2024 Wholesale Electricity Market Electricity Statement of Opportunities

18 June 2024

A report for the Wholesale Electricity Market in Western Australia's South West Interconnected System

AEMO

Important notice

Purpose

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Executive summary

The Wholesale Electricity Market (WEM) Electricity Statement of Opportunities (ESOO) is an annual AEMO publication that includes the 10-year Long Term Projected Assessment of System Adequacy (PASA) for the South West Interconnected System (SWIS) in Western Australia (WA).

Its primary purpose is to identify the investment in capacity from generation, storage, and Demand Side Programmes (DSP) needed to ensure a secure and reliable electricity supply for the SWIS over the coming 10 years.

The ESOO plays an important role in the Reserve Capacity Mechanism (RCM) process in the WEM. The 2024 WEM ESOO forecasts the Reserve Capacity Target (RCT) for each Capacity Year between 2024-25 and 2033-34, and, specifically, determines the Reserve Capacity Requirement (RCR) – the amount of capacity to be procured through the RCM – for the 2026-27 Capacity Year[1].

This WEM ESOO presents a significantly improved near term reliability outlook for the SWIS compared to the 2023 WEM ESOO and highlights the continued need for capacity investment from 2027 onwards.

- Over the 10-year outlook period, AEMO projects:
  - Significant growth in peak demand and electricity consumption, particularly in the second half of the outlook period, largely due to electrification and emerging clean technology industries.
  - Continued growth in distributed photovoltaics (DPV), with a corresponding decline in minimum operational demand.
  - Substantial improvement in available capacity in the near term, due to AEMO's procurement of over 1,000 megawatts (MW) of capacity through the Non-Co-optimised Essential System Services framework (NCESS).
- In the first half of the outlook period (2024-25 – 2028-29), AEMO projects:
  - A relatively small residual capacity shortfall risk for 2024-25.
  - Largely balanced supply and demand in 2025-26 and 2026-27.
  - A capacity shortfall emerging from 2027-28.
- In the second half of the outlook period (2029-30 – 2033-34), AEMO projects a growing capacity shortfall as demand continues to grow and coal-fired generation is retired.
- In the near term, capacity shortfalls could be mitigated by:
  - Synergy maintaining its Muja C Power Station unit 6 in 'reserve mode' for summer 2024-25.
  - AEMO procuring Supplementary Reserve Capacity (SRC).
- Later shortfalls could be mitigated by additional capacity – potentially incentivised by improvements to the RCM and the Federal Government's Capacity Investment Scheme[2] – and transmission upgrades.

[1] A Capacity Year commences on 1 October. All references to years in this report are Capacity Years unless otherwise specified.

[2] Available at https://www.dcceew.gov.au/about/news/have-your-say-design-and-rollout-capacity-investment-scheme-western-australia.

Notes

The purpose of the RCM is to ensure the SWIS has adequate installed capacity available from generation systems, Electric Storage Resources (ESR), and DSP at all times to:

- Meet one-in-10-year peak demand plus a margin to cover risks, such generation outages, while maintaining minimum requirements to maintain system frequency.
- Ensure energy shortfalls do not exceed a defined threshold.

The **RCM** achieves this by:

- Setting the RCR two years ahead, published in the WEM ESOO.
- Allocating Certified Reserve Capacity (CRC) and Capacity Credits based on a facility's technical capability and access to the network.
- Testing facilities to ensure they are meeting their Reserve Capacity Obligations.
- Assigning an Individual Reserve Capacity Requirement to each Market Customer, based on contributions to the system peak, to allocate the costs of Capacity Credits.

The **Planning Criterion is the reliability standard for the SWIS**, ensuring sufficient capacity to satisfy both:

- Limb A – meet the forecast 10% probability of exceedance (POE) peak demand under the Expected demand growth scenario plus a reserve margin.
- Limb B – limit expected energy shortfalls to 0.0002% of annual energy consumption.

The Planning Criterion is used to set the RCT for each Capacity Year.

The methodology for assessing and assigning CRC and Capacity Credits is based on the Facility Technology Type:

- **Non-Intermittent Generating Systems** such as coal, gas and diesel are assessed based on their sent-out capacity at 41°C, which accounts for efficiency at high temperatures.
- **Intermittent Generating Systems** such as solar, wind, and landfill gas are assessed based on an estimated contribution during periods of high demand and tight reserve margin.
- **ESR** such as batteries and hydro-powered generators are assessed based on their ability to sustain a level of output over a defined period.
- **DSP** are assessed based on the amount by which the demand from the load or aggregated loads can be curtailed.

In the WEM, the future energy capacity mix will rely on a range of technology solutions. New entrants will need to balance sustainability, reliability, and affordability when developing new capacity.

The potential investment opportunity in installed generation capacity is expected to be greater than the projected capacity shortfall. This is because Intermittent Generating Systems are evaluated at a lower level of capacity for Reserve Capacity purposes than their installed capacity, to account for their variability.

Significant growth is forecast for electricity consumption and peak demand, particularly in the second half of the outlook period[3]

Electricity consumption and peak demand are forecast to grow significantly over the next decade as the electricity sector provides a decarbonisation pathway for industry, transportation and to support emerging clean technology industries.

The Expected demand growth scenario in the 2024 WEM ESOO continues to be underpinned by the *Step Change* scenario from AEMO's 2023 *Inputs, Assumptions, and Scenarios Report* (IASR)[4]. This scenario reflects both the Federal and Western Australian Governments' respective commitments to mitigating climate change, which include reducing carbon emissions by 43% by 2030 and achieving net zero emissions by 2050. It accounts for moderate growth in both the global and domestic economy, with growing opportunities for electrifying transportation and industry.

In the Expected scenario, electricity consumption and peak demand are forecast to grow over the next 10 years, more strongly in the second five years than in the first. Forecast growth has moderated slightly since the 2023 WEM ESOO.

Table 1 Forecast operational consumption (gigawatt hours (GWh)) and peak operational demand (MW) and average annual growth rates[A], 2023-24 to 2033-34, Expected scenario

	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	First 5-year average annual growth rate	2033-34	Second 5-year average annual growth rate	10-year average annual growth rate
Operational consumption	17,800	18,018	18,082	18,287	18,530	19,188	1.5%	27,868	7.7%	4.6%
10% POE peak operational demand[B]	4,304	4,388	4,464	4,555	4,656	4,772	2.1%	6,163	5.3%	3.7%

A. 2023-24 is the base year (year 0) and 2033-34 is the final year (year 10) for the average annual growth rate calculation.
B. 2023-24 to 2031-32 are the summer 10% POE peak operational demand values. 2032-33 and 2033-34 are the winter 10% POE peak operational demand values.

AEMO forecasts operational consumption to grow in the Expected scenario at an average annual rate of 4.6% (compared to 5.6% in the 2023 WEM ESOO). Growth is stronger in the second half of the outlook period than in the first, averaging 7.7% annually.

- Forecast growth over the outlook period is primarily driven by the potential for increased industrial electrification, the emergence of a green hydrogen industry, and the strong uptake of electric vehicles (EVs), especially in the second half of the period. This growth is partially offset by the continued uptake of DPV.
- Growth is predicted to occur at a slower pace than forecast in the 2023 WEM ESOO due to a more moderate economic outlook and tempered forecasts for commodity prices, leading to more subdued business and large industrial load activities, respectively.

[3] Unless otherwise indicated, demand forecasts in this report are based on the Expected scenario.

[4] See https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/draft-2023-inputs-assumptions-and-scenarios-report.pdf.

- A relatively higher forecast for DPV uptake due to households installing larger systems also acts to reduce operational consumption.
- A downward revision in forecast EV uptake and expected delays in the commencement of the emerging hydrogen industry further contributes to this softening of growth.

AEMO forecasts the 10% POE peak operational demand to grow at an average annual rate of 3.7% over the 10-year outlook period (compared to 4.4% in the 2023 WEM ESOO), from 4,304 MW in 2023-24 to 6,163 MW in 2033-34. This growth is broadly consistent with forecast energy consumption growth, but with less offset from distributed PV, as operational peak demand is typically in the early evening, with little or no contribution from DPV.

- The main drivers of peak operational demand align with factors driving operational consumption growth, but with a smaller offset by DPV due to peak demand occurring as the sun sets.
- Forecasts of increasing cooling load, electrification, and demand from EVs contribute most to the growth trend.

The first peak demand record since 2016 was set on 23 November 2023, prior to the onset of summer. Over summer 2023-24 – the second hottest Western Australia summer on record[5] – seven of the top 10 highest SWIS peak demand records were set, including the current all-time maximum operational demand record of 4,233 MW on 18 February 2024. In anticipation of tight conditions over summer 2023-24, during 2023 AEMO procured approximately 160 MW of SRC for the period. This SRC was dispatched on 14 occasions, along with DSPs procured via the RCM. On some occasions, additional generation and demand reduction was also provided by off-market facilities connected to the SWIS, to ensure secure and reliable power supplies for consumers. Without demand reduction from SRC and off-market providers, peak demand of over 4,400 MW would have been recorded.

AEMO forecasts that from 2029-30, the difference between the 10% POE peak operational demand in summer and winter will significantly reduce, with the winter peak marginally surpassing the summer peak demand from 2032-33. This shift is largely due to the anticipated growth in operational consumption, driven by electrification of heating load and the comparatively lower impact of DPV generation to meet evening peak demand during winter as the sun sets earlier than summer.

The near-term supply-demand balance has improved significantly since the 2023 WEM ESOO, but substantial and sustained investment in new generation, storage, DSP and transmission capacity is still needed, particularly for the period from 2027 onwards

The RCT determined for the 2026-27 Capacity Year is 5,696 MW, which sets the RCR for the 2024 Reserve Capacity Cycle. This is 20 MW lower than the RCT determined for the 2026-27 Capacity Year in the 2023 WEM ESOO, due to a slightly lower 10% POE peak demand forecast.

Figure 1 shows the 10-year supply-demand outlook. **Table 2** provides an overview of the supply-demand balance forecast for the first half of the outlook period (2024-25 to 2028-29), with the actions AEMO has identified to mitigate capacity shortfalls. This near-term outlook has improved significantly since the 2023 WEM ESOO, largely due to AEMO's procurement of **over 1,000 MW of capacity** through the NCESS.

[5] See http://www.bom.gov.au/climate/current/season/wa/archive/202402.summary.shtml.

Figure 1 Forecast supply-demand balance, Expected scenario, 2024-25 to 2033-34 (MW)

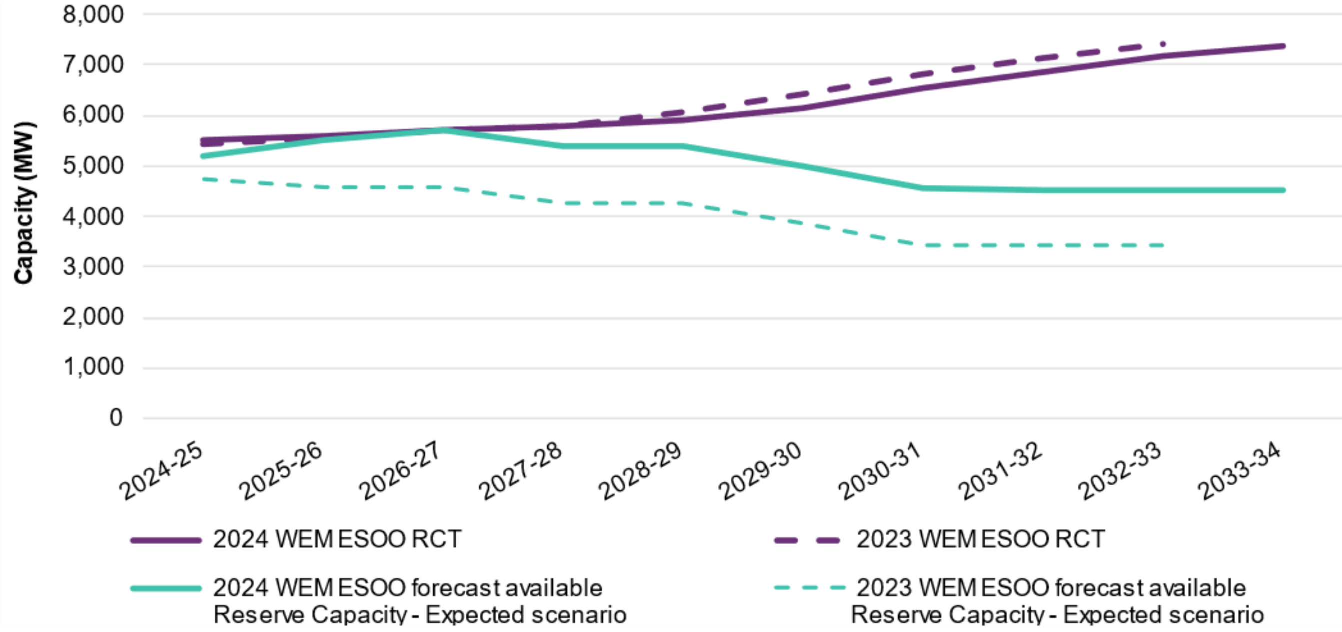


Table 2 Supply-demand balance for the Expected scenario, 2024-25 to 2028-29 (MW)

Capacity Year	2024-25	2025-26	2026-27	2027-28	2028-29
Reserve Capacity Cycle (WEM ESOO)	2022	2023	2024	2025	2026
Reserve Capacity Cycle Status	Capacity assigned	Capacity assigned	Capacity assignment over coming months	Not commenced	Not commenced
RCT	5,501	5,589	5,696	5,794	5,925
Capacity including NCESS	5,183	5,503	5,729	5,403	5,347
Capacity investment shortfall (-) or surplus	-317	-86	33	-391	-529
Potential mitigations					
Muja C unit 6 maintained in "reserve mode"[A]	+193				
Possible early entry of Synergy's Collie ESR[B,C]		+500			
Residual capacity shortfall (-) or surplus	-124	414	33	-391	-529
RCM processes to mitigate	SRC expected to be procured in 2024	SRC available, to be considered in 2025	Current Reserve Capacity Cycle	Future Reserve Capacity Cycle[D]	Future Reserve Capacity Cycle[D]

A. See announcement at https://www.wa.gov.au/government/media-statements/Cook-Labor-Government/Muja-C-Unit-6-in-reserve-mode-and-online-for-summer-2024-25-20230817.
B. The Synergy Collie ESR is included in the supply forecast from 2026-27, but it has an announced commencement date in late 2025 and therefore could be in operation in time for the summer of 2025-26.
C. See announcement at https://www.wa.gov.au/government/media-statements/Cook-Labor-Government/Construction-starts-on-one-of-Australia's-biggest-batteries-in-Collie-20240315.
D. For 2027-28 and future Capacity Years, it is anticipated than reforms to the RCM, including the introduction of the 'flexible' capacity product, along with the Capacity Investment Scheme, will provide further incentives for investment in new capacity.

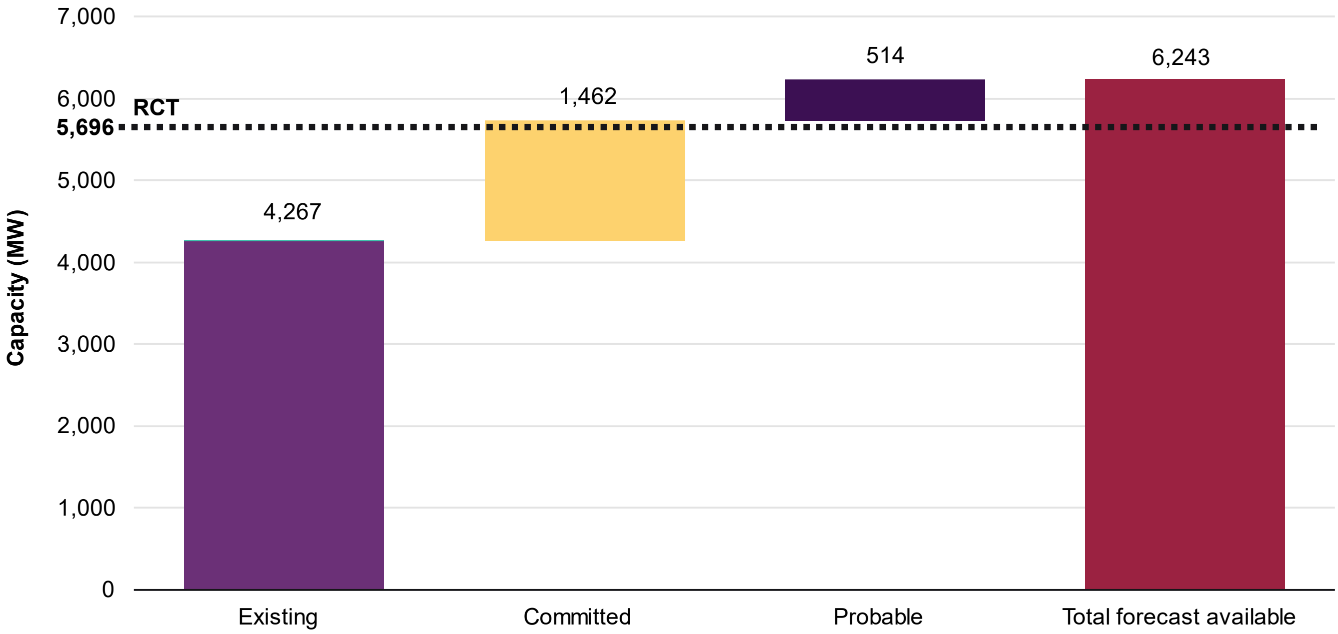
Timely delivery of committed capacity is essential to meeting the Reserve Capacity Target for 2026-27

Over the period 2025-26 to 2026-27, supply and demand are expected to be largely balanced due to the additional capacity procured through NCESS and announced Synergy Collie ESR.

Timely delivery of these committed projects is critical to ensuring the capacity requirement is satisfied. There are various factors impacting the delivery of planned projects across Australia, including global supply chain and labour constraints. As such, AEMO is monitoring the progress of committed projects and encouraging proponents to take early actions to mitigate any potential delays.

In addition to this committed capacity, as shown in **Figure 2**, additional 'probable' capacity projects may also be developed contributing to reliability in 2026-27 or future years.

Figure 2 Forecast existing, committed, and probable Reserve Capacity for 2026-27 (MW)



Procurement of Supplementary Reserve Capacity is required for the 2024-25 summer

Forecast available capacity in the short term has improved significantly from the 2023 WEM ESOO, due to AEMO's procurement of over 1,000 MW of new capacity through the NCESS framework, of which approximately 630 MW is expected to be available for the 2024-25 summer.

Despite this improvement, AEMO projects a shortfall in 2024-25 in the order of 317 MW. This is mitigated in part by the Western Australian Government's decision to maintain Synergy's Muja C unit 6 in 'reserve mode' over the summer before being retired.

The RCM operates on a two-to-three year ahead cycle, to enable new capacity to enter the WEM to manage any capacity shortfalls identified in the WEM ESOO. In the two-year period between certification of new capacity and the commencement of the relevant Capacity Year, there is a risk that a residual capacity shortfall will be identified – as is the case for 2024-25 – and the RCM includes the SRC mechanism to manage this risk.

AEMO can procure SRC within six months of commencement of a Capacity Year, where it considers that there is a risk that adequate Reserve Capacity may not be available in the SWIS to maintain power system security and reliability. AEMO can contract for capacity that does not hold Capacity Credits (and has not failed to satisfy Reserve Capacity obligations in the current or preceding Capacity Year).

AEMO will seek to procure at least 124 MW of SRC to mitigate the residual shortfall risk. The final quantity procured by AEMO is currently being assessed and will also need to take into account any major outages, fuel disruptions, or delays to connection of new committed capacity.

Strong capacity investment signals and planned transmission expansions have the potential to improve the long-term reliability outlook

Substantial and sustained investment in new capacity will be required beyond existing and committed capacity, with 391 MW required in 2027-28 increasing to 2,880 MW by 2033-34.

These longer-term shortfalls are driven by forecast strong demand growth and reduced supply due to anticipated retirements of coal-fired generation. This highlights a continued need for new investment in Reserve Capacity and enabling transmission network infrastructure.

AEMO is aware of a substantial pipeline of projects, including wind and solar generation, as well as battery storage, which could be developed in response to this investment opportunity.

Timely delivery of capacity and transmission projects will be essential to maintaining reliable supply. The delay risks identified in the section above also apply to projects in the longer term. As such, AEMO is monitoring the progress of committed projects and encourages proponents to take early actions to mitigate any potential delays.

Reforms to the RCM[6] and the introduction of the Capacity Investment Scheme could help to incentivise investment in new generation and storage capacity from 2027-28 and beyond.

Western Power's committed network augmentations, including the East Region Energy Project (EREP) and Clean Energy Link – North Region Project, are expected to enable connection of new utility scale renewables and firming capacity projects in the eastern and northern regions of the SWIS. Further transmission investment will be needed to ensure the ongoing reliability of the SWIS beyond 2030.

Committed and future storage investment is essential to mitigate forecast minimum demand risk

Projected growth in DPV is expected to cause a rapid decline in minimum operational demand over the outlook period. Without mitigation, operational demand could notionally fall below zero as early as 2026-27 under the 90% POE Expected demand growth scenario. In aggregate, DPV is the largest generation source in the SWIS, and is playing a key role in enabling a low-cost electricity supply and the transition of the power system and economy to net zero. However, periods of low operational demand and high, uncontrolled DPV output can present risks to the secure and reliable operation of the power system.

Periods of high solar output tend to correlate with low wholesale energy prices in the WEM, providing incentives for the charging of ESR and helping mitigate risks associated with low operational demand. In addition to the

[6] Available at https://www.wa.gov.au/government/document-collections/reserve-capacity-mechanism-review.

market price signals, the Wholesale Electricity Market Rules (WEM Rules) include the NCESS mechanism, which AEMO may seek to trigger to procure additional services to manage emerging risks to power system security and reliability.

The existing and committed entry of over 1,000 MW of storage by 2026-27 is expected to play a key role in soaking up excess solar and discharging it during periods of high demand. For the period 2024-25 to 2026-27, AEMO has also procured 446 MW of minimum demand NCESS from these storage providers, to support system security during periods of low operational demand.

As DPV growth continues and operational demands reduce, AEMO will continue to monitor any emerging risks to power system security and reliability. Over the longer term, greater orchestration of distributed energy resources (DER), including DPV and distributed batteries, will provide further options to maximise the value of these consumer assets and contribute to a secure and reliable power supply for all consumers.

Maintaining power system security and reliability as the capacity mix changes

As the SWIS capacity mix changes – with substantial ESR and intermittent renewable generators, such as wind and solar farms, entering the market and coal-fired power generation progressively exiting the market – it will become increasingly important to have the right mix of technologies to maintain a reliable electricity supply.

Since the 2023 WEM ESOO, changes to the WEM Rules have:

- **Revised the second limb of the Planning Criterion**, with the expected unserved energy (EUE) limit in Limb B reduced from 0.002% to 0.0002% of annual consumption. This follows a change prior to the 2023 WEM ESOO, which saw the previously static reserve margin in Limb A replaced by AEMO's assessment of the expected unavailable capacity at the time of peak, which can be adjusted over time.
- **Introduced a regional capacity shortfall assessment** to consider EUE occurring in sub-regions of the SWIS that cannot be addressed by additional Reserve Capacity outside that sub-region.
- **Amended requirements** relating to the duration required by new ESR capacity and the need for additional capacity by specific Capability Classes.

These changes are intended to enhance the effectiveness of the reliability assessment in identifying what is needed to maintain reliable supply across the SWIS as the energy transition continues.

Based on the analysis undertaken for this WEM ESOO, these enhancements have no immediate implications for the reliability outlook:

- Despite the tighter EUE limit, this WEM ESOO projects that the RCT will continue to be set by Limb A, which is sufficient to address the Limb B requirement for the outlook period.
- While the Goldfields region could experience EUE in excess of the reliability standard, this risk is expected to significantly reduce following completion of Western Power's EREP.
- The existing four-hour ESR Duration Requirement continues to apply for the 2024 Reserve Capacity Cycle, however AEMO anticipates the duration required may increase in future capacity cycles.
- The Capability Class assessment for 2026-27 does not indicate a need for specific capacity types in the near term, however AEMO anticipates this may change later in the decade as coal-fired generation retires and new intermittent renewable generation connects.

- The power system also requires sufficient security and stability services to ensure it remains stable and resilient. As existing synchronous generators retire, namely coal power stations, AEMO predicts that additional Essential System Services will be required.

Future WEM ESOOs will continue to explore the impact of duration-limited technologies on meeting demand, the ESR Duration Requirement and the optimal mix of intermittent and non-intermittent generation, ESR and DSP to maintain system reliability and security. AEMO anticipates these assessments will identify more targeted investment opportunities in coming years.

Contents

Notes

- This WEM ESOO uses many terms that have meanings defined in the Wholesale Electricity Market Rules (WEM Rules) 2024 and the Wholesale Electricity Market Amendment (Reserve Capacity Reform) Rules 2023. The WEM Rules meanings are adopted unless otherwise specified. Terms which are defined in the WEM Rules are capitalised. Other terms are defined throughout the report and in the Glossary.
- HH:MM Trading Interval means Trading Interval commencing at HH:MM.
- All data in this WEM ESOO is based on Capacity Years unless otherwise specified. A Capacity Year commences in 08:00 Trading Interval on 1 October and ends in 07:30 Trading Interval on 1 October of the following calendar year.
- All references to single year (as 20xx) present a calendar year.
- Consumption/demand is operational consumption/demand unless otherwise specified in this WEM ESOO.
- Key definitions of operational consumption and demand, as well as reliability assessment related terminology can be found in Chapter 1 and in the Glossary.
- The three seasons reported in this WEM ESOO are Hot Season/summer (covering a period from December to March), winter (covering a period from June to August), and shoulder (covering April, May, and September to November) Trading Months.
- This WEM ESOO provides low, expected, and high demand growth scenarios based on different levels of economic growth as defined in clause 4.5.10 of the WEM Rules. Unless otherwise indicated, demand forecasts are based on the expected demand growth scenario.
- All temperature data is reported at a half-hourly resolution and is based on the maximum temperature recorded in that Trading Interval.
- This WEM ESOO provides forecasts for the 2024 Long Term PASA Study Horizon, which covers the 2024-25 to 2033-34 Capacity Years, also referred to as the 10-year outlook period in this WEM ESOO. The first half of the outlook period refers to the period 2023-24 to 2028-29, and the second half refers to the period 2029-30 to 2033-34.
- The compound annual growth rate was used to calculate the average annual growth rate. AEMO refined the calculation by using the first outlook year (year 1) minus one year (year 0) as the base year instead of year 1 to calculate the 10-year average annual growth rate. 2023-24 and 2028-29 were used as year 0 to calculate the five-year average annual growth rates for the first half and second half of the outlook period, respectively.

1 Introduction

The Wholesale Electricity Market (WEM) Electricity Statement of Opportunities (ESOO) provides a 10-year view of projected electricity demand, capacity and other key parameters for the South West Interconnected System (SWIS) in Western Australia. It is designed to help inform decision-making by WEM participants, investors and policymakers.

Specifically, the WEM ESOO provides information on, and projections of:

- Electricity consumption and demand.
- Electricity supply from generation, storage, and Demand Side Programmes (DSP).
- Reserve Capacity Targets (RCT), used to identify the capacity required to meet the reliability standard.
- Investment opportunities to ensure power system reliability and security.

1.1 Purpose

The WEM ESOO provides advice on the volumes and types of investment in electricity generation, storage and DSP capacity needed to maintain a secure and reliable electricity supply in the SWIS. This advice is particularly important in Western Australia because the SWIS is an isolated power system, entirely reliant on local capacity to supply electricity to more than 1.1 million homes and businesses.

To help promote investment in local capacity, the WEM has a Reserve Capacity Mechanism (RCM). The RCM aims to ensure there is adequate capacity in the SWIS by providing a two-year-ahead view of the Reserve Capacity Requirement (RCR) and providing financial signals to encourage capacity development[7].

The WEM ESOO is a vital input into the RCM because it:

- Determines the RCT that will satisfy the Planning Criterion[8] for each Capacity Year[9] in the 10-year outlook period, and projects the supply-demand balance.
- Sets the RCR – the amount of capacity to be procured through the RCM for the relevant Reserve Capacity Cycle.

The WEM ESOO presents forecasts for electricity consumption and peak demand across a range of weather and demand growth scenarios. These forecasts are used to assess power system reliability and forecast the supply

[7] For more information on the RCM and how it works, visit AEMO's website: https://aemo.com.au/en/energy-systems/electricity/wholesale-electricity-market-wem/wa-reserve-capacity-mechanism.

[8] As defined in clause 4.5.9 of the WEM Rules. The Planning Criterion ensures there is sufficient capacity in the SWIS to meet peak demand forecasts plus a reserve margin, and limit expected unserved energy to less than 0.0002% of the annual forecast demand.

[9] All references to years in this WEM ESOO are Capacity Years, unless otherwise specified. A Capacity Year commences in the Trading Interval starting at 8:00 AM on 1 October and ends in the Trading Interval ending at 8:00 AM on 1 October of the following calendar year.

demand balance over the 10-year outlook period, accounting for the anticipated available supply capacity and impacts of network congestion.

This 2024 WEM ESOO:

- Covers the 10-year outlook period from **2024-25 to 2033-34**.
- Designates the RCT determined for **2026-27** as the RCR for the 2024 Reserve Capacity Cycle.

The forecasts in this 2024 WEM ESOO are used to determine the RCR for the 2024 Reserve Capacity Cycle, which relates to the capacity required for 2026-27. Following the publication of this WEM ESOO, applications for Certified Reserve Capacity (CRC) for 2026-27 will close[10], and AEMO will assign CRC to eligible Facilities for that Capacity Year.

While determining the RCR for 2026-27 is a key purpose of this WEM ESOO, it also provides updated forecasts of the supply-demand balance for the 10-year outlook period, commencing with the 2024-25 Capacity Year.

When insufficient capacity to meet demand is anticipated for the upcoming Capacity Year, the RCM includes a Supplementary Reserve Capacity (SRC) mechanism to address this challenge. The SRC mechanism is designed to manage the risk of under-supply of capacity, or of changing SWIS needs, by allowing AEMO to procure additional capacity within six months before the start of a Capacity Year. The forecasts in this 2024 WEM ESOO identifies that SRC is required for the summer of 2024-25[11] (see Section 5.1.1).

Additionally, at AEMO's request, the Coordinator of Energy (Coordinator) may trigger procurement of Non-Co-optimised Essential System Services (NCESS)[12], where required to maintain power system security and reliability. AEMO can contract for capacity that does not hold Capacity Credits (and has not failed to satisfy Reserve Capacity obligations in the current or preceding Capacity Year). WEM ESOO forecasts can also inform the need for procurement of NCESS.

1.2 Structure of this document

- **Chapter 1** summarises key definitions of demand and consumption, forecasting scenarios, forecasting methodologies and the scope of the reliability assessment.
- **Chapter 2** presents electricity consumption and demand projections.
- **Chapter 3** covers the supply outlook and network augmentations.
- **Chapter 4** presents the reliability assessment results, including RCT determinations and the regional capacity shortfall assessment.
- **Chapter 5** identifies investment opportunities for maintaining system reliability and security.

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[10] The 2024 Reserve Capacity Cycle timetable is available at https://aemo.com.au/en/energy-systems/electricity/wholesale-electricity-market-wem/wa-reserve-capacity-mechanism/reserve-capacity-timetable.

[11] In accordance with clause 4.24.1 of the WEM Rules, AEMO can determine the need for SRC using the most recent WEM ESOO forecasts and any other information AEMO considers relevant.

[12] A NCESS is an additional service that may be procured to keep the SWIS operating in a secure and reliable state. Examples to date include peak demand services and minimum demand services, whereby additional capacity can be injected or withdrawn from the system. A NCESS may be procured on a case-by-case basis.

1.3 Key definitions of consumption and demand

AEMO uses particular terminology, derived from the Wholesale Electricity Market Rules (WEM Rules), when referring to specific forecasts and concepts in the WEM ESOO. For clarity, the overarching definitions of electricity consumption and demand used in this WEM ESOO are as follows:

- **Electricity consumption** represents the amount of power used over a period of time, measured in megawatt hours (MWh), gigawatt hours (GWh), or terawatt hours (TWh), and reported as an annual figure.
- **Demand** is used to refer to the amount of power consumed at a particular point in time, measured in megawatts (MW) or gigawatts (GW), and reported as an average over a 30-minute period.

Definitions of different types of consumption and demand forecast in this WEM ESOO are summarised in the following section. A table summarising the definitions of other key terminology is provided in the Glossary.

1.3.1 WEM ESOO definitions of consumption and demand

Consumption and demand can be measured at different points of the electricity system, to communicate power system needs in different ways. **Figure 3** identifies consumption and demand definitions used in this WEM ESOO. Commonly used consumption and demand definitions are:

- **Underlying consumption/demand** – the total amount of electricity consumption/demand used by consumers at their power points. This electricity can be sourced from the grid, or from behind-the-meter distributed energy resources (DER) such as distributed photovoltaics (DPV) and battery storage.
- **Delivered consumption/demand** – the electricity supplied to customers from the grid, which excludes the portion of their consumption/demand that is met by behind-the-meter (typically DPV) generation.
- **ESOO operational consumption/demand**[13] – sent-out generation supplied by all market-registered Energy Producing Systems, which includes both distribution and transmission losses.
- **ESOO unscheduled operational consumption/demand** – operational consumption/demand that excludes any consumption/demand associated with scheduled loads (such as Electric Storage Resources (ESR) charging).
- **Operational maximum (peak) and minimum demand** – the highest and lowest level of electricity drawn from the grid, measured as an average over a 30-minute period in either summer (December to March[14]), winter (June to August), or shoulder months (April, May, September to November).
- **Unscheduled operational maximum (peak) and minimum demand** – these represent the operational peak and minimum demand forecasts that exclude the impact of scheduled load operations (such as ESR charging).

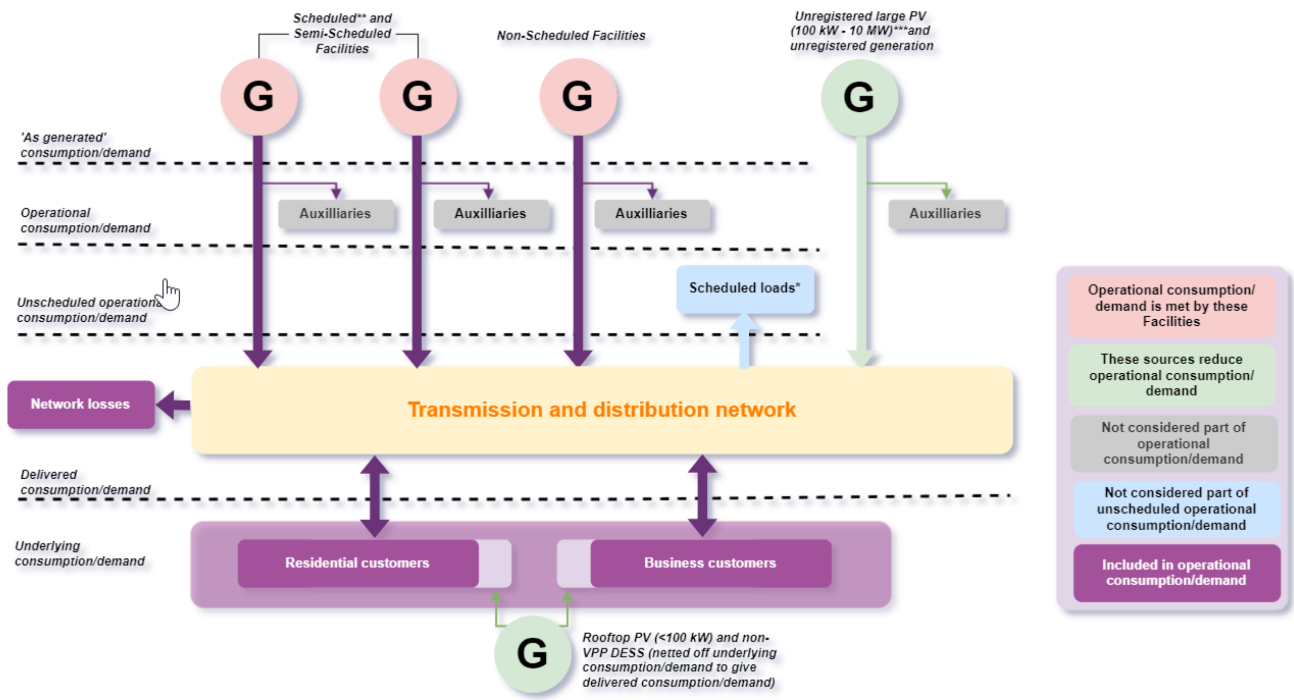
[13] ESOO (unscheduled) operational consumption/demand terms are also defined in the Undertaking the Long Term PASA WEM Procedure, available at https://aemo.com.au/en/energy-systems/electricity/wholesale-electricity-market-wem/procedures-policies-and-guides/procedures.

[14] These months are aligned with the Hot Season defined in the WEM Rules.

Figure 3 Overview of various consumption and demand definitions

operational consumption/demand (sent out) = unscheduled operational consumption/demand + scheduled loads*

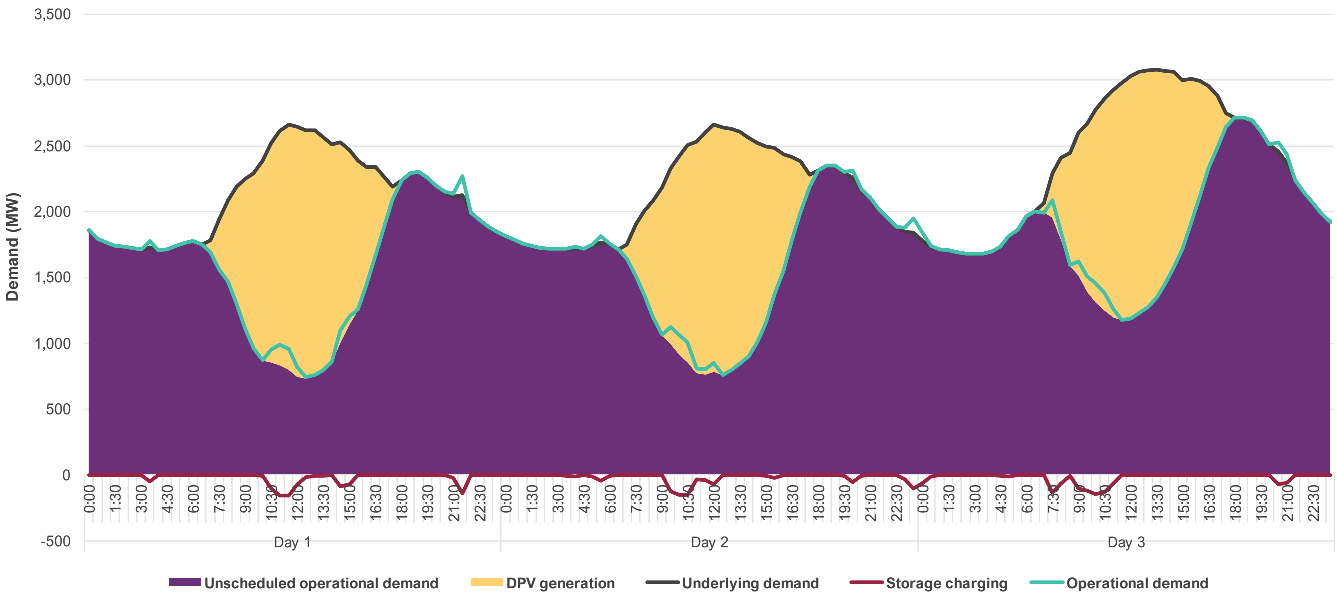
* Scheduled loads include Operational Withdrawals by registered Facilities, such as utility-scale storage charging and withdrawals by virtual power plants (VPP).
**Including VPP from distributed energy storage systems (DESS) and vehicle to grid electric vehicles (EV).
***Including onsite loads that are captured in the business customer sector.



