the end of the outlook period. Longer-term growth is less than the 2022 ESOO forecast, with a reduction of hydrogen production for export.

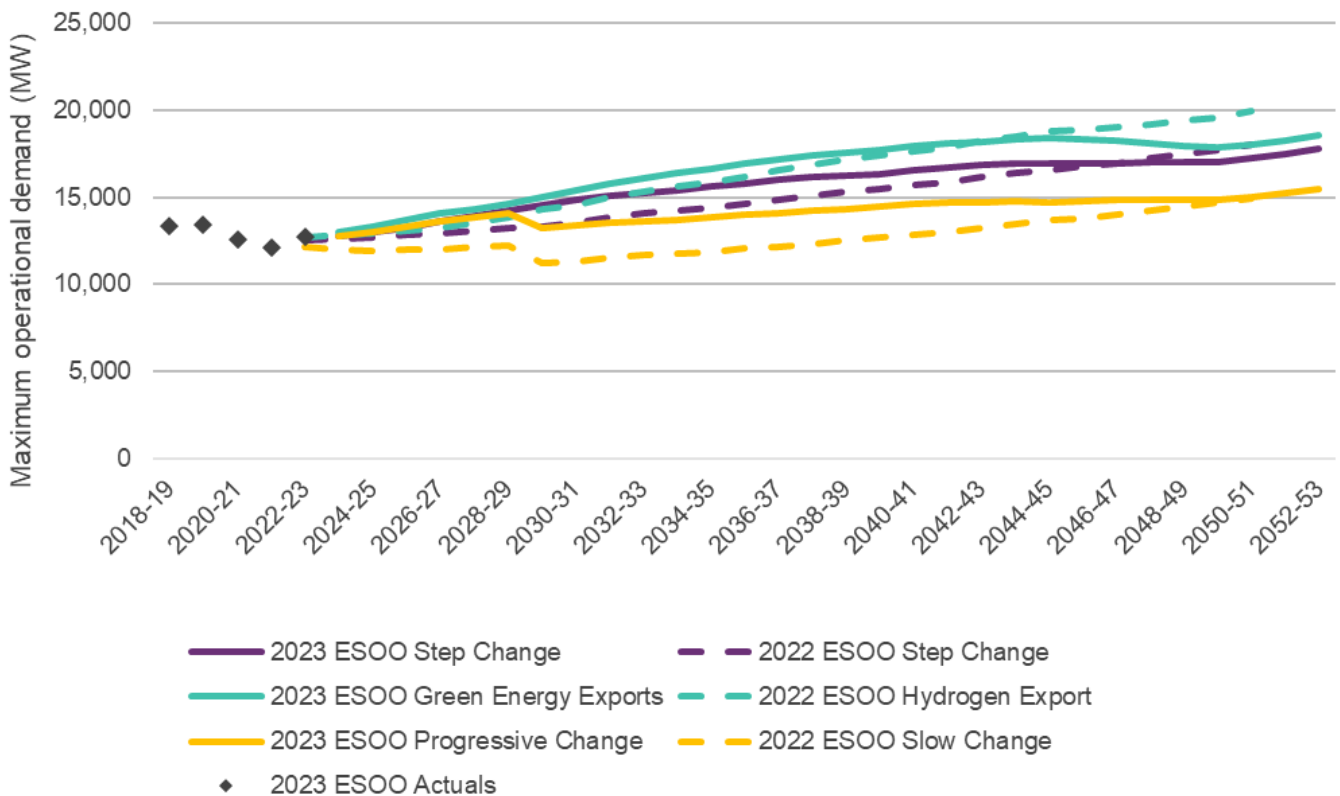
Figure 55 Actual and forecast New South Wales operational consumption, including hydrogen exports, all scenarios, 2018-19 to 2052-53 (TWh)



Maximum operational demand outlook

Figure 56 shows actual and forecast 50% POE maximum operational (sent-out) demand¹⁰⁸ from 2018-19 to 2052-53 in New South Wales for all scenarios, compared to matching 2022 ESOO scenarios.

Figure 56 Actual and forecast New South Wales 50% POE maximum operational (sent-out) demand, 2023 ESOO all scenarios and 2022 ESOO all scenarios, 2018-19 to 2052-53 (MW)



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

The key insights from these forecasts are:

- 2023-24 to 2032-33 (1-10 years):
 - Maximum operational demand is forecast to start at a broadly similar level in 2023-24 as in the 2022 ESOO, except the *Progressive Change* forecast is increased slightly, primarily due to growth in the underlying demand of BMM.
 - For all scenarios, the growth rates are faster than the 2022 ESOO, due to higher underlying demand of BMM. This trend is only partially offset by lower residential demand and reduced electrification.
 - As in previous forecasts, the *Progressive Change* scenario also considered the impact of risks of LIL closures that may result in a reduction in forecast maximum operational demand.
- 2033-34 to 2042-43 (11-20 years):

¹⁰⁸ 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/>.

- Due to the sustained growth of several key components, such as BMM, residential demand and LIL, maximum operational demand is forecast to grow. The growth rate of electrification has slowed compared to the 2022 ESOO, causing the spread between the 2022 and 2023 forecasts to narrow.
- 2043-44 to 2052-53 (21-30 years):
 - The growth rate of maximum operational demand is forecast to slow down and even exhibit a slight decrease, as energy efficiency continues to grow, reducing consumption and offsetting demand growth drivers. EVs constitute a significant portion of demand during this period, but their impact on maximum demand is expected to be relatively low on the basis that vehicle charging profiles will become smarter, minimising their contribution to the evening peak.

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

Table 19 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 19 New South Wales 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
2023-24	13,824	12,800	2024	12,921	12,546
2029-30	15,678	14,571	2030	14,828	14,391
2039-40	17,696	16,348	2040	16,530	16,028
2049-50	18,357	17,041	2050	17,137	16,595

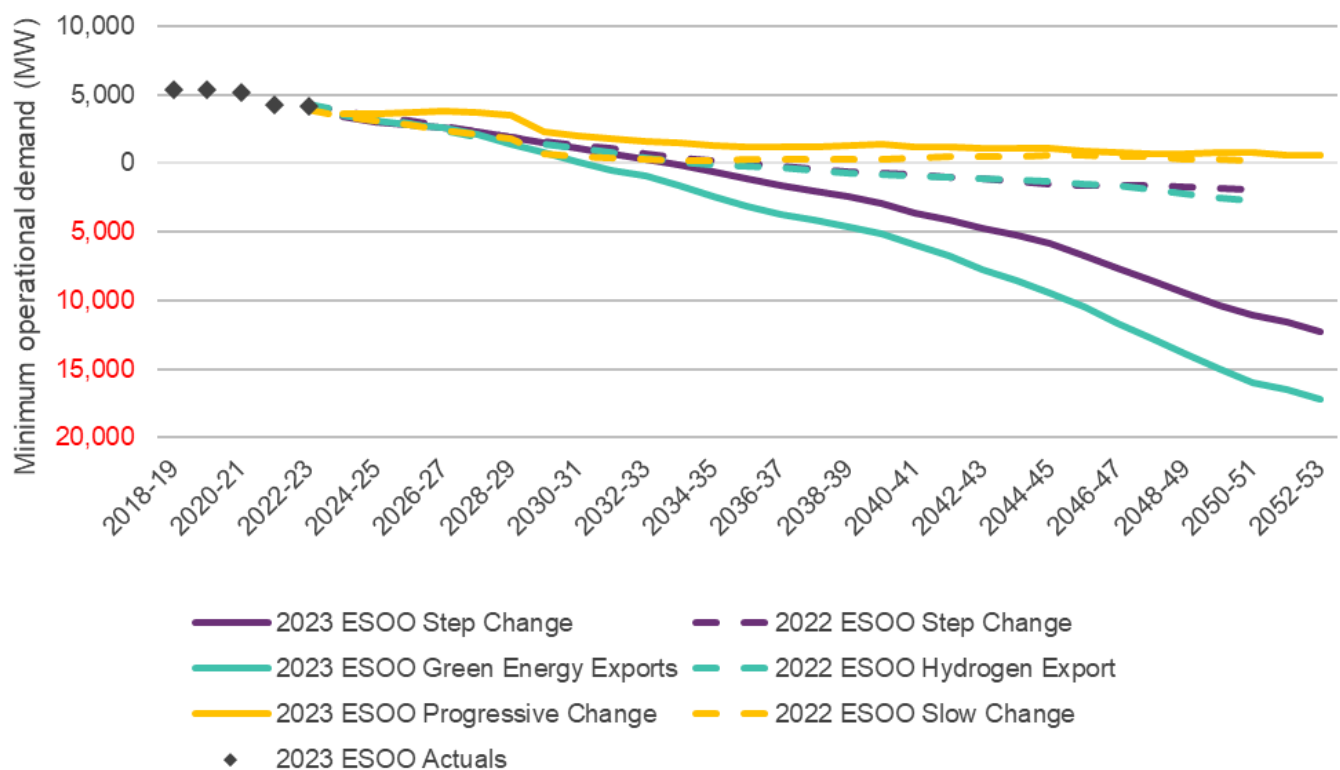
Minimum operational demand outlook

Figure 57 shows the actual and forecast 50% POE minimum operational (sent-out) demand from 2018-19 to 2052-53 for the 2023 ESOO compared to the 2022 ESOO for all scenarios in New South Wales. The key insights from these forecasts are:

- 2023-24 to 2032-33 (1-10 years):
 - Minimum operational demand is forecast to start slightly lower in 2023-24 compared to the 2022 ESOO for the ESOO Central (*Step Change*) scenario, due to a reduction in electrification forecast and model retraining.
 - Minimum operational demand is forecast to decline rapidly in *Step Change* and *Green Energy Exports* due to uptake of distributed PV. *Progressive Change* remains relatively stable due to the lesser growth of rooftop PV and energy efficiency, both factors increasing operational consumption and thereby increasing minimum operational demand.

- Risks of LIL closures that were considered in the *Progressive Change* scenario result in a further reduction in forecast minimum operational demand. This also was a consideration in the 2022 ESOO forecast.
- 2033-34 to 2042-43 (11-20 years):
 - Negative minimum operational demand continues to decrease, due to the growth of rooftop PV. Both *Step Change* and *Green Energy Exports* are below the 2022 ESOO, due to relatively higher distributed PV uptake (lowering operational demand) and relatively lower electrification (which lifts operational demand). *Progressive Change* is above the 2022 ESOO forecast because of higher BMM consumption and greater electrification than forecast previously.
- 2043-44 to 2052-53 (21-30 years):
 - Minimum operational demand reduces further in the *Step Change* and *Green Energy Exports* scenarios due to continued growth of rooftop PV. *Progressive Change* is forecast with minimal change over this period because the impact of PV uptake is offset by higher underlying demand including for EV charging.

Figure 57 Actual and forecast New South Wales 50% POE minimum operational (sent-out) demand, 2023 ESOO all scenarios and 2022 ESOO all scenarios, 2018-19 to 2052-53 (MW)



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

Supply adequacy assessment

Relative to last summer, approximately 650 MW of additional VRE generation is expected to be operational this summer. The following represents some of the largest projects that are expected to commission over the ESOO horizon, and listed at the date applied in the Central scenario modelling, which may vary from the commissioning date advised due to the application of default project commissioning delays:

- 716 MW of solar farm projects are expected to become operational in 2023-24 including Avonlie Solar Farm, New England Solar Farm and Wyalong Solar Farm.
- 250 MW/500 MWh of battery storage projects are expected to become operational in 2023-24 including Capital Battery, Darlington Point Energy Storage System and Riverina Energy Storage System 1 and 2.
- Tallawarra B Power Station (320 MW) becomes operational in 2023-24.
- Kurri Kurri Power Station (750 MW) becomes operational in 2024-25.
- Waratah Super Battery (850 MW) commences partial availability in 2024-25 with the remainder allocated to the SIPS, however the full capacity becomes available in 2030-31, once the five-year SIPS arrangement expires.
- Snowy 2.0 pumped hydro (2,040 MW/350,000 MWh) completes commissioning in 2029-30.
- The 2,880 MW Eraring Power Station has advised closure in August 2025.

Figure 58 shows the aggregate impact of generator and storage commissioning and decommissioning assumptions on assumed capacity during typical summer conditions.

Figure 58 New South Wales assumed capability during typical summer conditions, by generation type, 2022-23 to 2032-33 (MW)

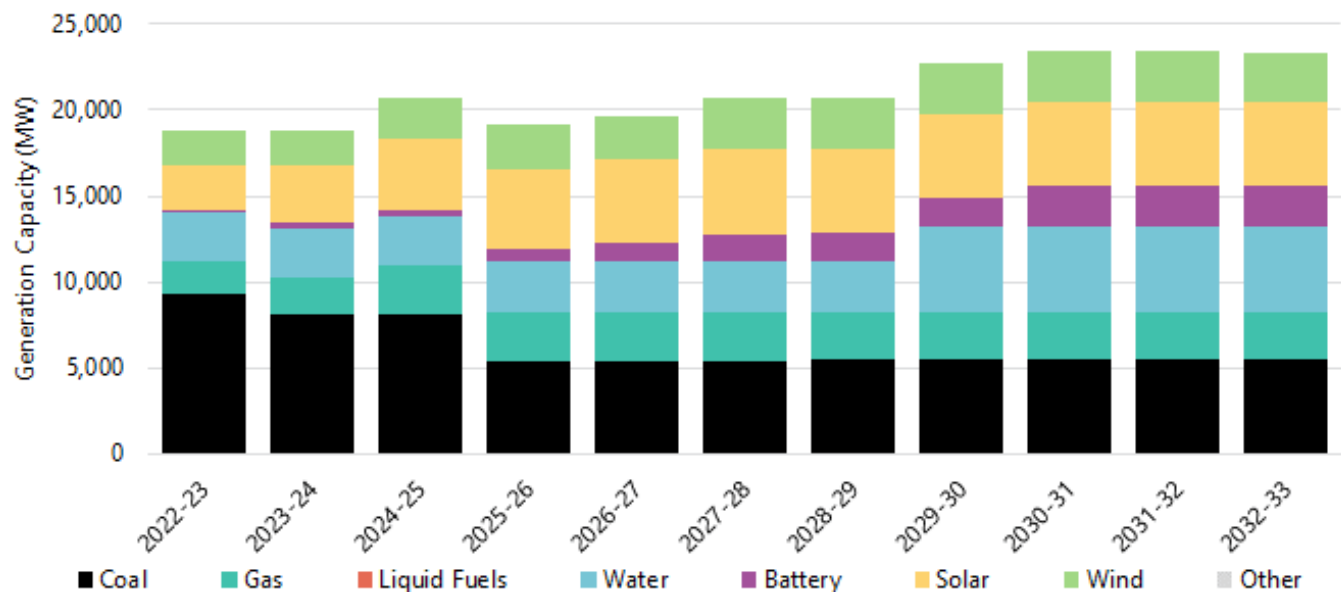


Figure 59 shows forecast expected USE for New South Wales under the modelled scenarios and sensitivities. It shows that:

- Expected USE is forecast within the IRM in all scenarios and sensitivities until 2025-26. In 2025-26, the Eraring Power Station has advised of its retirement; the *Eraring Sensitivity* demonstrates the impact of an extension to the retirement of two units, by two years. The retirement of Eraring is, however, partially offset by committed developments including the Waratah Super Battery project (including transmission upgrades, BESS and SIPS). The project is expected to be fully available by 2025-26, as well as numerous wind, solar and battery developments in New South Wales.
- Under the ESOO Central (*Step Change*) scenario, USE is forecast above the reliability standard from 2025-26 until the end of the modelling horizon. These reliability gaps were identified in the 2022 ESOO, but reduced

considerably in the February 2023 *Update to 2022 Electricity Statement of Opportunities*. The gaps have increased again, predominantly due to the treatment of demand side components, including a reduction in the forecast contribution of the New South Wales PDRS, and a higher demand forecast. The gaps have reduced in the latter part of the forecast due to the revised closure year for Vales Point Power Station shifting from 2029 to 2033. From 2030-31, reliability risks are forecast to increase because currently committed and anticipated battery developments and other wind and solar generation developments are as yet insufficient to offset forecast increases in electricity demand.

- Additional insights from sensitivity analysis include:
 - Under the *2022 Methodology* sensitivity, expected USE is higher than the ESOO Central scenario from 2025-26, due to the exclusion of anticipated projects, which reduce reliability risks more than the effect of excluding CER orchestration that is not committed and shallow storage derating.
 - Under the *CER Orchestration* sensitivity, expected USE is above the reliability standard from 2025-26, consistent with the ESOO Central scenario, however reliability risks are forecast to be lower over the horizon than the ESOO Central scenario.
 - Under the *Actionable transmission* sensitivity, expected USE is forecast to be under the reliability standard until 2027-28, with significantly lower reliability risks over the ESOO horizon relative to the ESOO Central scenario. The forecast USE is reduced in this sensitivity due to additional transmission developments including HumeLink from 2027-28 and Hunter Transmission Project from 2028-29, as well as the expected commissioning of Snowy 2.0 in 2029-30 which improves access to major New South Wales load centres with this transmission capacity.
 - The *Federal and state schemes* sensitivity and *Schemes without CER orchestration* sensitivity both show reliability risks within the reliability standard over the entire horizon, demonstrating the expected effectiveness of the developments from the various schemes, assuming all developments occur to the schedule and scope of the schemes and developments included.

Figure 59 New South Wales expected USE, scenarios and sensitivities, 2023-24 to 2032-33

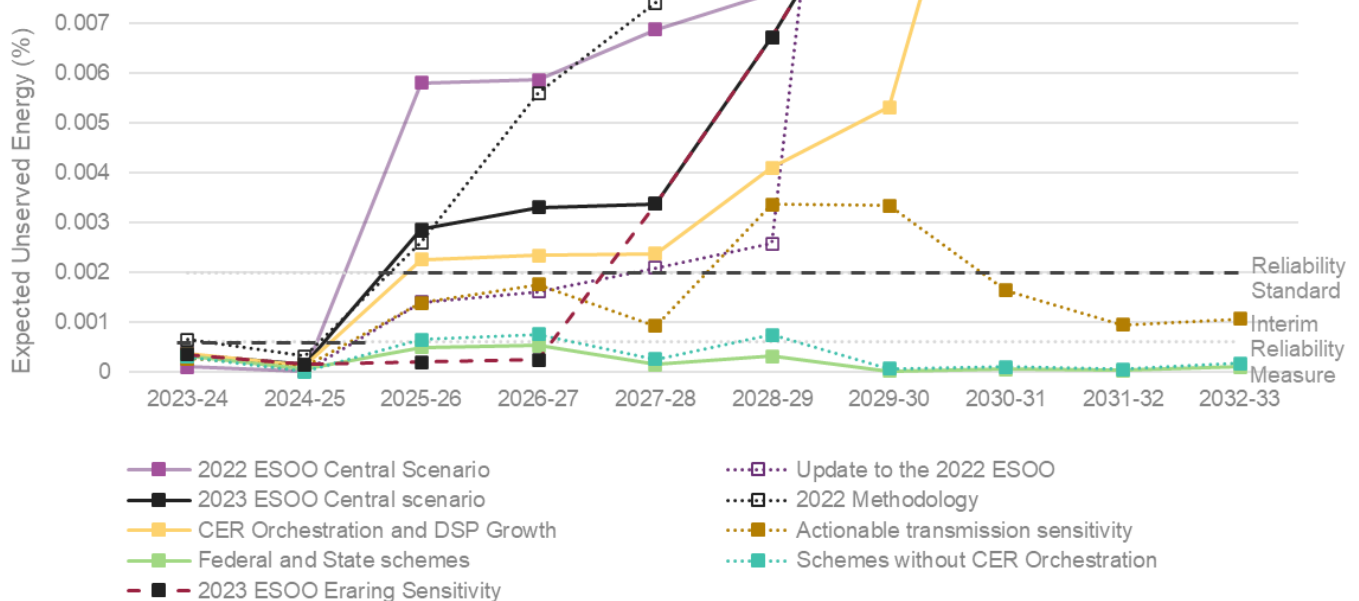


Figure 60 shows the reliability outcomes for the ESOO Central scenario for New South Wales in 2023-24 under different weather years. Under weather conditions similar to the 2016-17 reference year, expected USE would exceed the IRM. Under all other reference years, expected USE is forecast below the IRM.

Figure 60 Reliability outcomes for New South Wales in 2023-24 under different weather reference years, ESOO Central scenario

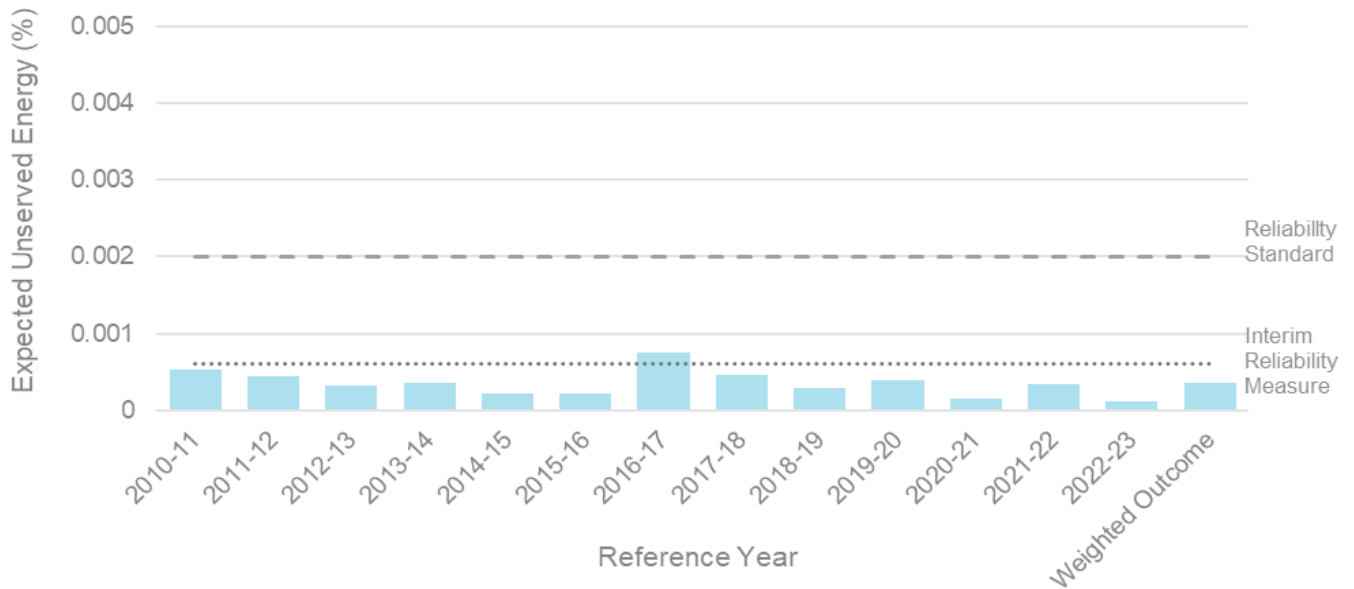
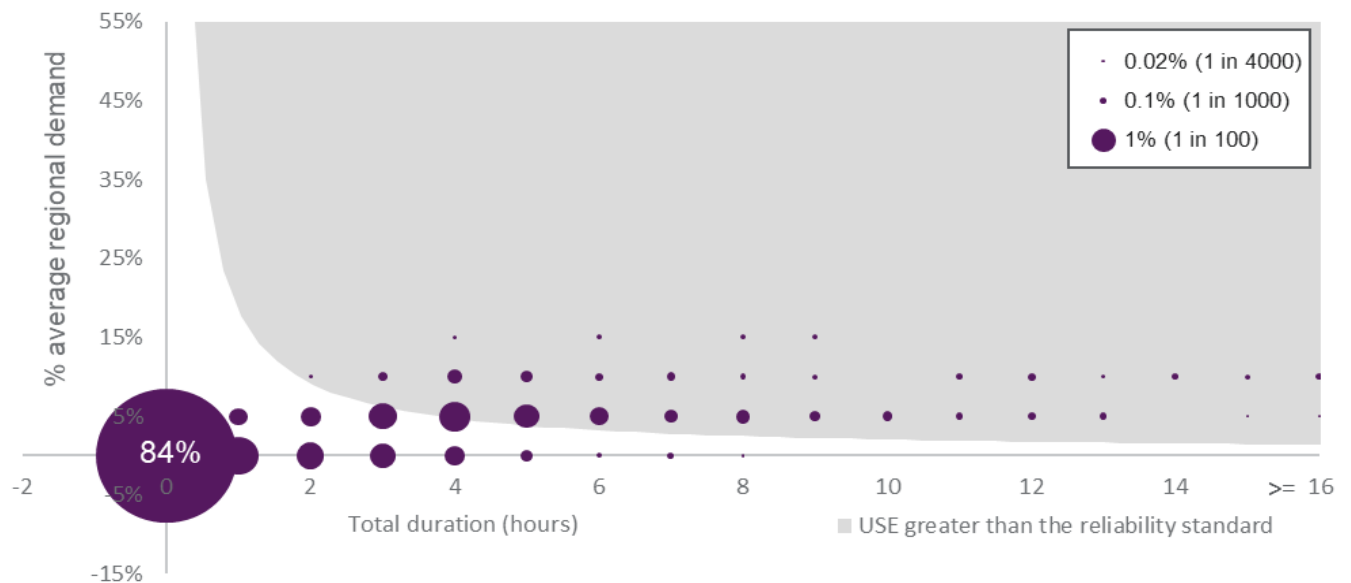


Figure 61 shows a bubble plot of the depth and duration of USE forecast in New South Wales for 2023-24 in the ESOO Central scenario, similar to that shown in **Section 4.3**. It shows that the most likely outcome is that USE does not occur in the coming year (the large purple dot), but that there is a 16% probability of a USE outcome. For those simulation outcomes that did have USE, the number of hours experiencing USE was likely to be approximately 1-8 hours, and of average depth up to 10% of average regional load.

