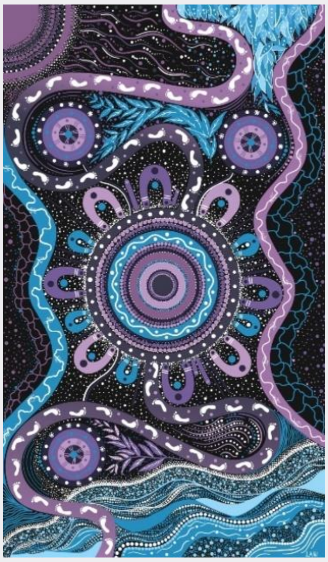
Forecast Accuracy Report

December 2024

Review of the 2023 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 Group is proud to have launched its first Reconciliation Action Plan in May 2024. 'Journey of unity: AEMO's Reconciliation Path' was created by Wiradjuri artist Lani Balzan to visually narrate our ongoing journey towards reconciliation - a collaborative endeavour that honours First Nations cultures, fosters mutual understanding, and paves the way for a brighter, more inclusive future.

Important notice

Purpose

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 2023 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 2024 unless otherwise indicated.

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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 2024 *Forecast Accuracy Report* primarily assesses the accuracy of AEMO's 2023 *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 2023-24 financial year, in particular the summer.

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, 2023-24

Forecast Component	NSW	QLD	SA	TAS	VIC	Assessability[A]	Comments
Energy consumption	🟢	🔴	🟡	🟡	🟡	Moderate	Reasonable alignment, though forecast accuracy has reduced for the 2023 ESOO. Notable is that the residual, or unknown portion of variance, was relatively large for Queensland, South Australia, and Victoria. The forecast accuracy for many of the measured components was relatively accurate in Queensland, with the large residual accounting for most of the under-forecast. For Victoria, the large residual exactly offset large variance in measured components, particularly large industrial loads (LILs). Tasmania's consumption forecast improved this year with most of the variation driven by unforeseen LIL outages.
Summer maximum demand	🟢	🟡	🟢	🟡	🟢	Weak - Moderate	Overall, observed actuals showed good alignment with forecasts across most regions, except in Queensland and Tasmania. In Queensland, summer maximum demand exceeded the 10% probability of exceedance (POE) forecast, largely driven by an atypical summer characterised by El Niño conditions and prolonged periods of high humidity, which likely increased cooling loads. In Tasmania, summer maximum demand fell below the forecast distribution, as it occurred during warmer conditions due to the absence of as cold weather during the summer period.
Winter maximum demand	🟡	🟢	🟢	🟢	🟡	Weak - Moderate	Overall, the winter maximum demand outcomes showed good alignment with forecasts across most regions, except in New South Wales and Victoria. In New South Wales, the observed actual fell just below 90% POE and in Victoria, the observed outcome fell above 10% POE.

[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
Annual minimum demand	🟢	🟢	🟢	🟢	🟢	Weak - Moderate	Overall, the observed actual annual minimum demand outcomes for all regions fell within the forecast range.
Demand side participation	🟢	🟢	🟢	🟢	🟡	Weak - Moderate	Generally, the observed demand side participation (DSP) was relatively similar to the forecast in New South Wales, Queensland and South Australia, especially for higher price bands. Similar to last year, no significant DSP response was observed in Tasmania; the forecast was also small. In Victoria, actual DSP responses exceeded forecasts across all price bands, leading to an upward revision in the DSP forecasts in the 2024 ESOO. Overall, prices were generally low at time of peak demand during 2023-24 and minimal price responses were observed.
Installed generation capacity	🟢	🟡	🟡	🟢	🟢	Strong	New generator installations matched expectations in Tasmania and were relatively close in New South Wales and Victoria. In Queensland, some projects began full operation earlier than assumed by the ESOO modelling methodology[B], resulting in higher installed capacity than forecast. Conversely, in South Australia, longer-than-expected project delays, compared to the ESOO modelling methodology, led to lower installed capacity than projected.
Summer supply availability	🟢	🟢	🟢	🟢	🟢	Moderate	Despite the absence of extreme temperatures in summer 2023-24 and the earlier-than-expected commencement of several projects compared to the ESOO modelling methodology, total observed supply was within simulated ranges across all regions, constrained by planned and unplanned outages, development delays, and lower than expected generation from VRE generators in some regions.

A. The assessability categories are defined in **Section 2.2.1.**
B. In the 2023 ESOO modelling, AEMO applied participant provided full commercial use dates, adjusted by default delays based on each project's development status, as specified in **Section 8.2.3**.

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.

This report highlights strong overall forecasting performance in areas critical to AEMO's reliability assessment. Variances in energy consumption and summer maximum demand are partly attributed to the second-warmest financial year on record with the presence of El Niño conditions. The increase in unknown variance components within energy consumption forecasts presents an opportunity for AEMO to refine and enhance its forecasting methods further.

Several potential forecasting improvements have been identified, particularly for summer maximum demand and supply forecasts.

In summary:

- While **annual consumption** across most NEM regions was reasonable, significant residual or unknown variance components were observed, particularly in Queensland, South Australia, and Victoria. Queensland's total variance was primarily driven by the unexplained residual, potentially linked to factors such as electrification, energy efficiency, or weather effects[2] that are being under- or over-stated in the modelling.

- Tasmania had the lowest residual impact, though an unforeseen large industrial load (LIL) shutdown and over-forecast for heating degree days contributed to significant total variance. Victoria's forecasts were the most accurate, however within the forecast the LILs were over-forecast by 20%. This large over-forecast was offset by a large negative residual. These findings highlight the need for AEMO to investigate currently unknown potential drivers of variance. For example, there is potential to explore electrification trends, broader weather effects, and sectoral responses to economic conditions other than electrification to enhance understanding of residual variances.
- The observed actual **summer and winter demand outcomes** were often in the range between the 10% probability of exceedance (POE)[3] and 90% POE forecasts, with some deviations from forecast expectations in some regions. In Queensland, the summer maximum demand exceeded the 10% POE forecast. This outcome can largely be attributed to the El Niño-induced hot summer conditions, which were associated with extreme humidity, driving higher cooling demand. For winter maximum demand, outcomes in New South Wales fell just below 90% POE which could be attributed to the mild winter and Victoria fell just above10% POE. For Tasmania, the actual summer maximum demand fell well below the 90% POE forecast, likely due to the absence of cold weather.
- For **annual minimum demand**, actual results were all observed within the forecast distribution range.
- **Rooftop photovoltaics (PV) and electric vehicles (EVs)** significantly influence electricity consumption and demand forecasts over the 10-year ESOO horizon. The 2023 ESOO underestimated rooftop PV capacity for 2023-24 in most NEM regions due to unexpected growth in system size. PV forecasts included in the 2024 ESOO have been revised upward across all scenarios to reflect the observed growth in system sizes. EV fleet size was also under-forecast, though its impact on energy consumption and demand remains minimal. Rapid adoption of this newly adopted technology has led to larger initial forecast errors. AEMO expects improved short-term EV forecast accuracy as sales stabilise, supported by enhanced forecasting models and better integration of plug-in EV trends in the 2024 ESOO.
- **Generator installed capacity** during the 2023-24 summer exceeded forecasts by 235 megawatts (MW) due to the mismatch between projects' actual start dates and AEMO's project delay assumptions applied under the current *ESOO and Reliability Forecast Methodology*. Some committed generation and storage projects became fully operational earlier than the ESOO modelling methodology[4], while others were delayed by a period greater than assumed by the methodology. AEMO proposes revisions to its methodology to allow greater responsiveness to recent trends in development delays for committed generation, storage, and transmission projects.
- **Planned and unplanned outages** impacted supply availability across regions and technologies. Unplanned outage rates aligned closely with participant projections. This *Forecasting Accuracy Report* also includes an assessment of planned outages, identifying a 2.5% planned outage rate (with recall time exceeding 10 days)

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

[3] The 10% POE forecast should on average only be exceeded one in 10 years.

[4] Among the 11 committed projects whose actual full commercial use date differed from the assumed start dates in the 2023 ESOO, more than half began operation earlier than assumed.

during supply scarcity periods. AEMO proposes to monitor planned outages throughout the 2024-25 summer, assess inflexible unavailability, and engage stakeholders on revising the ESOO and Reliability Forecast methodology to incorporate inflexible planned outages alongside unplanned outages in early 2025, which AEMO believes may further enhance forecast accuracy.

Forecast Improvement Plan

The improvement plan is an important tool to guide investigation work and improvements in forecasting. It is composed of forecast improvement priorities for 2024 and ongoing research and improvement areas.

The short-term, priority initiatives to be incorporated in the 2025 ESOO reliability forecasts are:

- **Consider potential sources of residual variances in the consumption forecasts.** AEMO acknowledges that residual variances in the energy consumption forecasts are higher than in previous years' forecasts. At the NEM level, residual variance was -3.3% of operational as generated consumption, a significant increase from -0.4% the year before. To address this, AEMO proposes to investigate potential sources of residual variances to provide deeper insights into key drivers of variance in future accuracy assessments, thereby improving forecast accuracy. Potential approaches include further disaggregation of residential and business loads when assessing forecast accuracy, tracking electrification impacts using existing project analysis, and assessing the influence of humidity on cooling loads in regions like Queensland.
- **Revise consideration for project development delays.** AEMO plans to revise its *ESOO and Reliability Forecast Methodology* to better align development delay assumptions with observed trends. Recent data shows some committed generation and storage projects are delivering capacity earlier than the modelling methodology, while transmission projects often face delays. Adjustments will allow more frequent updates to delay assumptions for committed projects, improving forecast accuracy. No changes are proposed for anticipated projects, as their timelines remain less predictable.
- **Monitor planned outages.** AEMO proposes to monitor planned outages during the 2024-25 summer, assessing inflexible unavailability including opportunistic maintenance. AEMO will consult stakeholders on potentially revising the *ESOO and Reliability Forecast Methodology* to account for planned outages during periods of supply scarcity risk in early 2025. Despite assumptions that planned outages are scheduled to avoid high-demand periods, around 1,000 MW of planned outage with recall time exceeding 10 days occurred on average in January and February for summer 2023-24, representing a 2.5% outage rate during critical times. Incorporating such planned outages into the 2025 ESOO is expected to improve accuracy and better reflect actual conditions.
- **Simplify the modelling of unplanned outages**. AEMO proposes simplifying the *ESOO and Reliability Forecast Methodology* by using average unplanned outage rates instead of year-to-year variability from the last four years. This reduces modelling complexity and costs, and has become less necessary due to recent stability in outage rate variability. The change offsets the increased complexity from expanding weather reference years via deploying synthetic demand trace methodologies in reliability assessments, ensuring more efficient and accurate forecasts.

Several initiatives to improve energy and demand forecasting are progressing as part of the 2024 *Electricity Demand Forecasting Methodology* consultation[5], currently underway. Key examples include:

- **LIL consumption forecasting** – revising consideration of new load commitment criteria and providing greater transparency on the integration of short- and medium-term survey data with longer-term scenario-based growth trajectories.
- **Data centre load segmentation** – separating data centre forecasts from other customer loads to provide clearer insights into this emerging segment.
- **Sub-regional forecasts** – developing forecasts aligned with standard geographical boundaries to improve spatial insights.
- **Solar rebound effect** – revising methodology by applying the effect to household consumption rather than rooftop PV generation volume, aligning with current literature.
- **Synthetic demand trace approach** – revising methodology for developing 30-minute traces of forecast electricity demand to better reflect consumer behaviour over a wider variety of weather inputs.

These efforts aim to enhance transparency in AEMO's forecasting approaches and deliver forecast improvements to support the 2025 ESOO reliability assessment.

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. Submissions are requested by **5:00 pm** (Australian Eastern Daylight Time) **Wednesday, 5 February 2025** and should be sent by email to energy.forecasting@aemo.com.au.

[5] See https://aemo.com.au/consultations/current-and-closed-consultations/2024-electricity-demand-forecasting-methodology-consultation.

Contents

Tables

Figures

1 Stakeholder consultation process

The publication of this *2024 Forecast Accuracy Report* marks the commencement of AEMO's Forecast Improvement Plan consultation.

Section 8 of this report, the Forecast Improvement Plan, has been guided by assessment of the main contributors to forecast inaccuracies in the rest of this report. This consultation covers the initiatives outlined in the Forecast Improvement Plan only, and not the *Forecast Accuracy Report Methodology*.

AEMO completed the Forecast Accuracy Report Methodology two-stage consultation and published the finalised report in October 2024[6], providing guidance on the development of this 2024 *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 2025 ESOO.

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 alternative or additional improvements should be considered to address the accuracy issues identified in this report?

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) **Wednesday, 5 February 2025**.

Table 2 below outlines AEMO's consultation timeline on the improvement plan. The consultation will follow the single-stage process outlined in Appendix B of the *Forecasting Best Practice Guidelines* (FBPG)[7] published by the Australian Energy Regulator (AER).

Table 2 Consultation timeline

Consultation steps	Indicative dates
Forecasting Reference Group discussion of draft report	11 December 2024
Forecast Accuracy Report and Forecast Improvement Plan published	20 December 2024
Submissions due on Forecast Improvement Plan	05 February 2025
Final Forecast Improvement Plan published along with a Submission Response document	13 March 2025

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

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

2 Introduction

In accordance with National Electricity Rules (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 *Electricity Statement of Opportunities* (ESOO) for the National Electricity Market (NEM). The objective of this transparency is to build confidence in the forecasts produced.

To meet this requirement, AEMO has prepared this *Forecast Accuracy Report* for a broad set of demand, supply, and reliability forecast components, consistent with AEMO's *Forecast Accuracy Report Methodology*[8] and *Reliability Forecast Guidelines*[9].

AEMO engaged the University of Adelaide to review the *Forecast Accuracy Report Methodology*[10] and updated it in October 2024 following the two-stage consultation[11]. The 2024 *Forecast Accuracy Report* reflects these methodological changes in assessing the accuracy of the 2023-24 demand and supply forecasts published in AEMO's 2023 ESOO for the NEM[12] and related products. It also evaluates the resulting reliability forecasts for each region in the NEM.

The 2023 ESOO forecasts are the latest that can be assessed against a full year of subsequent actual observations. While AEMO published formal updates to the 2023 ESOO in September 2023 and May 2024, respectively, they are not subject to review.

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) based on estimates of auxiliary load, which reflect 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.

[8] 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.

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

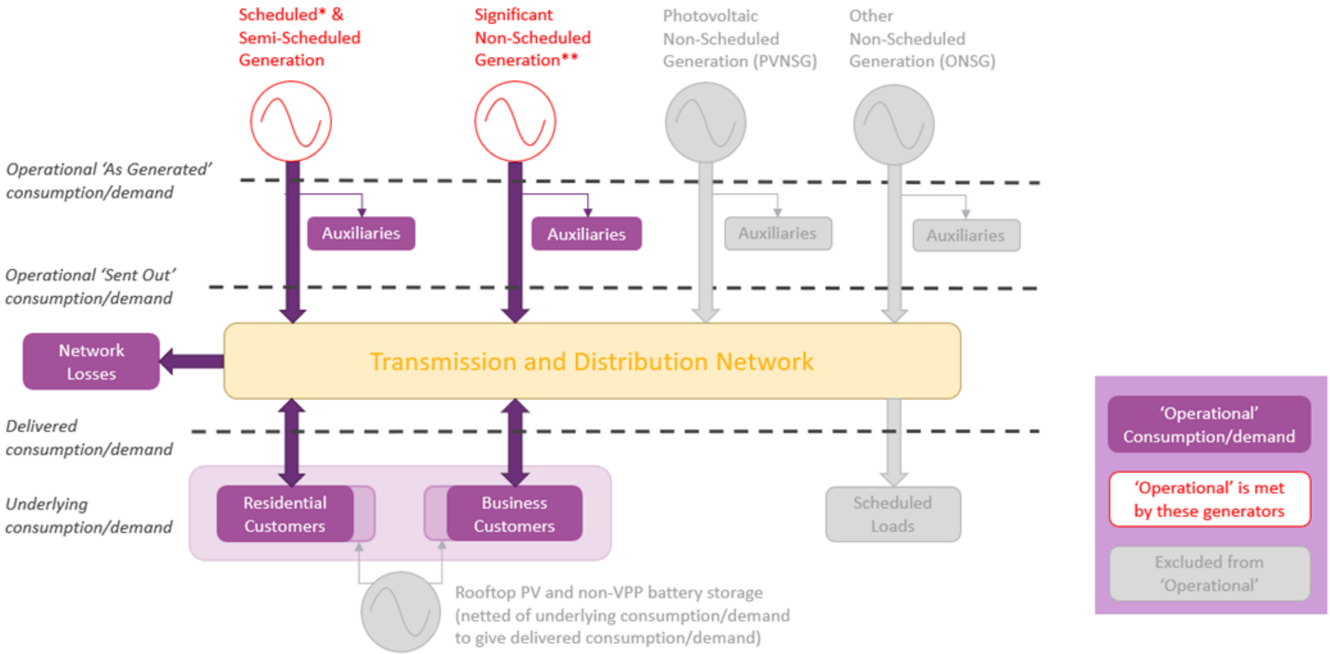
[10] See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/accuracy-report/2023-review-of-forecast-accuracy-metrics-report.pdf?la=en.

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

[12] See https://aemo.com.au/-/media/files/electricity/wem/planning_and_forecasting/esoo/2023/2023-wholesale-electricity-market-electricity-statement-of-opportunities-wem-esoo.pdf.

Figure 1 shows the demand definitions used in this document.

Figure 1 Demand definitions used in this document



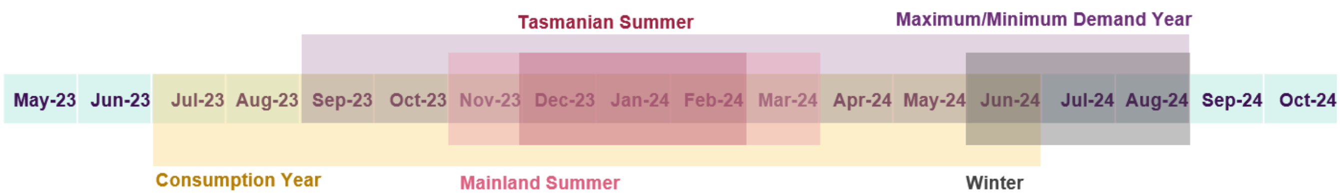
* Including injection from grid-scale storages and virtual power plants (VPP) from aggregated behind-the-meter battery storage.
** For definition, see https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Dispatch/Policy_and_Process/Demand-terms-in-EMMS-Data-Model.pdf.

Seasonal definitions

For consistency, data and methodologies of actual observations (or 'actuals') are the same as those used for the corresponding forecasts in the 2023 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 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*[13]:

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

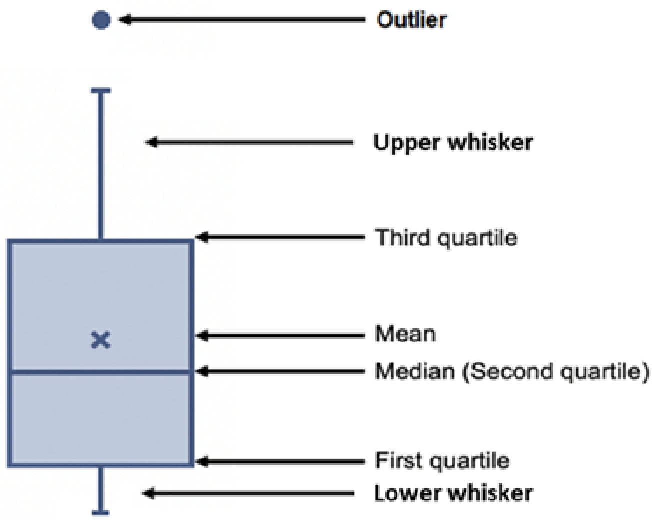
Using this approach, a negative percentage error indicates an under-forecast compared to actuals, where a positive error is an over-forecast. Specifically, a percentage error of -20% implies the forecast is 20% *lower* than actuals.

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. Occasionally, actual observations fall outside a certain range from the first and third quartiles and will be classified as outliers rather than form the upper whisker and lower whisker values otherwise shown. Such outliers are shown as dots.

Figure 3 Explanation of box plots used in this report



[13] 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.

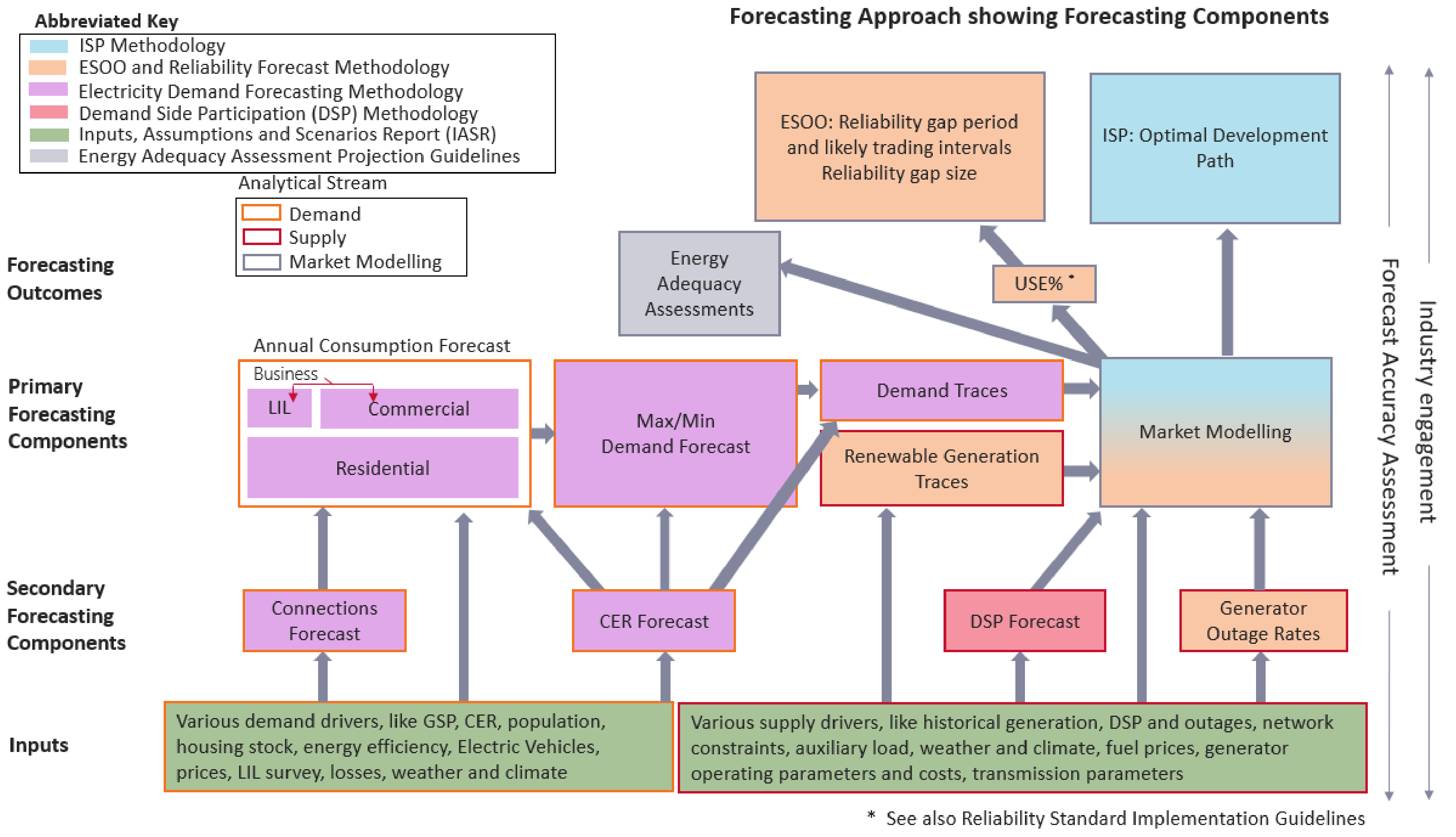
2.2 Forecast components

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

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[14]. 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 photovoltaics (PV), electric vehicles (EVs), and battery storage.

[14] 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. AEMO's Forecast Improvement Plan includes initiatives that seek to increase the assessability of forecast components.

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.
- **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 2023 ESOO are summarised in **Table 3**.

Table 3 Key scenarios and sensitivities used in the 2023 ESOO

Parameter	*Progressive Change*	*Step Change* (ESOO Central)	*Green Energy Exports*
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 Representative Concentration Pathway (RCP) 4.5 where relevant (~ 2.6°C)	Applies RCP 2.6 where relevant (~ 1.8°C)	Applies 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 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.
- Numerous other weakly assessable drivers including energy efficiency and appliance mix.

The 2023 ESOO detailed the changing social, economic, and political environment in which the NEM operates. As this environment evolves, the needs of the market and system will also evolve. As discussed in **Section 2.3**, three scenarios were developed to illustrate a range of possible pathways: *Progressive Change, Step Change (*which was applied as the ESOO Central scenario for RRO assessment purposes*), and Green Energy Exports*.

Not all input variables are measured regularly, or have material impacts on year-ahead outcomes. For example, distributed PV installations are measurable and have an impact on year-ahead outcomes, while other inputs are less measurable and are less likely to impact the year-ahead forecasts. Input drivers that are suitable for accuracy assessment and comment are discussed in this section.

3.1 Macroeconomic growth

AEMO uses various macroeconomic indicators as key inputs to the scenario forecasts. The 2023 ESOO incorporated consultant forecasts of economic components relevant for forecasting electricity consumption, such as Gross Domestic Product (GDP), Gross State Product (GSP), and Household Disposable Income (HDI)[15].

For 2023-24, annual GDP was forecast to grow by 3.1% in the ESOO Central scenario, with GSP growth supporting this increase through an average increase of 3.0% across the NEM regions. Beneath these relatively strong growth forecasts, HDI was forecast to grow by only 1.2% in 2023-24, reflecting persistent global inflation troubles, partly attributable to the ongoing Russia-Ukraine war.

In the time since the 2023 ESOO was published, inflation has yet to return to the Reserve Bank of Australia (RBA) target range of 2% to 3%. Part of Australia's persistent inflation challenge has been high global energy prices flowing through to increased energy bills for Australian consumers. High levels of migration coupled with elevated construction company insolvencies have also fuelled rent increases[16]. While the impacts of COVID-19 have largely subsided, international travel has yet to return to pre-COVID levels, which is symptomatic of household cost pressures that are limiting discretionary spending, particularly for younger demographics[17].

[15] Source: BIS Oxford Economics, 2022 Macroeconomic Projections Report, available at: https://www.oxfordeconomics.com/wp-content/uploads/2023/01/BIS-Oxford-Economics-2022-Macroeconomic-Outlook-Report.pdf.

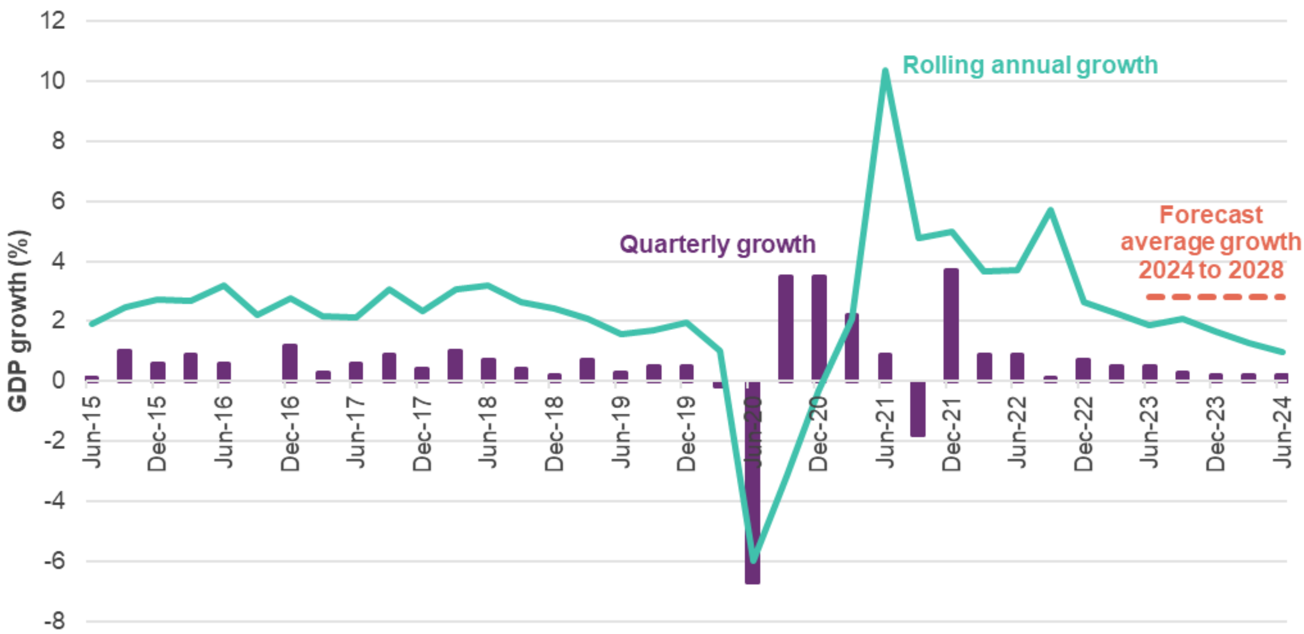
[16] Source: Reserve Bank of Australia, Statement on Monetary Policy, August 2024, available at: https://www.rba.gov.au/publications/smp/2024/aug/pdf/statement-on-monetary-policy-2024-08.pdf. Accessed 31 October 2024.

[17] Source: Australian Bureau of Statistics, Overseas arrivals and departures, Australia - 2023-24 financial year, available at: https://www.abs.gov.au/articles/overseas-arrivals-and-departures-australia-2023-24-financial-year. Accessed 31 October 2024.

The current challenging economic environment has meant that actual GDP growth was much lower than forecast in 2023-24, increasing by 1.0% for the year to June, as shown in **Figure 5**[18]. Real disposable household incomes fell by 0.3% for 2023-24, and on a per capita basis, fell by 2.7%, highlighting that much of Australia's growth is attributable to the large increase in population[19].

An average annual growth rate of 2.8% p.a. was forecast over the first five years of the forecast period, which is now less likely to occur given the much lower than forecast economic performance for the most recent financial year.

Figure 5 Macroeconomic growth rates, chain volume measures, June 2015 to June 2024, seasonally adjusted



All else equal, lower economic growth would lead to lower electricity consumption than forecast. However, the extent of this relationship is dependent on the sectors that have been most impacted by challenging economic conditions, given the differences in energy intensity[20] between sectors.

3.2 Connections growth

The number 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 (Oxford Economics Australia for the 2023 ESOO) and the Australian Bureau of Statistics (ABS) and are shown in **Table 4**. For the 2023 ESOO, the short-term projections were forecast by blending the short-term trend of

[18] Source: Australian Bureau of Statistics. Australian National Accounts: National Income, Expenditure, and Product, Jun 2024, available at https://www.abs.gov.au/statistics/economy/national-accounts/australian-national-accounts-national-income-expenditure-and-product/latest-release#data-download. Accessed 22 October 2024.

[19] Ibid.

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

National Metering Identifier (NMI) growth from the AEMO database with data provided by Oxford Economics Australia[21] and the ABS.

Table 4 Connections forecast and actuals for 2023-24

Region	2023 ESOO forecast for 2023-24 (number of customers)	Actual for 2023-24 (number of customers)*	Difference (%)^
NSW	3,614,380	3,599,491	0.4%
QLD	2,109,117	2,096,440	0.6%
SA	815,953	816,487	-0.1%
TAS	264,472	260,917	1.4%
VIC	2,835,048	2,811,282	0.8%
NEM	**9,638,970**	**9,584,617**	**0.6%**

* Actuals represent number of customers as at the end of financial year 2023-24 (30 June 2024).
^ Negative number reflects an under-forecast of actuals, positive number an over-forecast.

Connections forecasts for the NEM were 0.6% higher than actual connections for 2023-24. Despite strong population growth[22], building activity continued to trend lower through 2023-24[23], partly due to construction company insolvencies brought on by elevated material costs, interest rates that have remained high relative to recent history, and high labour costs in some areas.[24] In general, the actual number of connections is still aligned reasonably well with the forecast, and the contribution to the overall NEM consumption forecast variance is minimal (see **Figure 7** in **Section 4**).

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 megawatts (MW) in size.

To define actual rooftop PV installed capacity in the 2023 ESOO, AEMO received installation data from the Clean Energy Regulator and adjusted it to reflect estimated system replacements. 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.

[21] The Oxford Economics Australia dwellings forecasts are re-based to the previous census year.

[22] Australian Bureau of Statistics: National, state and territory population (September 2024 release), at https://www.abs.gov.au/statistics/people/population/national-state-and-territory-population/latest-release. Accessed 6 November 2024.

[23] Australian Bureau of Statistics: Building Activity Australia (Jun 2024 release), at https://www.abs.gov.au/statistics/industry/building-and-construction/building-activity-australia/latest-release. Accessed 6 November 2024.

[24] Source: Reserve Bank of Australia, Statement on Monetary Policy, August 2024, at https://www.rba.gov.au/publications/smp/2024/aug/pdf/statement-on-monetary-policy-2024-08.pdf. Accessed 31 October 2024.

AEMO's 2023 ESOO Central forecast adopted an averaging approach of the forecasts provided by AEMO's two CER consultants: CSIRO[25] and Green Energy Markets (GEM)[26]. For rooftop PV, the average was chosen[27] as the forecasts mapped to the ESOO Central scenario were considered to be each consultant's best estimates, consistent with the scenario narratives. For PVNSG, however, GEM's forecast was considered to better align with the narrative of the ESOO Central scenario. With two forecasts, using two independent models but aligned to the same assumptions and 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 2023 ESOO Central scenario.

Table 5 Rooftop PV and PVNSG installed capacity comparison by region, as of 30 June 2024

Installed as of 30 June 2024		NSW	QLD	SA	TAS	VIC	NEM
Rooftop PV	Estimated actual (MW)	7,017	6,342	2,443	317	4,655	20,775
	Central forecast (MW)	6,246	5,894	2,305	279	4,694	19,418
	Central forecast error (%)	-11.0%	-7.1%	-5.6%	-12.0%	0.8%	-6.5%
PVNSG	Estimated actual (MW)	469	280	298	14	431	1,492
	Central forecast (MW)	529	311	302	11	533	1,687
	Central forecast error (%)	13.0%	11.3%	1.5%	-19.1%	23.5%	13.1%
Total	Estimated actual (MW)	7,486	6,622	2,741	331	5,087	22,266
	Central forecast (MW)	6,775	6,206	2,608	291	5,226	21,105
	Central forecast error (%)	-9.5%	-6.3%	-4.9%	-12.3%	2.7%	-5.2%

Note: Actuals are based on AEMO's latest actual data as of 10 October 2024.

For all NEM regions (except Victoria, where the error was close to zero), rooftop PV forecasts were under-forecast, with growth in average system size not slowing down as expected, leading to higher total forecast capacity. As installed rooftop PV capacity is negatively correlated with operational consumption, maximum demand, and minimum demand in particular, these forecasts may be lower as a result. PV forecasts included in the 2024 ESOO, which are currently being consulted on for the Draft 2025 *Inputs, Assumptions, and Scenarios Report* (IASR)[28], have been subject to an upward revision for all scenarios relative to those applied in the 2023 ESOO, recognising and adjusting for the under-forecast.

PVNSG is a much smaller market than rooftop PV. As shown in the table, PVNSG was over-forecast in all regions except Tasmania, which was under-forecast. The actual figures, however, are subject to likely upward revision as the administrative process for recognising additional power stations lags physical installations. The under-forecast

[25] CSIRO: *Small-scale solar and battery projections 2022* (December 2022), at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/csiro-2022-solar-pv-and-battery-projections-report.pdf.

[26] Green Energy Markets: *Final Projections for distributed energy resources – solar PV and stationary energy battery systems* (December 2022), at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/gem-2022-solar-pv-and-battery-projection-report.pdf.

[27] This choice was described and consulted upon with stakeholders via the *Forecasting Assumptions Update* report.

[28] See https://aemo.com.au/consultations/current-and-closed-consultations/2025-iasr.

in Tasmania responds to the very low number of installed PVNSG systems (and capacity) in that region, which makes its trajectory more volatile and harder to predict.

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 2023 ESOO forecasts, relative to the actuals recorded in June 2024. Fleet size is defined as the count of EVs[29] currently on the road, while fleet share is the percentage of the total road fleet, which includes battery EVs (BEVs) and plug-in hybrid EVs (PHEVs).

The 2023 forecasts underestimated actual fleet size figures across all NEM regions, by around 30% despite a material increase in the central forecast, however the impact on energy consumption and demand forecasts remains negligible.

Table 6 Electric vehicle (BEV and PHEV) fleet size and fleet share by region, as of 30 June 2024

As of 30 June 2024		NSW	QLD	SA	TAS	VIC	NEM
Fleet size	Estimated actual*	86,788	51,943	14,543	4,008	65,020	222,302
	Central forecast	62,249	34,583	9,883	2,737	45,548	155,001
	Central forecast error (%)	-28%	-33%	-32%	-32%	-30%	-30%
Fleet share	Estimated actual	1.3%	1.1%	0.9%	0.8%	1.1%	1.2%
	Central forecast	1%	0.8%	0.7%	0.6%	0.9%	0.9%
	Central forecast error (%)	-23%	-25%	-26%	-29%	-18%	-22%

Note: For 2023 ESOO forecasts, at the national level, the historical data to end of financial year 2023 aligns with data published by the Electric Vehicle Council (2023) and the Federal Chamber of Automotive Industries (FCAI), June 2023 update (at https://www.fcai.com.au/get-vfacts/). For 2024 actuals, at the state level, the historical data to end of 2023-24 aligns with data published by the AAA EV index (https://www.aaa.asn.au/research-data/electric-vehicle/). Additional data is also sourced from FCAI (2024) to break down some technology types and from BITRE (2024) for postcode level information (https://www.bitre.gov.au/).

AEMO notes that the rate of EV sales has changed dramatically in recent years, indicating the 'knee-point' occurred around 2021-2022, short term trend-based models are expected to be more effective going forward.

3.5 Network losses

Network losses refers 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

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

transmission and distribution losses are sourced from either the Regulatory Information Notice submitted 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 2023-24. As shown in **Table 7**, transmission losses for New South Wales, South Australia, and Victoria are slightly higher than was forecast for the 2023 ESOO, while for Queensland and Tasmania it is slightly lower. Forecast of distribution losses were higher than the actual estimated losses for all regions.

Table 7 Estimated network loss factors

	Transmission loss factor		Distribution loss factor	
	Applied to 2023 forecast	Used to estimate actuals for 2023-24	Applied to 2023 forecast	Used to estimate actuals for 2023-24
New South Wales	2.40%	2.82%	4.10%	4.07%
Queensland	2.35%	2.32%	4.88%	4.30%
South Australia	3.31%	3.57%	6.90%	5.76%
Tasmania	2.80%	2.49%	4.00%	3.28%
Victoria	2.14%	2.24%	4.59%	4.45%

Using the latest reported network losses as estimates for 2023-24 contributed to -0.4% variance overall for the NEM in the 2023 ESOO consumption forecast (see **Table 9** in **Section 4**) meaning actual estimated losses were higher than forecast. The biggest impact was in New South Wales, where losses contributed to -0.9% forecast consumption variance, and accounted for three-quarters of the under-forecast impact at the NEM level.

4 Operational energy consumption forecasts

AEMO forecasts annual operational energy consumption by region on a financial year basis. **Figure 6** shows central forecasts prepared from 2019 to 2024, for each region, relative to history. 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, because of re-baselining the underlying business mass market (BMM) forecast with revised historical actuals data thereafter[30]. This section focuses on the 2023 ESOO forecasts, unless otherwise stated.