Note: 'As generated' consumption/demand is not forecast in this WEM ESOO. It refers to sent-out generation plus generators' auxiliary loads (the electricity used by a generator), which represents the gross electricity generation on site. Unregistered large PV is also referred to PV non-scheduled generation (PVNSG).

Figure 4 illustrates the relationships of various demand terms defined above by showing a demand profile spanning three days.

Figure 4 Example demand profiles, including underlying, operational, and unscheduled operational demand



Explaining the terms used in this WEM ESOO's consumption and demand forecasts

Further to the consumption and demand definitions above, there are some important points to be aware of when reading the consumption and demand forecasts provided in this WEM ESOO:

- The WEM ESOO modelling resolution is 30-minute Trading Intervals, which is based on the Total Sent Out Generation (TSOG). The TSOG is a non-network-loss adjusted metered MWh value. This means that ESOO (unscheduled) operational demand is distinct from the average operational demand reported in AEMO's *Quarterly Energy Dynamics* (QED) reports.
- The average operational demand reported in AEMO's QED reports is the average total injection (sent out, MW) from all registered Facilities in the WEM over a Dispatch Interval (five-minute period) based on non-loss adjusted Supervisory Control and Data Acquisition (SCADA) data.
- The WEM ESOO reports (unscheduled) operational consumption/demand. This is different from Operational Demand as defined in the WEM Rules, which is an instantaneous, end of Dispatch Interval measurement used for dispatch purposes.
- The WEM ESOO provides delivered consumption forecasts for residential and business sectors. Annual unscheduled operational consumption forecasts include this forecast delivered consumption for all consumer sectors, plus transmission and distribution losses.
- Unscheduled operational peak forecasts are expected to match the operational peak forecasts, because scheduled loads are unlikely to charge from the grid during peak periods.
- Unscheduled operational peak and minimum operational demand forecasts in this WEM ESOO are presented with:
  - A 50% probability of exceedance (POE)15, meaning they are expected statistically to be met or exceeded one year in two, and are based on average weather conditions (also called one-in-two-year).
  - A 10% POE (for maximum demand) or 90% POE (for minimum demand), based on more extreme conditions that could be expected one year in 10 (also called one-in-10-year).
  - A 90% POE (for maximum demand) or 10% POE (for minimum demand), based on mild conditions that could be expected nine years in 10.

1.4 Scenarios

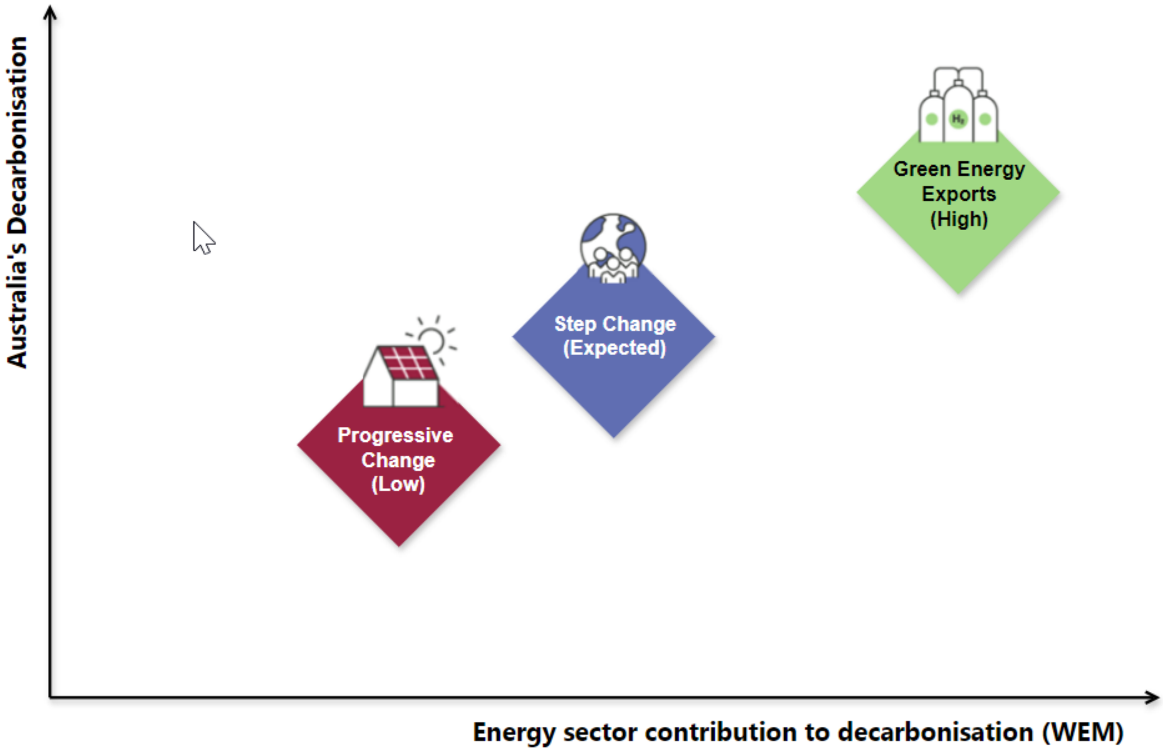
The WEM Rules require the WEM ESOO to use three demand growth scenarios:

- Low.
- Expected.
- High.

[15] POE is the likelihood a peak or minimum demand forecast will be met or exceeded.

For the 2023 WEM ESOO, AEMO selected three scenarios (*Progressive Change* for Low, *Step Change* for Expected, and *Green Energy Exports* for High) from its 2023 *Inputs Assumptions and Scenarios Report* (IASR)[16]. AEMO has retained these three scenarios unchanged for this 2024 WEM ESOO.

Figure 5 2024 WEM ESOO scenarios



As **Figure 5** shows, the three scenarios are based on different rates of decarbonisation in the WEM. Decarbonisation is a critical issue for the energy sector, with the federal, state and territory governments actively supporting the transition to renewable energy and related emissions reduction initiatives.

One of the most significant federal policies has been the commitment to reducing emissions by 43% by 2030, and a net zero target by 2050. The Safeguard Mechanism is another significant federal policy aimed at reducing emissions at Australia's largest industrial facilities in line with Australia's emission reduction targets[17].

On 30 November 2023, the Government of Western Australia brought the *Climate Change Bill 2023* to Parliament[18], aiming to lay down a comprehensive framework for emissions reduction and bolstering climate resilience in the region. The *Climate Change Bill 2023* seeks to formalise the State Government's commitment to reducing government emissions by 80% below 2020 levels by 2030, and set the long-term target of achieving net zero emissions by 2050.

[16] See https://aemo.com.au/-/media/files/major-publications/isp/2023/2023-inputs-assumptions-and-scenarios-report.pdf.

[17] See https://www.dcceew.gov.au/climate-change/emissions-reporting/national-greenhouse-energy-reporting-scheme/safeguard-mechanism.

[18] See https://www.wa.gov.au/service/environment/environment-information-services/climate-change-legislation#:~:text=On30 November2023the,netzerogreenhousegasemissions.

While these policies are driving decarbonisation, the rate of change is influenced by a range of interdependent factors, ranging from economic conditions through to network resilience. The WEM ESOO therefore considers the three credible yet disparate scenarios identified above for decarbonisation and associated electricity demand.

The three scenarios are summarised below:

- **Expected scenario** (*Step Change*) – this scenario centres on achieving a scale of energy transformation that supports Australia's contribution to limiting global temperature rise to below 2°C compared to pre-industrial levels. This scenario assumes a very strong contribution from consumers in the transformation, with rapid and significant continued investments in DER. In the Expected scenario, DER is highly orchestrated through aggregators or other providers, with the benefits being passed on to consumers. There is also strong transport electrification, as well as opportunities for large industry to electrify or use other low emissions alternatives to support domestic industrial loads. The scenario considers the growing interest in developing hydrogen production capabilities to meet emerging domestic and international energy demands.
- **Low scenario** (*Progressive Change*) – this scenario explores the challenges of achieving Australia's Paris Agreement commitment of a 43% emissions reduction by 2030 and net zero emissions by 2050. In this scenario, some transformational energy sector investments continue, but more challenging economic and international factors, higher technology costs and supply chain challenges relative to other scenarios result in a slower pace of change.
- **High scenario** (*Green Energy Exports*) – this scenario reflects very strong decarbonisation efforts, both domestically and globally, to limit temperature increase to 1.5°C. This leads to a rapid transformation of Australia's energy sectors and a strong emphasis on use of electrification and green hydrogen. This scenario includes the domestic use and export of green hydrogen through ammonia and energy-intensive manufacturing using hydrogen, such as green steel production.

These scenarios reflect an accelerated trajectory towards decarbonisation and energy transition in the WEM and shape the electricity consumption and demand forecasts, as well as the supply-demand balance, presented in this WEM ESOO.

Table 3 provides a summary of scenario assumptions for the 2024 WEM ESOO. A complete description of the scenarios, including narratives and key parameters, is presented in the 2023 IASR[19].

[19] See https://aemo.com.au/-/media/files/major-publications/isp/2023/2023-inputs-assumptions-and-scenarios-report.pdf.

Table 3 Scenario and assumption variations, 2024 WEM ESOO

Demand growth scenario WEM ESOO	*Progressive Change* (Low)	*Step Change* (Expected)	*Green Energy Exports* (High)
Global economic growth and policy coordination	Slower growth and lesser coordination	Moderate growth and stronger coordination	High growth and stronger coordination
Australian economic and demographic drivers	Lower	Moderate	High (partly driven by green energy)
DER uptake (DPV, distributed energy storage systems (DESS), and electric vehicles (EVs))	Lower	High	Higher
Storage aggregation and coordination such as virtual power plants (VPPs)	Lower	High	Higher
Energy efficiency	Lower	Moderate	Higher
Electrification (other than transportation sector)	Lower	High	Higher
Hydrogen use/hydrogen blending in gas distribution network[A]	Low production for domestic use, with no export hydrogen. Up to 10% blending in gas network.	Medium-Low production for domestic use, with minimal export hydrogen. Up to 10% blending in gas network.	High production for domestic and export use. Up to 10% blending in gas network.
Supply chain barriers	More challenging	Moderate	Less challenging
National decarbonisation target	At least 43% emissions reduction by 2030. Net zero by 2050.	At least 43% emissions reduction by 2030. Net zero by 2050.	At least 43% emissions reduction by 2030. Net zero by 2050.
Global/domestic temperature settings and outcomes[B]	Applies Representative Concentration Pathway 4.5 where relevant (~ 2.6°C)	Applies Representative Concentration Pathway 2.6 where relevant (~ 1.8°C)	Applies Representative Concentration Pathway 1.9 where relevant (~ 1.5°C)

A. Hydrogen blending in the gas network will need to accommodate the technical requirements of transmission and distribution pipelines, as well as the capabilities of connected gas appliances. Higher blends than ~10% may require appliance change and/or switches to dedicated hydrogen transmission pipelines.
B. Representative Concentration Pathways were adopted in the Intergovernmental Panel on Climate Change 's first Assessment Report; see https://www.ipcc.ch/report/ar5/syr/.

1.5 Consumption and demand forecasting methodology

The forecasting approach for unscheduled operational consumption and demand remains largely in line with the methodologies outlined in AEMO's *Forecasting Approach – Electricity Demand Forecasting Methodology* paper (Methodology Paper), published in August 2023[20].

This section provides a brief summary of the electricity consumption and demand forecasting approach, highlighting key differences in the assumptions and methodologies compared to the 2023 WEM ESOO. Where practical, AEMO has aligned methods used to develop electricity consumption and demand forecasts for both the National Electricity Market (NEM) and the WEM.

[20] An updated Methodology Paper, scheduled to be published by the end of August 2024, will be available at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-approach/forecasting-and-planning-guidelines. The 2023 Methodology Paper is available at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2023/forecasting-approach_electricity-demand-forecasting-methodology_final.pdf?la=en.

As the market develops and new trends emerge, AEMO will continue to evolve and refine its forecasting methodology in consultation with stakeholders.

1.5.1 Summary of the consumption forecasting methodology

AEMO has developed electricity consumption forecasts for the Low, Expected, and High scenarios, as presented in Chapter 2, based on projected consumption in the residential and business sectors, including electric vehicle (EV) charging.

For the **residential consumption** forecast, AEMO applied a growth model based on historical residential connections and monthly consumption data. The forecast was then adjusted by considering the impact of various external consumption drivers, including the rate of residential electrification and the uptake of energy efficiency measures[21].

To determine the **business sector consumption** forecast, AEMO employed a modelling approach that considered four components – business electrification, large industrial loads (LILs), business mass market (BMM), and hydrogen production.

- The **residential and business electrification** forecasts were informed by the output of the 2022 multi-sector modelling developed by the Commonwealth Scientific and Industrial Research Organisation (CSIRO) and ClimateWorks Centre (CWC)[22]. This modelling explored the least cost pathway to various scenario-driven decarbonisation targets[23].
- To better understand the pace and certainty of business electrification, AEMO carried out detailed surveys of LILs across the SWIS. These surveys also included dedicated interviews with larger sites. Alumina refineries represent the majority of forecast electrification[24] in the SWIS.
- The electricity consumption forecasts for **hydrogen production** considered production for both domestic and export markets. These projections drew from CSIRO-CWC's 2022 multi-sector modelling, with AEMO making subsequent adjustments to accommodate the uncertainty associated with the speed, scale, and timing of hydrogen projects. Progress of hydrogen production projects under development was cross-checked with market research in combination with the CSIRO HyResource project tracker[25].

Forecasts relating to **electricity consumption for EV charging** were derived from CSIRO's 2024 EV projections, which considered factors like EV uptake rates, charging profiles, and the distribution between charging profiles.

Total operational consumption forecasts were calculated by aggregating the underlying consumption from both the business and residential sectors, along with EV consumption forecasts. These were then adjusted for factors such as DPV generation, distributed energy storage systems (DESS), and distribution/transmission network losses.

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[21] Other external drivers include changing appliance penetration, changes in retail prices, climate change impacts, and consideration of rebound effects of consumer investments, particularly in rooftop PV.

[22] See https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/csiro-climateworks-centre-2022-multisector-modelling-report.pdf.

[23] Although the Safeguard Mechanism was not explicitly modelled, the 2022 multi-sector modelling achieved substantial industrial decarbonisation through electrification, aligning with the Safeguard Mechanism's emission reduction goals.

[24] Mechanical Vapour Recompression, electric calcination, and direct electrification of heat processes are being considered as feasible technologies for electrification.

[25] See https://research.csiro.au/hyresource/projects/facilities/.

1.5.2 Summary of the demand forecasting methodology

For the demand forecasts, AEMO considered both:

- Structural drivers, which can be estimated based on past trends and expert judgement, but which cannot be assigned a probability and are not influenced by weather or seasonal effects (these are captured through demand growth scenarios).
- Random drivers that affect outcomes at the times when peak and minimum demand occur, which can be modelled as probability distributions[26].

Summer and winter peak demands depend heavily on cooling and heating loads (in response to extreme temperature conditions), as well as the growth in loads that are unresponsive to temperature (referred to as base loads). In addition, LILs and hydrogen loads may reduce their production during peak demand periods to reduce their exposure to Reserve Capacity costs and elevated electricity prices.

To capture the full range of potential demand outcomes driven by random factors, AEMO first developed forecasts for the base year, which was the year with the latest summer actual demand data. Once the base year forecast was complete, AEMO applied half-hourly modelling to forecast the year-on-year demand changes. This half-hourly modelling considered shifts in demand timing for minimum and maximum demand periods.

The half-hourly demand forecast for the base year was then adjusted using growth indices derived from economic conditions such as:

- Price and gross state product (GSP).
- Demographic conditions such as connections growth.
- Any explicitly modelled growth drivers – such as EV charging and LILs – were also removed to avoid double-counting.

The half-hourly model for the base year forecast aims to characterise the relationship between underlying demand and key variables. Key variables include:

- Calendar effects like public holidays, days of the week and months.
- Weather effects such as temperature.
- Heatwave variables such as lagged temperature and moving averages.

These variables can reflect the impact of weather before peak demand occurs. For example, if the temperature is already high in the morning, it can lead to easier accumulation of heat, resulting in higher cooling demand. Moving averages can capture the impact of consecutive hot days on demand.

1.5.3 Changes in approach between the 2023 and 2024 WEM ESOOs

The 2023 WEM ESOO used a Generalised Extreme Value (GEV) model to rebase the base year forecasts generated by a linear regression model. For the 2024 WEM ESOO, AEMO adopted machine learning models and

[26] For description of structural and random drivers, see the Methodology Paper, at https://aemo.com.au/en/energy-systems/electricity/nationalelectricity-market-nem/nem-forecasting-and-planning/forecasting-approach/forecasting-and-planning-guidelines.

a refined selection of model variables. This allows for a more precise explanation of the relationship between weather and demand.

For the 2024 WEM ESOO, AEMO generated more than 3,000 simulations for each demand growth scenario using the half-hourly model, adjusting reference years, day shifts, and model residuals. AEMO then extracted seasonal peak and minimum demand values from these simulations. Sorting these values allowed forecasts for peak and minimum demand at 10%, 50%, and 90% POE to be determined.

Unlike the 2023 approach, which relied on resampling historical weather observations by blocks to create a year of 17,520 half-hourly weather observations, the 2024 approach constructed simulations based on individual weather reference years with day shifts. This allowed a more accurate representation of the El Niño-Southern Oscillation phase and the influence of specific days of the week on demand patterns.

Exclusions

Peak and minimum demand forecasts represent uncontrolled or unconstrained demand, without considering market-based or non-market-based interventions that may reduce system load during peak and minimum demand periods. As such, the forecast does not account for potential occurrences of:

- Dispatch of demand side participation capacity procured through the RCM and SRC.
- Any unserved energy as a result of directed load shedding or significant network outages.
- Calls for voluntary reduction in demand.
- Any coordinated, customer-controlled behind-the-meter battery and EV charging (through virtual power plants (VPPs)). The timing of VPP charging can materially influence the scale of grid demand. For example, charging during daytime periods when DPV generation is available, rather than during peak demand in the evening, would both reduce peak demand and increase minimum demand.
- Any impact of scheduled load operations (such as ESR charging).

To understand the primary drivers shaping the 2024 WEM ESOO unscheduled operational consumption and demand forecasts, please refer to Chapter 2. For detailed information on inputs contributing to these forecasts, including DER forecasts, refer to Appendix A1.

1.6 Reliability assessment methodology

The WEM ESOO considers power system reliability in the SWIS using the Long Term Projected Assessment of System Adequacy (PASA), otherwise referred to as the reliability assessment, as defined in section 4.5 of the WEM Rules.

1.6.1 Changes to the scope of the Long Term Projected Assessment of System Adequacy

On 13 December 2023, amendments were made to the scope of the Long Term PASA in the WEM Rules. These amendments were in response to the findings of the RCM Review[27] conducted by the Coordinator.

[27] See https://www.wa.gov.au/government/document-collections/reserve-capacity-mechanism-review.

Significant changes to the Long Term PASA include:

- **Revision of the Planning Criterion** – the limit for expected unserved energy (EUE) in Limb B was lowered from 0.002% to 0.0002%, aligning more closely with consumers' reduced tolerance for supply interruption risks. This follows a change prior to the 2023 WEM ESOO, when adjustments were made to the reserve margin component of Limb A to enable the reserve margin to be determined by AEMO with reference to a broader range of supply risks than that had previously been permitted.
- **Introduction of Capability Classes** – the previous two Availability Classes[28] were replaced by three Capability Classes[29] to offer a clearer distinction between the ability of capacity with different characteristics to maintain reliability within the SWIS.
- **Modification of Planning Criterion assessment** – the assessment of the Planning Criterion now revolves around the 10% POE peak demand forecasts assuming expected demand growth, departing from the previous evaluation across low, expected, and high demand growth scenarios.
- **Updates on RCT determination** – the determination of the RCT now assumes no network congestion, as the RCM accounts for the impact of network congestion within the Network Access Quantity (NAQ) framework when assessing the level of Capacity Credits to be assigned to each facility.
- **A focus on regional capacity shortfall assessment** – greater emphasis is placed on assessing potential capacity deficiencies localised within a sub-region of the SWIS, resulting from considering expected limitations on transmission network capacity or other factors. These shortfalls cannot be mitigated by additional Peak Capacity outside that sub-region.

1.6.2 Summary of the reliability assessment

The 2024 reliability assessment[30] considered the amendments discussed above. The assessment applied time sequential dispatch modelling that considered:

- Facility outages.
- Renewable resource variability.
- Weather-driven demand patterns.
- Network constraints (for regional capacity shortfall assessment only).

The modelling carried out iterations to evaluate unserved energy events and was based on the 2024 WEM ESOO electricity consumption and demand forecasts for the 10-year outlook period (2024-25 to 2033-34). The modelling has been used to:

- Determine whether the RCTs are set by Limb A or Limb B of the Planning Criterion and quantify the RCTs in MW.

[28] Availability Class 1 related to scheduled and intermittent generation capacity and any other capacity that is expected to be available for dispatch for all Trading Intervals, allowing for outages. Availability Class 2 related to capacity that is not expected to be available for dispatch for all Trading Intervals and includes Demand Service Providers and standalone batteries.

[29] This now includes Capability Class 1 (a firm capacity that is not energy limited, such as gas-fired Facilities that meet the 14-hour fuel availability requirements), Capability Class 2 (a firm capacity with energy or availability limitations, like DSP or ESRs), and Capability Class 3 (a non-firm capacity such as wind or solar Facilities with no associated firming capacity).

[30] AEMO engaged Ernst & Young (EY) to carry out the 2024 reliability assessment.

- Assess the extent to which the anticipated installed capacity of the energy producing systems and DSP capacity can satisfy both limbs of the Planning Criterion, identifying any regional capacity shortfalls and potential capacity supply and transmission options that would alleviate shortfalls.
- Determine the minimum capacity required to be provided by Capability Class 1 and Capability Class 3 for 2026-27.

For the 2024 reliability assessment outcome, refer to Chapter 4. For further information about the reliability assessment assumptions and methodology, refer to EY's 2024 reliability assessment assumption and methodology report[31]. For definitions of key reliability assessment related terminology, refer to the Glossary.

1.6.3 Forecasting ESR Duration and Peak demand Side Program Dispatch Requirements

As part of the RCM Review, another significant change has been introduced for AEMO to forecast the ESR Duration Requirements for new storage projects to provide capacity in the RCM. This new framework allows the ESR Duration requirement to be adjusted over time, but also provides for a storage project (typically battery storage) to retain its availability duration requirement that was applied at the time it first received Capacity Credits for five years.

The main aim of this framework is to ensure the obligations on duration-limited technologies remain aligned with the reliability needs of the SWIS. If the residual demand is higher outside of the existing duration requirement period, then AEMO will increase the number of contiguous Trading Intervals included in the ESR Duration Requirements period accordingly.

The WEM Rules include a transitional provision to keep the ESR Duration Requirement unchanged at eight Trading Intervals (four hours) for the 2024 Reserve Capacity Cycle. AEMO has forecast the ESR Duration Requirement for the 2024 Reserve Capacity Cycle for stakeholders' reference only, see Section 4.8 for the forecast results. For the modelling methodology, refer to Appendix A2.5. From the 2025 Reserve Capacity Cycle onwards, the ESR Duration Requirement will be determined as part of the Long Term PASA and published in the WEM ESOO.

The RCM Review also introduced the Peak Demand Side Programme Dispatch Requirement. This requirement has reduced the minimum number of Trading Intervals for which a DSP can be dispatched from 400 Trading Intervals to 100 Trading Intervals for the 2024 Reserve Capacity Cycle. The value will be determined annually as part of the Long Term PASA for future Reserve Capacity Cycles. See Section 4.11 for further information.

[31] See https://aemo.com.au/en/energy-systems/electricity/wholesale-electricity-market-wem/wem-forecasting-and-planning/wem-electricity-statement-of-opportunities-wem-esoo.

2 Consumption and demand forecasts

This chapter discusses forecasts of energy consumption and demand across the 10-year outlook period. In the Expected scenario:

- Operational consumption grows significantly, particularly in the second half of the outlook period, largely driven by projected growth in cooling load, business electrification and uptake of EVs. Consumption growth is expected to be more moderate than in the 2023 WEM ESOO, mainly due to more conservative economic and population growth, reduced LIL developments, slower uptake of EVs, and delayed hydrogen project development.
- Peak operational demand grows over the forecast outlook period, broadly consistent with energy consumption growth, with a smaller offset from DPV.
- Minimum operational demand declines in the first half of the outlook period, driven by high growth in DPV but offset slightly by the increasing heating load, uptake of EVs and electrification in later years.

Notes on the energy consumption and demand forecasts

- Underlying consumption includes business and residential consumption.
  - Business underlying consumption comprises LIL and BMM sectoral forecasts, business EV charging, and electricity for hydrogen production. Additional components include the impact of climate change, business electrification[A], and energy efficiency measures[B].
  - Residential underlying consumption considers population growth via an increased number of dwellings and connections[C], appliance uptake, residential EV uptake, residential electrification[D], the impact of climate change, and energy efficiency measures.
- To simplify reporting, unscheduled operational consumption/demand forecasts are referred to as operational consumption/demand. Refer to Chapter 1 for demand definitions.
- Peak and minimum demand refer to peak operational and minimum operational demand, respectively unless otherwise specified.
- Periods are referred to as:
  - Short term: between now and 2026-27 when the RCR is set for the 2024 Reserve Capacity Cycle.
  - Medium term: between now and 2028-29 (inclusive).
  - Long term: between 2028-29 and 2033-34 (inclusive).

A. Business electrification includes any process that involves fuel-switching to electricity (excluding fuel-switching in transportation), such as replacing an industrial gas hot water system with a heat pump, electrified heating, and cooling of air.
B. Energy efficiency measures reduce the energy required to perform a given task; for example, building insulation reduces the energy required for heating or cooling.
C. Residential base forecasts capture the growth in consumption with respect to connection points, reflecting population increase.
D. Residential electrification includes any process that involves fuel-switching to electricity (excluding fuel-switching in transportation), such as replacing a residential gas stovetop with electric stovetop, gas hot water system with a heat pump, electrified heating, and cooling of air.

2.1 Consumption and demand drivers

The main drivers of the energy consumption and demand forecasts considered in this 2024 WEM ESOO are:

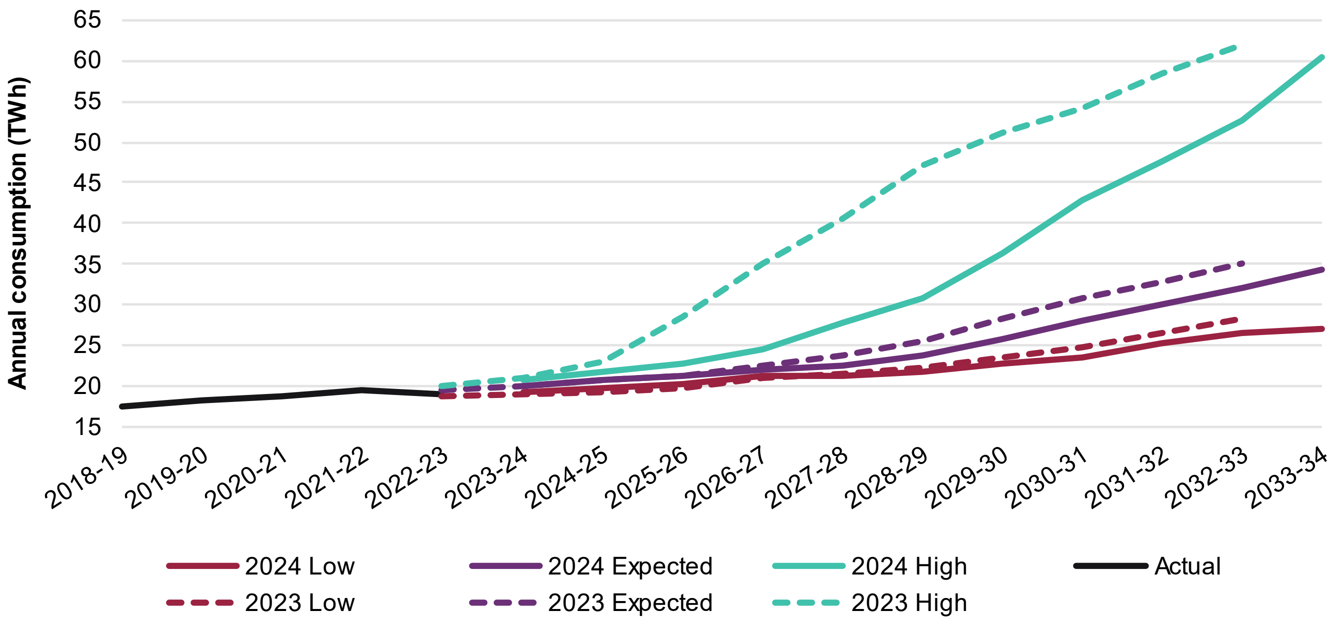
- Economic and population growth.
- New household connections.
- LIL activities.
- Uptake of EVs.
- DPV and DESS.
- Savings from energy efficiency measures.
- Electrification of non-transport sectors.
- Hydrogen production.

A summary of the forecasts for each of these drivers is provided in Section 2.1.1. Further discussion is in Appendix A1.

2.1.1 Underlying consumption is forecast to grow across the three scenarios, more prominently in the second half of the outlook period

The forecast growth in underlying consumption across the three scenarios is strongly influenced by projections for growth in electrification of both business and residential sectors, and strong uptake of EVs, offset by continued uptake of DPV. Emerging hydrogen production primarily for export is also an influence, especially for the High scenario.

Figure 6 Actual and forecast underlying consumption under three scenarios from 2023 and 2024 WEM ESOOs, 2018-19 to 2033-34 (TWh)



The drivers of energy consumption forecast a future with greater underlying consumption, but with more consumer-driven generation and storage. Traditional drivers of consumption – economic and population growth, investment in energy efficiency measures, and LILs – will continue to influence forecast underlying consumption, along with electrification, EV, and industrial activities.

This WEM ESOO projects slower growth in underlying consumption in all three scenarios compared to the 2023 WEM ESOO. This is due to forecasts of a slower pace in the uptake of EVs, lower commodity prices (with impacts to BMM and LIL), and a reduced forecast for hydrogen production over the 10-year outlook period.

Below is a summary of the key inputs that supported consumption (and demand[32]) forecasts in this WEM ESOO, and how these forecasts differ from the 2023 WEM ESOO:

- **Western Australia's economy** is projected to grow, but at a more modest rate than the previous forecasts. Slower economic growth compared to the previous forecasts over the first two years is primarily due to high inflation and interest rates, which slow down consumer spending. The forecast also assumes subdued demand for Western Australia's resource commodities as slower global economic activity weighs on exports. In the medium to long term, lower growth in economic forecasts is driven by slower **population growth** and a more modest labour force participation rate.
- **New household connections** for both attached dwellings and detached houses in Western Australia are forecast to grow at a slower rate compared to the previous forecasts. This is linked to the modest economic growth assumptions, which lead to fewer houses being built.
- **Existing and new LIL** are expected to grow at a slower rate than previous forecasts. LIL in Western Australia have been significantly impacted by recent commodity price drops and industry announcements (such as the mothballing of Alcoa's Kwinana Alumina Refinery). Nickel, alumina, and lithium prices have declined, leading to a more modest outlook for existing and new industrial load growth.
- **Uptake of EVs** is projected to grow strongly over the outlook period[33]. However, projected growth has been revised down significantly from previous forecasts based on recent stakeholder feedback[34] and updated data from the Bureau of Infrastructure and Transport Research Economics (BITRE). BITRE's data reveals vehicles last longer than expected (lower scrapping rates[35]), leading to fewer new vehicle sales. The data also reveals a significant decrease in road transportation as a share of passenger transport, coupled with changes in depreciation rates, further diminishes the future demand for vehicles.
- **Uptake of DPV** is forecast to continue growing over the outlook period. This is driven by population growth, a reduction in the cost of PV systems, and the relatively short payback period for DPV investments. Growth in DPV uptake is stronger than the previous forecasts, due to projections for larger system sizes along with anticipated lower purchase costs.

[32] Inputs that drive the peak and minimum demand forecasts are discussed in Section 2.1.2.

[33] This WEM ESOO assumed a portion of EV participating in coordinated charging and V2G, which were modelled dynamically, optimised within the reliability assessment to mitigate potential supply gaps. See Appendix A1.3 for further details.

[34] AEMO received feedback on assumptions underpinning the EV forecasts through the *2024 Forecasting Assumptions Update Consultation*. See https://aemo.com.au/en/consultations/current-and-closed-consultations/2024-forecasting-assumptions-update-consultation.

[35] AEMO's forecasts use scrapping rates to reflect the rate at which vehicles are withdrawn from use. Examples of scrapping include vehicles written-off after accidents, and vehicles no longer being economic to register (perhaps due to the cost of replacement parts).

- **DESS capacity** in the SWIS is expected to increase over the outlook period, at a similar rate to previous forecasts. There remains uncertainty about the uptake level, with some differences across the explored scenarios[36]. DESS forecasts are sensitive to forecast improvements in technology, as well as the rate of customer adoption.
- Investment in **energy efficiency measures**, which offset consumption, is forecast to grow at a higher rate than in previous forecasts, reflecting the inclusion of energy efficiency improvements in new technologies, buildings and processes, and uptake of energy efficient appliances and equipment across sectors. The forecasts account for policy ambition and demand drivers at varying levels to align with scenario narratives.
- **Electrification** (non-transport) is forecast to grow strongly for business and residential sectors throughout the outlook period. Growth projections are similar to the previous forecasts albeit with minor updates informed by 2024 LIL survey responses. This suggests that electrification continues to be one of the most cost-effective emission reduction strategies for Western Australian electricity consumers.
- **Green hydrogen production** using electrolysers is an emerging industry in Western Australia and AEMO continues to monitor early developments and prospective projects. For this WEM ESOO, AEMO has delayed the forecast development of significant hydrogen production, reflecting current uncertainty surrounding the pace, scale, and timing of hydrogen projects. Consequently, there is a notable reduction in the total amount of hydrogen produced for domestic use and export over the entire forecast period compared to previous forecasts, which is particularly evident in the second half of the outlook period.

2.1.2 Forecast peak and minimum demand largely impacted by updates in forecasting methodology and drivers of consumption forecasts

The forecast peak (and minimum) demand is not only driven by the components of consumption mentioned above, but also by weather-driven components, co-incidental consumer behaviours, and coordination of DER. It is also impacted by the updated demand forecasting methodology, discussed in Section 1.5. Overall, for 10%, 50%, and 90% POE, the 2024 WEM ESOO forecasts:

- Growth in peak demand across all three scenarios for both summer and winter. This is strongly influenced by the growth in base year forecasts, cooling and heating loads, electrification, and EV uptake. Peak demand periods are forecast to occur more frequently in the early evening because of strong DPV growth contributing to meeting demand during sunlight hours.
  - In the Expected scenario, the winter operational peak demand is forecast to exceed the summer operational peak demand from 2032-33 for 10% POE, from 2029-30 for 50% POE, and from 2028-29 for 90% POE. This is due to the anticipated faster growth of underlying consumption during winter, largely driven by electrification, and the early sunset time along with lower solar radiance reducing the impact of DPV on winter maximum demand.
- Minimum demand is forecast to decline throughout the outlook period in both the Low and Expected scenarios, driven by low growth forecast for LIL and strong DPV generation meeting daytime demand. The large volumes

[36] This WEM ESOO assumed a portion of DESS would be orchestrated via VPPs, which were modelled dynamically, and optimised within the reliability assessment to mitigate potential supply gaps.

of DVP installed capacity mean minimum operational demand is expected to occur during the middle of the day when DPV generation is at its peak.

- Across the scenarios, variations in the base year demand forecasts since the 2023 WEM ESOO are primarily driven by the updated forecasting methodology and the impacts of the most recent actual seasonal demand data. Throughout the outlook period, forecasts are further driven by updates in the supporting forecasts from the 2024 WEM ESOO, as summarised in Section 2.1.1. Compared to the 2023 WEM ESOO, this WEM ESOO projects:
  - **A lower peak operational demand during summer**, except in the initial years. Compared to the previous forecasts, lower peak forecasts for the initial years are strongly influenced by the higher 2024 summer actual data. Over the forecasting outlook period, the lower summer operational peak is driven by projections of lower industrial activity, lower demand from hydrogen sector[37], and a slower pace in EV uptake, partially offset by higher base year forecast and cooling load.
  - **A higher peak operational demand during winter**. This is driven by the updated forecasting methodology capturing the most recent user behaviour, which pushes up the peak demand forecast in the base year. This increase in the base year then influences subsequent years, even after considering electricity consumption growth factors such as lower industrial activities, lower demand from hydrogen, and a slower pace in EV uptake.
  - **A lower minimum demand during the shoulder months**. This is driven by projections for higher DPV generation, complemented by a slower pace in EV uptake and slower growth in LIL. Underlying consumption is forecast to grow continuously throughout the outlook period.