Figure 61 Bubble plot of depth and duration of forecast USE New South Wales 2023-24, ESOO Central scenario



A2. Queensland outlook

The following sections present, for Queensland:

- Operational consumption, maximum demand, and minimum demand outlooks for all three scenarios to 2052-53.
- Supply adequacy assessments for the next 10 years for the ESOO Central scenario, and other sensitivities published in this ESOO.

Annual consumption outlook

Figures 62 to 64 shows the component forecasts for operational consumption in Queensland under the ESOO Central scenario.

Figure 62 Actual and forecast Queensland electricity consumption, ESOO Central scenario, 2018-19 to 2052-53 (TWh)

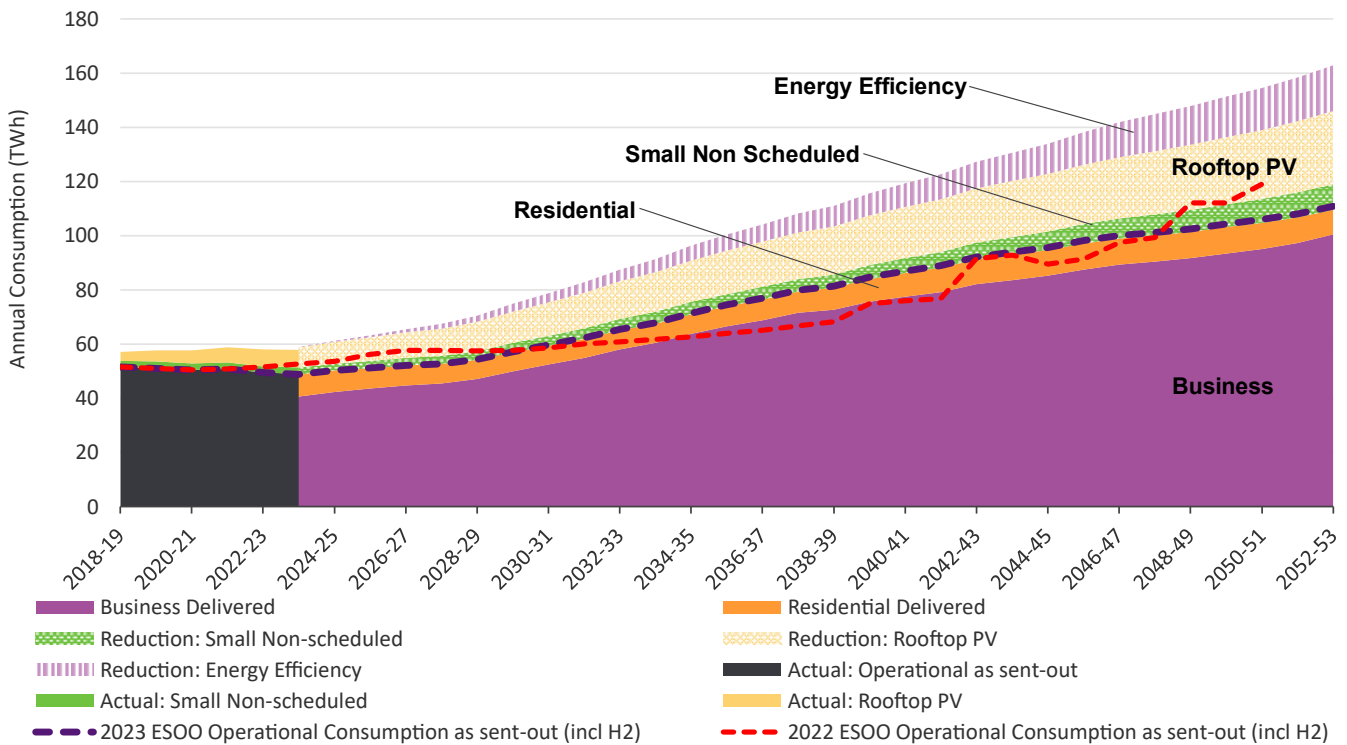


Figure 63 Components of Queensland residential electricity consumption forecast, ESOO Central scenario, 2023-24 to 2052-53 (TWh)

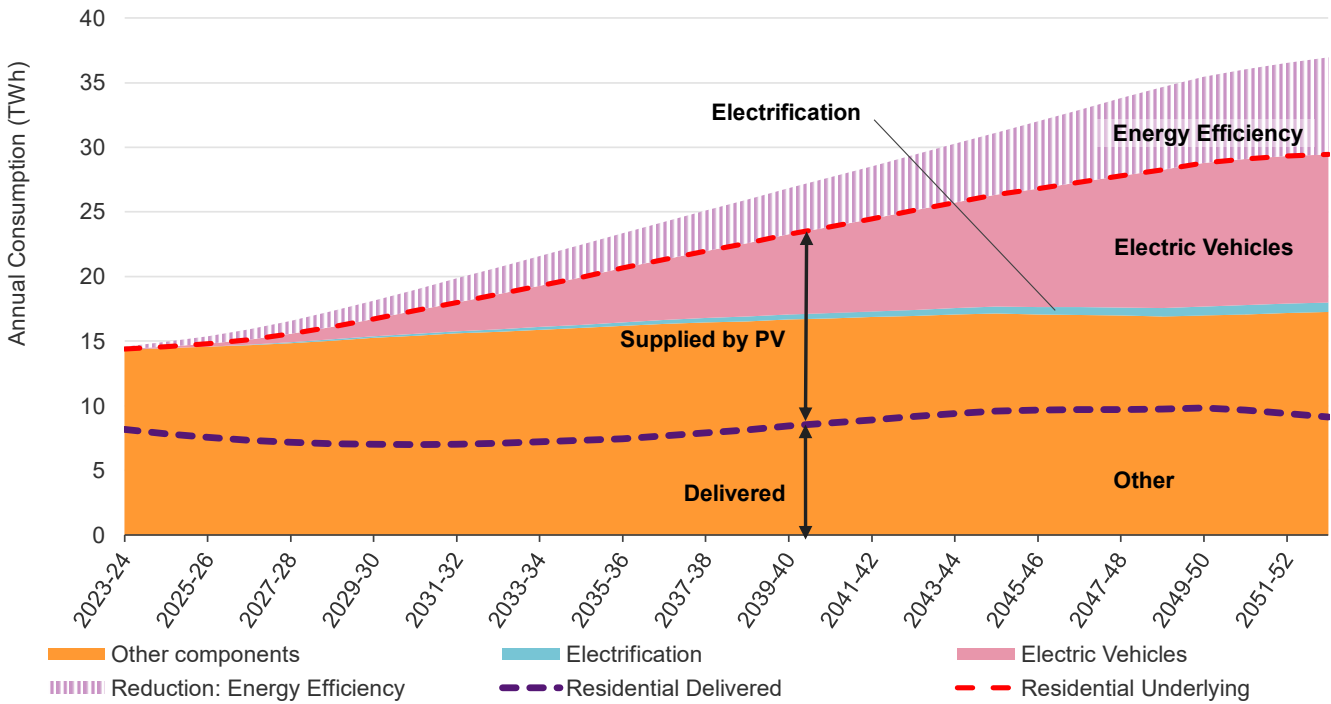
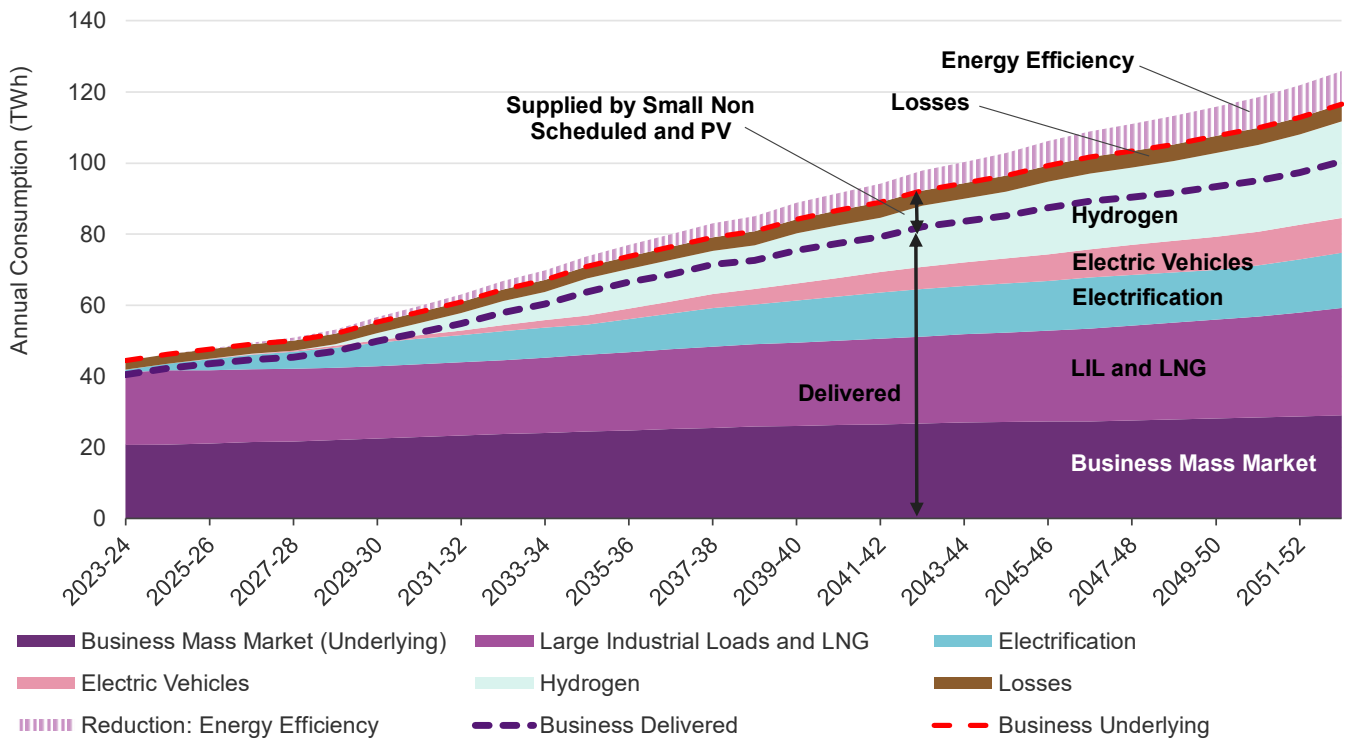


Figure 64 Components of Queensland business electricity consumption forecast, ESOO Central scenario, 2023-24 to 2052-53 (TWh)



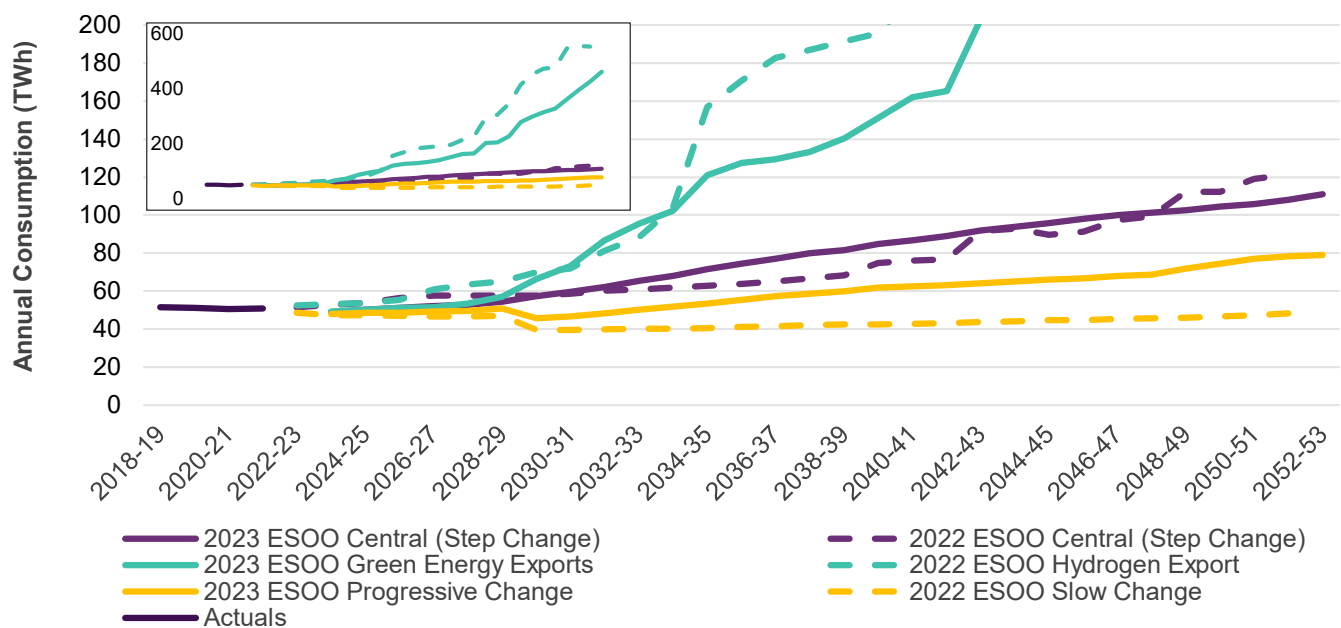
Note: Small non-scheduled combines PVNSG and ONSG.

In this scenario, AEMO forecasts:

- Short term (1-10 years) – residential consumption lower than the 2022 ESOO Central scenario, due in part to an improved allocation of historical consumption between the residential and business sectors. Business electrification and EV uptake drive consumption in the next decade. This is forecast to be partially offset by the continued uptake of distributed PV, reducing grid-delivered consumption. Minimal growth in LIL and LNG components are forecast over this period.
- Medium term (11-20 years) – continued growth in consumption with business electrification and EV uptake contributing significantly, partially offset by continuing growth in distributed PV and energy efficiency investment. Residential consumption is almost entirely met by distributed PV. The emergence of hydrogen production for the domestic market is forecast, with a share of expected electrolyser operation to service potential export demand. LNG consumption may lower depending on the ongoing demand for LNG globally. The ESOO Central scenario reflects a potential moderation of LNG operation.
- Long term (21-30 years) – growth is forecast to continue in this decade with continued EV uptake, LIL growth, and hydrogen production as the main drivers. This growth is forecast to be offset partially by LNG reduction, greater adoption of energy efficiency measures and continued uptake of distributed PV.

Figure 65 shows the consumption forecast across the scenarios.

Figure 65 Actual and forecast Queensland operational consumption, including hydrogen exports, all scenarios, 2018-19 to 2052-53 (TWh)



Note: 2022 ESOO Hydrogen Export and Green Energy Exports continue beyond the chart to reach approximately 554 TWh in 2051-52 and 462 TWh in 2052-53, respectively.

It highlights that:

- *Progressive Change* is lower than ESOO Central, particularly from the early 2030s. This is due to lower LIL forecasts that capture closure risks, lower rates of electrification and EV uptake. Domestic hydrogen production is limited to a relatively modest 6 TWh by 2053, with no hydrogen exports. The higher forecast relative to the 2022 ESOO *Slow Change* scenario reflects the inclusion of electrification and hydrogen

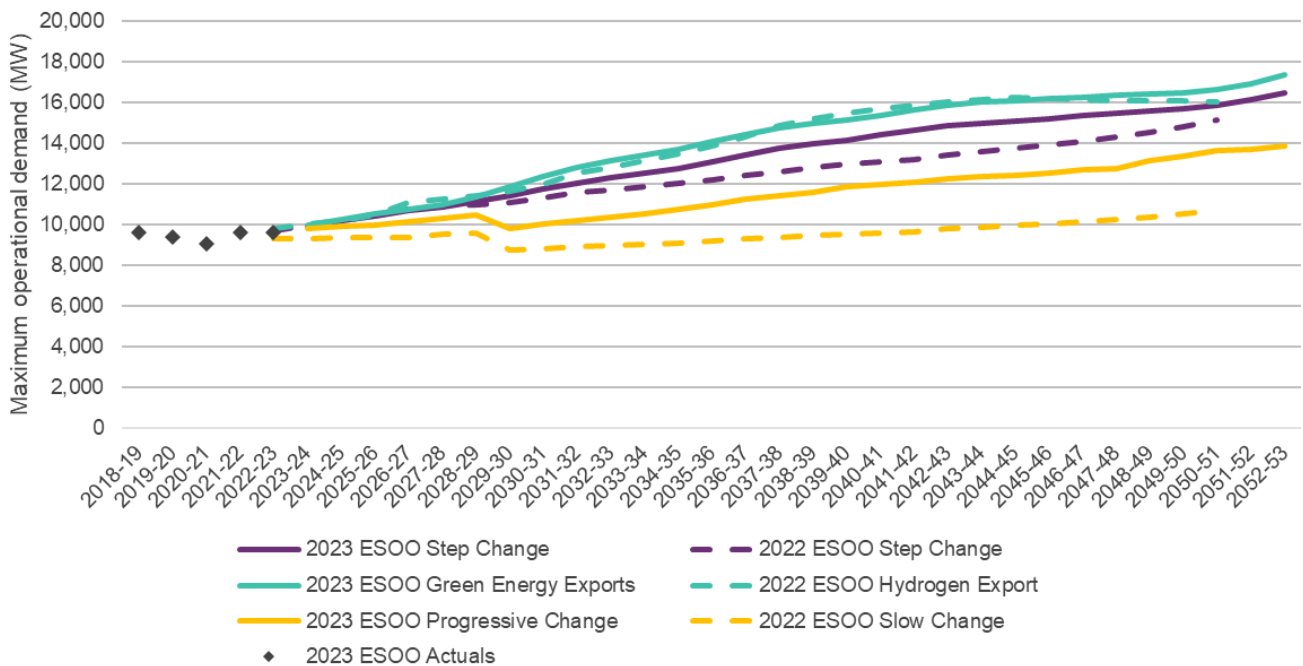
production, consistent with Australia’s efforts to meet its NDC to the Paris Agreement of 43% reduction in emissions levels by 2030 relative to 2005 levels, and achieving net zero emissions by 2050.

- *Green Energy Exports* is projected to experience rapid growth from the 2030s, with hydrogen exports assumed to develop at scale in the scenario, including other associated products such as green steel. Higher domestic hydrogen production is also forecast in this scenario, relative to the ESOO Central scenario. Greater uptake of EVs and higher rates of business electrification relative to the other scenarios further increases the forecast spread.

Maximum operational demand outlook

Figure 66 shows actual and forecast 50% POE maximum operational (sent-out) demand¹⁰⁹ from 2018-19 to 2052-53 in Queensland for all scenarios, compared to matching 2022 ESOO scenarios.

Figure 66 Actual and forecast Queensland 50% POE maximum operational (sent-out) demand, 2023 ESOO all scenarios and 2022 ESOO all scenarios, 2018-19 to 2052-53 (MW)



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

The key insights are:

- 2023-24 to 2032-33 (1-10 years):
 - Maximum operational demand is forecast to start broadly at the same level in 2023-24 (as in the 2022 ESOO) for the *Step Change* and *Green Energy Exports* scenarios, with the forecast model improvements and retraining confirming the 2022 forecast levels as appropriate, while the forecast model revisions has

¹⁰⁹ 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/>.

caused the Progressive Change scenario to start at a higher level than projected in the 2022 ESOO *Slow Change* scenario.

- Maximum operational demand is forecast to increase at a slightly faster rate than the 2022 ESOO due to the faster growth of underlying demand and LIL, and lower energy efficiency. However, the decrease in electrification offsets some of this growth.
- As in previous forecasts, the *Progressive Change* scenario also considered the impact of risks of LIL closures that may result in a reduction in forecast maximum operational demand.
- 2033-34 to 2042-43 (11-20 years):
 - Maximum operational demand is forecast to continue growing due to the stable growth of underlying consumption. However, the gap between the 2023 and 2022 forecasts is gradually narrowing in the final years of this decade because of the lower level of electrification in this 2023 ESOO Central forecast.
- 2043-44 to 2052-53 (21-30 years):
 - Maximum operational demand is expected to see continued growth in all scenarios as electrification of Australia's economy continues in response to the decarbonisation objectives of each scenario. *Progressive Change* increases more in the back end relative to the other scenarios, as it has less smart EV charging and that causes EV load at time of peak demand to be higher, despite EV uptake being a lower forecast.

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

Table 20 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 20 Queensland summer and winter 10% and 50% POE maximum operational demand (sent out) forecast, Step Change scenario, 2023-24 to 2049-50 (MW)

Financial year	Summer		Calendar year	Winter	
	10% POE	50% POE		10% POE	50% POE
2023-24	10,373	9,932	2024	8,554	8,342
2029-30	11,950	11,439	2030	9,952	9,698
2039-40	14,663	14,154	2040	12,253	11,920
2049-50	16,234	15,675	2050	13,570	13,162

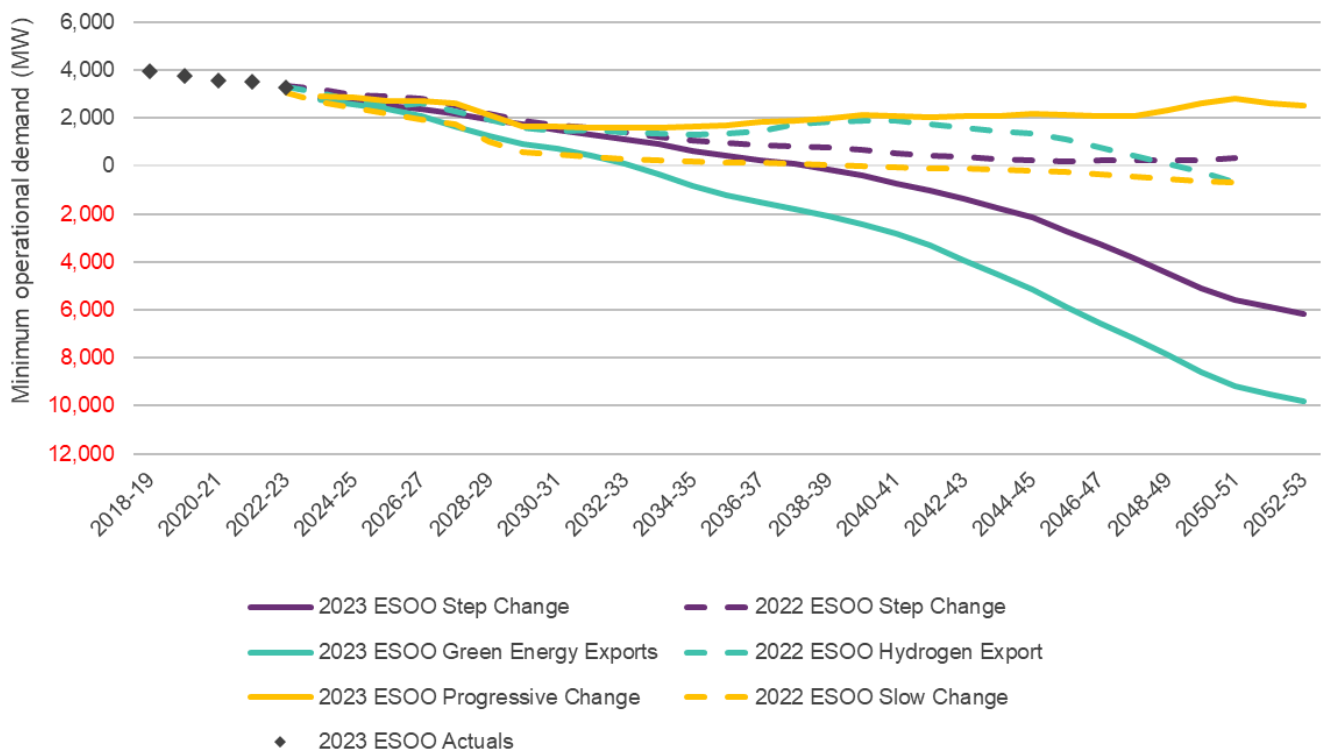
Minimum operational demand outlook

Figure 67 shows actual and forecast 50% POE minimum operational (sent-out) demand (MW) from 2018-19 to 2052-53 for the 2023 ESOO compared to the 2022 ESOO for all scenarios in Queensland. The key insights are:

- 2023-24 to 2032-33 (1-10 years):
 - Minimum operational demand is forecast to start lower than the 2022 ESOO forecasts due to model retraining to increase alignment with historical observations.