Figure 6 Recent annual energy consumption forecasts by region

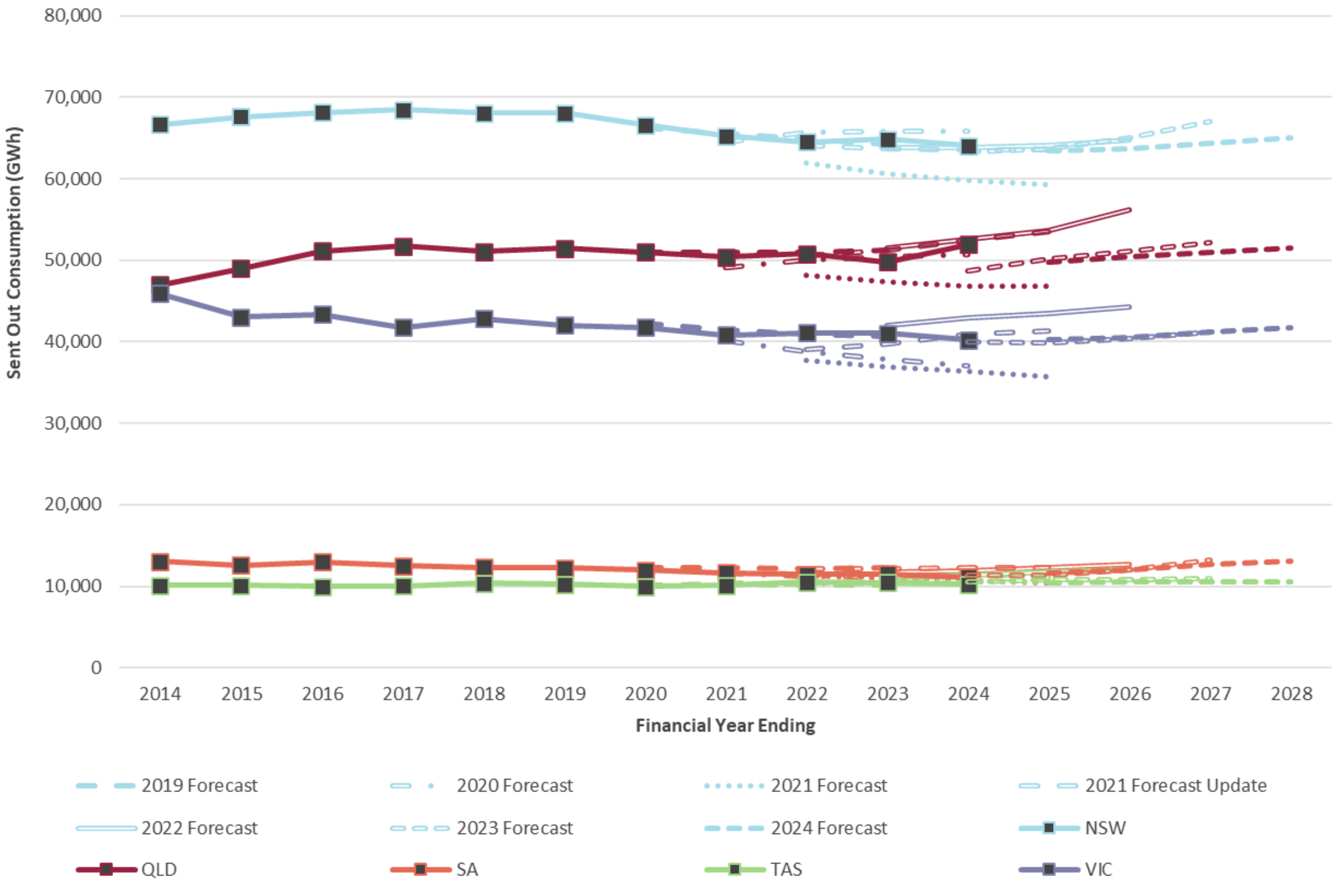


Table 8 shows the performance of the last five central forecasts against the year that followed, each being assessed one year ahead using the percentage error calculation outlined in **Section 2.1.** In the last five years, the percentage errors for forecasts in the individual regions were mostly within ±3% except for the 2021 ESOO. The largest variation between the 2022 and 2023 ESOO forecasts was in Queensland, with a 3.4% overestimate in

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

2022 and a 6.1% underestimate in 2023. Tasmania also had a relatively large forecast error with a 6.3% overestimate in 2022, and a 3.7% overestimate in 2023. The NEM weighted average percentage error has also flipped from a 1.4% overestimate to a - 2.0% underestimate in the 2023 ESOO. Prior NEM weighted average forecasts were mostly within a range of ±1.5%, except for the initial 2021 ESOO which had an error of -5.0%. This error subsequently reduced to -1.1% with improvements made in the Update to the 2021 ESOO.

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

One-year ahead annual operational consumption accuracy (%)	2019 ESOO forecast in 2019-20	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
New South Wales	-0.6%	-1.1%	-3.9%	-0.7%	-1.7%	-1.3%
Queensland	0.0%	-2.4%	-5.2%	-0.3%	3.4%	-6.1%
South Australia	2.6%	-0.3%	-0.8%	6.5%	2.7%	2.0%
Tasmania	2.2%	2.4%	-1.4%	-0.3%	6.3%	3.7%
Victoria	1.3%	-1.7%	-8.4%	-5.0%	2.3%	-0.5%
NEM	**0.4%**	**-1.3%**	**-5.0%**	**-1.1%**	**1.4%**	**-2.0%**

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

Table 9 shows the sources of variance for the 2023-24 consumption forecast of the NEM as published in the 2023 ESOO. 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, which has become influential for the 2023 ESOO, and is discussed later.

The largest known contributors to forecast error are the over-forecast for LILs (4.8%) and under-forecast for rooftop PV (-4.7%). The absolute size of consumption from these two components means that the size of the impact is 1.1% for the LIL over-forecast and 0.6% for rooftop PV, relative to operational as generated total consumption. The 2023-24 financial year was Australia's second warmest on record[31], contributing to an under-forecast for cooling degree days (-5.9%) and over-forecast for heating degree days (9.1%). For the NEM, relative variance in heating and cooling requirements have less of an impact on consumption forecasts than variance in LILs and solar PV.

Table 9 NEM operational energy consumption forecast accuracy by component

Category	2023 forecast (gigawatt hours [GWh])	Actual (GWh)	Difference (%)	Indicative impact on total consumption
Rooftop PV*	23,145	24,276	-4.7%	0.6%
PV non-scheduled generation*	2,557	2,507	2.0%	0.0%
Other non-scheduled generation*	4,574	4,351	5.1%	-0.1%
Cooling Degree Days	4,779	5,080	-5.9%	-0.2%
Heating Degree Days	8,309	7,618	9.1%	0.4%
Connections Growth	697	568	22.7%	0.1%

[31] Bureau of Meteorology, Financial year climate and water statement 2023-24, at http://www.bom.gov.au/climate/current/financial-year/aus/summary.shtml. Accessed 6 November 2024.

Category	2023 forecast (gigawatt hours [GWh])	Actual (GWh)	Difference (%)	Indicative impact on total consumption
Large industrial loads	45,432	43,339	4.8%	1.1%
Liquefied natural gas (LNG)	6,814	7,017	-2.9%	-0.1%
Network losses	9,604	10,368	-7.4%	-0.4%
Operational sent out	**173,925**	**177,560**	**-2.0%**	**-2.0%**
Auxiliary load	8,127	7,930	2.5%	0.1%
Operational as generated	**182,051**	**185,491**	**-1.9%**	

* 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.

Figure 7 shows the contribution of the components in **Table 9** in explaining the difference in forecast and actual operational as generated consumption.

As component variances may net out at the NEM level, region-specific variances are important to interpret forecast accuracy. The rest of this section details the regional breakdown of these components (see **Figure 7**). In summary:

- Cooling degree days, which influences the forecast cooling load, were above forecast in New South Wales and Queensland, and below forecast in South Australia and Victoria. All regions had lower than forecast heating load as represented by heating degree days due to the high area-average temperatures for 2023-24[32].
- NMI connections growth was over-forecast for 2023-24 partly due to elevated material costs, interest rates that have remained high relative to recent history, and high labour costs in some areas, that are negatively impacting the construction industry[33].
- LILs were over-forecast in all regions. The over-forecast in order of size was New South Wales (1.4%), Queensland (2.4%), South Australia (3.2%), Tasmania (5.3%), and Victoria (19.9%). These variances are typically explained by unplanned outages and lower production rates for existing loads. The large variance in Victoria was due to Portland Aluminium Smelter continuing to produce at a low rate[34] that was not advised as part of the forecast preparation, combined with committed projects that did not begin operating in 2023-24.
- Forecasts for liquefied natural gas (LNG) electricity consumption from in Queensland were slightly lower (- 2.9%) than actual consumption.
- Network losses were under-forecast except for South Australia and Tasmania, which typically observe the least losses of the NEM regions. The under-forecast was highest in New South Wales (-14.6%) which was influenced by significant upward revision in the transmission loss factor from 2.4% to 2.8% (see **Section 3.5**).
- Generator auxiliary loads were over-forecast in all states except for New South Wales. The variance in the auxiliary load forecast was due to variance in generation forecasts as well as updated auxiliary ratio estimates,

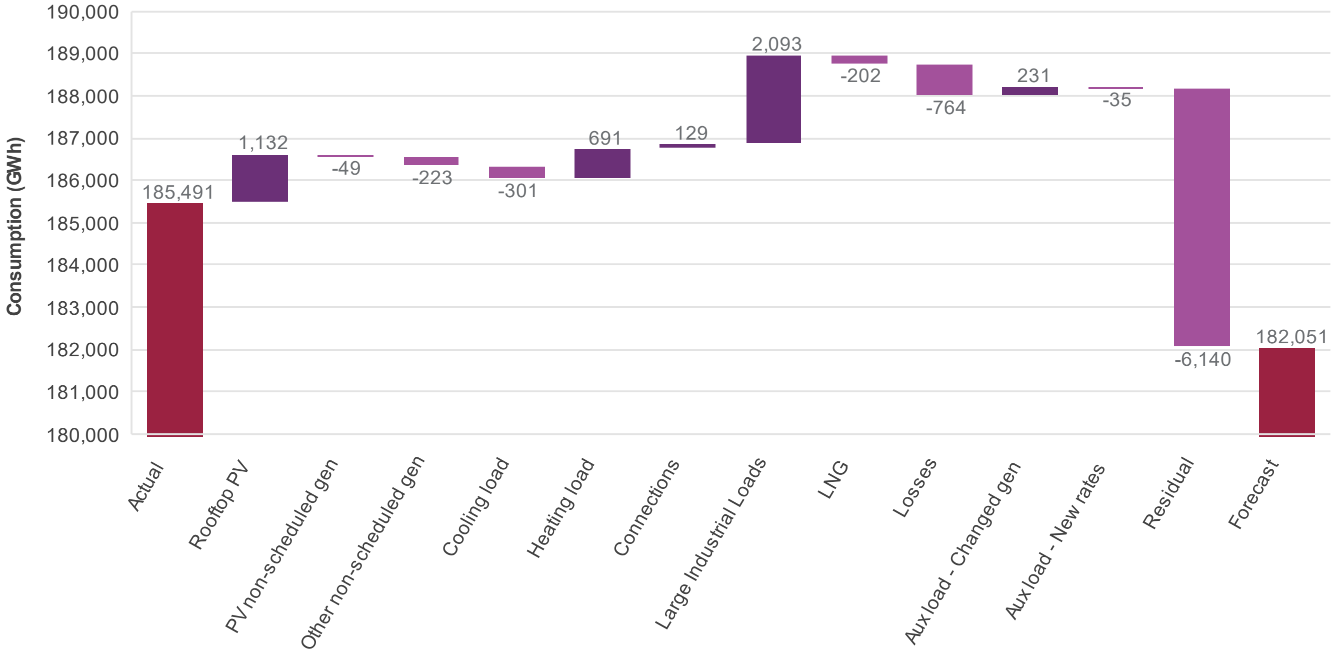
[32] Bureau of Meteorology, Financial year climate and water statement 2023-24, at http://www.bom.gov.au/climate/current/financial-year/aus/summary.shtml. Accessed 6 November 2024. Area in this context refers to Australian states and territories.

[33] Source: Reserve Bank of Australia, Statement on Monetary Policy, August 2024, at https://www.rba.gov.au/publications/smp/2024/aug/pdf/statement-on-monetary-policy-2024-08.pdf. Accessed 31 October 2024.

[34] Alcoa press release, 15 March 2023, Portland Aluminium joint venture in Australia to reduce production, https://news.alcoa.com/press-releases/press-release-details/2023/Portland-Aluminium-joint-venture-in-Australia-to-reduce-production/default.aspx. Accessed 25 November 2024.

which are revised from year to year. The impact of auxiliary load forecast was generally a small contributing factor to operational as generated forecasts, as shown in **Table 9.**

Figure 7 NEM operational as generated energy consumption variance by component



The components in **Table 9** represent the known sources of variance that can be isolated in forecast and actual consumption data. But there are multiple other components that cannot be isolated. **Figure 7** includes a residual variance category which represents the variance that is not explained by any of the measured components**.** The residual variance includes electrification that differs from what is derived from AEMO's models, other weather effects (such as humidity), sectoral specific activity levels not captured by economic inputs, and other factors not otherwise accounted for by the known forecast components. For the 2023 ESOO, electricity consumption attributable to the components that AEMO models suggests that actual consumption would be lower, but it was higher. The residual factor was equivalent to -3.3% of operational as generated consumption, a relatively large increase from the -0.4% residual from the previous *Forecast Accuracy Report*.

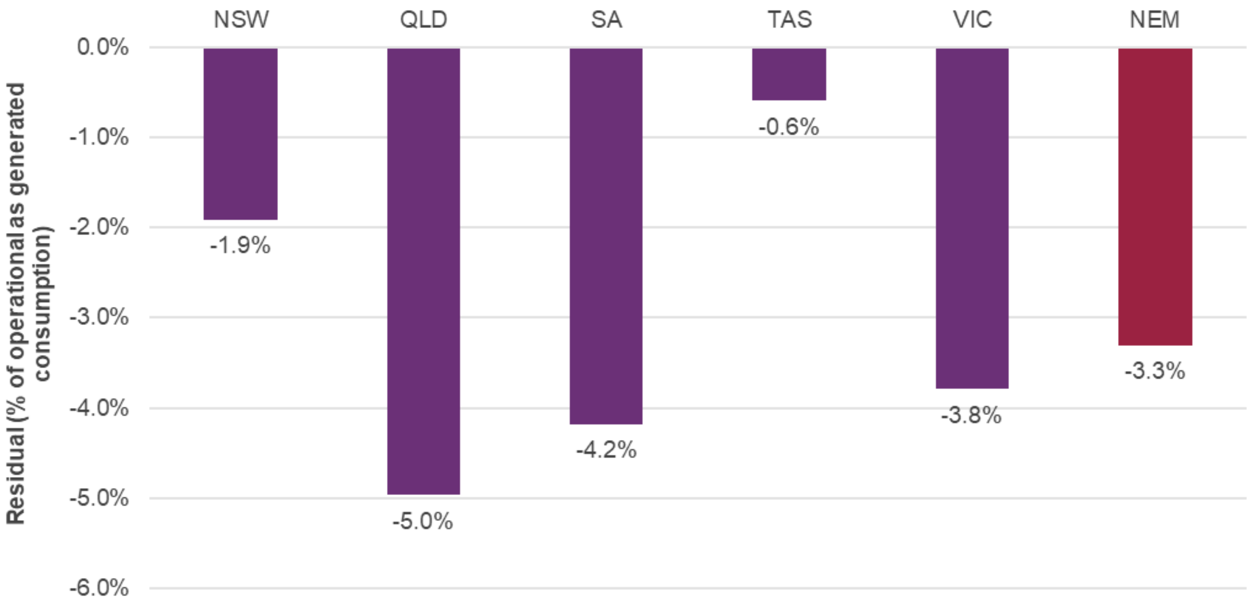
Figure 8 shows the size of this 2023 ESOO residual component relative to operational as generated consumption for each of the NEM regions. AEMO is committed to investigate the sources of this unknown variance to improve future consumption forecasts, as detailed in the Forecast Improvement Plan in **Section 8**. Without focusing on specific magnitudes, preliminary examination of candidate sources of residual variance reveals some insights:

- Residential heating and cooling consumption currently relies on temperature data. The explanatory power of these models may not be adequately accounting for the impact of humidity. For Queensland in particular, AEMO's estimate of actual cooling load may be an underestimate due to the high humidity levels observed[35]. A revision to actual cooling load that incorporated humidity may lead to higher actual consumption and a lower residual.

[35] AEMO analysis of relative humidity, wet bulb temperature, and 'real feel' estimates indicates that Queensland was subject to elevated heat impacts in 2023-24.

- Preliminary analysis suggests that increased BMM consumption in Queensland is higher than AEMO models forecast, due to an unanticipated up-tick in business connections. This up-tick has been corroborated by recent data from the AER and is a strong candidate to explain a portion of Queensland's residual[36].
- Electrification of different sectors is modelled and incorporated into ESOO consumption forecasts. 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.
- Energy efficiency estimates may be being overstated for certain sectors and contributing to lower consumption forecasts, if policy- and market-led improvements are lower than assumed.
- The under-forecast of EVs as discussed in **Section 3.4** is currently captured in the residual term rather than as a known source of variance. This impact is not assessed in isolation, as the assumptions used to calculate estimated actual electricity consumption attributable to EV charging (for example, consumption per vehicle) may change over time.

Figure 8 Residual variance in operational as generated consumption forecasts for NEM regions, 2023-24



Section 8 Forecast Improvement Plan discusses potential improvements. The remainder of this section focuses on each of the NEM regions.

4.1 New South Wales

Operational as generated energy consumption for New South Wales was under-forecast by -1.5% in 2023-24. **Table 10** and **Figure 9** show forecast accuracy by component. The largest source of measured variance was the under-forecast of network losses (-14.6%), with the variance equivalent to -0.9% of total consumption. The

[36] AER, Schedule 2 – Quarter 4 2023-24 retail performance data, at: https://www.aer.gov.au/documents/schedule-2-quarter-4-2023-24-retail-performance-data. Accessed 12 December 2024.

under-forecast of rooftop PV (-5.6%) and other non-scheduled generation (-25.8%) was also influential. **Section 3.3** provides more details for rooftop PV and PVNSG generation analysis.

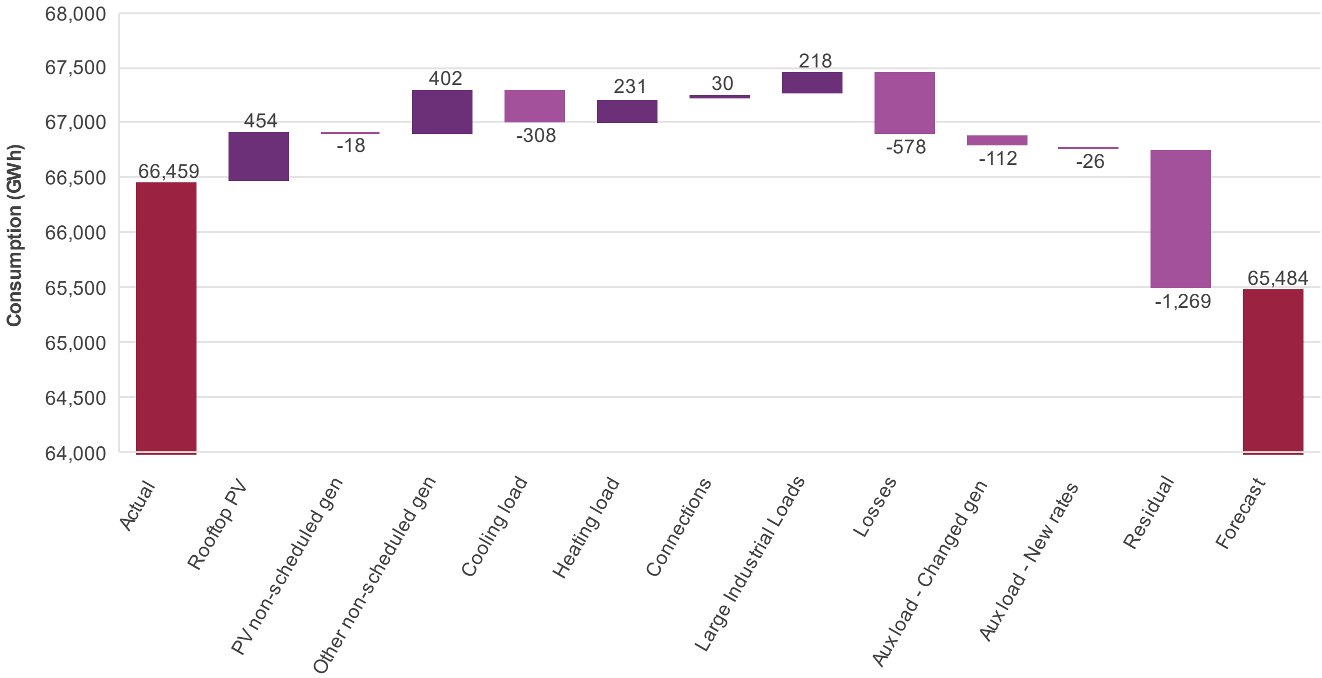
Higher than average temperatures in New South Wales also contributed to more cooling degree days (14.2% under-forecast) and less heating degree days (7.2% over-forecast). LIL forecasts for New South Wales were only 1.5% higher than actual consumption, which is a relatively accurate outcome for this influential component of the forecasts. Connections growth was one of the least accurate forecast components for New South Wales (15.1% over-forecast), though the relatively large variance proved inconsequential to the total forecast. See **Section 3.2** for more detail on connections growth.

Taken together, the measured components contributed to a 0.4% over-forecast, and yet, operational as generated consumption for New South Wales was under-forecast in 2023-24. Residual, or unexplained variance, was equivalent to -1.9% of consumption (-1,269 GWh as shown in **Figure 9**). As mentioned above, the residual is due to a combination of unidentifiable factors such as electrification. AEMO is endeavouring to isolate more components of the forecast that are currently captured by the residual, to improve forecast accuracy assessment.

Table 10 New South Wales operational energy consumption forecast accuracy by component

Category	2023 forecast (GWh)	Actual (GWh)	Difference (%)	Indicative impact on total consumption
Rooftop PV	7,593	8,048	-5.6%	0.7%
PV non-scheduled generation	757	739	2.4%	0.0%
Other non-scheduled generation	1,155	1,557	-25.8%	0.6%
Cooling degree days	1,861	2,169	-14.2%	-0.5%
Heating degree days	3,465	3,234	7.2%	0.4%
Connections growth	225	195	15.1%	0.0%
Large industrial loads	15,355	15,138	1.4%	0.3%
Network losses	3,383	3,961	-14.6%	-0.9%
Operational sent out	63,238	**64,076**	**-1.3%**	**-1.3%**
Auxiliary load	2,246	2,383	-5.8%	-0.2%
Operational as generated	65,484	**66,459**	**-1.5%**	

Figure 9 New South Wales operational as generated energy consumption variance by component



4.2 Queensland

From an overall impact perspective of the measurable components for Queensland (the last column of **Table 11**), AEMO performed relatively well, with no individual component outside ±1% in impacting forecast accuracy. Despite this relatively strong performance for the individual components, the residual was equivalent to -5.0% of operational as generated consumption (-2,723 GWh as shown in **Figure 10**), with AEMO providing an under-forecast equivalent to -5.6% of operational as generated consumption.

The residual variance for Queensland of -5.0% is large, contributing significantly to the similarly large residual variance of -3.3% for the broader NEM. Preliminary analysis by AEMO suggests that increased consumption from BMM customers and weather effects not currently captured by the consumption models (such as humidity) could explain part of this variance. AEMO is committed to understanding these sources of variance in future forecast accuracy publications, as discussed in **Section 8**.

As was the case with other NEM regions, higher average temperatures in 2023-24 (fourth-highest average temperatures for Queensland on record) contributed to more cooling degree days (-6.5% under-forecast) and less heating degree days (26.3%)[37]. As discussed above, cooling load may be higher than forecast due to evidence of elevated humidity levels in Queensland for 2023-24 leading to greater consumption at high temperatures, and potentially greater consumption at lower temperatures experiencing high humidity levels as well. Future inclusion of explanatory variables that account for humidity may mean cooling load variance would be better captured by the cooling degree days component, rather than the residual.

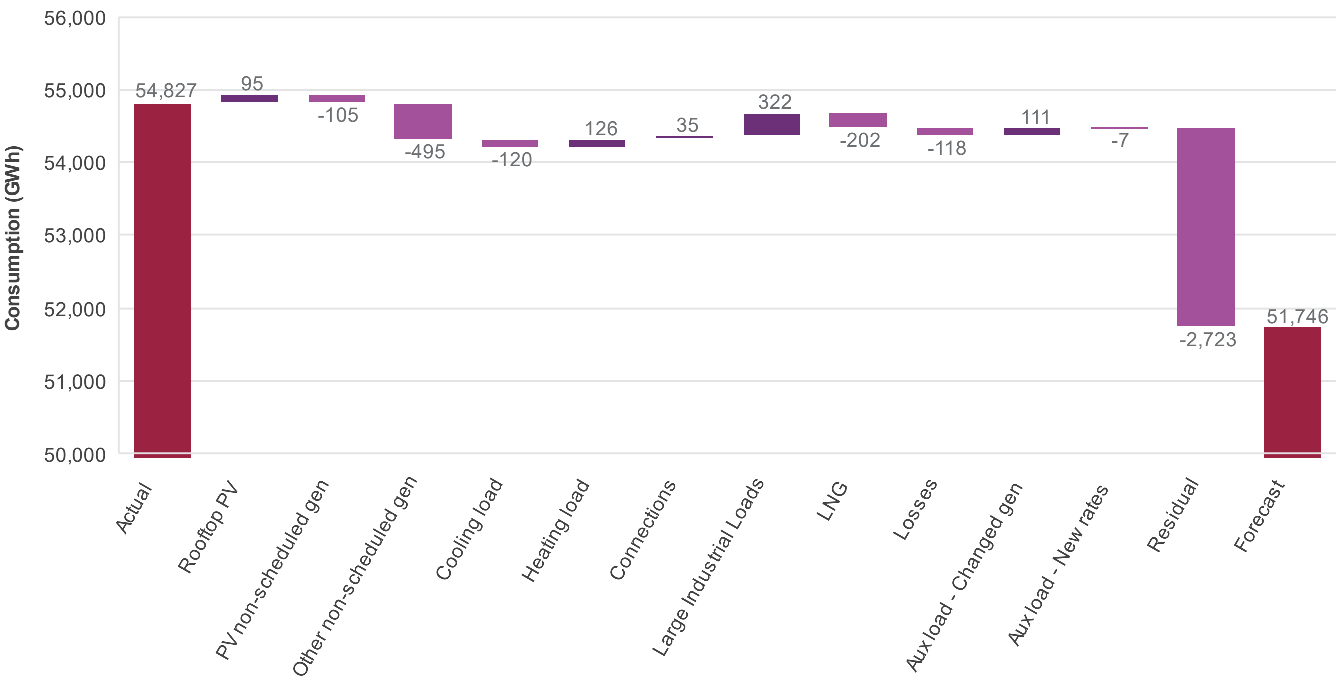
[37] Bureau of Meteorology, Financial year climate and water statement 2023-24, at http://www.bom.gov.au/climate/current/financial-year/aus/summary.shtml. Accessed 6 November 2024.

Similar to New South Wales, connections growth was significantly over-forecast in Queensland (25.6%) (refer to **Section 3.2** on connections growth), though the magnitude of impact on total consumption was relatively minor (0.1%).

Table 11 Queensland operational energy consumption forecast accuracy by component

Category	2023 forecast (GWh)	Actual (GWh)	Difference (%)	Indicative impact on total consumption
Rooftop PV	7,480	7,575	-1.3%	0.2%
PV non-scheduled generation	569	463	22.7%	-0.2%
Other non-scheduled generation	2,045	1,550	31.9%	-0.9%
Cooling degree days	1,725	1,845	-6.5%	-0.2%
Heating degree days	604	479	26.3%	0.2%
Connections growth	174	138	25.6%	0.1%
Large industrial loads	13,576	13,254	2.4%	0.6%
LNG	6,814	7,017	-2.9%	-0.4%
Network losses	2,534	2,651	-4.4%	-0.2%
Operational sent out	48,739	**51,923**	**-6.1%**	**-5.8%**
Auxiliary load	3,007	2,904	3.6%	0.2%
Operational as generated	51,746	**54,827**	**-5.6%**	

Figure 10 Queensland operational as generated energy consumption variance by component



4.3 South Australia

South Australia operational as generated consumption was over-forecast by 2.1% for 2023-24. Forecasts for the largest portion of consumption, LILs, were over-forecast by 3.2%, as shown in **Table 12**. An extended shutdown in March 2024 for Whyalla Steelworks led to consumption that was 85 GWh less than production advice that underpinned AEMO's forecast[38]. This accounts for most of the LIL over-forecast (see **Figure 11**), with the remainder caused by varying but minor levels of over- and under-forecasts for other LILs in South Australia.

Rooftop PV (under-forecast by -9.4%) and heating degree days (over-forecast by 19.1%) were the largest sources of known variance for South Australia. The over-forecast of heating degree days is to be expected for a high average temperature year. All other component variance had less than ±1% influence on operational as generated consumption.

Even though South Australia also recorded high average temperatures for 2023-24 (fourth-highest on record), cooling degree days were over-forecast (8.7%). This is at odds with similar temperature records in New South Wales and Queensland that resulted in cooling degree days being under-forecast. Mean temperatures for Adelaide and the Great Australian Bight, where most people in South Australia live, were not as high as for the rest of the state, which could explain at least part of this anomaly[39].

As is the case for all regions in the 2023 ESOO, the residual for South Australia was influential, equivalent to -4.2% of operational as generated consumption. Analysis by AEMO indicates that a steady shift from gas to electric heating is occurring in South Australia, and this may account for a portion of the residual. The size of the residual emphasises the need to focus on determining potential sources to assist with improving forecast accuracy. See the Forecast Improvement Plan in **Section 8** for proposed improvements.

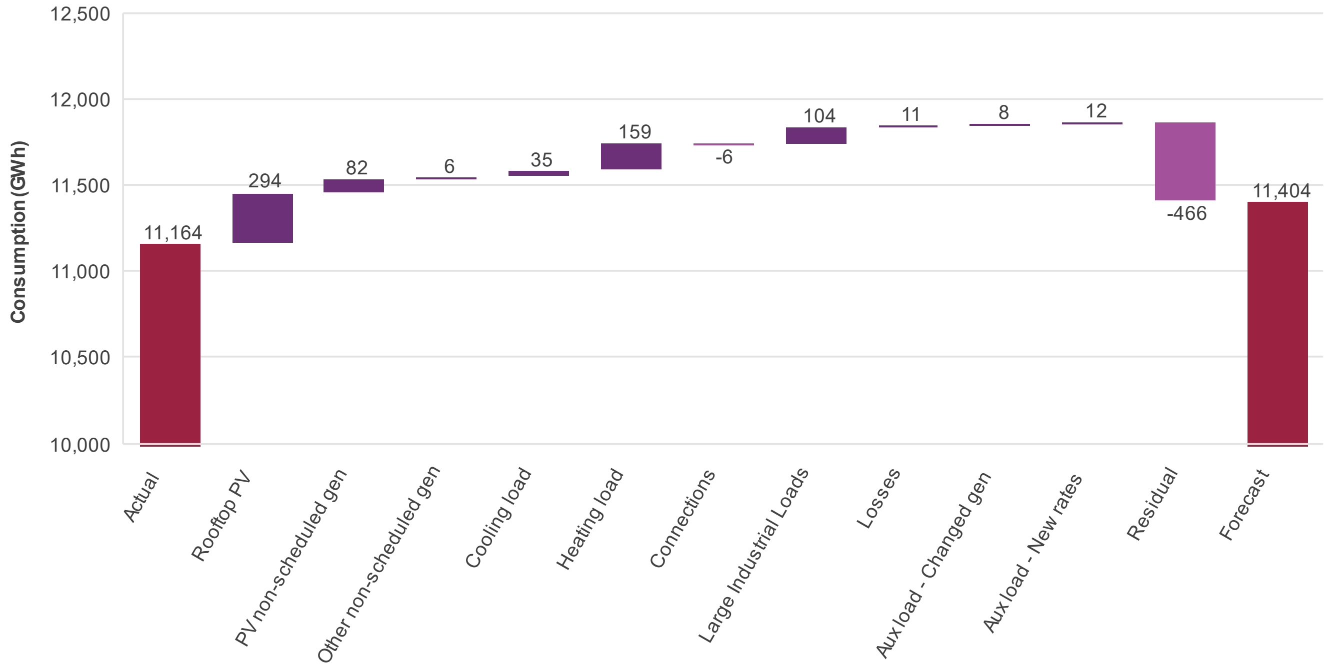
Table 12 South Australia operational energy consumption forecast accuracy by component

Category	2023 forecast (GWh)	Actual (GWh)	Difference (%)	Indicative impact on total consumption
Rooftop PV	2,835	3,129	-9.4%	2.6%
PV non-scheduled generation	507	589	-13.9%	0.7%
Other non-scheduled generation	64	71	-9.1%	0.1%
Cooling degree days	441	406	8.7%	0.3%
Heating degree days	990	831	19.1%	1.4%
Connections growth	39	45	-13.0%	-0.1%
Large industrial loads	3,351	3,247	3.2%	0.9%
Network losses	890	880	1.2%	0.1%
Operational sent out	11,314	**11,095**	**2.0%**	**2.0%**
Auxiliary load	90	69	29.5%	0.2%
Operational as generated	11,404	**11,164**	**2.1%**	

[38] GFG Alliance press release, 7 July 2024, Steelmaking resumes with an expert GFG Alliance team securing the recovery of the Whyalla blast furnace, at https://www.gfgalliance.com/media-release/steelmaking-resumes-with-an-expert-gfg-alliance-team-securing-the-recovery-of-the-whyalla-blast-furnace/. Accessed 25 November 2024.

[39] Bureau of Meteorology, Financial year climate and water statement 2023-24, at http://www.bom.gov.au/climate/current/financial-year/aus/summary.shtml. Accessed 6 November 2024.

Figure 11 South Australia operational as generated energy consumption variance by component



4.4 Tasmania

The known components that contribute to Tasmania's forecast variance were relatively benign, impacting total operational as generated consumption by less than ±1%, except for LILs (see **Table 13**). The over-forecast for LILs (5.3%) was equivalent to 3.1% of operational as generated consumption, and almost all the variances may be attributed to an extended shutdown of one facility, that was not advised to AEMO at the time of compiling the 2023 ESOO forecasts.

The 2023-24 financial year was the hottest average temperature year ever recorded for Tasmania, resulting in the 13.6% over-forecast of heating degree days, equivalent to 0.8% of operational as generated consumption[40]. This source of variance was matched by the similarly over-forecast other non-scheduled generation, though its impact on operational as generated consumption was in the other direction (-0.8% as shown in **Figure 12**). All other component variances were relatively inconsequential to total consumption. However, the variance for some of these individual components was significant, for example connections growth.

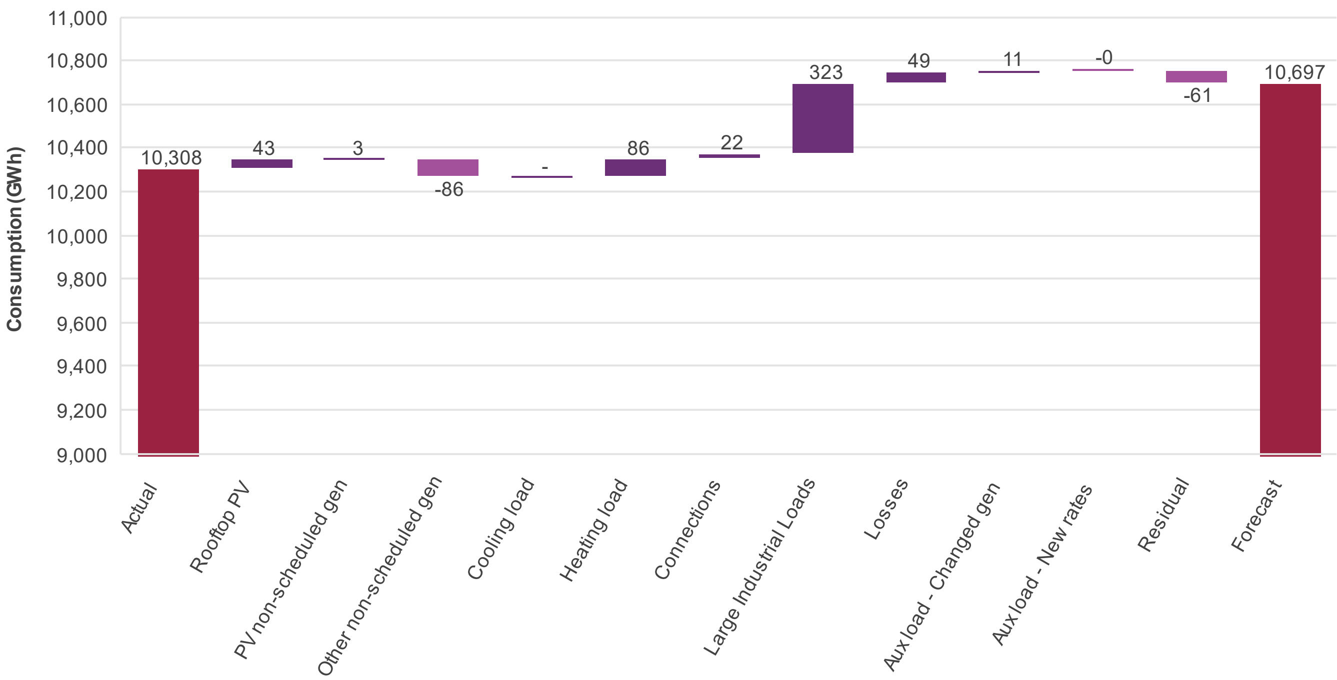
Tasmania's unknown residual variance was relatively minor, at only -0.6% of operational as generated consumption. However, when considering all known components and the unknown residual collectively, operational as generated consumption was over-forecast by 3.8%. Almost all of this variance may be attributed to the shutdown of one LIL facility. This represents an improvement to the 6.3% over-forecast in the 2022 ESOO, which itself was significantly contributed by LIL variance for a few facilities.

[40] Bureau of Meteorology, Financial year climate and water statement 2023-24, at http://www.bom.gov.au/climate/current/financial-year/aus/summary.shtml. Accessed 6 November 2024.

Table 13 Tasmania operational energy consumption forecast accuracy by component

Category	2023 forecast (GWh)	Actual (GWh)	Difference (%)	Indicative impact on total consumption
Rooftop PV	303	346	-12.4%	0.4%
PV non-scheduled generation	15	18	-15.6%	0.0%
Other non-scheduled generation	478	392	22.0%	-0.8%
Cooling degree days	0	0	0.0%	0.0%
Heating degree days	722	636	13.6%	0.8%
Connections growth	27	5	428.5%	0.2%
Large industrial loads	6,372	6,049	5.3%	3.1%
Network losses	468	419	11.7%	0.5%
Operational sent out	**10,603**	**10,226**	**3.7%**	**3.7%**
Auxiliary load	94	82	13.9%	0.1%
Operational as generated	**10,697**	**10,308**	**3.8%**	

Figure 12 Tasmania operational as generated energy consumption variance by component



4.5 Victoria

The forecast outcome for Victorian operational energy consumption in the 2023 ESOO was very close to actual consumption in 2023-24. Most of the known component sources of variance were within a ±0.6% influence on total consumption, though these were overshadowed by a significant LIL over-forecast of almost 20% (as shown in **Table 14**).

While the LIL over-forecast was large, unforeseen changes to industrial operations from a small number of facilities, that were not advised to AEMO at the time of compiling the 2023 ESOO, explain most of the over-forecast. Instability and production challenges at the Portland Aluminium Smelter contributed to 650 GWh lower electricity consumption than anticipated[41]. The Maryvale Paper Mill and other LILs also consumed significantly lower levels of electricity than expected at the time of compiling the forecasts[42].

The next most influential known components to forecast variance were an under-forecast in rooftop PV (-4.7%) and auxiliary load over-forecast (7.9%). Taken together, all known components contributed to an over-forecast of 3.8%. However, the unknown factors captured in the residual contributed to a -3.8% under-forecast, which meant that operational as generated forecast was equal to actual consumption (as shown in **Figure 13**). As was the case for almost all regions in the 2023 ESOO, the residual was large and influential in the forecasts. Additional work is required to isolate and understand the unknown factors that are proving influential in AEMO's consumption forecasts.

A likely candidate is that 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 electrification is happening at a faster rate than forecast, then estimates of actual cooling and heating load are under-estimated, contributing to a larger negative residual.

It should be noted that Victoria did not experience the same level of heat records as all other NEM regions[43]. For that reason, cooling degree days were over-forecast (14.0%). Heating degree days were also over-forecast, but to a lower level (3.6%). But again, actual cooling and heating load estimates may be on the low side if electricity intensity of cooling and heating is not appropriately capturing rapid electrification.