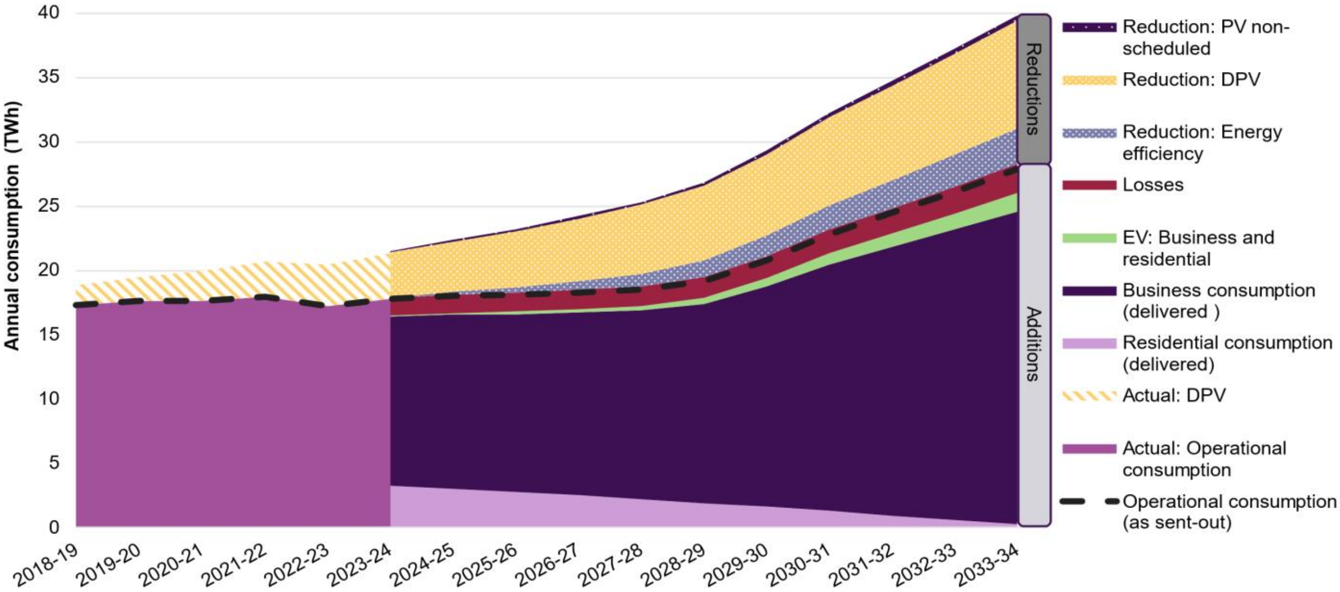
2.2 Underlying consumption is forecast to grow significantly, particularly in the second half of the outlook period, largely due to electrification and emerging clean technology industries

Figure 7 shows historical underlying consumption and a breakdown of the Expected scenario forecast into sectoral components over the 10-year outlook period. It also shows the operational consumption forecast (black dashed line) under this scenario.

Underlying consumption is forecast to grow continuously throughout the outlook period, adding 14 TWh between 2023-24 and 2033-34. In the Expected scenario, DPV generation and energy efficiency measures together offset nearly a quarter of underlying consumption.

[37] The forecasts assumed 90% curtailment of hydrogen load during peak demand, based on industry feedback. AEMO will continuously monitor industry trends and stakeholder feedback to refine this assumption for future WEM ESOO forecasts.

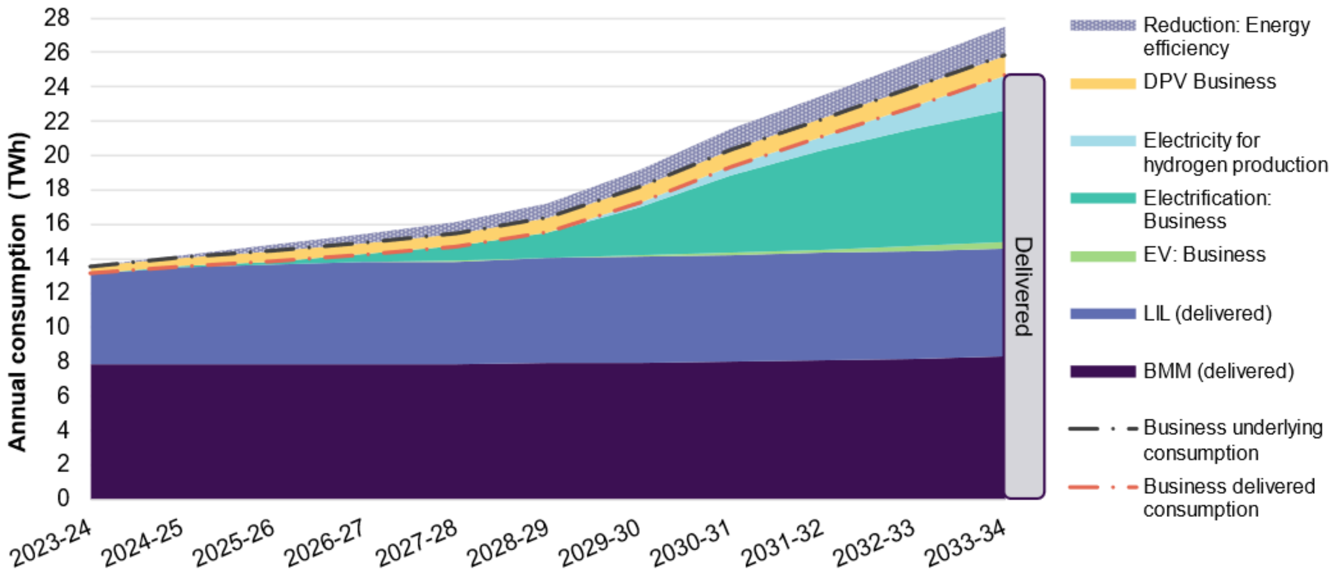
Figure 7 **Actual and breakdown of forecast annual consumption, by sectoral components, Expected scenario, 2018-19 to 2033-34 (TWh)**



Note: Impacts of distributed battery storage are negligible compared to other components and are therefore not shown separately.

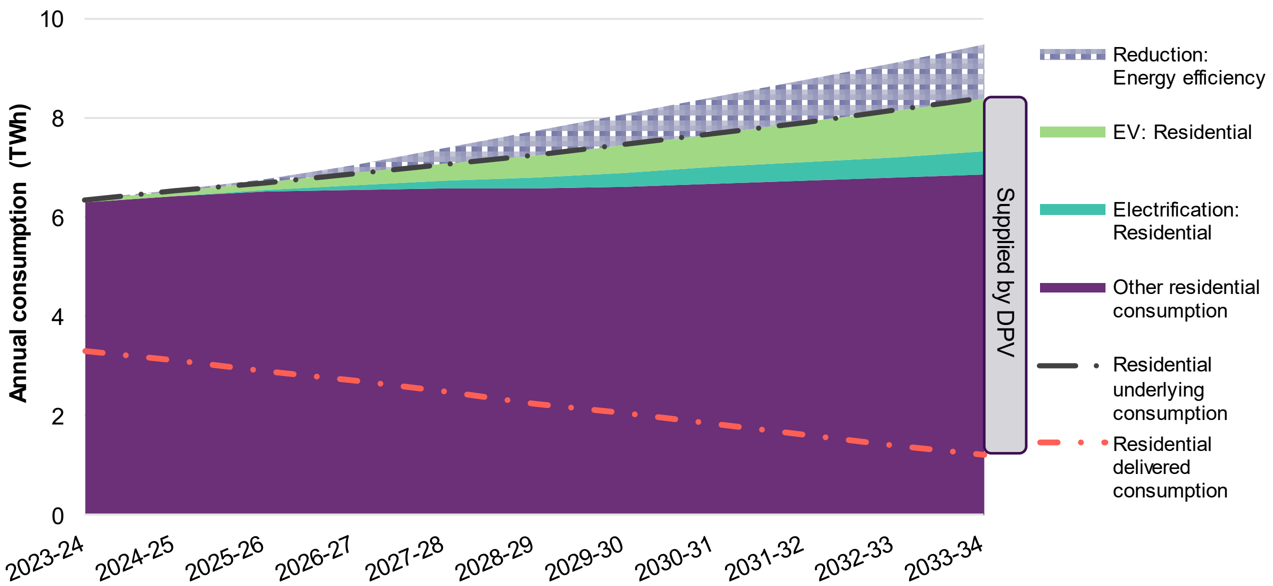
Figure 8 and **Figure 9** show components of forecast business and residential underlying consumption over the outlook period. The components that drive the forecast results for business and residential sectors are discussed in Sections 2.2.1 and 2.2.2, respectively.

Figure 8 **Components of forecast business underlying consumption, Expected scenario, 2023-24 to 2033-34 (TWh)[A, B]**



A. Components of business delivered consumption are presented here excluding round trip battery losses. Losses are aggregated in the calculation of total operational consumption.
B. Transmission and distribution losses are presented as a total in **Figure 7** to reflect forecast methodology and are not shown separately here.

Figure 9 Components of forecast residential underlying consumption, Expected scenario, 2023-24 to 2033-34 (TWh)[A, B]



A. Residential delivered consumption presented here excludes battery storage to reflect the forecast methodology.
B. Transmission and distribution losses are presented as a total in **Figure 7** to reflect forecast methodology and are not shown separately here.

Figures 7 to 9 show that between 2023-24 and 2033-34:

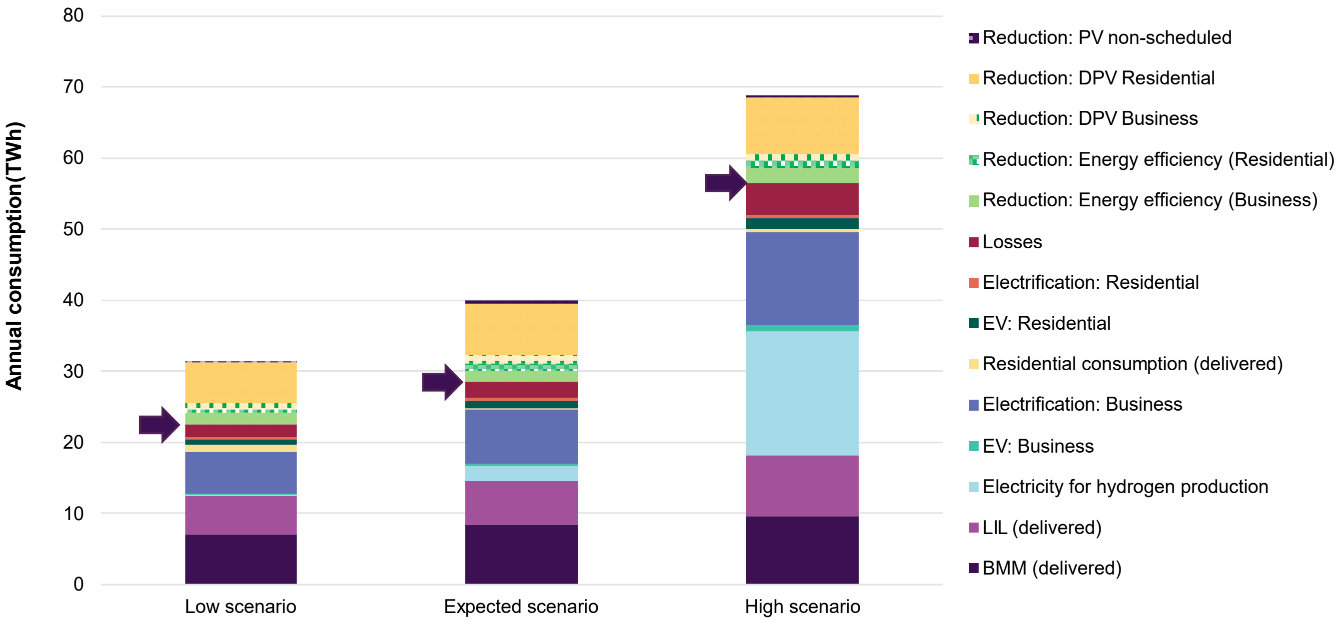
- Business delivered consumption is forecast to grow strongly in the medium to long term due to increases in electrification and electricity consumption for hydrogen production – projected to compensate for the slow growth in LIL consumption.
- Business and residential EV consumption is forecast to grow strongly, adding a further 1.4 TWh to current levels. The second half of the outlook period is forecast to show more EV uptake, due to several factors:
  - The forecasts aim to meet a trajectory of improving fuel efficiency standard to catch up with the United States' vehicle emissions standards by 2028[38], increasingly incentivising manufacturers to produce more EVs.
  - Additionally, price parity with internal combustion engine vehicles is forecast to be reached as production scales up, and increased EV availability will better cater to diverse consumer needs.
  - As EV adoption is forecast to grow, economies of scale benefit further EV growth while internal combustion engine vehicles are projected to suffer from declining economies of scale as production lowers and petrol supply chains reduce. This leads to a forecast strong uptake in EVs in the second half of the outlook period.
- Residential delivered consumption is forecast to decline over the outlook period, due to the sustained uptake of DPV with a trend towards larger PV systems, outpacing the growth in residential underlying consumption.

[38] On 17 May 2024 a legislation on New Vehicle Efficiency Standard passed through Australian Parliament and would be effective from 1 January 2025. It is aiming to reduce around 60 per cent emissions from new passenger vehicles and roughly halve the emissions of new commercial vehicles by 2030. See Minister for Climate Change and Energy 2024, *Joint media release: An Australian-made New Vehicle Efficiency Standard*, at https://minister.dcceew.gov.au/bowen/media-releases/joint-media-release-australian-made-new-vehicle-efficiency-standard. Appendix 1.3 includes further information on uptake of EVs.

Figure 10 shows the forecast impact of each sectoral component on underlying consumption at the end of the outlook period (in 2033-34), with the level of operational consumption indicated with an arrow. The High scenario shows that strong efforts towards decarbonisation, reflected by the significant uptake in hydrogen production and electrification, are forecast to drive operational consumption to exceed 55 TWh.

Sections 2.2.1 and 2.2.2 discuss components of business and residential underlying consumption, respectively and provides more context on key sectoral growth factors.

Figure 10 Breakdown of annual consumption forecasts under three scenarios in 2033-34 (TWh)



Note: Sectoral components that contribute to operational consumption are drawn in solid colours while those reducing operational consumption are drawn in shaded patterns.

2.2.1 Strong growth in business underlying consumption is driven by expansion in industrial activity and electrification

Business underlying consumption is forecast to increase throughout the outlook period. Between 2023-24 and 2033-34, underlying consumption from the business sector, excluding the impact of business EVs, is projected to add at least 5.7 TWh to up to 35.9 TWh depending on the scenario.

Figure 11 shows the influence of sectoral components in driving forecast business underlying consumption. In summary:

- **BMM** – economic growth is projected to outpace savings from energy efficiency measures, resulting in overall growth in BMM consumption in both the Expected and High scenarios. In the Low scenario, a weaker economy leads to a slight decrease in BMM consumption.
- **LIL** – across the three scenarios, LILs are forecast to grow faster during the first half of the outlook period compared to the second half, due to a number of greenfield developments and brownfield expansions[39]. Slower growth in consumption during the 2030s is due to the uncertainty around the entry of new LIL projects

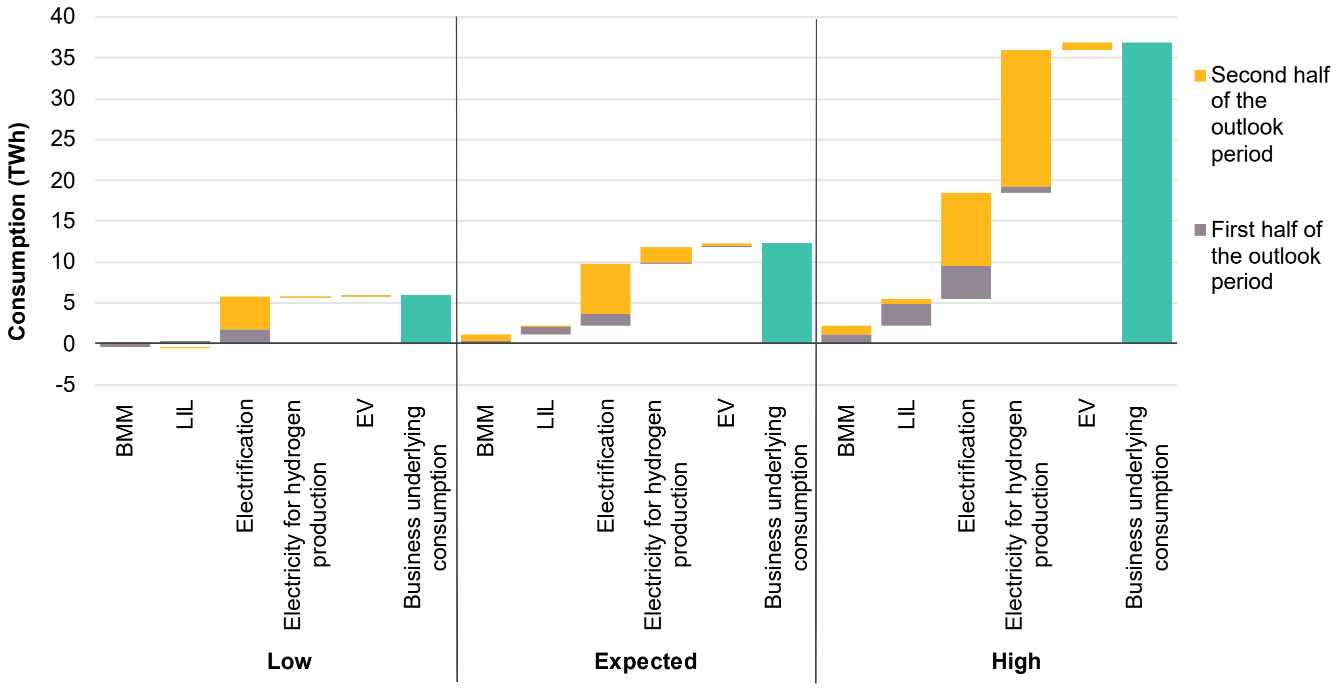
[39] Detail discussion on the new and existing LIL consumption forecast methodology is included in Appendix A1.7.

in the long term. Industrial customers have expressed their interest in securing electricity that is sourced from renewable generation, including behind-the-meter generation. The majority of growth in LIL consumption is forecast to stem from lithium mining and refining and the anticipated addition of the state's third desalination plant[40] .

- **Electrification** – significant forecast growth of business electrification is primarily driven by electrification of alumina refineries, which is substantially higher than projected residential electrification.
- **Hydrogen production** – delays to the commencement of hydrogen projects have resulted in markedly lower forecasts in the first half of the outlook period relative to the second half. There is the potential for significant increases in consumption arising from electrolyser loads in the early 2030s as green hydrogen projects are forecast to come online.
- **EVs** – in the Expected scenario, projected business EV uptake results in the addition of only 53 GWh during the first half of this outlook period but adds 329 GWh during the second half of the period following the trends explained above (production incentives for manufacturers, price parity with internal combustible vehicles, and economies of scale benefiting EVs). A similar trend is projected in the Low and High scenarios.

Overall, AEMO forecasts a higher growth for business underlying consumption in the second half of the outlook period, primarily due to projections for delayed start in hydrogen production, significantly higher pace of business electrification, and higher uptake of EVs. Approximately 75% of the growth in business underlying consumption is attributed to the second half of the outlook period.

Figure 11 Business underlying consumption growth forecasts under three scenarios by components for the first half (2023-24 to 2028-29) and second half (2028-29 to 2033-34) of the outlook period (TWh)



Note: The impacts of energy efficiency, battery, price, and climate change were factored into business underlying consumption forecasts and are not shown separately as their influence is relatively small.

[40] For detail see https://www.watercorporation.com.au/Our-water/Desalination/Alkimos-Seawater-Desalination-Plant.

2.2.2 Continued growth in residential underlying consumption is primarily driven by growing connections, electrification, and EV uptake

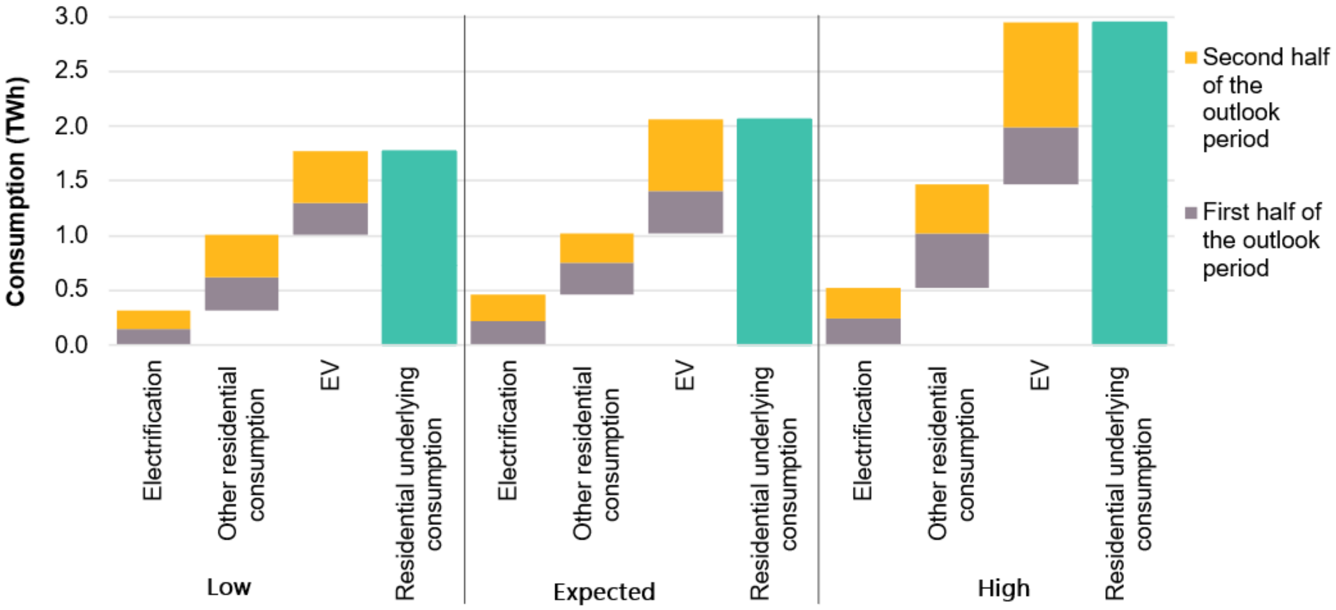
Residential underlying consumption is forecast to increase throughout the outlook period. Between 2023-24 and 2033-34, additional residential underlying consumption (excluding the impact of residential EVs) of 1 TWh to 1.5 TWh is expected depending on the scenario.

Despite the forecast growth in residential underlying consumption, residential delivered consumption is projected to decline in all three scenarios. This is because increased underlying consumption is offset by sustained growth in DPV, and to a lesser extent savings by ongoing improvements to household energy efficiency measures.

Figure 12 shows the influence of key sectoral components in driving residential underlying consumption throughout the outlook period. In summary:

- **Electrification and other residential consumption** – while residential underlying consumption growth is bolstered by increased residential connections and electrification, it is partially offset by household savings from energy efficiency measures.
- **EV** – in the Expected scenario, the residential EV uptake results in an addition of 390 GWh during the first half of this outlook period while adding 646 GWh during the second half (following the projected EV uptake trends explained previously). A similar trend also is projected in the Low and High scenarios.

Figure 12 Residential underlying consumption growth forecasts under three scenarios by components for the first half (2023-24 to 2028-29) and second half (2028-29 to 2033-34) of the outlook period (TWh)

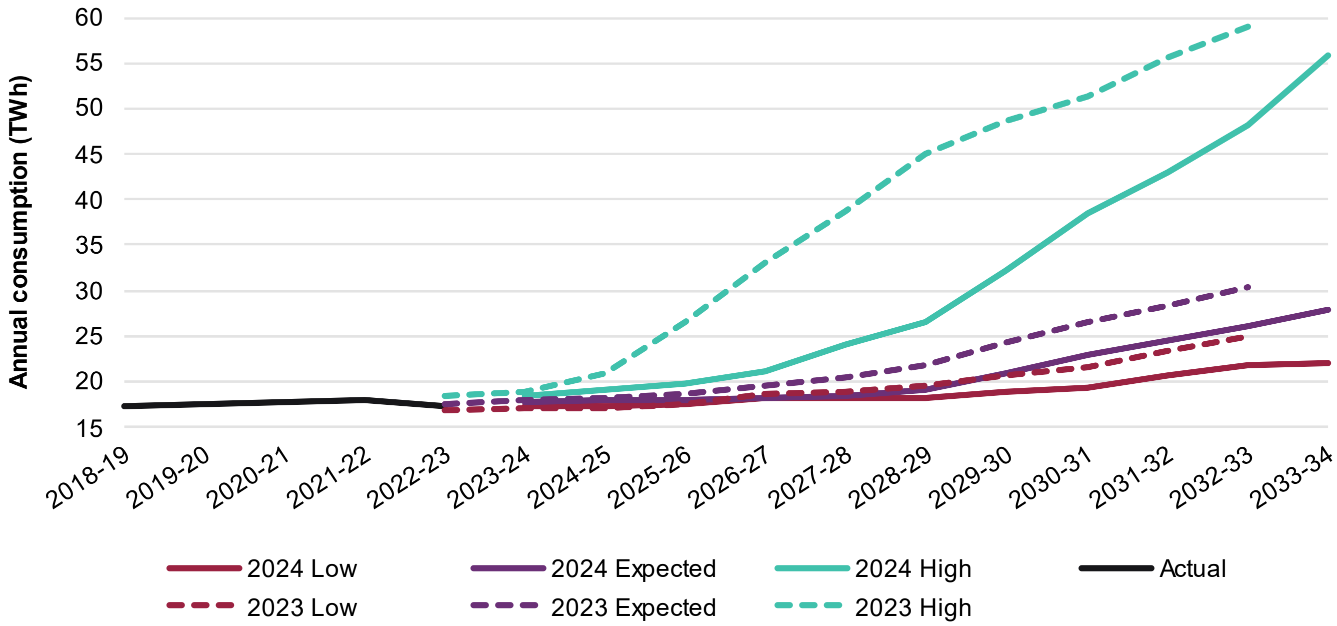


Note: The “other residential consumption” component shown here includes the impact of appliance uptake, energy efficiency, battery charging losses, climate change, and price on residential underlying consumption, not shown separately as their influence is relatively small.

2.2.3 Operational consumption is forecast to grow, heavily influenced by business sector electrification and EV uptake

Figure 13 compares the 2024 WEM ESOO operational consumption forecasts for the Low, Expected, and High scenarios with those forecast in 2023, and shows actual operational consumption from 2018-19 to 2022-23. Forecast operational consumption grows annually throughout the outlook period across all three scenarios, driven by growth in business delivered consumption, which more than offsets the decrease in residential delivered consumption.

Figure 13 Actual and forecast operational consumption under three scenarios from 2023 and 2024 WEM ESOO, 2018-19 to 2033-34 (TWh)



In summary, between 2023-24 and 2033-34, the forecast average annual growth rate for operational consumption by scenario in the 2024 WEM ESOO is:

- **Low scenario** – 2.5% growth, adding 4.9 TWh by the end of the outlook period. Relatively slower growth in the first five years is driven by a decline in both BMM and residential delivered consumption. This is led by steady growth in DPV, which reduces the overall quantity of electricity delivered by the grid. Growth is stronger in the second half of the period, driven by electrification in both business and residential sectors and increasing EV uptake.
- **Expected scenario** – 4.6% growth, adding 10.1 TWh by the end of the outlook period. This growth is driven by a stronger pace of business electrification compared to the Low scenario, complemented by strong EV uptake. The potential for green hydrogen production also contributes to growth, particularly in the second half of the period.
- **High scenario –** 11.7% growth, adding 37.3 TWh by the end of the outlook period. Growth is driven by business electrification over the first half of the period, then by the burgeoning green hydrogen industry, which would service both the domestic market and a substantial export market.

- Across all three scenarios, forecast growth for operational consumption is stronger in the second half of the outlook period (averaging 3.9%, 7.7%, and 16.0% annually for the Low, Expected, and High scenarios respectively) compared to the first half (averaging 1.2%, 1.5%, and 7.6% annually for the Low, Expected, and High scenarios respectively).

Figure 13 above also highlights that across the scenarios, this WEM ESOO forecasts a slower growth in operational consumption compared to the 2023 WEM ESOO, due to a more moderate economic outlook.

2.3 Summer and winter peak demand are forecast to increase throughout the outlook period

2.3.1 Record-breaking 2023-24 summer and 2022-23 winter peak demand

The peak demand forecasts in this WEM ESOO have been influenced by a record-breaking 2023-24 summer in the SWIS.

In 2023-24, Western Australia experienced an exceptionally intense summer – the second-warmest on record[41] – characterised by elevated temperatures and high humidity, with 27 days registering temperatures above 35°C and nine days experiencing maximum temperatures at or above 40°C.

The first peak demand record since 2016[42] was set on 23 November 2023, prior to the onset of summer. This record was subsequently broken on multiple days across the summer, which saw seven of the top 10 highest demand days on record, including the current all-time maximum operational demand record of 4,233 MW[43], which was set on 18 February 2024.

Figure 14 shows three consecutive maximum operational demand records over 18-20 February 2024. These were driven by prolonged heatwave conditions with temperatures exceeding 40°C and overnight minimums not dropping below 25°C. In response, AEMO dispatched capacity procured through the SRC mechanism and off-market generation, and demand response also provided support to reduce the demand by up to 158 MW. Without these additional interventions, the actual peak demand would have occurred on 19 February 2024, estimated at 4,334 MW, 106 MW higher than the observed peak demand.

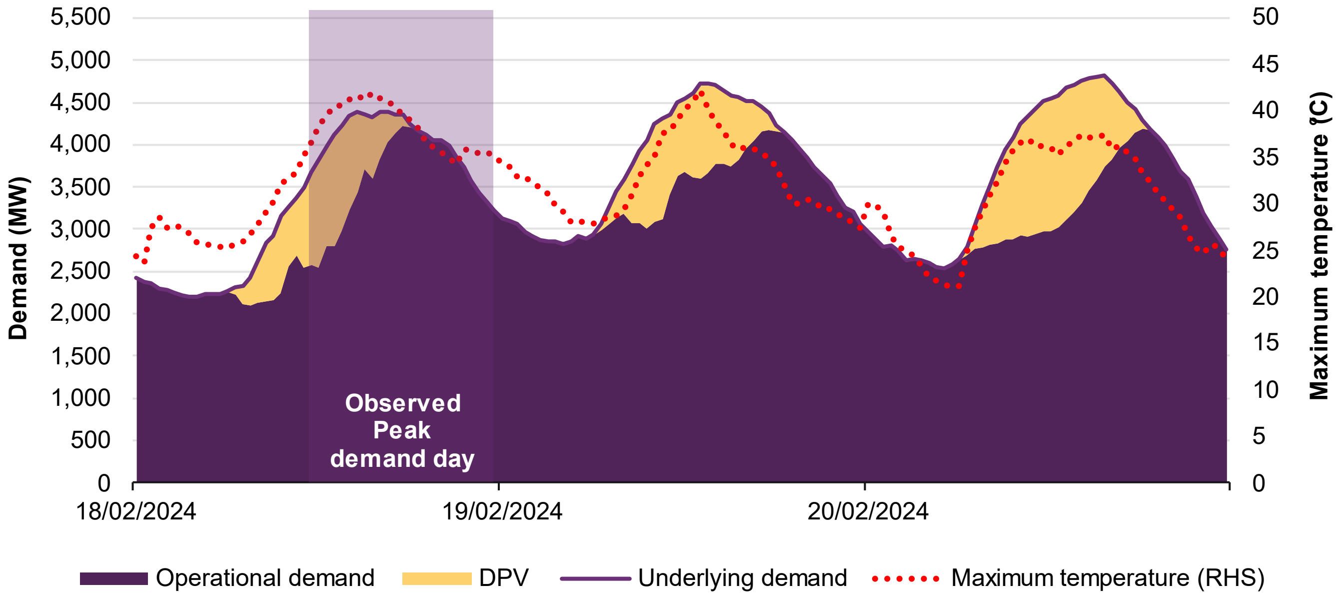
The peak demand, adjusted for load reduction, surpassed the 10% POE threshold and hovered around the 5% POE level, a consequence of the extreme climatic conditions witnessed that year. The peak temperature of 42.3°C, recorded on 19 February at the time of the peak demand, was coupled with high humidity and a Dew point of 24.3°C, coinciding with low DPV generation amounting to 8.2 GWh.

[41] See http://www.bom.gov.au/climate/current/season/wa/archive/202402.summary.shtml.

[42] The peak operational demand record of 4,006 MW was set on 8 February 2016. See https://aemo.com.au/energy-systems/electricity/wholesale-electricity-market-wem/data-wem/data-dashboard#records.

[43] This record was also published in AEMO's *Quarterly Energy Dynamics* Q1 2024, at https://aemo.com.au/-/media/files/major-publications/qed/2024/qed-q1-2024.pdf?la=en#:~:text=In%20Q1%202024%2C%20NEM%20operational,Q1%20average%20of%2024%2C822%20MW. For the 17:30 Trading Interval based on non-loss adjusted meter data, which included the 5-minute peak demand record of 4,233 MW in the 17:55 Dispatch Interval (based on non-loss adjusted SCADA data). The WEM ESOO modelling resolution is 30-minute Trading Intervals and uses verified metering data. In this context, the 5-minute peak of 4,233 MW contributed to a 30-minute Trading Interval operational demand used in this WEM ESOO of 4,228 MW.

Figure 14 Demand (MW) and temperature (°C) profiles for a three-day period covering the observed peak demand day



Source: AEMO and Bureau of Meteorology

Note: Operational demand data is based on the TSOG, sourced from AEMO's Market Data website.

In 2023, a passage of cold fronts during June brought moderate to heavy daily rainfall across multiple parts of Western Australia. A record winter maximum demand of 3,657 MW was observed in 18:00 Trading Interval on 26 June 2023 with temperature at 10.1°C[44] – 26 June 2023 was recorded as the coldest day for multiple parts of Western Australia except the southwest, where the coolest day was 6 June 2023 with near record peak operational demand of 3,593 MW. The 26 June winter peak demand of 3,657 MW is the highest recorded maximum operational demand in June on record since 2007. It is also 42 MW higher than the previous winter peak demand record set on 9 August 2022 and was only 0.7% lower than the 2022-23 summer peak demand (2022-23 had a relatively mild summer and warm winter).

The updated forecasting methodology, as described in Section 1.5, took into account the 2023-24 summer and 2022-23 winter weather and peak demand records. It also considered the most recent user behaviour. These factors have led to an increase in the winter and summer peak demand forecast in the base year compared to the 2023 WEM ESOO base year forecasts. This has contributed to the growth in the peak demand forecasts over the outlook period.

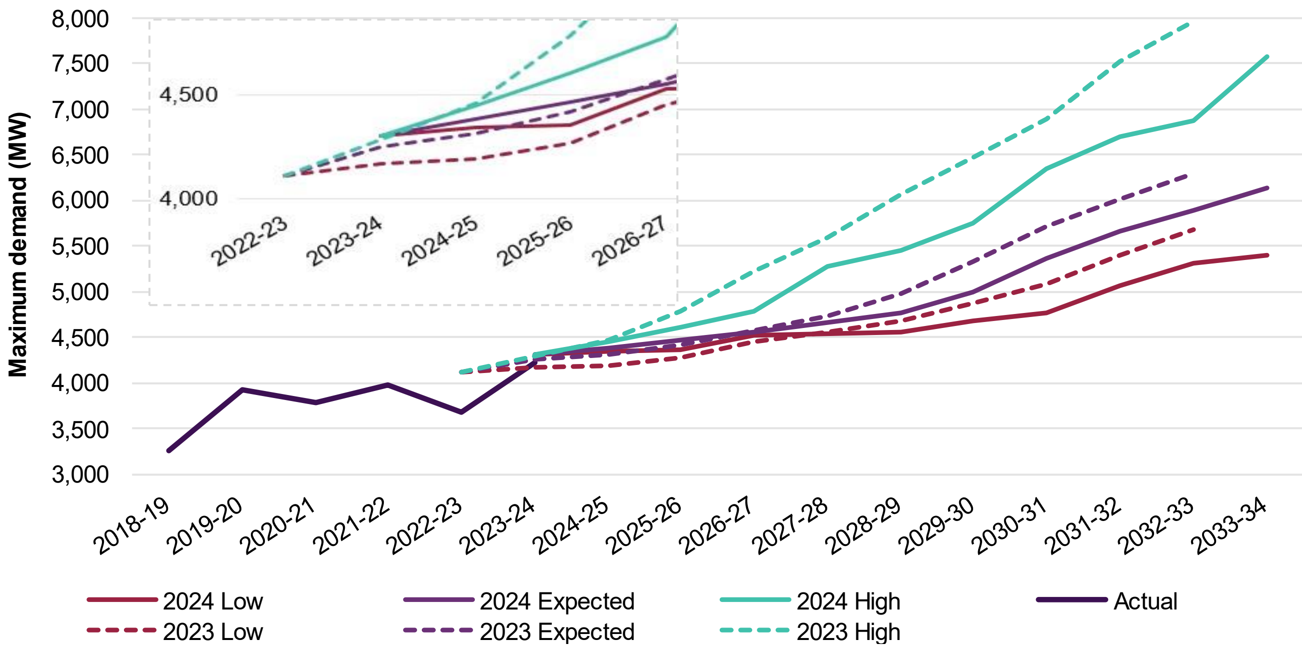
2.3.2 Strong growth in summer peak demand is primarily driven by increases in cooling load and electrification

AEMO prepares peak underlying and operational demand forecasts as a distribution, represented by the 10%, 50%, and 90% POE forecasts for three seasons – summer, shoulder, and winter.

[44] June 2023 was the coolest June since 1981 with mean maximum temperature 0.38°C lower than the 1961-1990 average. It is also the wettest June since 2016 with rainfall closer to the 1961-1990 average. For detail see http://www.bom.gov.au/climate/current/month/wa/archive/202306.summary.

Figure 15 shows the 10% POE peak demand forecasts under the Low, Expected, and High scenarios for the 2024 WEM ESOO, compared to the 2023 forecasts.

Figure 15 Actual and 10% POE summer peak demand forecasts under three scenarios from 2023 and 2024 WEM ESOOs, 2018-19 to 2033-34 (MW)



Note: The forecasts assumed 90% curtailment of hydrogen load during peak demand.