- Minimum operational demand is forecast to decrease rapidly, due to forecast uptake of distributed PV in the *Step Change* and *Green Energy Exports* scenarios. Lower electrification forecasts offset a higher BMM forecast, resulting in a forecast trajectory similar to the 2022 forecast in the early years. A higher PV uptake towards the end relative to the 2022 forecast, causing 2023 forecast to be lower than 2022.
- Risks of LIL closures that were considered within the *Progressive Change* scenario result in a further reduction in forecast minimum operational demand. This also was a consideration in the 2022 ESOO forecast.
- 2033-34 to 2042-43 (11-20 years):
 - Minimum operational demand is forecast to continue to decrease in the *Step Change* and *Green Energy Exports* scenarios as rooftop PV keeps growing; some of this impact is offset by the higher LIL demand and lower energy efficiency projections.
 - The *Progressive Change* scenario is expected to begin trending upwards as EVs and broader electrification increase, and it is forecast to remain as a positive minimum operational demand due to this, which differs from the 2022 ESOO.
- 2043-44 to 2052-53 (21-30 years):
 - Because of the steady growth of rooftop PV, minimum operational demand is forecast to decline in all scenarios except the *Progressive Change* scenario. In that scenario, growth in electrification is forecast to be needed to assist in meeting Australia’s emissions reduction goals by 2050.

Figure 67 Actual and forecast Queensland 50% POE minimum operational (sent-out) demand, 2023 ESOO all scenarios and 2022 ESOO all scenarios, 2018-19 to 2052-53 (MW)



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

Supply adequacy assessment

Relative to last summer, approximately 542 MW of additional VRE generation is expected to commence operation this summer. The following list represents the largest projects that are expected to commission over the 10-year ESOO horizon. Projects are listed at the date applied in modelling, which may vary from the commissioning data advised due to the application of default project commissioning delays:

- 720 MW of solar farm projects become operational in 2023-24 including Bluegrass Solar Farm, Columboola Solar Farm, Edenvale Solar Park, Kennedy Energy Park Phase 1 – Solar, and Wandoan South Solar Stage 1.
- 200 MW of wind farm projects become operational in 2023-24 including Kaban Wind Farm and Kennedy Energy Park Phase 1 - Wind.
- Callide C has advised a progressive return to service of its units after an extended outage, during summer 2023-24 for one unit and before summer 2024-25 for the second unit.
- 623 MW of wind farm projects become operational in 2024-25 including the Clark Creek Wind Farm and Dulacca Wind Farm.
- 814 MW/1,498 MWh of battery projects become operational in 2025-26 including Central Renewable Energy Zone BESS, Chinchilla BESS, Southern Renewable Energy Zone BESS, Ulinda Park BESS and Western Downs Battery.
- MacIntyre Wind Farm (923 MW) becomes operational in 2025-26.
- Borumba Pumped Hydro (1,998 MW/48,000 MWh) becomes operational in 2031-32.
- The 700 MW Callide B has advised expected retirement in 2028.

Figure 68 shows the aggregate impact of generator and storage commissioning and decommissioning assumptions.

Figure 68 Queensland assumed capability during typical summer conditions, by generation type, 2022-23 to 2032-33 (MW)

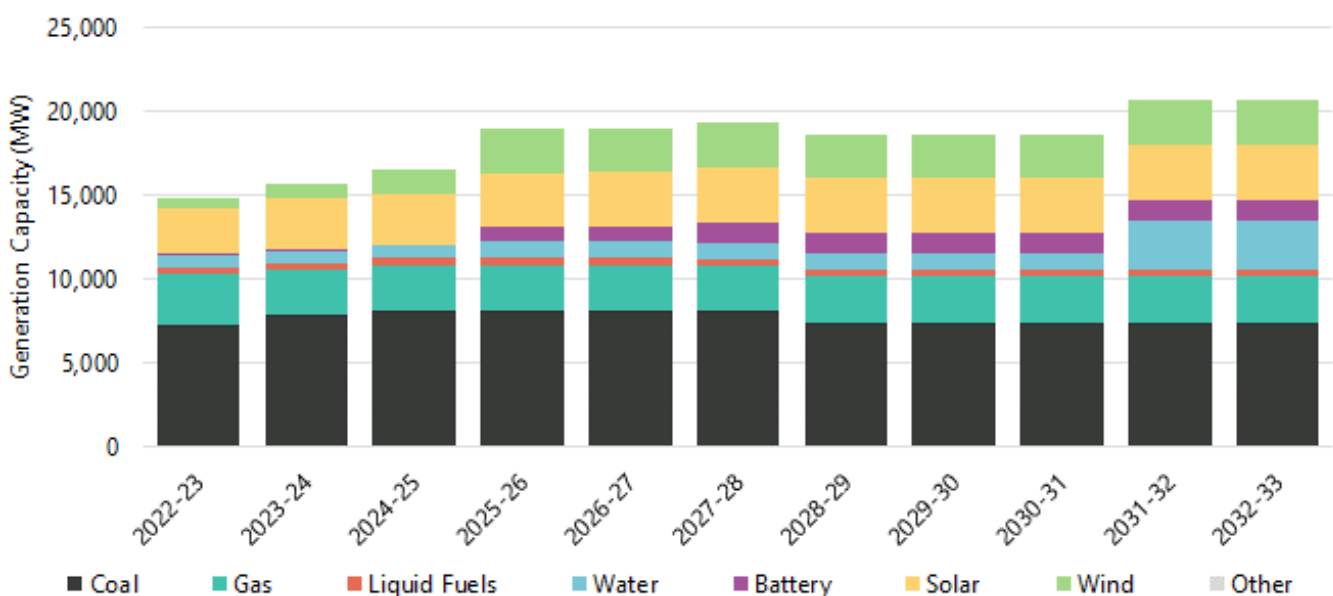


Figure 69 shows the forecast USE for Queensland under the relevant modelled scenarios and sensitivities. It highlights that:

- Forecast USE in the ESOO Central scenario remains below the reliability standard and IRM in the first six years of the ESOO horizon and then exceeds the reliability standard in 2029-30 and 2030-31 due to the retirement of Callide B Power Station in 2028. Expected USE reduces at 2031-32 due to the expected commissioning of Borumba Pumped Hydro project¹¹⁰.
- Expected USE is higher from 2025-26 in the 2022 Methodology sensitivity relative to the ESOO Central scenario, due to the previous methodology not including anticipated projects.
- Under the CER Orchestration sensitivity, Actionable transmission sensitivity, Federal and state schemes sensitivity, and Schemes without CER orchestration sensitivity, reliability risks are forecast within the reliability standard over the horizon, suggesting that the additional developments in these sensitivities will effectively mitigate reliability risks, relative to the ESOO Central scenario. While not modelled, if the Queensland Energy and Jobs Plan leads to earlier retirements of the state’s coal fleet, the need for further solutions to maintain reliability consistent with the reliability standard will be required. The Plan however anticipates that appropriate development of alternative generation and energy production capacity will be delivered prior to any change in closure arrangements.

Figure 69 Queensland expected USE, scenarios and sensitivities, 2023-24 to 2032-33

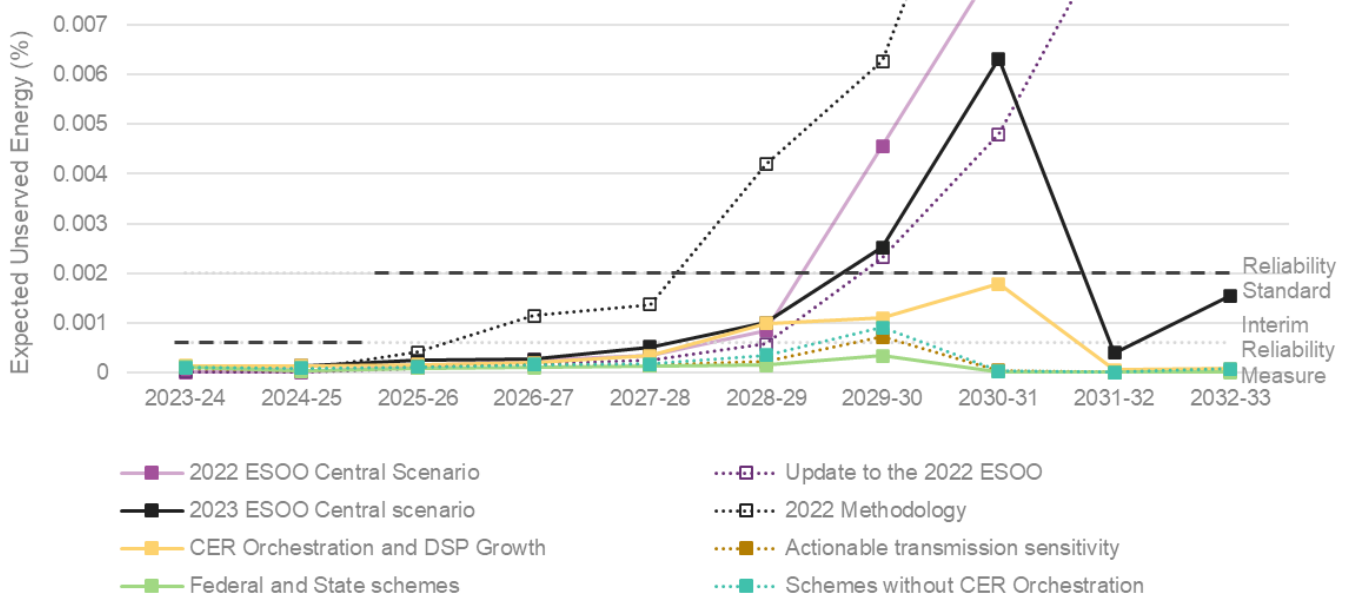


Figure 70 shows the reliability outcomes for the ESOO Central scenario for Queensland in 2023-24 under different weather years. Under all weather reference years, expected USE is less than the IRM.

¹¹⁰ The timing of this project in the ESOO Central scenario reflects a methodological delay to the project’s schedule, as outlined in Chapter 8.

Figure 70 Reliability outcomes for Queensland in 2023-24 under different weather reference years, ESOO Central scenario

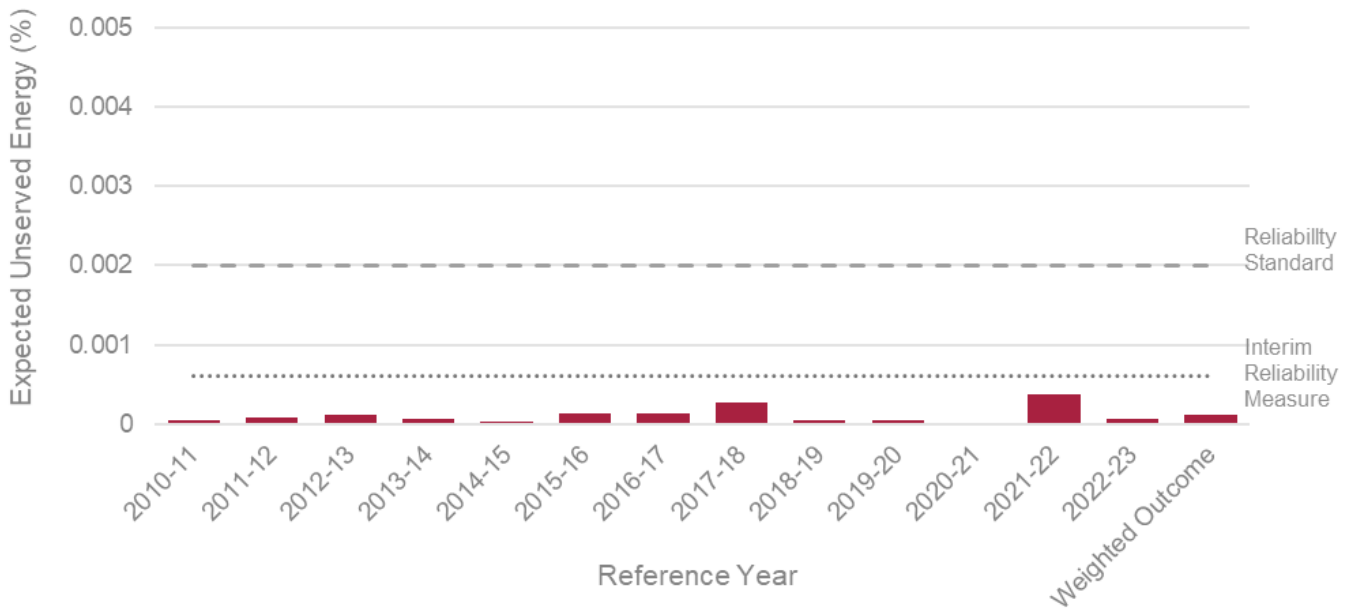
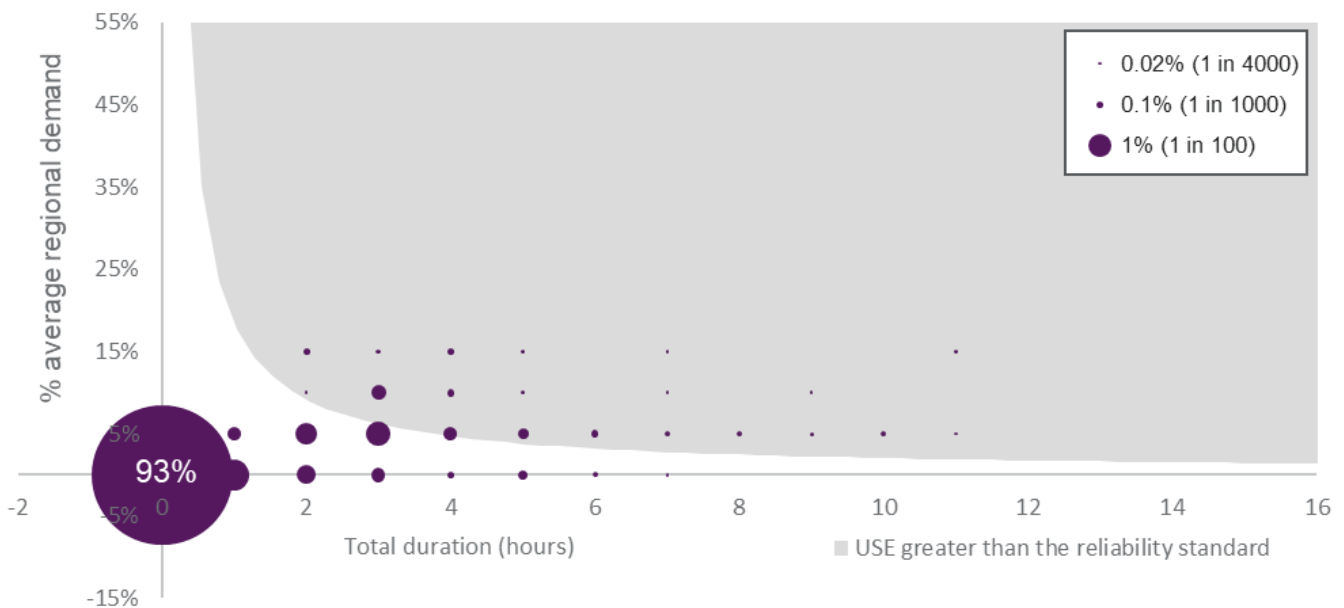


Figure 71 shows a bubble plot of the depth and duration of USE forecast in Queensland for 2023-24 in the ESOO Central scenario, similar to that shown in **Section 4.3**. It shows that the most likely outcome is that USE does not occur in the coming year (the large purple dot), but that there is a 7% probability of a USE outcome. For those simulation outcomes that did have USE, the number of hours experiencing USE was likely to be 1-3 hours in duration and of approximately 5% of average regional load.

Figure 71 Bubble plot of depth and duration of forecast USE Queensland 2023-24, ESOO Central scenario



A3. South Australia outlook

The following sections present, for South Australia:

- Operational consumption, maximum demand, and minimum demand outlooks for all three scenarios to 2052-53.
- Supply adequacy assessments for the next 10 years, for the ESOO Central scenario, and other sensitivities published in this ESOO.

Annual consumption outlook

Figures 72 to 74 show the component forecasts for operational consumption in South Australia under the ESOO Central scenario.

Figure 72 Actual and forecast South Australia electricity consumption, ESOO Central scenario, 2018-19 to 2052-53 (TWh)

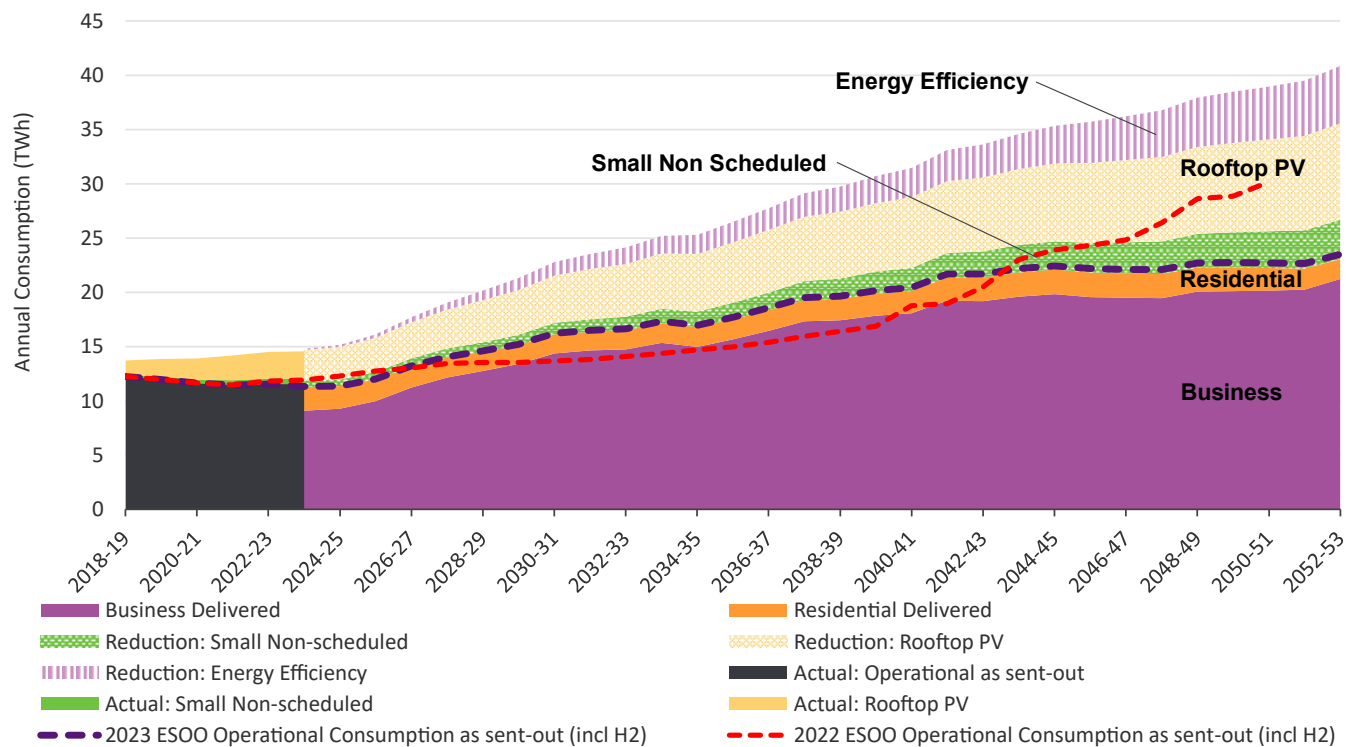


Figure 73 Components of South Australia residential electricity consumption forecast, ESOO Central scenario, 2023-24 to 2052-53 (TWh)

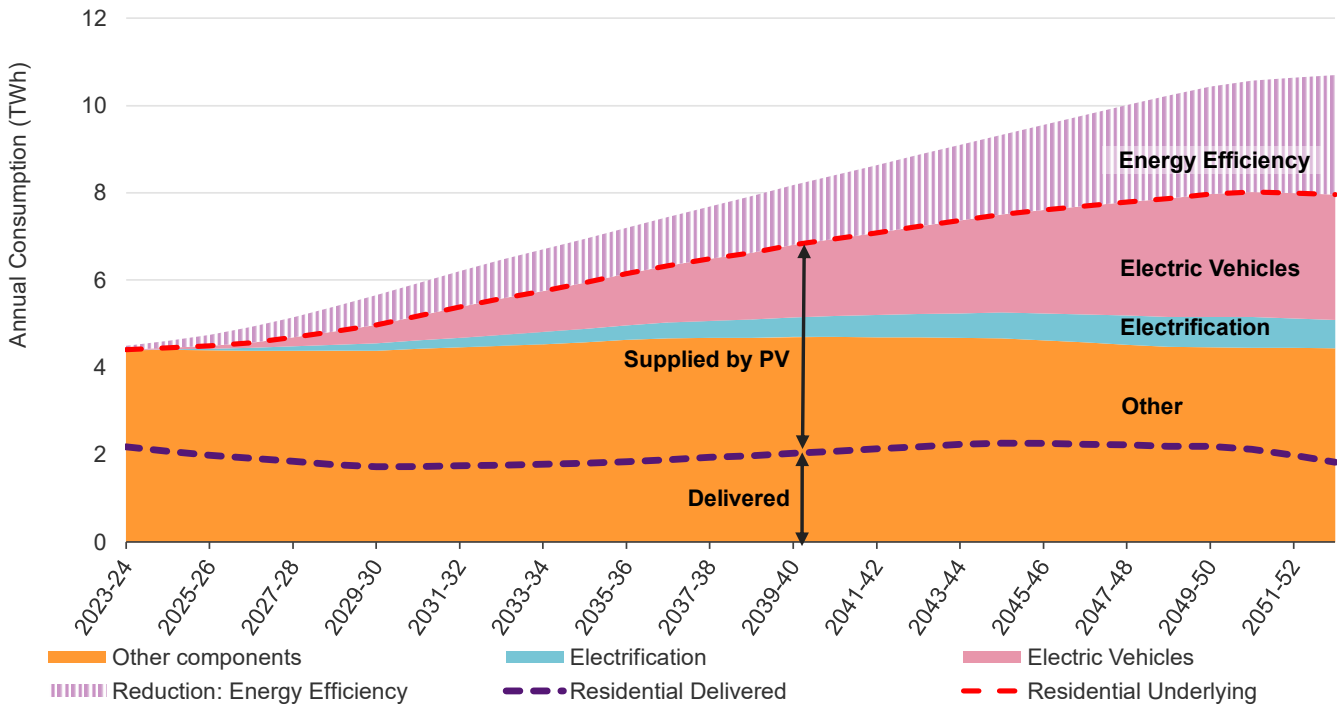
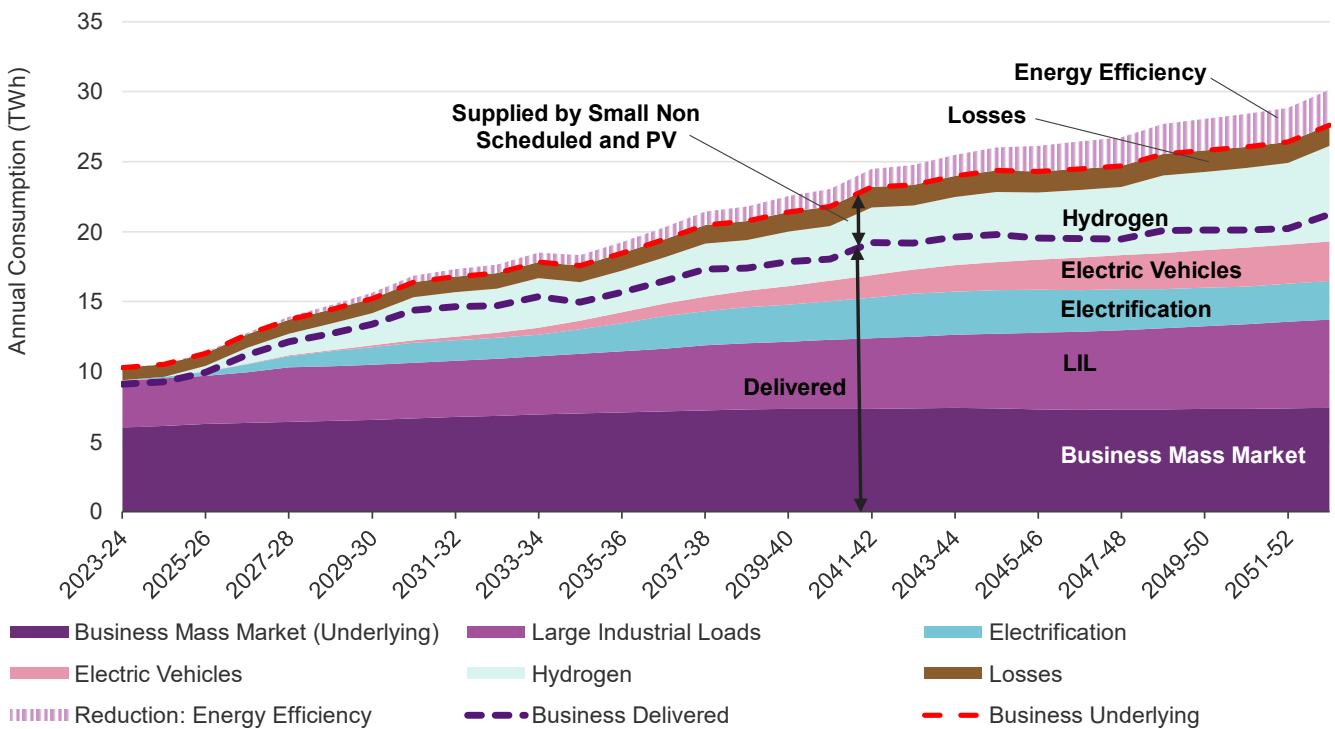


Figure 74 Components of South Australia business electricity consumption forecast, ESOO Central scenario, 2023-24 to 2052-53 (TWh)



Note: Small non-scheduled combines PVNSG and ONSG.