Table 14 Victoria operational energy consumption forecast accuracy by component

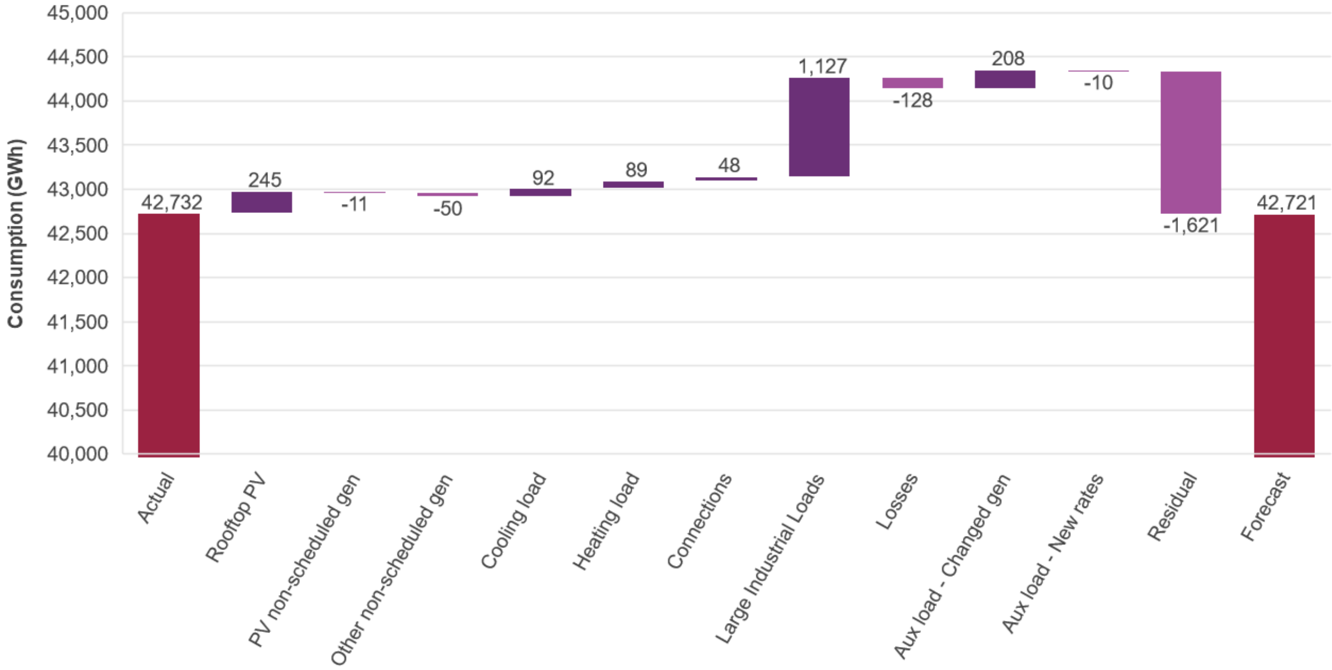
Category	2023 forecast (GWh)	Actual (GWh)	Difference (%)	Indicative impact on total consumption
Rooftop PV	4,934	5,179	-4.7%	0.6%
PV non-scheduled generation	709	698	1.5%	0.0%
Other non-scheduled generation	831	780	6.4%	-0.1%
Cooling degree days	752	660	14.0%	0.2%
Heating degree days	2,527	2,438	3.6%	0.2%
Connections growth	231	183	26.3%	0.1%
Large industrial loads	6,778	5,651	19.9%	2.6%
Network losses	2,329	2,457	-5.2%	-0.3%
Operational sent out	**40,030**	**40,240**	**-0.5%**	**-0.5%**
Auxiliary load	2,690	2,492	7.9%	0.5%
Operational as generated	**42,721**	**42,732**	**0.0%**	

[41] Alcoa press release, 15 March 2023, Portland Aluminium joint venture in Australia to reduce production, at https://news.alcoa.com/press-releases/press-release-details/2023/Portland-Aluminium-joint-venture-in-Australia-to-reduce-production/default.aspx. Accessed 25 November 2024.

[42] Opal press release, 6 February 2024, Maryvale Mill Update, at https://opalanz.com/news/maryvale-mill-update/. Accessed 25 November 2024.

[43] Bureau of Meteorology, Financial year climate and water statement 2023-24, at http://www.bom.gov.au/climate/current/financial-year/aus/summary.shtml. Accessed 6 November 2024.

Figure 13 Victoria operational as generated energy consumption variance by component



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.
- 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 coinciding with mild conditions which avoid high daytime heating or cooling appliance use.

Unlike the consumption forecast, which is a point forecast (a single estimate assuming typical weather conditions eventuate on average across the year), the minimum and maximum demand forecasts are represented by probability distributions. The minimum and maximum probability distributions are summarised for publishing via 10%, 50%, and 90% probability of exceedance (POE) forecast values. AEMO assesses the accuracy of those in accordance with the 2024 *Forecast Accuracy Report Methodology*[44].

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.
- Industrial operations.

While there is a strong relationship between weather and 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.

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[45].

[44] 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.

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

5.1 Extreme demand events in 2023-24

AEMO forecasts demand in the absence of load shedding, network outages, and any customer response to price and/or reliability signals, known as demand side participation (DSP). DSP is explicitly modelled as a supply option to meet forecast demand, as detailed in **Section 5.7.**

A maximum demand day observed during summer may have occurred at a time of supply shortages, leading to load shedding, or very high prices which may have led to demand response. Comparing actual observed demand with forecast values can only be done if compared on the same basis, so some adjustments to actual demand are necessary to accommodate these responses to align with the forecast definition.

For the purposes of assessing forecast accuracy, adjustments have been grouped into two types:

- Firm – adjustments estimated based on metering data.
- Potential – adjustments that are more speculative and are based on expected behaviour rather than metering data.

In 2023-24, only Queensland and Victoria were subject to minor adjustments for their summer maximum demand as follows (see **Table 15**):

- Queensland – a 110 MW firm adjustment was applied to account for the estimated impact of Energy Queensland's Peak Smart DSP program on Monday, 22 January 2024 being called during the half-hour maximum demand was reached. As a result, the adjusted maximum demand is 10,685 MW.
- Victoria – a total firm adjustment of 325 MW was applied to the maximum demand for 22 February 2024. This includes a 45 MW firm adjustment up applied due to AusNet Services' Critical Peak Demand program, which impacted the period 14:00 – 18:00 NEM time, and a 280 MW firm adjustment up resulting from Alcoa Portland Aluminium Smelter potline outage, bringing the total firm adjustment to 325 MW.

5.1.1 Summer 2023-24 maximum demand events

Table 15 shows the summer maximum demand periods for NEM regions in 2023-24, with slight adjustments for the mainland NEM regions (see above).

Table 15 Summer 2023-24 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	Thu, 29 February 2024, 17:00	13,643	403	13,240	-	-	13,240
QLD	Mon, 22 January 2024, 17:00	11,005	430	10,575	110	-	10,685
SA	Tue, 23 January 2024, 19:30	2,780	32	2,748	-	-	2,748
TAS	Thu, 22 February 2024, 17:30	1,325	17	1,308	-	-	1,308
VIC	Thu, 22 February 2024, 16:30	9,109	353	8,756	325	-	9,081

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

5.1.2 Winter 2024 maximum demand events

AEMO has also reviewed the winter maximum demand events to determine if any firm or potential adjustments were necessary. As indicated in **Section 5.7**, prices were generally too low at time of peak to trigger any price response. The winter maximum demand outcomes are shown in **Table 16** below.

Table 16 Winter 2024 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	Mon, 15 July 2024, 18:30	12,565	437	12,128	-	-	12,128
QLD	Wed, 17 July 2024, 18:30	8,867	397	8,470	-	-	8,470
SA	Tue, 25 June 2024, 18:30	2,549	32	2,517	-	-	2,517
TAS	Fri, 5 July 2024, 08:30	1,750	18	1,732	-	-	1,732
VIC	Mon, 15 July 2024, 18:00	8,612	375	8,237	-	-	8,237

5.1.3 Annual 2023-24 minimum demand events

AEMO has reviewed the minimum demand events across the year. All regions had daytime minimums, even Tasmania, which historically has had its annual minimum demand occurring overnight. Overall, the minimum demand days occur on weekends or arounds holidays when electricity consumption is relatively low, especially when the weather is mild and there is abundant sunlight, allowing rooftop PV to reach close to maximum output, but while temperature is not high enough to drive any significant cooling demand, or low enough to cause a need for heating.

In 2023-24, all regions except Tasmania reached their lowest minimum demand levels since the establishment of the NEM[46]. The minimum demand events are listed in **Table 17** by region.

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, 29 October 2023, 12:00	3,719	93	3,626	-	-	3,626
QLD	Sun, 18 August 2024, 13:00	3,096	208	2,888	-	-	2,888
SA	Sun, 31 December 2023, 13:30	-26	4	-30	-	-	-30
TAS	Sat, 23 September 2023, 13:30	869	5	864	-	-	864
VIC	Sun, 31 December 2023, 13:00	1,564	157	1,407	-	-	1,407

[46] Preliminary data suggests that new minimum demand records will likely be set for all regions except Tasmania in 2023-24.

5.2 New South Wales

Figure 14 shows the half-hourly time-series for New South Wales OPSO demand, and extreme demand events for the last year until the end of winter 2024. Further detail on the extreme demand events observed during the year is provided in **Table 18**.

Figure 14 New South Wales demand with extreme events identified

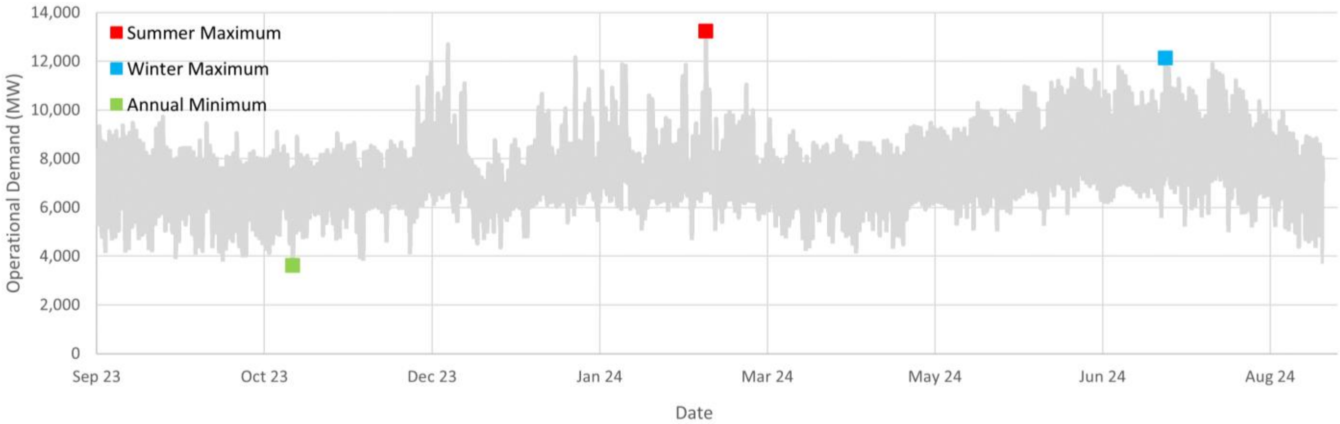


Table 18 New South Wales 2023-24 extreme demand events

Event	Summer maximum	Winter maximum	Annual minimum
NEM date and time	Thu, 29 February 2024, 17:00	Mon, 15 July 2024, 18:30	Sun, 29 October 2023, 12:00
Temperature* (°C)	36.8	10.9	25.4
Max temperature (°C)	39.0	14.9	27.1
Min temperature (°C)	21.3	4.3	8.7
Losses (MW)	855	777	201
Non-scheduled generation (NSG) output (MW)	382	203	477
Rooftop PV output (MW)	722	0	4,016
Sent out (OPSO)	**13,240**	**12,128**	**3,626**
Auxiliary (MW)	403	437	93
As generated (OPGEN)	**13,643**	**12,565**	**3,719**

* Bankstown Airport weather station. For more information please see Section 3.3.2 of the 2023 IASR (https://aemo.com.au/-/media/files/major-publications/isp/2023/2023-inputs-assumptions-and-scenarios-report.pdf).
^ Summer maximum demand is adjusted due to observed price-driven DSP.

Figure 15 shows the maximum and minimum demand event forecasts as a probability distribution of possible outcomes, while vertical lines show the actual observations for the past year. The forecast probability distribution reflects a range of likely outcomes, including variation arising from weather and customer behaviour. The summer maximum demand as well as annual minimum events both fell well within their respective forecast distributions, while the winter maximum demand event fell just below the forecast 90% POE.

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

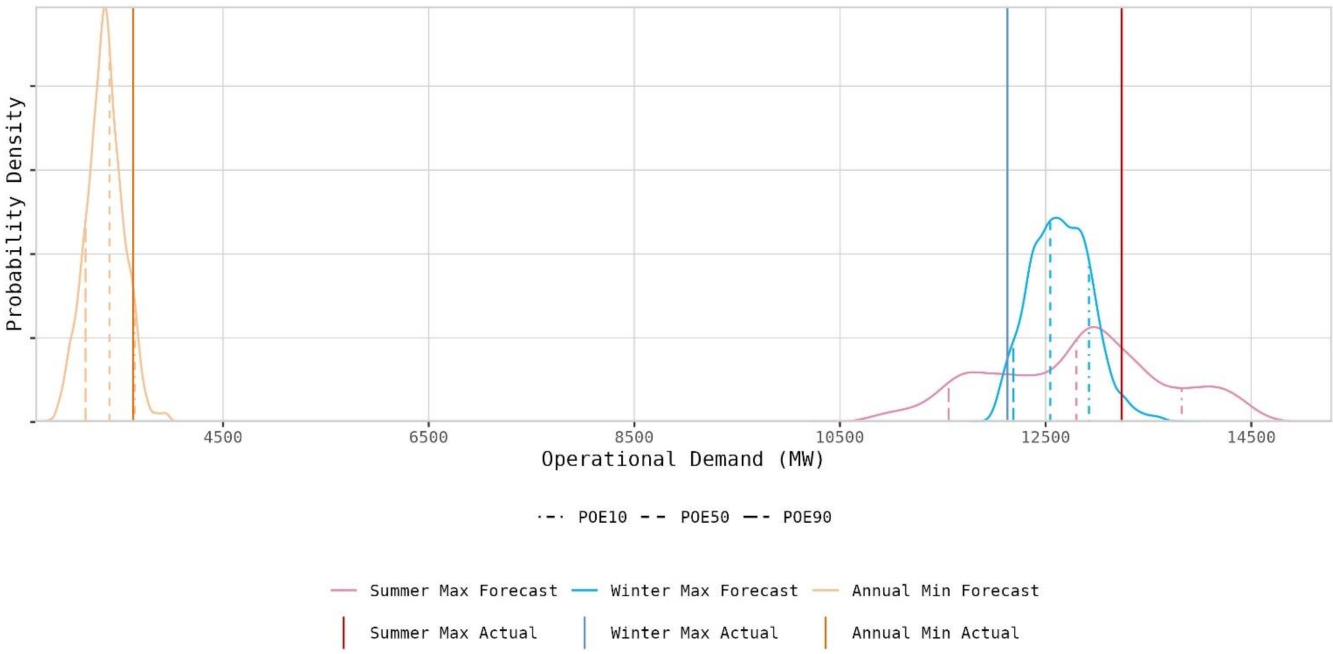


Figure 16 shows the probability distribution and actuals for relevant model inputs. A discussion of insights from these figures follows.

Summer maximum operational (sent out) demand occurred on Thursday, 29 February 2024 17:00 NEM time. At this time, Bankstown recorded a temperature of 36.8°C, with a daily maximum reaching 39°C.

- Overall, the summer maximum demand was within forecast expectations.
- The temperature at the time of the maximum demand was towards the upper end of the simulated temperature distribution for such events. This could be a factor contributing to the maximum demand exceeding the 50% POE. Additionally, New South Wales experienced an El Niño summer, which typically increases the likelihood of higher demand due to hotter conditions.
- On this day, electricity consumers experienced the third highest daily summer temperature starting with 29.4°C by 9 am NEM time, becoming 39°C by 1.30 pm, and remaining high at 36.8°C by 5 pm. The prolonged heat created significant cooling demand, leading to the maximum demand event.
- Simulations weighted maximum demand events towards January and February, which is consistent with the observed timing in late February. The occurrence of the event on a Thursday aligns with simulations showing that most maximum demand events happen on weekdays.
- The time of summer maximum demand event fell in the distribution, but slightly to the left. PV generation at time of maximum demand fell within the forecast PV generation distribution.

Winter maximum demand occurred on Monday, 15 July 2024 at 18:30 NEM time. Bankstown recorded a temperature of 10.9°C at the time, with a daily maximum of 14.9°C and a minimum of 4.3°C.

- The observed winter maximum fell just below the 90% POE forecast.

- Winter maximum demand events typically exhibit a narrow temperature range, with the highest density occurring in the range of 5-7.5°C. The observed temperature is towards the upper end of the simulated temperature range. During the winter months of 2024, New South Wales experienced temperatures that were generally above average. These milder-than-usual conditions contributed to reduced heating requirements, particularly for residential and commercial sectors, which are significant drivers of winter maximum electricity demand. Given these conditions, it is reasonable to attribute the observed maximum demand falling just below the 90% POE forecast to the unusually mild winter temperatures. The elevated temperatures during winter 2024 would have directly influenced energy consumption patterns, leading to lower-than-expected peaks and reflecting the sensitivity of demand forecasts to temperature variations.
- The maximum demand occurred at 18:30 NEM time, well after sunset, when PV generation was zero.
- 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 occurred on Sunday 29 October 2023 at 12:00 NEM time, with a temperature of 25.4°C.

- The actual minimum demand fell slightly below 10% POE forecasts. In general, p3.3redicting demand on weekends, especially during mild weather, is challenging, because firstly, unlike extreme maximum and minimum demand, temperature variations in the mild range do not have clear directional impact on demand and secondly, by their nature, weekends provide fewer data points over time than weekdays on which to assess demand drivers. The actual demand is influenced by several non-weather factors that cannot be modelled accurately due to a lack of available data, such as traffic patterns and appliance usage.
- Simulations weighted the minimum demand event towards occurring during weekends, with their lower commercial and industrial demand, and typically in October due to the mild temperatures, where there is less demand for either cooling and heating, and solar PV systems are not adversely affected by high temperatures, maintaining their efficiency. This is consistent with the actual occurrence of annual minimum demand on Sunday 29 October 2023.

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

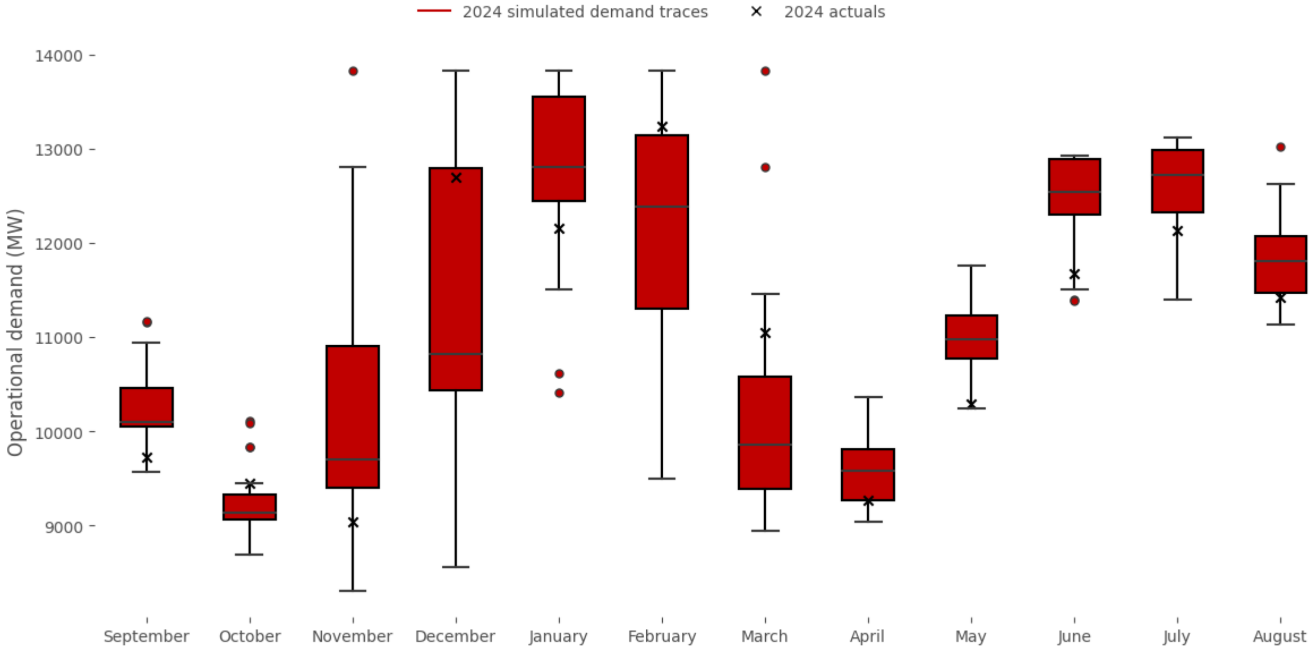
Monthly maximums

The operational energy consumption and extreme demand forecasts are used to develop profiles of 30-minute customer demand in time-series consistent with the weather patterns observed in 13 reference years (2010-11 to 2022-23), transformed to hit 10% POE and 50% POE demand forecasts, referred to as demand 'traces'. Each trace is independently scaled to achieve the summer and winter maximum demand forecasts at least once throughout summer and winter respectively. These traces are used in assessing reliability in the ESOO, the Energy Adequacy Assessment Projection (EAAP), and the Medium-Term Projected Assessment of System Adequacy (MT PASA).

Due to actual weather patterns in some months being warmer or cooler than the range of historical weather patterns observed across the reference years, it is reasonable to expect that a limited number of actuals may fall outside the range of monthly maximums of operational demand in the demand traces.

The box plot[47] in **0** illustrates the range of monthly demand maximums for the 2024 simulated demand traces[48] for 10% POE and 50% POE annual forecasts. 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. During both the summer and winter months, all actual monthly maximums fell within the simulated distribution range. However, notable trends were observed: the mild winter resulted in actual maximums consistently falling below the first quartile, reflecting weaker heating demand. In contrast, the El Niño conditions during summer likely contributed to actual maximums mostly occurring around the third quartile or higher, driven by elevated cooling demand.

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



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

[48] The simulated demand traces are provided on a maximum demand year basis, as defined in **Section 2.1.** The 2024 simulated demand traces cover the period from September 2023 to August 2024, inclusive.

5.3 Queensland

Queensland's half-hourly OPSO demand time-series and extreme events are shown below in . Further detail on the extreme demand events for the year is in **Table 19**.

Figure 18 Queensland demand with extreme events identified

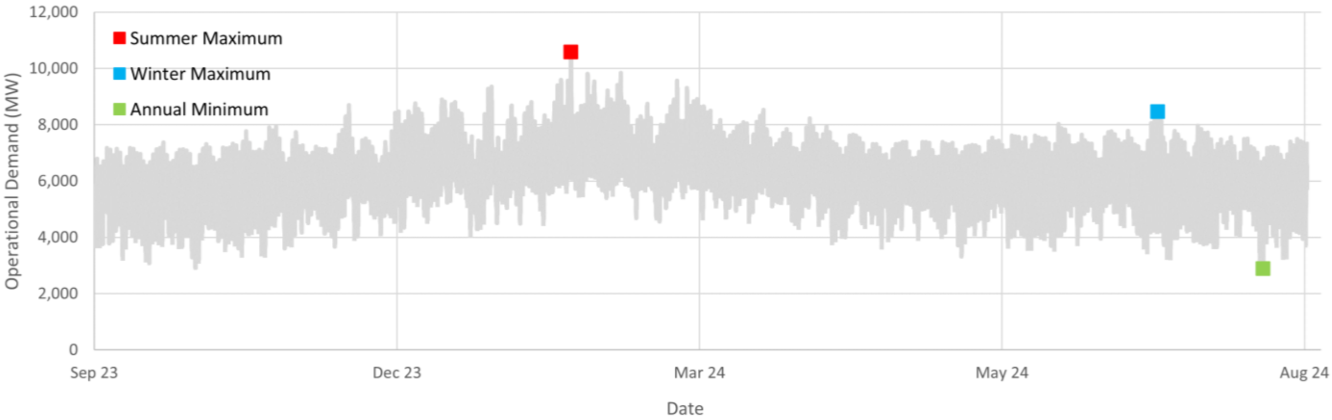


Table 19 Queensland 2023-24 extreme demand events

Event	Summer maximum	Winter maximum	Annual minimum
NEM Datetime	Mon, 22 January 2024, 17:00	Wed, 17 July 2024, 18:30	Sun, 18 August 2024, 13:00
Temperature* (°C)	28.1	12.3	23.6
Max temperature (°C)	37.4	16.5	24.8
Min temperature (°C)	24.3	7.9	9.1
Losses (MW)	605	476	103
NSG output (MW)	209	155	391
Rooftop PV output (MW)	715	0	3,830
Sent out (OPSO)	**10,575 (adjusted to 10,685)^**	**8,470**	**2,888**
Auxiliary (MW)	430	397	208
As generated (OPGEN)	**11,005 (adjusted to 11,115)^**	**8,867**	**3,096**

* Archerfield Airport weather station. For more information please see Section 3.3.2 of the 2023 IASR (https://aemo.com.au/-/media/files/major-publications/isp/2023/2023-inputs-assumptions-and-scenarios-report.pdf).
^ 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 shows the maximum and minimum demand event forecasts as a probability distribution of possible outcomes, while vertical lines show the actual observations for the past year. The winter maximum, and annual minimum events all fell within the forecast distribution range. However, the summer maximum demand fell above 10% POE.

Figure 19 Queensland simulated extreme event probability distributions with actuals

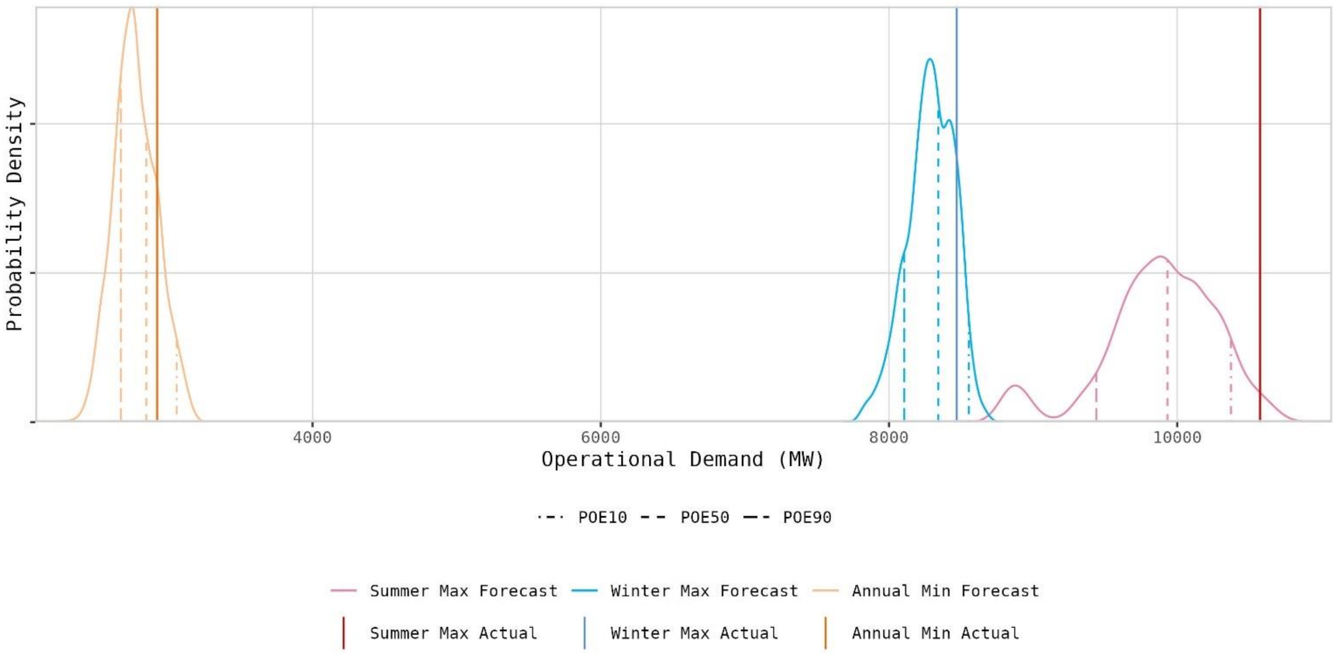


Figure 20 shows the probability distribution and actuals for relevant model inputs. A discussion of the insights from these figures follows.

Summer maximum demand occurred on Monday, 22 January 2024, at 17:00 NEM time. At the time of maximum demand, the temperature recorded at Archerfield reached 28.1°C, with a daily maximum of 37.4°C.

- The summer maximum demand fell just above the 10% POE, reflecting higher-than-median demand scenarios.
- After three consecutive years of La Niña conditions, Queensland experienced an El Niño summer, which typically brings hotter and drier conditions.
- However, contrary to expectations, the state faced unusually wet weather, with heavy downpours and multiple severe weather events unfolding since December.
- Humidity levels were notably high during this period. This high humidity contributed to oppressive conditions, making the heat feel more intense.
- This El Niño summer associated with high humidity could be a contributing factor to why the maximum demand has exceeded the 10% POE value.
- On the day the peak event recorded, the temperature started at 24.3°C in the morning and peaked at 37.4°C in the afternoon, creating sustained demand for cooling systems. This demand event aligns with simulation expectations, which weighted summer maximums toward January on weekdays.

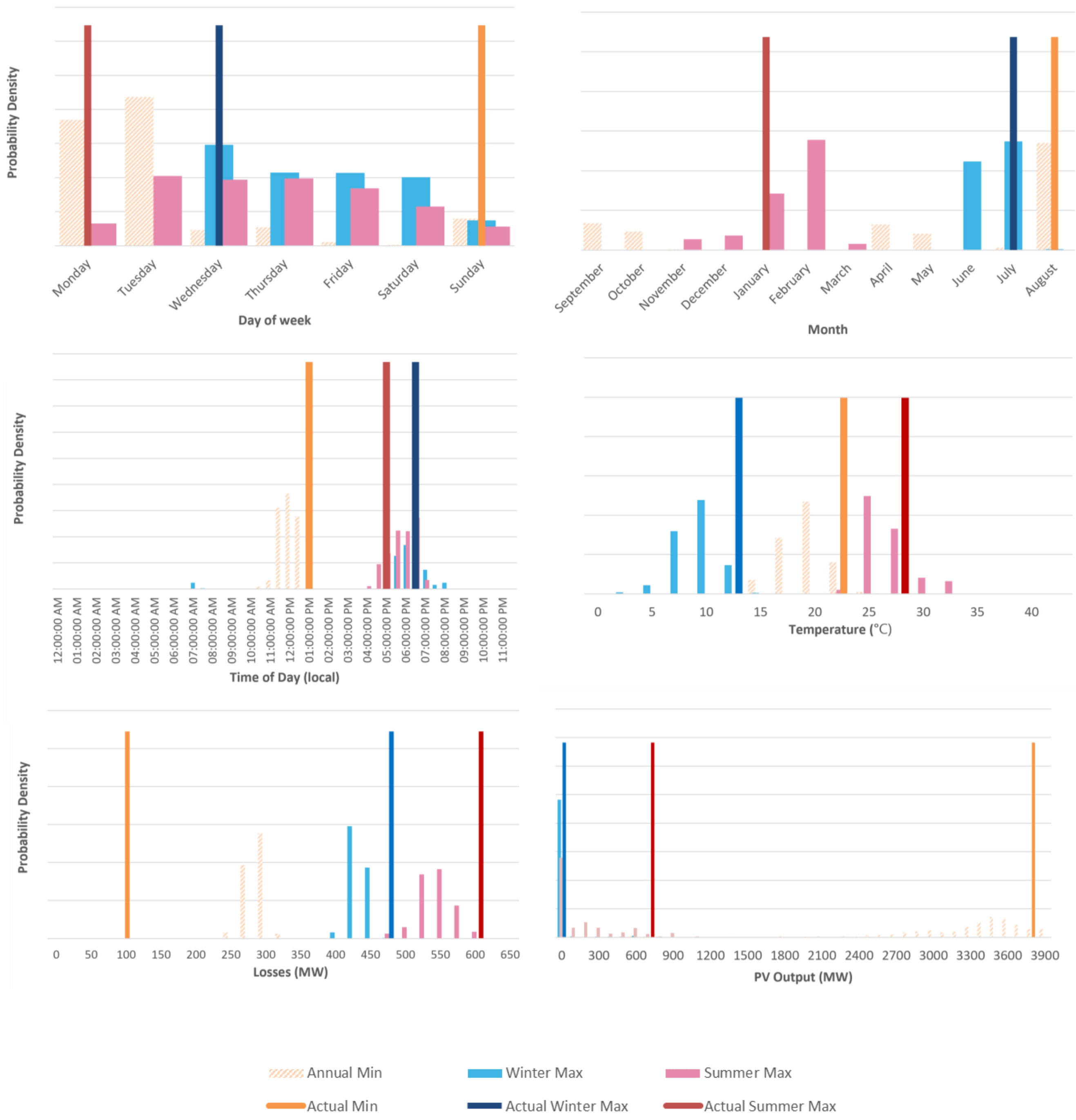
WFigure 19inter maximum demand occurred on Wednesday, 17 July 2024, at 18:30 NEM time, under cooler evening conditions with the temperature recorded at Archerfield reaching 12.3°C. The maximum temperature for the day was 16.5°C, while the minimum was 7.9°C.

- The winter maximum demand was observed between the 50% POE and 10% POE ranges, leaning closer to 10% POE. This event occurred after sunset, meaning PV generation was negligible, further increasing reliance on the grid. Simulation models accurately captured this trend, predicting winter maximum demand during July evenings, aligning with observed seasonal patterns.

Annual minimum demand occurred on Sunday, 18 August 2024, at 13:00 NEM time, with a mild temperature of 23.6°C. The demand fell between the 50% POE and 10% POE ranges, but closer to 50% POE, consistent with the influence of high solar PV generation during the middle of the day.

- This event occurred on a weekend, aligning with simulation outcomes that associate minimum demand with reduced industrial and commercial activities. Queensland's significant rooftop PV penetration resulted in lower grid reliance, contributing to the observed annual minimum demand.
- The time of minimum demand, temperature, and the PV generation matched with the simulation outcomes.

Figure 20 Queensland simulated input variable probability distributions with actuals

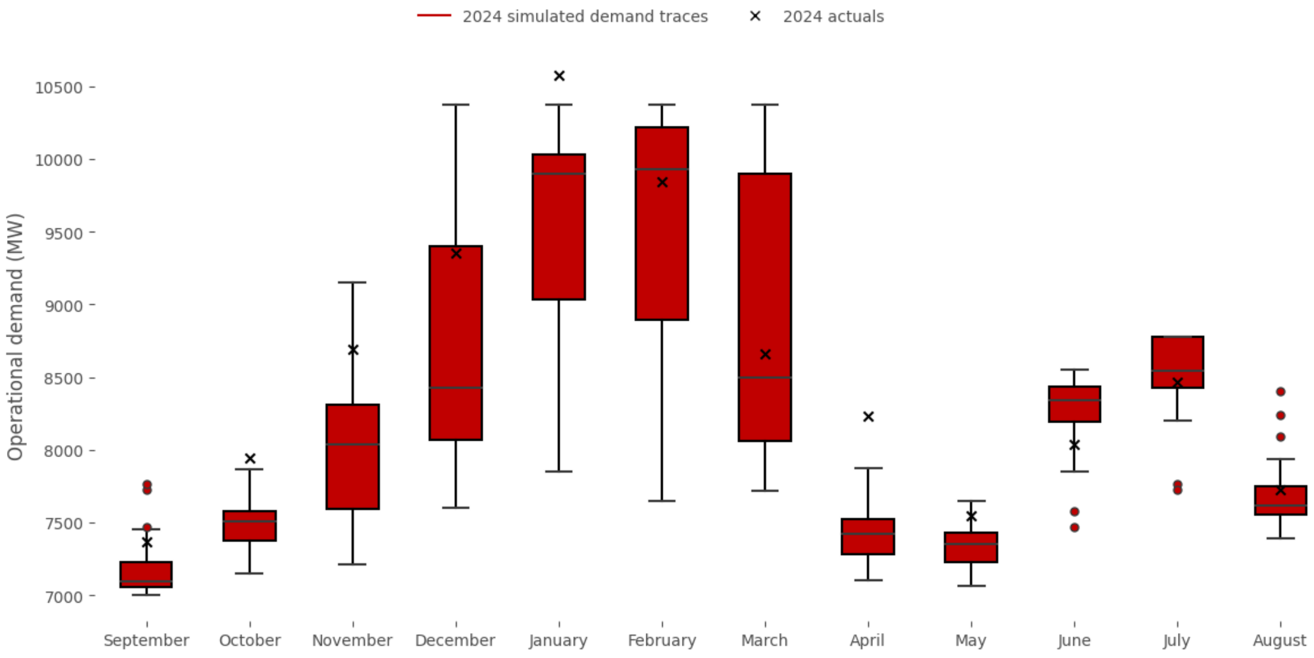


Monthly maximums

The box plot in **Figure 21** illustrates the range of monthly maximum demands for the 2024 simulated demand traces for 10% POE and 50% POE annual forecasts in Queensland. The red dots represent outliers, which are observations at the tail ends of the distribution. The black "x" markers represent the actual monthly maximum demand values recorded for 2024.

Overall, the actual maximum demands across most months aligned well with the simulated traces. During the summer months, most actual maximums were within the distribution range of the simulations. However, January recorded higher actual demand values compared with the simulated traces. This deviation could primarily be attributed to extreme heat events due to the El Niño summer, associated with high humidity which significantly increased cooling loads. In the winter months, actual maximum demand values aligned with the median distribution range of traces. The April actual also fell above the distribution of traces. However, a contributing factor to this observation could be the continuation of El Niño up to the middle of April before transitioning into ENSO-neutral. On Wednesday 03 April 2024 that recorded the maximum demand event at 17:30 NEM time for the month, the temperature started at 21.1°C in the morning and peaked at 32°C at 13:30 PM.

Figure 21 Queensland monthly maximum demand in demand traces compared with actuals



5.4 South Australia

South Australia's half-hourly OPSO demand time-series and extreme events are shown below in **Figure 22**. Further detail on the extreme demand events for the year is provided in **Table 20**.

Figure 22 South Australia demand with extreme events identified

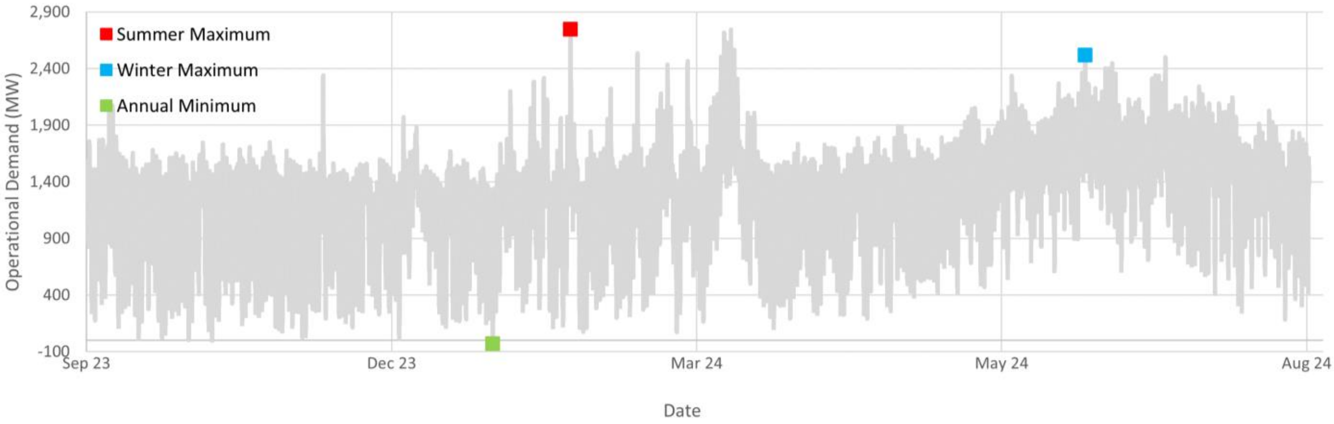


Table 20 South Australia 2023-24 extreme demand events

Event	Summer maximum	Winter maximum	Annual minimum
NEM Date and time	Tue, 23 January 2024, 19:30	Tue, 25 June 2024, 18:30	Sun, 31 December 2023, 13:30
Temperature* (°C)	35.2	11.4	22.9
Max temperature (°C)	40.1	12.3	26.1
Min temperature (°C)	24.4	8.4	12.4
Losses (MW)	235	213	20
NSG output (MW)	30	8	245
Rooftop PV output (MW)	16	0	1,540
Sent out (OPSO)	**2,748**	**2,517**	**-30**
Auxiliary (MW)	32	32	4
As generated (OPGEN)	**2,780**	**2,549**	**-26**

* 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 2023 IASR (https://aemo.com.au/-/media/files/major-publications/isp/2023/2023-inputs-assumptions-and-scenarios-report.pdf).
^ Summer maximum demand is adjusted to observed price-driven DSP at time of peak demand.

Figure 23 shows the maximum and minimum demand event forecasts as a probability distribution of possible outcomes, while vertical lines show the actual observations for the past year. The actual summer maximum demand, the winter maximum demand, and the annual minimum events all fell well within forecast distributions.