Between 2023-24 and 2033-34, in this WEM ESOO AEMO forecasts that:

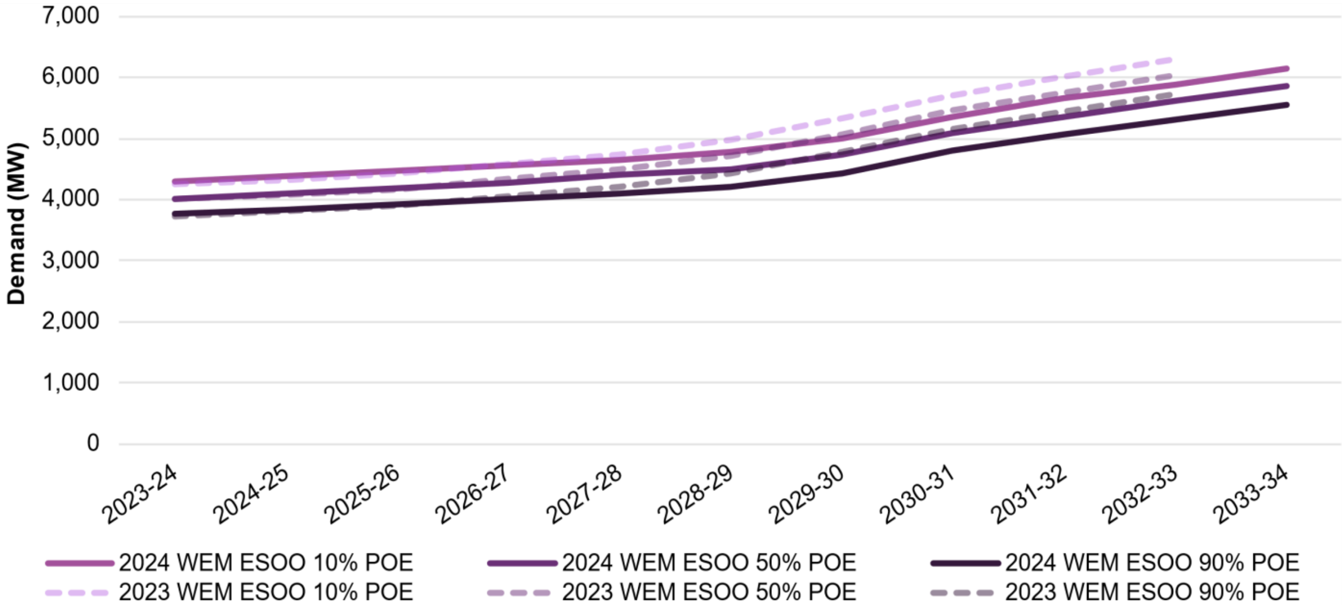
- In the **Low scenario**, peak demand increases at an average annual rate of 2.3%. Increases are more significant in the second half of the outlook period, primarily due to growth in electrification and cooling load. Uptake of EVs is a secondary driver across the whole period, with increase in LIL also contributing to growth.
- In the **Expected scenario**, peak demand increases at an average annual rate of 3.6%. Similar to the Low scenario, the rate of increase is notably higher in the second half of the period, driven by growth in electrification and cooling load. Forecast growth in uptake of EVs and demand from the hydrogen sector as secondary drivers are also stronger than in the Low scenario and compensate for slower growth in LIL.
- In the **High scenario**, peak demand increases at an average annual rate of 5.8%. Similar to the other two scenarios, the rate of increase is notably higher in the second half of the period. While cooling load continues to be one of the primary drivers throughout, growth in electrification and demand from the hydrogen sector respectively dominate growth across the outlook period. Forecast growth in EV uptake continues to be a secondary driver.

Across all three scenarios, forecast growth for 10% POE summer peak demand is stronger in the second half of the outlook period (averaging 3.4%, 5.2%, and 6.8% annually for the Low, Expected, and High scenarios respectively) compared to the first half (averaging 1.1%, 2.1%, and 4.9% annually for the Low, Expected, and High scenarios respectively).

Compared to the 2023 WEM ESOO, the 2024 WEM ESOO forecasts lower peak demand, except for some initial years[45]. Extreme weather conditions during the recent summer led to an increase in forecast peak demand for the base year 2023-24. However, the lower peak demand forecasts over the medium to long term are attributed mainly to lower industrial activity, lower demand from the hydrogen sector, and slower pace in EV uptake, all of which completely offset higher base and cooling load.

Figure 16[46] shows peak demand forecasts for the outlook period under the Expected scenario. All three forecasts show growth, with average annual growth rates between 3.6% and 4.0%. These are similar to the annual growth rates in the 2023 WEM ESOO forecasts. The spread between the 10%, 50%, and 90% POE peak demand forecasts remains mostly consistent throughout the outlook period[47].

Figure 16 10%, 50%, and 90% POE summer peak demand forecasts in the Expected scenario, 2023-24 to 2033-34 (MW)



2.3.3 Strong growth in winter peak demand is driven by forecast increases in electrification, heating load, and EV uptake

Winter operational peak demand in the Expected scenario is forecast to exceed summer operational peak demand for the first time in the SWIS for 10%, 50%, and 90% POE from 2032-33, 2029-30, and 2028-29 respectively. This shift is due to the anticipated faster growth of operational consumption during winter, driven by electrification, and the lower impact of DPV generation to meet evening peak demand during winter months. Moreover, the updated demand forecast methodology discussed in Section 1.5, which captures actual data for the recent winter, impacts the forecast for the base year. AEMO will continue to explore these trends in future WEM ESOOs.

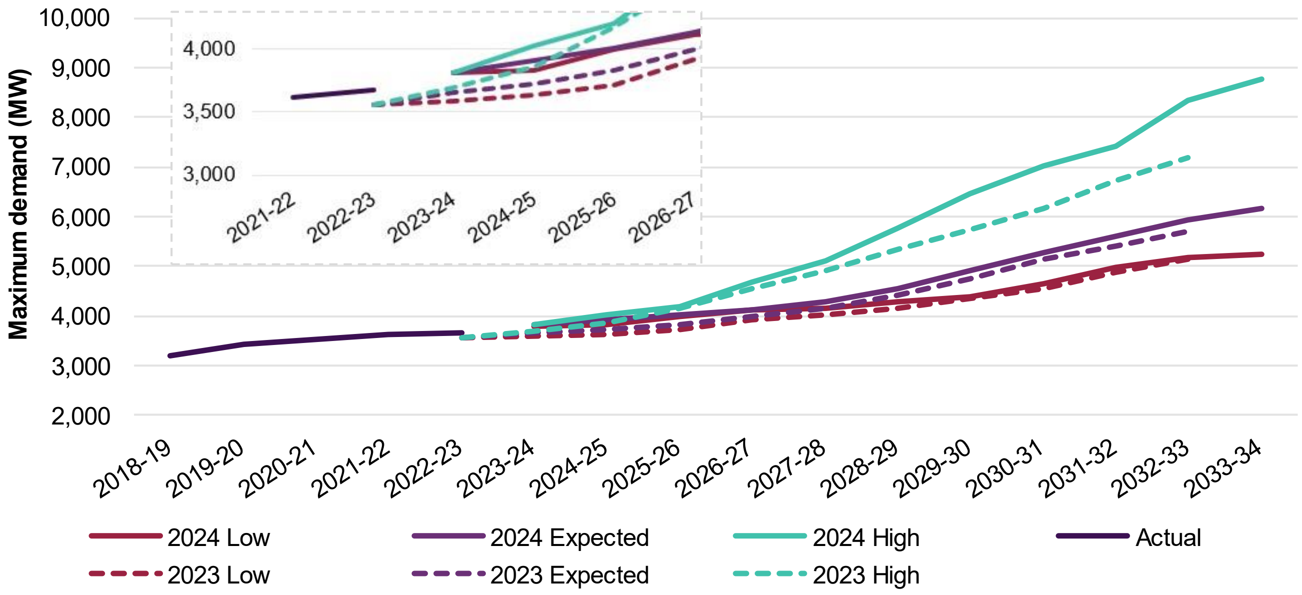
[45] The 2024 WEM ESOO forecasts for summer peak demand exceed previous forecasts for up to 2026-27 in Low, 2025-26 in Expected and 2023-24 in High scenarios.

[46] The difference in the POE distribution is the result of a probabilistic model that accounts for the variability in weather from year to year.

[47] On average, the 50% POE peak demand forecasts are 337 MW lower than the 10% POE peak demand forecasts and 296 MW higher than the 90% POE peak demand forecasts.

Figure 17 shows the 10% POE winter peak demand forecasts under the Low, Expected, and High scenarios from the 2023 and 2024 WEM ESOOs, with actuals from 2018-19 to 2022-23.

Figure 17 Forecast 10% POE winter peak demand forecasts under three scenarios from 2023 and 2024 WEM ESOOs, 2018-19 to 2033-34 (MW)



Note: The forecasts assumed 90% curtailment of hydrogen load during peak demand.

In summary, in this 2024 WEM ESOO AEMO forecasts:

- In the **Low scenario**, winter peak demand increases at an average annual growth rate of 3.2%. This is largely driven by forecast growth in electrification. Secondary drivers are heating load and EV uptake, partially compensating for slow growth in LIL.
- In the **Expected scenario**, winter peak demand increases at an average annual growth rate of 4.9%. This is driven by strong growth forecast for electrification, heating load and uptake of EVs partially compensating for slow growth in LIL.
- In the **High scenario**, winter peak demand increases at an average annual growth rate of 8.7%. This is driven by increasing load in the hydrogen sector. Secondary drivers are heating load, electrification, and EV uptake.

AEMO forecasts higher winter peak demand than in the 2023 WEM ESOO. The updated forecasting methodology took into account the most recent user behaviour and winter weather records, which increased the winter peak demand forecast in the base year compared to the 2023 WEM ESOO base year forecasts.

2.4 Minimum demand forecasts

Minimum demand conditions in the SWIS continue to be a challenge as DPV uptake continues to grow. The current minimum operational demand record of 595 MW[48] was set on 25 September 2023.

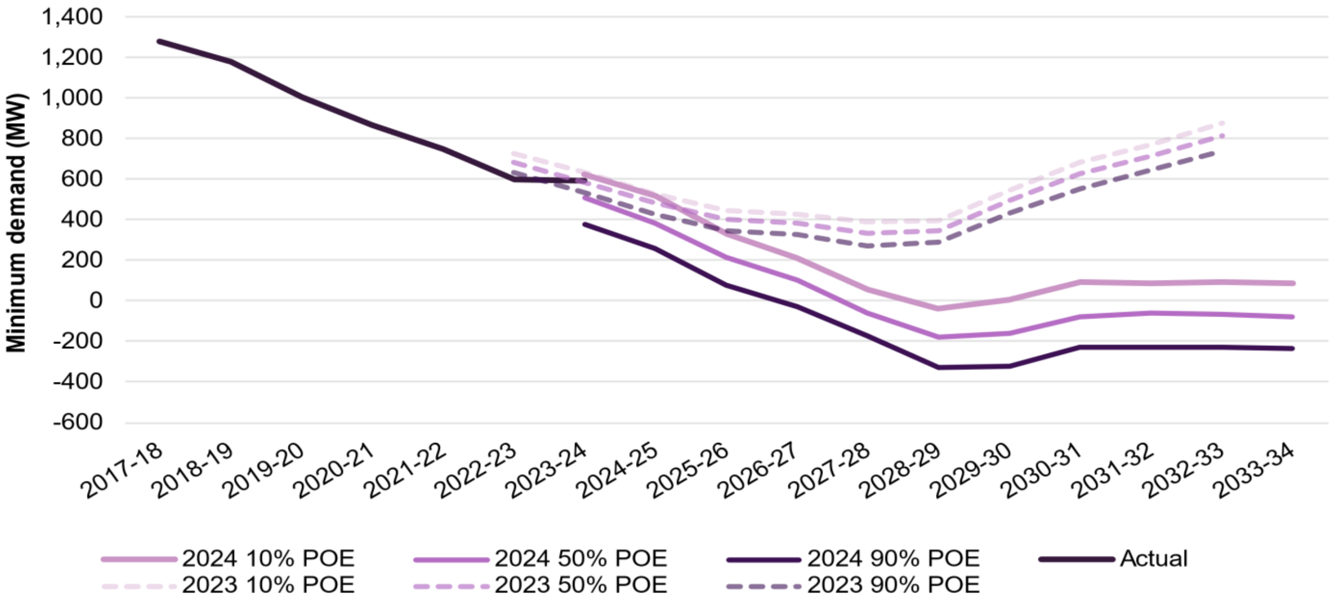
[48] This minimum operational demand of 525 MW is as reported in AEMO's *Quarterly Energy Dynamics* Q3 2023 report, derived using non-loss adjusted sent-out SCADA data.

Figure 18 shows the forecasts for 10%, 50%, and 90% POE minimum operational demand under the Expected scenario for 2023-24 to 2033-34, and actual minimum operational demand from 2017-18 to 2023-24 (as of 21 February 2024)[49] for the 2023 and 2024 WEM ESOOs, as well as actual minimum demand since 2017-18.

In summary, in the 2024 WEM ESOO, the 50% POE forecast declines rapidly from 510 MW in 2023-24 to 101 MW in 2026-27, then to below zero. Forecast demand below zero represents unscheduled operational demand, which excludes the impacts of charging ESR or any services that add to the demand. AEMO forecasts a minimum operational demand increase after 2028-29 for 10%, 50%, and 90% POE, primarily driven by strong growth in heating load, EV uptake, and electrification.

This is lower than the 2023 WEM ESOO forecast, due to higher forecast DPV generation meeting daytime demand.

Figure 18 Actual and 10%, 50%, and 90% minimum demand forecasts, Expected scenario, 2017-18 to 2033-34 (MW)



Note: Actual minimum demand for 2023-24 is a year-to-date value, based on data until 21 February 2024.

AEMO has identified material risks which, in the absence of a targeted response, may prevent the secure and reliable operation of the SWIS under minimum demand operation conditions for the period 2024 to 2026. AEMO expects the existing and committed entry of over 1,000 MW of storage by 2026-27 to play a key role in mitigating these risks through soaking up excess solar and discharging it during periods of high demand. For the period 2024-25 to 2026-27, AEMO has procured 446 MW of minimum demand NCESS from these storage providers, to support system security during periods of low operational demand.

As DPV growth continues and operational demands reduce, AEMO will continue to monitor any emerging risks to power system security and reliability. Over the longer term, greater orchestration of DER, including DPV and

[49] Seasonal minimum demand forecasts under the Expected scenario are provided in Appendix A7.

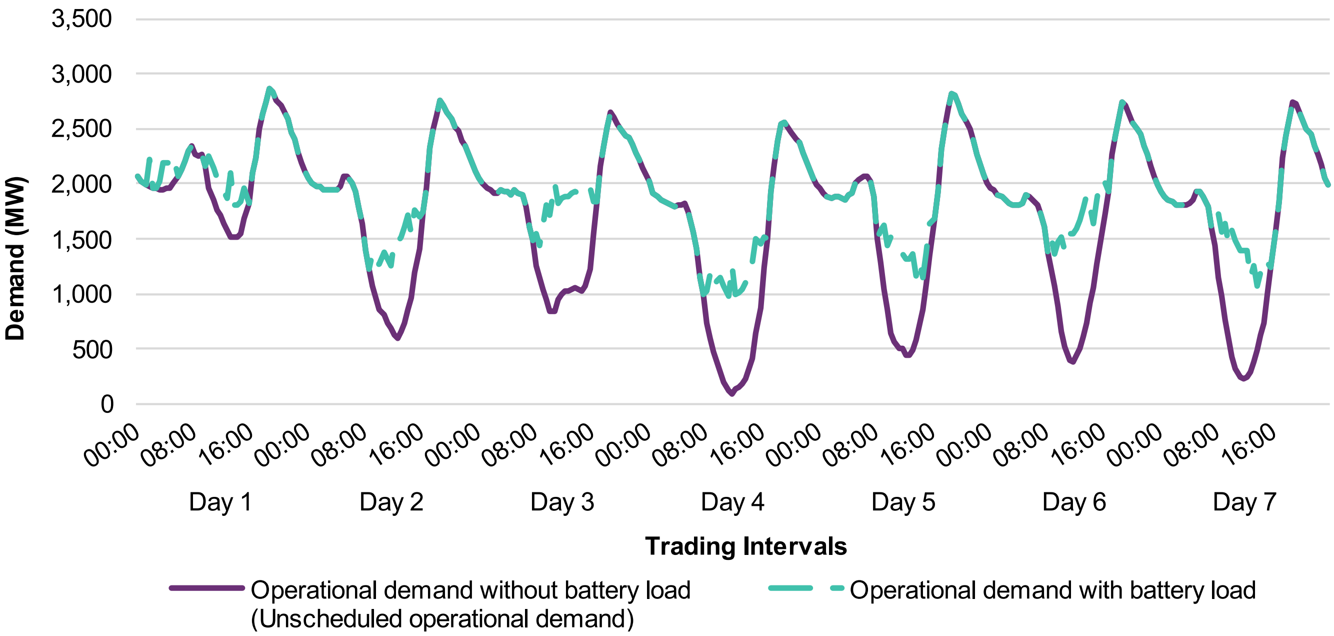
distributed batteries, will provide further options to maximise the value of these consumer assets and contribute to a secure and reliable power supply for all consumers.

2.4.1 Impact of ESR charging on increasing demand

The modelling carried out for the reliability assessment has also been used to examine the impact of ESR charging on minimum demand levels.

Figure 19 provides an illustration of this for a selected week in October of 2026-27, to compare the operational demand without battery load (unscheduled operational demand) and with battery load. The operational demand without the application of the minimum demand threshold (which curtails DPV to prevent operational demand falling below security thresholds) was modelled to demonstrate the full potential impact of battery charging on demand levels. Without additional battery load, the operation demand (unscheduled) is forecast to fall below security thresholds, even to negative demand levels, over the forecast period. These minimum demand events are shown to be avoided through the economic charging of batteries.

Figure 19 Operational demand with and without battery load, a week in October 2026-27 (MW)



Source: EY.

Note: Based on one iteration from one reference year simulation, a week in October 2026 for illustration. Includes large-scale battery charging and behind-the-meter VPP battery load.

AEMO will continue to review these incentives, drawing on operational experience with increasing storage volumes in the SWIS, to identify any further risks minimum demand may present to power system security.

2.5 Mid Peak Electric Storage Resource Obligation Interval

The Mid Peak Electric Storage Resource Obligation Interval (ESROI) is the reference Trading Interval for all ESRs. It is used to determine the Peak Electric Storage Resource Obligation Duration (ESROD). Determining the Mid Peak ESROI for the relevant Reserve Capacity Cycle is a new[50] requirement in the WEM Rules.

For the 2024 WEM ESOO, AEMO must:

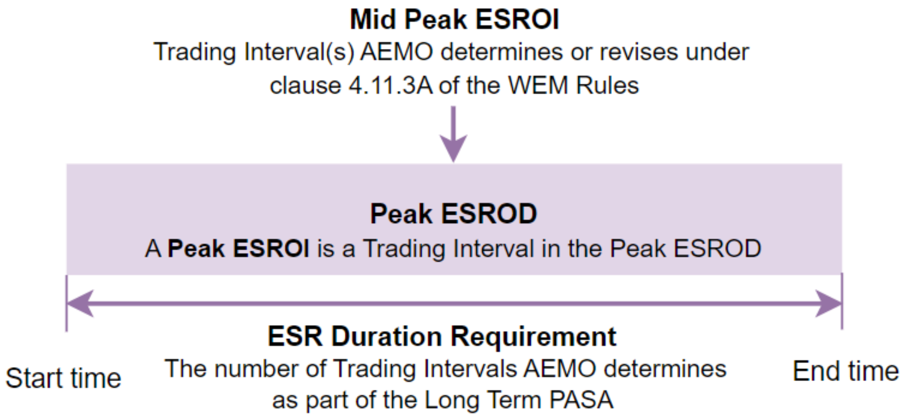
- Determine the Mid Peak ESROI for 2026-27 in accordance with clause 4.11.3A(a) of the WEM Rules, and
- Determine whether the Trading Intervals classified as the Mid Peak ESROI remain appropriate for 2024-25 and 2025-26 in accordance with clause 4.11.3A(b) of the WEM Rules[51].

Figure 20 shows the relationships between Mid Peak ESROI, Peak ESROD, and ESR Duration Requirement[52]:

- **Peak ESROD** is a set of contiguous Trading Intervals (individually referred to as Peak ESROI) in which an ESR is obligated to be available for each Trading Day for the relevant Capacity Year. Peak ESROD is determined using the Mid Peak ESROI and ESR Duration Requirement.
- **Mid Peak ESROI** is determined based on the Mid Peak ESROI WEM Procedure. Mid Peak ESROI is in the middle of the Peak ESROD if it has an odd number of Trading Intervals, otherwise is the last Trading Interval of the first half of the Peak ESROD.
- **ESR Duration Requirement** is the number of Trading Intervals in each Trading Day to be designated as the Peak ESROIs for ESRs, and must be determined for the relevant Capacity Year.

To provide investment certainty, ESRs will retain the same ESR Duration Requirement for the first five years of receiving Capacity Credits.

Figure 20 Conceptual diagram to illustrate the relationships between Mid Peak ESROI, Peak ESROI, and ESR Duration Requirement



[50] The 2023 WEM ESOO determined the ESROI as a set of eight contiguous Trading Intervals during which an ESR has an obligation to be available if participating in the RCM. The 2024 WEM ESOO determines the Mid Peak ESROI in accordance with the new requirement in the WEM Rules.

[51] See https://aemo.com.au/en/energy-systems/electricity/wholesale-electricity-market-wem/procedures-policies-and-guides/procedures.

[52] Refer to the terms defined in the Glossary in Chapter 11 of the WEM Rules.

To identify Peak Demand Periods, AEMO analysed individual Expected scenario demand forecasts of POE levels of less than 10% POE (representing the timing of extreme peak demand events), as well as simulation of POE levels of less than 50% POE (to maximise sample sizes). The Peak Demand Periods, which are an input for determination of the Indicative Mid Peak ESROI[53], are identified for 2024-25, 2025-26, and 2026-27 as:

- The period between the start of the 16:30 Trading Interval and end of the 20:00 Trading Interval for shoulder season and summer (Hot Season)[54].
- The period between the start of the 17:00 Trading Interval and end of 20:30 Trading Interval for the winter season.

AEMO has assessed the operational requirements of the SWIS under the Medium Term PASA and has identified that the Peak ESRODs, determined on a seasonal and Business/Non-Business Day basis, more accurately reflect the timing of peak demand than a single set of ESRODs across all seasons:

- For Non-Business Days in summer, winter, and shoulder seasons, the Peak ESRODs that match the identified Peak Demand Periods are forecast to be sufficient.
- For Business Days in summer and shoulder seasons, AEMO identifies that the Peak ESRODs need to be shifted Two Trading Intervals later, starting at the 17:30 Trading Interval and ending at the 21:00 Trading Interval. This shift is to allow for limited availability of DSP dispatch (ending at 20:00 on Business Days) and the high degree of solar availability in the 16:30 and 17:00 Trading Intervals during shoulder season and summer.
- For Business Days in winter, the Peak ESROD needs to be shifted one Trading Interval later, starting at the 17:30 Trading Interval and ending at the 21:00 Trading Interval. The reasons are similar to summer and shoulder Business Days, but these factors impact operational requirements less in winter.

AEMO has set the Mid Peak ESROIs for 2026-27 and revised the Mid Peak ESROI for 2025-26 to be based on seasonal and Business Day/Non-Business Day criteria, as detailed in **Table 4** and **Table 5**. For 2024-25, AEMO has revised the Mid Peak ESROI but maintained a single Mid Peak ESROI to allow for a transitional period before introducing more detailed Mid Peak ESROIs, as presented in **Table 6**. The established Mid Peak ESROIs and Peak ESRODs for 2024-25 and 2025-26 will replace the ones previously determined in the 2022 WEM ESOO and the 2023 WEM ESOO, respectively.

Table 4 Peak Demand Period and Mid Peak ESROI determined in the 2024 WEM ESOO for 2026-27

Season	Peak Demand Period	ESR Duration Requirement (Trading Intervals)	Non-Business Days		Business Days	
			Mid Peak ESROI	Peak ESROD	Mid Peak ESROI	Peak ESROD
Summer	16:30-20:00	8	18:00	16:30-20:00	19:00	17:30-21:00
Shoulder	16:30-20:00	8	18:00	16:30-20:00	19:00	17:30-21:00
Winter	17:00-20:30	8	18:30	17:00-20:30	19:00	17:30-21:00

[53] Refer to WEM Procedure: Mid-Peak Electric Storage Resource Obligation Intervals.

[54] The three seasons are Hot Season/summer (Trading Months December – March), winter (Trading Months June – August), and the shoulder season, which includes all other Trading Months.

Table 5 Mid Peak ESROI based on ESROD published in the 2023 WEM ESOO and Demand Period and Mid Peak ESROI determined in the 2024 WEM ESOO, for 2025-26

	2023 WEM ESOO		2024 WEM ESOO					
Season	Peak ESROD	Mid Peak ESROI	Peak Demand Period	ESR Duration Requirement (Trading Intervals)	Non-Business Days		Business Days	
					Mid Peak ESROI	Peak ESROD	Mid Peak ESROI	Peak ESROD
Summer	16:30-20:00	18:00	16:30-20:00	8	18:00	16:30-20:00	19:00	17:30-21:00
Shoulder	16:30-20:00	18:00	16:30-20:00	8	18:00	16:30-20:00	19:00	17:30-21:00
Winter	16:30-20:00	18:00	17:00-20:30	8	18:30	17:00-20:30	19:00	17:30-21:00

Table 6 Mid Peak ESROI based on ESROD published in the 2022 WEM ESOO and Demand Period and Mid Peak ESROI determined in the 2024 WEM ESOO, for 2024-25

	2022 WEM ESOO		2024 WEM ESOO			
Season	Peak ESROD	Mid Peak ESROI	Peak Demand Period	ESR Duration Requirement (Trading Intervals)	Mid Peak ESROI	Peak ESROD
Summer	16:30-20:00	18:00	16:30-20:00	8	19:00	17:30-21:00
Shoulder	16:30-20:00	18:00	16:30-20:00	8	19:00	17:30-21:00
Winter	16:30-20:00	18:00	17:00-20:30	8	19:00	17:30-21:00

In accordance with clause 6.3.1 of the WEM Rules, AEMO may determine to amend[55] the Mid Peak ESROI to reflect system needs. AEMO will make such amendments in the event of risks to Power System Security or Power System Reliability associated with peak demand timing for a specific Trading Day. Any updates to the Mid Peak ESROI will be determined based on AEMO's operational experience and as part of AEMO's Short Term PASA or Medium Term PASA obligations.

While AEMO retains operational flexibility, these published Mid Peak ESROI provide stakeholders likely timing of obligations for the relevant Capacity Year.

[55] Changes must be made by 6:50 AM on the Scheduling Day, which is, in respect of a Trading Day, the calendar day immediately preceding the calendar day on which the Trading Day commences.

3 Supply forecasts

This chapter presents the capacity supply forecasts for each Capacity Year in the 10-year outlook period. The projected capacity supply is a key input in the 2024 reliability assessment and supply-demand balance outlook. The chapter also includes a summary of the network limitations identified in the 2023 NAQ calculation. In the Expected scenario:

- Supply in the first half of the outlook period has improved since the 2023 WEM ESOO as a result of AEMO procuring more than 1,000 MW of additional capacity under the NCESS framework.
- Supply in the second half of the outlook period declines as a result of coal-fired power station retirements.

3.1 Capacity classification

The capacity supply forecasts consider existing capacity and new projects in the development pipeline. This includes capacity from generation, ESR, and DSP. Within the context of the RCM, capacity refers to assigned Capacity Credits, which consider both the Certified Reserve Capacity (CRC) and the level of access to the network under the NAQ framework, which represents the capacity expected to be available at times of peak demand. Assigned Capacity Credits represent the capacity expected to be available at times of peak demand.

AEMO assigns CRC and Capacity Credits based primarily on each facility's technology type[56], summarised in **Table 7**, with assigned Capacity Credits typically being lower than the nameplate capacity of the facility.

Table 7 CRC and capacity credit assignment method by technology type

Facility technology type	Technology description and examples	CRC and Capacity Credit assignment method
Non-Intermittent Generating Systems	Thermal generation that uses fuels such as coal, gas, and diesel.	Assessed based on sent-out capacity at 41°C, accounting for derating of the technology at elevated ambient temperatures and historical Forced Outage rates.
Intermittent Generating Systems	Renewable generation, such as solar, wind, and landfill gas.	Assessed based on estimated contribution during periods of high demand (or actual contribution for operational facilities).
Energy Storage Resources (ESR)	Energy storage systems, such as batteries and pumped hydro storage.	Assessed based on ability to sustain a level of output over a defined period (currently four hours).
Demand Side Programmes (DSP)	Demand curtailment, either by a customer load or generation from customers' embedded generators, to reduce operational demand when required. Includes direct response from industrial users and consumer response run by retailers, DSP aggregators, or network service providers.	Assessed based on the amount by which the demand from the load or aggregated loads can be curtailed.

[56] The methodology used for assessing and assigning CRC and Capacity Credits may differ depending on Facility Class as outlined in clause 4.10.2 of the WEM Rules.

The latest capacity supply forecast includes new projects and upgrades. In determining which projects to include in the forecast, AEMO has considered information from various sources, including the 2024 Expressions of Interest (EOI)[57] for CRC and the 2024 Long Term PASA formal information requests, and evaluated projects against three key criteria[58]:

1. The likelihood of new projects progressing towards a final investment decision (FID).
2. The likelihood of connection to the SWIS based on information sourced from Western Power.
3. The project's status in environmental approval processes.

Based on these criteria, AEMO assigned each new project or upgrade a percentage score (for further details on the evaluation methodology, refer to Appendix A2.9). AEMO also considered the contribution of capacity procured through NCESS, specifically the procurement of Reliability Services for 2024-25 and 2025-26[59] (2024-26 Peak Demand NCESS) and for 2025-26 and 2026-27[60] (2025-27 Peak Demand NCESS).

Depending on the information source and the criteria evaluation outcome, AEMO classified projects into the following categories[61]:

- **Existing capacity** – associated with existing Registered Facilities that have been assigned Capacity Credits for 2024-25 or 2025-26 and reflecting any announced or assumed retirements.
- **Committed capacity** – includes:
  - new projects that have been assigned Capacity Credits for 2025-26, or
  - have scored 80% or higher in the new project status evaluation, or
  - Facilities contracted for the 2024-26 Peak Demand NCESS[62], or
  - Facilities contracted or expected to be contracted for the 2025-27 Peak Demand NCESS[63].
- **Probable capacity** – new projects that have submitted a valid 2024 EOI[64] and scored 50% or more, but less than 80% in the new project status evaluation.
- **Proposed capacity** – all new projects that have been proposed but have not met the criteria to be in the existing, committed, or probable capacity categories.

Table 8 provides a summary of the capacity included under each scenario for the supply forecasts. Existing capacity was included in the Low, Expected, and High scenarios. Committed capacity was included in the

[57] See 2024 Expression of Interest summary report, 2024, at https://aemo.com.au/-/media/files/electricity/wem/reserve_capacity_mechanism/eoi/2024/2024-expression-of-interest-summary-report.pdf.

[58] New projects that received Capacity Credits for 2025-26, are in 2024-26 and 2025-27 NCESS – Reliability Services, or submitted a 2024 EOI, and are candidates for registration are not assessed using these three criteria.

[59] See https://www.wa.gov.au/system/files/2022-12/Coordinator%20of%20Energy%20Determination%20-%20Reliability%20Service%20-%20f2.pdf.

[60] See https://www.wa.gov.au/system/files/2023-10/coordinator-of-energy_determination-reliability_service-october_2023.pdf.

[61] This Chapter uses information available as of May 31, 2024, for each project in the criteria evaluation outcome.

[62] For 2024-26 Peak Demand NCESS, capacity is expected to be available for the entire outlook period for Registered Facilities and only for the contract period otherwise.

[63] For 2025-27 Peak Demand, capacity is expected to be available for Registered Facilities and upgrade of Registered Facilities for the entire outlook period and only for the contract period otherwise. Note that the expected capacity limited to contract period is overridden if the facility meets the score requirement in the new status evaluation.

[64] Valid EOI as defined in clause 4.4.1 of the WEM Rules.

Expected and High scenarios, while probable capacity was considered only in the High scenario. Proposed projects were not considered in any of the three scenarios, but may be considered in future WEM ESOOs, as the projects progress. Retiring capacity was included in each scenario until its scheduled or assumed retirement date (for more information, see Section 3.2.3). Note that the scenario classification for Low and High scenarios relates only to supply forecasts. Only the Expected scenario was applied for the purposes of reliability modelling (see Chapter 4).

The available capacity for the initial two Capacity Years, 2024-25 and 2025-26, was determined by the assigned Capacity Credits and NCESS Contract quantities for each respective year. For the subsequent Capacity Years, AEMO estimated the potential amount of available Reserve Capacity based on the anticipated technology type, taking into consideration the historical Forced Outage rates[65].

Table 8 Scenario inclusion for different capacity classifications and retirement cases

Scenario	Existing capacity	Committed capacity	Probable capacity	Proposed capacity
Low	**Yes**	No	No	No
Expected	**Yes**	**Yes**	No	No
High	**Yes**	**Yes**	**Yes**	No

3.2 Changes to existing and committed capacity

3.2.1 Changes in Capacity Credits for 2025-26

For 2025-26, the number of Facilities assigned Capacity Credits increased to 67 compared with 66 in 2024-25. A total of 4,716.7 MW of Capacity Credits were assigned, representing a 2.6% increase from the 4,596.4 MW assigned for 2024-25.

Reserve Capacity Price (RCP)

The RCP calculation formula aims to provide an effective price signal that reflects the level of excess capacity in the market. The RCP is determined by adjusting the Benchmark Reserve Capacity Price (BRCP), which is determined by the Economic Regulatory Authority (ERA)[66], based on the extent to which there is surplus capacity. For details of the calculations used to determine the RCP, refer to clause 4.29.1 of the WEM Rules.

The RCP for new facilities for 2025-26 has been set at $251,420/MW/year and the RCP for Transitional Facilities is $155,419/MW/year[67].

The RCP for 2026-27 will be determined in September 2024 following the assignment of Capacity Credits. This will be determined with reference to the 2024 BRCP, which was set at $230,000/MW/year in December 2023[68].

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[65] According to Clause 4.11.1A of WEM Rules, if a facility or Separately Certified Component has been in Commercial Operation for at least 12 months and has had a Forced Outage rate above the threshold over the past 36 months, AEMO must adjust its Peak Certified Reserve Capacity, unless it has re-entered service after significant maintenance or an upgrade within the last 12 months.

[66] See https://www.erawa.com.au/electricity/wholesale-electricity-market/price-setting/benchmark-reserve-capacity-price.

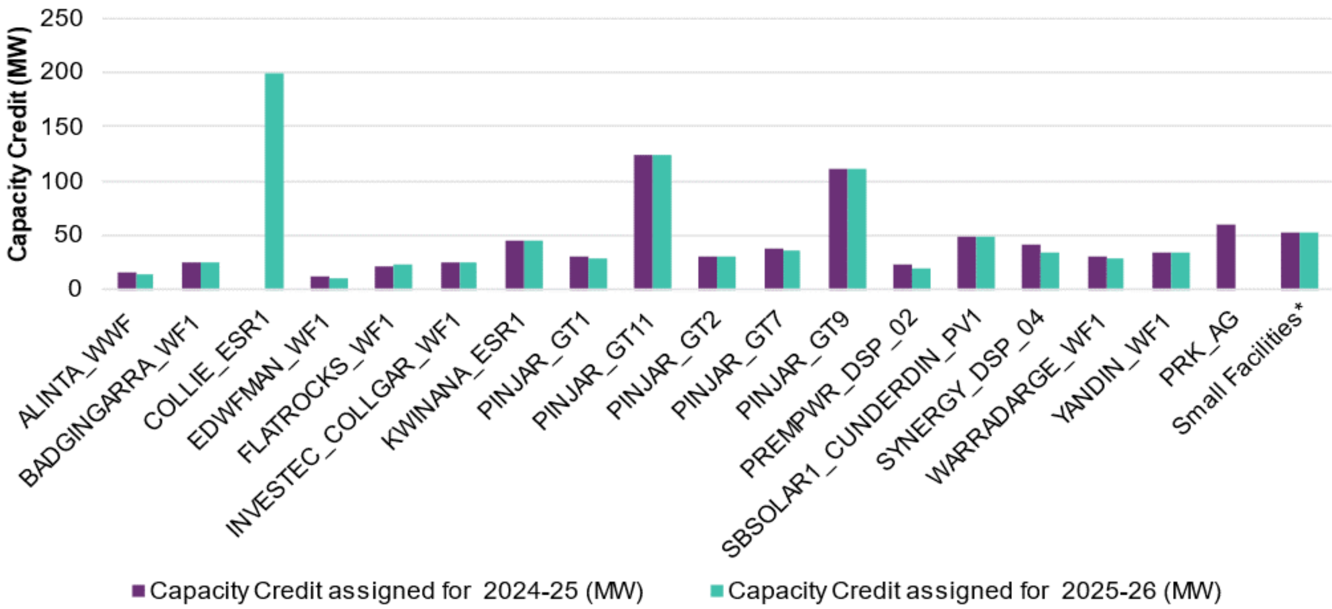
[67] See https://aemo.com.au/en/energy-systems/electricity/wholesale-electricity-market-wem/wa-reserve-capacity-mechanism/reserve-capacity-price.

[68] See https://aemo.com.au/en/energy-systems/electricity/wholesale-electricity-market-wem/wa-reserve-capacity-mechanism/benchmark-reserve-capacity-price.

Significant increases in capacity included the assignment of 200 MW of Capacity Credits to the new Neoen Collie ESR 1 (Collie_ESR1). Conversely, the Goldfields Power Facility (PRK_AG) did not seek Capacity Credits for 2025-26, a reduction of 59.7 MW from 2024-25[69]. Changes in Capacity Credit assignment for facilities from 2024-25 to 2025-26 are detailed in **Figure 21**.

- There were three facilities impacted by NAQ calculations for the first time, which saw their Capacity Credits reduced by 14.9 MW in total in 2025-26. The capacity reduction affecting all three facilities is directly attributed to the thermal limitations of the nearby network (see Section 3.4 for further information).
- The Capacity Credits assigned for Semi-Scheduled Facilities (SSF) and Non-Scheduled Facilities (NSF) are evaluated based on their contribution during peak demand periods. At the individual facility level, some experienced increases in their Capacity Credit allocation while others faced reductions or no changes. The net impact was a reduction of 1.3 MW of Capacity Credits for SSFs and NSFs in 2025-26, from the previous Capacity Year.

