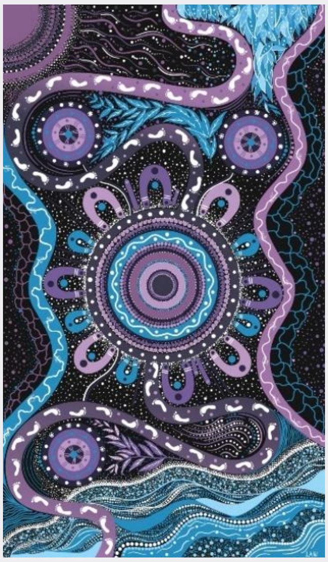
AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

Forecast Accuracy Report

December 2025

Review of the 2024 demand, supply and reliability forecasts for the National Electricity Market



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

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

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

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

Important notice

Purpose

This Forecast Accuracy Report has been prepared consistent with AEMO's Reliability Forecast Guidelines and the AEMO Forecast Accuracy Report Methodology for forecast improvements and accuracy. It is for the purposes of clause 3.13.3A(h) of the National Electricity Rules. It reports on the accuracy of demand and supply forecasts in the 2024 Electricity Statement of Opportunities (ESOO) and its predecessors for the National Electricity Market (NEM).

This publication is generally based on information available to AEMO as of 31 August 2025 unless otherwise indicated.

Disclaimer

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

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

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

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:

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Executive summary

Each year, AEMO publishes an assessment of forecast accuracy to help inform its Forecast Improvement Plan and build confidence in the forecasts produced. This 2025 *Forecast Accuracy Report* primarily assesses the accuracy of AEMO's 2024 *Electricity Statement of Opportunities* (ESOO)[1] for each region in the National Electricity Market (NEM). The report assesses the accuracy of forecast drivers and models of demand and supply that influenced the reliability assessments for the 2024-25 financial year, in particular the summer.

The accuracy of the forecasts is critical to ensure informed decision-making by AEMO – for the Retailer Reliability Obligation (RRO), Reliability and Emergency Reserve Trader (RERT), and *Integrated System Plan* (ISP) – and by industry and governments.

Given the varying nature of each component and forecast, quantitative metrics are not always feasible. **Table 1** summarises the qualitative assessment of forecasting accuracy in this report, using the following indicators:

- 🟢 Forecast has performed as expected.
- 🟡 Inaccuracy observed in forecast is explainable by inputs and assumptions. These inputs should be monitored and incrementally improved where possible, provided the value is commensurate with cost.
- 🔴 Inaccuracy observed in forecast needs attention and should be prioritised for improvement.

Table 1 Forecast accuracy summary by region, 2024-25

Forecast Component	NSW	QLD	SA	TAS	VIC	Assessability[A]	Comments
Energy consumption	🟢	🟡	🟡	🟡	🟡	Moderate	Forecast accuracy across most NEM regions was reasonable, with a smaller residual (unexplained or unmeasured components) for most regions, than was recorded last year: • **Tasmania** had the lowest consumption forecast accuracy (4.4%), but this was almost entirely explained by unforeseen production outages at one influential large industrial load (LIL). The Forecast Improvement Plan includes a new item to address LIL over-forecasts. • **Queensland** accuracy was impacted by revisions and inaccuracies to other non-scheduled generation (ONSG), which have been resolved for the 2025 ESOO. • **South Australia** and **Victoria** had the largest residuals, potentially owing to trends in electrification, energy efficiency and/or other behavioural changes. Further investigation and improvements are proposed in the Forecast Improvement Plan.
Summer maximum demand	🟢	🟡	🟢	🟡	🟢	Moderate	Across the NEM, summer maximum demand outcomes generally aligned with forecast expectations, with a few regions showing more notable deviations. • **Queensland** recorded a summer maximum above the 10% probability of exceedance (POE) forecast, driven by a sustained period of heat and elevated humidity. • In **Tasmania**, the summer maximum fell below the 90% POE forecast, consistent with exceptionally mild weather conditions during the period.

[1] See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2023/2023-electricity-statement-of-opportunities.pdf.

Forecast Component	NSW	QLD	SA	TAS	VIC	Assessability[A]	Comments
Winter maximum demand	🟢	🟡	🟢	🟡	🟡	Moderate	Across the NEM, winter maximum demand reflected generally expected patterns, with regional differences largely driven by local weather conditions. • **Queensland**'s winter maximum came in slightly below the 90% POE forecast, reflecting exceptionally warm winter temperatures. • **Tasmania**'s winter maximum again fell below the 90% POE threshold owing to exceptionally warm winter temperatures. • **Victoria** recorded a winter maximum marginally above the 10% POE level, driven by a cold weekday evening with minimal rooftop photovoltaic (PV) generation and limited temperature variations.
Annual minimum demand	🟢	🟡	🟢	🟢	🟢	Moderate	Annual minimum demand outcomes for all NEM regions remained within forecast bounds, except **Queensland** experienced minimum demand above the 10% POE forecast, mainly driven by an over-estimated distributed PV forecast, which kept demand higher than expected.
Demand side participation	🟢	🟢	🟢	🟡	🟡	Weak - Moderate	The observed demand side participation (DSP) was similar to the forecast in New South Wales, Queensland and South Australia, especially for higher price bands. • In **Tasmania**, DSP responses exceeded forecasts, primarily driven by a sharp rise in high-price intervals. Between 1 April 2024 and 31 March 2025, there were 1,532 half-hourly intervals with prices at or above $300/megawatt hour (MWh), compared to just 306 in the previous year. • In **Victoria**, DSP responses for prices above $7,500/MWh were lower than forecast, noting the forecast was revised upward in the 2024 ESOO to reflect higher-than-expected participation in previous years. This variance was largely due to the limited occurrence of such high-price intervals, only 26 in 2023-24 and 39 in 2024-25, which made accurately estimating DSP response challenging.
Installed generation capacity	🟡	🟡	🟡	🟡	🟡	Strong	Up to 2,333 MW of extra generation was available in February 2025 compared to forecast, mostly due to new entrants coming online earlier than modelled.
Summer supply availability /generation	🟢	🟡	🟢	🟢	🟢	Moderate	Availability and generation were mostly within the 95th percentile simulation range except for **Queensland**, which was affected by higher-than-forecast impacts from unplanned coal outages and solar farm curtailments.

A. The assessability categories are defined in **Section 2.2.1.**

This report highlights strong overall forecasting performance in areas critical to AEMO's ESOO forecasts. These findings reinforce confidence in the existing forecasting framework, while also identifying targeted areas where forecast accuracy can be further improved.

Key forecast accuracy findings

- **Annual consumption** accuracy across most NEM regions was reasonable, with a significantly smaller residual (unexplained or unmeasured components) for most regions, than was recorded last year. However, a larger unexplained residual remains for South Australia and Victoria, suggesting that trends in electrification, energy efficiency, or weather effects[2] are mostly being under-stated in the 2024 model (while the residual is negative in aggregate[3], unmeasured components may be driving consumption both higher and lower). AEMO is continuing to investigate these unknown components as identified in the 2024 Forecast Improvement Plan[4]. Tasmania had the largest consumption variance (4.4% operational as generated over-forecast), although an unforeseen large industrial load (LIL) shutdown explained most of the inaccuracy. LILs were over-forecast in all regions except for Victoria, partly due to advice from facility operators that does not typically consider operational outages. The 2025 Forecast Improvement Plan attempts to address this source of forecast inaccuracy (Improvement 5 in **Section 8.3.2)**.

- The observed **summer and winter maximum demand** outcomes generally fell between the 10% and 90% probability of exceedance (POE) forecasts, with some notable departures. In Queensland, the slight exceedance above the 10% POE during summer was not driven by a single extreme factor, but by the concurrence of sustained high temperatures, elevated humidity, and late-afternoon cloud cover that limited rooftop photovoltaic (PV) output prior to the evening peak. While none of these drivers were individually extreme, their combination created conditions that were atypical for the season, resulting in higher operational demand. Victoria observed a winter maximum marginally above the 10% POE threshold with the strong winter peak due to unusually cold conditions, a weekday evening load profile, and negligible PV after sunset. In Tasmania, both the summer and winter maximum demand events fell below the 90% POE forecasts, consistent with the unusually mild seasonal conditions experienced across the state.
- Annual **minimum demand** stayed within forecast ranges in all regions except Queensland. Variance in Queensland was mainly due to lower-than-expected rooftop PV output driven by an over-estimated rooftop PV forecast of around 400 megawatts (MW), which resulted in minimum demand in Queensland being higher than forecast. This issue has been addressed in the 2025 ESOO through revised rooftop PV forecasts that better reflect observed growth trends.
- Regarding **demand side participation (DSP)**, the occurrence of high prices was more frequent in 2024-25, which led to a slightly higher DSP participation across most regions and price bands. The DSP reliability responses were similar to the forecasts in the three regions where a network reliability event occurred during 2024-25 (New South Wales, Queensland and South Australia).
- **Rooftop PV and electric vehicles (EVs)** significantly influence electricity consumption and demand forecasts over the 10-year ESOO horizon. The 2024 ESOO overestimated rooftop PV capacity for 2024-25 in all NEM regions due to an overestimation of future growth in system size. Revised rooftop PV forecasts in the 2025 ESOO suggest current processes are adapting effectively to emerging trends. The EV fleet size was over-forecast, although its impact on energy consumption and demand remains minimal. AEMO expects improved short-term EV forecast accuracy as sales stabilise, supported by enhanced forecasting models and increased consideration of plug-in hybrid EVs (PHEVs) in the 2025 ESOO.
- **Generator installed capacity** during the 2024-25 summer exceeded forecasts by 2,333 MW, due to differences between projects' actual start dates and AEMO's commissioning assumptions applied under the current *ESOO and Reliability Forecast Methodology*[5]. Some new generation and storage projects became operational earlier than assumed in the 2024 ESOO after applying historically observed delays. AEMO does not consider that a change in method is required to

[2] For example, these weather effects include humidity and wet bulb temperatures.

[3] A negative residual indicates that the unmeasured components are contributing to an under-forecast (percentage errors).

[4] The weather modelling for residential and business consumption forecasting in this year's Forecast Improvement Plan is an extension of the investigation into the residual identified in the 2024 FAR.

[5] See https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2025/esoo-and-reliability-forecast-methodology.pdf.

capture this variance, as the existing *ESOO and Reliability Forecast Methodology* dynamically adjusts the default committed project delay period based on recent trends.

- **Supply availability/generation** was mostly within the 95th percentile simulation range, with Queensland the main exception due to a combination of higher unplanned coal unit outages and economic curtailment of solar farms. Factors that increased actual availability/generation relative to forecast mainly include new generators contributing capacity earlier than assumed, lower than the peak reference temperatures over the summer reducing expected de-ratings, and some Tasmanian units providing more capacity than their submitted seasonable capacities. Factors that decreased actual availability/generation relative to forecast include higher than forecast unplanned outage rates for Queensland coal units, planned outages that occurred but were not included in the forecast, and greater level of variable renewable energy (VRE) economic offloading in actual operations than forecast.

Forecast Improvement Plan

The Forecast Improvement Plan provides an important tool to guide investigation work and improvements in AEMO's forecasting approaches. In this 2025 Forecast Improvement Plan, it responds to two distinct drivers:

- forecast accuracy findings from the 2024 ESOO, as outlined above, where specific, evidenced gaps have been identified, and
- structural changes in the power system, which are reshaping the drivers of future reliability and demand risks, requiring ESOO forecasts to evolve to remain fit-for-purpose.

Structural change drivers

Forecast accuracy assessments are inherently backward-looking, while the ESOO must provide forward-looking signals under evolving system conditions. As the generation mix, operating environment, and demand drivers change, assumptions that were previously considered reasonable for both reliability and demand forecasting may no longer hold, even if they have not yet resulted in observable forecast inaccuracies.

On the supply side, thermal retirements and greater reliance on variable and energy-limited resources (VRE, storage and hydro) mean reliability risks are increasingly emerging over extended timeframes, not just short peak demand intervals. Recent analysis including sensitivities included in the 2025 ESOO shows planned outages can at times overlap with low reserve conditions, with less flexibility to be rescheduled to avoid high-risk periods as capacity margins tighten. Fuel and operational energy limits are also becoming more influential as the generation mix transitions and generators with high energy-production capability retire. The ability of dispatchable generators, particularly gas, hydro, and storage, to sustain output across weeks or seasons is becoming increasingly important.

On the demand side, electrification of households, transport, and industry, together with the growth of large and potentially flexible loads, is changing both the level and shape of demand. In response, AEMO is expanding its demand side analysis capability to support more granular and robust demand forecasting.

As a result, the priority initiatives proposed for incorporation in the 2026 ESOO, or investigated to support future incorporation, focus on addressing identified forecast accuracy issues while also preparing the ESOO to better reflect changing system conditions affecting both reliability and demand forecasts.

The initiatives are summarised below and provided in detail in **Section 8** of this report.

Reliability forecasts improvements (structural change driven)

- **Improvement 1: Outage modelling for scheduled generators and bi-directional units** – AEMO is proposing a major update to generator outage modelling to better forecast the real operational constraints with the potential to impact reliability outcomes, as analysis shows greater outage risks overlapping with high-risk periods than is currently modelled. The proposal includes incorporating planned outages alongside unplanned outages in future ESOO reliability forecasts, strengthening alignment with IEEE-762:2023[6] outage classifications, and collecting planned outage history and projections through the standing information request under National Electricity Rules (NER) 3.13.3A(d). This proposal ensures that reliability forecasts capture all outage types – forced, maintenance, and planned outages – and reflect the differing schedule flexibility with which they occur across the year in the ESOO modelling.
- **Improvement 2: Energy limits** – AEMO proposes to explicitly incorporate station-level energy limits into the *ESOO and Reliability Forecast Methodology*, supported by a new requirement included in the standing information request under NER 3.13.3A(d) for generators to submit energy limits that reflect sustained deliverable capability for relevant generating fuels (or other relevant inputs necessary to generate electricity) across multiple time horizons. This approach better captures real-world constraints that limit generators' ability to operate continuously over all periods – such as workforce constraints, fuel delivery constraints, or technical operating restrictions – and aligns the treatment of energy limits across the ESOO and the *Energy Adequacy Assessment Projection* (EAAP).
- **Improvement 3: Hydro inflow modelling** – AEMO proposes to use weather reference year-based inflows for hydro schemes with limited storage and constrained operational flexibility, while retaining long-term monthly averages for the Tasmanian Hydro Scheme. This enhancement captures year-to-year and intra-year variability in water availability and better reflects periods when low inflows coincide with extreme weather or outages – conditions relevant to reliability assessments. Aligning hydro inflow modelling with reference-year demand, wind and solar conditions will provide a more realistic representation of hydro energy availability and harmonise assumptions across AEMO's forecasting suite.

Electricity demand forecasts improvements (forecast accuracy-driven and structural change-driven)

- **Improvement 4: Distributed PV normalised generation profiles** – AEMO proposes a new methodology to calculate distributed PV normalised generation profiles. Due to increased availability of data, AEMO proposes to reference actual metered data, alongside irradiance-based and simulated distributed PV traces. AEMO proposes to investigate this approach and apply it for the 2026 ESOO if an improved model can confidently demonstrate forecast accuracy improvement.
- **Improvement 5: Large industrial load outages** – AEMO has observed that energy consumption estimates produced by aggregating site surveys often exceed actual consumption volumes due to some form of outage. AEMO proposes a change to the *Electricity Demand Forecasting Methodology*[7] to introduce a new 'outage factor' for application to currently operating LIL projections at the regional, sub-regional or sector level of the NEM that will reduce forecast consumption. AEMO proposes to investigate this approach and apply it for the 2026 ESOO if an improved model can confidently demonstrate forecast accuracy improvement.
- **Improvement 6: Residential and business classification** – AEMO currently has two methods available for estimating residential and business consumption history for use in modelling. AEMO is investigating the use of tariff data and

[6] IEEE 762-2023 defines standard terminology for reporting electric generating unit reliability, availability, and productivity.

[7] See https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2024-electricity-demand-forecasting-methodology-consultation/final-determination/electricity-demand-forecasting-methodology_.pdf.

machine learning algorithms to more accurately classify loads using each National Metering Identifier (NMI). AEMO proposes to update the methodology specified in Appendix 6 of the *Electricity Demand Forecasting Methodology* to add a third method for identifying the quantity of energy being consumed based on the summation of meter data for all NMIs classified as residential or business using this tariff data. AEMO could then use the three methodologies as appropriate to estimate consumption history, which AEMO anticipates may lead to more accurate history, and therefore more accurate forecasts. AEMO proposes to investigate this approach and apply it for the 2026 ESOO if an improved model can confidently demonstrate forecast accuracy improvement.

- **Improvement 7: Weather modelling for residential and business consumption forecasting** – recent analysis suggests that other weather variables may also be relevant in some regions (for example, humidity in Queensland). AEMO proposes to adjust the *Electricity Demand Forecasting Methodology* to potentially apply additional weather variables such as humidity in the weather consumption models. AEMO proposes to investigate this approach and apply it for the 2026 ESOO if an improved model can confidently demonstrate forecast accuracy improvement.
- **Improvement 8: Modelling otherwise unexplained consumer behaviour trends for residential customers** – in the November 2025 Forecasting Reference Group, some stakeholders suggested there may be trends in consumer behaviour (such as trends in the usage of appliances) that may explain recent growth in demand that may not be well captured by existing inputs. AEMO proposes to investigate the presence of consumer behaviour trends that are not otherwise explainable by existing factors, and apply it in future ESOOs pending the outcome of the investigation.

Together, these improvements and investigations are intended to enhance transparency in AEMO's forecasting approaches, deliver forecast improvements to support the 2026 ESOO and future publications, and ensure the ESOO remains a credible, forward-looking assessment of reliability risks as the power system continue to evolve.

Consultation focus: value versus administrative burden

For initiatives requiring additional participant data (notably planned outages and ESOO station level energy limits), consultation is explicitly focused on whether the information can be practically provided and whether the effort required is justified by the benefit. Stakeholders are asked to comment on the practical effort and cost of preparing and submitting the information, and whether the expected improvement in reliability forecasts justifies that administrative burden.

Invitation for written submissions

Stakeholders are invited to submit written feedback on any issues related to the Forecast Improvement Plan outlined in Section 8 of this report. Refer to Section 1 of this report for details on this process.

Contents

Tables

Figures

1 Stakeholder consultation process

The publication of this 2025 *Forecast Accuracy Report* marks the commencement of **AEMO's Forecast Improvement Plan consultation**. **Section 8** of this report, the Forecast Improvement Plan, has been informed by assessment of the main contributors to forecast inaccuracies in the rest of this report, as well as improvement initiatives emerging from AEMO's ongoing ESOO development process[8]. This consultation covers the initiatives outlined in the Forecast Improvement Plan only, and not the *Forecast Accuracy Report Methodology*.

AEMO last completed the *Forecast Accuracy Report Methodology* two-stage consultation and published the finalised report in October 2024[9], providing guidance on the development of this 2025 *Forecast Accuracy Report*.

The finalised Forecast Improvement Plan will be implemented, to the extent possible, prior to AEMO developing reliability forecasts to be published in the 2026 ESOO for the NEM.

AEMO is seeking feedback on the Forecast Improvement Plan, in particular:

- Is the Forecast Improvement Plan outlined in **Section 8** of this report reasonable, and does it focus on the areas that will deliver the greatest improvements to forecast accuracy?
- If not, what (if any) alternative or additional improvements should be considered to address the accuracy issues identified in this report?
- For initiatives that require more information provision from participants, what are the administrative costs associated with preparing this information, and does the value in improving reliability forecasts outweigh these costs?

AEMO welcomes stakeholder feedback on the above questions in the form of written submissions, which should be sent by email to energy.forecasting@aemo.com.au no later than 5.00 pm (Australian Eastern Daylight Time) Friday, 6 February 2026.

Table 2 outlines AEMO's consultation timeline on the Forecast Improvement Plan. The consultation will follow the single-stage process outlined in Appendix B of the *Forecasting Best Practice Guidelines* (FBPG)[10] published by the Australian Energy Regulator (AER).

Table 2 Consultation timeline

Consultation steps	Indicative dates
Forecasting Reference Group discussion of draft report	26 November 2025
Forecast Accuracy Report and Forecast Improvement Plan published	23 December 2025
Industry forum – outage and energy limit data collection and modelling implementation	21 January 2026
Submissions due on Forecast Improvement Plan	6 February 2026
Final Forecast Improvement Plan published along with a Submission Response document	18 March 2026

[8] Refer to the *Reliability Forecast Guideline* for an overview of the relevant processes, at https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2024-reliability-forecast-guidelines-consultation/final/reliability-forecasting-guidelines.pdf.

[9] See https://aemo.com.au/en/consultations/current-and-closed-consultations/consultation-on-forecasting-accuracy-report-methodology.

[10] See https://www.aer.gov.au/industry/networks/system-planning/guidelines-system-planning/forecasting-best-practice.

2 Introduction

In accordance with NER 3.13.3A(h), AEMO must, no less than annually, prepare and publish information related to the accuracy of its demand and supply forecasts, and any other inputs determined to be material to its reliability forecasts. Additionally, AEMO must publish information on improvements that will apply to the next ESOO for the NEM. The objective of this transparency is to build confidence in the forecasts produced.

To meet this requirement, AEMO has prepared this 2025 *Forecast Accuracy Report* for a broad set of demand, supply, and reliability forecast components, consistent with AEMO's *Forecast Accuracy Report Methodology*[11] and *Reliability Forecast Guidelines*[12].

AEMO last consulted and updated its *Forecast Accuracy Report Methodology* in October 2024 following a two-stage consultation[13]. The 2025 *Forecast Accuracy Report* reflects these methodologies in assessing the accuracy of the 2024-25 demand and supply forecasts published in AEMO's 2024 ESOO for the NEM[14]. It also evaluates the resulting reliability forecasts for each region in the NEM.

The 2024 ESOO forecasts are the latest that can be assessed against a full year of subsequent actual observations.

2.1 Definitions

Any assessment of accuracy relies on precise definitions of technical terms to ensure forecasts are evaluated on the same basis they were created. To support this:

- All forecasts are reported on a "sent out" basis unless otherwise noted.
- Historical operational demand "as generated" (OPGEN) is converted to "sent out" (OPSO) by excluding an estimate of auxiliary load, which reflects load used within generator sites.
- Auxiliaries are typically excluded from demand forecasts as they relate to the scheduling of generation and do not correlate well with underlying customer demand.
- All times mentioned are NEM time – Australian Eastern Standard Time (AEST, UTC+10) – not local times, unless otherwise noted.
- Terms used in this report are defined in the Glossary at the end of this report.

Figure 1 shows the demand definitions used in this document.

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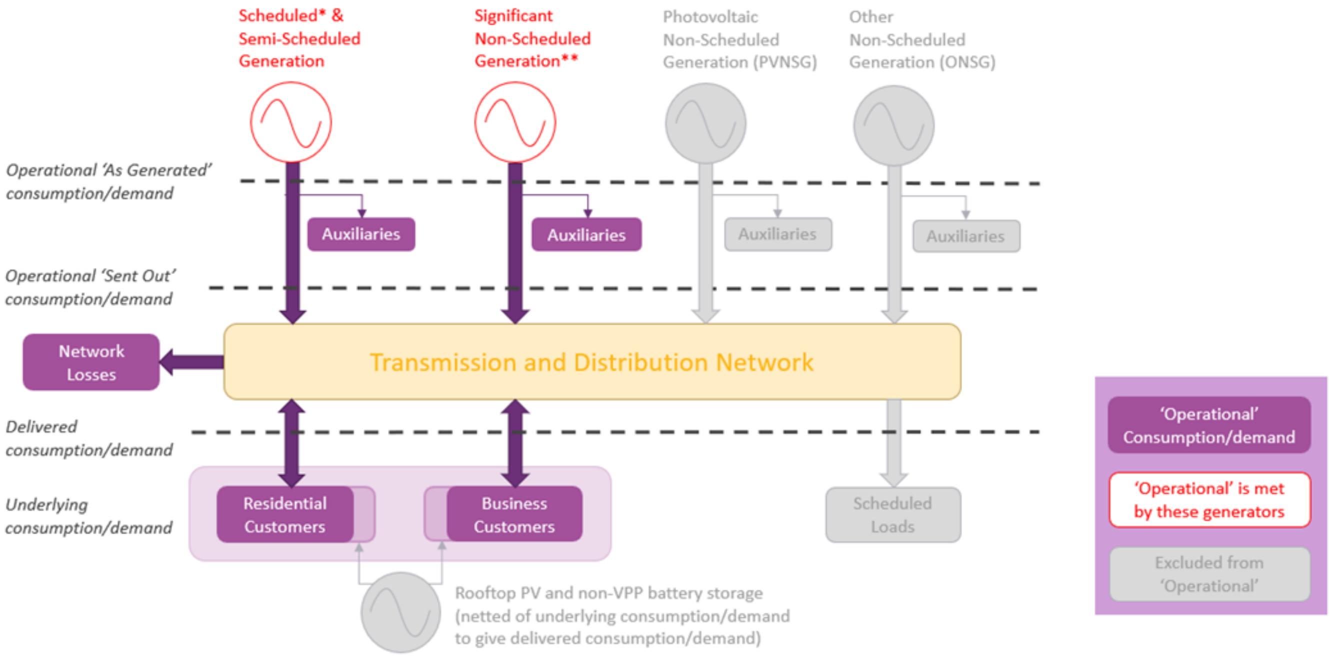
[11] See https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/consultation-on-forecasting-accuracy-report-methodology/final/forecast-accuracy-report-methodology.pdf?la=en.

[12] See https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2024-reliability-forecast-guidelines-consultation/final/reliability-forecasting-guidelines.pdf?lang=en.

[13] See https://aemo.com.au/en/consultations/current-and-closed-consultations/consultation-on-forecasting-accuracy-report-methodology.

[14] See https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2024/2024-electricity-statement-of-opportunities.pdf.

Figure 1 Demand definitions used in this document



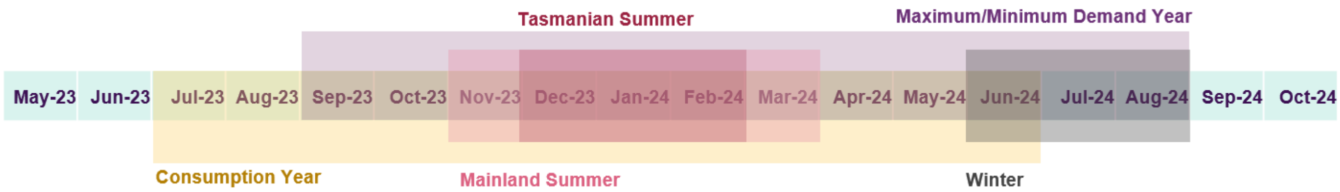
* Including virtual power plants (VPPs) from aggregated behind-the-meter battery storage.
** For definition, see https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Dispatch/Policy_and_Process/Demand-terms-in-EMMS-Data-Model.pdf.

Seasonal definitions

For consistency, data and methodologies of actual observations (or 'actuals') are the same as those used for the corresponding forecasts in the 2024 ESOO. This means an energy consumption year is aligned with the financial year, being July to June inclusive, and, as **Figure 2** shows:

- A year for the purposes of annual minimum demand is defined as September to August inclusive.
- Summer is defined as November to March inclusive for all regions, except Tasmania, where summer is defined as December to February inclusive.
- Winter is defined as June to August inclusive for all regions.

Figure 2 Seasonal definitions used in this document



Percentage errors

The percentage errors that measure the differences between forecast and actual values presented in the report are calculated in line with AEMO's *Forecast Accuracy Report Methodology*[15]:

$$percentage\ error = \frac{forecast - actual}{actual} \text{ x } 100$$

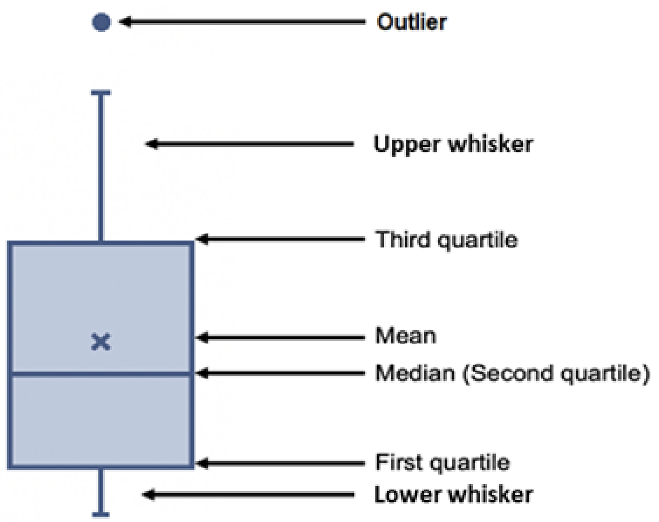
Using this approach, a negative percentage error indicates an under-forecast compared to actuals, where a positive error is an over-forecast. For example, a percentage error of -20% implies the forecast is 20% *lower* than actuals.

Box plots

In this report, some figures use box plots to illustrate the forecast accuracy. A box plot (sometimes also referred to as a box and whiskers plot) is a way of displaying the distribution of data based on the following five points: upper whisker, third quartile, median (second quartile), first quartile, and lower whisker. This way, it graphically shows if the distribution is symmetrical, how tight the distribution is, and if the data is skewed.

The vertical lines represent the upper whisker and lower whisker values, while the top and bottom of the box show the third and first quartiles respectively, as illustrated in **Figure 3**. The line through the box is the median and, if present, the cross will represent the mean. Sometimes, observed values may fall outside the range defined by the first and third quartiles. These values are then identified as outliers instead of contributing to the upper or lower whisker values. Such outliers are shown as dots.

Figure 3 Explanation of box plots used in this report



2.2 Forecast components

Production of AEMO's high-level outputs requires multiple sub-forecasts to be developed and appropriately integrated; these are called component forecasts (or forecast components).

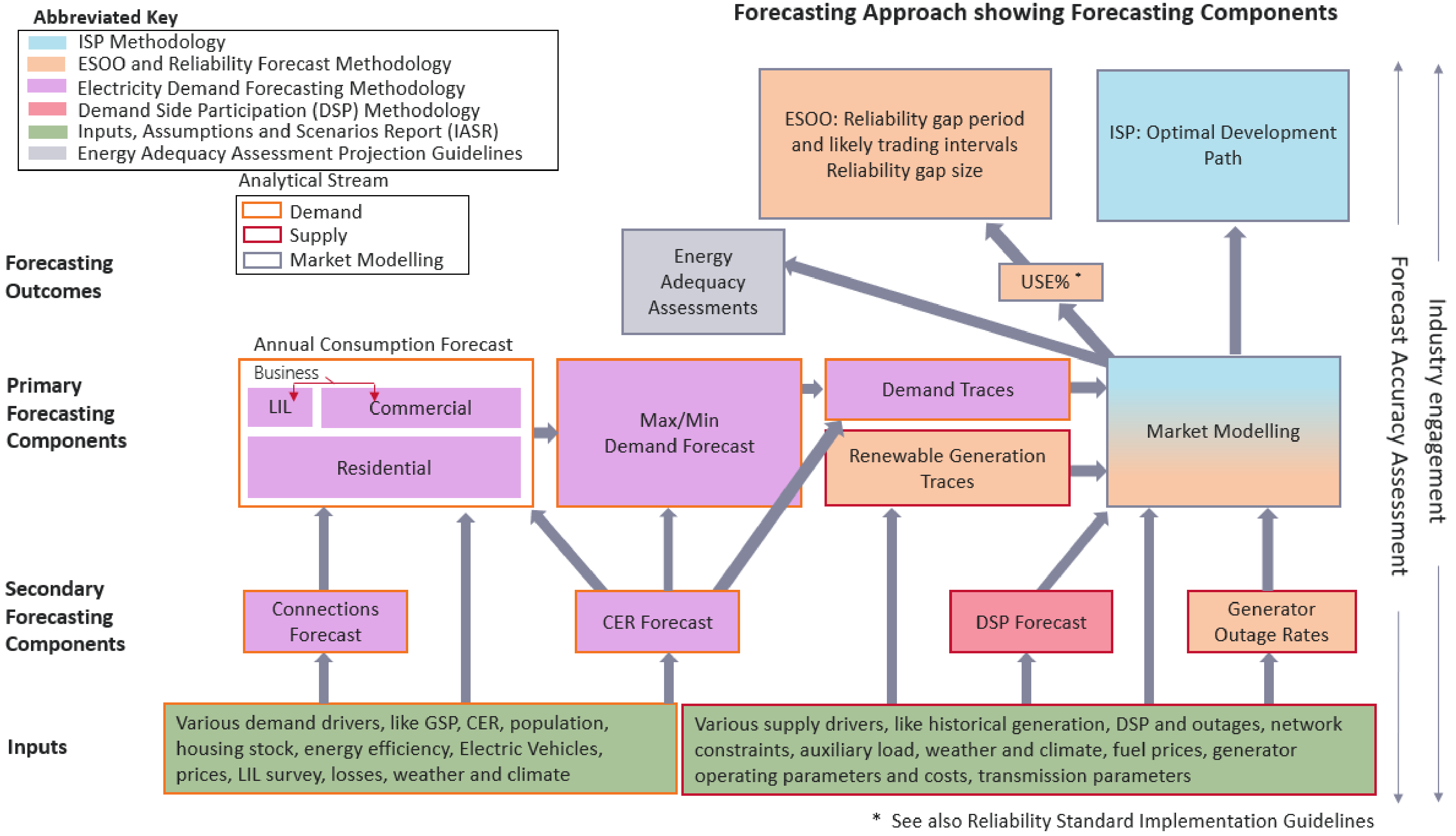
[15] See https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/consultation-on-forecasting-accuracy-report-methodology/final/forecast-accuracy-report-methodology.pdf?la=en.

Figure 4 shows the forecast components leading to AEMO's reliability forecast and the methodology documents (see colour legend) explaining these processes in more detail[16].

In **Figure 4**, inputs can be seen as data streams (including forecasts provided by consultants) used directly in AEMO's forecasting process. In some cases, AEMO processes such information, for example consumer energy resources (CER), where AEMO combines inputs from multiple consultants into its forecast uptake of distributed PV, EVs and battery storage.

[16] These documents are available at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-approach.

Figure 4 Forecasting components



2.2.1 Assessability of forecast accuracy

Forecasting is the estimation of the future values of a variable of interest. However, just because a variable of interest can be forecast, it does not mean that it can be rigorously assessed. There are three broad categories of forecasts:

1. **Strongly assessable** – exact and indisputable actual values for the variable of interest exist at the time of forecast performance assessment. This allows definitive comparison with forecasts produced earlier.
2. **Moderately assessable** – reasonable estimates for the actual variable of interest are available at the time of forecast performance assessment. The reader of forecast performance should be aware that the forecast performances quoted are estimates.
3. **Weakly assessable** – there are no acceptable actual values of the variable of interest at the time of forecast performance assessment. It is inappropriate to produce any forecast accuracy metrics for this category.

AEMO focuses the forecast accuracy assessment on strongly and moderately assessable forecast components.

As AEMO gains access to increasing proportions of relevant data, including smart meter data, some weakly assessable forecasts may become moderately assessable. This includes the split of the consumption forecast into residential and business consumption and potentially better insight into the impacts of energy efficiency schemes.

2.3 Scenarios and uncertainty

There are two types of uncertainties in AEMO’s forecasts:

- **structural drivers**, which are modelled as parameters that vary across scenarios, including considerations such as population and economic growth and uptake of future technologies, such as distributed PV, batteries and EVs, and
- **random drivers**, which are modelled as a probability distribution and include weather drivers and generator outages.

For the random drivers, a probability distribution of their outcomes can be estimated, and the accuracy of this assessed, as is the case for extreme demand forecasts (see **Section 5**) and generator availability (see **Section 6**).

For the structural drivers, such probability distributions cannot be established, and instead the uncertainty is captured using different scenarios and sensitivities.

The scenarios and sensitivities used for the 2024 ESOO are summarised in **Table 3**.

Table 3 Key scenarios and sensitivities used in the 2024 ESOO

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

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

3 Trends in demand drivers

Electricity consumption and demand forecasts are predicated on a wide selection of inputs, drivers, and assumptions. Input drivers to the demand models include:

- macroeconomic growth,
- electricity connections growth,
- distributed PV, EVs and behind-the-meter battery uptake, and
- numerous other drivers including energy efficiency and appliance mix.

As outlined in **Section 2.3** above, three scenarios were detailed in the 2024 ESOO to illustrate possible electricity consumption pathways: *Progressive Change*, *Step Change* (which was applied as the *ESOO Central* scenario for RRO assessment purposes), and *Green Energy Exports*.

Many of the input variables to these ESOO forecast scenarios are measured regularly and have material impacts on year-ahead forecast outcomes (for example, distributed PV installations). Other inputs, such as energy efficiency or electrification, are still influential, but are difficult to isolate in terms of the impact they have. Influential and assessable input drivers are discussed below.

3.1 Macroeconomic growth

AEMO engaged Deloitte Access Economics to prepare a suite of long-term macroeconomic forecasts to be used in preparation of long-term energy consumption forecasts[17].

For the 2024 ESOO Central scenario, real Australian GDP was forecast to grow by 1.2% in 2024-25, with Gross State Product for NEM regions slightly lower at 1.1% annual growth. These subdued growth forecasts were outpaced by Australia's actual GDP increasing by 1.8% for the year to June 2025[18]. The stronger than anticipated economic growth is partially due to a sustained annual increase in net overseas migration, that was higher than the 250,000 increase assumed by Deloitte[19]. While there has been international trade turmoil brought on by tariff increases in April 2025, Australia's inflation has been within the Reserve Bank of Australia (RBA) target range for 2024-25, with greater certainty of prices for consumers and businesses supporting higher than forecast growth[20].

While real disposable income per capita increased by 0.4% in 2024-25, there have been sustained increases in rents, increasing energy prices, and global supply chain challenges. **Figure 5** shows the magnitude of the short- to medium-term economic growth forecasts that underpin the 2024 ESOO forecasts in the context of recent economic performance,

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[17] Deloitte Access Economics, Economic forecasts 2023/24, Prepared for the Australian Energy Market Operator Limited, at https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2024/deloitte-access-economics-2023-24-economic-forecast-report.pdf?rev=b058908f55f94e01aebd3ab71c7f35cd&sc_lang=en.

[18] Australian Bureau of Statistics, 5206.0 Australian National Accounts: National Income, Expenditure and Product, released 3 September 2025, at https://www.abs.gov.au/statistics/economy/national-accounts/australian-national-accounts-national-income-expenditure-and-product/latest-release.

[19] The annual increase in net overseas migration was 315,924 to the end of March 2025. Australian Bureau of Statistics: National, state and territory population (September 2025 release), at https://www.abs.gov.au/statistics/people/population/national-state-and-territory-population/latest-release. Accessed 30 October 2025.

[20] Reserve Bank of Australia, Measures of Consumer Price Inflation, updated 29 October 2025, at https://www.rba.gov.au/inflation/measures-cpi.html.

demonstrating that actual economic growth was lower than the five-year average growth forecast by Deloitte. All else equal, lower economic growth will lead to lower electricity consumption than forecast. However, the extent of this relationship is dependent on the sectors that will be most impacted by continued challenging economic conditions, given the differences in energy intensity[21] between sectors.

Figure 5 Macroeconomic growth rates, chain volume measures, June 2016 to June 2025, seasonally adjusted

3.2 Connections growth

The quantity of new electricity connections is a key growth driver for electricity consumption in the residential sector. The forecasts are based on population and household growth forecasts from AEMO's economic consultant (Deloitte Access Economics for the 2024 ESOO) and the Australian Bureau of Statistics (ABS) and are shown in **Table 4**. For the 2024 ESOO, the short-term projections were forecast by blending short-term trends of NMI growth from the AEMO database with data provided by Deloitte Access Economics[22] and the ABS.

Connections forecasts for the NEM were 0.2% lower than actual connections for 2024-25, with the NEM-level results driven by under-forecasts for Victoria, Queensland, and South Australia. An under-forecast is associated with higher than anticipated dwelling completions

While connections are one of the most assessable inputs to the ESOO forecasting process, the contribution of connections forecasts to overall NEM consumption forecast variance remains minimal (see **Section 4**).

[21] Energy intensity is a measure of the general energy efficiency of an economy. It is calculated as units of energy per unit of economic output.

[22] Deloitte Access Economics, Economic forecasts 2023/24, Prepared for the Australian Energy Market Operator Limited, at https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2024/deloitte-access-economics-2023-24-economic-forecast-report.pdf?rev=b058908f55f94e01aebd3ab71c7f35cd&sc_lang=en.

Table 4 Connections forecast and actuals for 2024-25

Region	2024 ESOO forecast for 2024-25 (number of customers)	Actual for 2024-25 (number of customers)*	Difference (%)^
New South Wales	3,629,957	3,629,705	0.0%
Queensland	2,117,170	2,124,572	-0.3%
South Australia	821,895	826,882	-0.6%
Tasmania*	264,134	-	-
Victoria	2,848,457	2,855,654	-0.3%
NEM (not including Tasmania)*	**9,417,479**	**9,436,813**	**-0.2%**

* Actuals represent number of customers as at the end of financial year 2024-25 (30 June 2025). AEMO is in the process of reconciling Tasmania actuals.
^ Negative number reflects an under-forecast of actuals, positive number an over-forecast.

3.3 Rooftop PV and PV non-scheduled generation

In AEMO's modelling, distributed PV is split into:

- rooftop PV (installations typically on rooftops up to 100 kilowatts [kW] in size), and
- PV non-scheduled generation (PVNSG), which ranges from 100 kW to 30 MW in size.

To define actual rooftop PV installed capacity in the 2024 ESOO, AEMO received installation data from the Clean Energy Regulator. However, rooftop PV actuals are not known precisely at any point in time, and are subject to revision because PV installers have up to one year to submit applications for Small-scale Technology Certificates to the Clean Energy Regulator.

AEMO's 2024 ESOO Central forecast adopted an averaging approach of the forecasts provided by AEMO's CER consultants Green Energy Markets (GEM)[23] and CSIRO's 2022 forecasts[24] scaled by the relative change in GEM's 2023 to 2022 forecasts[25]. For rooftop PV and PVNSG, the scaled CSIRO forecasts were considered to better align with the narrative of the *Progressive Change* scenario, while GEM's forecasts were considered better suited to the *Green Energy Exports* scenario. For the ESOO Central scenario, AEMO considered an average of the two forecasts to better balance the divergent views for rooftop PV, while GEM's forecasts were chosen for PVNSG[26]. With two forecasts, using two independent models but aligned to similar assumptions and the same scenario narratives, AEMO considered that the accuracy of the forecasts should be improved over a single view.

The differences between forecasts and actuals by region are highlighted in **Table 5**, showing this for the 2024 ESOO Central scenario.

[23] Green Energy Markets: *Final Projections for distributed energy resources – solar PV and stationary energy battery systems* (December 2023), at https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2024/Green-Energy-Markets-2023-Consumer-Energy-Resources-Forecast-Report.

[24] CSIRO: Small-scale solar PV and battery projections 2022, at https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2024/Green-Energy-Markets-2023-Consumer-Energy-Resources-Forecast-Report.

[25] For details, see AEMO's 2024 *Forecasting Assumptions Update*, at https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2024/2024-forecasting-assumptions-update.pdf?rev=fde4b245c15a4cd0a0d3e97a43cbb8dd&sc_lang=en.

[26] These choices were described and consulted on with stakeholders via the *Forecasting Assumptions Update* report.

Table 5 Rooftop PV and PVNSG installed capacity comparison by region, as of 30 June 2025

Installed as of 30 June 2025		NSW	QLD	SA	TAS	VIC	NEM
Rooftop PV	Estimated actual (MW)	7,867	7,085	2,674	364	5,191	23,180
	Central forecast (MW)	8,024	7,493	2,937	368	5,635	24,457
	Central forecast error (%)	**2.0%**	**5.8%**	**9.8%**	**1.2%**	**8.6%**	**5.5%**
PVNSG	Estimated actual (MW)	628	326	341	16	500	1,811
	Central forecast (MW)	515	385	336	9	525	1,770
	Central forecast error (%)	**-18.1%**	**18.0%**	**-1.4%**	**-45.8%**	**5.1%**	**-2.3%**
Total distributed PV	Estimated actual (MW)	8,495	7,411	3,015	380	5,690	24,991
	Central forecast (MW)	8,539	7,878	3,273	377	6,160	26,226
	Central forecast error (%)	**0.5%**	**6.3%**	**8.6%**	**-0.8%**	**8.3%**	**4.9%**

Note: Actuals are based on AEMO's latest actual data as of 25 September 2025.

For all NEM regions, rooftop PV forecasts were over-forecast, with Tasmania being the most accurate with an error of 1.2%, and South Australia being the least accurate with an error of 9.8%. Further analysis indicated that these errors were due to an over-estimation of future growth in average PV system size, leading to higher forecast capacity than historical records. This assumption has been revised down in subsequent forecasts. AEMO notes that because installed rooftop PV capacity is negatively correlated with operational consumption, and minimum demand in particular, these forecasts may be slightly lower as a result. Less impact is anticipated for maximum demand, given that the timing of maximum demand events tends to be after sunset, when PV output is very low.

As shown in the table, PVNSG had a mix of under- and over-forecasts across regions, with South Australia being the most accurate with an error of -1.4%, and Tasmania being the least accurate with an error of -45.8%. Across the NEM, the PVNSG forecast had a small under-forecast of -2.3%, which is a significant improvement compared to an over-forecast of 13.1% reported on in the 2024 *Forecast Accuracy Report*.

3.4 Electric vehicles

The rapid uptake of EVs has been challenging to forecast, particularly in the short term. Typical methodologies for short-term forecasts, including those used by AEMO, incorporate regression and trend analyses, which have limited suitability for rapidly evolving consumer technology and particularly when externalities such as government policy introduce new consumer incentives. Furthermore, forecasts of new technologies suffer from low baseline figures, which tends to result in larger forecast errors when expressed as a percentage.

Table 6 shows forecast errors associated with fleet size and fleet share in the 2024 ESOO forecasts, relative to the actuals recorded in June 2025. Fleet size is defined as the count of EVs[27] currently on the road, while fleet share is the percentage of the total road fleet, which includes battery EVs (BEVs) and PHEVs.

While EV sales grew, sales for all new vehicles were lower, reflecting weak consumer spending[28] and more supply in the used vehicle market[29]. The 2024 central forecast anticipated higher than actual fleet sizes across all NEM regions by around 25%.

[27] The total of battery electric vehicles (BEVs) and plug-in hybrid electric vehicles (PHEVs).

[28] See https://www.coxautoinc.com.au/insights-reports/cox-automotive-australia-2025-new-market-forecast/.

[29] See https://www.aada.asn.au/press_release/used-car-supply-grows-but-sales-continue-to-decline/.

Accurately assessing the electricity consumption for EVs is not presently possible as there is insufficient means to isolate EV charging load. However, given the relatively small fleet size, AEMO considers it unlikely to introduce a material contribution to electricity consumption forecast inaccuracy.

Table 6 Electric vehicle (BEV and PHEV) fleet size and fleet share by region, as of 30 June 2025

As of 30 June 2025		NSW	QLD	SA	TAS	VIC	NEM
Fleet size	Estimated actual	131,227	77,153	21,425	5,595	100,511	335,911
	Central forecast	162,789	95,666	25,181	7,924	127,052	418,612
	Central forecast error (%)	**24%**	**24%**	**18%**	**42%**	**26%**	**25%**
Fleet share	Estimated actual	1.8%	1.6%	1.3%	1.1%	1.7%	1.7%
	Central forecast	2.4%	2.0%	1.6%	1.5%	2.2%	2.2%
	Central forecast error (%)	**31%**	**29%**	**23%**	**45%**	**33%**	**31%**

Note: For 2024 ESOO forecasts, at the national level, the historical data to end of financial year 2024 aligns with data published by the Electric Vehicle Council (2024) and the Federal Chamber of Automotive Industries (FCAI), June 2024 update (at https://www.fcai.com.au/get-vfacts/). For 2025 actuals, at the state level, the historical data to end of 2024-25 aligns with data published by the AAA EV index (https://www.aaa.asn.au/research-data/electric-vehicle/).

3.5 Network losses

Network losses refer to the electricity lost due to electrical resistance heating of conductors in the transmission and distribution networks. AEMO states losses as percentages of the energy entering the network. Intra-regional transmission and distribution losses are sourced from either the Regulatory Information Notice submitted to the AER by transmission or distribution network service providers, or directly from the relevant network service providers.