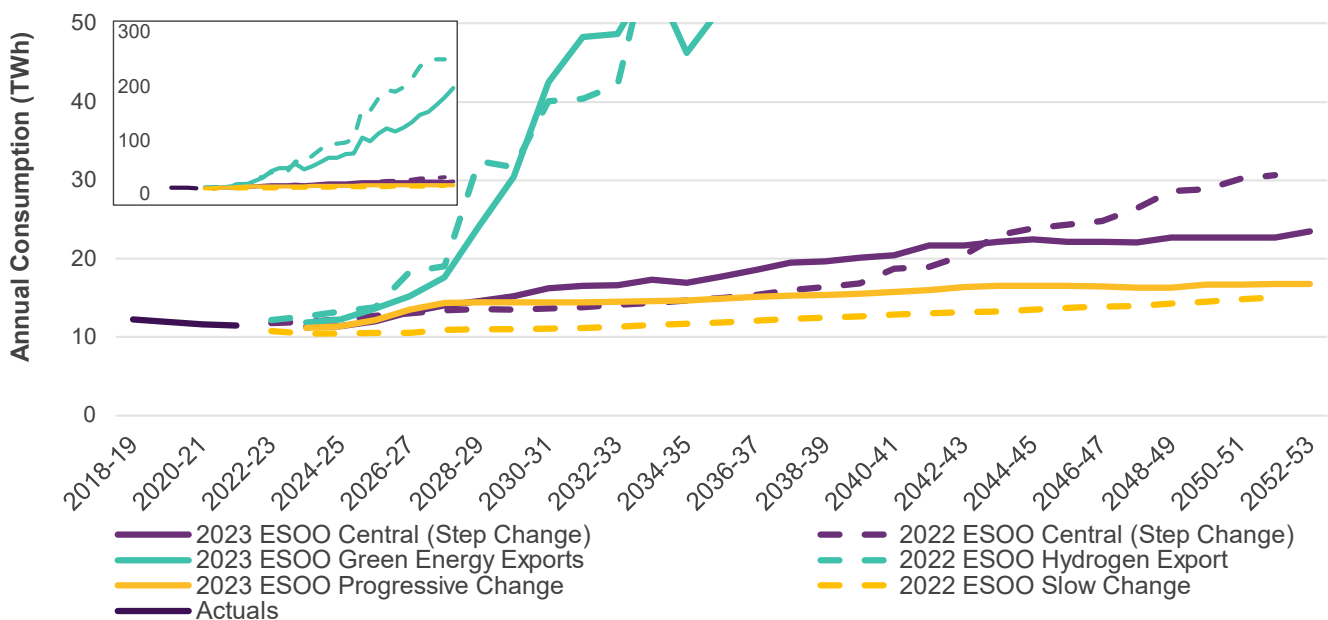
In this scenario, AEMO forecasts:

- Short term (1-10 years) – consumption growth driven by electrification, LIL growth and emerging hydrogen production to meet the South Australian Hydrogen Jobs Plan, tempered by continued uptake of distributed PV and energy efficiency investment. Growth in residential PV generation is expected to negate other residential consumption drivers.
- Medium term (11-20 years) – increasing electrification and EV uptake driving increasing consumption, partially offset by distributed PV and energy efficiency investments.
- Long term (21-30 years) – a slowing in business electrification and offset by continued investment in energy efficiency measures, distributed PV, and larger non-scheduled PV installations that collectively reduce operational consumption. Hydrogen production in this decade is forecast to grow at a slower but more consistent rate compared to the 2022 ES00.

Figure 75 shows forecasts across the scenarios, highlighting that:

- *Progressive Change* tracks closely to the ES00 Central scenario until 2027-28, after which LIL growth slows down. The higher forecasts relative to the 2022 ES00 *Slow Change* scenario reflect the inclusion of electrification and hydrogen production, consistent with Australia’s efforts to meet its NDC to the Paris Agreement of 43% reduction in emissions levels by 2030 relative to 2005 levels, and achieving net zero emissions by 2050.
- Hydrogen production for domestic and, in particular, export purposes dominates the growth trajectory of *Green Energy Exports*.

Figure 75 Actual and forecast South Australia operational consumption, all scenarios, 2017-18 to 2051-52 (TWh)

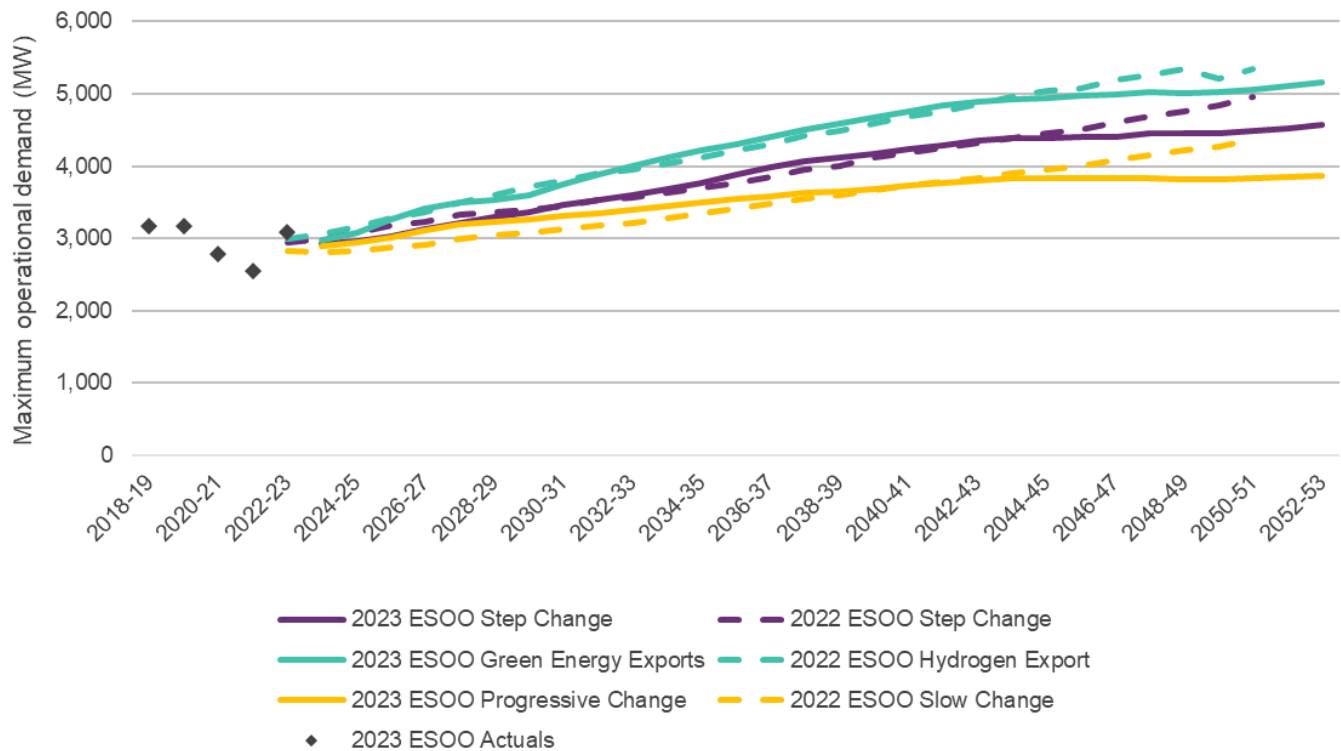


Note: 2022 ES00 *Hydrogen Export* and *Green Energy Exports* continue beyond the chart to reach approximately 250 TWh in 2051-52 and 197 TWh in 2052-53, respectively.

Maximum operational demand outlook

Figure 76 shows actual and forecast 50% POE maximum operational (sent-out) demand¹¹¹ from 2018-19 to 2052-53 for all scenarios in South Australia, compared to matching 2022 ESOO scenarios.

Figure 76 Actual and forecast South Australia 50% POE maximum operational (sent-out) demand, 2023 ESOO all scenarios and 2022 ESOO all scenarios, 2018-19 to 2052-53 (MW)



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

The key insights are:

- 2023-24 to 2032-33 (1-10 years):
 - Due to various factors offsetting each other, maximum operational demand is forecast to start at very similar levels in 2023-24 as forecast in the 2022 ESOO for all scenarios. The slightly higher *Progressive Change* forecast relative to the 2022 ESOO *Slow Change* scenario is attributed to higher residential consumption than that previously forecast.
 - The growth rate of maximum operational demand is similar to that projected in the 2022 ESOO. The *Step Change* scenario is slightly lower than the 2022 ESOO over this decade, primarily due to a lower relative forecast for LIL peak demand in the early years of the forecast.
- 2033-34 to 2042-43 (11-20 years):

¹¹¹ 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 LIL forecast for this decade is higher than the 2022 ESOO forecast for all scenarios. Lower energy efficiency investments relative to that forecast in 2022 is also contributing to higher demand forecasts.
- 2043-44 to 2052-53 (21-30 years):
 - Energy efficiency investments are forecast higher than in 2022, particularly for residential customers, dampening demand growth. Electrification is also forecast to slow over this decade. In addition, while EV uptake is forecast to grow, the impact of EV charging on maximum demand is expected to have a lower relative impact than the 2022 ESOO forecast based on a stronger expectation that charging profiles will become ‘smarter’, lowering the contribution to the evening peak.

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

Table 21 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 South Australia is forecast to continue occurring in the summer season over the forecast horizon.

Table 21 South Australia 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
2023-24	3,319	2,922	2024	2,668	2,583
2029-30	3,777	3,367	2030	3,121	3,018
2039-40	4,612	4,169	2040	3,873	3,740
2049-50	4,832	4,459	2050	4,095	3,962

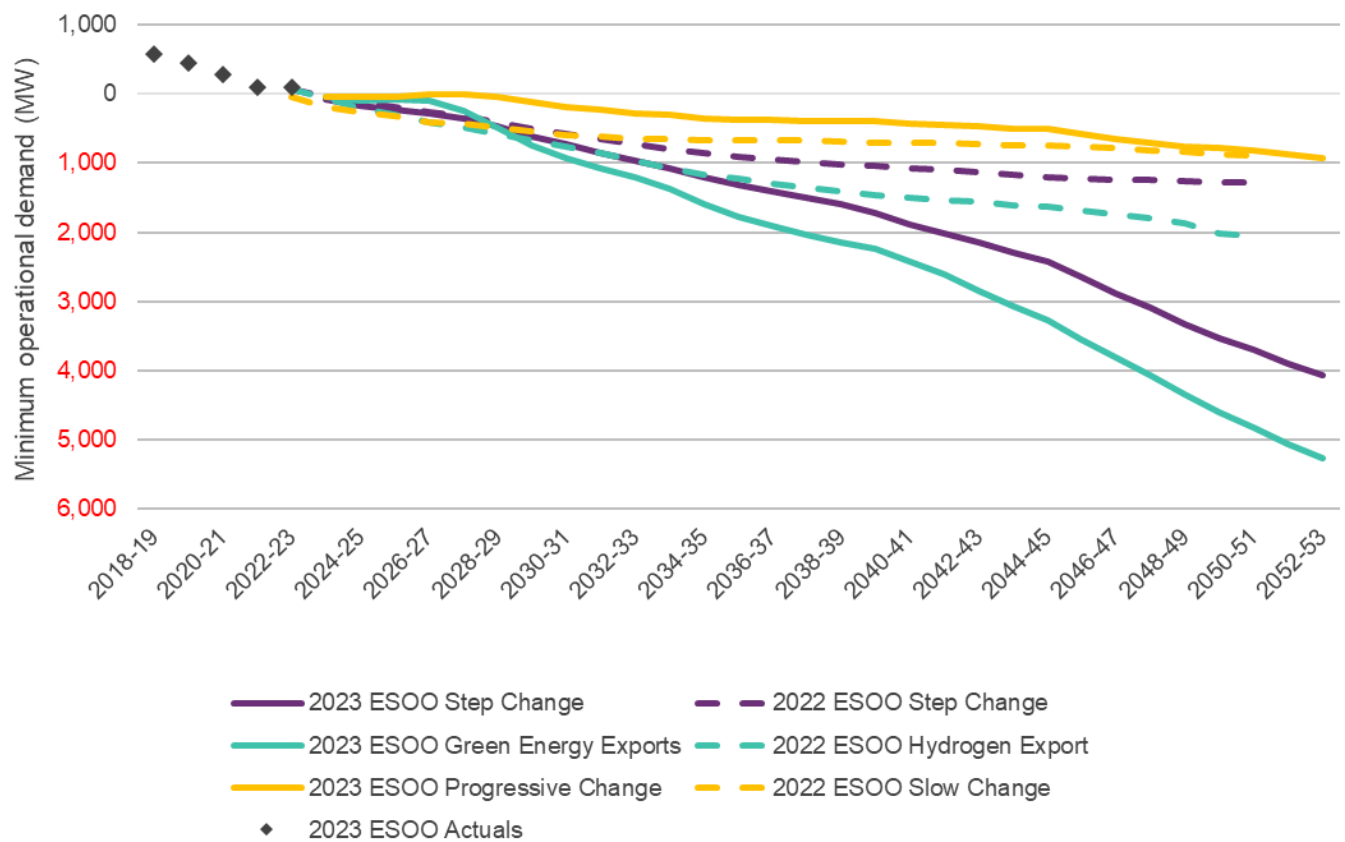
Minimum operational demand outlook

Figure 77 shows actual and forecast 50% POE minimum operational (sent-out) demand (MW) from 2018-19 to 2052-53 for the 2023 ESOO compared to the 2022 ESOO for all scenarios in South Australia. The key insights are:

- 2023-24 to 2032-33 (1-10 years):
 - Minimum operational demand is forecast to start at very similar levels in 2023-24 as the 2022 ESOO for *Step Change* and *Green Energy Exports*. The slightly higher *Progressive Change* forecast compared to the 2022 ESOO is attributed to lower energy efficiency.
 - The trend of the *Step Change* scenario closely aligns with the 2022 ESOO until the latter half of this decade when it gradually starts to deviate, becoming lower than the 2022 ESOO. This shift can be attributed to the anticipation of a higher number of PV installations entering the market and lower electrification during this period.
 - The higher *Green Energy Exports* forecast relative to the 2022 ESOO during the first half of this decade is because of the expansion of LIL. *Progressive Change* is above the 2022 ESOO *Slow Change* scenario due to a higher calibrated starting point in the forecast and lower PV capacity.
- 2033-34 to 2042-43 (11-20 years):

- Minimum operational demand is forecast to continue to decline for all scenarios. The *Step Change and Green Energy Exports* scenarios decline at a faster rate due to higher projected uptake of distributed PV and lower energy efficiency.
- 2043-44 to 2052-53 (21-30 years):
 - Minimum operational demand is forecast to continue to decline in all scenarios at a faster rate than the previous decade. This is due not only to the larger disparities in PV installation forecasts for this decade, but also to lower residential consumption and lower electrification exerting additional downward pressure on minimum demand.

Figure 77 Actual and forecast South Australia 50% POE minimum operational (sent-out) demand, 2022 ESOO all scenarios and 2021 ESOO all scenarios, 2018-19 to 2052-53 (MW)



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

Supply adequacy assessment

Relative to last summer, approximately 269 MW of additional VRE generation, and 250 MW/250 MWh of storage is expected to commence operation this summer. The following list represents the largest projects that are expected to commission over the ESOO horizon. Projects are listed at the date applied in modelling, which may vary from the commissioning data advised due to the application of default project commissioning delays:

- The 250 MW/250 MWh Torrens Island BESS is expected to be operational in 2023-24.
- From 2024-25, gas capacity increases due to the advised return to service of Torrens Island unit B1.
- The 200 MW/400 MWh Blyth BESS project is expected to become operational in 2025-26.

- The 357 MW Cultana Solar Farm project is expected to become operational in 2026-27.
- Both Osborne and Torrens Island B power stations (total 980 MW) have advised retirement in 2026-27.
- Numerous other gas generators totalling 383 MW are expected to retire in 2030 including Dry Creek, Mintaro, Port Lincoln and Snuggery power stations, followed by 12 out of 13 units of Hallett GT totalling 240 MW in 2032.

Figure 78 shows the aggregate impact of generator and storage commissioning and decommissioning assumptions.

Figure 78 South Australia assumed capability during typical summer conditions, by generation type, 2022-23 to 2032-33 (MW)

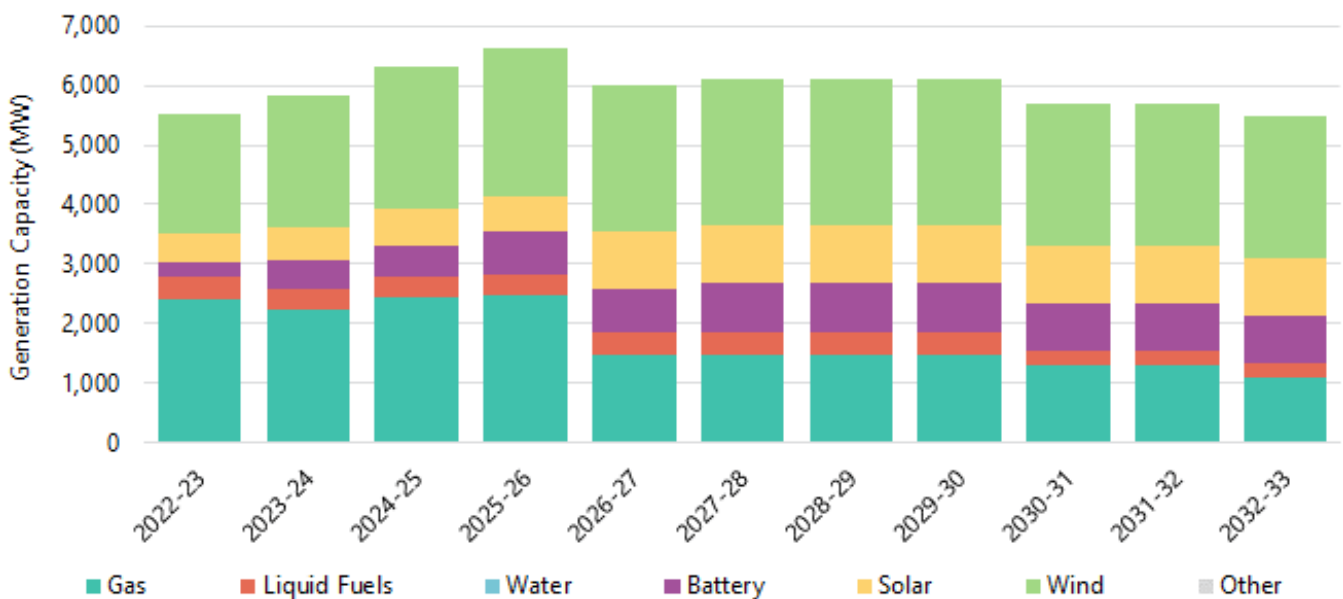


Figure 79 shows forecast USE for South Australia under the relevant modelled scenarios and sensitivities. It highlights that:

- The ESOO Central scenario projects USE greater than the IRM in 2023-24, but then expected USE decreases in 2024-25 due to the commissioning of the first stage of Project Energy Connect and the advised return to service of Torrens Island B1. From 2026-27, risks increase due to the advised retirement of Osborne Power Station and Torrens Island B Power Station. Reliability risks increase again in 2028-29 due to the retirement of Yallourn Power Station in Victoria and then again in 2030 and 2032 due to the retirement of various gas and liquid fuel generators. While new wind, solar and battery storage developments are expected to continue to connect in South Australia, Victoria and interconnected regions, these developments are not yet sufficient to offset expected generator retirements and the forecast increases in electricity demand.
- Additional insights from sensitivity analysis include:
 - Expected USE is forecast within the reliability standard until 2030-31 under the *CER Orchestration* sensitivity and the *Actionable transmission* sensitivity.
 - In the *Federal and state schemes* sensitivity and *Schemes without CER orchestration* sensitivity, reliability risks are forecast to remain within the reliability standard of 0.002% USE over the 10-year horizon.

- Under the 2023 ESOO *Eraring sensitivity*, forecast USE reduces in 2025-26 and particularly in 2026-27 compared with the Central scenario. This is due to the full commissioning of Project EnergyConnect, which increases inter-regional transfer capacity between New South Wales and South Australia.

Figure 79 South Australia expected USE, scenarios and sensitivities, 2023-24 to 2032-33 (%)

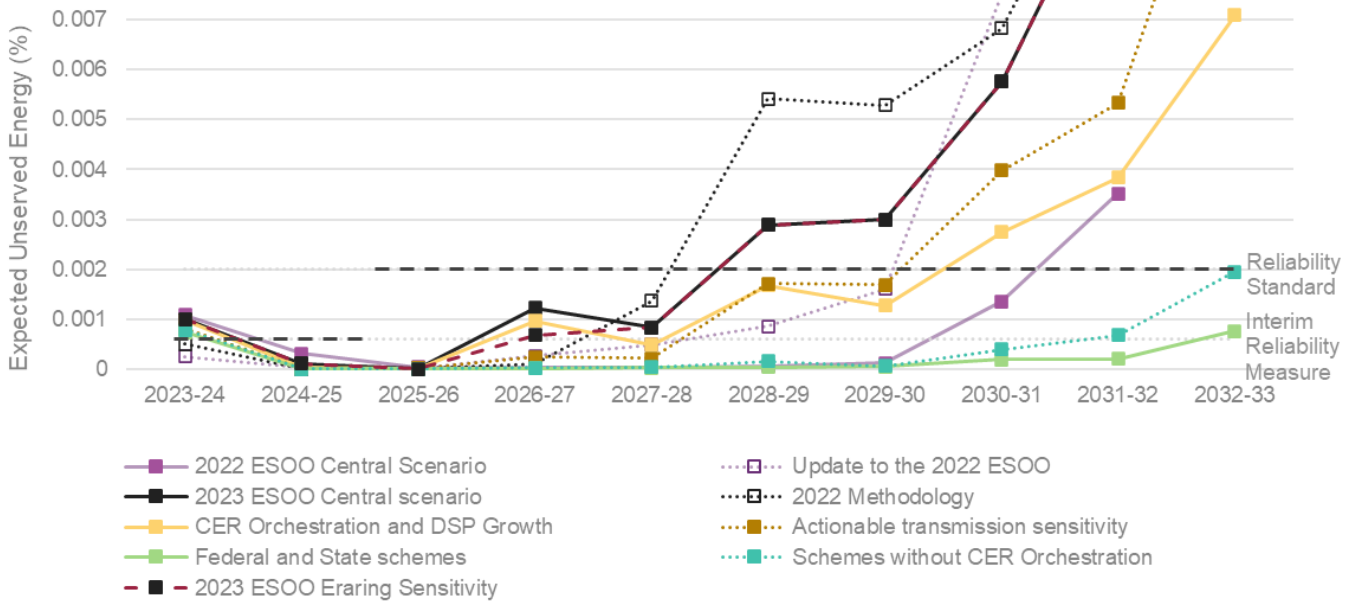


Figure 80 shows the reliability outcomes for South Australia in 2023-24 under different weather years. Under weather conditions similar to the 2014-15 and 2018-19 reference years, expected USE exceeds the reliability standard and IRM. Under weather conditions similar to the 2010-11 and 2017-18 reference years, expected USE exceeds the IRM, but is less than the reliability standard. Under all other reference years simulated, the outcome is less than the IRM. The average outcome exceeds the IRM but is within the reliability standard.