Figure 21 Change in Capacity Credits assigned to existing Facilities from 2024-25 to 2025-26 (MW)



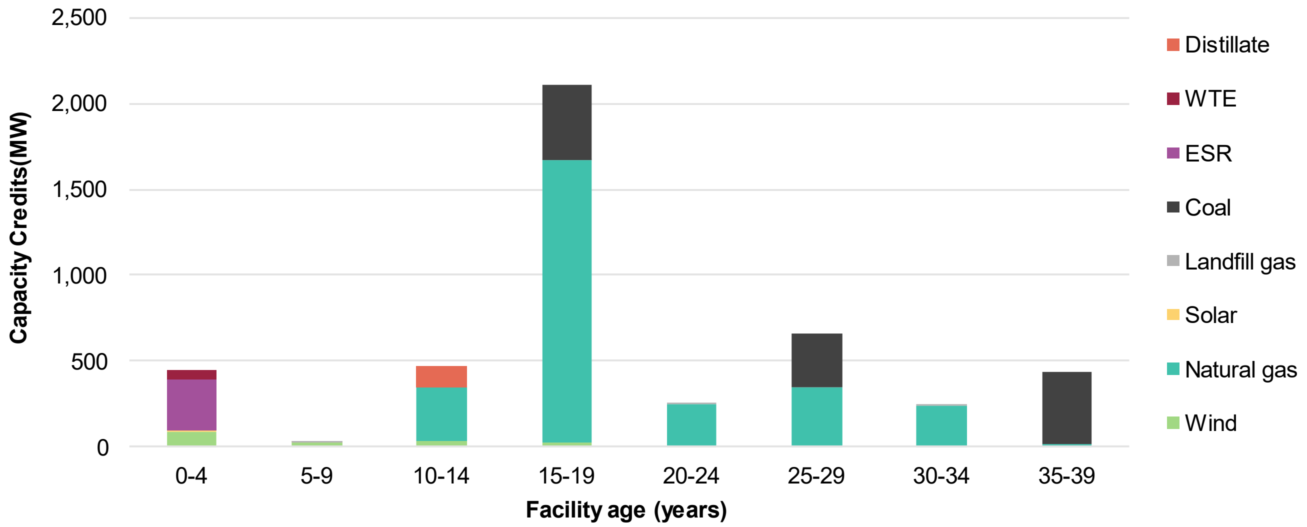
* "Small Facilities" refers to the aggregate sum of Capacity Credits for Facilities individually assigned less than 10 MW of Capacity Credits in 2025-26.

3.2.2 Facility age

Capacity Credits assigned for 2025-26 are summarised in **Figure 22**, categorised by fuel type and age of the associated facility. All Facilities less than five years old that have been assigned Capacity Credits in 2025-26 are either energy storage, waste to energy, wind, or solar. Among those, wind and solar contribute 22.0%, with the majority provided by ESR at 64.8%, and the rest from waste to energy (WTE) at 13.2%.

[69] PRK_AG, from the list of existing projects, did not receive Capacity Credits for 2025-26 and was assumed not to receive Capacity Credits from there onwards.

Figure 22 Capacity Credits assigned for 2025-26 by fuel type and facility age, as of 15 May 2024 (MW)



Note: The ESR grouping includes the battery components of hybrid Facilities, standalone batteries, and pumped hydro.

Further insights relating to facility age and Capacity Credits in 2025-26 are:

- The Muja D Power Station and the Alcoa Wagerup Facilities, the oldest generators in the SWIS with a service history of 38-39 years, were assigned a total of 438 MW of Capacity Credits.
- Facilities operating for 30-39 years make up 14.5% of the Capacity Credits assigned. The slight reduction in this proportion from 2024-25 is primarily driven by the increase in total Capacity Credits assigned to new facilities for 2025-26.

3.2.3 Facility retirements

AEMO's modelling assumed the staged retirement of state-owned coal generators in line with the Western Australian Government's retirement dates announced in 2022[70], and retirement of Bluewaters Power Station (the state's only privately owned coal plant) by 2030-31. Together, this will lead to a reduction of 1,173.2 MW[71] of capacity in the SWIS by 1 October 2030.

The following Facilities have been modelled to retire within the 10-year ESOO outlook period:

- **Collie Power Station** with 317.2 MW of Capacity Credits assigned for 2025-26 – modelled to retire on 1 October 2027.
- **Muja D Power Station units 7 and 8** with 211 MW of Capacity Credits each assigned for 2025-26 – scheduled for retirement on 1 October 2029.
- **Bluewaters Power Station units 1 and 2** with 217 MW of Capacity Credits for each unit assigned for 2025-26 – assumed by AEMO to retire on 1 October 2030.

[70] See Western Australian Government, *State-owned coal power stations to be retired by 2030 with move towards renewable energy*, 2022, at https://www.wa.gov.au/government/announcements/state-owned-coal-power-stations-be-retired-2030-move-towards-renewable-energy.

[71] The value includes the capacity retired from 1 October 2024. AEMO assumed Muja unit 6 is scheduled to be retired by 1 October 2024, prior to the ESOO outlook period, so is not included in the total Capacity to be retired.

The retirement of Bluewaters Power Station was assumed for modelling purposes only, reflecting the commercial pressures facing coal-fired power stations as the economy decarbonises and the operational characteristics of the power station change. This assumption was made wholly by AEMO and does not reflect any formal decision made by the operators of the facility to retire the generation plant. AEMO has consulted with industry on these retirement assumptions and has considered the expected impacts of reforms underway, including the impacts of emissions limits in the RCM considered as part of the WEM Investment Certainty Review[72].

In August 2023, the Western Australian Government announced the Muja C Power Station unit 6 retirement will be deferred to April 2025, and that the unit will be made available in 'reserve mode' from October 2024 to April 2025[73]. For modelling purposes, AEMO has maintained the Muja C Power Station unit 6 retirement as October 2024, as the unit's availability is likely to be operationally limited[74]. The limited availability of Muja C Power Station will be considered further in determining the quantity of SRC required to mitigate projected capacity shortfalls in the 2024-25 Hot Season.

3.2.4 Facility outage and availability

To inform AEMO's determination of an appropriate reserve margin for the RCT, AEMO conducted analysis of historical Forced Outage rates which may apply during peak demand.

Figure 23 shows the daily maximum Forced Outages[75] of firm capacity as a percentage of assigned Capacity Credits for the 2019-20 to 2023-24 Hot Seasons. This assesses the maximum Forced Outage size[76] of firm capacity for each day during periods where peak demand can be expected.

Planned Outages[77] are generally avoided over hot periods when demand is expected to be highest. Opportunistic Maintenance[78] is also accommodated based on an assessment of whether sufficient reserve is available.

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72 See https://www.wa.gov.au/government/document-collections/wholesale-electricity-market-investment-certainty-review.

73 See Western Australian Government, *Muja C Unit 6 in reserve mode and online for summer 2024-25*, 2023, at https://www.wa.gov.au/government/media-statements/Cook-Labor-Government/Muja-C-Unit-6-in-reserve-mode-and-online-for-summer-2024-25-20230817.

74 During reserve outage mode, AEMO will be able to request, with three days' notice, that Muja C Power Station unit 6 be made available for significant peak demand events. See https://www.wa.gov.au/government/media-statements/Cook-Labor-Government/Muja-C-Unit-6-in-reserve-mode-and-online-for-summer-2024-25-20230817.

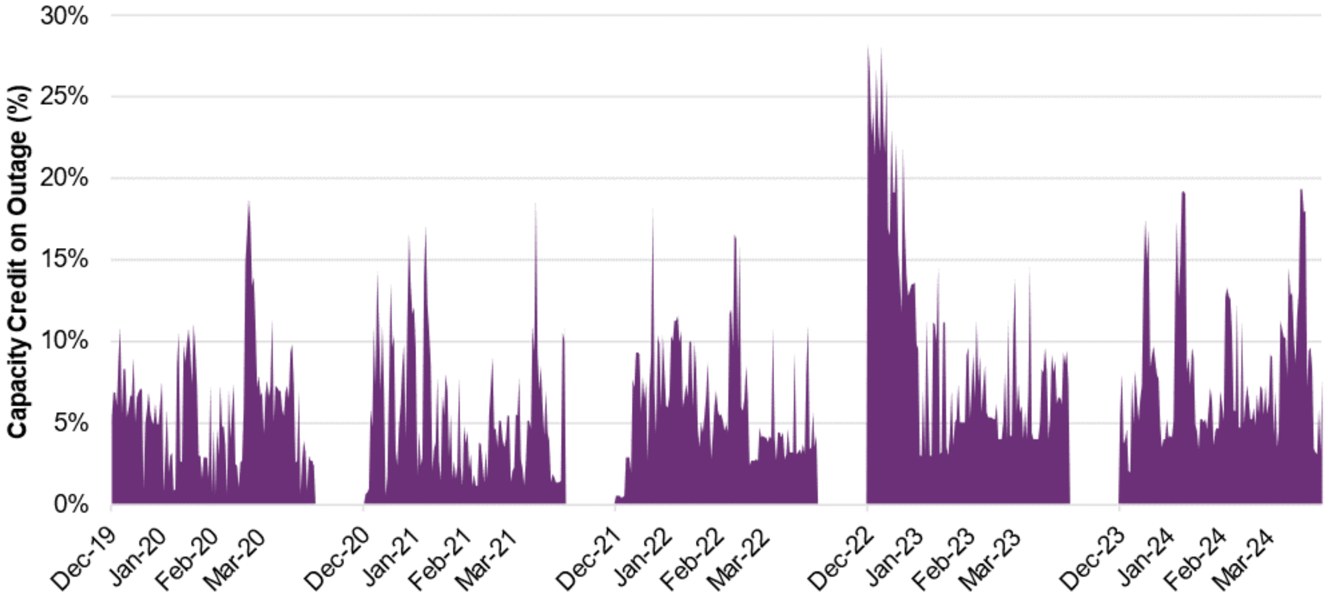
75 Forced Outage means outages that have not been approved by AEMO and defined in clause 3.21.1 of the WEM Rules.

76 Using outage data for Scheduled Facilities, available at https://aemo.com.au/energy-systems/electricity/wholesale-electricity-market-wem/data-wem/market-data-wa.

77 Planned Outages are those where an Outage Plan has been approved by AEMO.

78 Opportunistic Maintenance means an Outage Plan with an Outage Period of less than 24 hours submitted in accordance with clause 3.18B.8(b)(ii) of the WEM Rules, to take advantage of a short term opportunity to undertake minor maintenance.

Figure 23 **Daily maximum percentage of Capacity Credits on Forced Outage during Hot Season for 2019-20 to 2023-24**



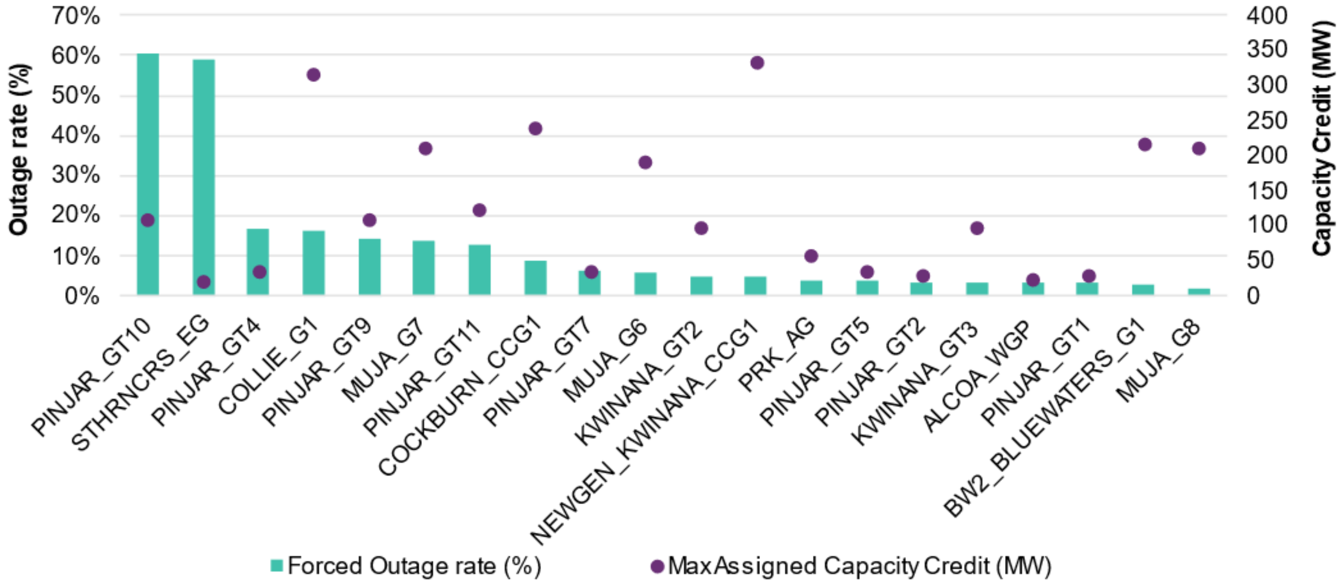
Note: Peak percentage of Capacity Credits on outage is calculated as the daily maximum Forced Outage over the total assigned Capacity Credits for the relevant Capacity Year.

The maximum Forced Outage quantity of firm capacity increased significantly during the 2022-23 Hot Season. In December 2022, the daily maximum total outage size reached almost 28.2% of the Capacity Credits assigned for 2022-23. For the remainder of 2022-23, the level of forced outages decreased. However, the 2023-24 Hot season saw high levels of Forced Outages again, with values peaking at 19.2% in January 2024 and 19.3% in March 2024. Some of the significant outages that contributed to the change in Forced Outage level from 2022-23 to 2023-24 are listed below:

- Pinjar Power Station unit 10 was on Forced Outage for the entirety of 2022-23 due to mechanoelectrical issues. The issue was resolved for 2023-24.
- Collie and Muja Power Stations faced coal supply issues that resulted in significantly higher levels of Forced Outages throughout 2022. However, the Forced Outage rates have significantly improved since 2023.
- NewGen Kwinana Power Station had higher levels of Forced Outages throughout 2022-23 Hot Season. However, it has shown significant improvement during 2023-24 Hot Season.
- Pinjar Power Station units 4, 9, and 11 experienced an increase in Forced Outages during 2023-24.

Figure 24 shows the 20 Non-Intermittent Generating Systems with the highest level of Forced Outages and their maximum assigned Capacity Credits over the 36 months ending on 23 May 2024.

Figure 24 Outage rate[A] (%) and maximum Capacity Credits (MW) assigned[B] by facility for 36 months ending on 23 May 2024[C]



A. Outage rate was calculated by dividing the outage MW by the Capacity Credit of the relevant year at each interval, then averaging this value over the 36-month period.
B. Maximum Capacity Credits assigned is the largest amount of Capacity Credits assigned to a given facility among each Capacity Year in the 36-month period (2020-21 to 2023-24).
C. Retired Facilities (KALAMUNDA_SG and MUJA_G5) and Facilities that have been operational for less than 12 months (KWINANA_ESR1) have not been included. The outage data for STHRNCRS_EG is not considered for 2023-24 as it did not receive Capacity Credits for that Capacity Year.

The largest contingency relating to loss of supply[79] has been determined with consideration of Forced Outage data from 2019-20 to 2023-24 Hot Seasons. Recent trends of tight operational conditions, due to frequent demand records exceeding the 10% POE forecast and rising Forced Outages for firm capacity [80] across recent Hot Seasons, highlights the need for a robust assessment of this determination.

Figure 25 shows the frequency of the total Forced Outages for Non-Intermittent Generating Systems units exceeding the capacity of the largest single generating unit, two generating units, and three generating units[81] during peak period[82] over the past five Hot Seasons.

[79] According to clause 4.5.9(a)(ii) of the WEM Rules, AEMO must determine the size, in MW, of the largest contingency relating to loss of supply (related to any facility, including a Network) expected at the time of forecast peak demand (including transmission losses and allowing for intermittent Loads).

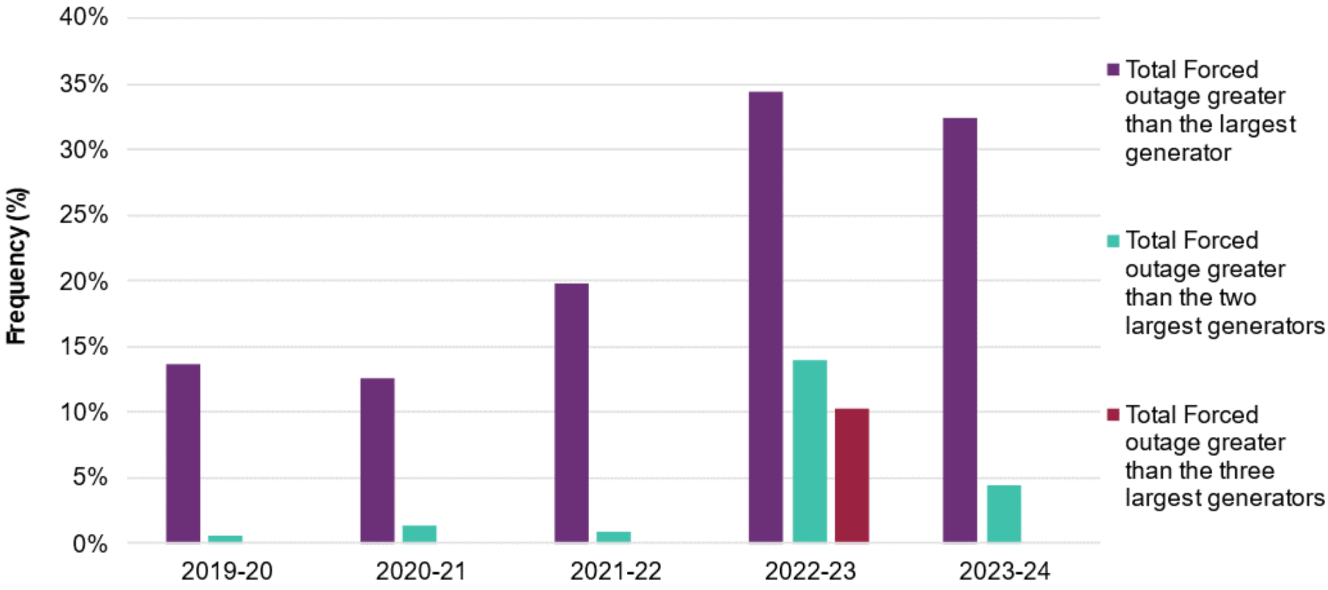
[80] The Forced Outages for Non-Intermittent Generating Systems surpassed 1.3 GW during critical times in December 2022 and multiple Trading Intervals of nearly 900 MW in January 2024.

[81] The following is the list of Facilities considered as the three largest Facilities:

- NewGen Kwinana Power Station (NEWGEN_KWINANA_CCG1) with 327.8 MW capacity.
- NewGen Neerabup Power Station (NEWGEN_NEERABUP_GT) with 330.6 MW capacity.
- Collie Power Station (COLLIE_G1) with 317.2 MW capacity.

[82] The peak period is indicated as the Trading Intervals from 16:30 to 20:00.

Figure 25 Frequency of Forced Outage exceeding the capacity of the largest single, two, and three largest generators during the peak Intervals for the 2019-20 to 2023-24 Hot Seasons



In 2022-23, the scale and frequency of Forced Outages increased significantly. There were periods in the 2022-23 Hot Season where total coincident Forced Outages exceeded the equivalent capacity of the three largest generators in the SWIS. Coal supply issues and consequent coal generation outages in early December 2022 were a major contributor.

The scale and frequency of Forced Outages in the 2023-24 Hot Season were materially lower than in 2022-23, primarily due to reduced outage rates from the NewGen Kwinana and Collie Power Stations. However, Forced Outage rates are still significantly elevated compared to rates in 2019-20 to 2021-22, including more periods where outages exceeded the two largest generating units.

The results highlight a material risk that the SWIS may need to operate with Forced Outage rates exceeding the largest two generating units. This means if the system is operating with the equivalent of the two largest generators in Forced Outage, it is necessary to maintaining a real-time reserve equivalent to the third largest unit in order to ensure system reliability and security.

3.3 Scenario observations

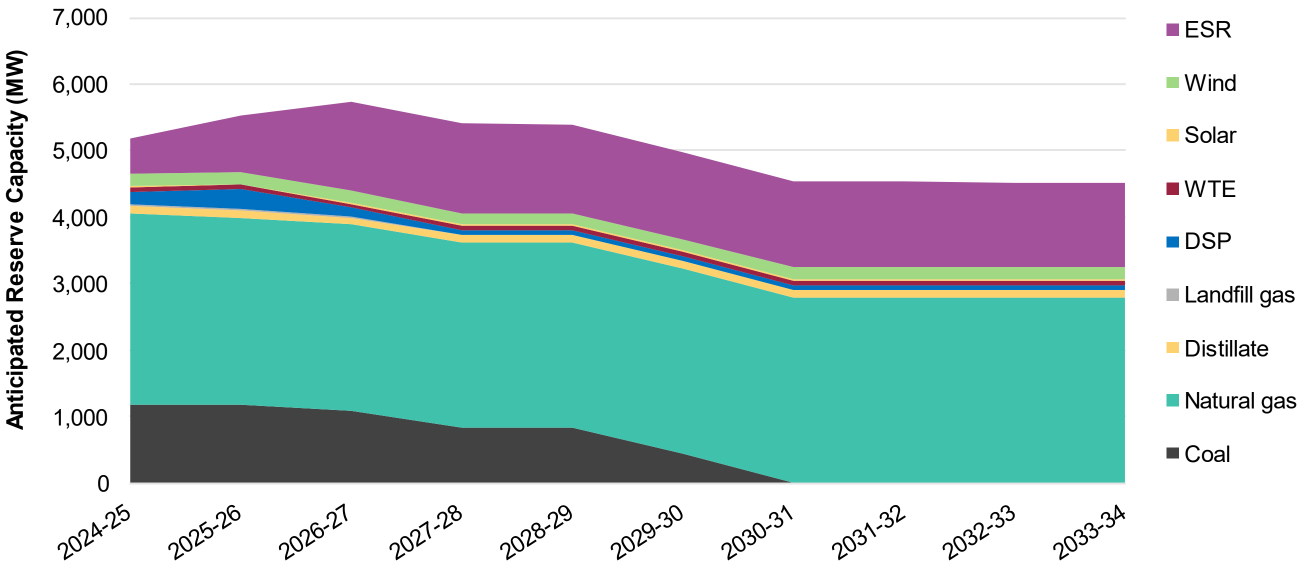
3.3.1 Reserve Capacity forecasts for the Expected scenario

Figure 26 shows the anticipated Reserve Capacity mix by fuel type, for the Expected scenario over the outlook period. The key observations for the Expected scenario are:

- A significant reduction in Reserve Capacity up until 2030-31 is due to retirement of coal-fired generation.
- The increase in Reserve Capacity is largely driven by an increased contribution from ESR, attributed to the additional capacity from the 2024-26 Peak Demand NCESS and 2025-27 Peak Demand NCESS projects.

- The anticipated Reserve Capacity is projected to reach a maximum of 5,742.3 MW (adding 1,475.5 MW[83] of committed Capacity to the existing capacity) in 2026-27, and then decline thereafter with the exit of the coal generators, before remaining constant after 2030-31. Overall, the net decrease is 668.0 MW by 2033-34.

Figure 26 Forecast capacity mix by fuel type, Expected scenario, 2024-25 to 2033-34 (MW)



Note: The ESR grouping includes the battery components of hybrid Facilities, standalone batteries, and pumped hydro.

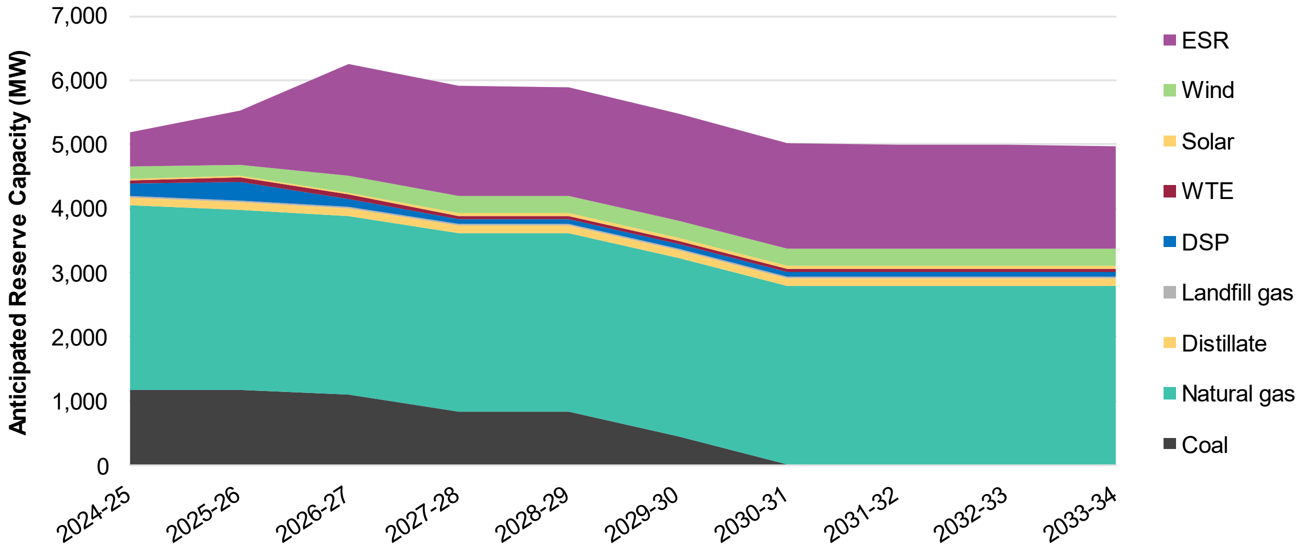
3.3.2 Reserve Capacity forecasts for the High scenario

Figure 27 shows the anticipated Reserve Capacity mix by fuel type, in the High scenario over the outlook period. The key observations for the High scenario are:

- The overall trend under the High scenario is similar to that of the Expected scenario, with an increase to maximum Reserve Capacity in 2026-27, followed by decline until 2030-31, then no change.
- The maximum capacity is 6,256.4 MW in 2026-27. This value included 514.2 MW of probable capacity in addition to the committed Capacity included under Expected scenario, largely due to additional ESRs (385 MW) included in the High scenario.
- Overall, the net decrease is 206.8 MW by 2033-34.

[83] This value includes the New Facilities received Capacity Credits for 2024-25 and 2025-26, committed capacity, coming from projects that have scored 80% or higher in the new project status evaluation, contracted under 2024-26 Peak Demand NCESS, or expected to be contracted for 2025-27 Peak Demand NCESS.

Figure 27 Forecast capacity mix by fuel type, High scenario, 2024-25 to 2033-34 (MW)



Note: The ESR grouping includes the battery components of hybrid Facilities, standalone batteries, and pumped hydro.

3.4 Network Access Quantity

The NAQ framework was applied for the first time in the 2022 Reserve Capacity Cycle to assign Capacity Credits. The framework considers the amount of available network capacity, taking network constraints[84] into account, and allocates NAQ to Facilities up to their CRC. In the 2022 Reserve Capacity Cycle, all Facilities were assigned NAQ equal to their assigned CRC. However, in the 2023 Reserve Capacity Cycle, three Facilities experienced a reduction in NAQ[85]:

- The Wesfarmers Kleenheat Gas DSP Facility (PREMPWR_DSP_02) – capacity reduced by 4.3 MW to 18.7 MW for 2025-26.
- The Synergy DSP Facility (SYNERGY_DSP_04) – capacity reduced by 8.9 MW to 33.1 MW for 2025-26.
- The Tesla Kemerton Facility (TESLA_KEMERTON_G1) – capacity reduced by 1.7 MW to 8.3 MW for 2025-26.

These reductions were all associated with the thermal limitations in the Picton, Kemerton, and Marriot regions, as shown in **Table 9,** along with other binding constraint identified by the NAQ model. Network limits that cause constraint in only a small proportion of dispatch scenarios (for example, less than 5% of possible peak dispatch scenarios) do not typically impact the assigned NAQ[86].

[84] AEMO formulates RCM Constraint Equations in accordance with clause 4.4B.4 of the WEM Rules which forms part of the NAQ model input. See https://aemo.com.au/energy-systems/electricity/wholesale-electricity-market-wem/system-operations/congestion-information-resource/constraints-library/rcm-constraints-library for complete RCM constraint Library and RCM Limit Advice.

[85] In accordance with clause 4.15.16 of the WEM Rules, AEMO publishes the inputs and outputs of the NAQ model. For relevant information for the 2023 Reserve Capacity Cycle, see https://aemo.com.au/-/media/files/electricity/wem/reserve_capacity_mechanism/network-access-quantities/naqprocesssummary_rcc2023.xlsx?la=en.

[86] In accordance with clause 4.15.9(c) of the WEM Rules.

Table 9 Network limitations identified to bind in at least one dispatch scenario of the NAQ model

Potentially limited network element	Relevant contingency
Picton Terminal (PIC) – Marriott Road Substation (MRR) 132 kilovolts (kV) line 1	Constraint for the contingency of Picton-Pinjarra-Busselton-Kemerton 132 kV line 1, causing a thermal overload of the monitored element Picton-Marriot Road 132 kV line 1.
Northern Terminal Transformer 1 (NT) T1	Constraint for the contingency of Northern Terminal Transformer 2 (including activation of the Northern Terminal Bus Coupler Reclose Scheme), causing a thermal overload of the monitored element Northern Terminal Transformer 1.

4 Reliability assessment

This chapter presents the outcomes of the 2024 reliability assessment, which include the determination of the RCT[87] for the 10-year outlook period (2024-25 to 2033-34) and an assessment of the level of EUE.

- The RCR[88] for the 2024 Reserve Capacity Cycle is 5,696 MW.
- EUE is forecast to be below the reliability standard until 2027-28. After that, operational consumption is forecast to grow faster alongside the assumed retirement of coal-fired power stations, leading to a significant increase in EUE for the rest of the outlook period.

4.1 Introduction

Under the WEM Rules (clause 4.5), AEMO is required to carry out an annual Long Term PASA, also known as the 'reliability assessment'. The main purpose of the reliability assessment is to:

- Determine how much capacity is required to meet the reliability standard for the SWIS.
- Assess the capability of forecast supply to meet these requirements.
- Identify any potential transmission, generation, storage, or demand side capacity augmentation options to alleviate any identified capacity shortfalls.

This chapter provides the outcomes of the reliability assessment as follows:

- Section 4.2 sets out the Planning Criterion that must be used in the reliability assessment, and details how this has changed in the WEM Rules since the 2023 assessment. Other changes to the WEM Rules that impact the reliability assessment were outlined in Chapter 1.
- Section 4.3 summarises the approach to determining each limb of the Planning Criterion.
- Sections 4.4 and 4.5 provide the outcomes of the assessment of Limb A and Limb B requirements, including a high-level overview of the unserved energy assessment under the Limb B analysis.
- Section 4.6 compares the Limb A and Limb B outcomes to determine the RCT for each Capacity Year of the 10-year outlook period.

[87] AEMO carries out the Long Term PASA study every year to forecast the RCT for each Capacity Year of a 10 Capacity Year Long Term PASA Study Horizon and publishes the results in the WEM ESOO. The RCT is AEMO's estimate of the total amount of Energy Producing Systems' capacity or DSP capacity required in the SWIS to satisfy the Planning Criterion. The RCT is updated in each Long Term PASA Study for the relevant Capacity Years to reflect the current forecasts.

[88] The RCR for a Reserve Capacity Cycle is the RCT determined for the Capacity Year commencing on 1 October of Year 3 of a Reserve Capacity Cycle as reported in the WEM ESOO for that Reserve Capacity Cycle. Once the RCR is determined for a Reserve Capacity Cycle, it will remain unchanged.

- Section 4.7 provides analysis on the regional capacity shortfall assessment, which considers the impact of network constraints and local supply and demand on forecast expected unserved energy, and is a new requirement for this 2024 WEM ESOO.
- Sections 4.8, 4.9, 4.10, and 4.11 provide the outcomes of the Availability Duration Gaps (ADG) analysis, Capability Class outcomes, forecast Availability Curves, and Peak Demand Side Programme Dispatch Requirement, respectively, also incorporating new and amended requirements for this 2024 WEM ESOO.

AEMO engaged EY to undertake the reliability assessment. A summary of the assessment methodology and key changes since the 2023 WEM ESOO are presented in Appendix A2.1. Further detail on methodology and assumptions is provided in EY's 2024 reliability assessment methodology and assumptions report[89].

4.2 Planning Criterion

Reliability standards are used in power systems to ensure the risk of failing to meet demand falls within acceptable limits. Standards between power systems vary depending on the risk and characteristics[90] of that system. The reliability standard in the WEM is called the Planning Criterion and is defined in clause 4.5.9 of the WEM Rules. AEMO uses the Planning Criterion to set the RCT for each Capacity Year in the 10-year outlook period.

The Planning Criterion has two limbs; A and B. Limb A requires the WEM to have enough capacity to meet the forecast annual peak demand and specified margins, while Limb B sets limits on the amount of unserved energy[91].

The Planning Criterion requires there is sufficient capacity available in the SWIS in each Capacity Year to meet both limbs, specifically:

- **Limb A** – the 10% POE peak demand forecast under the Expected scenario plus allowances for Intermittent Loads, Regulation Raise and a reserve margin.
- **Limb B** – limit EUE to 0.0002% of annual forecast expected energy consumption.

The Planning Criterion limbs are summarised in **Figure 28**.

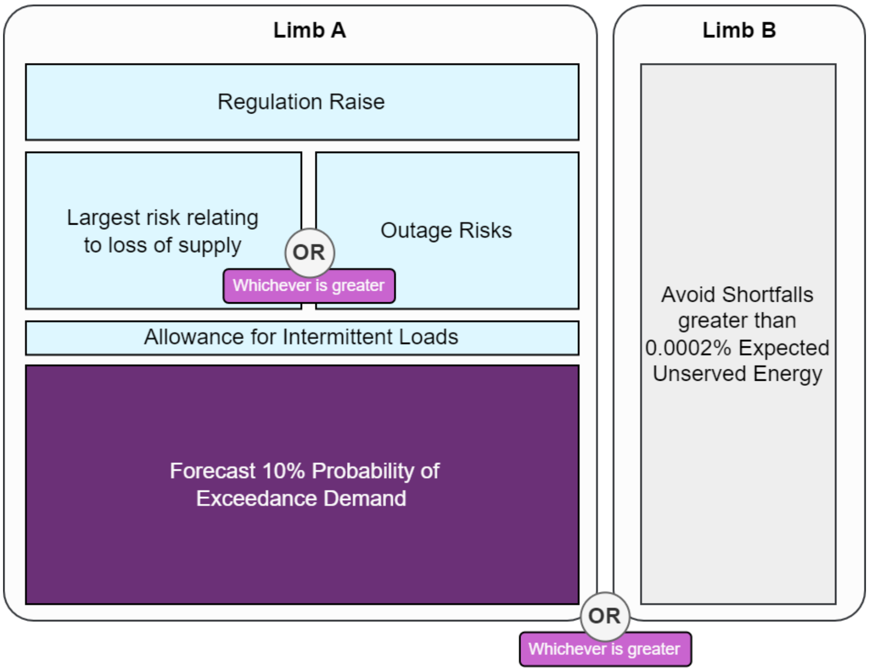
Since the RCM commenced in 2005, Limb A has set the RCT. This is because the capacity required to meet Limb A has always exceeded the capacity required to satisfy the EUE standard. This continues to be the case for the Long Term PASA horizon in this year's study.

[89] EY's 2024 reliability assessment assumption and methodology report is available at https://aemo.com.au/energy-systems/electricity/wholesale-electricity-market-wem/wem-forecasting-and-planning/wem-electricity-statement-of-opportunities-wem-esoo.

[90] For example, risk is determined by the power system's size, demand profiles, generator characteristics and outages, and level of interconnection.

[91] Electricity that cannot be supplied to consumers when demand exceeds supply.

Figure 28 The limbs of the Planning Criterion



4.2.1 Changes to the Planning Criterion since the 2023 WEM ESOO

The 13 December 2023 update to the WEM Rules[92] amended limbs A and B of the Planning Criterion[93], in addition to changes made to limb A in January 2023 which were applied in the 2023 WEM ESOO. **Table 10** summarises the changes, with the implications for determining the value of each of the limb requirements discussed in Section 4.3.

Table 10 Revisions to the Planning Criterion between the 2023 and 2024 reliability assessments

Limb requirement	Requirement at the time of 2023 study	Requirement at the time of 2024 study
Limb A: Reserve margin	Greater of: • 7.6% of peak demand (including transmission losses and allowing for Intermittent Loads) • the largest supply contingency	Greater of: • peak demand multiplied by the proportion of Capacity Credits expected to be unavailable at the time of peak demand due to Forced Outages • the largest supply contingency
Limb B: EUE percentage as a proportion of annual energy consumption	Not to exceed 0.002%	Not to exceed 0.0002%

At the time of the 2023 study, the WEM Rules required AEMO to assess the extent to which anticipated installed capacity in the WEM is capable of satisfying the **Planning Criterion** (and identify shortfalls) for the Low, Expected, and High demand scenarios. The current version of the WEM Rules only requires this assessment to be made for the one-in-10-year peak demand (10% POE) assuming expected demand growth.

92 Resulting from the RCM Review, see https://www.wa.gov.au/government/document-collections/reserve-capacity-mechanism-review.

93 The 1 January 2023 update of the WEM Rules amended the reserve margin portion of Limb A from the maximum capacity, measured at 41°C, of the largest generating unit, to the size, in MW, of the largest contingency relating to loss of supply (related to any facility, including a Network) expected at the time of forecast peak demand.

4.3 Approach to determining Limb A and Limb B requirements

4.3.1 Determining the Limb A requirement

The Limb A requirement is calculated based on the values projected for each of the Limb A building blocks, as set out in **Table 11.** Further detail on how the reserve margin and Regulation Raise components are estimated is provided below.

Table 11 Building blocks of Limb A

Building block of Limb A	Description
10% POE peak demand	Forecast annual operational sent-out peak demand for 10% POE under the Expected scenario.
Intermittent loads	Estimate of the capacity required to cover the forecast requirements of Intermittent Loads (ILs), which are excluded from the 10% POE peak demand forecast.
Reserve margin	Determined as the greater of: • peak demand multiplied by the proportion of Capacity Credits expected to be unavailable at the time of peak demand due to Forced Outages • the largest contingency relating to loss of supply at the time of peak demand. For the purposes of this WEM ESOO, AEMO has calculated the largest risk as equivalent to the loss of the three largest generating units as discussed below.
Regulation raise	Accounts for Regulation Raise quantities, escalated to account for the impact of new DPV and large-scale wind and solar capacity.

Determining the reserve margin requirement

The RCM Review amended the reserve margin component of Limb A, setting the reserve margin as the greater of the Forced Outage allowance and the largest supply contingency at peak demand. AEMO's assessment for the 2024 WEM ESOO confirms the largest contingency relating to loss of supply at the time of peak demand exceeds the Forced Outage allowance and determines the reserve margin. AEMO calculated the largest contingency as equalling the loss of the three largest generating units, then validated this with reference to other potential contingencies.