AEMO assumes the loss percentage for the latest financial year is a reasonable estimate for losses over the entire forecast period. AEMO has assessed this assumption against recent trends and found it is appropriate. Interconnector losses are modelled explicitly, predominantly as a function of regional load and network flow.

The latest reported losses provide a best estimate of the actuals for 2024-25. As shown in **Table 7**, transmission losses for New South Wales are higher than the loss factors applied in the 2024 ESOO forecasts. This higher loss factor contributes to New South Wales network losses being under-forecast by 19.7% (see **Section 4**). The combined impact of the change in both transmission and distribution loss factors across all regions contributes to a network loss under-forecast of 11.8% for the NEM region (**Table 9**). Note, in addition to updated loss factors, losses are also impacted by actual network flows being different than forecast network flows.

Table 7 Estimated network loss factors

Region	Transmission loss factor		Distribution loss factor	
	Applied to 2024 forecast	Used to estimate actuals for 2024-25	Applied to 2024 forecast	Used to estimate actuals for 2024-25
New South Wales	2.82%	3.5%	4.07%	4.15%
Queensland	2.32%	2.38%	4.30%	4.06%
South Australia	3.57%	2.9%	5.76%	6.06%
Tasmania	2.49%	2.55%	3.28%	3.42%
Victoria	2.24%	2.63%	4.45%	4.14%

4 Operational energy consumption forecasts

AEMO forecasts annual operational energy consumption by region on a financial year basis. **Figure 627** shows the central forecasts used in each year's formal reliability assessment prepared from 2020 to 2025, for each region, relative to actual consumption. The forecasts in the Update to the 2021 ESOO through to the 2024 ESOO generally project flat or steadily increasing consumption. The original 2021 ESOO forecasts showed lower and declining consumption in comparison, due to an earlier baselining approach applied to the underlying business mass market forecast with revised historical actuals data thereafter[30]. This section focuses on the 2024 ESOO forecasts, unless otherwise stated.

Figure 6 Recent annual energy consumption forecasts by region (gigawatt hours [GWh])

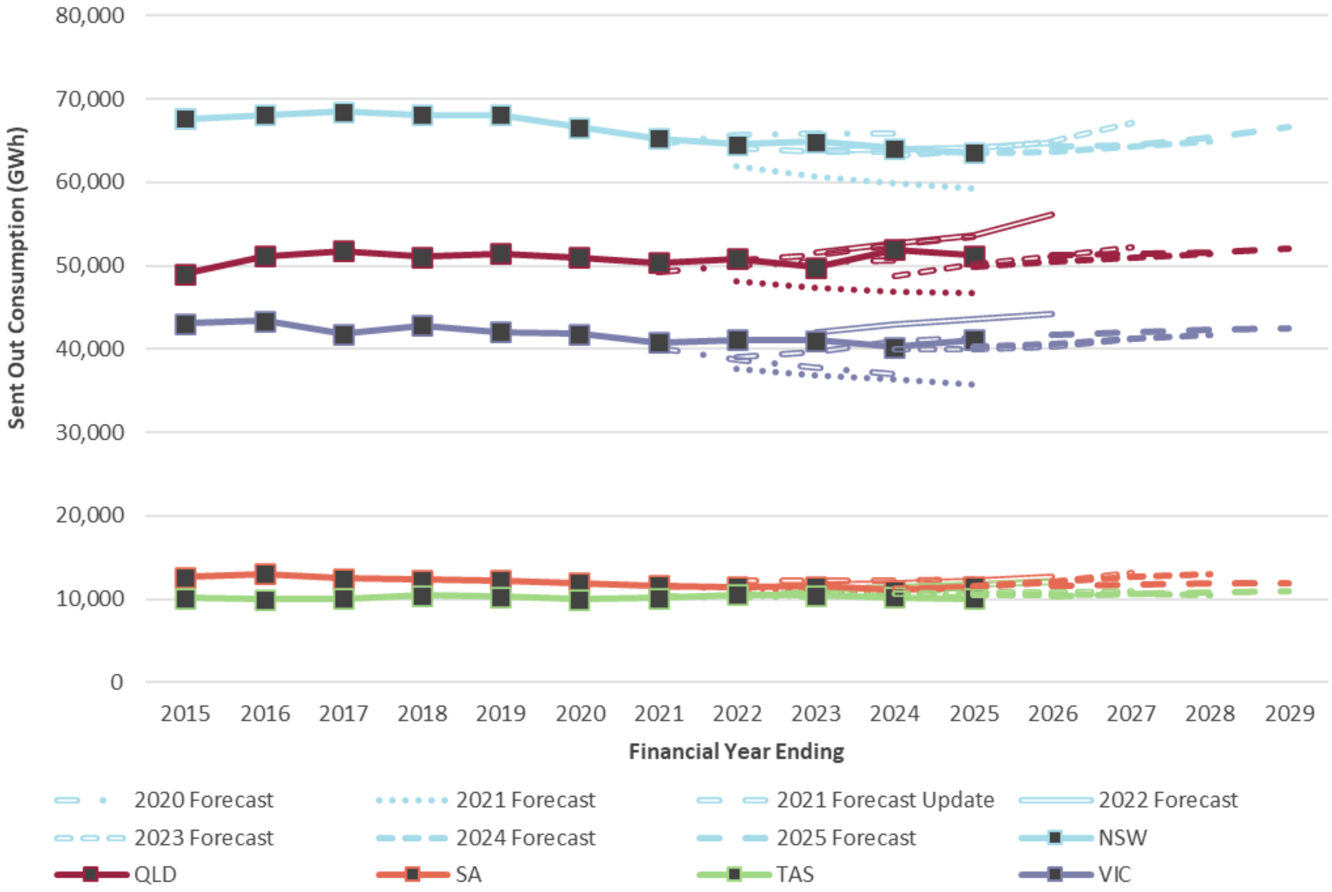


Table 8 shows the forecast accuracy of the OPSO forecasts for the last five years, assessed one year ahead using the error calculation outlined in **Section 2.1**. Individual region errors have been mostly within ±3%, with some notable large errors from the original 2021 ESOO, and for Queensland and Tasmania in some of the most recent assessable ESOOs. At the NEM

[30] See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2022/update-to-2021-electricity-statement-of-opportunities.pdf.

level, the weighted average percentage error has improved from -2.0% in the 2023 ESOO to -1.0%, which is the lowest recorded error for the most recent five years.

Table 8 Recent one-year ahead operational sent out energy consumption forecast accuracy by region

One-year ahead annual operational consumption accuracy (%)	2020 ESOO forecast in 2020-21	2021 ESOO forecast in 2021-22	2021 ESOO update forecast in 2021-22	2022 ESOO forecast in 2022-23	2023 ESOO forecast in 2023-24	2024 ESOO forecast in 2024-25
New South Wales	-1.1%	-3.9%	-0.7%	-1.7%	-1.3%	-0.1%
Queensland	-2.4%	-5.2%	-0.3%	3.4%	-6.1%	-2.8%
South Australia	-0.3%	-0.8%	6.5%	2.7%	2.0%	1.5%
Tasmania	2.4%	-1.4%	-0.3%	6.3%	3.7%	4.2%
Victoria	-1.7%	-8.4%	-5.0%	2.3%	-0.5%	-2.0%
NEM	**-1.4%**	**-5.0%**	**-1.1%**	**1.4%**	**-2.0%**	**-1.0%**

Note: Negative number reflects an under-forecast of actuals, positive numbers an over-forecast.

Table 9 shows the sources of variance for the 2024-25 consumption forecast of the NEM as published in the 2024 ESOO, relative to actual 2024-25 consumption. The sources of variance documented are non-exhaustive, because AEMO cannot currently isolate factors such as energy efficiency improvements, electrification of household heating, cooling, and weather effects not currently considered in the methodology. Anything not explicitly assessed in **Table 9** is captured by the residual.

Table 9 NEM operational energy consumption forecast accuracy by component, 2024-25

Category	2024 forecast (GWh)	Actual (GWh)	Difference (%)	Indicative impact on total consumption
Rooftop PV*	26,960	27,270	-1.1%	0.2%
PV non-scheduled generation*	2,970	2,974	-0.1%	0.0%
Other non-scheduled generation*	4,082	3,386	20.5%	-0.4%
Residential cooling load	5,017	5,798	-13.5%	-0.4%
Residential heating load	8,233	6,931	18.8%	0.7%
Connections Growth	673	644	4.5%	0.0%
EVs	719	596	20.7%	0.1%
Large industrial loads	48,679	47,504	2.5%	0.6%
Liquefied natural gas (LNG)	6,567	7,123	-7.8%	-0.3%
Network losses	9,533	10,806	-11.8%	-0.7%
Operational sent out	**175,566**	**177,283**	**-1.0%**	**-0.9%**
Auxiliary load	7,928	8,077	-1.8%	-0.1%
Operational as generated	**183,494**	**185,360**	**-1.0%**	

* Note that as rooftop PV, PV non-scheduled generation and other non-scheduled generation all reduce operational demand, as such, an over-forecast of these items indicates a negative forecast error (under-forecast) of total consumption, and vice versa.

The known components assessed identify both under- and over-forecast directions. The largest contributors were the under-forecast in network losses (-0.7% impact on the operational as generated forecast) and the over-forecast in residential heating load (0.7% impact). The combined impact of the known components and unknown components (residual shown below in **Figure 7**) contributed to a -1.0% under-forecast in OPSO for the NEM.

The forecast accuracy of components shown in **Table 9** do not necessarily represent AEMO's modelling performance. For example, AEMO considers that the notable large under-forecast in residential cooling load (-13.5%) and over-forecast in residential heating load (18.8%) is largely associated with the 2024-25 financial year being Australia's hottest year since records began in 1910-11[31], which is extreme against the climate trend modelled by AEMO. AEMO energy forecasting models estimate consumption in a mean, climate adjusted weather year, hence variation should be expected year to year. The headline figure of a -1.0% level of accuracy is influenced by various factors that are more predictable (such as economic outcomes and connections growth), and variables that are not as predictable (such as the level of significant weather outcomes that influence the forecasts).

Figure 7 shows the contribution of the components in **Table 9** in explaining the difference in forecast and actual operational as generated consumption. Beneath the NEM aggregate level, region-specific variances provide additional insight:

- Record hot temperatures contributed to an under-forecast in residential cooling load for all NEM regions (noting that modelling for Tasmania assumes zero cooling load)[32]. These temperature records also contributed to an over-forecast in residential heating load in all regions, with South Australia over-forecast by 38%. For NEM regions individually, mean temperature area-averages[33] were either the highest (New South Wales, Victoria, and South Australia) or second-highest (Queensland and Tasmania) on record.
- Unforeseen LIL outages can be a major factor in forecast accuracy. For the 2024 ESOO, LILs in New South Wales (1.2%), Queensland (3.8%), South Australia (5.0%), and Tasmania (7.9%) were over-forecast, likely due to advice from the operators of each facility that did not consider operational outages, whereas Victoria (-2.8%) was under-forecast. The under-forecast in Victoria was influenced by significant growth in data centres. The NEM-wide accuracy of 2.5% may be able to be improved through updates to methodology discussed in the Forecast Improvement Plan (**Section 8**).
- Forecasts for liquefied natural gas (LNG)-related electricity consumption in Queensland were lower (-7.8%) than actual consumption due to an un-forecast increase in electricity consumption at one gas field.
- Network losses were under-forecast for all regions except South Australia, which typically has some of the highest proportional losses due to a combination of distance from major generation, multiple remote communities, and the flow of energy to and from other NEM regions. The under-forecast was highest in New South Wales (-19.7%) which was influenced by another large upward revision in the transmission loss factor (see **Section 3.5**).
- Generator auxiliary loads were under-forecast in all states except for Tasmania. Auxiliary ratio estimates are revised from year to year, but the updated ratios are not applied to historical generation. Auxiliary load is generally a small contributing factor to forecast accuracy, with the largest impact in South Australia (-0.3% impact to operational as generated consumption).
- NMI connections were slightly under-forecast for 2024-25 in Victoria (-0.3%), Queensland (-0.3%), and South Australia (-0.6%), though this is ultimately only a small source of variance in the forecasts.

[31] Bureau of Meteorology, Financial year climate and water statement 2024-25, at http://www.bom.gov.au/climate/current/financial-year/aus/summary.shtml. Accessed 6 November 2025.

[32] Bureau of Meteorology, Financial year climate and water statement 2024-25, at http://www.bom.gov.au/climate/current/financial-year/aus/summary.shtml. Accessed 6 November 2025. Area in this context refers to Australian states and territories.

[33] Area-averages are calculated using a 5 km resolution grid, representative for the entire area, described in *Calculating average temperatures*, at https://www.bom.gov.au/climate/change/about/temp_timeseries.shtml. Accessed 20 November 2025. The area-averages are not weighted for electricity consumption and are therefore an imperfect guide to explaining variance in temperature sensitive loads.

- EVs have been assessed separately for the first time in this year's report. While the 2024 ESOO forecast consumption was 20.7% higher than estimated EV consumption at the NEM level, the component remains small against other categories, leading to a small impact on total NEM forecast accuracy. The over-forecast is observed to be consistent across all NEM regions.
- Residual variance is an aggregation of all components not currently measured. Electrification, other weather effects not specifically modelled (such as humidity), energy efficiency, and sectoral specific activity levels not captured by economic inputs, are examples of factors captured within the residual. For the 2024 ESOO, the residual factor was equivalent to -0.7% of operational as generated consumption, which is a significant fall from the -3.3% residual from the 2024 *Forecast Accuracy Report*.

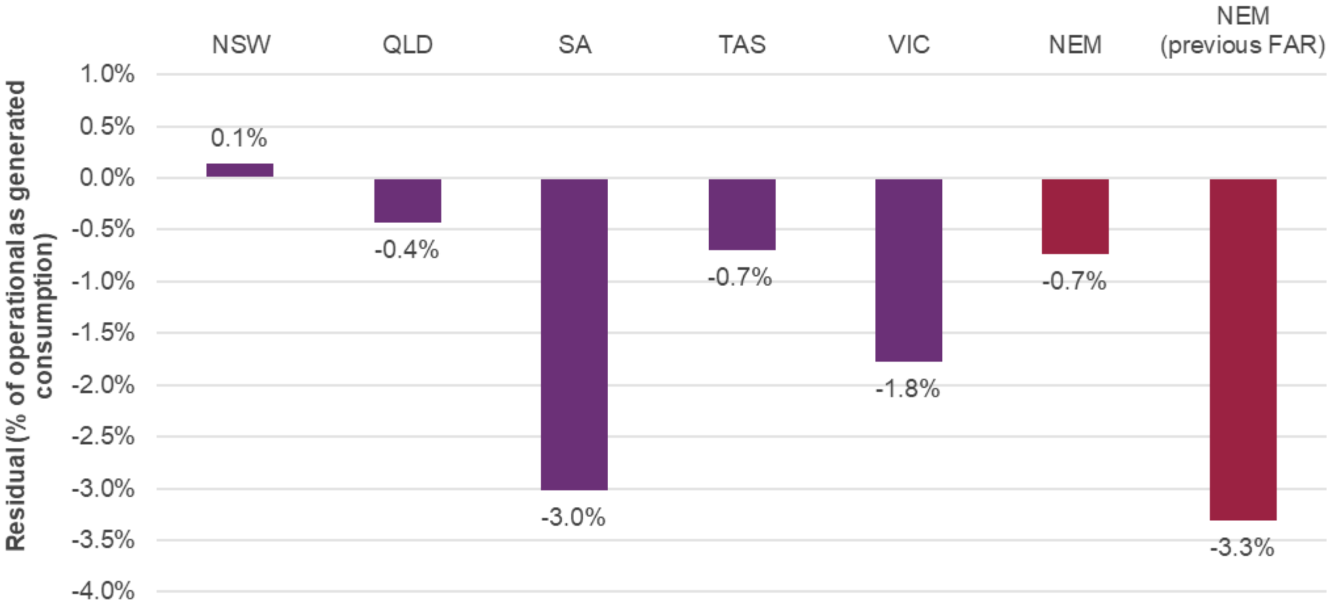
Figure 7 NEM operational as generated energy consumption variance by component, 2024-25 (GWh)

Figure 8 shows the size of the 2024 ESOO assessed residual component relative to operational as generated consumption for each of the NEM regions. The residual component is highest for South Australia (-3.0%) and Victoria (-1.8%). While the residual has fallen significantly from last year, AEMO is continuing to investigate factors identified in the 2024 Forecast Improvement Plan (**A1**) that may be able to reduce the residual. Additional factors include:

- Residential heating and cooling consumption currently relies on temperature data, but does not incorporate humidity. AEMO has proposed a Forecast Improvement Plan (**Section 8**) item to test whether humidity data is appropriate in the residential and business mass market forecast model, particularly for regions such as Queensland[34].
- Trends in fuel-switching from natural gas to electricity may not be fully captured by the forecast electrification load, leading to an underestimation of forecast consumption.
- Estimated energy efficiency actuals remain difficult to isolate to compare to the energy efficiency forecasts.

[34] AEMO analysis of relative humidity, wet bulb temperature, and 'real feel' estimates indicates that Queensland was subject to elevated heat impacts in 2023-24, but this is now less of a concern with the 2024-25 results.

Figure 8 Residual variance in operational as generated consumption forecasts for NEM regions, 2024-25



FAR: Forecast Accuracy Report.

The Forecast Improvement Plan in **Section 8** discusses potential improvements. The rest of this section focuses on assessments of the 2024 ESOO operational energy consumption forecasts for 2024-25 for each NEM region.

4.1 New South Wales

Operational as generated energy consumption for New South Wales was forecast with a difference of -0.1% in 2024-25. The highest area-average temperature for New South Wales on record observed in this year had more of an influence in reducing heating load, than increasing cooling load, contributing to a net 0.4% indicative impact on operational as generated accuracy (**Table 10** and **Figure 9)**.

Network losses accounted for the largest error, with an under-forecast of -19.7%. This large network losses under-forecast is due to a significant revision to the New South Wales transmission loss factor – assumed to be 2.82% in the forecast, but updated to 3.5% in calculating actuals (see **Section 3.5** for details). The aggregation of all other measured components, combined with the non-measured components (captured by the residual), was enough to almost fully offset the network losses discrepancy.

Forecasts for the behind-the-meter generation components – rooftop PV, PV non-scheduled generation, and other non-scheduled generation (ONSG) – as well as the LILs were all particularly close to actuals, emphasising the accurate consumption level forecasts for New South Wales.

Table 10 New South Wales operational energy consumption forecast accuracy by component, 2024-25

Category	2024 forecast (GWh)	Actual (GWh)	Difference (%)	Indicative impact on total consumption
Rooftop PV*	9,075	9,025	0.6%	-0.1%
PV non-scheduled generation*	878	958	-8.3%	0.1%
Other non-scheduled generation*	1,170	1,263	-7.4%	0.1%
Residential cooling load	1,954	2,186	-10.6%	-0.4%
Residential heating load	3,428	2,873	19.3%	0.8%
Connections Growth	225	187	20.3%	0.1%
EVs	275	238	15.7%	0.1%
Large industrial loads	17,423	17,221	1.2%	0.3%
Network losses	3,558	4,429	-19.7%	-1.3%
Operational sent out	**63,449**	**63,506**	**-0.1%**	**-0.1%**
Auxiliary load	2,463	2,468	-0.2	0.0%
Operational as generated	**65,912**	**65,974**	**-0.1%**	

* Note that as rooftop PV, PV non-scheduled generation and other non-scheduled generation all reduce operational demand, as such, an over-forecast of these items indicates a negative forecast error (under-forecast) of total consumption, and vice versa.

Figure 9 New South Wales operational as generated energy consumption variance by component, 2024-25 (GWh)

4.2 Queensland

The largest change in the forecast accuracy results for Queensland this year is that the residual (non-measured components of variance) has fallen from -5.0% to -0.4%. This result means that additional consumption identified by a bespoke analysis of the business mass market, for last year's forecast accuracy report, has not persisted. Humidity was also considered a possible cause of the large residual, but that appears to be less likely with these updated results.

Nine out of the 12 variance components (including the residual) contributed to an under-forecast. The net result of a -2.8% under-forecast means that Queensland is the second least accurate region forecast, behind Tasmania (4.2% over-forecast).

From an overall impact perspective of the measurable components for Queensland (the last column of **Table 11**), ONSG -1.2%), LNG (-1.0%), and LILs (1.0%) were the most influential components. Multiple LIL sites and facilities recorded lower production than anticipated in the forecasts, contributing to a 3.8% over-forecast in Queensland. Part of these lower production results were due to the higher-than-average rainfall in Queensland, which disrupted surface mines and export volumes exiting through Queensland coal terminals[35].

ONSG was lower than forecast due to classification inaccuracies and revisions, which have been resolved within AEMO's data for the 2025 ESOO.

The hot temperatures (second highest mean area-average record in 2024-25), led to a residential cooling load under-forecast (-7.7%) that overshadowed the residential heating load over-forecast (16.0%)[36], which is much less significant given the naturally warmer climate. While the residual for Queensland is now much smaller (**Figure 10**), ongoing development of the residential model will test whether humidity effects are appropriate to include.

The other large source of variance for Queensland was the under-forecast for LNG. This consumption is associated with coal seam gas production that is largely produced for export markets. The under-forecast of this electricity consumption more than offset the entire LIL over-forecast (**Figure 10**).

Table 11 Queensland operational energy consumption forecast accuracy by component, 2024-25

Category	2024 forecast (GWh)	Actual (GWh)	Difference (%)	Indicative impact on total consumption
Rooftop PV*	8,612	8,393	2.6%	-0.4%
PV non-scheduled generation*	591	521	13.3%	-0.1%
Other non-scheduled generation*	1,604	951	68.6%	-1.2%
Residential cooling load	1,885	2,042	-7.7%	-0.3%
Residential heating load	603	520	16.0%	0.2%
Connections Growth	161	185	-13.0%	0.0%
EVs	182	144	26.3%	0.1%
Large industrial loads	14,584	14,050	3.8%	1.0%
Liquefied natural gas (LNG)	6,567	7,123	-7.8%	-1.0%
Network losses	2,374	2,546	-6.8%	-0.3%
Operational sent out	**49,811**	**51,236**	**-2.8%**	**-2.6%**
Auxiliary load	2,855	2,956	-3.4%	-0.2%
Operational as generated	**52,666**	**54,192**	**-2.8%**	

* Note that as rooftop PV, PV non-scheduled generation and other non-scheduled generation all reduce operational demand, as such, an over-forecast of these items indicates a negative forecast error (under-forecast) of total consumption, and vice versa.

[35] Department of Industry, Science, and Resources, Resources and Energy Quarterly, June 2025, at https://www.industry.gov.au/sites/default/files/2025-06/resources-and-energy-quarterly-june-2025.pdf. Accessed 7 November 2025.

[36] Bureau of Meteorology, Financial year climate and water statement 2024-25, at http://www.bom.gov.au/climate/current/financial-year/aus/summary.shtml. Accessed 6 November 2025.

Figure 10 Queensland operational as generated energy consumption variance by component, 2024-25 (GWh)

4.3 South Australia

South Australia operational as generated consumption was over-forecast by 1.2% for 2024-25, with rooftop PV (-7.3% under-forecast) and residential heating load (37.9% over-forecast) being most influential in driving the forecast higher (see **Figure 11**). The 2024-25 financial year had the hottest average, maximum, and minimum area-average temperature in South Australia on record, which is most likely to be the main cause for the heating load over-forecast. The under-forecast cooling load was also significant (-24.9%), but less influential.

South Australia LILs were over-forecast by 5.0%, as shown in **Table 12**. Over-forecasts are often common for LILs due to unforeseen outages that are not advised by facility operators as part of their annual survey process. One of these unforeseen events was associated with Whyalla steelworks when its parent company entered financial administration in 2024-25[37].

For 2024-25, South Australia recorded the highest residual of -3.0% among the regions. This is an improvement over the residual of -4.2% from the previous year, but is nevertheless significant. EVs are now assessed separately outside the residual. Additional effort, including estimating electrification, energy efficiency, and other difficult to measure subsets of the results, will allow for a better assessment of the components that are driving the greatest variance in forecast consumption compared to actual consumption. See the Forecast Improvement Plan in **Section 8** for proposed improvements.

[37] Australian Mining, South Australia pledges $650m for Whyalla steelworks, 6 June 2025, at https://www.australianmining.com.au/south-australia-pledges-650m-for-whyalla-steelworks/. Accessed 7 November 2025.

Table 12 South Australia operational energy consumption forecast accuracy by component, 2024-25

Category	2024 forecast (GWh)	Actual (GWh)	Difference (%)	Indicative impact on total consumption
Rooftop PV*	3,226	3,480	-7.3%	2.2%
PV non-scheduled generation*	642	640	0.4%	0.0%
Other non-scheduled generation*	63	35	80.3%	-0.2%
Residential cooling load	440	585	-24.9%	-1.3%
Residential heating load	973	706	37.9%	2.3%
Connections Growth	42	55	-23.2%	-0.1%
EVs	40	33	20.1%	0.1%
Large industrial loads	3,549	3,378	5.0%	1.5%
Network losses	862	853	1.1%	0.1%
Operational sent out	**11,598**	**11,426**	**1.5%**	**1.5%**
Auxiliary load	46	79	-42.5%	-0.3%
Operational as generated	**11,644**	**11,506**	**1.2%**	

* Note that as rooftop PV, PV non-scheduled generation and other non-scheduled generation all reduce operational demand, as such, an over-forecast of these items indicates a negative forecast error (under-forecast) of total consumption, and vice versa.

Figure 11 South Australia operational as generated energy consumption variance by component, 2024-25 (GWh)

4.4 Tasmania

Tasmania's operational as generated consumption was over-forecast by 4.2%, which was the worst headline performance of all the NEM regions. Ore supply challenges and global price volatility impacting the Liberty Bell Bay smelter accounted for most of the region over-forecast, as shown by the LIL over-forecast (7.9%)[38]. All other known components that contribute to Tasmania's forecast variance were relatively benign in terms of their influence on consumption accuracy (see **Table 13** and **Figure 12**). While the headline figure may be the most inaccurate, the unpredictable nature of LIL production changes means that Tasmania's consumption accuracy is one of the most explainable.

The 2024-25 financial year was the second-hottest average temperature year ever recorded for Tasmania, resulting in a 9.7% over-forecast of heating degree days, equivalent to 0.6% of operational as generated consumption[39]. For the supply side components (the first three component categories in **Figure 12**), the other non-scheduled generation over-forecast (5.2%) was almost offset by a rooftop PV under-forecast (-4.2%). The variance for some of the other individual components was significant, for example EVs, but the impact was low due to the small contribution of this component.

Tasmania's unknown residual variance was -0.9% of operational as generated consumption. Efforts to isolate the accuracy of additional, currently unknown, forecast components will assist AEMO to improve consumption forecasts. See the Forecast Improvement Plan in **Section 8** for proposed improvements.

Table 13 Tasmania operational energy consumption forecast accuracy by component, 2024-25

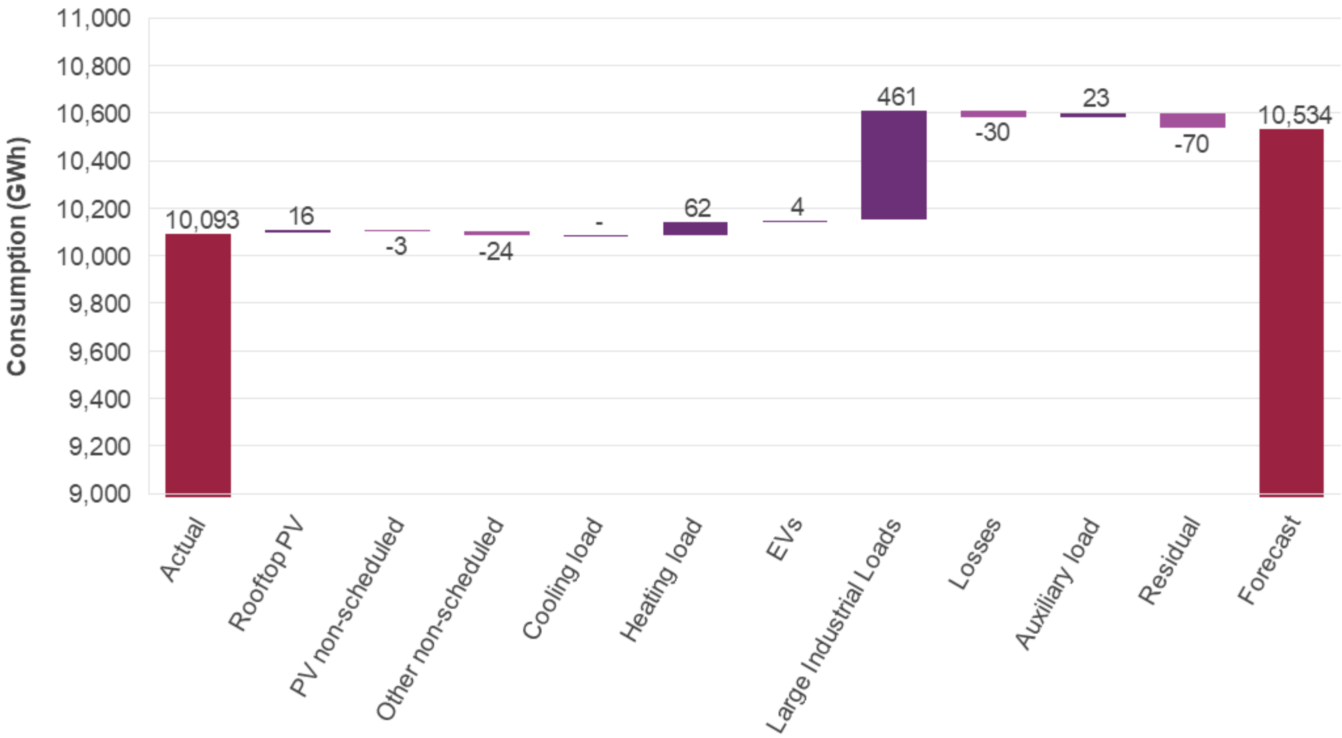
Category	2024 forecast (GWh)	Actual (GWh)	Difference (%)	Indicative impact on total consumption
Rooftop PV*	367	383	-4.2%	0.2%
PV non-scheduled generation*	29	25	12.6%	0.0%
Other non-scheduled generation*	477	454	5.2%	-0.2%
Residential cooling load	-	-	-	-
Residential heating load	705	643	9.7%	0.6%
EVs	13	9	43.7%	0.0%
Large industrial loads	6,312	5,851	7.9%	4.6%
Network losses	401	431	-6.9%	-0.3%
Operational sent out	**10,445**	**10,027**	**4.2%**	**4.1%**
Auxiliary load	89	66	35.0%	0.2%
Operational as generated	**10,534**	**10,093**	**4.4%**	

* Note that as rooftop PV, PV non-scheduled generation and other non-scheduled generation are supply side items, an over-forecast of these items indicates a negative forecast error (under-forecast) of total consumption, and vice versa.

[38] See ABC News, 19 May 2025: *Liberty Bell Bay smelter in Tasmania's north enters 'limited operations', no 'forced redundancies'*, at https://www.abc.net.au/news/2025-05-19/liberty-bell-bay-tasmania-smelter-limited-operations/105298336. Accessed 9 November 2025.

[39] Bureau of Meteorology, Financial year climate and water statement 2024-25, at http://www.bom.gov.au/climate/current/financial-year/aus/summary.shtml. Accessed 6 November 2025.

Figure 12 Tasmania operational as generated energy consumption variance by component, 2024-25 (GWh)



4.5 Victoria

Victorian operational as generated consumption for 2024-25 was under-forecast by 2.0% in the 2024 ESOO. The known component sources of variance were all well within a ±1% influence on total consumption (as shown in **Table 14**). However, unmeasured components (captured by the residual), were equivalent to -1.8% of operational as generated consumption (shown in **Figure 13**), suggesting a need to better understand components of the forecast that are currently difficult to measure (such as electrification and energy efficiency).

Victoria was the only region that had a LIL under-forecast (-2.8%). Over-forecasts are more common through the influence of production outages that are difficult to anticipate. Some of the under-forecast for Victoria is due to unexpected growth in data centres, that were mostly captured within the LIL sector for the 2024 ESOO[40].

The most influential known components of the forecast were rooftop PV (-4.7%) contributing to a 0.7% impact on operational as generated consumption, and residential heating load (15.3%) contributing to a 0.8% impact. The 2024-25 financial year was the hottest average year on record for Victoria which explains much of this reduced heating load. The hot year also contributed to a significant under-forecast in residential cooling load (-25.0%), but residential heating load is much more influential in Victoria (**Table 14**).

While the heating load is large, it may currently be under-estimated if electrification of heating loads is happening at a faster rate than forecast. Analysis by AEMO indicates a steady shift from gas to electric heating, particularly in Victoria. If

[40] Data centres have been broken out as their own sector for the 2025 ESOO and beyond. For the 2024 ESOO, data centres were captured withing the LIL or BMM sectors, depending on their size.

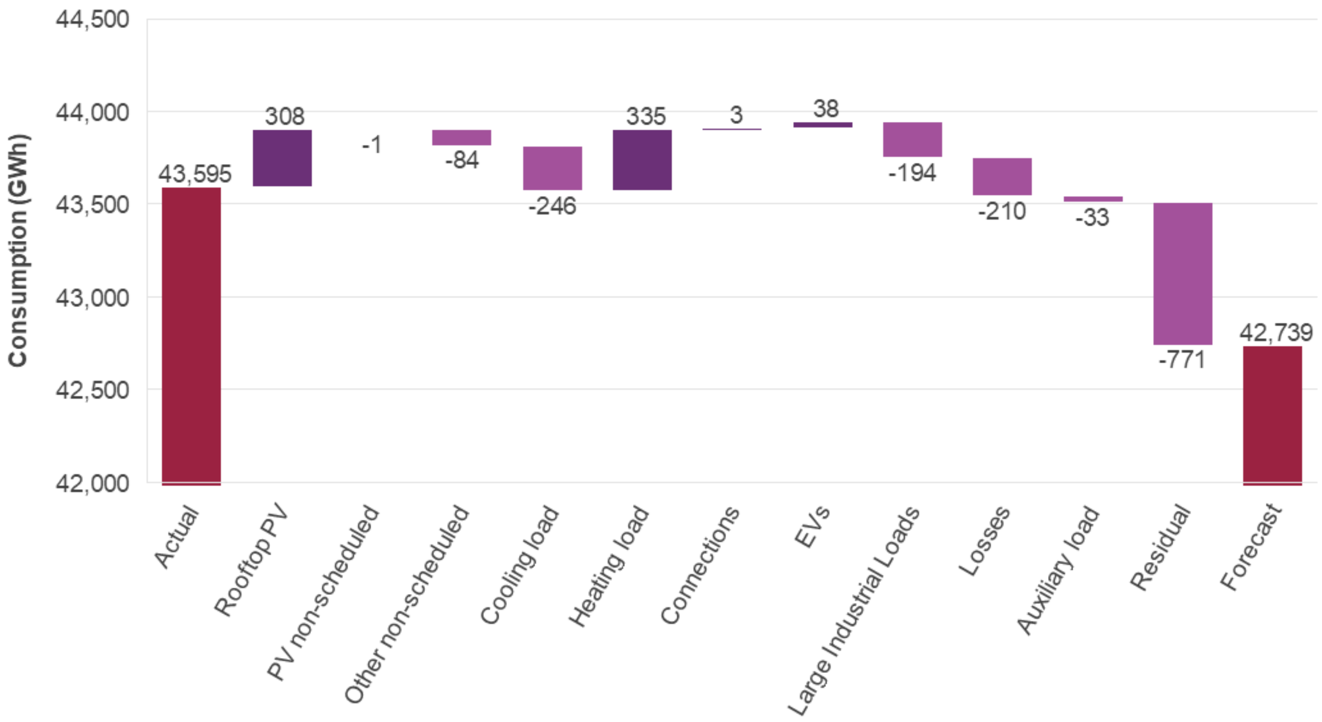
electrification is happening at a faster rate than forecast, then estimates of heating load may be under-estimated, contributing to a larger negative residual.

Table 14 Victoria operational energy consumption forecast accuracy by component, 2024-25

Category	2024 forecast (GWh)	Actual (GWh)	Difference (%)	Indicative impact on total consumption
Rooftop PV*	5,680	5,988	-5.1%	0.7%
PV non-scheduled generation*	831	830	0.2%	0.0%
Other non-scheduled generation*	768	683	12.4%	-0.2%
Residential cooling load	739	985	-25.0%	-0.6%
Residential heating load	2,524	2,189	15.3%	0.8%
Connections Growth	220	217	1.4%	0.0%
EVs	210	172	21.8%	0.1%
Large industrial loads	6,811	7,005	-2.8%	-0.4%
Network losses	2,337	2,547	-8.2%	-0.5%
Operational sent out	**40,264**	**41,087**	**-2.0%**	**-1.9%**
Auxiliary load	2,475	2,508	-1.3%	-0.1%
Operational as generated	**42,739**	**43,595**	**-2.0%**	

* Note that as rooftop PV, PV non-scheduled generation and other non-scheduled generation all reduce operational demand, as such, an over-forecast of these items indicates a negative forecast error (under-forecast) of total consumption, and vice versa.

Figure 13 Victoria operational as generated energy consumption variance by component, 2024-25 (GWh)



5 Extreme demand forecasts

There are three extreme demand events of interest for assessing reliability and system security, and each has differing relevance for forecasting and system engineering:

- summer maximum,
- winter maximum, and
- annual minimum.

Maximum demand events are driven by high business and industrial loads coincident with high residential appliance use, typically in response to extreme heat or cold. Minimum demand events typically occur with extremely mild weather, sometimes overnight when customer demand is low, though more frequently now during the day when high solar irradiance results in high rooftop PV generation that reduces the load drawn from the grid. During these periods, high rooftop PV generation provides a much greater proportion of consumers' electricity, particularly when mild conditions reduce the need for heating or cooling appliance use.

Unlike the consumption forecast, which is a single estimate assuming typical weather conditions eventuate on average across the year, the minimum and maximum demand forecasts are represented by probability distributions of load (with weather and temperature being the key explanatory variable for the distribution). The minimum and maximum probability distributions are summarised via 10%, 50%, and 90% POE forecast values. AEMO assesses the accuracy of those in accordance with the *Forecast Accuracy Report Methodology*[41].

Probability distributions of demand extremes aim to capture a variety of random drivers including weather driven coincident customer behaviour and non-weather driven coincident behaviour. Non-weather driven coincident customer behaviour is driven by a wide variety of random and social factors, including:

- work and school schedules, traffic, and social norms around mealtimes,
- many other societal factors, such as whether the beach is pleasant, or the occurrence of retail promotions that may influence where people may congregate, and therefore what level of energy they will consume if at home, at work, or at another location, and
- the operating level of major industrial customers.

While there is a strong relationship between weather and electricity demand, non-weather factors are also a large driver of variance, so for the same temperature, maximum demand can vary by thousands of megawatts across the NEM due to other factors. Forecasting minimum conditions is often more difficult than maximums, relying on mild conditions and typically occurring during weekend or public holiday conditions that provides fewer historical observations. Unlike extreme temperatures, milder conditions do not produce a strong, consistent demand response.

[41] At https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/consultation-on-forecasting-accuracy-report-methodology/second-stage/forecast-accuracy-reporting-methodology-draft.pdf?la=en.

To better elucidate model performance in the presence of this variance, AEMO reports the probabilistic drivers of extreme events graphically, overlaid with the actual value of the input. This is consistent with the recommendations from the expert review of AEMO's 2020 *Forecast Accuracy Report Methodology* by the University of Adelaide, conducted in 2023[42].

5.1 Extreme demand events in 2024-25

AEMO's demand forecasts exclude the effects of load shedding, network interruptions, and customer reactions to price or reliability signals which is referred to as demand-side participation (DSP). Instead, DSP is modelled separately as a supply option that contributes to meeting forecast demand, as outlined in Section 5.7.

On some summer maximum demand days, supply shortages or very high prices may have triggered load shedding or demand response. To compare actual and forecast demand accurately, actual demand must be adjusted to account for these effects and align with the forecast definition, enabling an appropriate assessment of the performance of the forecast models.

To evaluate forecast accuracy, adjustments are divided into two main categories:

- firm – these adjustments are derived directly from metering information, providing a reliable and data-driven basis for quantifying actual demand outcomes, and
- potential – these adjustments are more indicative and rely on expected customer behaviour or market responses rather than measured metering data, offering insight into possible but less certain demand variations.

During summer 2024-25, adjustments were made to account for local demand response programs and operational factors influencing maximum demand outcomes in Queensland, South Australia, and Victoria (see **Table 15**):

- In Queensland, a total adjustment of around 105 MW was applied to the maximum demand day. This reflects the combined effects of the Peak Smart DSP program and typical industrial demand responses from Townsville Zinc and Boyne Island. The adjusted summer maximum demand was 10,767 MW, recorded on Wednesday, 22 January 2025.
- For South Australia, an adjustment of 40 MW was identified during an event that coincided with a Level 2 Low Reserve Condition (LOR2), with no RERT call or load shedding required. The adjusted maximum demand reached 3,314 MW on Wednesday, 12 February 2025.
- In Victoria, the AusNet's GoodGrid event on Monday, 16 December 2024 resulted in a firm adjustment of approximately 45 MW. After applying this adjustment, the peak demand for the period was 9,553 MW.

5.1.1 Summer 2024-25 maximum demand events

Table 15 presents the summer maximum demand periods for NEM regions in 2024-25, incorporating minor adjustments for the mainland NEM regions as noted above.

[42] See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/accuracy-report/2023-review-of-forecast-accuracy-metrics-report.pdf?la=en.

Table 15 Summer 2024-25 maximum demand with adjustments per region (MW)

Region	Date/time of maximum demand	Operational as generated	Auxiliary load	Operational sent-out	Adjustment (firm)*	Adjustment (potential)	Adjusted sent out
NSW	Tue, 17 December 2024, 17:00	12,463	342	12,121	-	-	12,121
QLD	Wed, 22 January 2025, 18:00	11,144	482	10662	105	-	10,767
SA	Wed,12 February 2025, 19:00	3,318	44	3,274	40	-	3,314
TAS	Thu, 27 February 2025, 07:00	1,283	14	1,268	-	-	1,268
VIC	Mon,16 December 2024, 17:00	9,851	343	9,508	45	-	9,553

* Queensland, South Australia and Victoria include firm adjustments as outlined above the table.

5.1.2 Winter 2024 maximum demand events

AEMO examined winter maximum demand events to identify whether firm or potential adjustments were needed. As outlined in **Section 5.7**, the relatively low prices during peak periods were insufficient to trigger a noticeable demand response. **Table 16** summarises the winter maximum demand results.

Table 16 Winter 2025 maximum demand with adjustments per region (MW)

Region	Date/time of maximum demand	Operational as generated	Auxiliary load	Operational sent out	Adjustment (firm)	Adjustment (potential)	Adjusted sent out
NSW	Tue, 1 July 2025, 18:00	13,204	404	12,800	-	-	12,800
QLD	Thu, 12 June 2025, 19:00	8,622	452	8,170	-	-	8,170
SA	Wed, 9 July 2025, 18:30	2,594	14	2,580	-	-	2,580
TAS	Wed, 4 June 2025, 08:30	1,604	15	1,589	-	-	1,589
VIC	Wed, 25 June 2025, 18:00	8,818	317	8,501	-	-	8,501

5.1.3 Annual 2024-25 minimum demand events

AEMO has analysed the minimum demand events observed throughout 2024-25 across all NEM regions. Consistent with recent years, each region recorded its lowest operational demand during daylight hours. These events generally occurred during mild weather conditions and periods of high solar generation, typically on weekends or public holidays when electricity use was low. For example, Tasmania's minimum demand occurred on Christmas Day (25 December 2024), and Victoria's on New Year's Day (1 January 2025) with both public holidays characterised by widespread business closures and low industrial and commercial activity. Such conditions, combined with strong solar output, resulted in notably reduced operational demand levels.

Minimum demand conditions are generally associated with moderate temperatures and abundant sunlight, which allows rooftop PV systems to operate near peak output while limiting the need for cooling or heating.

The annual minimum demand outcomes for each region are presented in **Table 17** below.

Table 17 Annual minimum demand with adjustments per region (MW)

Region	Date/time of maximum demand	Operational as generated	Auxiliary load	Operational sent out	Adjustment (firm)	Adjustment (potential)	Adjusted sent out
NSW	Sun, 16 February 2025, 12:30	2,718	157	2,561	-	-	2,561
QLD	Sun, 31 August 2025, 11:30	2,790	0	2,790	-	-	2,790
SA	Sat, 19 October 2024, 13:00	-205	4	-209	-	-	-209
TAS	Wed, 25 December 2024, 13:30	728	2	726	-	-	726
VIC	Wed, 1 January 2025, 12:30	1,504	162	1,342	-	-	1,342

Note: Negative operational demand in South Australia reflects periods of high rooftop PV export exceeding underlying demand.

5.2 New South Wales

Figure 14 shows the half-hourly time-series for New South Wales OPSO demand, highlighting extreme demand events observed during 2024-2025. **Table 18** summarises the key characteristics of these events.

Figure 14 New South Wales demand with extreme events identified (MW)

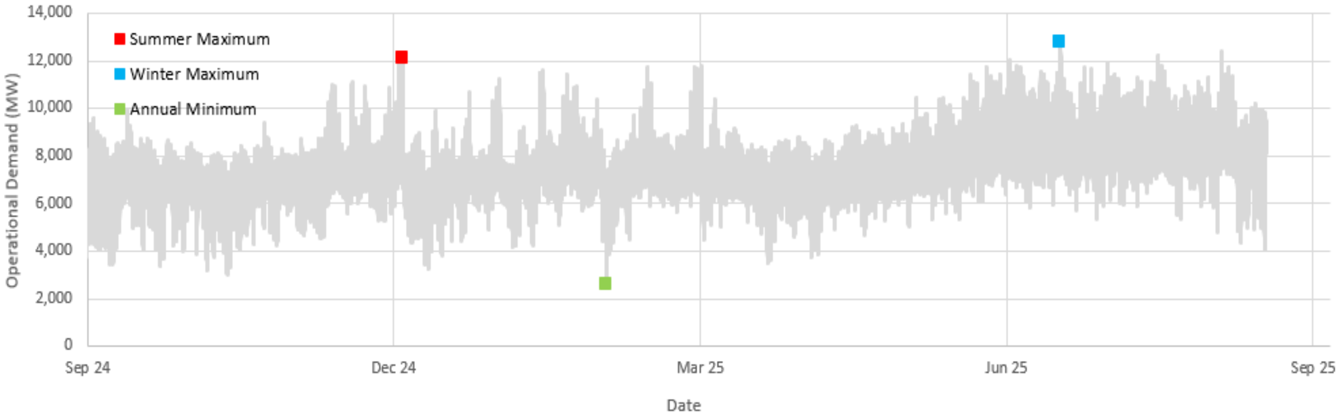


Table 18 New South Wales 2024-25 extreme demand events

Event	Summer maximum	Winter maximum	Annual minimum
NEM date and time	Tue, 17 December 2024, 17:00	Tue, 1 July 2025, 18:00	Sun, 16 February 2025, 12:30
Temperature* (°C)	25.0	11.0	21.5
Max temperature (°C)	38.5	12.5	23.0
Min temperature (°C)	19.8	10.8	14.0
Losses (MW)	872	922	157
Non-scheduled generation (NSG) output (MW)	363	111	574
Rooftop PV output (MW)	1,213	0	5,090
Sent out (OPSO)	12,121	12,800	2,561
Auxiliary (MW)	342	404	157
As generated (OPGEN)	12,463	13,204	2,718

* Bankstown Airport weather station. For more information, see Section 3.3.2 of the 2025 *Inputs, Assumptions and Scenarios Report* (IASR) (https://www.aemo.com.au/consultations/current-and-closed-consultations/2025-iasr).
^ Summer maximum demand is adjusted due to observed price-driven DSP.

Figure 15 presents the probability distributions for maximum and minimum demand events in New South Wales for 2024-25, with vertical lines indicating actual observed values. These distributions capture the range of forecast outcomes, considering model variance due to weather and customer behaviour. The summer maximum, winter maximum, and annual minimum demand events all fell well within their respective forecast distributions, indicating robust model performance.