Figure 23 South Australia simulated extreme event probability distributions with actuals

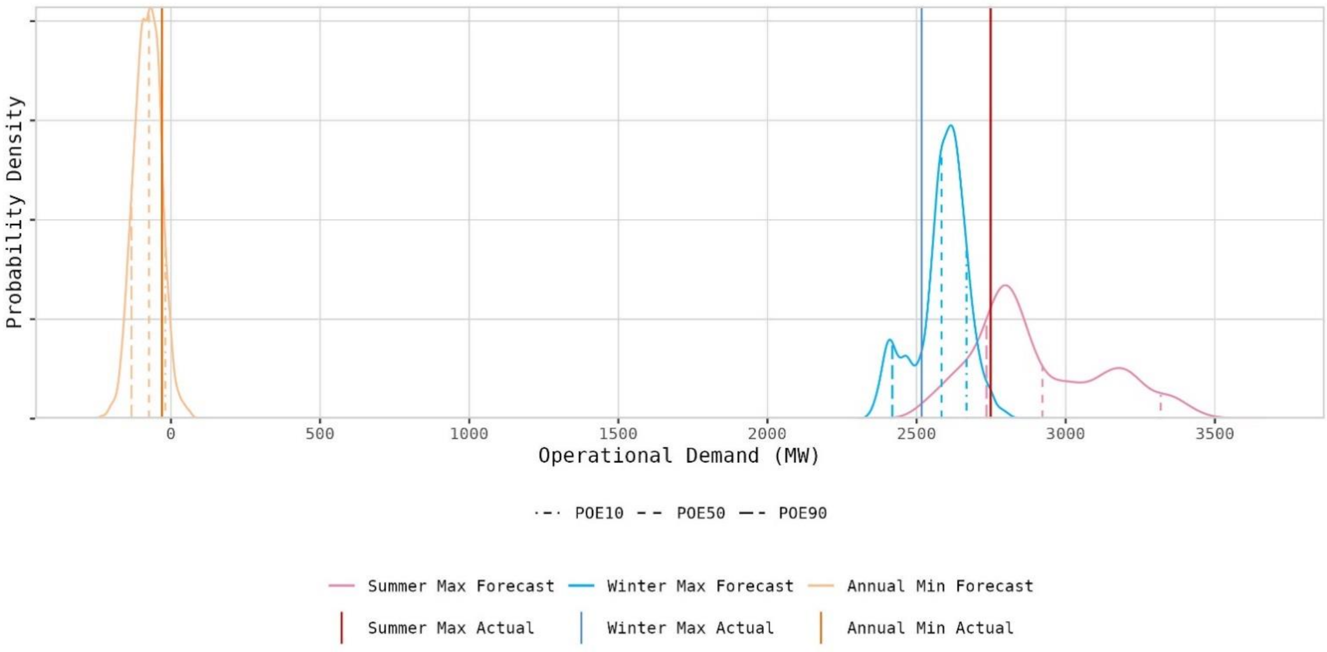


Figure 24 shows the probability distribution and actuals for relevant model inputs. A discussion of insights from these figures follows.

Maximum summer demand occurred on Tuesday, 23 January 2024, 19:30 NEM time with a temperature of 35.2°C recorded at Adelaide (West Terrace).

- The maximum demand was within the distribution of the simulations falling just above the 90% POE forecast.
- Simulation outcomes were weighted toward the maximum occurring on a weekday and in January or February, consistent with what was observed.
- The temperature at the time of maximum demand occurred within the simulated temperature range, which was after the midpoint of the distribution.
- The summer maximum demand event coincided with the working day of the highest temperature. The temperature on 23 January 2024 started high, reaching 30.3°C as early as 9:00 NEM time and hitting peak temperature around 15:00 NEM time. By the time of maximum demand, the temperature had cooled to 35.2°C, which fell just above the median temperature in the simulations.
- The time of the maximum demand was consistent with the simulations also, peaking at 19:30 NEM time.
- PV output at the time of maximum demand was in the middle of the PV forecast distribution, in line with the time of day being in the middle of its distribution as well.

Winter maximum demand occurred on Tuesday, 25 June 2024, 18:30 NEM time, with a temperature of 11.4°C recorded at Adelaide (West Terrace).

- The winter maximum demand was well within the distribution of the simulations falling between 90% POE and 50% POE forecast.

- The winter of 2024 was warm, as the ENSO condition was on El Niño Alert. A temperature of 11.4°C was recorded at the time of maximum demand, which fell just outside the range of the simulated temperature distribution.
- The winter maximum demand event happened on a weekday in June at 18:30 NEM time in line with expectations and following the simulation outcomes closely.
- The late timing of the peak, as usual for winter, meant that rooftop PV did not contribute to lower demand at the time as expected.

Annual minimum demand occurred on Sunday, 31 December 2023, 13:30 NEM time, when the temperature was 22.9°C; this is a typical temperature for such events, requiring minimal cooling or heating demand.

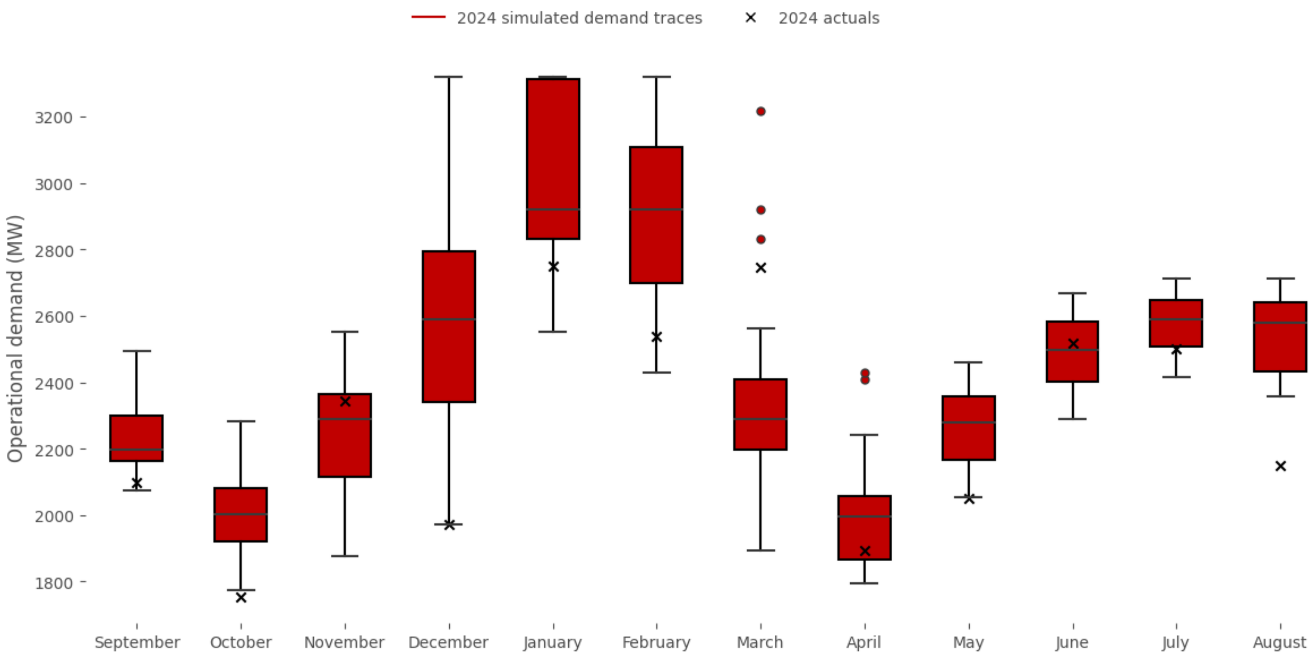
- The minimum demand fell within the simulation distribution, close to the 10% POE. Simulation outcomes suggest that the minimum demand is likely to happen on a weekend in January, in the middle of the day. The actual minimum demand event was consistent with the simulations.
- Although PV generation was just within the simulated outcomes, it was higher than expected. This coincides with the high temperatures recorded during this time and with the under-estimation of PV uptake in South Australia.

Figure 24 South Australia simulated input variable probability distributions with actuals

Monthly maximums

The box plot in **Figure 25** shows the range of monthly demand maximums for the 2024 simulated demand traces for 10% POE and 50% POE annual forecasts. The actual monthly maximum for October falls slightly below the ranges formed by the traces, while August and March fall much lower and higher, respectively. This observation could be attributed to the influence of ENSO variations, as El Niño conditions typically result in monthly maximums falling below the 50% POE during an El Niño winter, while summer conditions often bring higher maximums due to the warmer and drier climate associated with El Niño events.

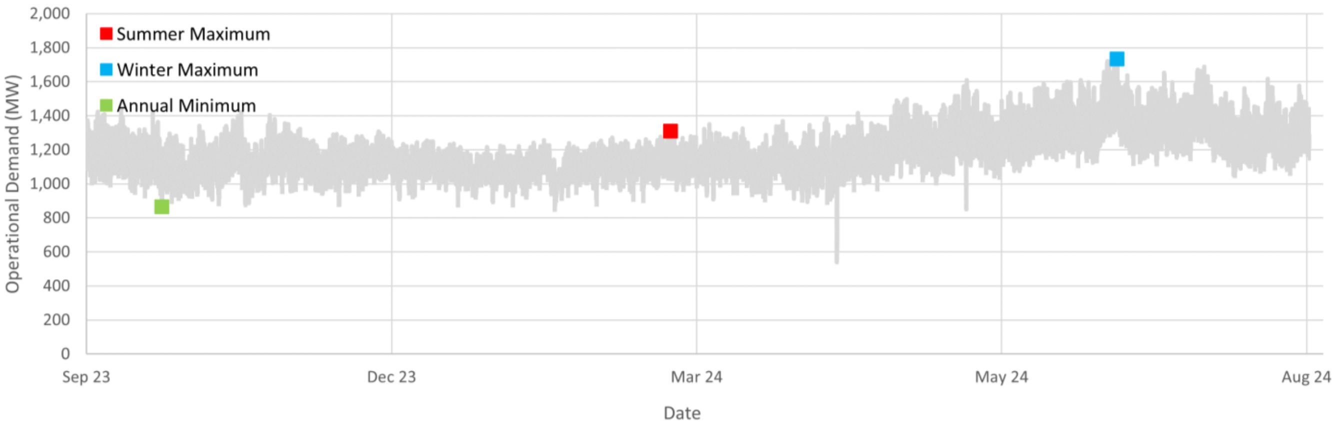
Figure 25 South Australia monthly maximum demand in demand traces compared with actuals



5.5 Tasmania

Tasmania's half-hourly OPSO demand time-series and extreme events are shown below in **Figure 26**. Tasmania is winter peaking, with summer maximums substantially below the winter maximums. Further detail for the extreme demand events for the year is provided in **Table 21**.

Figure 26 Tasmania demand with extreme events identified



Note: three events above have been excluded for the assessment of annual minimum demand, with dips in demand on 19 January 2024, 12 April 2024 and 21 May 2025 being caused by load shedding.

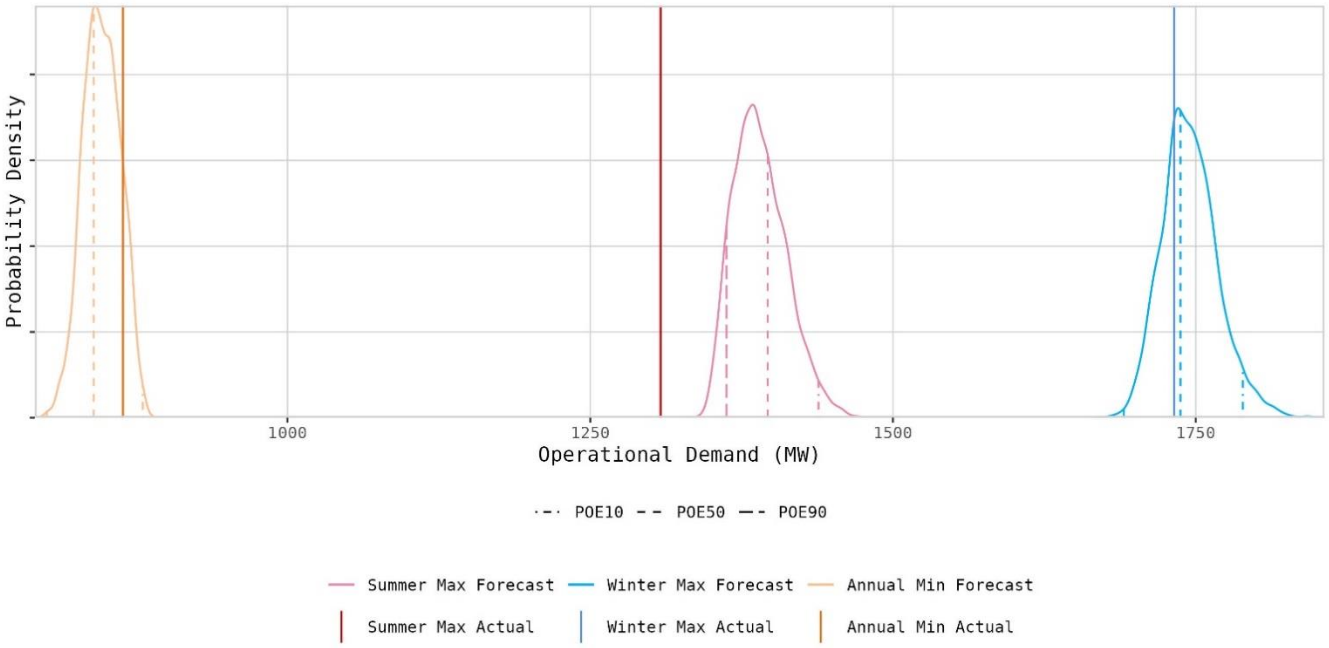
Table 21 Tasmania 2023-24 extreme demand events

Event	Summer maximum	Winter maximum	Annual minimum
NEM Date and time	Thu, 22 February 2024, 17:30	Fri, 5 July 2024, 08:30	Sat, 23 September 2023, 13:30
Temperature* (°C)	31.8	2.3	14.6
Max temperature (°C)	34.8	12.2	16.6
Min temperature (°C)	18.9	1.2	6.7
Losses (MW)	57	80	35
NSG output (MW)	77	69	83
Rooftop PV output (MW)	48	29	146
Sent out (OPSO)	**1,308**	**1,732**	**864**
Auxiliary (MW)	17	18	5
As generated (OPGEN)	**1,325**	**1,750**	**869**

* Hobart (Ellerslie Road) weather station. For more information please see Section 3.3.2 of the 2023 IASR (https://aemo.com.au/-/media/files/major-publications/isp/2023/2023-inputs-assumptions-and-scenarios-report.pdf).

Figure 27 shows the maximum and minimum demand event forecasts as a probability distribution of possible outcomes, while vertical lines show the actual observations for the past year. The summer maximum demand events fell below their respective forecast probability distributions, while the winter maximum demand and annual minimum was well within the projected outcomes.

Figure 27 Tasmania simulated extreme event probability distributions with actuals



Demand in Tasmania is different from the mainland regions in two ways:

- Tasmania is consistently winter peaking; that is, its annual maximum demand is driven by winter heating load rather than summer cooling loads.

- Tasmania is influenced to a much larger extent by LIL operations, and weather (such as temperature) has a therefore smaller impact relative to other regions.

Figure 28 shows the probability distribution and actuals for relevant model inputs. A discussion of insights from these figures follows.

Maximum demand occurred in winter on Thursday, 5 July 2024 at 8:30 NEM time, with a temperature of 2.3°C recorded at Hobart (Ellerslie Road).

- Figure 19The maximum demand was within the range expected by the forecast, falling around the 50% POE.
- Tasmania experienced a winter maximum demand event on the day with the lowest daily minimum temperature (1.2°C) recorded at 7:30 NEM time reaching to 2.3°C when the maximum winter demand recorded.
- Simulation outcomes were weighted towards maximum demand occurring during a weekday evening in June to August. The time of peaking can be either in the morning or in the evening, depending on the weather profile and other factors like what large industrial load was doing at the time. The actual time of maximum demand event was consistent with the simulation.
- The temperature at the time of maximum demand event was around the middle of the simulation outcomes.
- Occurring around sunrise, PV generation was nearly zero at the time of the observed maximum demand.
- LILs at time of peak were 712.5 MW, and the forecast had a 50% POE value of 694 MW (10% POE was 699 MW, and the 90% POE was 691 MW).

Summer maximum demand was recorded on Thursday, 22 February 2024 at 17:30 NEM time, with a temperature of 31.8°C at Hobart (Ellerslie Road). The maximum demand coincided with the working day of the highest recorded temperature of the summer. The temperature on 22 February started high, reaching the maximum temperature of 34.8°C at 15:00 NEM time.

- The observed demand fell below 90% POE outcome by approximately 53 MW.
- Maximum demand in summer was forecast to occur during cold weather, typically below 8°C. In summer 2023-24, the actual maximum demand event occurred during higher temperature conditions. Due to the absence of cold weather, maximum demand during summer did not occur as forecast.
- Simulation outcomes were weighted towards occurring on a weekday and in December to February, which is consistent with the Thursday, 22 February occurrence. Similarly, PV generation at time of maximum was within expectations.
- LILs at the time of summer maximum were at 700 MW, slightly lower than the forecast 90% POE outcome (705 MW). Accordingly, LIL contribution to peak cannot explain why the overall actuals value fell below the 90% POE.

Annual minimum demand occurred on Saturday, 23 September 2023 at 13:30 NEM time, when the temperature was 14.6°C. Tasmania is particularly affected by industrial demand, and variation in this causes minimum demand to be more volatile and unpredictable in terms of timing. The occasional low points of LIL were excluded in this analysis.

- The annual minimum demand fell within the distribution between 50% POE and 10% POE.

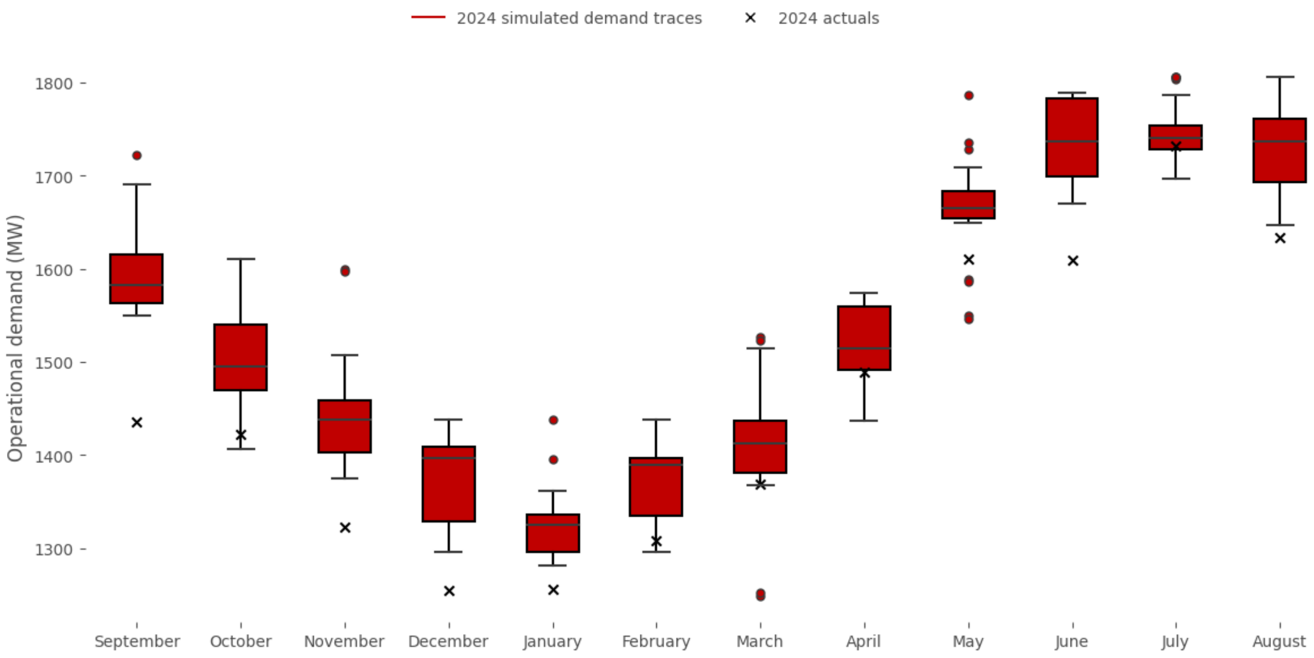
- Minimum demand was forecast to most likely occur in the middle of the day, on days with moderate temperatures and moderate PV generation.
- Simulation outcomes were weighted towards occurring on the weekday, whereas the actual annual minimum demand occurred on a weekend. AEMO will review components contributing to this difference in simulations and forecast.

Figure 28 Tasmania simulated input variable probability distributions with actuals

Monthly maximums

The box plot in **Figure 29** shows the range of monthly demand maximums for the 2024 simulated demand traces for 10% POE and 50% POE annual forecasts. Many of the monthly actual maximum demand events fell below the range formed by the traces. It should be noted that these exclude 90% POE and it is therefore expected that some values would fall below the range formed by the 10% and 50% POE traces. The magnitude of values falling below the range suggests that simulated traces were too high for the shoulder and winter maximum demand values, and this will be further investigated as discussed earlier.

Figure 29 Tasmania monthly maximum demand in demand traces compared with actuals



5.6 Victoria

Victoria's half-hourly OPSO demand time-series and extreme events are shown below in **Figure 30**. Further detail on the extreme demand events observed during the year is in **Table 22**.

Figure 30 Victoria demand with extreme events identified

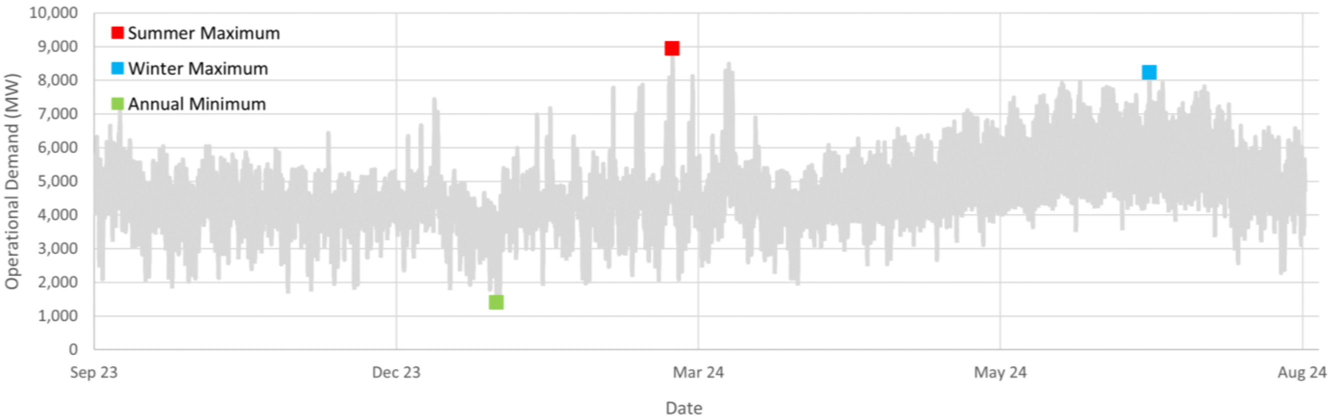


Table 22 Victoria 2023-24 extreme demand events

Event	Summer maximum	Winter maximum	Annual minimum
NEM Datetime	Thu, 22 February 2024, 16:00	Mon, 15 July 2024, 18:00	Sun, 31 December 2023, 13:00
Temperature* (°C)	35.2	10.1	19.2
Max temperature (°C)	35.7	11.1	19.8
Min temperature (°C)	19.6	7.4	14.2
Losses (MW)	575	520	71
NSG output (MW)	317	128	379
Rooftop PV output (MW)	1,157	0	2,894
Sent out (OPSO)	**8,947 (adjusted to 9,087)^**	**8,237**	**1,407**
Auxiliary (MW)	347	375	157
As generated (OPGEN)	**9,294 (adjusted to 9,434)^**	**8,612**	**1,564**

* Melbourne (Olympic Park) weather station. For more information please see Section 3.3.2 of the 2023 IASR (2023-inputs-assumptions-and-scenarios-report.pdf).
^ Summer maximum demand is adjusted to include the impact of Ausnet Services' CPD program that was called for that day.

Figure 31 shows the maximum and minimum demand event forecasts as a probability distribution of possible outcomes, while vertical lines show the actual observations. The actual summer maximum and annual minimum demand outcomes fell well within forecast expectations, while the actual winter maximum demand outcome was above the forecast 10% POE. The likely reasons are discussed below.

Figure 31 Victoria simulated extreme event probability distributions with actuals

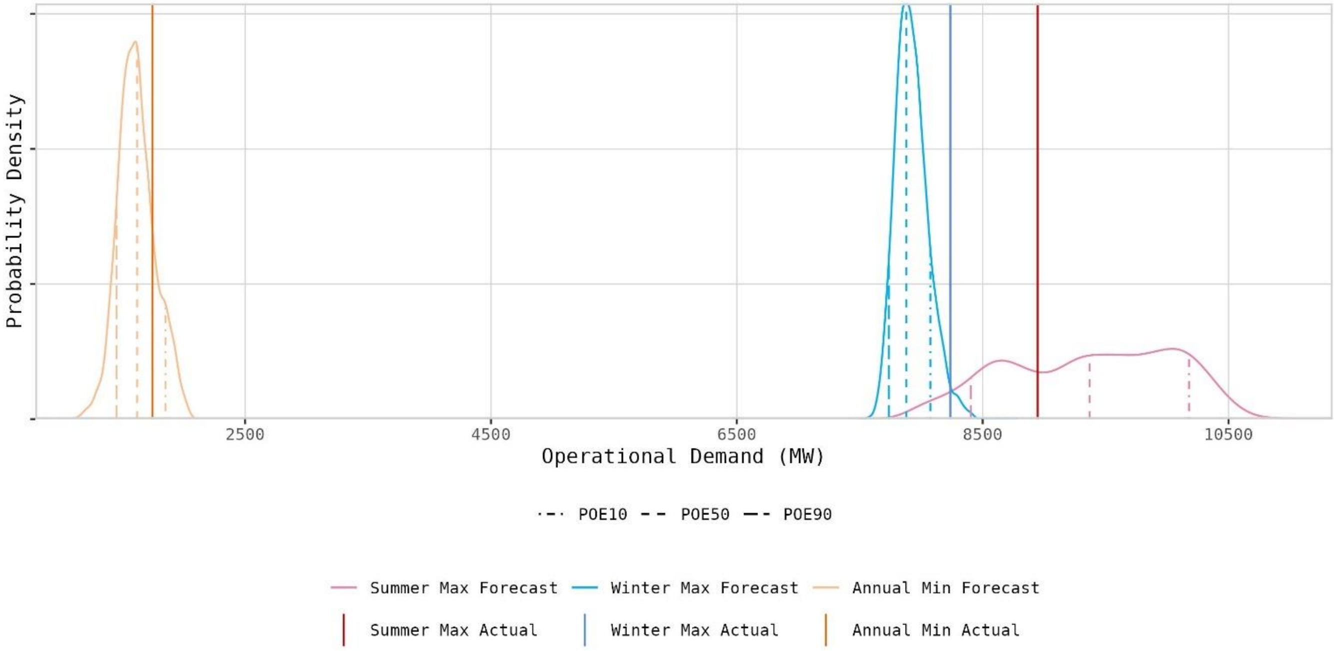


Figure 32 shows the probability distribution and actuals for relevant model inputs. A discussion of insights from these figures follows.

Maximum demand was recorded in summer, on Thursday, 22 February 2024, 16:00 NEM time. However, a firm adjustment from AusNet Services' Good Grid program (Critical Peak Demand program), impacting the period 14:00–18:00 NEM Time and APD's potline outage (280 MW) resulted in the following interval, 16:30 NEM time, having a higher adjusted demand. As AEMO forecasts unconstrained maximum demand, the adjusted maximum value at 16:30 NEM time will be used as a point of comparison against the simulations. At the time of maximum demand, Melbourne (Olympic Park) recorded a temperature of 35.2°C, with an earlier daily maximum temperature of 35.7°C.

- The actual maximum demand was between 90% POE and 50% POE forecast.
- The maximum demand of the summer occurred on the second hottest working day, rather than on the day with the highest daily temperature. On the hottest working day, 13 February 2024, temperatures peaked at 39.6°C at 14:00 NEM time but dropped sharply to 27.6°C by 15:00, marking a rapid 12°C decrease within just one hour. This sudden cooling limited the duration of high cooling load demand. In contrast, on 22 January 2024, the day when maximum demand occurred, temperatures were relatively high from the morning, starting at 28.1°C at 9:00 NEM time. The maximum temperature reached 35.7°C later in the afternoon and remained steady at this level until 15:00 NEM time. This sustained heat throughout the day drove elevated cooling loads, keeping electricity demand high until 18:30 NEM time. Temperatures began to decline significantly after 18:30, eventually reducing cooling load demand.
- The simulation outcomes were weighted towards the maximum demand event happening on a weekday in January or February in the late afternoon to early evening period. They are consistent with the actual maximum demand event, although the time of day was in the lower range of simulations.

- Actual PV generation was above the median of the simulated outcomes, which is consistent with the earlier time of day.
- The temperature at the time of maximum demand was in the upper range of the simulation outcome, but still well within the expected range.

Winter maximum demand occurred on Monday, 15 July 2024, 18:00 NEM time, with a temperature of 10.1°C recorded at Melbourne (Olympic Park).

- The maximum demand fell above the 10% POE.
- Victoria had its winter evening peak in 2024 on a cold day with a very small temperature range, a daily maximum temperature of 11.1°C and a daily minimum of 7.4°C. The temperature is towards the very top end of the simulated range, so there would have been relatively less need for heating. The demand outcome above the 10% POE forecast is therefore higher than expected. AEMO will review other components contributing to the under-forecast of winter maximum demand.
- Simulation outcomes were weighted towards a maximum demand event in July period, which is in line with the actual event.
- The actual maximum demand event fell on a Monday at 18:00 NEM time, matching the simulation outcome of event more likely to happen on a weekday, in late afternoon to early evening.
- Given the timing after sunset, PV generation was 0 MW at the time of the maximum demand event, consistent with the simulation outcomes.

Annual minimum demand occurred on Sunday, 31 December 2023, 13:00 NEM time, when the temperature was 19.2°C. This is the fifth year where minimum demand has during the day rather than overnight.

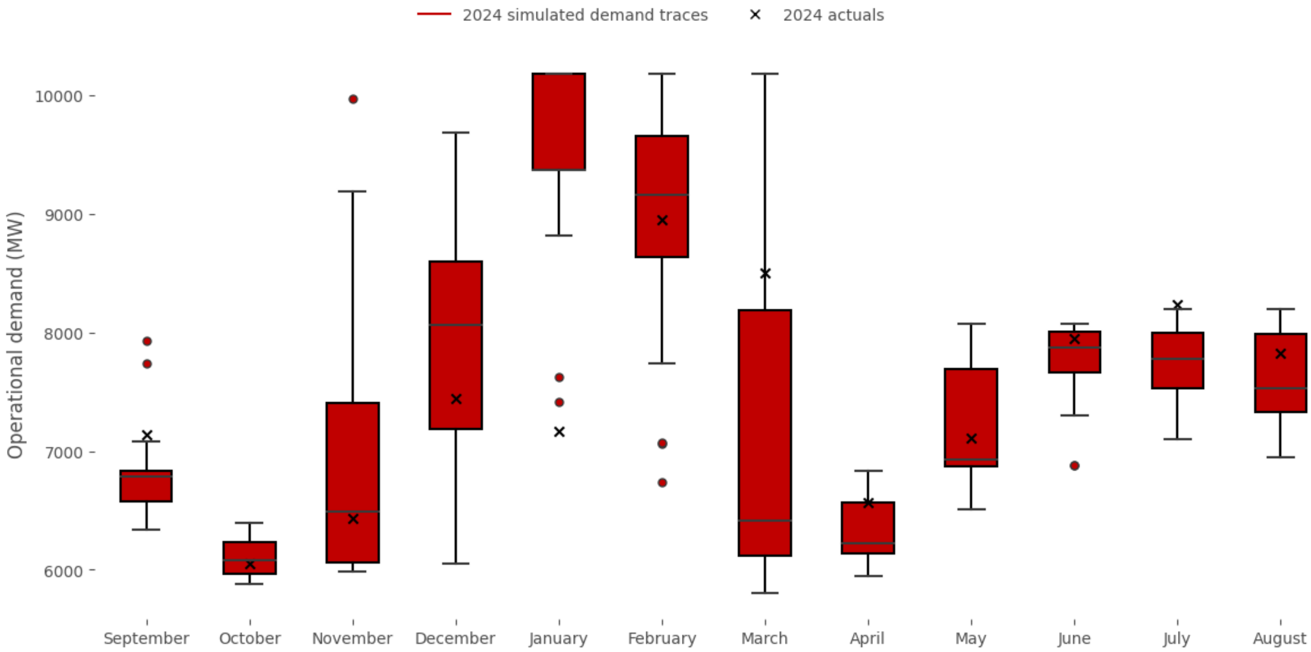
- The actual minimum demand fell between the 50% POE and 10% POE.
- PV generation at time of minimum was in the upper end of the distribution, which is consistent with the prevailing weather conditions on the day.
- The minimum demand event occurred in December, which is consistent with simulation outcomes.
- Simulation outcomes were weighted towards a minimum event over the weekend in the late morning to early afternoon period, consistent with the Sunday 13:00 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 2024 simulated demand traces for 10% POE and 50% POE annual forecasts. The majority of monthly maximums fell within the predicted range, but mostly on the higher end. In January, the actual maximum demand fell well below the simulated range, due to the lower than average temperatures observed. This was surprising given the El Niño conditions for Summer 2024.

Figure 33 Victoria monthly maximum demand in demand traces compared with actuals



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 2023 ESOO was published along with the 2023 ESOO in August 2023; its accuracy is assessed in the following section.

5.7.1 Background

AEMO's existing DSP forecast methodology[49] estimates the demand response from LILs and any other market participants. Note that subsequent to the publication of the 2023 ESOO, AEMO commenced a consultation on its DSP forecast methodology[50], which led to changes in forecasts for the 2024 ESOO and beyond.

[49] 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.

[50] See https://aemo.com.au/consultations/current-and-closed-consultations/demand-side-participation-forecasting-methodology-and-dsp-information-guidelines-consultation.

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[51]. 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 2023 DSP forecast excluded:

- Regular (such as daily) demand variations including responses to time-of-use tariffs and hot water load control.
- 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[52].

AEMO's DSP forecast is used in reliability forecasting to assess the need for reserves under the Reliability and Emergency Reserve Trader (RERT) framework[53], 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 2023-24 year compared to the 2023 forecast median response.
- 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 2023 to 31 March 2024 consumption data for the same list of DSP resources as the 2023 DSP forecast. This is compared to the forecast DSP responses that were based on consumption data from the three previous years (1 April 2020 to 31 March 2023). The comparisons highlight the difference between the forecast DSP and the median observed response across different price triggers.

[51] 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.

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

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

The comparison does not evaluate performance of the calculation of responses (in particular the baseline estimation). 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 can be attributed to a higher rate of DSP participation compared to previous years, as the relevant programs have potentially gained more interest. This pattern is relatively consistent across all regions, except for South Australia and Tasmania; the forecast and observed DSP are relatively similar in South Australia, while no significant DSP participation was observed in Tasmania. Finally, there has been a significant increase in the observed response for all price bands in Victoria, with actual DSP being higher than forecast. This did lead to an uplift to the 2024 DSP forecast published in the 2024 ESOO[54].

Key insights from each region are summarised below:

- No response was forecast in **New South Wales** for price bands less than $1,000/megawatt hour (MWh) due to lack of DSP participation in these bands over the previous years. However, an average response of between 23 MW and 36 MW has been observed for these price bands. Overall, prices between $300/MWh and $1,000/MWh were observed less frequently compared to the previous year, although there were more occasions where the prices were higher than $1,000/MWh; there were 410 intervals for which the price was higher than $1,000/MWh in 2023-24 compared to 90 intervals in 2022-23. For prices bands $1,000/MWh-$2,500/MWh, $2,500/MWh-$5,000/MWh and over $7,500/MWh, the observed DSP response was relatively similar to the forecast DSP. The only price band for which the observed DSP response was significantly lower than the forecast response was $5,000/MWh-$7,500/MWh. The observed DSP response for this price band is slightly larger than the previous price band ($2,500/MWh-$5,000/MWh), while it is significantly smaller than the DSP response for prices over $7,500/MWh. This potentially indicates that the majority of load which could be flexed by participants for prices over $2,500/MWh has already been reduced and there is not much difference between the price bands of $2,500/MWh-$5,000/MWh and $5,000/MWh-$7,500/MWh. However, more loads can be reduced for prices over $7,500/MWh, due to significant price incentives.
- In **Queensland**, for all price bands a relatively constant response of 145 MW (on average) was observed. This response was higher than the forecast response in the first four price bands, it was consistent with the forecast response for the $5,000/MWh-$7,500/MWh price band, and it was lower than the forecast response for prices over $7,500/MWh. This indicates a consistent DSP participation in the region, regardless of the price variations, when the prices are over $300/MWh. This pattern 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 lower than the forecast for all price bands, although the difference between the observed and forecast DSP was small for most price bands. The largest difference between the two were for the price band of $300/MWh-$500/MWh (12 MW), followed by the last price band

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

(10 MW) which can be attributed to an overestimation of the forecasting method due to its sensitivity to fluctuations in historical values.

- For **Tasmania**, the median observed DSP was lower than the forecast, and no significant DSP responses were observed.
- For **Victoria**, the median DSP observation for all price triggers were significantly larger than the forecast, reflecting higher level of participation. Higher resolution of data submitted by participants through the DSP information portal also contributed to the higher values of DSP observed during 2023-24.