Figure 80 Reliability outcomes for South Australia in 2023-24 under different weather reference years, ESOO Central scenario

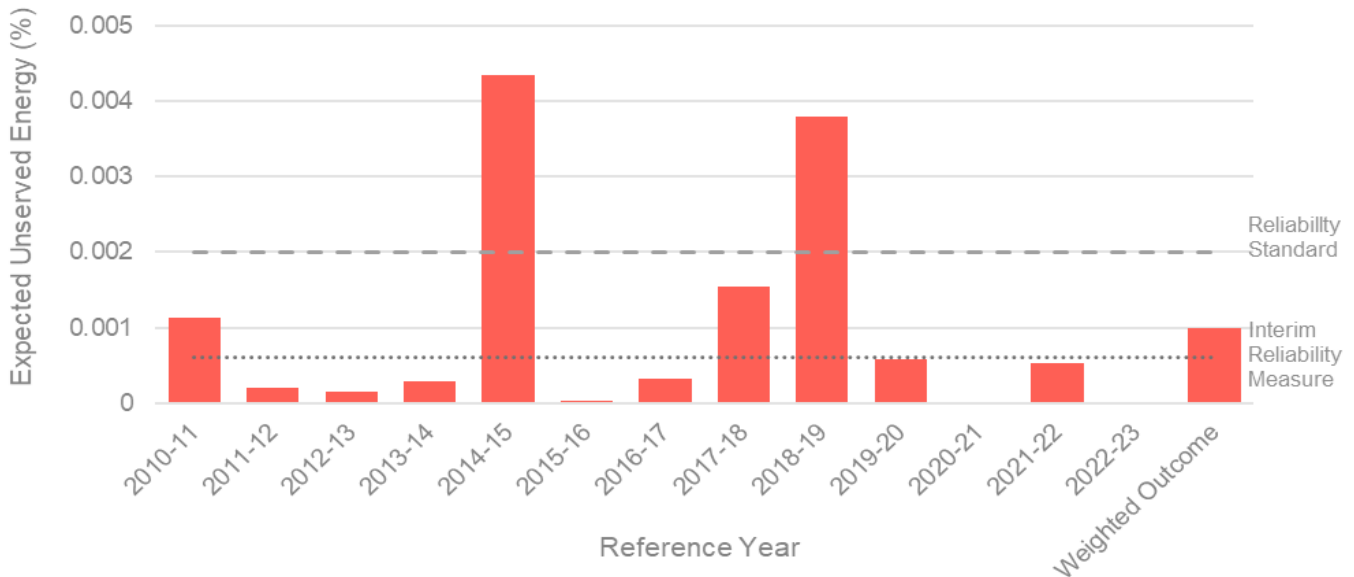
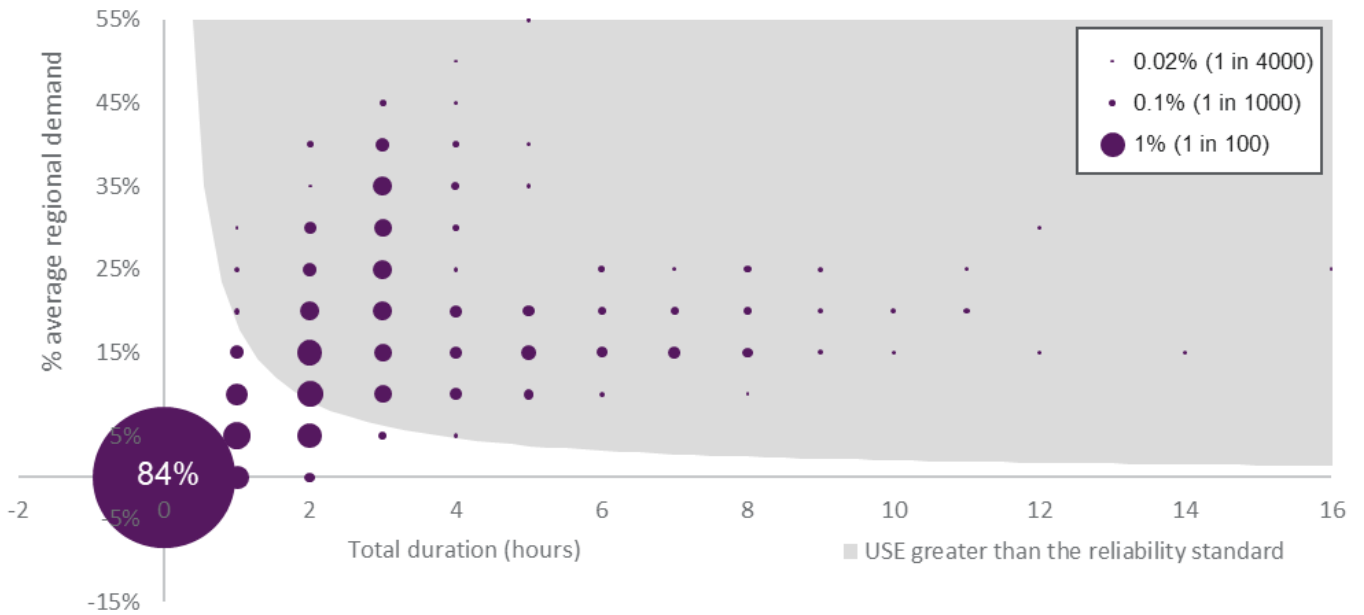


Figure 81 shows a bubble plot of the depth and duration of USE forecast in South Australia for 2023-24 in the ESOO Central scenario, as also shown in **Section 4.3**. It shows that the most likely outcome is that USE does not occur in the coming year (the large purple dot), but that there is a 16% probability of a USE outcome. For those simulation outcomes that did have USE, the total number of hours experiencing USE was likely to be 1-3 hours in duration, and of average depth up to 35% of average regional load.

Figure 81 Bubble plot of depth and duration of forecast USE in South Australia 2023-24, ESOO Central scenario



A4. Tasmania outlook

The following sections present, for Tasmania:

- Operational consumption, maximum demand, and minimum demand outlooks for all three scenarios to 2052-53.
- Supply adequacy assessments for the next 10 years, for the ESOO Central scenario, and other sensitivities published in this ESOO.

Annual consumption outlook

Figures 82 to 84 show the component forecasts for operational consumption in Tasmania under the ESOO Central scenario.

Figure 82 Actual and forecast Tasmania electricity consumption, ESOO Central scenario, 2018-19 to 2052-53 (TWh)

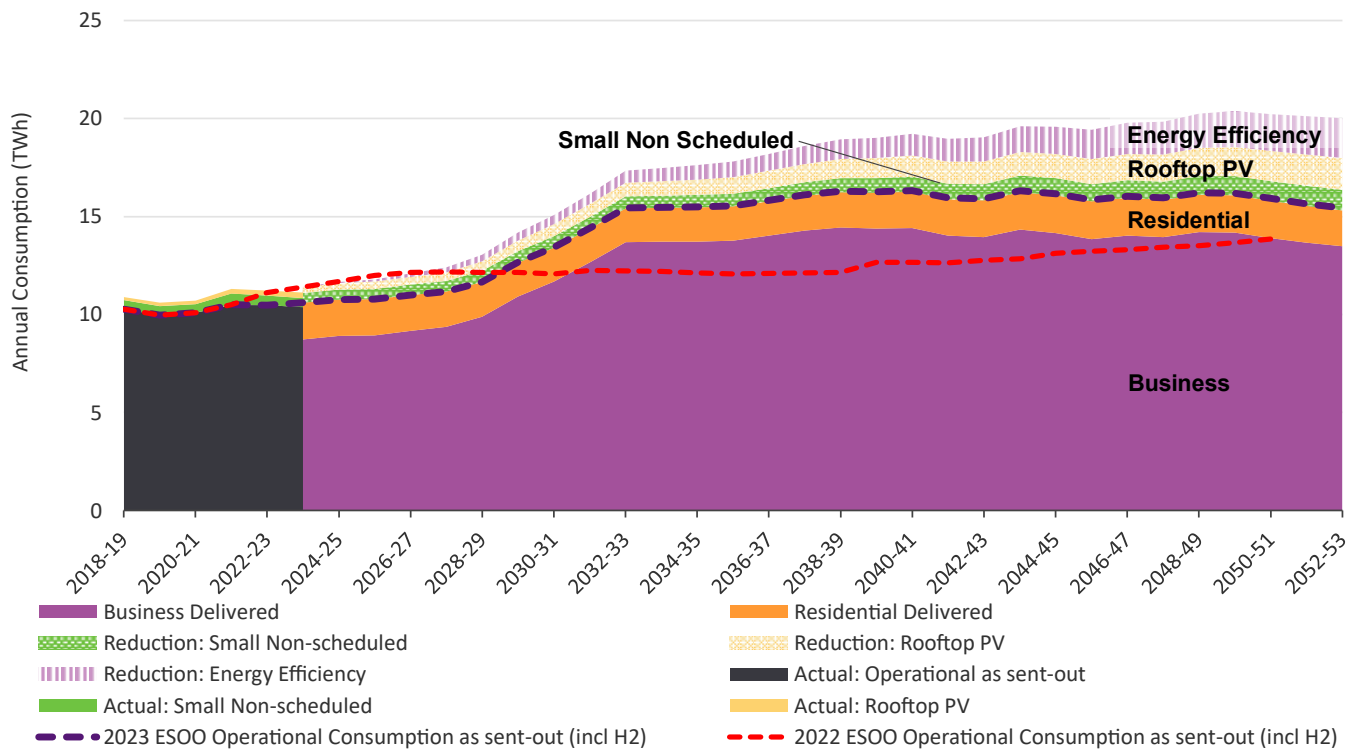


Figure 83 Components of Tasmania residential electricity consumption forecast, ESOO Central scenario, 2023-24 to 2052-53 (TWh)

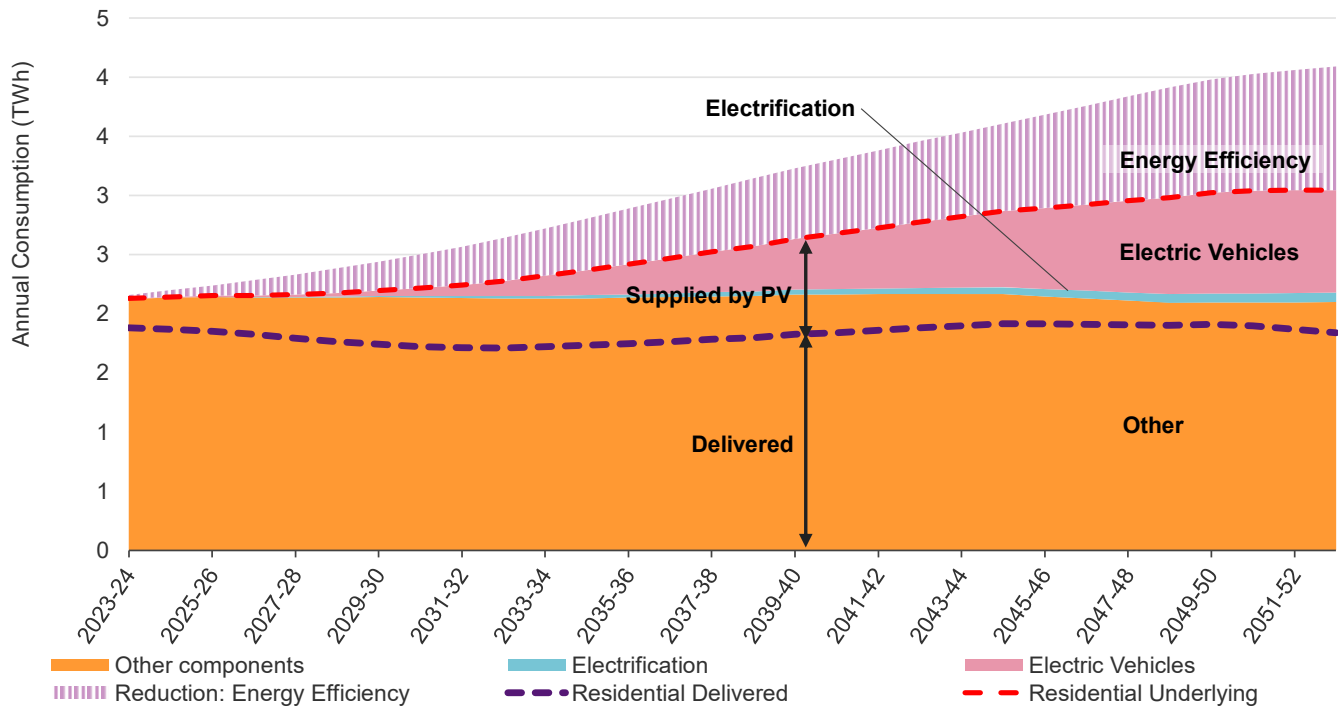
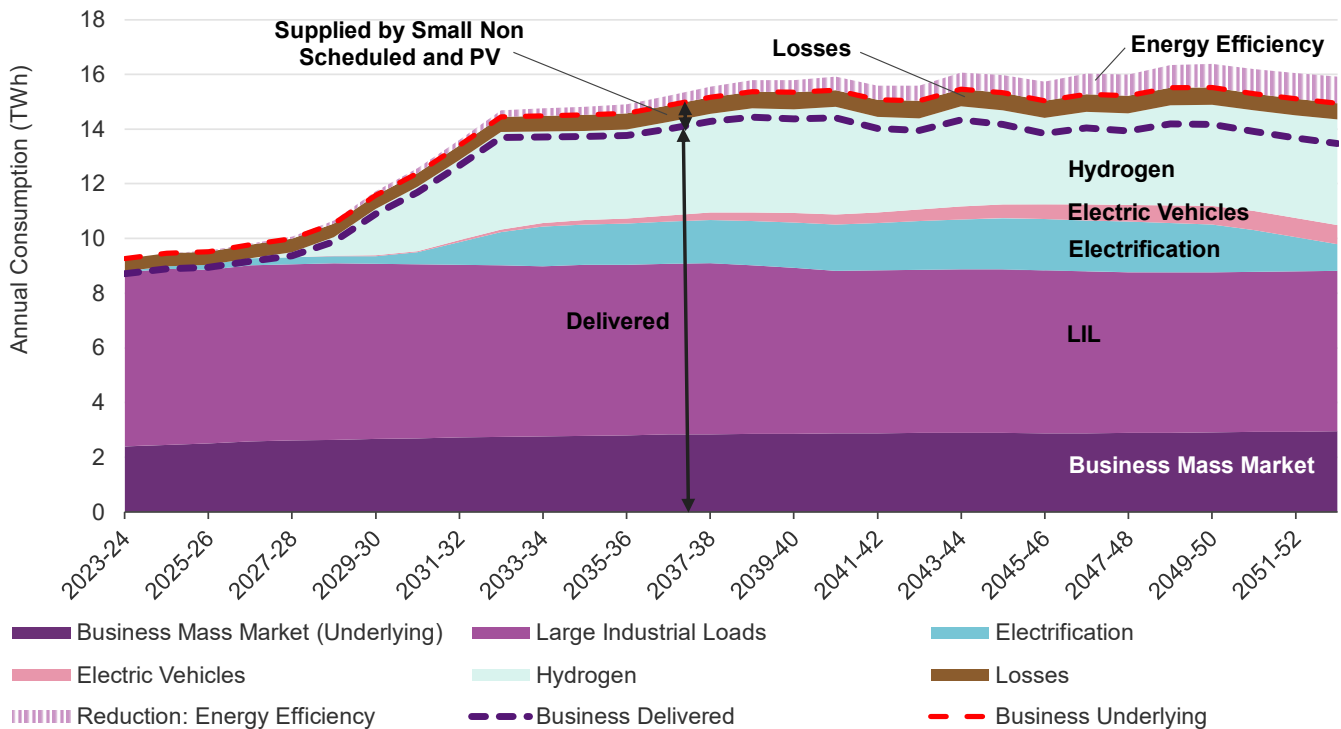


Figure 84 Components of Tasmania business electricity consumption forecast, ESOO Central scenario, 2023-24 to 2052-53 (TWh)



Note: Small non-scheduled combines PVNSG and ONSG.

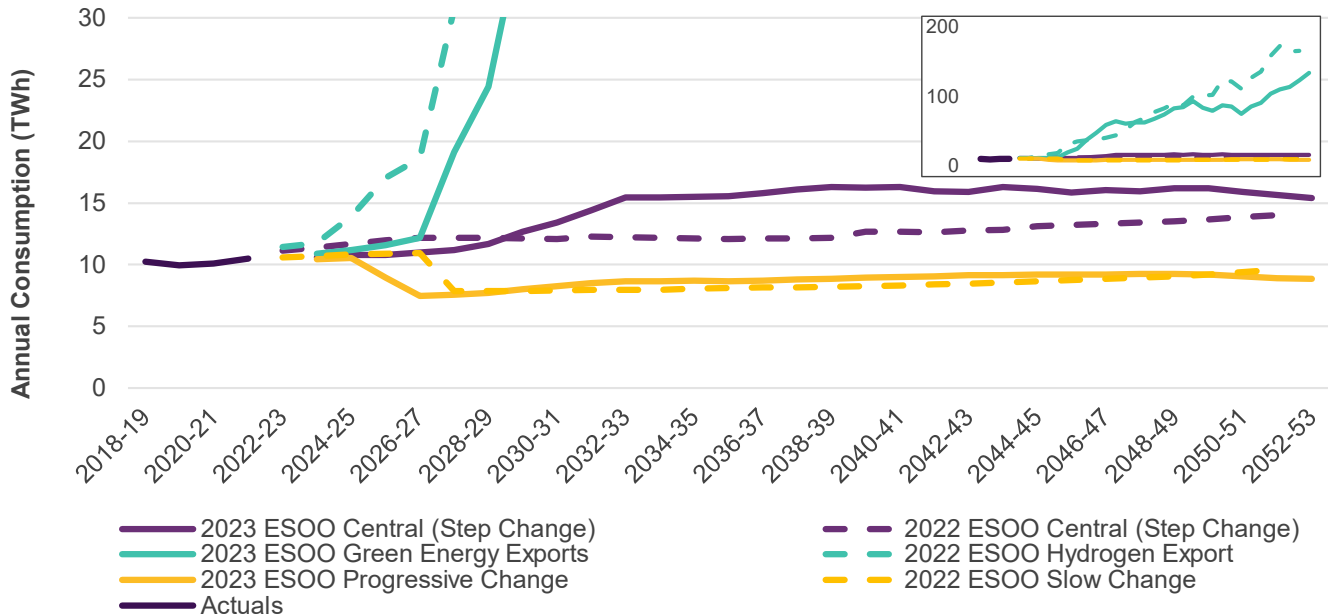
In this scenario, AEMO forecasts:

- Short term (1-10 years) – higher consumption in the second half of the decade compared to the 2022 ESOO, largely due to the anticipated emergence of the hydrogen production industry. This increase is partially offset by a lower BMM and business electrification forecast than in the 2022 ESOO. LIL and distributed PV forecasts are expected to be stable over this time.
- Medium term and long term (11-20 years and 21-30 years) – slowing growth in consumption, with positive growth driven by an increase in business electrification in agriculture and the uptake of EVs and offset with increased penetration of distributed PV and energy efficiency investment.

Figure 85 shows forecasts across the scenarios, highlighting that:

- *Progressive Change* follows a similar trajectory to the 2022 ESOO *Slow Change* scenario. As in previous ESOO forecasts, the scenario also explored the impact of potential LIL closure risk. This scenario included some electrification and hydrogen production for the domestic market, consistent with Australia’s efforts to meet its NDC to the Paris Agreement of 43% reduction in emissions levels by 2030 relative to 2005 levels, and achieving net zero emissions by 2050. However, a reduction in forecast BMM load growth partially offsets these consumption drivers.
- *Green Energy Exports* ramps up in the late 2020s due to hydrogen production for the domestic and, in particular, export market. To a lesser extent, relatively higher electrification, EV uptake and LIL expansion also drive this scenario above ESOO Central.

Figure 85 Actual and forecast Tasmania operational consumption, including hydrogen exports, all scenarios, 2018-19 to 2052-53 (TWh)

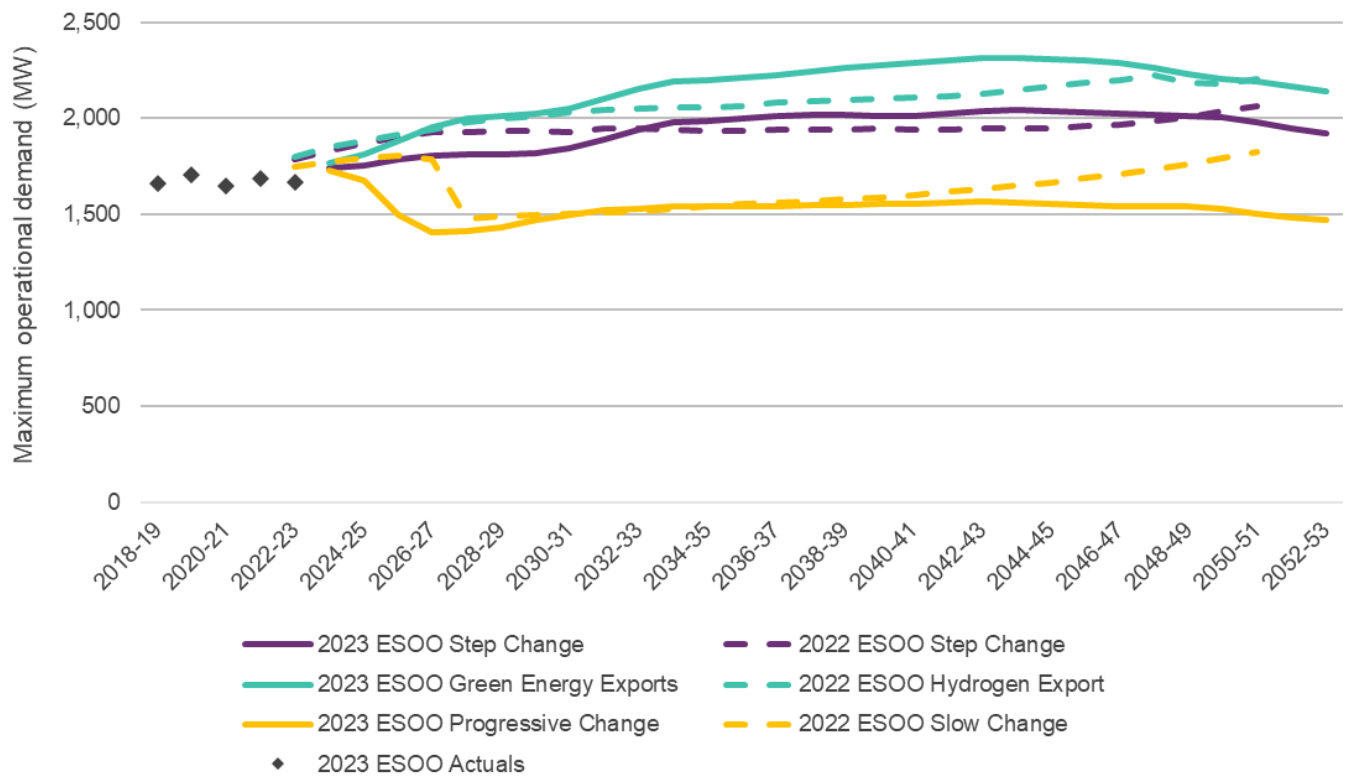


Note: 2022 ESOO Hydrogen Export and Green Energy Exports continue beyond the chart to reach approximately 166 TWh in 2051-52 and 134 TWh in 2052-53, respectively.

Maximum operational demand outlook

Figure 86 shows actual and forecast 50% POE maximum operational (sent-out) demand¹¹² from 2018-19 to 2052-53 for all scenarios in Tasmania, compared to matching 2022 ESOO scenarios.

Figure 86 Actual and forecast Tasmania 50% POE maximum operational (sent-out) demand, 2022 ESOO all scenarios and 2021 ESOO all scenarios, 2018-19 to 2052-53 (MW)



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

The key insights are:

- 2023-24 to 2032-33 (1-10 years):
 - Maximum operational demand is forecast to start lower in 2023-24 than in the 2022 ESOO for all scenarios, as a result of reductions in the pace of electrification investment that has not yet impacted actual outcomes in the manner originally forecast, partially offset by lower energy efficiency.
 - *Step Change* is lower than the 2022 ESOO, attributed to lower near-term LIL consumption as informed by surveyed operators. Growth over the decade is largely driven by electrification and growth in LIL consumption in the later years.
 - As in previous forecasts, the *Progressive Change* scenario also considered the impact of risks of LIL closures that may result in a reduction in forecast maximum operational demand. For this ESOO those risks have been forecast slightly earlier than in the 2022 ESOO.

¹¹² 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/>.

- 2033-34 to 2042-43 (11-20 years) and 2043-44 to 2052-53 (21-30 years):
 - Maximum operational demand is forecast to remain relatively flat in all scenarios as the increasing underlying demand is offset by lower energy efficiency. *Green Energy Exports* increases slightly due to the upward trend in LIL consumption. Despite the increasing demand for EVs, their impact on maximum demand is expected to be weaker compared to the projections in 2022 ESOO, with greater expectations for smarter charging profiles. The long-term drivers of maximum operational demand are relatively stable, with some factors that may influence peak demand reductions in the longer term.

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 were included in the maximum operational demand forecasts.