Forced Outage allowance methodology

AEMO assessed the Forced Outage allowance via the following method:

- AEMO evaluated the anticipated installed capacity (AIC) and Forced Outage Rates[94] of existing Facilities following the CRC assessment methodology[95].
- The expected unavailable capacity was calculated by multiplying AIC with the Forced Outage Rate for each facility[96].
- The proportion of Capacity Credits expected to be unavailable at the time of peak demand due to Forced Outages is the sum of expected unavailable capacity divided by the total AIC.

[94] The historical 36-month Forced Outage is based on data as of 23 March 2024.

[95] The WEM Procedure: Certification of Reserve Capacity. See https://aemo.com.au/en/energy-systems/electricity/wholesale-electricity-market-wem/procedures-policies-and-guides/procedures.

[96] Excluding Forced Outages of Facilities, to which clause 4.11.1A of the WEM Rules are expected to apply for the CRC assessment.

- The Forced Outage allowance is the forecast 10% POE peak demand multiplied by the proportion of Capacity Credit expected to be unavailable at the time of peak demand due to Forced Outages.

Using this approach, the expected unavailable capacity ranges from 167 MW to 234 MW over the Long Term PASA Horizon.

Assessing the largest contingency risk

To assess the largest contingency risk, AEMO has used the same approach as for the 2023 WEM ESOO. This involves considering factors, including fuel disruptions, project delays, outage frequency (forced and planned) during peak conditions, unplanned generation exits, and network element failures.

AEMO analysed outage records during the previous five Hot Seasons (2019-20 to 2023-24) and identified that the largest Power System Security risk relates to the coincident Forced Outage of multiple generating units. All five Hot Seasons experienced instances where the total capacity on Forced Outage exceeded the magnitude of the two largest generating units. This occurred during 5% of the peak intervals in the 2023-24 Hot Season (down from 14% in the 2022-23 Hot Season). Incidents in the 2022-23 Hot Season included up to three units.

This analysis suggests that there is significant risk that the SWIS may need to operate with Forced Outages exceeding the capacity of the two largest generating units. Consequently, AEMO considers that the largest supply contingency at peak demand should be based on the three largest generating units. This margin would ensure Power System Security can be maintained during any outage equivalent of the two largest generators on Outage while maintaining a real-time reserve equivalent to the third largest unit.

The largest supply contingency at peak demand in this 2024 WEM ESOO is expected to cover the risks associated with an ageing thermal generation fleet and transitional risks associated with retirements and new investments. For more details of the analysis, refer to Section 3.2.4. The contingency component's size has increased to 958 MW from 2027-28 onwards, compared with 898 MW in the 2023 WEM ESOO. This increase is due to Neoen Collie 2 ESR (300 MW) replacing Cockburn Power Station (240 MW) as the third-largest unit, after the retirement of Collie Power Station (317.2 MW) in 2027-28.

To confirm the adequacy of this risk assessment, AEMO has validated the resultant margin with reference to the range of factors described above.

Determining the Regulation Raise requirement

Building on the 2023 WEM ESOO approach, AEMO has estimated the minimum Regulation Raise requirement using the Frequency Co-optimised Essential System Services framework, ensuring frequency is maintained within the Normal Operating Frequency Band. Forecast quantities account for the increasing penetration of intermittent generation, particularly DPV[97].

The requirement increases across the 10-year outlook period and to a greater extent than in the 2023 WEM ESOO (details in Section 4.4). This reflects AEMO's updated forecasts for sources of volatility, which are driven mainly by the growing impact of DPV.

[97] Regulation Raise is formulated as the existing Regulation Raise requirement escalated by 3% of installed capacity of new wind generation in North Country, Mid-West, and Neerabup nodes 1.8% of installed capacity of new wind generation at other nodes, 5% of installed capacity of new grid-scale solar generation, and 4% of new DPV installed capacity.

4.3.2 Determining the Limb B requirement

The Limb B requirement is assessed by modelling the WEM, taking into account the forecast demand and supply, and assessing the capacity required for EUE to not exceed 0.0002% of annual energy consumption.

EUE refers to the expected amount of customer demand that cannot be supplied in the SWIS due to a shortage of generation, storage or demand side response, renewable resource availability patterns, or requirements to operate the SWIS securely and within a technical envelope (for example, Essential System Services (ESS) requirements or Thermal Network Limits). Loss of supply to customers due to local distribution network issues do not contribute to EUE for the purpose of this reliability assessment and are not captured in this modelling.

To determine the Limb B requirement for RCT purposes, EUE modelling without the inclusion of network constraints is required. The RCT is set by the greater of Limb A and Limb B capacity requirements. Modelling for Limb B reveals that the RCT is set by the Limb A requirement for each Capacity Year from 2024-25 to 2033-34. The modelling results are summarised in the following sections. Appendix A.2 provides further detail on the modelling approach and methodology.

4.4 Outcome of Limb A requirement

Table 12 shows the building blocks of the Limb A requirement for the 10% POE peak demand Expected scenario for each Capacity Year of the 10-year outlook period.

Table 12 Limb A requirements (MW)[A]

Capacity Year	10% POE peak demand	Intermittent loads	Reserve margin[B]	Regulation raise	Total
2024-25[C]	4,388	8	976	129	5,501
2025-26[C]	4,464	8	976	142	5,589
2026-27	4,555	8	976	157	5,696
2027-28	4,656	7	958	172	5,794
2028-29	4,772	7	958	187	5,925
2029-30	4,998	7	958	202	6,165
2030-31	5,361	7	958	219	6,545
2031-32	5,662	6	958	235	6,861
2032-33	5,944	6	958	251	7,159
2033-34	6,163	6	958	267	7,395

A. All figures are rounded to the nearest MW. Totals may have a 1 MW difference due to rounding.
B. Calculated as the greater of Forced Outage Allowance and the largest contingency relative to loss of supply expected at the time of forecast peak demand in accordance with clause 4.5.9(a) of the WEM Rules.
C. These figures represent the building blocks of Limb A for the purposes of the 2024 reliability assessment and are not intended to be comparable to the RCT as determined for 2023. The RCT as determined between Limb A and Limb B requirements for 2024 is set out in Section4.6. Figures have been updated to reflect the 2024 WEM ESOO forecasts. However, the RCR of 4,526 MW set in the 2022 WEM ESOO for the 2022 Reserve Capacity Cycle (2023-24) (see https://aemo.com.au/-/media/files/electricity/wem/planning_and_forecasting/esoo/2022/2022-wholesale-electricity-market-esoo.pdf?la=en) and the RCR of 5,543 MW set in the 2023 WEM ESOO for the 2023 Reserve Capacity Cycle (2024-25) do not change (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?la=en).

The outcome against Limb B of the reliability standard is discussed in the following section, while the supply-demand balance against the RCT is set out in Section 5.1.

4.5 Outcome of Limb B requirement

For all Capacity Years of the Long Term PASA, the market modelling determined that the capacity required to limit EUE to less than 0.0002% of annual energy consumption was below the Limb A requirement. Further detail behind the steps carried out to reach this conclusion are in Appendix A2.3.

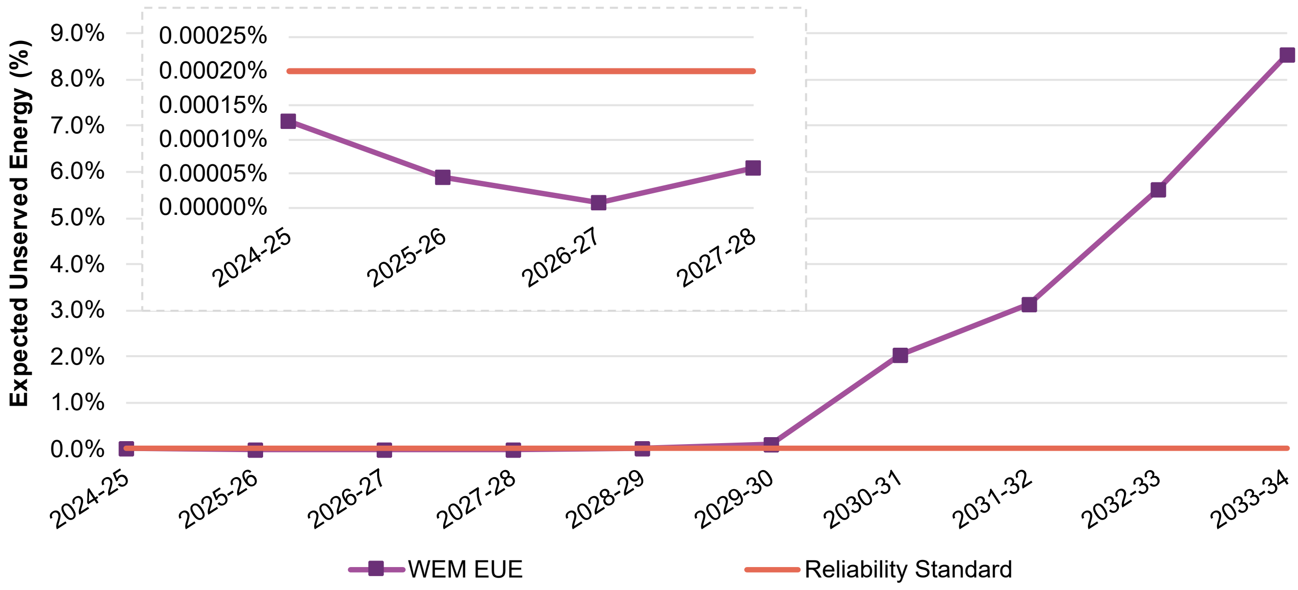
4.5.1 Unserved energy analysis for Limb B assessment

For each Capacity Year of the 10-year outlook period, 100 Monte Carlo simulations (iterations) were modelled for random generator forced outage profiles for each of the 12 historical weather reference years. This allows the modelling to capture a range of weather variability and random forced outage patterns (resulting in a total of 1,200 iterations for each forecast Capacity Year). Each simulation is therefore a different potential combination of weather and outage patterns for each Capacity Year and represents the full Capacity Year being modelled for each iteration.

The analysis below presents EUE metrics in the absence of network constraints to demonstrate levels of EUE driven by other factors. Section 4.7 explores the impact on EUE with transmission network constraints added to the modelling.

Figure 29 presents the forecast EUE for each Capacity Year, as averaged across all 1,200 iterations for each year.

Figure 29 EUE forecast, 2024-25 to 2033-34, anticipated installed capacity only for the 10% POE Expected scenario, excluding any impacts of network constraints



Source: EY

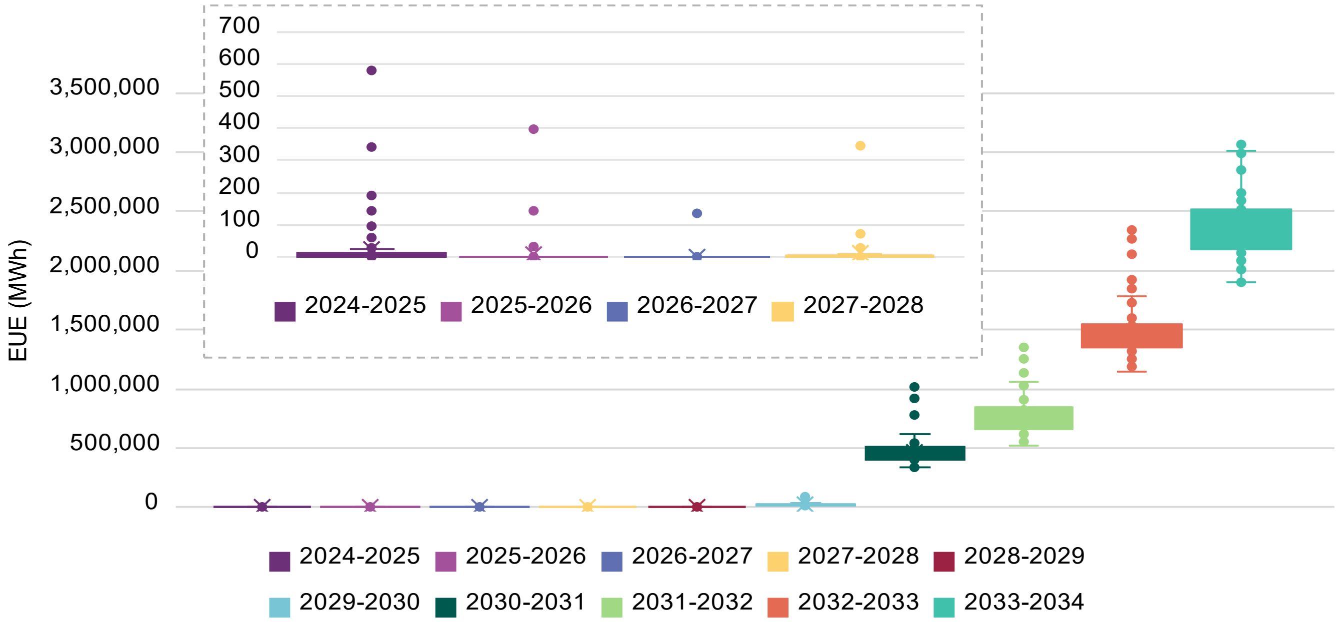
The EUE outcomes can be characterised into three distinct periods over the 10-year outlook period, with the following observations:

- **2024-25 to 2027-28** – EUE is forecast to be below the reliability standard each Capacity Year, reaching a minimum in 2026-27 where the forecast Reserve Capacity is at its peak over the forecast period and operational consumption growth is still relatively low. While the EUE limit is expected to be satisfied, certain circumstances or combinations of weather and outages can lead to more extreme EUE events which contribute to the annual average EUE (see Appendix A2.4 for examples and further details).

- **2028-29** sees an increase in operational consumption, and with no new installed capacity assumed. This leads to a higher EUE, of around 0.0005% or 98 MWh. EUE is forecast for every weather reference year, but the majority occurs in the evening peak hours in February and March.
- **2029-30 to 2033-34** – from 2029-30 onwards, EUE starts to increase more significantly and is expected to occur in all months and times of the day due to continued growth in demand and anticipated retirements of the Muja D and Bluewaters Power Stations. EUE is forecast to increase from 2029-30 onwards. Appendix 2.4 provides further detail on timing of EUE occurring at all times of the day and year (and across all historical weather reference years).

Figure 30 provides box and whisker plots of EUE across the 100 random forced outage iterations (averaged across the 12 historical weather reference years) to show the spread of potential EUE outcomes across different random outage profiles. **Table 13** summarises the drivers and explanations behind the three periods discussed, while further details are provided in Appendix 2.4.

Figure 30 Box and whisker plot of annual EUE for 2024-25 to 2033-34 (by iteration, averaged across reference years) (MWh)



Source: EY.

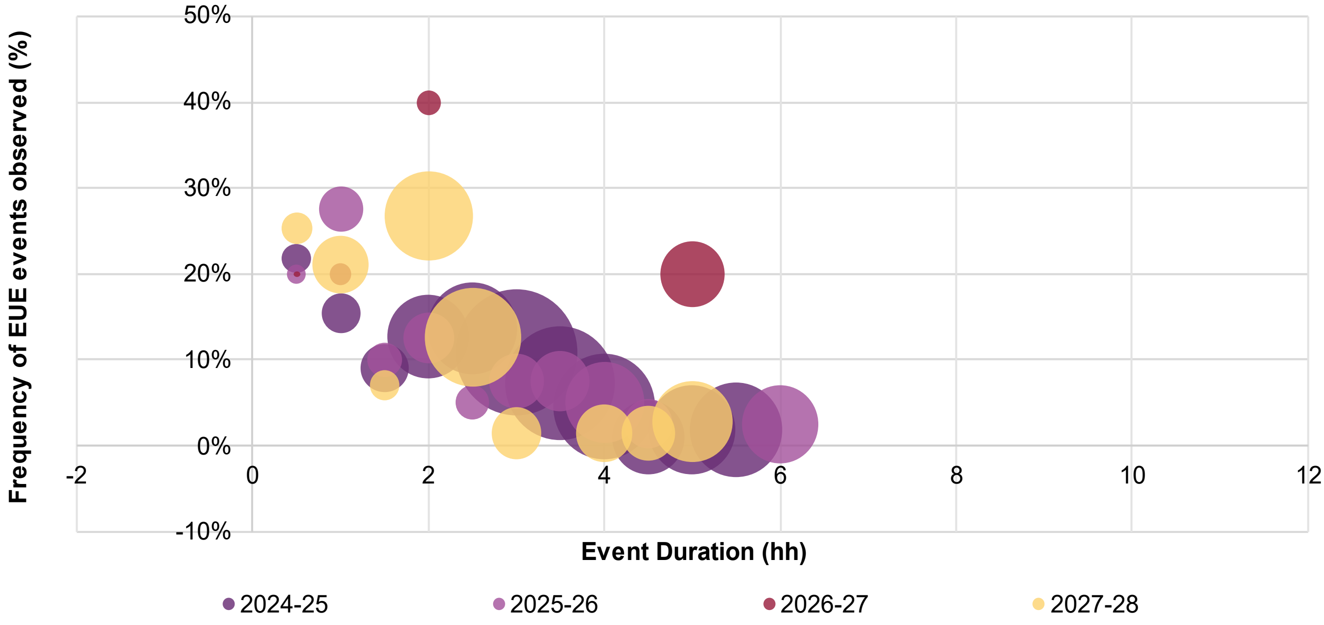
Table 13 Summary of EUE trends and drivers for the three periods (2024-25 to 2033-34)

Capacity Year	EUE outcome	Energy consumption growth (average p.a.)	Supply trends	EUE trends across iterations	Example EUE event	Conditions
2024-25 to 2027-28	<0.0002%	Slight (less than 1%)	Supply peaks in 2026-27	Most iterations have no EUE but particular weather and outage patterns can lead to EUE >0.0002%	6pm to 11pm business day in February 2027 2014-15 reference year 1,400 MWh EUE	Mostly outside of solar PV hours Combined forced outage of storage, coal and gas (over 1,400 MW unavailable) Wind drops to as low as 20 MW availability (of over 1 GW installed capacity)
2028-29	>0.0002%	Moderate (3.6%)	Muja D and Bluewaters Power Stations still online	Majority of 1,200 iterations show no EUE but 160 have EUE >0.0002%		
2029-30 to 2033-34	>0.0002%	High (8%)	All coal assumed retired (2029 Muja D Power Station and 2030 Bluewaters Power Station)	Weather, outage patterns, time of year and time of day are not deciding factors in whether EUE will occur or not. EUE is expected across each iteration, weather reference year, time of day and month. Times of higher demand, low renewable output, or combinations of large units being on outage at the same time will still drive higher levels of EUE relative to other times but due to a general shortfall in supply relative to demand EUE is more or less certain to be above the standard in all 1,200 iterations.		

Figures 31 to 33 represent these trends in bubble chart format to display the frequency, duration, and depth of EUE events for the different Capacity Years of the Long Term PASA. As can be seen from these plots:

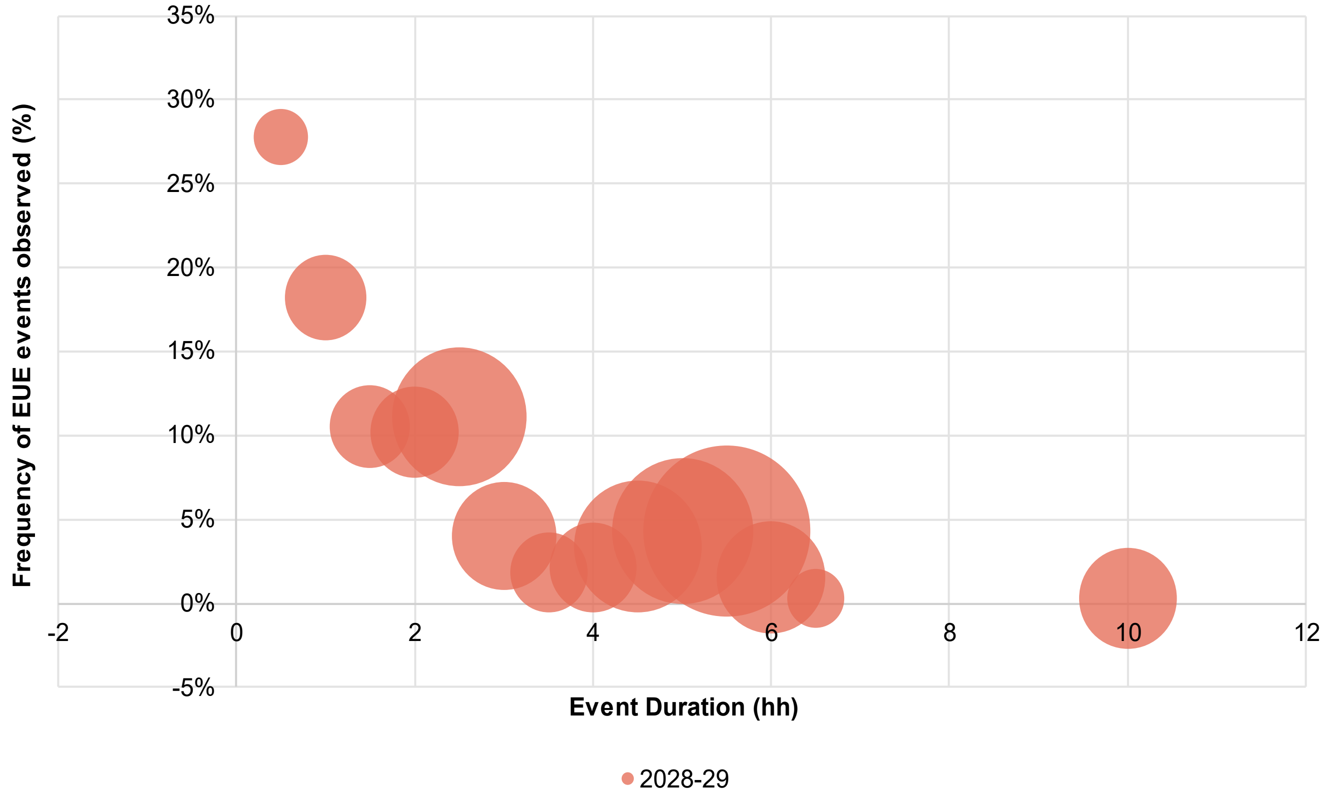
- **2024-25 to 2027-28** – the majority of potential modelled EUE events are relatively small in magnitude and have durations of less than two hours. At much lower frequency, there are instances of EUE which last longer and are of higher magnitude.
- **2028-29** – modelled EUE increases to 98 MWh (or 0.0005% of energy consumption, averaged across all iterations) but the majority of this EUE occurs in shorter duration events (70% of EUE occurs in durations of two hours or less). In line with tighter supply conditions and growing operational consumption, longer duration EUE events are seen in the modelling, with EUE events lasting up to 10 hours.
- **2029-30 to 2033-34** – after 2029-30 when demand starts to increase significantly and the last remaining coal units in the WEM are assumed to close, the frequency and duration of possible EUE events increase significantly. A sample for the Capacity Year 2030-31 is shown, where around half of the forecast EUE occurs in events of ten hours or less duration. Also shown is a long tail of possible EUE events lasting longer than 10 hours (up to over 70 hours), accounting for around half of the forecast EUE in total for that year.

Figure 31 Bubble chart showing EUE frequency (%), duration (hh), and depth (MWh) of possible events for 2024-25 to 2027-28



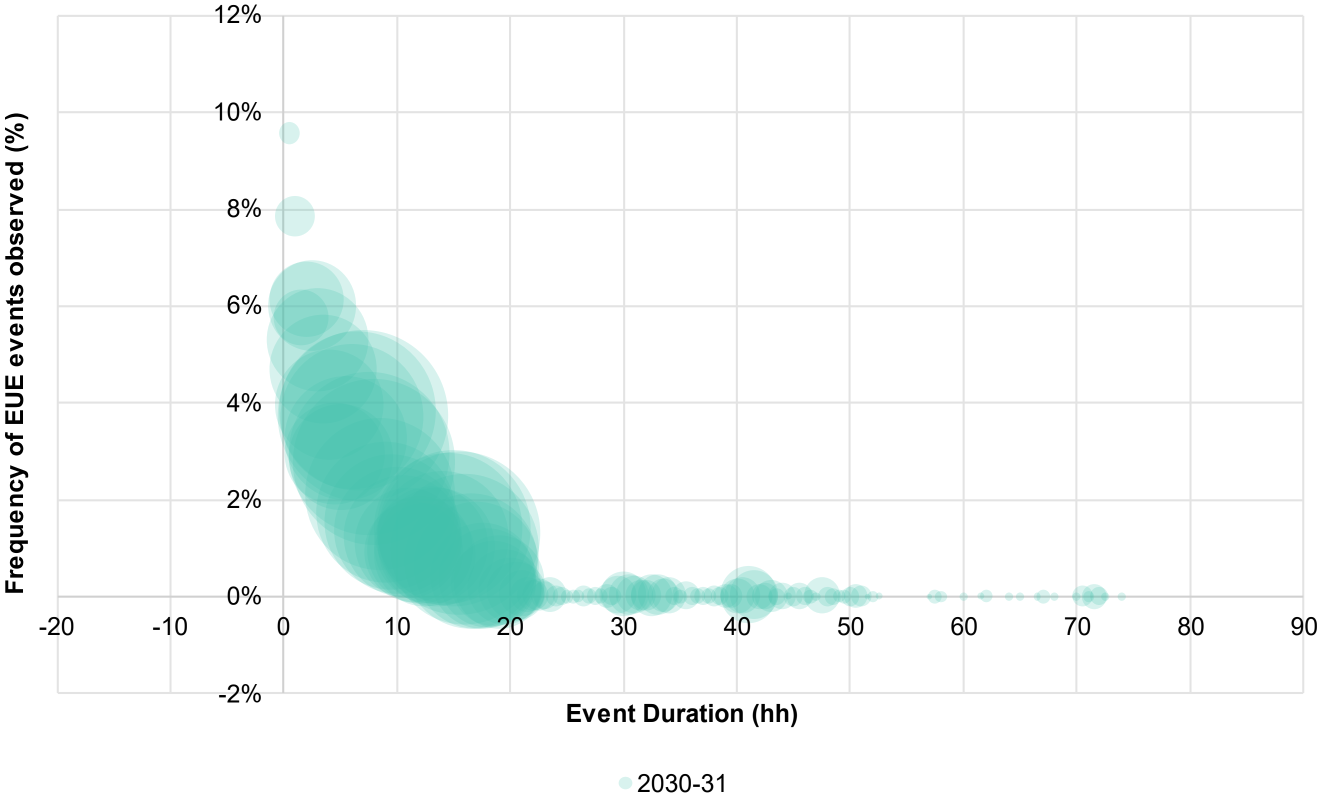
Source: EY.

Figure 32 Bubble chart showing EUE frequency (%), duration (hh), and depth (MWh) of possible events for 2028-29



Source: EY.

Figure 33 Bubble chart showing EUE frequency (%), duration (hh), and depth (MWh) of possible events for 2030-31



Source: EY.

4.6 The Reserve Capacity Target

Under clause 4.5.10(b) of the WEM Rules, AEMO is tasked with forecasting the **Peak RCT** for each Capacity Year throughout the 10-year outlook period. The amended clause 4.5.10(b) specifies this forecast should assume no network congestion under the modelled scenario (the one-in-10-year peak demand assuming expected demand growth). This is because the NAQ framework is now in place, meaning AEMO accounts for these constraints when assigning Capacity Credits to capacity providers based on their available Sent Out capacity during peak demand periods.

Table 14 shows the RCT. Limb A sets the RCT for all years of the Long Term PASA horizon.

The RCT for 2026-27 is 5,696 MW, which sets the RCR for the 2024 Reserve Capacity Cycle. It is 153 MW higher than the RCR set for 2025-26 (5,543 MW) and 20 MW lower than the RCT forecast for 2026-27 (5,716 MW) in the 2023 WEM ESOO. The increase from the 2025-26 RCT is primarily due to forecast growth in peak demand and a small increase in the Regulation Raise requirement (to account for the impacts of increasing penetration of intermittent generation in the power system).

Table 14 Reserve Capacity Targets (MW)

Capacity Year	RCT
2024-25	5,501
2025-26	5,589
2026-27	**5,696**
2027-28	5,794
2028-29	5,925
2029-30	6,165
2030-31	6,545
2031-32	6,861
2032-33	7,159
2033-34	7,395

4.7 Regional capacity shortfall assessment

As well as determining the RCT, the reliability assessment identifies regional capacity shortfalls and reports on EUE outcomes including the impact of network constraints. This Increased focus on sub-regional capacity shortfalls requires AEMO in accordance with clause 4.5.10(c) of the WEM Rules to: “identify and assess any potential capacity shortfalls isolated to a sub-region of the SWIS resulting from expected restrictions on transmission capability or other factors and which cannot be addressed by additional Peak Capacity outside that sub-region”.

In the 2023 reliability assessment, the analysis included reporting of the top binding and violating constraints to indicate areas of the network where transmission network capability may impact on the dispatch of generation facilities in the electricity market, or where the network may need to be reinforced to maintain system security. In response to the updated WEM Rules requirement, further in-depth analysis on sub-regional capacity shortfalls is provided in this year’s assessment.

Although the RCT determination is carried out without network constraints applied in the modelling, thermal network constraints are included in the regional capacity shortfall assessment. This modelling does not include any further generation capacity expansion beyond what is modelled as AIC.

This section sets out the capacity shortfall assessment as follows:

- Section 4.7.1 summarises the approach to including network constraints.
- Sections 4.7.2 and 4.7.3 present the impact of including thermal network constraints on the outcome of the regional and sub-regional analysis of EUE.
- Section 4.7.4 summarises the key areas of the transmission network that may be subject to network congestion.
- Section 4.7.5 presents potential options for network augmentation to alleviate regional EUE.

4.7.1 Network constraints

The reliability gap assessment includes constraint equations that represent the thermal limits of the transmission network in the SWIS. This allows the modelling to consider the impact of network congestion on EUE. The constraint equations are based on information provided by Western Power and consider the following states of the network[98]:

- 2024-25: Existing network.
- 2025-26: Ratings upgrade associated with the East Region Stage 1 project[99], also known as East Regional Energy Project (EREP).
- 2026-27: A portion of the full Clean Energy Link - North Region project.
- 2027-28: Clean Energy Link – North Region project.

Assumptions are made regarding the development of the transmission network beyond 2027-28 (see Section 4.7.5 for further details).

4.7.2 Regional analysis of EUE

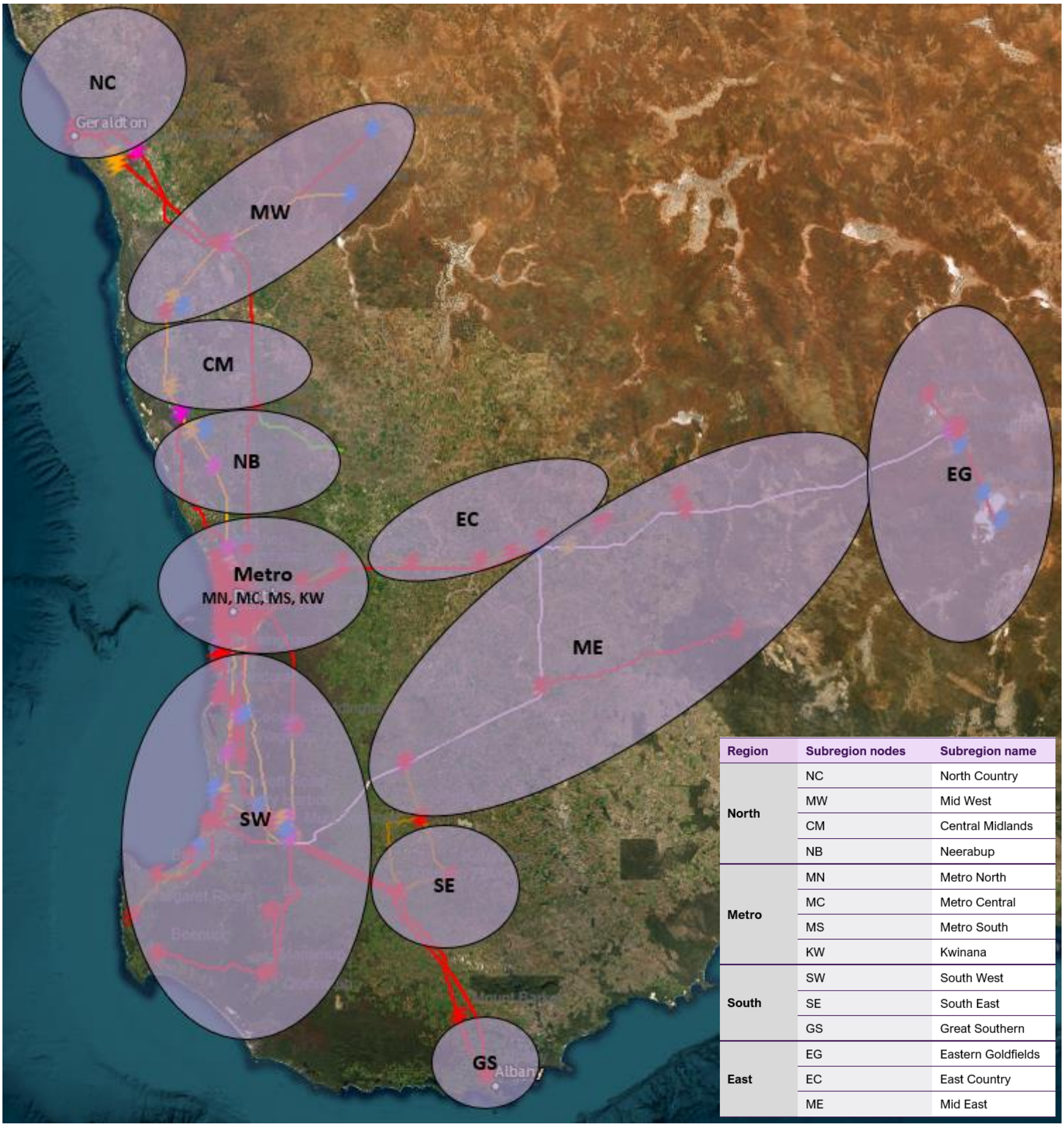
This section presents EUE on a regional basis. The SWIS regions and subregions are presented in **Figure 34**, using the nodal configuration used in the SWIS Whole of System Plan and later refined for the SWIS Demand Assessment[100].

[98] The earliest date for commissioning the Clean Energy Link project (previously known and referred to as the North Region Energy Project 'NREP') is summer 2027-28. This has been modelled in two states – for 2026-27 and for 2027-28.

[99] See https://www.westernpower.com.au/siteassets/documents/transmission-system-plan-2023-20230929.pdf.

[100] The nodal structure in the WA Whole of System Plan was revised for the SWIS Demand Assessment to include the Central Midlands and Greater Southern nodes. https://www.wa.gov.au/system/files/2023-05/swisda_report.pdf

Figure 34 SWIS regions and sub-regions



Region	Subregion nodes	Subregion name
North	NC	North Country
	MW	Mid West
	CM	Central Midlands
	NB	Neerabup
Metro	MN	Metro North
	MC	Metro Central
	MS	Metro South
	KW	Kwinana
South	SW	South West
	SE	South East
	GS	Great Southern
East	EG	Eastern Goldfields
	EC	East Country
	ME	Mid East

Source: EY.

Table 15 presents a summary of EUE by region. It identifies where there may be customer demand that cannot be supplied due to a combination of inadequate local generation supply and insufficient power transfer capability from the transmission network.

If growth in regional demand does not eventuate, then the more sizeable projected EUE outcomes in the second half of the 10-year outlook period are less likely to occur. If regional consumption is different from forecast, this will impact the regional reliability outcomes.

Table 15 EUE by region[A], between 2024-25 and 2033-34 (MWh)

Region	First half of the outlook period					Second half of the outlook period				
	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34
North	0	0	-	-	-	-	-	1	15	92
Metro	1	0	-	-	-	0	17	80	196	341
South	-	-	-	-	0	0	-	-	-	-
East [B]	338	185	254	317	434	660	1,127	1,681	2,231	2,708
Non-region specific EUE[C]	5	3	1	3	38	15,311	384,424	675,688	1,341,220	2,220,108
Total SWIS EUE	344	188	255	320	472	15,972	385,568	677,450	1,343,663	2,223,248
Total SWIS EUE as % of operational consumption	0.0019	0.0010	0.0014	0.0017	0.0025	0.0768	1.6887	2.7691	5.1446	7.9779
Total SWIS EUE (excluding East) as % of operational consumption	0.0000	0.0000	0.0000	0.0000	0.0002	0.0736	1.6837	2.7622	5.1361	7.9682

A. Where there is a value of zero in the table a small amount of EUE was identified and has been rounded down. A dash means EUE was not observed for this subregion in the modelling.
B. East region EUE includes unserved energy for loads with "non-reference" connection arrangements. Refer to "EUE in the east region" below.
C. EUE observed at the regional reference node (RRN) does not have a locational element to it. This portion of EUE is driven primarily by a SWIS wide generation supply shortfall rather than transmission network limitations.

EUE in the east region

In the first half of the 10-year outlook period, the majority of region-specific EUE occurs in the east region of the SWIS. This includes unserved energy for loads with "non-reference" connection arrangements, such as the Eastern Goldfields Load Permissive Scheme (ELPS). These loads have contracted with Western Power for a connection on the basis that they will be curtailed when demand is greater than supply, typically to avoid having to self-fund transmission augmentation or new local generation.

This EUE could be reduced by:

- The addition of local generation to meet local demand in the Eastern Goldfields.
- Increasing the transfer capability of the network supplying the Eastern Goldfields.

Current challenges in the east region

Network limitations in the Eastern Goldfields region have caused challenges for new load seeking to connect. In order to connect in the region without funding new local generation or substantial network augmentations, customers have accepted a lower level of reliability under the ELPS[101]. Under this scheme, these customers may

[101] See Western Power Transmission System Plan 2023 – Section 12.2.4 regarding key developments in the Goldfields region. EUE associated with ELPS has not been separately identified.

be curtailed by Western Power when there are very high loadings on the 220 kilovolts (kV) line. The EUE outcomes presented in **Table 15** include EUE for loads that have accepted the terms of the ELPS.

The use of NCESS (previously referred to as Network Control Services) in the Goldfields region has also been an important feature in managing regional reliability in recent years[102]. Western Power is considering Expressions of Interest from potential NCESS providers in the Eastern Goldfields region to further improve reliability and to mitigate potential system strength risks[103]. Evaluation of proposals has not yet concluded. As such, the impact of any new NCESS service is not reflected in the findings presented in **Table 15.**

Impact of EREP on EUE in the east region

Completion of the EREP[104] in 2025-26 is expected to reduce East region-specific EUE, as it materially improves thermal transfer capability in the region. However, as load grows there will likely be a commensurate increase to EUE if it is not mitigated, such as through further transmission network augmentation or local capacity investment.