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

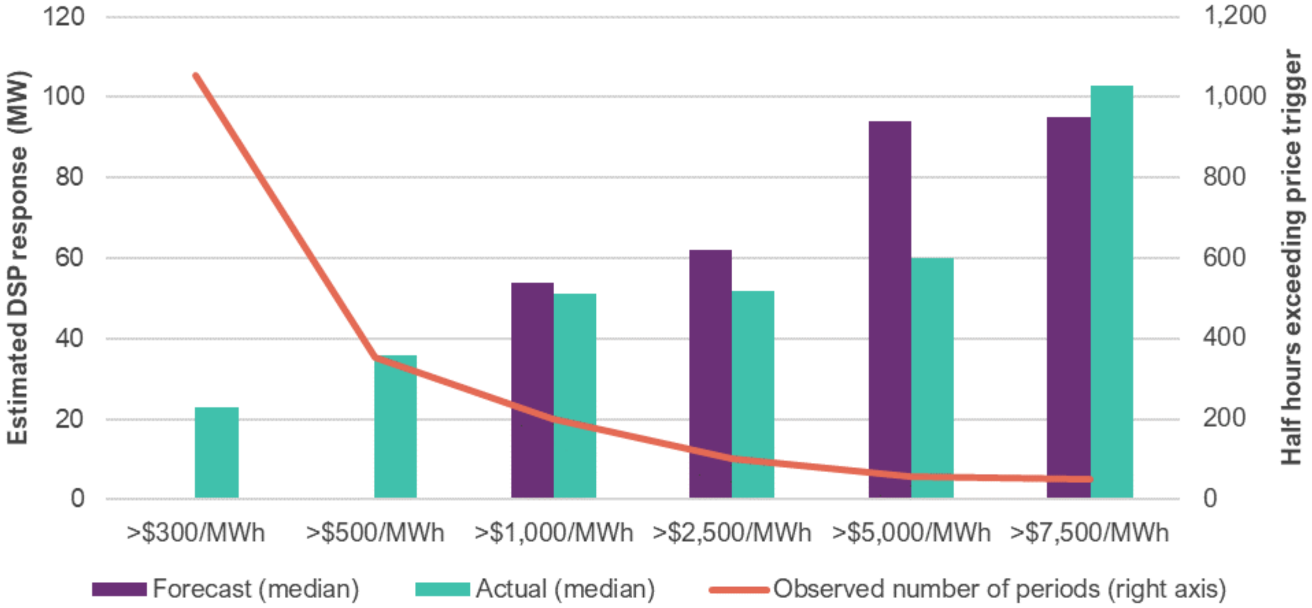


Figure 35 Evaluation of actual compared to forecast price-driven DSP in Queensland

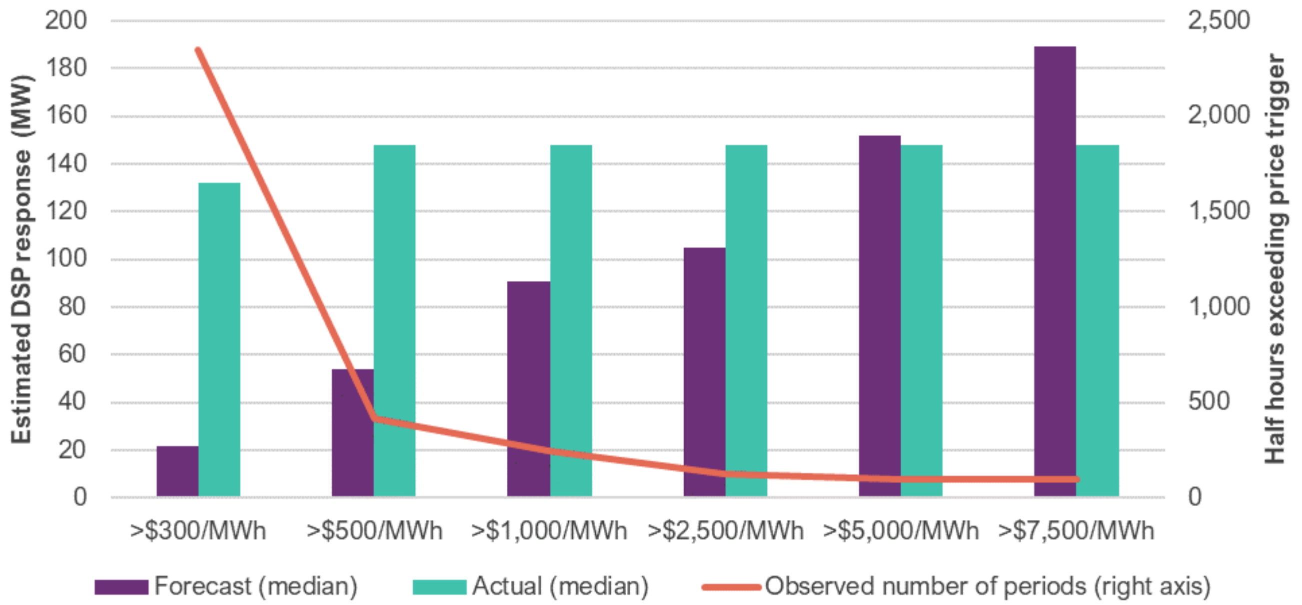


Figure 36 Evaluation of actual compared to forecast price-driven DSP in South Australia

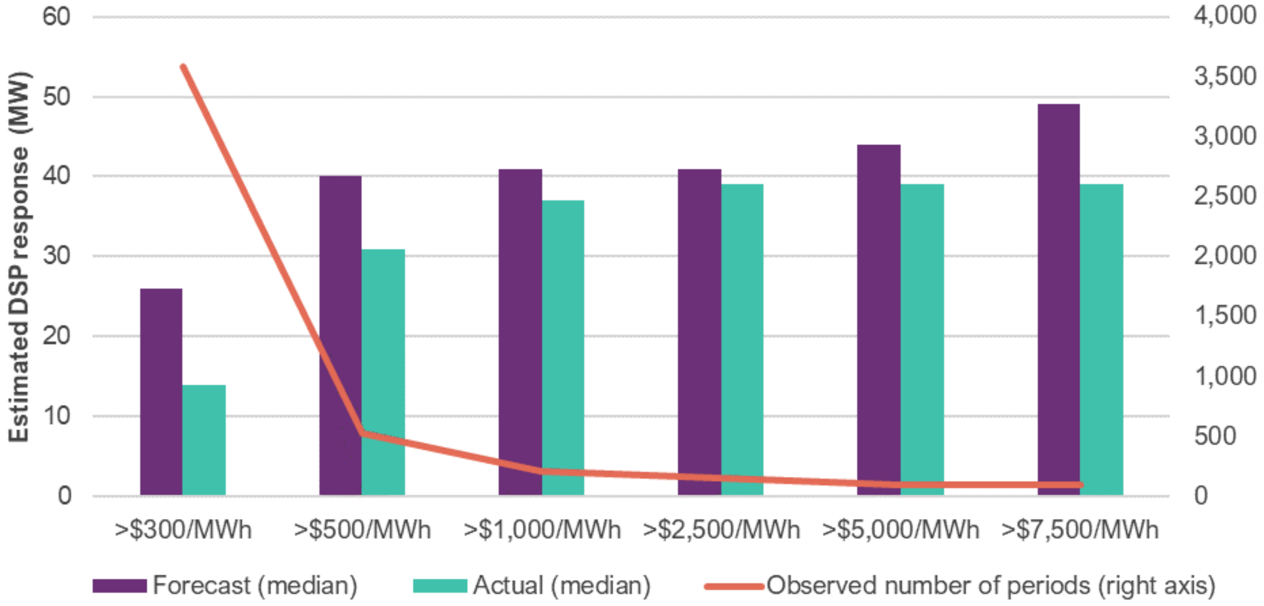


Figure 37 Evaluation of actual compared to forecast price-driven DSP in Tasmania

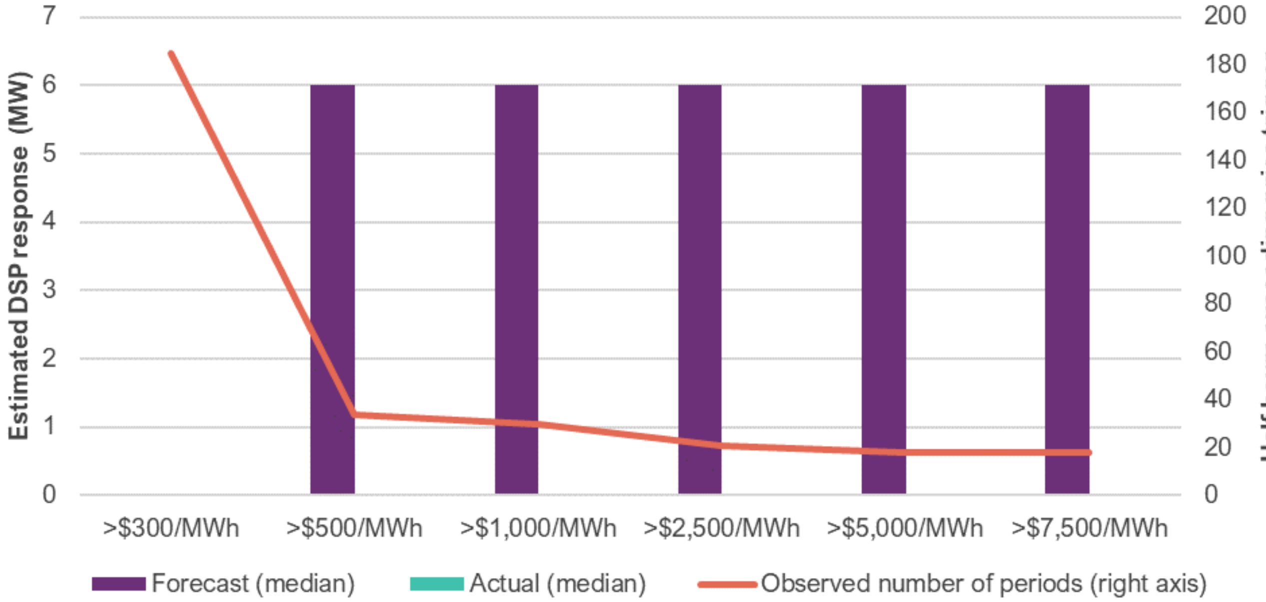
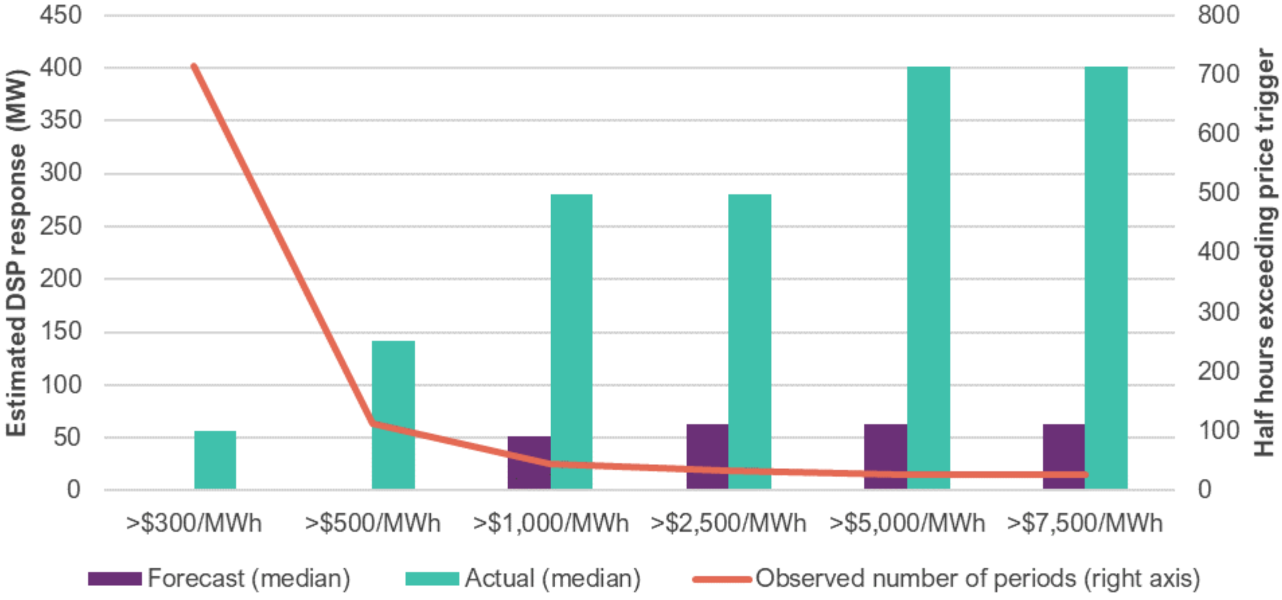


Figure 38 Evaluation of actual compared to forecast price-driven DSP in Victoria



Included in the above discussion of AEMO's DSP forecasts and actuals is the impact of the Wholesale Demand Response (WDR) mechanism[55]. 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 2023 ESOO forecast WDR for all regions except Tasmania, and as per the forecast, WDR has been dispatched across all NEM mainland regions. As shown in **Table 23**:

- In New South Wales and Victoria, the actual WDR was reasonably close to forecast.
- In Queensland and South Australia, WDR was lower than forecast. At the time of preparing the 2023 ESOO, WDR forecasts were based on assumptions linked to how DSP in those jurisdictions may compare to Victoria. This assumption proved to over-estimate the amount of WDR in Queensland and South Australia and subsequent forecasts will be informed by the actual WDR observed in 2023-24.

Table 23 Forecast versus actual WDR in 2023/24 (MW)

	New South Wales		Queensland		South Australia		Tasmania		Victoria	
	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast	Actual
>$300	0	1	0	0	0	0	0	0	0	0
>$500	0	4	0	0	0	0	0	0	0	6
>$1,000	9	7	1	0	1	0	0	0	3	6
>$2,500	12	7	1	0	1	0	0	0	7	6
>$5,000	12	7	1	0	1	0	0	0	7	6
>$7,500	13	9	1	0	1	0	0	0	7	6

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

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

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

5.7.4 DSP response during extreme events

The reliability response from the 2023 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 LOR2 or LOR3 for 2023-24 summer and 2024 winter

	New South Wales	Queensland	South Australia	Tasmania	Victoria
Summer	337	262	49	6	257
Winter	337	189	49	6	212

Only New South Wales, South Australia and Victoria recorded either an LOR 2 or an LOR3 event in summer. However, none of these events coincided with the maximum demand day in the respective region. The DSP response during each region's maximum demand is described below, while further details are provided for the response to the reliability events in the aforementioned 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 29 February 2024, when prices were particularly high (above $12,000/MWh for 12 intervals), and reached the market price cap ($16,600/MWh) in five intervals between 15:00 and 17:00. On that day, a maximum DSP response of 137 MW was observed at 17:00. No significant response was observed during the only LOR 2 event occurred in summer (on 14 December 2024). Therefore, the estimated reliability responses in New South Wales were considerably lower than the 337 MW forecast, with relatively little response from the most significant industrial loads, which often respond to price (and not just RERT)[56].
- **Queensland** – the maximum demand in summer was reached on 22 January 2024. There were intervals at which the prices were relatively high (reached a maximum of $9,800/MWh at 18:25). The brief price spikes during the day triggered a maximum DSP price response of 20MW. No LOR event was observed during this time.
- **South Australia** – the region had its summer maximum demand on 23January 2024. No LOR events were observed this day. The only LOR 2 event occurred on 27 October 2023, during which approximately 7 MW of DSP response could be observed.
- **Tasmania** – Tasmania had its annual maximum demand on 3 July 2023. The price was well below the trigger price of $300MWh, so no DSP response was observed.
- **Victoria** – this region observed several intervals with LOR 2 and LOR 3 conditions on 13 February 2024. On that day, the price reached the market cap ($16,600/MWh) during 39 intervals. An estimated DSP response of 174MW was observed during the LOR 2 and LOR 3 events. Victoria had its maximum demand on 22 February

[56] The Australian Aluminium Council noted in a submission that in May and June 2022 Tomago Aluminium provided 32 hours of response across 18 events, which were a mixture of RERT and responding to high market price. See https://aluminium.org.au/wp-content/uploads/2022/11/221117-Aluminium-Response-Operational-Security-Mechanism.pdf.

2024. The price on that day was relatively low (only four intervals had a price higher than $300/MWh). This caused no price-driven DSP events. There were no LOR events observed on this day either.

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. No significant DSP response was observed in Tasmania. Victoria was the only region which observed estimated DSP responses which were significantly larger than the forecast across all price bands.

The high number of price intervals over $300/MWh and $500/MWh has made assessing DSP in these price trigger bands difficult.

The lack of high demand days with LOR conditions hindered validating the accuracy of the reliability response for 2023-24.

As a result of the higher observed DSP responses in Victoria during 2023-24, AEMO increased its DSP forecasts for the region in 2024 ESOO. AEMO will continue to monitor observed DSP against forecast (including use of WDR) over the coming summer to assess whether the higher 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

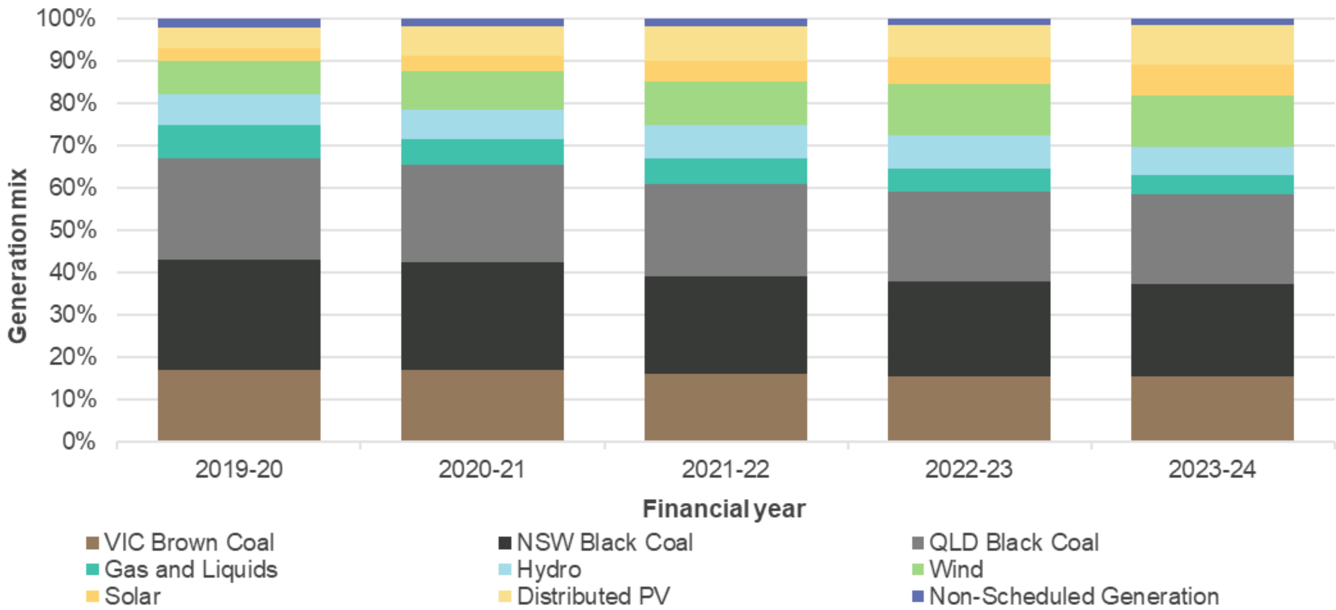
Generation supply in the NEM comes from a variety of fuel sources, with the energy supply balance shifting over recent years, as shown in **Figure 39**. The accuracy of supply forecasts discussed in this chapter considers most fuel sources, with focus on the technologies that contribute most to electricity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

Black and brown coal remain the largest source of electricity production in the NEM, yet show a decrease in the relative proportion of electricity supplied from 67.0% in 2019-20 to 58.4% in 2023-24. The share of electricity supplied by hydro remains relatively stable over this period, while electricity supplied by gas and liquid fuel has declined from 8.0% in 2019-20 to 4.7% in 2023-24. Solar and wind generation show the largest increase in the relative proportion of electricity supplied, rising from 11.0% in 2019-20 to 19.4% in 2023-24. Additionally, the contribution of distributed PV has grown from 5.0% in 2019-20 to 9.3% in 2023-24.

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

- Forecasts of new generator connections.
- Unplanned outage rates for major generation sources.
- Supply availability, per region.

Figure 39 NEM generation mix change by energy, including demand side components, from 2019-20 to 2023-24



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 variable renewable energy (VRE) generation output. Supply forecasts are therefore assessed by the degree to which capacity availability estimated in the 2023 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, including:

- Commissioning or decommissioning of generators may not match schedules provided by generator participants.
- Generator ratings during peak temperatures may not match ratings provided by generator participants.
- Unplanned outages may vary from expectations, as informed by unplanned outage rates (full, partial, or high impact outages).
- Planned outages or unit decommitment may occur during peak periods, which 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 curtailment due to constraints representing system security and network limitations, varying from network expectations informed by equations that represent network capability in the reliability assessments.
- Participants provided different capacities compared with actual plant capability.

Consistent with the *Forecast Accuracy Report Methodology*[57], 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 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.
- Generation output for scheduled bidirectional units, and semi-scheduled and significant VRE non-scheduled generators, comparing actual generation with simulated generation.

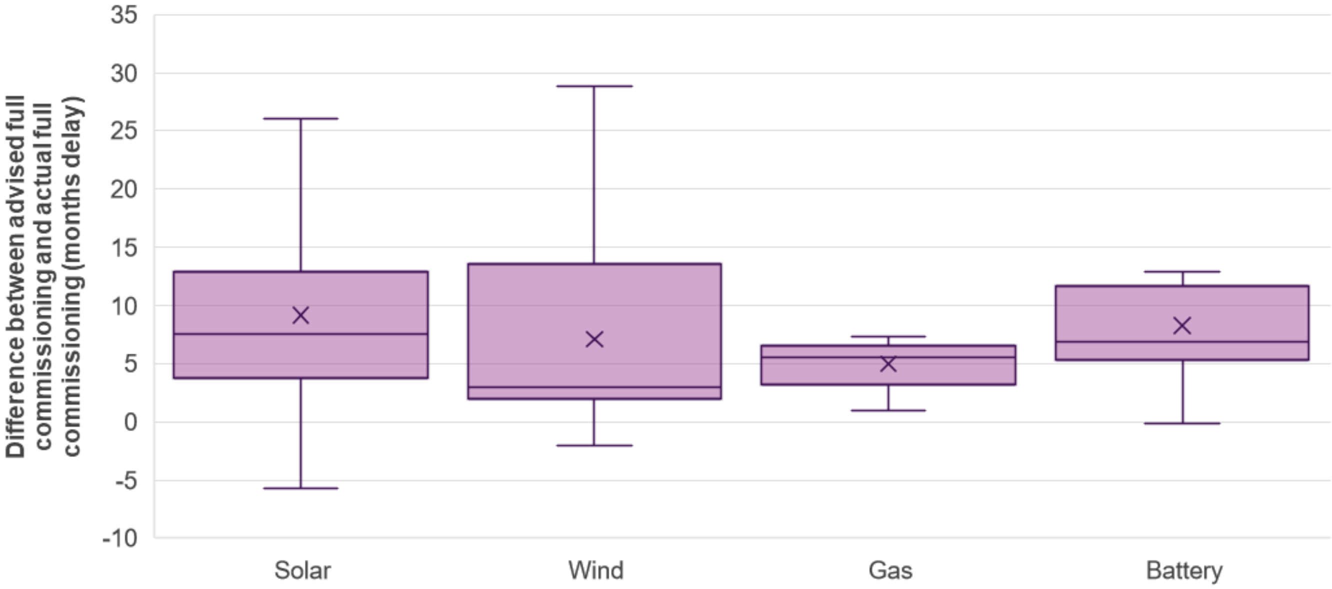
Generator commissioning schedules

For the purposes of the reliability forecast, AEMO applies new generation and storage projects at dates that are often later than the commissioning date provided by the proponent. The application of delays attempts to ensure that the reliability forecast does not overestimate generator availability, informed by historical delays that have been incurred during development and commissioning stages of other projects. **Figure 40** shows a box plot of differences between the full commissioning dates provided by participants and the actual commissioning date of those projects. In the figure, the box plot shows the distribution of outcomes observed, where the average outcome is shown by the ‘x’. On average, projects are noted to have approximately a 6-8 month delay.

While delays against full commissioning dates occur, projects often release partial capacity throughout the commissioning process. For each region and technology, AEMO assesses the forecast and actual number of projects, and their capacity that is available in early February, incorporating any capacity which may have been released in advance of full commissioning.

[57] 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 40 Difference in full commissioning dates for participant submissions between October 2021 and May 2024



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

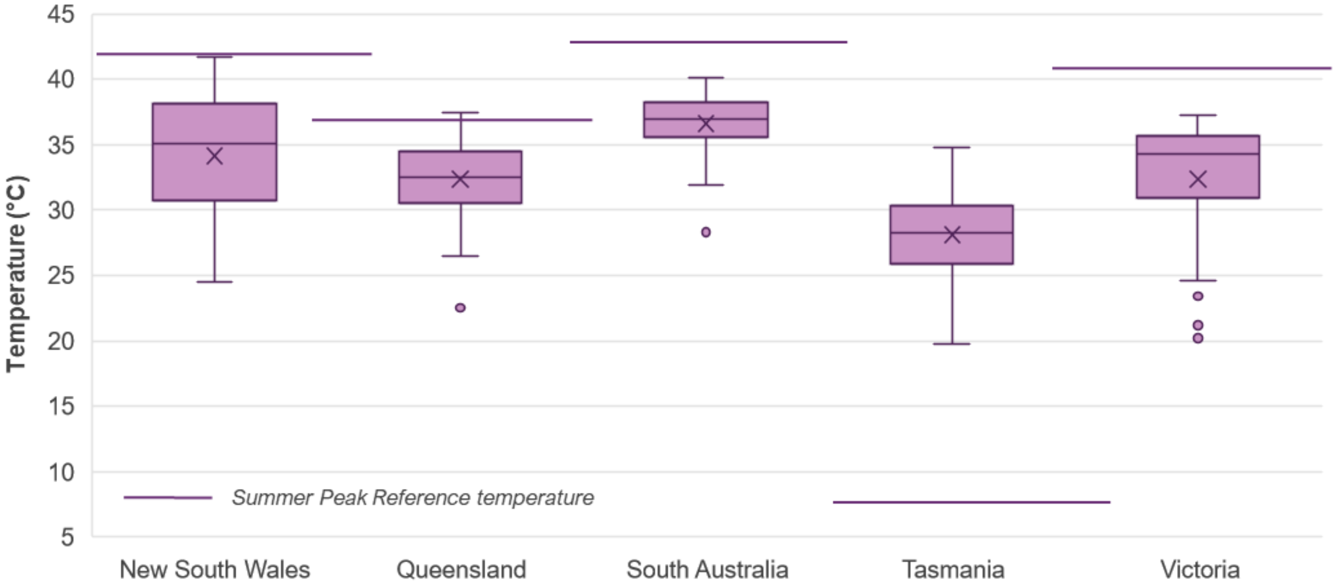
On average, summer 2023-24 was one of the warmest on record, with all the regions experiencing above average temperatures[58]. However, as shown in **Figure 41**, the sampled temperatures from the top 10 hottest summer days, including annual maximum events, were mostly below the summer peak reference temperature. This reference temperature, used to define summer peak capacity values, representing the ratings for the 10% POE demand conditions in each region. **Figure 41** shows a box plot[59] comparing the temperature range of the 40 sampled hours to the summer peak reference temperature for each region.

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

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

Due to the absence of extreme temperatures and the associated equipment derating, actual supply availability is expected to be generally higher than forecast availability during these 10 hottest days assessed.

Figure 41 Box plot of temperatures of 40 hours sampled from the 10 hottest days in 2023-24 summer



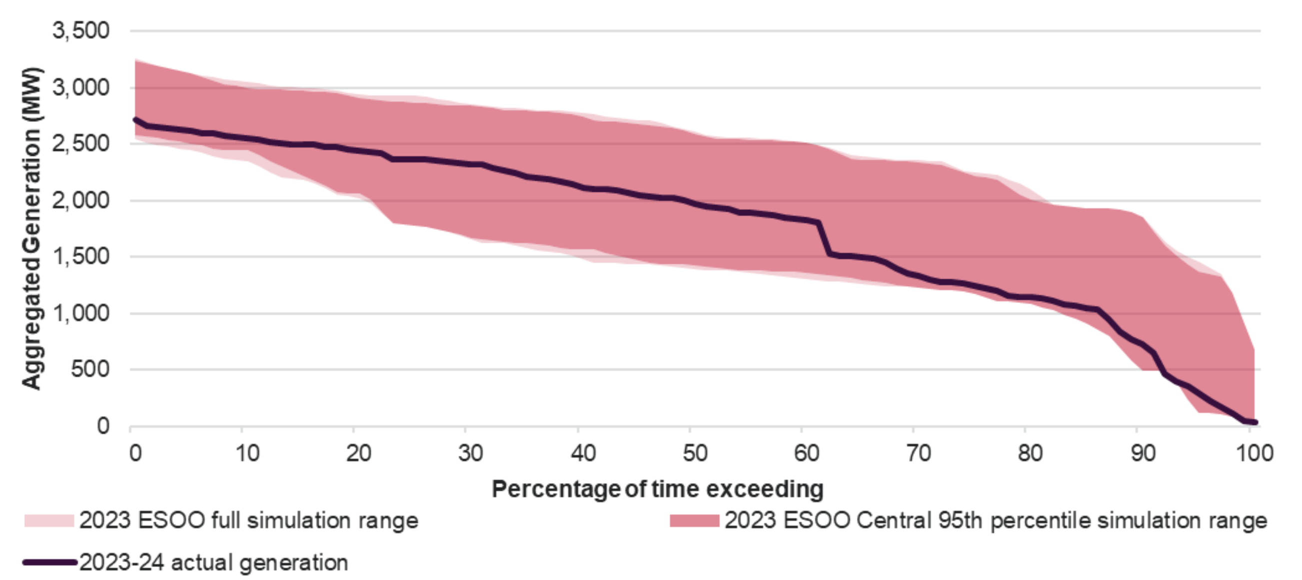
Note: The summer peak reference temperature for New South Wales is 42°C, Queensland is 37°C, South Australia is 43°C, and Victoria is 41°C. The summer peak reference temperature for Tasmania is 7.7°C, reflecting summer maximum demand in the region occurs during colder temperature.

6.1 Supply availability assessment

Example generation interpretation

Figure 42 shows an example graph of generation modelling accuracy, using New South Wales' large-scale solar generators as an example. It compares simulated generation (semi-scheduled generators and scheduled bidirectional units) or simulated availability (scheduled generators) 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) or actual availability (scheduled generators) for identified periods of each simulated, or actual year, ordered from highest to lowest availability. The red range shows the 2023 ESOO simulated aggregate generation of this generation class for 80 intervals (40 hours) from the top 10 hottest days.

Figure 42 Example simulated and actual supply (New South Wales large-scale solar generation)



The 2023 ESOO simulated ranges, shown in red, demonstrate that aggregate solar output was expected to be as high as 3,237 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 2,722 MW and 30 MW. In this example, actuals are primarily within the simulation range, suggesting that actual generation output aligned with forecast outcomes.

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

- **New projects** – actual supply availability from all technology types of new projects was observed to be within or above forecast availability range in most regions, largely due to more projects commissioned earlier than the dates AEMO assumed.
- **Wind generation** – wind availability inputs provided by participants typically apply significant derating under high temperature conditions. Actual wind generation in Victoria and Tasmania largely exceeded the simulated range, likely due to relatively milder temperature conditions and potentially above expectation wind resources. Actual wind generation in other regions are within the simulated range despite the milder temperature observed.
- **Battery generation** – actual battery generation exceeded the simulated range in Queensland, driven by early commissioning of a project. In New South Wales, South Australia, and Victoria, battery generation mostly fell within simulated ranges.
- **Total actual supply availability** – despite milder temperatures and some projects beginning full operation earlier than anticipated by the ESOO modelling methodology, total observed supply was within simulated ranges across all regions, constrained by planned and unplanned outages, development delays, and lower than expected generation from VRE generators.

6.1.1 New South Wales

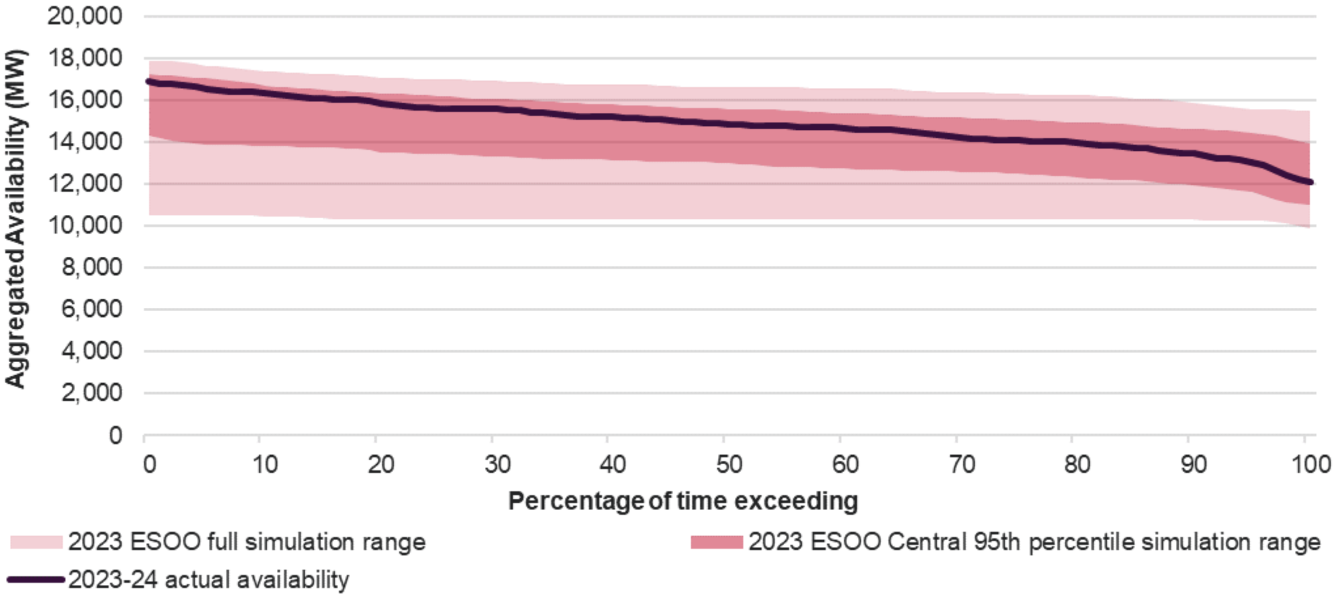
AEMO collects generation information from participants on the commissioning, decommissioning, and the capacity of individual production units. **Table 25** compares data from the 2023 ESOO to actual generator characteristics in February 2024. Five projects, including two wind farms and three batteries, released capacity ahead of the schedule assumed in the ESOO that incorporated expected development and commissioning delay[60], and contributed to additional capacity. However, this additional capacity was partially offset by longer-then-expected delays, as applied by the ESOO methodology, for a gas-fired generator and a battery project. As a result, the actual capacity exceeded the forecast by 76 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	49	5,558	51	5,799	-241	-4.2%
Non-VRE generation/storage	51	13,349	53	13,184	165	1.3%
All generation	100	18,907	104	18,983	-76	-0.4%

Figure 43 shows total summer availability during the identified high temperature periods. Milder than expected summer temperatures could have resulted in higher than forecast generation availability, but actual aggregate availability remained within the simulated range, with lower availability across solar, gas and liquid, and hydro generators.

Figure 43 New South Wales supply availability for the top 10 hottest days



[60] See Section 2.7 of the *ESOO and Reliability Forecast Methodology Document*, at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/reliability-forecasting-guidelines-and-methodology-consultation/final/esoo-and-reliability-forecast-methodology-document.pdf?la=en.

Black coal

Figure 44 shows New South Wales black coal generators equivalent full unplanned outage rates, considering partial, full, and long duration outages. Compared to previous years, historical coal-fired generation reliability in New South Wales showed performance improvement in 2023-24, which represented higher availability than projected in the 2023 ESOO.

Figure 44 New South Wales black coal equivalent full unplanned outage rates, including long duration outages

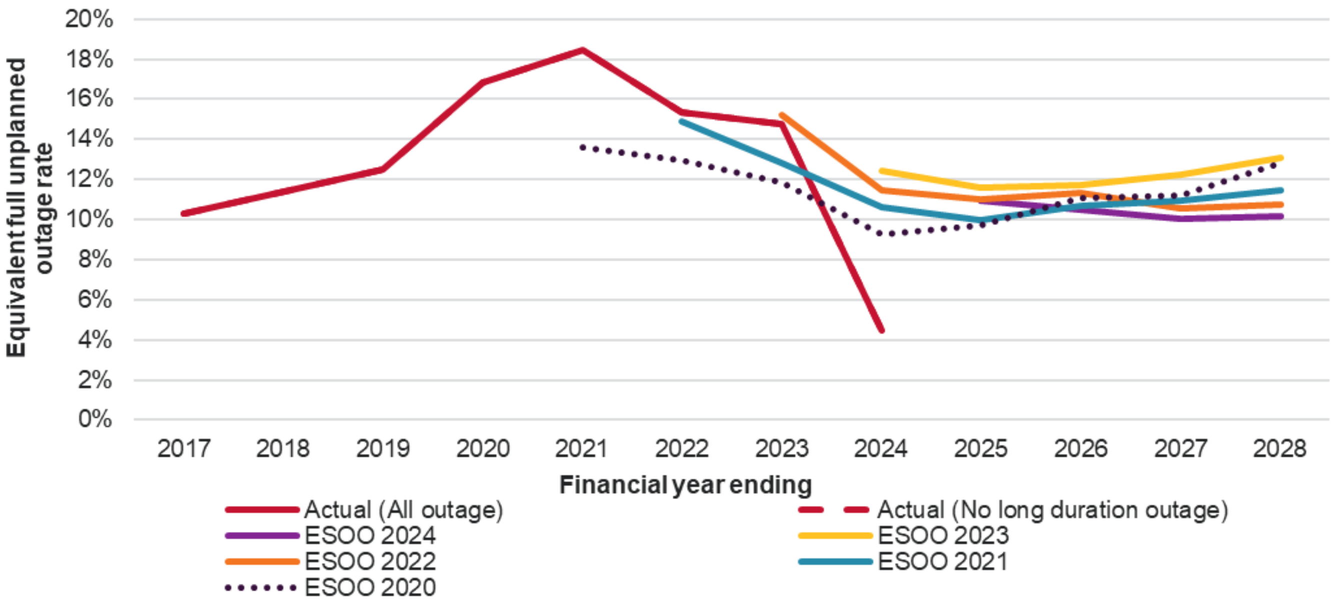
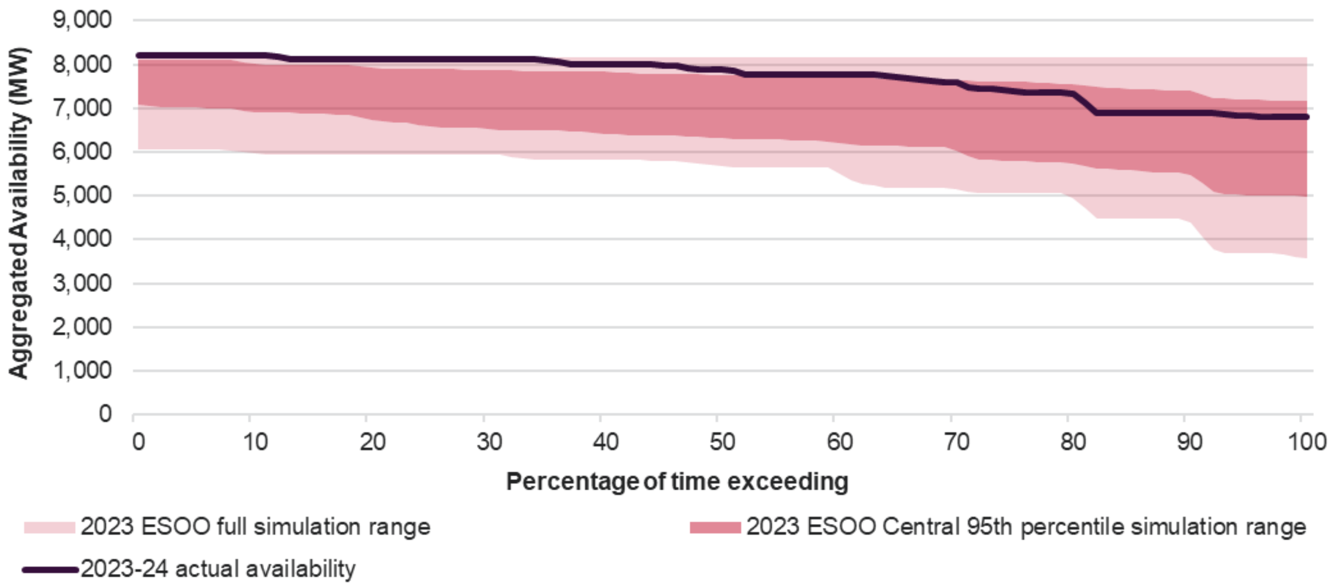


Figure 45 shows actual availability for New South Wales black coal generators over the top 10 hottest days was within the 2023 ESOO simulated range, with availability mostly above the central 95th percentile range.

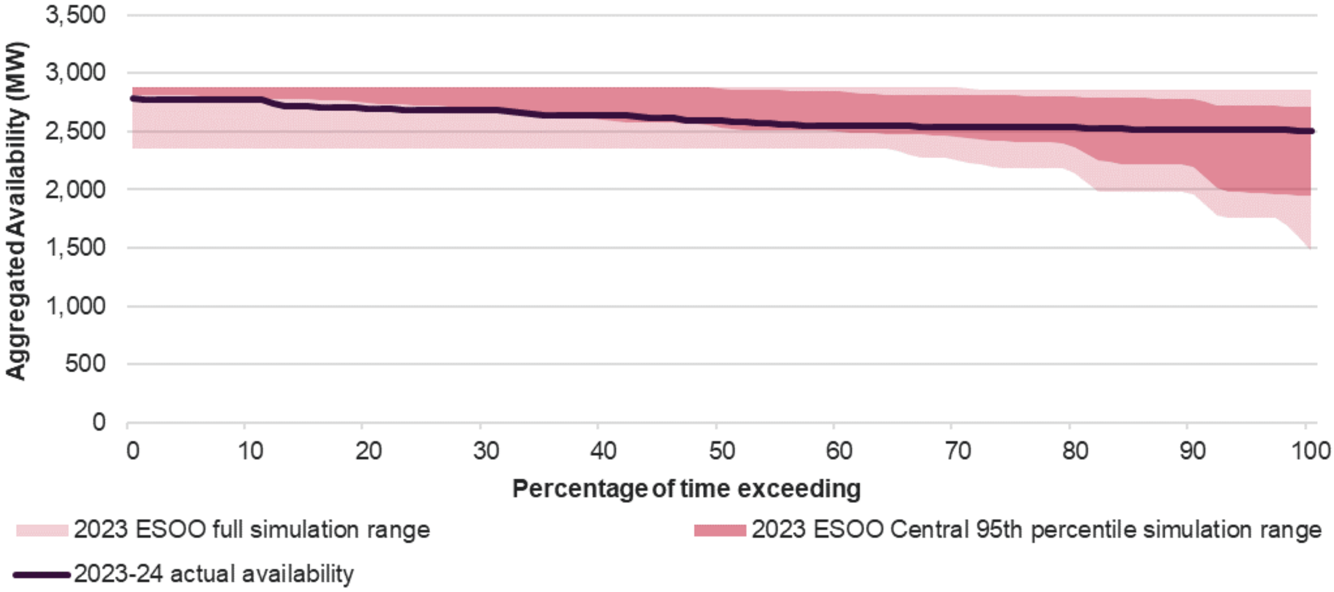
Figure 45 New South Wales black coal supply availability for the top 10 hottest days



Hydro

Figure 46 shows supply availability for New South Wales hydro generators over the top 10 hottest days, comparing actual with simulated availability. In 2023-24, the observed availability fell toward the lower end of the 2023 ESOO central 95th simulation range, largely due to unplanned outages at Shoalhaven.