Figure 15 New South Wales simulated extreme event probability distributions with actuals

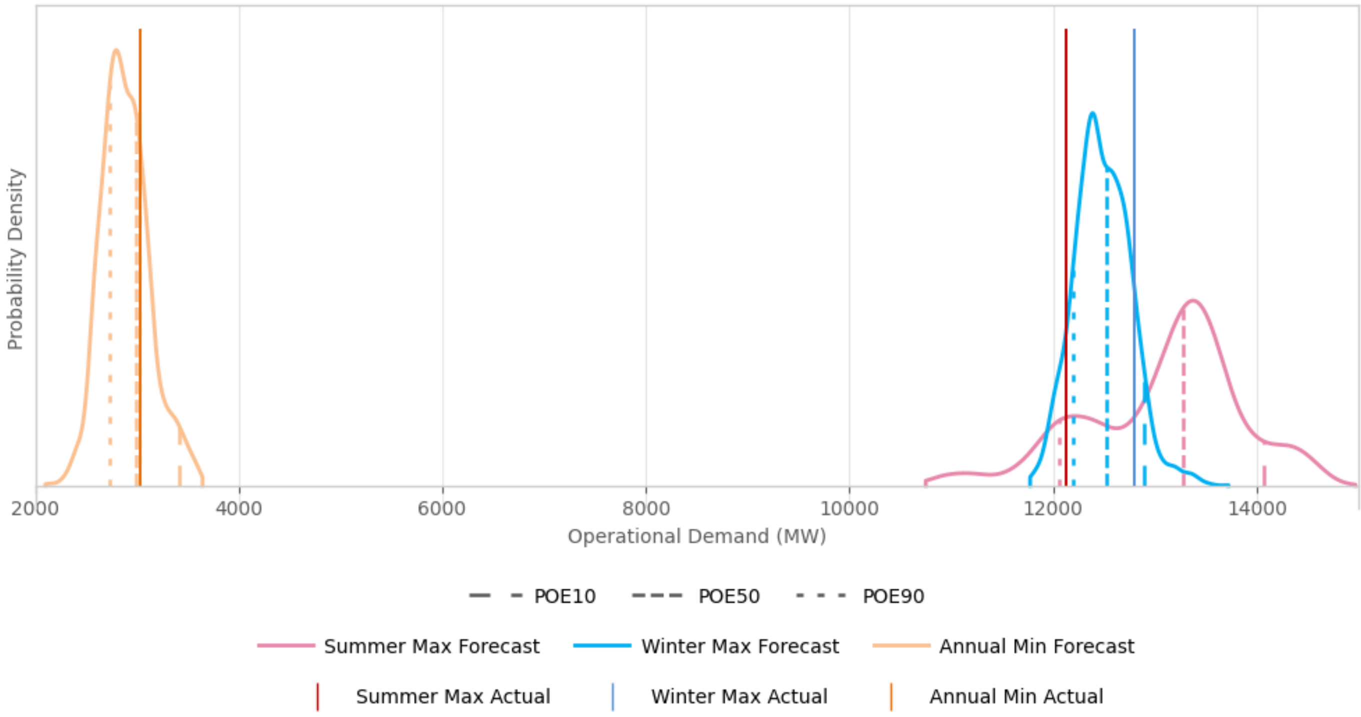


Figure 16 shows the probability distribution and adjusted actuals for relevant model inputs. Insights from these figures are discussed below.

Summer maximum demand:

- The summer maximum operational (sent out) demand occurred on Thursday, 17 December 2024 at 17:00 NEM time (18:00 local time).
- On this day, Bankstown Airport recorded a daily maximum reaching 38.5°C, although by the evening the temperature had cooled to 25°C. The day began with 28.6°C at 9:00 am NEM time, rising to 38.5°C by 1:00 pm, the second highest temperature observed in New South Wales in that summer. This sustained heat resulted in significant cooling demand. The peak also coincided with elevated humidity, as the dew point reached 24.2 °C. Notably, this event followed 16 December peak, which recorded the second-highest operational demand of the summer, highlighting the persistence of high cooling loads across the period.
- PV generation at the time of maximum demand was within the forecast distribution, but towards the left (lower end), reflecting relatively low solar output for such high temperatures.
- The event was driven by sustained high temperatures and humidity throughout the day, which increased cooling loads. Although simulations weighted maximum demand events towards January and February, this event occurred in

mid-December during an early heat wave, and was preceded with the second-highest operational demand of the summer the day prior, highlighting the persistence of high cooling loads across the period. The Tuesday occurrence is consistent with the model's expectation that most maximum demand events fall on weekdays.

- The observed summer maximum demand was between the 90% and 50% POE forecasts, closer to the 90% POE. The temperature at the time of peak demand was at the lower end of the simulated distribution, which may explain why the event was closer to the 90% POE.

Winter maximum demand:

- The winter maximum demand occurred on Tuesday, 1 July 2025 at 18:00 NEM time (18:00 local time). Notably, this winter peak surpassed the summer maximum demand, making it the highest New South Wales operational demand within the 2024-25 season.
- Bankstown recorded a temperature of 11°C at the time, with a daily maximum of 12.5°C and a minimum of 10.8°C. The event coincided with the first major cold outbreak of the season, marked by a strong cold front and coastal low that brought widespread rain, and wind across New South Wales. The combination of weather lifted evening heating demand while solar generation was zero. The conditions on 1 July aligned the key peak-demand factors – weekday timing, and, evening conditions that increases both heating demand, and no rooftop PV contribution at the exact peak interval.
- The observed winter maximum fell between the 50% and 10% POE forecasts. The forecasts anticipated that winter maximum demand would occur in late June or in July, when heating loads are normally significantly higher, which is consistent with the observed maximum demand.

Annual minimum demand:

- The annual minimum operational demand occurred on Sunday 16 February 2024 at 12:30 NEM time (13:30 local time).
- At the time of minimum demand, Bankstown Airport recorded a temperature of approximately 21.5°C, with the day's maximum reaching near 23°C. Clear skies and mild midday conditions prevailed.
- Strong midday solar irradiance resulted in high rooftop PV output, further reducing operational demand.
- The minimum occurred on a Sunday, when many businesses were closed and underlying demand was already lower than on a typical weekday. The minimum did not occur during the traditional shoulder period as expected, but rather in late summer under shoulder-like conditions with clear skies, mild temperatures, and weekend load.
- The actual minimum demand fell just above the 50% POE forecast. The simulations correctly weighted weekends as the most likely time for a minimum, consistent with the observed outcome. However, the model timed the minimum in the shoulder months when these weather conditions are more likely to occur.

Figure 16 New South Wales simulated extreme event probability distributions with actuals

Monthly maximums

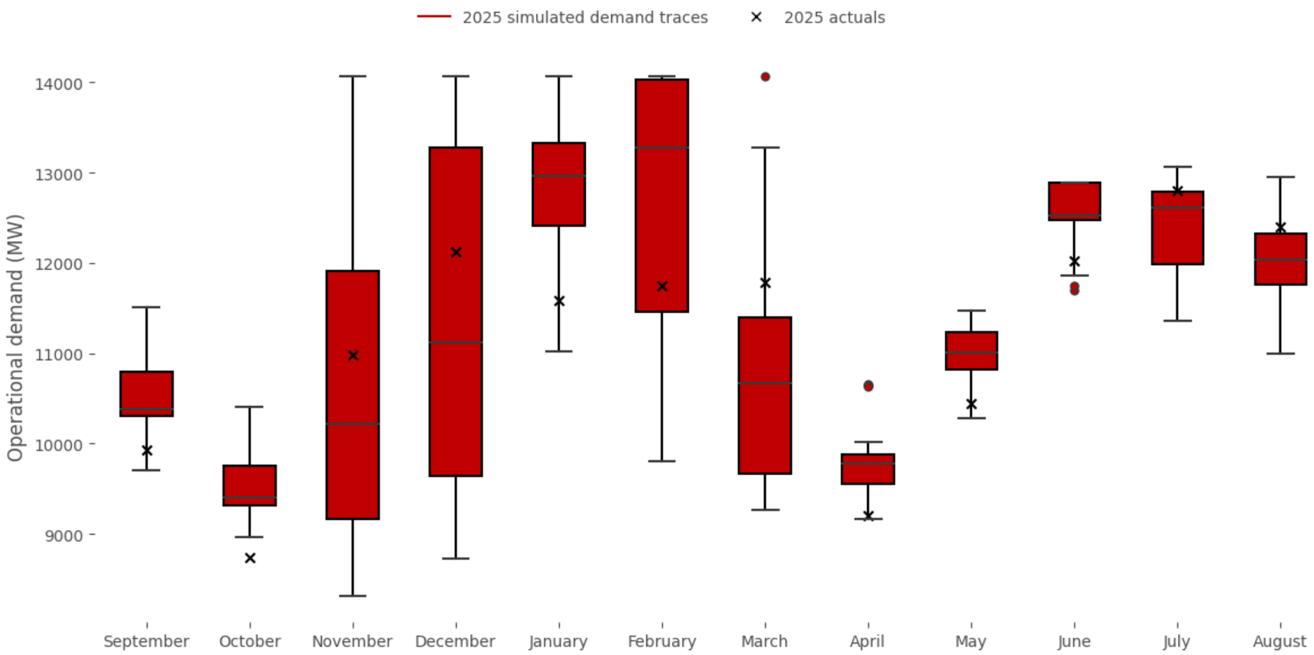
The operational energy consumption and extreme demand forecasts are used to generate 30-minute customer demand profiles ("demand traces"), consistent with the weather patterns observed in 13 reference years (2011-12 to 2023-24). Each trace is independently scaled to ensure that the summer and winter maximum demand forecasts (being summer and winter maximums at either 10% POE or 50% POE) are achieved at least once in their respective seasons. These traces are used in assessing reliability in the ESOO, the EAAP, and the Medium Term Projected Assessment of System Adequacy (MT PASA).

Reliability assessments in these publications may then analyse a combination of simulations across the probability distribution (for example, simulating both 10% POE and 50% POE traces).

Because actual weather conditions may fall outside the range represented in the 13 historical reference years, it is reasonable to expect that a small number of observed monthly maximum operational demand values will fall outside the simulated distribution of monthly maxima derived from demand traces.

The box plot[43] in **Figure 17** illustrates the range of monthly demand maximums for the 2025 simulated demand traces[44]. Outliers, represented by red dots, indicate observations at the tail ends of the distribution. The black "x" markers represent the actual monthly maximum demand values recorded for 2024-25. During summer, winter, and shoulder months, except October, all actuals fell within the simulated distribution range. However, actual New South Wales shoulder-season operational demand consistently fell below the 25th percentile of simulations because mild weather and rapid PV growth suppressed grid load beyond what was captured in model assumptions.

Figure 17 New South Wales monthly maximum demand in demand traces compared with actuals (MW)



5.3 Queensland

Figure 18 presents Queensland's half-hourly OPSO demand time series and corresponding extreme events for 2024-25. Additional details on the extreme demand events observed during the year are summarised in **Table 19**.

[43] Box plots are explained in **Section 2.1.**

[44] The simulated demand traces are provided on a maximum demand year basis, as defined in **Section 2.1.** The 2025 simulated demand traces cover the period from September 2024 to August 2025, inclusive.

Figure 18 Queensland demand with extreme events identified (MW)

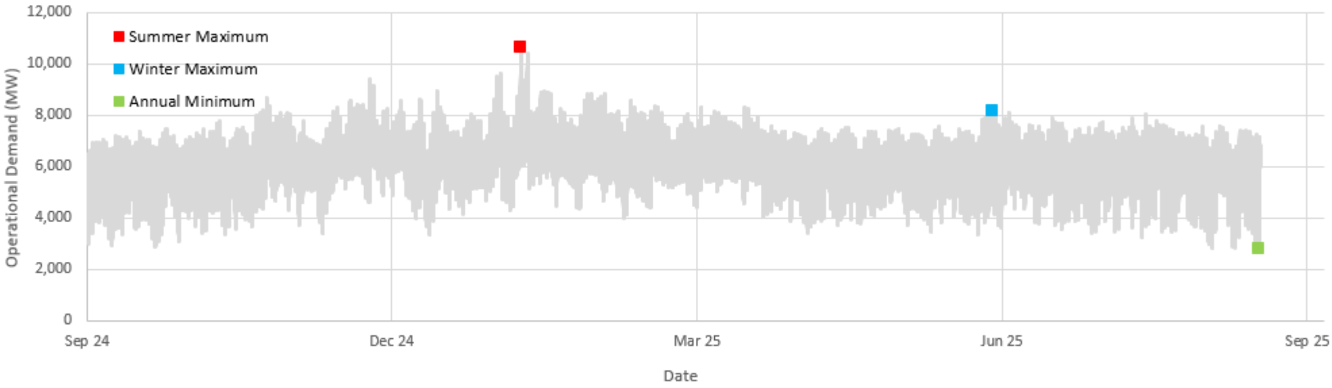


Table 19 Queensland 2024-25 extreme demand events

Event	Summer maximum	Winter maximum	Annual minimum
NEM Datetime	Wed, 22 January 2025, 18:00	Thu, 12 June 2025, 19:00	Sun, 31 August 2025, 11:30
Temperature* (°C)	31.1	11.1	20.3
Max temperature (°C)	36.4	18.5	22.2
Min temperature (°C)	22.6	6.0	7.4
Losses (MW)	598	442	98
NSG output (MW)	137	109	401
Rooftop PV output (MW)	252	0	4,412
Sent out (OPSO)	**10,662** **(adjusted to 10,767)^**	**8,170**	**2,790**
Auxiliary (MW)	482	452	0
As generated (OPGEN)	**11,144** **(adjusted to 11,249)^**	**8,622**	**2,790**

* Archerfield Airport weather station. For more information, see Section 3.3.2 of the 2025 IASR (https://www.aemo.com.au/consultations/current-and-closed-consultations/2025-iasr).
^ Summer maximum demand is adjusted to include the impact of Energy Queensland's Peak Smart program, which was called during the half-hour where maximum demand was observed.

Figure 19 presents the forecast probability distributions for Queensland's maximum and minimum demand events, with vertical lines indicating the actual observations for the past year. The summer maximum demand slightly exceeded the 10% POE threshold, indicating a higher-than-expected peak under extreme conditions. In contrast, the winter maximum was marginally below the 90% POE threshold, reflecting a lower-than-typical winter peak. The annual minimum demand was approximately 200 MW above the 10% POE forecast, highlighting a higher minimum than anticipated under the most extreme low-demand assumptions.

Figure 19 Queensland simulated extreme event probability distributions with actuals

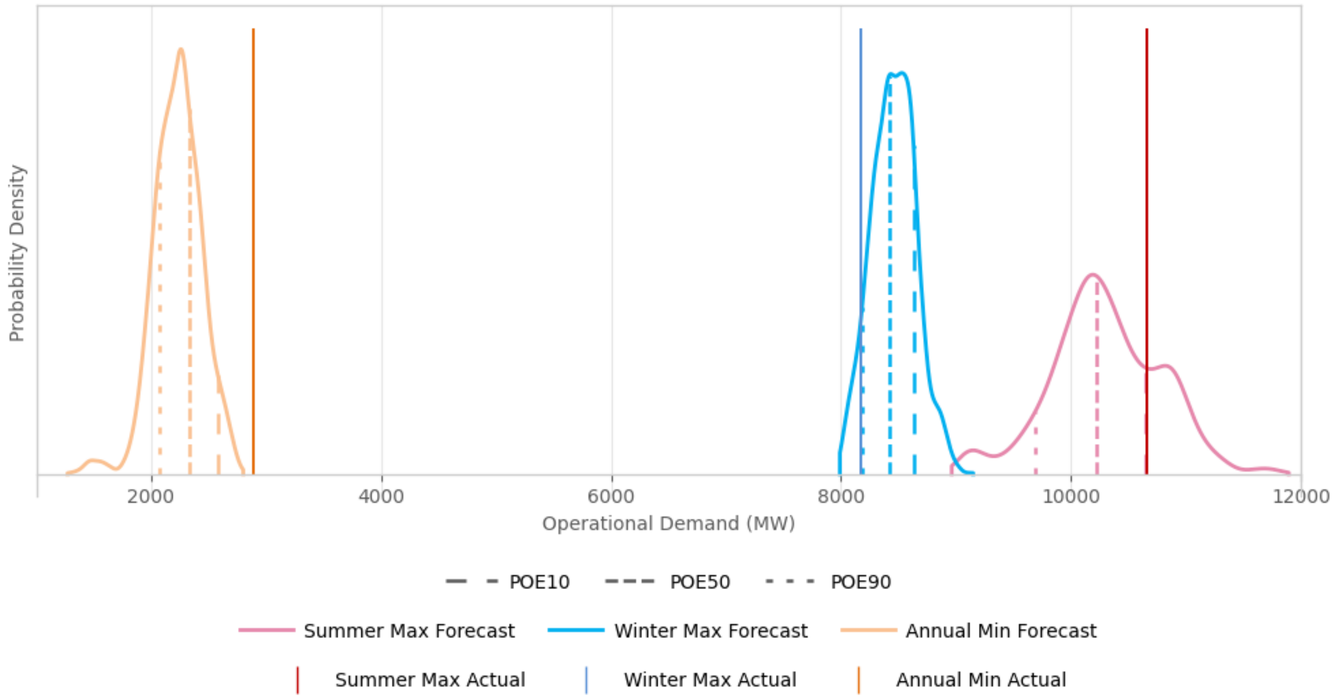


Figure 20 shows the probability distribution and actual values for key model inputs relevant to Queensland's demand outcomes. Insights derived from these figures are discussed below.

Summer maximum demand:

- The summer maximum demand occurred on Wednesday, 22 January 2025, at 18:00 NEM time (NEM time is equivalent to Queensland local time).
- Archerfield Airport recorded a temperature of 31.1°C, with the daily maximum reaching 36.4°C. Dew-point values peaked at 25.4°C, with a minimum around 20.2°C, indicating high humidity and contributing to greater cooling load and thermal discomfort. January 2025 was exceptional across Queensland, with the state average maximum temperature reaching 37.8 °C, making it the equal warmest January on record for Queensland since 1910.
- The event occurred under exceptionally humid conditions, with dew-point values remaining above 20°C and peaking at 25.4°C, consistent with the sustained humidity typical of south-east Queensland in late January. This level of moisture significantly increases latent cooling load, causing air-conditioning systems to operate far more intensively than under dry heat alone. The persistence of high humidity into the evening contributed to demand rising above the 10% POE forecast. The summer maximum demand was slightly above the 10% POE, reflecting higher-than-median demand scenarios.

Winter maximum demand:

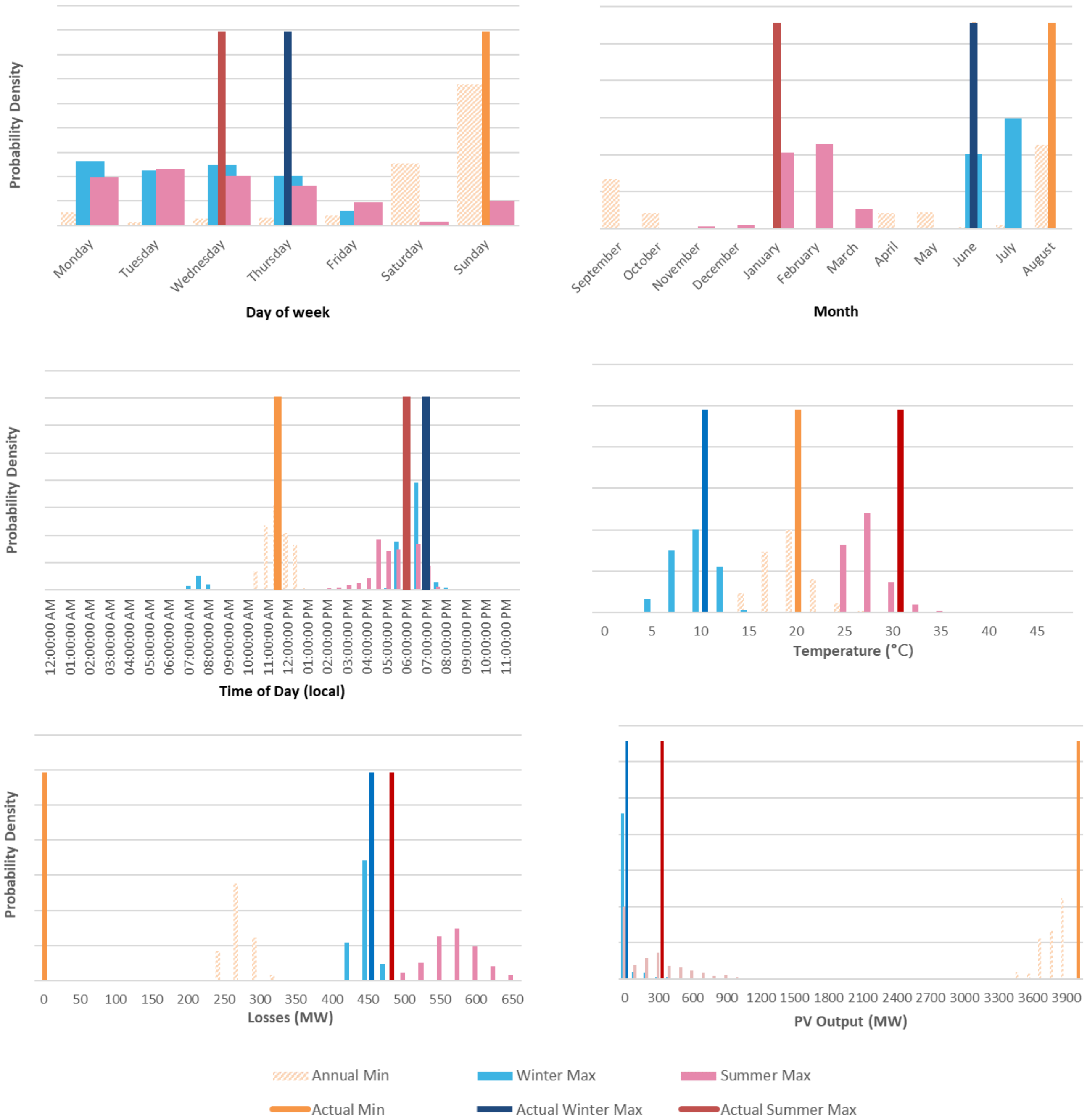
- The winter maximum demand occurred on Thursday, 12 June 2025, at 19:00 NEM time.
- At the time of peak demand, Archerfield Airport recorded a temperature of 11.1°C. The day's maximum temperature was 18.5°C, and the minimum was 6.0°C, indicating relatively cool evening conditions.

- Queensland's winter 2025 conditions were warmer than the long-term average based on temperature records. These conditions reduced the intensity of key winter demand drivers such as residential heating and other evening loads, resulting in actual maximum demand remaining below the model's 90% POE scenario.
- The winter maximum demand was marginally below the 90% POE threshold, reflecting lower-than-median demand scenarios. Simulation models slightly over-forecast the winter maximum demand, consistent with the season's weaker temperature-driven load response.

Annual minimum demand:

- The annual minimum operational demand occurred on Sunday, 31 August 2025, at 11:30 NEM time.
- At the time of minimum demand, the temperature at Archerfield Airport was a mild 20.3°C.
- This event occurred on a weekend, when industrial and commercial activity is typically low. Actual operational demand did not fall as deeply as the 10% POE forecast, primarily because distributed PV generation was lower than expected in the simulation – cloud cover and less-than-optimal solar irradiance during the late-morning period suppressed PV output relative to model expectations.
- The actual installed rooftop PV capacity appears to have been over-estimated by around 400 MW in Queensland, with a further 60 MW over-estimation in PVNSG. This discrepancy implies that minimum demand would naturally track higher than forecast.
- The annual minimum demand was above the 10% POE forecast, reflecting the combined effect of lower-than-expected PV output and the level of underlying daytime load that persisted during the event, which prevented the actual demand from falling to the deeper levels represented in the forecast probability distribution.

Figure 20 Queensland simulated input variable probability distributions with actuals



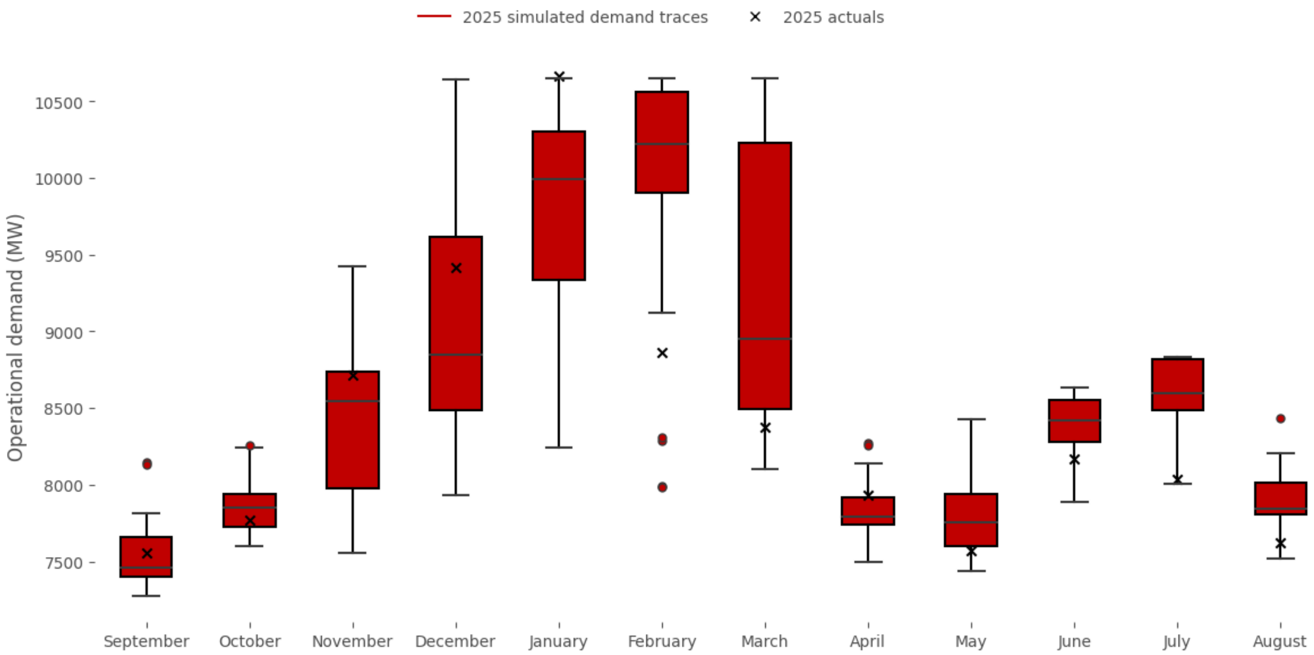
Monthly maximums

The box plot in **Figure 21** illustrates the range of monthly maximum demands for the 2025 simulated demand traces for the 10% POE and 50% POE annual forecasts in Queensland. The red dots represent outliers — observations at the tail ends of the distribution. The black "x" markers represent the actual monthly maximum demand values recorded for 2025.

Overall, the actual maximum demands across most months aligned well with the simulated traces. In January, actual maximum demand exceeded the simulated trace range. This deviation reflects the period of hot conditions across Queensland, combined with particularly humid weather in south-east Queensland, which significantly increased cooling loads. In February, however, actual maximum demand was significantly lower than the forecast due to rainfall totals being above average across large parts of Queensland. The elevated rainfall and associated cloud cover suppressed temperature extremes and lowering cooling demand. In March, actual maximum demand remained slightly lower than forecast, with maximum temperatures observed under typical summer peak levels.

During the winter months (June, July and August), the model over-forecast the maximum demand. This can be attributed to a warmer-than-normal winter in Queensland, which reduces the intensity of cold-weather demand drivers. As a result, actual maximums in those months tracked below the forecast levels.

Figure 21 Queensland monthly maximum demand in demand traces compared with actuals (MW)



5.4 South Australia

Figure 22 shows the half-hourly time-series for South Australia OPSO demand, highlighting extreme demand events observed during 2024-2025. **Table 20** summarises the key characteristics of these events.

Figure 22 South Australia demand with extreme events identified (MW)

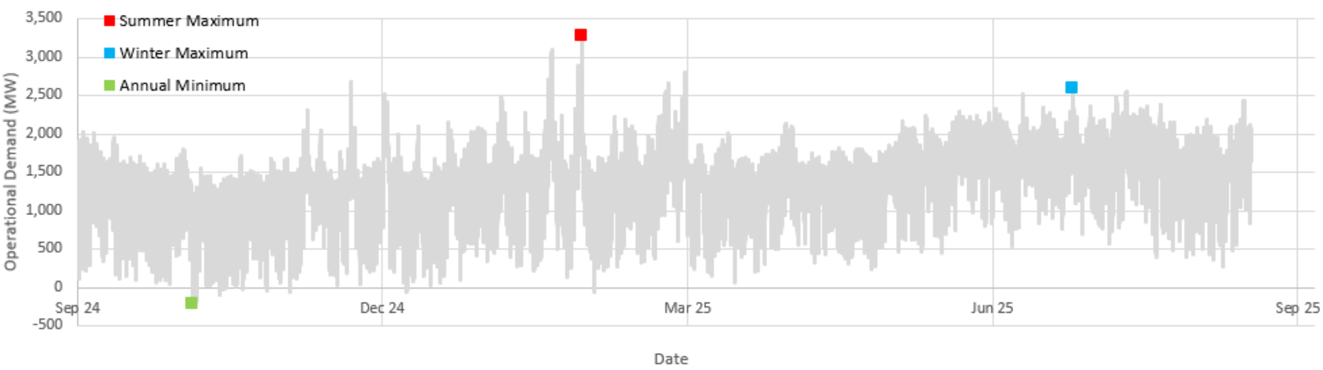


Table 20 South Australia 2023-24 extreme demand events

Event	Summer maximum	Winter maximum	Annual minimum
NEM Date and time	Wed, 12 February 2025 19:00	Wed, 9 July 2025 18:30	Sat, 19 October 2024 13:00
Temperature* (°C)	39.8	11.8	20.4
Max temperature (°C)	42.7	13.5	21.2
Min temperature (°C)	26.9	9	8.1
Losses (MW)	272	208	-27
NSG output (MW)	39	2	239
Rooftop PV output (MW)	102	0	1,634
Sent out (OPSO)	3,274	2,580	-209
Auxiliary (MW)	44	14	4
As generated (OPGEN)	3,318	2,594	-205

* From 1 August 2020 measurements use the Adelaide (West Terrace) weather station, Bureau of Meteorology station 023000. For more information, see Section 3.3.2 of the 2025 IASR ((https://www.aemo.com.au/consultations/current-and-closed-consultations/2025-iasr).
^ Summer maximum demand is adjusted to observed price-driven DSP at time of peak demand.

Figure 23 presents the forecast probability distributions for South Australia's maximum and minimum demand events, with vertical lines indicating the actual observations for the past year. The observed summer and winter maximum demand events, as well as the annual minimum, all occurred well within the forecast ranges.

Figure 23 South Australia simulated extreme event probability distributions with actuals

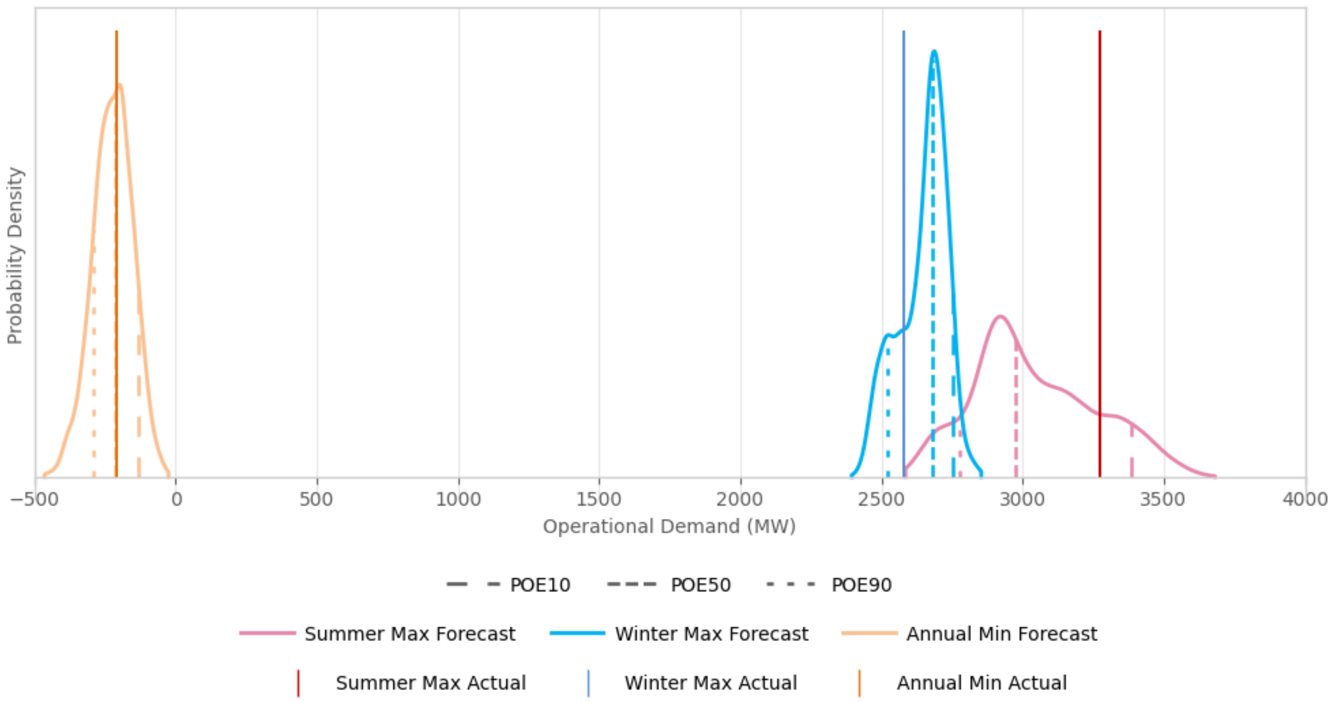


Figure 24 shows the probability distribution and actuals for relevant model inputs. A discussion of insights from these figures follows.

Summer maximum demand:

- South Australia recorded its summer maximum demand on Wednesday, 12 February 2025, at 19:00 NEM time (19:30 local time).
- At the time of peak demand, the temperature at Adelaide (West Terrace) was approximately 39.8°C, with the day's maximum reaching 42.7°C. Temperatures remained exceptionally high throughout the day before easing slightly by the evening peak, maintaining substantial cooling demand across households and businesses. The event sat within the expected simulation range, aligning closely with the 10% POE forecast, which reflects conditions typical of an extreme summer heat day. Model simulations had indicated that peak demand was most likely to occur on a weekday in February, in the evening when PV generation had declined considerably, which matched the observed outcome.

Winter maximum demand:

- South Australia experienced its winter maximum demand on Wednesday, 9 July 2025, at 18:30 NEM time (19:00 local time).
- At the time of peak demand, the temperature at Adelaide (West Terrace) was approximately 11.8°C. The temperature during the peak was moderate for the season, supporting steady residential heating use into the evening.
- Rooftop PV generation was minimal and business and industrial load, together with residential heating, were the primary drivers of operational demand.
- The observed peak sat comfortably within the forecast range, falling between the 50% and 90% POE simulations. The forecast simulations indicated that mid-winter weekday evenings were the most likely period for peak demand, which was consistent with the timing of this event. Overall, winter demand patterns in 2025 reflected typical seasonal behaviour, with no major weather-related anomalies influencing the outcome.

Annual minimum demand:

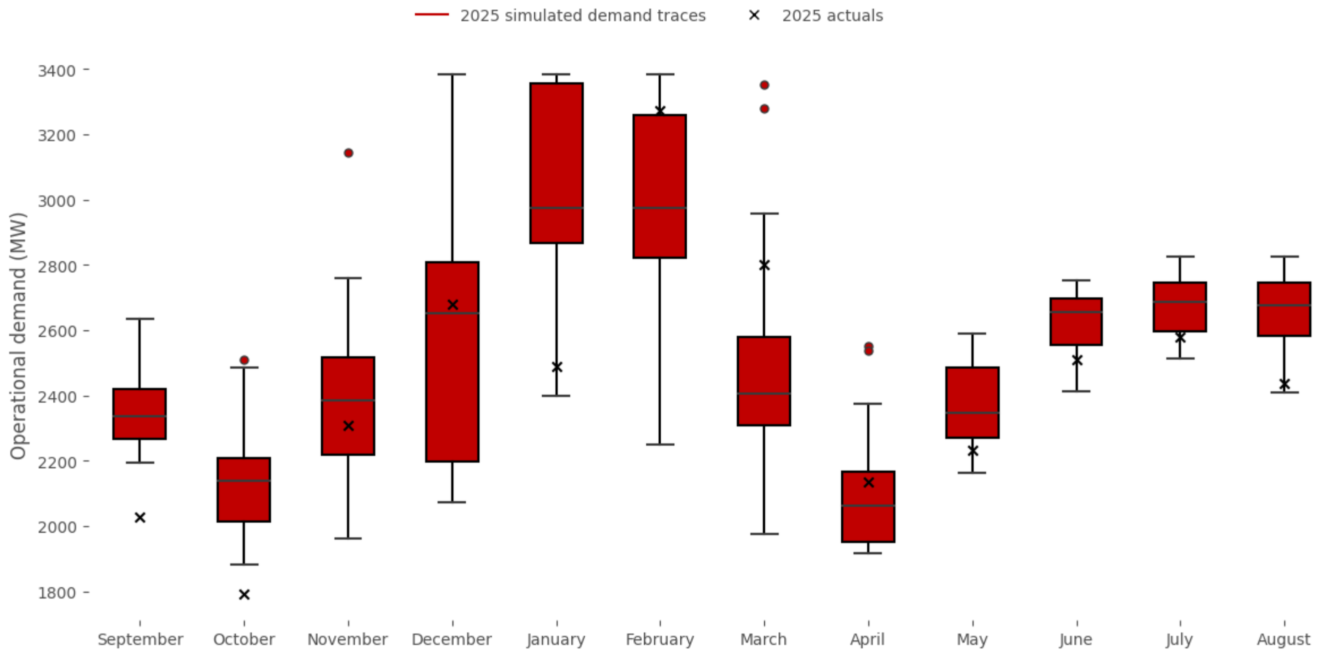
- South Australia's annual minimum demand was recorded on Saturday, 19 October 2024, at 13:00 NEM time (13:30 local time).
- At the time of minimum demand, the temperature at Adelaide (West Terrace) was approximately 20.4°C. Conditions were typical for early spring, with mild weather limiting both heating and cooling needs.
- PV output at the time of the event was higher than the median of simulated outcomes, reflecting continued growth in rooftop solar capacity across the region. The combination of strong solar output and moderate weather resulted in the lowest operational demands observed for the year.
- The observed minimum fell within the simulated range, aligning closely with the 50% POE forecast. Simulation outputs indicated that minimum demand events typically occur on mild spring weekends, during the middle of the day when solar generation is high and operational demand is low, consistent with this outcome.

Figure 24 South Australia simulated input variable probability distributions with actuals

Monthly maximums

The box plot in **Figure 25** illustrates the range of monthly maximum demand from the 2024-25 simulated traces compared with actual observations. The majority of monthly peaks were well captured within the simulated range, with only minor deviations. The October maximum was slightly below the central range, while March and July showed outcomes toward the upper edge of the simulations. These results indicate strong alignment between observed and forecast demand, with variations consistent with expected seasonal behaviour.

Figure 25 South Australia monthly maximum demand in demand traces compared with actuals (MW)



5.5 Tasmania

Tasmania's half-hourly OPSO demand time series and corresponding extreme events are presented in **Figure 26**. As a winter-peaking region, Tasmania's summer maximums remain substantially below winter maximums. Further details on the year's extreme demand events are provided in **Table 21**.

Figure 26 Tasmania demand with identified extreme events (MW)

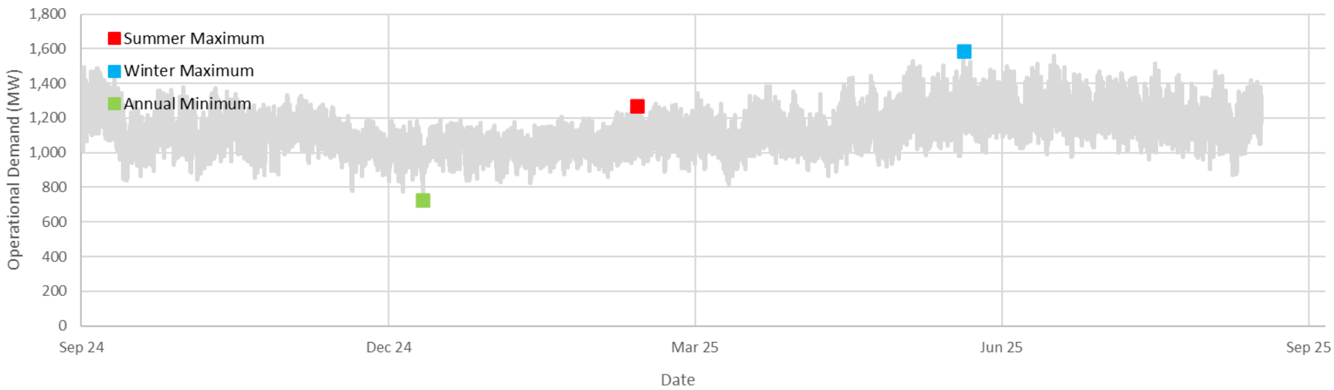


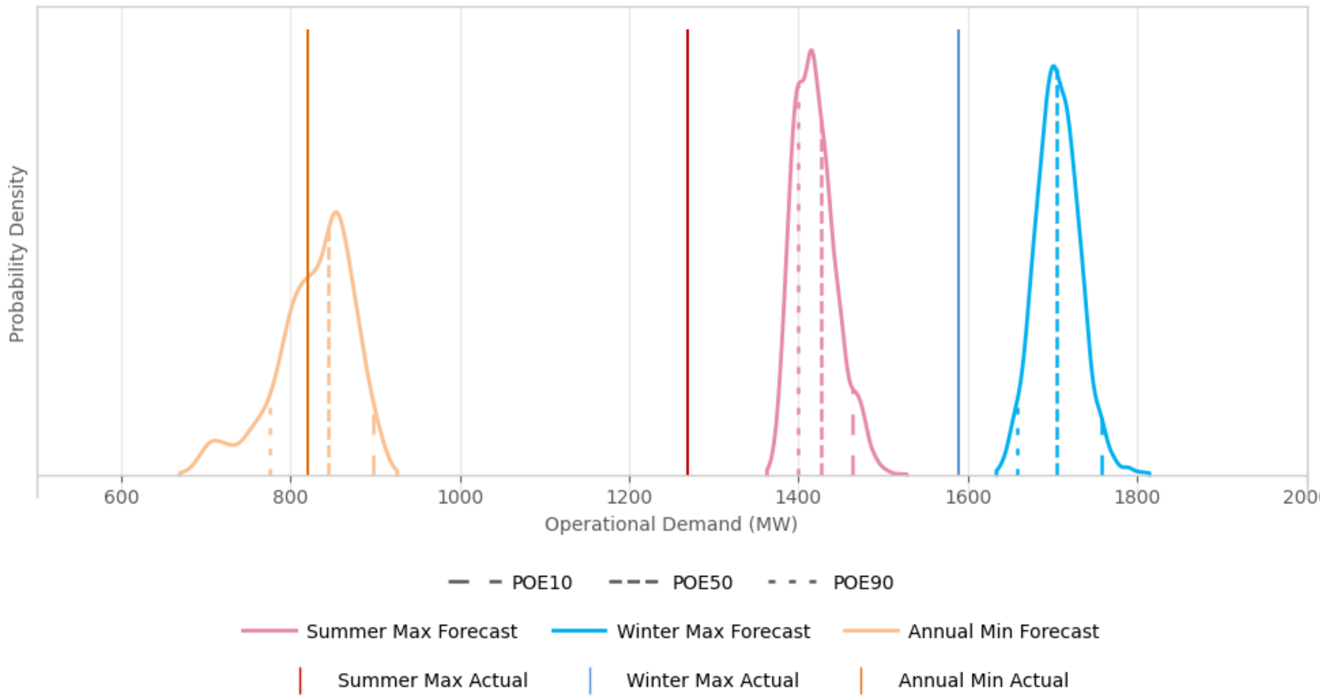
Table 21 Tasmania 2024-25 extreme demand events

Event	Summer maximum	Winter maximum	Annual minimum
NEM Date and time	Thu, 27 February 2025, 07:00	Wed, 4 June 2025, 08:30	Wed, 25 December 2024, 13:30
Temperature* (°C)	14.5	8.1	20.1
Max temperature (°C)	20.8	11.2	20.1
Min temperature (°C)	14.2	5.1	11.0
Losses (MW)	55	75	29
NSG output (MW)	40	39	72
Rooftop PV output (MW)	8	35	175
Sent out (OPSO)	**1,269**	**1,589**	**726**
Auxiliary (MW)	14	15	2
As generated (OPGEN)	**1,283**	**1,604**	**728**

* Hobart (Ellerslie Road) weather station. For more information, see Section 3.3.2 of the 2025 IASR (https://www.aemo.com.au/consultations/current-and-closed-consultations/2025-iasr).

Figure 27 presents the forecast probability distributions for Tasmania's maximum and minimum demand events, with vertical lines indicating the actual observations for the past year. Both the summer and winter maximum demand events were approximately 150 MW below their respective forecast distributions, while the annual minimum demand was well within the projected range of outcomes.

Figure 27 Tasmania simulated input variable probability distributions with actuals



Demand in Tasmania differs from the mainland regions in two key ways:

- Tasmania is consistently winter-peaking, with annual maximum demand driven primarily by heating loads during cold conditions rather than by summer cooling.
- Tasmanian demand is more strongly influenced by large industrial load (LIL) operations, meaning that weather variables such as temperature have a comparatively smaller effect on overall demand than in other NEM regions.

Figure 28 presents the probability distributions and corresponding actual observations for the relevant model input variables. A discussion of the insights derived from these figures is provided in the following section.

Summer maximum demand:

- Tasmania's summer maximum demand was recorded on Thursday, 27 February 2025 at 07:00 NEM time (8:00 local time).
- At the time of peak demand, the temperature at Hobart (Ellerslie Road) was 14.5°C. The day's maximum temperature reached 20.8°C, with a minimum of 14.2°C. February 2025 was mild to cool overall, with the state-wide average maximum temperature for the month at 21.25°C, consistent with the warmer February conditions observed in Tasmania over the long-term climate record. The peak occurred early in the morning, triggered by cooler temperatures, high residential hot-water usage, and the ramp-up of commercial and industrial activities. LIL at the time of the summer peak was 703 MW, which was below the simulated 50% POE assumption of 728 MW, reducing the industrial demand contribution to the peak.
- Actual temperature conditions were milder, and industrial loading was slightly lower than forecast, and the limited morning heating load associated with this mild summer temperatures was the primary driver of the peak. As a result, the actual summer maximum demand fell approximately 130 MW below the 90% POE forecast. This outcome highlights the influence of mild summer conditions and lower industrial activity on Tasmania's summer peak, resulting in operational demand well below the upper forecast range.