Table 22 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 22 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
2023-24	1,439	1,396	2024	1,789	1,737
2029-30	1,505	1,464	2030	1,873	1,819
2039-40	1,688	1,650	2040	2,065	2,009
2049-50	1,677	1,635	2050	2,062	2,005

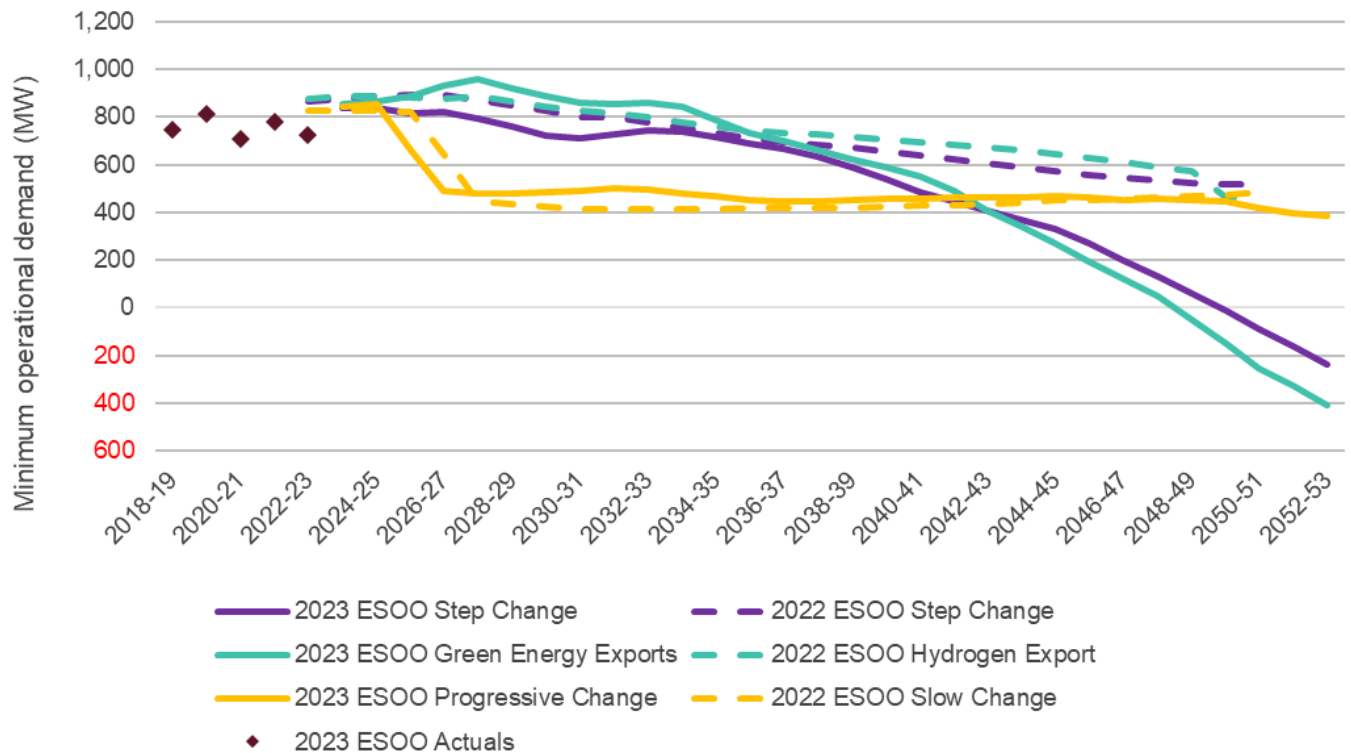
Minimum operational demand outlook

Figure 87 shows actual and forecast 50% POE minimum operational (sent-out) demand (MW) from 2018-19 to 2052-53 for the 2023 ESOO compared to the 2022 ESOO for all scenarios in Tasmania. The key insights are:

- 2023-24 to 2032-33 (1-10 years):
 - Minimum operational demand is forecast to be lower for *Step Change* than in the 2022 ESOO, due to lower operational consumption. *Green Energy Exports* is higher than 2022 ESOO because of the expansion of LIL, while *Progressive Change*'s earlier reduction than the 2022 forecast reflects the earlier applied closure risk, as outlined previously.
 - Minimum operational demand is forecast to decrease as the projected uptake of distributed PV applies downward pressure on minimum operational demand. *Progressive Change* remains relatively flat, mainly due to its lower PV growth relative to other scenarios, and lower energy efficiency which offsets some of the downward pressure on demand.
- 2033-34 to 2042-43 (11-20 years):
 - In the *Step Change* and *Green Energy Exports* scenarios, it is forecast to decline at a faster rate than the 2022 ESOO forecasts, as more rooftop PV and PVNSG are forecast to enter the market while the higher LIL demand offsets some of the PV impact.

- *Progressive Change* is flat because LIL remains stable, and the slow growth of PV, EV, and the adjusted lower energy efficiency offset each other.
- 2043-44 to 2052-53 (21-30 years):
 - The trend remains similar to the previous decade, with rooftop PV and PVNSG continuing to show steady growth.

Figure 87 Actual and forecast Tasmania 50% POE minimum operational (sent-out) demand, 2023 ESOO all scenarios and 2022 ESOO all scenarios, 2018-19 to 2052-53 (MW)



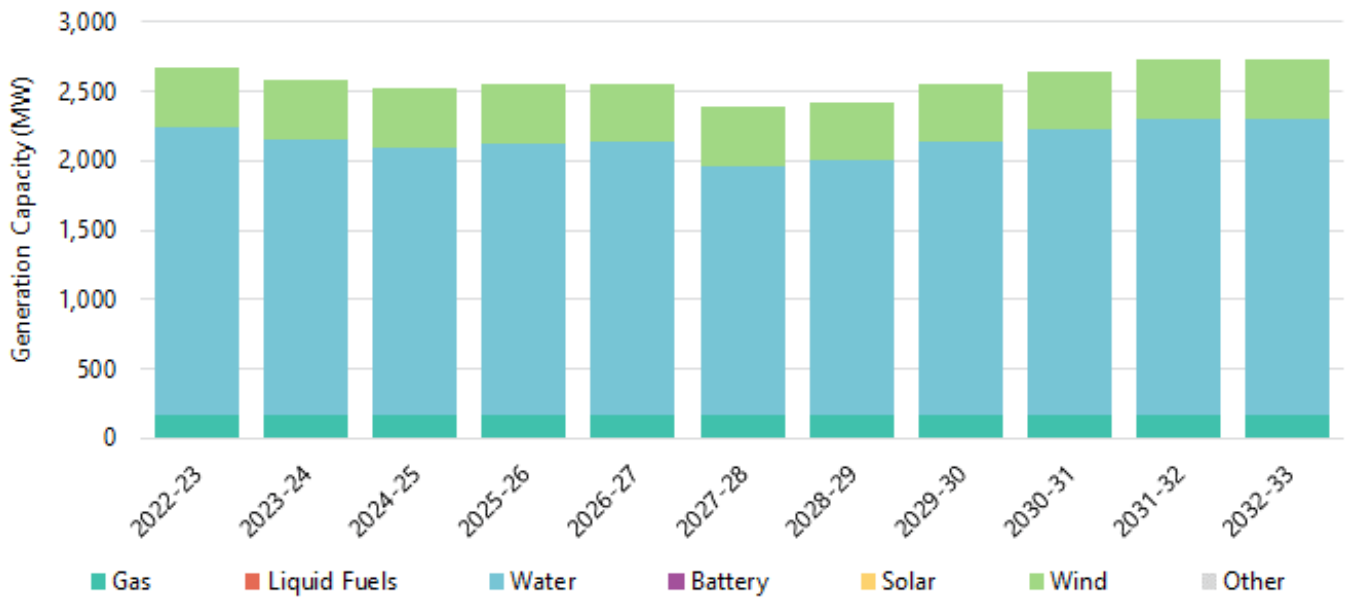
Note: The actuals displayed are not weather-corrected or adjusted for system events and exclude DSP.

Supply adequacy assessment

There are currently no projects that are classified as either committed or anticipated expected to commence operations in Tasmania during the 2023 ESOO modelling horizon, when compared against AEMO’s commitment criteria.

Figure 88 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 from Hydro Tasmania. As Tasmania has greater capacity requirements in winter, summer maintenance schedules are typical.

Figure 88 Tasmania assumed capability during typical summer conditions, by generation type, 2022-23 to 2032-33 (MW)



No USE is forecast for Tasmania in any of the scenarios or sensitivities modelled in this ESOO.

A5. Victoria outlook

The following sections present, for Victoria:

- Operational consumption, maximum demand, and minimum demand outlooks for all three scenarios to 2052-53.
- Supply adequacy assessments for the next 10 years, for the ESOO Central scenario, and other sensitivities published in this ESOO.

Annual consumption outlook

Figures 89 to 91 show the component forecasts for operational consumption in Victoria under the ESOO Central scenario.

Figure 89 Actual and forecast Victoria electricity consumption, ESOO Central scenario, 2018-19 to 2052-53 (TWh)

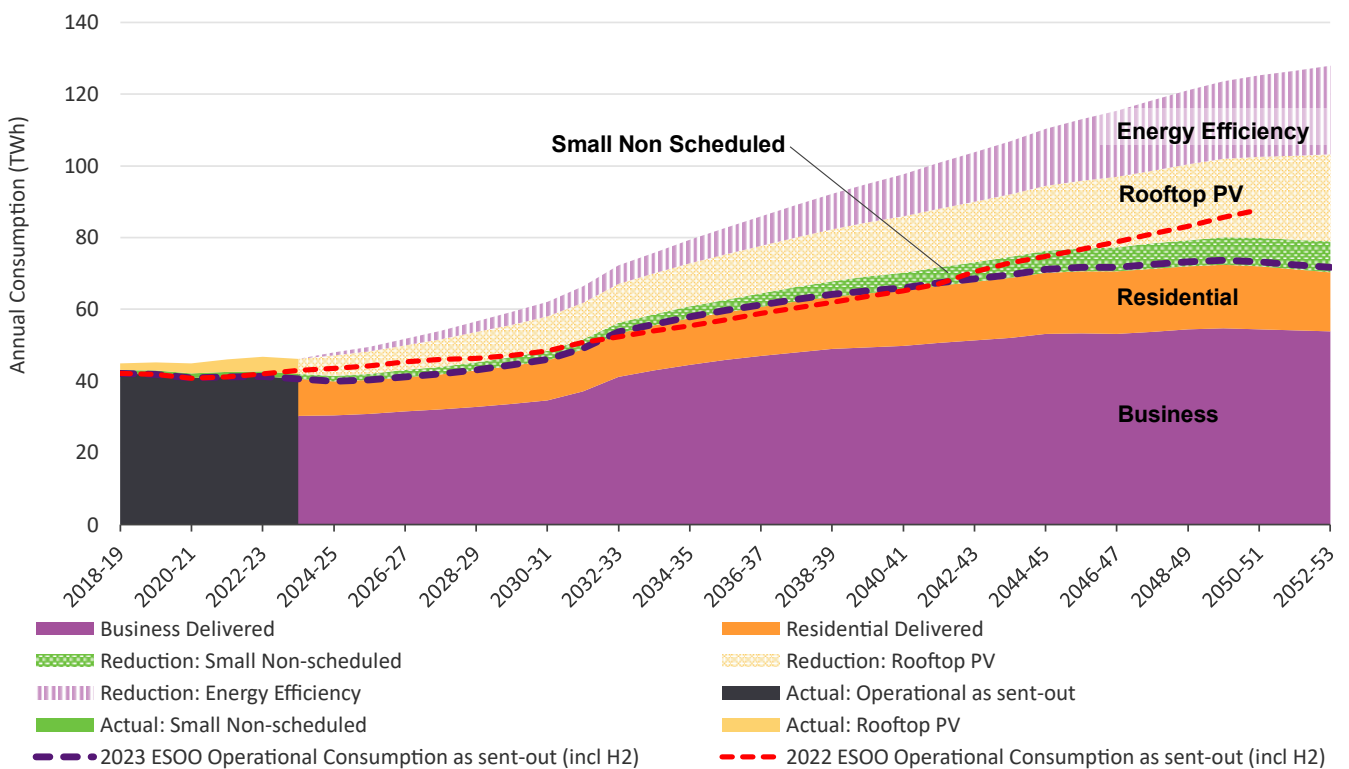


Figure 90 Components of Victoria residential electricity consumption forecast, ESOO Central scenario, 2023-24 to 2052-53 (TWh)

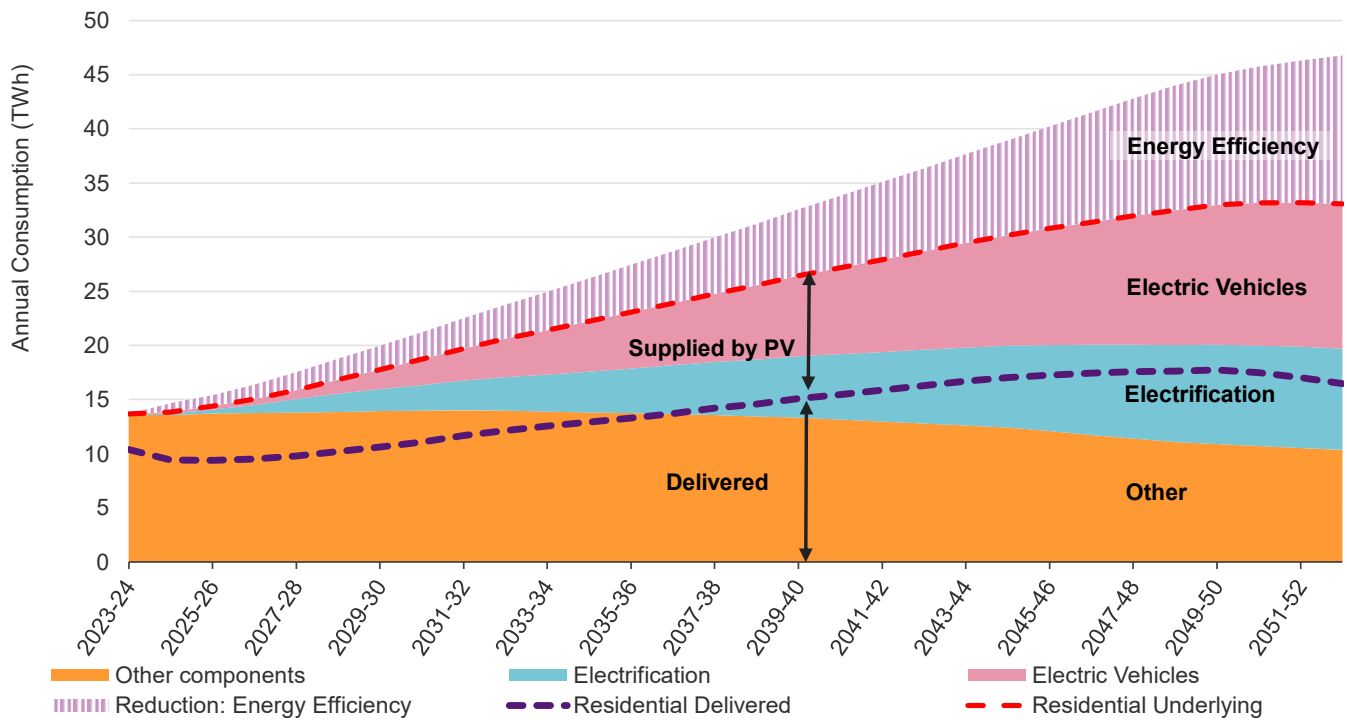
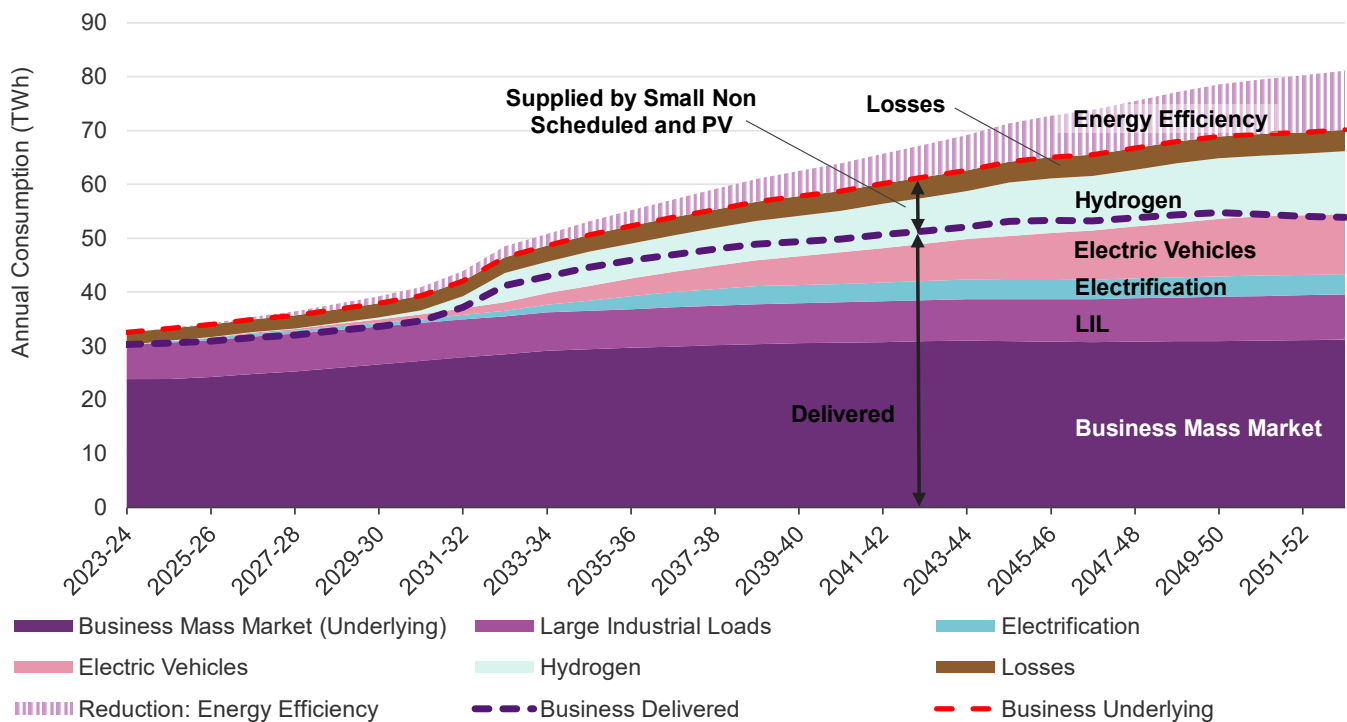


Figure 91 Components of Victoria business electricity consumption forecast, ESOO Central scenario, 2023-24 to 2052-53 (TWh)



Note: Small non-scheduled combines PVNSG and ONSG.

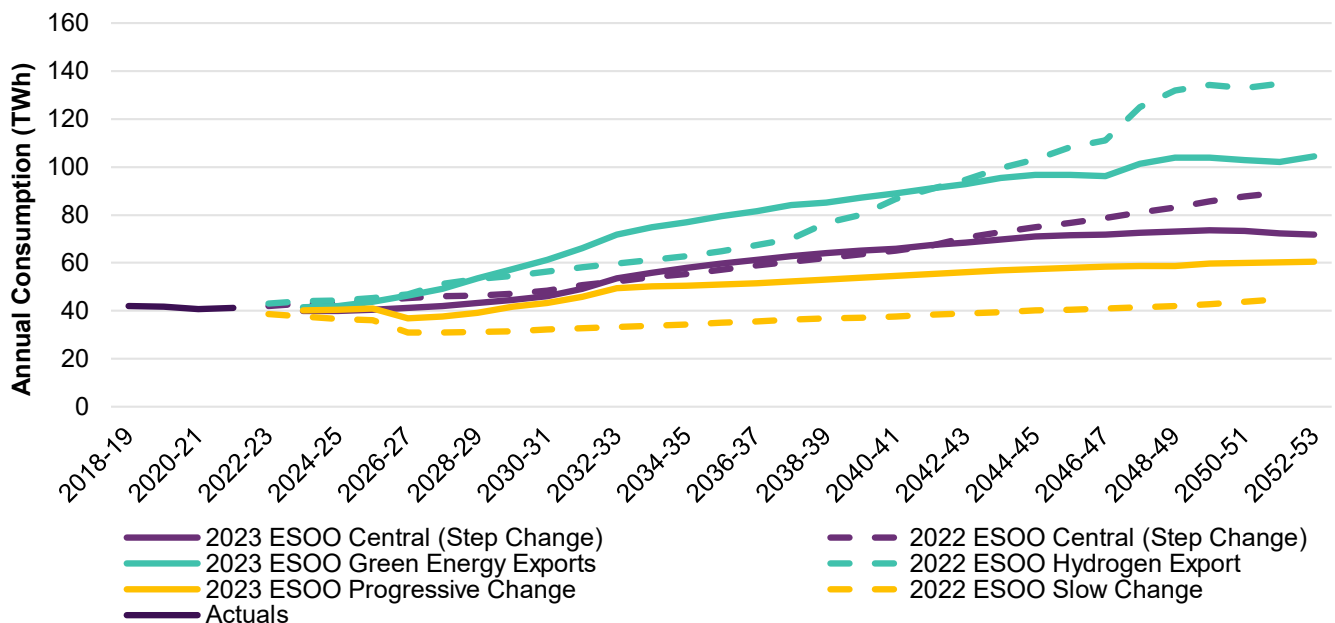
In this scenario, AEMO forecasts:

- Short-term (1-10 years) – a gradual increase in consumption in the first half of the decade from residential and business electrification, which is largely offset by uptake of PV. Consumption ramps up in the second half of the decade from growth in domestic hydrogen production and significant adoption of EVs. BMM load and electrification are forecast to steadily increase during this time¹¹³.
- Medium-term (11-20 years) – strong consumption growth as EVs continue to replace petrol- and diesel-powered vehicles. Residential and business electrification as well as domestic hydrogen production further contribute to the growth observed. Uptake of energy efficiency measures and PV partially offsets this growth.
- Long-term (21-30 years) – similar growth trends continuing from the preceding decade, but at a slower pace. Increased energy efficiency investment is projected to significantly curb consumption growth, as is strong uptake of distributed PV.

Figure 92 shows forecasts across the scenarios, highlighting that:

- *Progressive Change* contains the lowest consumption forecast, due to early LIL closure risks, and relatively limited electrification and hydrogen production. The higher forecast relative to the 2022 ESOO *Slow Change* scenario reflects the inclusion of electrification and hydrogen production, consistent with Australia’s efforts to meet its NDC to the Paris Agreement of 43% reduction in emissions levels by 2030 relative to 2005 levels, and achieving net zero emissions by 2050.
- Domestic production of hydrogen dominates the *Green Energy Exports* growth trajectory, although updates to Victoria’s hydrogen production forecasts result in a lower longer-term outlook compared to the 2022 ESOO *Hydrogen Export* scenario.

Figure 92 Actual and forecast Victoria operational consumption, including hydrogen exports, all scenarios, 2018-19 to 2052-53 (TWh)

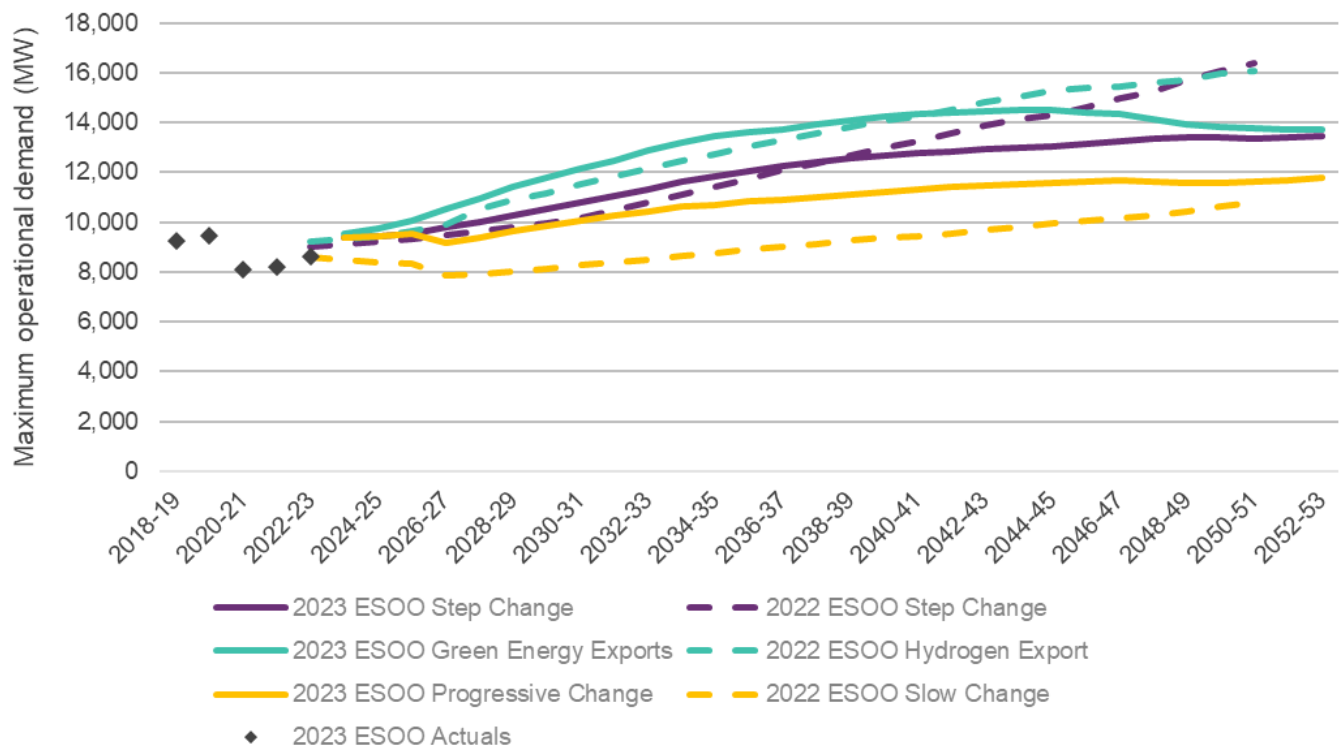


¹¹³ The Victorian Government has banned gas connections in new homes and government buildings, which will likely most impact winter consumption. While the electrification adjustment accounts for customers partially or fully switching away from gas, the announcement has not been explicitly modelled in this ESOO.