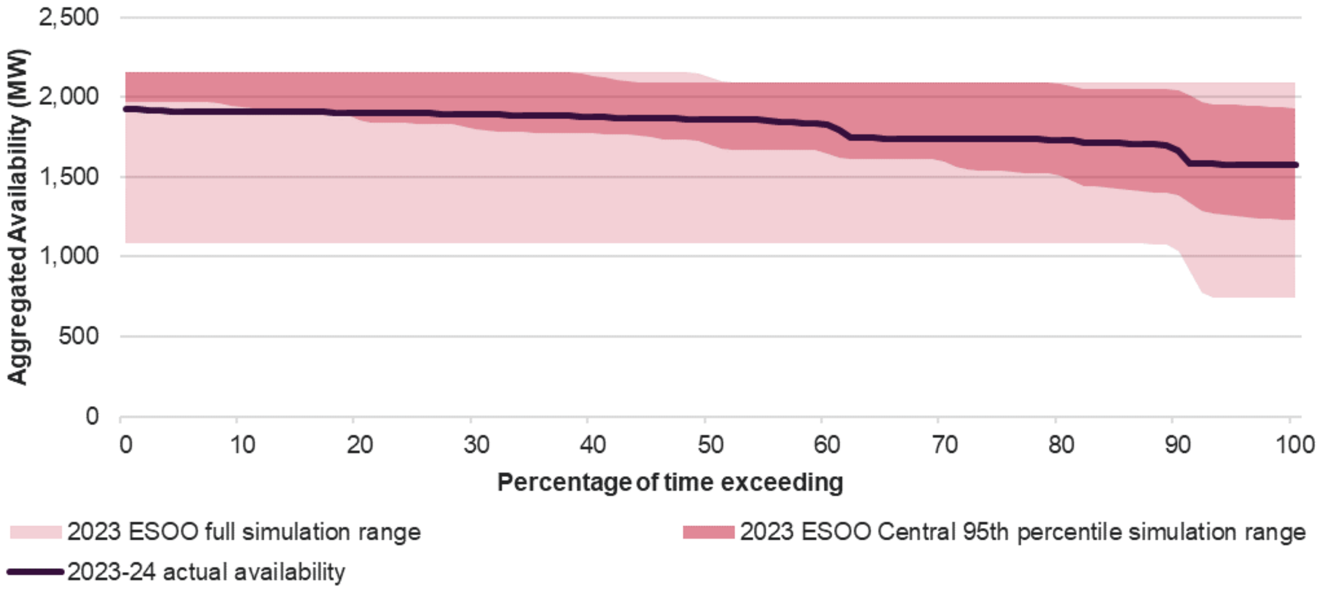
Figure 46 New South Wales hydro generation supply availability for the top 10 hottest days



Gas and liquids

Figure 47 shows supply availability for New South Wales gas and liquid generators over the top 10 hottest days, comparing actual with simulated availability. Actual availability is within the central 95th percentile simulated range, limited by planned and unplanned outages as well as the late commissioning of a gas generator.

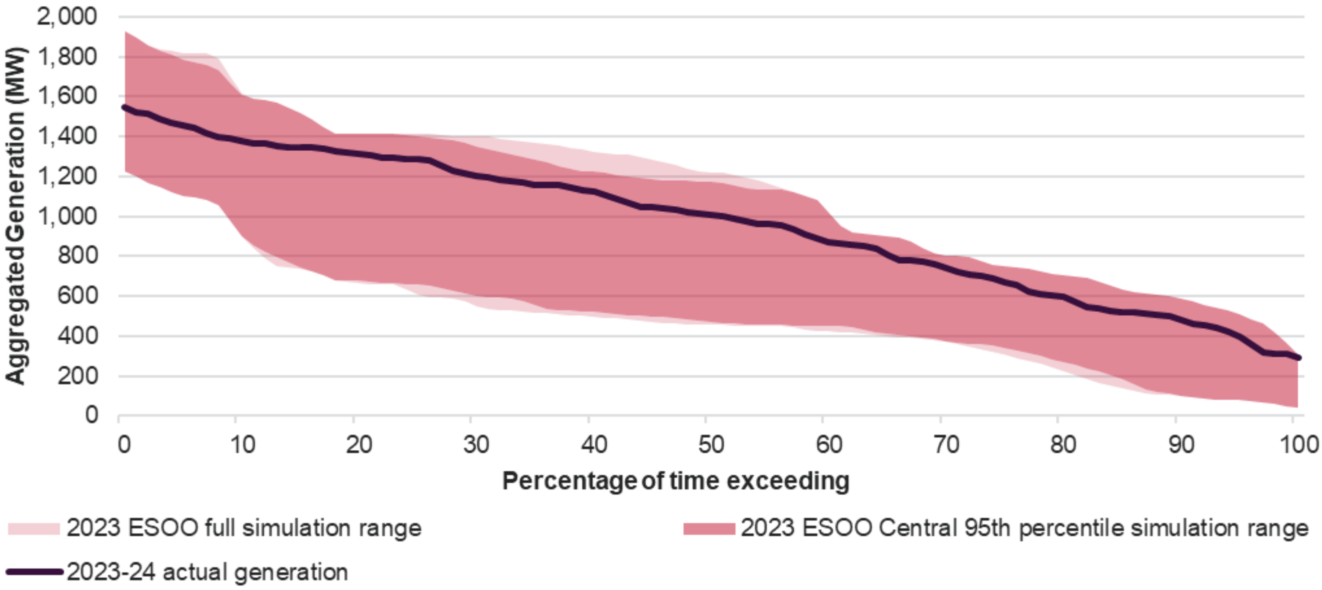
Figure 47 New South Wales gas and liquid supply availability for the top 10 hottest days



Wind

Figure 48 shows aggregate generation for New South Wales wind generators over the top 10 hottest days, comparing actual generation with simulated generation. Due to the absence of extreme temperatures in 2023-24 and commissioning of two wind farms earlier than their advised full commercial use dates (FCUD), which resulted in partial capacity being released during the summer, actual generation should have been above, or towards the upper end of the simulation range. Consistent with expectation, observed output is mostly within the higher end of the simulated range.

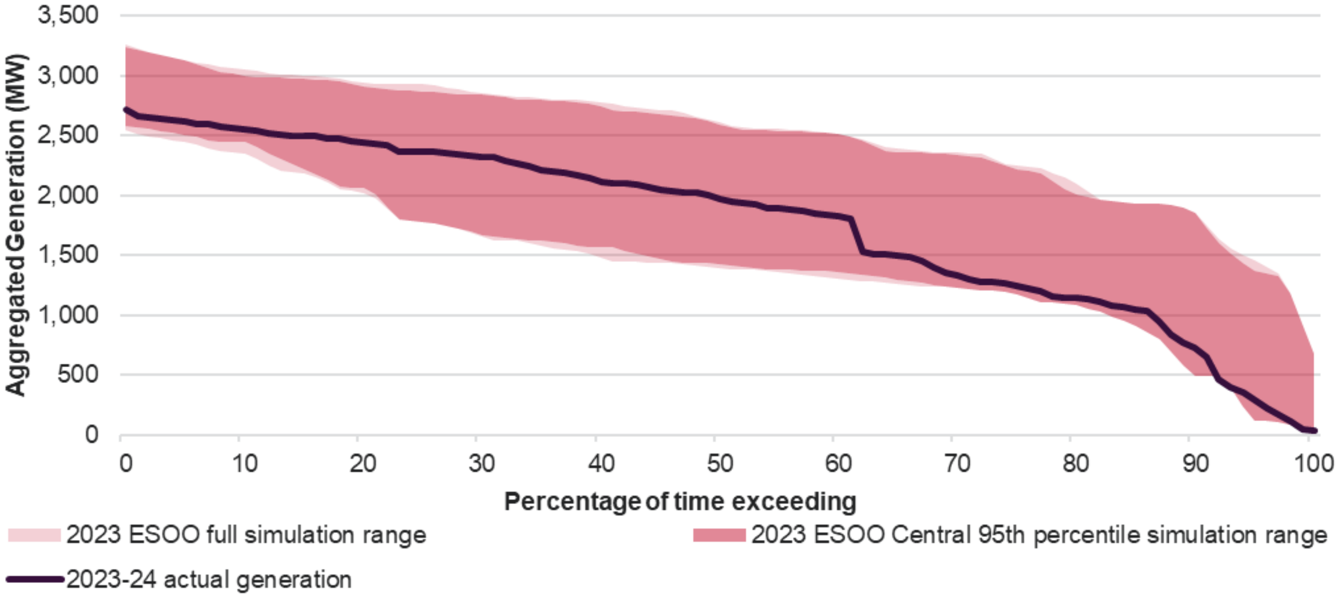
Figure 48 New South Wales wind generation for the top 10 hottest days



Large-scale solar

Figure 49 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 2023 ESOO. Solar generators output is noted towards the middle to lower end of the simulated range.

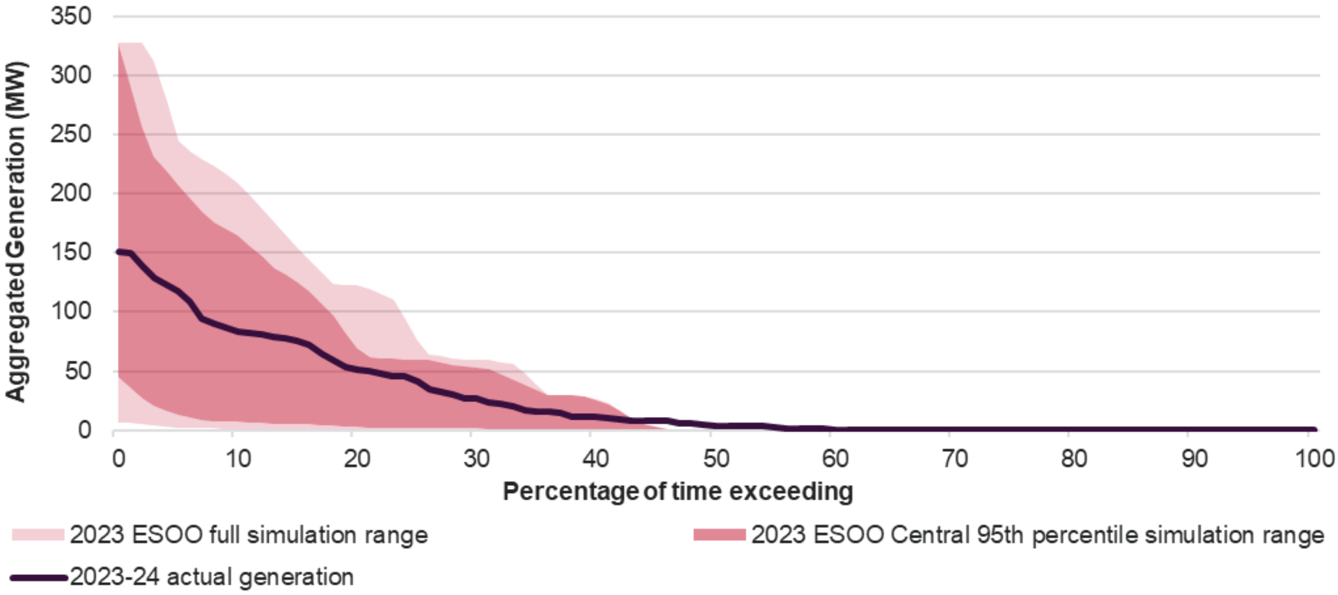
Figure 49 New South Wales large-scale solar generation for the top 10 hottest days



Battery

Figure 50 shows aggregate generation for New South Wales batteries over the top 10 hottest days, comparing actual generation with simulated generation in the 2023 ESOO. Actual battery generation is aligned well with the centre of the simulation range.

Figure 50 New South Wales battery generation for the top 10 hottest days



6.1.2 Queensland

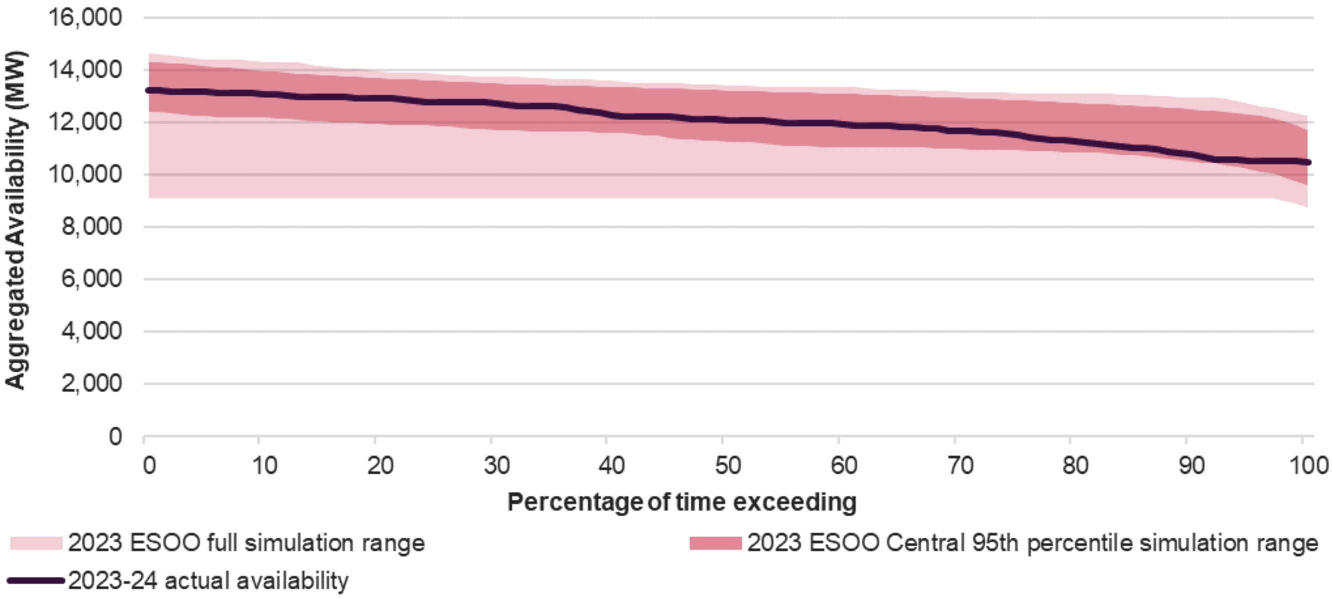
Table 26 shows how participant-provided generation information was implemented in the 2023 ESOO, compared to actual generator characteristics in February 2024. It highlights three projects that commenced full operation earlier than the ESOO modelling methodology, adding capacity in the summer, including one battery project, one solar project, and one wind project. In total, this results in 348 MW more actual capacity than was assumed would be available in the simulations.

Table 26 Forecast and actual generation count and capacity, February 2024

Queensland generation	Facilities forecast to operate		Facilities actually operating		Difference in capacity (forecast-actual)	
	Count	MW	Count	MW	MW	%
VRE generation	38	3,841	40	4,139	-298	-7.2%
Non-VRE generation/storage	54	11,676	55	11,726	-50	-0.4%
All generation	92	15,516	95	15,864	-348	-2.2%

Figure 51 shows total summer generation availability for Queensland's identified high temperature periods, comparing actual with simulated availability in the 2023 ESOO. Actual aggregate availability was mostly within the middle or towards the lower end of the 2023 ESOO simulated range, with lower availability from hydro and VRE generators.

Figure 51 Queensland supply availability for the top 10 hottest days



Black coal

Figure 52 shows the actual unplanned outage rate in 2023-24 was higher than the projection used in the 2023 ESOO, primarily due to the increased occurrences of long duration outages.

Figure 52 Queensland black coal equivalent full unplanned outage rates, including long duration outages

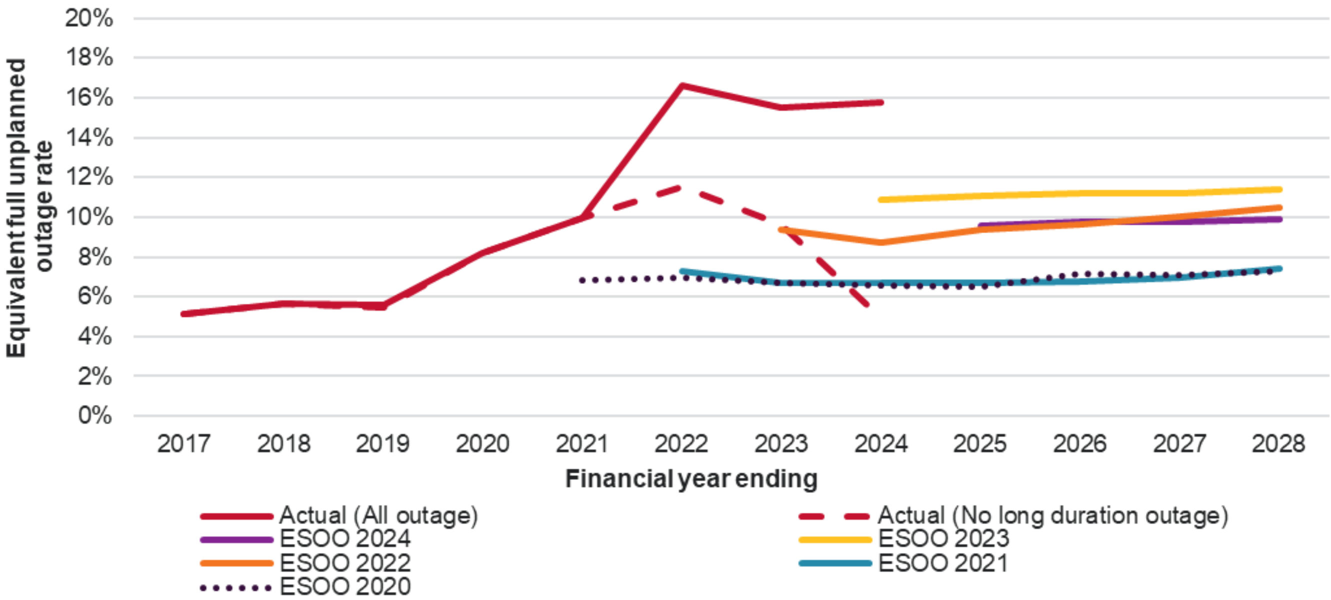
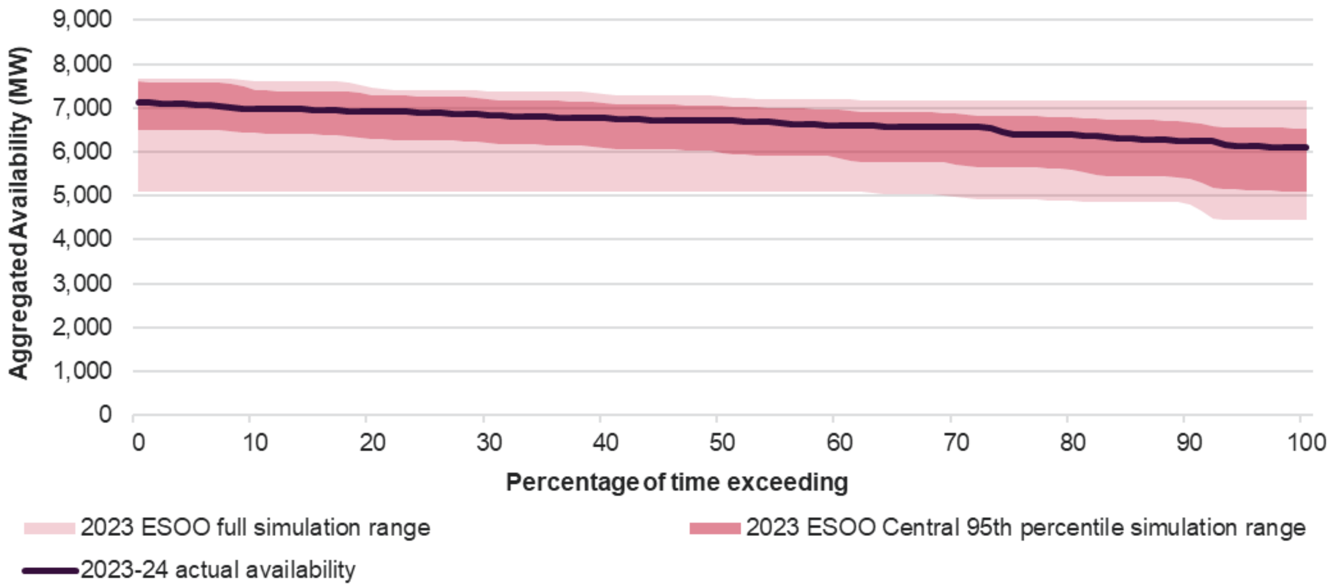


Figure 53 shows supply availability for Queensland black coal generators over the identified high temperature days, comparing actual with simulated availability. Actual availability is within the simulated range, due to lower than modelled temperatures and more planned and unplanned outages during the identified high temperature periods.

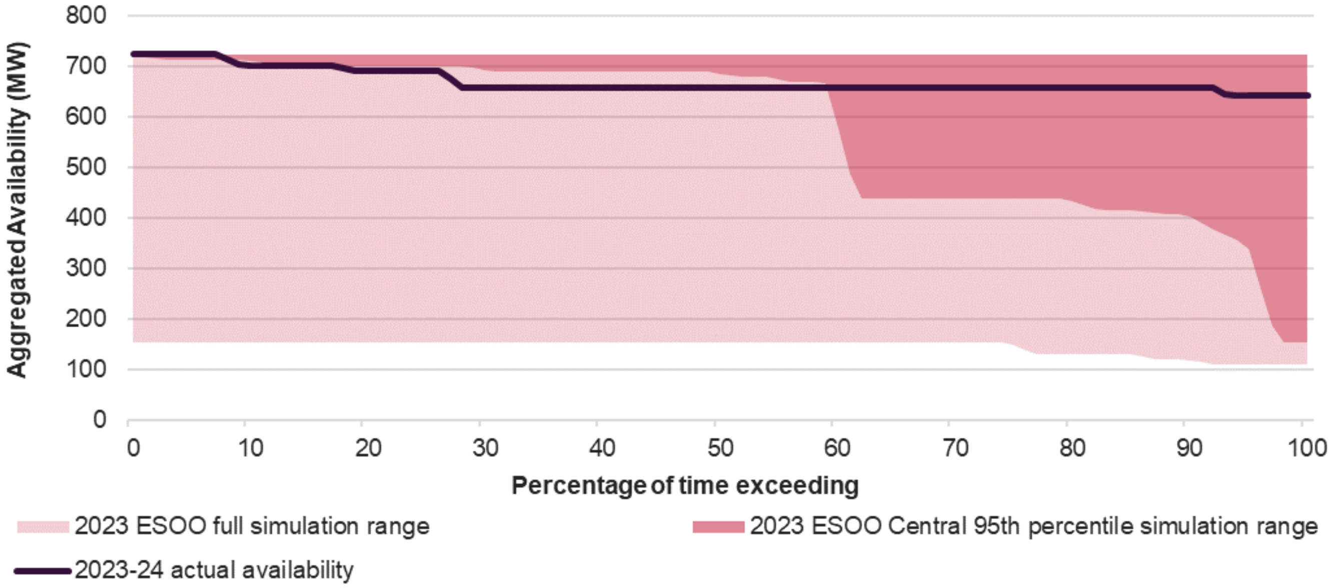
Figure 53 Queensland black coal supply availability for the top 10 hottest days



Hydro

Figure 54 shows supply availability for Queensland hydro generators over the top 10 hottest days, comparing actual with simulated availability. The observed actual availability was within or slightly below the central 95th percentile simulated range, influenced by the impact of planned and unplanned outages during the identified high temperature periods.

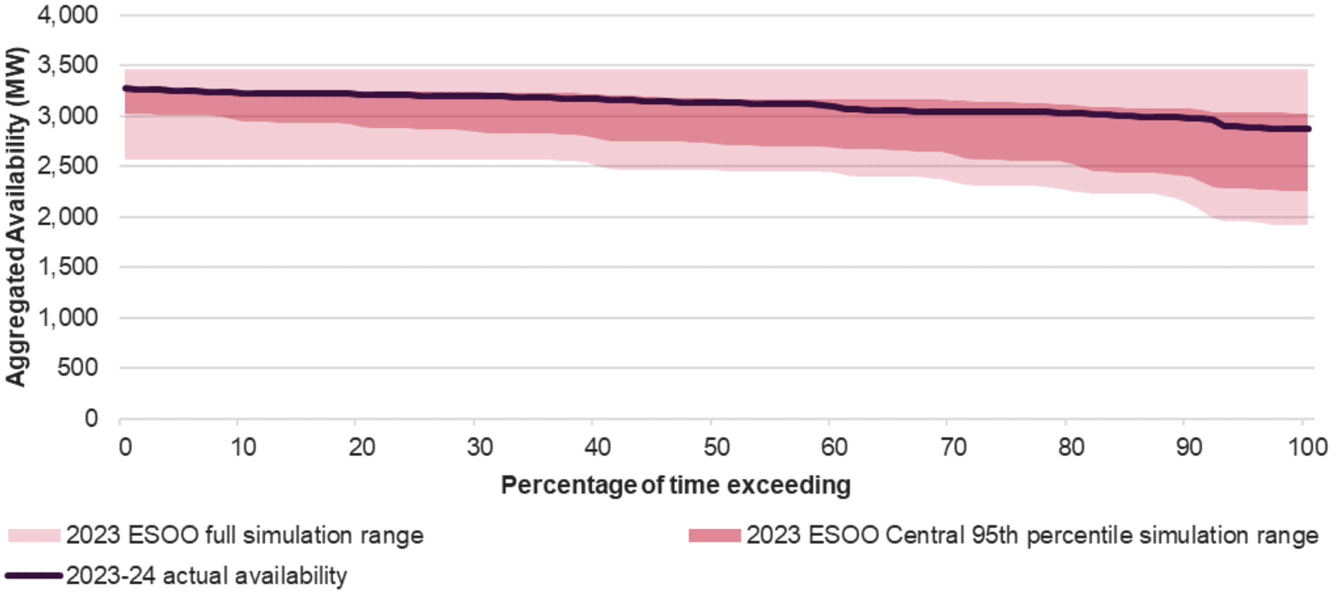
Figure 54 Queensland hydro generation supply availability for the top 10 hottest days



Gas and liquids

Figure 55 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 expected given the predominantly milder temperatures observed.

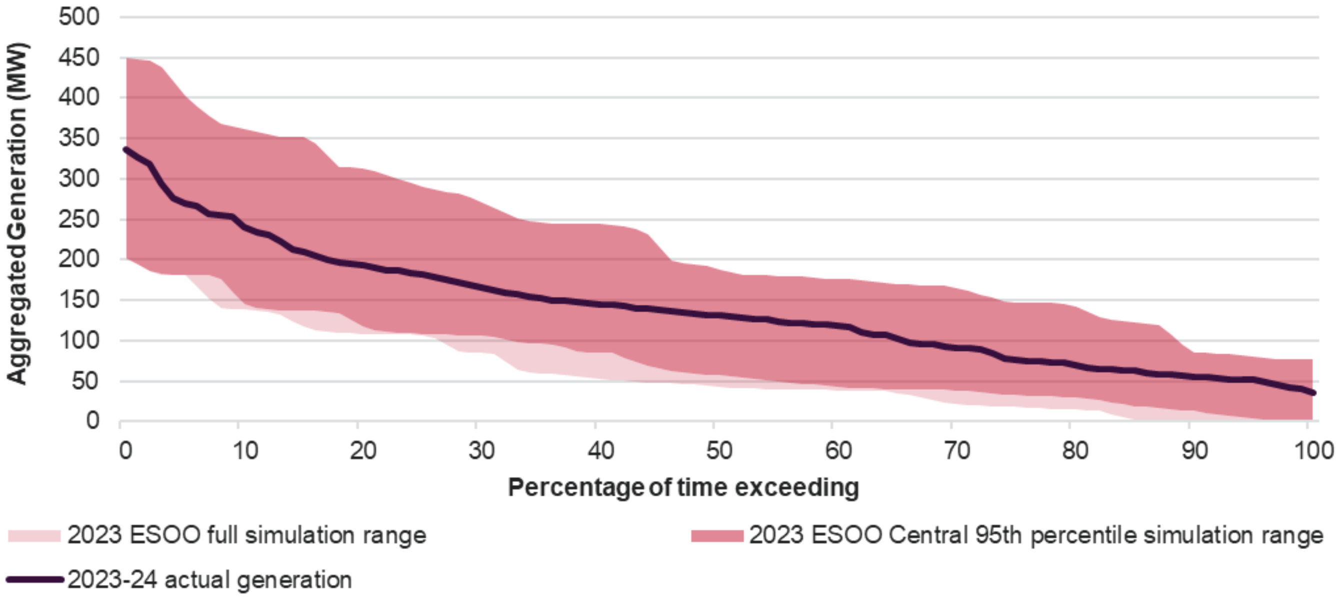
Figure 55 Queensland gas and liquids supply availability for the top 10 hottest days



Wind

Figure 56 shows wind generation supply for Queensland over the top 10 hottest days, comparing actual generation with the 2023 ESOO simulated generation range. The observed output was within the central 95th percentile simulated range; early commissioning of a wind farm and predominantly lower temperatures observed may be partially offset by potentially low wind conditions.

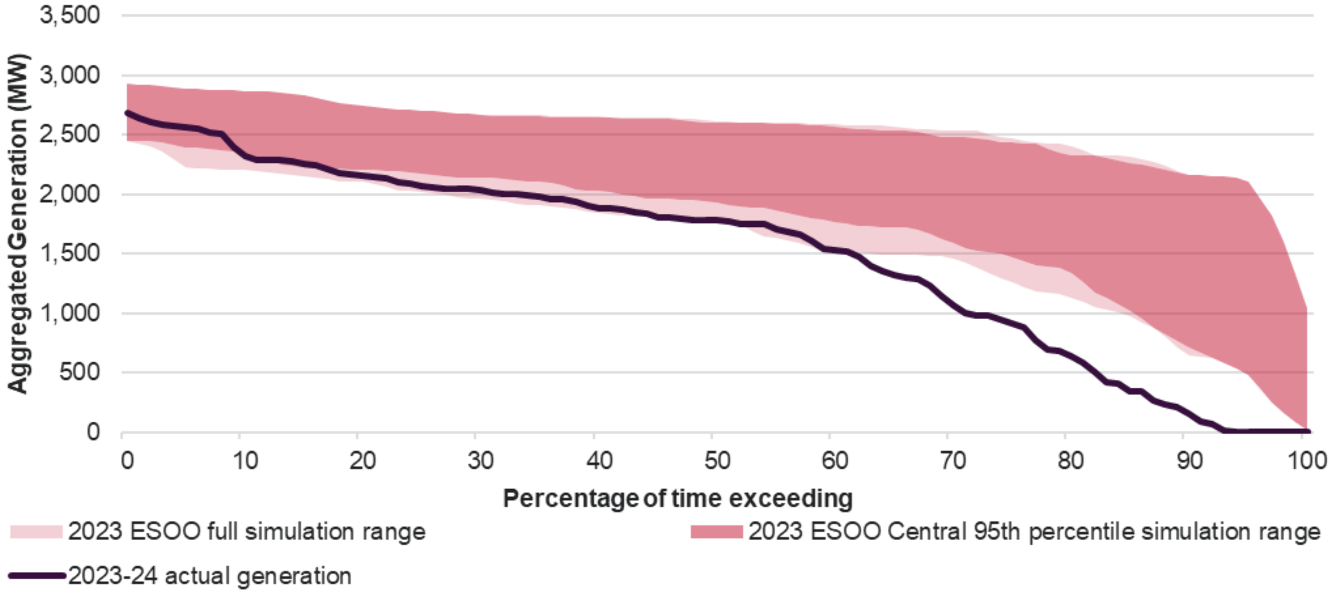
Figure 56 Queensland wind generation for the top 10 hottest days



Large-scale solar

Figure 57 shows the output of Queensland large-scale solar generators over the top 10 hottest days, comparing actual with the 2023 ESOO simulated generation range. Actual generation was mostly towards the lower end of or below the simulated availability range, despite early commissioning of a solar farm. This could be due to generator outages, or variation in the timing of maximum temperatures, which could result in more late day intervals included in the actual dataset compared to sampled intervals from ESOO simulations.

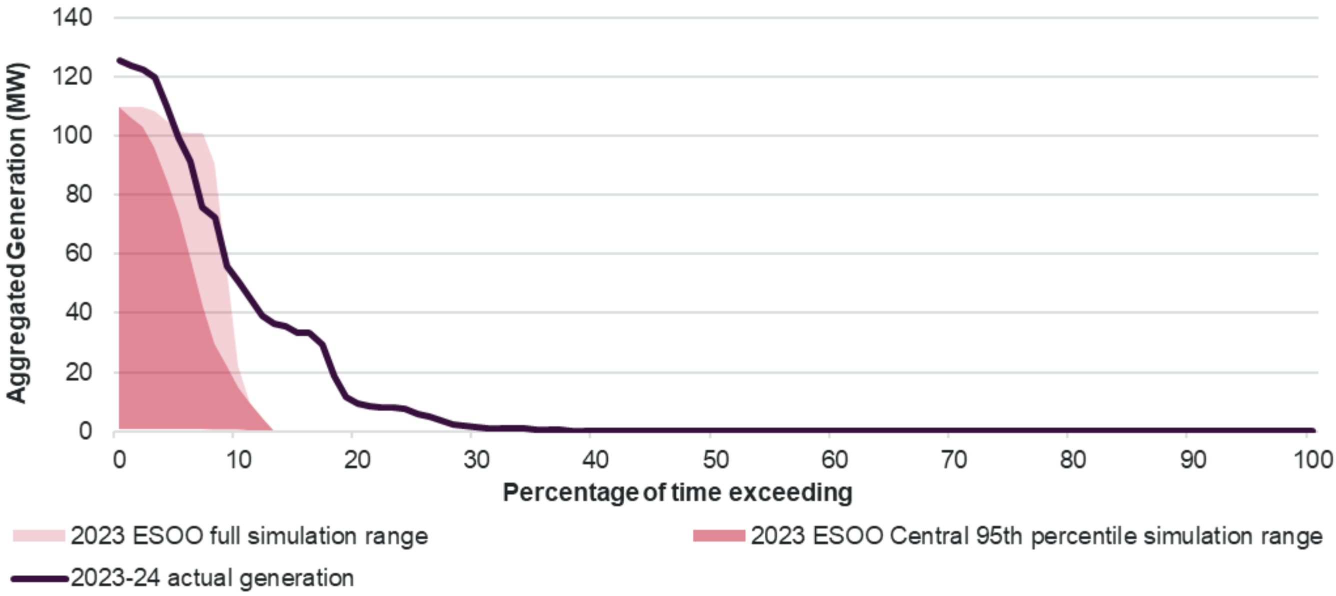
Figure 57 Queensland large-scale solar generation for the top 10 hottest days



Battery

Figure 58 shows aggregate generation for Queensland battery generators over the top 10 hottest days, comparing actual generation with simulated generation in the 2023 ESOO. Among mainland regions, Queensland had the lowest forecast battery capacity available for the 2023-24 summer, with only one large-scale battery along with distributed batteries committed under VPPs included in the simulation. The observed output of batteries was mostly above the simulated range, driven by a battery project commencing full operation earlier than the ESOO modelling methodology.

Figure 58 Queensland battery generation for the top 10 hottest days



6.1.3 South Australia

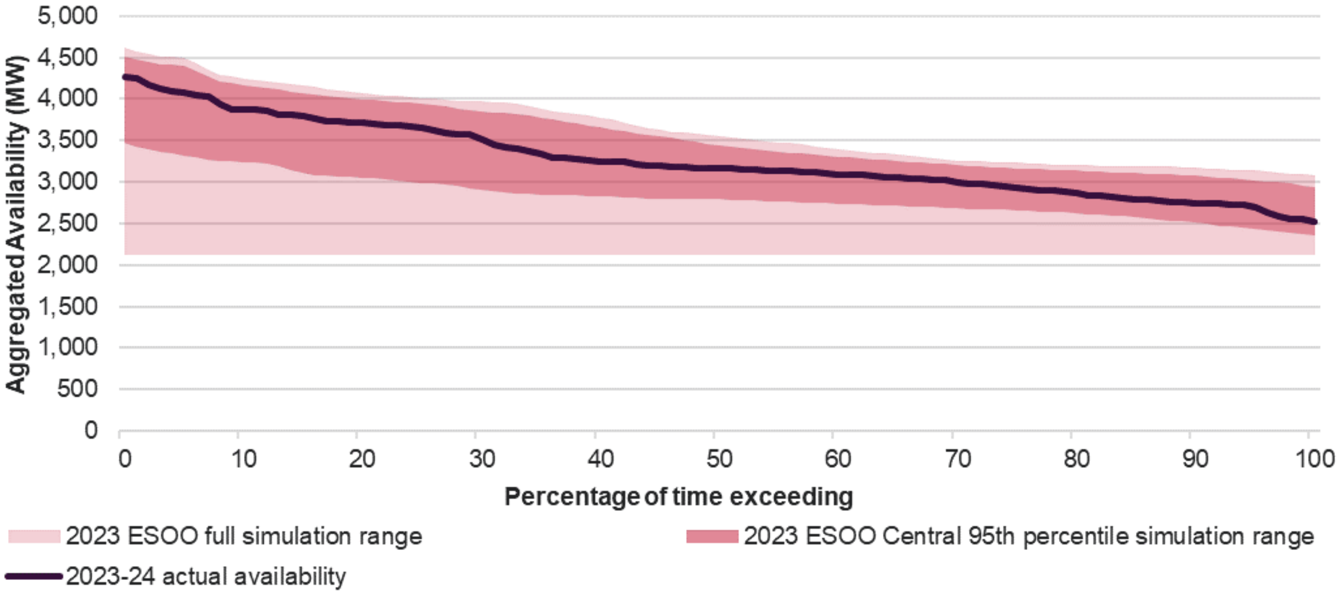
Generation information for South Australia, as reported by participants for the 2023 ESOO, is shown in **Table 27** alongside actual generator characteristics in February 2024. One solar project is noted to have been commissioned ahead of expectation, however the impact is offset by a wind project which did not meet advised schedules. Variation in these two projects led to 196 MW less actual VRE capacity than the 2023 ESOO forecast.

Table 27 Forecast and actual generation count and capacity, February 2024

South Australia	Facilities forecast to operate		Facilities actually operating		Difference in capacity (forecast-actual)	
	Count	MW	Count	MW	MW	%
VRE generation	39	3,120	39	2,924	196	6.7%
Non-VRE generation/storage	64	3,300	64	3,300	0	0.0%
All generation	103	6,420	103	6,224	196	3.1%

Figure 59 shows aggregate summer availability for South Australia during its identified high temperature periods. Actual aggregate availability was mostly within the 2023 ESOO simulated range, with lower availability from VRE and battery generators.

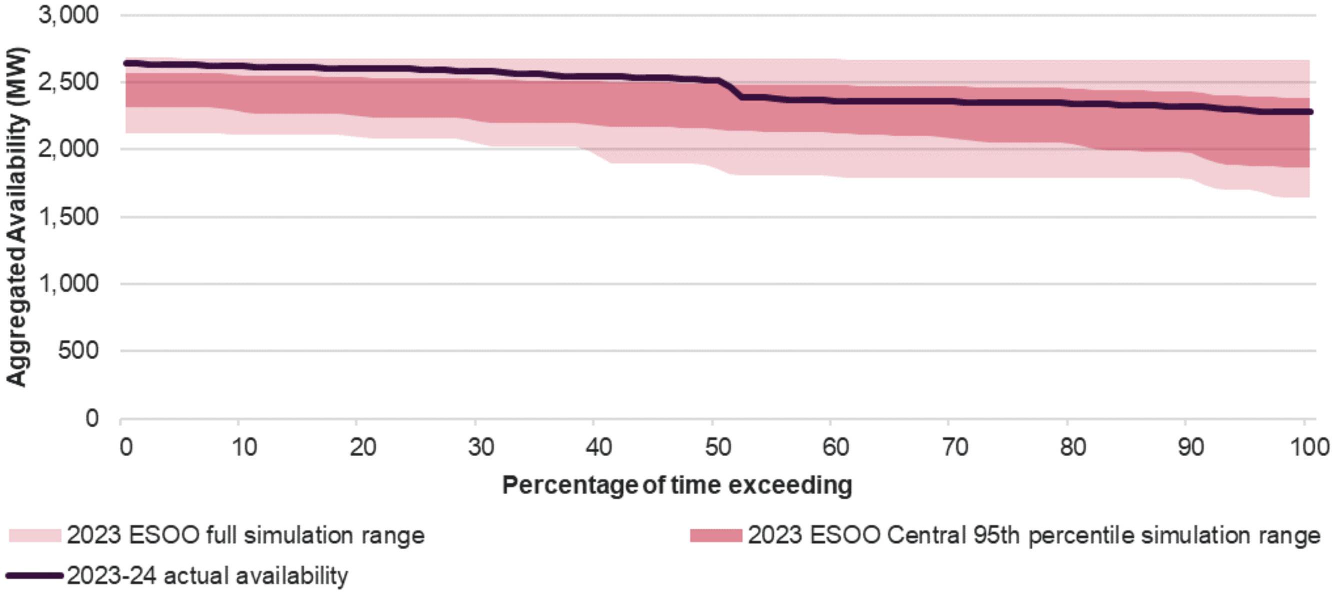
Figure 59 South Australia supply availability for the top 10 hottest days



Gas and liquids

Figure 60 shows that availability over the top 10 hottest days for gas and liquid generators was mostly above or towards the upper end of the 2023 ESOO central 95th percentile simulation range. This result aligns with expectation given the milder temperatures observed in 2023-24 in South Australia.