Winter maximum demand:

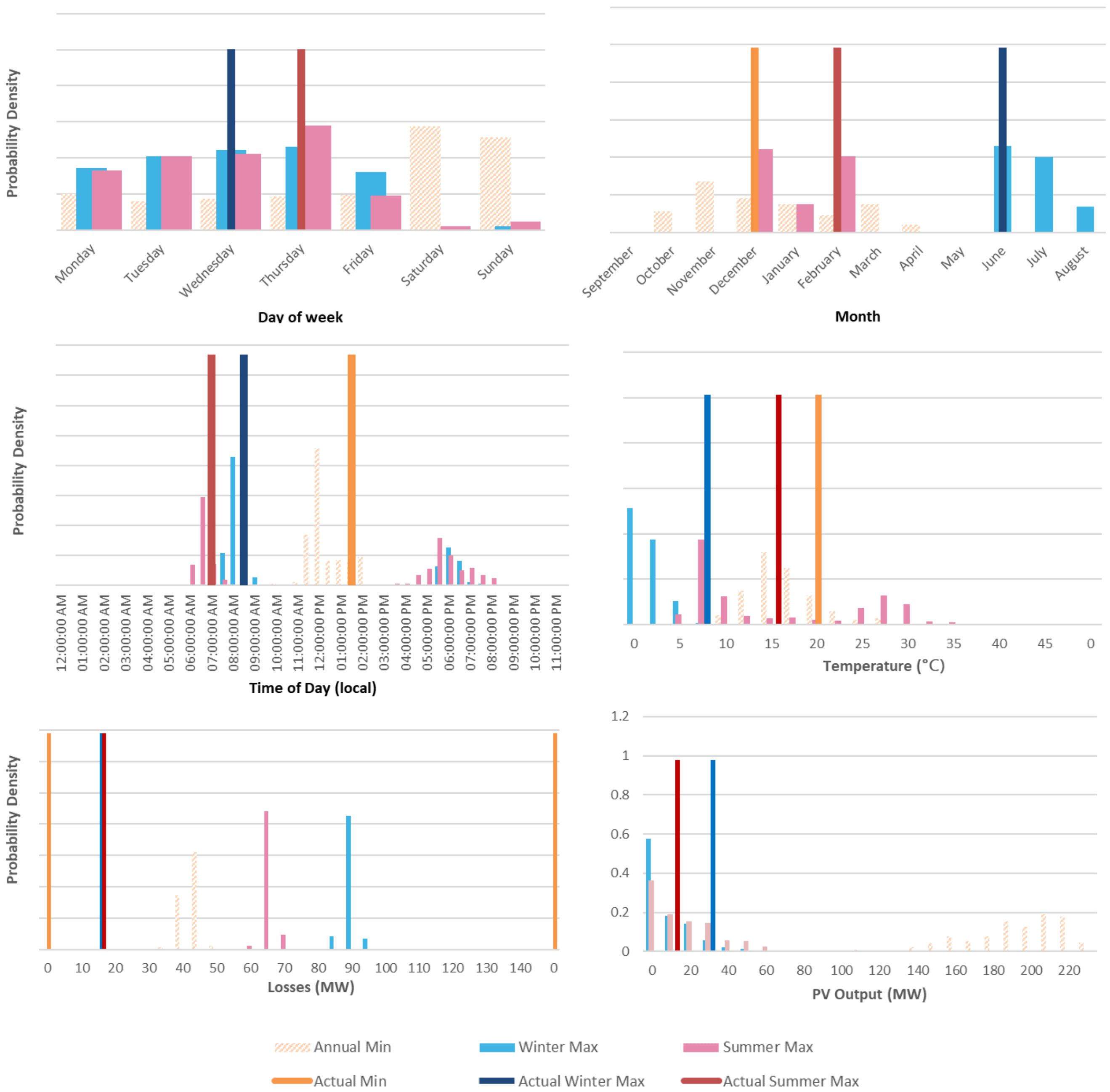
- Tasmania's winter maximum demand occurred on Wednesday, 4 June 2025 at 8:30 NEM time. At the time of peak demand, the temperature at Hobart (Ellerslie Road) was 8.1°C, with a daily minimum of 5.1°C. Tasmania recorded its sixth-warmest winter on record, with mean maximum temperatures across the state approximately 0.98°C above the long-term average, indicating a notably warmer winter than the model's cold-weather demand assumptions.
- The temperature during the peak event was moderately cold, not the extreme cold conditions that typically drive very high heating loads. LIL operations at the time of peak were 673.2 MW, below the simulated 50% POE value of 732 MW (and the 90% POE of 719 MW), reducing the industrial demand component.
- The combination of a milder-than-assumed winter demand driver (providing weaker heating load stimulus) and lower than assumed industrial load contribution resulted in the maximum demand realisation falling below the model's 90% POE forecast distribution by around 150 MW.
- This outcome highlights the sensitivity of Tasmania's winter peak demand to both temperature anomalies and industrial activity, with actual demand well below the upper forecast range due to milder weather and reduced industrial load.

Annual minimum demand:

- Tasmania's annual minimum operational demand occurred on Wednesday, 25 December 2024, at 13:30 NEM time (14:30 local time).

- At the time of minimum demand, the temperature was 20.1°C, with a daily minimum of 11°C and a maximum of 20.1°C. The event took place on a public holiday (Christmas Day), when commercial and industrial activity is typically very low.
- Minimum demand occurred around the middle of the day under moderate temperatures and high distributed PV generation, consistent with expectations from the simulation model.
- The annual minimum demand fell within the distribution range between the 50 % POE and 90 % POE forecasts. This outcome reflects the combined influence of public holiday load reduction, mild weather, and strong PV output, resulting in a minimum demand event well captured by the model's forecast range.

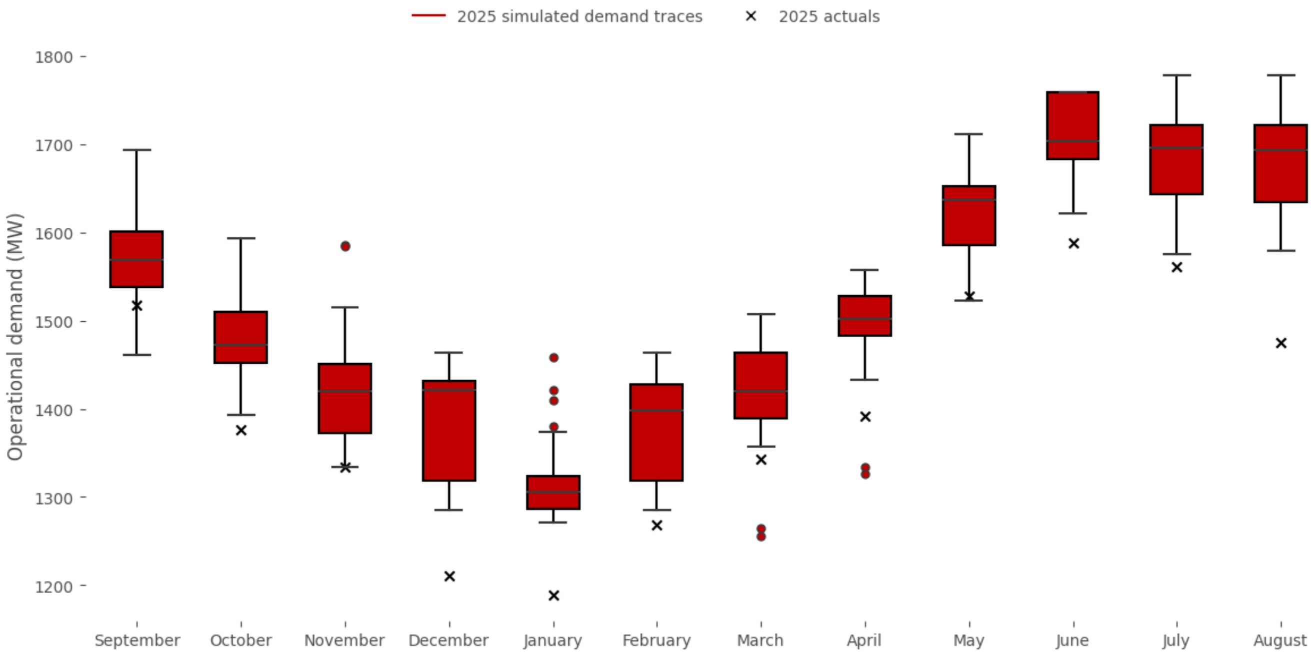
Figure 28 Tasmania simulated input variable probability distributions with actuals



Monthly maximums

Figure 29 compares Tasmania's monthly maximum operational demand for 2025 actuals against simulated demand traces. The box plots represent the range of monthly maximum demands from the 2024-25 simulated traces aligned with the 10% and 50% POE annual forecasts, while the crosses indicate observed actuals. Several observed monthly peaks fall below the simulated range, particularly during summer and winter months. The frequency and magnitude of these deviations suggest the simulated traces may be biased high in these periods. This discrepancy will be examined further as part of the ongoing model review and calibration process outlined earlier.

Figure 29 Tasmania monthly maximum demand in demand traces compared with actuals (MW)



5.6 Victoria

Figure 30 presents the half-hourly OPSO demand profile for Victoria, highlighting the key periods of extreme demand observed throughout the year. A detailed summary of these events is provided in **Table 22**.

Figure 30 Victoria demand with extreme events identified (MW)

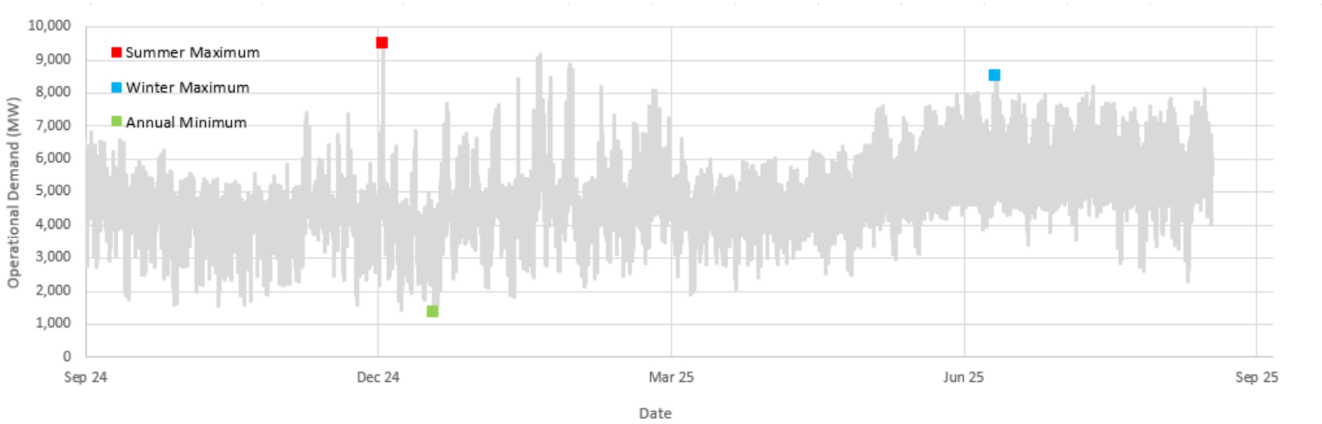


Table 22 Victoria 2023-24 extreme demand events

Event	Summer maximum	Winter maximum	Annual minimum
NEM Datetime	Mon, 16 December 2024, 17:00	Wed, 25 June 2025, 18:00	Wed, 1 January 2025 12:30
Temperature* (°C)	39.1	7.8	20.8
Max temperature (°C)	39.1	10.3	21.1
Min temperature (°C)	19.4	7.3	15
Losses (MW)	612	545	68
NSG output (MW)	201	118	270
Rooftop PV output (MW)	652	0	3,289
Sent out (OPSO)	**9,508 (adjusted to 9,553)^**	8,501	1,342
Auxiliary (MW)	343	317	162
As generated (OPGEN)	**9,851 (adjusted to 9,896)^**	8,818	1,504

* Melbourne (Olympic Park) weather station. For more information, see Section 3.3.2 of the 2025 IASR (https://www.aemo.com.au/consultations/current-and-closed-consultations/2025-iasr).
^ Summer maximum demand is adjusted to include the impact of Ausnet Services' critical peak demand (CPD) program that was called for that day.

Figure 31 presents the forecast probability distributions for Victoria's maximum and minimum demand events, with vertical lines indicating the actual observations for the past year.

The summer maximum demand fell near the 50% POE threshold. This outcome suggests that typical summer drivers were captured reasonably well in the simulations, even though temperature outcomes at the time of peak were near 40°C (described further below).

The annual minimum demand outcome also fell within the forecast distribution, reflecting the continuing impact of high rooftop PV generation during mild conditions. However, the winter maximum demand slightly exceeded the forecast 10% POE threshold, reflecting higher-than-expected consumption on a cooler-than-average winter day. The key factors contributing to this deviation are discussed in the following section.

Figure 31 Victoria simulated extreme event probability distributions with actuals

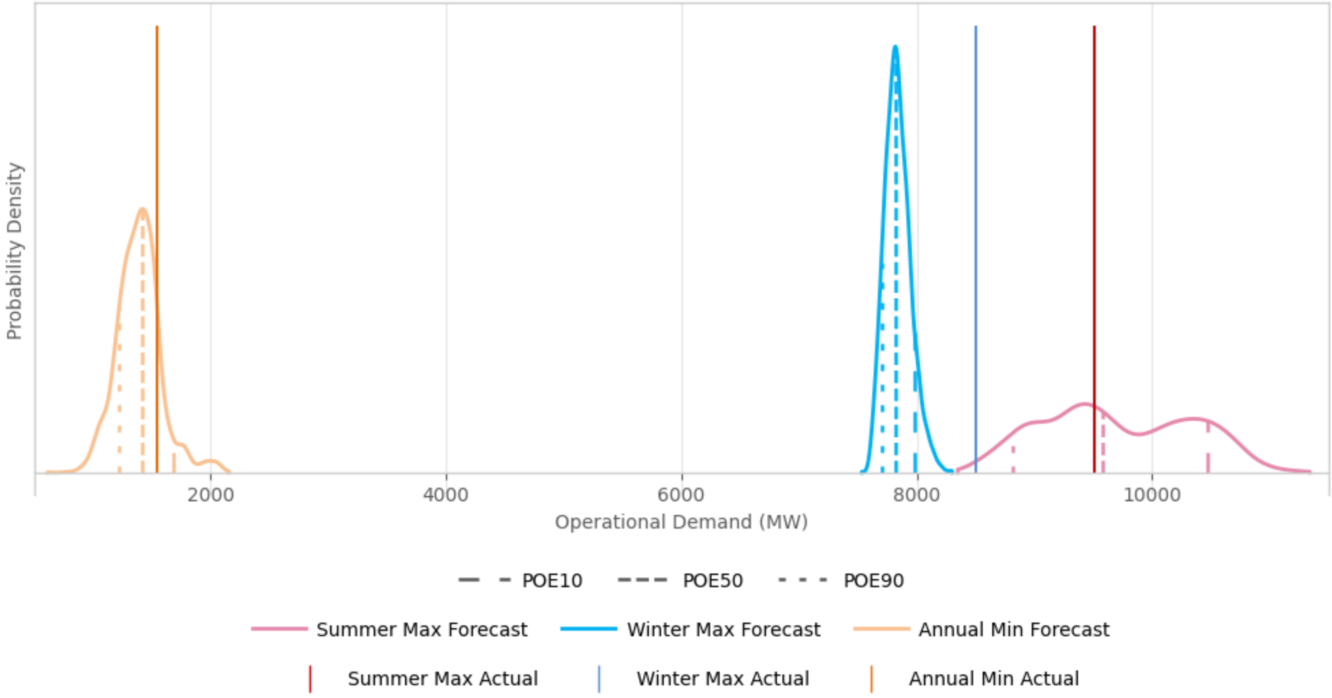


Figure 32 shows the probability distribution and actuals for relevant model inputs relevant to Victoria. A discussion of insights from these figures follows.

Summer maximum demand:

- Maximum demand in Victoria was recorded on Monday, 16 December 2024, at 17:00 NEM time (18:00 local time).
- At the time of peak demand, Melbourne (Olympic Park) recorded 39.1°C, with hot conditions across much of the state supporting elevated air-conditioning load.
- OPSO reached 9,508 MW, increasing to 9,553 MW after accounting for the AusNet-initiated GoodGrid demand-response action on 16 December. This DNSP-led load reduction reduced the observed evening demand. OPGEN was 9,851 MW, adjusted to 9,896 MW.
- Rooftop PV output was around 650 MW at the time of the event, still providing some offset to underlying demand but declining as the event moved into the early evening.
- The actual summer maximum demand was consistent with a 50% POE outcome. While the day reached 39°C, such single-day heat spikes are still within normal 50% POE variability for mid-December in Victoria despite the high temperature. Simulation outcomes were weighted towards a maximum-demand event on a weekday in December during the late-afternoon to early-evening period, which closely matched the actual observation.

Winter maximum demand:

Winter maximum demand occurred on Wednesday, 25 June 2025, at 18:00 NEM time, with a temperature of 7.8°C recorded at Melbourne (Olympic Park).

- Winter maximum demand occurred on Wednesday, 25 June 2025 at 18:00 (NEM time) and exceeded the 10% POE level. The event followed an extended period of generally cool conditions across Victoria from mid-June, with persistently low overnight temperatures and limited daytime warming, which is consistent with sustained space-heating usage and an elevated underlying demand level. While daytime temperatures briefly increased between 20 and 23 June, a sharp cool change occurred on 24–25 June. On the peak day, temperatures remained low throughout the afternoon and into the evening, with a small diurnal range, limiting thermal recovery in buildings and supporting continued heating load into the evening peak.
- The timing of the peak (18:00 NEM time) aligns with simulation outcomes for a weekday winter evening, when commercial and industrial demand remains significant alongside increasing residential heating and appliance use.
- Rooftop PV generation was negligible after sunset, consistent with the expected conditions of the winter evening peak.
- Simulation outcomes were weighted toward June and July for winter maximum demand events, matching the timing and conditions observed in 2025.

Annual minimum demand:

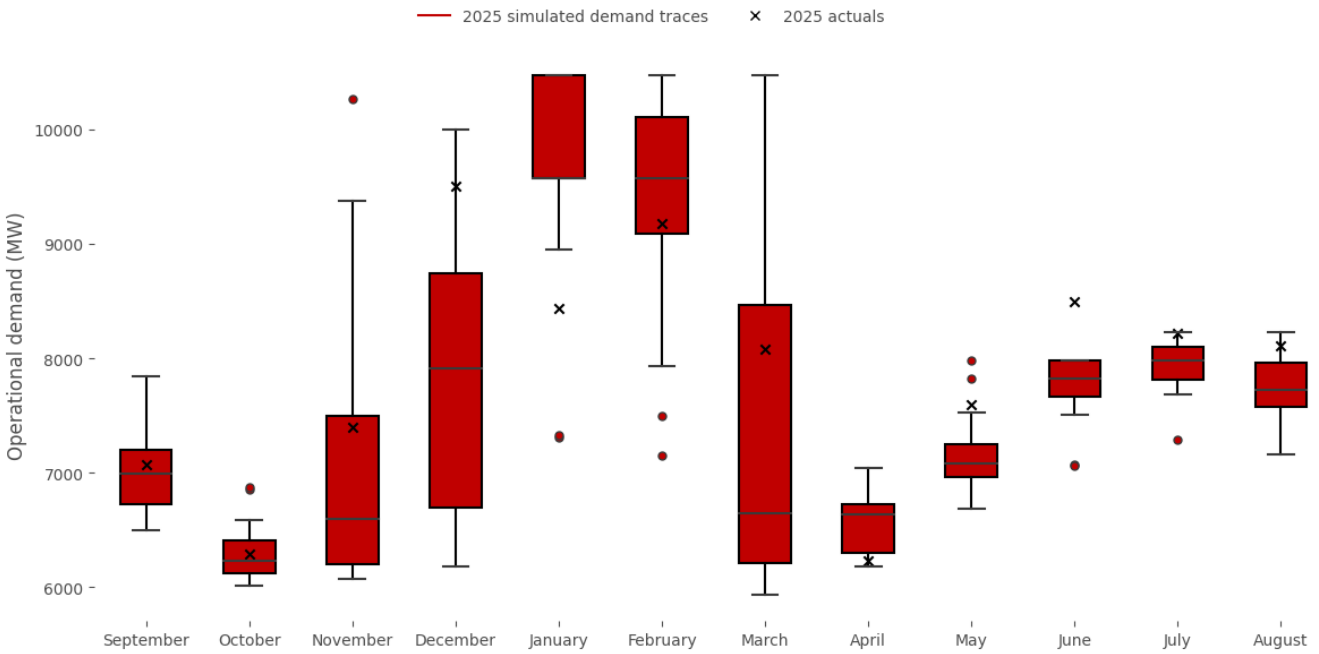
- Annual minimum demand occurred on Wednesday, 1 January 2025, at 12:30 NEM time (13:30 local time), when the temperature was 21.1 °C recorded at Melbourne (Olympic Park). The actual minimum demand was 1,342 MW, between the 50% POE and 10% POE forecasts.
- The event coincided with high rooftop PV generation under clear-sky summer conditions, consistent with the upper end of simulated PV generation outcomes.
- The minimum demand occurred on New Year's Day, a public holiday with reduced business and industrial load, allowing high midday solar generation to offset a naturally lowered demand.
- Simulation outcomes were weighted towards midday to early-afternoon minimums in December–January, consistent with the observed 12:30 NEM time occurrence.

Figure 32 Victoria simulated input variable probability distributions with actuals

Monthly maximums

The box plot in **Figure 33** shows the range of monthly demand maximums for the 2025 simulated demand traces for 10% POE and 50% POE annual forecasts. The majority of monthly maxima fell within the predicted range, with actual outcomes generally close to the simulated medians. In February, actual maximum demand was toward the upper end of the simulated range, reflecting sustained hot conditions and limited evening cooling that maintained elevated loads through the late afternoon. In contrast, other summer months recorded milder conditions with lower cooling demand, while autumn and winter maximums remained broadly consistent with simulation outcomes. Overall, monthly maximums were within forecast expectations, with small deviations mainly explained by short-term temperature variation and the moderating influence of rooftop PV.

Figure 33 Victoria monthly maximum demand in demand traces compared with actuals (MW)



5.7 Demand side participation

AEMO forecasts DSP for use in its reliability assessments (ESOO, EAAP and MT PASA) as well as the ISP. DSP represents a reduction in demand from the grid in response to price or reliability signals. AEMO models DSP similarly to supply options.

AEMO publishes an updated DSP forecast typically once per year. The DSP forecast used for the 2024 ESOO was published along with the 2024 ESOO in August 2024; its accuracy is assessed in the following section.

5.7.1 Background

AEMO's existing DSP forecast methodology[45] estimates the demand response from LILs and any other market participants. The methodology considers DSP responses at a half-hourly level to various price triggers over the previous three years. The aggregate response in a region for a particular trigger is then estimated by taking the 50th percentile of the recorded historical responses.

In addition to DSP in response to various price triggers, additional DSP may operate during periods of extreme scarcity, typically when the system is in an actual lack of reserve (LOR) 2 or LOR 3 state[46]. These programs operated by network service providers are generally only active in summer, contributing to the difference in forecast DSP between summer and winter.

Consistent with the DSP forecasting methodology, AEMO's 2024 DSP forecast excluded:

[45] See https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/dsp-forecasting-methodology-and-dsp-information-guidelines-consultation/final-stage/2023-dsp-forecast-methodology.pdf.

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

- regular (such as daily) demand variations including responses to time-of-use tariffs and hot water load control, and
- load reductions driven by 'passive' embedded battery storage installations.

These items are excluded from AEMO's DSP forecasts to avoid double-counting, as they are directly accounted for as a reduction in the maximum demand forecasts[47].

AEMO's DSP forecast is used in reliability forecasting to assess the need for reserves under the RERT framework[48], therefore AEMO excludes all RERT resources in the DSP forecasts. However, it has been observed that some sites that have been on the short-notice RERT panel, but not under a RERT contract, have been providing DSP responses voluntarily at times where RERT was not needed. AEMO's 2024 DSP forecast therefore included an additional DSP response from such sites in the reliability-driven DSP forecast, to reflect their likely contribution.

5.7.2 Assessment of DSP forecast accuracy

This post-assessment DSP forecast accuracy comprises an assessment of the:

- median (50th percentile) observed DSP response for various wholesale price triggers during the 2024-25 year compared to the 2024 forecast median response, and
- estimated DSP response against the forecast DSP price or reliability response during the most challenging conditions in the last year, typically the time of regional maximum demand events or periods with an actual LOR 2 or LOR 3 condition.

5.7.3 DSP response by price trigger levels

The median price-driven DSP responses for different wholesale price triggers were assessed using 1 April 2024 to 31 March 2025 consumption data for the same list of DSP resources as the 2024 DSP forecast. This was compared to the forecast DSP responses that were based on consumption data from the three previous years (1 April 2021 to 31 March 2024). The comparisons highlight the difference between the forecast DSP and the median observed response across different price triggers.

The comparison does not evaluate performance of the calculation of responses (in particular the baseline estimation method). It does, however, highlight whether past observed behaviour (adopted for the DSP forecast) is a reasonable indicator of what DSP response may be expected for the coming year.

The comparison of observed with forecast DSP is limited by the number of events that occurred in each season. A low number of observed events makes a comparison challenging, as it may be insufficient to provide a high confidence estimate of the median observed response.

Comparison results are shown in **Figure 34** through to **Figure 38**. Overall, there is generally more DSP observed than forecast for lower price bands. This pattern is relatively consistent across all regions, except for South Australia; the forecast and observed DSP are relatively similar in South Australia. Moreover, there has been a significant increase in the observed response for all price bands in Tasmania, compared to last year; this has resulted in the actual DSP being much higher than

[47] In addition to passive energy storages, aggregated energy storages (such as VPPs) are modelled in AEMO's supply-side model optimisations.

[48] See https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Emergency-Management/RERT.

the forecast. Finally, the observed DSP for prices higher than $7,500/megawatt hour (MWh) has been almost half of the forecast DSP in Victoria; this did lead to a decline in the 2025 DSP forecast for Victoria published in the 2025 ESOO[49].

Key insights from each region are summarised below:

- Small response was forecast in **New South Wales** for price bands less than $500/MWh based on the little DSP participation in these bands over the previous years. However, the median response of between 33 MW and 64 MW has been observed for these price bands. For price band over $7,500/MWh, the observed DSP response was relatively similar to the forecast DSP. Overall, prices between $300/MWh and $1,000/MWh were observed more frequently compared to the previous year, and there were more occasions where the prices were higher than $1,000/MWh. In total, there were 2,584 intervals for which the price was higher than $300/MWh in 2024-25, compared to 1,819 intervals in 2023-24. This has led to a larger DSP participation due to significant price incentives.
- In **Queensland**, a relatively constant response of 112 MW (on average) was observed for all price bands – when the prices are over $300/MWh. This response was higher than the forecast response in the first two price bands, while it was lower than the forecast response for the over $7,500/MWh price band. This pattern is similar to last year, and it can be attributed to the relatively small to medium size of loads which can be flexed by the existing participants.
- For **South Australia**, the median observed DSP was slightly lower than the forecast for all price bands, similar to last year. This indicates a small overestimation of the forecasting method due to its sensitivity to fluctuations in historical values.
- For **Tasmania**, the median observed DSP was significantly larger than the forecast. This is mostly due to a lack of DSP participation in the previous years, as well as a significantly higher occurrence of prices over $300/MWh; there were a total of 1,532 intervals for which the price was higher than $300/MWh in 2024-25, compared to only 306 intervals in 2023-24.
- For **Victoria**, the median DSP observation for the first two price bands were significantly larger than the forecast, whereas the median DSP participation was half of the corresponding forecast for the last price band. Higher DSP participation in the first two price bands, which was consistent across all regions except South Australia, is mostly because of higher occurrence of these prices compared to previous years. In Victoria, there were a total of 1,482 intervals during which the price was between $300/MWh and $7,500/MWh in 2024-25, compared to 933 intervals in 2023-24. Similar to other regions, an over-estimation of the DSP participation was observed for prices higher than $7,500/MWh, which potentially is due to a rather small number of observations and the sensitivity of the forecasting method to such conditions. The current methodology is due for review and potential adjustment in 2027.

[49] See https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2025/2025-esoo-appendix-a3-demand-flexibility.pdf.

Figure 34 Evaluation of actual compared to forecast price-driven DSP in New South Wales

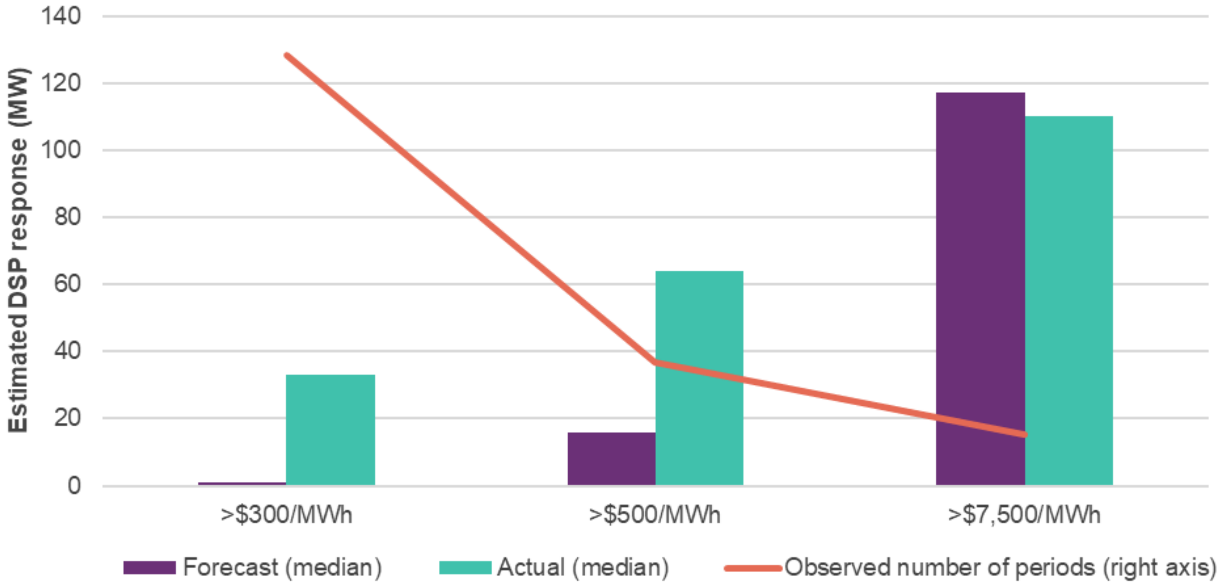


Figure 35 Evaluation of actual compared to forecast price-driven DSP in Queensland

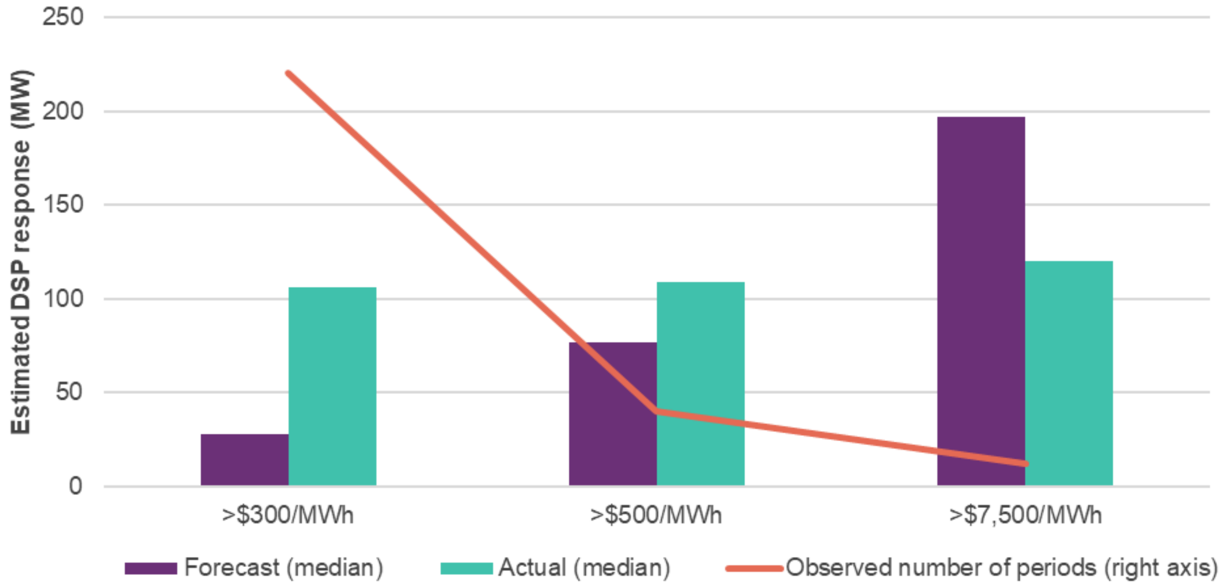


Figure 36 Evaluation of actual compared to forecast price-driven DSP in South Australia

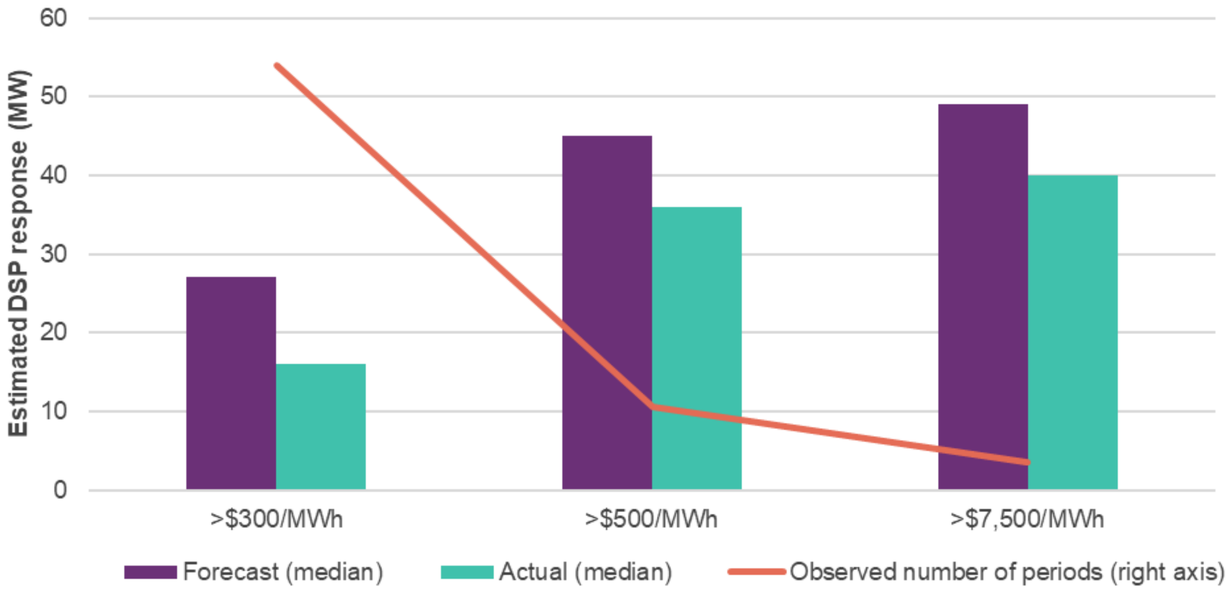


Figure 37 Evaluation of actual compared to forecast price-driven DSP in Tasmania

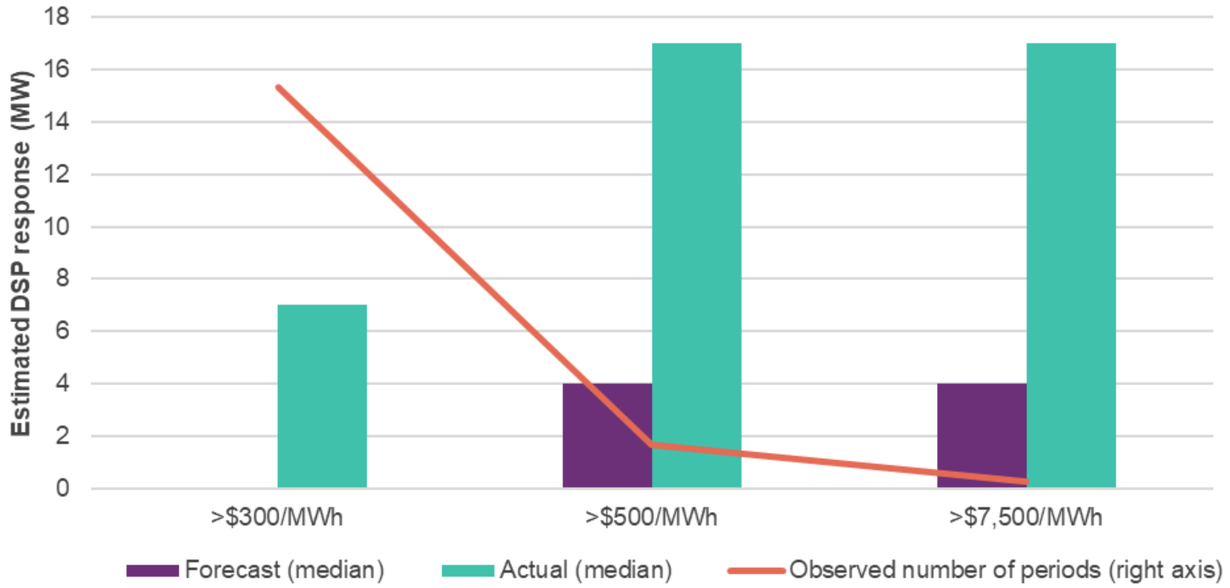
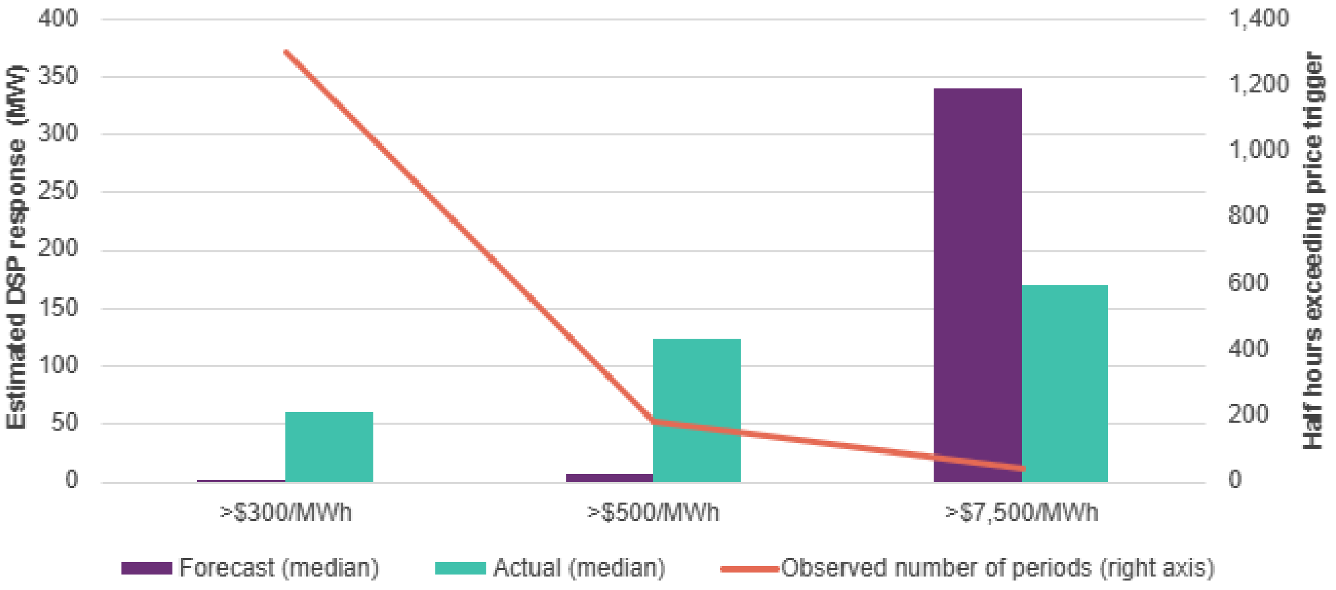


Figure 38 **Evaluation of actual compared to forecast price-driven DSP in Victoria**



Included in the above discussion of AEMO's DSP forecasts and actuals is the impact of the Wholesale Demand Response (WDR) mechanism[50]. While WDR is included within the overall DSP forecast, it is forecast as a separate component, using a separate methodology to the rest of DSP. The 2024 ESOO forecast WDR for all regions except Tasmania. As **Table 23** shows:

- WDR has been dispatched in New South Wales, Queensland and Victoria, as per the forecast. South Australia did not have any WDR participation; the forecast WDR was also very small for this region.
- In all regions, the actual WDR was reasonably close to forecast.
- In New South Wales, WDR was slightly higher than forecast. This increase is reflected in the 2025 ESOO's forecast for WDR participation[51].

Table 23 **Forecast versus actual WDR in 2024/25 (MW)**

	New South Wales		Queensland		South Australia		Tasmania		Victoria	
T($/MWh)	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast	Actual
>$300	1	1	1	0	1	0	0	0	1	1
>$500	5	6	1	0	1	0	0	0	6	2
>$7,500	9	13	1	1	1	0	0	0	6	4

* Figures are rounded to nearest MW and therefore the small amount of WDR observed in Queensland and South Australia is not apparent.

Compared to other DSP, WDR is limited in scale and does not materially affect overall DSP forecast accuracy.

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

[51] See https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2025/2025-esoo-appendix-a3-demand-flexibility.pdf.

5.7.4 DSP response during extreme events

The reliability response from the 2024 ESOO forecast is shown in **Table 24**. It represents the forecast DSP where the system is in an actual LOR 2 or LOR 3 state.

Table 24 Forecast reliability response in MW during LOR 2 or LOR 3 for 2024-25 summer and 2025 winter

	New South Wales	Queensland	South Australia	Tasmania	Victoria
Summer	359	240	49	4	533
Winter	359	197	49	4	488

Only New South Wales, Queensland and South Australia recorded an LOR 2 event in summer (no occurrence of LOR 3 was observed during this period). These events coincided with the maximum demand day in Queensland and South Australia. The DSP response during each region's maximum demand and the LOR 2 event is described below, while further details are provided for the response to the reliability events in the three regions. Overall, AEMO considers that the forecast remains reasonable in the absence of greater evidence of a more permanent change to industrial load reliability responses.

- **New South Wales** – the maximum demand in summer was reached on 17 December 2024, when prices were not very high (slightly above $500/MWh). On that day, an estimated DSP response of 135 MW was observed between 15:30 and 17:30 AEST. There were three days during which an LOR 2 event occurred in this region (26 and 27 November 2024, as well as 13 January 2025). DSP responses were observed during the first two dates; the prices were not particularly high on the last day (below $300/MWh at the time of LOR 2 event), hence there was less incentive for DSP participation. A maximum of 323 MW response was dispatched on 26 of November 2024. These reliability responses were similar to the 359 MW forecast in the 2024 ESOO.
- **Queensland** – the maximum demand in summer was reached on 22 January 2025. There were intervals at which the prices were relatively high (reached a maximum of $14,319/MWh at 19:00 AEST). The brief price spikes during the day triggered a maximum DSP price response of 20 MW. An LOR 2 condition was observed between 19:00 to 20:00 AEST on this day. An estimated DSP response of 234 MW was observed at this time, which is very close to the reliability response forecast for the region.
- **South Australia** – the region had its summer maximum demand on 12 February 2025. The prices were above $300/MWh between 18:00 and 20:30 AEST on that day, with a maximum of $12,723/MWh observed at 19:00. An LOR 2 event also occurred at the same time, when an estimated DSP response of 37 MW could be observed. This response is slightly lower than the forecast reliability response for the region.
- **Tasmania** – Tasmania had its annual maximum demand on 5 July 2024. The price was below the trigger price of $300/MWh, except for two intervals (with the prices of $336/MWh and $308/MWh). No DSP response was observed on that day.
- **Victoria** – Victoria had its maximum demand on 16 December 2024. The price on that day was relatively low (only two intervals had a price higher than $300/MWh). A maximum DSP response of 42 MW was observed on the day. There were no LOR events observed in Victoria during this year.

5.7.5 DSP forecast conclusions

Overall, the estimated DSP responses were relatively close to the forecast in New South Wales, Queensland, and South Australia, especially for higher price bands. Different to last year, significant DSP responses were observed in Tasmania. Victoria was the only region which observed estimated DSP responses which were significantly lower than the forecast for prices higher than $7,500/MWh. This inaccuracy is mostly due to a relatively low number of occurrences of such prices (26 intervals in 2023-24 and 39 intervals in 2024-25) which made the estimation of DSP response difficult. The reliability response for 2024-25 was similar to the forecast values, especially in the three regions where a reliability event occurred (New South Wales, Queensland and South Australia).

As a result of the lower observed DSP responses in Victoria during 2024-25, AEMO decreased its DSP forecasts for the region in the 2025 ESOO. AEMO will continue to monitor observed DSP against forecast (including any use of WDR) over the coming summer to assess whether the forecast responses are consistent with what can be observed on the most extreme demand days, or if any further adjustments are required.

6 Supply forecasts

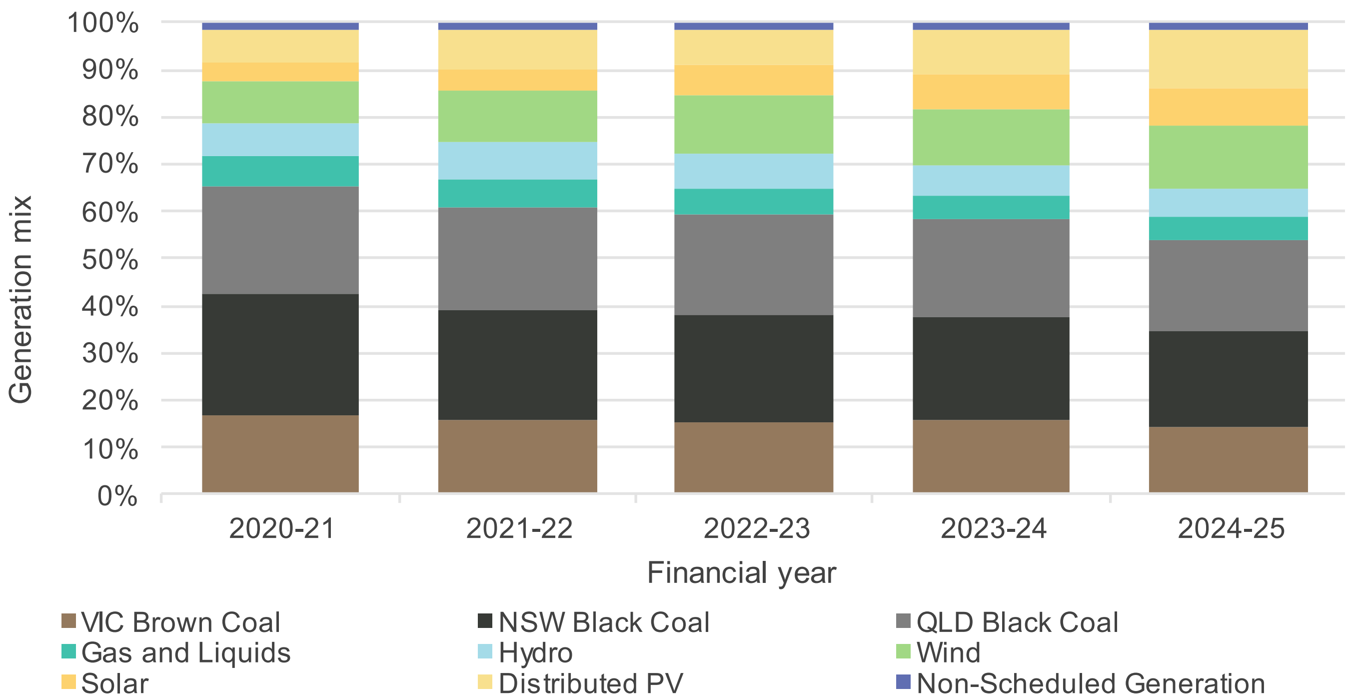
Generation supply in the NEM comes from a variety of fuel sources, with the energy supply balance shifting over recent years, as shown in **Figure 39**. The accuracy of supply forecasts discussed in this chapter considers most fuel sources, with focus on the technologies that contribute most to electricity production and the reliability of the NEM.

Coal generation (black and brown in aggregate) remains the largest source of electricity production in the NEM, yet showed a decrease in the relative proportion of electricity supplied, from 65.6% in 2020-21 to 54.1% in 2024-25. While there has been volatility, the share of electricity supplied by hydro has declined slightly over the period, from 7.1% in 2020-21 to 6.0% in 2024-25, while electricity supplied by gas and liquid fuel has declined from 5.9% in 2020-21 to 4.7% in 2024-25. Solar and wind generation show the largest increase in the relative proportion of electricity supplied, rising from 12.8% in aggregate in 2020-21 to 21.2% in 2024-25. Additionally, the contribution of distributed PV has grown from 6.9% in 2020-21 to 12.7% in 2024-25.

To assess the performance of supply forecasts, this section assesses:

- forecasts of new generator connections,
- unplanned outage rates for major generation sources, and
- supply availability, per region.

Figure 39 NEM generation mix change by energy, including demand side components, from 2020-21 to 2024-25



Note: The category 'gas and liquids' includes open and combined cycle gas turbines, diesel generators, and other similar peaking plant.

Supply availability is an important input in reliability studies, given that supply outages are a key driver of unserved energy (USE) estimates during periods of high demand and low VRE generation output. Supply forecasts are therefore assessed by the degree to which capacity availability estimated in the 2024 ESOO matched actual generation availability.