Maximum operational demand outlook

Figure 93 shows actual and forecast 50% POE maximum operational (sent-out) demand¹¹⁴ from 2018-19 to 2052-53 for all scenarios in Victoria, compared to matching 2022 ESOO scenarios.

Figure 93 Actual and forecast Victoria 50% POE maximum operational (sent-out) demand, 2023 ESOO all scenarios and 2022 ESOO all scenarios, 2018-19 to 2052-53 (MW)



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

The key insights are:

- 2023-24 to 2032-33 (1-10 years):
 - The 2023 ESOO includes a slight increase compared to the 2022 ESOO, as a result of various factors, including improved forecasting methods to increase forecast accuracy of the base year (see **Chapter 8**).
 - The growth rate is similar to that forecast in the 2022 ESOO, mainly due to the continuous and steady increase in underlying consumption. The influence of consumption growth will shift over time, as PV growth offsets annual consumption much more significantly than it reduces maximum demand, particularly as the maximum demand tends to occur between 6:00 pm and 8:00 pm, when there will generally not be enough sunlight to generate any significant PV output.
 - As in previous forecasts, the *Progressive Change* scenario also considered the impact of risks of LIL closures that may result in a reduction in forecast maximum operational demand.

¹¹⁴ 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/>.

- All scenarios show slightly higher values than the 2022 ESOO, because the starting point has been raised, while the growth rate is comparable.
- 2033-34 to 2042-43 (11-20 years):
 - Due to the relatively steady growth of the business sector, maximum demand also increases accordingly, even after accounting for the offset from energy efficiency, which dampens growth towards the end of the period.
 - Relative to the 2022 ESOO, there is less assumed electrification, higher forecast energy efficiency and also more flexible EV charging assumed that has a lesser impact on maximum demand. The combined net impact of these factors results in the 2023 ESOO being higher during the early part of the decade but gradually being surpassed by the 2022 ESOO in the later part.
- 2043-44 to 2052-53 (21-30 years):
 - Due to the declining trend of residential consumption over this period (partly due to higher energy efficiency) and a flattening trend in electrification, the maximum demand forecast shows only slight growth in the *Step Change* and *Progressive Change* scenarios in the first few years after 2044 before plateauing. In the *Green Energy Export* scenario, consumption is projected to experience a more significant decline after 2045, with even stronger energy efficiency measures forecast, resulting in a similar downward trend in maximum demand. Maximum operational demand is forecast to switch from occurring in the summer season to the winter season in the ESOO Central scenario, due to the contribution from the electrification of heating loads.

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 were included in the maximum operational demand forecasts.

Table 23 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 2045-46 (it was 2031-32 in 2022 ESOO; the 2023 forecast switches the peak season later than in the 2022 scenarios because of the reduction in the magnitude of electrification¹¹⁵) in the 50% POE forecast. The 10% POE summer forecast remains higher than the winter in the medium term, due to the cooling demand on extremely hot summer days exceeding the heating demand on extremely cold winter days.

Table 23 Victoria summer and winter 10% and 50% POE maximum operational (sent-out) demand forecast, *Step Change* scenario, 2023-24 to 2049-50 (MW)

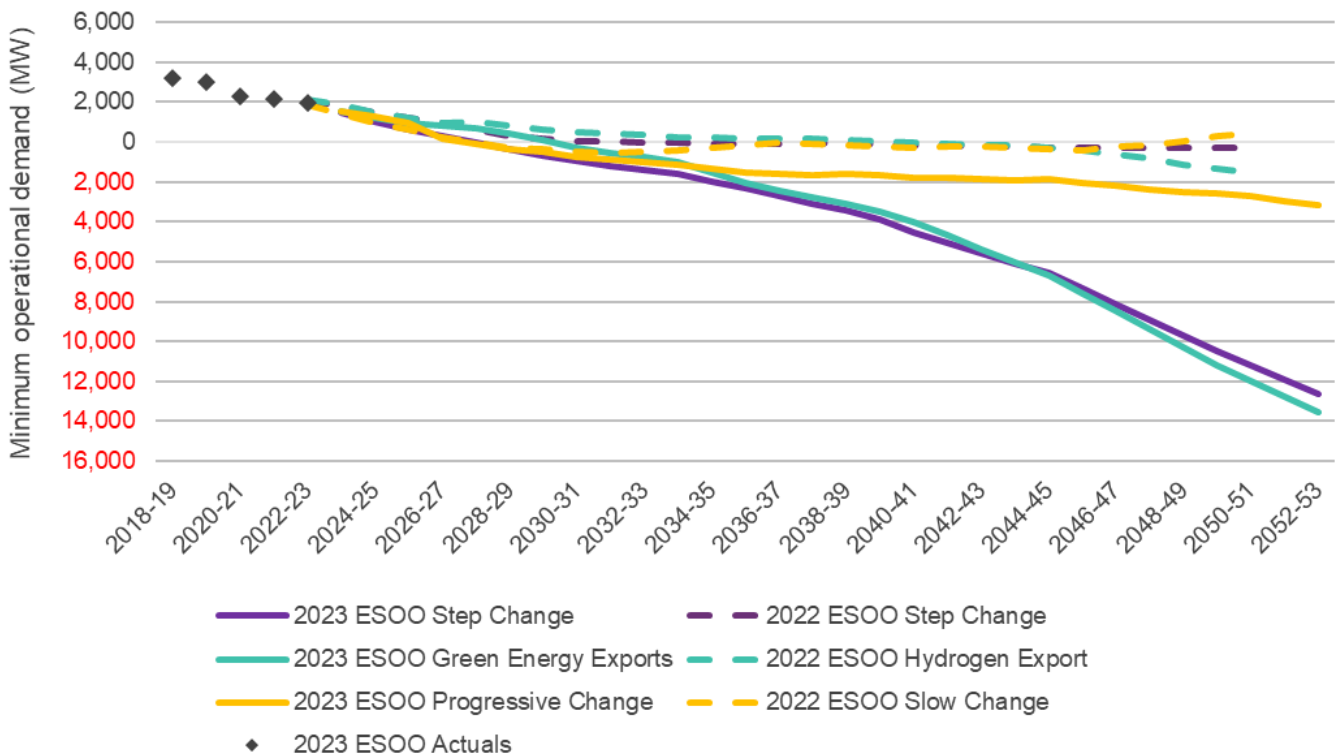
Financial year	Summer		Calendar year	Winter	
	10% POE	50% POE		10% POE	50% POE
2023-24	10,178	9,370	2024	8,074	7,879
2029-30	11,403	10,518	2030	9,790	9,578
2039-40	13,685	12,695	2040	12,540	12,324
2049-50	14,088	13,075	2050	13,660	13,433

¹¹⁵ The announcement to ban new residential gas connections was announced too late for explicit inclusion in this forecast, although the impact of heating electrification has been considered.

Minimum operational demand outlook

Figure 94 shows actual and forecast 50% POE minimum operational (sent-out) demand from 2017-18 to 2053-54 for the 2023 ESOO compared to the 2022 ESOO for all scenarios in Victoria.

Figure 94 Actual and forecast Victoria 50% POE minimum operational (sent-out) demand, 2023 ESOO all scenarios and 2022 ESOO all scenarios, 2018-19 to 2052-53 (MW)



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

The key insights are:

- 2023-24 to 2032-33 (1-10 years):
 - For the *Step Change* and *Green Energy Exports* scenarios, the starting points are slightly lower relative to the 2022 ESOO because the models have been adjusted based on the latest data and using improved model formulations. On the other hand, the starting point for the *Progressive Change* scenario is slightly higher, primarily due to higher electrification forecast in the short term.
 - The continuous decline in the minimum demand forecast is attributed to the projected update of distributed PV installations. The rate of decrease is slightly faster than forecast in the 2022 ESOO due to less assumed electrification, while there is no significant difference in PV capacity in the short term. From around 2027-28, more distributed PV is forecast relative to 2022, causing a faster pace of decline compared to the 2022 ESOO from this point.
 - In the ESOO Central (*Step Change*) scenario, the point at which 50% POE becomes negative has shifted earlier, moving from 2034 to 2028.
- 2033-34 to 2042-43 (11-20 years):

- The faster PV growth, slowed electrification, and stronger energy efficiency uptake all contribute to a more rapid decline in minimum demand forecast in the 2023 ES00 compared to the 2022 ES00
- The slower decline in minimum demand in the *Progressive Change* scenario, compared to the other two scenarios, is due to the relatively slower increase in rooftop PV and PVNSG
- 2043-44 to 2052-53 (21-30 years):
 - The similar trend continues, and the downward trend in minimum demand slightly increases due to continued forecast energy efficiency.

Supply adequacy assessment

Relative to last summer, approximately 166 MW of additional VRE generation and 155 MW/160 MWh of storage is expected to commence operation this summer. The following projects are expected to commission over the ES00 horizon; the dates listed reflect the modelled commissioning, accommodating default project commissioning delays in accordance with the 2023 methodology and each project’s commitment status:

- 490 MW/950 MWh of battery storage projects become operational in 2025-26 including the Gnarwarre BESS and Rangebank BESS.
- 756 MW Golden Plains Wind Farm East project becomes operational in 2025-26.
- 180 MW/360 MWh Koorangi BESS project becomes operational in 2026-27.
- 350 MW/1,400 MWh Wooreen BESS project becomes operational in 2027-28.
- The 1,450 MW Yallourn Power Station is expected to retire in 2028.

Figure 95 shows the aggregate impact of generator and storage commissioning and decommissioning assumptions.

Figure 95 Victoria assumed capability during typical summer conditions, by generation type, 2022-23 to 2032-33 (MW)

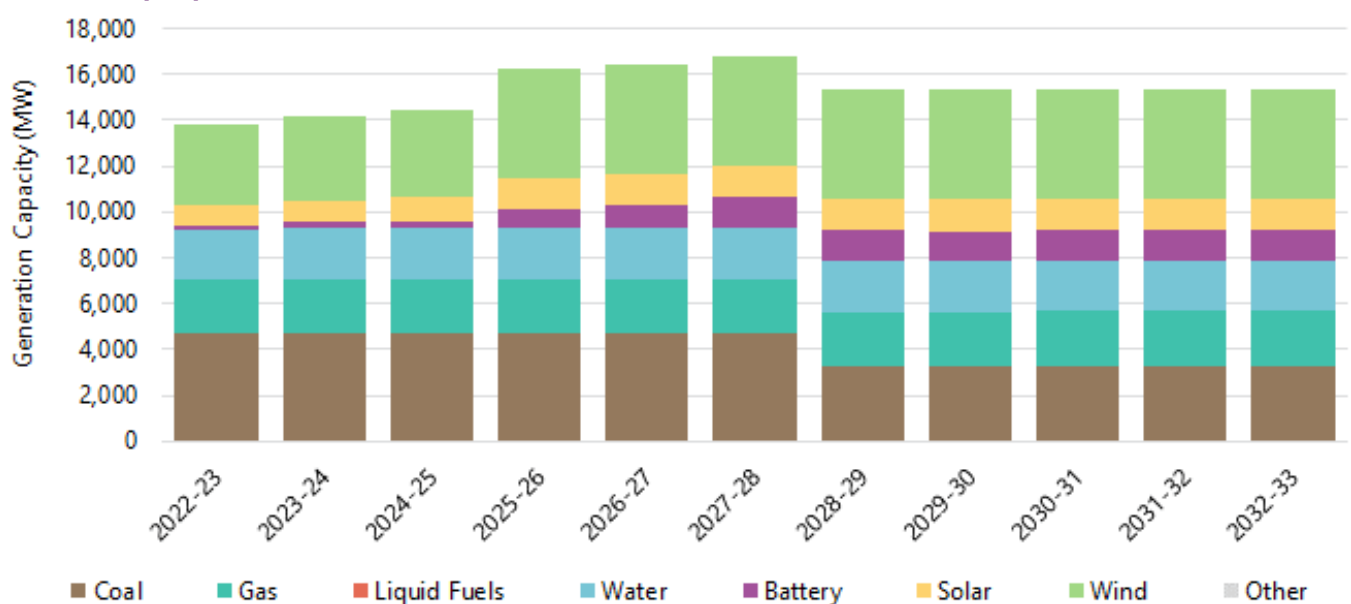
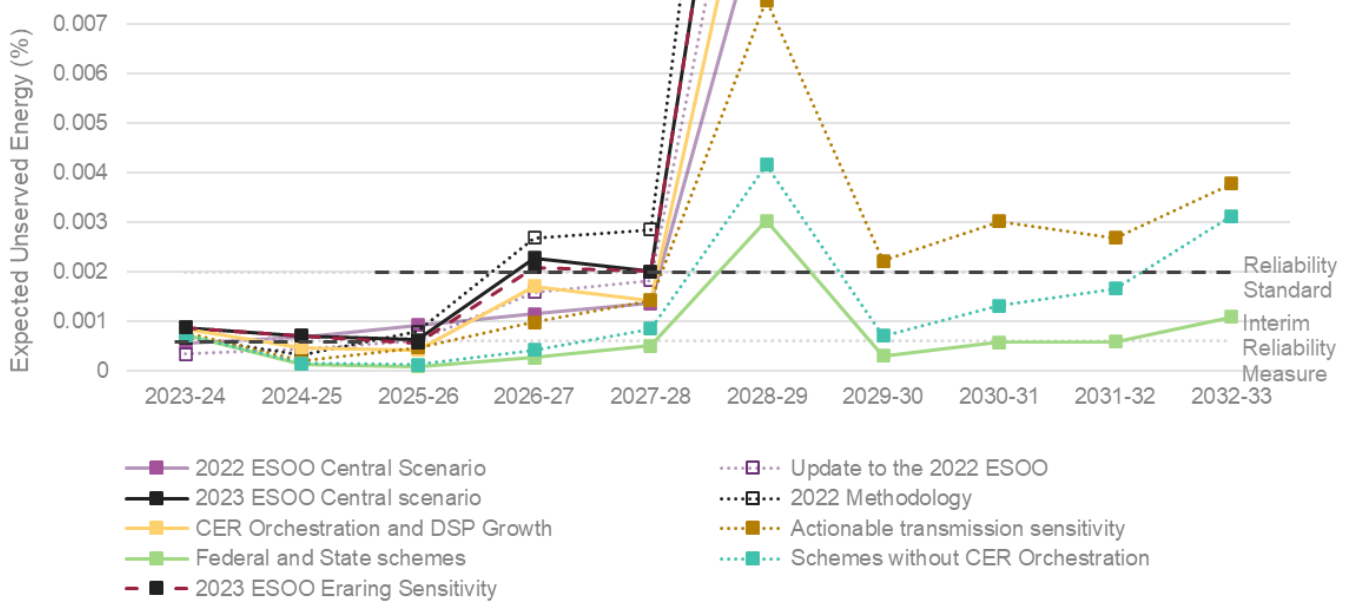


Figure 96 shows expected USE for Victoria under the relevant modelled scenarios and sensitivities considered in this 2023 ES00.

Figure 96 Victoria expected USE, scenarios and sensitivities, 2023-24 to 2032-33 (%)



It shows that:

- In the ES00 Central scenario, expected USE is greater than the IRM in 2023-24 to 2025-26, and greater than the reliability standard from 2026-27 when all four units of Torrens Island B and Osborne Power Station in South Australia have advised they expect to have retired, reducing available generation capacity across these tightly coupled regions. Expected USE continues to increase from 2028-29, following the 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.
- Under the *CER Orchestration* sensitivity, expected USE remains within the reliability standard in 2026-27 and 2027-28, however exceeds the reliability standard from 2028-29.
- Under the *Actionable transmission* sensitivity, reliability risks fall under the reliability standard until (and including) 2027-28, due to the modelled delivery of all projects as scheduled, with risks lower than the Central scenario over the entire horizon. From 2031-32, reliability risks reduce considerably due to the commissioning of Marinus Link and VNI West, and the improved transmission access for newly commissioning generators in New South Wales and northern Victoria, including Snowy 2.0.
 - Western Renewables Link is included in the Central scenario as an anticipated project. The benefit of this development is better reflected in this sensitivity (alongside Marinus Link and VNI West), as other small-scale projects under consideration from AEMO Victorian Planning to unlock transmission limitations in the Latrobe and Melbourne 500/220 kV ring are also included from 2028-29.
- Both the *Federal and state schemes* and the *Schemes without CER orchestration* sensitivities show reliability risks within the reliability standard except in 2028-29 when Yallourn Power Station has retired, but VNI West

and Marinus Link cable 1 have not yet been commissioned. The reliability risks are lower than the Central scenario over the forecast horizon due to the modelled on-time delivery of all included transmission, generation and storage projects and the inclusion of additional generation projects. These sensitivities demonstrate the effectiveness of several schemes considered in the sensitivity (as defined in Chapter 7.3), and demonstrate the continued opportunity for market developments and other Victorian policies (such as the VRET, offshore wind policy and storage targets) to further reduce reliability risks.

- Under the 2023 ESOO *Eraring* sensitivity, forecast USE reduces in 2025-26 and in 2026-27 compared with the Central scenario.

Figure 97 shows the reliability outcomes for Victoria in 2023-24 under the 13 different weather years considered in the 2023 ESOO. Under weather conditions similar to the 2014-15 reference year, expected USE exceeds the reliability standard and IRM. Under seven other reference years, expected USE exceeds the IRM, but is less than the reliability standard, and under five other reference years, the outcome is less than the IRM. The average outcome exceeds the IRM.

Figure 97 Reliability outcomes for Victoria in 2023-24 under different weather reference years, ESOO Central scenario

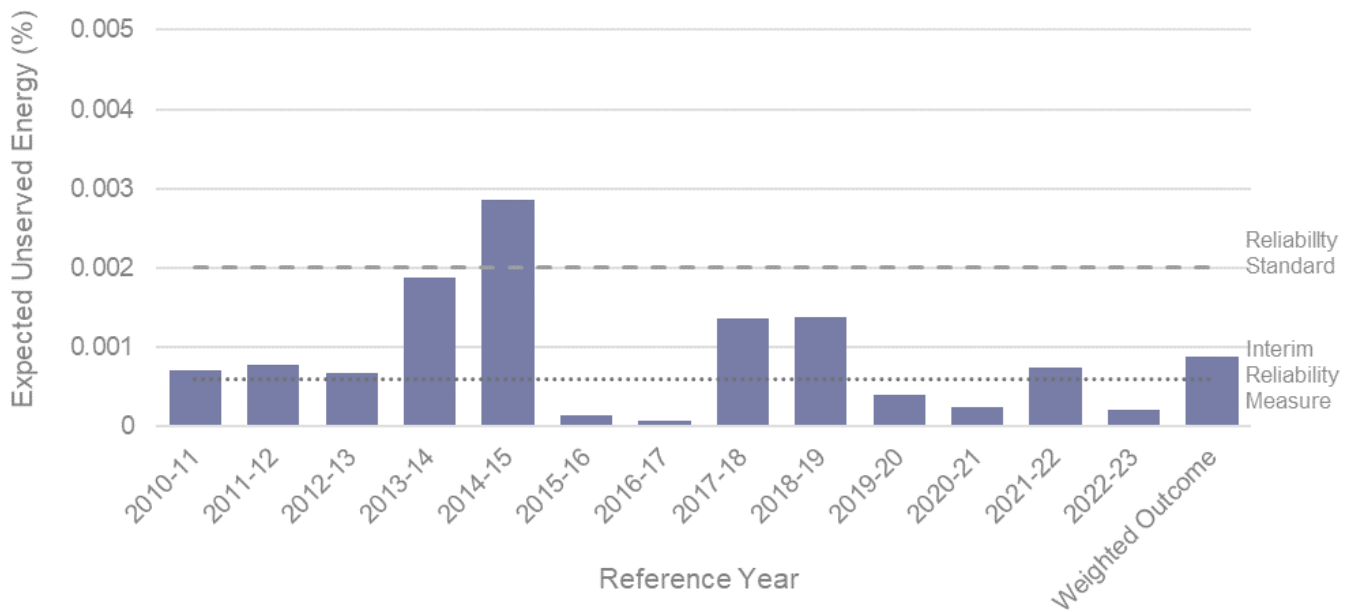
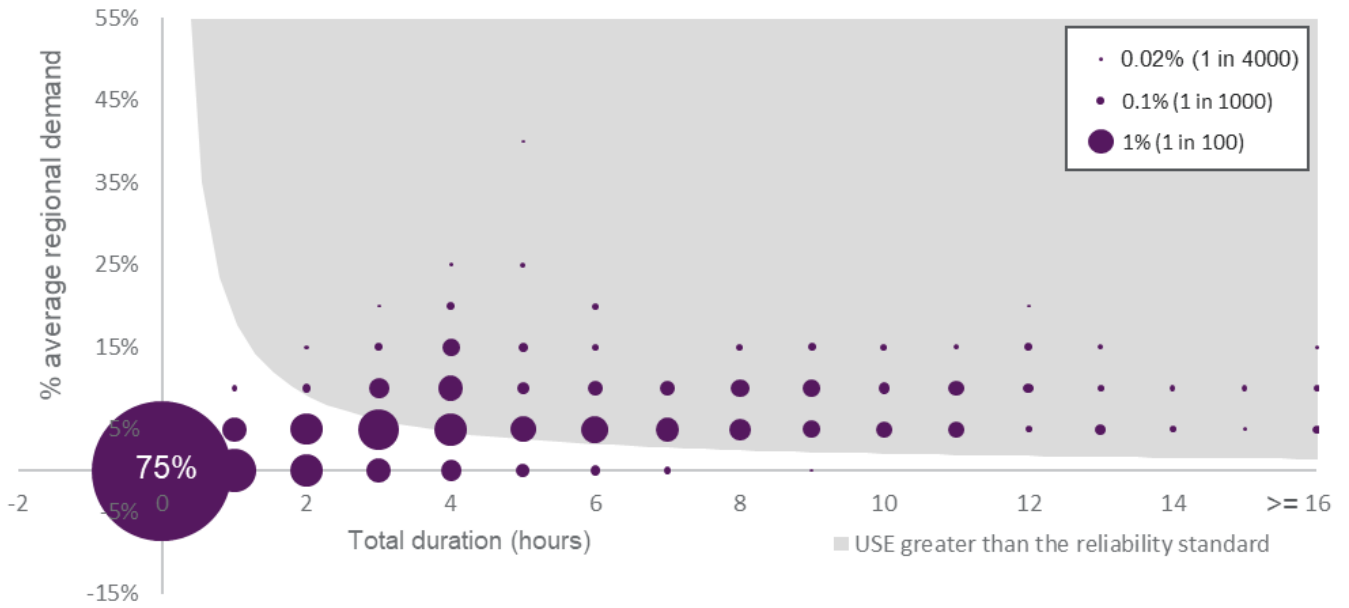


Figure 98 shows a bubble plot of the depth and duration of USE forecast in Victoria for 2023-24 in the ESOO Central scenario, similar to that shown in **Section 4.1**. It shows that the most likely outcome is that USE does not occur in the coming year (the large purple bubble at the intersection of 0 hours and 0% depth), indicating that there is a 25% probability of a reliability incident. In Victoria. For those simulation outcomes that did have USE, the total length was likely to be up to 11 hours in duration and up to 10% of average regional load.

Figure 98 Bubble plot of depth and duration of forecast USE Victoria 2023-24, ESOO Central scenario



A6. Demand side participation forecast

AEMO must publish details, no less than annually, on the extent to which, in general terms, DSP information received under rule 3.7D of the NER has informed AEMO's development or use of load forecasts for the purposes of the exercise of its functions under the NER. This appendix outlines AEMO's DSP forecast for the 2023 ESOO, in fulfilment of its obligation under the NER, and explains the key differences from the 2022 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.

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 99**:

- The categories listed to the left in **Figure 99** 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 99**).
- The categories that are included in DSP are listed in the middle column of **Figure 99**.