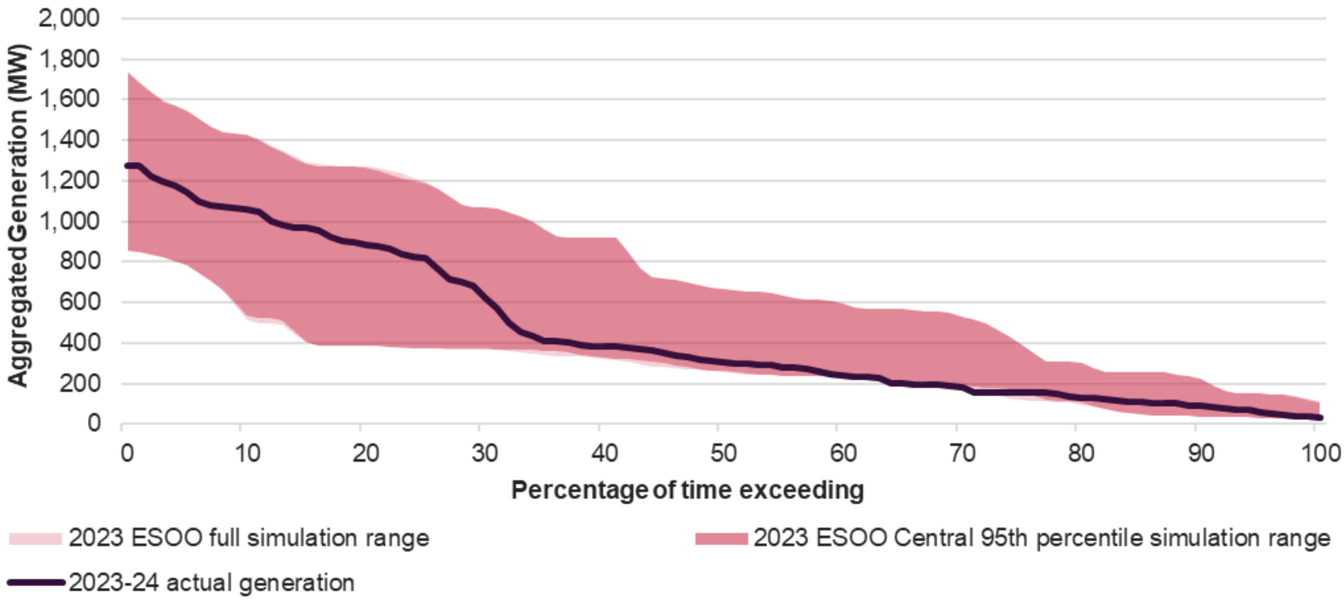
Figure 60 South Australia gas and liquids supply availability for the top 10 hottest days



Wind

Figure 61 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 lower end of the 2023 ESOO central 95th percentile simulation range, due to development delays and potentially low wind conditions.

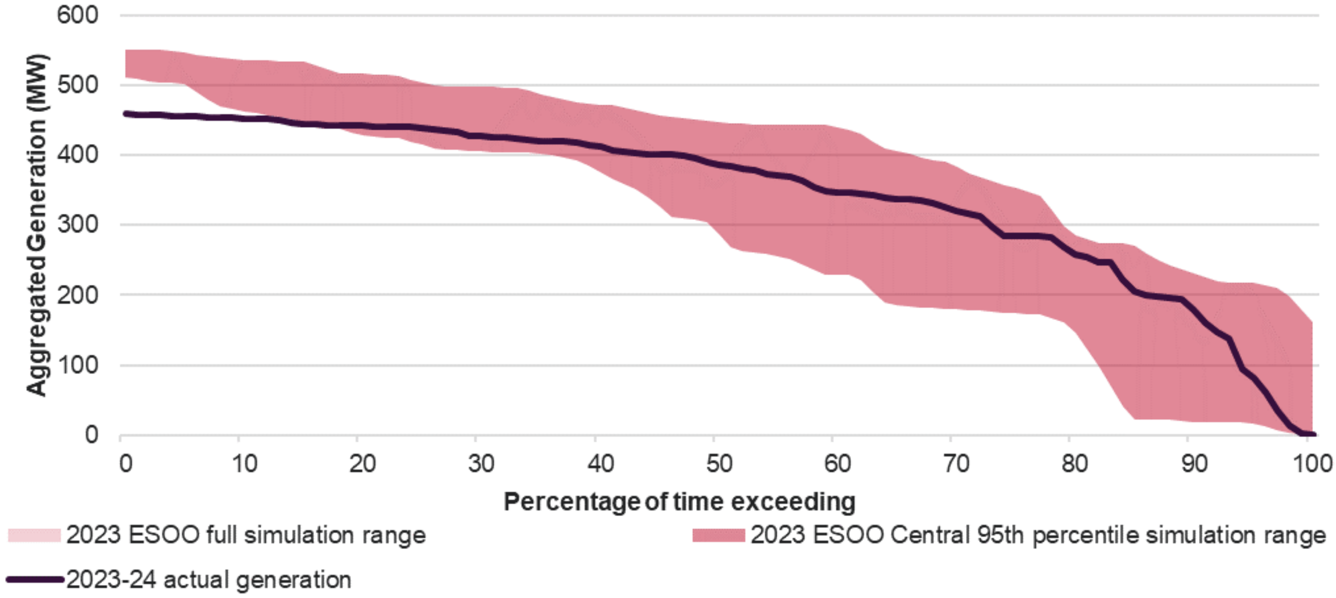
Figure 61 South Australia wind generation for the top 10 hottest days



Large-scale solar

Figure 62 shows aggregate generation for South Australian large-scale solar generators over the top 10 hottest days, comparing actual generation with simulated generation. In 2023-24, the observed generation was predominantly within the simulation range.

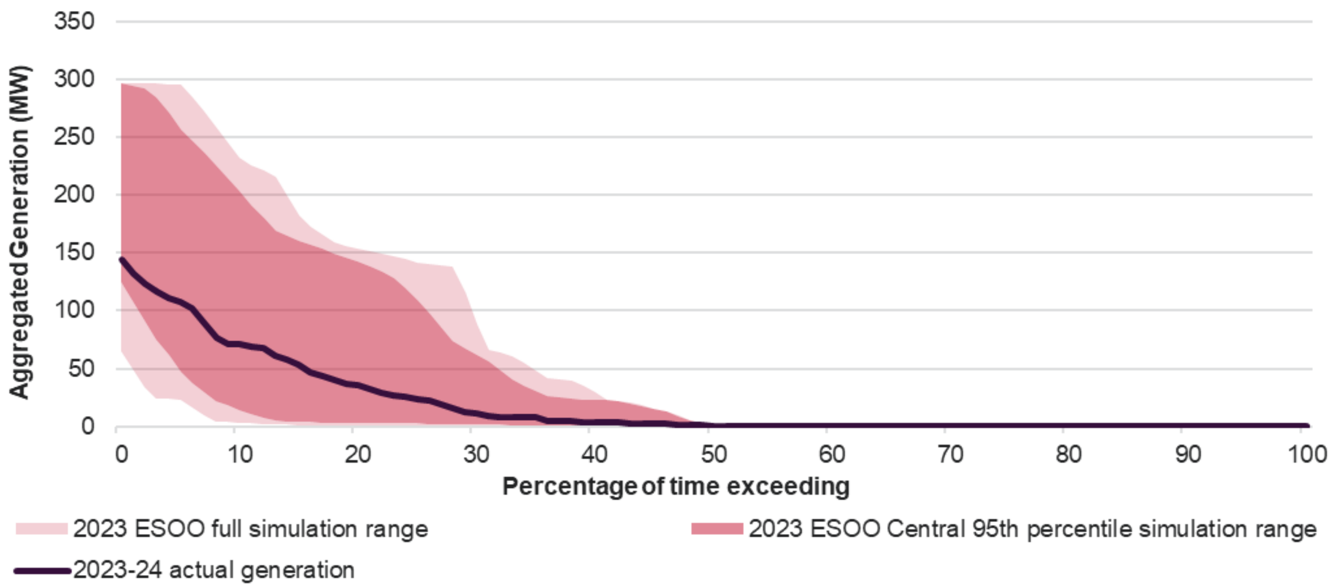
Figure 62 South Australia large-scale solar generation for the top 10 hottest days



Battery

Figure 63 shows aggregate generation for South Australian battery generators over the top 10 hottest days, comparing actual generation with simulated generation in the 2023 ESOO. The observed output of batteries was at the lower end of the simulated range.

Figure 63 South Australia battery generation for the top 10 hottest days



6.1.4 Tasmania

Table 28 shows how generation information for Tasmania was implemented in the 2023 ESOO, compared to actual generator characteristics for February 2024. No new developments were expected to commission in Tasmania, and therefore new developments did not provide a cause for variation. While Tasmania is a winter-peaking region, the availability of surplus dispatchable hydro generation coupled with the availability of Basslink provides important support to the mainland during summer peak demand events.

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	563	4	563	0	0%
Non-VRE generation/storage	46	2,145	46	2,145	0	0%
All generation	50	2,708	50	2,708	0	0%

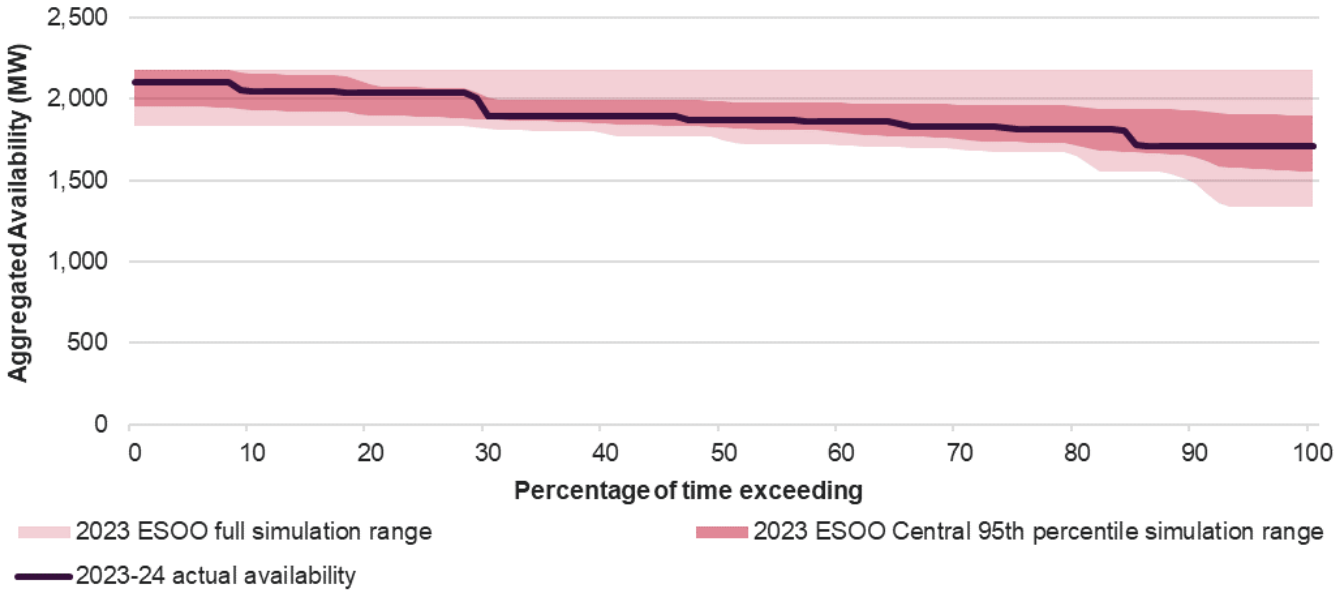
Figure 64 shows total summer availability for Tasmania for the highest temperature periods. Actual aggregate availability was mostly within the simulation range, with higher than expected wind availability compensating for lower gas and liquid capacity.

Figure 64 Tasmania supply availability for the top 10 hottest days

Hydro

Figure 65 Figure 65shows supply availability for Tasmanian hydro generators over the top 10 hottest days, comparing actual with simulated availability. The observed availability is within the 2023 ESOO simulated range with some planned outages during the identified high temperature periods noted.

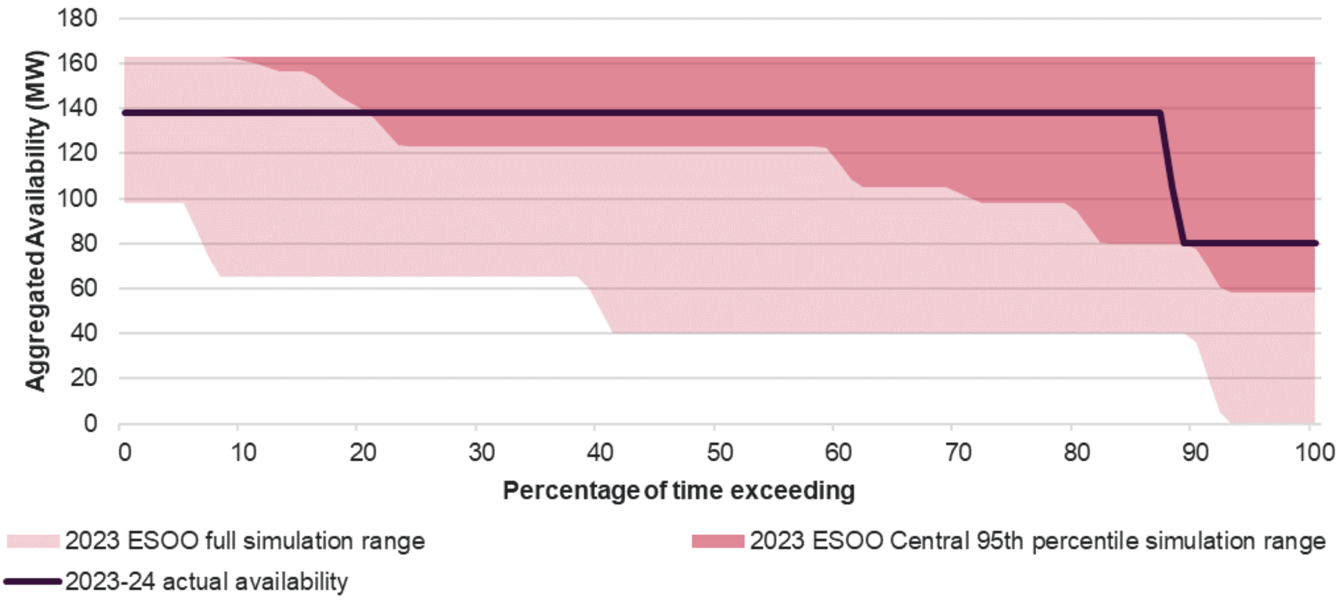
Figure 65 Tasmania hydro generation supply availability for the top 10 hottest days



Gas and liquids

Figure 66 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 within the 2023 ESOO central 95th percentile simulated range, with unavailability noted on some gas generators.

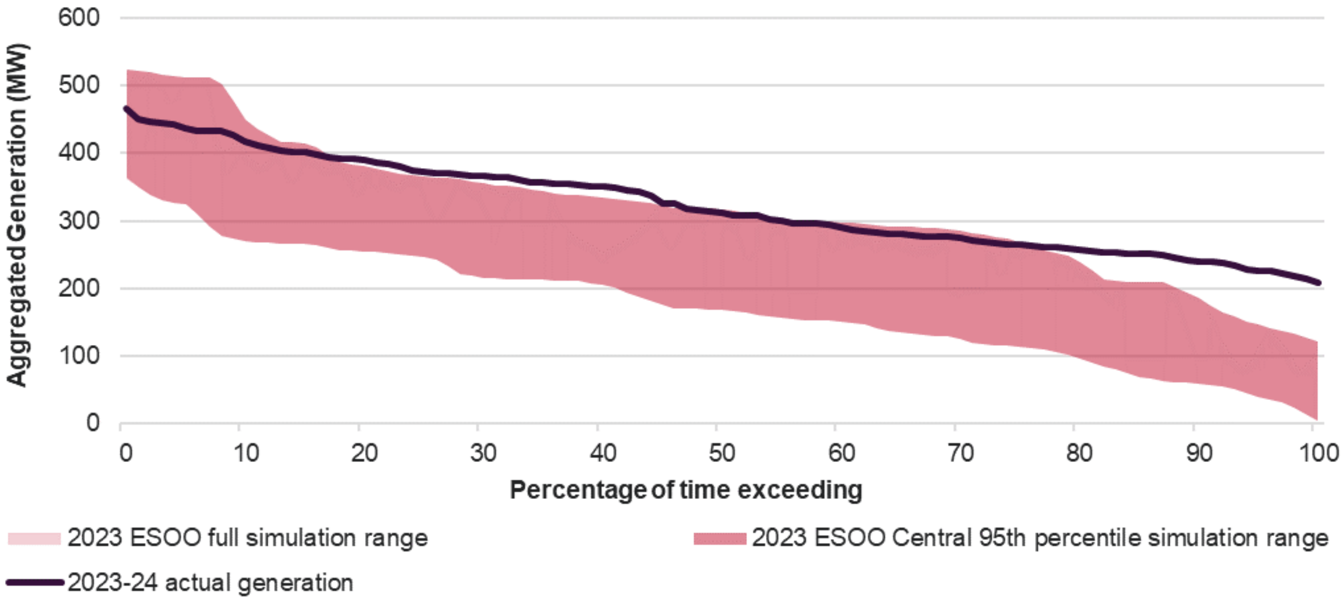
Figure 66 Tasmania gas and liquids supply availability for the top 10 hottest days



Wind

Figure 67 shows the output of Tasmanian wind generators over the top 10 hottest days, comparing actual generation with 2023 ESOO simulated generation. The observed wind output was mostly above or at the higher end of the 2023 ESOO central 95th percentile simulated range, likely due to more favourable wind conditions in Tasmania in summer 2023-24.

Figure 67 Tasmania wind generation for the top 10 hottest days



6.1.5 Victoria

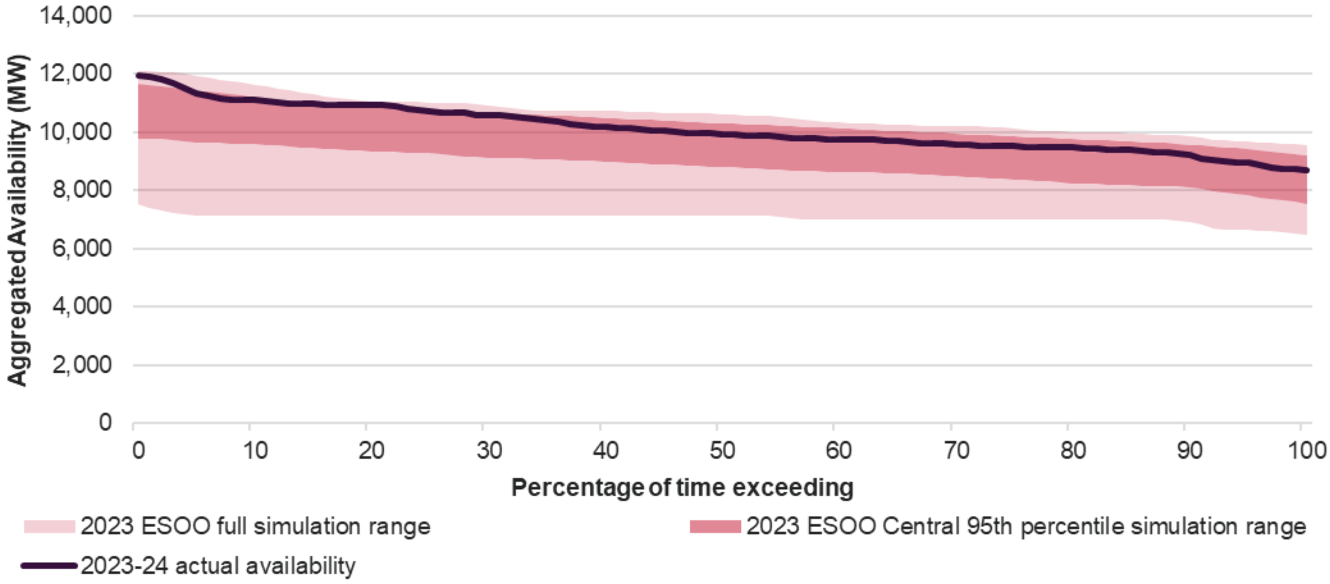
Victorian generation information, as reported by generator participants for the 2023 ESOO, is shown in **Table 29** alongside actual generator characteristics for February 2024. It identifies one early commissioned solar project and delays in the commissioning of two wind projects, providing marginally less actual aggregate availability (7 MW) than forecast.

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	38	5,182	39	5,189	-7	-0.1%
Non-VRE generation/storage	69	9,628	69	9,628	0	0.0%
All generation	107	14,811	108	14,817	-7	0.0%

Figure 68 shows aggregate summer availability for Victoria during its highest temperature periods. Actual availability generally aligned with the upper end of the 2023 ESOO simulated range. In general, hydro generation was less available than forecast, while VRE, brown coal, and gas and liquids performed at the upper end of forecast ranges, as expected given the milder temperatures observed comparing to the reference summer peak temperature in Victoria.

Figure 68 Victoria supply availability for the top 10 hottest days



Brown coal

Figure 69 demonstrates that the actual unplanned outage rate in 2023-24 was closely aligned with the 2023 ESOO forecasts, reflecting improved forecast accuracy from participant outage projection submissions.

Figure 69 Victoria brown coal equivalent full unplanned outage rates, forecasts including long duration outages

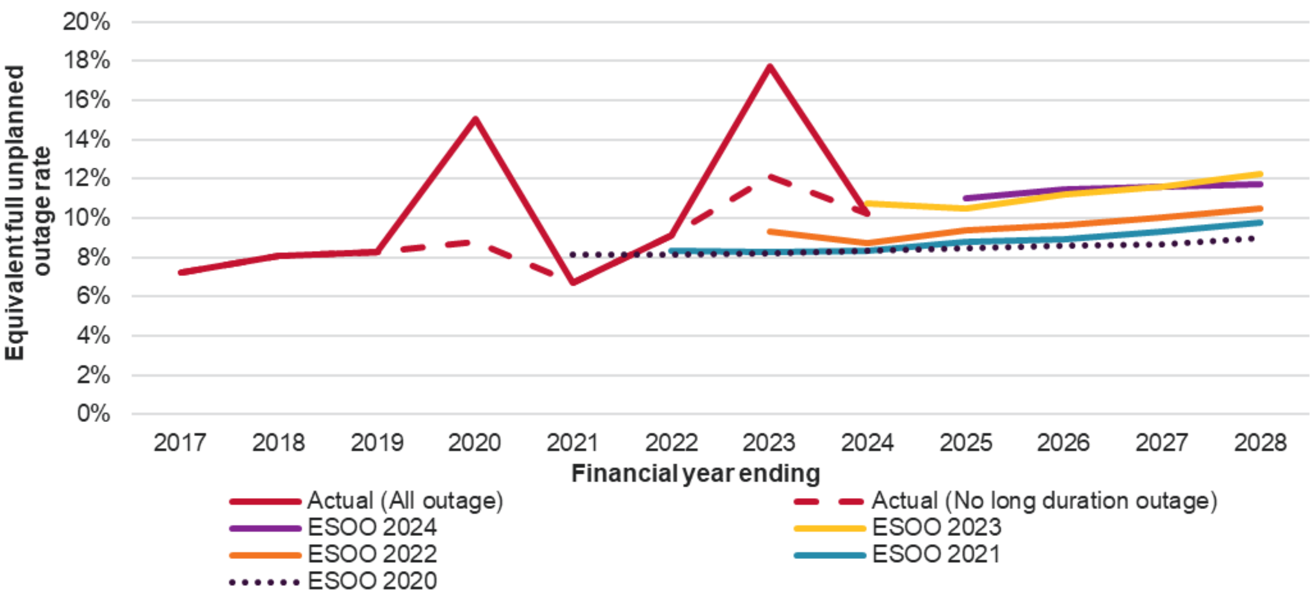
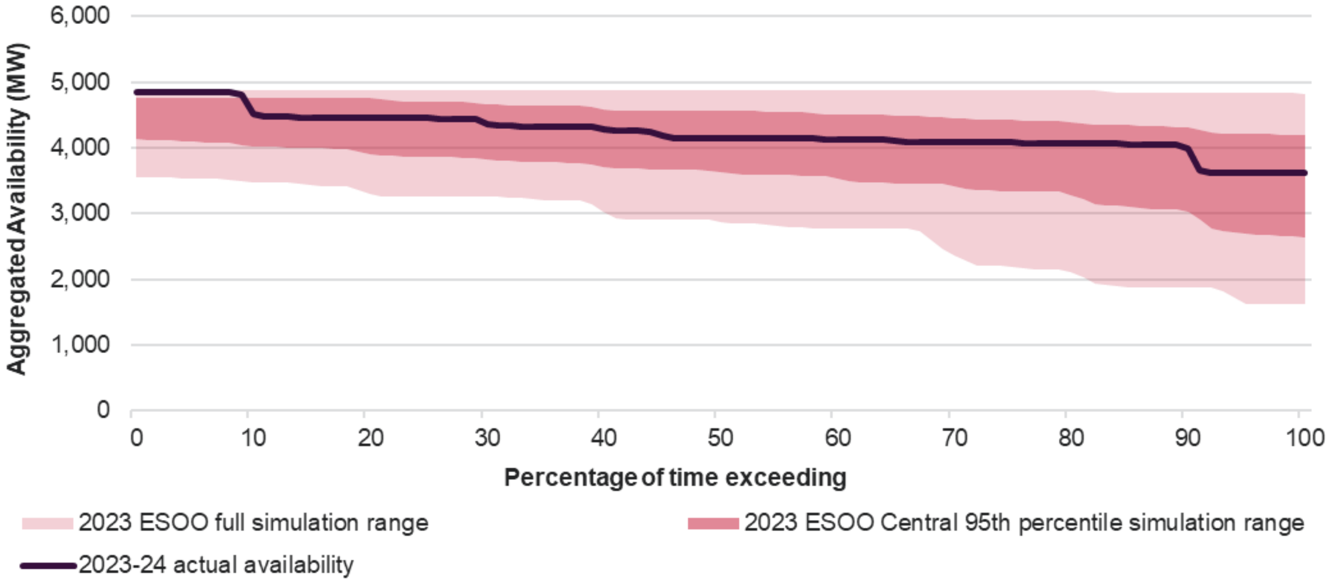


Figure 70 shows supply availability for Victorian brown coal generators over the top 10 hottest days, comparing actual with simulated availability. Due to the lack of extreme temperatures in the summer, actual availability should have been above the simulated range, but it remained within the 2023 ESOO central 95th percentile simulation range, due to planned and unplanned outages and deratings.

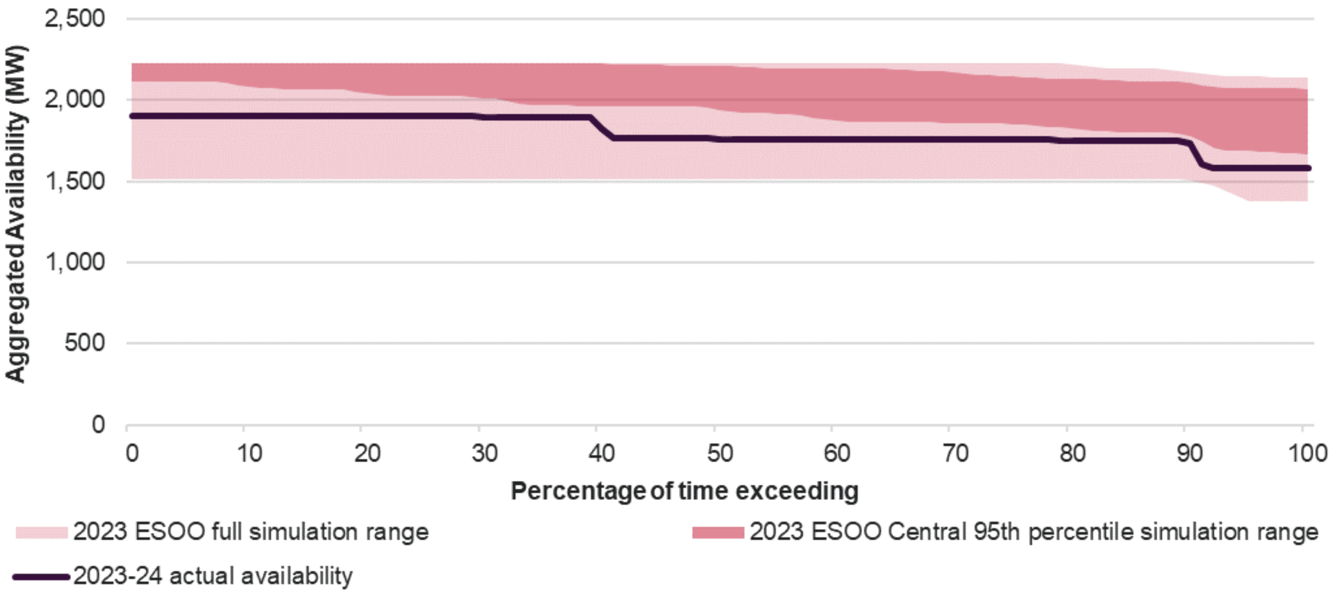
Figure 70 Victoria brown coal supply availability for the top 10 hottest days



Hydro

Figure 71 shows supply availability for Victorian hydro generators over the top 10 hottest days, comparing actual with simulated availability. Observed availability was below the 2023 ESOO central 95th percentile simulated range, contrary to expectations for a milder temperature summer. This is primarily due to unplanned outages at Murray and planned outages at Eildon.

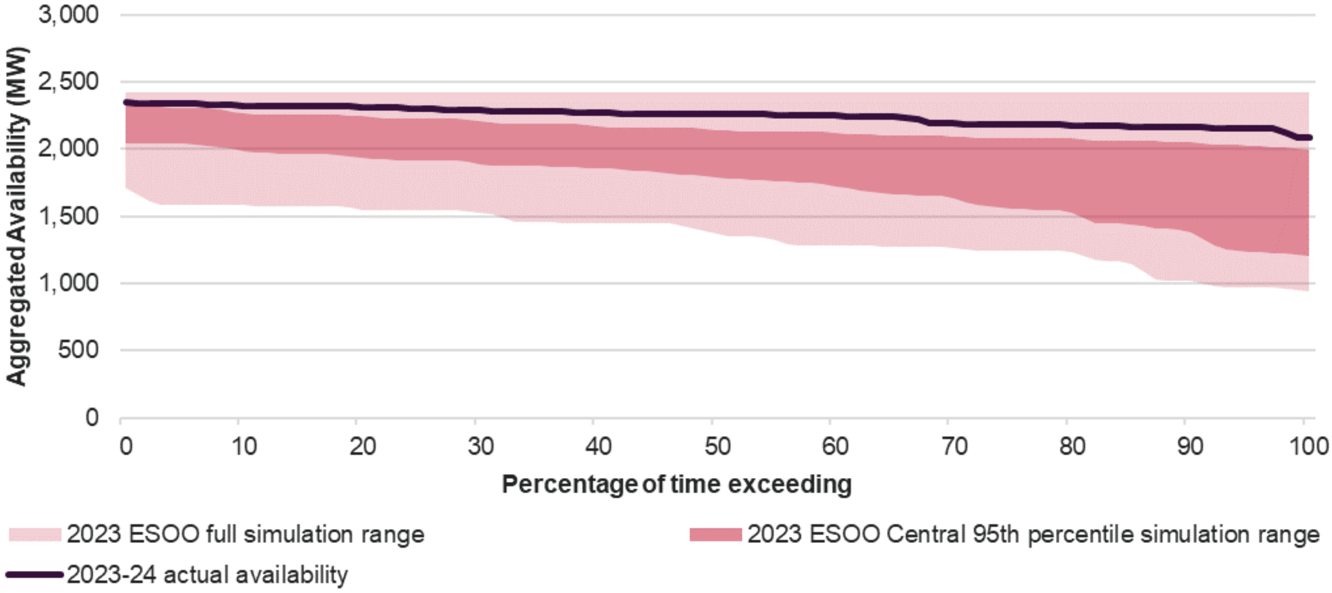
Figure 71 Victoria hydro generation supply availability for the top 10 hottest days



Gas and liquids

Figure 72 shows that observed availability over the top 10 hottest days was mostly above the 2023 ESOO central 95th percentile simulated range. This was mainly due to lower temperature derating, as expected given the relatively mild temperatures observed during these hottest days when comparing to the reference summer peak temperature.

Figure 72 Victoria gas and liquids supply availability for the top 10 hottest days

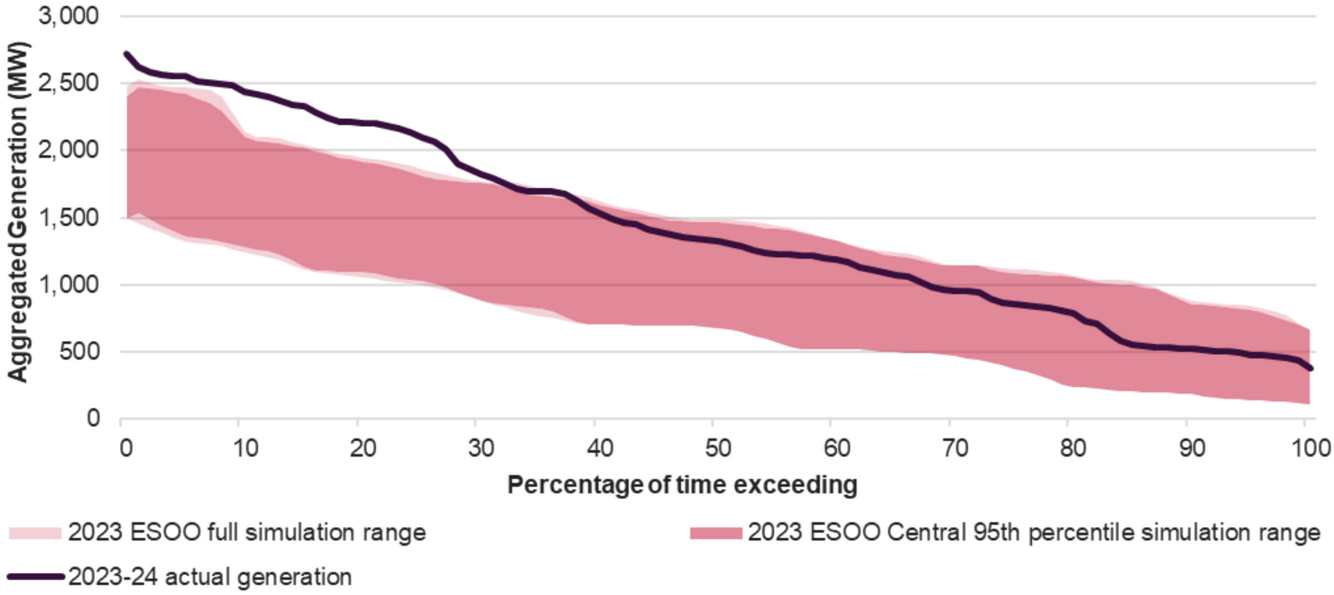


Wind

Figure 73 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 or within the upper end of the 2023 ESOO central 95th percentile simulated range, despite two wind farms[61] reaching full output later than the participants advised FCUDs. This was largely driven by reduced derating of wind generation due to lack of the extreme temperatures in Victoria in summer 2023-24 and potentially above expectation wind resources.

[61] As these two wind farms were in the commissioning phase, they were assumed as per the ESOO modelling methodology to become fully operational on the FCUD provided by the developers in the 2023 ESOO.

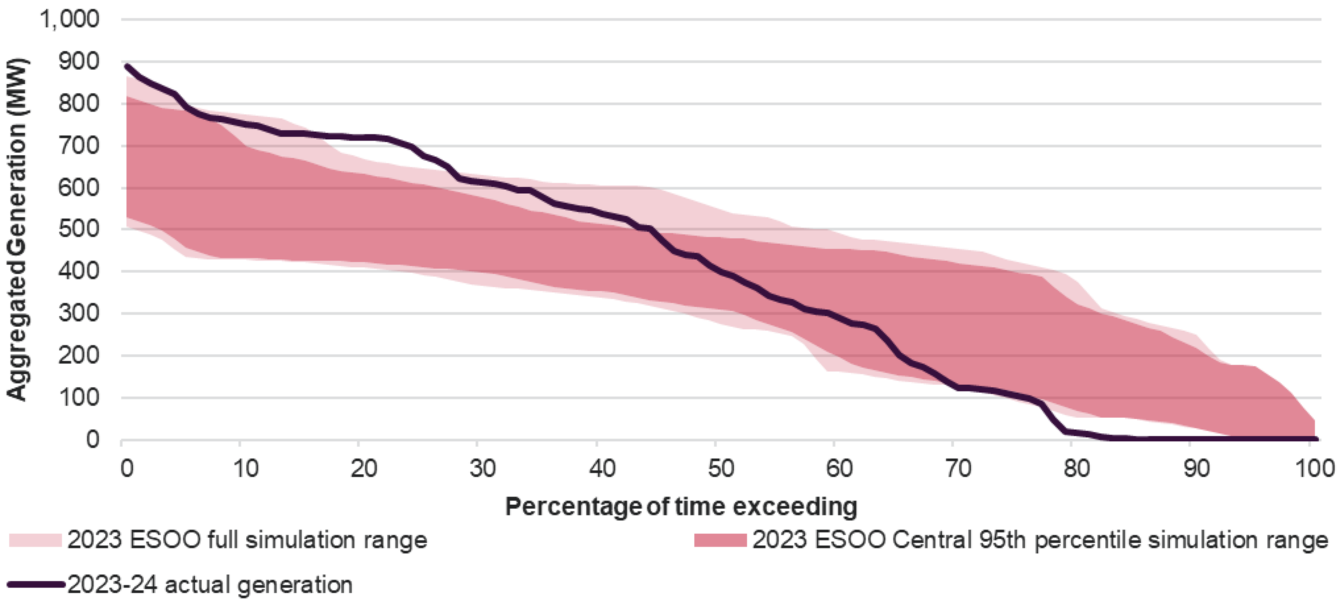
Figure 73 Victoria wind generation for the top 10 hottest days



Large-scale solar

Figure 74Figure 74 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 varied, being above the central 95th percentile simulated range for almost half the time, likely driven by early commissioning of a solar farm, which began full operation ahead of the timeline assumed by the ESOO modelling methodology. Other times actual output is noted below the simulation range, likely due to the timing of events included in the comparison, with actual events likely occurring later in the day where solar irradiance is lower.

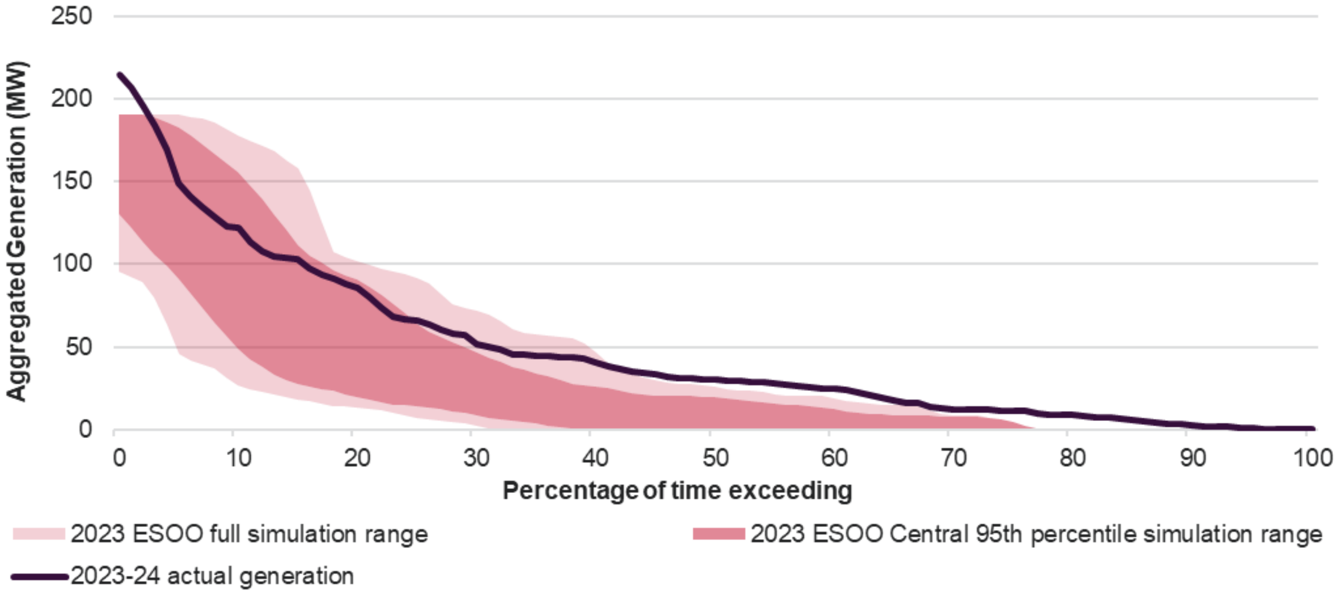
Figure 74 Victoria large-scale solar generation for the top 10 hottest days



Battery

Figure 75 shows aggregate generation for Victorian batteries over the top 10 hottest days, comparing actual generation with simulated generation in the 2023 ESOO. Observed battery generation was mostly within or at the upper end of the simulated range. In limited circumstances, battery generation was found to be above the simulated range due to short duration storages dispatching at full or near full capacity for short intervals, which is inconsistent with storage capacity derating assumptions applied in the hourly ESOO model[62].