There are numerous reasons why actual supply availability from scheduled generators or actual generation from semi-scheduled generators may not match that forecast during peak periods of interest in the reliability forecast[52]; for example:

- Commissioning or decommissioning of generators may not match assumed schedules.
  - For commissioning schedules, AEMO applied delays to the dates provided by project proponents of six months for committed projects; and the latter of 12 months or the first day after the T-1 period for RRO purposes (1 July 2026 for the 2024 ESOO) for Anticipated projects.
  - For decommissioning schedules, AEMO assumed generator retirements occur on dates provided by participants – either on the specific closure date provided under the three-and-half-year notice of closure rules, or on 31 December of the provided expected closure year.
- Generator ratings during peak temperatures may not match ratings provided by generator participants.
- Unplanned outages (full, partial, or long duration outages) may vary from projected outcomes.
- Planned outages or unit decommitment may occur during peak periods, which current forecasts assume will not occur.
- Weather resources for VRE generators may fall outside the forecast simulation range, or the efficiency of VRE generators to convert wind or solar resources to electricity may be different to that which is assumed.
- Generation may be curtailed due to constraints representing system security and network limitations, varying from network expectations informed by equations that represent network capability in the reliability forecast.
- Participants may provide different capacities compared with actual plant capability.

Consistent with the *Forecast Accuracy Report Methodology*[53], AEMO implements and publishes a variety of metrics to assess supply forecast accuracy. For each region, AEMO assesses the following aspects:

- the accuracy of participant-submitted and modelled generator availability including commissioning and decommissioning schedules,
- the accuracy of unplanned outage rate projections for a variety of generation technology types,
- supply availability for scheduled generators and significant non-scheduled generators, comparing actual availability with simulated availability, and
- generation output for scheduled bidirectional units, and semi-scheduled and significant VRE non-scheduled generators, comparing actual generation with simulated generation.

Sample days and reference temperatures

AEMO collects three capacity values to account for variations in generator performance under different temperature conditions in the ESOO supply availability forecasts. Many generators experience reduced operating capacity during high temperature conditions. Temperature-related derating varies by generator, but is common across coal, gas and wind

[52] AEMO's reliability forecast for the 2024 ESOO covers the first five years based on the *Committed and Anticipated Investments* sensitivity. For this reliability assessment, AEMO applied its consulted-on ESOO methodology that reflects commissioning uncertainties in projects that are committed and anticipated but have not yet reached specific commissioning milestones.

[53] See https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/consultation-on-forecasting-accuracy-report-methodology/final/forecast-accuracy-report-methodology.pdf?la=en.

powered generators, with operating capacity typically lower in hot temperature conditions compared with mild temperatures. Each region uses its own reference temperatures to define the following capacity values:

- summer peak capacity – representative of 10% POE demand conditions,
- typical summer capacity – representative of typical summer conditions, and
- winter capacity – representative of winter conditions.

To access the accuracy of the supply availability forecasts, AEMO compares ESOO simulated availability to actual availability using 40 hours sampled from the top 10 hottest days (taken from the maximum temperature period and the periods that follow) of the summer period for each region, ranked by supply availability. This simulated availability primarily reflects periods where generators' summer peak capacity is applied and is represented as two ranges in this year's report:

- the full simulated range, and
- the central 95th percentile simulated range, showing the variation between the 2.5th and 97.5th percentile of the forecast simulations used.

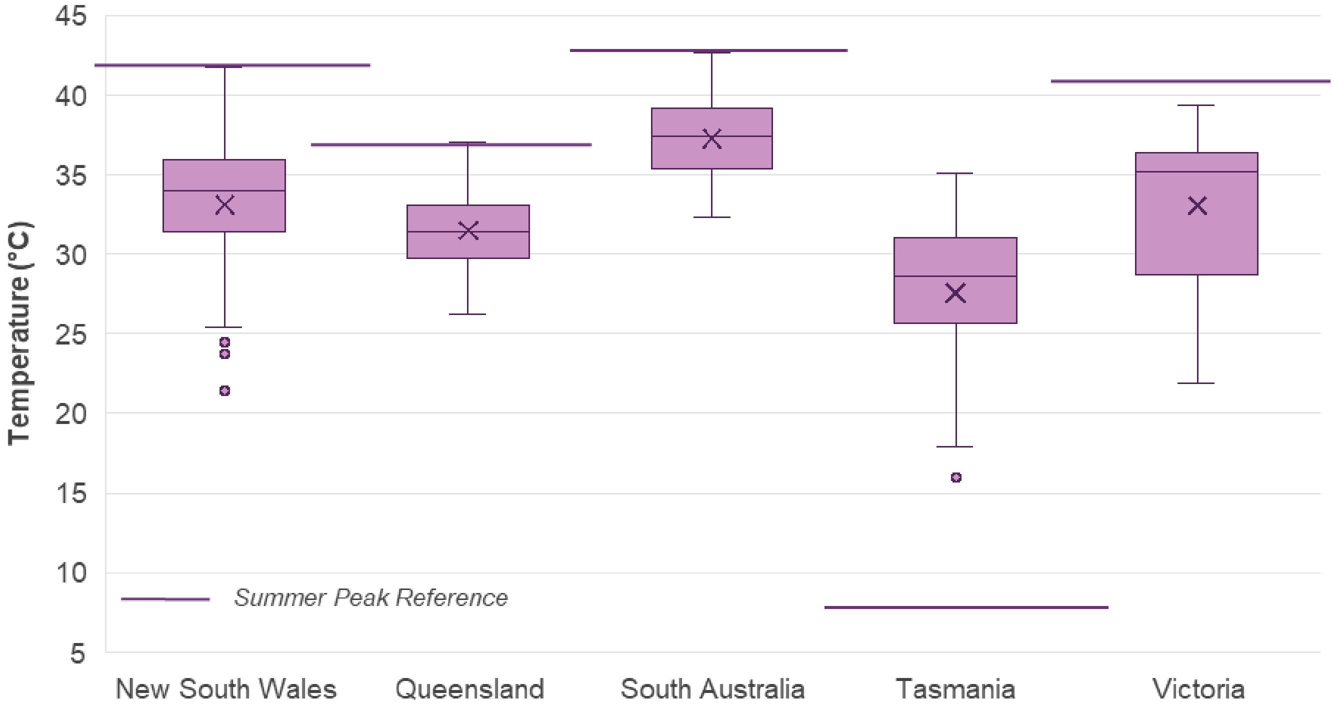
On average, summer 2024-25 was the warmest on record[54]. However, as shown in **Figure 40**, the sampled temperatures from the top 10 hottest summer days, including annual maximum events, were mostly below the summer peak reference temperature. The reference temperature is based on historical data to estimate the temperatures frequently associated with times of 10% probability of exceedance (POE) maximum demand in the major load centres for each region. The reference temperate is used to define summer peak capacity values for generators, which are used in the ESOO modelling. **Figure 40** shows a box plot[55] comparing the temperature range of the 40 sampled hours to the summer peak reference temperature for each region.

Due to the absence of extreme temperatures and the associated equipment derating, actual supply availability is not expected to de-rate as much as forecast availability during the 10 hottest days assessed.

[54] See http://www.bom.gov.au/climate/current/financial-year/aus/summary.shtml.

[55] For explanation of box plots, see **Section 2.1**.

Figure 40 Box plot of temperatures of 40 hours sampled from the 10 hottest days in 2024-25 summer



Note: The summer peak reference temperature for New South Wales is 42°C, Queensland is 37°C, South Australia is 43°C, and Victoria is 41°C. The summer peak reference temperature for Tasmania is 7.7°C, reflecting summer maximum demand in the region occurs during colder temperature.

6.1 Supply availability assessment

This section details the regional assessment of supply availability forecast performance. Key findings include:

- **New projects** – more projects were online in February 2025 compared to what AEMO assumed in the 2024 ESOO forecast. Several of these projects were still in their commissioning phase, meaning they were not providing full capacity and were not yet a consistently reliable source of generation.
- **Wind generation** – actual wind generation in Victoria largely exceeded the 95th percentile simulated range, driven by an additional wind farm beginning service earlier than simulated, and potentially due to relatively mild temperature conditions leading to lower capacity derating. In other regions, actual wind generation are mostly within the 95th percentile simulated range.
- **Solar generation** – actual solar generation was generally below or towards the lower end of the 95th percentile simulated range, particularly in Queensland and South Australia. This occurred despite several regions bringing new projects earlier than assumed in the forecast. Factors that contributed to lower actual generation included constrained generation, economic offloading[56], and the hot day time periods sometimes occurring later than assumed in the simulations, resulting in lower solar output compared to earlier periods due to reduced solar irradiance.

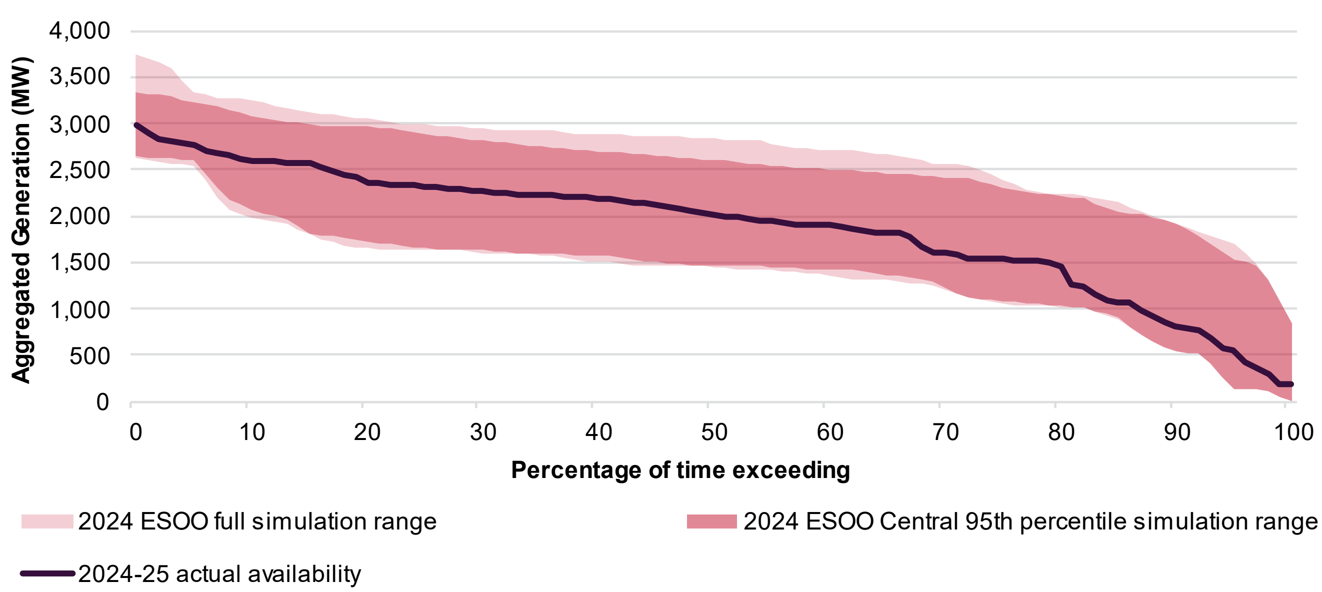
[56] Economic offloading refers to a generator being dispatched below its maximum availability, because some or all of its output was bid into price bands greater than the regional reference price. This may also be referred to as economic 'spill' or 'spilled energy' as generators reduce output due to low market prices or lack of available demand.

- **Battery generation** – actual battery generation exceeded the simulated range in Queensland and Victoria, driven by early commissioning of one project in each region. In New South Wales, South Australia, and Victoria, battery generation mostly fell within simulated ranges.
- **Total actual supply availability/generation** – total observed supply was within the 95th percentile simulated ranges for most regions and most of time. Queensland availability was lower due to higher outages and solar generation being economically offloaded due to low prices. In Victoria, total available capacity trended toward the upper end of 95th percentile range due to additional wind generation and higher availability of gas and liquid fuelled generators, partly due to lower temperatures leading to a lower capacity derating compared to the forecast.

Example generation interpretation

Figure 41 shows an example graph of generation modelling accuracy, using New South Wales' large-scale solar generators as an example. For a given year it compares simulated generation (semi-scheduled generators and scheduled bidirectional units) under full simulation range and central 95th percentile simulation range (between the 2.5th and 97.5th percentile), to actual generation (semi-scheduled generators and scheduled bidirectional units) for identified periods ordered from highest to lowest availability. For scheduled generators simulated and actual availability would be compared rather than generation. The red range shows the simulated aggregate generation of this generation class for 80 intervals (40 hours) from the top 10 hottest days.

Figure 41 Example simulated and actual supply (New South Wales large-scale solar generation, MW)



The 2024 ESOO simulated ranges, shown in red, demonstrate that aggregate solar output during selected periods was expected to be as high as 3,738 MW, and as low as 3 MW, depending on time of day and variability in cloud cover. Actual (observed) generation, shown as the dark line, predominantly is within the simulated range during the high temperature days of interest, between 2,972 MW and 184 MW. In this example, actuals are primarily within the simulation range, suggesting that actual generation output aligned with forecast outcomes.

6.1.1 New South Wales

AEMO collects generation information from participants on the commissioning, decommissioning, and the capacity of individual production units. **Table 25** compares data from the 2024 ESOO to actual generator characteristics in February 2025. This may include projects that are still in commissioning.

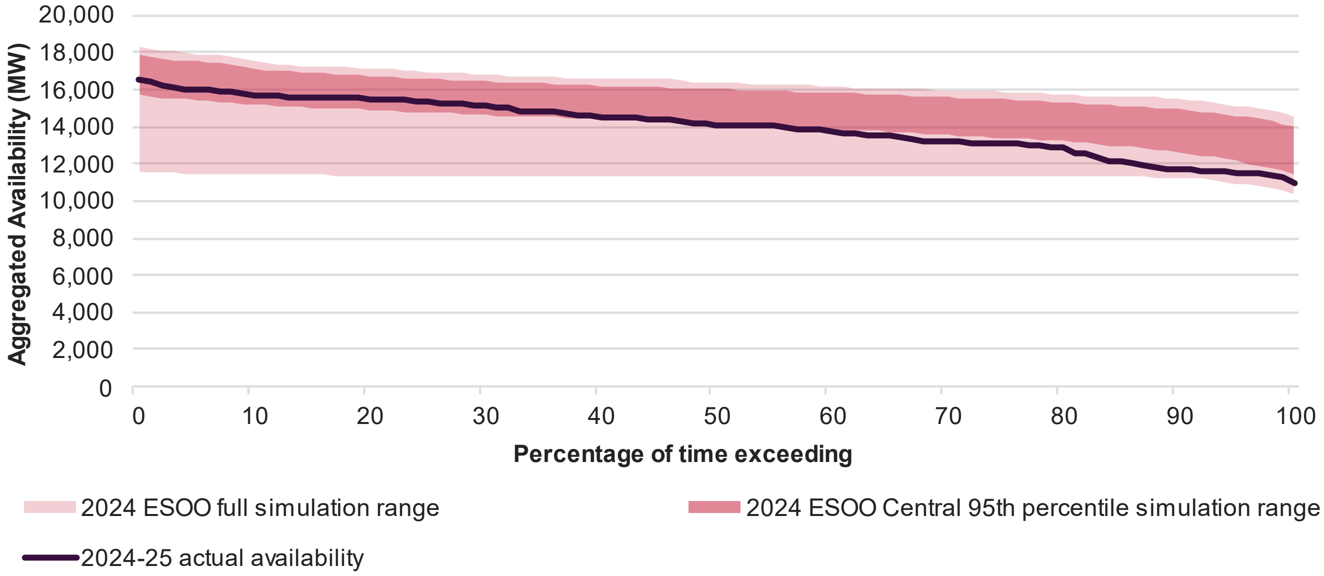
The variance between forecast and actual facilities reflects two solar projects that were generating in February 2025 but were not assumed to be online until after the 2024-25 summer in the forecast. This resulted in an extra 463 MW of VRE capacity during this period, contributing to the observed variance. An additional battery project with a capacity of 100 MW came online earlier than anticipated in the reliability forecast. Additionally, a 20 MW generator that was originally classified as a non-scheduled generator and excluded from the 2024 ESOO forecasts was later reclassified as a scheduled generator. As a result, the net difference between the forecast and actual generation values was 583 MW.

Table 25 Forecast and actual generation count and capacity, February 2024

New South Wales	Facilities forecast to operate		Facilities actually operating		Difference in capacity (forecast-actual)	
	Count	MW	Count	MW	MW	%
VRE generation	55	6,726	57	7,189	-463	-6.9%
Non-VRE generation/storage	54	13,430	56	13,550	-120	-0.9%
All generation	109	20,156	113	20,739	-583	-2.9%

Figure 42 shows total summer availability during the identified high temperature periods. Actual aggregate availability remained within or at the lower end of the simulated range, with coal and hydro fuel trending towards the lower end of their respective simulation ranges.

Figure 42 New South Wales supply availability for the top 10 hottest days (MW)



Black coal

Figure 43 shows New South Wales black coal generators' equivalent full unplanned outage rates[57], considering partial, full, and long duration outages. Actual outage levels rose in 2024-25 compared to the previous year but were still below the forecast, with the level of outages differing from that forecast in the 2024 ESOO by approximately 1.3%. No long duration outages occurred, so the two actuals cases (including and excluding long duration outages) are coincident.

Figure 43 New South Wales black coal equivalent full unplanned outage rates, including long duration outages

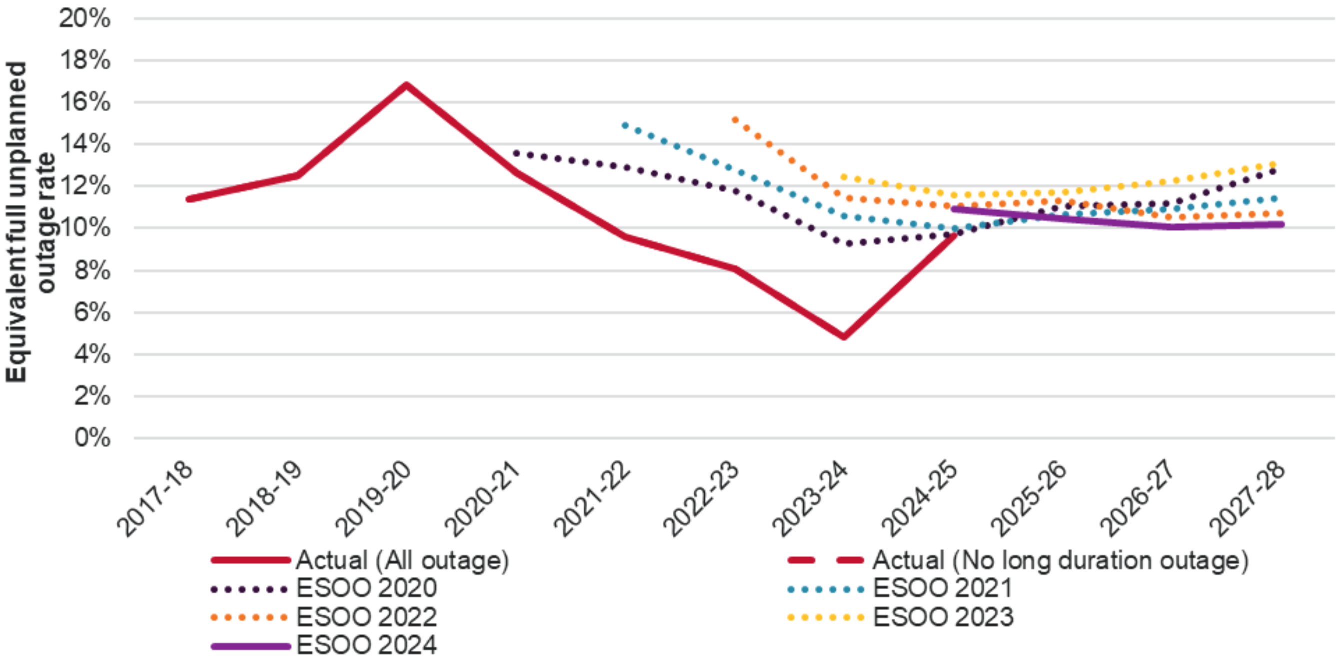
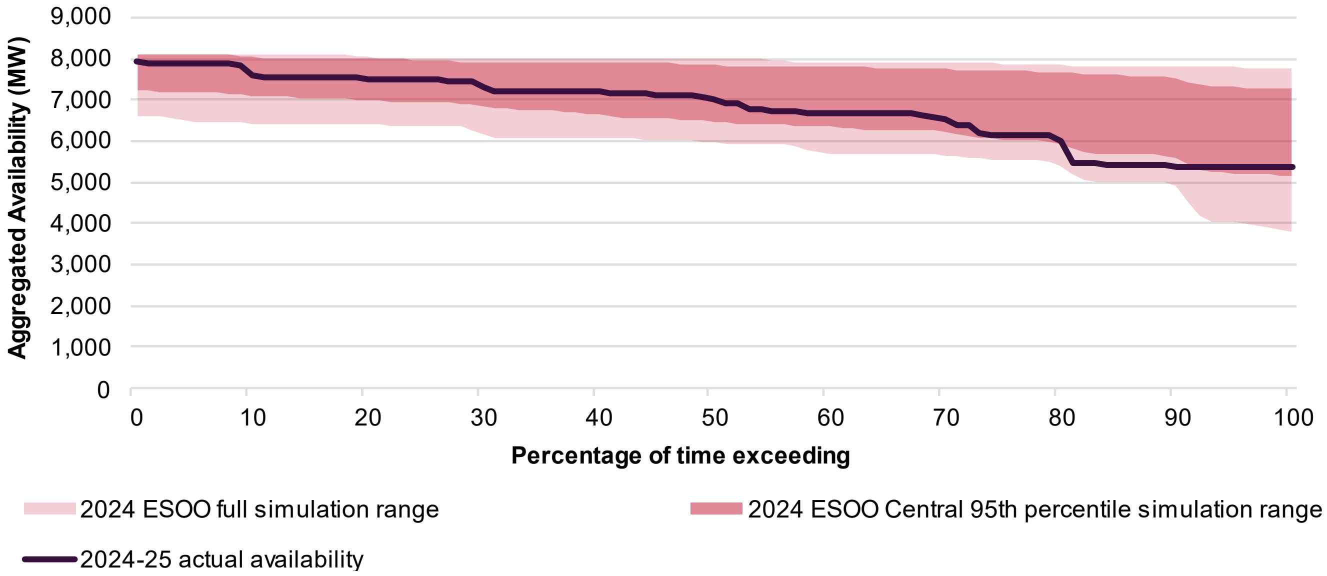


Figure 44 shows actual availability for New South Wales black coal generators over the top 10 hottest days was mostly within the 2024 ESOO 95th percentile simulated range. Despite the average unplanned outages being lower than forecast, several coal units were on planned outages during these periods, reducing actual availability, including during three periods of low-reserve conditions.

[57] Further information on unplanned outages rates applied is in the 2024 *Forecasting Assumptions Update*, at https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2024/2024-forecasting-assumptions-update.pdf.

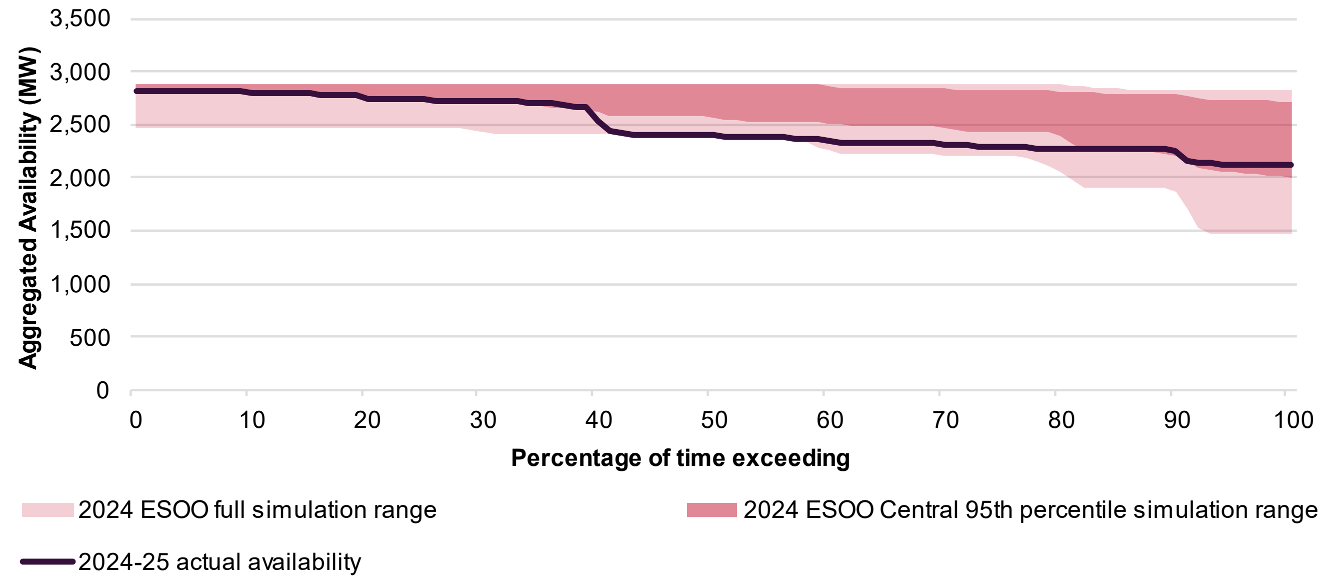
Figure 44 New South Wales black coal supply availability for the top 10 hottest days (MW)



Hydro

Figure 45 shows supply availability for New South Wales hydro generators over the top 10 hottest days, comparing actual with simulated availability. In 2024-25, the observed availability fell toward the lower end of the 2024 ESOO simulation range, largely due to an unplanned derating of Tumut 3 during actual hot day periods.

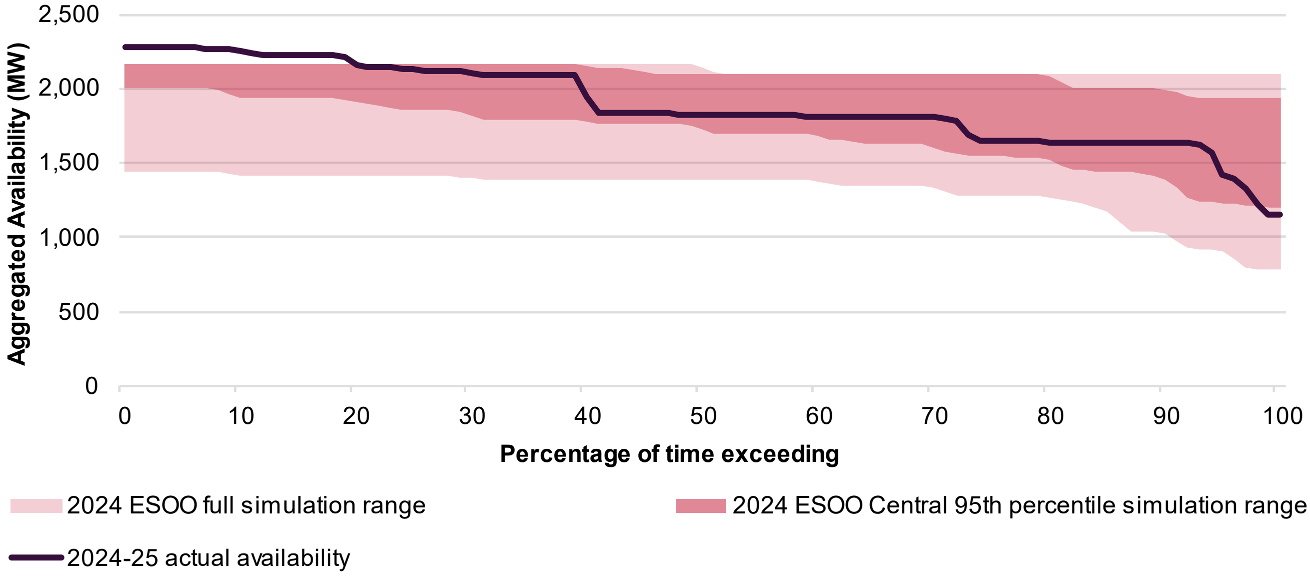
Figure 45 New South Wales hydro generation supply availability for the top 10 hottest days (MW)



Gas and liquids

Figure 46 shows supply availability for New South Wales gas and liquid generators over the top 10 hottest days, comparing actual with simulated availability. Actual availability varies mostly within the central 95th percentile simulated range. However, it is higher at the upper end, mainly because of generators advising of higher available capacities for dispatch than assumed in the 2024 ESOO, due to lower temperature-related derating. Since observed temperatures during the top 10 hottest summer days were mostly below the summer peak reference temperature used in the forecast, generators experienced less derating in practice than was assumed in the forecast. Additionally, the inclusion of Hunter Economic Zone as a scheduled generator increased actual capacity.

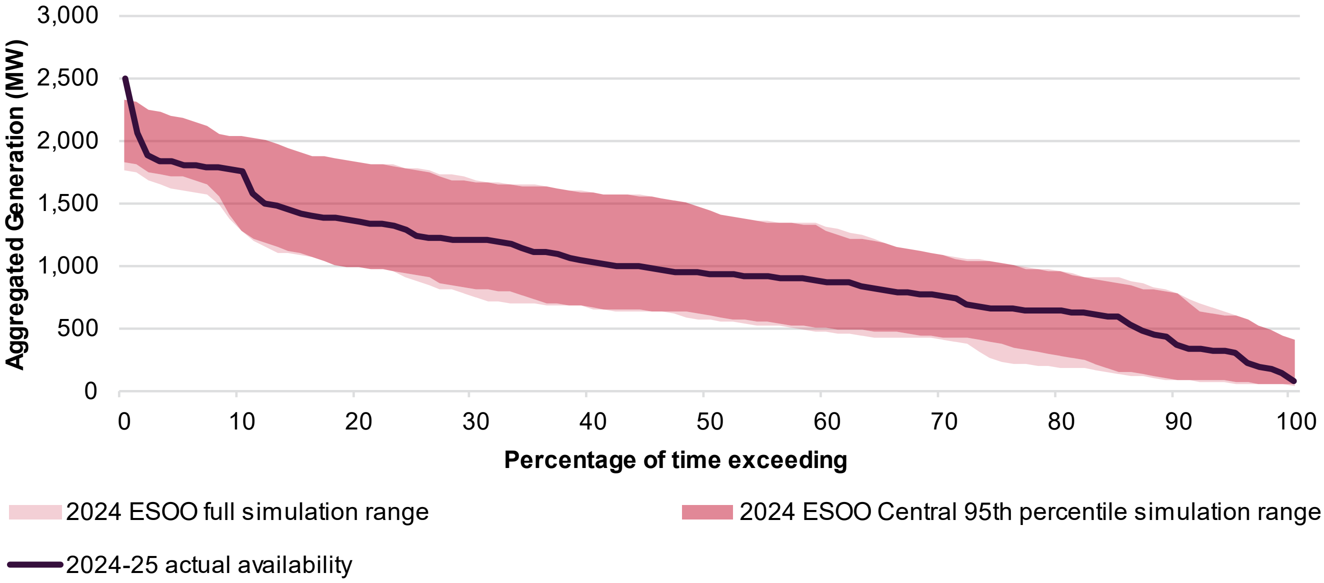
Figure 46 New South Wales gas and liquid supply availability for the top 10 hottest days (MW)



Wind

Figure 47 shows aggregate generation for New South Wales wind generators over the top 10 hottest days, comparing actual generation with simulated generation. The majority of generation is within the 95th percentile simulated range.

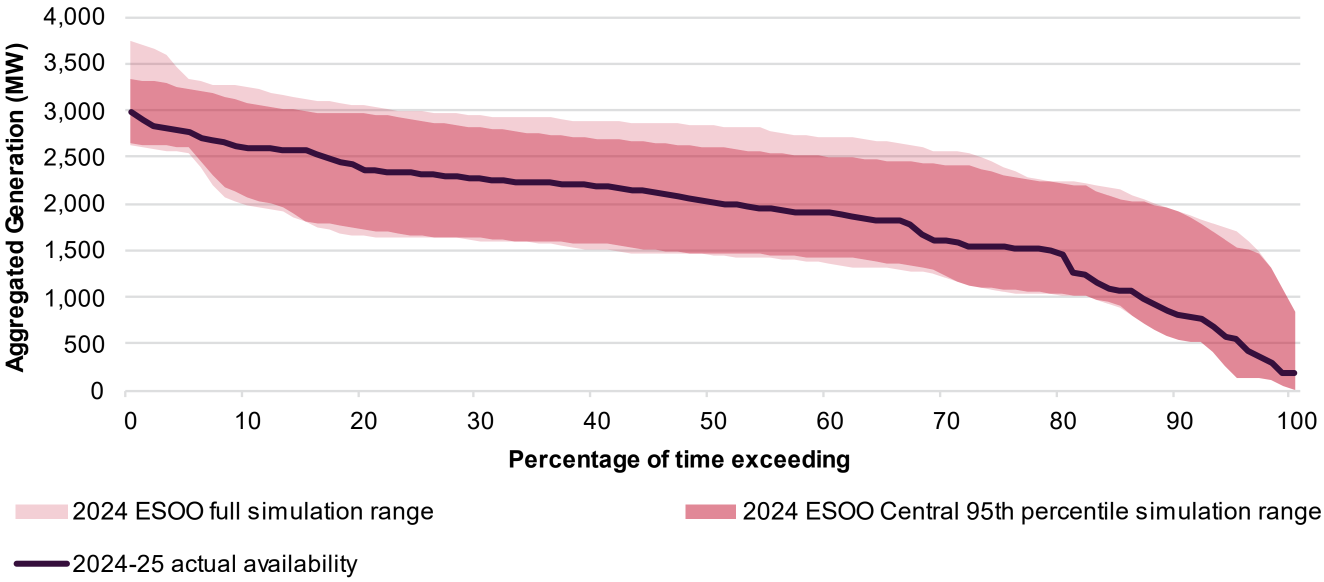
Figure 47 New South Wales wind generation for the top 10 hottest days (MW)



Large-scale solar

Figure 48 shows aggregate generation for New South Wales large-scale solar generators over the top 10 hottest days, comparing actual generation with simulated generation in the 2024 ESOO. Solar generator output is captured within the central 95th percentile simulated range.

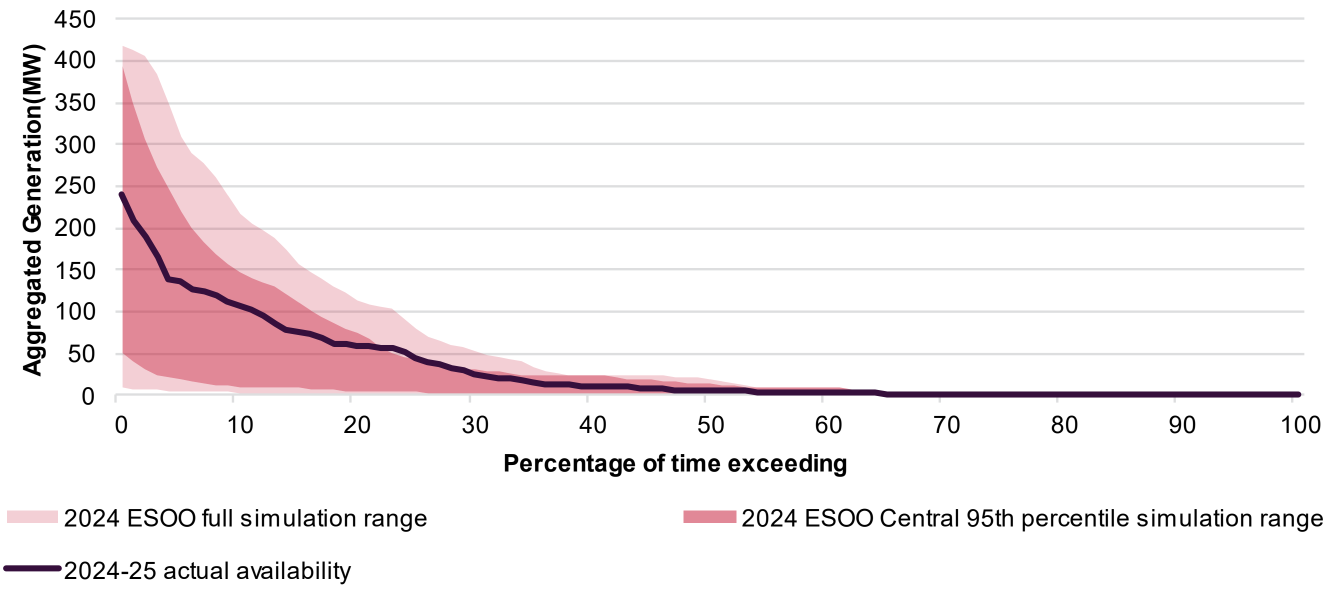
Figure 48 New South Wales large-scale solar generation for the top 10 hottest days (MW)



Battery

Figure 49 shows aggregate generation for New South Wales batteries over the top 10 hottest days, comparing actual generation with simulated generation in the 2024 ESOO. Actual battery generation is towards the upper end of the 95th percentile simulation range.

Figure 49 New South Wales battery generation for the top 10 hottest days (MW)



6.1.2 Queensland

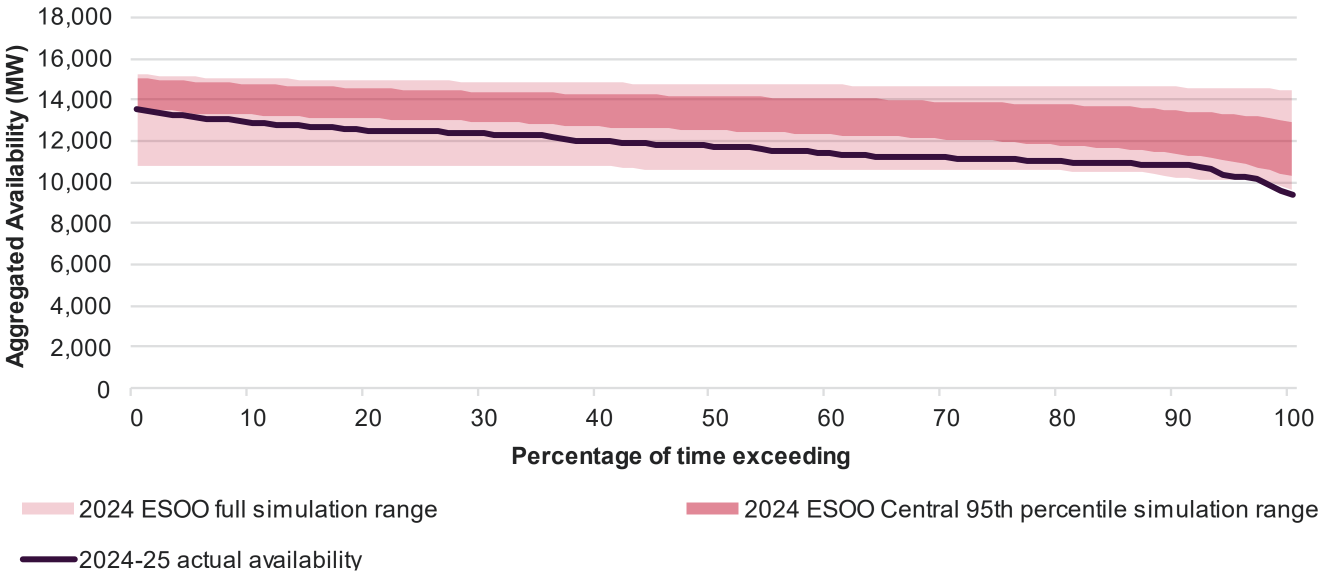
Table 26 shows how participant-provided generation information was implemented in the 2024 ESOO, compared to actual generator characteristics in February 2025. One solar project and one wind project delivered a combined capacity of 188 MW ahead of the ESOO forecast, and a 255 MW battery project was also online earlier than forecast. The actual generation capacity exceeded the forecast by 443 MW.

Table 26 Forecast and actual generation count and capacity, February 2025

Queensland generation	Facilities forecast to operate		Facilities actually operating		Difference in capacity (forecast-actual)	
	Count	MW	Count	MW	MW	%
VRE generation	40	4,091	42	4,279	-188	-4.6%
Non-VRE generation/storage	58	12,213	59	12,468	-255	-2.1%
All generation	98	16,304	101	16,747	-443	-2.7%

Figure 50 shows total summer generation availability for Queensland's identified high temperature periods, comparing actual with simulated availability in the 2024 ESOO. Actual aggregate availability was mostly below the 2024 ESOO 95th percentile simulated range, with lower availability from coal and solar generators.

Figure 50 Queensland supply availability for the top 10 hottest days (MW)



Black coal

Figure 51 shows the actual unplanned outage rate in 2024-25 increased from the previous year and was higher than the projection used in the 2024 ESOO[58] which expected an availability improvement.

[58] Further information on unplanned outages rates applied is in the 2024 *Forecasting Assumptions Update*, at https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2024/2024-forecasting-assumptions-update.pdf.

Figure 51 Queensland black coal equivalent full unplanned outage rates, including long duration outages

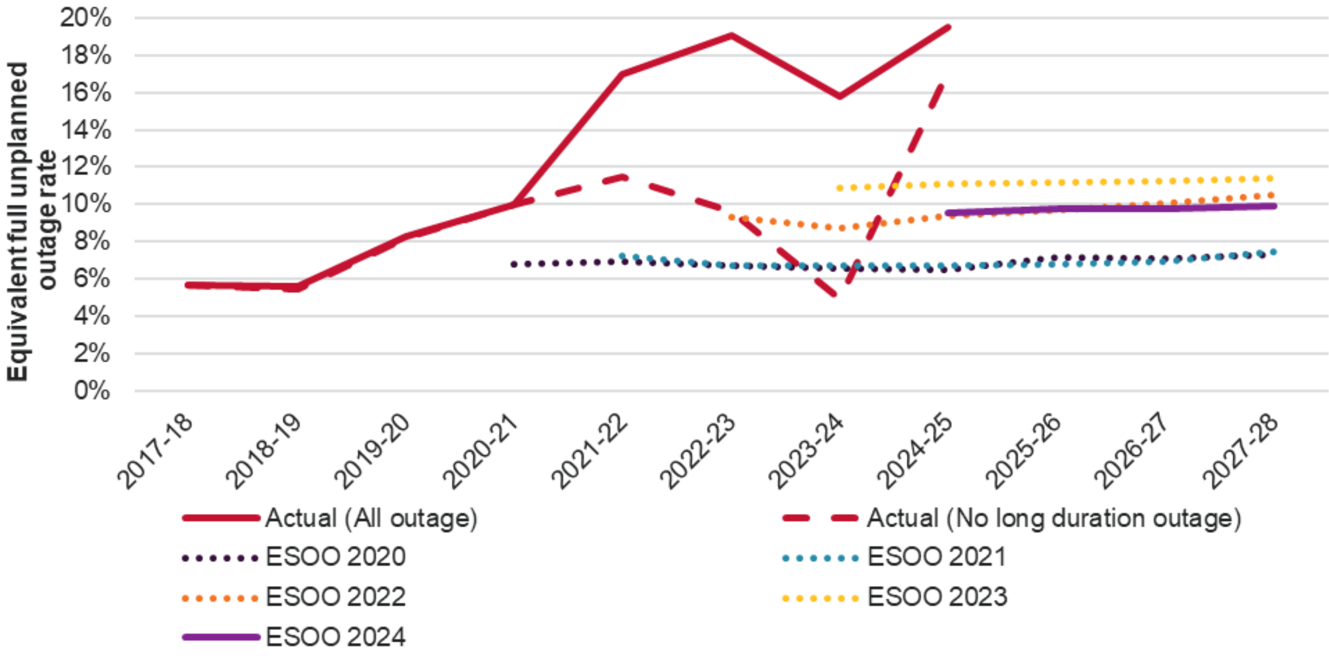
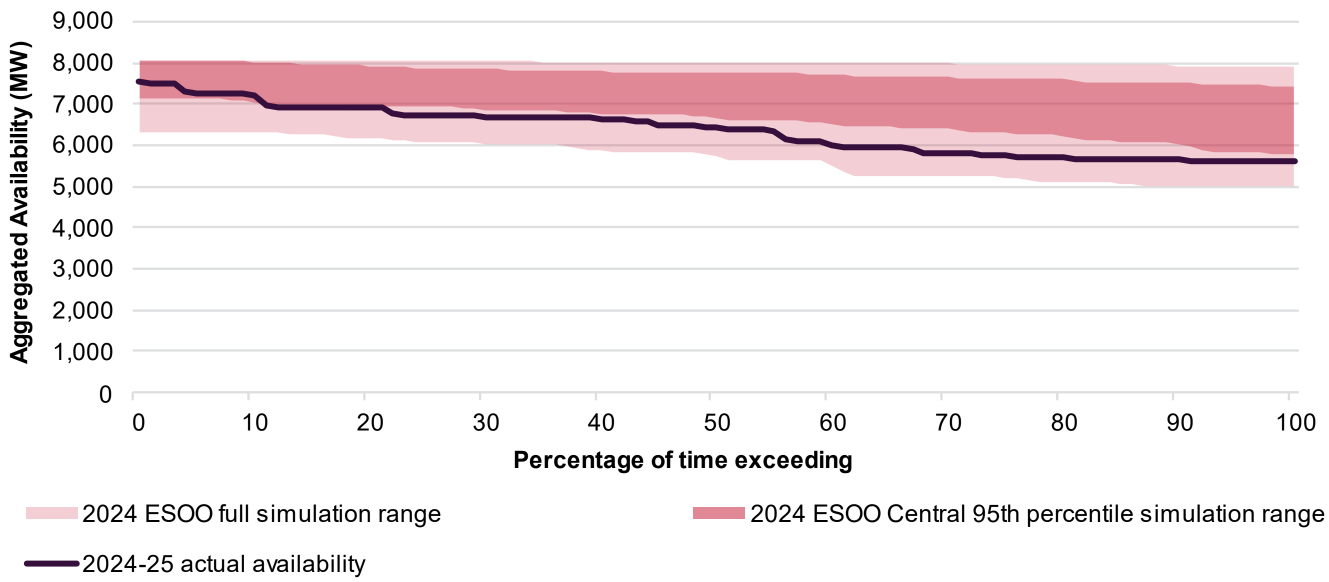


Figure 52 shows supply availability for Queensland black coal generators over the identified high temperature days, comparing actual with simulated availability. Actual availability is towards the lower end of the simulated range and mostly outside of the 95th percentile simulation range, due to multiple generators experienced more outgas during the identified high temperature periods, which aligns with the higher actual unplanned outage rate noted above.

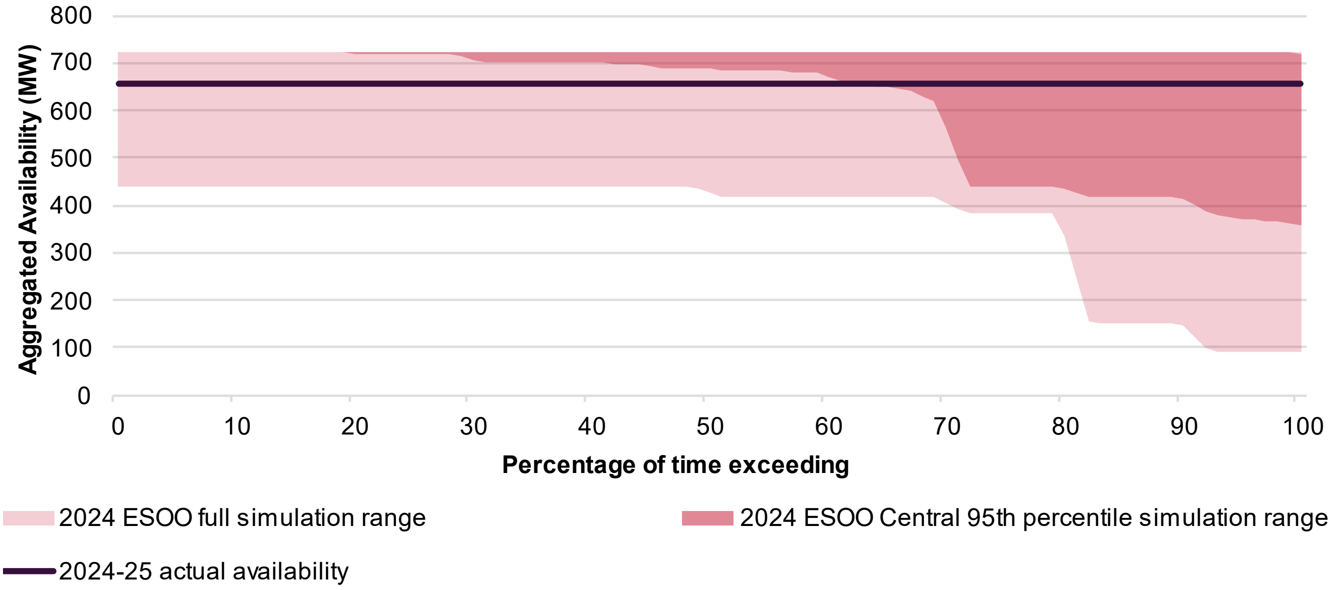
Figure 52 Queensland black coal supply availability for the top 10 hottest days (MW)



Hydro

Figure 53 shows supply availability for Queensland hydro generators over the top 10 hottest days, comparing actual with simulated availability. The observed actual availability was static and was below the 95th percentile simulated range for more than half of the selected periods. This was mostly due to both Barron Gorge units being on unplanned outage during the selected hot day periods.