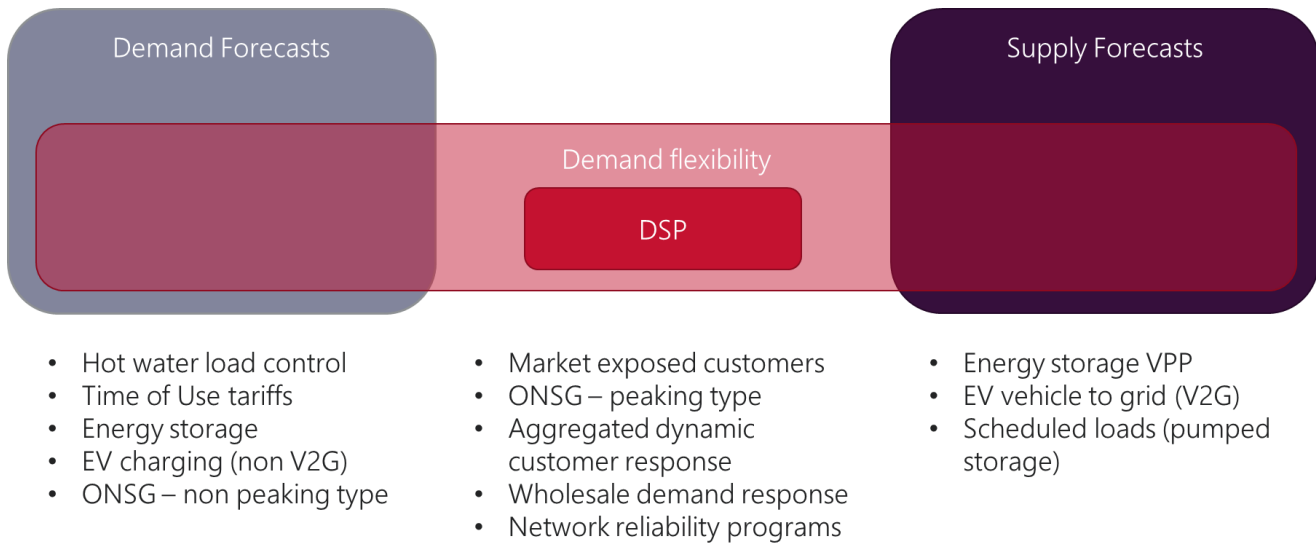
It should also be noted that AEMO's DSP forecast specifically excludes RERT. The DSP forecast is used in the ESOO and in the MT PASA, which highlights the risk of shortfalls to determine the need for RERT capacity, so the analysis needs to exclude it in the first instance.

The WDR mechanism was introduced in October 2021¹¹⁶. In 2023, WDR is forecast based on dispatch data during the 12 months until end of March 2023. Analysing the data during this period showed that the dispatched WDR was lower than was forecast in the 2021 ESOO, but broadly consistent with the WDR forecast provided in the 2022 ESOO¹¹⁷.

¹¹⁶ See <https://www.aemc.gov.au/rule-changes/wholesale-demand-response-mechanism>.

¹¹⁷ The exceptions being Queensland and South Australia, which did not have any actual WDR data to base the 2022 ESOO forecasts on and therefore the 2022 ESOO forecasts for those regions were assumptions-driven. Actual WDR data for those regions in the 12 months to end of March 2023 has resulted in lower forecasts in the 2023 ESOO.

Figure 99 Flexible demand sources included in AEMO's DSP forecast



A6.2 DSP forecast by component

The 2023 DSP forecast was based on information collected by registered participants through AEMO's DSP Information Portal during April 2023. 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 history¹¹⁸. 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.

Contribution of demand response service providers (DRSPs) via the WDR mechanism that came into effect in October 2021 have been taken into account since the 2022 ESOO. Registration for DRSP started in June 2021, and minimal voluntary reporting¹¹⁹ occurred through the DSP Information Portal in April 2021. For the 2023 ESOO, the WDR forecast is based on the dispatch data for the 12 months until March 2023. 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 24** 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.

¹¹⁸ The most recent three years of history are used by default with the cut-off date as the end of March 2023.

¹¹⁹ Stakeholders could report expected WDR capacity voluntarily as part of AEMO's DSP data collection process in April 2021.

Table 24 WDR observations (2022-23)

Region	Trigger	Counts of intervals with WDR	Counts of intervals with price above the trigger	Calculated weight
NSW	>\$500/MWh	369	2,919	0.13
NSW	>\$2500/MWh	48	21	0.63
NSW	>\$7500/MWh	40	14	0.65
VIC	>\$500/MWh	119	2,123	0.06
VIC	>\$2,500/MWh	16	21	0.76
VIC	>\$7,500/MWh	10	14	0.71
QLD	>\$500/MWh	24	226	0.11
QLD	>\$2,500/MWh	2	28	0.07
QLD	>\$7,500/MWh	1	23	0.04
SA	>\$500/MWh	8	120	0.07
SA	>\$2,500/MWh	3	31	0.1
SA	>\$7,500/MWh	0	15	-

The WDR forecasts for 2023 are broadly consistent with the predictions published in the 2022 ESOO. As of June 2022, WDR had only been dispatched in New South Wales and Victoria, so Queensland and South Australia and Tasmania had WDR forecasts in the 2022 ESOO which were based on assumptions rather than data.

In 2022-23, WDR was activated in Queensland and South Australia, allowing their WDR forecasts in the 2023 ESOO to be based on data rather than assumptions. Based on the actual operation of WDR in 2022-23, the 2023 ESOO forecasts for WDR are as per **Table 25**.

Table 25 Price-driven WDR forecast (MW)

Trigger	New South Wales	Queensland	South Australia	Tasmania	Victoria
>\$300/MWh	0	0	0	0	0
>\$500/MWh	0	0	0	0	0
>\$1,000/MWh	9	1	1	0	3
>\$2,500/MWh	12	1	1	0	7
>\$5,000/MWh	12	1	1	0	7
>\$7,500/MWh	13	1	1	0	7

The price-driven DSP forecasts are summarised in **Table 26**.

Table 26 Price-driven DSP forecast including WDR (cumulative response in MW)

Trigger	New South Wales	Queensland	South Australia	Tasmania	Victoria
>\$300/MWh	0	22	26	0.5	0
>\$500/MWh	0	54	40	6	0
>\$1,000/MWh	54	91	41	6	52
>\$2,500/MWh	62	105	41	6	63
>\$5,000/MWh	94	152	44	6	63
>\$7,500/MWh	95	189	49	6	63

Focusing on the DSP forecasts above the \$7,500/MWh trigger, and comparing to the 2022 ESOO:

- There was more DSP response overall in all NEM regions except Tasmania (as per **Table 27**). The major factor that contributed to the general uplift in DSP response in all these regions is the higher electricity prices relative to earlier years. These higher prices have led to more benefits to customers participating in DSP schemes or acting directly to market signals.
- In Tasmania, however, the power price separation from the mainland explains why the drivers above did not result in similar observed growth. This is also attributed to only having limited observations of the high-price events required to estimate the DSP response with reasonable confidence.

Forecast DSP responses by region are presented in **Table 27**.

Table 27 Forecast levels of DSP for prices exceeding \$7,500/MWh in the 2023 ESOO and 2022 ESOO (MW)

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

Reliability response

The reliability response represents the estimated DSP response during reliability events, which AEMO defines as cases where an actual LOR2 or LOR3 is declared¹²⁰. 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 captured¹²¹.

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:

- 72 MW in Queensland.
- 45 MW in Victoria.

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

AEMO has maintained the adjustments made in the 2022 DSP forecast for New South Wales and Victoria. These adjustments reflect the average of the response seen across the periods where LOR 2 conditions were in the regions in the last three years¹²² plus any anticipated increase in the responses, and sum to:

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

¹²⁰ 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.

¹²¹ 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.

¹²² Cut-off date is the end of March 2023.

Based on this, the combined DSP forecasts for the coming summer 2023-24 and winter 2024 are shown in **Table 28** and **Table 29** respectively.

Table 28 Estimated DSP responding to price or reliability signals, summer 2023-24

Trigger	New South Wales	Queensland	South Australia	Tasmania	Victoria
> \$300/MWh	0	22	26	0	0
> \$500/MWh	0	54	40	6	0
> \$1,000/MWh	54	91	41	6	52
> \$2,500/MWh	62	105	41	6	63
> \$5,000/MWh	94	152	44	6	63
> \$7,500/MWh	95	189	49	6	63
Reliability response	337	262	49	6	257

Table 29 Estimated DSP responding to price or reliability signals, winter 2024

Trigger	New South Wales	Queensland	South Australia	Tasmania	Victoria
> \$300/MWh	0	22	26	0	0
> \$500/MWh	0	54	40	6	0
> \$1,000/MWh	54	91	40	6	52
> \$2,500/MWh	62	105	40	6	63
> \$5,000/MWh	94	152	44	6	63
> \$7,500/MWh	95	189	49	6	63
Reliability response	337	189	49	6	212

The reliability response estimate is a key input to the ESOO process, showing the megawatts of estimated demand reduction possible to avoid USE during supply shortfalls. For most regions, AEMO has no information about committed additional DSP resources, hence the estimates in **Table 28** and **Table 29** are used for the entire 10-year ESOO horizon.

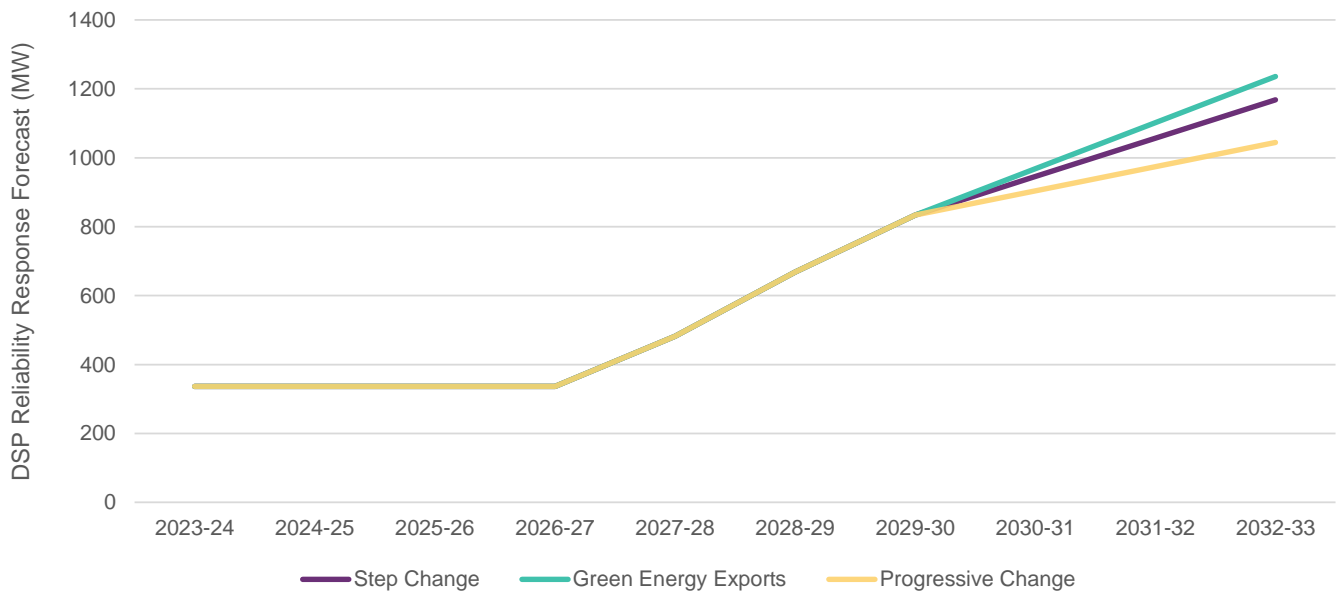
For New South Wales, however, the PDRS will create a financial incentive to reduce electricity consumption during peak times in summer in New South Wales¹²³. AEMO included this scheme in all scenarios, resulting in a DSP forecast which increases over time and beyond the above tabulated values. The PDRS has been modelled based on information provided by the New South Wales Government, but 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 100 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 summer¹²⁴.

¹²³ 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.

¹²⁴ For New South Wales' summer, the forecasts shown in are used in the 2023 ESOO while the winter forecasts stay the same as the values listed in Table 29.

Figure 100 DSP applied in forecasts for the summer period in New South Wales, 2023-24 to 2032-33 (MW)



Reliability response outlook in the longer term

The tables above show the DSP forecast for use in the 2023 ES00, 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 2050 or beyond to account for DSP resources that may be developed consistent with the defined scenario settings¹²⁵.

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 WDR¹²⁶ in 2020, NER 3.7D(c) requires AEMO since October 2021 to include analysis of volumes and types of demand response in its reporting, including:

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

This section presents statistics on the full set of submitted DSP information to provide transparency about demand flexibility in the NEM. As it covers demand flexibility beyond what was included in the DSP forecast, the reported potential in megawatts differs from the forecast provided in **Section A6.2** above. Also, some late submissions have been included in the analysis to ensure the most comprehensive coverage of reported DSP in the NEM, noting they did not include demand flexibility that affected the DSP forecast covered above.

¹²⁵ 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>.

¹²⁶ See <https://www.aemc.gov.au/rule-changes/wholesale-demand-response-mechanism>.

A key part of the statistics is the reported National Meter Identifier (NMI) for each site that has demand flexibility of some sort. **Table 30** shows how many NMIs were submitted per region.

Table 30 Submitted NMIs per region

Region	Number of NMIs submitted
NSW	2,563,368
QLD	1,488,497
SA	582,300
TAS	3,324
VIC	1,022,749

Participant programs delivering demand flexibility

Table 31 and **Table 32** present the change in program numbers as submitted by participants to AEMO's DSP Information Portal over time. Note that 2019 was the first year in which all parties with significant DSP resources (to AEMO's knowledge) submitted information, so 2018 data is not directly comparable with subsequent years.

In 2020, in response to the WDR rule change¹²⁷, AEMO was required to review and consult on changes to the DSP information guidelines¹²⁸, which resulted in changes being made to the categories of DSP programs available in submissions. The number of programs allocated to the new set of categories is shown in **Table 32**.

The category change challenges the ability to make direct comparisons to previous years. A decrease in the "Other" category from 2020 to 2021 was the result of the removal of the requirement that all large (>1 MW) programs fall under this category. This has resulted in more informative submissions as far more programs are assigned to a category.

In 2022 there were increases in all categories, partly driven by increased compliance with NER 3.7D requiring all participants to submit DSP information. The number of "Market exposed connections" was particularly high in 2022 as many sites were listed as individual programs, whereas in 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 31 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

¹²⁷ See <https://www.aemc.gov.au/rule-changes/wholesale-demand-response-mechanism>.

¹²⁸ See <https://aemo.com.au/en/consultations/current-and-closed-consultations/dspi-guidelines>.

Table 32 Program numbers from DSP Information portal, 2021-23

Category	2021	2022	2023
Market exposed connections	143	211	141
Connections on dynamic event tariffs	5	16	19
Directly controlled connections (dynamic operation)	33	37	50
Directly controlled connections (fixed schedule)	6	17	27
Connections on fixed time-of-use tariffs	49	62	56
Other	14	35	25

Statistics by program category

Table 33 summarises category-level information from submissions to AEMO’s DSP Information Portal in 2023. Participants reported each individual customer connection, based on their NMIs, that belong to each program. Some customer connections may belong to multiple programs: for example, a residential customer’s NMI could appear both with having a controlled hot water tank (directly controlled load – fixed schedule) and an interruptible air-conditioner (directly controlled load – dynamic schedule).

Table 33 Program statistics grouped by program category for 2023 submissions

Category	Number of programs	Number of connections (connections may appear in more than one program)	Number of programs that included firm response information in submission
Connections on dynamic event tariffs	19	7,524	11
Connections on fixed time-of-use tariffs	56	1,792,027	4
Directly controlled connections (dynamic operation)	50	1,166,253	18
Directly controlled connections (fixed schedule)	27	2,054,472	1
Market exposed connections	141	522,802	89
Other	25	117,160	16

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.

Participants may report their firm response in megawatts for each program. **Table 33** 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 2023 are summarised in **Table 34**, with the numbers of distinct connections reported since 2021 for comparison.

Due to the changes to compliance rules that led to more programs reported in 2022 (see **Table 32**), more NMIs were also reported in that year. However, **Table 34** highlights that for a greater portion of the NMIs, the connection types were not specified, and as result, in 2022 a decrease was observed in the number of connections reported as being residential relative to 2021, while for 2023 a similar number of residential connections were recorded. Industrial load saw a larger relative increase in 2023, but remains very low in absolute terms.

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 34 Load types of reported connections

Load type	Number of distinct connections			Dominant program category in each load type as percentage (2023)
	2021	2022	2023	
< not specified >	2,500,874	3,405,255	3,569,964	50% are on fixed time-of-use tariffs
Commercial	10,806	9,415	3,190	96% are on fixed time-of-use tariffs
Industrial	92	90	182	73% have 'other' listed as category
Residential	2,085,018	1,735,756	2,086,902	50% Directly controlled connections (dynamic schedule) and 45% Directly controlled connections (fixed schedule)

Number of connections by category and type

Table 35 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 5,855 MW of firm response exists, although more could be unquantified or simply not reported. This value is significantly higher than what was provided in the 2022 ESOO. It is important to note that the reported 2,216 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, 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 DSP type. The reported responses are quite large, but are directly modelled in the reliability forecast rather than through the DSP forecast.

Table 35 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	337,392	2216	64
	Energy storage	29,614	157	12
	Load reduction	340	246	29
	Load reduction; Embedded generation	2	20	1
	<not specified>	155,454	2	35
Connections on dynamic event tariffs	Energy storage	36	689	9
	Load reduction	3,030	712	2
	<not specified>	4,458	0	8
Directly controlled connections (dynamic operation)	Embedded generation	227	30	7
	Energy storage	1,727	10	6
	Load reduction	1,044,704	716	8
	<not specified>	119,585	4	30
Directly controlled connections (fixed schedule)	Load reduction	1,190,352	300	9
	<not specified>	864,120	0	18
Connections on fixed time-of-use tariffs	Load reduction	1,355,784	0	33
	<not specified>	436,243	143	23
Other	Embedded generation	32	1	0
	Energy storage	7,095	8	0
	Load reduction	110,032	15	340
	<not specified>	1	1	270

Tariffs used by network service providers and retailers

Table 36 summarises the number of connections reported for the different tariff categories for both retailers and NSPs. Note that 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. The relative low number of connections with time-of-use tariffs being reported by the NSPs relative to the retailers suggests that not all such customers are reported, although some retailers might offer time-of-use tariffs to customers even if the network company does not charge the retailer for time-of-use for the same customers.

Table 36 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	3,066	4,458
Connections on fixed time-of-use tariffs	269,016	1,523,011
Directly controlled connections (dynamic operation)	1,046,598	119,655
Directly controlled connections (fixed schedule)	984,557	1,069,915
Market exposed connections	366,928	155,874
Other	117,027	133

A7. EAAP detailed results

Consistent with the EAAP Guidelines, AEMO must publish the expected USE for the first 12 months and second 12 months in the study period for each of the scenarios on regional basis. These results are presented in this section aggregated annually and monthly for the full EAAP forecast horizon, from July 2023 to June 2025.

A7.1 Central scenario

Annual regional expected USE values for EAAP Central scenario are expressed in **Table 37** in both megawatt hours and as a percentage of regional demand. Expected USE in Tasmania in 2023-24 is negligible.

Table 37 Annual expected USE in EAAP Central scenario

Region	2023-24 USE		2024-25 USE	
	(MWh)	(% of regional demand)	(MWh)	(% of regional demand)
New South Wales	407	0.0006%	151	0.0002%
Queensland	75	0.0001%	62	0.0001%
South Australia	121	0.0010%	17	0.0001%
Tasmania	0	-	1	0.0000%
Victoria	428	0.0010%	413	0.0010%

Table 38 shows EAAP Central scenario regional expected USE per month over the EAAP's two-year horizon.

Table 38 Monthly expected USE in EAAP Central scenario, MWh

Month	New South Wales	Queensland	South Australia	Tasmania	Victoria
Jul-23	12.5	0.0	0.0	0.0	0.0
Aug-23	2.3	0.0	0.0	0.0	0.0
Sep-23	0.0	0.0	0.0	0.0	0.0
Oct-23	0.0	0.0	0.0	0.0	0.0
Nov-23	2.7	0.0	0.0	0.0	22.7
Dec-23	54.8	3.3	0.9	0.0	2.8
Jan-24	175.2	47.4	106.2	0.0	327.1
Feb-24	122.5	19.9	14.3	0.0	61.5
Mar-24	13.9	4.0	0.1	0.0	13.6
Apr-24	0.0	0.0	0.0	0.0	0.0
May-24	1.3	0.0	0.0	0.0	0.0
Jun-24	21.8	0.0	0.0	0.1	0.0
Jul-24	12.0	0.0	0.0	0.7	0.0
Aug-24	1.9	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	11.3	0.0	0.0	0.0	19.4

Month	New South Wales	Queensland	South Australia	Tasmania	Victoria
Dec-24	68.7	7.4	0.0	0.0	5.3
Jan-25	18.6	16.4	9.1	0.0	247.7
Feb-25	32.8	35.1	8.4	0.0	128.9
Mar-25	4.7	3.5	0.0	0.0	11.2
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	1.0	0.0	0.0	0.1	0.0

A7.2 Low Rainfall scenario

Annual regional expected USE values for EAAP Low Rainfall scenario are expressed in **Table 39** in both megawatt hours and as a percentage of regional demand. Expected USE in Tasmania in 2023-24 is negligible.

Table 39 Annual forecast expected USE in EAAP Low Rainfall scenario

Region	2023-24 USE		2024-25 USE	
	(MWh)	(% of regional demand)	(MWh)	(% of regional demand)
New South Wales	368	0.0006%	146	0.0002%
Queensland	81	0.0002%	68	0.0001%
South Australia	132	0.0011%	16	0.0001%
Tasmania	0	-	1	0.0000%
Victoria	424	0.0010%	454	0.0011%

Table 40 shows expected USE per month for the EAAP Low Rainfall scenario over the two-year horizon.

Table 40 Monthly forecast expected USE in EAAP Low Rainfall scenario, MWh

Month	New South Wales	Queensland	South Australia	Tasmania	Victoria
Jul-23	14.5	0.0	0.0	0.0	0.0
Aug-23	2.6	0.0	0.0	0.0	0.0
Sep-23	0.0	0.0	0.0	0.0	0.0
Oct-23	0.0	0.0	0.0	0.0	0.0
Nov-23	1.3	0.0	0.0	0.0	21.3
Dec-23	57.6	4.5	1.8	0.0	3.0
Jan-24	165.9	47.0	115.3	0.0	329.1
Feb-24	108.0	24.4	14.2	0.0	54.1
Mar-24	7.2	5.3	0.2	0.0	16.2
Apr-24	0.0	0.0	0.0	0.0	0.0
May-24	0.6	0.0	0.0	0.1	0.0
Jun-24	10.2	0.0	0.0	0.1	0.0

Month	New South Wales	Queensland	South Australia	Tasmania	Victoria
Jul-24	10.7	0.0	0.0	0.1	0.0
Aug-24	0.9	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	9.3	0.0	0.0	0.0	26.8
Dec-24	62.0	4.5	0.1	0.0	6.9
Jan-25	17.7	16.8	7.6	0.0	242.3
Feb-25	32.3	38.3	8.5	0.0	166.3
Mar-25	11.9	8.4	0.0	0.0	12.2
Apr-25	0.0	0.0	0.0	0.0	0.0
May-25	0.0	0.0	0.0	0.3	0.0
Jun-25	1.6	0.0	0.0	0.1	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 41**.

Table 41 Annual forecast expected USE in EAAP Low Thermal Fuel scenario

Region	2023-24 USE		2024-25 USE	
	(MWh)	(% of regional demand)	(MWh)	(% of regional demand)
New South Wales	2956	0.0045%	2987	0.0045%
Queensland	340	0.0007%	316	0.0006%
South Australia	345	0.0029%	70	0.0006%
Tasmania	0	-	0	-
Victoria	588	0.0014%	625	0.0015%

Table 42 shows expected USE per month for the EAAP Low Thermal Fuel scenario over the two-year horizon.

Table 42 Monthly forecast expected USE in EAAP Low Thermal Fuel scenario, MWh

Month	New South Wales	Queensland	South Australia	Tasmania	Victoria
Jul-23	185.1	10.6	0.1	0.0	0.0
Aug-23	46.3	0.0	0.0	0.0	0.8
Sep-23	1.1	0.0	0.0	0.0	0.0
Oct-23	0.0	0.0	0.0	0.0	0.0
Nov-23	28.7	0.0	0.0	0.0	15.4
Dec-23	261.0	13.0	14.3	0.0	4.2
Jan-24	1768.8	181.3	268.2	0.0	450.9

Month	New South Wales	Queensland	South Australia	Tasmania	Victoria
Feb-24	507.8	122.8	58.4	0.0	83.3
Mar-24	66.4	12.1	3.4	0.0	33.4
Apr-24	0.0	0.0	0.0	0.0	0.0
May-24	11.0	0.0	0.0	0.0	0.0
Jun-24	79.4	0.0	0.4	0.0	0.0
Jul-24	247.3	5.5	0.0	0.3	0.1
Aug-24	6.9	0.0	0.0	0.1	0.0
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	65.2	0.3	0.1	0.0	24.6
Dec-24	360.3	35.8	0.2	0.0	9.0
Jan-25	1521.3	132.2	29.7	0.0	328.8
Feb-25	572.4	125.2	39.8	0.0	242.8
Mar-25	105.2	16.0	0.0	0.0	19.5
Apr-25	0.0	0.0	0.0	0.0	0.0
May-25	2.1	0.3	0.0	0.0	0.0
Jun-25	106.6	1.1	0.0	0.0	0.0