Impact of Clean Energy Link – North on non-region specific EUE

The Clean Energy Link – North transmission upgrades are assumed to be in-service by 2027-28. This unlocks additional network transfer capacity in the northern region of the SWIS and is a key enabler for future generation to be connected along the 330 kV infrastructure in the Mid West.

After the Clean Energy Link – North is built, generation projects connecting into the northern region of the SWIS (at or south of Three Springs Terminal along the 330 kV) are expected to help reduce non-region specific SWIS EUE below what is reported[105].

By 2028-29, 38 MWh of non-region specific EUE is projected due to a SWIS-wide generation capacity shortfall driven by:

- Projected demand growth.
- Retirement of coal-fired power stations.

Any transmission network augmentation that is modelled to be in service for this sub-regional capacity assessment may relieve EUE in a sub-region by improving network transfer capability, but in the absence of any additional generation capacity being installed (modelled), a supply shortfall could still be observable.

The modelling also made assumptions around where the demand uptake associated with electrification and hydrogen may occur, and factors in network augmentation options that could be built to cater for these load connections. Demand increases in the SW, KW and CM/MW nodes associated with electrification and hydrogen loads are a driver of EUE increasing over time. These assumptions impact the location of the EUE identified[106].

[102] See Western Power Transmission System Plan 2023 - Section 12.3.7 regarding reliability in the Goldfields.

[103] Prospective NCESS providers may participate in the RCM, subject to meeting certification requirements. See https://www.westernpower.com.au/resources-education/suppliers/tenders-and-registrations-of-interest/expression-of-interest-for-ncess---reliability-and-system-strength-services-for-the-eastern-goldfields-region/.

[104] The EREP will uprate thermal network limits along the 220 kV network and deliver minor 132 kV network upgrades in the East Country and Eastern Goldfields.

[105] The modelling scenario does not include the impact of future generation beyond AIC. The EUE presented does not consider the impact that future 330 kV connected generation enabled by the Clean Energy Link north may have on sub-regional EUE.

[106] Demand associated with electrification is split between Kwinana (40%), Mid West (40%) and South West (20%). Hydrogen load is split between Kwinana (50%) and North Country (50%).

4.7.3 Sub-regional capacity shortfalls

Further analysis was conducted to identify the sub-regional capacity shortfall associated with each node under the different combinations of weather reference years and Monte Carlo outage iteration scenarios. **Table 16** presents the sum of the maximum shortfall in supply at different connection points within each node of the SWIS. It quantifies the MW dispatch that a generator would need to be dispatched at to mitigate against EUE events identified under the different combinations of weather conditions and outage conditions modelled[107].

Table 16 Sub-regional capacity shortfall by Capacity Years across all weather reference years and Monte Carlo iterations, between 2024-25 and 2033-34 (MW)[A]

Node / Capacity Year	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34
NC	-	-	-	-	-	-	-	-	-	-
MW	-	-	-	-	-	-	-	-	-	6
CM	-	-	-	-	-	-	-	9	87	172
NB	-	1	-	-	-	-	-	-	-	-
MN	-	4	-	-	-	0	5	12	14	20
MC	-	-	-	-	-	5	4	10	11	13
MS	-	-	-	-	-	2	62	81	104	121
KW	-	-	-	-	-	3	38	45	60	67
SW	-	-	-	-	0	1	4	9	10	12
SE	-	-	-	-	-	-	-	-	-	-
GS	-	-	-	-	-	-	-	-	-	-
ME	12	16	20	14	15	19	33	36	43	46
EC	3	2	2	2	2	5	15	19	23	25
EG	15	10	12	13	14	17	22	23	25	26
Non-region specific EUE[B]	64	99	45	127	393	1,698	2,545	2,839	3,086	3,220

A. Where there is a value of zero in the table a small amount of shortfall was identified and has been rounded down. A dash means a shortfall was not observed for this subregion in the modelling.
B. Shortfalls observed at the regional reference node (RRN) does not have a locational element to it. This portion of EUE is driven primarily by a SWIS wide generation supply shortfall rather than transmission network limitations.

A shortfall in supply is observed only after all existing generation, DSP and storage has been exhausted, and considering impacts on transmission network limitations. This provides the maximum capacity shortfall (in MW) for each Capacity Year by subregion and identifies that the SWIS may benefit from additional capacity located at the right connection points. This is described below:

- **The East region (EG, EC, ME)** – the East region is forecast to have a sub-regional capacity shortfall from 2024-25. This is related to a number of 220 kV and 132 kV constraints that may constrain the import of power into the Eastern Goldfields. There is insufficient local generation to support the demand in the region. The commissioning of EREP in 2025-26 increases the capability of the region to import power, helping reduce the

[107] The capacity identified for each region is on the basis that each MW of capacity is distributed across each modelled connection point in a way that maximises the benefit to each network constraint.

maximum supply shortfall observed. This increased network capability is partially offset by the withdrawal of Parkeston Power Station (PRK_AG) from the RCM in 2025-26. This reduces the capacity of generation in the region to meet existing and future demand locally.

- **SWIS-wide (RRN)** – from 2029-30 onwards, the sub-regional capacity shortfall increases significantly across the SWIS and is specifically identified to be at the RRN. This is driven primarily by the retirement of coal-fired power stations and future demand growth resulting in a general system wide capacity shortfall that is not isolated to a specific subregion. This persists across the study period and increases to a maximum capacity shortfall of 3,220 MW. In practice, generation capacity is not connected to the RRN and is developed considering a combination of resource availability, network access, land availability, costs, social and community issues and more.
- **Metropolitan (MN, MC, MS, KW)** – from 2030-31 onwards, capacity shortfalls are identified in the metropolitan regions due to future demand growth. These parts of the SWIS typically have minimal local generation (apart from what is supplied from DER) and rely on the transmission network being capable of importing power from remote generation sources. Network limitations on 132 kV lines are forecast to restrict this import capability leading to capacity shortfalls. While Kwinana is included in the metropolitan region for reporting purposes, it has different regional characteristics compared to other nodes. Future demand growth in Kwinana is forecast to be driven by industrial load and emerging industries discussed below.
- **Emerging industries and electrification loads (CM, MW, KW, SW)** – future demand growth associated with electrification of processes and hydrogen is forecast to result in sub-regional capacity shortfalls by the end of the study period in the north (CM, MW), Kwinana (KW) and in the South West. These capacity shortfalls are highly dependent on the timing and location of emerging industries and a number of discrete loads increases due to electrification.

4.7.4 Transmission network congestion

The presence of network congestion in a power system reflects a designed economic trade-off between building large amounts of network to allow unconstrained dispatch of generation versus accepting a level of curtailment risk.

Table 17 summarises the key areas of the transmission network that may be subject to network congestion. This is identified through how often during the year a constraint equation along that flow path was found to be binding throughout the study period. A binding constraint equation may reduce generation output and/or increase generation output depending on the prevailing power flow conditions at the time. The table presents the percentage of the given year where the flow path was found to be constrained by one or more constraint equations in the dispatch modelling simulations[108].

[108] The network congestion modelling for this reliability assessment was undertaken with the best available operational and forecast Limit Advice, considering relevant protection schemes and other operational mitigations. This may be different from the RCM Limit Advice used for NAQ modelling. For example, RCM Limit Advice network limits are based on environmental conditions that are not necessarily reflective of the scenario examined as part of the reliability assessment. In addition, more recent operational and forecast limit advice may include changes or network augmentations not considered in older RCM Limit Advice.

Table 17 Key constrained pathways, between 2024-25 and 2028-29 (% of time binding in the year)

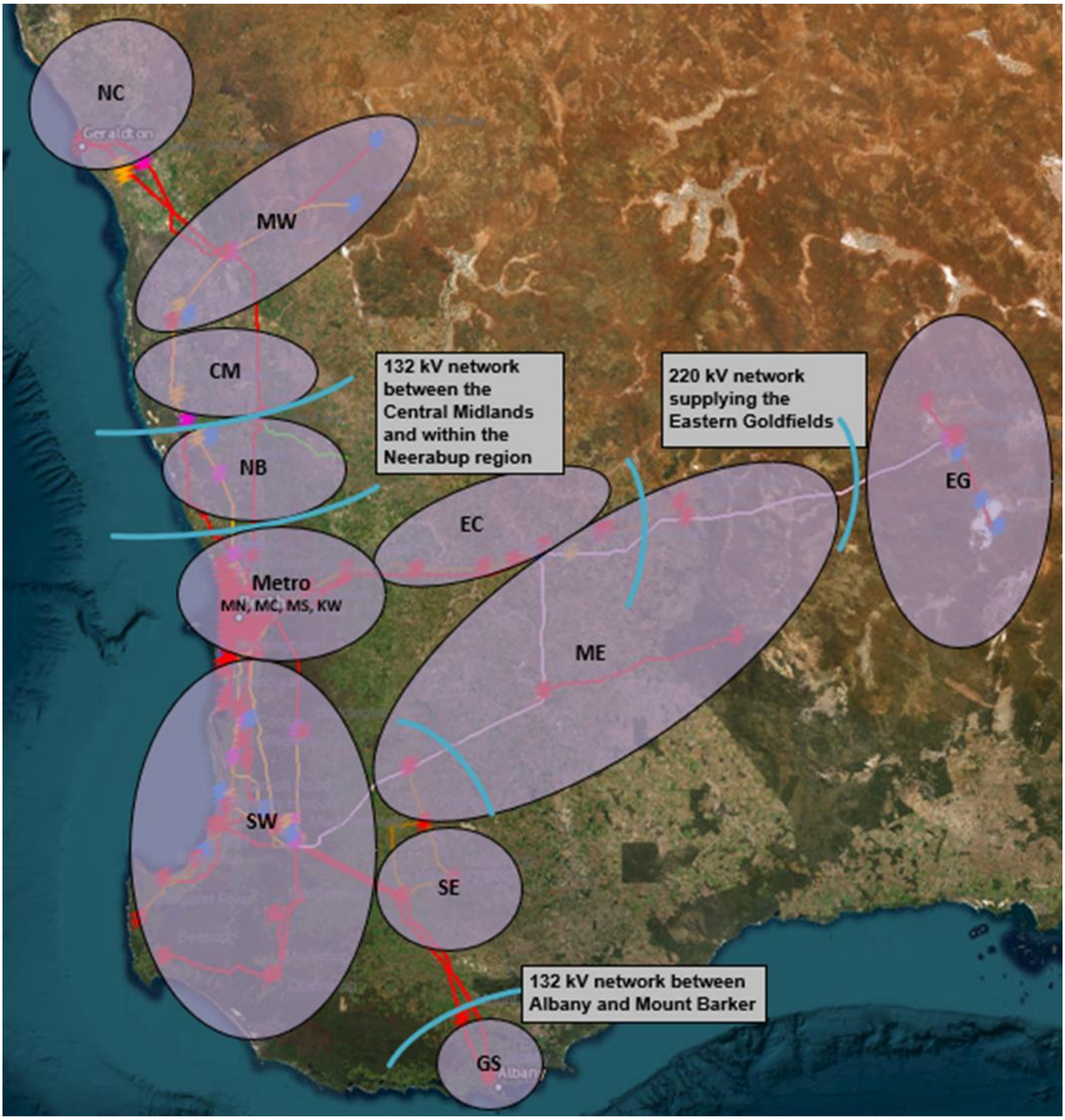
Constrained flow path	Subregion	2024-25	2025-26	2026-27	2027-28	2028-29
132 kV network between Albany and Mount Barker for a contingency of the parallel Albany to Kojonup 132 kV circuit	GS-SE	24.4	23.3	23.1	22.4	21.5
220 kV network supplying West Kalgoorlie for a contingency of a 132 kV network circuit around Merredin and Northam[A]	SE-ME ME-EG	6.8	-	-	-	-
132 kV network between the Central Midlands and Neerabup region for loss of a parallel 132 kV circuit in the same region or for a loss of the single 330 kV network between Neerabup and Three Springs Terminal	CM-NB NB-MN	1.9	1.7	1.6	-	-

A. While the EREP project uprates the existing 220 kV line and reduces binding constraints in market dispatch, it does not completely remove EUE risk associated with 132 kV zone substations supplied in the Goldfields region and at Bounty Zone Substation which may be subject to a 132 kV single circuit risk or local 132 kV network limitations presented in this table.

Figure 35 presents a diagram of the congested network areas. The constraints are described below:

- The transmission network around Kojonup, Albany and Mount Barker is forecast to be constrained due to a thermal limit on the 132 kV network. Excess generation that is not consumed by demand in the Albany area flows northward and there may be times when generation is curtailed to limit the export of surplus power from this region.
- The 220 kV network supplying the West Kalgoorlie Terminal may constrain generation connected to the 220 kV network following the loss of 132 kV transmission network circuits around Merredin Terminal and Northam.
  - Numerous existing special protection schemes and operational measures are in place to assist in managing the generation output and demand that might contribute to transmission network congestion in this region. These schemes allow the network to operate at higher utilisations whilst facilitating connection of customers in an otherwise congested part of the network.
  - During periods of very high coincident generation from the wind farms and solar farms in this region, the 220 kV network may be subject to a thermal limit based on its current thermal ratings. The delivery of EREP in 2025-26 is expected to remove a number of the thermal transmission network limitations in this region.
  - It is important to note that stability constraints in this region may bind before thermal limits (that is, be more restrictive). However, existing power system stability constraints in this region tend to require constraining generators on (rather than off) and have less of an impact when assessing EUE in this reliability study.
- The 132 kV network in and around the Central Midlands and Neerabup Region may be subject to thermal limits following the loss of a parallel 132 kV circuit in the region. These overloads present on 132 kV lines around Pinjar, Cataby, and Regans for high coincident generation dispatch from wind farms and solar farms in the region and further south on a number of 132 kV circuits near Joondalup, Wanneroo and the Yanchep area. Several existing runback schemes and line overload protection schemes act together to assist in reducing how often these constraints may bind. The delivery of Clean Energy Link – North by 2027-28 will improve the power transfer capability across this region enabling further generation to be connected to the 330 kV network in the north region post 2028.

Figure 35 Diagram of congested areas



Source: EY.

4.7.5 Network changes and augmentation

For the period beyond 2027-28, in the absence of any further network augmentation commitments, several regions are forecast to experience network congestion and system security risks due to a combination of assumed demand growth and insufficient generation supply[109]. Unmitigated, this will lead to:

[109] This is observed via an assessment of violating constraint equations for the network post 2028.

- Existing users of the SWIS experiencing a lower level of reliability (below what is required in the reliability standard).
- New customers connected on lower levels of reliability (via non-reference services and schemes such as the ELPS).
- Delayed connections.
- An increased risk of system wide shortfalls.

Co-optimised planning of generation developments and transmission network augmentation in response to forecast demand growth is important for the efficient development of the SWIS.

Network augmentations are forecast to be needed in the SWIS for drivers including:

- Generation developed to replace retiring capacity and cater for demand growth. Some of this will be located in regions that have diverse renewable resources but not the benefit of existing transmission network infrastructure or access to the bulk transmission grid to export the large amounts of power needed to meet the demand.
- General load growth across the SWIS, concentrated in the metropolitan regions that necessitate intra-nodal augmentations to increase import capability. These regions do not have access to local generation supply and have limited land availability to develop new greenfield generation and will ultimately rely on DER, DSP and importing power from regional generation sources.
- Electrification of industrial processes and the emergence of hydrogen industries. These are assumed to be located in the South West, Kwinana and Mid West nodes[110] and connected to the bulk 330 kV transmission network requiring increased transfer capability across the main bulk transmission grid.

In the absence of co-ordinated development between supply, network and demand, transmission network augmentations are at risk of being developed in isolation to address a localised issue without consideration of a wider perspective of what is occurring at a system level.

This co-ordinated approach to generation and network planning is facilitated through the WEM planning cycle that involves the SWIS Whole of System Plan, Western Power's Transmission System Plan and the WEM ESOO. AEMO's Western Australian *Gas Statement of Opportunities* (GSOO) also provides insights into the role of gas-powered generation as a major source of gas demand in Western Australia. There is an opportunity to continue to improve how these planning processes interact with each other in the future, which will enable greater coordination in generation and network planning.

Network augmentation assumptions for the period beyond 2029-30 consider these principles and information published through the above SWIS transmission planning processes[111]. These assumptions are based on a combination of simulation outcomes that observed the impact of future demand growth on the SWIS, highlighting areas where system security risks may emerge due to inadequate local supply and transmission network capability.

[110] See SWIS Demand Assessment 2023 to 2042 report, at https://www.wa.gov.au/system/files/2023-05/swisda_report.pdf.

[111] Such as the SWIS Demand Assessment 2023 to 2042 and the SWIS Transmission Infrastructure Planning Update.

These network augmentations are modelled to represent the potential for improved transfer capability throughout the SWIS as described in **Table 18**[112]. Western Power will review the drivers and investigate appropriate network augmentations through its annual Transmission System Plan process.

Table 18 Key constrained pathways, between 2024-25 and 2028-29

Potential network augmentation project	Drivers of project	Potential network benefit
South West 330 kV Bulk Expansion	Forecast demand growth associated with electrification of industrial processes in the South West may result in limitations on certain parts of the 330 kV bulk transmission network transferring power to meet local demand in the South West and towards the Kwinana and Metro South regions.	Increased 330 kV power transfer capability in the local South West region and on the network supplying the metropolitan regions from the south. These augmentations may also enable further generation developments in the South West and South East to be connected to the SWIS. These regions present an alternative location for generation capacity developments to complement those that are delivered and enabled by the Clean Energy Link project in the north. These areas have diverse wind profiles that compliment wind resources located in the north, improving system reliability and security of supply.
Intra-nodal 132 kV augmentations within the Perth metropolitan region	Forecast demand growth within the Perth metropolitan regions may result in 132 kV network limitations around major terminal stations. These regions have limited access to local generation supplies (apart from those that are provided by distributed resources). Demand growth will necessitate reinforcement to mitigate against any sub-regional capacity shortfalls that may present.	Increased 132 kV power transfer capability around the major terminal stations in the metropolitan region to import power from regional generation which may include new augmentations or thermal line uprates.
Kwinana 132 kV network reinforcement	Forecast demand growth in the Kwinana region may result in 132 kV network limitations restricting power flow capability around the Kwinana area network and constrain the import of power from southern generation sources transferring power from the south to the north.	Increased 132 kV power transfer capability within the local Kwinana 132 kV network acting together with a new South West 330 kV terminal (or greater transfer capability between the Kwinana 330 kV and Kwinana 132 kV network) can relieve congestion associated with the meshed 132 kV network that exists in between Kwinana and the South West. The augmentation enables future demand to be connected at Kwinana including potential benefits for hydrogen developers and generation supply developments in the south.
South-West 132 kV network	Forecast demand growth in the South West region may result in 132 kV network limitations restricting import capability on the transmission network around the South West. This is driven mainly by electrification of industries and potential expansion of new large industrial loads.	Increased 132 kV power transfer capability on the network supplying the South West region. Further generation development in the South West and South East may also benefit from increased 132 kV transfer capability.

112 The network augmentations presented show one network development pathway assumed for the purpose of this reliability assessment and have been formulated to address specific sub-regional network constraints and system security violations. It does not consider the impact future generation connection may have on specific parts of the transmission network (as no further generation expansion is considered beyond the committed projects in the Expected scenario). The network augmentations do not result in EUE being addressed as network by itself cannot reduce EUE on a power system that does not have enough generation. EY has not conducted a market benefit assessment associated with the network development pathway presented. This process does not replace network planning processes undertaken in the Transmission System Plan or the WA Whole of System Plan or other such planning processes.

4.8 Electric Storage Resource Duration Requirements

4.8.1 Availability Duration Gap Load Scenario and Availability Duration Gap

The obligation to determine the ESR Duration Requirement is a new requirement from the WEM Rules for the 2024 WEM ESOO. This is determined via the Availability Duration Gap Load Scenario (ADGLS) and the ADG. The timing of the ESR Duration Requirement is discussed in Section 2.5. The RCM Review modelling found there will be a duration gap between the end of the evening ramp (when flexible capacity that ramps up to meet the evening peak load may have exhausted its availability) and sunrise (when distributed and grid scale solar start to ramp up). The ESR Duration Requirement is therefore incorporated in the RCM to provide a signal of the required availability duration and to provide incentives for new entrant technologies to meet this requirement. The ESR Duration Requirement is intended to increase over time to match the requirement for other technology types and is set in year one of a Reserve Capacity Cycle for year three of that cycle.

The Availability Duration Gap (ADG) is calculated by modelling the ADGLS. The sum of the ADG and the ESR Duration Requirement from the previous Reserve Capacity Cycle determines the applicable ESR Duration Requirement for the current Reserve Capacity Cycle.

Each ESR will retain its ESR Duration Requirement for five Capacity Years from the Capacity Year in which it first received Capacity Credits. A newly certified ESR will be subject to the ESR Duration requirement determined for the current Capacity Year.

The sections below provide AEMO's assessment of the ADG for 2026-27, as required by clause 4.5.12 of the WEM Rules. This assessment will not be used as an input to the RCM for 2026-27, as per the transitional rules which set the ESR Duration Requirement at eight Trading Intervals (four hours)[113], but will be used in future Capacity Years.

Through undertaking this assessment, AEMO has identified that ADG set in accordance with the current WEM Rules are significantly higher on low demand days with a flatter demand profile, which may not correlate with system needs for ESR capacity. Energy Policy WA is currently undertaking public consultation on draft amendments to the WEM Rules to address this issue.

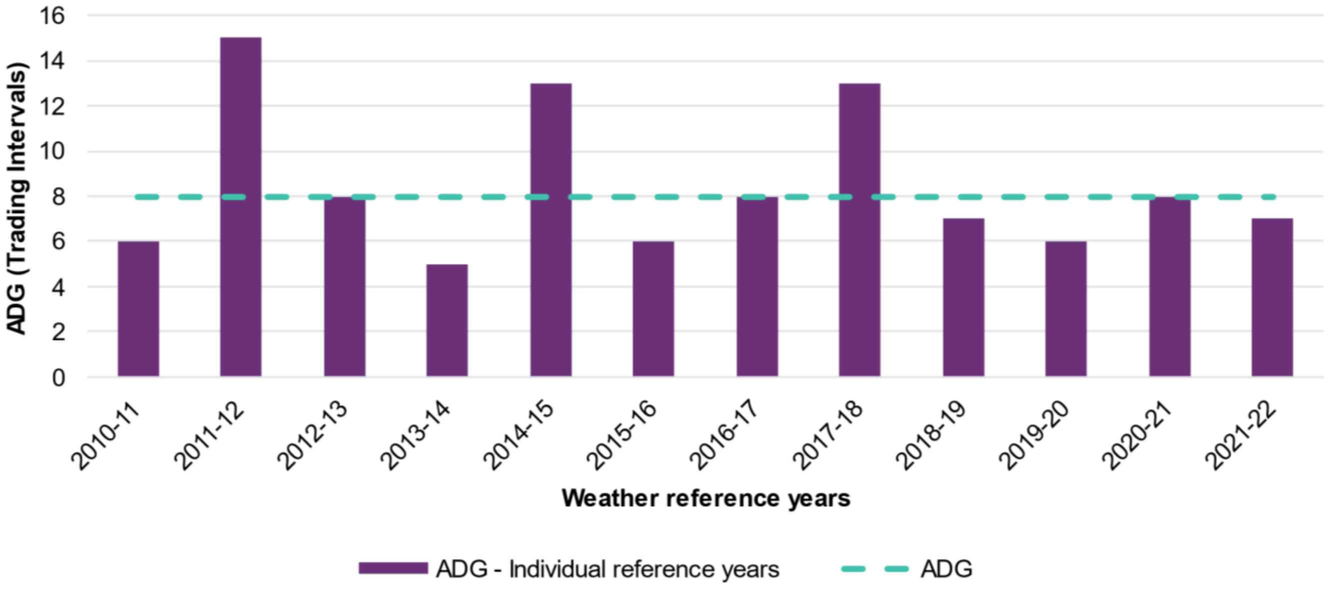
4.8.2 Indicative ESR Duration Requirement for 2026-27

AEMO modelled 12 ADGLS, each based on historical weather reference years from 2010-11 to 2021-22. For each of the 12 ADGLS, AEMO determined the maximum ADG value over Trading Days, resulting in 12 ADG values in total. The median of the 12 ADG values is used to determine the final ADG value.

Figure 36 illustrates the ADG value for each of the 12 ADGLS, as well as the final ADG value, which is eight Trading Intervals. This has resulted in an indicative ESR Duration requirement for 2026-27 of 16 Trading Intervals (8 hours), which is the sum of the ESR Duration Requirements from the 2023 Reserve Capacity Cycle (eight Trading Intervals) and the final ADG value. Refer to Appendix A1.4 for the methodology of the ADGLS, as well as for the assumptions applied for the 2026-27 determination.

[113] See clause 1.63.1 of the WEM Rules and the definition of ESR Duration Requirement in Chapter 11 of the WEM Rules.

Figure 36 ADG value and individual ADG value for each of 12 historical weather reference years



The Indicative Peak ESROI is an input for the determination of ADGLS. The Indicative Peak ESROI determined for 2026-27 varies across seasons and Business/Non-Business Days. It is derived based on Mid Peak ESROI and ESR Duration of eight Trading Intervals presented **Table 4** of Section 2.5.

Table 19 Indicative Peak ESROI determined in 2024 WEM ESOO for 2026-27

Season	Indicative Peak ESROI	
	Non-Business Days	Business Days
Summer	16:30-20:00	17:30-21:00
Shoulder	16:30-20:00	17:30-21:00
Winter	17:00-20:30	17:30-21:00

In addition, clause 4.5.12(e) of the WEM Rules requires determination of the maximum ADGLS demand difference, which identifies the magnitude of residual demand outside of the Peak ESROD that ESR did not provide. This is the maximum value among all Trading Days in the ADGLS, calculated as the greater of zero and the maximum demand in a Trading Interval that is not an Indicative Peak ESROI in that Trading Day minus the maximum demand in a Trading Interval that is an Indicative Peak ESROI in that Trading Day. The maximum ADGLS demand difference is 326 MW[114].

4.8.3 Review of ADGLS and ADG approach

This 2024 WEM ESOO is the first time AEMO has applied the amended WEM Rules requirement to calculate ADGLS and ADG. In undertaking this first assessment, AEMO has identified two issues with the approach specified in the WEM Rules:

[114] The determination of this requirement is taken as the median of the variable(s) derived from each of the ADGLS corresponding to the 12 historical weather reference years.

1. The ADG determined for Trading Days of low to moderate demand, with gradual evening ramp, is notably higher than for Trading Days closer to peak demand, with a sharper evening ramp. This results in a high final value of the ADG (and thus ESR Duration) for 2026-27. This occurs because on the days with a gradual evening ramp, the demand outside Indicative Peak ESROI falls slowly, resulting in a higher number of intervals adjacent to the Indicative Peak ESROI where the demand exceeds the maximum demand in any of the Indicative Peak ESROIs for that Trading Day. While the intention of the ESR Duration is to ensure the contribution of ESRs could sufficiently cover the demand during peak demand periods, this analysis highlights the limitations of the current ADGLS approach which includes ADG values for Trading Days of relatively lower demand and inflates the final ADG value and ESR duration.
2. The current WEM Rules specify that ESR is to dispatch evenly across the Indicative Peak ESROI in the ADGLS. As demonstrated in its determination for 2026-27 under Section 4.8.1, the Indicative Peak ESROI is set in advance, which can result in higher ADG on days with a shifted evening peak. Fixed Indicative Peak ESROI is inconsistent with AEMO's operational flexibility to adjust the ESR dispatch prior to each Scheduling Day to optimise the utilisation of ESRs in the SWIS as per clause 6.3.1 of the WEM Rules.

Modifications of the current approach could include:

- Update clause 4.5.12 (c) to evaluate ADG values only for Trading Days with a daily peak demand higher than 90th percentile of the daily peak demand for the entire Capacity Year. This proposed change aims to determine a more realistic ADG value and mitigate the risk of high ADG values in deterring market investment decisions in future ESR development.
- Update clause 4.5.12(a)(i) to set ESRs to dispatch evenly over a set of contiguous Trading Intervals with duration equivalent to the ESR Duration Requirement from the previous Reserve Capacity Cycle that minimise peak demand of each Trading Day. This proposed change aims to seek alignment between the ADGLS methodology and actual provision of ESR dispatch.

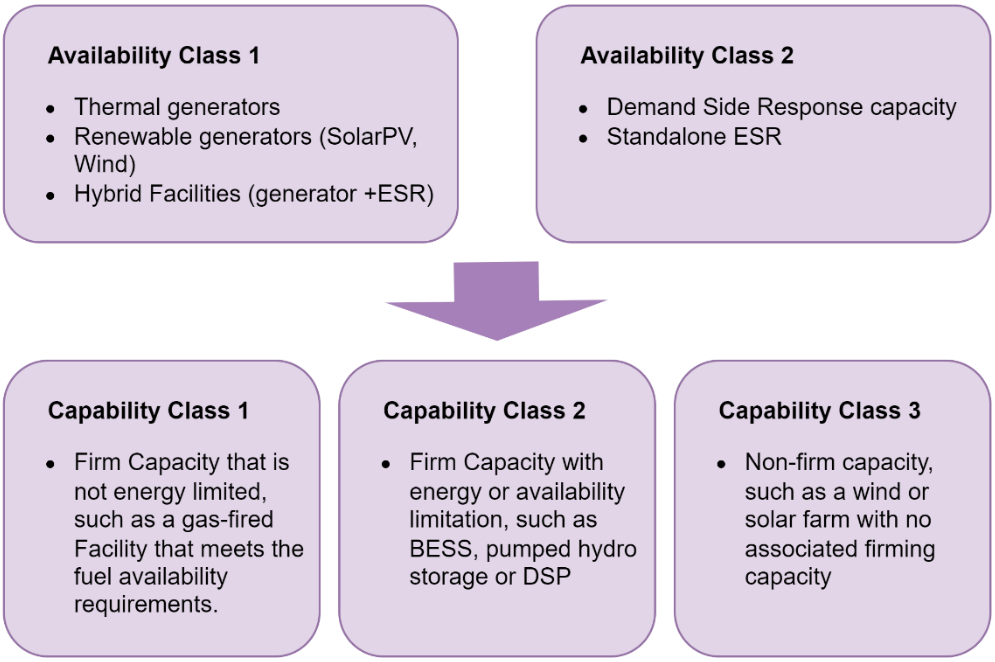
AEMO encourages stakeholders to review the exposure draft of the Miscellaneous Amendments No. 3 WEM Amending Rules[115] and provide feedback to ensure that the proposed changes promote an efficient approach to future capacity planning and investments.

4.9 Capability Classes

New changes to the WEM Rules include an update to capacity classification from Availability Classes to Capability Classes. These changes aim to better align capacity allocation with firmness of delivery and availability obligations. **Figure 37** shows the revised categorisation of the different technology types following this update. Clause 4.5.12 (i) of the WEM Rules requires the reliability assessment to determine the minimum capacity required capacity for Capability Class 1 and Capability Class 3. The assessment must identify an appropriate mix of additional Capability Class 1 and Capability Class 3 capacity if any shortfall is identified for 2026-27 under the 10% POE Expected demand scenario.

[115] See https://www.wa.gov.au/government/announcements/exposure-draft-of-the-miscellaneous-amendments-no3-wem-amending-rules-consultation-released.

Figure 37 Previous Availability Classes vs new Capability Classes



There is a surplus against both Limb A and Limb B in 2026-27 for the 10% POE Expected scenario. The methodology to determine the balance of capacity across Capability Classes is provided in Appendix 2.6 and the outcome is presented in **Table 20**.

Table 20 Capability Classes (MW)

Assessment	2023 WEM ESOO	2024 WEM ESOO
Capacity Year assessed	2025-26	2026-27
Baseline Forecast Reserve Capacity for AIC	4,598	5,742
Of which Availability / Capability Class 2	*177*	*1,485*
Comparison against RCT	-945 MW	+46 MW
Minimum capacity required to be provided from Availability Class 1 / Capability Class 1 and 3	4,510	3,648
Capacity associated with Availability Class 2 / Capability Class 2	1,033	2,048
RCT	5,543	5,696

For 2026-27, the minimum capacity required to be provided by Capability Class 1 and Capability Class 3 is 3,648 MW, and capacity associated with Capability Class 2 is 2,048 MW. The minimum capacity required to be provided by Capability Class 1 and Capability Class 3 is lower than the 4,510 MW required to be provided by Availability Class 1 for 2025-26 as determined in the 2023 WEM ESOO.

Conversely, the capacity for Capability Class 2 is higher than the previously determined 1,033 MW for Availability Class 2. This difference is due to a higher starting baseline Reserve Capacity associated with Capability Class 2 of more than 1,300 MW compared to that for Availability Class 2 for 2025-26, and a majority of which consists of four-hour ESR.

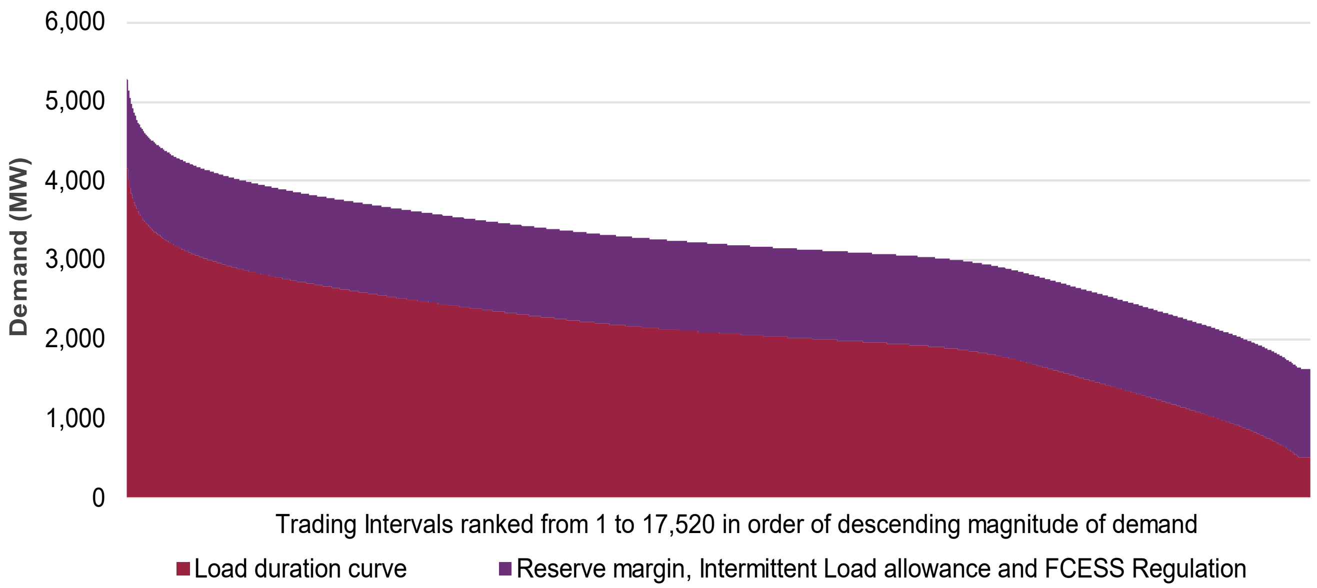
For both 2023 and 2024 WEM ESOOs, DSP is identified as the technology type that reaches EUE limitation first in the incremental capacity adjustment assessment. The higher starting baseline Reserve Capacity for Capability Class 2 allows for greater energy availability over the year than DSP, which has a limitation of 200 Trading Intervals for 2025-26 and 100 Trading Intervals for 2026-27.

4.10 Availability Curves

The Availability Curve[116] is a two-dimensional duration curve of forecast minimum capacity requirement for each Trading Interval over a Capacity Year. The minimum capacity requirement for each Trading Interval is calculated as the sum of the forecast demand for that Trading Interval, reserve margin, and allowances for Intermittent Loads and Regulation Raise.

The Availability Curves[117] for 2025-26 and 2026-27, as required under clause 4.5.13(f) of the WEM Rules, are shown in **Figure 38** and **Figure 39,** respectively. Note that for both Availability Curves (more noticeable for 2026-27) the lower end of demand remains constant at a minimum of 500 MW as a result of the implementation of a minimum demand threshold in reliability modelling.

Figure 38 Availability Curve, 2025-26 (MW)

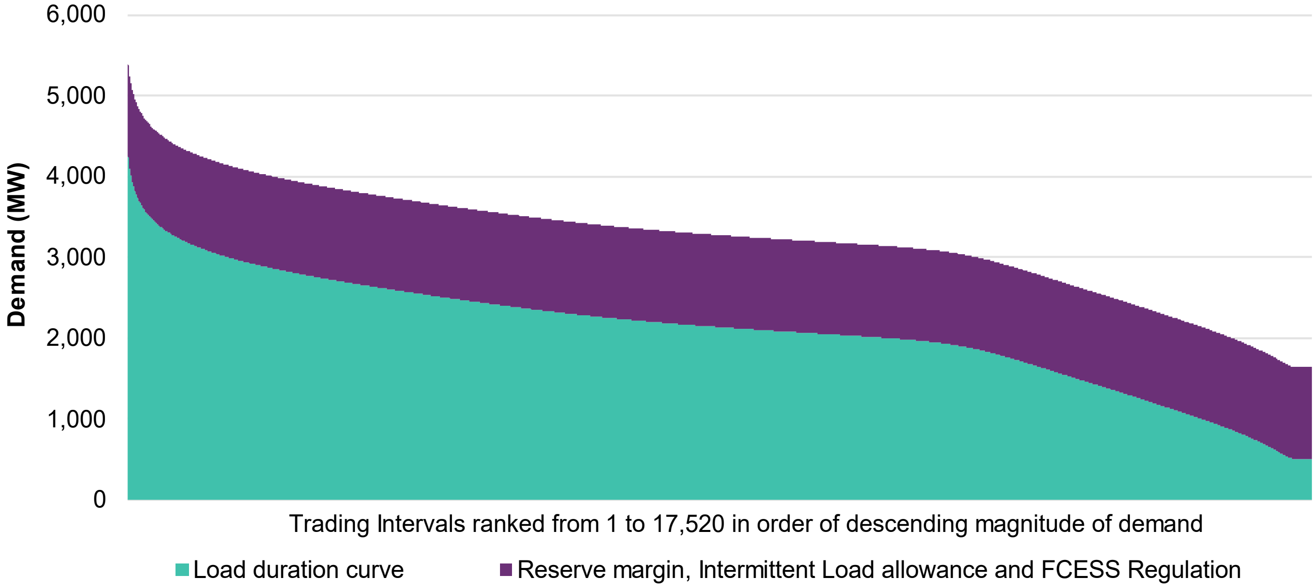


Source: AEMO and EY.

[116] The Availability Curve (defined in clause 4.5.10(e) of the WEM Rules) shows the demand arranged in an order based on magnitude over a Capacity Year, with demand on the vertical axis and Trading Intervals on the horizontal axis. It can be used to determine the number of hours when the capacity requirement exceeds a given level of demand plus an amount of available capacity margins.