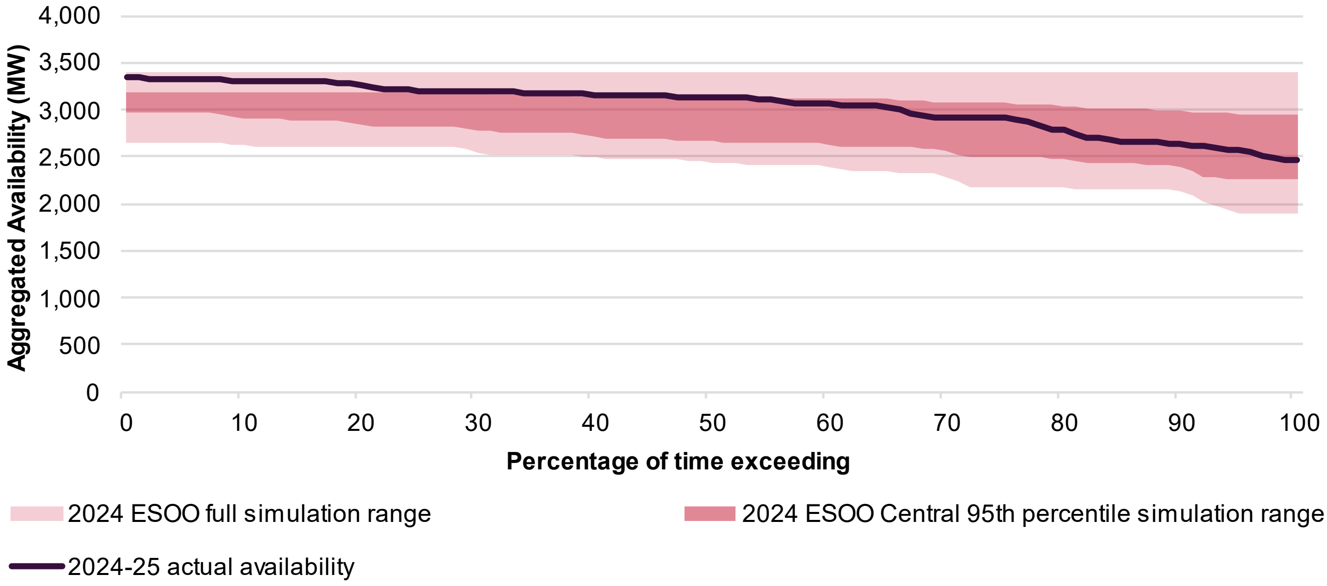
Figure 53 Queensland hydro generation supply availability for the top 10 hottest days (MW)



Gas and liquids

Figure 54 shows supply availability for Queensland gas and liquids generators over the top 10 hottest days, comparing actual with simulated availability. Actual availability was towards the upper end of the central 95th percentile simulated range, as many generators had slightly more capacity available than forecast, likely due to milder temperatures reducing the capacity derating.

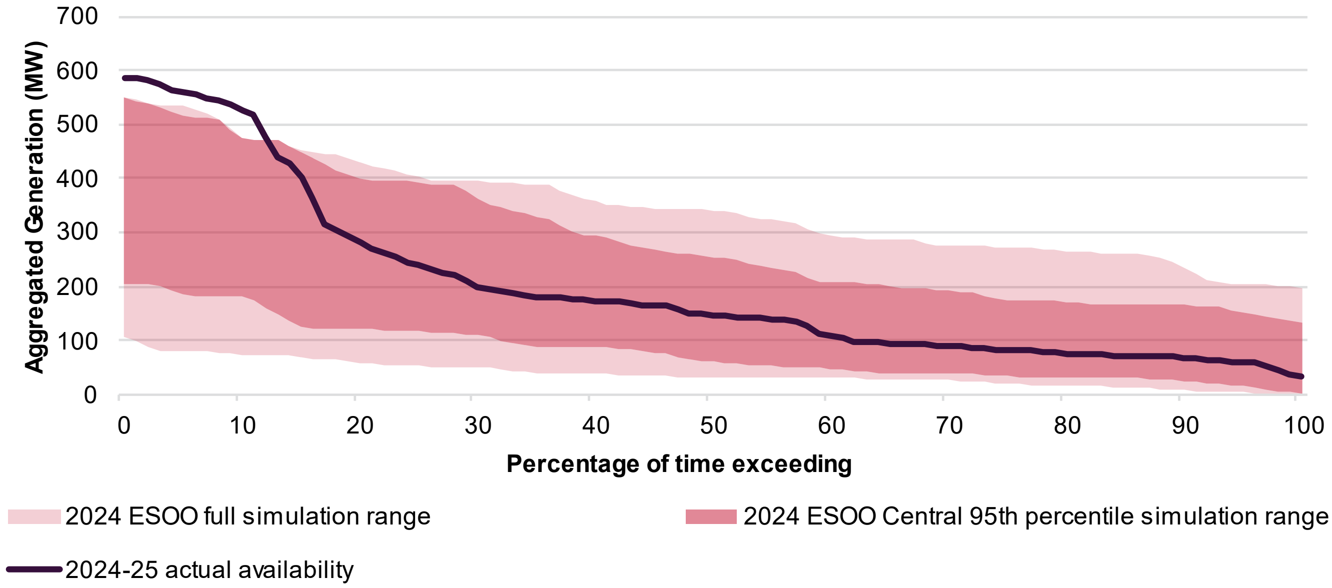
Figure 54 Queensland gas and liquids supply availability for the top 10 hottest days (MW)



Wind

Figure 55 shows wind generation supply for Queensland over the top 10 hottest days, comparing actual generation with the 2024 ESOO simulated generation range. The observed output was mostly within the central 95th percentile simulated range; early commissioning of a wind farm elevated actual generation above the upper end of the simulation range.

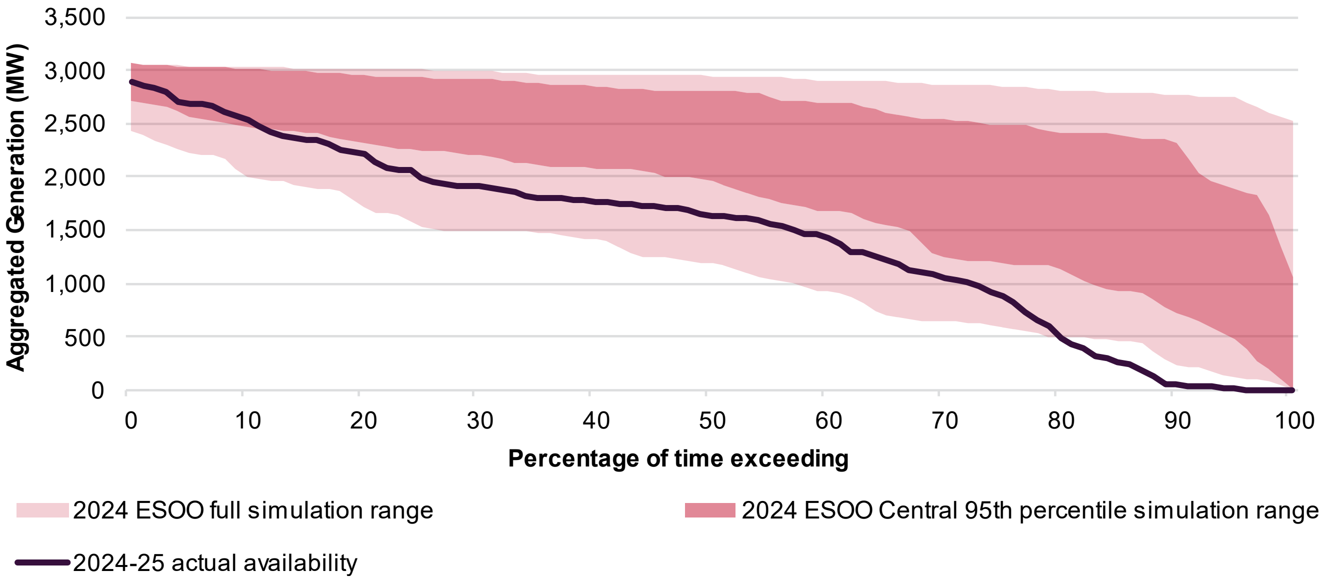
Figure 55 Queensland wind generation for the top 10 hottest days (MW)



Large-scale solar

Figure 56 shows the output of Queensland large-scale solar generators over the top 10 hottest days, comparing actual with the 2024 ESOO simulated generation range. Actual generation was mostly towards the lower end of or below the simulated generation range, despite early commissioning of a solar farm. The lower actual generation is partially due to the later timing of maximum temperatures in the 2024-25 summer, leading to more late day intervals when solar irradiance was lower included in the actual dataset than in ESOO simulations. Additionally, curtailment (mostly economic offloading) also appears to have played a role in reducing actual solar output.

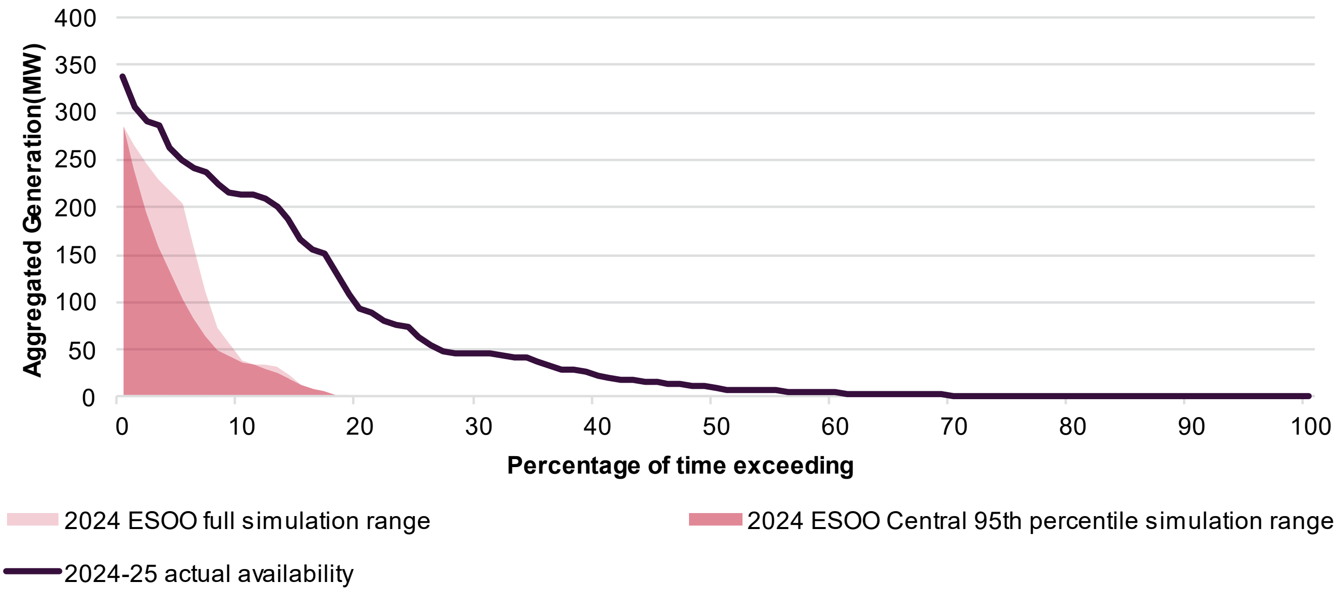
Figure 56 Queensland large-scale solar generation for the top 10 hottest days (MW)



Battery

Figure 57 shows aggregate generation for Queensland battery generators over the top 10 hottest days, comparing actual generation with simulated generation in the 2024 ESOO. The observed output of batteries was entirely above the simulated range, driven by one battery project commencing full operation earlier than assumed in the ESOO modelling which contributed to actual generation during the selected periods.

Figure 57 Queensland battery generation for the top 10 hottest days (MW)



6.1.3 South Australia

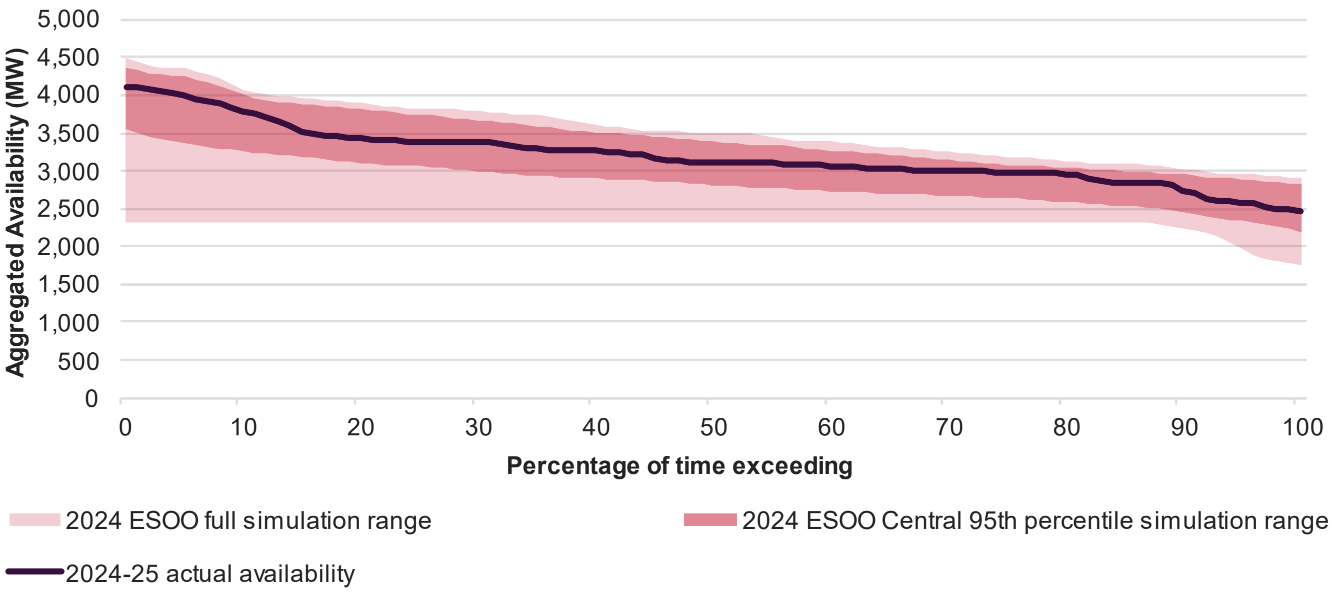
Generation information for South Australia, as reported by participants for the 2024 ESOO, is shown in **Table 27** alongside actual generator characteristics in February 2025. Two wind projects that were in commissioning contributed 297 MW during this period. Additionally, a battery (200 MW) in commissioning also contributed during the February 2025 period. The net result is an additional 497 MW of capacity beyond what was forecast. Snuggery and Port Lincoln generators which were forecast to be mothballed for the summer were later contracted as emergency out-of-market reserves based on a temporary rule change by the Australian Energy Market Commission (AEMC)[59]. This additional out-of-market capacity supported South Australia during several low reserve periods over the summer, but it was excluded from the actual operating capacity used in this forecast accuracy assessment.

Table 27 Forecast and actual generation count and capacity, February 2025

South Australia	Facilities forecast to operate		Facilities actually operating		Difference in capacity (forecast-actual)	
	Count	MW	Count	MW	MW	%
VRE generation	39	2,943	41	3,240	-297	-10.1%
Non-VRE generation/storage	60	2,745	61	2,948	-200	-7.3%
All generation	99	5,688	102	6,185	-497	-8.7%

Figure 58 shows aggregate summer availability for South Australia during its identified high temperature periods. Actual aggregate availability was within the 2024 ESOO 95th percentile simulated range.

Figure 58 South Australia supply availability for the top 10 hottest days (MW)

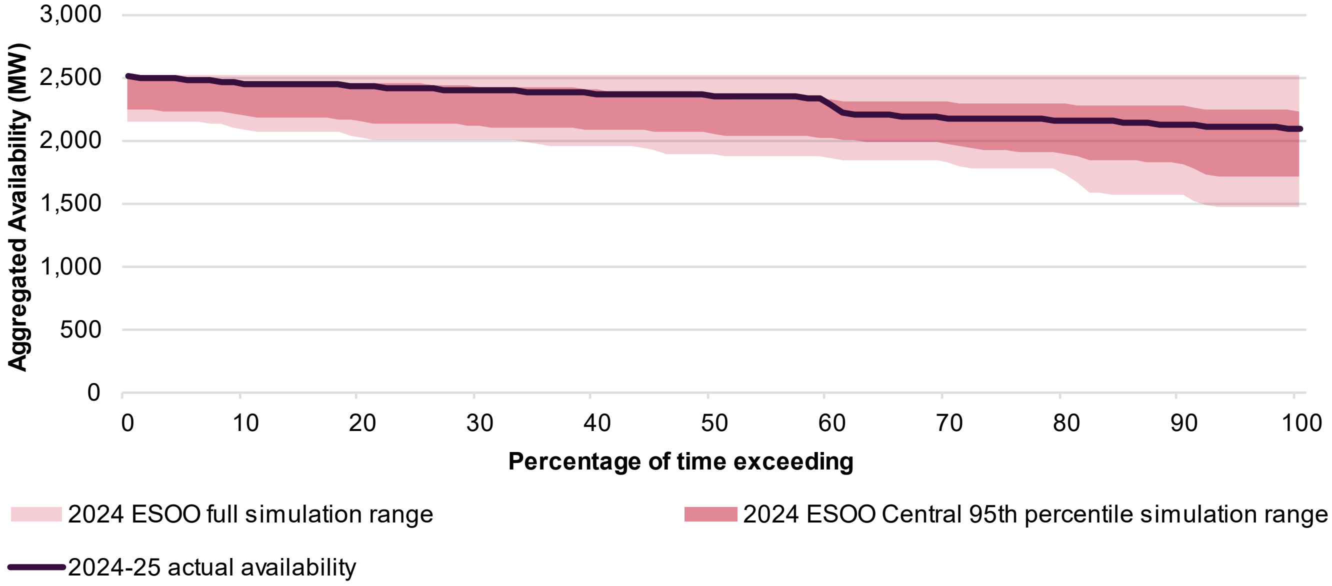


[59] See https://www.aemc.gov.au/news-centre/media-releases/aemc-makes-jurisdictional-derogation-support-reliability-south-australia.

Gas and liquids

Figure 59 shows that availability over the top 10 hottest days for gas and liquid generators was mostly above or towards the upper end of the 2024 ESOO central 95th percentile simulation range.

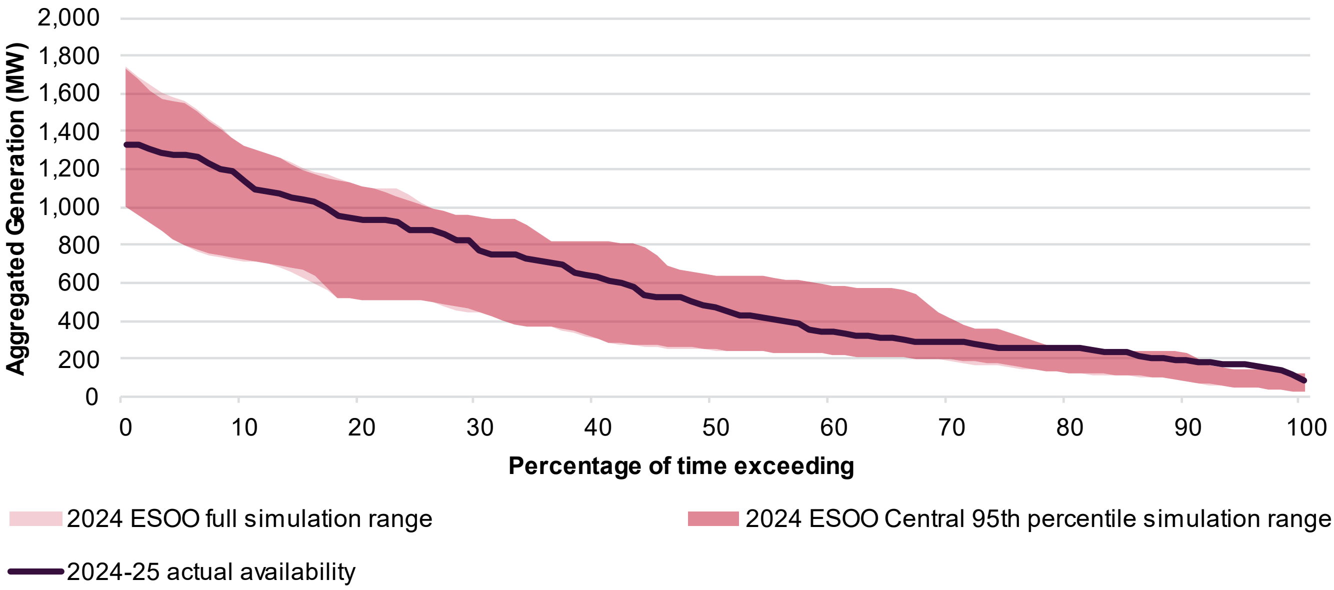
Figure 59 South Australia gas and liquids supply availability for the top 10 hottest days (MW)



Wind

Figure 60 shows the output of South Australian wind generators over the top 10 hottest days, comparing actual output with the range of simulated generation. The observed output was mostly within or towards the upper end of the 2024 ESOO central 95th percentile simulation range, likely impacted by the early commissioning of two wind facilities.

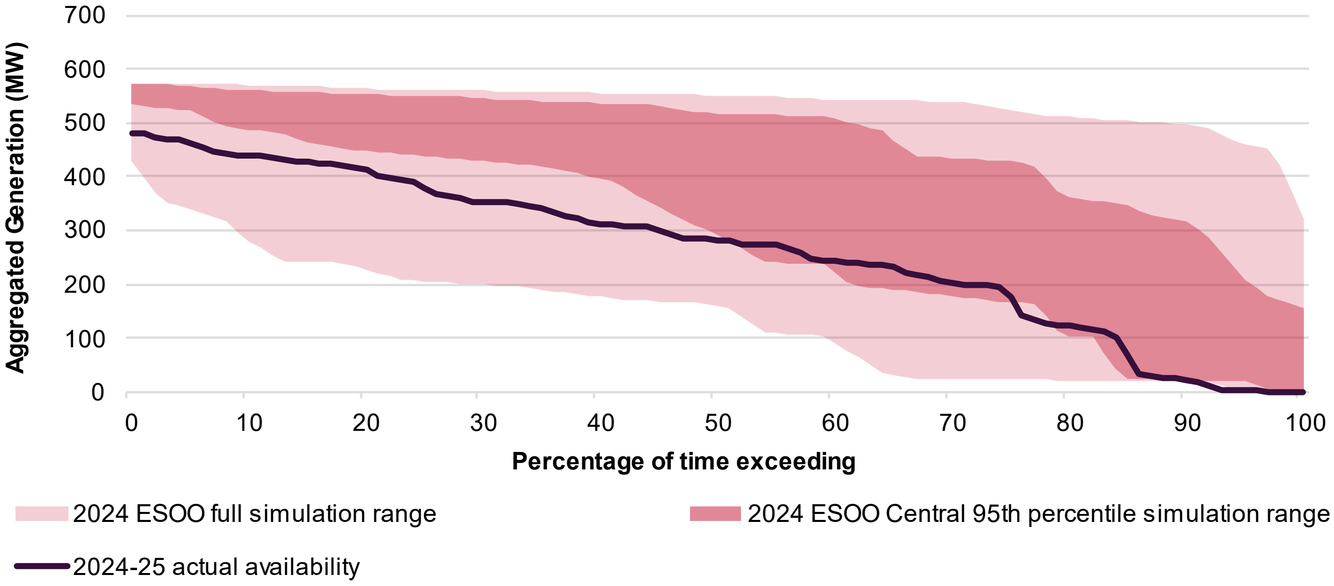
Figure 60 South Australia wind generation for the top 10 hottest days (MW)



Large-scale solar

Figure 61 shows aggregate generation for South Australian large-scale solar generators over the top 10 hottest days, comparing actual generation with simulated generation. In 2024-25, the observed generation was predominantly lower than the 95th percentile simulation range, likely reflective of economic offloading.

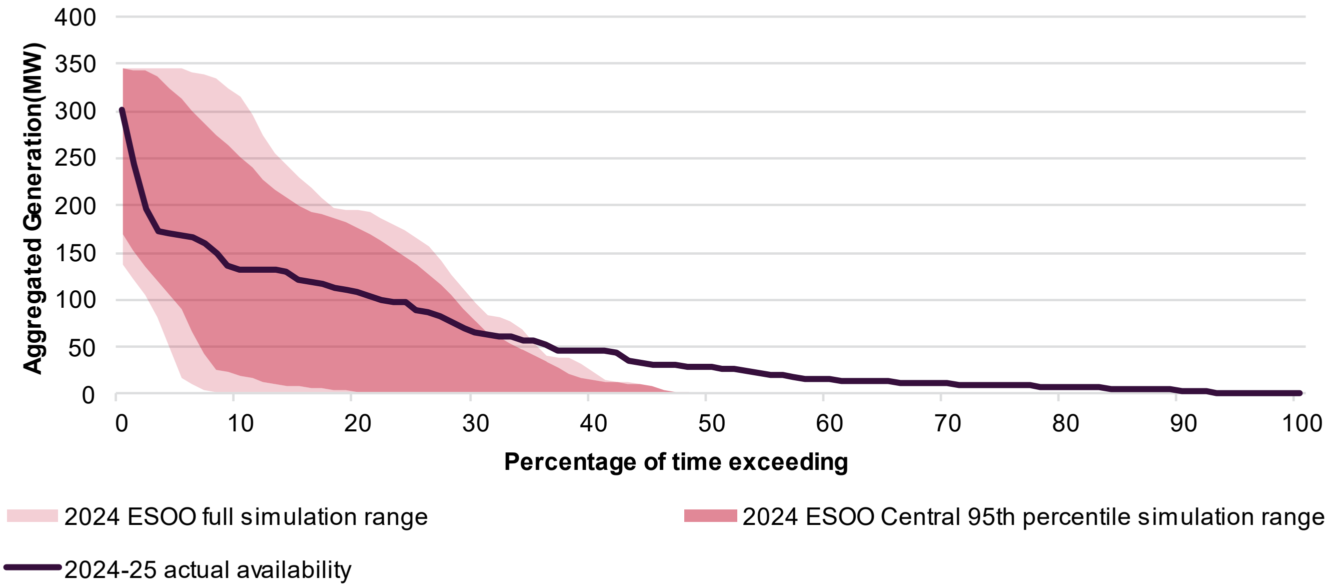
Figure 61 South Australia large-scale solar generation for the top 10 hottest days (MW)



Battery

Figure 62 shows aggregate generation for South Australian battery generators over the top 10 hottest days, comparing actual generation with simulated generation in the 2024 ESOO. The observed output of batteries was mostly within the 95th percentile of the simulated range.

Figure 62 South Australia battery generation for the top 10 hottest days (MW)



6.1.4 Tasmania

Table 28 shows how generation information for Tasmania was implemented in the 2024 ESOO, compared to actual generator characteristics for February 2025.

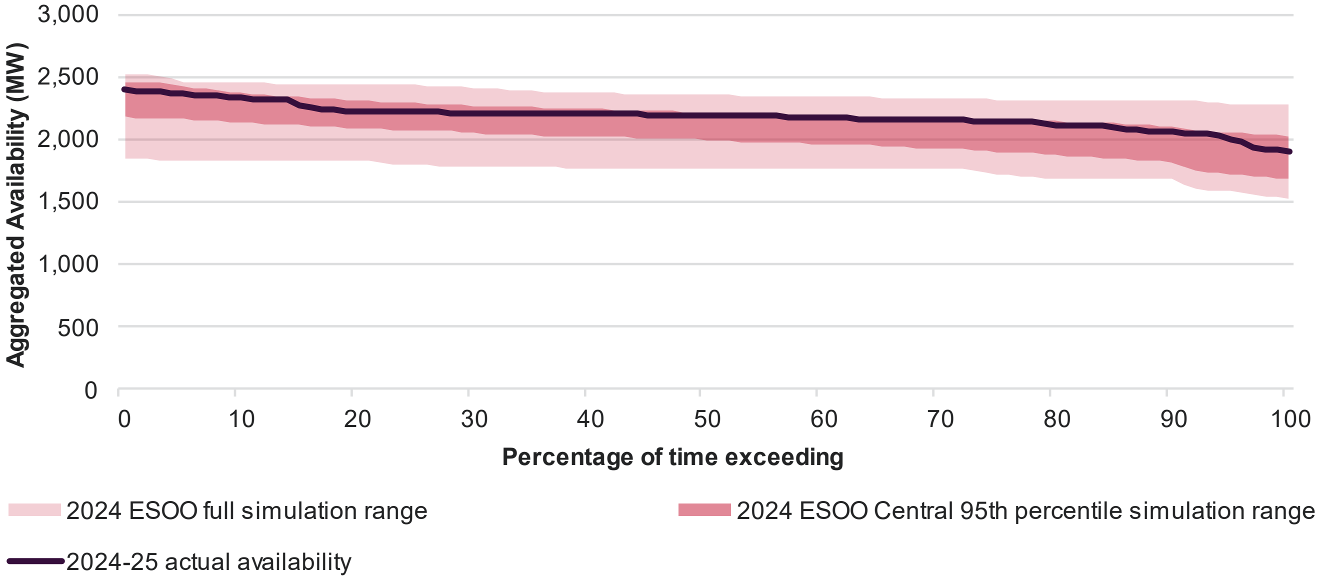
Three hydro facilities were forecast to be unavailable during the 2024-25 summer as per participant-submitted seasonal scheduled capacities used for the 2024 ESOO modelling. However, these generators actually provided available capacity during the selected periods. One of the Tamar Valley Combined Cycle units that was forecast to be available did not contribute to summer capacity. Together, these differences resulted in a net increase of 208 MW capacity in February 2025 compared to the forecast scheduled capacity. No new solar and wind developments were expected to commission in Tasmania during this period, therefore new developments did not contribute to the observed variation.

Table 28 Forecast and actual generation count and capacity, February 2024

Tasmania	Facilities forecast to operate		Facilities actually operating		Difference in capacity (forecast-actual)	
	Count	MW	Count	MW	MW	%
VRE generation	4	562	4	562	-	-
Non-VRE generation/storage	46	1,944	48	2,152	-208	-10.7%
All generation	50	2,506	52	2,714	-208	-8.3%

Figure 63 shows total summer availability for Tasmania for the highest temperature periods. Actual aggregate availability was at the upper end of the 95th percentile simulation range, driven mostly by higher than forecast hydro availability.

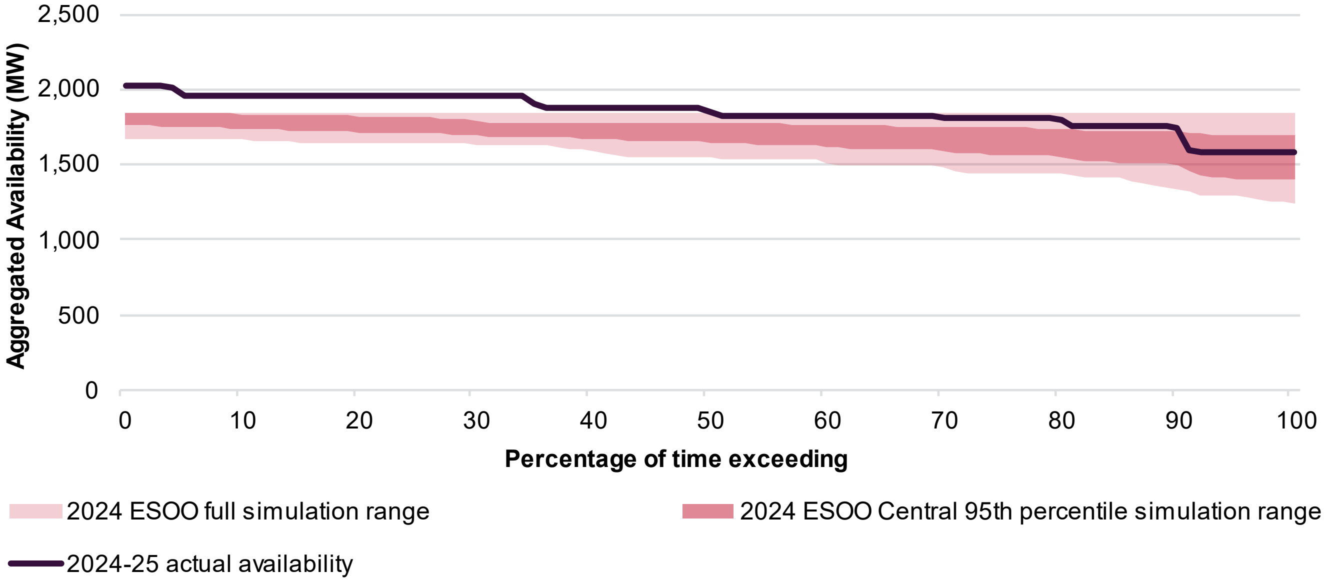
Figure 63 Tasmania supply availability for the top 10 hottest days (MW)



Hydro

Figure 64 shows supply availability for Tasmanian hydro generators over the top 10 hottest days, comparing actual with simulated availability. The observed availability is above the 2024 ESOO simulated range. This is mainly due to existing hydro generators providing capacity during hot periods, despite being forecast to be offline based on participant-submitted generation information.

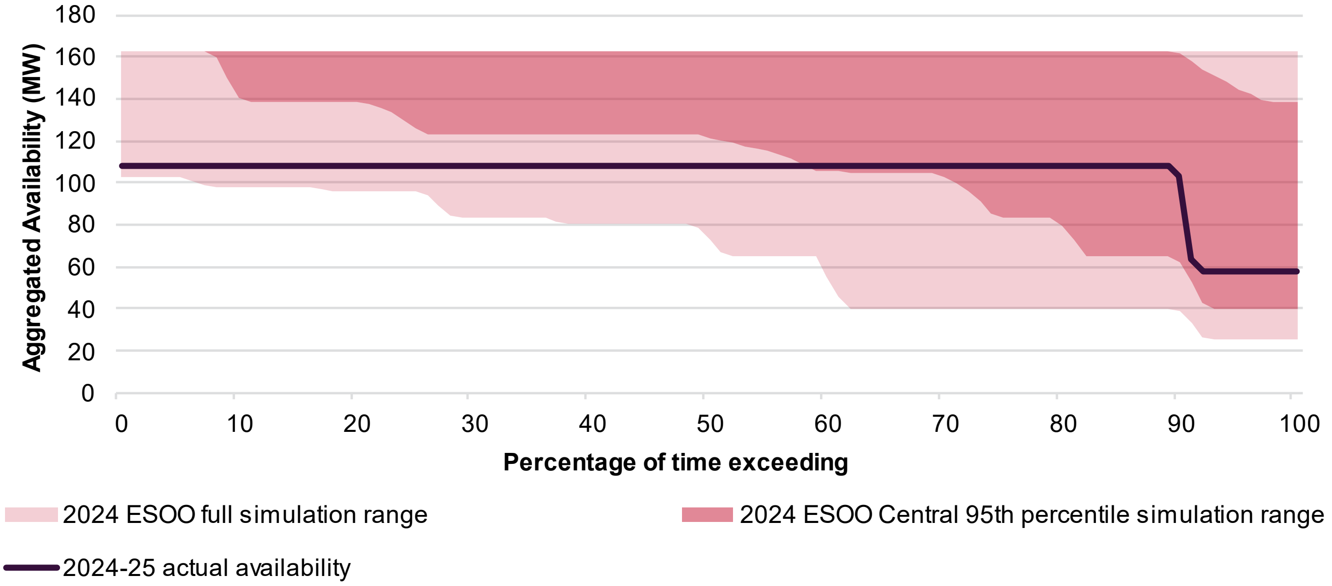
Figure 64 Tasmania hydro generation supply availability for the top 10 hottest days (MW)



Gas and liquids

Figure 65 shows supply availability for Tasmanian gas and liquid generators over the top 10 hottest days, comparing actual with simulated availability. The observed availability was mostly below the 2024 ESOO central 95th percentile simulated range, with several gas units being unavailable due to unplanned outages during hot periods .

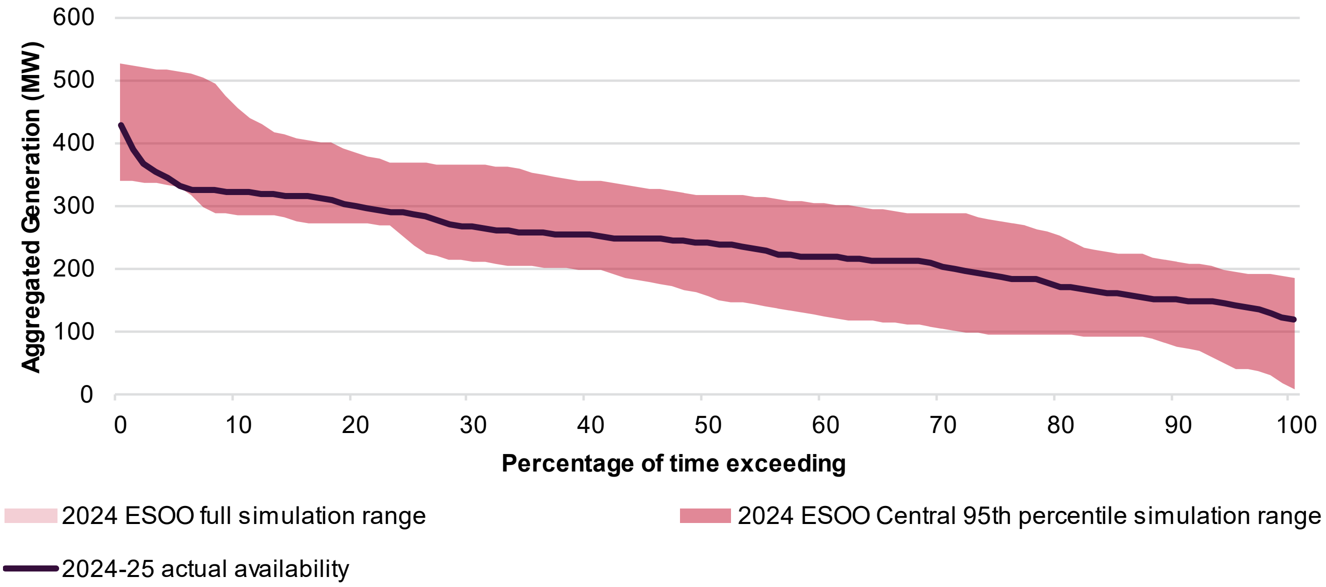
Figure 65 Tasmania gas and liquids supply availability for the top 10 hottest days (MW)



Wind

Figure 66 shows the output of Tasmanian wind generators over the top 10 hottest days, comparing actual generation with 2024 ESOO simulated generation. The observed wind output was within the 95th percentile generation band from the forecast.

Figure 66 Tasmania wind generation for the top 10 hottest days (MW)



6.1.5 Victoria

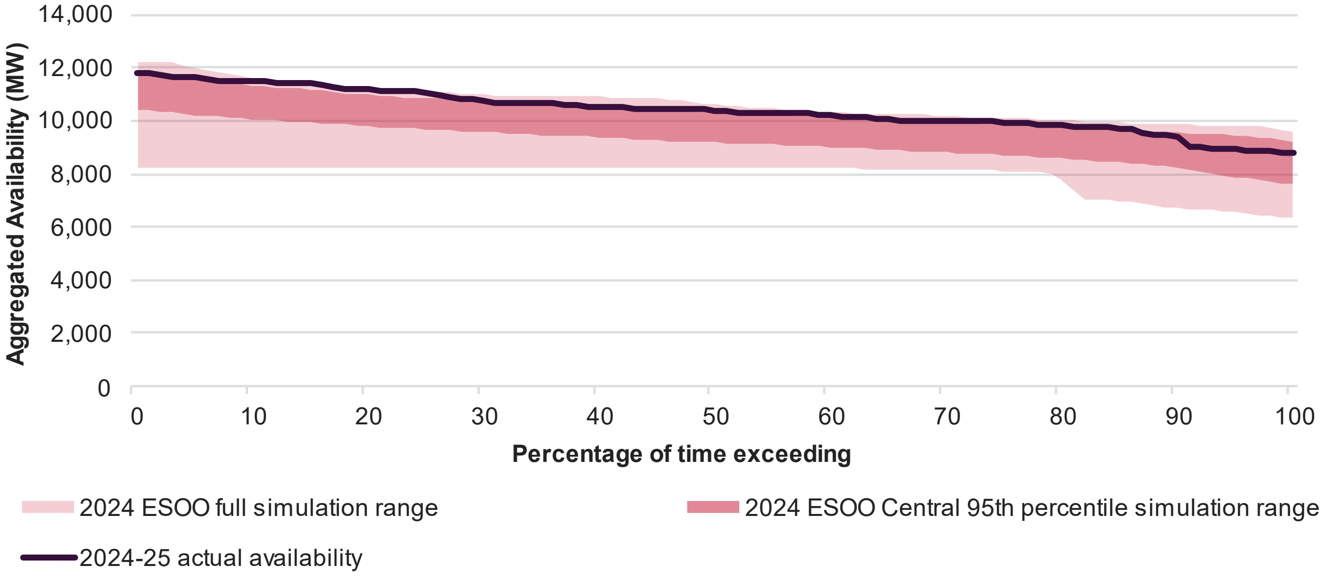
Victorian generation information, as reported by generator participants for the 2024 ESOO, is shown in **Table 29** alongside actual generator characteristics for February 2025. Three solar projects and one wind project totalling 402 MW were generating earlier than forecast. In addition, one battery project contributed generation up to 200 MW during this period, although it was not forecast to be online until later. In total, Victoria had 602 MW more available capacity than forecast in the 2024 ESOO.

Table 29 Forecast and actual generation count and capacity, February 2024

Victoria	Facilities forecast to operate		Facilities actually operating		Difference in capacity (forecast-actual)	
	Count	MW	Count	MW	MW	%
VRE generation	41	5,338	45	5,740	-402	-7.5%
Non-VRE generation/storage	71	9,636	72	9,836	-200	-2.1%
All generation	112	14,974	117	15,576	-602	-4.0%

Figure 67 shows observed aggregate summer availability for Victoria during its highest temperature periods compared to the 2024 ESOO simulated range. Actual availability mostly aligned with the upper end of the 2024 ESOO simulated range. In general, hydro availability was lower than forecast, while wind and gas and liquids performed at the upper end of forecast ranges, potentially reflective of the conditions in Victoria during hot periods.

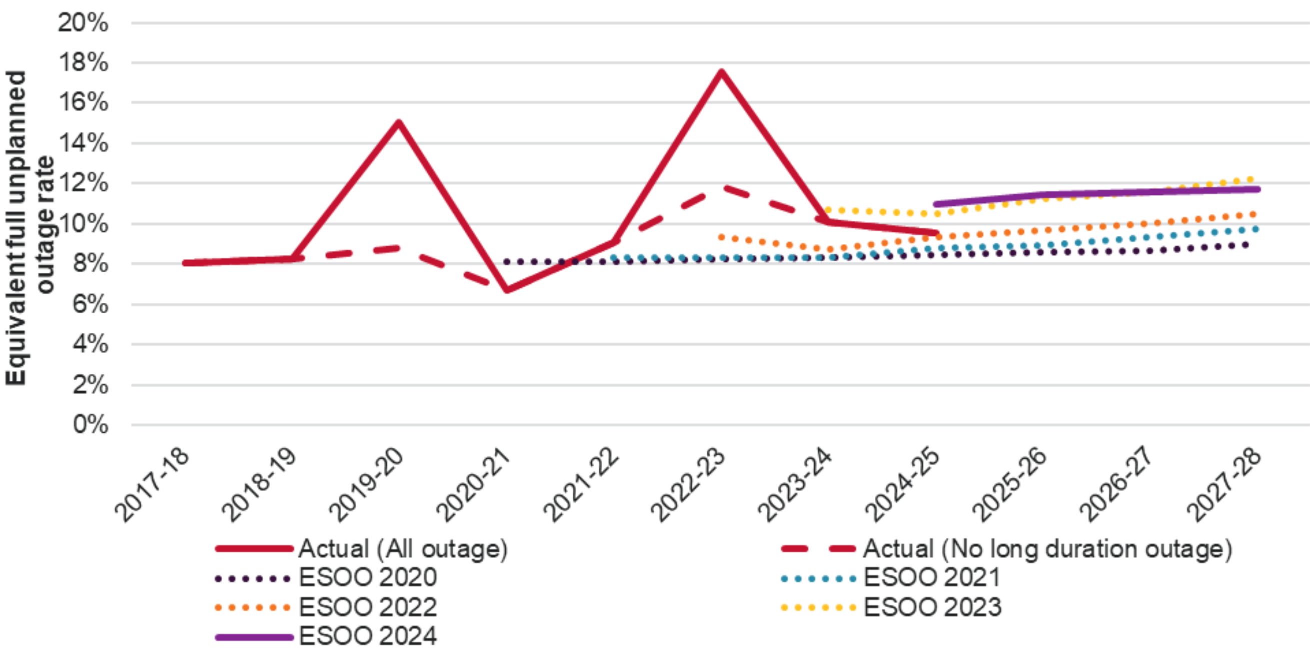
Figure 67 Victoria supply availability for the top 10 hottest days (MW)



Brown coal

Figure 68 demonstrates that the actual unplanned outage rate for 2024-25 declined slightly from the previous year, and was below the 2024 ESOO forecast[60].

Figure 68 Victoria brown coal equivalent full unplanned outage rates, forecasts including long duration outages

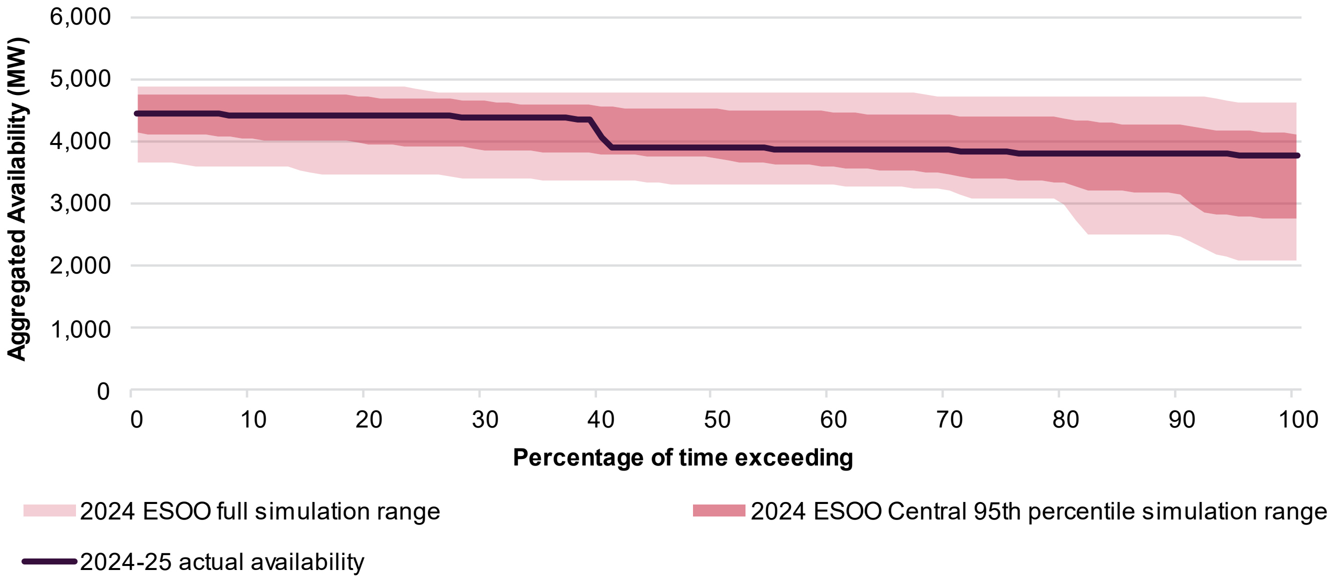


[60] Further information on unplanned outages rates applied is in the 2024 *Forecasting Assumptions Update*, at https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2024/2024-forecasting-assumptions-update.pdf.