Figure 75 Victoria battery generation for the top 10 hottest days



[62] AEMO applies derating factors to the storage capacity of all short-duration storage systems. Since market modelling assumes perfect foresight in dispatching generation and storage, these factors are used to prevent the model from overestimating the optimal allocation of limited energy for such short-duration storages. See Section 2.6 of the *ESOO and Reliability Forecast Methodology for further information,* at: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2023/esoo-and-reliability-forecast-methodology-document.pdf?la=en.

7 Reliability forecasts

AEMO forecasts and reports on scarcity risk of generation supply availability, DSP, and inter-regional transmission capability, relative to demand. This forecast of supply scarcity risk is an implementation of the reliability standard[63] and Interim Reliability Measure[64], 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.

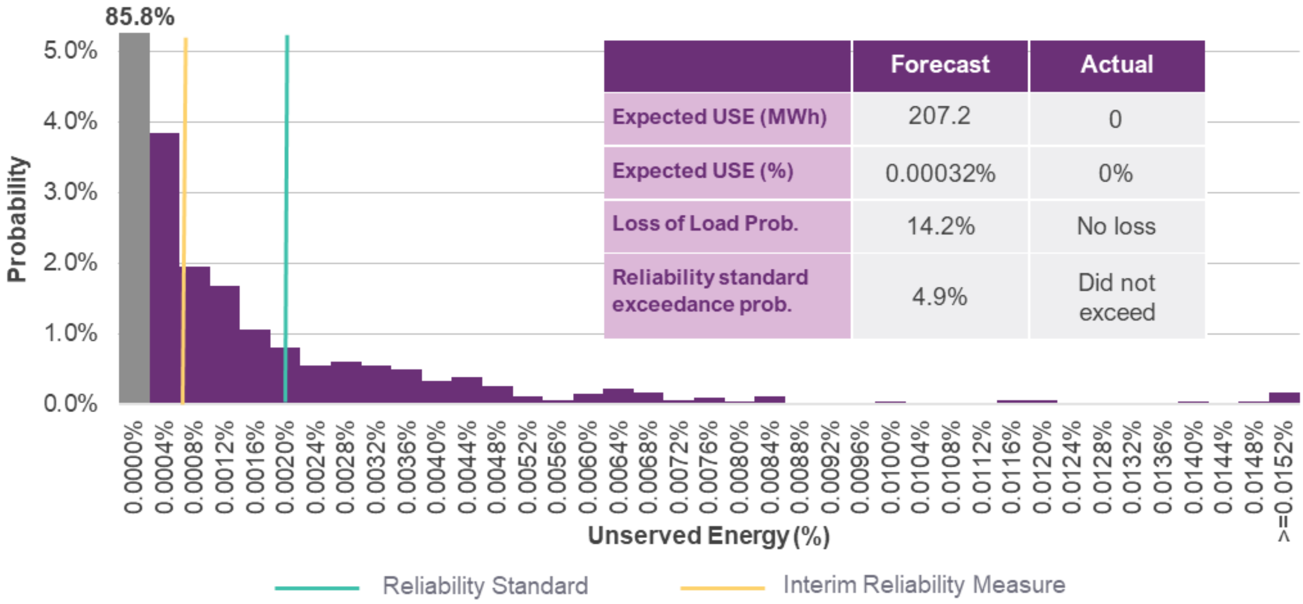
No USE events[65] occurred in 2023-24 in any region.

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. Further, if effective in soliciting a response from market or through RERT, the forecast USE should not eventuate.

7.1 New South Wales

Figure 76 shows the forecast distribution of USE in New South Wales for the 2023-24 summer in the 2023 ESOO. The probability of any loss of load was assessed at 14.2%. In 2023-24, no USE in accordance with the reliability standard definition was observed, an outcome predicted by 85.8% of simulations.

Figure 76 New South Wales USE forecast distribution for 2023-24 summer



	Forecast	Actual
Expected USE (MWh)	207.2	0
Expected USE (%)	0.00032%	0%
Loss of Load Prob.	14.2%	No loss
Reliability standard exceedance prob.	4.9%	Did not exceed

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

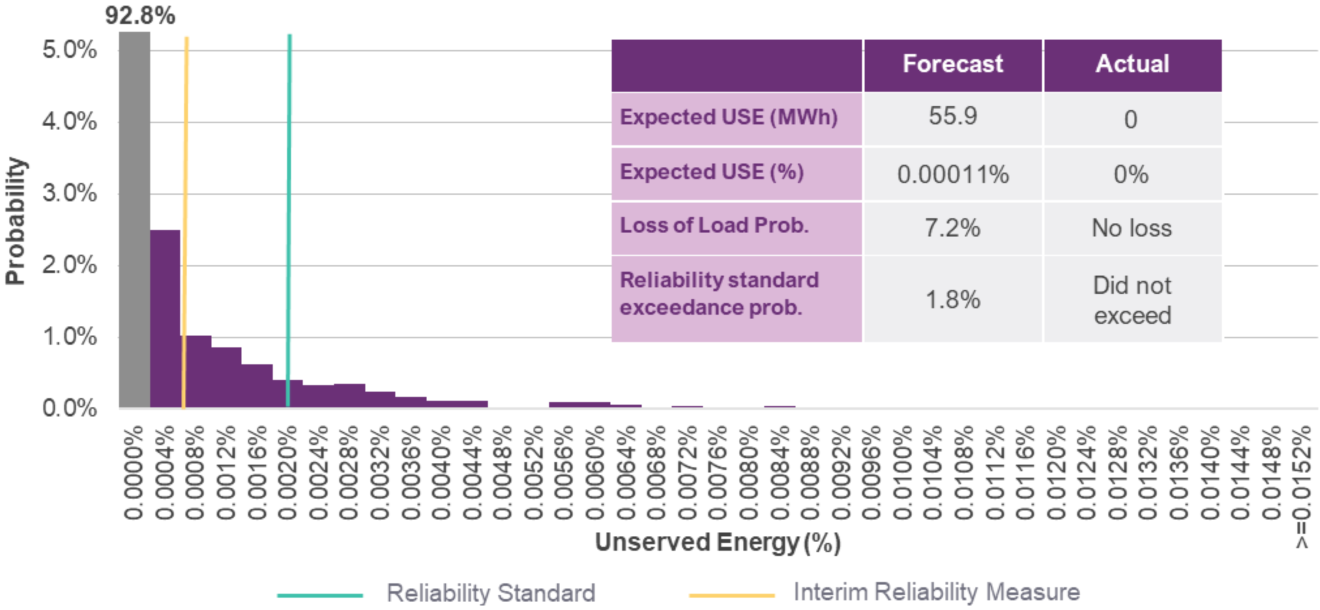
[64] The application of the interim reliability measure of 0.0006% was extended to 30 June 2028 on 21 September 2023, in accordance with NER 11.160.

[65] As defined under Chapter 10 of the NER.

7.2 Queensland

Figure 77 shows the forecast distribution of USE in Queensland for the 2023-24 summer in the 2023 ESOO. The probability of any loss of load was assessed at 7.2%. In 2023-24, no USE in accordance with the reliability standard definition was observed, an outcome predicted by 92.8% of simulations.

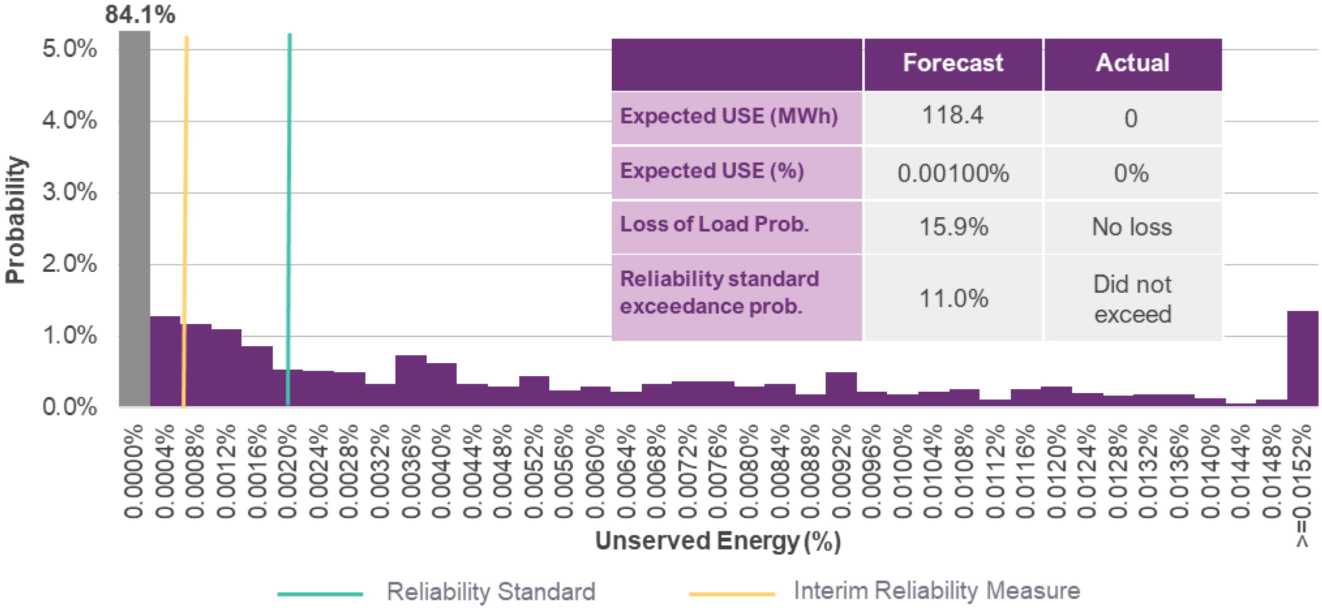
Figure 77 Queensland USE forecast distribution for 2023-24 summer



7.3 South Australia

Figure 78 shows the forecast distribution of USE in South Australia for the 2023-24 summer in the 2023 ESOO. It shows a long low probability tail of a large USE event, where the probability of any loss of load was assessed at 15.9%. In 2023-24, no USE in accordance with the reliability standard definition was observed, an outcome predicted by 84.1% of simulations.

Figure 78 South Australia USE forecast distribution for 2023-24 summer

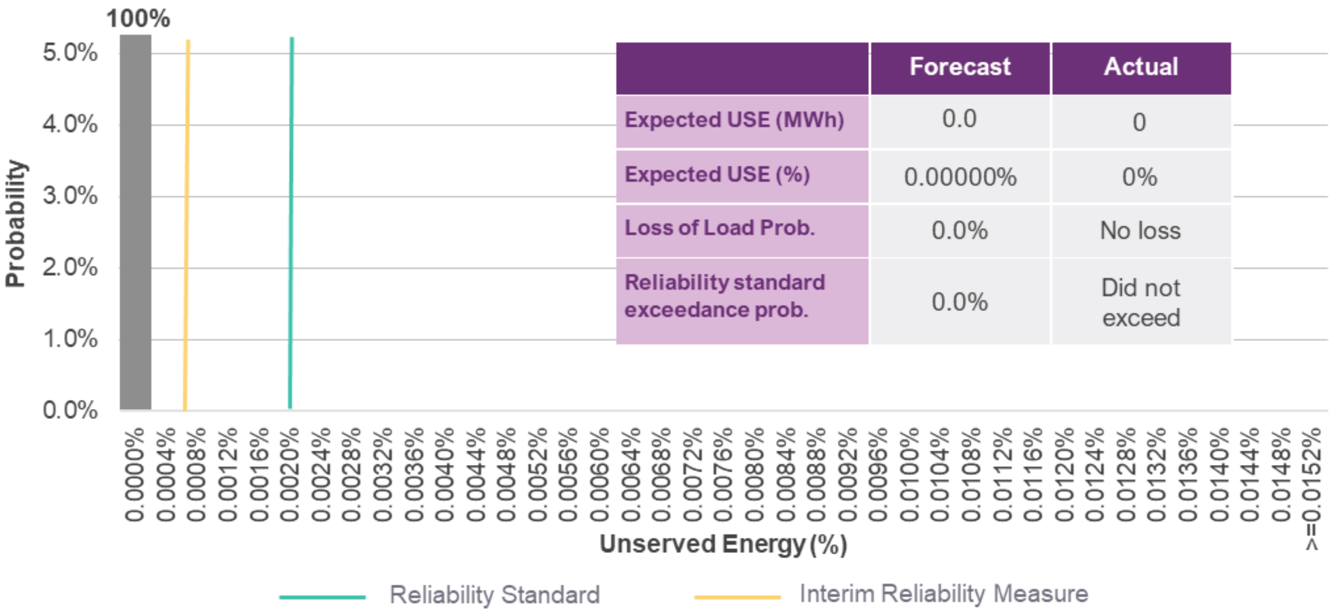


	Forecast	Actual
Expected USE (MWh)	118.4	0
Expected USE (%)	0.00100%	0%
Loss of Load Prob.	15.9%	No loss
Reliability standard exceedance prob.	11.0%	Did not exceed

7.4 Tasmania

Figure 79 shows the forecast distribution of USE in Tasmania for the 2023-24 financial year in the 2023 ESOO. The distribution shows that no USE events were forecast by the simulations.

Figure 79 Tasmania USE forecast distribution for 2023-24 financial year

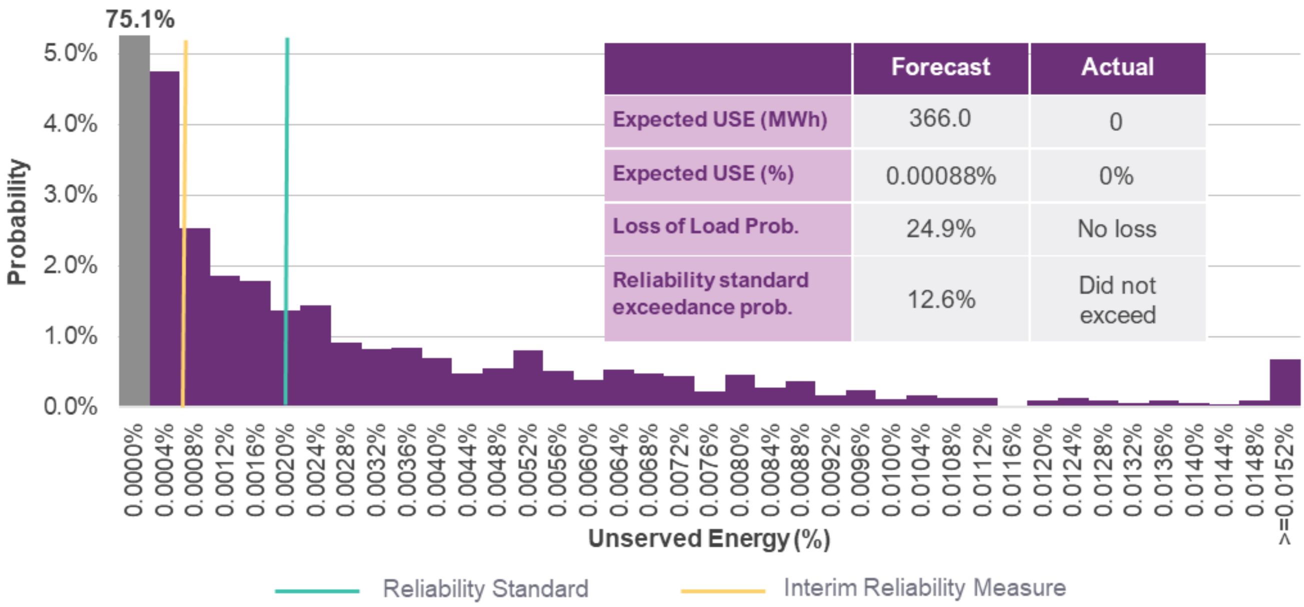


	Forecast	Actual
Expected USE (MWh)	0.0	0
Expected USE (%)	0.00000%	0%
Loss of Load Prob.	0.0%	No loss
Reliability standard exceedance prob.	0.0%	Did not exceed

7.5 Victoria

Figure 80 shows the forecast distribution of USE in Victoria for the 2023-24 summer in the 2023 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 24.9%. In 2023-24, no USE in accordance with the reliability standard definition was observed, an outcome predicted by 75.1% of simulations.

Figure 80 Victoria USE forecast distribution for 2023-24 summer



8 Forecast Improvement Plan

AEMO acknowledges the importance of forecast accuracy to industry decision-making. 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 facilities supported by electrical loads associated with coal seam gas operations), 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 an emissions reduction limb to the National Energy Objectives is increasing considerations of emissions reduction activities and policies within AEMO's planning functions.

AEMO's proposed Forecast Improvement Plan, presented in the following sections, focuses on initiatives to improve forecast accuracy. It is guided by the key observations on the performance of the 2023 forecasts summarised in **Section 8.1** and the relevant initiatives currently under the 2024 *Electricity Demand Forecasting Methodology* (EDFM) consultation[66].

[66] See https://aemo.com.au/consultations/current-and-closed-consultations/2024-electricity-demand-forecasting-methodology-consultation.

The Forecast Improvement Plan comprises initiatives and areas with potential to support improvements in reliability forecasting, as outlined in **Section 8.2**.

Appendix A1 lists the improvements presented in the *2023 Forecast Improvement Plan*, along with a summary of the implementation status of each of these initiatives, and any other improvements implemented for the 2024 ESOO.

Consistent with the FBPG[67], 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 2023 ESOO forecasts – summary of findings

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

- **Annual consumption** in the NEM overall was within the forecast target. On a regional basis, there were some improvements to overall forecast accuracy, however significant residuals were observed.
  - In Queensland, an over-forecast in the 2022 ESOO has been met with a notable under-forecast in the 2023 ESOO. While the known components were all relatively accurate, the unexplained residual was equivalent to -5.0% of operational as generated consumption. This large source of variance could potentially be attributed to factors such as growth in consumption from BMM customers, weather effects not currently captured in the models (for example, humidity), a faster pace of electrification, or other unidentified sources. AEMO will endeavour to investigate, where possible, these unknown drivers to improve consumption forecasts, for Queensland and other NEM regions with a high variance.
  - In Tasmania, the variance was mostly attributable to an explicable over-forecast of LIL consumption and heating degree days, with a very low residual of -0.6%.
  - In Victoria, consumption forecasts were the most accurate, however, this was largely from the combined over-forecast of known components, including an explicable 20% over-forecast of LILs, which was entirely offset by the residual. This highlights the importance of examining individual components of forecasts rather than relying on headline results.
  - In New South Wales, South Australia and in particular Victoria, dwelling-level analysis by AEMO indicates a steady shift from gas to electric heating, that is occurring at a faster rate than forecast for 2023-24. This effect is likely to account for a portion of the residual variance.
  - LIL forecast accuracy is influential for most NEM regions. The nature of unplanned outages or production disruptions for certain large facilities means that there can be significant variance to forecasts for any one year. AEMO is committed to closely engaging with influential LILs in order to better understand their likely consumption levels, and electricity (and gas) consumption, in the coming years, however where outages or disruptions are unplanned and unpredicted, forecast accuracy is by its nature unlikely.

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

- The observed actual **summer and winter demand outcomes** generally fell within the 10% POE and 90% POE forecast range, with notable deviations in some regions.
  - In Queensland, the summer maximum demand exceeded the 10% POE forecast, driven by El Niño-induced hot and humid conditions, increasing cooling demand.
  - In New South Wales, the winter maximum demand fell just below the 90% POE forecast, attributed to a mild winter.
  - In Victoria, the winter maximum demand slightly exceeded the 10% POE.
  - For winter maximum demand, outcomes in New South Wales fell just below 90% POE, which could be attributed to the mild winter and Victoria fell just above10% POE.
  - In Tasmania, summer maximum demand was well below the 90% POE forecast due to the absence of cold weather.
- For **annual minimum demand**, actual results were observed all within the forecast range.
- **Rooftop PV and EVs** significantly influence electricity consumption and demand forecasts. The 2023 ESOO underestimated rooftop PV capacity for 2023-24 in most NEM regions due to unexpected growth in system size. EV fleet size was also under-forecast, although its impact on energy consumption and demand remains minimal. Rapid adoption of this newly adopted technology has led to forecast errors. AEMO expects improved short-term EV forecast accuracy as sales stabilise, supported by adjusting short-term forecast models to respond more dynamically to recent sales data and better integration of PHEV trends in the 2024 ESOO. Revised rooftop PV forecasts in the 2024 ESOO, and ongoing updates for the 2025 IASR, suggest current processes are adapting effectively to emerging trends.
- **Generator installed capacity** during the 2023-24 summer exceeded forecasts by 235 MW due to the mismatch between projects' actual start dates and AEMO's commissioning assumptions applied under the current *ESOO and Reliability Forecast Methodology*. Some committed generation and storage projects became operational earlier than assumed in the 2023 ESOO after applying historically observed delays, while others were delayed greater than AEMO assumed. AEMO proposes revisions to its methodology to allow greater responsiveness to recent trends in development delays for committed generation, storage, and transmission projects.
- **Planned and unplanned outages** impacted supply availability across regions and technologies. Unplanned outage rates aligned closely with participant projections. This *Forecasting Accuracy Report* also includes an assessment of planned outages (**Section 8.2.4**), identifying a 2.5% planned outage rate (with recall time exceeding 10 days) during supply scarcity periods. AEMO proposes to monitor planned outages throughout the 2024-25 summer, assess inflexible unavailability, and engage stakeholders on revising the *ESOO and Reliability Forecast Methodology* to potentially incorporate inflexible planned outages alongside unplanned outages, which AEMO believes may further enhancing forecast accuracy for the 2025 ESOO.

8.2 Forecast improvement initiatives for 2024-25

This section describes how AEMO proposes to address the findings described in **Section 8.1** to improve the forecasts ahead of the 2025 ESOO. In some cases, AEMO had already detected these issues and took steps to address them in the forecasts for the 2024 ESOO.

8.2.1 2024 *Electricity Demand Forecast Methodology* (EDFM) improvement initiatives

In addition to the forecast improvement initiatives outlined below, several initiatives to improve energy and demand forecasting are being progressed as part of the 2024 EDFM consultation, currently underway. Key examples include:

- 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.
- The separation of data centre load forecasts from other customer loads to provide greater transparency and consideration of this new customer segment.
- The development of sub-regional forecasts aligned with standard geographical boundaries to support improved spatial insights.
- AEMO's proposed enhancement to the solar rebound forecast methodology by applying the rebound effect to a proportion of household consumption rather than solely the volume of solar PV generation, aligning with current literature. The methodology will also consider ongoing solar PV system replacements and upgrades.
- AEMO's proposed revisions to the methodology for developing 30-minute traces of forecast electricity demand to better reflect consumer behaviour over a wider variety of weather inputs.

These efforts aim to enhance transparency in AEMO's forecasting approaches and deliver forecast improvements to support the 2025 ESOO reliability assessment. For further information about these initiatives, refer to AEMO's 2024 EDFM consultation[68].

8.2.2 Consider potential sources of residual variances in the consumption forecasts

AEMO recognises that residual variances in the 2023 ESOO consumption forecast are greater than identified in previous years. The Forecast Improvement Plan includes provision for further disaggregation of the residual variance, to provide AEMO and stakeholders with further insights on the source of forecast inaccuracy.

AEMO is investigating a number of potential approaches to further disaggregate the forecasting components, not limited to:

- Sectoral disaggregation such as splitting out Residential and BMM components would assist in assessing the forecast accuracy by sector. AEMO forecasts these two sectors separately, so this approach would improve

[68] See *https://aemo.com.au/consultations/current-and-closed-consultations/2024-electricity-demand-forecasting-methodology-consultation*.

alignment between future Forecast Accuracy Reports and AEMO's *Electricity Demand Forecasting Methodology*.

- Track the impact of electrification on consumption actuals, leverage existing dwelling-level analysis of gas and electricity consumption patterns. This improvement is in progress, as part of the 2023 Forecast Improvement Plan.
- Further consideration of the impact of humidity for states such as Queensland where high humidity weather (elevated wet bulb temperature) can be a significant driver for increasing cooling loads.

8.2.3 Revise consideration for project development delays in reliability assessments

The current *ESOO and Reliability Forecast Methodology* specifies fixed intervals for application of project development delays in reliability assessments. For generation and storage projects:

- In Service and In Commissioning projects are applied at the FCUD advised by the developer.
- Committed projects[69] are applied six months after the FCUD advised.
- Anticipated projects are applied at the latest of:
  - The first day after the T-1 year for RRO purposes, or
  - One year after the FCUD submitted by the developer.

For transmission projects:

- In Service, In Commissioning, and Committed projects are applied at the commissioning dates advised by the developer.
- Anticipated projects are applied with a 12-month delay to the commissioning date advised.

In previous accuracy reports, large over-forecast variations were noted between new generation and storage capacity considered in forecasts, and actual capacities, justifying the application of development delays. This 2024 *Forecast Accuracy Report,* however, identifies that in some cases (but not all), committed generation and storage projects released capacity closer to the FCUD provided by the developer, rather than the six-month delay timeline used in the ESOO methodology, which is based on historical trends. This suggests that the six-month delay time may exceed more recently observed trends for committed projects for some technologies. No clear trends were observed for anticipated projects, as their advised FCUDs were further from summer 2023-24, making it less likely for them to begin full operation during the assessment period of the *2024 Forecast Accuracy Report*.

Conversely, commissioning of committed transmission projects throughout 2023 and 2024 routinely exceeded the timeframes and dates advised by developers. This suggests that revising the no-delay methodology to account for development delays in this category may be warranted.

AEMO proposes to revise the *ESOO and Reliability Forecast Methodology*, so that committed generation, storage and transmission projects incorporate development delays consistent with recently observed actual trends, rather than fixing this assumption in the methodology. AEMO considers that this will allow development delay

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

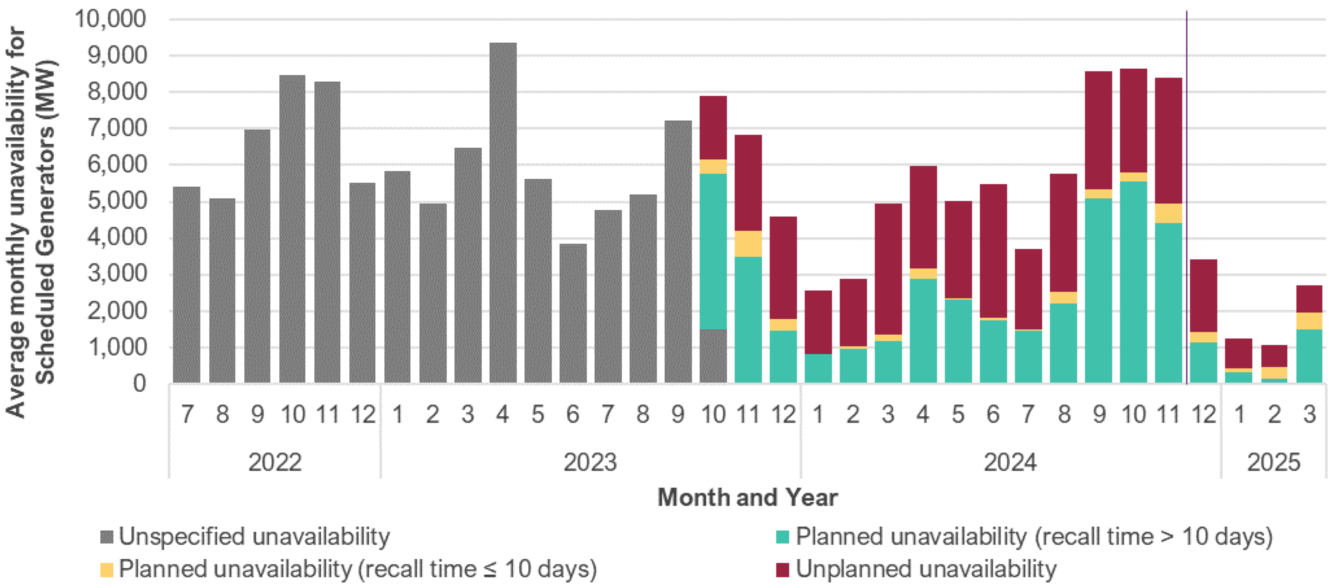
assumptions to be revised more frequently based on observed trends in industry, ensuring more accurate forecasts. AEMO proposes no change to the treatment of Anticipated projects in the methodology.

8.2.4 Monitor planned outages

The current *ESOO and Reliability Forecast Methodology* excludes consideration for generator planned outages, on the basis that participants are assumed to schedule such outages outside periods of supply scarcity. Planned outages, however, continue to be observed during periods of high demand, and during potential periods of supply scarcity, challenging this assumption. AEMO has identified this as a challenge in previous accuracy reports that requires monitoring.

On 9 October 2023, the Enhancing Information on Generator Availability in MT PASA rule commenced[70], requiring participants to submit daily information on unit state and recall time. This information provides new insights on generator availability from October 2023 onwards. **Figure 81** shows the aggregated average generator unavailability observed across NEM regions from July 2022.

Figure 81 Aggregated average scheduled generator unavailability submitted for MT PASA



Note: The data was based on MT PASA submissions as of 1 December 2024.

Figure 81 categorises scheduled generator unavailability as follows:

- Unspecified unavailability – for submissions prior to 9 October 2023, when the unit state was not provided.
- Planned unavailability (recall time > 10 days) – for submissions where the unit state was marked as "Basic Planned Outage" or "Basic Planned Derating," accompanied by recall times greater than 10 days or unrecallable. This represents more than 10 days advance notice required, under normal conditions, to make the unit available to normal operation on the day for which the recall time has been submitted. This category indicates a lack of flexibility in rescheduling planned outages.

[70] See https://www.aemc.gov.au/rule-changes/enhancing-information-generator-availability-mt-pasa.

- Planned unavailability (recall time ≤ 10 days) – for submissions with the same unit states ("Basic Planned Outage" or "Basic Planned Derating") but with recall times of less than or equal to 10 days.
- Unplanned unavailability – includes all unavailability caused by unplanned outages or extensions of planned outages. This type of unavailability is captured by AEMO's unplanned outage rate methodology or similar approaches for assessing generator unavailability.

A large portion of the planned unavailability was submitted with no recall, indicating the outages were immovable even under high-demand or supply scarcity conditions. During the critical months of January and February 2024, an average of approximately 1,000 MW of planned unavailability with recall time greater than 10 days was recorded, representing an approximate 2.5% planned outage rate during conditions where supply scarcity risks are typically forecast.

Ongoing challenges with the scheduling of planned outages suggests that the previous assumption that planned outages would be scheduled outside periods of supply scarcity may no longer hold. AEMO proposes to:

- Monitor planned outages – continue tracking planned outages for scheduled generators throughout the 2024-25 summer.
- Assess inflexible unavailability – identify cases of inflexible unavailability, considering instances of opportunistic maintenance.
- Consult with stakeholders – engage with stakeholders in early 2025 on potential revisions to the *ESOO and Reliability Forecast Methodology* to better account for inflexible planned outages during supply scarcity periods, to ensure that the 2025 ESOO effectively captures both inflexible planned outages and unplanned outages, improving reliability forecasts and addressing supply scarcity risks.
- AEMO welcomes feedback and suggestions from stakeholders regarding potential methodologies for consideration in the *ESOO and Reliability Forecast Methodology* that would capture the most likely level of generator unavailability during periods of supply scarcity due to planned outages.

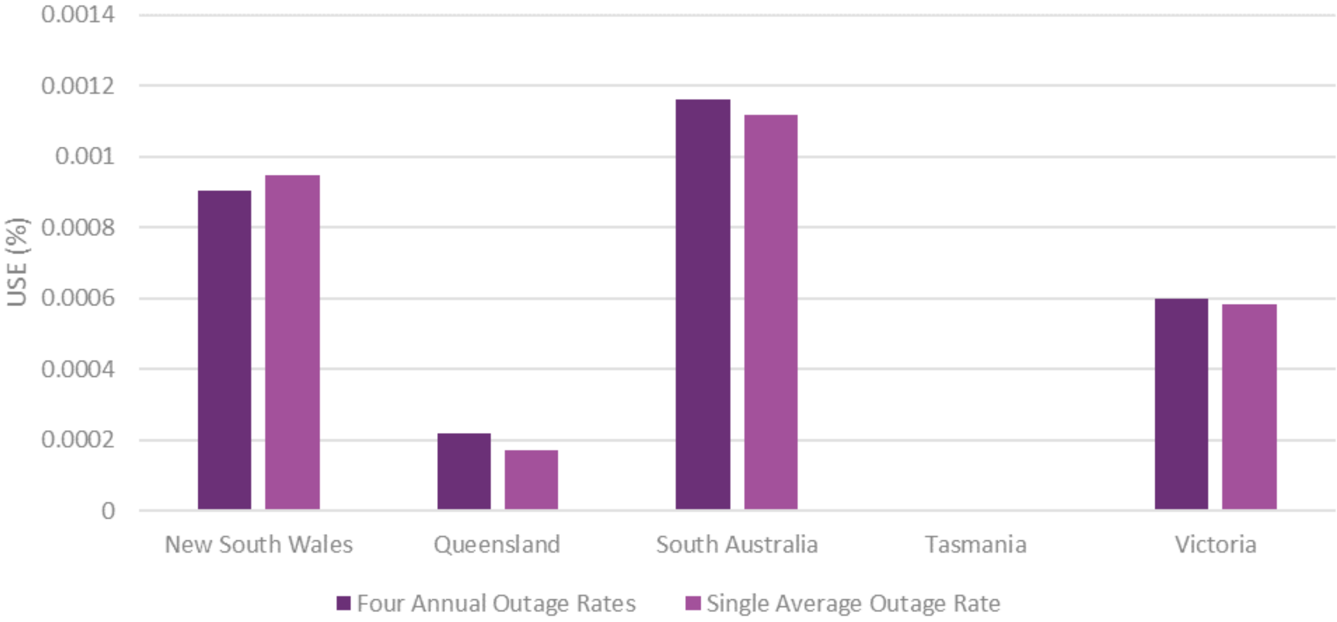
8.2.5 Simplify the modelling of unplanned outages to support additional weather modelling

The current *ESOO and Reliability Forecast Methodology* specifies that AEMO applies each of the last four yearly generator unplanned outages statistics with equal likelihood in modelling. In cases where participant projections are applied, the variability observed over the last four yearly outage statistics is also applied. This approach increases modelling complexity, and cost, but was found to be necessary in 2019, when annual variability in outage rates were found to be very high. Recent unplanned outage rate results show less variability than was previously observed, reducing the value from such complexity.

Through the *Electricity Demand Forecasting Methodology* consultation, AEMO is proposing to revise the demand forecasting methodology to deploy modelled (synthetic) demand trace methodologies, that allow AEMO to increase the number of weather (reference) years considered in reliability assessments. For AEMO to deliver the ESOO at a reasonable cost and time, the additional complexity introduced by increasing the number of reference years needs to be offset by reduced complexity in another area.

Figure 82 shows the 2024-25 results of the 2024 ESOO *Committed and Anticipated* sensitivity (which applied four annual outage rates) relative to sensitivity analysis where only average outage rates were applied. Little differences are observed between the two sensitivities, representing only minor variation that is likely due to sampling randomness.

Figure 82 2024 ESOO *Committed and Anticipated* sensitivity with four outage rates, and one average outage rate, 2024-25, 10% POE only



AEMO proposes to revise the *ESOO and Reliability Forecasting Methodology* such that average unplanned outage rates are applied instead of four unplanned outage rates that capture year to year variability.

A1. Status of improvements proposed in 2023

The 2023 Forecast Improvement Plan was published in the 2023 *Forecast Accuracy Report*[71]. It proposed a number of improvements planned for the 2024 ESOO or beyond. For visibility of progress, each improvement is listed below along with a summary of feedback and the implementation status.

Table 30 Forecast improvement priorities for 2023-24 outlined in the 2023 Forecast Improvement Plan

Improvement	Status
Review the sensitivity of short-term annual consumption models AEMO proposed to expand the annual review of recent growth trends for Tasmania in particular, to ensure that short-term consumption models respond effectively to capture trends that may have been leading to forecast variances in that region.	**Under consultation through the EDFM** The 2023 ESOO incorporated a downwards adjustment to Tasmania's consumption forecast model. The energy forecast accuracy for 2023-24 has improved in the 2023 ESOO. The variance is still relatively high compared to other NEM regions, however this is largely attributed to an unforeseen extended shutdown of one facility. Residual variance has decreased from 477 GWh (4.5%) in the 2022 ESOO to -61 GWh (-0.6%) in the 2023 ESOO forecasts for 2023-24. For the 2024 ESOO, AEMO further adjusted the short-term regression model of the BMM sector to account for anomalous behaviour in a non-LIL data centre in Tasmania. Through the 2024 EDFM consultation, AEMO is proposing to forecast data centres as a separate customer segment across all regions, including commercial-scale sites that would otherwise form part of the BMM forecast.
Review large industrial load AEMO proposed to expand the annual review of LIL forecasting. This review will monitor LIL consumption that shows the largest variances compared to the forecast, including unplanned outages and significant operational variations.	**Ongoing process** Forecast LIL variance was generally improved for the 2023 ESOO, though large unplanned outages resulted in a 20% over-forecast for Victoria. AEMO completed the second round of sectoral consumption analysis which has helped to inform its forecasts for LILs. Through the 2024 EDFM consultation, AEMO is proposing revisions 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. AEMO has also commenced development of internal monitoring dashboards to track site-LIL forecasts against actual consumption.
Review minimum demand models AEMO planned to undertake further review of its minimum demand forecast models to further establish whether the lower-than-90% POE results recorded for minimum demand were related to under-forecast of rooftop PV or some other factor(s).	**Complete** In the 2023 ESOO, AEMO made a significant enhancement in the accuracy of the half-hourly model used to guide the POE distribution for extreme events. This improvement has effectively eliminated the need to rebase forecasts using the Generalized Extreme Value model, as previously discussed in Forecasting Approach – Electricity Demand Forecasting Methodology*. Consequently, the observed actual minimum demand across all regions aligned well within the forecast distribution range, reflecting the increased reliability of the updated modelling approach.
Improve EV forecast approaches AEMO planned to improve EV forecasts by: • Adjusting short-term forecast models to respond more dynamically to recent sales data. • Improving the consideration of the popularity and longevity of PHEVs.	**Complete** Both of these changes were considered in the 2024 ESOO EV forecasts.

*See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2023/forecasting-approach_electricity-demand-forecasting-methodology_final.pdf.

[71] See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/accuracy-report/2023-forecast-accuracy-report.pdf.

Table 31 Ongoing research and improvement areas outlined in the 2023 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, which includes EV and battery charge/discharge profiles. Analysis of this data will progress in the coming months, and is expected to provide further insights into consumers' present and future load shape and technology usage.
Track electrification trends AEMO planned to investigate meter data to determine whether electrification trends were observable in those data.	**In progress** AEMO has commenced an 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 2024 ESOO, including a limited number of synthetic years, and expected to create demand traces for them.	**Under consultation through the EDFM** The 2024 ESOO increased the number of weather reference years used from 13 in the 2023 ESOO to 14, covering 2010-11 to 2023-24. As part of the 2024 EDFM consultation, AEMO is proposing revisions to its demand forecasting methodology, including adopting synthetic demand trace methodologies, which would enable AEMO to consider a greater number of weather reference years in the 2025 ESOO reliability assessments. This approach aims to better capture the range of potential weather outcomes in the forecasts.
Improve visibility of sectoral consumption AEMO planned to review both the LIL and other non-scheduled generation 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 to 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 currently reviewing the DSP Information portal interface for enhancing 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 long periods of high demand and price.
Monitor planned outages AEMO planned to monitor planned outages for scheduled generators and determine whether methodology changes are required for planned outages in the ESOO model.	**Under consultation through this FIP** This *Forecasting Accuracy Report* assesses planned outages, identifying an approximate 2.5% outage rate during periods typically associated with supply scarcity risks. To enhance forecast accuracy, AEMO proposes revising the *ESOO and Reliability Forecast Methodology*** to include inflexible planned outages during these critical periods, alongside unplanned outages.

** The *ESOO and Reliability Forecast Methodology* is available at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/reliability-forecasting-guidelines-and-methodology-consultation/final/esoo-and-reliability-forecast-methodology-document.pdf.

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).

Term	Definition
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* 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	kilowatts
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
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
GEM	Green Energy Markets
GSP	Gross State Product

Abbreviation	Full name
HDI	Household Disposable Income
LNG	liquefied natural gas
LOR	lack of reserve
MT PASA	Medium Term Projected Assessment of System Adequacy
NEM	National Electricity Market
NER	National Electricity Rules
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