[117] The Availability Curves are determined by developing a half-hourly load profile, which is based upon a series of reference years and scaling this profile to align with the 10% POE forecast at the annual peak and minimum, and the expected annual energy forecast across the full year.

Figure 39 Availability Curve, 2026-27 (MW)



Source: AEMO and EY.

4.11 Indicative DSP Dispatch Threshold and Peak DSP Dispatch Requirement

The Peak Demand Side Programme Dispatch Requirement for a Reserve Capacity Cycle represents the minimum number of Trading Intervals in the applicable Capacity Year during which a DSP can be dispatched. The 2024 Reserve Capacity Cycle has a transitional provision that sets the minimum at 100 Trading Intervals[118]. For future Reserve Capacity Cycles, AEMO will determine the value as part of the Long Term PASA.

In accordance with clause 4.5.12 (f) of the WEM Rules, the Indicative DSP Dispatch Threshold[119] for this Capacity Cycle is calculated as the MW peak demand in 50% POE Expected load scenario less the number of Peak Capacity Credits issued to the Demand Side Programmes in 2023 Capacity Cycle. The MW peak demand in 50% POE Expected scenario for 2026-27 is 4,278 MW and total number of Peak Capacity Credits issued to DSP is 71.82 MW, resulting in an Indicative DSP Dispatch Threshold of 4,206.2 MW.

In Chapter 11 of the WEM Rules, the Peak Demand Side Programme Dispatch Requirement is defined as the minimum number of Trading Intervals that a DSP can be dispatched during a Capacity Year. For 2026-27, this requirement is set at 100 Trading Intervals (equivalent to 50 hours). Changes regarding the determination of the Peak Demand Side Programme Dispatch Requirement have been gazetted in the Wholesale Electricity Market

[118] For Reserve Capacity Cycles up to and including the 2023 Reserve Capacity Cycle, the Peak Demand Side Programme Dispatch Requirement is 400 Trading Intervals.

[119] This WEM ESOO needs to determine the Flexible Demand Side Programme Dispatch Requirement for 2026-27, which is 100 Trading Intervals. The determination is based on the greater of eight Trading Intervals and the Peak Demand Side Programme Dispatch Requirement for 2026-27, as required under clause 4.5.12(h) of the WEM Rules. This determination is for information purposes only, as Flexible Capacity is a new form of Reserve Capacity, and procurement of Flexible Capacity is expected to take place in future Reserve Capacity Cycles.

Amendment (Reserve Capacity Reform) Rules 2023[120], and will come into effect for future Reserve Capacity Cycles.

[120] See https://www.wa.gov.au/system/files/2023-12/wholesale_electricity_market_amendment_reserve_capacity_reform_rules_2023.pdf.

5 Opportunity for investment

The primary purpose of the WEM ESOO is to determine the necessary investment in generation, storage, demand-side response, and transmission projects to ensure a secure and reliable electricity supply for the SWIS over the next 10 years.

This chapter presents the forecasts for the balance between supply and demand over the outlook period, highlighting:

- The near-term reliability outlook for the SWIS has improved significantly since the 2023 WEM ESOO.
- The importance of continued investment in new capacity in the SWIS, particularly from 2027-28 onwards.
- The need for future network expansion to increase power transfer capability across the SWIS.

The energy transition is underpinned by a transition from fossil-fuelled generation to renewable sources, enabled through network augmentation, firmed by energy storage and backed up by gas-fired generation. The journey to decarbonise energy systems across Australia requires significant investment in new generation, network and enabling technologies, introducing significant uncertainty in timing and scale.

5.1 Supply-demand balance

In **Table 21**, the RCT is compared to the expected level of capacity in each Capacity Year of the 10-year outlook period. This comparison indicates the need for additional capacity across most of the 10-year outlook period. It highlights:

- In the first half of the outlook period (2024-25 – 2028-29), AEMO projects:
  - A relatively small residual capacity shortfall risk for 2024-25.
  - Largely balanced supply and demand in 2025-26 and 2026-27.
  - A capacity shortfall emerging in 2027-28.
- In the second half of the outlook period (2029-30 – 2033-34), AEMO projects a growing capacity shortfall as demand continues to grow and coal-fired generation is retired.

Figure 40 presents the forecast supply-demand balance across the outlook period, including the projections from the 2023 WEM ESOO for comparison. It presents a significantly improved near term reliability outlook for the SWIS compared to the 2023 WEM ESOO and highlights the continued need for capacity investment from 2027 onwards. The substantial improvement in available capacity in the near term is due to AEMO's procurement of over 1,000 MW of capacity through the NCESS framework.

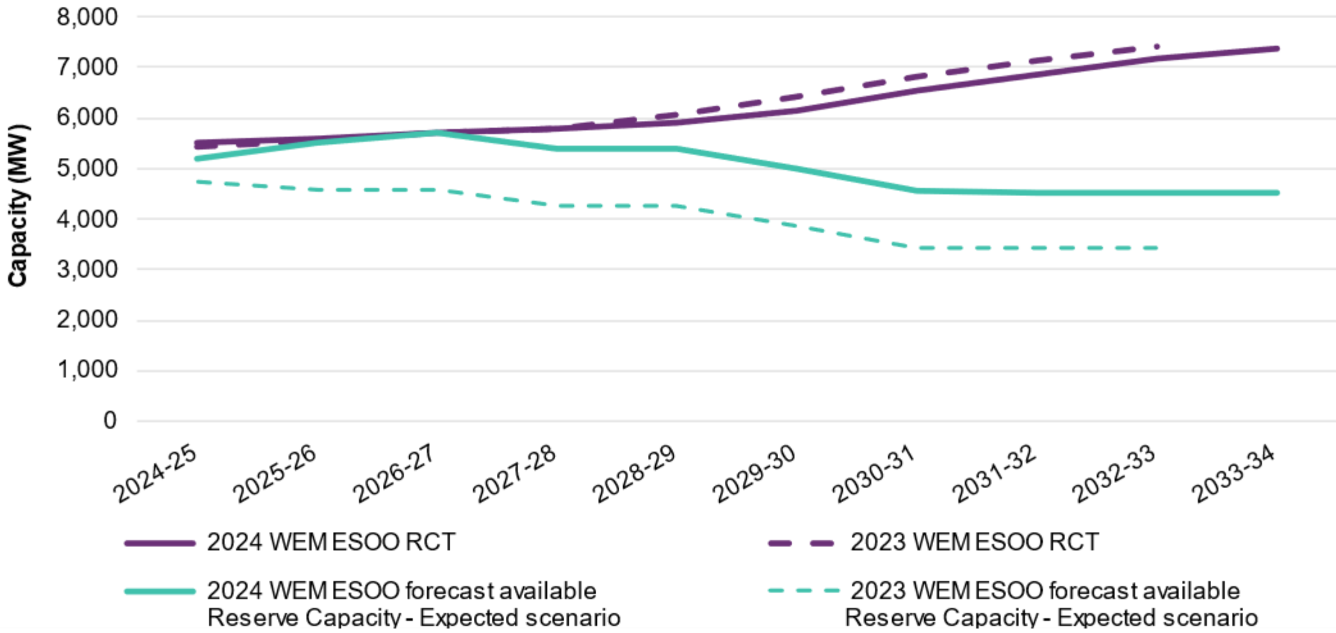
The RCT determined for 2026-27 is 5,696 MW, which sets the RCR for the 2024 Reserve Capacity Cycle. This is 20 MW lower than the RCT determined for 2026-27 in the 2023 WEM ESOO, due to a slightly lower 10% POE peak demand forecast.

Table 21 Supply-demand balance for the Expected scenario, 2024-25 to 2033-34[A]

	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34
RCT[B] (MW)	5,501	5,589	5,696	5,794	5,925	6,165	6,545	6,861	7,159	7,395
Capacity (MW)	5,183 [C]	5,503 [C]	5,729 [D]	5,403[E]	5,396	4,987	4,543	4,535	4,524	4,515
Capacity Credit shortfall (-) or surplus (MW)	-317 [F]	-86 [F]	33	-391	-529	-1,178	-2,002	-2,326	-2,635	-2,880
Capacity credit shortfall (-) or surplus (%)	-5.8%[G]	-1.5%[G]	0.6%	-6.7%	-8.9%	-19.1%	-30.6%	-33.9%	-36.8%	-38.9%

A. All figures have been rounded to the nearest MW. Consequently, totals may have a 1 MW difference due to rounding.
B. The quantities reported are the RCTs. The RCRs for 2024-25 and 2025-26 are 4,526 and 5,543 MW, respectively.
C. The 2024-25 and 2025-26 available capacity values are the total quantities of Capacity Credits assigned plus the NCESS contract service capacity.
D. The capacity value for 2026-27 includes NCESS contract service quantity and the forecast Reserve Capacity for existing and committed supply capacity (see Section 3.3.1).
E. The capacity value for 2027-28 and remaining Capacity years represent the forecast quantity of Reserve Capacity for existing and committed supply capacity (see Section 3.3.1).
F. Based on the RCRs for 2024-25 and 2025-26, the available capacity figures represent a capacity surplus of 657 MW and a capacity shortfall of 40 MW, respectively.
G. Based on the RCRs for 2024-25 and 2025-26, the available capacity figures represent a capacity surplus of 14.5% and a capacity shortfall of 0.7%, respectively.

Figure 40 Forecast supply-demand balance, Expected demand growth scenario, 2024-25 to 2033-34 (MW)



Note: For this WEM ESOO, the Reserve Capacity for 2024-25 and 2025-26 is based on Capacity Credits and NCESS contract service quantity. The forecast available capacity for 2026-27 includes NCESS contract service quantity and forecast Reserve Capacity for existing and committed capacity. The forecast available capacity for 2027-28 to 2033-34 represents the forecast Reserve Capacity for existing and committed capacity.

5.1.1 Procurement of Supplementary Reserve Capacity is required for the 2024-25 summer

Forecast available capacity in the short term has improved significantly from the 2023 WEM ESOO, due to AEMO's procurement of over 1,000 MW of new capacity through the NCESS framework, of which approximately 630 MW is expected to be available for the 2024-25 summer.

Despite this improvement, AEMO projects a shortfall in 2024-25 in the order of 317 MW. This is mitigated in part by the Western Australian Government's decision to maintain Synergy's Muja C unit 6 in 'reserve mode' over the summer before being retired, which reduces the residual shortfall to 124 MW.

The RCM includes the SRC mechanism, which enables AEMO to procure additional capacity within the six months prior to the start of a Capacity Year. AEMO triggered the SRC mechanism for 2023-24 to secure up to 326 MW to address the capacity shortfall identified for the 2023-24 summer. A total of 160 MW of SRC was ultimately contracted, and this capacity was activated 14 times to help meet extreme peak demand over the 2023-24 summer compared to three activations of SRC in the 2022-23 Hot Season.

AEMO will need to procure at least 124 MW of SRC to mitigate the residual shortfall risk for the 2024-25 summer. The final quantity procured by AEMO is currently being assessed and will also need to take into account any major outages, fuel disruptions, or delays to connection of new committed capacity.

The annual review of the 2023-24 SRC process is currently underway by the Coordinator of Energy, and is expected to be completed by end of June 2024. Following this, AEMO will commence the 2024-25 SRC procurement activities. The timeline and procedures for the SRC procurement will be made available on the AEMO website.

5.1.2 Timely delivery of committed capacity is essential to meeting the RCT for 2026-27

Over the period 2025-26 to 2026-27, supply and demand are expected to be largely balanced due to the additional capacity procured through NCESS and announced Synergy Collie ESRs.

In the 2023 WEM ESOO, a significant reliability gap was forecast for 2025-26. In response, AEMO initiated the procurement of NCESS to provide peak demand services for 2025-26 in October 2023. The goal was to secure up to 436 MW for 2025-26 and 2026-27 (2025-27 Peak Demand NCESS). AEMO is currently finalising negotiations with successful proponents to ensure their availability from 1 October 2025. Additionally, the Synergy Collie ESR project is included in the supply forecast from 2026-27 as committed capacity. This is the first Reserve Capacity year for which the Project could hold Capacity Credits, however, the announced commencement date in late 2025[121] may present an opportunity to support the system in the 2025-26 summer, contributing to meeting the forecast RCT.

Figure 41 provides an overview of existing, committed and probable capacity for 2026-27. A total of 5,729 MW of capacity is expected to be available. This comprises 4,267 MW of existing capacity and 1,462 MW of committed capacity. If the 1,462 MW of capacity from committed generation and storage projects are delivered on time, the supply and demand will be largely balanced for 2026-27 with a minor surplus of 33 MW.

[121] See https://www.synergy.net.au/Our-energy/SynergyRED/Large-Scale-Battery-Energy-Storage-Systems/Collie-Battery-Energy-Storage-System.

In forming this view, AEMO has assessed the development status of new projects from a range of information sources, in particular:

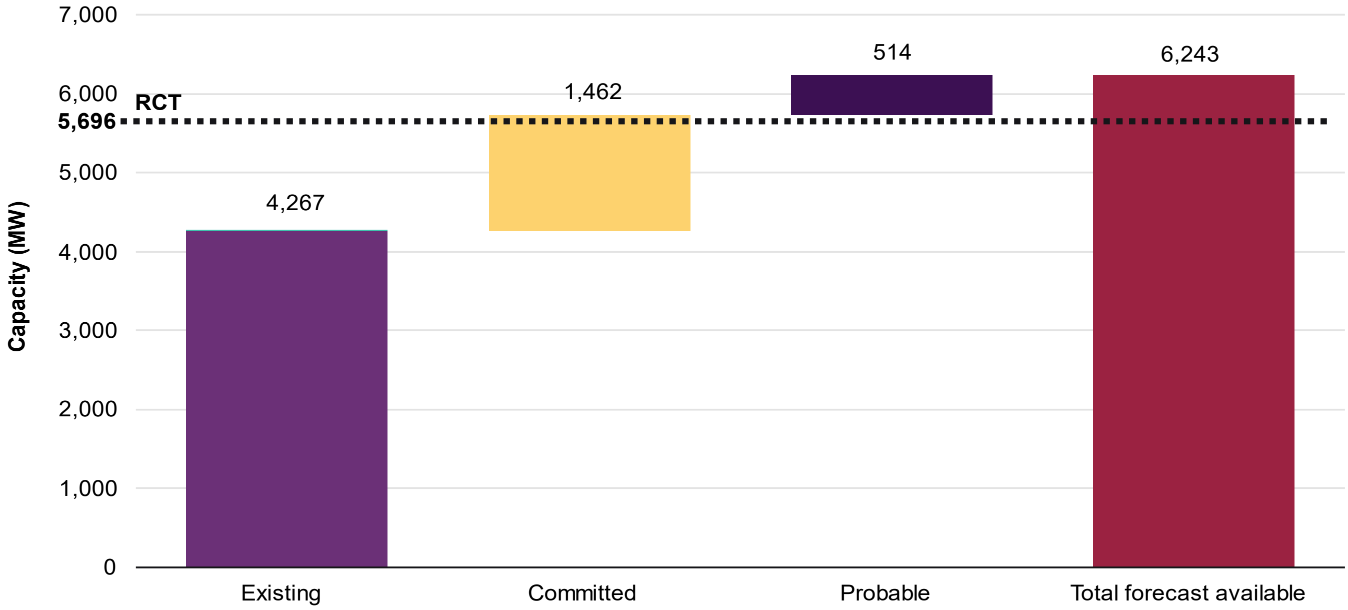
- 2024 EOI provided as part of the RCM.
- 2024 Long Term PASA formal information requests.
- Outcomes of the 2025-27 Peak Demand NCESS process.

This assessment, considering factors like network access, project financing status, and environmental approvals identifies several generation and storage projects in various development stages, ranging from proposed to probable, but not yet meeting all criteria to be considered committed by AEMO.

The assessment has identified an additional 514 MW of capacity from probable projects in the pipeline[122] that may also be developed, contributing to reliability in 2026-27 or future years, including:

- 385 MW of battery energy storage systems.
- 87 MW of wind generation.
- 22 MW of solar generation.
- 20 MW of diesel fuelled peaking generation[123].

Figure 41 Forecast Reserve Capacity status for 2026-27 (MW)



Timely delivery of these committed projects is critical to ensuring the capacity requirement is satisfied in 2026-27. There are various factors impacting the timely delivery of planned projects across Australia, including global

[122] Probable capacity is considered only in the high demand growth scenario for the capacity supply forecasts. It is associated with new projects that are candidates for registration but have not received Capacity Credits for 2025-26. These projects have scored at least 50% but less than 80% in the new project status evaluation.

[123] The MW capacity reported in this paragraph represents the estimated Reserve Capacity that could potentially be available, based on the anticipated quantity of CRC for the relevant technology.

supply chain and labour constraints. As such, AEMO is closely monitoring the progress of committed projects and encourages proponents to take early actions to mitigate any potential delays.

5.1.3 Strong capacity investment signals are expected to improve the long-term supply outlook

This report underscores the ongoing need for new investment in generation, storage, demand-side response and transmission network capacity in the SWIS to ensure a reliable and secure power system. Based on existing and committed capacity, a projected additional 391 MW of capacity is anticipated to be required by 2027-28 following the retirement of the Collie Power Station, increasing to 2,880 MW by 2033-34.

These longer-term shortfalls are driven by forecast strong demand growth and reduced supply due to anticipated retirements of coal-fired generation. This continued need for new capacity investment is consistent with the SWIS Demand Assessment[124], which highlighted the need for significant investments in firmed renewables over the next two decades.

AEMO is aware of a substantial pipeline of projects, including wind and solar generation, as well as battery storage, which could be developed in response to this investment opportunity.

Reforms to the RCM[125] and the introduction of the Capacity Investment Scheme[126] could help to incentivise investment in new generation and storage capacity from 2027-28 and beyond.

Implications for the need for investment and future capacity mix

The projected additional capacity reported against the RCT for each year in the outlook period is agnostic to the technology providing that capacity. It is therefore important to consider the implications for investment for various technologies in meeting the RCT.

Table 22 provides an indicative illustration demonstrating that the physical generation capacity investment opportunity may be in the range of three to four times the Reserve Capacity requirement, depending on the technology type installed.

Taking 2027-28 as an example, supply-demand modelling projects a capacity shortfall of 391 MW for 2027-28 (see **Table 21** above). Two cases of the generation mix and thus of different installed capacity could result in the same quantity of capacity to address the shortfall. Case 1, with a high proportion of solar PV capacity, is shown to result in the need for an overall greater installed capacity (1,367 MW) compared to Case 2 (948 MW), which has a higher contribution of wind and flexible gas than Case 1. **Table 22** also highlights the key considerations in making investment decisions for different technology types.

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[124] See https://www.wa.gov.au/government/document-collections/swis-demand-assessment.

[125] Available at https://www.wa.gov.au/government/document-collections/reserve-capacity-mechanism-review.

[126] Available at https://www.dcceew.gov.au/about/news/have-your-say-design-and-rollout-capacity-investment-scheme-western-australia.

Table 22 Indicative opportunity for different technology types for 2027-28

	Units of measurement	Solar	Wind	Flexible gas (or other future fuel)	Storage (4-hour or greater) / DSP	Total
Reserve Capacity Contribution Estimate	Scalar[A]	0.08	0.16	0.96	1.0	N/A
Case 1: High proportion of solar						
Investment opportunity by technology	Percentage[B]	50%	30%	5%	15%	**100%**
Reserve Capacity required	MW	55	66	66	205	**391**
Installed capacity required	MW	684	410	68	205	**1,367**
Case 2: High proportion of wind and flexible gas						
Investment opportunity by technology	Percentage	33%	33%	17%	17%	**100%**
Reserve Capacity Credits required	MW	25	50	155	161	**391**
Installed capacity required	MW	313	313	161	161	**948**
Considerations						
Considerations by technology	N/A	• Land availability. • Community support. • Network access. • Economic spill. • Competition with rooftop PV. • Geographic wind diversity.		• Contracting for daily maximum gas requirement. • Emissions from gas fired generation.	• Storage requires low-cost energy to charge. • DSP has limited running hours per year, currently set at 200 hours p/a and declining to 50 hours p/a from 1 October 2026.	N/A

A. The scalar has been estimated based on published Capacity Credits assigned for 2024-25 and maximum capacity by facility. Energy storage systems scalar is based on WEM Rules applying 100% credits to 4hr storage and linear derating for <4hrs. DSP receives a Capacity Credit in line with the MW of available DSP. These proportions are indicative and are not a forecast of long term assignment of Capacity Credits to particular technology types.
B. The range of scenario proportions for installed capacity investment are indicative based on a long-term least cost development pathway for the SWIS and represents just two of many different possible outcomes. The illustrative proportions are based on the outcomes of the Western Australian Government's SWIS Demand Assessment (available at www.wa.gov.au/system/files/2023-05/swisda_report.pdf).

The above examples are based on the treatment of various technologies in the RCM, however, they do not consider the fleet mix and the relative contribution to reliability for that fleet mix.

While the reliability assessment underpinning Limb B of the Planning Criterion did not set the RCT in any year across the 10-year outlook period, satisfying this limb required a similar quantity of capacity to Limb A. The assessment considers the contribution from existing and committed projects, taking into account their specific characteristics and generation profiles, however any additional capacity required to satisfy Limb B is modelled as firm unconstrained generation.

This additional capacity, referred to as capacity for reliability (CFR), is modelled in this way to demonstrate the effective quantity of capacity required to be available after taking into account constraints on availability of the capacity that is eventually installed (for example, constraints due to network limits, running hours, fuel, maintenance, forced outages, storage capacity, or renewable resource).

As such, it is likely that future assessments under Limb B will be sensitive to the types of capacity which enter the system. That is, the mix of capacity types is likely to become increasingly important as demand and the supply mix change into the future.

5.1.4 Potential changes to the supply-demand balance

The supply-demand balance in the SWIS may vary from the 2024 WEM ESOO forecasts during the 10-year outlook period, due to:

- Changes in peak demand forecasts, which are affected by economic, technological, and public policy drivers.
- Entry of new capacity in the WEM, or decisions by Market Participants to withdraw existing capacity from service.
- Changes to the RCM resulting from the RCM Review and introduction of the Capacity Investment Scheme[127], which may improve capacity investment signals and affect the way in which the RCR is determined, or capacity is certified in future Reserve Capacity Cycles.
- Changes to the NAQ framework outcomes due to introduction of new facilities and/or network augmentation.

The different demand scenarios (High, Expected, and Low) considered by AEMO capture some of this potential variability in the future supply-demand balance. The supply-demand balance for Low and High scenarios is presented in Appendix 2.8 and the peak demand forecasts are presented in Chapter 2.

5.2 Transmission network investment opportunities

Future transmission network augmentation is essential to increase power transfer capability across the SWIS and enable sufficient generation to be connected in regions that have strong, diverse supply characteristics to compliment the current generation capacity mix and meet future demand needs.

This WEM ESOO has been developed with key insights from Western Power, relating to significant new network augmentations proposed under the EREP and Clean Energy Link Project. These are both significant projects set to enable the connection of new utility scale renewables and firming capacity projects in the eastern and northern regions of the SWIS. AEMO has modelled the timing of these projects in alignment with the Western Australian Government's announcements (see Section 4.7.1).

The modelling reaffirms the need for continued transmission investment – in addition to EREP and Clean Energy Link – North – and timely connection of new generation and storage projects to meet demand growth and maintain reliability of the SWIS.

The regional EUE analysis highlights several network investment opportunities to improve network transfer capacity and enable sufficient generation to connect, as summarised in **Table 23** below.

The investment opportunities identified below have been highlighted in other planning studies including (but not limited to) the Western Australian Government's SWIS Demand Assessment[128] and SWIS Transmission Planning

[127] See https://www.dcceew.gov.au/about/news/have-your-say-design-and-rollout-capacity-investment-scheme-western-australia.

[128] See https://www.wa.gov.au/system/files/2023-05/swisda_report.pdf.

Update[129] as part a longer-term vision for the SWIS. These investment opportunities present in the short-term and long-term and are subject to business case approvals with timing heavily dependent upon how the SWIS and the WEM evolve across the next 10 years.

Table 23 Opportunities for regional network and generation investment

Region	Drivers	Other information
Eastern Goldfields / East Country regions	The current transmission network supplying the East Country and Eastern Goldfields regions is subject to power transfer limits that restrict the import of power. The region is subject to a series of complex constraints that involve thermal and stability limitations. The connection of future load and additional generation capacity in the region will continue to be impacted by these constraints. Opportunities exist for supply solutions that improve reliability outcomes for the region both in the short-term and long-term. A longer-term solution for the region is being investigated, with recent transmission network planning studies identifying that the development of a Goldfields Regional Network may be part of an optimal development plan for the SWIS. Under this proposal, new transmission network infrastructure would be constructed to support the regional growth. This represents an opportunity for private sector investment in the network and supply infrastructure required for the region.	Western Power is currently evaluating NCESS proposals to improve reliability during islanding events, across the next five years. Prospective NCESS providers may offer either a reliability service or a system strength service, or both. The reliability service is required to minimise power supply disruptions in the event of a planned or unplanned network outage that causes the Eastern Goldfields region to be islanded from the SWIS. If participating in the RCM, NCESS providers may be required to meet certification requirements and obligations. The SWIS Transmission Planning Update discusses the concept of the Goldfields Regional Network as an alternative solution that warrants further consultation.
Central region (Perth metropolitan) **(Neerabup, North Metro, Metro South, Perth region)**	Forecast demand growth in the Perth metropolitan region may result in 132 kV network limitations in subregions of the SWIS, particularly on the networks that are around key metropolitan terminal sites. These regions have limited large-scale supply options due to minimal land availability and network solutions may be subject to delivery challenges associated with highly built up areas. These areas may benefit from co-ordinated aggregation of DER and or demand flexibility services.	The SWIS Transmission Planning Update also highlights this central region (described as Perth Metropolitan) for further network investment.
Kwinana region	Forecast demand growth in the Kwinana region may result in 132 kV network limitations restricting the transfer of power in the region. The region may benefit from greater transfer capability between the 330 kV and 132 kV networks, local generation and demand flexibility services to meet future growth.	The SWIS Transmission Planning Update also highlights the Western Trade Coast (as a subset within the central region) as a region that may benefit from network investment to enable connection of future industrial loads.
South-West region (Busselton region)	Forecast demand growth in the South West associated with large industrial loads will result in 330 kV and 132 kV network limitations restricting the transfer of power throughout the region. The region will benefit from additional transfer capability throughout the 330 kV and 132 kV bulk transmission network that connects the South West region to the rest of the SWIS. Additional infrastructure will also support the connection of large-scale generation and supply projects in the region, which have been shown to improve reliability on the SWIS via diverse wind profiles that compliment those in the north.	The SWIS Transmission Planning Update highlights the south region as a region of significant transformation and opportunities arising from industrial load connections and new generation developments.

A. See https://www.westernpower.com.au/resources-education/suppliers/tenders-and-registrations-of-interest/expression-of-interest-for-ncess---reliability-and-system-strength-services-for-the-eastern-goldfields-region/.
B. See https://www.wa.gov.au/system/files/2024-05/swis-transmission-planning-update.pdf.

[129] See https://www.wa.gov.au/system/files/2024-05/swis-transmission-planning-update.pdf.

6 Glossary, measures, and abbreviations

Glossary

This document uses many terms that have meanings defined in the Wholesale Electricity Market (WEM) Rules. Meanings under the WEM Rules are adopted unless otherwise specified.

Term	Definition
10-year outlook period	2024-25 to 2033-34 Capacity Years, inclusive.
anticipated installed capacity (AIC)	The anticipated quantity of Reserve Capacity available from existing, committed, or probable capacity.
business mass market (BMM)	BMM covers those business loads that are not included in the LIL sector.
business sector	Business sector includes industrial and commercial users. This sector is subcategorised further to include large industrial loads (LILs) and business mass market (BMM).
capability at 41°C	Sent out capacity calculated at air temperature of 41°C. This accounts for efficiency loss at high temperatures, which are typical during peak demand periods.
committed and prospective LIL	New LILs are segmented into committed and prospective LILs based on AEMO's evaluation criteria, including final investment decision (FID), environmental approval, network access status, and decarbonisation (see Appendix A1.7 for further information). Committed LILs are included in both expected and high scenarios, while prospective LILs are only included in the high demand growth scenario.
committed capacity	Capacity includes new projects that are candidates for registration and have been assigned Capacity Credits for 2025-26 or have scored 80% or higher in the new project status evaluation. This category also includes Facilities contracted for the 2024-26 Peak Demand NCESS, and Facilities contracted or expected to be contracted for 2025-27 Peak Demand NCESS.
consumption	The amount of power used over a period of time, conventionally reported as megawatt hours (MWh), gigawatt hours (GWh), or terawatt hours (TWh), depending on the magnitude of power consumed. It is reported on a "sent-out" basis (excluding electricity used by a generator[130]) unless otherwise stated.
daytime hours	Trading Intervals commencing 08:00 to 16:30.
delivered consumption (or demand)	The total amount of electricity supplied to customers from the grid, which excludes the portion of their consumption/demand that is met by behind-the-meter (typically DPV) generation.
demand	The amount of power consumed at any time. Peak and minimum demand is measured in megawatts (MW) and averaged over a 30-minute period. It is reported on a "sent-out" basis (excluding electricity used by a generator) unless otherwise stated.
distributed battery storage	Behind-the-meter battery storage systems installed for residential, commercial, and large commercial, that do not hold Capacity Credits in the WEM.
distributed energy resources (DER)	Includes distributed photovoltaics (DPV), distributed battery storage, and electric vehicles (EVs).
distributed energy storage systems (DESS)	These are small distributed behind-the-meter battery storage systems installed for residential, commercial, and large commercial customers, that do not hold Capacity Credits in the WEM.
distributed photovoltaics (DPV)	Used to capture both rooftop PV and PV non-scheduled generation (PVNSG).
electric vehicle (EV)	Electric-powered vehicles, ranging from small residential vehicles such as motor bikes or cars, to large commercial trucks and buses.

[130] This may be called 'auxiliary load', 'parasitic load', or 'self-load', and refers to energy generated for use within power stations.

Term	Definition
ESOO operational consumption[131] (or demand)[132]	Electricity consumption (or demand) that is met by sent-out electricity supply of all market registered energy producing units[133]. It includes losses incurred from the transmission and distribution of electricity and electricity consumption (or demand) of EVs but excludes electricity consumption (or demand) met by DPV generation. Operational consumption includes energy efficiency losses of distributed battery storage operation. Operational demand includes impacts of distributed battery storage discharging (reducing operational demand) and charging (increasing operational demand).
ESOO unscheduled operational consumption (or demand)[134]	Operational consumption/demand that excludes any consumption/demand associated with scheduled loads (such as ESR charging). Peak and minimum operational demand forecasts represent uncontrolled or unconstrained demand, free of market-based solutions that might increase or reduce operational demand (including storage, coordinated EV charging and demand response). Only non-coordinated, consumer-controlled battery and EV charging is considered in the unconstrained peak and minimum operational demand forecasts.
existing capacity	Capacity provided by Registered Facilities that have been assigned Capacity Credits for 2024-25 or 2025-26 and reflecting any announced or anticipated retirements. Existing capacity is included in the low, expected, and high scenarios for the capacity supply forecasts.
expected unserved energy (EUE)	A normalised metric, which does not have a unit. It represents the estimated percentage of forecast electricity operational consumption for a Capacity Year which cannot be met by all AIC in that Capacity Year.
expression/s of interest	An annual call out for expressions of interest from new generation or DSM Facilities that may seek CRC and Capacity Credits for the relevant Capacity Year.
installed capacity	The generating capacity (in MW) of a single or multiple generating units.
large industrial loads (LIL)	Users that consume, or are forecast to consume, at least 10 MW for a minimum of 10% of the time (around 875 hours a year) or at least 50 GWh per year. LILs include existing and new LILs.
load shedding	The controlled reduction of electricity supply to parts of the power system servicing homes and businesses to protect system security and mitigate damage to infrastructure.
maximum capacity	The net sent-out generation or installed capacity of a facility, as detailed on AEMO's Market Data website.
operational maximum (peak) and minimum demand	The highest and lowest level of electricity drawn from the grid, measured as an average over a 30-minute period in either summer (December to March[135]), winter (June to August), or shoulder months (April, May, September to November).
peak demand	The highest amount of demand consumed at any one time. Peak demand refers to operational peak demand unless otherwise stated.
photovoltaics	Systems to convert sunlight into electricity.
probability of exceedance (POE)	A measure of the likelihood of a value being met or exceeded. For example, a 10% POE maximum demand forecast is expected to be met or exceeded, on average, one year in 10, while a 90% POE maximum demand forecast is expected to be met or exceeded nine years in 10.
probable capacity	Capacity comprised of new projects that: • Are a candidate for registration and have submitted a valid Expression of Interest for the 2024 Reserve Capacity Cycle (2024 EOI)[136], • Have scored 50% or more but less than 80% in the new project status evaluation. Probable capacity is included only in the High scenario for the capacity supply forecasts.

[131] Historical operational consumption is measured as the TSOG over a 30-minute Trading Interval. It is a non-network-loss adjusted MWh value.

[132] Historical operational demand is calculated as the TSOG multiplied by two, to convert MWh to MW for a 30-minute Trading Interval. The historical operational peak demand and minimum demand are identified as the highest and lowest operational demand calculated for a Trading Interval in a Capacity Year, respectively.

[133] Includes market generators and ESR.

[134] ESOO (unscheduled) operational consumption/demand terms are also defined in the undertaking of the Long Term PASA WEM Procedure, available at https://aemo.com.au/en/energy-systems/electricity/wholesale-electricity-market-wem/procedures-policies-and-guides/procedures.

[135] These months are aligned with the Hot Season defined in the WEM Rules.

[136] The information that a 2024 EOI must include to be deemed valid is outlined in clause 4.4.1 of the WEM Rules.

Term	Definition
proposed capacity	Capacity includes all new projects that have been proposed but have not met the criteria to be in the existing, committed, or probable capacity categories.
PV non-scheduled generation (PVNSG)	Non-scheduled photovoltaic generators larger than 100 kilowatts (kW) but smaller than 10 megawatts (MW) that do not hold Capacity Credits in the WEM.
rooftop photovoltaics	Photovoltaics installed on a residential building (less than 15 kW) or business premises (less than 100 kW).
reliability standard	The Planning Criterion defined in clause 4.5.9 of the WEM Rules.
residential sector	Includes non-contestable[137] residential customers (supplied by Synergy) only.
shoulder season	The period including Trading Months of April, May, August, and September.
summer	The Hot Season as defined in the WEM Rules, including Trading Months of December, January, February, and March.
unscheduled operational maximum (peak) and minimum demand	This represents the operational peak and minimum demand forecasts that exclude the impact of scheduled load operations (such as ESR charging).
underlying consumption (or demand)	The total amount of electricity consumption (or demand) used by consumers at their power points. This electricity can be sourced from the grid, or from behind-the-meter distributed energy resources (DER) such as distributed photovoltaics (DPV) and battery storage.
virtual power plant (VPP)[138]	An aggregation or grouping of DER that is actively controlled and coordinated via an Orchestration System[139] by an operator. VPPs can operate in a coordinated manner to provide services to other parties (such as the wholesale market and/or network).
winter	The period including all Trading Months from June to August.

Units of measure

Abbreviation	Unit of measure
°C	Celsius
GW	Gigawatt
GWh	Gigawatt hour
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt hour
MW	Megawatt
MWh	Megawatt hour
TWh	Terawatt hour

[137] A non-contestable customer is a customer that uses less than 50 MWh of electricity per year and is connected to Western Power's distribution network.

[138] As defined in AEMO's VPP Visibility Guideline (p8), see https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/wa_wem_consultation_documents/2022/proposed-design-for-a-visibility-framework/vpp-visibility-guideline.pdf.

[139] Orchestration System means, without limitation, the technologies, technology platform(s), algorithms, process and systems used to coordinate the Injection and Withdrawal of energy from the DER within an Aggregation of DER. See AEMO's VPP Visibility Guideline.

Abbreviations

Term	Definition
ADG	Availability Duration Gap
AIC	Anticipated Installed Capacity
AEMO	Australian Energy Market Operator
BESS	Battery energy storage system
BITRE	Bureau of Infrastructure and Transport Research Economics
BMM	Business mass market
BRCP	Benchmark Reserve Capacity Price
CBD	Commercial Building Disclosure
CER	Clean Energy Regulator
CFR	Capacity for Reliability
Coordinator	Coordinator of Energy
CRC	Certified Reserve Capacity
CSIRO	Commonwealth Scientific and Industrial Research Organisation
CWC	ClimateWorks Centre
DER	Distributed energy resources
DESS	Distributed energy storage systems
DPV	Distributed photovoltaics
DSP	Demand Side Programme
ELPS	Eastern Goldfields Load Permissive Scheme
EOI	Expressions of Interest
EPA	Environmental Protection Authority
ERA	Economic Regulation Authority
EREP	East Regional Energy Project
ESOO	Electricity Statement of Opportunities
ESR	Electric Storage Resources
ESROI	Electric Storage Resource Obligation Intervals
ETS	Energy Transformation Strategy
EUE	Expected unserved energy
EV	Electric vehicle
EY	Ernst & Young
FCESS	Frequency Control Essential System Services
FID	Final Investment Decision
FRG	Forecasting Reference Group
FSC	Fixed shape consumption
GEM	Green Energy Market
GEV	Generalised extreme value
GSP	Gross state product
IASR	Inputs, Assumptions and Scenarios report
IGS	Intermittent Generating Systems

Term	Definition
LDC	Linearly Derating Capacity
LFAS	Load following ancillary service
LIL	Large industrial load
NABER	National Australian Built Environment Rating System
NAQ	Network Access Quantity
NCC	National Construction Code
NCESS	Non-Co-optimised Essential System Services
NEM	National Electricity Market
NMI	National Metering Identifiers
NSF	Non-scheduled Facilities
NVES	New Vehicle Efficiency Standard
PASA	Projected Assessment of System Adequacy
POE	Probability of exceedance
PV	Photovoltaic
PVNSG	Photovoltaic non-scheduled generator
QED	Quarterly Energy Dynamics
RCM	Reserve Capacity Mechanism
RCP	Reserve Capacity Price
RCR	Reserve Capacity Requirement
RCT	Reserve Capacity Target
RLM	Relevant Level Methodology
SCADA	Supervisory Control and Data Acquisition
SPR	Strategy Policy Research
SRC	Supplementary Reserve Capacity
SRES	Small-scale renewable energy scheme
SSF	Semi-scheduled Facilities
STC	Small-scale technology certificates
SWIS	South West Interconnected System
TSOG	Total Sent Out Generation
VPP	Virtual power plant
WEM	Wholesale Electricity Market

List of tables and figures

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