Coal

Figure 69 shows supply availability for Victorian brown coal generators over the top 10 hottest days, comparing actual with simulated availability. Actual availability remained within the 2024 ESOO central 95th percentile simulation range.

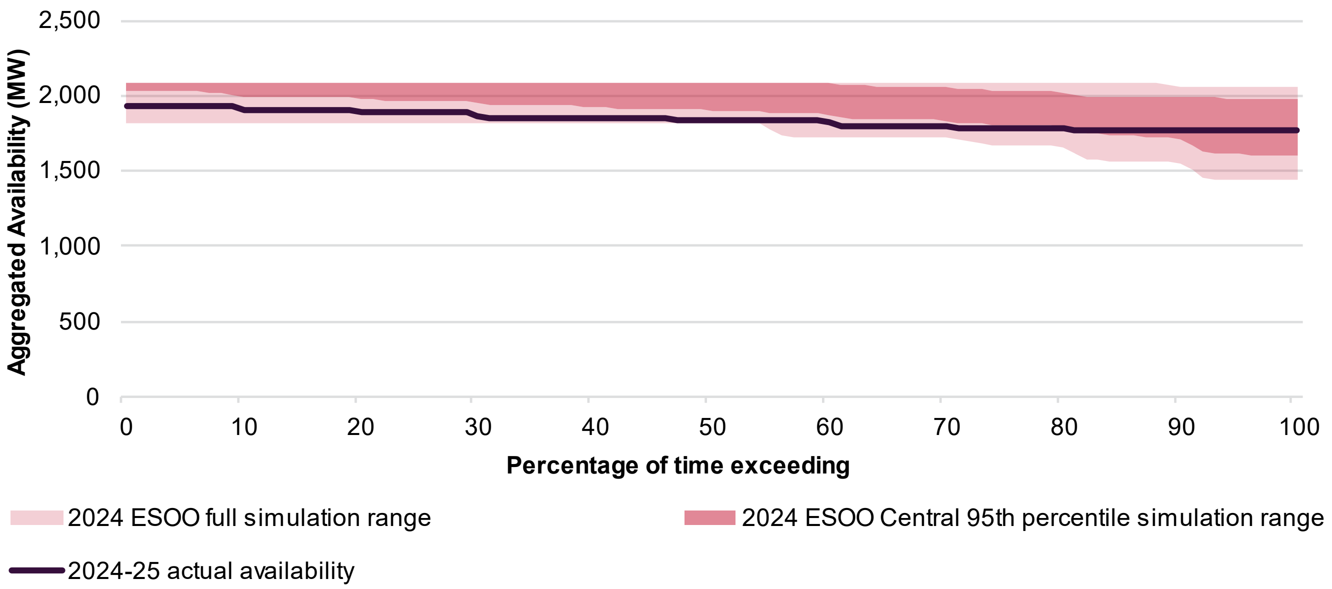
Figure 69 Victoria brown coal supply availability for the top 10 hottest days (MW)



Hydro

Figure 70 shows supply availability for Victorian hydro generators over the top 10 hottest days, comparing actual with simulated availability. Observed availability was below the 2024 ESOO central 95th percentile simulated range for most of the selected periods. This is primarily due to an unplanned outage derating of Murray across the summer period.

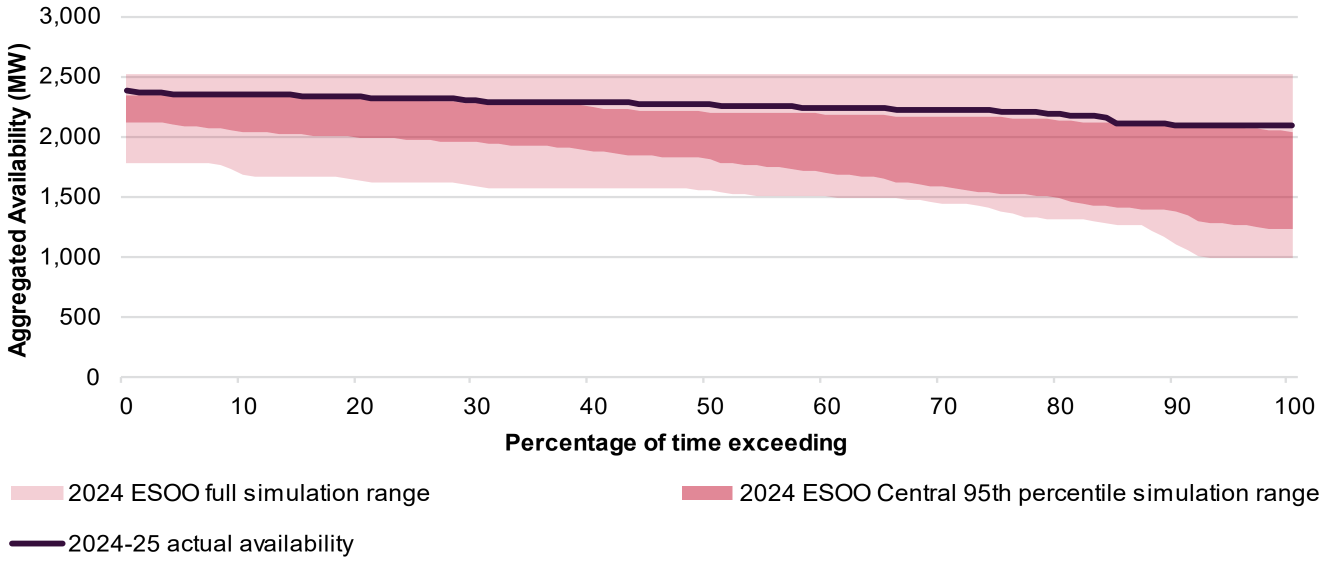
Figure 70 Victoria hydro generation supply availability for the top 10 hottest days (MW)



Gas and liquids

Figure 71 shows that observed availability over the top 10 hottest days was slightly above the 2024 ESOO central 95th percentile simulated range for most periods. This was likely driven by fewer outages during these periods and milder weather conditions, which resulted in less temperature related derating than assumed in the forecast.

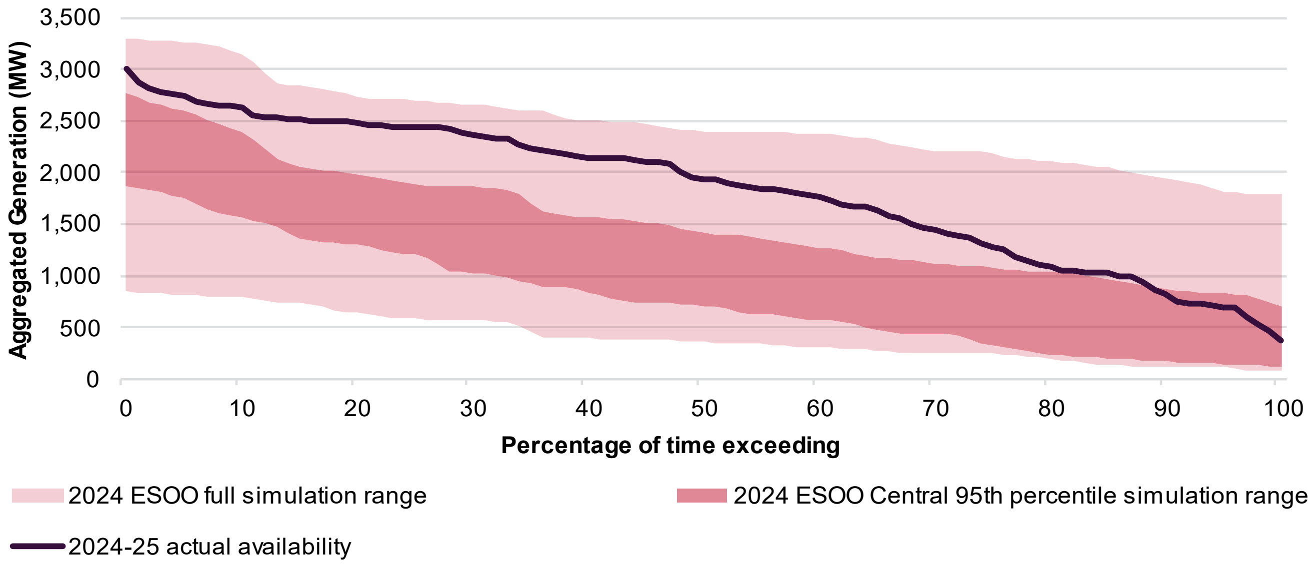
Figure 71 Victoria gas and liquids supply availability for the top 10 hottest days (MW)



Wind

Figure 72 shows the aggregate output for Victorian wind generators over the top 10 hottest days, comparing actual output with simulated generation. Observed wind output was mostly above the 95th percentile simulated range, contributed by lower temperatures where wind farms did not de-rate as much compared to the hot temperatures assumed in the forecast. The early commissioning of a wind farm (205 MW) also contributed to higher generation levels.

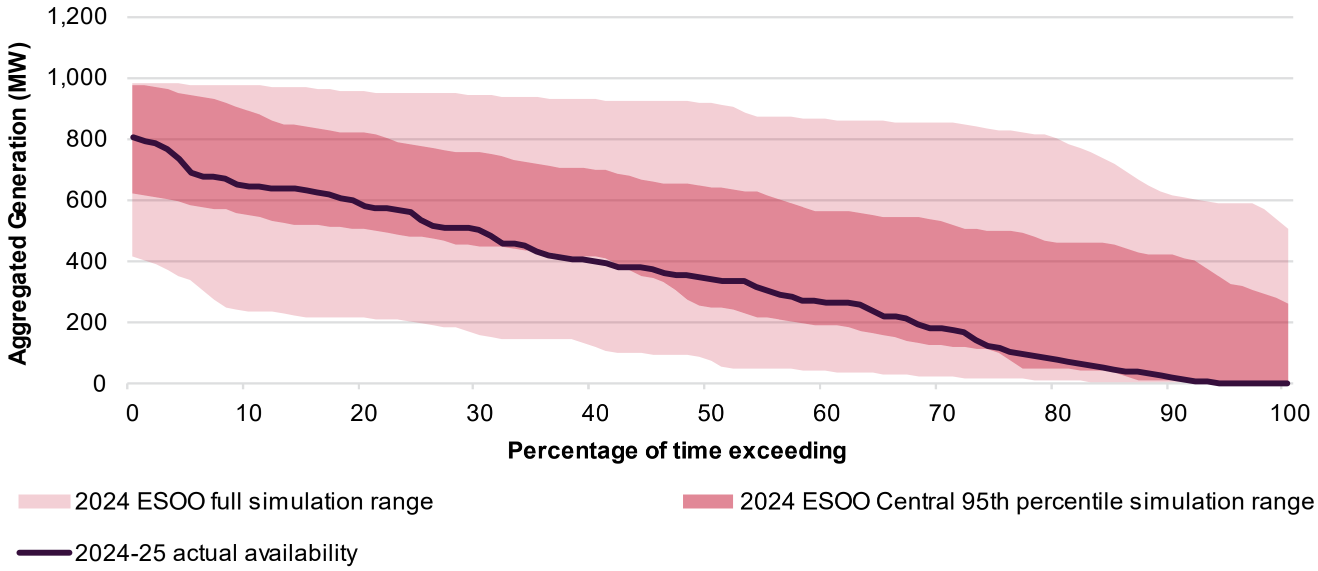
Figure 72 Victoria wind generation for the top 10 hottest days (MW)



Large-scale solar

Figure 73 shows aggregate output for Victorian large-scale solar generators over the top 10 hottest days, comparing actual generation with the forecast generation range. Actual generation was variable but mostly remained within or towards the lower end of the 95th percentile simulated range, despite three solar projects operating earlier than forecast. One of the new solar projects did not generate on any of the hot day periods, and several large-scale solar generators appeared to be out of service during some of the hot day periods, reducing actual generation.

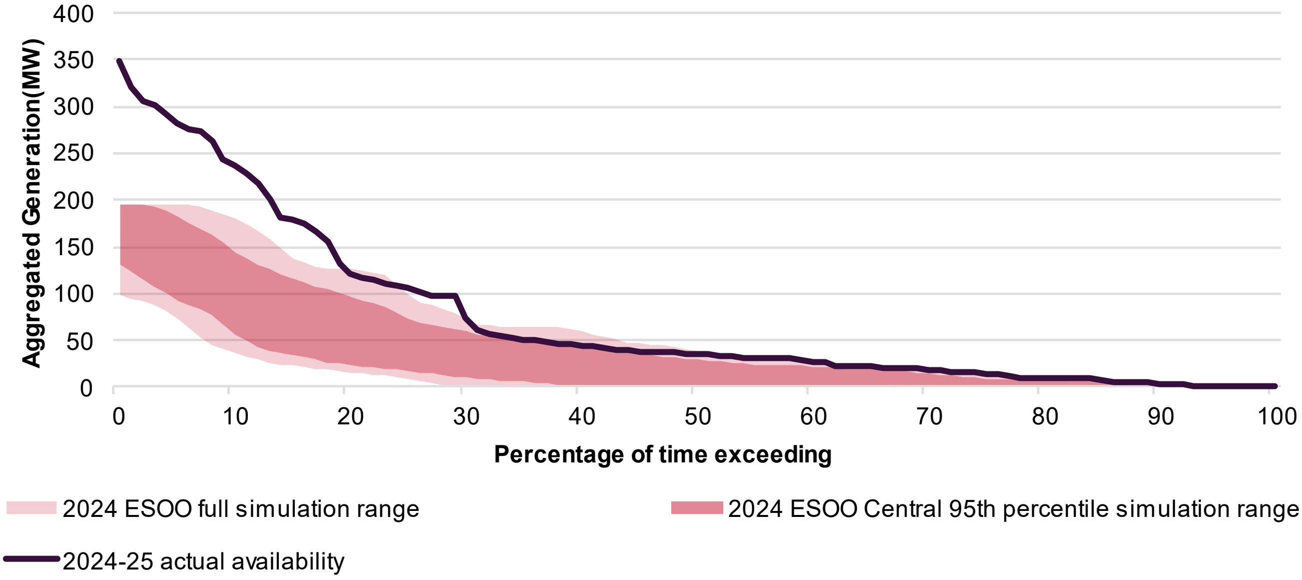
Figure 73 Victoria large-scale solar generation for the top 10 hottest days (MW)



Battery

Figure 74 shows aggregate generation for Victorian batteries over the top 10 hottest days, comparing actual generation with simulated generation in the 2024 ESOO. Observed battery generation was mostly above the simulated range due to the early completion of a large battery project in Victoria.

Figure 74 Victoria battery generation for the top 10 hottest days



7 Reliability forecasts

AEMO forecasts and reports on scarcity risk of generation supply availability, DSP, CER and inter-regional transmission capability, relative to demand. This forecast of supply scarcity risk is an implementation of the reliability standard[61] and Interim Reliability Measure[62], with the expectation that the market will respond to avoid USE occurring. Further, in operational and planning timeframes, AEMO uses operational mechanisms to avoid USE events where possible.

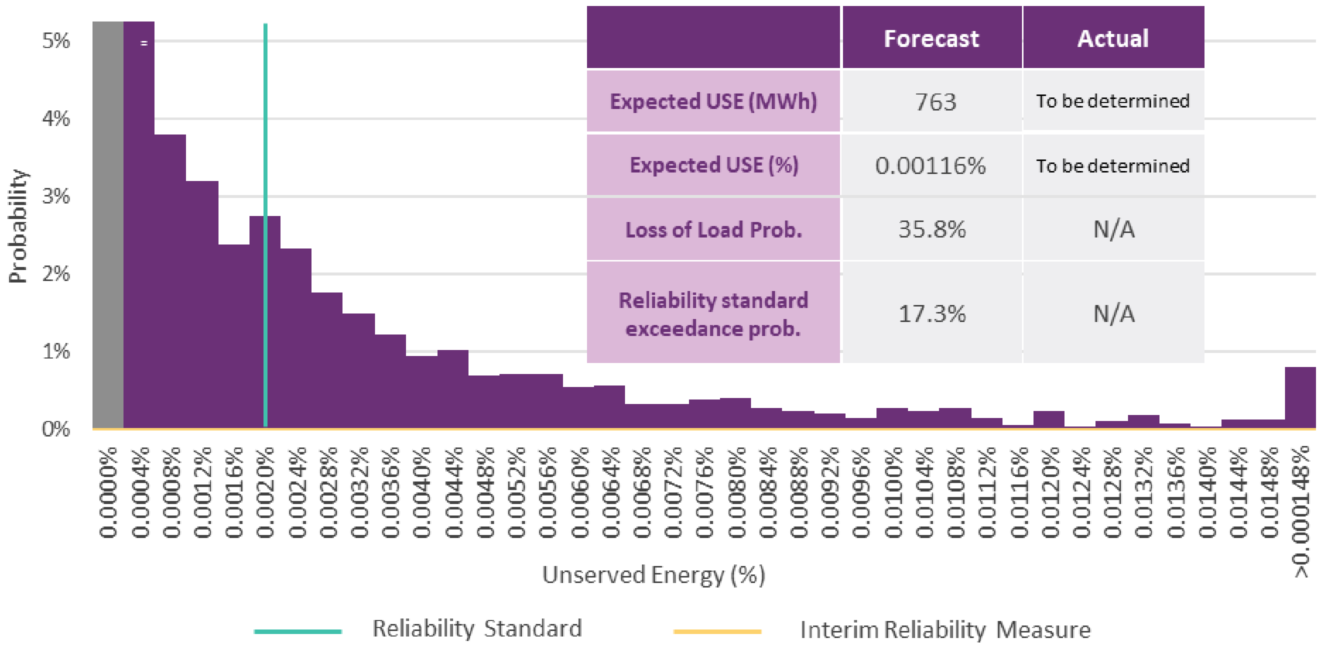
No USE events[63] were recorded in Queensland, South Australia, Tasmania, and Victoria in 2024-25. Assessment for New South Wales is ongoing, with investigations still in progress to determine whether any USE events occurred during the period.

Reliability forecasts are not presented for the purposes of assessing forecast accuracy, but for information only. Risk of USE is forecast as a probability distribution which is long-tailed – that is, most simulations do not involve a USE event, while a small number involve large USE events. Also, if the market or RERT responds effectively, the forecast USE may not occur.

7.1 New South Wales

Figure 75 shows the forecast distribution of USE in New South Wales for the 2024-25 financial year in the 2024 ESOO. The probability of any loss of load was assessed at 35.8%. For 2024-25, it has not yet been determined whether USE occurred in New South Wales, based on the definitions set out under the reliability standard.

Figure 75 New South Wales USE forecast distribution for 2024-25



	Forecast	Actual
Expected USE (MWh)	763	To be determined
Expected USE (%)	0.00116%	To be determined
Loss of Load Prob.	35.8%	N/A
Reliability standard exceedance prob.	17.3%	N/A

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

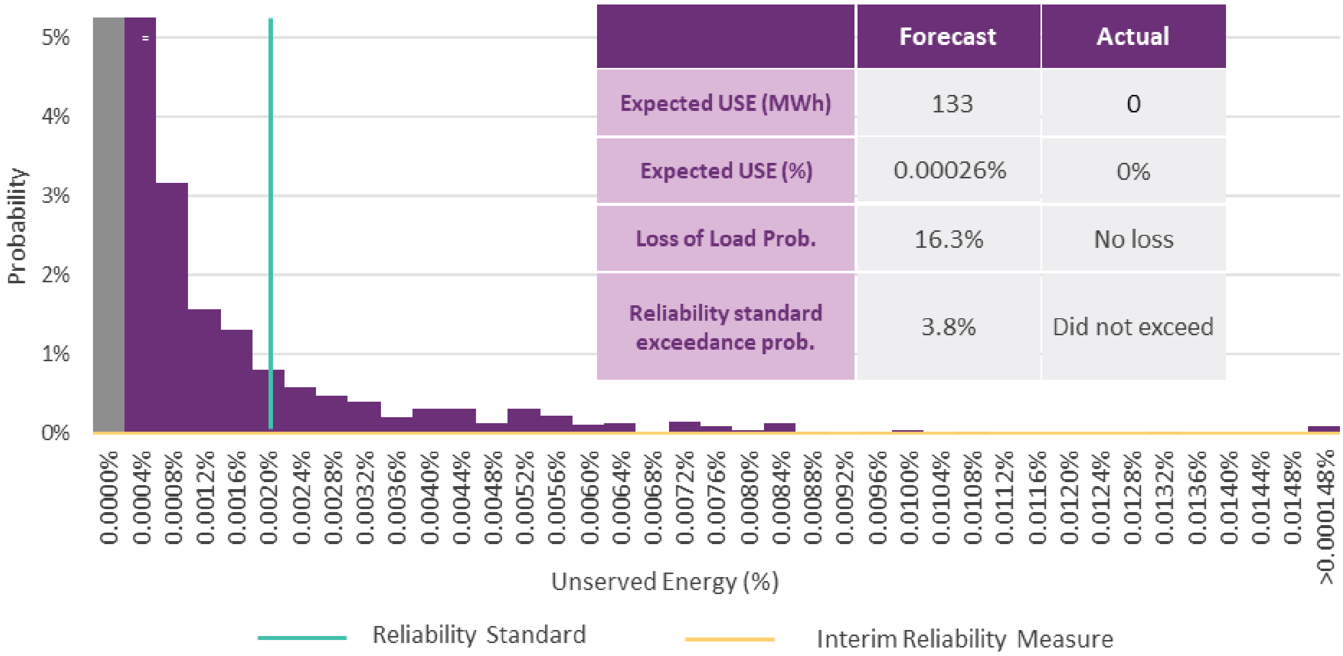
62 The application of the interim reliability measure of 0.0006% was extended to 30 June 2028 on 21 September 2023, in accordance with NER 11.160.

63 As defined under Chapter 10 of the NER.

7.2 Queensland

Figure 76 shows the forecast distribution of USE in Queensland for the 2024-25 financial year in the 2024 ESOO. The probability of any loss of load was assessed at 16.3%. In 2024-25, no USE was observed, as defined by the reliability standard, an outcome predicted by 83.7% of simulations.

Figure 76 Queensland USE forecast distribution for 2024-25

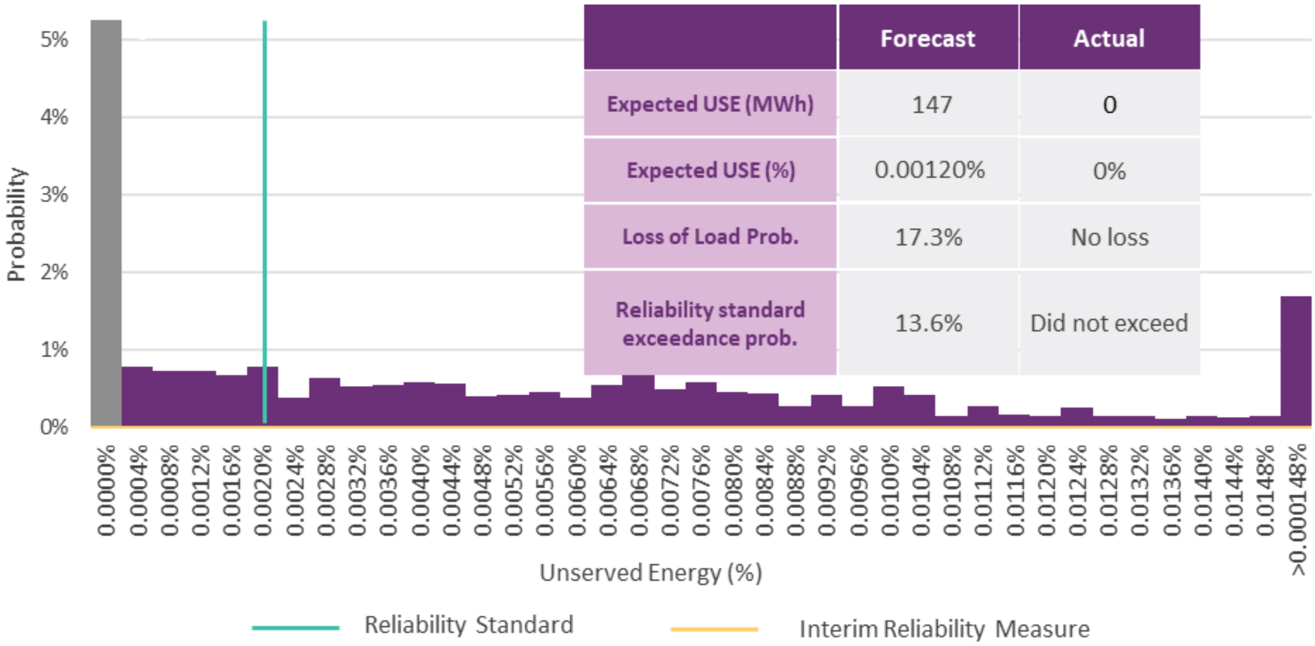


	Forecast	Actual
Expected USE (MWh)	133	0
Expected USE (%)	0.00026%	0%
Loss of Load Prob.	16.3%	No loss
Reliability standard exceedance prob.	3.8%	Did not exceed

7.3 South Australia

Figure 77 shows the forecast distribution of USE in South Australia for the 2024-25 financial year in the 2024 ESOO. It shows a long low probability tail of a large USE event, where the probability of any loss of load was assessed at 17.3%. In 2024-25, no USE was observed, as defined by the reliability standard, an outcome predicted by 82.7% of simulations.

Figure 77 South Australia USE forecast distribution for 2024-25

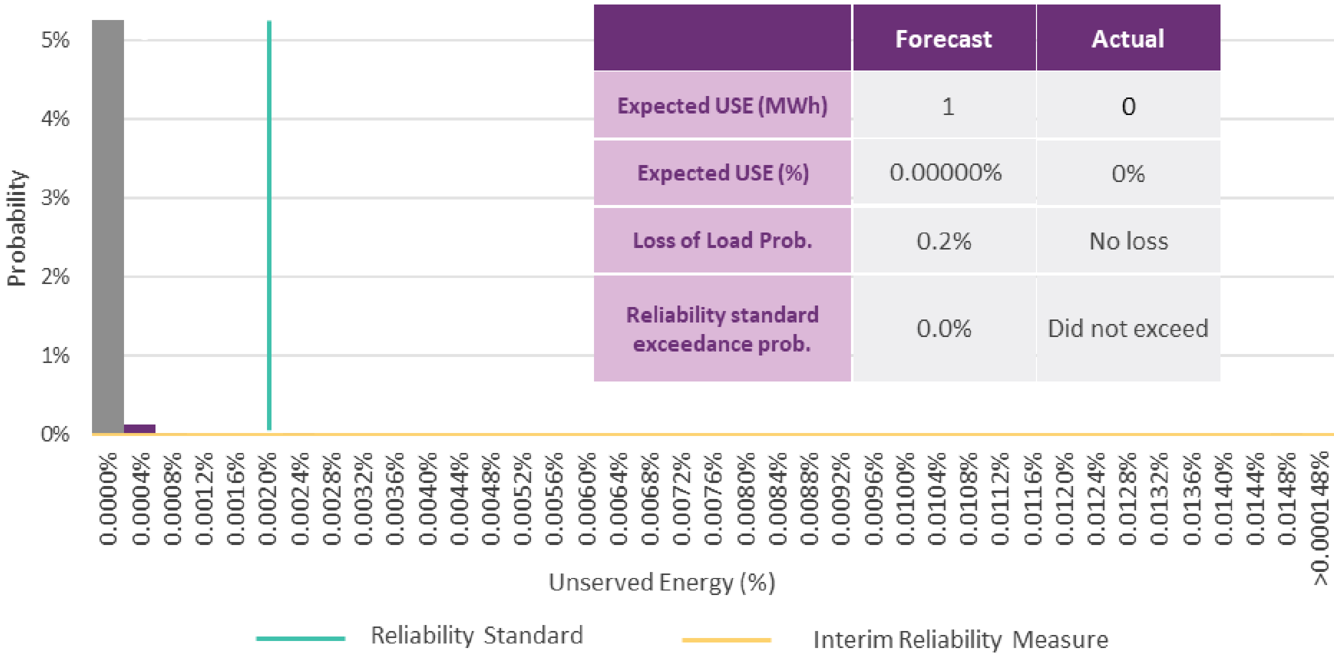


	Forecast	Actual
Expected USE (MWh)	147	0
Expected USE (%)	0.00120%	0%
Loss of Load Prob.	17.3%	No loss
Reliability standard exceedance prob.	13.6%	Did not exceed

7.4 Tasmania

Figure 78 shows the forecast distribution of USE in Tasmania for the 2024-25 financial year in the 2024 ESOO. The probability of a loss of load event was assessed at 0.2%. In 2024-25, no USE was observed, as defined by the reliability standard, an outcome predicted by 99.8% of simulations.

Figure 78 Tasmania USE forecast distribution for 2024-25

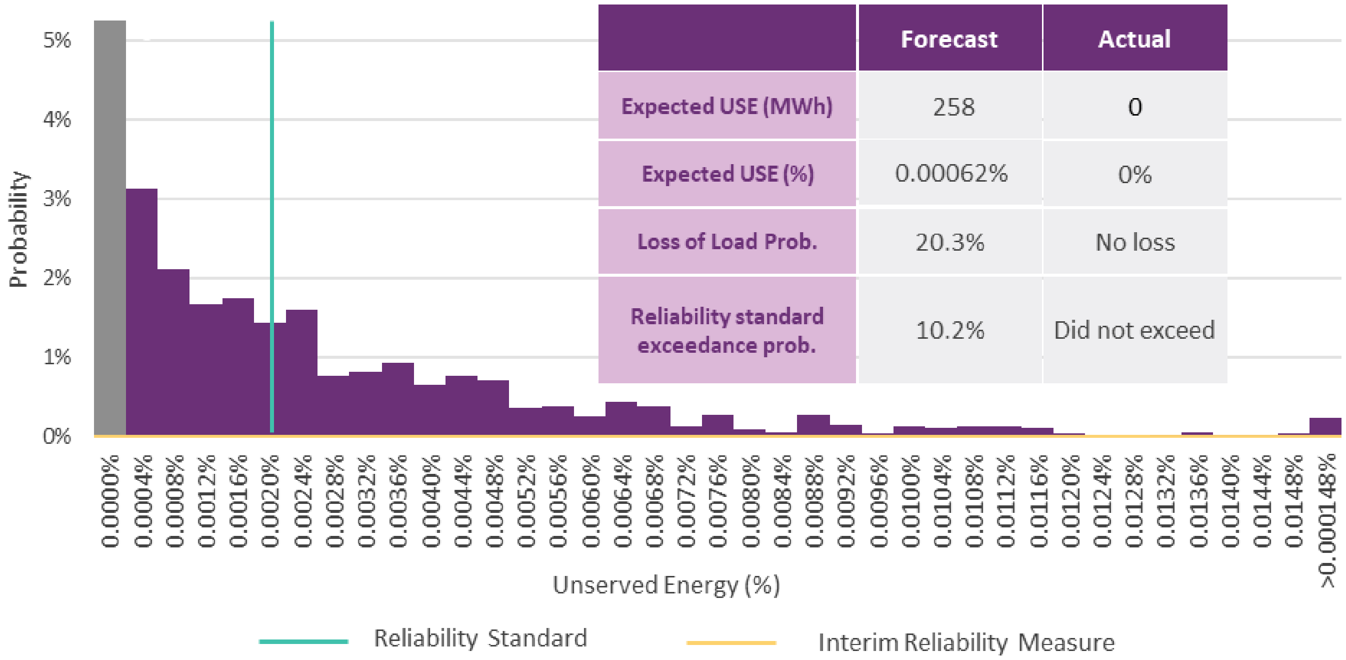


	Forecast	Actual
Expected USE (MWh)	1	0
Expected USE (%)	0.00000%	0%
Loss of Load Prob.	0.2%	No loss
Reliability standard exceedance prob.	0.0%	Did not exceed

7.5 Victoria

Figure 79 shows the forecast distribution of USE in Victoria for the 2024-25 financial year in the 2024 ESOO. The distribution shows a long low probability tail of a large USE event, where the probability of any loss of load was assessed at 20.3%. In 2024-25, no USE was observed, as defined by the reliability standard, an outcome predicted by 79.7% of simulations.

Figure 79 Victoria USE forecast distribution for 2024-25



	Forecast	Actual
Expected USE (MWh)	258	0
Expected USE (%)	0.00062%	0%
Loss of Load Prob.	20.3%	No loss
Reliability standard exceedance prob.	10.2%	Did not exceed

8 Forecast Improvement Plan

AEMO acknowledges the importance of forecast accuracy to industry decision-making as well as the importance of balancing the reliability and efficiency limbs of the NEO in long term interest of consumers. The purpose of the annual *Forecast Accuracy Report* is to assess forecast accuracy performance and provide transparency around areas where AEMO intends to focus efforts to improve future forecasts.

The process has three key steps:

1. **Monitor** – track performance of key forecasts and their input drivers against actuals.
2. **Evaluate** – for any major differences, seek to understand whether the reason behind the discrepancy is due to forecast input deviations (actual inputs differed from forecast inputs) or a forecast model error (the model incorrectly translates input into consumption or maximum/minimum demand).
3. **Action** – seek to improve input data quality or forecast model formulation where issues have been identified, prioritising actions based on materiality and time/cost to correct.

This section focuses on the third point, outlining AEMO's intended actions following the review of forecast accuracy, and inviting feedback on those proposals prior to implementation.

It should be noted that not all forecast improvements stem from the actions identified following the forecast accuracy assessment. It is only one of three drivers for changes to the forecasting models and processes:

1. **Forecast accuracy improvements** – in addition to the annual *Forecast Accuracy Report* and Forecast Improvement Plan (and associated consultation), AEMO regularly tracks forecast performance and consults through the Forecasting Reference Group (FRG), and this may drive minor updates to forecasting models, data or assumptions to address identified forecast accuracy issues within the yearly cycle.
2. **Evolution of the energy system** – over time, electricity consumption and demand change in response to structural changes of Australia's economy, such as the emergence of a new sector (for example, the development of LNG export, or data centre industries), or consumer behavioural or technological changes (such as EVs or battery storage systems or responses to physical or financial stimuli, such as changing usage patterns to best utilise rooftop PV generation). These developments may impact the total energy consumed across a year by consumers, or the daily demand profile of energy consumption, or both. The demand forecasting process continually evolves to account for these changes, in particular for the longer-term forecasting and planning processes.
3. **Regulatory requirements** – changes to rules and regulations can cause changes to how forecasts are produced, or what needs to be forecast. For example, the RRO required a number of changes to AEMO's forecasting process, and the introduction of emissions reduction limbs to the national energy objectives[64] required specific consideration of emissions reduction activities and policies within AEMO's planning functions.

AEMO's proposed Forecast Improvement Plan, presented in the following sections, sets out targeted changes to forecasting approaches and inputs to ensure reliability forecasts remain fit-for-purpose. The proposed Forecast Improvement Plan responds to two related but distinct considerations:

[64] For example, the national electricity objective in section 7 of the National Electricity Law.

- forecast inaccuracies identified in the assessment of the 2024 ESOO, and
- emerging reliability and demand risks driven by structural changes in the power system.

Section 8.1 summaries the key forecasting accuracy issues from the 2024 ESOO. **Section 8.2** explains how system evolution is changing the drivers of reliability and demand risks. **Section 8.3** then presents the proposed Forecast Improvement Plan, outlining actions to address identified inaccuracies and to prepare the ESOO for evolving system conditions.

Appendix A1 lists the improvements presented in the 2024 Forecast Improvement Plan, along with a summary of the implementation status of each of these initiatives, and any other improvements implemented for the 2025 ESOO.

Consistent with the FBPG[65], this Forecast Improvement Plan is subject to a single stage consultation (as initiated by this document). AEMO welcomes stakeholder feedback on the plan.

8.1 2024 ESOO forecasting accuracy drivers for improvements

While AEMO's forecast models have generally performed well, multiple potential forecasting improvements have been identified in response to the forecast outcomes identified in this report. These issues are summarised below:

- The accuracy of the 2024 ESOO **annual consumption** forecasts has shown there is scope to incorporate additional weather variables in the modelling, lessen the likelihood of LIL over-forecasting, and better establish residential and business load in historical data.
  - AEMO hypothesised in the 2024 *Forecast Accuracy Report* that a portion of consumption variance is attributable to factors such as weather effects not currently captured in the models (for example, humidity). Accounting for this separate weather variable may be able to improve forecast accuracy (see **Section 8.3.2**, Improvement 7).
  - LIL forecast accuracy continues to be influential for NEM regions. AEMO is committed to continue to engage with LILs to better understand their likely consumption levels, and electricity (and gas) consumption. However, given many outages or disruptions are unplanned, LIL forecasting remains susceptible to over-forecasts. The Forecast Improvement Plan identifies a potential improvement to address this challenge (see **Section 8.3.2**, Improvement 5).
  - Isolating the performance of specific residential and business consumption forecast sub-components is not currently available in the *Forecast Accuracy Report* (**Section 4**). Moreover, establishing emerging load types, such as EVs and data centres, that are components within the residential and business sectors, remains challenging. The Forecast Improvement Plan describes potential improvements to better classify and analyse customer meter data to provide improved forecast granularity (see **Section 8.3.2**, Improvements 6 and 8).
- **Maximum and minimum demand** forecasts describe how well the models capture peak and trough demand conditions across the year. In reviewing recent outcomes, most regional variations were driven by short-term weather effects such as temperature swings, seasonal mildness, and changes in solar availability rather than structural shifts in underlying consumption. These findings indicate that improving the representation of weather sensitivities and refining temperature–demand relationships will continue to be key areas of focus for enhancing future forecast accuracy.
- Observed **DSP** responses were broadly consistent with forecasts across most regions. Where discrepancies occurred, they were largely driven by limited occurrences of extreme price events, constraining reliable estimation rather than

[65] See https://www.aer.gov.au/system/files/AER%20-%20Forecasting%20best%20practice%20guidelines%20-%2025%20August%202020.pdf.

indicating methodological issues. Victoria showed lower-than-forecast DSP at very high prices due to sparse data, leading to a downward adjustment in the 2025 ESOO forecast. Tasmania recorded higher DSP responses reflecting increased high-price intervals, though the impact is small and does not warrant methodological change. AEMO will continue monitoring observed DSP and WDR outcomes to assess whether further refinements are required as additional data becomes available.

- **Rooftop PV** significantly influences electricity consumption and demand forecasts. The 2024 ESOO overestimated rooftop PV capacity for 2024-25 in all NEM regions due to an over-estimation of future growth in system size. Revised rooftop PV forecasts in the 2025 ESOO suggest current processes are adapting effectively to emerging trends. Although forecasts do update key assumptions like system size to continued trends, AEMO has identified that PV generation improvement may be found by using newly available meter data to refine the method for normalised generation profile development (see **Section 8.3.2**, Improvement 4).
- **Generator installed capacity** during the 2024-25 summer exceeded forecasts by 2,333 MW, due to differences between projects' actual start dates and AEMO's commissioning assumptions applied under the current *ESOO and Reliability Forecast Methodology*[66]. Some new generation and storage projects became operational earlier than assumed in the 2024 ESOO after applying historically observed delays. AEMO does not consider that a change in method is required to capture this variance, as the existing *ESOO and Reliability Forecast Methodology* dynamically adjusts the default committed project delay period based on recent trends.
- **Supply availability/generation** was mostly within the 95th percentile simulation range, with Queensland the main exception. In Queensland, lower actual availability was primarily driven by a combination of economic offloading of solar generation and higher unplanned coal unit outages. AEMO updates unplanned outage rate assumptions on an annual basis using observed historical data, and the higher unplanned coal outages observed in Queensland has already been reflected in the 2025 ESOO. Accordingly, this outcome reflects normal model updating rather than a separate forecast improvement action.

8.2 Structural change drivers for improvements

Some improvements proposed in this Forecast Improvement Plan arise directly from forecast accuracy issues discussed in **Section 8.1**. Others respond to structural changes in the power system that are reshaping how reliability and demand risks emerge over the ESOO horizon. This section focuses on the latter.

Forecast accuracy assessments are inherently backward-looking, while the ESOO must provide forward-looking signals under evolving system conditions. As the generation mix, operating environment, and demand drivers change, assumptions that were previously considered reasonable for both reliability and demand forecasting may no longer hold, even if they have not yet resulted in observable forecast inaccuracies.

Sections 8.2.1 and **8.2.2** describe how system evolution is changing the underlying drivers of reliability and demand risk, providing the context for forecast improvements in **Section 8.3** that have been proposed in response to these emerging risks.

[66] See https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2025/esoo-and-reliability-forecast-methodology.pdf.

8.2.1 Increasing importance of energy adequacy in reliability outcomes

Historically, reliability risk in the NEM was dominated by short-duration peak demand events, typically during extreme summer or winter conditions. Planned outages could reasonably be assumed to avoid periods of system stress as sufficient dispatchable capacity and energy generation capability existed when demand levels were not extreme. Consistent with this operating environment, the ESOO reliability forecasts assumed planned outages and energy limits would not meaningfully affect reliability outcomes.

The system is evolving away from this paradigm. Following major thermal retirements, the margin between the energy production potential and the energy that is forecast to be demanded by consumers is tightening, and the system increasingly relies more on variable and energy-limited resources (VRE, storage and hydro). As a result, forecast reliability risks are increasingly emerging over extended timeframes, not just short peak demand intervals.

This shift is evident in recent operational and ESOO modelling outcomes:

- MT PASA results and 2025 ESOO operational sensitivities – which explicitly consider planned outages and energy limits – identify materially higher reliability risks than the 2025 ESOO reliability forecasts. These results show that elevated risk increasingly arises outside traditional summer or winter peak demand periods.
- These risks are most pronounced in New South Wales following Eraring retirement, where MT PASA modelling shows high levels of expected USE in 2027-28 under conditions where coincident planned outages are projected, and considering energy limits.

The absence of these risks in the 2025 ESOO reliability forecasts does not indicate they are absent in reality. It reflects that the current ESOO reliability forecasts methodology does not yet fully represent these evolving drivers of reliability risks.

In this context, energy adequacy and sustained energy production capability rather than short-term peak capacity alone are becoming central to reliability outcomes. Updating the methodologies that support the reliability forecast to incorporate these elements is therefore a forward-looking and proportionate response to system evolution, rather than a correction of past forecast errors.

Planned outages

As part of the 2024 Forecast Improvement Plan, AEMO assessed the interaction between planned outages and system conditions by cross-referencing generator planned outages with periods of low reserve, including LOR events. The analysis covered the 2023-24 and 2024-25 summer periods and focused on MT PASA submitted planned outages with recall times greater than 10 days. This work was presented to the FRG in April 2025[67].

The assessment identified that approximately 2.5% of capacity was on planned outages during peak summer months and observed LOR periods. More broadly, the results indicate that planned outages are no longer consistently confined to low-risk windows. As capacity exits the system, the flexibility to reschedule planned outages away from emerging risk windows is diminishing. This effect is expected to become more pronounced following further thermal retirements, consistent with findings in the 2025 ESOO *Generator Maintenance sensitivity*, which highlighted the increasing importance of planned outage coordination under tighter capacity margins.

[67] The planned outage analysis presented in the ESOO methodology improvements session at the April 2025 FRG shows that, on average, planned outage rates of 2-3% occur during peak summer months (January and February), including periods coinciding with actual LOR events. See https://www.aemo.com.au/-/media/files/stakeholder_consultation/working_groups/other_meetings/frg/2025/frg-meeting-pack-1-___.zip.

Energy limits

Similarly, energy limits were previously unlikely to bind at the system level, therefore had limited influence on reliability outcomes. As the generation mix transitions and generators with high energy-production capability retire, the ability of dispatchable generators, particularly gas, hydro, and storage, to sustain output across weeks or seasons is becoming increasingly important.

Operational experience shows that these constraints can materially affect system outcomes. During June 2022, coal, gas, and VRE units simultaneously faced fuel constraints, directly reducing their ability to sustain output during high-stress periods. Operational sensitivities in the 2025 ESOO applying EAAP-sourced energy limits across the 10-year outlook period demonstrated these limits materially increased expected USE, particularly after major coal power station retirements.

Without adequately representing realistic longer duration energy limits, ESOO modelling risks overstating system adequacy in future years, even where near-term forecasts perform well.

Hydro inflows and correlated weather risk

Hydro generation is increasingly relied on to support reliability as thermal capacity exits the system. As hydro generation plays a larger role in providing both capacity and energy, it becomes more important that modelled hydro generation reflects operational limits associated with storages, inflows and competing water uses, such as irrigation releases.

The ESOO currently uses long-term monthly average inflows, which smooth variability across months and weather years. While appropriate historically, this approach limits the model's ability to represent the timing and scale of inflow changes associated with different weather years. Correlated hydro inflows with weather reference years would enable the ESOO to better reflect variation in hydro generation across years, months, and weeks, and to better capture conditions where low inflows, extreme weather, and outages occur at the same time. This consideration becomes increasingly relevant during the transition period following coal power station closures, when energy production risks are higher and greater reliance on hydro generation will exist to maintain reliable supply.

Conclusion

As reliability risks increasingly emerge over extended timeframes and are driven by sustained availability and energy adequacy, the inputs required to support reliability forecasts should also evolve. **Section 8.3.1** sets out the proposed reliability forecasts changes, explains why additional data may be required, and seeks stakeholder feedback on how these changes can be implemented in a proportionate and cost-effective manner that remains aligned with the National Electricity Objective.

8.2.2 Increasing importance of consumer behaviour and technology changes

Multiple emergent consumer behaviour and technology changes are impacting Australia's electricity demand, including the electrification of residential, commercial, and industrial sectors (primarily away from gas), the electrification of personal transport, and the rapid uptake of cloud computing and artificial intelligence and associated growth in large scale data centres.

While most of these changes will contribute to increased electricity consumption, many of these technologies are associated with opportunities that are expected to mitigate their load on the electricity system and in many instances yield new generation, storage or load flexibility resources. For instance, coordinated charging is expected to transform participating EVs into a flexible load and/or battery storage resource. Similarly, data centres or industrial loads switching from gas to electricity may also be designed to contribute load flexibility.

In response, AEMO is extending its capability to undertake detailed demand side analysis, enabling improved granularity in its demand forecasts. Key actions already undertaken to support this include the development of

- a prototype industrial classification capability for customer meters, in collaboration with DCCEEW[68],
- a new sector-specific data centre forecasting methodology, applied in the 2025 ESOO with support from Oxford Economics[69], and
- a prototype electrification detection and analysis capability, in collaboration with DCCEEW[70].

Section 8.3.2 identifies several further steps toward enhancing the demand insights in AEMO's forecasting approach, including a new residential and business classification method, and analysis of customer meter trends (improvement 6 and 8 in **Section 8.3.2**). These investigations and improvements are expected to enable AEMO to increase spatial and sectoral granularity of its forecasting approach. AEMO considers that doing so will likely provide improved insights incorporating greater consideration of important consumer behaviour and technology changes.

8.3 Forecast improvement initiatives for 2025-26

This section describes how AEMO proposes to address the inaccuracies identified in the 2024 ESOO forecasts, as outlined in **Section 8.1**, as well as improvement initiatives in response to structural changes driven by system evolution, as described in **Section 8.2**, to improve future forecasts, including the 2026 ESOO. The proposed improvements cover both the *ESOO and Reliability Forecast Methodology*, as well as the *Electricity Demand Forecast Methodology*, incorporating proposed new inclusions and enhancement to the existing elements.

8.3.1 Reliability forecasts improvements

Improvement 1: Scheduled generator and bi-directional unit outages

Improvement 1.1: Incorporate planned outages into the ESOO reliability forecast

Based on the drivers discussed in **Section 8.2.1**, AEMO proposes to update the *ESOO and Reliability Forecast Methodology* to include planned outages alongside unplanned outages in the ESOO reliability forecasts, providing a more accurate representation of generator availability and its impact on system reliability.

To facilitate the inclusion of planned outages in the ESOO reliability forecasts, AEMO needs to identify an appropriate data source for planned outages that can support long-term, probabilistic modelling of generator availability across a 10-year horizon. Currently, MT PASA includes participant-submitted planned outage information on a daily basis for a forward-looking period of up to 36-months, primarily to support operational outage scheduling.

[68] Presented to the FRG, April 2024, see https://www.aemo.com.au/-/media/files/stakeholder_consultation/working_groups/other_meetings/frg/2024/2024-frg-meeting-pack-2.zip.

[69] Oxford Economics Australia, Data Centre Energy Demand, July 2025, at https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2025-iasr-scenarios/final-docs/oxford-economics-australia-data-centre-energy-consumption-report.pdf.

[70] Gas-Electricity Meter Data Linking Project Report, at https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/gaselectricity-meter-data-linking-project/gas-electricity-meter-data-linking-project-report.pdf.

While fit-for-purpose for their intended operational role, AEMO's analysis of historical data submitted shows that MT PASA planned outage data does not provide a reliable or internally consistent basis for long term reliability modelling. Several examples were identified where outages submitted as planned in MT PASA later appeared as unplanned in the unplanned outage survey[71] or operational dispatch records[72].

Further, MT PASA submissions frequently lack consistency with observed operational dispatch outcomes. Planned outages submitted for MT PASA purposes are often revised, cancelled, or partially executed, yet MT PASA does not always retain a stable record of what occurred. As a result, MT PASA data alone cannot be used to reconstruct reliable historical patterns of planned outage behaviour without extensive reconciliation against dispatch data and unplanned outage survey.

Using MT PASA planned outage data for ESOO reliability forecasts purposes would therefore require significant reconciliation effort, including identifying overlaps with unplanned outage records, resolving classification conflicts, and removing double counting (if found), with high potential for participant engagement to validate these conclusions. Even with this effort, uncertainty would remain, as classification ambiguity, limited visibility of outage flexibility, and reliance on participants' current planning assumptions rather than their long term planned outage behaviour remain unresolved.

For these reasons, AEMO considers that direct collection of planned outage history and high-level projections for ESOO reliability forecast purposes provides a more robust and transparent basis for long-term reliability forecast. AEMO proposes to include planned outages history and projections in the NER 3.13.3A(d) standing information request, requiring participants to provide:

- planned outage history, including outage periods and level of capacity that was unavailable, for the previous 12-month period, and
- an annual planned outage rate projection for a 10-year horizon, where relevant.

Consultation questions – planned outages

Data source – to support the inclusion of planned outages in ESOO reliability forecasts, AEMO is considering alternative data sourcing approaches:

- Option A (Preferred): Participants provide ESOO-specific planned outage history and high-level projections directly to AEMO.
- Option B: AEMO implements planned outages using MT PASA data, enhanced by reconciliation with unplanned outage survey and operational dispatch records, accepting residual uncertainty.

Consultation questions

- Which option do you consider most appropriate, and why? In your response, please comment on data availability, forecast accuracy, and transparency.

[71] Each year, AEMO collects information from all scheduled production units on the timing, duration, and severity of actual unplanned outages, and projections of future unplanned outages.

[72] Operational dispatch records show the available capacity for each DUID during actual periods, along with non-standardised brief notes explaining any changes in that capacity. However, this data does not provide sufficient information on why capacity may be unavailable, meaning any reductions in availability cannot be reliably mapped to a specific outage type.

- For options that require additional information provision from participants, AEMO seeks feedback on the administrative effort and cost associated with preparing and submitting planned outage history and projections for ESOO purposes.
- Do you consider that the expected improvement in long-term reliability forecasts, including the impact that this improvement may have on potential reliability responses such as reliability instrument requests under the Retailer Reliability Obligation framework, justifies this effort?

Improvement 1.2: Clarifying and enhancing the treatment of forced and maintenance outages

This initiative represents a refinement and clarification of existing unplanned outage data requirements, rather than the introduction of a new outage category or reporting obligation.

During the 2022 consultation on the *ESOO and Reliability Forecast Methodology*, AEMO aligned outage terminology with IEEE-762[73] by adopting the term "unplanned outages" to encompass both forced and maintenance outages. Under this framework, unplanned outages are intended to include both outage types, consistent with the IEEE definition. Participants were asked at that time to submit data covering both components.

However, experience from the 2024 and 2025 ESOO unplanned outage collection rounds indicates that, in practice, most participants continued to submit forced outage data only, with maintenance outages either omitted or inconsistently reported. In addition, feedback from participants highlighted ongoing ambiguity in the definition of a forced outage, particularly around the degree of deferability. These outcomes suggest that the intent of the changes was not sufficiently clear, rather than that participant lacked the ability to provide the information.

To address this, AEMO proposes the following enhancements to clarify definitions, while remaining within the scope of existing unplanned outage framework:

- Clarifying outage definitions and reporting expectations – explicitly state that unplanned outages include both forced outages and maintenance outages (IEEE-762:2023 definition), and that participants are required to submit maintenance outage history, as well as maintenance outage projections, where relevant, as part of the unplanned outage data collection.
- Clarifying the definition of forced outages – to improve consistency with IEEE-762:2023 while accommodating existing participant systems, AEMO proposes to clarify that a forced outage may be defined as either:
  - an outage that cannot be deferred before the end of the next weekend (IEEE-762:2023 definition), or
  - an outage that cannot be deferred more than 48 hours (strong participant preference[74] given existing data management systems).

AEMO considers that these enhancements improve alignment with IEEE-762:2023 and address observed gaps in data submission, without expanding the scope of unplanned outage categories or fundamentally increasing reporting burden.

[73] IEEE-762 defines standard definition for use in reporting electric generating unit reliability, availability, and productivity.

[74] As part of the 2025 FAR consultation, in addition to the FRG held on 26 November 2025, AEMO also engaged with several individual market participants to discuss the proposed refinement to the outage classifications and received their feedback.

Consultation questions – unplanned outage definitions

Clarify definitions – AEMO proposes to clarify existing reporting requirements by explicitly distinguishing forced and maintenance outages within the current unplanned outage framework, with maintenance outages reported separately.

- Does this clarification provide sufficient guidance on how forced and maintenance outages should be classified and reported under the existing arrangements?
- Are there any practical challenges in implementing these clarified reporting expectations within your current systems or processes that are greater than existing obligations, and what transition or guidance would assist implementation?

Improvement 1.3: Introduce a four category outage framework for the ESOO modelling methodology

As the power system evolves, outage timing and flexibility play a growing role in reliability outcomes, particularly under tighter capacity margins, requiring ESOO modelling to distinguish more clearly between inflexible outages and those with some scheduling discretion.

IEEE-762 distinguishes outages based on whether the cause of the outage must be addressed immediately (inflexible) or can be scheduled with discretion (flexible). Applying this principle, AEMO proposes moving to a four-category outage framework in the ESOO modelling that spans both planned and unplanned outages and reflects their scheduling flexibility.

- Forced outages will continue to be represented stochastically.
- Maintenance outages will be modelled separately as flexible outages, reflecting their limited scheduling discretion.
- Planned outages will be treated as moderately flexible.
- Long-duration unplanned outages as effectively inflexible.

AEMO intends to adapt the data template used in previous years for this data collection. This should avoid any large changes to current participant processes to support this data provision. The main change will be to add additional planned outage data which has not previously been collected.

The outage categories, description and proposed implementation are described in **Table 30** below.

Table 30 Four category outage framework and proposed ESOO model implementation

Outage Type	Current or new inclusions	Description	Timing	ESOO model implementation	IEEE-762 category mapping
Long Duration Unplanned Outages	Current Inclusion. Uses data collected in annual survey.	Unplanned outages that can occur at any point throughout the year when the plant fails, requiring a long duration outage that does not have flexibility in scheduling.	Inflexible	**No change proposed to existing approach.** Stochastic unplanned outage rate which applies across consistently all reference years, across all periods within a financial year.	Any unplanned outages > 5 months
Forced Outages	Current Inclusion. Uses data collected in annual survey.	Forced outages that can occur at any point throughout the year when the plant fails, requiring an outage that has limited flexibility in scheduling.	Inflexible	**No change proposed to existing approach.** Stochastic unplanned outage rate which applies consistently across all reference years, across all periods within a financial year.	Forced outages/deratings
Planned Outages	**New** **Inclusion**	Planned outages that are scheduled with sufficient lead time, allowing the outage to be scheduled in periods of low demand and system need.	Moderately flexible	**Proposed approach:** Planned outage rates applied for the year, with outage factors applied per month. Monthly outage factors developed to apply consistently across all reference years, considering generation energy production and capacity requirements across the reference years. This implementation allows the planned outages to be scheduled around demand requirements with knowledge of seasonal adequacy profiles, but with low immediate daily foresight.	Planned outages/deratings (those scheduled with long notice lead times)
Maintenance Outages	Currently included (but not always submitted by participants and these are modelled stochastically) Proposing more flexibility in modelled outage scheduling. Uses data collected in annual survey.	Those outages which occur without long notice, either due to: • a plant failure that can be rectified with some flexibility in scheduling, or • opportunistic maintenance undertaken by the operator.	Flexible	**Amended approach proposed:** Maintenance rates applied for the year, with maintenance factors applied per week (Monday to Sunday) for each reference year. Weekly maintenance factors developed for each reference year, for each forecast year, considering generation energy production and capacity requirements per reference year. This implementation allows the outages to be scheduled around demand requirements with a high degree of foresight.	Maintenance outages/deratings ('Opportunistic' planned outages and those scheduled on short notice belong in this category)

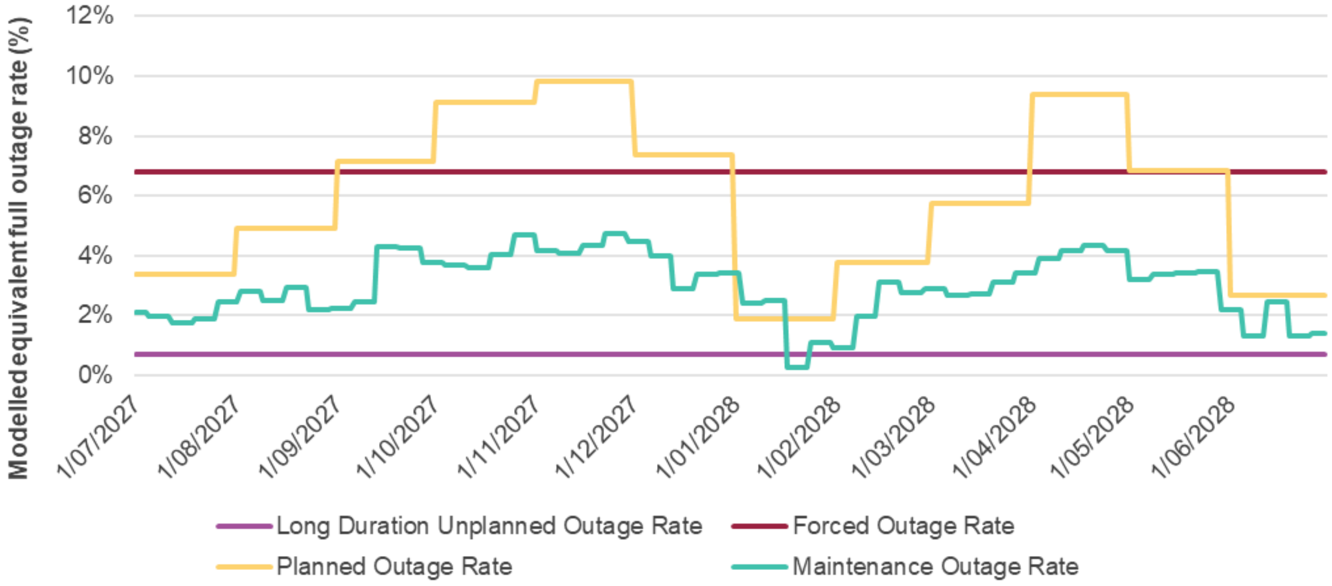
Figure 80 shows the proposed implementation across the four equivalent outage rates:

- Long duration forced outages and forced outages rates are the least flexible – with stochastic outage rates allocated evenly across the year.
- Planned outages are moderately flexible – allocated across the months based on the average supply scarcity expected across all weather conditions.

- Maintenance outages are the most flexible – allocated per week based on the specific supply scarcity expected for a single reference year (weather expectation).

The above allocations are proposed to be developed using a simplified supply scarcity model that considers both capacity (MW) and energy (MWh) requirements across the year using demand, PV and wind availability inputs.

Figure 80 Theoretical outage rate application for a reference year



These proposed changes aim to ensure the *ESOO and Reliability Forecast Methodology* more accurately captures the likely level of generator availability during supply scarcity periods across all seasons and improves the robustness of future reliability forecasts.

Consultation questions – outage flexibility representation

AEMO proposes to distinguish outages by their degree of scheduling flexibility in ESOO modelling, including treating maintenance outage as flexible and forced outages as inflexible.

- Does this approach appropriately reflect operational reality, particularly under tighter capacity margins?
- Are there any practical issues or unintended consequences that AEMO should consider when applying this distinction in reliability forecasts?

Improvement 2: Energy limits

As discussed in **Section 8.2.1,** the evolution of the power system is increasing the importance of energy generation capability in reliability outcomes, particularly over extended periods of elevated risk. To ensure ESOO reliability forecasts remain fit-for-purposes under these conditions, AEMO proposed to strengthen how generator energy limits are represented in ESOO modelling.

AEMO proposes to update the *ESOO and Reliability Forecast Methodology* to explicitly state the inclusion of station-level energy limits, incorporating station-level generator energy limits into the ESOO reliability forecasts to better reflect real-world operating constraints across the 10-year outlook.

Proposed definition of energy limits

For ESOO purposes, AEMO proposes a definition of two levels of energy limits, including station level and market level, as outlined in **Table 31.** The station level energy limits represent physical and technical capability, and should consider all fuel a participant reasonably considers it could procure should market conditions require energy production.

AEMO proposes to apply station level limits in ESOO reliability forecasts, as these reflect constraints that directly affect a generator's ability to sustain output. Market level energy limits arise from shared fuel constraints and depend on how the market responds over time. Because these outcomes are more uncertain and influenced by future investment and commercial decisions, AEMO proposes to assess market level energy limits only in ESOO reliability assessment sensitivities. This allows their potential impact on reliability to be explored without relying on assumptions that are highly uncertain.

Table 31 Station level and market level energy limits

Level	Description	Examples of constraints
Station level	Reflects any limit on a generator's ability to operate continuously over all periods, which may arise for a variety of operational plant characteristics.	• Workforce constraints • Noise/emissions requirements • Availability of cooling water, deionized water, or other inputs • Local fuel delivery limitations • Fuel supplies[A]
Market level	Reflects conditions where the market is unable to supply all stations at the same time, which may arise for a variety of operational reasons	• Insufficient gas supply to meet multiple generators' fuel needs simultaneously • Insufficient gas transmission to meet numerous generators' fuel needs simultaneously • Insufficient diesel haulage capability to meet numerous generators' fuel needs simultaneously

A. Energy limits should often exceed contracted fuel quantities where the participant reasonably expects it can procure additional fuel from the spot market.

Limitations of the current data sources

To support the inclusion of station level energy limits in ESOO reliability forecasts, AEMO is required to identify an appropriate data source. AEMO has assessed whether existing MT PASA and Generator Energy Limitation Framework (GELF) energy limit data could be adapted for this purpose. While both frameworks provide valuable insights, they do not capture energy constraints over the longer timeframes relevant to the ESOO's 10-year horizon, and adapting them would require material judgement.

- Horizon and purpose mismatch – MT PASA weekly energy limits and GELF monthly energy limits are submitted for short-term planning (up to two or three years ahead). Extending these submissions across the ESOO horizon would require assumptions about how limits persist or evolve well beyond the intent of the original data.
- Misalignment with how energy constraints bind – in practice, many operational energy production limits do not align well with a weekly or monthly period. Some generators are constrained at seasonal or annual levels that are not visible in short-term weekly or monthly limits. For example, coal-fired power stations often have significant coal storage capability, hence are unlikely to reach any energy production limit in any given week or month, but may have quarterly, half-yearly, or annual limits on production. Conversely, some gas plants may experience intra-day gas supply limits that

are poorly reflected in weekly or monthly energy limits provided as part of MT PASA or GELF. While both weekly and monthly limits may be applied they still may not capture annual or other limits.

- Data inconsistency and reconciliation effort – differences are often observed between GELF monthly limits and MT PASA limits aggregated to a monthly basis. While both may be valid within their respective framework, understanding and reconciling these differences frequently requires additional investigation, participant engagement, and in some cases, resubmissions of data. This increases reliance on manual intervention and judgement.
- Energy limit definition – the purpose of the energy constraints proposed to be applied to reliability modelling is to capture limitations relating to technical capabilities within selected time periods. It is possible that many GELF and MT PASA energy limits take into account current contract positions, outages and other factors that would be unsuitable to assume extend beyond the GELF and MT PASA horizons.

Potential adaption of MT PASA and GELF data

AEMO could attempt to adapt existing MT PASA and GELF data for ESOO purposes by:

- extrapolating short-term limits across the ESOO horizon, and
- applying judgement based assumptions about the persistence and evolution of energy limits.

This approach would require additional analysis, data reconciliation, intervention by AEMO, including resolving inconsistencies between datasets, engaging with participants, and making assumptions where information is incomplete. Even with this effort, the resulting inputs would still rely on AEMO-imposed assumptions rather than participant-verified capability. This may leave material residual risks, including:

- Energy limits may only reflect current operating conditions, but not future variations arising from changes, such as plant operations or investment decisions.
- Constraints that matter over longer periods may be missed entirely in short-term data, even though they materially limit how long a generator can operate.
- Assumptions applied by AEMO may not align with participant expectations or operational reality.

For these reasons, AEMO considers ESOO-specific station level energy limit data provided directly by participants, to be the most transparent and robust approach for long-term reliability forecasting.

Proposed changes to ESOO modelling and data collection

AEMO therefore proposes to request ESOO-specific station-level energy limit data from participants under NER 3.13.3A(d). This would be implemented through a clearly identified ESOO component within the GELF survey. The survey is proposed to be completed by participants in early 2026 in advance of the 2026 ESOO/EAAP.

These updates will enable AEMO to model sustained generator capability more accurately and assess reliability risk with a better understanding of fuel, water, and operating constraints.

Participants would be requested to submit energy limits for all scheduled DUIDs (or logical station level groupings), for use in ESOO reliability forecasts across the full 10-year horizon. These limits must:

- apply to individual DUIDs or appropriate DUID groupings across the entire 10-year ESOO horizon,

- reflect realistic, sustained-deliverable energy production limits under normal conditions for any station-level technical reason (workforce, noise, emissions, fuel delivery),
- represent technical capability within any selected time period, for any selected forecast period:
  - energy limit period – for example daily, weekly, monthly, quarterly, half yearly, yearly, and
  - forecast period – for example applicable over the full 10 years, applicable every January, and/or applicable for a shorter duration until a committed investment, and
- advise if any committed investments would impact energy limits over the 10 year horizon, and how the limit would change – for example, a committed rail unload capacity increase could increase quarterly capacity factor limit from 80% to 100%.

Including these energy limits in ESOO modelling will deliver a more realistic and internally consistent representation of generator behaviour, particularly during extended scarcity conditions. The proposed change will strengthen AEMO's ability to identify emerging energy adequacy risks, improve the usefulness of long-term reliability assessments, and ensure the ESOO continues to meet its intent of advising on reliability risks to consumers and the market.

Consultation questions – energy limits

Data source – to support the inclusion of station level energy limits into ESOO reliability forecasts, AEMO is considering alternative data sourcing approaches:

- Option A (Preferred): Participants provide ESOO-specific station level energy limit data directly to AEMO.
- Option B: AEMO implements station level energy limit data using adapted MT PASA and GELF data, accepting residual uncertainty.

Consultation questions

- Which option do you consider most appropriate, and why? In your response, please comment on data availability, forecast accuracy, and transparency.
- For options that require additional information provision from participants, AEMO seeks feedback on the administrative effort and cost associated with preparing and submitting station level energy limit data for ESOO purposes.
- Do you consider that the expected improvement in long-term reliability forecasts justifies this effort, particularly in regions and periods facing tighter capacity margins?

Improvement 3: Hydro inflow modelling

Hydro reservoirs in the 2025 and 2024 ESOOs were modelled using long-term average monthly inflow rates. These inflow rates capture broad seasonal trends but do not apply weather consistently with other forecast components that track the weather patterns of each historical reference year, being demand, wind, and solar generation.

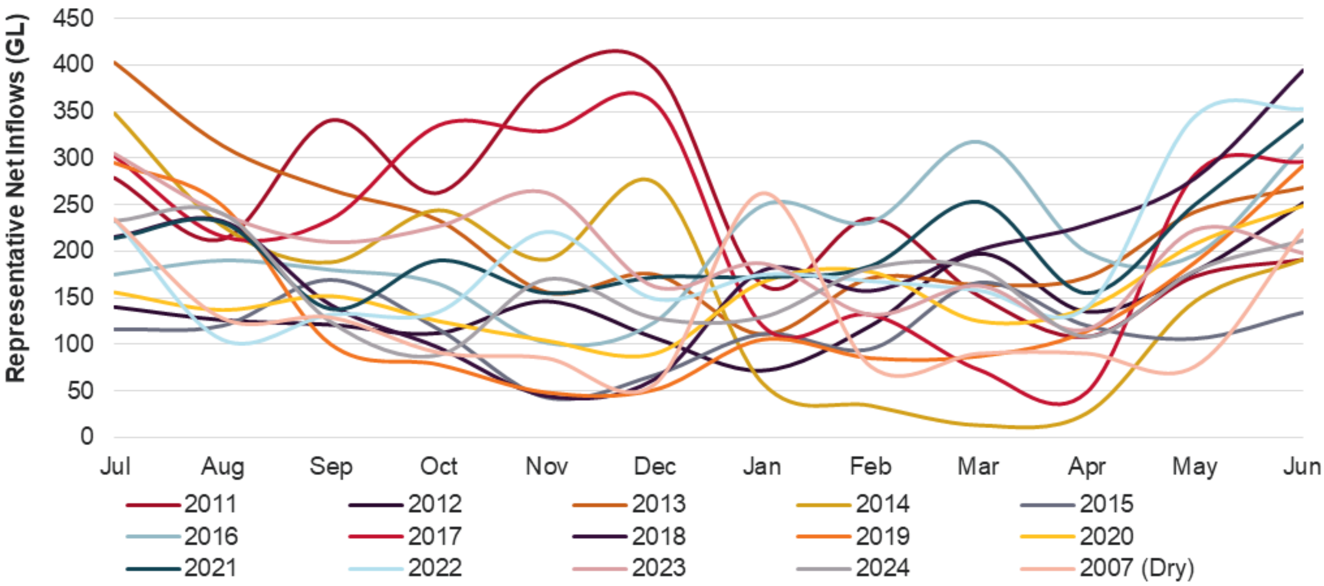
For hydro schemes with limited storage and constrained operational flexibility, AEMO proposes to apply weather reference year-based hydro inflow data. Many of these storage schemes have limited operational flexibility, rely on recent water inflows and/or are influenced by irrigation release requirements. Using inflows relating to weather reference years would allow hydro generation to be modelled consistently with demand and VRE, as illustrated in **Figure 81**. This would improve representation of inter-annual, seasonal, and intra-seasonal variability, and better capture conditions where low inflows coincide with other system stresses. For hydro generators that operate as a pumped hydro scheme, these generators do not rely solely on water inflows due to the manner in which their pumps and generators can balance upper and lower reservoirs.

For Tasmania's hydro generators, AEMO proposes to continue using long-term monthly average inflows. This reflects the scheme in aggregate having larger storage capacities and therefore more operational flexibility with regards to how much generation can be produced each year, in total.

AEMO also proposes introducing a look-ahead period to the reliability modelling, allowing storages to better allocate their water usage over a defined forward window rather than across the full forecast year. This approach would approximate operational decision-making more closely, taking into account limited foresight of short-term weather and demand forecasts while still ensuring sufficient storage is preserved for periods of system need.

A similar approach is applied to some of AEMO's other forecasting and planning activities, particularly in time-sequential modelling in the ISP. The ISP inflow datasets are developed using publicly available information and data provided by hydro operators, with the methodology and assumptions published through the IASR or the Forecasting Assumptions Update. AEMO therefore proposes to update the *ESOO and the Reliability Forecast Methodology* to incorporate weather reference year hydro inflow data and to align these assumptions with the *Inputs, Assumptions and Scenarios Report* (IASR).

Figure 81 Snowy hydro scheme – weather variability representative net inflows (gigalitres [GL])



Note: This figure is sourced from the 2025 IASR workbook, at https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp/2025-26-inputs-assumptions-and-scenarios. It shows an aggregate of the scheme for the purposes of demonstrating weather variability in the scheme; it is not a complete or accurate representation of the data used in AEMO's modelling of the Snowy Hydro Scheme, and is provided to demonstrate weather variability only.

Consultation questions – hydro inflow modelling

- Do stakeholders consider the proposed use of weather reference year-based inflows for hydro schemes with limited storage and constrained operational flexibility, while retaining long-term monthly averages for the Tasmanian Hydro Scheme, to be a reasonable representation of operational behaviour for ESOO reliability forecasts?
- Does the proposed introduction of a look-ahead period for hydro storage operation appropriately reflect how hydro operators manage water under uncertainty, or are there alternative approaches that would better represent operational decision-making?

8.3.2 Electricity demand forecast improvements

Improvement 4: Distributed PV normalised generation profiles

AEMO uses normalised generation profiles for distributed PV combined with rooftop PV and PVNSG capacity, to produce historical distributed PV generation traces, a key input to the ESOO forecasts.

Currently, this is produced using a modelling framework primarily based on irradiance data but also other weather variables. For rooftop PV, normalised generation is directly procured by an external data provider, who carries out the modelling. For PVNSG, irradiance data is obtained from the same data provider, and the modelling is done by AEMO. This is described in more detail in AEMO's *Electricity Demand Forecasting Methodology*[75].

Metered, gross distributed PV generation data is becoming increasingly available in Australia. A statistically robust sample of distributed PV sites can provide an accurate estimate of normalised distributed PV generation for regions or sub-regions. AEMO has recently assessed the suitability of such a dataset, paying special attention to the spatial distribution of sites across the NEM (and Western Australia's Wholesale Electricity Market, or WEM), with what it considers is satisfactory results. AEMO proposes to reference this alternate actual metered data, and combine it with irradiance based simulated distributed PV traces. This is anticipated to improve the accuracy and transparency of AEMO's distributed PV generation traces and ESOO forecasts, as it:

- uses actual electricity measurements in-situ, instead of modelled outcomes based on remotely sensed data,
- gives AEMO greater control over an important forecast component, enabling potentially improved spatial disaggregation and more transparent reporting of key internal assumptions, such as the PV inverter system size ratio (sometimes referred to as the DC/AC ratio), and
- maintains alignment with proven and trusted historical irradiance-based PV generation records.

To achieve the above benefits in a single consistent data set spanning history, current and future timeframes, the proposed methodology is to:

- develop a model for PV normalised generation based on solar irradiance normalised generation, irradiance and temperature, using gross metered PV generation, irradiance and temperature actuals to calibrate and validate the model, that is:

  PV normalised generation ≈ f(solar irradiance normalised generation, irradiance, temperature)

[75] See https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2024-electricity-demand-forecasting-methodology-consultation/final-determination/electricity-demand-forecasting-methodology_.pdf.

- for reference years and locations with access to meter data, adopt the meter data normalised PV data, and
- for reference years and locations without access to meter data, estimate PV normalised generation using the model.

AEMO proposes to **investigate** this approach ahead of the 2026 ESOO, by examining the performance of the proposed method. AEMO proposes to provide stakeholders with further insight on the performance of the method at a Forecasting Reference Group meeting in early 2026, and **consult with stakeholders to apply the updated approach** for the 2026 ESOO if the model change can confidently demonstrate forecast accuracy improvements.

Consultation questions – distributed PV normalised generation profiles

- Do stakeholders support the use of metered gross distributed PV generation data to produce distributed PV generation traces?
- Do stakeholders see any specific risks or pitfalls in the proposed new method that AEMO should be aware of in designing the method?
- Do stakeholders have any other recommendations for improving the proposed new method?

Improvement 5: Large industrial load outages

Large industrial loads are often over-forecast at the NEM and regional level. The average over-forecast for the last five ESOOs equates to 1% of NEM consumption – this for a component that is very stable year-on-year, typically changing by +/-0.25% for recent years (NEM level). AEMO notes that many of these over-forecasts occur due to a variety of events which may be unforeseeable for a single site, but routinely occur across the NEM. Such events include:

- extreme weather events,
- economic shocks,
- equipment failure, and
- unplanned maintenance.

AEMO collects LIL surveys from the operator of each major industrial site to inform its forecasts. Even for sites that have operated for many years, projections provided by operators are often shown to exceed actual volumes, leading to over-forecasting. While it is reasonable for each site to forecast its consumption without unexpected outages, the survey responses in aggregate are frequently above observed levels of industrial consumption.

AEMO proposes a change to the *Electricity Demand Forecasting Methodology* to introduce a new 'outage factor' for application to currently operating LIL projections at the region, sub-regional and/or sector level of the NEM that will reduce forecast consumption. The 'outage factor' will be developed by:

- Taking survey-based consumption projections for the three most recent years.
- Aggregating the past projections and actual consumption across the surveyed sites to the region, sub-region and/or sector level and compare to obtain the 'outage factor'.
- Ensuring that the spread of 'outage factors' across regions, sub-regions and/or sectors is not being unduly influenced by outliers (removing influence of the most extreme outages/closures or consumption increases).

- Applying the 'outage factor' to region, sub-region and/or sector level LIL survey-based forecasts for all years in the projection.

AEMO proposes to **investigate** this approach ahead of the 2026 ESOO, by examining the performance of the proposed LIL outage method. AEMO proposes to provide stakeholders with further insight on the performance of the method at a FRG meeting in early 2026, and **consult with stakeholders to apply the updated approach** for the 2026 ESOO if the model change can confidently demonstrate forecast accuracy improvements.

Consultation questions – large industrial load outages

- Do stakeholders support the application of outage factors to the large industrial load forecast?
- Are there alternative approaches to reducing over-forecasts of large industrial loads?

Improvement 6: Residential and business classification

Disaggregating residential and business mass market load from historical load is a process documented in Appendix 6 of the *Electricity Demand Forecasting Methodology*[76]. This methodology describes two methods available to AEMO for identifying the quantity of energy being consumed between residential and business customers for any given historical period. AEMO is investigating the use of metering data in the Market Settlement and Transfer Solutions (MSATS) to classify every consumer meter as either residential or business. The proposed approach uses tariff code data, augmented by machine learning methods applied to metered consumption to more accurately classify the load at each NMI. The machine learning algorithm will look at factors such as load size, location, temperature response and weekly consumption patterns in classifying meters. This approach would provide AEMO with greater clarity than MSATS standing data alone, allowing for a bottom-up aggregation of historical actuals and less reliance on previously adopted sampling approaches[77].

AEMO proposes to update the methodology specified in Appendix 6 of the *Electricity Demand Forecasting Methodology* to add a third potential method for identifying the quantity of energy being consumed, based on the summation of meter data for all NMIs classified as residential or business using this tariff data. AEMO could then utilise the three methodologies as best as possible to estimate consumption history, by load type, more accurately, supporting improved consumption forecasting discussed in **Section 8.2.2**.

AEMO proposes to **investigate** this approach ahead of the 2026 ESOO, by examining the performance of the residential and business classification model and comparing to existing methods. AEMO proposes to provide stakeholders with further insight on the performance of the method at a FRG meeting in early 2026, and **consult with stakeholders to apply the updated approach** for the 2026 ESOO if the model change can confidently demonstrate forecast accuracy improvements.

Consultation questions – residential and business classification

[76] AEMO, A6. Residential-business segmentation, *Electricity Demand Forecasting Methodology* (2024), at https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2024/electricity-demand-forecasting-methodology.pdf?la=en.

[77] AEMO is exploring the use of ANZSIC division level industry segmentation to disaggregate historical consumption data for the business mass market sector. This approach will enable deeper insights into consumption trends across different industries.

- Do stakeholders support the proposed new method for classifying residential and business historical loads?
- Are there any risks or pitfalls with the proposed new method?
- Do stakeholders have any recommendations for improving the proposed new method?

Improvement 7: Weather modelling for residential and business consumption forecasting

AEMO applies daily and monthly weather modelling for establishing weather impacts on residential and business consumption. The *Electricity Demand Forecast Methodology* specifies the specific weather variables currently used in models. Analysis since the 2024 Forecast Improvement Plan, that committed to investigating potential sources of residual variance in the consumption forecasts, suggests that additional weather variables may be relevant to consumption modelling for some regions (for example, humidity in Queensland). Several additional weather variables are already being used to forecast peak demand.

AEMO proposes to adjust the *Electricity Demand Forecasting Methodology* to allow the flexibility to apply variables such as humidity in modelling should the variable prove to improve the weather consumption models. This proposed improvement is an extension of the 2024 Forecast Improvement Plan initiative.

AEMO proposes to **investigate** this approach ahead of the 2026 ESOO, by examining additional weather variables that may improve forecast accuracy, and train the relevant residential and business models on these additional variables. AEMO proposes to provide stakeholders with further insight on the method and its outputs at a Forecasting Reference Group meeting in early 2026, and **consult with stakeholders to apply the updated approach** for the 2026 ESOO if the model change can confidently demonstrate forecast accuracy improvements.

Consultation questions – weather modelling for residential and business consumption forecasting

- Do stakeholders consider the application of additional weather variables including humidity will provide potential improvements in forecast accuracy?
- Do stakeholders recommend any specific weather variables as priority candidates for improving the accuracy of consumption forecasting?

Improvement 8: Modelling otherwise unexplained consumer behaviour trends

When developing residential energy consumption projections, AEMO applies numerous factors as inputs, including appliance uptake, energy efficiency, and connections growth. In the November 2025 FRG, some stakeholders suggested that there may be trends in consumer behaviour – such as trends in the usage of appliances – that may explain recent growth in both consumption and demand that may not be well captured by existing inputs. This item is a commitment to investigate incorporating consumer behaviour to improve consumption forecasts, as discussed in **Section 8.2.2**.

Investigating the presence of consumer behaviour trends may include:

- analysis of the relationship between customer meter data and prevailing weather conditions to identify potential shifts in heating and cooling behaviour
- analysis of electricity and gas meter data to identify the rate and impact of electrification
- analysis of changes in the building and appliance stock to detect appliance adoption and/or shifting consumer preferences

AEMO will also explore potential improvements to technology and behavioural modelling to better incorporate these consumer trends.

AEMO proposes this improvement as an **investigation only** at this stage, and no specific methodology improvements are proposed for the 2026 ESOO. If any improvements to the forecasting approach arise from the investigation, these will be consulted in an FRG or in the following Forecast Improvement Plan.

Consultation questions – modelling otherwise unexplained consumer behaviour trends

- Do stakeholders support the increased analysis of customer meter data to identify and characterise emerging consumer behaviour trends?
- Do stakeholders have a view on any specific consumer behaviour trends worthy of priority investigation?

AEMO welcomes feedback and suggestions from stakeholders regarding the methodology changes proposed above.

A1. Status of improvements proposed in 2024

The 2024 Forecast Improvement Plan was published in the 2024 *Forecast Accuracy Report*[78]. It proposed multiple improvements for the 2025 ESOO or beyond. For visibility of progress, each improvement is listed below along with the implementation status.

Table 32 Forecast improvement priorities for 2024-25 outlined in the 2024 Forecast Improvement Plan

Improvement	Status
LIL consumption forecasting (Electricity Demand Forecasting Methodology [EDFM] Consultation) AEMO's proposed expansion of the criteria for inclusion of proposed LIL projects, and provision of greater transparency on how model inputs are integrated, including the interactions between surveys and scenario based growth trajectories.	**Complete** Prospective loads inclusion criteria have been updated to factor in status and development potential of proposed future large industrial and data centres projects. These criteria define scenario and temporal allocation of the projects. The new criteria were used in the 2025 ESOO and update is documented in the EDFM. CSIRO's multi-sectoral modelling results drive the medium- to long-term growth of the LIL sector in recognition that the survey approach only provides limited value for what is happening beyond the short-term. The blended growth methodology is incorporated in the 'Step 5: Finalise forecasts' portion of the LIL forecast methodology in the 2024 EDFM.
Data centres (EDFM Consultation) The separation of data centre load forecasts from other customer loads to provide greater transparency and consideration of this customer segment.	**Complete** AEMO leveraged an external consultant to develop data centre specific forecasts that have fed into the 2025 ESOO.
Sub-regional forecasts (EDFM Consultation) The development of sub-regional forecasts aligned with geographical boundaries to support improved spatial insights.	**Complete** For the 2025 ESOO, forecasts were produced at the NEM sub-regional level, as defined in the IASR. LIL forecasts leverage site information to effectively provide sub-regional forecasts. Residential and business mass market modelling is undertaken at the regional level but then split to the sub-regional level using proxies and sub-regional actuals data. All other components – such as EVs, hydrogen, electrification, data centres, and PV – are provided at sub-regional level. Additional bottom-up analysis, such as improvements to the residential-business split detailed in this year's Forecast Improvement Plan, will extend this improvement.
Solar rebound (EDFM Consultation) Enhancement to the forecast methodology by applying the solar rebound effect to a proportion of household consumption rather than solely the volume of solar PV generation.	**Complete** Consumption increase after solar installation is now proportional to historical consumption. Magnitude of rebound is informed by current literature.
Consider potential sources of residual variances in the consumption forecasts AEMO proposed to investigate potential sources of residual variances to provide deeper insights into key drivers of variance in future accuracy assessments, thereby improving forecast accuracy.	**Ongoing** AEMO continues to investigate the appropriateness of incorporating the impact of humidity into the residential and BMM electricity consumption models.

[78] See https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/accuracy-report/2024-forecast-accuracy-report.pdf.

Improvement	Status
Synthetic demand traces approach (Electricity Demand Forecasting Methodology Consultation) AEMO proposed to revise the EDFM to reflect a new 'synthetic' approach to developing 30 minute traces of demand per region and sub-region.	**Complete** AEMO has developed and implemented the synthetic demand trace methodology for the 2025 ESOO, as elaborated in the EDFM. This framework produces long-horizon half-hourly operational and underlying demand traces by integrating historical weather-normalised demand. The resulting synthetic demand traces has allowed AEMO to increase the number of weather (reference) years considered in reliability assessments. The methodology is now embedded in the forecasting workflow and will be refined as improved CER and electrification datasets become available.
Revise consideration for project development delays AEMO proposed to revise its ESOO and Reliability Forecast Methodology to better align development delay assumptions with observed trends.	**Complete** AEMO made changes to the latest *ESOO and Reliability Forecast Methodology Document* so that 'committed' and 'committed*' projects now apply a delay to the full commercial use date submitted by the developer consistent with delays observed for recently commissioned projects. This methodology was applied in the 2025 ESOO.
Monitor planned outages AEMO proposed to monitor planned outages during the 2024-25 summer, assessing inflexible unavailability including opportunistic maintenance.	**Ongoing** Analysis of planned outages were presented at the April 2025 FRG which showed outages occurring during reliability risk periods. A sensitivity including planned outages based on historic values was modelled in the 2025 ESOO, which indicated higher reliability risks and suggested that the impact of outages could become more significant in the future. AEMO has proposed to incorporate four categories of generator and storage outage categories, including planned outages, in the 2026 ESOO under the Forecast Improvement Plan in this 2025 Forecast Accuracy Report.
Simplify the modelling of unplanned outages. AEMO proposed to simplify the ESOO and Reliability Forecast Methodology by using average unplanned outage rates instead of year-to-year variability from the last four years.	**Complete** This change was updated in August 2025 *ESOO and Reliability Forecast Methodology Document* and was implemented in the 2025 ESOO.

*The *ESOO and Reliability Forecast Methodology* is at https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2025/esoo-and-reliability-forecast-methodology.pdf.
** The *Electricity Demand Forecasting Methodology* is at https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2024-electricity-demand-forecasting-methodology-consultation/final-determination/electricity-demand-forecasting-methodology_.pdf.

Table 33 Ongoing research and improvement areas outlined in the 2024 Forecast Improvement Plan

Improvement	Status
Understand changes in future load shape from technology uptake and usage AEMO planned to assess data from Project Edge and Project Symphony to support insights into future load shapes, and will continue to collaborate with industry participants, researchers and government in researching the uptake and operation of EVs and battery storage.	**In progress** AEMO has recently acquired a large data set with behind-the-meter generation and consumption data at the premise level with ongoing updates, which includes EV and battery charge/discharge profiles. AEMO has started using this data to produce actual PV normalised generation profiles (as outlined in Section 8.2.4), and further analysis of this data will progress in the coming months to provide further insights into consumers' present and future load shape and technology usage, with a particular focus on battery charging and discharging behaviour.
Track electrification trends AEMO planned to investigate meter data to determine whether electrification trends were observable in those data.	**Ongoing** AEMO has commenced analysis of a large number of customer sites that have had electricity and gas (or lack of gas) information linked, to better understand the impact of the electrification of gas appliances. This is expected to provide a measure of validation against the scale and pace of AEMO's electrification forecasts.
Improve renewable generation and demand traces, including the quantity used, and their shape AEMO planned for more weather reference years to be available for the 2025 ESOO, based on synthetic weather data for renewable and demand traces.	**Complete** As part of the 2024 EDFM consultation, AEMO revised its electricity demand forecasting methodology, to adopt synthetic demand traces, which enabled AEMO to consider a greater number of weather reference years in the 2025 ESOO. The 2025 ESOO increased the number of weather reference years used from 14 in the 2024 ESOO to 23 in the 2025 ESOO, covering historical reference years 2003-04 to 2024-25. AEMO will continue to consider the most appropriate number of reference years for future modelling.

Improvement	Status
Improve visibility of sectoral consumption AEMO planned to review both the LIL and ONSG forecast components, to better understand both their impacts on consumption and their contributions at time of maximum and minimum demand.	**Ongoing process** AEMO completed the second round of sectoral consumption analysis which has helped inform its business forecasts. AEMO has also investigated the use of alternative datasets which may make future sectoral analyses more efficient and cost effective. Additionally, through the 2024 EDFM consultation, AEMO is proposing to forecast data centres as a separate customer segment across all regions. AEMO is also proposing to expand the criteria for inclusion of proposed LIL projects, and to provide greater transparency on the integration of short- and medium-term survey data with longer-term scenario-based growth trajectories.
Monitor demand side participation trends AEMO planned to continue to monitor how WDR is used compared to forecast and to monitor the response of large DSP providers during LOR events.	**Ongoing process** AEMO is reviewing the DSP Information portal interface to enhance the accuracy and granularity of data obtained from participants across different demand flexibility programs. Moreover, a review of the baseline method has been initiated to assess possibilities of improving the accuracy of DSP response estimation, especially during extended periods of high demand and price.

* The *Electricity Demand Forecasting Methodology* is at https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2024-electricity-demand-forecasting-methodology-consultation/final-determination/electricity-demand-forecasting-methodology_.pdf.

Glossary, measures, and abbreviations

Glossary

This document uses many terms that have meanings defined in the National Electricity Rules (NER). The NER meanings are adopted unless otherwise specified.

Term	Definition
Auxiliary load	Auxiliary load, also called 'parasitic load' or 'self-load', refers to energy generated for use within power stations, excluding pumped hydro. The electricity consumed by battery storage facilities within a generating system is not considered to be auxiliary load. Electricity consumed to charge by battery storage facilities is a primary input and treated as a market load.
Capacity	The maximum rating of a generating or storage unit (or set of generating units), or transmission line, typically expressed in megawatts (MW). For example, a solar farm may have a nominal capacity of 400 MW.
Consumer energy resources (CER)	Generation or storage assets owned by consumers and installed behind-the-meter. These can include rooftop solar, batteries and electric vehicles (EVs). CER may include demand flexibility.
Consumption	The electrical energy used over a period of time (for example a day or year). This quantity is typically expressed in megawatt hours (MWh) or its multiples. Various definitions for consumption apply, depending on where it is measured. For example, underlying consumption means consumption being supplied by both CER and the electricity grid.
Cooling degree day	The number of degrees that a day's average temperature is above a critical temperature. It is used to account for deviation in weather from normal weather standards.
Demand	The amount of electrical power consumed at a point in time. This quantity is typically expressed in megawatts (MW) or its multiples. Various definitions for demand, depending on where it is measured. For example, underlying demand means demand supplied by both CER and the electricity grid.
Demand side participation (DSP)	The capability of consumers to reduce their demand during periods of high wholesale electricity prices or when reliability issues emerge. This can occur through voluntarily reducing demand, or generating electricity.
Distributed photovoltaics (PV)	Distributed PV is the term used for rooftop PV and non-scheduled PV generators combined.
Electric vehicle (EV)	Electric-powered vehicles, ranging from small residential vehicles such as motor bikes or cars, to large commercial trucks and buses.
Heating degree day	The number of degrees that a day's average temperature is below a critical temperature. It is used to account for deviation in weather from normal weather standards.
Large industrial loads (LIL)	Customers that are connected directly to the transmission network or distribution connected customers that consume greater than 10 MW for more than 10% of the latest financial year.
Other non-scheduled generation	It is the generation of other non-scheduled generators that are smaller than 30 MW and are not PV.
Probability of exceedance (POE)	POE is the likelihood a maximum or minimum demand forecast will be met or exceeded. A 10% POE maximum demand forecast, for example, is expected to be exceeded, on average, one year in 10, while a 90% POE maximum demand forecast is expected to be exceeded nine years in 10.
PV non-scheduled generation	It is the generation from non-scheduled PV generators that are larger than 100 kW but smaller than 30 MW.
Renewable energy	For the purposes of the ESOO, the following technologies are referred to under the grouping of renewable energy: "solar, wind, biomass, hydro, and hydrogen turbines". Variable renewable energy is a subset of this group, explained below.
Rooftop PV	Rooftop PV is defined as a system comprising one or more PV panels, installed on a residential building or business premises (typically a rooftop) to convert sunlight into electricity. The capacity of these systems is less than 100 kilowatts (kW).
Scenario	A possible future of how the NEM may develop to meet a set of conditions that influence consumer demand, economic activity, decarbonisation, and other parameters. For the 2024 ESOO, AEMO considered three scenarios: *Progressive Change*, *Step Change(ESOO Central),* and *Green Energy Exports*.
Unserved energy (USE)	Unserved energy is the amount of energy that cannot be supplied to consumers, resulting in involuntary load shedding (loss of consumer supply). USE is calculated consistent with NER 3.9.3C.
Variable renewable energy (VRE)	Renewable resources whose generation output can vary greatly in short time periods due to changing weather conditions, such as solar and wind.

Units of measure

Abbreviation	Full name
°C	celsius
GW	gigawatt/s
GWh	gigawatt hour/s
kW	kilowatt/s
MW	megawatt/s
MWh	megawatt hour/s

Abbreviations

Abbreviation	Full name
ABS	Australian Bureau of Statistics
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AEST	Australian Eastern Standard Time
BEV	battery electric vehicle
BMM	business mass market
CER	consumer energy resources
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DCCEEW	Department of Climate Change, Energy, the Environment and Water
DNSP	distribution network service provider
DSP	demand side participation
EAAP	*Energy Adequacy Assessment Projection*
ESOO	*Electricity Statement of Opportunities*
EV	electric vehicle
FCAI	Federal Chamber of Automotive Industries
FCUD	full commercial use date
FBPG	*Forecasting Best Practice Guidelines*
FRG	Forecasting Reference Group
GDP	Gross Domestic Product
GELF	Generator Energy Limitation Framework
GEM	Green Energy Markets
GSP	Gross State Product
HDI	Household Disposable Income
LNG	liquefied natural gas
LOR	lack of reserve
MSATS	Market Settlement and Transfer Solutions
MT PASA	Medium Term Projected Assessment of System Adequacy
NEM	National Electricity Market
NER	National Electricity Rules

Abbreviation	Full name
NMI	National Metering Identifier
OPGEN	operational demand as generated
OPSO	operational demand sent-out
PHEV	plug-in hybrid electric vehicle
POE	probability of exceedance
PV	photovoltaic
PVNSG	PV non-scheduled generation
RCP	Representative Concentration Pathway
RERT	Reliability and Emergency Reserve Trader
RRO	Retailer Reliability Obligation
USE	unserved energy
VRE	variable renewable energy
WDR	Wholesale Demand Response